Cenovus FCCL Ltd.
Christina Lake In-situ Progress Report
Scheme 8591
2017 update

Subsurface
June 19, 2018

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Oil & gas and financial information

Oil & gas information

The estimates of reserves were prepared effective December 31, 2017. All estimates of reserves were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. Additional information with respect to pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2017 available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Advisory

This presentation contains information in compliance with:

AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc.

Subsection 3.1.1-1) Brief Background

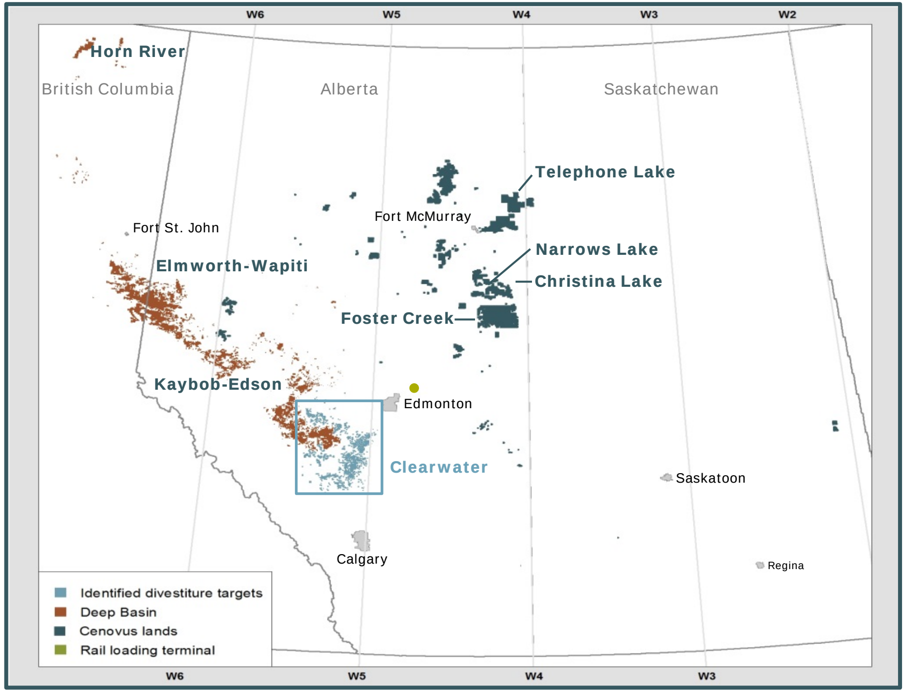
About Cenovus

TSX, NYSE | CVE

Enterprise value	C$ 23 billion
Shares outstanding	1,229 million

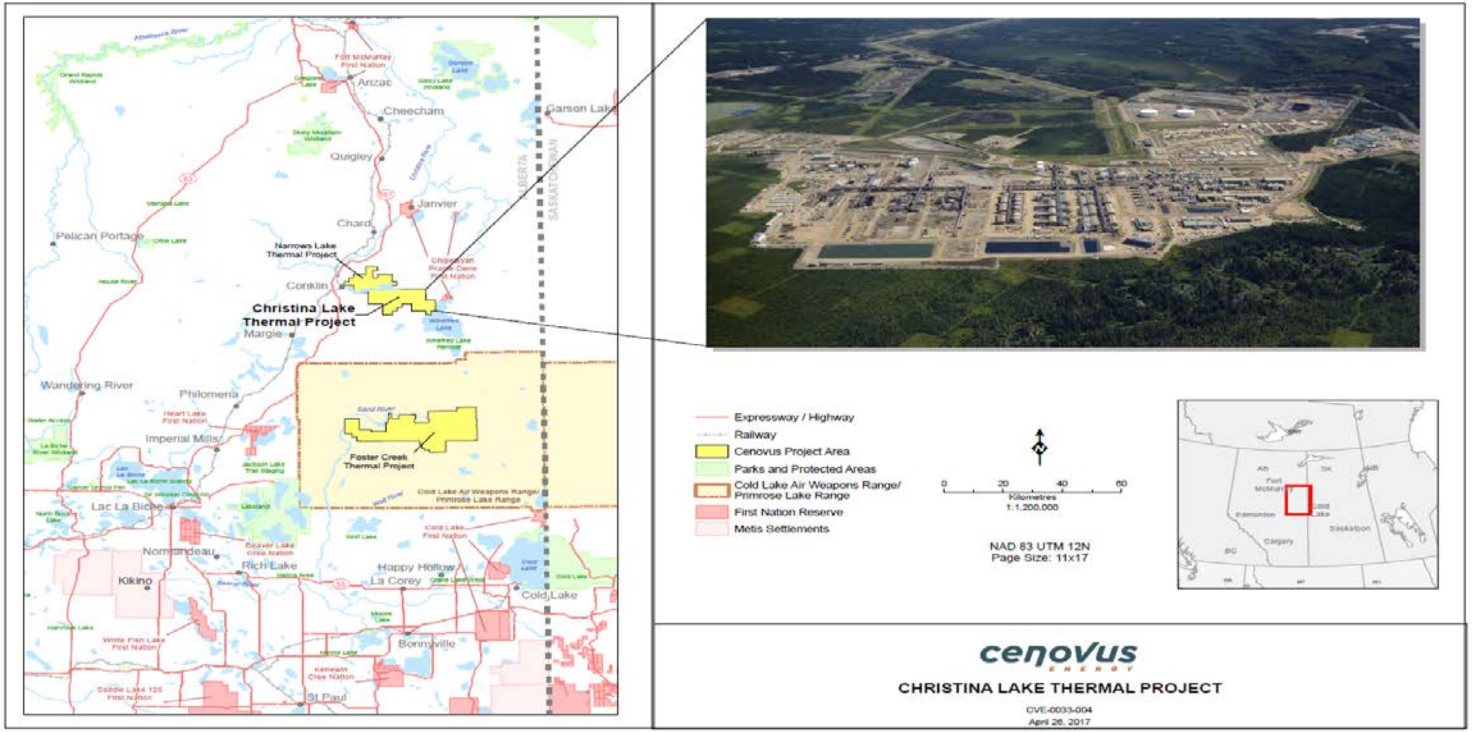
2018F production	
Oil sands	373 Mbbls/d
Deep Basin	
Oil & liquids	32 Mbbls/d
Natural gas	540 MMcf/d
Total liquids	405 Mbbls/d
Total natural gas[1]	550 MMcf/d
Total production	**497 MBOE/d**

2017 proved + probable reserves	7.1 BBOE
Refining capacity	230 Mbbls/d net



Note: Values are approximate. 2018F production based on the midpoint of December 13, 2017 guidance. [1] 2018F total natural gas includes production from the Deep Basin and Cenovus's Athabasca natural gas asset. See advisory.

Area map



Fort McMurray First Nation
Anzac
Cheecham
Garson Lake
Quigley
Janvier
Chard
Pelican Portage
Narrows Lake Thermal Project
Conklin
Christina Lake Thermal Project
Margie
Wandering River
Philomena
Imperial Mills
Foster Creek Thermal Project
Cold Lake Air Weapons Range/ Primrose Lake Range
Lac La Biche
Normandeau
Rich Lake
Kikino
Happy Hollow
La Corey
Cold Lake
Bonnyville
St Paul
ALBERTA
SASKATCHEWAN
Expressway / Highway
Railway
Cenovus Project Area
Parks and Protected Areas
Cold Lake Air Weapons Range/ Primrose Lake Range
First Nation Reserve
Metis Settlements
0 20 40 60
Kilometres
1:1,200,000
NAD 83 UTM 12N
Page Size: 11x17
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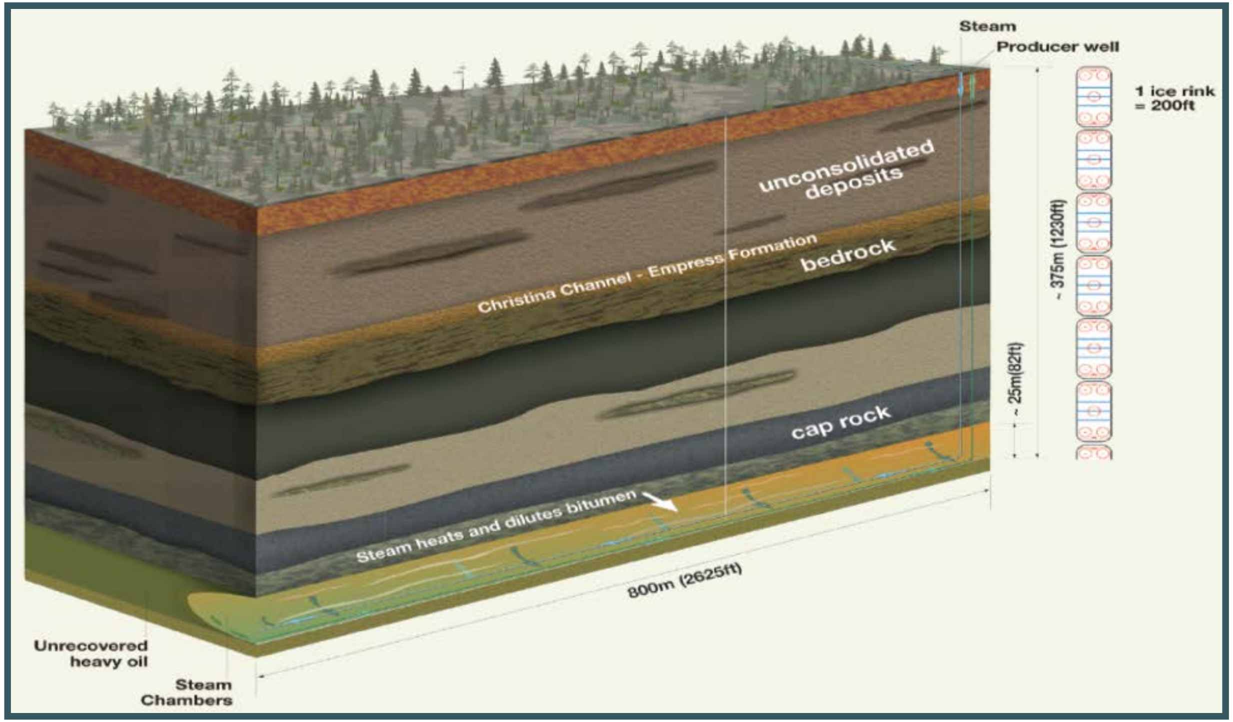
CHRISTINA LAKE THERMAL PROJECT
CVE-0033-004
April 26, 2017

Recovery Process

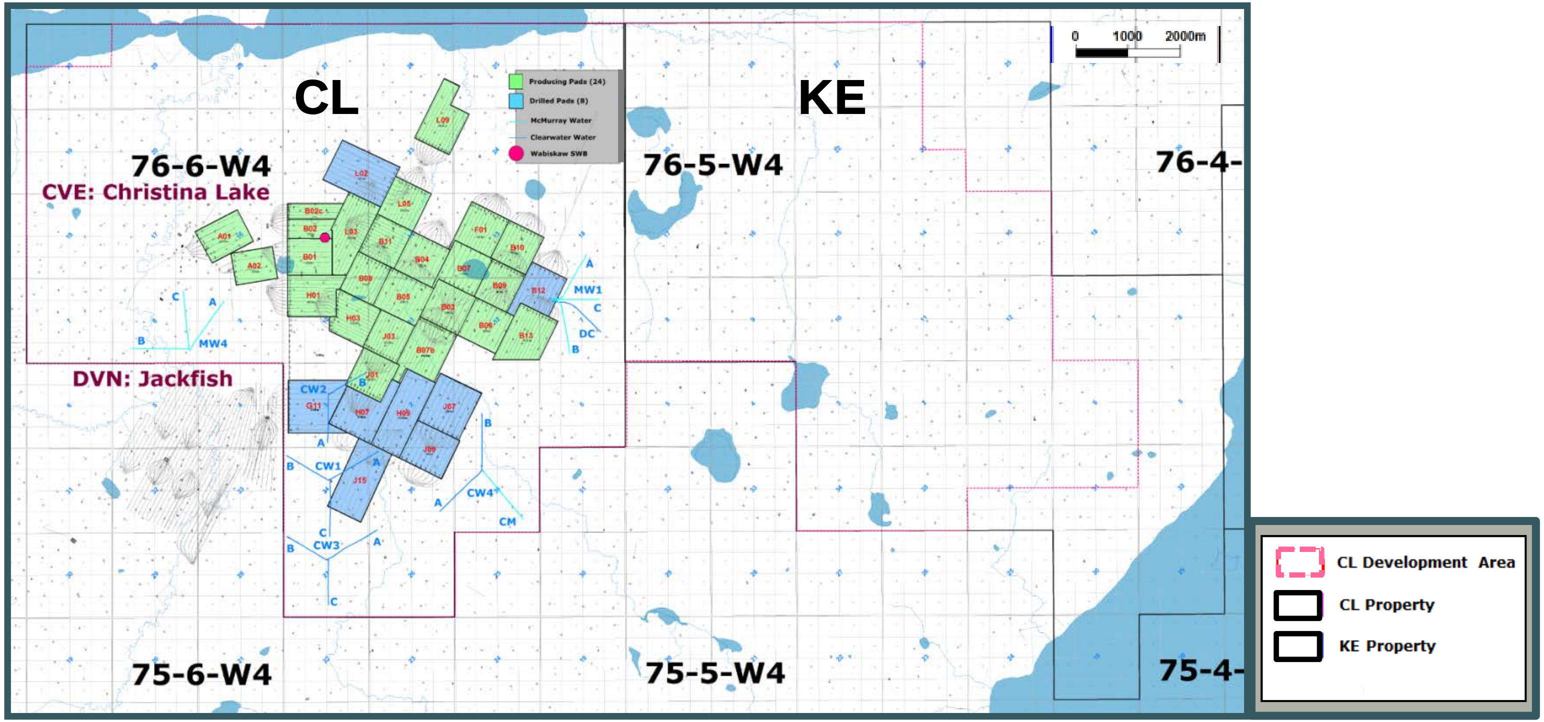
<u>Christina Lake Thermal Project</u>

Uses the dual-horizontal well SAGD (steam-assisted gravity drainage) process to recover oil from the McMurray formation

- Two horizontal wells one above the other approximately 5 m apart
- Steam is injected into the upper well where it heats the oil and allows it to drain into the lower well
- Oil and water emulsion pumped to the surface and treated



Scheme Map: Christina Lake & Kirby East



Subsection 3.1.1 – 2) Geology and Geoscience

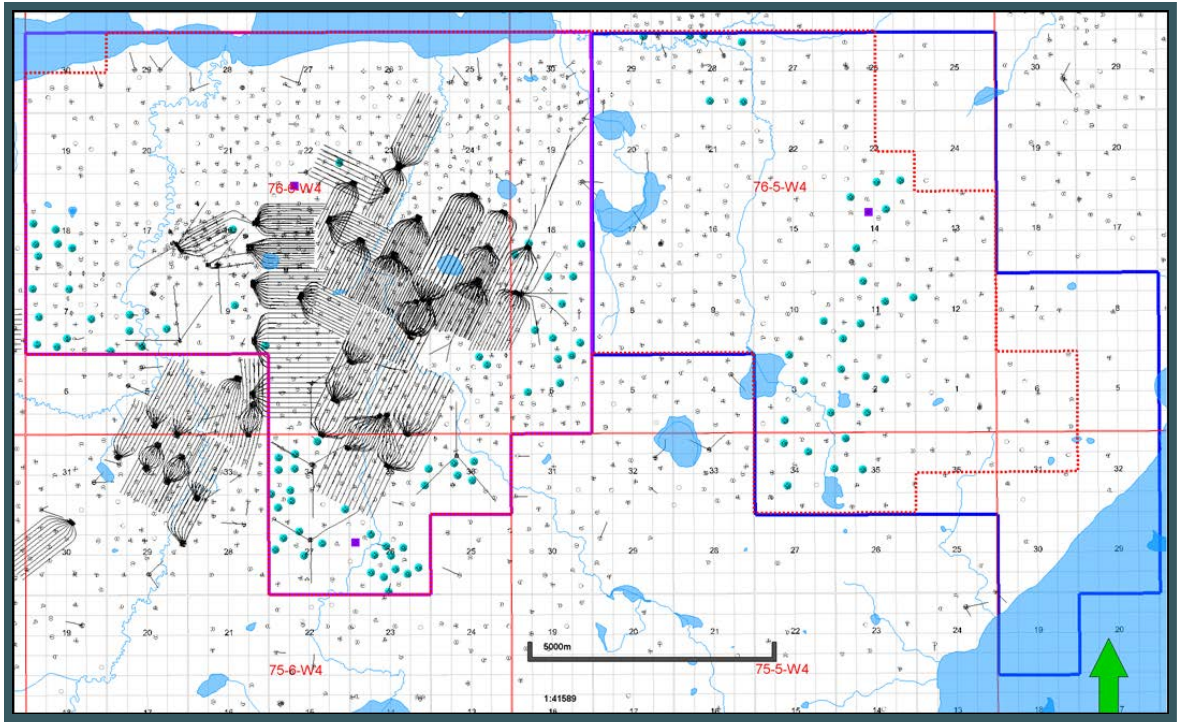
Reservoir properties and SOIP*

Property	Christina Lake Project Area	Kirby East Project Area	Approved Development Area
Reservoir Depth	350m TVD	350m TVD	350m TVD
Original Reservoir Pressure	2500 kPa	2500 kPa	2500 kPa
Original Reservoir Temperature	12°C	12°C	12°C
Average SAGD Pay h	22m	19m	21m
Average Kv	4.2D	4.2D	4.2D
Average Kh	7.0D	7.0D	7.0D
Average Phi	31%	29%	30%
Average So	79%	76%	78%
SOIP (MMm3)	487	193	680
SOIP (MMBbl)	3,064	1,211	4,275

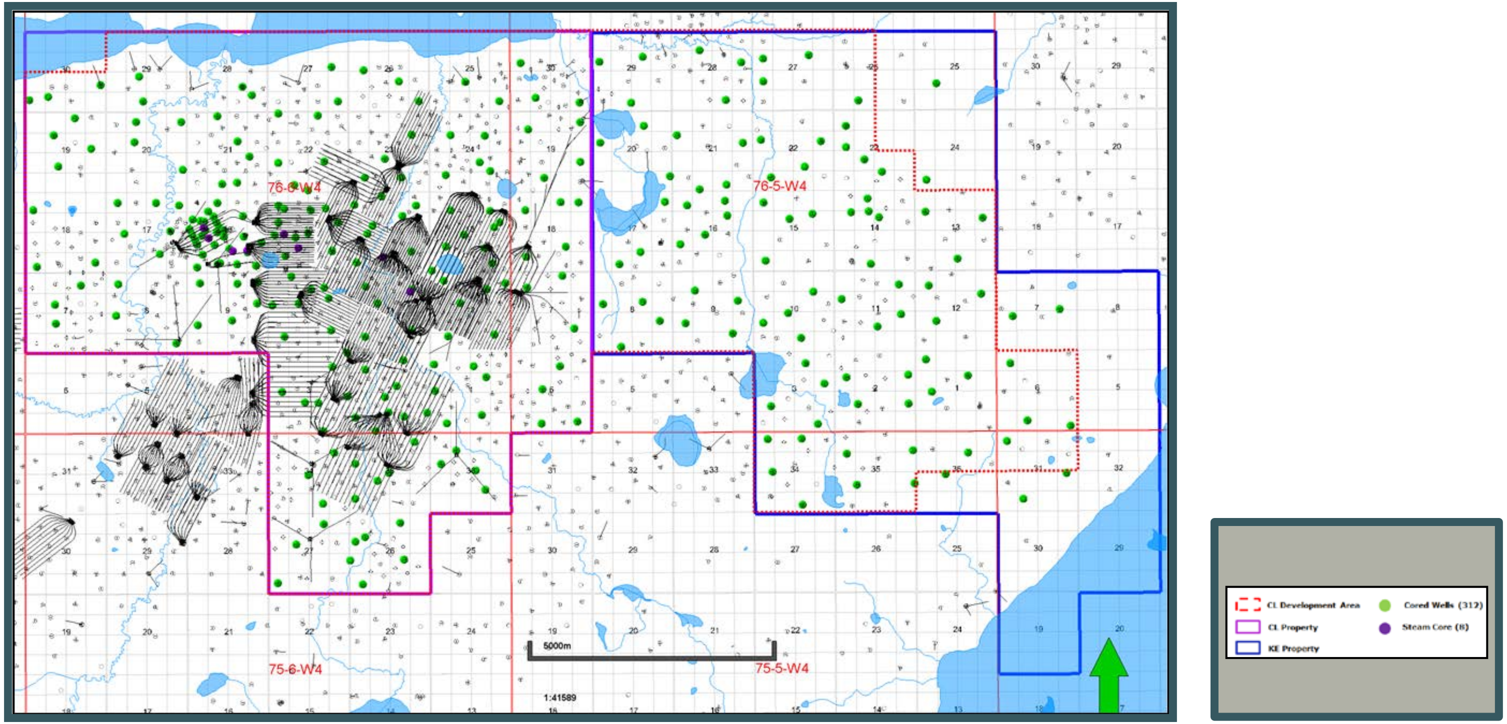
*Volumes include Main and Upper Main

*All SAGD-able (SOIP) estimates are internal estimates. There is no certainty that any portion of such quantities will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such quantities.

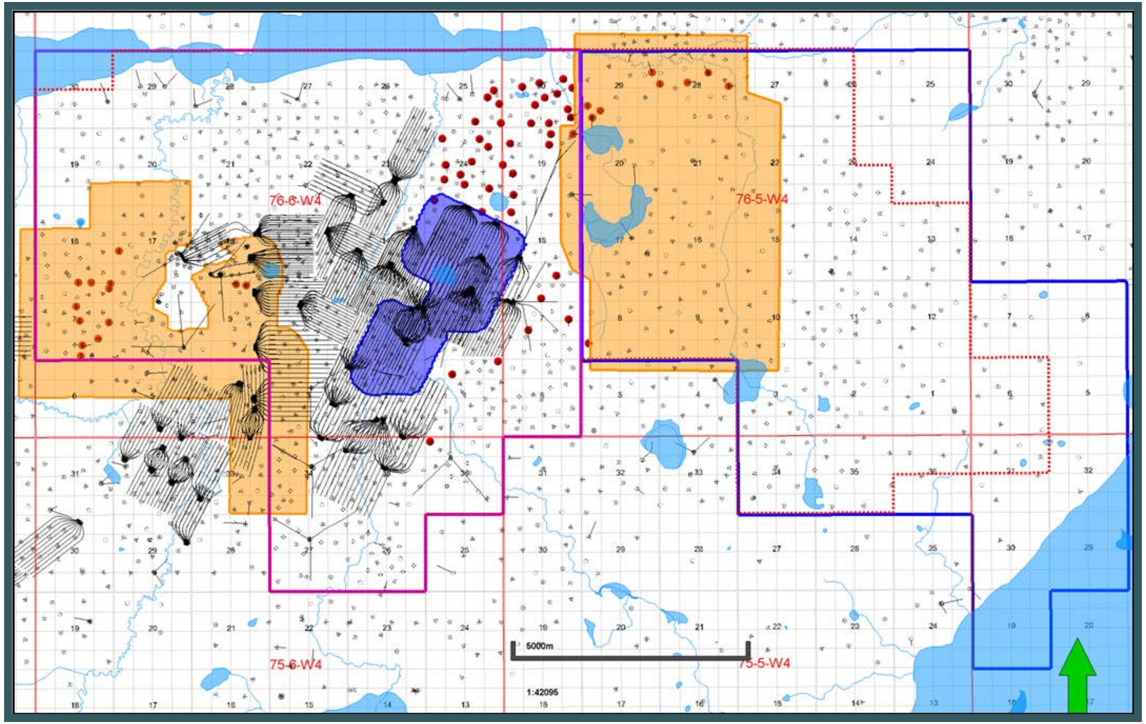
2017/18 drilling program and cored wells

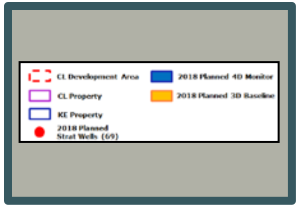


Project area core and steam core



2018 planned strat and seismic program





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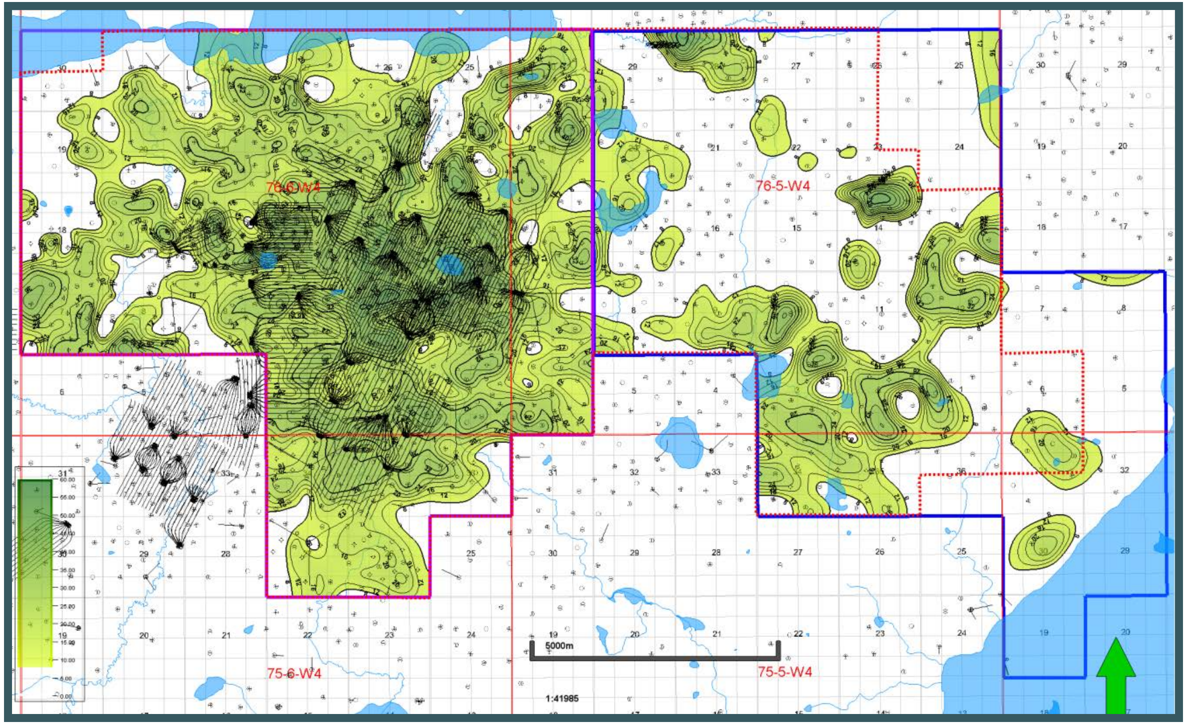
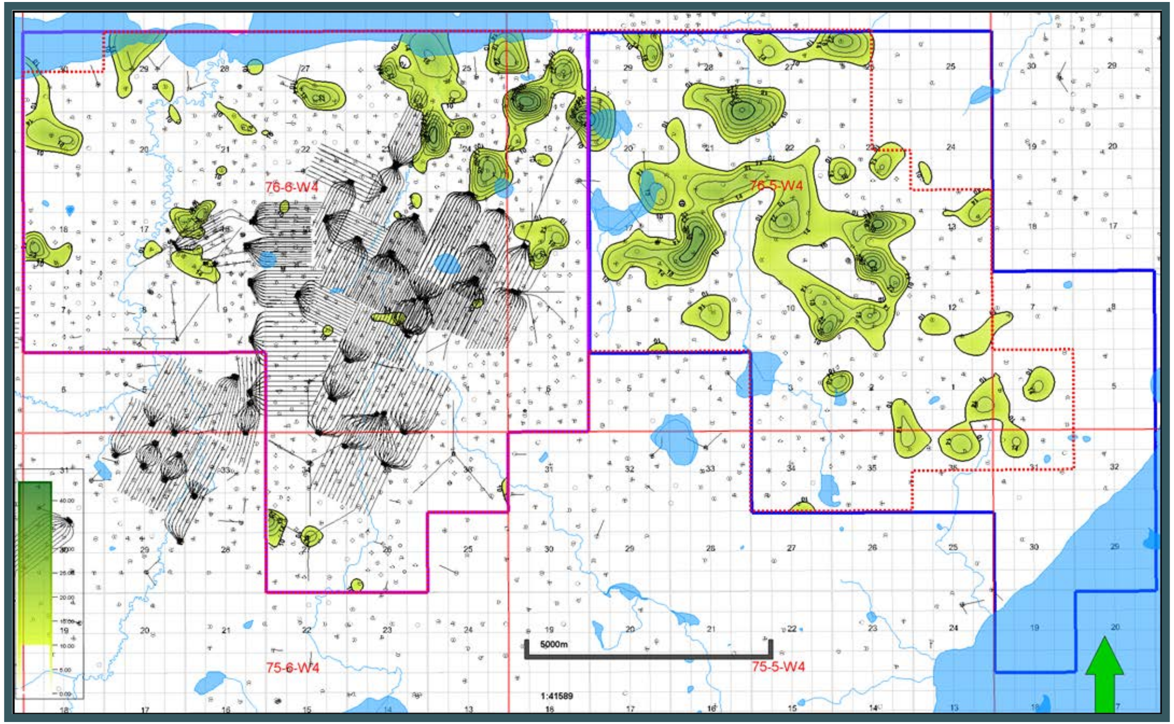
Geological maps

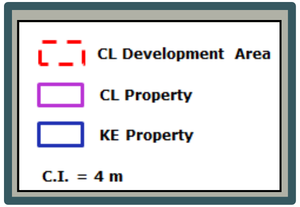
SAGD pay isopach map (main zone)



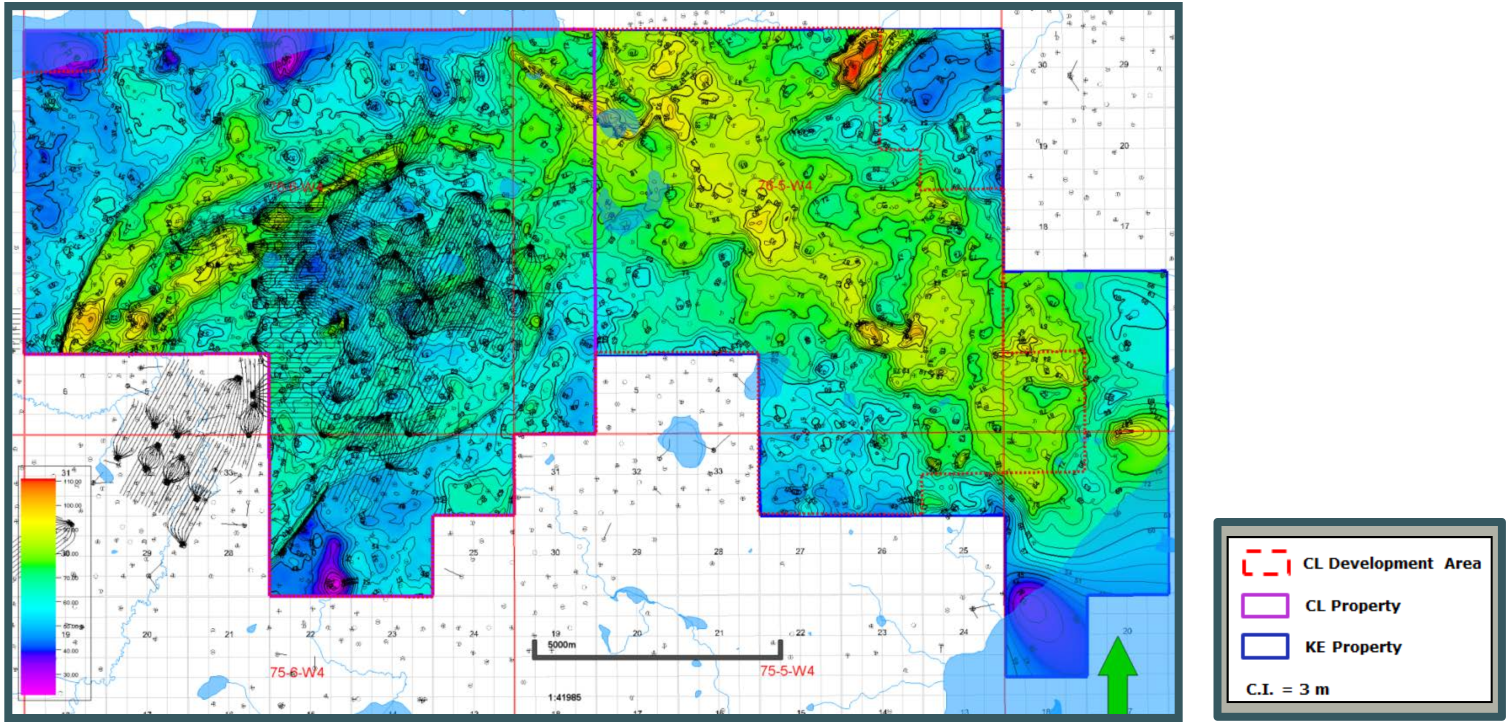
CL Development Area
CL Property
KE Property
C.I. = 4 m

SAGD pay isopach map (upper zone)

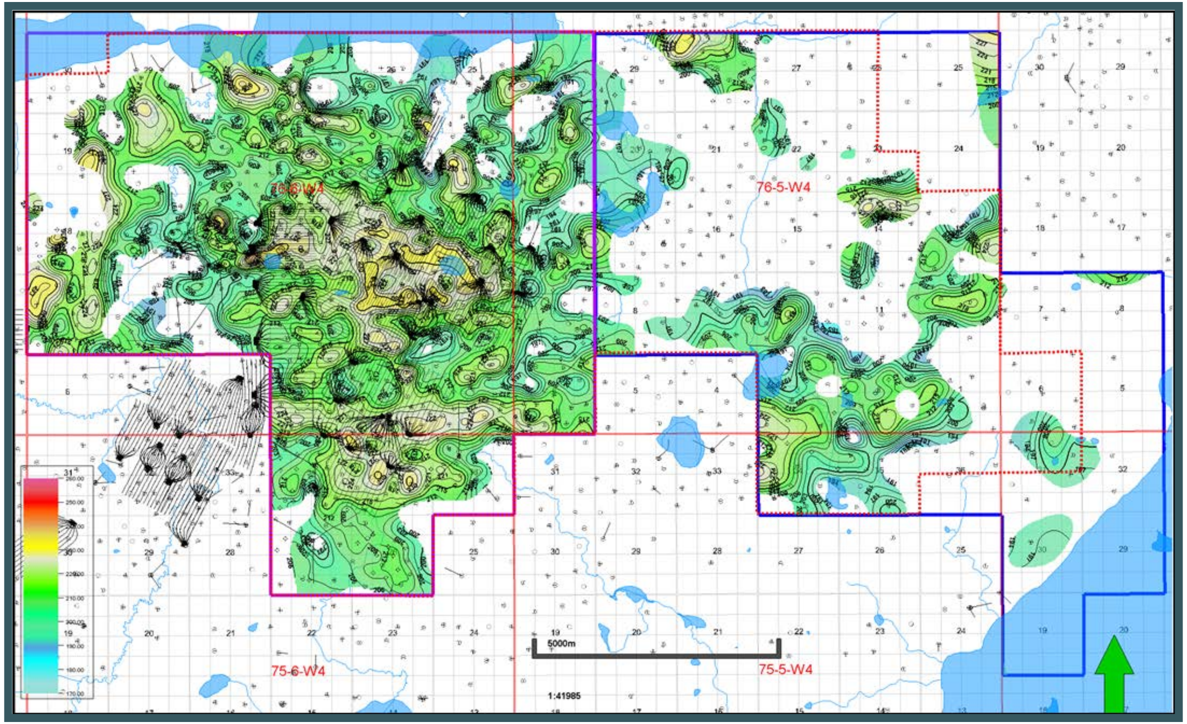


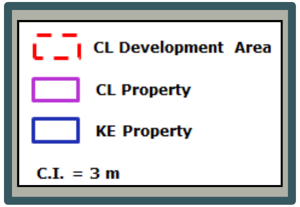


McMurray isopach map

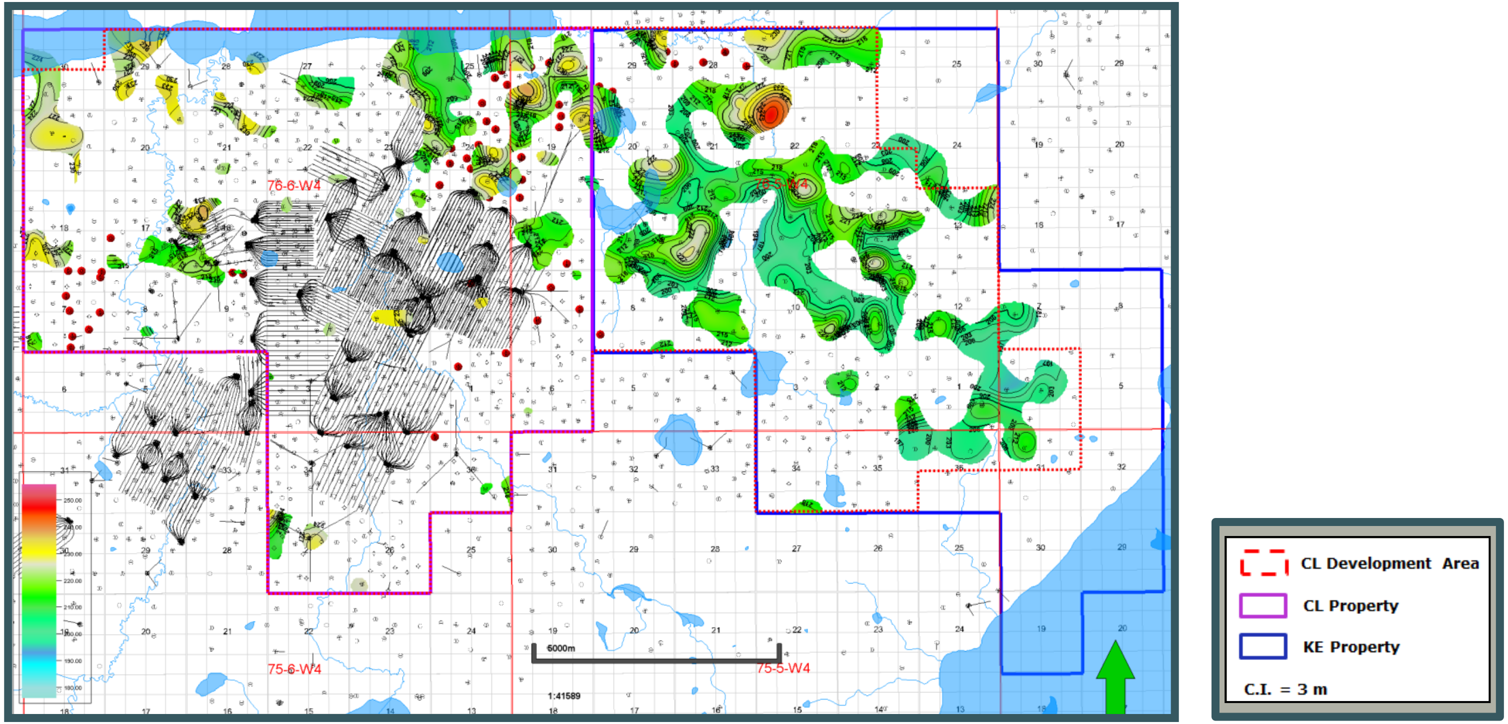


SAGD pay top structure map (main)

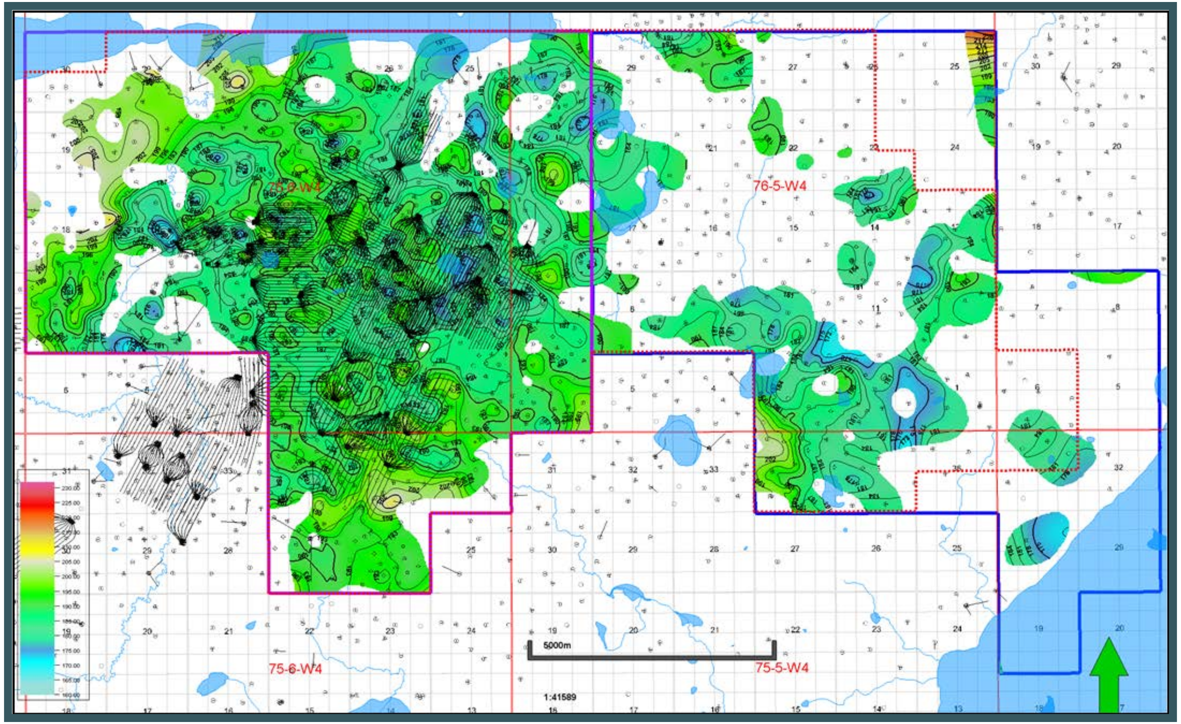


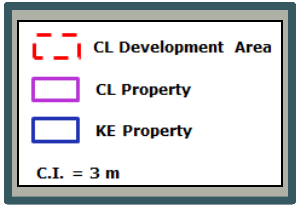


SAGD pay top structure map (upper)

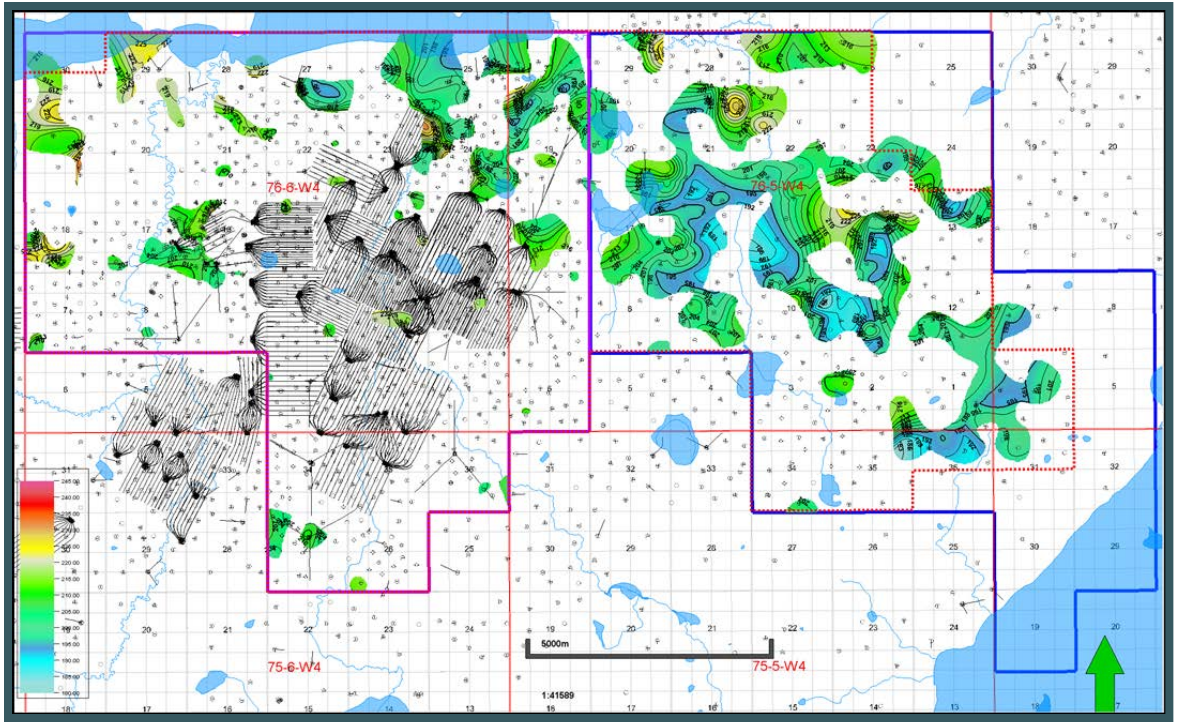


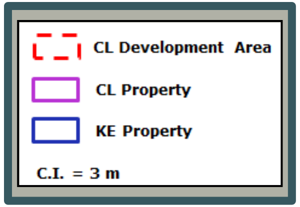
SAGD pay base structure map (main)



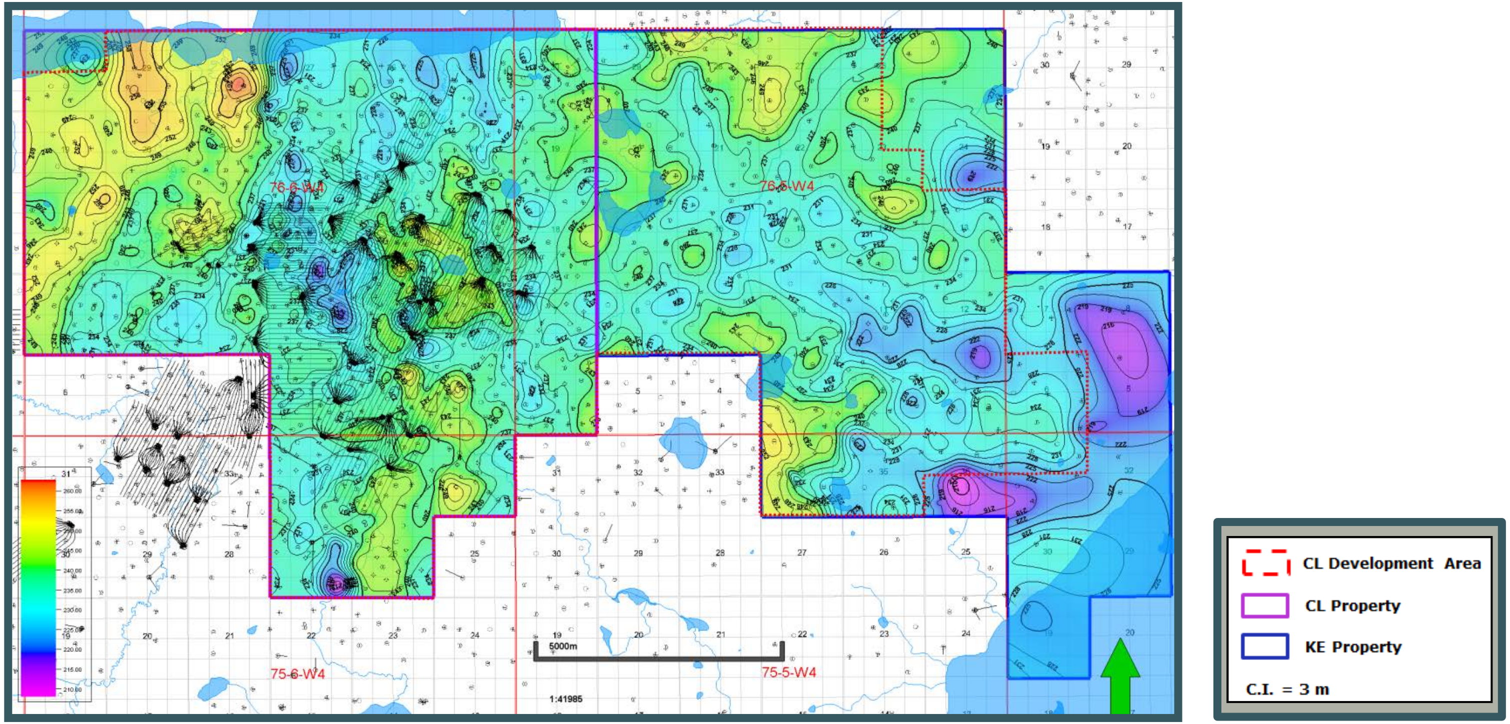


SAGD pay base structure map (upper)

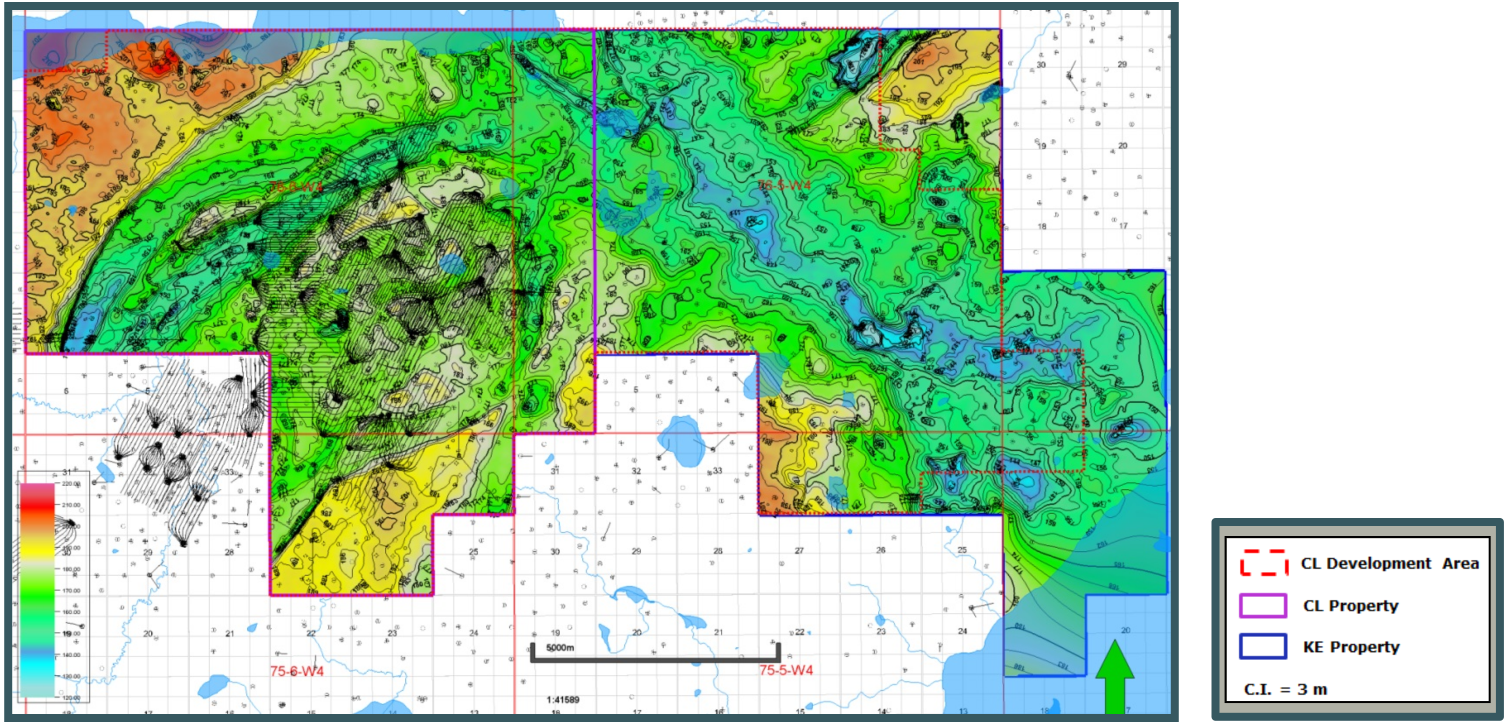




McMurray structure map



Paleozoic structure map

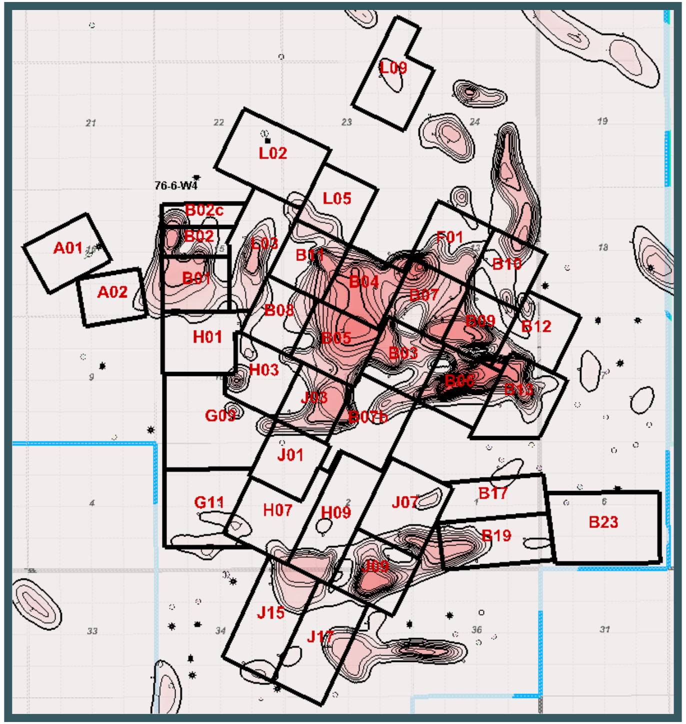


SAGD top gas isopach

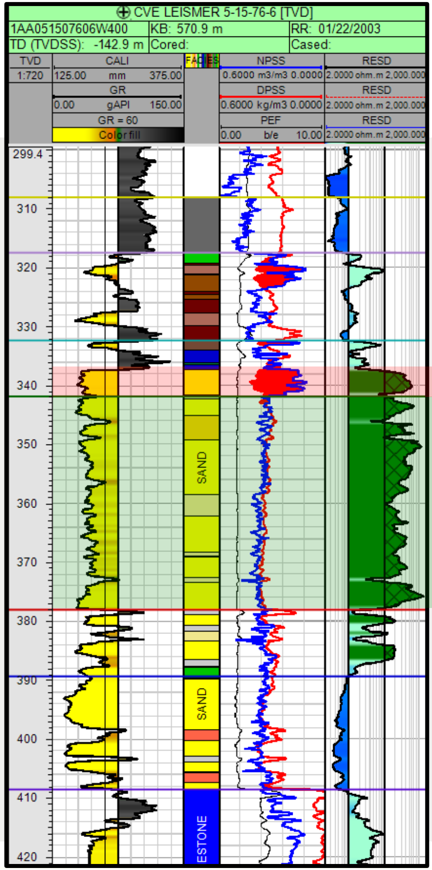
1m contour interval

3 main gas pockets:

- **‘Sec 15’**
  - centered over Section 15
- **‘11-14’**
  - centered over Section 11
- **‘Southern’**
  - centered over Section 2



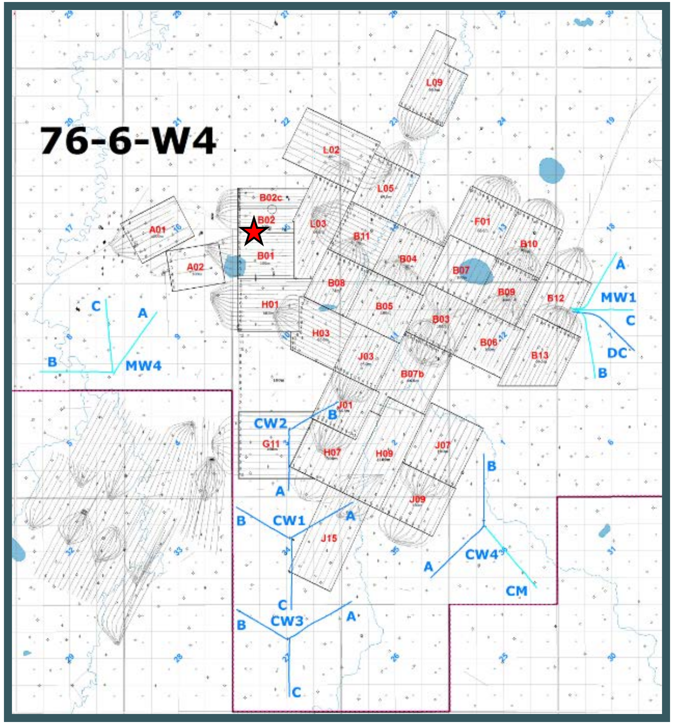
Type log: B01 pad



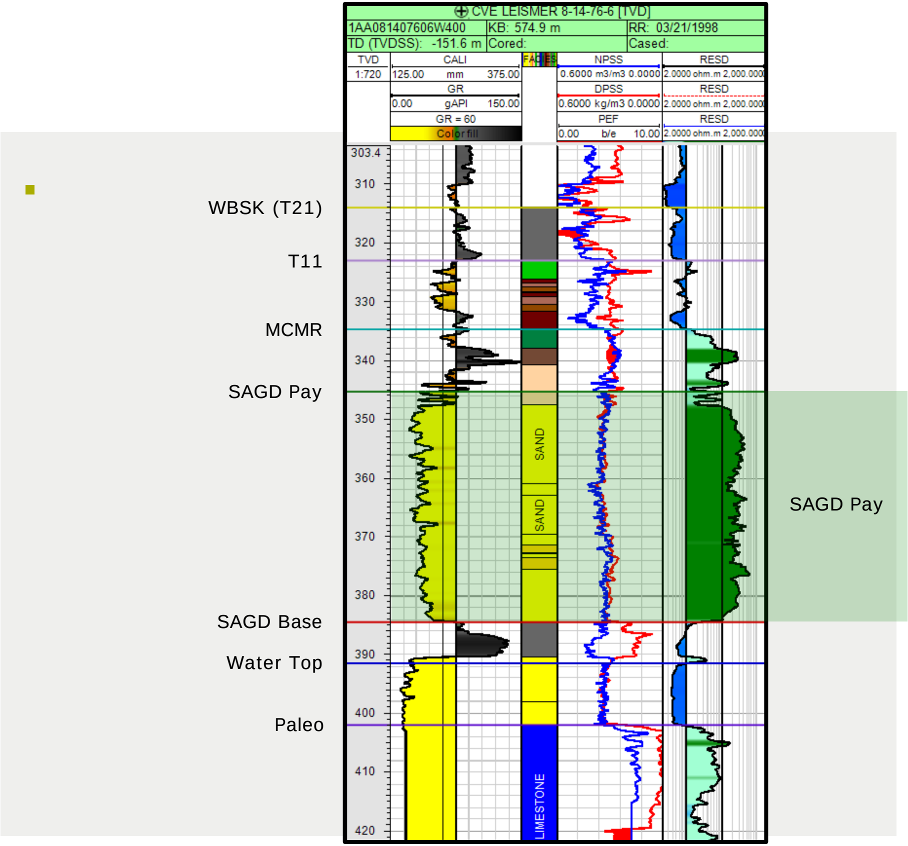
- WBSK (T21)
- T11
- MCMR
- SAGD Pay
- SAGD Base
- Water Top
- Paleo

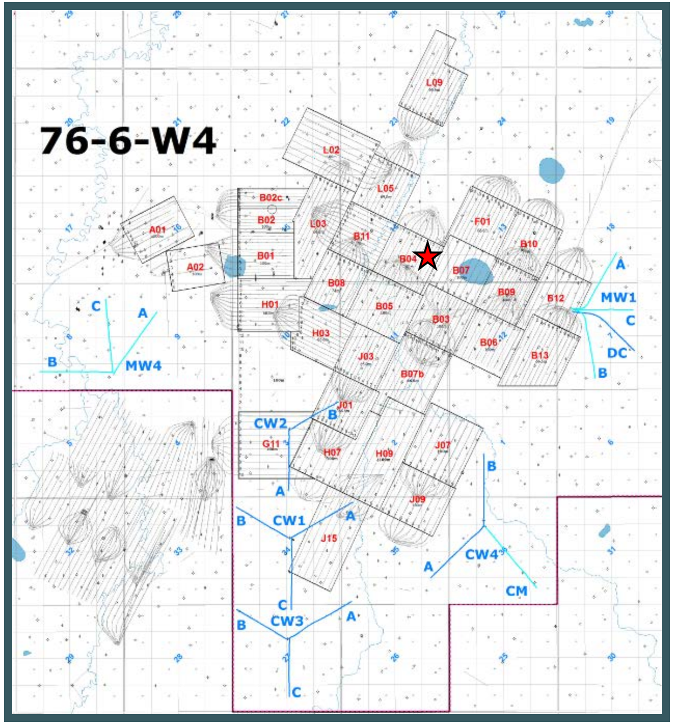
SAGD Gas

SAGD Pay

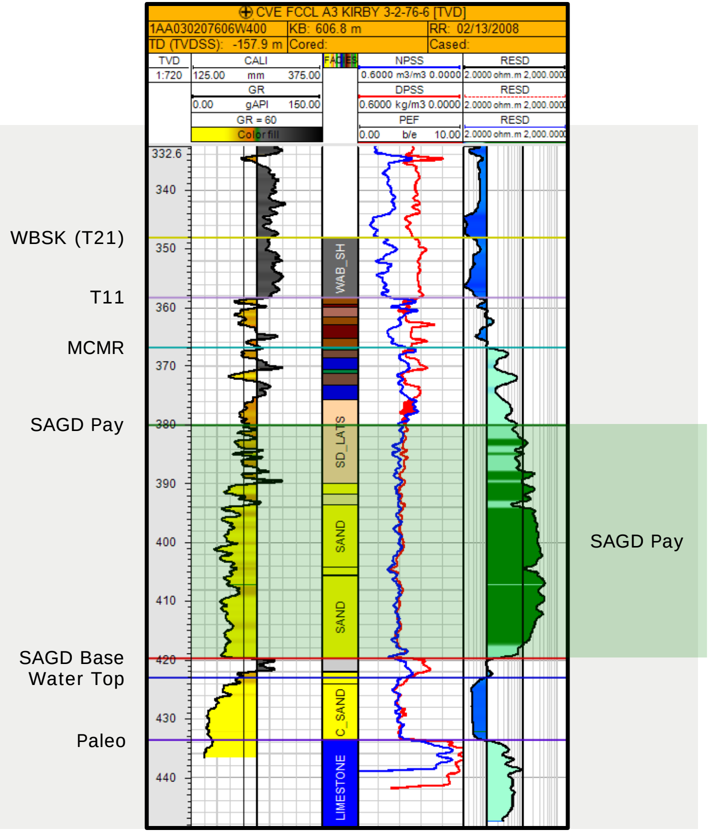


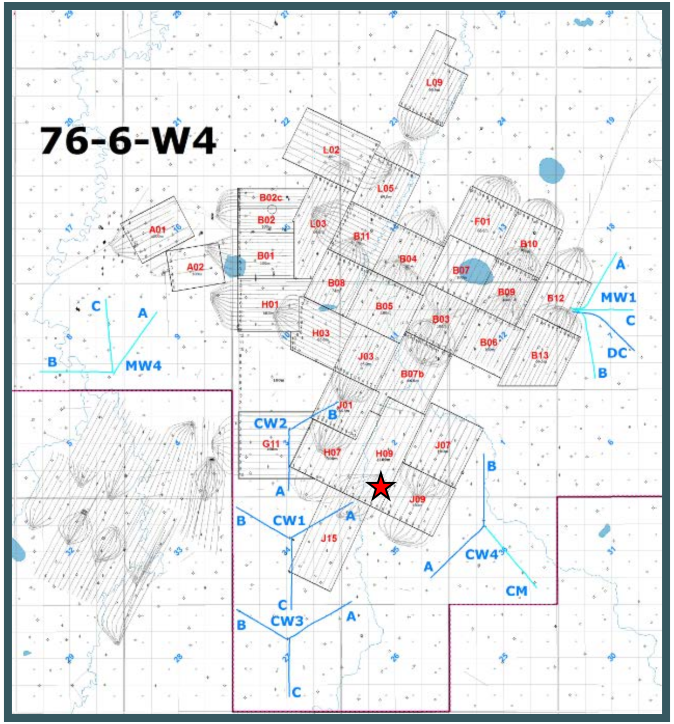
Type log: B04 pad



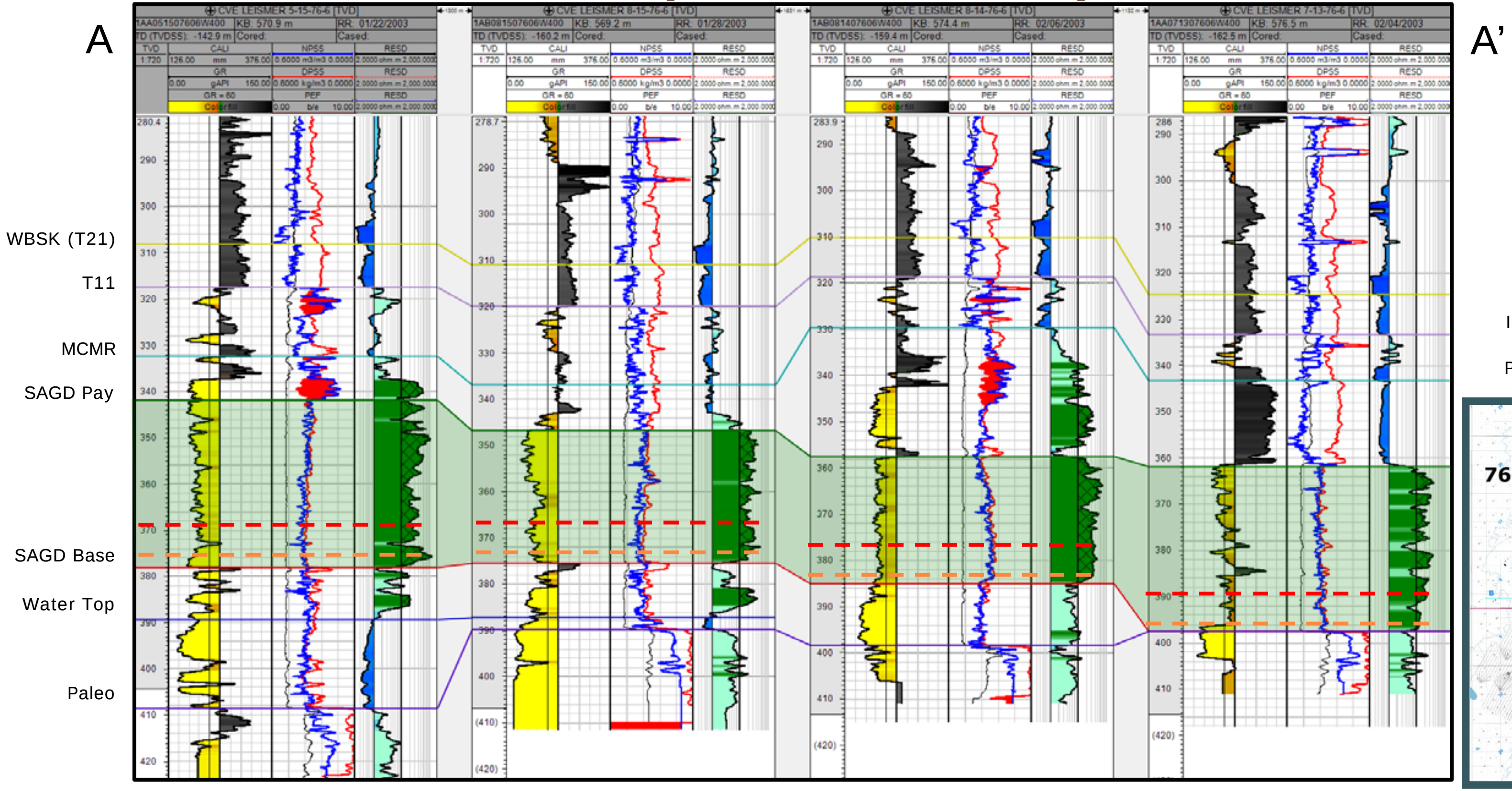


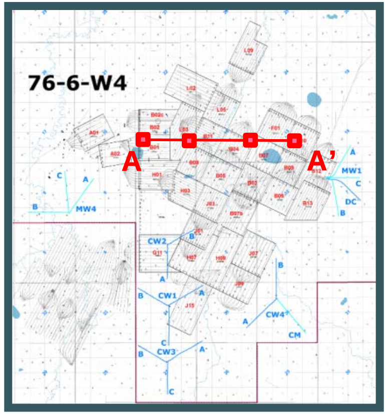
Type log: H09 pad



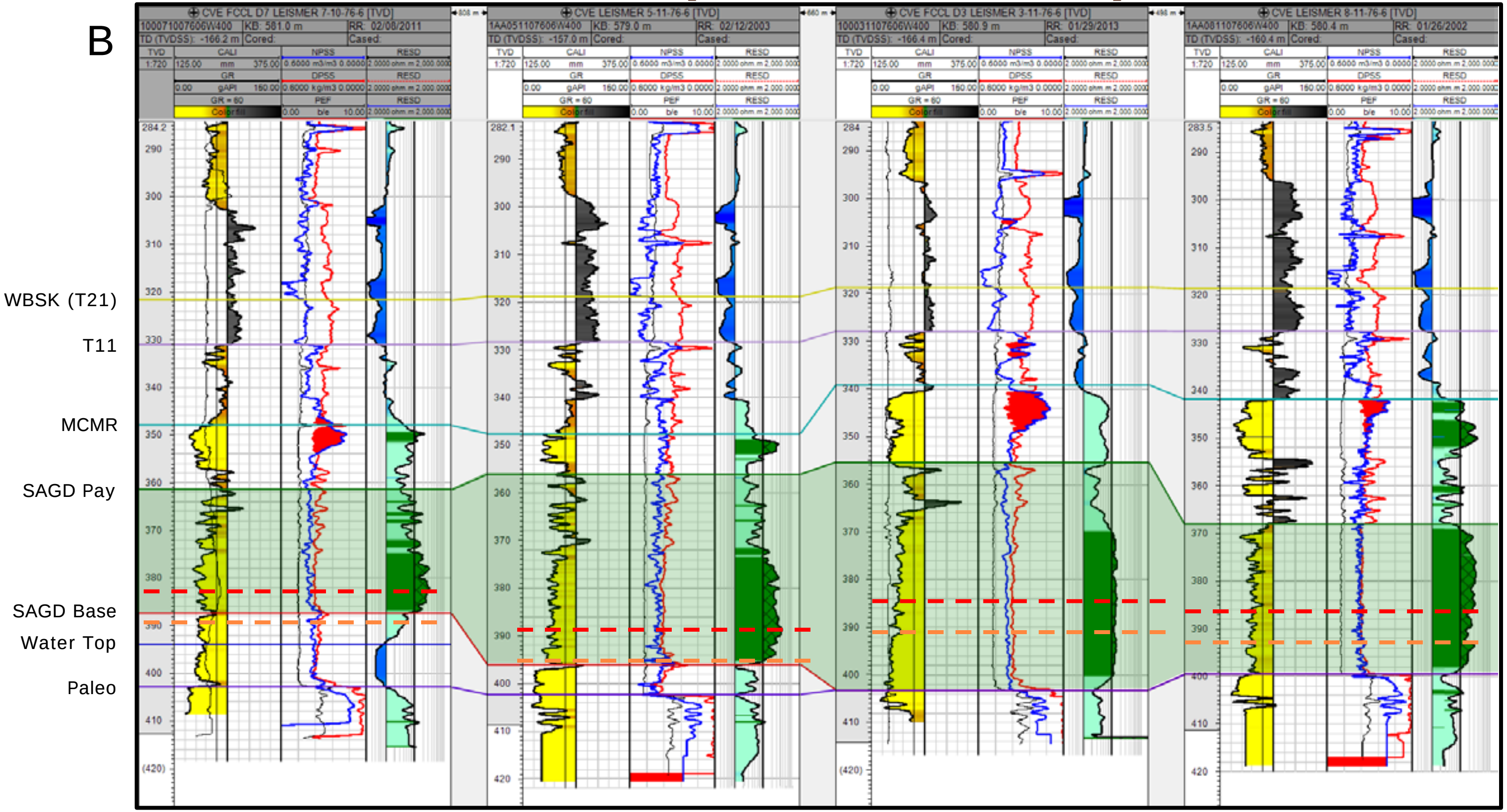


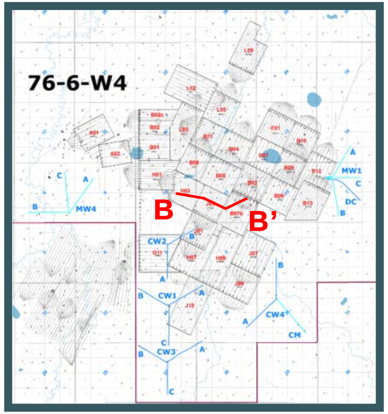
Cross-section (structural): north





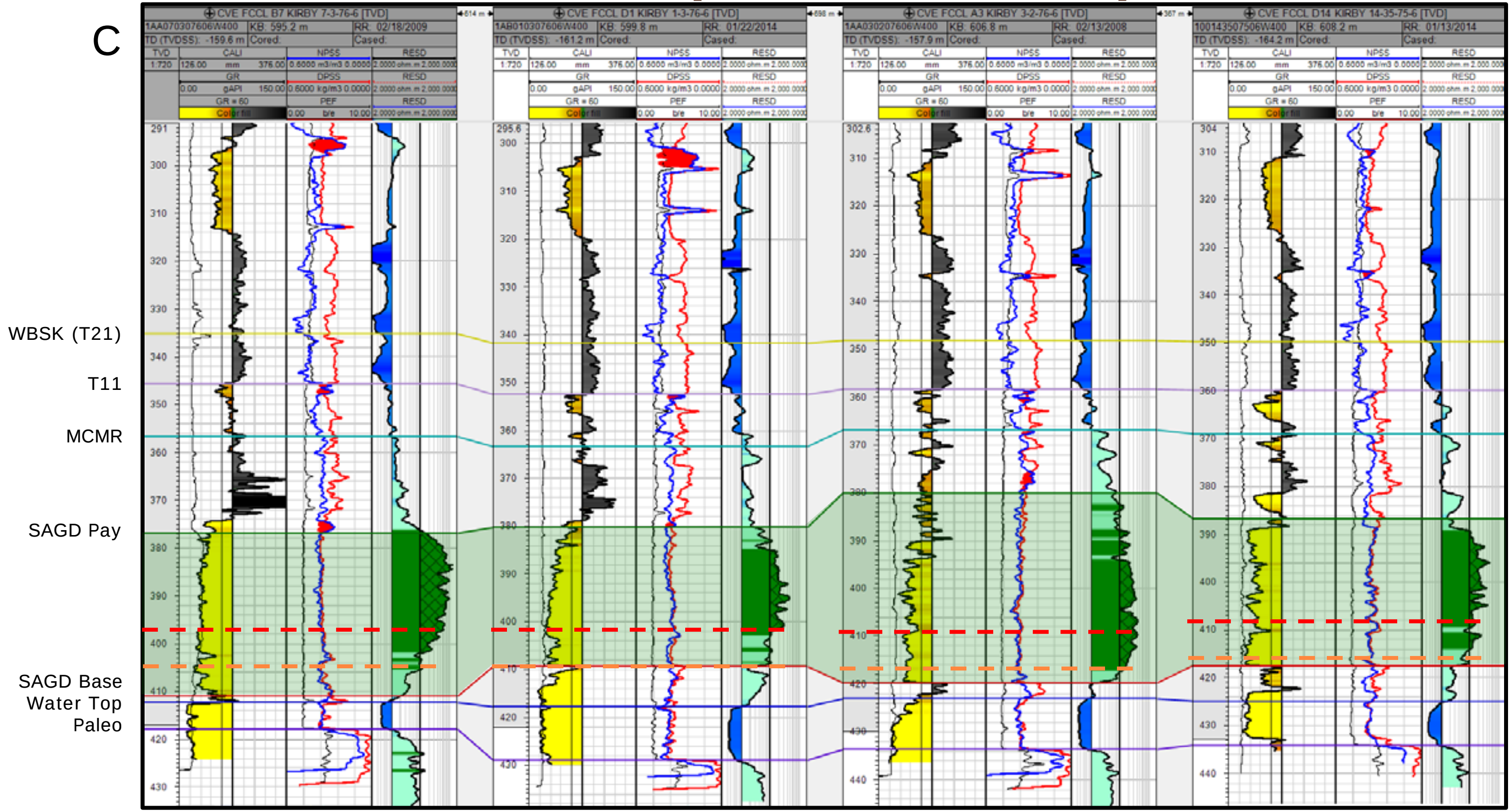
Cross-section (structural): mid





Cross-section (structural): south

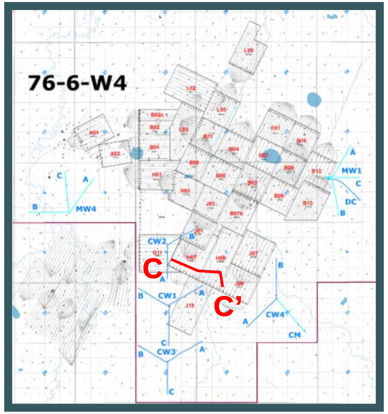
C



C'

Injector Level (est.)

Producer Level (est.)

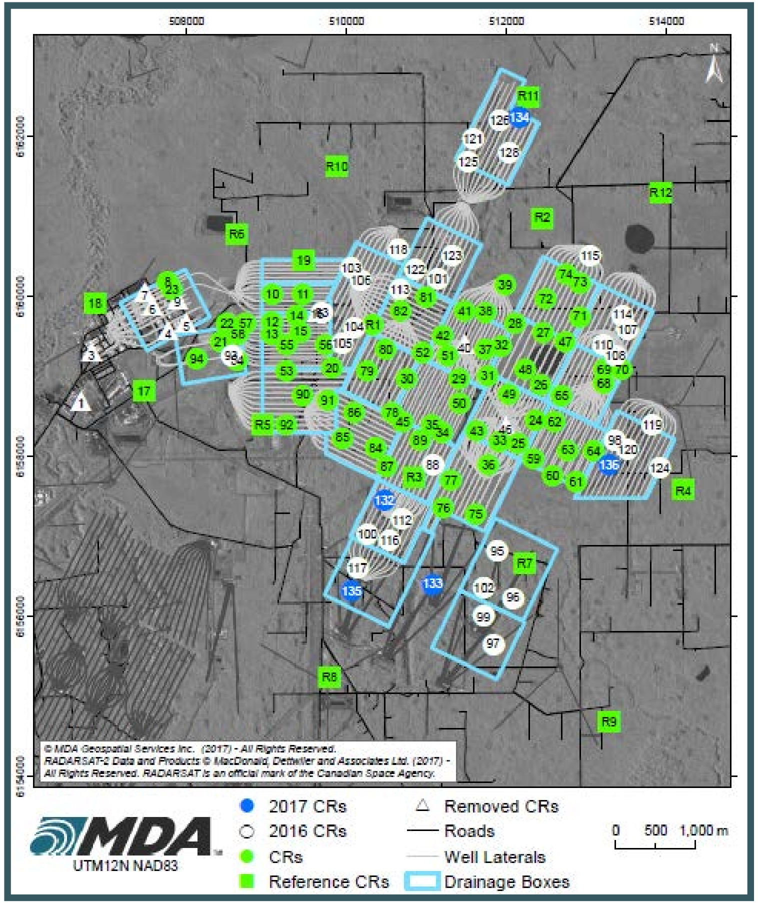


Heave monitoring

Ground heave monitoring (InSAR)

Corner reflector layout for Cenovus Christina Lake.

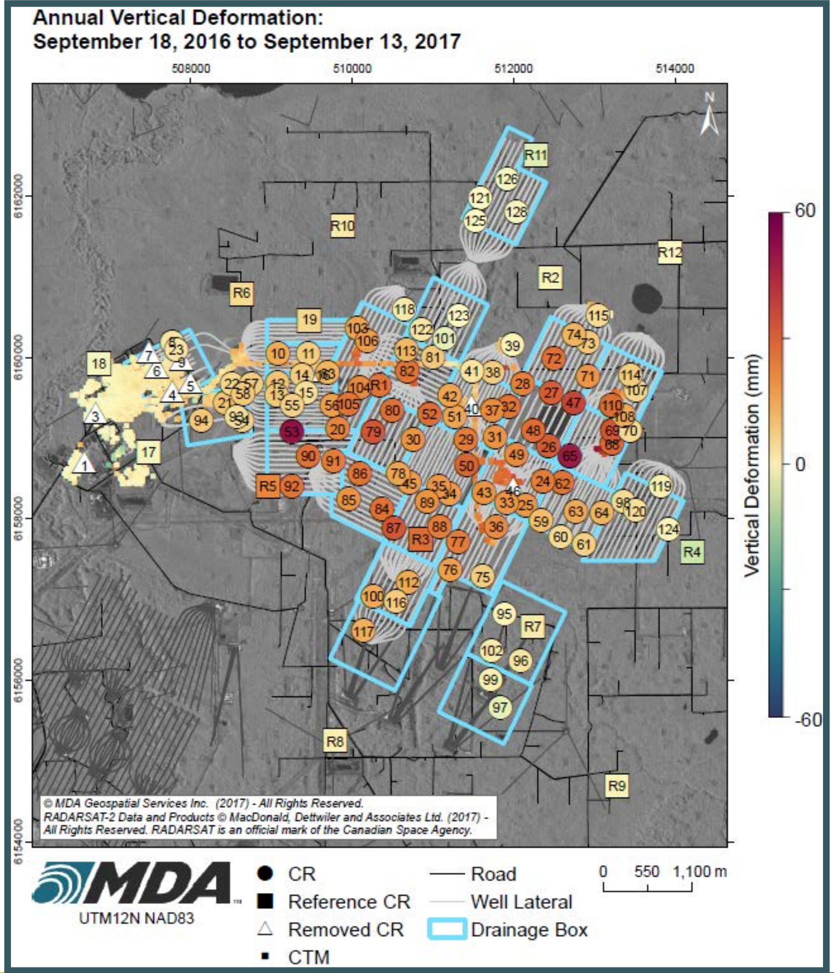
New reflectors were added to new pads before startup.



Ground heave monitoring (InSAR)

Conventional vertical deformation map with CRs for the image pair.

Maximum annual changes in 2017 were below 60mm.

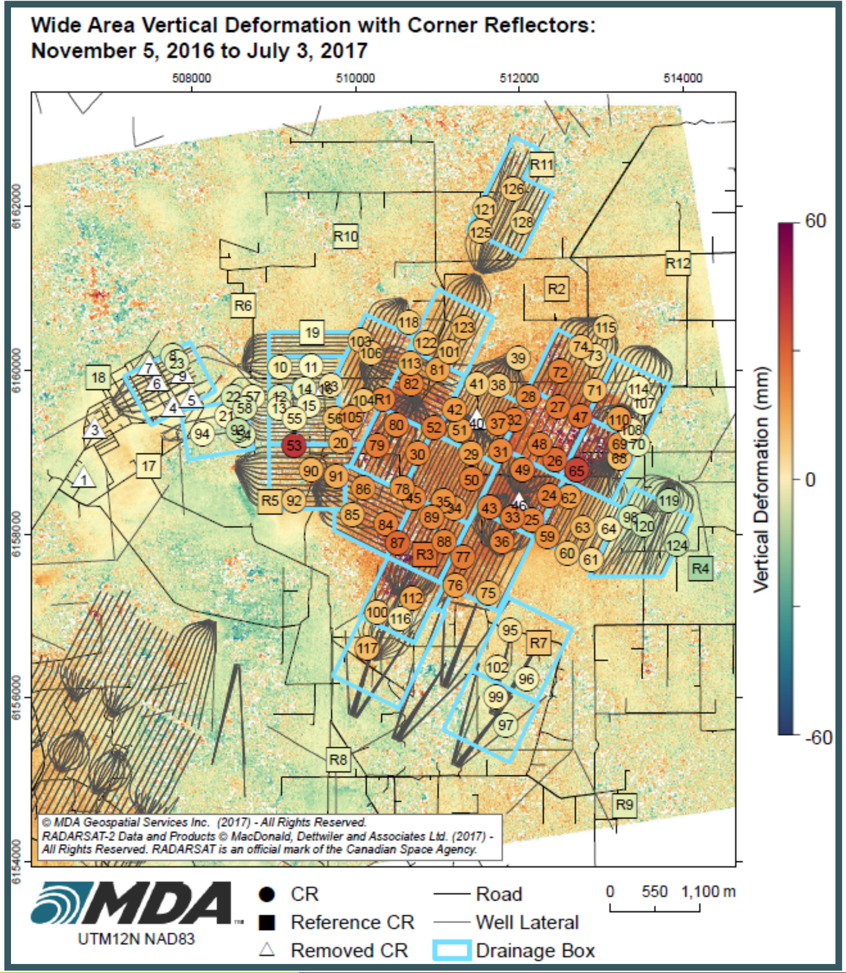


Ground heave monitoring (InSAR)

CR and CTM annual vertical deformation at Christina Lake.

For visualization purposes, the CTM have been spatially averaged and resampled to a 25 m by 25 m grid.

Maximum annual changes in 2017 were below 60mm.

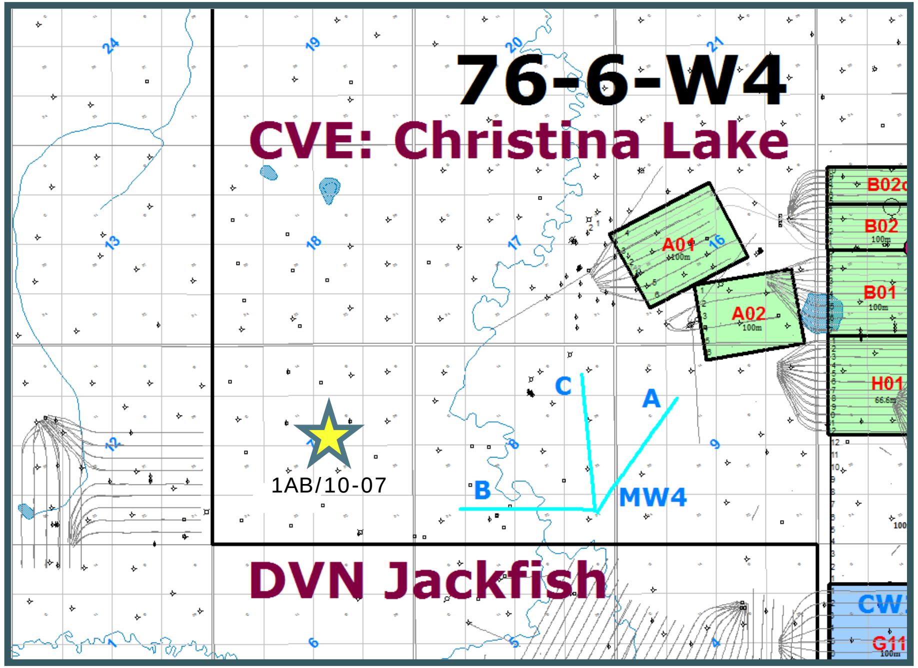


Caprock integrity

Caprock Integrity: new DFIT well & core

1AB/10-07-076-06W4 (C10)

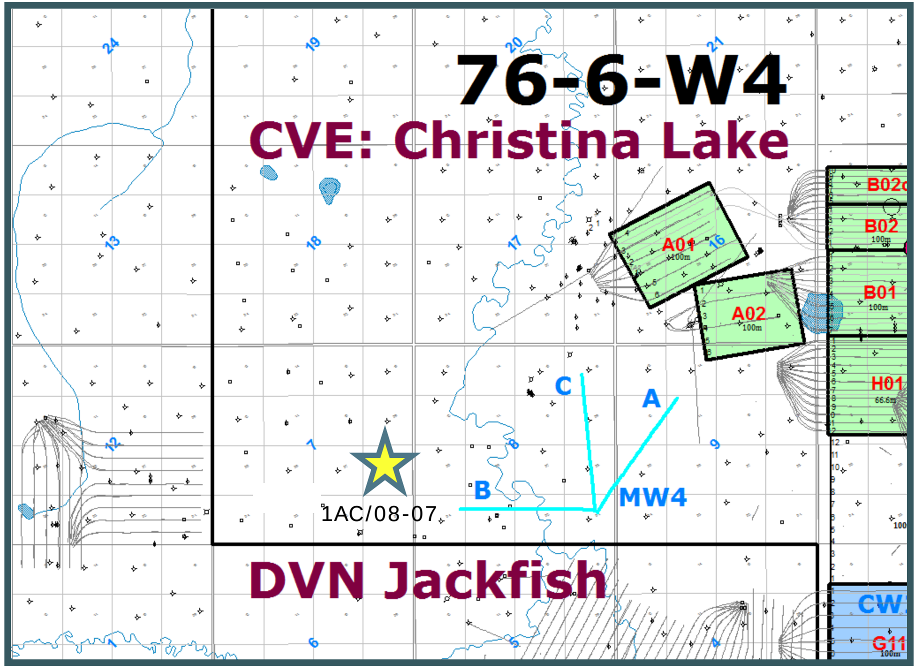
- **Caprock Integrity Test**
  - Drilled Jan, 2018
  - Cored, cased, DFIT tested and abandoned
    - DFIT: Diagnostic Fracture Injection Test
    - Cored caprock: Quaternary, Grand Rapids, Clearwater
    - Cored non-caprock: McMurray and Paleo
  - Expect results relevant to our MOP in the coming months



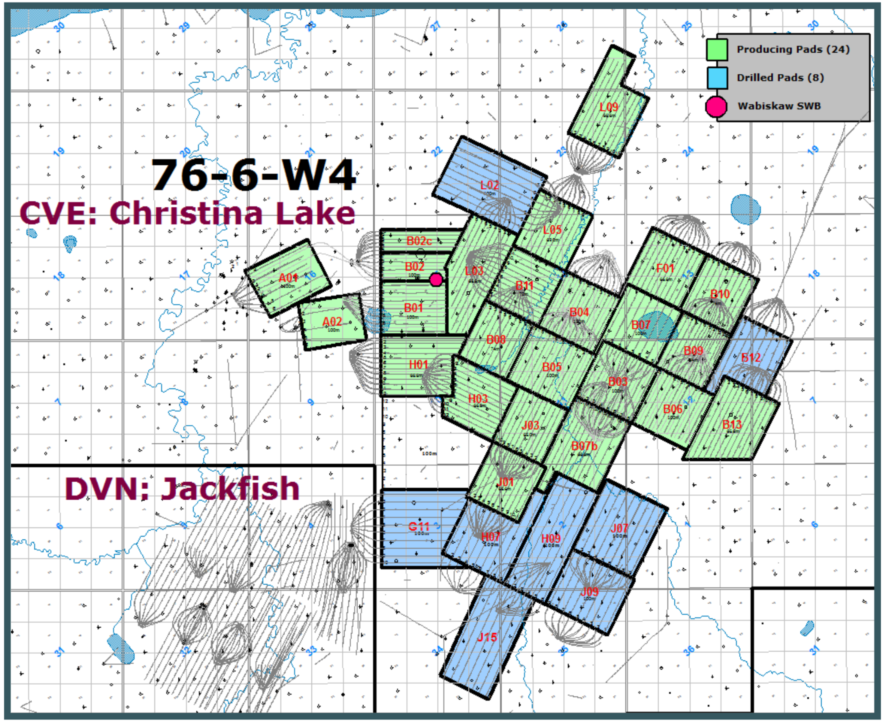
Caprock Integrity: core

1AC/08-07-076-06W4 (B8)

- **Caprock Core**
  - Drilled Dec, 2017
  - Cored, cased and abandoned
    - Cored caprock: Wabiskaw
    - Cored non-caprock: McMurray



Maximum Operating Pressure (by Pad)



Pad	MOP (kPa)		Pad	MOP (kPa)
A01	5000		H01	5000
A02	5000		H03	5000
B01	5000		H07	5500
B02	5000		H09	5500
B03	5000		J01	5000
B04	5000		J03	5000
B05	5000		J07	5000
B06	5000		J09	5500
B07	5000		L03	5000
B07b	5000		L05	5000
B08	5000		L09	5000
B09	5000		L02	5000
B10	5000		B12	5000
B11	5000		G11	5500
B13	5000		J15	5500
F01	5000			

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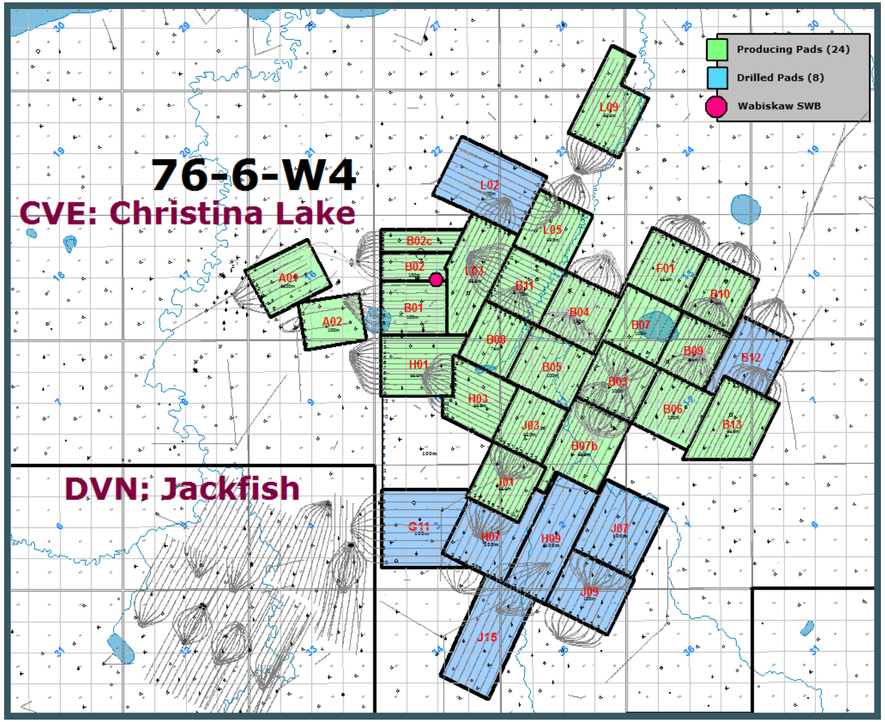
Subsection 3.1.1 – 3) Drilling and Completions

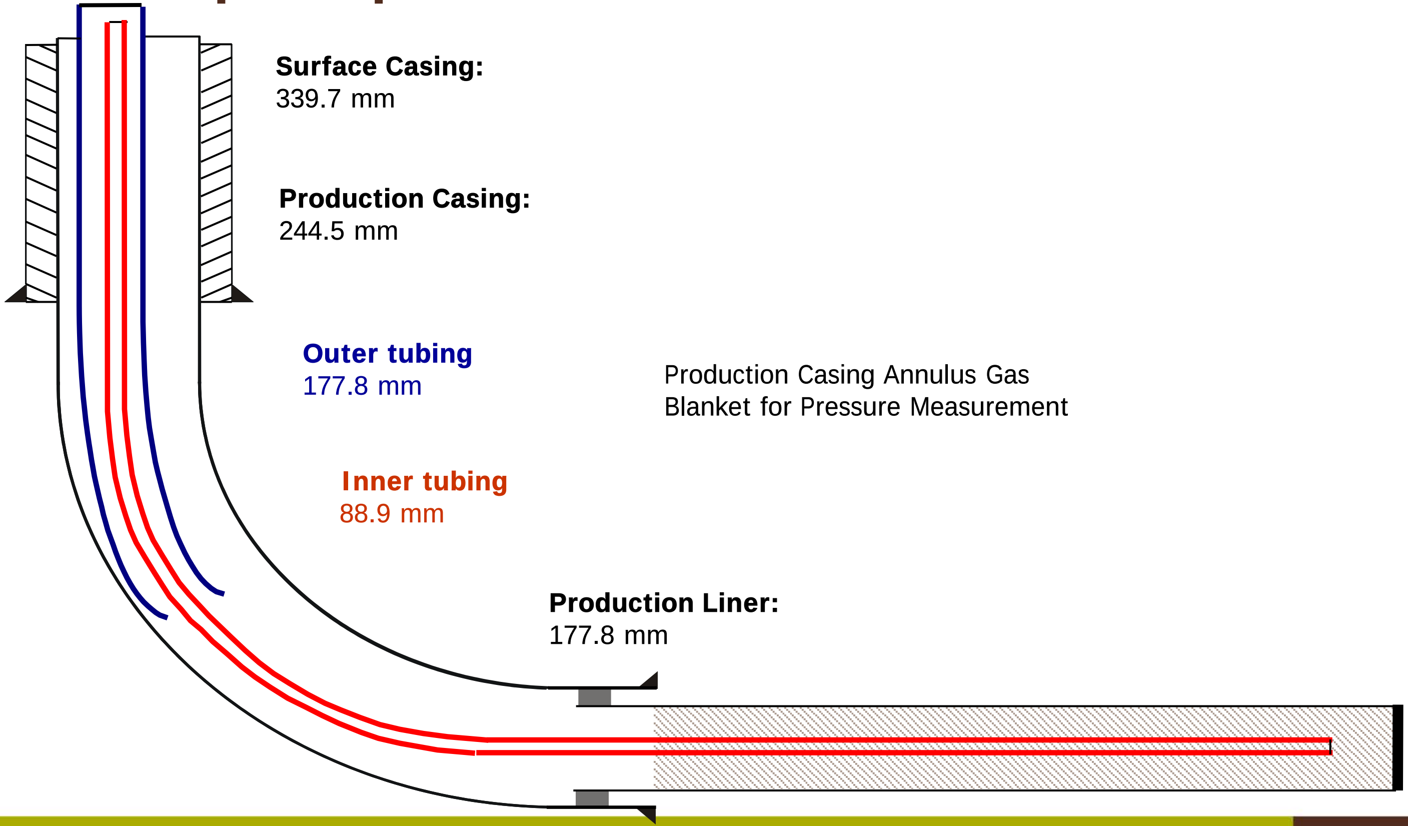
Bitumen wells: drilled SAGD & verticals



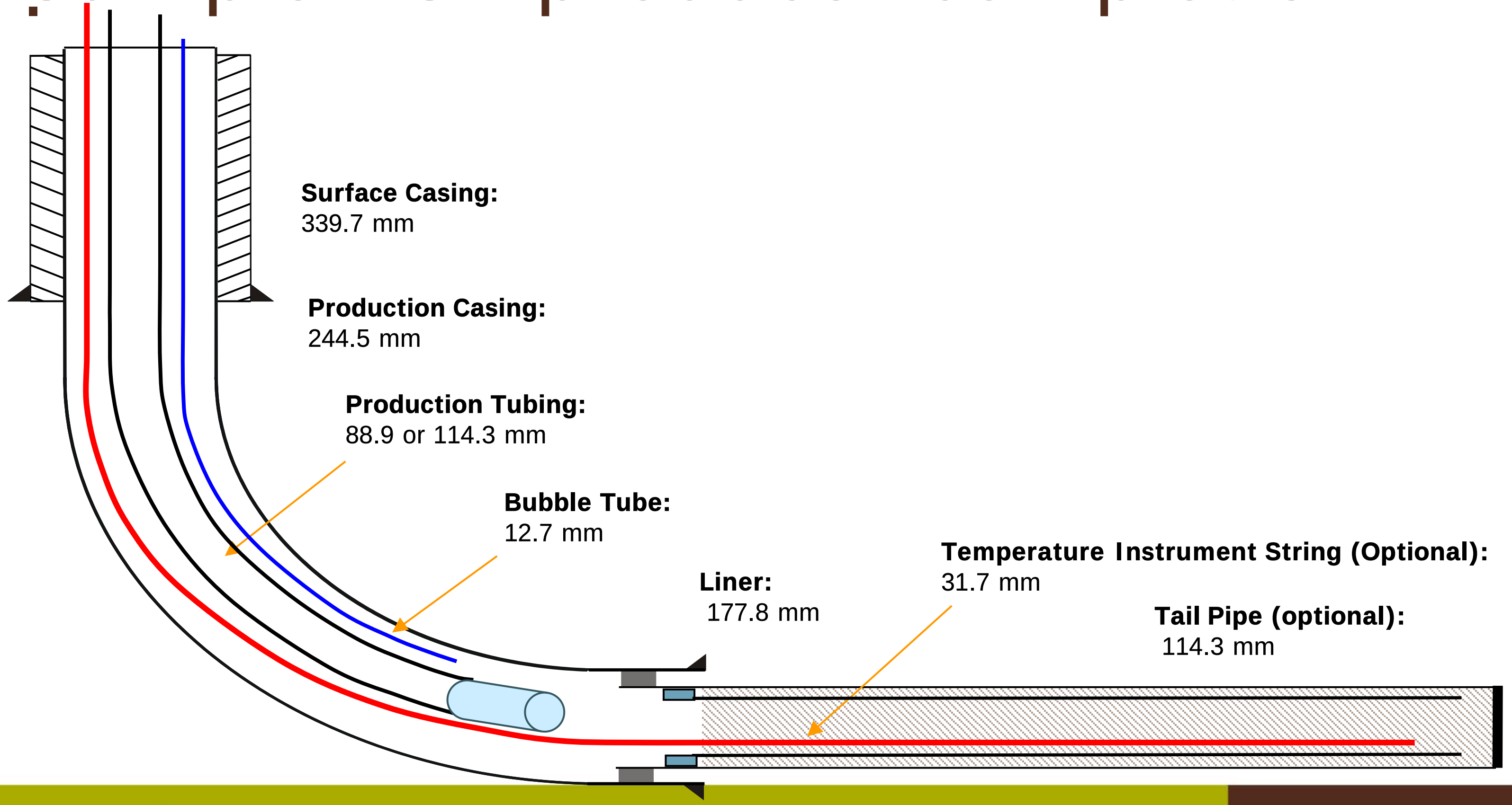
Pad	Pairs	WWs*		Pad	Pairs	WW*
A01	6	2		H01	12	-
A02	2	-		H03	12	-
B01	7	6		H07	9	-
B02**	10	6		H09	6	-
B03	8	8		J01	11	-
B04	8	8		J03	11	-
B05	9	9		J07	9	-
B06	8	9		J09	9	-
B07	8	-		L03	9	-
B07b	11	-		L05	9	-
B08	10	-		L09	11	-
B09	11	-		L02	8	-
B10	10	-		B12	8	-
B11	12	-		G11	10	-
B13	12	-		J15	7	-
F01	12	-		*WBSK*	*1 Vertical*	-

*Wedge Well™ Technology **B02 includes B02c

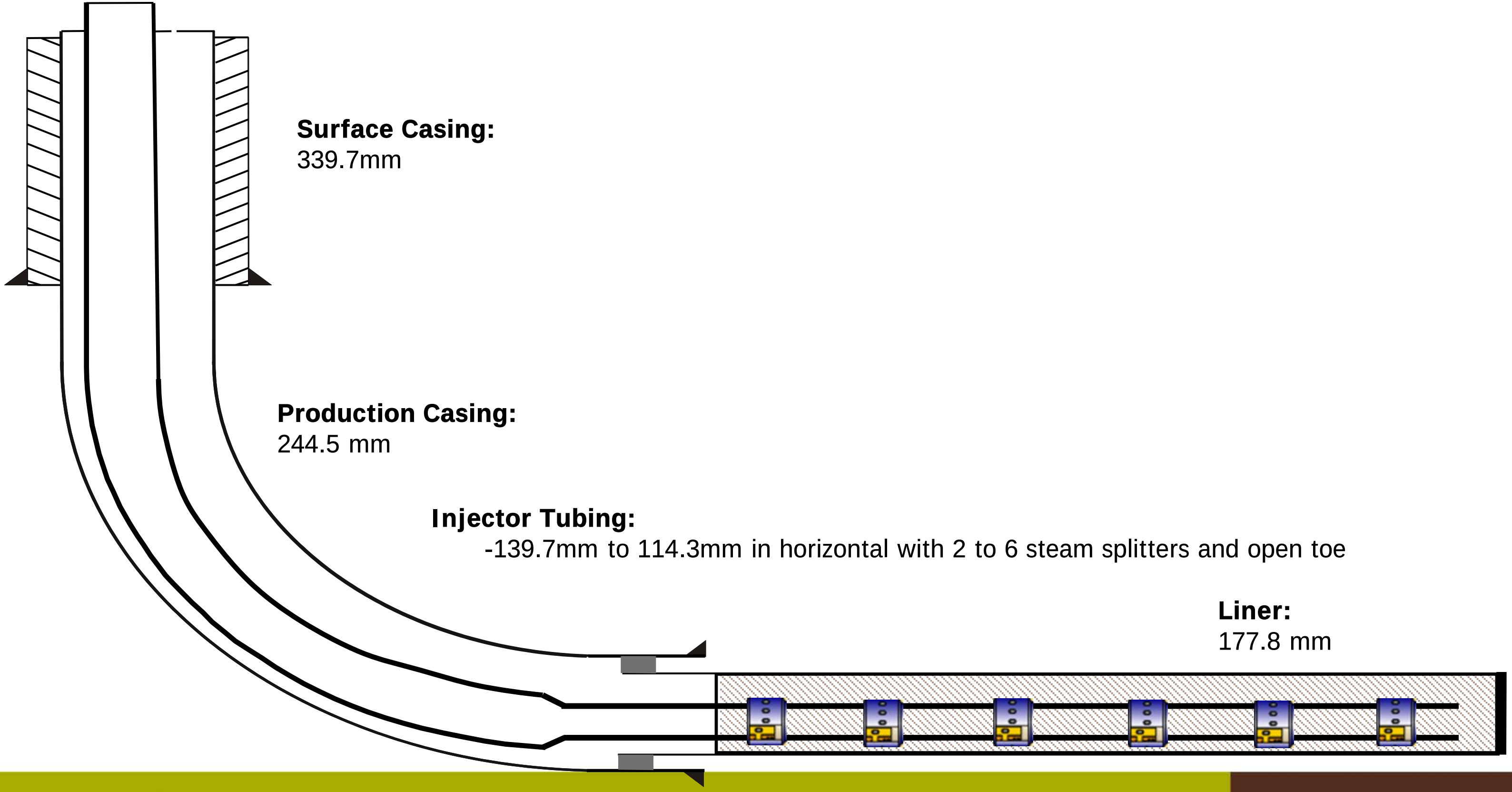
Sample producer circulation completion



Sample ESP producer completion



Sample injector completion



2017 liner failures

Well Name	Reason for Failure
J01P10	Poor Geology
J01P09	Poor Geology
J01P02	Poor Geology
B07P19	Poor Geology

Flow control devices

- **Currently testing 5 flow control devices**
  - 3 liner deployed ICDs
  - 2 tubing deployed ICDs
- **Production from wells commenced in 2015**
- **ICD effectiveness review ongoing**

Well Name	Well Type	Production Date	Deployment
F01P08	Producer	08/09/2015	Tubing Deployed
F01P10	Producer	08/03/2015	Tubing Deployed
B07P10	Producer	12/10/2015	Liner Deployed
H01P03	Producer	12/18/2016	Liner Deployed
L09P07	Producer	02/18/2018	Liner Deployed

ICD: inflow control device

Subsection 3.1.1 – 4) Artificial Lift

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Artificial lift by well

Pad	Start date	Total producers (including Wedge Wells)	Lift Type
A Pad	2002	6	SAGD ESP
A02 Pad	2008	2	SAGD ESP
B01 Pad	2008	13	SAGD ESP
B02 Pad	2006	8	SAGD ESP
B02c Pad*	2013	6	SAGD ESP
B03 Pad	2011	15	SAGD ESP
B04 Pad	2011	15	SAGD ESP
B05 Pad	2012	18	SAGD ESP
B06 Pad	2012	15	SAGD ESP
B07 Pad	2012	8	SAGD ESP
B07b Pad	2015	10	SAGD ESP
B08 Pad	2013	10	SAGD ESP
B09 Pad	2014	11	SAGD ESP
B10 Pad	2016	10	SAGD ESP
B11 Pad	2013	12	SAGD ESP
B13 Pad	2017	6	SAGD ESP
H01 Pad	2016	12	SAGD ESP
H03 Pad	2016	12	SAGD ESP
L03 Pad	2016	8	SAGD ESP
L05 Pad	2017	7	SAGD ESP
L09 Pad	2017	6	SAGD ESP
J01 Pad	2016	11	SAGD ESP
J03 Pad	2016	11	SAGD ESP
F01 Pad	2015	12	SAGD ESP

*B02C refers to the 6 well pairs on the north side of the B02 Pad Approved Drainage Box, which were drilled at a 50m lateral downhole spacing

Artificial lift performance

ESP (229 operating):

- All 2017 & 2018 wells were put into ESP mode post-steam stimulation
- No new pads were in gas-lift mode
- Typical operating pressure 1,800 – 4,000 kPag
- No temperature limitations, go as hot as ~235^{o}C BHT
- Average emulsion flow rate ~ 200-1400 m^3/d

Operational challenges:

- Designing ESPs with adequate downturn for late-life
- Gas Handling for high GOR wells

Subsection 3.1.1 – 5) Instrumentation

SAGD well pressure instrumentation

Pressure Measurement:

- Producer – Mostly ½” capillary tubes or 3/8”
- Injector – Casing blanket gas

SAGD well temperature instrumentation

Type 'K' Thermocouples (2 types)

- Single point installed at the heel
- 6 point that is installed along the producer horizontal

Distributed Temperature Sensing (DTS)

- Temperature reading every ~1 m along entire wellbore
- Instrumentation of choice for 2016 and onward

DTS: distributed temperature sensing

DTS

DTS is installed on 166 wells at Christina Lake

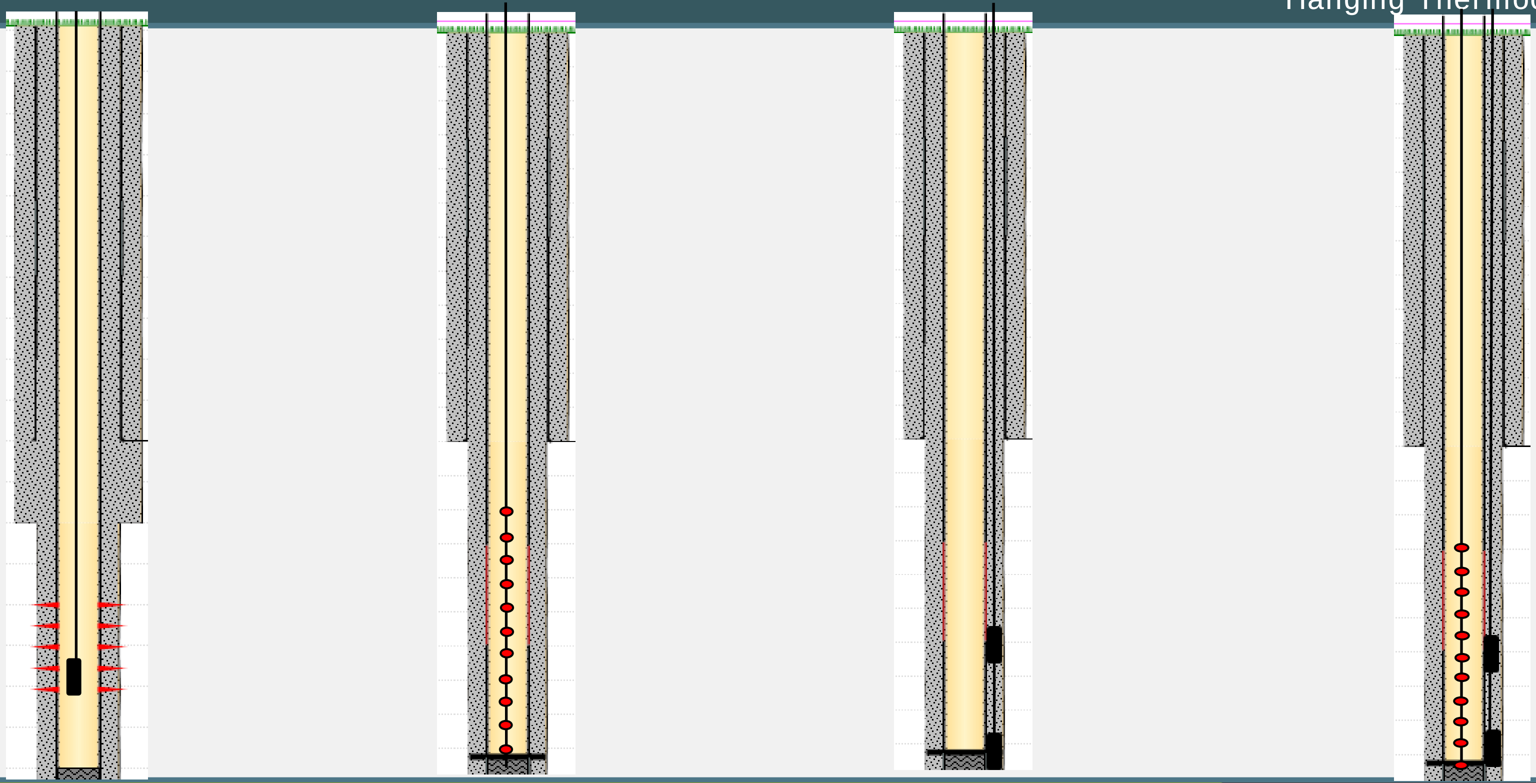
- 137 wells are tied in for live readings
- 29 wells require drive-by shots

DTS is being installed on all new wells including any re-drill

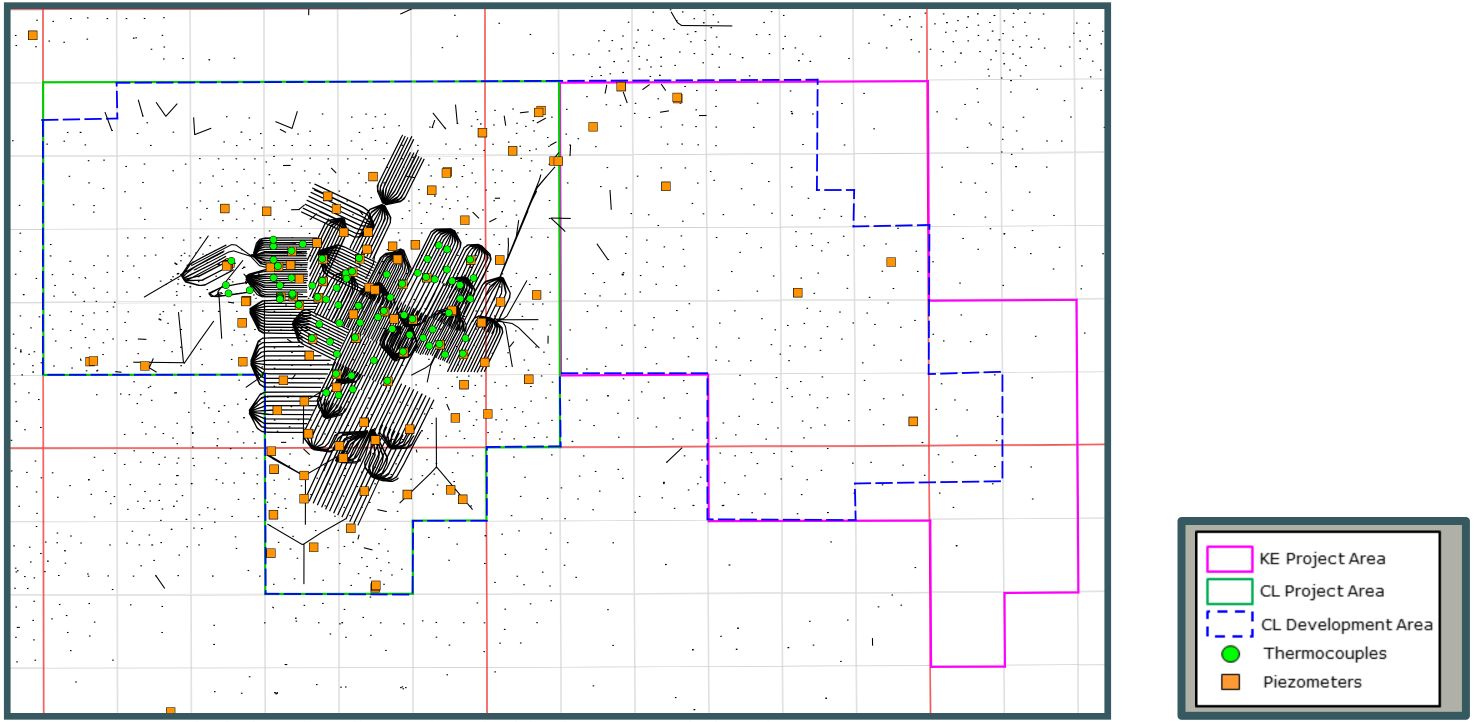
DTS: distributed temperature sensing

Instrumentation in observation wells (typical completions)

Hanging Piezometer	Hanging Thermocouples	Cemented Piezometers	Cemented Piezometers and Hanging Thermocouples



Surveillance wells map



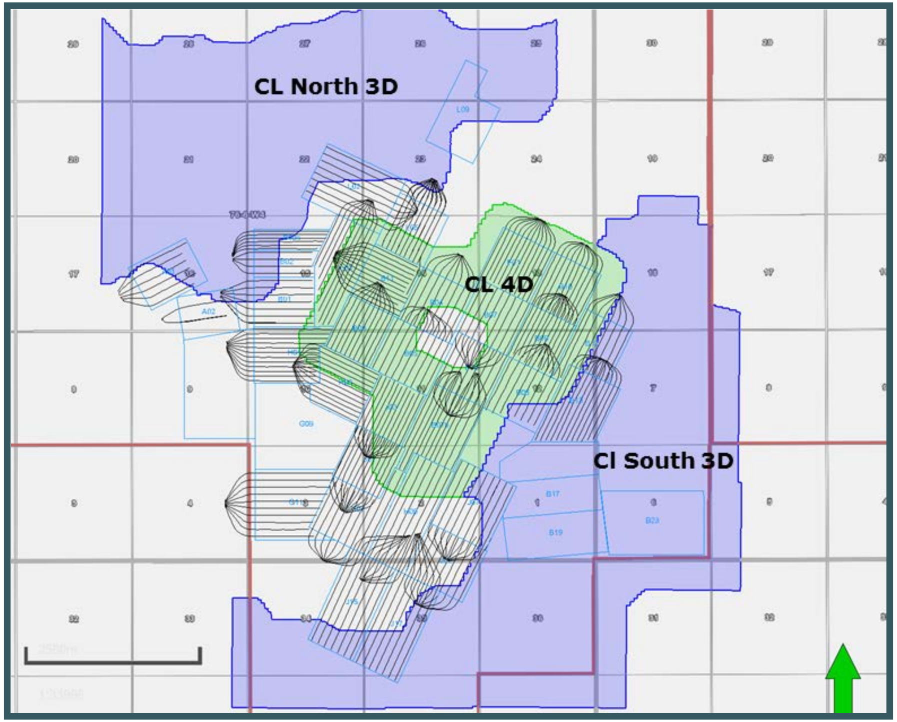
includes all wells equipped with piezometers below the Quaternary

Subsection 3.1.1–5c) & d) instrumentation data

Requirements under subsection 3.1.1 5c) and d) are located in Appendices 2 & 3

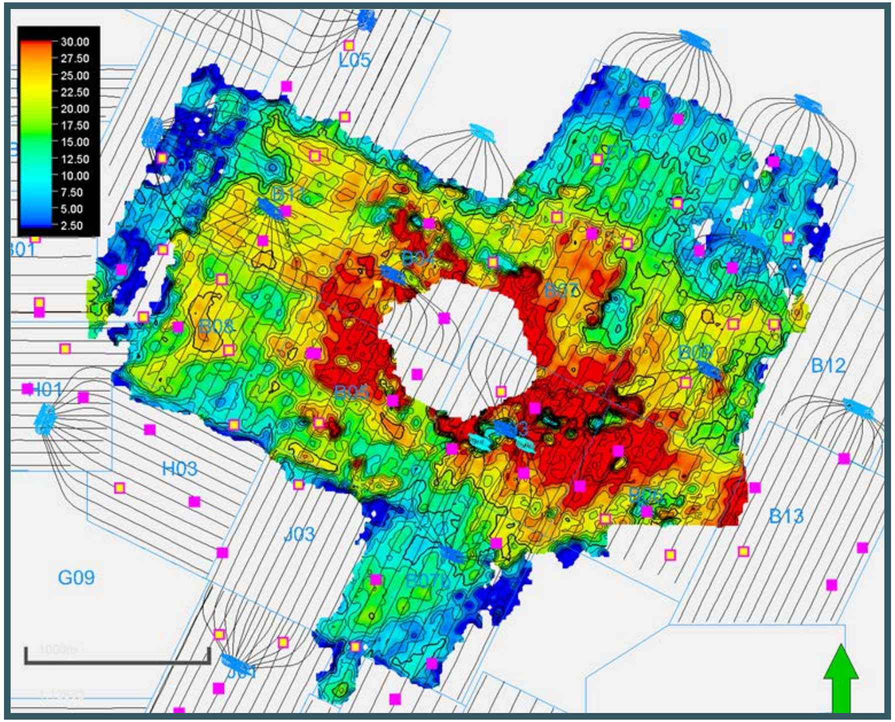
Subsection 3.1.1 – 6) Seismic

Seismic lines location map 2017

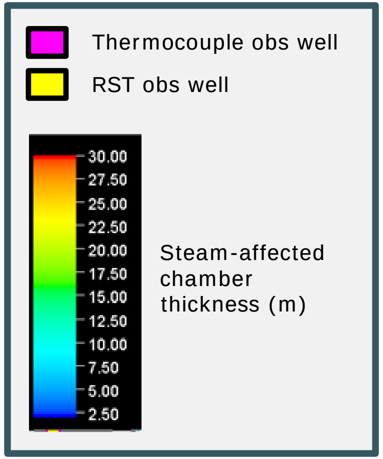


Name	Purpose	Area (km2)
CL North 3D	Baseline	16.7
CL 4D	Monitor	11
Cl South 3D	Baseline	22.6

4D seismic chamber thickness 2017

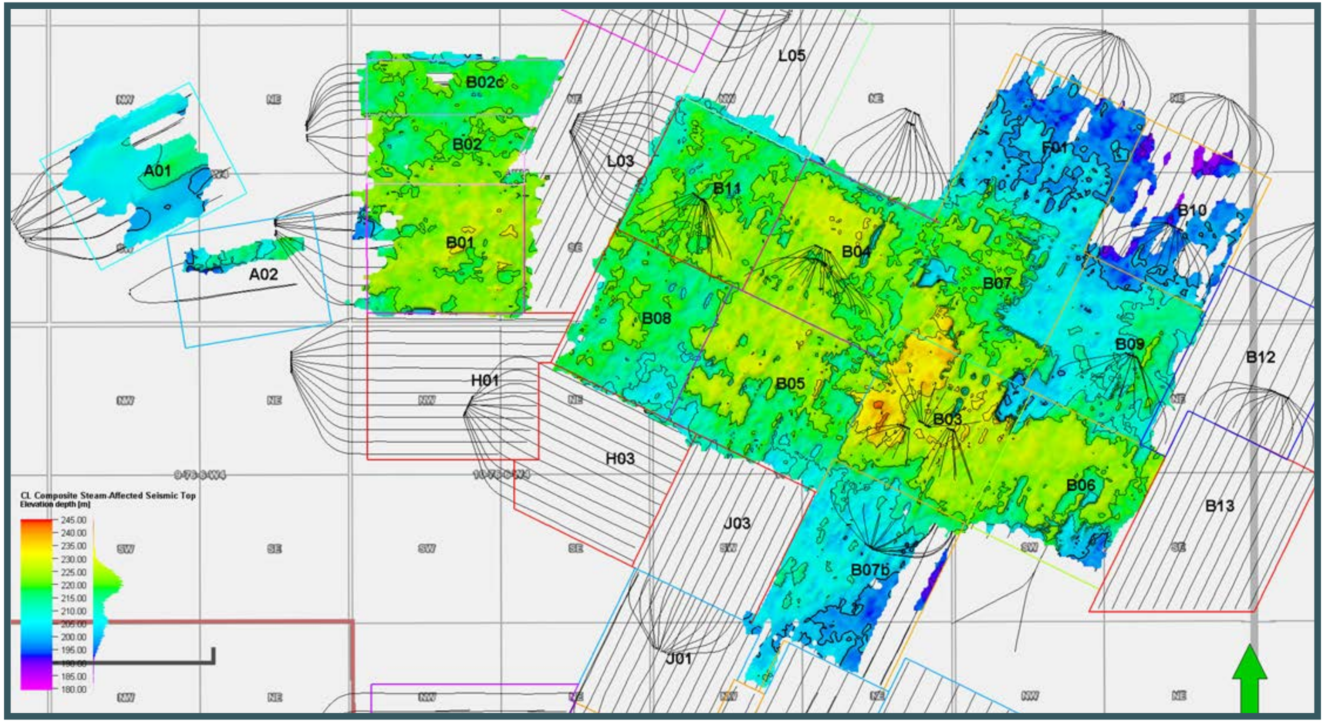


Interpreted steam-affected chamber thickness to producer wells (m)



4D seismic was not deemed necessary in the middle of the operation

4D seismic: historical composite

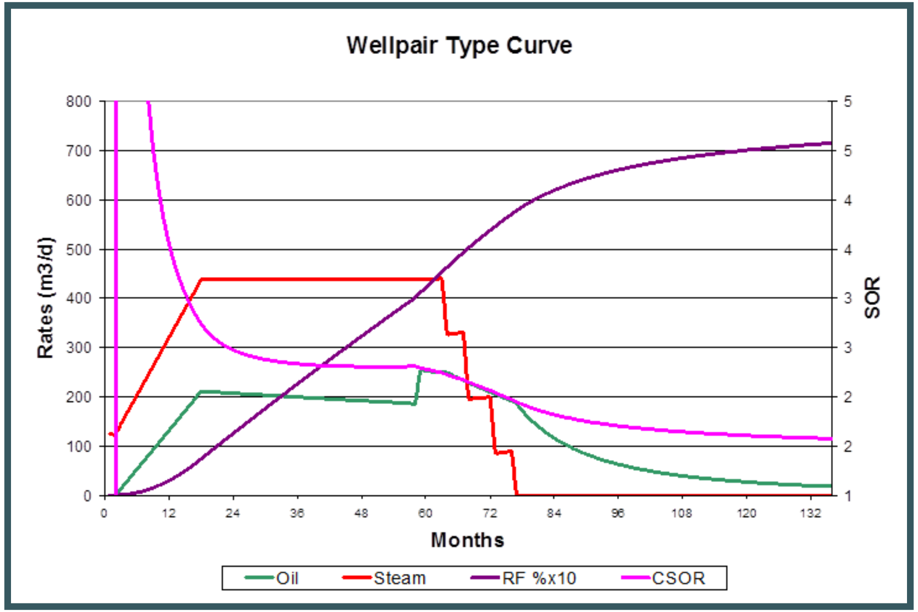


Composite Interpreted steam-affected structure top (TDVD SS)

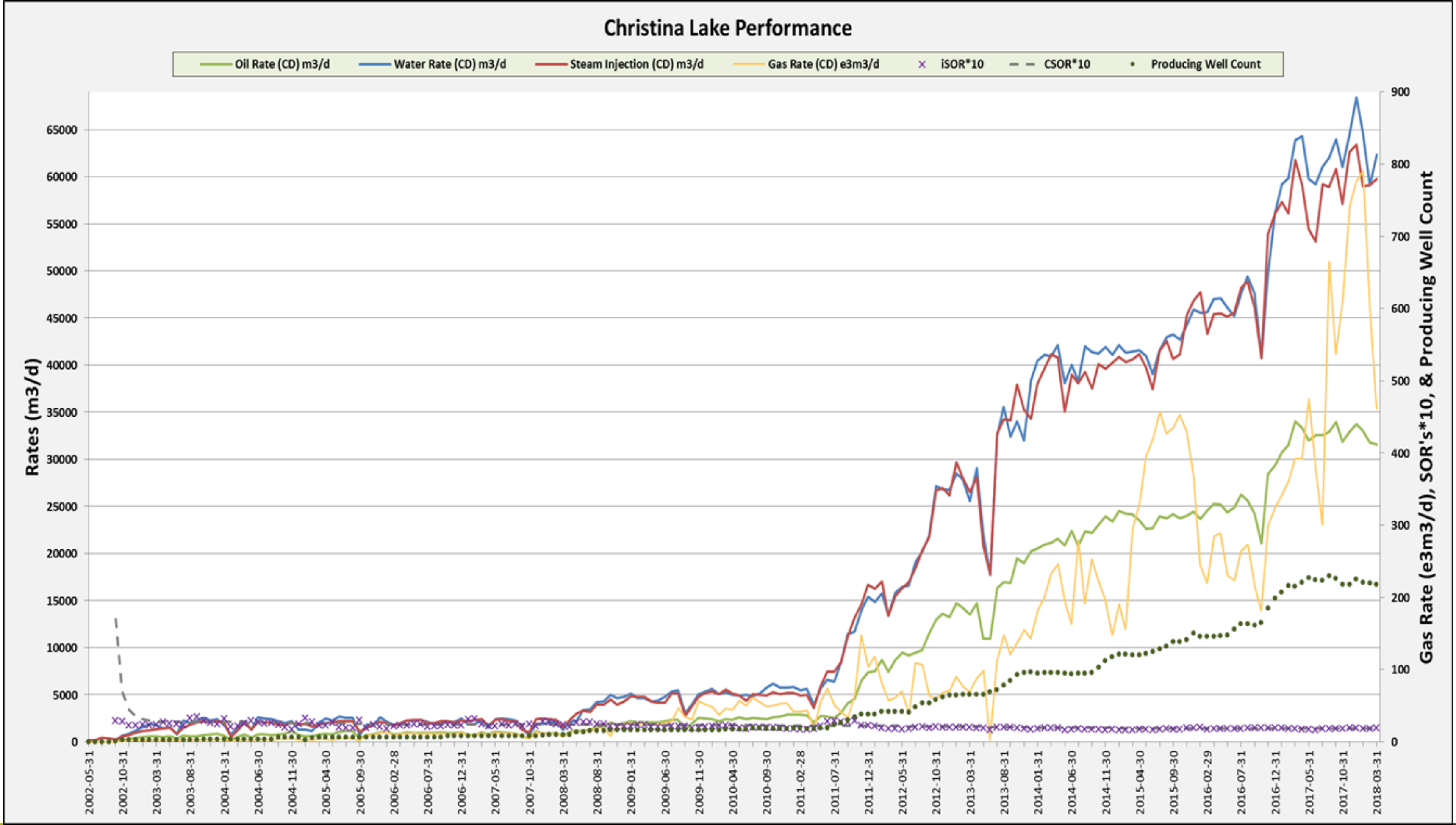
Subsection 3.1.1 – 7) Scheme performance

Scheme performance prediction

- **Predict well pair performance based on modified Butler's equation**
- **Predict well pair CSOR using published CSOR correlations (*Edmunds & Chhina 2002*)**
- **Generate overall scheme production performance by adding individual well forecasts over time to honour predicted steam capacity and water treating availability**



Full Historical



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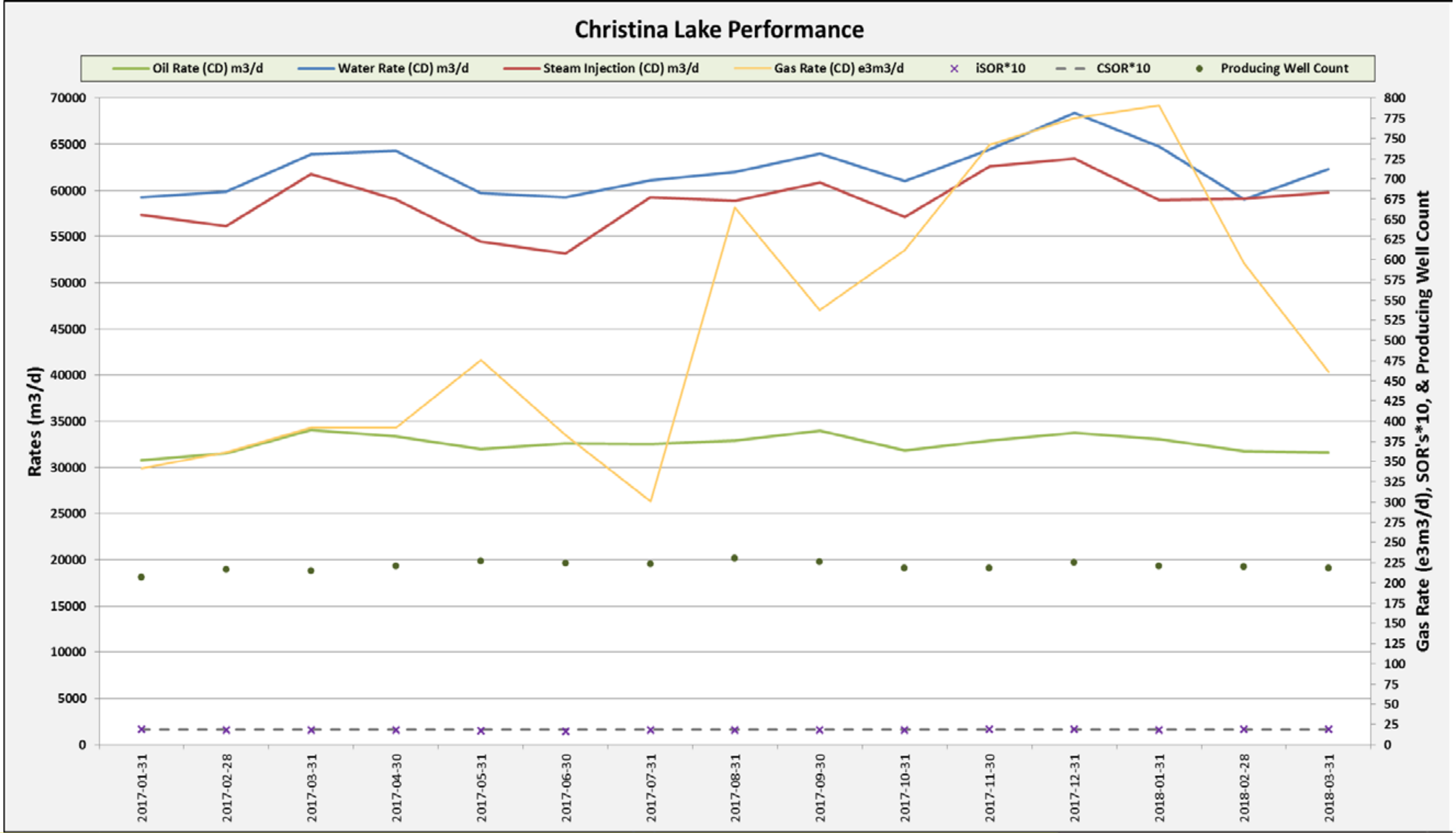
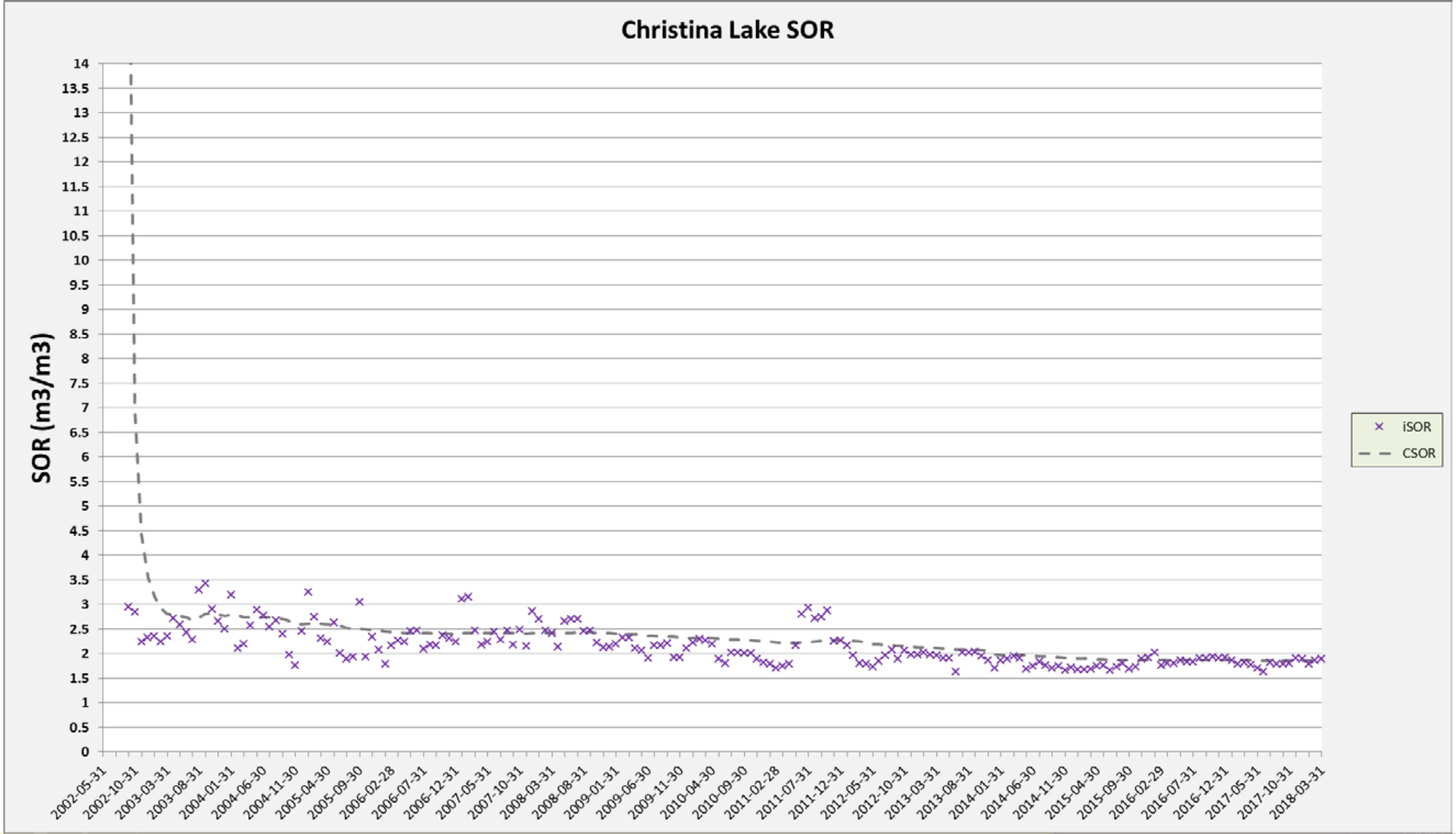


Full Historical



Oil in Place Definitions

SAGD-able Oil In Place (SOIP) Quantification

- Oil volume within a drainage box area between the SAGD base surface to SAGD Pay Top surface
  - Drainage box area = drainage box length x wellpair spacing
    - Default drainage box length is the length of overlapping injector/producer slots + 20m heel/toe extension
      - Modified to account for well to well interactions and surveillance data
- The porosity and oil saturation within this volume are generated from stratigraphic wireline log data

Estimated Ultimate Recovery

- Cum oil produced to date + forecasted production

All oil in place quantities and estimated ultimate recovery quantities are internal estimates. There is no certainty that any portion of such quantities will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such quantities.

OIP and RF per pad

**As of March 31, 2018*

PAD	Area (m3)	Height (m)	Porosity (%)	So (%)	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2018)	Recovery % SOIP	Expected Ultimate Recovery (Mm3)	Ultimate Recovery as % of SOIP
A01 PAD	514,091	30	33%	77%	4,013	2,287	57%	2,298	57%
A02 PAD	174,295	33	32%	83%	1,552	463	30%	751	48%
B01 PAD	594,458	36	31%	85%	5,497	3,768	69%	4,331	79%
B02 PAD	323,950	37	30%	85%	3,111	2,601	84%	2,842	91%
B02C PAD	296,275	35	31%	83%	2,662	1,663	62%	1,866	70%
B03 PAD	637,645	48	31%	81%	7,783	5,120	66%	6,043	78%
B04 PAD	642,947	43	30%	81%	6,811	5,431	80%	5,813	85%
B05 PAD	731,534	45	30%	81%	8,212	5,120	62%	6,275	76%
B06 PAD	605,198	35	31%	81%	5,410	3,897	72%	4,746	88%
B07 PAD	642,341	44	29%	81%	6,619	4,860	73%	6,239	94%
B07B PAD	884,240	34	31%	77%	6,971	1,786	26%	5,043	72%
B08 PAD	568,267	35	34%	85%	5,615	2,925	52%	3,516	63%
B09 PAD	558,380	48	30%	86%	6,790	3,205	47%	4,066	60%
B10 PAD	595,522	35	30%	80%	4,997	802	16%	2,842	57%
B11 PAD	603,192	40	31%	83%	6,147	3,904	64%	4,285	70%
B13 PAD	803,738	36	30%	81%	5,289	992	19%	4,271	81%
F01 PAD	649,357	34	29%	77%	5,070	1,843	36%	3,321	66%
H01 PAD	753,516	29	33%	82%	5,993	980	16%	4,240	71%
H03 PAD	645,148	31	33%	79%	5,190	978	19%	3,567	69%
J01 PAD	593,254	22	33%	79%	3,375	371	11%	2,343	69%
J03 PAD	561,300	42	32%	80%	6,112	1,282	21%	4,481	73%
L03 PAD	707,586	35	33%	85%	7,068	809	11%	4,671	66%
L05 PAD	500,175	36	29%	78%	4,071	108	3%	1,854	46%
L09 PAD	715,617	29	31%	84%	5,489	23	0%	3,486	63%
Total CL	**13,086,233**				**129,847**	**55,218**	**43%**	**93,187**	**72%**

Start up strategy

- Gain communication between producer and injector with circulation
- Establish conformance with even steam distribution
- Convert to ESP and ramp up to peak rate
- No changes from older pad start up procedures

Casing failures

- Well 11-3-76-6W4 was found to have a casing break
- Well was bought from Devon, it was an abandoned gas well
- Casing was repaired and well was properly abandoned
- Well was located over G11 pad, once 11-3-76-6W4 was abandoned, drilling G11 pad progressed
- No indication of any casing failures in SAGD wells at Christina lake

Recovery Examples

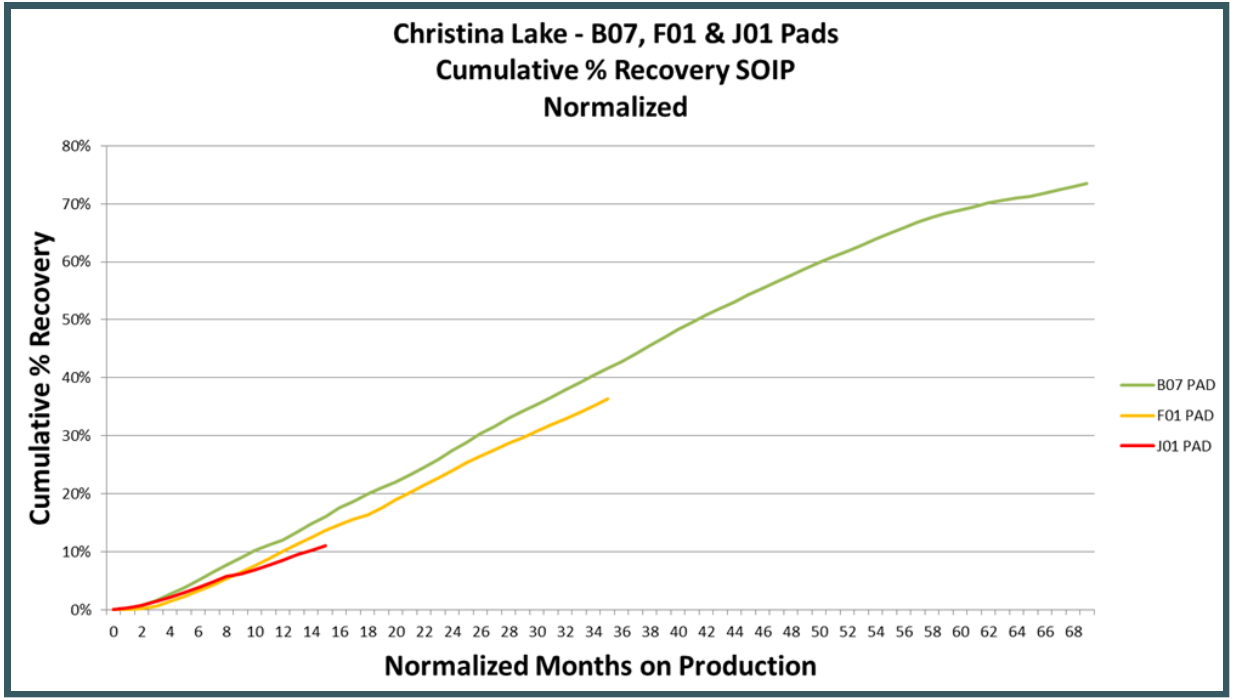
Recovery examples

J01 Pad: Low recovery example

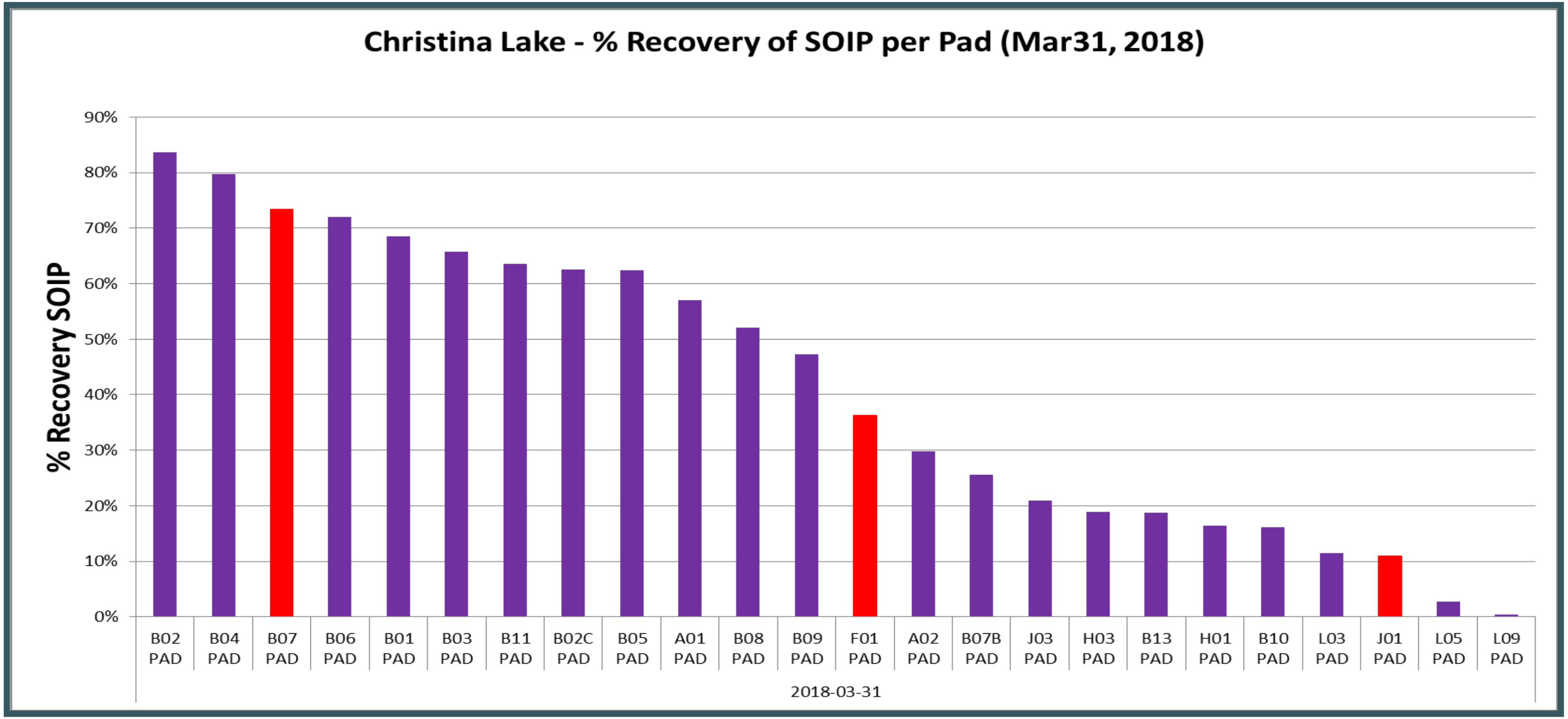
F01 Pad: Medium recovery example

B07 Pad: High recovery example

Recovery examples: Cumulative percent recovery SOIP



Current percent recovery of SOIP (pad totals)



Low recovery example: J01 pad

Subsection 3.1.1 – 7 c, iii)

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J01 pad overview

J01 pad started production in January 2017

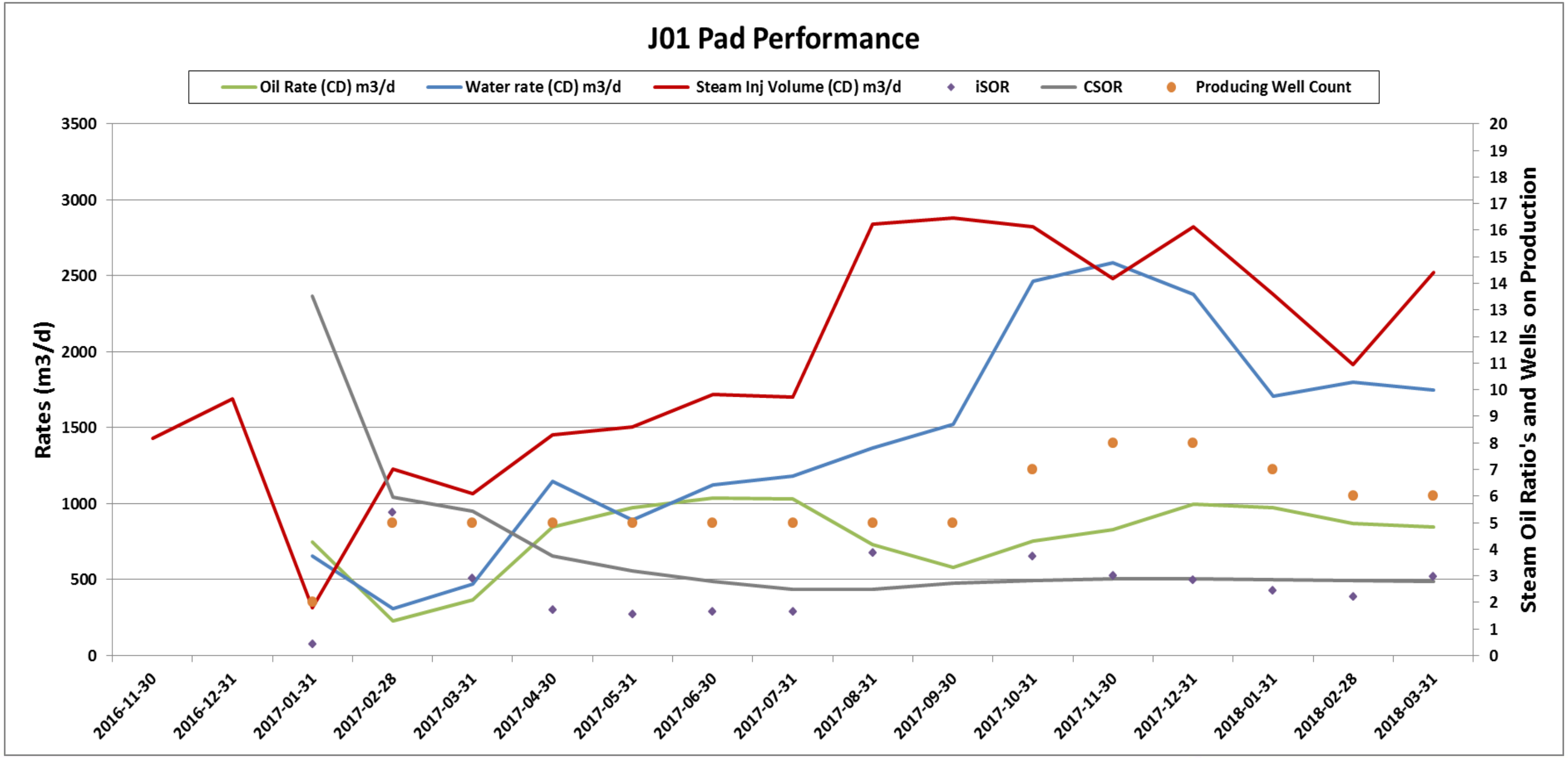
- 11 well pairs

Low roof/thin pay & heterogeneous quality geology

Current:

- Operating pressure ~ 3 MPa
- SOIP recovery ~11%
- CSOR ~2.8

J01 pad performance



CSOR 2.79

J01 thermocouple data

Immature Pad: No TC data yet active

Medium recovery example: F01 pad

Subsection 3.1.1 – 7 c, iii)

F01 pad overview

F01 pad started production in May 2015

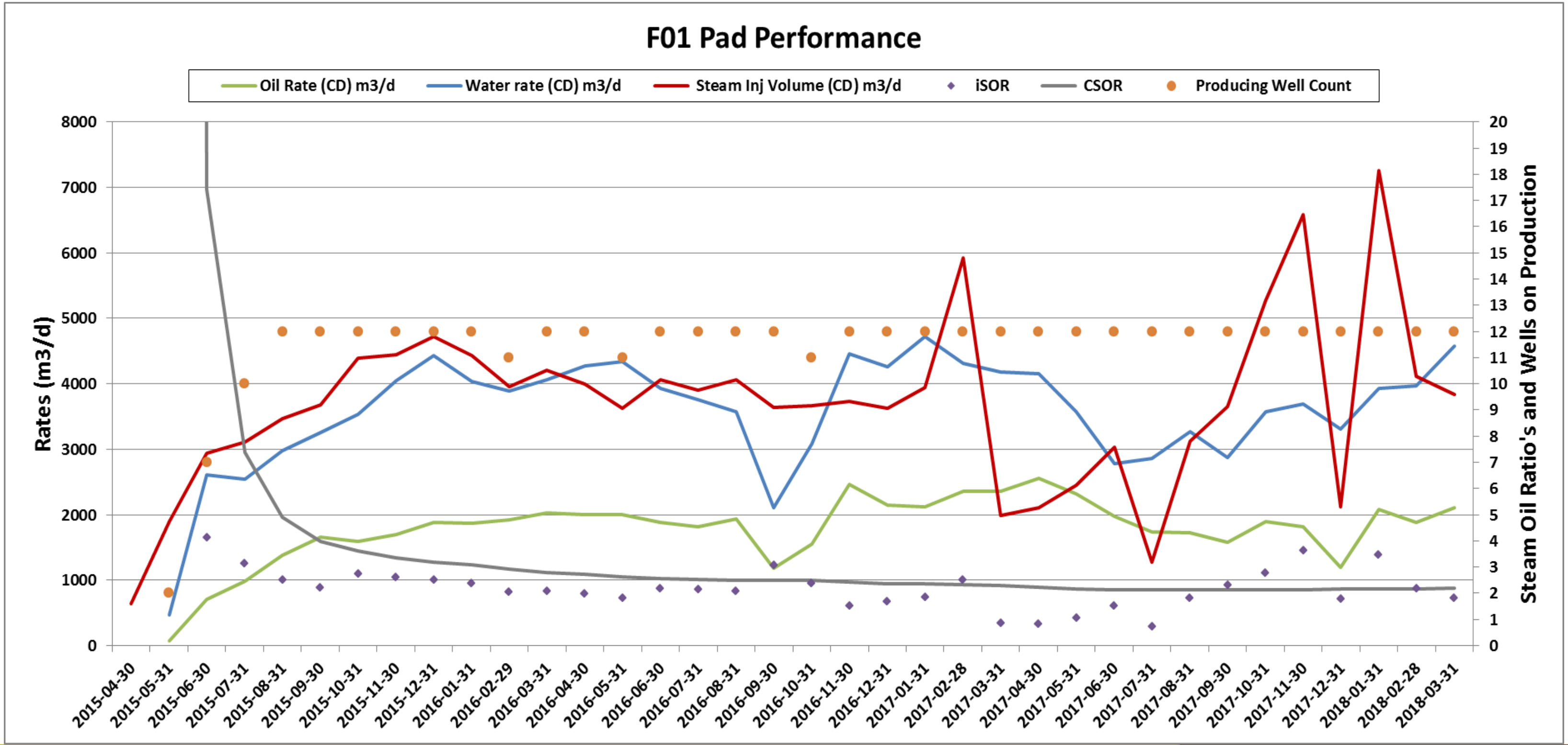
12 well pairs

Higher percentage sand facies in reservoir (compared to J01 pad)

Current:

- Operating pressure ~2.7 MPa
- SOIP recovery ~35%
- CSOR ~2.2

F01 pad performance

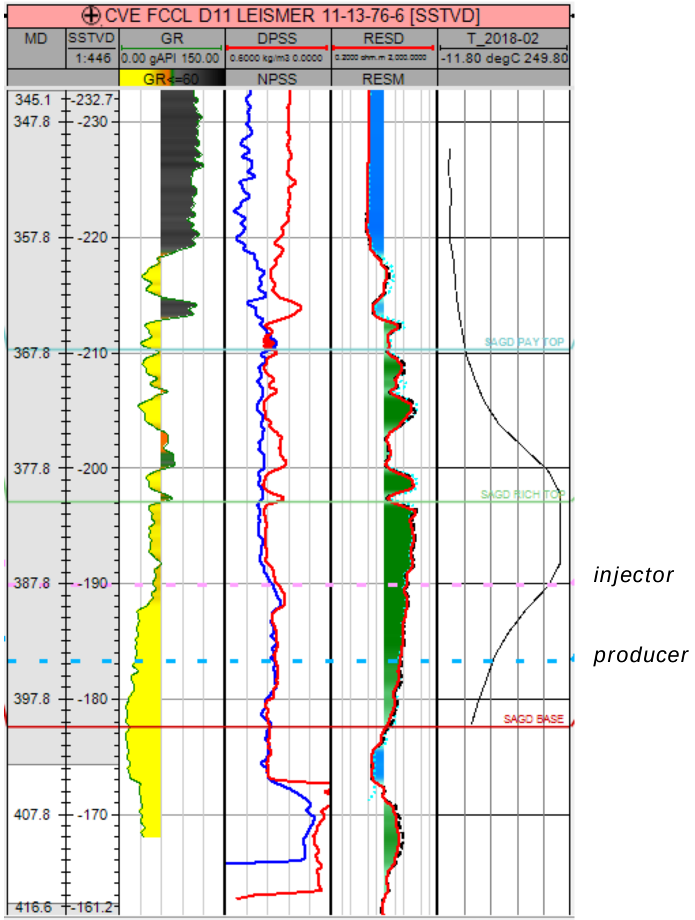


CSOR 2.18

F01 thermocouple data

F01P04: 100111307606W400

- **20m from P04**
- **Temp from Feb, 2018**
- **Chamber is growing downward**



High recovery example: B07 pad

Subsection 3.1.1. – 7c, iii

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B07 pad overview

B07 Pad started production in July 2012

- 8 well pairs

Good quality reservoir with pay thickness exceeding 50m

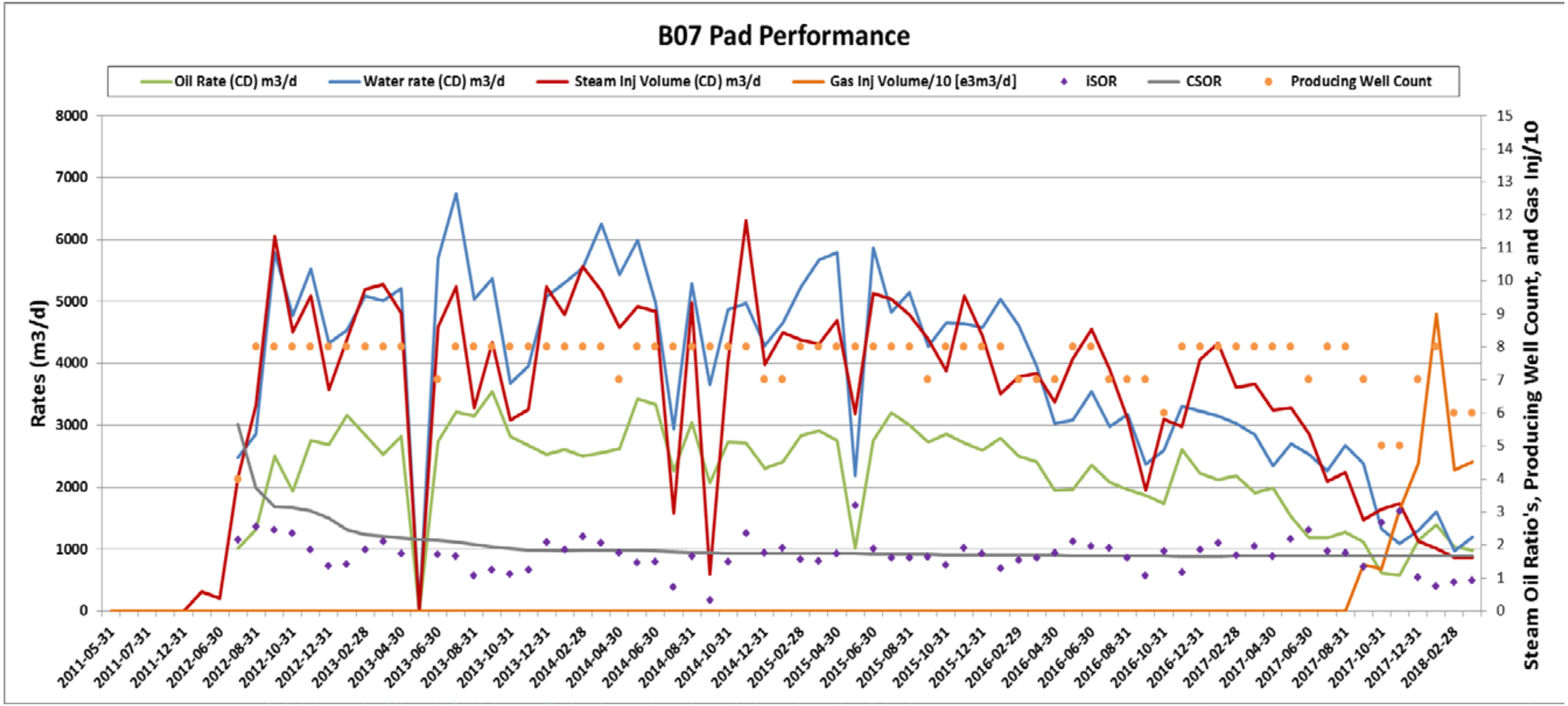
Co-injection started July 2017

B07 Pad is connected to larger Christina Lake Pod

Current:

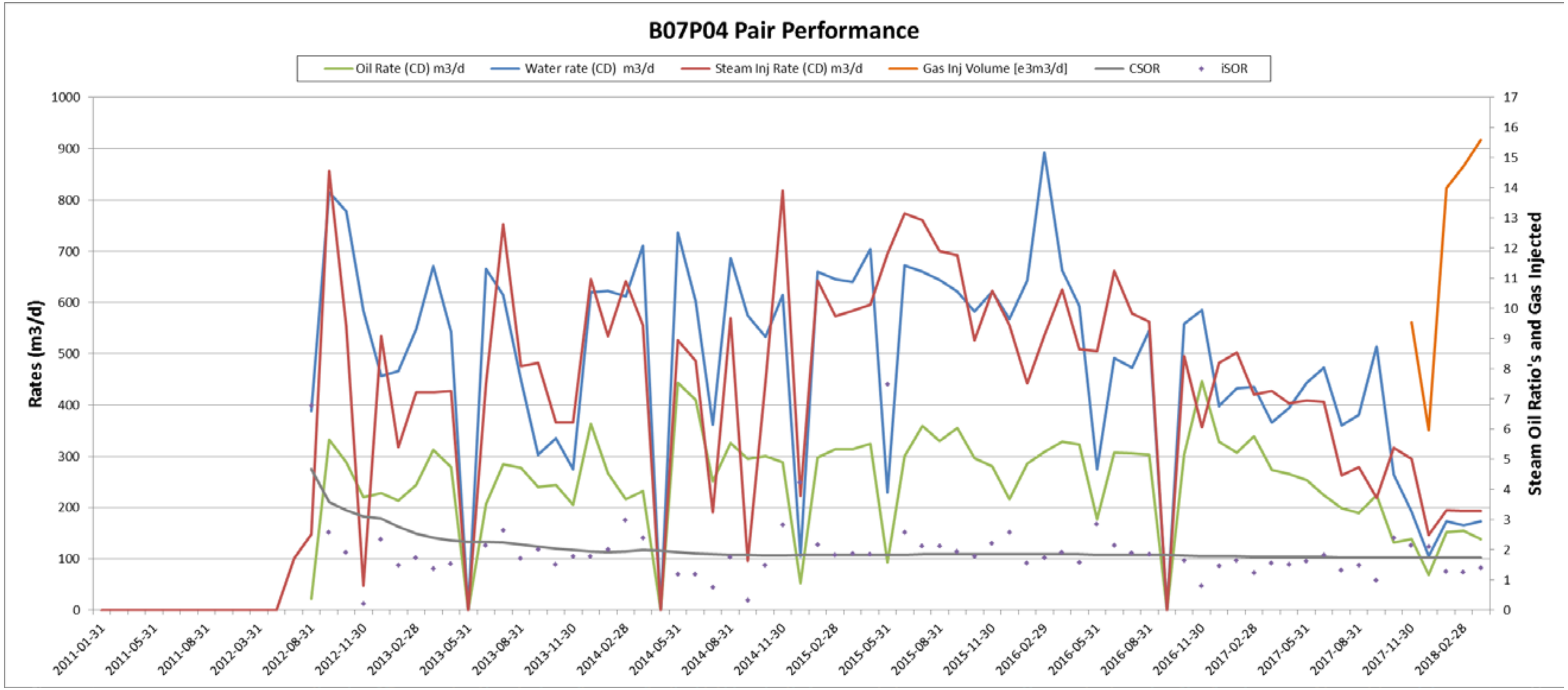
- Operating pressure ~2.7 MPa
- SOIP recovery ~73%
- CSOR ~1.7

B07 pad performance



CSOR
1.66

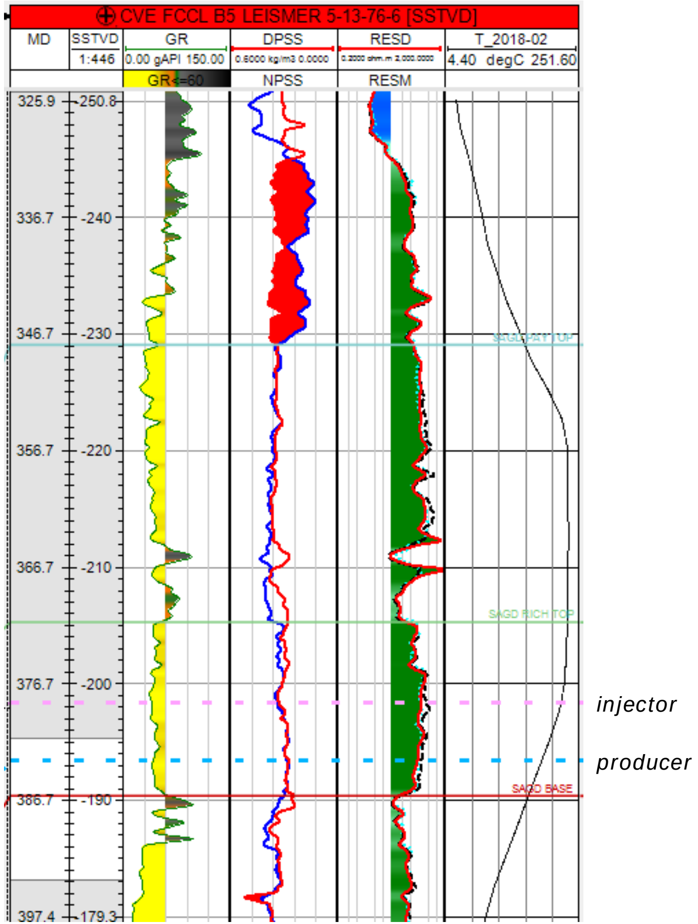
B07P04 performance



B07 thermocouple data

B07P02: 100051307606W400

- **11m from P02**
- **Temp from Feb, 2018**
- **Chamber is mature and is being held down by methane cap**



Subsection 3.1.1 – 7c) & 7d) Abandonment Plans and Steam Quality

Five year outlook – pad abandonments

There are no anticipated pad abandonments for any of the Christina Lake wells in the next five years.

Wellhead steam quality

Steam quality will be impacted by pipeline size and distance

Current steam quality injected into all pads is calculated to be greater than 95%

Currently steam header pressure is operated at 7-8 MPag with a corresponding steam temperature of 295°C

Steam quality is not expected to impact well performance

Subsection 3.1.1 – 7e)
Injected fluids

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Co-injection and Blowdown Trials

Full blowdown on A01 Pad

Full Blowdown as of November 2014

- November 2014: Steam ramp down began on the entire pad
- February 2015: Full steam shut-in to all wells on the pad. Pressure maintenance continued through natural gas injection
  - Current chamber average operating pressure ~ 2480 kPag
  - No negative impact has been observed with the pad operations as a result of full methane injection
  - Average concentration for Jan 2017 – Mar 2018
    - Average methane injection rate 85 e^3m^3/d
    - CSOR of 2.39

B01/B02 pad rampdown/blowdownpilot

Temporary wind-down test on B01 and B02 pads started June 2015

- Well pairs: B01-1 to B01-4 including WWs 01-03; B02-1 to B02-4 included.
- Steam brought back on July 2017

B01-1 to B01-4: Blowdown test

- Shut-in steam on all four wells
- Using gas cap (top down blowdown) to maintain pressure
- iSOR being managed ~2.0

B02-1 to B02-4: Steam ramp-down test

- Cut steam by 25% every 3 months (75%, 50%, 25%, 0%)
- Final steam cut delayed to manage gas production
- iSOR being managed ~2.0

Key learnings from trials:

- Gas management during blowdown
- Neighboring SAGD pads appear unaffected by blowdown at this time
- Currently optimizing wells with resumption of steam injection
- Multiple wells have been redeveloped to capture reserves under original (affects baselines)

Field wide co-injection and blowdown

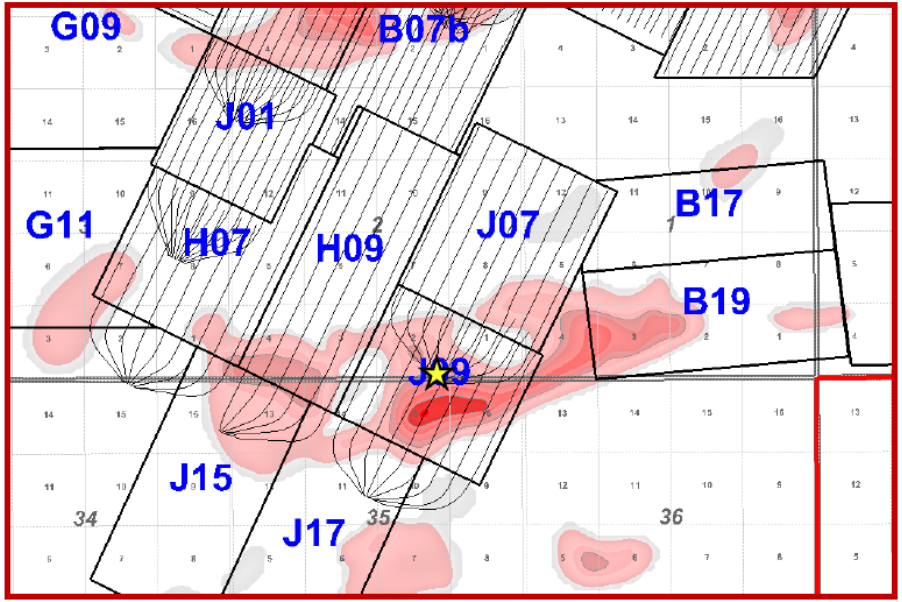
Current pads on co-injection and/or blowdown as of Mar 31, 2018:

- A01, B01, B02, B02C, B03, B04, B06, B07, B09, and B11 pads

Cenovus continues to manage SORs on mature pads by leveraging co-injection

New Southern Gas Cap Gas Injector

Southern gas cap injector: 16-35



102/16-35-076-06W4/00

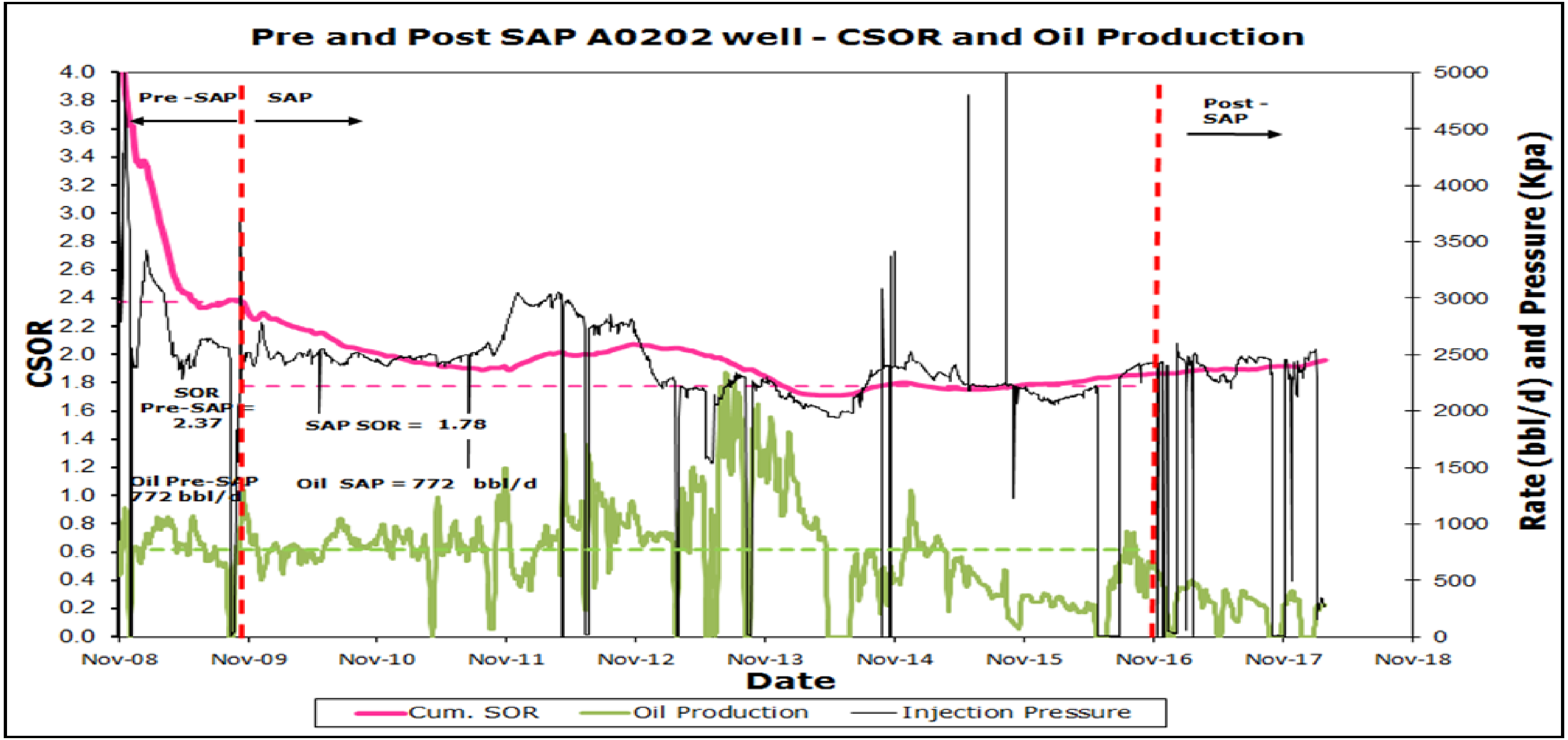
Vertical well injecting natural gas into McMurray to re-pressurize depleted gas cap in anticipation of upcoming pad startups (H07, H09, J07, J09)

AER granted Temporary Maximum Operating Pressure authorization in January 2018

Pressure injection is ongoing with success

A02-2 SAP Project

A02P02



Pre and Post SAP A0202 well - CSOR and Oil Production
CSOR
Rate (bbl/d) and Pressure (Kpa)
Pre -SAP
SAP
Post - SAP
SOR Pre-SAP = 2.37
SAP SOR = 1.78
Oil Pre-SAP 772 bbl/d
Oil SAP = 772 bbl/d
4.0
3.8
3.6
3.4
3.2
3.0
2.8
2.6
2.4
2.2
2.0
1.8
1.6
1.4
1.2
1.0
0.8
0.6
0.4
0.2
0.0
5000
4500
4000
3500
3000
2500
2000
1500
1000
500
0
Nov-08
Nov-09
Nov-10
Nov-11
Nov-12
Nov-13
Nov-14
Nov-15
Nov-16
Nov-17
Nov-18
Date
Cum. SOR
Oil Production
Injection Pressure

A0202 SAP (solvent aided process)

- **Started butane co-injection in November 2009**
- **Cumulative SOR of 1.96**
- **Cumulative solvent recovery factor of 87.2%**
  - Recent process review shows solvent recovery is higher than previously measured. Reported data will be corrected
- **SAP has shown benefit of reducing SOR**
- **Stopped butane co-injection and operated A0202 on steam in Q4 2016**
- **Commenced NCG co-injection in Q1 2017**
- **A0201 Early SAP injection well pair started injecting butane in Q4 2016 and stopped Q3 2017 (well failure)**

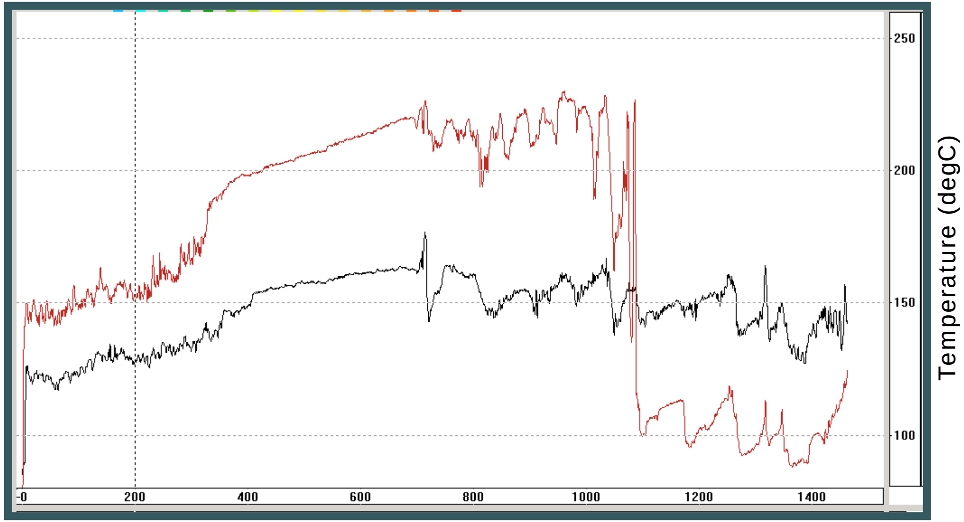
Subsection 3.1.1 – 7f)
2017 key learnings

Splitter Shift Timing

Splitter shift timing

- **Instant shifting of steam distribution post startup can help conformance**
  - Proactively promote steam chamber growth in cold areas to improve conformance
  - If cold area is observed, post start up, push steam to the cold area
  - After conformance is established, shift splitters back to a more even steam distribution

Splitter shift timing: J03P02 example



- Red temp log is 8 days post steam circulation
- Toe temps dropped to below 100 C
- Shifted all splitters closed to force steam injection to the toe
- Black temp log is 2 days post shift
- Conformance improves greatly
- Ran like this for a couple of months and switched back to a more even steam distribution

Wabiskaw Zone at Christina Lake

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Wabiskaw overpressure

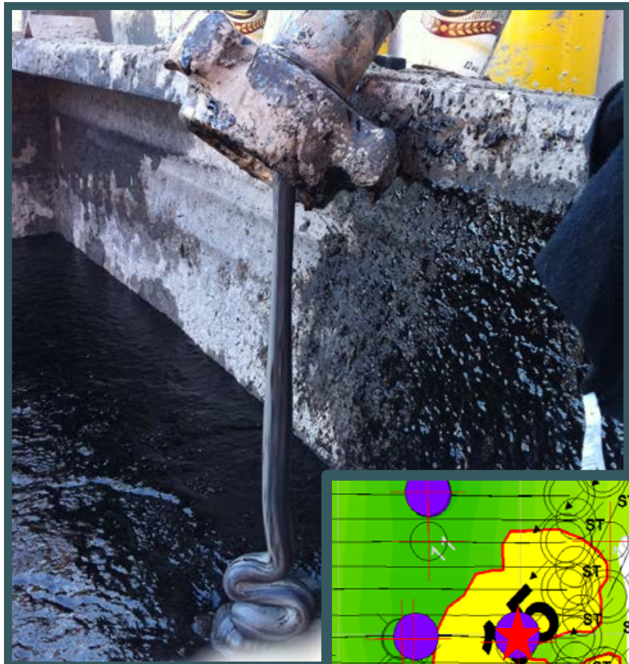
Unexpected Discovery:
steam-core drill in April 2013

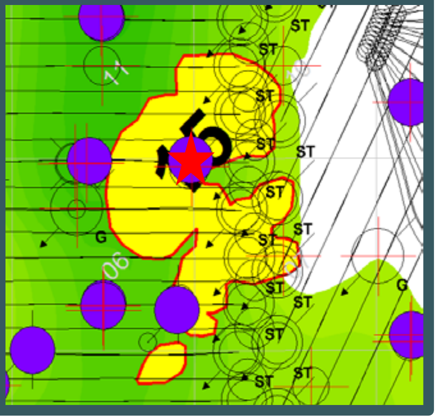
6,500kPa Overpressure:
conductive thermal expansion in WBSK
(above 5,400kPa MOP)

4D Seismic Identification

WBSK Producer:
107/06-15 depressurization well

Monitoring:
enhanced observation capabilities in the area



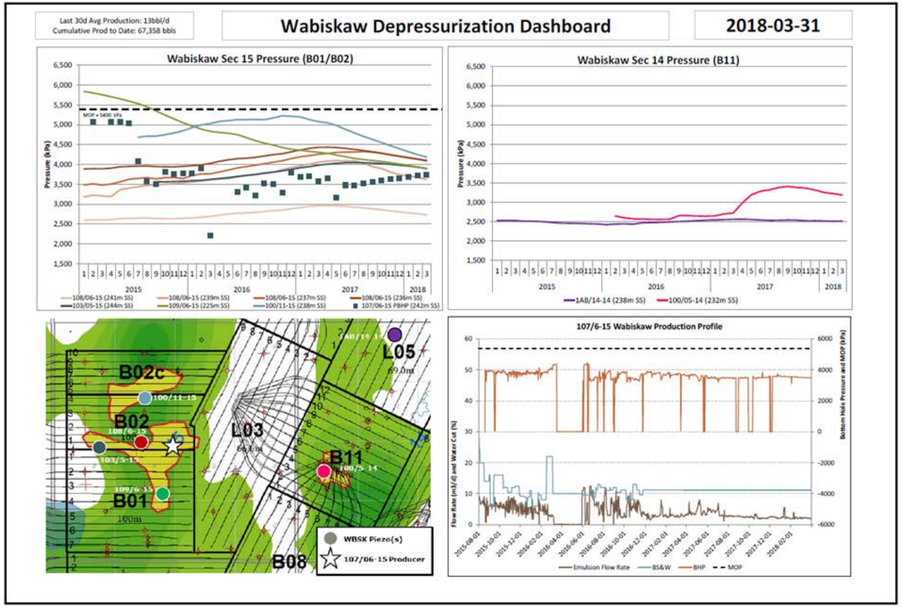


Wabiskaw overpressure update

All Wabiskaw piezometers are reading below Maximum Operating Pressure

Overall Wabiskaw pressures are trending down:

- Less steam is injected into the McMurray injectors below as pads mature
- Production of Wabiskaw oil to the Single Well Battery continues to depressurize west area
- New 4D anomaly drilled into and installed piezo, monitoring but early indications are that it is not overpressured



Subsection 3.1.1 – 7g) Information requests

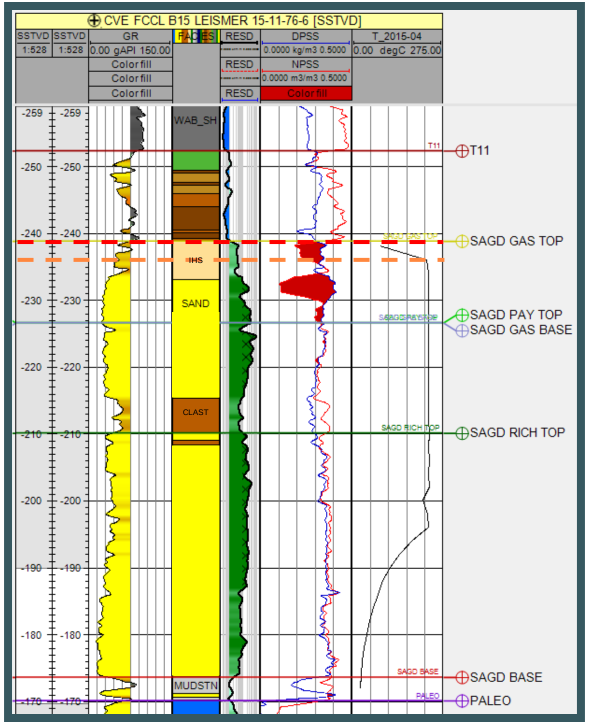
SAGD top revisions

Revised SAGD Top

Revised SAGD Rich Top

Some SAGD tops have been revised to reflect surveillance data

In this example, the thermocouple shows the steam top rise through the clast zone, and then displace some of the top gas, to come to rest in the sandy IHS



Subsection 3.1.1 – 7h)
Pad production plots

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Pad production plots

Requirements under subsection 3.1.1 7h) are located in Appendix 4

Subsection 3.1.1 – 8) Future plans

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Resource recovery strategy

Well / pad placement:

- 2018/2019 well pairs are planned to be drilled as per the existing (or future) applications and approvals
- Well spacing/trajectories planned to be submitted for approval prior to construction/drilling

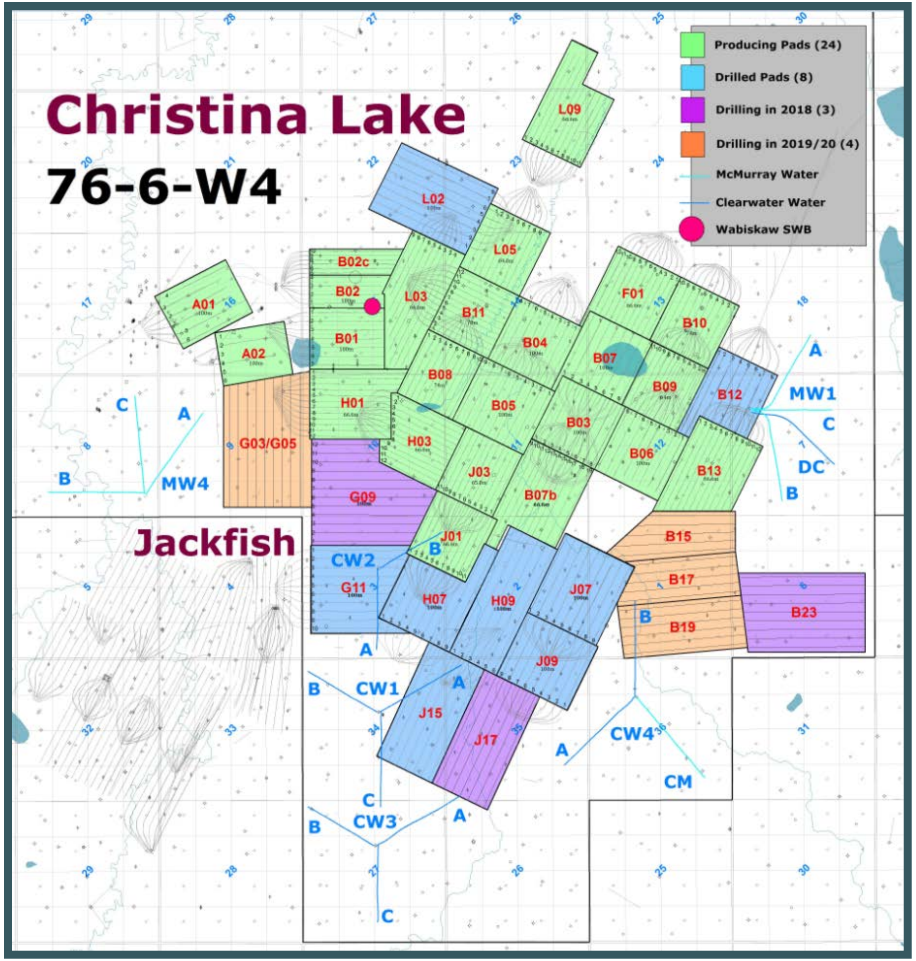
No changes in the overall resource recovery strategy (operating pressure, composition of injected fluid)

Any deviations will be applied for as future amendments

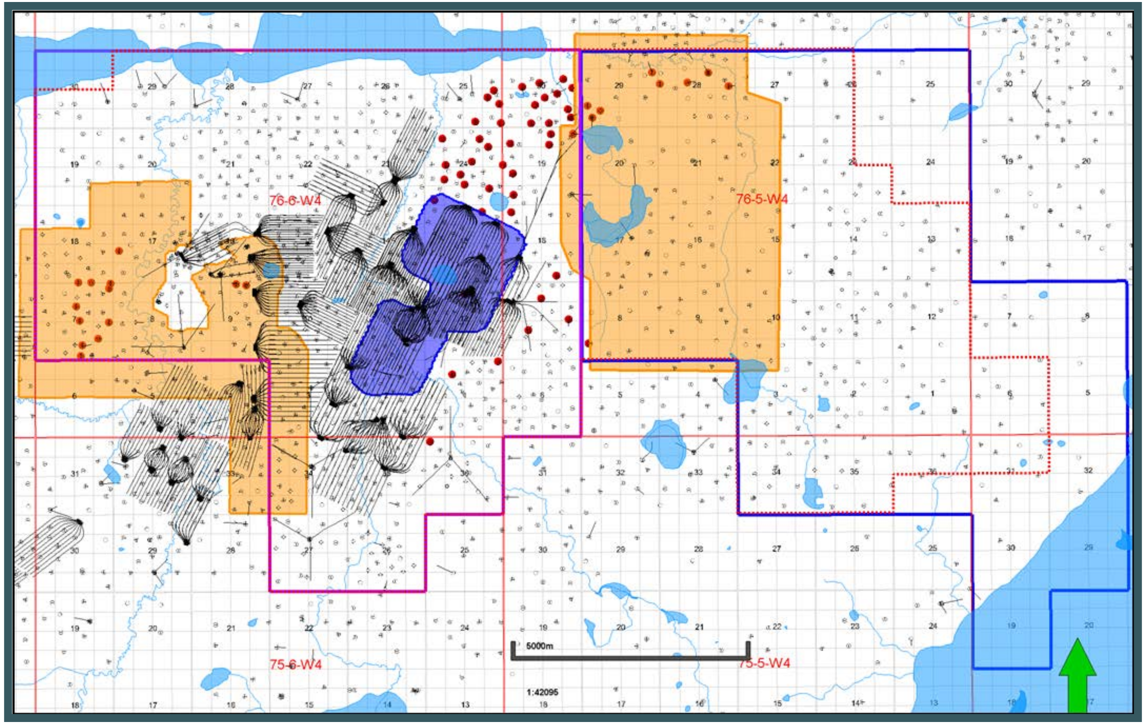
2018 SAGD drilling plans

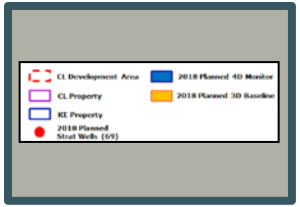
Planned SAGD well-pairs to be drilled in 2018 (rig start)

Pad	Pad type	Well count	Timing
J17	Production	7 Well-pairs	Q1 2018 *spudded Q4 2017*
G09	Production	12 Well-pairs	Q3 2018
B23	Production	9 Well-pairs	Q4 2018



2018 planned strat and seismic program





2018-2019 steam strategy plans

- **Cenovus allocates steam to maintain targeted steam chamber operating pressures from pad to pad**
- **Steam rampdown is used to optimize steam allocation across the field by freeing up steam to be used in starting up new pads**
- **Overall strategy is to optimize field SOR**

Questions?

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