

2017 Annual Performance Review

Cold Lake Approvals 8558 and 4510

Cold Lake Approvals 8558 and 4510

2017 Annual Performance Review

Table of Contents

Acronyms	5
Background of Scheme	6
CSS Process Overview	8
Injector Only Infills (IOI)	10
Steamflood Process Overview	11
LASER Process Overview.....	12
Pad Design	13
Geoscience Overview	14
Average Reservoir Properties and OBIP.....	15
Manville Group: Geologic Setting	16
Representative Type Log	17
2014 Stratigraphic Framework	18
Top Bitumen Pay Structure	19
Base Bitumen Pay Structure	20
Isopach of Net Bitumen Pay	21
Approved Development Area	22
Representative Structural Well Log Cross Section	23
Nabiye Field Geology: Top Clearwater Structure.....	25
Nabiye Field Geology: Isopach of Net Effective Bitumen Pay	26
Nabiye Field Geology: Geoscience Summary and EOD Interpretation	27
Nabiye Geobodies: Seismic Mapping	28
Drilling and Completions	29
Typical Deviated CSS Well Design	30
Horizontal CSS or HIP Well Design.....	31
Horizontal Steam Injection Well Design	32
Artificial Lift	33
Artificial Lift Performance.....	34
Instrumentation in Wells	35
Scheme Performance	38
Cold Lake Recovery Determination.....	39
Cold Lake Production Performance.....	40
Individual Site Performance.....	41
Abandonment Outlook.....	42
Steam Quality	43
Cold Lake N-Pad – Approval 4510.....	44
Cold Lake Water Management.....	46

Pad Performance Reviews	47
Late Life Steamflood Performance	55
LASER Recovery Process	59
LASER H Trunk Project – Cycle 1	60
LASER H Trunk Project – Cycle 2	63
Mahihkan North LASER – Cycle 1	64
Factors Impacting Recovery	65
Pad Recovery	73
Future Plans	77
T13 SA-SAGD Pilot	85
Grand Rapids Monitoring Program	86
Investigation of BTEX in Deep Groundwater Monitoring Wells	91
Facilities	92
Facility Modifications	93
Facility Performance	94
Measurement and Reporting	99
Proration Factors	100
Water Sources and Use	101
Cold Lake Water Use	102
Freshwater Reduction	104
Water Disposal and Waste Management	105
Produced Water Disposal to Cambrian – Approval 4510	106
Cold Lake Waste Management	107
Environmental Summary	108
Approval Renewals and Amendments	109
Monitoring Programs	110
Environmental and Community Initiatives	123
Sulphur	124
Sulphur Removal	125
SO ₂ Emissions	126
Compliance	127
AER Compliance	128
Future Plans	129
AER Approvals 8558 and 4510	131
Attachments	132
Attachment 1: Approval 8558II Compliance Conditions	133
Attachment 2: Approval 4510 Compliance Conditions	142
Attachment 3: Water Disposal and Storage	144
Attachment 4: Facility Performance by Plant	147
Attachment 5: Sulphur Balances by Plant	148

Attachment 6: 2017 Bitumen in Shale Report	151
Attachment 7: Process Flow Schematics	157
Attachment 8: Cold Lake Water Use	165
Attachment 9: Plant License Limits	168
Attachment 10: Monitoring Programs – Flare and Vent	170
Attachment 11: SRU Description - Mahihkan and Mahkeses	174

Electronic Attachments

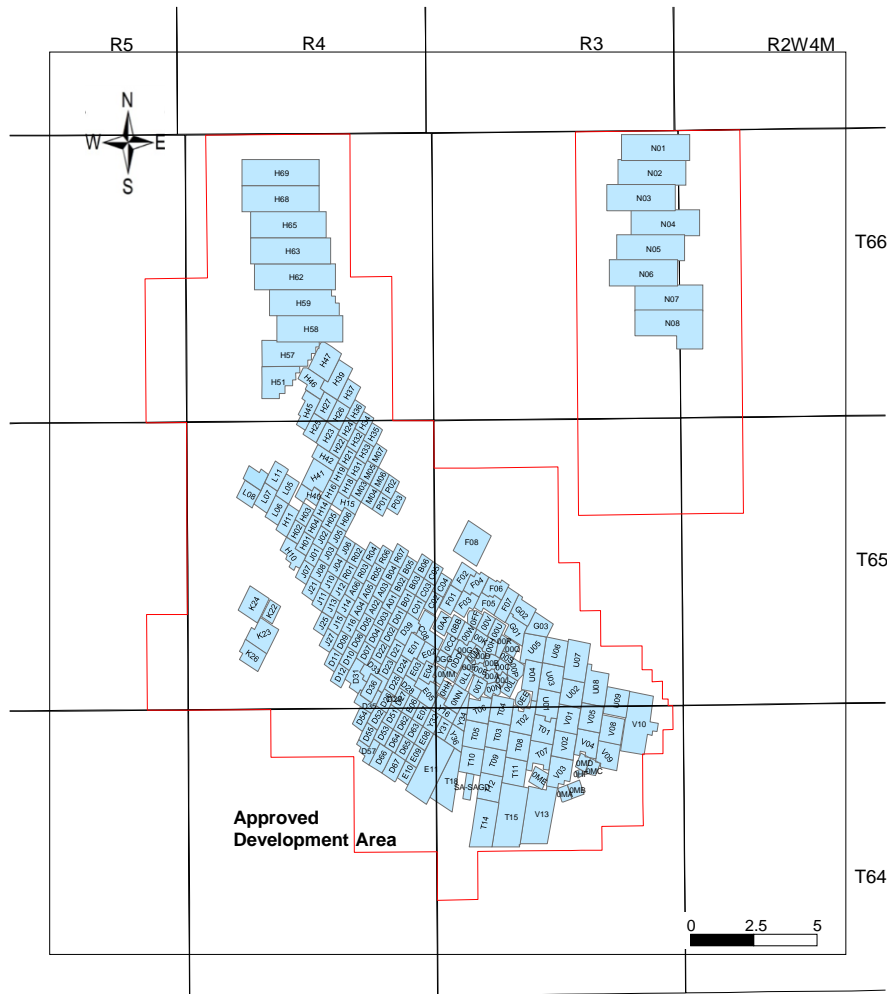
- Piezometer Plots
- Temperature Logs
- Injection Pressures
- Pad Production Plots

Note: The following information covers the period from September 30th 2016 to September 30th 2017, 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
HIP	Horizontal Injector-Producer
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 of Scheme

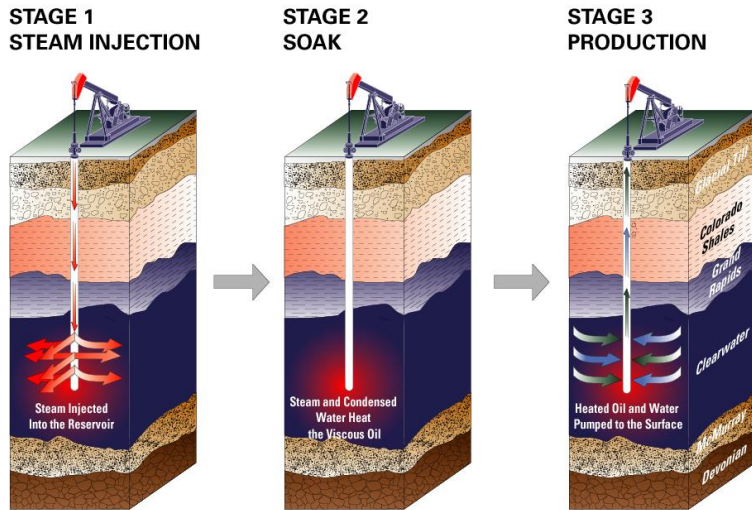
Background



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

CSS Process Overview



Cyclic Steam Stimulation

- High-pressure, high-rate, cyclic process with multiple drive mechanisms
 - > compaction
 - > solution gas drive
 - > gravity drainage
- Steam injection heats bitumen to reduce its viscosity (4 - 6 weeks)
- Brief soak phase to confirm casing integrity and control inter-well communication (3 days – several weeks)
- Length of the production period increases from a few months in early cycles to multiple years in late cycles
- Full well life: 8 -17 cycles and up to 50 years including follow-up processes

Mobilizing Agent: Heat

Mobilizing Agent Delivery System: Steam

Drive Mechanisms: Compaction, solution gas drive, gravity drainage

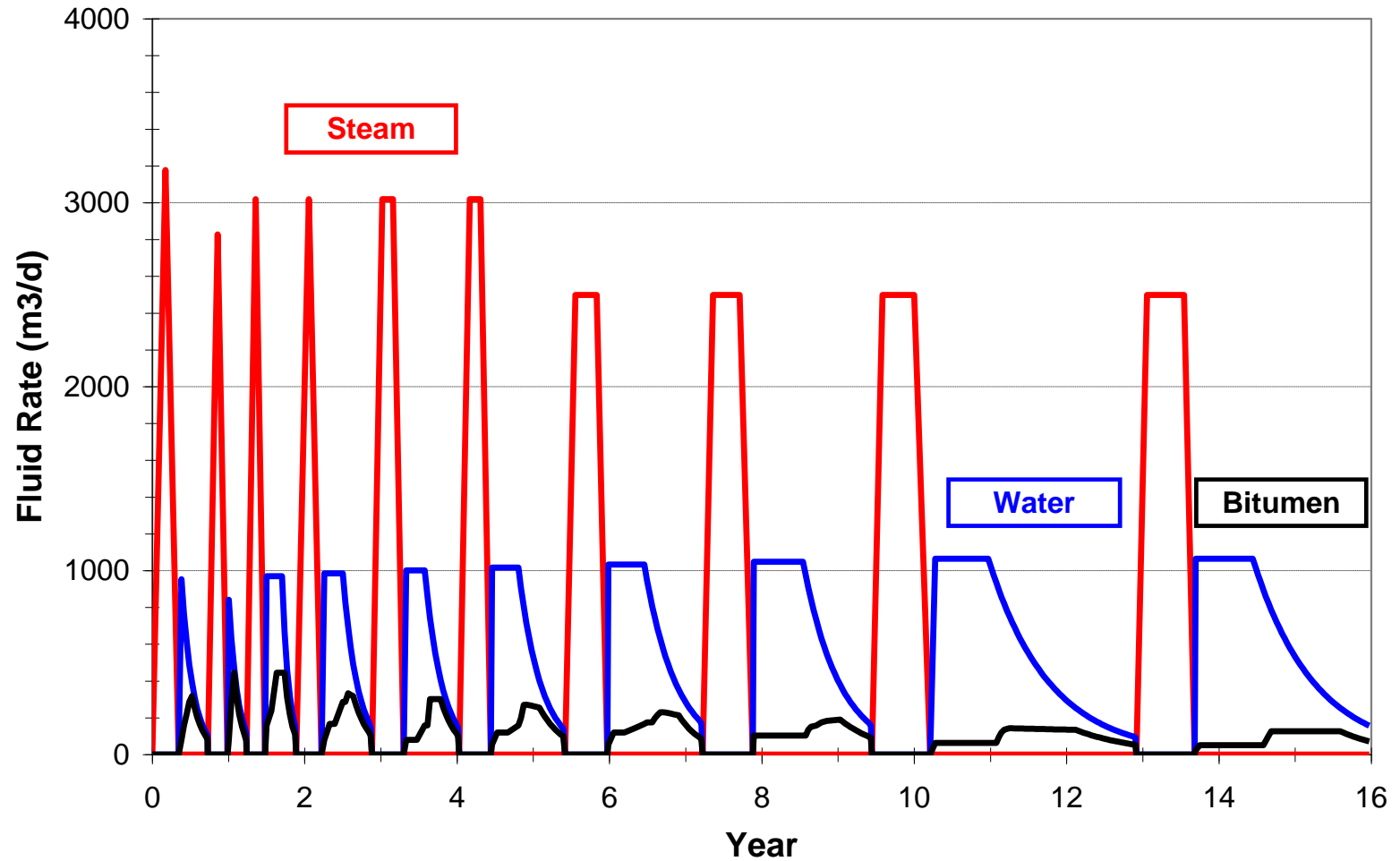
Wells Required: 1

Well Type: Deviated or horizontal

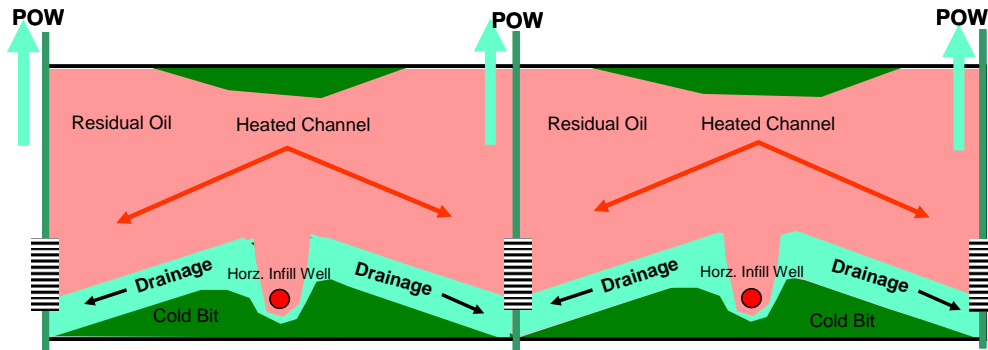
Operating Pressure: Above fracture pressure

CSS Process Overview

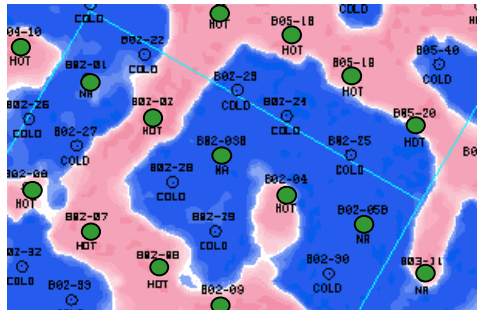
Injection/Production Rates for a Typical 4 Acre Cold Lake pad



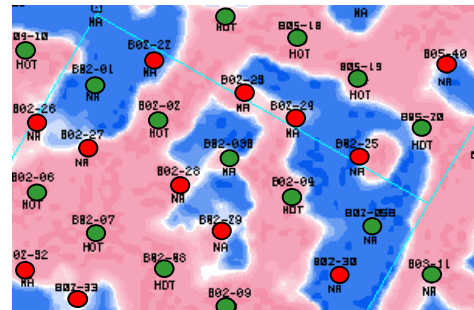
Injector Only Infills (IOI)



- 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

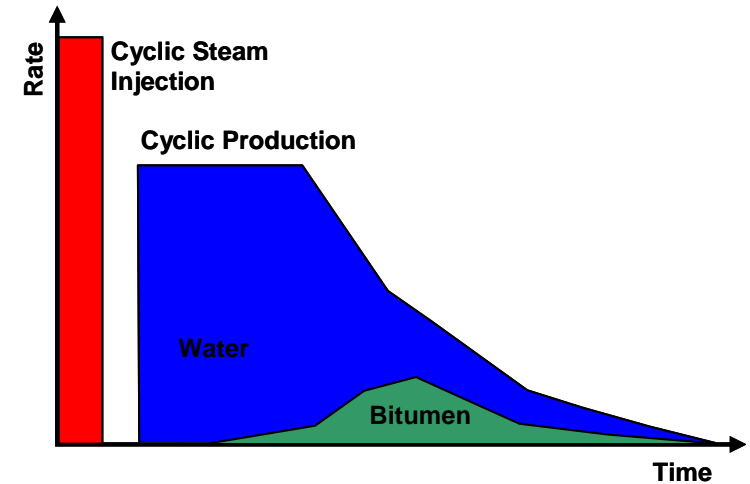


Pre-Infill 3D Seismic

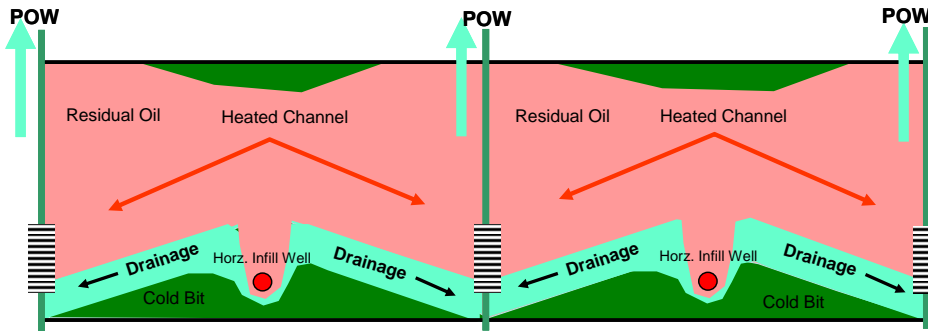


Post-Infill 3D Seismic

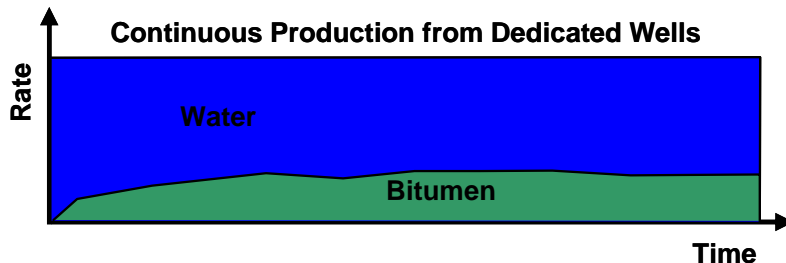
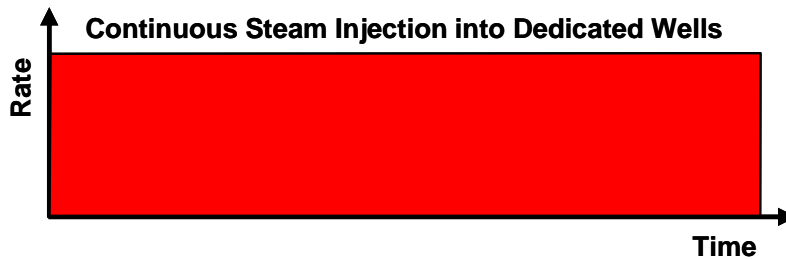
- Hot reservoir (partially depleted)
- Cold reservoir (undepleted)
- CSS wells
- Infill wells



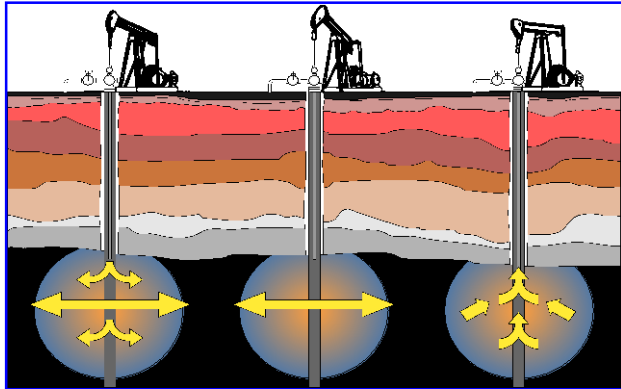
Steamflood Process Overview



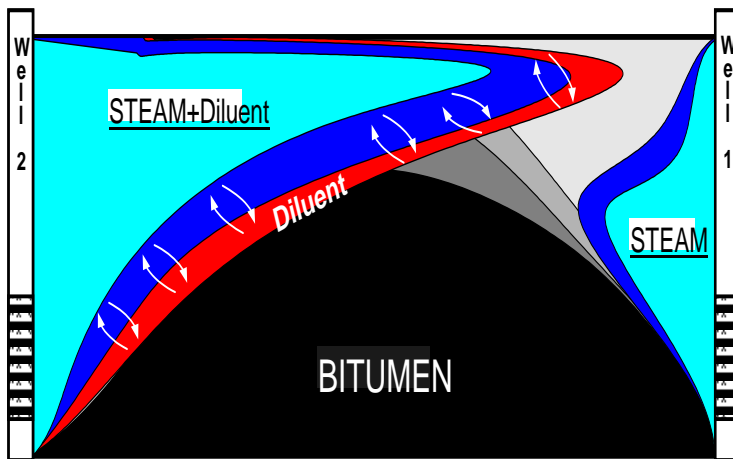
- Continuous steam injection, at low rates has the potential to:
 - > Lower operating costs
 - > Improve well operability
 - > Reduced casing stress
- Target reservoir pressure between 0.5 to 1.5 MPa
- Continuous rather than cyclical steam injection through dedicated injection-only and production-only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



LASER Process Overview



CSS Thermal Process

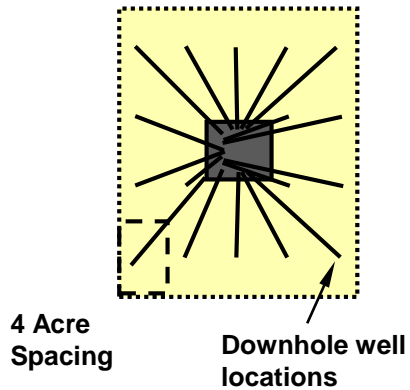


Liquid Addition to Steam for Enhancing Recovery

- 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

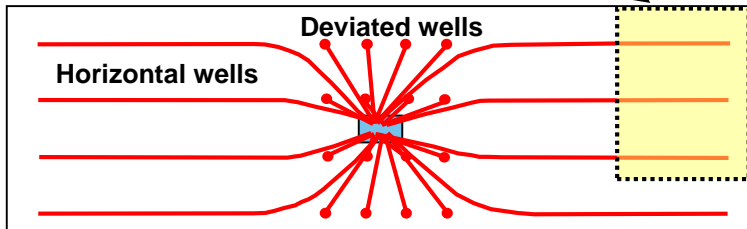
Original Pad Design



- 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

Mega Pad

Subsurface area of original Cold Lake Pad design



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%
	<u>Range</u>	<u>Average</u>
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)

<i>Clearwater Fm</i>	<u>8 Wt %</u>		<u>6 Wt %</u>	
	(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 %)

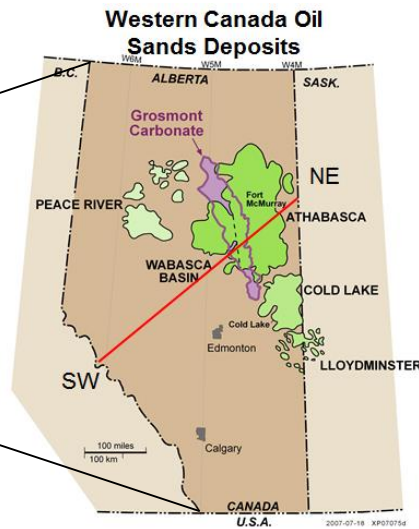
P = avg Porosity

Mannville Group: Geologic Setting

Paleogeography (~100 Ma)

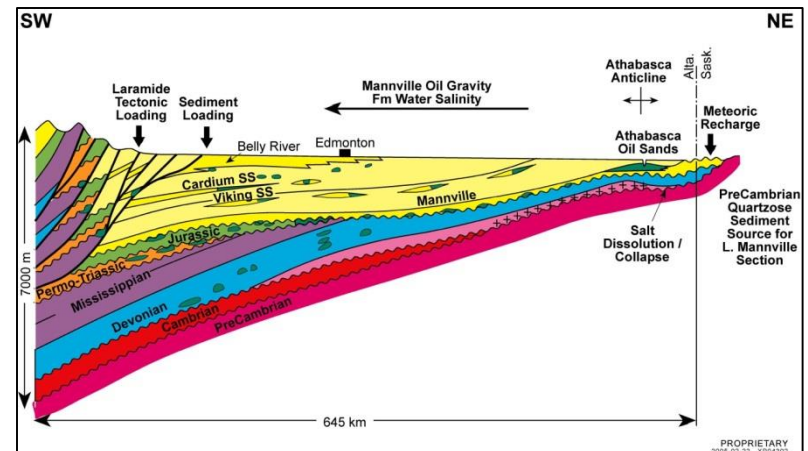
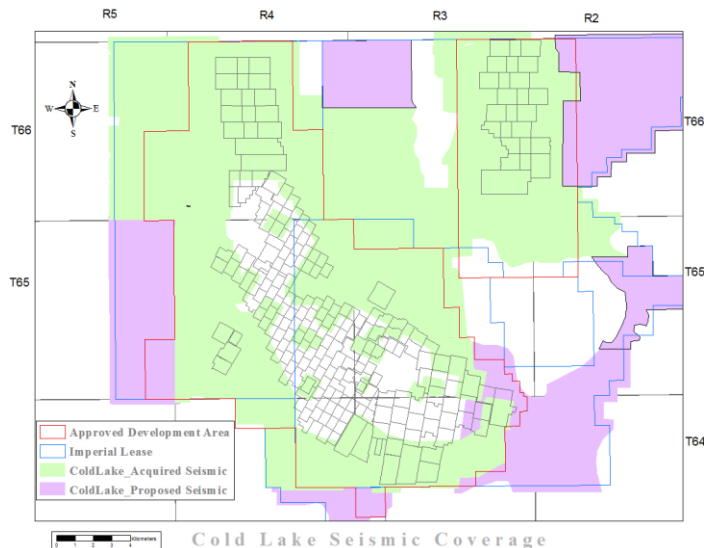


Blakey, www2.nau.edu/rcb7/index.html



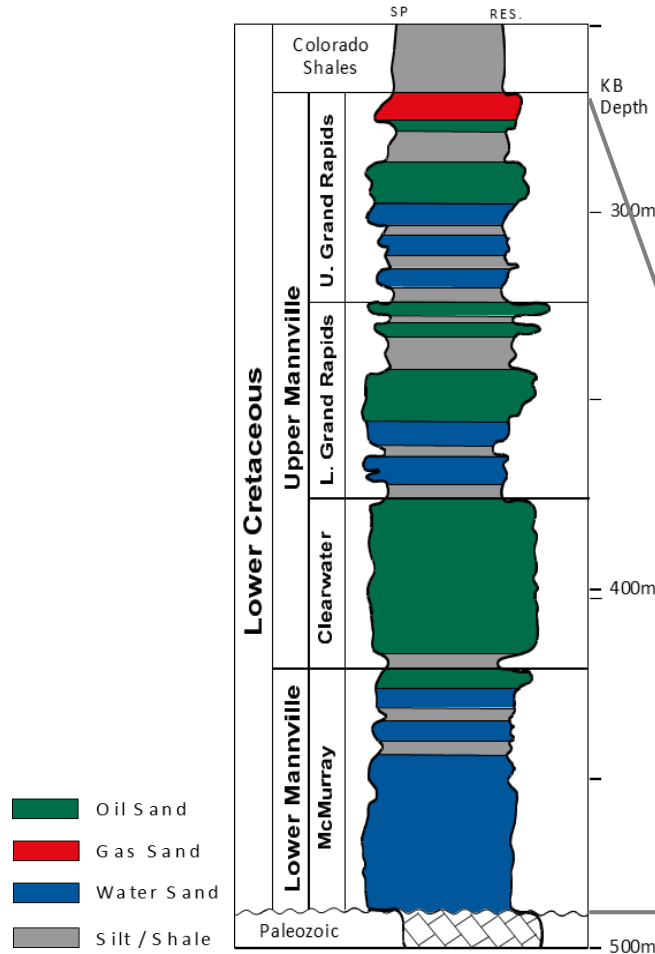
Depositional Environment

- Mannville 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



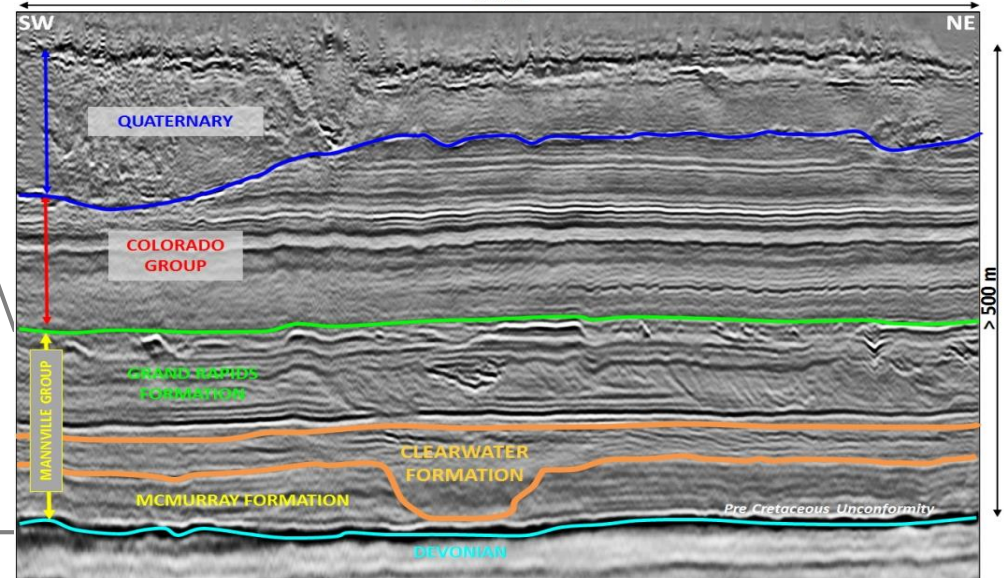
Representative Type Log

**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)
~ 10 km



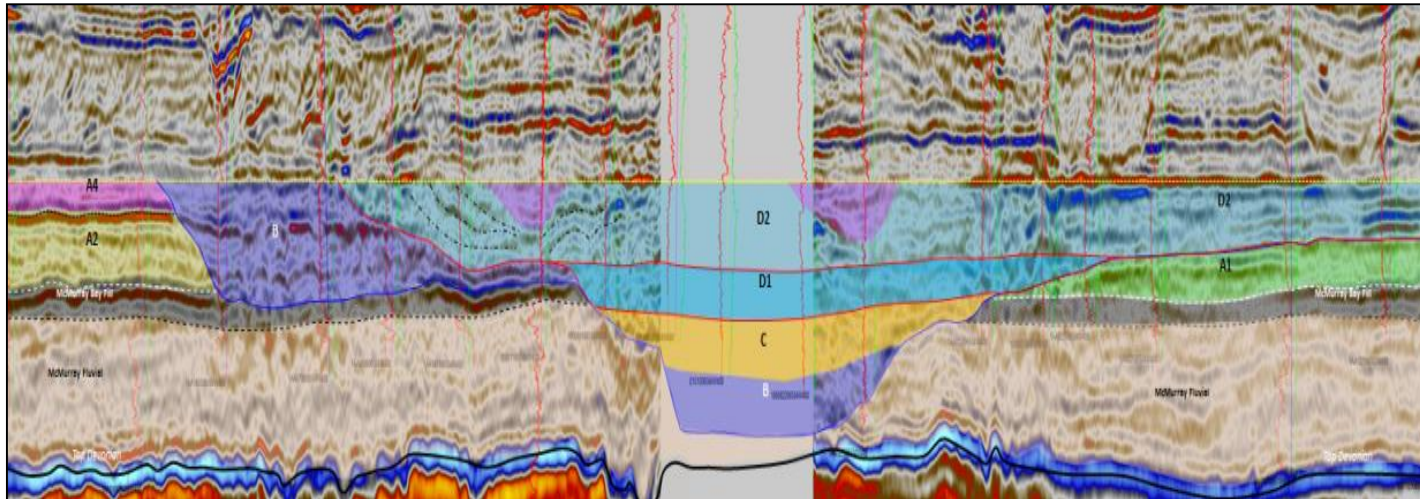
2014 Stratigraphic Framework

History

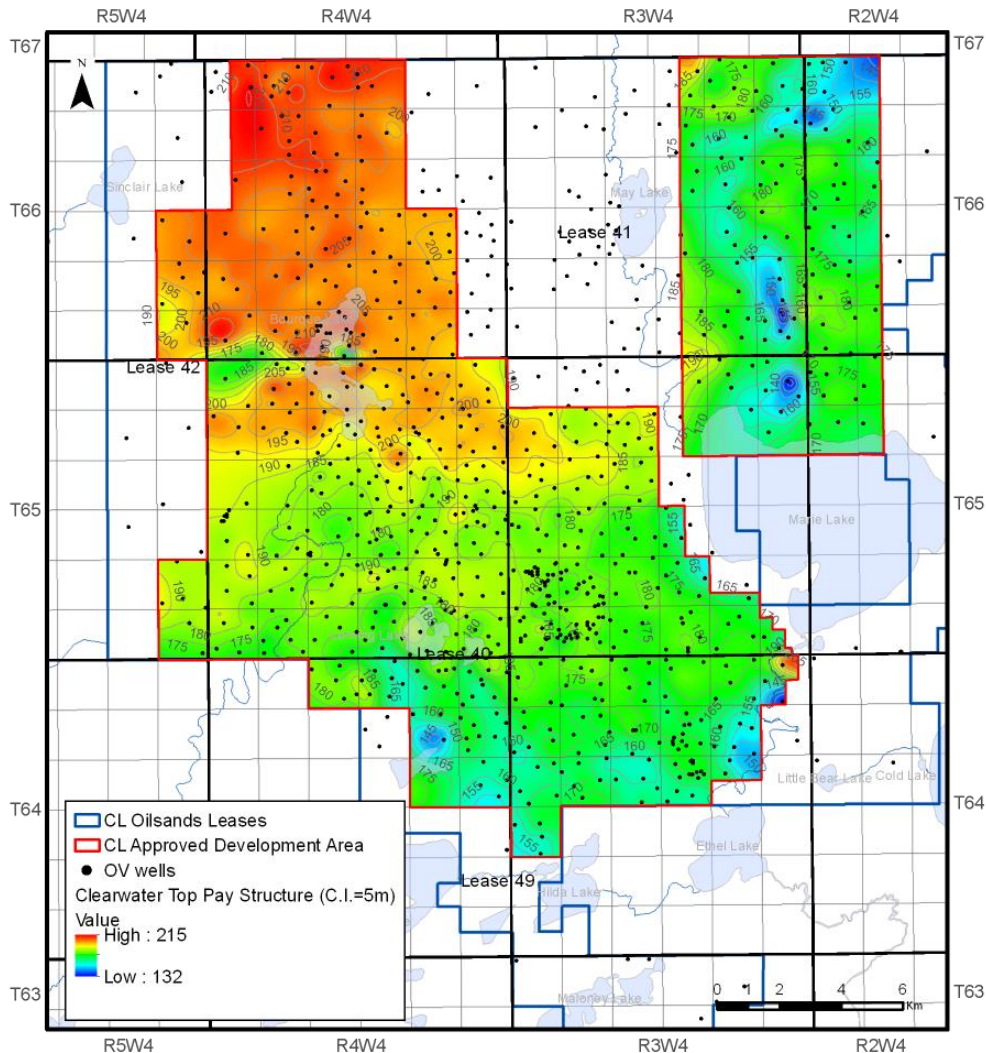
- Previous Cold Lake Clearwater stratigraphic framework developed in 1998
 - Adequate framework for majority of Cold Lake development projects
- Increasing complexity of recent & future development opportunities requires more predictive framework. Revised framework integrates 370 km² of hi-res 3D seismic and 1500 cores/logs
 - Identified four genetic units within the Clearwater that were mappable sub-regionally

Ongoing Implementation

- Application of framework to Nabiye is providing insights into pad performance variations
- Improved predictability of EOD distribution and impact on RQ has assisted with understanding production characteristics at Mahihkan North & K26
- Broader application in the field is fundamental to assessing potential for future development opportunities

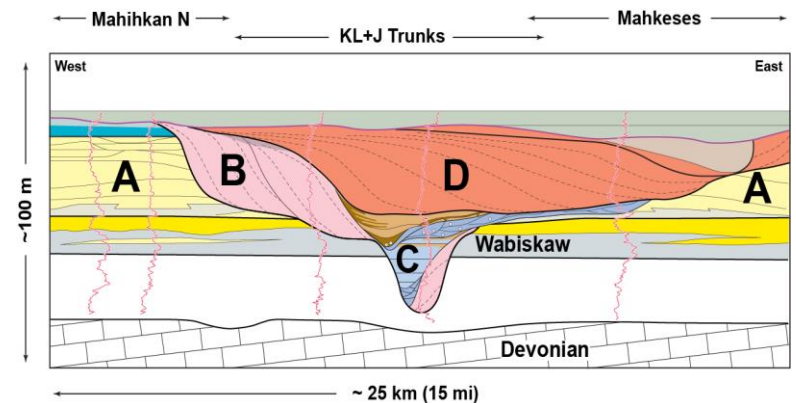


Top Bitumen Pay Structure

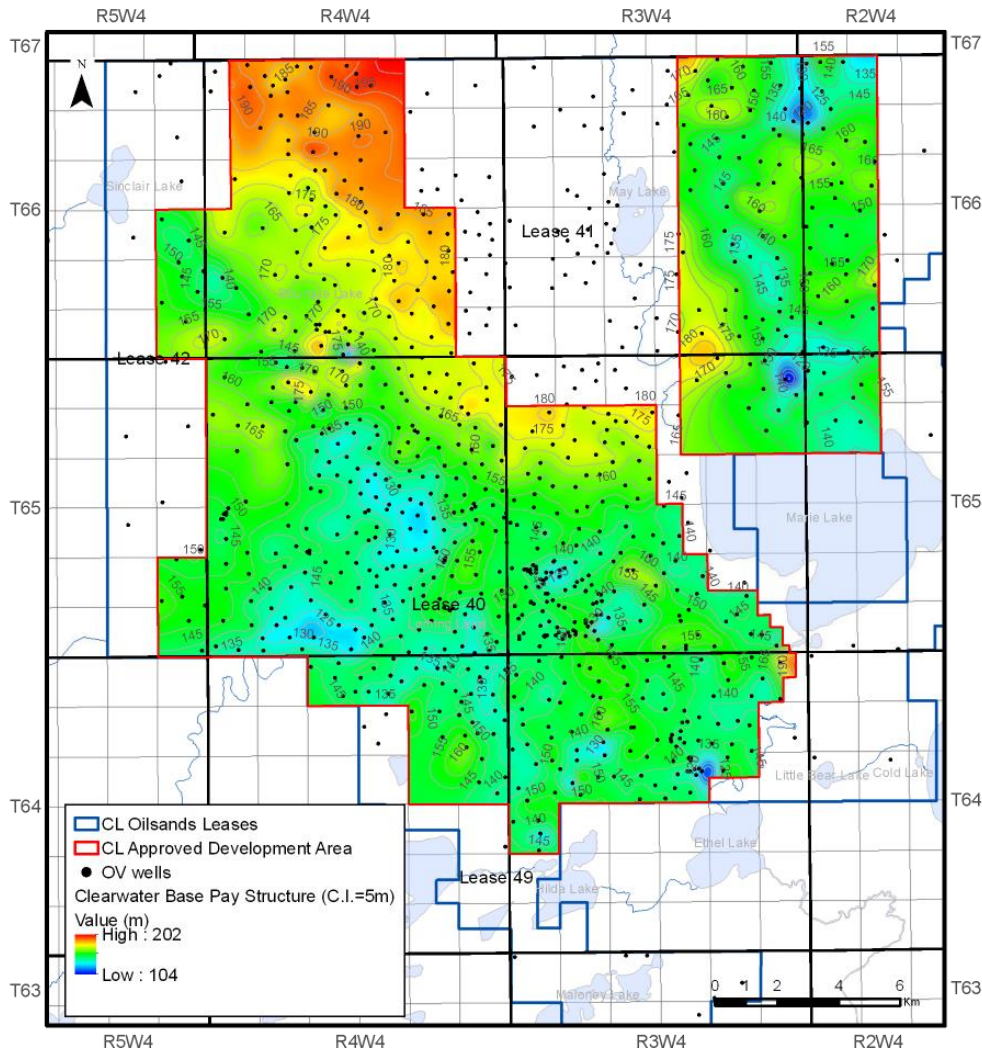


- Top of bitumen pay is a smoothly varying surface which gently dips from a high of 220m above sea level (A.S.L.) in the NW to a low of 136m A.S.L. in the SE
- Top of bitumen structure varies more greatly in the Nabiye area
- Mapped surface is either a rock/bitumen or a gas/bitumen contact

Clearwater Formation Stratigraphic Framework

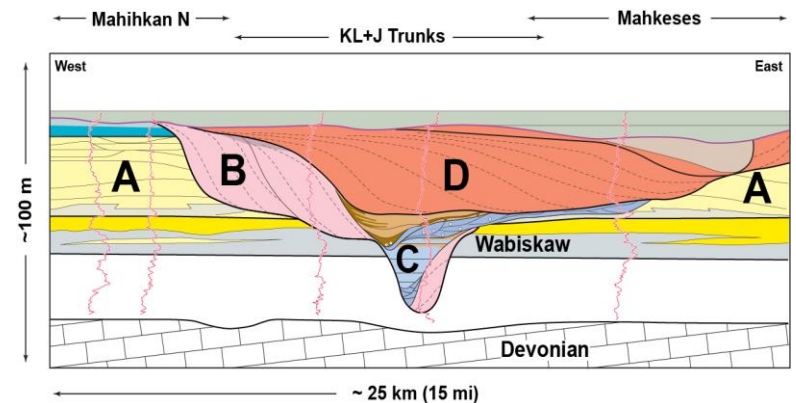


Base Bitumen Pay Structure

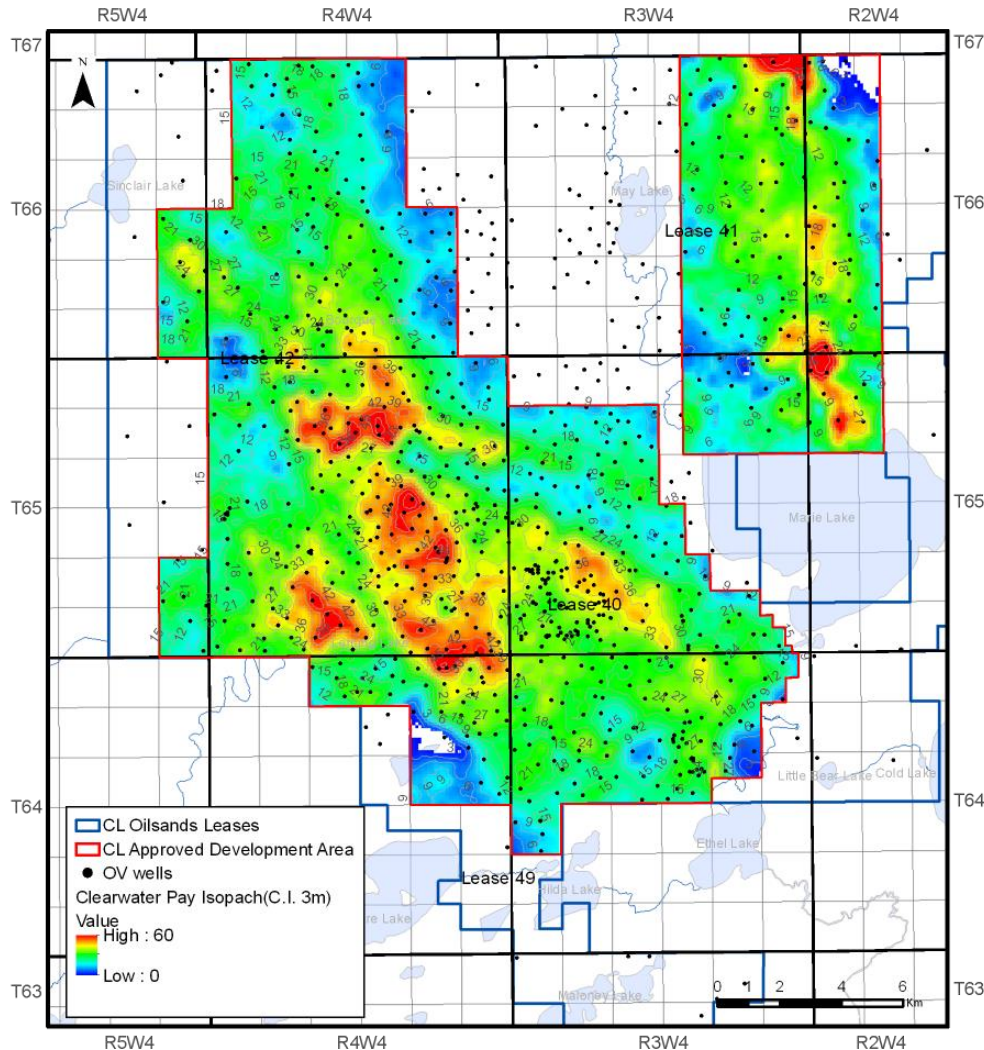


- Map represents amalgamated incised valley fills associated with low-stand erosional events
- Different successions, depending on their depositional environment are filled with varying amounts of sand and shale.
- Mapped surface is either a bitumen/rock, a bitumen/water transition zone or a bitumen/water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

Clearwater Formation Stratigraphic Framework

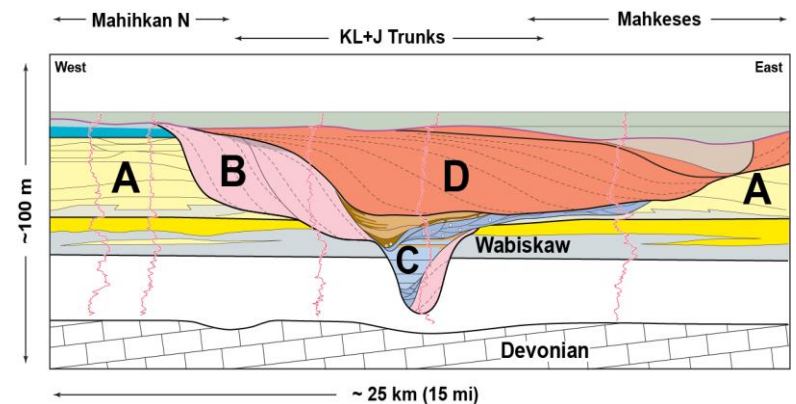


Isopach of Net Bitumen Pay (>8 wt %)

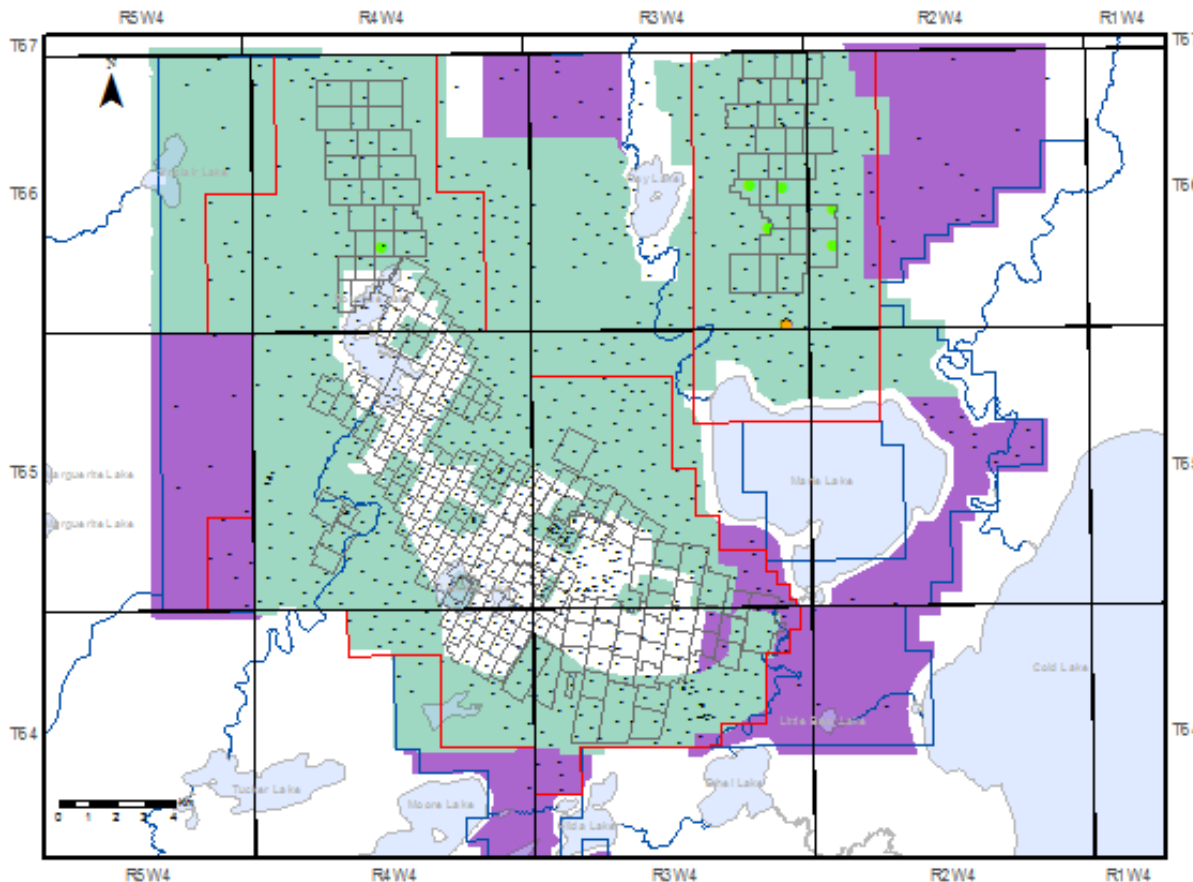


- Map illustrates distribution of pay above 8 wt% saturation cut off
- Thin pay and pay immediately adjacent to water included in isopach calculation
- Thickness trend is consistent with orientation of main valley incision

Clearwater Formation Stratigraphic Framework



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 2016 / 17
- 3D seismic coverage
- Future 3D Proposals

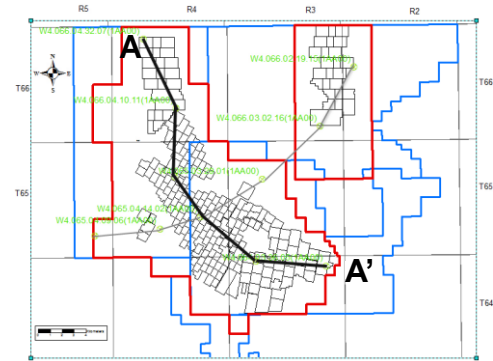
OV Wells by Years

- OV wells Before 2016
- OV Wells Clearwater, 2016/2017
- OV Wells Grand Rapids, 2016/2017

CL Oilsands Leases
 CL Approved Development Area
 Cold Lake Proposed Seismic
 Cold Lake Acquired Seismic

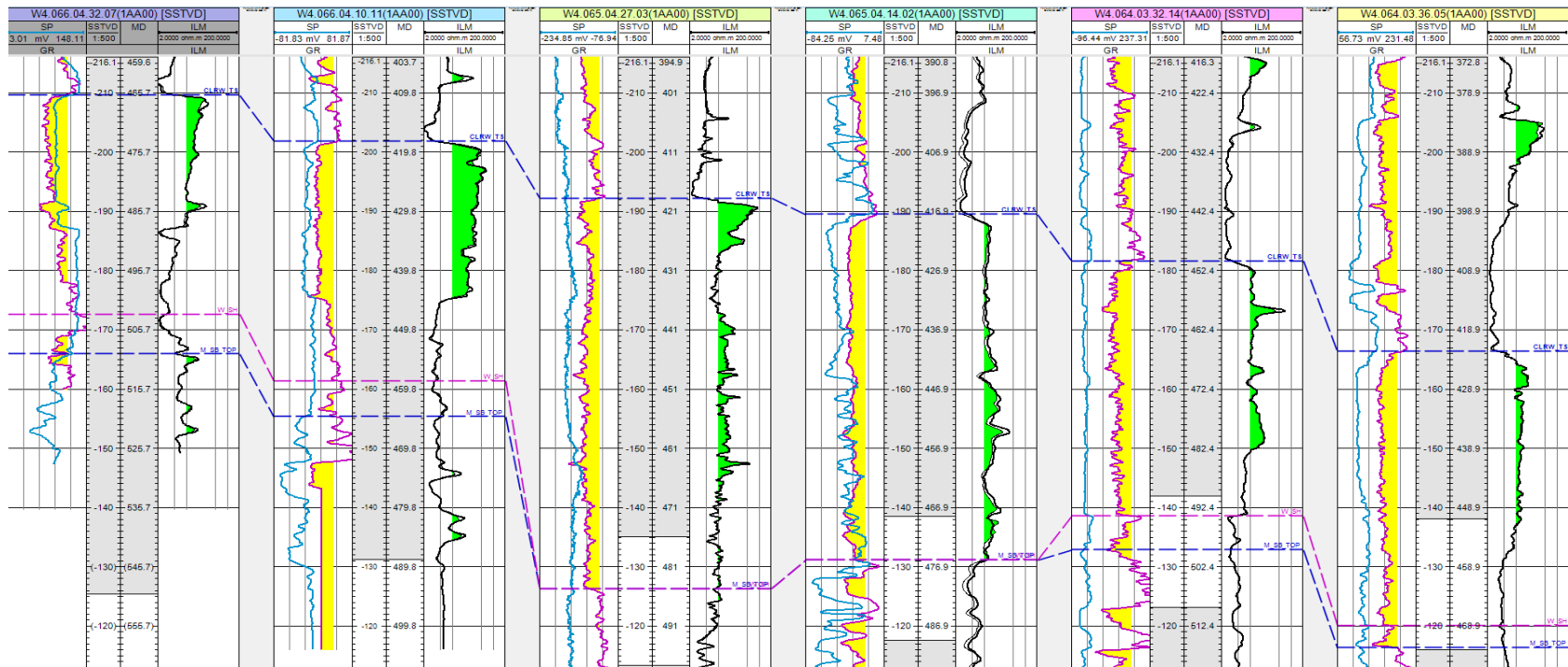
Representative Structural Well Log Cross Section

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



- Cold Lake Leases
- Approved development boundary
- Developed pads

A

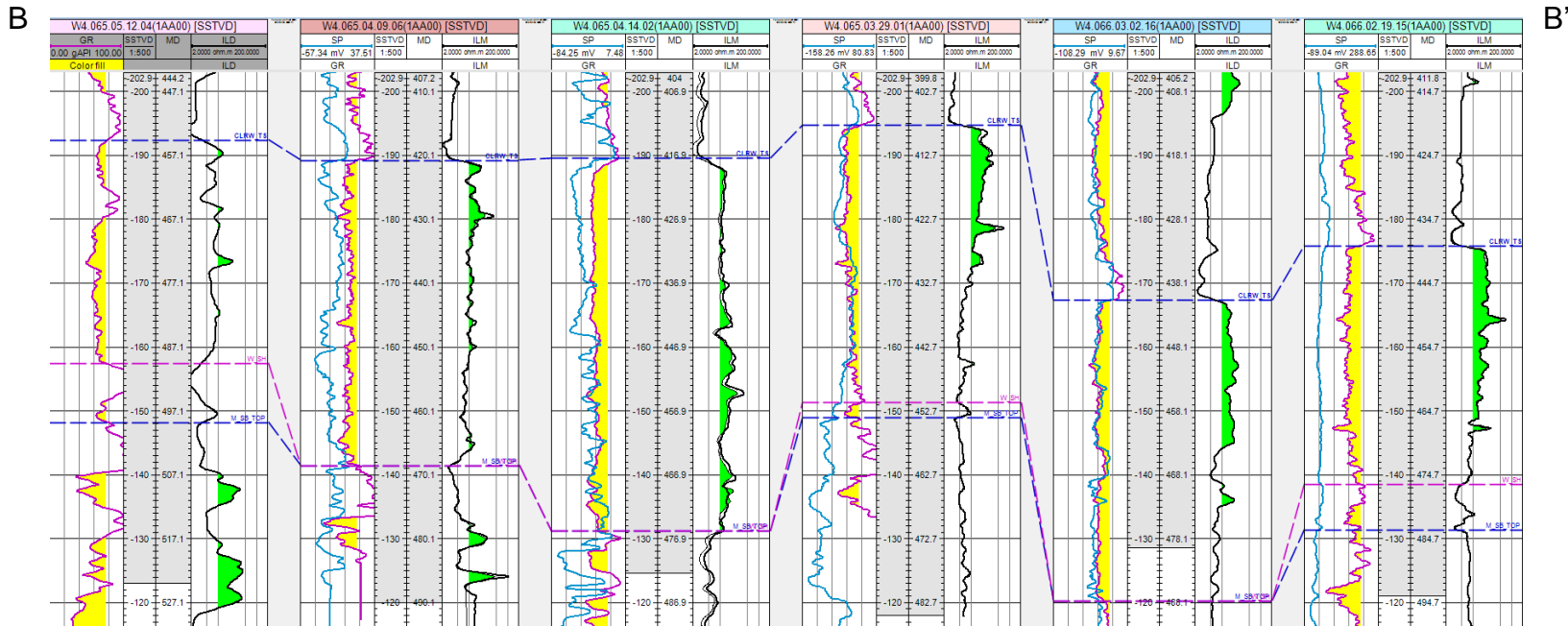
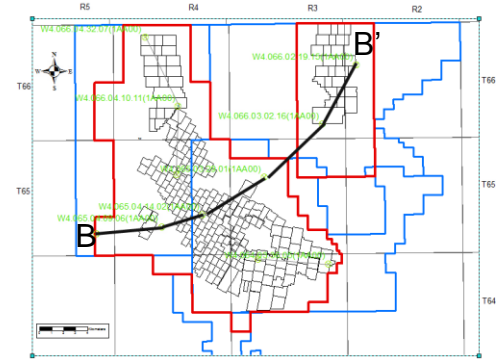


A'

Representative Structural Well Log Cross Section

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

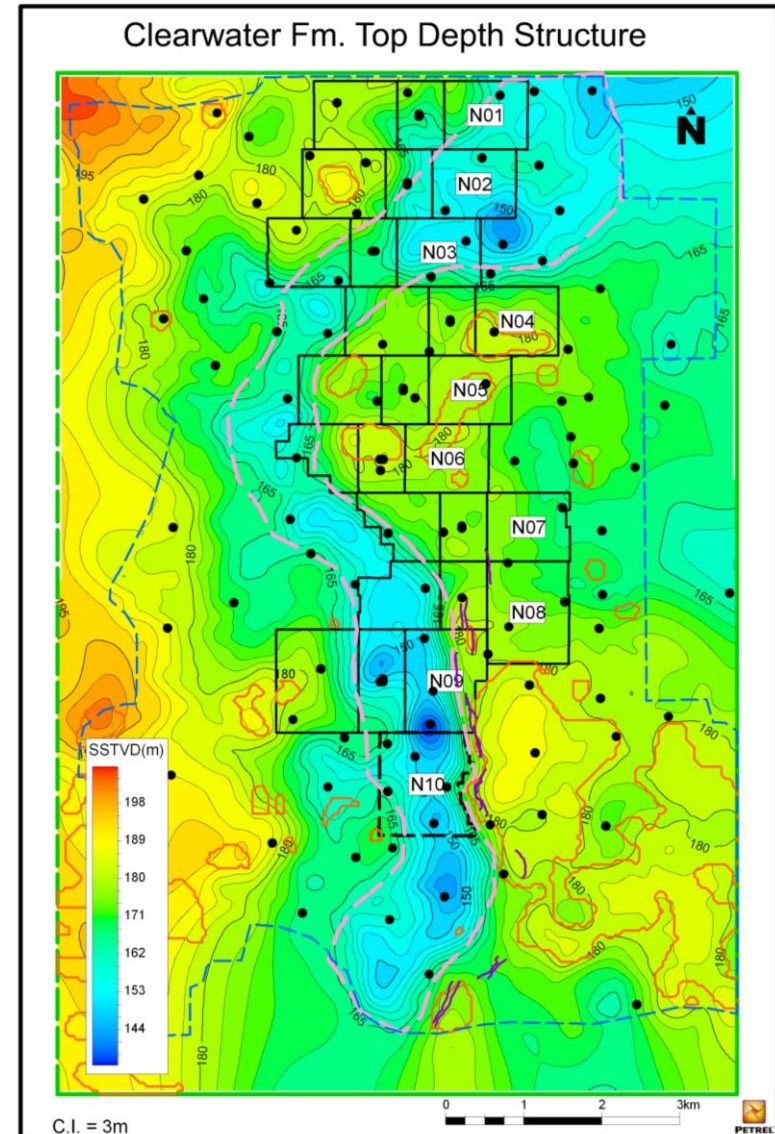
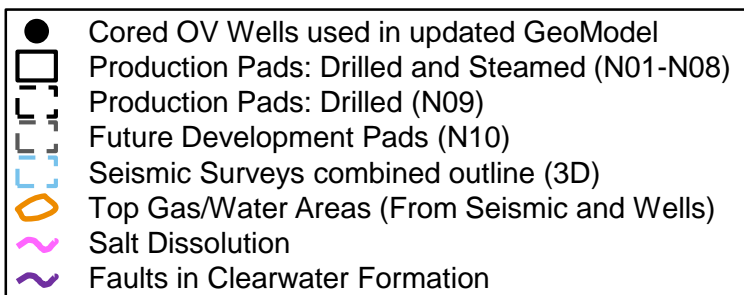
- Cold Lake Leases
- Approved development boundary
- Developed pads



Nabiye Field Geology: Top Clearwater Structure

Map illustrates:

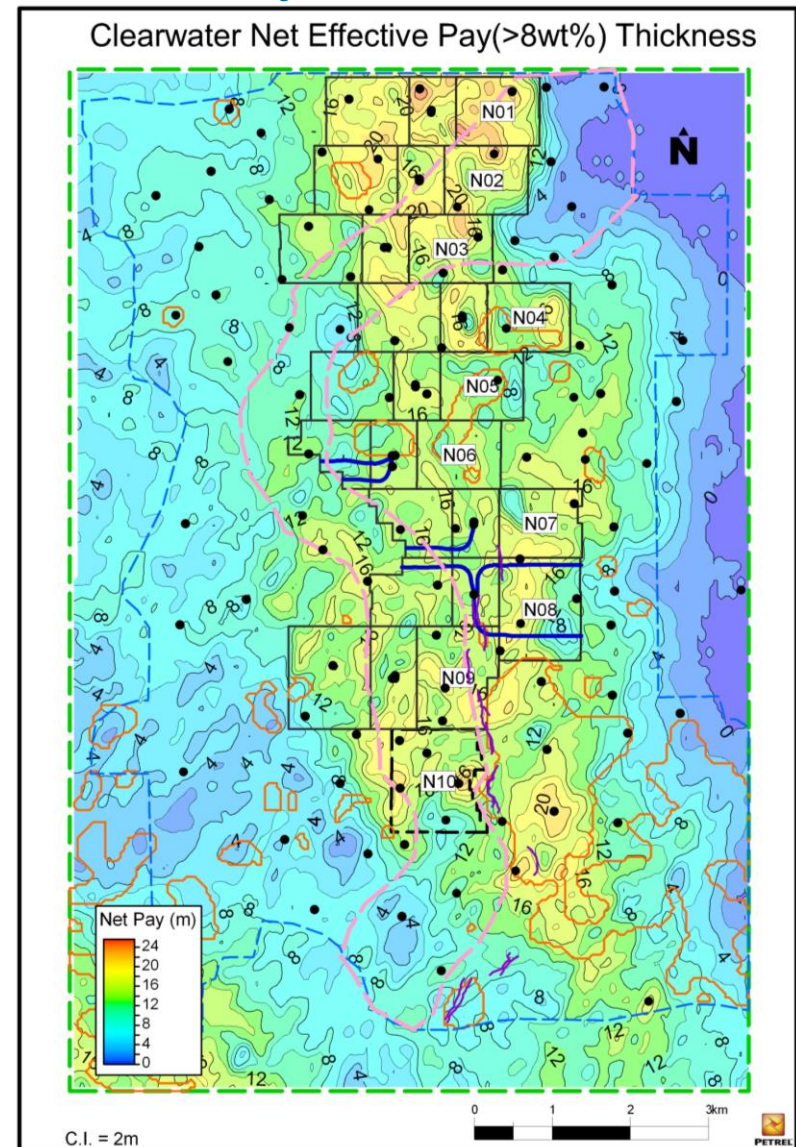
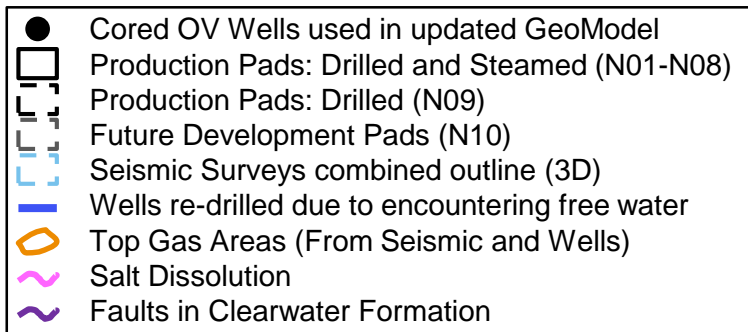
- Depth (Elevation) of the Top Clearwater Formation across the greater Nabiye Development area
 - Clearwater Top structure map integrates 3D seismic surveys and all well data
 - Significant structural change from 200 m asl to 140 m asl due to underlying salt dissolution of Paleozoic evaporites
 - Salt 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



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 (lateral stand-off); and east side of pad N08 (vertical stand-off)
- Presence of top gas/water areas
- Distribution of the OV wells used in GeoModel



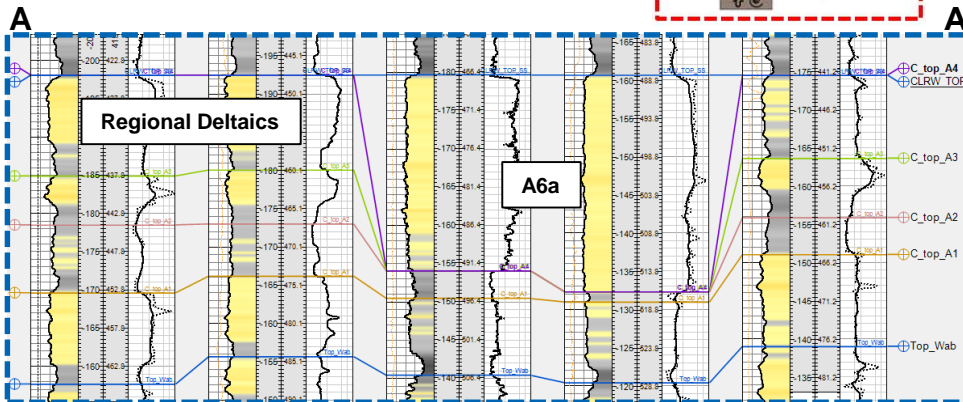
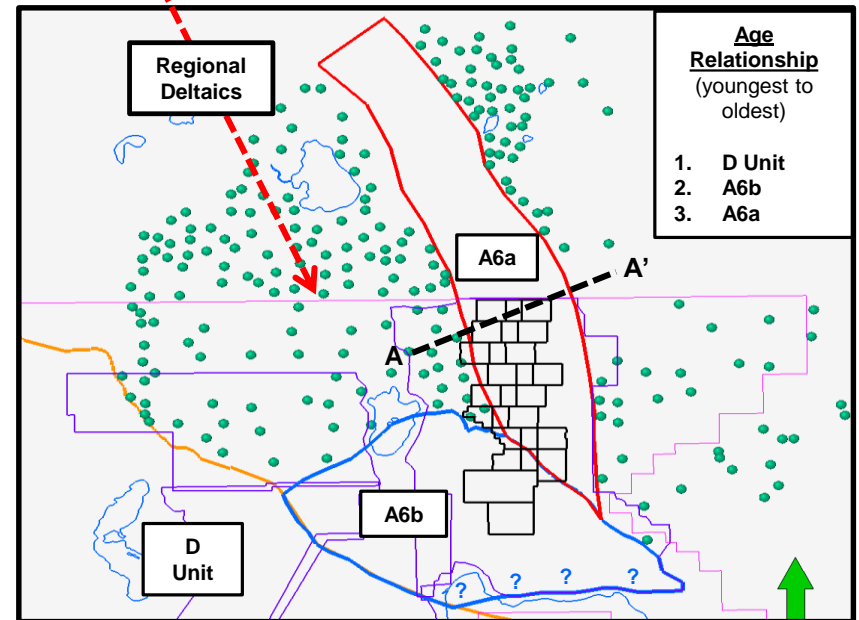
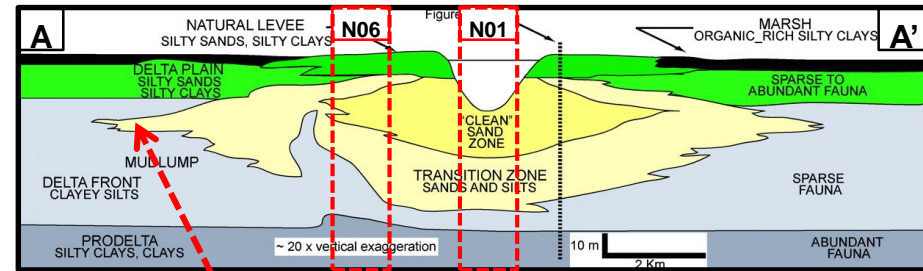
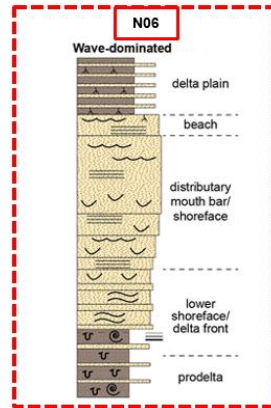
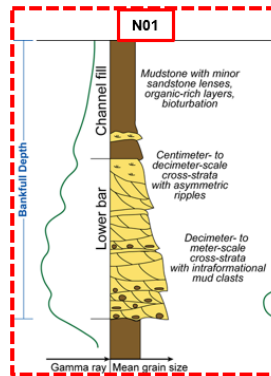
Nabiye: Geoscience Summary & EOD Interpretation

Nabiye genetically related to older deltaic "A" units rather than younger fluvial "D" units

Nabiye subdivided into 3 main Geobodies (A6a; A6b; Regional Deltaics):

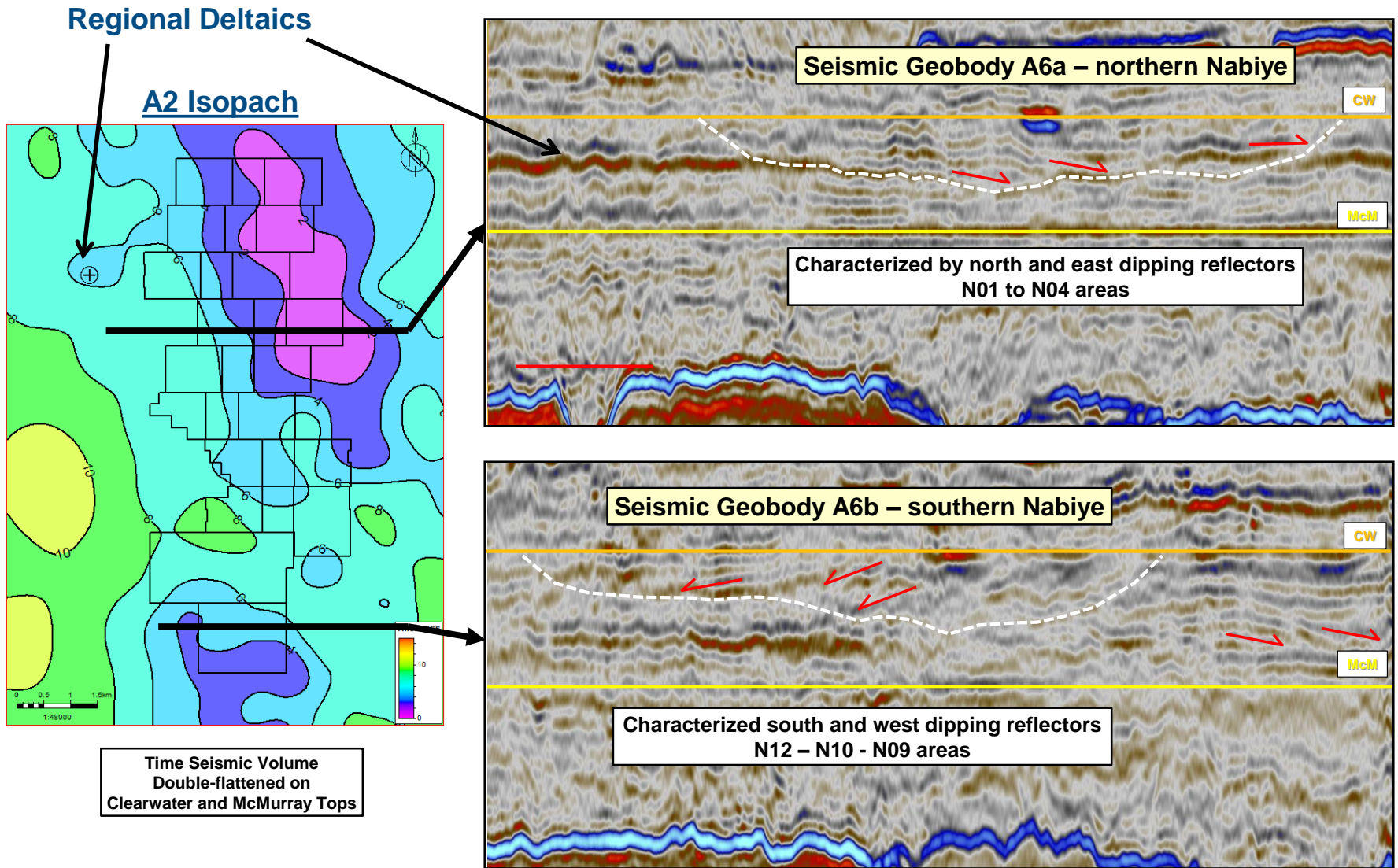
Age-relationships resolved and tied to OSC framework based on cross-cutting relationships

Reservoir differences may represent down-dip and lateral facies changes relative to the main axis of deposition within individual lobes (e.g. distributary channel vs. terminal distributary channel/mouth-bar vs. proximal and distal delta-front EODs)



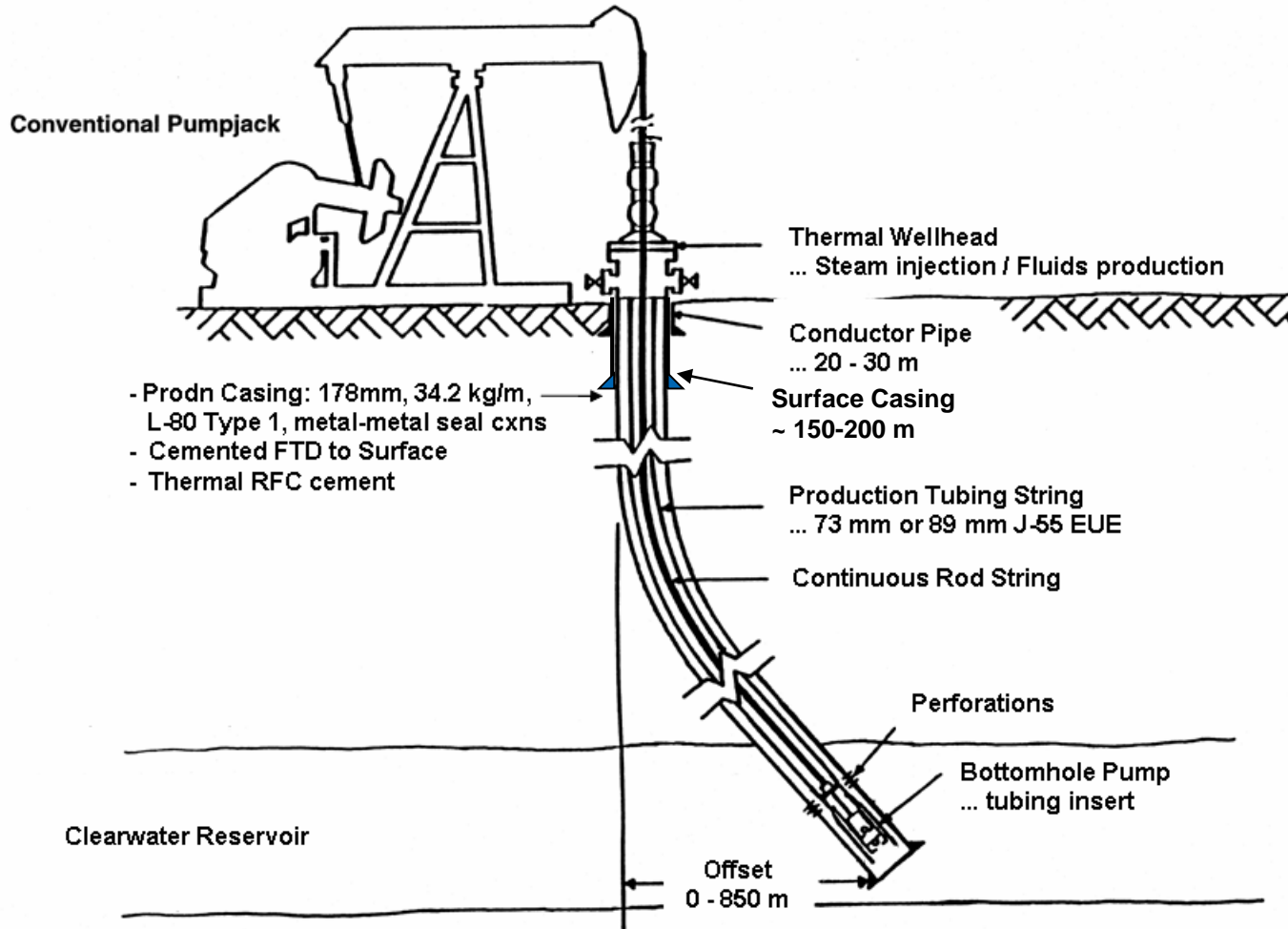
Well log cross section dated on Top Clearwater surface displaying the internal stratigraphy across Nabiye field (pad N01/N02 area)

Nabiye Geobodies: Seismic Mapping

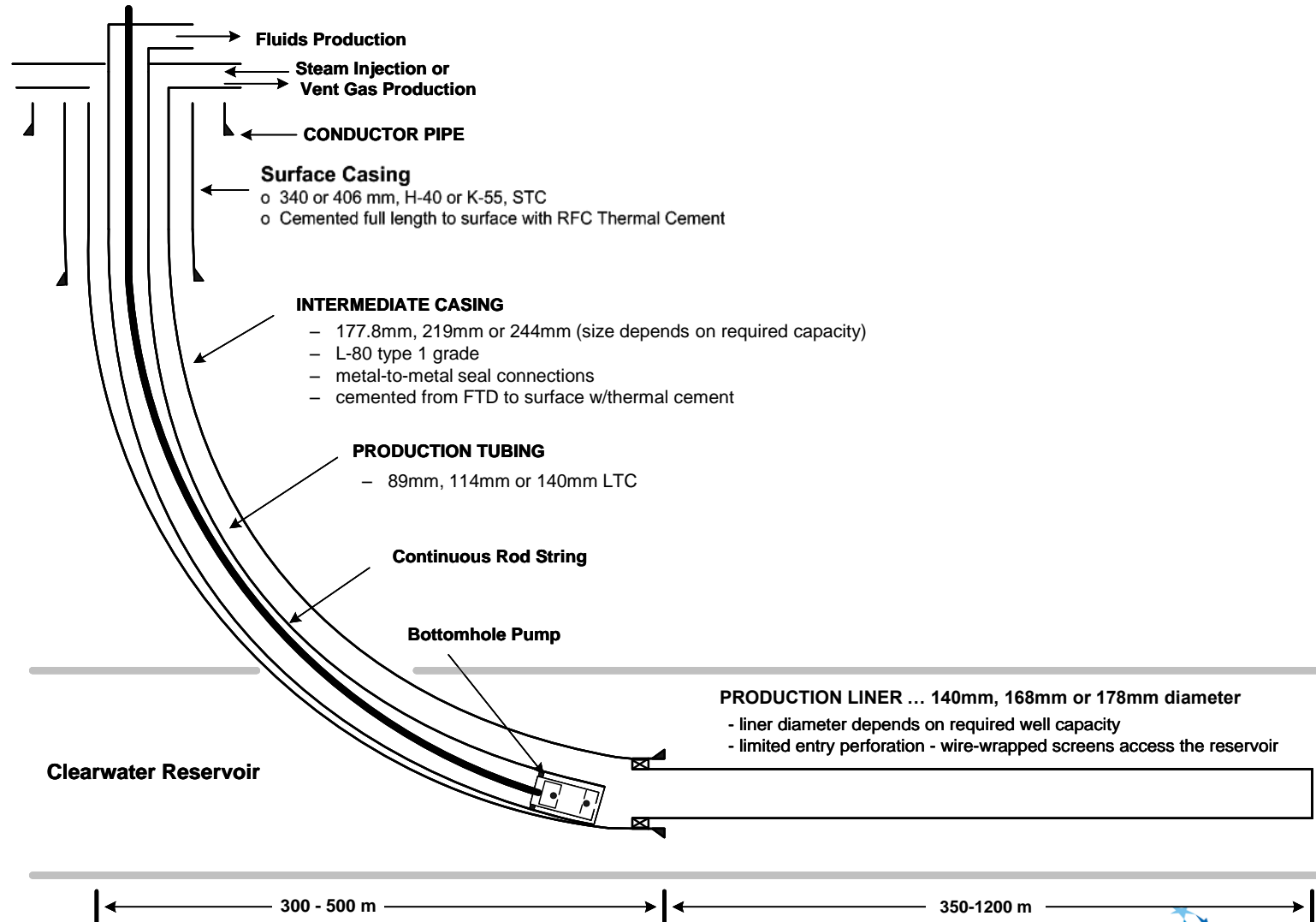


Drilling and Completions

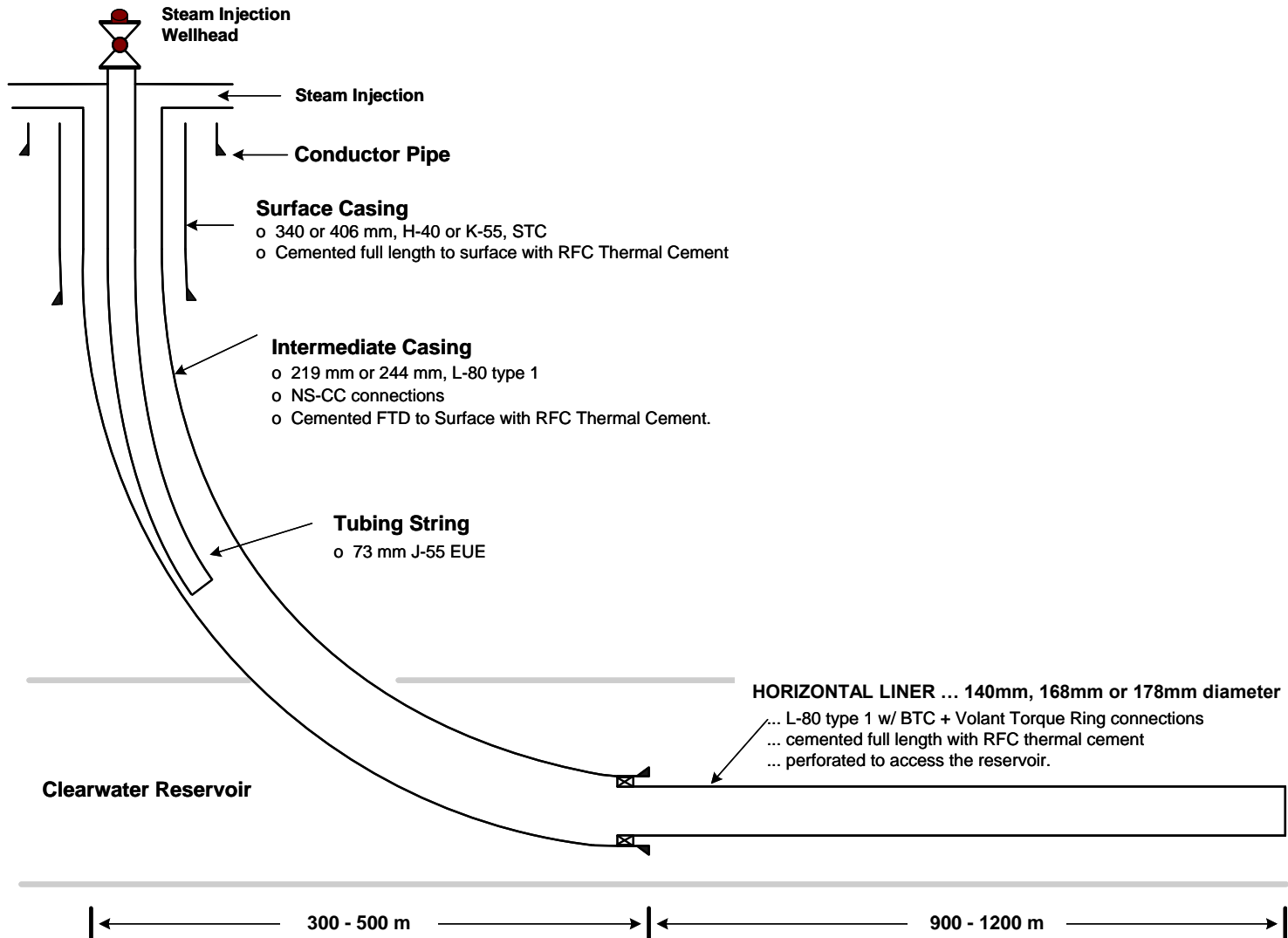
Typical Deviated CSS Well Design



Horizontal CSS or HIP Well Design



Horizontal Steam Injection Well Design



Artificial Lift

Artificial Lift Performance

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

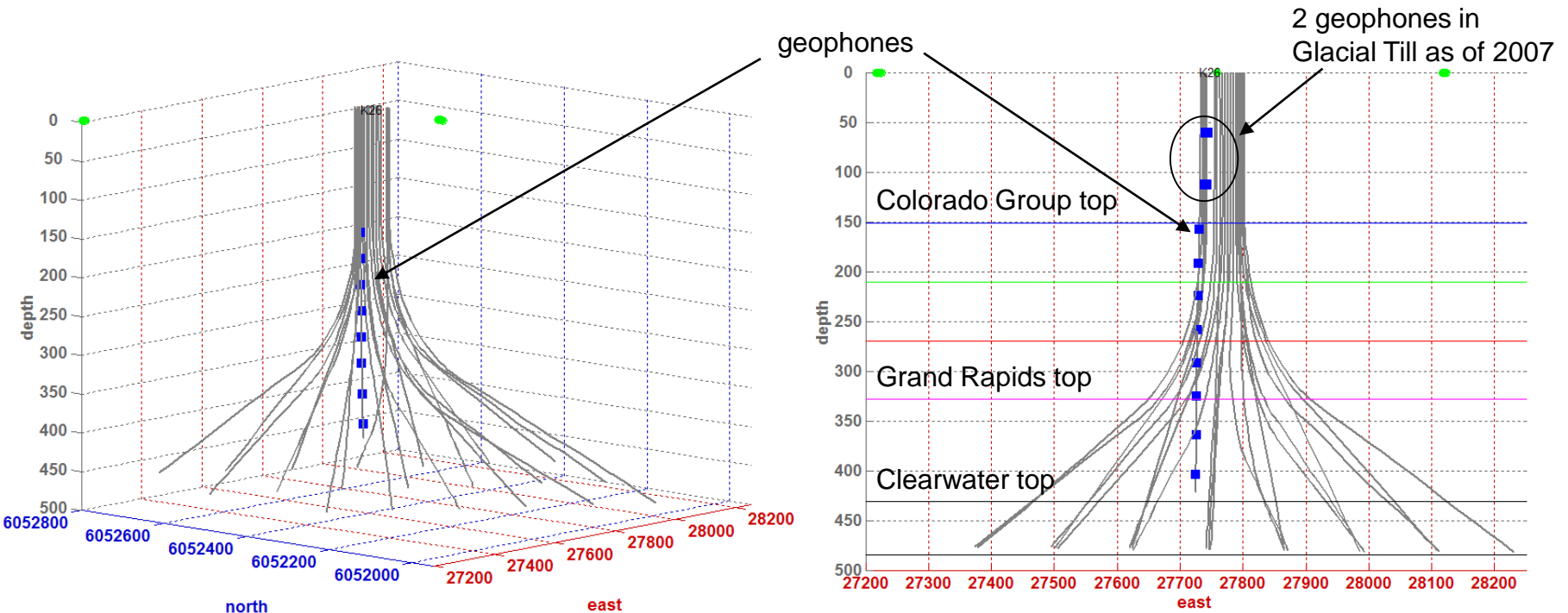
- Insert rod pumps used across field
- Size of lift system depends on:
 - Offset to reservoir target
 - Well deliverability: deviated versus horizontal wells
- Operating Conditions
 - Pumping temperature 75 – 220°C
 - Pump Intake pressure 6 MPa to less than 500 kPa
 - Average run life of rod pumps is 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

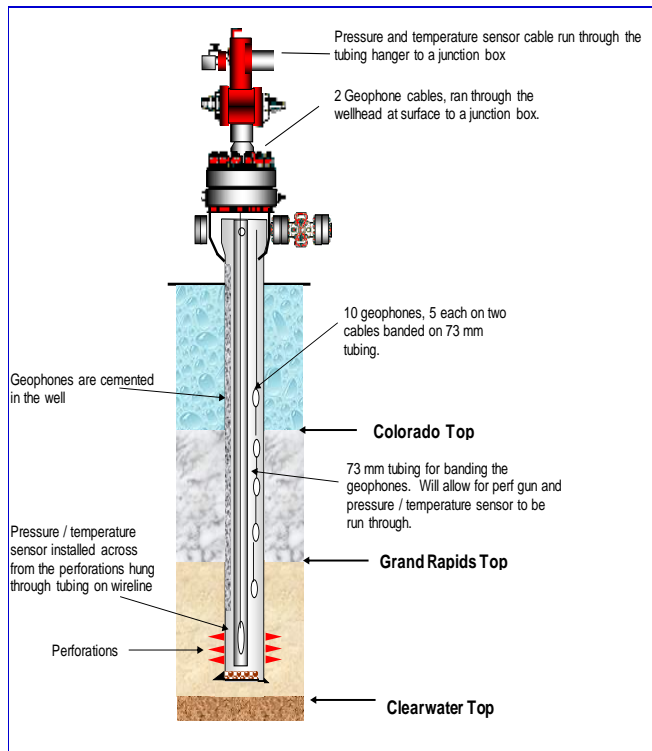
Typical Passive Seismic Configuration



Instrumentation in Wells

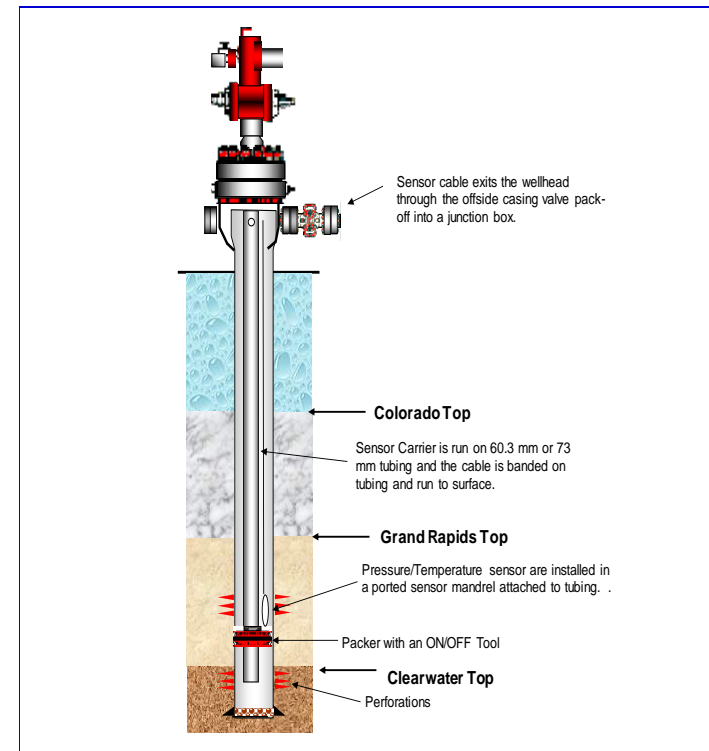
Hybrid Passive Seismic Well

- 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.



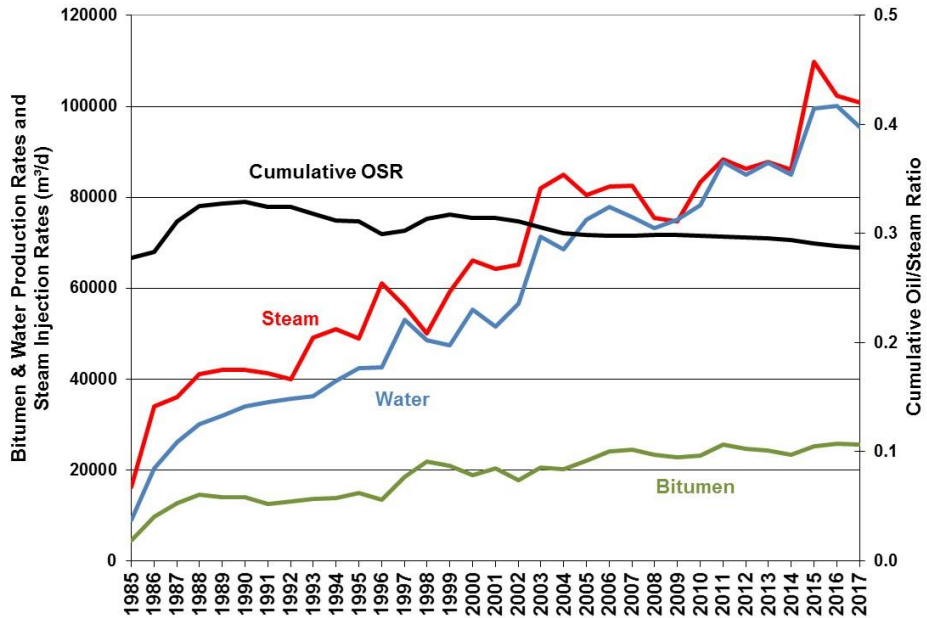
Scheme Performance

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



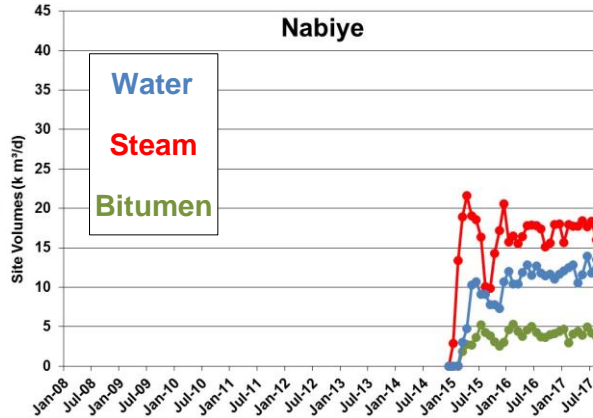
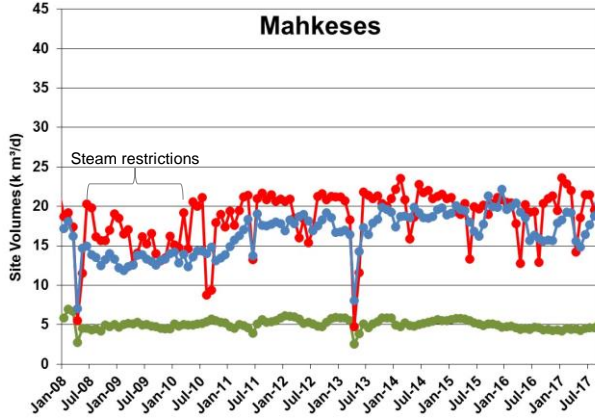
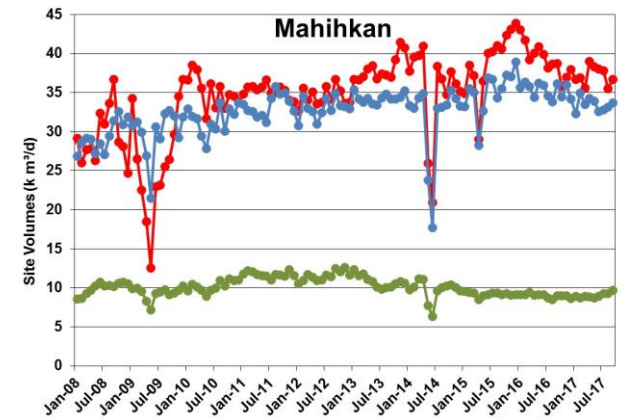
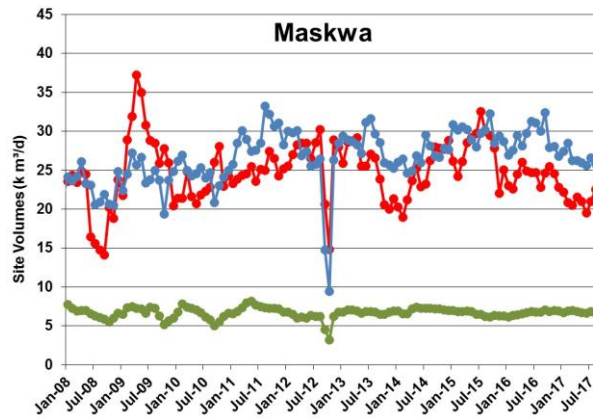
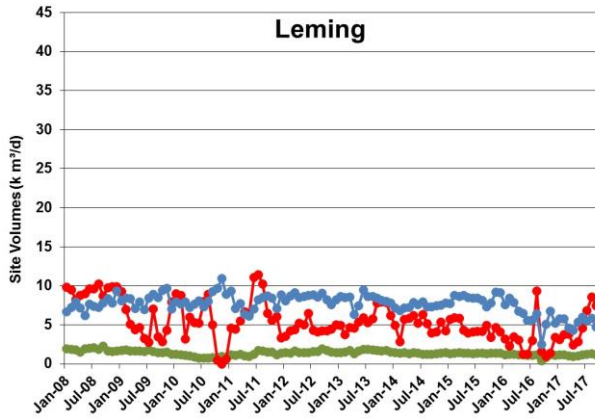
- Maximum daily bitumen production under approval 8558 is 40,000 m³/d

	Bitumen Production 10 ³ m ³ /d	Steam Injection 10 ³ m ³ /d	Cumulative	
			OSR	SOR
2016	25.7	102.4	0.29	3.5
2017 YTD Sep	25.5	100.8	0.29	3.5

Notes

- Production data includes CSP and SA-SAGD pilot projects
- SOR on wet steam basis

Individual Site Performance



Plant	2017 Average	
	OSR	SOR
Leming	0.23	4.3
Maskwa	0.32	3.2
Mahihkan	0.24	4.1
Mahkeses	0.22	4.5
Nabiye	0.24	4.1

Steam Transfers (10³ m³)

Maskwa to Mahihkan:
 Mahihkan to Maskwa:
 Leming to Maskwa:
 Leming to Mahkeses:
 Mahkeses to Leming:

588
 72
 512
 0
 898

D04 Infills (Oct 2016 – Sep 2017), A06 Infills (Oct 2016 – Sep 2017)
 J10 Infills (Jun 2017 – Sep 2017)
 OFF Infills (Oct 2016 – Sep 2017), 00U Infills (Oct 2016 – Sep 2017)
 T05 Infills (Dec 2016 – Sep 2017)

Abandonment Outlook

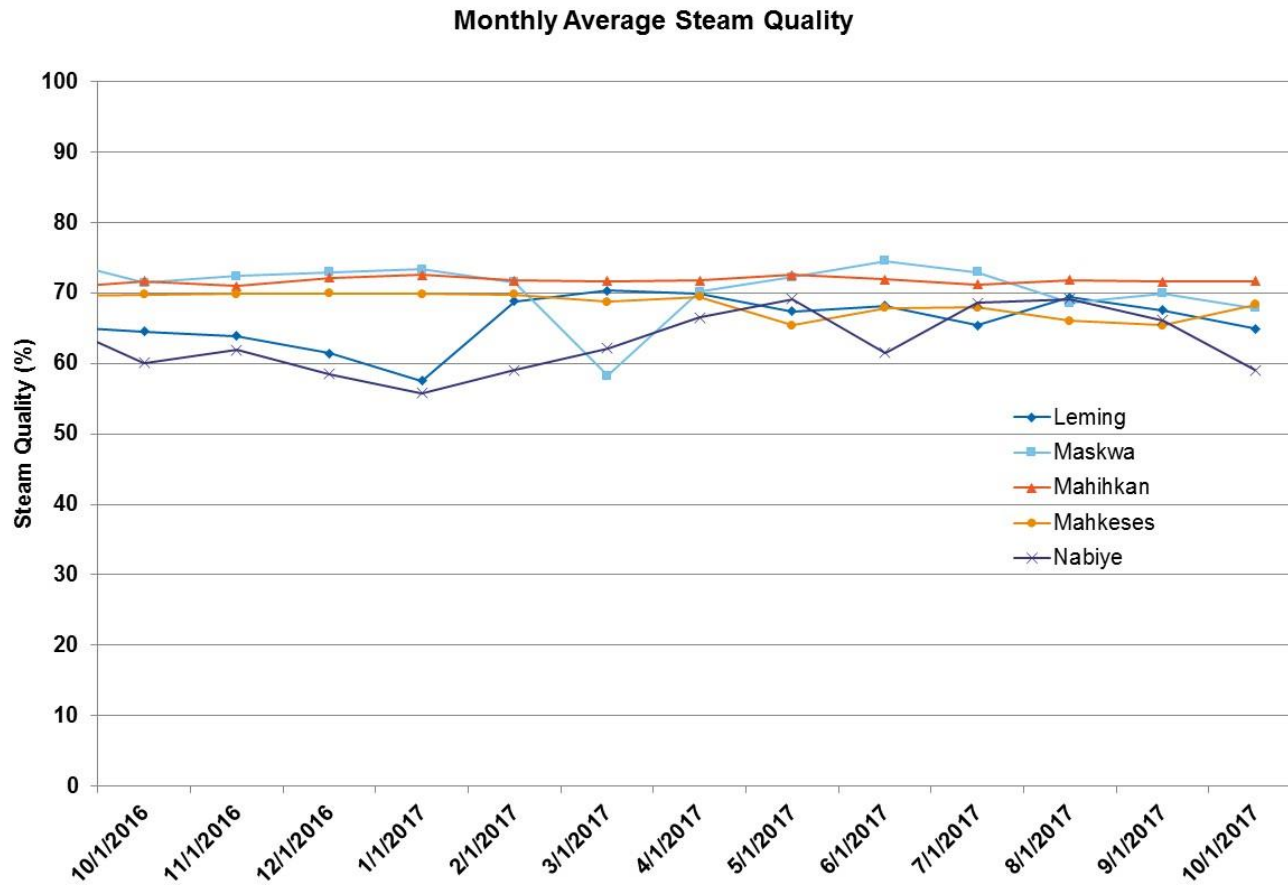
- 5 year outlook for pad abandonment
 - 'Flow Behind Pipe' assessment (inc. E07 pad testing) confirms hydraulic isolation behind casing on Cold Lake wells.
 - Assessment also demonstrates that post-steam cement bond logs do not reflect degree of hydraulic isolation behind casing
 - Aquifer isolation study completed in 2016 confirms that isolation of aquifers at the time of full subsurface abandonment is not necessary
 - E07 pad wells have been fully abandoned except for two wells which have been retained for monitoring of adjacent D29 pad high pressure steaming operations
 - CC/DD/GG pad abandonment progressed; 44 wells fully or partially abandoned, remainder will continue 2018+
 - Q and S pad scheme approval in place, abandonments to follow CC, DD & GG
 - Discontinue monitoring for Q-01 approved by AER in 2016
 - B03 pad abandonment progressed, 18 wells partially abandoned, 2 fully subsurface abandoned, remainder will continue 2018+
 - Began abandonments on 20 Shale monitoring wells in low pressure areas as per AER approval
 - Pads with support from adjacent pads will continue operation
- Individual wells that are uneconomic will be zonally abandoned to meet Directive 13:
 - 15 individual wells had appropriate abandonment work completed in 2017

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
00W	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
0BB	Operating with support from adjacent pads
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
00W	Operating with support from adjacent pads
A01	Operating with support from adjacent pads
A02	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	Abandonment process started
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
H34	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	Operating with support from adjacent pads
M04	Operating with support from adjacent pads
M06	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
T11	Operating with support from adjacent pads

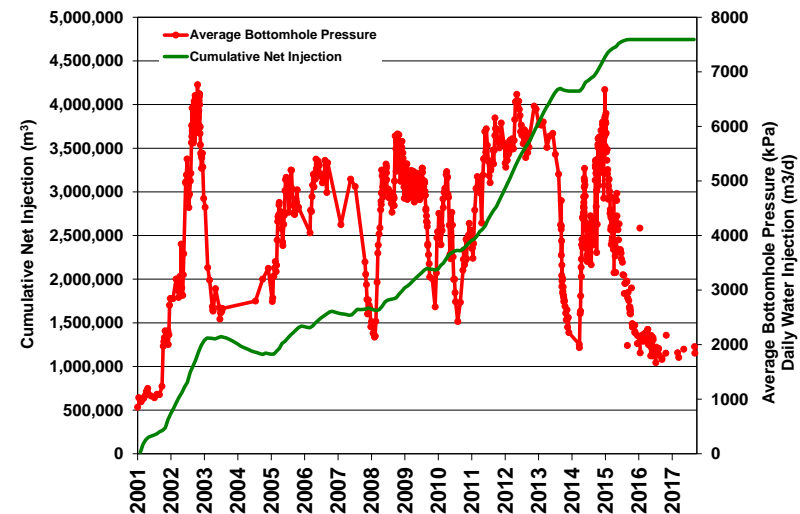
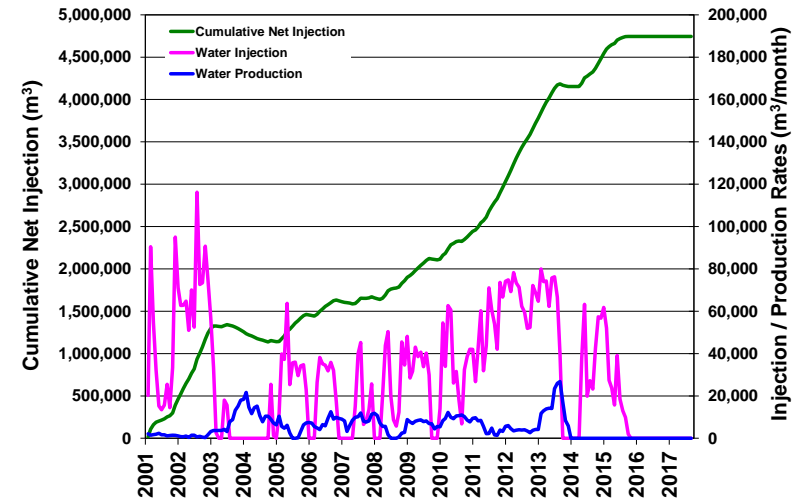
Steam Quality

- Nabiye / Leming steam qualities low in late 2016 / early 2017 because of water treatment issues



Cold Lake N-Pad – Approval 4510

- Approval 4510 is for utilization of Leming N-pad as a temporary water storage scheme
- No N-Pad water production since Dec 2013
- No N-Pad water injection since Oct 2015
- Adjacent pad performance indicates connection to N-Pad storage volume
 - Water production from N pad storage will continue through adjacent pad wells
- Plan to continue current operating strategy of no water injection at N pad



Cold Lake N-Pad – Approval 4510

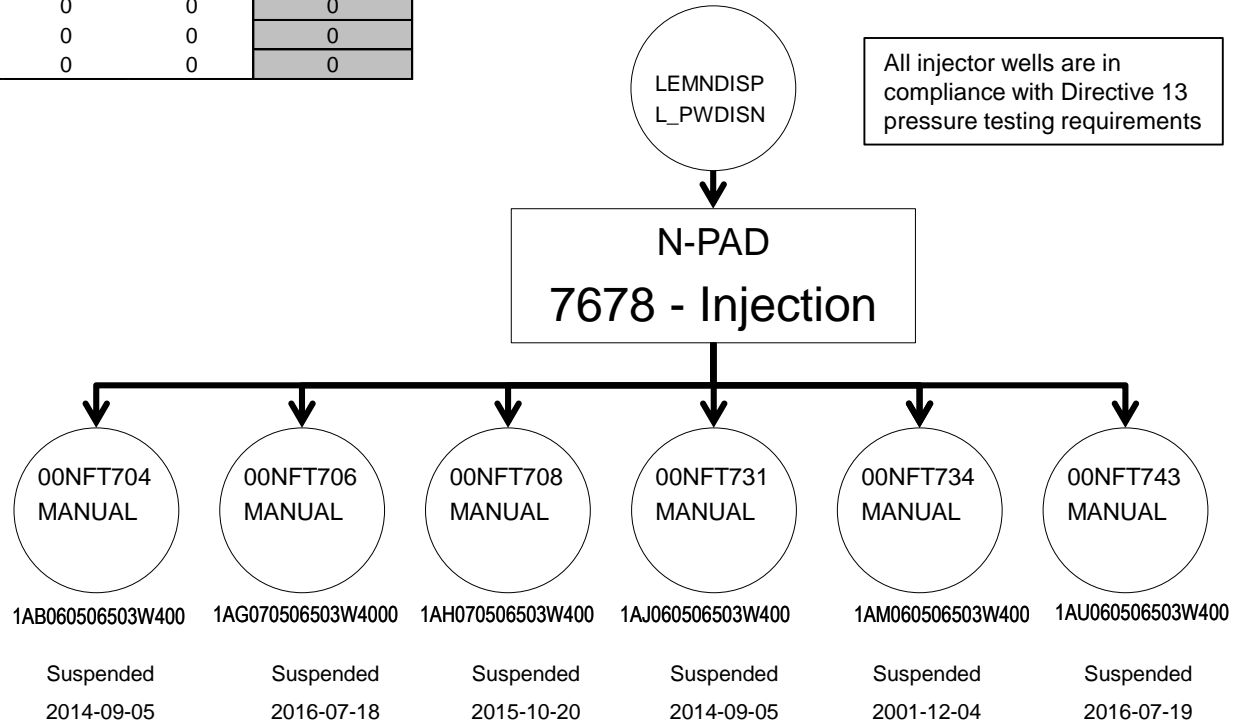
Table 1: N-Pad Water Injection (m3)

Month	N-04	N-06	N-08	N-31	N-34	N-43	Monthly Total
Oct-16	0	0	0	0	0	0	0
Nov-16	0	0	0	0	0	0	0
Dec-16	0	0	0	0	0	0	0
Jan-17	0	0	0	0	0	0	0
Feb-17	0	0	0	0	0	0	0
Mar-17	0	0	0	0	0	0	0
Apr-17	0	0	0	0	0	0	0
May-17	0	0	0	0	0	0	0
Jun-17	0	0	0	0	0	0	0
Jul-17	0	0	0	0	0	0	0
Aug-17	0	0	0	0	0	0	0
Sep-17	0	0	0	0	0	0	0

N-Pad Schematic

ERCB injection system #7678

Produced Water From Leming



Cold Lake Water Management

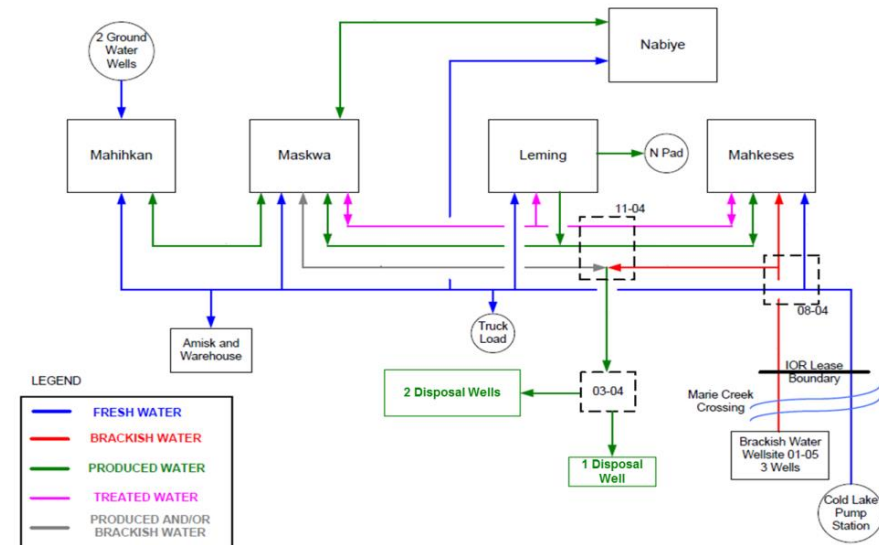
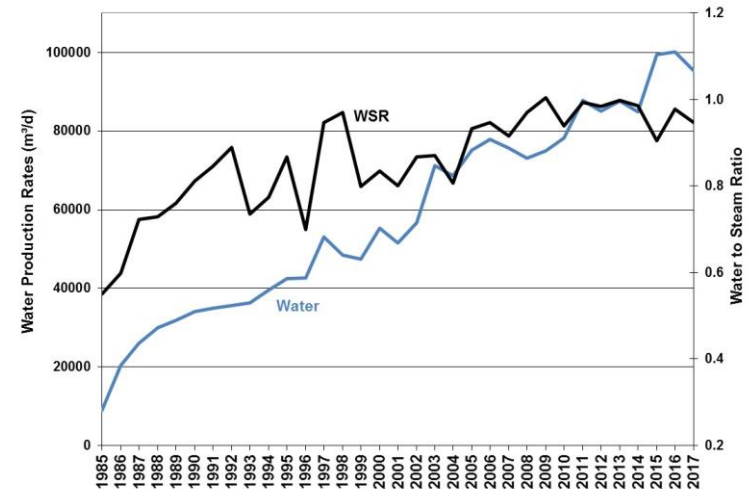
• Cold Lake Water Production

- 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

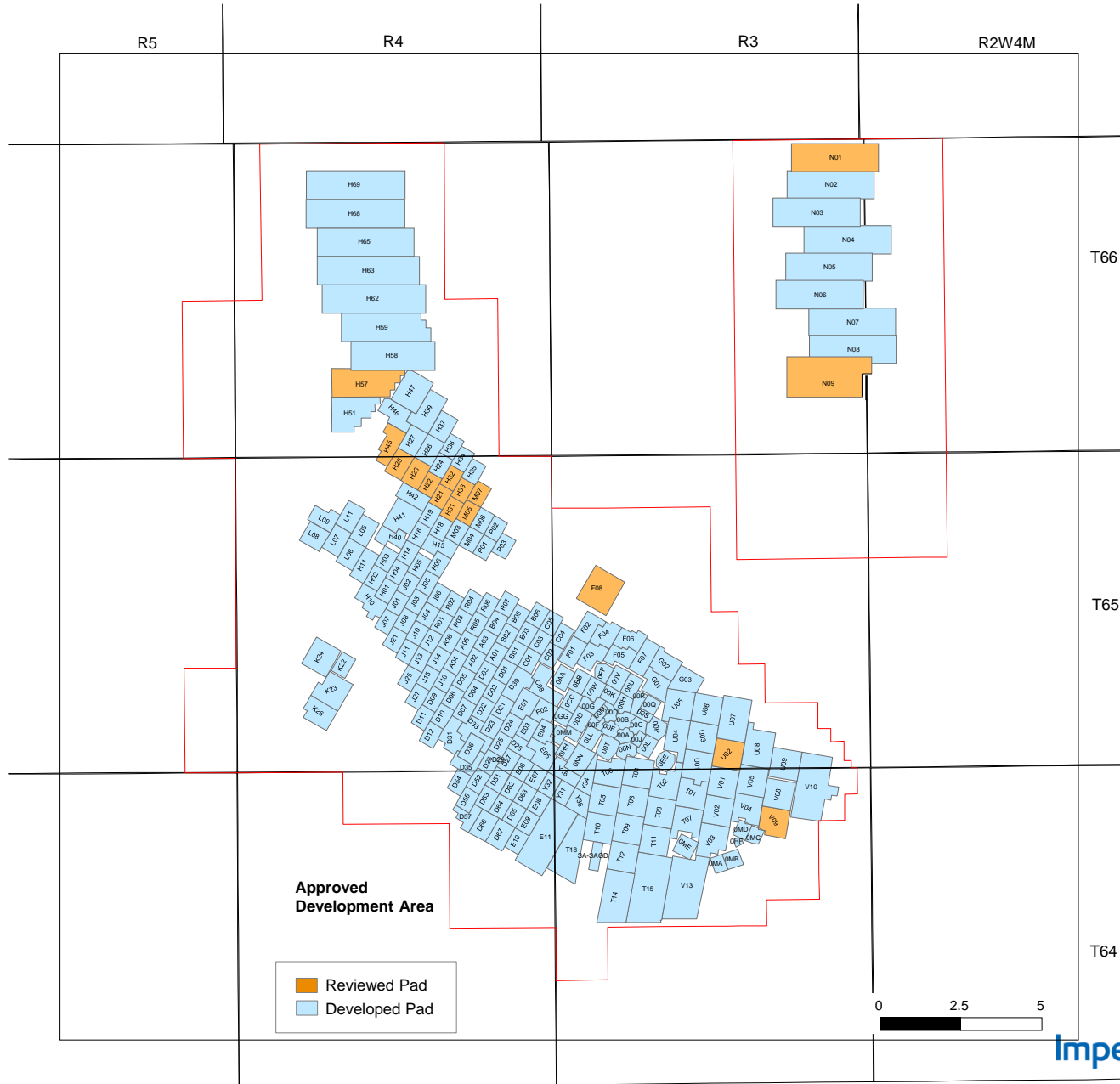
• Operating Strategies

- 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

Cold Lake Water Production

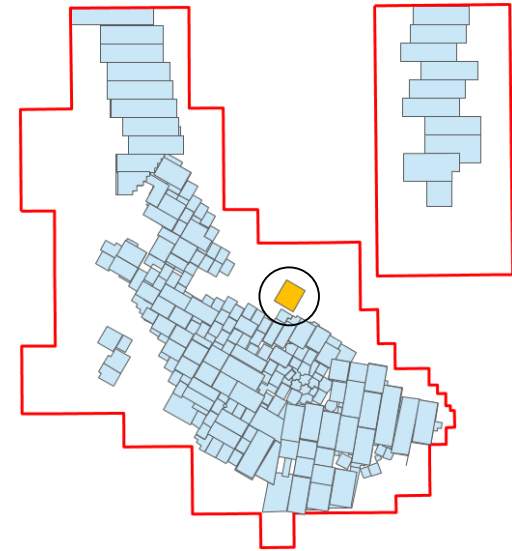


Pad Performance Reviews

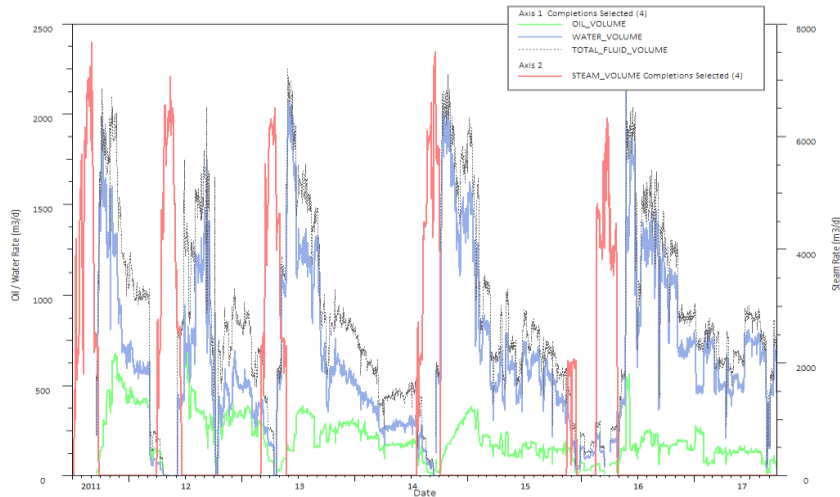


Maskwa F08 Thin Pay Trial

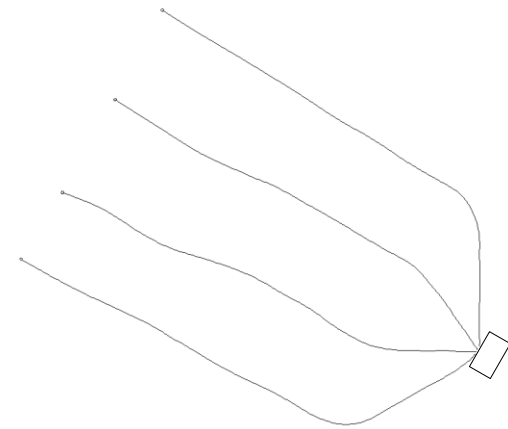
- Maskwa F08 is an 11 acre spacing / 4 horizontal well pad in thin pay
- Trial uses CSS process
- Currently in Cycle 5, next cycle scheduled for Q1 2018
- Production performance within the range of expectations, steam distribution still being understood
- Performance will be used to evaluate future thin pay application



F08 Production



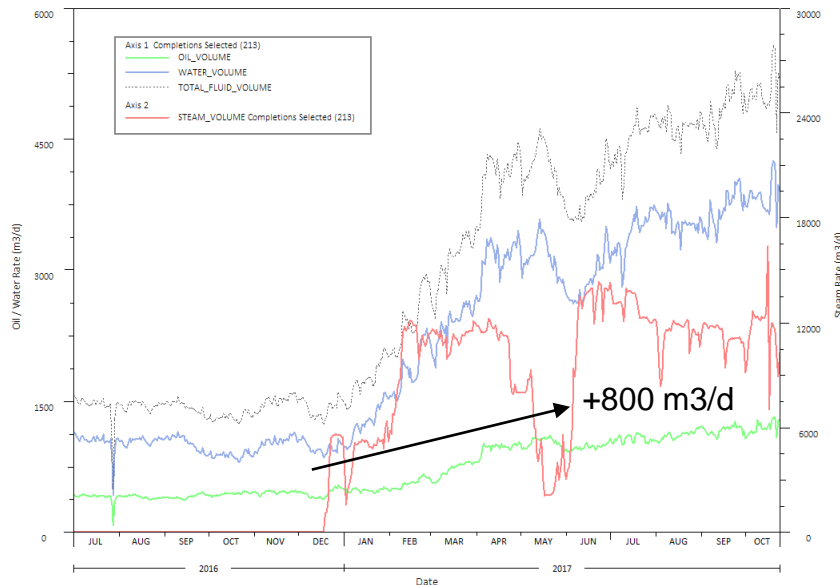
Well Layout



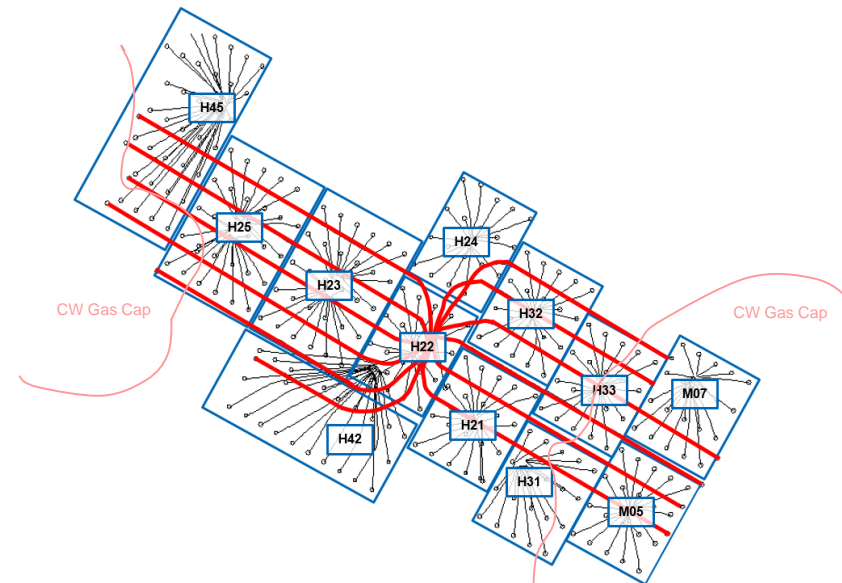
Mahihkan H22 Injector Only Infills

- H22 'mega' infills, include two wings with 12 injector only wells
- Infills Mahihkan H21, H23, H25, H31, H32, H33, H42, H45, M05, M07 (~168 adjacent bottom hole locations)
- First cycle steam began in late 2016
- Vintage LASER pilot area, additional recovered diluent production observed
- Substantial improvement in production rate in a short amount of time due to new reservoir drive
- Performance under Clearwater gas cap better than expected

H22 IOI Area Production



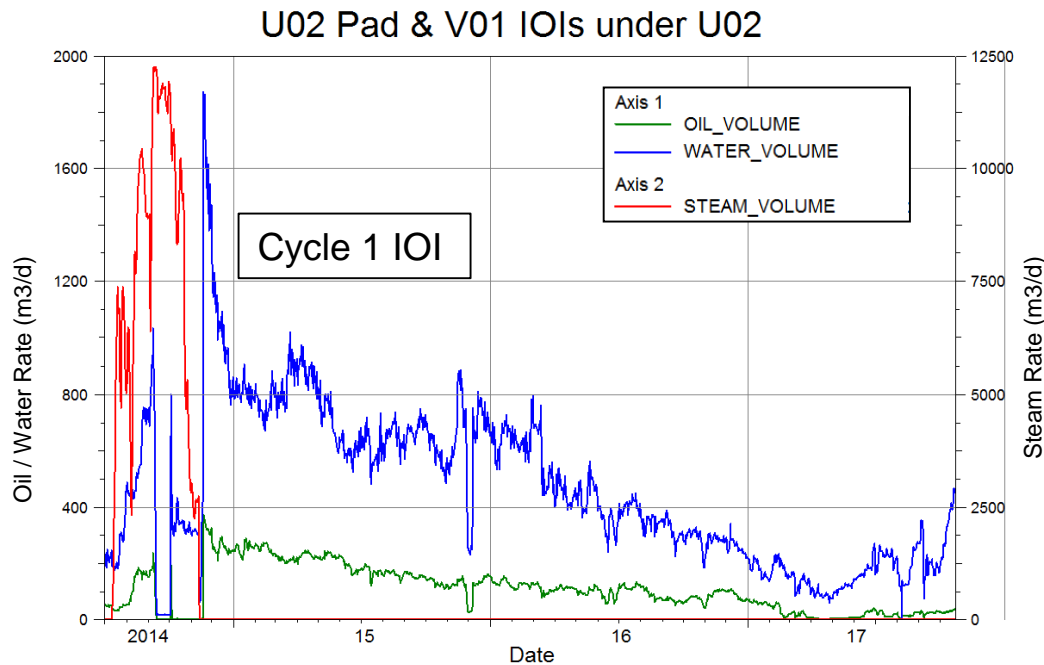
H22 IOI Well Layout



Mahkeses V01 Injector Only Infills

- U02 is an 8 acre 24 well pad infilled by V01 IOIs
- Cycle 1 IOI steamed July– November 2014
 - Steamed through IOIs only, CSS wells did not steam
 - OSR performance below expectation
- Cycle 2 IOI steam planned for November 2017
 - Steam strategy to steam both IOI and CSS wells to improve performance
 - Repair campaign completed to increase ability to inject steam

U02 Wellbore Utility



Cycle 1 IOI

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

Cycle 2 IOI

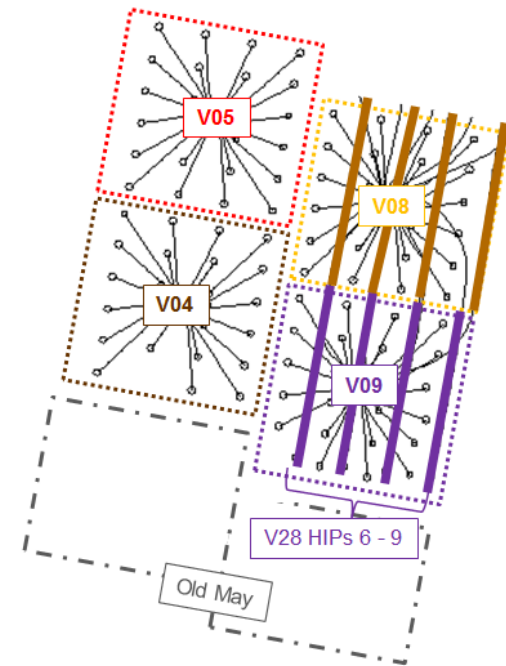
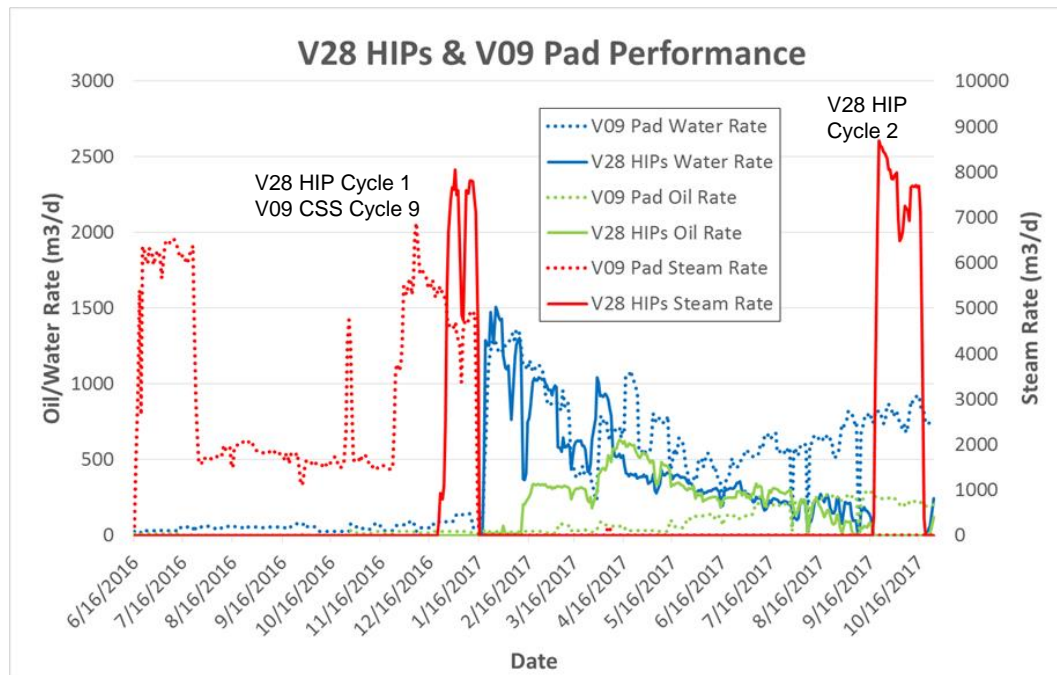
1	7	13	19
2	8	14	20
3	9	15	21
4	10	16	22
5	11	17	23
6	12	18	24

— V01 IOIs

HPCSS
Subfrac
LPCSS
POW W/O Plug
POW W/ Plug
Suspended

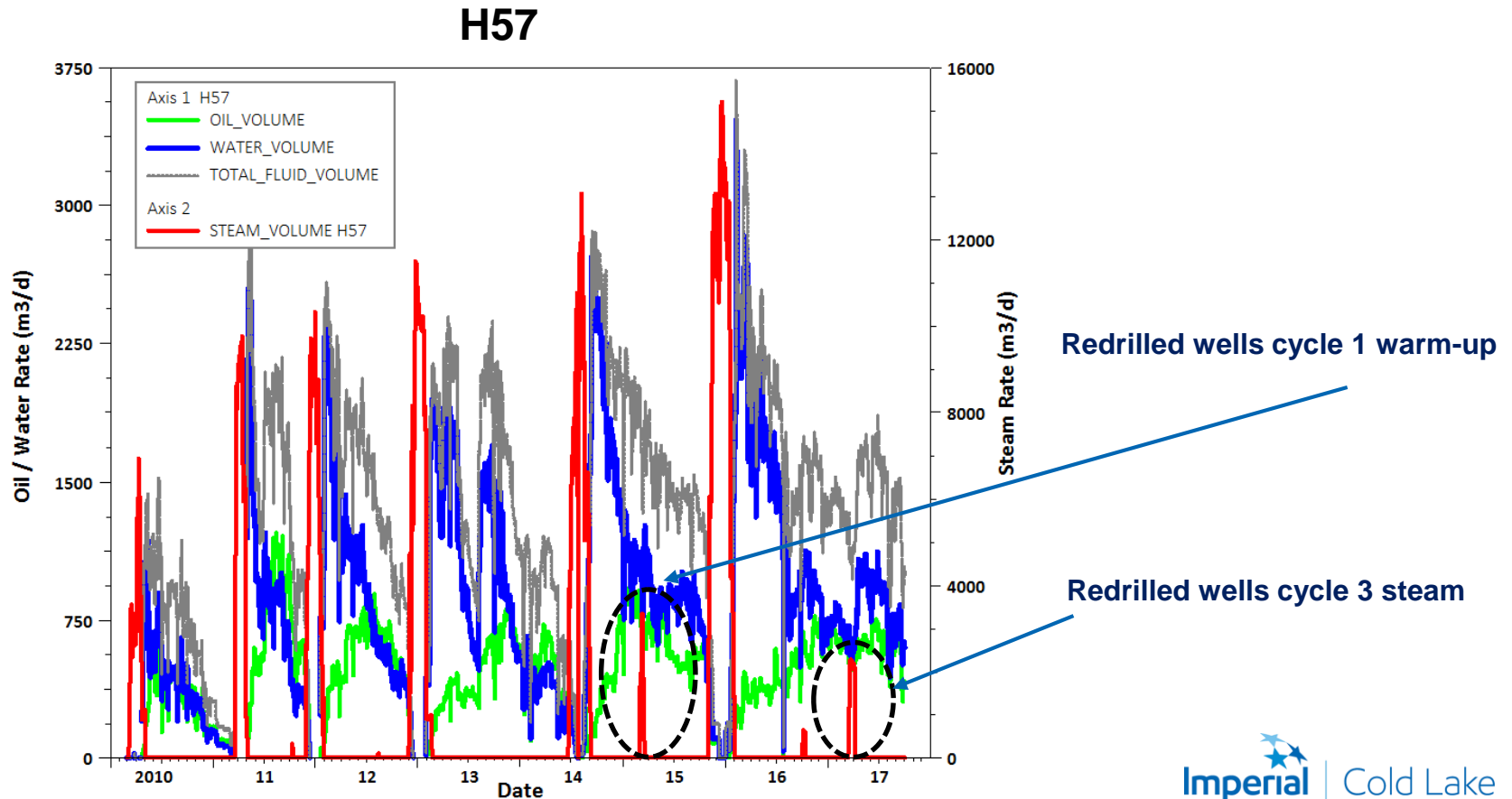
Mahkeses V28 HIPs under V09 Pad

- V09 is an 8 acre 23 well pad infilled by V28 HIPs
- HIP Cycle 1 steamed in December 2016 to January 2017
 - Steamed concurrently with V09 Pad Cycle 9
 - V09 Pad performance on track with Cycle 9 expectations
 - V28 HIPs reflect early-cycle performance vs. mature cycle performance of base CSS pad
- HIP Cycle 2 steamed in September to October 2017
 - Steam injected into HIP wells only to better reflect cycle timing of early-cycle wells
 - V09 Pad continues to produce on track with CSS Cycle 9 expectations



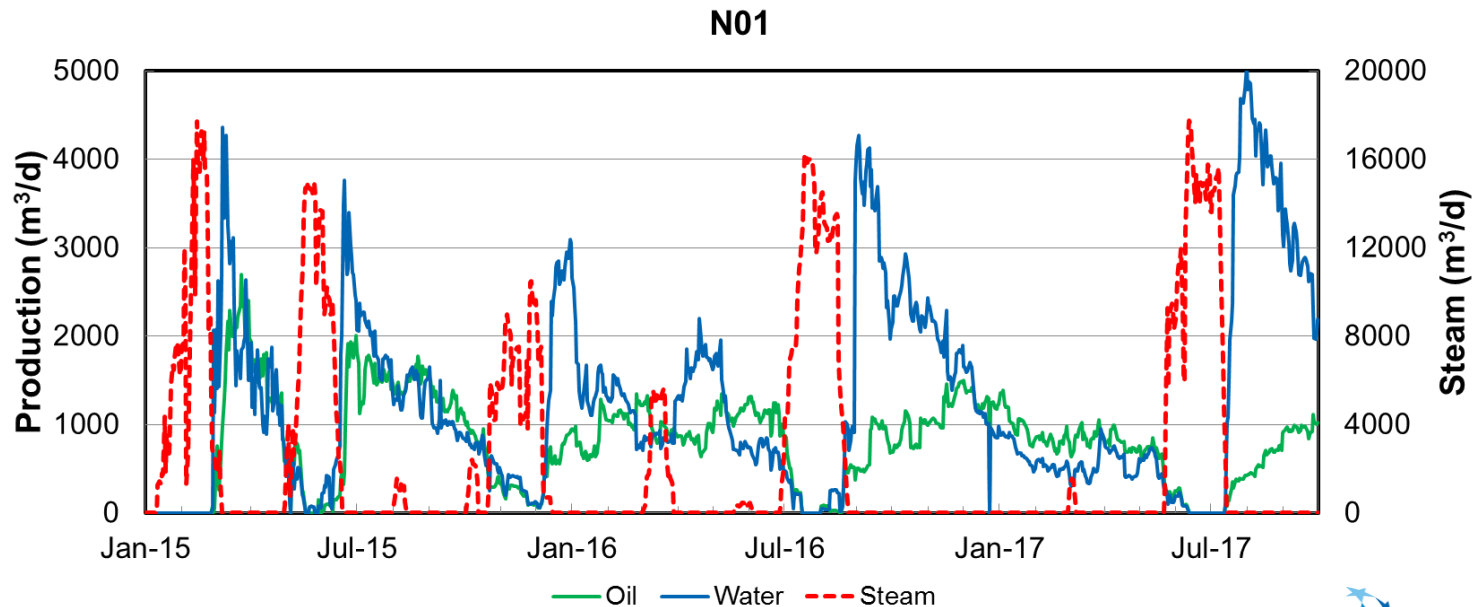
Mahihkan H57 Pad

- Mahihkan H57 is an 8 acre spacing / 24 well (16 vertical, 8 horizontal) pad, currently in cycle 6
- Overview:
 - Dominantly fluvial facies environment of deposition
 - Cycle steam was injected as per Best Practice. Typical CSS performance
 - 2 vertical and 1 horizontal wells were redrilled in 2014 and received 3 cycles of steam
- Cycle 7 steam-in scheduled for Nov. 2017 with LASER injection



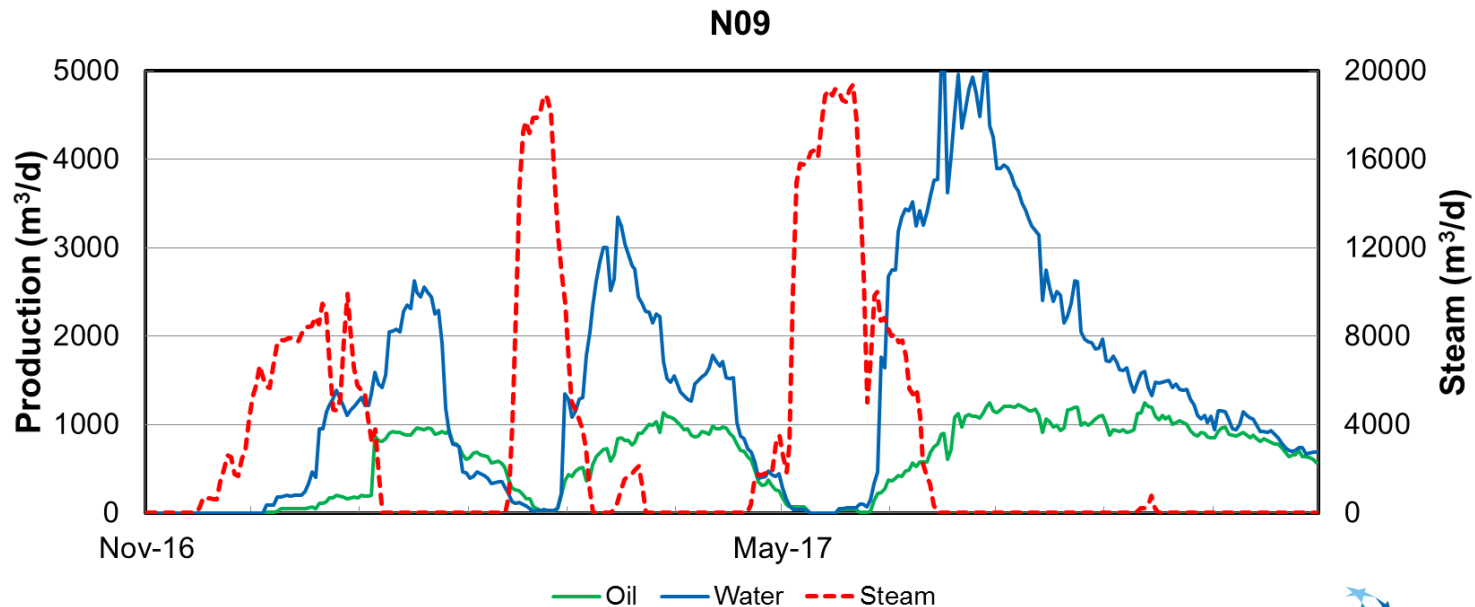
Nabiye N01 Pad

- Nabiye N01 is a 24 well pad (16 deviated, 8 horizontal), accessing 70 bottom-hole locations on 8 acre spacing
- Currently in the production phase of cycle 5
- Steam volumes have been reduced from Cold Lake best practices to manage pressure responses in the Grand Rapids
- Production performance is typical for CSS at Cold Lake



Nabiye N09 Pad

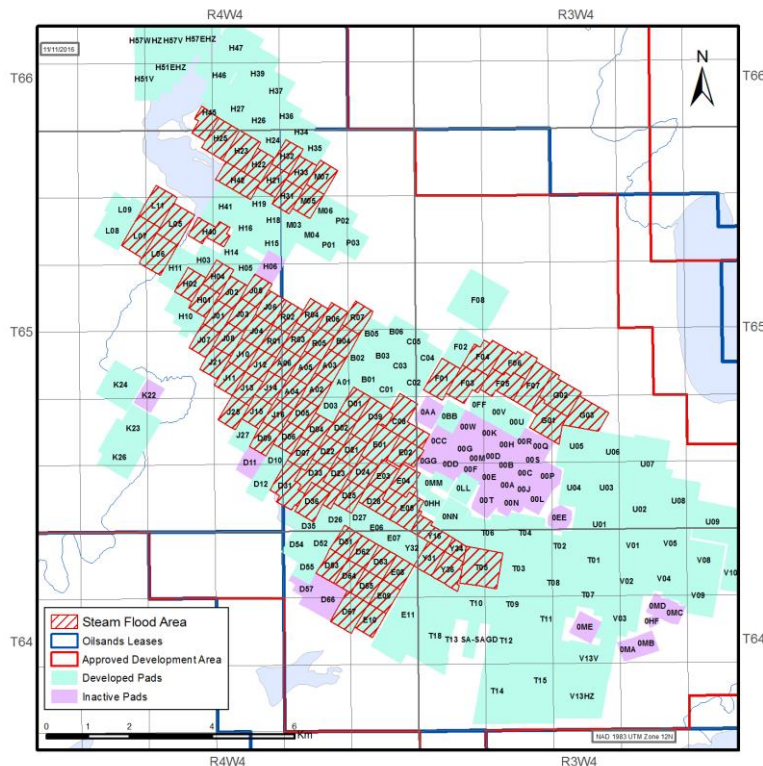
- Nabiye N09 is a 36 well pad (24 deviated, 12 horizontal), accessing 101 bottom-hole locations on 8 acre spacing
- Currently in the steam injection phase of cycle 3
- Cycle 1 was split into two smaller injection cycles to mitigate the risk of pressure responses in the Grand Rapids formation. Steam volumes for each injection were roughly half of the typical first-cycle steam volume
- Small initial steam volumes caused significant challenges for well servicing as wells cooled off before their bottom-hole pressures were low enough to work on with a rig.
- Resulting downtime caused production to fall short of expectations in the first 3 cycles



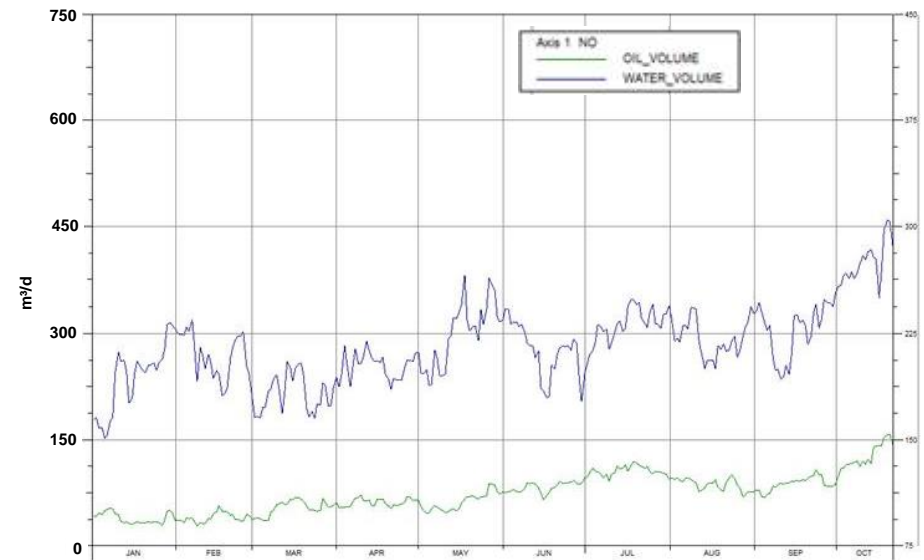
Late Life Steamflood Performance

Late Life Steamflood

- Steamflood approved for entire Cold Lake Development Area
- Currently ~125 infills on steamflood into 85 producing pads (~1,500 wells)
- Workover program undertaken to reactivate/improve steamflood wells in 2017 – 23 wells repaired to date
 - Production was increased 120 m³/d and wells continue to improve with IOI support
- 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
 - Attempting to optimize steamflood performance by trialing different steam strategies including injecting at higher rates (1,000 – 2,000 m³/d) to ensure steam distribution
 - Reservoir pressure to remain less than 6 MPa as per approval



Steamflood Repairs – Production



2017
Date

Late Life Steamflood

Mahihkan Steamflood Area

23 Pads: A06, H01, H02, H15, H16, H26, H27, J01, J02, J03, J05, J06, J08, J10-J15, J21, J25, L06, L07

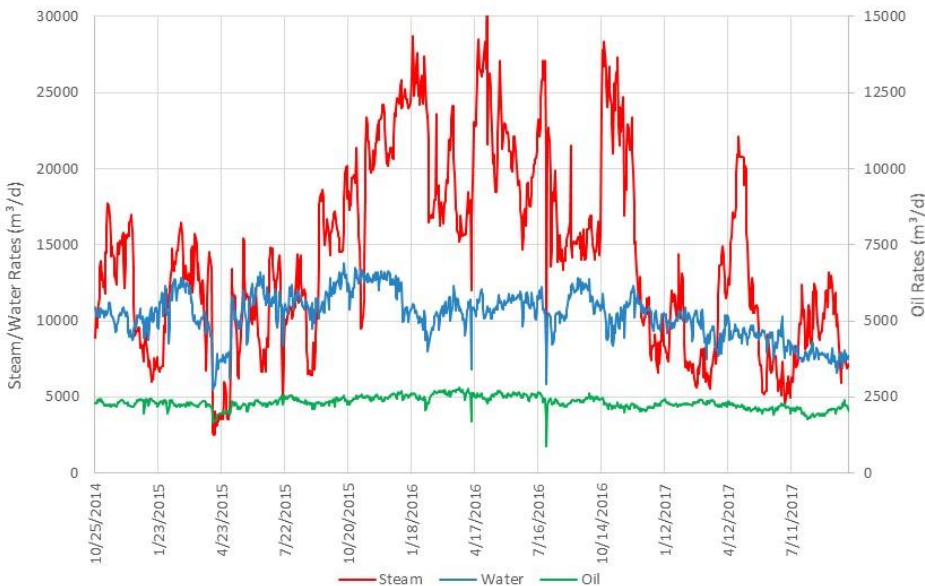
- Steamflood performance at Mahihkan as expected
- Steamflood injection rates reduced in the past year
- Oil rates have decreased slightly in the past year
- Recovery factors as high as 70-85% for pads in this area

Maskwa Steamflood Area

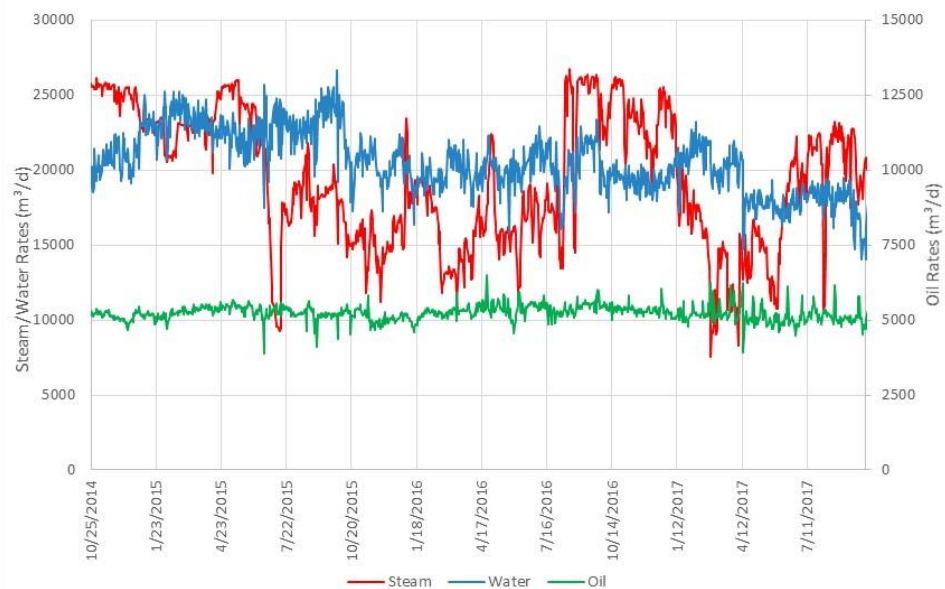
38 Pads: A02, A04, D02-D07, D09, D10, D21-D25, D28, D31, D33, D35, D39, D51, D57, D62-D65, E01-E05, F01-F04, J04, J16, R01

- Steamflood performance at Maskwa as expected
- Steamflood injection rates reduced in the past year
- Oil rates have decreased slightly in the past year
- Recovery factors are approaching 70% on some of these pads

Steamflood Volumes - Mahihkan



Steamflood Volumes - Maskwa

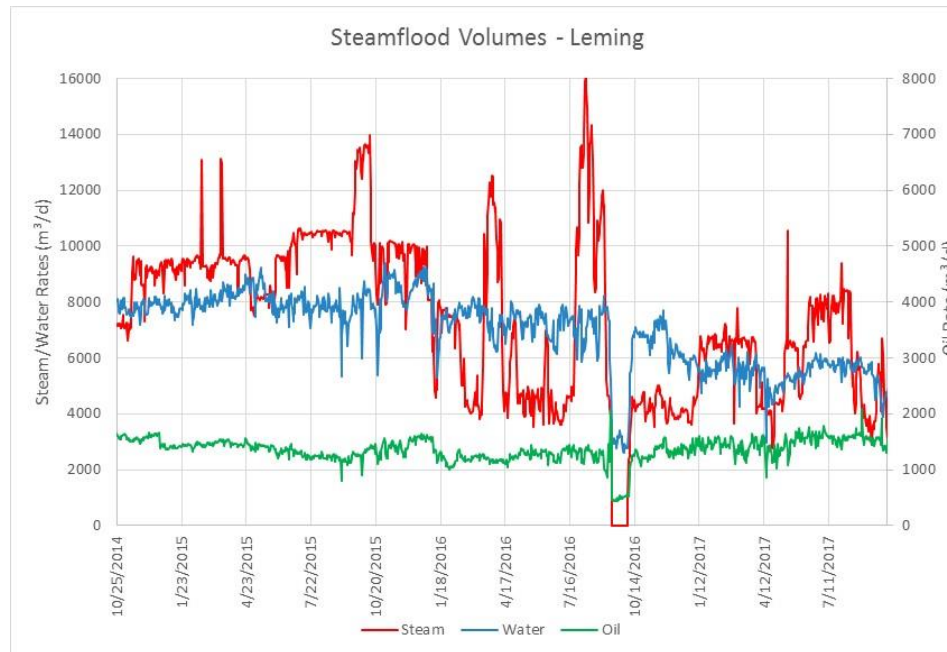


Late Life Steamflood

Leming Steamflood Area

10 Pads: F05, F06, F07, G01, G02, G03, Y16, Y31, Y34, Y36

- Steamflood performance at Leming as expected
- Steamflood injection rates relative unchanged from prior year
- Oil rates have increased slightly in the past year
- Recovery for pads in this area ranges from 35-50%



LASER Recovery Process

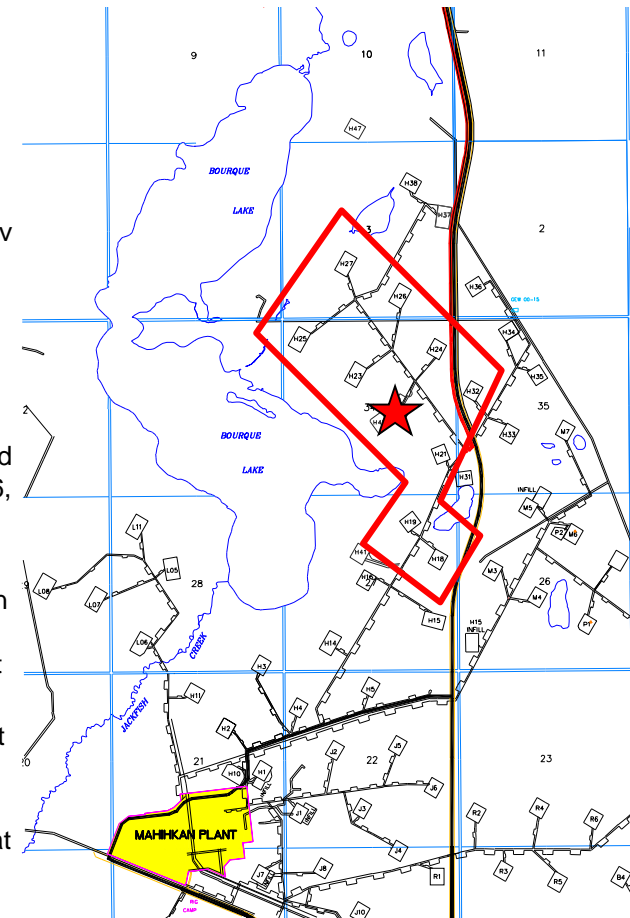
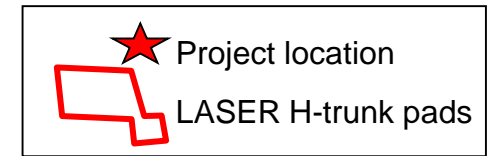
LASER H Trunk Project- Cycle 1 Summary

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

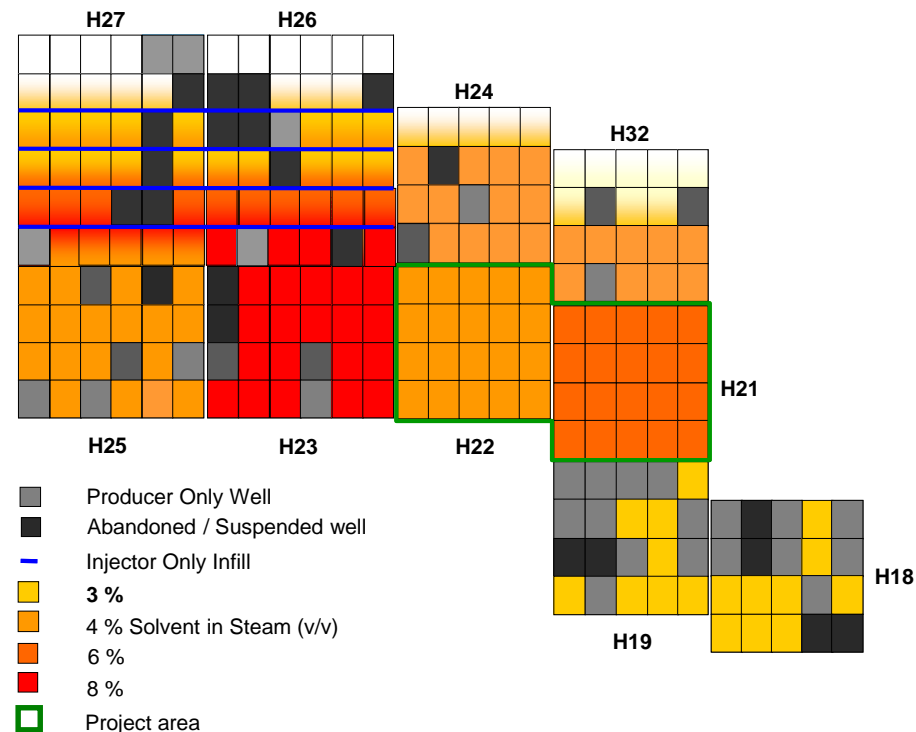
- Overall first cycle LASER performance was in line with expectations
 - Average 0.10 OSR uplift was achieved compared to no LASER implementation, due to the 5% v/v diluent injected with the steam in this first LASER cycle. This is approximately a 50% improvement in oil production performance.
 - Range of 0.04 to 0.18 OSR uplift for the 10 pads
 - 59% of the injected diluent was recovered in LASER cycle 1, in line with expectations
 - Range of 30% to 90% recovery of injected diluent for the 10 pads
 - Some fluid migration from the LASER pads was observed, 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
 - 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. 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.
 - LASER 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
 - Sustainability of 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)
<u>LASER POW</u>	2		
9 injectors	H18	3%	3.2%
8 injectors	H19	3%	3.0%
<u>LASER CSS</u>	6		
Standard	H21	4%	6.1%
3 rd 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%
<u>LASER IOI</u>	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)

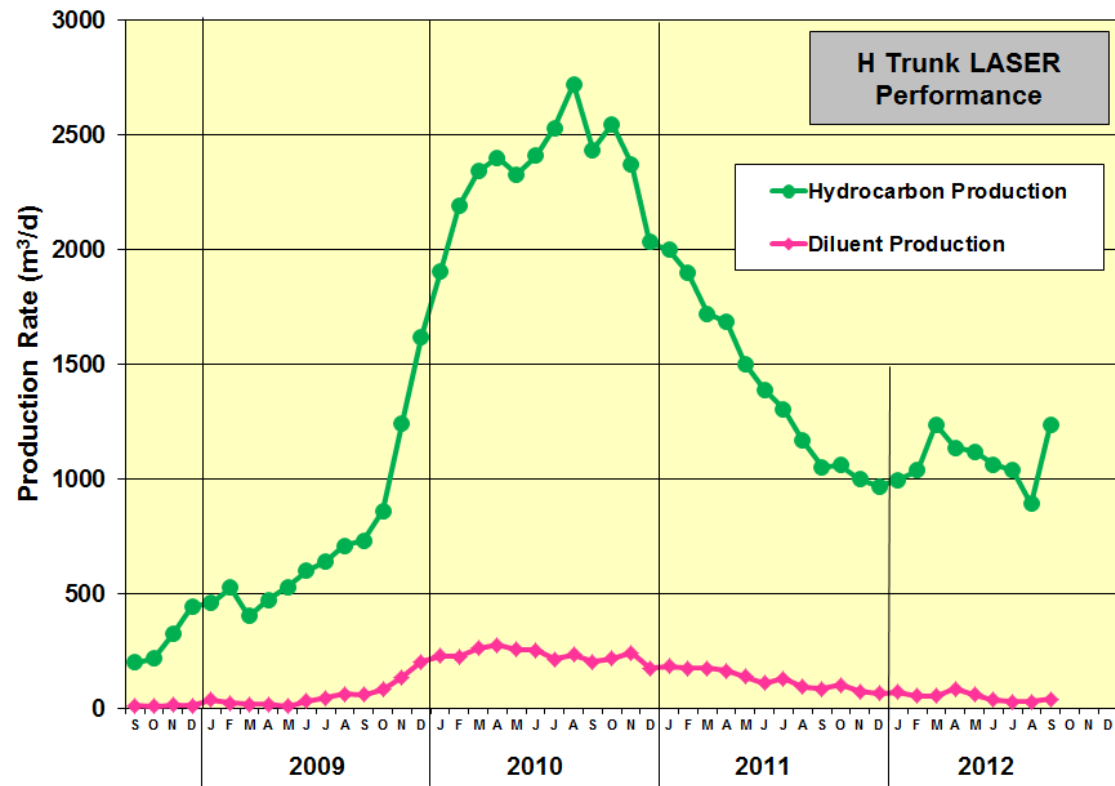
Cumulative (km ³)	to 09/30/2012
Steam Injection	6,246
Diluent Injection	297

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	

Cycle 2 LASER H Trunk - Production Performance

Background

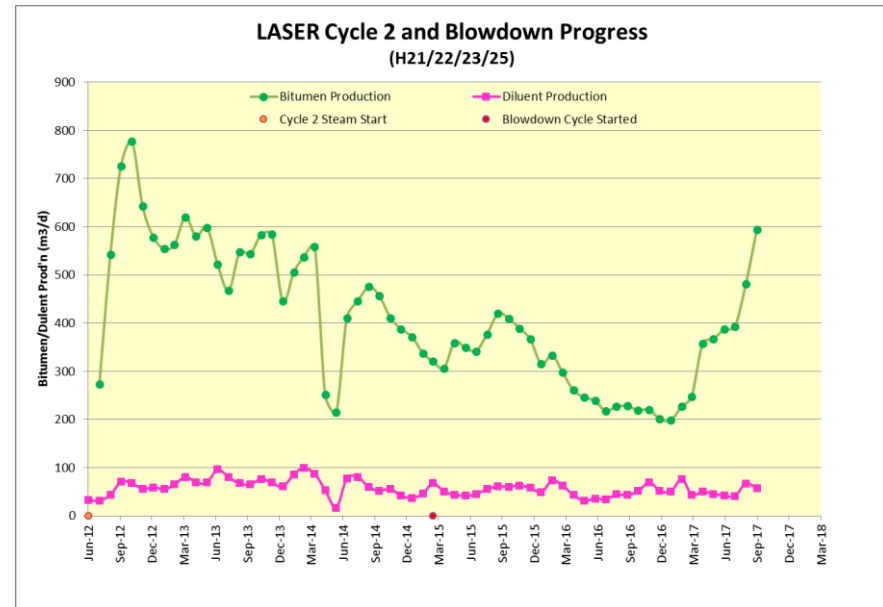
- H21, H22, H23 and H25 steamed with diluent for cycle 2
- 2nd Cycle injection focus strictly on CSS strategy
- Focus on longer term performance understanding

Injection

- Steamed with diluent from Sept - Dec 2012
- Total steam injection - 1638 km³
- Total diluent injection – 77 km³ (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 in Cycle 2: 534 km³
- Diluent recovery to date: 281 km³
- 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% by the end of the cycle
- The four pads went into a blowdown cycle (March 2015) 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 for cycle 1 & 2 is 75%.
- H22 infills into H21, H23, H25 pads were first steamed in late 2016 through 2017. The increased production due to the infill steam is evident in the chart above.



Production Data to Date:

Updated to 10/01/2017	Cycle 1	Cycle 2	Blowdown
Cycle Start	May 2007	Jul 2012	Mar 2015
Diluent Injection	297	77	0
Diluent production	174	58	47
Cumulative Diluent Recovery	59%	62%	75%

Mahihkan North LASER – Cycle 1

Background

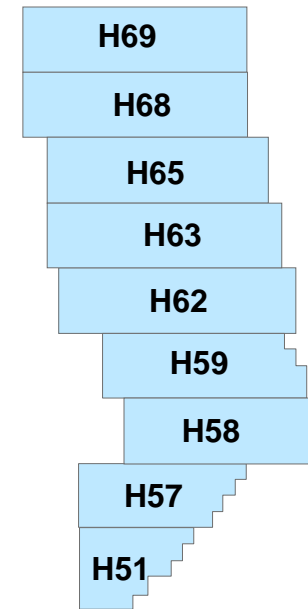
- Cycle 1 of LASER on 9 Mahihkan North pads (H51, H57, H58, H59, H62, H63, H65, H68, H69) has commenced
- First application of LASER on 8-acre spacing pads

Injection

- Diluent injection started May 15, 2017 at H65 and H68 pads
- A total of 1,787 km³ of steam and 74 km³ of diluent has been injected across H65, H68 and H69 pads through the end of September 2017.
- The average diluent concentration to date has been 4.1% (by steam volume).

Production Performance

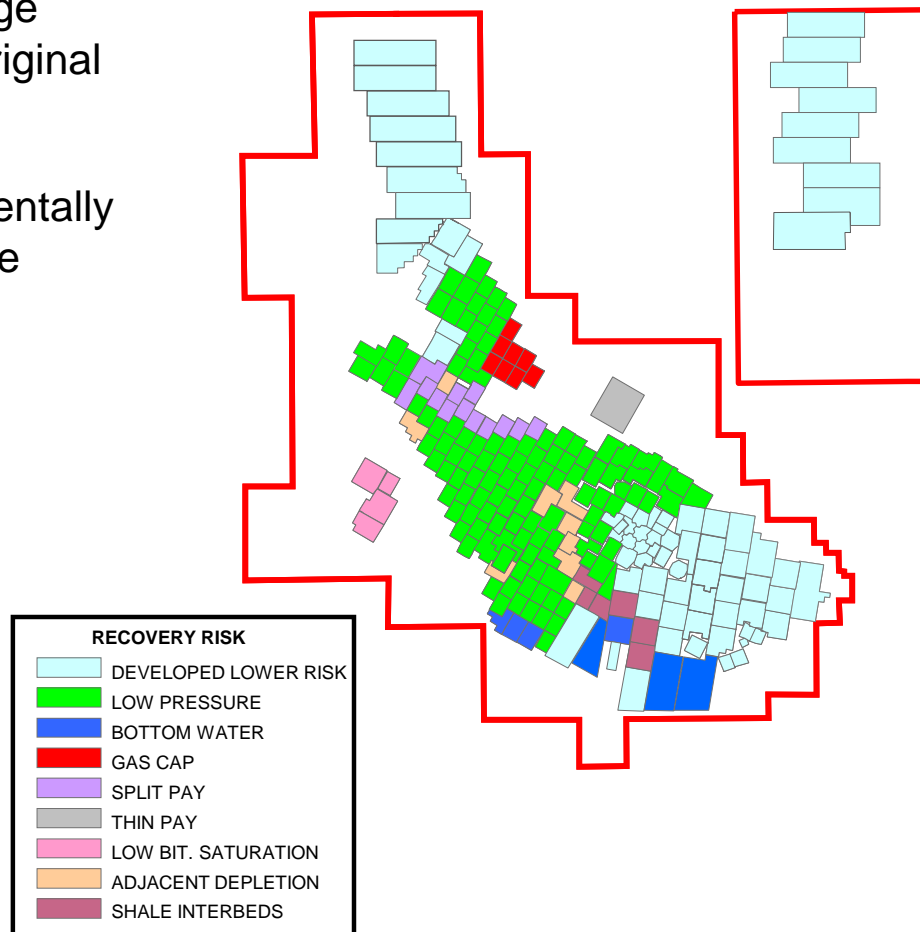
- It is very early in the production cycle of the first pads, and most wells are still in the initial flow-back stage of the production cycle
- Diluent production sampling to quantify the amount of reproduced diluent is occurring as planned



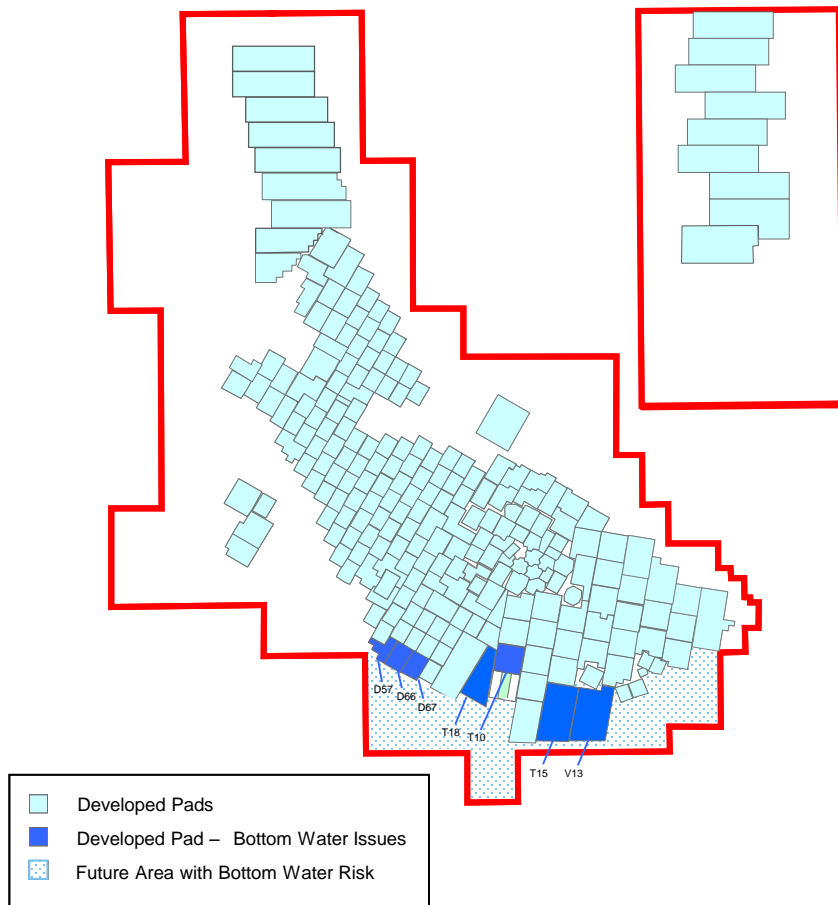
Factors Impacting Recovery

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



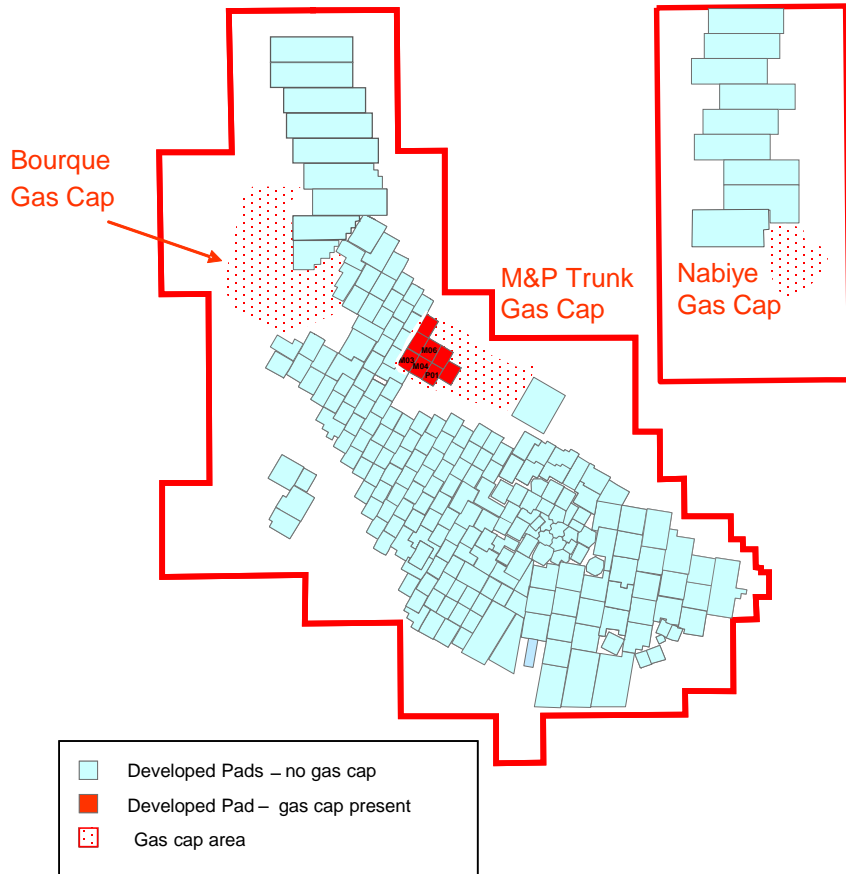
• Performance issues:

- Bottom water is a thief zone for steam injection
- High mobility water excludes bitumen production

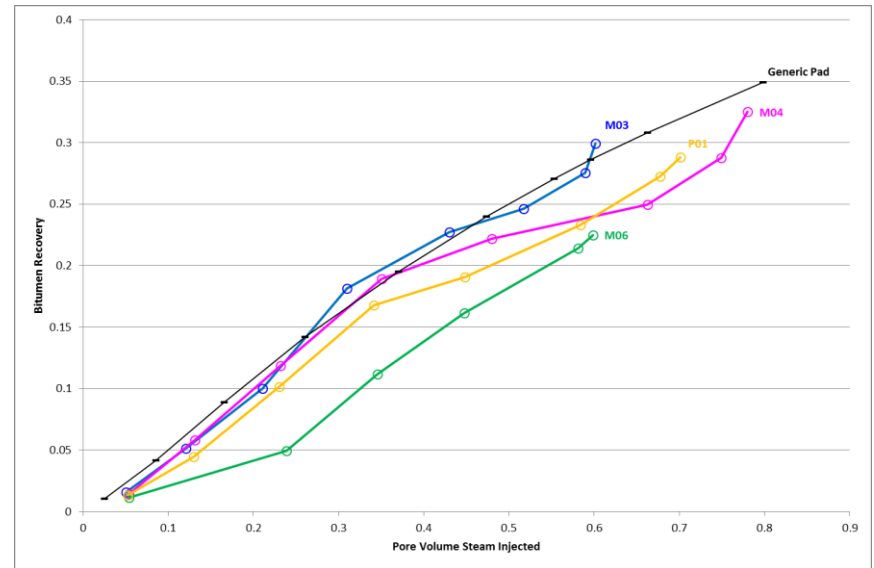
• Mitigation

- 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



Performance of Gas Cap Pads

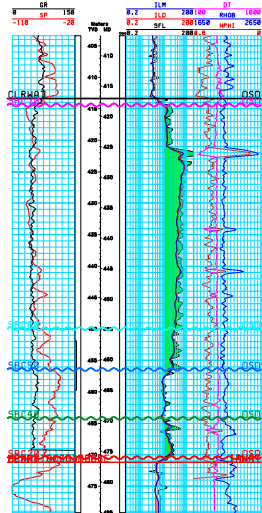


- Three significant Clearwater gas cap areas
 - M&P Trunk – producing
 - Bourque Lake gas cap – undeveloped
 - South Nabiye - undeveloped
- M&P Trunk pads exhibited poorer performance due to pressure losses to the gas cap
- Steaming all pads under a gas cap together reduces steam losses and improves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

CSS Performance - Split Pay

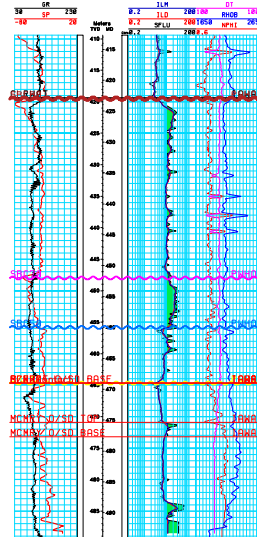
Thick Continuous Pay

UWI# 104031106504400
 Name# D07-08 #1 04/3-11
 ELEV# KB 600.8 METERS
 TD# 479.2 METERS TVD

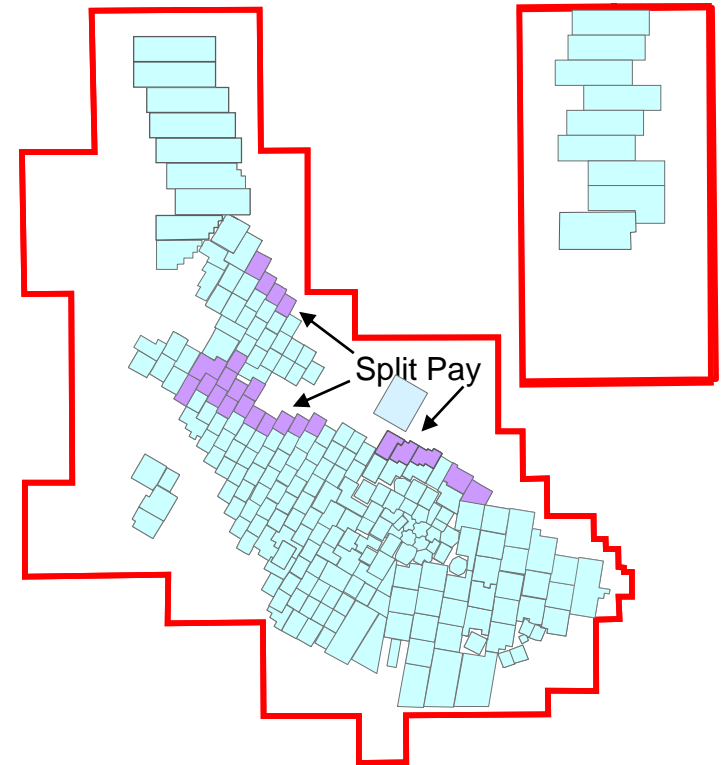


Thin Split Pay

UWI# 100112406504400
 Name# R08-08 #1 11-24
 ELEV# KB 613.4 METERS
 TD# 489.2 METERS TVD



Interbedded sequence

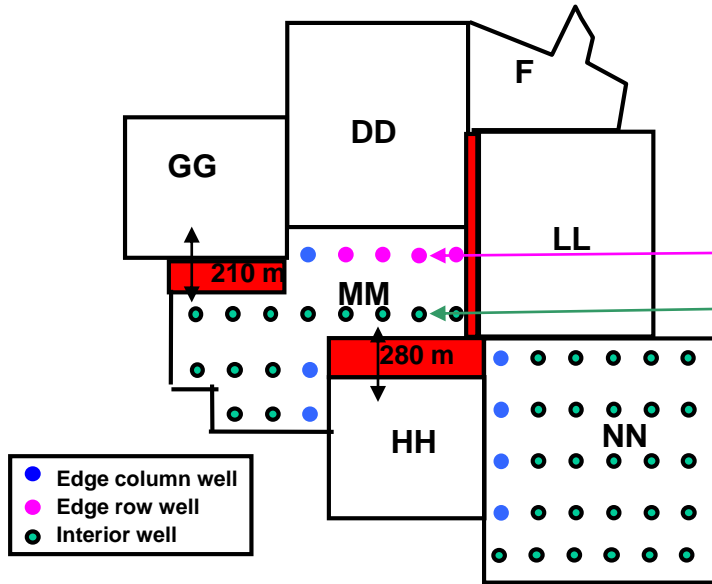


- Split pay occurs where an interbedded sequence has cut through lower reservoir sequences
- Interbedded sands and shales act as vertical permeability barrier between lower reservoir sequences and good quality sand in upper sequence

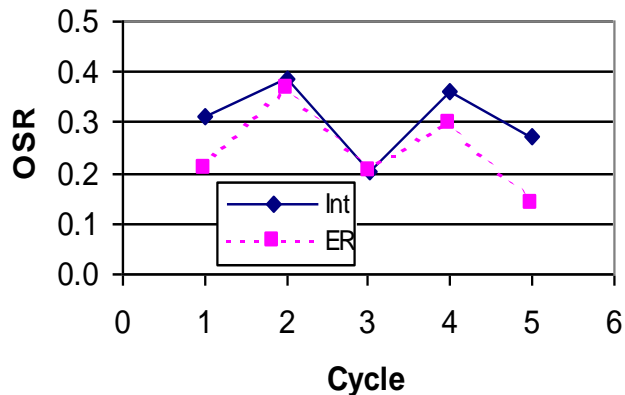
- Upper zone can be accessed through recompletion after lower zone depletion
- Concurrent depletion trials with limited entry perforations resulted in poor inflow performance
- Thin zones have substantially lower recovery due to heat losses to surrounding non-reservoir rock
- Split pay can be used to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

Adjacent to Depletion Example- MM Pad

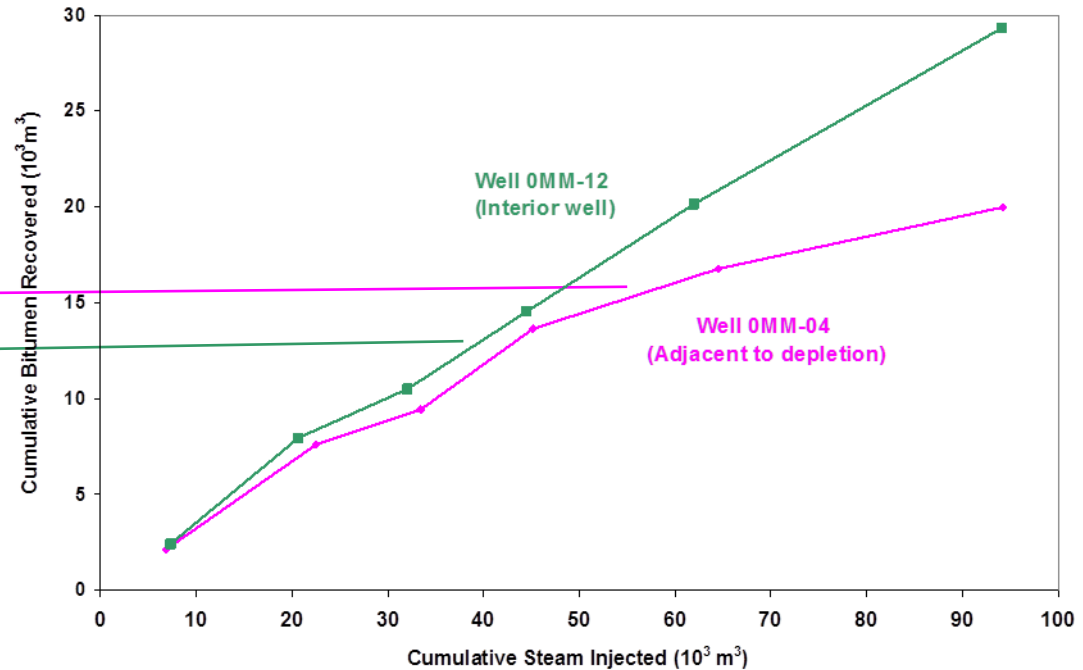
- MM pad is adjacent to depletion in DD pad which acts as thief zone for steam



0MM - OSR

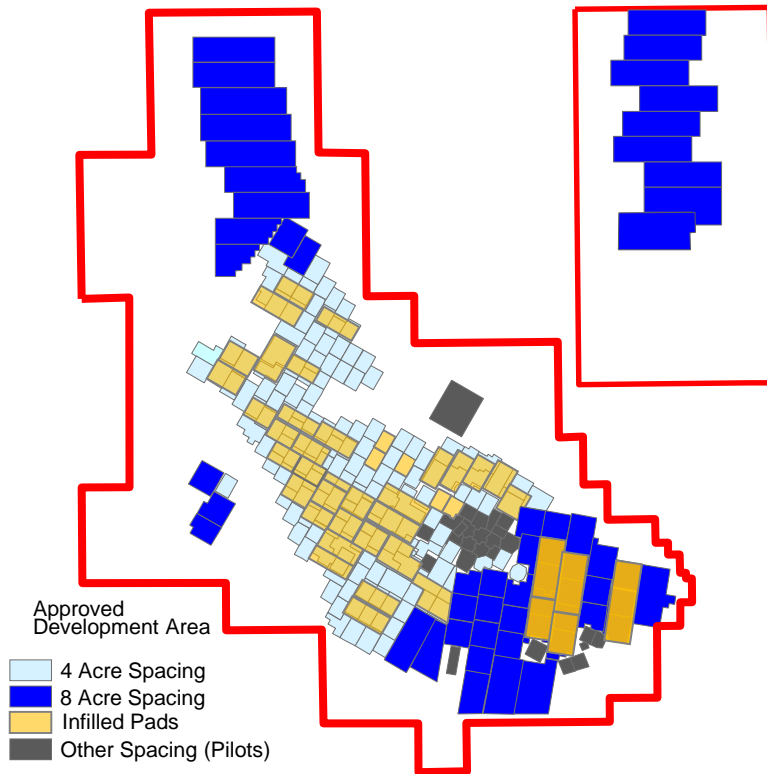


Performance Comparison - Adjacent Depletion



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

Well Spacing



Infill Drilling

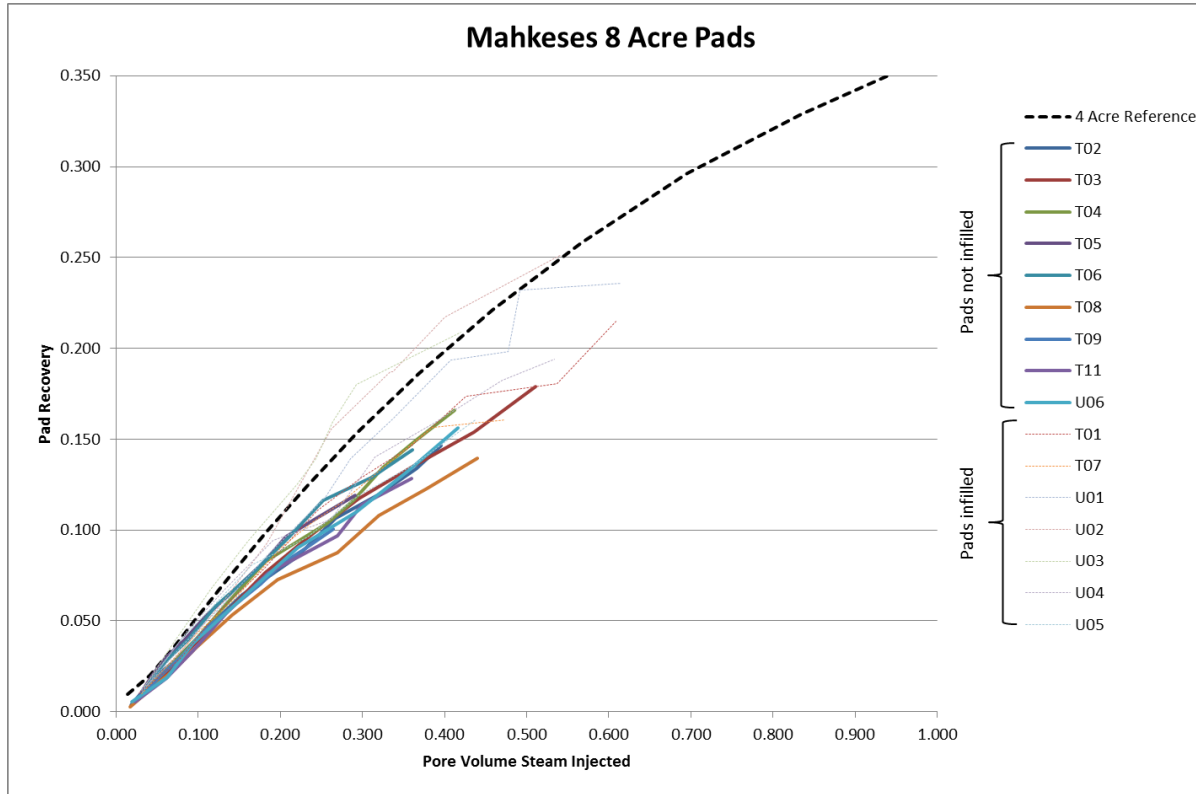
- Where economic, horizontal injector-only-infills are drilled between the rows of wells at mature pads
- Infill steam is directed to bypassed bitumen to increase recovery by 15 to 30% relative to CSS
- Infill steam injection volumes per pad are similar to CSS volumes

- 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 2}
 - > Cycle 1 8,000 m³
 - > Cycle 2 7,000 m³
 - > Cycle 3 8,000 m³
- 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 m³ (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

¹11 Acre Spacing steam strategy approved by the ERCB in July 2011 allowing for 12,000 m³ over fill-up per cycle.

²Cycle 1 volumes are limited to 5,000 m³ per effective bottom-hole spacing at Nabiye

Impact of Well Spacing on Recovery



- 4 acre performance curve shown for equivalent resource to Mahkeses 8-acre pads
- Most mature Mahkeses pads not sufficiently depleted to validate ultimate recovery expectations

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
00A	30	0.67	1184	193,591	152	13%	EUR = Recovery to date
00B	27	0.68	1772	231,800	126	7%	EUR = Recovery to date
00C	25	0.68	1559	211,035	216	14%	EUR = Recovery to date
00D	29	0.67	1236	169,839	212	17%	EUR = Recovery to date
00E	28	0.69	1257	207,993	150	12%	EUR = Recovery to date
00F	22	0.68	1079	152,336	233	22%	EUR = Recovery to date
00G	29	0.67	2097	262,431	358	17%	EUR = Recovery to date
00H	28	0.69	2010	257,344	291	14%	EUR = Recovery to date
00J	36	0.68	850	134,339	249	29%	EUR = Recovery to date
00K	31	0.70	1905	233,962	489	26%	EUR = Recovery to date
00L	35	0.72	2019	280,504	450	22%	EUR = Recovery to date
00M	26	0.66	982	129,945	68	7%	EUR = Recovery to date
00N	28	0.67	1648	245,719	490	30%	EUR = Recovery to date
00P	32	0.69	2341	331,516	714	30%	EUR = Recovery to date
00Q	35	0.73	1988	220,552	342	17%	EUR = Recovery to date
00R	33	0.71	1764	210,698	116	7%	EUR = Recovery to date
00S	26	0.68	1174	135,701	136	12%	EUR = Recovery to date
00T	35	0.70	2644	381,551	846	32%	EUR = Recovery to date
00U	28	0.76	2122	311,961	1031	49%	49% - 50%
00V	29	0.74	2301	339,636	745	32%	40% - 45%
00W	30	0.66	2103	337,998	1341	64%	65% - 70%
0AA	30	0.69	2533	348,059	1115	44%	EUR = Recovery to date
0BB	32	0.66	2191	324,732	1619	74%	75% - 80%
0CC	34	0.71	2546	302,957	941	37%	37% - 40%
0DD	27	0.66	1883	356,675	920	49%	49% - 50%
0EE	36	0.72	1854	273,856	575	31%	EUR = Recovery to date
0FF	34	0.70	1909	248,143	1139	60%	60% - 65%
0GG	27	0.72	1403	229,132	511	36%	36% - 40%
0HF	20	0.72	297	60,352	102	34%	EUR = Recovery to date
0HH	25	0.69	1210	218,243	628	52%	52% - 55%
0LL	24	0.70	1734	327,247	732	42%	42% - 45%
0MA	27	0.73	1454	202,030	126	9%	EUR = Recovery to date
0MB	29	0.70	1942	251,322	452	23%	EUR = Recovery to date
0MC	26	0.78	1087	206,478	496	46%	EUR = Recovery to date
0MD	30	0.73	816	209,255	496	61%	EUR = Recovery to date
0ME	31	0.71	2276	352,968	533	23%	EUR = Recovery to date

- Pad production updated to September 2016
- Pad EBIPs changes are due to a new geological model
- E07 and D29 pad combined as they are now depleted by one set of horizontal wells
- Effective OBIP (Original Oil in Place) is volume of bitumen >8 wt% between top of Effective Pay and base of Effective Pay

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
OMM	23	0.69	1659	336,044	662	40%	40% - 45%
ONN	24	0.69	2613	521,709	955	37%	40% - 45%
A01	31	0.69	2230	326,575	954	43%	43% - 45%
A02	34	0.69	2486	334,641	984	40%	45% - 50%
A03	31	0.69	2235	335,477	970	43%	43% - 45%
A04	35	0.77	2837	330,758	1298	46%	50% - 55%
A05	28	0.69	1980	326,066	795	40%	40% - 45%
A06	32	0.73	2554	335,476	993	39%	39% - 40%
B01	28	0.69	2058	327,676	938	46%	46% - 50%
B02	26	0.74	2045	327,521	1023	50%	50% - 55%
B03	28	0.73	2104	325,540	876	42%	50% - 55%
B04	27	0.70	2005	339,121	981	49%	49% - 55%
B05	27	0.70	1998	326,038	1452	73%	73% - 75%
B06	27	0.70	2013	329,908	1048	52%	52% - 55%
C01	30	0.69	2150	330,162	876	41%	41% - 45%
C02	26	0.71	1984	328,513	1104	56%	56% - 60%
C03	32	0.73	2405	324,721	1367	57%	65% - 70%
C04	26	0.73	1971	339,736	911	46%	50% - 55%
C05	26	0.72	1946	326,483	792	41%	41% - 45%
C08	34	0.70	5074	654,866	1001	20%	50% - 60%
D01	30	0.69	2199	329,560	957	44%	45% - 50%
D02	31	0.70	2233	327,006	760	34%	45% - 55%
D03	39	0.70	2818	318,726	1154	41%	41% - 50%
D04	41	0.76	3269	331,740	1521	47%	50% - 60%
D05	38	0.75	2956	325,578	1579	53%	55% - 65%
D06	48	0.81	3980	322,502	2677	67%	75% - 80%
D07	42	0.78	3498	330,569	2010	57%	60% - 70%
D09	40	0.79	3305	330,529	2238	68%	75% - 80%
D10	41	0.78	3307	325,822	1871	57%	57% - 65%
D11	24	0.71	2431	319,000	80	3%	EUR = Recovery to date
D12	28	0.71	2135	337,254	559	26%	26% - 35%
D21	28	0.68	2014	328,433	718	36%	45% - 50%
D22	34	0.75	2659	331,754	1263	48%	50% - 55%
D23	40	0.72	2934	321,196	1311	45%	50% - 60%
D24	29	0.67	2007	325,503	859	43%	50% - 55%
D25	35	0.72	2597	326,409	1175	45%	45% - 50%

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
D26	37	0.79	3021	325,318	1538	51%	51% - 55%
D27	34	0.72	2562	324,687	964	38%	38% - 40%
D28	30	0.68	2430	356,683	681	28%	40% - 50%
D31	42	0.76	5743	561,922	1991	35%	50% - 65%
D33	36	0.75	4385	499,814	1723	39%	55% - 70%
D35	38	0.73	3427	368,988	904	26%	50% - 60%
D36	34	0.76	3447	431,876	1038	30%	50% - 60%
D39	32	0.69	3867	555,722	945	24%	40% - 50%
D51	36	0.80	3019	332,199	1117	37%	50% - 70%
D52	36	0.76	2904	333,491	789	27%	27% - 30%
D53	33	0.74	2610	345,284	1367	52%	55% - 65%
D54	23	0.69	1705	334,858	644	38%	38% - 40%
D55	19	0.68	1363	327,587	649	48%	48% - 50%
D57	9	0.68	769	380,454	97	13%	13% - 15%
D62	33	0.76	2563	315,544	1251	49%	55% - 65%
D63	30	0.70	2213	333,936	1019	46%	55% - 65%
D64	32	0.76	2499	316,147	1356	54%	55% - 65%
D65	30	0.75	2427	331,446	1018	42%	50% - 60%
D66	13	0.73	1498	494,818	187	12%	EUR = Recovery to date
D67	27	0.74	3180	496,595	668	21%	25% - 35%
E01	30	0.67	3179	514,745	1044	33%	50% - 60%
E02	27	0.68	2321	409,248	857	37%	40% - 50%
E03	29	0.67	2025	320,130	798	39%	40% - 50%
E04	31	0.68	2293	343,432	768	33%	50% - 65%
E05	31	0.67	3843	583,592	1002	26%	50% - 60%
E07	34	0.68	2438	330,043	263	11%	20% - 25%
E08	24	0.67	1734	328,747	591	34%	40% - 45%
E09	26	0.73	1971	330,440	684	35%	35% - 40%
E10	25	0.74	1946	330,934	619	32%	35% - 40%
E11	20	0.71	8736	1,846,967	1104	13%	35% - 50%
F01	27	0.70	2770	454,370	953	34%	35% - 40%
F02	20	0.70	2174	484,521	749	34%	35% - 40%
F03	28	0.71	3166	490,118	1310	41%	45% - 55%
F04	20	0.69	2242	494,641	992	44%	45% - 55%
F05	27	0.74	2995	468,232	1506	50%	55% - 65%

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
F06	19	0.72	2141	482,036	911	43%	45% - 50%
F07	27	0.70	3282	541,922	1325	40%	50% - 60%
F08	9	0.70	2687	1,156,520	395	15%	15% - 25%
G01	30	0.73	3852	559,883	1573	41%	50% - 60%
G02	21	0.69	2585	573,215	1003	39%	50% - 55%
G03	15	0.67	1734	561,124	1055	61%	61% - 65%
H01	35	0.75	2763	329,061	1863	67%	70% - 75%
H02	25	0.75	1949	328,573	1149	59%	59% - 65%
H03	15	0.67	1048	328,976	447	43%	45% - 50%
H04	17	0.71	1249	326,043	511	41%	50% - 55%
H05	21	0.70	1547	330,248	339	22%	25% - 30%
H06	31	0.67	2213	327,229	147	7%	07% - 10%
H10	17	0.67	2101	562,300	585	28%	30% - 35%
H11	20	0.71	2234	488,848	1242	56%	60% - 70%
H14	28	0.68	2043	330,480	366	18%	20% - 25%
H15	28	0.72	3079	483,319	1161	38%	38% - 45%
H16	30	0.74	2366	331,325	930	39%	45% - 50%
H18	34	0.77	2718	329,107	819	30%	35% - 45%
H19	26	0.77	2074	331,169	1064	51%	65% - 70%
H21	30	0.76	2421	329,180	1137	47%	60% - 65%
H22	34	0.77	2720	327,643	1287	47%	50% - 60%
H23	34	0.77	4105	491,422	1968	48%	65% - 70%
H24	29	0.77	2332	327,075	723	31%	31% - 35%
H25	32	0.76	3786	489,048	1752	46%	60% - 65%
H26	29	0.78	3574	493,206	1009	28%	30% - 35%
H27	33	0.79	4048	489,320	1369	34%	45% - 50%
H31	28	0.75	2161	327,260	834	39%	45% - 50%
H32	29	0.74	2208	326,110	657	30%	30% - 40%
H33	26	0.71	1923	329,580	556	29%	35% - 40%
H34	20	0.72	1460	322,027	323	22%	22% - 25%
H35	19	0.71	1447	329,729	326	23%	25% - 35%
H36	22	0.72	1664	330,145	353	21%	21% - 25%
H37	16	0.72	1838	491,579	511	28%	28% - 30%
H39	22	0.74	3892	822,158	519	13%	40% - 50%
H40	33	0.69	2949	411,352	787	27%	45% - 55%
H41	27	0.73	4939	820,397	1679	34%	60% - 65%

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
H42	28	0.73	3181	481,582	1302	41%	55% - 65%
H45	32	0.75	4343	606,922	842	19%	30% - 40%
H46	26	0.72	3557	598,473	1350	38%	50% - 65%
H47	22	0.73	4901	984,121	1033	21%	50% - 65%
H51	25	0.72	6700	1,178,021	845	13%	35% - 50%
H57	21	0.72	8733	1,768,000	1028	12%	35% - 55%
H58	18	0.68	8726	#N/A	1944	22%	40% - 50%
H59	18	0.70	9191	#N/A	1868	20%	30% - 45%
H62	15	0.69	9144	2,734,667	1245	14%	20% - 35%
H63	11	0.67	6798	2,742,767	1046	15%	15% - 35%
H65	12	0.67	7266	2,641,134	1274	18%	18% - 30%
H68	13	0.68	7016	2,490,035	986	14%	20% - 35%
H69	13	0.68	7816	2,630,744	673	9%	20% - 35%
J01	38	0.77	3002	322,674	2112	70%	72% - 75%
J02	25	0.76	1926	319,882	1280	66%	70% - 80%
J03	31	0.78	2576	334,676	1682	65%	70% - 75%
J04	35	0.78	2804	323,742	1753	63%	63% - 65%
J05	20	0.74	1515	326,851	796	53%	53% - 55%
J06	31	0.74	2451	338,008	958	39%	40% - 45%
J07	28	0.75	2147	325,143	1734	81%	81% - 83%
J08	34	0.83	3027	331,895	2566	85%	85% - 87%
J10	36	0.83	3068	318,930	2059	67%	70% - 73%
J11	37	0.80	3136	316,976	1284	41%	41% - 45%
J12	34	0.80	2773	309,991	1848	67%	67% - 70%
J13	40	0.86	3480	310,583	2413	69%	70% - 75%
J14	43	0.82	3692	335,978	1635	44%	65% - 70%
J15	39	0.84	3356	321,799	2366	71%	71% - 75%
J16	41	0.82	3424	315,616	1974	58%	65% - 70%
J21	32	0.78	2584	342,840	1361	53%	53% - 60%
J25	30	0.75	2358	324,313	796	34%	34% - 40%
J27	25	0.80	2080	328,353	395	19%	20% - 25%
K22	22	0.65	1526	329,325	516	34%	34% - 35%
K23	15	0.65	2648	848,469	677	26%	26% - 30%
K24	11	0.65	1897	809,848	507	27%	27% - 30%
K26	14	0.66	1954	645,847	288	15%	15% - 20%
L05	27	0.67	2831	495,108	1244	44%	50% - 60%

Pad Recovery

Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
L06	20	0.72	2234	490,761	1533	69%	70% - 75%
L07	20	0.74	2382	501,860	1453	61%	61% - 65%
L08	8	0.65	812	473,030	475	58%	60% - 65%
L09	24	0.66	2332	540,745	300	13%	25% - 30%
L11	25	0.69	2755	489,823	1387	50%	55% - 65%
M03	36	0.75	2807	327,035	843	30%	30% - 35%
M04	32	0.76	2599	330,753	842	32%	35% - 45%
M05	26	0.73	1998	327,665	482	24%	25% - 35%
M06	25	0.73	1977	333,545	456	23%	25% - 30%
M07	20	0.68	1454	328,371	285	20%	20% - 25%
N01	20	0.73	11101	2,407,368	538	5%	20% - 35%
N02	16	0.71	8621	2,409,732	297	3%	15% - 30%
N03	15	0.71	7777	2,401,245	211	3%	15% - 30%
N04	13	0.74	7589	2,399,090	313	4%	20% - 35%
N05	14	0.76	7828	2,396,682	277	4%	20% - 35%
N06	13	0.74	6383	2,119,119	227	4%	20% - 35%
N07	14	0.71	6878	2,200,195	215	3%	20% - 35%
N08	13	0.69	9307	2,736,576	201	2%	20% - 35%
N09	12	0.66	9179	3,464,504	0	0%	15% - 30%
P01	35	0.77	2730	317,709	789	29%	30% - 35%
P02	25	0.73	1894	317,130	347	18%	20% - 25%
P03	28	0.76	2255	329,951	487	22%	22% - 25%
R01	32	0.74	2410	313,829	1093	45%	50% - 55%
R02	32	0.71	2341	317,549	793	34%	45% - 55%
R03	35	0.68	2580	336,378	755	29%	35% - 40%
R04	28	0.70	2089	332,424	489	23%	25% - 30%
R05	24	0.68	1734	325,946	613	35%	45% - 50%
R06	17	0.71	1293	324,779	466	36%	36% - 40%
R07	22	0.71	1631	337,454	651	40%	40% - 40%
T01	28	0.72	4759	743,062	983	21%	40% - 50%
T02	29	0.71	5216	806,525	768	15%	35% - 45%
T03	23	0.70	3997	775,850	726	18%	25% - 35%
T04	23	0.68	3908	775,056	657	17%	25% - 35%
T05	31	0.69	5528	774,841	705	13%	25% - 35%
T06	29	0.70	4696	710,449	712	15%	40% - 50%
T07	33	0.72	5676	745,035	888	16%	35% - 45%

Pad Recovery

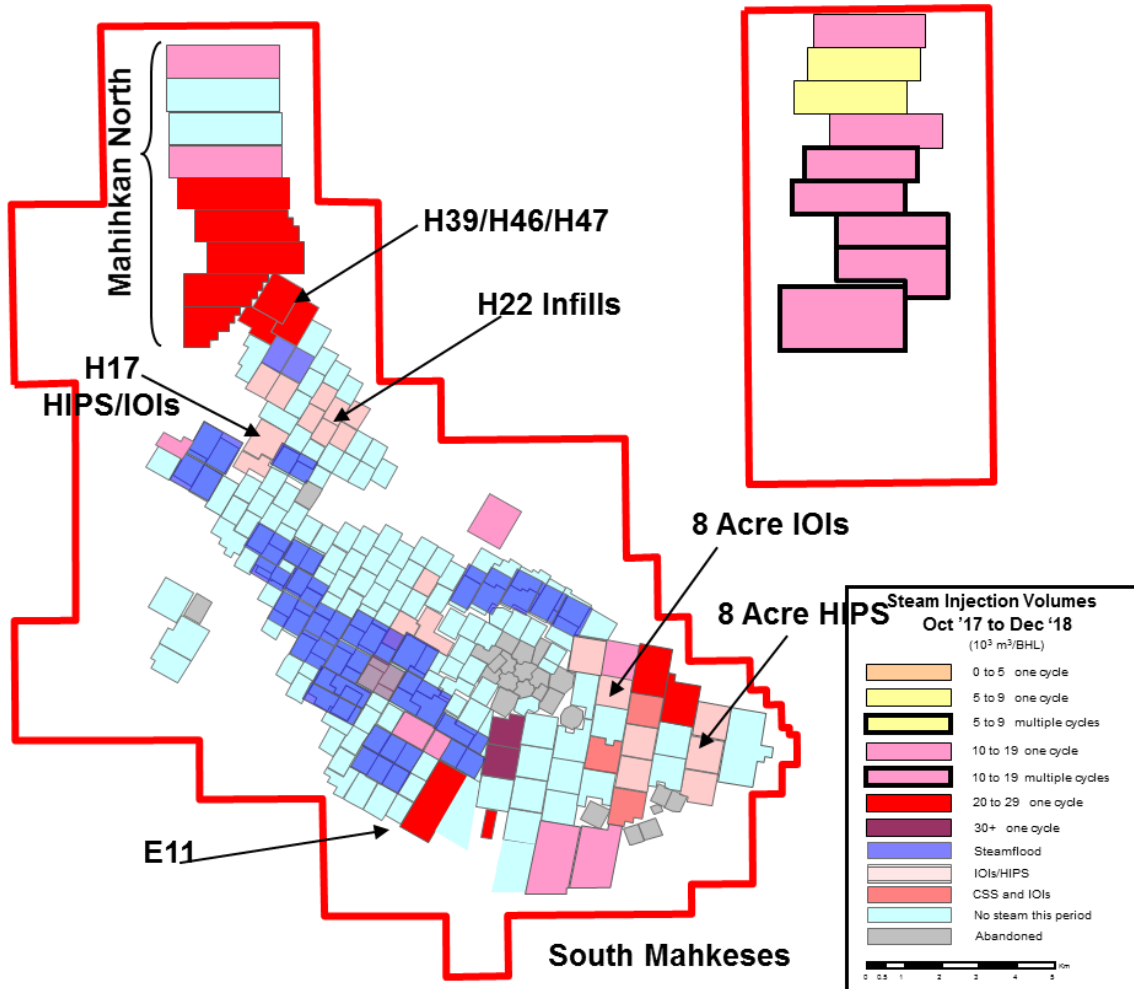
Pad	Net Pay (m)	Average Effective So	Effective OBIP (e3m3)	Drainage Area (m2)	Recovery to Sept 2016		Ultimate Recovery (% EBIP)
					e3m3	% EBIP	
T08	30	0.72	5401	774,990	755	14%	35% - 45%
T09	29	0.70	5005	775,378	530	11%	35% - 45%
T10	35	0.70	5996	774,721	583	10%	30% - 40%
T11	26	0.70	4499	774,660	637	14%	20% - 30%
T12	26	0.70	4553	775,105	653	14%	20% - 30%
T13	27	0.67	1489	777,953	191	13%	25% - 35%
T14	19	0.72	6287	1,404,366	719	11%	25% - 40%
T15	19	0.72	9624	2,275,165	834	9%	25% - 40%
T18	18	0.69	5366	1,129,443	369	7%	25% - 40%
U01	26	0.70	4668	809,886	1083	23%	40% - 50%
U02	23	0.67	3772	777,104	937	25%	45% - 60%
U03	29	0.69	4931	775,924	1005	20%	50% - 65%
U04	30	0.72	5162	742,187	943	18%	35% - 50%
U05	33	0.71	5912	805,485	912	15%	35% - 45%
U06	23	0.68	3840	776,382	660	17%	25% - 30%
U07	22	0.68	5617	1,177,350	679	12%	20% - 30%
U08	20	0.68	4523	1,052,598	782	17%	25% - 40%
U09	21	0.69	3822	824,646	641	17%	30% - 45%
V01	29	0.69	4915	775,459	1003	20%	40% - 50%
V02	29	0.72	5226	775,578	868	17%	25% - 35%
V03	24	0.71	4454	807,966	697	16%	20% - 30%
V04	29	0.71	4934	740,131	1018	21%	40% - 55%
V05	27	0.67	4666	790,676	974	21%	40% - 55%
V08	30	0.72	5380	775,455	946	18%	40% - 55%
V09	27	0.77	4978	740,326	880	18%	40% - 50%
V10	20	0.71	8774	2,046,491	1249	14%	25% - 40%
V13	18	0.71	8516	2,003,100	700	8%	20% - 30%
Y16	29	0.67	2444	439,317	802	33%	40% - 50%
Y31	30	0.67	2146	326,381	663	31%	40% - 50%
Y32	35	0.67	2539	328,955	268	11%	45% - 50%
Y34	29	0.68	2123	376,127	670	32%	40% - 45%
Y36	33	0.68	2917	437,859	774	27%	40% - 50%

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
- Steam patterns are developed to balance cycle timing optimization, shear stress management and interwell communication
- Additional factors
 - Setback requirements between drilling and steaming operations

Steam Plans to End 2018



• Mahkeses

- 8 acre Injector Only Infill (IOI) sweep (IOIs: U01, V01, V02, U04)
- 8 acre HIP Cycle 3 (V28/U09)
- CSS cycles at U02, U07, U06, U08, V13, V03, T15, T05, and T06
- T13 SA-SAGD

• Leming

- F, U, and Y-Trunk steamfloods
- Y32

• Maskwa

- A, D, E and F-Trunk steamfloods
- E11, F08 and D29
- D01 IOI+C08 Row 1 CSD
- C03 IOI

• Mahihkan

- H, J, and, R, and L-Trunk steamfloods
- Mahihkan North sweep (H69, H51, H57, H58, H59, H62, H63)
- CSS cycles at L09 and H39/H46/H47
- H41/H17 HIPS, H22 IOIs, H17 IOIs

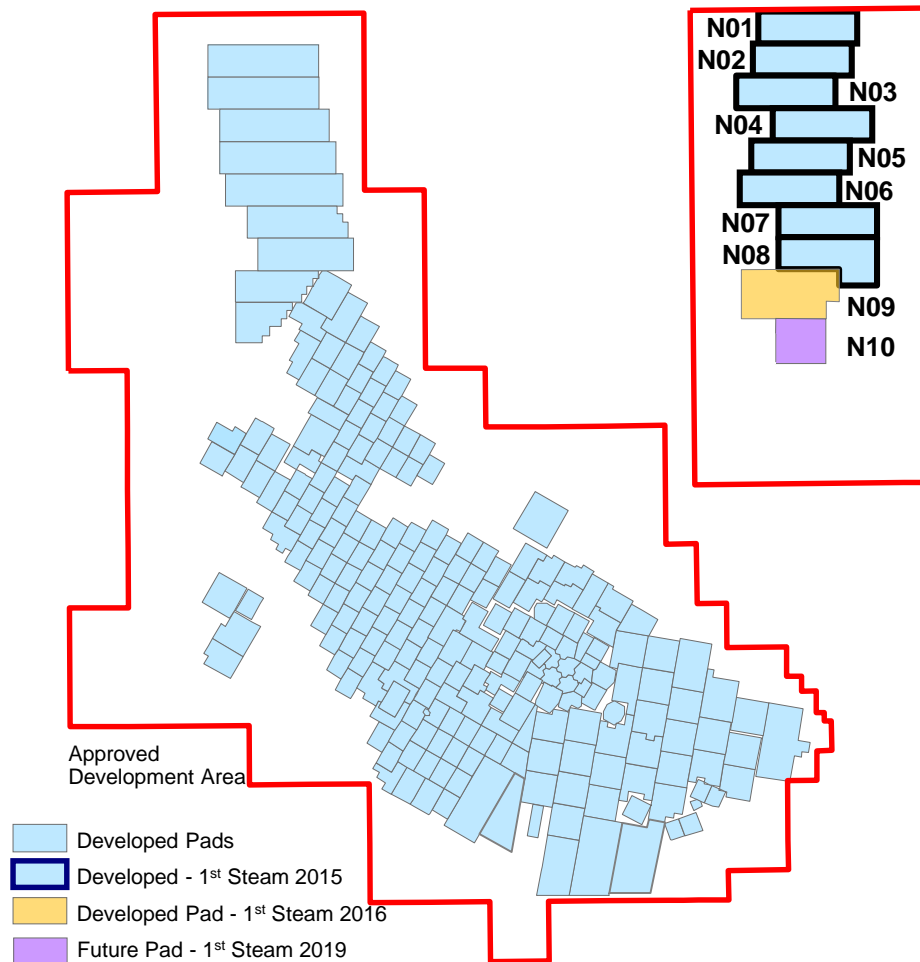
• Nabiye

- N01-N07 cycle 5 and/or 6 steaming
- N08 cycle 4 and 5 steaming
- N09 cycle 3 and 4

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	2018	2019

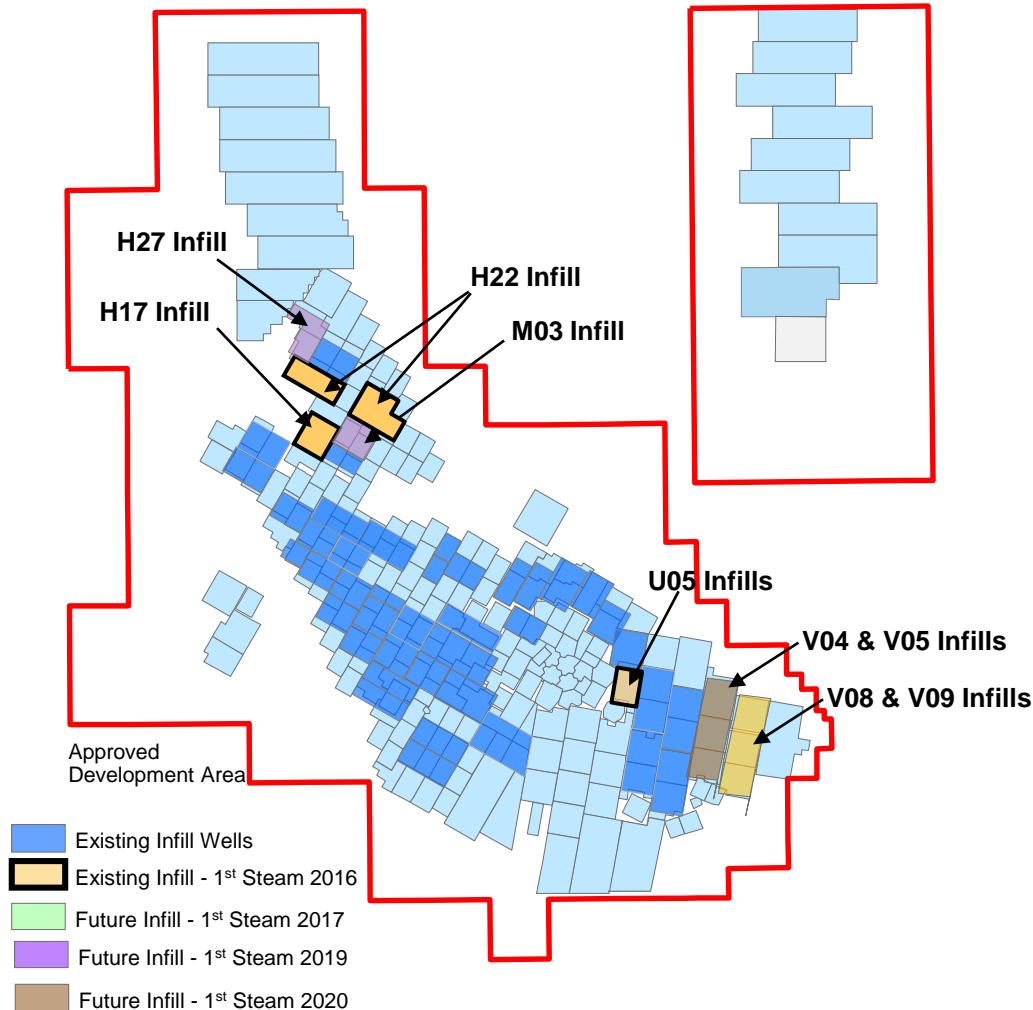


Extensive well repair program and positive steam flood performance has deferred previously planned pad development program

Infill Drilling Program

Drilling and Steaming Schedule

Infill Pad	Year Drilled	1st Steam
V08	2014	2016
V09	2014	2016
H17	2015	2016
H22	2015	2016
U05	2015	2016
M03	2018	2019
V04	2019	2020
V05	2019	2020
H27	2018	2019



T13 SA-SAGD Pilot

- Solvent Assisted - Steam Assisted Gravity Drainage (SA-SAGD)
- Pilot Design:
 - Two horizontal well pairs (WP)
 - Six observation wells (OB wells)
 - Injection and testing facilities
 - Located in Mahkeses Field

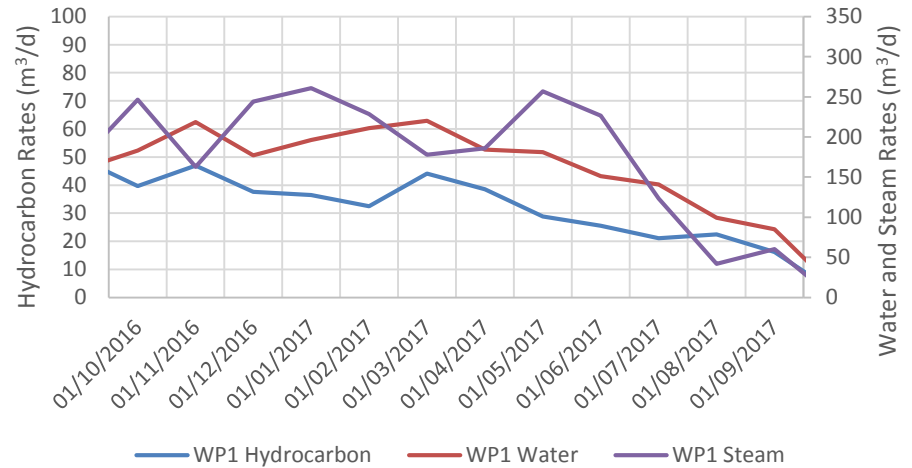
Key Milestones:

- Q4 2009: Pilot start-up
- 2010 - 2012: WP2 SA-SAGD, WP1 SAGD
- 2012 – 2016: WP2 SAGD, WP1 SA-SAGD
- 2016: WP2 Shut-in, WP1 SAGD

Key 2017 Events:

- WP2 - No injection, < 1 day production
- Q4 2016 – Q2 2017: WP1 Steam Chamber repressurized to ~ 3.6 MPa
- July 2017: Commenced new pilot stage by dropping operating pressure to ~ 3 MPa

T13 Well Pair 1 Production



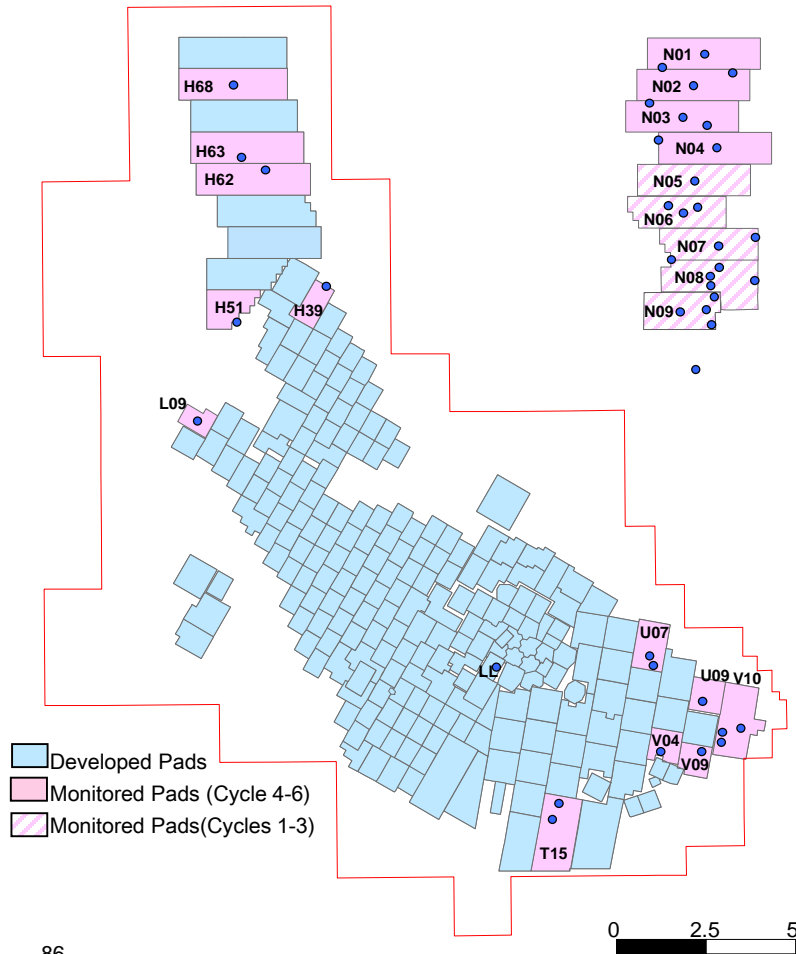
Key Performance Indicators

	Cumulative Production (km3)	OBIP (km3)	Bitumen Recovery to Date (%)	Expected Recovery (%)	Solvent Recovery (%)	
					WP1	WP2
T13	163	1062	15	40-50	71	87

Grand Rapids Monitoring Program

Objective

- Apply risk-based approach and monitor specific pads at Cold Lake for potential fluid excursions into the Grand Rapids formation.
- If excursion occurs, identify sources, determine volumes, notify AER, mitigate, and take steps to limit future fluid excursions.
- Cold Lake Commercial Scheme (8558II) amended Aug 2017 for Nabiye Operating Practices



Pad	Basis
U07	Elevated Upper Grand Rapids (UGR) pressure
U09	Elevated Lower Grand Rapids (LGR) pressure
V04	Increase monitoring network
V09	Increase monitoring network
V10	Poor primary cement bond log
T15	Potential cement channels
LL	Unsuccessful abandonment of adjacent OV well
L09	Control pad
H39	Increase monitoring network
H51	Possible ghost hole in the Grand Rapids
H62	Poor primary cement bond log
H63	Poor primary cement bond log
H68	Control pad
Nabiye	Geologic factors and proximity to FTS

U/V Trunk Grand Rapids Monitoring

Grand Rapids Monitoring Program

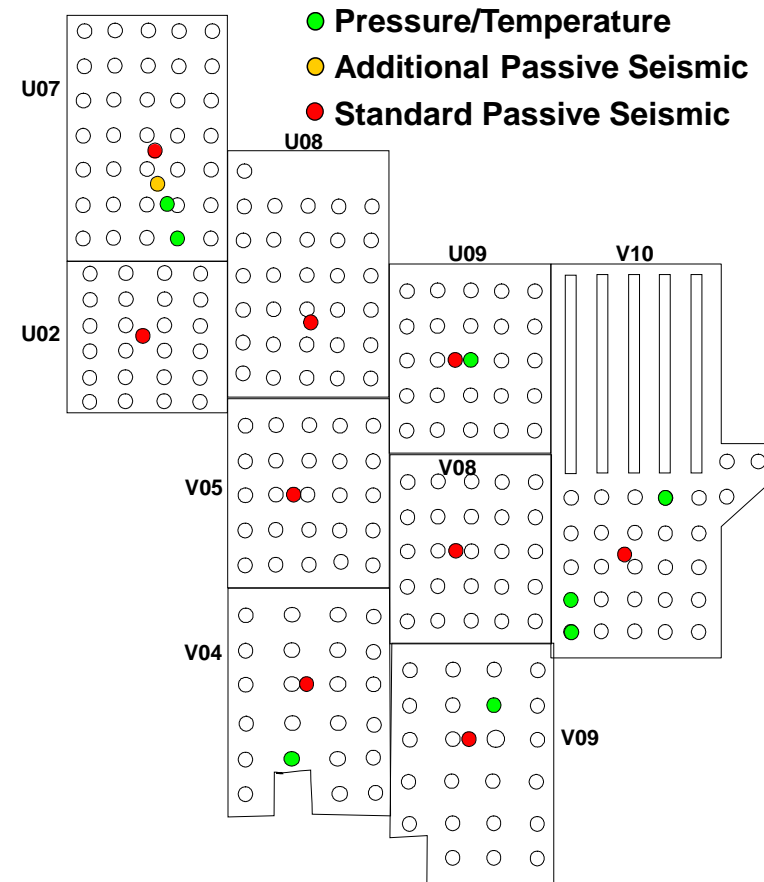
- All Pads:
 - Standard passive seismic
 - Steam injection rates and pressures
- U07: One pressure monitoring well in LGR and two wells in UGR, and one additional passive seismic well to monitor the Grand Rapids
- U09: Monitoring discontinued at U09-08 in 2016 and U09-13 recompleted as UGR/LGR pressure monitoring well
- V04: One pressure monitoring well in LGR
- V09: One pressure monitoring well in LGR
- V10: Three pressure monitoring wells, one in LGR and Clearwater (V10-05), two in LGR (V10-06/20)

Observations

- Pressure responses in the LGR and UGR observed at U07 in Cycle 2 and 3 were not observed in Cycle 4 when most likely source wells were selectively steamed. Poro-elastic response observed in Cycle 5 and minor fluid excursion observed at well U07-20 in Cycle 6 (2015) under Cold Lake steaming best practices.
- GR pressure responses at V10 diminished between cycles 2 – 6. Fluid excursion detected in Cycle 7 (2017).
- Pressure responses in the LGR and UGR observed at U09-13 during Cycle 8 steam. Poro-elastic response observed in UGR and a fluid excursion detected in the LGR.

Conclusions

- Previous conclusion that excursions are an early cycle phenomenon is challenged by recent observations of excursions on pads that had a number of cycles without excursions
- High pressures in UGR bitumen zones can be highly localized



Plans

- Steam all pads with high overlap strategy per Cold Lake best practices –including infill wells on U09, V08 and V09
- Continue monitoring the pressure response in the Grand Rapids

Mahihkan North Grand Rapids Monitoring

Grand Rapids Monitoring Program

- H39: 1 LGR & UGR pressure monitoring well
- H51: 1 LGR pressure monitoring well
- H62: 1 LGR pressure monitoring well
- H63: 1 LGR pressure monitoring well
- H68: 1 Hybrid Passive Seismic Well with LGR pressure monitoring

Observations

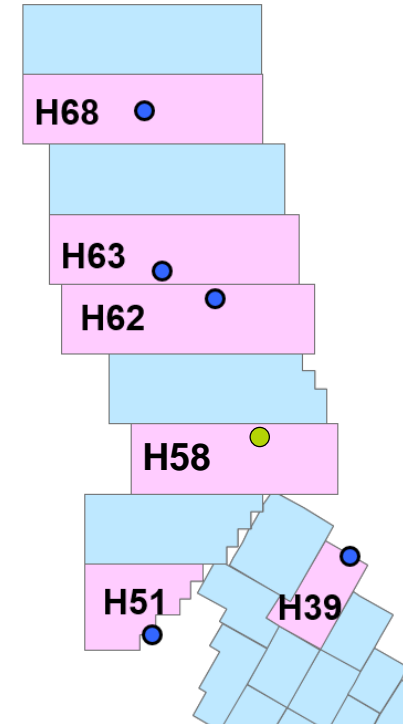
- H51 – Fluid excursion was detected in Cycle 7 (2015). Monitoring well re-perforated into higher quality Lower Grand Rapids water sand 13 metres above original perforations
- H62 – Fluid excursion was detected in Cycle 6 (2016)
- H63 – Only poro-elastic responses observed during steaming
- H68 – Possible excursion identified in Cycle 3 (2013). Poro-elastic responses observed during steaming Cycle 5 (2015). Fluid excursion was detected in Cycle 6 (2017)

Conclusions

- Cement channels on H62-H63 are not significant pathways for fluid excursions to the Grand Rapids

Plans

- Progress additional GR monitoring at H58



- Existing Monitoring Wells
- Planned Monitoring Wells

Nabiye Grand Rapids Practices

Factors that may impact fluid containment in the Clearwater formation at Nabiye

- Salt dissolution can create fractures in the overlying Clearwater shale
- Thicker overburden increases likelihood of vertical fracturing
- Presence of Mannville faults that intersect the Clearwater shale
- Proximity to CNRL Primrose East flow-to-surface events

Prevention Practices – Designed to prevent out-of-zone fluid excursions

- Reduced steam volume targets for all Nabiye pads compared to Cold Lake Best Practices when necessary
- Increased well spacing at Nabiye reduces uplift-induced stress changes in the Colorado shale
- Increased well spacing at Nabiye reduces risk of multi-well excursion event
- Proven drilling and cementing practices
- Nearby abandoned wells thoroughly reviewed and confirmed as being competent
- Extensive casing integrity program

Detection Practices – Designed to identify and locate excursions

- Pressure monitoring network of 25 wells covering 40 zones within the Grand Rapids
- Automated alarm system to detect rapidly changing pressure
- 4-D seismic surveys; first survey acquired across pads N01-N04, additional surveys planned for N01,N02,N07,N08 in 2018
- Passive seismic monitoring, well injectivity monitoring and casing integrity verification

Response Practices – Designed to minimize the volume of excursions

- Identify suspect steaming wells which are then shut-in and may be re-started with lower target volumes
- Reduce steam to field when necessary to manage reduced target well volumes
- Reduce steam rates
- Re-steam suspect wells in the same or subsequent cycles to build horizontal stress to favour horizontal fractures

Nabiye Grand Rapids Monitoring

Pad	Wells (year installed)	Monitored Zones	Fluid Excursion Confirmed
N01	N01 (2013)	LGR,UGR	All cycles
N02	N02-C (2014), N02-E (2016), N02-W (2016)	LGR,UGR	All cycles
N03	N03-C (2014), N03-E (2016), N03-W (2016)	LGR,UGR	All cycles
N04	N04-C (2014), N04-W (2016)	LGR,UGR	Cycles 1 and 3
N05	N05 (2013)	LGR,UGR	Cycles 2 and 3
N06	N06-C (2014), N06-E (2017), N06-W (2017)	LGR	Cycle 3
N07	N07-FMW* (2013), N07-C (2014), N07-E (2017)	LGR, UGR, PS	All cycles
N08	N08-C (2013), N08-FMW* (2014), N08-E (2017), N08-W (2017)	LGR, UGR, PS	All Cycles
N09	N09 (2014), N09-FMW1 (2015), N09-FMW2 (2015), N09-FMW3 (2015)	LGR, PS	All Cycles
N10	N10-S (2017)	LGR, UGR	Not yet steamed

*Note: All FMW wells include passive seismic monitoring

Observations

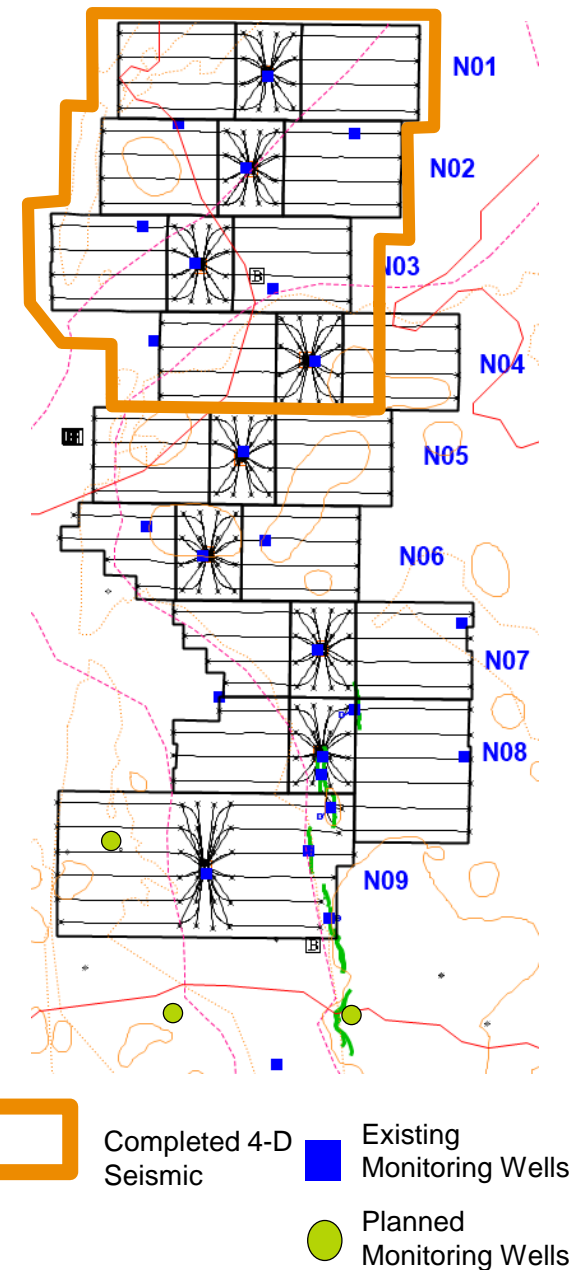
- Fluid excursions to the Grand Rapids have been observed consistently during early cycles
- Post-steam seismic anomalies identified via 4-D seismic on pads N01 and N02

Conclusions

- Combination of geologic factors likely contributing to increased fluid excursions relative to the rest of Cold Lake
- Monitoring and response practices effective at identifying and mitigating fluid excursions

Plans

- Continue to apply the Prevention, Detection and Response Practices developed for Nabiye (see previous page)
- 3 additional Grand Rapids monitoring wells planned, 1 over N09 west horizontal wells and 2 at N10 future pad
- Additional 4-D seismic over N01,N02, N07, N08 in 2018

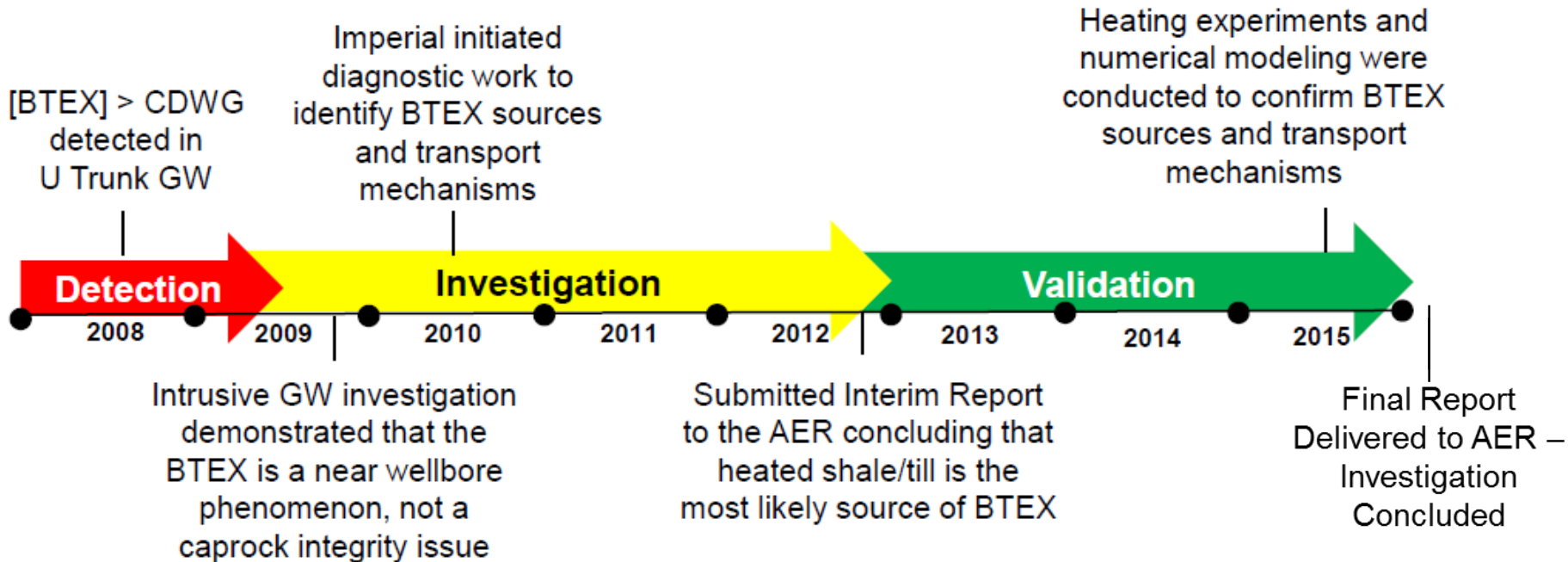


Investigation of BTEX in Deep Groundwater Monitoring Wells

Purpose

- Confirm the sources and transport mechanism of BTEX in groundwater

Background



Conclusions

- Heated Colorado Shales and Glacial Tills are the primary sources of BTEX
- No pathway from the Grand Rapids or Clearwater formations to aquifers
- Flow outside casing in Colorado Shales and Quaternary and direct fluid exchange from the shales or tills are the most likely transport mechanisms for BTEX introduction to the aquifers
- BTEX generation ceases when heating stops and attenuation in the aquifers will reduce BTEX concentration over time

Facilities

Facility Modifications

Mahihkan North LASER Start-up

- “Liquid Addition to Steam for Enhancing Recovery”
- Addition of low concentration diluent to injected steam during mid/late cycles to improve energy efficiency and recovery performance of the cyclic steam processes (by enhancing gravity drainage oil production through viscosity reduction)
- Tie-in to existing diluent supply infrastructure to allow diluent injection into Mahihkan North steam trunk line to H51-69 pads
- Install enhanced metering at LASER pads to monitor production performance vs base
- Leverage existing diluent recovery unit at Mahihkan, installed during previous commercial application
- More bitumen for same steam volume; ~20% reduction in greenhouse gas emissions intensity
- Diluent injection started in May 2017; expect to see diluent returns at year end

Mahkeses Plant Debottleneck

- Cleaned SRU inlet gas piping and upgraded HRSG duct burners
- Installed clean out hot taps for online line cleaning
- Installed additional hot lime softener outlet lines to reduce pressure loss
- Increased treated water capacity by >4000m³/day

Facility Performance

Bitumen Treatment and Vapour Recovery

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

AER Inlet License	Maskwa	Mahihkan	Leming	Mahkeses	Nabiye
Bitumen License (m ³ /d)	11,000	15,000	5,000	8,000	8,000
Actual Oct/16 – Sep/17 (m ³ /d monthly avg)	6,788	8,971	1,094	4,458	4,118

- Issues & Limitations

- None

- Major Downtime

- Mahkeses GTG/HRSG's inspection - 22 days Apr-May 2017
- Nabiye GTG inspections/HRSG inspection – 8 days maintenance & 28 days planned inspections Aug-Sep 2017

- Major Equipment Failures

- None

- Vapour Recovery Performance - >99% produced gas recovery Oct/16 to Sept/17

- Recent activities to improve venting performance:
 - Continued use of Forward Looking Infra-red (FLIR) camera
 - Optimizing tank PVRV settings and increased surveillance

Facility Performance

Water Treatment

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

AER Inlet License	Maskwa	Mahihkan	Leming	Mahkeses	Nabiye
Water License (m ³ /d)	38,000	41,000	13,500	28,000	22,665
Actual Oct/16 – Sep/17 (m ³ /d monthly avg)	26,519	33,805	5,392	17,459	12,209

- Issues & Limitations
 - Continued focus on improving treated water transfer from Maskwa & Mahkeses to Leming
- Major Downtime
 - Mahkeses GTG/HRSG inspection Apr 2017
 - Nabiye GTG/HRSG inspection Sep 2017
- Major Equipment Failures
 - None

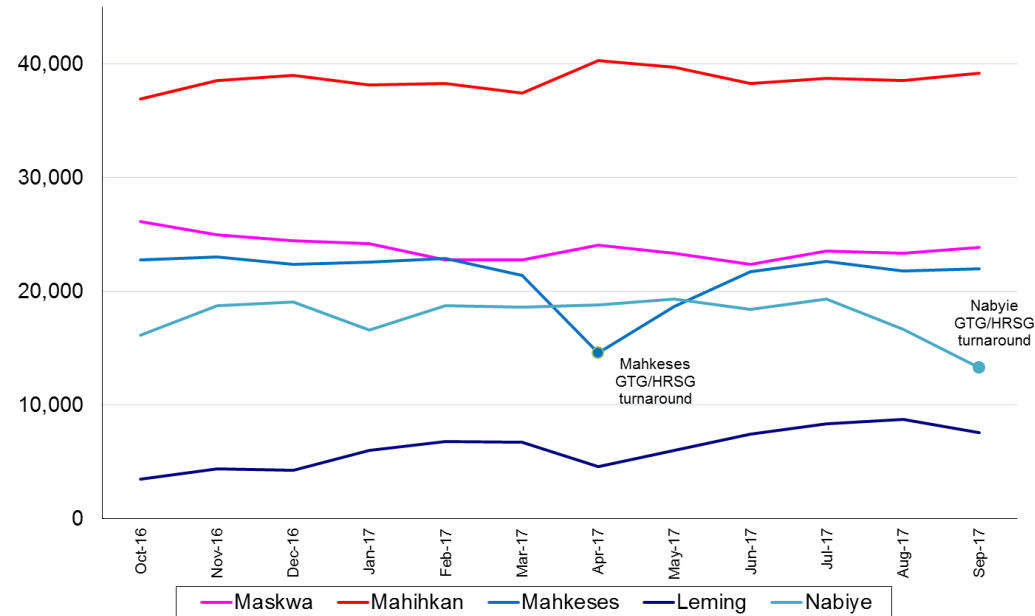
Facility Performance

Steam Generation

Cold Lake District HP Steam Generation (m3/d)						
2011	2012	2013	2014	2015	2016	2017 YTD
92,132	90,386	93,445	90,361	118,144	108,158	107,810

- Nabiye steam reduction ↓2000 m3/d
 - Field steam strategy / maintenance
- Leming steam reduction ↓3800 m3/d
 - Field steam economics/strategy
- Major Downtime
 - Mahkeses GTG/HRSG inspection
 - 22 days Apr-May 2017
 - Nabyie GTG/HRSG inspections
 - 8 days UT & sample system Jan 2017
 - 28 days Aug-Sep 2017
- Major Equipment Failures
 - None

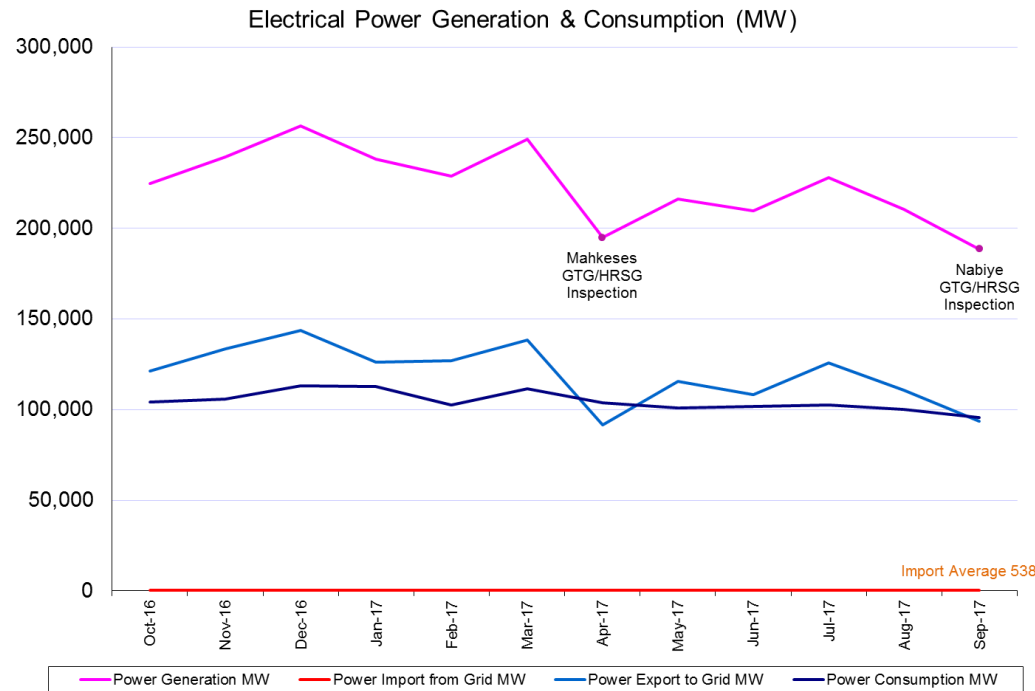
High Pressure Steam Generation
Monthly Averages m³/d



Facility Performance

Electrical Power Generation and Consumption

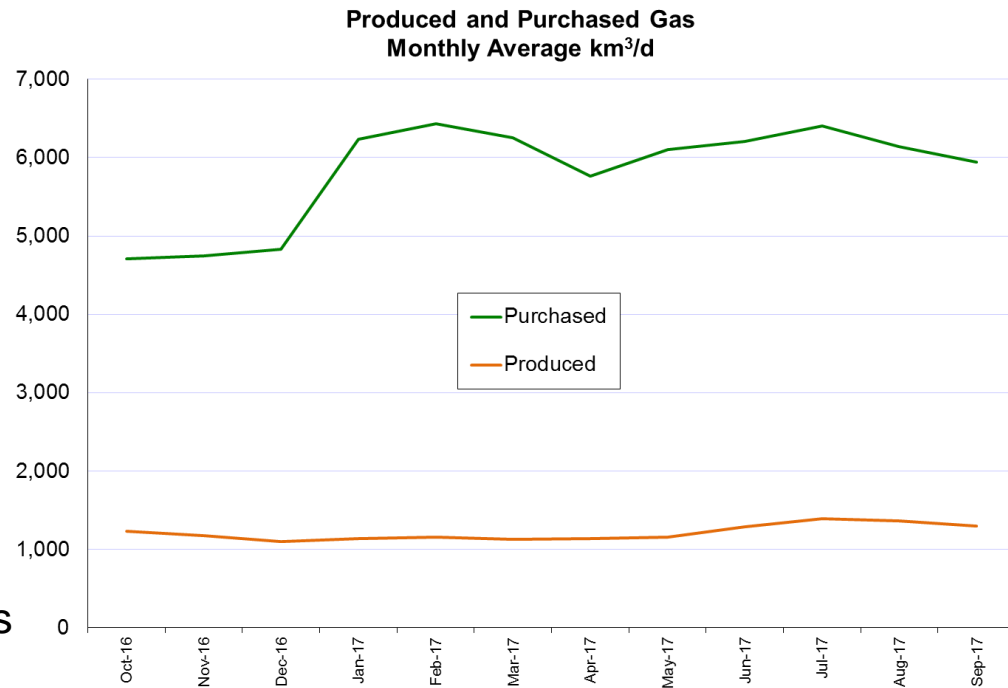
- Mahkeses & Nabiye Plants each have two gas turbine electrical power generators within a co-generation steam plant that generates power for the district and exports power to the Alberta power grid
- Power in 2017 was imported only to Imperial facilities that are outside the district power grid, from the Alberta power grid
- Issues & Limitations
 - None
- Major Downtime
 - Mahkeses gas turbine generator planned inspections – 22 days planned inspections Apr-May 2017
 - Nabiye gas turbine generator planned bore-scope inspection – 8 days maintenance & 28 days planned inspections Aug-Sep 2017
- Major Equipment Failures
 - None



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



Measurement & Reporting

- There were zero compliance issues with volume reporting for CLO in Q4 2016 & 1 compliance issue in 2017 YTD – Road Maintenance not entered Nov / Dec 2016 after rework was completed resulted in a \$200 fine
- Completed the MARP District schematics & allocations for the 5 Cold Lake facilities.
- Voluntary self-disclosure re: Mahihkan Facility (AB BT 0051212) P2 produced gas meter error, rework June 2016 – June 2017 data in progress.
- New reporting process implemented to ensure compliance (Petrinex) relating to monthly volumetric venting threshold (changed to 15.0 km³) for all reporting facilities.
- Commenced MahNo Laser project in May 2017

Proration Factors

Cold Lake 2016 - 2017 Profac Report

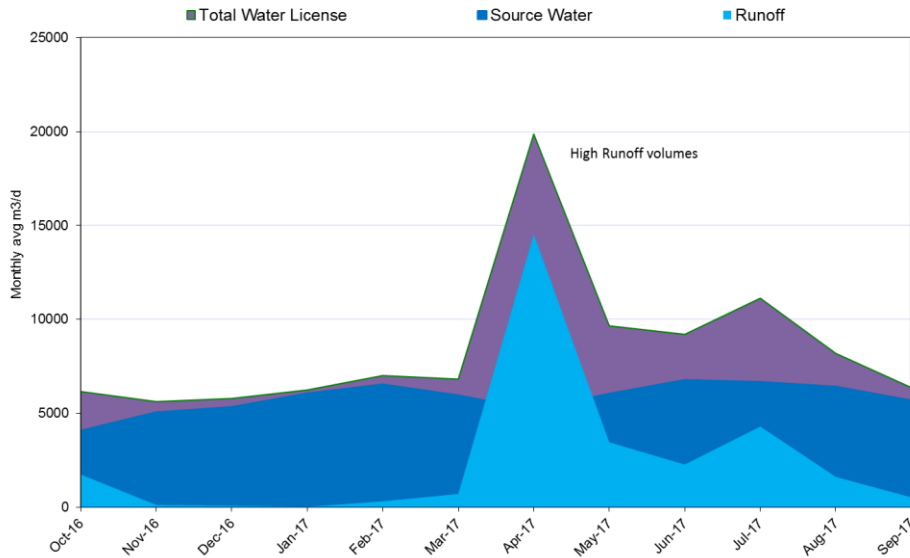
Profacs which are over Deviation Limit			2016					2017							
Battery Code (1330520)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
LEMING	OIL	0.85-1.15%	0.91	1.03	1.31	1.04	1.22	1.12	1.00	1.19	1.20	1.14	1.17	1.02	1.11
	WATER	0.85-1.15%	1.11	1.18	1.32	1.14	1.15	1.14	1.16	1.14	1.15	1.18	1.11	1.10	1.16
	GAS		0.74	0.90	1.23	0.96	1.12	0.91	0.87	0.91	1.40	1.31	1.24	1.15	1.06
Leming Steam Inj IF:0007678	STEAM		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
			1.15	1.19	1.38	1.07	1.29	1.11	1.22	1.05	0.99	0.81	0.98	1.00	1.10
Battery Code (0111783)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MAHKESES	OIL	0.85-1.15%	0.84	0.89	0.87	0.82	0.80	0.78	0.72	0.69	0.74	0.79	0.88	0.95	0.81
	WATER	0.85-1.15%	1.13	1.19	1.19	1.15	1.16	1.22	1.06	1.05	1.08	1.14	1.13	1.17	1.14
	GAS		0.91	1.01	0.89	0.80	0.82	0.77	0.67	0.72	0.81	0.88	0.90	0.88	0.84
Mahkeses Steam Inj IF:0111784	STEAM		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
			1.01	1.03	0.98	1.00	1.00	1.02	1.05	1.06	1.03	1.01	1.01	1.00	1.02
Battery Code (0051211)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MASKWA	OIL	0.85-1.15%	0.97	0.99	0.99	0.98	1.01	1.05	1.05	1.05	1.02	1.04	1.05	1.04	1.02
	WATER	0.85-1.15%	1.08	1.06	1.05	1.14	1.21	1.22	1.22	1.17	1.13	1.10	1.11	1.10	1.13
	GAS		0.69	0.58	0.54	0.69	0.72	0.68	0.73	0.77	0.79	0.96	0.99	0.88	0.75
Maskwa Steam Inj IF:0000797	STEAM		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
			0.97	0.99	0.98	0.98	0.99	1.04	1.00	1.00	0.98	0.98	1.01	0.99	0.99
Battery Code (00051212)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
MAHIHKAN	OIL	0.85-1.15%	0.85	0.83	0.84	0.85	0.82	0.84	0.84	0.81	0.83	0.81	0.76	0.80	0.82
	WATER	0.85-1.15%	1.01	0.97	0.91	0.91	0.98	0.98	0.99	0.95	0.98	0.95	0.93	0.97	0.96
	GAS		0.71	0.66	0.62	0.70	0.73	0.75	0.75	0.72	0.78	0.78	0.75	0.73	0.72
Mahihkan Steam Inj IF:0008798	STEAM		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
			0.95	0.95	0.98	0.95	0.97	0.99	0.97	0.95	0.96	0.99	0.98	0.98	0.97
Battery Code (0119087)			Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
NABIYE	OIL	0.85-1.15%	1.04	0.97	1.01	0.97	0.92	1.07	0.99	0.95	0.99	0.90	1.03	0.98	0.98
	WATER	0.85-1.15%	1.03	0.99	0.92	0.93	0.81	0.86	0.91	1.00	0.92	1.01	1.06	0.93	0.95
	GAS		1.53	1.26	1.25	0.72	0.87	0.82	0.70	0.84	0.70	0.78	0.98	0.92	0.95
Nabiye Steam Inj IF:0119086	STEAM		Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	AVG
						1.11	1.05	1.03	0.98	1.00	1.01	0.99	1.02	1.01	1.02

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)

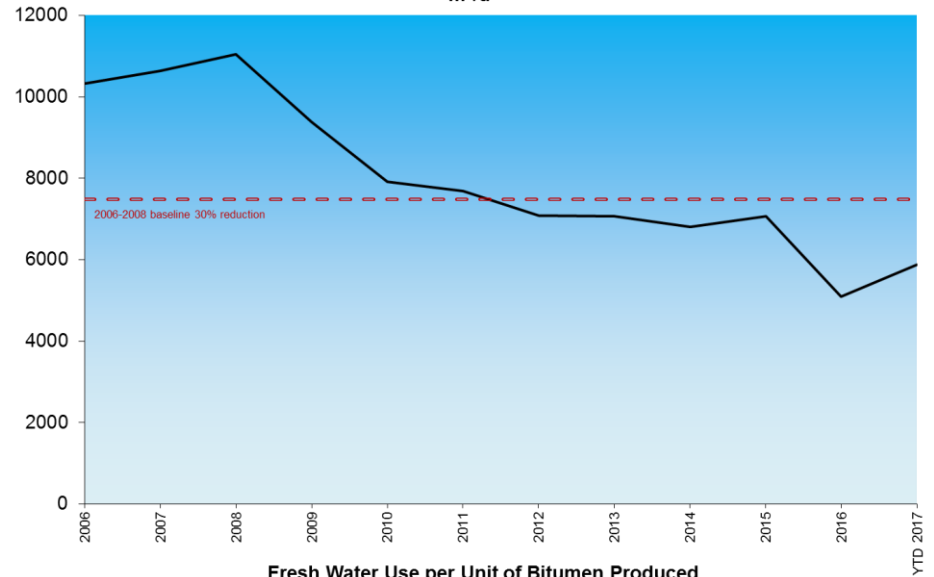
Water Sources and Use

Cold Lake Water Use

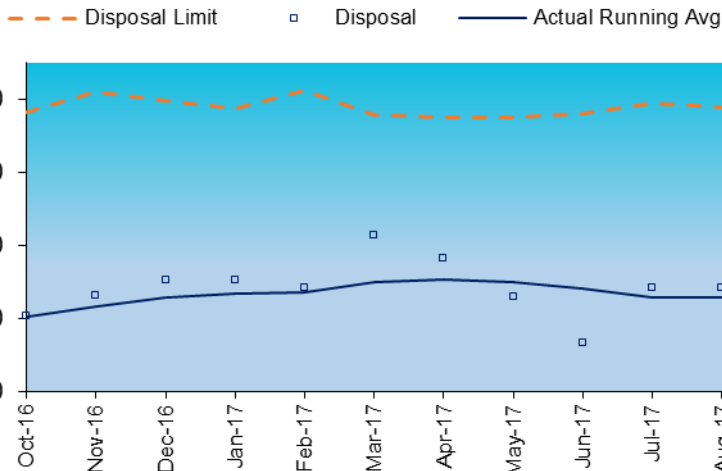
District Source Water Usage, Treated Water Transfer



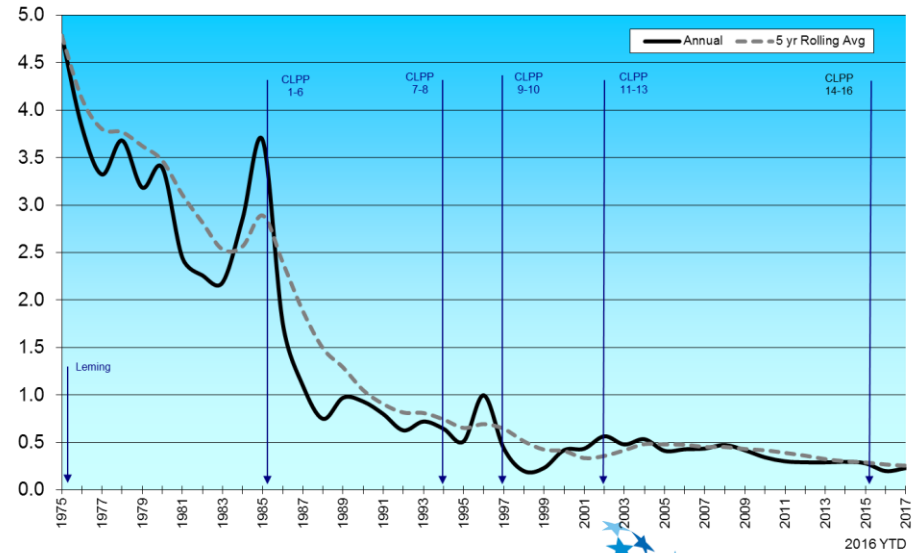
Fresh Water Use for Cold Lake Operations m³/d



Actual Disposal vs. Disposal Limit for Cold Lake Operations m³/d



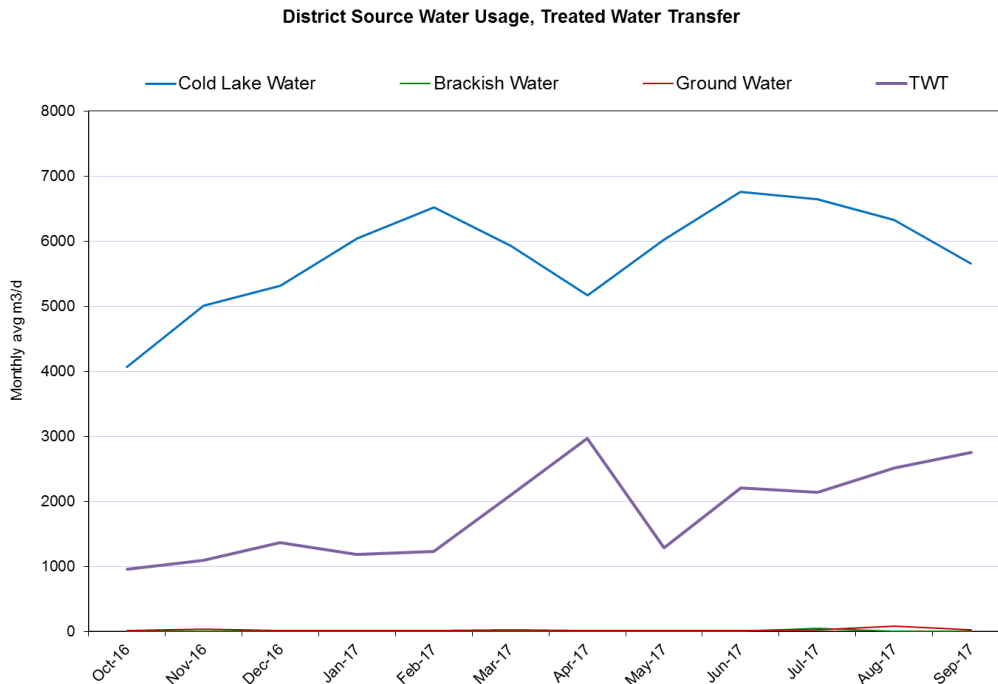
Fresh Water Use per Unit of Bitumen Produced Fresh Water m³ / Bitumen m³



Cold Lake Water Use (cont'd)

Fresh Water Use & Actual Disposal vs. Disposal Limit

- 2016-2017 ground water used only for Cold Lake source water system maintenance
- Decreased FW usage with Leming steam injection strategy, Fresh water reduction initiatives and treated water transfer “TWT” from Maskwa and Mahkeses
- Transitioned to disposal limit formula November 2015
 - 2016 actual disposal volumes 3,372 vs. disposal limit of 7,973 m³/d
 - 2017 YTD Actual Disposal volumes 2,643 m³/day vs. disposal limit of 7,677 m³/d
- Disposal volumes forecasted to remain low with produced water import to Nabiye remaining high



	Disposal Limit, m ³ /d	Actual Disposal m ³ /d
Jan-16	7,822	3,082
Feb-16	8,021	4,210
Mar-16	8,008	5,008
Apr-16	7,781	4,403
May-16	7,924	4,186
Jun-16	8,265	3,485
Jul-16	8,249	3,254
Aug-16	8,064	2,443
Sep-16	7,759	2,732
Oct-16	7,636	2,046
Nov-16	8,208	2,613
Dec-16	7,947	3,053
YE*	7,973	3,372

Freshwater Reduction

- Freshwater reduction continues to be key focus area
- 2017 YTD (Sept 30) non-saline water consumption ~6,141 m³/d, continuing strong performance since 2011
- 1M m³ of allocation from Cold Lake released during water license renewal driven by performance and focus on continued reductions
- Technical assessments of alternatives ongoing in freshwater utility boilers, inlet cooling, and improved treated water transfer

Water Disposal and Waste Management

Produced Water Disposal to Cambrian – Approval 4510

Monthly Injection Volumes and Average Wellhead Injection Pressures

WELL IDENTIFIER	Disposal Zone	2015						2016																	
		OCTOBER		NOVEMBER		DECEMBER		JANUARY		FEBRUARY		MARCH		APRIL		MAY		JUNE		JULY		AUGUST		SEPTEMBER	
		(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)	(MPA)	(m ³)
00 01 19 064 03 4 00 (SWDFT701)	Cambrian	11.1270	35052	11.3930	43,052	11.9900	46,645	11.2770	39,451	10.800	36,257	12.2630	46,158	12.2480	38,068	12.1130	38,778	11.4550	19,176	0.0000	0	0.0000	0	12.6690	0
00 01 32 064 03 4 00 (SWDFT702)	Cambrian	10.8260	27086.9	11.5970	34,619	11.9100	42,796	11.3230	34,428	11.826	40,226	12.3770	52,493	12.4690	45,755	12.0730	24,242	12.2860	11,919	12.6000	4,941	11.9500	58,757	12.7450	62,303
02 02 03 064 03 4 00 (SWDFT703)	Cambrian	0.0000	0	0.0000	0	11.0830	4,532	11.3400	19,902	11.174	1,561	12.2930	34,661	11.9760	25,099	12.1930	15,479	12.2590	8,575	12.4000	1,162	12.2770	29,695	0.0000	29,283
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 (m³)			62139		77,671		93,972		93,781		78,044		133,311		108,922		78,499		39,670		6,104		88,452		91,586
DAILY AVERAGE(m³)			2004		2,589		3,031		3,025		2,787		4,300		3,631		2,532		1,322		197		2,853		3,053

- 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

Cold Lake Waste Management

2016 Annual Waste Volumes

	Volume (m3 unless otherwise specified)
Class II Landfill	
Lime Sludge	51,566
All Other Waste Streams	10,242
Maskwa Ecopit (OWBSF)	
Oily Waste	1746
Off Site Disposal / Recycled	
Empty Containers (EMTCON)	162
Steel	121 tonnes
Wood (burned on site)	67 tonnes
Landfill Leachate Collection and Recycle at Mahkeses Plant	37,605
Solid Waste (Rags, soils, etc.)	719
Liquid Waste (Glycol, etc.)	1823
Sludge (sludge cont. hydrocarbons)	995

Environmental Summary

Approval Renewals and Amendments

AER Approvals

- No change

Approvals under the Environmental Protection and Enhancement Act (EPEA)

- No change

Approvals under the Water Act

- Cold Lake Water Act license renewal for surface water diversion submitted in June 2016 (Approval No. 79923-01-00), received July 30, 2017
- Water Act license renewal for back-up groundwater wells submitted in June 2016 (Approval No. 148301-01-00), received July 30, 2017

Monitoring Programs – Wildlife

Cold Lake Operations continues to enhance and restore wildlife habitat.

- 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.
 - > 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.
- Continue implementation of AEP-approved *Wildlife Monitoring and Mitigation Plan* and *Caribou Mitigation and Monitoring Plan*, which address wildlife habitat preservation measures.
- Annual issuance of AEP *Research and Collection License*.

Monitoring Programs – Groundwater

Cold Lake Operations maintains an extensive groundwater monitoring program.



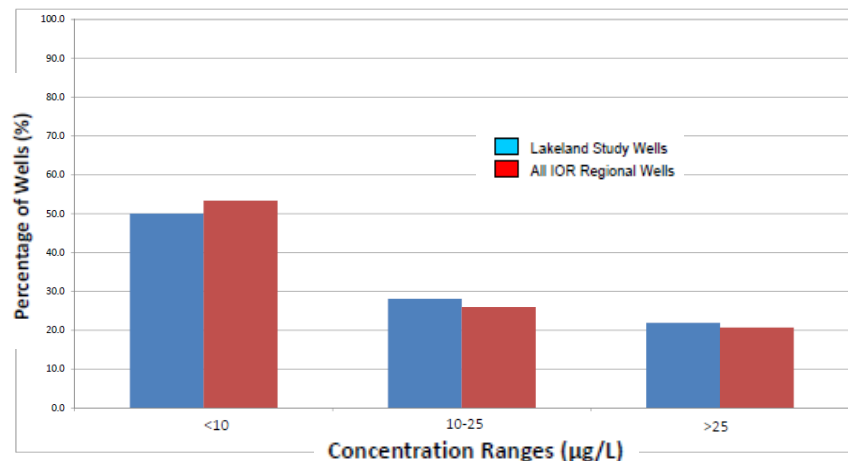
- Monitoring
 - > 400 deep groundwater wells (including 17 domestic), and
 - > 220 shallow wells
- Monitoring includes chemistry & water levels
- Drilling activity in 2016/2017
 - > Deep:
 - V10 16-1 and 16-2 GEW Nests for Arsenic Monitoring
 - E (ML)-R to replace E(ML)
 - T08 GEW 17-1 (ML) for pad investigation
 - > Shallow:
 - Planned Landfill Wells for Q4
- 2016/2017 Abandonment:
 - > LNFL-8-X and MWPO-22-5.
 - > E (BNV) and E(ML), REG 00-2 (WT), GEW 97-7(SR), REG 09-3(EL), GEW 97-5(ML), GEW 97-12(E3), P2 97-1(E1), REG00-2R(E1), REG 11-4(CS)

Monitoring Programs – Thermal Mobilization

Based on groundwater monitoring to date, there is no evidence that mobilized arsenic has impacted domestic or livestock groundwater wells. Cold Lake Operations continues its extensive groundwater monitoring program.

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, Oct 2000).
- In 2017, 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 monitors thermally mobilized arsenic at D55, D57, L08 and V10.
- 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 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 indicate that arsenic attenuates as it moves down gradient.
- Additional downgradient monitoring wells are positioned to measure the rate and extent of attenuation. These are key objectives of ongoing work.
- In 2015 and 2016, Imperial shared technical updates with the AER and has an AEPEA requirement to complete a technical update report in 2020.



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 - 2017)

Monitoring Programs – Surface Water

Cold Lake Operations maintains an extensive surface water monitoring program.

Comprised of 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

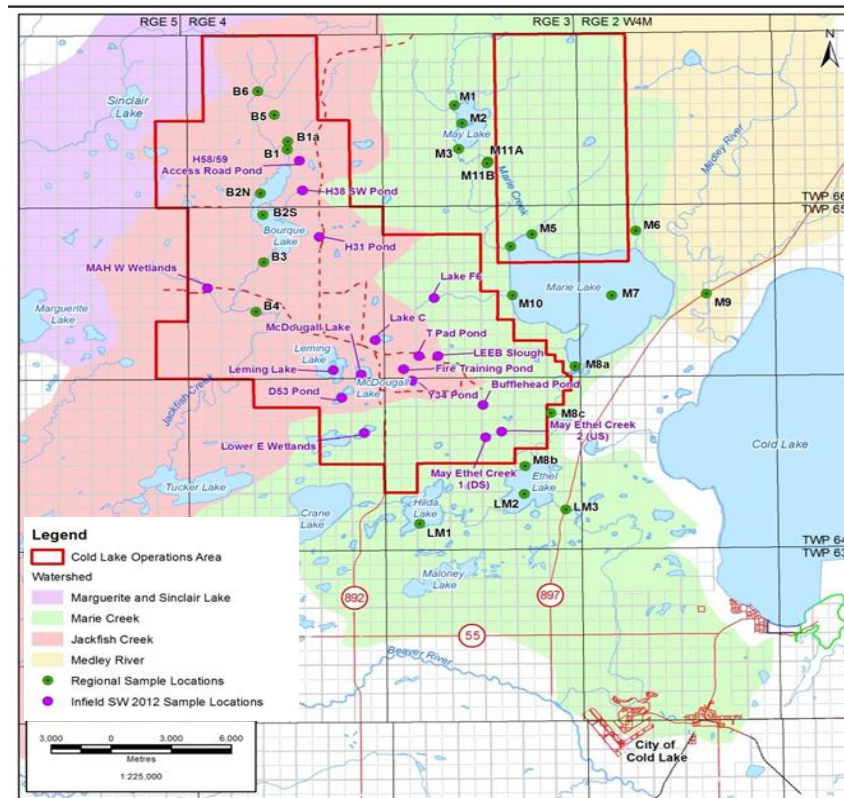
Data and observations support the absence of effects directly or indirectly associated with Cold Lake operations.

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.

Infield

- 18 Sites sampled bi-annually for field and routine parameters, total and dissolved metals, nutrients, and hydrocarbons
- Concentrations measured during 2016 are consistent with historic data, with some exceptions related to stagnant water and higher sediment



Sampling

- 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 Drainage

Drainage and culvert assessments help monitor and minimize the environmental impact of Cold Lake Operations.

- Completed on an annual basis since 2002
- Drainage Assessment: Includes examination of drainage impediments, erosion and/or sedimentation
- Culvert assessment: culvert integrity and erosion

Monitoring Programs – Surface Water Wetland Monitoring

Program Status:

- In 2015/2016, piezometers were monitored for levels using transducers.
- All upstream and downstream locations across CLO had consistent levels, with the exception of downstream Leming Wetland due to blocked culvert
- Water levels and water quality results were typically within expected ranges, with the exception of Maskwa wetland, which had an increase chloride concentration (investigation underway).

Monitoring Programs – Surface Water

Long-term Wetland Monitoring Plots

Vegetative stress was not identified the field assessments.

- 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
- Next Monitoring Date:
 - 2020
- 2015 Results
 - Evidence indicates that wetlands studied are influenced by precipitation, rather than groundwater levels.

Monitoring Programs – Vegetation

No impact to species richness have been observed.

Overview:

- In 2006 a long-term vegetation monitoring program was established, per the commitments made in Section 9, Subject 10 of the Imperial 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:

- 2015 edge effects and rare plants monitoring (next survey to occur in 2018).
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.
- Vegetation stress assessment conducted in 2016 (5 years frequency). Consultant (AMEC) concluded that there was no vegetation stress due to SO₂, nor in 2010 nor in 2016.



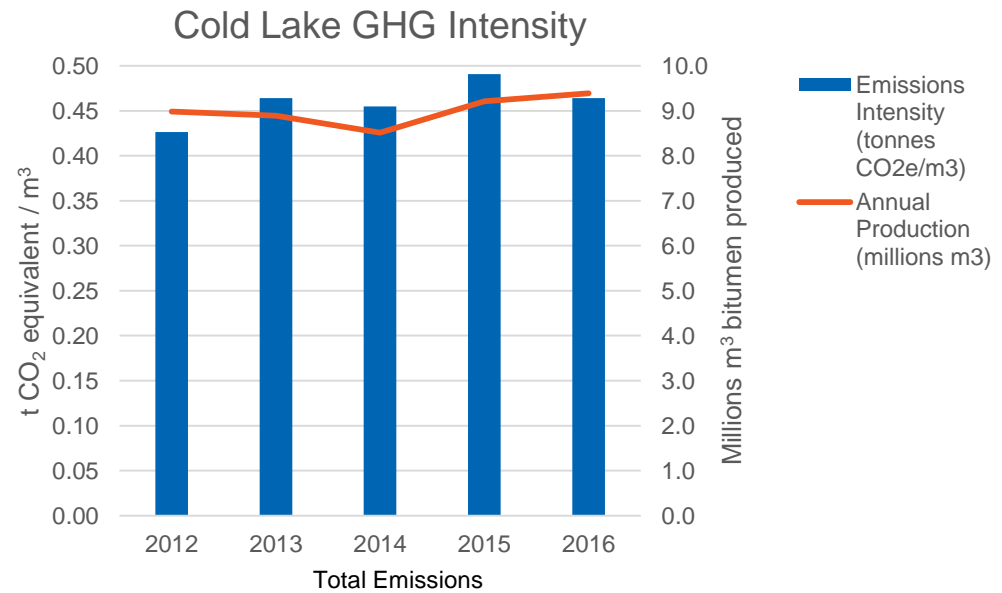
Pitcher Plant (*Sarracenia purpurea*)

Monitoring Programs – Air Emissions

Cold Lake's greenhouse gas (GHG) emission intensity has been stable. Next-generation technologies reducing emissions are being leveraged.

Examples include:

- **Liquid Addition to Steam for Enhancing Recovery (LASER)** reduces GHG intensity by 20 to 25% by adding solvent to the current Cyclic Steam Simulation process. LASER has been commercially demonstrated at 10 pads and deemed successful; it was recently implemented at an additional 9 pads.
- **Cyclic Solvent Process (CSP)** is a non-thermal process that injects solvent instead of steam to recover bitumen. A \$100-million pilot facility was initiated in 2014. Direct GHG emissions are reduced by approximately 90 %.
- **Solvent-Assisted Steam-Assisted Gravity Drainage (SA-SAGD)** is a recovery process enhanced by the addition of solvent to the steam. It is the technology of choice for the Cold Lake Expansion Project (Grand Rapids reservoir) and other SAGD developments such as Aspen. Cold Lake has operated a \$50M field pilot since 2010. A 25 % reduction in GHG intensity compared to SAGD is expected.



Monitoring Programs – Air Emissions

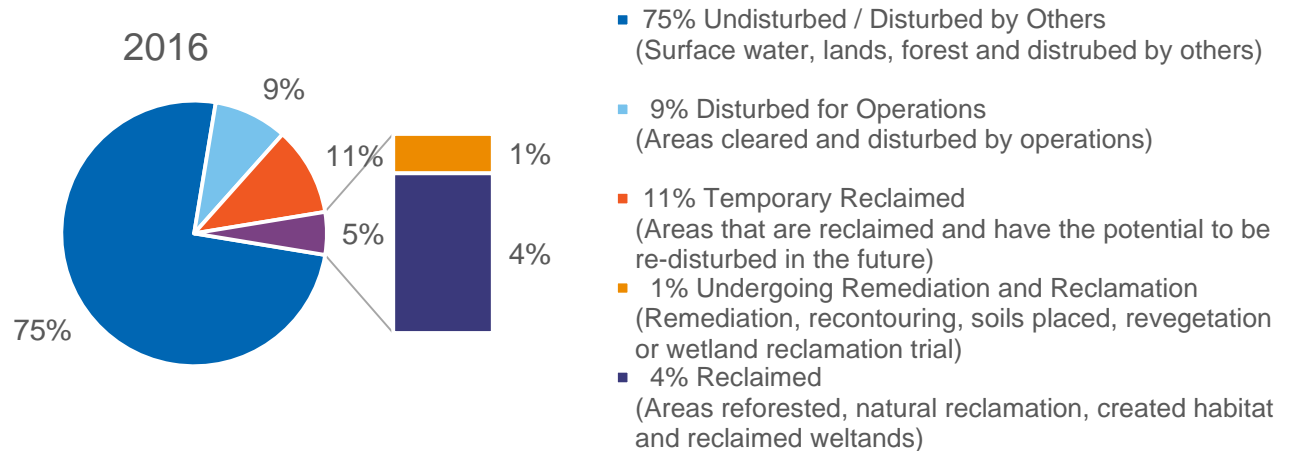
Air quality has been meeting provincial objectives. Data is shared with communities.

- The Maskwa station is maintained and operated by LICA (Lakeland Industry and Community Association).
 - Maskwa station performs continuous monitoring of SO₂, H₂S, NO_x, Total Hydrocarbons.
 - Passive monitoring is performed for SO₂, H₂S, NO₂.
 - Alberta Ambient Air Quality Objectives (AAAQO) includes target concentrations for certain compounds. Hourly averages measurements are below the AAQO targets.
- Fugitives emissions detection program
 - Annual program; each location sampled on a 3 years frequency
 - Fugitives emissions are minor; represent less than 0.5% of Cold Lake Operations green house gas (GHG) emissions
 - Leak Detection and Repair (LDAR) program is implemented to detect unintentional hydrocarbon emissions (seals, valves, flanges, etc.).

Monitoring – Reclamation

Reclamation is integral to Cold Lake Operations’ activities. More land is being reclaimed (16%) than the footprint disturbed for Operations (9%).

Since 1999, Imperial’s Cold Lake operation has planted over 1.7 million tree and shrub seedlings. In 2017, 12,540 trees and 4,140 shrubs seedlings were planted.



2016 – Cold Lake Operations Mineral Surface Lease = 14240.4 ha

Year	Total Area Disturbed (ha)	% Undergoing Temporary Reclamation, Remediation and Reclamation	% Reclaimed	Total % Undergoing Reclamation Activity
2013	3,482	47%	14%	61%
2014	3482	47%	15%	62%
2015	3534	48%	15%	63%
2016	3558	47%	17%	64%

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
 - > 2016 results - sites have adequate topsoil replaced

Revegetation

- Monitoring has been deferred until the approved Project –Level Conservation, Reclamation and Closure Plan (PLCRCP) implementation (Mahihkan & Nabiye submission Oct 31, 2017)
- Fall assessments ongoing to ensure re-vegetation establishment



Environmental and Community Initiatives

Imperial Cold Lake Operations continues to support environmental initiatives through both financial contributions and participation in regional committees.

- Cold Lake Operations makes financial contributions to JOSM (Joint Oil Sands Monitoring) to support regional monitoring programs.
- Imperial continues to be involved with COSIA (Canada's Oil Sands Innovation Alliance).
- Imperial continues to sit on the LICA (Lakeland Industry and Community Association) board and committees as an industry member and to fund local environmental programs.
- Imperial holds the annual "Neighbor Night" that allows the community to learn and enquire about Cold Lake Operations.
- Imperial engages with Marie Lake Air and Watershed Society (MLAWS) and domestic well owners.

Sulphur

Sulphur Removal

Mahihkan Site – Plant Sulphur Removal

- Sustained reliability achieved over reporting period:
 - Achieved greater than 69.7% recovery in all quarters of 4Q16, 1/2/3Q17 and was continuously below emissions limit
- Achieved 95% uptime in 2016/2017
- Downtime related to SRU vessel and piping repairs

Mahkeses Site – Plant Sulphur Removal

- Sustained reliability achieved over reporting period:
 - Achieved greater than 69.7% recovery in all quarters of 4Q16, 1/2/3Q17 and was continuously below emissions limit
- Achieved 95% uptime in 2016/2017
- Downtime related to SRU vessel and scavenger tank maintenance

Leming Site – No Plant Sulphur Removal

- Leming SO₂ emissions were below limits in all quarters of 4Q16, 1/2/3/Q17 and was continuously below daily emissions limit

Maskwa Site – No Plant Sulphur Removal

- Maskwa SO₂ emissions were below limits in all quarters of 4Q16, 1/2/3/Q17 and was continuously below daily emissions limit

Nabiye Site – Plant Sulphur Removal

- Nabiye SO₂ emissions were below limits in all quarters of 4Q16, 1/2/3/Q17 and was continuously below daily emissions limit
- Achieved 100% uptime in 4Q16, 1/2/3Q17

Sulphur Removal, SO₂ Emissions

- Compliant with D56, EPEA, and ID2001-3 over the review period

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	Removal	Sulphur	SO ₂
Q4 2016	0.24	0.48	0.94	1.89	0.68	1.35	70.09%	0.47	0.95	71.09%	0.18	0.36	70.11%	2.52	5.03
Q1 2017	0.24	0.48	1.00	1.99	0.49	0.98	69.96%	0.39	0.78	70.11%	0.32	0.65	70.21%	2.44	4.88
Q2 2017	0.27	0.54	1.00	2.00	0.42	0.83	73.22%	0.39	0.79	70.37%	0.21	0.42	70.08%	2.29	4.58
Q3 2017	0.36	0.72	1.00	1.99	0.49	0.98	69.75%	0.35	0.69	70.10%	0.26	0.52	70.20%	2.45	4.90
	<1.0 t/d Sulphur		<1.0 t/d Sulphur		<1.80 t/d SO ₂		≥69.70%	<1.08 t/d SO ₂		≥69.70%	<1.08 t/d SO ₂		≥70.00%	-	

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 2016	0.39	0.78	1.22	2.43	1.96	3.91	1.38	2.76	0.29	0.57	3.59	7.18	
Q1 2017	0.31	0.62	1.29	2.58	1.55	3.10	0.62	1.23	0.66	1.32	4.00	8.01	
Q2 2017	0.32	0.65	1.41	2.82	1.26	2.51	0.98	1.95	0.32	0.64	3.13	6.27	
Q3 2017	0.49	0.98	1.23	2.46	1.07	2.15	0.48	0.97	0.47	0.94	2.97	5.94	

Compliance

AER Compliance

Cold Lake Operations activities pursued without adverse impact on the environment.

Inspections and Compliance

- 24 satisfactory inspections
 - Includes inspections pertaining to Cold Lake Operations dams, well servicing procedures, management of suspended wells, etc
- 5 voluntary self-disclosures
 - Proactive identification of improvement opportunities pertaining to licensing, measurement and tank usage.
- 22 non-compliances and 5 contravention reports
 - 11 relating to enhancements of our pipeline program
 - 4 pertaining to secondary containment
 - 3 relating to records retention
 - Other miscellaneous items include illegible signage, exhaustiveness of the flare and vent log, and management of runoff during heavy rainfalls.

Future Plans

Future Plans

- Continue to pursue freshwater reduction opportunities
- 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

Attachment 1

Approval

855811

Compliance Conditions

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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.	Matt Dawe (CLRE), Hsao-Hsien Chio (CL Fac)	8558II – Nabiye specific operating procedures
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.	Matt Dawe (CLRE), Hsao-Hsien Chio (CL Fac)	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, Seann Strandberg (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, Seann Strandberg (CLO)	In compliance with all requirements. PW recycle rate has been replaced with annual disposal limits. Disposal limits are within the requirements of D81.
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, Dawn Herle (CLO)	There were zero compliance issues with volume reporting for CLO in Q4 2016 & 1 compliance issue in 2017 YTD – Road Maintenance not entered Nov / Dec 2016 after rework was completed resulted in a \$200 fine Completed the MARP District schematics & allocations for the 5 Cold Lake facilities New reporting process implemented to ensure compliance (Petrinex) relating to monthly volumetric venting threshold (changed to 15 103m3) for all reporting facilities Voluntary self-disclosure re: Mahihkan Facility (AB BT 0051212) P2 produced gas meter error, rework June 2016 – June 2017 data in progress. Commenced MahNo Laser project in May 2017
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.	Seann Strandberg (CLO)	No issues to report.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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.	Mark Wood (CLGeo)	Operating practice is for one or more wells per pad and all OV wells to be logged by LWD, wireline or pipe conveyed methods. Exceptions are requested for some Passive Seismic wells and the horizontal sections of Injection-Only-Infill wells. AER logging waivers are 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 full 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.	Mark Wood (CLGeo)	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. Core and analysis from cored wells in the 2016 / 17 winter program submitted to AER through September, 2017 (note: core submitted was over Colorado shale interval from CEW well)
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.	Mark Wood (CLGeo)	All OV wells and one well per pad were logged using wireline or pipe conveyed Gamma Ray - Neutron-Density tools. Wireline data from 2016 / 17 winter program submitted to AER January - April
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.	Sarah Mason (D&C)	Only non-toxic water-based mud systems were used in all drilling activities conducted in 2017.
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: <i>Injection and Disposal Wells – Well Classifications, Completions, Logging, and Testing Requirements</i> .	Keith Dares (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.	Keith Dares (CLSSE)	Annual casing integrity report submitted April 17, 2017, followed by review on May 1, 2017. No follow-ups. Amended report submitted on May 5, 2017 to correct a typo.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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.	Keith Dares (CLSSE)	Well casing failure prevention / detection practices discussed with AER through annual casing integrity submission. There were no CSS or Injector-Only-Infill wells drilled during 2017.
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.	Charles Wierstra (CLO)	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.	Kelly Wiebe (SSHE)	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 down-gradient. A technical update was submitted in May 2017. Imperial conducts reviews of arsenic every 2 years to confirm that arsenic concentrations have not increased on a regional scale due to thermal operations at Imperial CLO. This was confirmed in 2017 based on 2015/2016 data.
12	The Operator shall install surface casing, in a manner satisfactory to the AER, through the glacial drift on all disposal wells.	Sarah Mason (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.	Nathan Toone (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.	Matt Dawe (CLRE)	IOR submitted the annual pressure survey to the AER on Sept 1, 2017
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.	Cheryl Trudell (Research)	Multiple field investigations underway: infills, LASER, steamflood, HIPs, SAGD, SA-SAGD, and CSP.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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.	Matt Dawe (CLRE)	Submitted Cold Lake Expansion project application in Mar 2016 for bitumen recovery from the Grand Rapids formation using the SA-SAGD process.
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.	Matt Dawe (CLRE)	Nothing new to report
17.2	<p>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:</p> <ul style="list-style-type: none"> 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. 	Matt Dawe (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, OFF, 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.	Nathan Toone (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.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 Status/Comments
19.1	A well shall not be abandoned without prior written AER approval.	Keith Dares (CL SSE)	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.	Keith Dares (CL SSE)	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.	Kelly Wiebe (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 148301-02-00, 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.	Kelly Wiebe (SSHE)	The groundwater-monitoring network continues to provide information on water level responses. Poroelastic response has been observed due to steam injection.
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.	Matt Dawe (CLRE)	Continuous monitoring of the Grand Rapids Formation has been incorporated into Cold Lake operational practices.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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, Seann Strandberg (CLO)	<p>Imperial continues to support and participate in regional monitoring programs and initiatives such as the ones conducted by the Lakeland Industry and Community Association (LICA). Imperial acts as an industry representative on the LICA Board of Directors. Recommendations from industry and the community are incorporated into LICA's programs, which have included air quality monitoring and education about environmental receptors.</p> <p>Imperial participates in the environmental monitoring programs as dictated by the Joint Oil Sands Monitoring (JOSM). JOSM activities represent a significant portion of the provincial (Alberta Environment and Parks (AEP)) monitoring program. The data collected by JOSM is provided to management agencies to help support decision-making with scientific knowledge about provincial biodiversity.</p> <p>Cold Lake Operations periodically hosts information sessions and tours addressed to community members. Questions or suggestions from members drive change in operating practices. For example, noise levels have been reduced at CLO following discussion with a community member.</p> <p>Imperial continues to be involved with Canada's Oil Sands Innovation Alliance (COSIA).</p>
23.1	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 ₂ S) 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 <i>Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta</i> 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, Seann Strandberg (CLO)	Sulfur recovery units are installed and operational at Nabiye, Mahihkan and Mahkeses Plants. Maskwa and Leming manage sulfur limits below the 1 t/day threshold.
23.2	The Operator is required to meet the minimum sulphur recovery requirements as set out in Table 1 of AER <i>Interim Directive (ID) 2001-03: Sulphur Recovery Guidelines for the Province of Alberta</i> based on the number of days in the quarter that the non-regenerative sulphur recovery unit is operational. The Operator must maintain a minimum of 95% uptime for the non-regenerative sulphur recovery units. This clause will expire on December 31, 2017 ¹ (1) Application No. 1863213	Darlene Gates, Seann Strandberg (CLO)	All of the sulfur recovery guidelines were met during the period of Q4 2016 to Q3 2017.
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.	Matt Dawe (CLRE)	No scheme wells have been drilled within 100m of a lease boundary
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.	Keith Dares (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 is complete.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 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 <i>Directive 020</i> .	Keith Dares (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.
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 <i>Directive 020: Well Abandonment</i> . 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 <i>Directive 020</i> . 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 non-routine 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.	Keith Dares (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.
27	The Operator is permitted to abandon the OCC, ODD and OGG Pads as described in Application No. 1797105. For abandonment of wells on these pads a non-routine well abandonment plan must be submitted for each well to the AER's Operational Authorization Group for review and approval in accordance with Section 2 of <i>Directive 020: Well Abandonment</i> .	Keith Dares (CLSSE)	Full or partial abandonment completed on 44 wellbores. Remainder will continue in 2018+. All wells remain D013 compliant.
28	The Operator is permitted to use Steam-Assisted Gravity Drainage (SAGD), utilizing steam as the injection fluid, or Solvent Assisted-Steam Assisted Gravity Drainage (SA-SAGD), utilizing solvents and steam as the injection fluids, as the recovery process at the following Pad T13 wells: AA/01-30-064-03W4/0 (observation well) AB/01-30-064-03W4/0 (producer) AC/01-30-064-03W4/0 (injector) AA/02-30-064-03W4/0 (observation well) AB/02-30-064-03W4/0 (producer) AC/02-30-064-03W4/0 (injector) AA/07-30-064-03W4/0 (observation well) AA/08-30-064-03W4/0 (observation well) AB/08-30-064-03W4/0 (observation well) AD/08-30-064-03W4/0 (observation well)	Matt Dawe (CLRE)	T-13 SAGD and SA-SAGD operations ongoing.

AER Approval 8558

Clause	Requirement Summary -	Responsibility	2017 Status/Comments
29.a	Before commencing initial steam injection of a CSS well, a risk assessment of the integrity of wellbores within 1000 metres of the well must be conducted, and any wellbores with integrity concerns must be remediated. The Operator must ensure that the wellbore integrity of the CSS well be maintained thereafter.	Keith Dares (CLSSE)	All new CSS development pads undergo the risk assessment as described in the requirement.
29.b	For CSS wells with eight acres of drainage area per equivalent bottom hole spacing (EBHS), the total steam injection volume of cycles 1,2, and 3 is limited to 5,000 m ³ /EBHS, 7,000 m ³ /EBHS, and 8,000 m ³ /EBHS, respectively. Steam injection volume over fill-up for subsequent cycles is limited to 10,000 m ³ /EBHS.	Nathan Toone (CLRS)	All Nabiye steam cycles followed this criteria for the reporting period.
29.c	All (Nabiye) steaming operations must have adequate Grand Rapids Formation water sand pressure monitoring coverage over the drainage area. Monitoring networks must be designed based on area-specific properties of the water sand within the Lower and Upper Grand Rapids Formations where both zones are present.	Matt Dawe (CLRE)	Drilled three new Nabiye Grand Rapids monitoring wells in 2017: N08-E, N08-W, N10-S.
29.c.i	The Operator must notify the AER within 24 hours from the time the Operator becomes aware that the pressure of the Grand Rapids Formation exceeds 80 per cent of the fracture closure pressure calculated at the base of the Joli Fou Formation. The Operator must shut-in steam to a specific well, or multiple wells, which are suspected to be contributing to the pressure increase and provide operational strategies to stabilize the pressure.	Matt Dawe (CLRE)	All relevant events disclosed to the AER and acted upon during the reporting period.
29.c.ii	When the pressure of the Grand Rapids Formation exceeds 60 per cent of the fracture closure pressure calculated at the base of the Joli Fou Formation, the Operator must shut-in steam to a specific well or multiple wells which are suspected to be contributing to the pressure increase. The Operator must document the events.	Matt Dawe (CLRE)	All relevant events documented and acted upon during the reporting period.
29.c.iii	The Operator must notify the AER within 24 hours from the time the Operator becomes aware that the pressure in the Grand Rapids Formation increases by more than 200 kilopascals in a 24 hour period. The Operator must shut-in steam to a specific well, or multiple wells, which are suspected to be contributing to the pressure increase and provide operational strategies to stabilize the pressure.	Matt Dawe (CLRE)	All relevant events disclosed to the AER and acted upon during the reporting period.
29.c.iv	The Operator must shut-in steam to a specific well, or multiple wells, which are suspected to be contributing to a pressure increase that exceeds 100 kilopascals over a 24 hour period in the Lower Grand Rapids Formation, or 50 kilopascals over a 24 hour period in the Upper Grand Rapids Formation. The Operator must document the events.	Matt Dawe (CLRE)	All relevant events documented and acted upon during the reporting period.
29.c.v	When an injectivity event is detected and pressure increase in the Grand Rapids Formation is observed associated with the injectivity event, the Operator must notify the AER within one week from the time the pressure increase is observed and provide operational strategies to stabilize the pressure in the Grand Rapids Formation.	Matt Dawe (CLRE)	All relevant events disclosed to the AER and acted upon during the reporting period.

Attachment 2

Approval 4510

Compliance Conditions

AER Approval 4510

Clause	Requirement Summary	Responsibility	2017 Status/Comments
4510_2	The disposal of fluids...in the wells...which have satisfied Guide 51 requirements, may commence or continue.	Keith Dares (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.	Scott Cooper, Lyle Robins (CLO)	In compliance. All N Pad injection has ceased as of November 2015 . Injection line to N-pad has been discontinued and no longer able to injected.
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	Scott Cooper, Lyle Robins (CLO)	In compliance. All N Pad injection has ceased as of November 2015. Injection line to N-pad has been discontinued and no longer able to injected.
4510	Submit an annual report for Approval 4510 Nov. 2016	Nathan Toone (CLRS)	2016 Report to be submitted Nov. 2016

Attachment 3

Water Disposal and Storage

Water Disposal and Storage

PW Disposal & Storage District Summary – Volumes in m³

	2016			2017								
	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
Disposal Volumes, m3	63,430	78,404	94,647	94,413	79,079	132,508	108,733	80,001	40,229	6,946	87,382	92,155
N-Pad Storage, m3	0	0	0	0	0	0	0	0	0	0	0	0
Disposal Limit, m3	236727	246250	246369	239641	230455	234518	224667	232679	228675	244735	240832	219740
Actual Disposal, m3	63,430	78,404	94,647	94,413	79,079	132,508	108,733	80,001	40,229	6,946	87,382	92,155
Actual Disposal (%)	1.8%	2.2%	2.6%	2.7%	2.3%	3.8%	3.1%	2.3%	1.2%	0.2%	2.4%	2.8%
Disposal Limit (%)	6.8%	6.8%	6.8%	6.8%	6.8%	6.8%	6.3%	6.7%	6.7%	6.6%	6.7%	6.8%

Actual Disposal (%) = Actual disposal / (Total produced water + Total Fresh water including run off and remediation + brackish water)

Disposal Limit (%) = Disposal Limit / (Total produced water + Total Fresh water including run off and remediation + brackish water)

- N pad storage no longer used for disposal

Attachment 4

Facility Performance by Plant

Cold Lake Facility Performance

Maskwa Plant																					
Bitumen Production m ³ /d	6126.4	6360.2	6468.3	6602.8	6744.0	6849.1	6793.3	6798.3	7091.6	6834.6	6975.3	6913.8	6734.4	6925.6	7025.5	6820.4	6717.0	6672.4	6863.3	6613.1	6359.7
Produced Water m ³ /d	26908.4	27589.6	29448.0	28117.9	29724.1	31247.1	31080.5	30033.8	32429.8	27908.9	28060.3	26784.1	27406.1	28510.9	26224.8	26216.6	25946.9	25634.7	26605.9	25818.3	23213.8
HP Steam Generation m ³ /d	26109.7	24770.1	24767.1	25524.7	25050.9	25087.8	25038.8	23000.2	27016.9	26169.3	24966.4	24442.3	24228.8	22777.7	22783.7	24061.1	23342.6	22419.2	23564.1	23347.9	23920.5
HP Steam Injection m ³ /d	24355.8	23192.6	22989.9	23672.3	23139.4	23149.4	23402.2	21611.2	25536.1	24695.7	23216.2	22788.7	22593.2	21015.0	20673.7	22225.9	21711.0	20657.1	21657.1	21397.8	21969.9
Steam Quality %	69.9	70.6	71.4	66.1	64.7	66.8	67.1	72.1	74.7	71.7	71.7	73.2	71.4	71.4	59.1	70.4	73.6	74.3	72.3	67.8	67.8
Produced Gas km ³ /d	281.6	286.9	287.4	300.6	318.7	335.5	328.2	331.5	348.1	333.8	281.7	257.1	275.1	281.2	257.0	270.3	295.1	291.5	356.8	350.1	303.9
Purchased Gas km ³ /d	1302.1	1226.2	1216.7	1219.3	1132.7	1154.3	1226.5	1143.3	1402.8	1349.3	1277.7	1271.5	1258.7	1172.1	1084.1	1220.0	1201.0	1141.8	1177.9	1169.1	1226.8
Mahihkan Plant																					
Bitumen Production m ³ /d	9165.2	9166.6	9417.4	9060.9	9115.8	9148.0	8715.1	8548.9	8999.9	8993.0	9065.6	8680.3	8940.0	8776.2	8888.7	8831.6	8722.6	8936.8	9266.7	9293.8	9701.1
Produced Water m ³ /d	35675.3	36352.1	35751.5	34389.5	36237.4	35951.5	34589.7	33832.9	36152.6	34466.9	36012.6	34169.2	32267.4	34955.4	33512.4	34267.7	33898.3	32605.0	32791.4	33163.4	33710.2
HP Steam Generation m ³ /d	38399.3	39131.3	38904.0	40301.7	40899.3	40087.9	38126.3	38829.0	39087.8	36945.0	38560.0	39030.0	38193.6	38296.8	37459.8	40342.8	39745.8	38297.8	38781.3	38543.4	39180.3
HP Steam Injection m ³ /d	37605.1	37394.3	36952.4	38045.6	39207.1	38071.8	36295.3	36996.8	37020.7	34057.5	35332.5	36213.0	35076.7	35310.0	34384.4	37264.8	36578.4	35655.0	36163.5	35717.8	36394.9
Steam Quality %	72.7	73.9	72.6	71.9	73.0	72.3	72.5	70.1	72.2	70.9	71.4	72.8	71.7	72.1	71.5	72.7	72.0	71.4	71.6	71.5	72.1
Produced Gas km ³ /d	404.4	417.0	444.5	407.0	428.0	424.9	383.1	361.4	415.7	426.5	409.6	372.0	394.5	411.9	415.4	420.8	415.2	444.5	473.1	484.6	471.3
Purchased Gas km ³ /d	1817.6	1788.8	1765.7	1860.2	1869.1	1821.1	1752.7	1782.0	1786.7	1625.6	1693.0	1778.6	1732.4	1738.8	1709.3	1851.8	1827.6	1791.4	1808.0	1794.1	1817.8
Mahkeses Plant																					
Bitumen Production m ³ /d	4715.4	4796.0	4604.9	4410.7	4502.9	4428.1	4651.1	4580.8	4308.9	4404.8	4260.6	4298.9	4181.4	4504.9	4410.3	4448.6	4228.0	4551.9	4594.2	4622.2	4993.5
Produced Water m ³ /d	19622.9	19943.0	20399.0	19221.7	18540.0	15694.1	16363.6	15921.4	15565.9	15730.4	15629.4	17865.8	18293.0	19238.1	19184.1	15614.9	14841.8	16389.6	17669.5	18786.6	20373.5
HP Steam Generation m ³ /d	22227.2	22245.5	21563.5	21585.4	21517.8	20414.5	22332.2	22146.0	22806.2	22765.9	23054.9	22387.8	22583.7	22896.5	21407.4	24620.0	18710.3	21773.8	22649.2	21834.2	21983.9
HP Steam Injection m ³ /d	20524.4	20427.3	19999.3	14588.0	20220.1	19280.8	21018.2	20774.1	21321.2	20995.9	21321.0	20571.8	26226.9	25518.7	24836.1	15578.1	20459.2	24454.4	26752.5	24889.6	23241.1
Steam Quality %	68.7	68.1	68.0	67.4	66.7	68.2	69.5	69.7	69.6	69.9	69.9	69.7	69.9	69.9	69.6	67.8	65.5	68.3	68.0	66.1	65.7
Produced Gas km ³ /d	292.3	305.1	305.8	285.3	305.0	299.6	292.5	284.6	258.3	277.0	277.2	251.9	254.4	287.1	272.1	260.5	270.0	311.1	314.2	291.1	279.2
Purchased Gas km ³ /d	1592.6	1566.8	1505.6	1009.2	1417.9	1345.7	1485.9	1481.6	1563.5	1572.1	1597.2	1614.7	1622.8	1604.9	1557.5	957.3	1281.8	1482.2	1518.2	1474.1	1512.3
Leming Plant																					
Bitumen Production m ³ /d	1147.1	1232.1	1250.4	1162.6	1181.3	1095.6	1081.1	1143.8	398.8	791.6	1169.6	1085.0	1145.5	1179.1	994.7	916.2	1025.3	1149.9	1199.3	1295.5	1173.4
Produced Water m ³ /d	7546.3	8441.3	7826.5	6747.3	6434.4	5553.4	5638.0	6407.0	2482.3	5057.0	6768.7	5187.0	5762.3	5744.0	4571.6	4284.2	5347.8	5969.7	5508.4	5849.0	4695.7
HP Steam Generation m ³ /d	7373.6	6204.4	5195.5	5874.3	5071.4	4908.9	4655.0	4569.0	1455.0	3532.6	4426.1	4312.6	6184.1	6785.6	6768.8	4587.7	6094.9	7489.3	8373.0	8763.0	7587.6
HP Steam Injection m ³ /d	7218.6	5986.8	4992.5	5633.4	4677.3	4661.3	4328.2	4365.7	1413.5	3483.8	4336.0	4023.7	1793.8	2523.2	2021.8	2059.8	1944.4	2813.5	2484.9	4016.1	4840.5
Steam Quality %	71.6	69.6	67.8	69.7	68.0	66.5	70.9	69.6	63.4	49.8	61.8	57.0	68.5	69.5	72.7	65.4	68.9	66.3	67.5	68.8	66.7
Produced Gas km ³ /d	59.2	77.3	77.0	71.2	75.2	64.7	60.2	56.6	24.0	45.9	73.3	73.1	59.5	61.2	45.9	44.8	44.8	76.2	77.7	77.1	74.1
Purchased Gas km ³ /d	372.6	266.4	225.0	283.1	223.2	205.9	204.7	209.8	51.5	166.7	181.4	164.4	301.1	337.8	360.1	189.5	303.3	363.5	421.9	455.8	401.7
Nabiye																					
Bitumen Production m ³ /d	4621.6	5310.7	4406.2	3741.8	4622.9	5041.8	4256.8	3685.3	3609.8	4013.2	4112.8	4429.3	4703.6	2945.8	4029.3	4424.5	3898.5	4985.0	4159.6	3732.0	3980.7
Produced Water m ³ /d	12005.9	10409.4	10398.7	11864.1	12793.7	11492.0	12664.8	11795.9	11477.8	11631.2	11029.6	11662.8	12071.4	12495.4	12813.3	10578.1	11617.1	13912.9	11773.7	13538.7	13426.0
HP Steam Generation m ³ /d	16491.4	17227.4	16027.5	17049.5	18426.2	18463.3	18412.4	18113.4	15491.8	16196.3	18731.0	19103.0	16628.3	18790.1	18631.5	18843.4	19326.3	18453.7	19374.1	16663.0	13336.4
HP Steam Injection m ³ /d	15735.6	16514.6	15502.6	16428.3	17820.1	17837.9	17809.3	17409.9	15080.1	15591.6	17941.3	18028.1	15886.4	17965.8	17733.4	17710.2	18435.5	17692.7	18360.8	16013.1	12837.9
Steam Quality %	67.6	70.0	62.6	58.3	66.7	67.9	61.0	63.0	65.7	60.2	60.3	56.9	56.8	62.0	63.4	69.2	66.5	63.6	69.4	66.8	61.9
Produced Gas km ³ /d	145.1	149.3	131.1	123.7	158.7	177.4	169.2	161.9	154.4	151.5	138.4	145.7	154.3	118.8	137.4	142.7	150.6	163.0	168.3	166.4	170.8
Purchased Gas km ³ /d	1532.1	1518.1	1378.9	1287.3	1433.0	1403.8	1368.9	1379.6	1154.7	1258.6	1522.3	1579.5	1318.9	1578.3	1543.8	1542.2	1488.8	1428.0	1482.6	1427.2	984.8
SA-SAGD																					
Bitumen Production m ³ /d	56.7	46.2	58.6	58.9	49.6	35.4	43.5	62.9	50.7	40.6	48.1	38.5	37.3	33.3	45.2	39.4	32.1	26.2	21.6	23.0	16.5
Produced Water m ³ /d	208.4	306.4	319.6	268.7	145.4	108.7	101.0	151.1	176.7	183.2	218.6	176.7	196.3	210.9	220.6	184.2	184.1	151.1	141.1	99.3	85.2
HP Steam Injection m ³ /d	389.3	454.4	379.1	299.9	75.7	20.8	146.2	251.0	170.6	247.2	162.8	244.7	260.9	228.2	177.9	186.7	256.2	227.1	123.5	42.1	60.6
Produced Gas km ³ /d	1.0	0.8	0.6	0.3	0.3	0.2	0.2	0.3	0.4	0.3	0.9	0.5	0.3	0.3	0.6	0.8	0.3	0.1	0.0	0.1	0.1
District																					
Bitumen Production m ³ /d	25775.6	26865.5	26147.2	24978.8	26166.9	26562.6	25497.4	24757.1	24409.0	25037.2	25584.0	25407.4	25705.0	24364.8	25393.7	25480.8	24623.5	26322.1	26104.6	25579.6	26224.9
Produced Water m ³ /d	101758.8	102733.8	103823.7	100340.4	103729.5	99938.1	100336.6	97991.0	98108.4	94794.4	97500.6	96588.9	95800.3	101154.5	96526.8	91145.7	91836.0	94662.9	94490.0	97255.3	95504.4
HP Steam Generation m ³ /d	111601.2	109578.7	106457.6	110465.6	110965.7	108962.4	108464.6	106757.6	105857.7	105609.1	109738.5	109275.6	107682.5	109546.7	107051.1	102455.0	107173.9	108433.7	112741.7	109151.6	106008.7
HP Steam Injection m ³ /d	105439.5	103515.5	100436.6	98367.5	105063.9	102992.7	102891.2	101157.7	100371.6	98824.6	102147.0	101624.7	101377.0	102560.9	99827.3	95025.5	99434.6	101499.8	105542.3	102076.4	99344.9
Produced Gas km ³ /d	1183.6	1236.4	1246.2	1188.0	1285.9	1302.3	1233.4	1196.3	1200.9	1234.9	1181.1	1100.3	1118.1	1160.4	1128.3	1139.9	1131.6	1129.5	1369.1	1369.3	1299.4
Purchased Gas km ³ /d	5084.9	4848.2	4713.1	4371.7	4642.9	4527.1	4671.8	4616.5	4804.5	4713.8	4749.3	4									

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-16	Nov-16	Dec-16	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17
District	Sulphur Inlet	145.14	134.06	146.23	139.39	155.58	156.70	140.46	142.27	135.08	149.96	149.17	148.53
	Sulphur Removed	54.34	60.99	83.27	75.61	88.32	68.25	71.52	70.02	67.98	74.29	70.46	77.45
	Sulphur Emissions	90.80	73.07	62.96	63.77	67.26	88.45	68.94	72.25	67.10	75.68	78.71	71.08
	SO ₂ Emissions	181.60	146.14	125.92	127.55	134.53	176.91	137.88	144.50	134.21	151.35	157.41	142.16
	Sulphur Recovery	37.44%	45.50%	56.94%	54.25%	56.77%	43.55%	50.92%	49.22%	50.32%	49.54%	47.24%	52.14%
Leming	Sulphur Inlet	3.72	9.21	8.93	7.49	7.26	6.98	8.00	8.62	8.02	10.97	11.79	10.32
	Sulphur Removed	0	0	0	0	0	0	0	0	0	0	0	0
	Sulphur Emissions	3.72	9.21	8.93	7.49	7.26	6.98	8.00	8.62	8.02	10.97	11.79	10.32
	SO ₂ Emissions	7.44	18.41	17.86	14.99	14.51	13.95	16.00	17.25	16.04	21.94	23.58	20.63
	Sulphur Recovery	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Maskwa	Sulphur Inlet	33.75	27.36	25.83	27.66	28.02	33.89	34.75	29.33	26.75	34.79	29.12	27.78
	Sulphur Removed	0	0	0	0	0	0	0	0	0	0	0	0
	Sulphur Emissions	33.75	27.36	25.83	27.66	28.02	33.89	34.75	29.33	26.75	34.79	29.12	27.78
	SO ₂ Emissions	67.51	54.72	51.66	55.32	56.03	67.77	69.51	58.66	53.49	69.58	58.25	55.57
	Sulphur Recovery	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Mahihkan	Sulphur Inlet	53.13	55.70	53.59	44.56	36.97	43.62	48.95	49.94	42.64	46.55	45.84	44.64
	Sulphur Removed	31.50	30.85	42.43	32.62	26.29	22.21	37.34	37.55	28.74	33.82	26.64	31.37
	Sulphur Emissions	21.63	24.84	11.16	11.94	10.68	21.41	11.61	12.39	13.90	12.73	19.20	13.26
	SO ₂ Emissions	43.26	49.68	22.33	23.88	21.36	42.81	23.22	24.77	27.80	25.47	38.40	26.53
	Sulphur Recovery	59.29%	55.40%	79.17%	73.20%	71.11%	50.92%	76.28%	75.20%	67.40%	72.65%	58.11%	70.28%
Mahkeses	Sulphur Inlet	35.86	25.32	36.99	34.56	39.14	43.49	30.57	31.11	35.24	39.23	31.00	36.04
	Sulphur Removed	9.84	18.51	26.18	25.15	27.29	29.73	21.43	16.09	23.60	27.52	21.73	25.24
	Sulphur Emissions	26.03	6.80	10.82	9.41	11.86	13.76	9.14	15.02	11.64	11.71	9.26	10.80
	SO ₂ Emissions	52.05	13.61	21.63	18.82	23.71	27.53	18.27	30.05	23.29	23.42	18.52	21.60
	Sulphur Recovery	27.43%	73.13%	70.76%	72.77%	69.71%	68.35%	70.11%	51.71%	66.96%	70.15%	70.12%	70.03%
Nabiye	Sulphur Inlet	18.68	16.48	20.89	25.12	39.17	33.76	18.19	23.27	22.44	18.42	31.42	29.75
	Sulphur Removed	13.00	11.63	14.67	17.85	32.02	19.03	12.75	16.38	15.65	12.95	22.09	20.84
	Sulphur Emissions	5.67	4.86	6.23	7.27	7.15	14.73	5.44	6.89	6.79	5.47	9.33	8.91
	SO ₂ Emissions	11.34	9.71	12.45	14.54	14.30	29.45	10.88	13.78	13.58	10.94	18.66	17.83
	Sulphur Recovery	70%	71%	70%	71%	82%	56%	70%	70%	69.73%	70.30%	70.30%	70.04%

Sulphur Measurement & Reporting

Sulphur (H₂S) Sampling Process

- Manual gas samples taken to monitor H₂S 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)

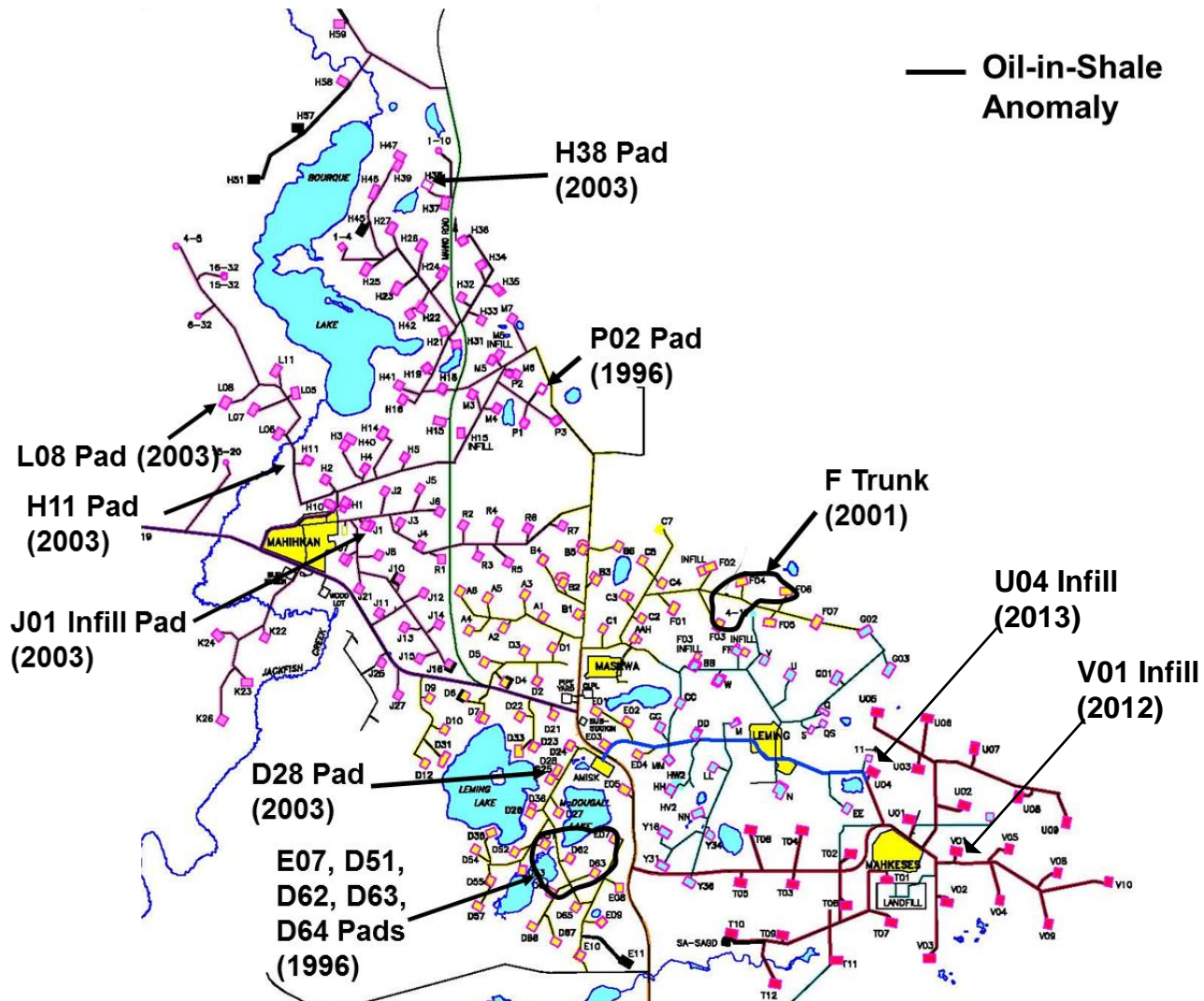
	Gas sample locations	Sampling Frequency
Maskwa Plant	Inlet gas P1 & P3	Weekly
Mahihkan Plant	Inlet gas P2/P4, P4 SRU outlets, P4 Treater gas, P4 Combined gas	Weekly (P2) MWF (P4)
Leming Plant	Inlet gas	Weekly
Mahkeses Plant	Inlet gas, SRU outlet, Treater Gas, Combined gas	TTh
Nabiye Plant	Inlet gas, SRU outlet, Treater Gas, Combined gas	TTh

- Sulphur measurement process accuracy is within the requirements of ID 2001-03 for reporting (+/- 0.1 tonnes S and +/- 0.1 km³ gas)
- Sulphur emissions are documented on a daily basis and monitored against the quarterly limits for each plant

Attachment 6

2017 Bitumen in Shale Report

Oil in Shale Summary



Oil In Shale 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.	Q4 2018 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), consistent with thermally mobilized BTEX.	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. No anomalous pressures in CEW observed since then. Closest GEW well has shown BTEX levels over CDWQG in the past but are now below detection limits.	Q2 2018
H38/H39	Oil reported during drilling of H38-12 and H38-22.	2003	No	Steaming restriction lifted Nov 25, 2004. No anomalous pressures in CEW observed since then. In Feb 2011 groundwater had benzene concentrations above CDWQG on H39. Since April 2013, chemistry has been below CDWQG.	Q3 2018
H11	Oil reported during drilling of H11-02 and H11-05	2003	No	No anomalous pressures in CEW observed since 2003. 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 2017

Oil In Shale 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	Q1 2018 (via infills)
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	Q2 2019 (via infills)

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
H38-CEW-24	106/16-3-66-4W4/0	297208	

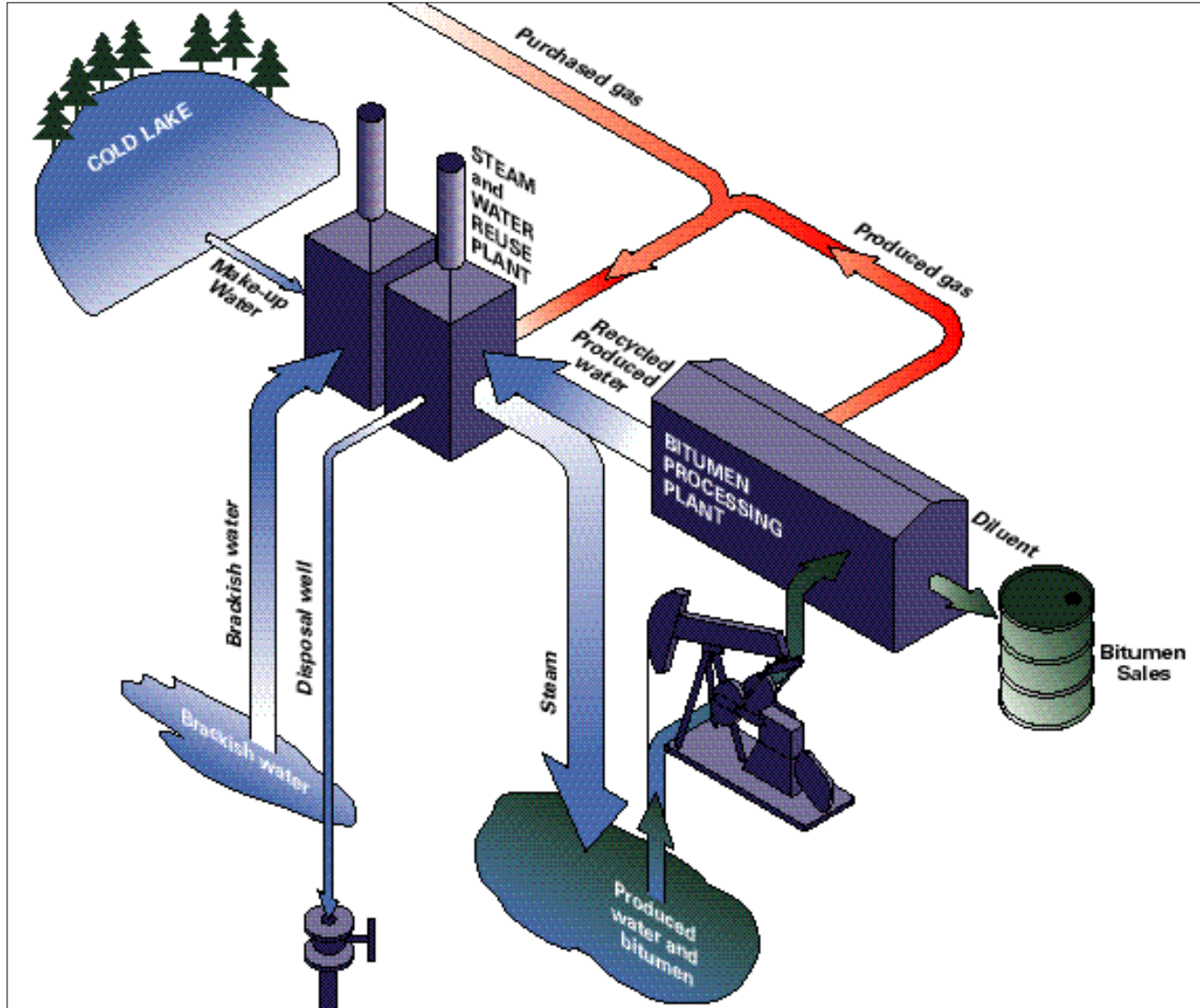
Table 2 – Colorado Evaluation Wells (CEWs) proposed for abandonment

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-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

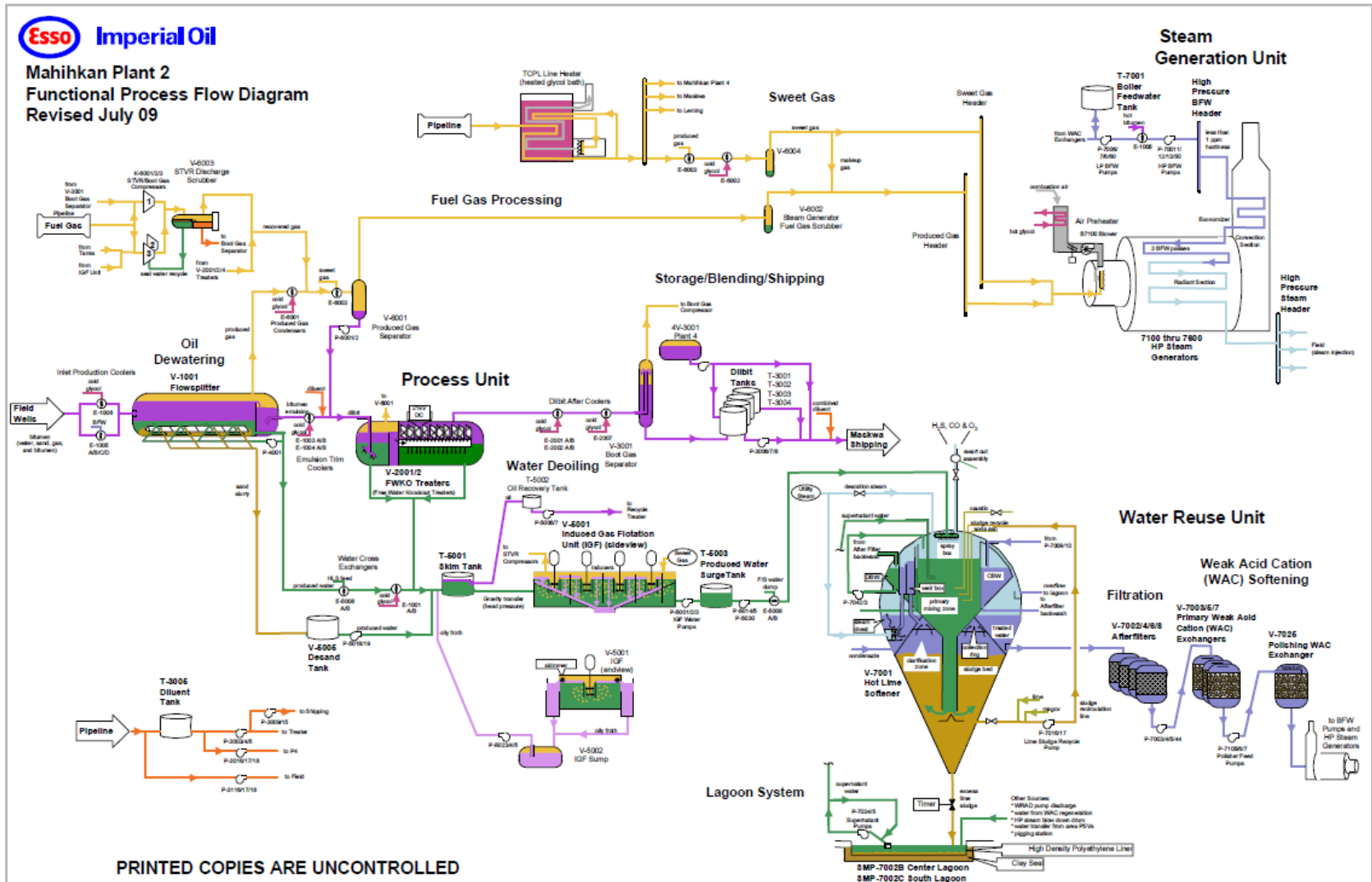
Attachment 7

Process Flow Schematics

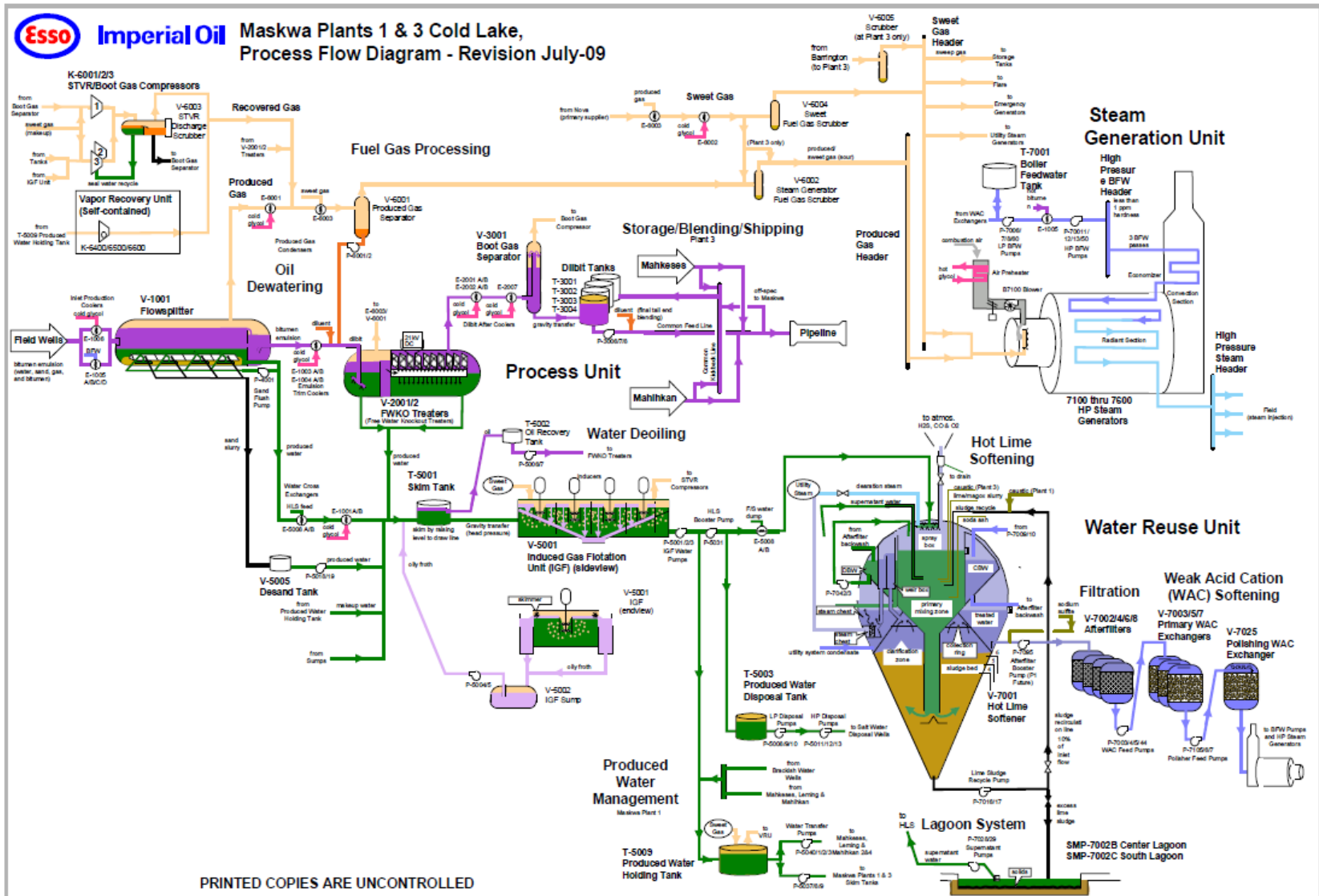
Cold Lake Operations Process Overview



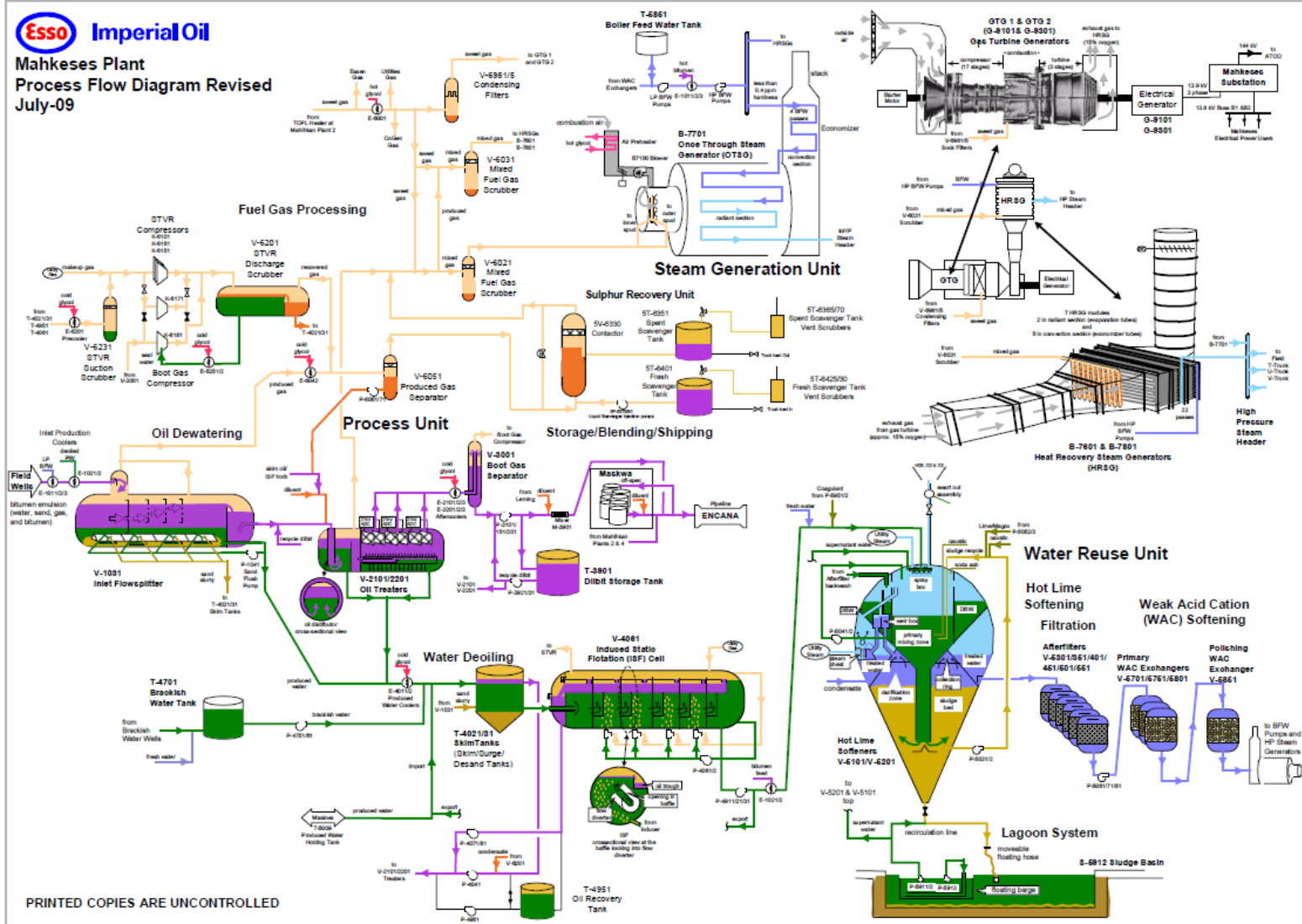
Process Flow Schematics



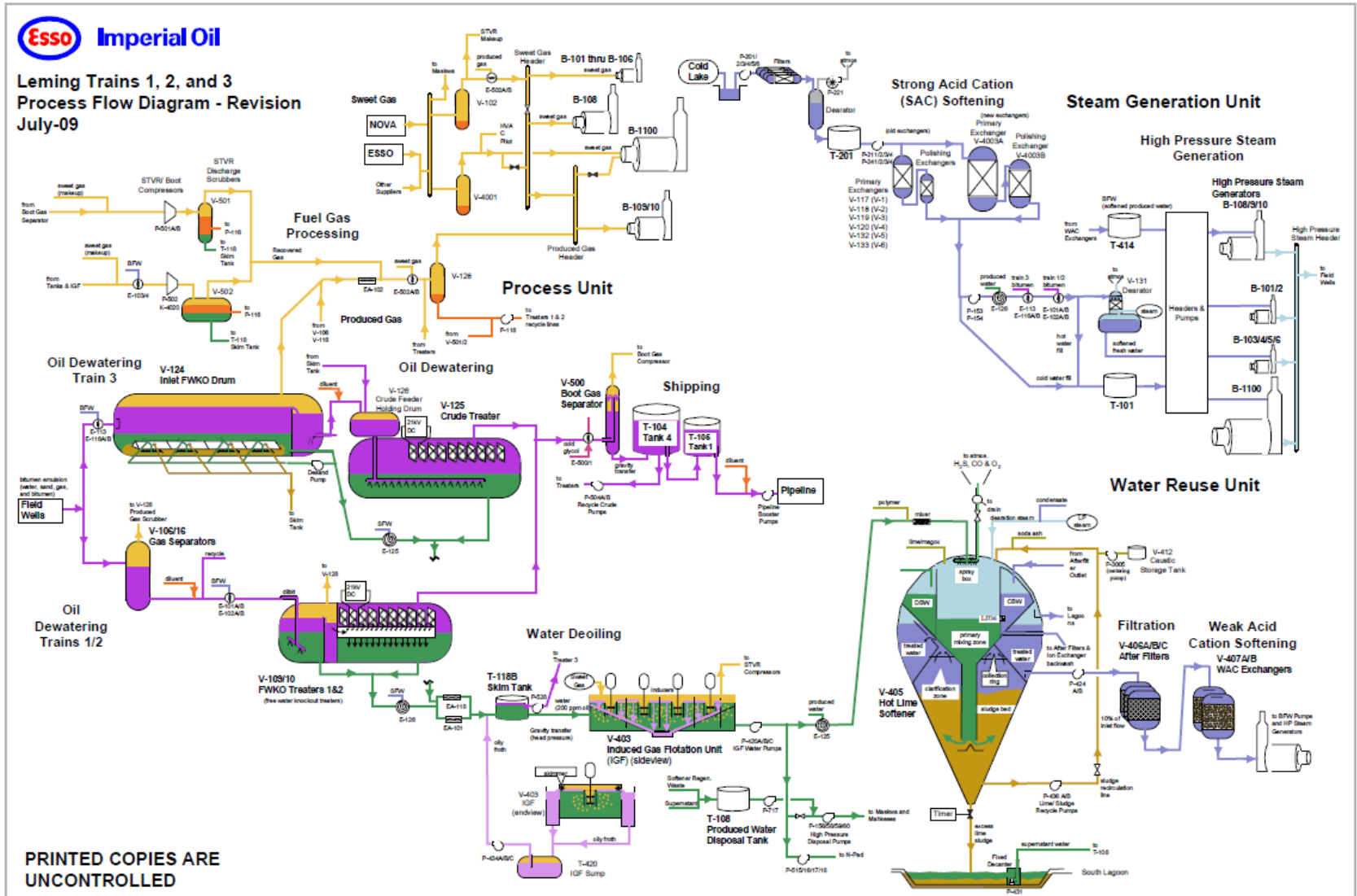
Process Flow Schematics



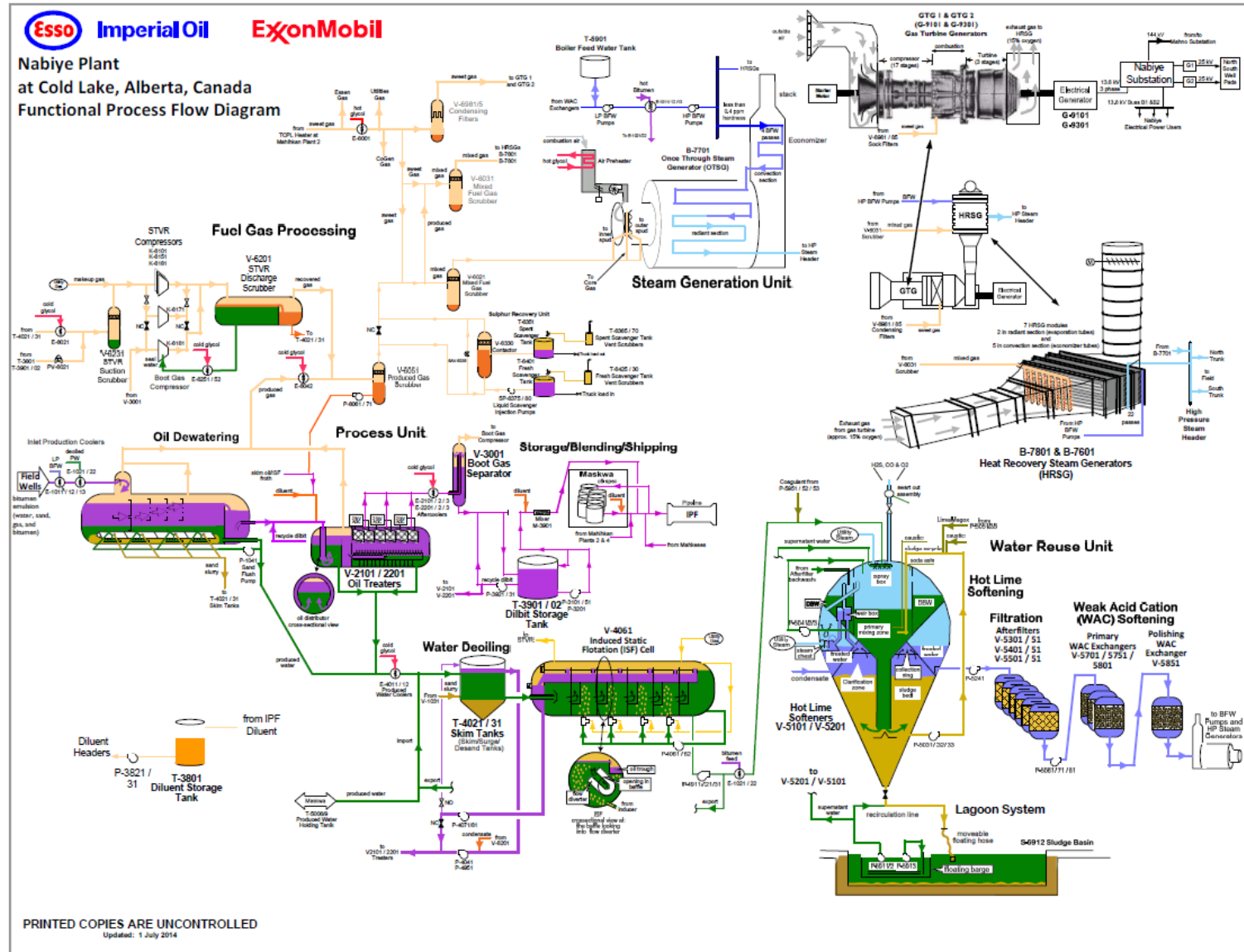
Process Flow Schematics



Process Flow Schematics



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
- Utilize brackish make-up water where appropriate
- 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 & Nabiye freshwater consumption significantly lower than other plants (<100 m³/d)
- 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 reduced freshwater consumption on site by 30% (reduction based on average consumption, 2006-2008)
- 20% of Cold Lake Water Diversion Licence released with 2017 renewal
- Commitment in 2017 renewal to continue to evaluate opportunities for non-saline water use reduction

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 CO₂

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 00148301-02-00		
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 00079923-02-00		
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 CaCO ₃	150 - 300 ppm	85 ppm	90 ppm	200 ppm	150 - 400 ppm
Mg as CaCO ₃	5–25 ppm	95 ppm	40 ppm	150 ppm	5–100 ppm
Total Hardness as CaCO ₃	155–325 ppm	180 ppm	130 ppm	350 ppm	155–500 ppm
Alkalinity "M"	450 ppm	1000 ppm	150 ppm	550 ppm	450 ppm
Alkalinity "TIC"	300 ppm	1000 ppm	150 ppm	550 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	CH ₄ , CO ₂ , H ₂ S	CH ₄ , CO ₂	Dissolved Oxygen	CO ₂	CH ₄ , CO ₂ , H ₂ S

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	400	250	280	--
AER	Water Inlet	m ³ /d	38,000	50,000	28,000	13,500	22,665	--
AER	H ₂ S 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	2.00	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	4,917.00	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

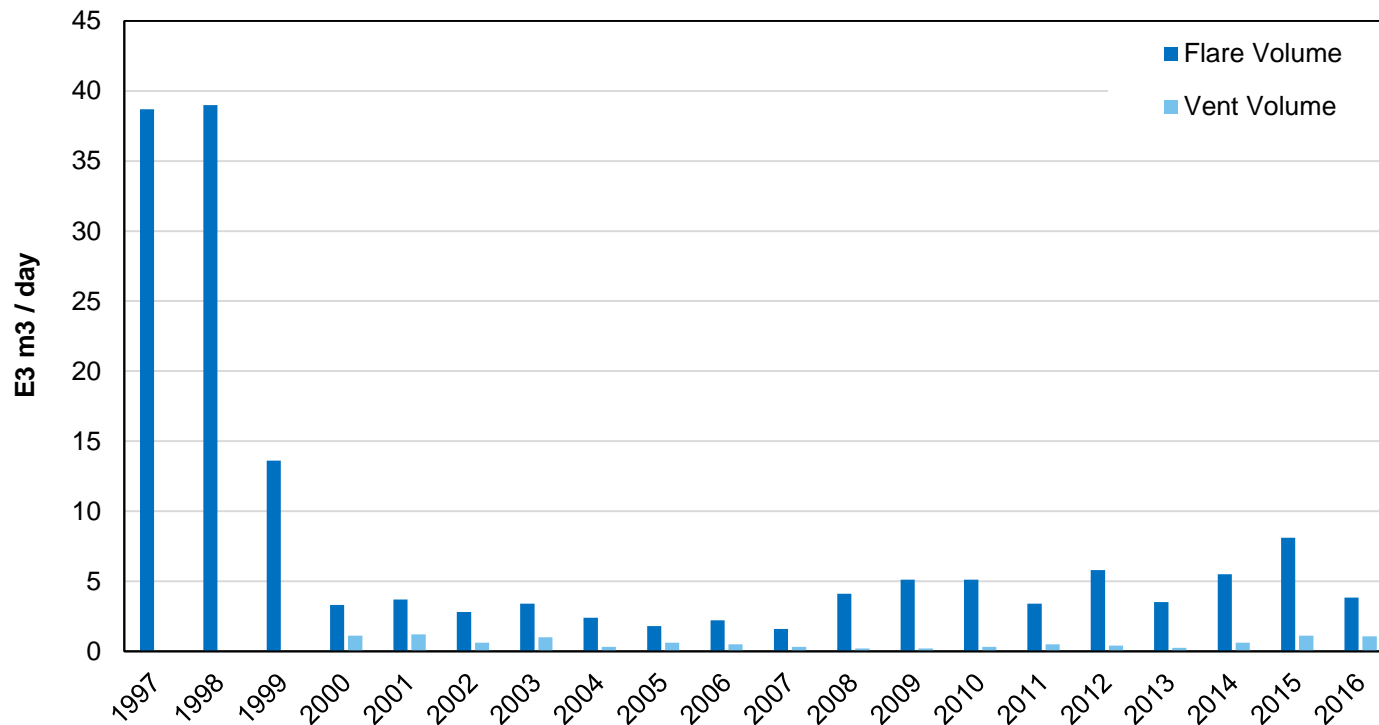
Flare and Vent

Monitoring Programs – Air Flare and Vent

Flare and vent volumes remain minimal.

Decrease in flaring volumes attributable to conservation efforts and reduction in overall plant upsets.

Average Flare and Vent Volumes



Attachment 11

SRU

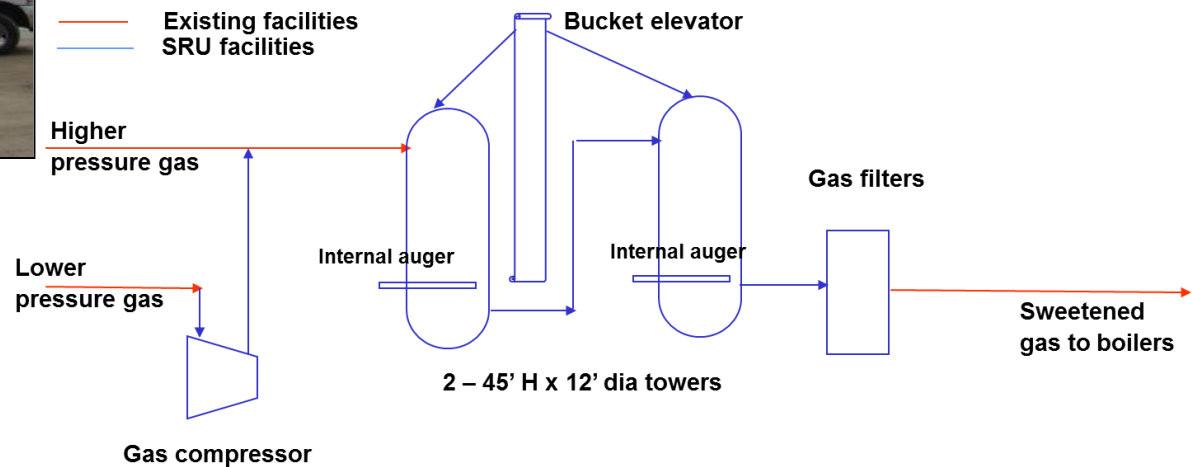
Description

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



Mahkeses SRU Description

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

- Selectively reacts with H₂S
- Forms water soluble compounds

8' dia x 30' H integral contactor tower and liquid/vapor separator

Sweetened gas to fuel system

