Cenovus Energy Inc.
Foster Creek In-situ Progress Report
Scheme 8623
2018 update

Subsurface
May 15, 2019

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Oil & gas and financial information

Oil & gas information

The estimates of reserves were prepared effective December 31, 2018. 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, 2018 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.

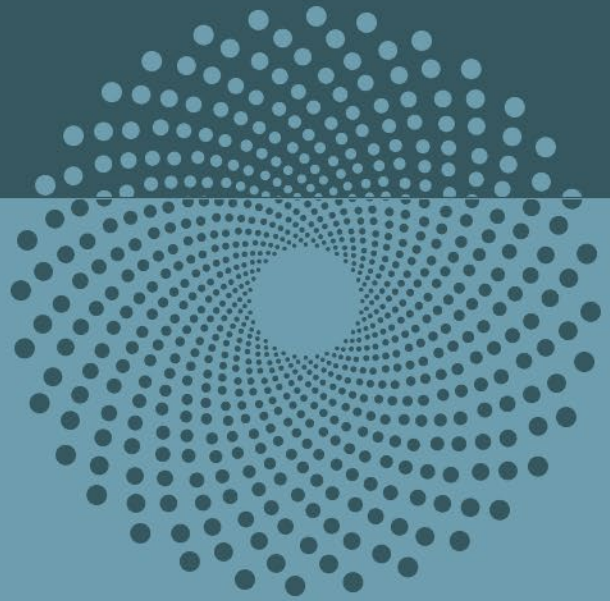
Advisory

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



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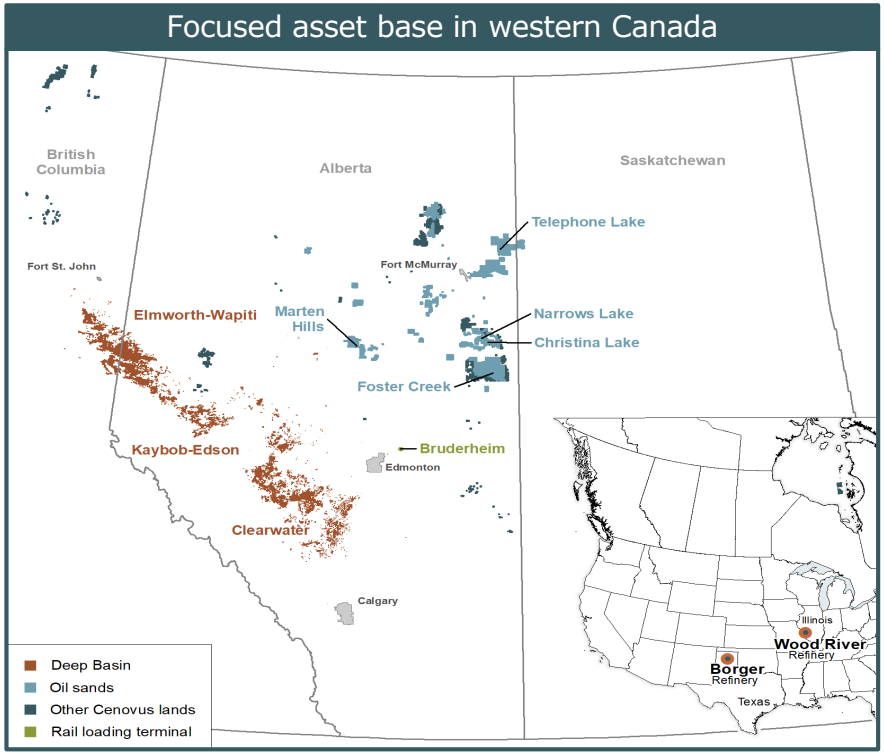
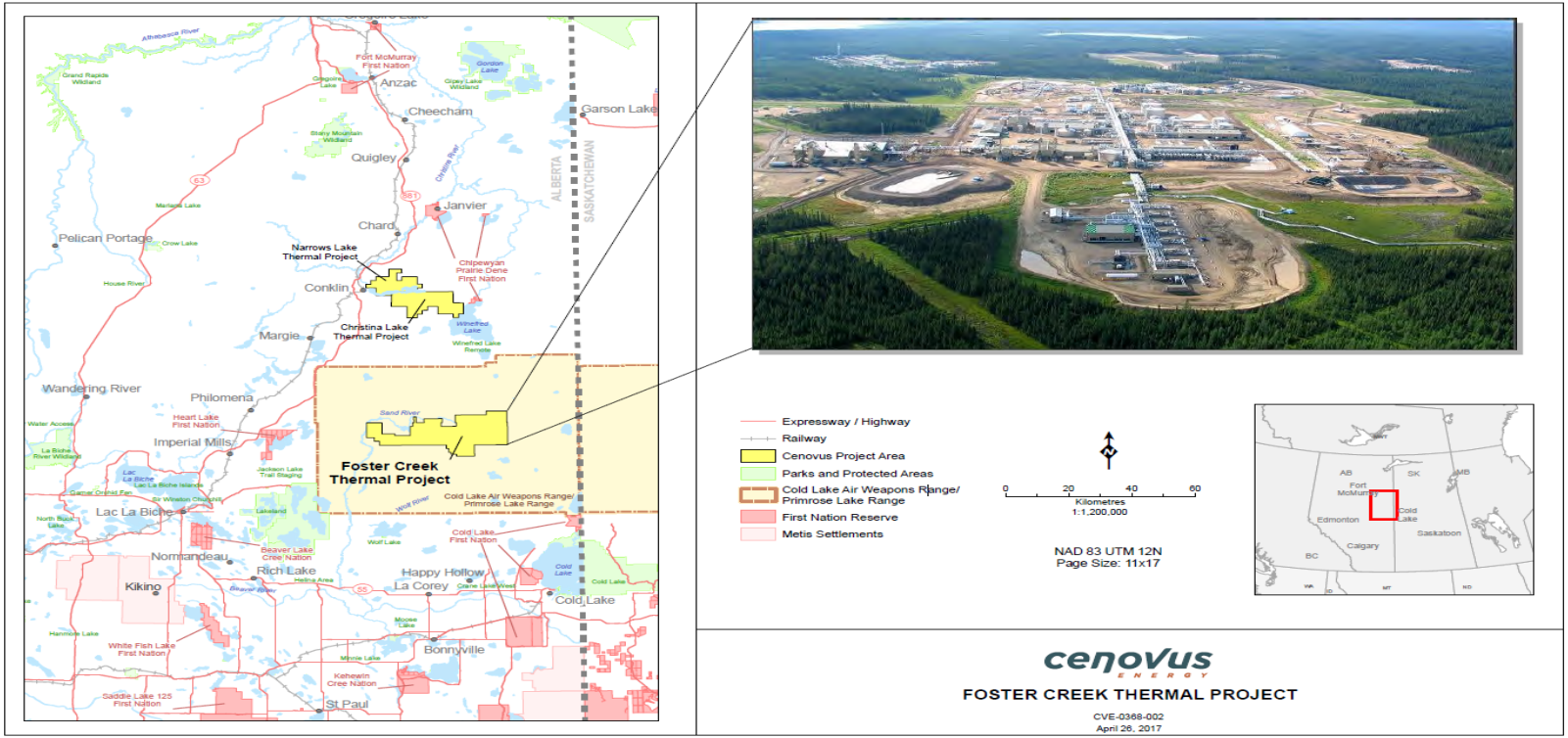
About Cenovus

TSX, NYSE | CVE	
Enterprise value	C$22 billion
Shares outstanding	1,229 million
2019F production	
Oil sands	360 Mbbls/d
Deep Basin	
Oil & liquids	26 Mbbls/d
Natural gas	445 MMcf/d
Total liquids	386 Mbbls/d
Total natural gas	445 MMcf/d
Total production	**460 MBOE/d**
2018 proved + probable reserves	7.0 BBOE
Refining capacity	241 Mbbls/d net



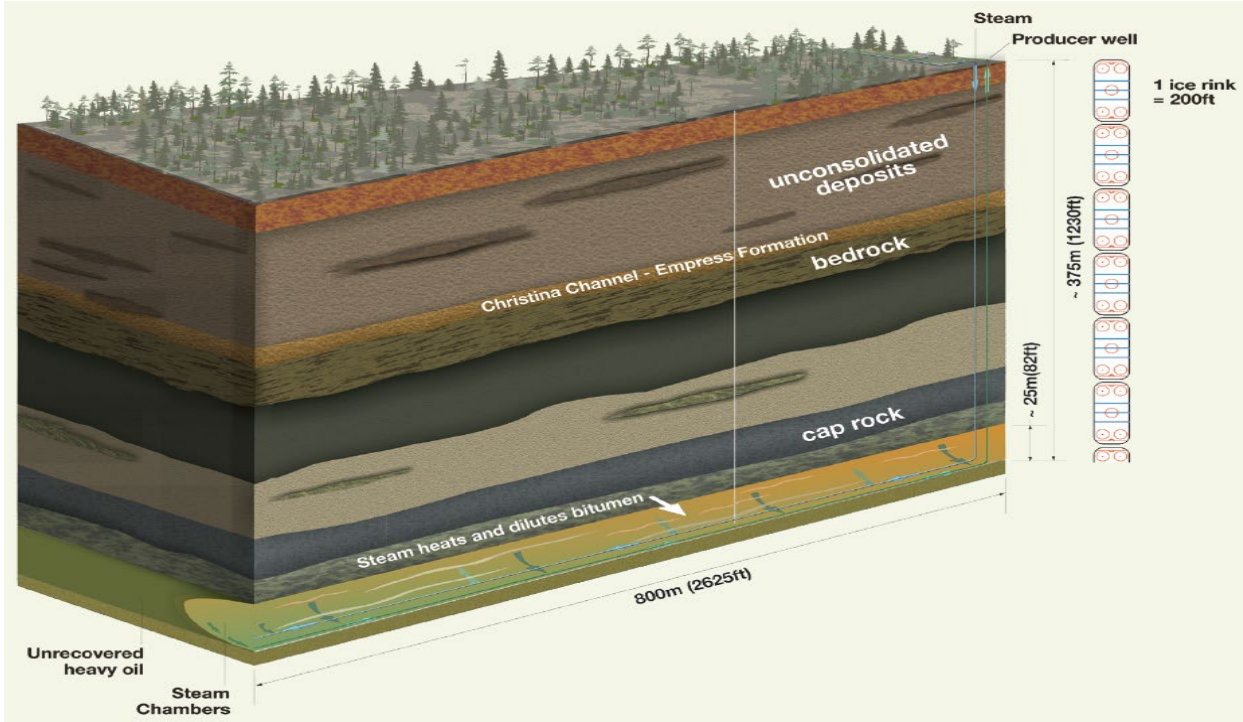
Note: Values are approximate. Enterprise value as at March 31, 2019. 2019F production based on the midpoint of April 23, 2019 guidance. Reserves are on a before-royalty basis and exclude royalty interest.

Area map

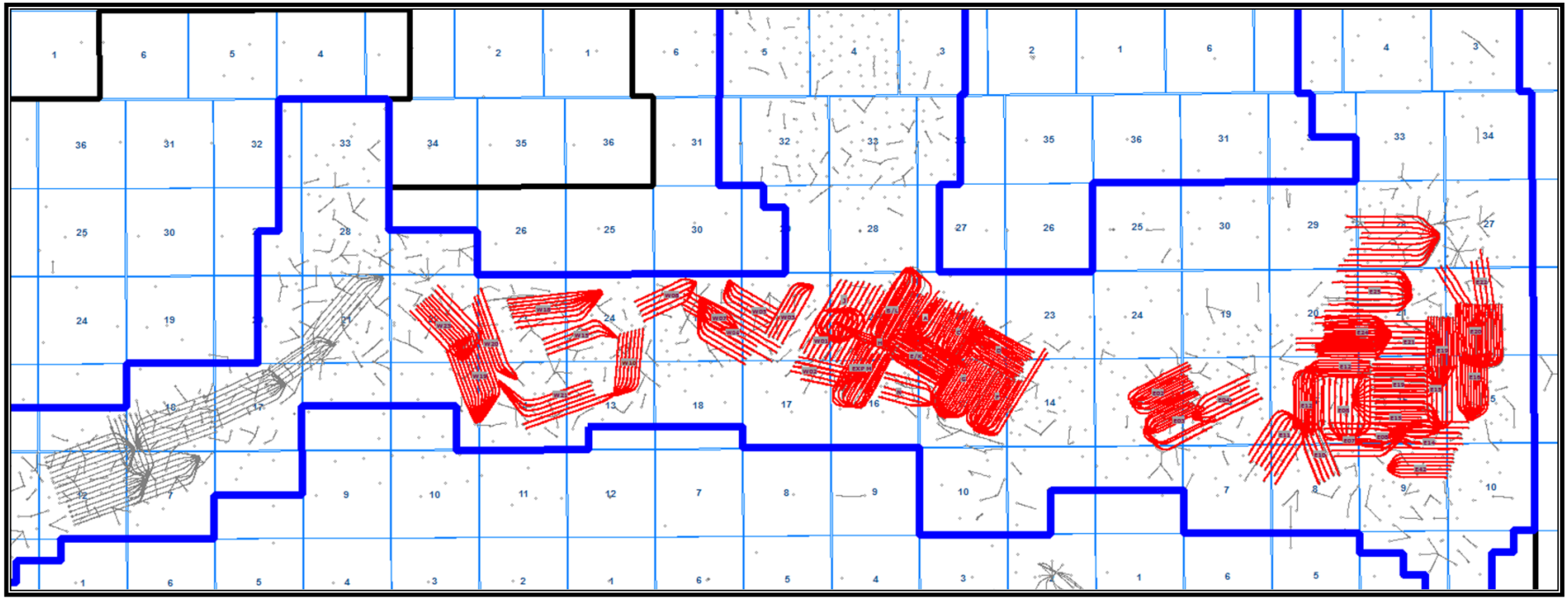


Recovery process

- 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



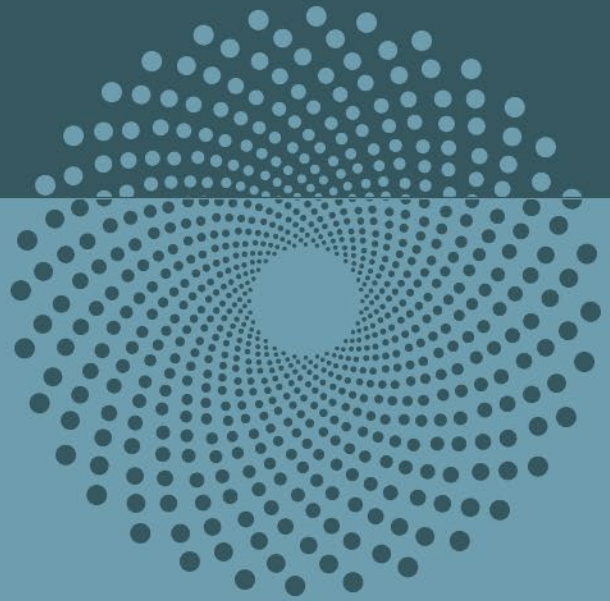
Scheme map



Well Pairs on Production

Well Pairs Drilled Not Producing

Subsection 3.1.1 – 2) Geology and Geoscience



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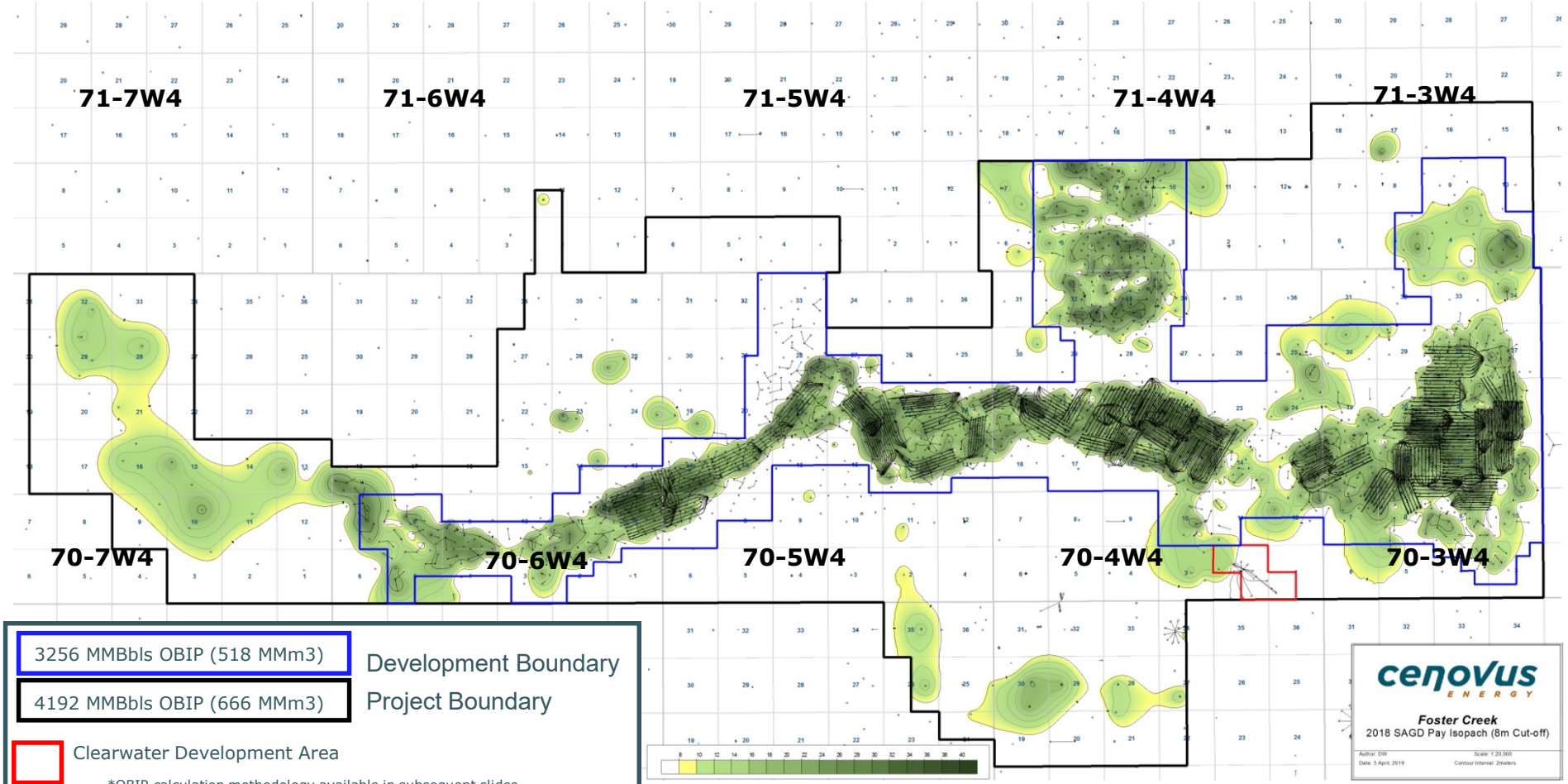
Current Project Status – SAGD Resource



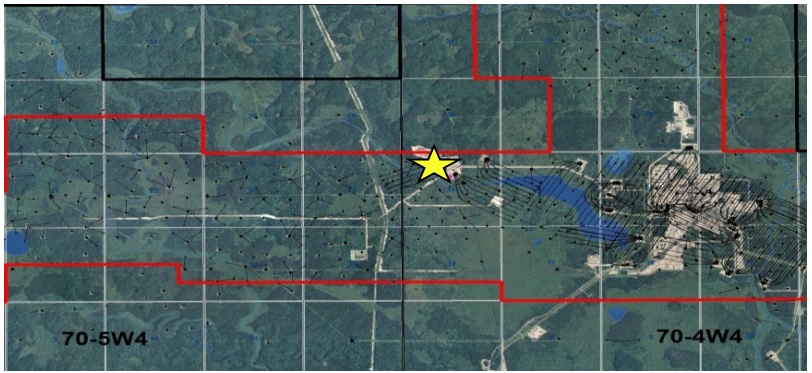
Reservoir characteristics

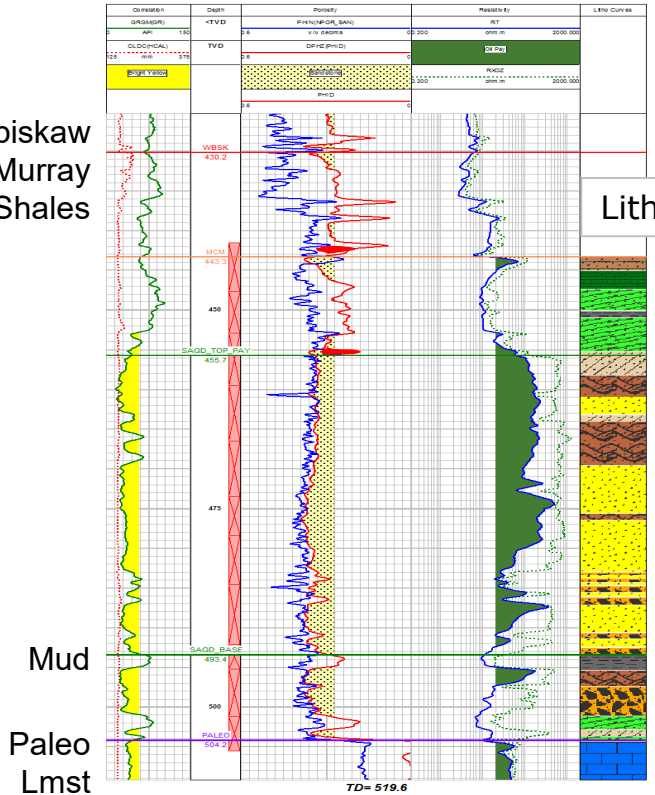
Reservoir Characteristic	West Area	Central Area	East Area
Depth (m subsea)	180 – 225	180 – 225	180 – 225
Thickness (m)	Up to 30+	Up to 30+	Up to 30+
Porosity (%)	34%	34%	32%
Horizontal Permeability (D)	Up to 10 D	Up to 10 D	Up to 8 D
Vertical Permeability (D)	Up to 8 D	Up to 8 D	Up to 6 D
Oil Saturation	~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 (ºC)	12 ºC	12 ºC	12 ºC

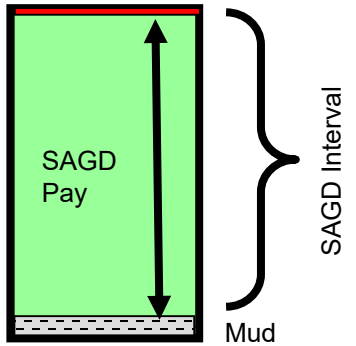
Composite type log: central wells

- 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



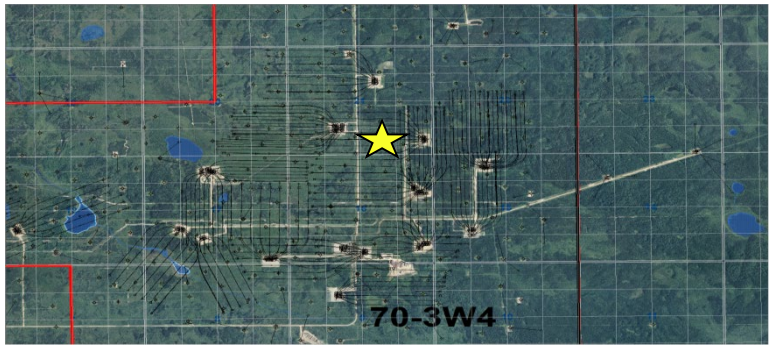


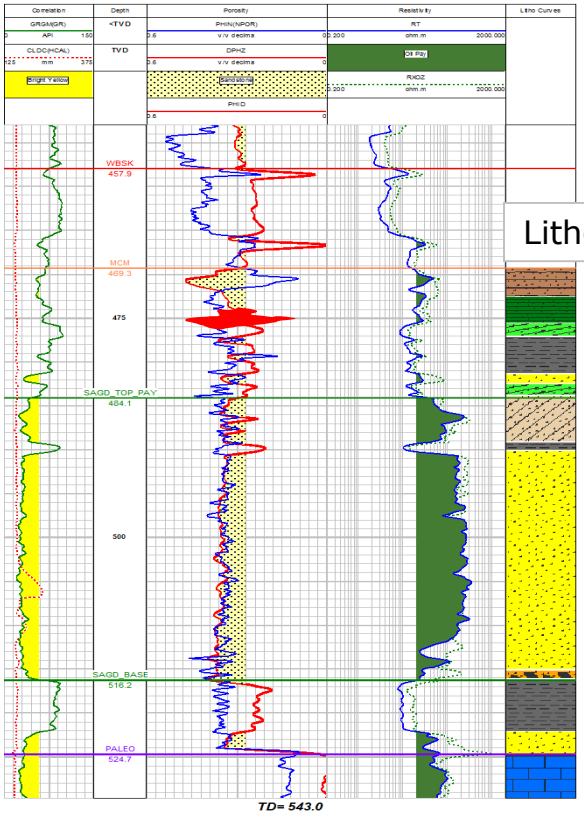


Composite type log: east wells

- 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





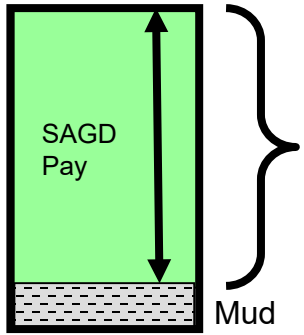
Wabiskaw McMurray Shales

Mud

Paleo Lmst

Lithology

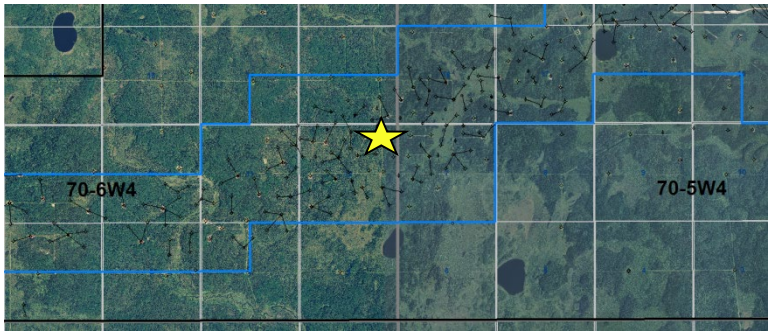
Brackish Bay Gas

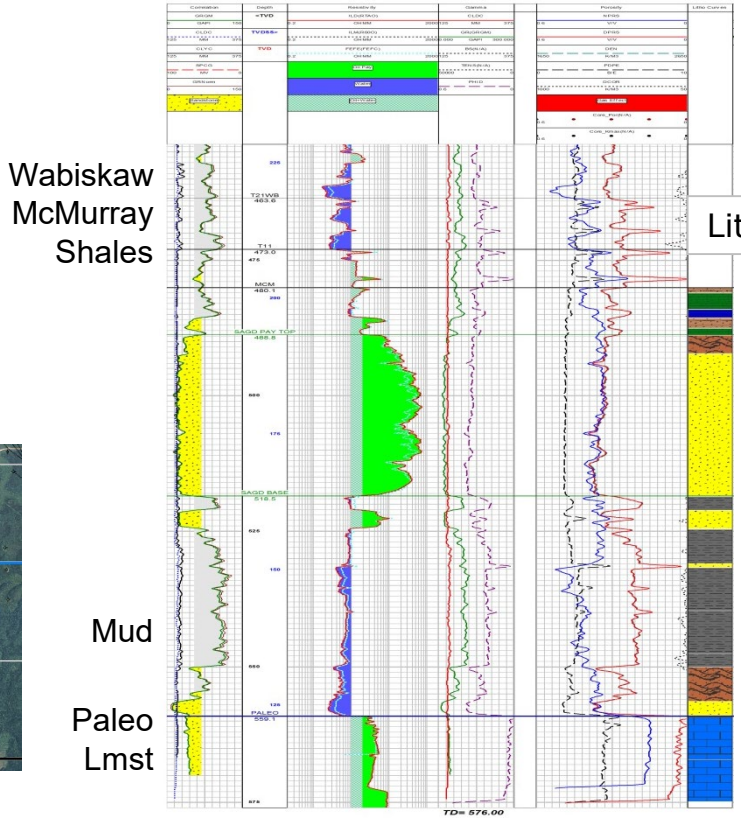


Composite type log: west wells

- 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

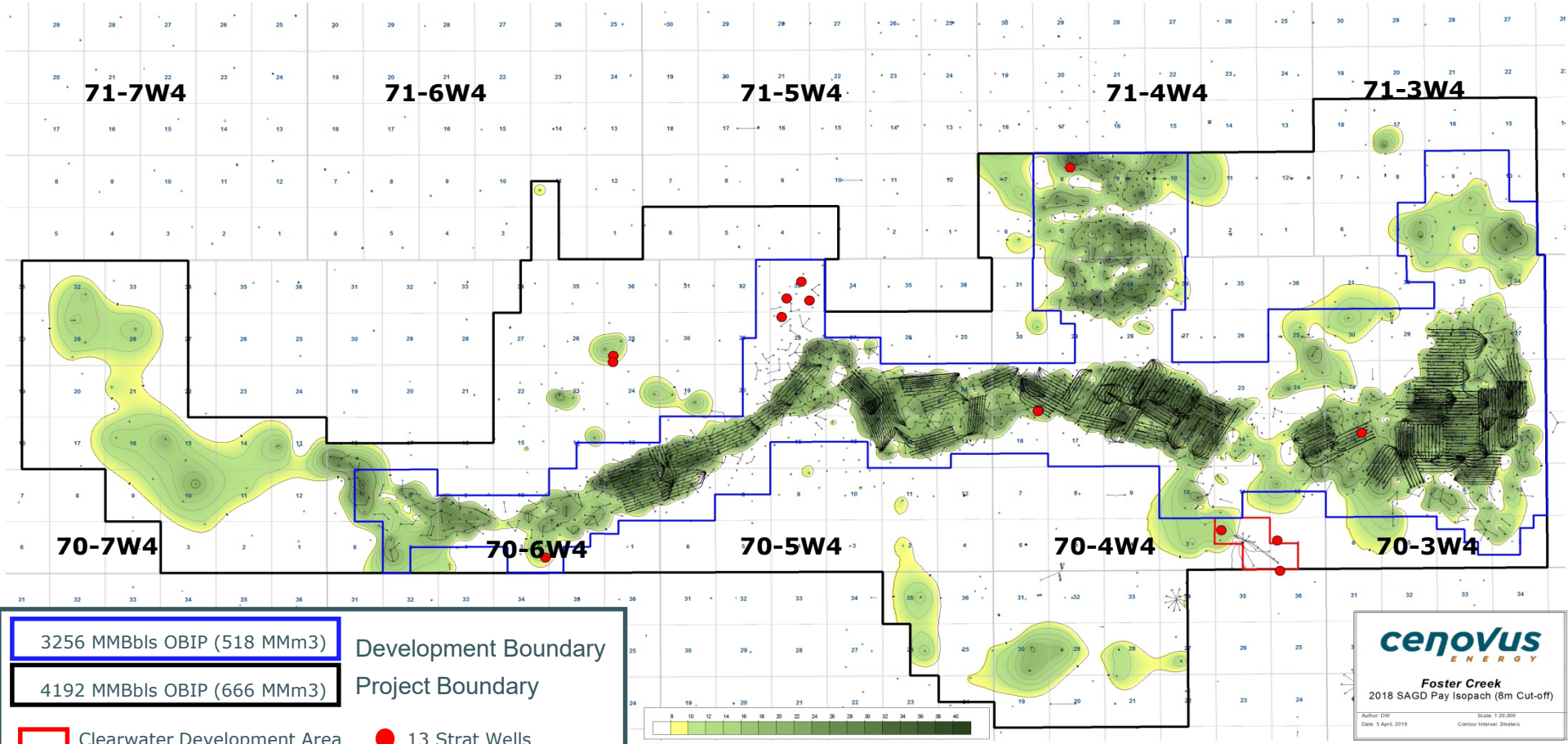
Location: 16-12-70-6W4



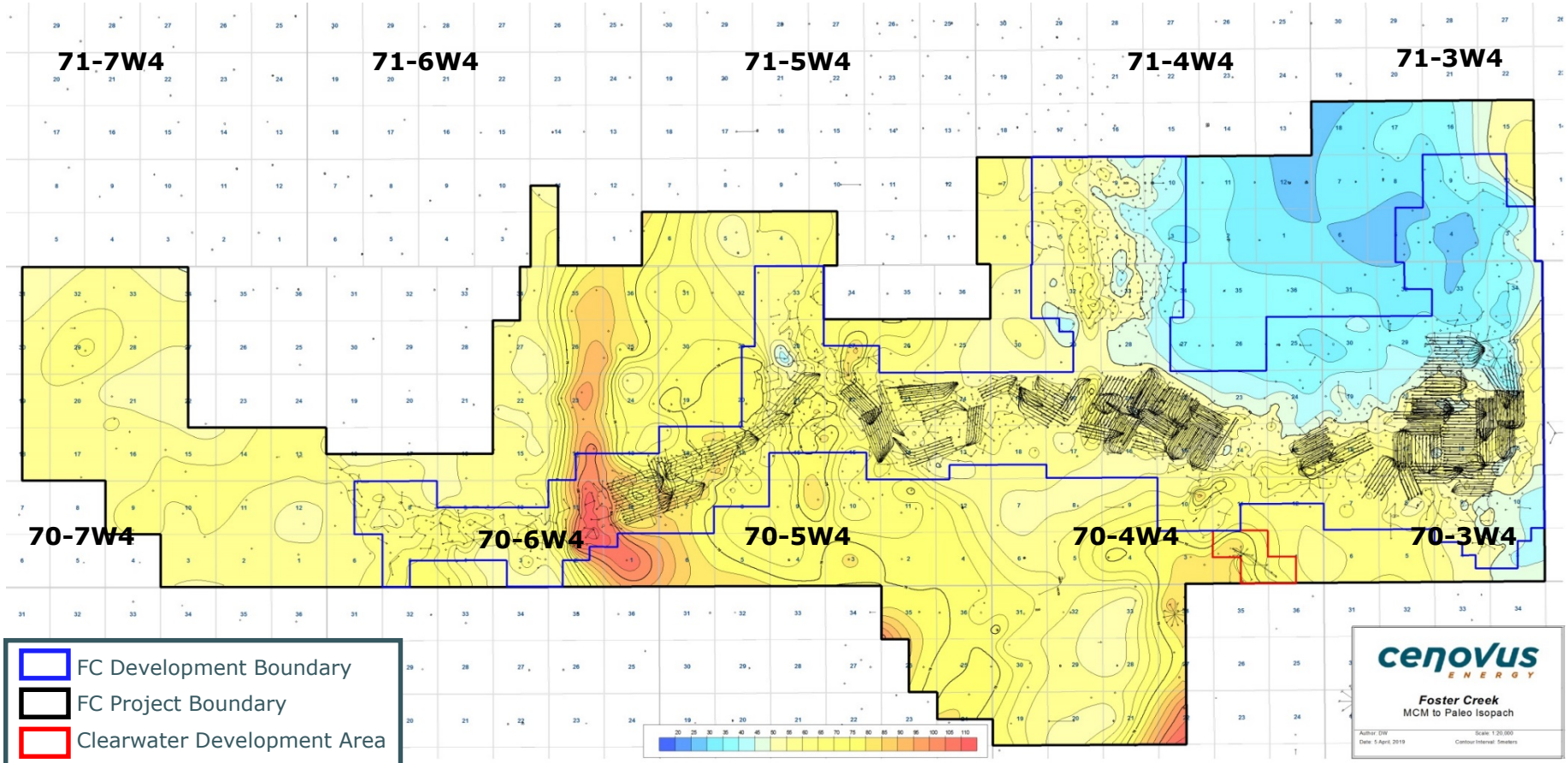


Geological Maps

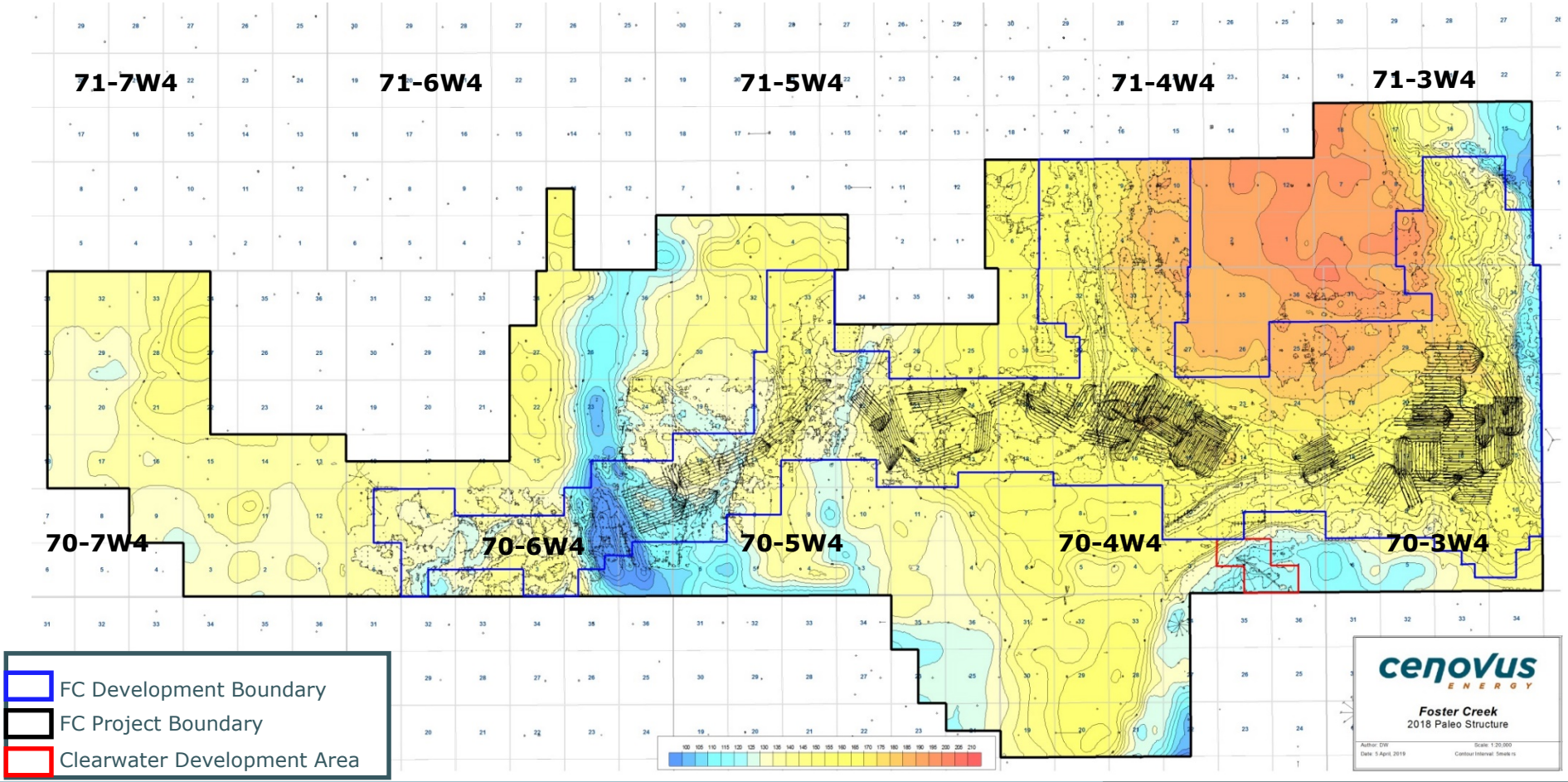
2018 SAGD Pay Isopach (2019 Strats)



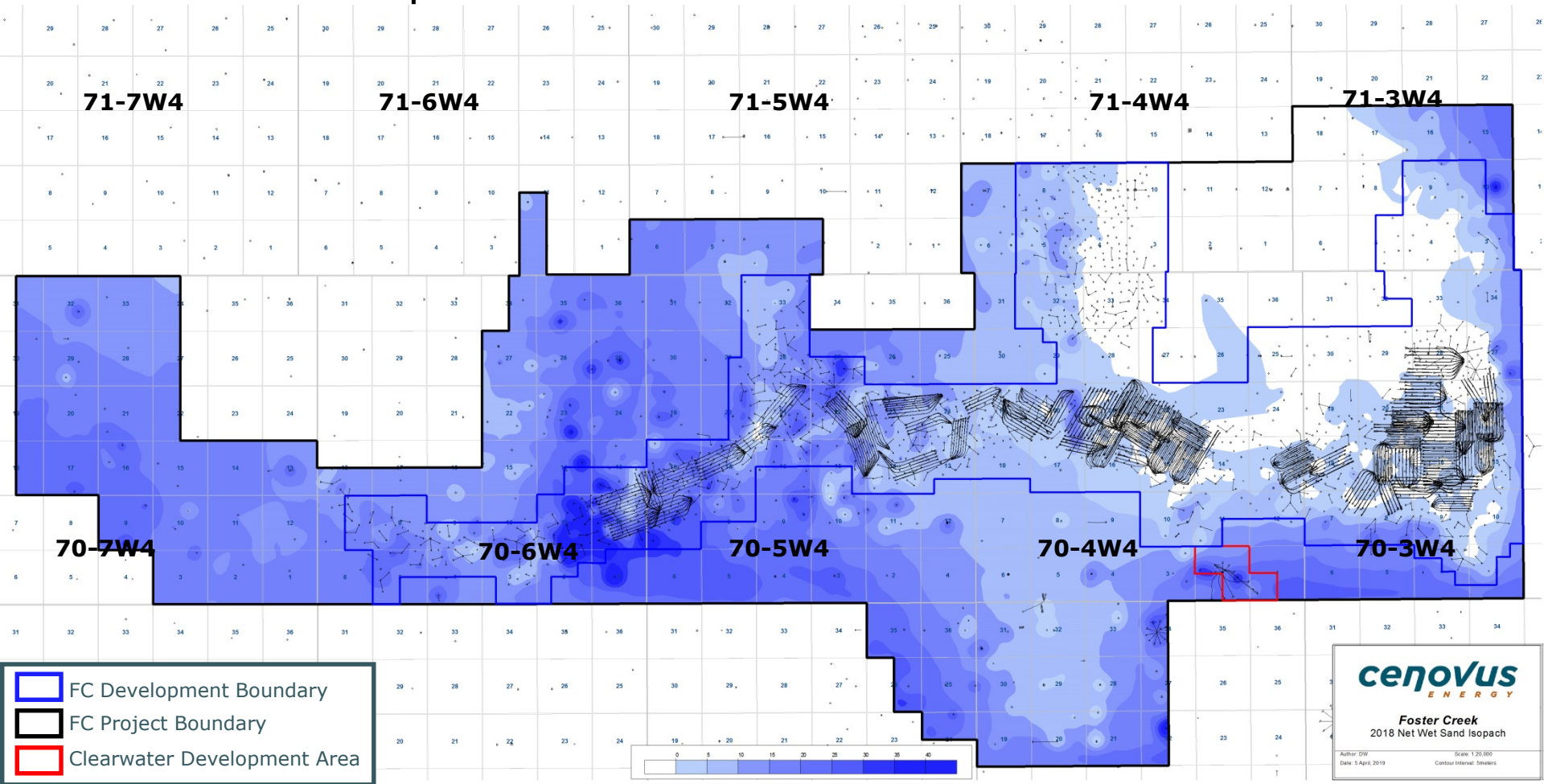
McMurray to Paleozoic Isopach



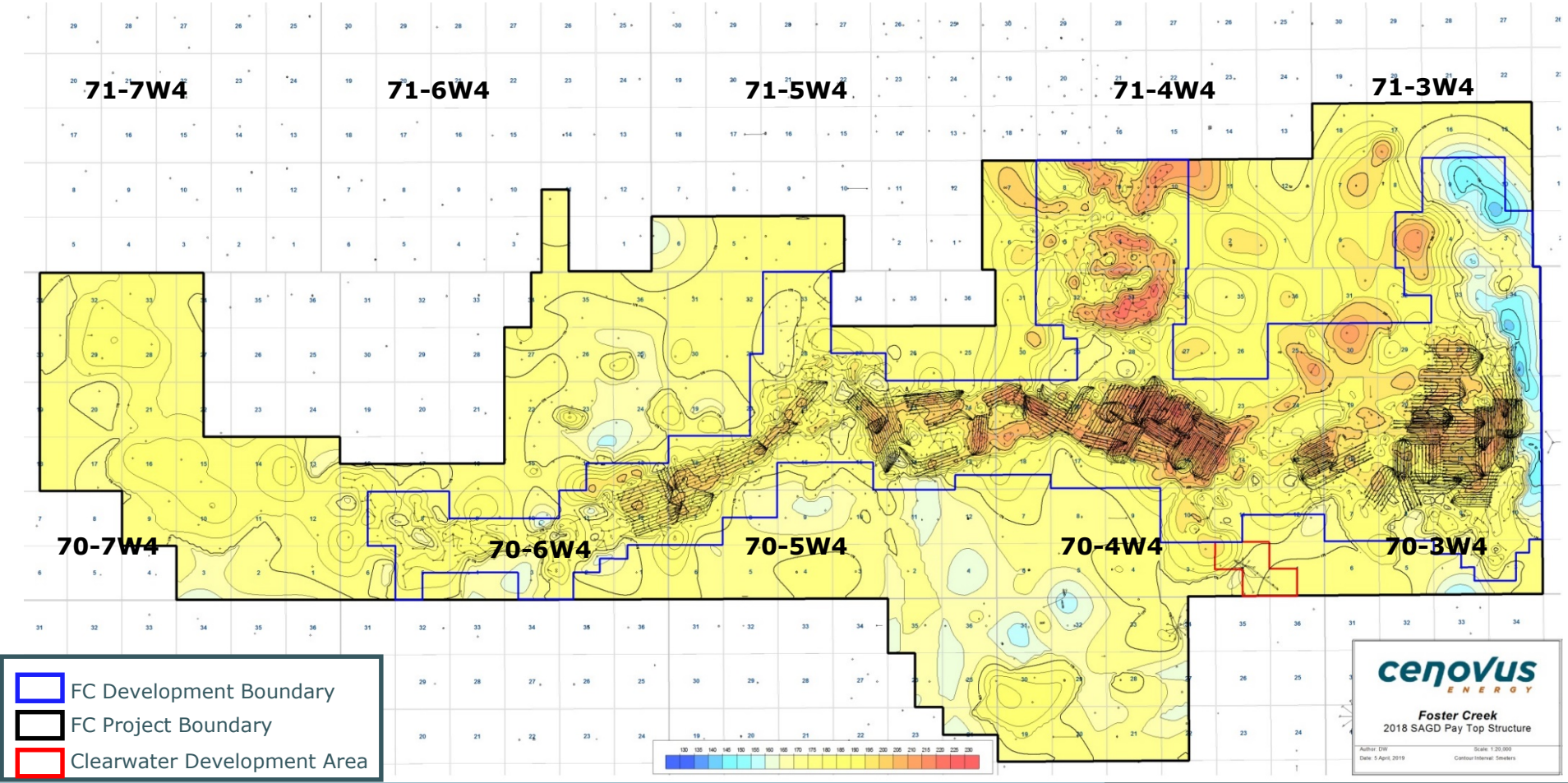
Paleozoic Structure



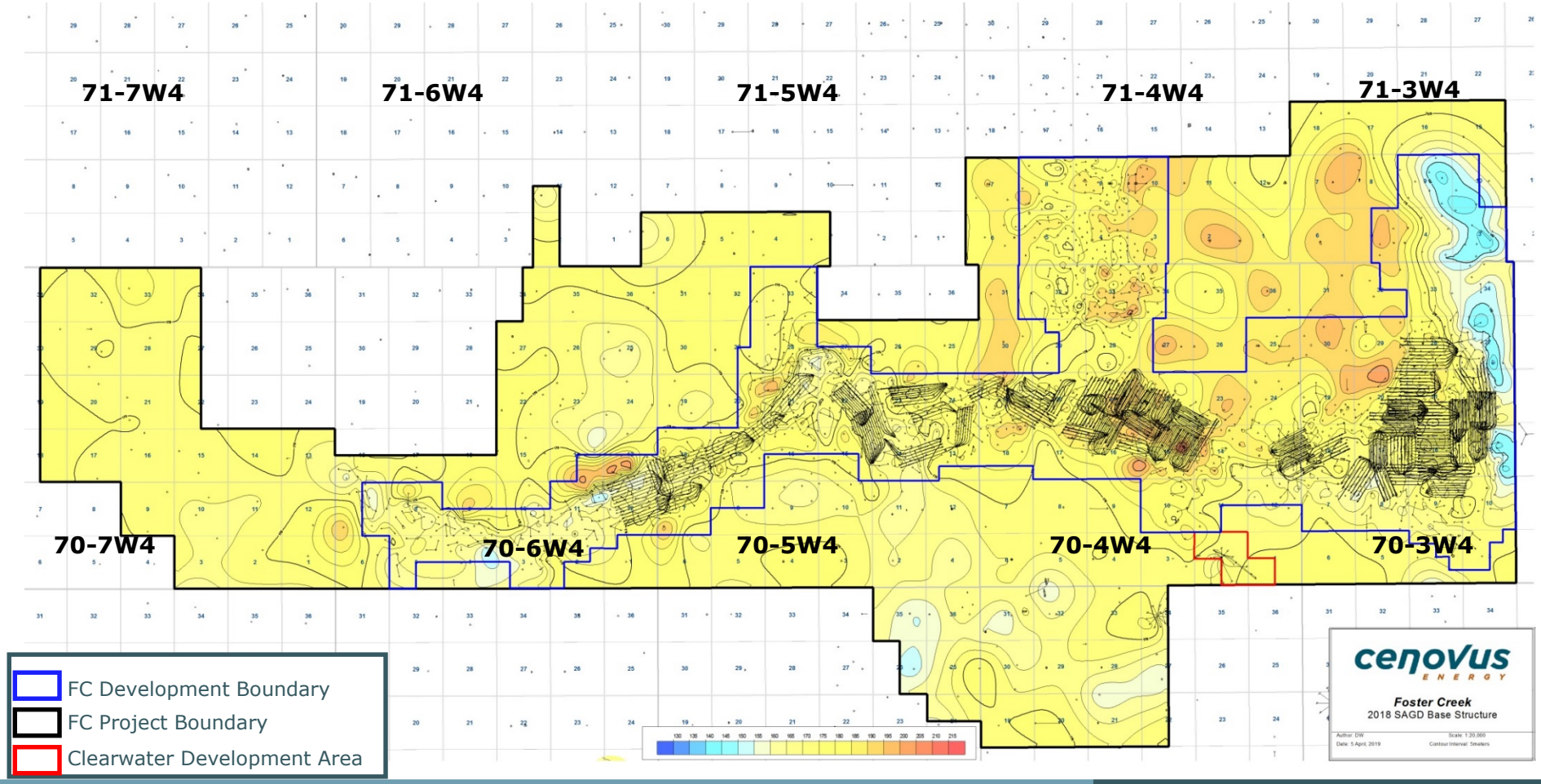
Net Wet Sand Isopach



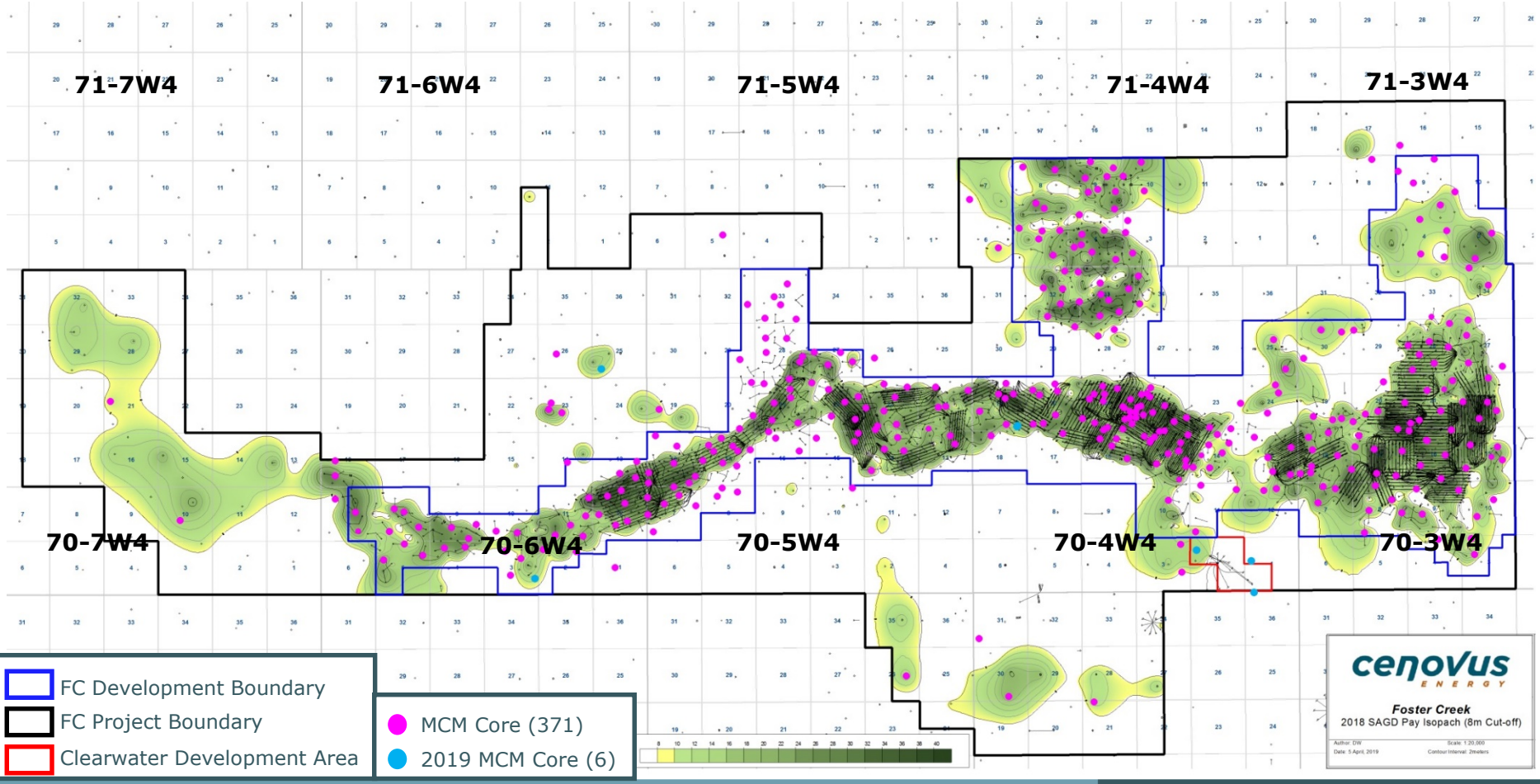
SAGD Pay Top Structure



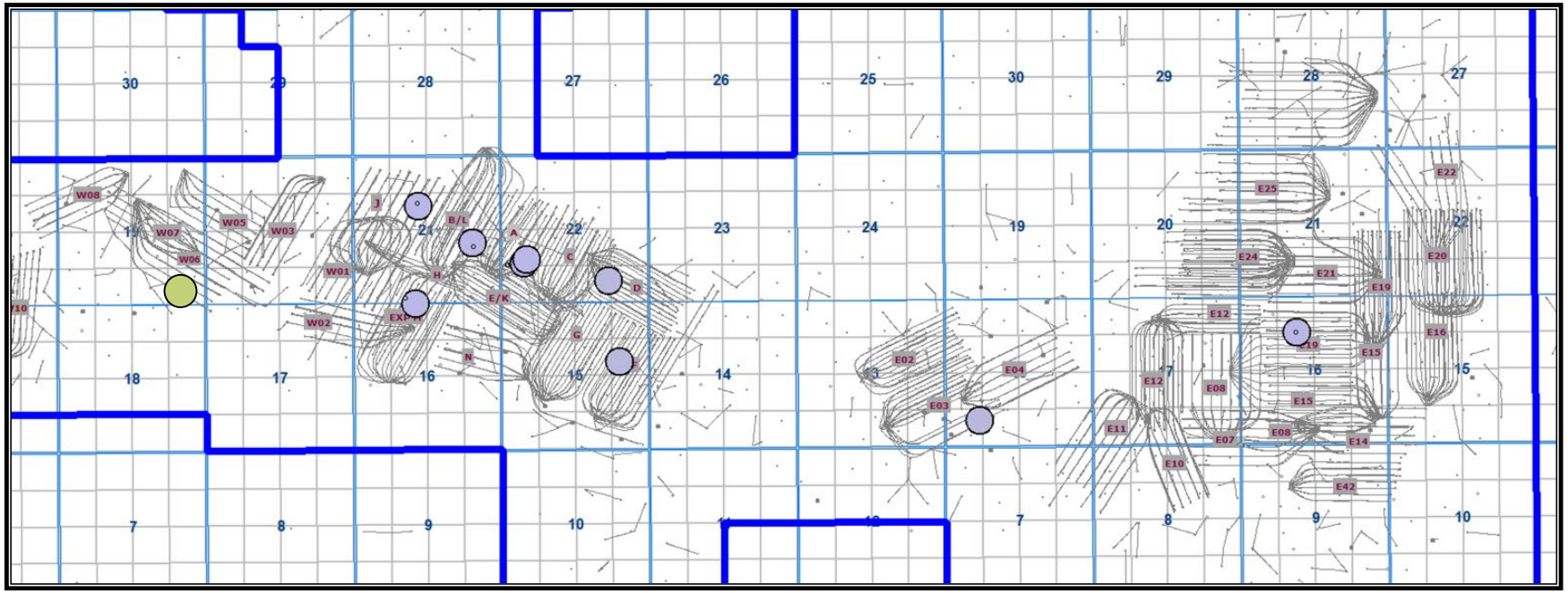
SAGD Base Structure



Cored Locations (2019)

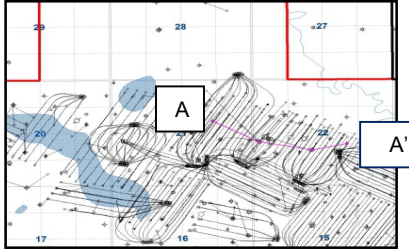


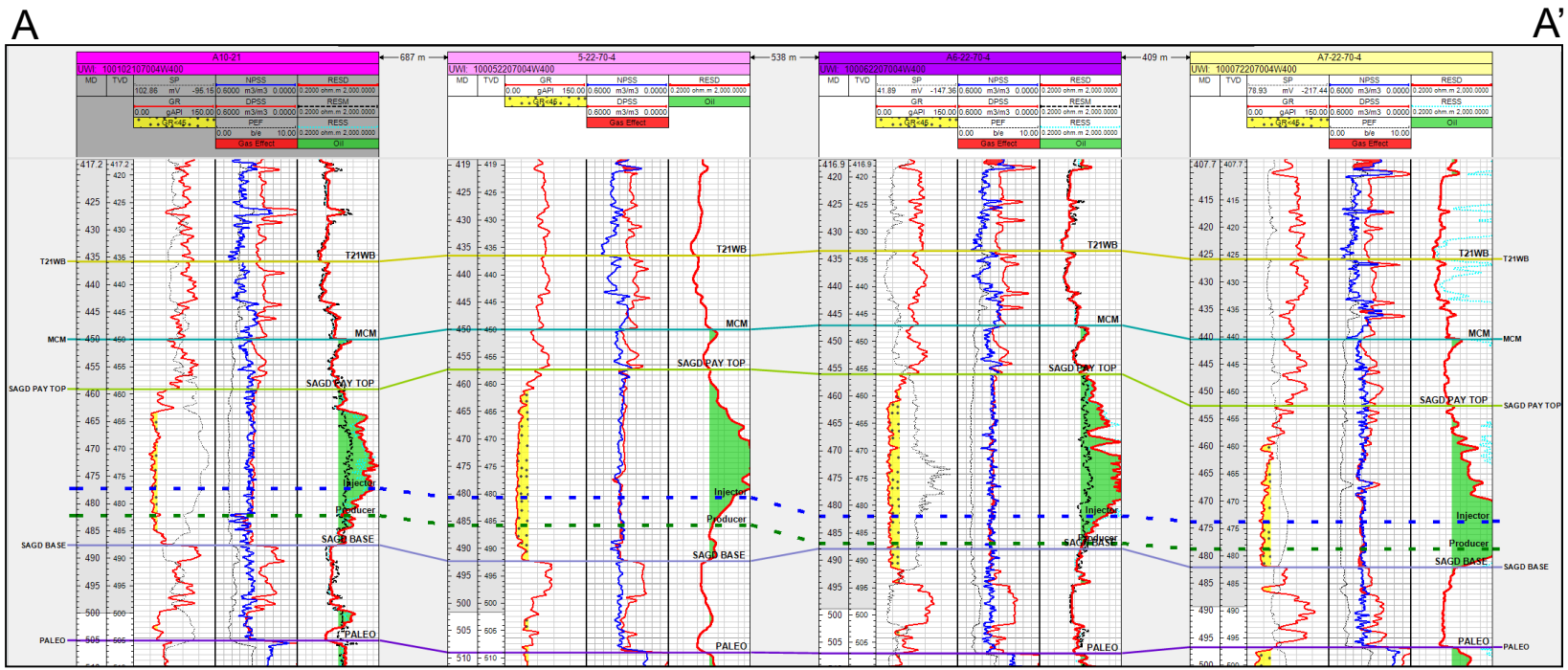
Post-steam core locations



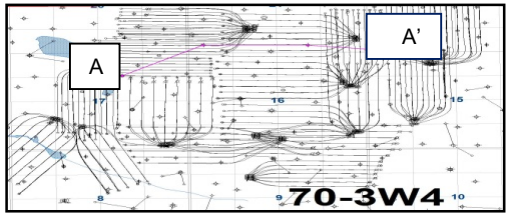
Cross Sections

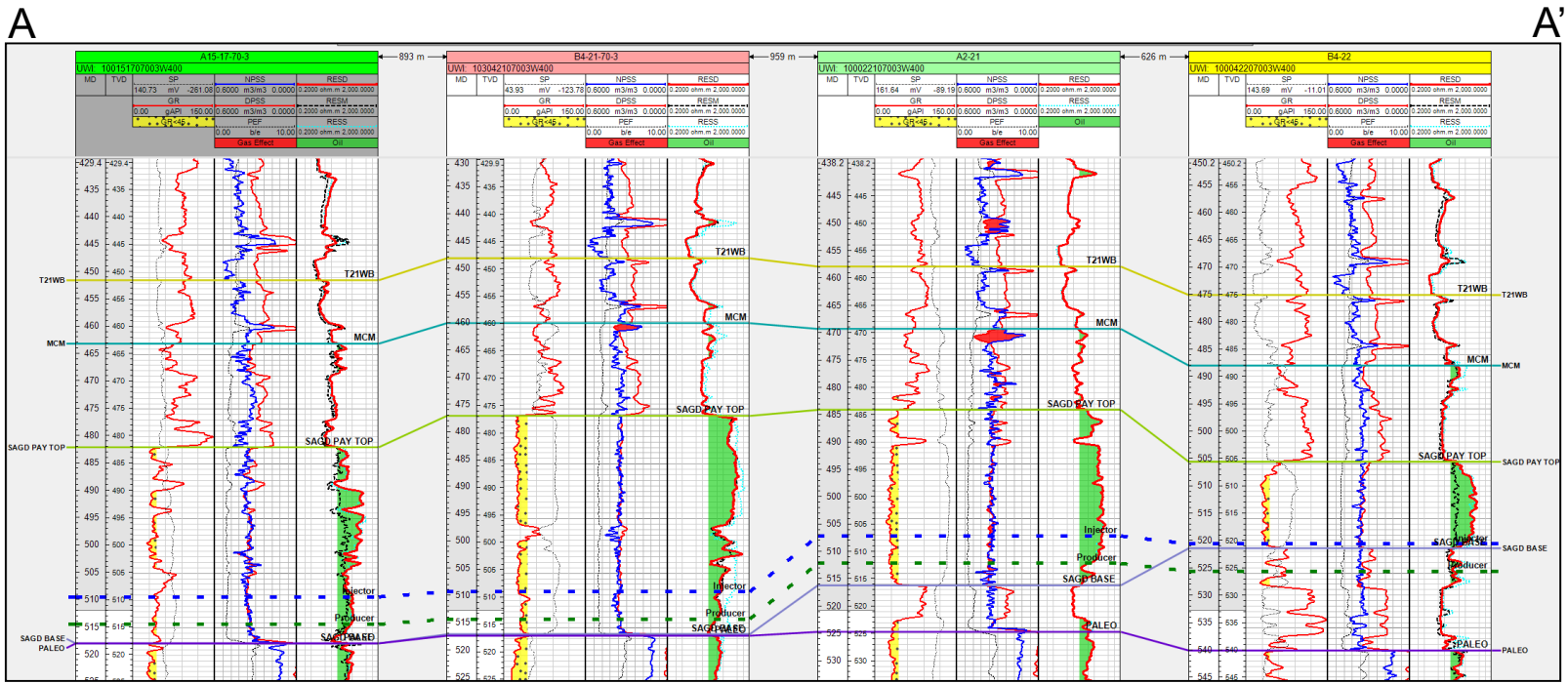
Representative structural cross-section over Central area



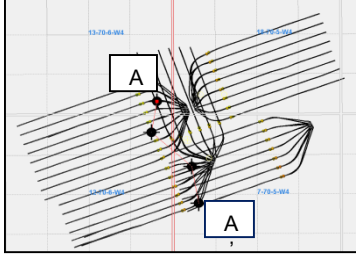


Representative structural cross-section over East area



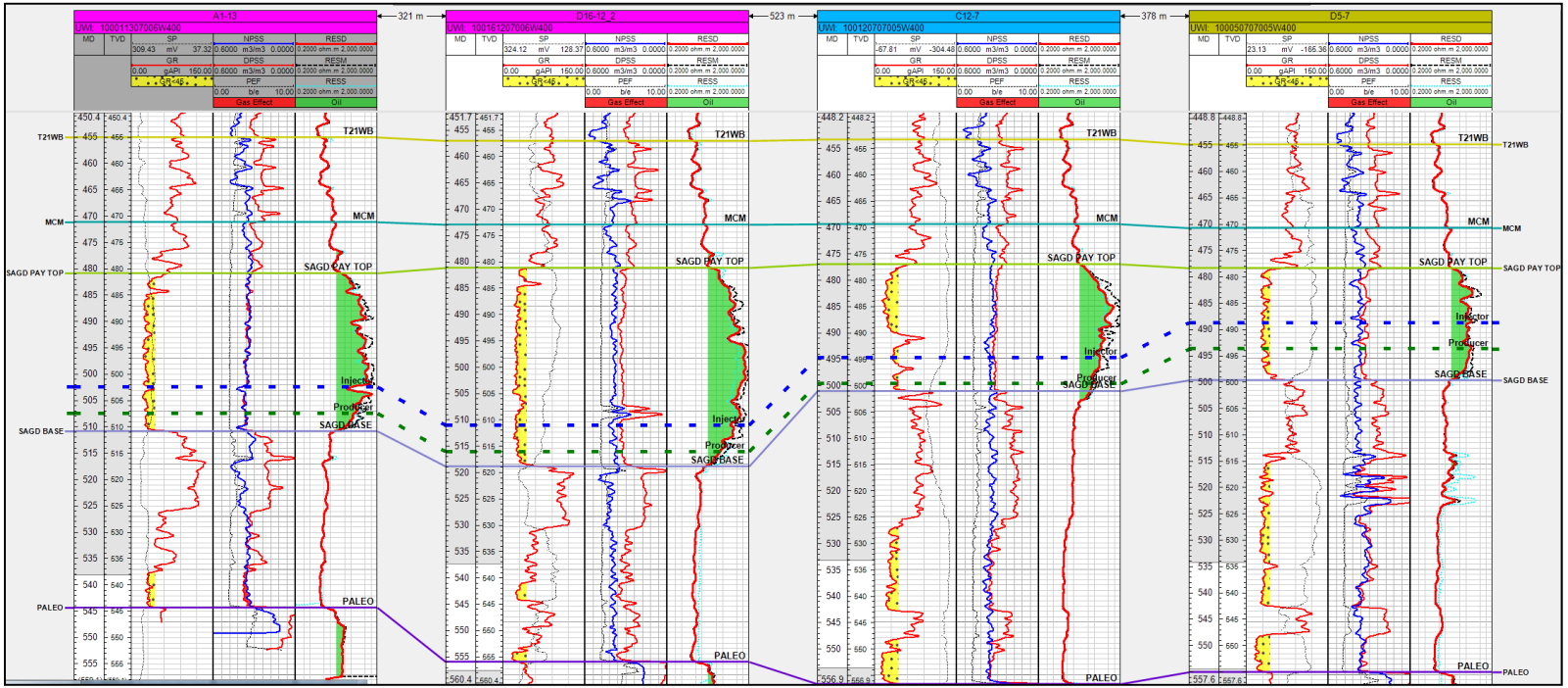


Representative structural cross-section over West area



A

A'

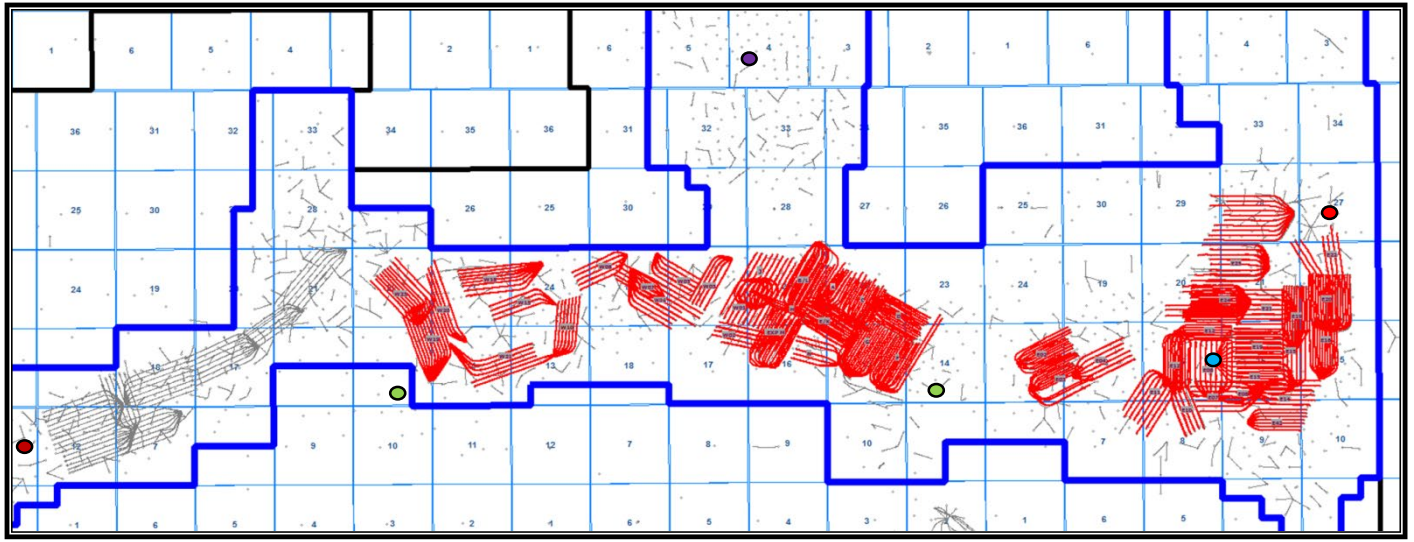


Geo-mechanical Data

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

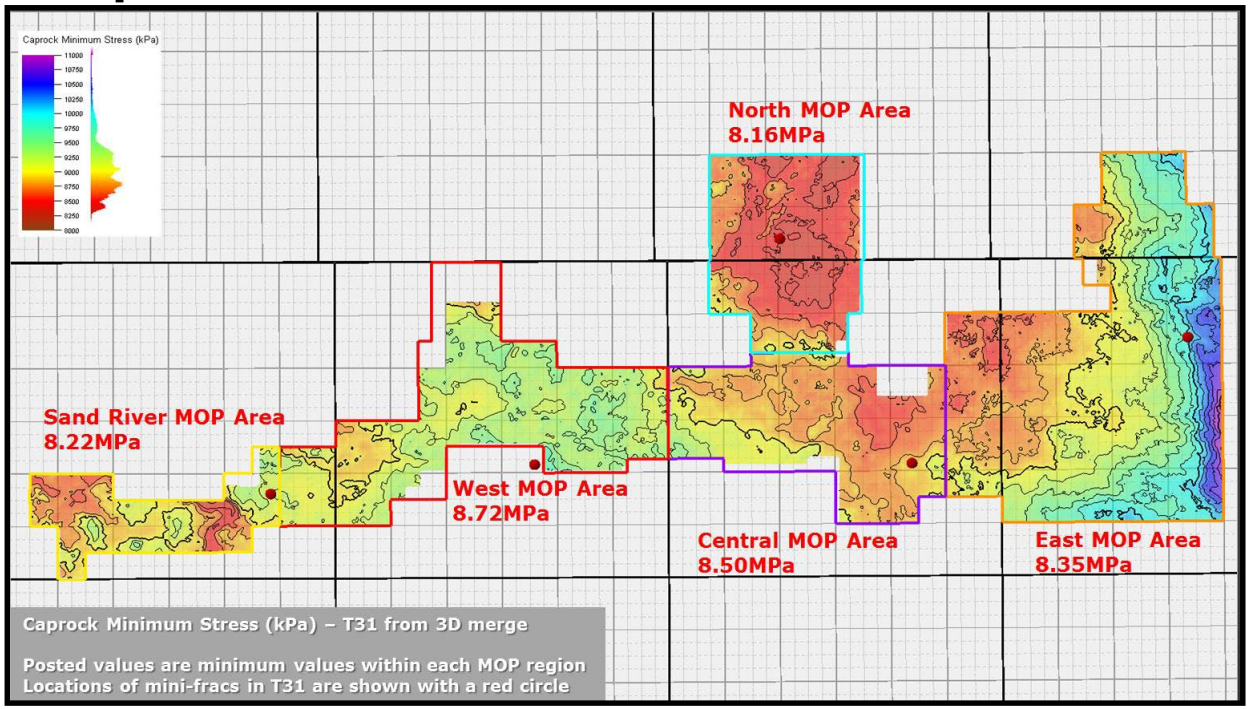
Caprock Integrity

Caprock monitoring plans

Cenovus monitors caprock integrity through:

1. SAGD injection pressure monitoring
2. Piezometer monitoring in the T31 caprock
    - Currently 8 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 development area

Current project contains five regions with different approved MOP values

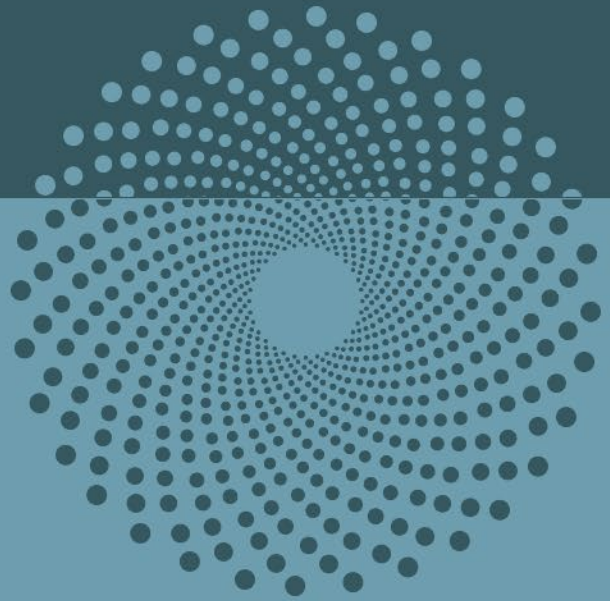
- North – 6.5 MPag
- Central – 6.8 MPag
- West – 7.0 MPag
- East – 6.7 MPag
- Sand River – 6.6 MPag

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

Subsection 3.1.1 – 3)
Drilling and Completions



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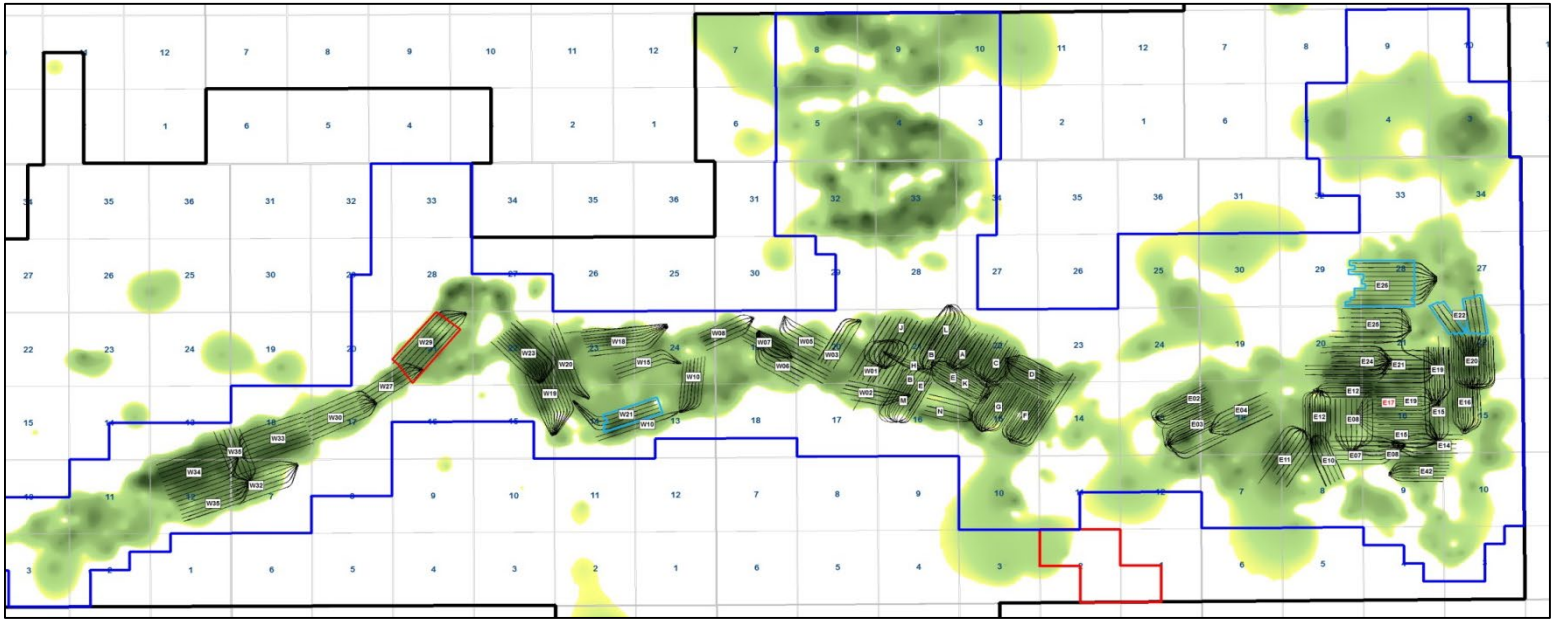
March 2018 - March 2019 new SAGD well pair drilling



Pads:

- W29
- W21,E22,E26

Mar 2018 - Mar 2019 Drilling

2018 Production

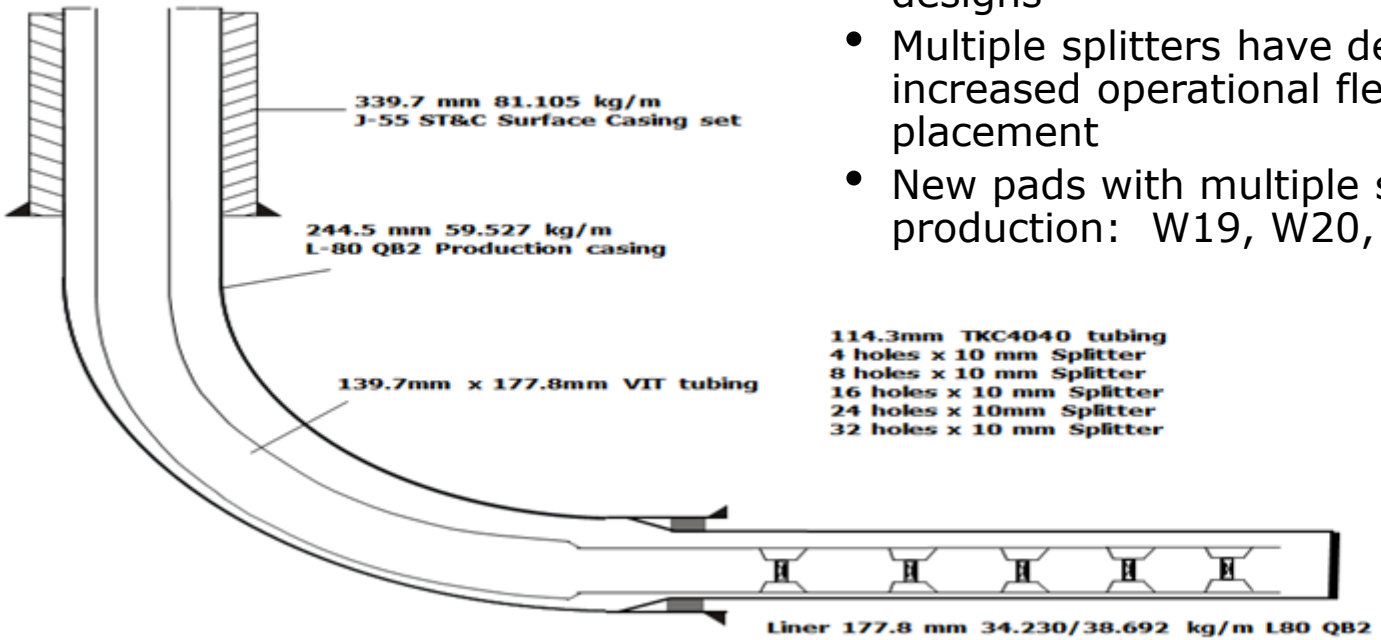
Re-drills and re-entries

List of SAGD re-drill and re-entry wells in Foster Creek since March 1, 2018

Well Name	Type	Drill Start Date	Status
W01P07-1	Producer	27-Apr-18	Drilled
W20P02-1	Producer	2-May-18	Drilled
W10P01	Producer	8-May-18	Drilled
CP14-2	Producer	22-May-18	Drilled
CP39	Producer	28-May-18	Drilled
NP01-1	Producer	10-Jun-18	Drilled
NP07	Producer	15-Jun-18	Drilled
NI07	Injector	20-Jun-18	Drilled
W03P02-1	Producer	25-Jun-18	Drilled
MP02-1	Producer	30-Jun-18	Drilled
E03P06-1	Producer	5-Jul-18	Drilled
W10P09	Producer	10-Jul-18	Drilled
W15P02-1	Producer	7-Sep-18	Drilled
W15P01-1	Producer	12-Sep-18	Drilled
E07P01-1	Producer	17-Sep-18	Drilled
E07P04-1	Producer	22-Sep-18	Drilled
E25P07-1	Producer	27-Sep-18	Drilled
E26P04	Producer	2-Oct-18	Drilled
E26P02	Producer	8-Oct-18	Drilled
E21P02-1	Producer	15-Oct-18	Drilled
W23P01	Producer	20-Oct-18	Drilled
E22P05	Producer	8-Mar-19	Drilled
JP03	Producer	14-Mar-19	Drilled
W18I06-1	Injector	20-Mar-19	Drilled
W06P04-1	Producer	27-Mar-19	Drilled

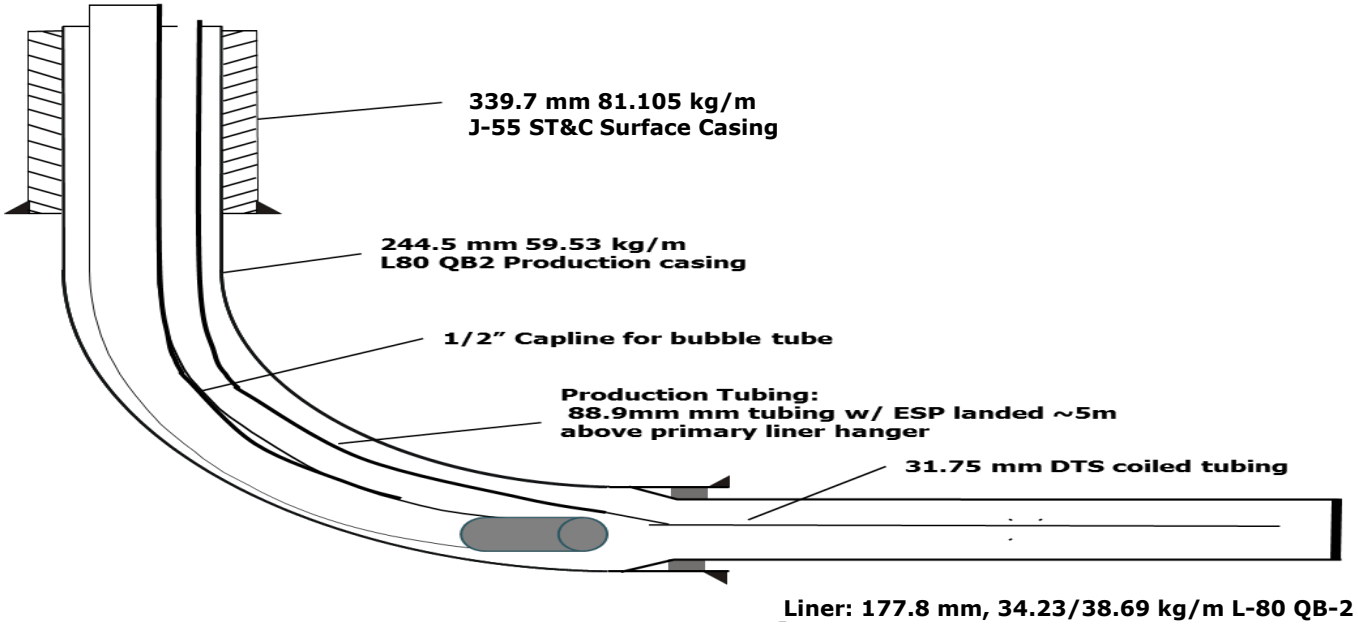
- Wells are re-drilled if loss of sand control occurs or for redevelopment opportunities

Standard injector completion

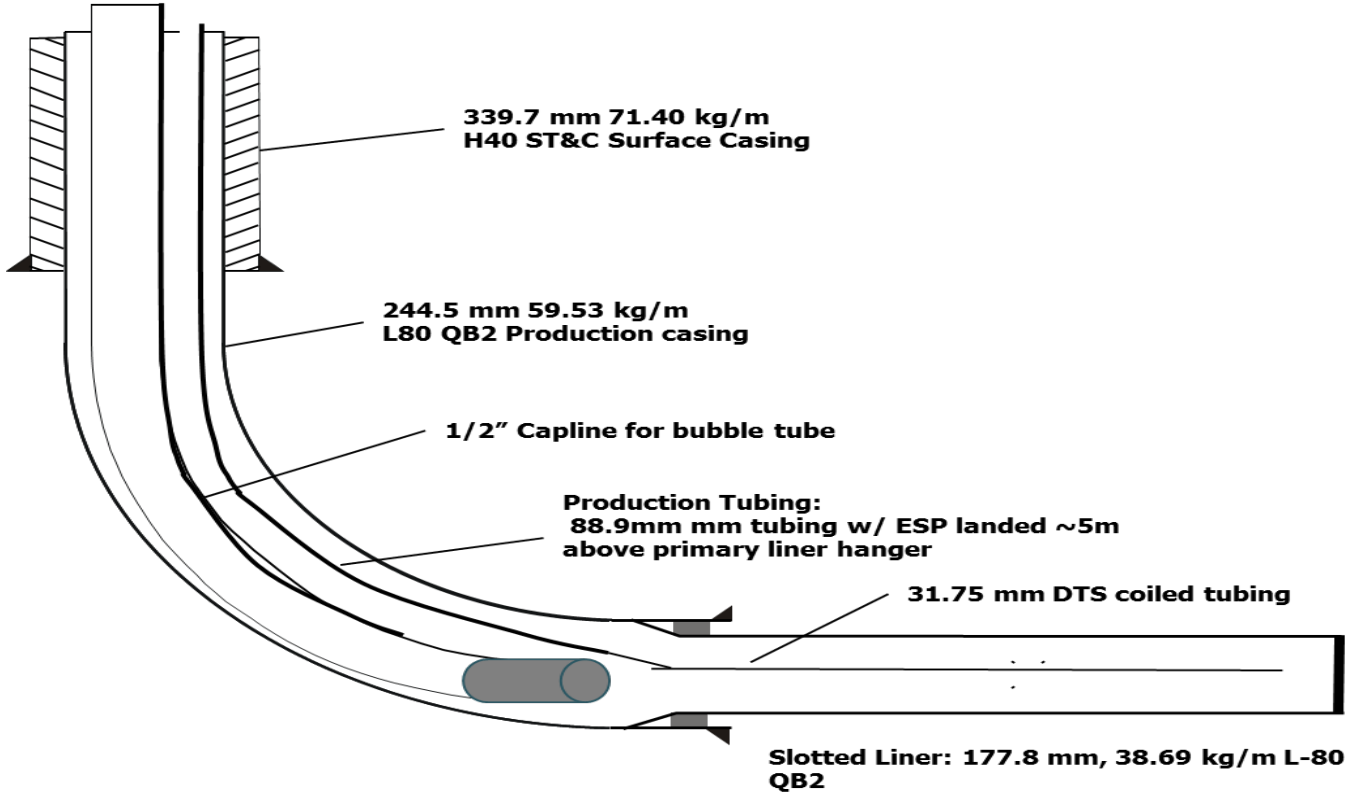


- Majority of well pairs at Foster Creek have been started up with single splitter injector designs
- Multiple splitters have demonstrated increased operational flexibility with steam placement
- New pads with multiple splitter designs on production: W19, W20, W10ext, E22, E26

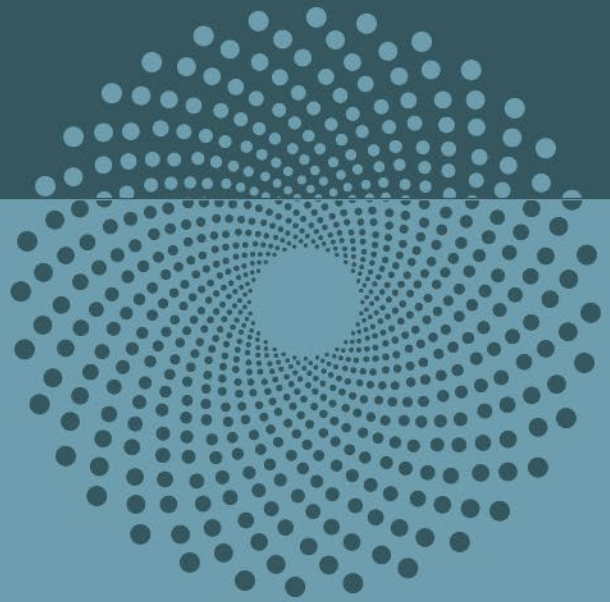
Standard producer Electric Submersible Pump (ESP) completion



Standard Wedge Well™ technology completion



Subsection 3.1.1 – 4) Artificial Lift



Artificial lift

Electric submersible pumps (ESPs)

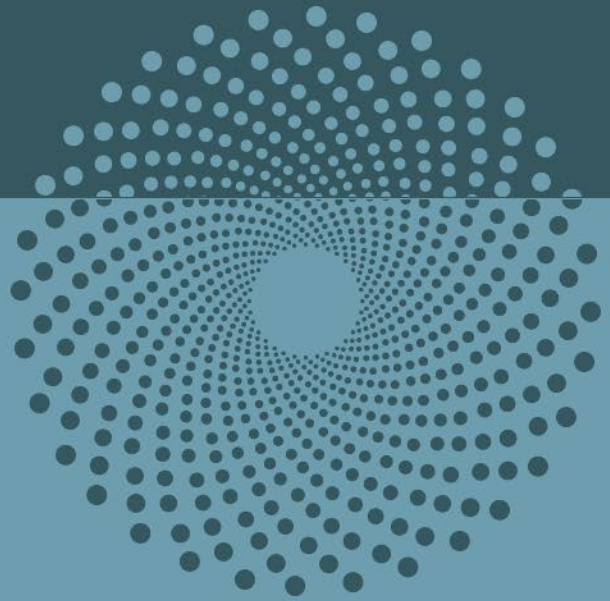
- all operating SAGD pairs (~245 producers) are currently equipped with ESPs
- Continue to work with vendors to increase runtime

Rod pumps

- Historically utilized with Wedge Well™ technology
- 20/62 operating wells utilizing Wedge Well™ technology are equipped with rod pumps

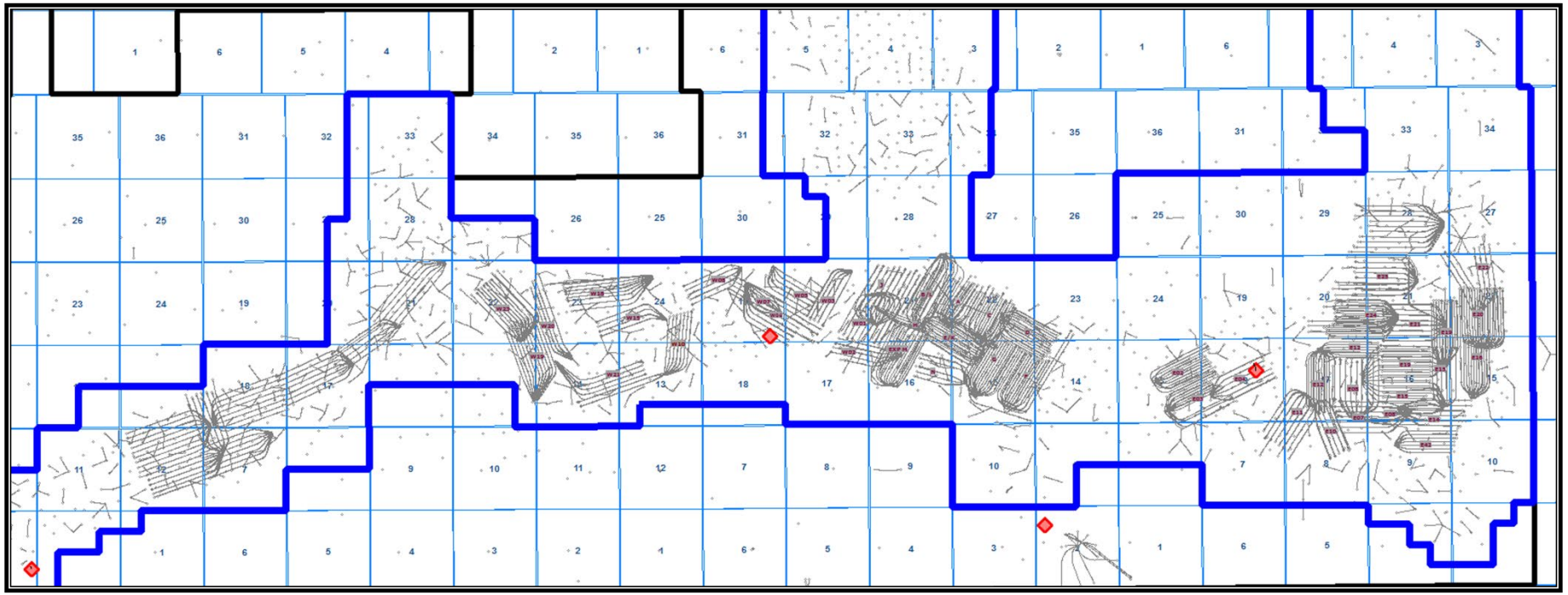
	ESPs	**Rod pumps**
Turn down (m^3/d)	72	0
Max. rate (m^3/d)	1500	350
Max. operating temp (°C)	250	200+
Number of pumps	287	20
Average run life (months)	14.2	12.0

Subsection 3.1.1 – 5) Instrumentation



cenovus ENERGY

2019 Piezometer Locations



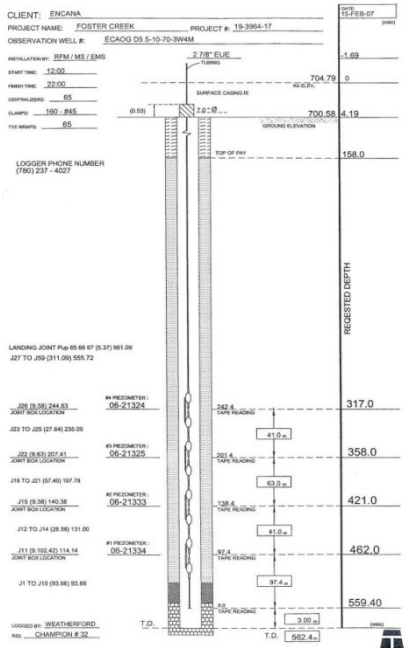
2019 new piezometers (4)

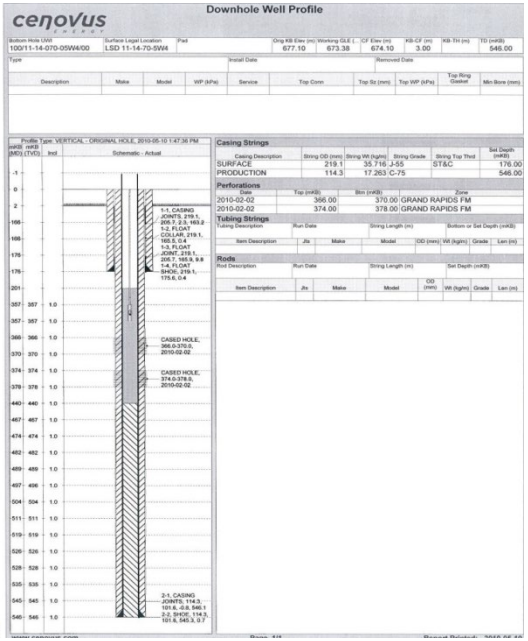
Piezometer details

Three installation types:

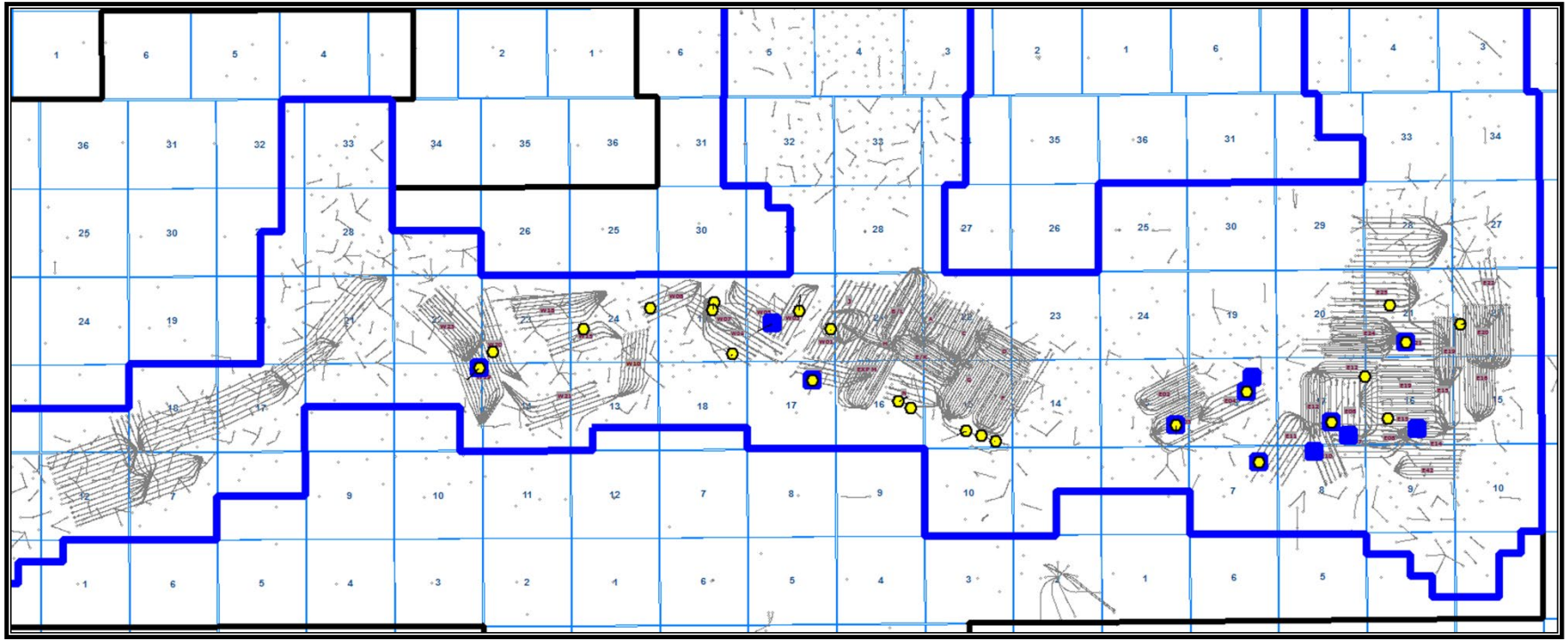
1) Cemented tubing - vibrating wire piezometers mounted on tubulars and cemented in place (14 wells)
2) Hanging wire – pressure / temperature gauges hung from the wellhead to about 10-15m above perforations (10 wells)
3) Cemented casing – High temperature Optical pressure sensors strapped and cemented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

- Four new piezometer wells completed in past year





Foster Creek 2019 Temperature and RST Data



2019 RST (24)
2019 DTS (12)

Instrumentation in SAGD wells

SAGD steam injector

- blanket gas for pressure measurement

SAGD producer

- ½” capline strapped to tubing for bubble tubes
- distributed temperature sensing (DTS) strings installed in majority of new wells

SAGD using our patented Wedge Well™ technology

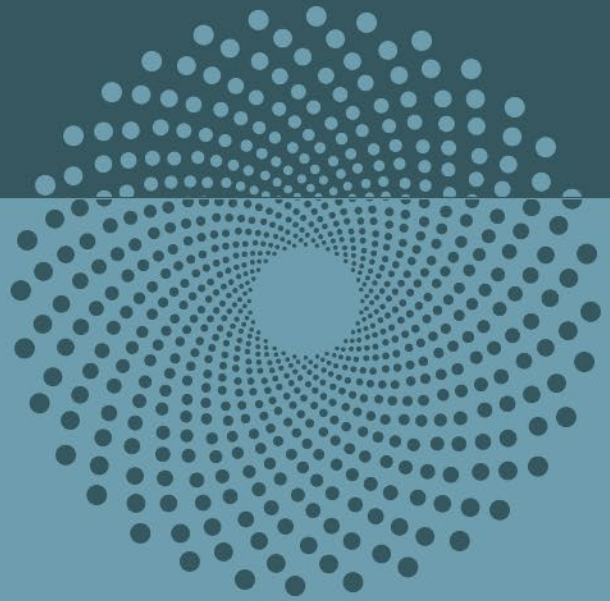
- no downhole instrumentation with rod pumps
- new wells with ESPs to be equipped with ½” capline strapped to production tubing string to measure pressure

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

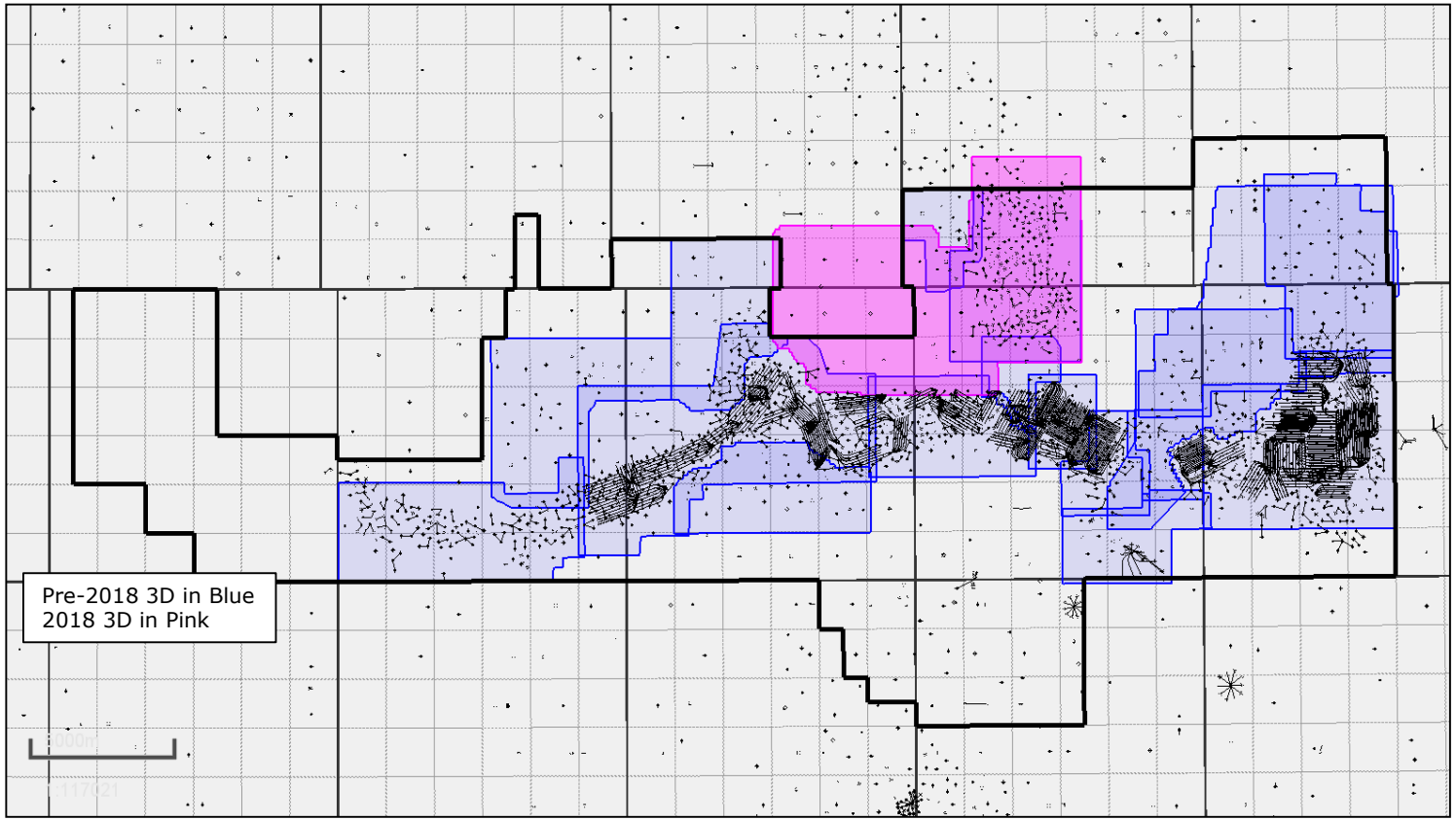
Subsection 3.1.1 – 5 c) and d) – instrumentation data

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

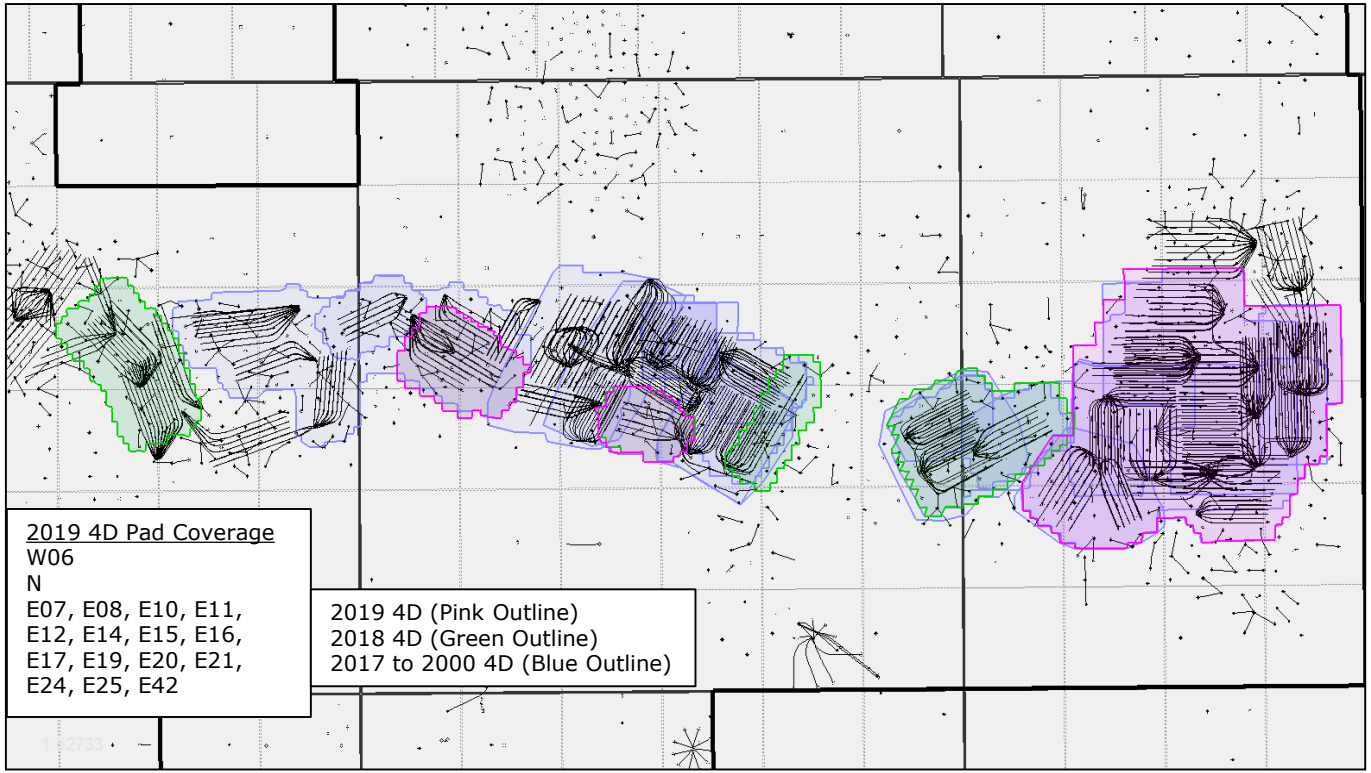
Subsection 3.1.1 – 6) Seismic

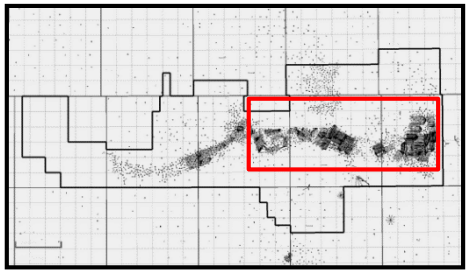


3D seismic within Project Area

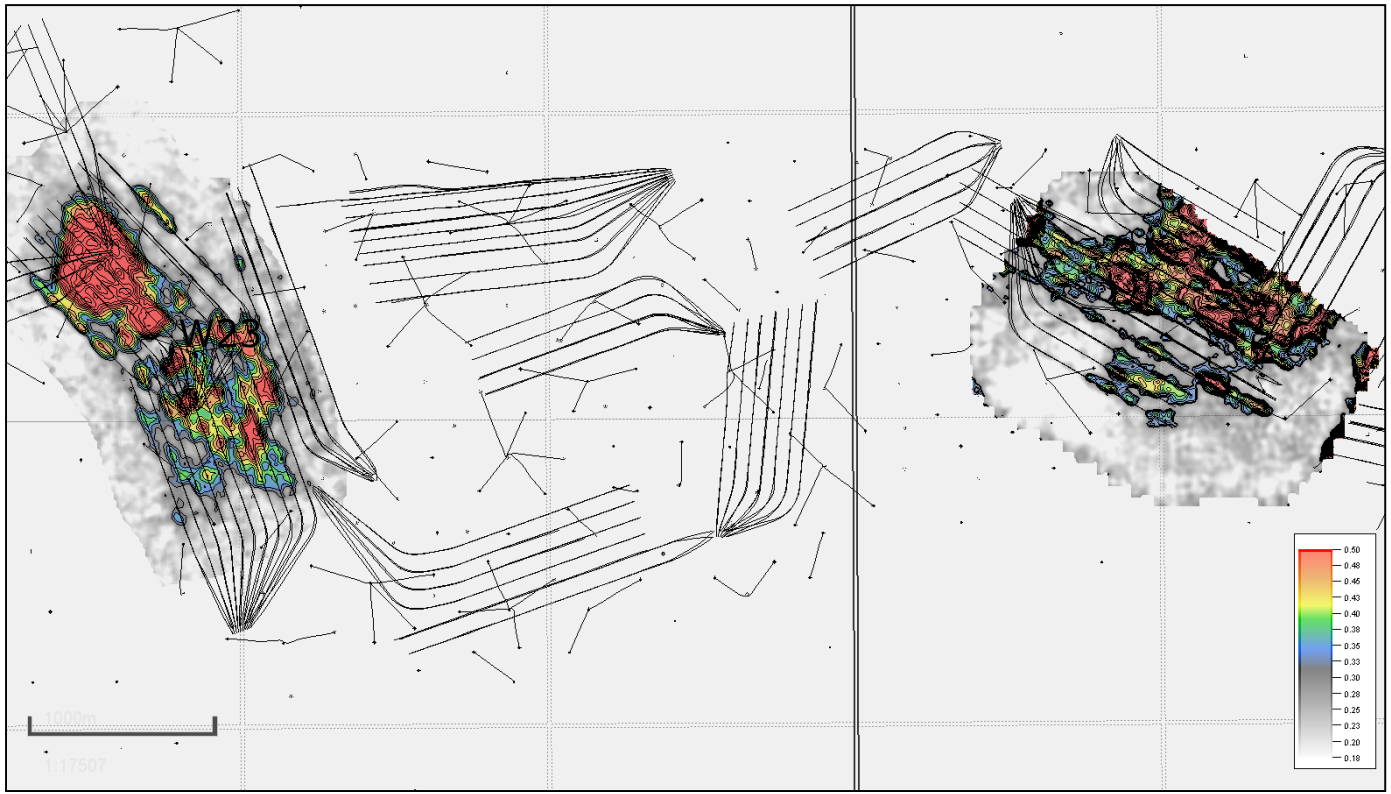


4D seismic within Project Area





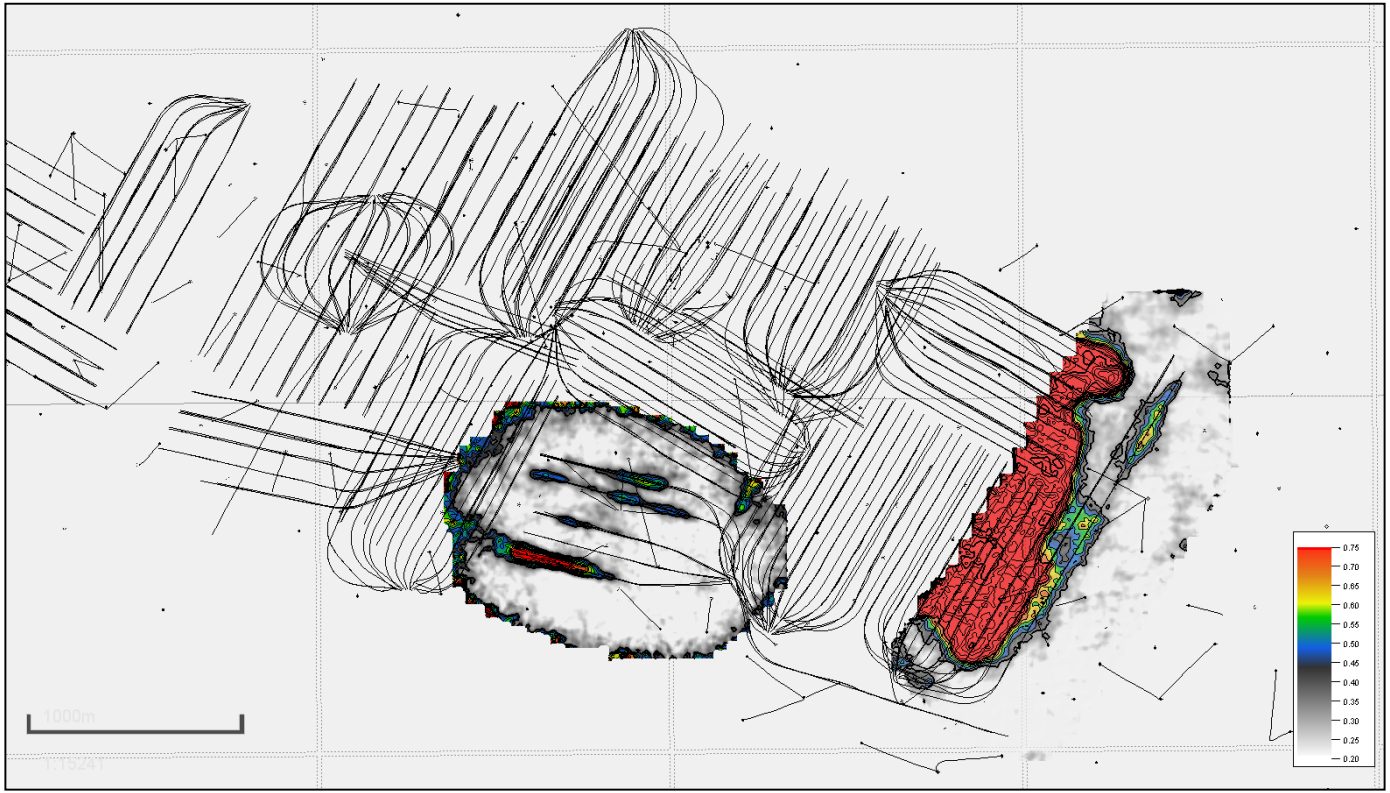
W06, W19/W23 2018 NRMS



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

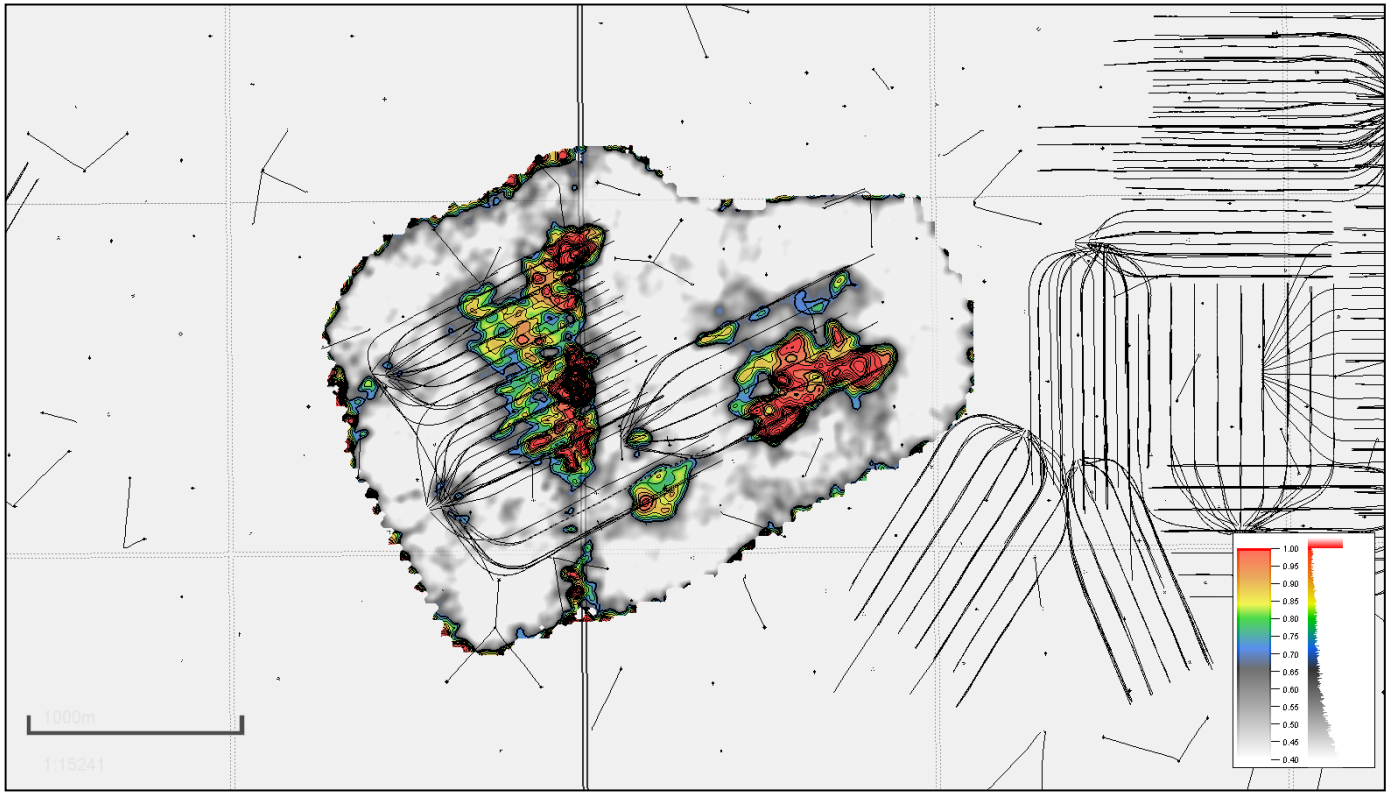
F Pad, N Pad 2018 NRMS

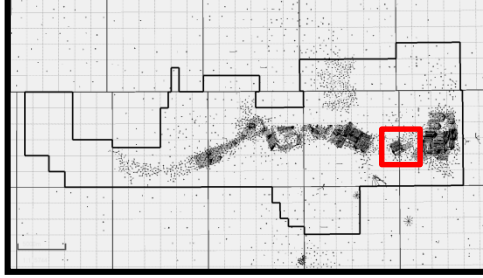


4D NRMS

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

E02, E03 and E04 2018 NRMS

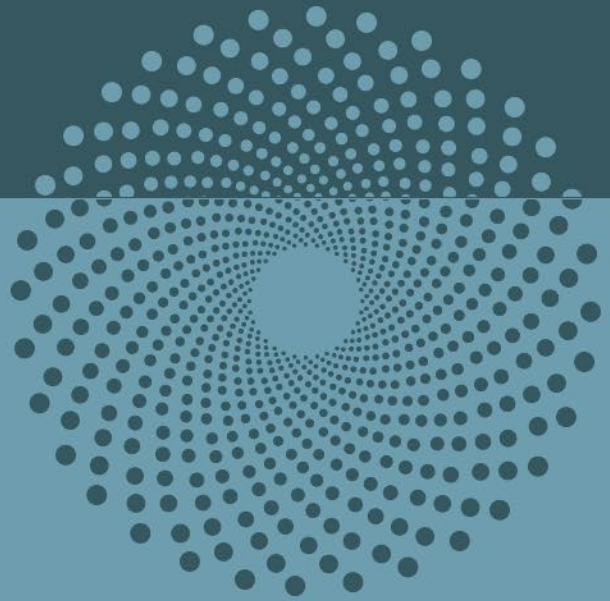




4D NRMS

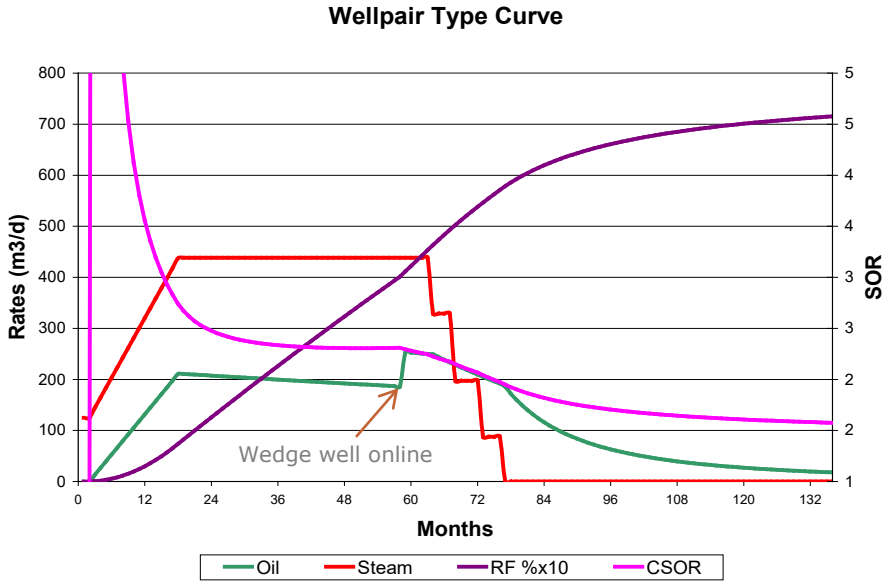
Normalized Root Mean Square is a measure of repeatability between the baseline and monitor surveys. Higher values indicate less repeatability and heated reservoir

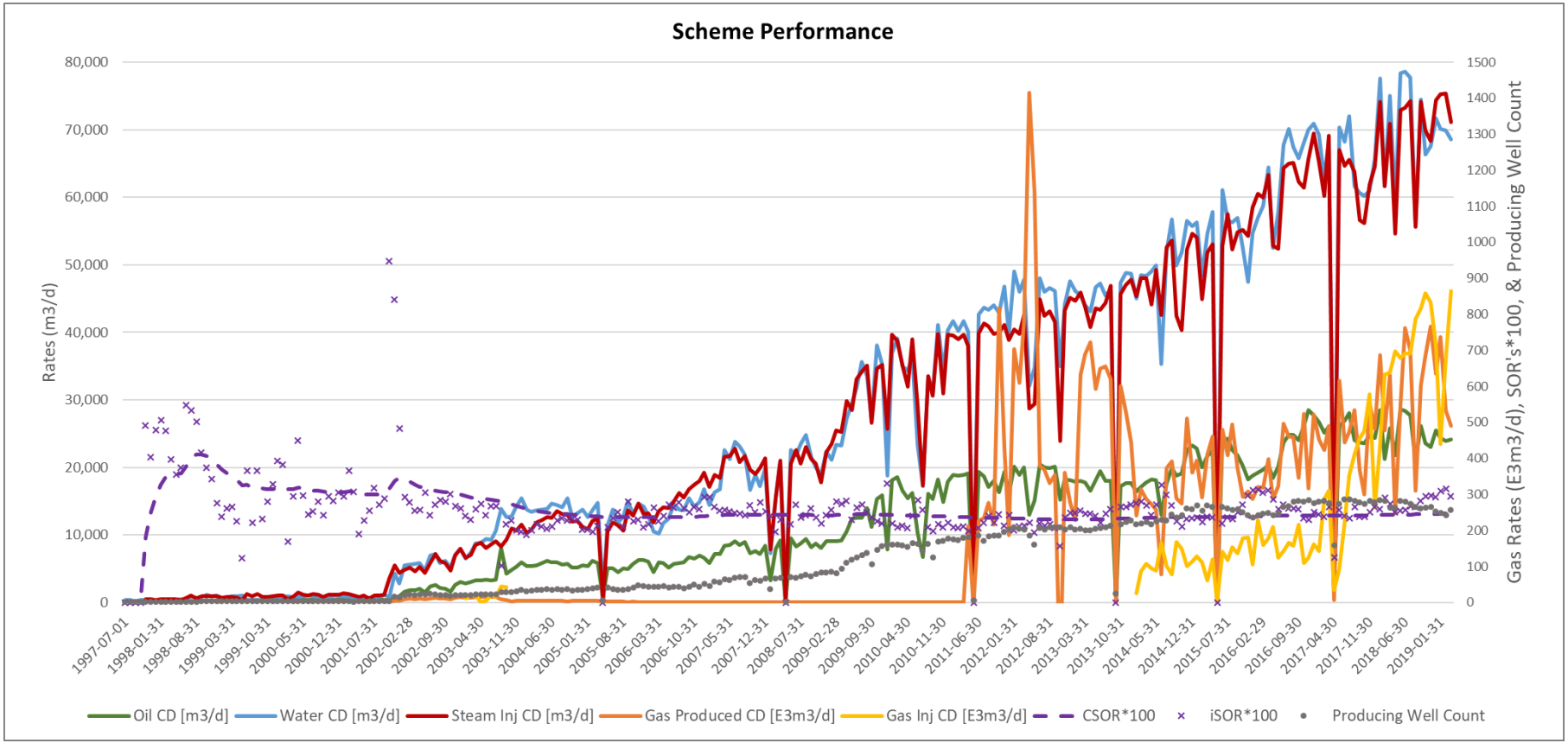
Subsection 3.1.1 – 7) Scheme performance

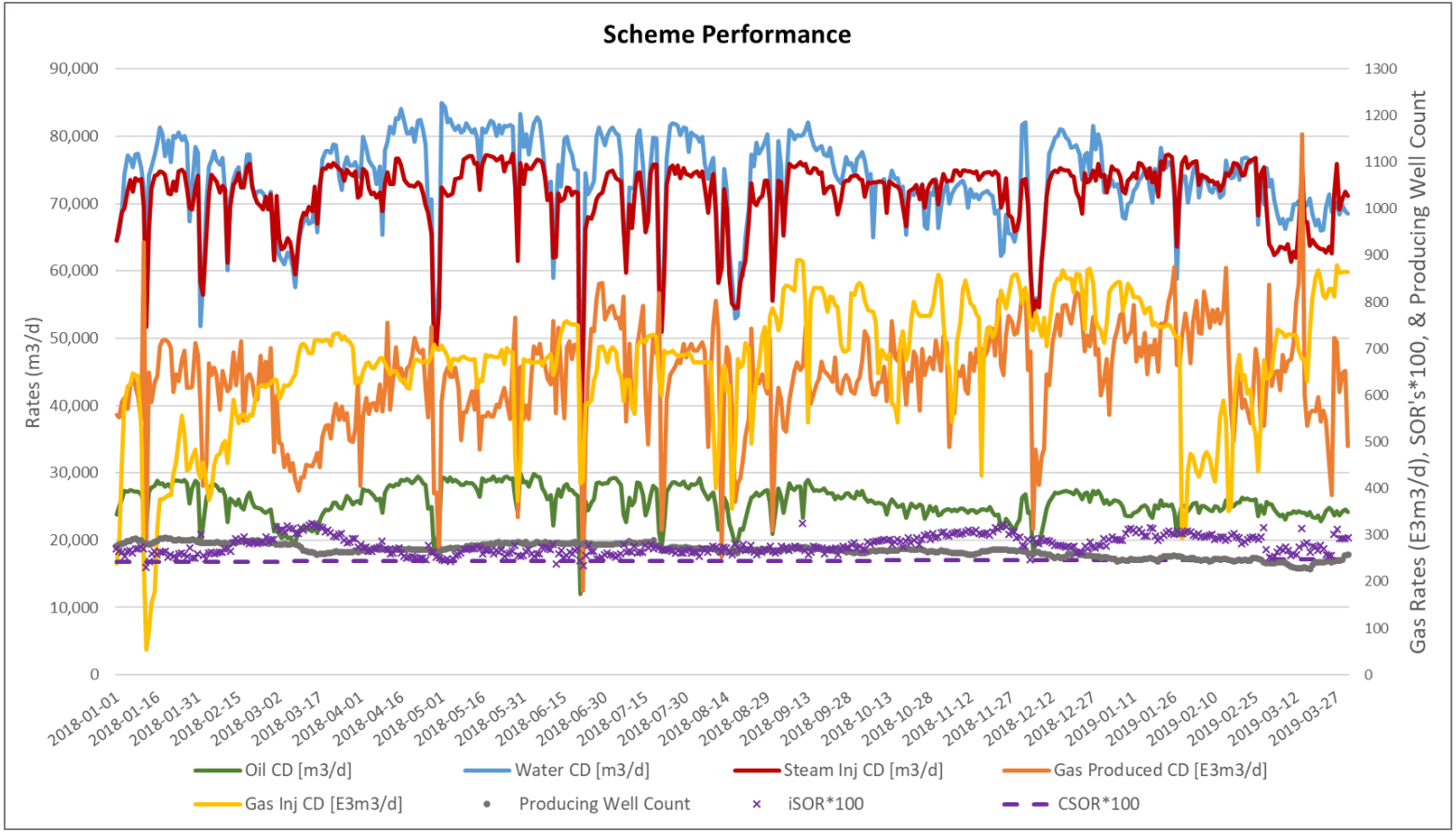


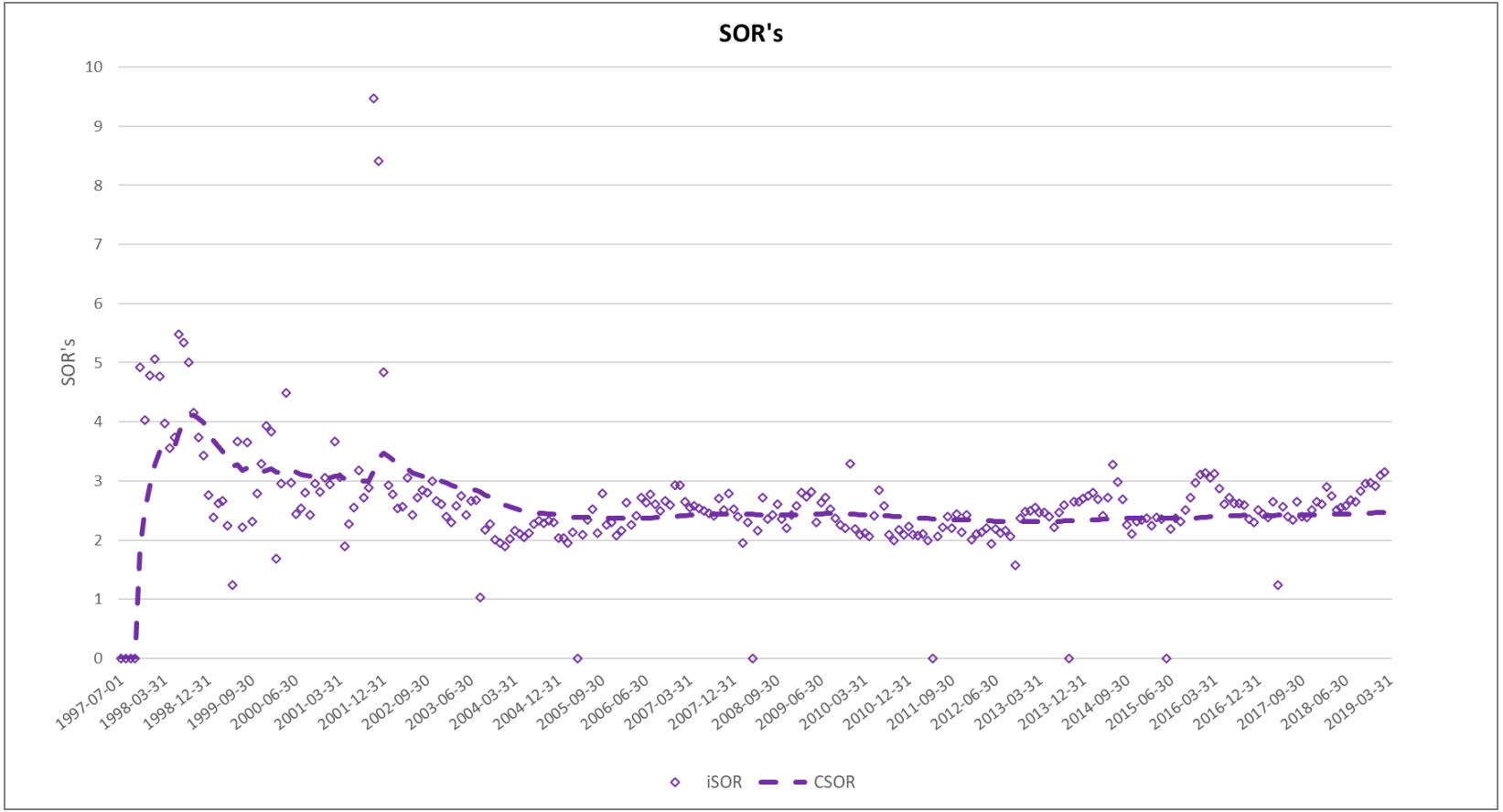
Scheme performance prediction

- 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









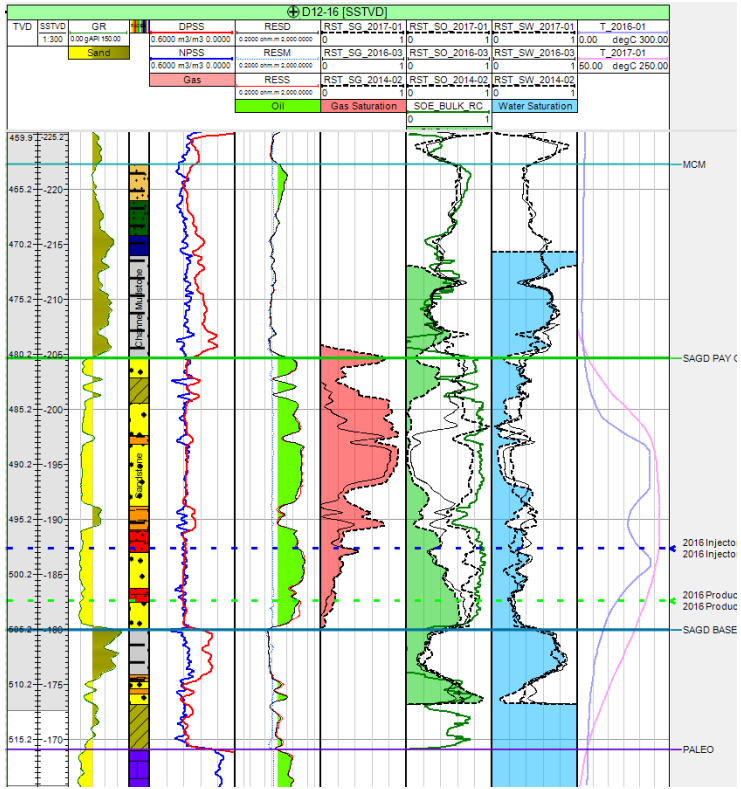
Methods for monitoring chamber development

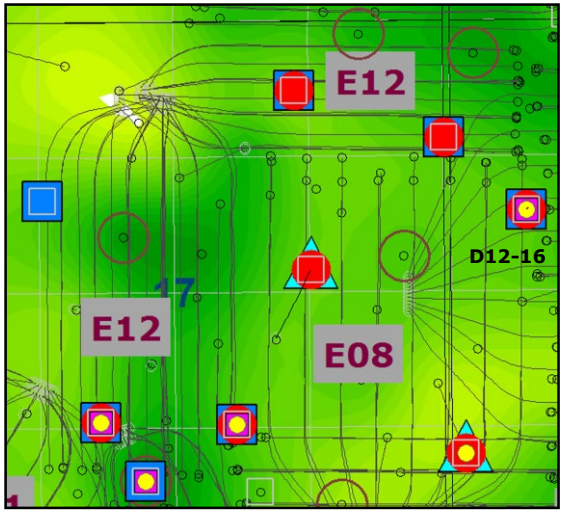
Cenovus uses the following methods for monitoring chamber development:

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

Foster Creek temperature wells

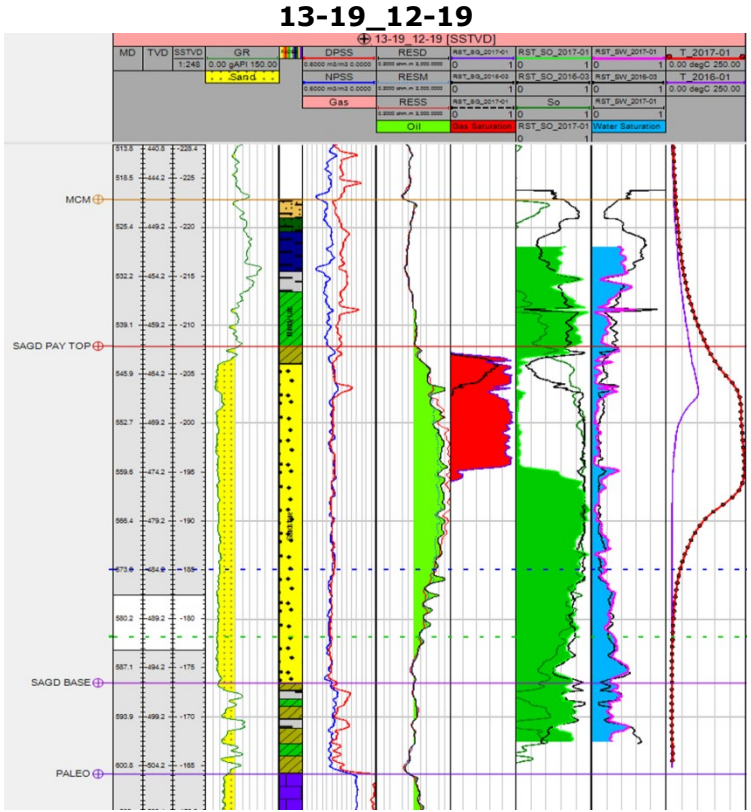
D12-16

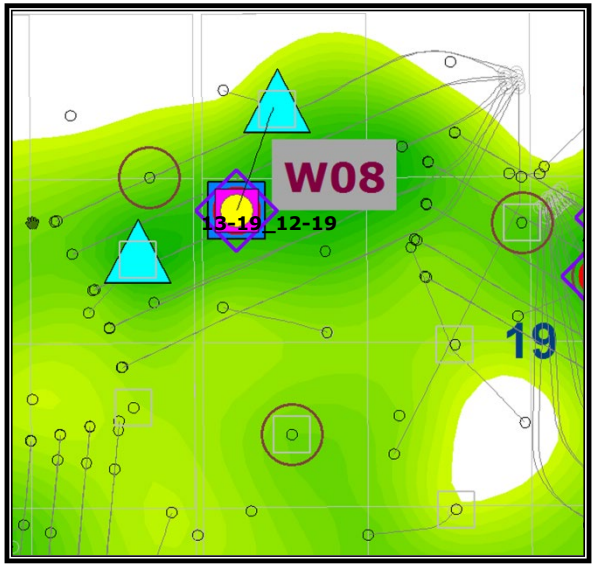




21m offset E08P03

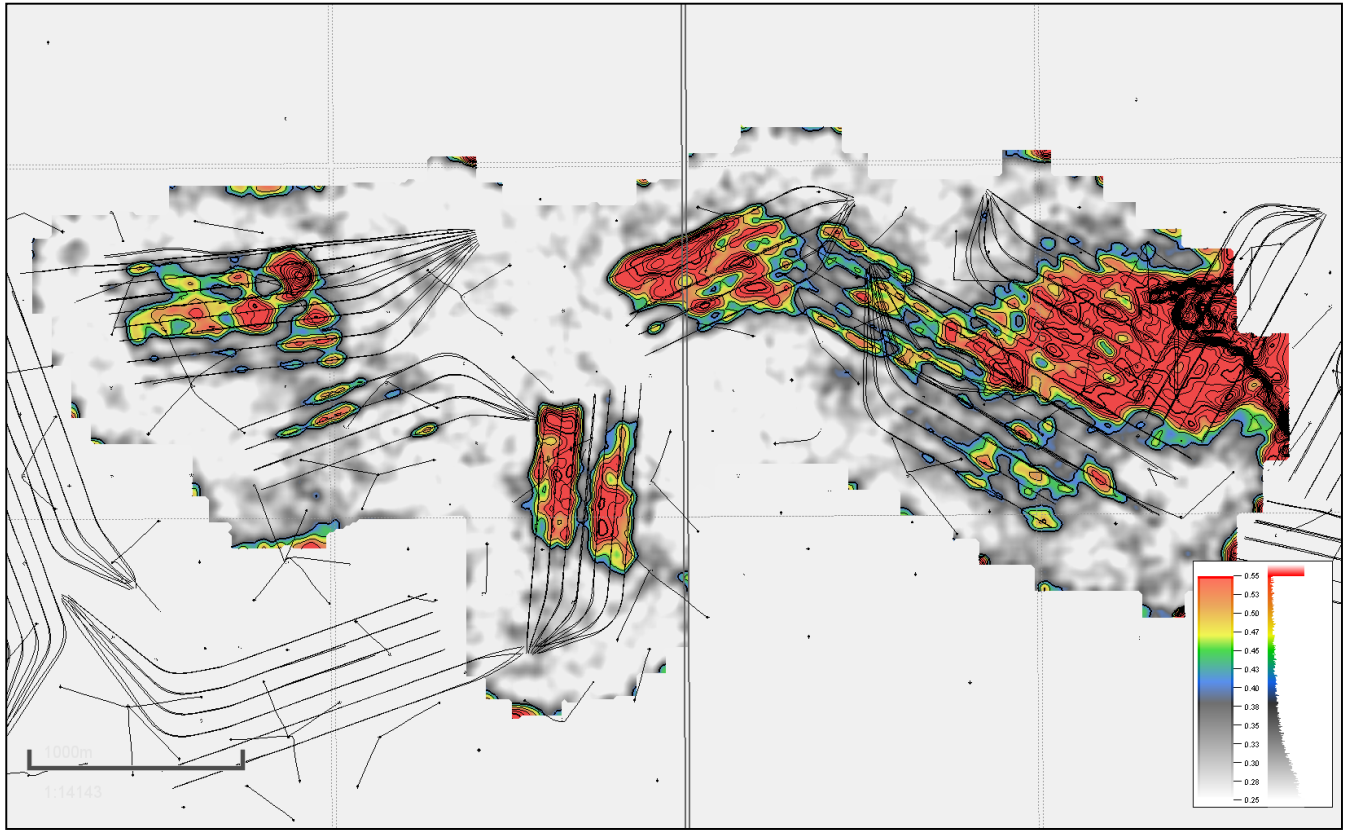
Foster Creek temperature wells

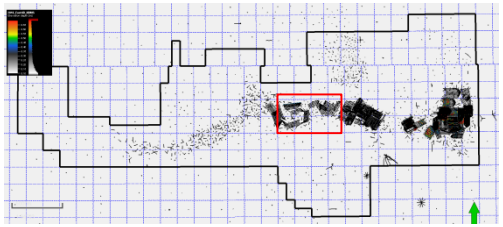




44m offset W08P03 well pair

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

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

Central Pad	Area (m2)	Height (m)	Porosity (%)	So (%)	SOIP (Mm3)	Cum Oil (Mm3) to Mar 31, 2019	Recovery % SOIP	Expected Ultimate Recovery (Mm3)	Ultimate Recovery as % of SOIP
A PAD	524,980	27	34%	82%	4,013	3,630	90.5%	3,643	91%
B_L PAD	569,545	25	34%	78%	3,791	2,685	70.8%	2,739	72%
C PAD	541,344	29	35%	82%	4,534	4,469	98.6%	4,534	100%
D PAD	676,265	27	32%	80%	4,641	4,535	97.7%	4,553	98%
E_K PAD	576,442	24	34%	79%	3,611	3,055	84.6%	3,080	85%
EXP_M PAD	656,745	24	34%	81%	4,304	2,568	59.7%	2,607	61%
F PAD	817,054	25	33%	78%	5,645	3,593	63.6%	3,875	69%
G PAD	619,867	23	33%	80%	4,063	2,927	72.0%	3,132	77%
H PAD	121,557	20	35%	71%	608	188	30.9%	284	47%
J PAD	722,666	24	32%	75%	3,848	1,774	46.1%	1,996	52%
N PAD	322,899	18	34%	81%	1,501	190	12.7%	663	44%
W01 PAD	673,003	23	33%	79%	4,089	2,154	52.7%	2,478	61%
W02 PAD	376,851	19	32%	83%	2,009	632	31.5%	816	41%
Total Central	**7,199,218**				**46,659**	**32,401**	**69.4%**	**34,400**	**74%**
Total FC	**26,925,076**				**172,663**	**87,566**	**50.7%**	**116,192**	**67%**

To Mar 31, 2019

SOIP and percent recovery - East

East Pad	Area (m2)	Height (m)	Porosity (%)	So (%)	SOIP (Mm3)	Cum Oil (Mm3) to Mar 31, 2019	Recovery % SOIP	Expected Ultimate Recovery (Mm3)	Ultimate Recovery as % of SOIP
E02 PAD	400,710	27	33%	75%	2,623	1,639	62.5%	1,940	74%
E03 PAD	400,335	27	33%	77%	2,717	1,580	58.2%	2,099	77%
E04 PAD	522,570	22	34%	79%	3,014	1,144	38.0%	1,850	61%
E07 PAD	532,122	18	27%	72%	1,863	244	13.1%	388	21%
E08 PAD	811,692	23	32%	77%	4,548	1,473	32.4%	2,700	59%
E10 PAD	417,700	22	31%	73%	2,060	908	44.1%	1,063	52%
E11 PAD	706,325	29	33%	74%	5,040	3,195	63.4%	3,460	69%
E12 PAD	878,701	33	34%	79%	7,988	5,245	65.7%	5,516	69%
E14 PAD	436,503	21	33%	80%	2,418	971	40.2%	1,504	62%
E15 PAD	1,082,645	25	33%	81%	7,216	4,070	56.4%	4,649	64%
E16 PAD	536,177	24	35%	79%	3,580	2,758	77.0%	2,951	82%
E19 PAD	1,133,757	26	34%	79%	7,877	5,450	69.2%	5,961	76%
E20 PAD	779,565	26	34%	83%	6,099	4,525	74.2%	4,987	82%
E21 PAD	792,643	20	32%	79%	4,602	2,052	44.6%	2,357	51%
E22 PAD	554,124	19	34%	83%	3,033	180	5.9%	2,068	68%
E24 PAD	921,513	26	35%	85%	6,959	4,299	61.8%	4,798	69%
E25 PAD	865,015	23	33%	82%	5,322	2,619	49.2%	3,126	59%
E26 PAD	1,197,131	19	33%	80%	5,886	493	8.4%	4,114	70%
E42 PAD	353,299	17	32%	78%	1,487	778	52.3%	982	66%
Total East	**13,322,527**				**84,331**	**43,623**	**51.7%**	**56,513**	**67%**
Total FC	**26,925,076**				**172,663**	**87,566**	**50.7%**	**116,192**	**67%**

To March 31, 2019

SOIP and percent recovery – West

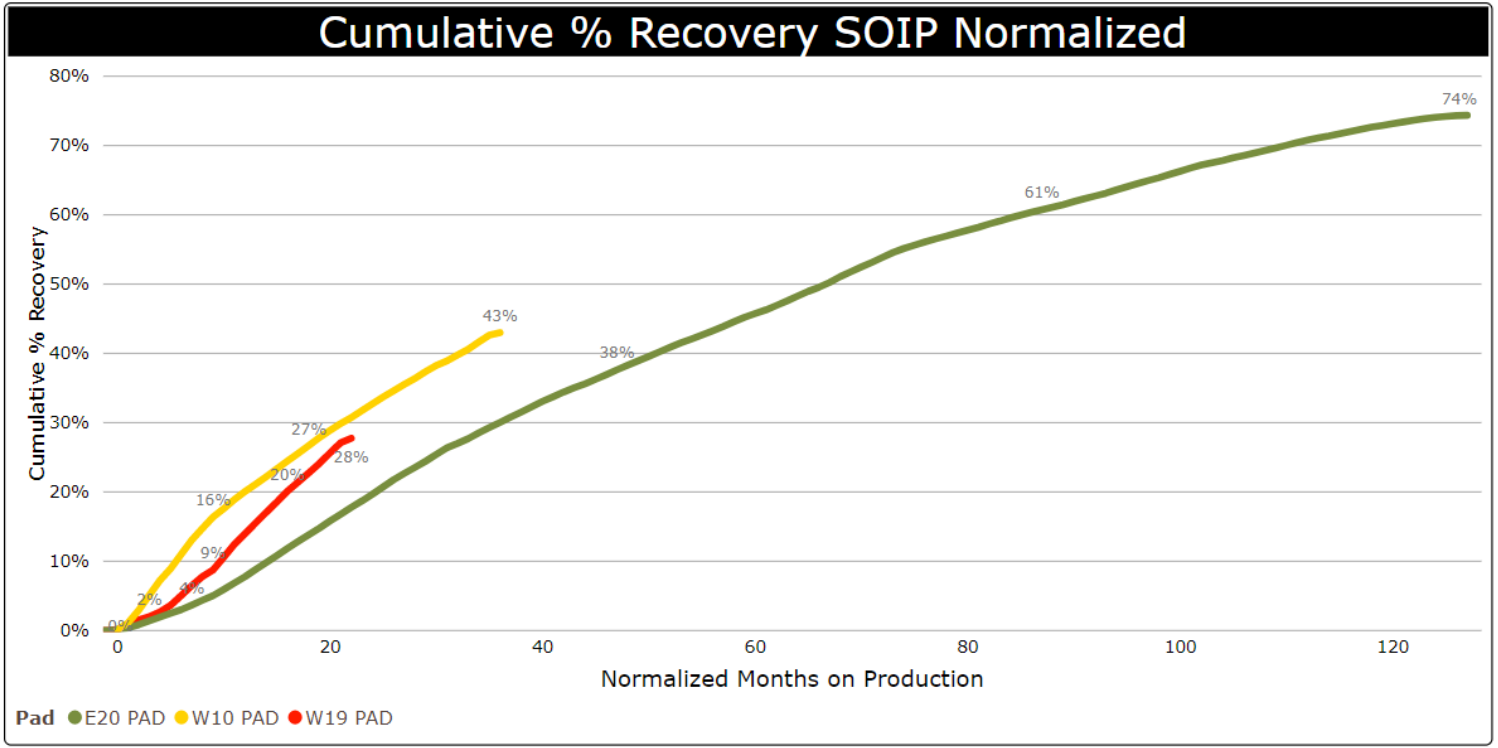
West Pad	Area (m2)	Height (m)	Porosity (%)	So (%)	SOIP (Mm3)	Cum Oil (Mm3) to Mar 31, 2019	Recovery % SOIP	Expected Ultimate Recovery (Mm3)	Ultimate Recovery as % of SOIP
W03 PAD	421,984	21	32%	76%	2,159	517	24.0%	1,228	57%
W05 PAD	341,146	21	31%	75%	1,677	267	15.9%	628	37%
W06 PAD	684,280	24	31%	81%	4,085	1,023	25.0%	2,518	62%
W07 PAD	334,674	25	34%	79%	2,164	547	25.3%	950	44%
W08 PAD	433,024	25	33%	79%	2,833	1,168	41.2%	1,722	61%
W10 PAD	467,500	22	32%	83%	2,748	1,170	42.6%	1,876	68%
W15 PAD	379,950	21	31%	86%	2,108	535	25.4%	1,558	74%
W18 PAD	675,868	25	32%	89%	4,721	2,004	42.4%	3,258	69%
W19 PAD	756,225	30	33%	81%	6,142	1,658	27.0%	3,982	65%
W20 PAD	426,744	27	33%	81%	2,930	390	13.3%	1,133	39%
W21 PAD	704,560	23	33%	83%	4,444	163	3.7%	2,214	50%
W23 PAD	777,376	26	33%	85%	5,663	2,101	37.1%	4,211	74%
Total West	**6,403,331**				**41,673**	**11,543**	**27.7%**	**25,278**	**61%**
Total FC	**26,925,076**				**172,663**	**87,566**	**50.7%**	**116,192**	**67%**

To March 31, 2019

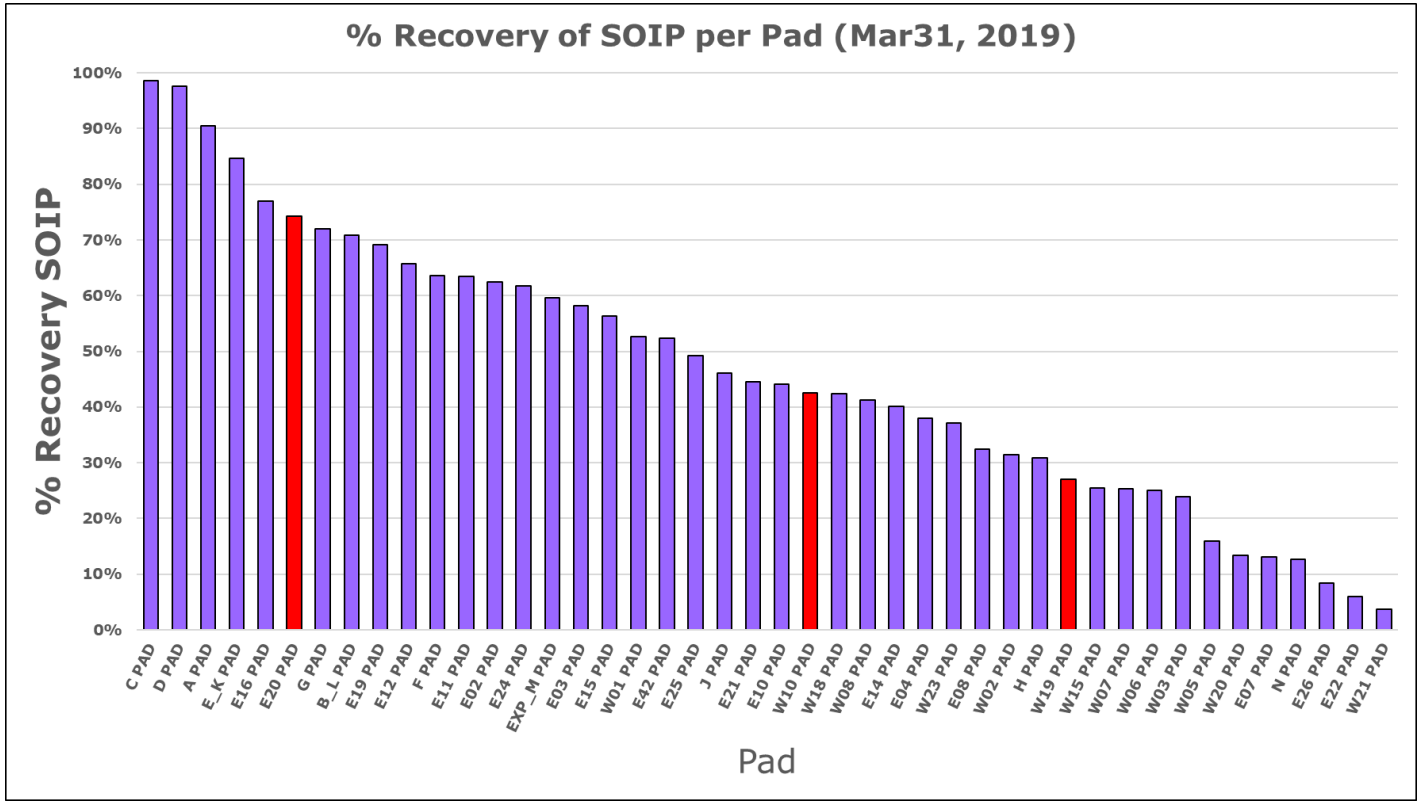
Recovery examples

- W19 pad low recovery example
- W10 pad medium recovery example
- E20 pad high recovery example

Recovery examples
cumulative percent recovery SOIP



Current Percent Recovery of SOIP: Pad Totals



Subsection 3.1.1 – 7 c, iii)

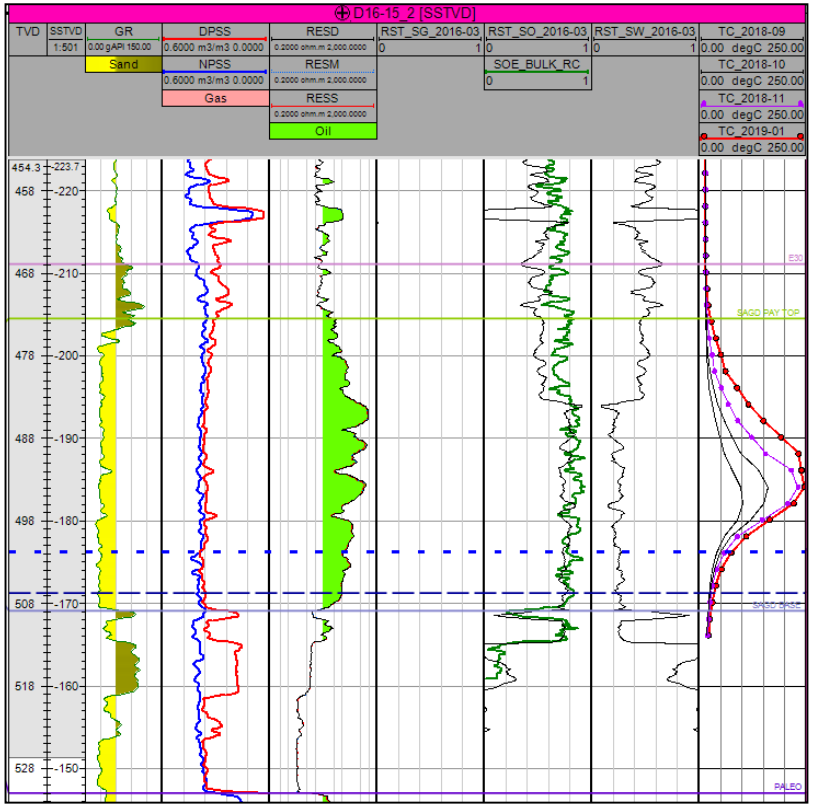
Low recovery example:
W19 Pad

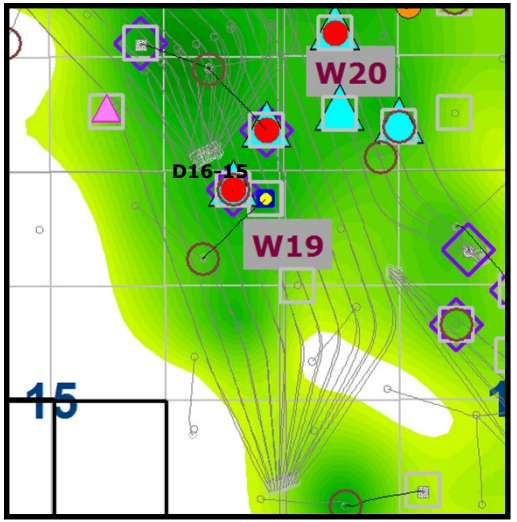
W19 pad overview

- W19 pad started production in July 2017 (eleven pairs)
- Excellent reservoir quality
- Initial operating pressures ~4.5 MPa, currently producing ~4.3 MPa
- Currently at ~27% recovery of SOIP, in line with forecasting expectations
- CSOR is currently 2.5
- Wells are ramping up as forecasted

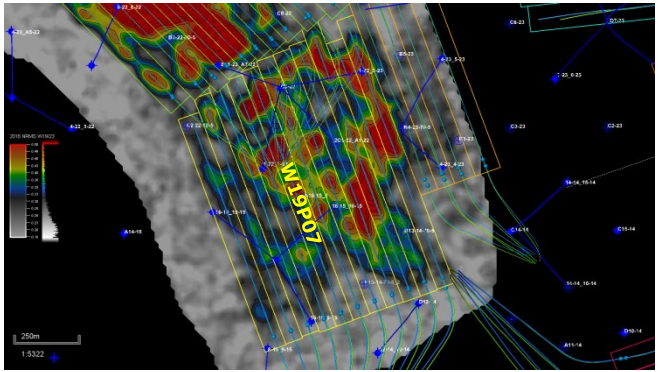
W19 pad temperatures

D16-15

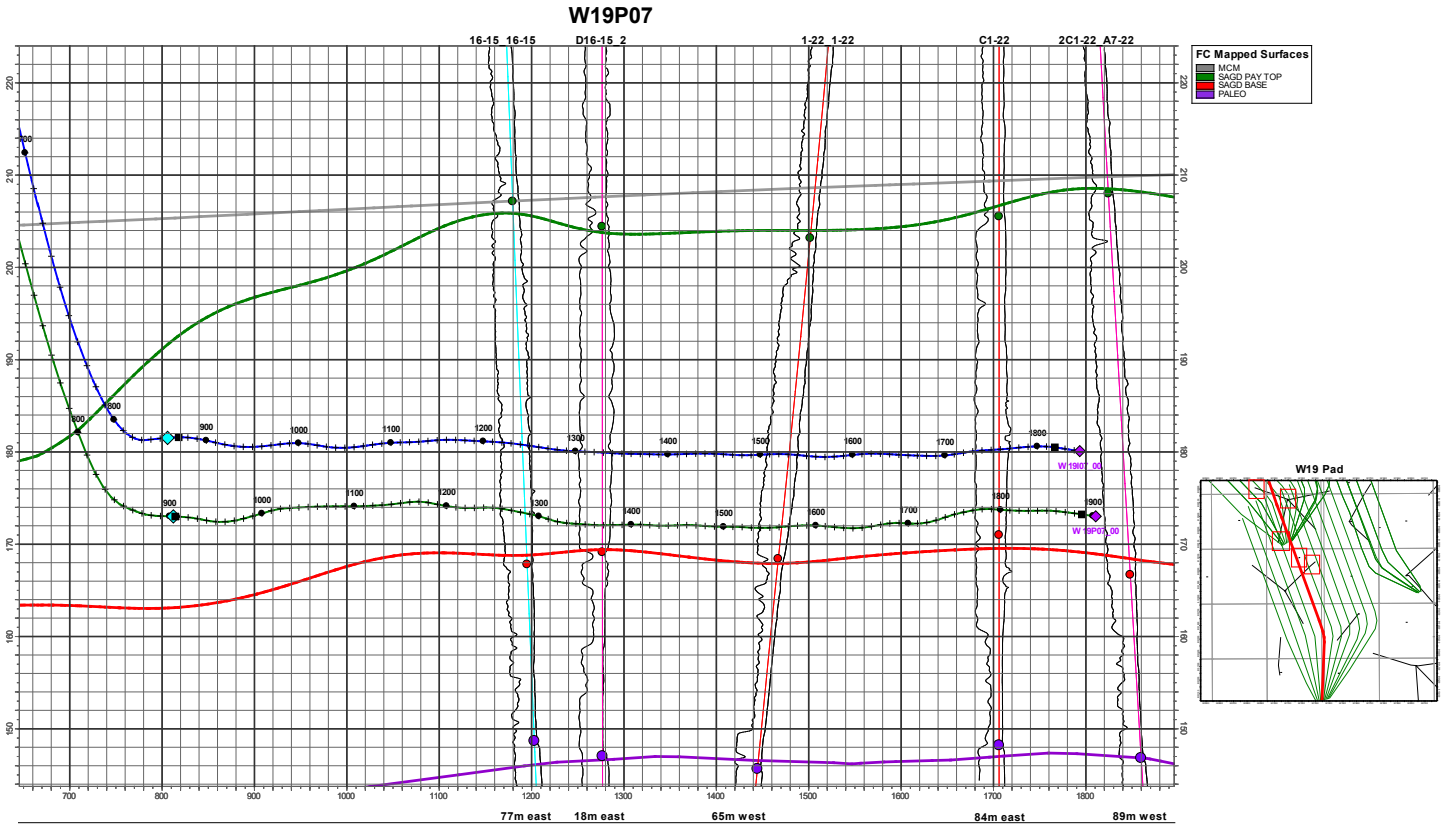




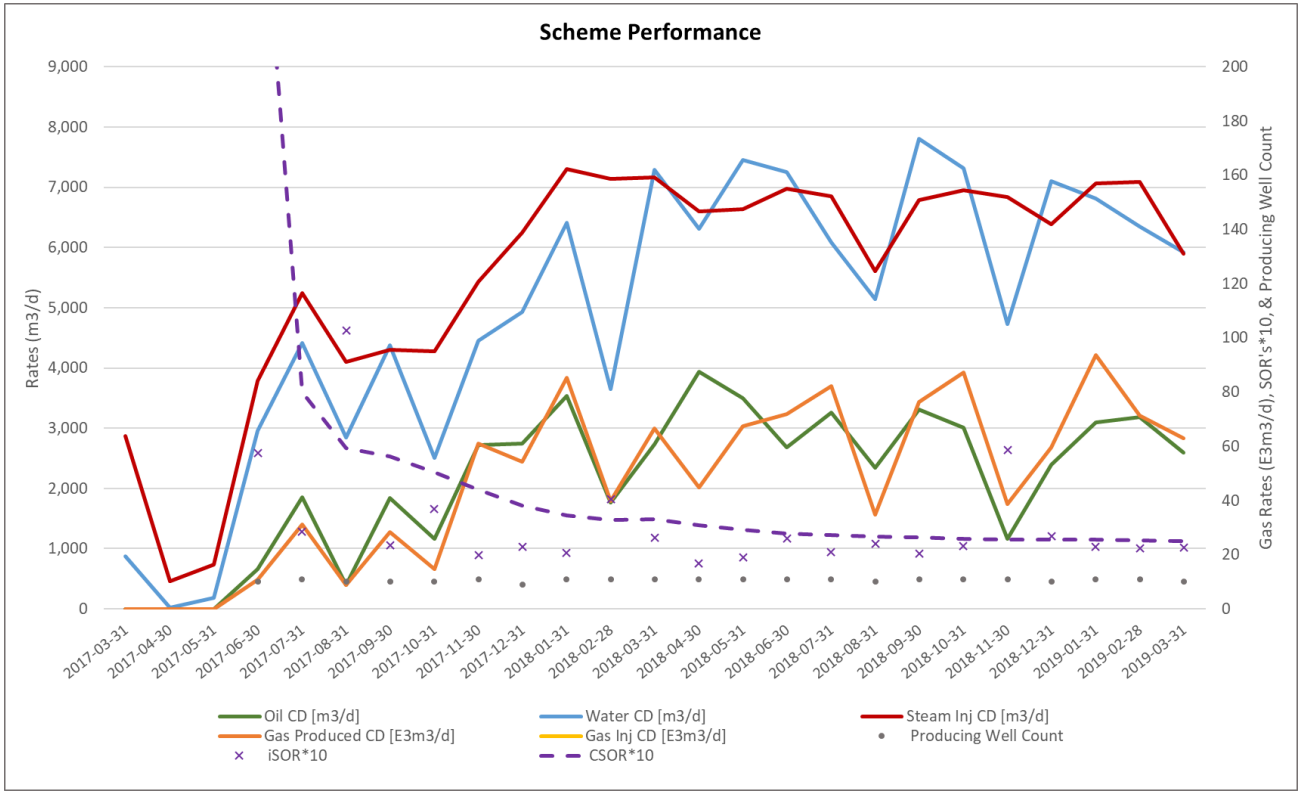
19m offset W19-07 well pair



W19-7 Geological Profile



W19 pad performance



CSOR
2.5

W19 pad conclusions

- Currently at ~27% recovery of SOIP
- Pad ramp-up in top quartile of all Foster Creek pads
- Optimization of pad ongoing to maximize recovery
- Recently acquired TC data and 4D seismic
- Balance reservoir pressures with adjacent pads

Subsection 3.1.1 – 7 c, iii)

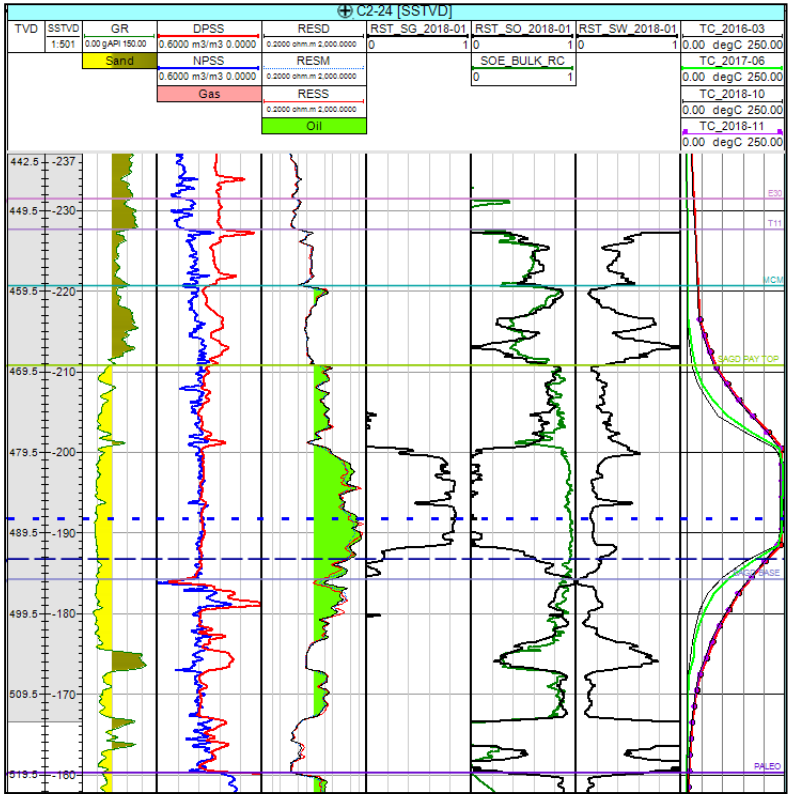
Medium recovery example:
W10 pad

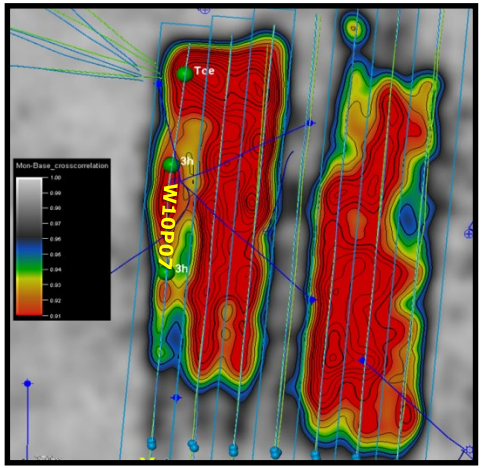
W10 pad overview

- W10 pad started production in May 2016 (seven pairs)
  - W10P04 redrilled
- Heterogeneous producer/injector toes on East side of pad
- Initial operating pressures ~5.0 MPa, currently producing ~3.2 MPa
- Currently at ~43% recovery of SOIP
- CSOR is currently ~2.2

W10 Pad Temperatures

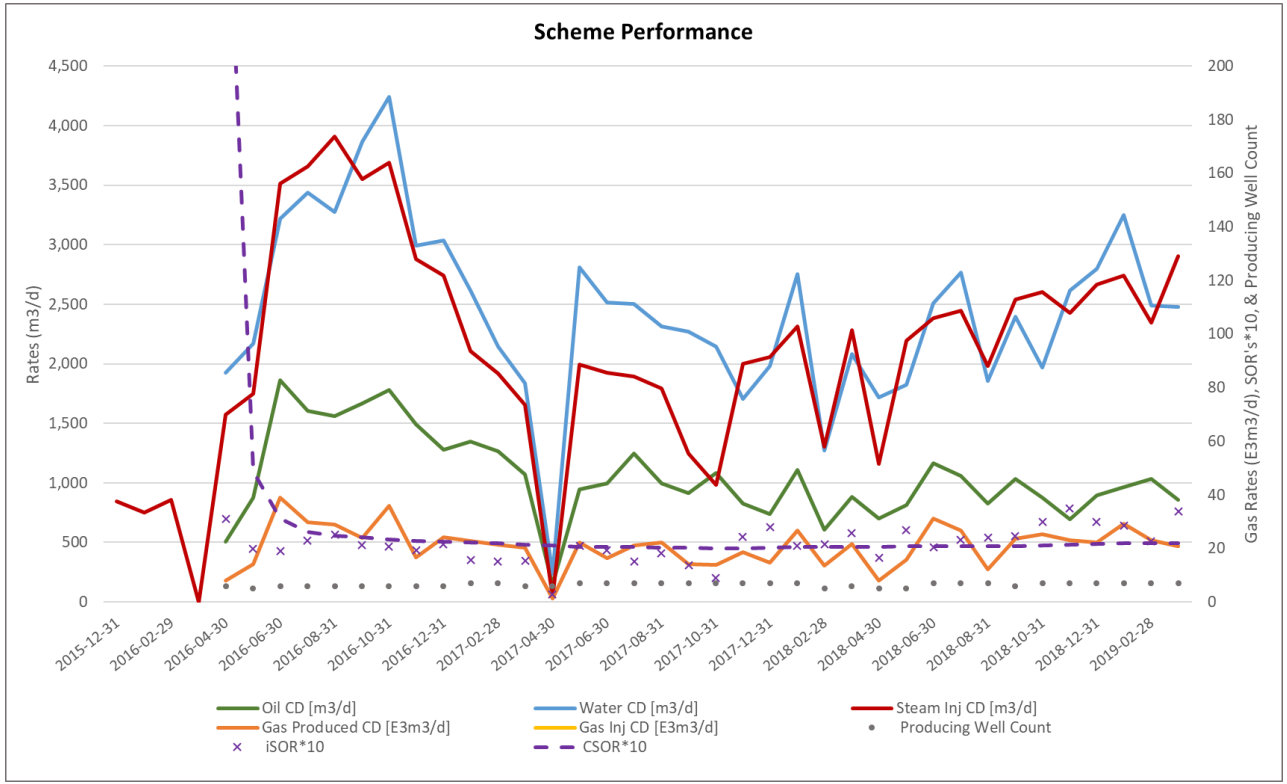
C2-24





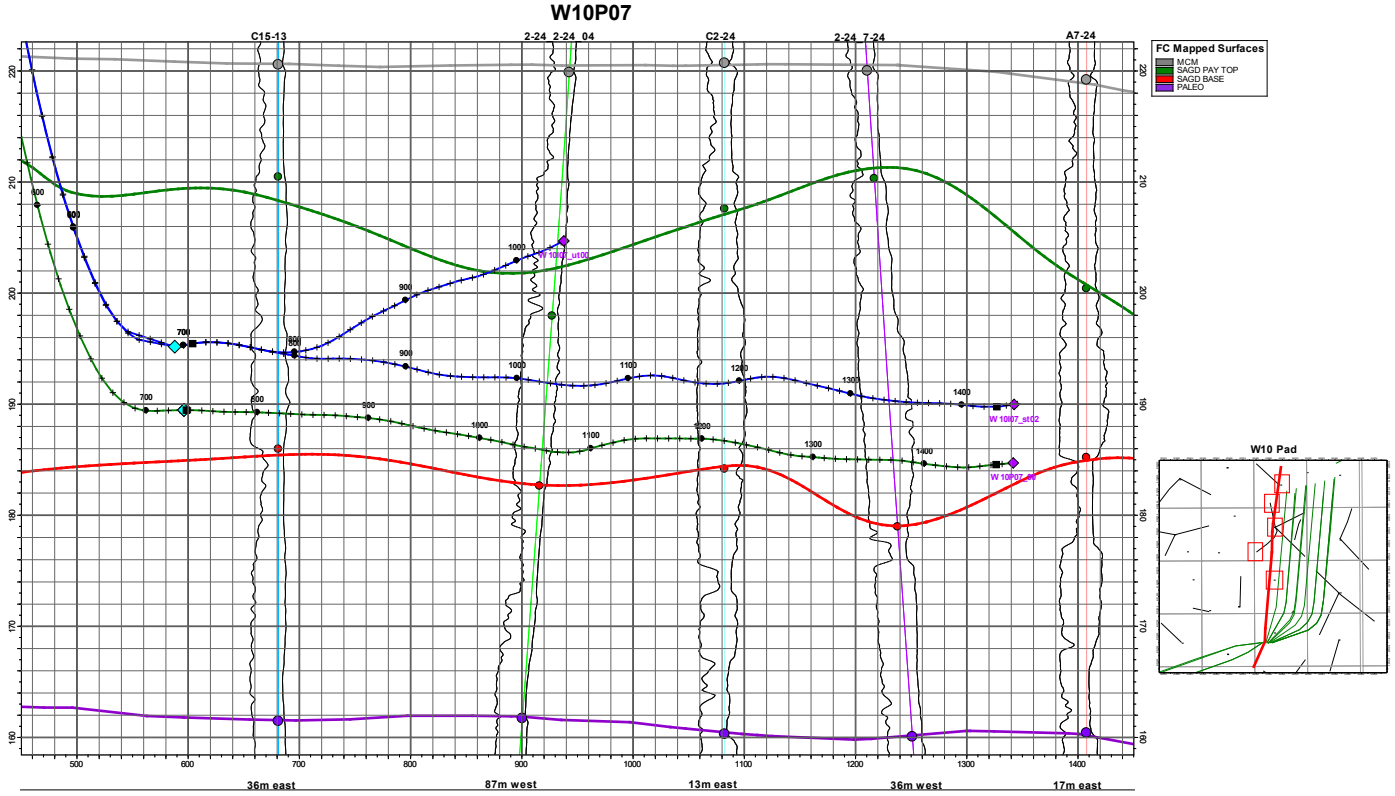
9m offset W10-07 well pair

W10 pad performance



CSOR 2.2

W10-07 Geological Profile



W10 pad conclusions

- Currently at ~43% recovery of SOIP
- Optimization of pad on-going to maximize recovery
- Recently acquired RST and TC data
- Balance reservoir pressures with adjacent pads

Subsection 3.1.1 – 7 c, iii)

High recovery example:
E20 pad

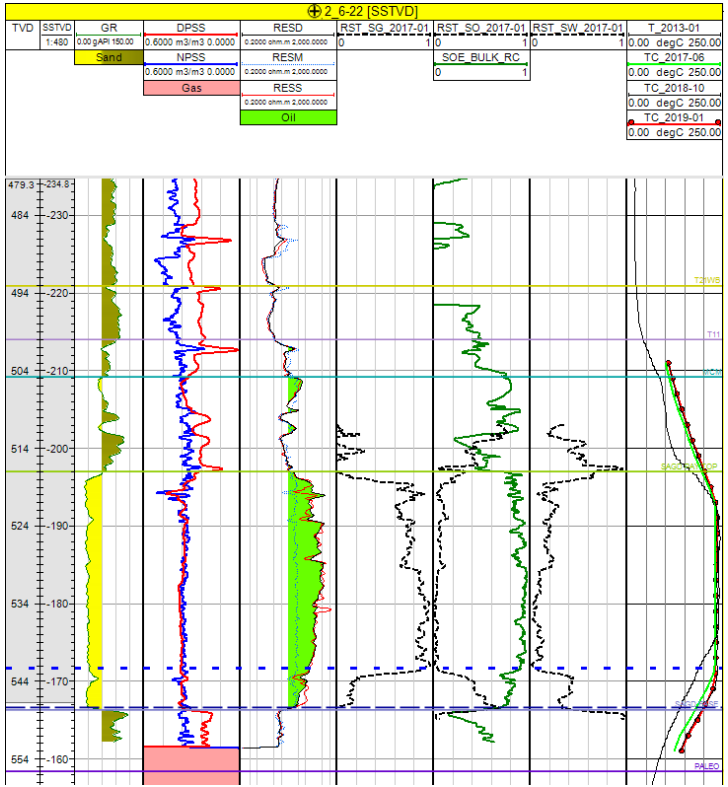
E20 pad overview

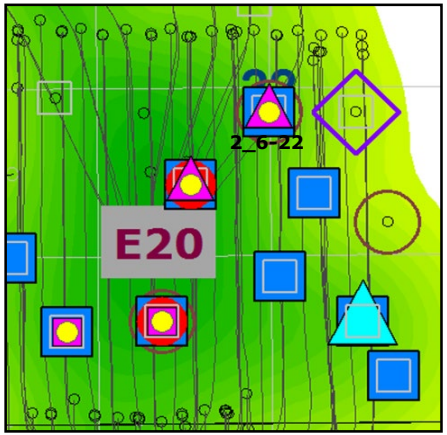
- E20 Pad started production in October 2008 (eight original pairs, 8 wells utilizing Wedge Well™ technology)
  - Wedge well production started in August 2014
  - Several re-drills, addition of ninth pair, conversion of E20W08 to a pair
  - Co-injection started August 2017

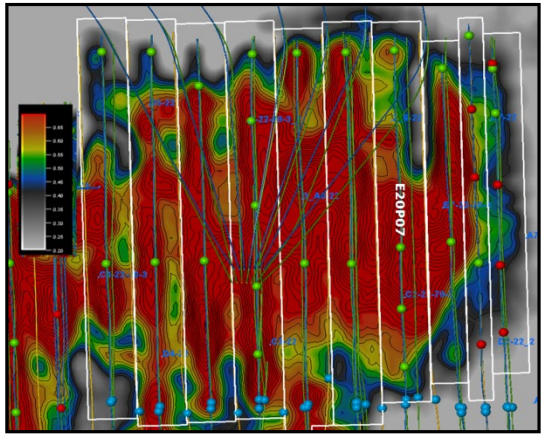
- Excellent reservoir quality, SAGD base sloping to the East (P8)
- Initial operating pressures ~4.0 MPa, currently producing ~3 MPa
- Currently at ~74% recovery of SOIP
- CSOR is currently 2.5

E20 pad temperatures

6-22

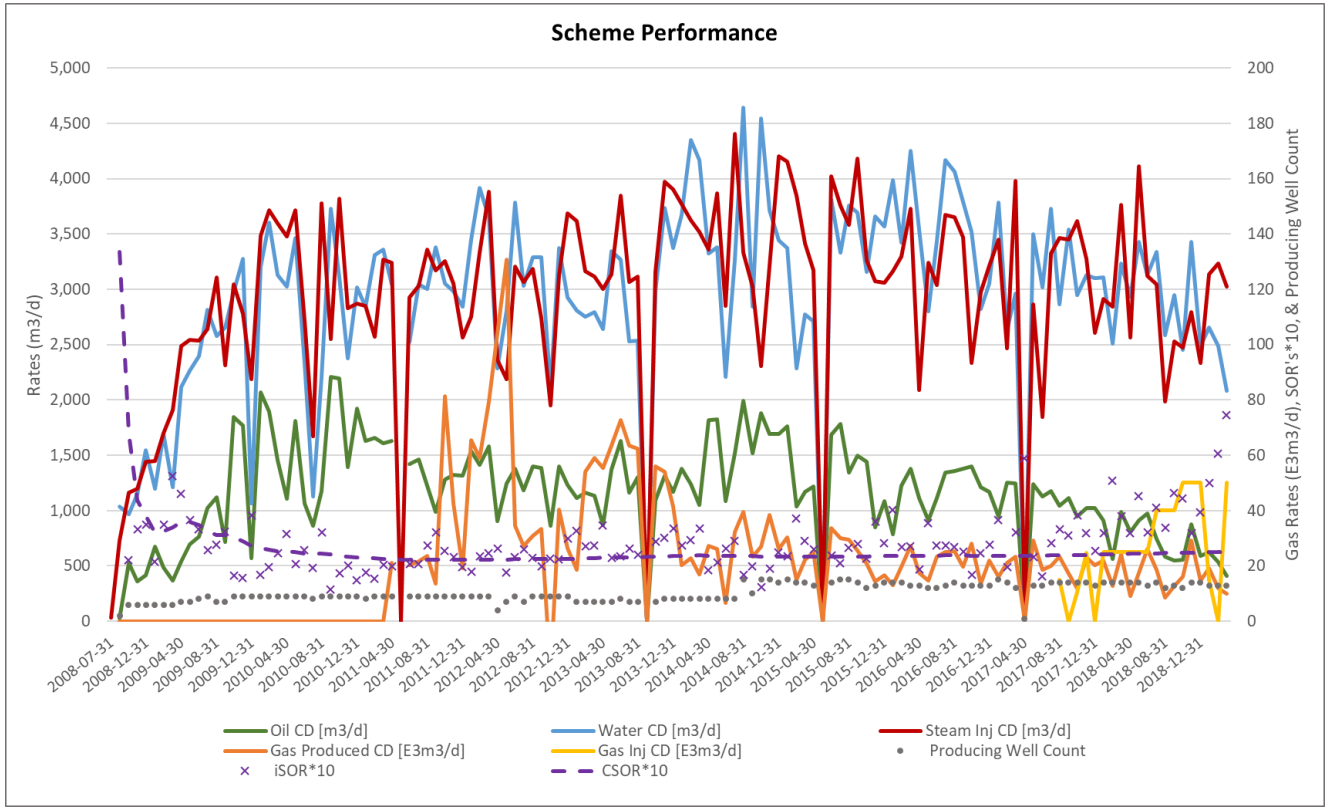






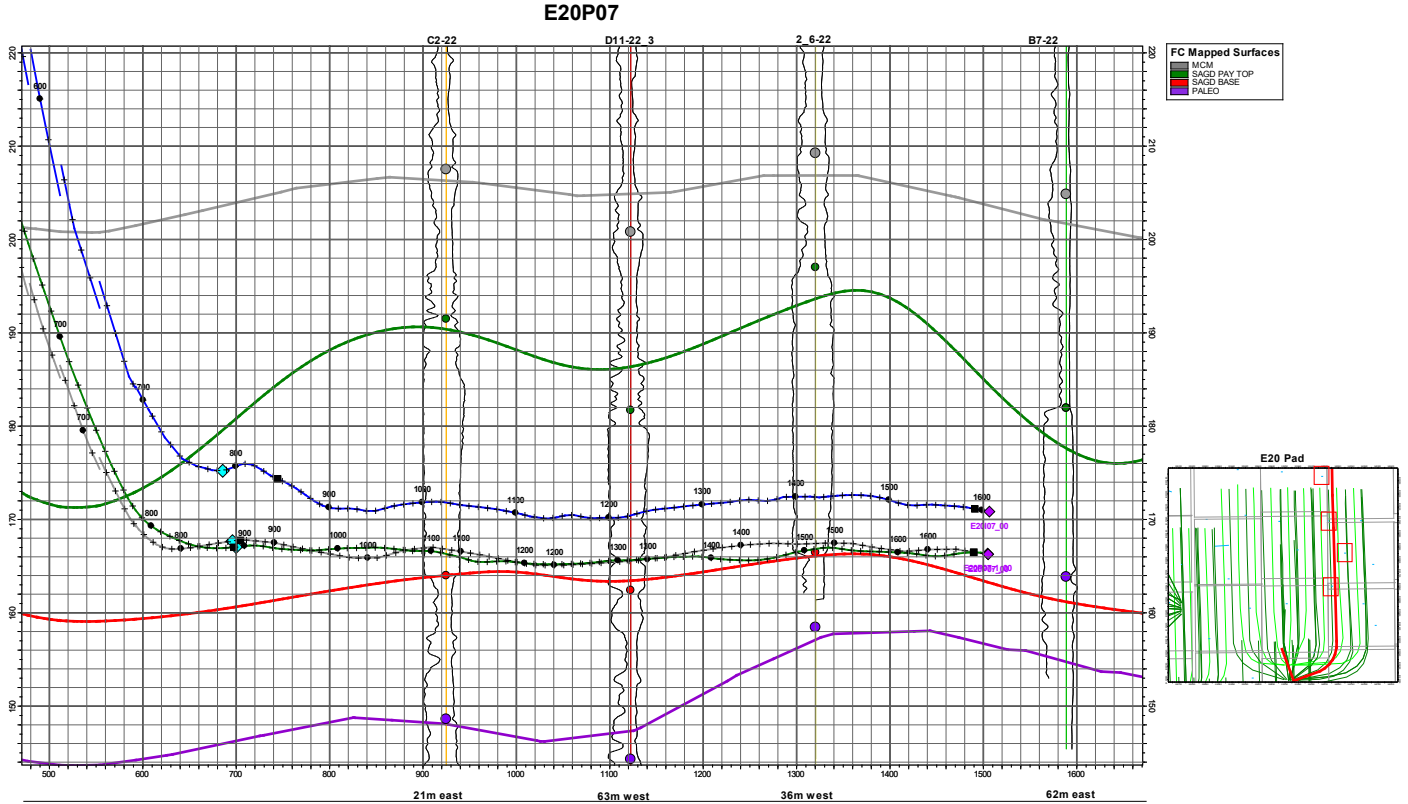
16m offset E20-07 well pair

E20 pad performance



CSOR
2.5

E20-07 Geological Profile



E20 pad conclusions

- Currently at ~74% 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

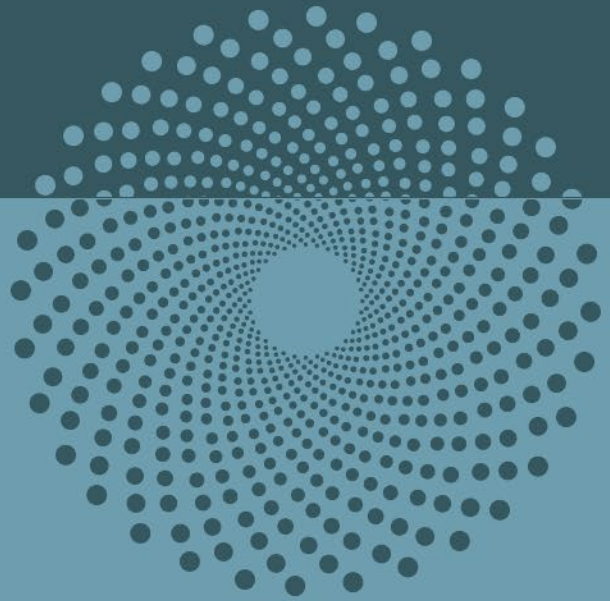
Stimulation treatments

- 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

Subsection 3.1.1 – 7f)
2018 key learnings

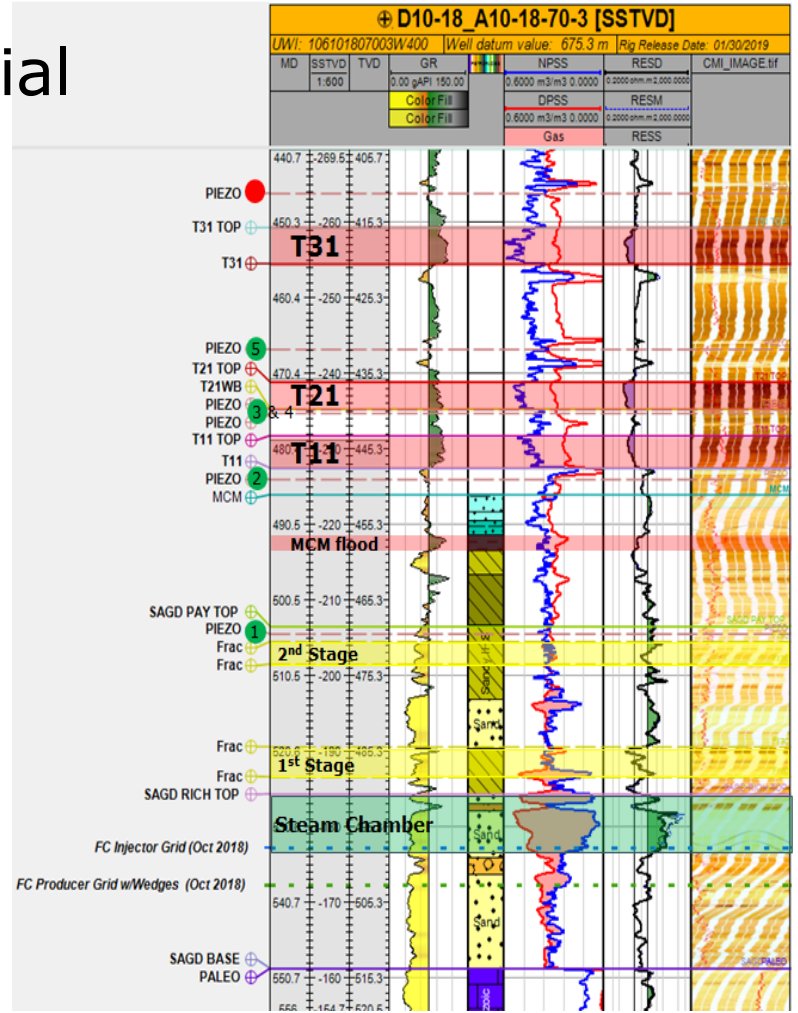


E04 Permeability Enhancement Trial

E04 Permeability Enhancement Trial

- Cenovus conducted two hydraulic fracture treatments in an observation well over the E04 pad to enhance the vertical permeability, improve drainage and increase oil recovery in poor quality reservoir
- Cenovus considers the trial a success in that the two fracture treatments were placed generating a fracture network, while maintaining the integrity of the primary caprock (T31)
- Improvements in drainage and oil recovery will be measured in Q4 2019 with the use of a reservoir saturation tool
- Ongoing surveillance of the reservoir and caprock intervals will be monitored with real time thermocouple and piezometer data

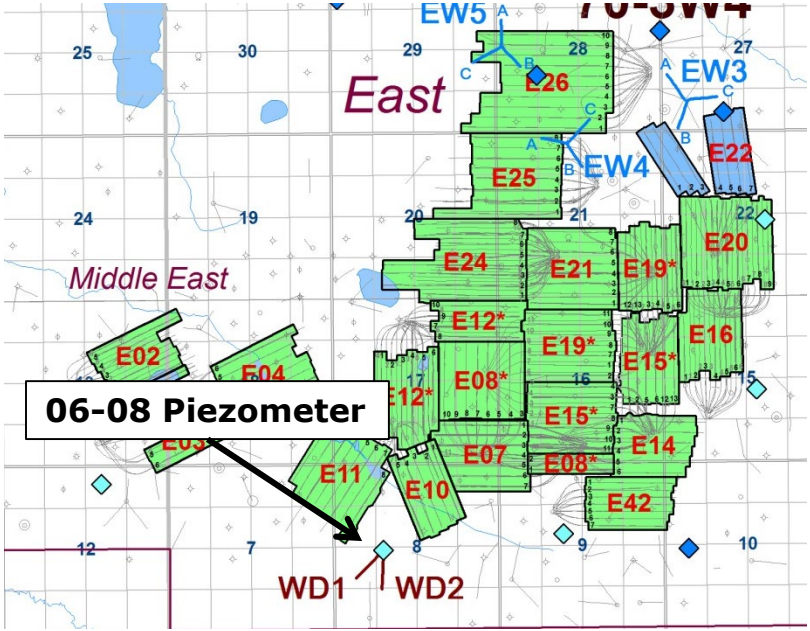
Caprock zone	MOP Region	Lowest Minimum In-situ Stress (Mpag)	Downhole MOP (Mpag)	Maximum Piezo pressure recorded on piezo immediately below caprock (Mpag)	Fracture treatment	Piezo reference number
T31	East	8.35	6.7	3.06	Upper (2nd stage)	5
T21	East	9.44	7.6	3.81	Upper (2nd stage)	3 and 4
T31	East	8.35	6.7	2.51	Lower (1st stage)	5
T21	East	9.44	7.6	3.87	Lower (1st stage)	3 and 4



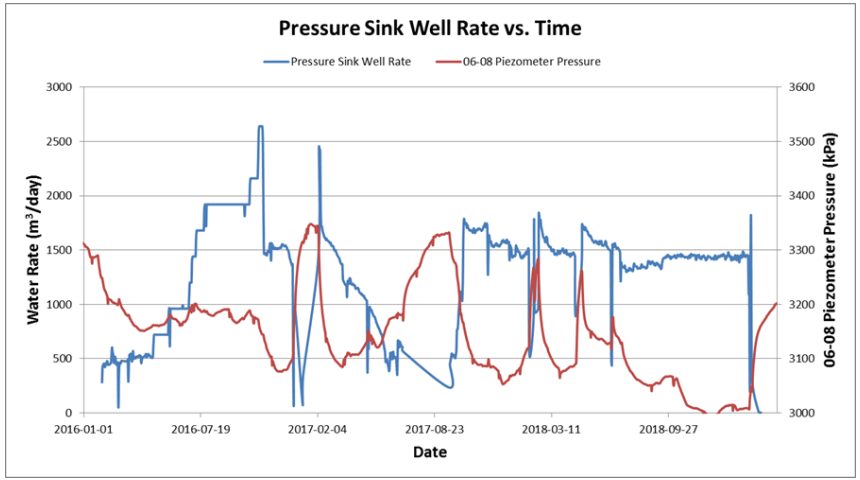
Pressure Sink Update

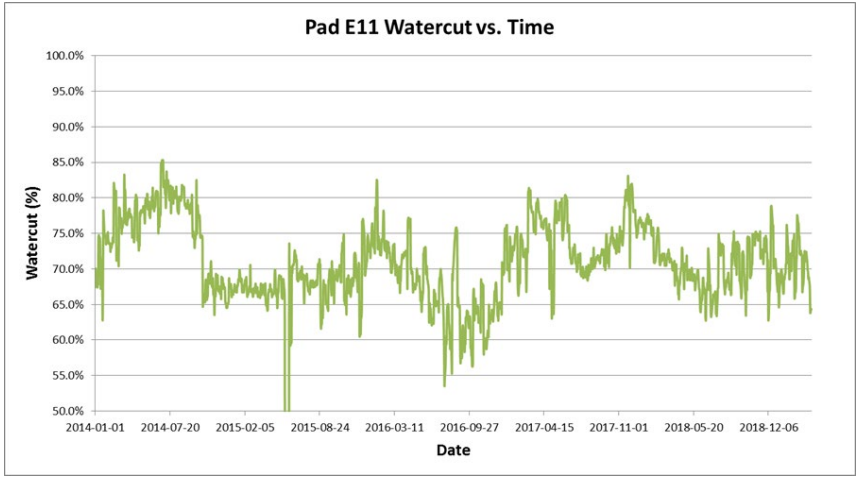
Pressure Sink Update

- 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



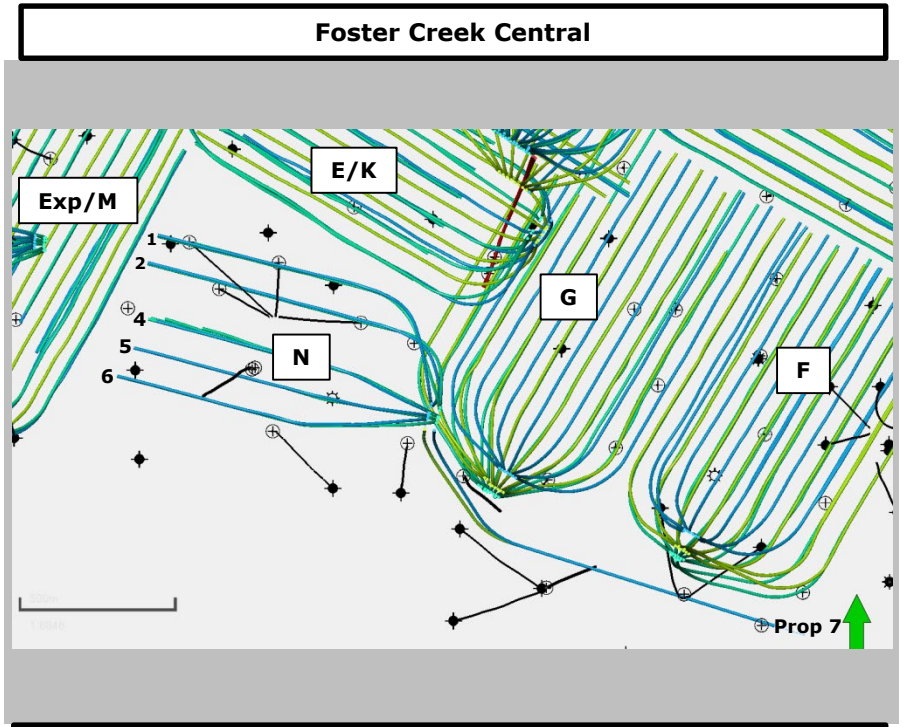


- At the 06-08 piezometer bottom-water pressure decreases 200-250 kPa when pressure sink well operates at full rates
- Sink well production will be re-instated following current control valve repair

- 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



5 well pairs, 100m spacing, No wedge wells; 160m between P2 & P4; P07 to be drilled behind F/G surface

Thin Pay Pilot

- NP01/NP02 are thin pay SAGD pilot wells
  - NP01 liner failure Q1/2018, redrilled full height

Propane SAP Pilot

- NP04/NP06 are propane SAP pilot wells
  - NP04 liner failure Q2/2017
- NP03 was not drilled to maintain isolation between the two pilot wells
- NP05 was left off to provide a buffer between pilot wells
- SAGD startup in Q2 2016, propane injection initiated after SAGD baseline established
- NP07 drilled behind F/G surface in Q2/2018 as a further SAP pilot well

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 on NP02

Propane SAP Pilot Overview

- Pilot goal is to increase our understanding of propane SAP @ 1-20 wt%
- Propane (C3) SAP pilot is located at NP04 (failed), NP06 & NP07
- Wells have rich pay thickness ~12-16 m
- ~1 year SAGD baseline prior to C3 injection on NP06
- Trial on-going:
  - currently injecting propane on NP06
  - ramping up steam injection on NP07 to establish SAGD baseline prior to propane injection trial

Rampdown/Blowdown Update

Field wide co-injection and blowdown

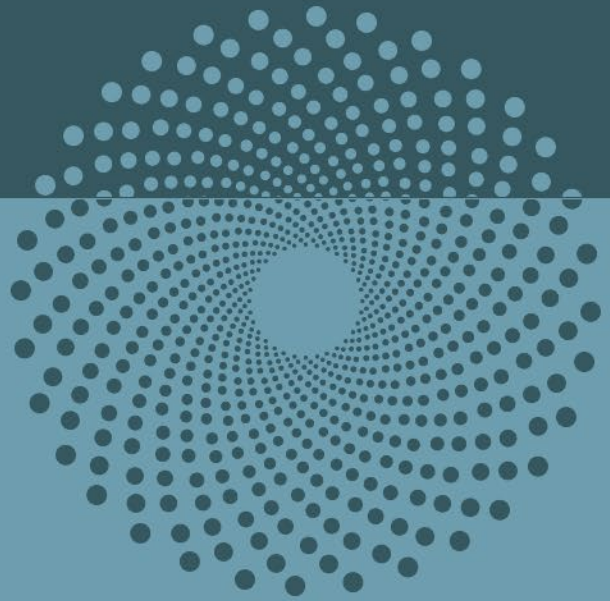
Current pads on co-injection and blowdown as of Mar 31, 2019:

- 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

Subsection 3.1.1 – 7g) Information requests



Well integrity - casing

2018 Intermediate Casing Mitigation Program:

- 11 intermediate casings inspected, coated and returned to service
- Ongoing monitoring and inspection program to assess casing condition and repair as required
- Cenovus complies with all regulations surrounding inactive wells, including tracking compliance status and reporting well suspensions in the DDS system

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 - Wellheads

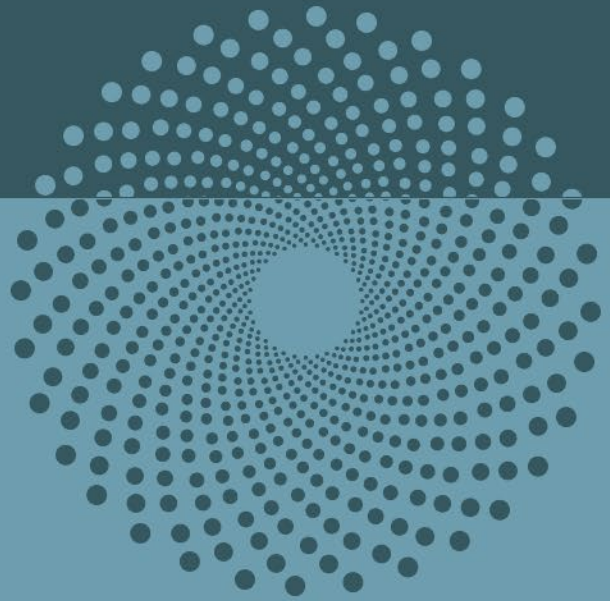
- Wellhead integrity monitoring is ongoing. No wellhead failures observed

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

Subsection 3.1.1 – 8)
Future plans

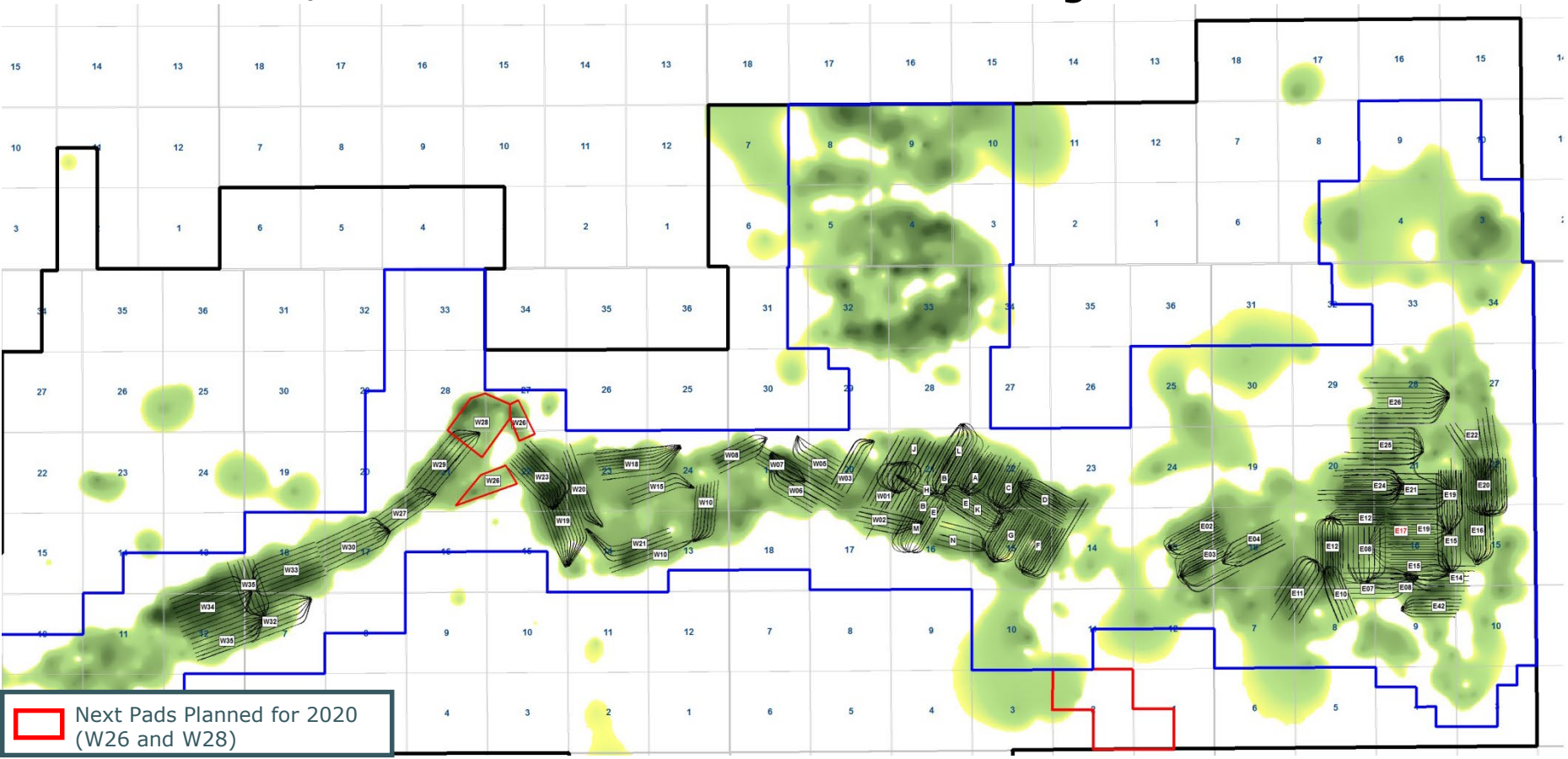


2019 initiatives

- Alternate liner trials continue on various pads
- Evaluating potential follow-up work related to E04 Permeability Enhancement Trial
- 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
W21P04	ICD	Liner	Producer

March 2019/2020 New SAGD Well Pair Drilling Plans



2019-2020 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
  - During periods of curtailment our goal is to use steam to protect reservoir integrity

Questions

please contact us