SOUTHERN PACIFIC
RESOURCE CORP.

2015 Annual Performance Presentation

STP - McKay River Thermal Project

Outline

Introductions

3.1.1 Subsurface Overview Related to Resource Evaluation and Recovery

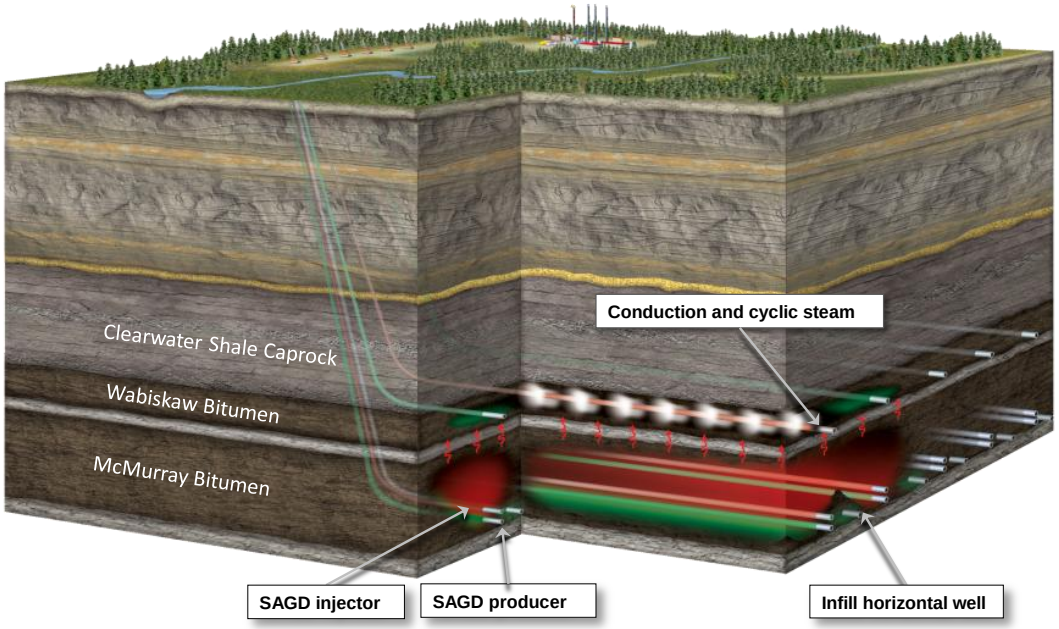
3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

Subsurface Summary Table of Contents

PROJECT BACKGROUND

Project Background

STP-McKay: Full Bitumen Exploitation Plan



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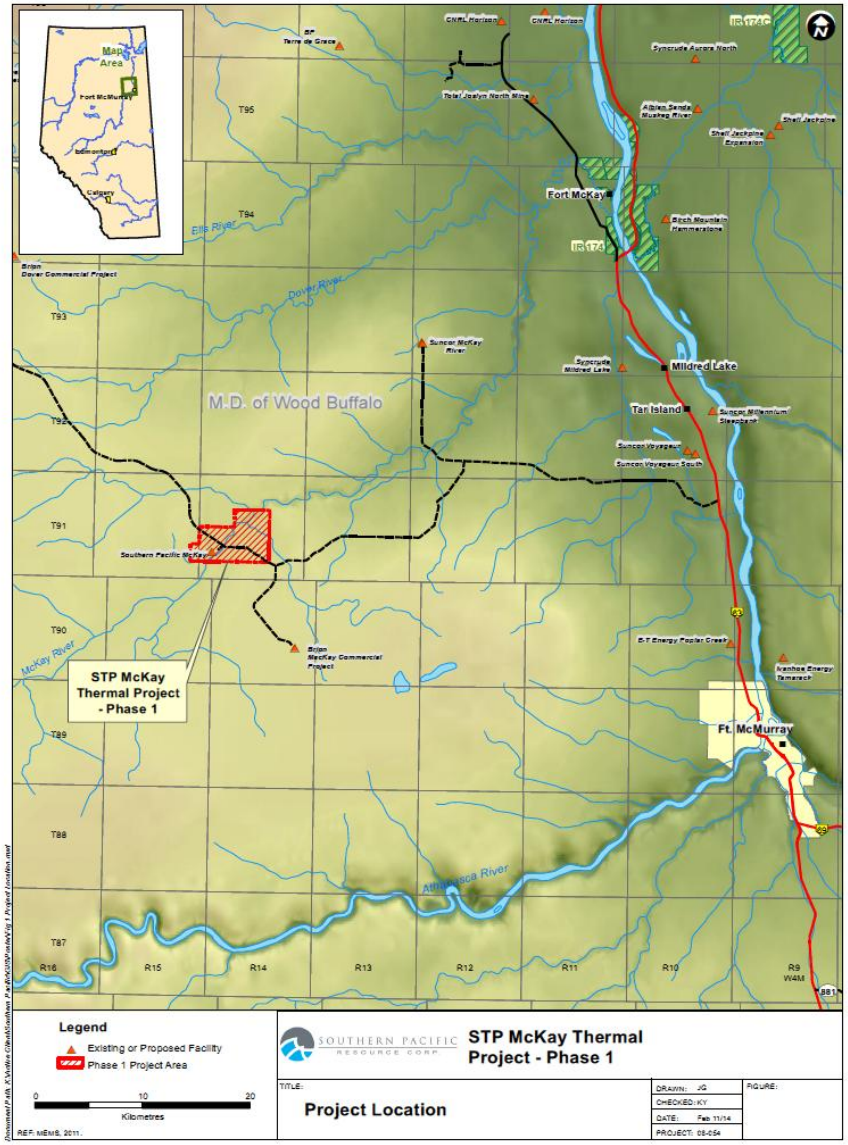
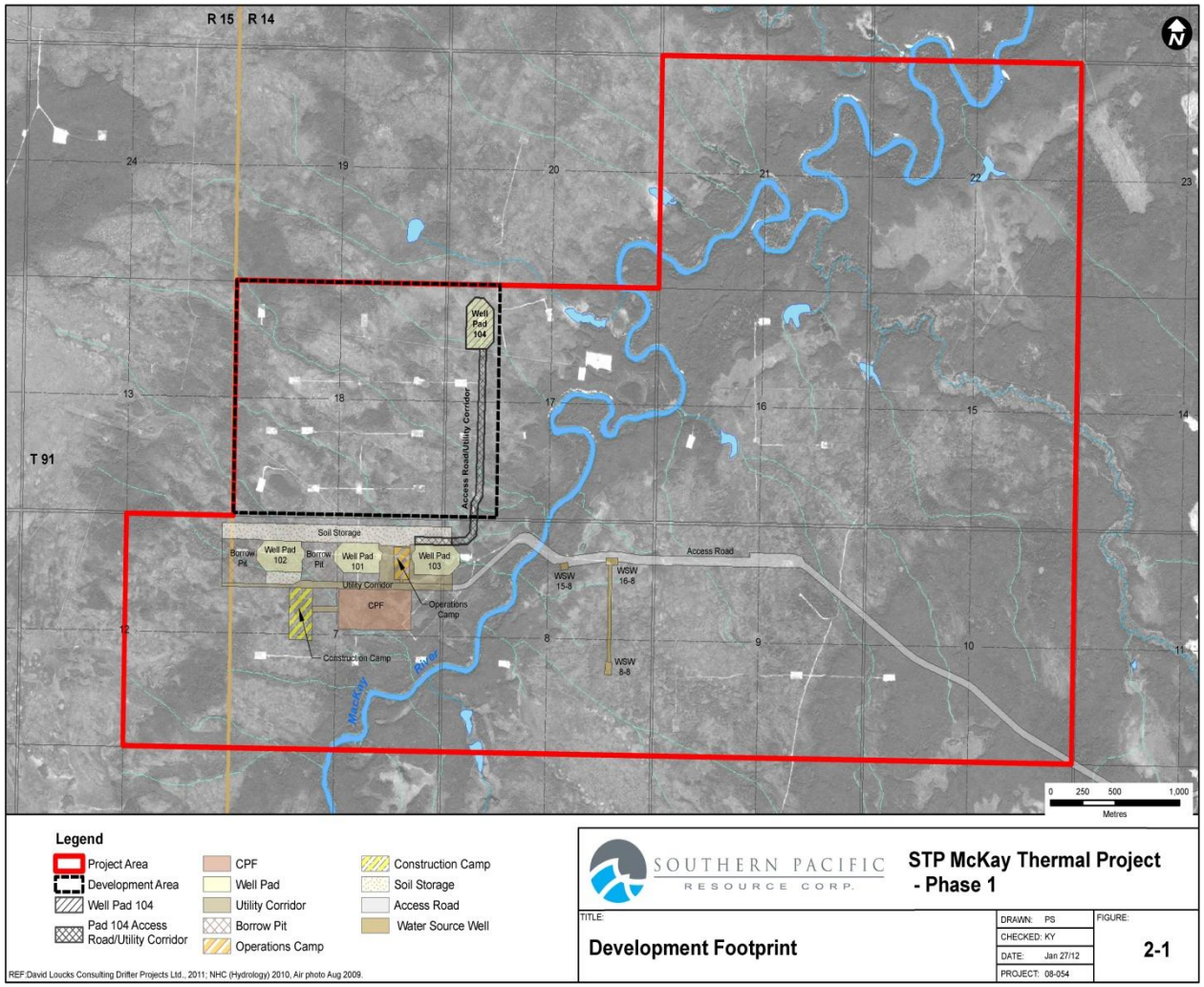
- The STP - McKay Thermal Project uses Steam Assisted Gravity Drainage technology to recover bitumen from the underlying McMurray Formation.
- May 2009 – joint AESRD and ERCB application to construct STP - McKay Thermal Project (Phase 1).
- November 2010 - STP receives project approval:
  - *EPEA Approval No. 255245-00-00*
  - *Oil Sands Conservation Act Approval No. 11461.*
- Phase 1 first steam in July 2012.
- Phase 1 first oil in October 2012.
- The Project consists of a central processing facility (CPF), well pads (2), borrow pits, water source wells (3), observation wells, a water treatment plant, a wastewater treatment plant, access roads and operations camps.
- The facility is approved to produce 1,900m^3/d (~12,000 bpd) of bitumen.
- In November of 2011 an expansion application (Phase 2) was submitted to AESRD and ERCB seeking approval to construct a second CPF on the east side of the MacKay River that would produce an additional 24,000 bpd of bitumen.
- In October of 2012 a Project Update was submitted to amend the Phase 2 application to increase production at the Phase 1 facility from 12,000 bpd to 18,000 bpd while decreasing production at the proposed Phase 2 facility from 24,000 bpd to 18,000 bpd.

Project Background



- The Project is located approximately 45 km northwest of Fort McMurray and 45 km southwest of the community of Fort MacKay in Section 7-91-14W4M
- Project Area is 10.5 sections in Township 91, Range 14, W4M and Township 91, Range 15, W4M.
- Development Area is 1.25 Sections in Township 91, Range 14, W4M.

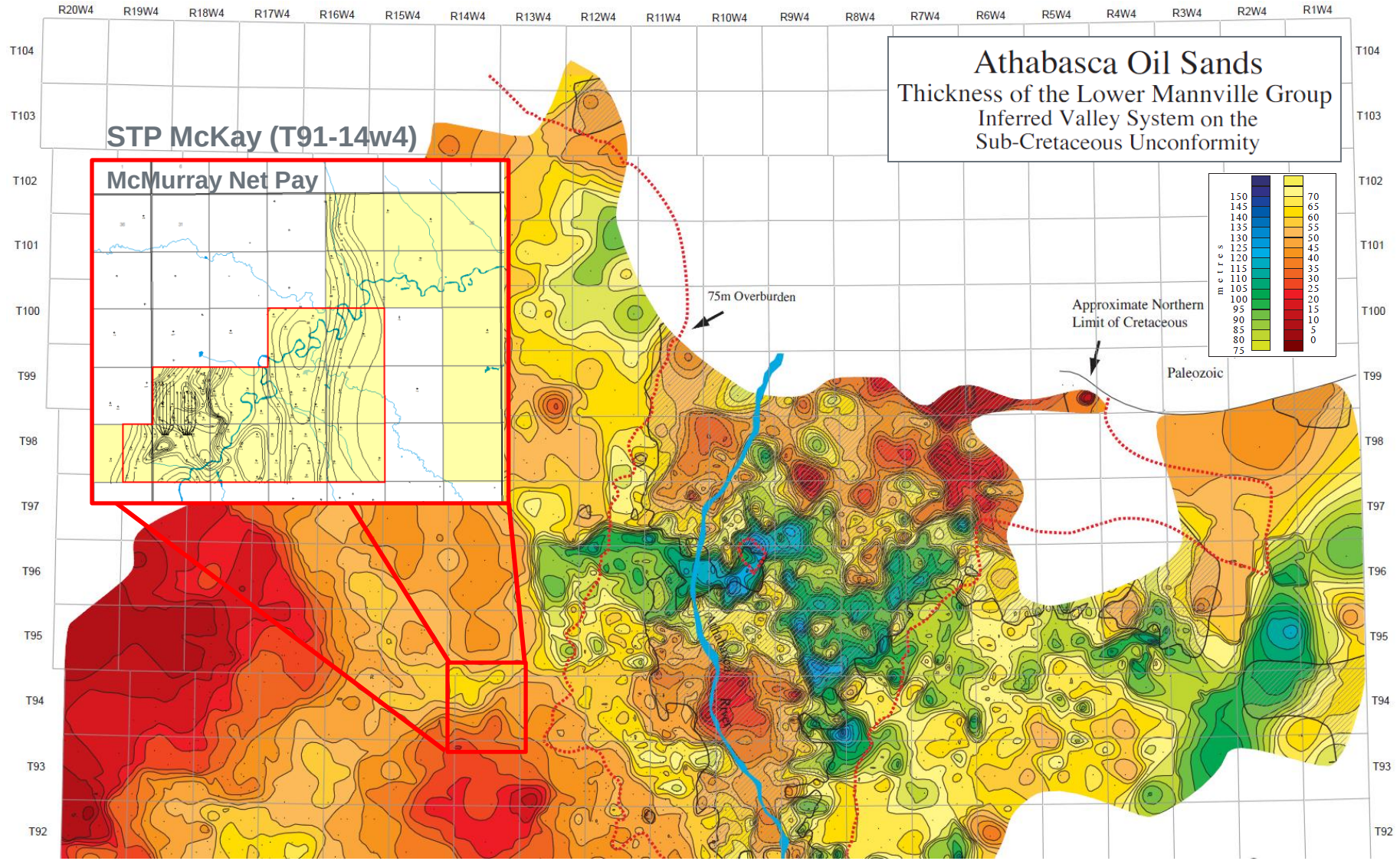
Project Background



- The approved development includes 4 well pads (101- 104).
- The initial development is west of the MacKay River and includes 2 well pads (101 & 102) in close proximity to the CPF.

GEOLOGY/GEOSCIENCE

Geology Overview
Regional Geology – McMurray



Source: Mike Ranger's Regional Study, 2011

McKay OBIP by Volumetrics

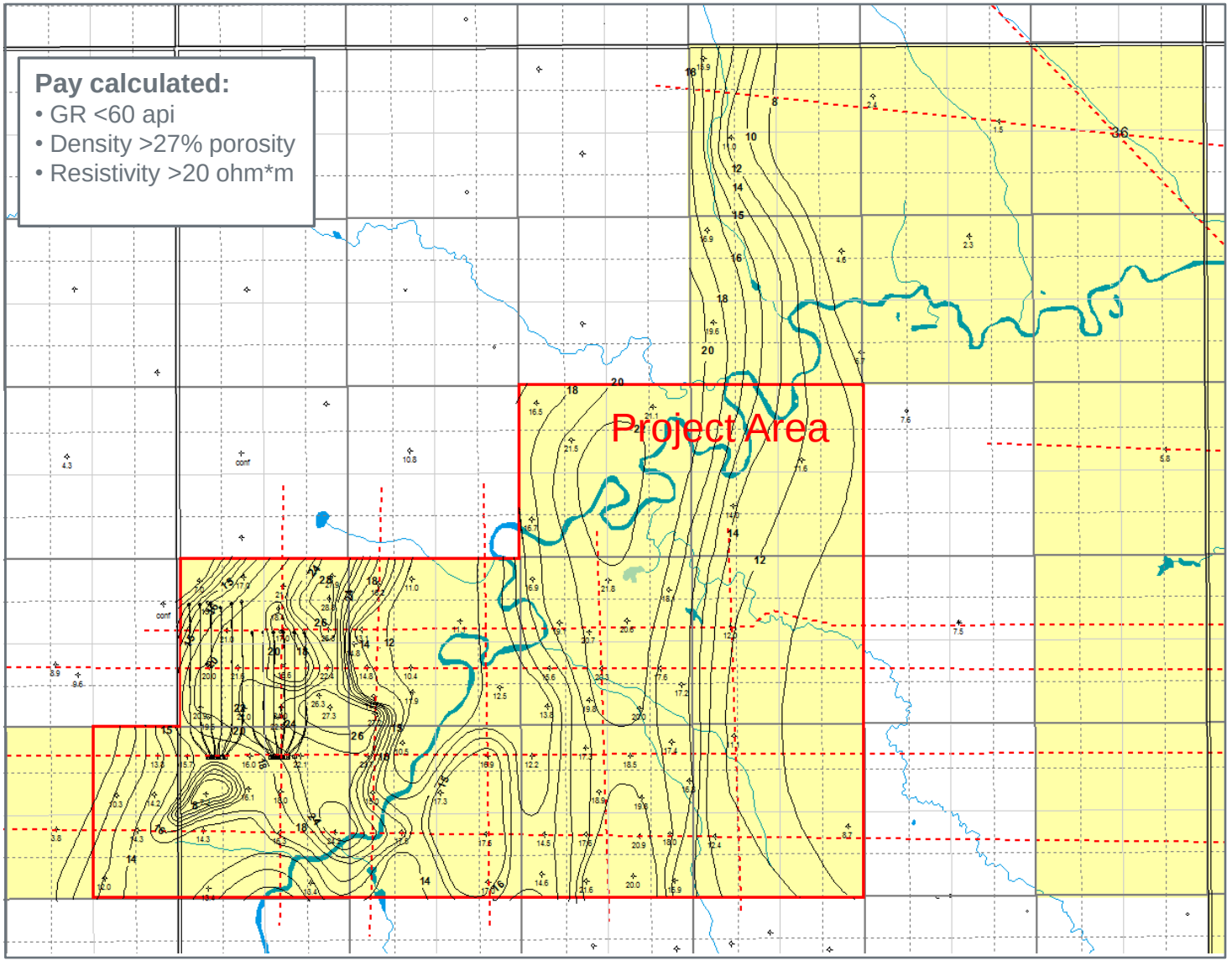
- Approval Area OBIP
  - 89,376 E^3m^3
- Approval Area Reservoir Properties:
  - Porosity: 30-33%, Oil Saturation: 65-75%, Height: 10-27m

Average Reservoir Properties

- Initial Operating Area (Pads 101,102) OBIP
  - 5,890 E^3m^3

Operating Area Key Reservoir Parameters	Value
Depth (m TVD)	190
Pay Zone Thickness (m)	17 - 27
Lateral Well Pair Spacing (m)	100
Horizontal Well Length (m)	800 - 1100
Porosity	32
Oil Saturation	74
Original Reservoir Pressure (kPa)	650
Original Reservoir Temperature (°C)	8.5

Isopach Map of Net Bitumen Pay with 2D Seismic lines

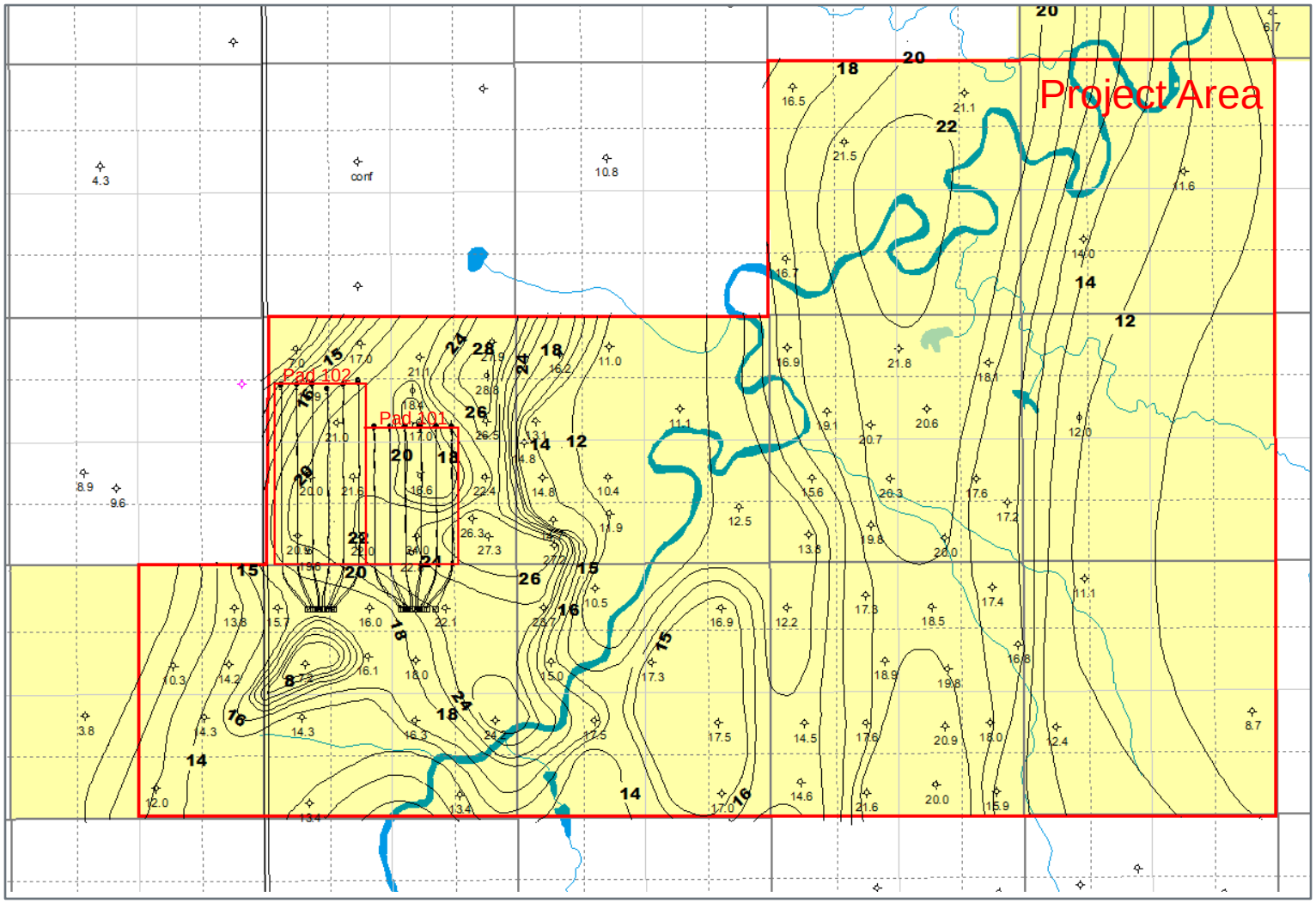


T. 91

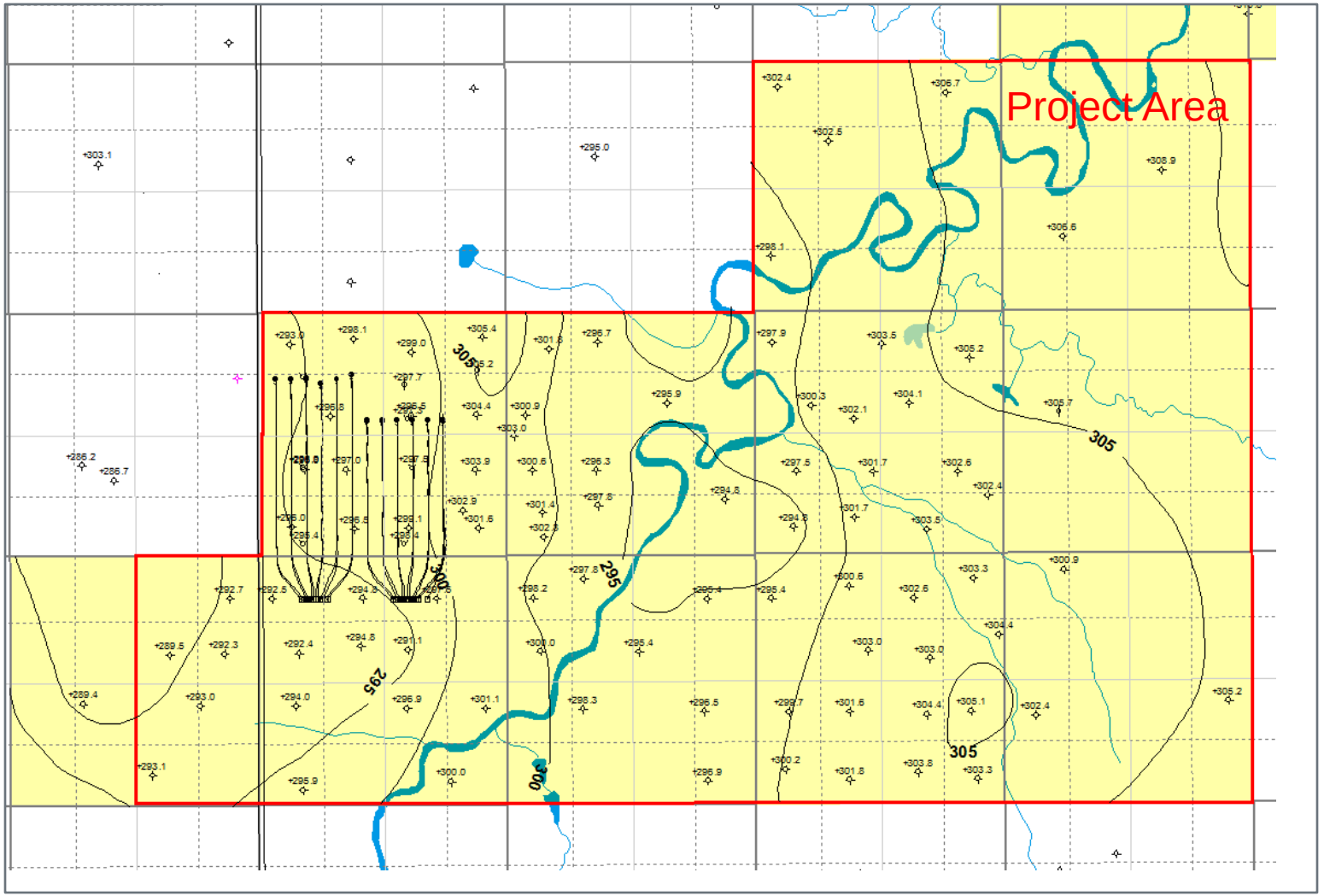
R. 15

R. 14W4

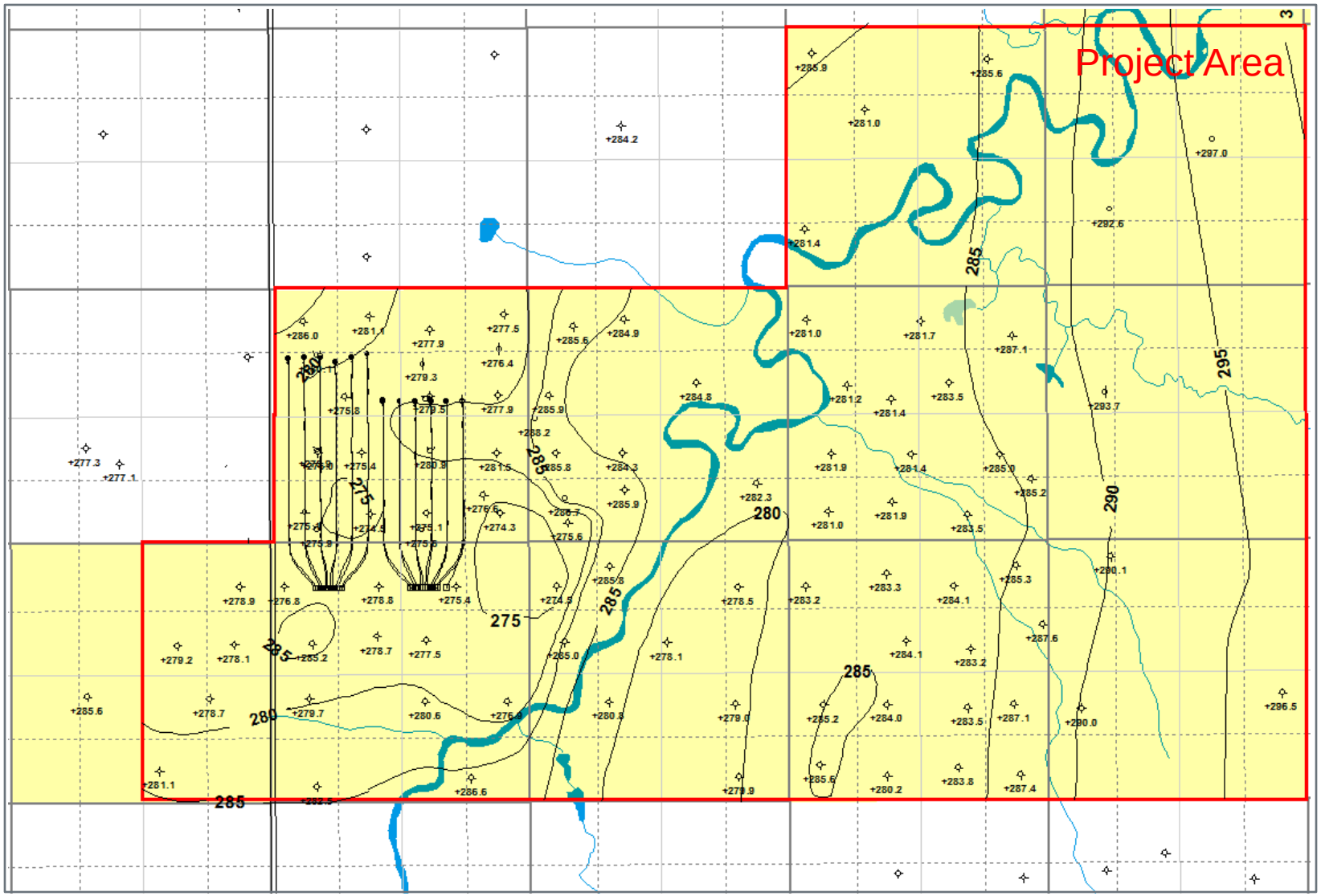
Volumetric Polygons on McMurray Net Bitumen Pay Map



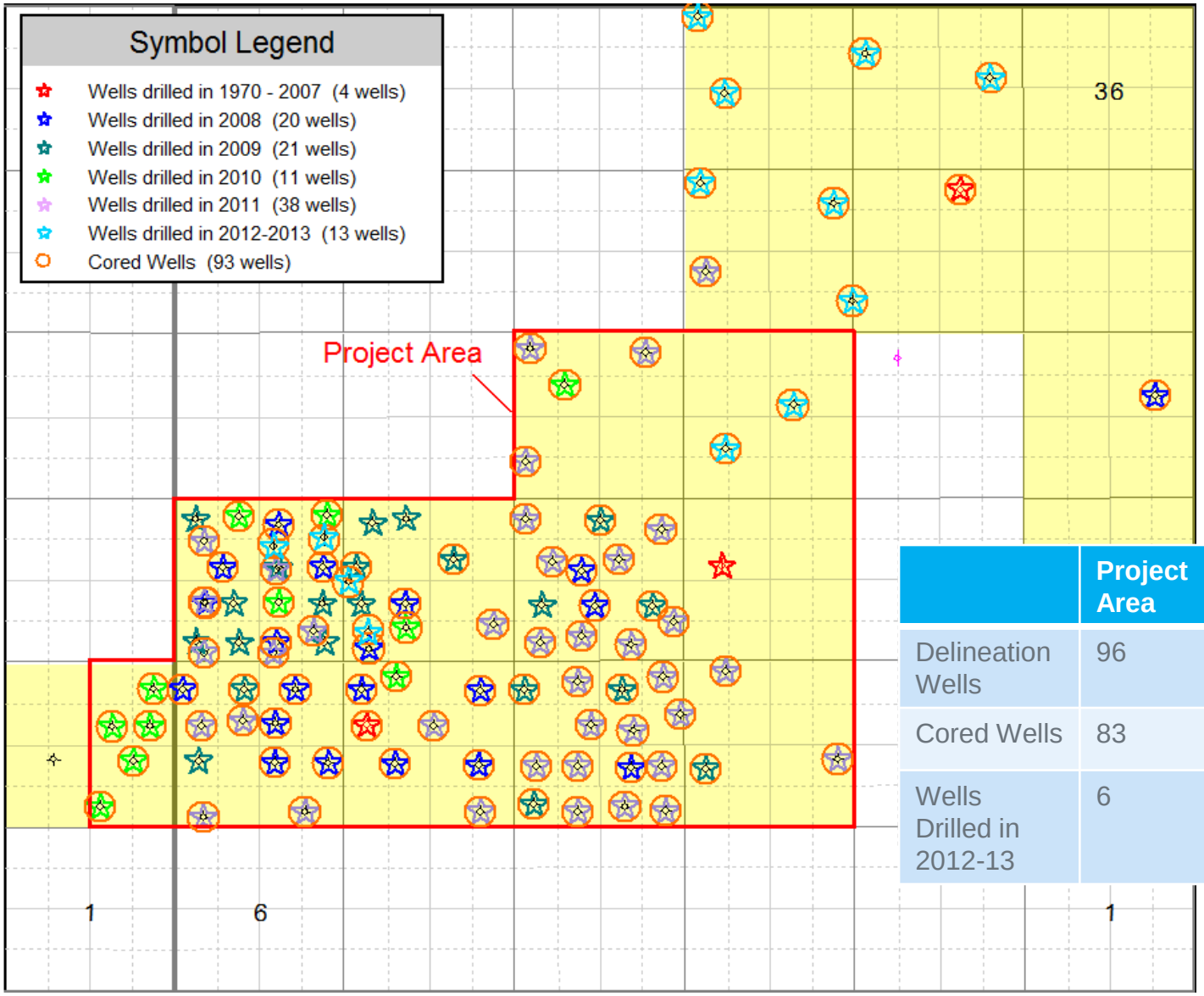
Structure Map on the Top of Bitumen Pay



Structure Map on the Base of Bitumen Pay

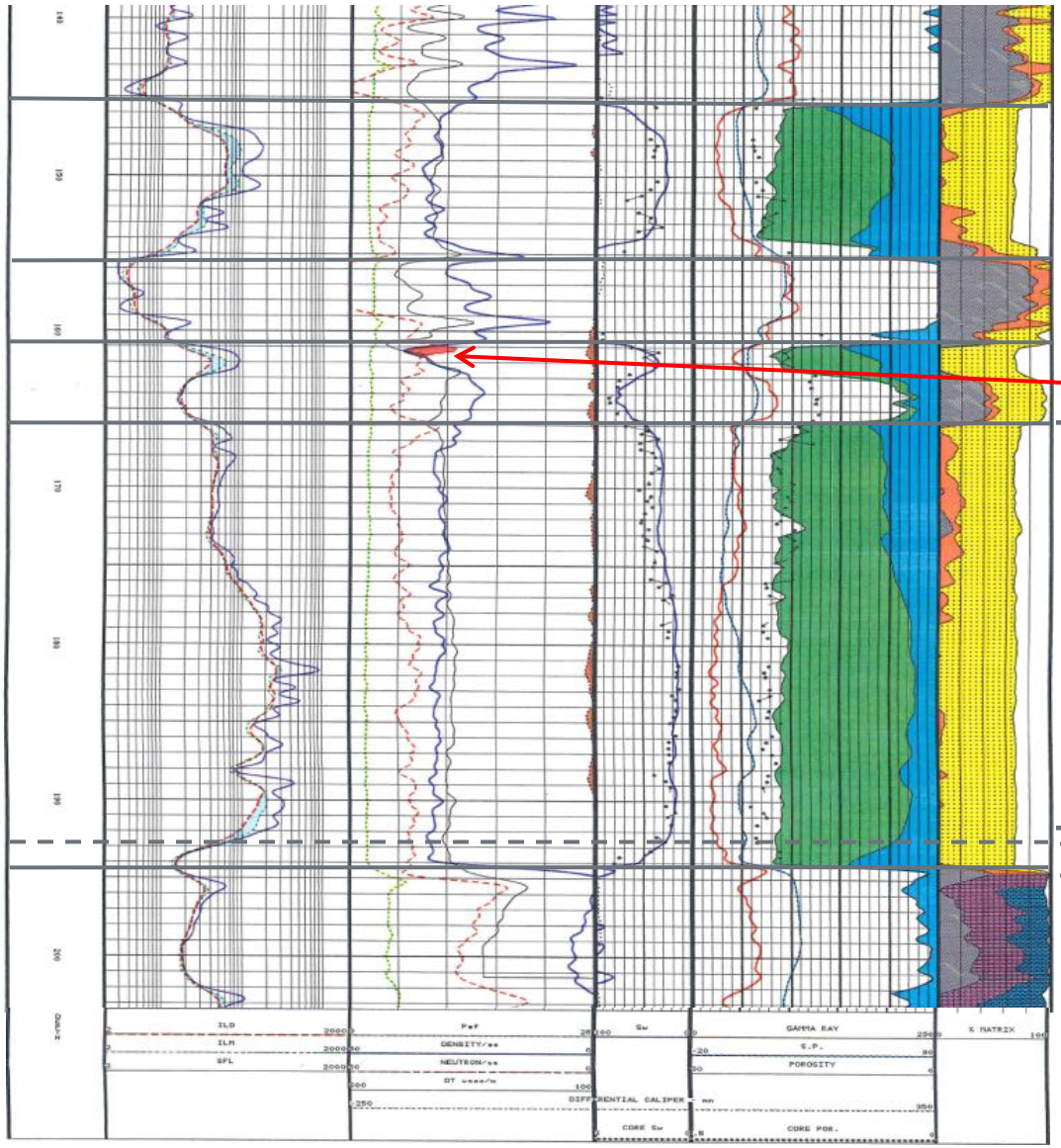


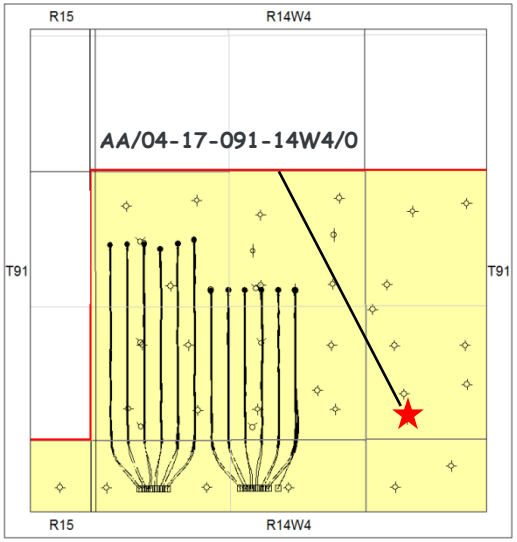
STP-McKay Core Data



	Project Area	STP Lands
Delineation Wells	96	107
Cored Wells	83	93
Wells Drilled in 2012-13	6	13

STP-McKay Type Log

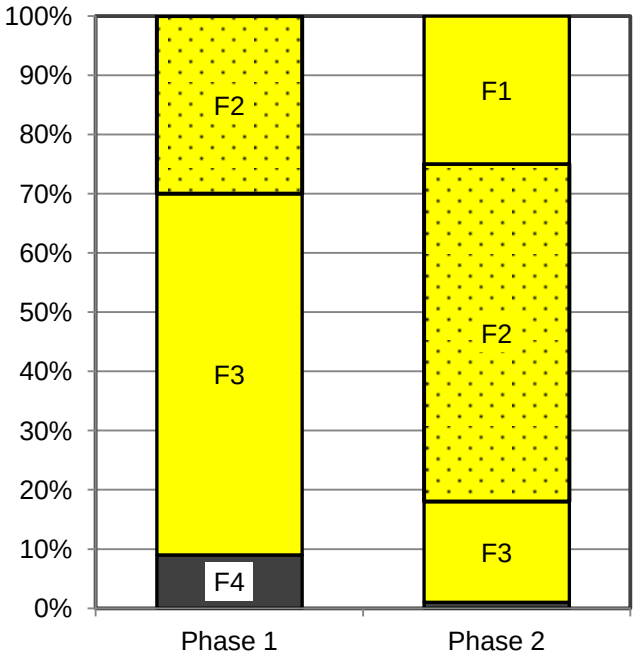




Pay calculated:

- GR < 60 api
- Density >27% porosity
- Resistivity >20 ohm*m

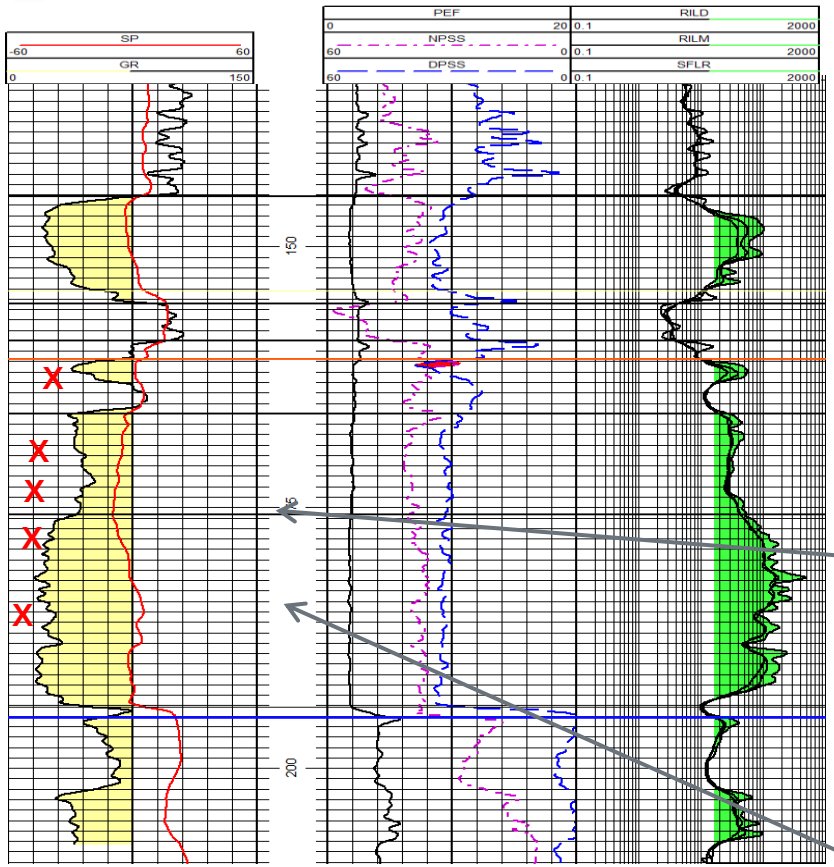
STP-McKay McMurray Facies Types



- High quality reservoir identified in Phases 1 & 2
  - No significant lean (“thief”) zones in either Phase

Facies Name		% Shale	Sample Photo
F1	Upper Clean Sand	2.5%	
F2	Bioturbated Facies	8.1%	
F3	Lower Clean Sand	2.5%	
F4	Interbedded Sand	20.0%	

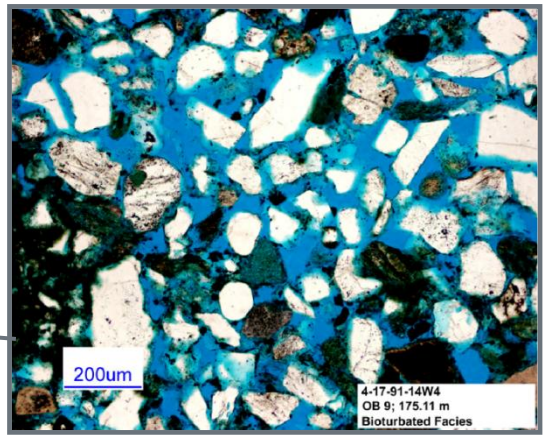
STP-McKay Core Analysis/Thin Section

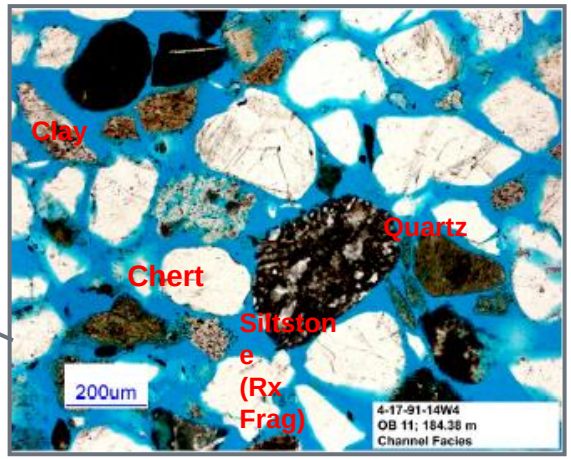


X = Thin Section Samples

Upper Reservoir (Bioturbated)

- Very Fine to Fine grained (<180 um)
- Moderately sorted, Subangular with elongate grains
- Framework consists of quartz, common chert, siltstones with some feldspars
- Clays are within the microporosity of the chert or are grains that were transported as a clast, but also exist within the pore spaces. Pore space has 10% clay in the pore space.
- **XRD:** Analysis shows 86% qtz, 4% K-feldspar, 2% Plagioclase, 1% dolomite, 1% pyrite and 6% total clay.

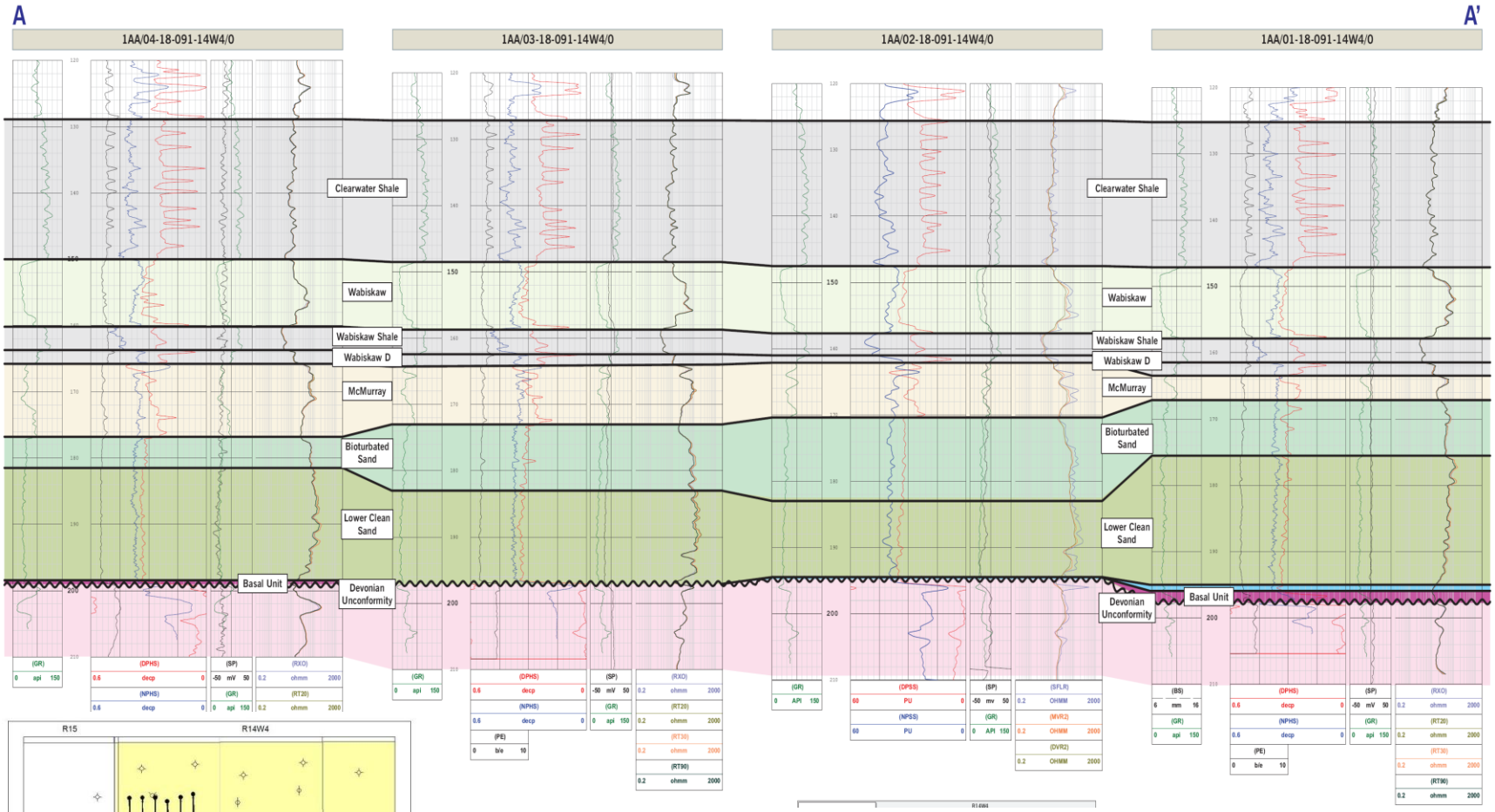




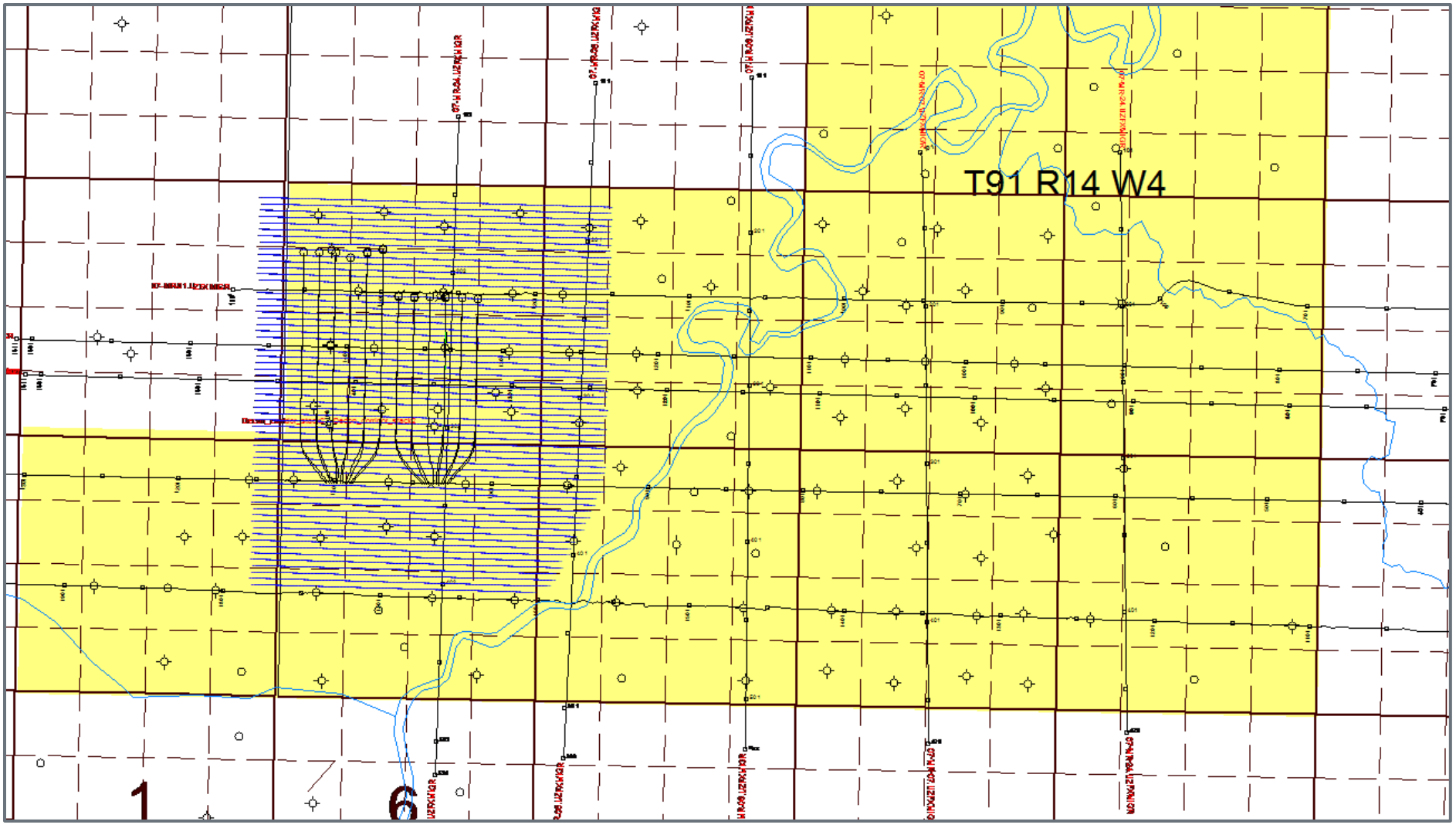
Main Reservoir

- Fine to Medium grained (180-250 um)
- Moderately sorted, Subrounded with elongate and spherical grains
- Framework consists of quartz, chert, siltstones with some feldspars
- Similar clays with less interstitial clay found in the rock matrix.
- **XRD:** Analysis shows 93% qtz, 2% K-feldspar, 1% pyrite and 4% total clay.

Structure Cross-Section

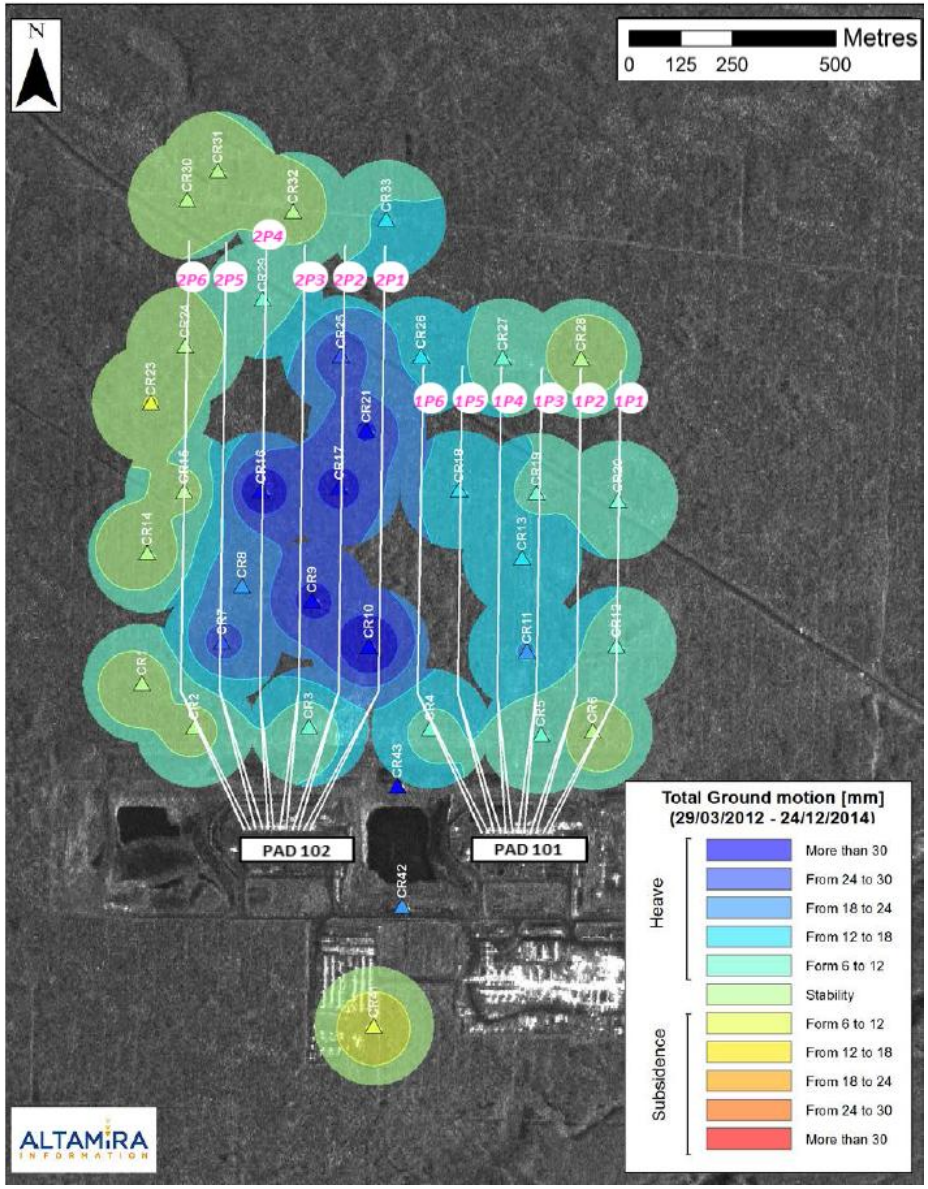


3D Seismic Map



HEAVE MONITORING AND CAPROCK

Surface Monitoring (Heave Monuments)



- 35 Corner reflectors were installed in the first quarter of 2012
- Surface monitoring started on March 2012
- The cumulative movement to Jan. 2015 of the surface since SAGD operations started is insignificant. It ranged between -10 mm (subsidence) and 38 mm (heave).

Caprock Integrity

- AER approved Maximum Operating Pressure (MOP) of 2450 kPa.
  - STP met all ERCB conditions and information requests and received approval June 2011
- Detailed caprock characterization studies were completed by STP and leading industry experts to evaluate sustained, caprock integrity at a MOP of 2450 kPa.
- Caprock integrity studies focused on:
  - Core and geological log evaluations (Weatherford,Advanced Geotechnology)
    - No fault planes observed on logs or in core.
    - No borehole breakouts/drilling induced fractures observed from 17 HMI logs.
  - Laboratory testing (reservoir & geomechanical)
    - Low permeability caprock.
    - Geomechanical properties derived from lab testing.
  - Mini-frac testing for characterizing *in situ* stress state
    - Mini-frac tests conducted at 2 wells.
  - Geomechanical simulation (Taurus Reservoir Solutions)
    - 2450kPa operating pressure is conservative.
- MOP exceeded during approved High Pressure Steam Stimulation (HPSS).

Caprock Integrity – *Mini-Frac Tests*

- Mini-frac tests completed at wells 5-16 and 1-18 by BitCan Geoscience & Engineering.
- Stress gradient results are consistent and similar to those expected in the Athabasca Oil Sands.
- Vertical stress gradient is ~21.5 kPa/m.

Well	5-16-91-14W4	Date	March 2009
Depth (m TVD)	**Lithology**	**Minimum Stress (kPa)**	**Minimum Stress Gradient (kPa/m)**
126	Clearwater Shale	2520	20.0
140	Clearwater Shale	2760	19.7
155	Wabiskaw Shale	2710	17.5
174	McMurray Sandstone	2900	16.7

Well	1-18-91-14W4	Date	April 2011
Depth (m TVD)	**Lithology**	**Minimum Stress (kPa)**	**Minimum Stress Gradient (kPa/m)**
131	Clearwater Shale	No Breakdown	
138	Clearwater Shale	2900	21.0
147	Wabiskaw Sandstone	3060	20.8
156	Wabiskaw Shale	3250	20.8
164	Upper McMurray Sandstone	3300	20.1
186	McMurray Sandstone	3060	16.5

Caprock Integrity – Caprock Fracture Pressure

- Assessment of minimum fracture pressure (S_{min}) at the base of the Clearwater Formation using mini-frac test results.
- S_{min} from both wells 5-16 and 1-18 are consistent.
- S_{min} fracture pressure at the base of the Clearwater Formation caprock is between ~2860 kPa and ~ 3020 kPa.

Well	Depth to Caprock Base (m)	Fracture Gradient (kPa/m)	Smin Fracture Pressure (kPa)
5-16	145	19.7	2857
1-18	144	21.0	3024

Caprock Integrity – Monitoring

- Clearwater Formation:
  - 6 vertical, nested observation wells measuring pressure and temperature.
- Wabiskaw Member:
  - 1 horizontal well measuring temperature and pressure
- Surface heave monitoring program.
- Blanket Gas system to monitor bottomhole injection pressures.

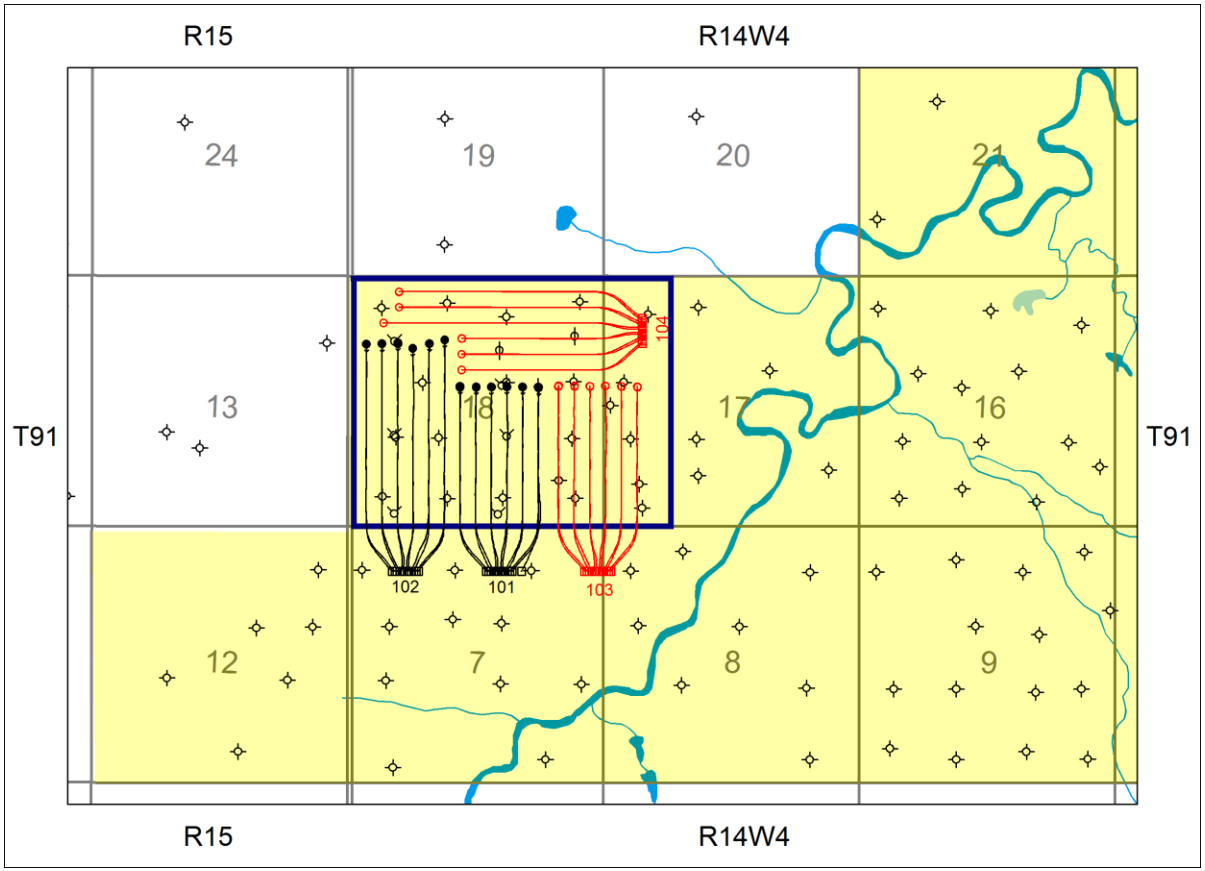
DRILLING/COMPLETIONS

Drilling and Completions – Well Layout

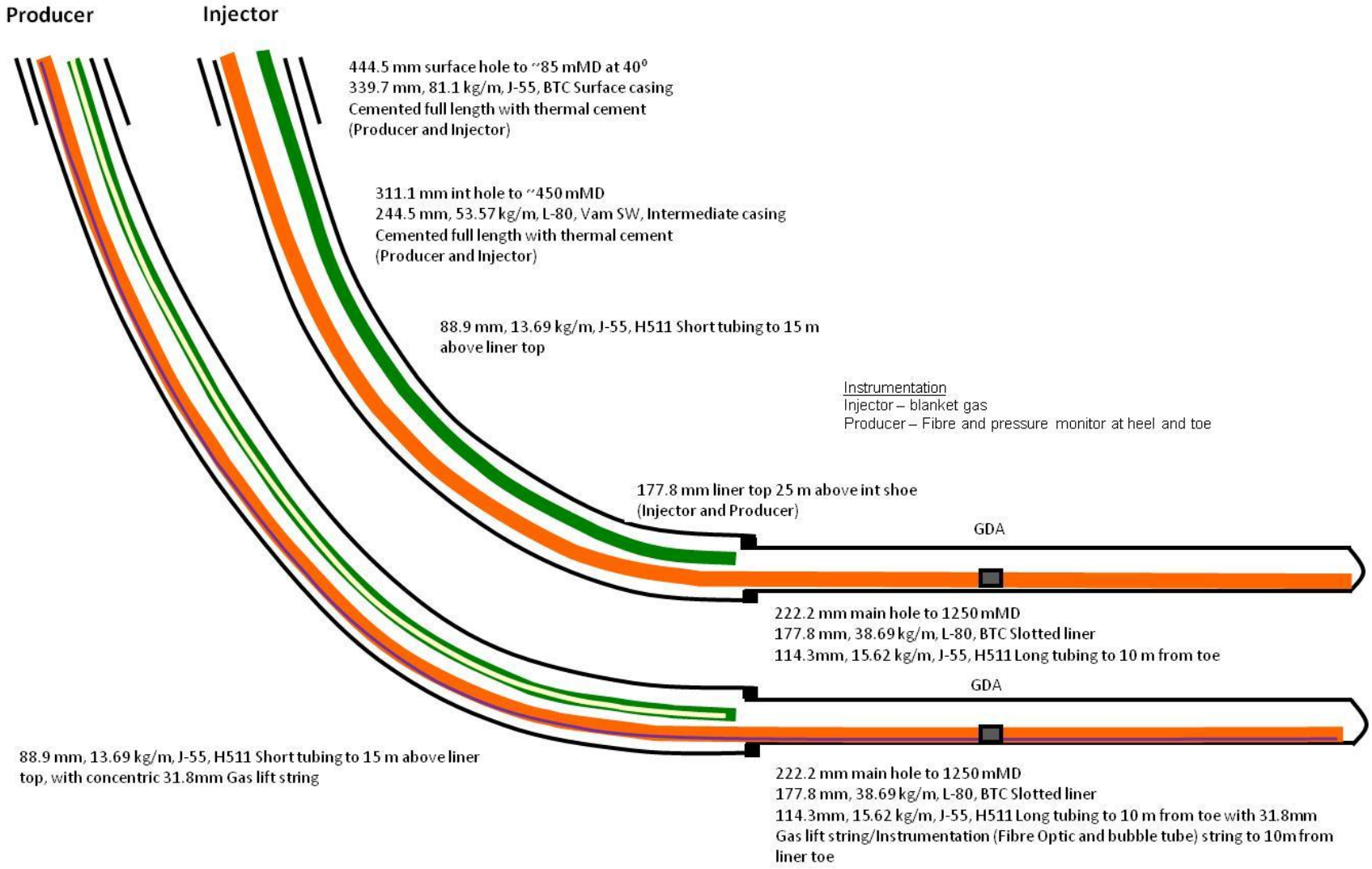
Phase 1 Drilling Program

- Approved Development area outlined in blue
- Drilled to date (black):
  - Pad 101 (6 pairs)
  - Pad 102 (6 pairs)
  - Wabiskaw observation well (lies above 1P1)

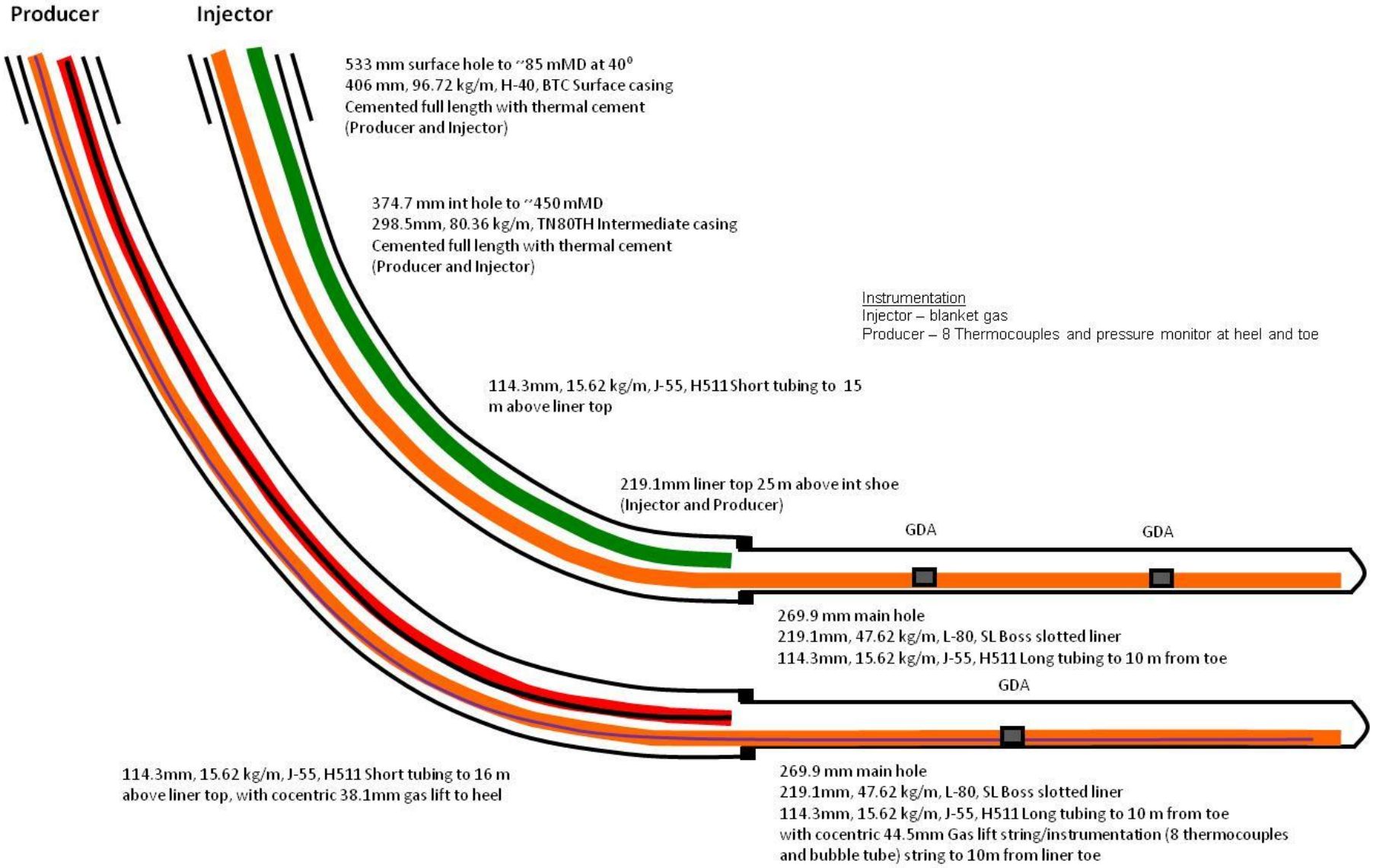
- Approved Pads (red):
  - Pad 103 (6 pairs)
  - Pad 104 (6 pairs)



Drilling and Completions – Pad 101 SAGD Well Design for Injection and Production (Gas Lift)



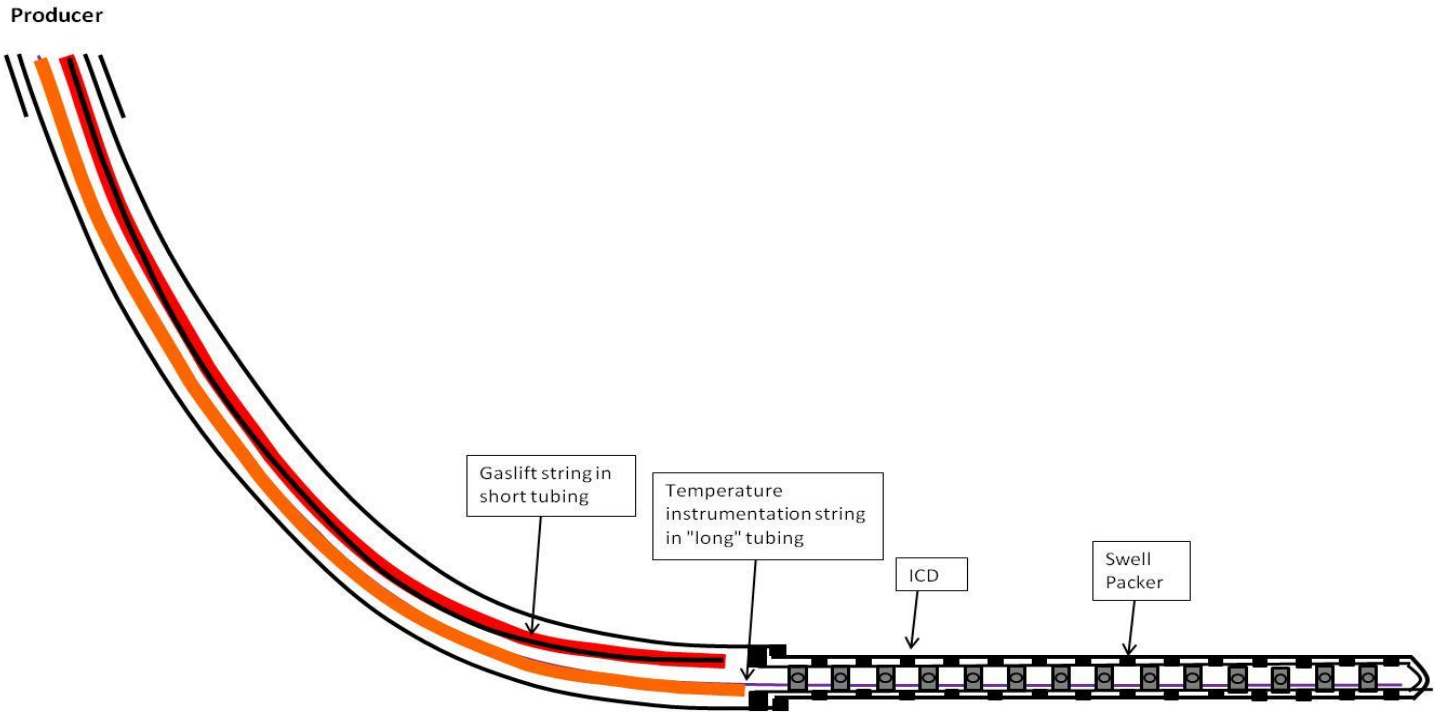
Drilling and Completions – Pad 102 SAGD Well Design for Injection and Production (Gas Lift)



Drilling and Completions – ICD Installation for Production (Gas Lift)

Installation

- Scab liner with swell packers and ICD tools were run.
- Six installations done to date in production wells (1P2,1P5,1P6,2P1,2P2,2P5)
- Both short and long string terminate at the heel.
- Coil tubing with temperature instrumentation is run to toe.

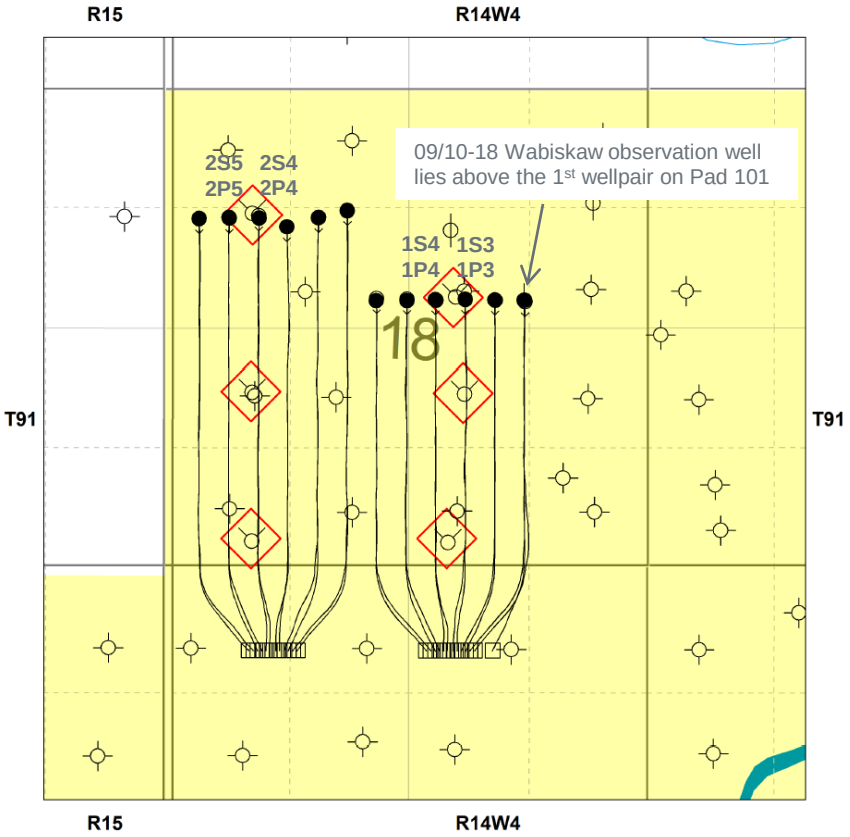


Artificial Lift

- All production wells are equipped for gas lift
- Amount of lift gas required is dependent on operating pressure/temperature of the well.
  - Using 3.5 to 7.2 E3m3/d lift gas volume and well operating range has varied from 1200kPa to 2250kPa.
- Gas lift has been successful in achieving lift through various down hole operating temperatures and pressure.

INSTRUMENTATION

Instrumentation in Wells

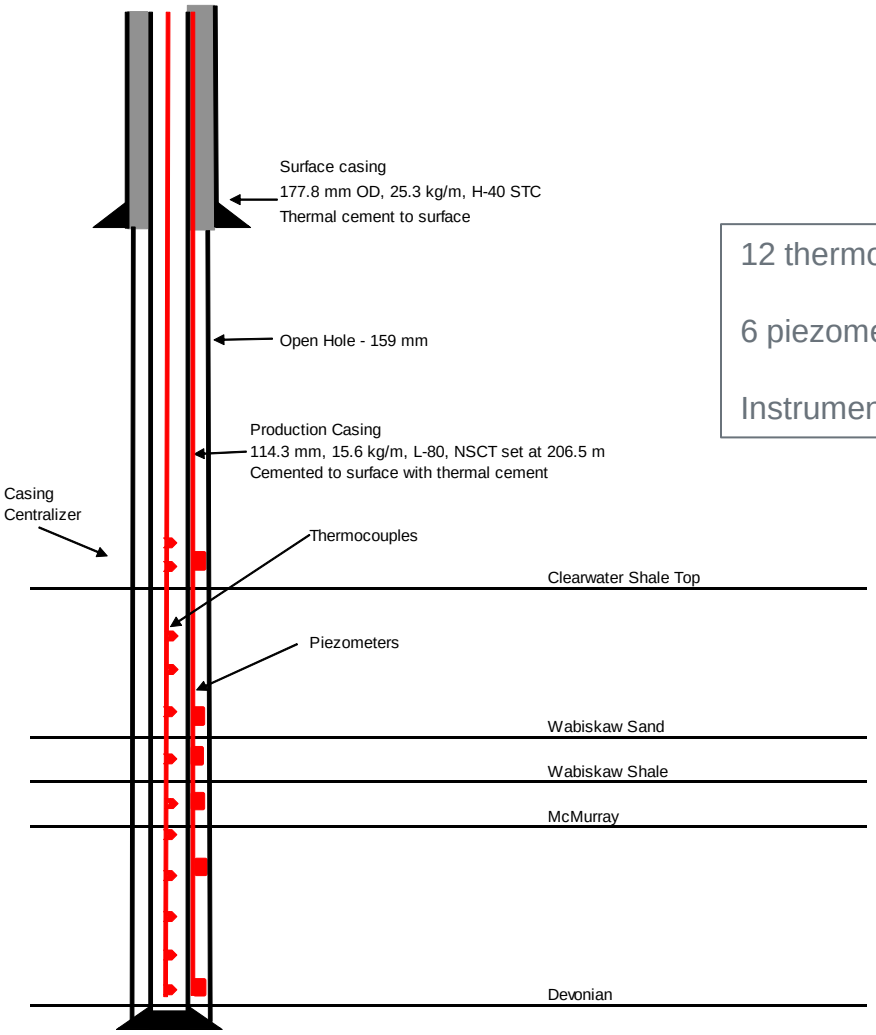


- 6 Vertical, Nested Observation Wells:
  - Pressure and temperature measurements extending from McMurray to Clearwater Formations
  - 10-18 and12-18 wells have experienced 1 TC failure each. 5-18 has experienced 4 TC failures.
  - Transmission issues in early 2013 resolved.
- Horizontal Observation Well:
  - Wabiskaw Member
  - Temperature/Pressure measurements

Well	Temperature	Pressure
100/2-18-91-14W4	12 temperature points	6 pressure points
100/4-18-91-14W4	12 temperature points	6 pressure points
100/5-18-91-14W4	12 temperature points	6 pressure points
100/7-18-91-14W4	11 temperature points	5 pressure points
110/10-18-91-14W4	12 temperature points	6 pressure points
109/12-18-91-14W4	12 temperature points	6 pressure points
109/10-18-914-14W4	High Temperature Fibre/1 PT	1 pressure point

Instrumentation in Wells – Typical Vertical Observation Well

Southern Pacific Resource Corp



12 thermocouples spaced between the Base of McMurray to Clearwater

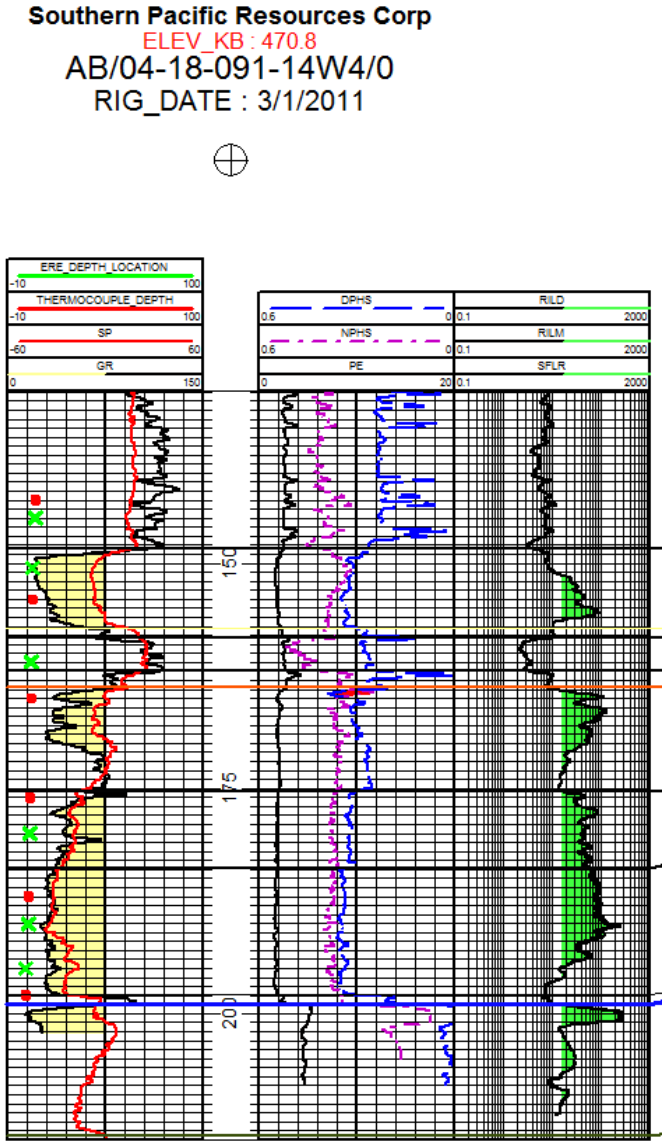
6 piezometers spaced between Base of McMurray to Clearwater

Instrumentation strapped to outside of casing string

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location



~80m to the West

2S5 (~187.5m TVD)

2P5 (~194.2m TVD)

~20m to the East

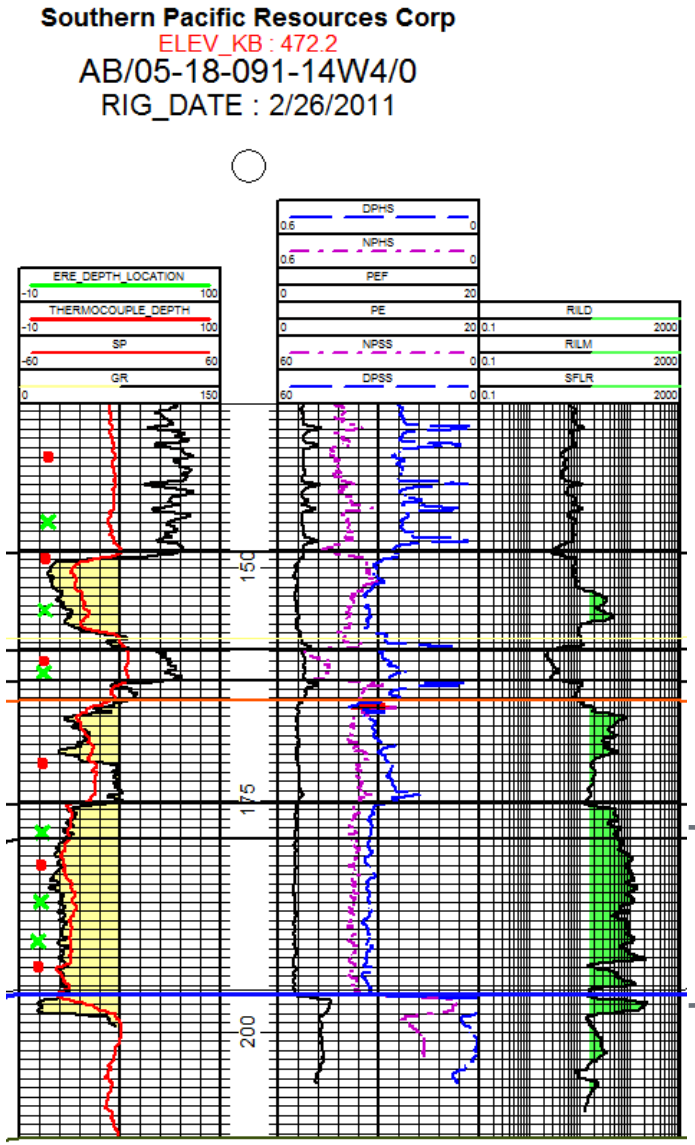
2S4 (~188.3m TVD)

2P4 (~195.5m TVD)

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location



Clearwater Shale

Wabiskaw Sand

Wabiskaw Shale McMurray Fm

McMurray Reservoir

Devonian Carbonate

~77m to the West

2S5 (~186.6m TVD)

2P5 (~192.5m TVD)

~23m to the East

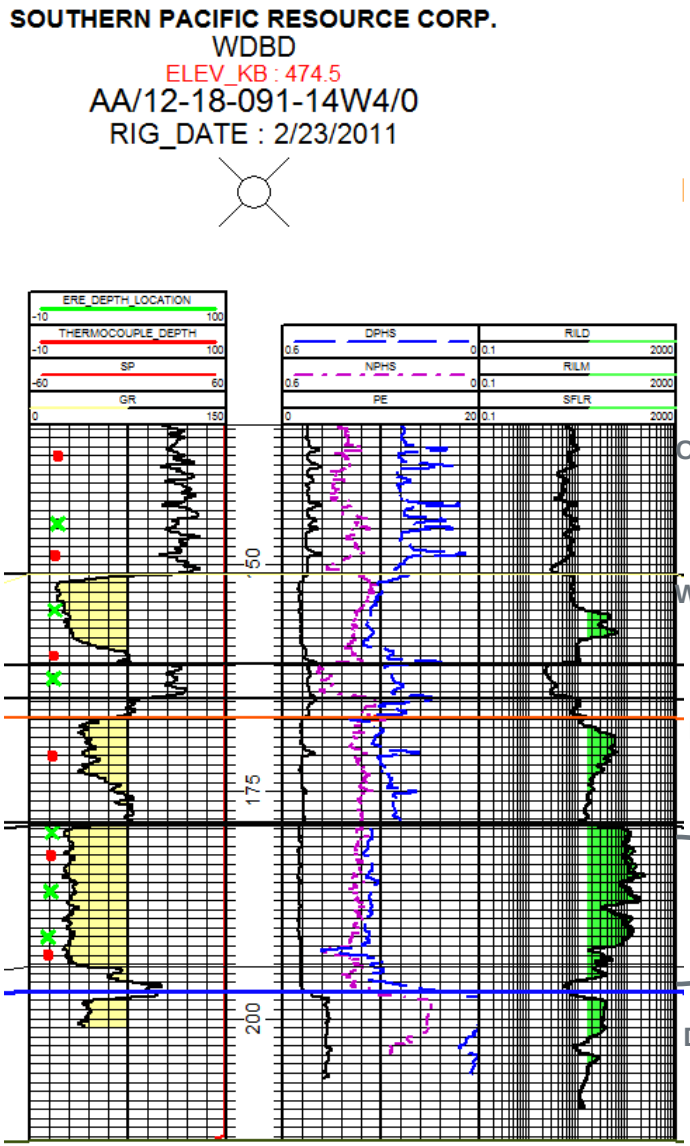
2S4 (~188.6m TVD)

2P4 (~194.8m TVD)

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location



~80m to the West

2S5 (~185.8m TVD)

2P5 (~191.2m TVD)

~20m to the East

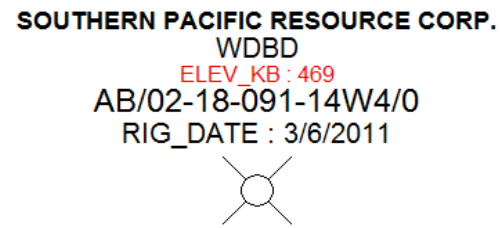
2S4 (~187.8m TVD)

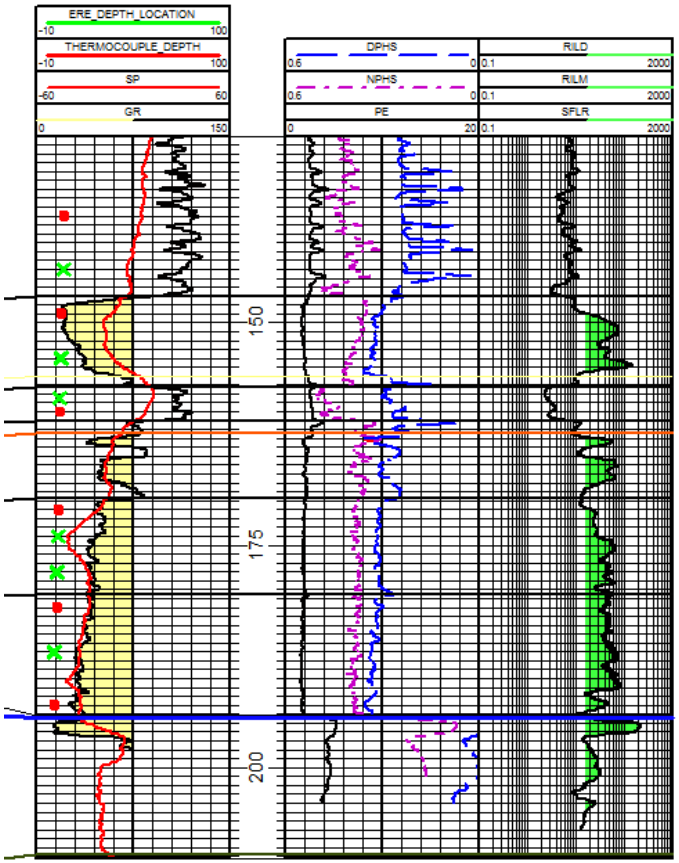
2P4 (~192.3m TVD)

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location





Clearwater Shale

Wabiskaw Sand

Wabiskaw Shale

McMurray Fm

McMurray Reservoir

Devonian Carbonate

~40m to the West

1S4 (~186.7m TVD)

1P4 (~193.2m TVD)

~60m to the East

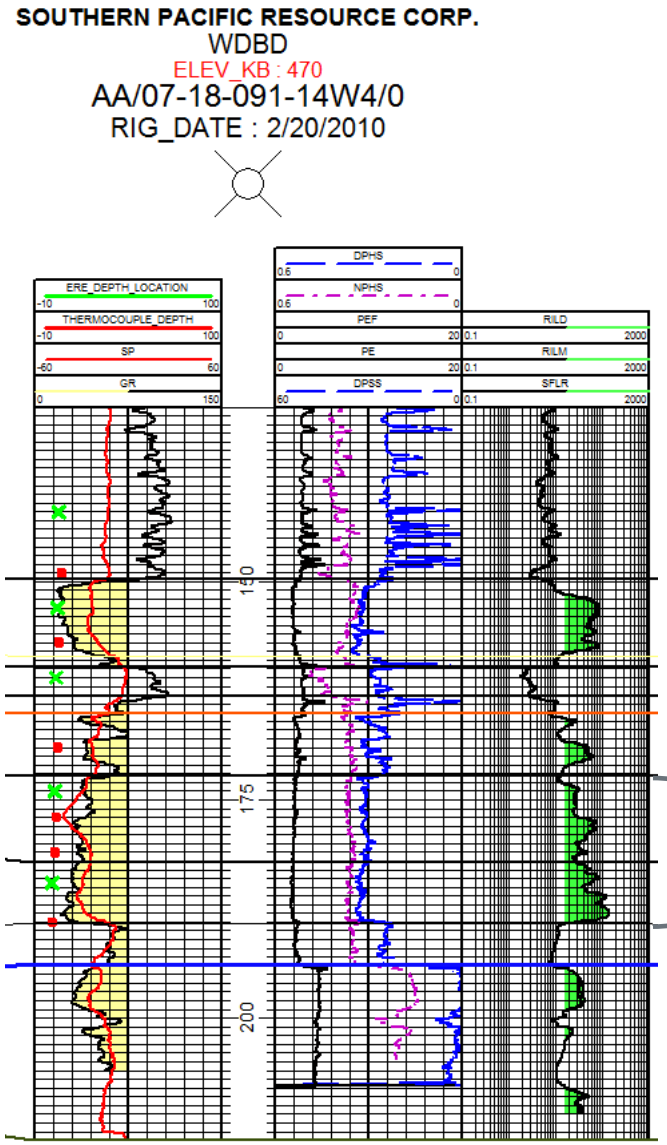
1S3 (~186.5m TVD)

1P3 (~193.5m TVD)

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location



Clearwater Shale

Wabiskaw Sand

Wabiskaw Shale McMurray Fm

McMurray Reservoir

Devonian Carbonate

~93m to the West

1S4 (~183.5m TVD)

1P4 (~189.1m TVD)

~14 m to the East

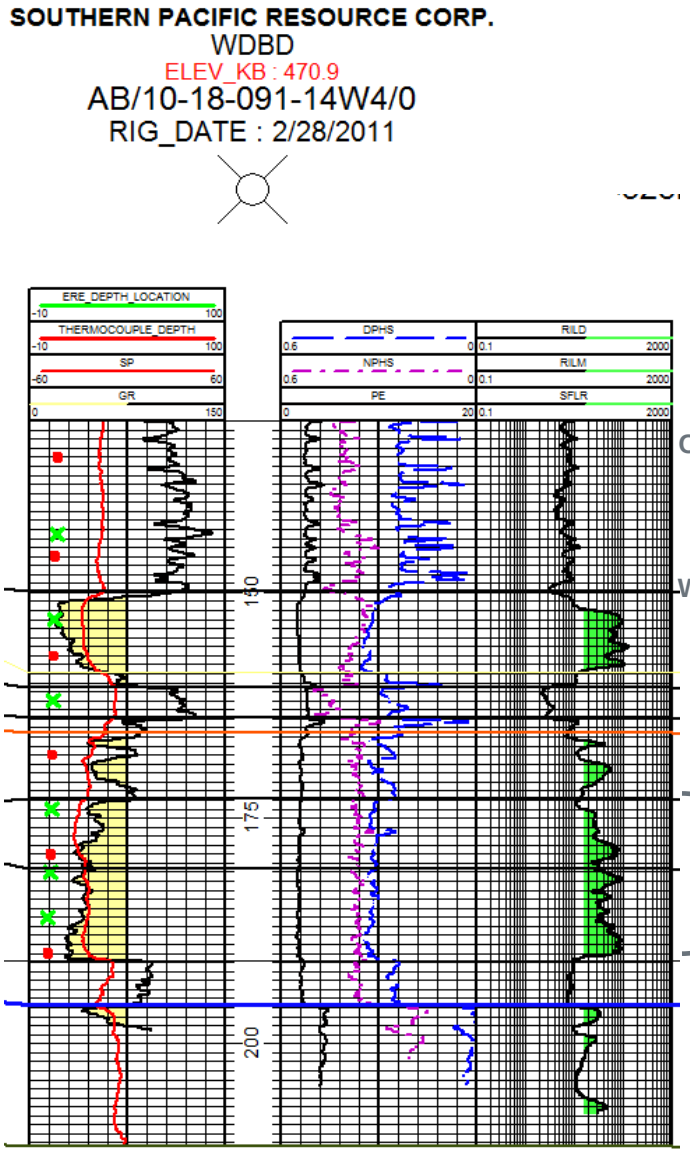
1S3 (~184.6m TVD)

1P3 (~190.8m TVD)

Observation Wells

Pressure Gauge and Thermocouple Location

Thermocouple Location



Clearwater Shale

Wabiskaw Sand

Wabiskaw Shale

McMurray Fm

McMurray Reservoir

Devonian Carbonate

~70m to the West

1S4 (~183.5m TVD)

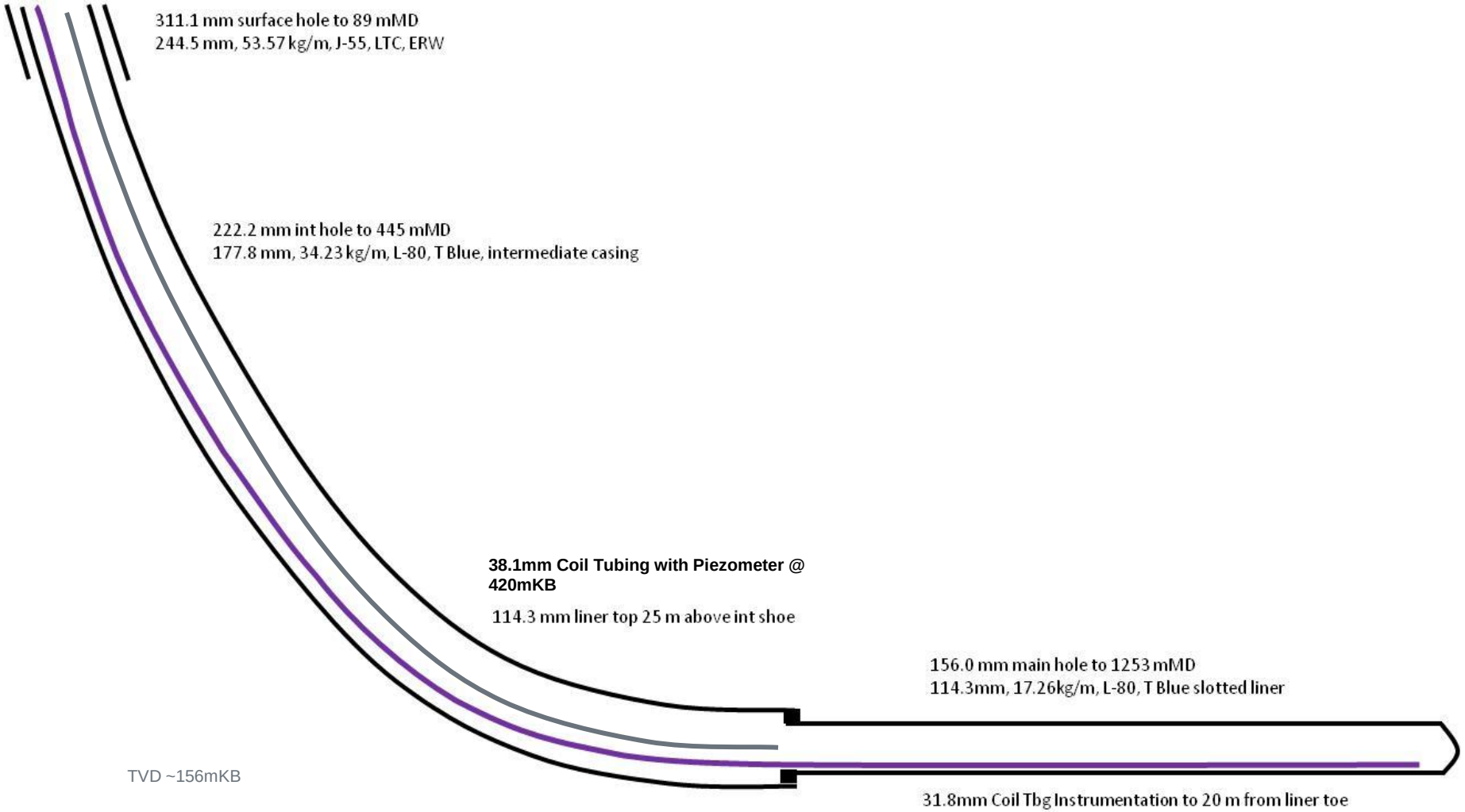
1P4 (~188.9m TVD)

~30m to the East

1S3 (~184m TVD)

1P3 (~190m TVD)

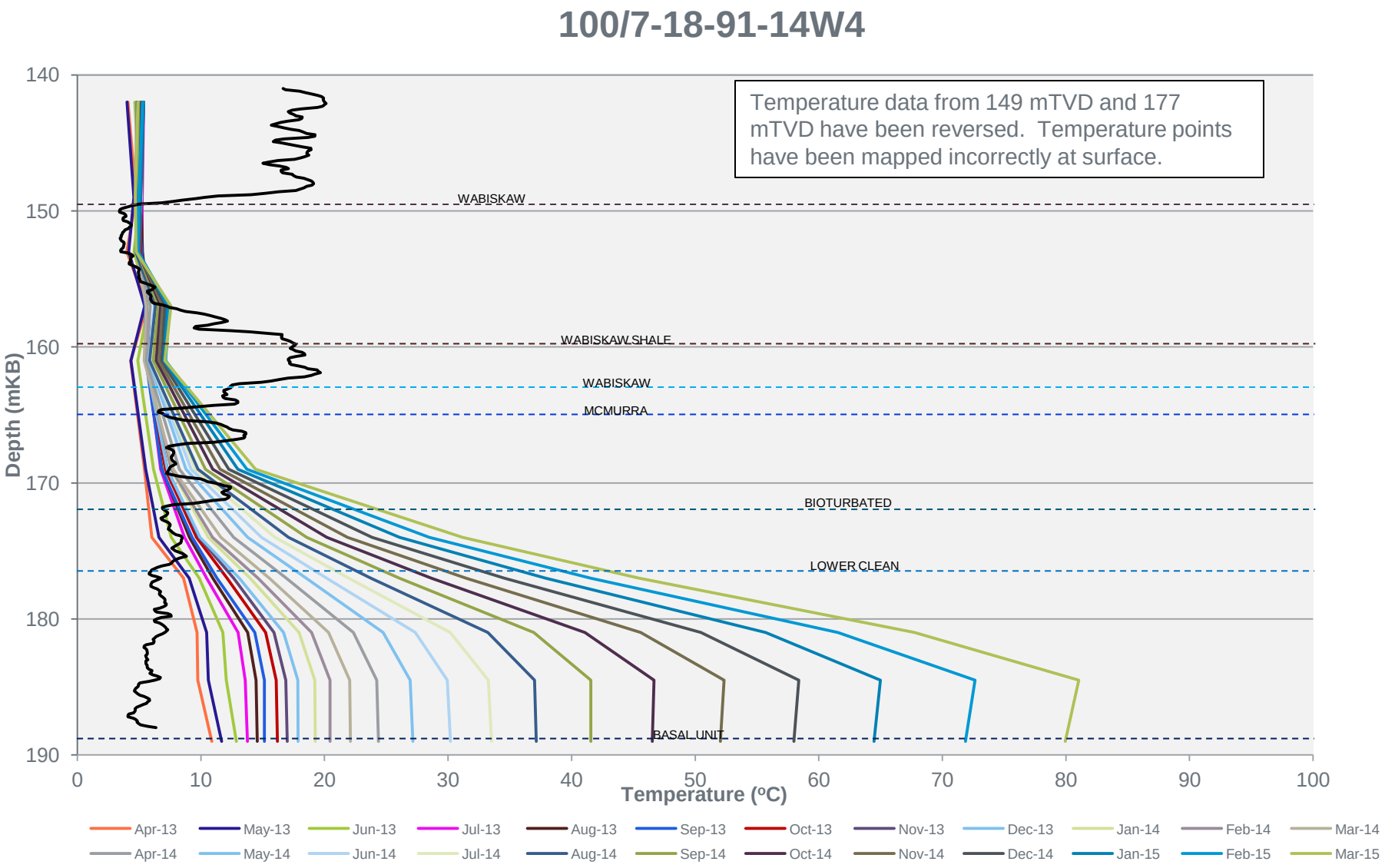
Drilling and Completions – Pad 101 Wabiskaw Observation Well Design



- Horizontal observation well designed and drilled in Wabiskaw formation for potential future production from zone.

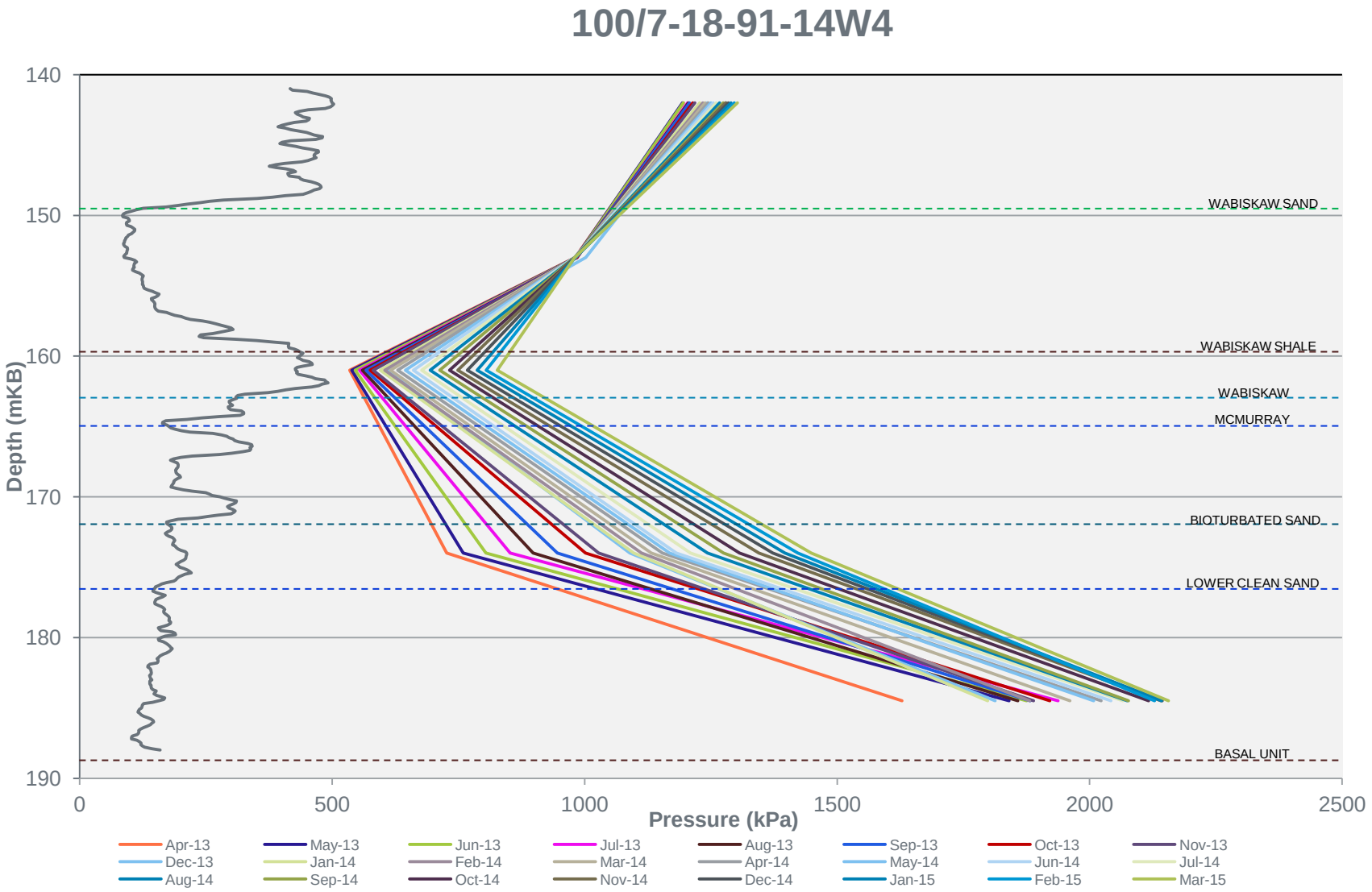
Observation Wells

07-18-091-14W4 Temperature – 1P3 Midpoint



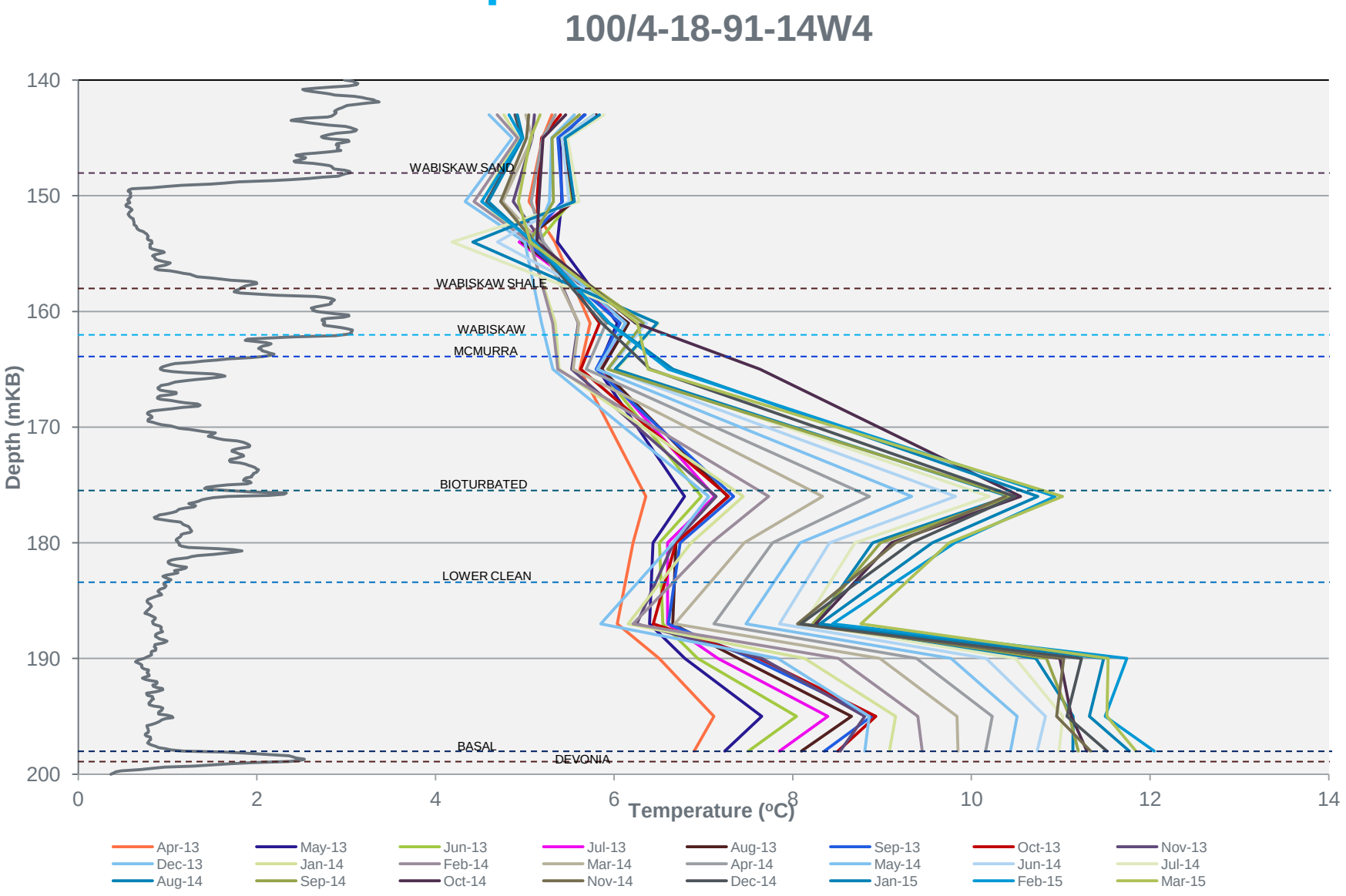
Observation Wells

07-18-091-14W4 Pressure – 1P3 Midpoint



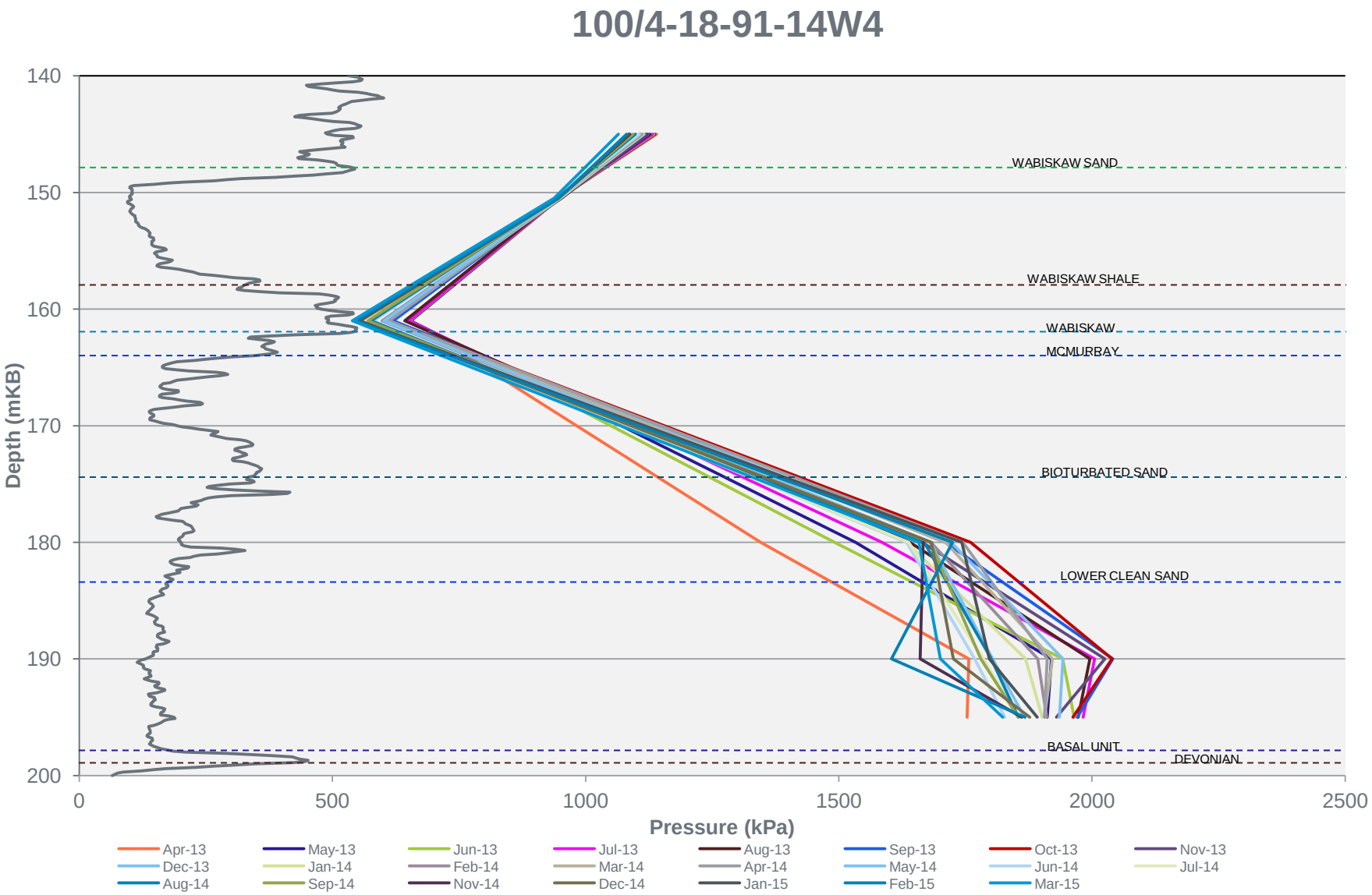
Observation Wells

04-18-091-14W4 Temperature – 2P4 Heel



Observation Wells

04-18-091-14W4 Pressure – 2P4 Heel



Instrumentation in Wells

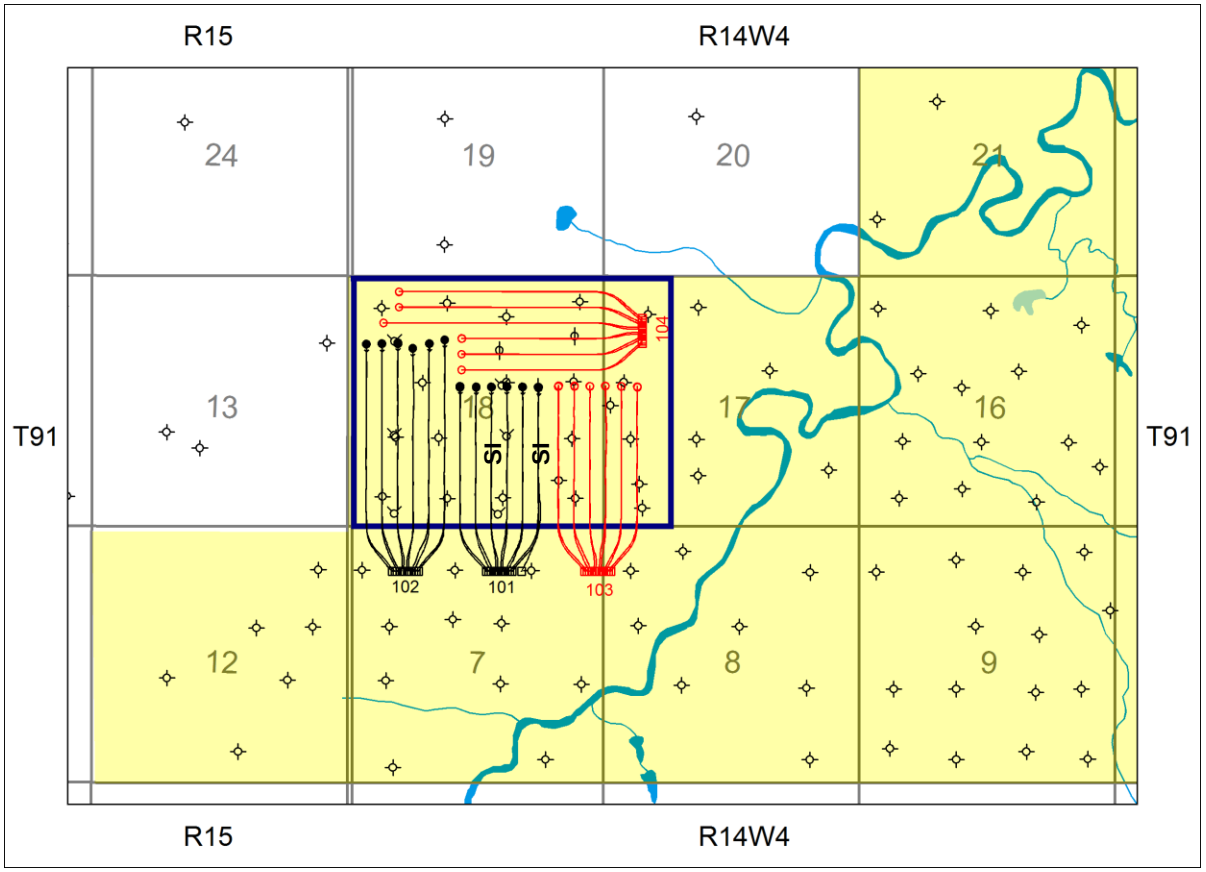
- Continuing to replace failed fiber strings in Pad 1 when opportunities arise.
  - Fiber strings in 1P3 and 1P5 need to be replaced.
- Original Pad 1 fibers failed as a result of moisture invading the capillary lines. Previous manufacturing process has been revised to ensure proper containment of fiber.
- Pad 2 Thermocouples continue to provide accurate data.
- No appreciable temperature response in McMurray observation wells as of yet. Hottest temperature ~80 Deg C.
- As expected, there has been no temperature or pressure response observed in the Wabiskaw observation well.

Scheme Performance

Scheme Performance

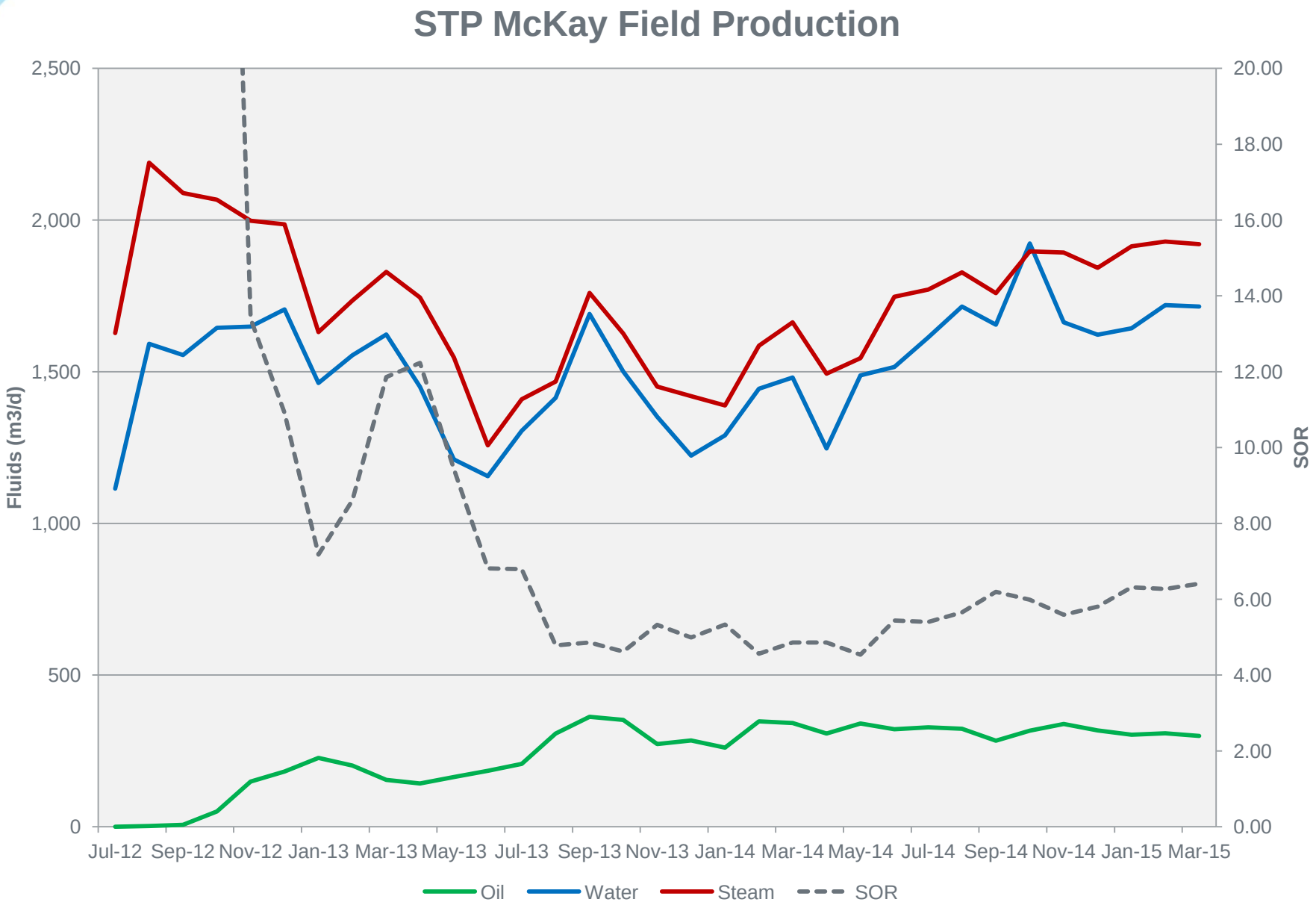
Well	Current Status
101-1	Shut In
101-2	SAGD
101-3	SAGD
101-4	Shut In
101-5	SAGD
101-6	SAGD
102-1	SAGD
102-2	SAGD
102-3	SAGD
102-4	SAGD
102-5	SAGD
102-6	SAGD

Highlighted wells are currently shut in.

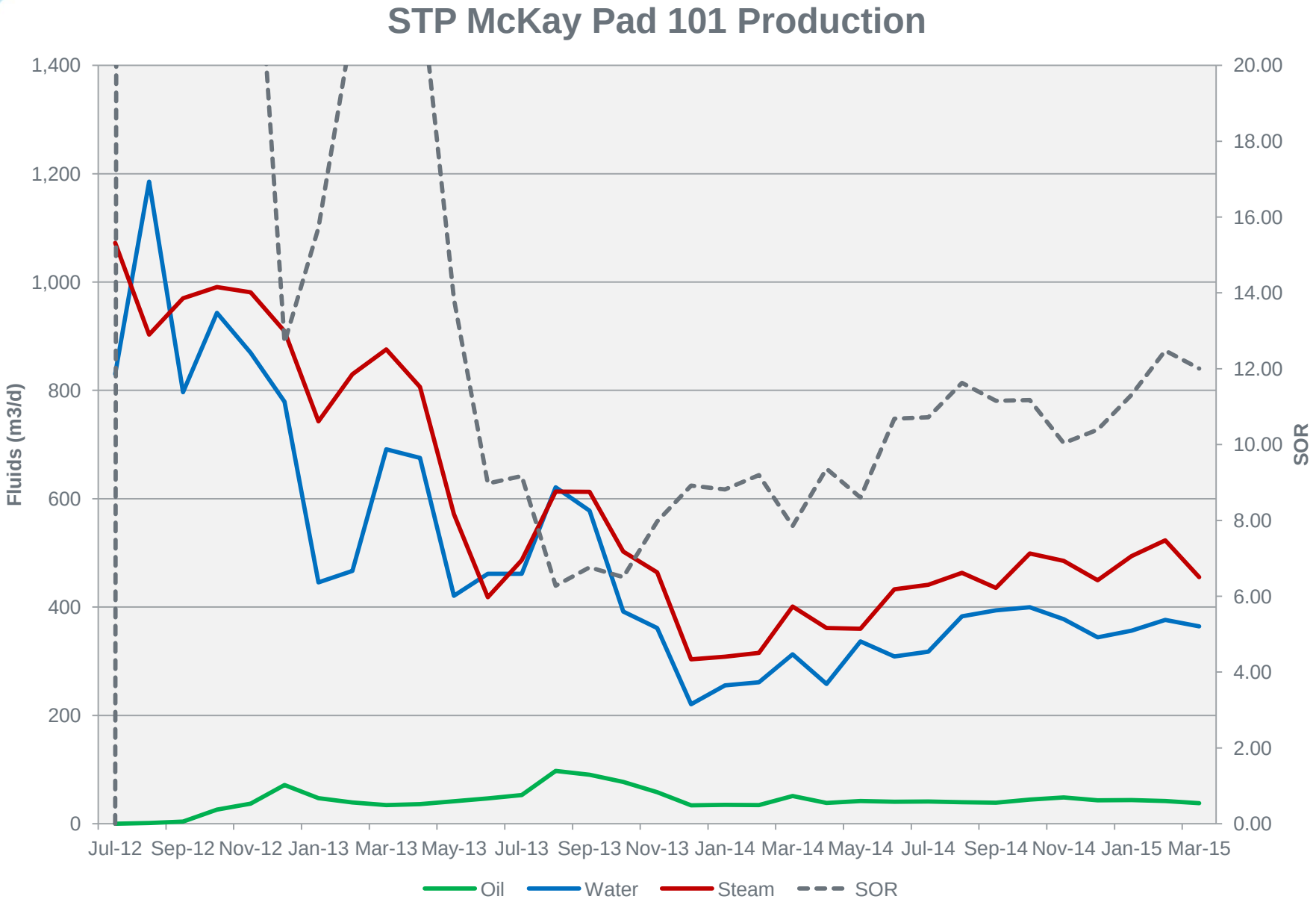


- All producing wells are currently operating in SAGD.
- 101-1 Shut in due to non-economic performance.
- 101-2 Shut in due to workover string being stuck in lateral section of well.

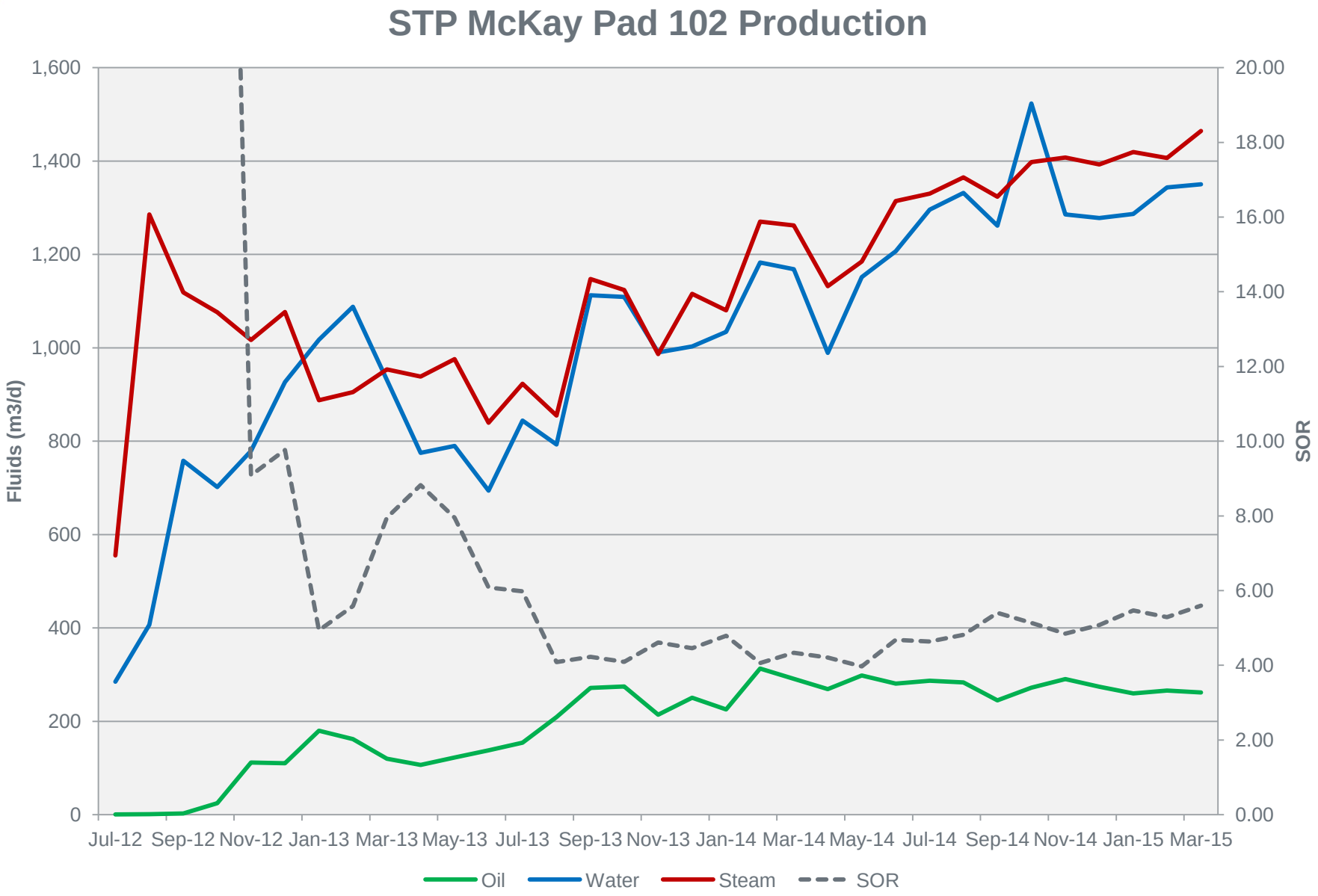
Scheme Performance



Scheme Performance



Scheme Performance



Scheme Performance

Pad	Drainage Area E3 m2	Average Net Pay, m	Porosity, fraction	Sw, fraction	OOIP, E3 m3	Cum Oil, E3 m3	Current Recovery Factor, fraction	Ultimate Recovery Factor, fraction
101	540	18	0.33	0.26	2374	43.1	0.018	0.50
102	720	20	0.33	0.26	3516	199.5	0.057	0.50

Scheme Performance

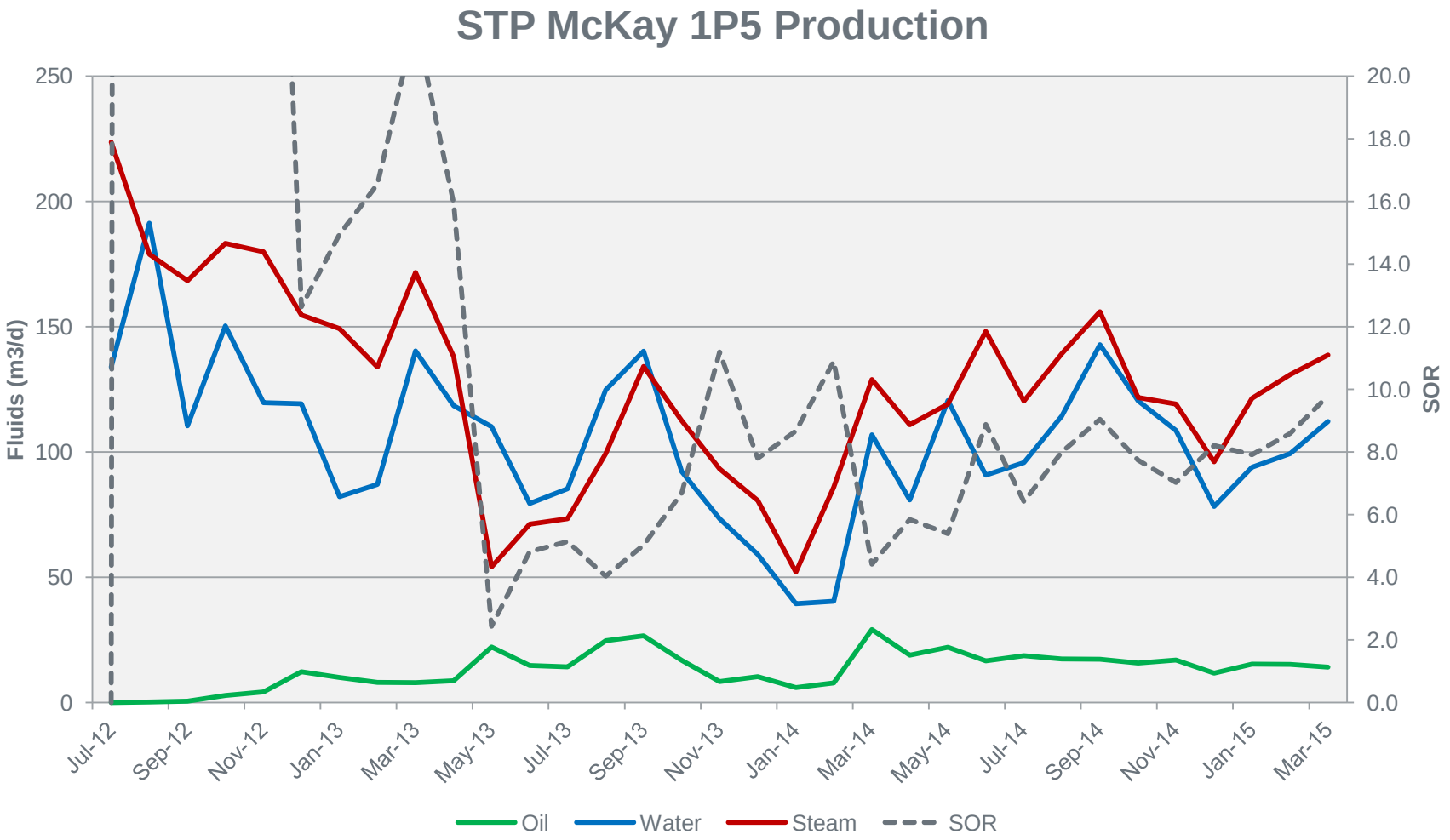
Pattern Examples Based on Recovery to Date

- Oil forecasting is based on theoretical flow equations for growing steam chambers (Butler)

- All examples below are based on cumulative recovery to date and not necessarily expected ultimate recovery.

Scheme Performance

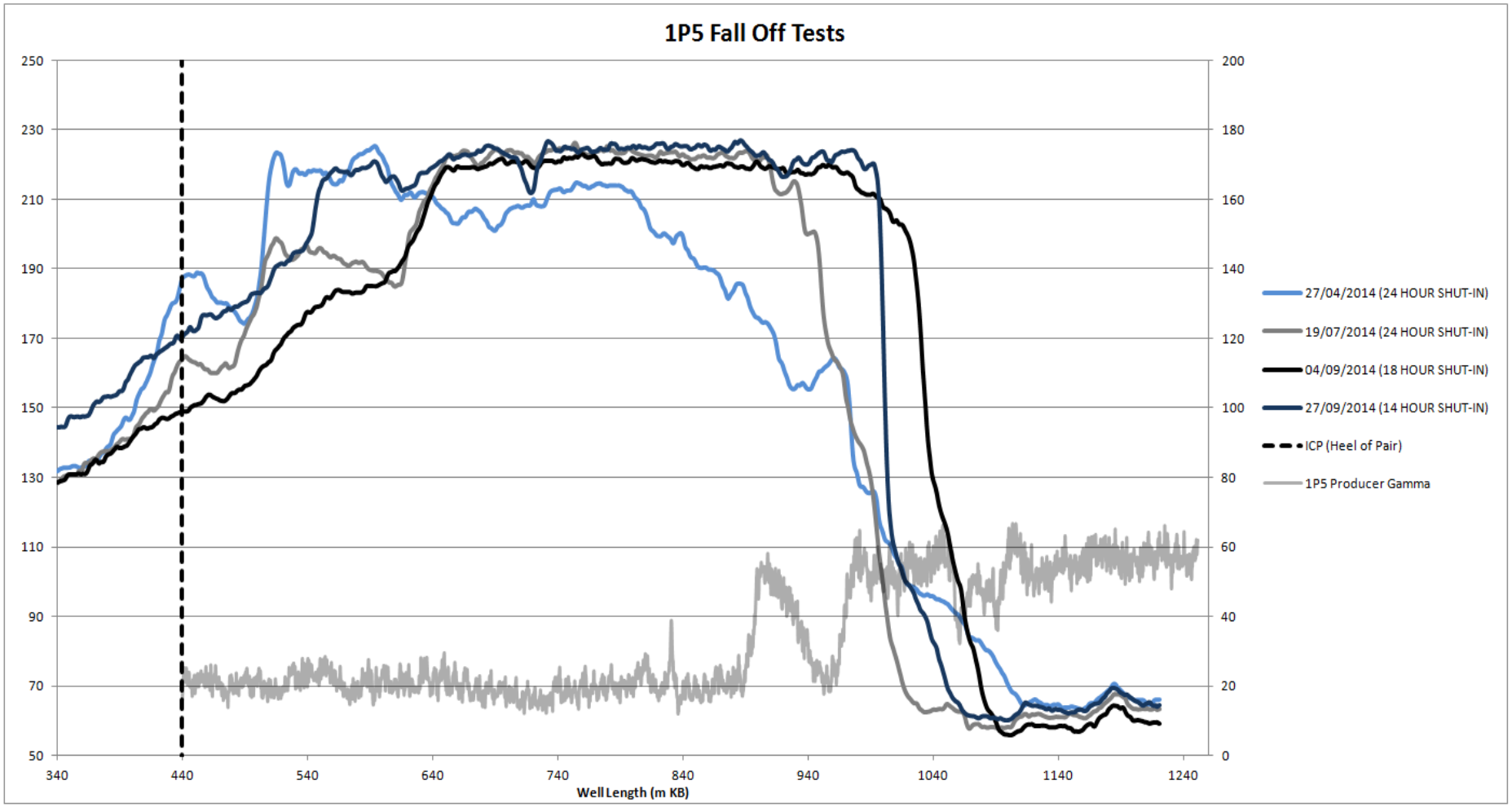
Lower Recovery Example 1P5



- ICD was installed in February of 2014.

Scheme Performance

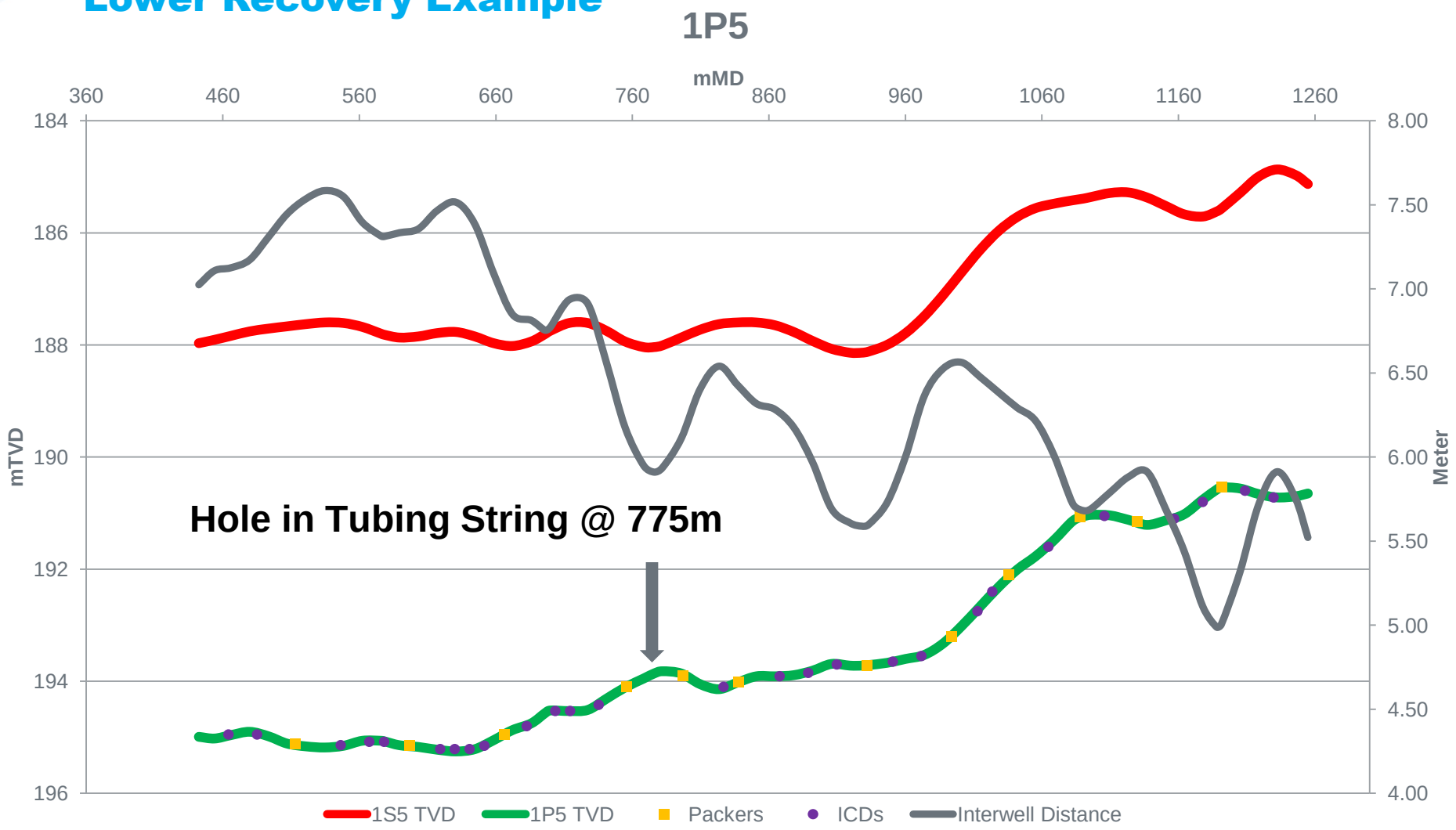
Lower Recovery Example 1P5



- Instrumentation was not functioning prior to ICD installation.
- Have not been successful in heating toe section of well.

Scheme Performance

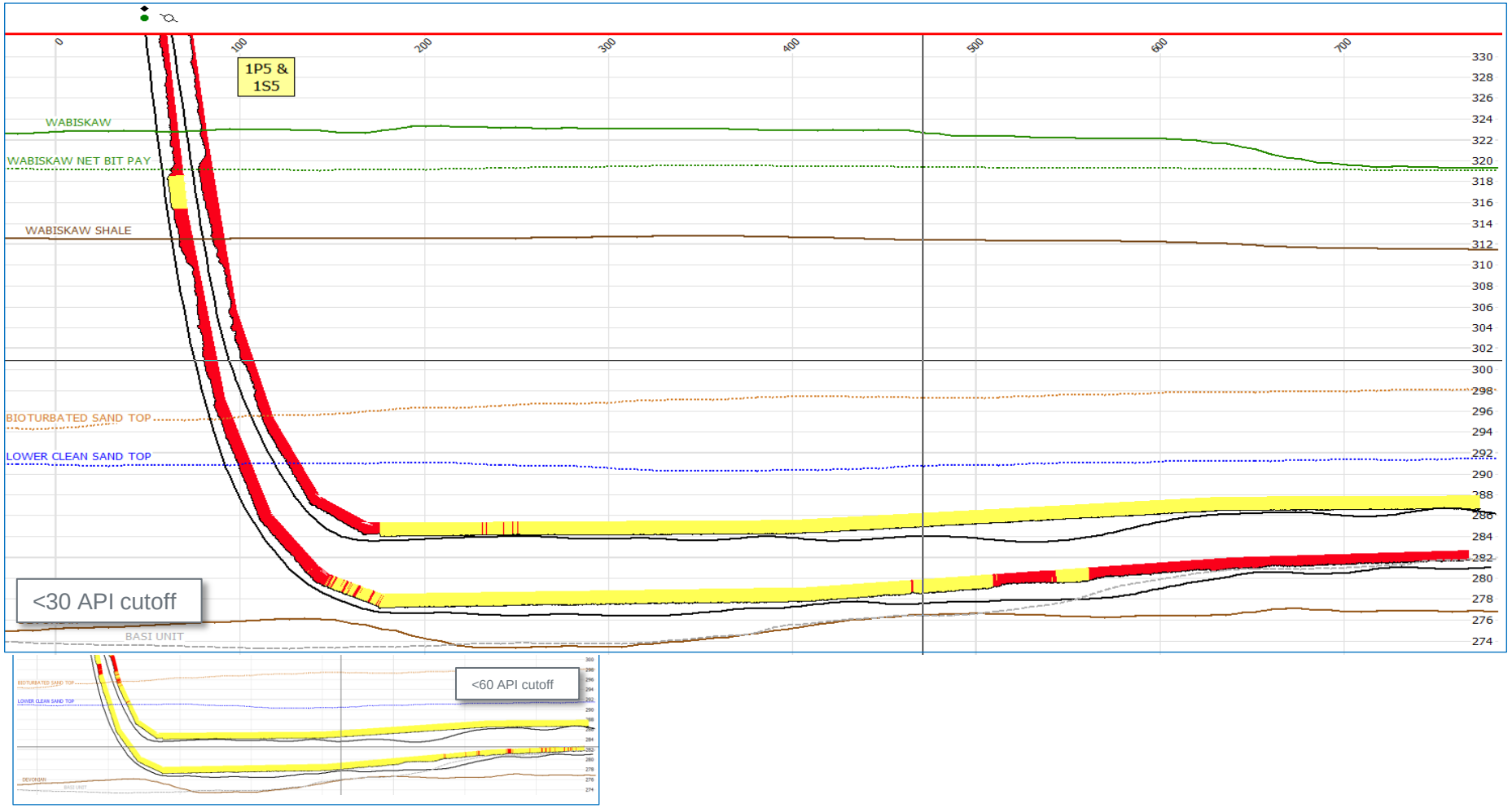
Lower Recovery Example



- Hole in Long Tubing string found at ~775 m was isolated with blank scab liner.

Scheme Performance

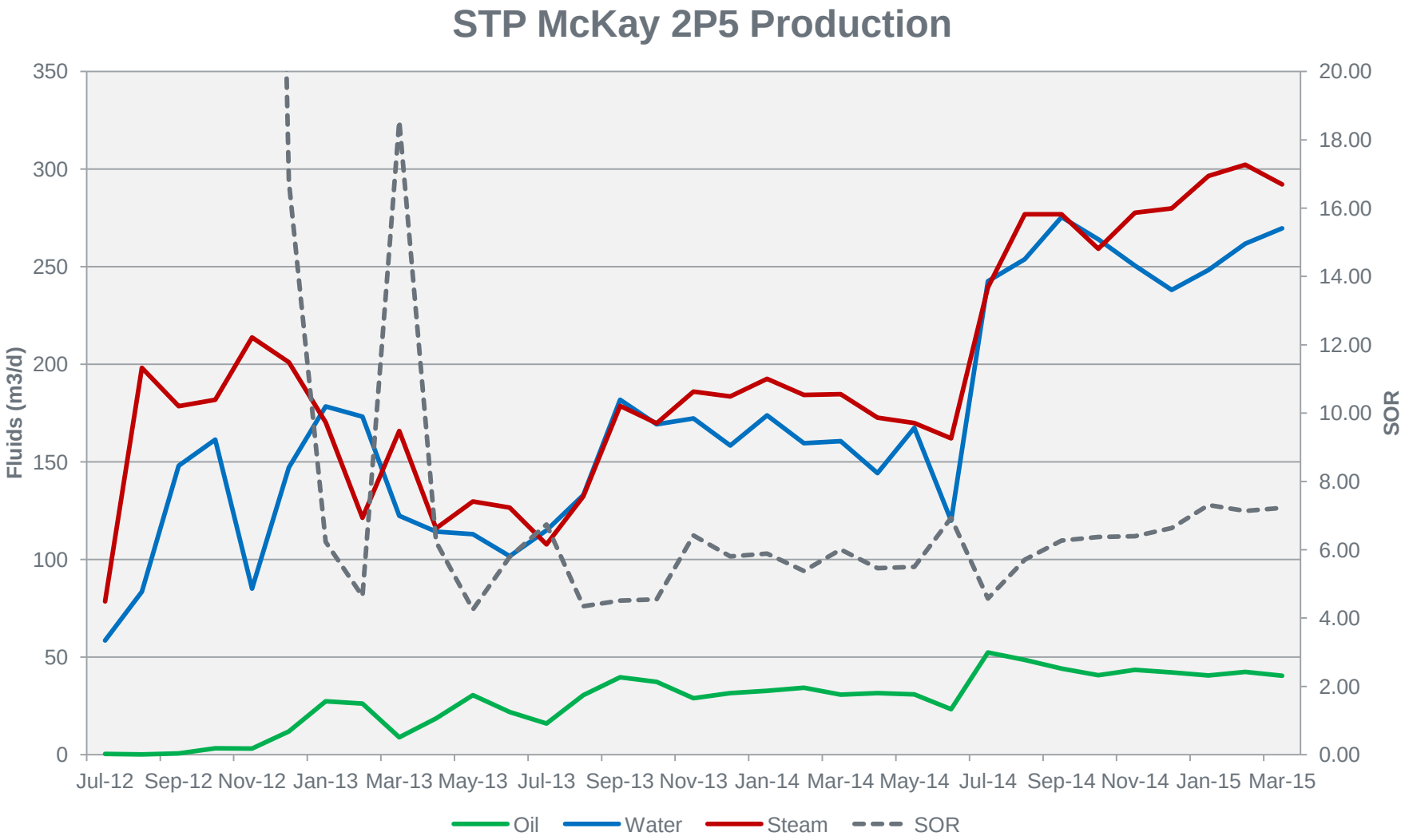
Lower Recovery Example 1P5 Flowing Temperatures & Trajectory



- Majority of well is clean with API cut off of 60. Cold section of toe clearly aligns with 30 API cut off.

Scheme Performance

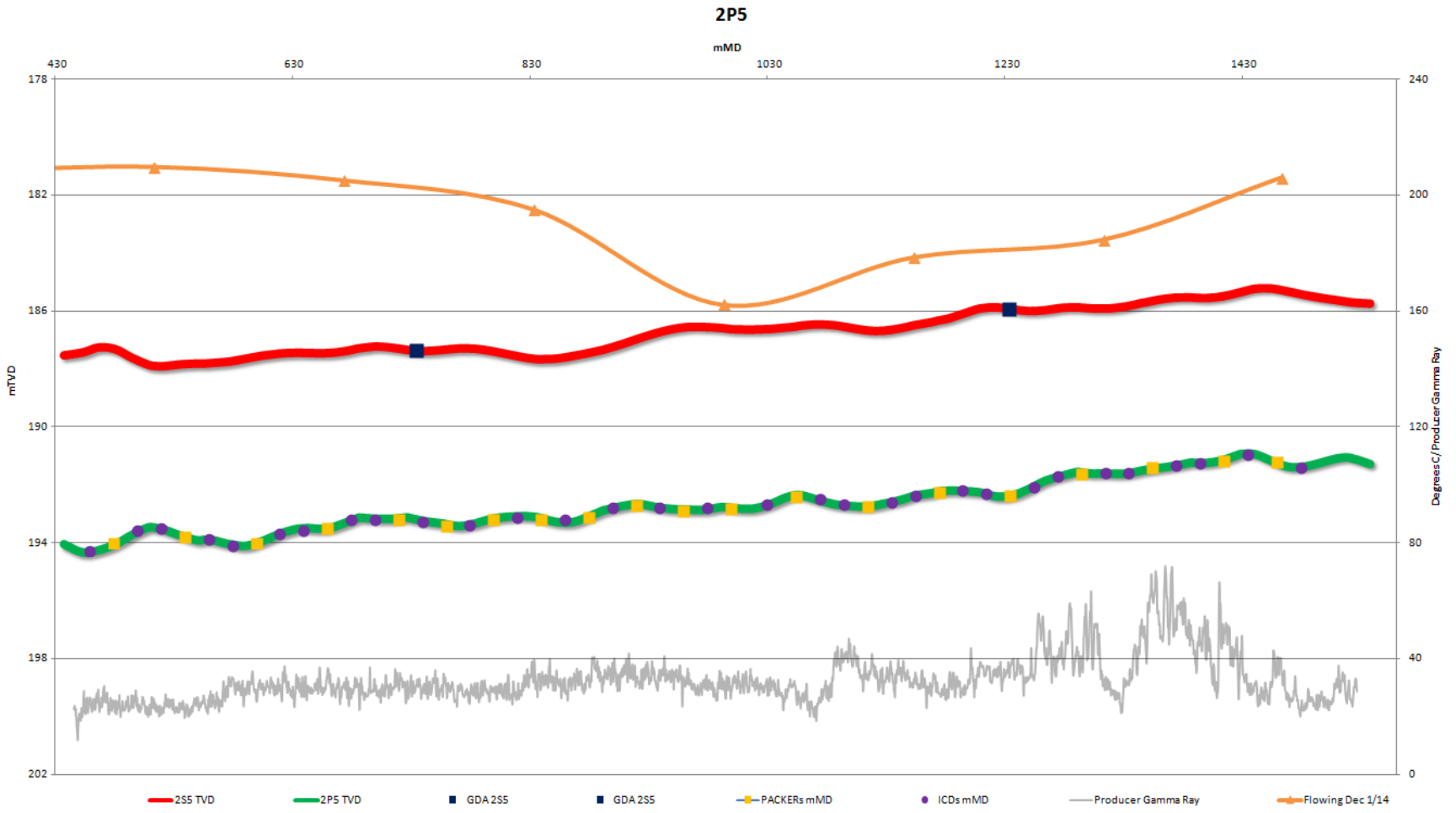
Medium Recovery Example 2P5



- ICD installed in June of 2014.

Scheme Performance

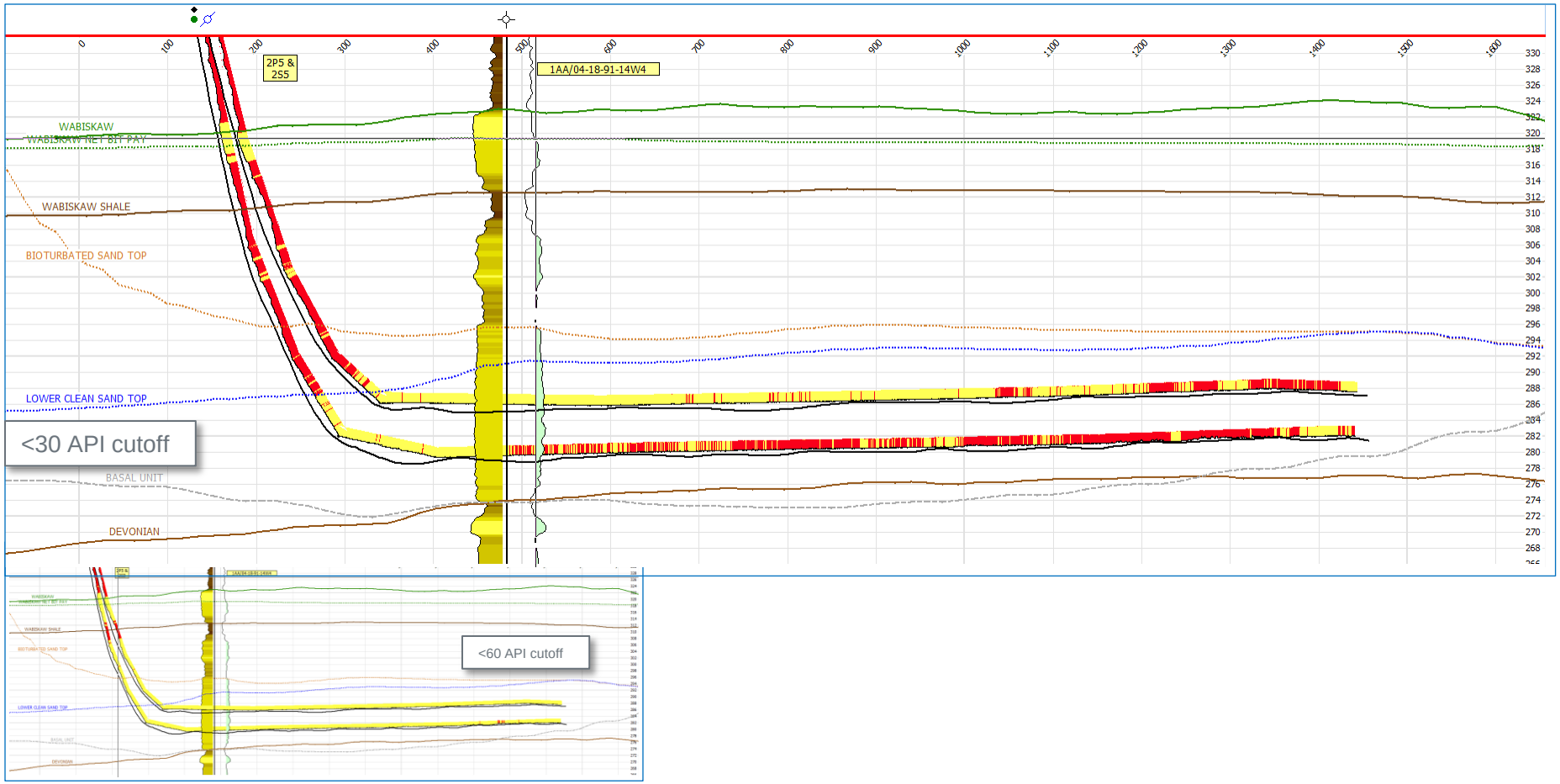
Medium Recovery Example 2P5



- Cooling trend observed from toe to midpoint of well.

Scheme Performance

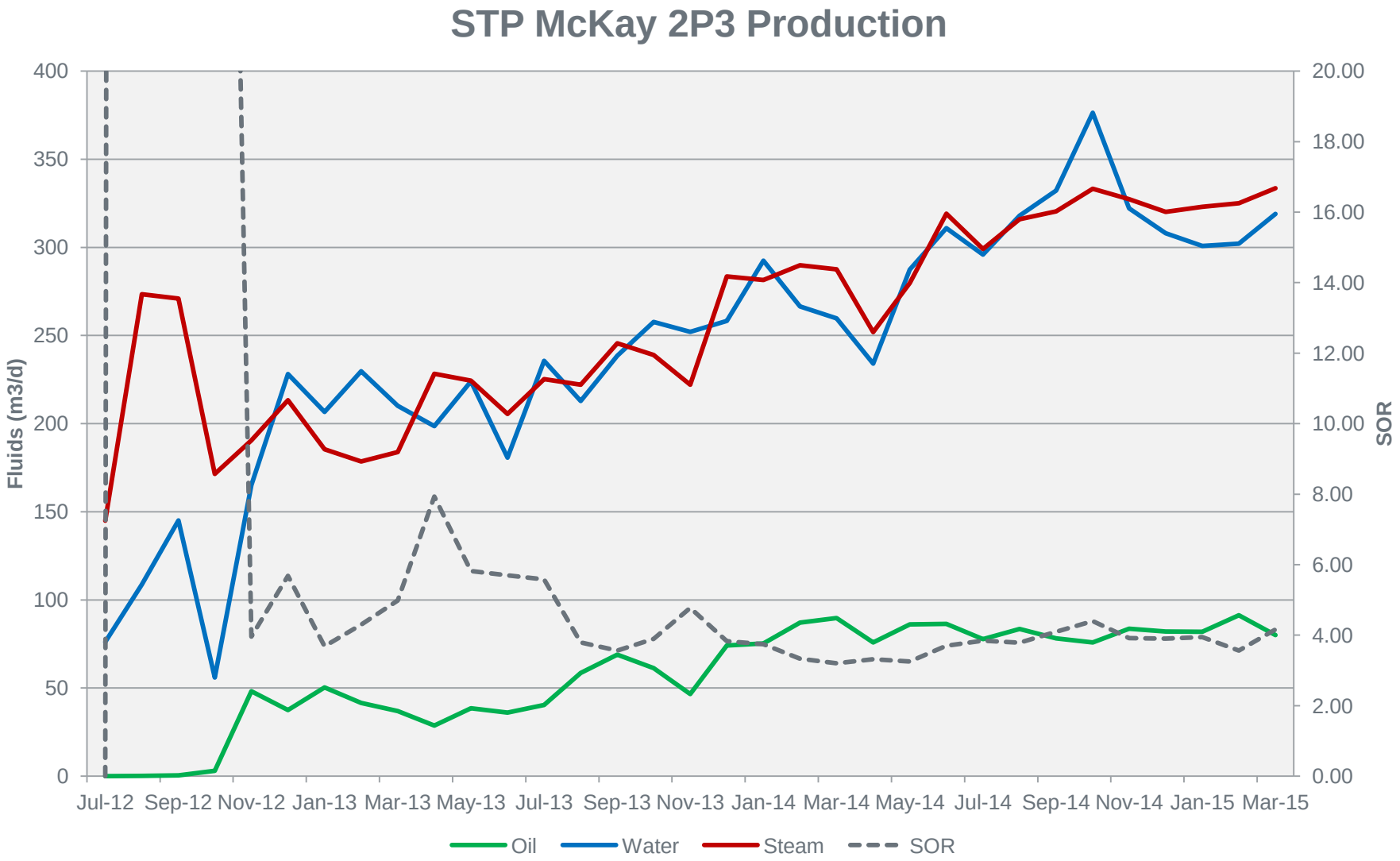
Medium Recovery Example 2P5



- This pair's producer has considerable LWD gamma readings between 30 and 60 API.
- This could be because the wellbore is closer to the Basal Unit below, or that it has been drilled through slightly shalier sand.

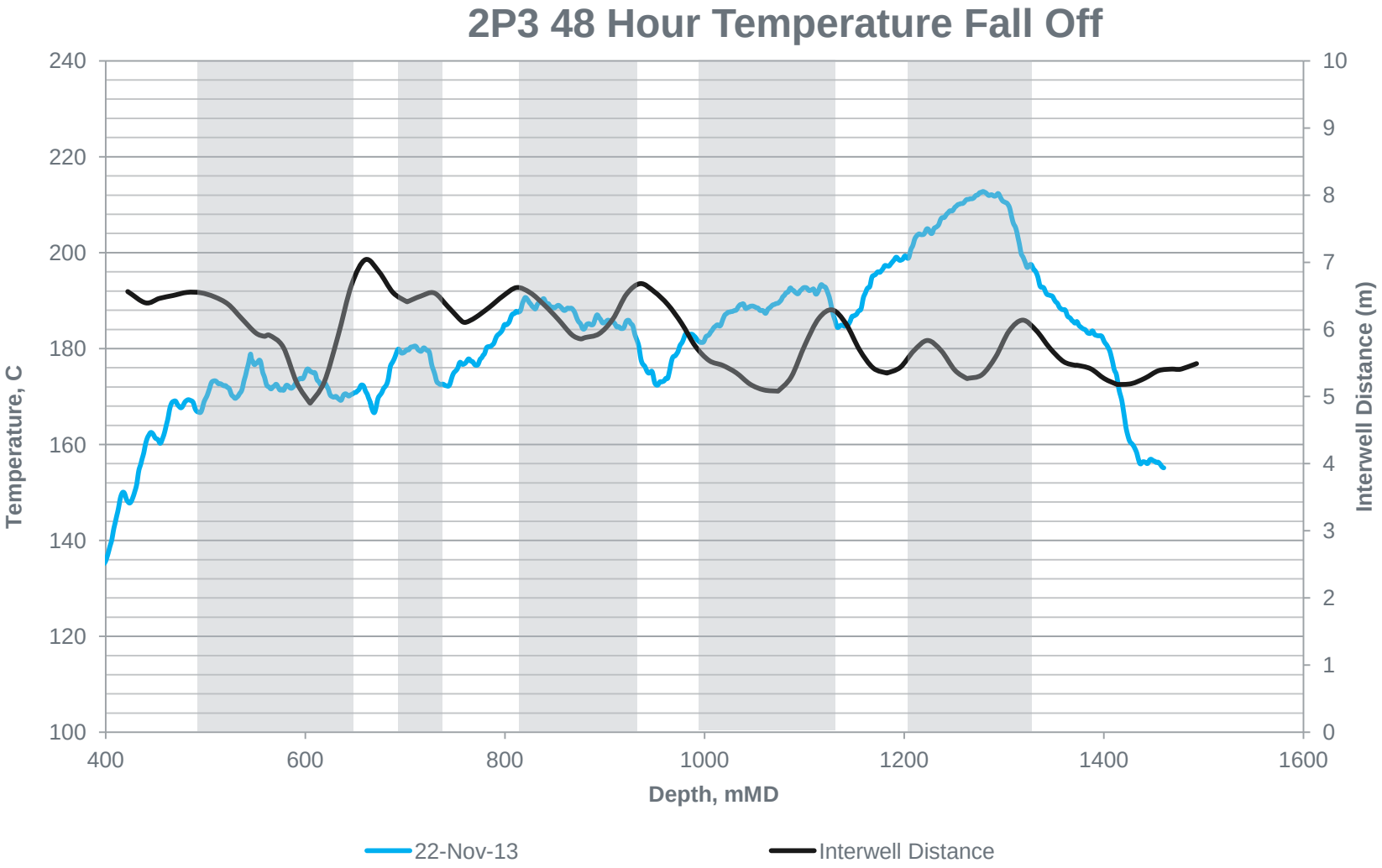
Scheme Performance

Higher Recovery Example 2P3



Scheme Performance

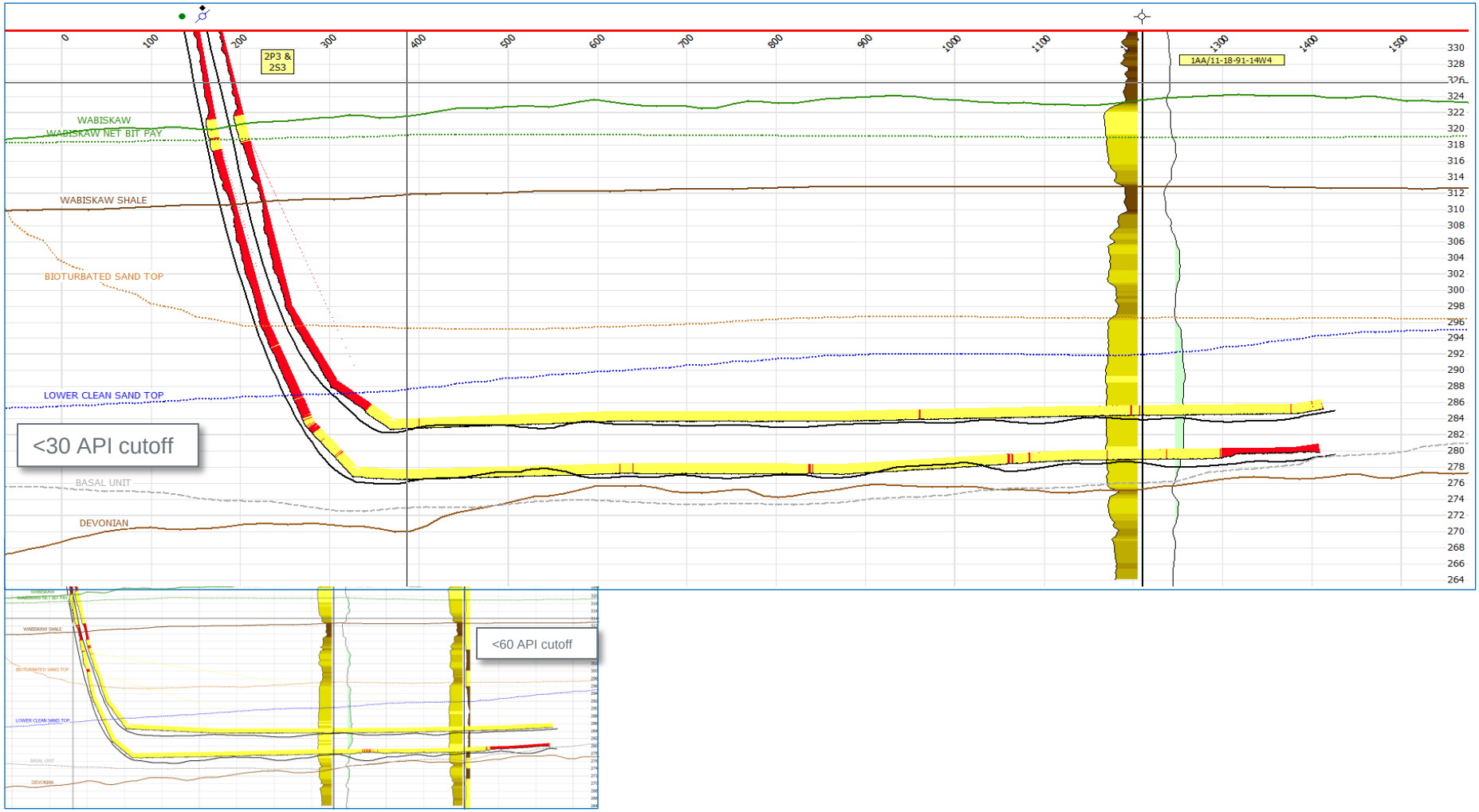
Higher Recovery Example 2P3 Temperature Log



- Temperature log indicates well was between 50-60% conformed in Nov 2013.

Scheme Performance

Higher Recovery Example 2P3



- At a cut off of 30 API, the majority of the well is still clean.

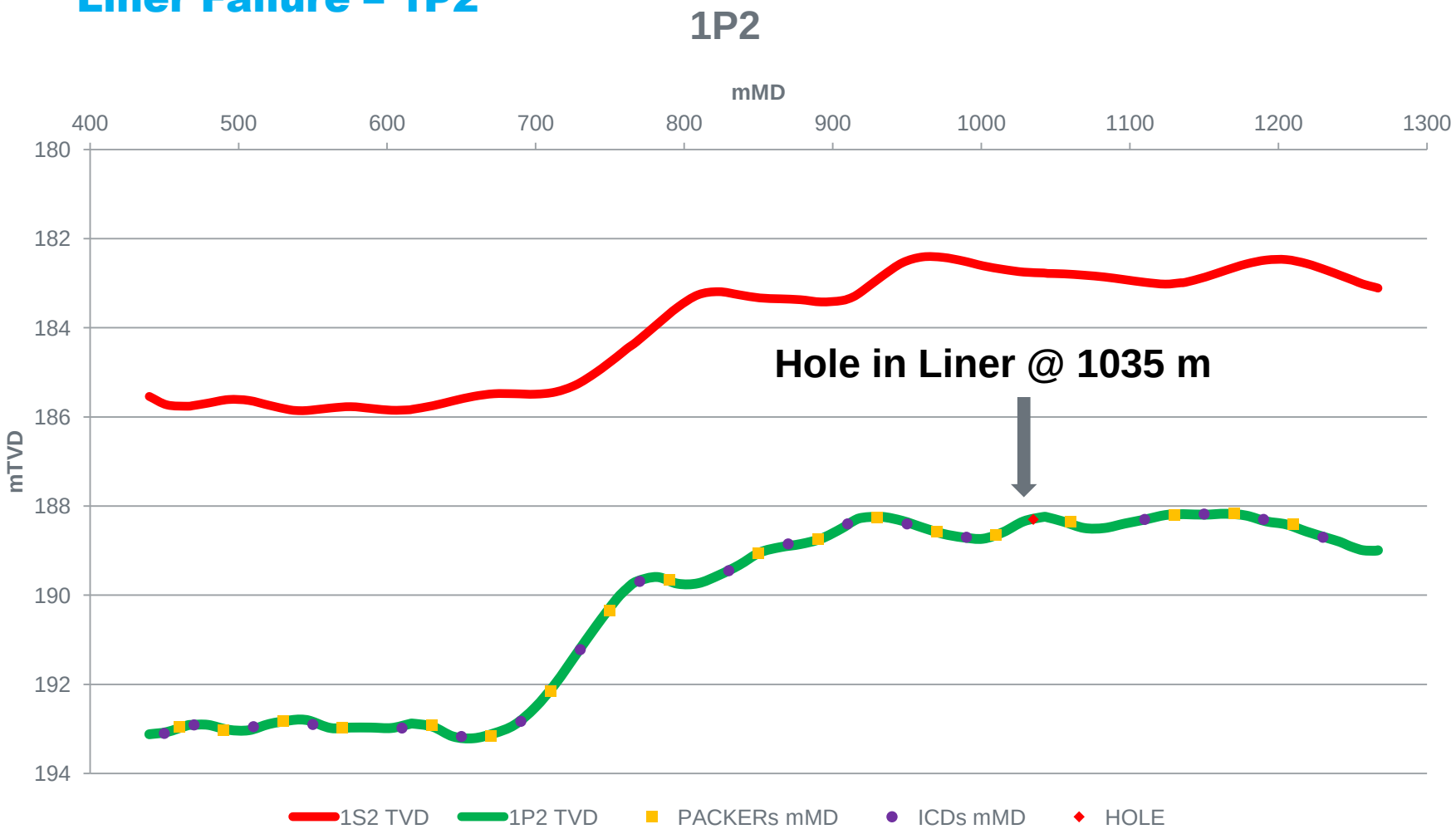
Scheme Performance

Liner Failures – 2P4/1P2

- Pad 102 - 2P4 Liner Failure
  - Well Failed in December 2012 during circulation.
  - See 2013 STP Performance Presentation for details.
- Pad101 - 1P2 Liner Failure
  - Well failed in October 2013 during SAGD.
  - High vapor rates and solids production were observed in test immediately after failure.

Scheme Performance

Liner Failure – 1P2



- Liner failure at 1035 mMD repaired using ICD Scab liner with blank section from 1010 – 1060 mMD.
- Interval isolated using swellable packers.
- Completion installed during October of 2014.

ICD Summary

Why

- STP's biggest challenge has been conformance.
  - Production rate impeded by single point breakthrough.
  - Unbalanced wellbore inflow due to varied wellbore separation and reservoir heterogeneities.

Theory

- Producer wellbore is segmented and placement/number of ICD's in each segment varied to promote and control flow by increasing pressure differential.

- Sections of the wellbore experiencing high vapour production will see an increased pressure drop through the device, allowing for more uniform inflow and drawdown along the length of the well.

ICD Summary

ICD Scorecard

WELL	INSTALLED	OIL RATE IMPROVEMENT?	INCREASED DIFFERENTIAL?	iSOR IMPROVEMENT?	HOT SPOT CONTROLLED?
2P1	January 2014	YES	YES	NO	YES
1P5	February 2014	YES	YES	YES	N/A
2P5	June 2014	YES	YES	NO	YES
2P2	September 2014	NO	YES	NO	YES
1P2	October 2014	NO	YES	NO	YES
1P6	October 2014	NO	YES	NO	YES

ICD Summary

- 2P1 – ICD Installation
  - Slight improvement in bitumen rate.
  - Believe well pair will continue to improve as SAGD chamber develops.
- 1P5 – ICD Installation
  - Short circuit has been repaired.
  - Unable to gain inflow in toe section of well.
- 2P5 – ICD Installation
  - Short circuit has been repaired.
  - Slight improvement in bitumen rate.
- 2P2 – ICD Installation
  - No significant bitumen rate improvements to date.
  - Believe well pair will continue to improve as SAGD chamber develops.
  - Previous short circuit has been repaired.
- 1P2 – ICD Installation
  - Well was shut-in for over a year and has cooled off.
  - Was on steam circulation (bullhead to producer) for ~ 2 months to warm up.
  - Only recently brought on stream, may require a few steam injection/production cycles before well pair converts fully to SAGD.
- 1P6 – ICD Installation
  - Short circuit has been minimized.
  - Having difficulty establishing meaningful rates from heel section.

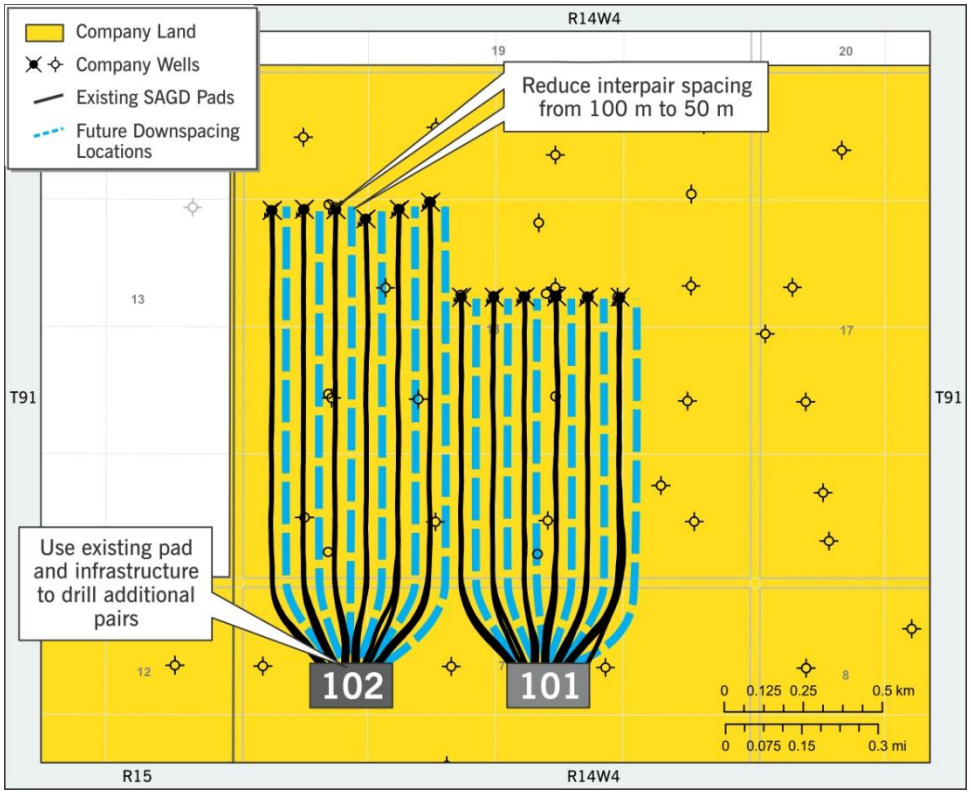
Scheme Performance

Key Learnings

Wellbore conformance has been the biggest issue in delaying the ramp up rate at McKay to date	• Almost every wellpair has developed discrete high temperature sections in the horizontal section • Managing subcool to the highest temperature in the well limits well productivity and steam chamber development
Wider spacing on heel sections of Pad 101 has exacerbated conformance issues	• Required longer circulation period • Toe section developing short circuits, which further delays opening up heel sections
Higher differential pressure (between injector and producer) has been required to initiate the flow of bitumen than anticipated	• However, the better conformed well pairs have developed very reasonable and stable differential pressure drops once communication has been initiated
Based on observed production performance, reservoir permeability to oil has been reduced from original core data estimates	• Attributed to revised interpretation of rock properties: grain maturity (lower roundness)
From a geological perspective, minimal alterations to the original mapping have been made since the wells were brought on stream	• No material thief zones are present, zone can be pressured up with relative ease to MOP. We are not seeing lateral communication between well pairs
Shalier sand sections in producer well bores have not contributed meaningful inflow to date	• Correlative production/temperature data suggests that <30 API gamma sands conform the best, while >30 API are not contributing much to inflow in the well pairs so far.

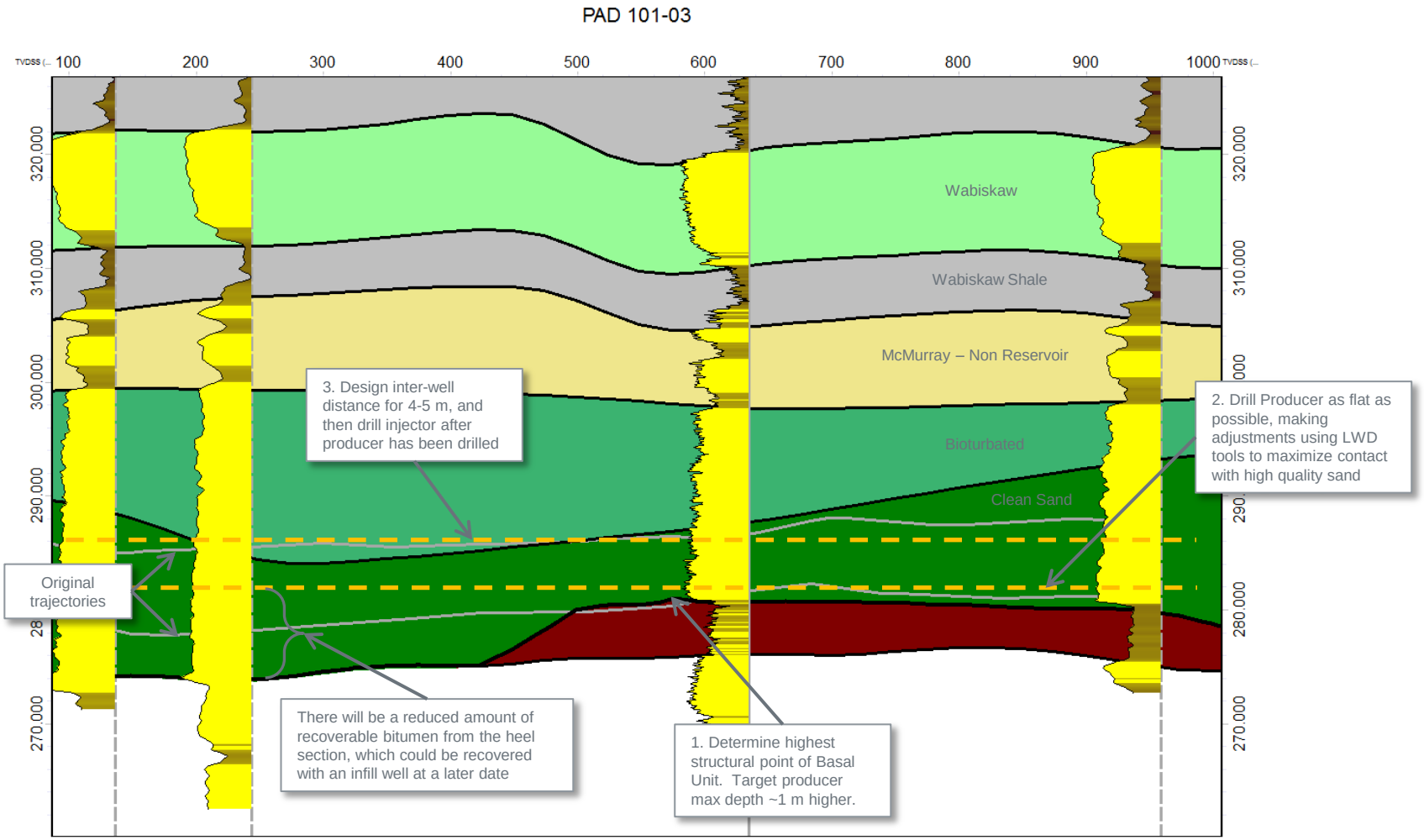
Subsurface Future Plans

- Downspacing accelerates rate and recovery, and minimizes additional capital infrastructure
- 50 m spacing on downspaced SAGD pairs on Pads 101 and 102 provides improved recovery and rapid economic enhancement of the project
- Pad 102 will be the first downspacing project
- Timing of Pad 101 downspacing dependent on steam availability and Pad 102 performance
- AER approval in place.



The most cost effective method to fill the plant is to drill additional SAGD well pairs within the existing pads

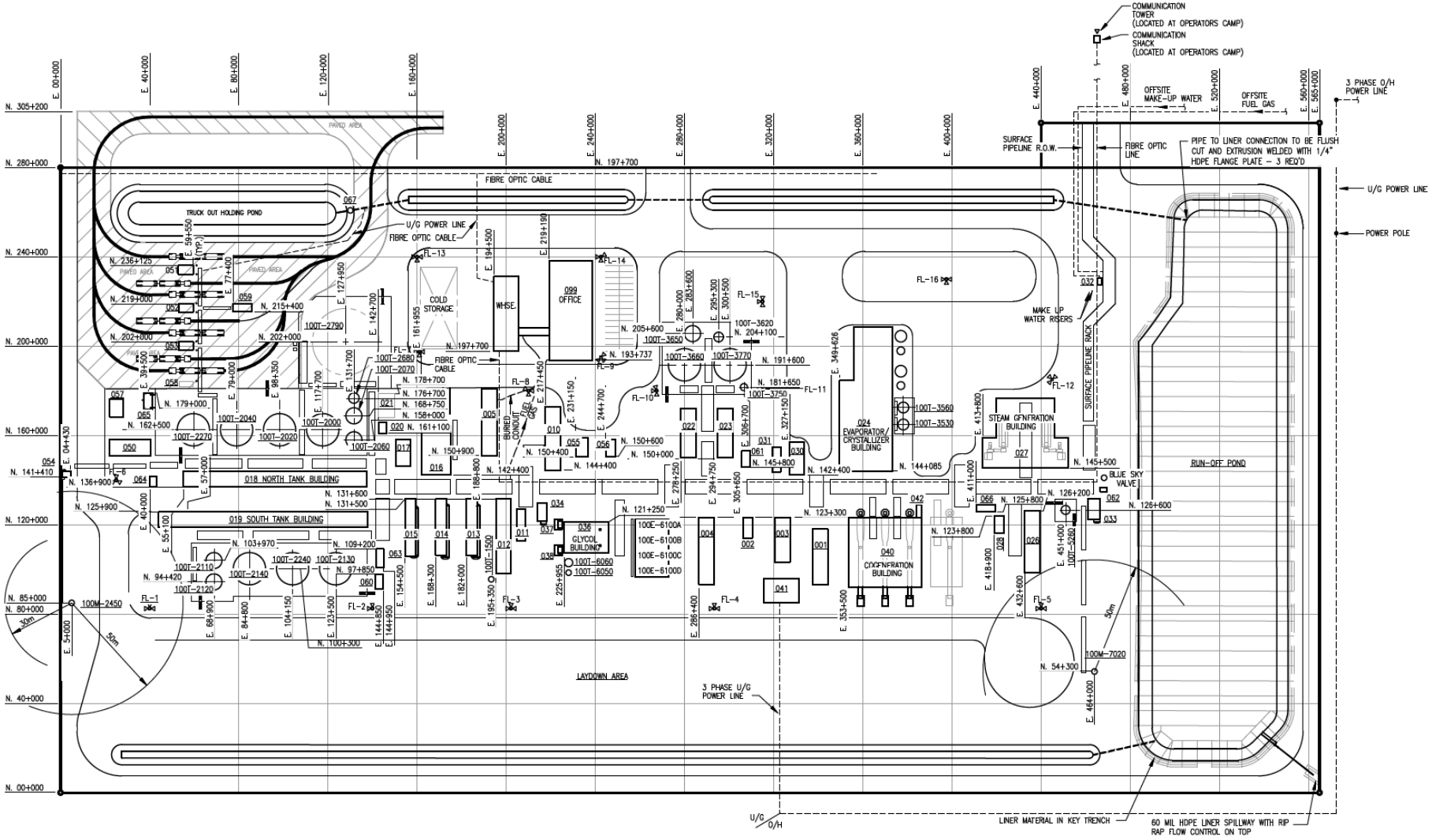
New Well Pair Trajectory Strategy



Use the learnings gathered to date to drill lower risk, higher rate, commercial well pairs.

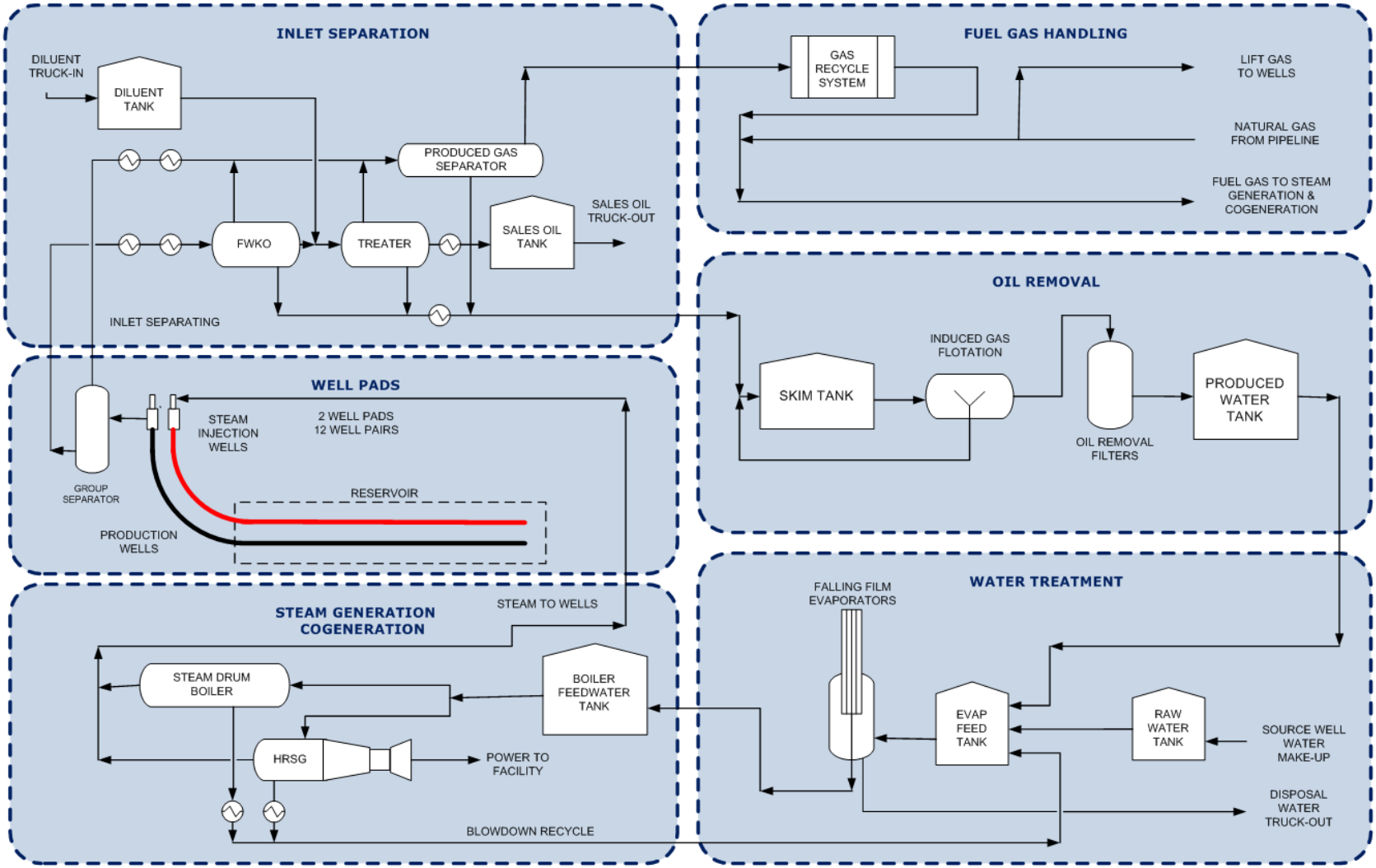
Surface Facilities & Environmental Table of Contents

Facility Plot Plan – 2014 Amendments



- No facility amendments completed in 2014

Facilities – Simplified Facility Schematic



Measurement/Reporting

General

- Annual 2014 MARP Update submitted February 16, 2015
- Review of Controls for EPAP Declaration completed, declaration submitted February 27th. Work to date indicates that all of the measurement related controls are adequate and functioning as intended.
- Some issue with fouling of orifice plates in Produced Water service has led to some metering challenges during the year. Use of backup produced water meter (Mag-type) for reporting, and as a tool to identify fouling of primary meter has been successful at mitigating this concern.
- Accurate produced gas measurement at high lift gas use (>60:1 Sm^3 gas / Sm^3 emulsion) and high facility turndown has been a challenge.

Well Production / Injection Volumes

- Well production is prorated from bulk scheme production using intermittent test data via dedicated test separators on Pads 101 and 102. (6 pairs per separator)
- Wells meet or exceed the current minimum well test requirements per Directive 17. With six producers per pad, 11 testing hours every three days is the current operating protocol for each operating producer (12 hour test duration – 1 hour flush, 11 hours test data).
- Manual samples are taken to determine bitumen, water, solids and chloride content and have proven reliable and repeatable.

Measurement/Reporting

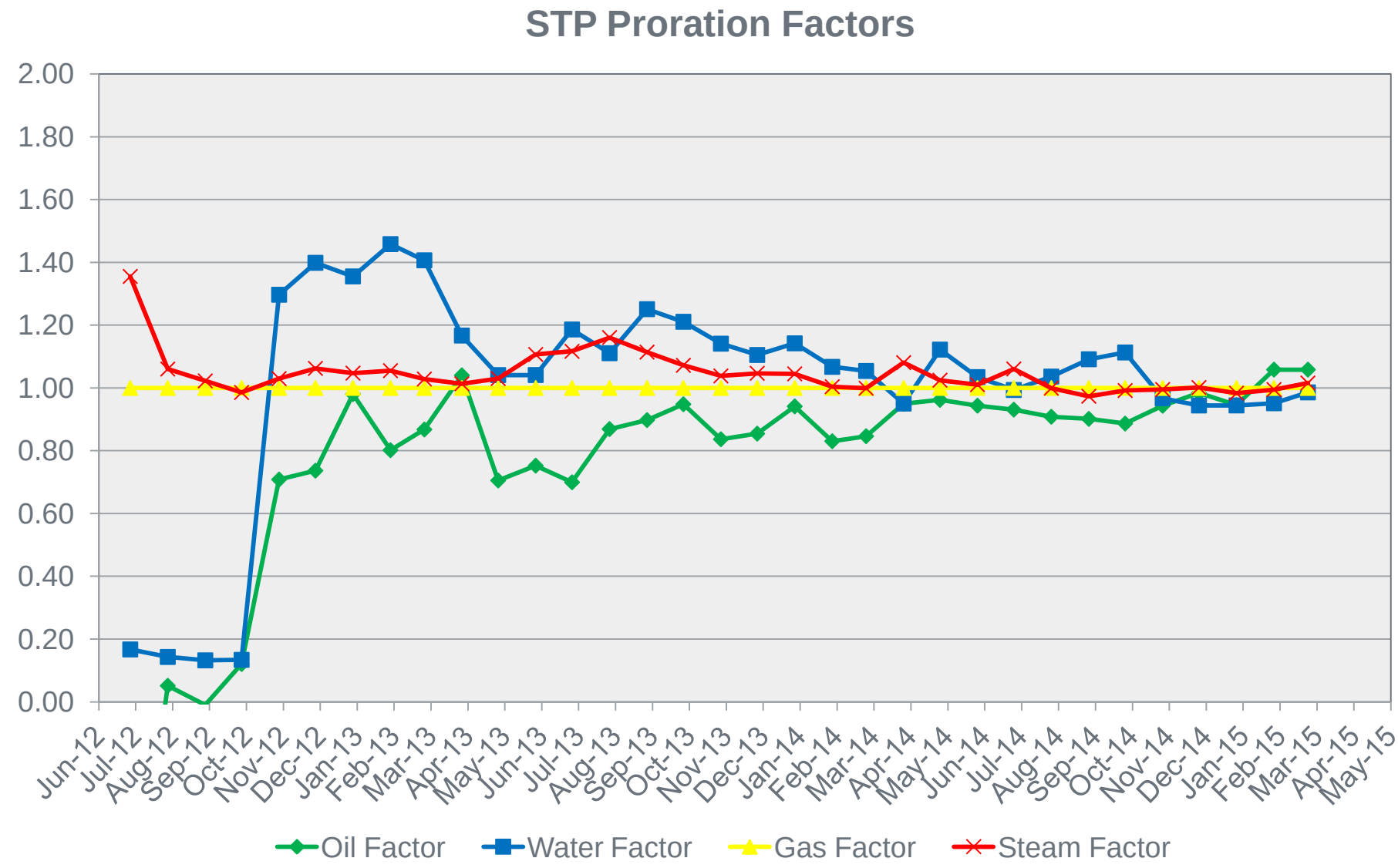
Water Balance

- Balance closure < 5%, but some room for improvement. Tightening the water balance will again be an area of focus for 2015.
- Water Recycle Performance per Calculation defined in Directive 81 averaged **99.2%** for the period analyzed.
- Per Disposal Limit formula in Directive 81, (3% of Fresh Volumes + 10% of Produced Water Volumes). The maximum disposal limit for McKay was **9.01%** of inlet volumes for the period analyzed. McKay averaged a disposal of **0.73%** of inlets for the period (**8.1%** of allowable).
- Evaporative / Venting Losses were primarily associated with venting HP Steam due to temporary water long imbalances in the CPF

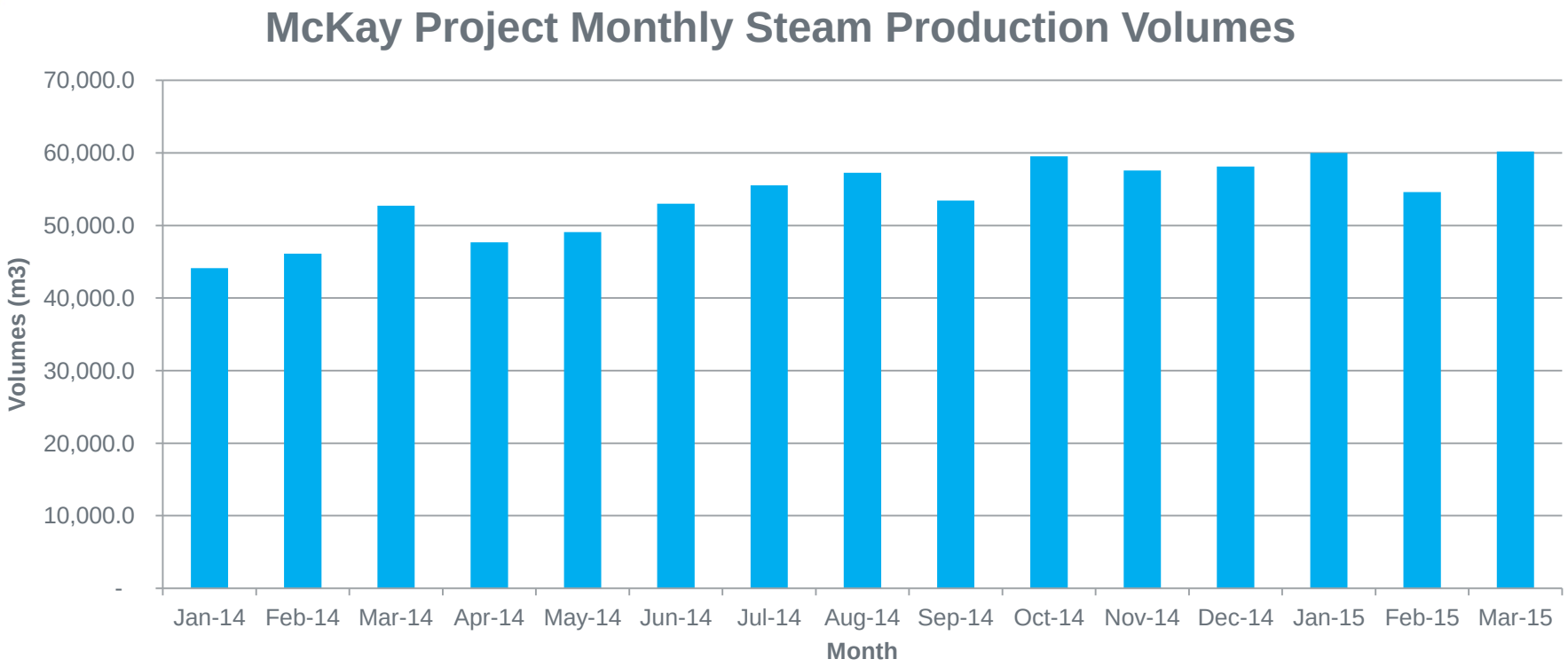
McKay Water Balance - 2014
Feb 1, 2014 - Mar 31, 2015

Inlet Flow		
Produced Water	723,395.5	m^3
Source Water	118,686.0	m^3
Total Inlet	842,081.6	**m^3**
Accumulation		
Opening Inventory (Produced)	5,073.7	m^3
Closing Inventory (Produced)	4,679.0	m^3
Opening Inventory (Fresh)	1,595.6	m^3
Closing Inventory (Fresh)	1,463.0	m^3
Total Accumulation	(527.3)	**m^3**
Outlet Flow		
Steam Injection to Wells	793,982.7	m^3
Evaporative and Venting Losses	3,016.0	m^3
Disposal Volumes	6,129.4	m^3
Water in Sales	840.5	m^3
Total Outlet	**803,968.6**	**m^3**
Difference (Inlet - (Outlet + Accum))	**38,640.3**	m^3
% Imbalance	**4.59%**	

Monthly Proration Factors



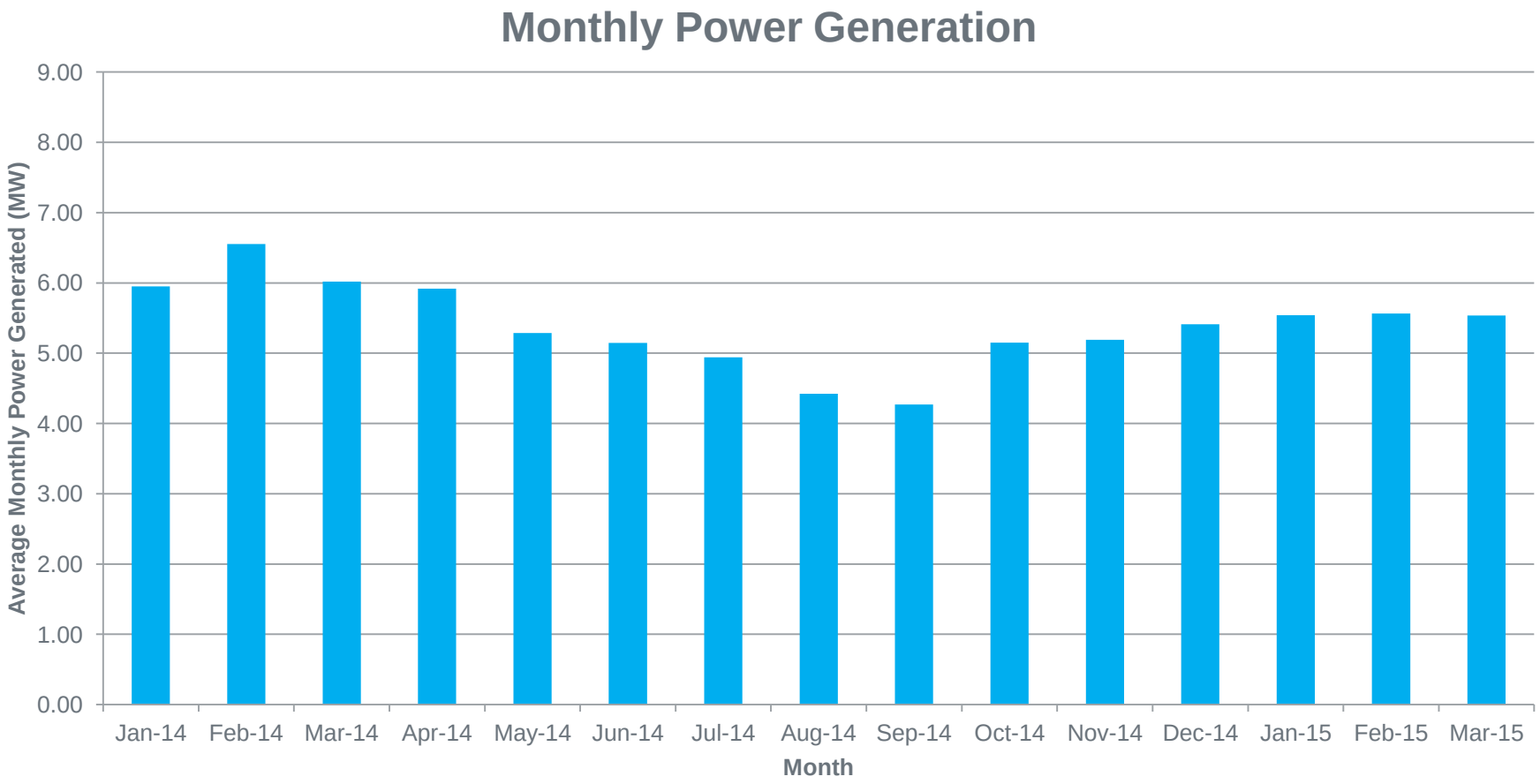
Steam Generation



Process Steam is produced at the McKay Project via:

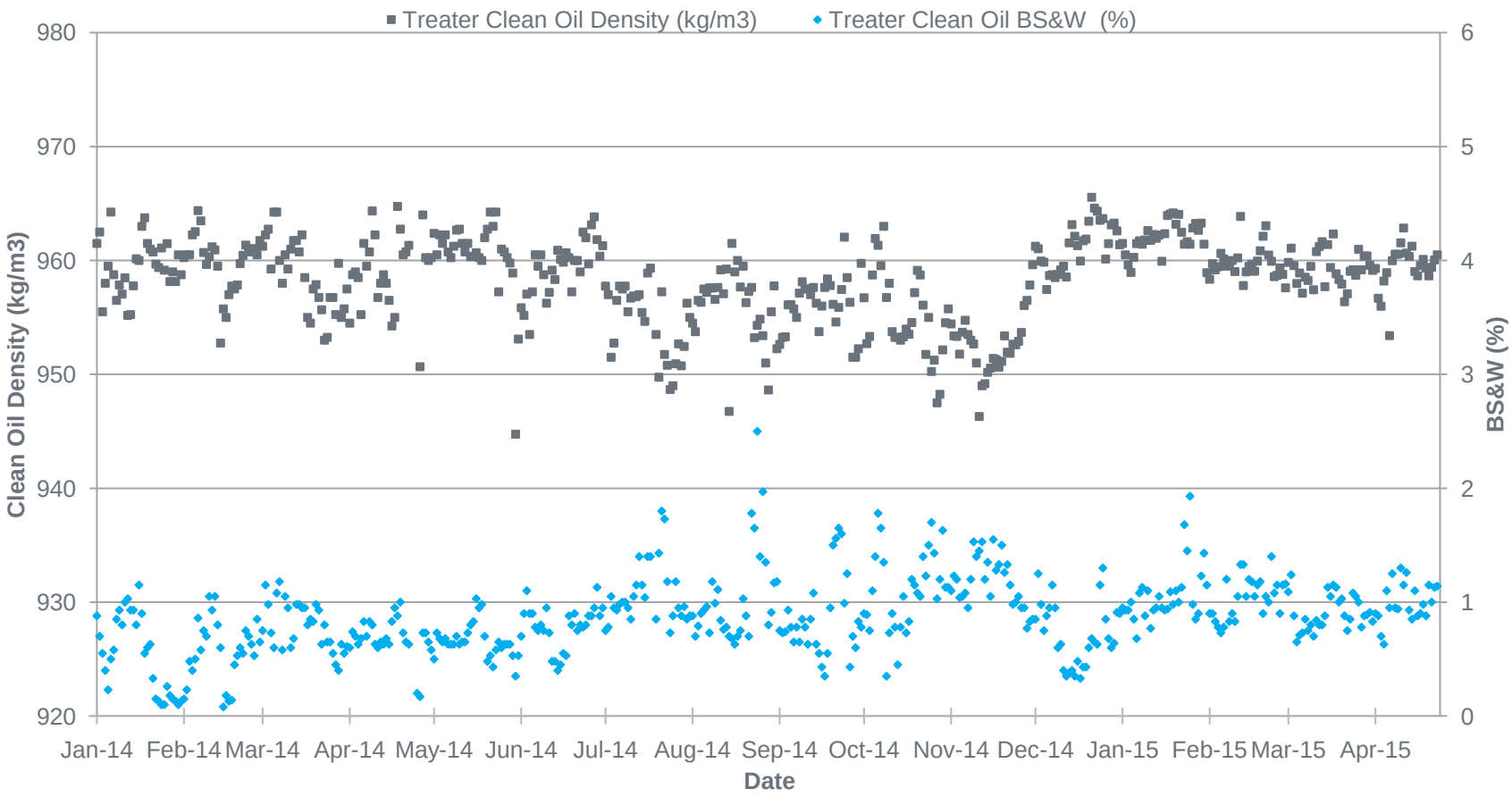
- 2 x 100 T/hr Drum-type Natural Circulation Boilers.
- 3 x 5.67 MW Gas Turbines equipped with duct fired HRSG's (2 operating, 1 standby).
- No significant process issues with Steam Generation equipment in 2014.

Power Generation



- Power is produced at the McKay Project via 3 x 5.67 MW Gas Turbines.
- Until July 2014, two turbines were operating while one was on standby, current normal operating mode is one turbine operating while two are on standby.
- The McKay Project produces all its own power and has no connection to grid power, all power generated is consumed on-site.

Oil Treatment



- Inlet Emulsion at McKay is treated conventionally via diluent blending and oil-water separation in two stages (FWKO / Treater).
- Treating typically at target density of 960 kg/m^3 with product oil < 1.2% BS&W (product from tanks typically < 1.0% BS&W)

Water Sources & Uses

Fresh Water Uses - make-up water for the project to be drawn from the McKay Channel Empress Formation. Details on the *Water Act* licence are as follows:

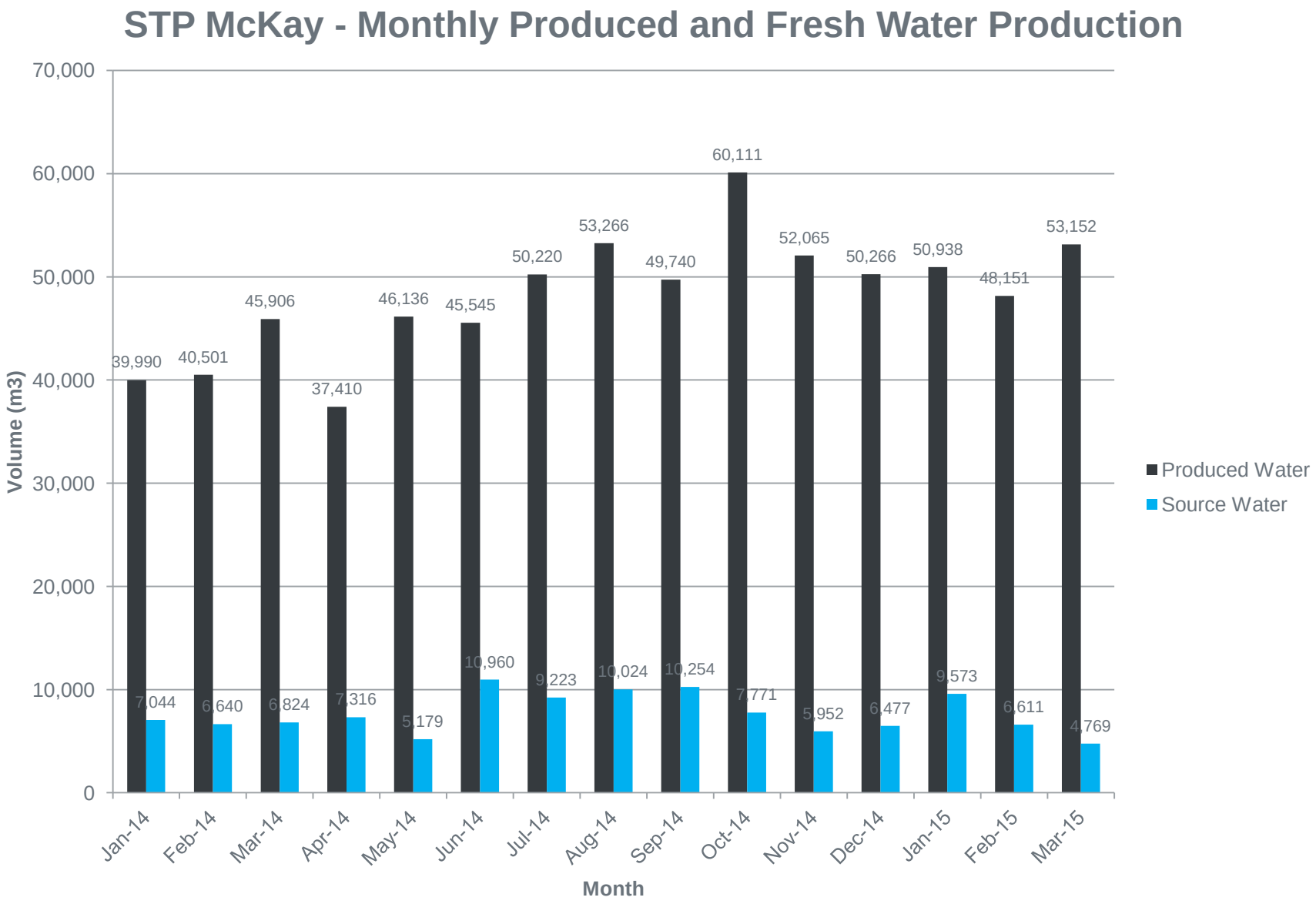
	Licence No. 00262149-01-00 (issued July 4, 2013)
8-8-91-14-W4M	853 m^3/ day
16-8-91-14-W4M	2,401 m^3/ day
15-8-91-14-W4M	2,475 m^3/ day
Daily Maximum Diversion	5,729 m^3/ day
Annual Maximum Diversion	**419,750 m^3**

From Jan 1, 2014 to Dec 31, 2014: **99,471 m^3** withdrawn

8-8-91-14-W4M:	10,757 m^3
16-8-91-14-W4M:	49,855 m^3
15-8-91-14-W4M:	38,859 m^3

The total withdrawn from Jan.1 2015 to March 31, 2015 is: **25,815 m^3**
STP's current *Water Act* licence expires on July 5, 2018.

Water Sources and Uses



Water Sources and Uses

Produced and Fresh Water Quality Summary

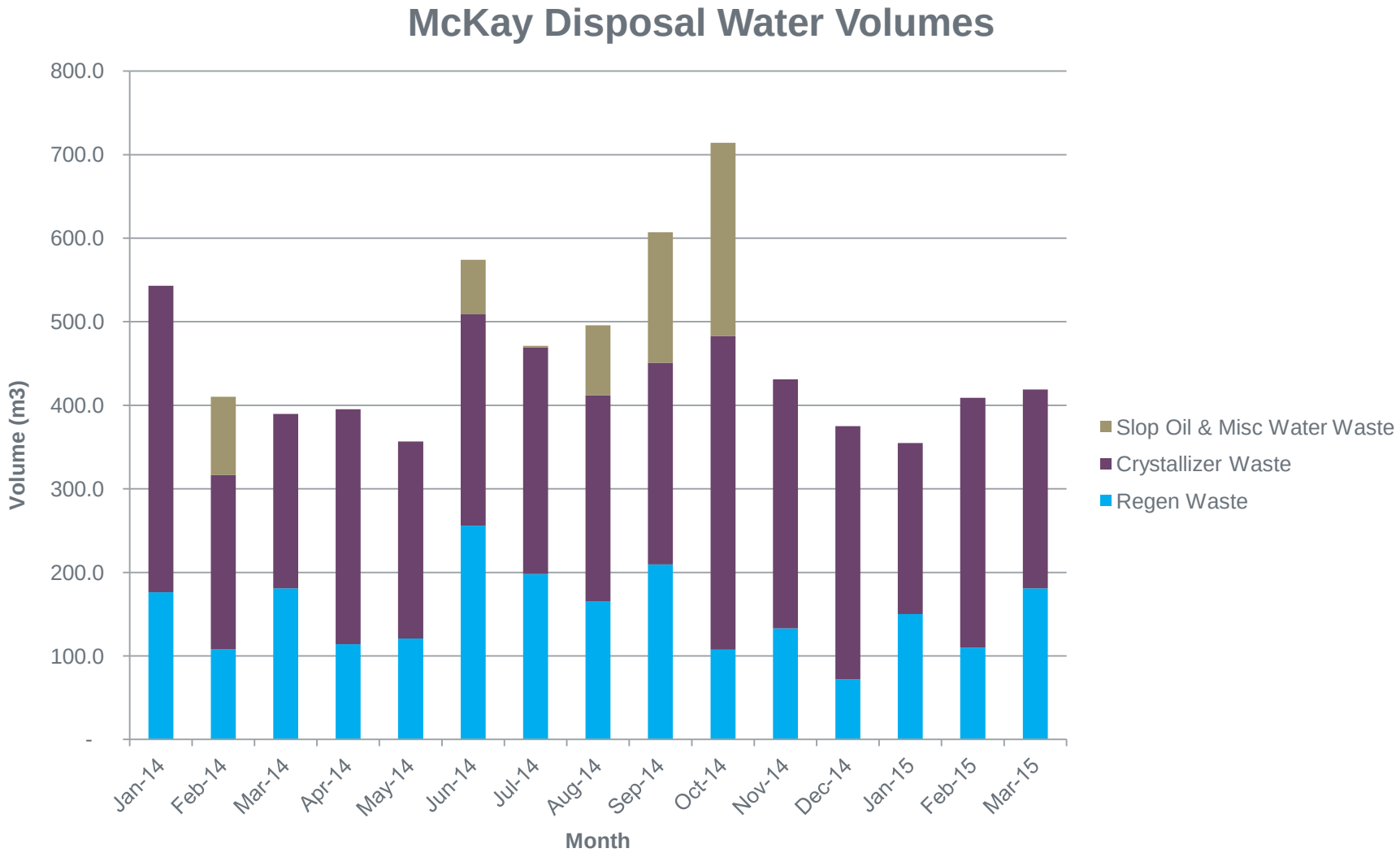
		Produced Water	Source Water
Na	mg/L	249	271
K	mg/L	6.6	7.9
Ca	mg/L	0.8	53.5
Mg	mg/L	Trace	24.3
Ba	mg/L	Trace	Trace
Sr	mg/L	Trace	0.7
Fe	mg/L	Trace	Trace
Cl	mg/L	122	12
Br	mg/L	11	Trace
I	mg/L	570	0.4
HCO3	mg/L	309	669
SO4	mg/L	22.7	244
CO3	mg/L	38	6
TDS	mg/L	1380	1080
Reactive Silica	mg/L	236	Not Measured
pH		8.81	8.31

Water Treatment

Water Treatment Technology

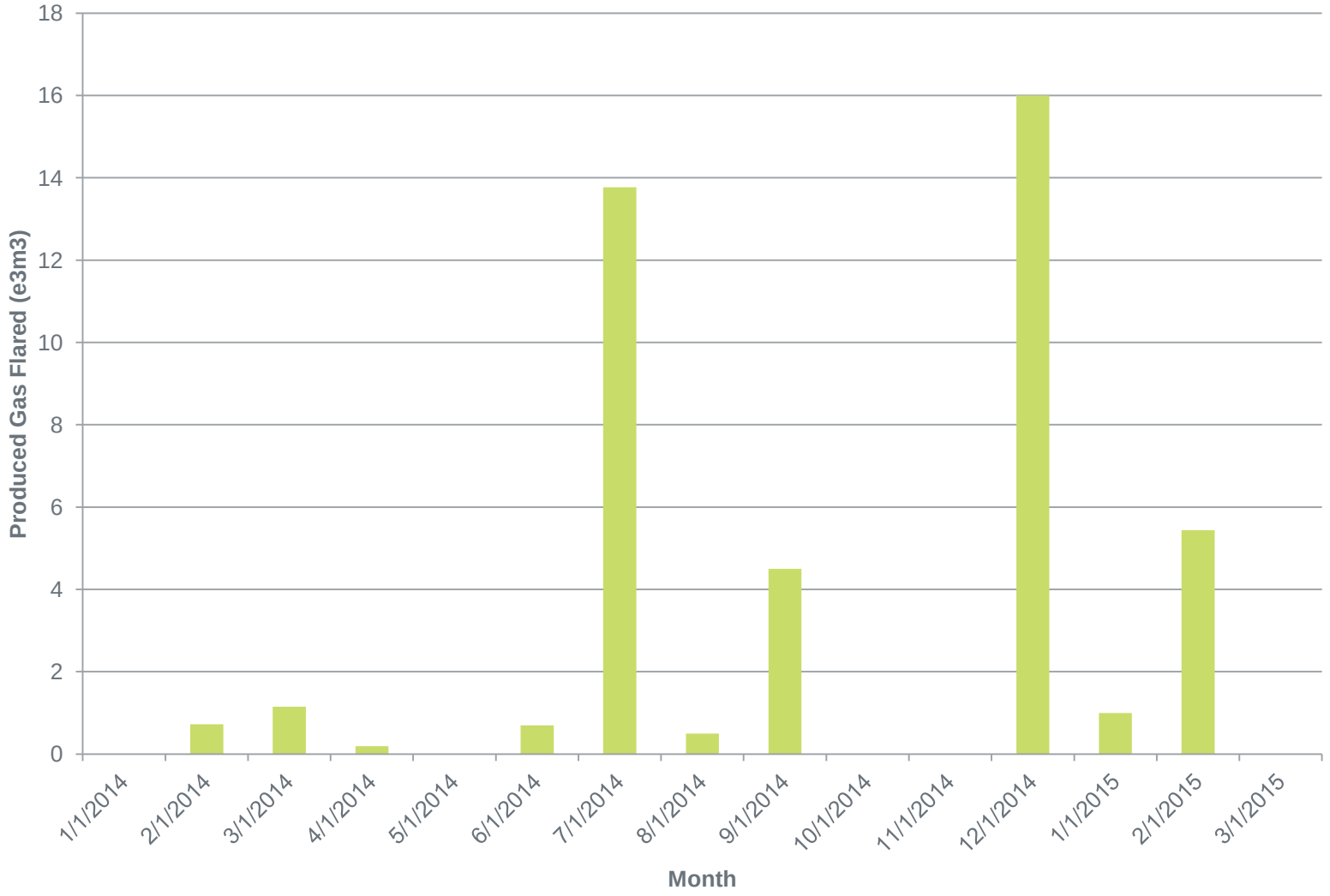
- Mechanical Vapour Recompression (MVR) Evaporator technology is utilized for produced water treatment and production of boiler feedwater.
- Feed to MVR System is pretreated with MgO to facilitate silica removal.
- Make-up Water is treated using conventional cation exchange softening.
- Evaporator concentrate is directed to a steam-driven crystallizer unit for further concentration and distillate recovery.

Waste Disposal Summary



•All Disposal Water at McKay is trucked out to third party disposal sites.

McKay Monthly Flared Volumes



Environmental Summary
Sulphur Production & Ambient Air Monitoring

- EPEA approval limit for SO_2 emissions from 2 steam generators and CPF flare stack is 0.50 tonnes/ day
- SO_2 emissions from January 1, 2014 to December 31, 2014 were 80.31 tonnes
- Sulphur is tracked via monthly third party sampling and compositional analysis of the mixed gas stream to the Steam Generators.
- Average SO_2 emission was 0.22 tonnes / day; peak emission was 0.30 tonnes / day. This puts plant inlet sulfur at an average of 0.11 tonnes / day, and peak of 0.15 tonnes / day
- STP is compliant with all requirements of ID2001-3
- 4 passive air monitoring stations at McKay that monitor H_2S and SO_2. 2014 results are as expected and within compliance limits.
- Passive air monitoring results from January 1, 2014 to December 31, 2014 :
  - Average monthly H_2S concentration was 0.07 ppb; peak concentration was 0.16 ppb
  - Average monthly SO_2 concentration was 0.50 ppb; peak concentration was 1.3 ppb (SO_2 AAAQO 30-day limit = 11 ppb)

Continuous ambient air quality monitoring station was in operation from January 1, 2014 to March 31 2014. Results are as expected and within compliance limits.

- H_2S average concentration was 0.17 ppb; peak 1-hour concentration was 3.2 ppb; peak 24-hour concentration was 1.2 ppb
- SO_2 average concentration was 0.53 ppb; peak 1-hour concentration was 34.8 ppb; peak 24-hour concentration was 6.1 ppb
- NO_x average concentration was 3.47 ppb; peak 1-hour concentration was 63 ppb; peak 24-hour concentration was 25.4 ppb

Environmental Summary

- AER Commercial Scheme Approval No. 11461 - no compliance issues since last presentation.
- EPEA Approvals No. 255245-00-01 (facility) & 287052-00-00 (Wastewater System) 2014 non-compliance summary:

AER Reference No.	Description	Resolved (Y/N)
284268	Manual Stack Emissions Exceedance	Y
292396	Grey Water Spill	Y
AER FIS No.	**Description**	**Resolved (Y/N)**
20140065	Process Water (Steam Condensate) spill	Y
285818	Pipeline Leak - Venting	Y

- Water Act Diversion License No. 00262149 - no compliance issues in 2014.

Environmental Summary

Corporate Initiatives

- Active Member of Canadian Association of Petroleum Producers (CAPP)
- Member of the CAPP Joint Oil Sands Monitoring Initiative Committee (JOSM)
- Member of the Fort McKay First Nation Sustainability Department

Compliance Statement

Southern Pacific Resource Corp. is currently in compliance with all conditions of it's OSCA and EPEA Approvals, the company is also aware of and meeting all of it's regulatory requirements.

2014 Regulatory Summary

Regulatory Amendment Filings

- Directive 78, Category 1 Amendment Application - Inflow Control Device Installation in 2P1.
  Submitted on Dec. 20, 2013; Approved on January 7, 2014
- Directive 78, Category 1 Amendment Application - Inflow Control Device Installation in 1P5.
  Submitted on Jan. 10, 2014; Approved on January 20, 2014
- Directive 78, Category 2 Amendment Application – Drilling of Infill wells at Pad 101 & 102.
  Submitted on Feb. 18, 2014; Approved on July 2, 2014
- Directive 78, Category 1 Amendment Application - Inflow Control Device Installation in 1P2 and 2P2.
  Submitted on Mar. 28, 2014; Approved on April 10, 2014
- Directive 78, Category 1 Amendment Application - Inflow Control Device Installation in 2P5.
  Submitted on May 8, 2014; Approved on May 15, 2014
- Directive 78, Category 1 Amendment Application - Inflow Control Device Installation in 2P6.
  Submitted on May 29, 2014; AER advised that applications are no longer required.

Key Approval Filings

- Soil Management Plan Proposal
  Submitted to ESRD on Jan. 31, 2014

QUESTIONS?

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