ATHABASCA OIL CORPORATION

AER LEISMER UPDATE

May 2018

ATHABASCA OIL CORPORATION

INTRODUCTION

SUBSURFACE

- Project Description & Status
- Geoscience
- 4-D Seismic & Monitoring
- Well Design & Instrumentation
  - *Drilling & Completions*
  - *Artificial Lift*
  - *Instrumentation*
  - *Scheme Performance*
- Pilots
- Future Plans

SURFACE OPERATIONS & COMPLIANCE

- Facilities
- Measurement & Reporting
- Water Production, Injection & Uses
- Sulphur Production
- Compliance
- Future Plans

SUBSURFACE

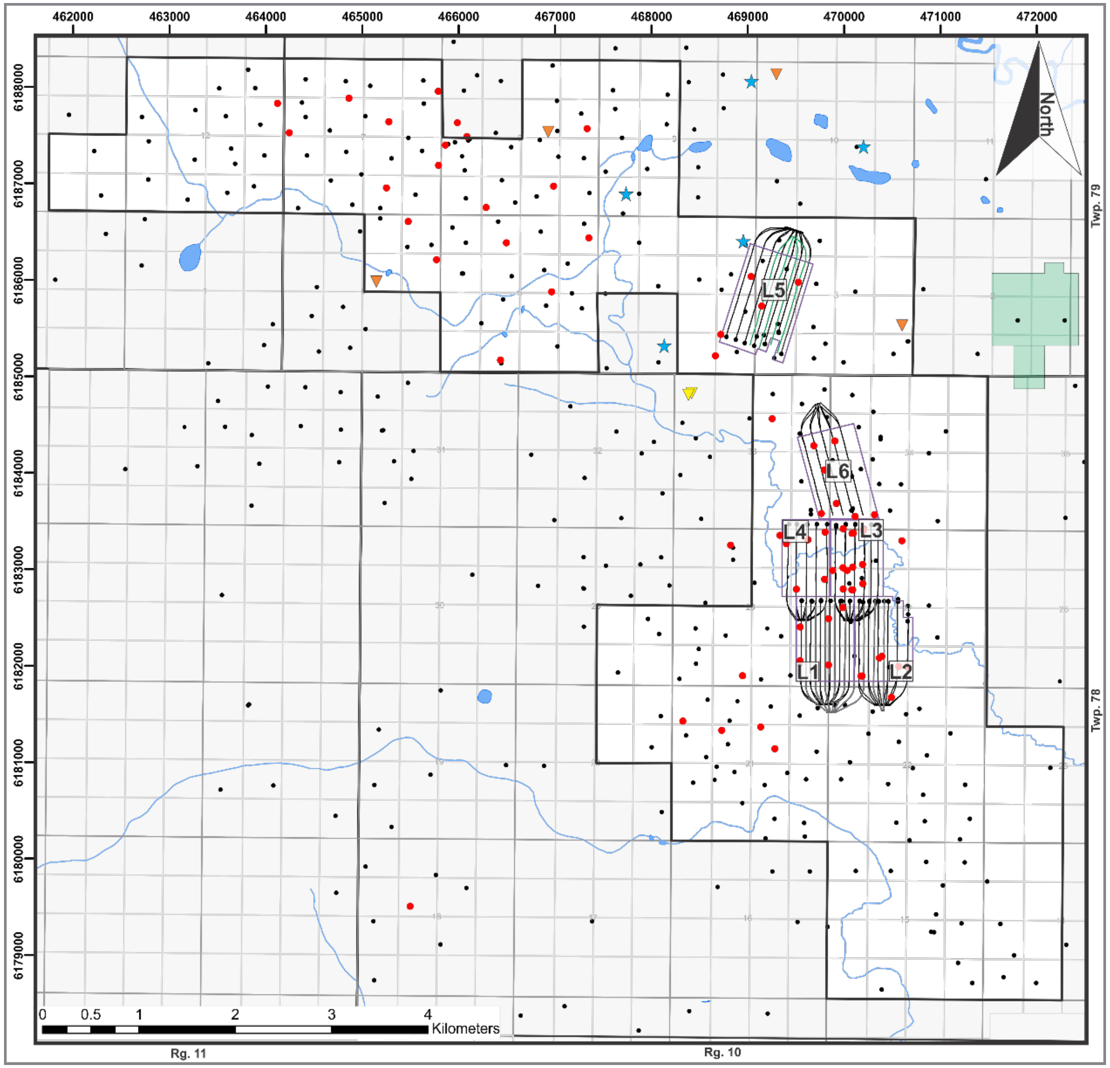
GEOSCIENCE OVERVIEW

ATHABASCA
OIL CORPORATION

LEISMER DEVELOPMENT AREA (LDA): WELL COUNT

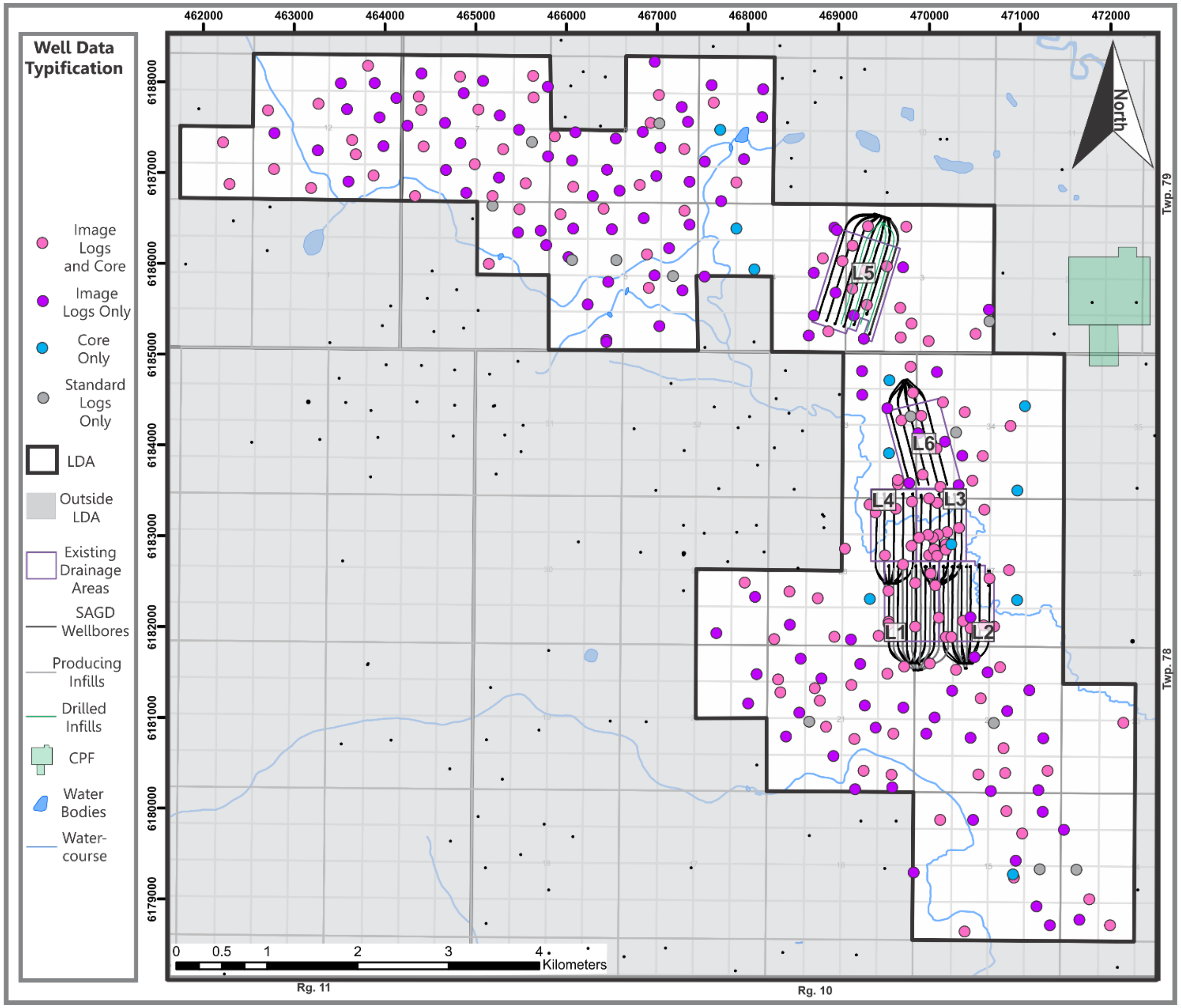
The Leismer Project currently includes a Central Processing Facility (CPF) and six well pads, with 35 well pairs and 9 producing infill wells

LEGEND
OSE – Oil Sands Evaluation (211)
OBS – Observation Wells Pre-2016 (65)
WDW – Granite Wash Disposal (4)
WDW – McMurray Water Disposal (2)
WSW – Lower Grand Rapids Source (5)
SAGD – well pairs in Pads L1–L6 pre-2016 (35)
SAGD – infill wells in Pads L1–L2 pre-2016 (9)
SAGD – infill wells in Pad L5 in 2016 (4)
Existing Drainage Areas (6)
Leismer Development Area (LDA)
Watercourse
Water bodies
Central Processing Facility (CPF)



LEISMER DEVELOPMENT AREA GEOSCIENCE ANALYSIS

- No new cores were obtained or analyzed in 2017 within the LDA
- No petrographic analyses were conducted in 2017
- No geomechanical analyses were conducted in 2017
- No reservoir fracture pressure and caprock integrity tests were conducted in 2017



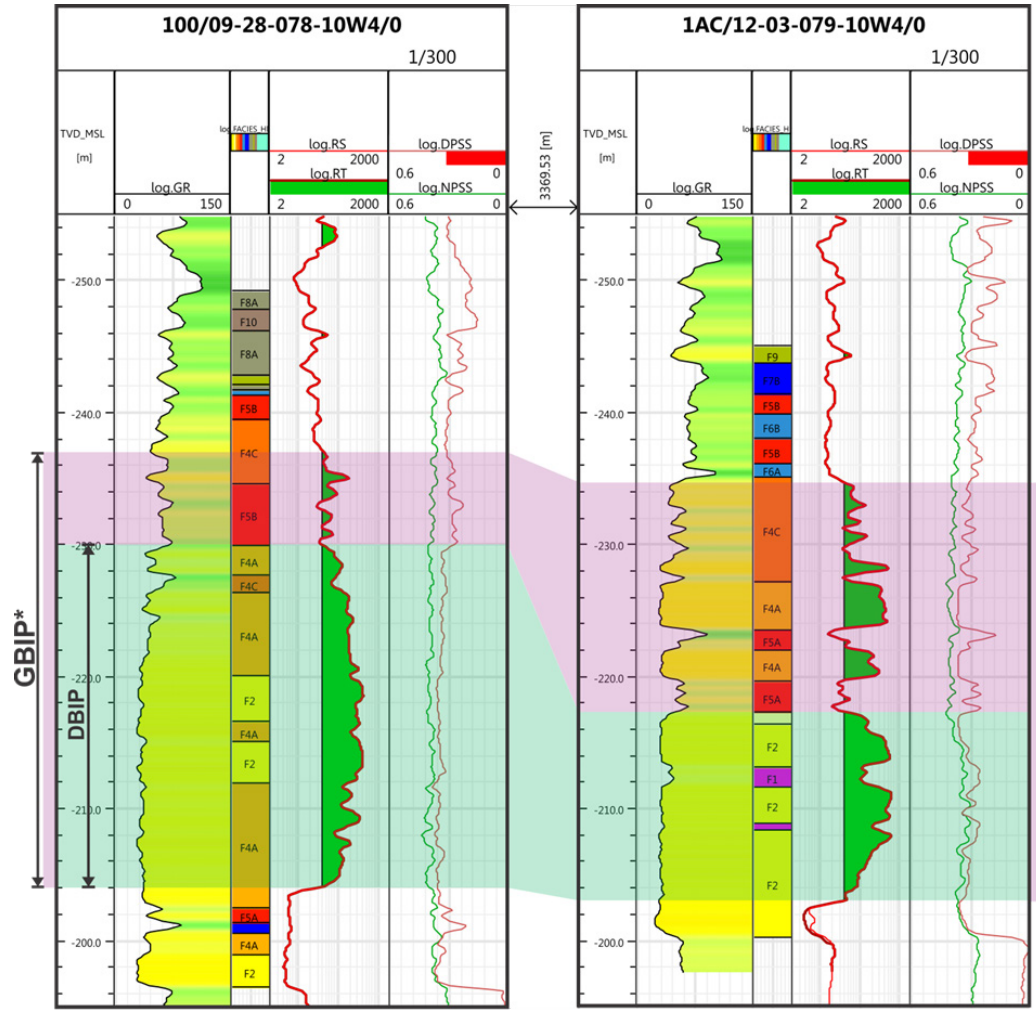
BITUMEN PAY CLASSIFICATION

GROSS BITUMEN IN PLACE (GBIP)

- Represents the total package that may be accessible via SAGD
- Petrophysical criteria:
  - *Gamma Ray (GR) <= 75 API*
  - *Resistivity (RT) >= 40 ohm-m*
  - *Porosity (DPSS) >= 27%*

DEVELOPABLE BITUMEN IN PLACE (DBIP)

- A more conservative definition used for planning well pair placement
- Same petrophysical criteria as GBIP

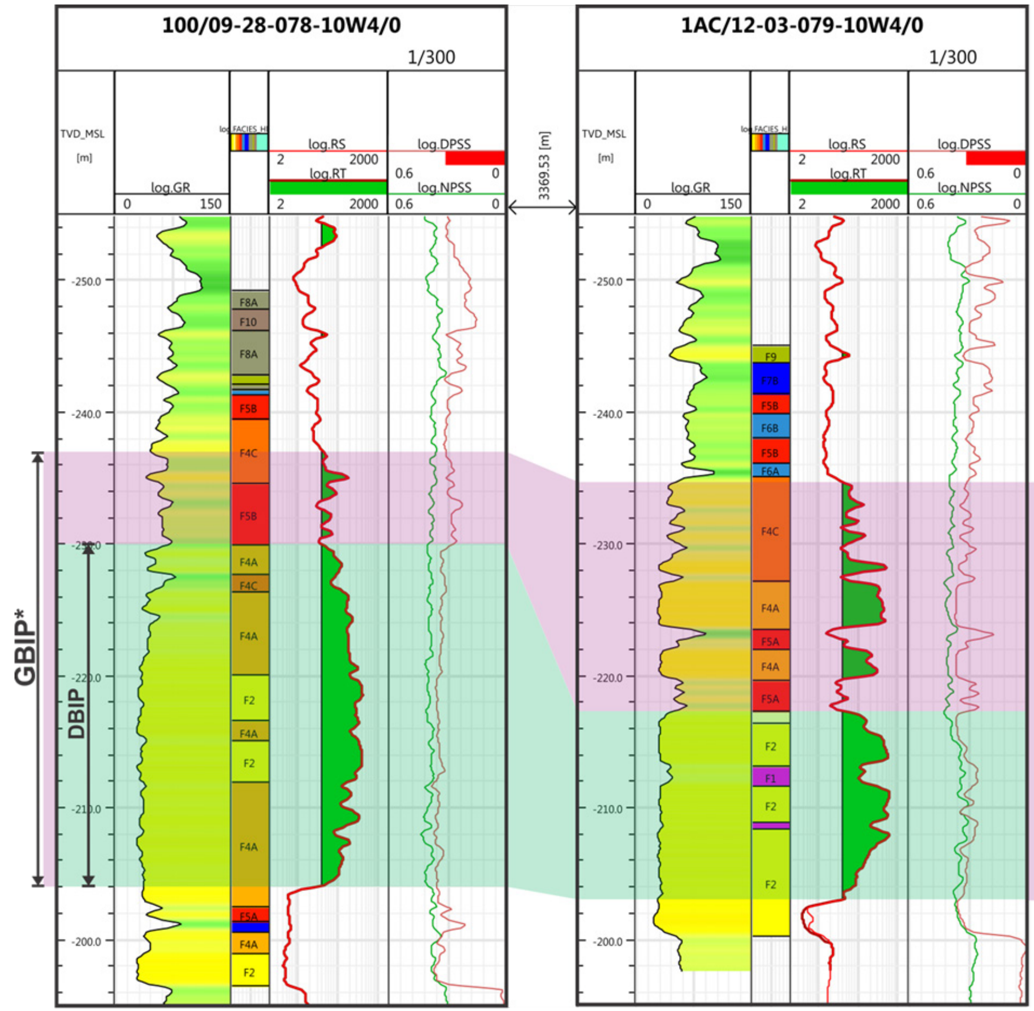


*GBIP Includes DBIP Section

BITUMEN PAY CLASSIFICATION

BOTH GBIP AND DBIP ARE RESTRICTED BY LITHOFACIES ENCOUNTERED IN CORE AND IMAGE LOGS:

- DBIP is restricted to higher quality lithofacies:
  - *F1: Shale-Clast Breccia (if <5m)*
  - *F2: Trough Cross-Bedded Sand*
  - *F3: Current-Ripple Laminated Sand*
  - *F4A-B: Sand with 5–10% Mud Interbeds*
- GBIP includes DBIP lithofacies, and:
  - *F4C-D: Sand with 10–30% Mud Interbeds*
  - *F5A-B: Sand with 30–70% Mud Interbeds*
- Non-reservoir lithofacies (F6–F7) are not included if they are greater than 2m in thickness



*GBIP Includes DBIP Section

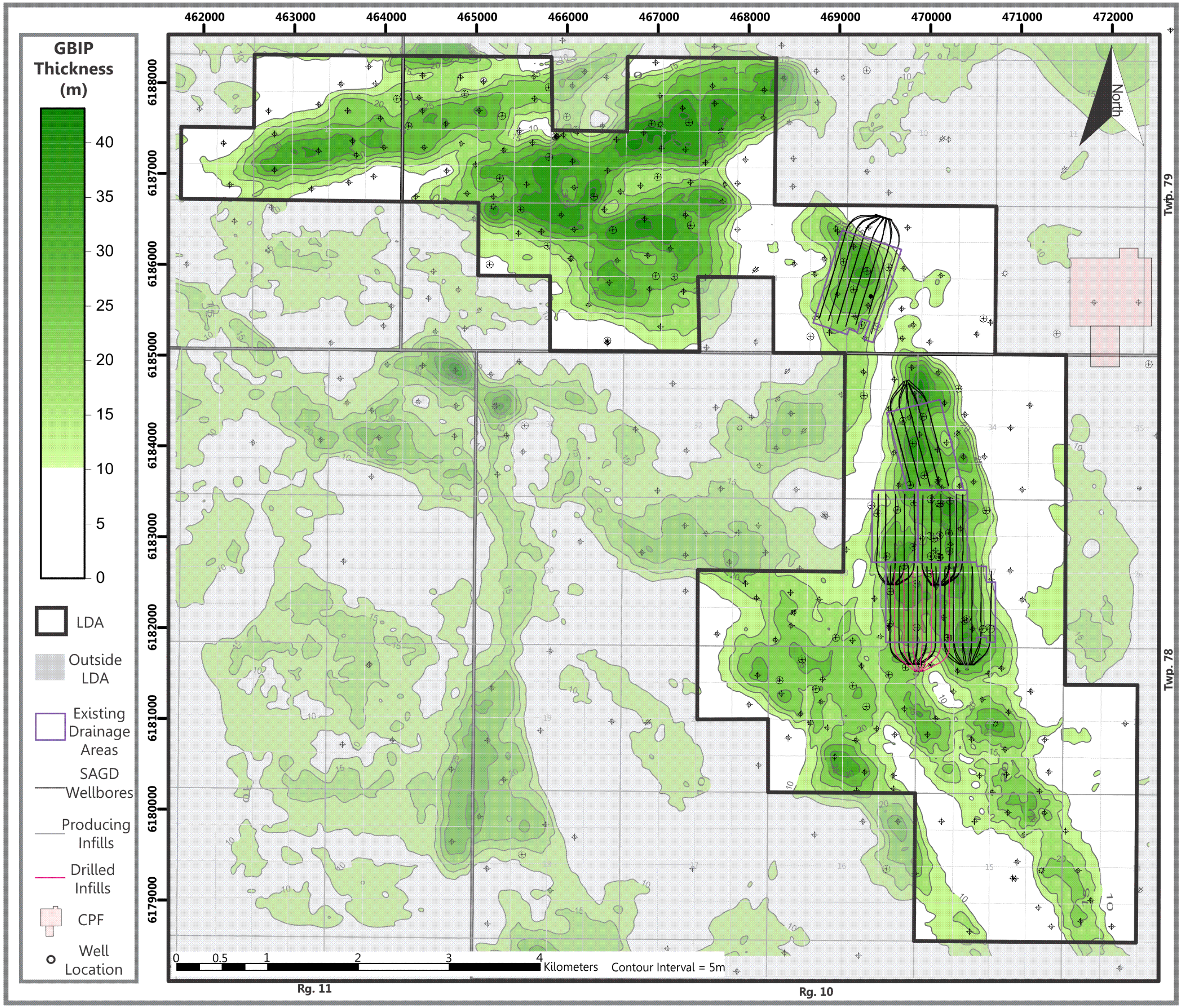
LEISMER RESERVOIR PROPERTIES

Well Pad	Area (10^3 m^2)	Avg. DBIP Thickness (m)	Avg. GBIP Thickness (m)	Avg. Porosity * (%)	Avg. Oil Saturation* (%)	DBIP (10^3 m^3)	GBIP (10^3 m^3)
L1	526	22.5	26.7	33	89	3,467	3,914
L2	498	19.2	24.5	32	86	2,821	3,344
L3	411	23.6	29.1	34	87	3,003	3,443
L4	389	19.6	22.4	33	87	2,236	2,433
L5	708	17.6	24	33	86	3,477	4,479
L6	571	25.3	28.9	33	87	3,471	3,836
Total/Avg.	3,103	21.3	25.9	33	87	18,475	21,449
LDA Total	24,166	15.5	17.3	32	85	116,054	144,403

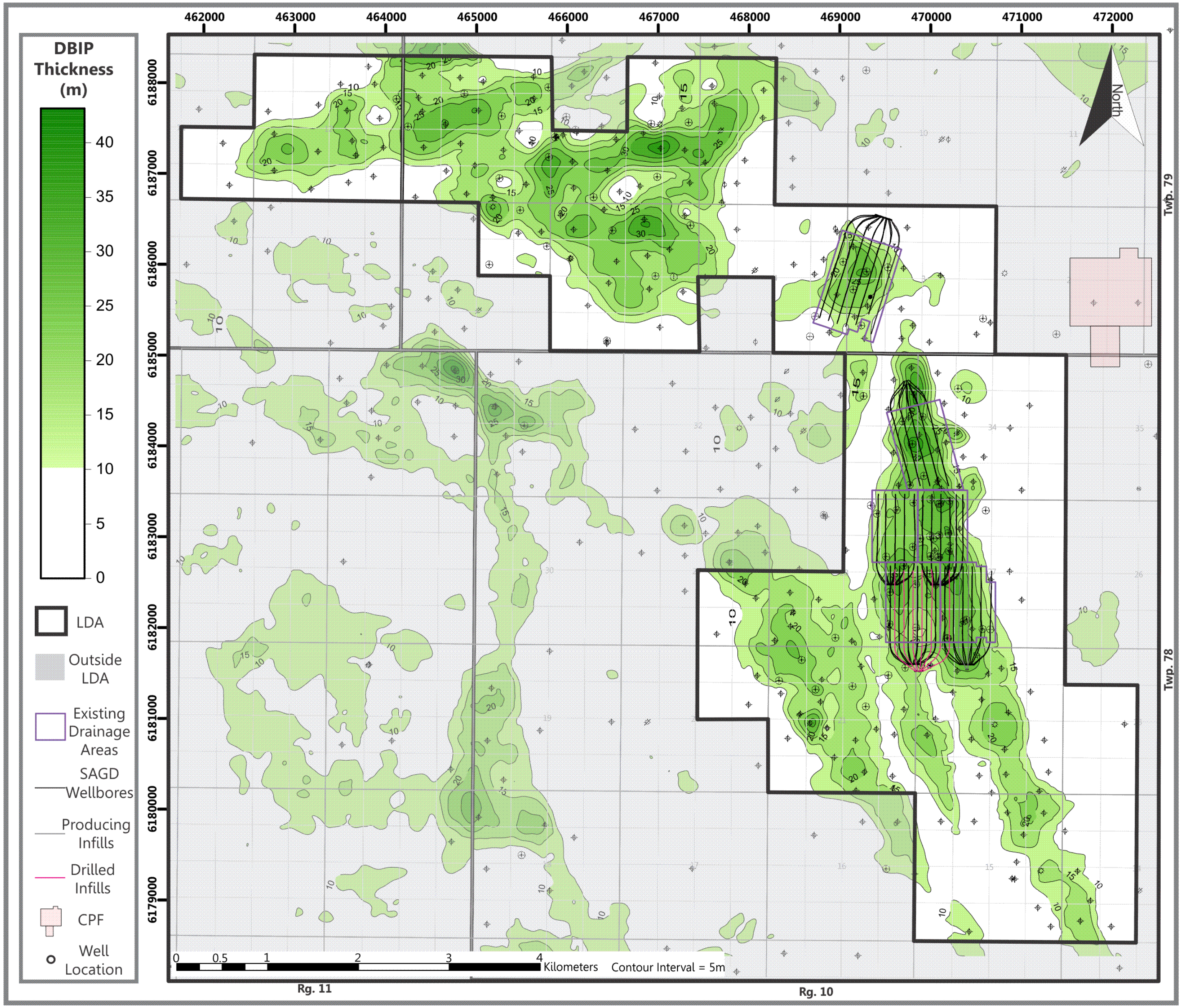
* DBIP VALUES SHOWN

- Original Reservoir Pressure: 2,300 to 2,600 kPa
- Original Reservoir Temperature: 14^{o}C
- Average Horizontal Permeability: 5 to 6 D
- Average Vertical Permeability: 4 to 5 D
- Depth: 410 to 444 m TVD (-230 to -216 m subsea)
- Variations in GBIP Volumes have occurred due to changes in the methodology in averaging porosity, oil saturation and drainage area boxes

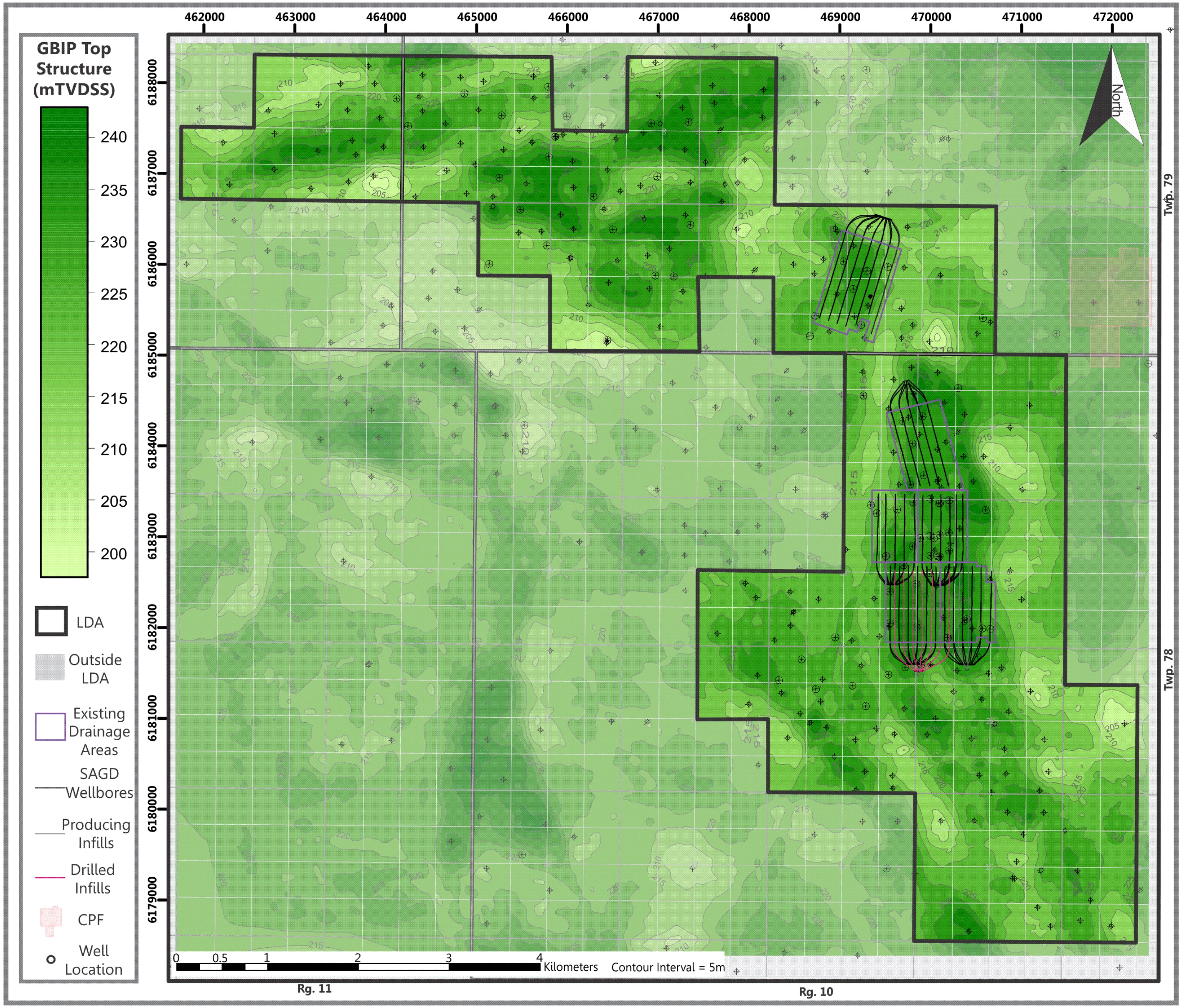
GBIP THICKNESS MAP



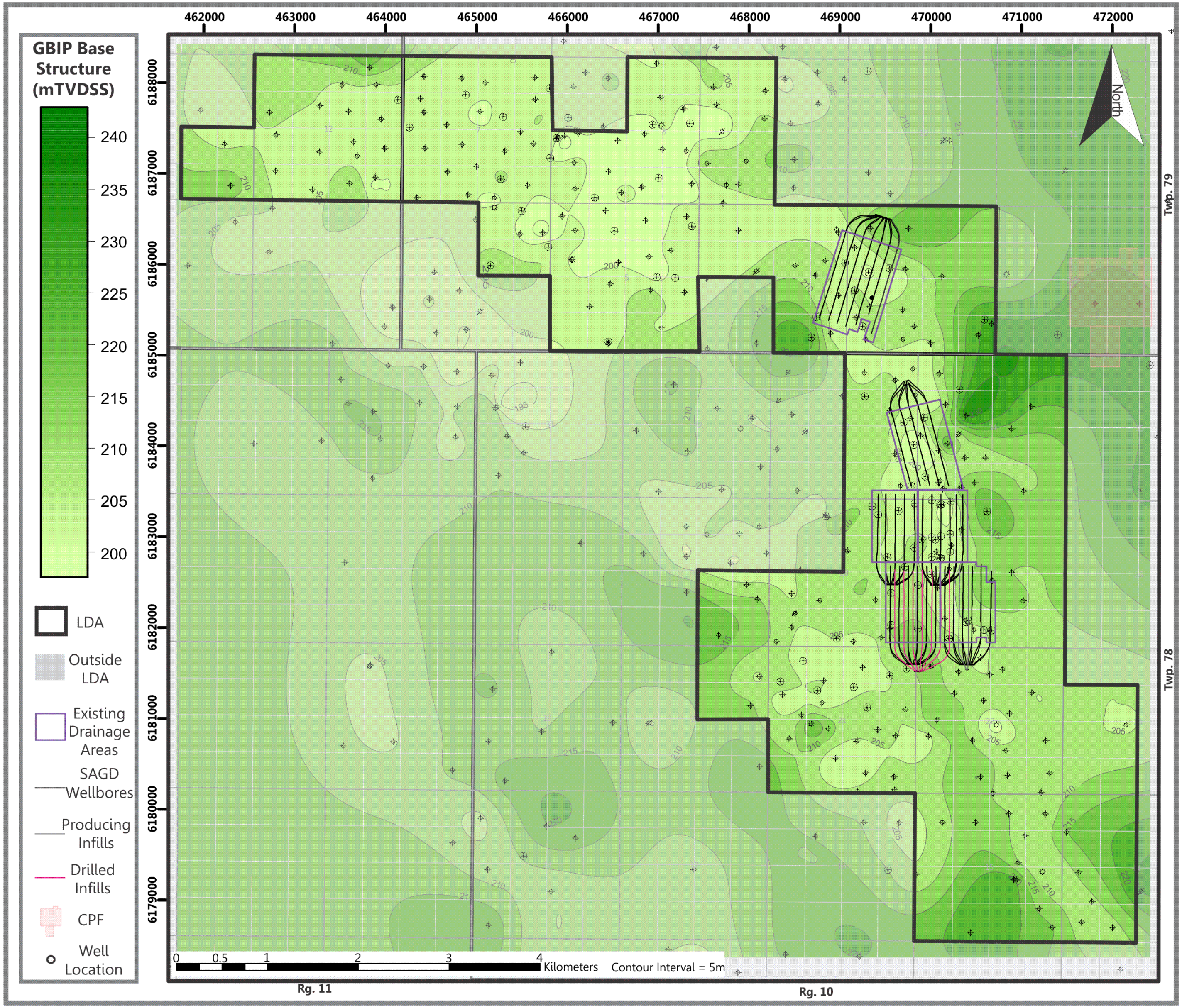
DBIP THICKNESS MAP



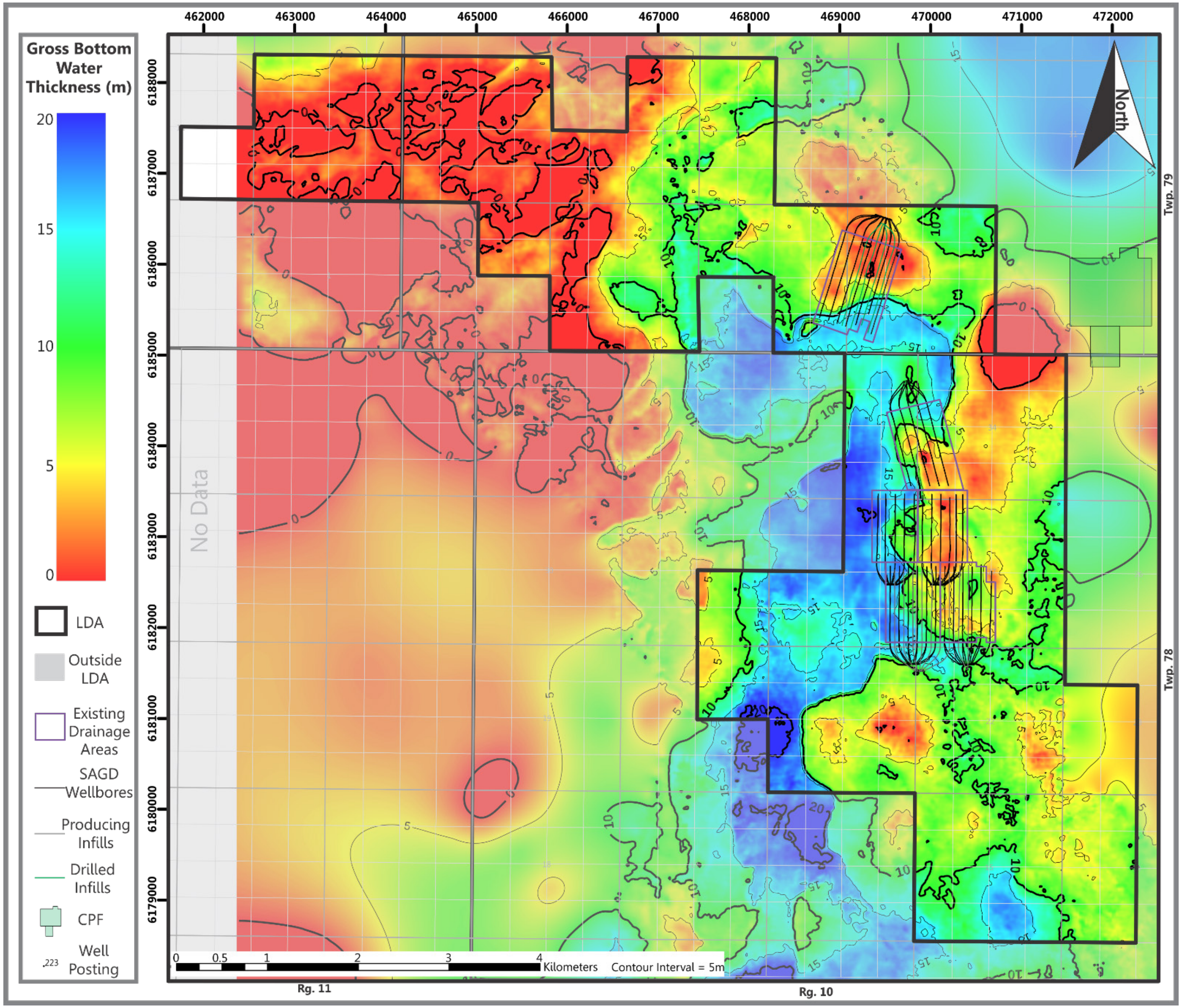
GBIP TOP STRUCTURE MAP



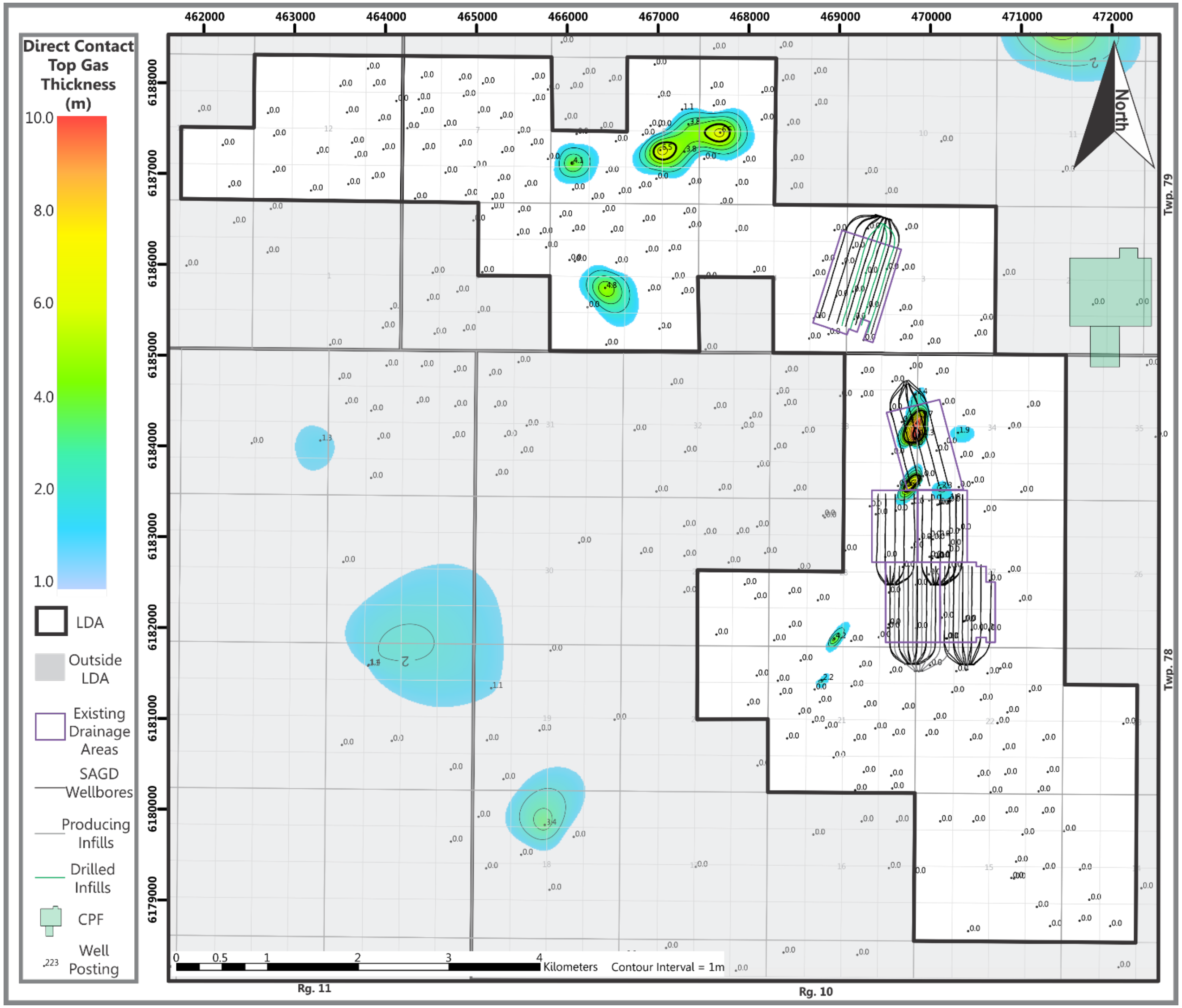
GBIP BASE STRUCTURE MAP



GROSS BOTTOM WATER THICKNESS MAP

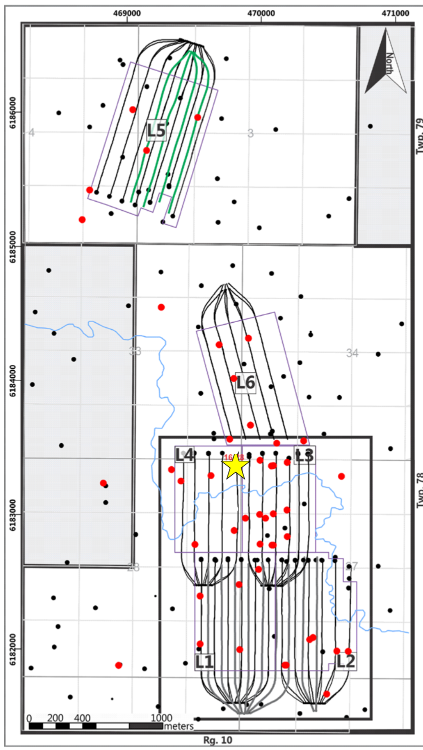


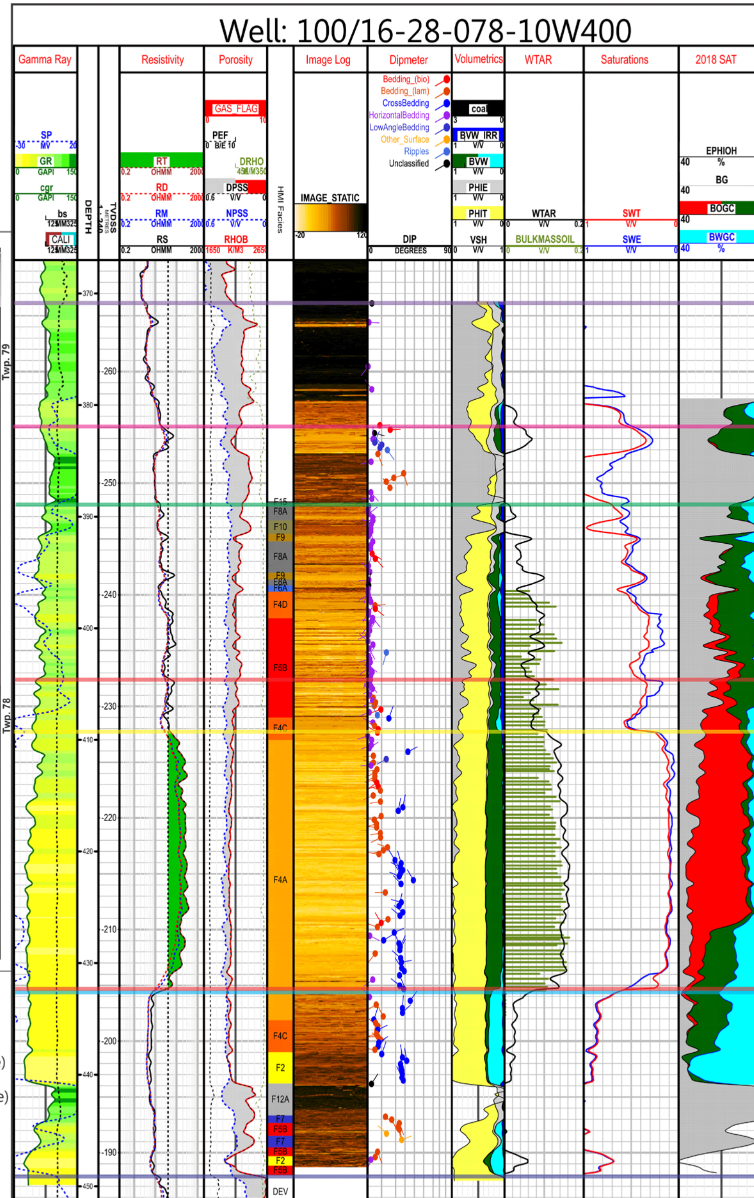
DIRECT CONTACT TOP GAS THICKNESS MAP



Direct Contact = Gas in direct connection to the bitumen column

LDA PAD L4 EXAMPLE: 100/16-28-078-10W4/0





Top Wabiskaw Member

Top McMurray Formation

A2 Mudstone

Top GBIP

Top DBIP

Base GBIP

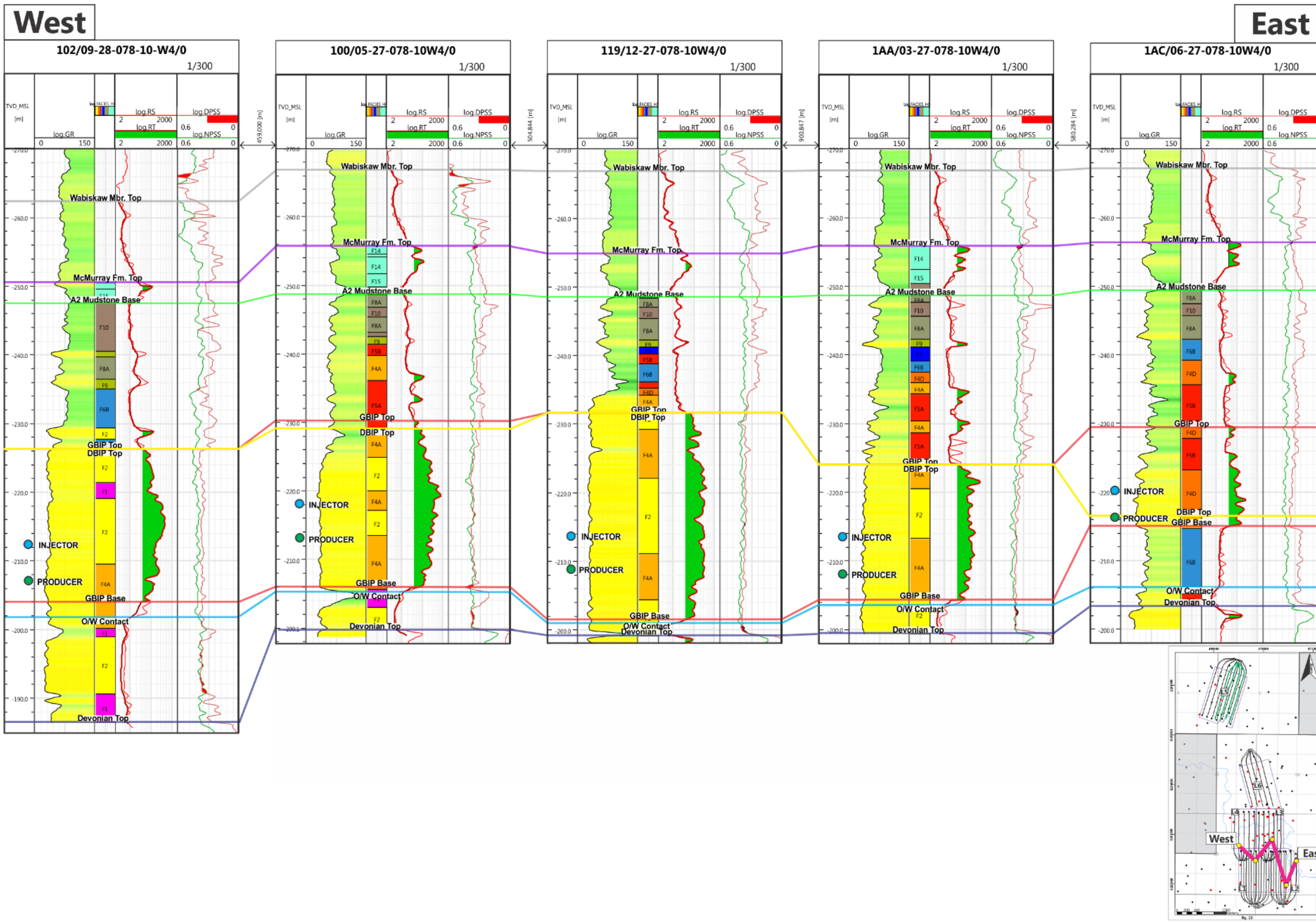
Oil-Water Contact

Top Devonian

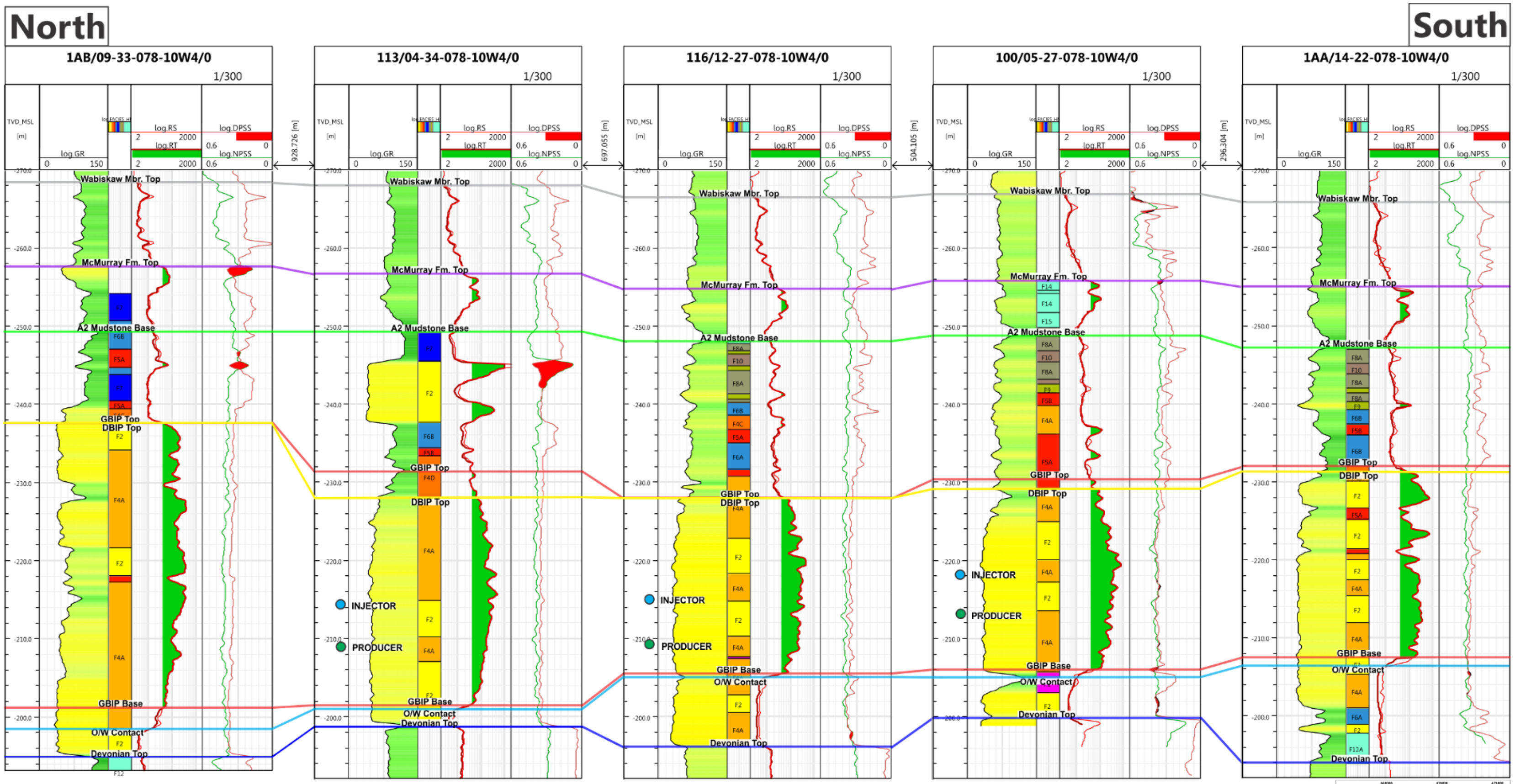
Volumetrics

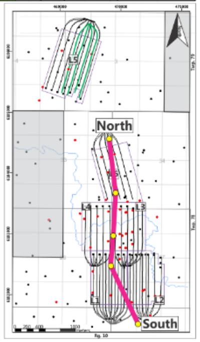
- Sand
- Bitumen
- Residual Water
- Free Water
- VSH Mud (Silt and Shale)
- PHIT Mud (Silt and Shale)

WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L1 TO L6 AREA

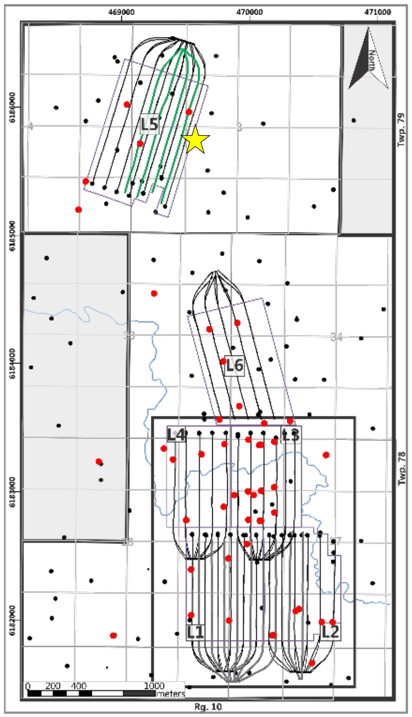


NORTH TO SOUTH PETROPHYSICAL LOG CROSS-SECTION: L1 TO L6 AREA



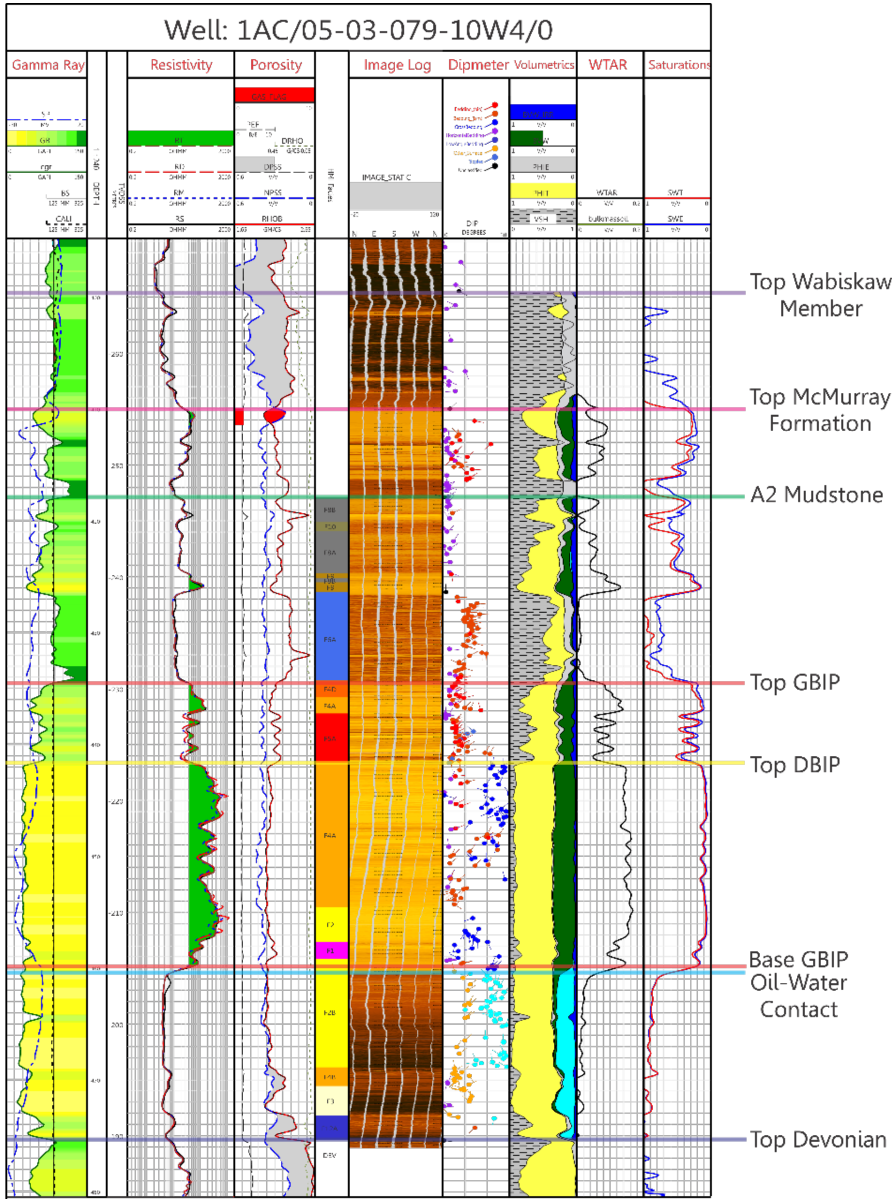


LDA PAD L5 EXAMPLE: 1AC/05-03-079-10W4/0

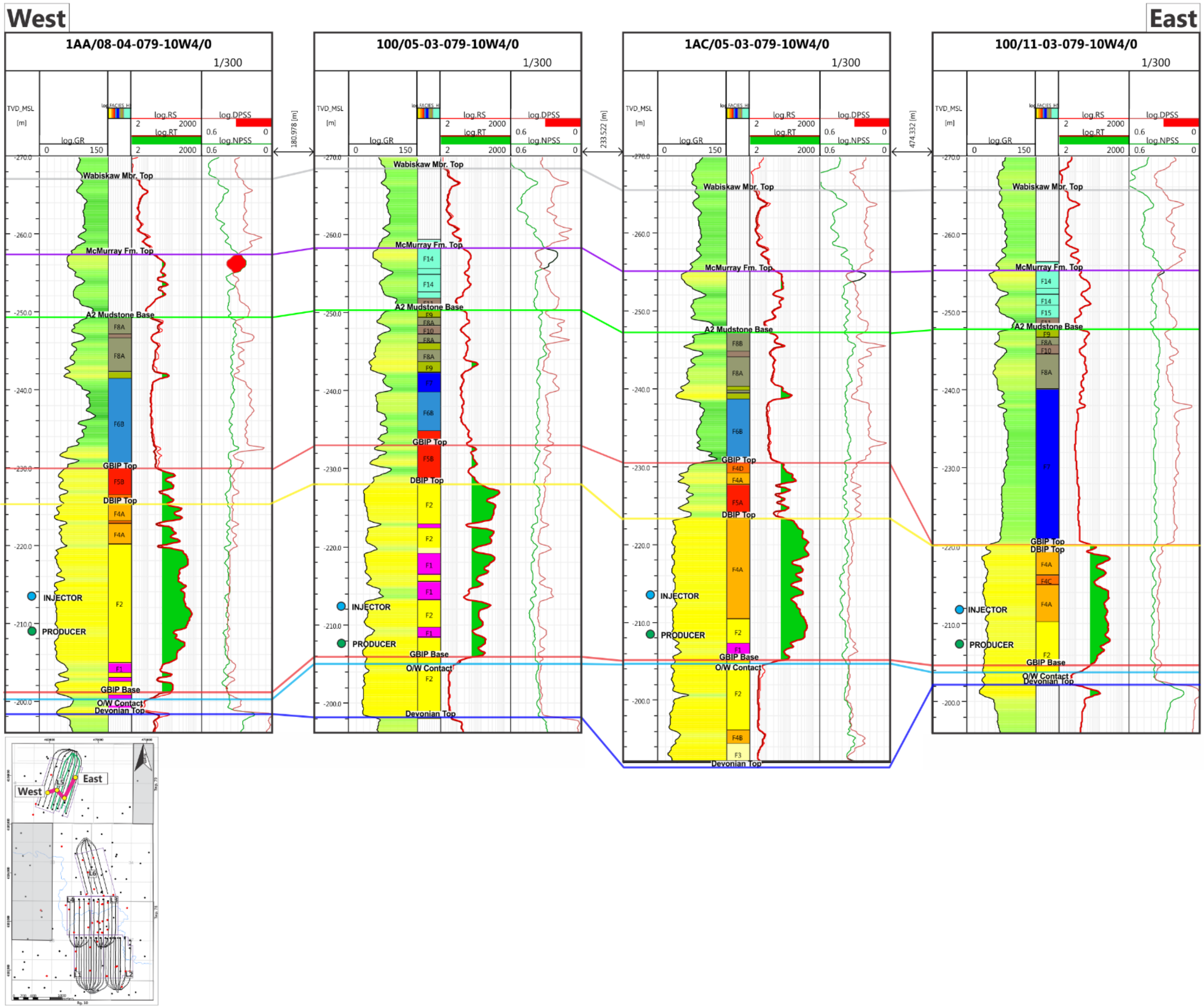


Volumetrics

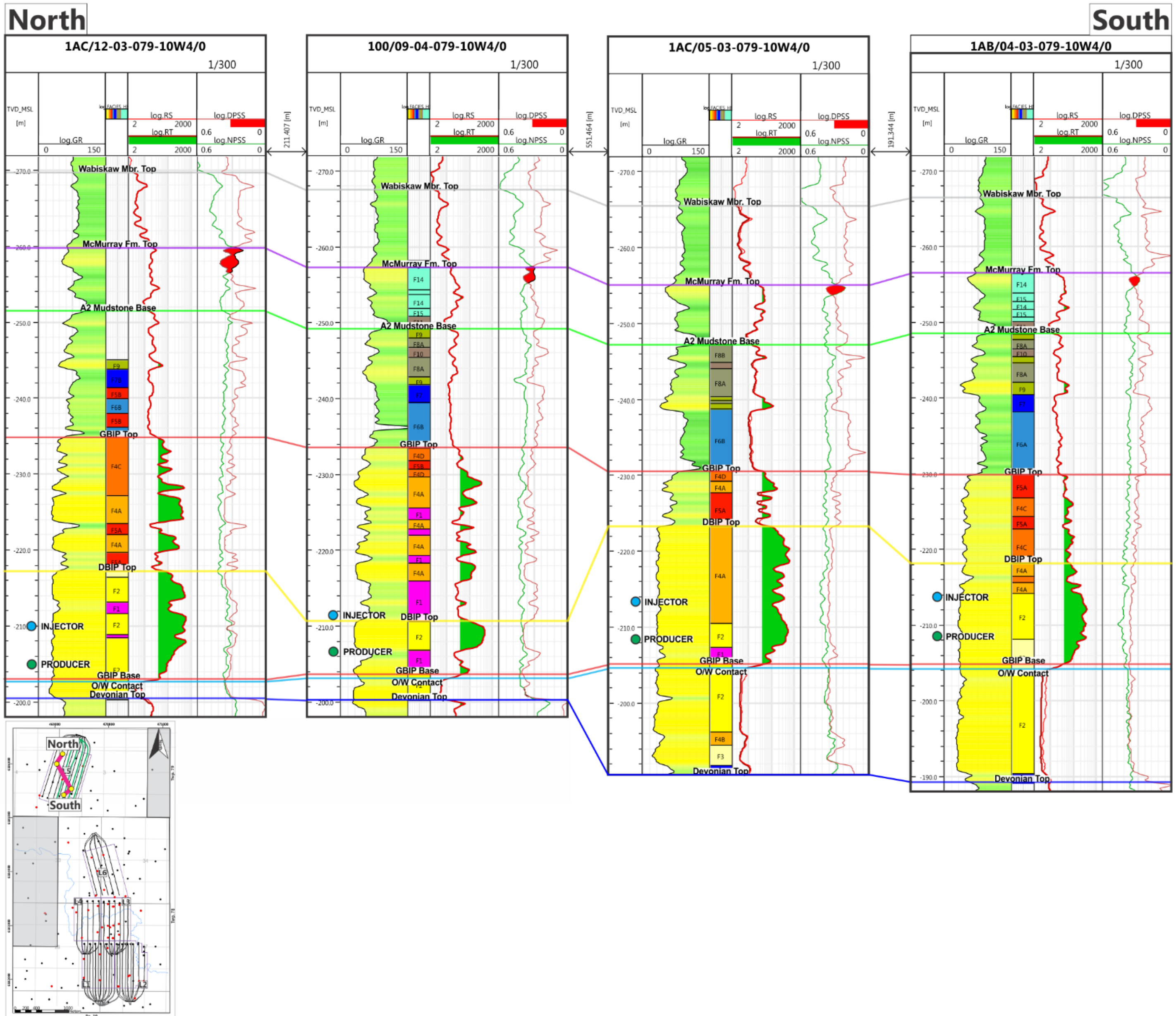
Sand	Free Water
Bitumen	VSH Mud (Silt and Shale)
Residual Water	PHIT Mud (Silt and Shale)



WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L5 AREA

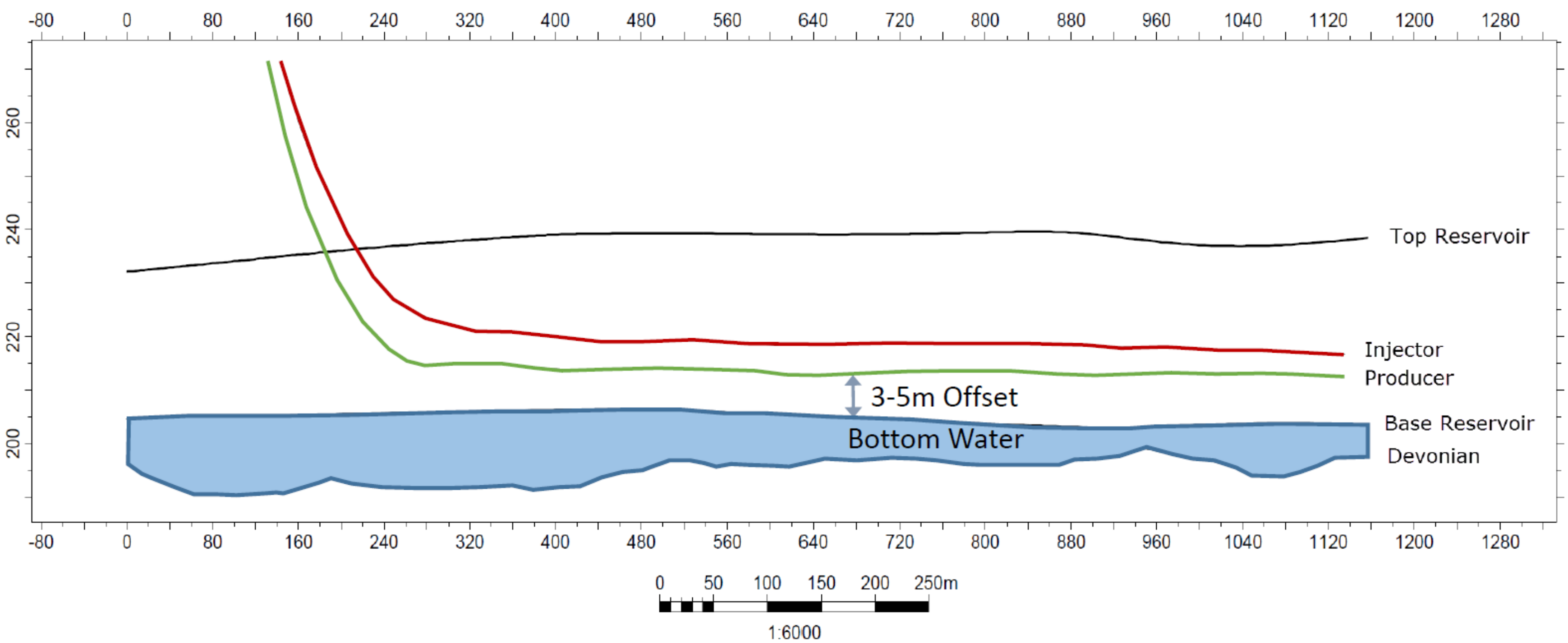


NORTH TO SOUTH PETROPHYSICAL LOG CROSS-SECTION: L5 AREA



SAGD WELL PLACEMENT STRATEGY

- The vertical offset between the SAGD producer wells and bottom water is 3 m to 5 m
  - *The infill wells were placed at the same elevation as the SAGD producer wells*
- The vertical offset between the producer and injector well is 5 m



MINI-FRAC LOCATION

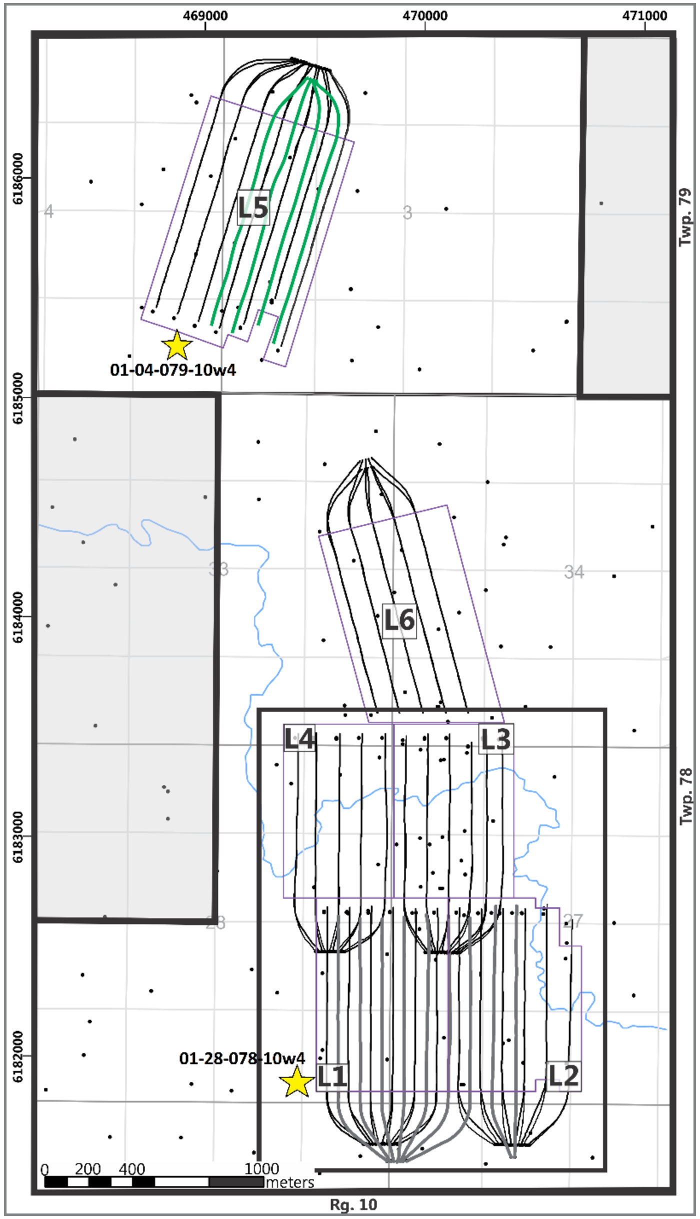
2017

No new mini-frac testing conducted in 2017

HISTORICAL MINI-FRAC TESTS (2010)

Caprock at Leismer is defined as the Clearwater Formation including regionally continuous shale of the Wabiskaw Member

- 6 tests at 01-04-079-10 W4
- 7 tests at 01-28-078-10 W4



MINI-FRAC RESULTS

2017

- No new caprock core, mini-frac or triaxial testing conducted in 2017
- Current SAGD operating pressure range 2,500 - 4,500 kPa

HISTORICAL

- Interpreted fracture closure pressure within the Wabiskaw Member at 386 m (TVD) of 7,350 – 7,520 kPa
- Approved Maximum Operating Pressure (MOP) is 5,500 kPa
- Results included in Leismer MOP Application (No. 1732216) submitted to ERCB July 2012

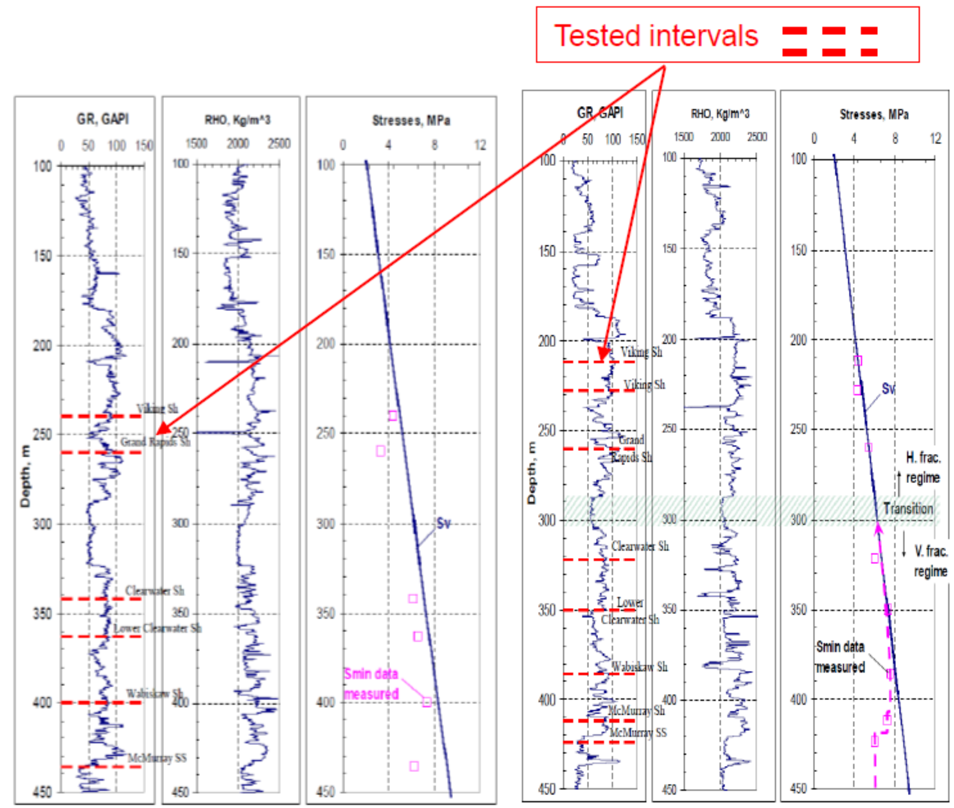


Figure 1: Summary on the in-situ minimum stresses measured from well 1-4. Red dotted lines on the gamma log denote the mini-frac test intervals. "Sv" denotes the vertical overburden stress calculated from the density log. "Smin" in squares is the interpreted minimum stress from the mini-frac tests.

01-04-079-10w4

Figure 2: Summary on the in-situ minimum stresses measured from well 1-28. Red dotted lines on the gamma log denote the mini-frac test intervals. "Sv" denotes the vertical overburden stress calculated from the density log. "Smin" in squares is the interpreted minimum stress from the mini-frac tests. The dotted line for SHmin means that its profile is assumed.

01-28-078-10w4

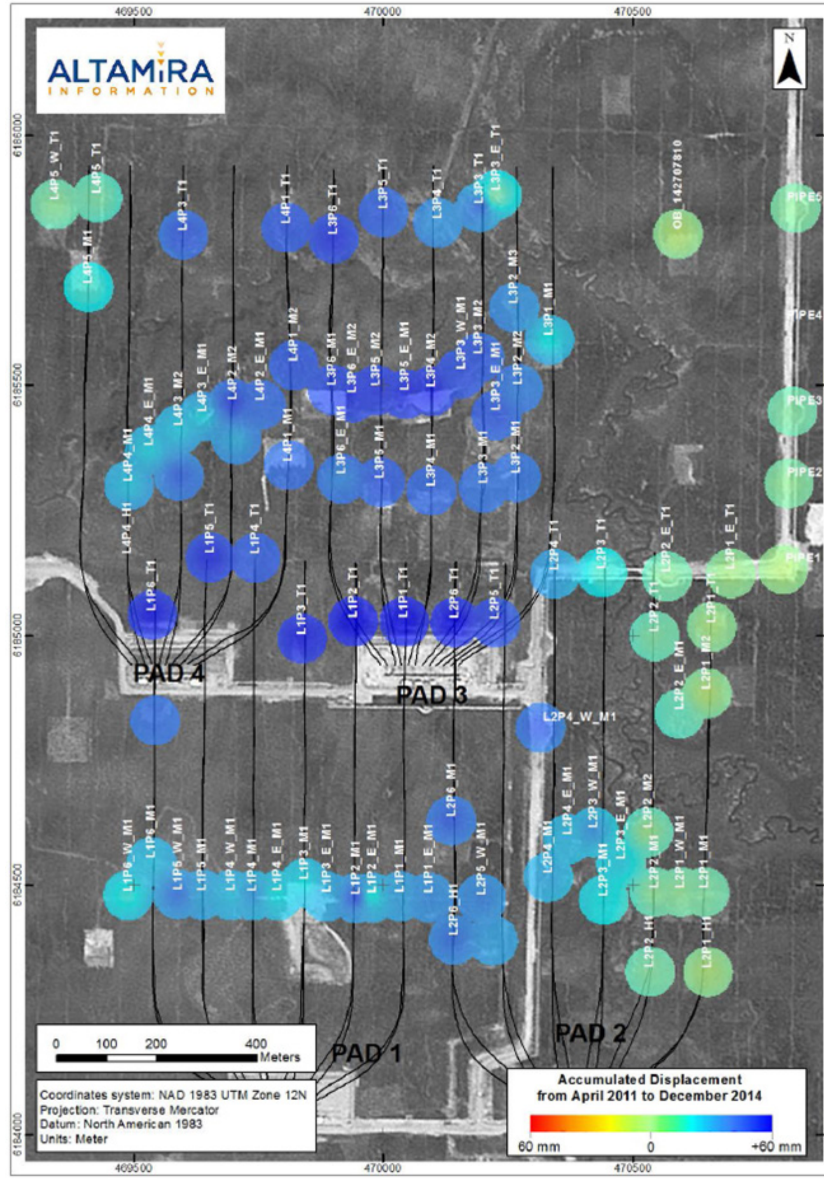
INSAR CUMULATIVE SURFACE HEAVE: L1 TO L4

2017

- No Interferometric Synthetic Aperture Radar (InSAR) data collected in 2017

HISTORICAL

- Satellite-based radar technique used for mapping surface changes
- InSAR deformation monitoring commenced in April of 2011
    - *89 corner reflectors (with supplemental natural points) installed for Pads L1 to L4 and primary steam pipelines*
    - *5 corner reflectors (with supplemental natural points) installed for Pad L5*
- Results on Pads L1–L4 to December 27th, 2014 show minimal surface heave (Maximum = 65 mm, Mean = 28.5 mm)



SUBSURFACE

4D SEISMIC & MONITORING

ATHABASCA
OIL CORPORATION

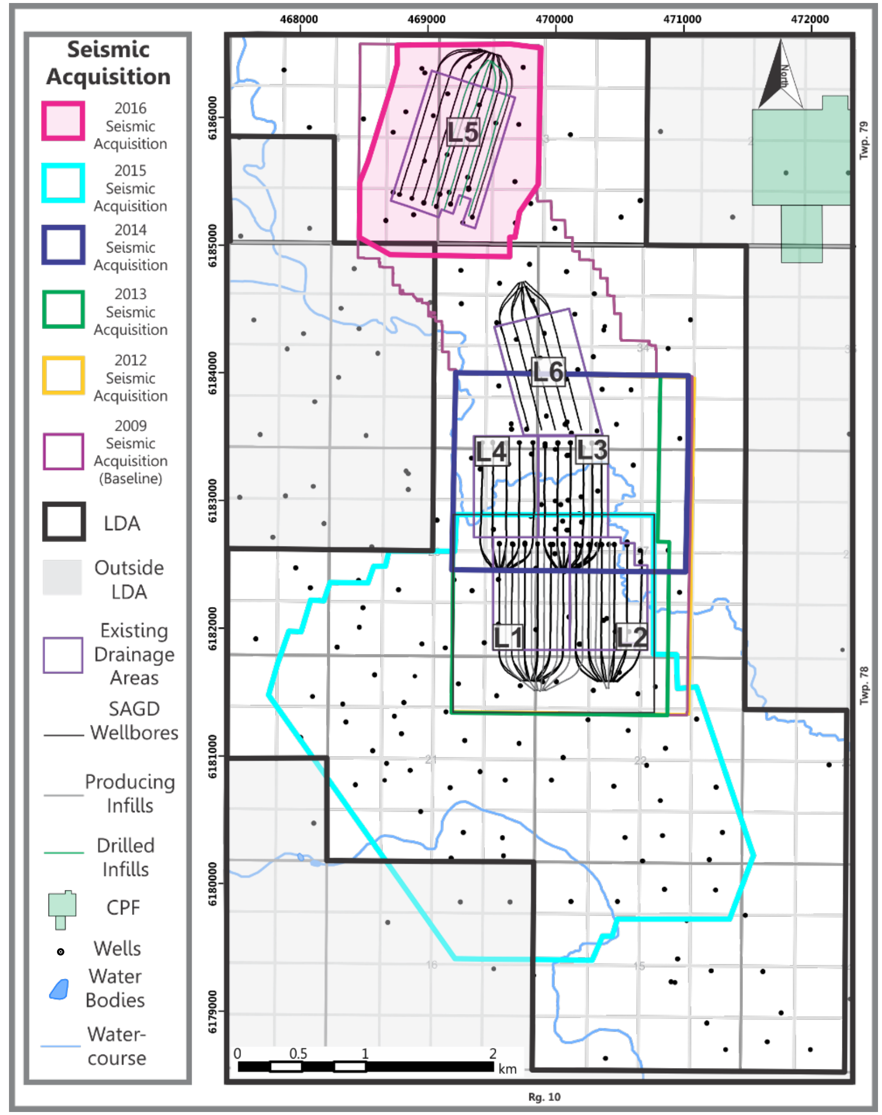
4D SEISMIC ACQUISITION HISTORY

2017

- No new acquisition in 2017

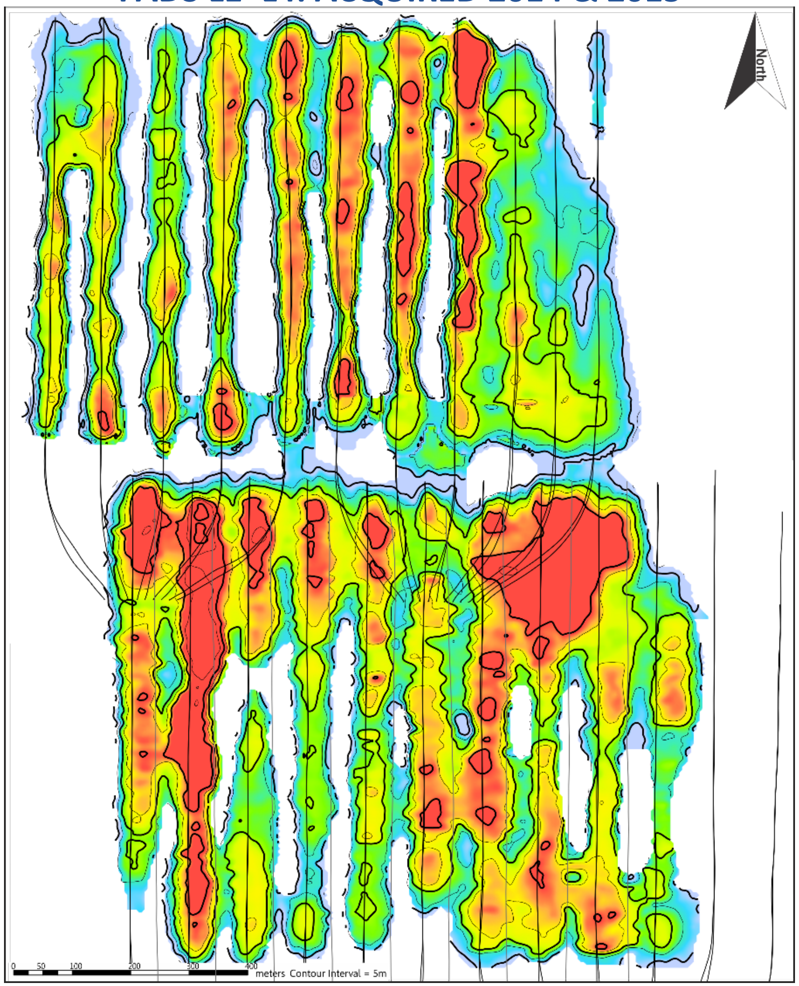
HISTORICAL

- Q1 2016: 2.0 km² first 4D survey for Pad L5
- Q1 2015: 9.0 km² 3D survey
  - *Third 4D repeat survey (2.2 km² of active SAGD Pads L1 and L2)*
  - *Repeat 3D seismic for higher resolution data*
- Q1 2014: 2.1 km² 4D survey (active SAGD Pads L3 and L4)
- Q1 2013: 4.5 km² 3D survey
  - *Second repeat survey (4.9 km² of active SAGD Pads L1– L4)*
- Q1 2012: 8.6 km² 3D survey
  - *First 4D survey (4.9 km² of active SAGD Pads L1–L4)*
  - *New baseline survey for Pads L5 and L6 (3.7 km²)*
- Q1 2009: 4.9 km² baseline survey acquired (pre-steam) over Pads L1–L4

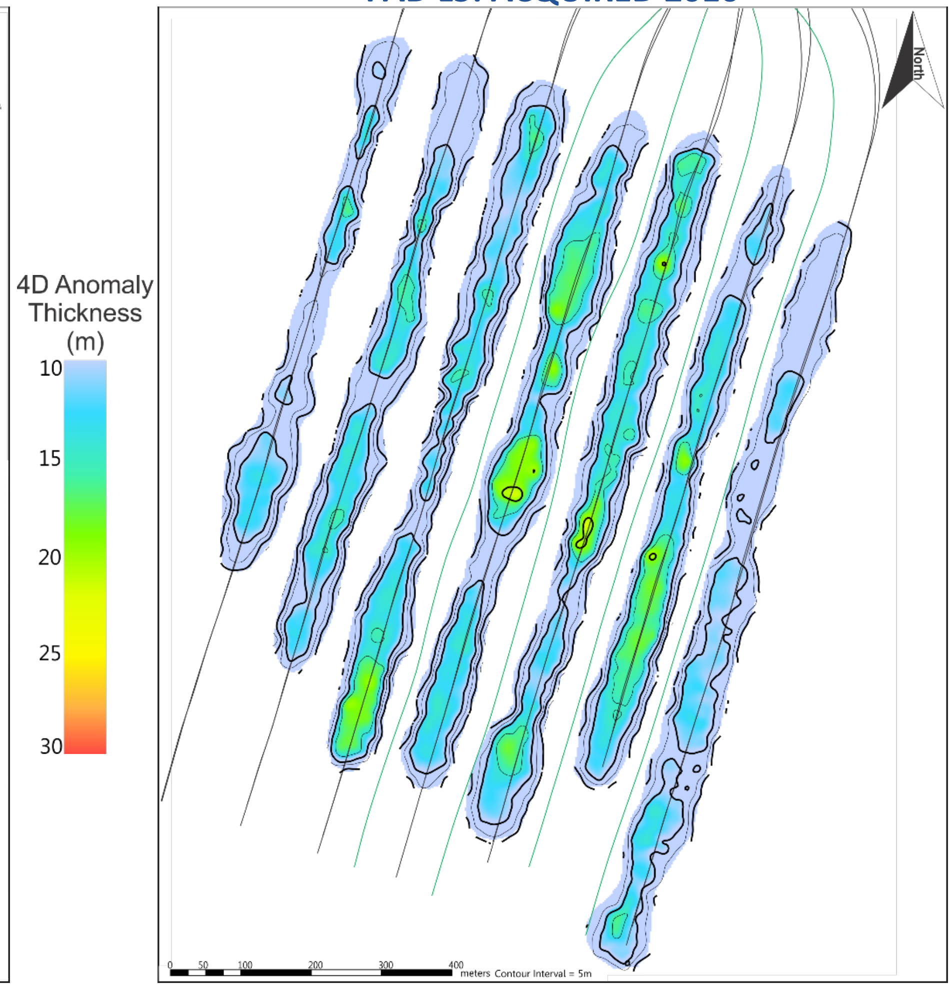


4D SEISMIC RESULTS

PADS L1–L4: ACQUIRED 2014 & 2015



PAD L5: ACQUIRED 2016

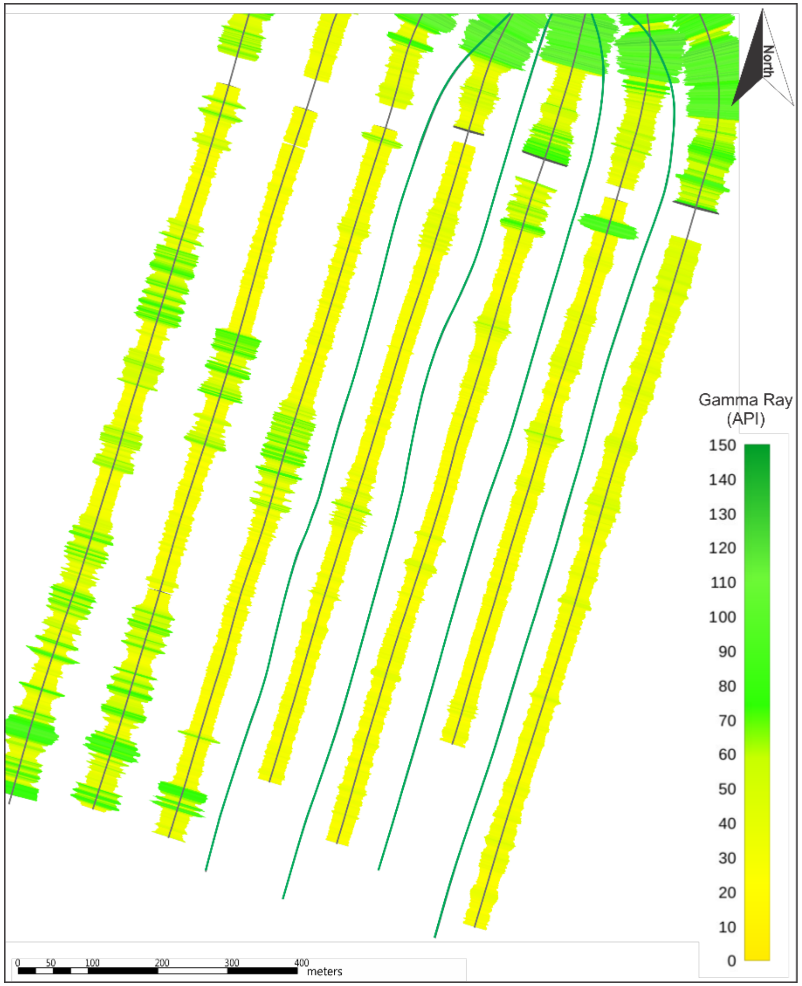


- Pads L1–L4: No new 4D seismic data acquired
- 2014–2015 data shows high degree of conformance along SAGD well pairs

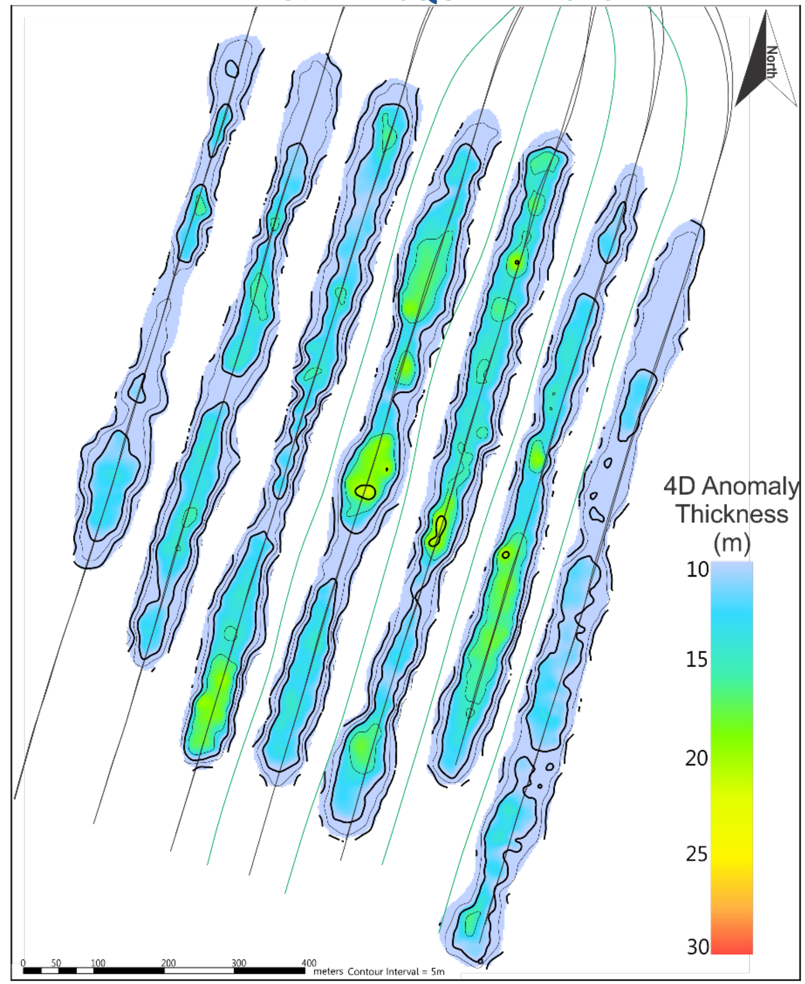
- Pad L5: First 4D data acquired (2 years after start-up)
- 4D seismic anomalies indicate high degree of conformance along SAGD well pairs
- Irregularities are attributed to reservoir heterogeneity and well placement

4D SEISMIC RESULTS

PAD L5: PRODUCER GAMMA RAY PROFILES



PAD L5: 4D ACQUIRED 2016



- Western well pairs have increasing amounts of Breccia within the Injector-Producer Elevation
- This decreasing reservoir quality explains the lower conformance within the toes in L5P5–L5P7

WELL DESIGN & INSTRUMENTATION

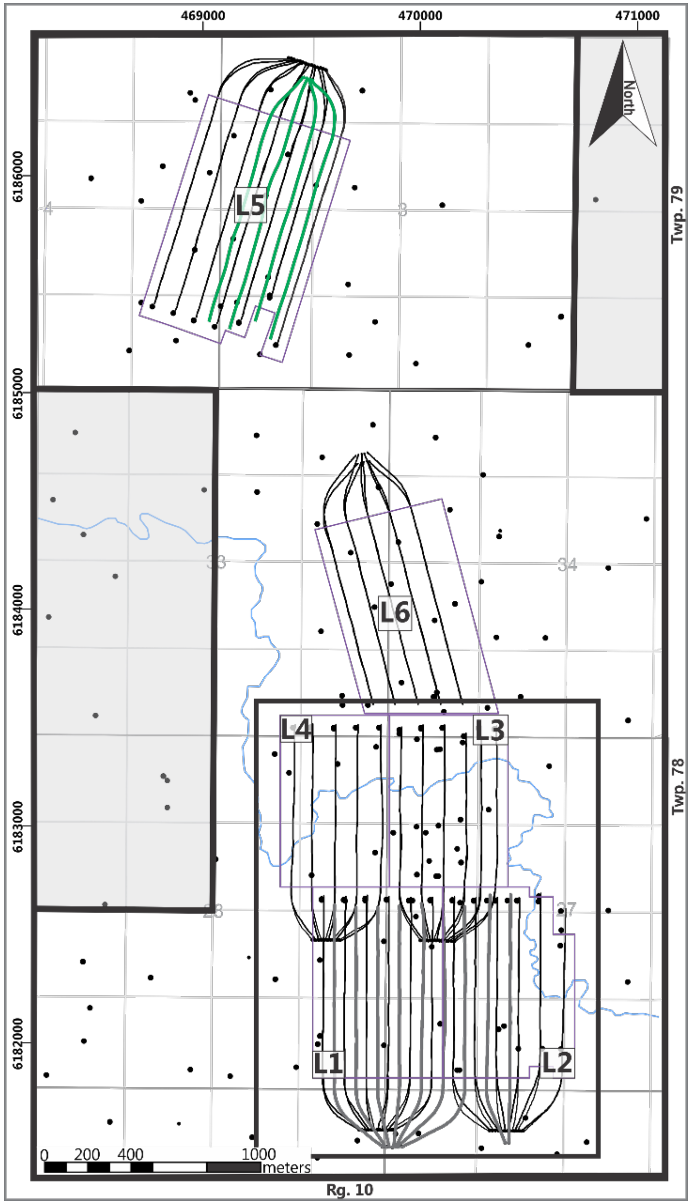
DRILLING & COMPLETIONS

ATHABASCA OIL CORPORATION

WELL LAYOUT

HISTORICAL

- The Leismer Project includes a Central Processing Facility (CPF) and six well pads, with 35 well pairs and 9 producing infill producing wells



WELL PAIR SPACING

Pad	Wells	Spacing (m)
L1	P1–P1	100
	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100
L1L2	L2P6–L1P1	100
L2	P1–P2	100–110
	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100
L3	P1–P2	75
	P2–P3	75
	P3–P4	100
	P4–P5	100
	P5–P6	100

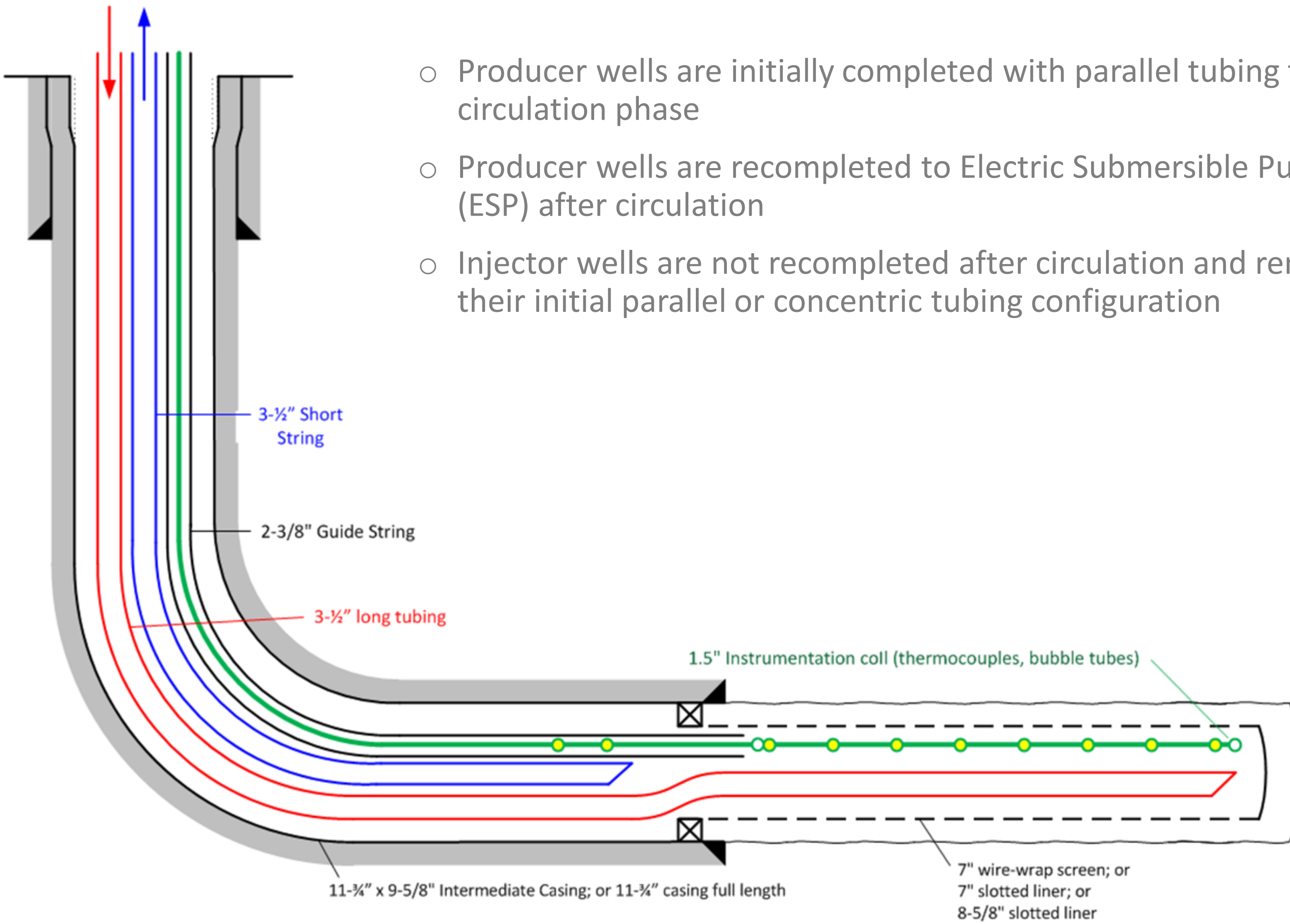
Pad	Wells	Spacing (m)
L3–L4	L3P6–L4P1	85–95
L4	P1–P2	110
	P2–P3	100
	P3–P4	110
	P4–P5	85
L5	P1–P2	95
	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100
	P6–P7	100
L6	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100

COMPLETIONS OVERVIEW: TUBING & LINER CONFIGURATION

Pad	Year Drilled	Number of Wells	Injector Sand Control	Injector Tubing	Producer Sand Control	Flow Control Devices (FCD)
L1	2009	6 well pairs	8-5/8” slotted	Parallel	7” or 8-5/8” slotted or wire-wrap screen	None
L2	2009	6 well pairs	8-5/8” slotted	Parallel	7” or 8-5/8” slotted or wire-wrap screen	None
L3	2009	6 well pairs	8-5/8” slotted	Parallel	7” slotted	2 producers (on tubing)
L4	2009	5 well pairs	8-5/8” slotted	Parallel	7” or 8-5/8” slotted or wire-wrap screen	1 injector (on tubing)
L5	2013	7 well pairs	7” slotted	Concentric	6-5/8” or 7” wire-wrap screen	2 injectors (on liner) 4 producers (on liner) 1 producer (on tubing)
L6	2014	5 well pairs	7” slotted	Concentric	6-5/8” or 7” wire-wrap screen	3 injectors (on tubing) 3 producers (on liner)
L2	2014	2 infills	n/a	n/a	7” wire-wrap screen	None
L1,L2	2015	7 infills	n/a	n/a	7” wire-wrap screen	1 producer (on tubing)
L5	2016	4 infills	n/a	n/a	7” wire-wrap screen	None

Indicates change in 2017

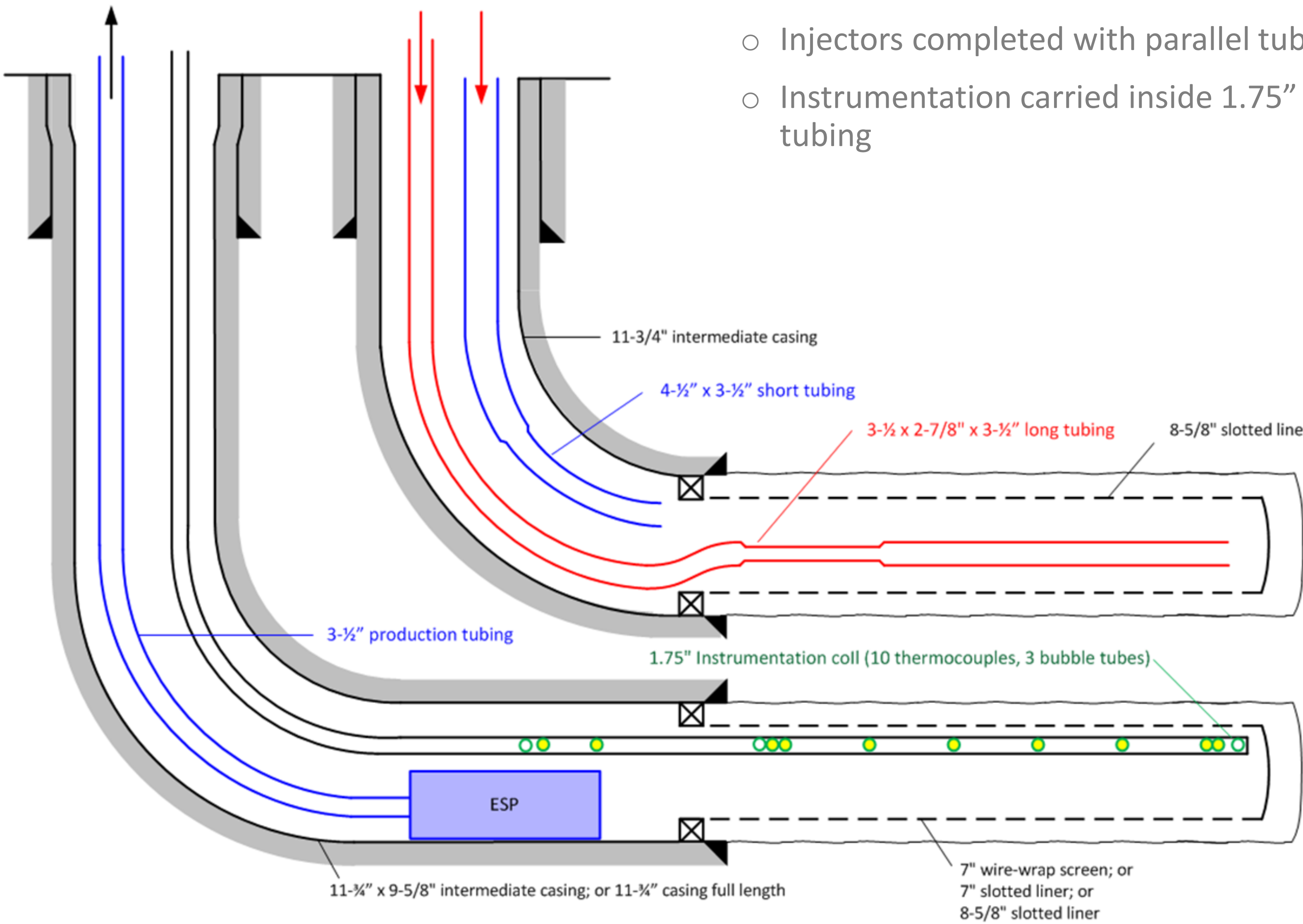
PRODUCER WELL COMPLETION DURING START-UP CIRCULATION



- Producer wells are initially completed with parallel tubing for the circulation phase
- Producer wells are recompleted to Electric Submersible Pump (ESP) after circulation
- Injector wells are not recompleted after circulation and remain in their initial parallel or concentric tubing configuration

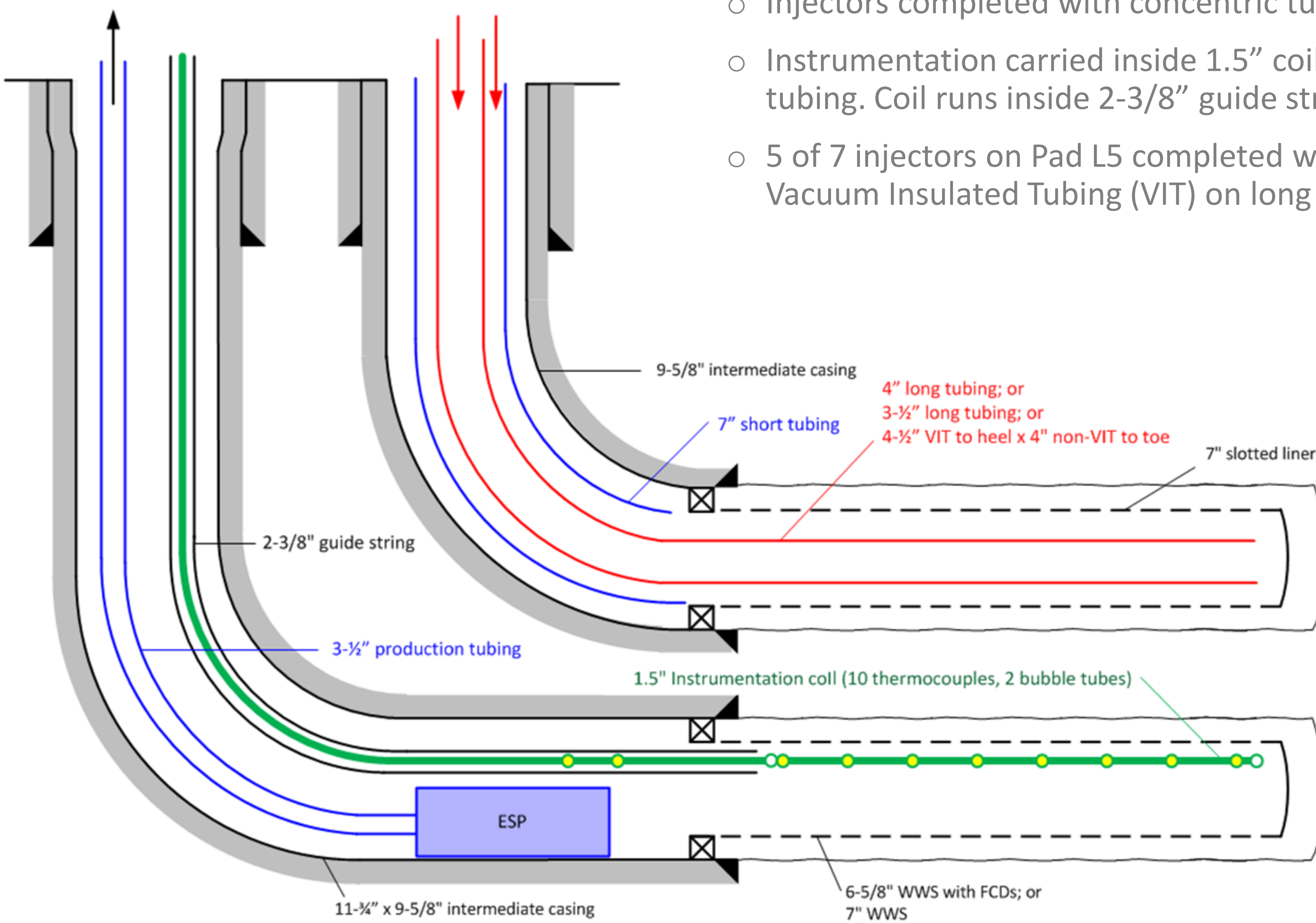
TYPICAL WELL COMPLETION DURING PRODUCTION PHASE: PADS L1–L4

- Injectors completed with parallel tubing
- Instrumentation carried inside 1.75” coiled tubing

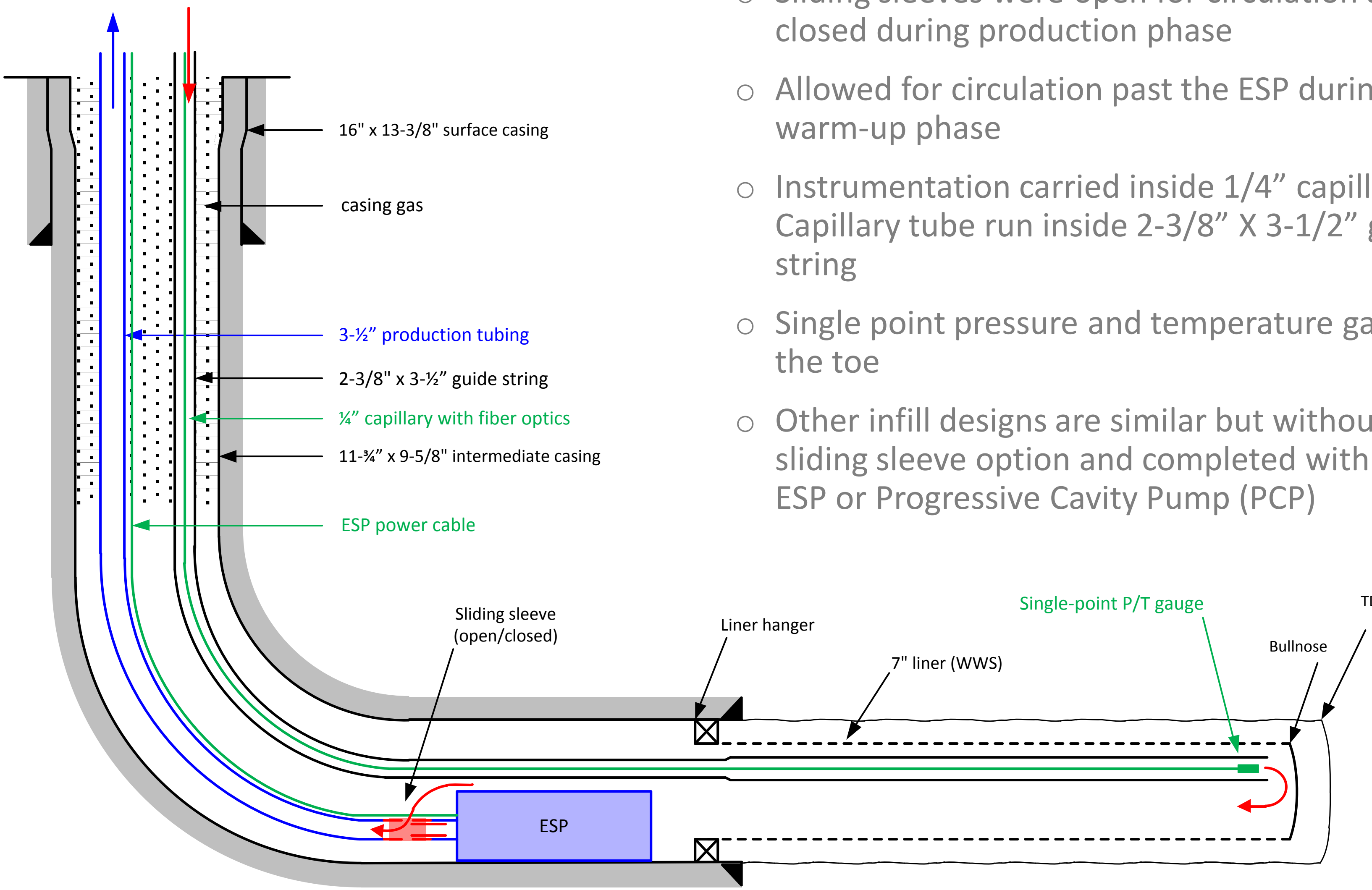


TYPICAL WELL COMPLETION DURING PRODUCTION PHASE: PADS L5–L6

- Injectors completed with concentric tubing
- Instrumentation carried inside 1.5” coiled tubing. Coil runs inside 2-3/8” guide string.
- 5 of 7 injectors on Pad L5 completed with Vacuum Insulated Tubing (VIT) on long tubing



TYPICAL WELL COMPLETION DURING START-UP PHASE: INFILL WELL



- Sliding sleeves were open for circulation and closed during production phase
- Allowed for circulation past the ESP during warm-up phase
- Instrumentation carried inside 1/4” capillary. Capillary tube run inside 2-3/8” X 3-1/2” guide string
- Single point pressure and temperature gauge at the toe
- Other infill designs are similar but without the sliding sleeve option and completed with either ESP or Progressive Cavity Pump (PCP)

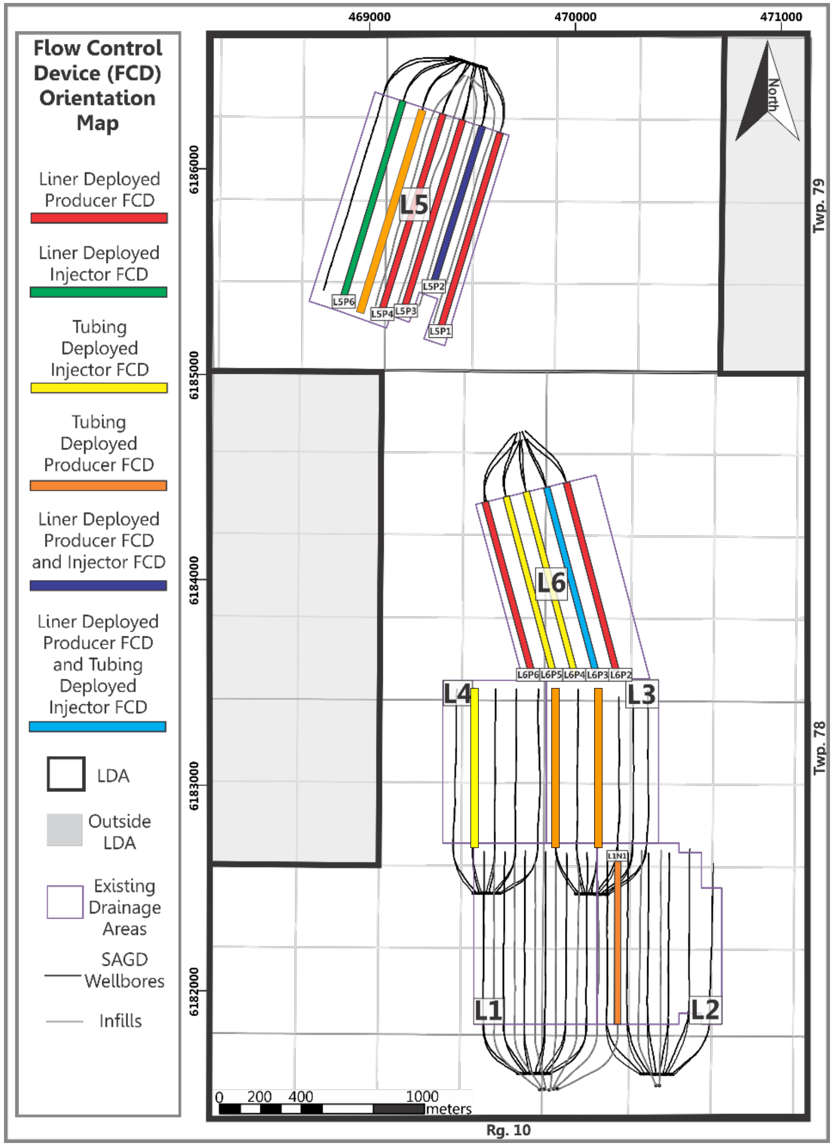
FLOW CONTROL DEVICES (FCD)

2017

- Installed 3 retro-fitted tubing deployed FCDs on production wells

HISTORICAL

- Liner-deployed FCDs installed on 7 producer wells and 2 injector wells
  - *Installed prior to first steam*
- Tubing-deployed FCDs installed on 3 injector wells
  - *Pad 6 start-up was accelerated by exploiting producer FCDs*
  - *FCDs on injector wells have resulted in more uniform subcool conformance in the corresponding producer well*
- Tubing-deployed FCD installed on 1 producer wells



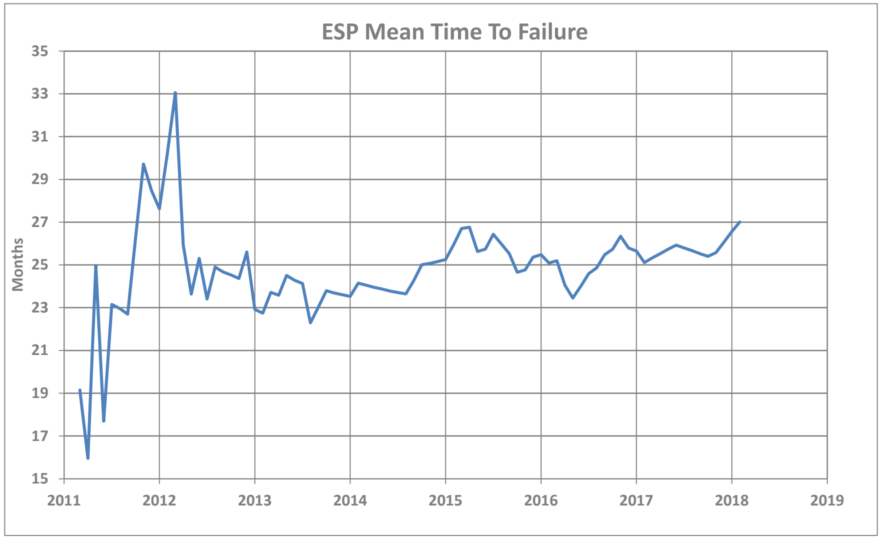
WELL DESIGN & INSTRUMENTATION

ARTIFICIAL LIFT

ARTIFICIAL LIFT

ELECTRICAL SUBMERSIBLE PUMP (ESP)

- 42 ESPs running
  - *27 month mean time to failure (MTTF) since field start-up*
  - *21 month average run life (2 year window)*
- ESP sizes allow for rates 200–1,200 m³/d
- Intake conditions:
  - *180–235°C*
  - *2,500–3,300 kPag*



PROGRESSING CAVITY PUMP (PCP)

- 1 PCP running
  - *Planning conversion to ESP*
  - *Longest running PCP >580 days*
- PCP sizes allow for rates 90–400 m³/d
- Intake conditions:
  - *180–235°C*
  - *2,500–3,300 kPag*

WELL DESIGN & INSTRUMENTATION

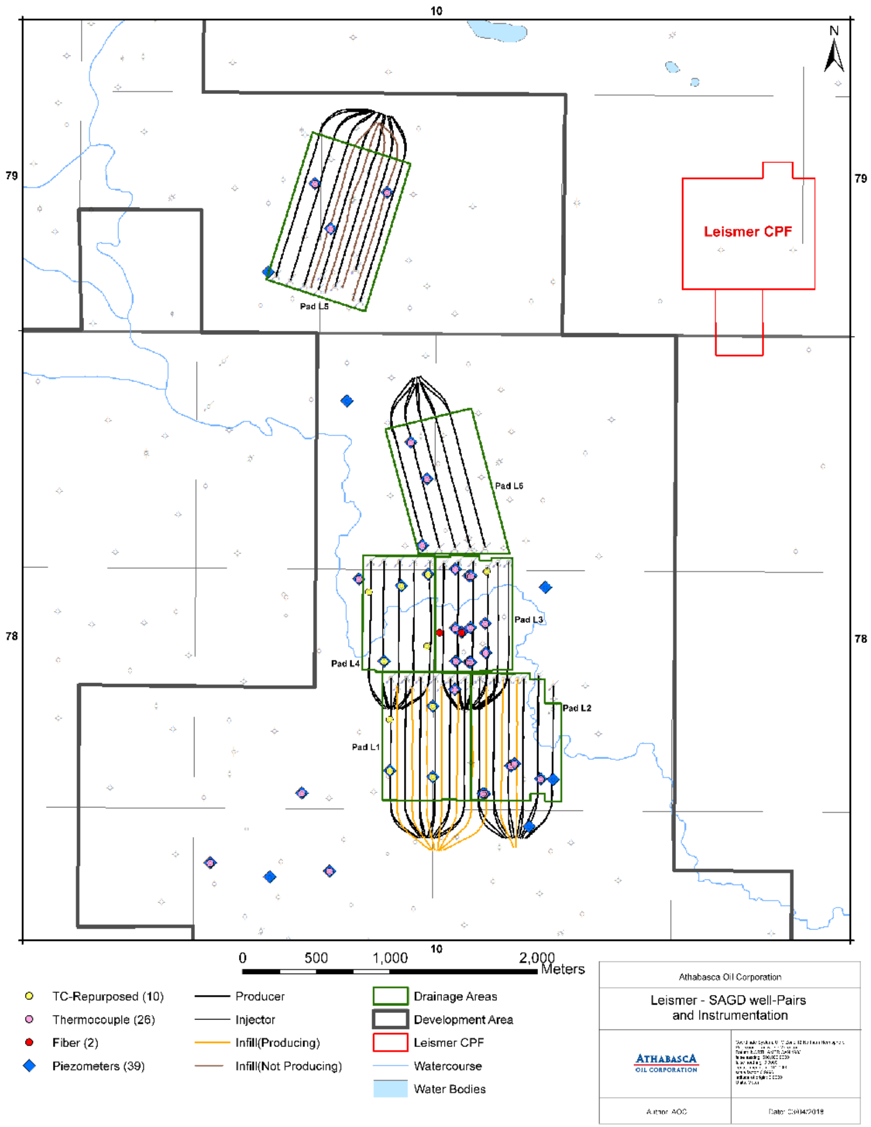
INSTRUMENTATION

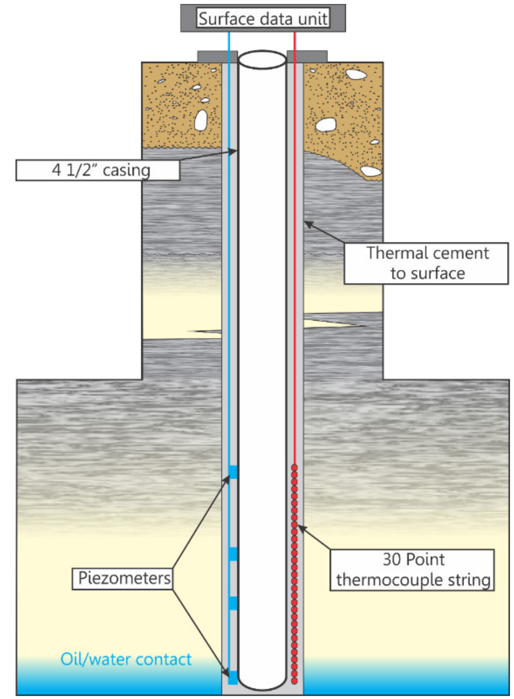
INSTRUMENTATION: SAGD WELLS

Pad	Number of Wells	Wellbore Instrumentation	Additional Instrumentation
L1	6 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well	L1P3, L1P4, L1P5: distributed temperature sensing (DTS) fibre L1I3: 5 thermocouples + 2 piezos + bubble tubes
L2	6 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well	L2P2: DTS fibre L2I3: 6 thermocouples + bubble tubes
L3	6 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well	L3P1, L3P2, L3P3: 40 point fibre L3I3: 6 thermocouples + bubble tubes L3P3: fibre pressure gauge L3P4, L3P6: 40 point fiber & toe pressure
L4	5 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe) Blanket gas in injector well	L4P4: 2 thermocouples
L5	7 well pairs	10 thermocouples in horizontal 2 bubble tubes (heel, toe) Blanket gas in injector well	L5P7, L5I1: fibre pressure gauge (heel) L5I5, L5P5, L5I7, L5P7: 3 thermocouples on sfc. csg. L5P5: 40 point fiber & toe pressure
L6	5 well pairs	10 thermocouples in horizontal 2 bubble tubes (heel, toe) Blanket gas in injector well	L6I2, L6I4, L6I6: DTS fibre
L2	2 infills	40 point fibre 2 fibre pressure gauges (heel, toe)	None
L1	7 infills	40 point fibre 1 fibre pressure gauge (toe)	L1N1: fibre pressure gauge heel

Indicates change in 2017

INSTRUMENTATION: OBSERVATION (OBS) WELLS



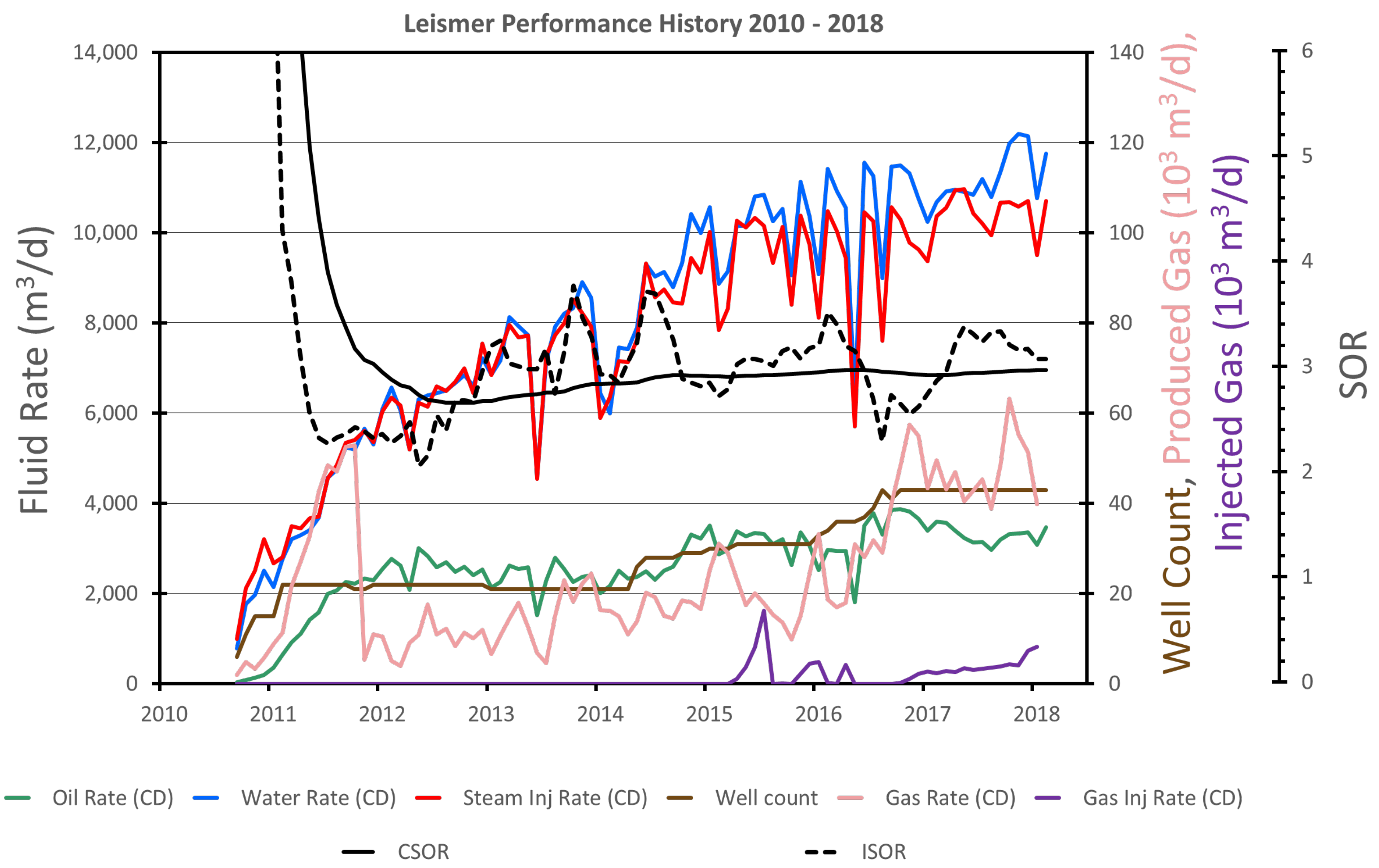


- 30 thermocouples, spaced at 1 m above, below, and within SAGD pay
- 10 thermocouple bundles installed in wells previously equipped with fibre optics (DTS) in February 2018
- 3 to 4 piezometers in bitumen, bottom water, and top lean/gas zone
- 90% thermocouples and 70% piezometers are in working condition, and reading temperature and pressure properly

SUBSURFACE

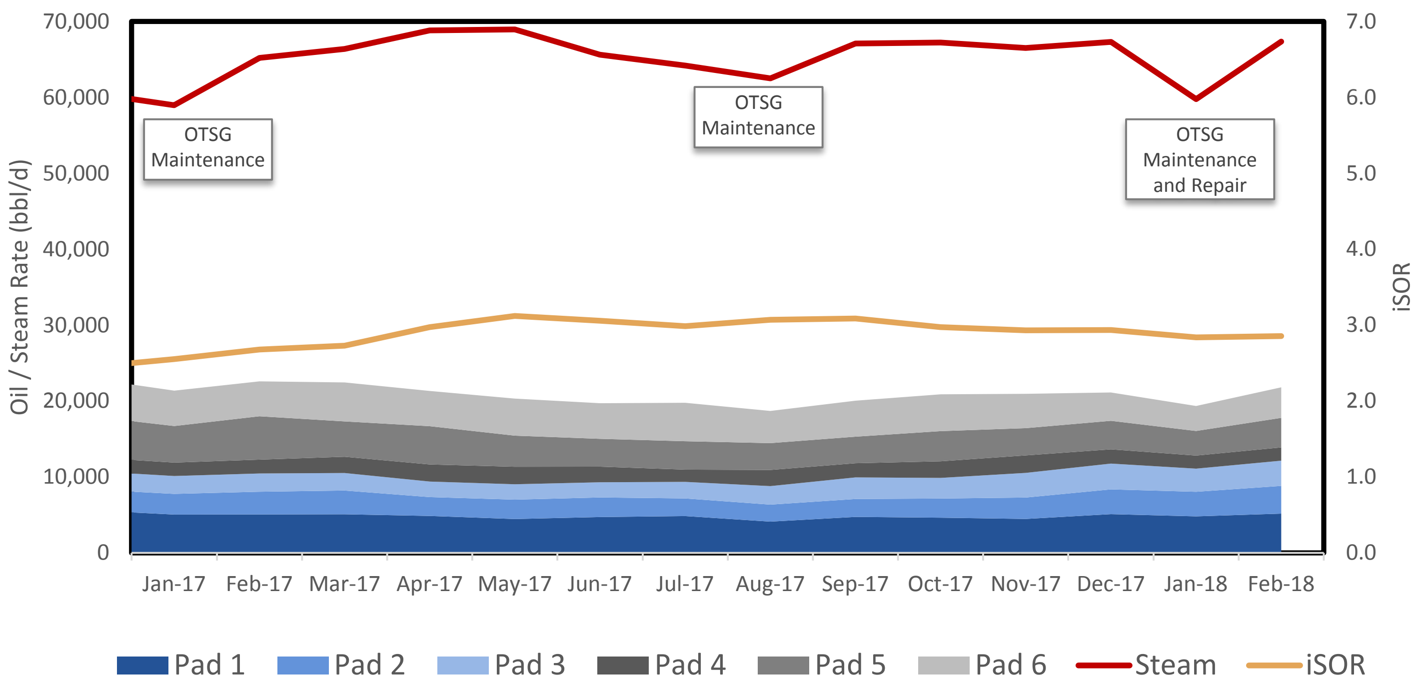
SCHEME PERFORMANCE

LEISMER PROJECT TREND

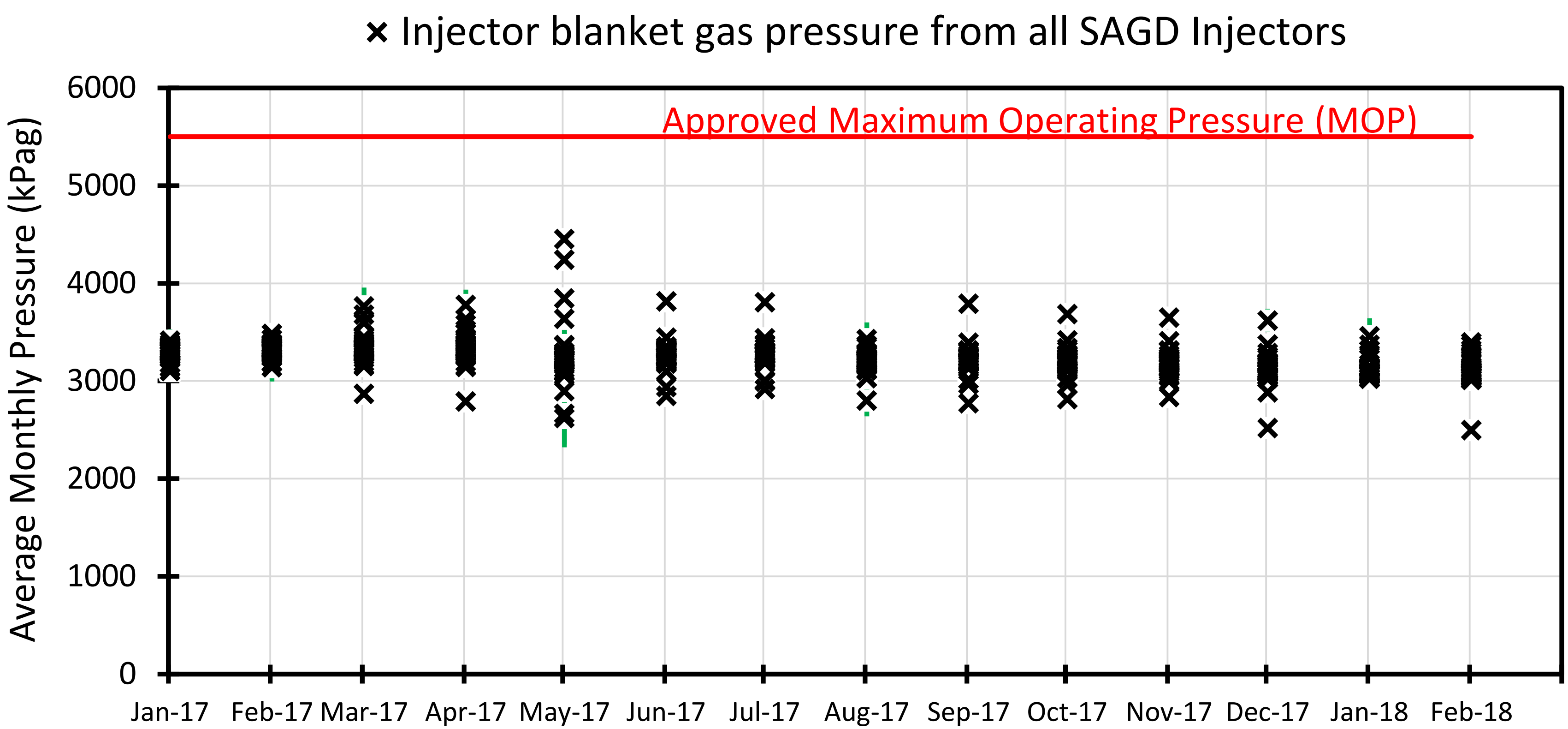


LEISMER PRODUCTION PERFORMANCE

- 2017 Average production 3,301 m³/d (20,763 bbl/d)
  - *Highest oil and steam annual average production in Leismer history*
- Production increase in 2017 supported by implementation of 3 flow control device installations and 3 infill well liner plug backs



OPERATING PRESSURE



- Approved maximum operating pressure (MOP) is 5,500 kPag
- All injectors are operating around 3,200 kPag

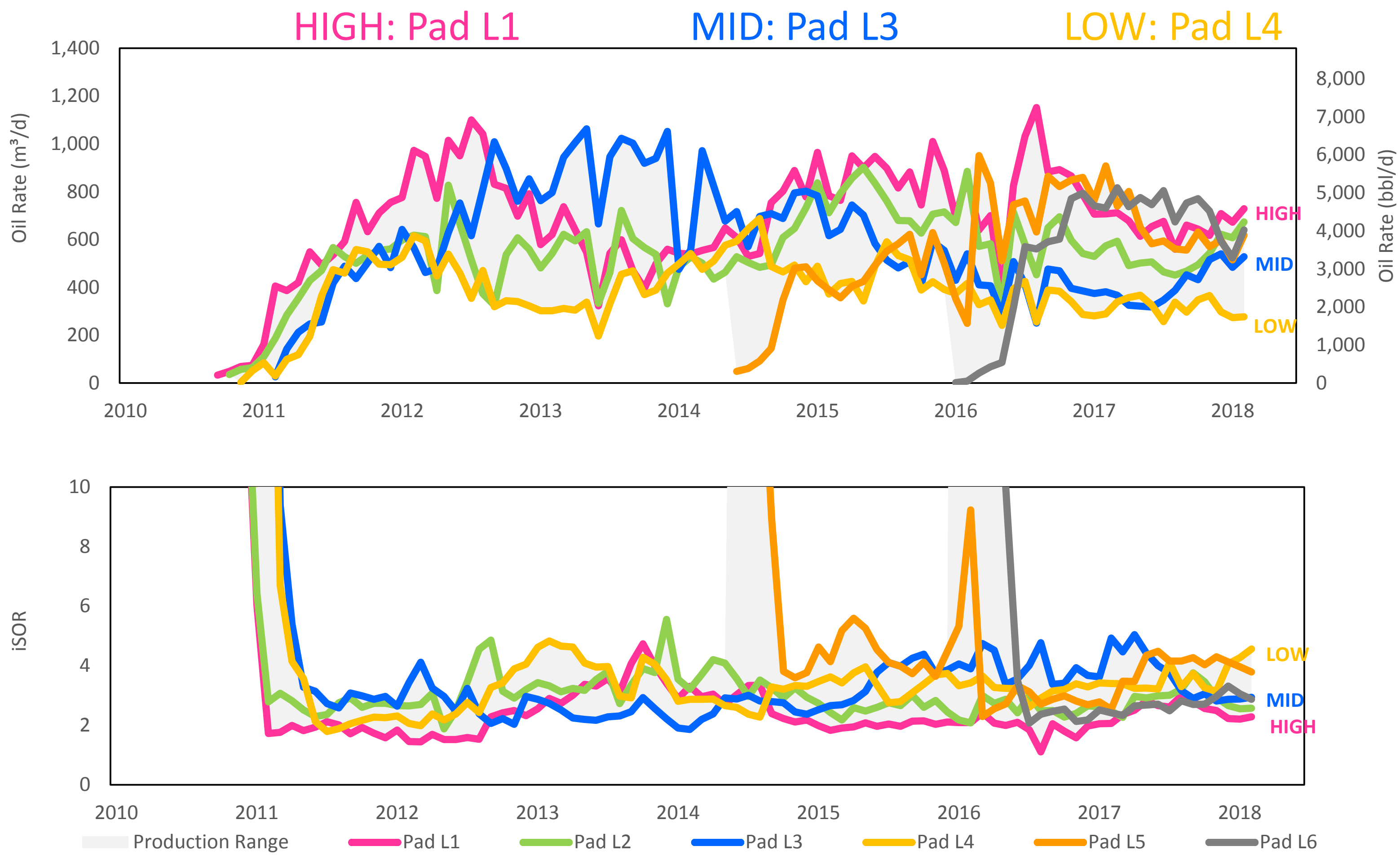
PAD RECOVERIES

Well Pad	DBIP (10^3 m^3)	GBIP (10^3 m^3)	Cumulative Production (10^3 m^3)	DBIP Recovery to Date	GBIP Recovery to date	Predicted Recovery after 15 years (DBIP)
L1	3,467	3,914	1,862	54%	48%	65–75%
L2	2,821	3,344	1,465	52%	44%	65–75%
L3	3,003	3,443	1,514	51%	44%	50–60%
L4	2,236	2,433	1,033	46%	42.5%	50–60%
L5	3,477	4,479	761	22%	17%	50–60%
L6	3,471	3,836	439	13%	11.5%	65–75%
Total	18,475	21,449	7,075	38%	33%	~65%

- DBIP, Cumulative Production, and Recovery Factor valid as of February 28th, 2018
- Predicted Recovery Factor is based on 2D volumetric and simulations

2017 PAD PERFORMANCE: PERFORMANCE SELECTION

- 2017 Peak oil rate 366 – 816 m³/d (2,300–5,130 bbl/d)
- 2017 iSOR: 2.2 – 4.5
- Selection of High/Mid/Low cases based on Oil Rate and iSOR

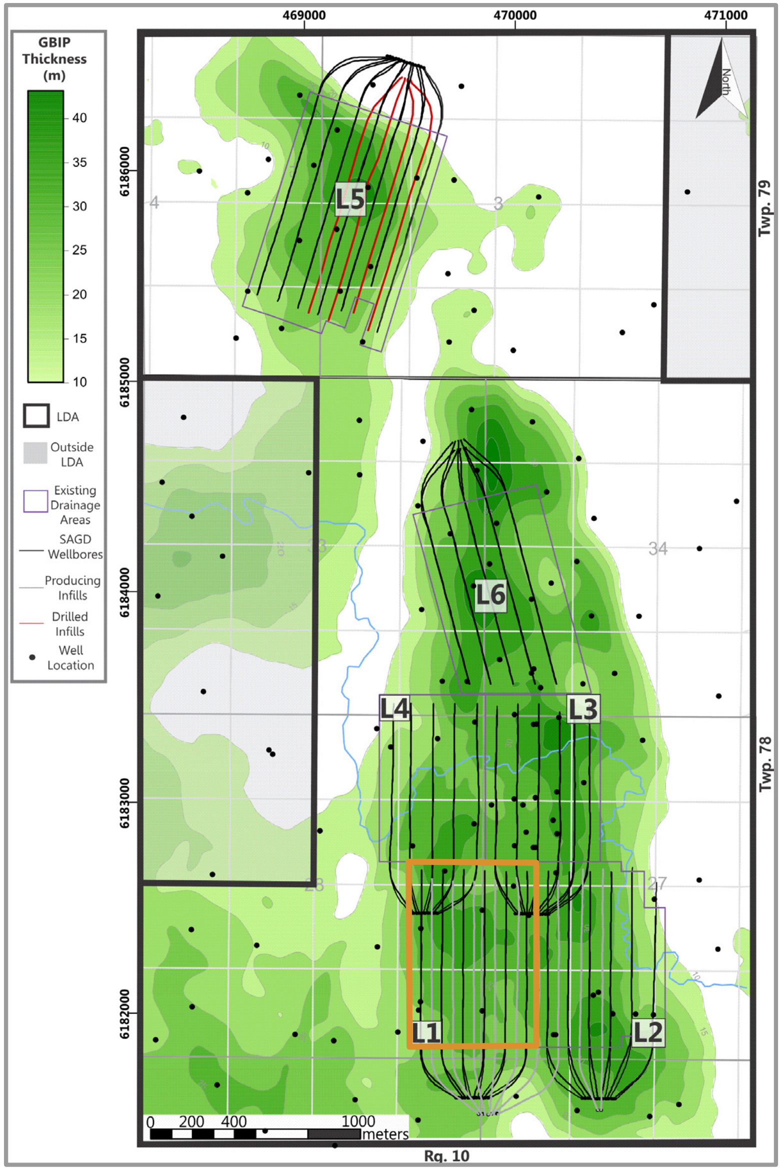


PAD PERFORMANCE - HIGH: PAD L1

PAD L1 GEOLOGY

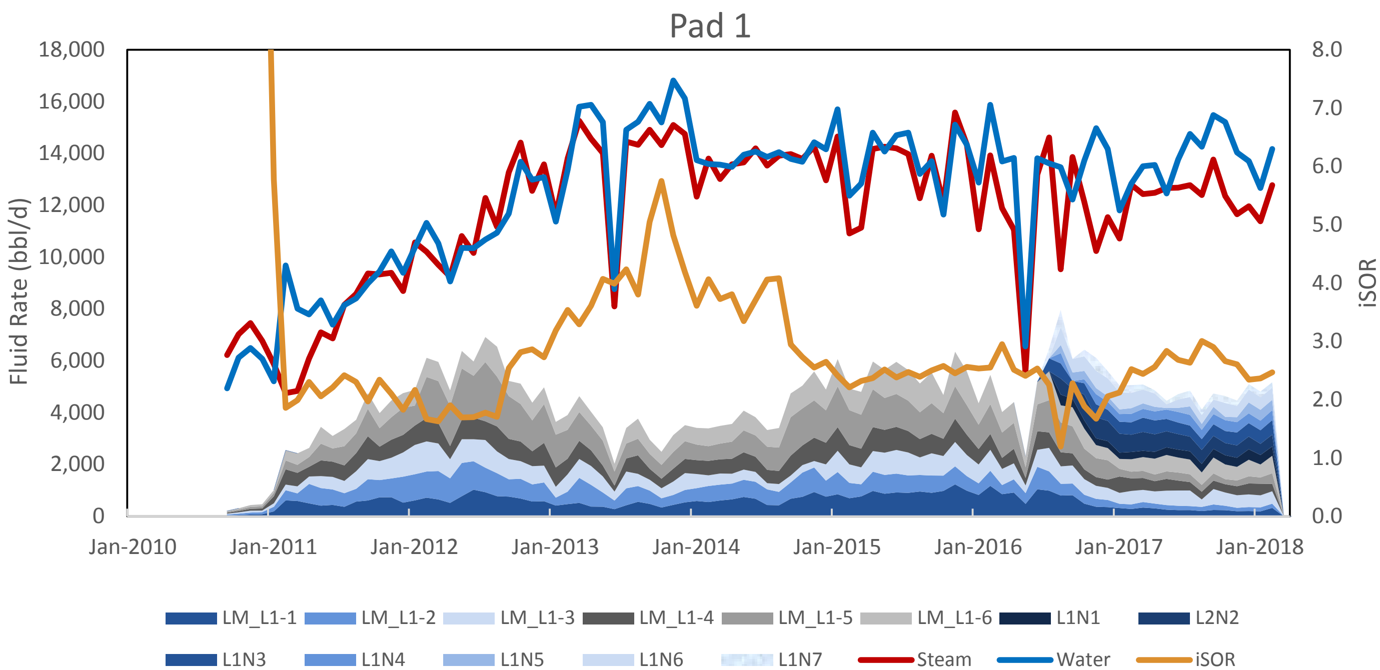
- Pad L1 has a consistent, thick net pay in both the GBIP and the DBIP
- Has highest oil saturation (89%) and above average permeability (Kh 5.6D)

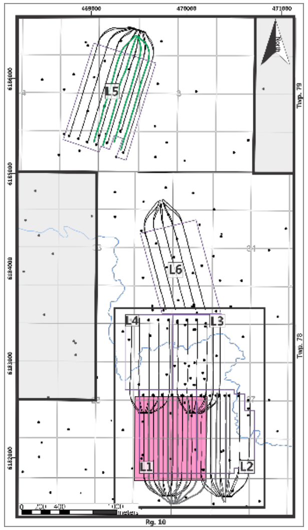
Well Pad	Area (10^3 m^2)	Avg. DBIP Thickness (m)	Avg. GBIP Thickness (m)	Avg. Porosity * (%)	Avg. Oil Saturation* (%)
L1	526	22.5	26.7	33	89
L2	498	19.2	24.5	32	86
L3	411	23.6	29.1	34	87
L4	389	19.6	22.4	33	87
L5	708	17.6	24	33	86
L6	571	25.3	28.9	33	87
Total/Avg.	3,103	21.3	25.9	33	87
LDA Total	24,166	15.5	17.3	32	85



2017 PAD PERFORMANCE – HIGH: PAD L1

- SAGD well pairs on production in 2010
  - *Infill wells drilled in 2015 and started in 2016*
- 2017 Peak bitumen rate ~ 822 m3/d (5,170 bbl/d)
- 2017 iSOR: 1.9 – 2.6
- Pad L1 continues to be a high performing pad
  - *Infill wells contribute ~45% of total pad production i.e. ~320–400 m³/d (2,000–2,500 bbl/d)*
  - *Infill wells have provided significant oil rates and reductions in SOR on the pad*



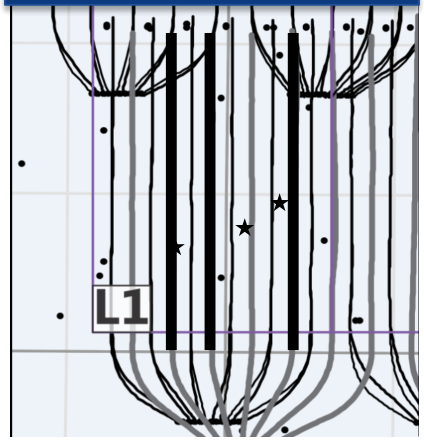


INFILL WELLS PRODUCTION OPTIMIZATION

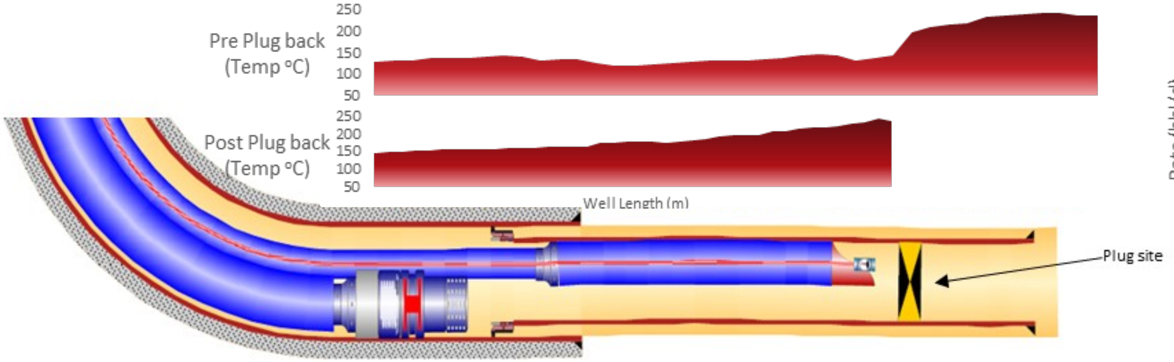
PLUG BACKS

- In 2017 three infill wells were plugged back to isolate thermally hot regions
- The infill system deliverability improved despite shortening of horizontal well length by ~25%
  - *The infill system is defined as the infill well plus 50% production from the adjacent SAGD pairs*
- TFSR and reservoir retention targets are based off the infill well system emulsion and steam

Infill wells with bridge plug

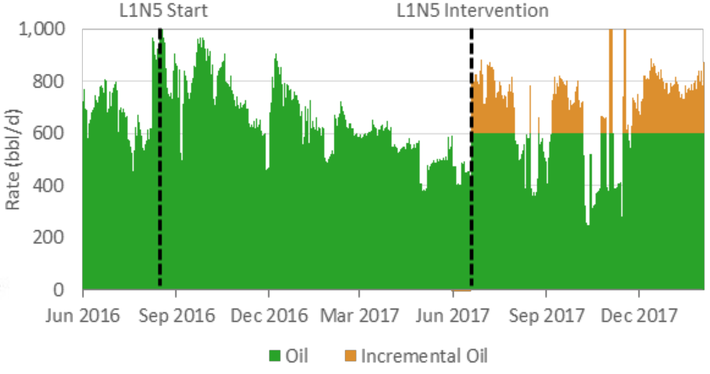


L1N5 well schematic and temperature profile before and after plug back



Improved temperature profile post plug back

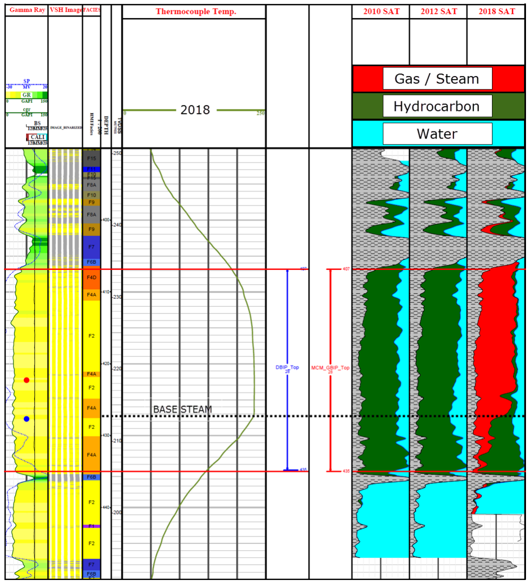
L1N5 infill system production uplift



Improved oil rates post plug back

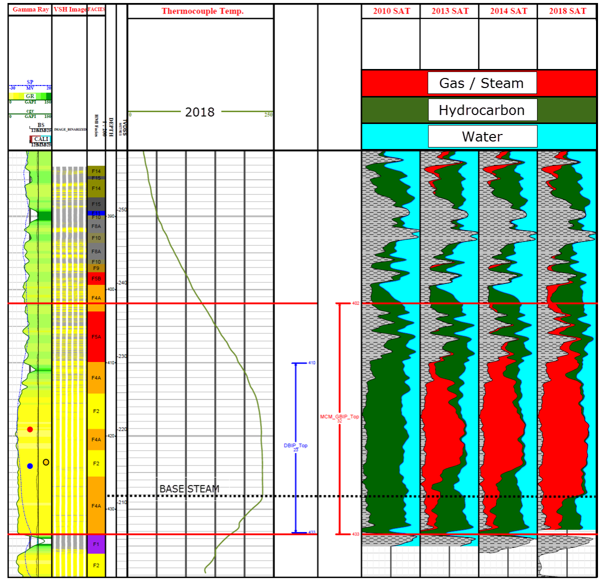
PAD 1
GEOLOGICAL, TEMPERATURE, SATURATION AND SEISMIC DATA

L1P6T – 100/08-28



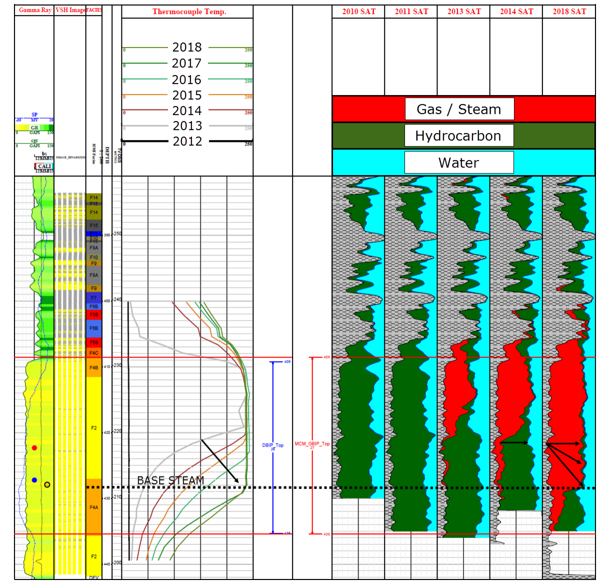
4m from L1P6

L1P3T – 100/05-27



13m from L1P3, 50m from L1N5

L1P2T – 102/05-27

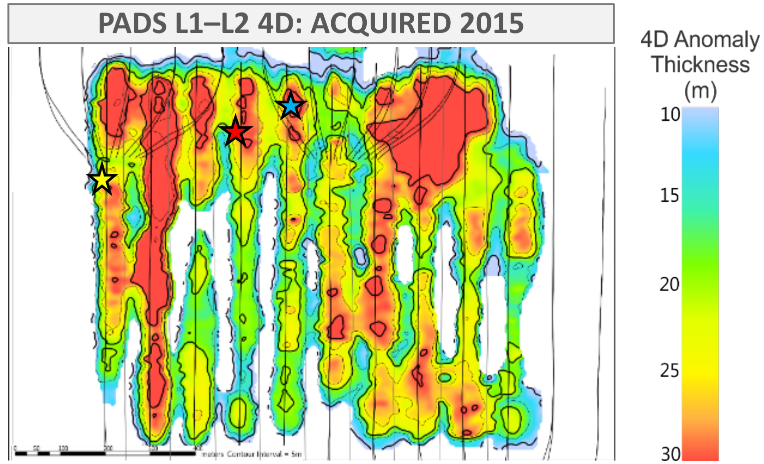


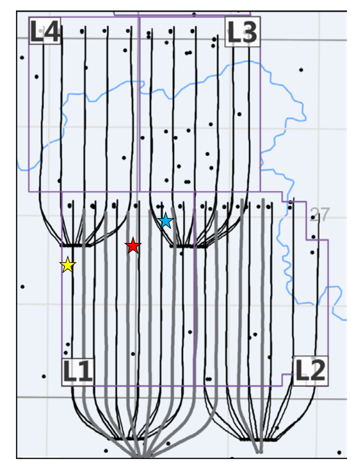
33m from L1P2, 8m from L1N3

OBSERVATION WELL AND SEISMIC DATA

- 2015 4D seismic in Pad L1 showed the steam chamber was fully developed in the toe region
- 2018 saturation logs demonstrate the positive impacts of the 2017 plug back initiatives
  - *100/08-28 shows drainage from top of the reservoir*
  - *102/05-27 and 100/5-27*
    - *Shows full steam chamber development and conductive heating drainage*
    - *Steam chamber drawn down below infill well elevation*

PADS L1–L2 4D: ACQUIRED 2015



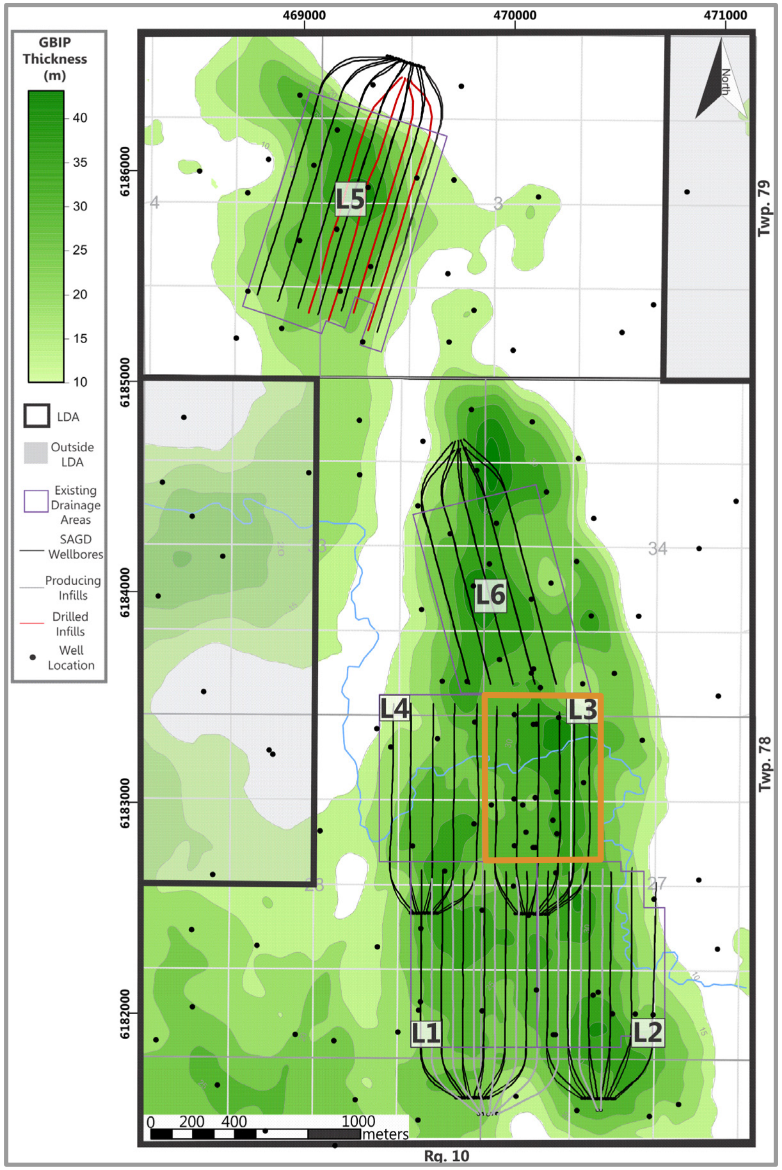


PAD PERFORMANCE – MID: PAD L3

PAD L3 GEOLOGY

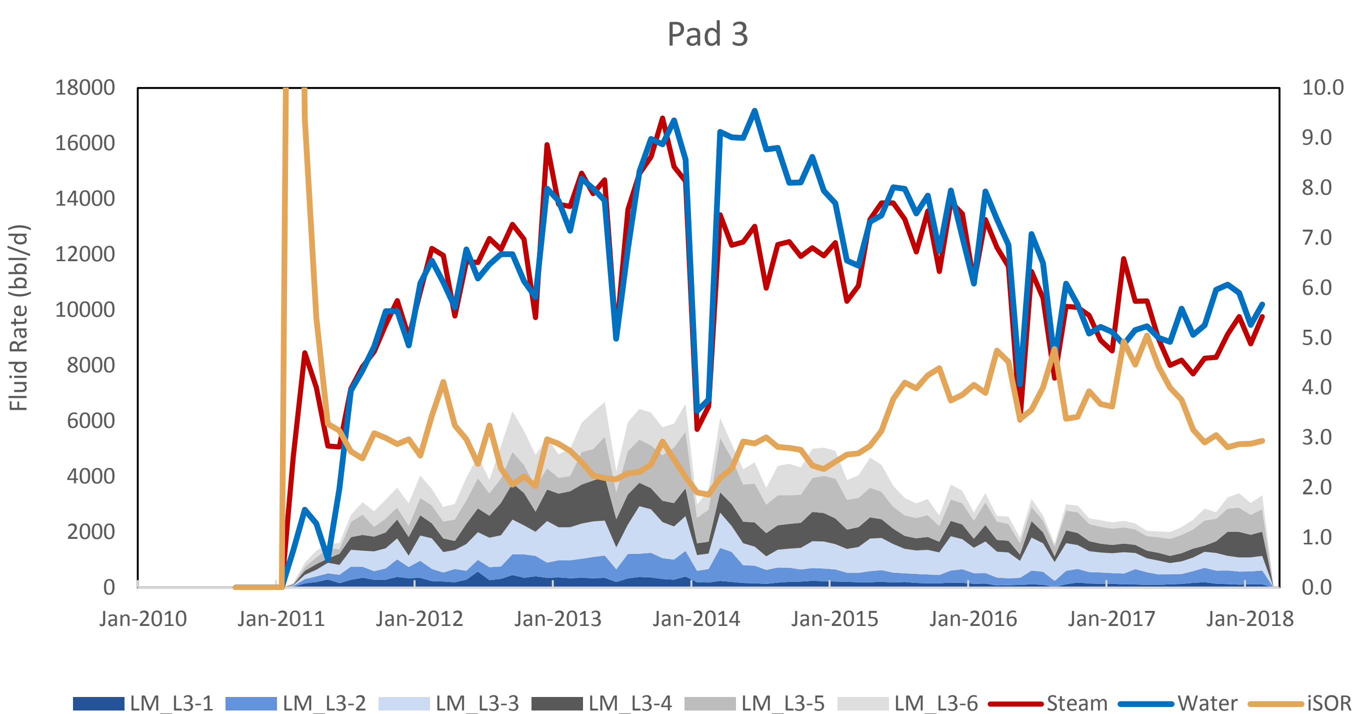
- Pad L3 has a consistent, thick GBIP with thinning DBIP and heterogeneity to the east
- Has average oil saturation (87%) and high permeability (Kh 6.4D)
- No infill wells on this pad

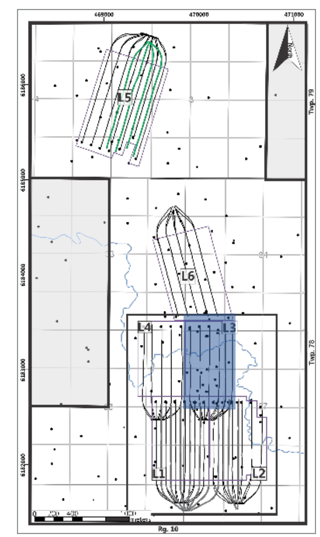
Well Pad	Area (10^3 m^2)	Avg. DBIP Thickness (m)	Avg. GBIP Thickness (m)	Avg. Porosity * (%)	Avg. Oil Saturation* (%)
L1	526	22.5	26.7	33	89
L2	498	19.2	24.5	32	86
L3	411	23.6	29.1	34	87
L4	389	19.6	22.4	33	87
L5	708	17.6	24	33	86
L6	571	25.3	28.9	33	87
Total/Avg.	3,103	21.3	25.9	33	87
LDA Total	24,166	15.5	17.3	32	85



2017 PAD PERFORMANCE – MID: PAD L3

- SAGD well pairs on production in 2010
- 2017 Peak bitumen rate ~ 540 m3/d (3,400 bbl/d)
- 2017 iSOR: 2.8 – 4.4
- In 2017 installed FCDs in L3P4 and L3P6
  - *Pad L3 oil production improved by 36% and SOR reduced by 27%*



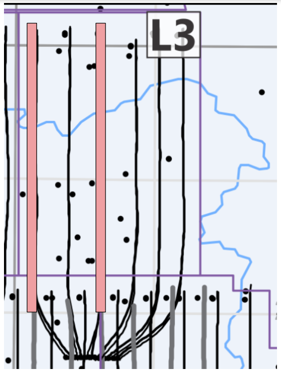


2017 FCD INSTALLATIONS

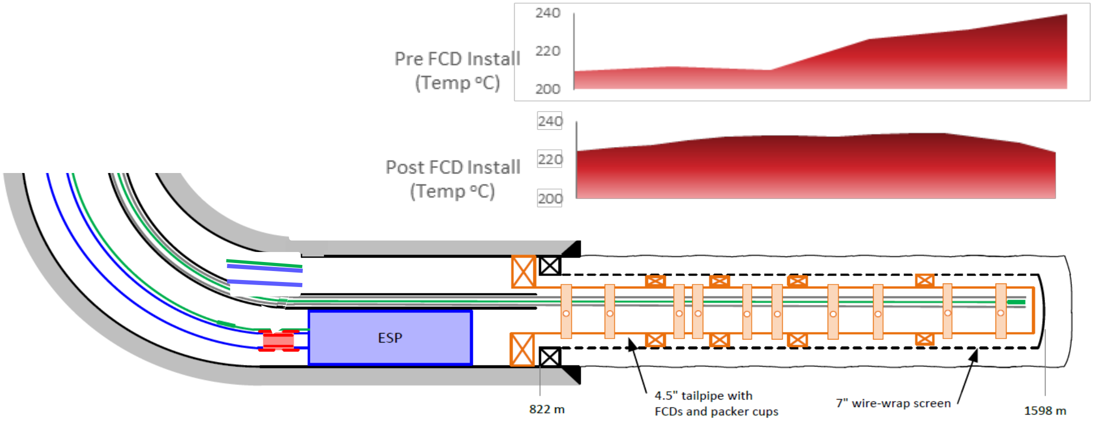
FLOW CONTROL DEVICES (FCDs)

- Q4-2017 installed 2 FCDs in Pad L3
- The FCDs improved the well performance
    - Oil uplift: >250 bbl/d per well

Pad L3 wells with FCDs

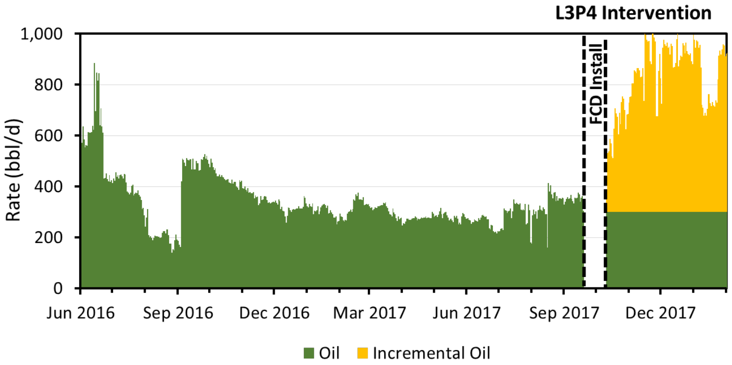


L3P4 well schematic and temperature profile before and after FCD installation



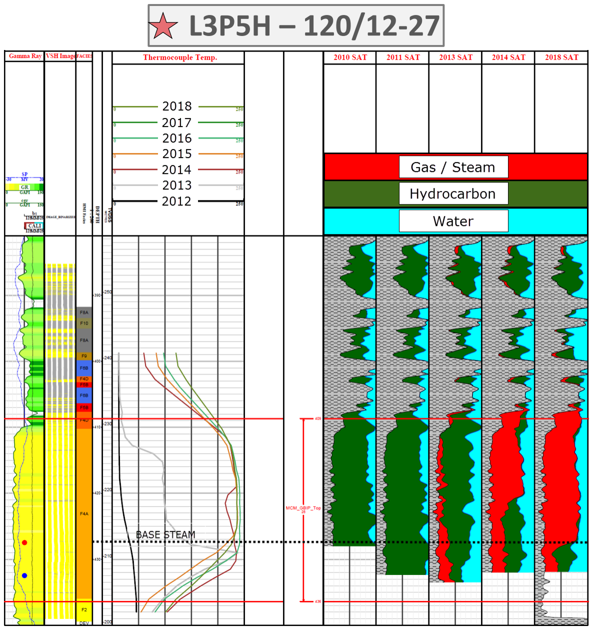
Improved temperature profile post FCD installation

L3P4 well production uplift

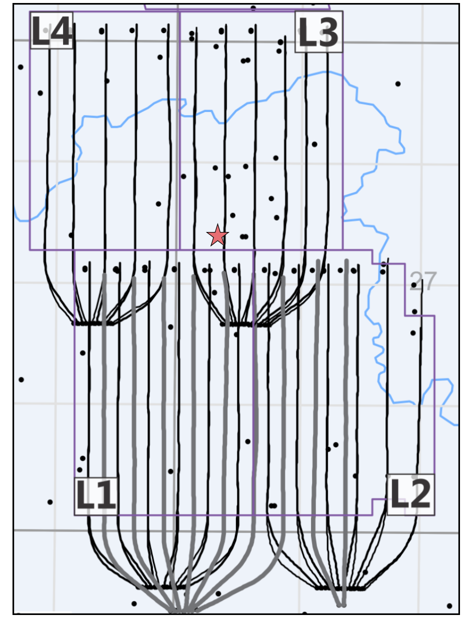


Improved oil rates post FCD installation

PAD 3
GEOLOGICAL, TEMPERATURE, SATURATION AND SEISMIC DATA

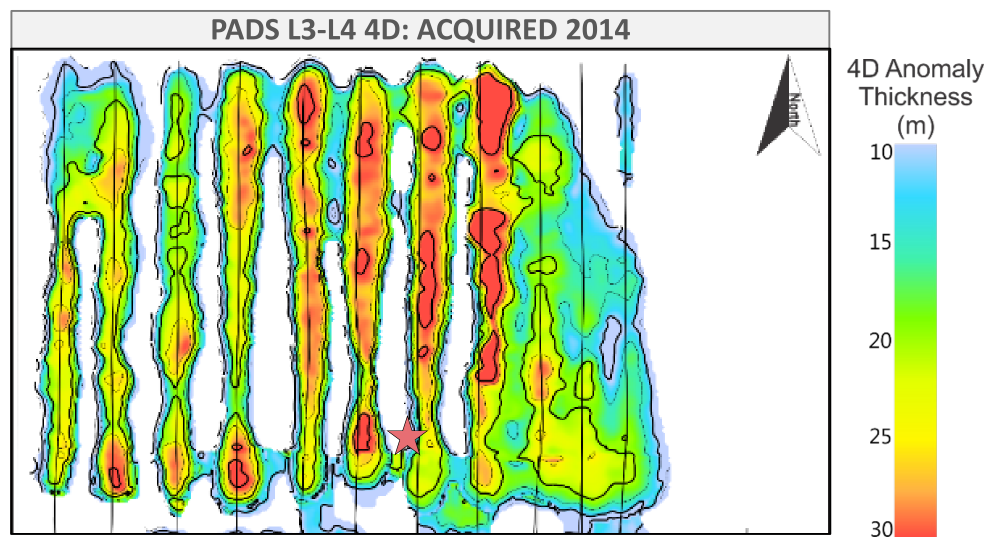


20.5m from L3P5



OBSERVATION WELL AND SEISMIC DATA

- 2014 4D seismic showed good conformance along the well trajectory
  - *L3P1 and P2 lower conformance in the toe region is influenced by reservoir quality*
- Q4-2017 installed flow control devices to achieve better temperature conformance
- 2018 saturation logs show the steam chamber has grown vertically and demonstrates drainage from the conductive heating interval

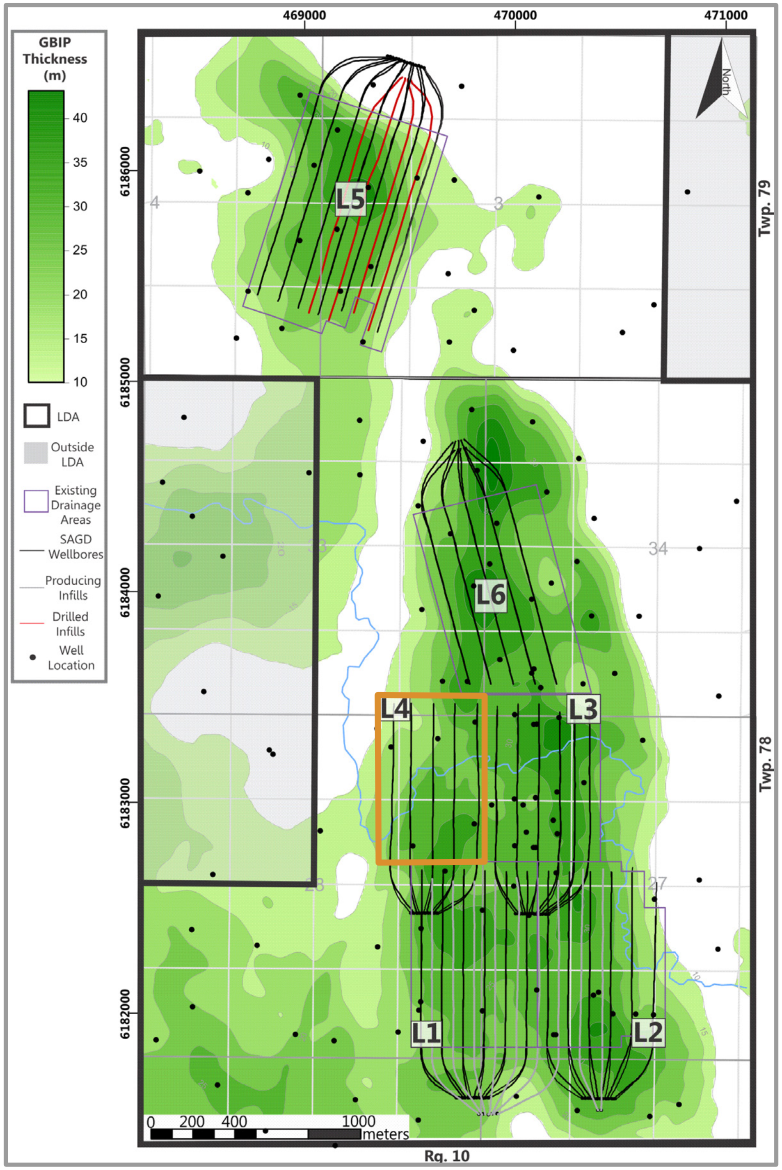


PAD PERFORMANCE - LOW: PAD L4

PAD L4 GEOLOGY

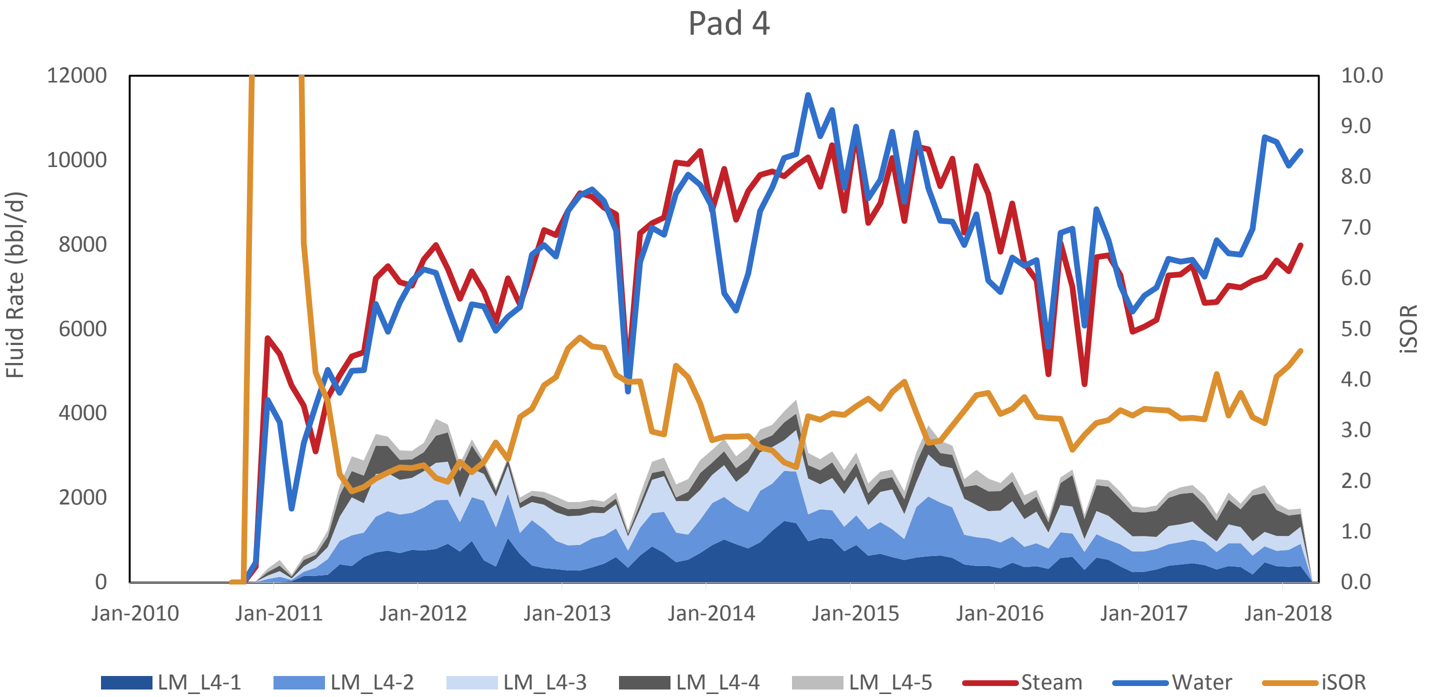
- Pad L4 has thickest GBIP/DBIP to the East
- Has average oil saturation (87%) and slightly below average permeability (Kh 5.2 D)
- No infill wells on this pad

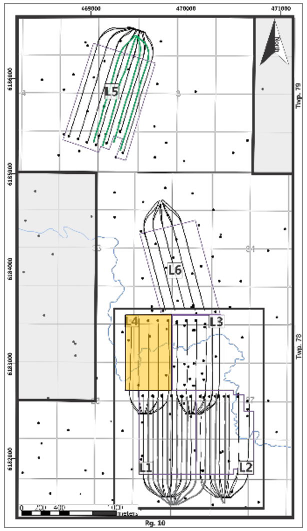
Well Pad	Area (10^3 m^2)	Avg. DBIP Thickness (m)	Avg. GBIP Thickness (m)	Avg. Porosity * (%)	Avg. Oil Saturation* (%)
L1	526	22.5	26.7	33	89
L2	498	19.2	24.5	32	86
L3	411	23.6	29.1	34	87
L4	389	19.6	22.4	33	87
L5	708	17.6	24	33	86
L6	571	25.3	28.9	33	87
Total/Avg.	3,103	21.3	25.9	33	87
LDA Total	24,166	15.5	17.3	32	85



2017 PAD PERFORMANCE – LOW: PAD L4

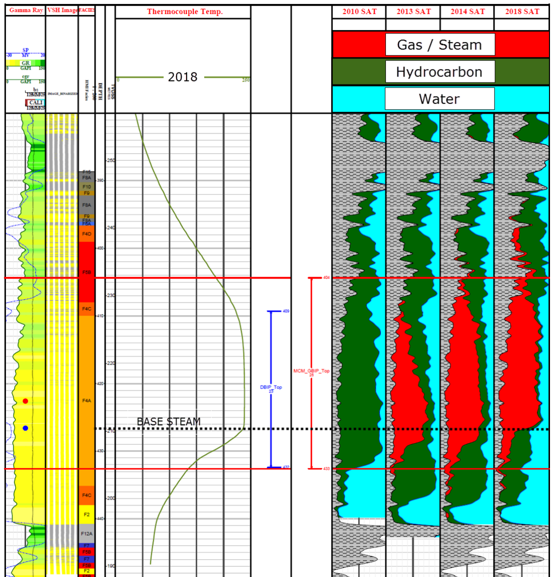
- 2017 Peak bitumen rate ~ 370 m3/d (2,330 bbl/d)
  - *Performance indicative of the historical steam reductions on the pad*
- 2017 iSOR: 3.1 – 4.5
  - *Expanded NCG co-injection to remaining three well pairs on this pad in 2017*





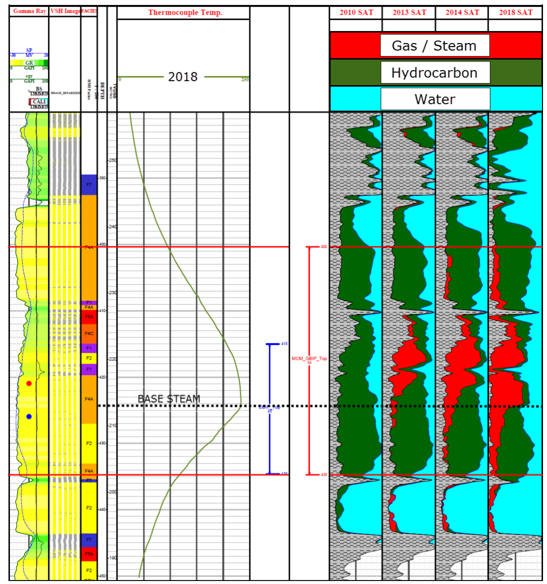
PAD 4
GEOLOGICAL, TEMPERATURE, SATURATION AND SEISMIC DATA

L4P1T – 100/16-28



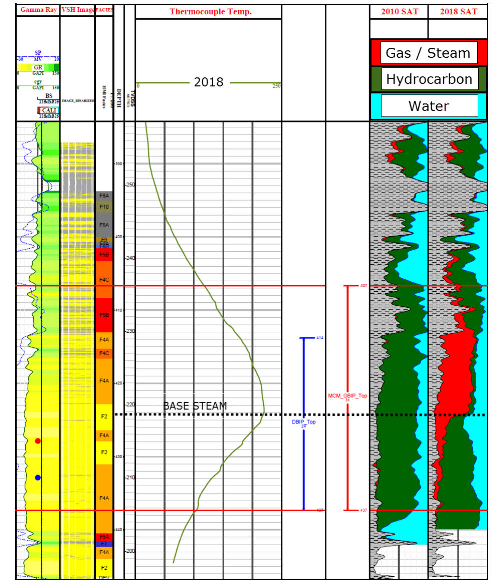
4.5m from L4P1

L4P3T – 102/16-28



19m from L4P3

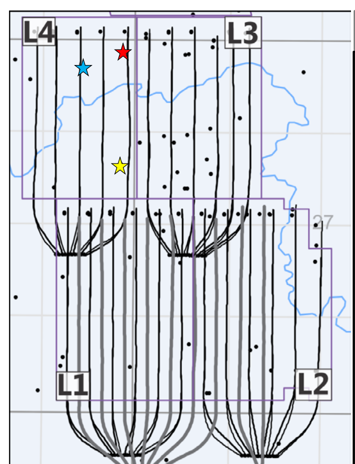
L4P1M – 100/9-28



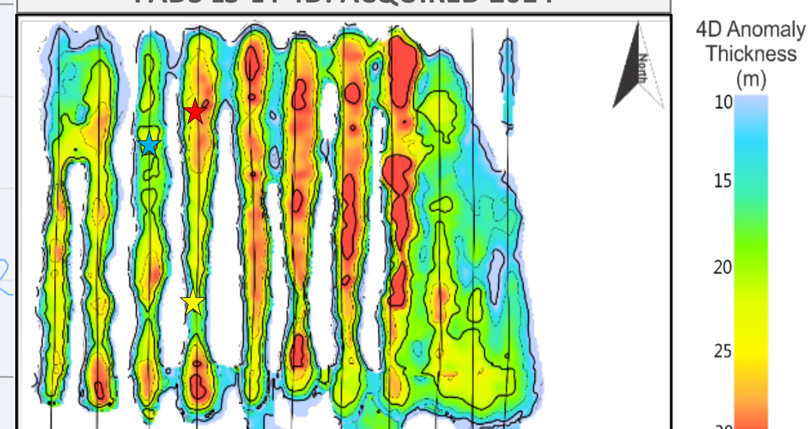
20m from L4P1

OBSERVATION WELL AND SEISMIC DATA

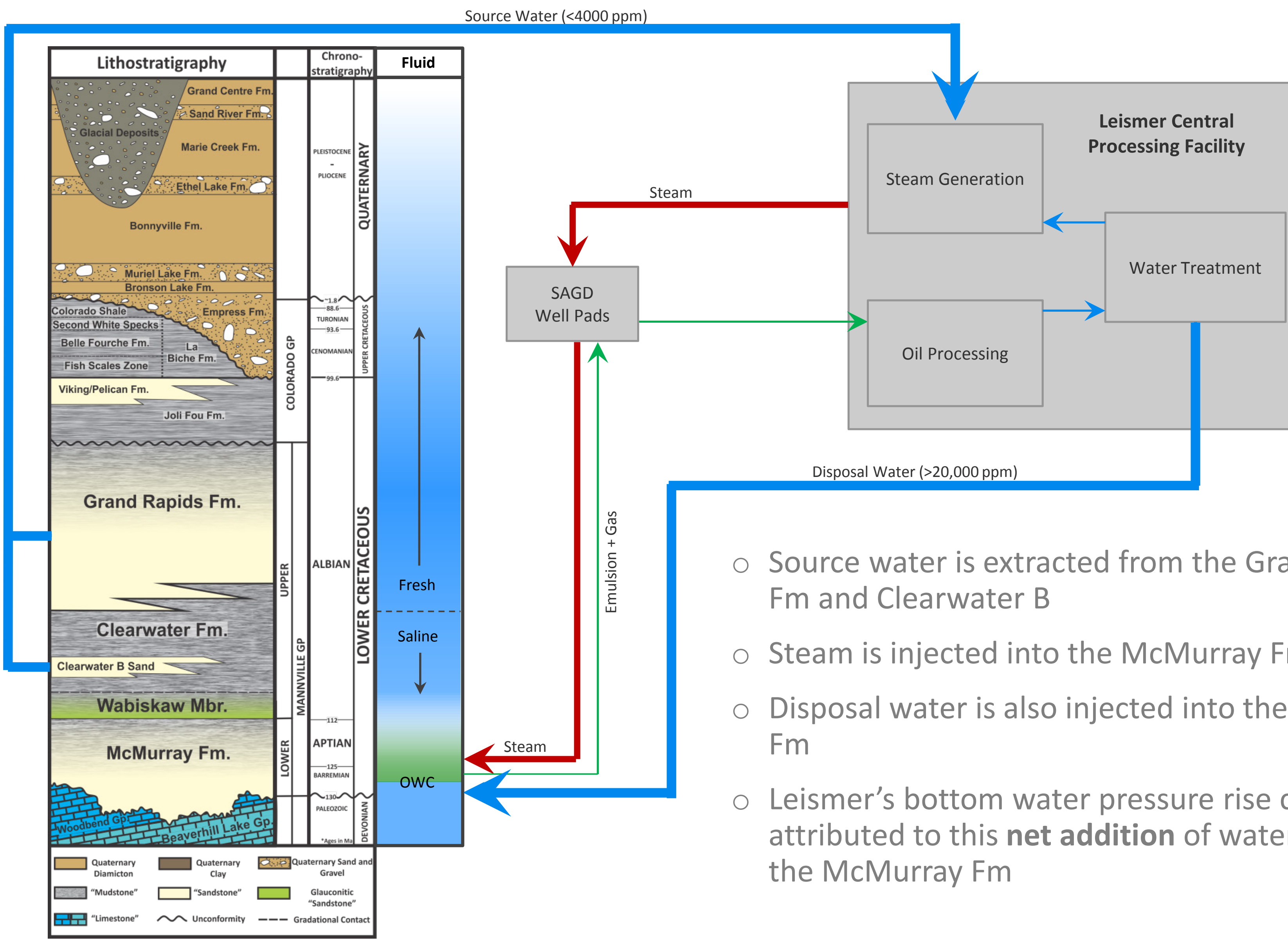
- 2014 4D seismic showed good conformance along the well pairs
- The steam chambers have developed to the top of DBIP in 100/16-28 and 100/09-28
  - *All wells show a well developed steam chamber at the top of DBIP and up to 7m of reservoir still to drain via conductive heating*
- The saturation logs confirm the opportunity to draw down the steam chamber



PADS L3-L4 4D: ACQUIRED 2014



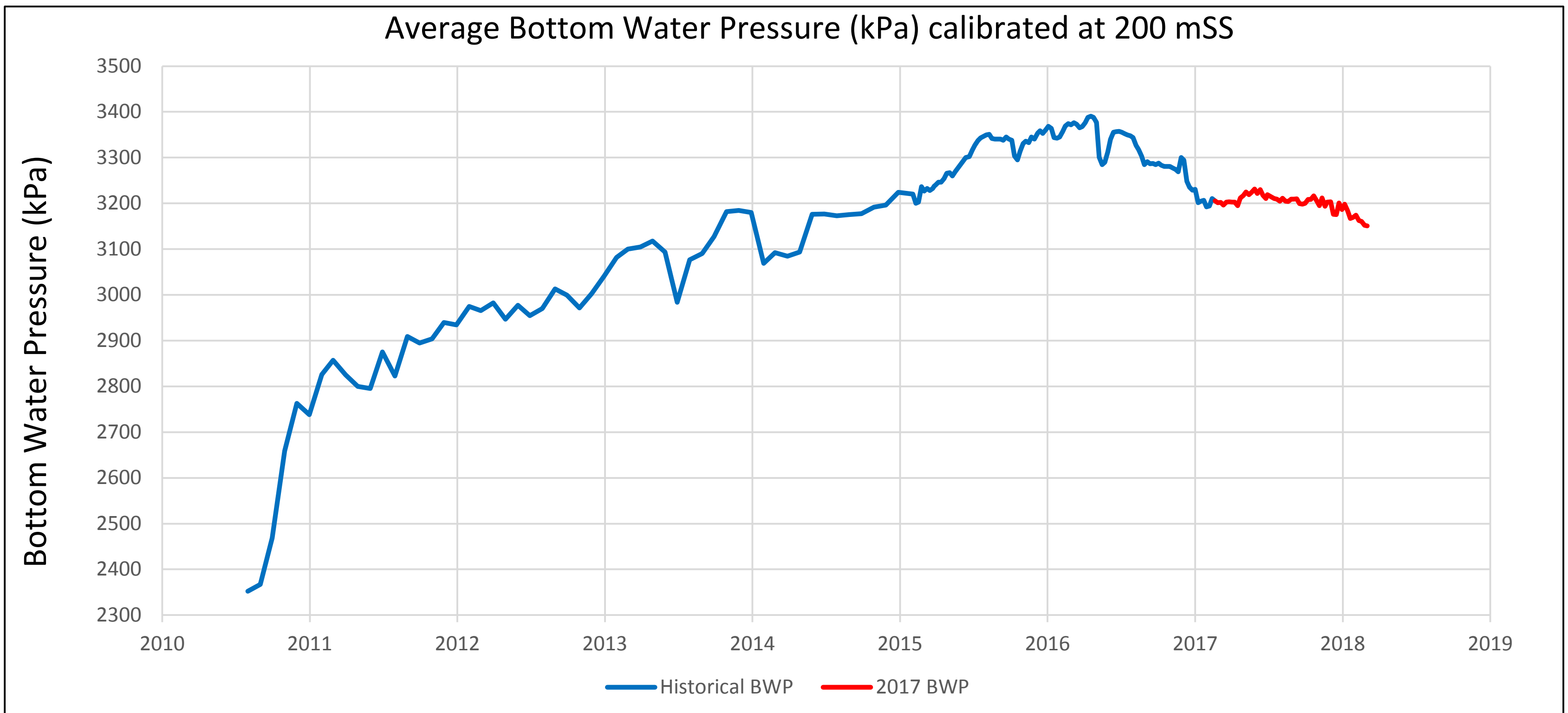
BOTTOM WATER PRESSURE



- Source water is extracted from the Grand Rapids Fm and Clearwater B
- Steam is injected into the McMurray Fm
- Disposal water is also injected into the McMurray Fm
- Leismer's bottom water pressure rise can largely attributed to this **net addition** of water/mass into the McMurray Fm

BOTTOM WATER PRESSURE (BWP)

- Initial bottom water pressure was approximately 2,300 kPa
- Bottom water pressure rose rapidly once Pads L1 - L4 were started
- Strong bottom water pressure communication is observed between pads
- Throughout 2017, bottom water pressure reduced by ~70 kPa by steam re-allocation efforts and source water management across the field

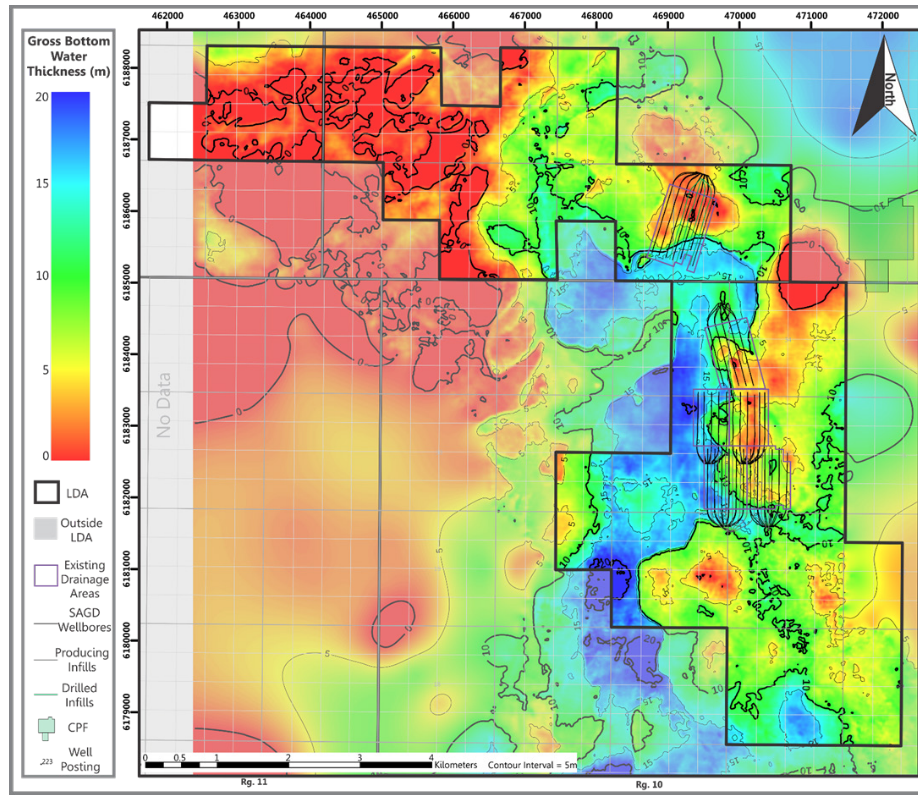


BOTTOM WATER PRESSURE STRATEGY

FIELD PRESSURE STRATEGY

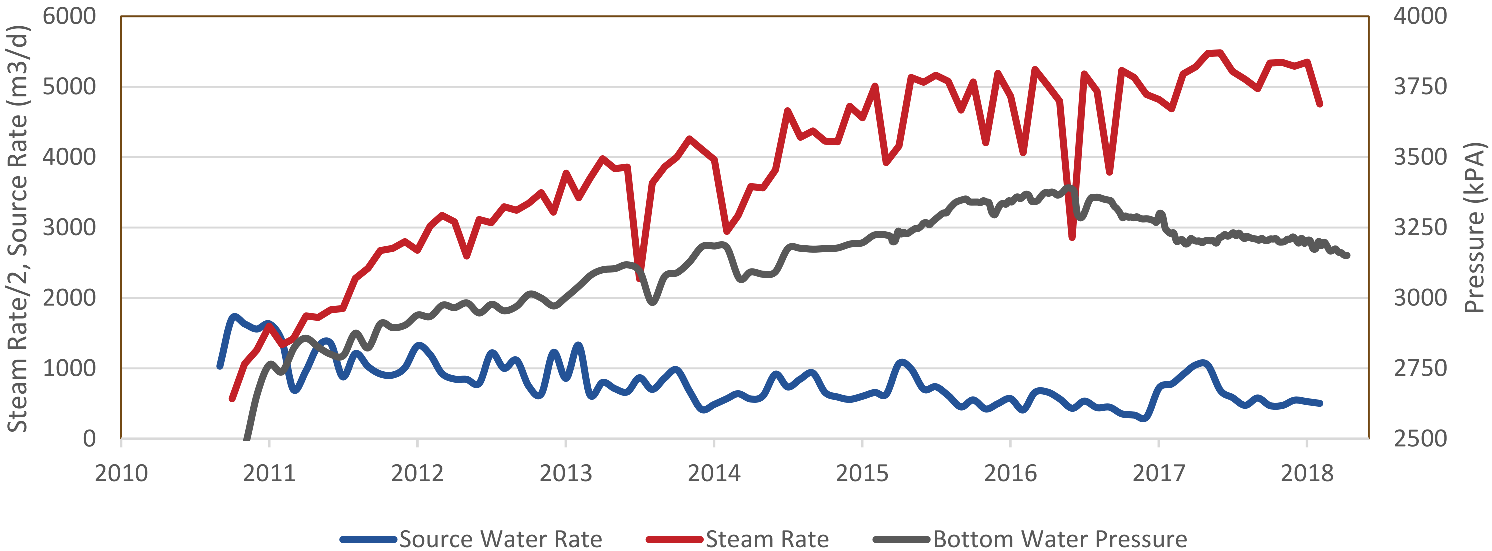
- Moving towards an even pressure across the field as Pad L1-L4 and L6 are in coalescence
- In order to minimize bottom-water influx, need to operate the wells with a positive dP between producer well and bottom-water
- Stabilize the bottom-water pressure across the field by controlling source and disposal rates

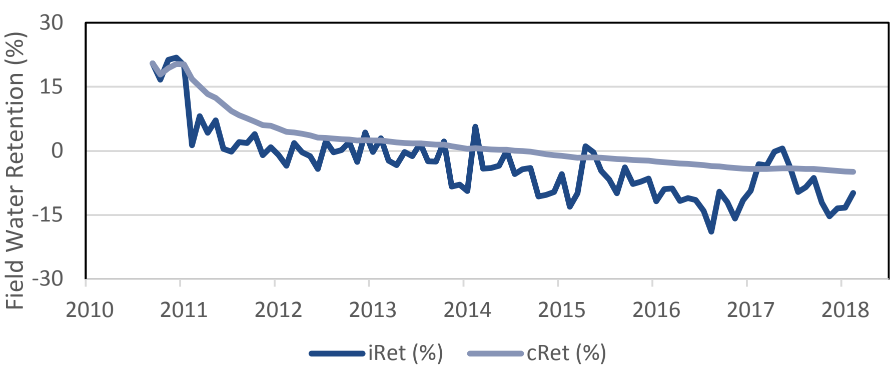
Gross bottom water thickness map

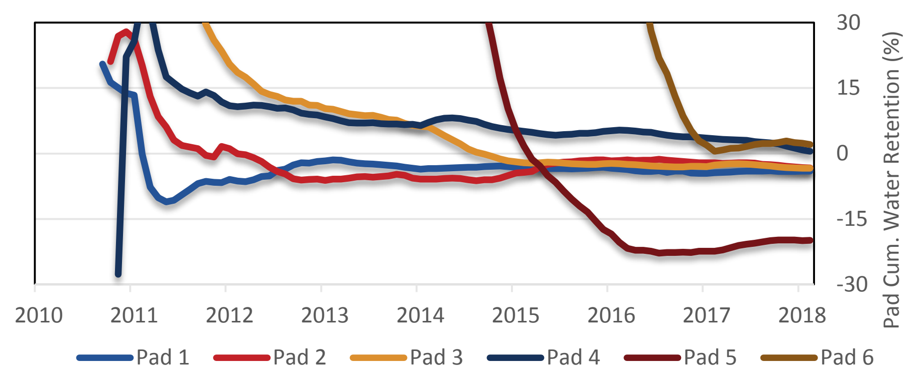


SOURCE WATER AND RESERVOIR RETENTION

- Source water and retention are managed to minimize bottom water pressure variations
- Currently managing the reservoir pressure and steam allocation across the field to achieve a more balanced reservoir retention







WELLHEAD STEAM QUALITY

STEAM PRESSURE

- Steam is delivered to pads at about 7,000–9,000 kPa
- Steam pressure dropped to 5,000–6,000 kPa at the pad

TYPICAL STEAM QUALITY

- Steam quality decreases during transportation to well pads due to heat losses
  - *Estimated at 95% at Pads L1–L4*
  - *Estimated at 90% at Pad L5 due to longer, larger diameter pipe line*

STEAM QUALITY VARIATIONS

- Steam quality varies as steam rates are increased/decreased
- Most consistent at Pads L1–4 due to shared trunk line
- Most variable at Pad L5 due to additional 4 km steam line off main trunk line

SURFACE CASING VENT FLOW (SCVF)

CURRENT STATUS

Most SAGD wells have steam vent flow while producing or injecting

- Steam vent is considered non-serious in accordance with AER Interim Directive ID 2003-01
- Steam vent is present all times of the year
- Steam vent disappears when the wells are shutdown
- Steam vent does not contain H_2S

MONITORING

- No liner or casing failures occurred during the reporting period
- Steam vent is checked monthly
  - *Regular monitoring of temperature, flow estimation, presence of bubbles & H_2S*
  - *Changes are reported as per ID 2003-01*
- Future SCVF is prevented through thermal cementing during drilling where the cement is circulated until there is a full density return to surface

SUBSURFACE

PILOTS

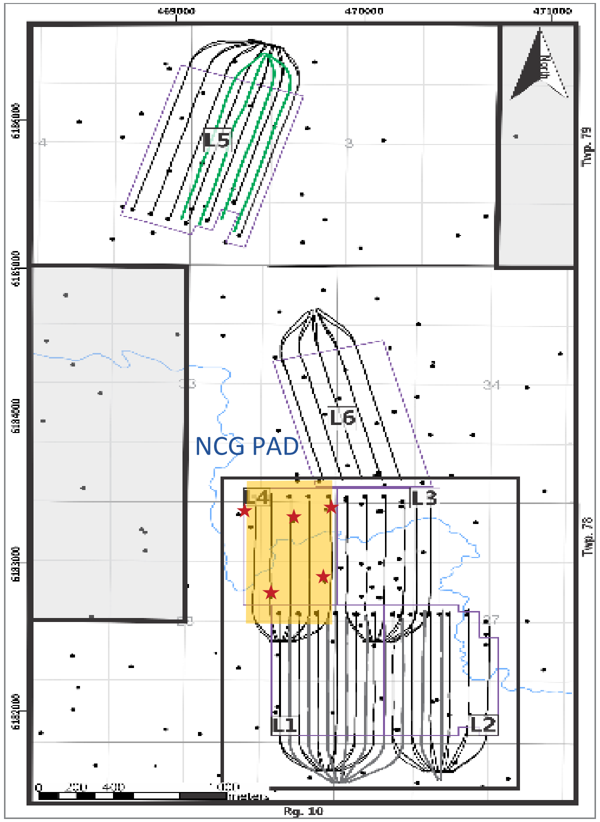
NON-CONDENSABLE GAS (NCG) PILOT

Initially the NCG Co-Injection Pilot was conducted on two well pairs on Pad L4

- NCG Co-Injection helped reduce the steam oil ratio (SOR)

Based on positive results from the initial two well pairs in 2017, NCG Co-Injection was expanded to an additional three well pairs on Pad L4

- Five OBS wells (★) in the Pad L4 were repurposed with new thermocouple strings in Q1 2018
  - *Temperature data will help to evaluate and optimize the NCG Co-Injection performance*
- The evaluation is ongoing, with continued monitoring and optimization of the NCG Co-Injection well performance



SUBSURFACE

FUTURE PLANS

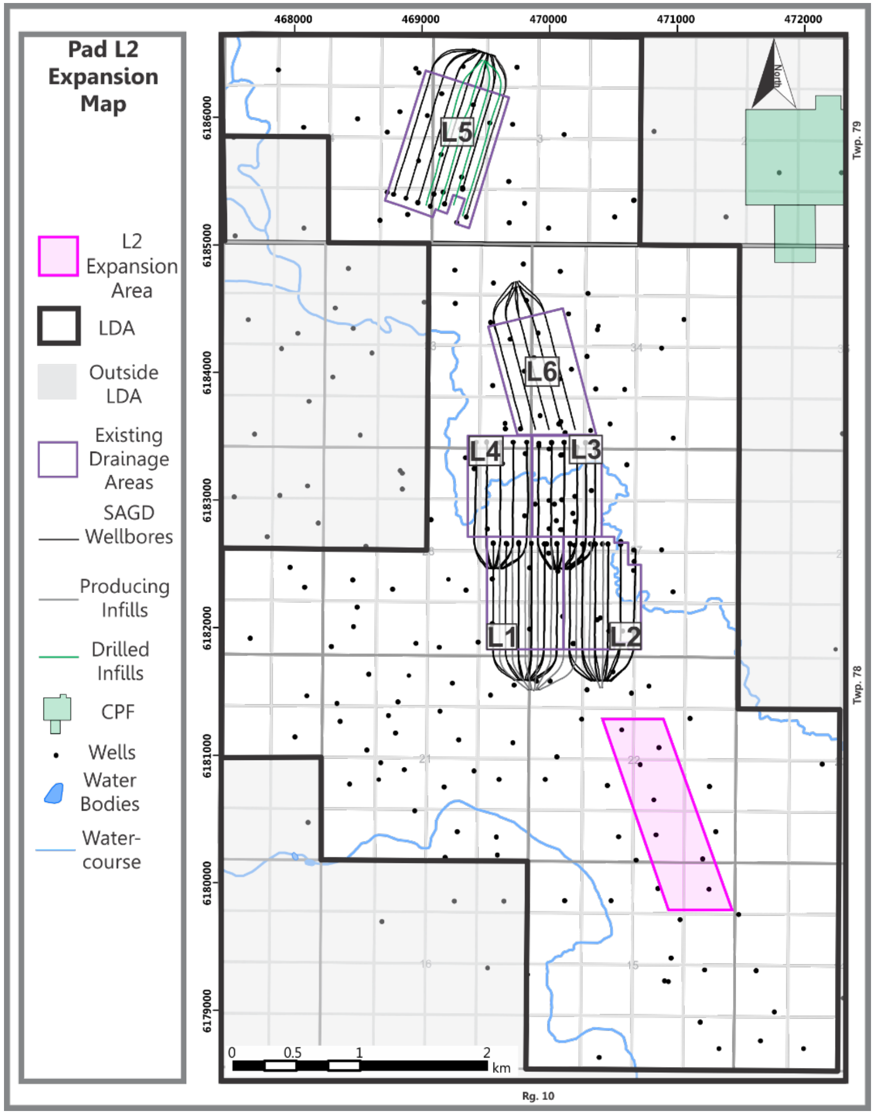
LEISMER FUTURE DEVELOPMENT PLANS

2018 SUBSURFACE DEVELOPMENT PLANS

- Continue evaluating NCG co-injection on Pad L4
- Evaluate the feasibility of NCG co-injection on Pads L1, L2 and L3
- Conduct Pad L5 infill well completions (4 wells)
  - *Potential start-up Q3 2018*
  - *2 wells will be completed with rod pumps*
  - *2 wells will be completed with ESPs*
- Continue Pad L2 expansion design / planning

PAD ABANDONMENTS

- No pad abandonments anticipated at Leismer within next five years



SURFACE OPERATIONS

FACILITIES

ATHABASCA OIL CORPORATION

2017 OVERVIEW

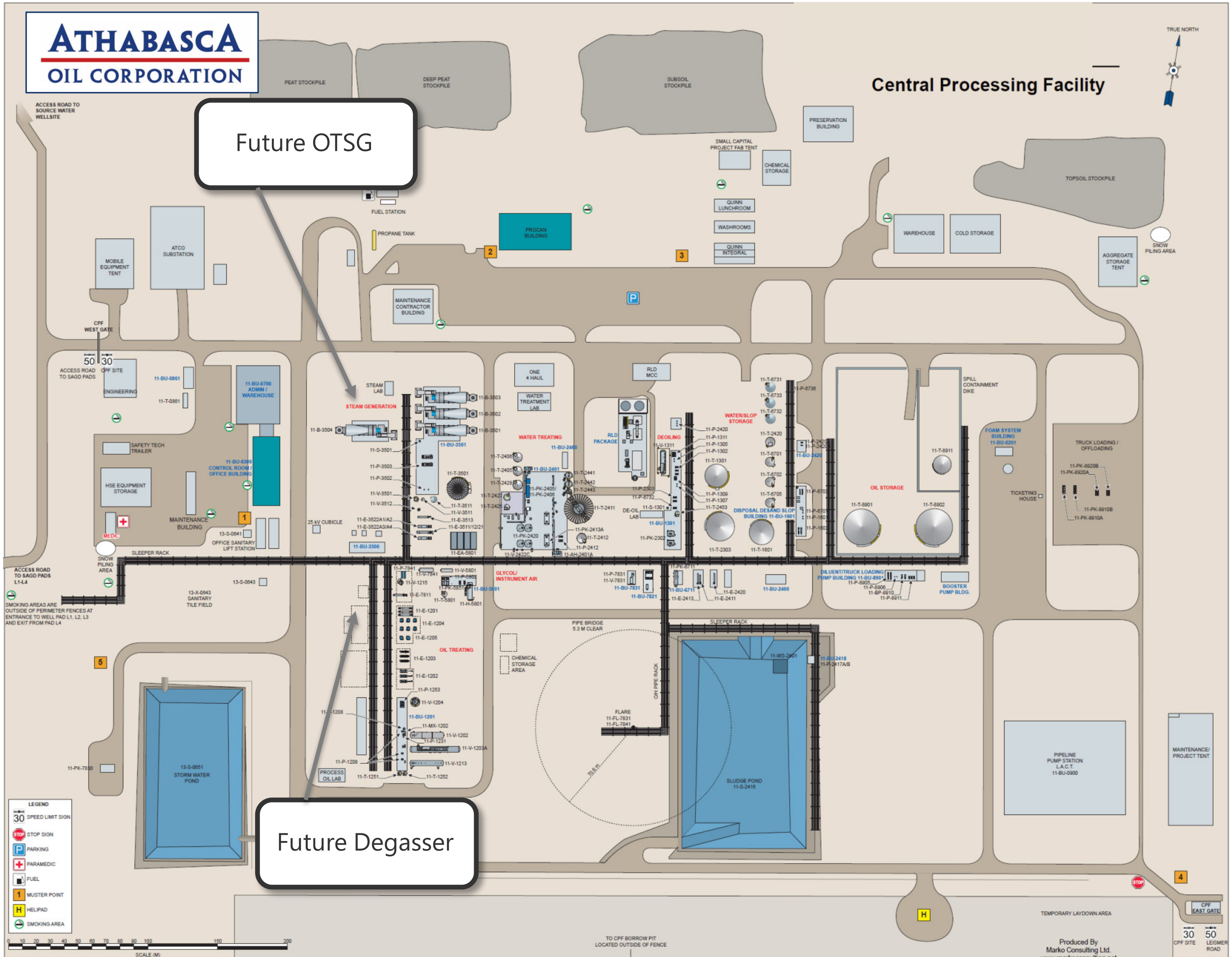
2017 OVERVIEW

- Degasser Project design completed and site installation commenced in 2017
- 5th OTSG project sanctioned and site preparation started in Q4 -2017
- Earthwork and construction of surface facilities completed for pad 5 infill wells

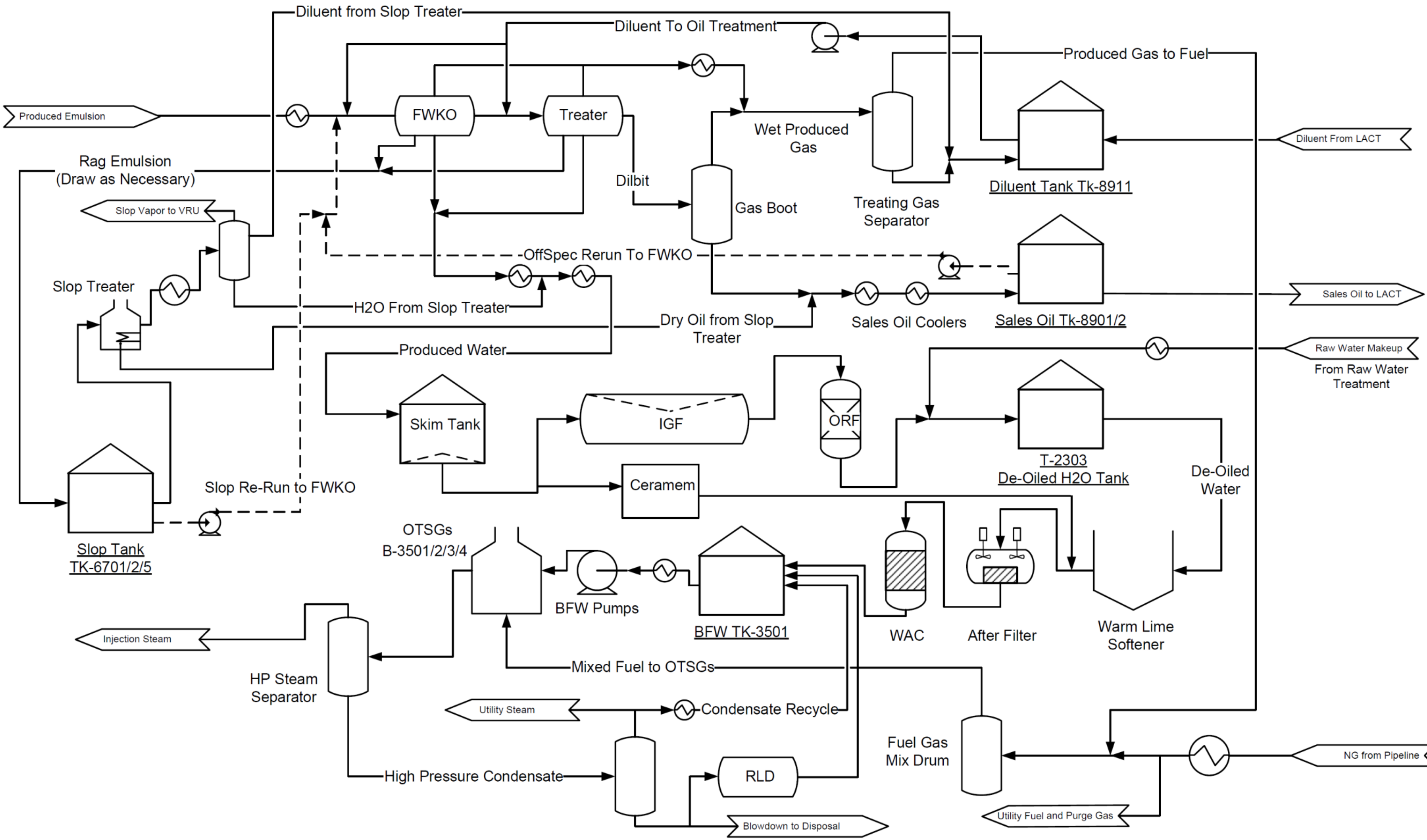
2017 OPERATIONS

- Successfully completed chemical trials for water and oil processing
- Significantly reduced slop volumes throughout the year
- Preparations and planning commenced for upcoming 2018 turnaround (Q2- 2018)

LEISMER CENTRAL PROCESSING FACILITY



SIMPLIFIED SCHEMATIC



CERAMIC MEMBRANE PILOT

Design Capacity: 75 tonnes/hour

Total Membranes: 44 (4 banks of 11 membranes)

Feed Streams: Skim Tank Outlet, IGF outlet, De-oilied Water

Design Flux: 160 LMH

- Field testing of ceramic membrane pilot project completed in Q1-2017
- ROSS TM system was installed for simultaneous removal of oil and silica from produced water
- System was tested at flow rates from 30 – 75 t/h
- Technical evaluation and technology report was completed in 2017
- Membrane system successfully removed oil and silica. Water quality exceeded conventional treatment (de-oiling and WLS)
- Overall design throughput was not achieved on consistent basis
- Further field testing is not planned at this time

ROSS TM = Removal of Oil and Silica Simultaneously

SURFACE OPERATIONS

FACILITY PERFORMANCE

ATHABASCA OIL CORPORATION

FACILITY PERFORMANCE

SITE RELIABILITY HAS REMAINED HIGH (~97%)

- Based on steam performance
- Facility operating near or at maximum design capacity

MAJOR ACTIVITIES

- Pigged steam generators in August 2017 and January 2018
- Replaced burner shield on one steam generator in January 2018
- Replaced section of steam outlet piping and check valve on one OTSG with upgraded material
- Completed chemical trials for water and oil treating processes and switched chemical provider in Q3-2018
- Inspected and conducted integrity digs on sales and diluent pipelines in February 2018

FACILITY PERFORMANCE

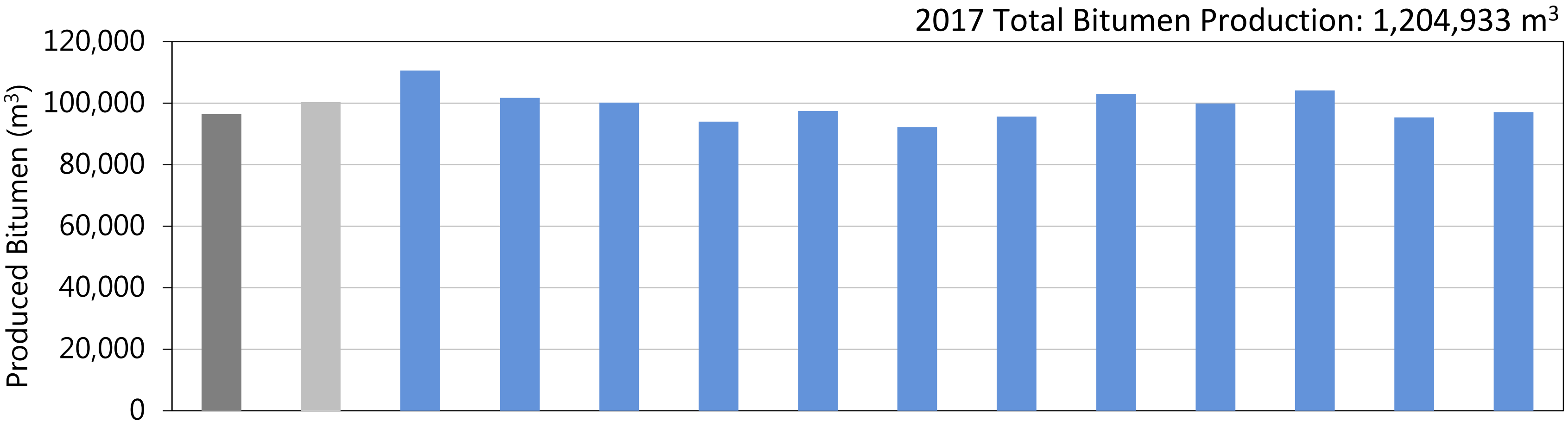
CHALLENGES

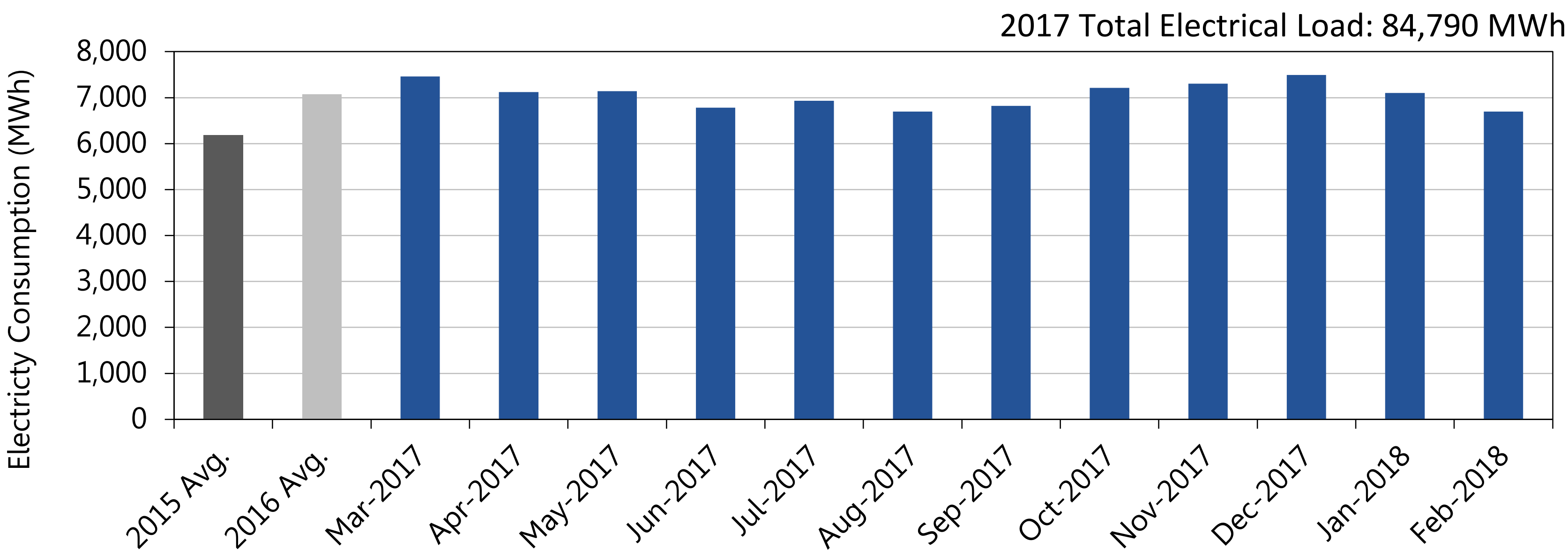
- Corrosion on steam outlet piping currently being monitored with some piping sections scheduled to be upgraded in 2018 turnaround
- Failure of fresh water pipeline in November 2017
- Increased pigging frequency due to moderate fouling on OTSGs

OPPORTUNITIES

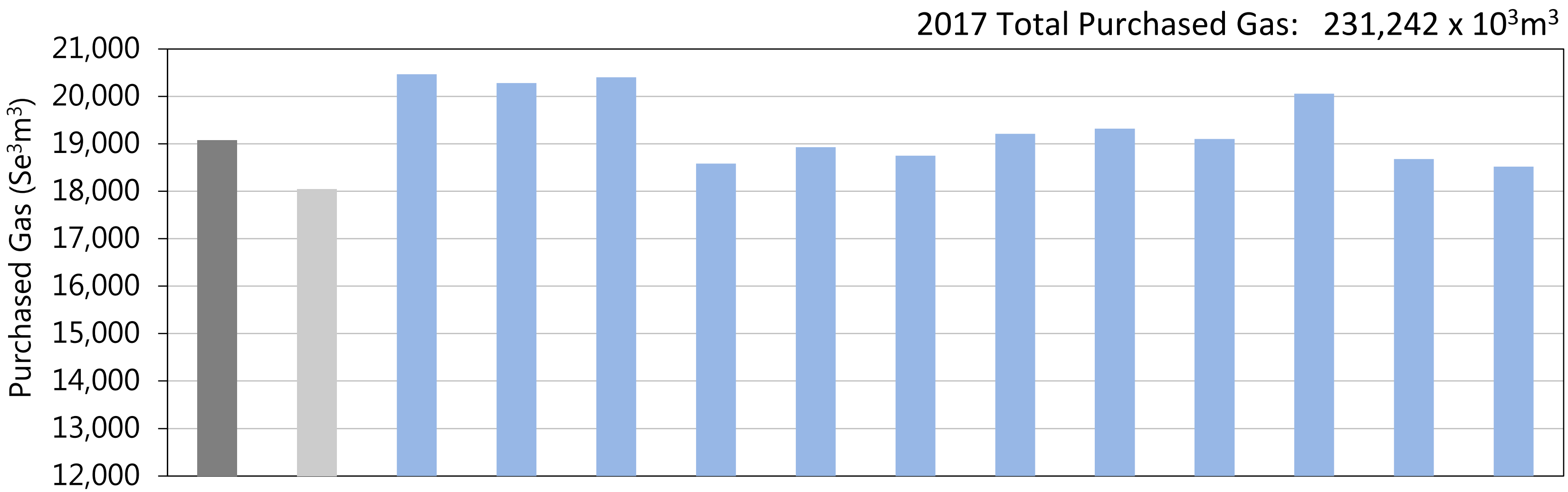
- Degasser Project initiated to handle lower density diluent supply and reduce losses
- Chemical trials showing promise for improved oil treatment and reduced slop generation

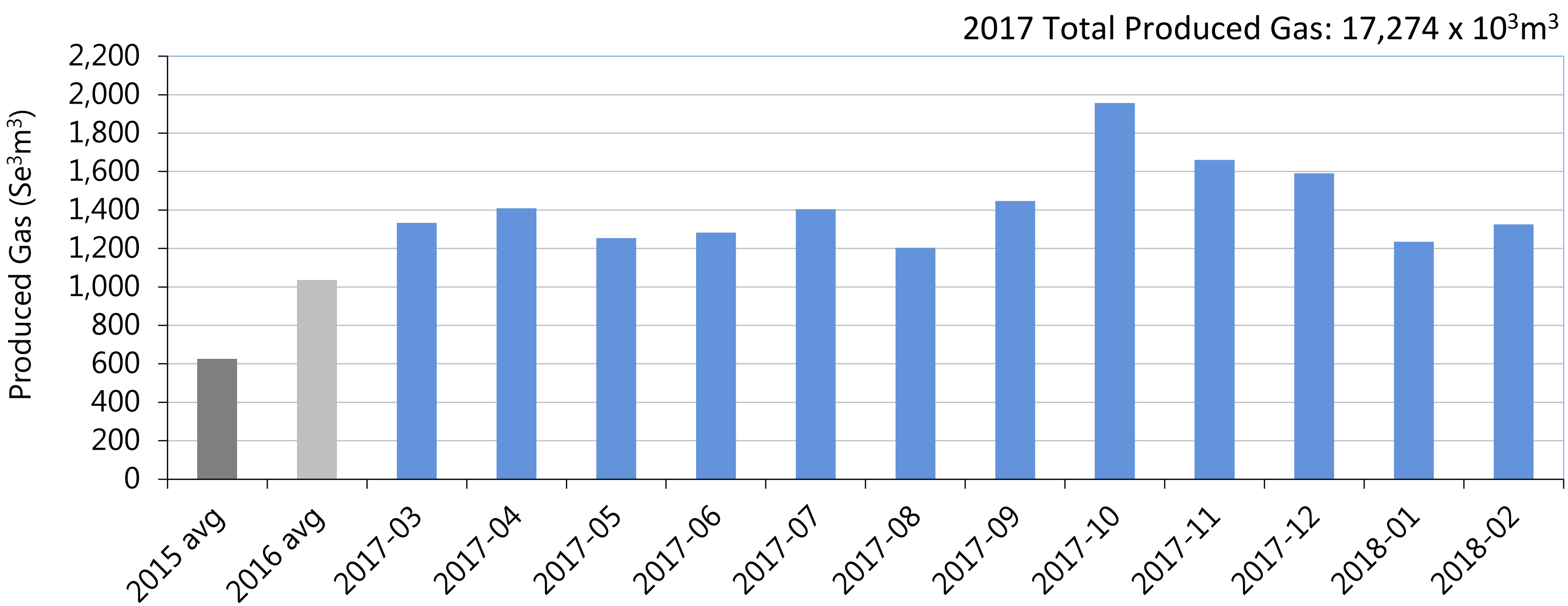
PRODUCTION & ELECTRICITY CONSUMPTION



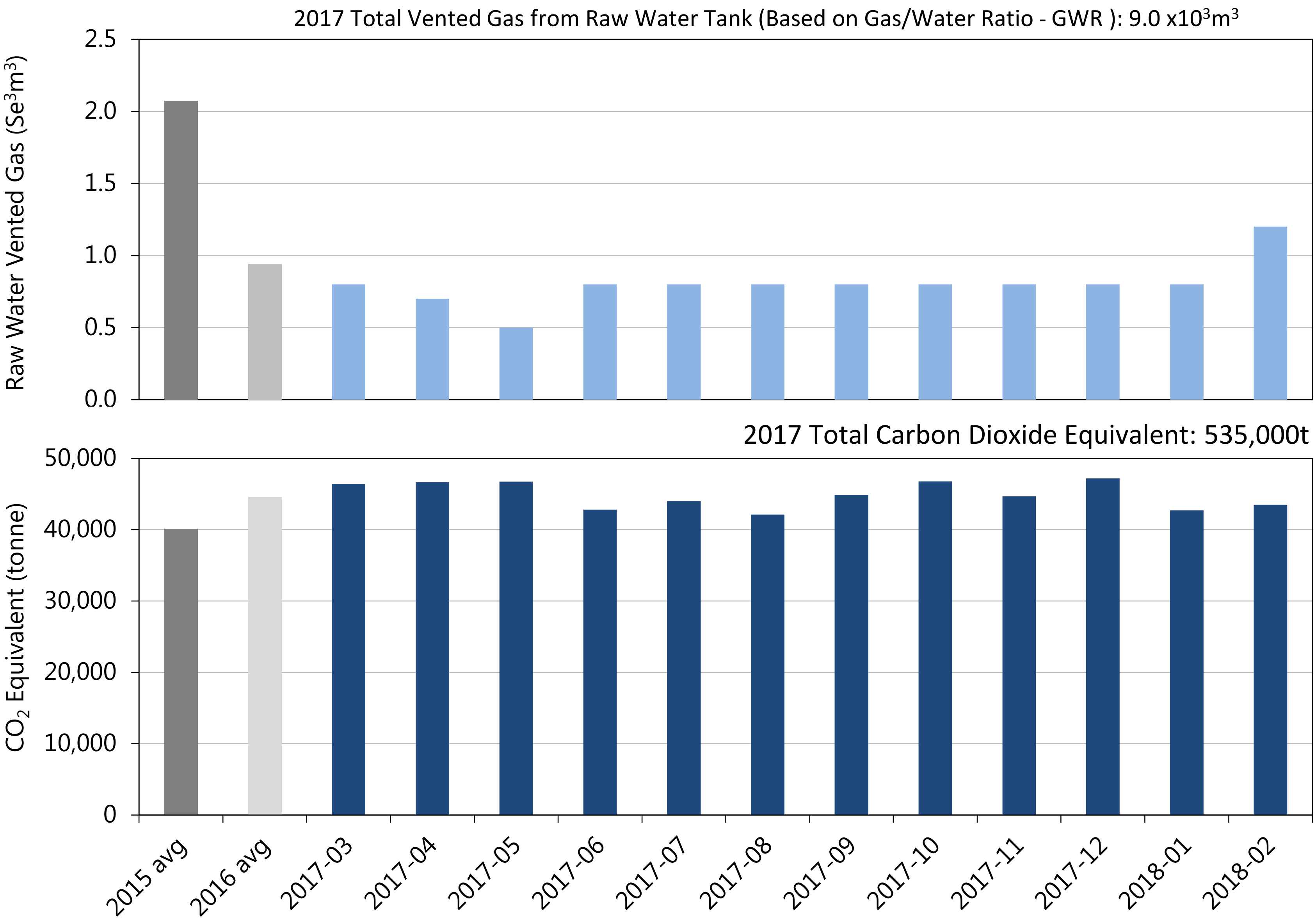


PURCHASED & PRODUCED GAS VOLUMES



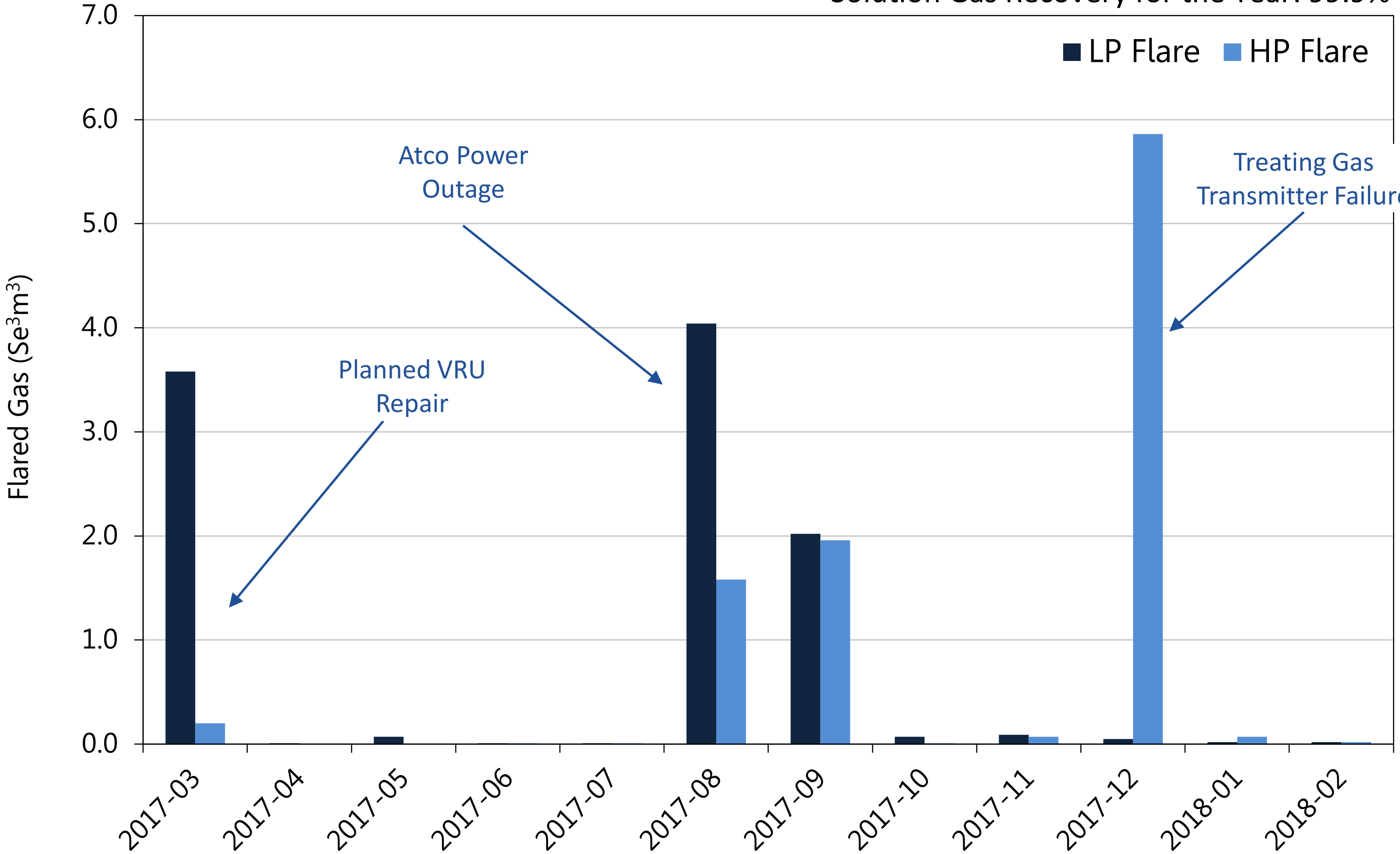


GAS VENTING & CO_2 EMISSIONS



GAS FLARING

2017 Total HP Flare: 10.3 $x10^3m^3$
2017 Total LP Flare: 11.9 $x10^3m^3$
Solution Gas Recovery for the Year: 99.9%



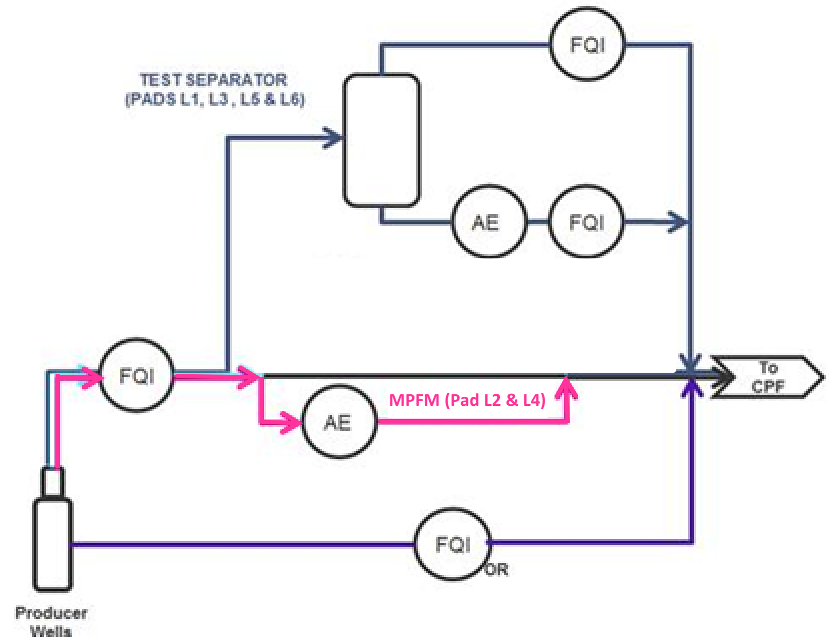
SURFACE

MEASUREMENT, ACCOUNTING AND REPORTING PLAN (*MARP*)

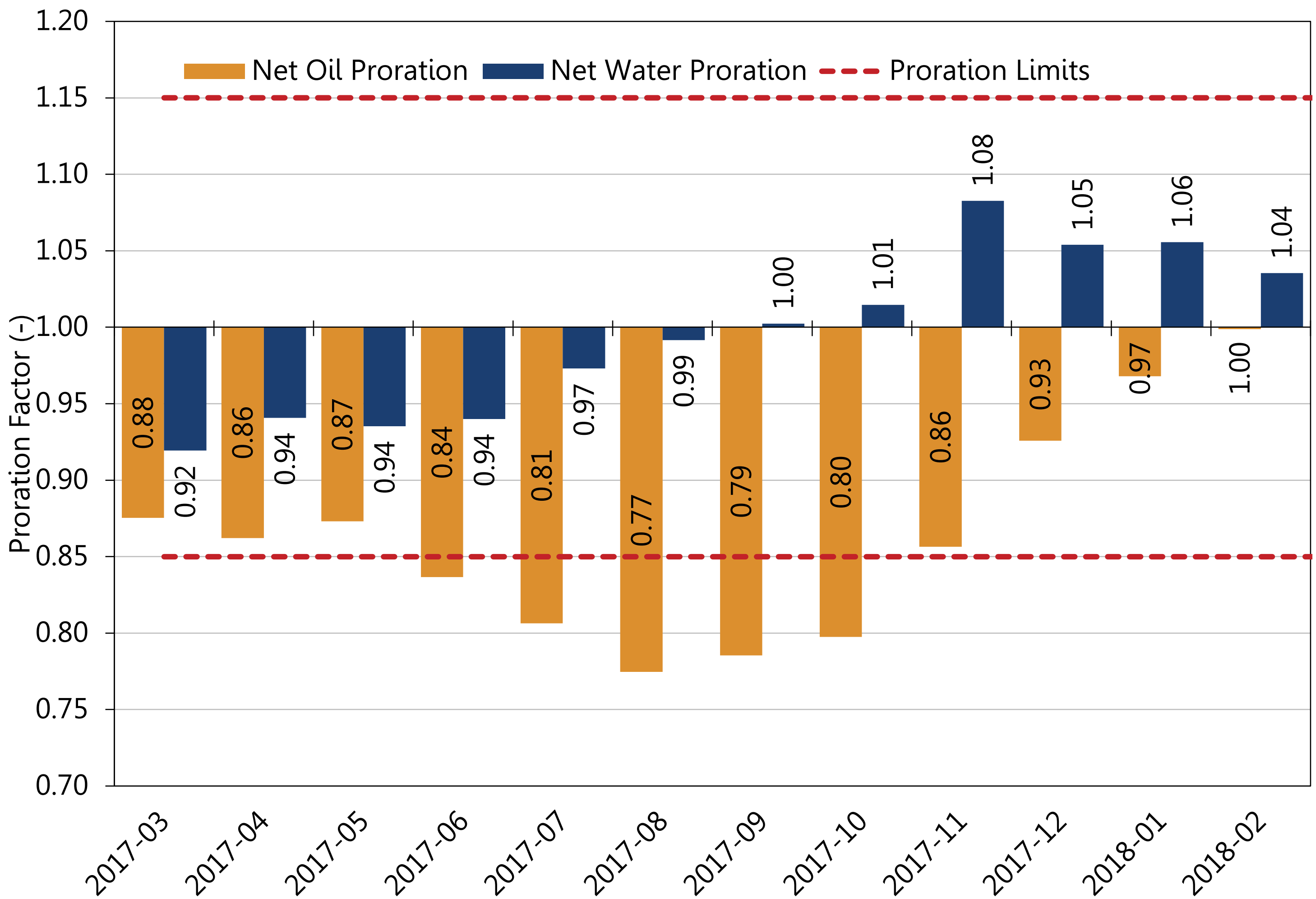
ATHABASCA OIL CORPORATION

WELL TESTING

- Well tests used to calculate daily bitumen and water production
- Six hour test with 1 hour purge utilized to improve accuracy of oil calculation
- Pads L1, L3, L5 and L6 are equipped with full test headers and test separators
- Pad L4 equipped with full test header and Multi-Phase Flow Meters (MPFM)
- MPFM installed on Pad L2 in late 2016 and verified with the existing water cut meter in 2017. MPFM now utilized for Pad L2 well testing data
- Auto samplers installed at the pads in 2017 to improve accuracy and consistency of water cut samples used for meter calibrations



PRORATION FACTORS



2017 Proration Improvement

- AGAR meter re-calibration
- Corrected well test data to standard conditions

SURFACE

WATER PRODUCTION, INJECTION & USES

ATHABASCA OIL CORPORATION

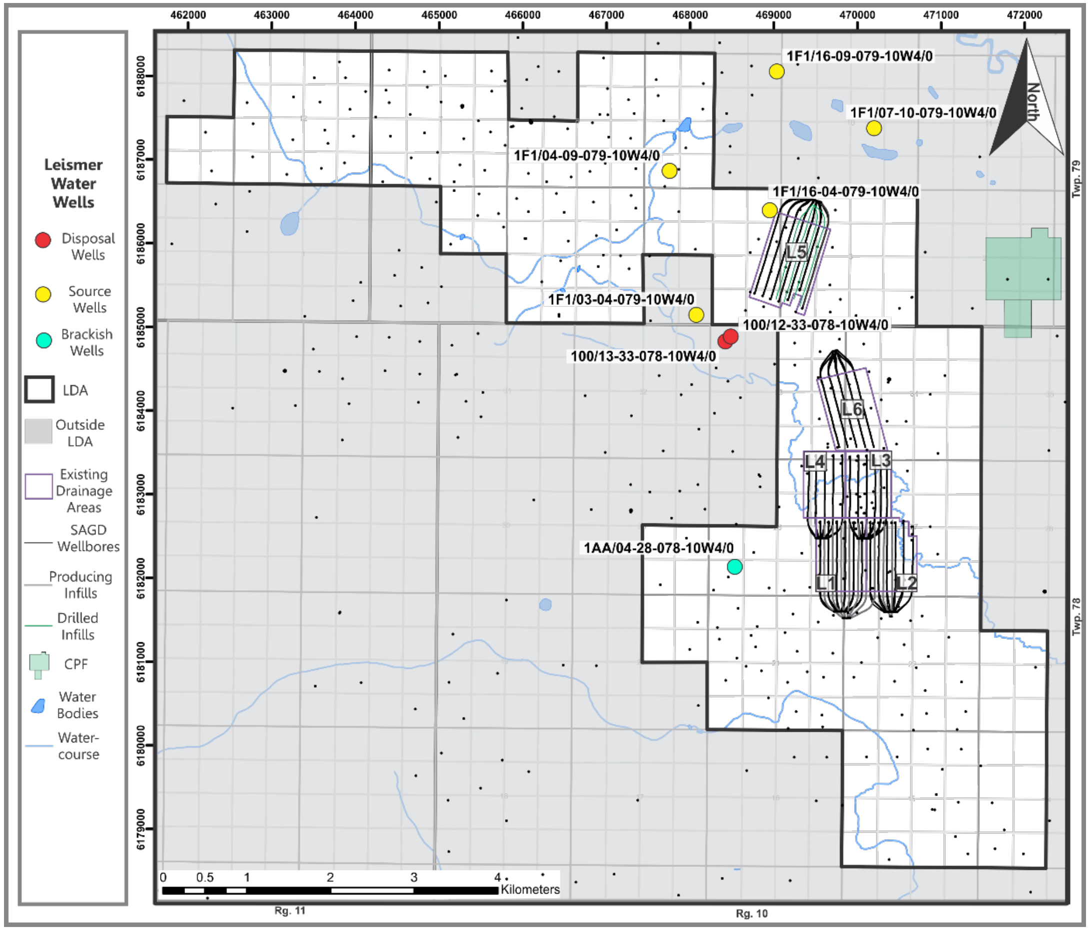
SOURCE AND DISPOSAL WELLS

LEISMER WATER NETWORK

- 5 Wells completed in Lower Grand Rapids Formation
- 1 Brackish water well in Clearwater B formation

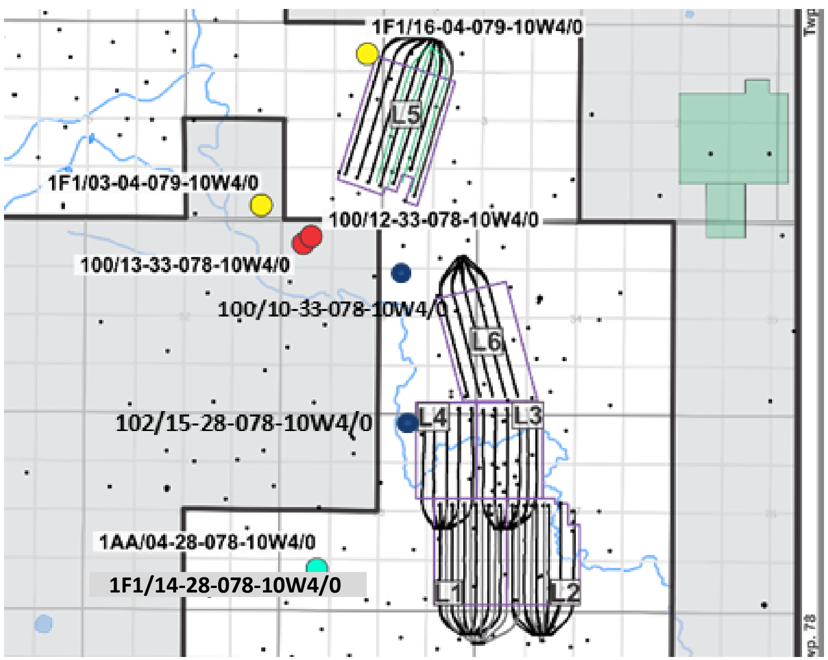
LEISMER DISPOSAL WELLS

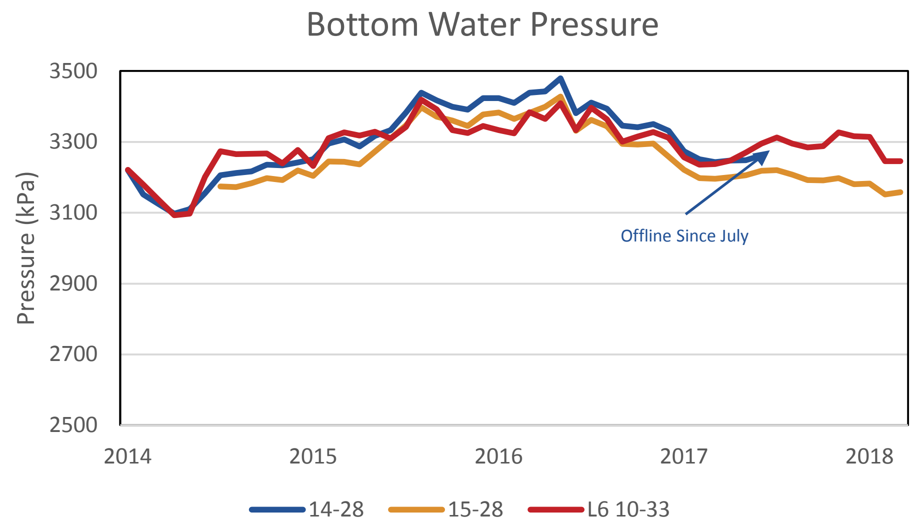
- 2 Disposal wells in the Basal McMurray; one operating, one standby
- Both wells are Class 1b (Disposal Approval No. 11479)

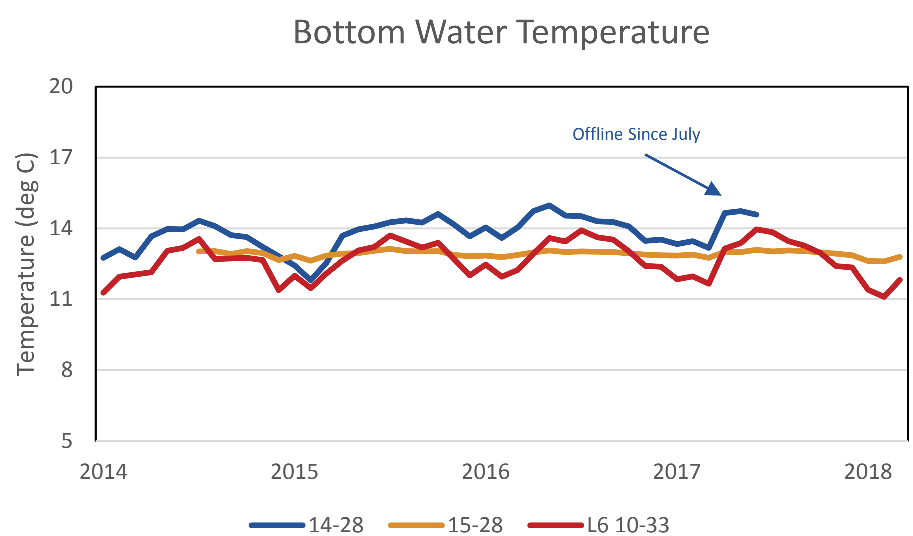


DISPOSAL WELL MONITORING

- Pressure and temperature monitoring
- OBS well 1F1/14-28-078-10W4/0 offline since July 2017
- Proposed 100/10-33-078-10W4/0 to replace 14-28 for disposal well monitoring







CPF WATER USES

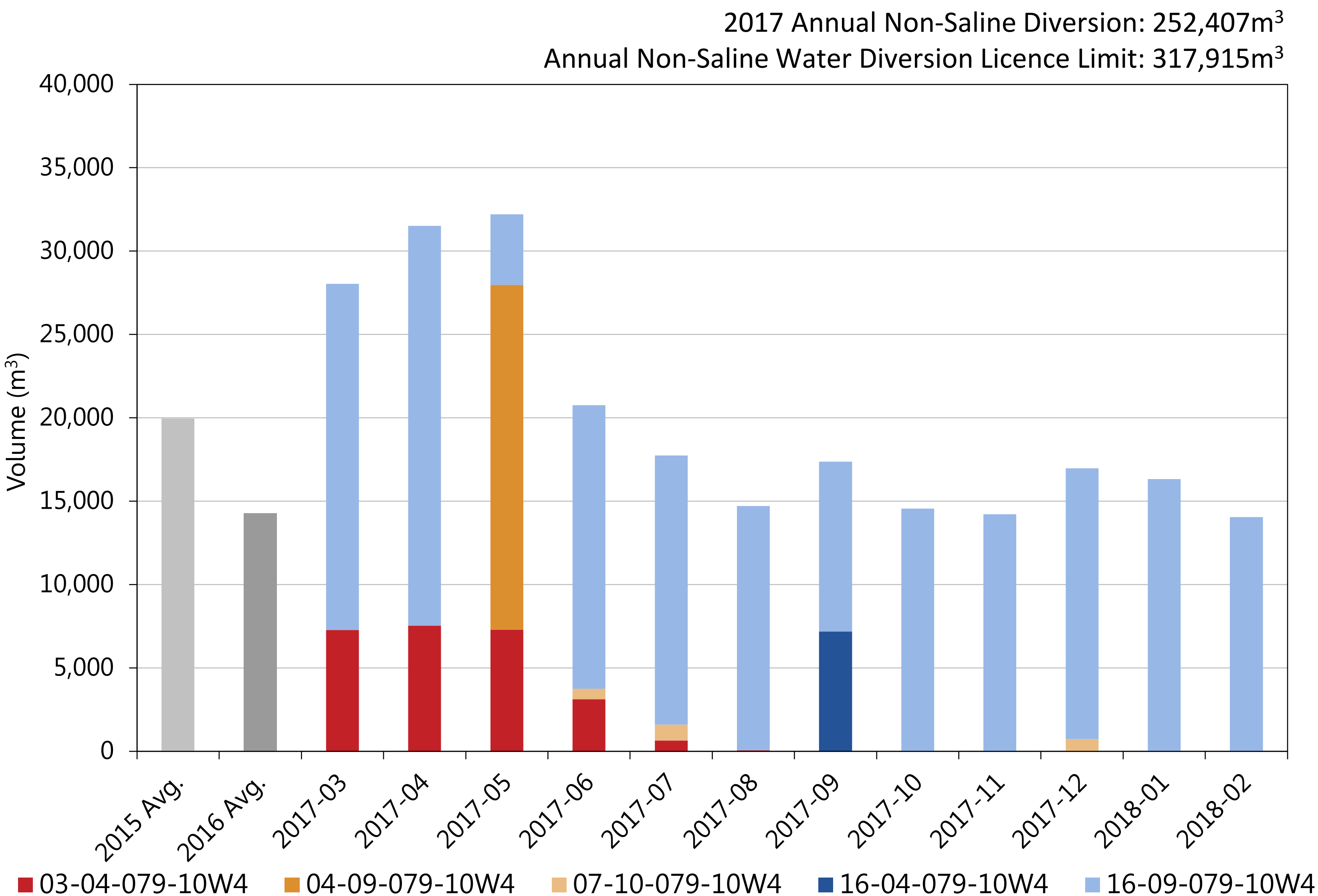
WATER DIVERSION LICENCE (WDL) 00239880 FOR 317,915 m^3/y (871 m^3/d)

- Total non-saline water pumped from source wells at Leismer in 2017 was 252,000 m^3 (690 m^3/d) or 79% of allowable WDL amount
  - *~ 98.5% went to Leismer CPF for process use*
  - *~ 1.5% for domestic use at CPF*

SOURCE WATER MINIMIZED BY OPERATING AT BALANCED RESERVOIR RETENTION

- Source water intensity was 0.21 bbl-water/bbl-bitumen in 2017
- Higher source volumes required in March – May 2017 due to increased steam retention
- Based on reservoir conditions with WSR > 1 for the majority of the year, source water requirements remained low and required mainly used for CPF utility requirements
- High blowdown recycle rates have been maintained

FLOW FROM GRAND RAPIDS

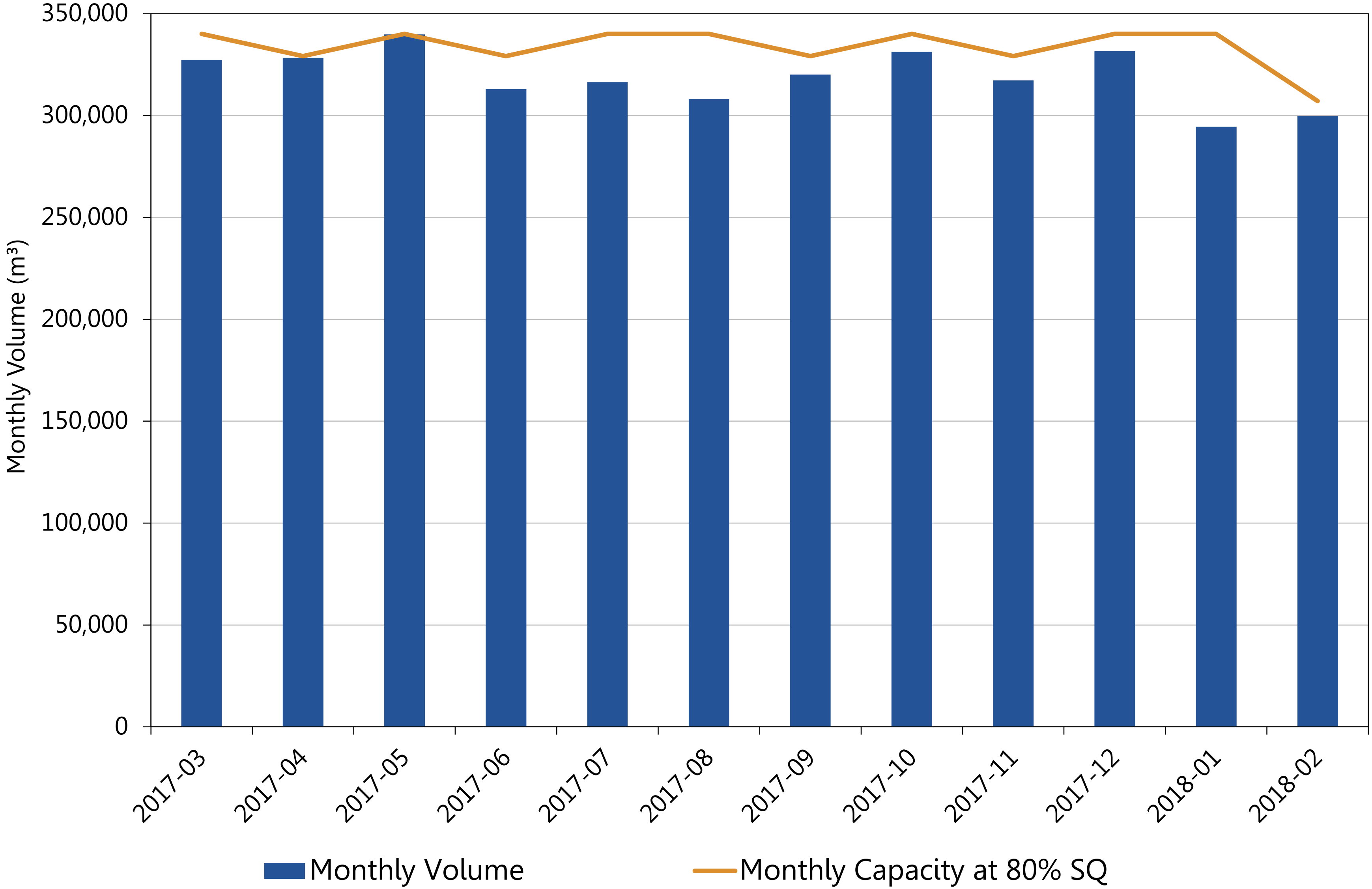


TYPICAL WATER QUALITY

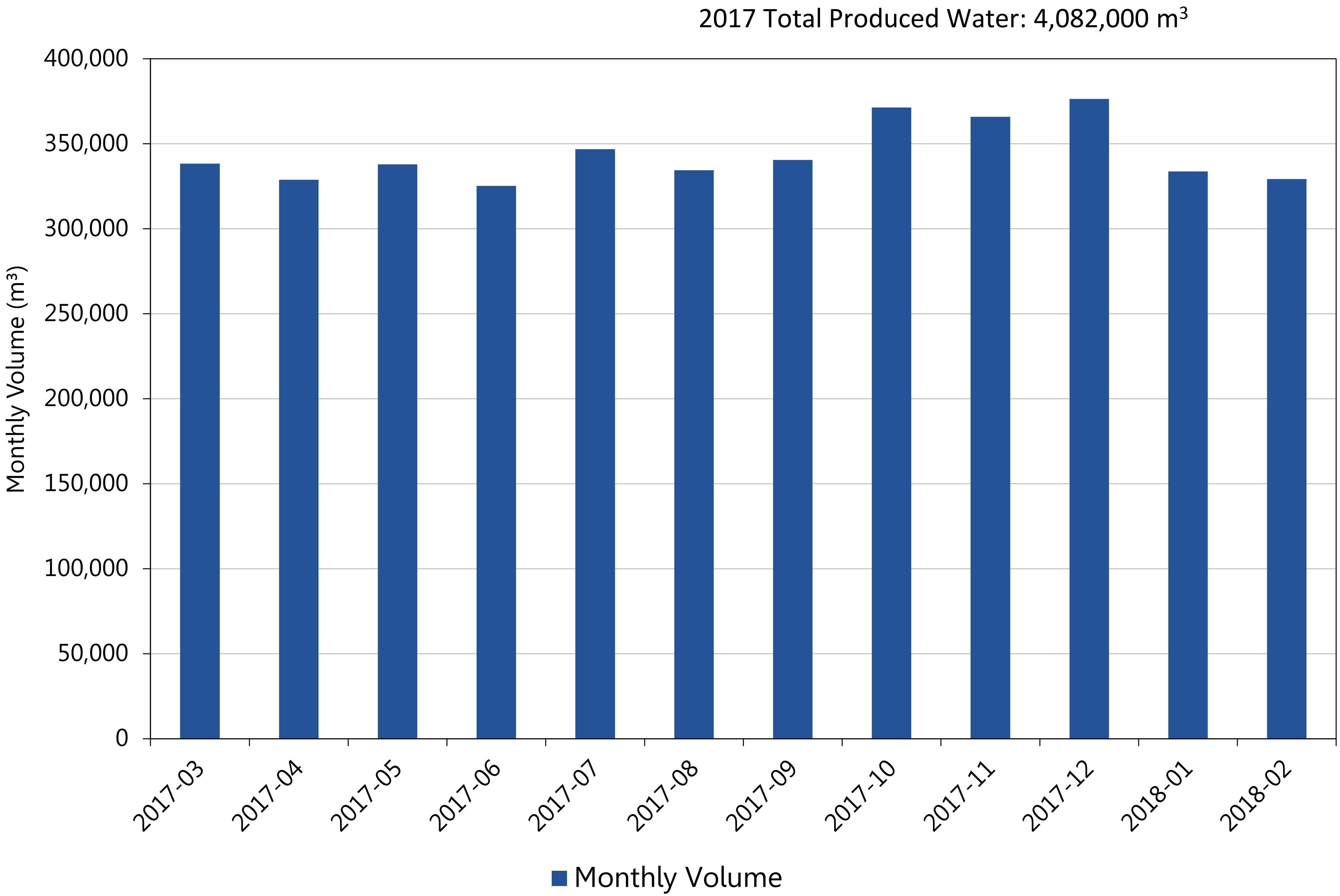
Parameter	Brackish Water	Non-saline Water	Produced Water	Disposal Water
TDS [mg/L]	5,700	1,450	2,300	32,000
pH [-]	8.5	8.3	7.1	12.1
Hardness [mg/L as $CaCO_3$]	70	4.5	20	1.5
Total Alkalinity [mg/L as $CaCO_3$]	880	850	230	6,900
SiO_2 [mg/L]	0	0	250	225
Cl [mg/L]	2,800	230	925	12,500

STEAM INJECTION

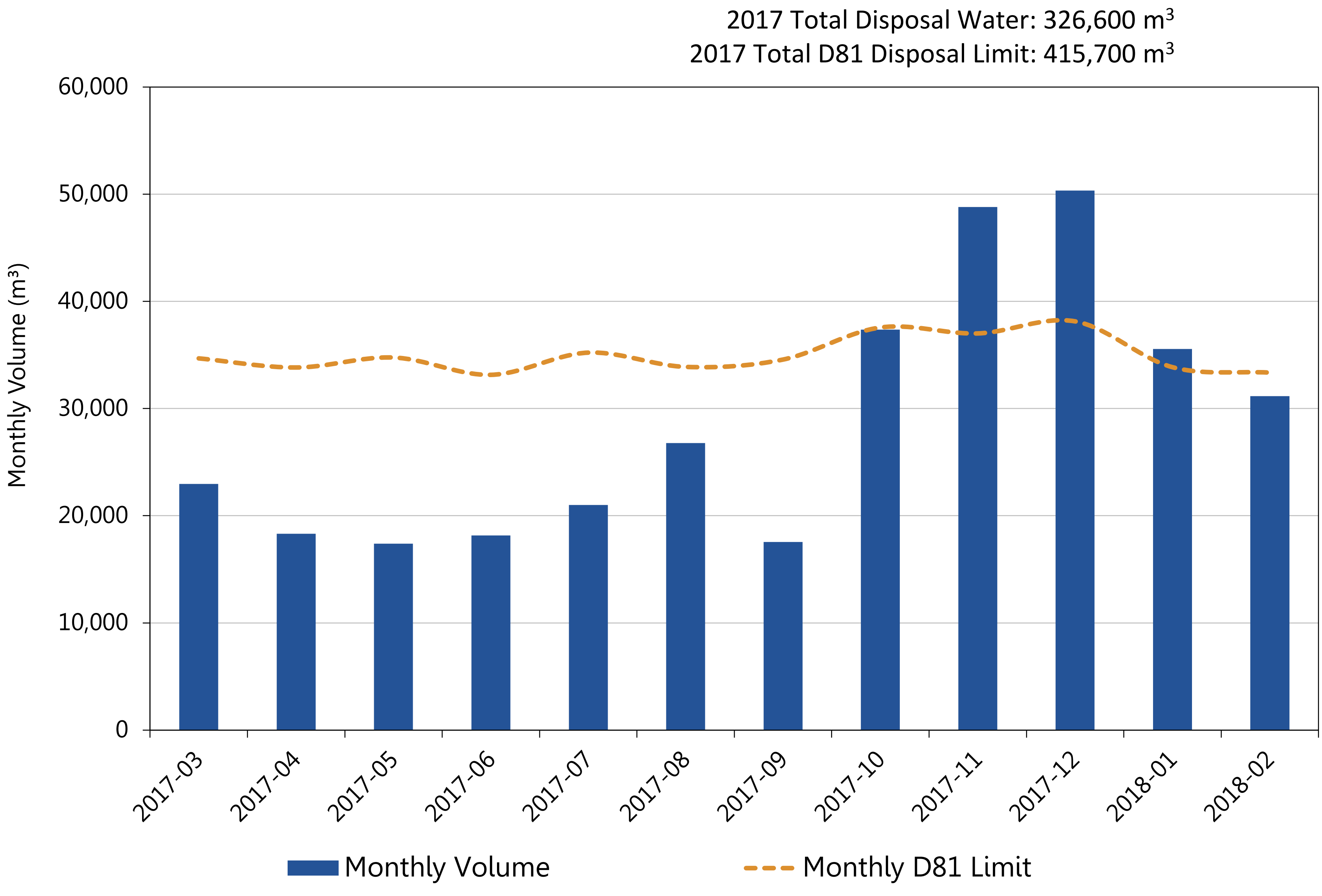
2017 Annual Steam Production: 3,814,000 m^3



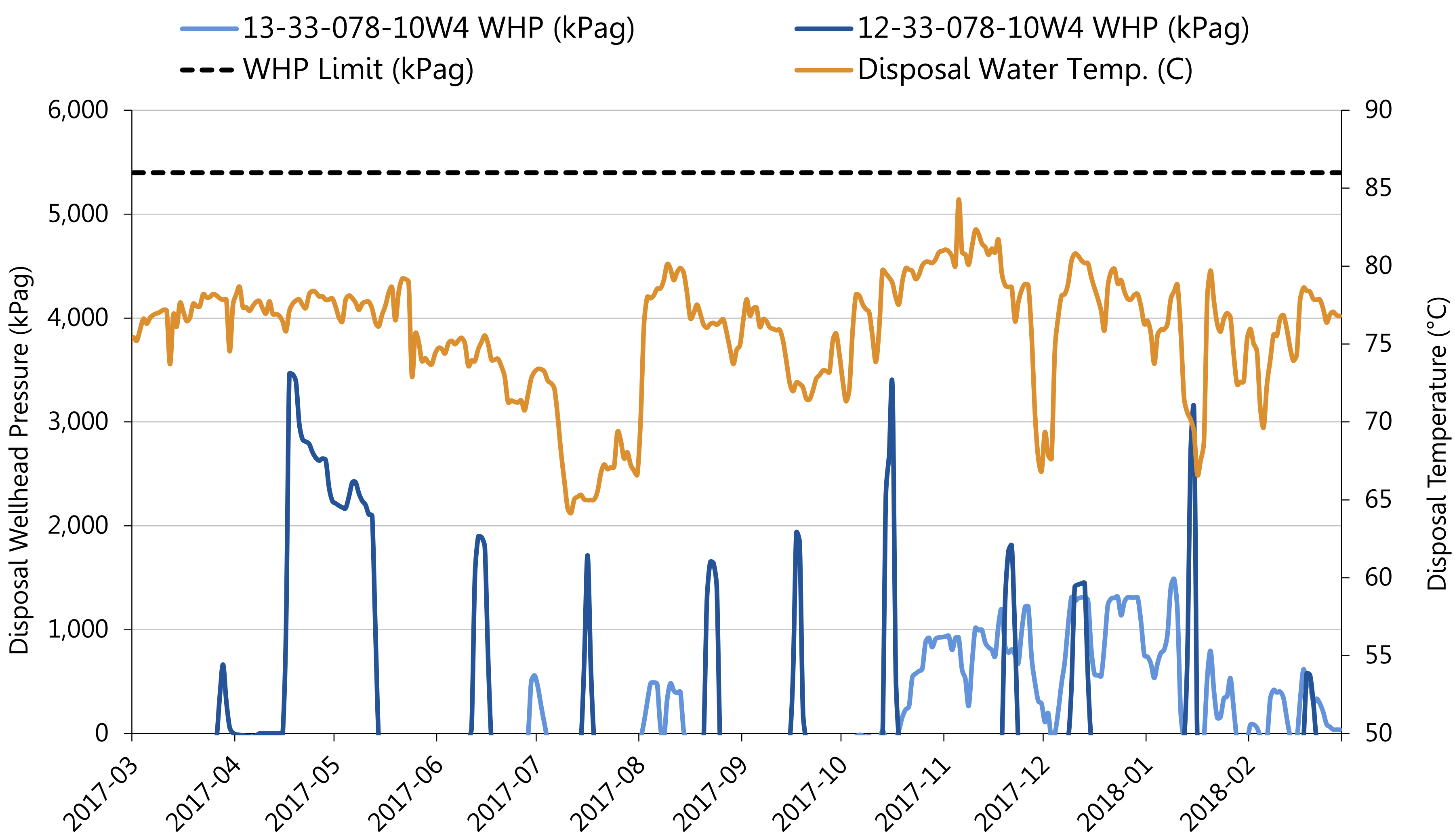
PRODUCED WATER



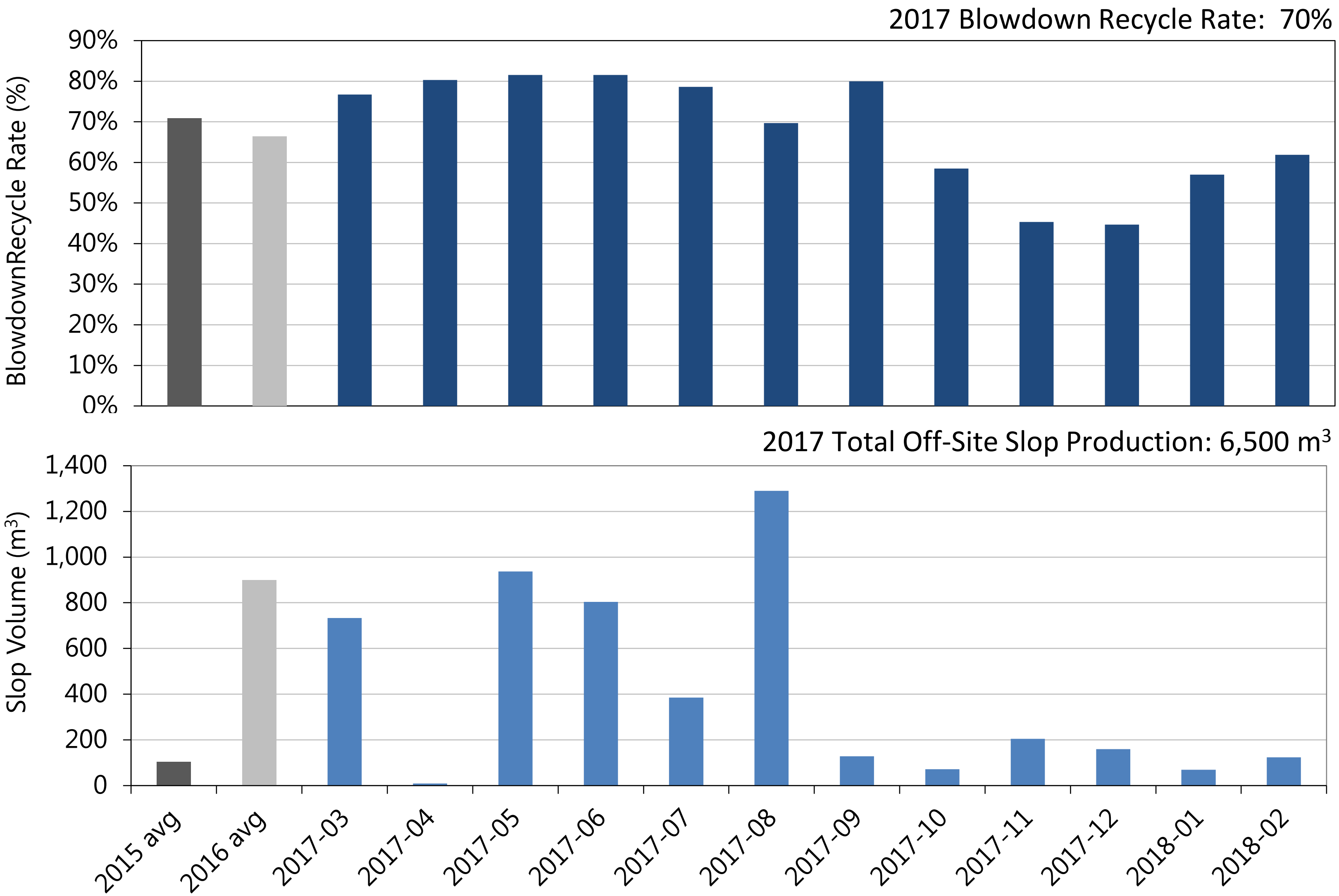
DISPOSAL WATER



DISPOSAL WATER PRESSURE & TEMPERATURE



BLOWDOWN RECYCLE & SLOP



BLOWDOWN RECYCLE & SLOP

SLOP HANDLING:

- 4,300 m^3 of water was trucked off site within slop volume
- Water volume disposed in 2017 was 40% lower than previous year

SOLIDS DISPOSAL:

- Water treatment related solids (lime softening sludge) is allowed to settle in the sludge pond at site and is removed periodically
- No sludge was disposed from the pond in 2017

SURFACE

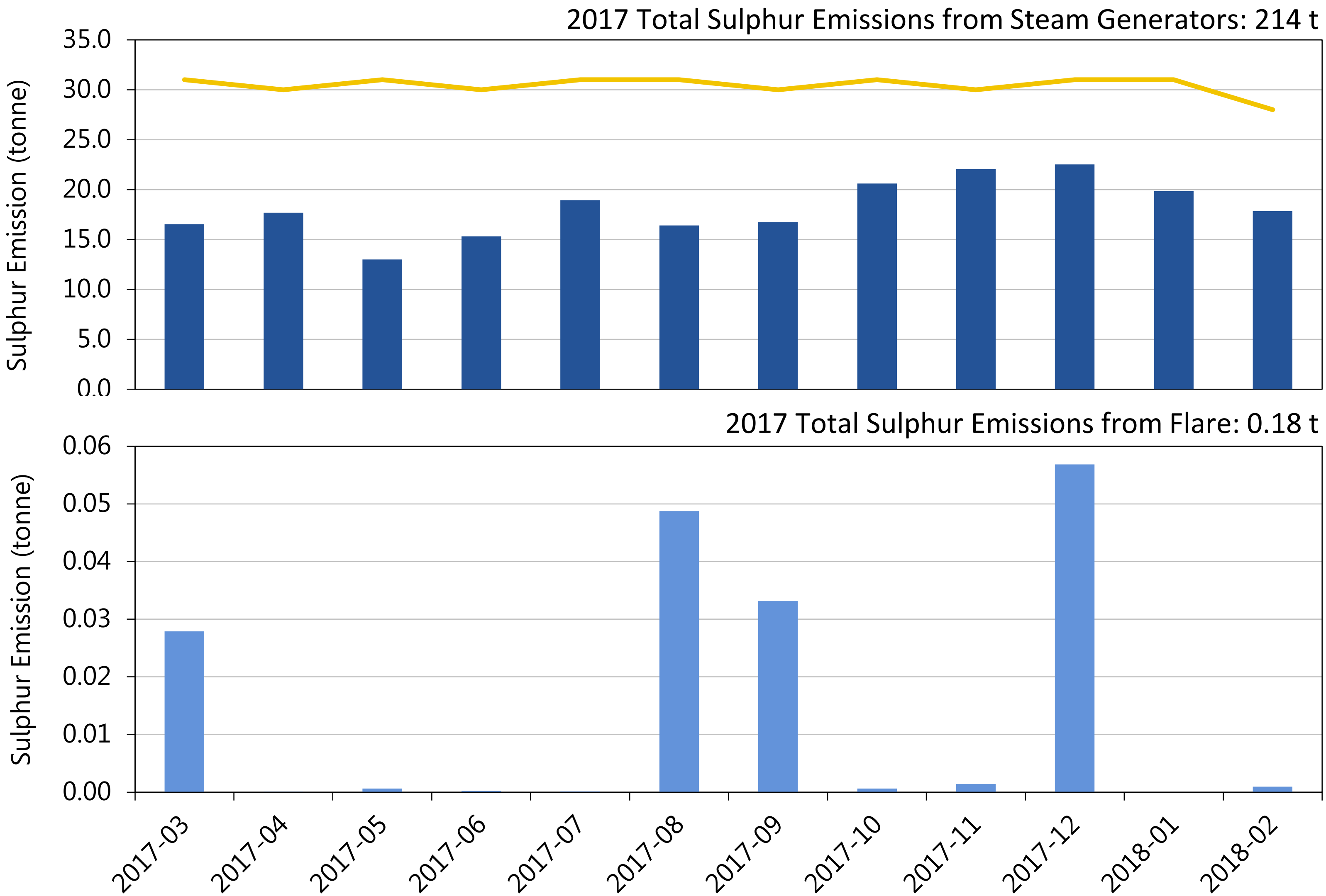
SULPHUR PRODUCTION

ATHABASCA
OIL CORPORATION

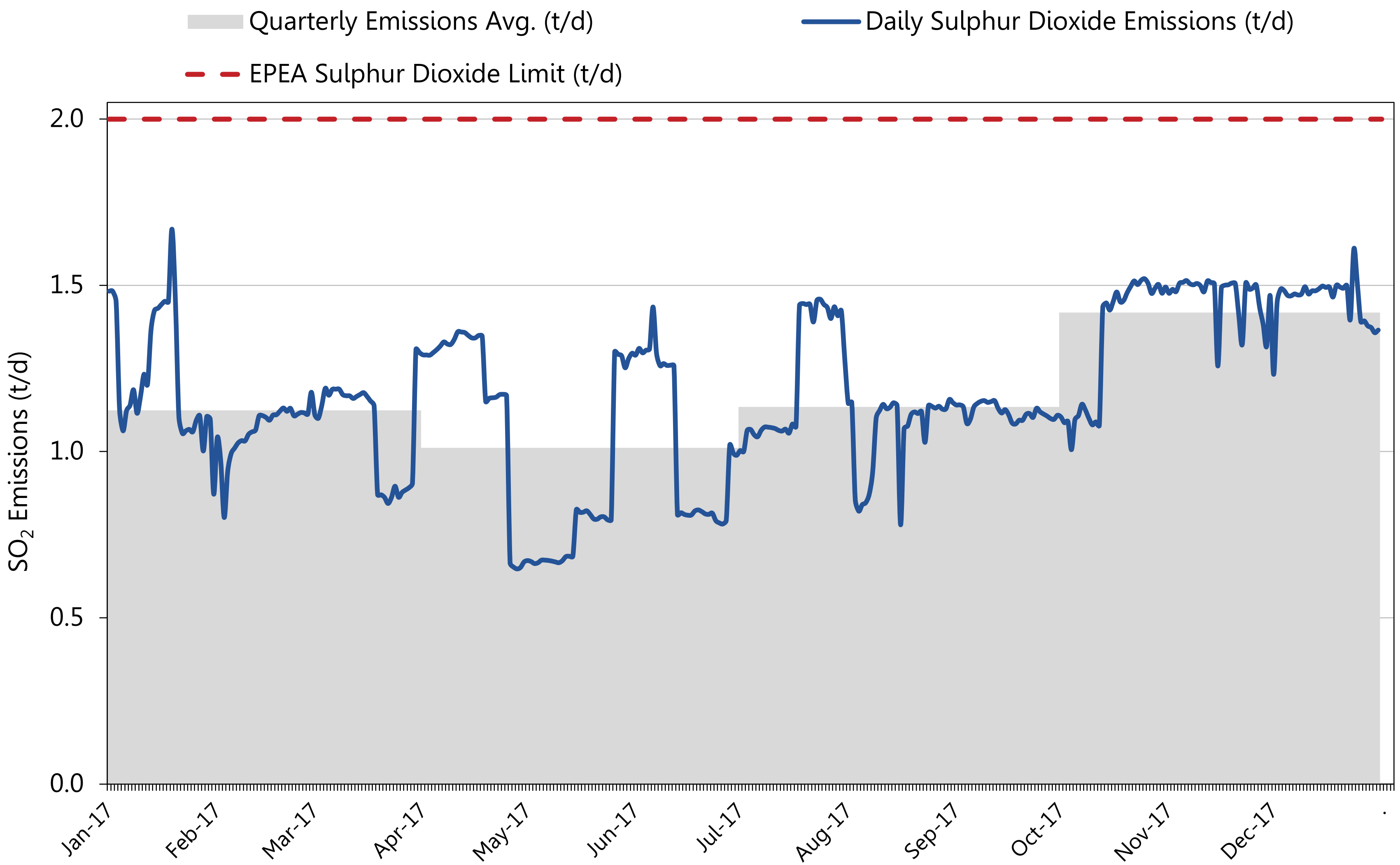
SULPHUR & SULPHUR DIOXIDE

- Leismer average daily sulphur dioxide (SO_2) emissions in 2017 was 1.17 t/d in 2017 (59% of approval limit)
  - *Note: EPEA approval limit for the Leismer Project is 2.0 t/d of SO_2 emissions*
- Total annual SO_2 emissions for 2017 was 428 tonnes
- Leismer currently does not have sulphur recovery facilities

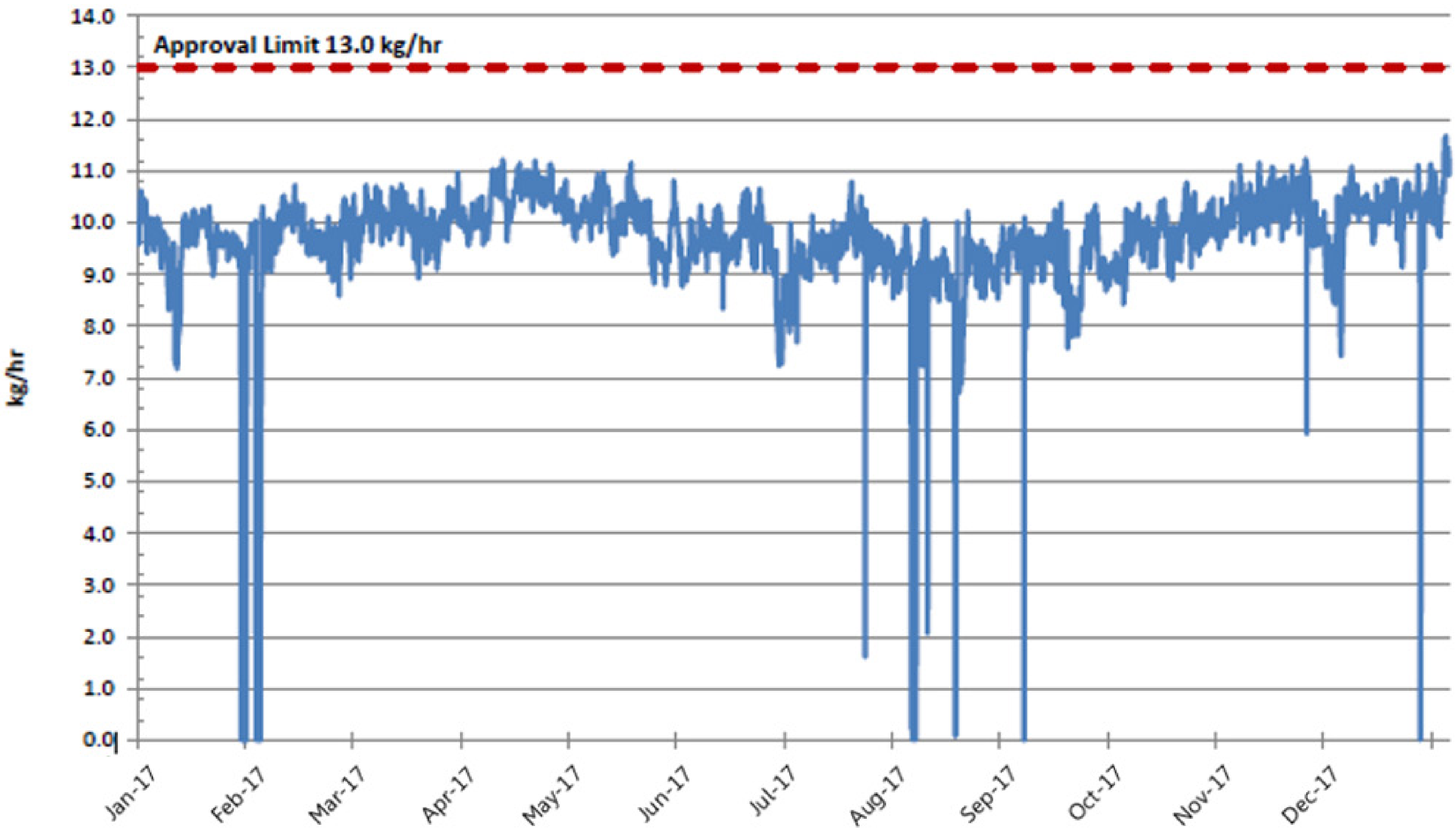
MONTHLY SULPHUR EMISSIONS



DAILY & QUARTERLY SULPHUR EMISSIONS



OTSG NOX EMISSIONS



AMBIENT AIR QUALITY MONITORING RESULTS

ALBERTA ENERGY REGULATOR APPROVAL LIMITS BASED ON ALBERTA AMBIENT AIR QUALITY OBJECTIVES AND GUIDELINES:

- SO_2 (1-hour average): 172 ppbv
- H_2S (1-hour average): 310 ppbv
- NO_2 (1-hour average): 300 ppbv

Passive Ambient Monitoring 2017		
Month	**Peak SO_2 (ppb)**	**Peak H_2S (ppb)**
January	1.3	0.19
February	1.2	0.21
March	2.0	0.14
April	n/a	0.10
May	1.2	0.06
June	1.1	0.11
July	0.8	0.14
August	1.4	0.16
September	1.2	0.17
October	2.1	0.16
November	2.2	0.04
December	2.7	0.13

Continuous Ambient Monitoring 2017			
	October	November	December
Peak SO_2 1-Hour Average (ppb)	32.0	21.0	1.0
Peak H_2S 1-Hour Average (ppb)	1.0	4.0	4.0
Peak NO_2 1-Hour Average (ppb)	13.0	37.0	37.0
Operational Time SO_2 (%)	99.9	100	100
Operational Time H_2S (%)	97.7	99.7	99.7
Operational Time NO_2 (%)	100	100	100

SURFACE

ENVIRONMENTAL ISSUES

ATHABASCA OIL CORPORATION

COMPLIANCE: STATEMENT OF COMPLIANCE

ATHABASCA OIL CORPORATION BELIEVES IT IS IN COMPLIANCE WITH THE AER SCHEME APPROVAL AND REGULATORY REQUIREMENTS

- For the period of March 1, 2017 to February 28, 2018, AOC has no unaddressed non-compliant events

APPROVALS AND AMENDMENTS

Date	Approval Summary
July 24, 2017	Directive 56 Facility Licence amendment for continuous sulphur emission rate
September 1, 2017	Commercial Scheme amendment for L2 Expansion reduced well length (10935U)
December 20, 2017	Class II Disposal Well Approval for disposing produced water into the Clearwater formation (11874A)

105

LEISMER MONITORING PROGRAMS

EPEA APPROVAL REPORTS & PROPOSALS SUBMITTED

- Monthly Air Reports
- Soil Management Program Report – February 8, 2018
- Annual Groundwater Monitoring Report – March 27, 2018
- Annual Conservation and Reclamation Report – March 23, 2018
- Annual Air Report – March 23, 2018
- Annual Industrial Wastewater Report – March 28, 2018
- Annual Industrial Runoff Report – March 28, 2018
- Annual Wetland Monitoring Report – March 28, 2018

WATER ACT REPORTS

- WDL: Monthly use reporting
- Annual Water Use Report – February 20, 2018

REGIONAL WORKING GROUPS AND INITIATIVES

PARTICIPATION IN MULTI-STAKEHOLDER REGIONAL INITIATIVES:

- Oil Sands Monitoring (OSM)
- Wood Buffalo Environmental Association (WBEA)
- Regional Industry Caribou Collaboration (RICC)

SURFACE

NON-COMPLIANCE EVENTS

COMPLIANCE: SUMMARY OF NON-COMPLIANCE

- The following list summarizes non-compliance events for the period of March 2017 to February 2018
- For all events, corrective actions were identified and tracked to completion

Event	Corrective Action
November 22, 2017: Source water pipeline failed	Heat trace controller settings verified on other pipelines. Verification of heat trace set points were included in annual inspection criteria

SURFACE

FUTURE PLANS

ATHABASCA OIL CORPORATION

MAJOR ACTIVITIES & TARGET DATES

CPF DEGASSER PROJECT AND NORLITE DILUENT SUPPLY

- Construction to be completed mid 2018 and start up scheduled for Q2-2018
- Degasser start up in conjunction with new diluent supply
- New diluent supply from Enbridge Norlite pipeline to be connected to Leismer in Q2-2018

PAD L5 INFILL WELLS

- Earthworks and facility construction completed with start-up scheduled for Q3-2018

PAD L2 EXPANSION

- Continue Pad L2 expansion design / planning

5TH OTSG ADDITION

- Start up scheduled for Q4-2018

ATHABASCA OIL CORPORATION
SUITE 1200, 215 - 9TH AVENUE SW
CALGARY, AB T2P 1K3
P:403-237-8227
F:403-264-4640