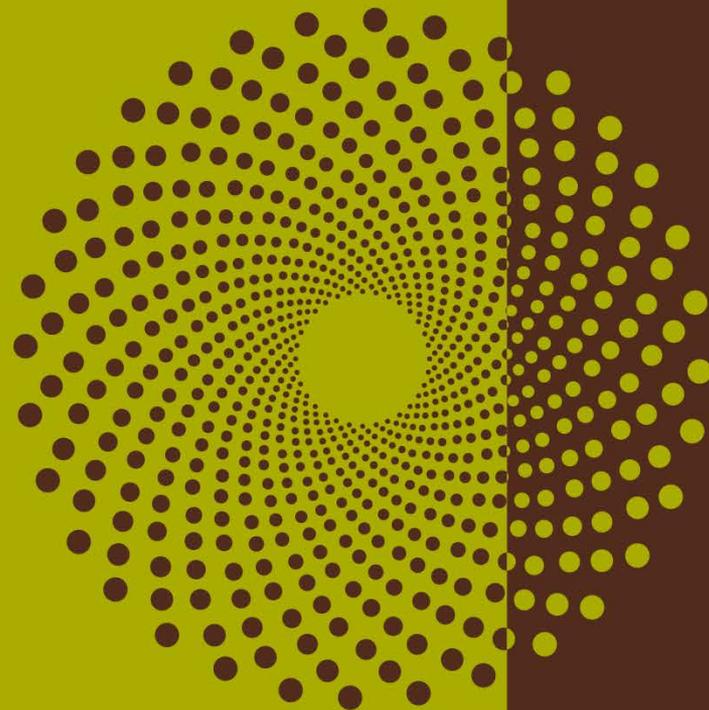


Cenovus FCCL Ltd.  
Foster Creek In situ Progress Report  
Scheme 8623  
2017 Update

Subsurface Presentation  
May 30, 2018



# 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](http://www.sedar.com), EDGAR at [www.sec.gov](http://www.sec.gov) and on our website at [cenovus.com](http://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.

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# Advisory

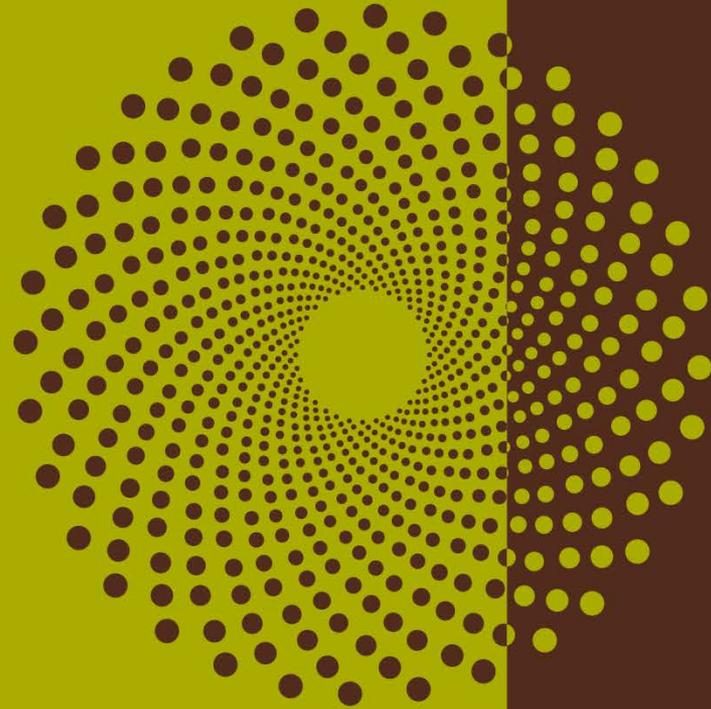
This presentation contains information in compliance with:

*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.

# Brief background

Subsection 3.1.1-1)



# 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

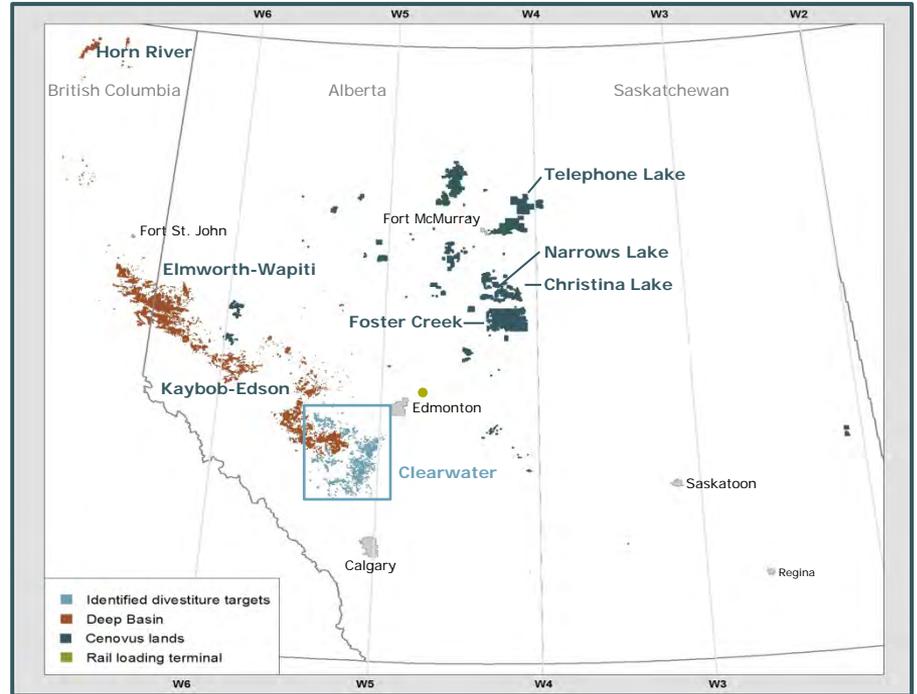
Total liquids 405 Mbbls/d

Total natural gas<sup>1</sup> 550 MMcf/d

**Total production 497 MBOE/d**

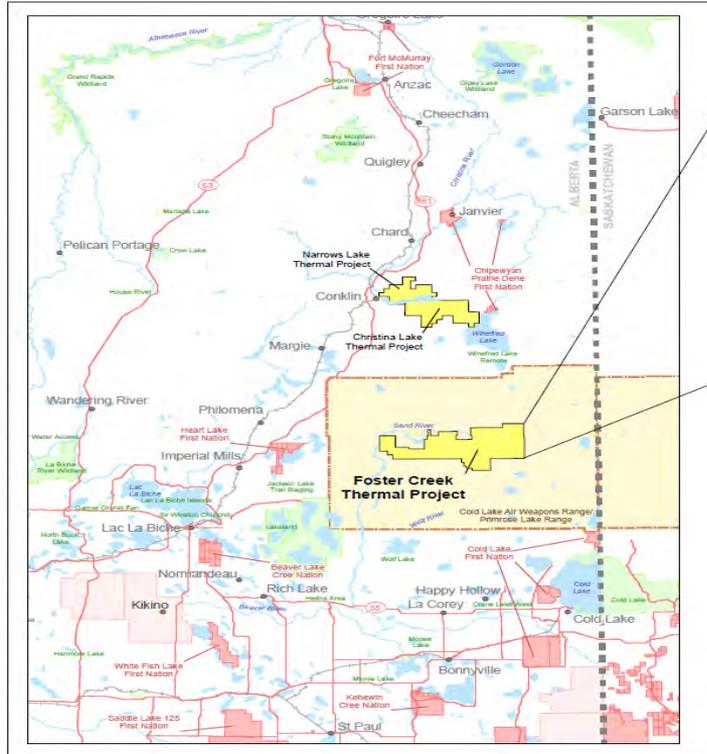
2017 proved + probable reserves 7.1 BBOE

Refining capacity 230 Mbbls/d net

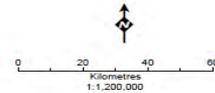


Note: Values are approximate. 2018F production based on the midpoint of December 13, 2017 guidance. <sup>1</sup> 2018F total natural gas includes production from the Deep Basin and Cenovus's Athabasca natural gas asset. See advisory.

# Area map



- Expressway / Highway
- Railway
- Cenovus Project Area
- Parks and Protected Areas
- Cold Lake Air Weapons Range/ Primrose Lake Range
- First Nation Reserve
- Metis Settlements



NAD 83 UTM 12N  
Page Size: 11x17



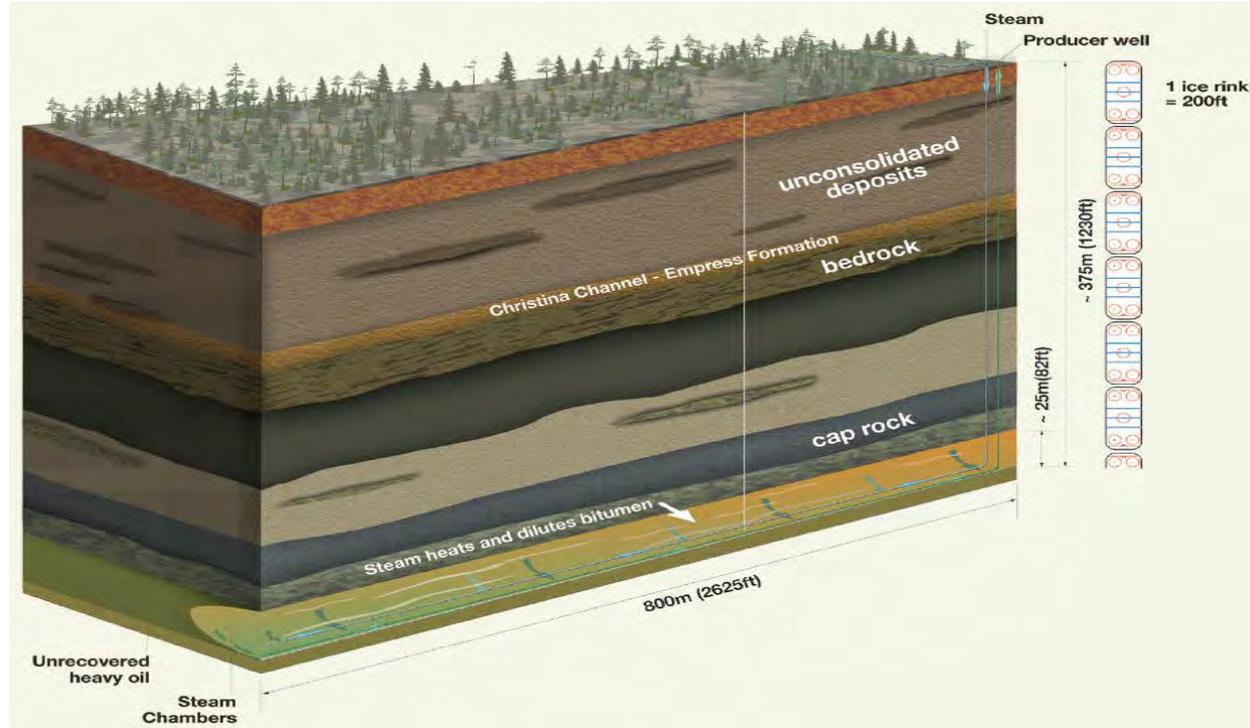
**cenovus**  
ENERGY

**FOSTER CREEK THERMAL PROJECT**

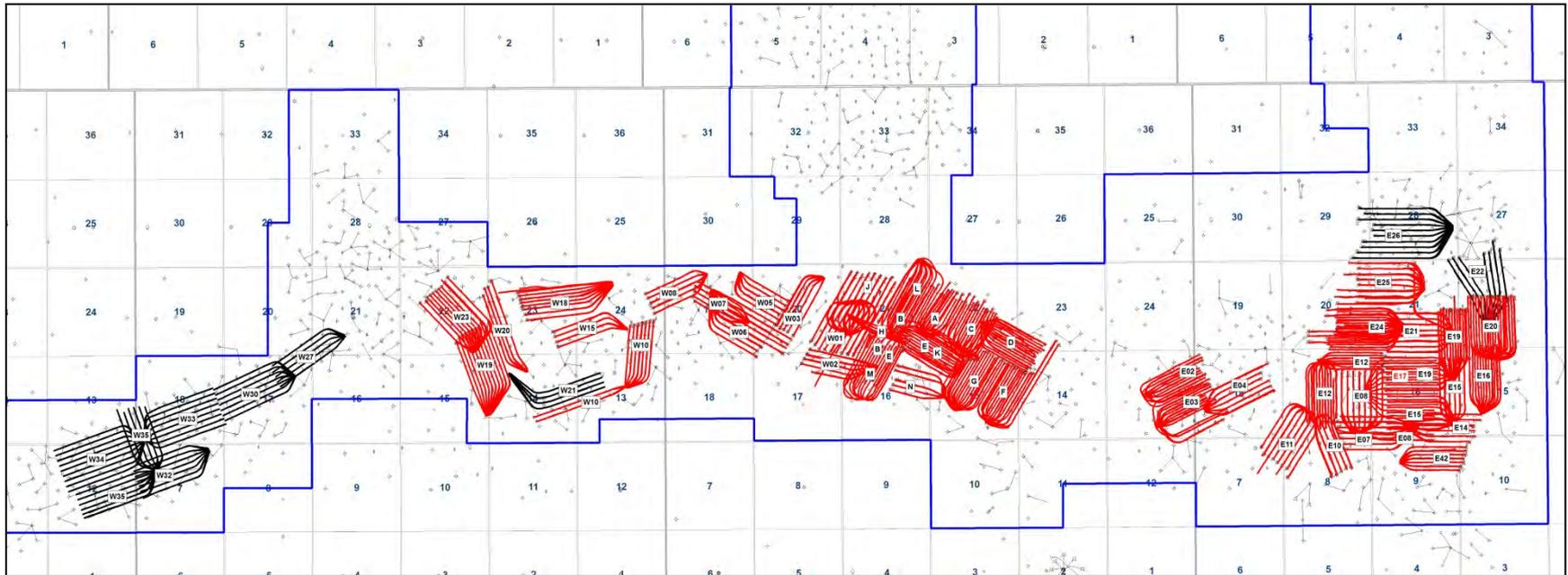
CVE-0368-002  
April 26, 2017

# Recovery process

- The Foster Creek Thermal Project 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



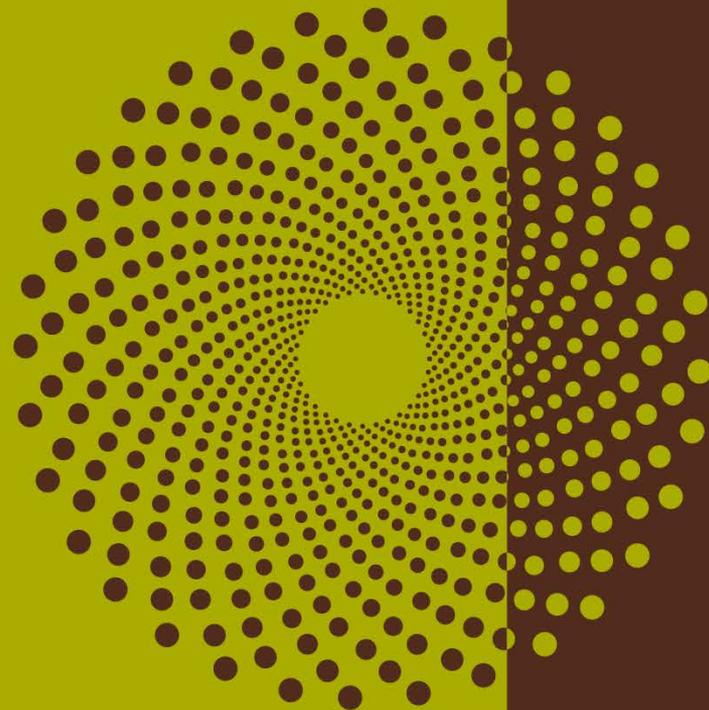
# Scheme map



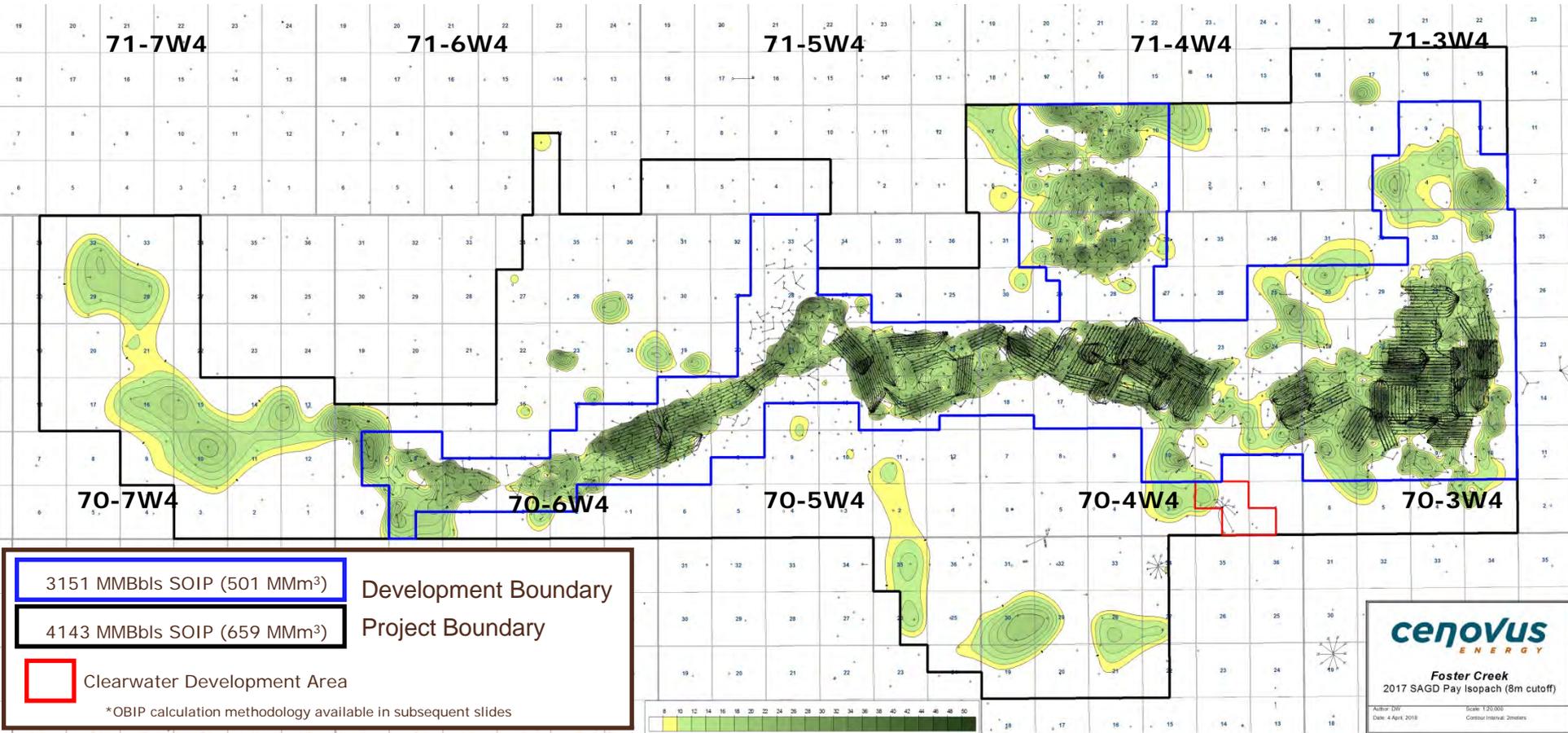
- Well Pairs on Production
- Well Pairs Drilled Not Producing

# Geology and Geoscience

Subsection 3.1.1 – 2)



# Current Project Status – SAGD Resource



# Reservoir characteristics

Reservoir Characteristic	West Area	Central Area	East Area
Depth (m subsea)	180 – 225	180 – 225	180 – 225
Thickness (m)	Up to 30+	Up to 30+	Up to 30+
Porosity (%)	34%	34%	32%
Horizontal Permeability (D)	Up to 10 D	Up to 10 D	Up to 8 D
Vertical Permeability (D)	Up to 8 D	Up to 8 D	Up to 6 D
Oil Saturation	~0.85 (0.50 in transition)	~0.85 (0.50 in transition)	~0.85 (0.50 in transition)
Water Saturation	~0.15 (0.50 in transition)	~0.15 (0.50 in transition)	~0.15 (0.50 in transition)
Original Pressure (kPa)	~2700	~2700	~2700
Original Temperature (°C)	12 °C	12 °C	12 °C

# Composite type log: central wells

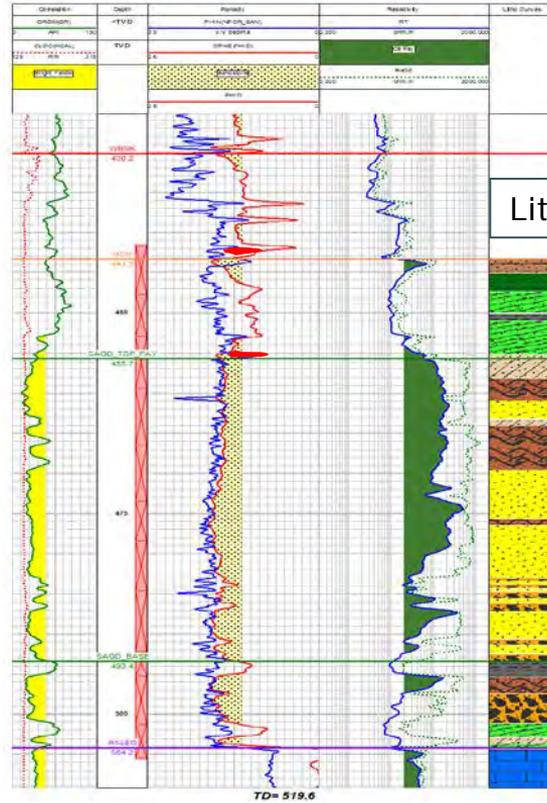
- Basal mud defines base of pay
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

Location: 11-19-70-4W4



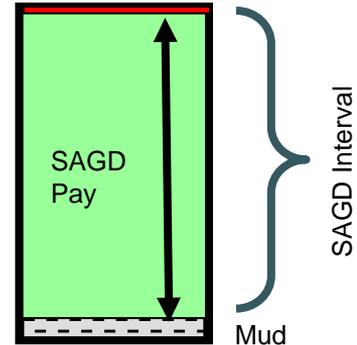
Wabiskaw  
McMurray  
Shales

Mud  
Paleo  
Lmst



Lithology

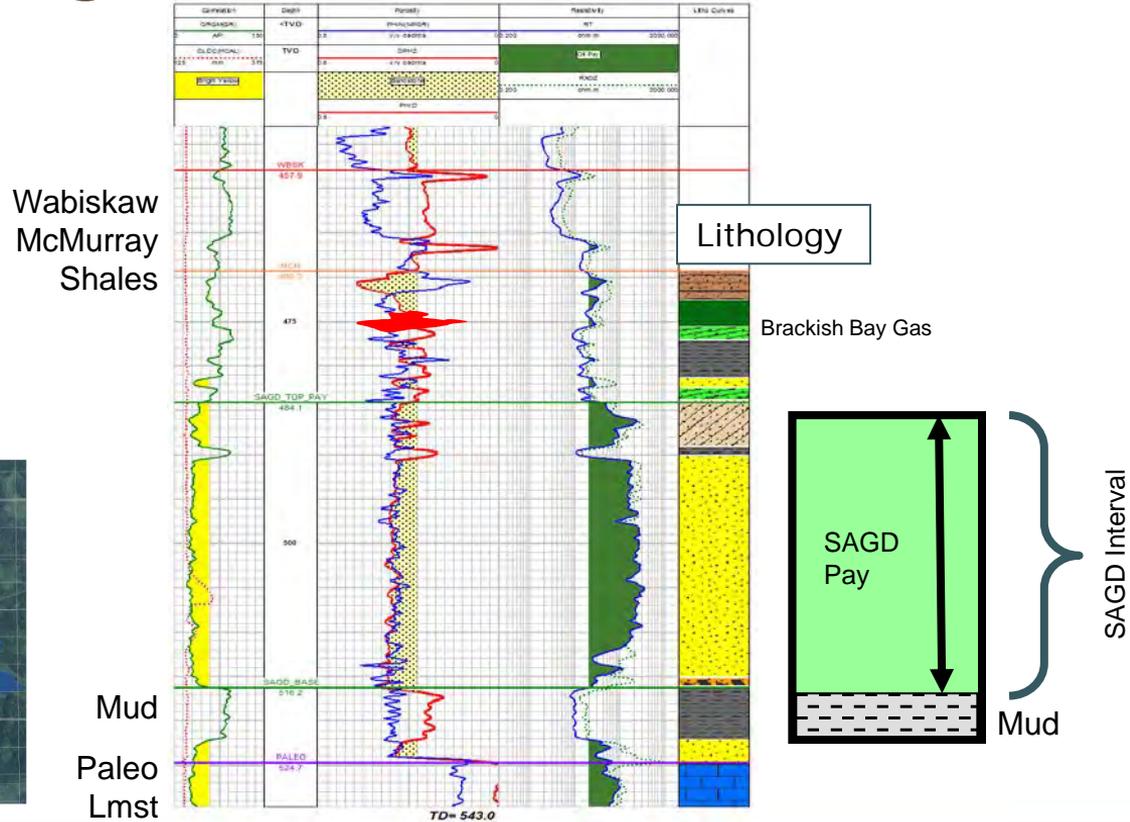
Brackish Bay Gas



# Composite type log: east wells

- Basal mud defines base of pay
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

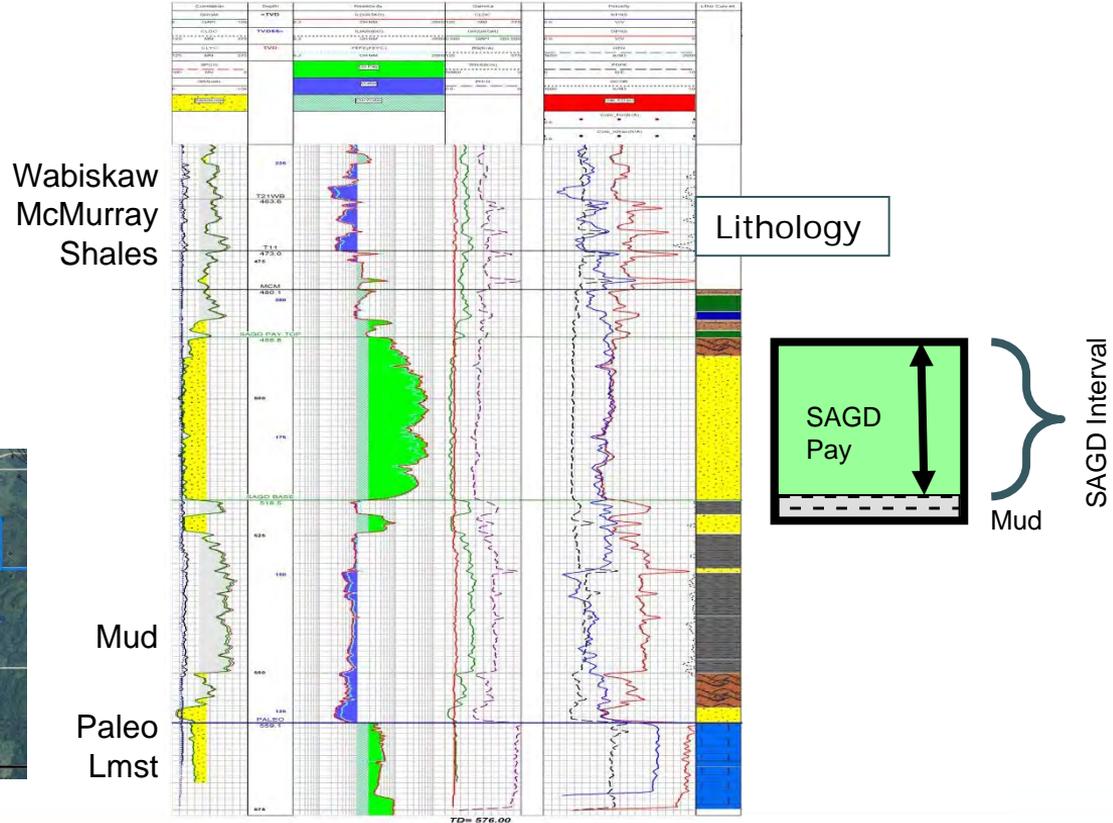
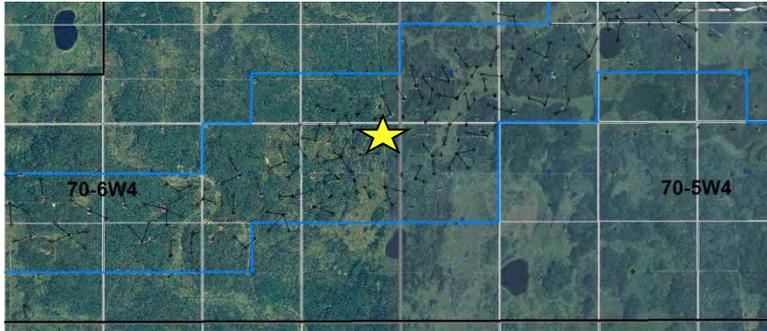
Location: 2-21-70-3W4



# Composite type log: west wells

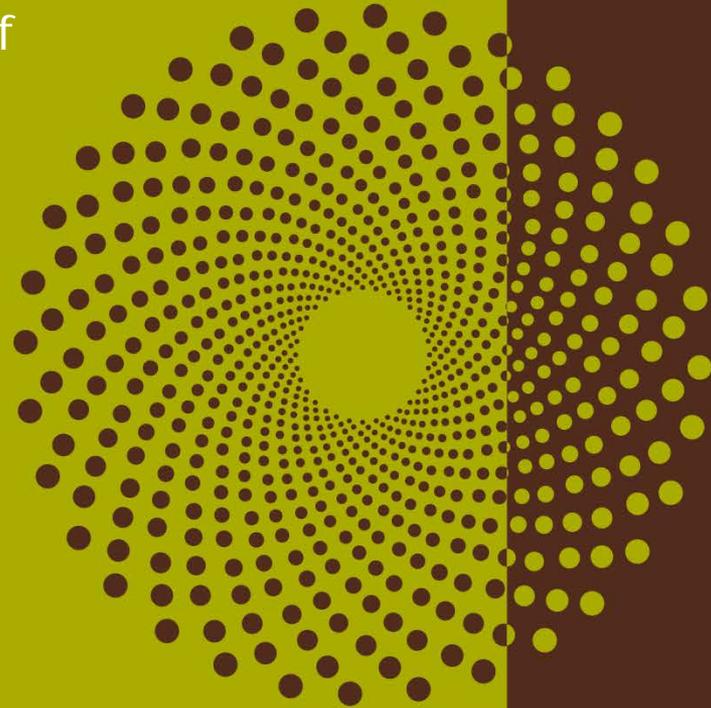
- Basal mud defines base of pay
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations

Location: 16-12-70-6W4

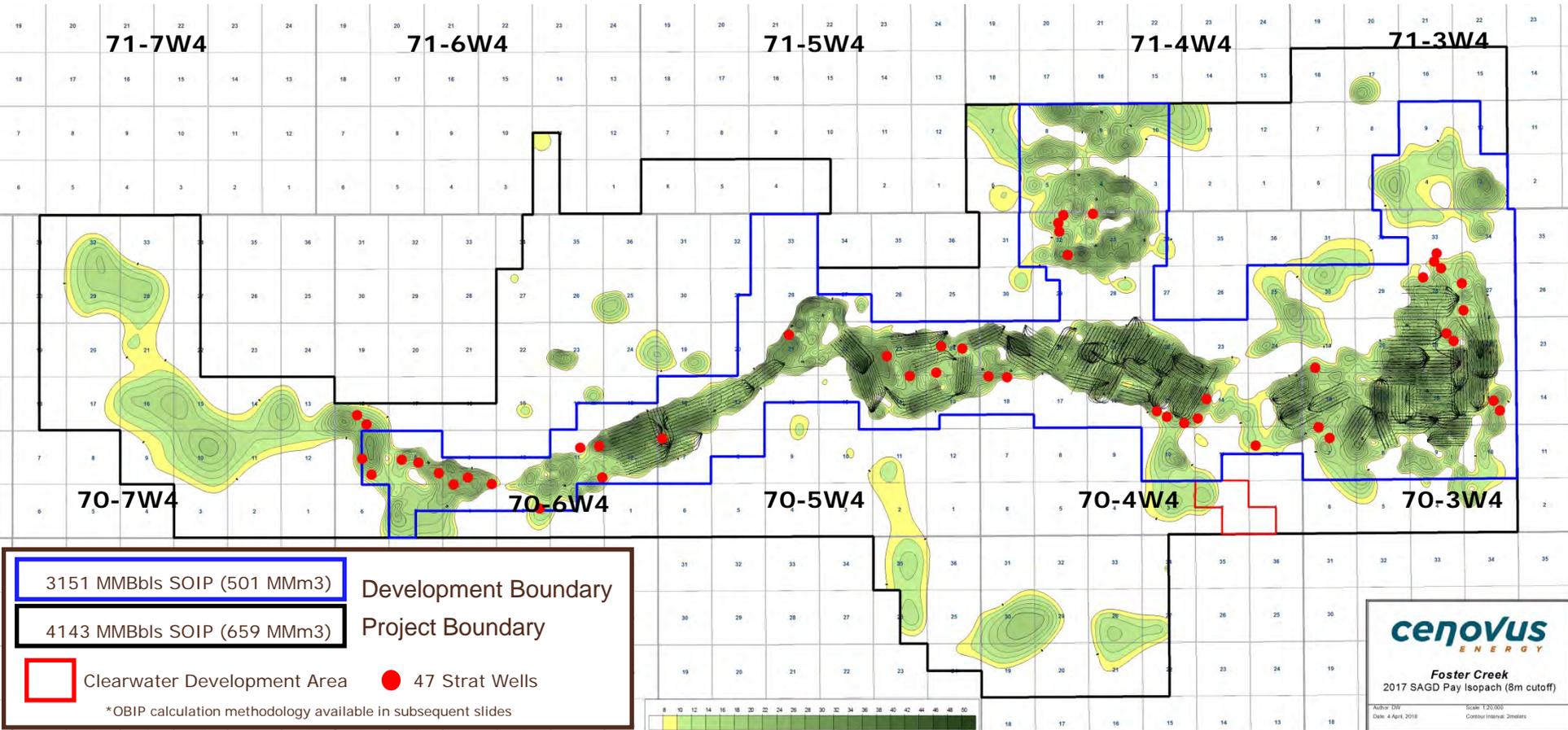


# Maps and Core

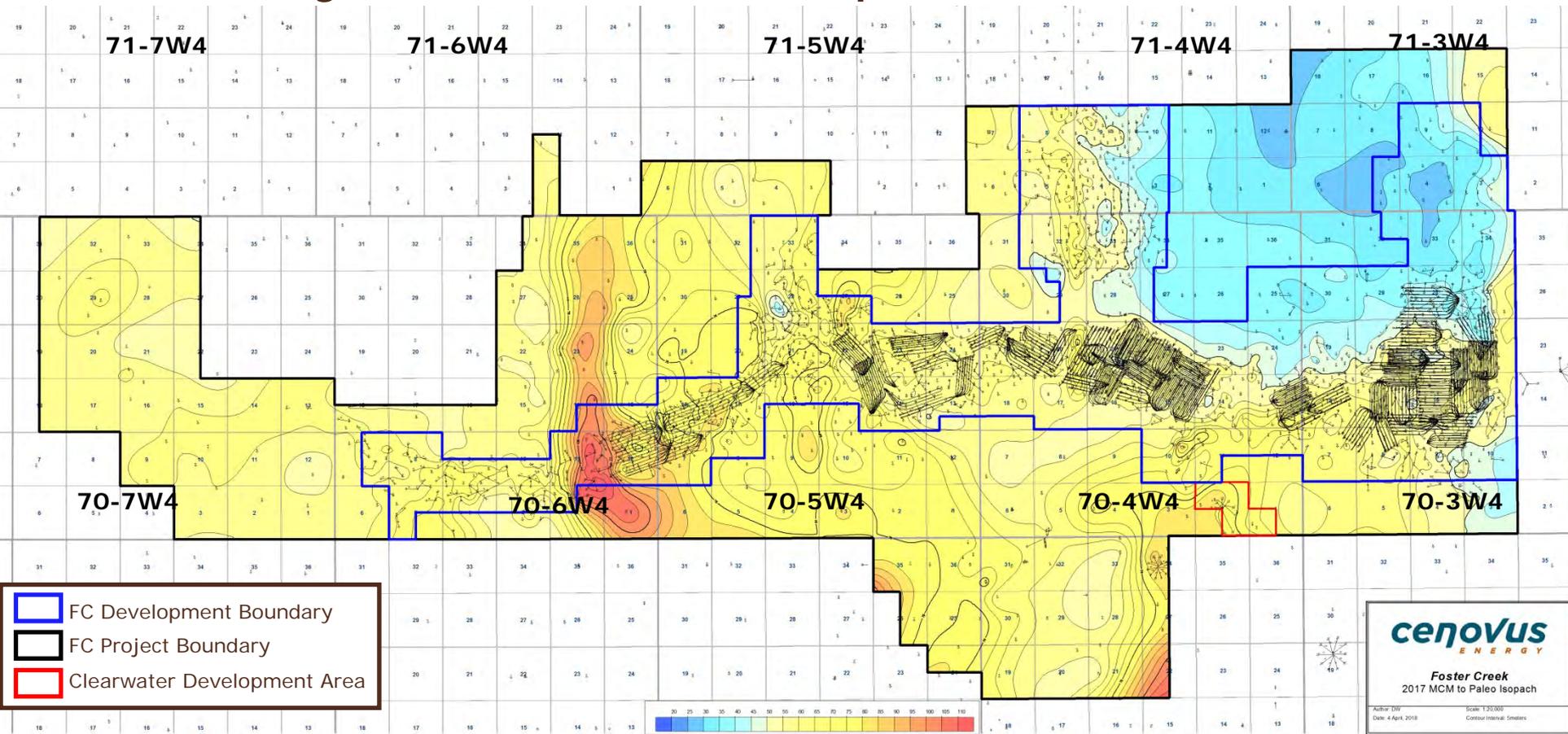
Subsections 3.1.1 – 2) b-d and f



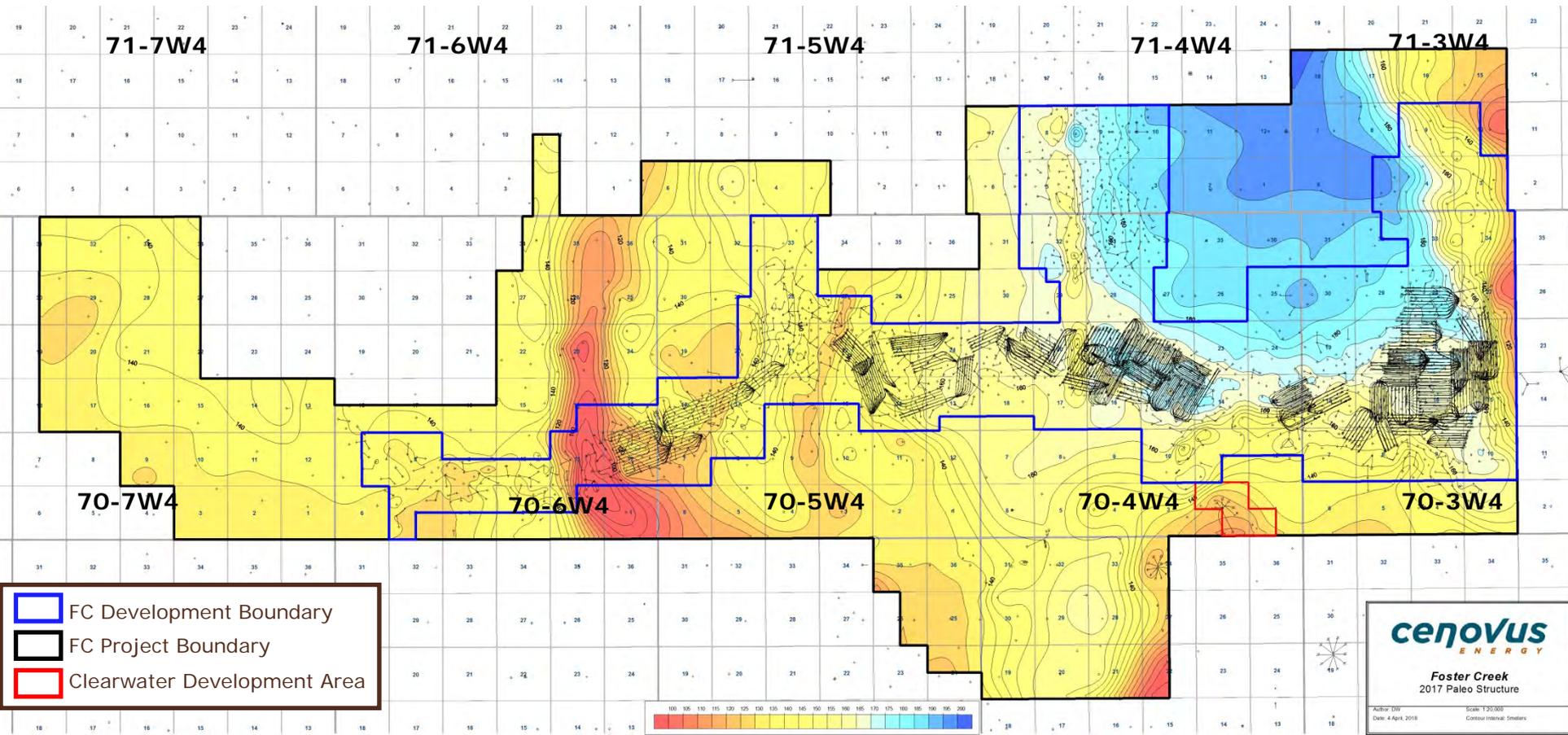
# 2017 SAGD Pay Isopach (2018 Strats)



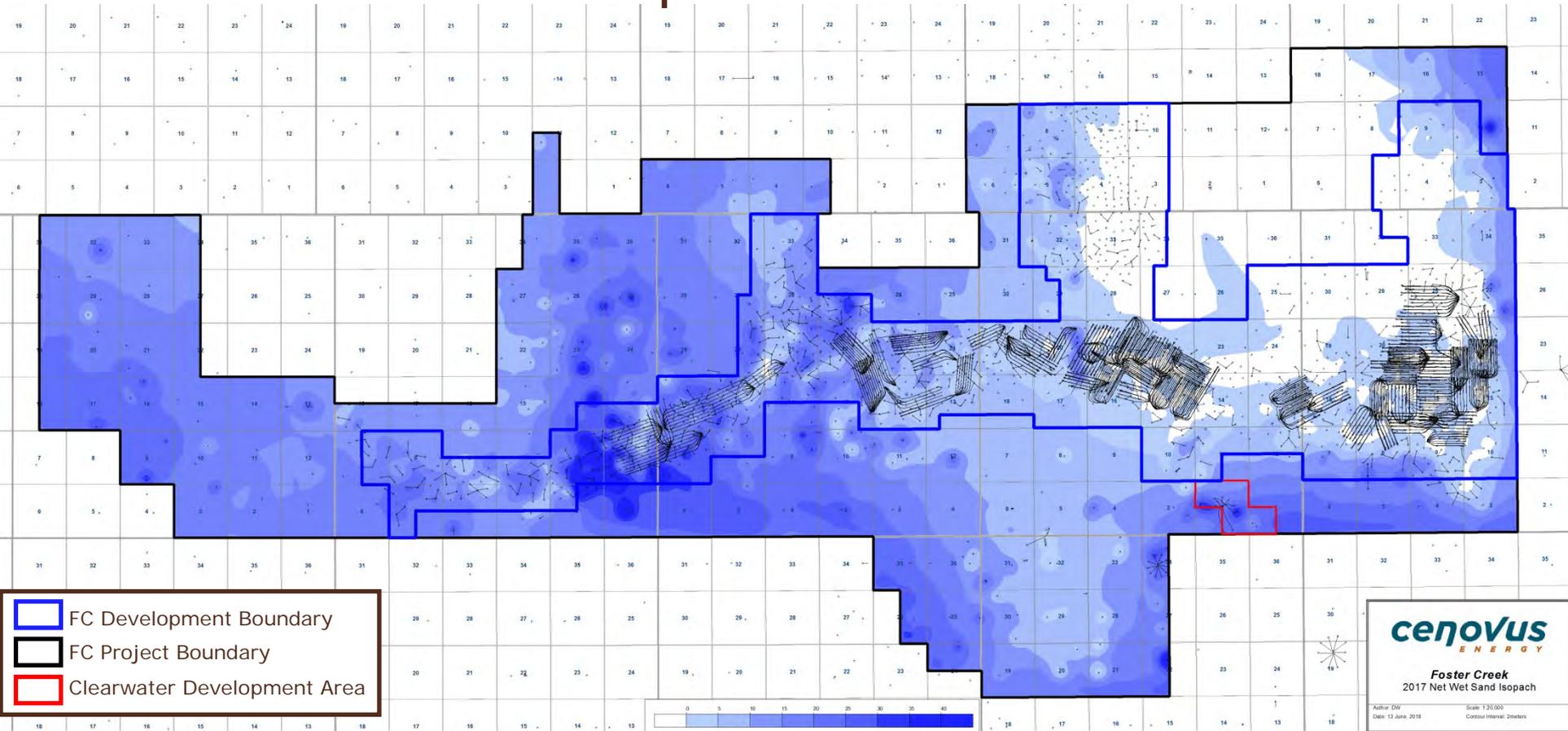
# McMurray to Paleozoic Isopach



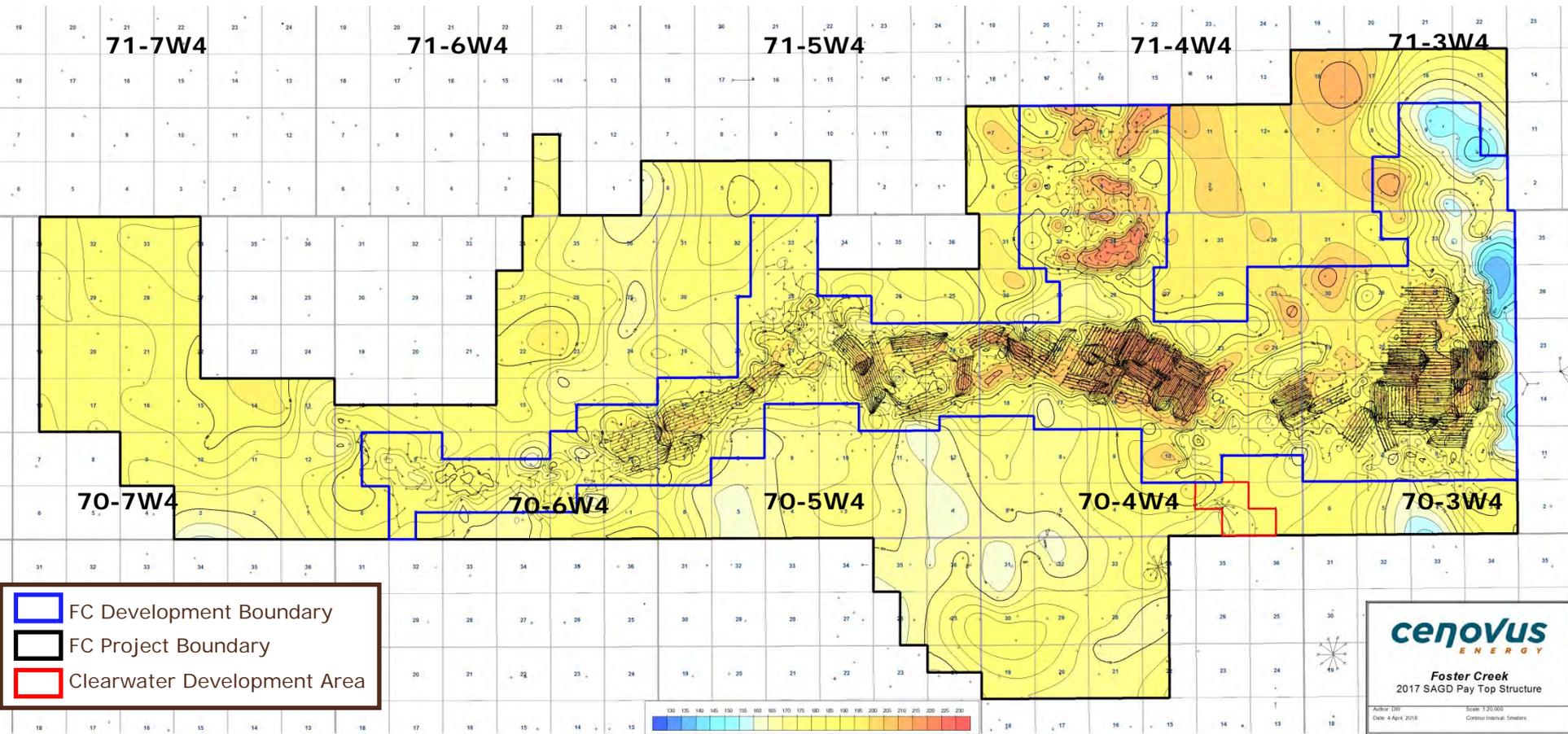
# Paleozoic Structure



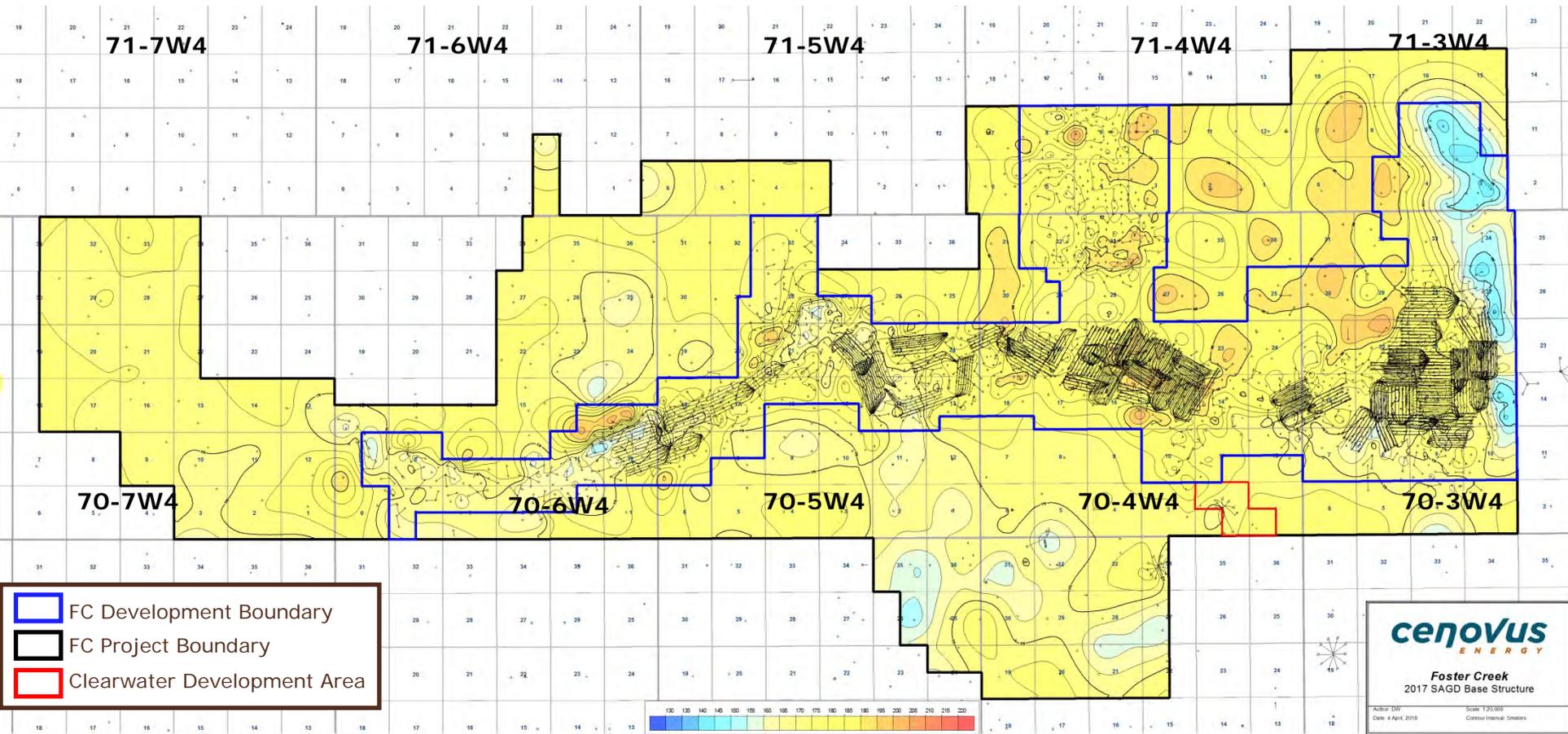
# Net Water Sand Isopach



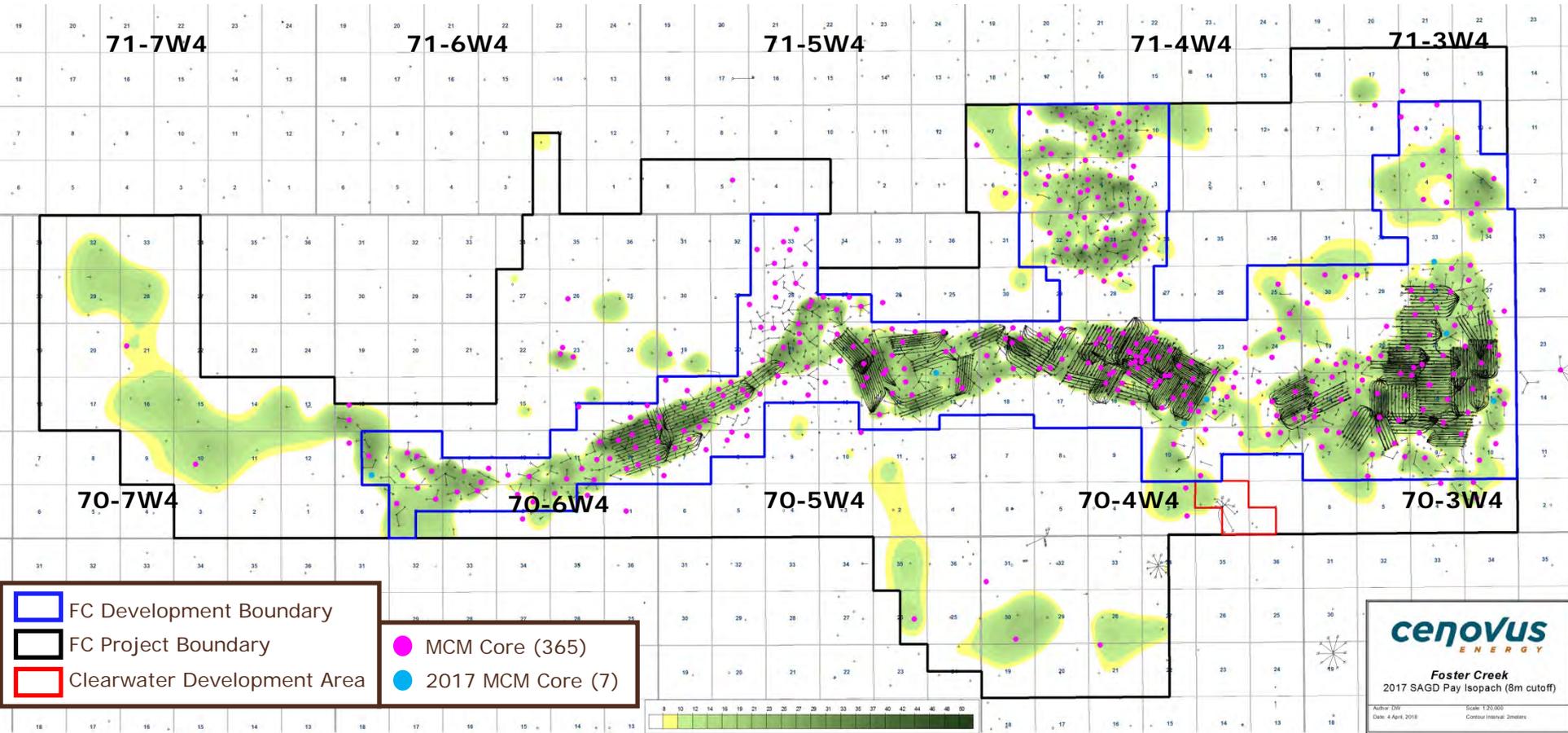
# SAGD Pay Top Structure



# SAGD Base Structure



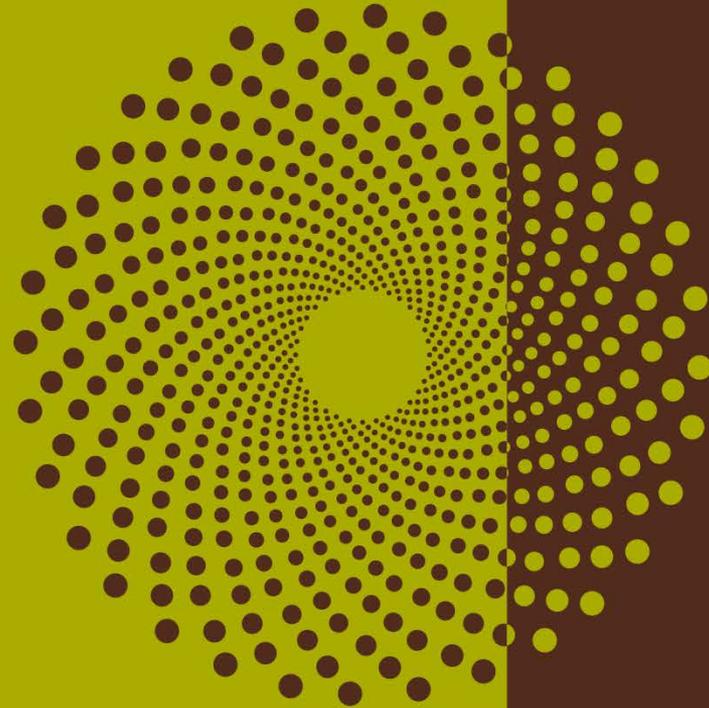
# Cored Locations (2018)



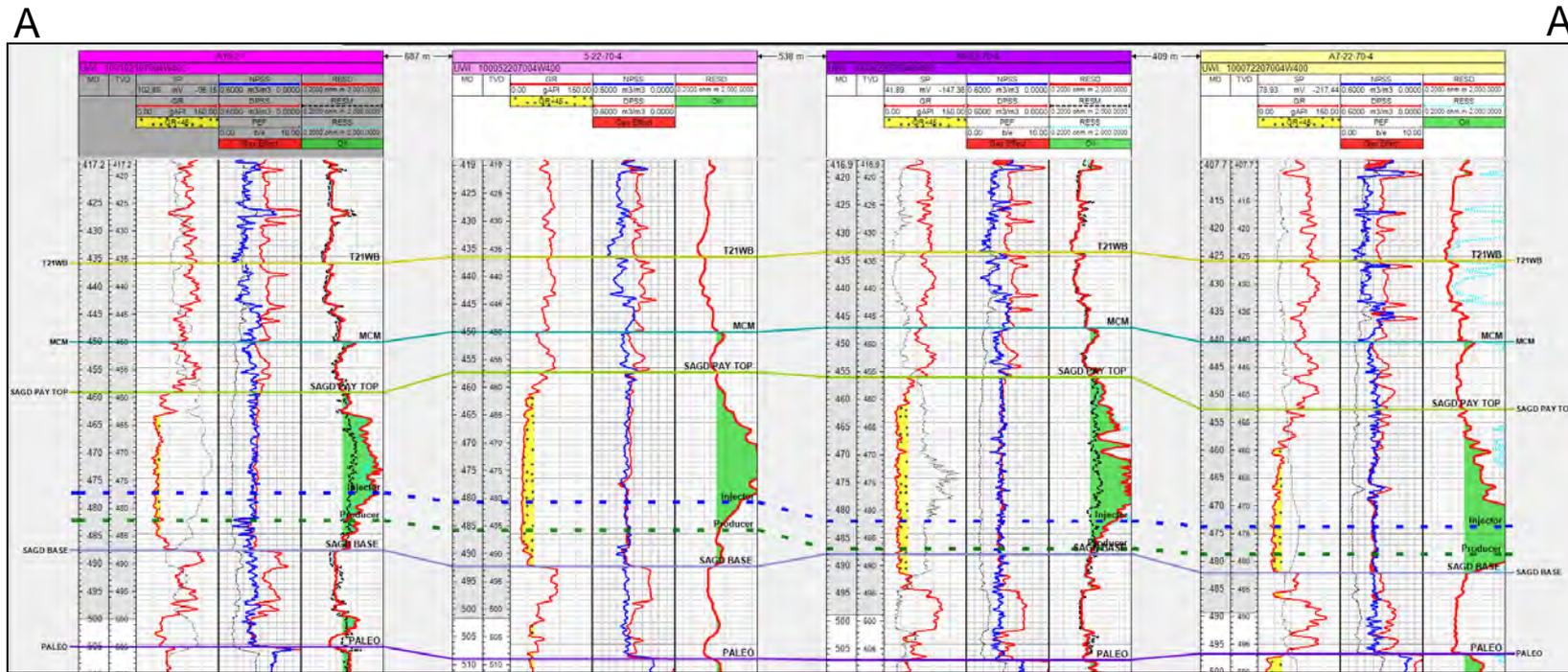
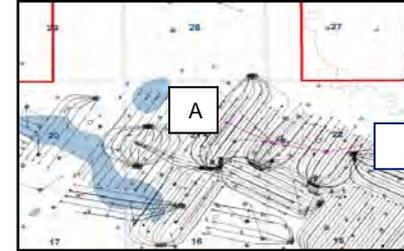


# Cross Sections

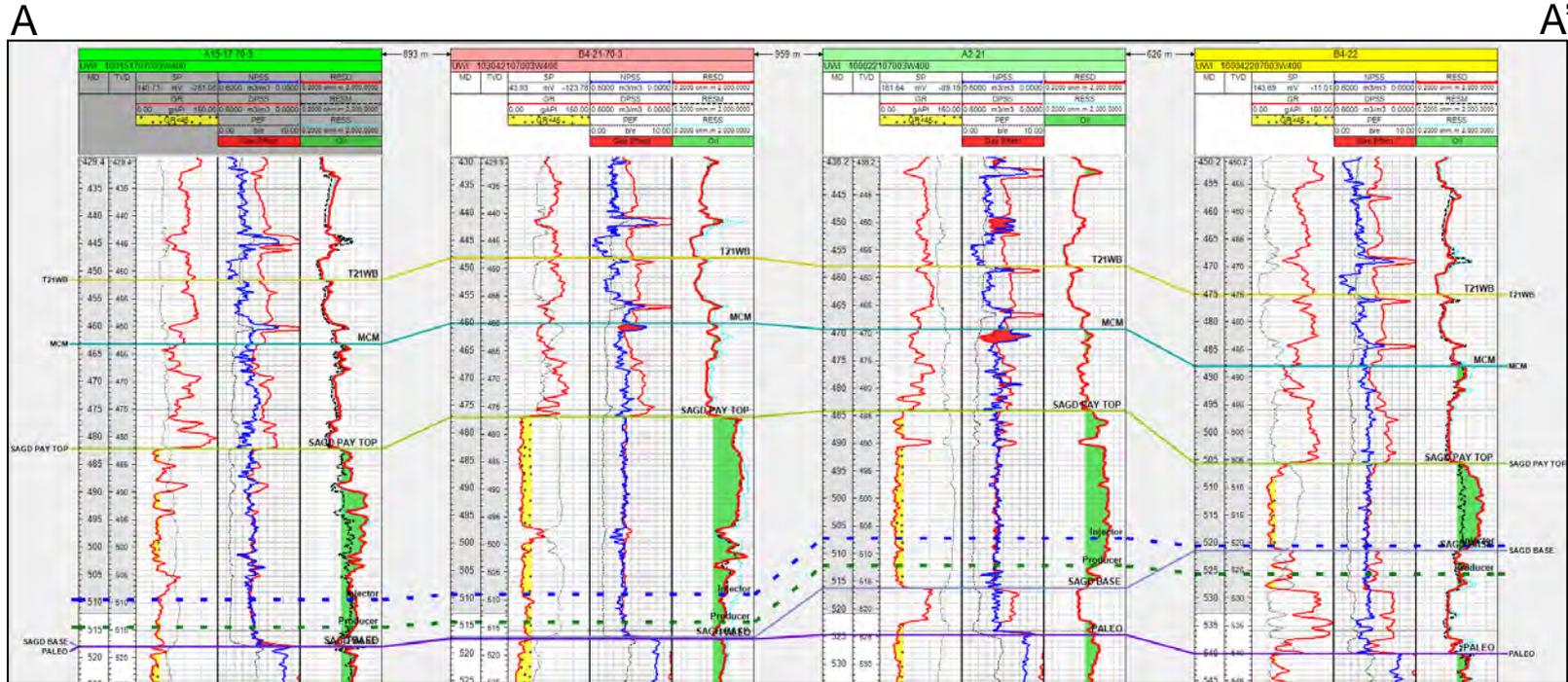
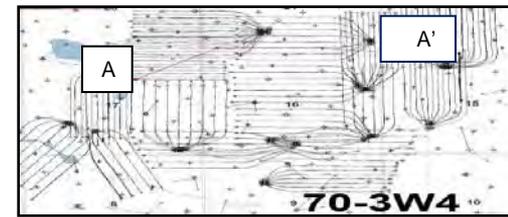
Subsections 3.1.1-2e) i-iii and f



# Representative structural cross-section over Central area



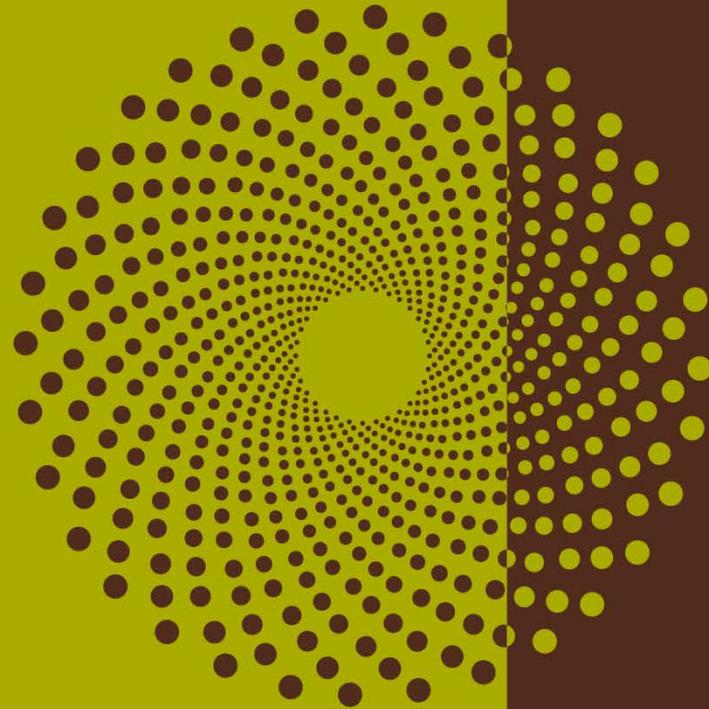
# Representative structural cross-section over East area





# Geo-mechanical Data

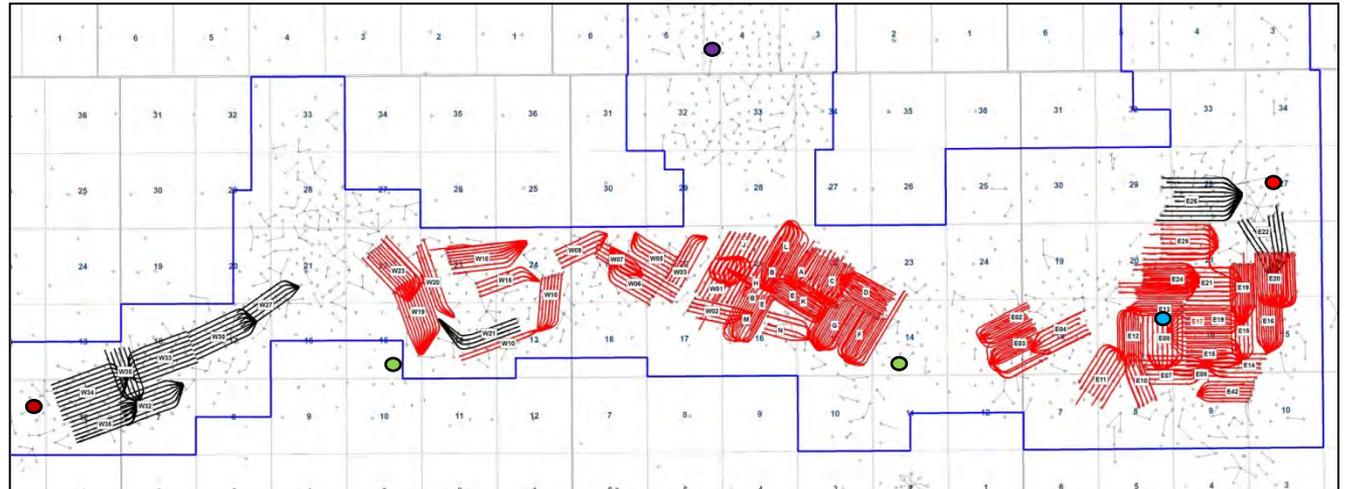
Subsection 3.1.1-2) j



# Mini-frac and DFIT wells

- CVE recognizes that tensile and shear failure are two possible ways for integrity to be compromised
- Mini-frac or DFIT data give information about failure mechanisms and stress magnitudes

9-17-70-3 (2009)  
2-15-70-5 (2010)  
3-14-70-4 (2010)  
6-27-70-3 (2011)  
9-11-70-6 (2012)  
5-04-71-4 (2017)

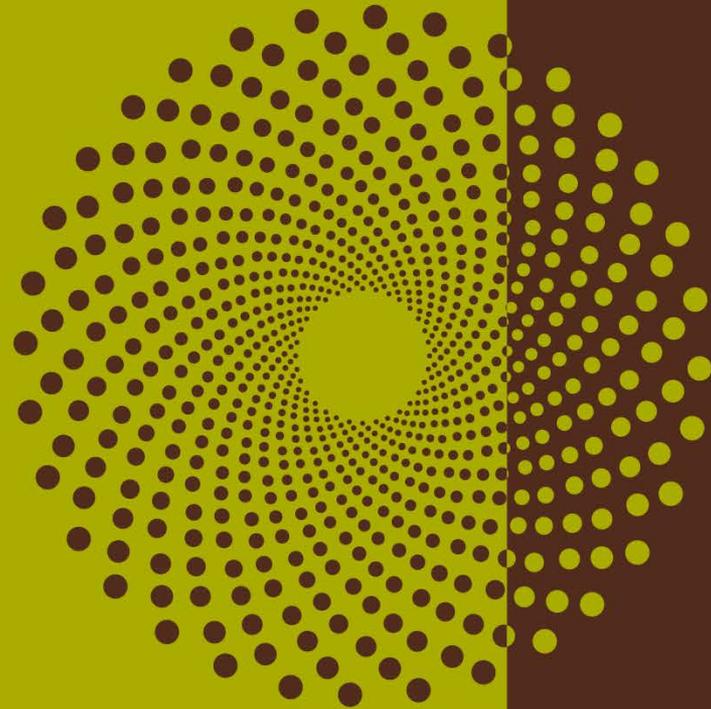


# Summary of Mini-frac and DFIT test results

Test date	UWI	Zone	TVD (m)	Measured Closure Pressure (kPa/m)
2009	9-17-70-3	McMurray Sand	500.3	12.49
2010	2-15-70-5	Westgate Shale	280.3	21.79
2010	2-15-70-5	Grand Rapids Shale	360.8	17.55
2010	2-15-70-5	Clearwater Shale Caprock	421.3	20.98
2010	2-15-70-5	T31 (Clearwater Shale) Caprock	437.5	22.24
2010	2-15-70-5	Clearwater Sand	447.3	14.09
2010	2-15-70-5	Clearwater Sand	455.8	14.88
2010	2-15-70-5	Wabiskaw Shale (T11) Caprock	477.8	18.13
2010	3-14-70-4	Westgate Shale	260.3	21.67
2010	3-14-70-4	Grand Rapids Shale	344.3	16.91
2010	3-14-70-4	T31 (Clearwater Shale) Caprock	416.5	21.25
2010	3-14-70-4	Wabiskaw Shale (T11) Caprock	447.3	20.00
2010	3-14-70-4	McMurray Mudstone	459.3	19.29
2011	6-27-70-3	Westgate Shale	270.3	21.05
2011	6-27-70-3	Joli Fou Shale	330.3	23.69
2011	6-27-70-3	Grand Rapids Shale	395.8	17.22
2011	6-27-70-3	T31 (Clearwater Shale) Caprock	470.0	21.08
2011	6-27-70-3	T21 (Clearwater Shale) Caprock	493.3	22.91
2011	6-27-70-3	McMurray Sand	532.3	12.56
2012	9-11-70-6	Joli Fou Shale	313.7	23.46
2012	9-11-70-6	Clearwater Shale Caprock	434.0	19.94
2012	9-11-70-6	T31 (Clearwater Shale) Caprock	449.5	20.41
2012	9-11-70-6	T21 (Clearwater Shale) Caprock	471.5	21.55
2012	9-11-70-6	McMurray Sand	525.5	11.73
2017	5- 4-71-4	T31 (Clearwater Shale) Caprock	404.0	20.90

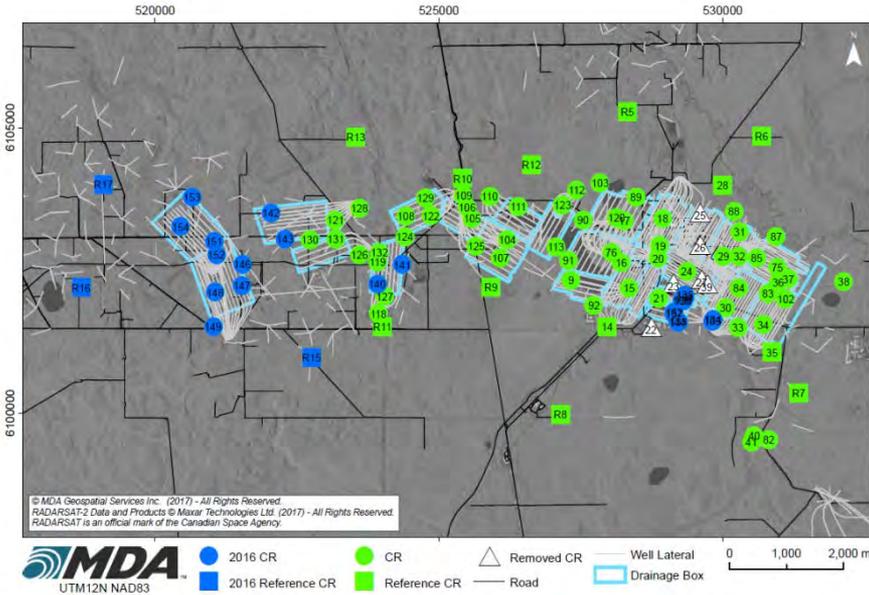
# Surface Monitoring

Subsection 3.1.1 – 2) k

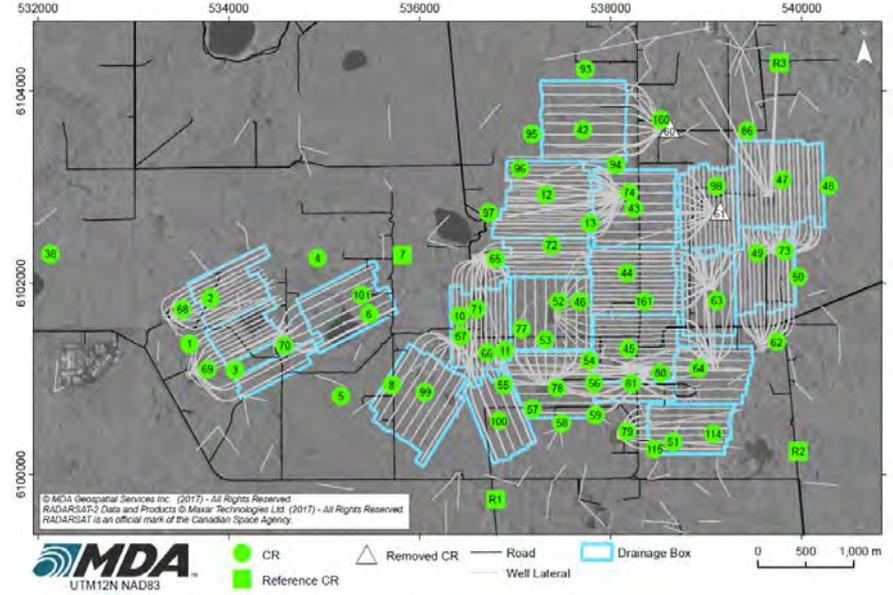


# 2017 ground heave monitoring

Active Corner Reflectors (CR): 161



WEST / CENTRAL

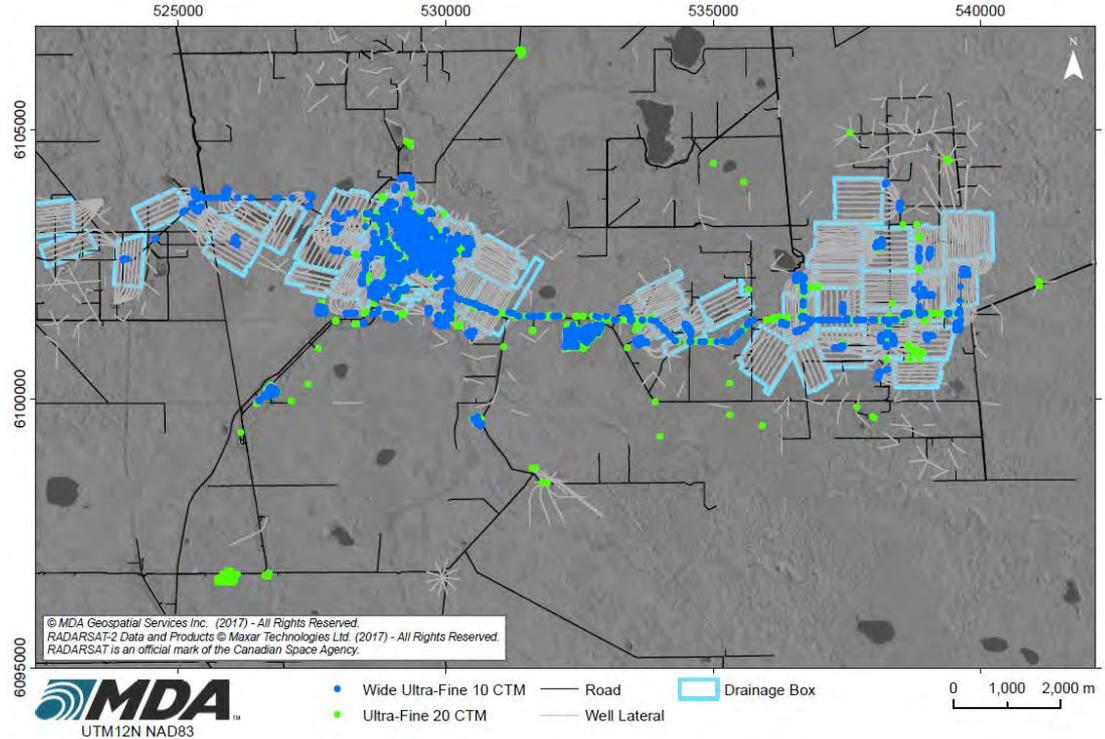


EAST

# 2017 ground heave monitoring

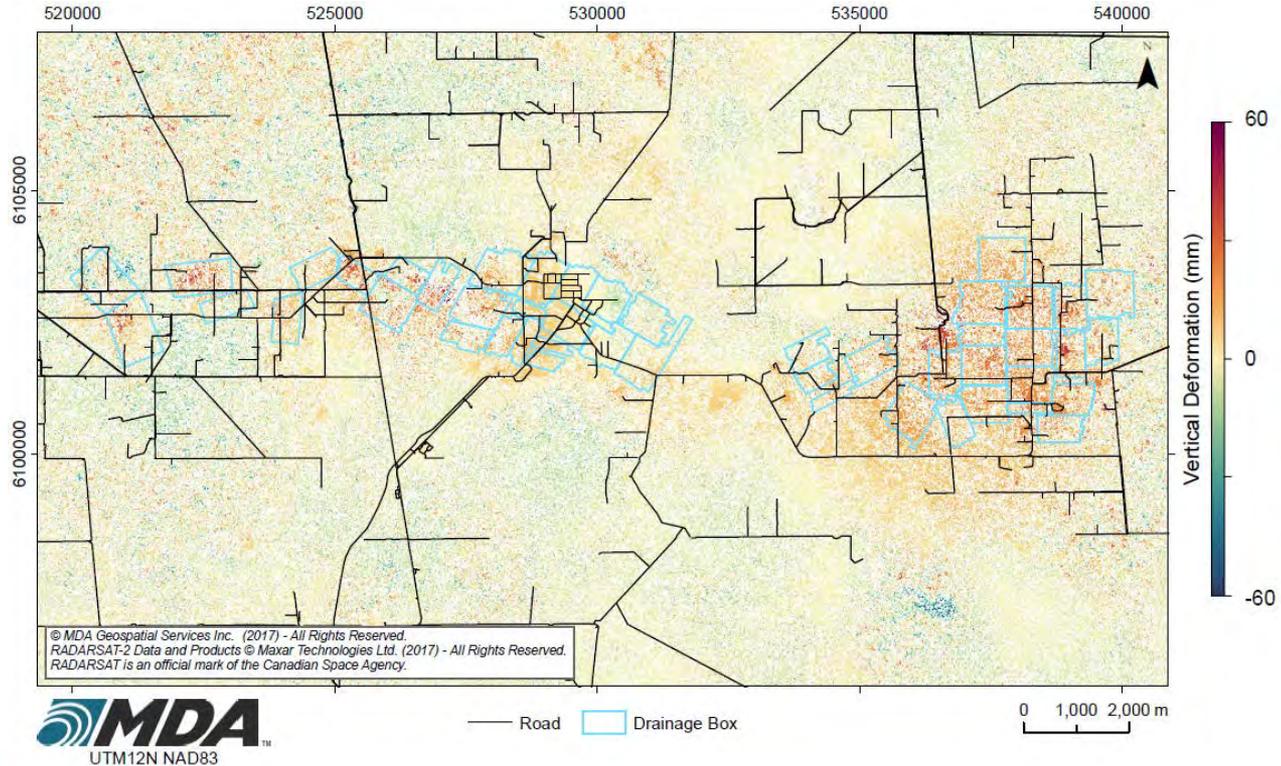
Coherent Target Monitoring (CTM):

20,902 targets



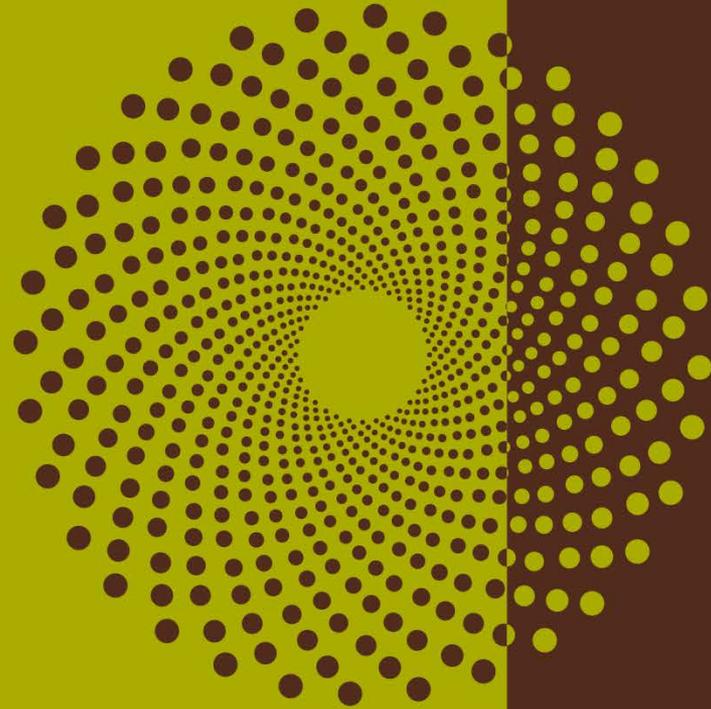
# 2017 ground heave monitoring

Vertical Deformation Map



# Caprock Integrity

Subsection 3.1.1 – 2) m

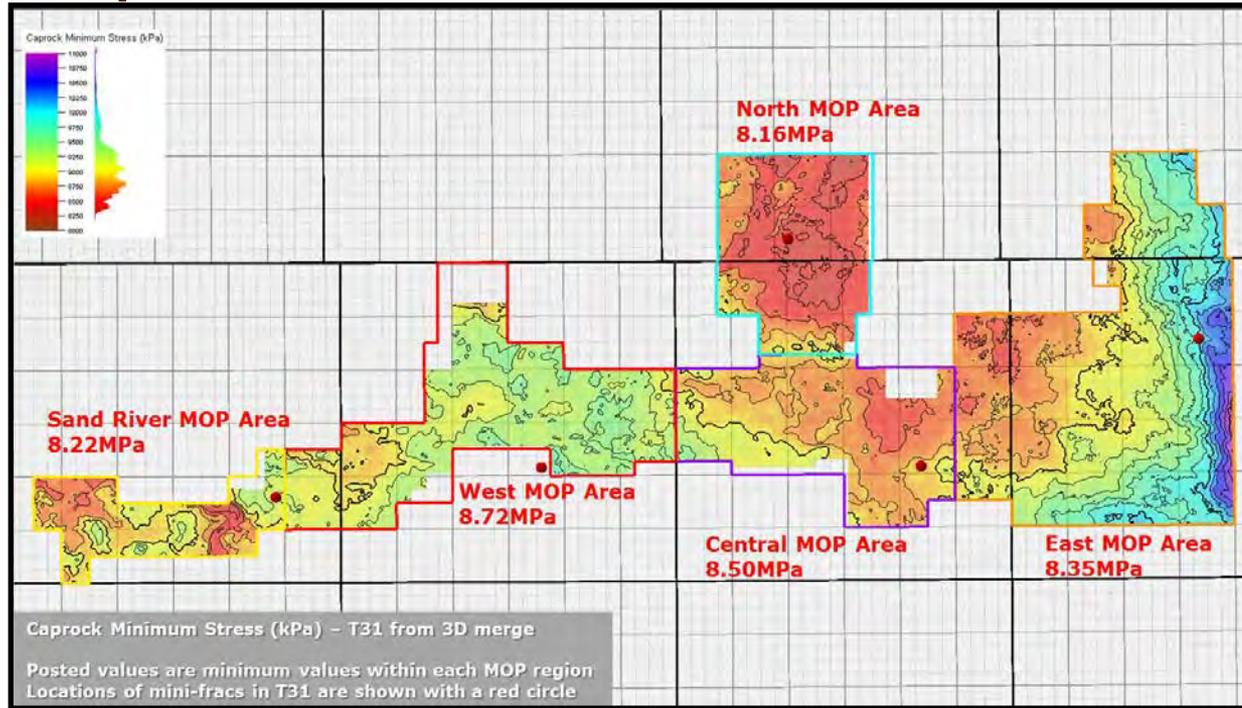


# Caprock monitoring plans

Cenovus monitors caprock integrity through:

1. SAGD injection pressure monitoring
2. Piezometer monitoring in the T31 caprock
  - Currently 7 locations
3. 4D seismic monitoring

# Caprock minimum in-situ stress



Minimum in-situ stress values in the caprock vary across the project  
Smallest minimum in-situ stress values in each sub-area are shown in the above map

# Criteria for determining caprock integrity

**Cenovus determines the minimum in-situ stress of the caprock over the project area through mini-frac testing and seismic mapping**

**Minimum in-situ stresses have shown variability across our development area**

**Current project contains four regions with different approved MOP values**

- North – 6.5 MPag
- Central – 6.8 MPag
- West – 7.0 MPag
- East – 6.7 MPag
- Sand River – 6.6 MPag

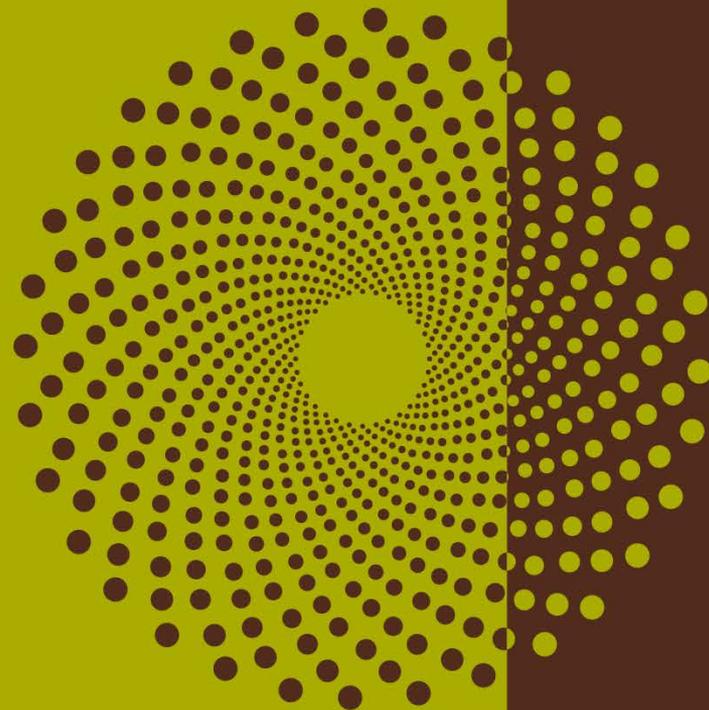
**Operating pressures in the project vary through the various well stages**

- steam stimulation/circulation: (5.5 – 6.6 MPa)\*
- ramp-up: (3.5 – 5.5 MPa)
- normal operating conditions: (2.0 – 3.5 MPa)

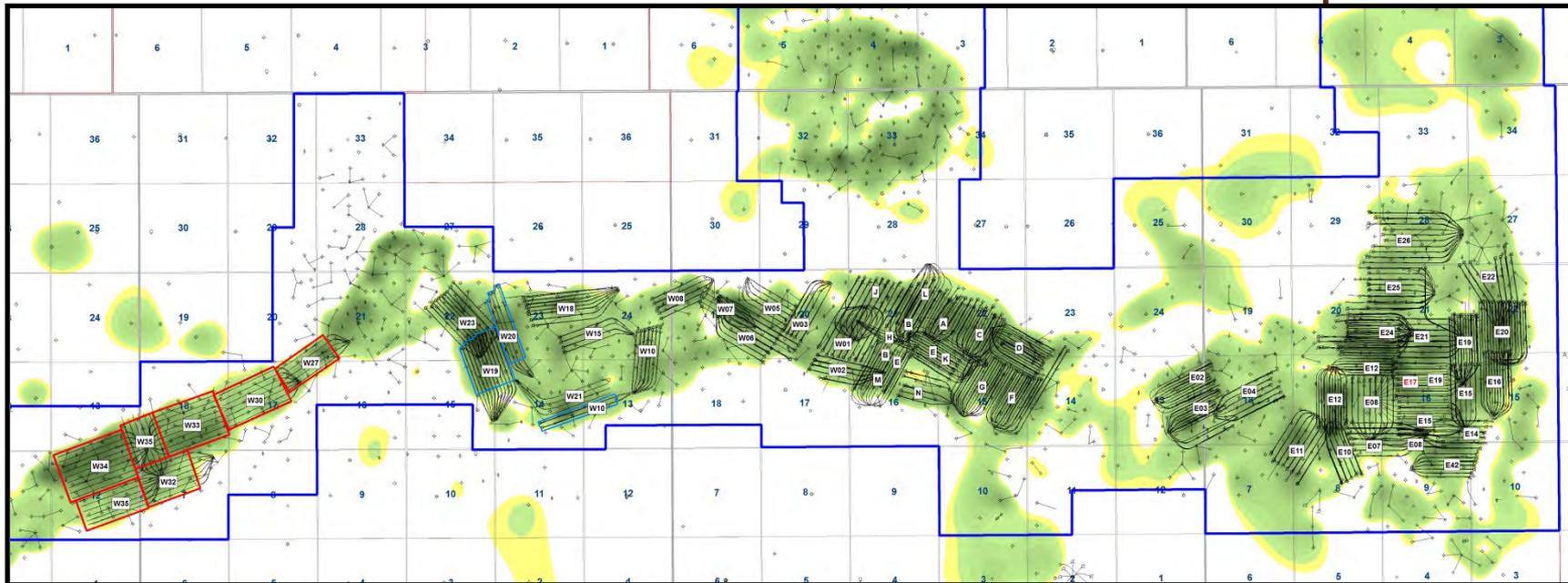
**\* Note that this upper limit is specific to the MOP of each region**

# Drilling and Completions

Subsection 3.1.1 – 3)



# March 2017 - March 2018 new SAGD well pair drilling



## West Pads:

- W27, W30, W32, W33, W34, W35
- W19, W20, W10ext



Mar 2017 - Mar 2018 Drilling



2017 Production

# Re-drills and re-entries

## List of SAGD re-drill and re-entry wells in Foster Creek since January 1, 2017

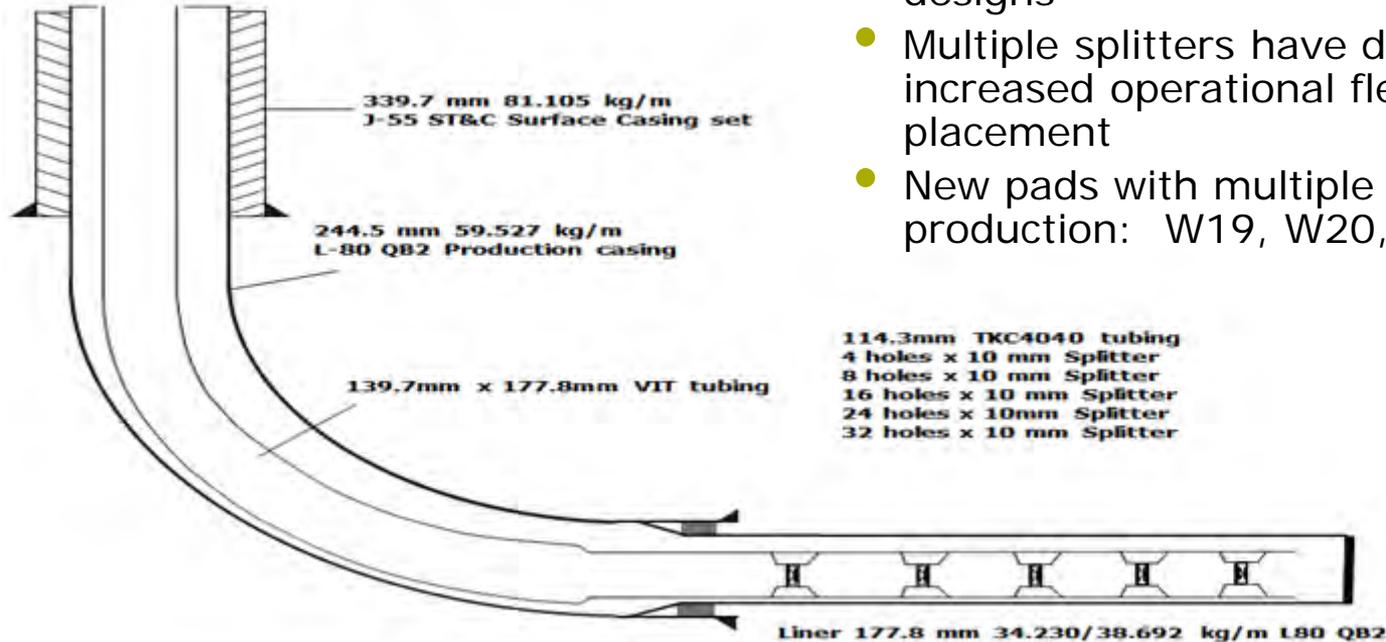
Well Name	Type	Drill Start Date	Status
W08P03	Producer	17-Mar-17	Drilled
LP02	Producer	21-Mar-17	Drilled
LP06	Producer	30-Mar-17	Drilled
CP16-3	Producer	01-Apr-17	Drilled
W23P03	Producer	07-Apr-17	Drilled
E02P03-1	Producer	09-Apr-17	Drilled
W15I02-1	Injector	13-Apr-17	Drilled
E25P02-1	Producer	16-Apr-17	Drilled
E11P05-1	Producer	20-Apr-17	Drilled
E25I02	Injector	23-Apr-17	Drilled
E11P02-1	Producer	27-Apr-17	Drilled
W01P09-1	Producer	30-Apr-17	Drilled
E21P08-1	Producer	03-May-17	Drilled
E20P07-1	Producer	10-May-17	Drilled
HP04-1	Producer	11-May-17	Drilled
E03P03-1	Producer	16-May-17	Drilled
HI04-1	Injector	17-May-17	Drilled
MP10	Producer	22-May-17	Drilled
E12P02-1	Producer	23-May-17	Drilled
W03P05-1	Producer	28-May-17	Drilled
E14P03	Producer	02-Jun-17	Drilled
E08P10-1	Producer	03-Jun-17	Drilled

Well Name	Type	Drill Start Date	Status
E10P05-1	Producer	05-Jun-17	Drilled
E19P09-1	Producer	11-Jun-17	Drilled
E20P09-1	Producer	17-Jun-17	Drilled
E16I05-1	Injector	24-Jun-17	Drilled
JP01	Producer	31-Jul-17	Drilled
E12P02-2	Producer	04-Aug-17	Drilled
E21P01-1	Producer	10-Aug-17	Drilled
E25P03-1	Producer	17-Aug-17	Drilled
E25I03	Injector	23-Aug-17	Drilled
W23P02-1	Producer	01-Sep-17	Drilled
W23I02	Injector	06-Sep-17	Drilled
W18P08-1	Producer	11-Sep-17	Drilled
W18I08	Injector	17-Sep-17	Drilled
E11P03-1	Producer	23-Sep-17	Drilled
FI07	Injector	30-Nov-17	Drilled
E19P04-1	Producer	06-Dec-17	Drilled
E42P02	Producer	13-Dec-17	Drilled
E12P05-1	Producer	04-Jan-18	Drilled
W01P05	Producer	12-Jan-18	Drilled
W01P06	Producer	17-Jan-18	Drilled
W06P01	Producer	22-Jan-18	Drilled

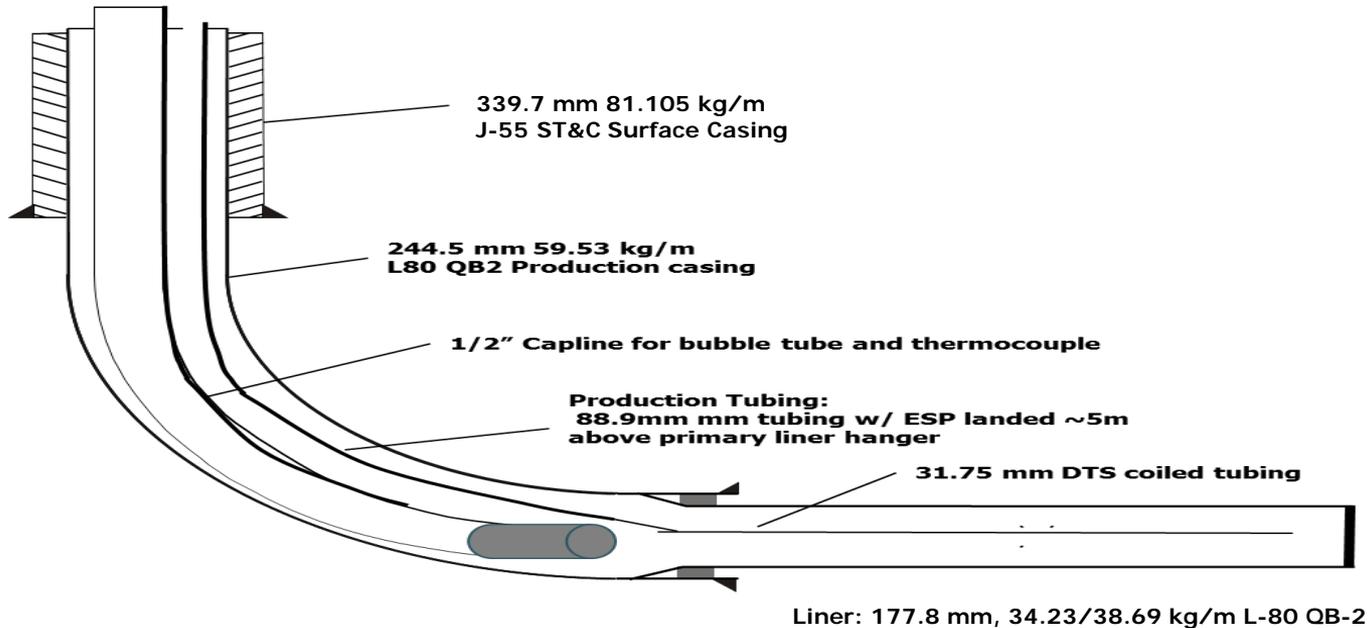
- Wells are re-drilled if loss of sand control occurs or for redevelopment opportunities

# Standard injector completion

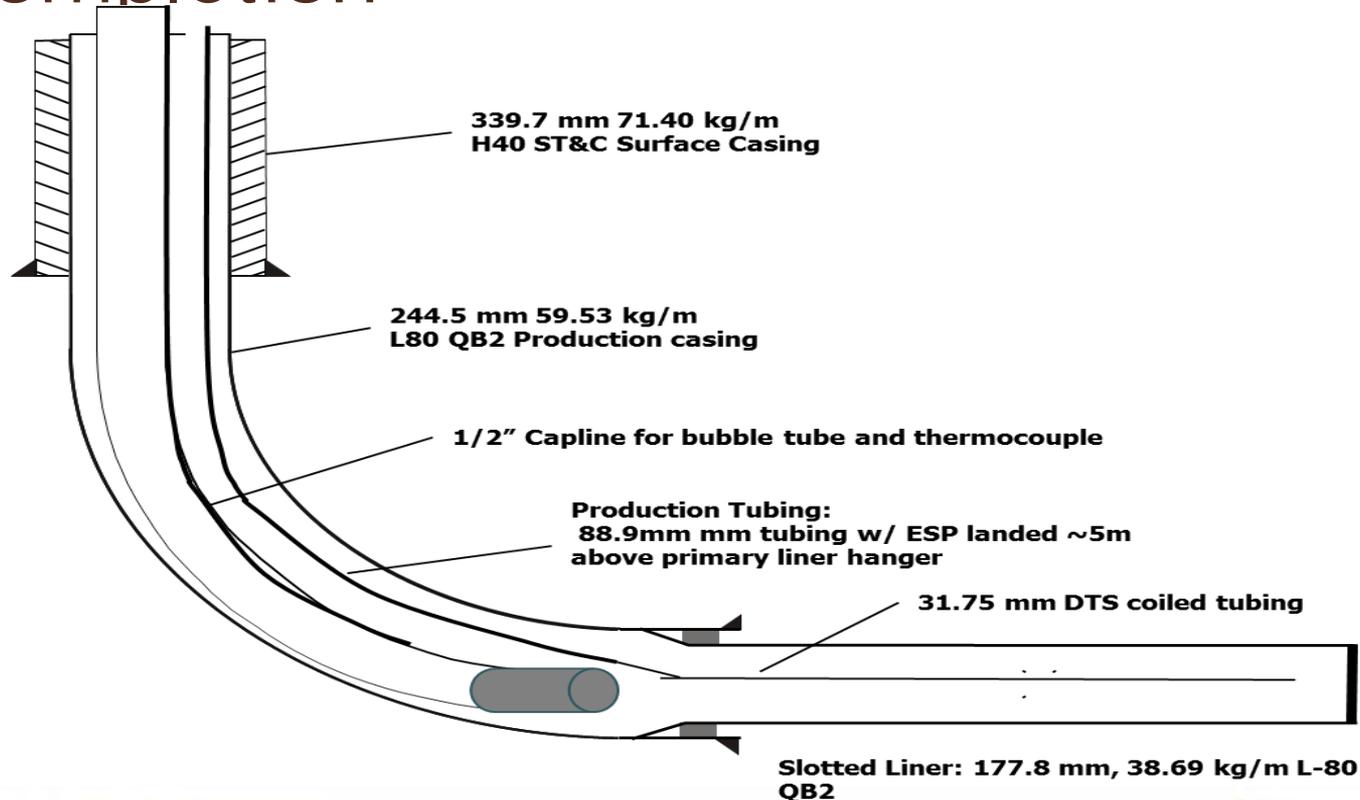
- Majority of well pairs at Foster Creek have been started up with single splitter injector designs
- Multiple splitters have demonstrated increased operational flexibility with steam placement
- New pads with multiple splitter designs on production: W19, W20, W10ext



# Standard producer Electric Submersible Pump (ESP) completion

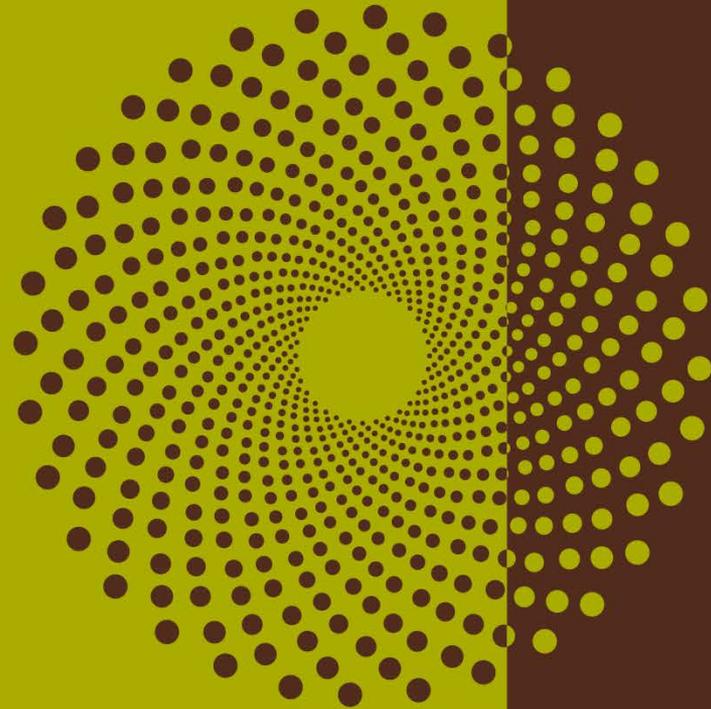


# Standard Wedge Well™ technology completion



# Artificial lift

Subsection 3.1.1 – 4)



# Artificial lift

## Electric submersible pumps (ESPs)

- all operating SAGD pairs (~227 producers) are currently equipped with ESPs
- Continue to work with vendors to increase runtime

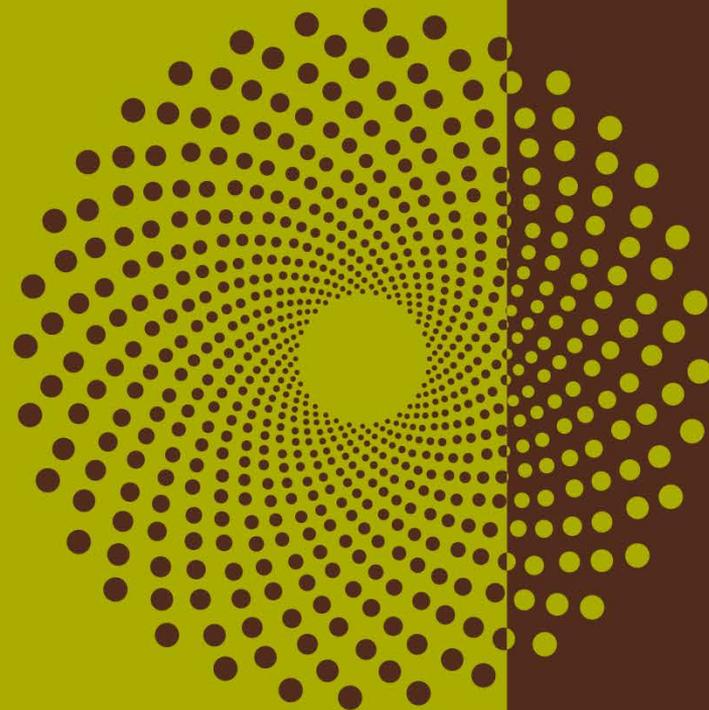
## Rod pumps

- Historically utilized with Wedge Well™ technology
- 25/67 operating wells utilizing Wedge Well™ technology are equipped with rod pumps

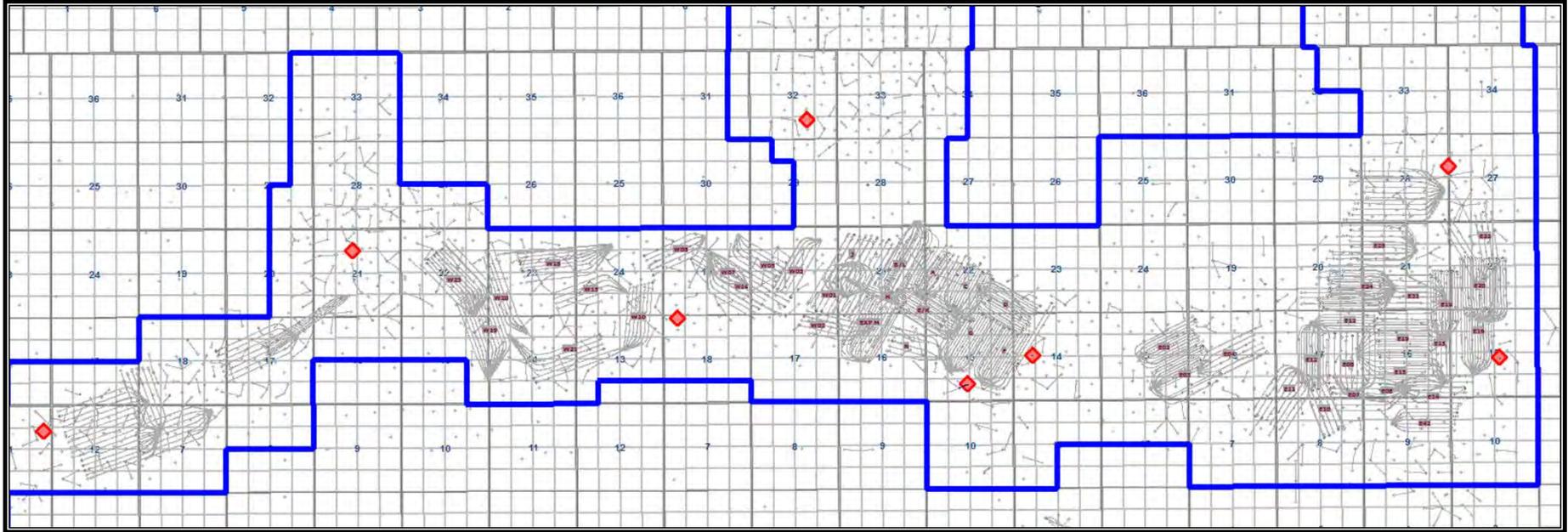
	ESPs	Rod pumps
Turn down (m <sup>3</sup> /d)	72	0
Max. rate (m <sup>3</sup> /d)	1500	350
Max. operating temp (°C)	250	200+
Number of pumps	269	25
Average run life (months)	13.5	12.0

# Instrumentation in wells

Subsection 3.1.1 – 5)



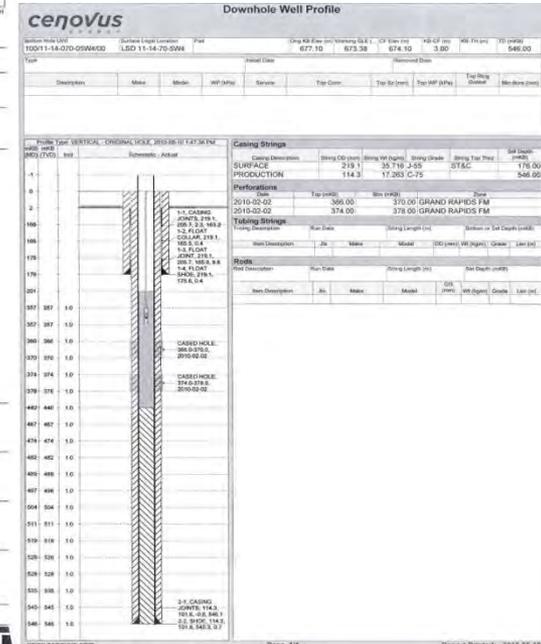
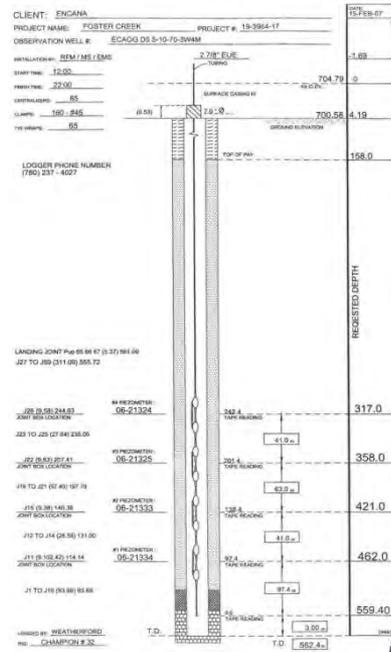
## Foster Creek 2018 Piezometer Locations



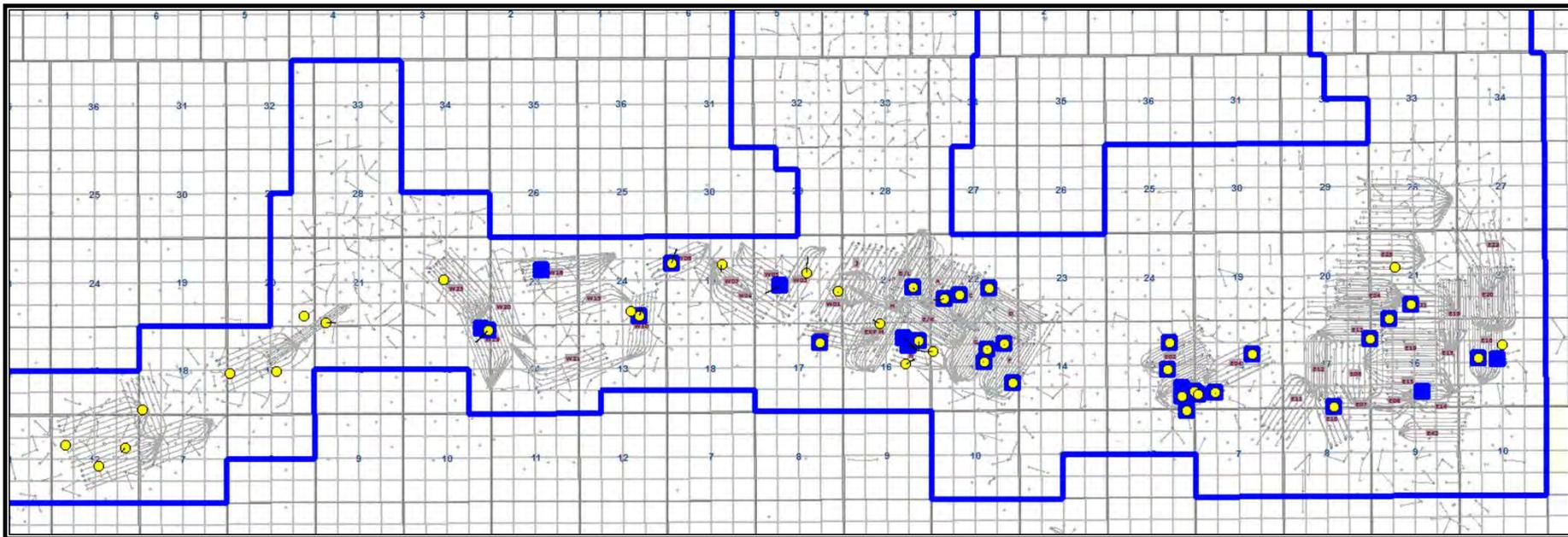
# Piezometer details

## Three installation types:

- Cemented tubing - vibrating wire piezometers mounted on tubulars and cemented in place (14 wells)
- Hanging wire – pressure / temperature gauges hung from the wellhead to about 10-15m above perforations (10 wells)
- Cemented casing – High temperature Optical pressure sensors strapped and cemented to the production casing (47 wells)
- Eight new McMurray piezometers installed



## Foster Creek 2018 Temperature and RST Data



- 2018 RST (44)
- 2018 DTS (33)

# Instrumentation in SAGD wells

## SAGD steam injector

- blanket gas for pressure measurement

## SAGD producer

- ½" capline strapped to tubing for bubble tubes and single point thermocouple
- distributed temperature sensing (DTS) strings installed in majority of new wells

## SAGD using our patented Wedge Well™ technology

- no downhole instrumentation with rod pumps
- new wells with ESPs to be equipped with ½" capline strapped to production tubing string to measure pressure and temperature

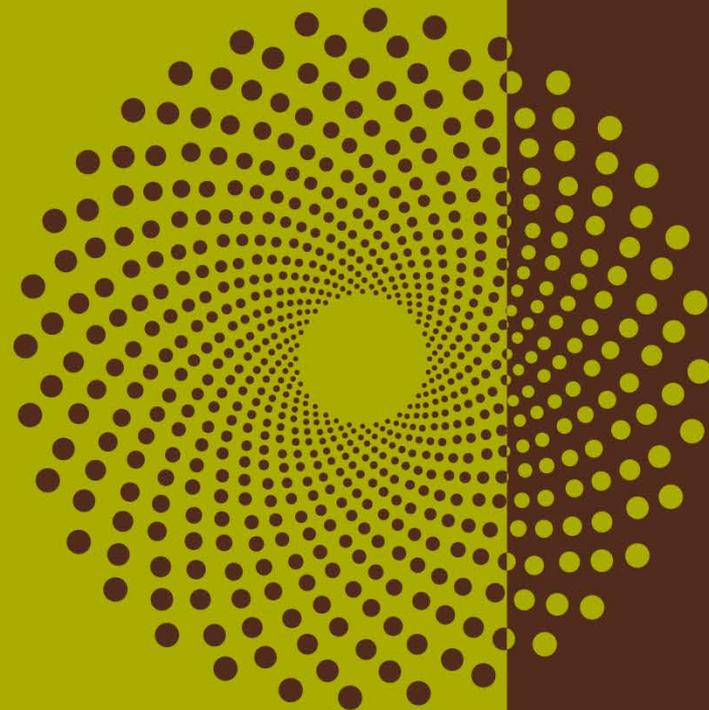
\* Schematics can be referenced in subsection 3.1.1 – 3 c)

# Subsection 3.1.1 – 5 c) and d) – instrumentation data

**Requirements under Subsection 3.1.1 5c) and d) are  
located in the Appendix**

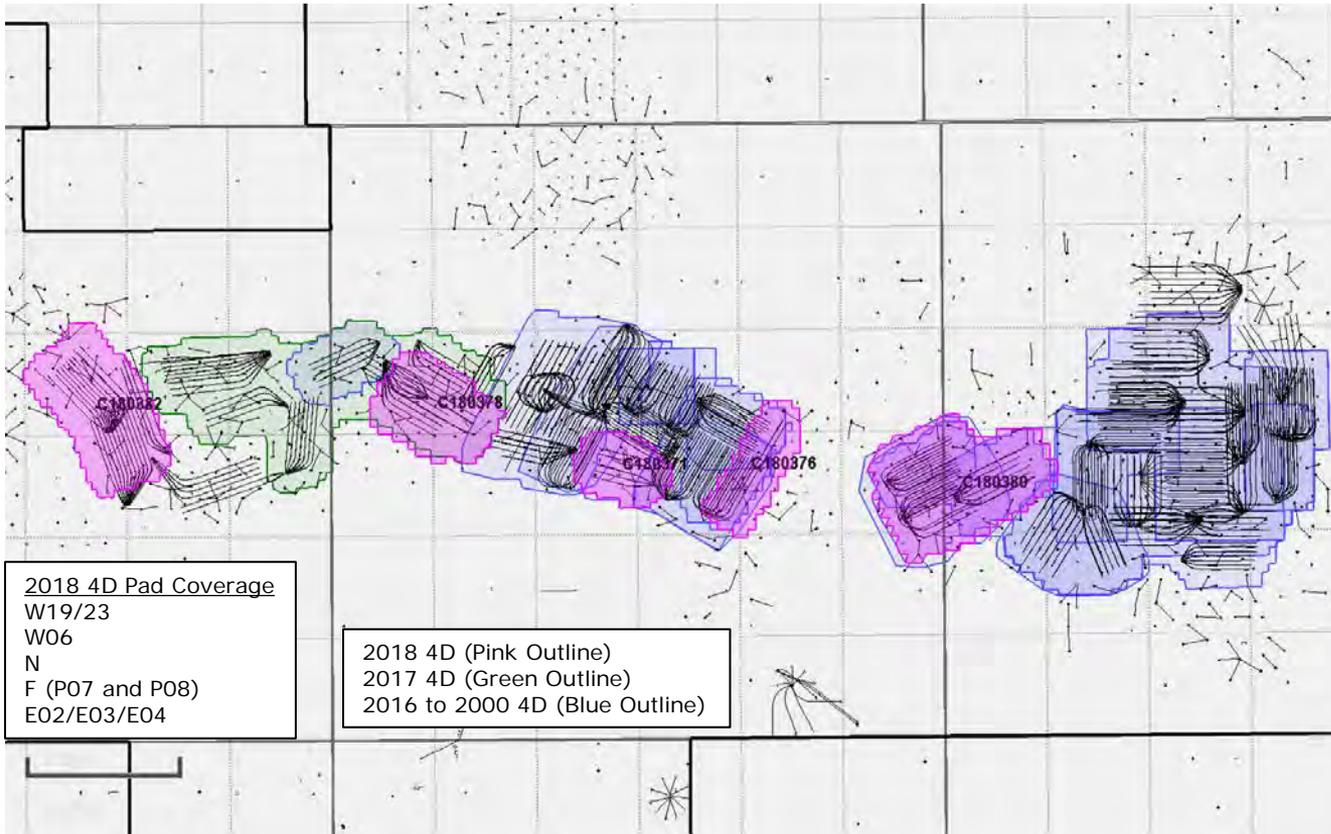
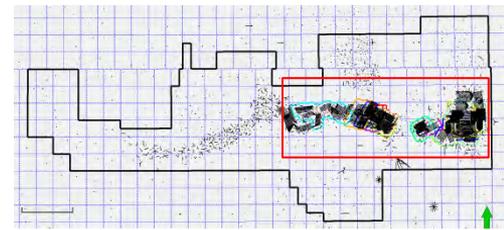
# 4D seismic

Subsection 3.1.1 – 6)





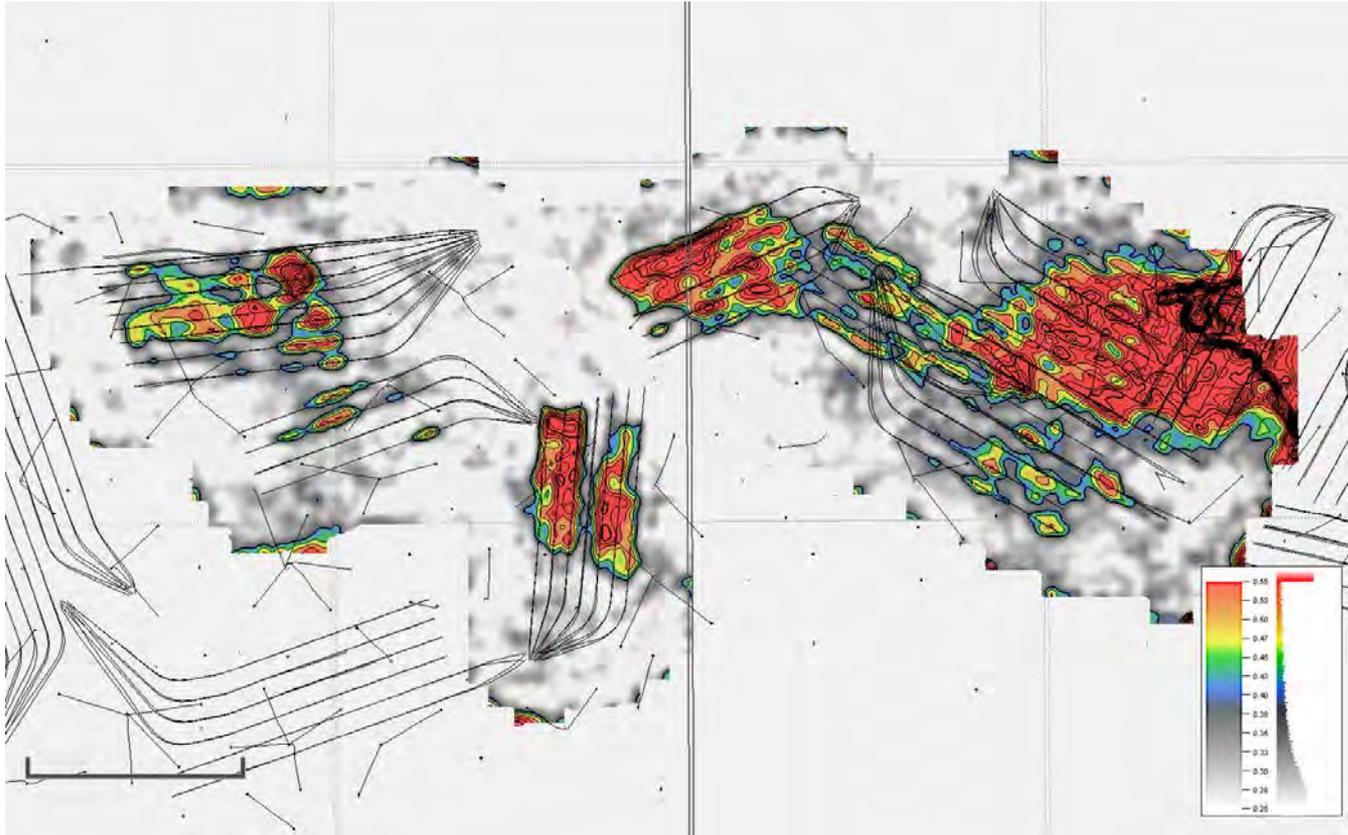
# 4D seismic within Project Area



2018 4D Pad Coverage  
W19/23  
W06  
N  
F (P07 and P08)  
E02/E03/E04

2018 4D (Pink Outline)  
2017 4D (Green Outline)  
2016 to 2000 4D (Blue Outline)

# 2017 West 4D seismic

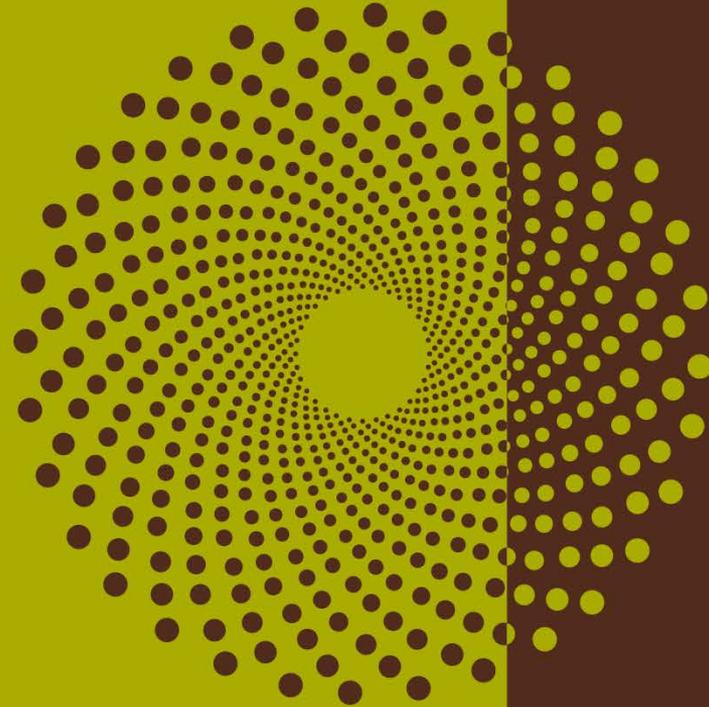


## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

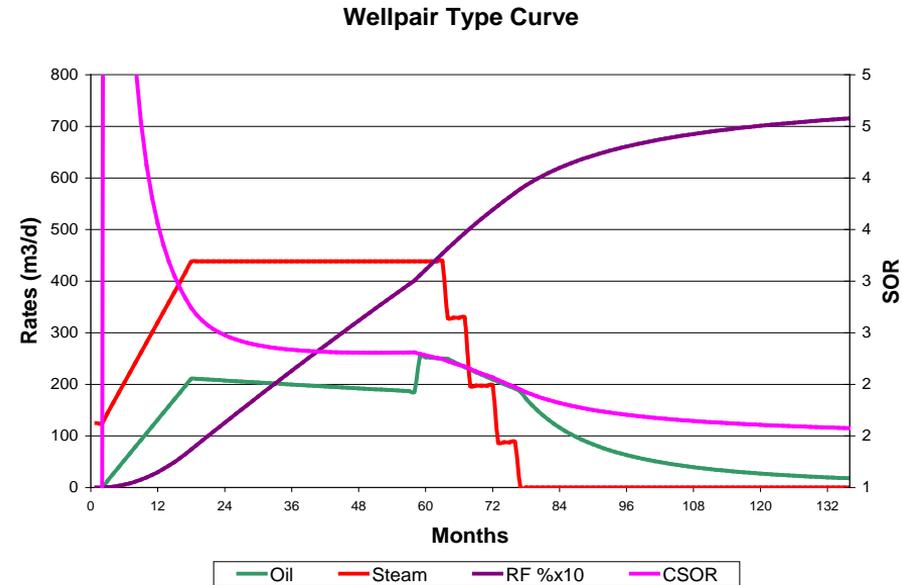
# Scheme performance

Subsection 3.1.1 – 7 a)

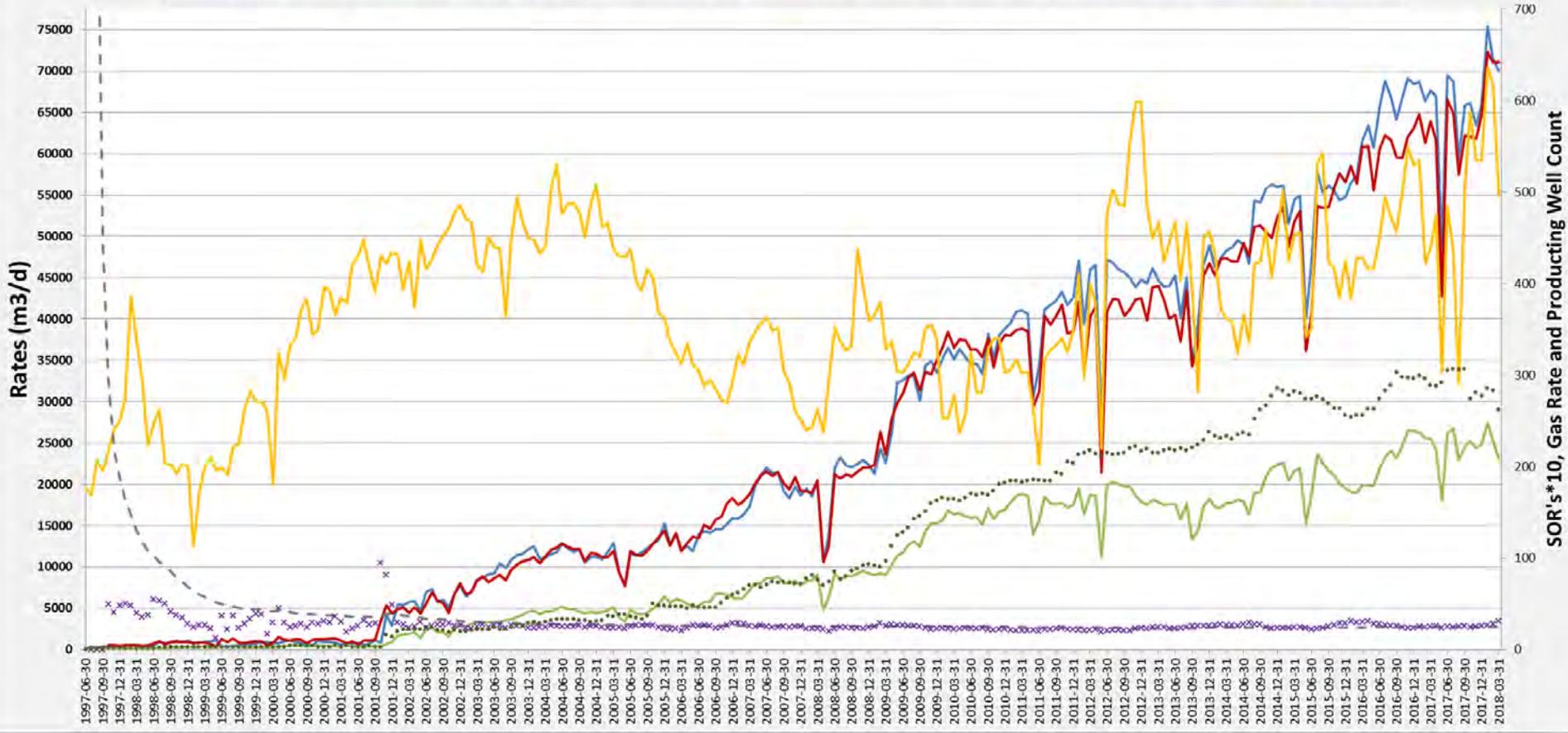


# Scheme performance prediction

- 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



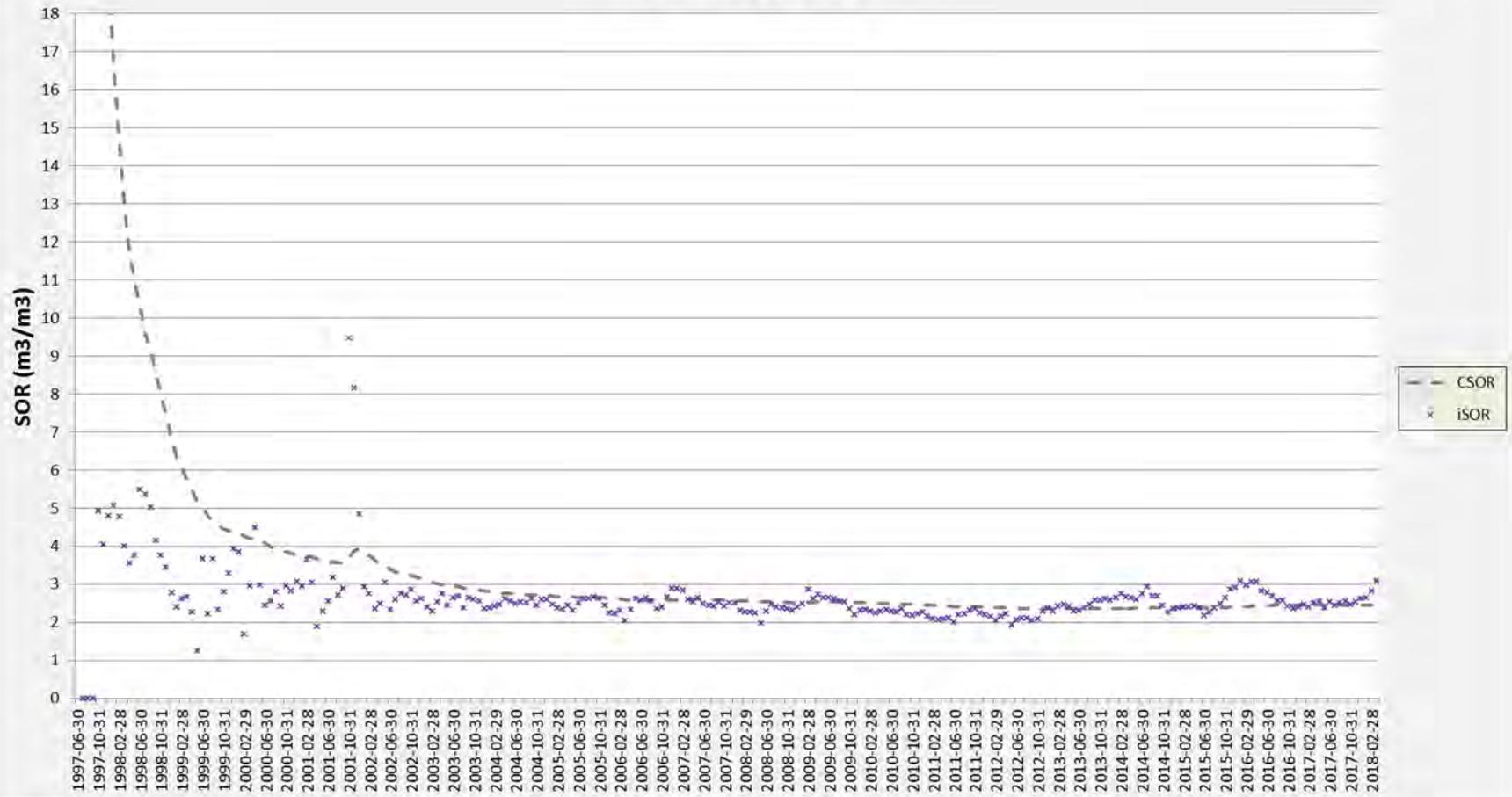
# Foster Creek Performance



## Foster Creek Performance



# Foster Creek SOR



# Methods for monitoring chamber development

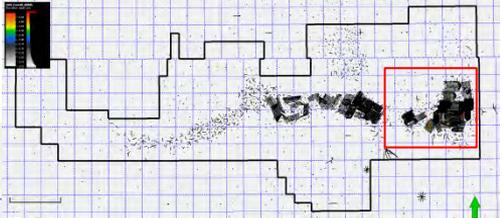
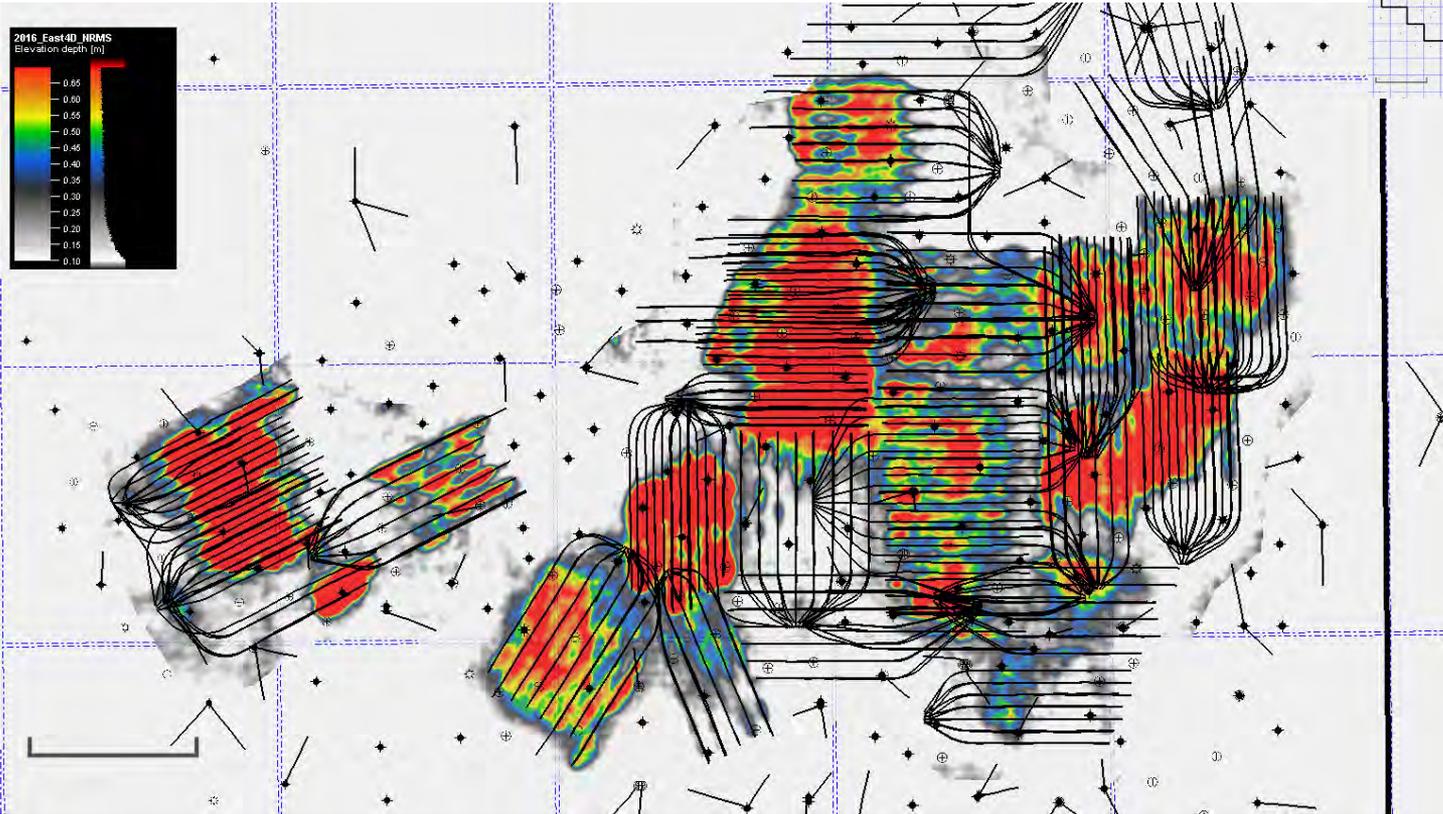
**Cenovus uses the following methods for monitoring chamber development:**

- Observation wells
- Specialized logging and coring
- Seismic
- Volumetrics





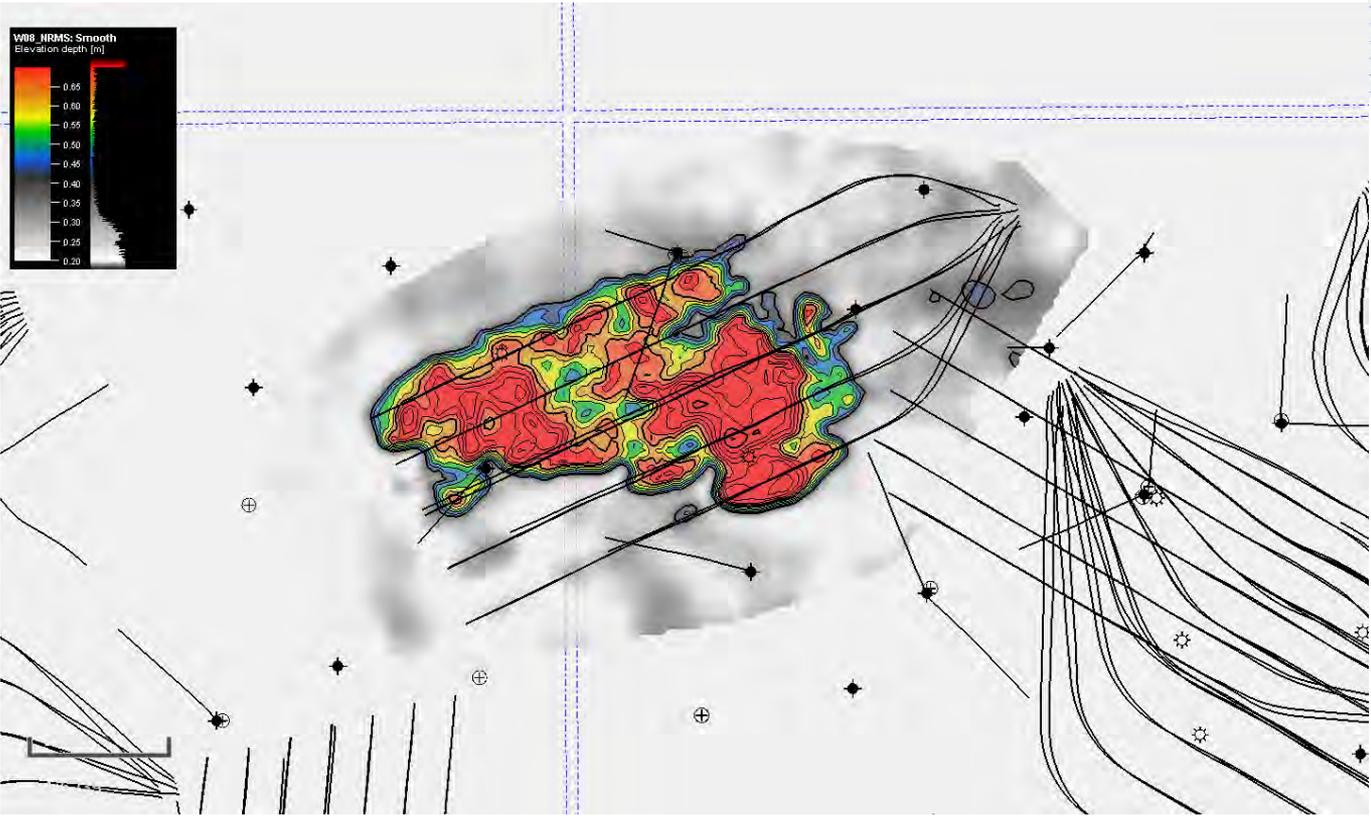
# 2016 East 4D seismic



## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

# 2016 W08 4D seismic



## 4D NRMS

Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

# 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 + 50m 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.

# SOIP & percent recovery – Central

PAD	Average Well Spacing (m)	Area (m <sup>2</sup> )	Height (m)	Φ (%)	S <sub>o</sub> (%)	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2018)	Recovery % SOIP	Estimated Ultimate Recovery (Mm3)	Estimated Ultimate Recovery as % of SOIP
A	117	543,506	28	33%	81%	4,053	3,580	88%	3,653	90%
B_L	103	605,382	24	34%	79%	4,000	2,554	64%	2,806	70%
C	105	541,344	29	35%	82%	4,575	3,805	83%	3,870	85%
D	100	676,265	27	33%	81%	4,884	4,535	93%	4,559	93%
E_K	89	576,134	22	35%	81%	3,502	3,028	86%	3,131	89%
EXP M	106	640,418	25	34%	81%	4,455	2,498	56%	2,583	58%
F	98	817,054	26	34%	79%	5,474	3,573	65%	4,361	80%
G	96	596,677	27	34%	80%	4,061	2,843	70%	3,223	79%
H	113	139,402	20	34%	74%	692	172	25%	324	47%
J	99	722,666	22	33%	76%	4,010	1,669	42%	1,926	48%
N	100	322,899	18	34%	83%	1,679	124	7%	855	51%
<b>Total Central</b>						<b>41,385</b>	<b>28,382</b>	<b>69%</b>	<b>31,292</b>	<b>76%</b>
<b>Total FC</b>						<b>167,101</b>	<b>77,302</b>	<b>46%</b>	<b>107,168</b>	<b>64%</b>

To Mar 31, 2018

# SOIP and percent recovery - East

PAD	Average Well Spacing (m)	Area (m2)	Height (m)	$\Phi$ (%)	$S_o$ (%)	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2018)	Recovery % SOIP	Estimated Ultimate Recovery (Mm3)	Estimated Ultimate Recovery as % of SOIP
E02	106	401,512	30	33%	74%	2,946	1,489	51%	1,917	65%
E03	112	400,335	34	33%	71%	3,198	1,516	47%	2,012	63%
E04	100	522,570	26	34%	79%	3,610	1,050	29%	2,003	55%
E07	100	584,261	16	28%	73%	1,965	184	9%	319	16%
E08	104	811,692	24	31%	77%	4,703	1,237	26%	2,679	57%
E10	100	417,700	22	32%	75%	2,142	803	37%	1,221	57%
E11	100	706,863	29	32%	75%	4,960	2,871	58%	3,599	73%
E12	103	878,701	33	35%	80%	7,772	4,983	64%	5,590	72%
E14	100	436,503	21	33%	81%	2,422	801	33%	1,506	62%
E15	96	1,082,645	25	33%	81%	7,228	3,758	52%	4,698	65%
E16	96	536,177	24	35%	79%	3,578	2,612	73%	2,997	84%
E19	102	1,134,109	26	34%	80%	7,844	5,014	64%	5,720	73%
E20	90	779,459	29	34%	83%	6,301	4,143	66%	4,796	76%
E21	100	712,643	24	32%	79%	4,189	1,823	44%	2,558	61%
E24	100	921,568	26	35%	85%	7,032	3,921	56%	4,822	69%
E25	104	813,888	24	32%	81%	5,006	2,393	48%	3,153	63%
E42	74	381,823	21	32%	77%	1,969	657	33%	1,100	56%
<b>Total East</b>						<b>76,864</b>	<b>39,255</b>	<b>51%</b>	<b>50,689</b>	<b>66%</b>
<b>Total FC</b>						<b>167,101</b>	<b>77,302</b>	<b>46%</b>	<b>107,168</b>	<b>64%</b>

To March 31, 2018

# SOIP and percent recovery – West

PAD	Average Well Spacing (m)	Area (m2)	Height (m)	Φ (%)	S <sub>o</sub> (%)	SOIP (Mm3)	Cum Oil Mm3 (to Mar 31, 2018)	Recovery % SOIP	Estimated Ultimate Recovery (Mm3)	Estimated Ultimate Recovery as % of SOIP
W01	100	676,167	23	34%	79%	4,126	2,014	49%	2,424	59%
W02	97	376,851	19	33%	85%	1,991	586	29%	748	38%
W03	92	421,984	24	32%	74%	2,395	380	16%	982	41%
W05	98	341,146	25	31%	76%	2,001	198	10%	640	32%
W06	99	758,366	25	31%	80%	4,787	748	16%	2,426	51%
W07	87	334,674	31	33%	78%	2,662	407	15%	965	36%
W08	100	428,285	28	32%	79%	2,976	954	32%	1,654	56%
W10	75	467,500	26	31%	82%	3,088	821	27%	1,493	48%
W15	100	379,950	23	31%	86%	2,276	336	15%	1,250	55%
W18	78	676,409	24	32%	89%	4,615	1,391	30%	2,966	64%
W19	68	756,225	31	33%	81%	6,329	524	8%	3,481	55%
W20	82	426,744	26	33%	80%	2,931	36	1%	1,287	44%
W21	90	430,910	23	32%	84%	2,698	29	1%	1,053	39%
W23	79	777,376	28	33%	85%	5,976	1,241	21%	3,820	64%
<b>Total West</b>						<b>48,851</b>	<b>9,664</b>	<b>20%</b>	<b>25,187</b>	<b>52%</b>
<b>Total FC</b>						<b>167,101</b>	<b>77,302</b>	<b>46%</b>	<b>107,168</b>	<b>64%</b>

To March 31, 2018

# Recovery examples

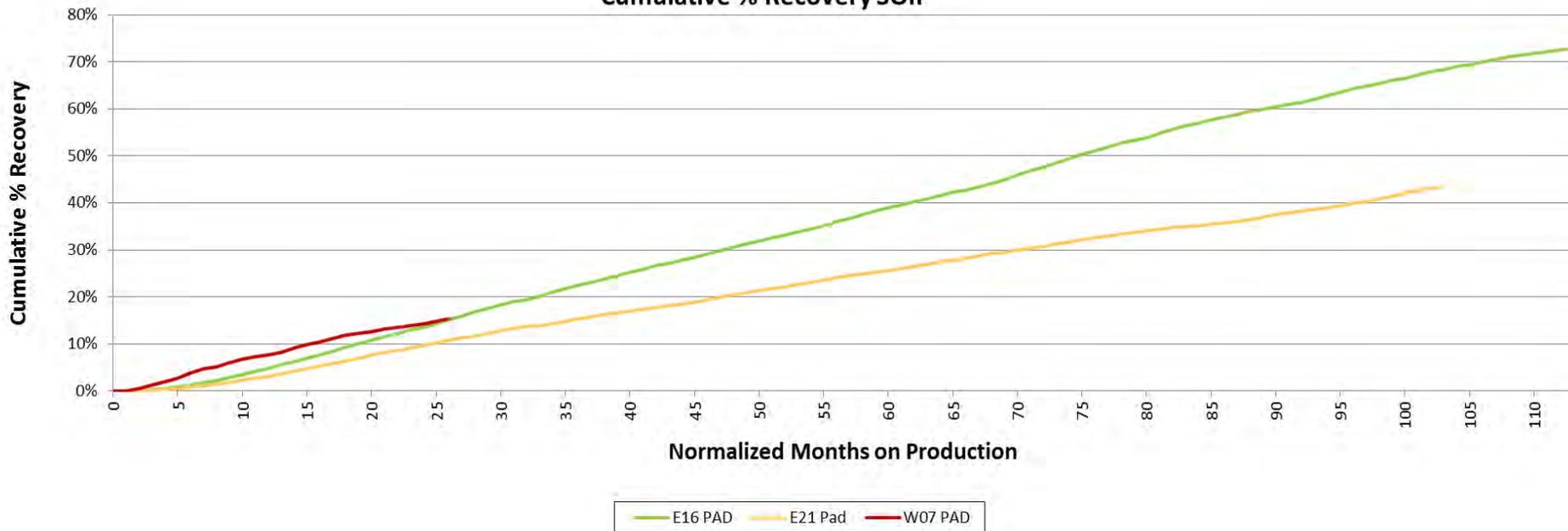
- W07 pad low ultimate recovery example
- E21 pad medium ultimate recovery example
- E16 pad high ultimate recovery example

# Recovery examples cumulative percent recovery SOIP

Foster Creek - E16, E21 & W07 Pads

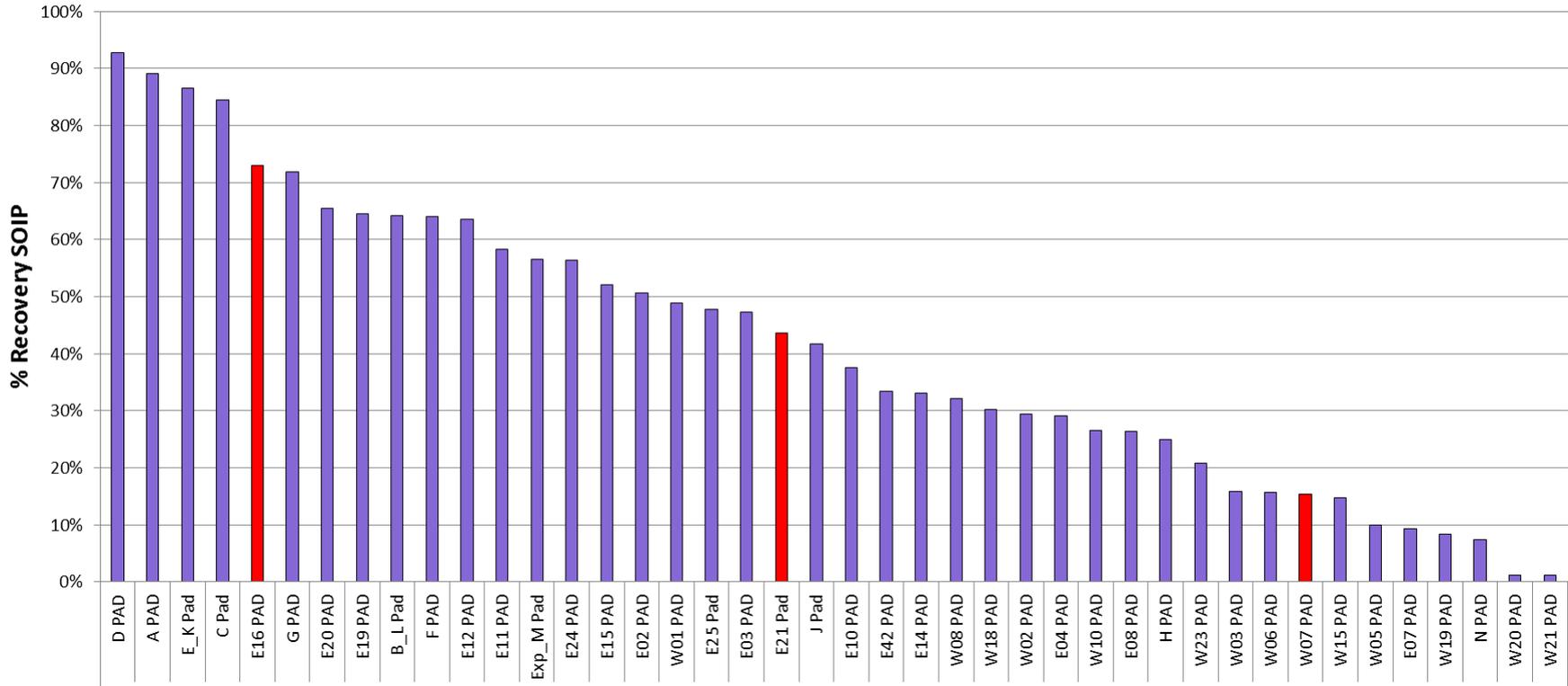
Normalized

Cumulative % Recovery SOIP



# Current Percent Recovery of SOIP: Pad Totals

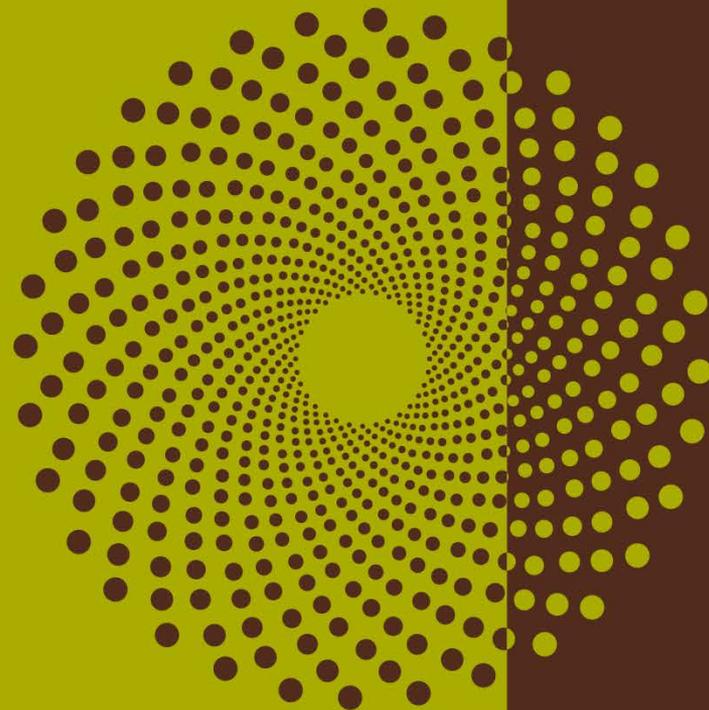
Foster Creek - % Recovery of SOIP per Pad (Mar31, 2018)



# OBIP – low example

## W07 pad

Subsection 3.1.1 – 7 c) iii

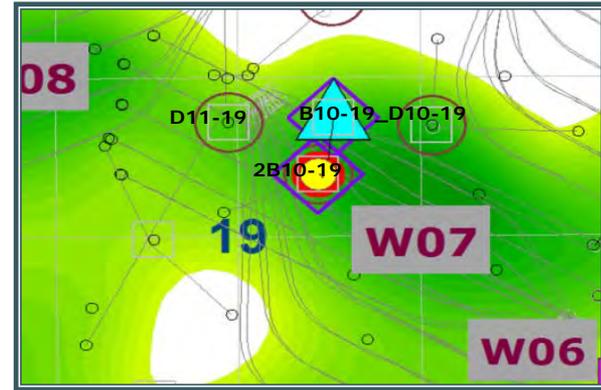
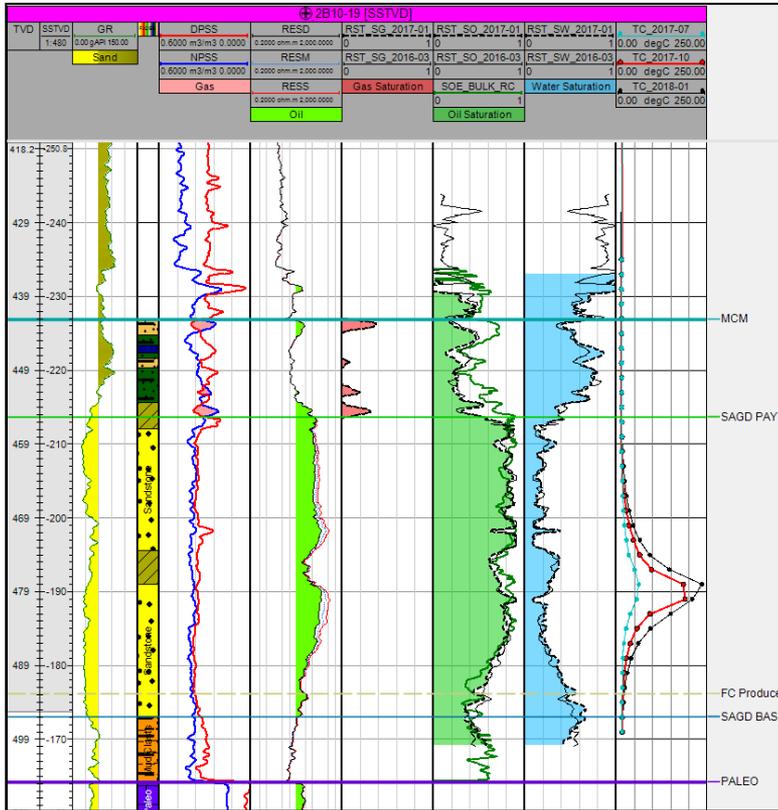


# W07 pad overview

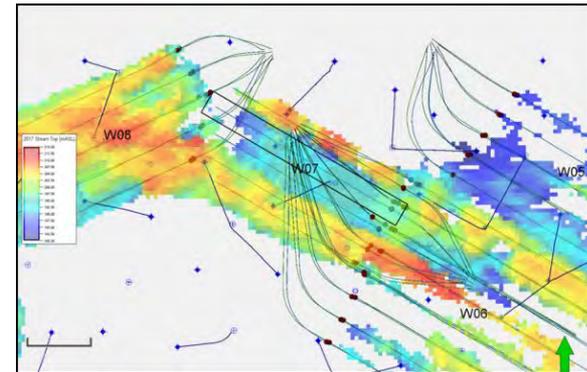
- W07 pad started production in January 2016 (five pairs)
- Heterogeneous quality geology, variations in SAGD base between well pairs
- Initial operating pressures ~4.5 MPa, currently producing ~3.0 MPa
- Currently at ~15% recovery of SOIP, in line with forecasting expectations
- CSOR is currently 3.00
- Wells are ramping up as forecasted

# W07 pad temperatures

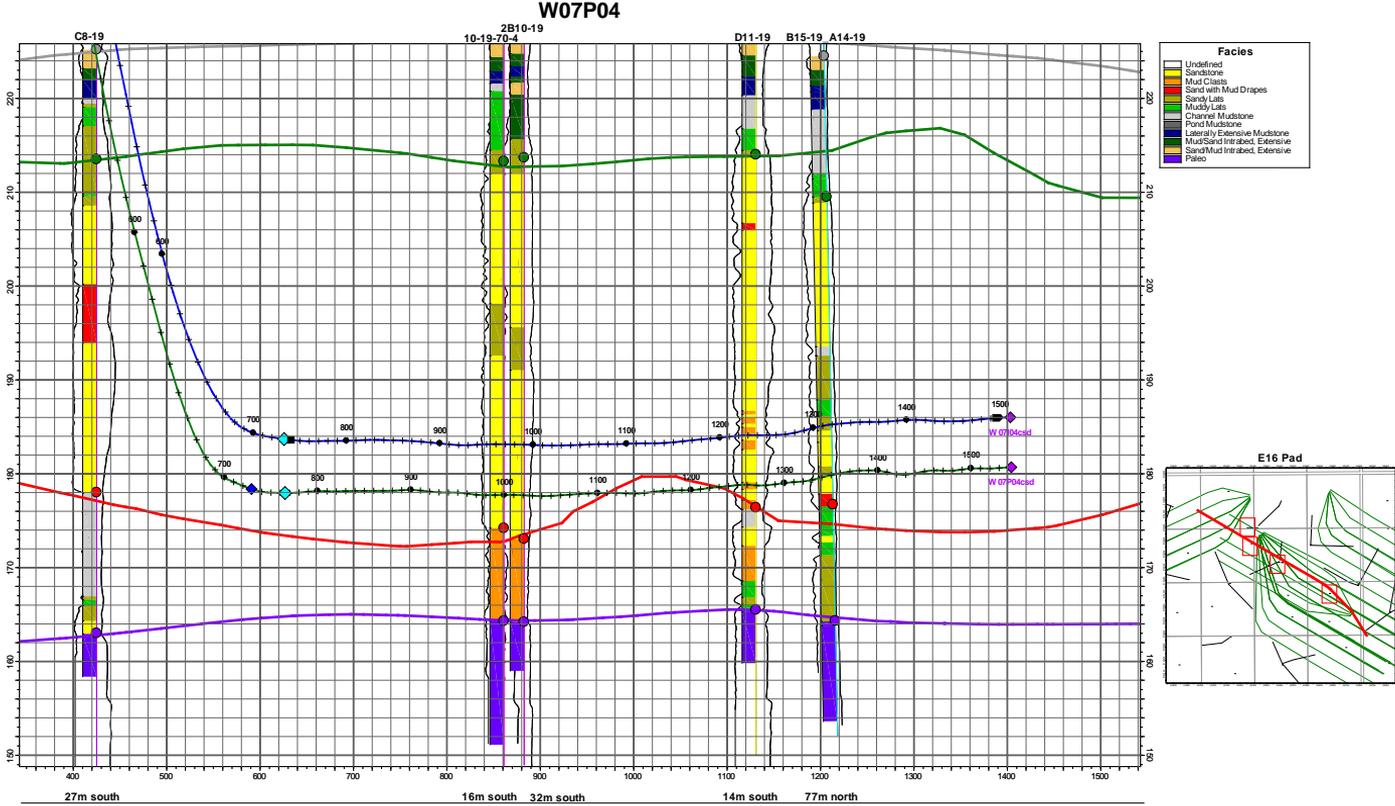
2B10-19



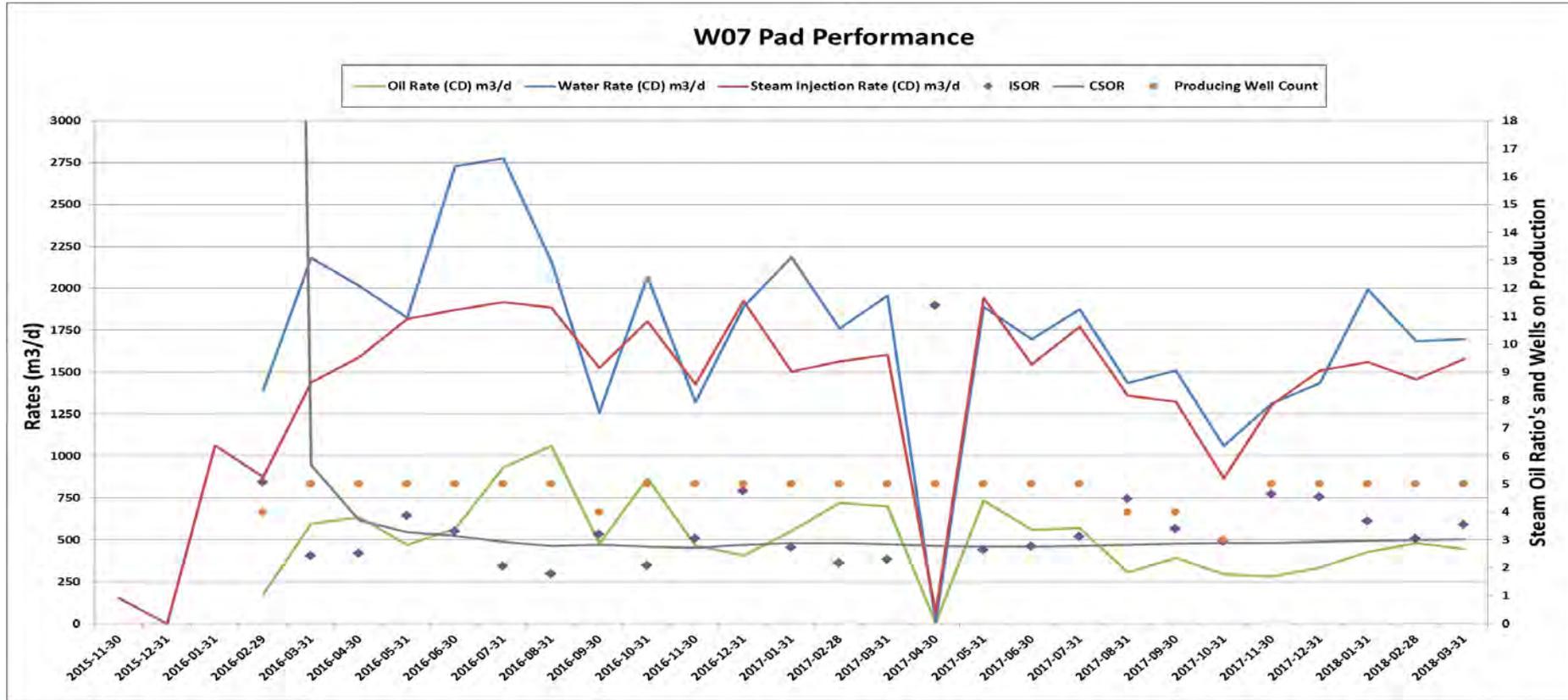
27m offset W07-04 well pair



# W07-04 Geological Profile



# W07 pad performance

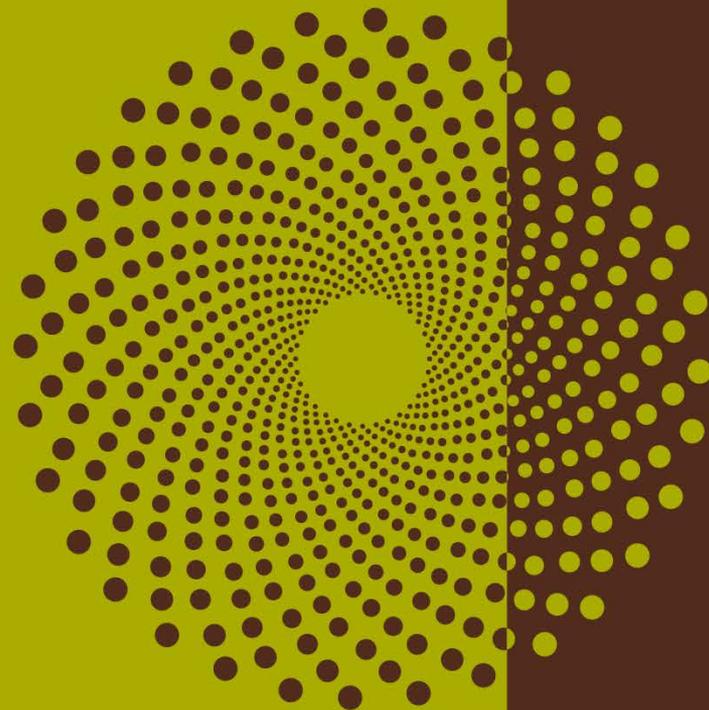


# W07 pad conclusions

- Currently at ~15% recovery of SOIP
- Optimization of pad ongoing to maximize recovery
- Recently acquired TC data and 4D seismic
- Balance reservoir pressures with thief zones and adjacent pads

# OBIP – medium example E21 pad

Subsection 3.1.1 – 7 c) iii

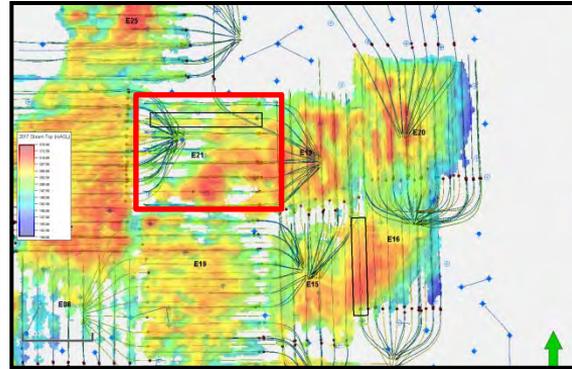
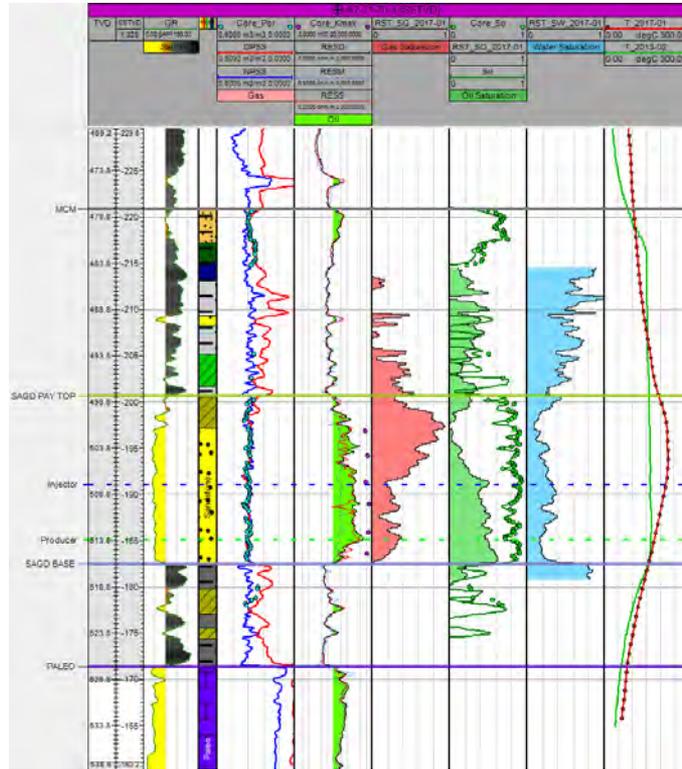


# E21 pad overview

- **E21 pad started production in September 2009**
  - 8 original well pairs
  - Several producer and injector redrills
- **Heterogeneous producer and injector geology, SAGD base sloping to the south (P01)**
- **Initial operating pressures ~3.5 MPa, currently producing ~2.7 MPa**
- **Currently at ~44% recovery of SOIP**
- **CSOR is currently ~2.84**

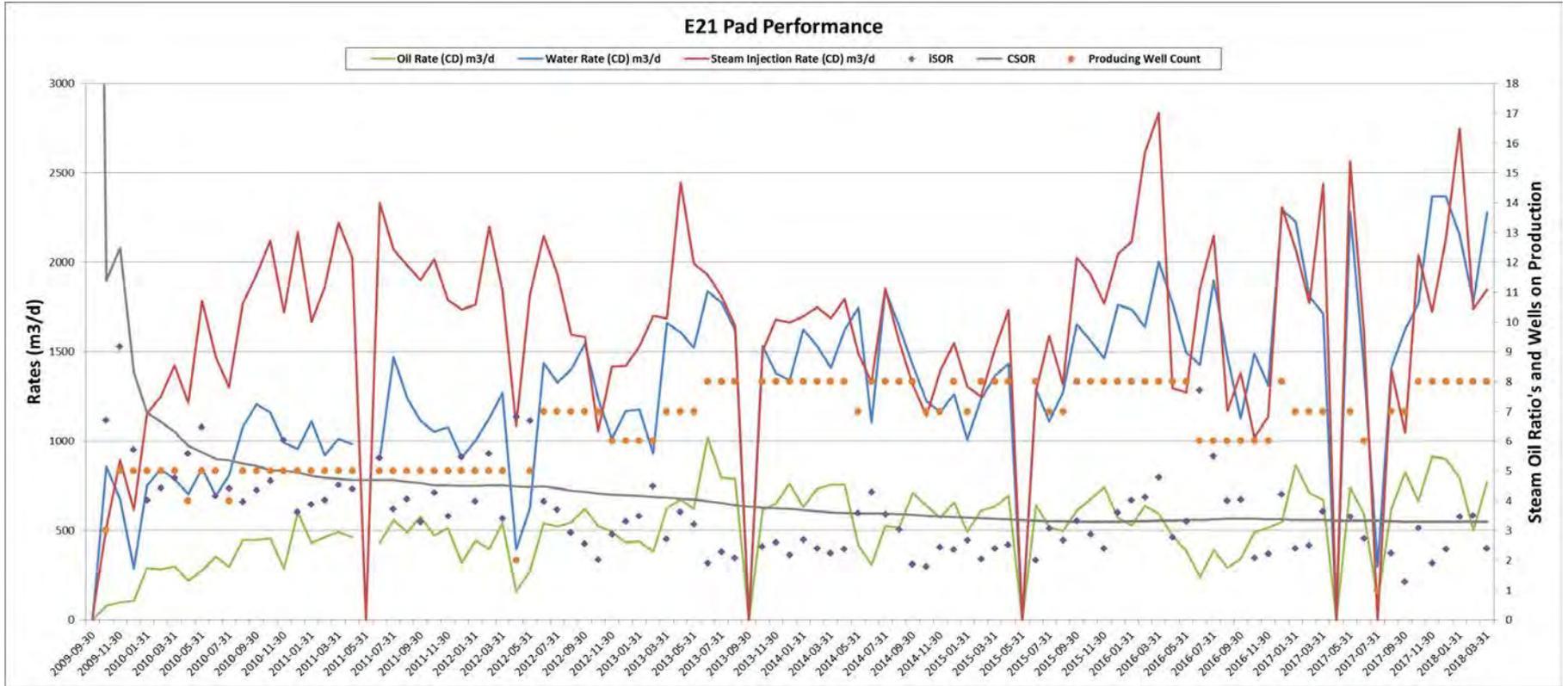
# E21 Pad Temperatures

A7-21



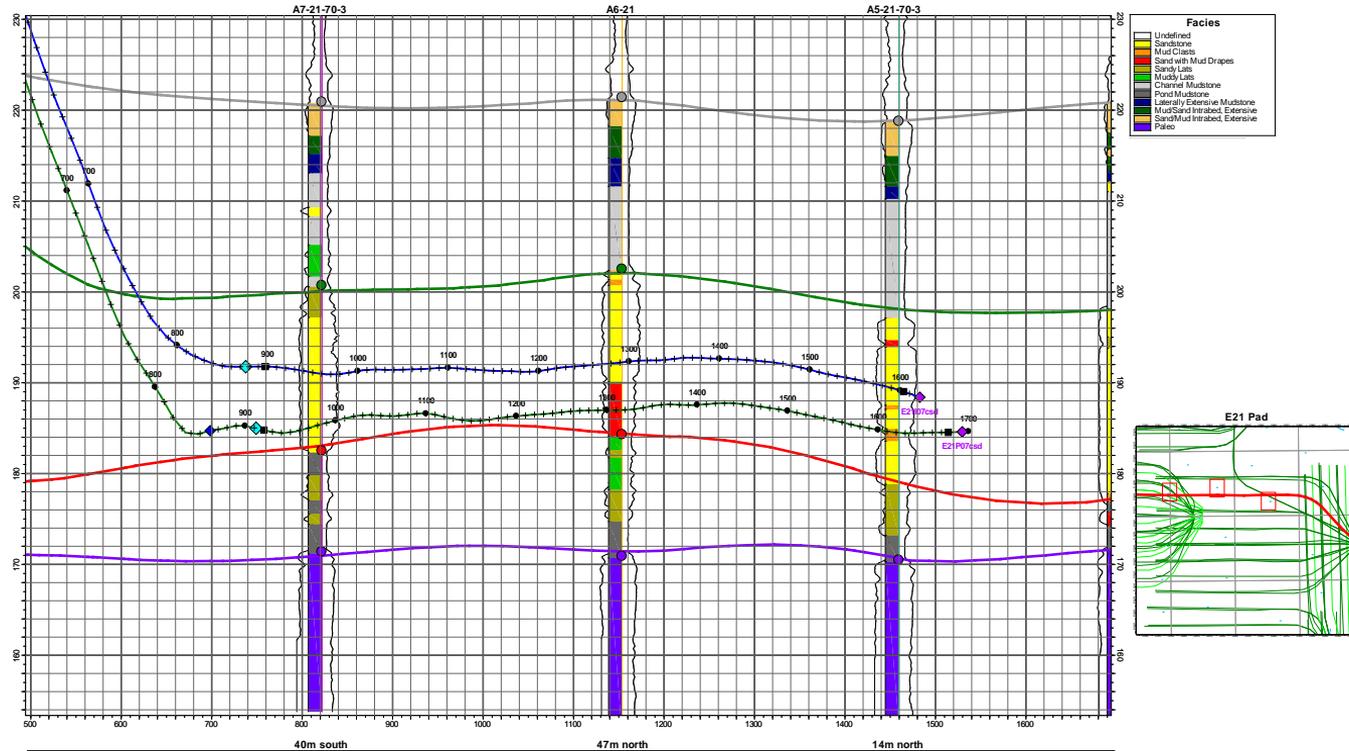
41m offset E21-04 well pair

# E21 pad performance



# E21-07 Geological Profile

E21P07



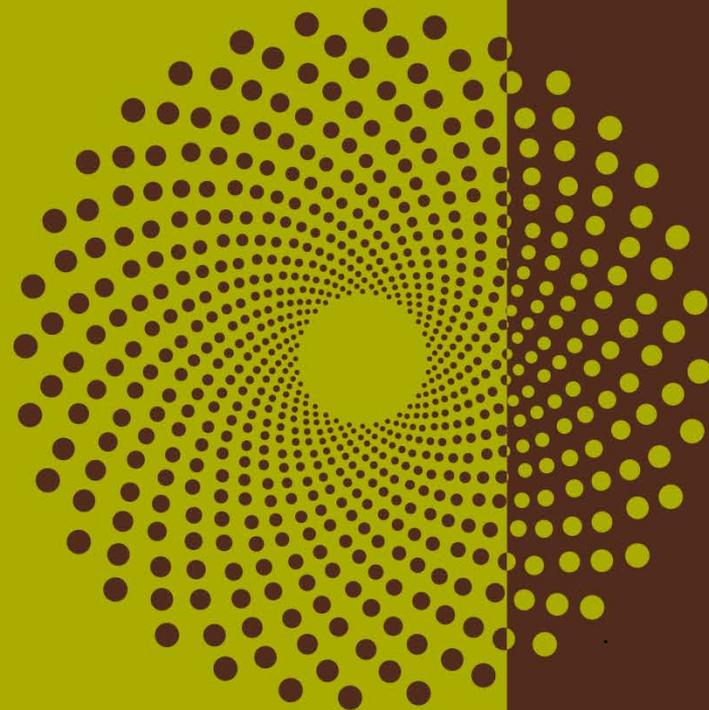
# E21 pad conclusions

- Currently at ~44% recovery of SOIP
- Optimization of pad on-going to maximize recovery
- Heterogeneous geology causes poorer conformance
- Balance reservoir pressures with thief zones and adjacent pads

# OBIP – high example

## E16 pad

Subsection 3.1.1. – 7 c) iii

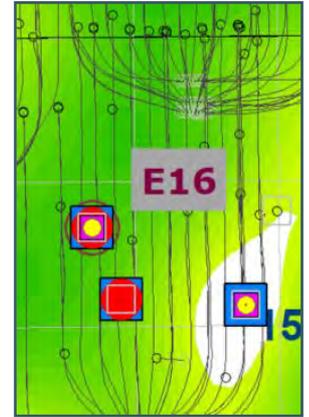
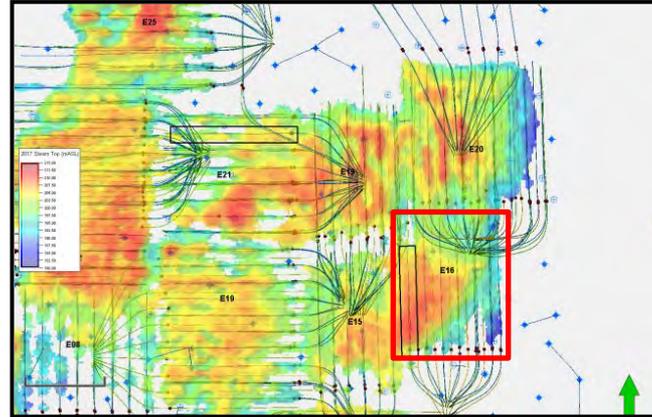
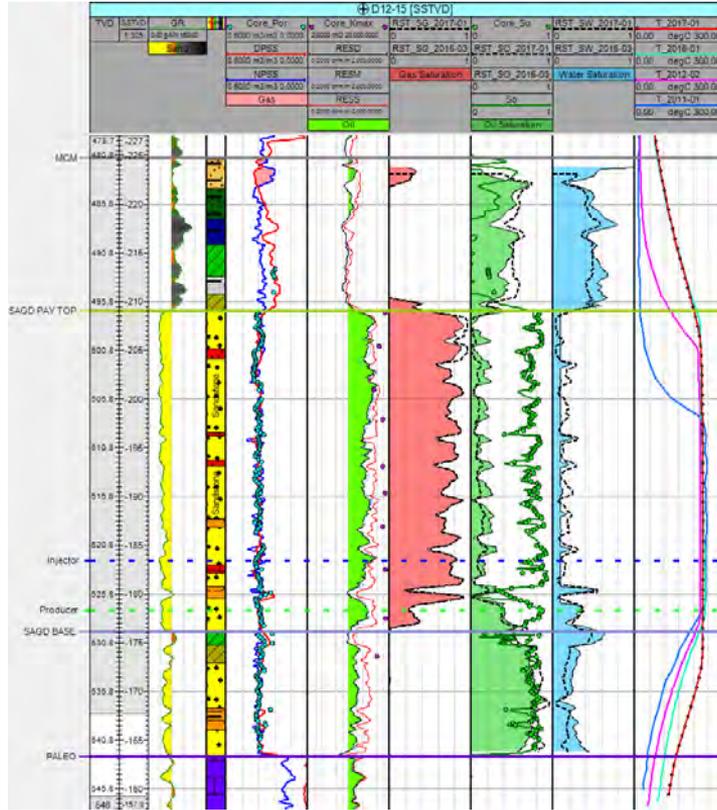


# E16 pad overview

- **E16 Pad started production in November 2008 (six pairs, 6 wells utilizing Wedge Well™ technology)**
  - Wedge wells started production in Q3 2014
  - Injector drilled over E16W06 in Q2 2016; online Q4 2016
  - Co-injection started November 2017
- **Heterogeneous producers and clean injectors, SAGD base sloping to the East (P6)**
- **Initial operating pressures ~3 MPa, currently producing ~2.62 MPa**
- **Currently at ~73% recovery of SOIP**
- **CSOR is currently 2.44**
- **Overall performance is good**

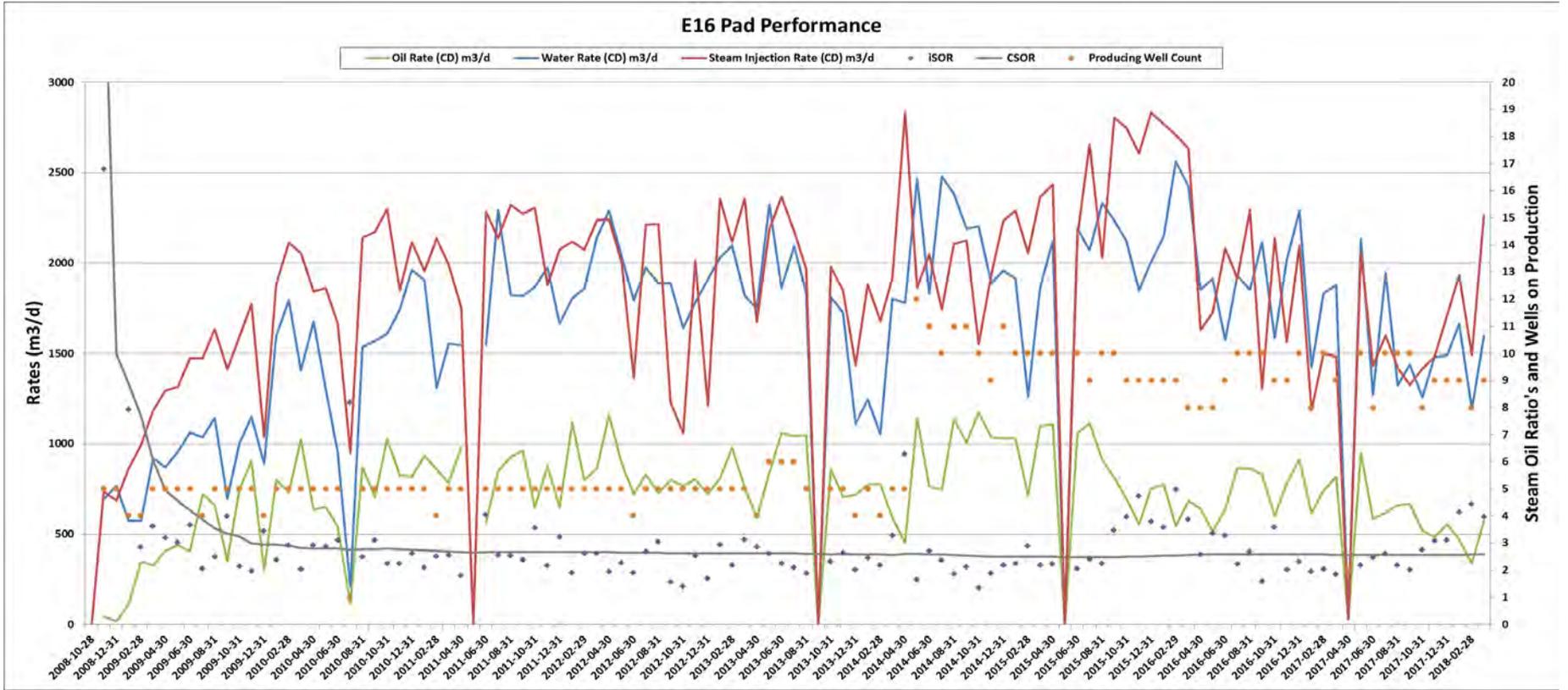
# E16 pad temperatures

D12-15

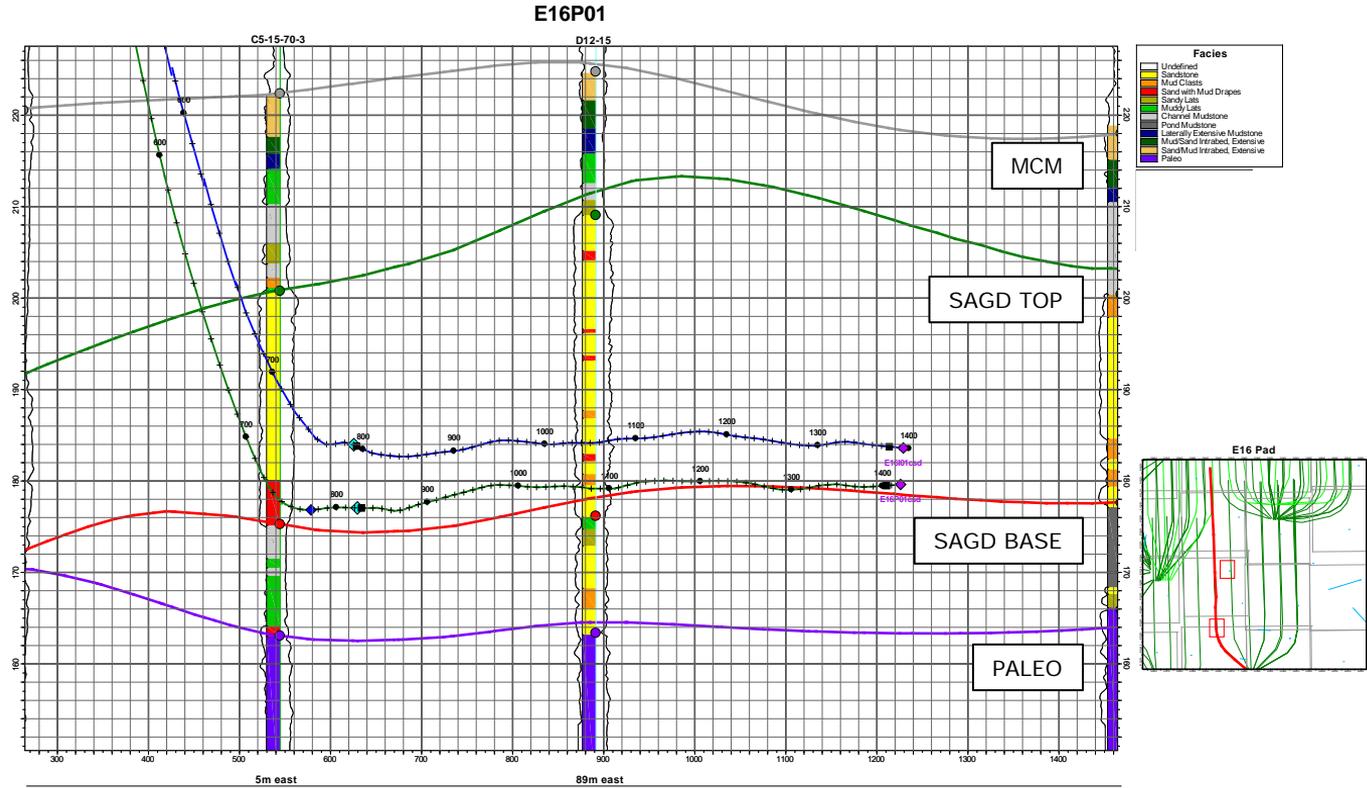


89m offset E16-01 well pair

# E16 pad performance



# E16-01 geological profile



# E16 pad conclusions

- Currently at ~73% recovery of SOIP
- Balance reservoir pressures with thief zones and adjacent pads
- Wells declining in late life; optimize as required
- Maximize recovery

# Scheme Performance

Subsection 3.1.1. – 7 c) iv d) e)



# Pad abandonments

- No pad abandonments are currently planned at Foster Creek in the next 5 years

# Steam quality

- Steam quality will be impacted by pipeline size and distance
- Currently at Foster Creek the steam qualities under normal operation conditions are as follows:
  - central ~ 95%
  - east ~ 94%
  - west ~ 95%
- Steam is delivered to pads at approximately 7000 – 9000 kPa
- Steam quality is not expected to impact well performance at this time

# Injected fluids

## Non-condensable gas

- NCG currently injected on A, C, D, F, G, M\_Exp, B/L, E/K, E02, E03, E04, E11, E12, E16, E19, E20, E25, E42

## Stimulation treatments

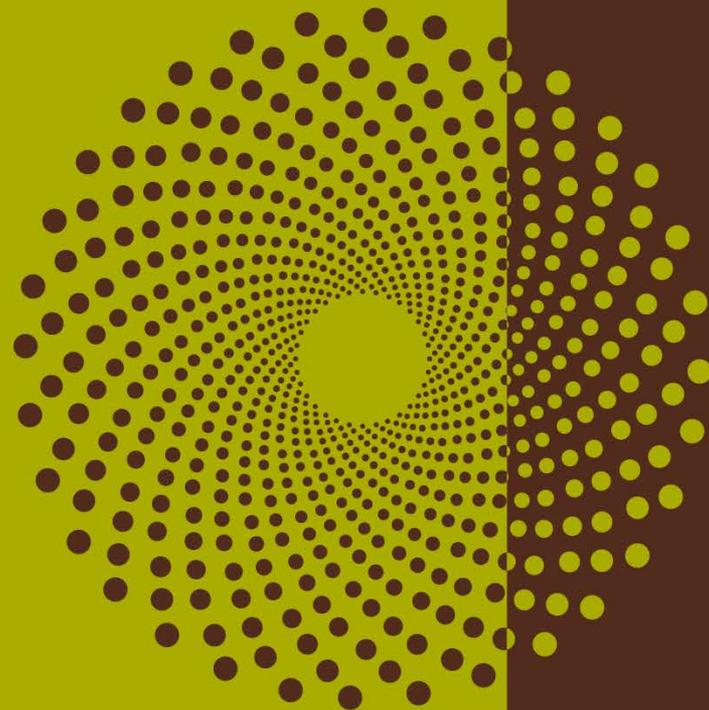
- Wells are occasionally treated with HCl and/or Thermosolv to minimize skin

## Solvent

- Have used solvent in start-up work-overs and have approval to use this as a potential start-up process
- N pad propane (C3) SAP pilot
- W06 pad propane co-injection pilot

# 2018 key learnings

Subsection 3.1.1 – 7 f)

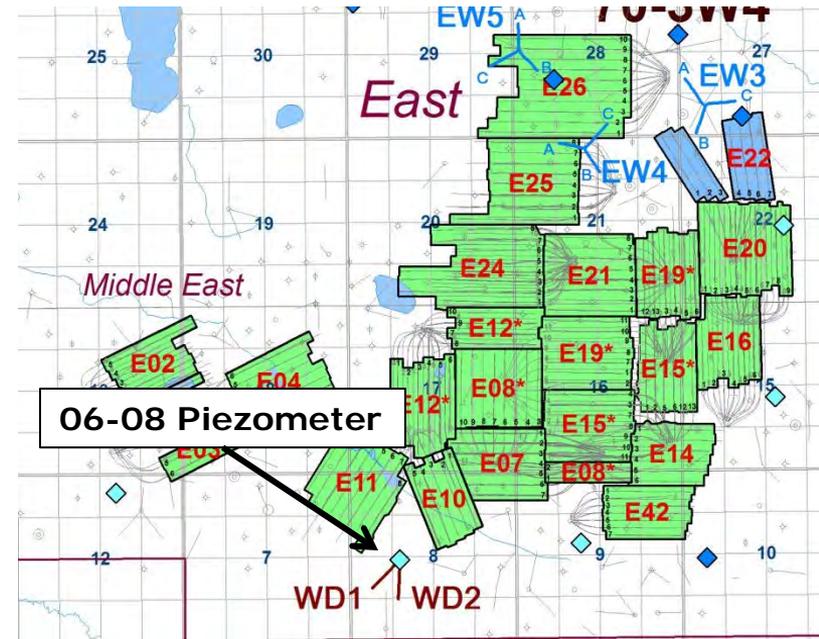


# Pressure sink update

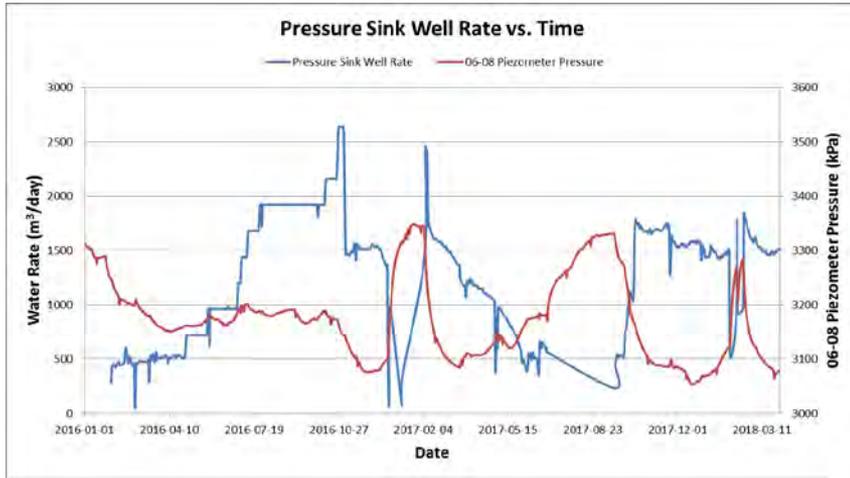


# Pressure Sink Update

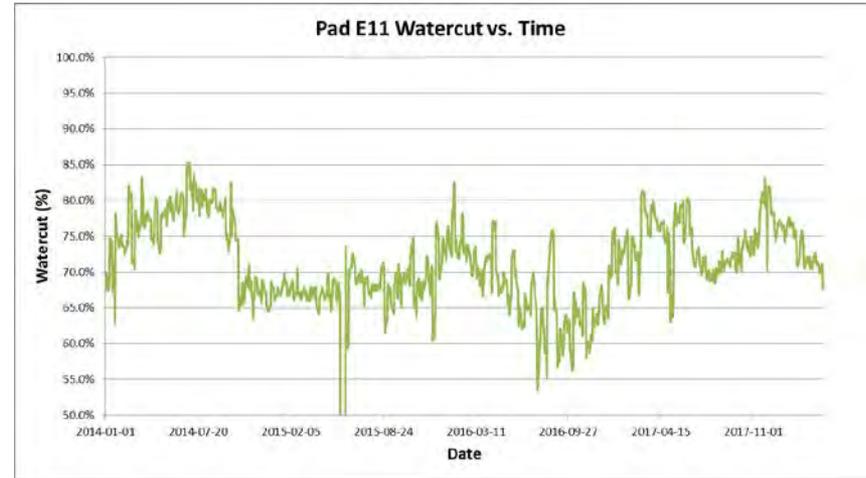
- Pad E11 had a history of bottom-water encroachment operating at lower SAGD target pressure
- Pressure sink well started up in 2016 to mitigate encroachment of bottom-water into E11 and east pod



# E11 Pad Performance

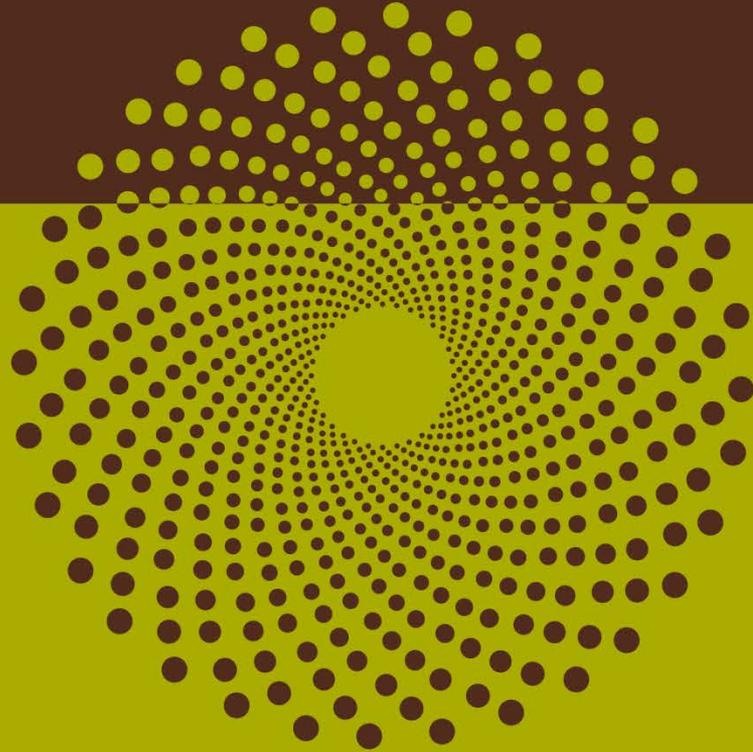


- At the 06-08 piezometer bottom-water pressure decreases 200-250 kPa when pressure sink well operates at full rates

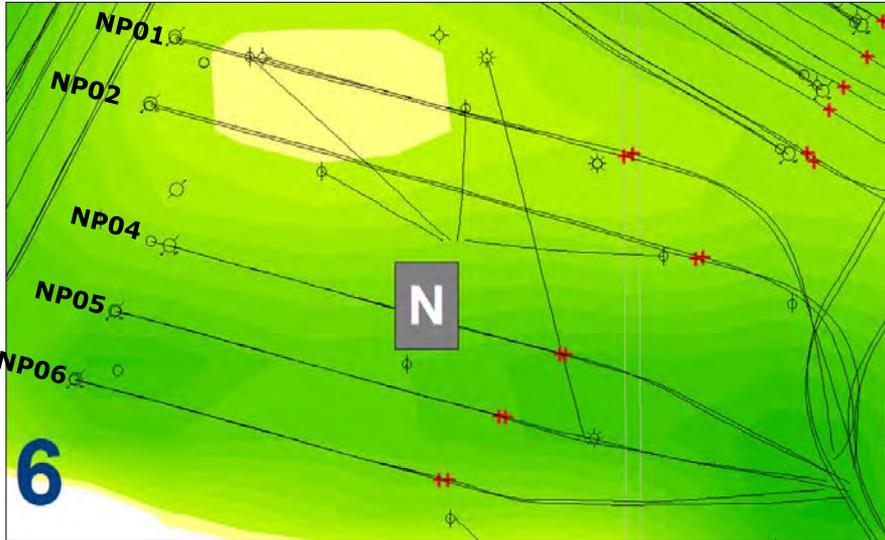


- Watercut values at Pad E11 and in the East Pod area confirm that the pressure sink well mitigates bottom-water encroachment into SAGD chambers

# N-Pad Pilot Update



# N pad overview



- NP01/NP02 are thin pay pilot wells
- NP04-NP06 are propane SAP pilot wells
- NP03 was not drilled to maintain isolation between the two pilots
- SAGD startup in Q2 2016

# Thin pay pilot overview

- **Pilot goal is to prove that Cenovus can produce and operate thin pay reservoirs**
- **NP01 and NP02 drilled 6 & 7m from the SAGD TOP**
- **NI01 and NI02: drilled 4m high and 3m laterally from producer**

Vertical ranging from observation wells was used to verify drilling depths and correct MWD uncertainties to ensure accurate thin pay for pilot wells (N01-N02)

- **Circulation startup since wells were drilled off SAGD base**

Wells drilled above the transition zone present in FC Central

- **Trial on-going.**

# SAP Pilot Overview

- **Pilot goal is to increase our understanding of propane SAP**
- **Propane (C3) SAP pilot is located at NP04-NP06**
- **Wells have rich pay thickness ~12-16m**
- **~1 year SAGD baseline prior to C3 injection**
- **Trial on-going**

# Well Integrity Update



# Well integrity - casing

## 2017 Intermediate Casing Failures

- Ongoing monitoring and inspection program to assess casing condition and repair as required

## Casing Corrosion

Corrosion Location	Status
Surface Casing Exterior	Mitigation program in place
Surface Casing Interior / Intermediate Casing Exterior	Mitigation program in place
Pack-Off	Investigation on-going

# Well Integrity - SCVF

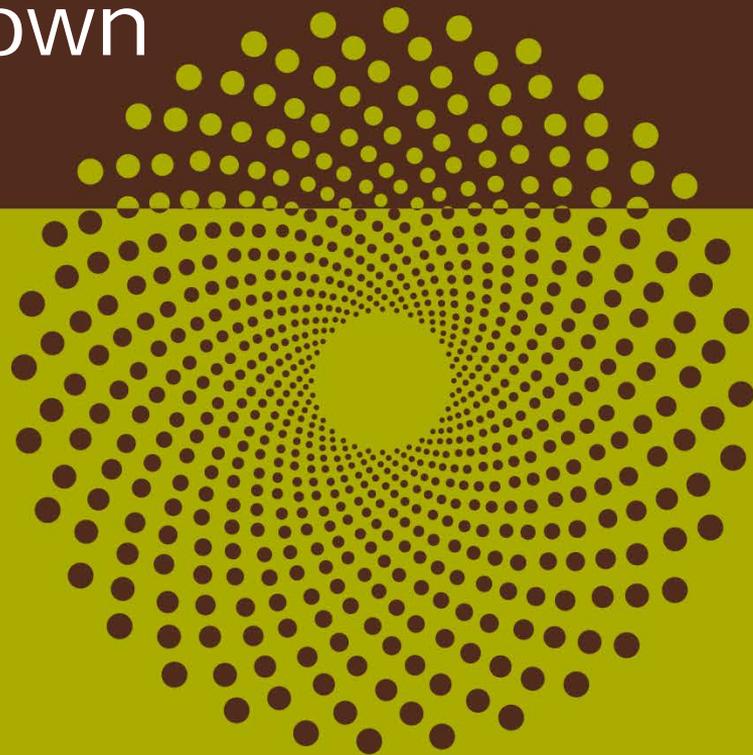
- Cenovus complies with all regulations and when a surface casing vent flow is identified, Cenovus reports non-serious and serious surface casing vent flows into the DDS system per ID 2003-01
- Cenovus engages with the AER to discuss appropriate strategies related to managing SCVFs
- Cenovus communicates with the AER regularly on the status of the vents and presents an annual update on activities executed to manage surface casing vent flows

# Well integrity – strain monitoring

## Strain monitoring wells installed

- Baseline data in non-thermally affected zones and in lateral sections
  - 102/03-23-070-05W4/00 (FC W20 Pad)
  - 102/05-23-070-05W4/00 (FC W20 Pad)
  - 100/05-28-070-03W4/00 (FC E26 Pad)
  - 100/14-14-070-05W4/00 (FC W20 Pad)
  - 106/13-07-070-05W4/00 (FC W32/35 Pad)
  - 1AB/02-32-070-04W4/00 (FC North)
- Field measurements scheduled relative to milestone dates

# Rampdown/Blowdown Update



# Field wide co-injection and blowdown

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

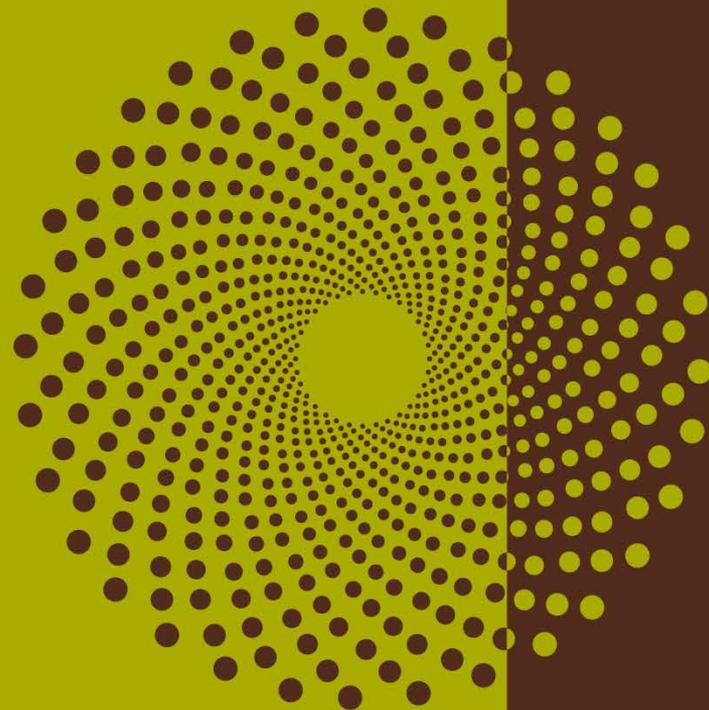
- A, C, D, F, G, B/L, E/K, Exp\_M, E02, E03, E04, E11, E12, E16, E19, E20, E25, E42

Currently evaluating additional infrastructure requirements based on forecasts

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

# Future plans 2018 initiatives

Subsection 3.1.1 – 8



# 2018 initiatives

- **Alternate liner trials continue on various pads**
- **Liner and tubing deployed FCDs**
  - Trial is on-going
  - Challenges: high differential pressure restricts flow, limited conformance improvement
- **Co-injection**
  - Solvent
- **Insulated tubing**
  - Proved VIT in injectors
- **N pad Trials**
  - Thin pay pilot
  - Propane SAP pilot

Well	FCD	Tubing/Liner	Injector/Producer
DF1	ICD	Tubing	Producer
E12P07-1	ICD	Tubing	Producer
E15P02-1	ICD	Liner	Producer
E15P11-1	ICD	Liner	Producer
E16P06	ICD	Tubing	Producer
E26P02	ICD	Liner	Producer
FI07	OCD	Liner	Injector
FP07	ICD	Liner	Producer
FP2-1	ICD	Tubing	Producer
GP5-1	ICD	Liner	Producer
GP6-1	ICD	Liner	Producer
W05P05	ICD	Liner	Producer
W08P01	ICD	Liner	Producer
W10P09	ICD	Liner	Producer
W20P02	ICD	Liner	Producer

# New pad well spacing and start-up

**Average well spacing listed in SOIP tables**

**Current well designs yield improved conformance**

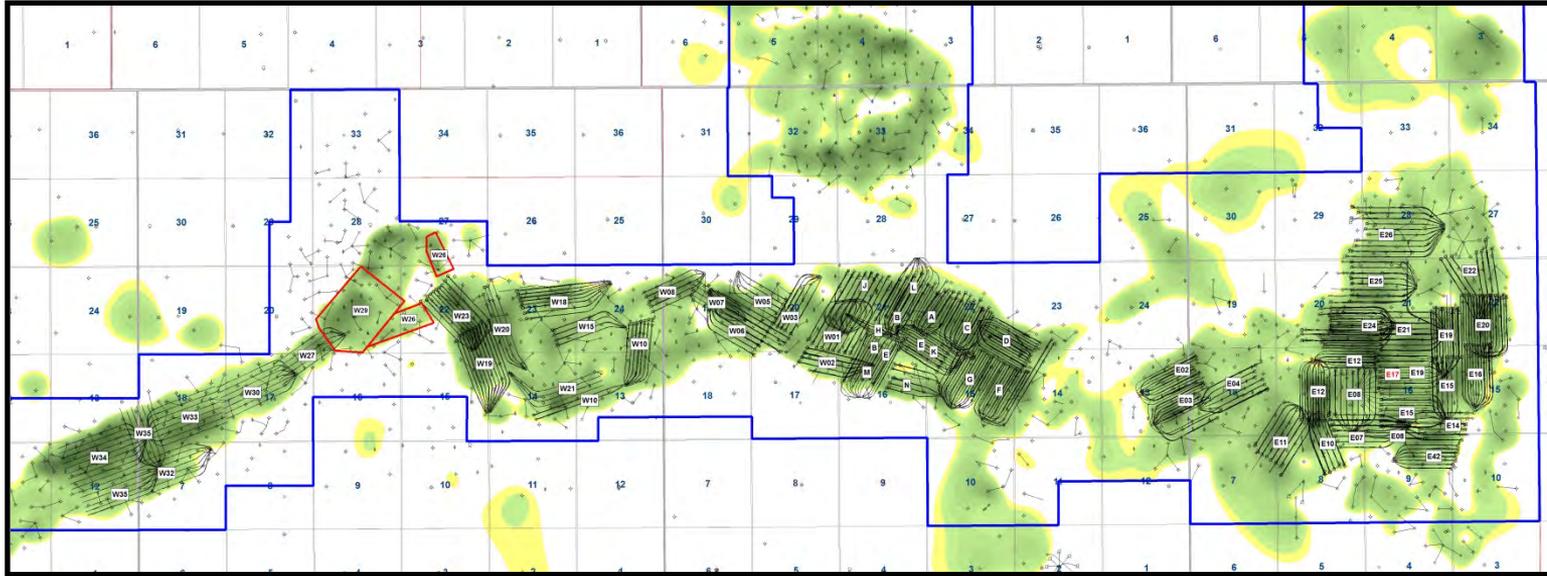
**Wedge Well™ technology is utilized in later stages if required to maximize recovery, not expected on highly conformed pads**

**Start up strategy consistent across the Field**

**Operating pressures during start up and ramp up stages**

- steam stimulation/circulation: (5.5 – 6.6 MPa)\*
  - Note\*: this upper limit is specific to the MOP of each region
- ramp-up: (3.5 – 5.5 MPa)

# 2018 new SAGD well pairs drilling plans



## West Pads:

- W26, W29

 Mar 2017 - Mar 2018 Drilling

# 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

Thank you