PetroChina Canada

2018 Performance Presentation

MacKay River Commercial Project

AER Scheme Approval No. 11715

April 1, 2017 to March 31, 2018

Outline

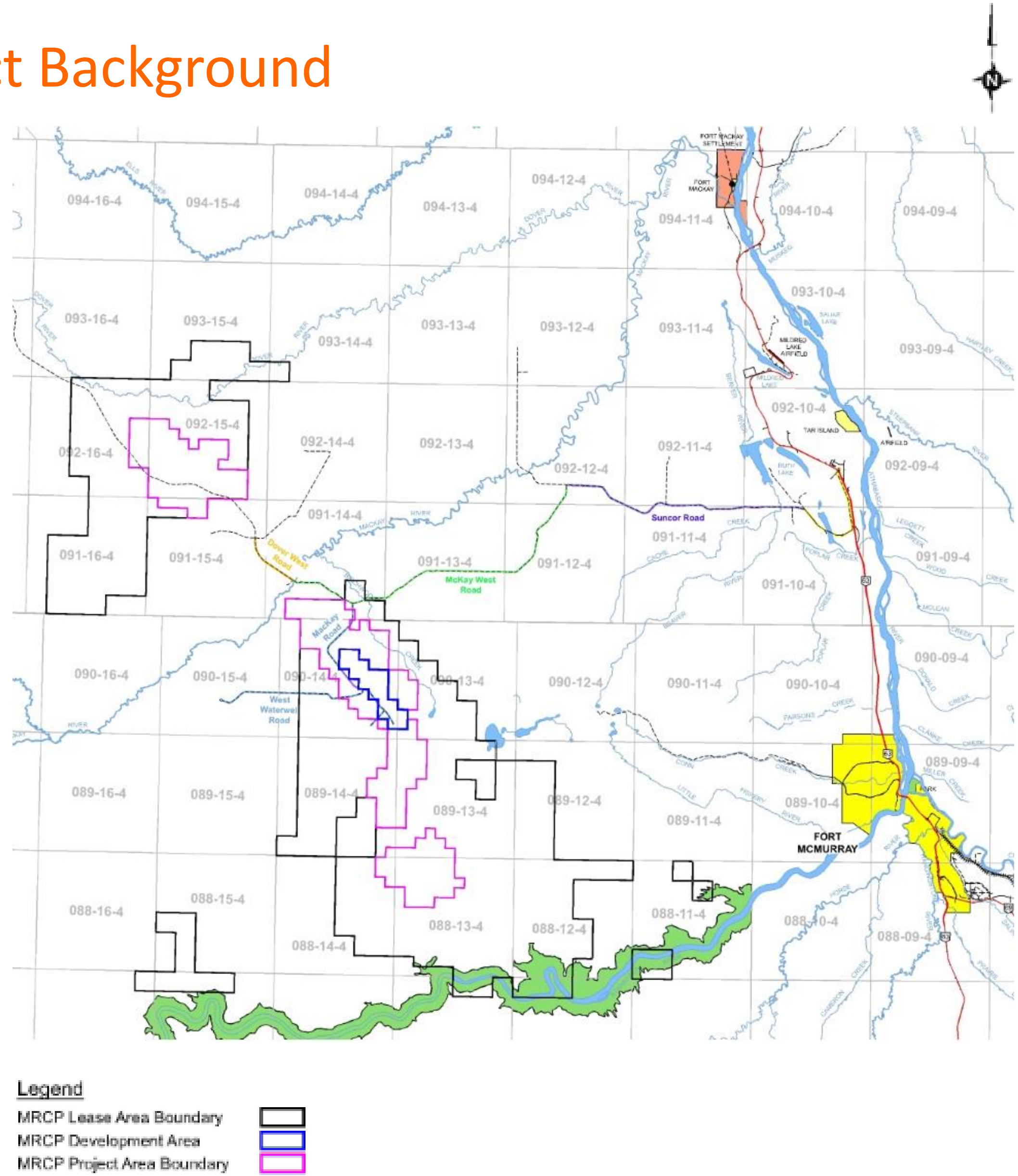
- Introduction: Devin Newman

- 3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery:
  - Rod McLennan, Manager, Reservoir Engineering
  - Brayden Gilewicz, Manager, Production Engineering

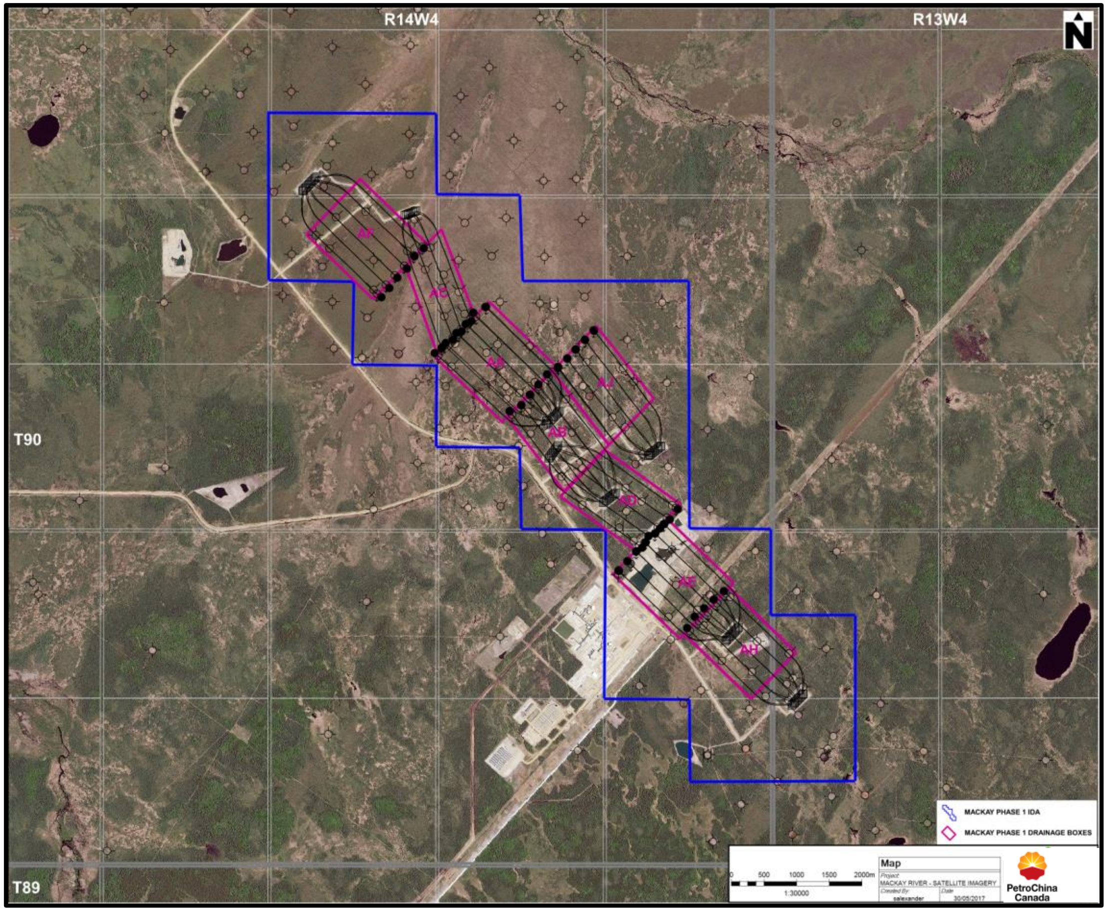
- 3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery:
  - John Yang, Manager, Engineering
  - Devin Newman, Lead, Regulatory Affairs and Surface Land

Project Background

- PetroChina Canada (“PCC”) owns and operates the MacKay River Commercial Project (“MRCP”)
- The MRCP is a bitumen recovery project located within the Regional Municipality of Wood Buffalo (“RMWB”) in northeast Alberta; approximately 30 km northwest of Fort McMurray
- The MRCP utilizes steam-assisted gravity drainage (SAGD) technology
- The MRCP is planned for phased development to peak capacity of 150,000bbl/d bitumen



MRCP Phase 1 Overview



- Phase 1 has a bitumen capacity of 35,000 bpd
- The Phase 1 development area (DA) includes:
    - 8 SAGD surface well pads and associated subsurface drainage patterns
    - 42 SAGD Horizontal well pairs
    - 850m long horizontals
    - 125m well spacing
    - The Central Processing Facility ("CPF")
    - Water source wells and associated pipelines
    - Observation wells
    - Borrow areas
    - Access roads
    - Camps

Directive 078 - Scheme Approval Amendments

Amendments to Scheme Approval No. 11715		
Amendment No.	Purpose	Approval Date
11715A	Drainage patterns AF and AG were combined into a single subsurface drainage pattern (AF)	12-Jun-2012
11715B	Equipment reconciliation and design changes at the MRCP CPF	5-Sep-2013
11715C	Amalgamation of MacKay Operating Corporation and Brion Energy Corporation into a single corporate entity.	15-Sep-2015
11715D	Addition of 17 down-spaced well pairs in four subsurface drainage patterns (AA, AB, AC and AF) and deferral of the development of AI drainage pattern.	9-Nov-2015
NA	Approval to temporarily exceed the maximum operating pressure for 42 well pairs at MRCP.	21-Dec-2016
11715E	FUSE™ polymer fluid dilation process	03-March-2017
11715F	Update for Corporate Name Change from Brion Energy Corporation to PetroChina Canada Ltd.	20-Oct-2017
NA	Approval to temporarily exceed the MOP for well workovers	23-March-2018
11715 (Pending)	Application for the Steam Stimulation Process	TBD
11715 (Pending)	Application to Update the MOP at the MRCP	TBD
11715 (Pending)	Application for Gas Cap Pressurization	TBD

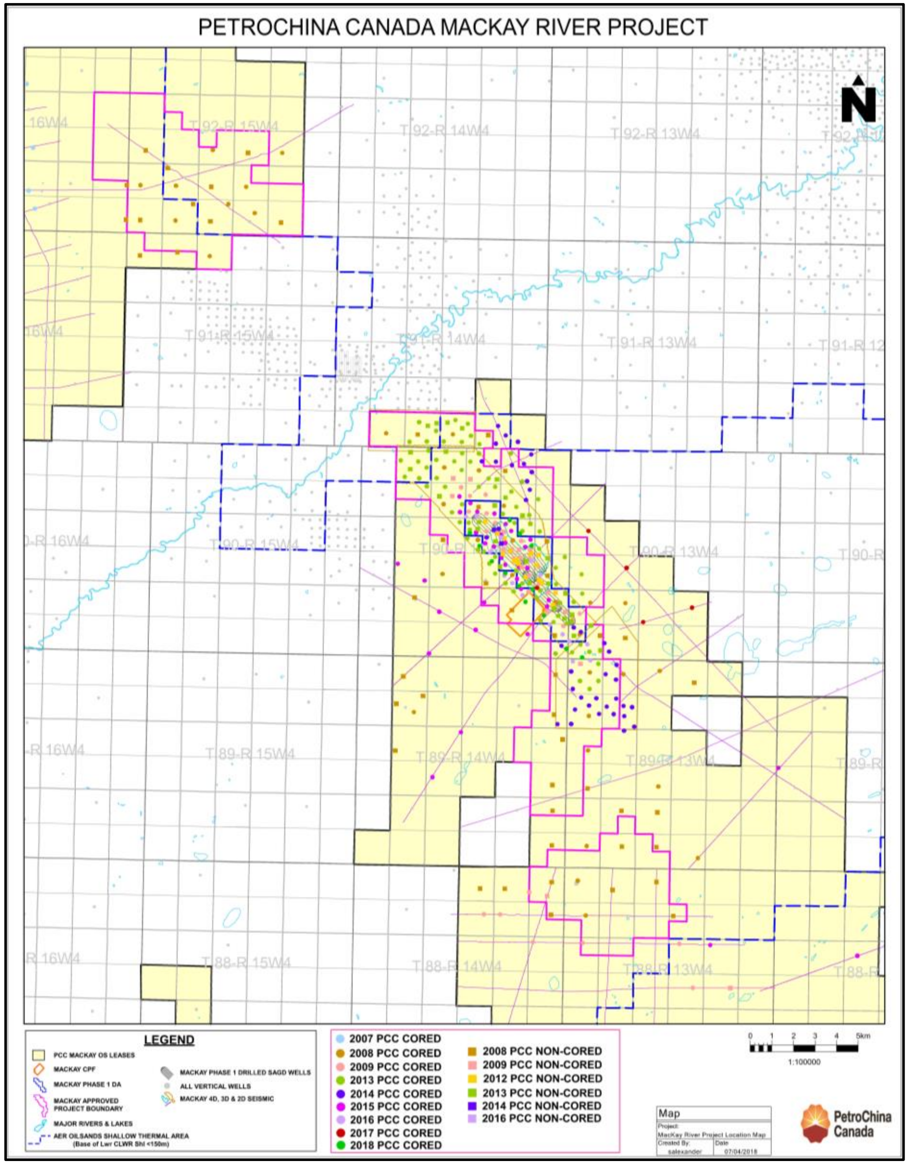
Summary of Activities

- Activities since last Progress Report in June 2017:
    - All 42 well pairs converted from circulation to SAGD mode.
        - First steam to well pairs started in December 2016
        - Last well converted in Oct 2017 – AH02 dilation start up test well.
    - Completed the FUSE^{TM} Dilation test (Fast and Uniform SAGD Start-up Enhancement)
    - Successfully filled Grand Rapids Pipeline and began selling production to market.

3.1.1 SUBSURFACE ISSUES RELATED TO RESOURCE EVALUATION AND RECOVERY

Rod McLennan, Manager, Reservoir Engineering
Brayden Gilewicz, Manager, Production Engineering

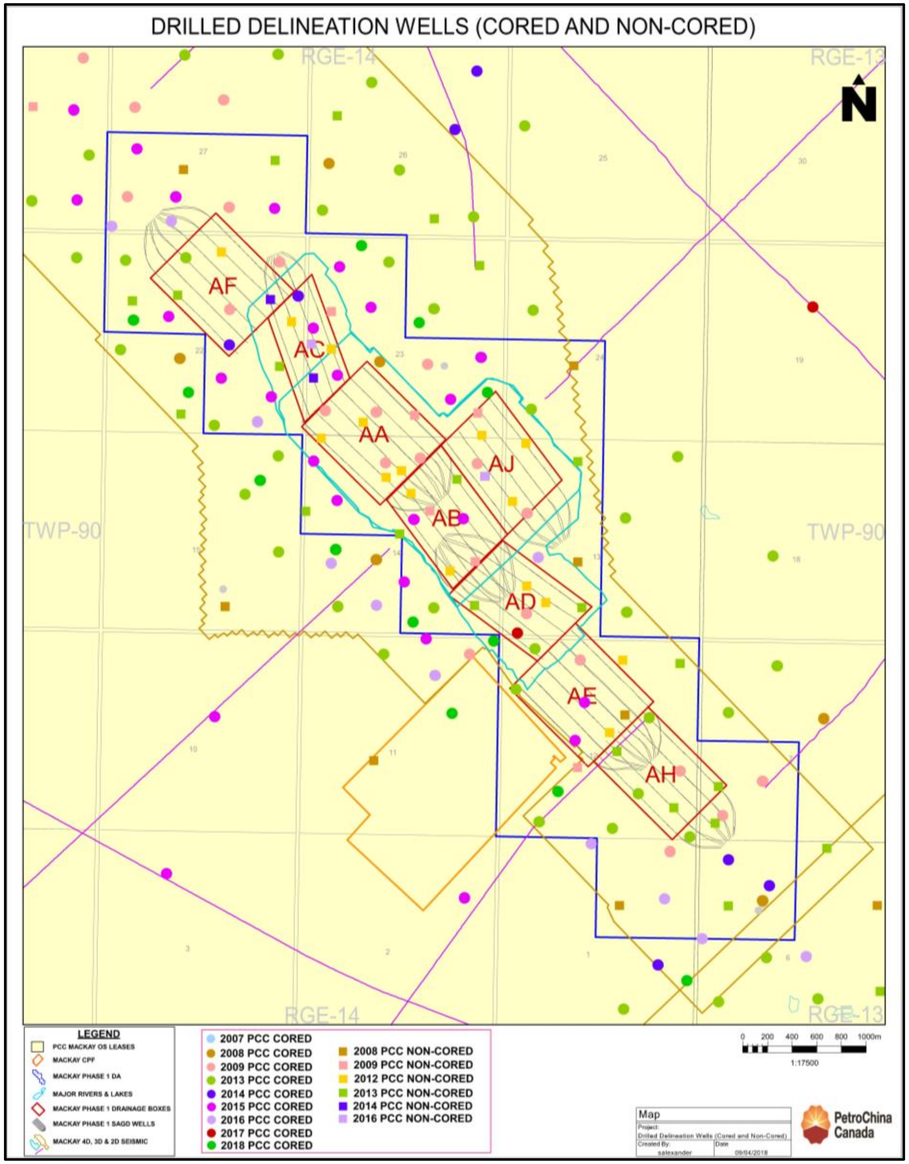
Scheme Approval Area Overview



PetroChina Canada MacKay River								
	MRCP Project Area				MRCP Phase 1 DA			
	Total Wells	Cored Wells	Speciality Logged	Petrographically Analysed	Total Wells	Cored Wells	Speciality Logged	Petrographically Analysed
2013 & Prior	206	119	55	17	76	33	17	11
2014 - 2017	68	64	58	18	33	29	28	15
2018	13	13	13	0	5	5	5	0
TOTAL	**287**	**196**	**126**	**35**	**114**	**67**	**50**	**26**

- 287 total vertical wells in the MRCP Project Area (“PA”)
- 13 vertical wells drilled in the MRCP PA since PCC’s 2017 Annual Performance Presentation

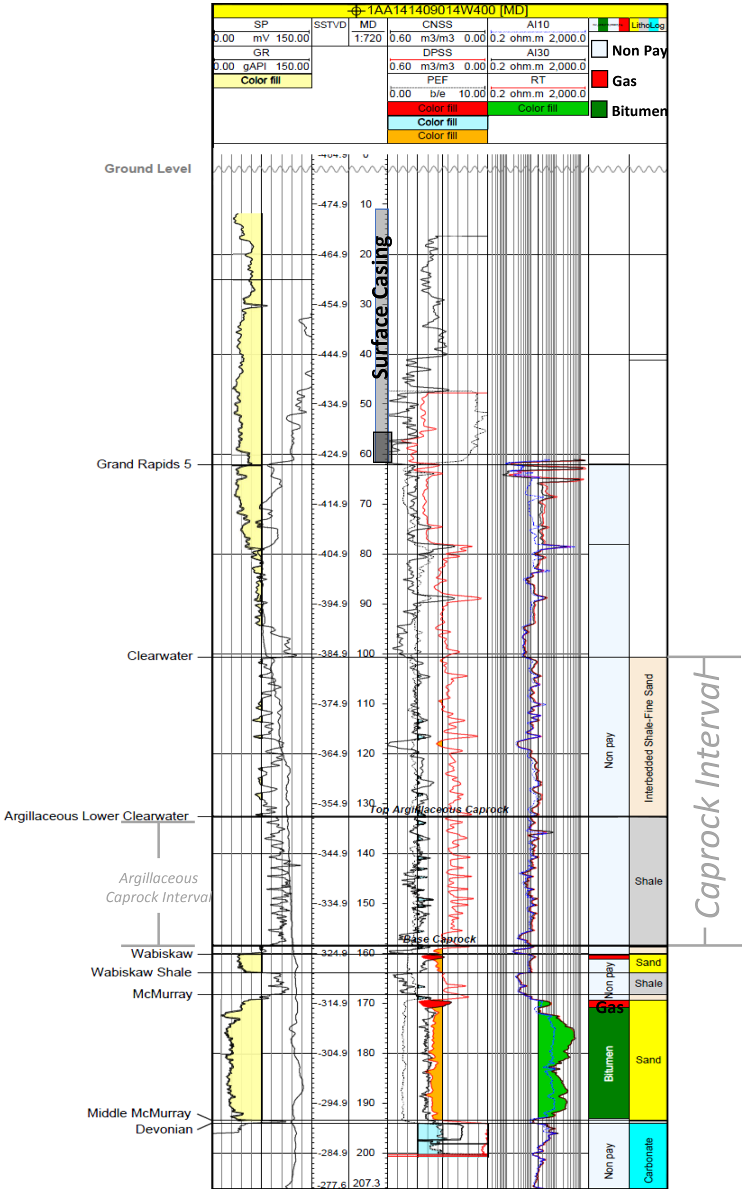
MRCP1 Wells – Vertical & SAGD

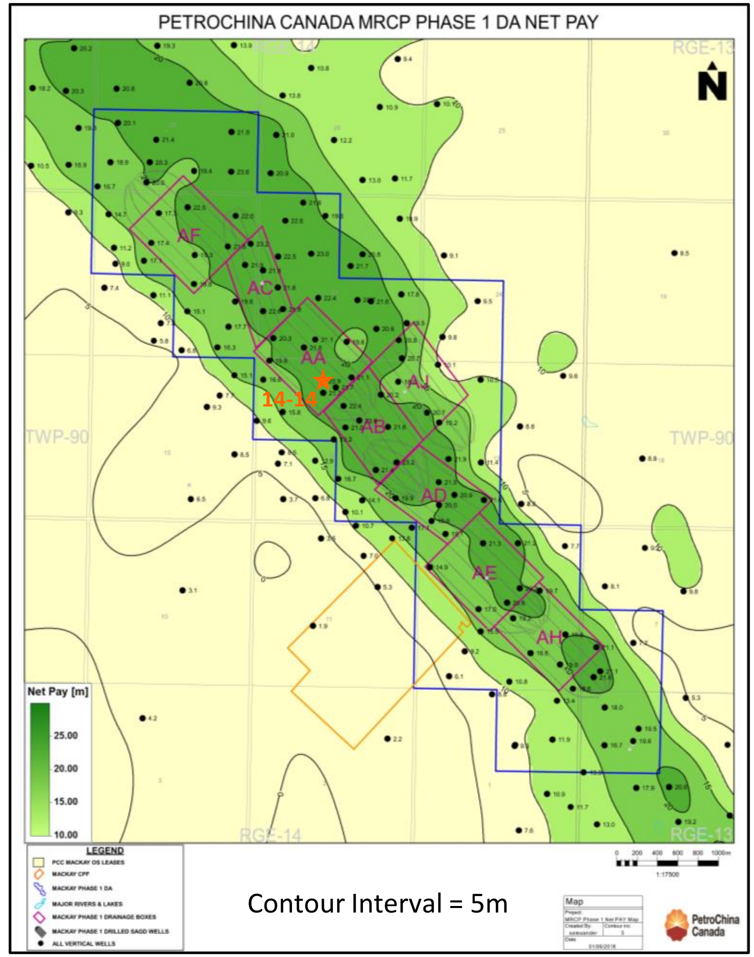


PetroChina Canada MacKay River				
	MRCP Phase 1 DA			
	Total Wells	Cored Wells	Speciality Logged	Petrographically Analysed
2008	7	2	0	1
2009	23	17	11	5
2010	1	1	1	0
2011	0	0	0	0
2012	16	0	0	0
2013	29	13	5	5
2014	6	4	2	3
2015	19	19	18	12
2016	7	5	7	0
2017	1	1	1	0
2018	5	5	5	0
TOTAL	114	67	50	26

- 114 vertical wells in MRCP Development Area ("DA")
- 42 horizontal well pairs in MRCP DA
- 5 vertical wells drilled in MRCP DA since PCC 2017 Annual Performance Presentation

MacKay River Stratigraphy





- Caprock is Argillaceous Lower Clearwater
- Wabiskaw sand above McMurray across DA
- Target reservoir is Upper McMurray

Oil Sands Pay Facies

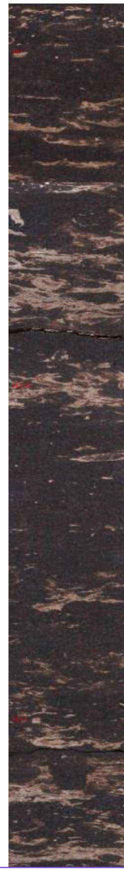
MRCP Upper McMurray Facies

F8b:Bioturbated Heterolithic Sands with Continuous Mud Beds (Core Scale)

15-70% Vsh
over 50cm interval

F8a: Bioturbated Herolithic Sands with Discontinuous Mud Beds

15-30% Vsh
over 50cm interval



F9: Bioturbated Wavy-Bedded Sands

<15% Vsh
over 50cm interval

F10: Ripple Cross-Laminated to Cross-Bedded Sands

<5% Vsh
over 50cm interval

F11: Cross-Bedded Sands

<5% Vsh
over 50cm interval

F12: Bioturbated Hummocky Cross-Stratified Sands (Lam-Scram)

5-15% Vsh
over 50cm interval

F13: Bioturbated Muddy Sands

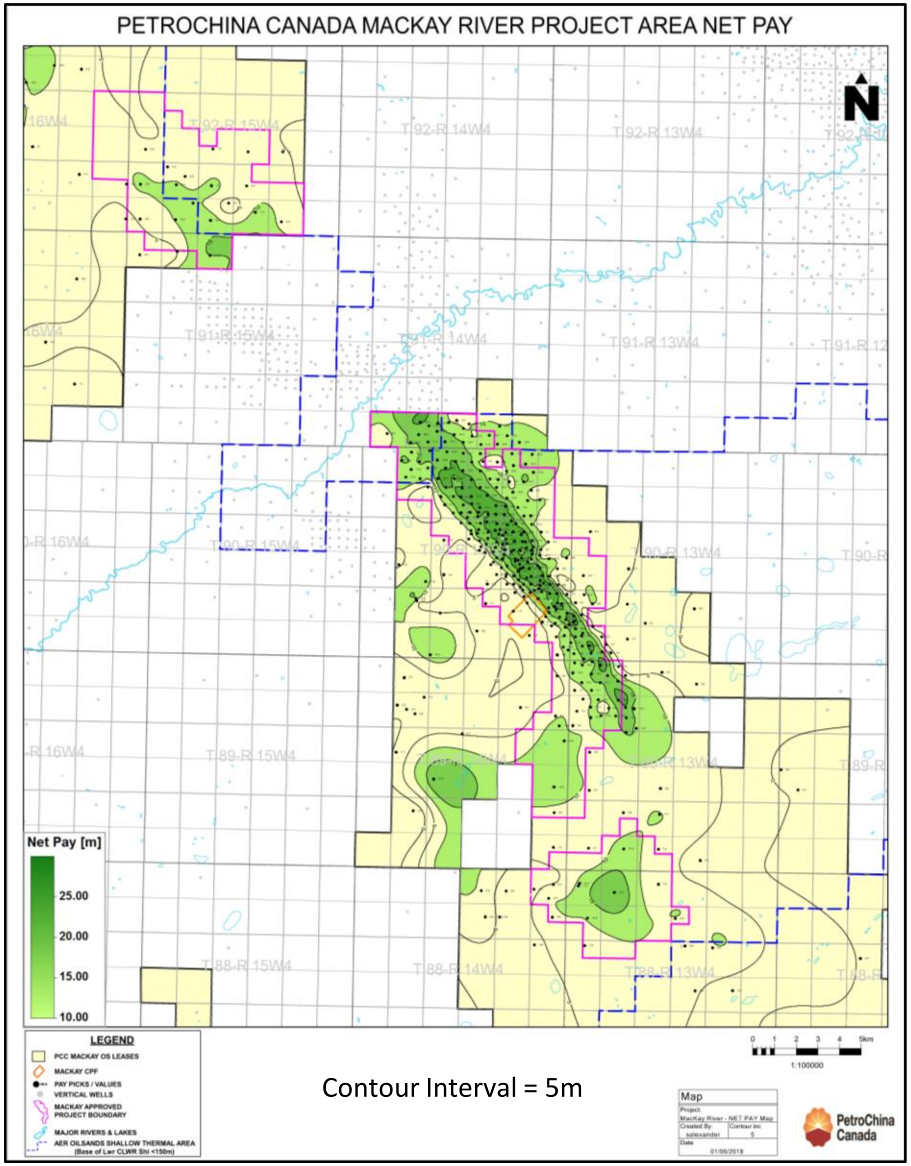
>15% Vsh
over 50cm interval

PAY FACIES

Pay Facies:

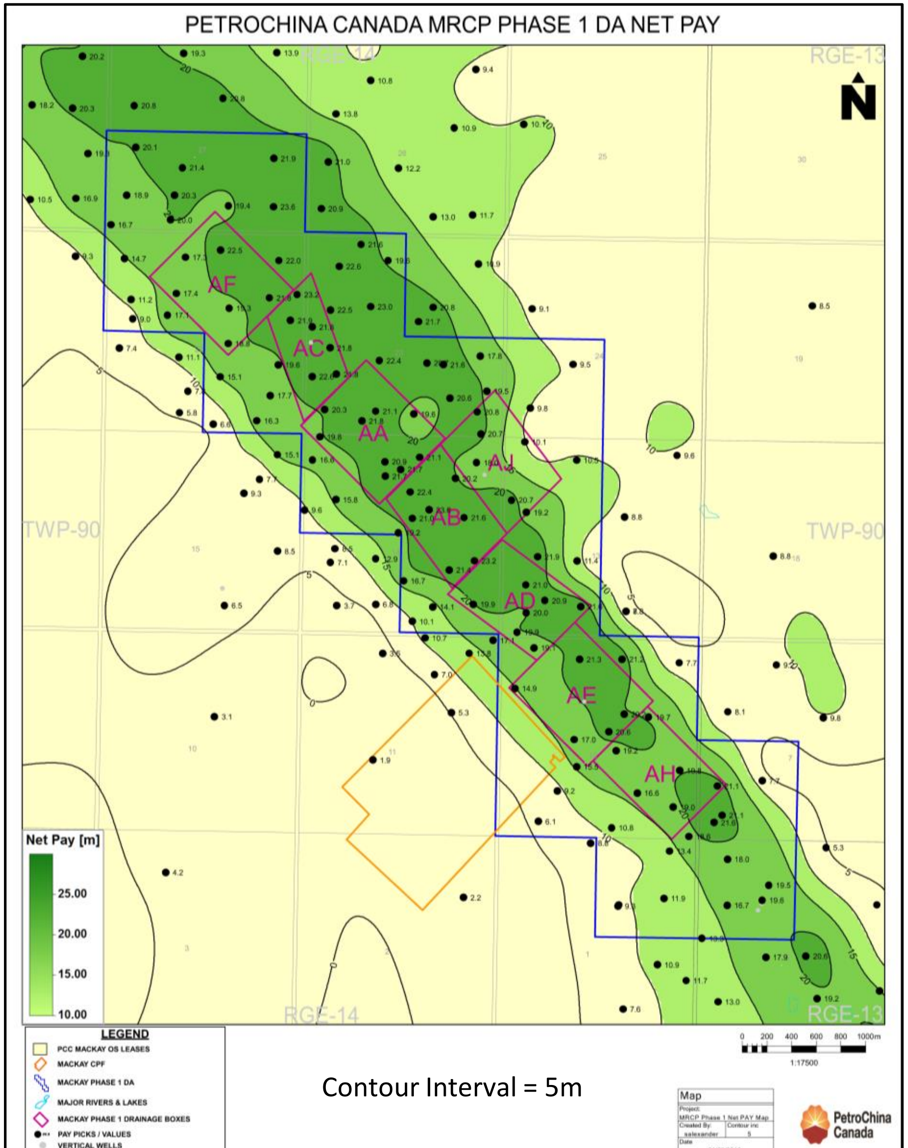
- Includes Facies F8a, F9, F10, F11, F12
- Typically >30% Porosity
- Weight percent bitumen >8%
- Permeability ~0.9-2.7 Darcy's

Bitumen Net Pay Map – Project Area



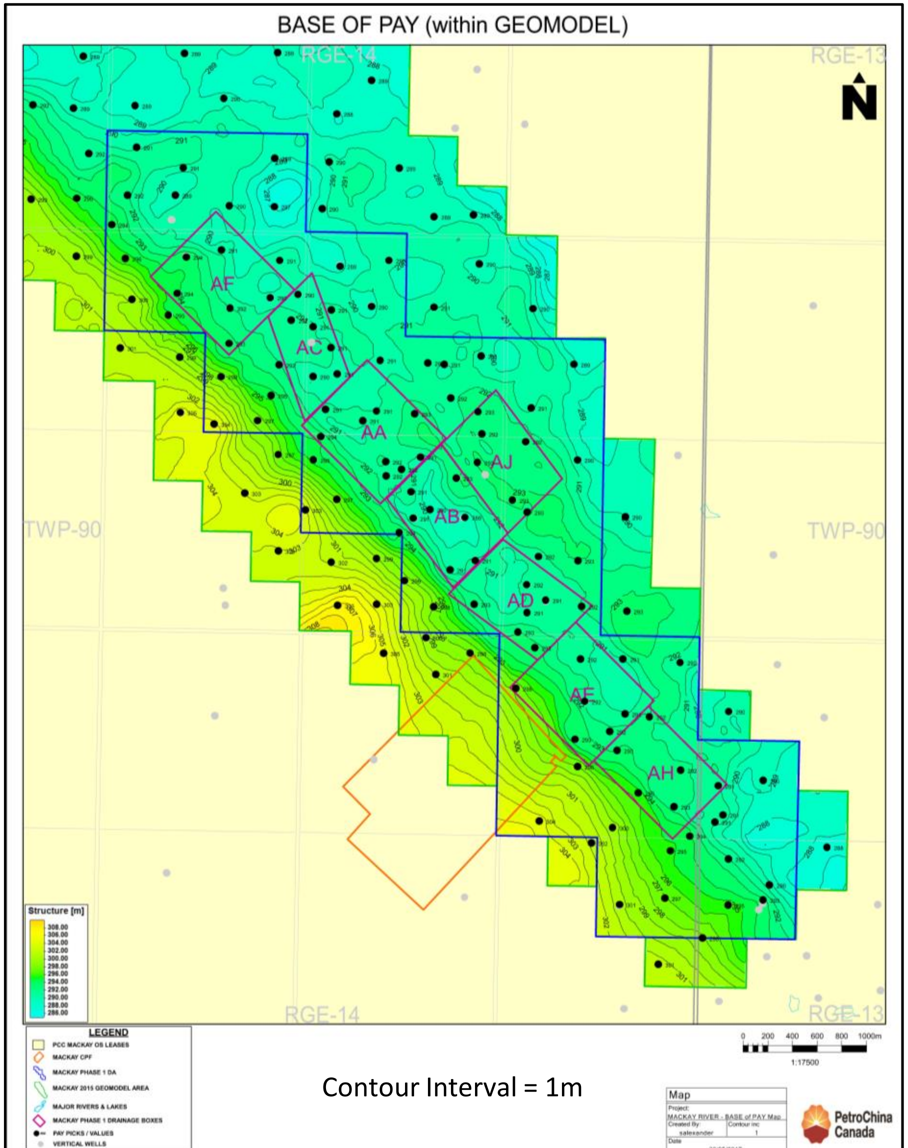
- Net pay cut-off at ≥10m
- Thickness ranges from 10-25m in the DA
- Upper McMurray reservoir shows strong NW-SE trend
- DA lies 2km South of AER Oil Sands Shallow Thermal Area

Bitumen Net Pay Map – Development Area



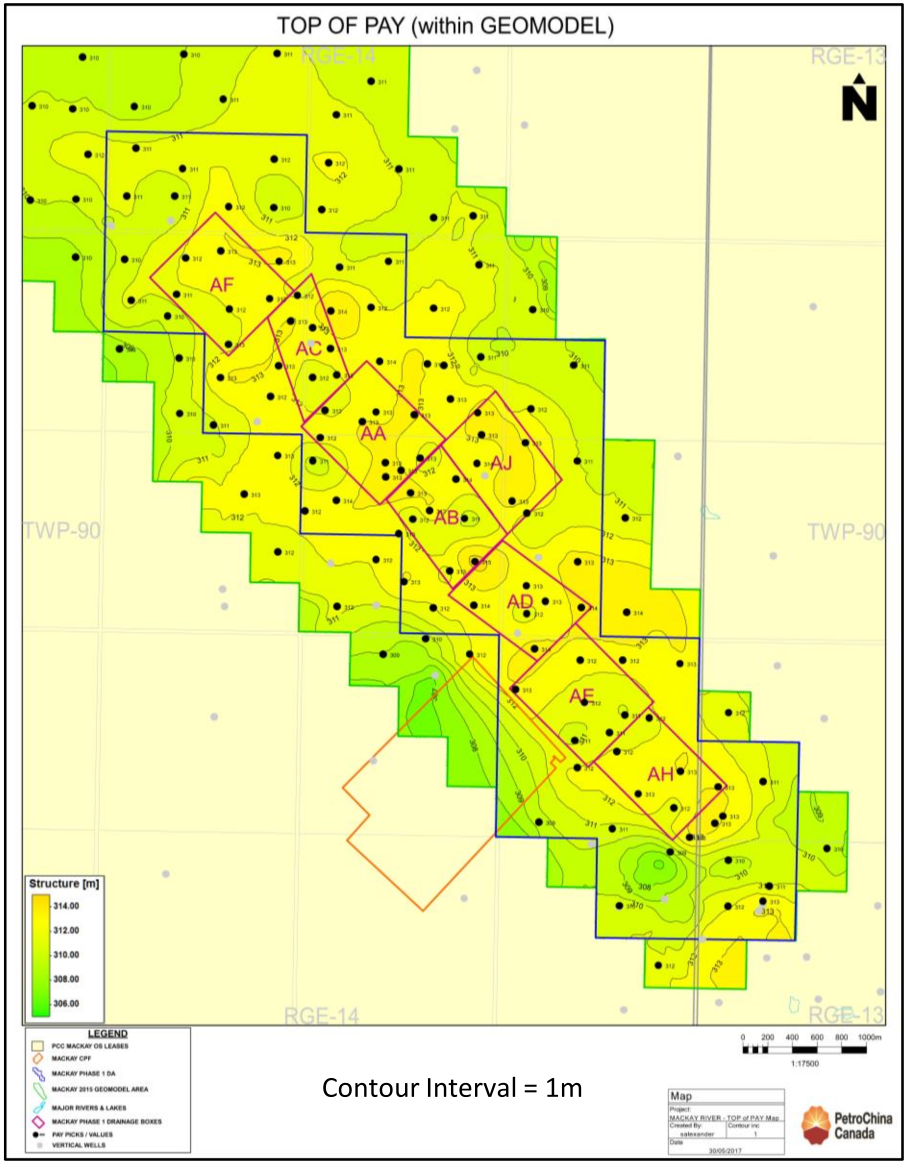
- Net pay cut-off at ≥10m
- Thickness ranges from 10-25m in the DA
- Upper McMurray reservoir shows strong NW-SE trend
- Central processing facility located Southwest of development area
- Majority of 8 drainage boxes are in >15m bitumen pay

Base of Pay Structure Map



- Base of pay is reasonably flat across existing 8 drainage boxes
- Base of pay elevation rises on Southwest side of DA

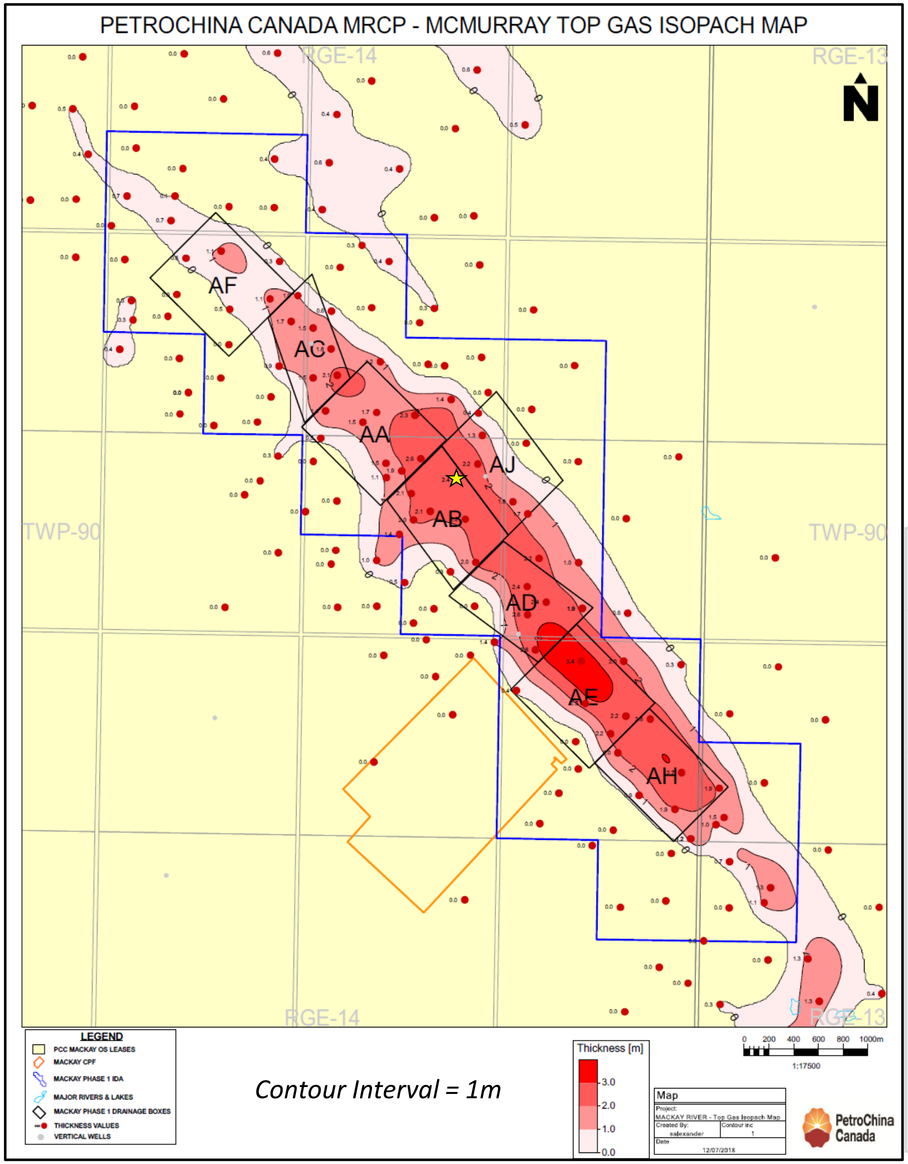
Top of Pay Structure Map



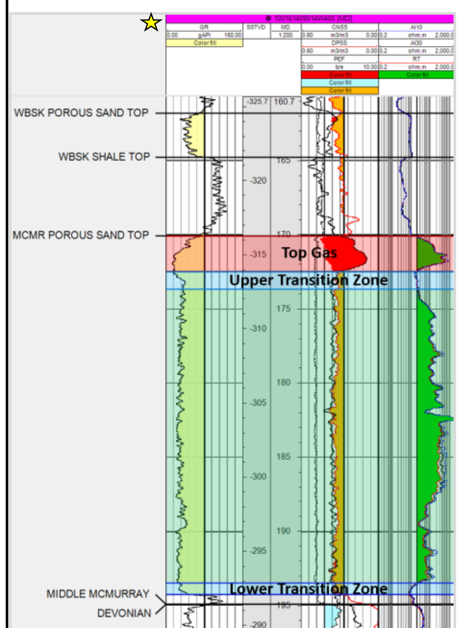
- Top of Pay is relatively consistent over the 8 drainage boxes in the DA

- The Top of Pay fluctuates only ~6m between 308-314m SS across the entire DA

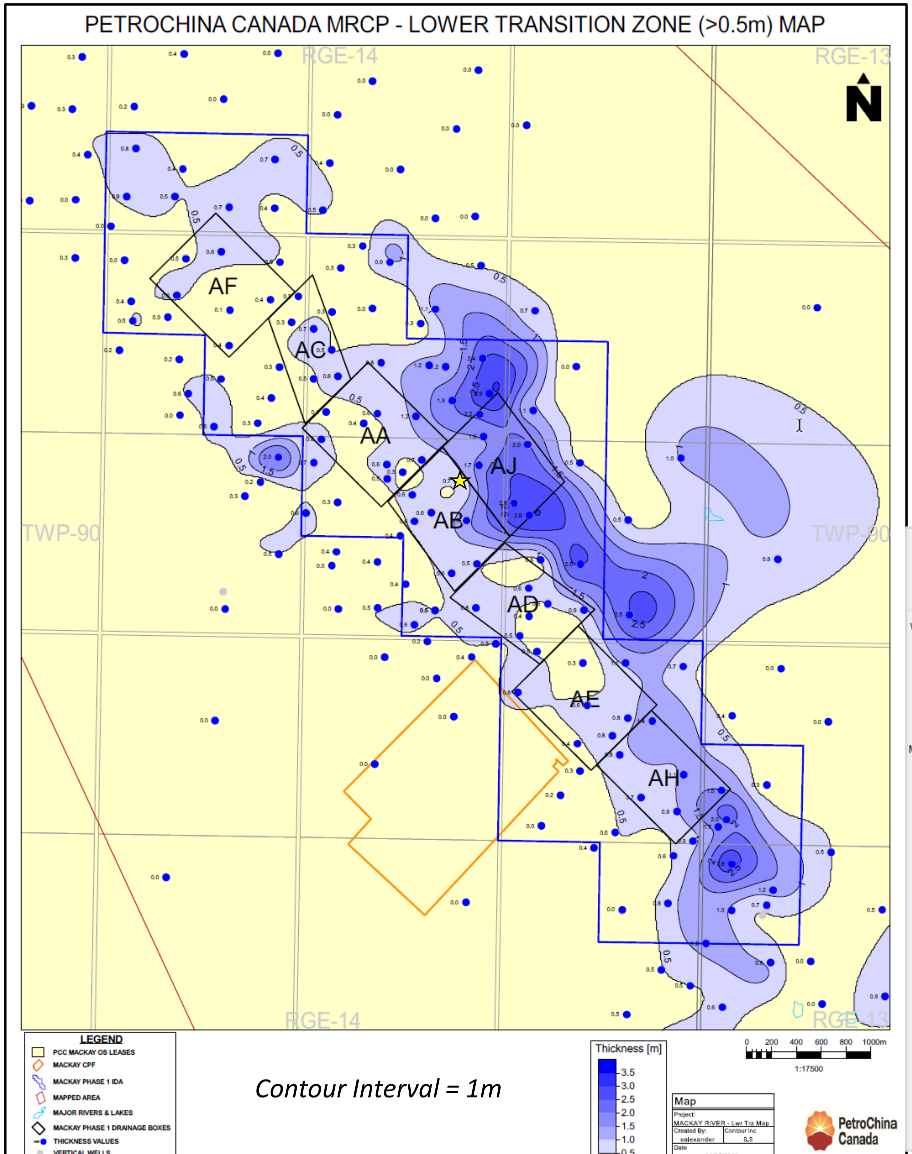
MCMR Top Gas Isopach Map



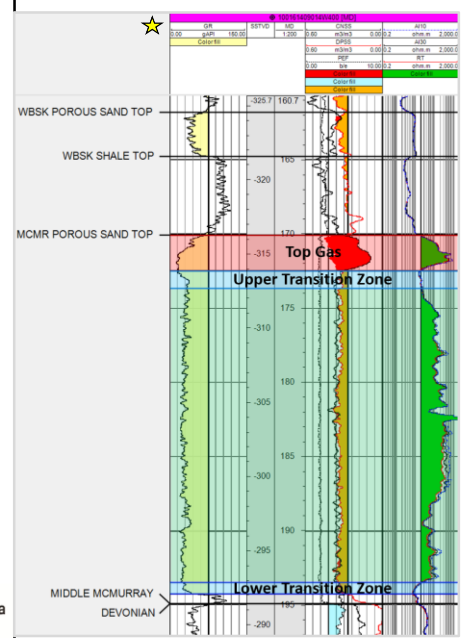
- Top gas zone present in the upper McMurray over the IDA
- Ranges in thickness from approximately 0 to 3 meters



Lower Transition Zone Map

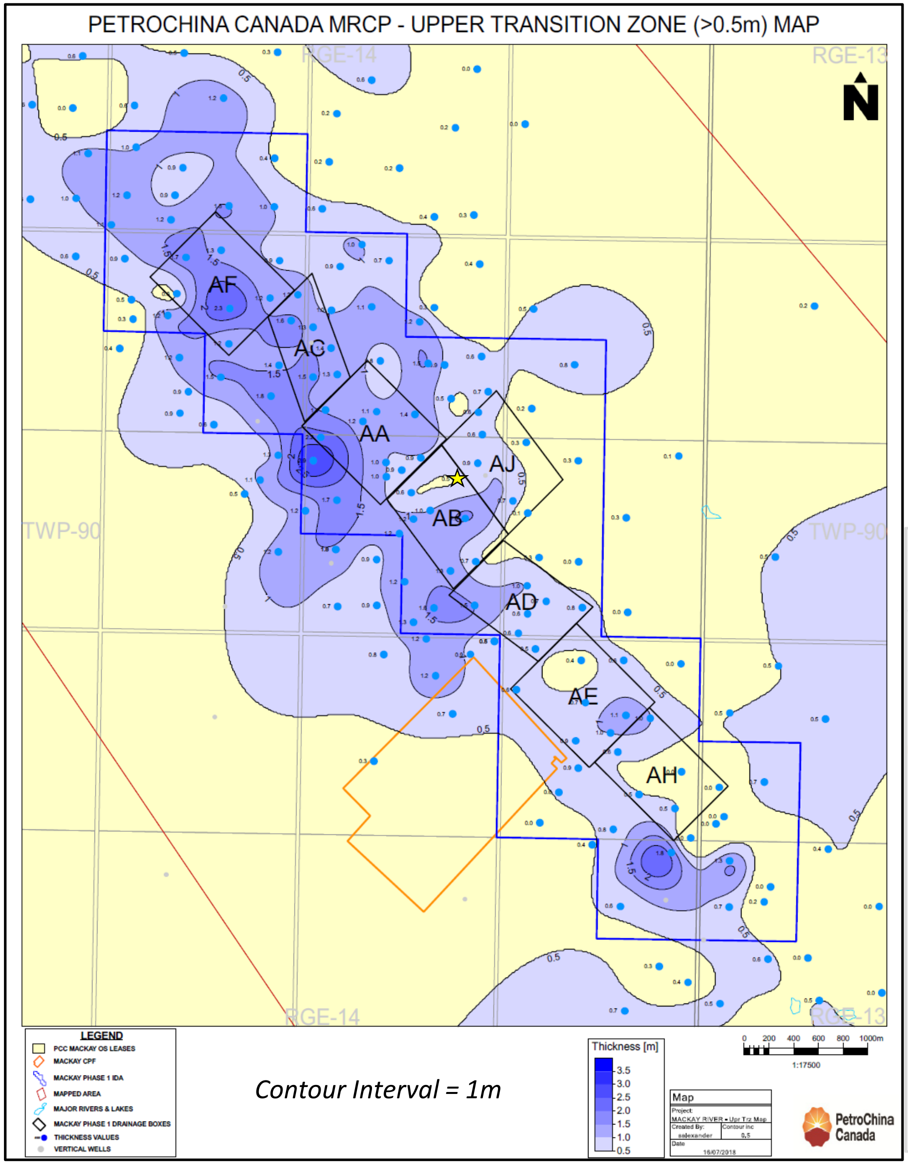


- Criteria:
  - Porous & clean sandy facies with >50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies)
  - In communication with and below pay zone
- Characteristics:
  - Thin: <1.0m over most of the Phase 1 drainage boxes
  - Limited Lateral Extent

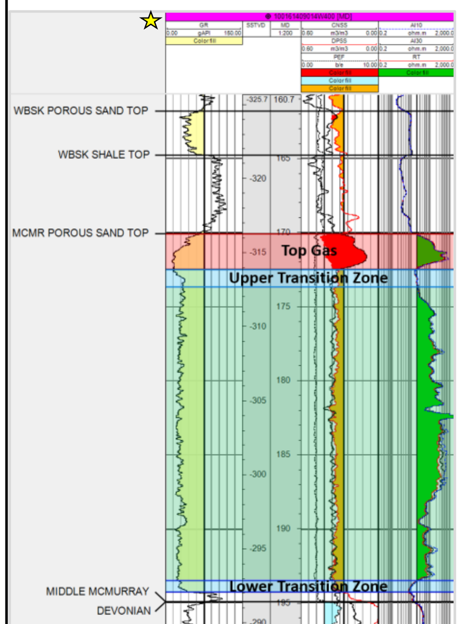


Lower Transition Zone Properties	
Parameter	**Average**
Total Water Saturation	70%
Total Porosity	33%
Horizontal Permeability (Core)	3300 mD
Vertical Permeability (Core)	2400 mD

Upper Transition Zone Map

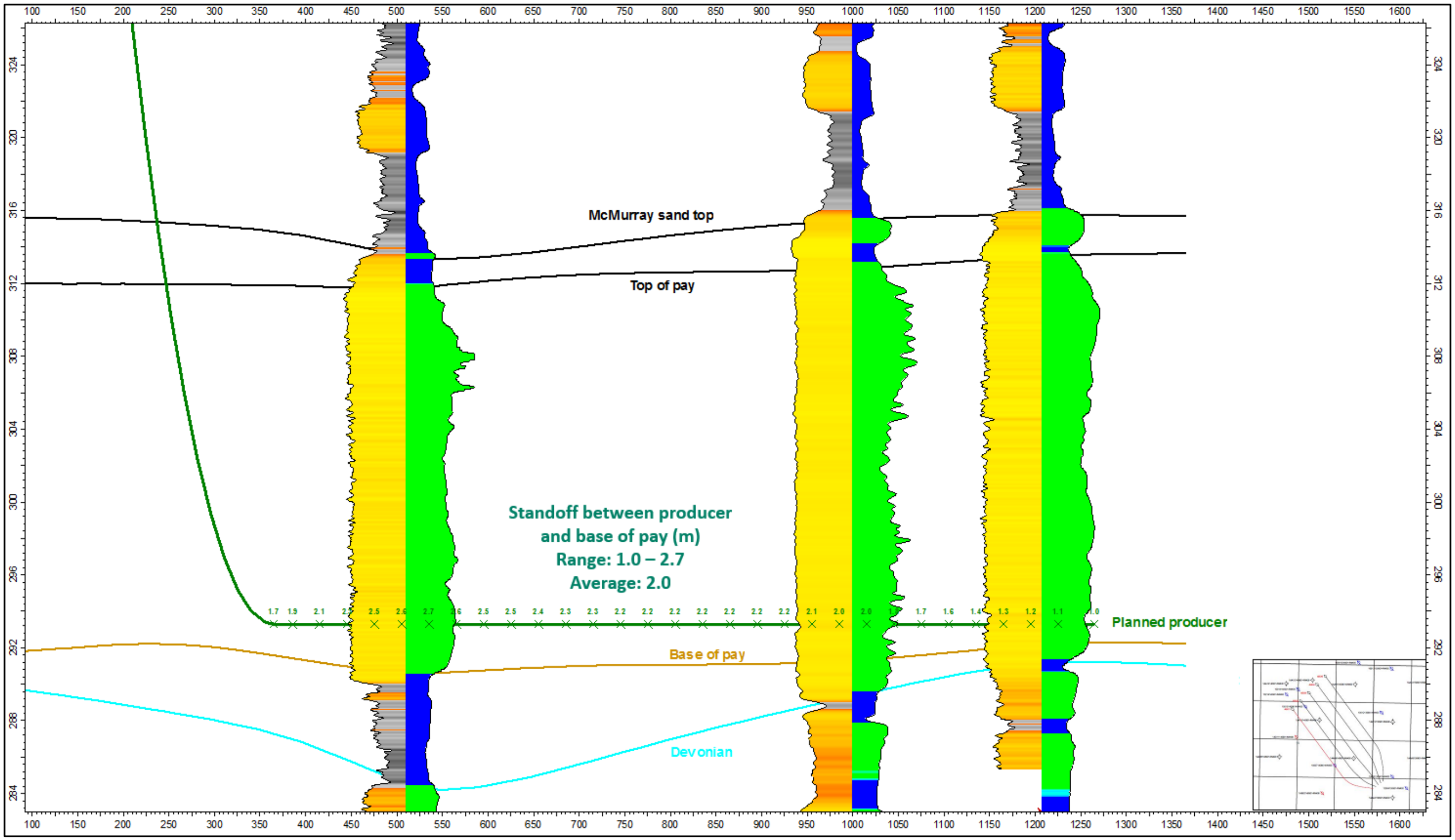


- Criteria:
  - Porous & clean sandy facies with >50% water saturation (GR ≤ 75API, DPSS≥27%, RT<20ohmm, sandy facies)
  - In communication with and above pay zone
- Characteristics:
  - Thin: <1.5m over most of the Phase 1 drainage boxes
  - Limited Lateral Extent



Horizontal Well Placement Criteria (2012-2014)

- The base of pay (BOP) cutoff is less than 50% bitumen saturation
- Producer wells are planned to be 1m above the highest point of the BOP along the producer horizontal section
- While drilling, producer well should stay a minimum of 1m away from any bottom water interval (Lower transition zone)
- Standard producer/injector separation is to be 5m with a min of 4.5m and max of 5.5m



Geologic and Reservoir Properties – OBIP FOR OPERATING AREA

Drainage Box	# Well Pairs	Drainage Box Area (m^2)	Average S_o (frac)	Average Φ (frac)	Average K_h (D)	Average K_v (D)	Average Bitumen Pay Thickness (m)	Drainage Box OBIP (10^6 bbl)	Estimated RF (%)*	Estimated Drainage Box RBIP (10^6 bbl)*
AA	6	698,200	0.83	0.34	2.7	1.1	21.3	26.4	54	14.3
AB	5	562,600	0.8	0.34	2.7	1.1	22.6	21.8	57	12.4
AC	4	418,700	0.85	0.34	2.6	1	21.9	16.7	63	10.5
AD	5	560,100	0.77	0.33	2.6	1	20.8	18.6	54	10.1
AE	6	674,700	0.76	0.33	2.2	0.9	20.8	22.1	53	11.7
AF	6	675,400	0.82	0.34	2.6	1	22	26.1	62	16.2
AH	5	594,300	0.77	0.34	2.6	1	20.4	20	48	9.6
AJ	5	562,300	0.75	0.34	2.5	0.9	20.5	18.5	57	10.5
Total	*42*	*4,746,300*	*0.79*	*0.34*	*2.6*	*1*	*21.3*	*170.2*	*56*	*11.9*

OBIP = Original Bitumen In-Place and measured in $10^6 m^3$ units and converted to 10^6 barrels using conversion factor of 6.2898

NRV = Net Rock Volume in $10^6 m^3$ derived from deterministic mapping of SAGDable net pay, or from geomodel calculations

SO = Average bitumen saturation from the SAGD exploitable reservoir interval generated from 1-SWT (in fractions)

PORT = Average porosity from the SAGD exploitable reservoir interval generated from PORT (in fractions)

$$OBIP = (NRV \times PORT \times SO)$$

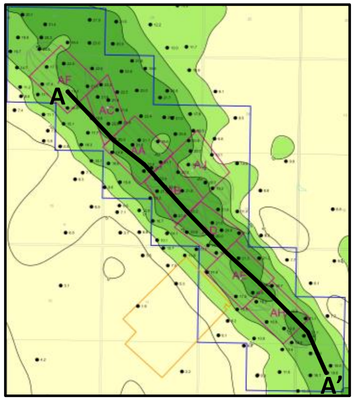
Geologic and Reservoir Properties – OBIP

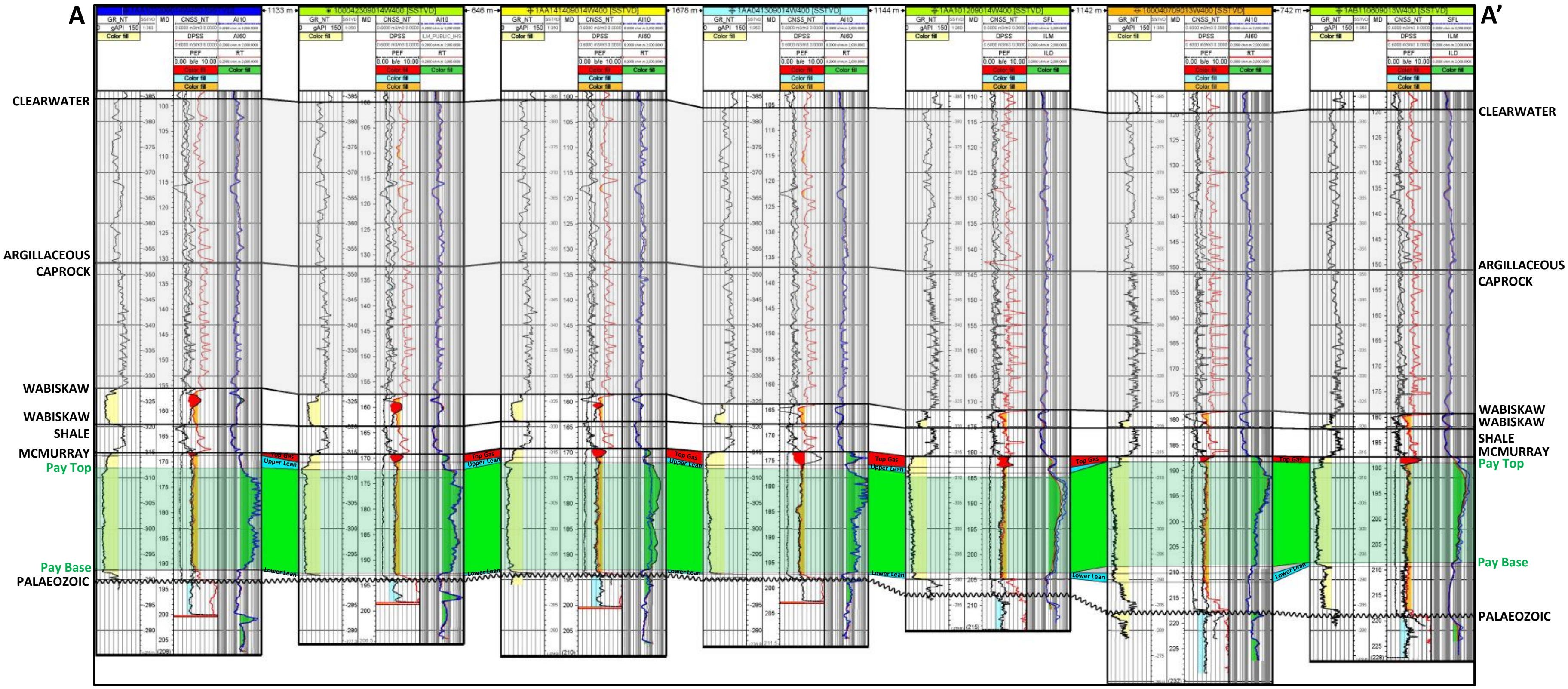
Parameters	Development Area	Project Area
Top of Reservoir Depth (mTVD)	176	175
Top of Reservoir Depth (TVD masl)	315	311
Base of Reservoir Depth (mTVD)	197	193
Base of Reservoir Depth (TVD masl)	294	293
Net Pay Thickness (m)	21.3	12.8
Porosity (frac)	0.34	0.33
Bitumen Saturation (frac)	0.79	0.75
OBIP (10^6 bbl)	170.2	2890.8
OBIP (10^6 m^3)	27.1	459.6
Initial Pressure (kPaa)	220 (top) – 400 (bottom)	220 (top) – 400 (bottom)*
Original Reservoir Temperature (^oC)	6	6*

** Extrapolated from operating area*

Structural Cross-Section across MRCP

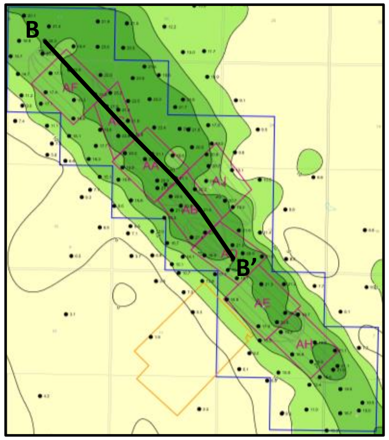
- Good reservoir quality with continuity along Development Area
- Minor structural variation at base of pay
- Thick and laterally continuous caprock with consistent lithology

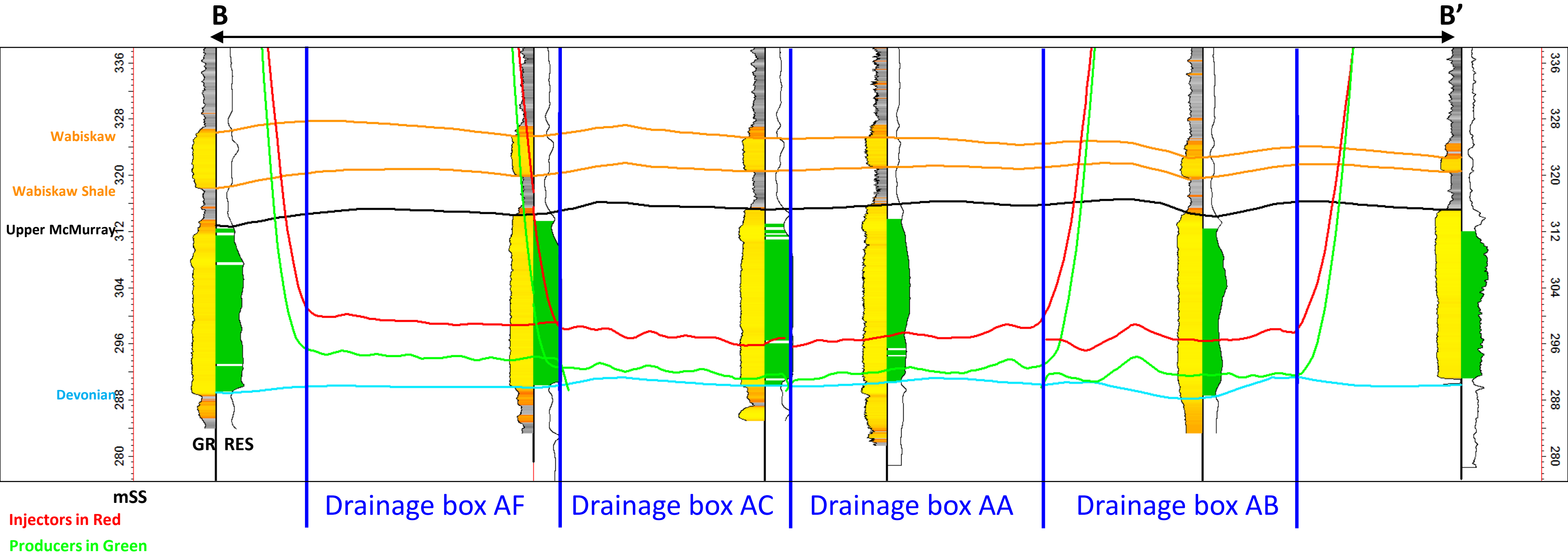




NW–SE Structural Cross-Section: Drainage boxes: AF, AC, AA, AB

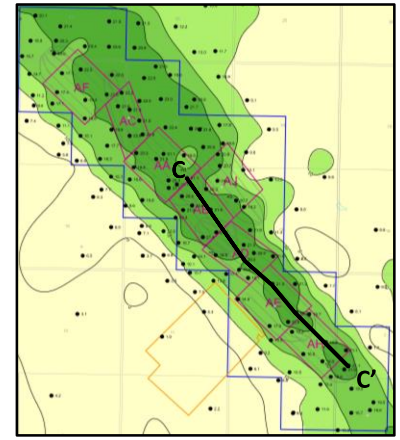
- Clean and consistent reservoir thickness over the 4 drainage boxes
- Bitumen thickness ranges from 15 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer

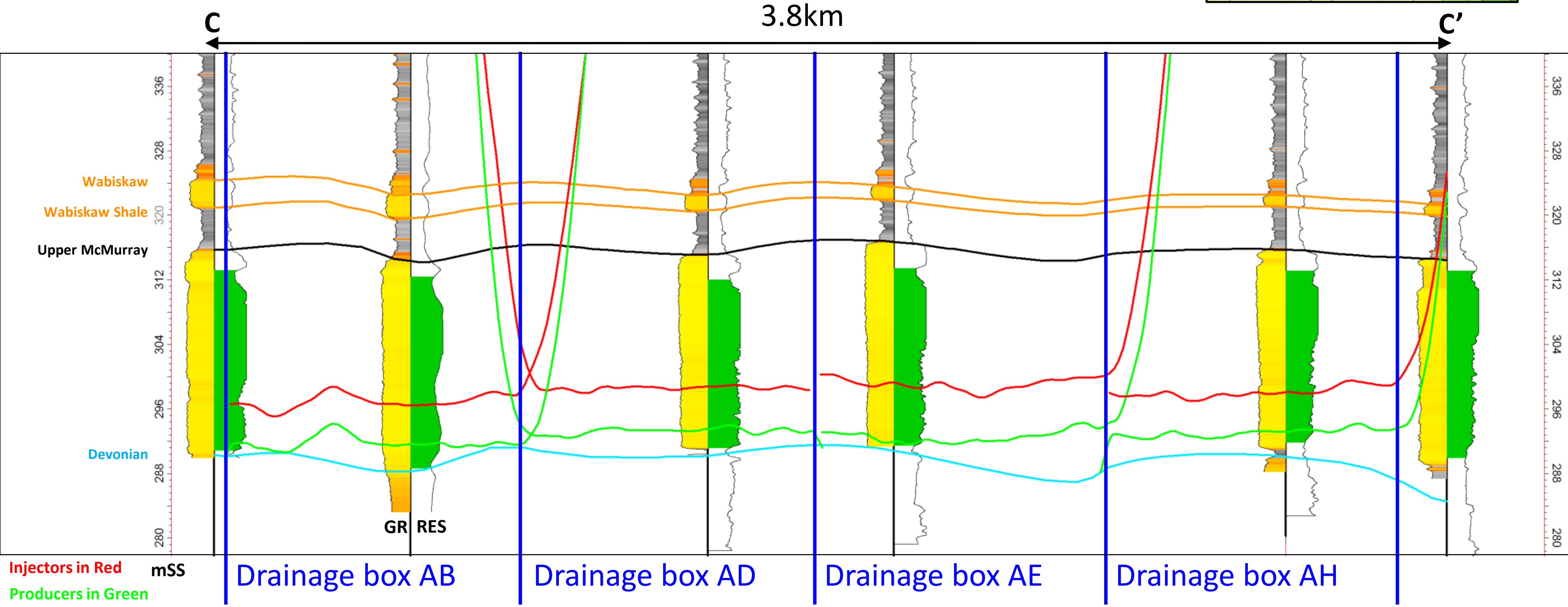




NW–SE Structural Cross-Section: Drainage boxes: AB, AD, AE, AH

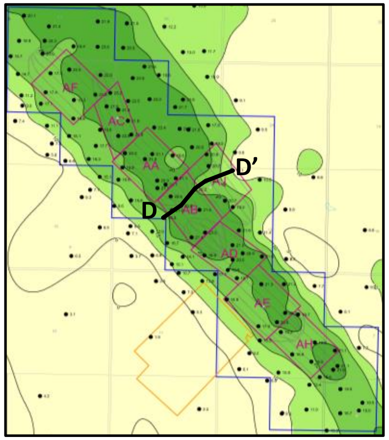
- Clean and consistent reservoir thickness over the 4 drainage boxes
- Bitumen thickness ranges from 15 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer

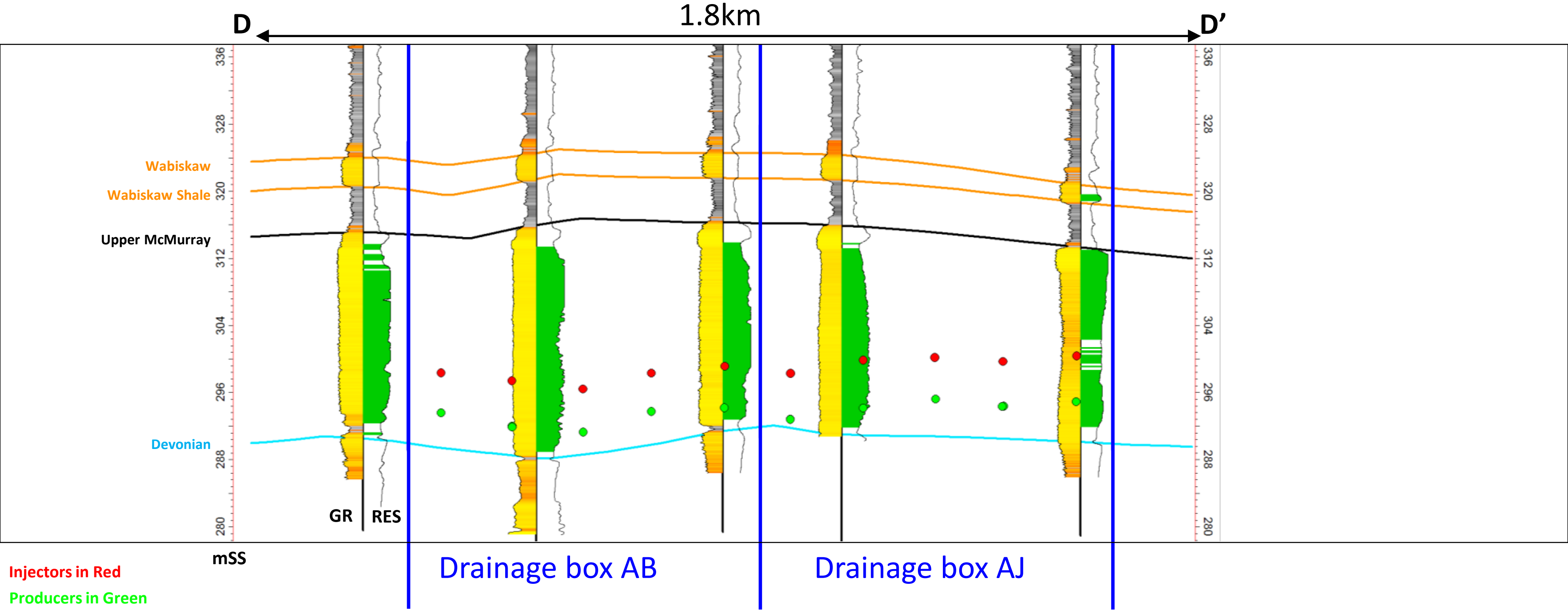




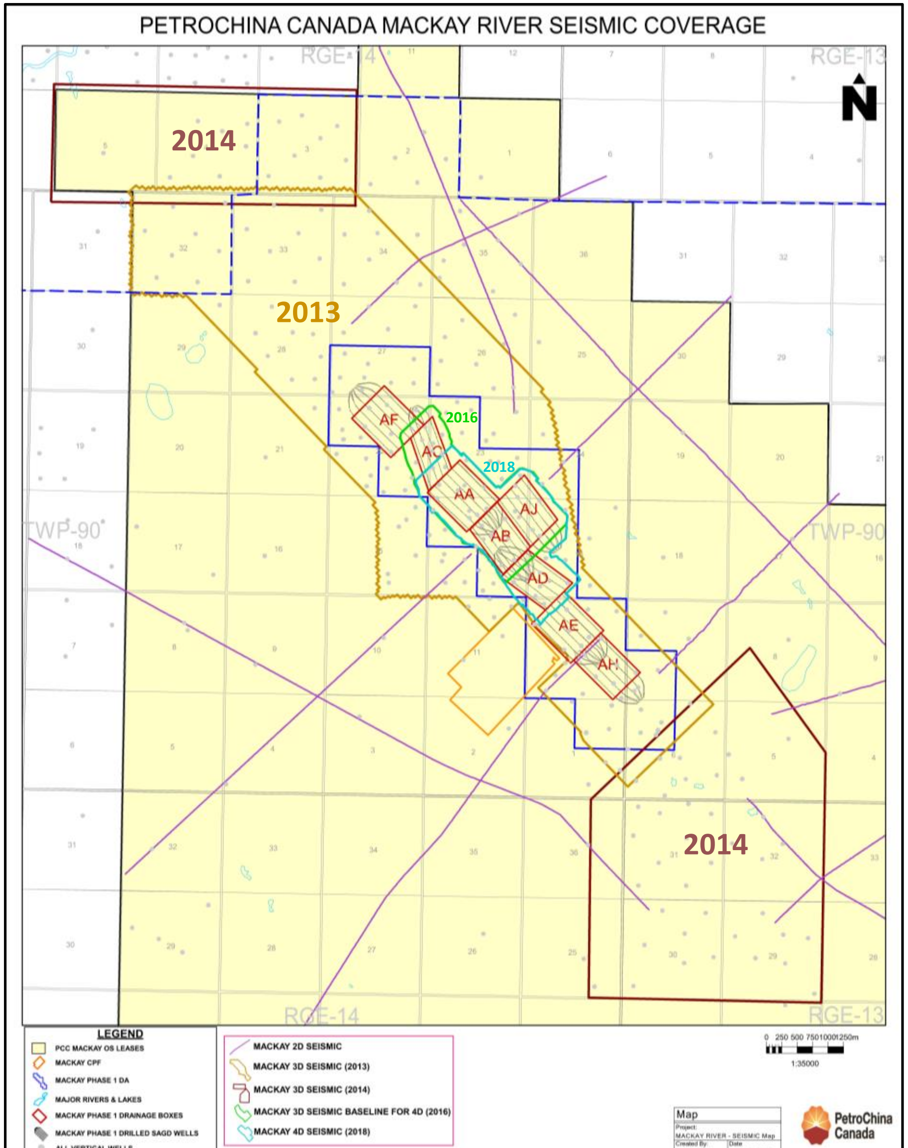
W–E Structural Cross-Section: Drainage boxes: AB, AJ

- Bitumen thickness ranges from 10 to 20+m
- Producer wells placed 1m from base of pay
- Injector wells placed 5m above producer





MRCP Seismic



Coverage Across MRCP includes:

- ~96 km of 2D
- ~58.4 km^2 of 3D
- ~3.9 km^2 of 3D baseline for 4D
- ~3.5 km^2 of 4D in 2018

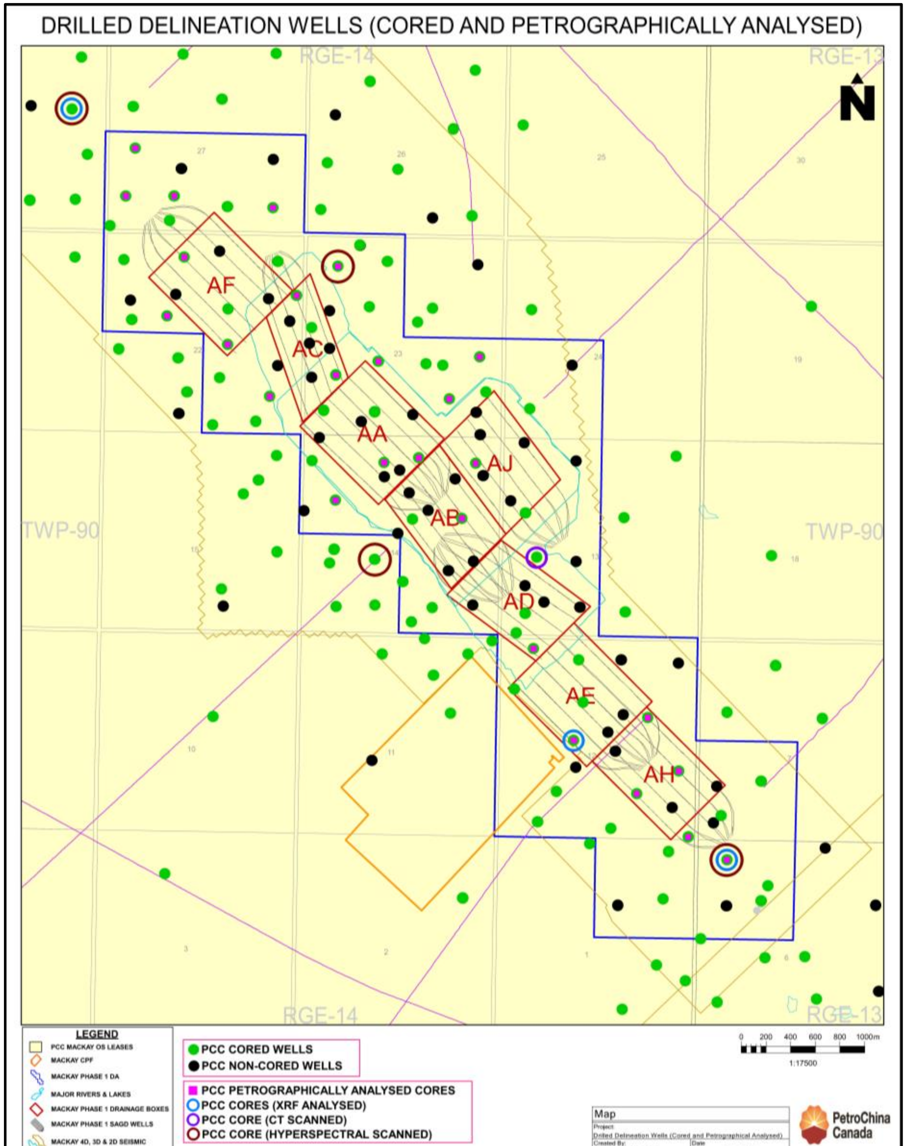
3D acquired in MRCP to help:

- Assess Caprock
- Plan/drill horizontal well trajectories
- Assess McMurray reservoir

4D seismic survey acquired at MRCP in 2018

- Will monitor steam chamber growth in DA
- 3D baseline for 4D was shot in 2013 and 2016

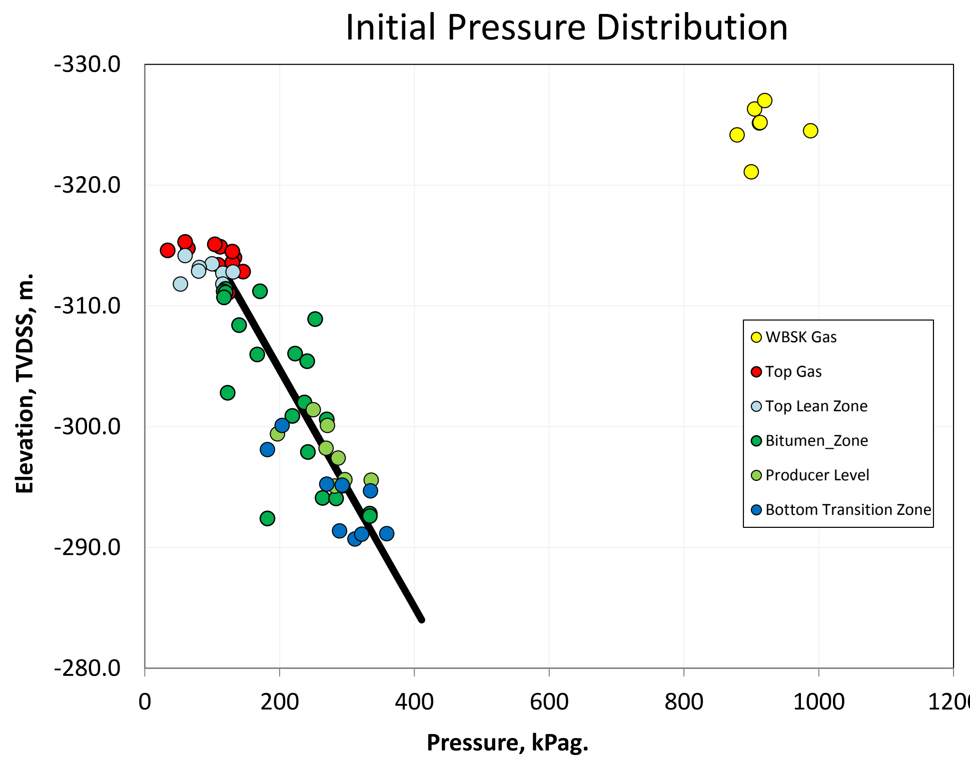
Special Core Analysis – Petrographic Analysis



- PCC has conducted a combination of different studies on 26 cored wells in the initial Development Area.
- Studies done on highlighted wells include:
  - CT Scan - 1
  - XRF - 3
  - SEM - 17
  - XRD - 26
  - Thin sections - 24
  - Grain size analysis – 24
  - Hyperspectral Imaged – 4

Reservoir Pressure Update

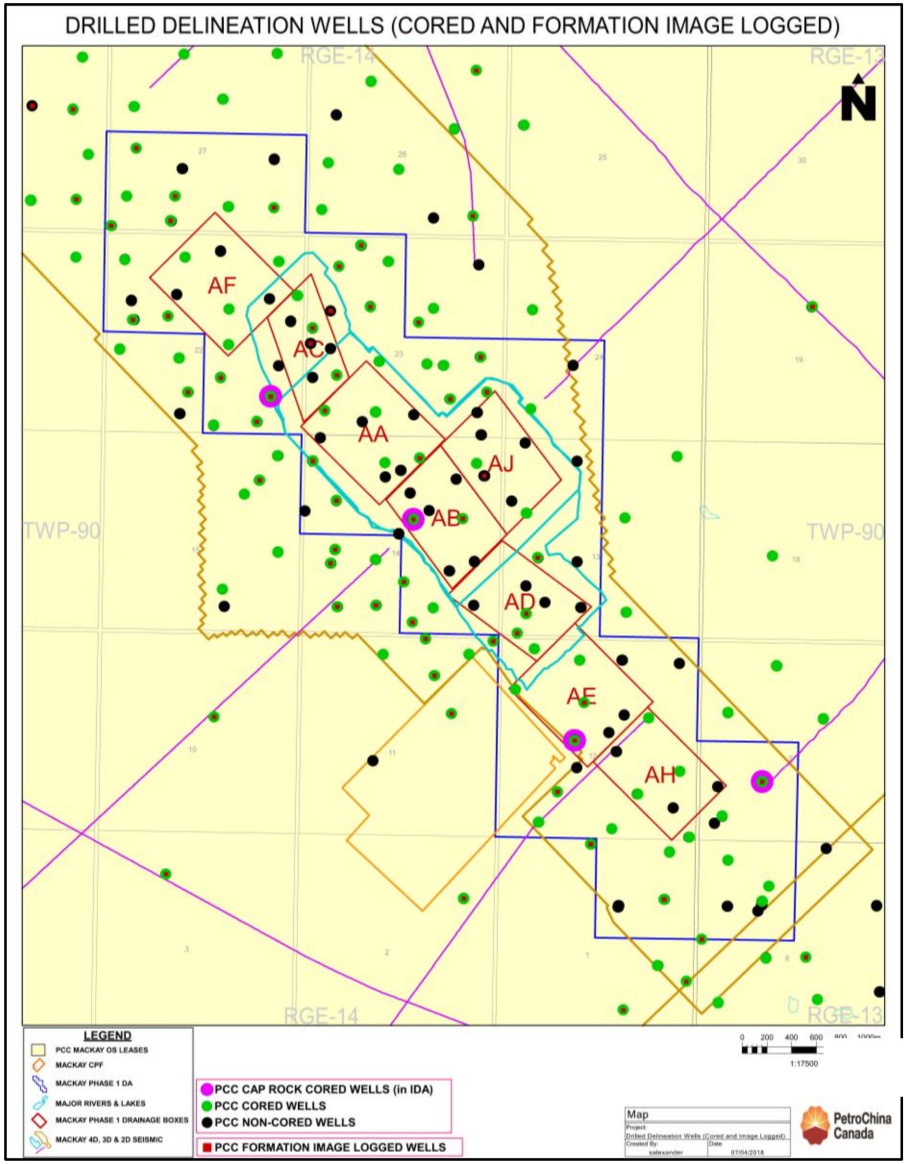
- The McMurray Formation was initially at low pressure:
  - Initial pressure of 100 – 200 kPag at the top of reservoir
  - Initial pressure of 300 - 400 kPag at the base of reservoir
  - Pressure of 900 to 1,000 kPag in Wabiskaw sand above reservoir indicates competent isolation from the McMurray
- MRCP Pressure Update:
  - PCC is operating MRCP at MOP of 2,200 kPag
  - Since project start-up the pressure built-up and pressure distribution in the various zones in the reservoir has been closely monitored by PCC through its observation well's network.
  - Pressure is close to MOP at well pair level, the top lean zone and top gas zones are starting to increase slowly in few locations.



The following two wells are exclusively monitoring the Wabiskaw Sand:

UWI	Well Name	Formation (Member)	Zone
108/05-23-090-14-W4/00	AC02CR	Clearwater (Wabiskaw)	Gas
102/16-14-090-14-W4/00	AJ02CR	Clearwater (Wabiskaw)	Water

Characterization of Caprock



PCC has collected the following dataset for caprock characterization from delineation and coreholes within the DA:

- Formation Image logs for 37 wells
- Cored 67 wells
- 4 Caprock core

MRCP Geomechanics: Mini-frac tests

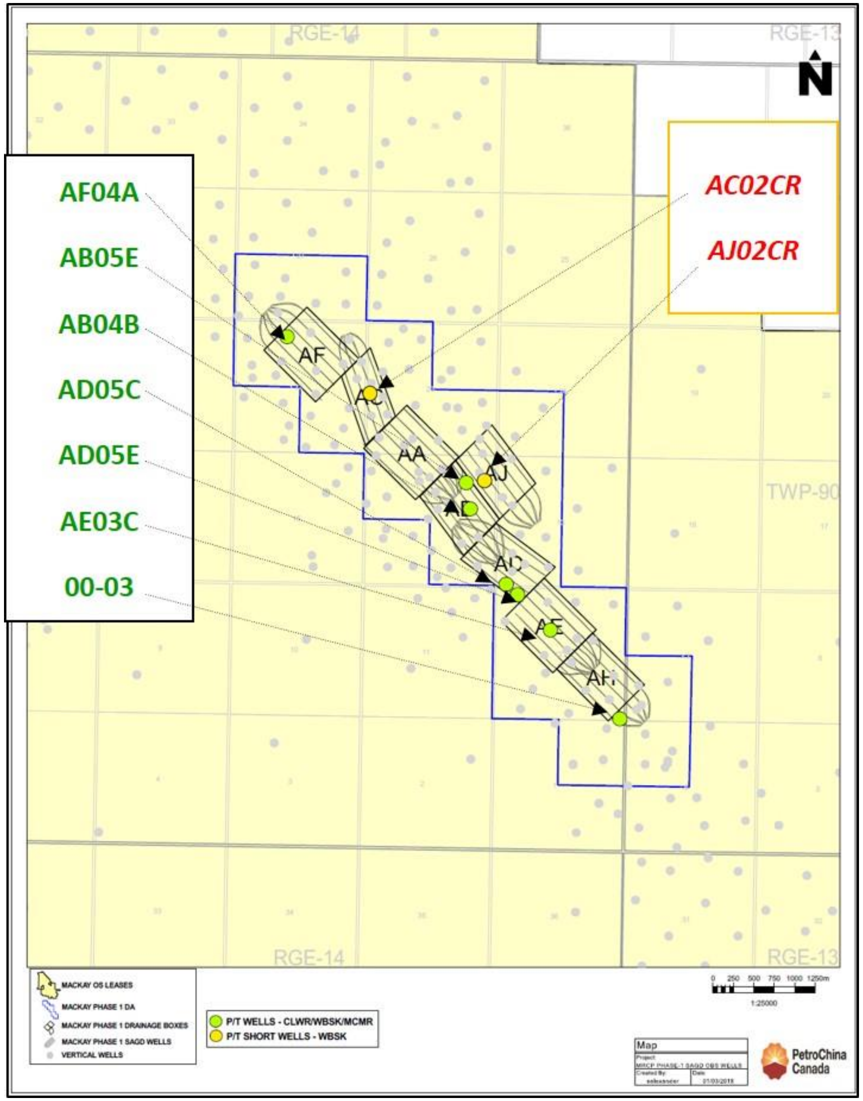
- Mini-frac tests were conducted between 2009-2016
- The results are in agreement with local and regional trends
- The average caprock fracture gradient measured for the MRCP region within the argillaceous Clearwater is 21.59 kPag/m
- Approved maximum operating pressure (MOP):
    - MOP of 2,200 kPag calculated from base of Clearwater caprock in Phase 1 area of 150.2 mTVD and a gradient of 14.7 kPag/m
    - Represents a conservative safety factor of 68% below the caprock fracture closure gradient
    - PCC has applied to update the MOP to the industry standard 80% safety factor

Well	Year	Formation	Fracture Gradient (kPag/m)
100/04-23-90-14W4M	2009	McMurray Oil Sand	16.7
1AA/06-07-90-13W4M	2009	Clearwater Caprock	21.5
1AA/14-28-90-14W4M	2013	McMurray Oil Sand	14.9
		Clearwater Caprock	20.6
		Wabiskaw shale	21.3
100/03-14-090-15W4	2016	McMurray Oil Sand	16.9
		Clearwater Caprock	22.3
		Wabiskaw shale	18.8

MRCP Geomechanics

- Caprock integrity testing and geomechanical
  - Caprock core testing was completed in well 1AA/06-07-090-13W4: tri-axial laboratory testing, and X-ray diffraction analysis.
  - Field measured in-situ stress conditions and fracture criteria were also inputs to the geomechanical model, minifrac: 1AA/06-07-090-13W4 / 100/04-23-90-14W4M
  - Geomechanical simulations using ABAQUS, a commercial finite element stress analysis software, ran by BitCan were conducted to provide confirmation that SAGD operations at MRCP will not pose any risk to the caprock integrity.

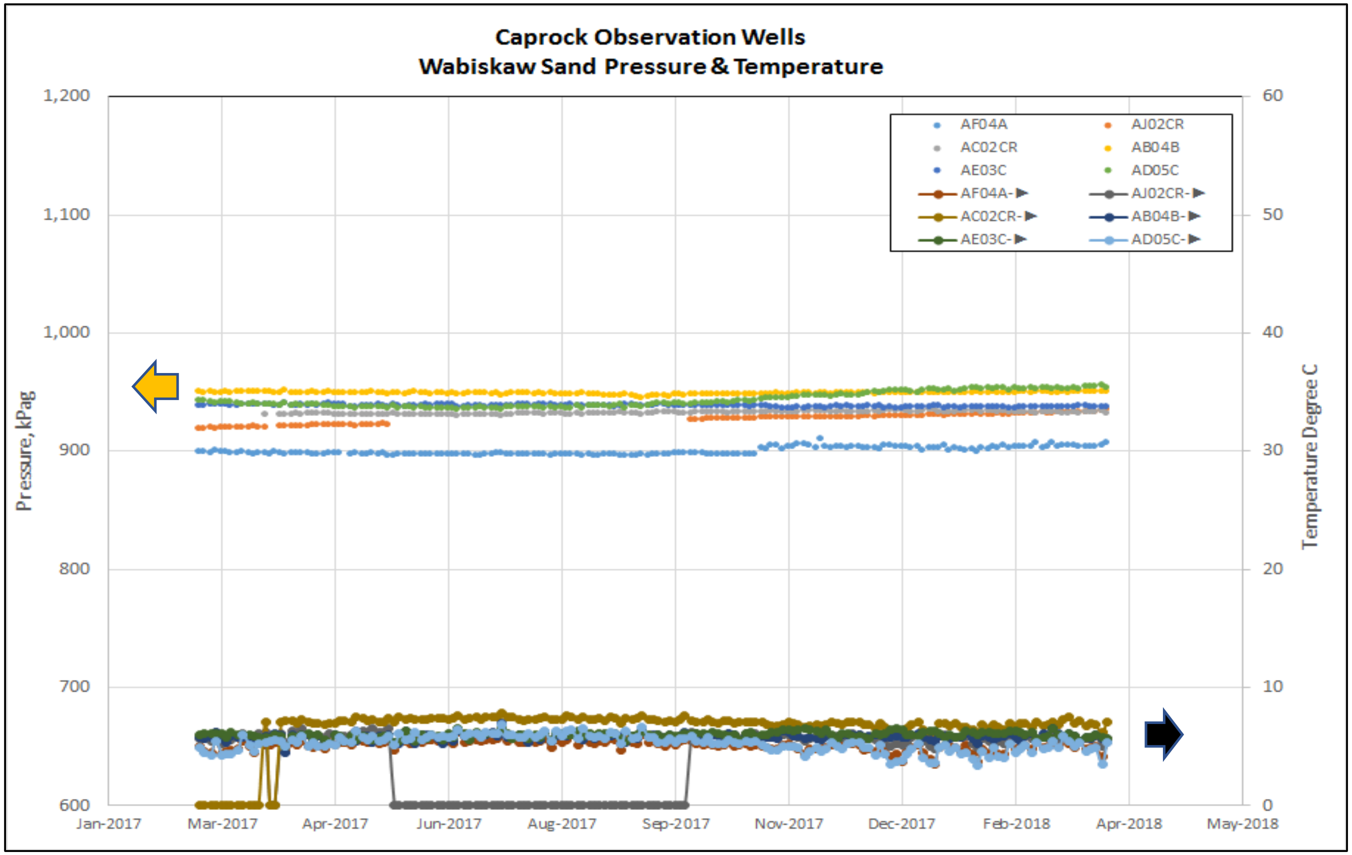
Caprock Monitoring



- Monitoring caprock pressure and temperature in 9 vertical wells
- Electromagnetic Resonating Element (ERE) gauges for pressure and temperature on exterior of production casing or interior with perforation.
- Wabiskaw Sand Monitoring:
    - 2 vertical wells drilled to base Wabiskaw (isolated from McMurray reservoir): AJ02CR and AC02CR
    - Equipped with interior pressure/temperature ERE
- Caprock Monitoring – Wabiskaw and Clearwater:
    - 7 vertical wells drilled to the base of the McMurray Formation: AB05E, AD05E, AF04A, 00-03, AB04B, AE03C and AD05C.
    - Pressure and temperature in one to four layers within the caprock intervals on the exterior of production casing.

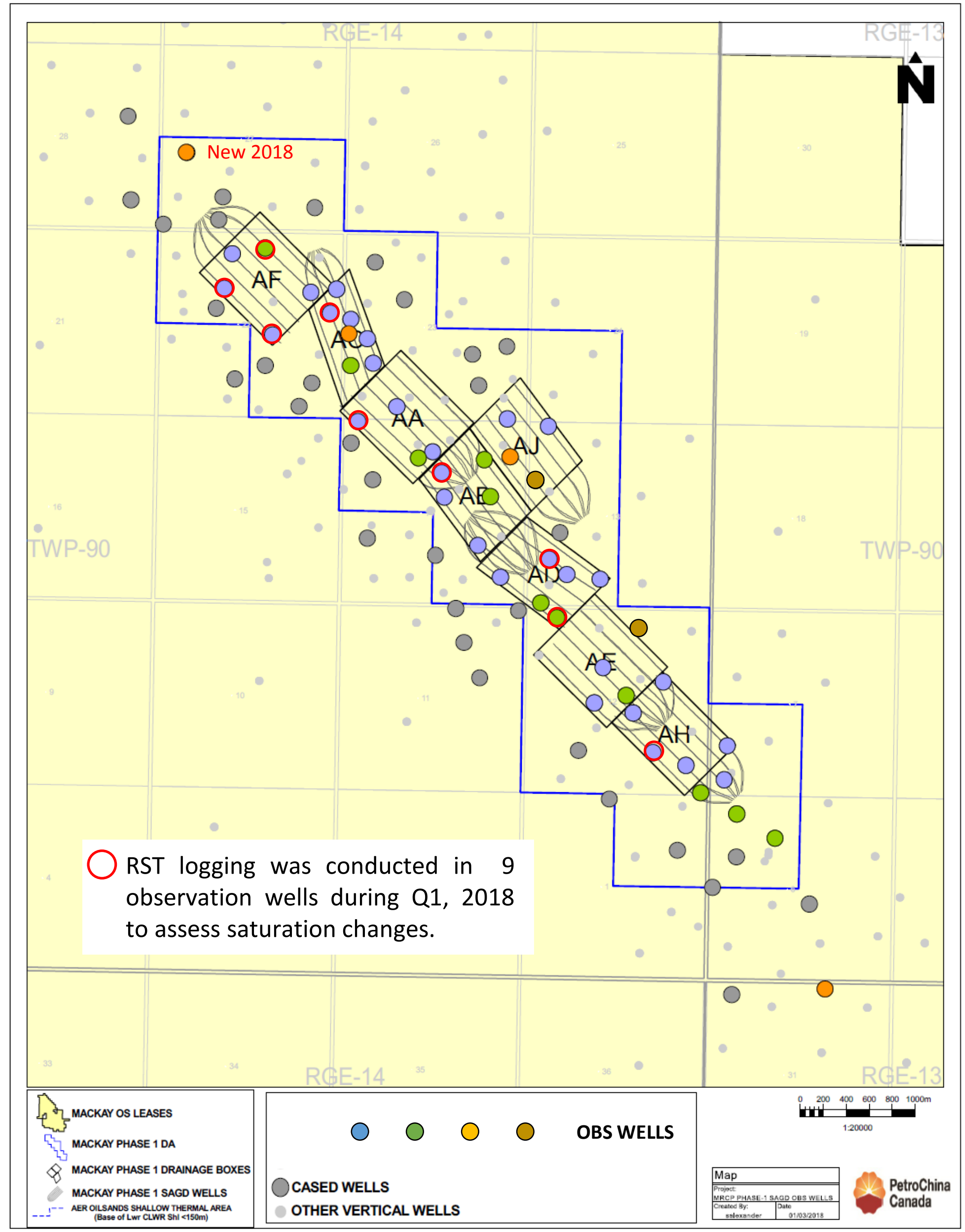
Caprock Monitoring – Pressure and Temperature

- Caprock average pressures and temperatures:
  - Pressure 900 - 950 kPag
  - Temperature 5-7 ^oC
  - No changes seen after steaming started
- Caprock observation well data pressure and temperature is reviewed bi-weekly.



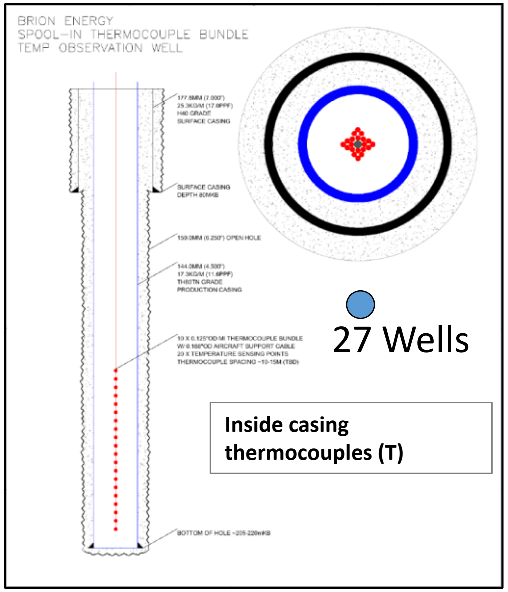
Observation Well Overview

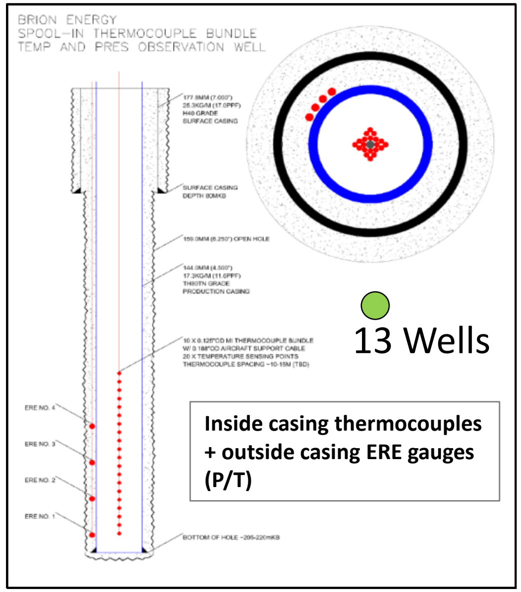
- Total of 46 observation wells for MRCP
  - One additional observation well conversion: North West of Pad AF
- This network has been designed to monitor the following themes:
  - Caprock Monitoring
  - Reservoir Top Gas
  - Bottom Transition Zone
  - Baffles/barriers above injector
  - Baffles/barriers between producer/injector
  - History Match / Chamber Development
    - Early Stage (< 10 m)
    - Late Stage (> 10 m)
  - Lateral/Regional Monitoring (> 100m)
- According to their design, they are classified as:
  - Obs Wells w/ just Thermocouples
  - Obs Wells w/ Thermocouples and EREs
  - Perforated Obs Wells w/ Thermocouples and/or EREs (Single Zone)
  - Perforated Obs Wells w/ Thermocouples and/or EREs (Multi Zone)

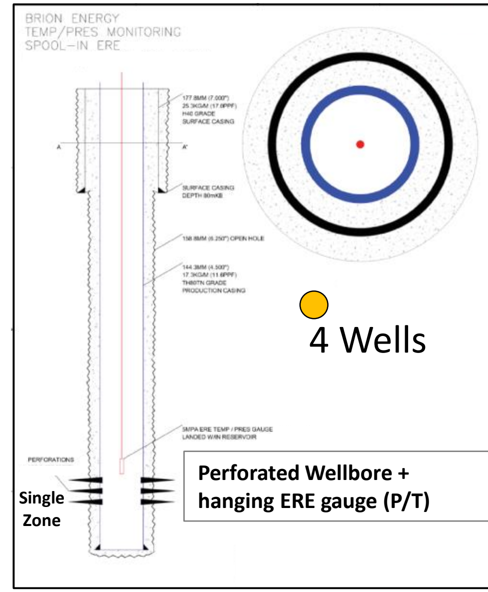


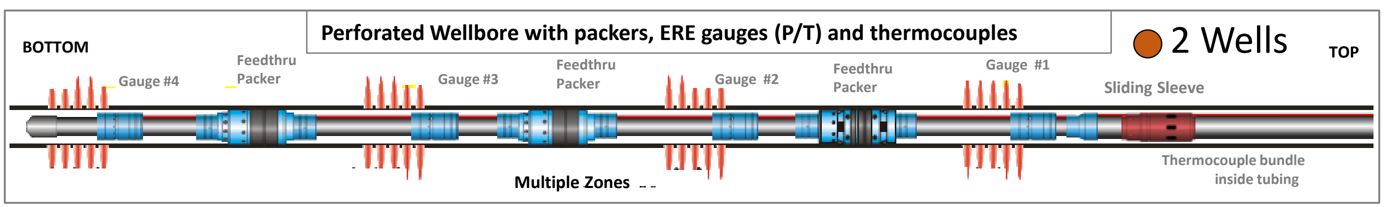
Typical Observation Well Design

- Example of the types of observation well design and instrumentation configurations at MRCP:









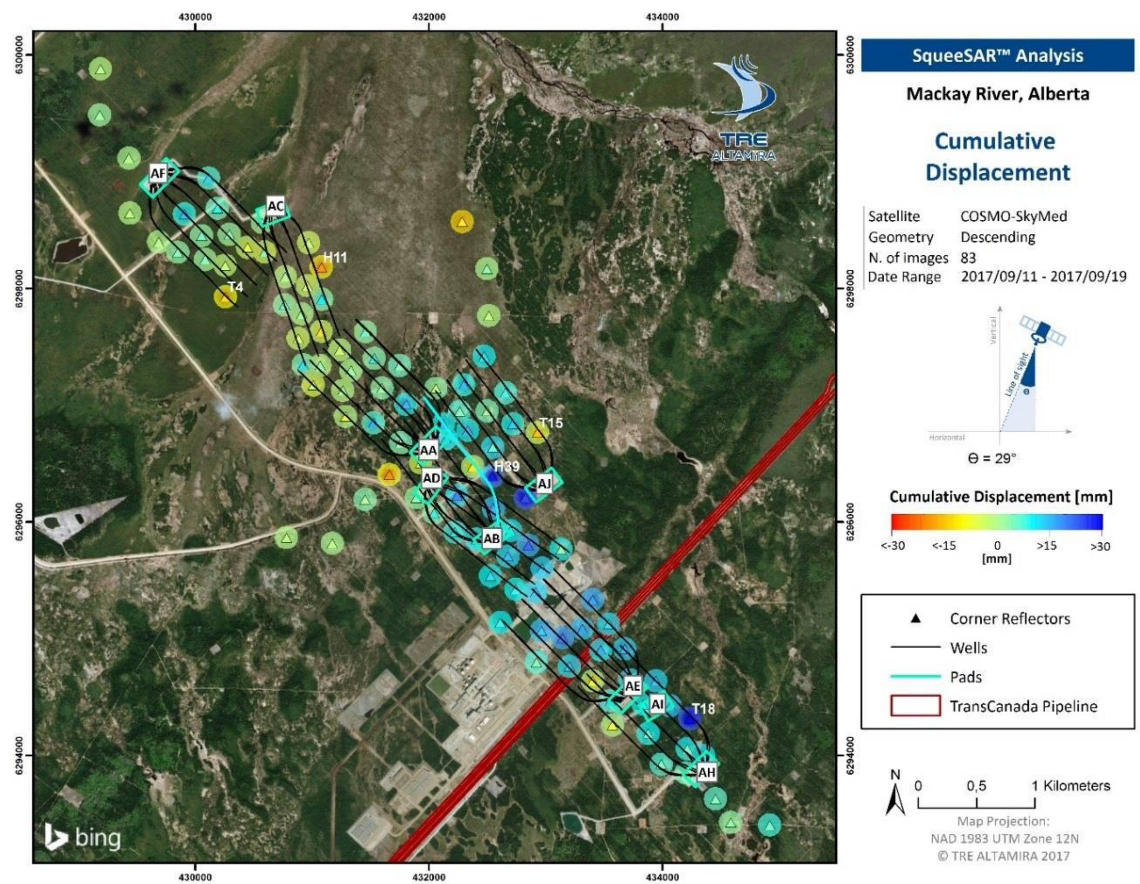
Type of gauge reading:
- (T) Only temperature
- (P/T) Temperature & Pressure

Vendor provided diagrams: Petrospec Engineering Ltd. and Packers Plus

Surface Displacement Monitoring

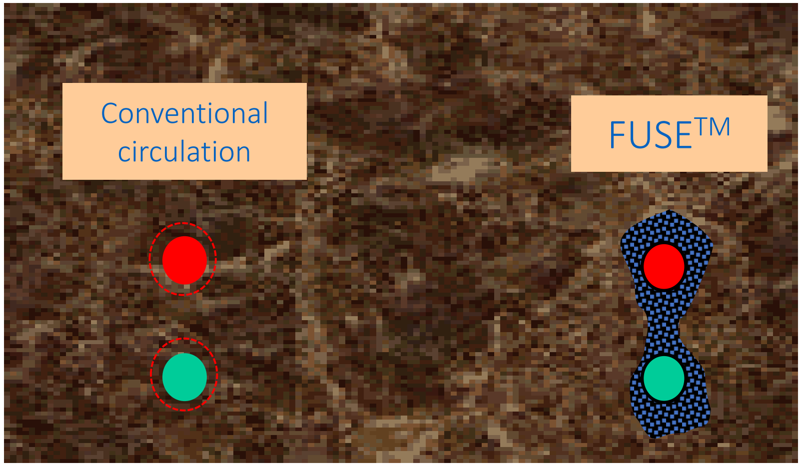
- PCC has an extensive network of corner reflectors installed for surface displacement and heave monitoring
  - Detection and measurement of ground motion by InSAR technology
  - The total amount of displacement measured from September 2014 to September 2017 is shown in the map
  - Subsidence was observed at the toes of Pad AF and within Pad AC.
  - Other areas of localized subsidence were identified off pad
  - The southern half of the MacKay River Field showed cumulative heave between Pads AD and Pad AH.
  - Minimum and maximum heave values over individual pads from December 2016 to September 2017 are shown in the table:

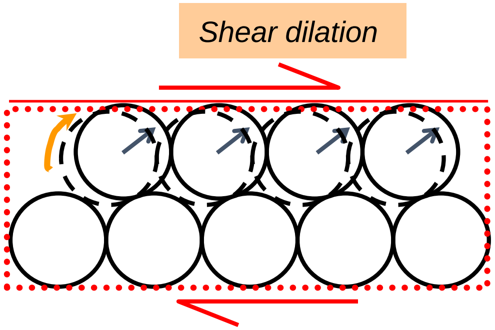
Pad	Min value [mm] (CR)	Max value [mm] (CR)
Pad AF	-10.5 (T4)	+9.5 (H8)
Pad AC	-13.2 (H11)	+6.8 (H4)
Pad AA	+0.3 (H10)	+17.6 (H34)
Pad AD	+5.2 (H50)	+18.1 (H41)
Pad AJ	+0.5 (T15)	+23.3 (H39)
Pad AB	-14.3 (R6)	+17.3 (T12)
Pad AE	-0.2 (H55)	+15 (H54)
Pad AH	+2.1 (H61)	+25.4 (T18)



FUSE™ – Field Test

- Low injection rate, low volume and high pressure water injection to form a high-porosity dilation zone between the SAGD well pair
  - Vertically connect the well pair;
  - Horizontally uniform along the well length;
  - Dilated zone has enhanced porosity and a large storage volume
- Polymer was used to mitigate water leak off due to expected high mobility





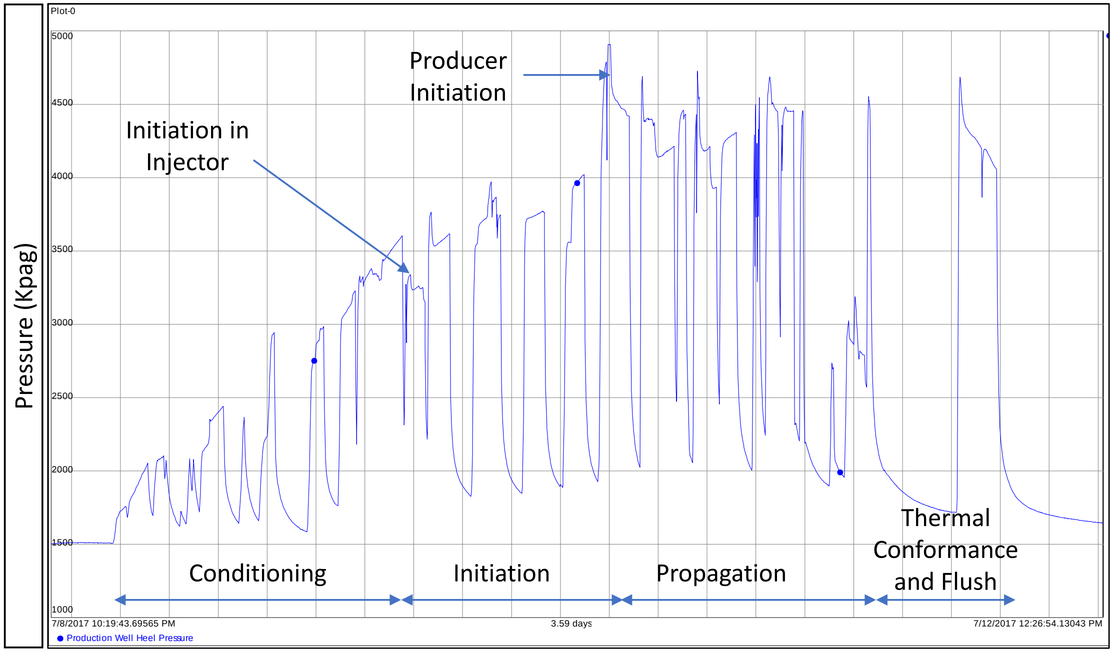
Process is a combination of shear dilation and micro tensile parting:

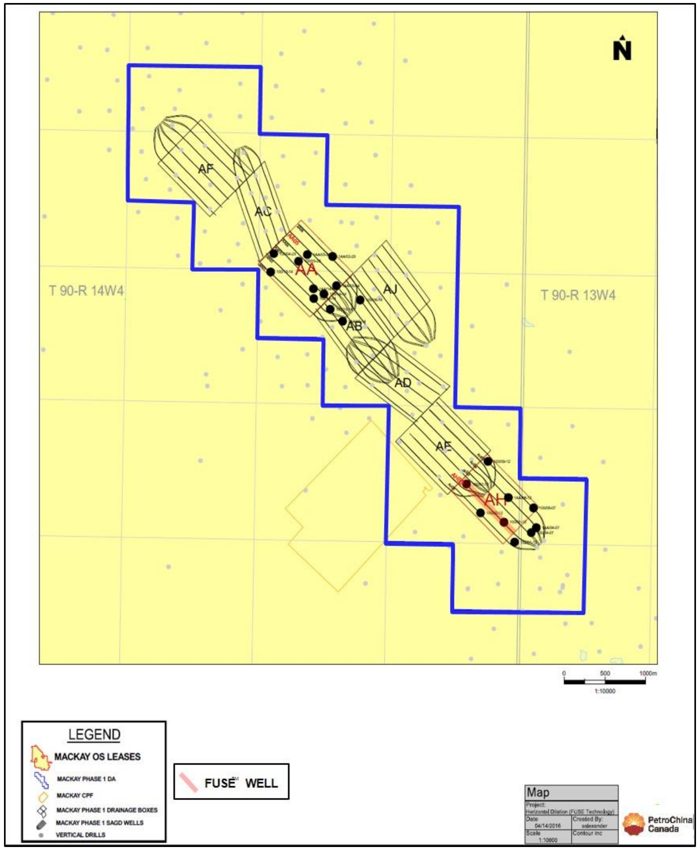
Dilation to loosen

Micro-cracking to create micro-cracks

FUSE™ – Field Operation & Execution

- Test Location: Well Pair AH02





- Polymer viscosity 300-400 cP
- Injector pressure at surface 3,000 kPag
- Injector downhole initiation at about ~5,000 kPag
- Producer initiation at ~4,850 kPag (consistent with surface 2,850 kPag at surface)
- Injection rates varied through operation from minimum of ~100 L/min to a maximum of ~600 L/min

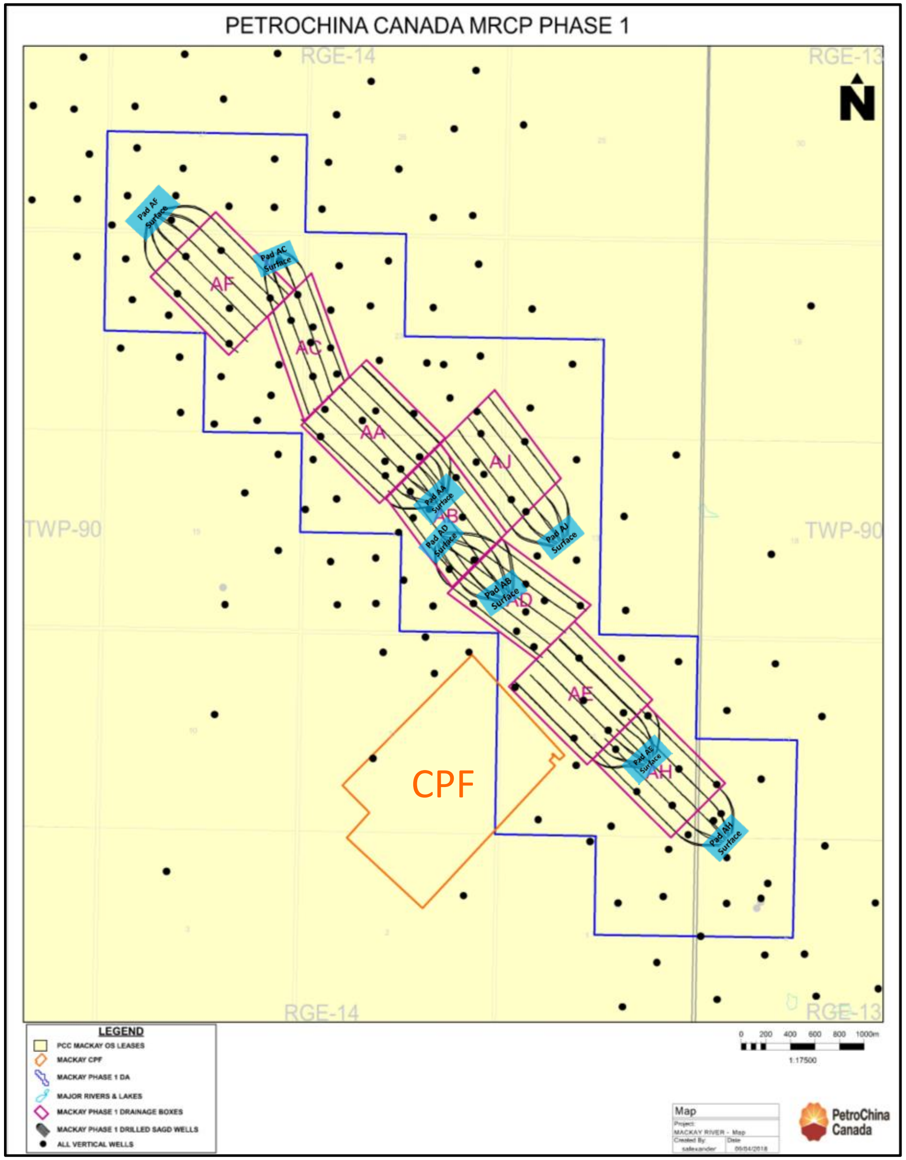
FUSE^{TM} – Field Dilation Summary

- Completed in well pair AH02 within 5 days
- Average dilation pressure ~ 5,000 kPag
- Cumulative injection of ~1,300 m^3 (limit was 1,500 m^3)

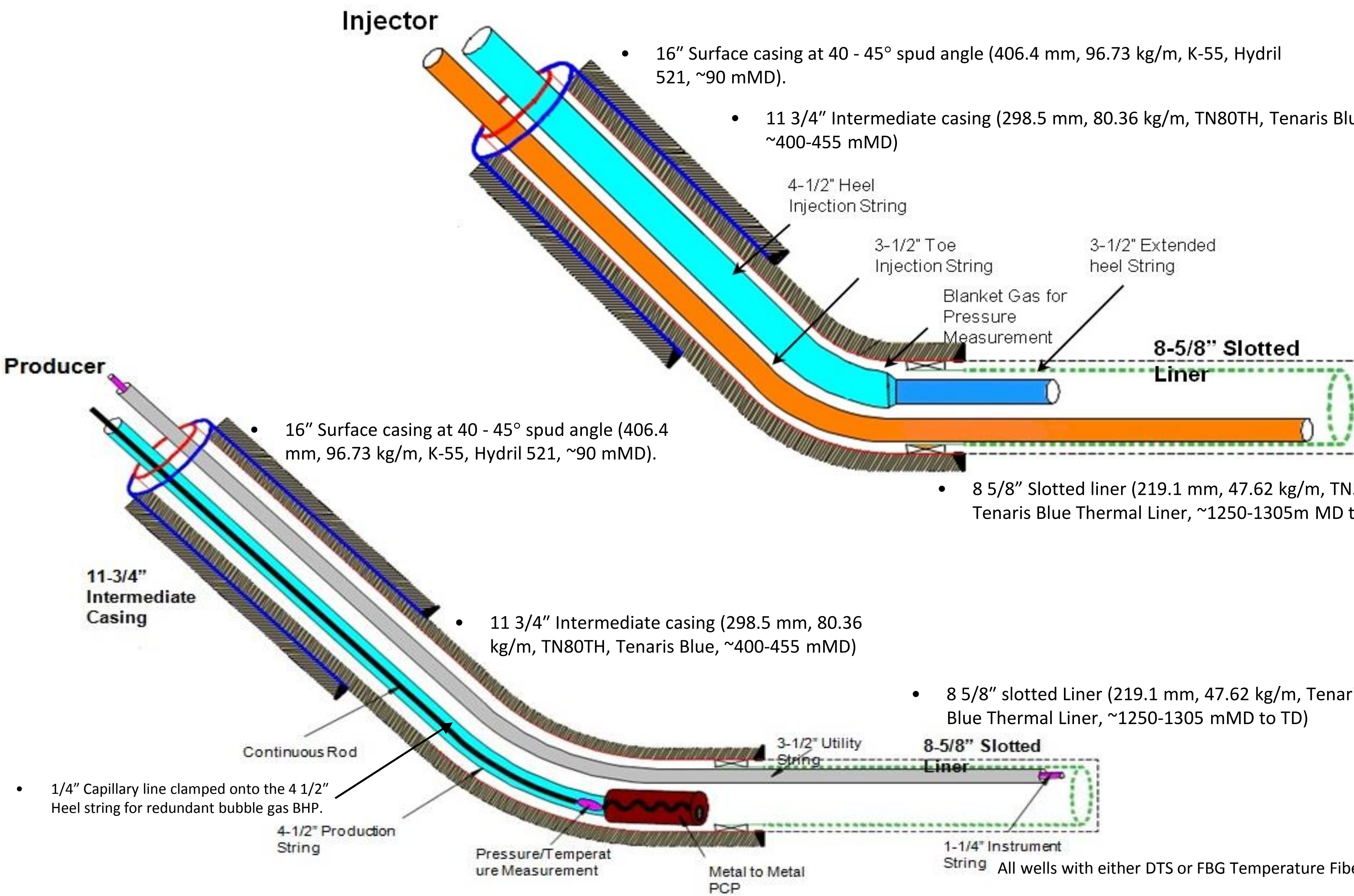
Final Remarks:

- FUSE^{TM} field trial was safely executed in the field on well pair AH02.
- The preliminary results from AH02 indicate potential shorter circulation time and faster ramp-up rate.
- Further evaluation will continue as additional production data is collected and analyzed.

MRCP Wellpair Layout



MRCP Standard Completion Schematic



- 16” Surface casing at 40 - 45° spud angle (406.4 mm, 96.73 kg/m, K-55, Hydril 521, ~90 mMD).
- 11 3/4” Intermediate casing (298.5 mm, 80.36 kg/m, TN80TH, Tenaris Blue, ~400-455 mMD)
- 8 5/8” Slotted liner (219.1 mm, 47.62 kg/m, TN55TH, Tenaris Blue Thermal Liner, ~1250-1305m MD to TD)

- 16” Surface casing at 40 - 45° spud angle (406.4 mm, 96.73 kg/m, K-55, Hydril 521, ~90 mMD).
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- 8 5/8” slotted Liner (219.1 mm, 47.62 kg/m, Tenaris Blue Thermal Liner, ~1250-1305 mMD to TD)
- 1/4” Capillary line clamped onto the 4 1/2” Heel string for redundant bubble gas BHP.

All wells with either DTS or FBG Temperature Fiber

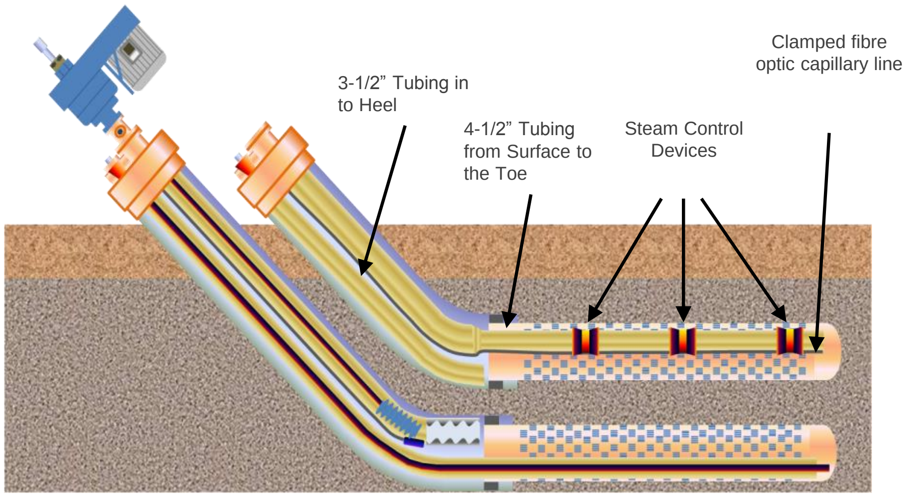
Summary of Alternate Completions

System	Principle	Use in
Steam distribution control devices	Reduction of pressure gradient in the liner- better distribution of steam	AA02I, AB02I and AD02I
Inflow control devices Liner Based	Reservoir inflow equalization	AC01P and AD02P
Alternative sand control using Wire Wrap Screens (WWS)	Maximization of opened flow area to reduce completion drawdown	AE03P
Alternative sand control using Precision Punched Screens (PPS)	Improved filter media resistance to wearing using: better metallurgy and change of fluid momentum. Reduced tendency to plugging minimizing the thickness of the slots.	AH04P and AF02P

Trial status to-date (March 2018):

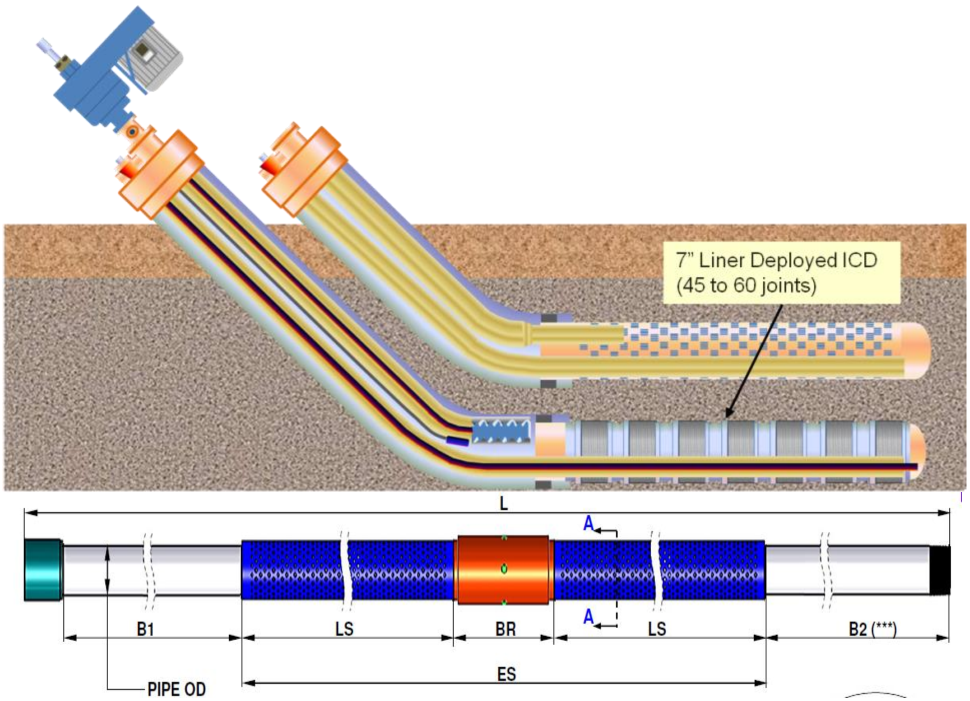
- No specific advantages of using WWS on AE03P or PPS on AH04P have been observed thus far
- On the contrary, AF02P equipped with PPS has shown very good performance after conversion to SAGD
  - Constantly low drawdown (dP) of ~100 kPa (the lowest on the pad)
  - Highest normalized emulsion production rate on the pad
  - Highest normalized cumulative emulsion production on the pad
- Saturated wellbore conditions in AE03P and AH04P impose limits on well production rate and make it difficult to evaluate benefits of a specific sand control media type (masking the media performance)

Steam Control Devices Test



- The injector wells that have steam control devices installed are: AA02I, AD02I and AB02I.
- These wells have a full fibre optic temperature sensor in the injector to allow better monitoring of the steam chamber growth.

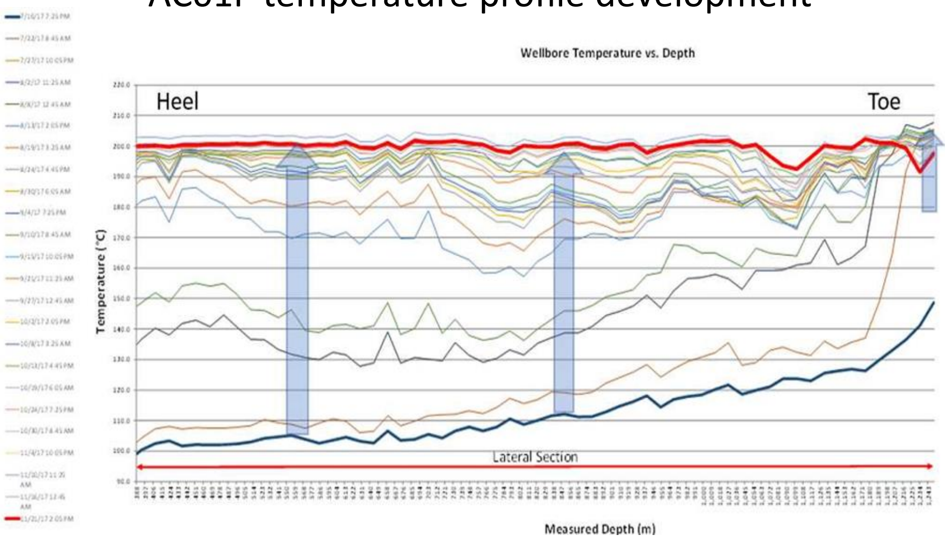
Inflow Control Devices Test



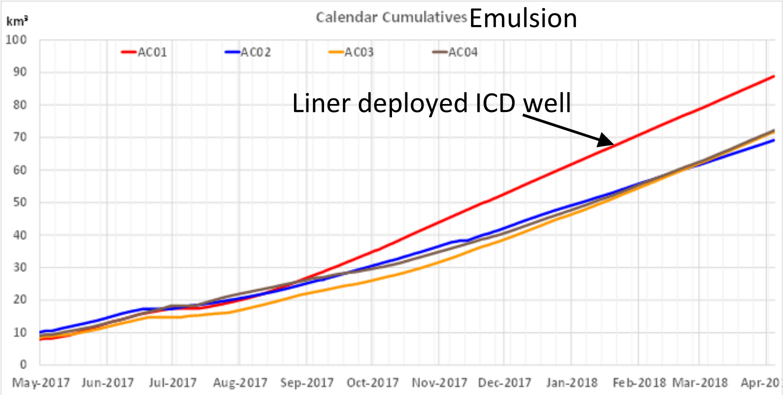
- PCC is conducting two field trials with ICDs in production wells AD02P and AC01P.
- This trial may allow PCC to improve or optimize future phase SAGD well designs with reduced liner/casing sizing which means the ability to drill longer wells at a lower capital cost per well pair.

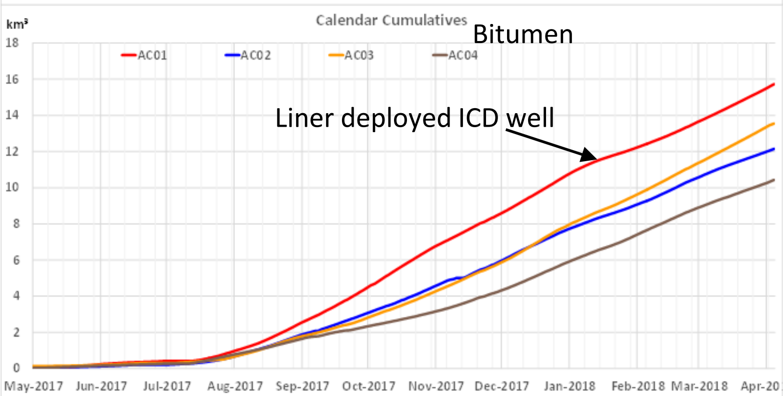
Inflow Control Devices Test - Results

AC01P temperature profile development



NON- Prorated production plots



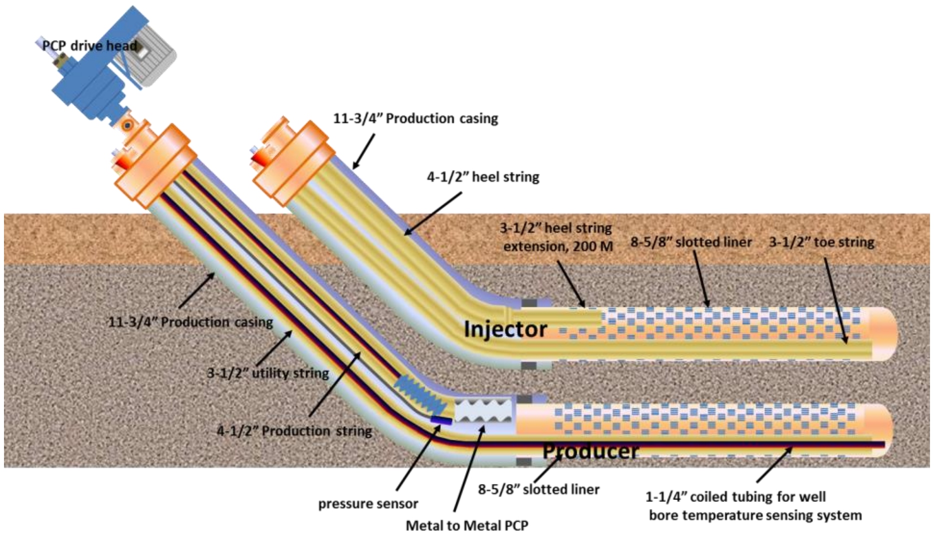


- The temperature along the AC01 ICD well which was continuously monitored via an LxData (FBG) since startup, July 2017. The most recent temperature profile shows an almost uniform temperature distribution along the wellbore despite the initial development of a toe "hot spot"

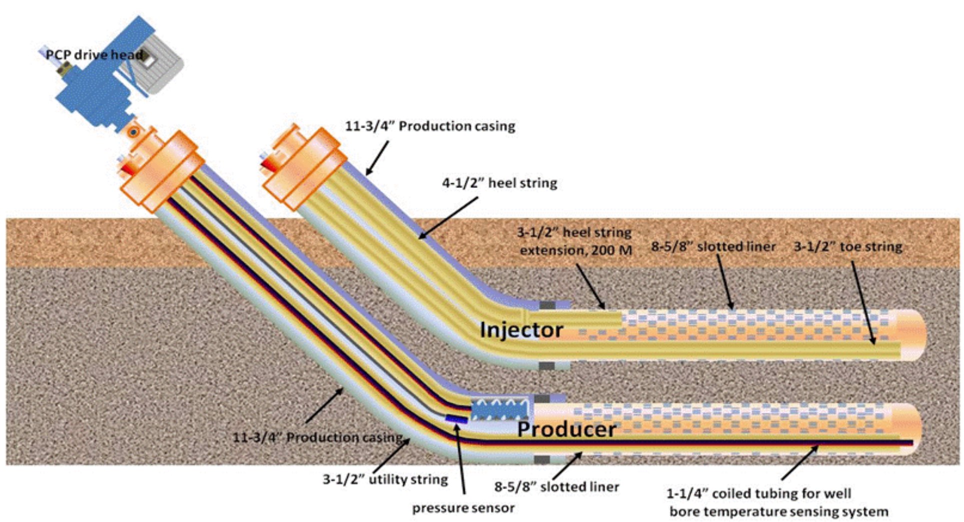
- Well pairs AC01 and AD02, with liner deployed ICDs, are the best performing wells on their respective pads.
- Most of the additional production is achieved during the first six months of operation
- The results are encouraging enough that a tubing deployed ICDs completion has been proposed for trial in 2018.

Artificial Lift - Metal to Metal PCP

Completion for steam circulation- PCP rotor out of the stator



Completion for SAGD operation - PCP rotor spaced out



- **Metal to metal Progressing Cavity Pump (PCP)s installed as original artificial lift method:**

- **PAD AA**: 6 pumps
- Capacity: 300 m3/d at 100 RPM
- Lift: 600 m of water

- **On PADs:**
- AB: 5 pumps
- AD: 5 pumps
- AE: 6 pumps
- AF: 6 pumps
- AJ: 5 pumps
- AH: 5 pumps
- Capacity: 220 m3/d at 100 RPM

- Pumps were installed and sat idle downhole for approximately two years prior to circulation, and all started up without any significant problems.

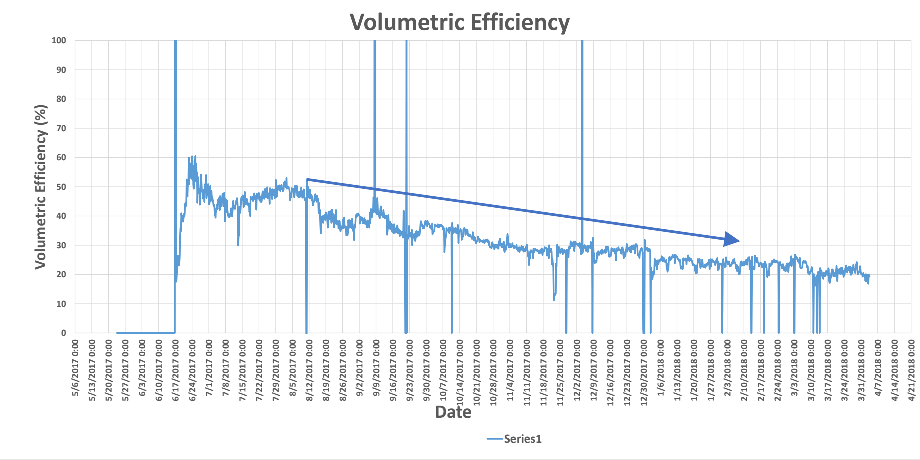
Artificial Lift - Metal to Metal PCP Performance

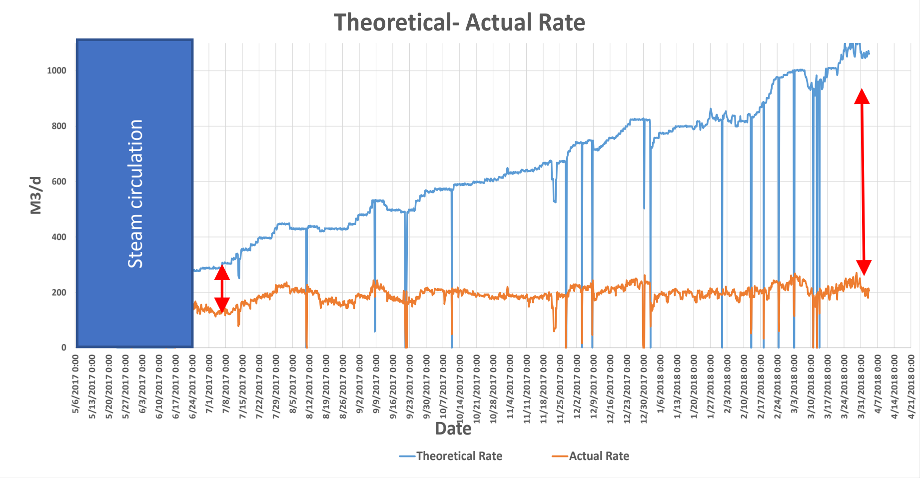
AA01: 300 V 600 pump

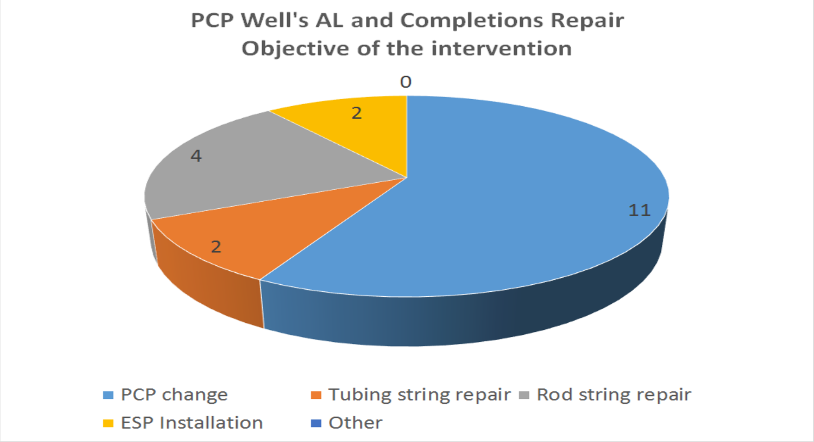
- 42 Weeks in operation
- Volumetric efficiency dropped from 50% initially to 20%. Stable during the last 3 weeks
- Slippage at 850 m3/d. Initial slipage125 m3/d

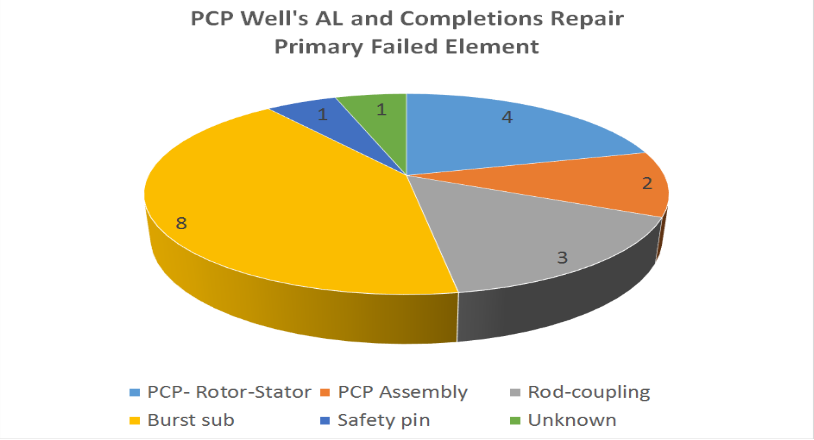
General Comments

- MTTF data is not accurate due to premature burst sub issues
- Some PCPs have been converted to ESP due to lift capacity



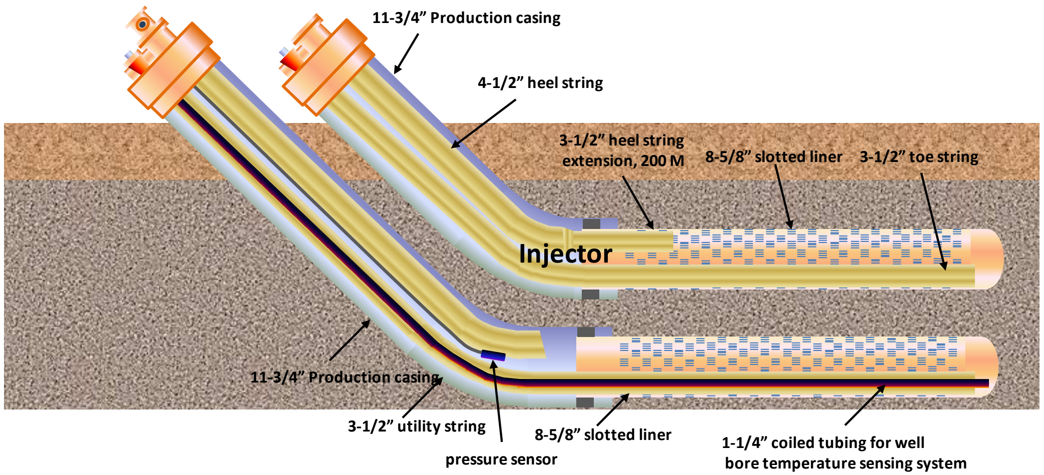




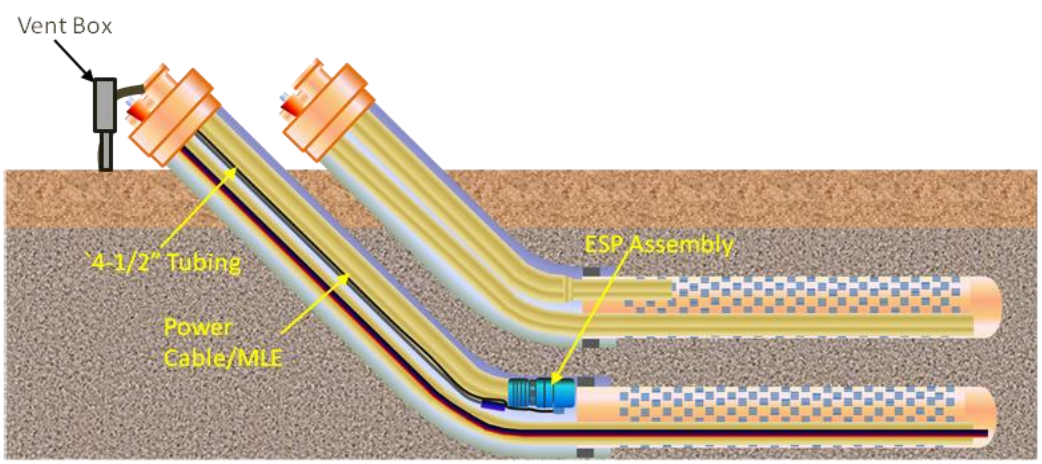


Artificial Lift - Alternative Artificial Lift ESP

Completion for steam circulation



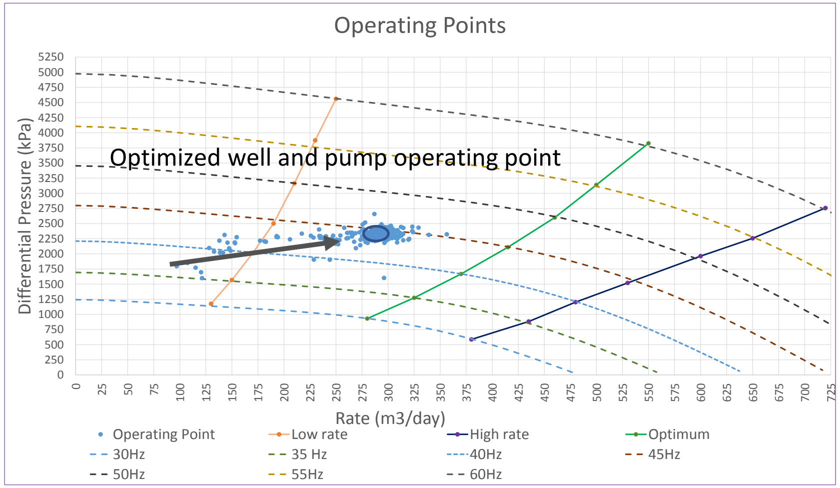
Completion for SAGD operation



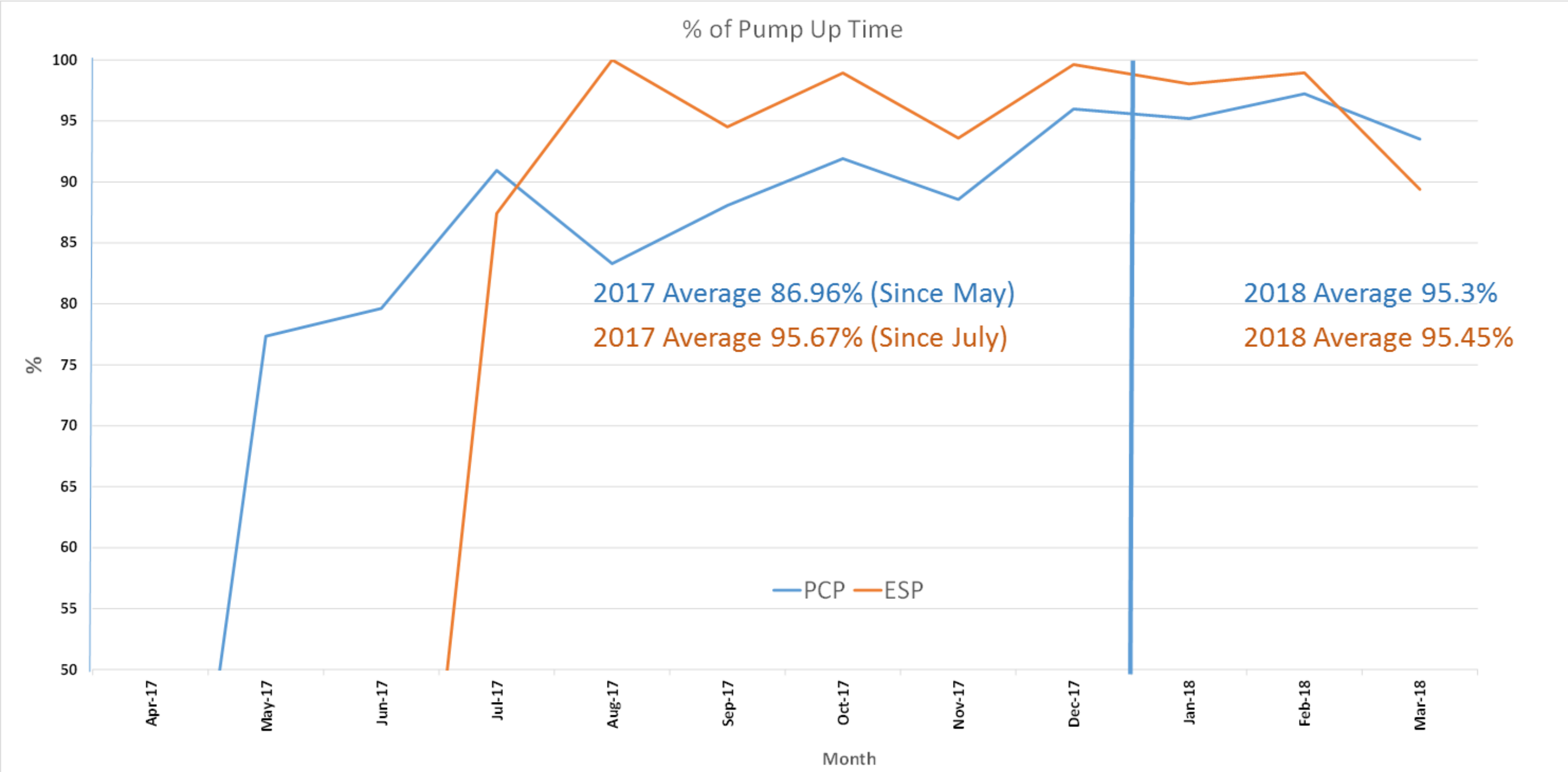
- Electrical Submersible Pump (ESP)s were installed as the original artificial lift method between June and July 2017 on Pad PAD AC: 4 pumps.
- In January 2018 , AF06P was converted to an ESP.
- In March 2018, AF02P was converted to an ESP
- 16 PCP to ESP conversions are proposed for 2018

Ex.: AC01: 400DN3500 47 pump

- Started on July 13th (37.5 weeks), pump operating close the optimum point.
- Rate limited by high wellbore draw down (ICD)



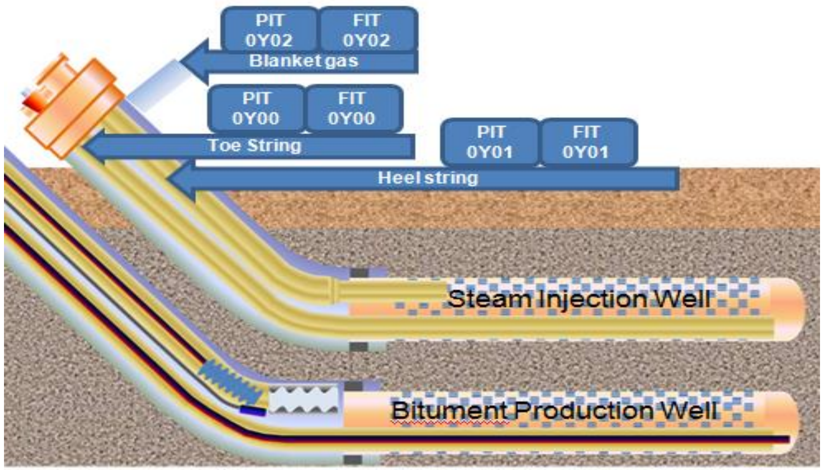
Artificial Lift- performance



- PCP MTTF by March 31st , 2018 was ~***342.5 days.*** 42% of the PCP system's failures has been cause by burst sub failure and only 31% are caused by the PCP.
- March 31st, PCP average run time of active wells = 226.1 days
- No ESP systems failures were identified by March 31st
- March 31st ESP average run time of active wells = 223.6 days
- Average BHP – 1750 kPag, Average BHT – 165 ^{o}C

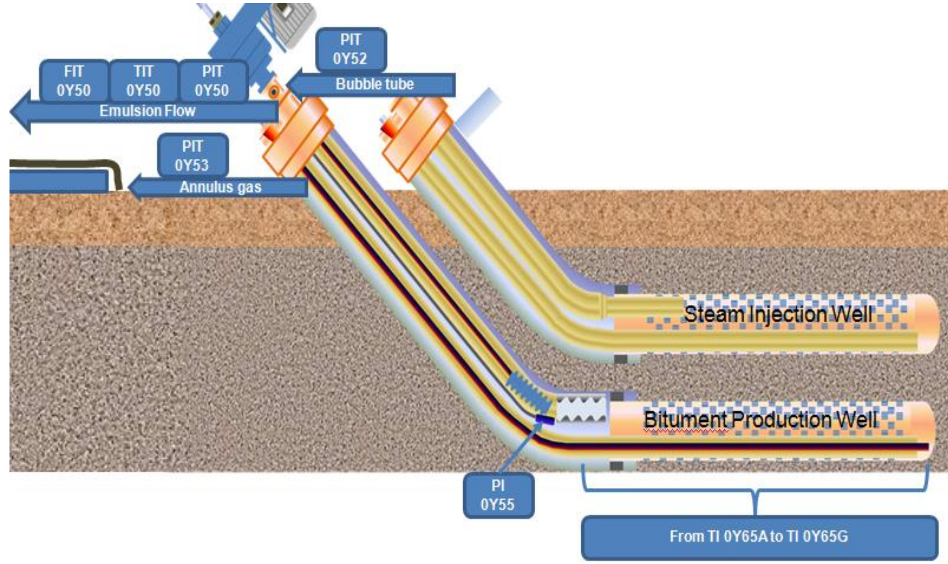
Summary of Downhole Instrumentation

Injection Well Instrumentation



Variable	Type of Instrument
Down hole pressure	Blanket gas / Pressure Transmitter
Blanket gas injection rate	Coriolis meter
Toe string steam injection rate	Vortex meter
Toe string well head pressure	Pressure transmitter
Heel string steam injection rate	Vortex meter
Toe string well head pressure	Pressure transmitter

Producer Well Instrumentation



Variable	Type of instrument
Down hole pressure	Optic pressure sensor
Down hole pressure	Blanket gas/ Pressure transmitter
Blanket gas injection rate (Circ)	Coriolis meter
Toe string steam rate (Circ)	Vortex meter
Toe string well head pressure (Circ)	Pressure transmitter
Well bore temperature	DTS or FBG fibre optic system
Return well head pressure	Pressure transmitter
Return well head temperature	Temperature transmitters
Return rate	Coriolis meter

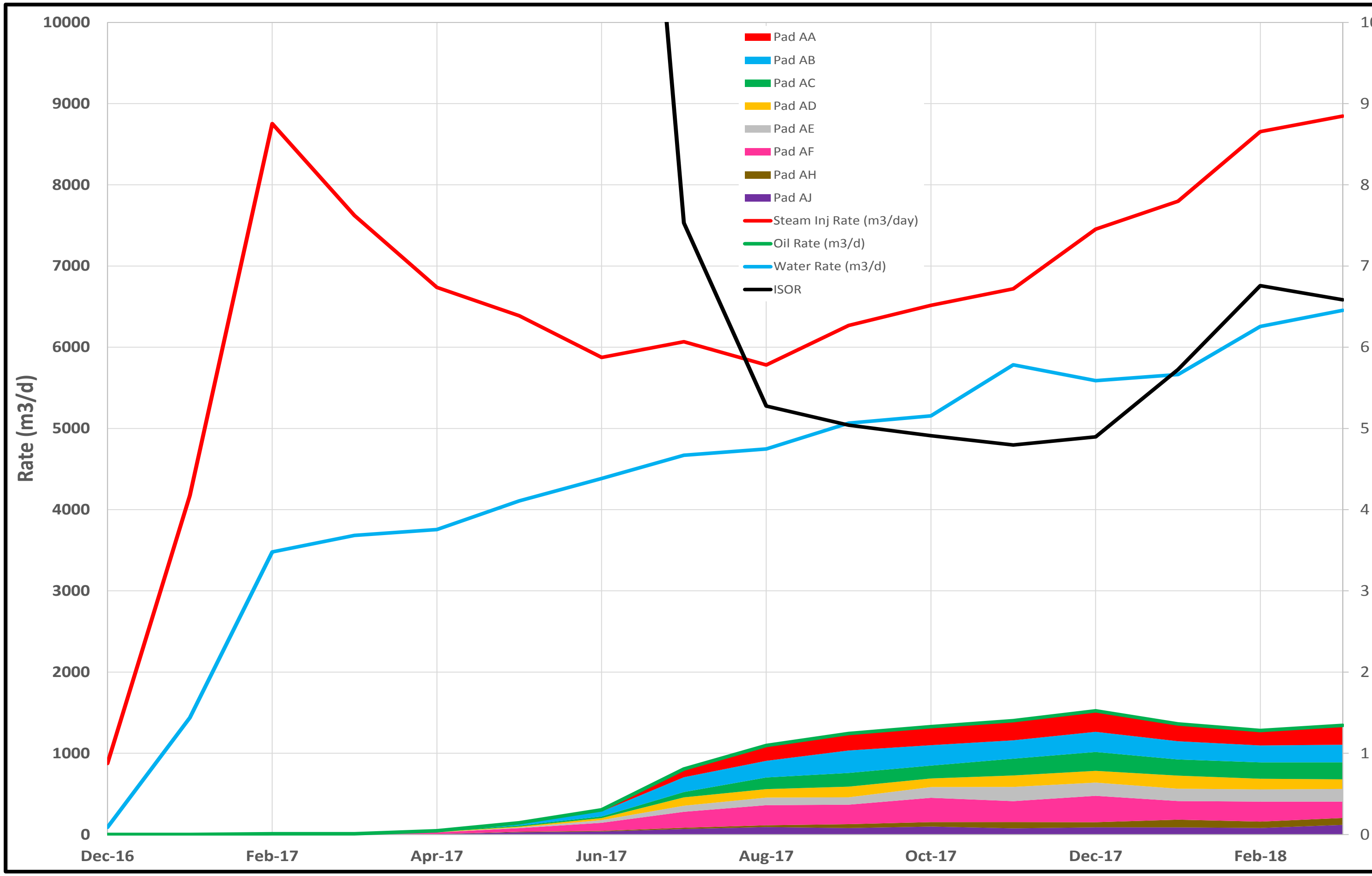
Summary of Additional Downhole Instrumentation

System	Type	Use in
Pressure and temperature sensor at the heel Pressure and Temperature sensor at heel	Optic sensor Piezo meter	Installed in every producer except Pad AC and on injectors AE02I and AJ03I. Installed with ESPs on AC . 4 systems
DTS well bore temperature sensing system	Fibre optic DTS	Installed in every producer on PADs: AA, AD, AF, AJ and AH. Installed on injectors: AA02I, AA03I, AD02I, AJ02I and AJ03I.
LxData well bore temperature sensing system	Fibre optic FBG	Installed in every producer on PADs: AB, AC and AE. Installed on injector AB02I.
Pressure sensor at the toe of the well	Fibre optic FBG	On AB02P, AC01P, AE03P and AE04P

Well Production Testing

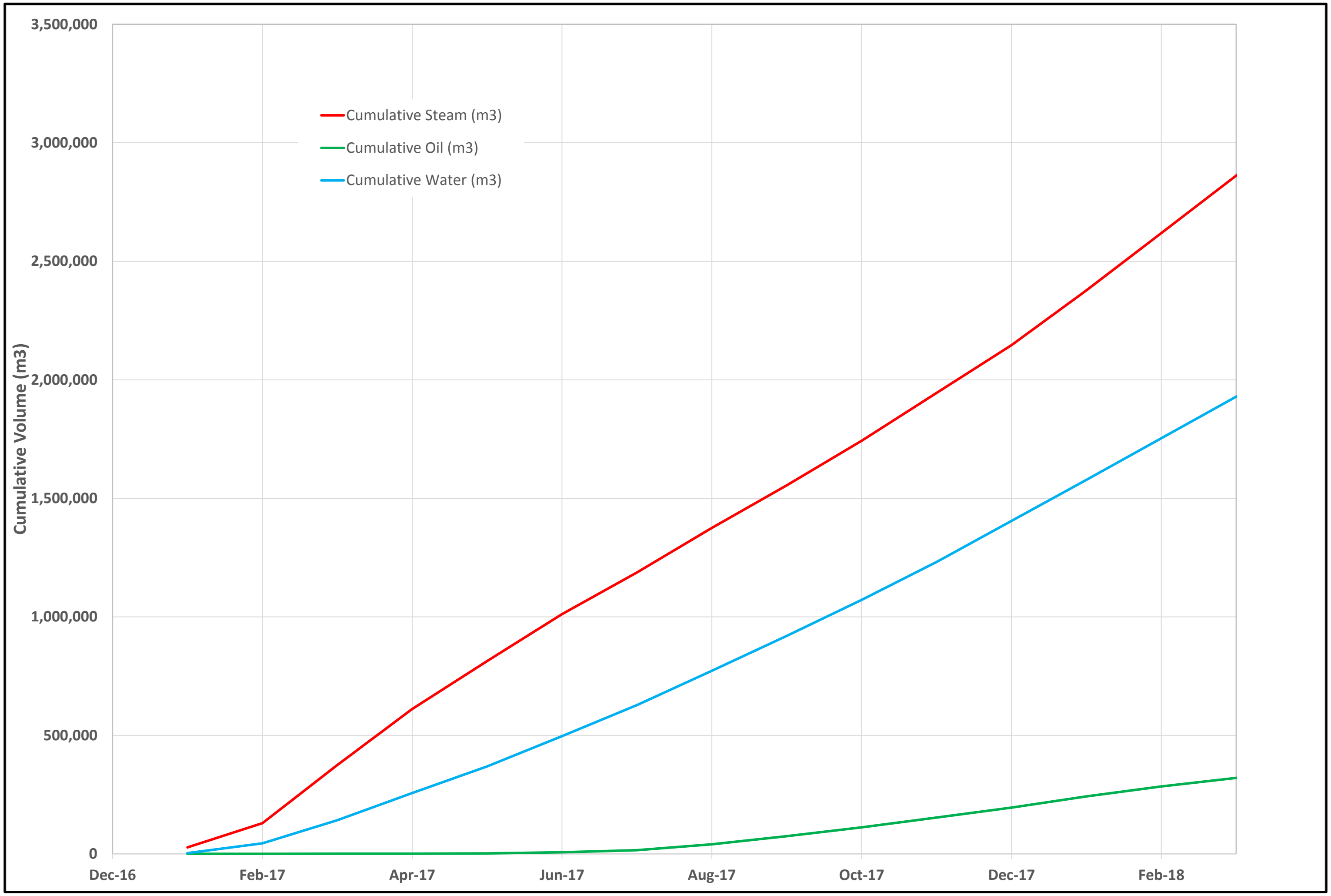
- Well production and injection volumes are estimated by the use of Coriolis meters (emulsion) and vortex meters (injection) for each well as the raw data check for the well tests
- MRCP utilizes one test separator per pad that automatically cycles through each well on the pad every 24 hours.
  - Typically each well will be in test for at least 120 hours per month
  - Well testing validations are completed once per week per pad within the Energy Components software
- This data is rolled up and balanced with the facility production and injection volumes to determine month end pro-rations prior to submission to Petrinex

MRCP – Field Performance



- MRCP is continuing to ramp up production
- Achieved a 2017 monthly exit rate (1521 m3/d)
- Steam and thus SOR impacted by top gas zone effects and areas of thicker lower transition zone
- Early 2018 production primarily impacted by workovers (as outlined in artificial lift section) and geological baffle impacting chamber growth in areas

MRCP – Cumulative Fluid Volumes



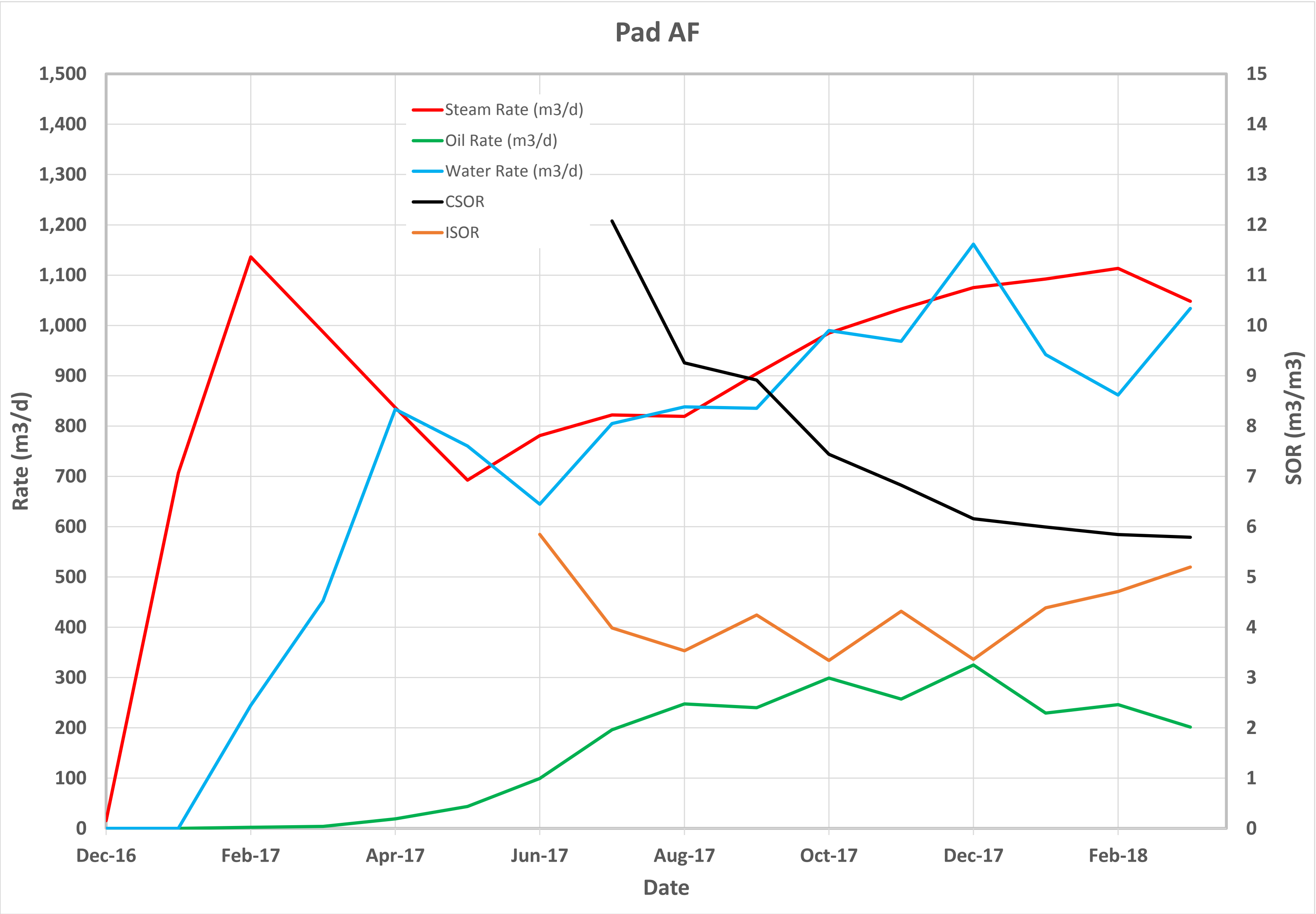
- In a few areas, early steam chamber interactions with top gas and losses to the lower transition zone has resulted in higher retention by the reservoir.
- Mitigation strategies are in place to be executed on in 2018/2019

MRCP – Performance Indicators by Pad

Pad	OBIP (m^3)	Cum. Oil to March 31 2018 (m^3)	Recovery to March 31 2018 (%)	CSOR	ISOR	Ultimate Recovery (%)
AA	4,197,138	57,616	1.37%	6.8	4.4	54
AB	3,465,819	65,100	1.88%	6.8	5.8	57
AC	2,655,008	49,437	1.86%	5.5	3.9	63
AD	2,957,075	35,982	1.21%	9.9	7.1	54
AE	3,513,514	37,402	1.06%	10.7	7.0	53
AF	4,149,444	73,382	1.77%	5.8	5.2	62
AH	3,179,650	16,843	0.53%	24.5	14.1	48
AJ	2,941,176	26,166	0.89%	16.8	13.1	57
Total	27,058,824	371,788	1.34%	8.7	6.6	56

- Higher SORs experienced on AE, AH, AJ pads primarily due to gas cap contact and slightly larger lower transition zone leak off. All other SORs are trending lower.
- Mitigations:
  - Analysis is being completed to pressure balance accordingly with the lower transition zone
  - Gas cap pressurization with natural gas to be executed in 2018

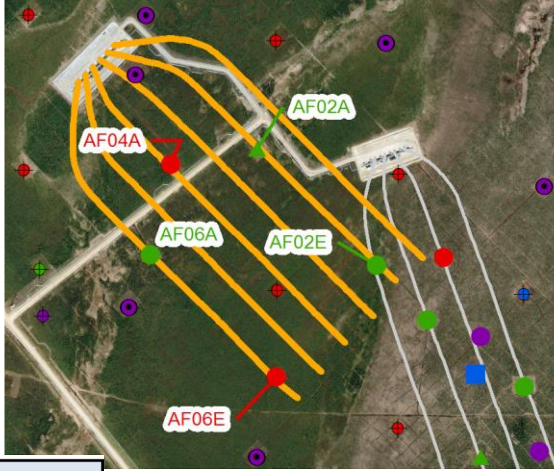
MRCP – Pad AF: High Performance Example



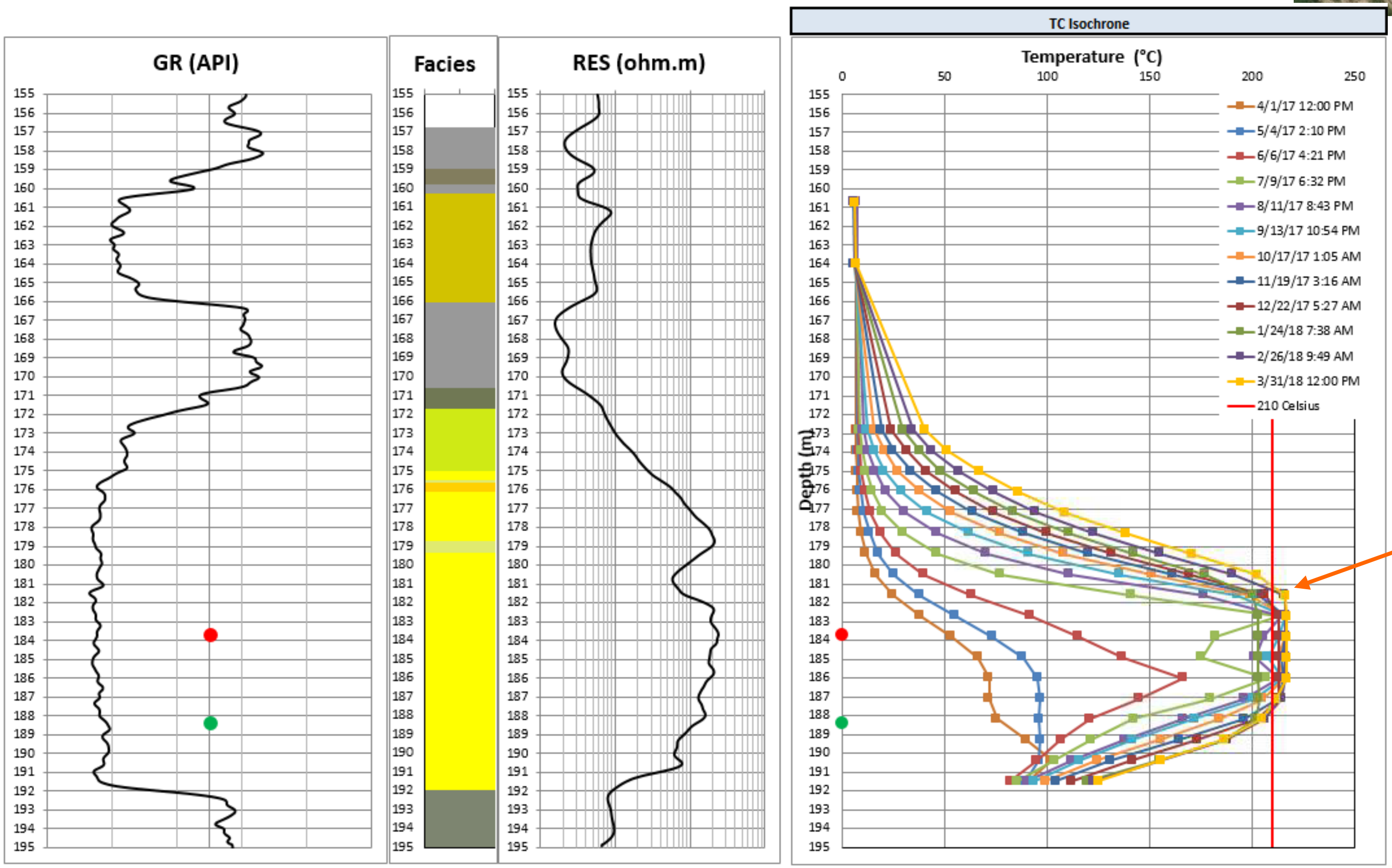
MRCP – Observation Well Examples: Pad AF

5 Observation Wells in the Pad for steam chamber monitoring:

- Example: AF06E – 2.33 m from toe of AF06
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 07/2017

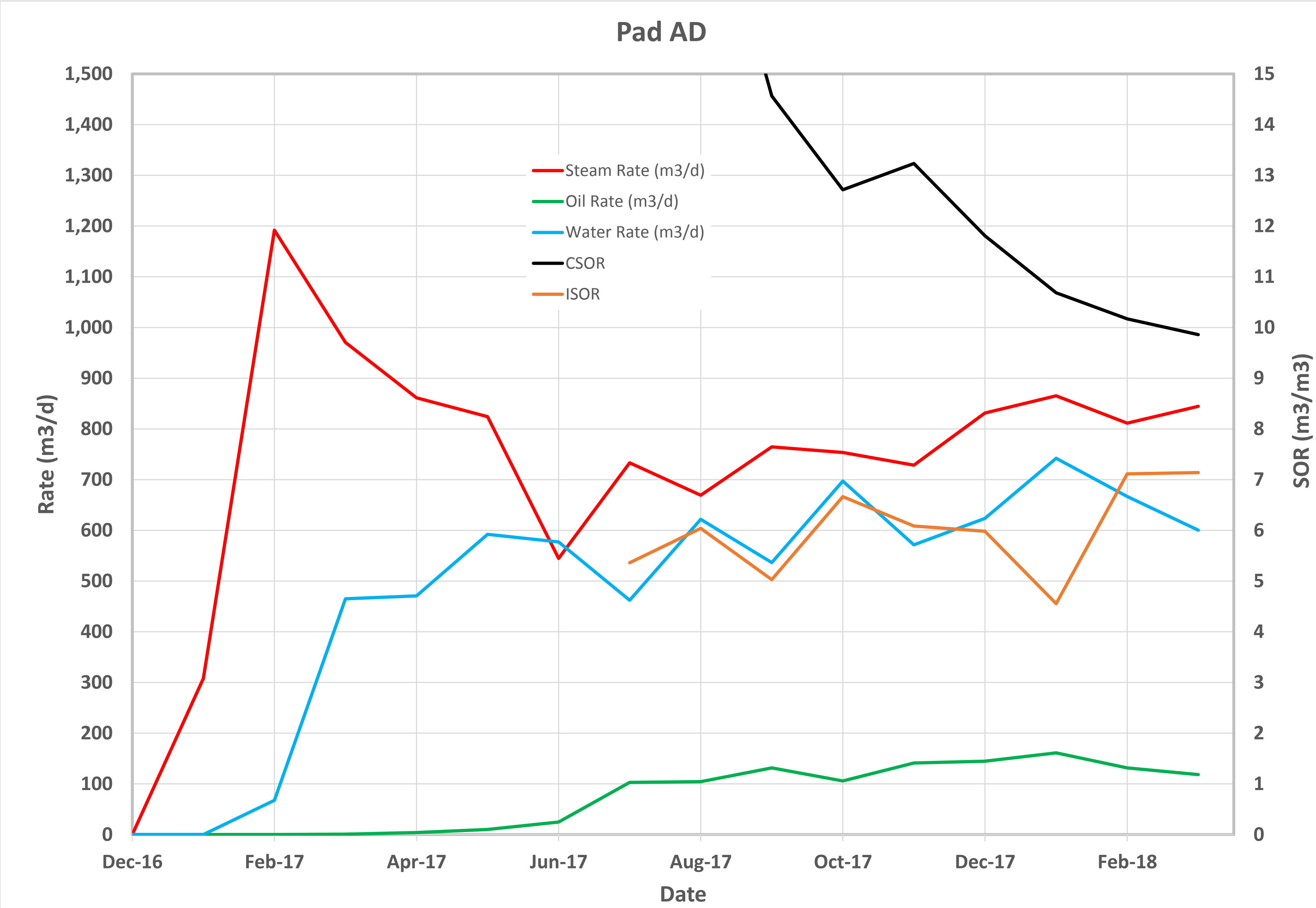


- ERE and Image
- ERE, Image and Core
- Thermocouple
- Thermocouple and Core
- Thermocouple, Image and COre
- Thermocouple and ERE
- Thermocouple, ERE and Core
- Thermocouple, ERE, Image and Core

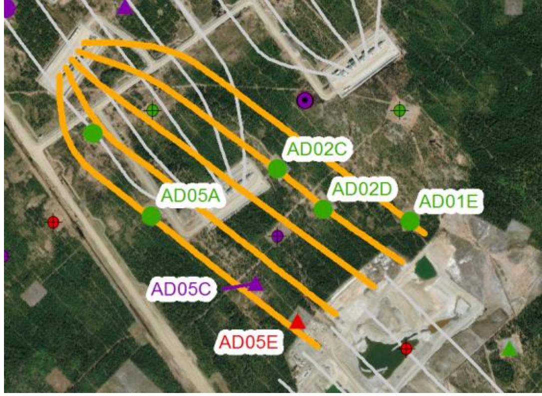


Steam Chamber growth above injector level

MRCP – Pad AD: Medium Performance Example



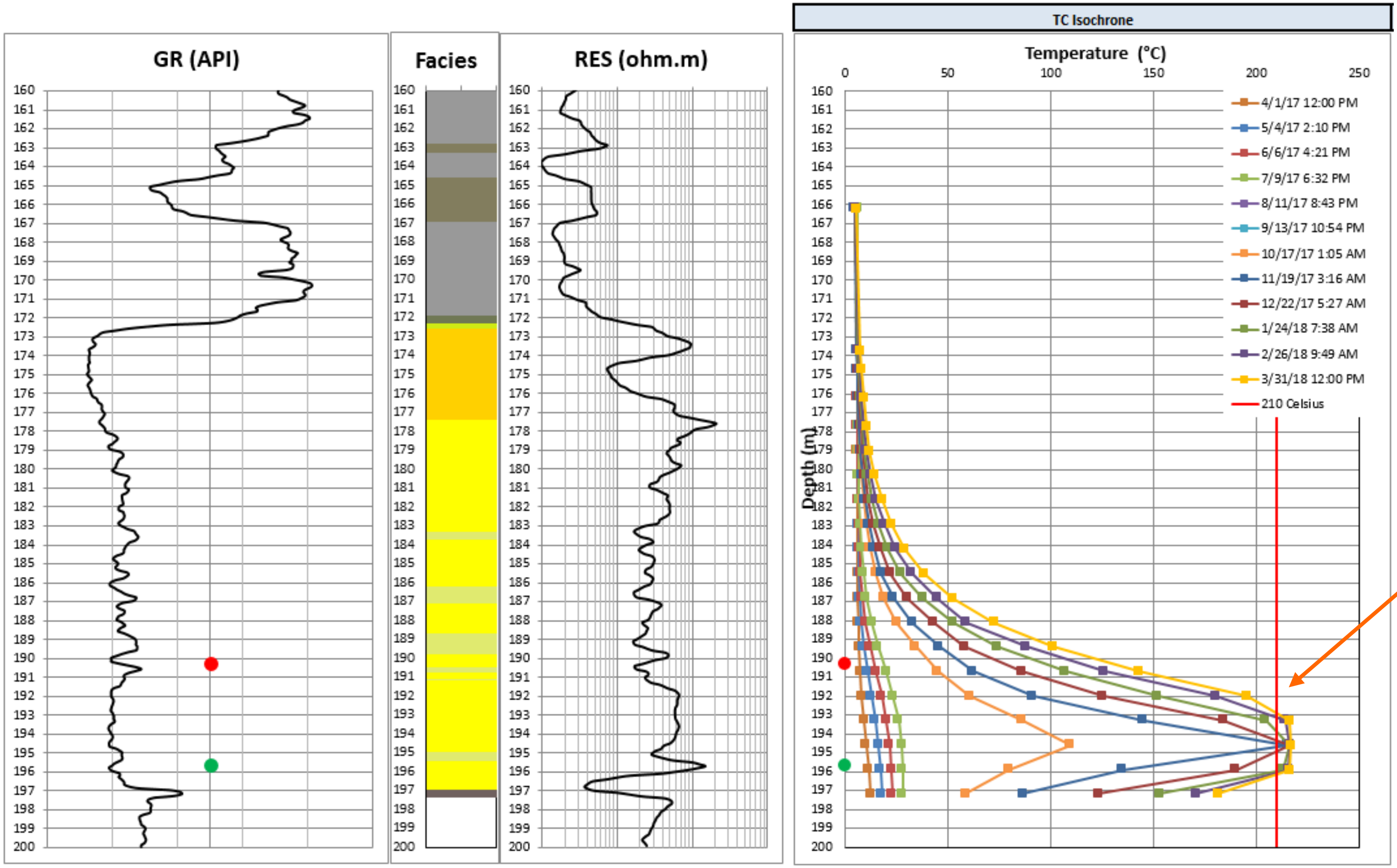
MRCP – Observation Well Examples: Pad AD



ERE and Image
ERE, Image and Core
Thermocouple
Thermocouple and Core
Thermocouple, Image and COre
Thermocouple and ERE
Thermocouple, ERE and Core
Thermocouple, ERE, Image and Core

6 Observation Wells in the Pad for steam chamber monitoring:

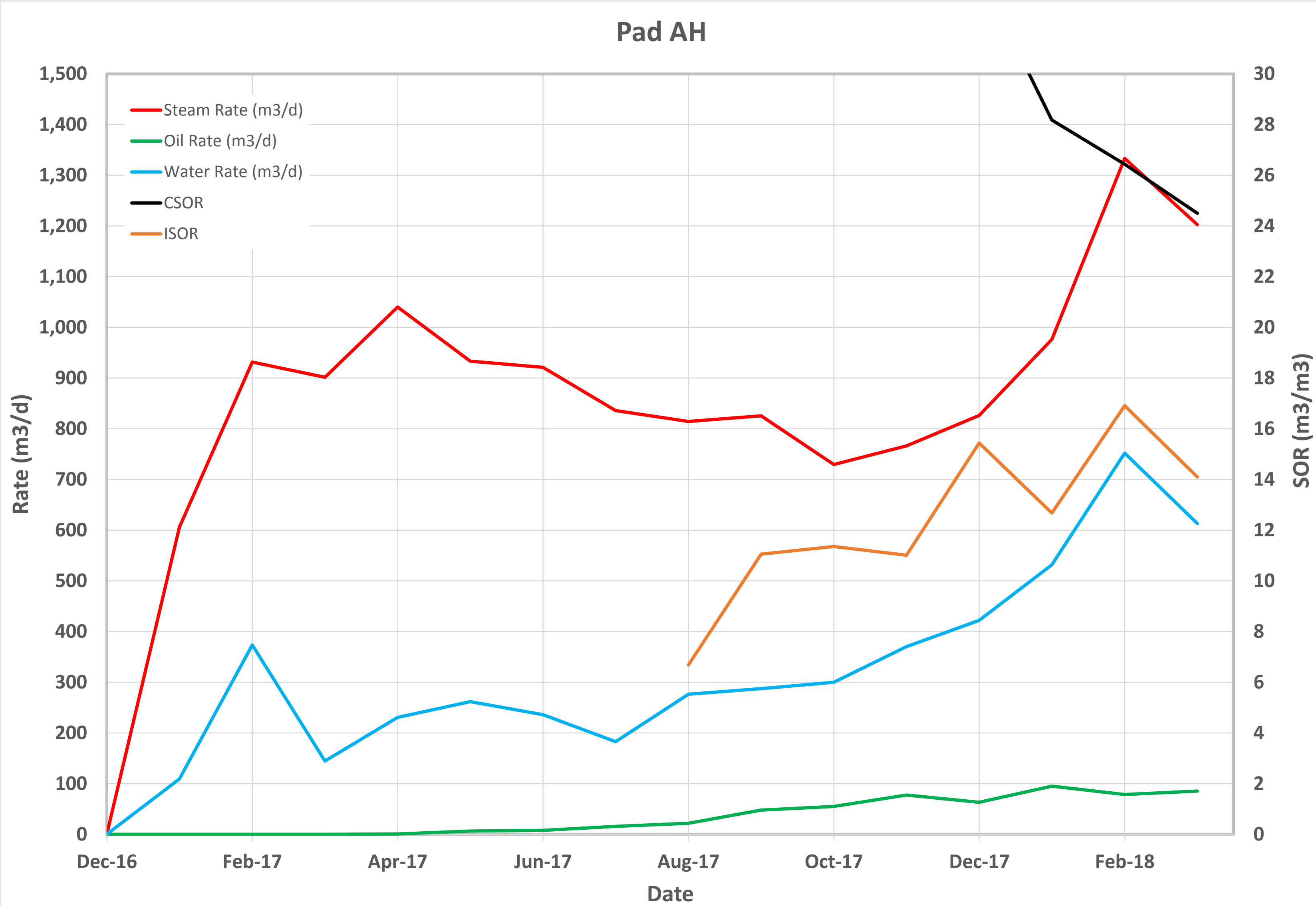
- Example: AD02D – 5.59 m from toe of AD02
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 11/2017



Steam Chamber between injector and producer

Influenced by mud baffles present between injector and producer

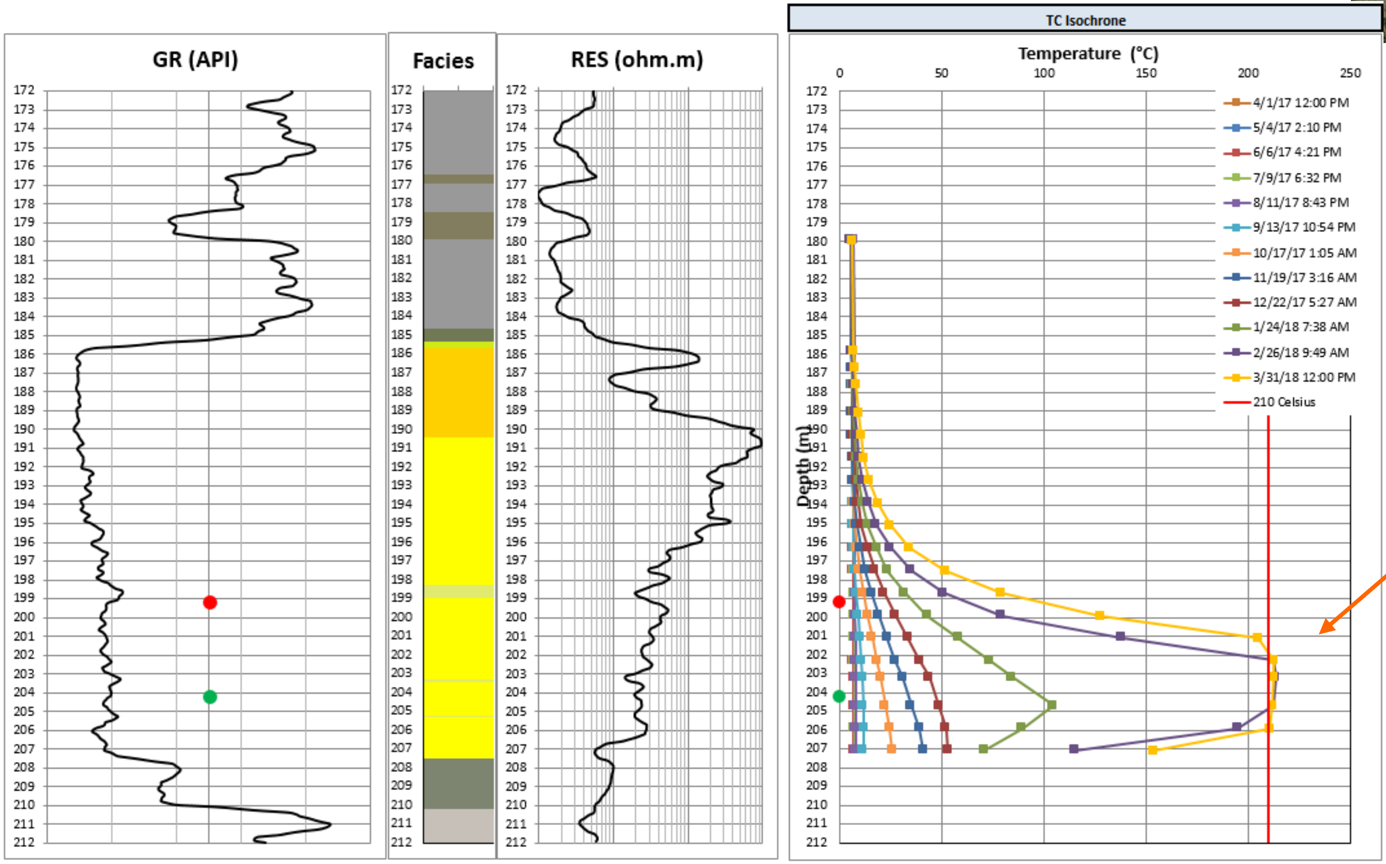
MRCP – Pad AH: Low Performance Example

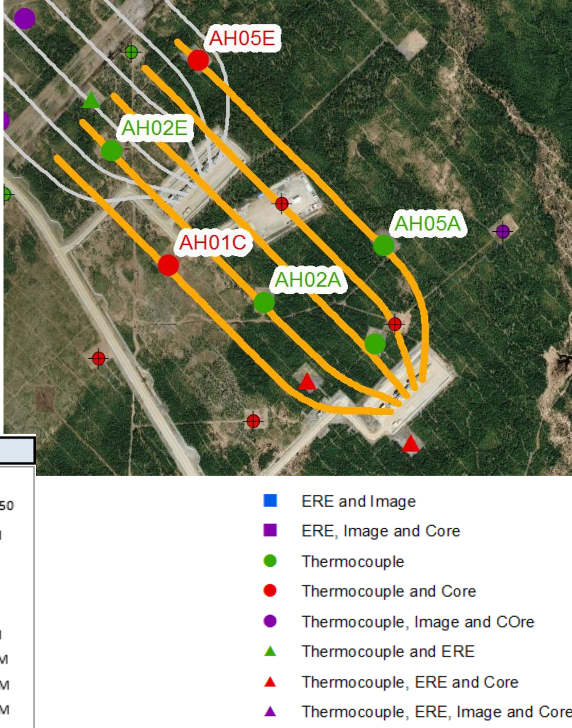


MRCP – Observation Well Examples: Pad AH

5 Observation Wells in the Pad for steam chamber monitoring:

- Example: AH02A – 8.36 m from mid-section of AH02
- Design: Obs Well w/ thermocouples
- Steam Chamber conditions seen since 02/2018

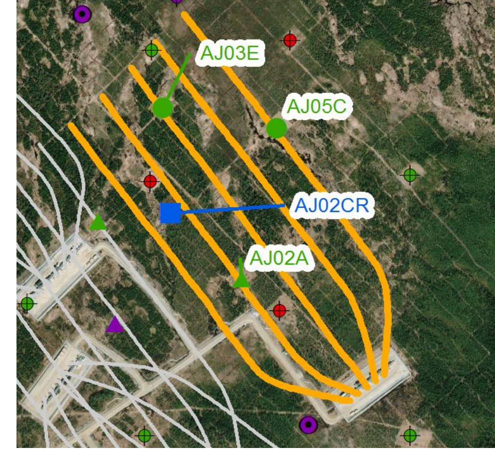




Steam Chamber between injector and producer

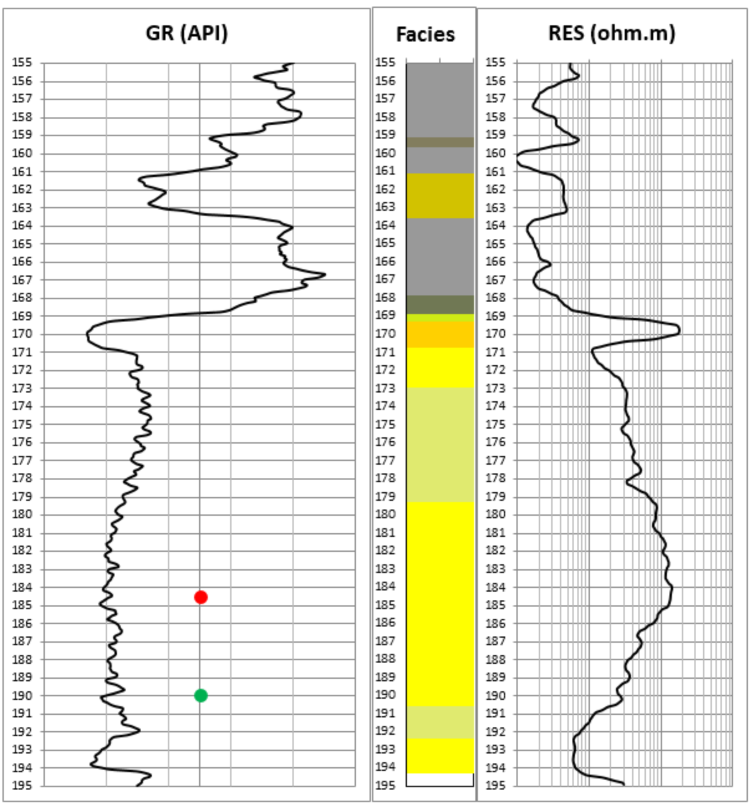
Influenced by mud baffles present between injector and producer and higher Sw to the bottom of the reservoir

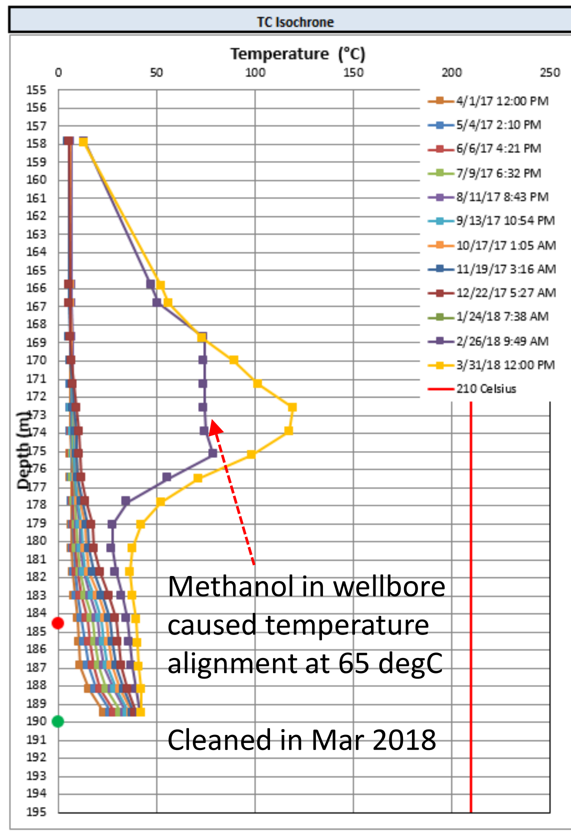
MRCP – Observation Well Examples: Pad AJ

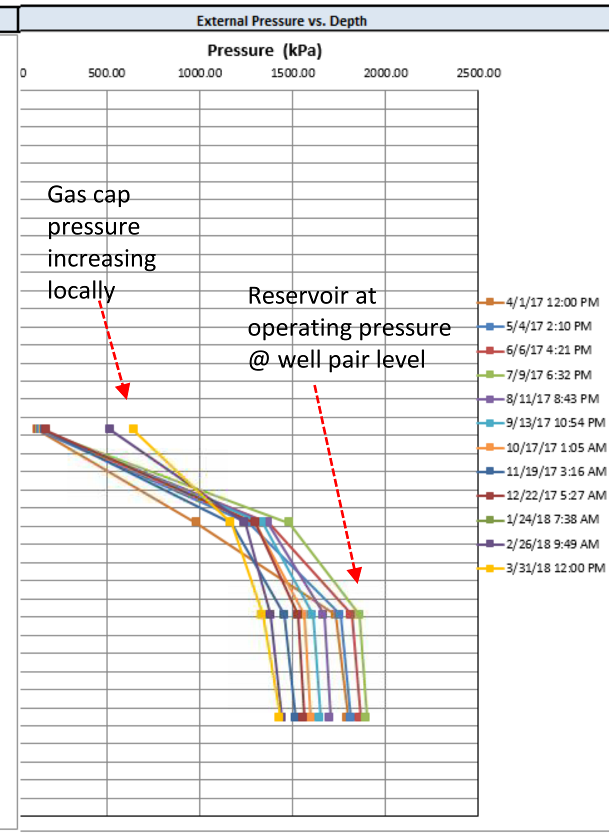


3 Observation Wells in the Pad for steam chamber monitoring:

- Example: AJ02A – 13.99 m from heel of AJ02
- Design: Perforated Obs Well w/ Thermocouples and EREs (Multi Zone)
- Growing temperature response
- This well shown a temperature alignment identified in other observation wells:
  - Temperature alignment caused by presence of methanol inside wellbores.
  - PPC has cleaned the wells where this has occurred.
- Early interaction of AJ02 with upper lean zone and gas cap identified through this well, upper reservoir zones slowly increasing temperature and pressure







Key Learnings To-Date

- Circulation
  - The reservoir has built pressure from original reservoir pressure of 400 kPag to 2,000 kPag as expected, but some wells required additional measures:
    - Bullheading was used to address high reservoir mobility in 19 wells for short term with success in meeting target pressures and switching back to circulation
    - Approved MOP of 2,300 kPaa was not sufficient to overcome the fluid column at a TVD of 210 m, therefore an application was made and approved to unload wells with a temporary elevated pressure (2,650 kPaa) to establish circulation
  - Multi-Phase Pump (MPP) at the pads were critical equipment for circulation
    - Used to drawdown the surface pressure for the returns during circulation
- SAGD
  - Continuing to ramp-up production through optimization efforts and mitigating the effects of:
    - Top gas and thicker lower transition zones
    - Circulation timing coupled with areas of the reservoir lower transition zone which influenced hot spots
  - The use of PCP was the best low cost conversion solution

MRCP – Field Performance

- **MRCP CPF design is 5,565m3/d (35,000bbls/d) bitumen production**
  - As of March 2018, MRCP was at 7 months into SAGD ramp-up from final conversions to SAGD
    - The first few months of full SAGD have shown higher rates, which was attributed to the “flush” production from circulation
- **Some areas are showing lower production and slower chamber development which is interpreted as being impacted by:**
  - Areas of thicker lower transition zone
    - During circulation, the steam leak-off was higher than what was anticipated in specific areas towards the south portion of the asset
    - This changed the operational strategies for the affected areas and will increase the ramp up duration
  - Top gas zone effects
    - At the early stages of ramp-up, a few wells were increasing steam rates faster than predicted
    - Upon investigations and through observation well data, it was determined that a few wells have come into contact with the top of zone gas earlier than expected
    - Thus reducing near term conformance development
  - Geological Baffles
    - Observation well and production data indicates that chamber development in various well pairs is being interrupted by baffles either in-between the injector and producer or above the injector

Future Initiatives

- Winter Appraisal Program:
  - Under evaluation
  - One groundwater monitoring well

- Commercial Amendments:
  - MOP Update – application submitted to the AER
  - Steam Stimulation Process – application submitted to the AER
  - Gas Cap Pressurization – application submitted to the AER

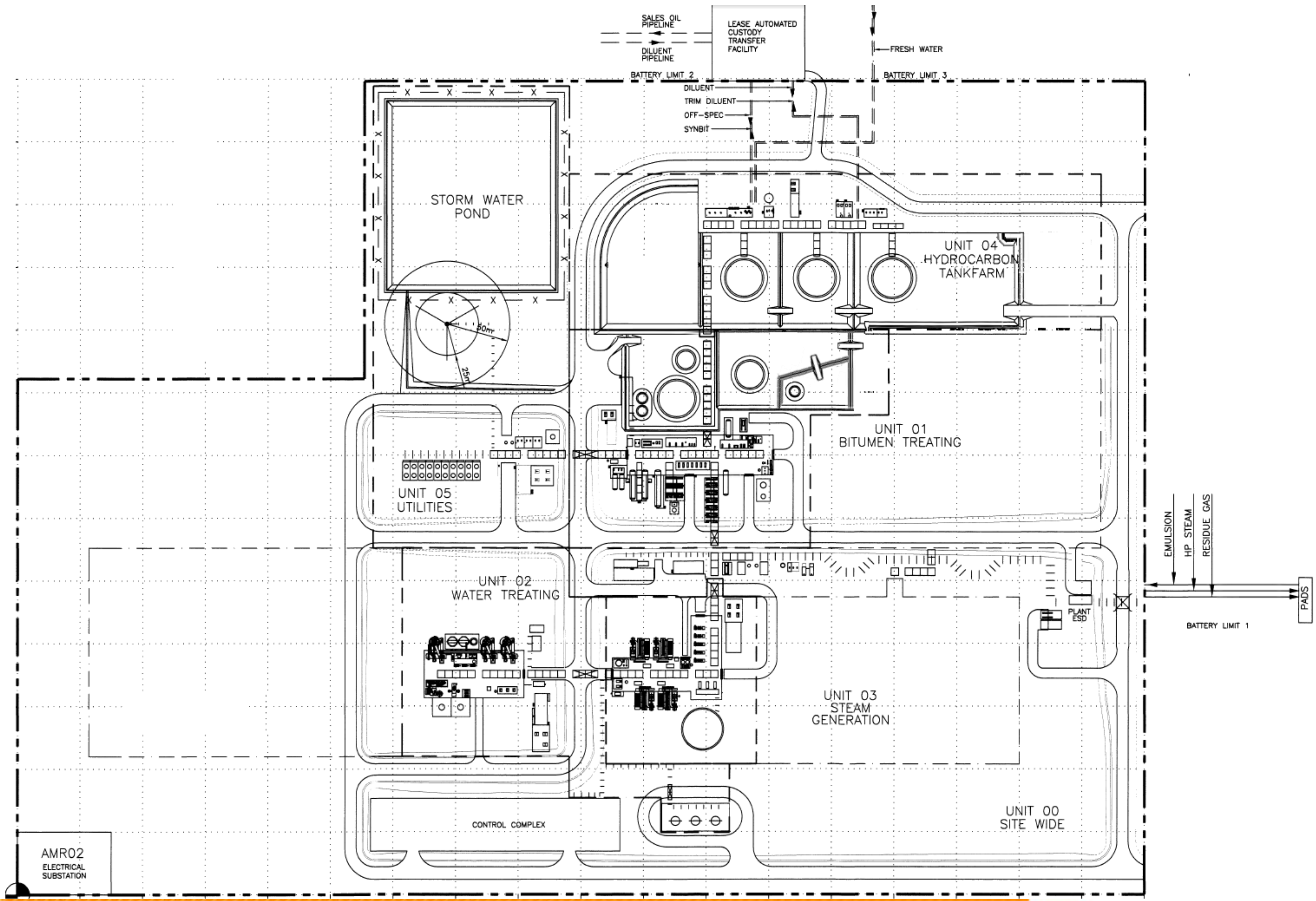
- New Wellpair Additions:
  - MacKay Phase 1A:
    - PCC received regulatory approval for 17 down spaced well pairs in 2015
    - Field construction has been deferred with potential to start in 2019
  - Next Sustaining Wellpair additions
    - Continue the internal project development process for the first group of sustaining well pairs

- Pad/Well Abandonments:
  - There are no pad or well abandonments planned in the next reporting cycle

3.1.2 SURFACE OPERATIONS, COMPLIANCE AND ISSUES NOT RELATED TO RESOURCE EVALUATION

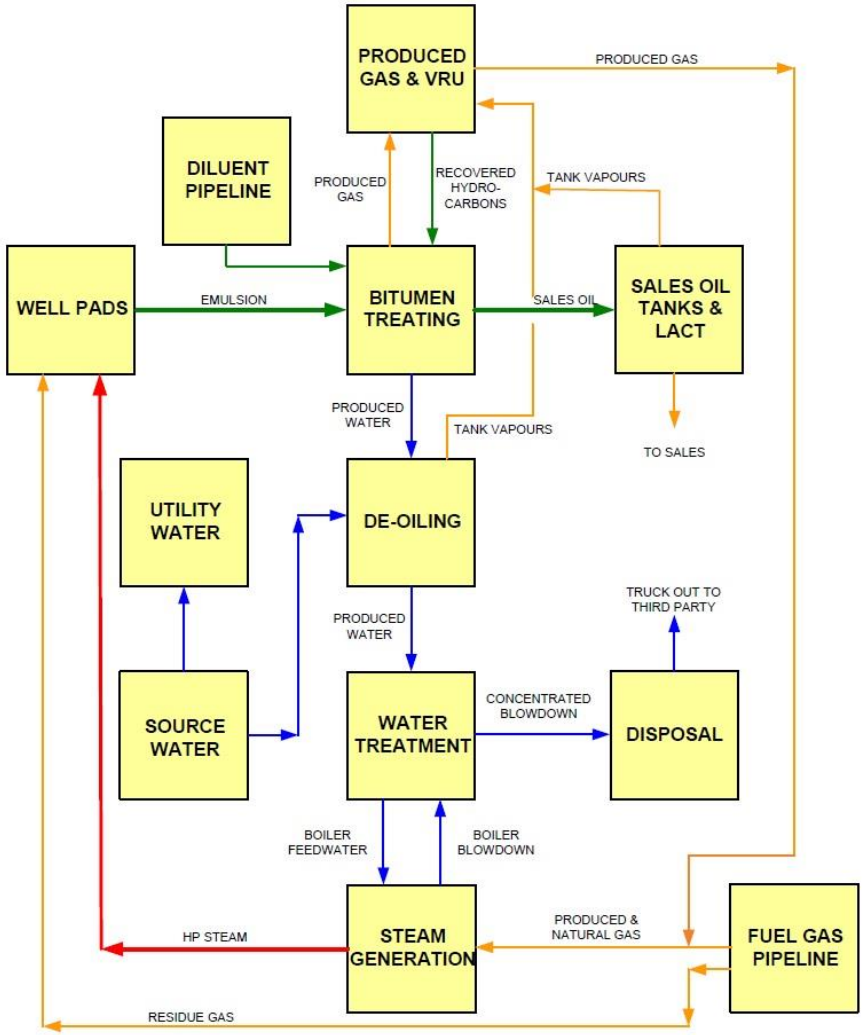
John Yang, Manager, Engineering
Devin Newman, Lead, Regulatory Affairs and Surface Land

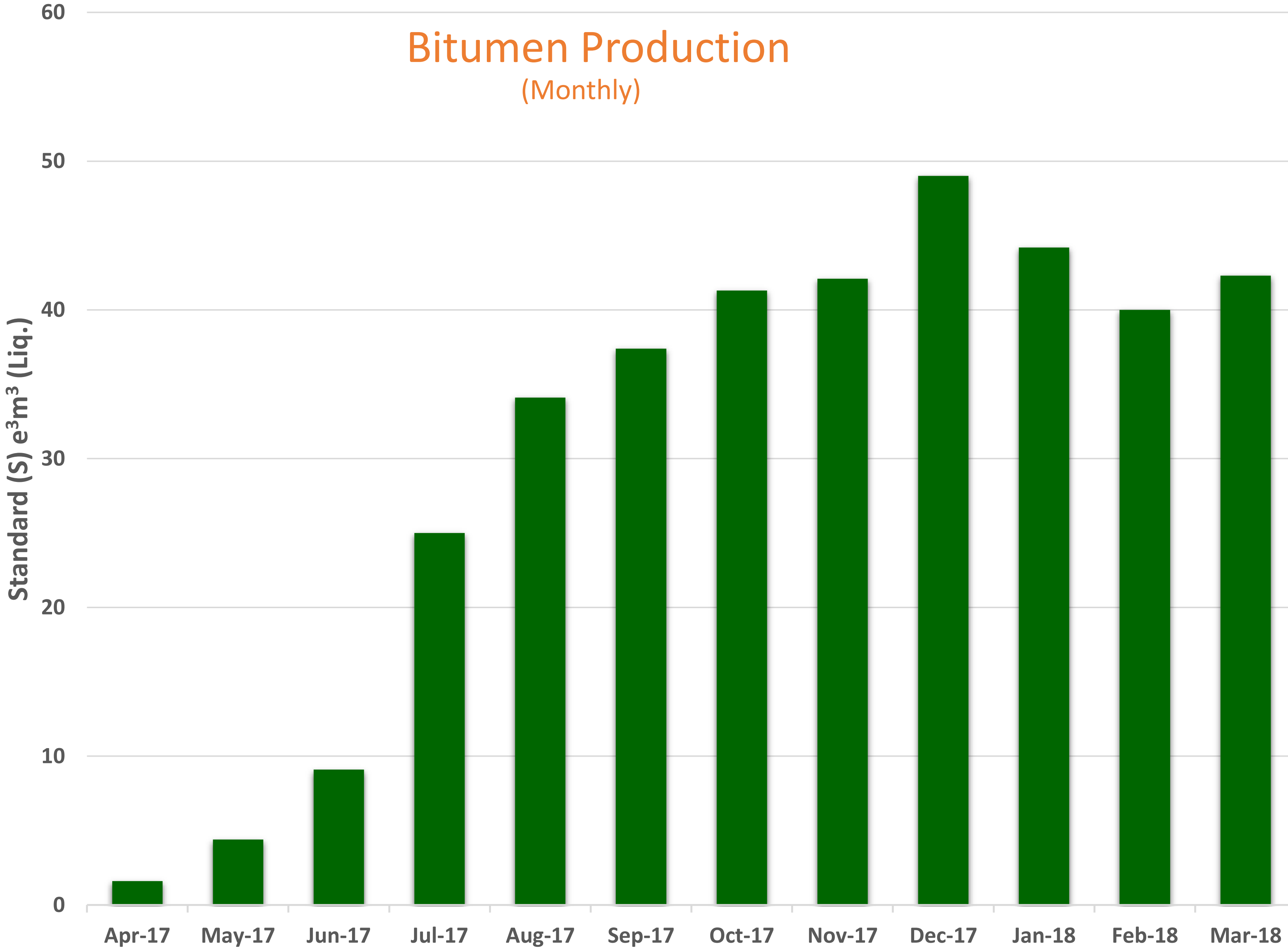
MRCP Central Processing Facility Phase 1 Plot Plan



MRCP Central Processing Facility – Aerial View

MRCP CPF General Block Flow Diagram





Bitumen Production
(Monthly)
Standard (S) e³m³ (Liq.)
60
50
40
30
20
10
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18

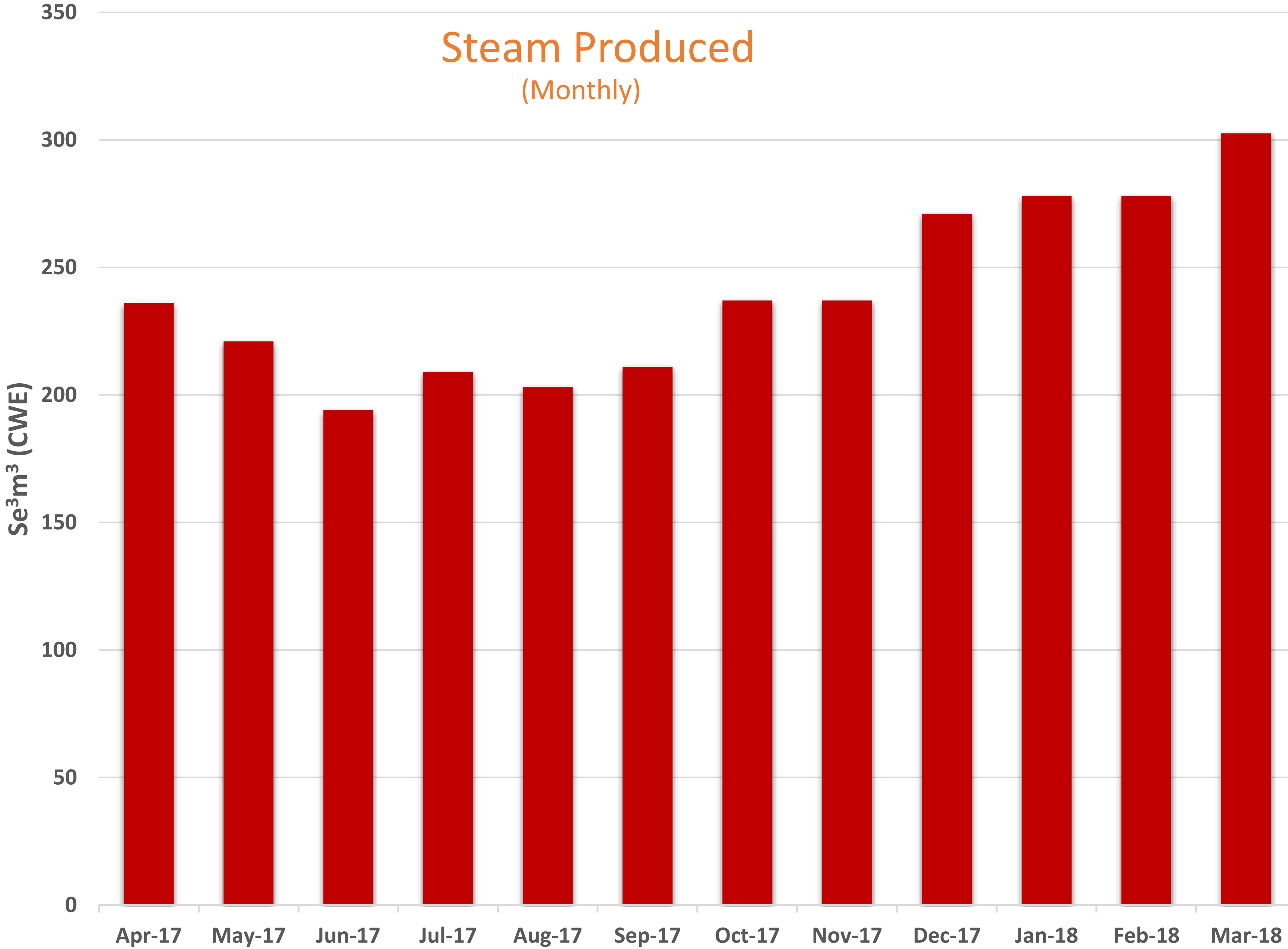
Water Treatment Technology

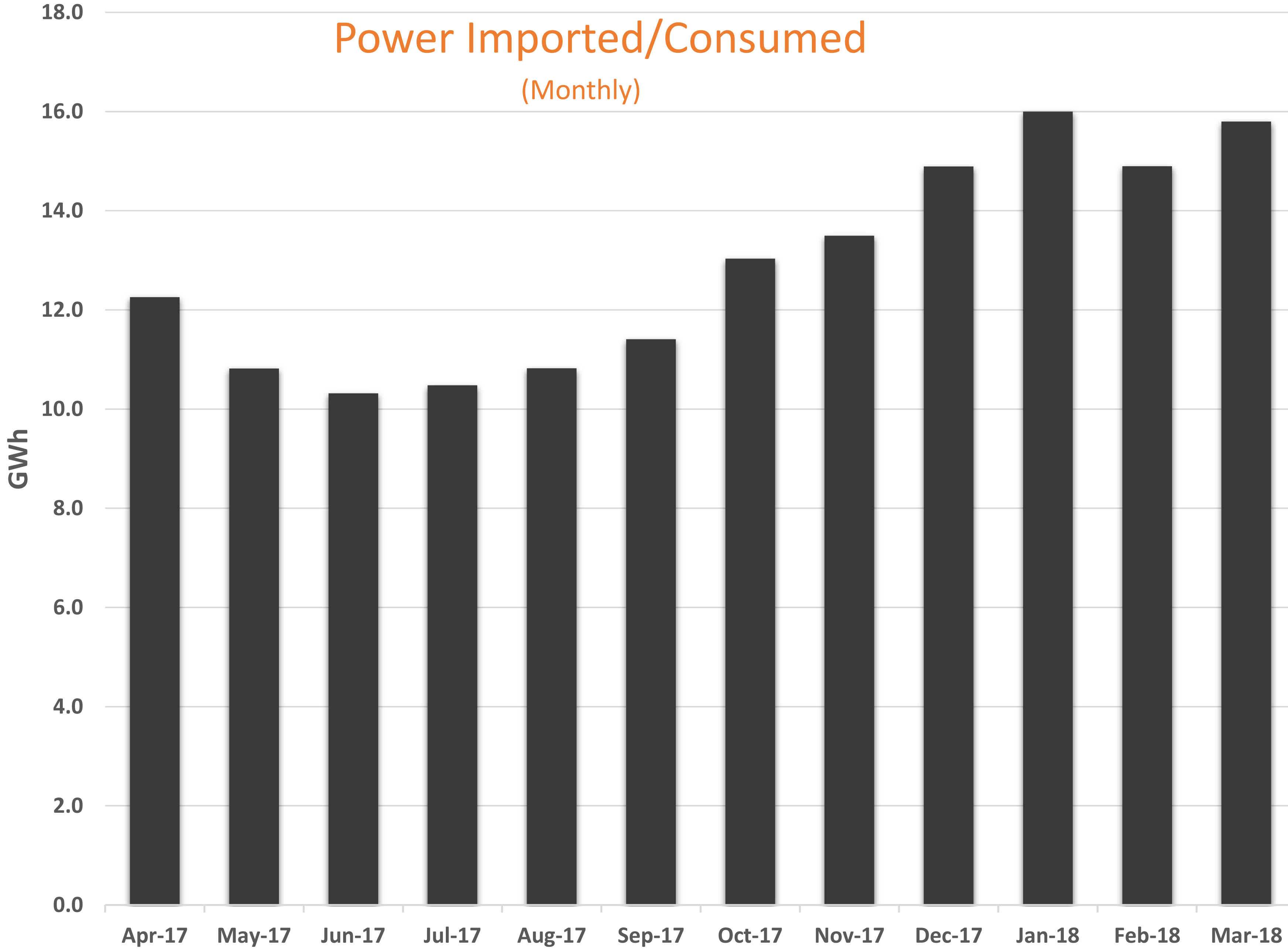
- High pH Vertical Tube Falling Film Mechanical Vapor Compression (MVC) Evaporators for produced water treating:
  - First Stage Evaporators x (2)
  - Second Stage Evaporator x (1)
- Forced Circulation MVC driven Concentrator for further concentrating of evaporator blowdown to Reduced Liquid Discharge (RLD)

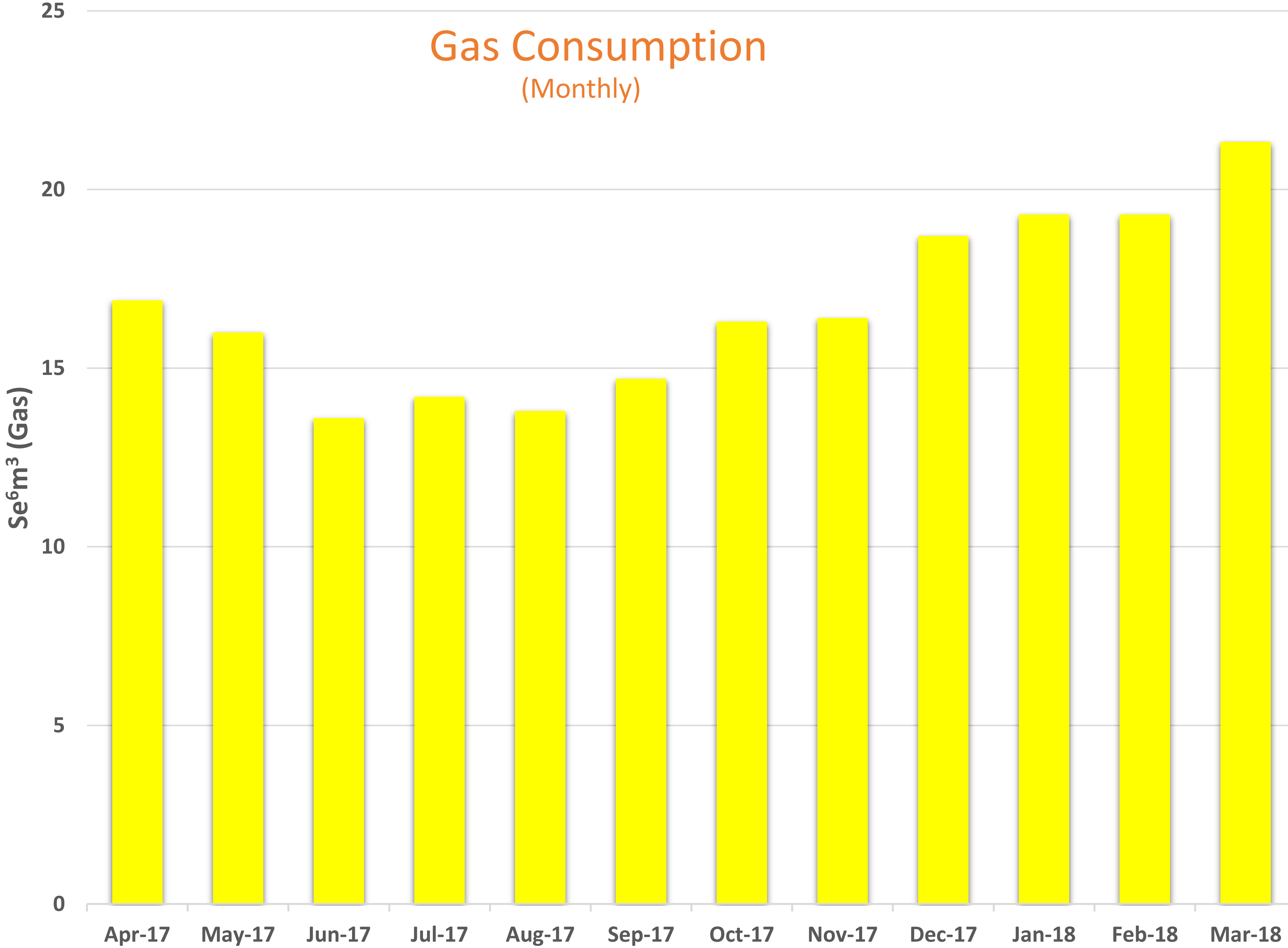
Water Treatment Successes and Challenges

- Successes:
  - The performance of evaporators and concentrator are meeting design expectations in general

- Challenges:
  - Equipment scaling due to hard non saline water service water. Source water of service water is switched to BFW.
  - Evaporator feed water system is experiencing solids deposition. PCC is currently evaluating the plan for modification.


Steam Produced
(Monthly)
Se³m³ (CWE)
350
300
250
200
150
100
50
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18

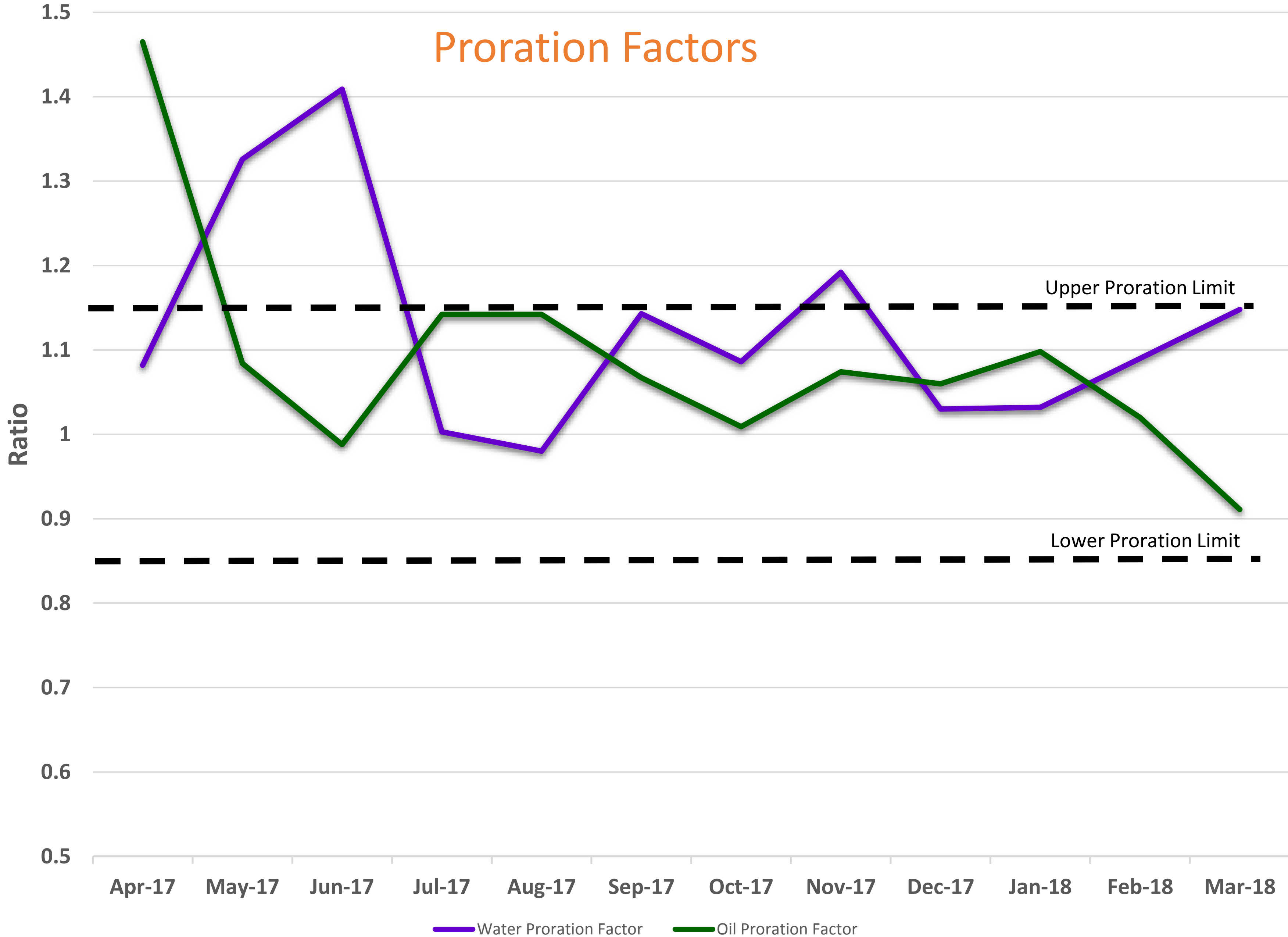

Power Imported/Consumed
(Monthly)
GWh
18.0
16.0
14.0
12.0
10.0
8.0
6.0
4.0
2.0
0.0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18


Gas Consumption
(Monthly)
Se^6m^3 (Gas)
25
20
15
10
5
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18

Measurement Accounting & Reporting Plan (MARP)

- AER Audit - MARP submitted in March, 2017
  - 2017 MARP Audit for PCC's MRCP was officially closed on November 11, 2017

- Mackay River Report Codes:
  - Production Battery AB BT 0142085
  - Injection Facility AB IF 0142086
  - Meter Station (Fuel Gas) AB MS 0136386
  - Custody Transfer Point (Diluent) AB PL 0142114
  - Custody Transfer Point (Product) AB PL 0144307


Proration Factors
Ratio
1.5
1.4
1.3
1.2
1.1
1
0.9
0.8
0.7
0.6
0.5
Upper Proration Limit
Lower Proration Limit
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18
Water Proration Factor
Oil Proration Factor

Non-Saline Water

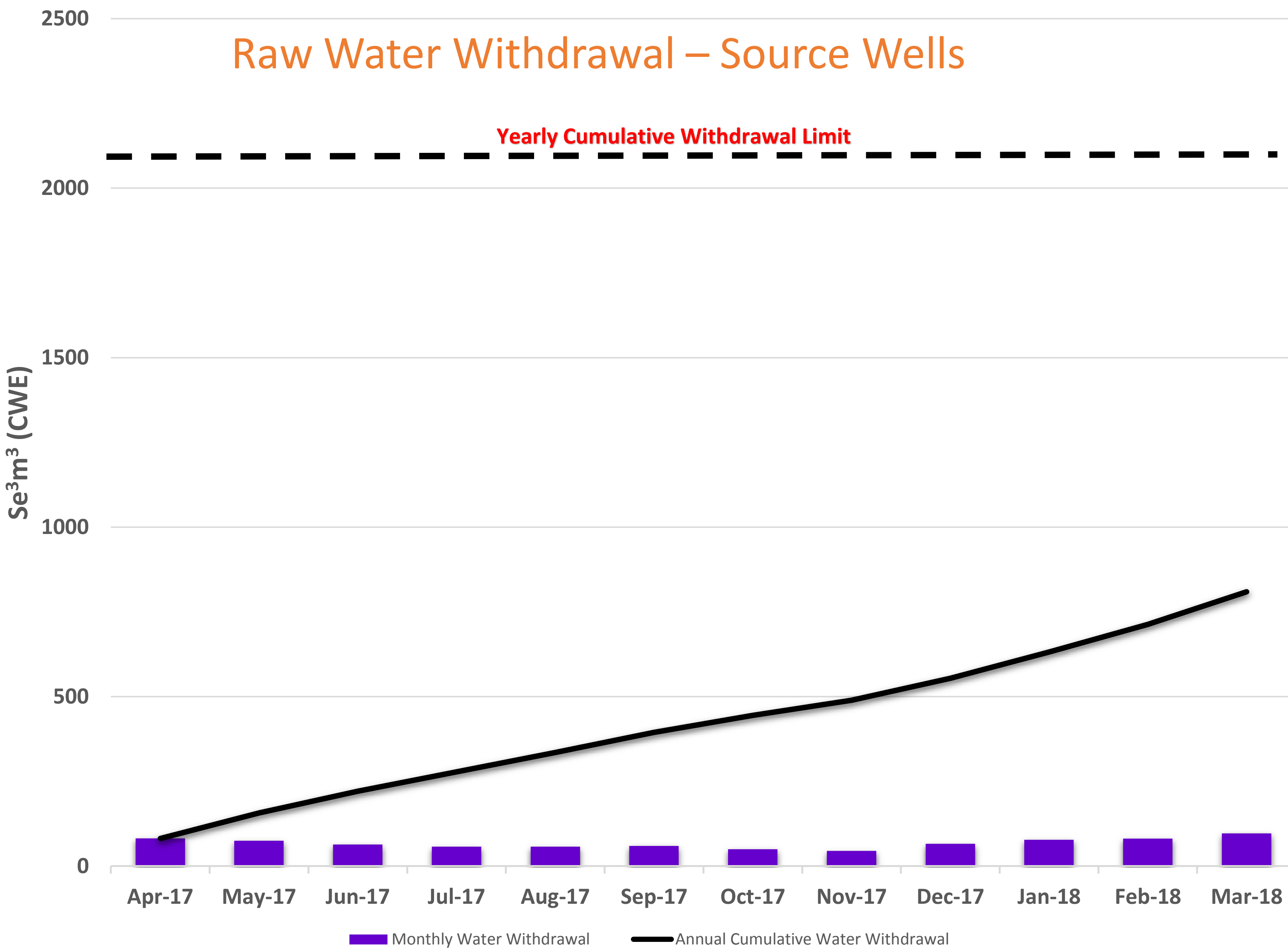
Source Water Wells

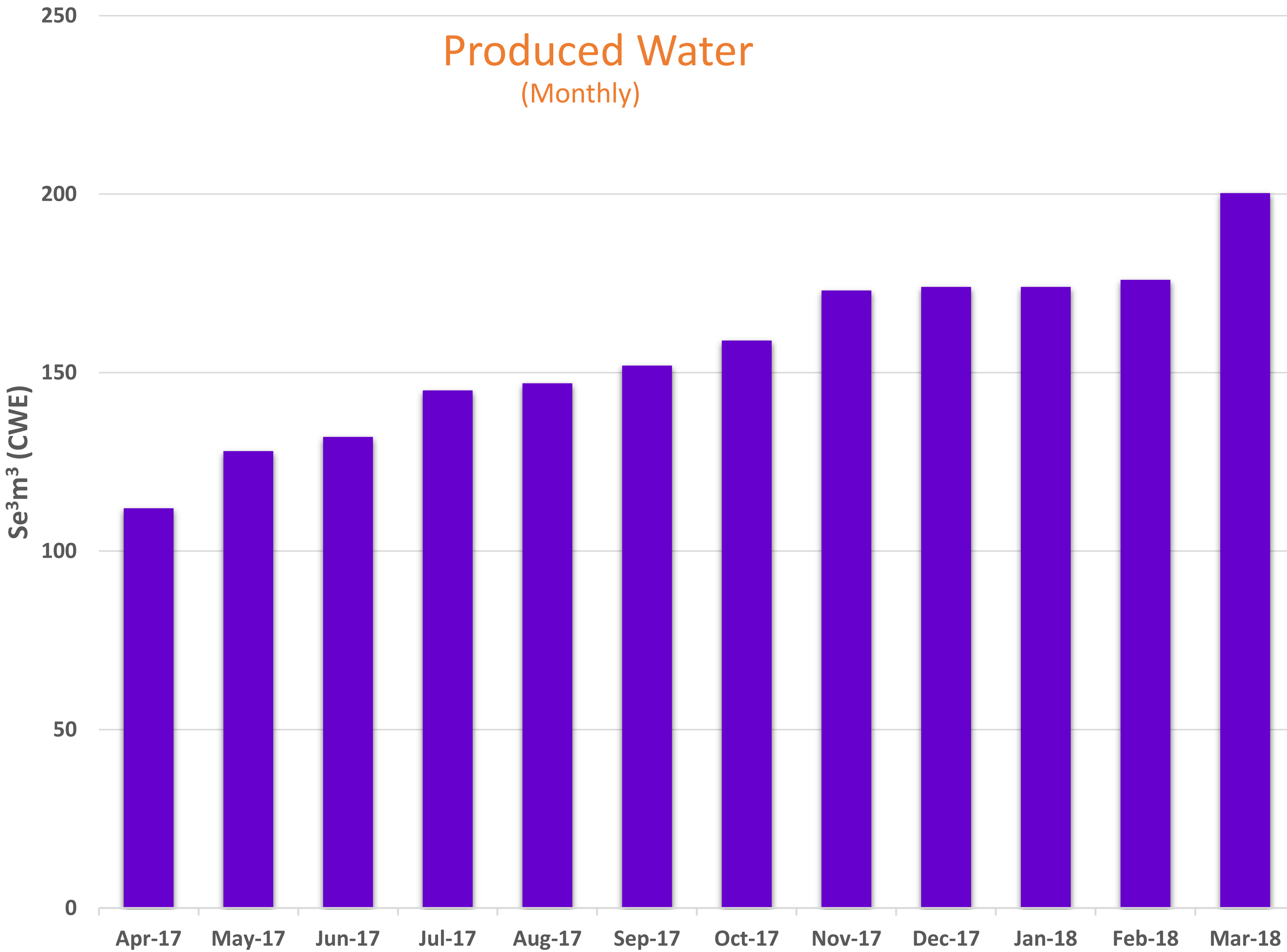
- Water Act Licence No. 00266369-01-03:
    - Approved Annual Withdrawal Volume = 2,116,964 m^3/year from the Empress Channel
        - 13-10-90-15W4, max rate 2,930 m^3/d
        - 14-11-90-15W4M, max rate 3,000 m^3/d
        - 02-13-90-15W4M, max rate 2,900 m^3/d
        - 08-13-90-15W4M, max rate 3,100 m^3/d

Domestic Water Wells

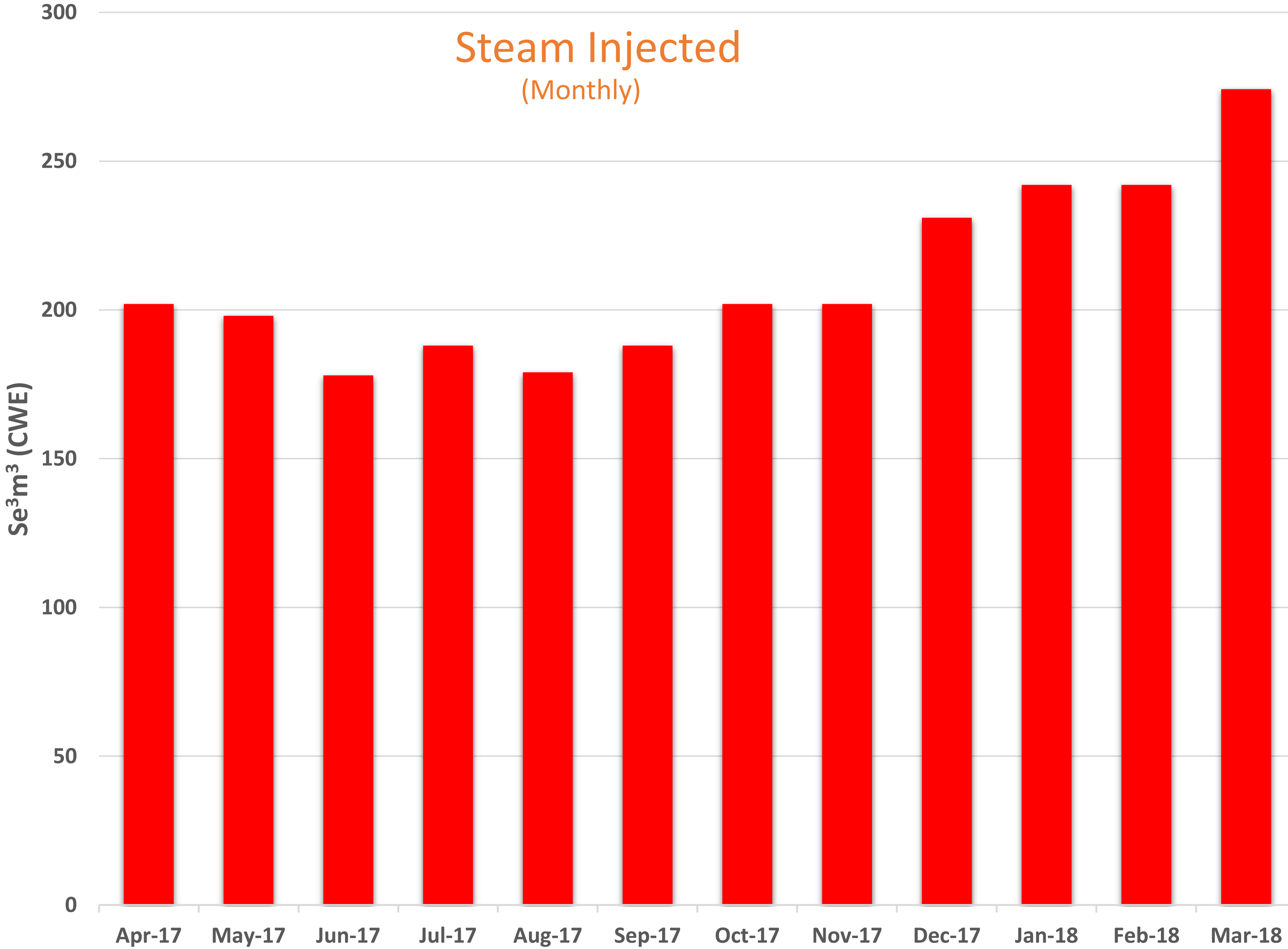
- Water Act Licence No. 00316276-00-00:
    - Approved Annual Withdrawal Volume = 82,125 m^3/yr from the Grand Rapids 4
        - 16-02-90-14W4M North, max rate 400 m^3/d
        - 16-02-90-14W4M South, max rate 360 m^3/d

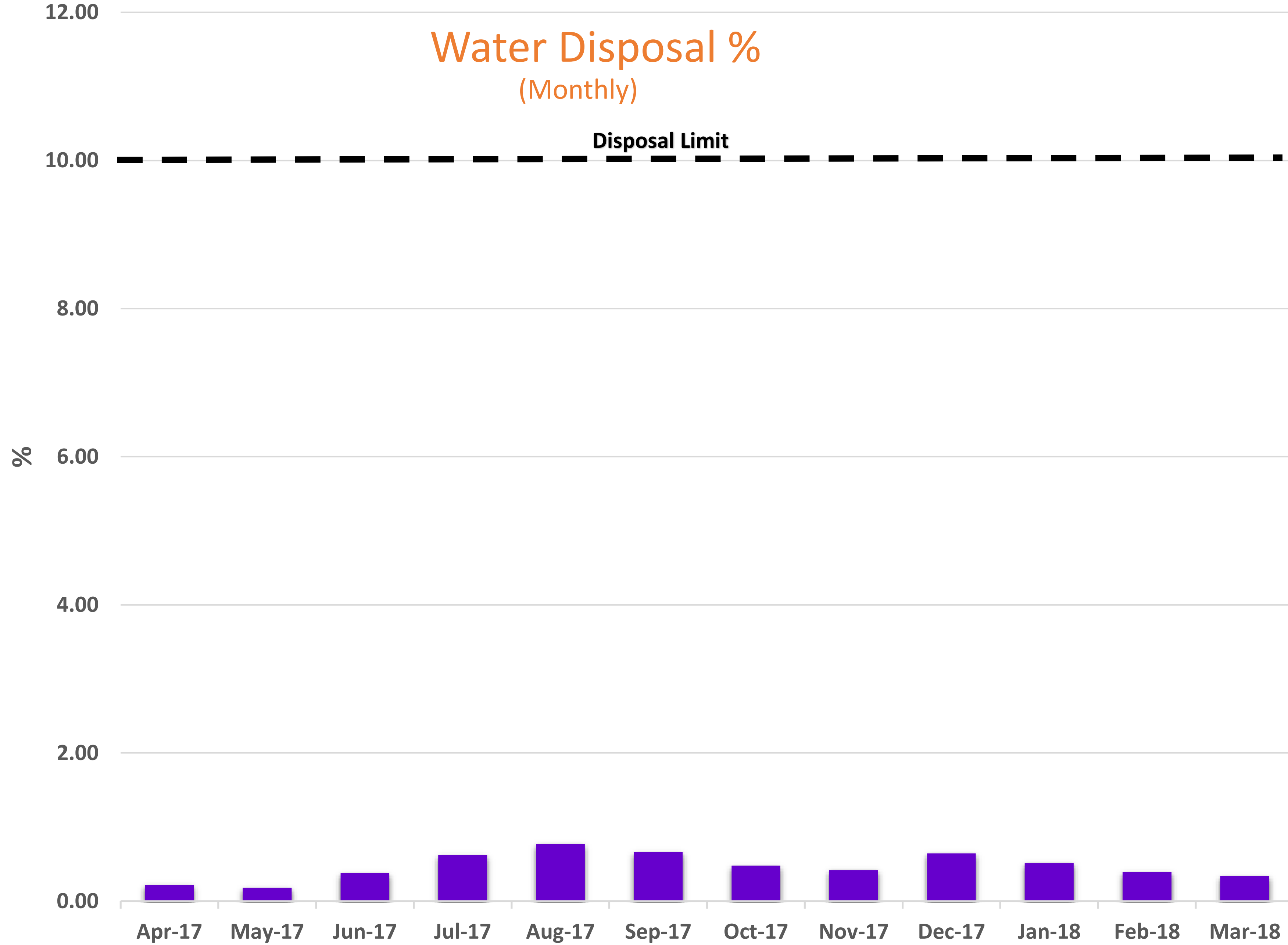
Raw Water Withdrawal – Source Wells





Produced Water
(Monthly)
Se^{3}m^3 (CWE)
250
200
150
100
50
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18


Steam Injected
(Monthly)
Se³m³ (CWE)
300
250
200
150
100
50
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18


Water Disposal %
(Monthly)
Disposal Limit
%
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18

Blowdown, Waste and Disposal Wells

Blowdown Recycle

- Continuous blowdown from boilers is injected into the HP steam line.
- Intermittent blowdown from boilers is recycled to Water Treatment.

Waste and Disposal Wells

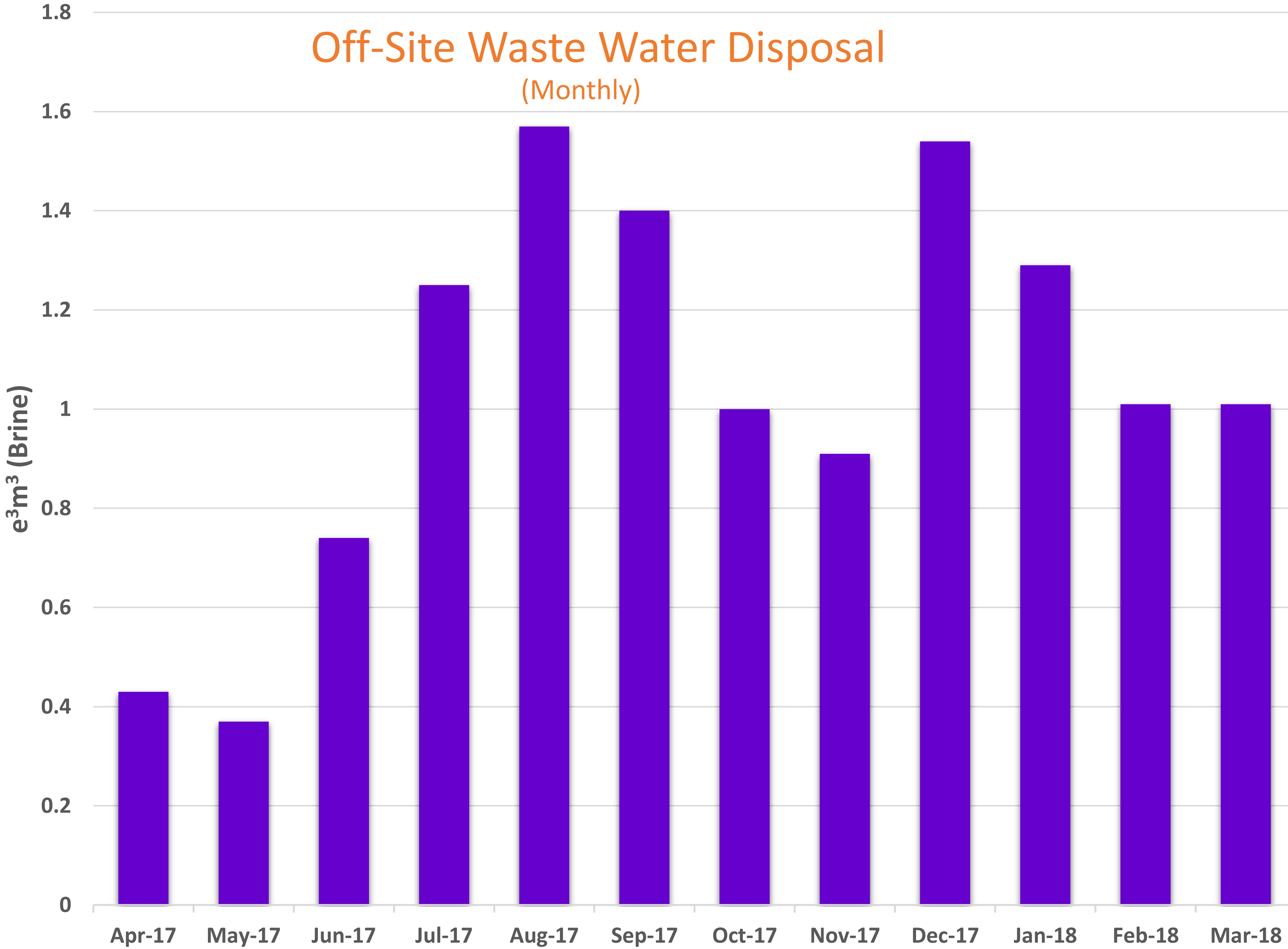
- Waste Tracker software and AER manifests are used to track and submit data to AER.
- No disposal wells are associated with MRCP Phase 1.

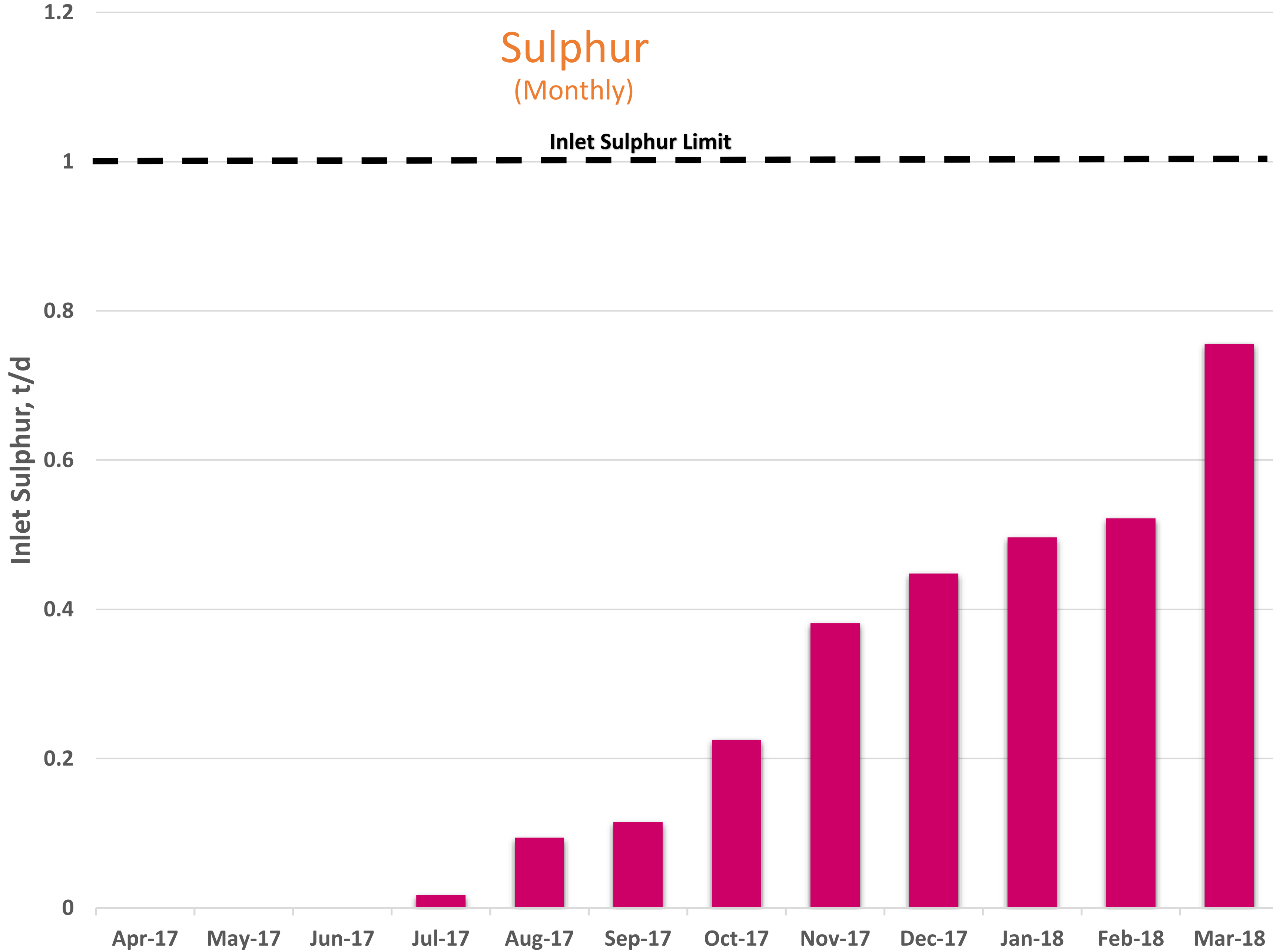
Off-Site Waste Water Disposal

- Concentrated waste brine, emulsified slop oil, and desand slurry water streams are disposed of off-site.

- Location of disposal sites:
  - Tervita Lindbergh – AB WP 0000557 (For evaporator/concentrator brine water)
  - Newalta Fort McMurray - AB WP 0133414 (For emulsified slop oil water and de-sand slurry water)

- Sources of disposal water:
  - Evaporator/Concentrator Waste Water Tanks
  - Slop Oil Tank
  - Desand/Decant Tanks


Off-Site Waste Water Disposal
(Monthly)
e³m³ (Brine)
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18


Sulphur
(Monthly)
Inlet Sulphur Limit
Inlet Sulphur, t/d
1.2
1
0.8
0.6
0.4
0.2
0
Apr-17
May-17
Jun-17
Jul-17
Aug-17
Sep-17
Oct-17
Nov-17
Dec-17
Jan-18
Feb-18
Mar-18

Future Plans – Sulphur Recovery

- The inlet sulphur production at the MRCP was steadily increasing from late 2017.

    - PCC is currently evaluating the potential for H_2S sequestration if the 1 tonne/day sulphur limit is approached in the near term.

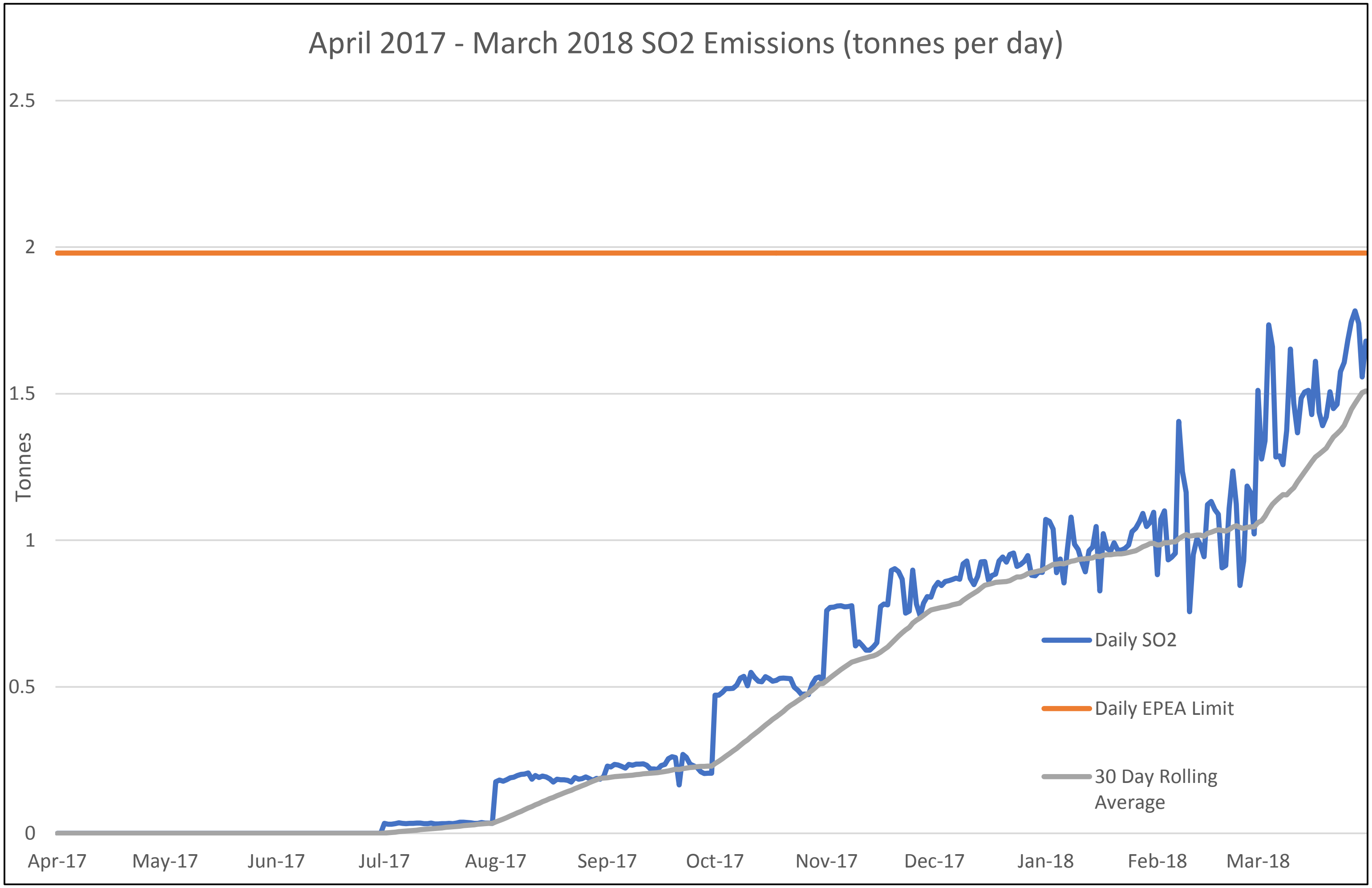
Future Plans – Surface Facilities

- PCC is currently focused on optimization and efficiency gains to support further production growth. No major changes to surface facilities are proposed at this time.
- Minor surface modifications will be required for the Gas Cap Pressurization project.
- Routine maintenance may require temporary shutdowns of equipment.

Actual Calendar Quarter-Year Sulphur Emissions

	Total Sulphur Emissions (tonnes)	Average Daily Sulphur Emissions (tonnes)
2017-Q2	0.00	0.00
2017-Q3	6.88	0.07
2017-Q4	44.61	0.36
2018-Q1	57.58	0.59

Peak Daily and Rolling Average SO_2 Emissions



Sulphur / SO_2 Emission Compared to Limits

EPEA Limit – SO2 = 1.98 t per day

ID 2001-3 – Sulphur Inlet Rate = 1 t per day requires 70% Sulphur Recovery

Month	Total Daily Average – Sulphur (t)	Calendar Quarterly Average - Sulphur (t)	Peak Daily Maximum – SO2 (t)
July	0.017	0.115	0.04
August	0.094		0.21
September	0.115		0.27
October	0.225	0.351	0.55
November	0.381		0.90
December	0.448		0.96
January	0.494	0.589	1.10
February	0.522		1.41
March	0.752		1.78

Regulatory Compliance – Voluntary Self Disclosures

- On April 27, 2018 PCC submitted a voluntary self-disclosure for a Directive 056 licenced Sulphur inlet and emission rate exceedance.
  - The approved rate for the total Sulphur inlet and the total continuous Sulphur emission is 0.26 t/d.
  - The licenced rate of 0.26 t/d is based on estimated values, with actual Sulphur rates being higher than predicted at the licencing stage.

- On February 16, 2018 PCC submitted a voluntary self-disclosure for a short-term MOP exceedance.
  - A residue gas line which provides gas to our bottom hole pressure management system froze resulting in inaccurate pressure readings.
  - Persistent cold weather combined with intermittent supply of residue gas is believed to have created condensation in the gas supply line which froze and created an ice blockage.
  - This incident was isolated to the AH02 injector well and MOP was believed to be exceeded by approximately 125 kPa for 42-43 hours.
  - To ensure this issue does not occur again PCC will inject a continuous residue gas supply to all bottomhole pressure gauges during colder months of the year.

Non-Compliances related to EPEA and Water Act Approvals

Date Reported	Incident No.	Incident Type	Contravention	Resolution
6/2/2017	325140	During surface water pump off, representative samples for laboratory analysis were not collected.	EPEA Approval Schedule 3, Clause 4	Re-educated personnel on surface water pump off procedure.
8/28/2017	328985	The Unit 01 Vapour Recovery Unit (VRU) tripped, resulting in a venting event for 40 minutes.	AER Directive 60 Section 8.2	System process upset.
9/18/2017	329828	The foul vent compressor in Unit 02 overpressured, in order to lower the pressure within the compressor the compressor was vented.	AER Directive 60 Section 8.2	System process upset.
12/29/2017	333220	The Unit 01 Vapour Recovery Unit (VRU) tripped, resulting in a venting event for 18 minutes.	AER Directive 60 Section 8.2	System process upset.
1/17/2018	333803	Diversion of water for unauthorized purposes.	Water diverted for a purpose not identified in the Water Act Approval.	Approval amended to include further uses.
2/22/2018	334965	The software that calculates the Cylinder Gas Audit (CGA) results showed passing results, however the linearity calculation was not used to determine the pass or fail.	Section 5.2.3. of the CEMS code.	Steam Generator and CEMS unit operating normally, awaiting repairs on the CGA system. Once repaired, the CEMS will be calibrated and CGAs completed.

EPEA and Water Act Amendments

- There have been no amendments to EPEA approval No. 254465-00-02 since the last performance presentation.
  - PCC submitted an application to amend EPEA approval No. 254465-00-02 together with the category 2 application to amend commercial scheme approval No. 11715 for gas cap pressurization.
- Water Act approval No. 00266369-01-04 was amended to reflect the corporate name change from Brion Energy Corporation to PetroChina Canada Ltd. It is now approval No. 00266369-01-05.

Compliance Statement

To the best of our knowledge, PCC's MRCP is compliant with all conditions of its approvals and associated regulations with the exception of items disclosed in previous slides.

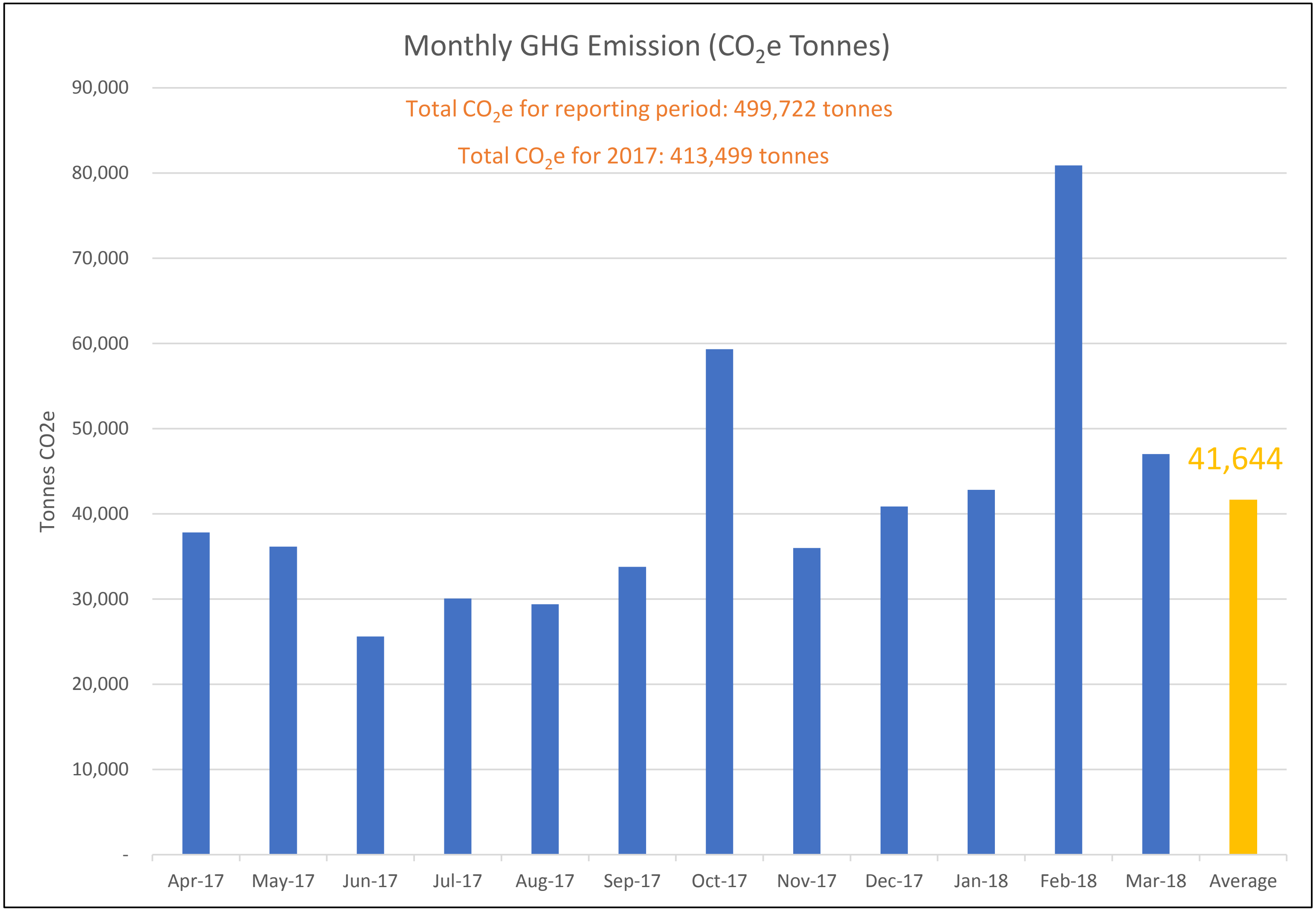
EPEA Monitoring Programs

Monitoring Programs Required under EPEA Approval	
Program	**Progress and Results**
Groundwater Monitoring	• Groundwater monitoring was conducted in May and September 2017 at the MCP and Pad AJ • MCP groundwater quality was generally consistent with baseline levels • Groundwater levels in the Grand Rapids 4 and 5 aquifers were relatively stable in 2017 and consistent with historical conditions
Wetland Monitoring	• The next comprehensive wetland monitoring report is due to the AER on December 31, 2018 • The program continued in 2017 with soil, vegetation and water monitoring in the designated locations. • The next sample period will be in 2019
Wetland Reclamation Trial	• A comparison of samples collected from unsalvaged soil beneath SAGD Pad AH, stockpiled soil, and undisturbed soil. ○ Samples are to be collected at 2, 3, 5, 10, and 20 years post construction of SAGD Pad AH. ○ Samples have been collected for years 2, and 3. Samples for year 5 will be collected in 2018. ○ After three years, the soil under SAGD Pad AH tended to have properties that were more comparable to undisturbed soil than stockpiled soil.
Wildlife Mitigation and Monitoring	• The next comprehensive wildlife report is due to the AER on May 30, 2018 • Goal is to reduce wildlife-human conflicts, minimize vehicle-wildlife collisions, manage access roads and right-of-ways, reduce impact to wildlife during sensitive periods, improve worker awareness of wildlife, minimize sensory disturbance, eliminate barriers to movement and minimize habitat loss
Caribou Mitigation and Monitoring	• The six locations from the caribou habitat restoration trial were evaluated for survival of transplanted lichen, black spruce seedlings and the emergence of other vegetation species again in 2017 • Early assessment indicates that some locations have had better success in discouraging access than others; there is now an active game trail through the tree line adjacent to one of the high density placements, which is an indication of success of that study location
Project-Level Conservation, Reclamation and Closure Plan	• Completed and submitted to the AER on November 30, 2017 • Currently in the AER review stage
Reclamation Monitoring Program	• Currently being implemented on reclaimed portions of Borrow Areas 12, 38, and 118. • Monitoring will continue until the AER issues the requisite reclamation certificates

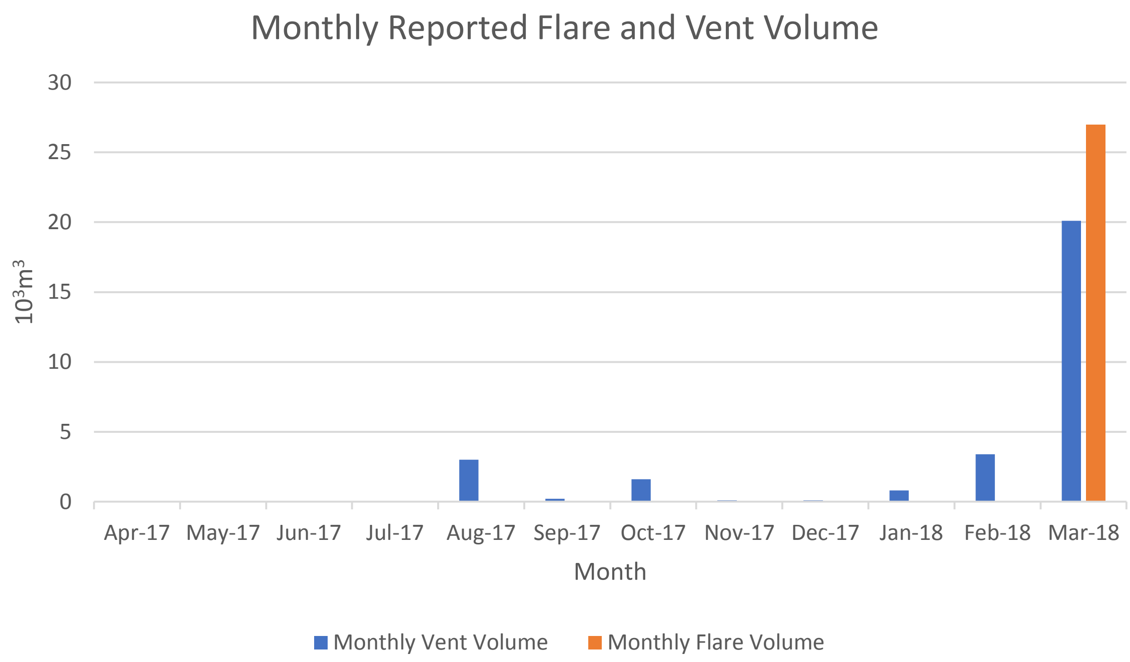
Ambient Air Quality Monitoring Results

2017 Q2 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	4	23	33	3.20
Average	0.03	1.29	0.49	2.12
AAAQO Limit	10	159	172	N/A
2017 Q3 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	3	11	16	2.90
Average	0.03	0.80	0.24	2.13
AAAQO Limit	10	159	172	N/A
2017 Q4 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	2	28.8	35	3.10
Average	0.11	1.90	0.51	2.27
AAAQO Limit	10	159	172	N/A
2018 Q1 1-hour Averages				
	H_2S (ppb)	NO_2 (ppb)	SO_2 (ppb)	THC (ppm)
Maximum	7	27.9	15	3
Average	0.15	3.22	0.66	2.30
AAAQO Limit	10	159	172	N/A

Greenhouse Gas Emissions



Flaring and Venting at the MRCP



	Number of Incidents per Month	
Month	**Vent**	**Flare**
Apr-17	0	0
May-17	0	0
Jun-17	0	0
Jul-17	0	0
Aug-17	1	0
Sep-17	1	0
Oct-17	2	0
Nov-17	1	0
Dec-17	1	0
Jan-18	1	0
Feb-18	3	0
Mar-18	1	1

- PCC submitted a total of 11 planned and unplanned venting reports and 1 flaring event.

Sources of venting include:

- The skim tank (due to vapour recovery unit trips and planned maintenance)
- The evaporator foul vent (due to foul vent compressor trips)

Flaring event was due to a power outage.

- PCC has not experienced any major operational issues that resulted in significant flaring or venting of gas at the MRCP.

Regional Monitoring and Initiatives

PCC continues to participate in and/or fund the following initiatives:

- Oil Sands Environmental Monitoring Program (OSEMP)
- Canada’s Oil Sands innovation Alliance (COSIA) Monitoring Working Group
- Wood Buffalo Environmental Association (WBEA)
- Alberta Biodiversity Monitoring Institute (ABMI)
- Black Bear Partnership Project
- Alberta Upstream Petroleum Research Fund (AUPRF)

Future Plans – Regulatory Applications

- No additional EPEA or Water Act Licence amendments are proposed for the remainder of 2018

- Current scheme amendments under review by the AER:
    - Increase to MOP
    - Steam Stimulation Process (SSP) test
    - Gas Cap Pressurization

- MacKay Infill Program:
    - PCC has received Scheme approval for 17 downspaced wellpairs
    - Field construction may start in 2019
    - Public land amendments are complete, D56 and D51 applications to be filed

- Sustaining wellpairs
    - Continue the internal project development process for the first group of sustaining well pairs

PetroChina Canada

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