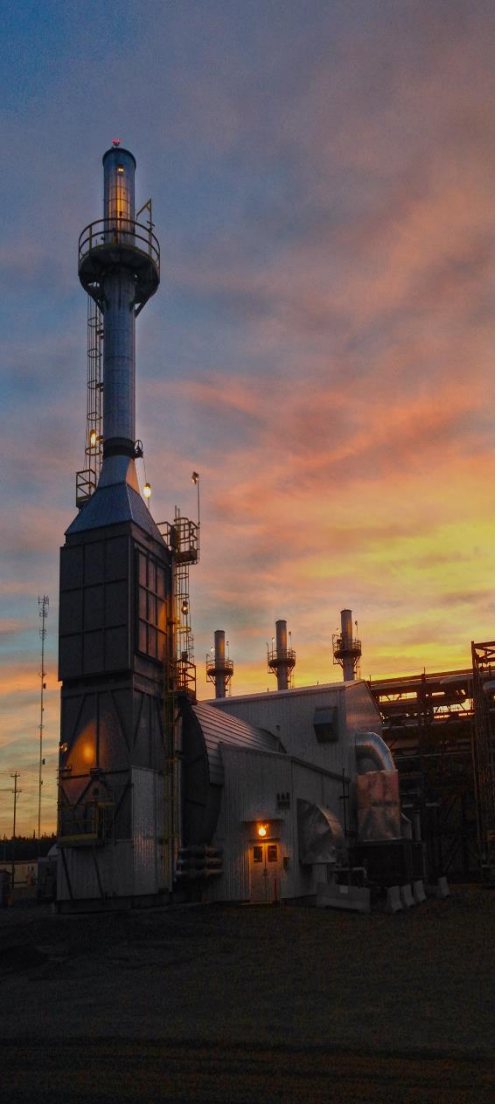


ATHABASCA OIL CORPORATION

AER LEISMER UPDATE

May 2017

ATHABASCA OIL CORPORATION

INTRODUCTION

SUBSURFACE	
○ Project Description & Status ○ Geoscience ○ 4-D Seismic & Monitoring	Marcus Hoehn
○ Well Design & Instrumentation • *Drilling & Completions* • *Artificial Lift* • *Instrumentation* ○ Scheme Performance	Shaista Esmail
○ Pilots ○ Future Plans	Kevin Ma
SURFACE	
○ Facilities ○ Measurement & Reporting ○ Water Production, Injection & Uses ○ Sulphur Production	Scott Martin
○ Compliance ○ Future Plans	Jerry Demchuk

SUBSURFACE

GEOSCIENCE OVERVIEW

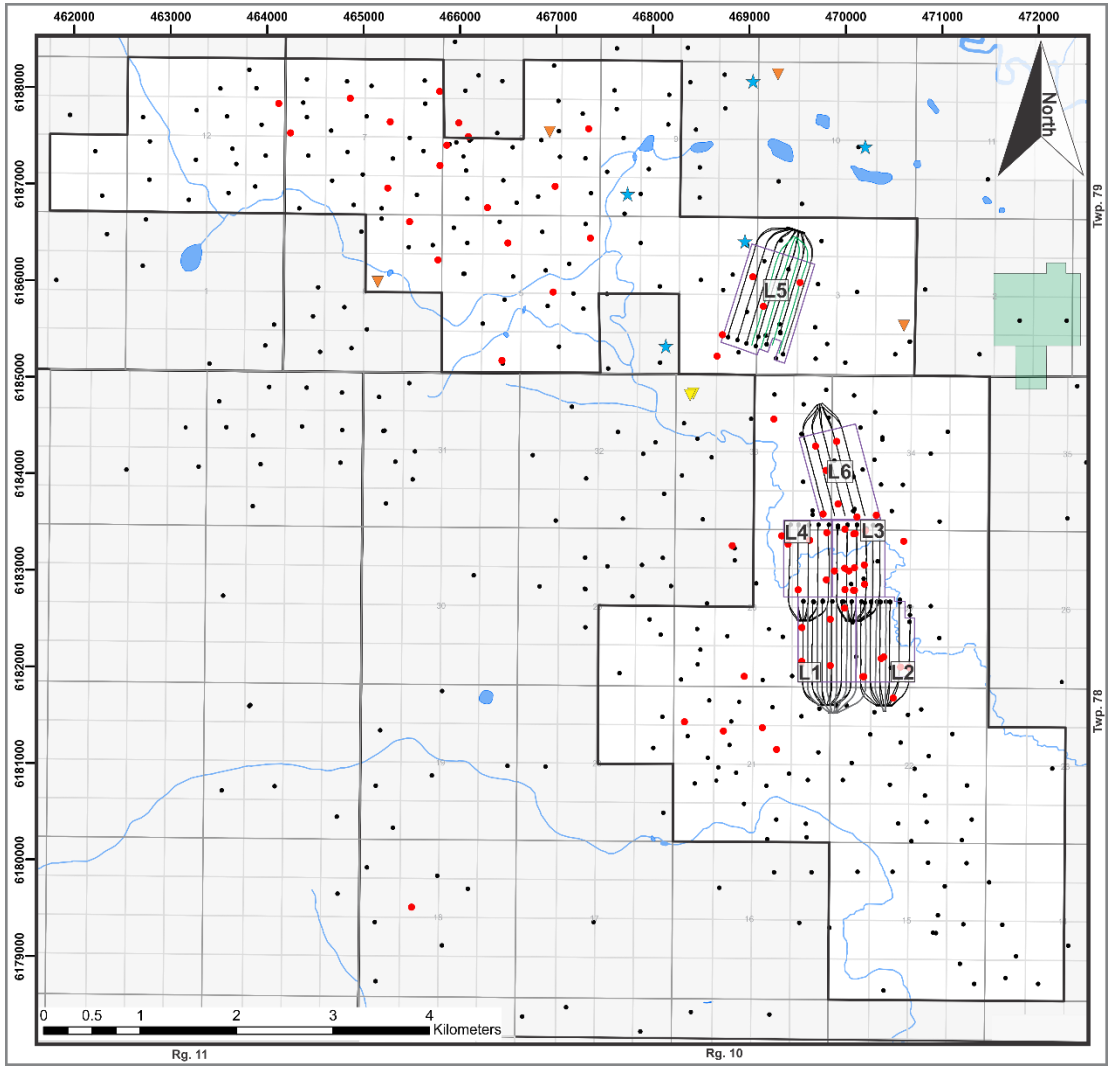
ATHABASCA OIL CORPORATION

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

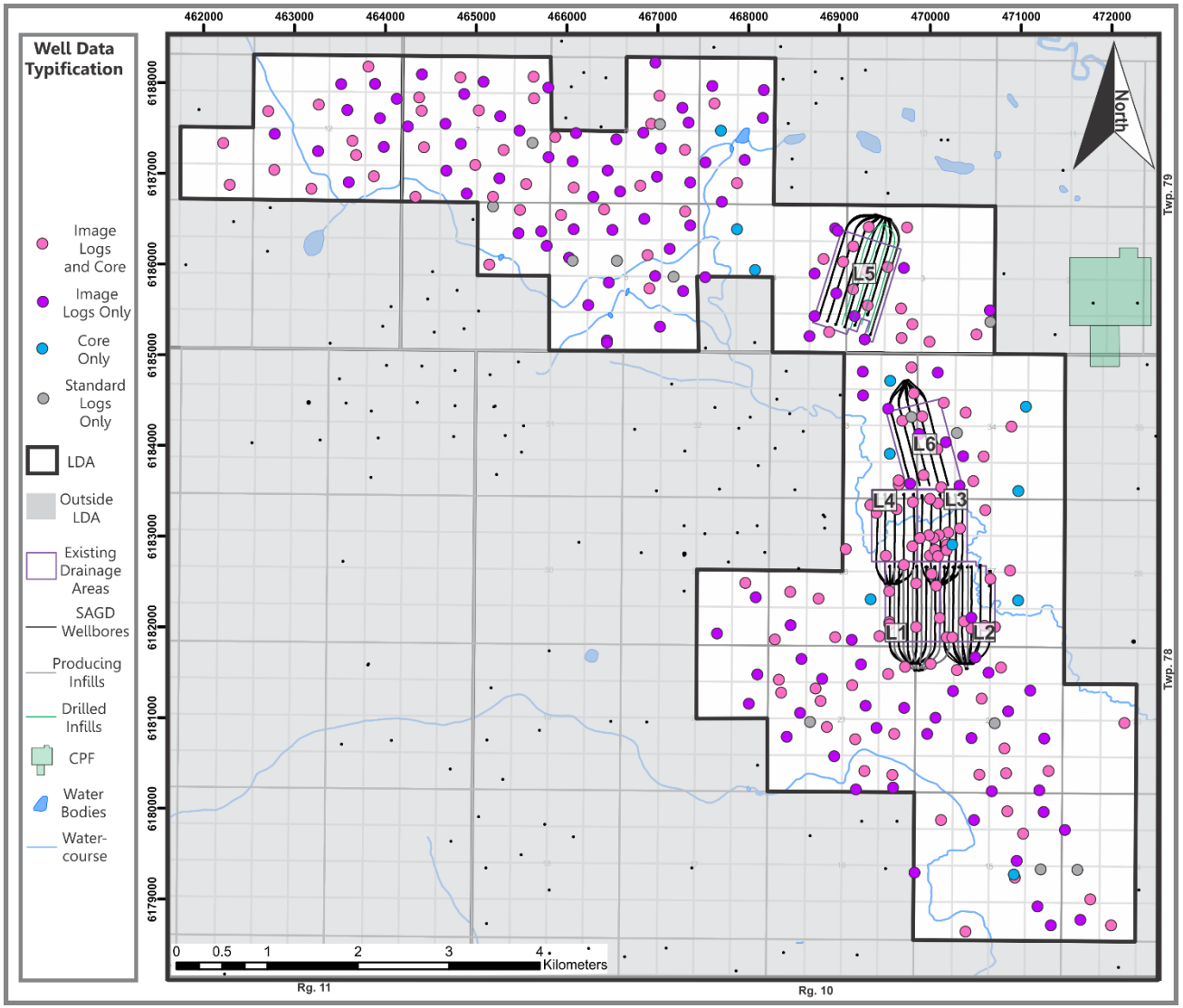
LEGEND

- 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)



LDA GEOSCIENCE ANALYSIS

- No new cores were obtained or analyzed in 2016 within the LDA
- No petrographic analyses were conducted in 2016
- No geomechanical analyses were conducted in 2016
- No reservoir fracture pressure and caprock integrity tests were conducted in 2016



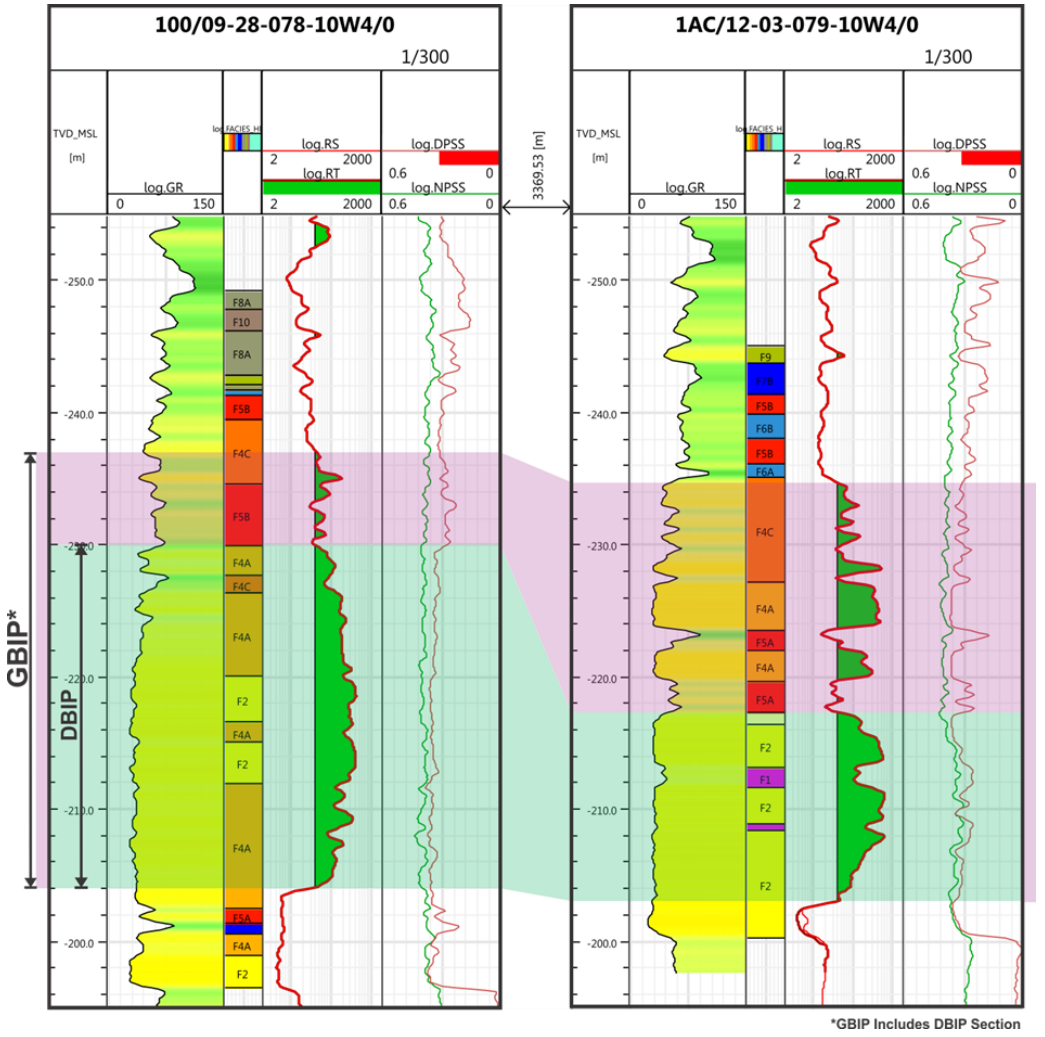
BITUMEN PAY CLASSIFICATION

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)

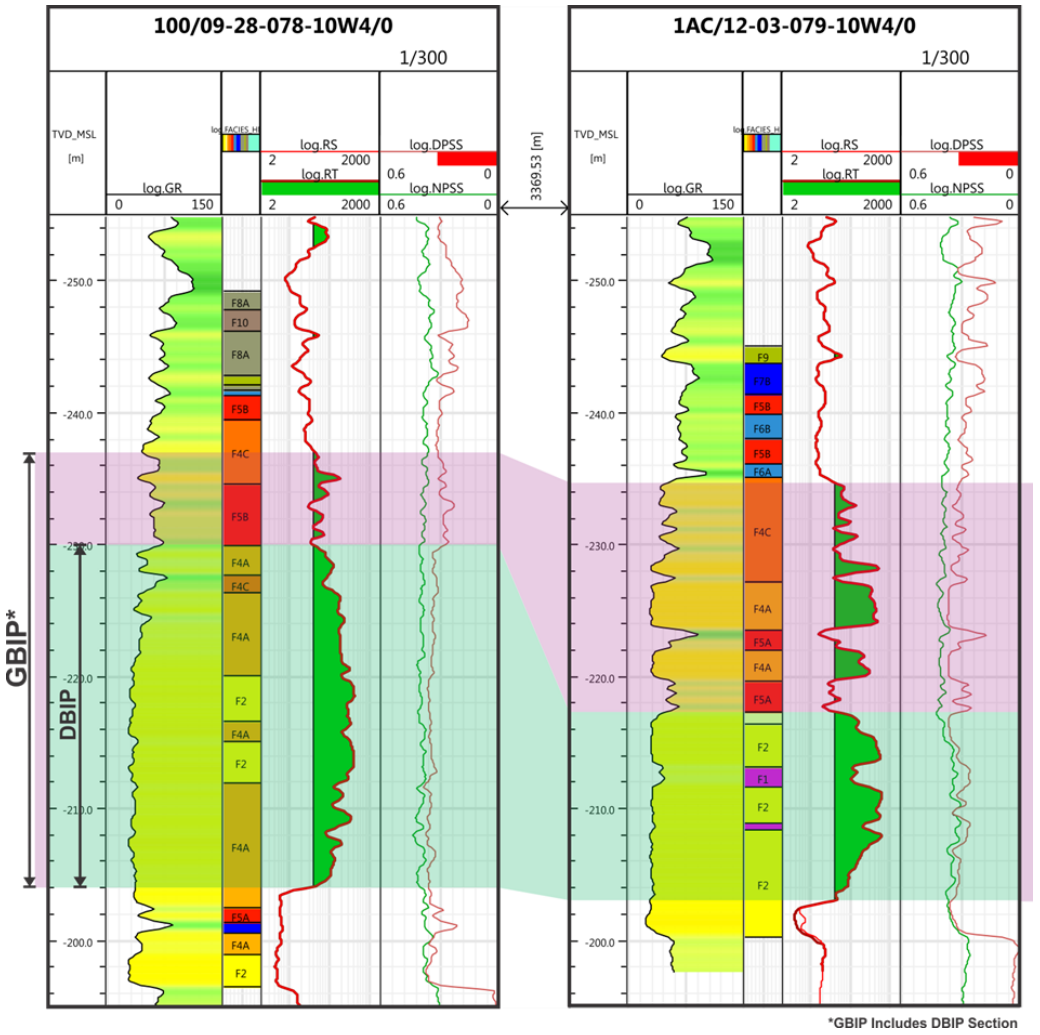
- A more conservative definition used for planning well pair placement
- Same petrophysical criteria as GBIP



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



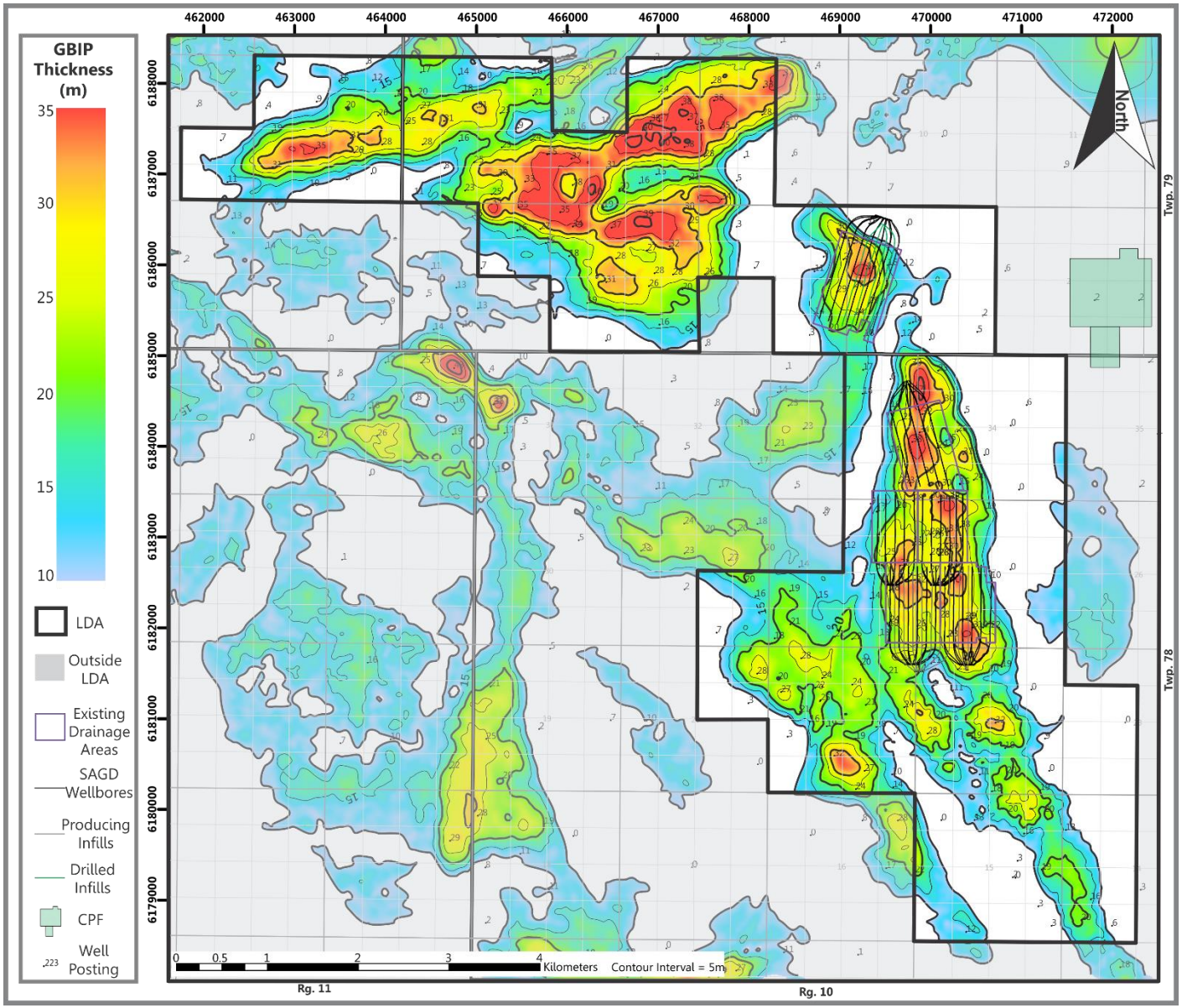
LEISMER RESERVOIR PROPERTIES

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

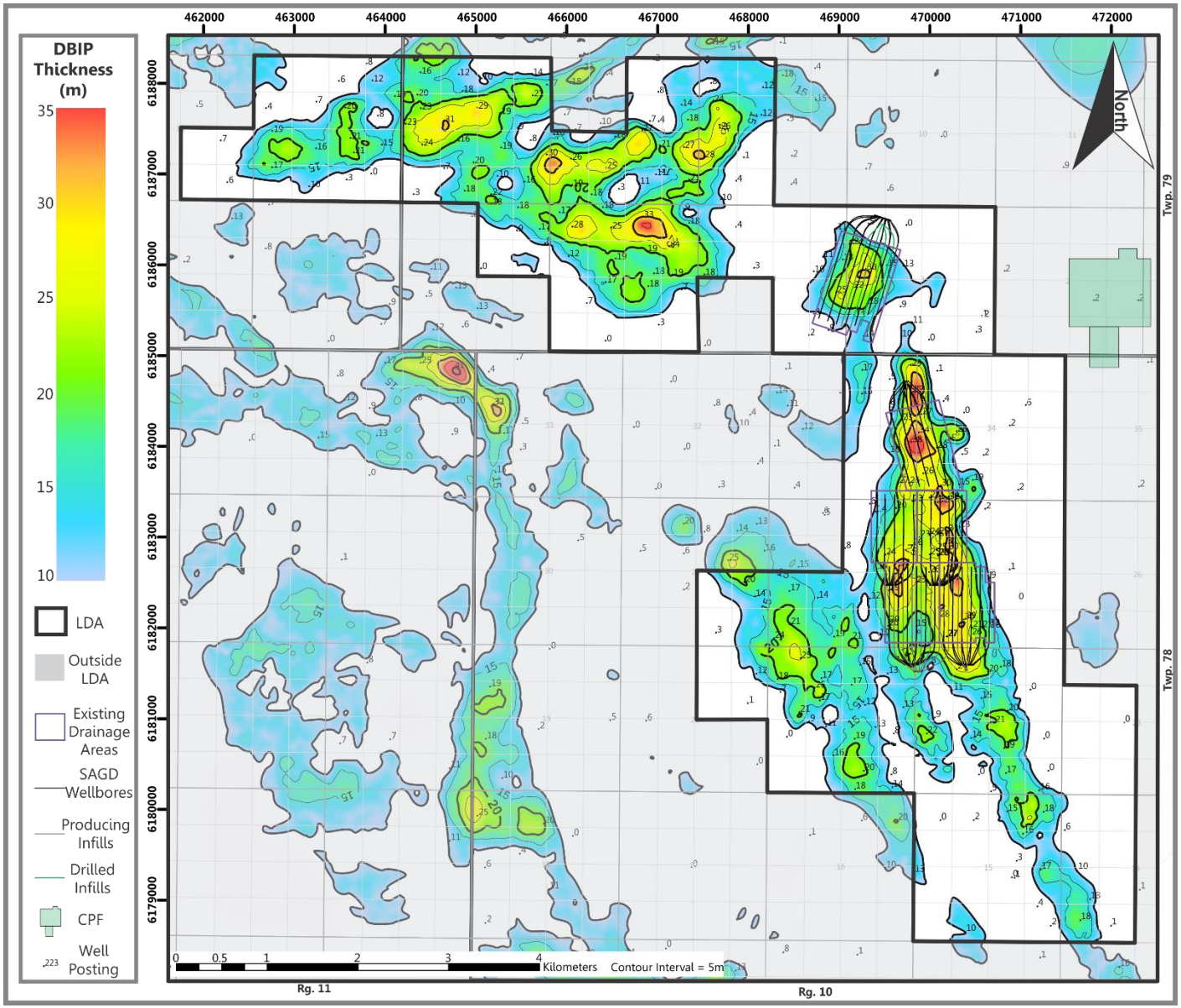
* DBIP VALUES SHOWN

- Original Reservoir Pressure: 2,400 to 2,600 kPa
- Original Reservoir Temperature: 14°C
- Average Permeability: 5 to 6 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

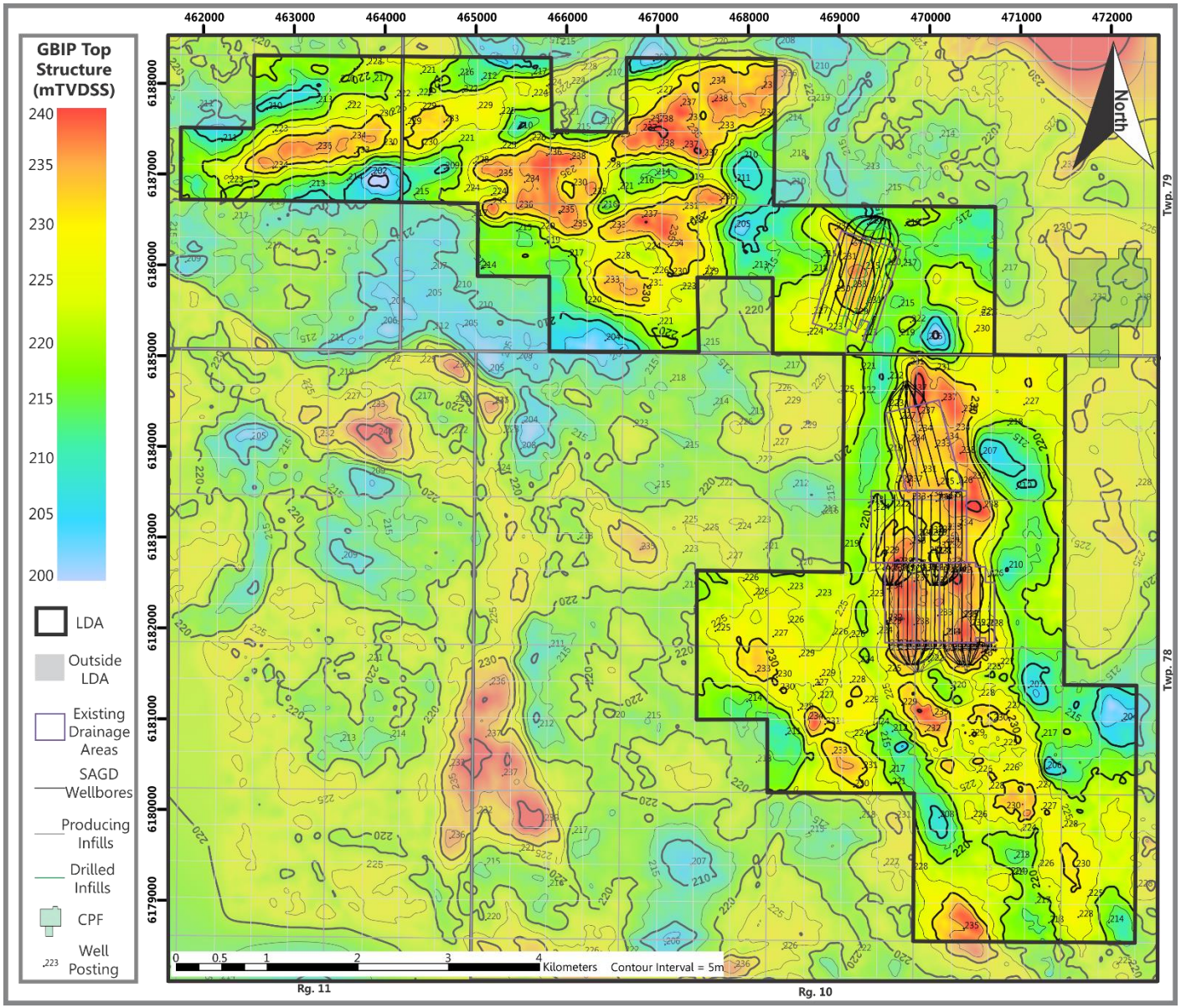
GBIP THICKNESS MAP



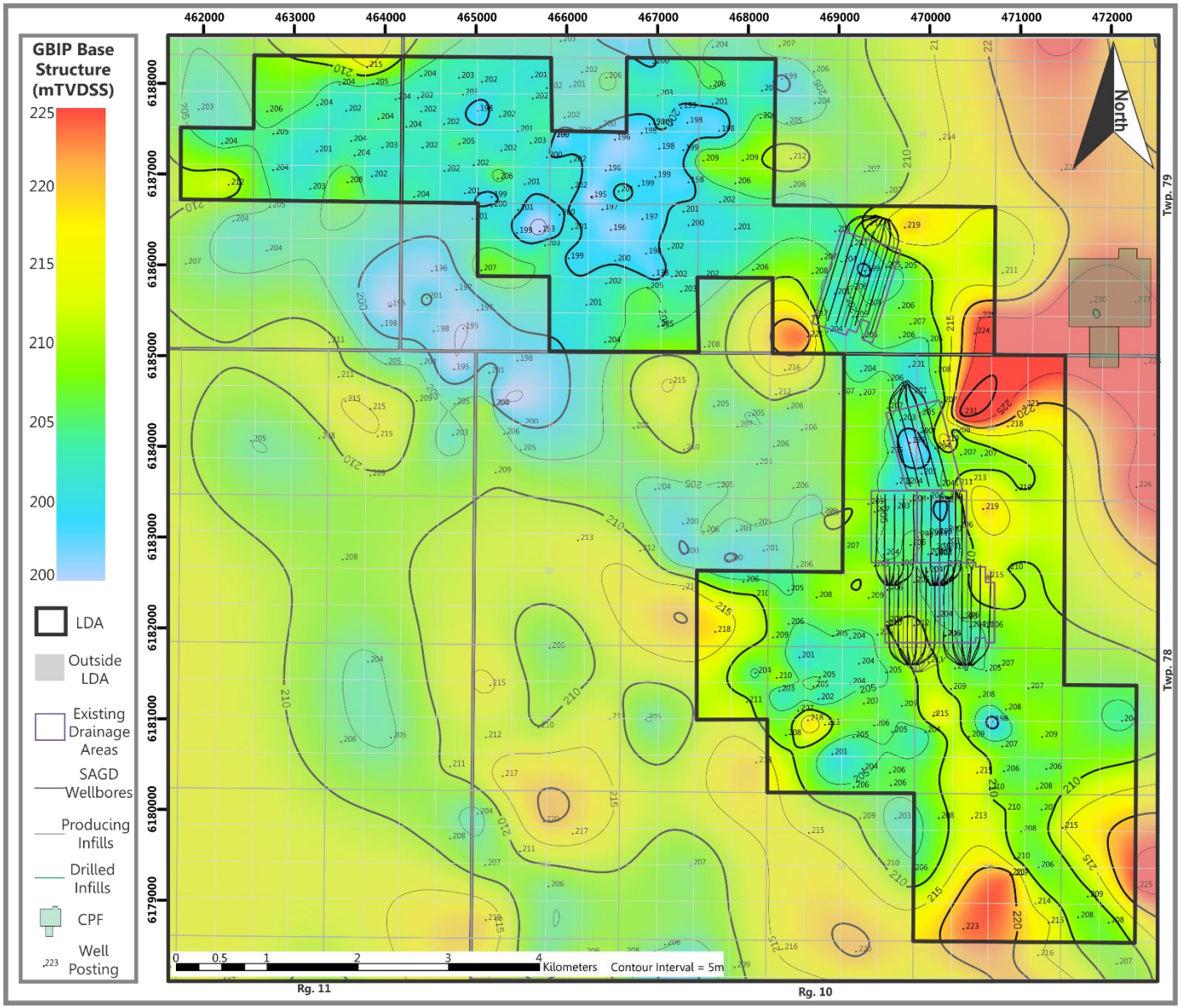
DBIP THICKNESS MAP



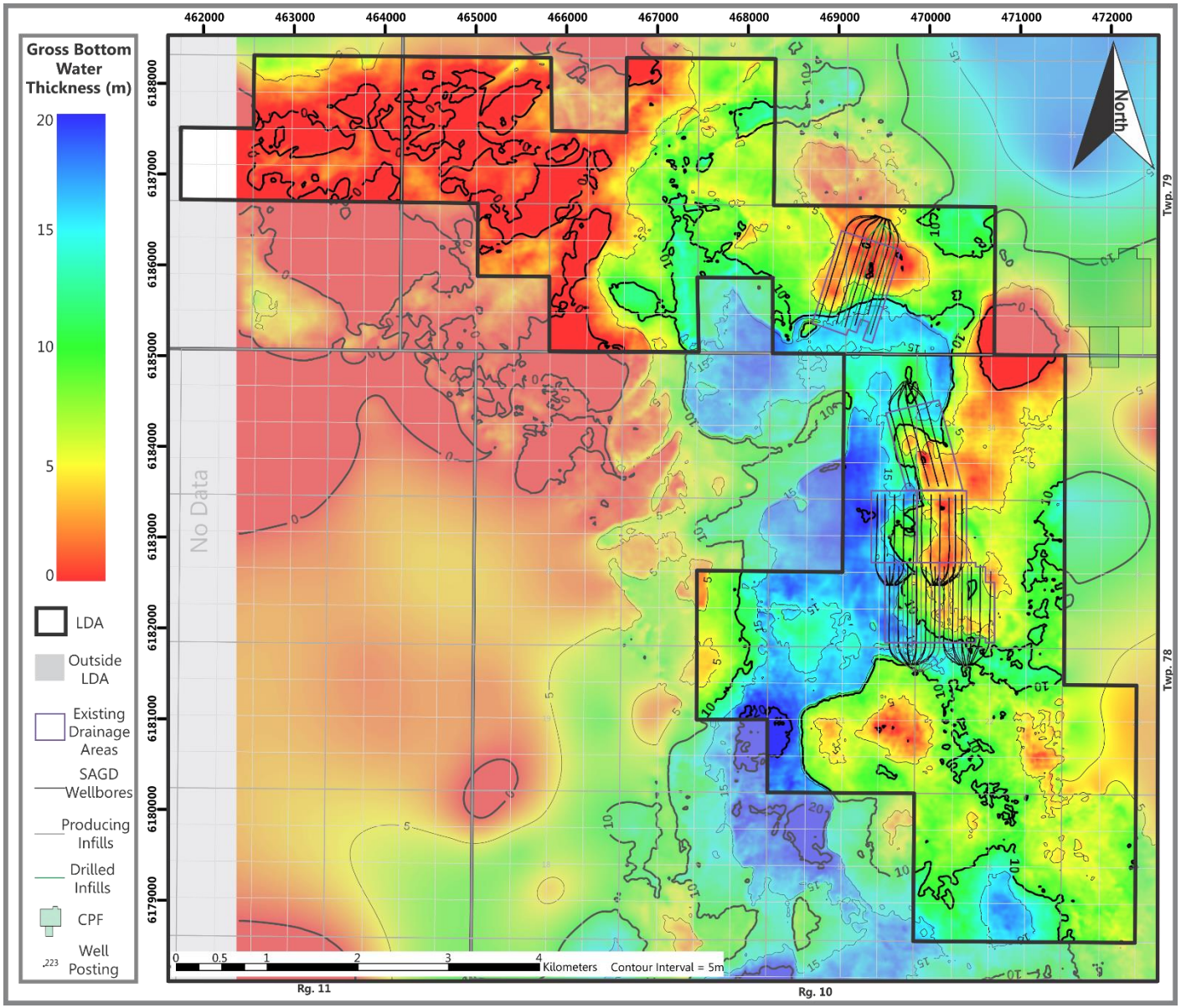
GBIP TOP STRUCTURE MAP



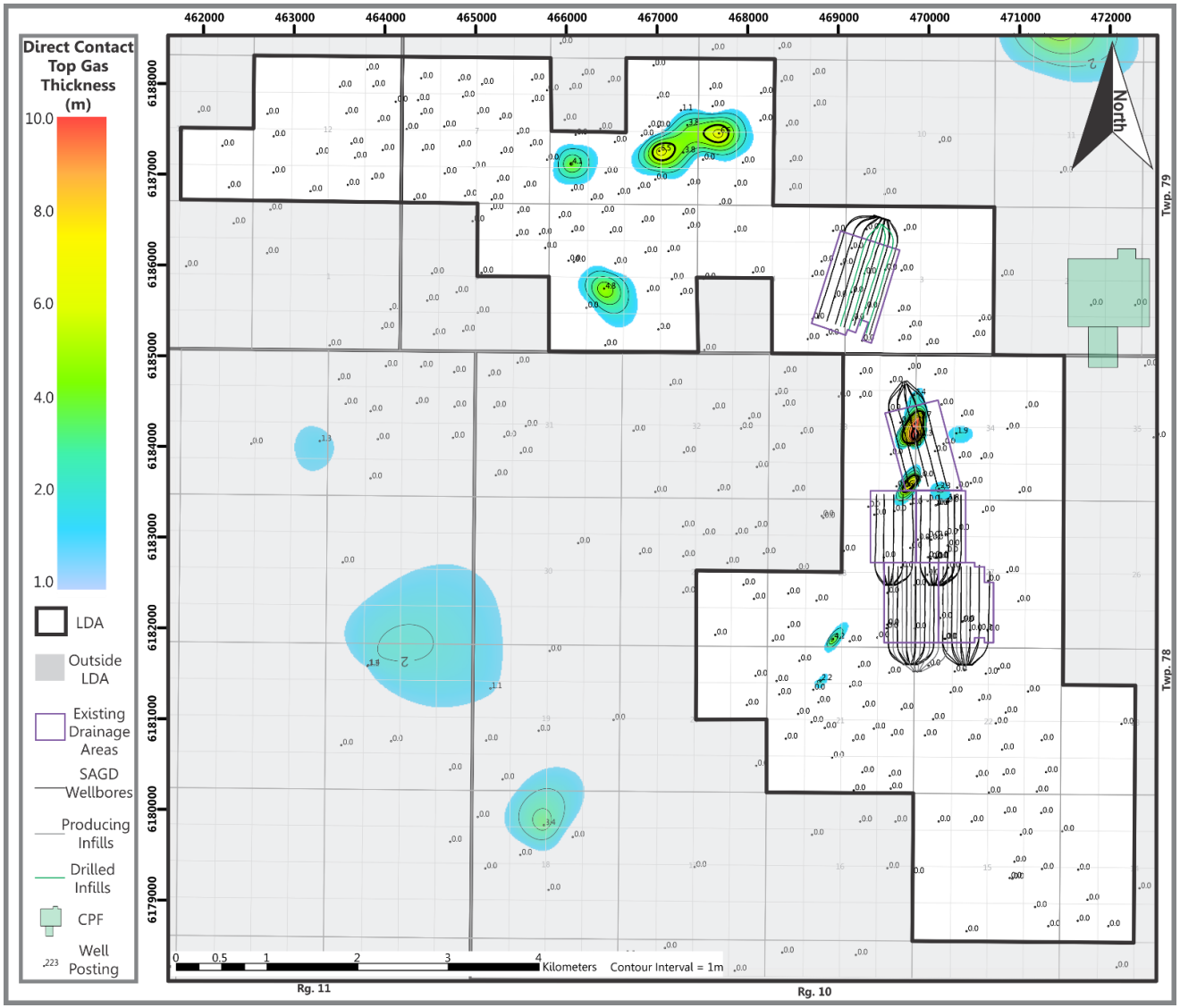
GBIP BASE STRUCTURE MAP



GROSS BOTTOM WATER THICKNESS MAP

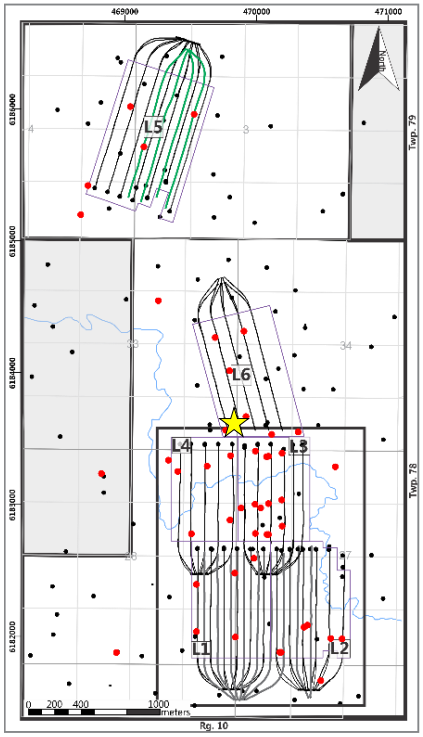


DIRECT CONTACT TOP GAS THICKNESS MAP



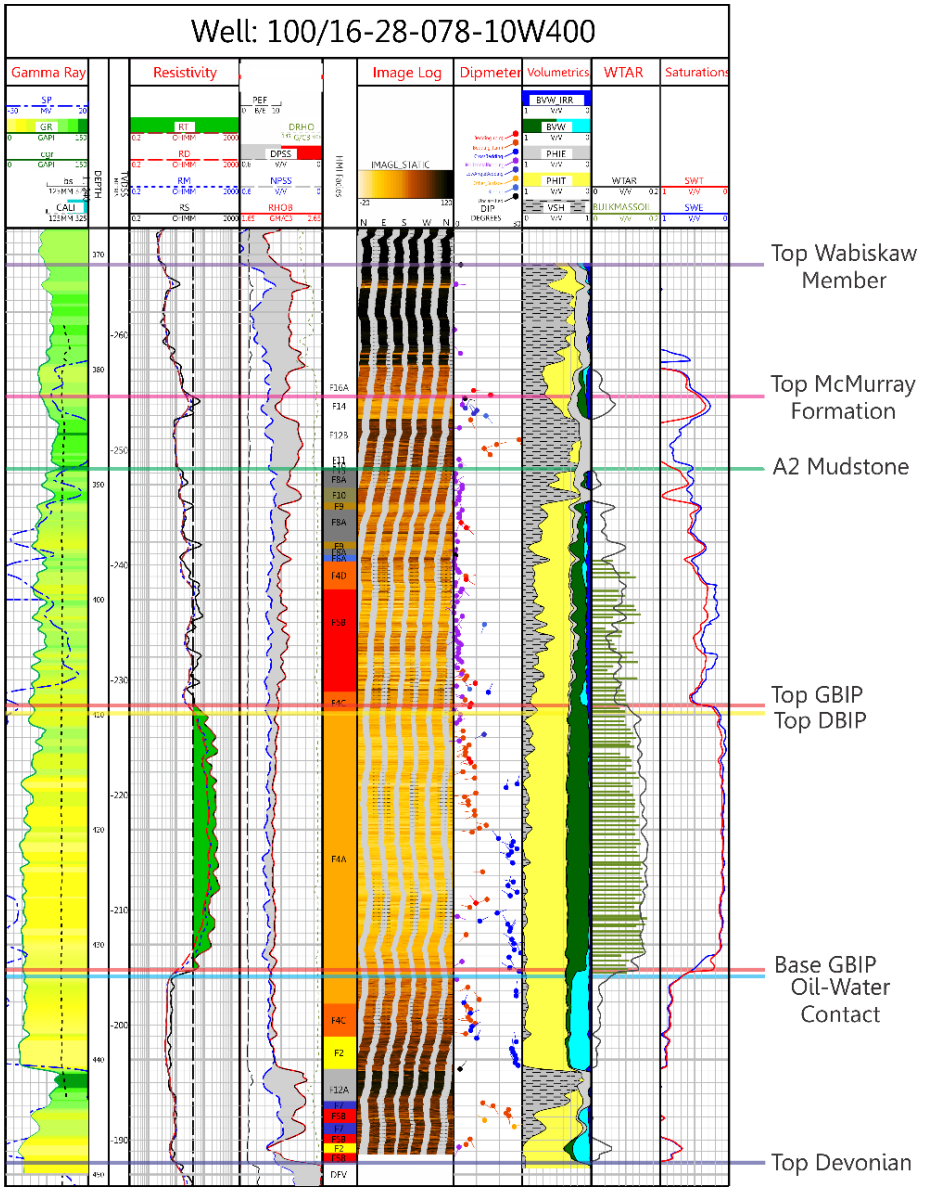
Direct Contact = Gas in direct connection to the bitumen column

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

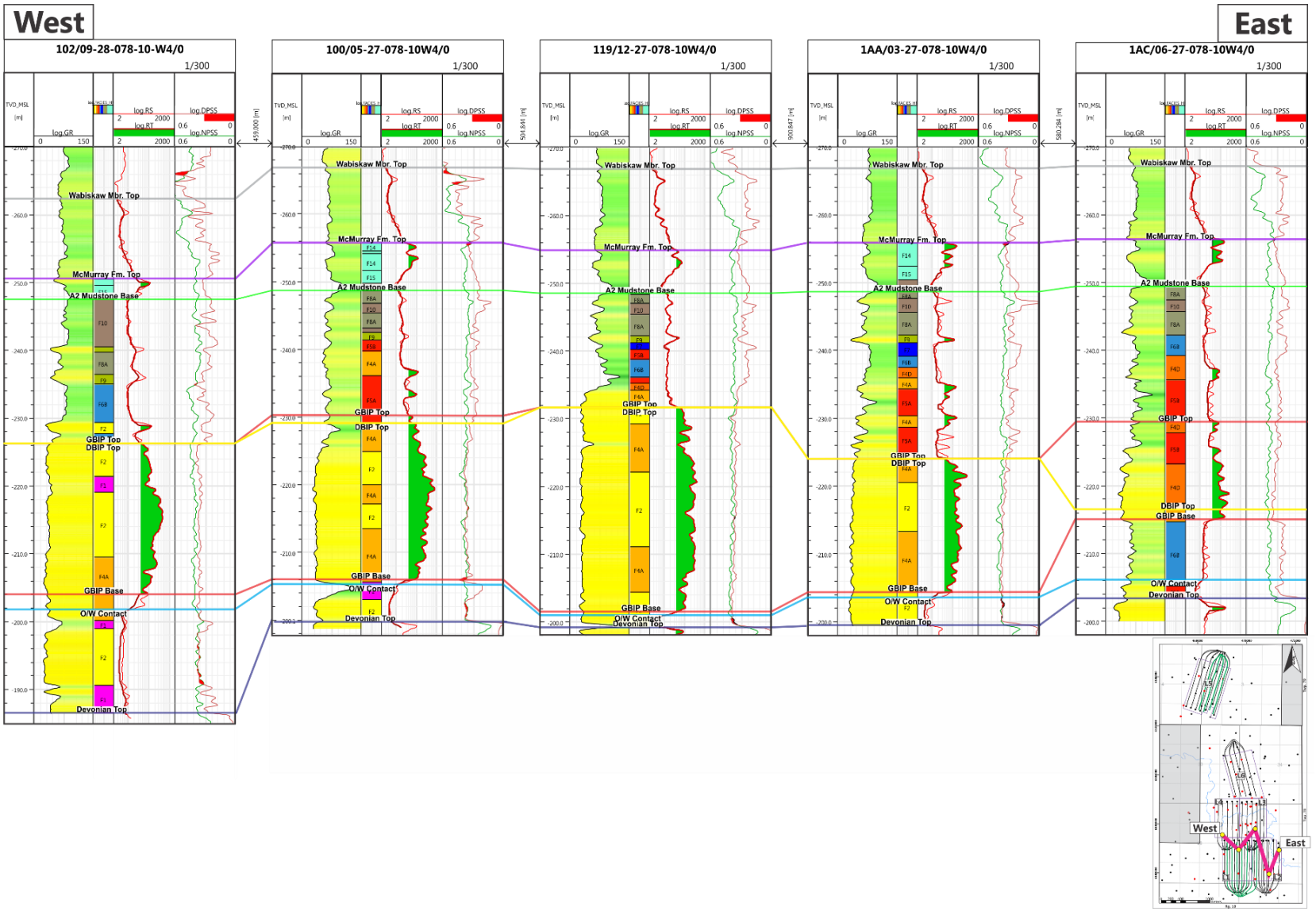


Volumetrics

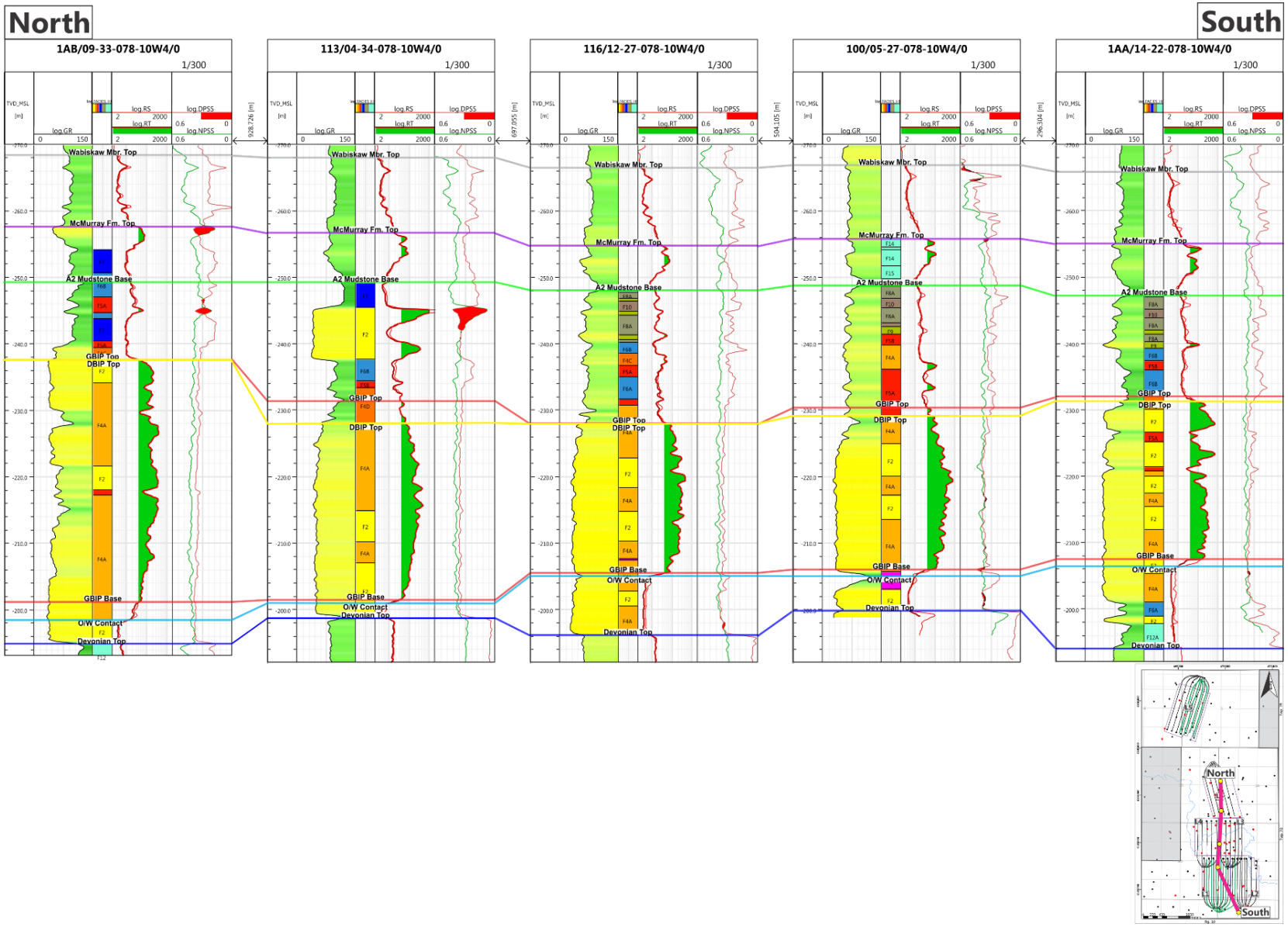
- Sand
- Bitumen
- Residual Water
- Free Water
- VSH Mud (Silt and Shale)
- PHIT Mud (Silt and Shale)



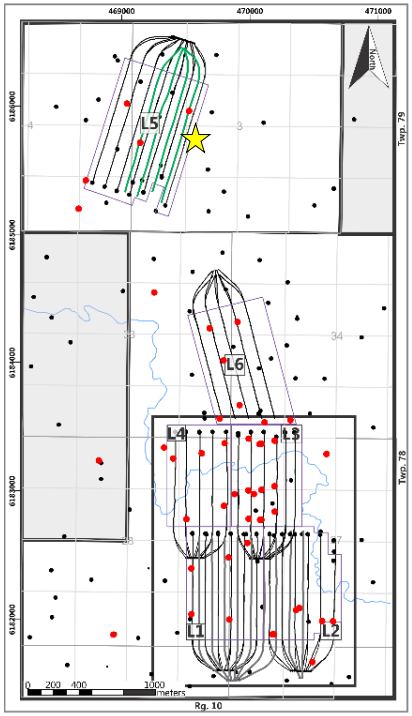
WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L1 TO L6 AREA



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

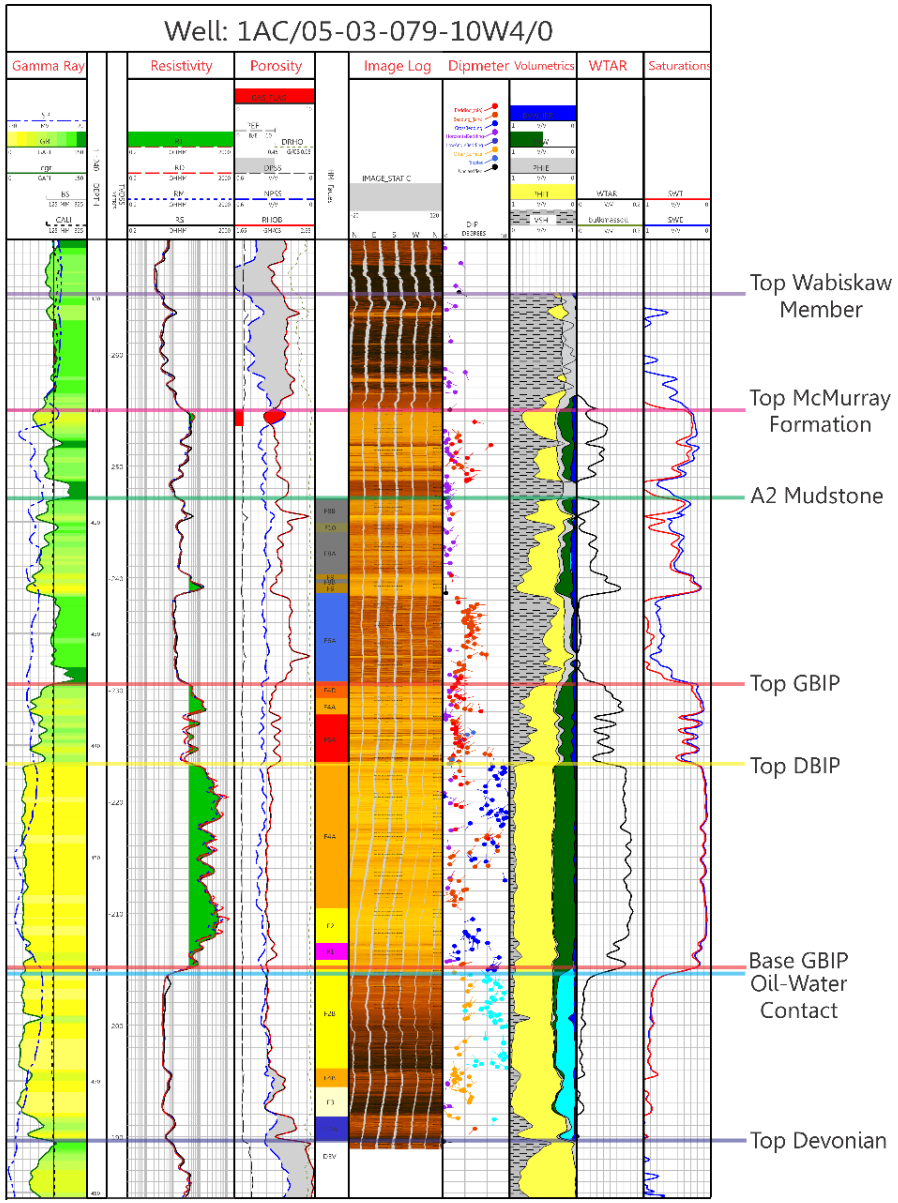


LDA PAD L5 EXAMPLE: 1AC/05-03-079-10W4/0

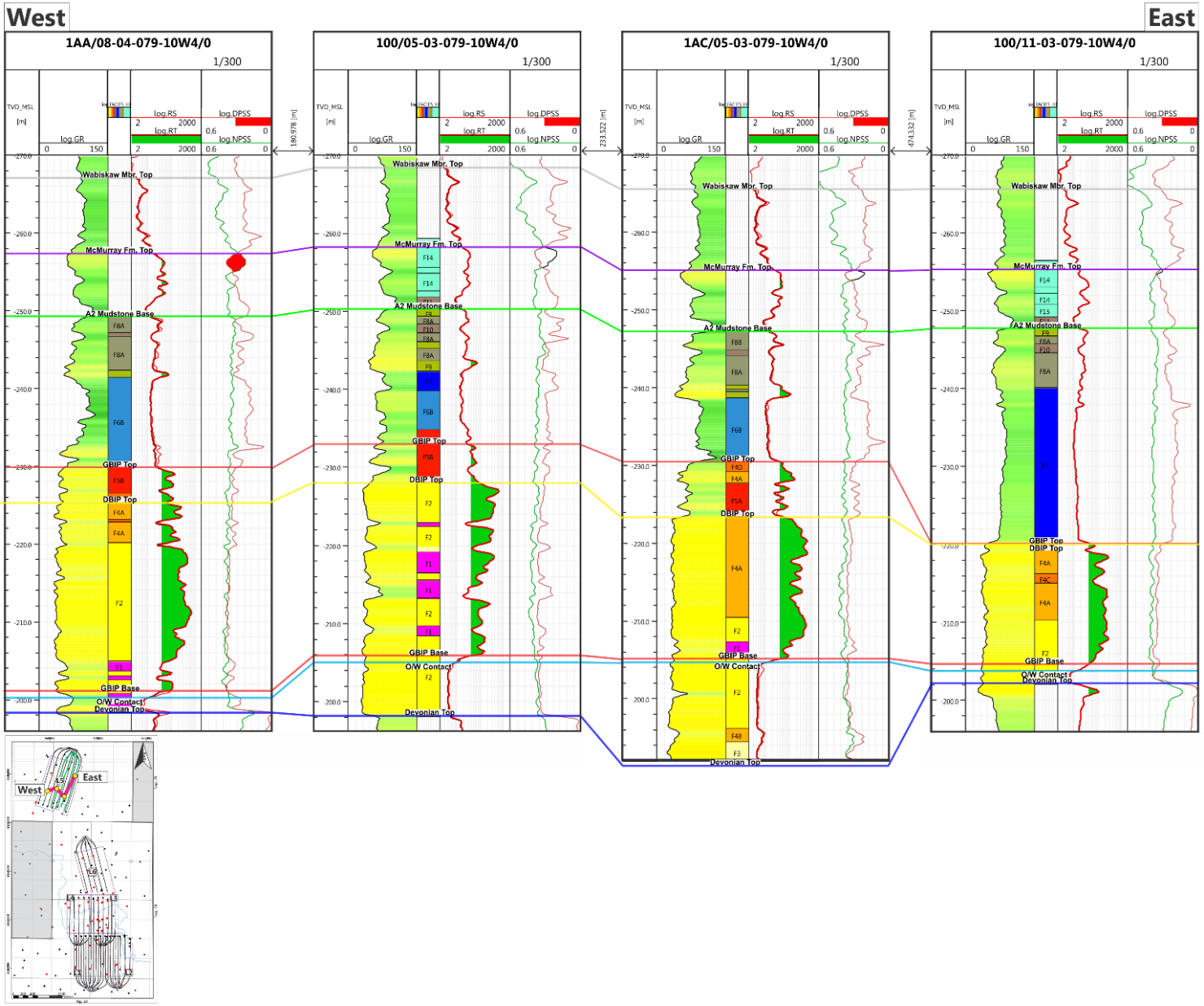


Volumetrics

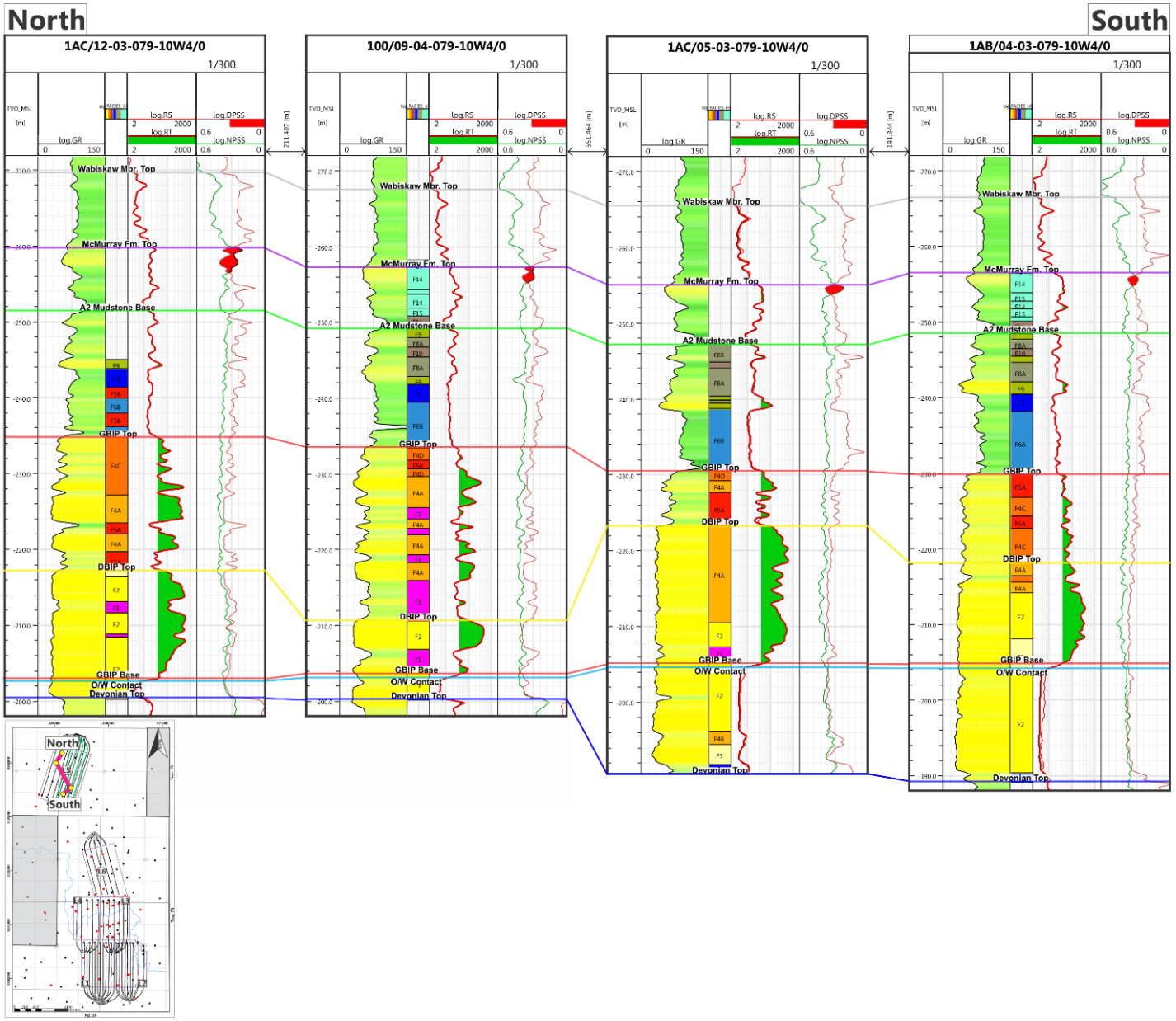
- Sand
- Free Water
- Bitumen
- VSH Mud (Silt and Shale)
- Residual Water
- PHIT Mud (Silt and Shale)



WEST TO EAST PETROPHYSICAL LOG CROSS-SECTION: L5 AREA



NORTH TO SOUTH PETROPHYSICAL LOG CROSS-SECTION: L5 AREA



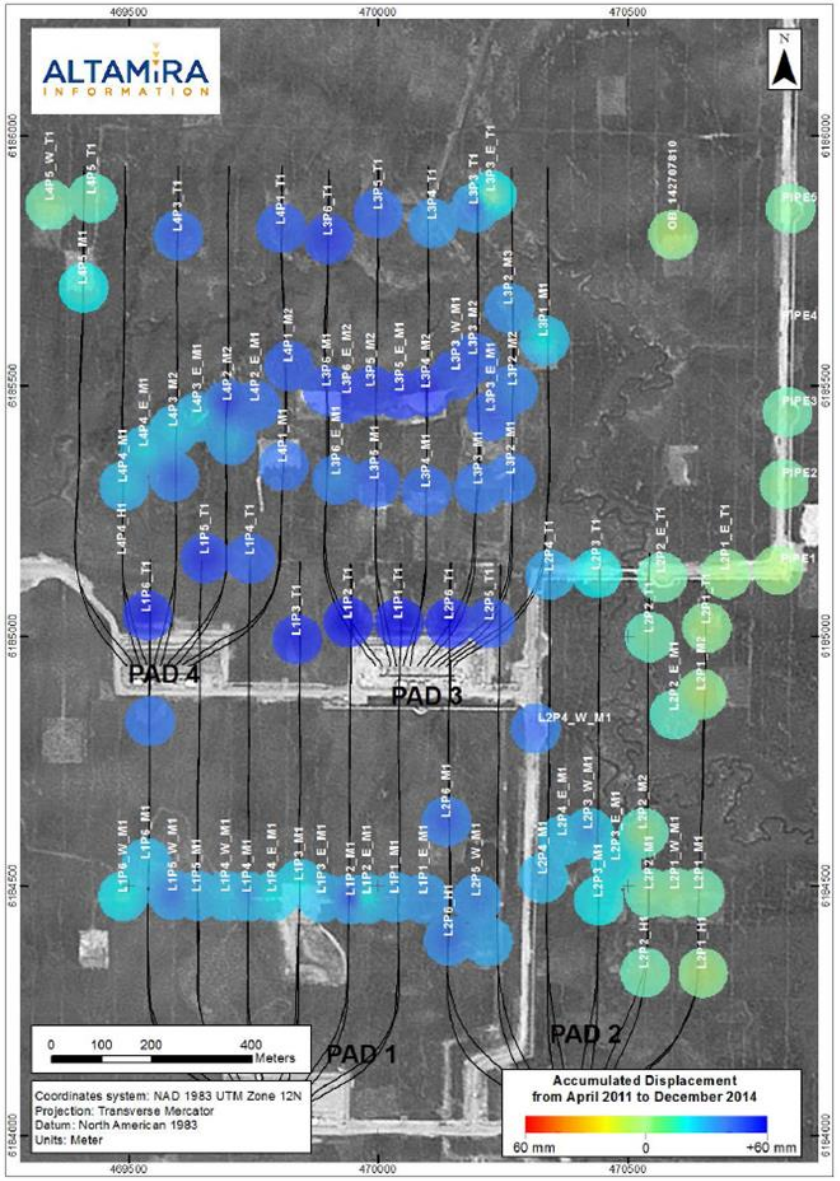
INSAR CUMULATIVE SURFACE HEAVE: L1 TO L4

2016

- No Interferometric Synthetic Aperture Radar (InSAR) data collected in 2015 & 2016

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

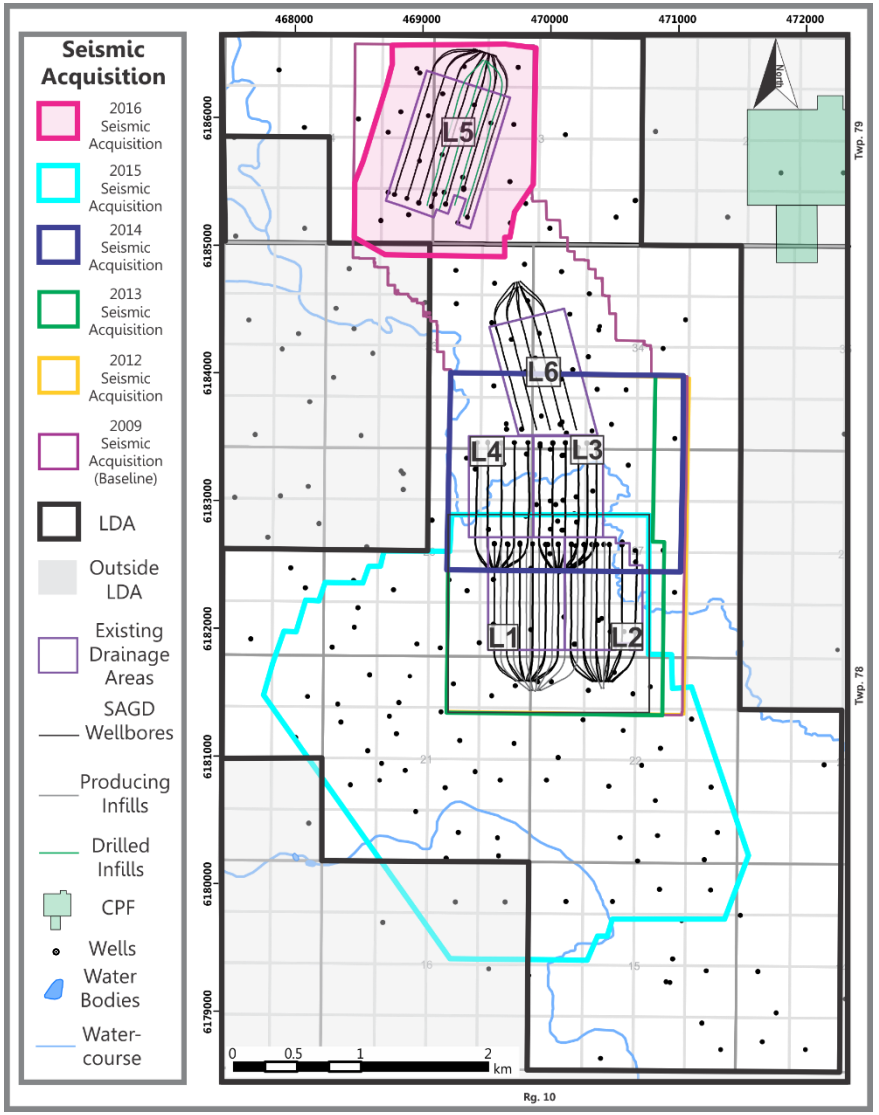
4D SEISMIC ACQUISITION HISTORY

2016

- Q1 2016: 2.0 km^2 first 4D survey for Pad L5

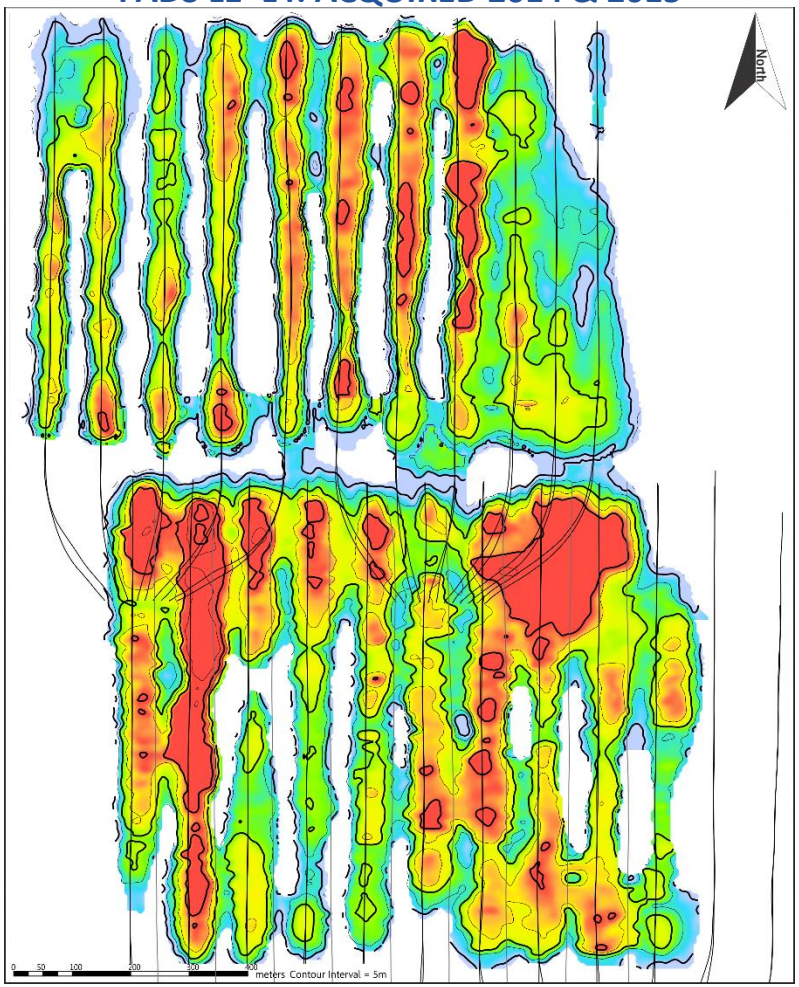
HISTORICAL

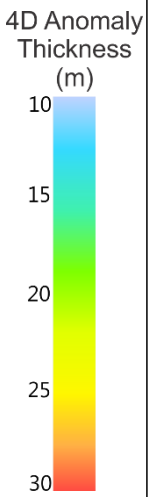
- Q1 2015: 9.0 km^2 3D survey
  - *Third 4D repeat survey (2.2 km^2 of active SAGD Pads L1 and L2)*
  - *Repeat 3D seismic for higher resolution data*
- Q1 2014: 2.1 km^2 4D survey (active SAGD Pads L3 and L4)
- Q1 2013: 4.5 km^2 3D survey
  - *Second repeat survey (4.9 km^2 of active SAGD Pads L1– L4)*
- Q1 2012: 8.6 km^2 3D survey
  - *First 4D survey (4.9 km^2 of active SAGD Pads L1–L4)*
  - *New baseline survey for Pads L5 and L6 (3.7 km^2)*
- Q1 2009: 4.9 km^2 baseline survey acquired (pre-steam) over Pads L1–L4



4D SEISMIC RESULTS

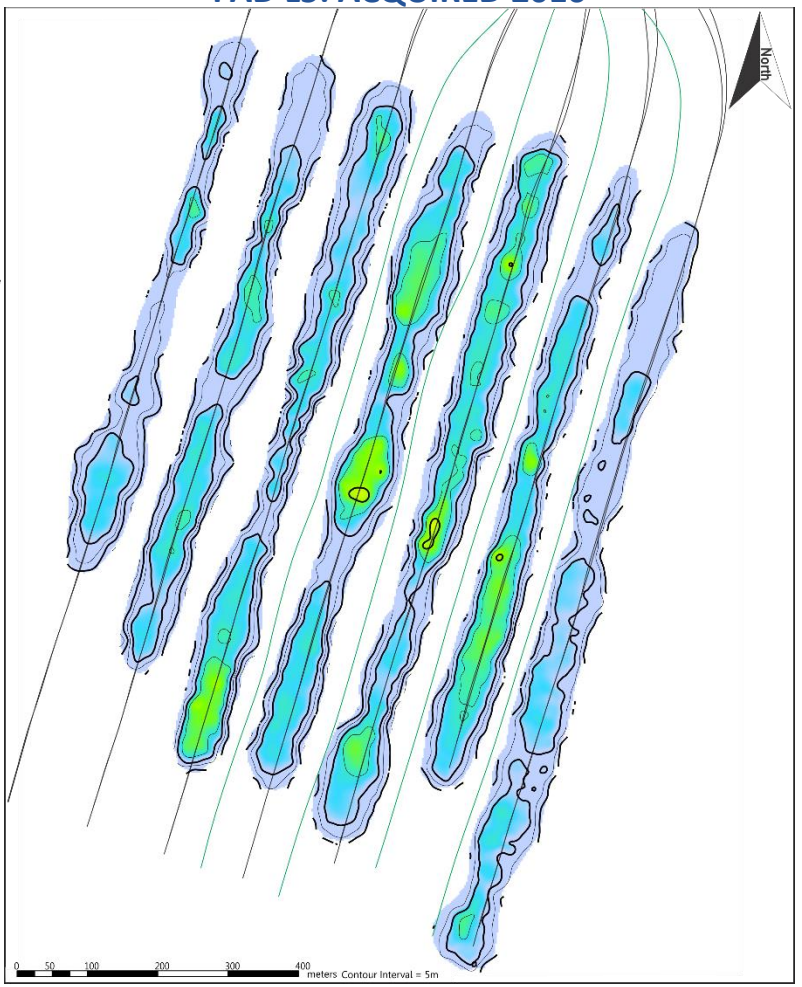
PADS L1–L4: ACQUIRED 2014 & 2015





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

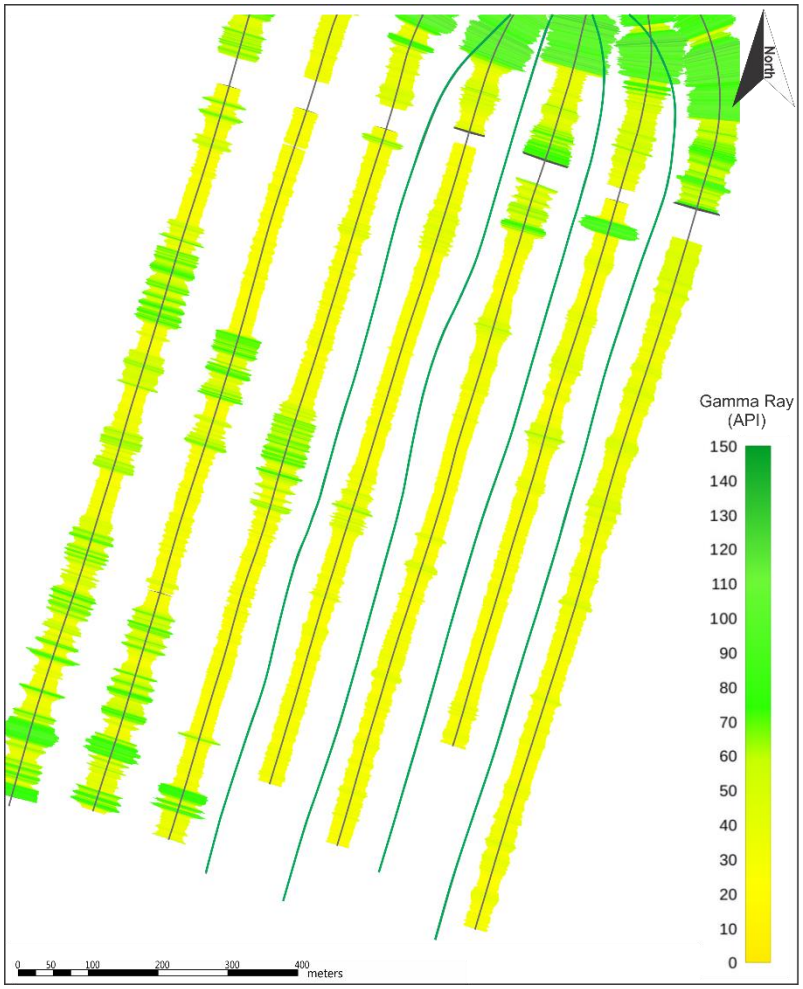
PAD L5: ACQUIRED 2016



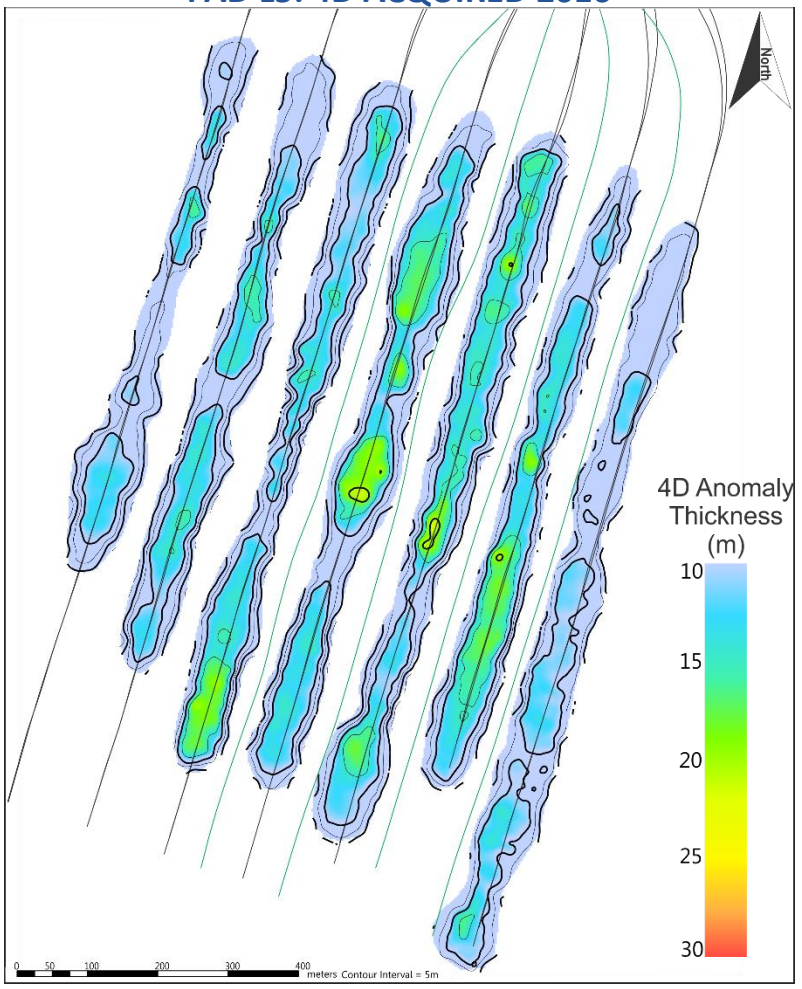
- Pad L5: First 4D data acquired (2 years after start-up)
- 4D seismic anomalies indicate high degree of conformance along SAGD well pairs
- Irregularities are attributed to reservoir heterogeneity and well placement

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

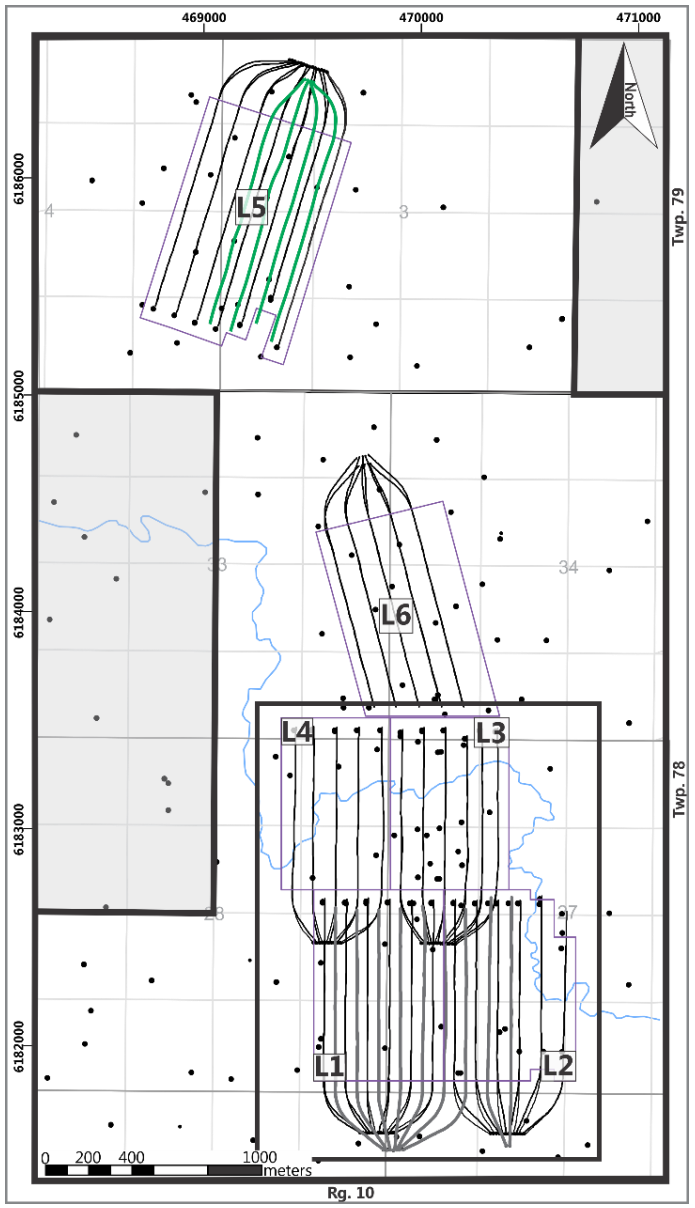
WELL LAYOUT

2016

- 4 new infill wells drilled in Pad 5

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

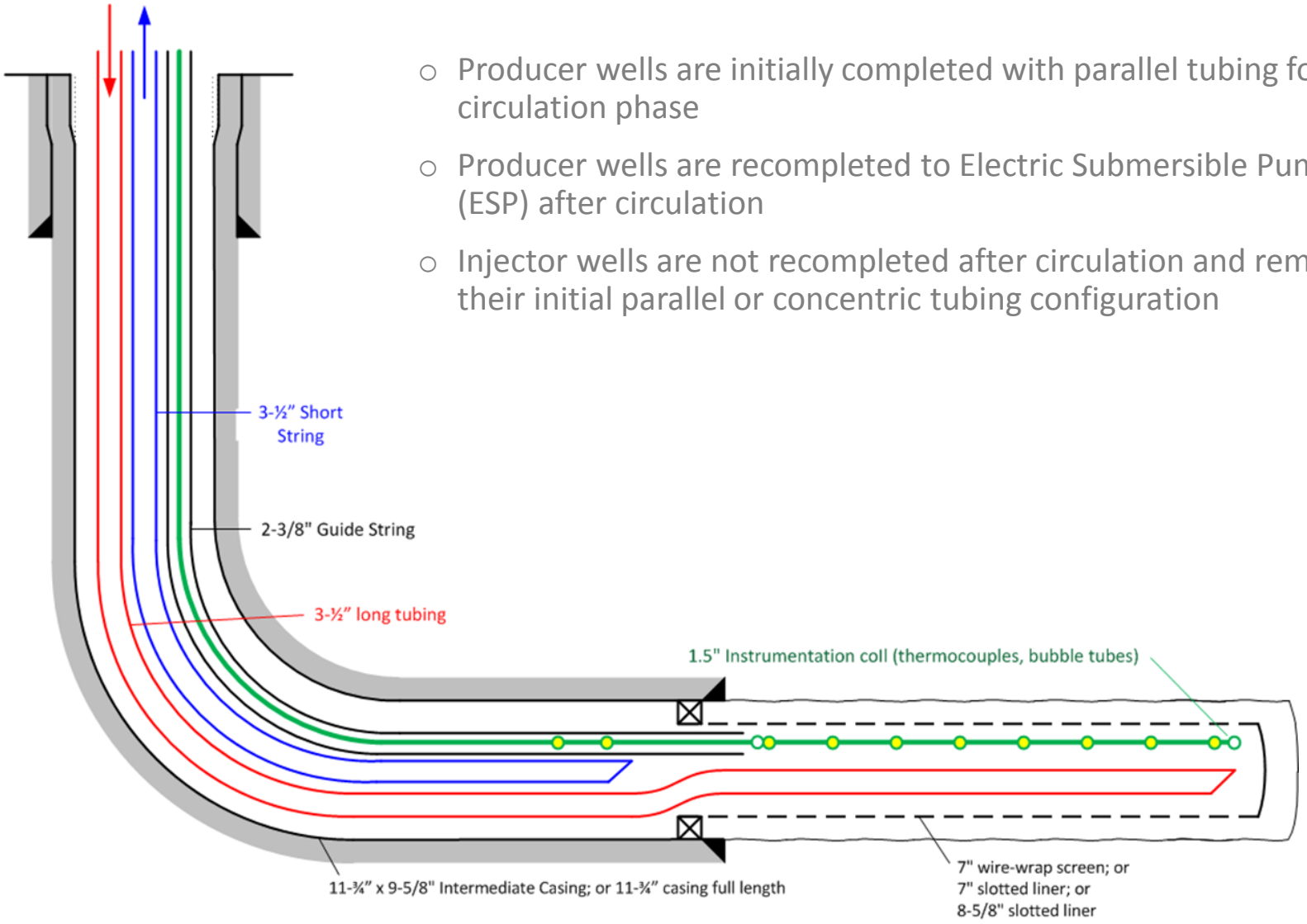
Pad	Wells	Spacing (m)
L3–L4	L3P6–L4P1	85–95
L4	P1–P2	110
	P2–P3	100
	P3–P4	110
	P4–P5	85
L5	P1–P2	95
	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100
	P6–P7	100
L6	P2–P3	100
	P3–P4	100
	P4–P5	100
	P5–P6	100

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	None
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)
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	2 infills	n/a	n/a	7” wire-wrap screen	1 producer (on liner)
L5	2016	4 infills	n/a	n/a	7” wire-wrap screen	None

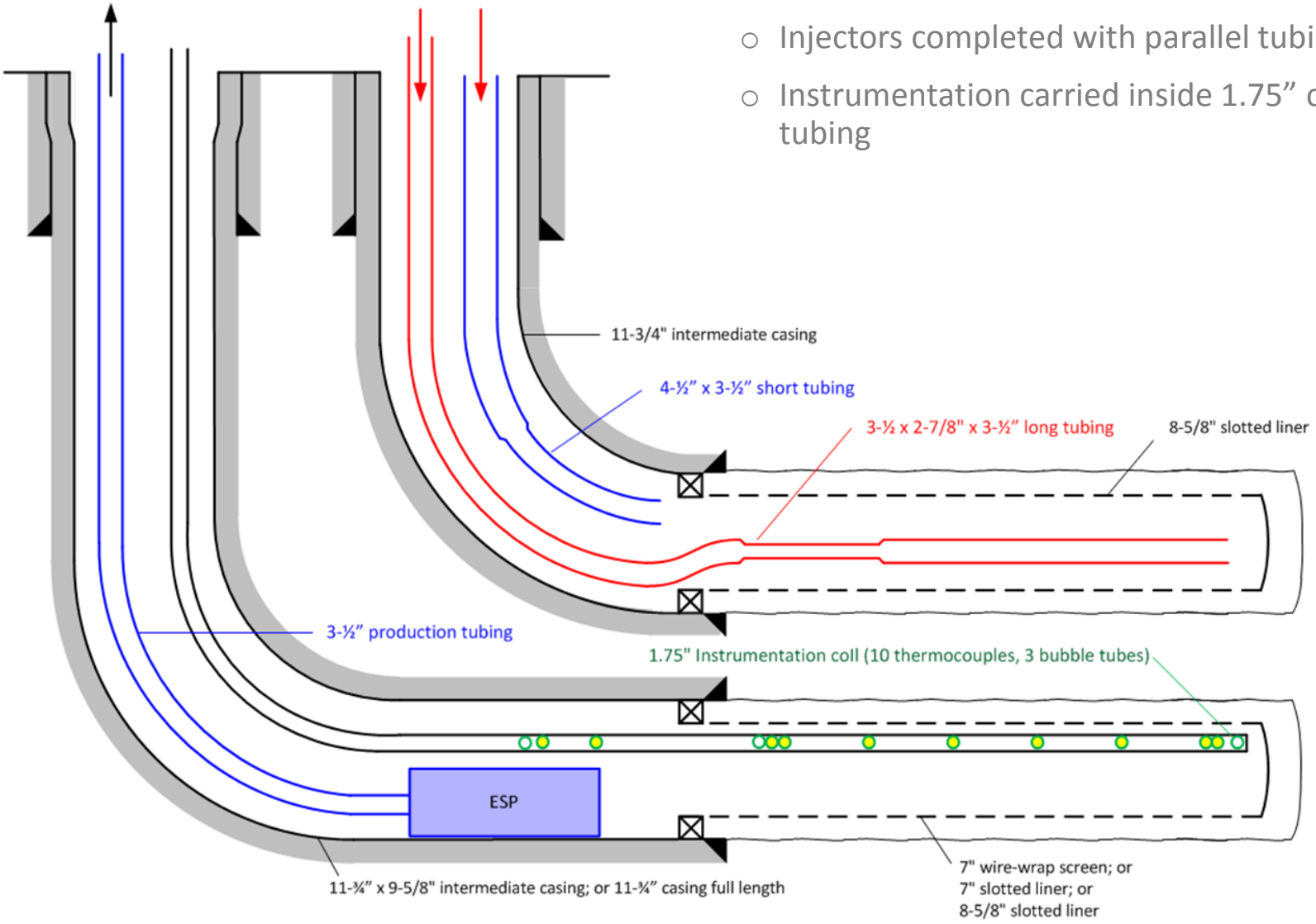
PRODUCER WELL COMPLETION DURING START-UP CIRCULATION

- 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



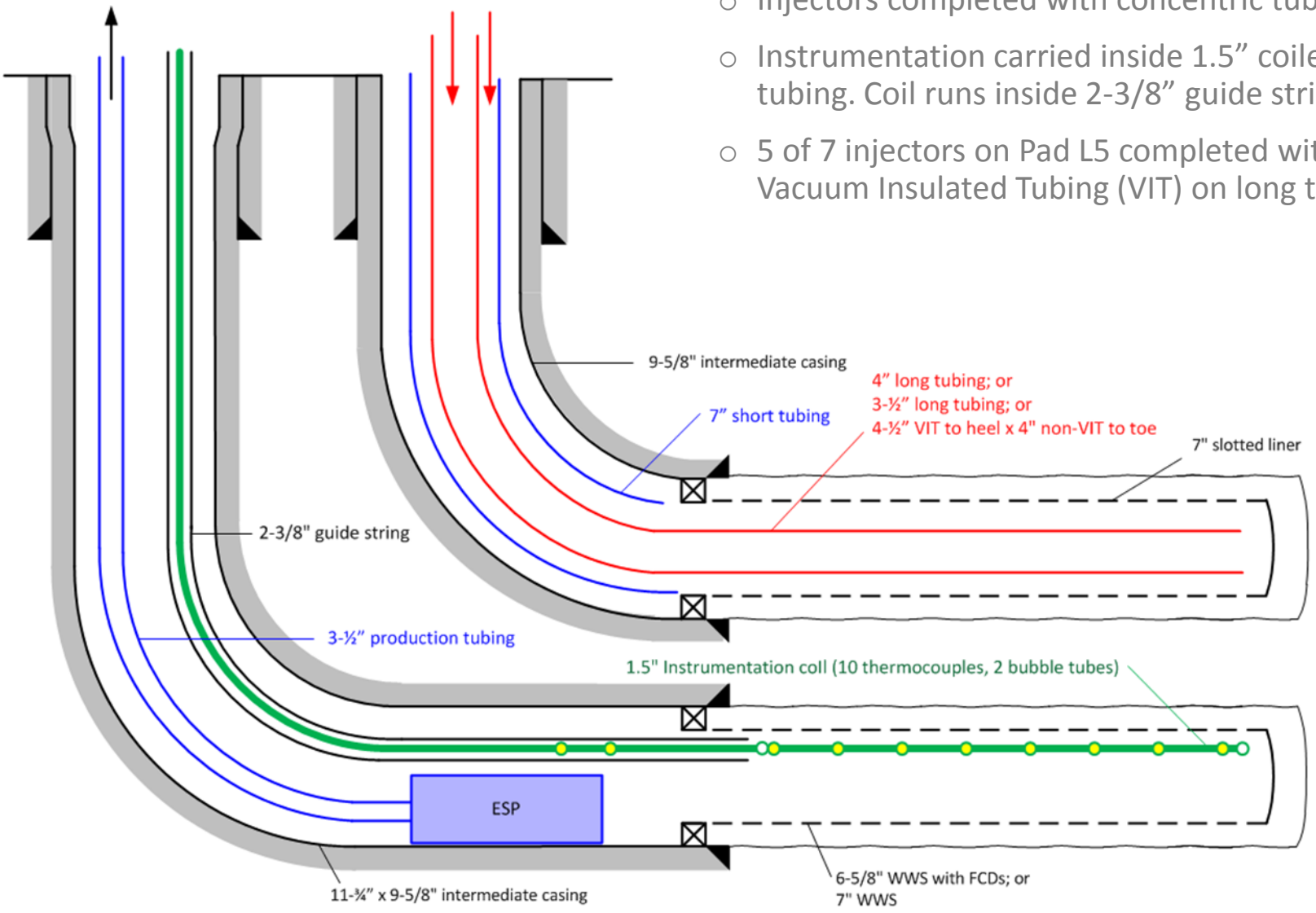
TYPICAL WELL COMPLETION DURING PRODUCTION PHASE: PADS L1–L4

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

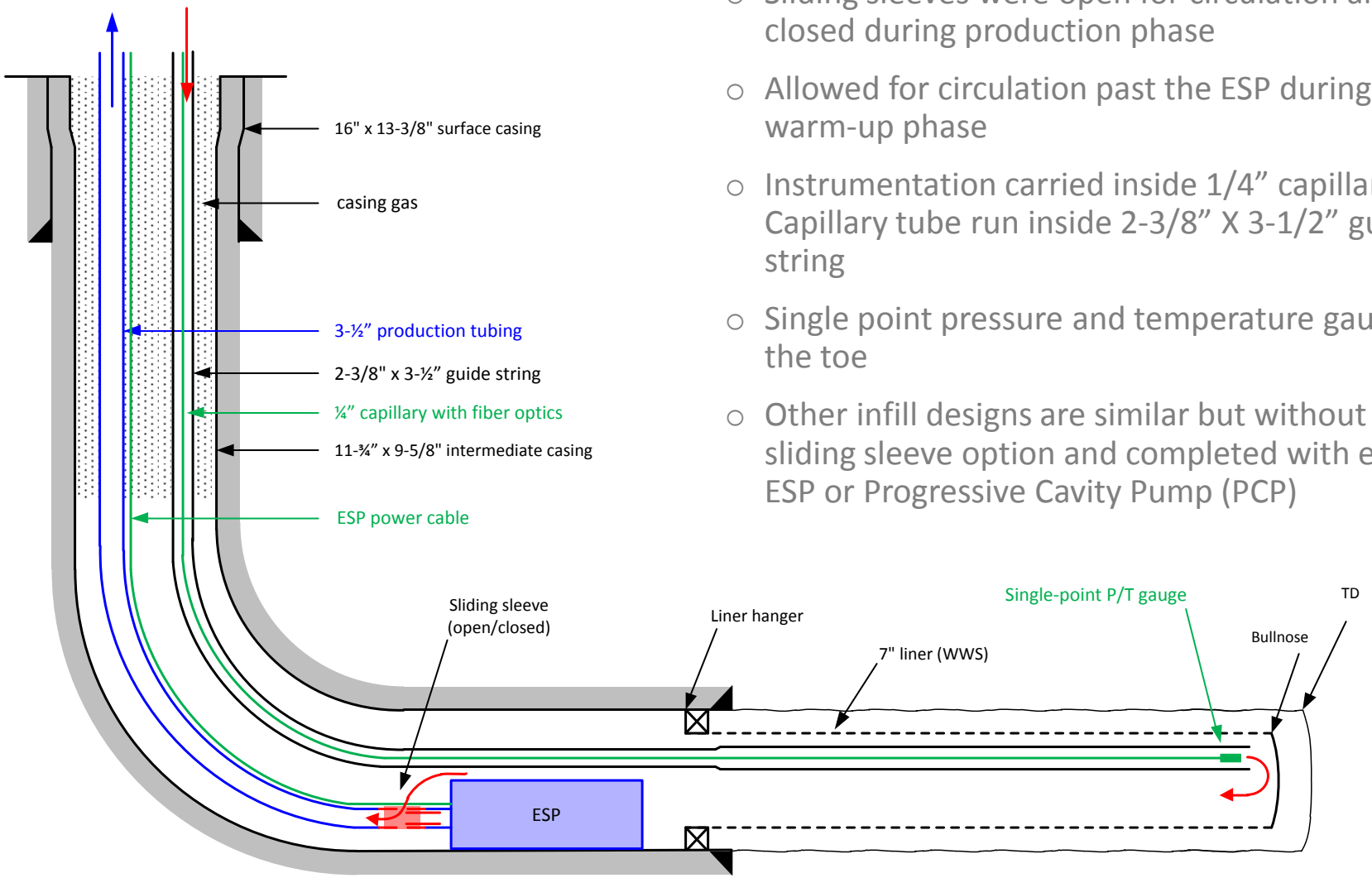


TYPICAL WELL COMPLETION DURING PRODUCTION PHASE: PADS L5–L6

- 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

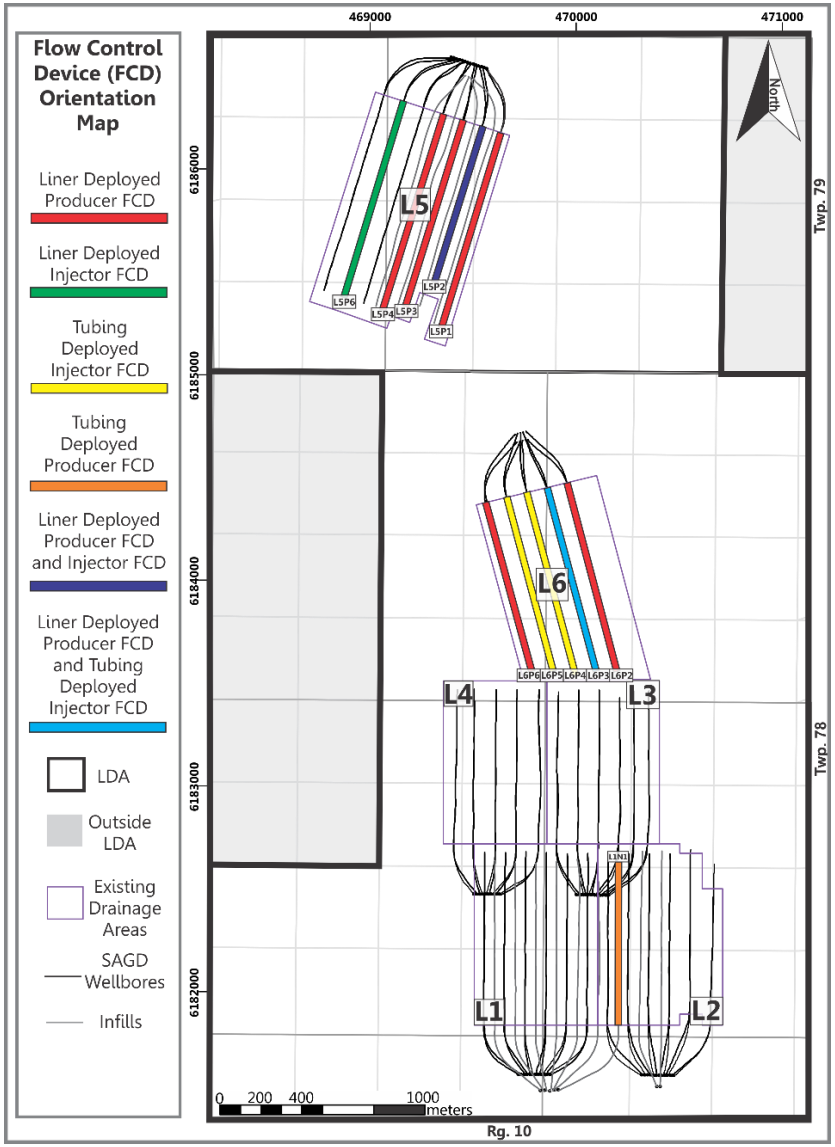


- Sliding sleeves were open for circulation and closed during production phase
- Allowed for circulation past the ESP during warm-up phase
- Instrumentation carried inside 1/4" capillary. Capillary tube run inside 2-3/8" X 3-1/2" guide string
- Single point pressure and temperature gauge at the toe
- 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)

- Liner-deployed FCDs installed on 7 producer wells and 2 injector wells
- Tubing-deployed FCD installed on 1 producer well
- 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*

Too early to determine results of the producer FCD performance from Pad 5 and Pad 6



WELL DESIGN & INSTRUMENTATION

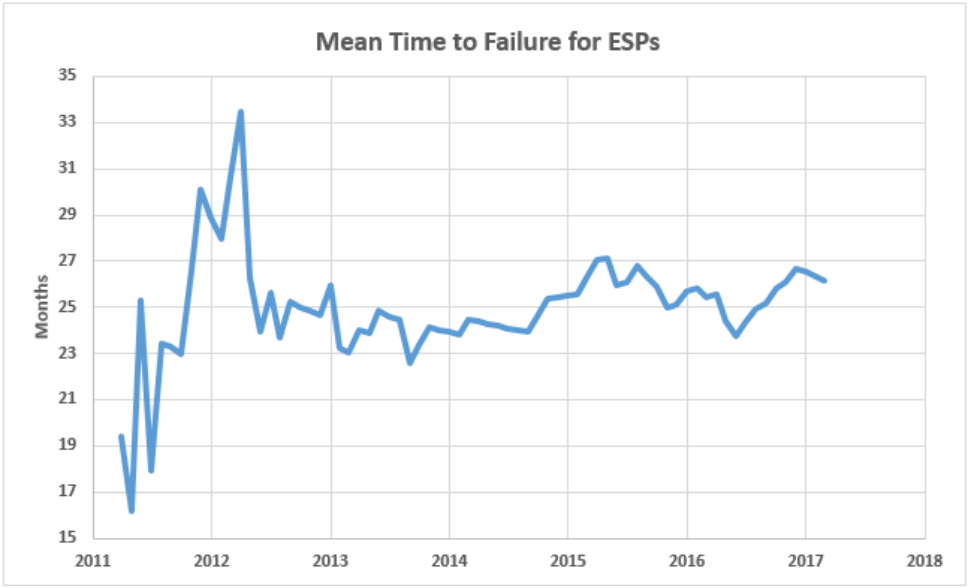
ARTIFICIAL LIFT

ATHABASCA OIL CORPORATION

ARTIFICIAL LIFT

- 41 ESPs running
  - *26 month mean time to failure (MTTF) since field start-up*
  - *23 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*

- 2 PCPs running
  - *No replacements or failures to date*
  - *Longest running PCP 209 days*
- PCP sizes allow for rates 90–400 m³/d
- Intake conditions:
  - *180–235°C*
  - *2,500–3,300 kPag*



WELL DESIGN & INSTRUMENTATION

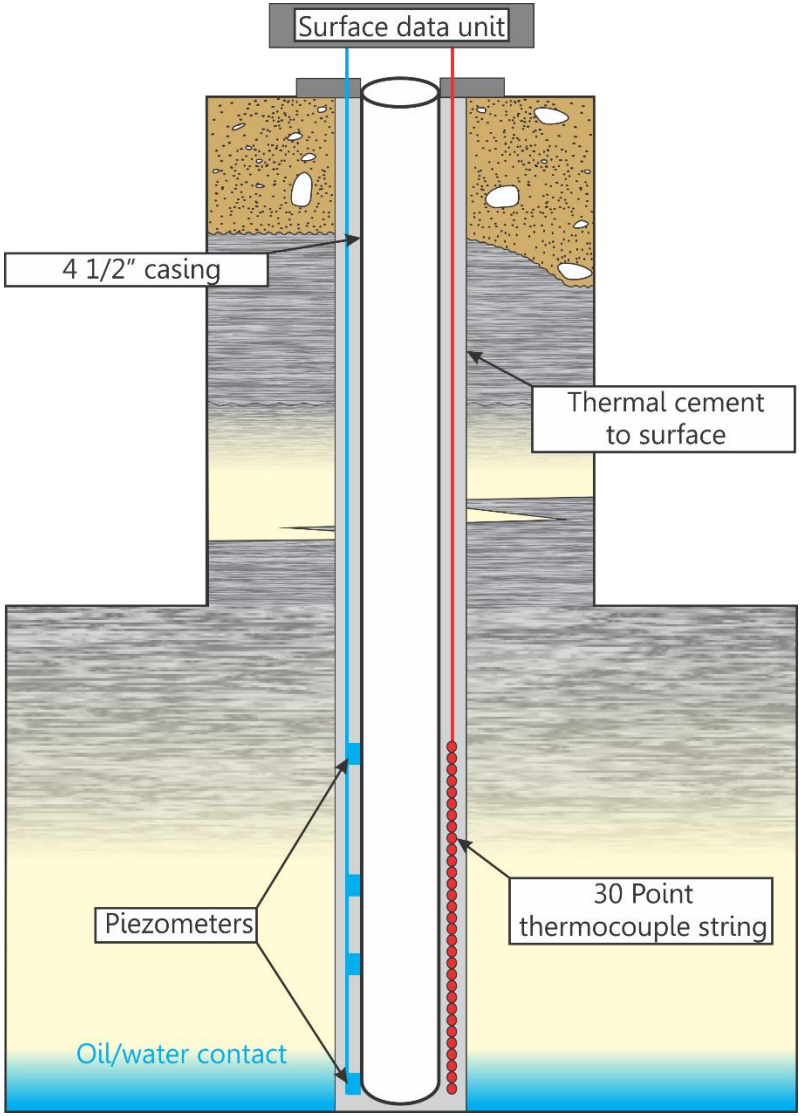
INSTRUMENTATION

ATHABASCA OIL CORPORATION

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)	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)	L2P2: DTS fibre L2I3: 6 thermocouples + bubble tubes
L3	6 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe)	L3P1, L3P2, L3P3: 40 point fibre L3I3: 6 thermocouples + bubble tubes L3P3: fibre pressure gauge
L4	5 well pairs	10 thermocouples in horizontal 3 bubble tubes (pump, heel, toe)	None
L5	7 well pairs	10 thermocouples in horizontal 2 bubble tubes (heel, toe)	L5P7, L5I1: fibre pressure gauge (heel) L5I5, L5P5, L5I7, L5P7: 3 thermocouples on surface casing
L6	5 well pairs	10 thermocouples in horizontal 2 bubble tubes (heel, toe)	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 gauges (toe)	L1N1: fibre pressure gauge heel

INSTRUMENTATION: OBSERVATION (OBS) WELLS



Example observation wellhead

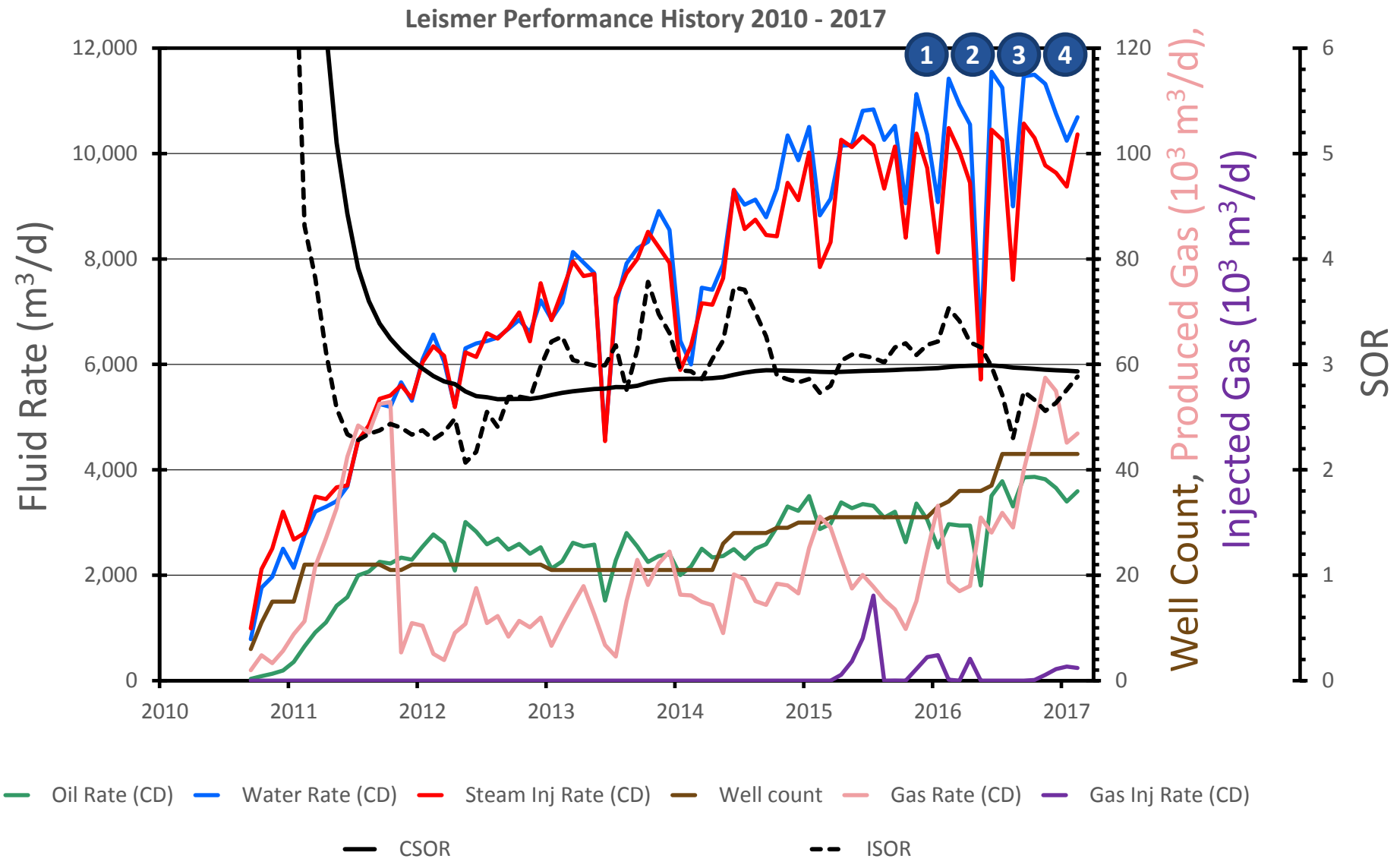
- 30 thermocouples, spaced at 1 m above, below, and within SAGD pay
- Some wells are equipped with fibre optics (DTS) instead of thermocouples
- 3 to 4 piezometers in bitumen, bottom water, and top lean/gas zone

SUBSURFACE

SCHEME PERFORMANCE

ATHABASCA OIL CORPORATION

LEISMER PROJECT TREND



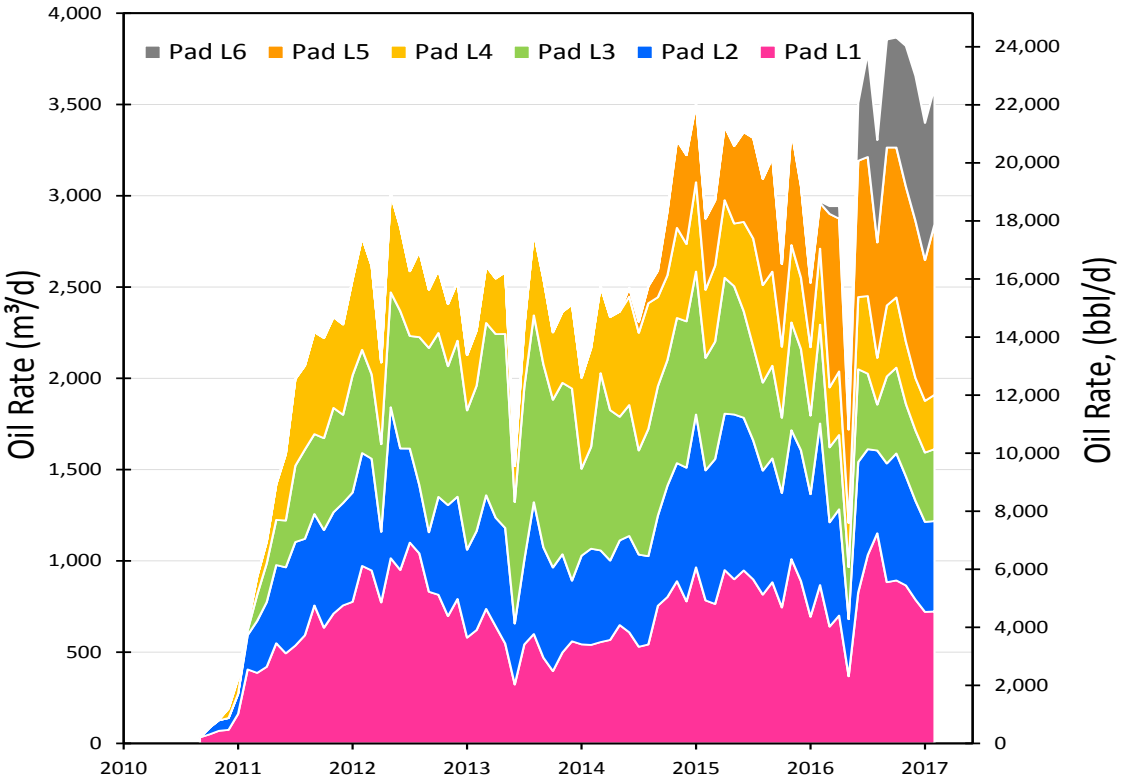
1 Diluent shortage

2 4 OTSG Maintenance

3 Fort McMurray Fire

2016 HIGHLIGHTS

- Average production 3,246 m³/d (20,417 bbl/d)
- Achieved full plant capacity
- Production increased in 2016 due to:
  - *Additional infill wells on-stream*
  - *Pad L6 start-up*
  - *Pad L5 continuing to ramp-up*
  - *Reduced ESP intervention downtime*

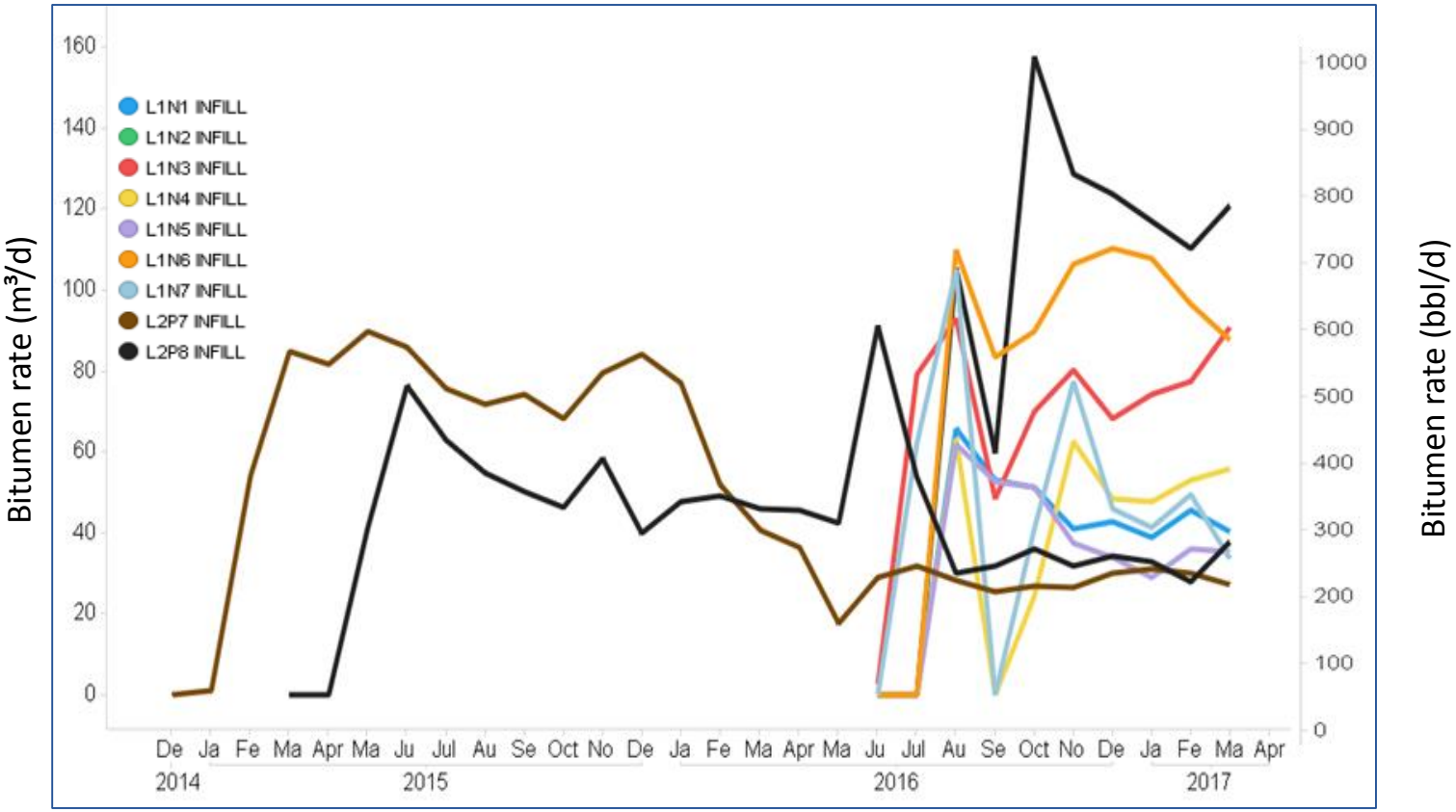


PAD RECOVERIES

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	1,632	47%	42%	65–75%
L2	2,821	3,344	1,270	45%	38%	65–75%
L3	3,003	3,443	1,363	45%	40%	50–60%
L4	2,236	2,433	917	41%	38%	50–60%
L5	3,477	4,479	536	15%	12%	50–60%
L6	3,471	3,836	179	5%	5%	65–75%
Total	18,475	21,449	5,897	32%	27%	~65%

- DBIP, Cumulative Production, and Recovery Factor (RF) valid as of February 28th, 2017
- Predicted Recovery Factor is based on 2D volumetric and simulations

INFILL WELL PERFORMANCE

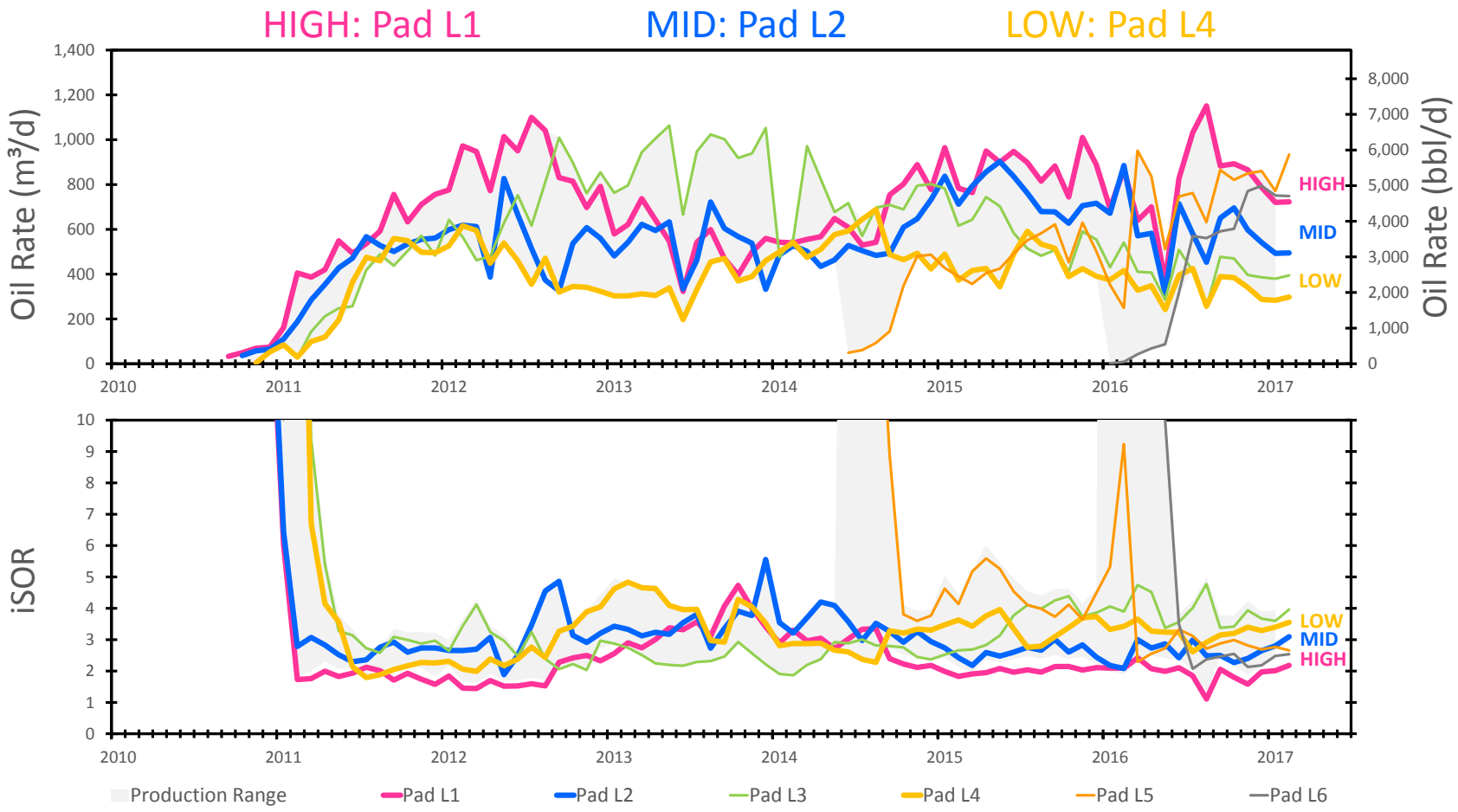


- Infill well rates are ranging of 35–120 m³/d (210–750 bbl/d)
- The infill wells contribute to low iSOR for the Pads L1 and L2
- Optimization of the interactions between the infill and SAGD wells is ongoing

PAD PERFORMANCE: PERFORMANCE SELECTION

PAD PERFORMANCE:

- Peak bitumen rate 425–1,151 m³/d (2,670–7,240 bbl/d)
- iSOR: 1.3–4.8
- Selection of High/Mid/Low cases based on Oil Rate and iSOR



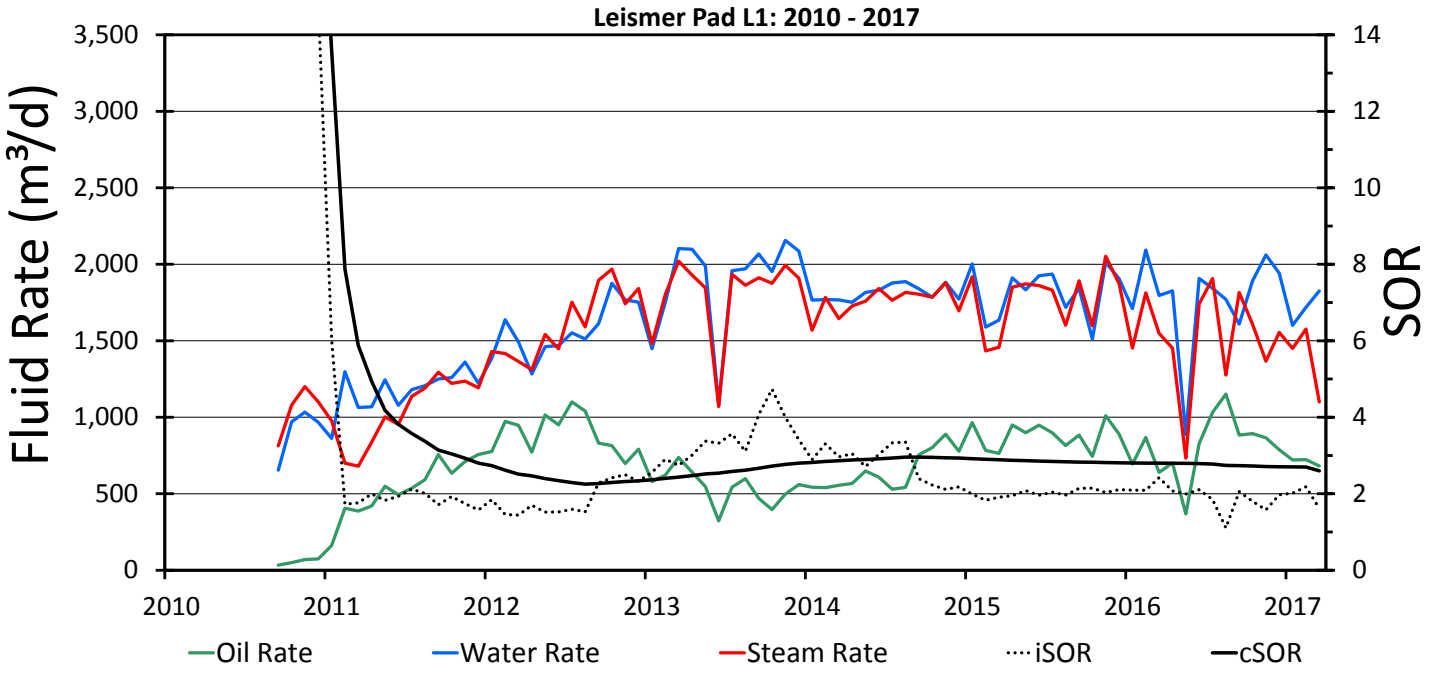
PAD PERFORMANCE – HIGH: PAD L1

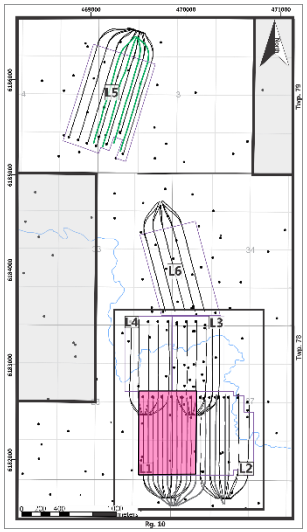
2016 PAD PERFORMANCE

- Peak bitumen rate ~ 1,151 m³/d (7,240 bbl/d)
- iSOR: 1.3–3.0

WELL PERFORMANCE

- Average oil rates in 2016 range between 70–150 m³/d (460–910 bbl/d)
- 2016 iSOR decrease associated to the infill wells coming on-stream

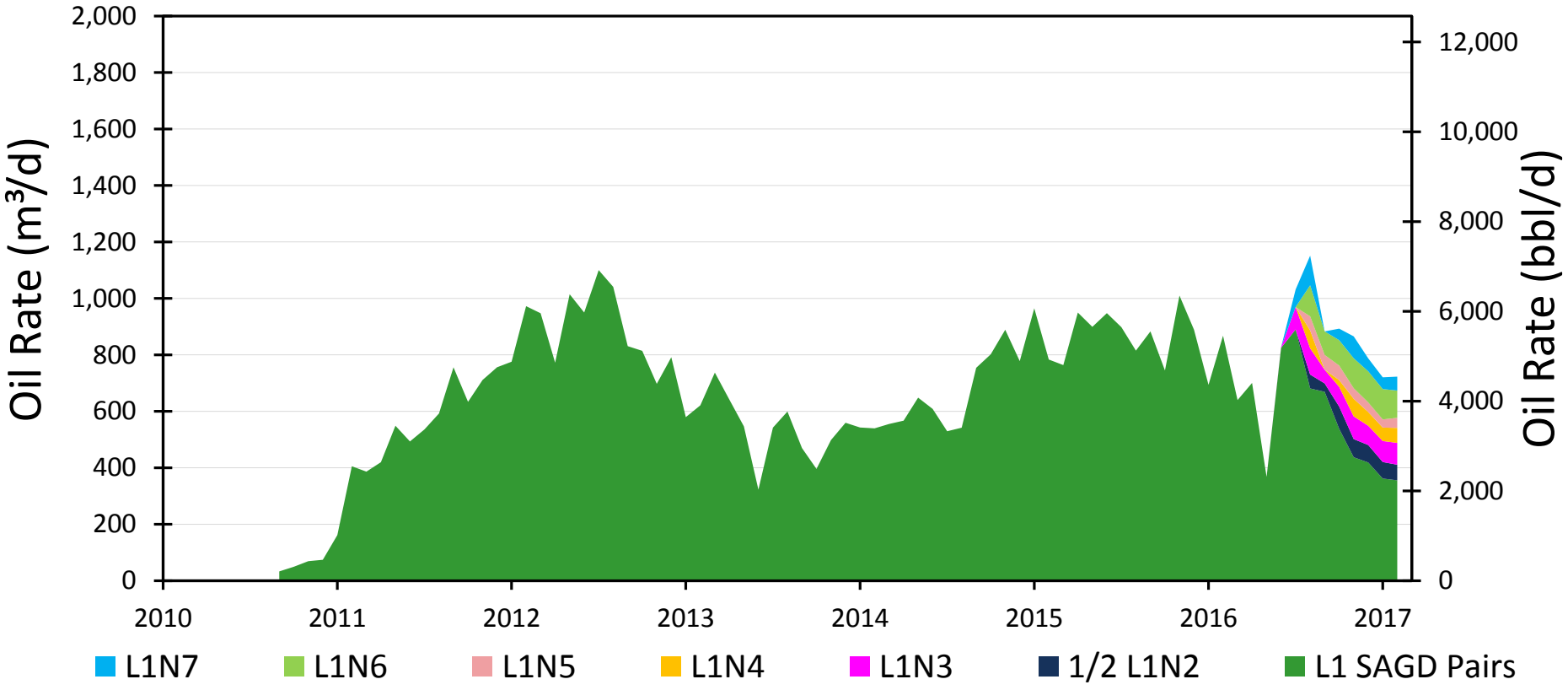




PRODUCTION PERFORMANCE: PAD L1

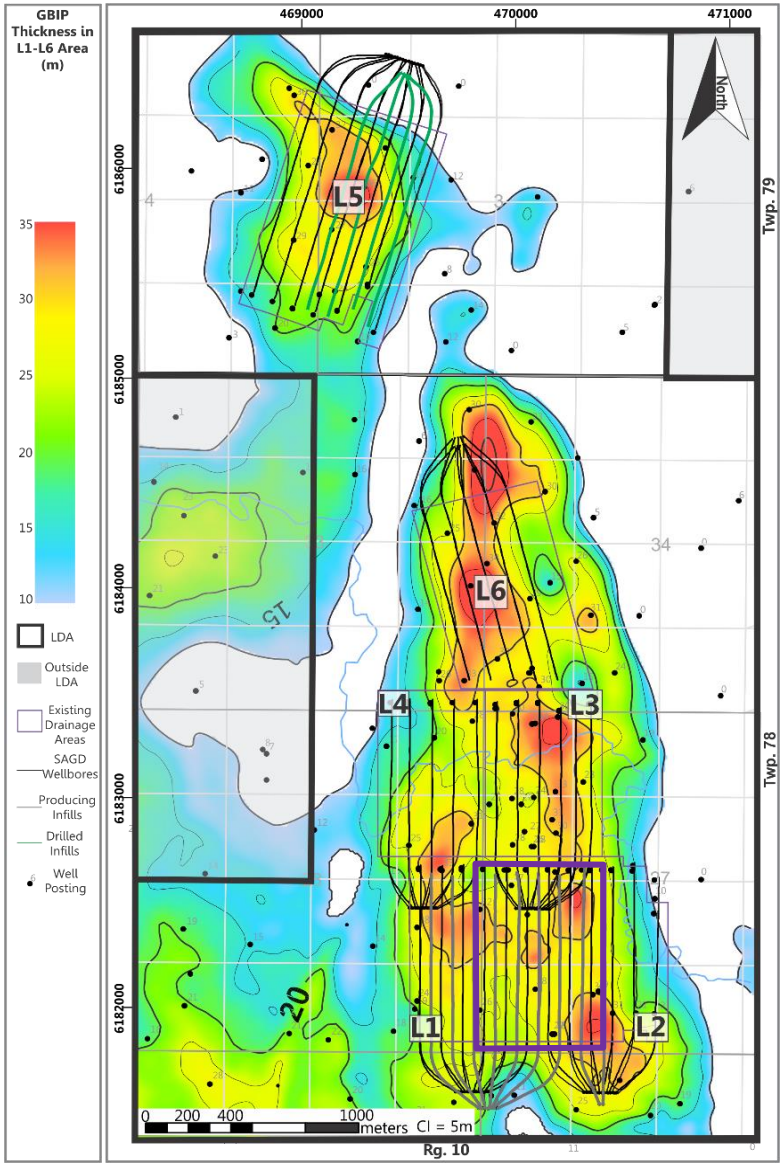
Pad L1 2016 average production = 809 m³/d (5,088 bbl/d) from 6 well pairs and 5.5 infills

- L1 infill well started in June 2016
  - *Infill wells contributed ~45% of production by end of 2016*

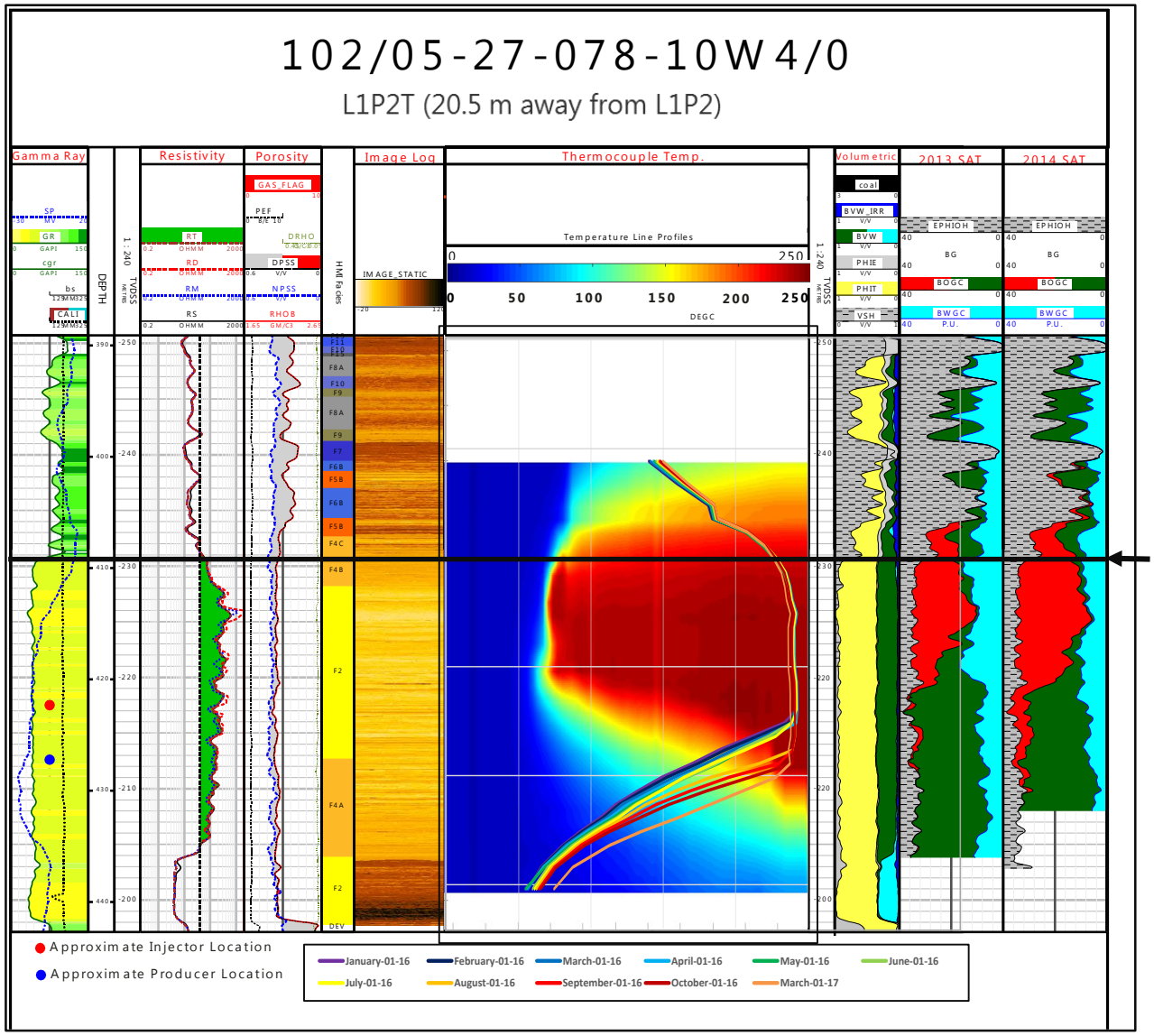


PRODUCTION PERFORMANCE: PAD L1

- Pad L1 has a consistent, thick GBIP/DBIP with high oil saturation and permeability
- Infill wells drilled in 2015 and started in 2016
- Pad L1 continues to be a strong performing pad

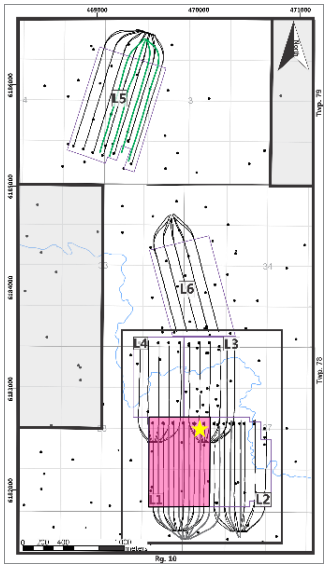


PAD L1 OBSERVATION WELL



HIGHLIGHTS

- Steam chamber has reached top of reservoir
- Uniform vertical steam chamber
- Steam chamber continues to grow
- Reservoir Saturation Tool (RST) in excellent agreement with temperature log



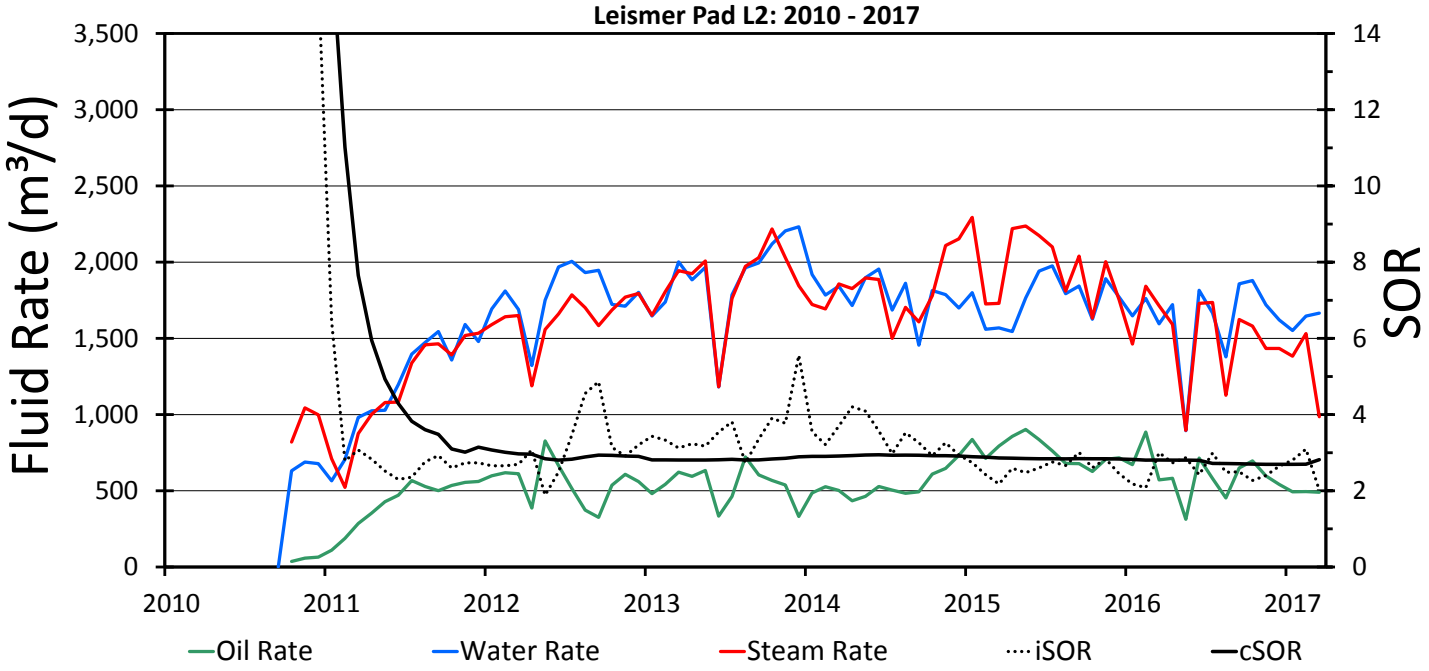
PAD PERFORMANCE – MID: PAD L2

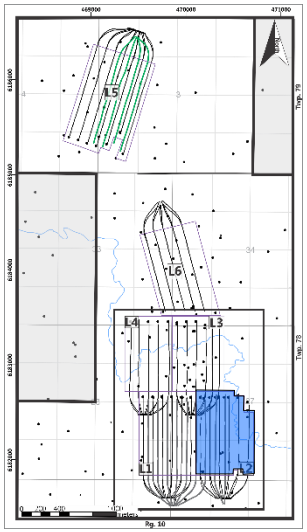
2016 PAD PERFORMANCE

- Peak bitumen rate ~ 910 m³/d (5,720 bbl/d)
- iSOR: 1.9–2.9
- Steam reduced in this pad and allocated to other pads

WELL PERFORMANCE

- Average oil rates in 2016 range between 30–200 m³/d (210–1,260 bbl/d)

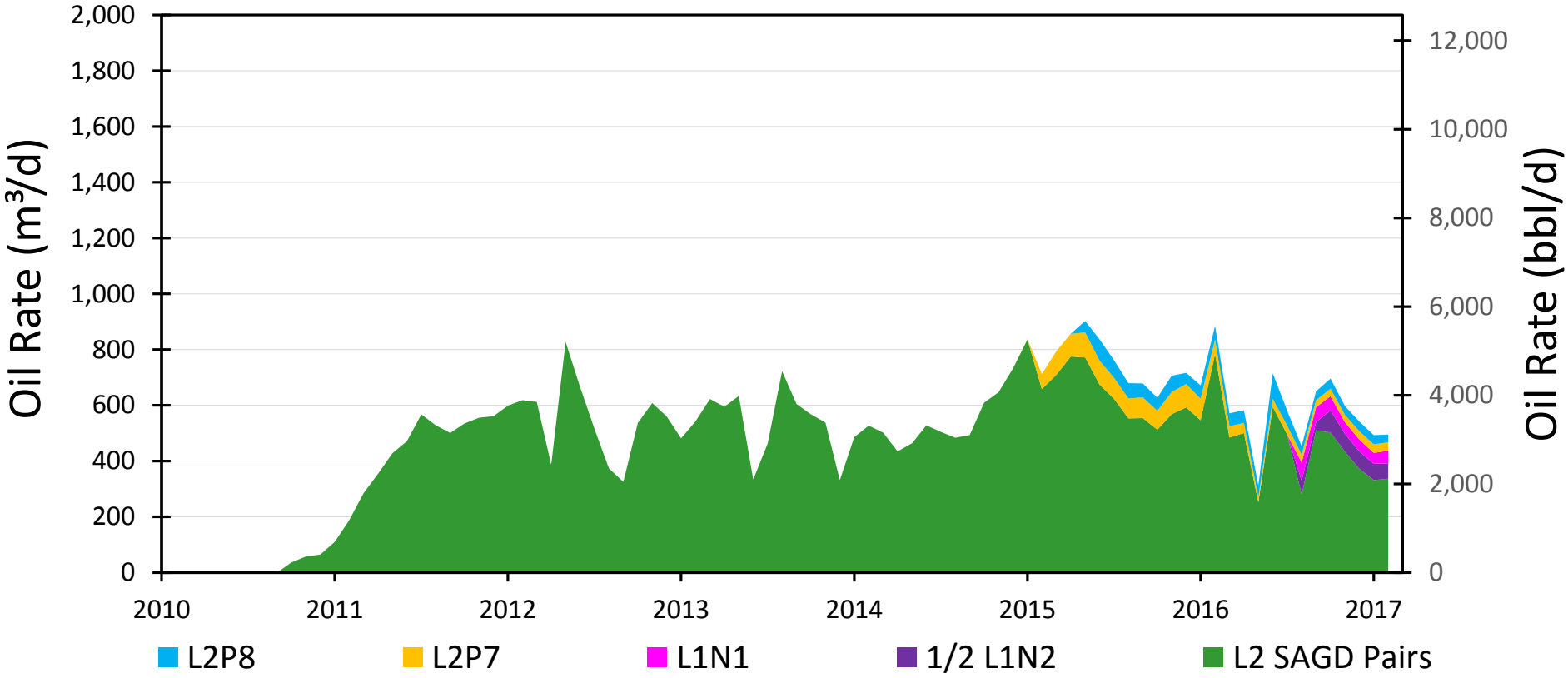




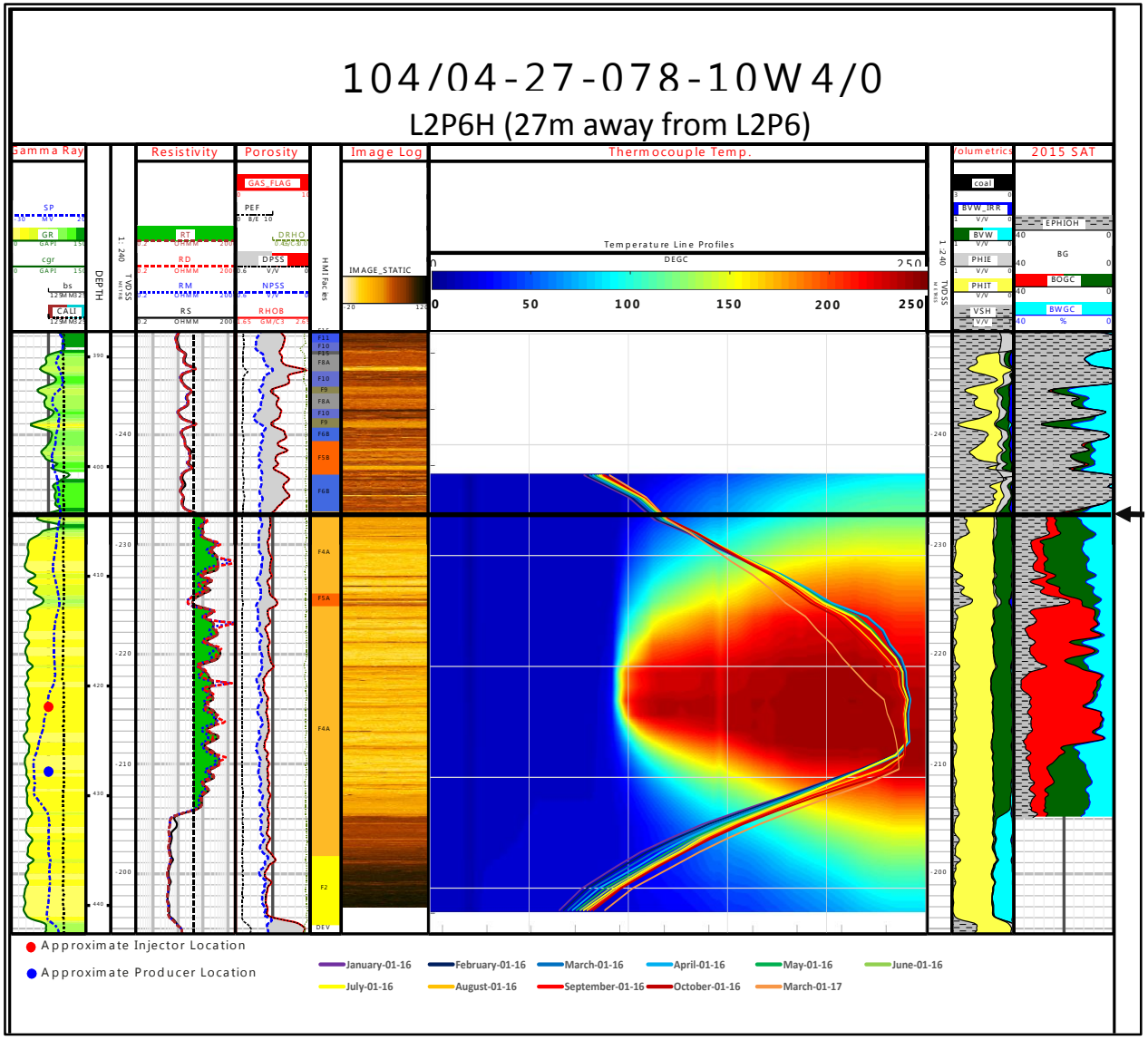
PRODUCTION PERFORMANCE: PAD L2

PAD L2 2016 AVERAGE PRODUCTION = 605 m^3/d (3,805 bbl/d) FROM 5 WELL PAIRS AND 3.5 INFILLS

- Additional infill wells on Pad L2 started in June 2016
- Infills contributed ~30% of production by end of 2016



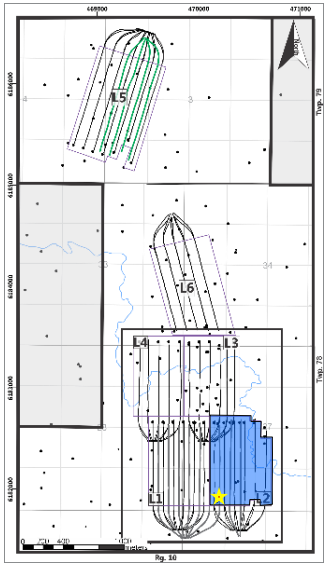
PAD L2 OBSERVATION WELL



DBIP top

HIGHLIGHTS

- Muddier Inclined Heterolithic Stratification (IHS) interval has thus far impeded vertical chamber growth
- Cooling of steam chamber evident
  - *Steam was reduced in order to be allocated to other pads*
- Expect upside to oil rate once steam chamber breaks through the top portion of reservoir



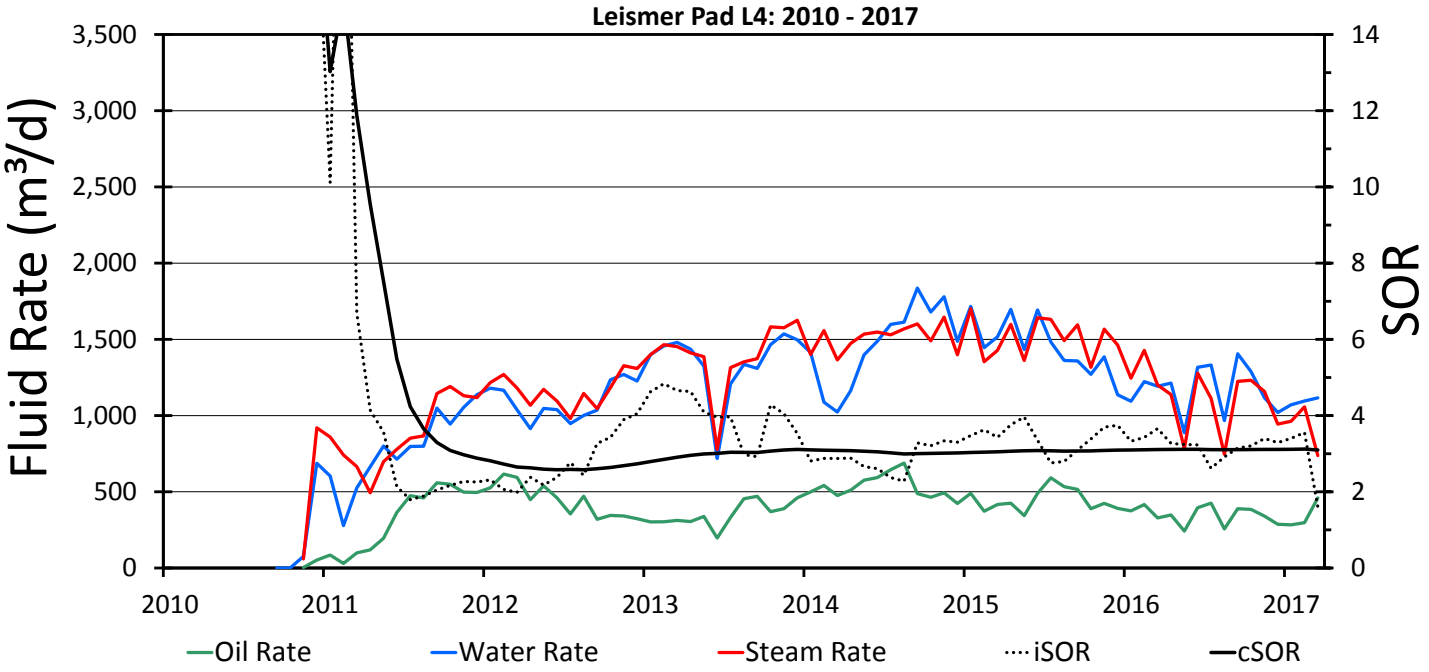
PAD PERFORMANCE – LOW: PAD L4

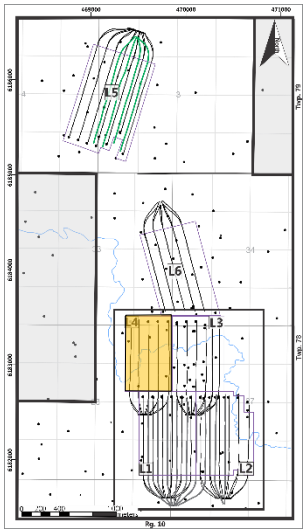
2016 PAD PERFORMANCE:

- Peak bitumen rate ~425 m³/d (2,670 bbl/d)
- iSOR: 2.6–3.7
- Steam reduced in this pad and allocated to other pads

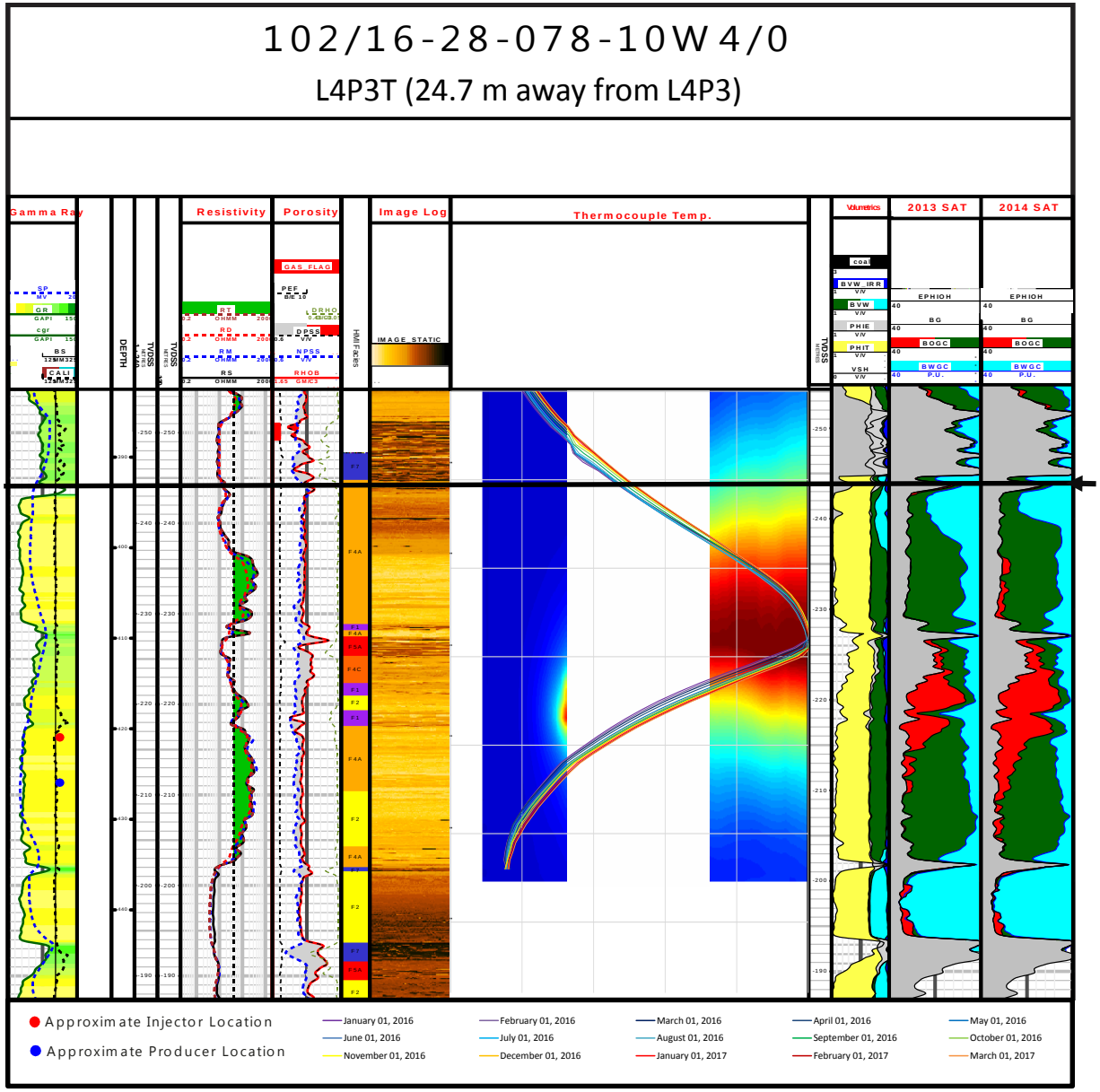
WELL PERFORMANCE:

- Average oil rates in 2016 range between 20–90 m³/d (150–560 bbl/d)
- Non-Condensable Gas (NCG) pilot on L4I4 and L4I5



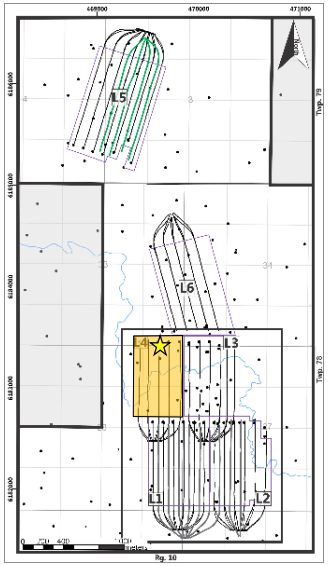


PAD L4 OBSERVATION WELL

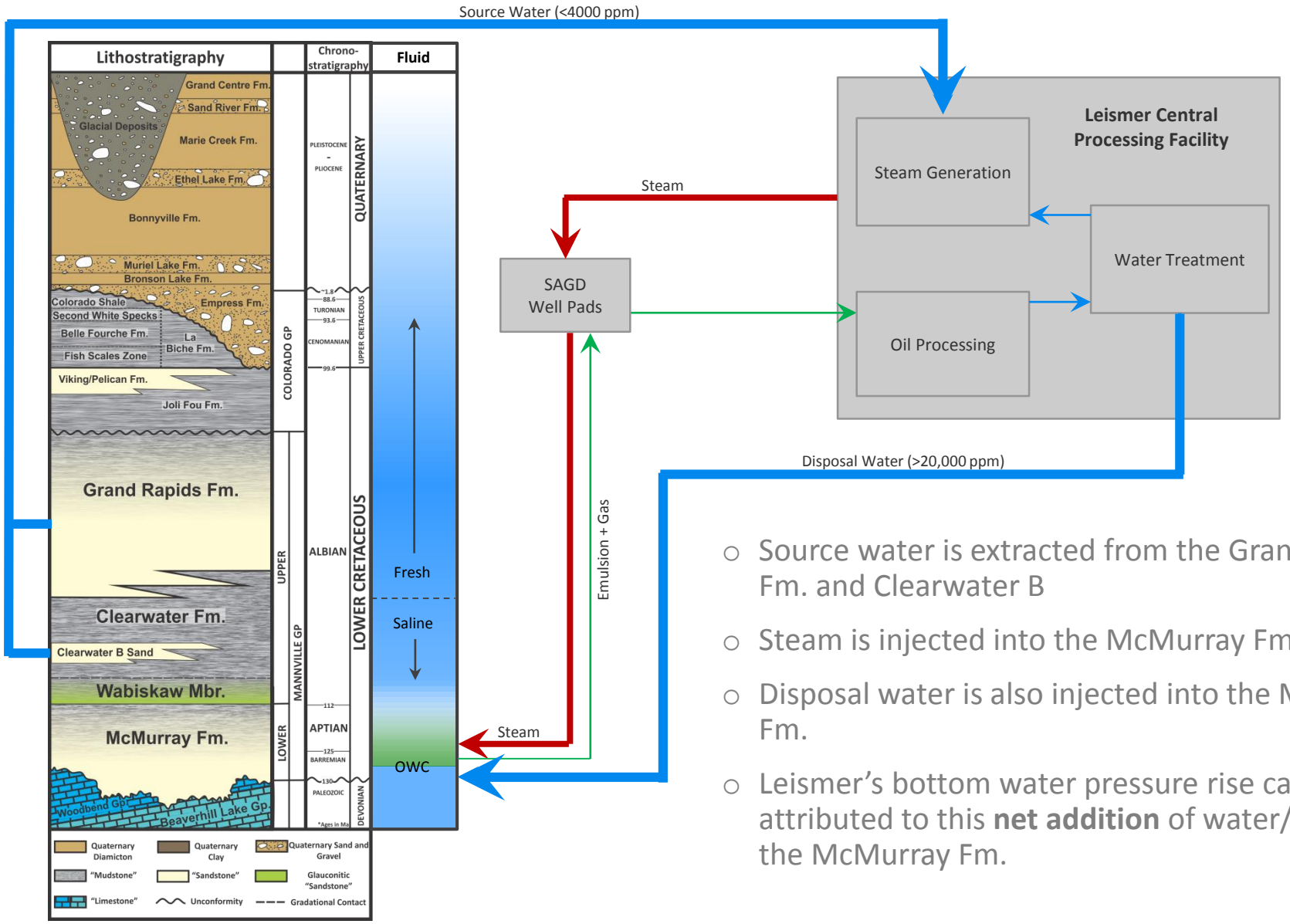


HIGHLIGHTS

- Steam chamber has not yet reached the DBIP top
- Missing temperature data due to faulty readings



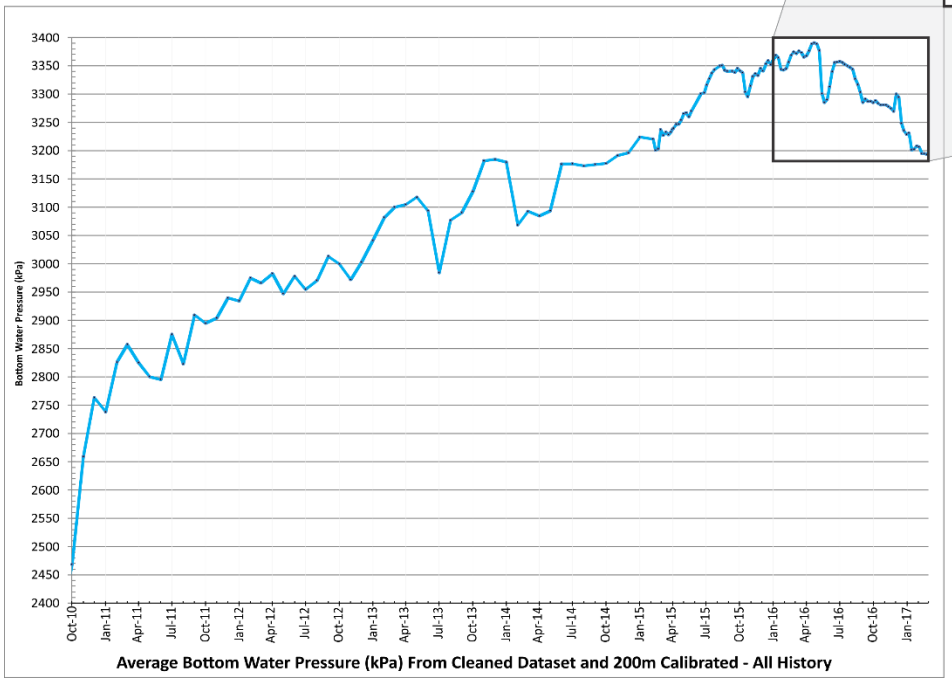
BOTTOM WATER PRESSURE

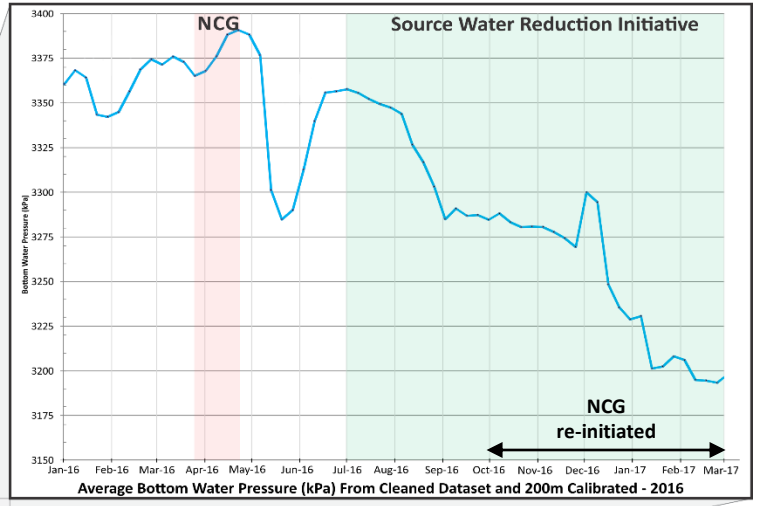


- Source water is extracted from the Grand Rapids Fm. and Clearwater B
- Steam is injected into the McMurray Fm.
- Disposal water is also injected into the McMurray Fm.
- Leismer's bottom water pressure rise can largely attributed to this **net addition** of water/mass into the McMurray Fm.

BOTTOM WATER PRESSURE

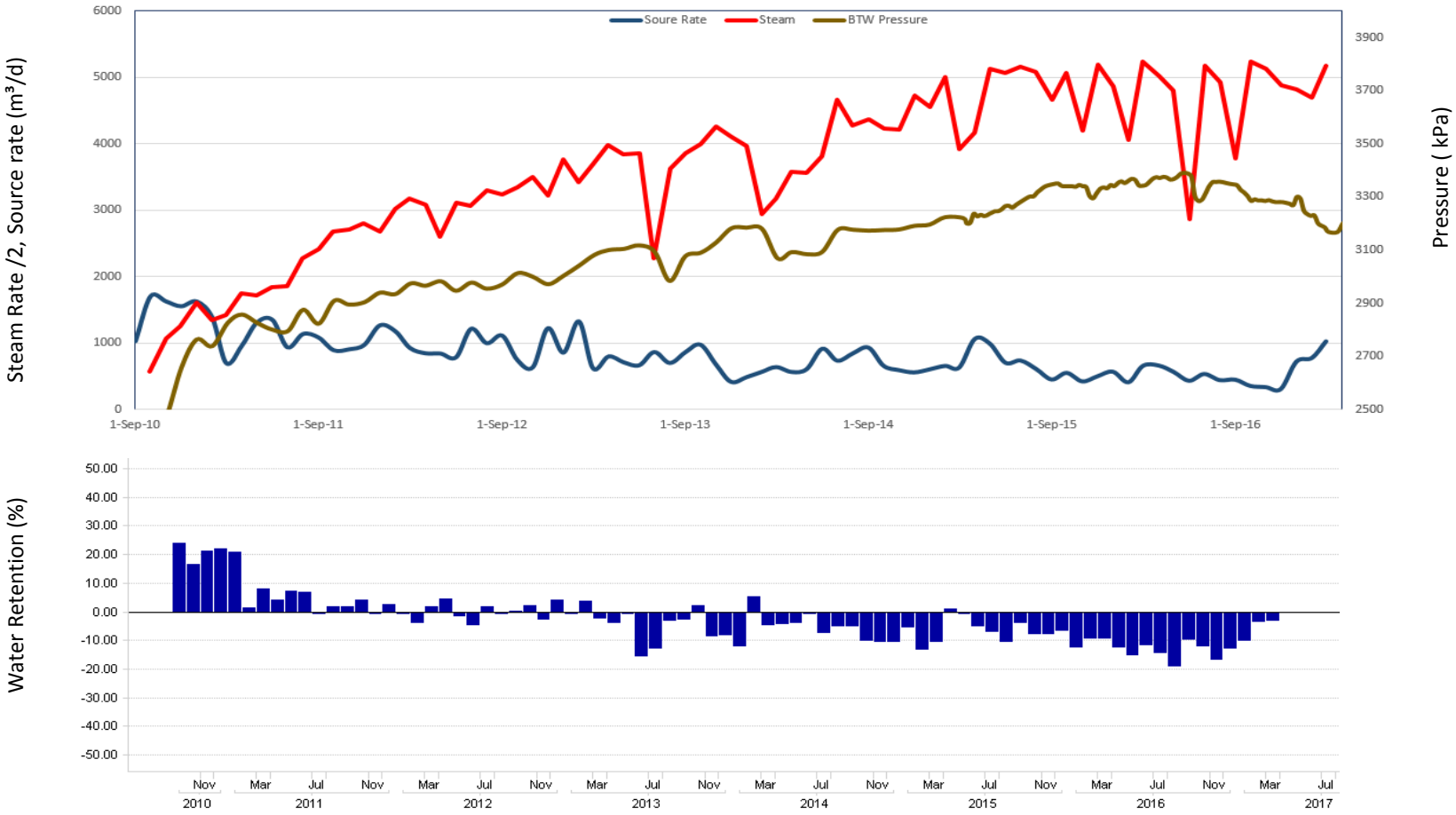
- Bottom water pressure originally 2,300 kPa
- Pressure rose rapidly with start-up of initial 4 pads
- Strong pressure communication between pads
- Source water reduction initiative confirms potential to manage bottom water pressures by minimizing source water





- Throughout 2016, bottom water pressure dropped ~150 kPa in 2016
- In Q1–Q2 2016, bottom water pressure rose due to Non-Condensable Gas (NCG) piloting
- In Q3 2016, a source water reduction initiative stabilized and minimized introduction of source water into the system
- In Q4 2016, NCG was reinitiated, but NCG injection was balanced by steam cuts
- In Q4 2016, steam reductions due to steam generation restrictions further decreased bottom water pressure

SOURCE WATER AND RESERVOIR RETENTION



- Negative retention was maintained since Q4 2013
- Source water and retention are controlled to minimize bottom water pressure variations

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

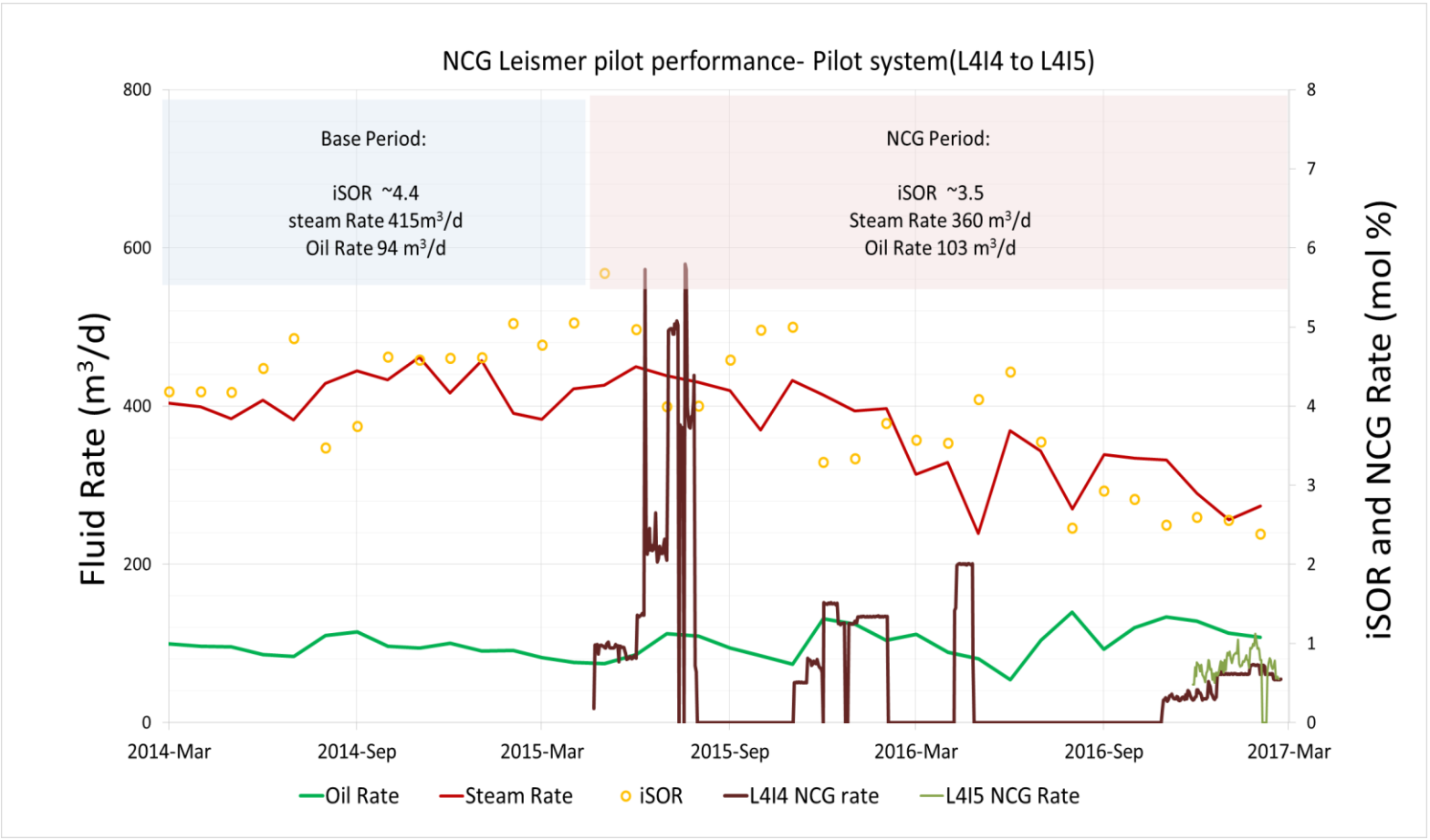
- Steam quality varies as steam rates are increased/decreased
- Most consistent at Pads L1–4 due to shared trunk line
- Most variable at Pad L5 due to additional 4 km steam line off main trunk line

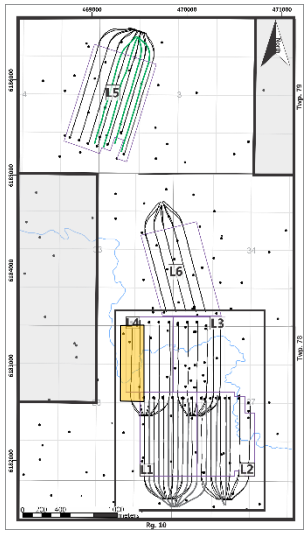
SUBSURFACE

PILOTS

ATHABASCA OIL CORPORATION

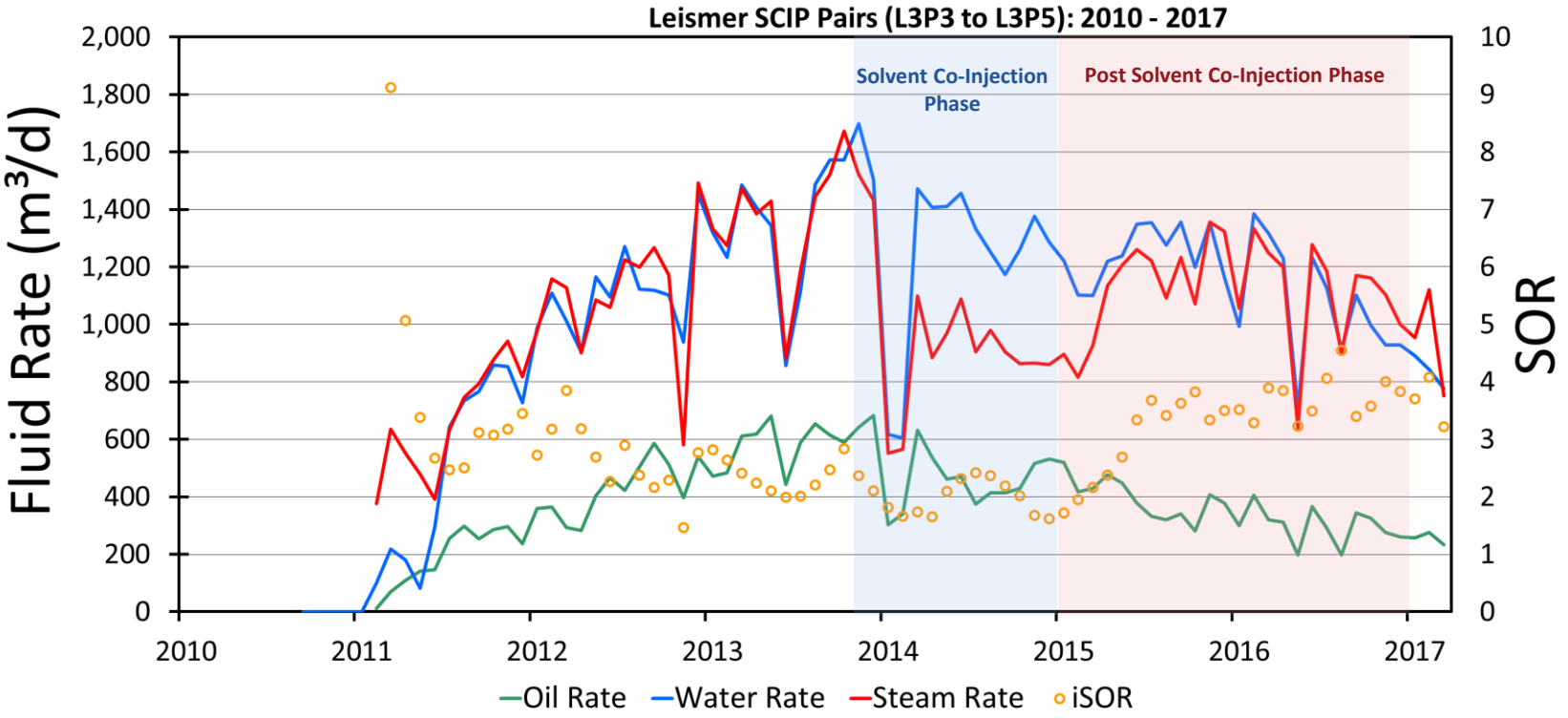
NON-CONDENSABLE GAS (NCG) CO-INJECTION PILOT AT PAD L4





- Four injection periods have been conducted since April 2015
- NCG co-injection helped reduce the steam oil ratio from 4.5 to 2.5
- The evaluation is ongoing, with continued monitoring and optimization of the NCG co-injection well performance

SOLVENT CO-INJECTION PILOT (SCIP) AT PAD L3



- Solvent co-injection was conducted from November 2013 to December 2014
- Sampling and monitoring of solvent production were concluded in Q4 2016
- The solvent recovery from the reservoir is estimated to be 75% at the end of 2016
- Current results from the SCIP pilot are inconclusive

SUBSURFACE

FUTURE PLANS

ATHABASCA OIL CORPORATION

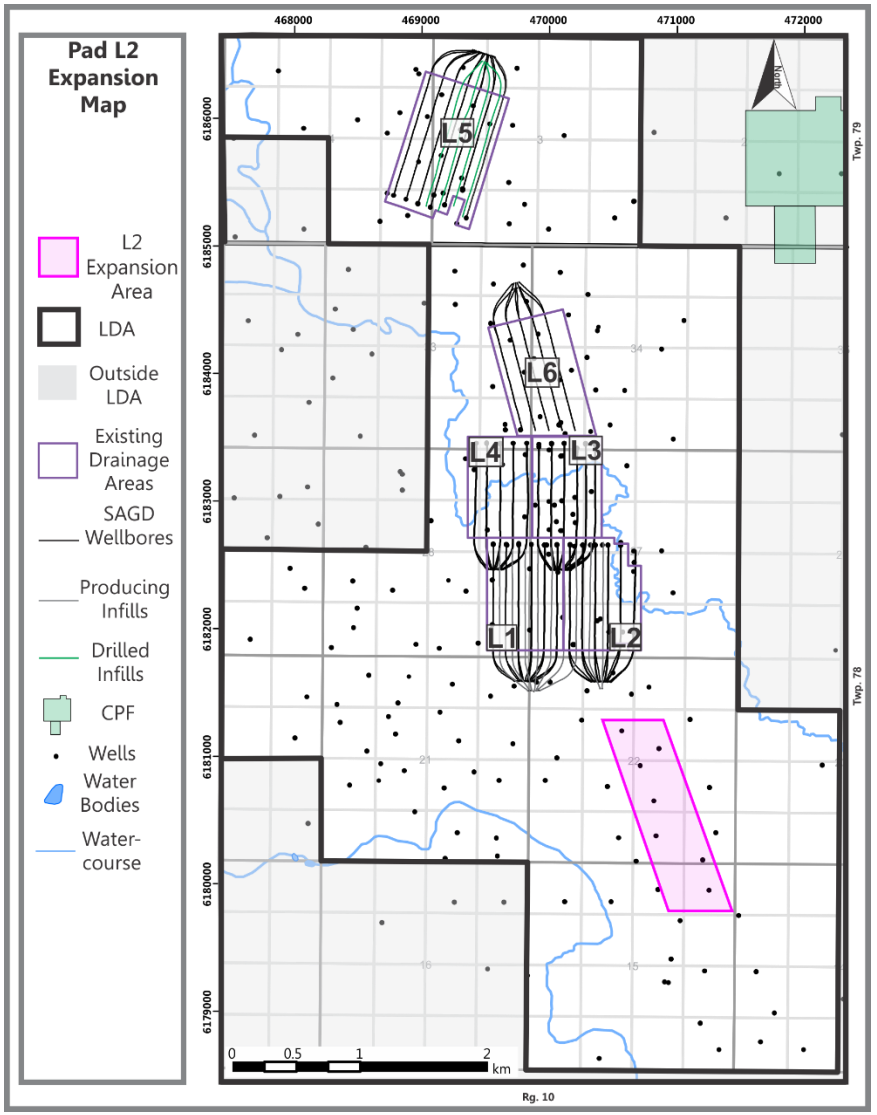
LEISMER FUTURE DEVELOPMENT PLANS

2017 SUBSURFACE DEVELOPMENT PLANS

- Continue evaluating NCG co-injection in Pad L4
- Evaluate the feasibility of NCG co-injection in Pad L1 to L3
- Conduct Pad L5 infill well completions (4 wells)
  - *Potential start-up Q1 2018*
  - *2 wells will be completed with rod pumps*
  - *2 wells will be completed with ESPs*
- Continue the evaluation of Pad L2 expansion

PAD ABANDONMENTS

- No pad abandonments anticipated at Leismer within next five years



SURFACE OPERATIONS

FACILITIES

ATHABASCA OIL CORPORATION

2016 OVERVIEW

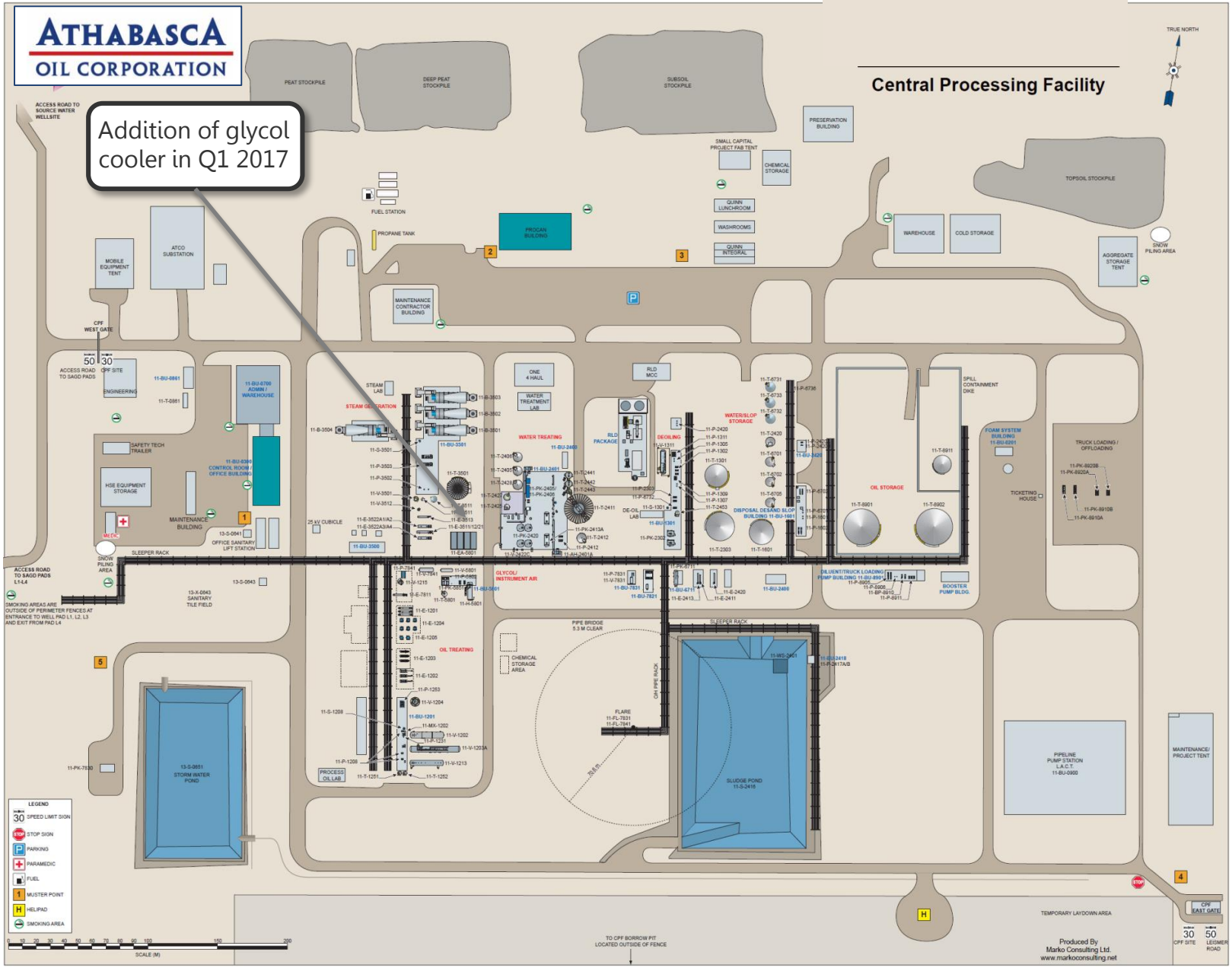
2016 OVERVIEW

- Completed field testing of Ceramic membrane water treatment system
- Degasser Project sanctioned and design work commenced
- Added glycol cooling capacity at CPF

2016 OPERATIONS

- Diluent supply changed due to supply interruption in Q1 2016
- Evacuation and shutdown of site during May wildfires
- Increased slop oil volumes due processing challenges with new well start-ups

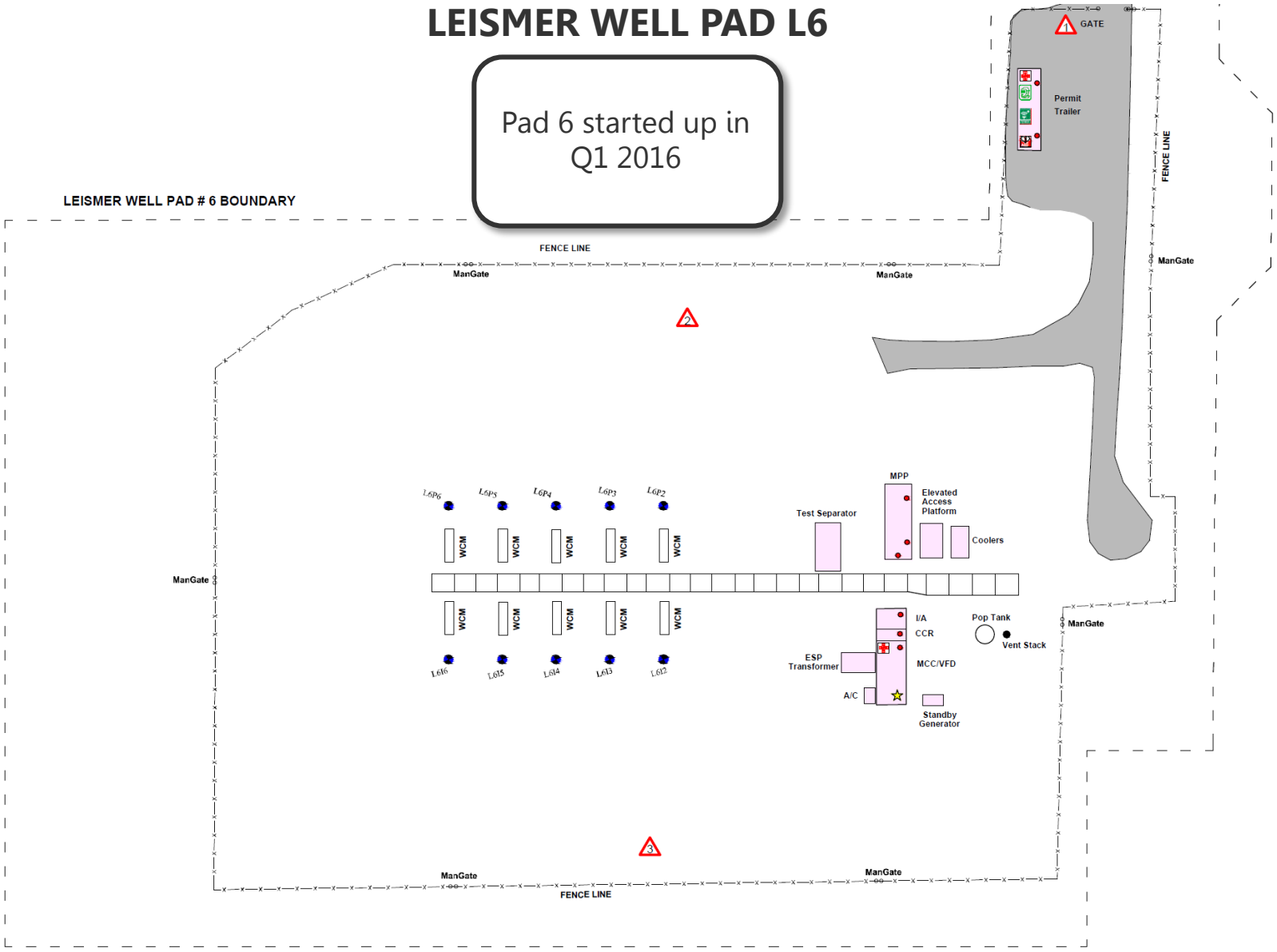
LEISMER CENTRAL PROCESSING FACILITY



LEISMER WELL PADS

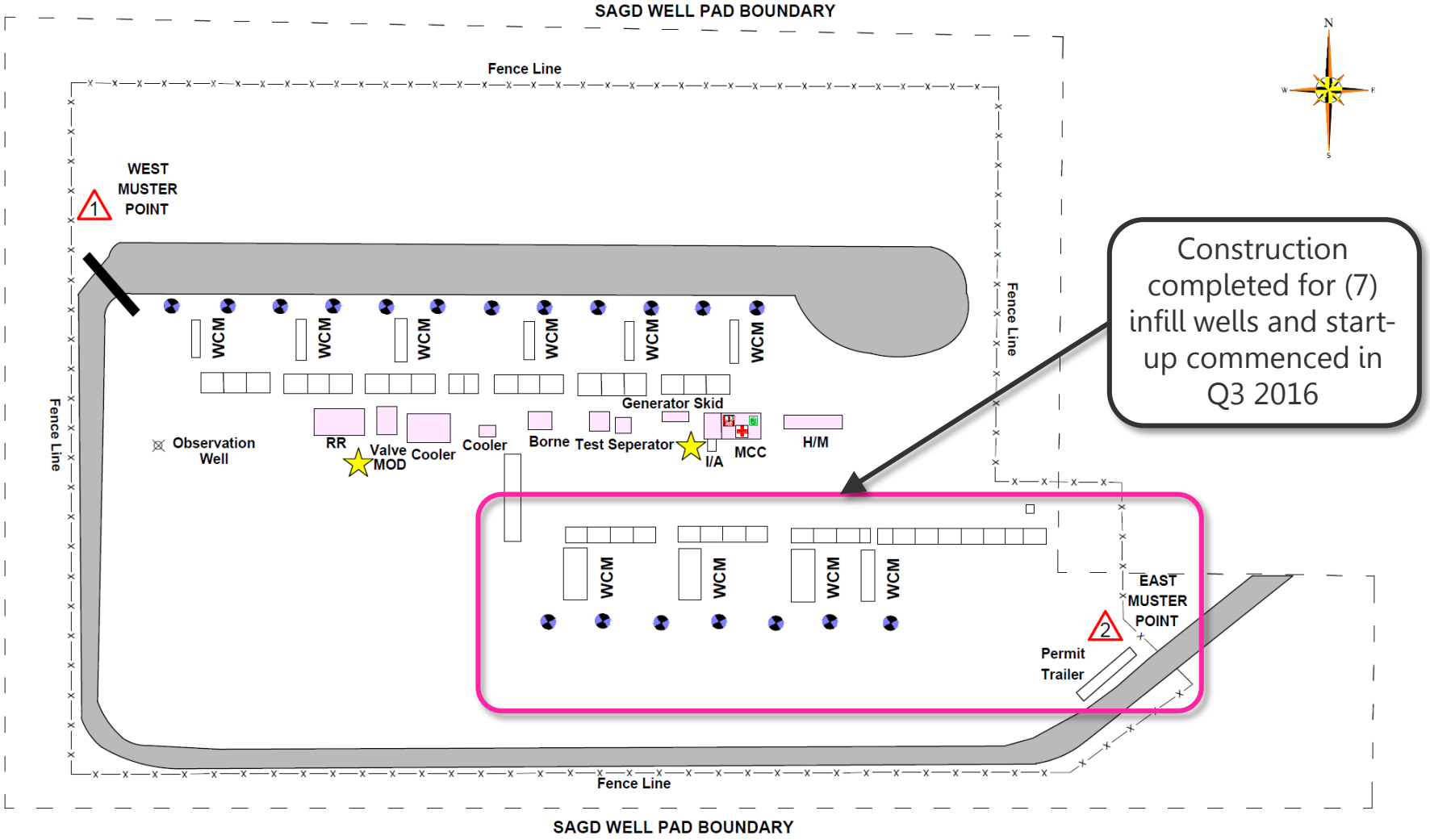
LEISMER WELL PAD L6

Pad 6 started up in Q1 2016

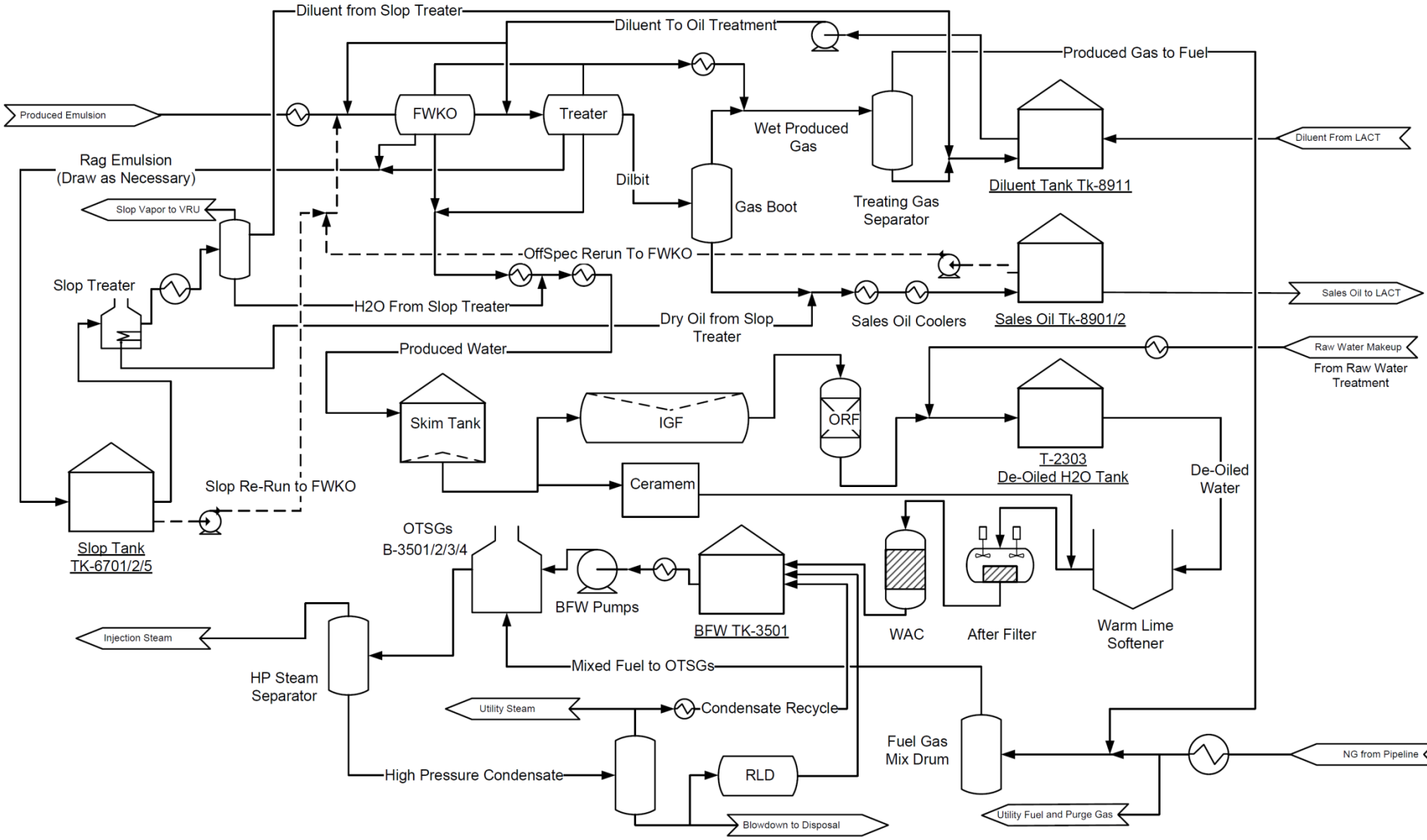


LEISMER WELL PADS

LEISMER WELL PAD L1



SIMPLIFIED SCHEMATIC



SURFACE OPERATIONS

FACILITY PERFORMANCE

ATHABASCA OIL CORPORATION

FACILITY PERFORMANCE

SITE RELIABILITY HAS REMAINED HIGH (~95%)

- Based on steam performance (excluding Fort McMurray wildfire)
- Facility operating near or at maximum design capacity

MAJOR ACTIVITIES

- Replaced insulation on roof of sales oil tank due to failed cladding
- Cleaned and inspected diluent tanks
- Upgraded heat exchangers and gasket materials for two sales oil exchangers
- Completed routine dredging on Warm Lime Softener (WLS) sludge pond
- Completed field testing of Ceramic Membrane water treatment pilot
- Replaced rubber lining in one Weak Acid Cation (WAC) vessel with upgraded material. Monitoring status to determine path forward on remaining vessels
- Pigged steam generators in January and August of 2016
- Replaced two rows of convection tubing on two Once Through Steam Generators (OTSG) in 2016. Replaced tubing with upgraded piping to 2-¼ Cr materials
- Added additional glycol cooler bank to increase cooling capacity

FACILITY PERFORMANCE

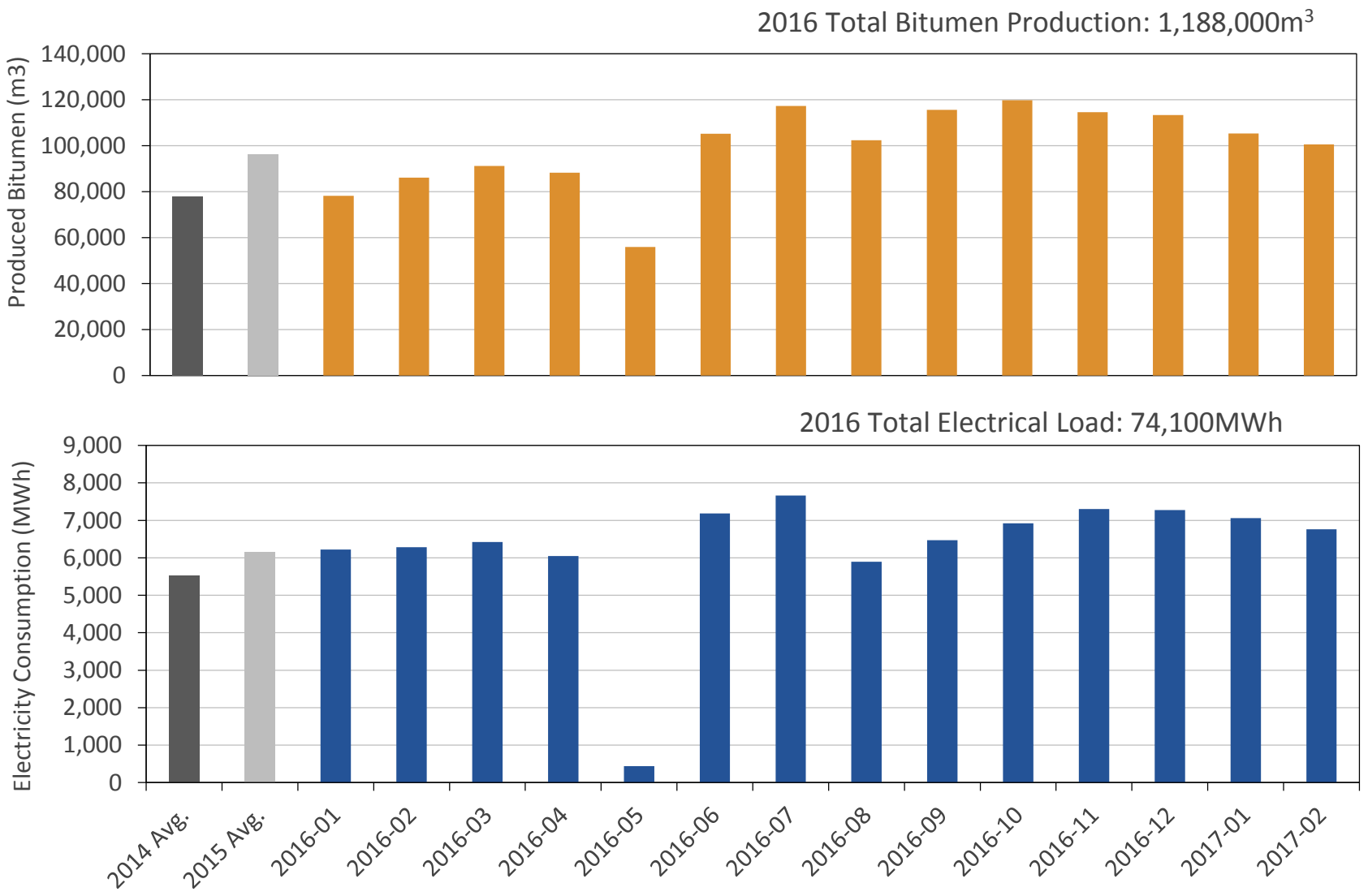
MAJOR CHALLENGES

- Changes in diluent due to supply interruption in Q1 2016 resulted in higher diluent losses
- New well start-ups caused treating difficulties resulting in additional slop volumes and challenges for oil and water treatment processes
- Process sludge pond primary liner leak; exceeded leakage rates (ALR) in May 2016 when operating pond at high level in preparation for maintenance activities. Pond is currently operated at lower level below the leak point
- Failure of non operating brackish water line in December 2016
- Shutdown and restart of facility due to Fort McMurray wildfire

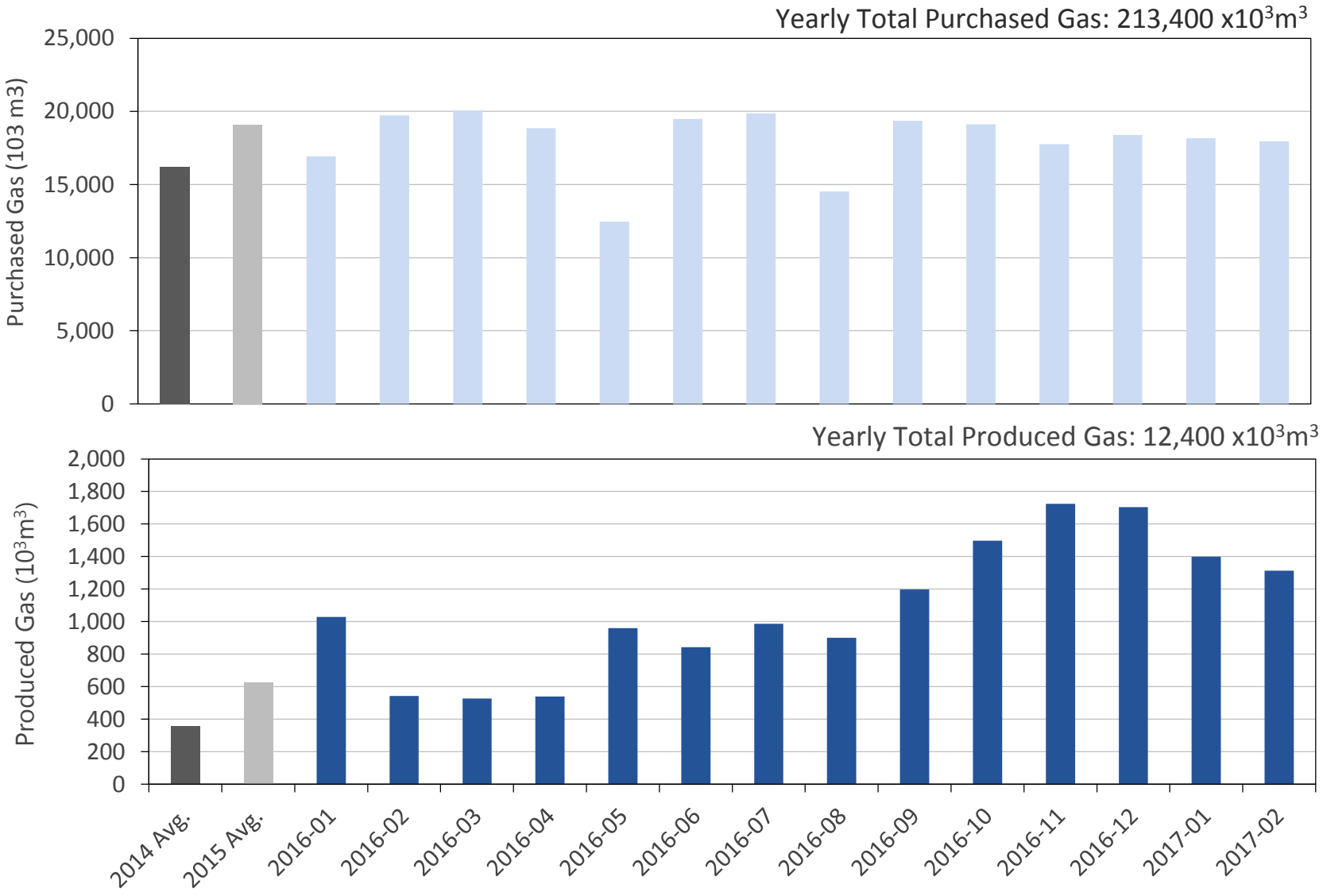
OPPORTUNITIES

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

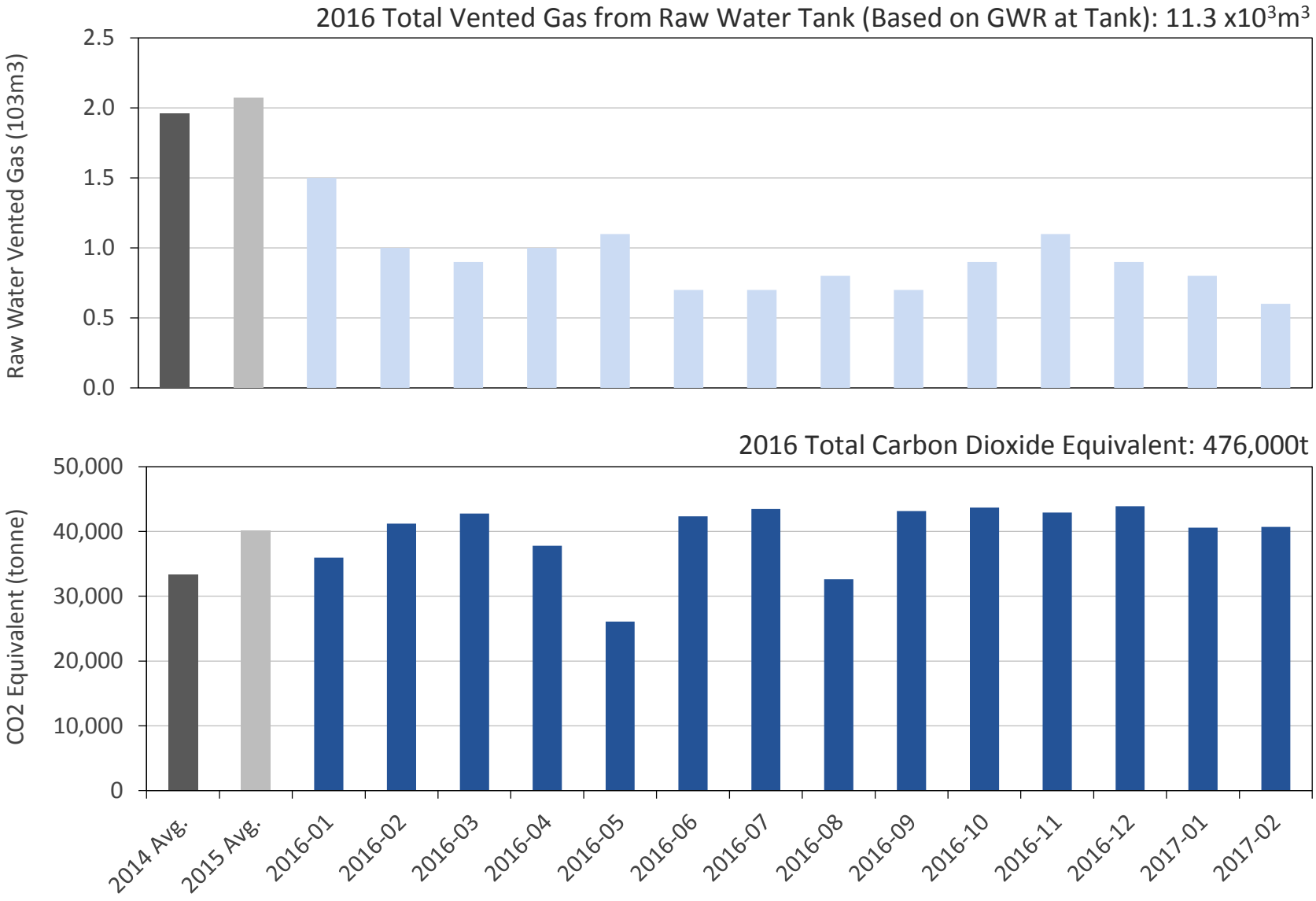
PRODUCTION & ELECTRICITY CONSUMPTION



PURCHASED & PRODUCED GAS VOLUMES

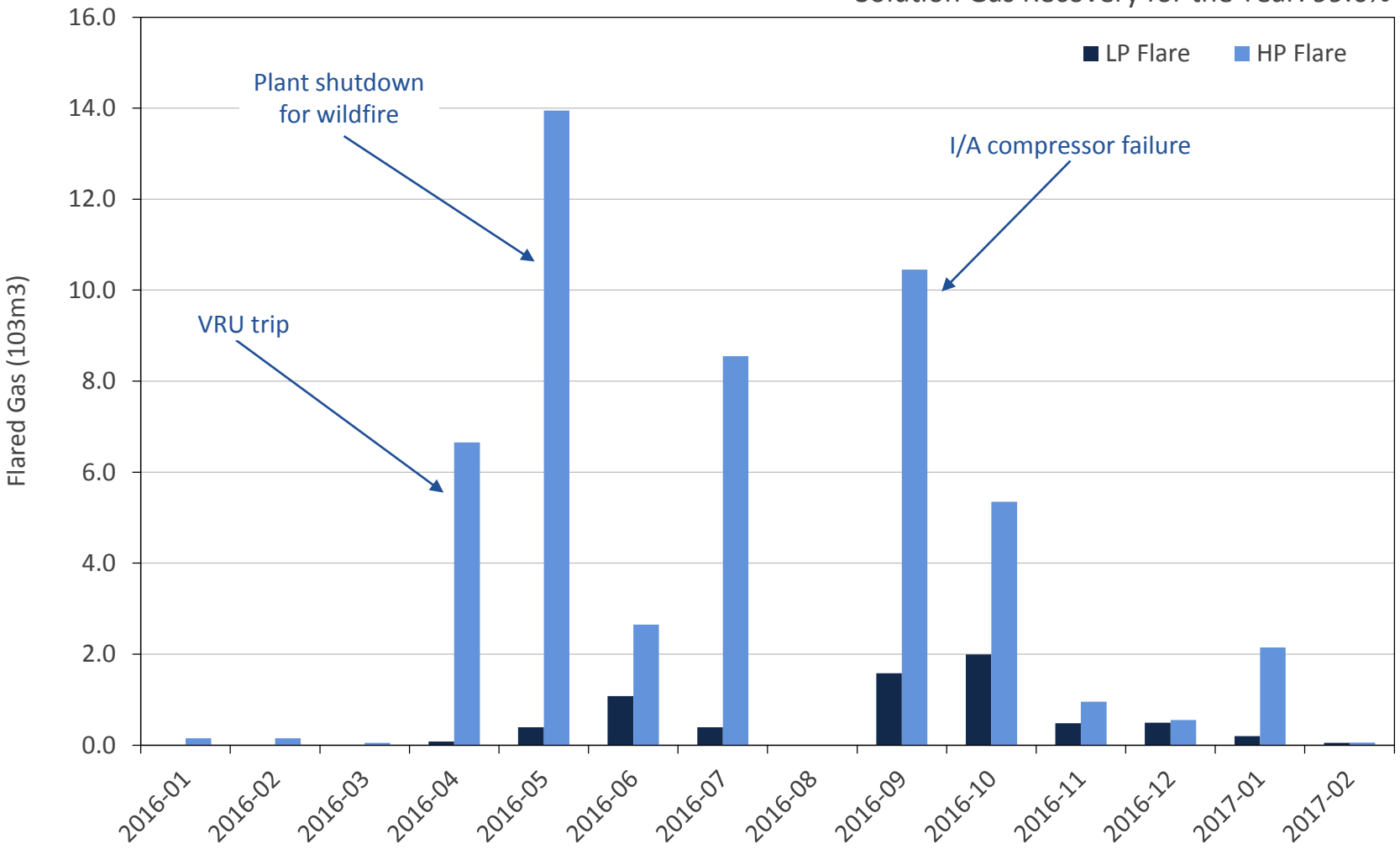


GAS VENTING & CO_2 EMISSIONS



GAS FLARING

Yearly Total HP Flare: 49.4 x$10^3 m^3$
Yearly Total LP Flare: 6.5 x$10^3 m^3$
Solution Gas Recovery for the Year: 99.6%



OVERALL PERFORMANCE & EXPECTATIONS

OVERALL OPERATION

- Surface facilities have operated close to design rates
- Overall facility performance has met expectations

CHALLENGES

- May wildfire required partial evacuation and shutdown of facilities on two occasions
- Oil treating challenges with new pad start-ups resulting in higher slop volumes

OPPORTUNITIES

- Ongoing evaluation and optimization of oil treating chemicals

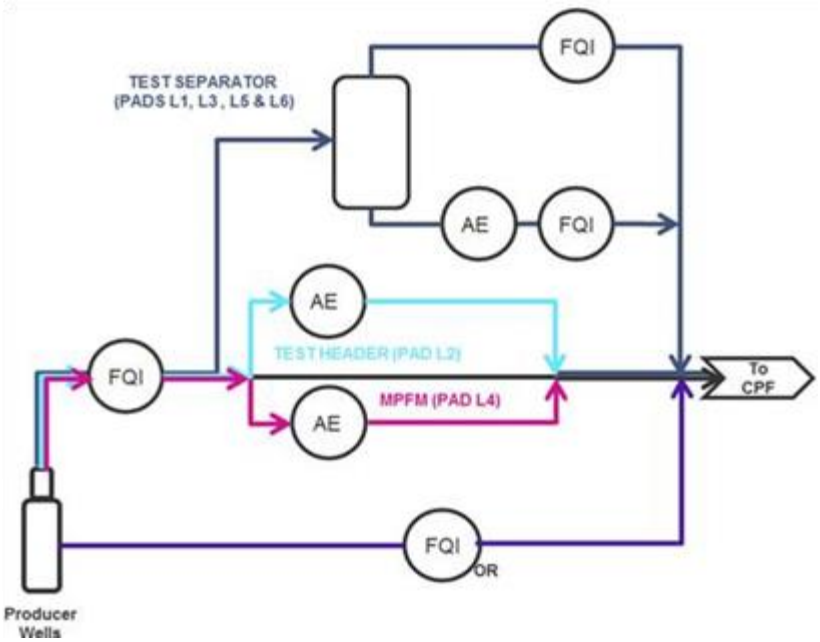
SURFACE

MEASUREMENT, ACCOUNTING AND REPORTING PLAN (*MARP*)

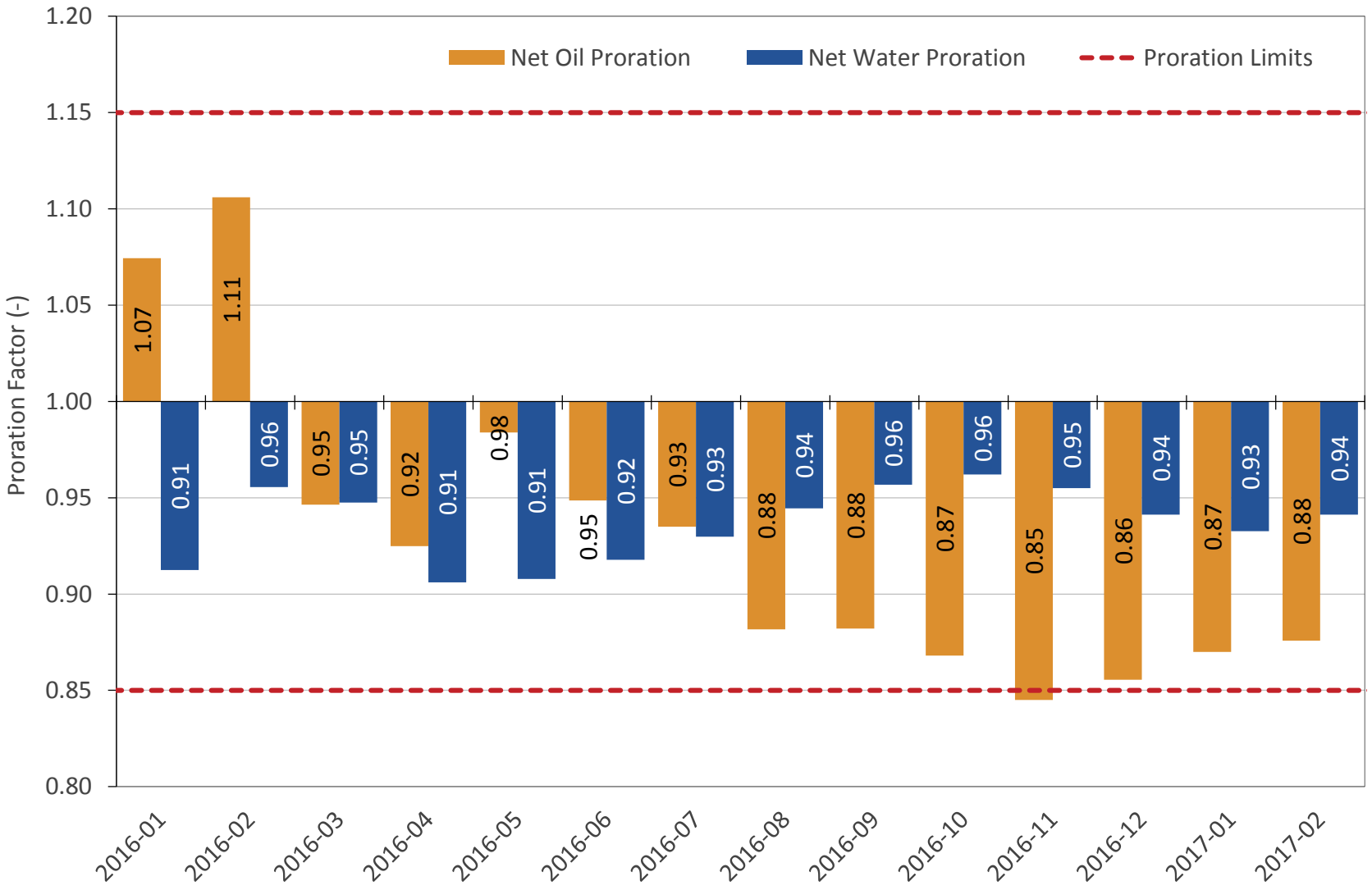
ATHABASCA OIL CORPORATION

WELL TESTING

- Well tests used to calculate daily bitumen and water production
- Five 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
- Multi-Phase Flow Meter (MPFM) and full test header installed and operational at Pad L4 in 2016
- MPFM installed on Pad L2 in late 2016. Currently completing verification period of MPFM and existing water cut meter.



PRORATION FACTORS



SURFACE

WATER PRODUCTION, INJECTION & USES

ATHABASCA OIL CORPORATION

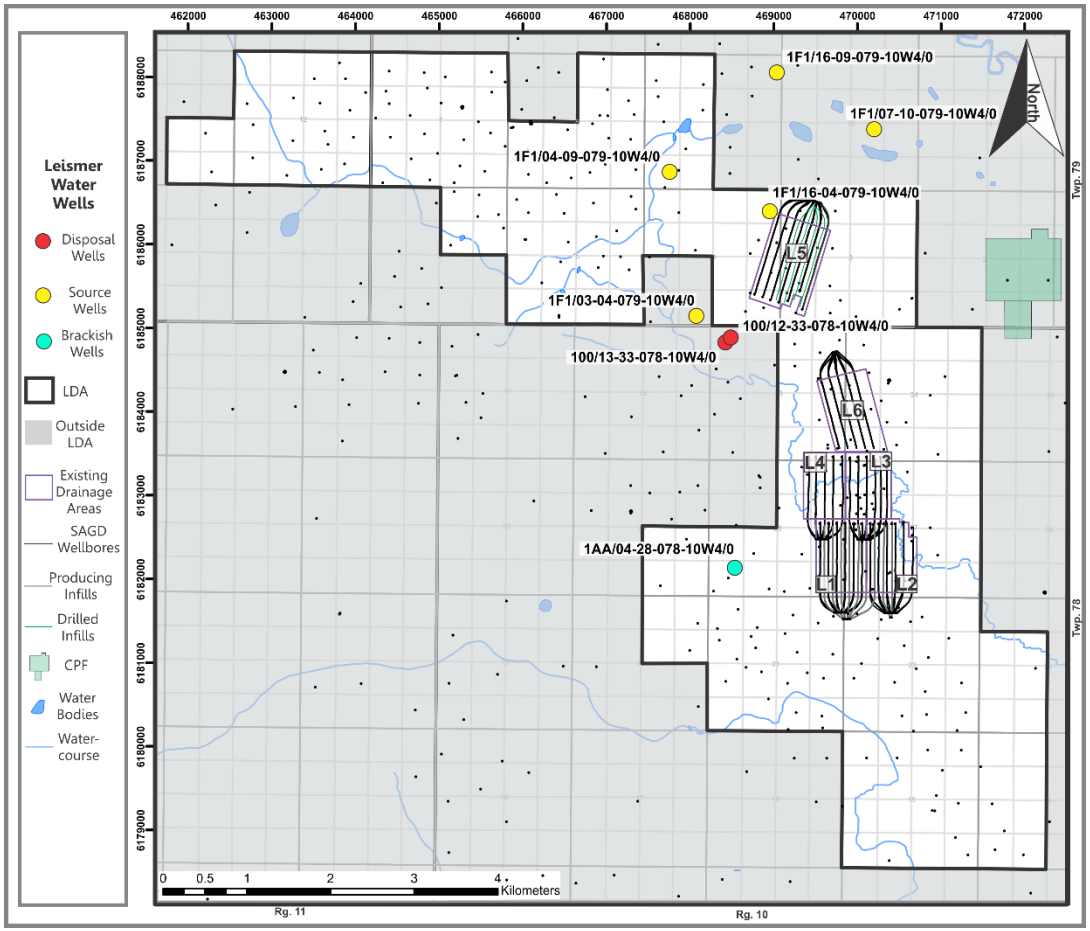
SOURCE AND DISPOSAL WELLS

LEISMER'S 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)



CPF WATER USES

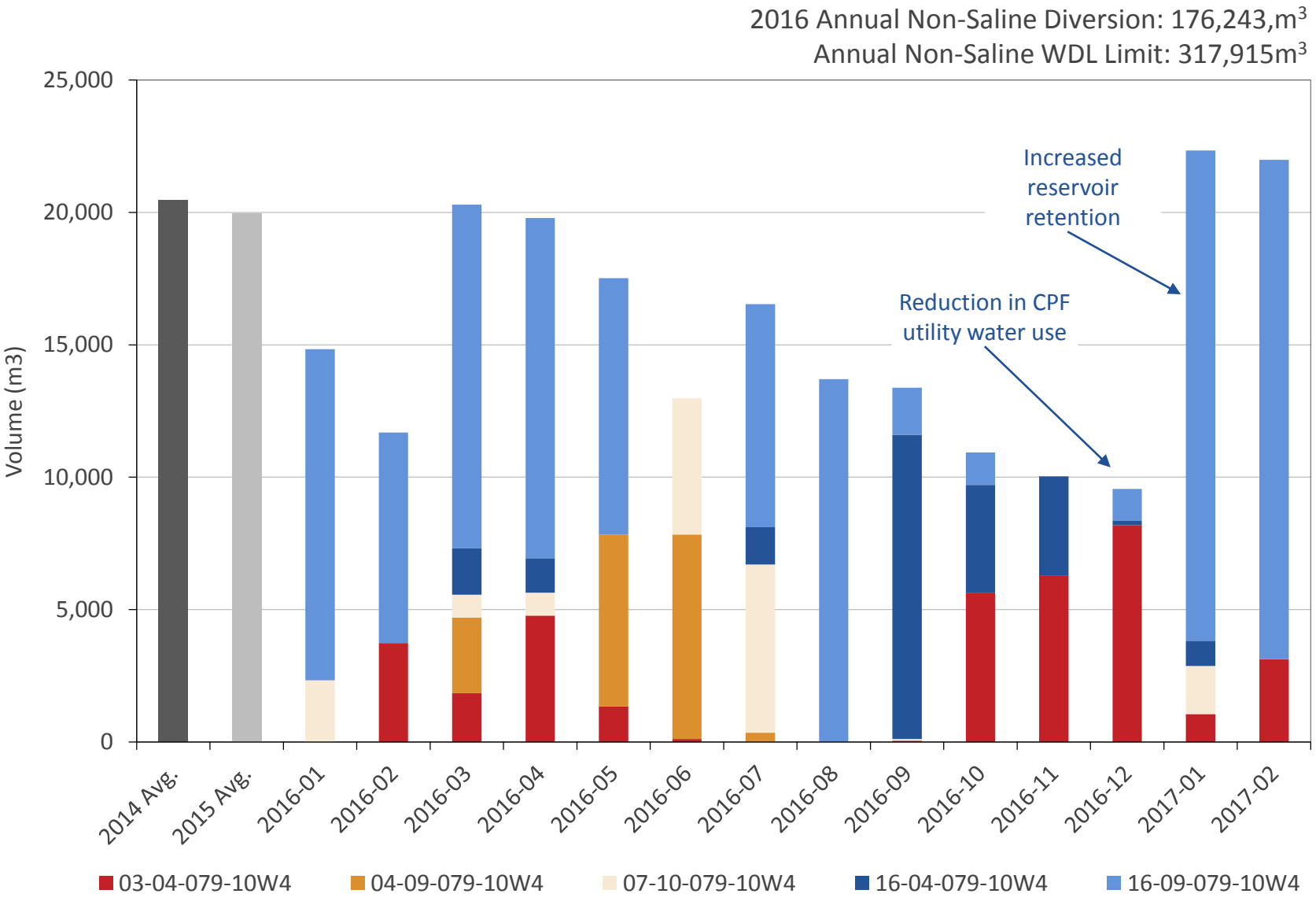
WATER DIVERSION LICENCE (WDL) 00239880 FOR 317,915 m^3/y (871 m^3/d)

- Total non-saline water pumped from source wells at Leismer in 2016 was 176,243 m^3 (480 m^3/d) or 55% of allowable WDL amount
  - *~98% went to Leismer CPF for process use*
  - *~2% for domestic use at CPF*

SOURCE WATER MINIMIZED BY OPERATING AT BALANCED RESERVOIR RETENTION AND HIGH BLOWDOWN RECYCLE RATES

- Source water intensity was 0.15 bbl-water/bbl-bitumen in 2016 representing a decrease of 25% from 2015
- Based on reservoir conditions with WSR > 1, source water requirements remain low and mainly used for CPF utility requirements
- Utility water use has been reduced approximately 30% from previous year
- No brackish water was used in 2016 due to low overall source water requirements
- High blowdown recycle rates have been maintained

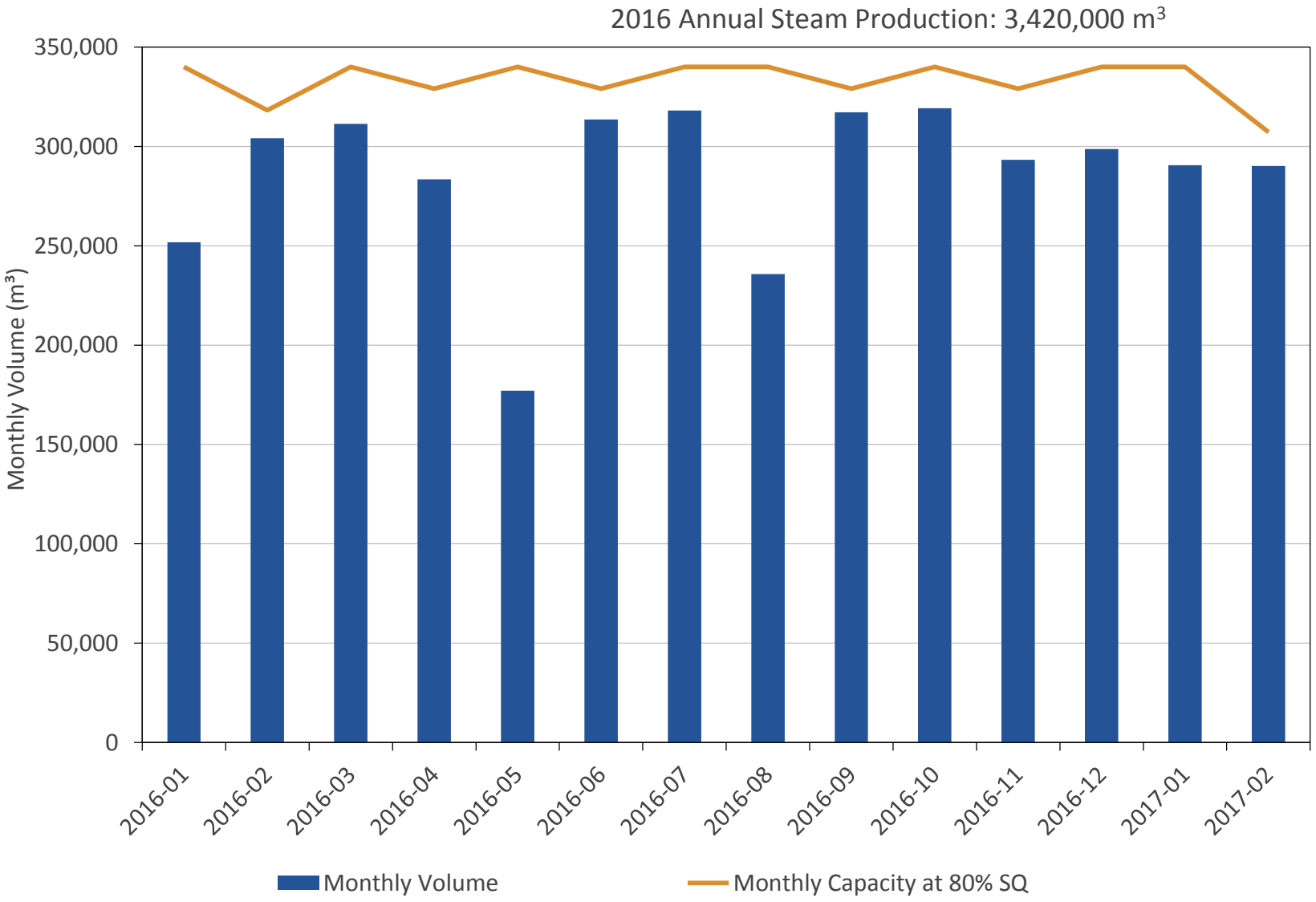
FLOW FROM GRAND RAPIDS



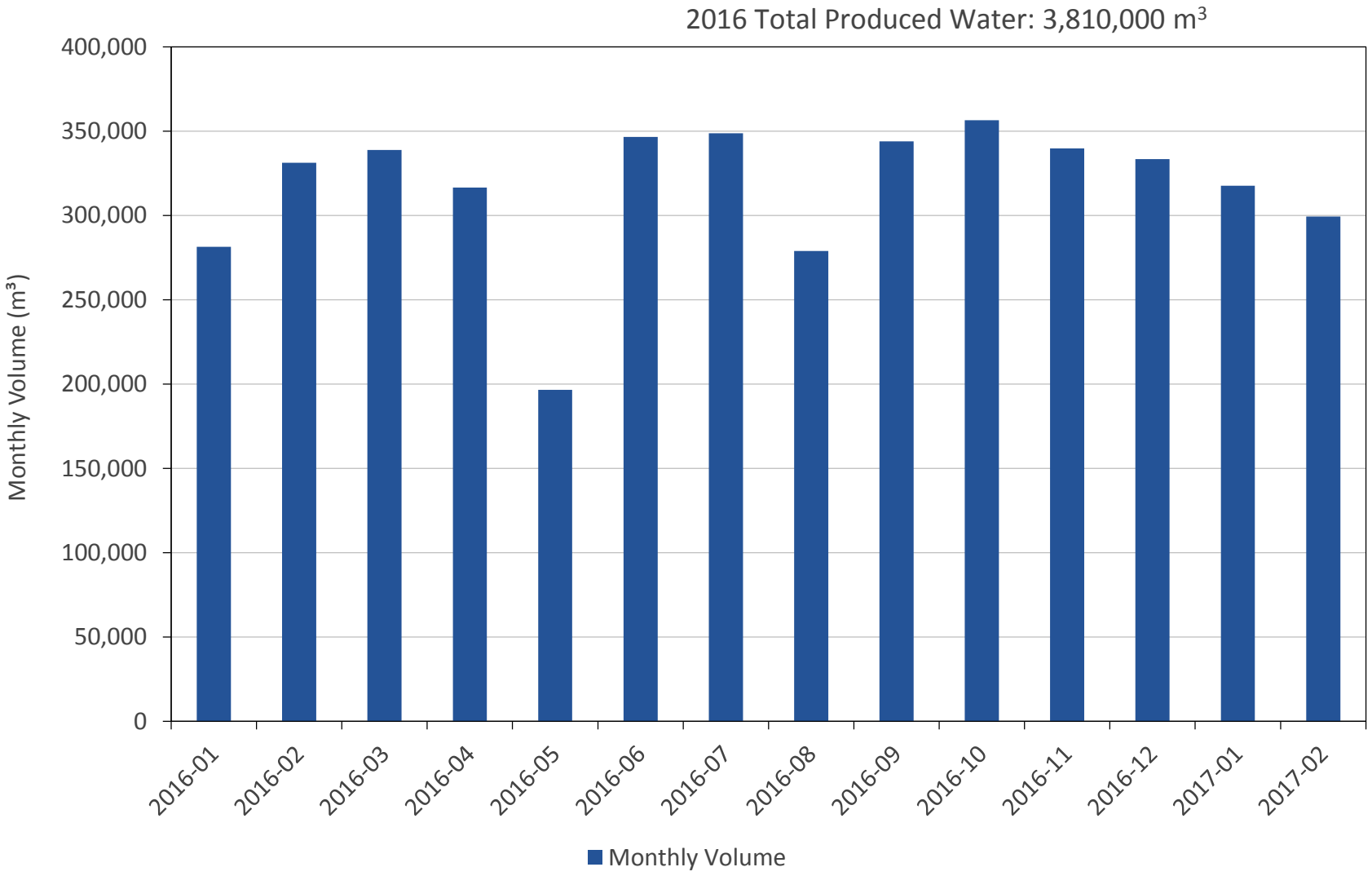
TYPICAL WATER QUALITY

Parameter	Brackish Water	Fresh Water	Produced Water	Disposal Water
TDS [mg/L]	5,700	1,450	2,050	27,000
pH [-]	8.5	8.7	7.3	12.1
Hardness [mg/L as $CaCO_3$]	70	4.5	18	1.5
Total Alkalinity [mg/L as $CaCO_3$]	880	820	230	6,900
SiO_2 [mg/L]	0	0	275	275
Cl [mg/L]	2,800	250	925	12,500

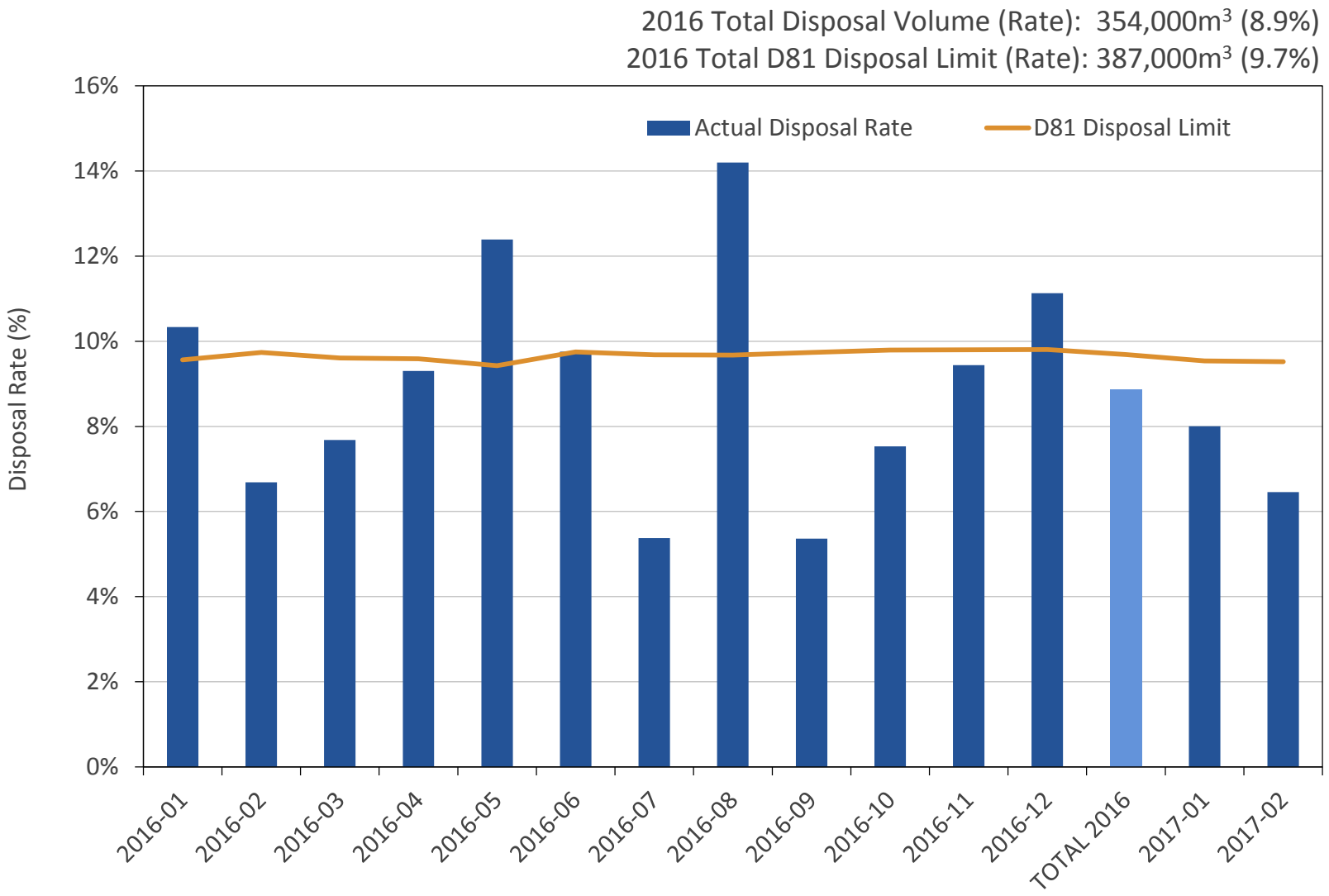
STEAM INJECTION



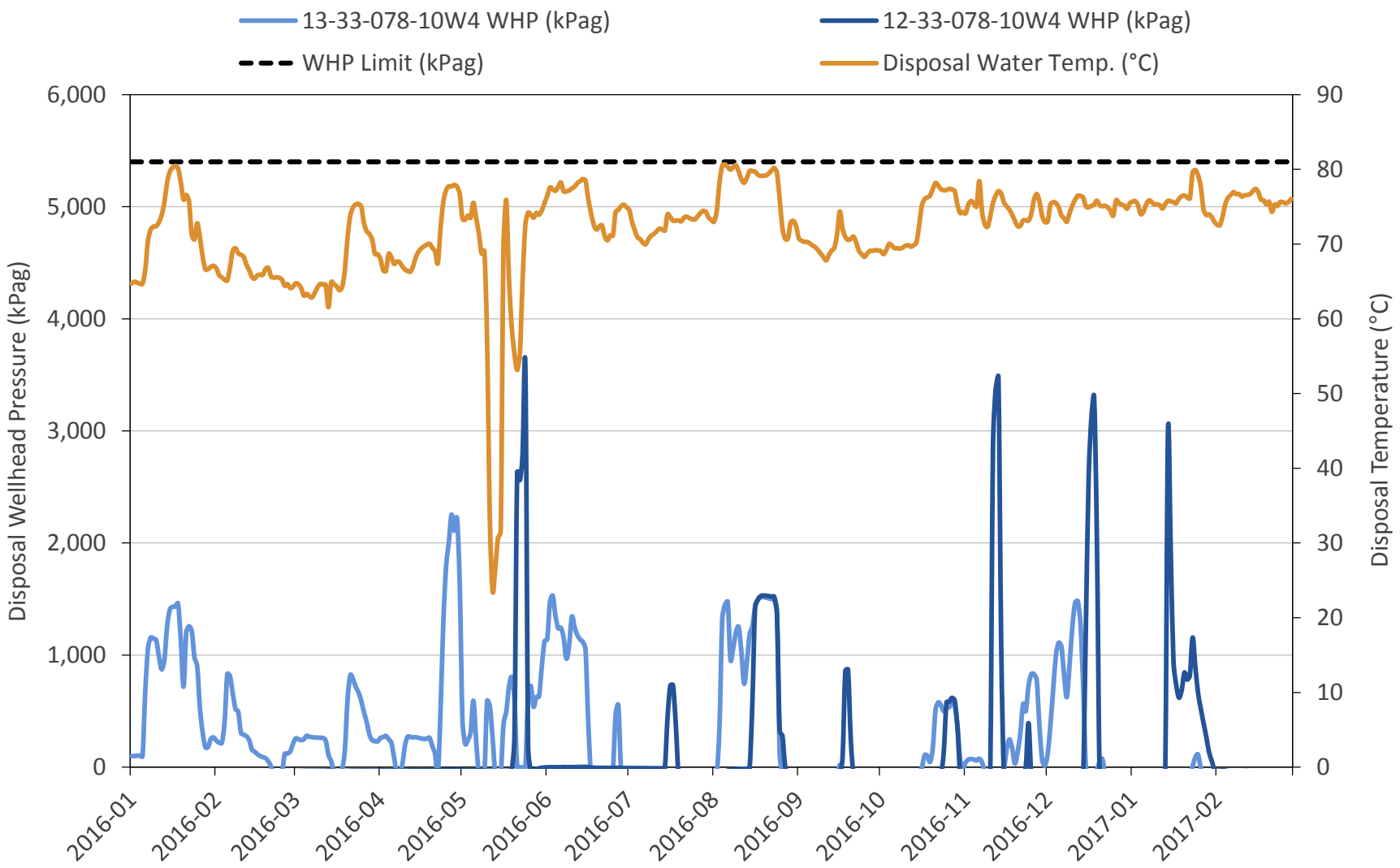
PRODUCED WATER



DISPOSAL WATER

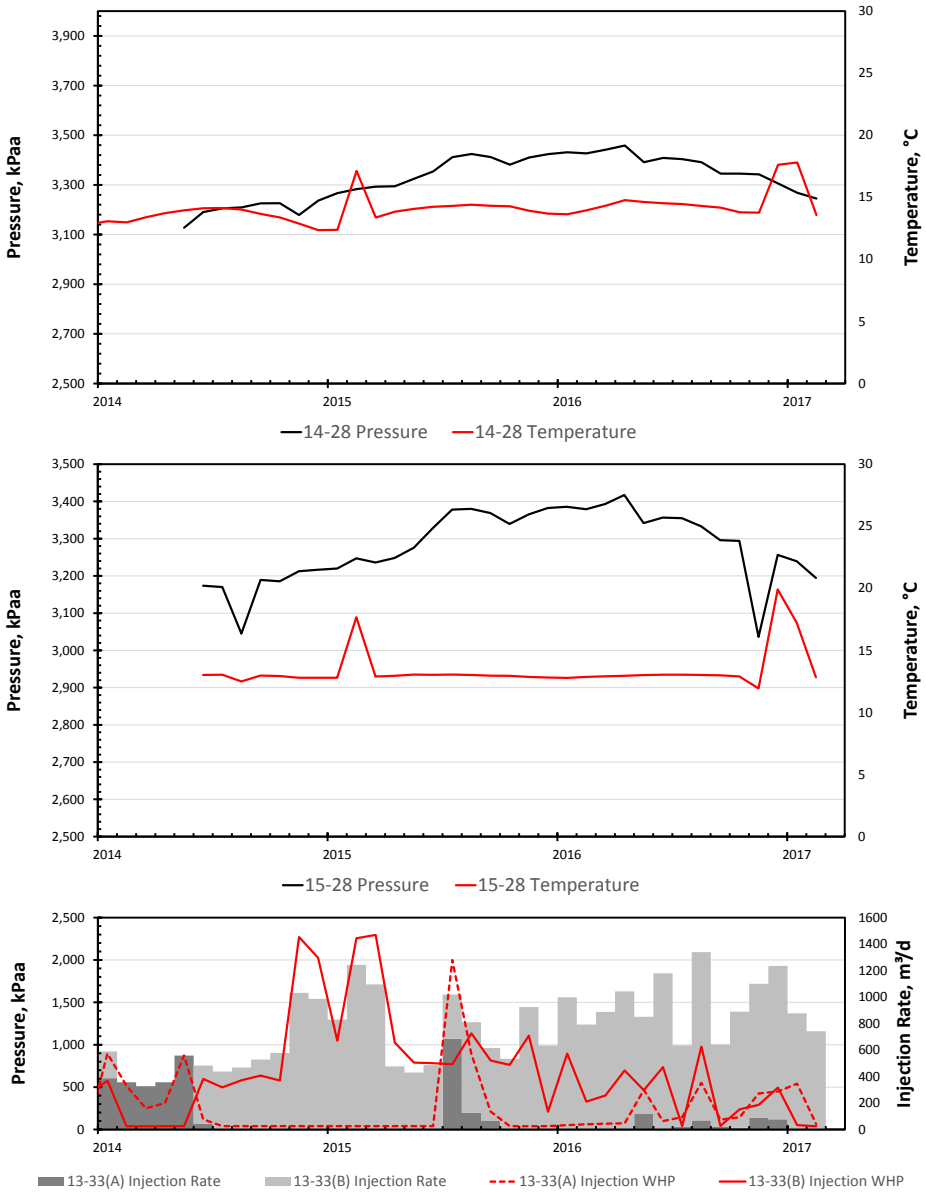


DISPOSAL WATER PRESSURE & TEMPERATURE

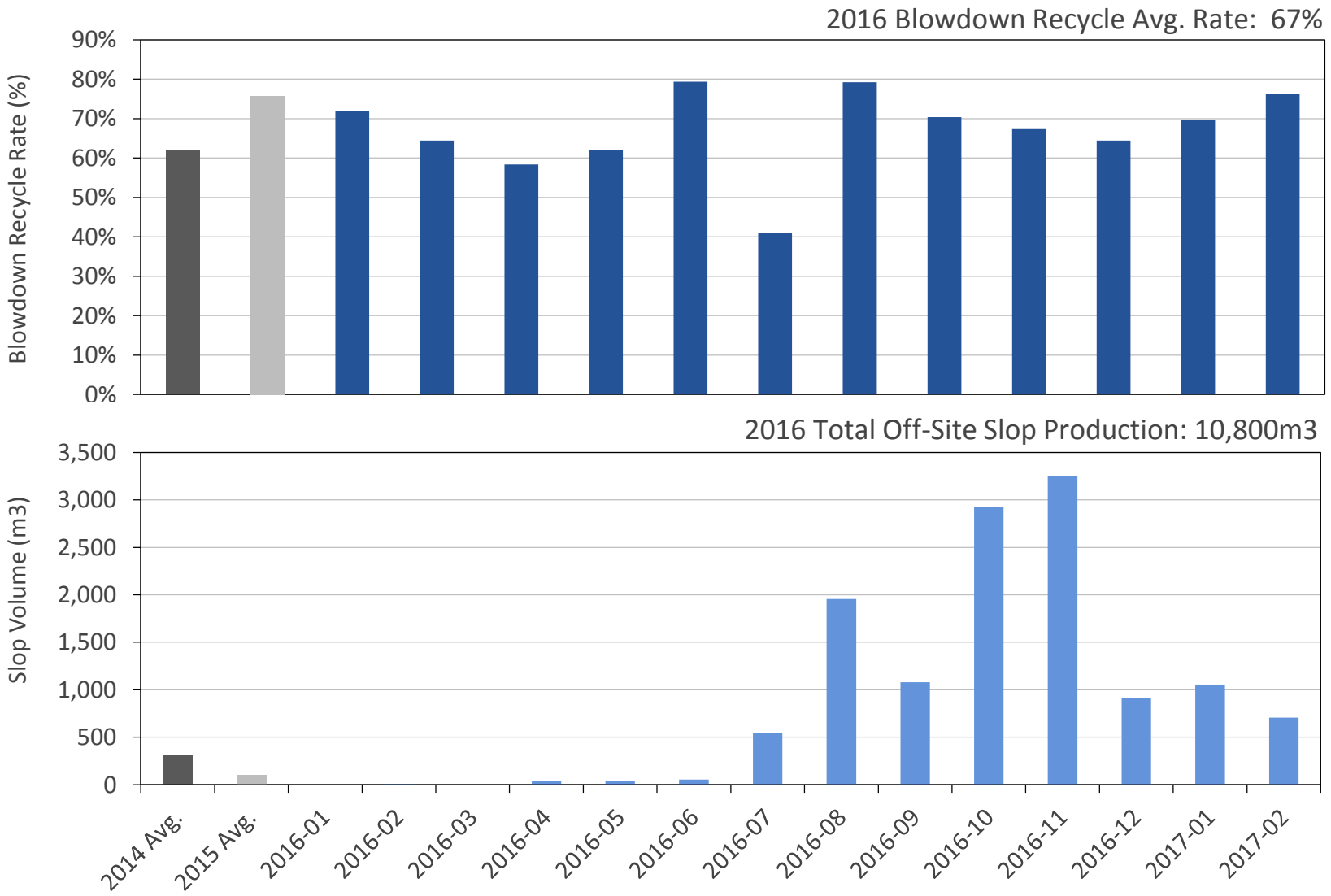


DISPOSAL WELL MONITORING

- Monitoring pressure and temperature at
  1F1/14-28-078-10W4/0
  102/15-28-078-10W4/0
- Disposal well has negligible impact on McMurray Deposit
- Pressure changes in McMurray basal water are more dependent on source water usage and SAGD operations of near-by pads
- Slight temperature increases observed during periods of high rate disposal



BLOWDOWN RECYCLE & SLOP



BLOWDOWN RECYCLE & SLOP

SLOP HANDLING:

- 7,480 m^3 of water was trucked off site within slop volume to the Lindbergh cavern facility

SOLIDS DISPOSAL:

- Water treatment related solids (lime softening sludge) is allowed to settle in the sludge pond at site
- Sludge pond dredged in August–October 2016; total of 9,700 dry tonnes of lime sludge were removed from pond and disposed to landfill

SURFACE

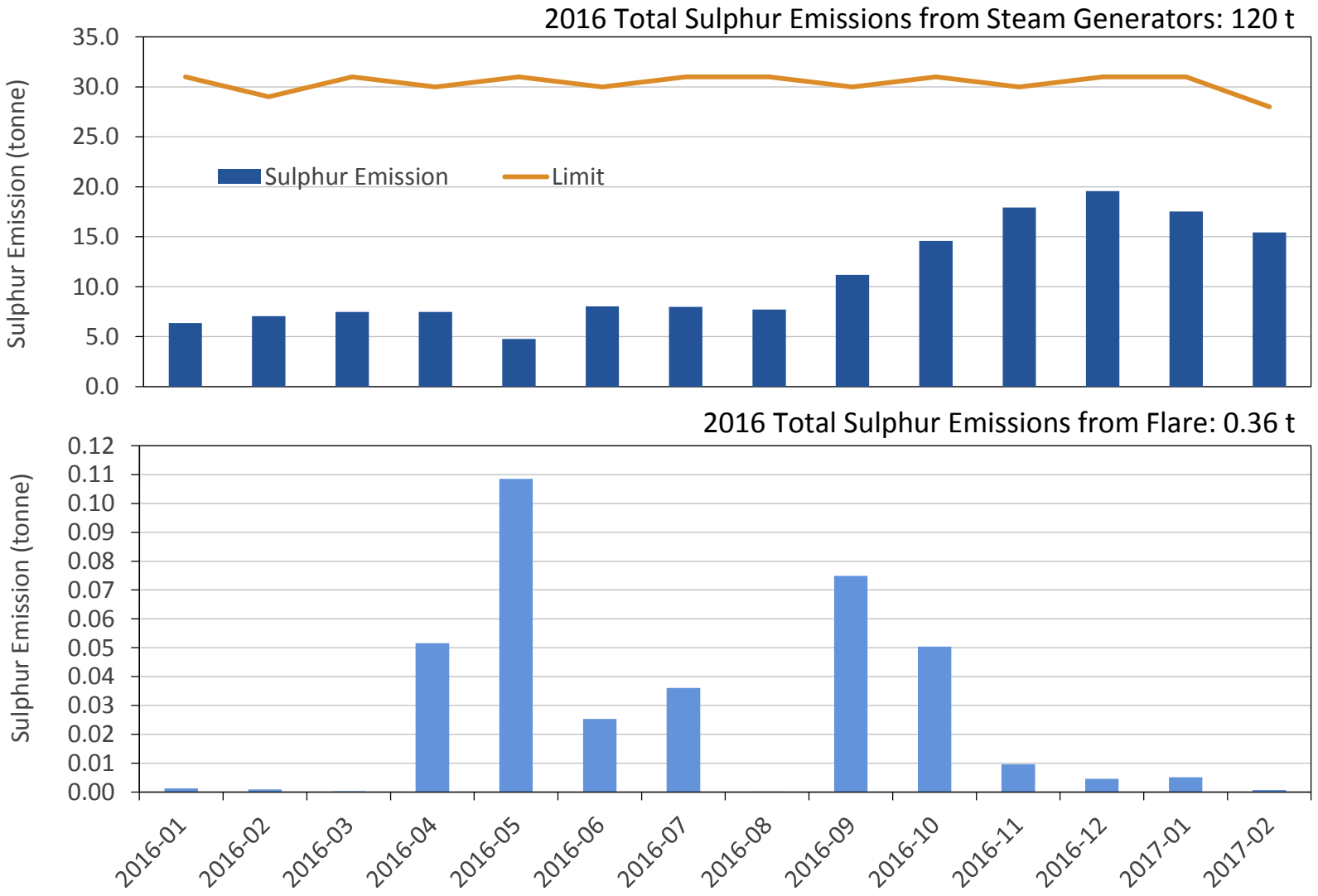
SULPHUR PRODUCTION

ATHABASCA OIL CORPORATION

SULPHUR & SULPHUR DIOXIDE

- Leismer average daily sulphur dioxide (SO_2) emissions was 0.66 t/d in 2016 (33% 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 2016 was 240 t
- Leismer currently does not have sulphur recovery facilities

MONTHLY SULPHUR 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 ppb
- H_2S (1-hour average): 10 ppb
- NO_2 (1-hour average): 159 ppb

Passive Ambient Monitoring 2016		
Month	**Peak SO_2 (ppb)**	**Peak H_2S (ppb)**
January	1.0	0.17
February	0.6	0.18
March	1.6	0.11
April	0.6	0.15
May	0.3	0.10
June	1.0	0.11
July	1.0	0.10
August	0.9	0.15
September	2.4	0.19
October	1.1	0.08
November	2.1	0.27
December	1.8	0.18

Continuous Ambient Monitoring 2016			
	January	**February**	**March**
Peak SO_2 1-Hour Average (ppb)	13.0	9.0	11.0
Peak H_2S 1-Hour Average (ppb)	1.0	1.0	0
Peak NO_2 1-Hour Average (ppb)	15	11	12
Operational Time SO_2 (%)	99.87	96.26	97.04
Operational Time H_2S (%)	97.31	99.14	99.87
Operational Time NO_2 (%)	100	99.71	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 January 1, 2016 to February 28, 2017, AOC has no unaddressed non-compliant events

APPROVALS AND AMENDMENTS

Date	Approval Summary
February 29, 2016	Revised Project level Conservation and Reclamation authorization received (00241331-00-04)
April 15, 2016	10-day Temporary Water Diversion Licence from surface runoff for steam injection use (00380578)
April 19, 2016	Commercial Scheme amendment for Pad L2 Expansion (10935R)
May 16, 2016	1-year Temporary Water Diversion Licence from surface runoff for steam injection use (00381276)
June 16, 2016	5-month Temporary Water Diversion Licence from Pad 5 for steam injection use (00382401)
October 21, 2016	Tier II Water Act Licence amendment to change name from StatOil Hydro Ltd. to StatOil Canada Ltd. (00251282-00-01)
February 1, 2017	Change of ownership from StatOil Canada Ltd. to Athabasca Oil Corporation (all licenses and approvals)

LEISMER MONITORING PROGRAMS

EPEA APPROVAL REPORTS & PROPOSALS SUBMITTED

- Monthly Air Reports
- Soil Management Program Report – January 8, 2016
- Annual Groundwater Monitoring Report CPF – March 7, 2016
- Annual Groundwater Monitoring Report Pad 1 – March 10, 2016
- Annual Conservation and Reclamation Report – March 30, 2016
- Annual Air Report – March 24, 2016
- Annual Industrial Wastewater Report – February 18, 2016
- Annual Industrial Runoff Report – February 18, 2016
- Annual Wetland Monitoring Report – March 24, 2016

WATER ACT REPORTS

- WDL: Monthly and annual water use reporting

REGIONAL WORKING GROUPS AND INITIATIVES

STATOIL PARTICIPATED IN SEVERAL MULTI-STAKEHOLDER REGIONAL INITIATIVES:

- Joint Oil Sands Monitoring (JOSM) / Alberta Environmental Monitoring, Evaluation and Reporting Agency (AEMERA)
- Wood Buffalo Environmental Association (WBEA)
- Regional Industry Caribou Collaboration (RICC)
- Participates on various Canadian Oil Sands Innovation Alliance (COSIA) projects designed to reduce GHG emissions, improve water management and mitigate impacts to terrestrial ecosystems (land and wildlife)

SURFACE

NON-COMPLIANCE EVENTS

ATHABASCA OIL CORPORATION

COMPLIANCE: SUMMARY OF NON-COMPLIANCE

- The following list summarizes non-compliance events for the period of January 2016 to February 2017
- For all events, corrective actions were identified and tracked to completion

Event	Corrective Action
April 2016: Exceeded Action Leakage Rate for CPF Sludge Pond due to temporary operation at high level for maintenance activity	Reduced pond level to below leak point to ensure low leakage rates. Installed online monitoring for leakage between primary and secondary liners and dredged pond to allow for operation at low level
July 9, 2016: Overflow of runoff water from CPF Storm Water Pond and Well Pad 2 containment due to heavy rainfall	Water samples were collected prior to and during the release. Samples met criteria for the release of industrial run-off as per EPEA Approval 00241311-00-04
December 9, 2016: Suspended brackish water pipeline failed	Removed failed piping and soil testing to be completed in Q2 2017

SURFACE

FUTURE PLANS

ATHABASCA OIL CORPORATION

MAJOR ACTIVITIES & TARGET DATES

CPF DEGASSER PROJECT

- Project sanctioned with objective to reduce diluent losses
- Design to be completed in 2017 with start-up target for Q2 2018

PAD L5 INFILL WELLS

- Earthworks and facility construction throughout 2016–2017 with potential start-up Q1 2018

PAD L2 EXPANSION

- Continue the evaluation of Pad L2 expansion

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