Performance Presentation for In-Situ Oilsands

Experimental Scheme Approval No. 11825
Reporting Period September 1, 2016 – August 31, 2017

AER Directive 054 - 2016 Performance Presentation

Section 3.1.1

Subsurface Issues Related to Resource Evaluation and Recovery

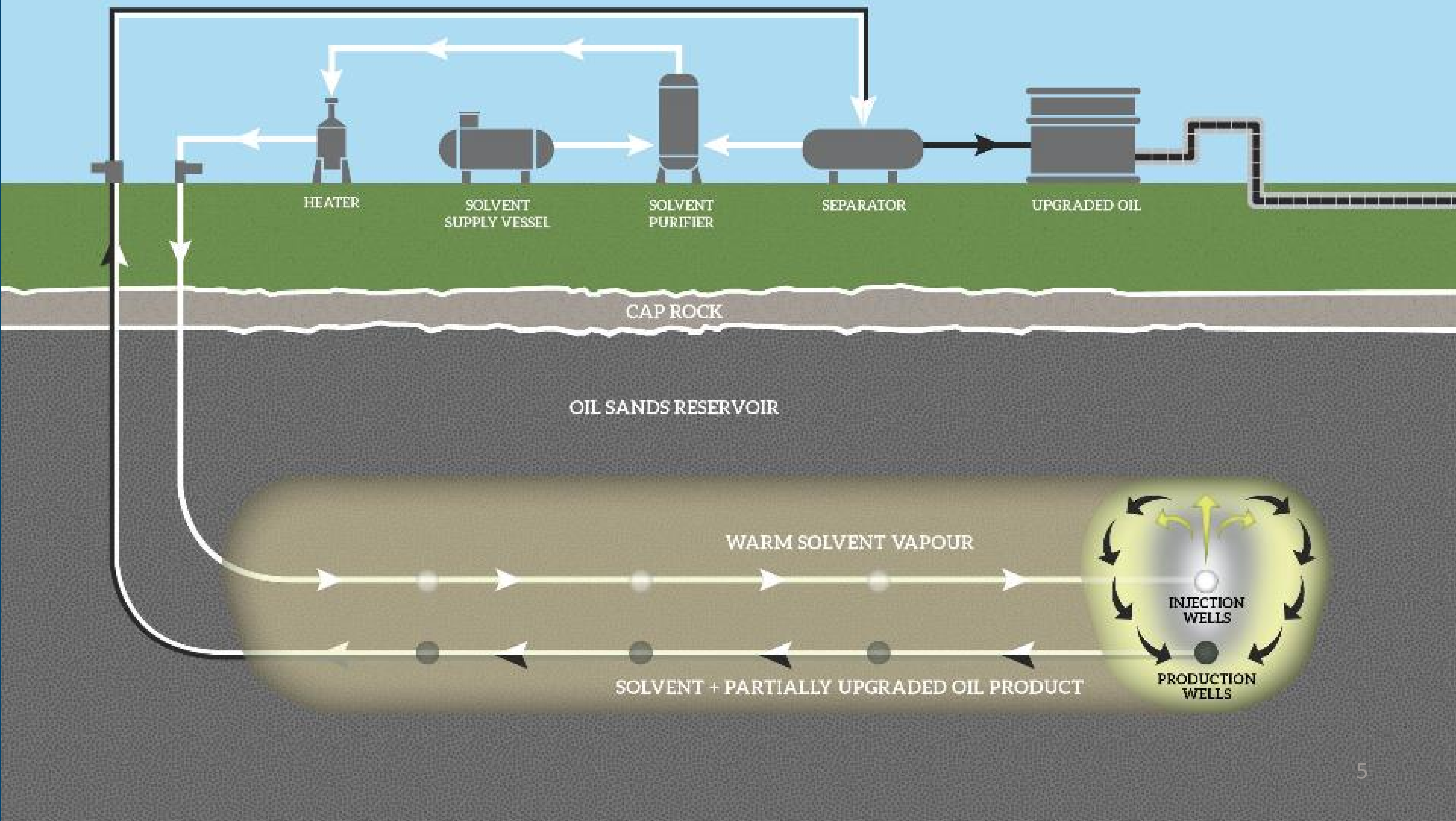
Table of Contents

Background

Nsolv is an in-situ technology that uses warm solvent to extract bitumen from oil sands efficiently and sustainably:

- Over 75% reduction in GHGs compared to SAGD
- In-situ upgrading → downstream GHG benefits
  - Observed upgrade from 8 to 14 API
- Zero process water usage
- Lower capital intensity and smaller CPF footprint compared to SAGD

How it works


HEATER
SOLVENT SUPPLY VESSEL
SOLVENT PURIFIER
SEPARATOR
UPGRADED OIL
CAP ROCK
OIL SANDS RESERVOIR
WARM SOLVENT VAPOUR
INJECTION WELLS
PRODUCTION WELLS
SOLVENT + PARTIALLY UPGRADED OIL PRODUCT

Background – BEST Pilot Plant

nsolv

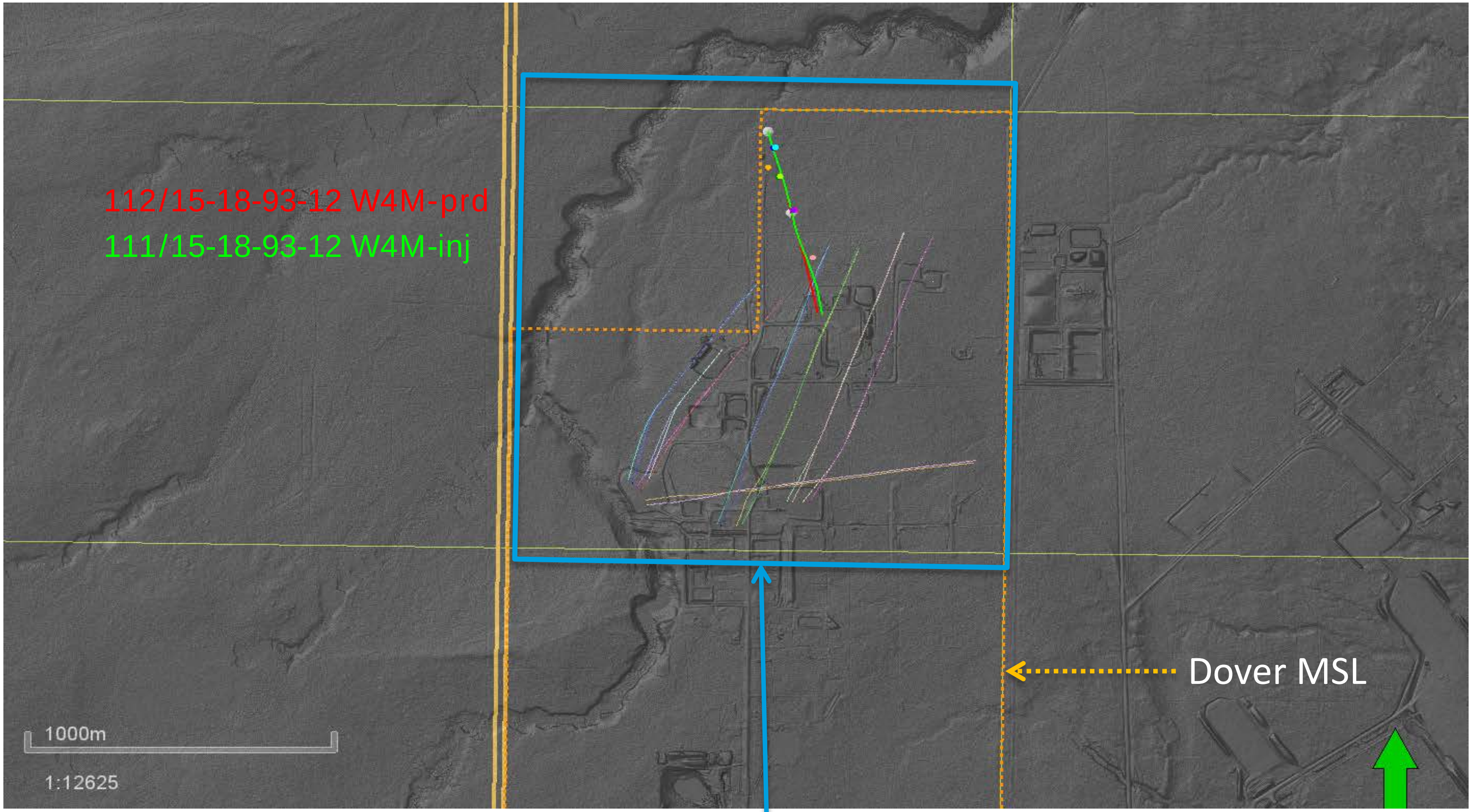
- Bitumen Extraction Solvent Technology
- Purpose: demonstrate commercial viability of the Nsolv process in a field setting
- 1 x 300 m HZ well pair
- 7 x vertical observation wells
- 238.5 m^3/d (1500 bpd) solvent delivery capability
- 79.5 m^3/d (500 bpd) oil processing capability

Background – BEST Pilot Plant

- Ability to use either propane or butane
  - In order to minimize any potential for solvent losses to the bitumen reservoir, the solvent chamber is kept in balance with the native reservoir pressure
  - The targeted operating temperature for reservoir is between 35-75 °C as this provides an adequate rise in the bitumen temperature to significantly reduce the bitumen viscosity
  - Choice of solvent is therefore based upon the solvent whose vapour pressure between 35 to 75 °C is balanced with the native reservoir pressure
  - Butane was chosen since at an operating pressure of ~600 kPag its bubble point temperature is ~57°C

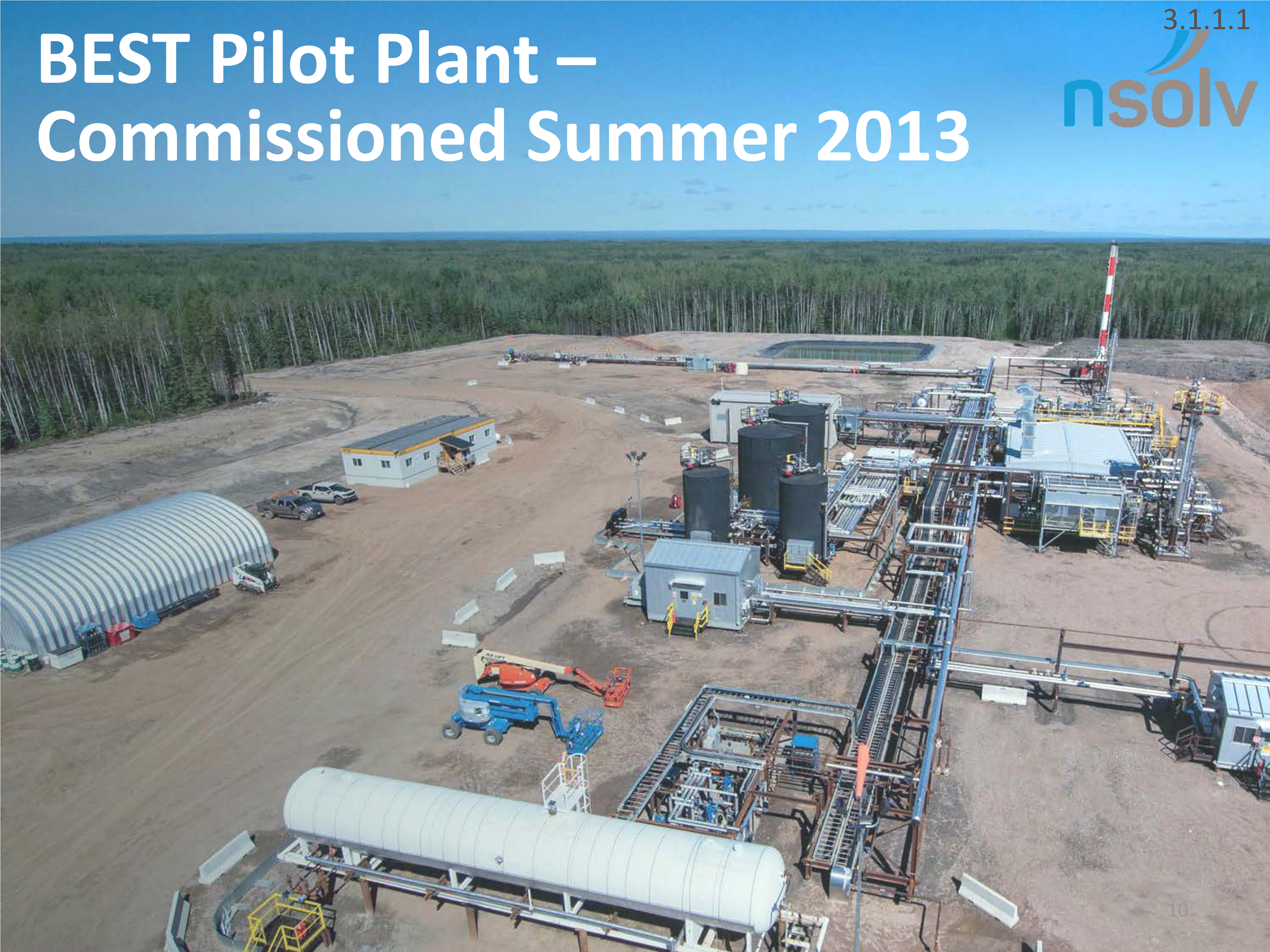
Background – Project Location

Project Location

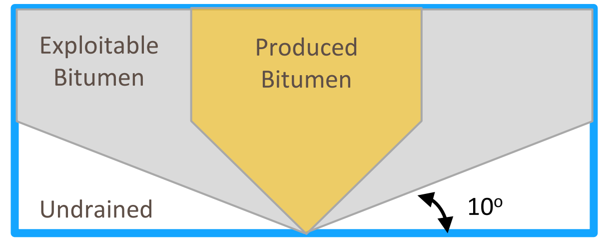


Section 18, Twn. 93 Rng. 12W4

BEST Pilot Plant – Commissioned Summer 2013



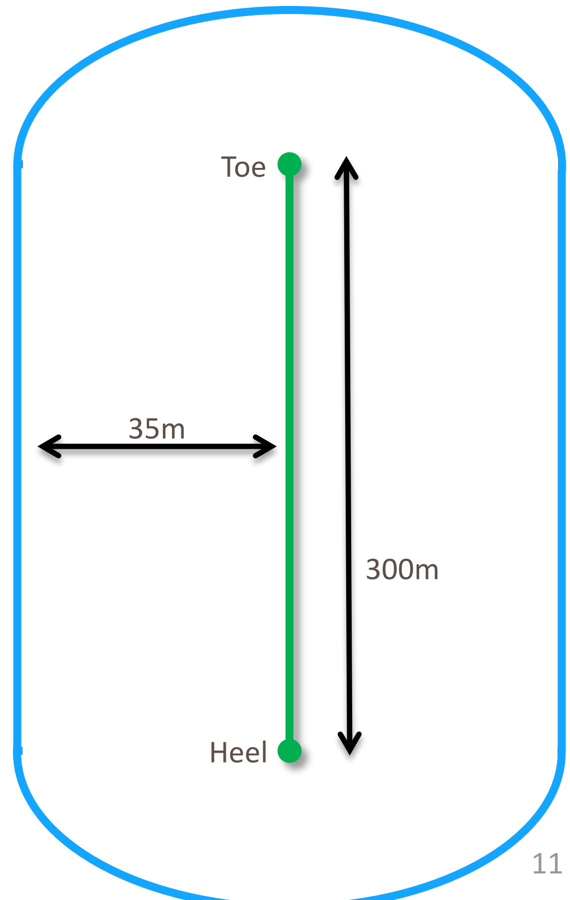
Volumetrics



<u>Volume Calculation</u>

- Drainage Area = 24,848m2
- Pay Thickness = 13m above producer
- So=75%, Porosity=33.4%
- 80,919m3 Exploitable PIIP
- Recoverable Bitumen
  - 10° drainage angle
  - 80% chemical yield
  - 48,576m3 (60% recoverable)
  - 19,677 m3 bitumen recovered as of May 31st, 2017

  - 41% of recoverable
  - 24% of exploitable PIIP



PIIP=Area x Pay thickness above producer* Oil Saturation* Porosity

Average Reservoir Parameters

Porosity	33.4%
Effective Porosity	29%
Oil Saturation	75%
Horizontal Perm	4160mD*
Vertical Perm	3200mD*
Exploitable Pay	13m
Net Pay	18m
Depth to top of Pay	123.5m
Native Reservoir Pressure (Top of Pay)	600kPag
Native Reservoir Temperature	7°C

*Changed from 2016 values, see next slide

Permeability Adjustment

Nsolv permeability data appeared abnormally high compared to surrounding projects and to other top tier reservoirs and needed an adjustment to make it more comparable with its peers.

Data Used:

- 20 OB/VOB samples from three Nsolv pilot wells
- 67 samples from 15 additional wells surrounding pilot (within 1.2 km radius)

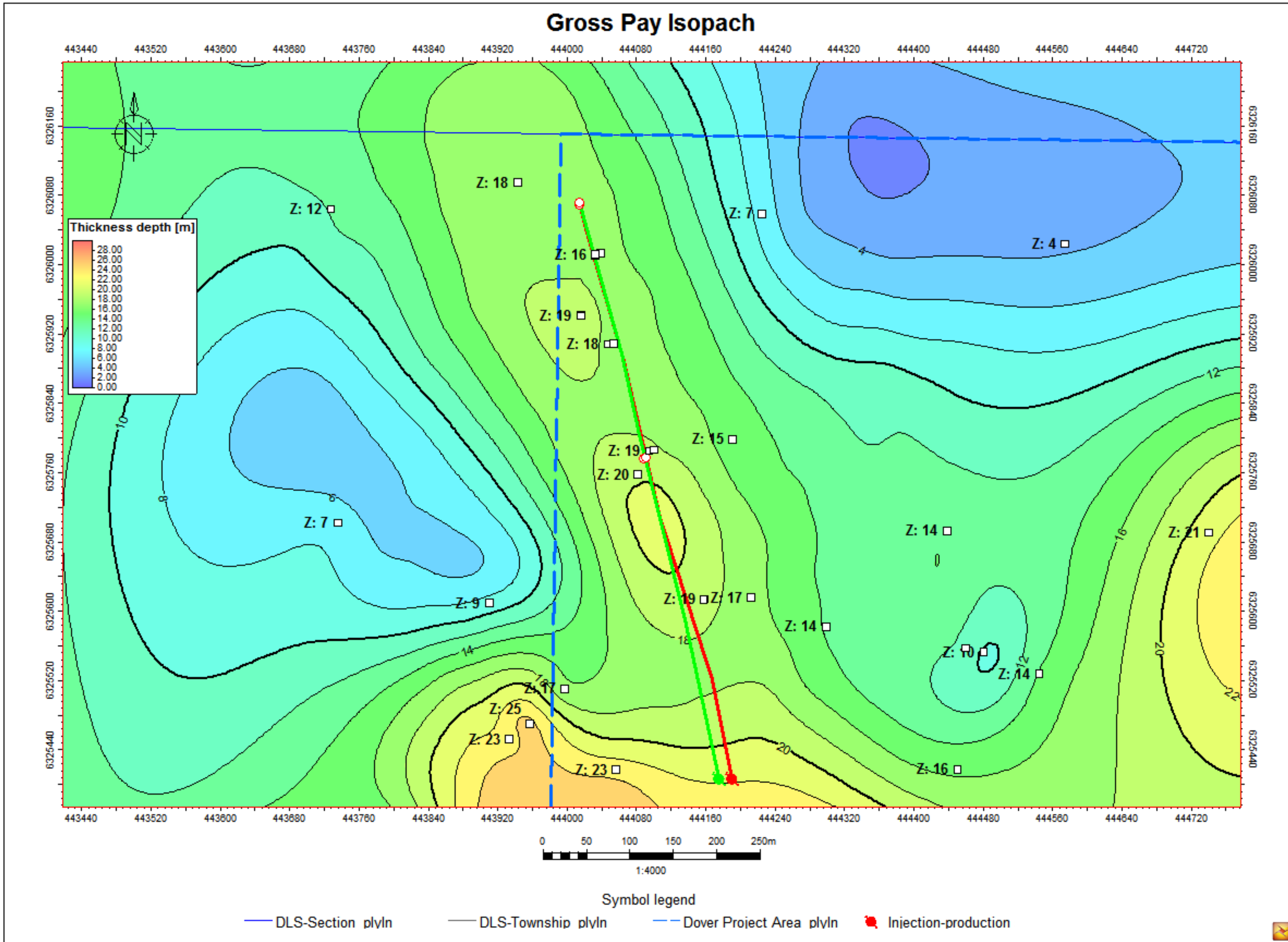
Porosity from permeability samples was reduced by 1.8% (abs), as informed by comparison to wireline derived porosity in the Nsolv pilot well data set. Using a cubic relationship between porosity and permeability a correction factor of 0.86 was used to correct the average permeability values. To determine Kv Nsolv lab data was used and gave a Kv:Kh ratio of 0.77.

Averages from above data:

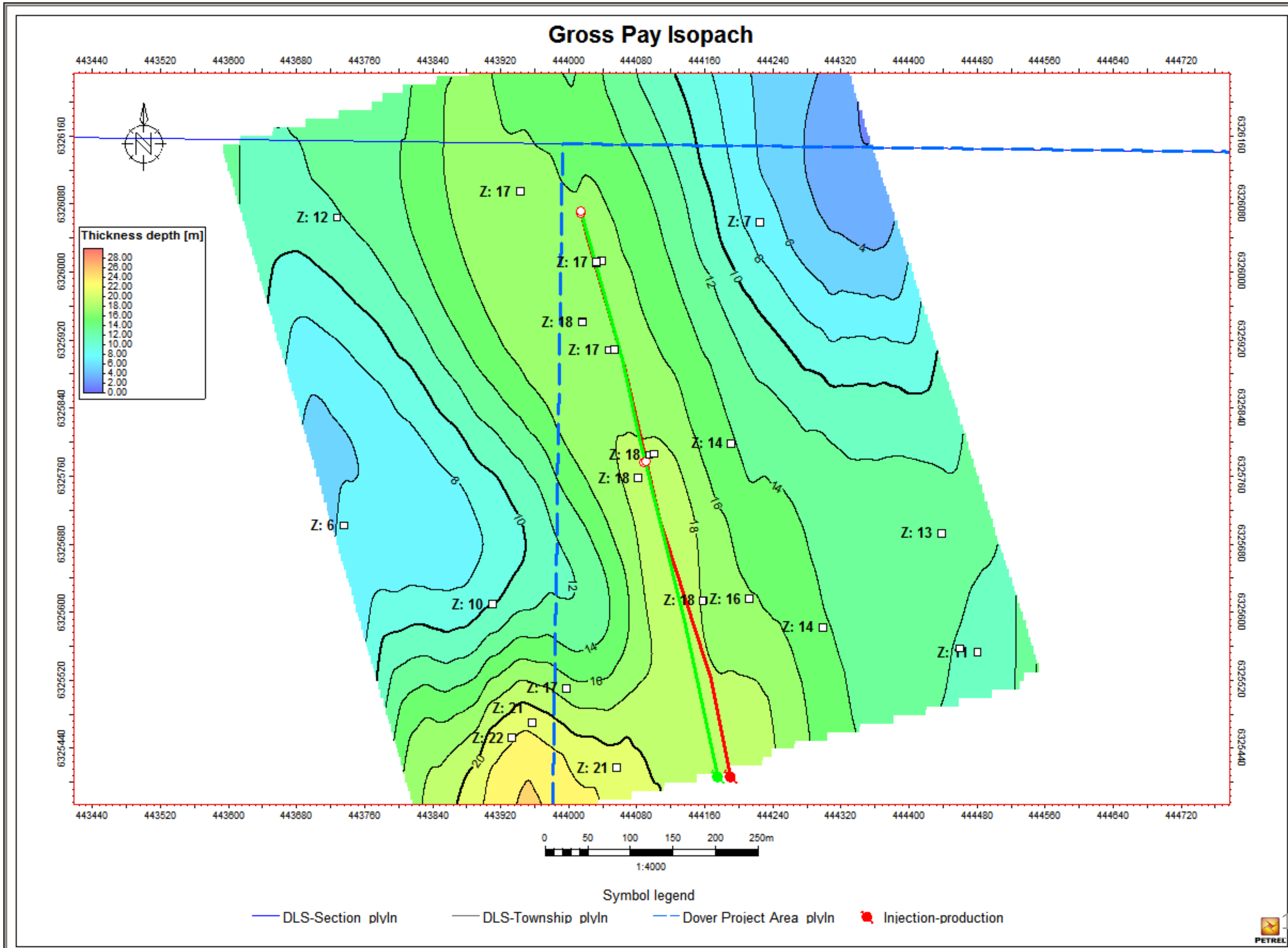
- Kh average = 4844mD x 0.86 = <u>4157mD*</u>
- Kv:Kh ratio used; 4157 x 0.77 = <u>3200mD*</u>

*Original values were 6500mD and 5370mD for Kh and Kv respectively.

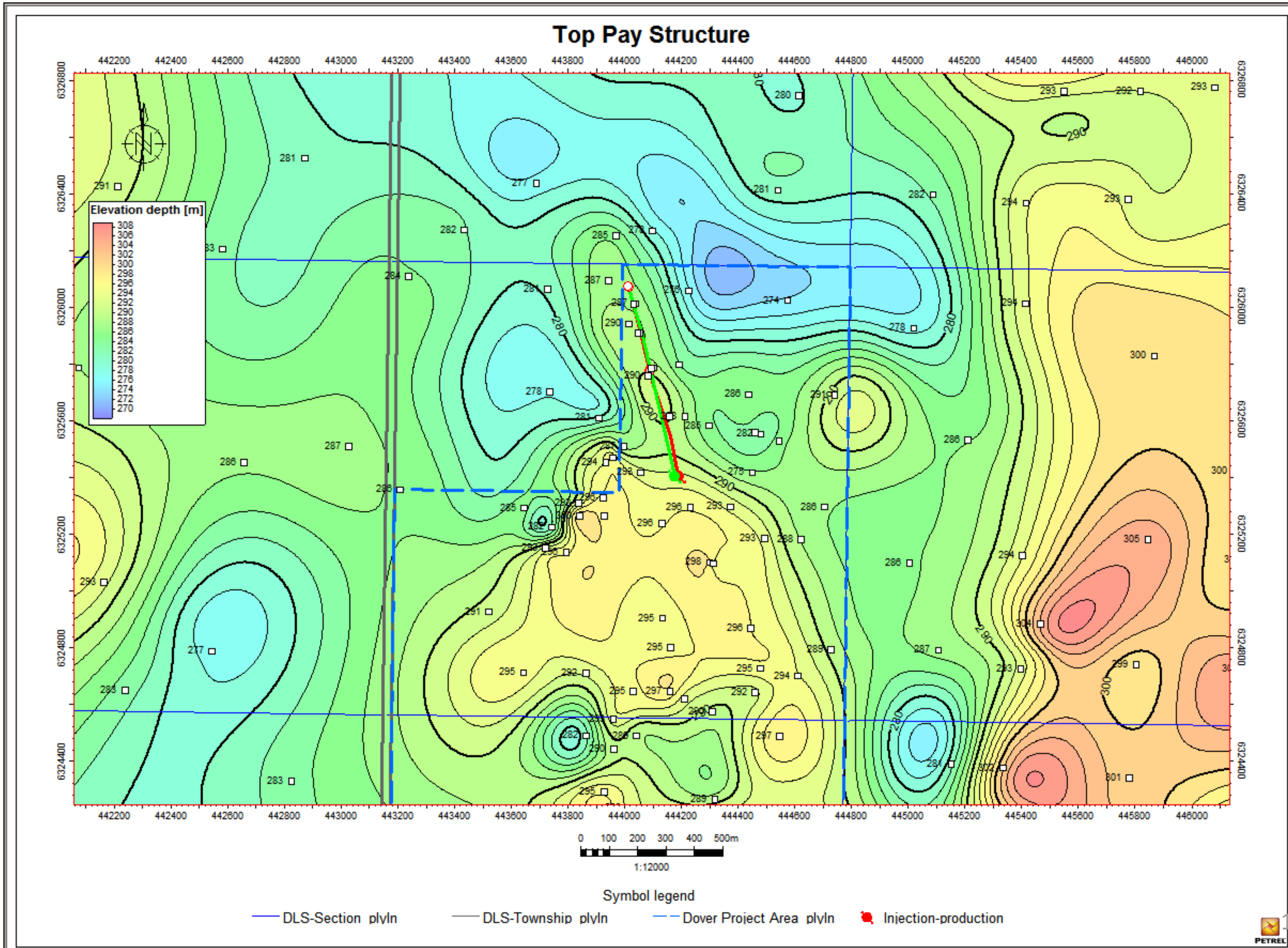
Geology – Gross Pay Interval



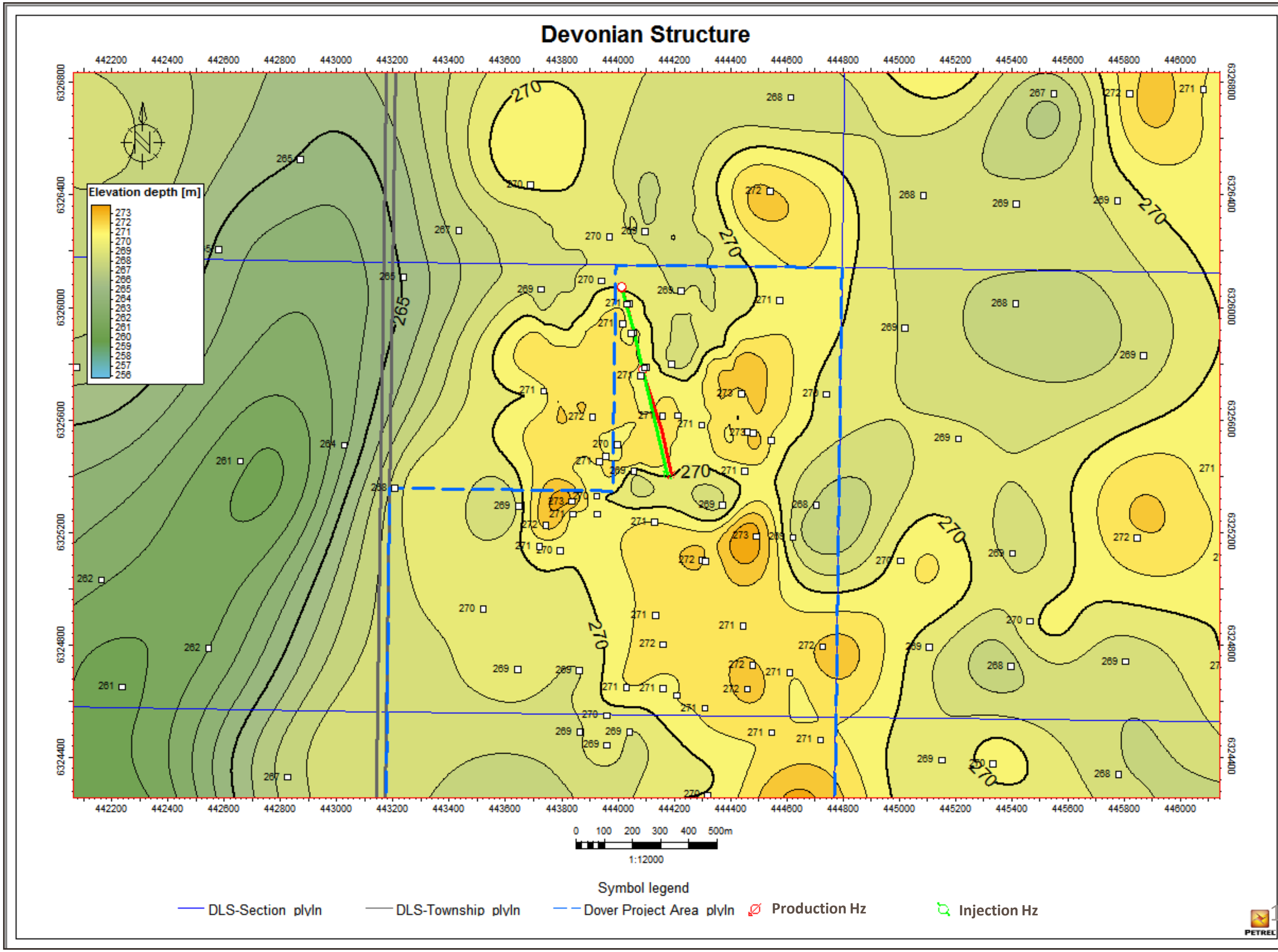
Geology – Net Bitumen Pay



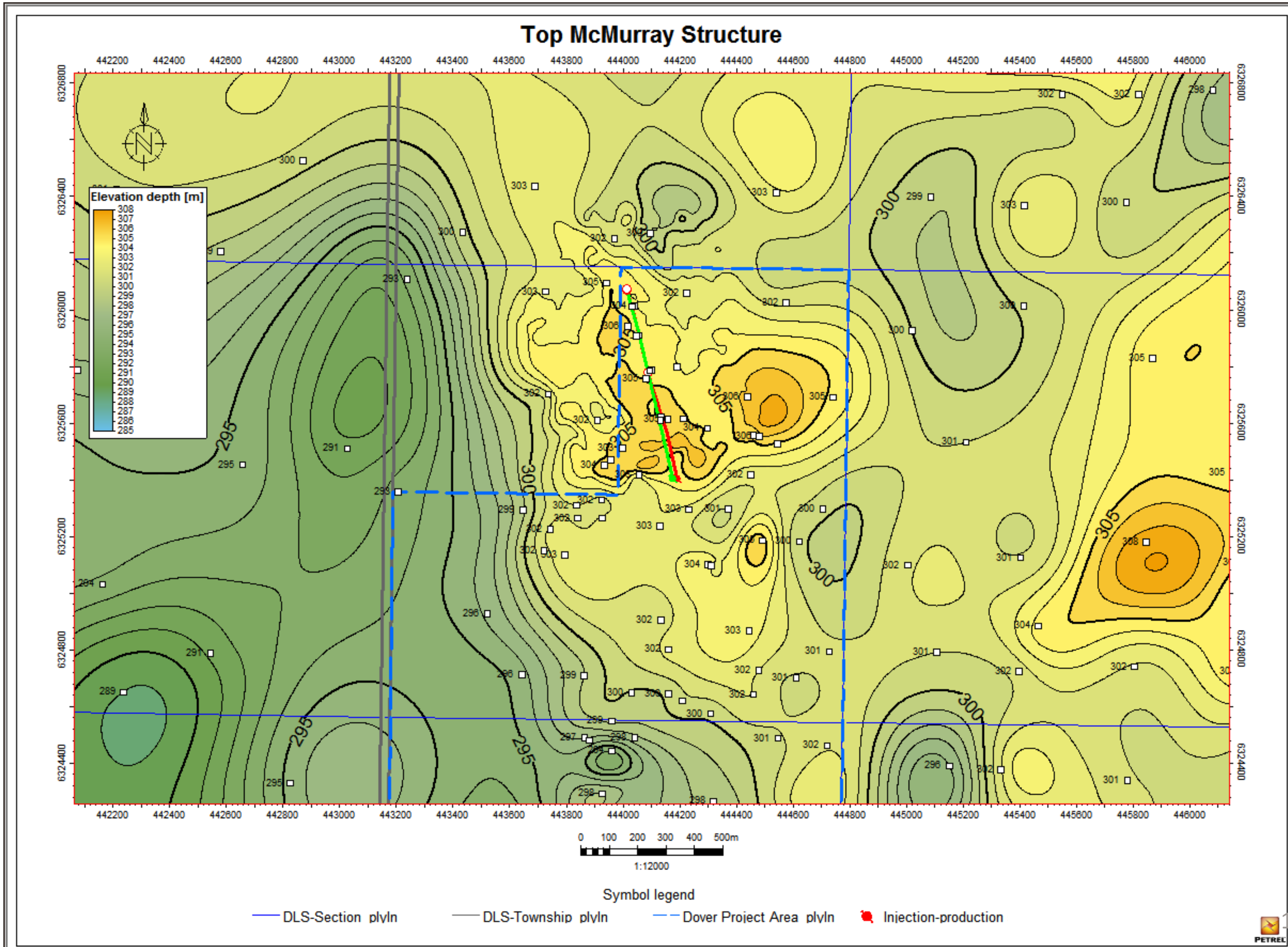
Geology – Top Pay Structure



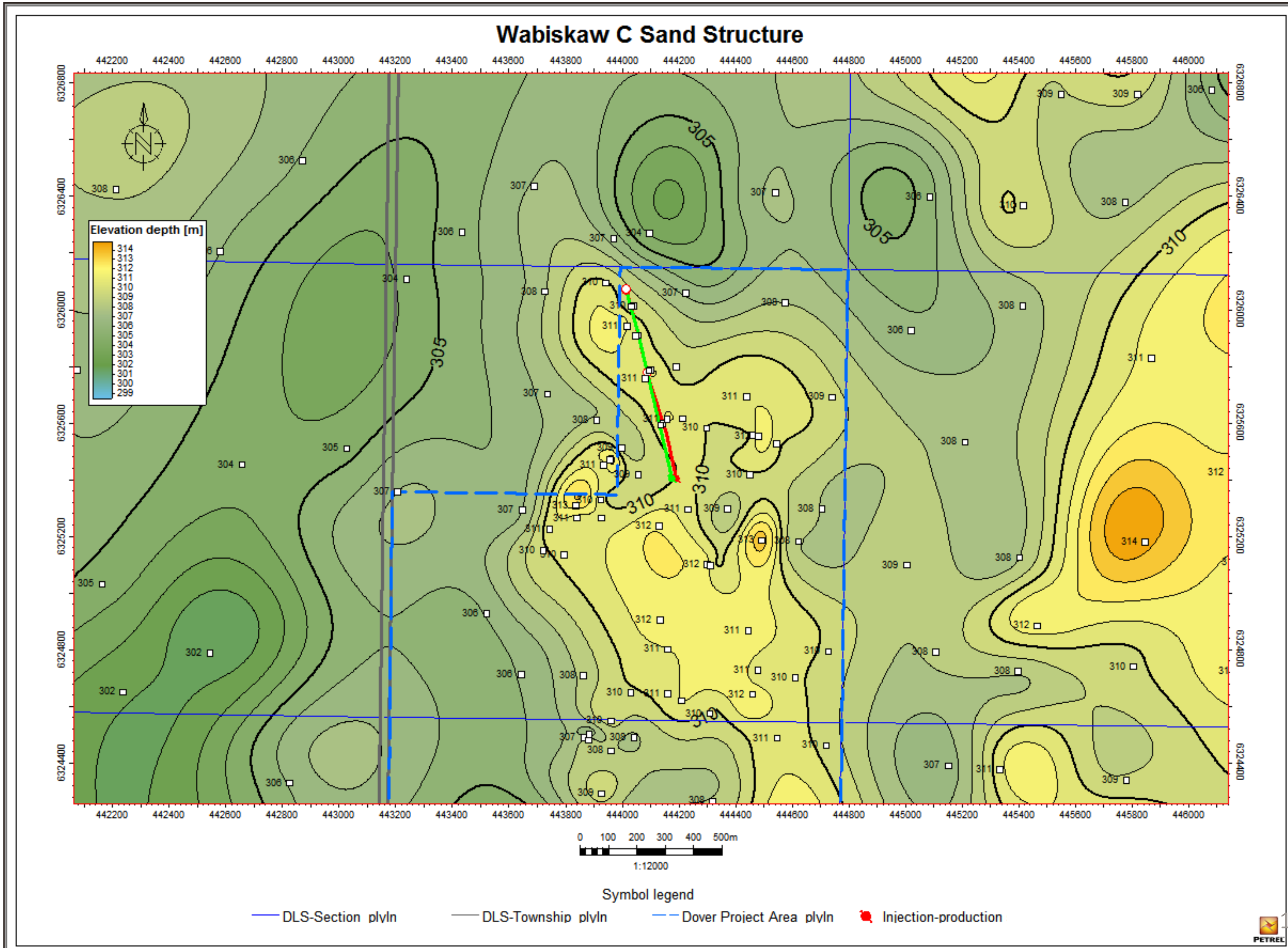
Geology – Devonian Structure



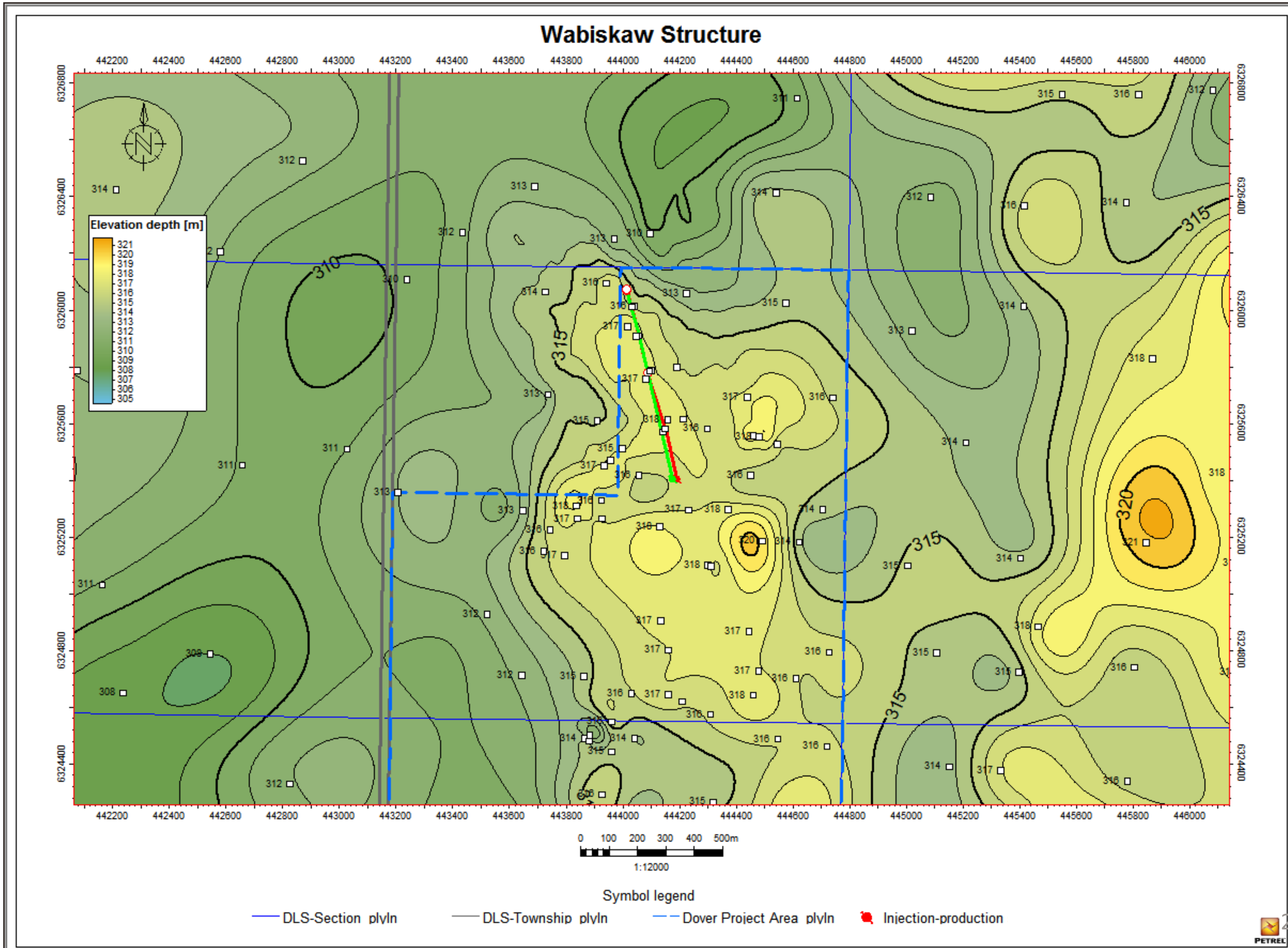
Geology – McMurray Structure



Geology – Wab C Sand Structure

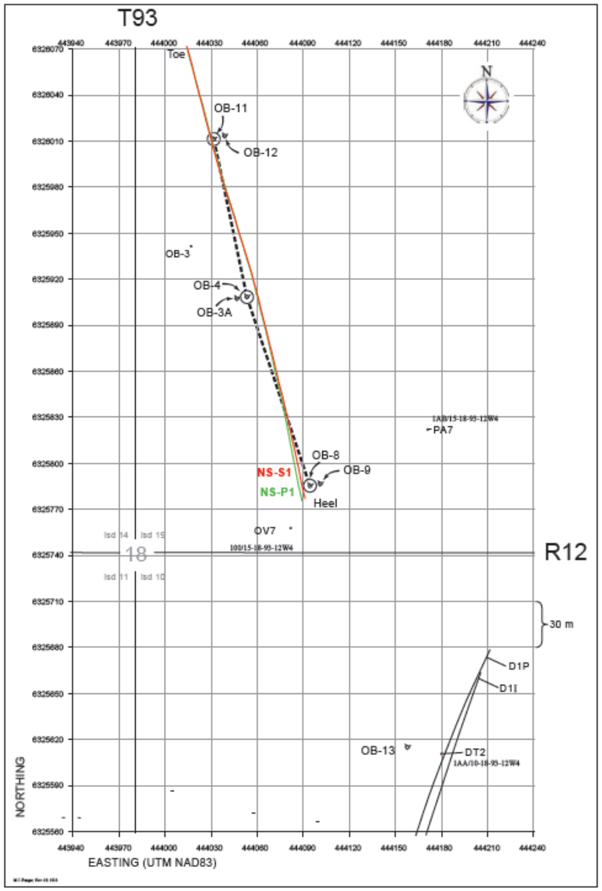


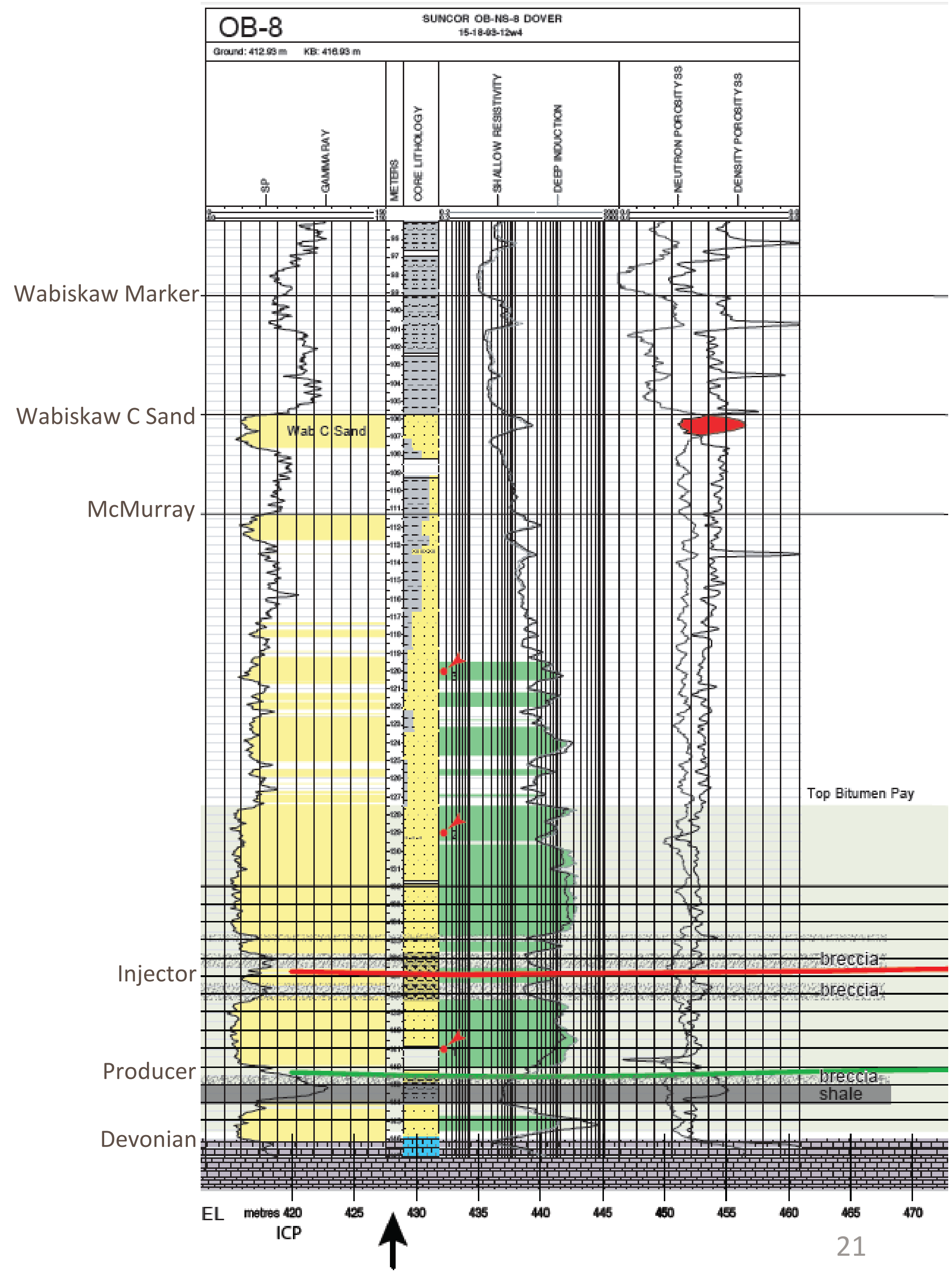
Geology – Wabiskaw Structure



Geology – Logs

OB-08
Offset 6.7m





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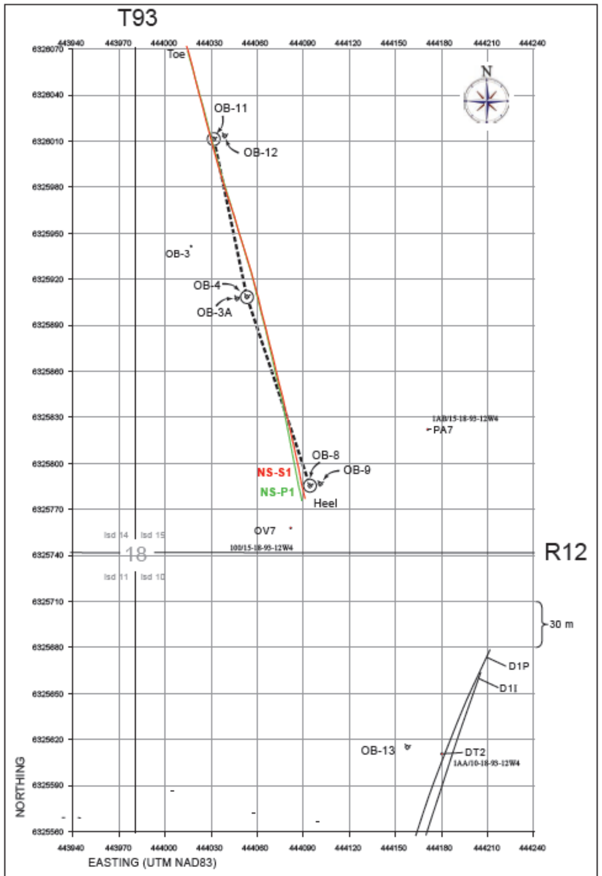
Geology – Logs

OB-04
Offset 3.6m



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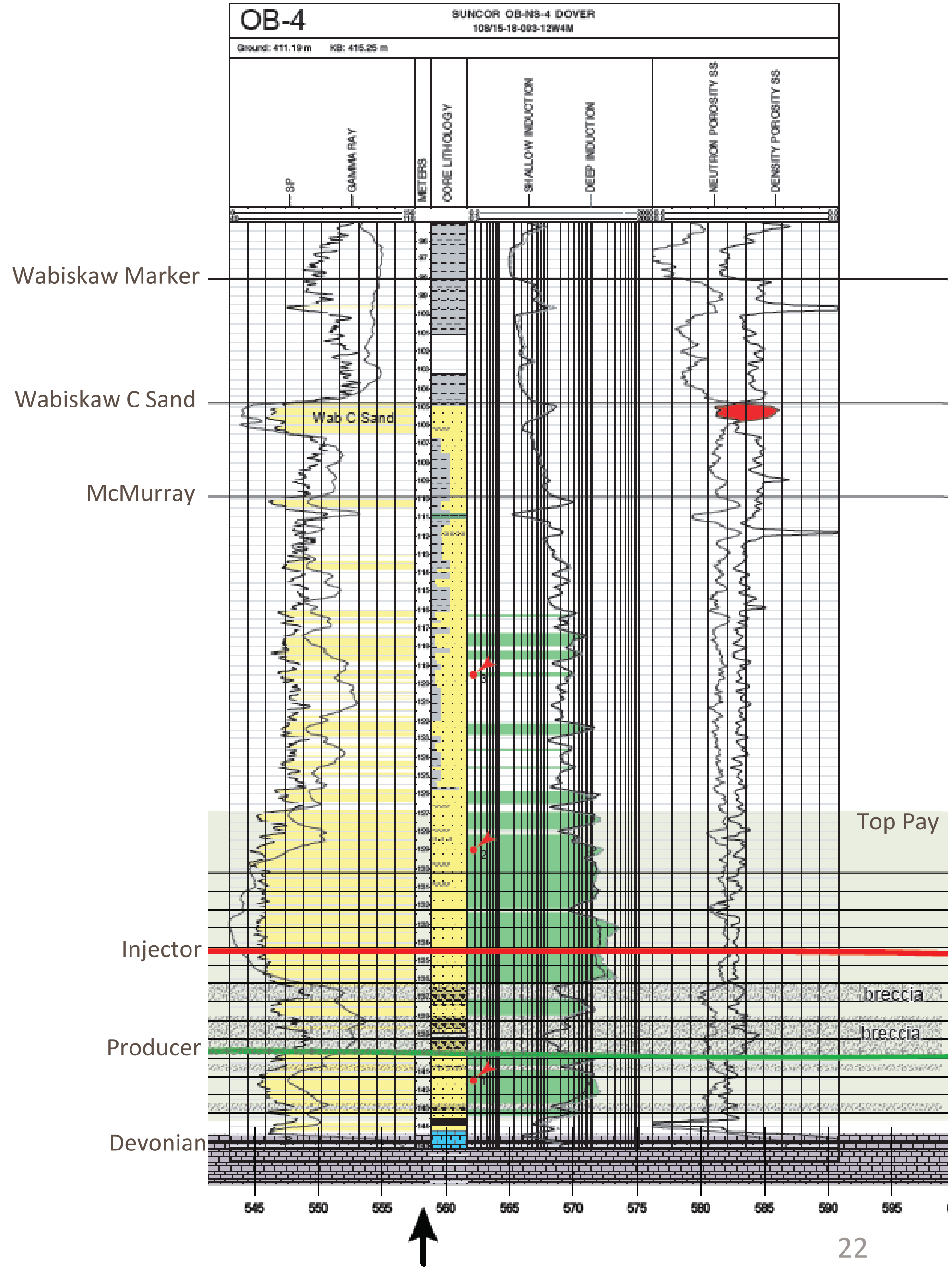
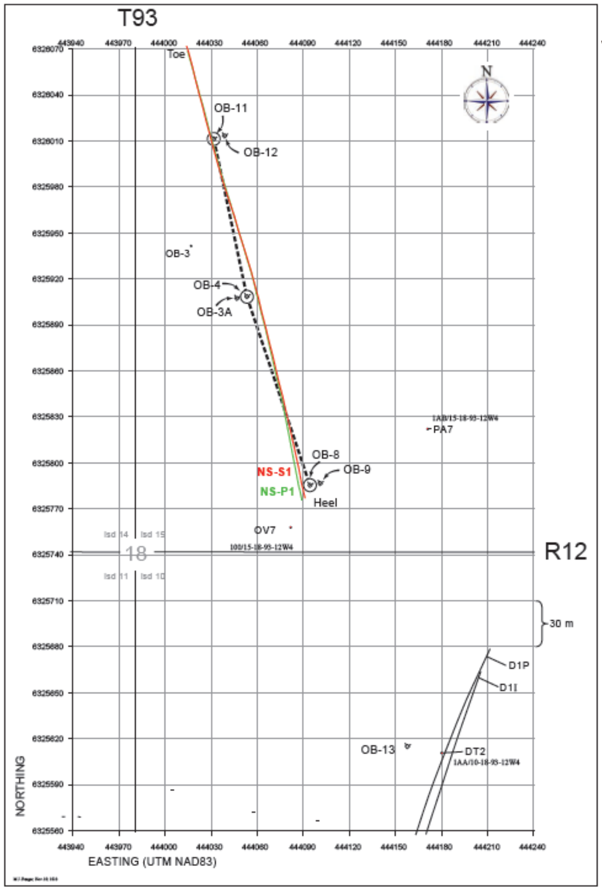
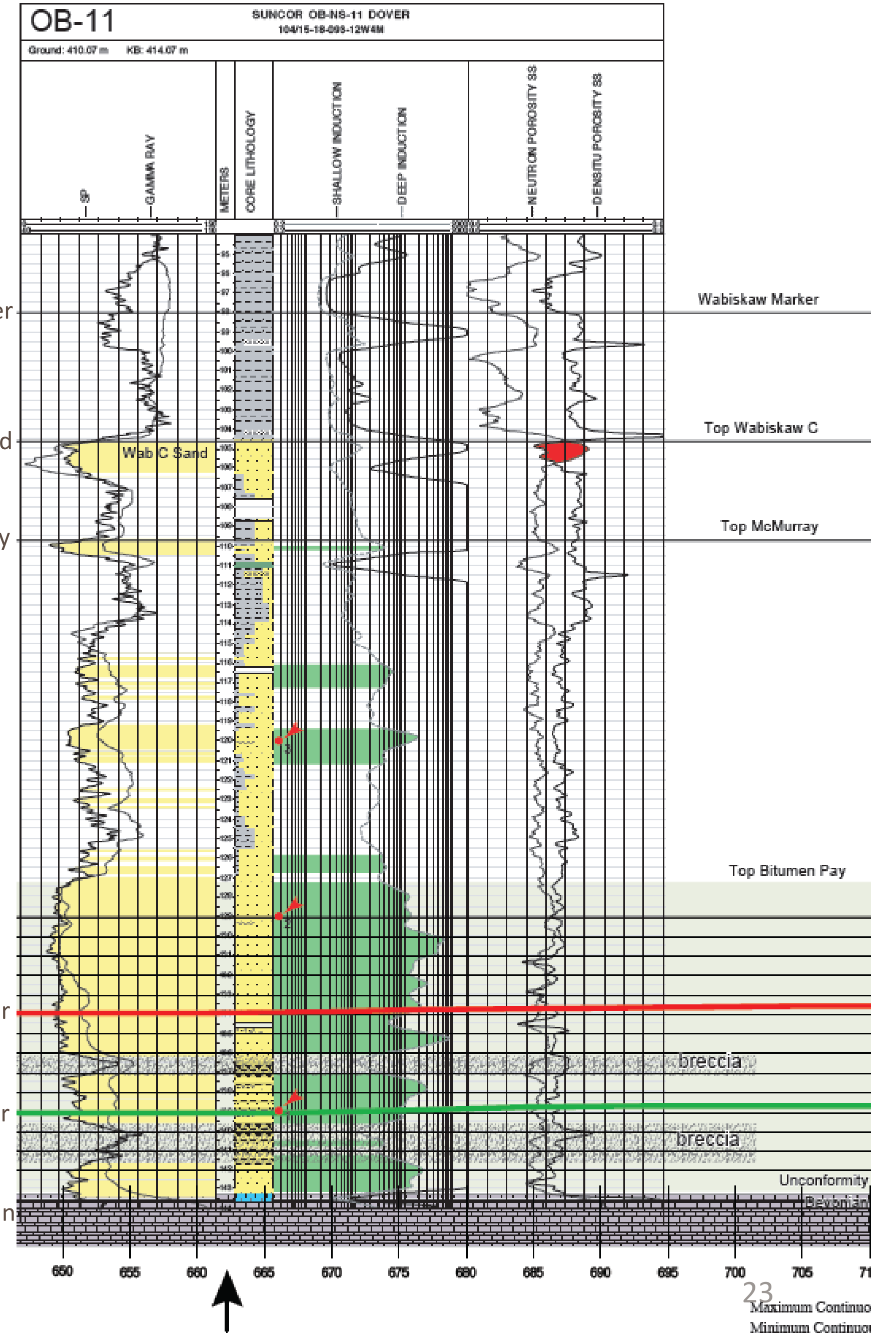


Geology – Logs

OB-11
Offset 4.3m



104/15-18-093-12W4

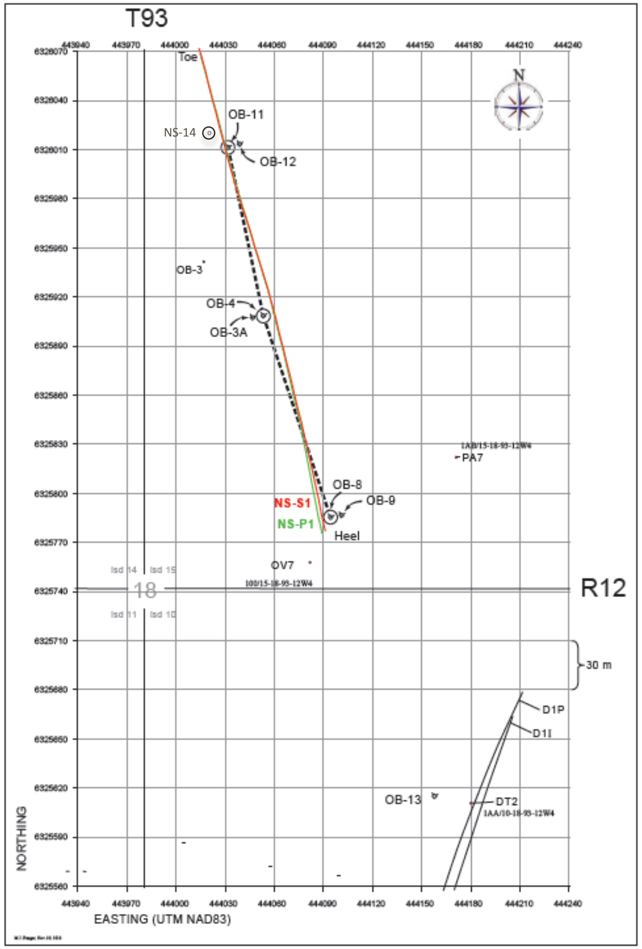


Geology

Cored Wells:

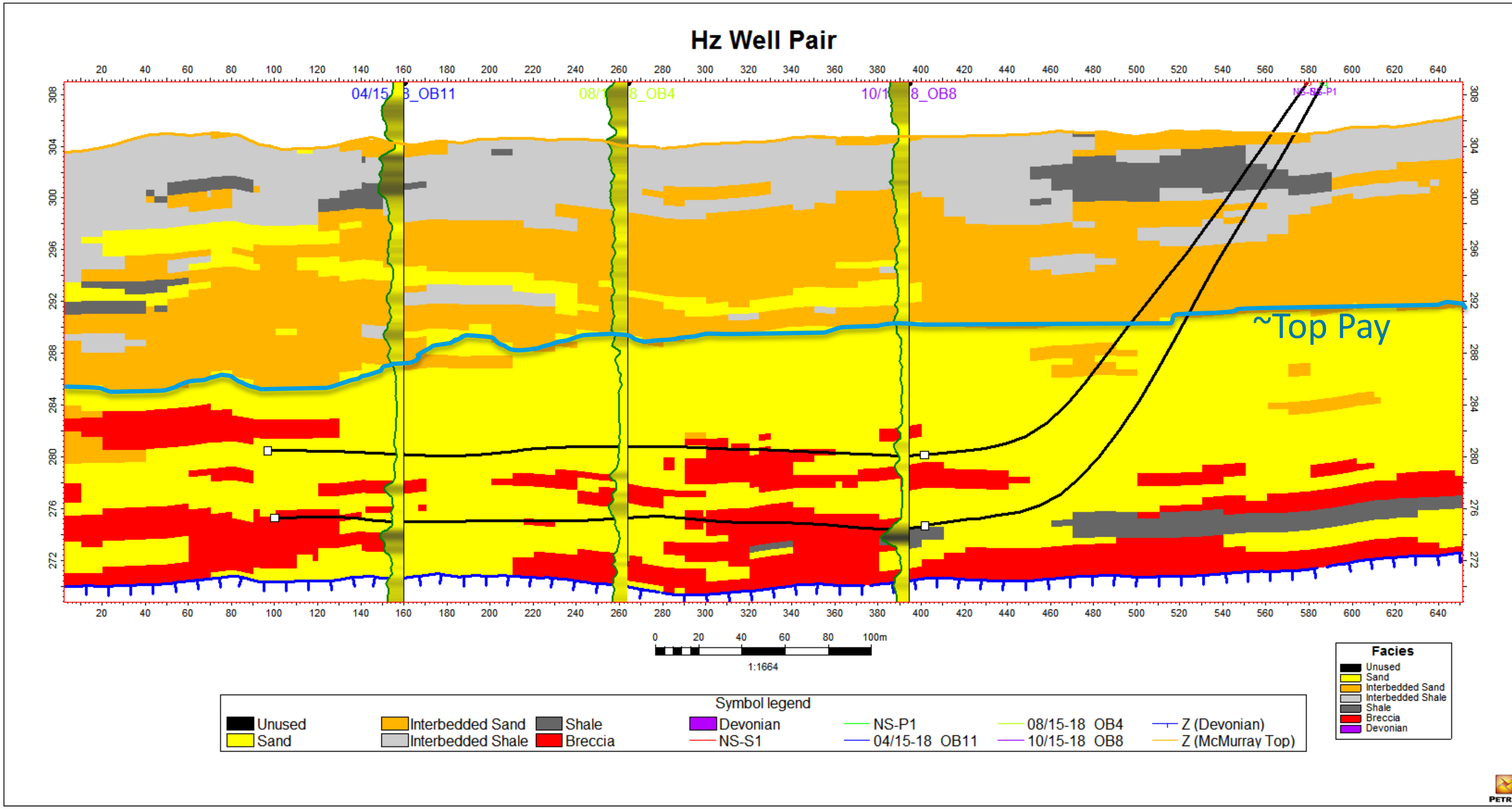
- OB 13
- OB 08
- OB 04
- OB 11
- NS 14*

- Routine analysis
- Bitumen characterization
- N + S + metal contents



*more detail on NS-14 post solvent core analysis provided in slide 56-63

Hz Well Cross Section



Operating Pressure

As per AER Bulletin 2014-03

MOP=0.8 x caprock fracture closure gradient x depth to base of caprock

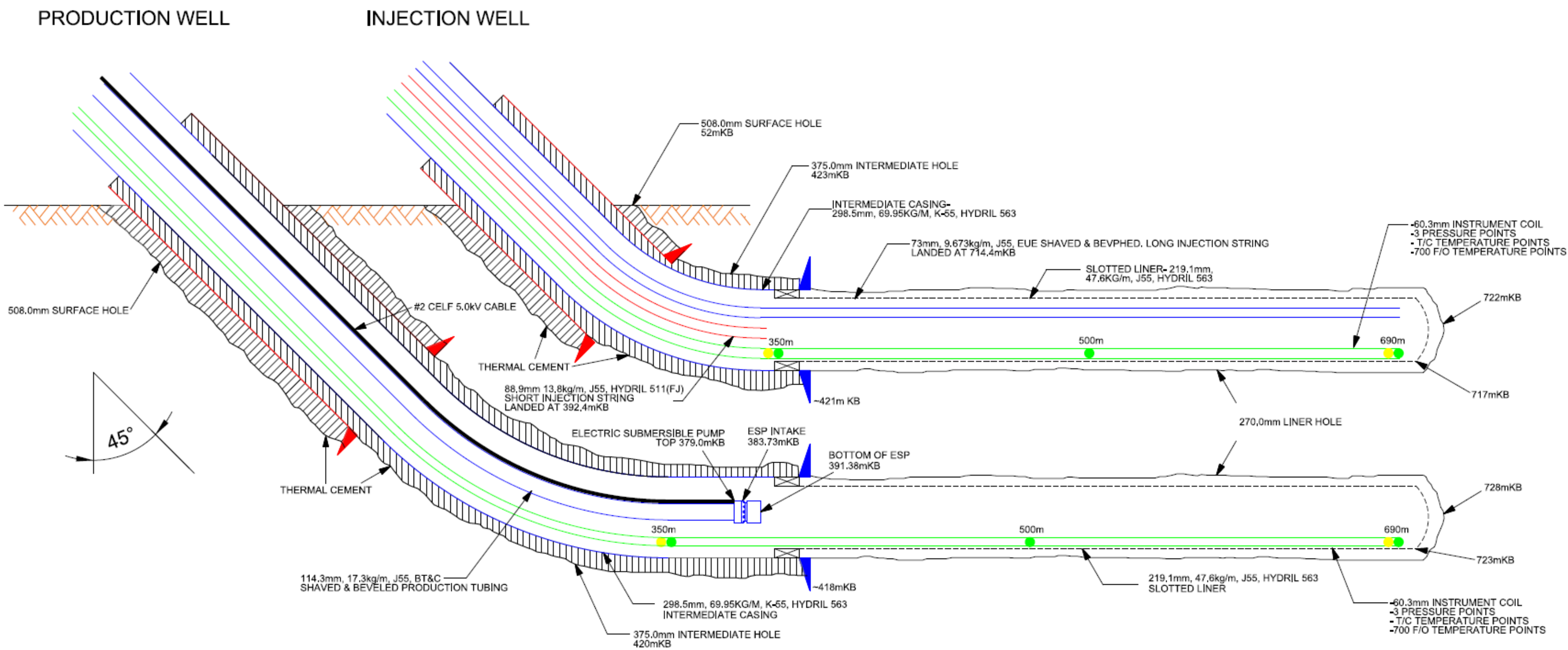
Caprock fracture gradient = 21 kPa/m*
Shallowest Wabiskaw D shale is in well OB-3 (102/15-18-093-12W4) @105m MD

MOP = 0.8 x 21 kPag/m x 105m = 1,764 kPag

Our current operating window is 570-600 kPag or ~ 34% of MOP as per AER bulletin 2014-03.

*From Suncor MacKay River mini frac analysis

Completions – ESP



Artificial lift

- Production well was equipped with metal PCP pump (Project start – 1 Apr 2015):
  - Capacity: 300 m3/ day / 100 RPM @ 100% efficiency
  - Rated lift: 600 m of water column
  - Pump efficiency: degraded over time down to 10%, exacerbated by low viscosity fluid
- PCP was changed to an ESP (15 Apr 2015 – September 2015), increasing lift capacity.
  - Capacity: 400 m3/ day
- ESP failure in September 2015. ESP was replaced and has been operating from September 2015 to project shutdown

Instrumentation

- Each HZ well is equipped with the same instrumentation package:
  - Heel and toe thermocouple
  - Heel, mid and toe bubble tubes
    - Ethane used for bubble tube gas instead of methane – reduction in potential introduction of non-condensable gas into the reservoir which could hinder oil flux rates
  - Fiber optic temperature sensor (700 m)
- Production well monitoring at the pump intake for P&T
- Observation wells equipped with:
  - 26 point thermocouple bundle
  - 2-3 piezometers per well

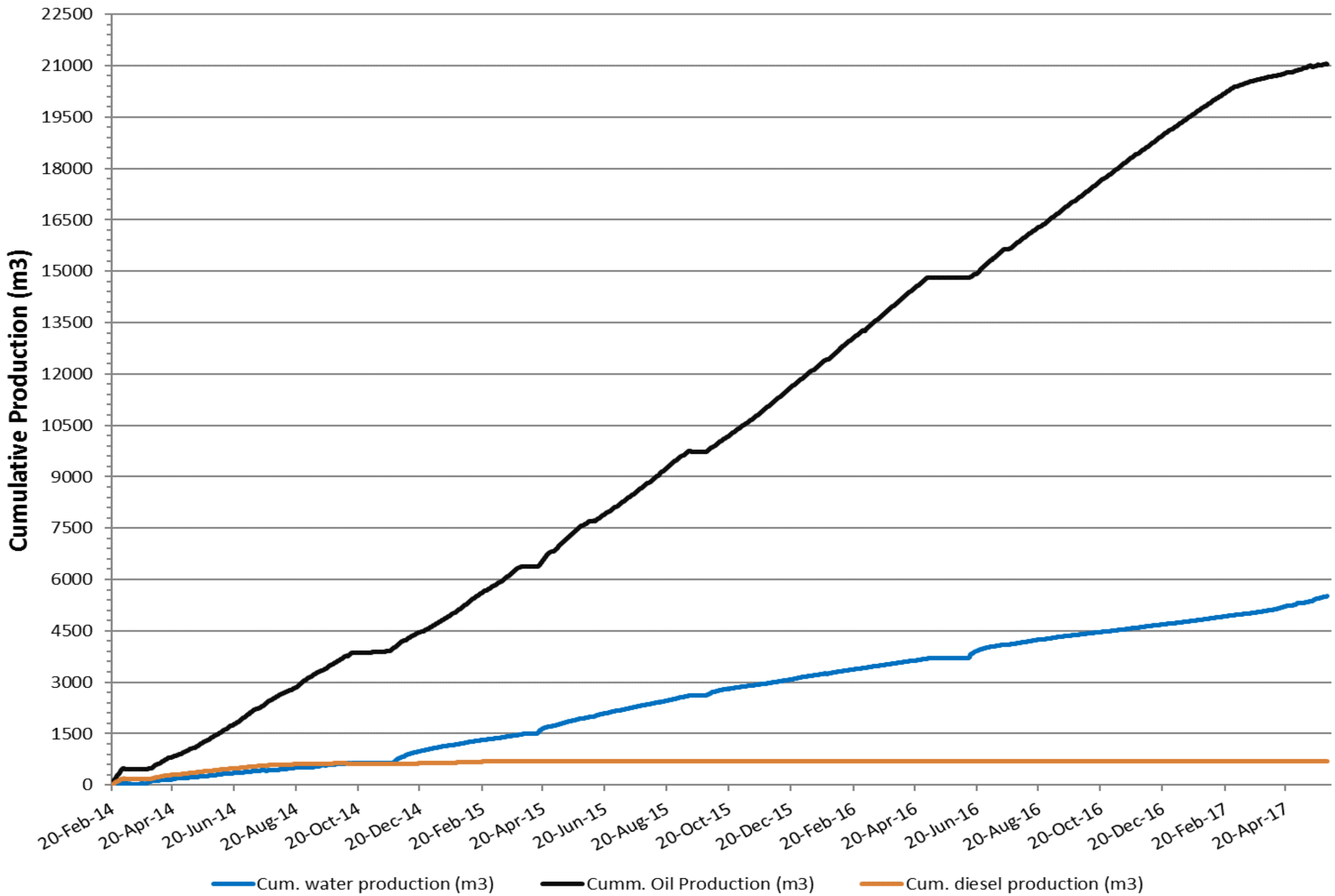
Scheme Performance – Timeline

nsolv

Pre-heating → Warm-up → Displace → Dilution & Cooling → Solv Inj & Drain → Prod. → Blow-down

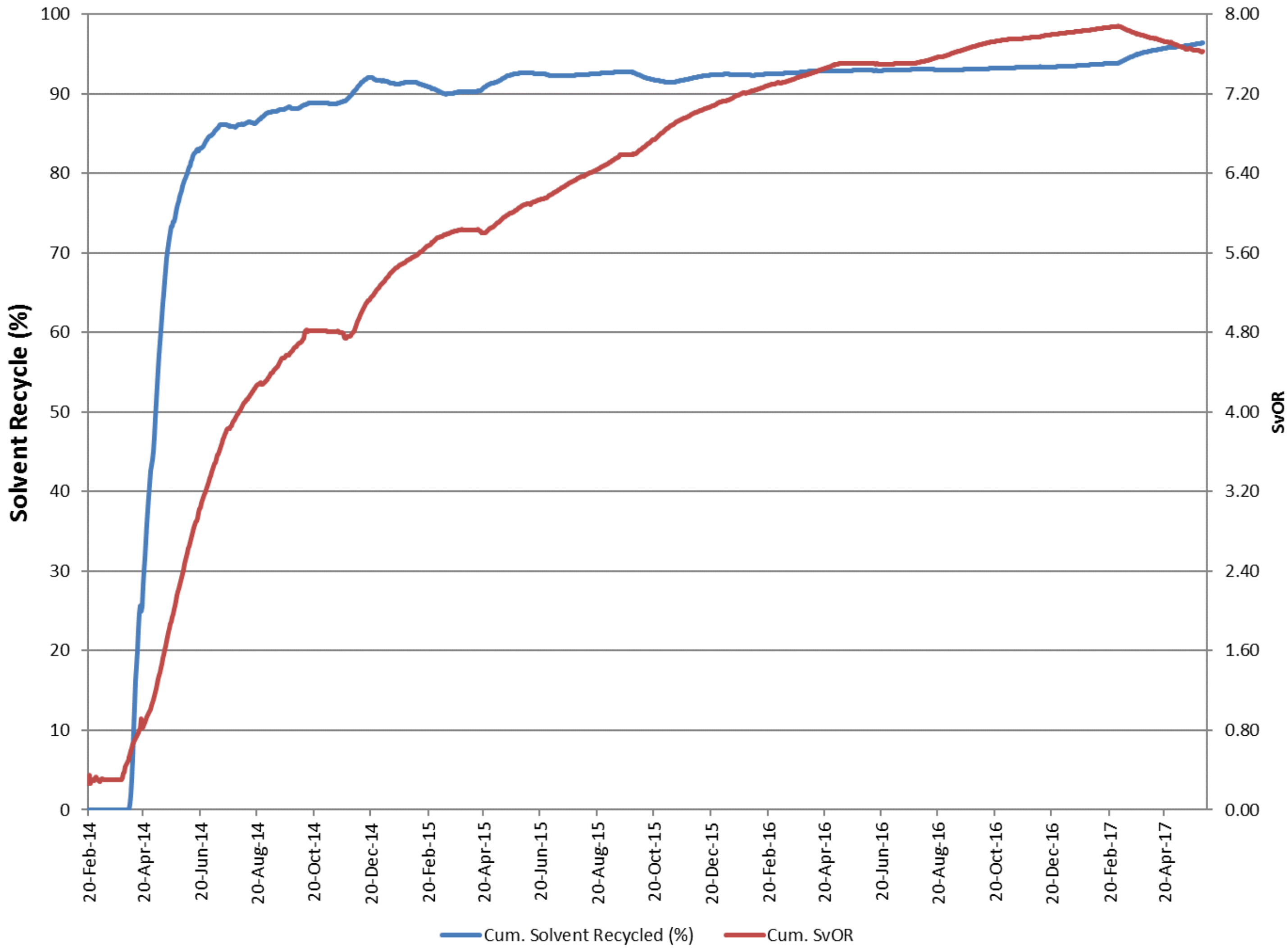
2013							2014							2015/16/17			2017		
Mar	Apr	May	…	Oct	Nov	Dec	Jan	Feb	Mar	Apr	May	…	Dec	Jan	…	Feb	Mar	…	Jun
Pre-heating		Warm-up			Displacement			Dilution	Solv Inj & Drain		Production Phase						Blow-down		

Scheme Performance – Cumulative Fluid Volumes



- 100% diesel recovery achieved in February 2015 (within measurement limits)
- 41% recoverable bitumen recovered 24% of exploitable PIIP bitumen recovered (Refer to Slide 11 (Volumetrics) for calculation details)

Scheme Performance – Solvent Balance



3,917 of 9,500 M3 help-up solvent recovered during shortened blowdown

Thermal Energy Injection Ratio

Energy Carrier	Operating Pressure (kPag)	Injection Ratio (v/v)	Latent Heat of Condensation (kJ/kg)	Condensate Density at 15ºC (kg/m3)	Thermal Energy Injection Ratio (GJ/bbl oil)
Butane	600	SvOR = 7.6	322	577	0.22
Steam	1394 (79% MOP)	SOR = 0.71	1948	999	0.22 (equivalent)

- Thermal energy injection drives fuel gas consumption and GHG intensity for SAGD and Nsolv alike
- Latent heat of condensation was the dominant contributor to thermal energy injection in the BEST pilot
- In the above simplified calculation, the cumulative SvOR for BEST has a thermal energy equivalent to a cSOR of 0.71

Scheme Performance – Solvent Balance

- Solvent delivery capacity of 1500 bpd.
- Sustained peak solvent injection rate of 1410 bpd at near dew point injection, leading up to wild fire shut in.
- Cumulative Solvent Oil Ratio (SvOR) at end of the project was 7.6 and thermal energy equivalent steam oil ratio was 0.71.
- There are several reasons why these ratios were higher than originally anticipated:
  - Conformance: Additional heat is currently being lost heating regions of non-conformance – increasing conformance should lead to a reduction in SvOR as those areas start to contribute to bitumen production.

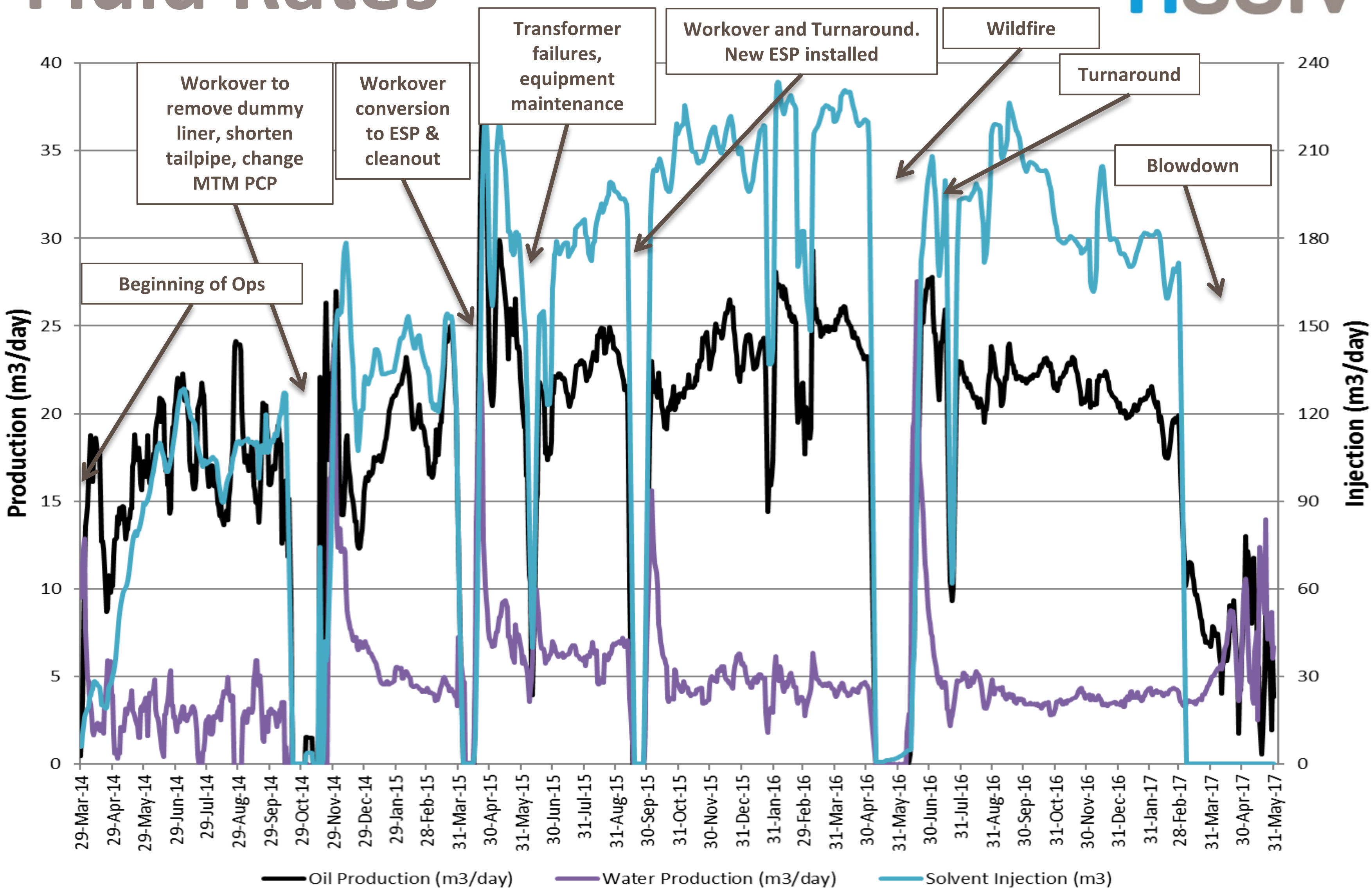
Scheme Performance – Solvent Balance

- Gas Coning: Evidence of significant levels of solvent vapour being drawn directly into the producer without condensing and liberating oil, thus increasing SvOR.
- Reduced pay thickness: Original pay height was expected to be 18.5 m however the average pay thickness was reduced to 12.8 m when the wellpair was raised up to avoid a shale plug encountered while drilling OB 08.
- Other heat losses: Injector incline heat losses can be moderated with commercially available technologies.

Scheme Performance – Gas Coning

- Poor conformance at the heel of the well was a significant contributor for gas coning at the BEST Pilot. The heel separation bias (i.e., well separation distance averaging 6 m at the heel and converging to 5 m at toe) contributed to the poor conformance at start-up
  - higher drawdown was employed at times to try to encourage better drainage at the heel resulting in gas intake at the toe – the converging trend described above exacerbated the effect of the (otherwise normal) undulations in producer elevation, further contributing to higher gas intake at the toe
- Additionally, over the course of the BEST Test Program, varying levels of liquid submergence (subcool) were trialed for the production well
- Optimization for future projects to minimize gas coning may include:
  - Improved start-up techniques to establish better initial conformance
  - A less aggressive drawdown on the production well
  - Potential use of inflow control devices specifically designed for the Nsolv process

Scheme Performance – Fluid Rates



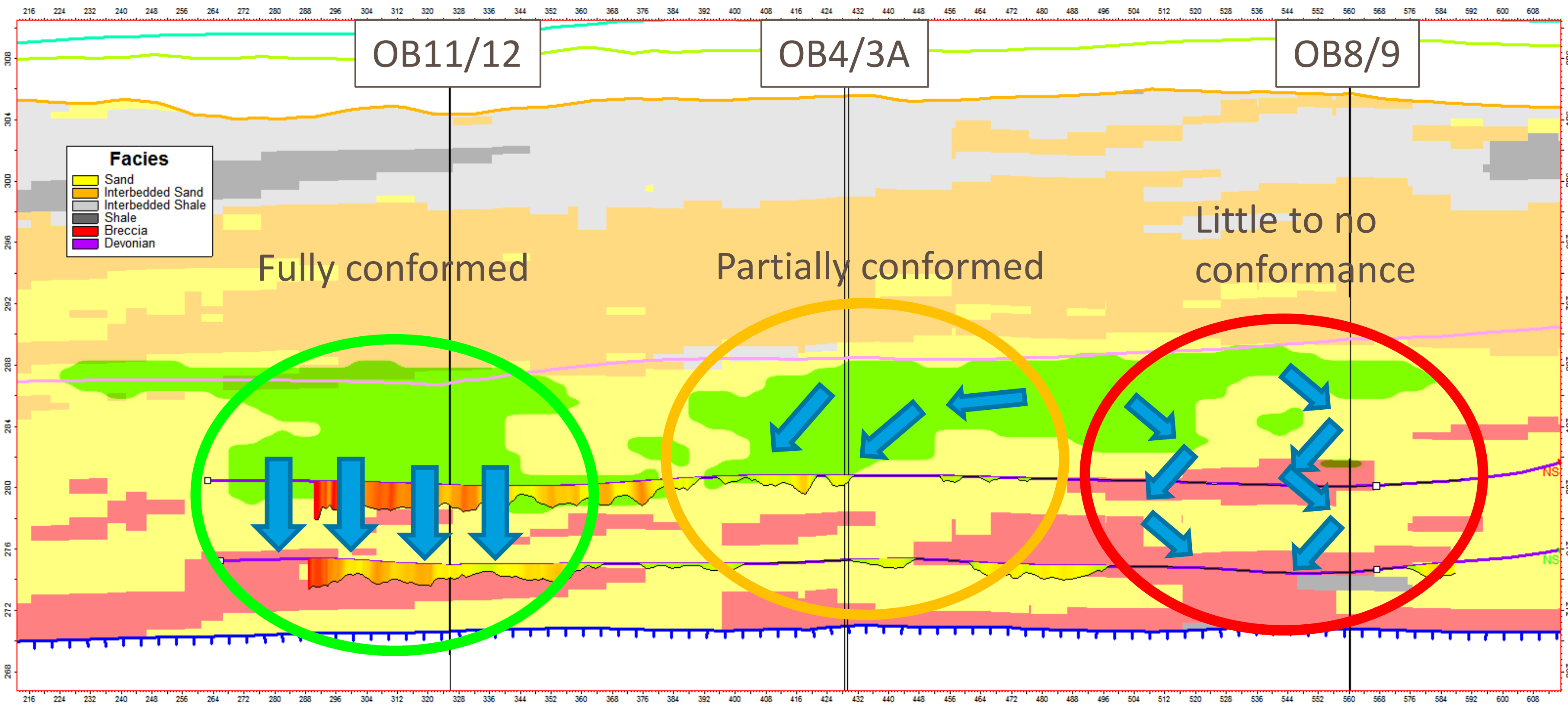
Scheme Performance – Well Pair Conformance

- Well pair conformance monitored by:
  - DTS data
  - temperature fall-off data
  - Seismic data
- Conformance is approximately 60% or 180m of the 300m wells.
  - This was overestimated in 2015
  - Optimizations of start-up operating conditions using the pilot history match model show that a more intensive warm-up period would result in a higher interwell temperature at heel, thereby resulting in significantly higher conformance from displacement.

Scheme Performance – Chamber Growth

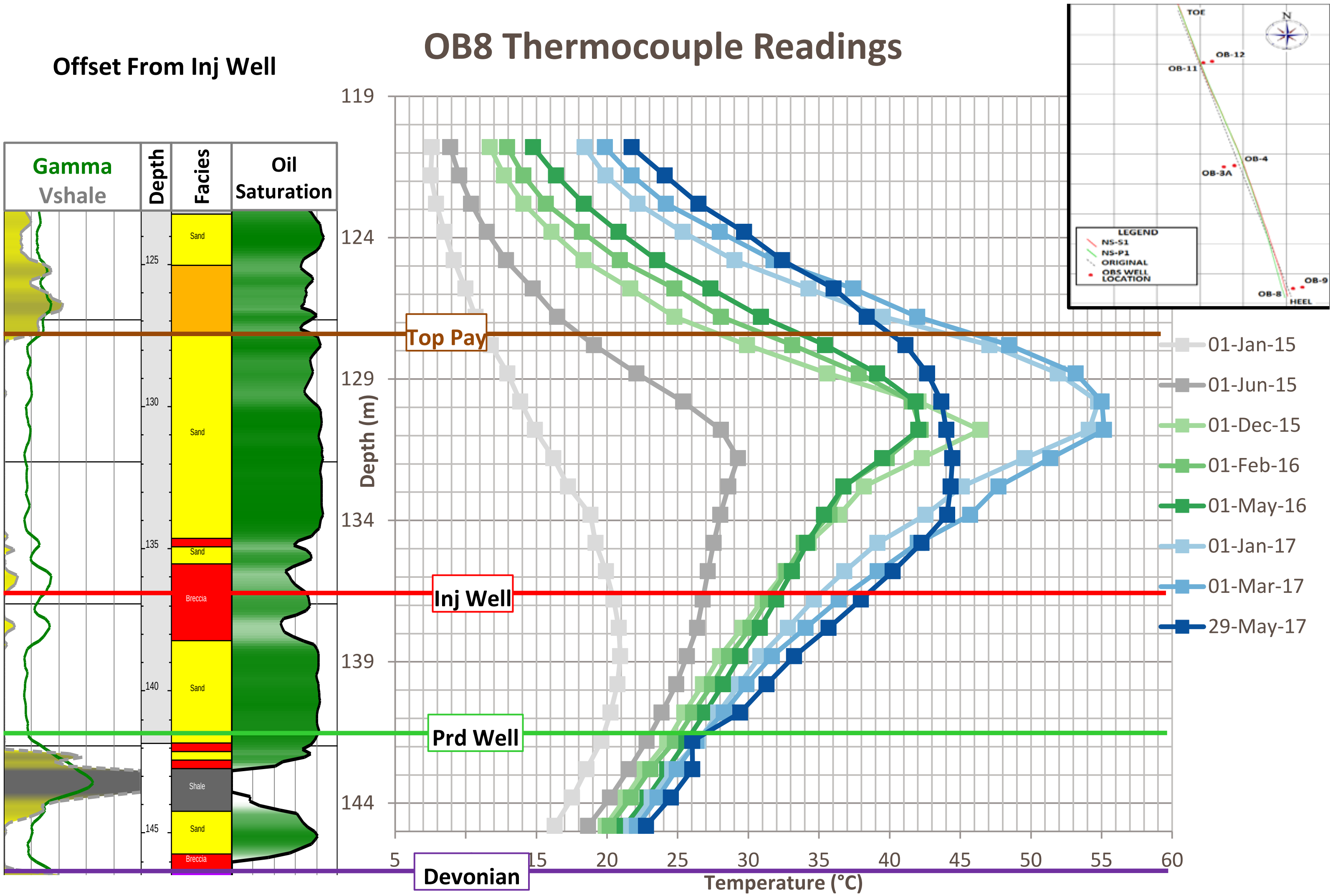
- Overall chamber growth monitored by thermocouples, RST logs at observation wells, and seismic data.
- Solvent chamber has intersected all observation wells
  - Top of pay reached
  - Chamber segmentation:
    - Toe chamber growth rates of ~2.6cm/d as observed at toe OB wells; fall off tests and seismic data indicate full level of conformance attained in the toe section
    - Mid-heel chamber growth rates of ~1.1cm/d as observed at mid OB wells; fall off tests and seismic indicate a partial level of conformance attained in these sections
    - Minor developments observed at the heel OB wells
  - The difference in growth rates is mainly attributable to the level of conformance achieved, since geology above the injector is less variable.
  - Chamber width has exceeded 40-60m in most areas

Hz Well Conformance

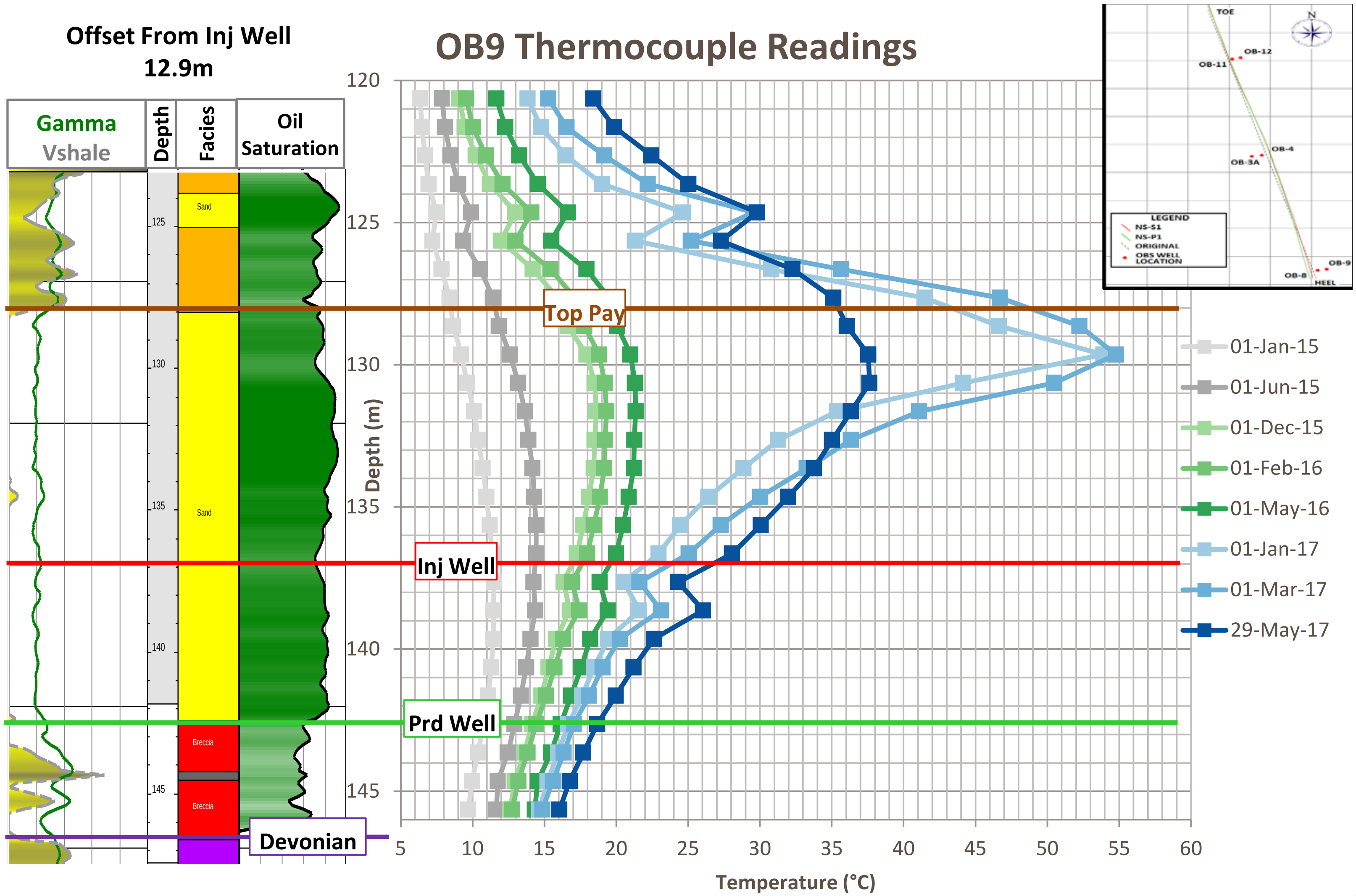


- Top of pay reached in all areas with developed chamber.
- Still large areas to grow conformance & production rate over time.
- Chamber growth rates are directly related to Hz well conformance.

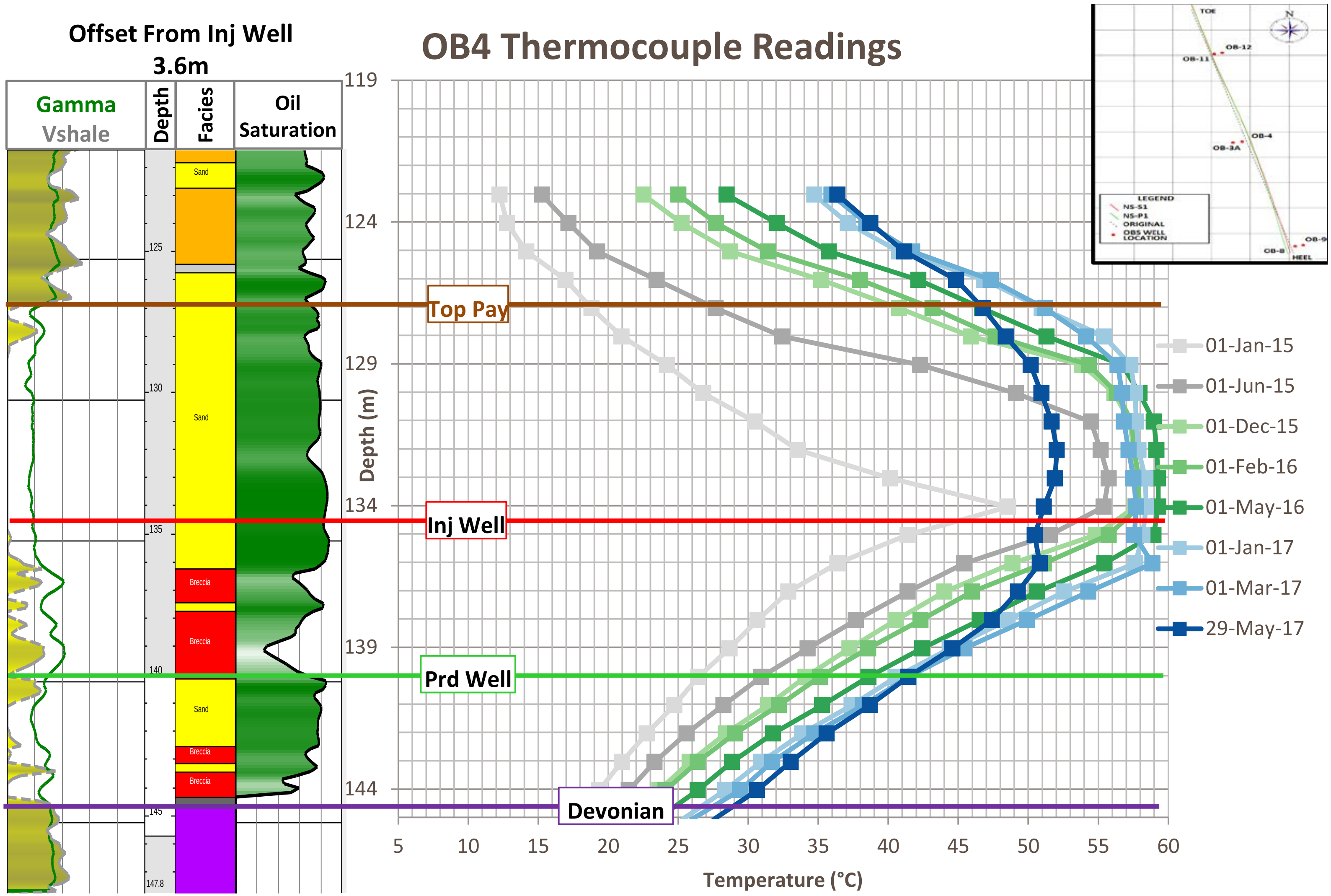
Scheme Performance – Chamber Growth



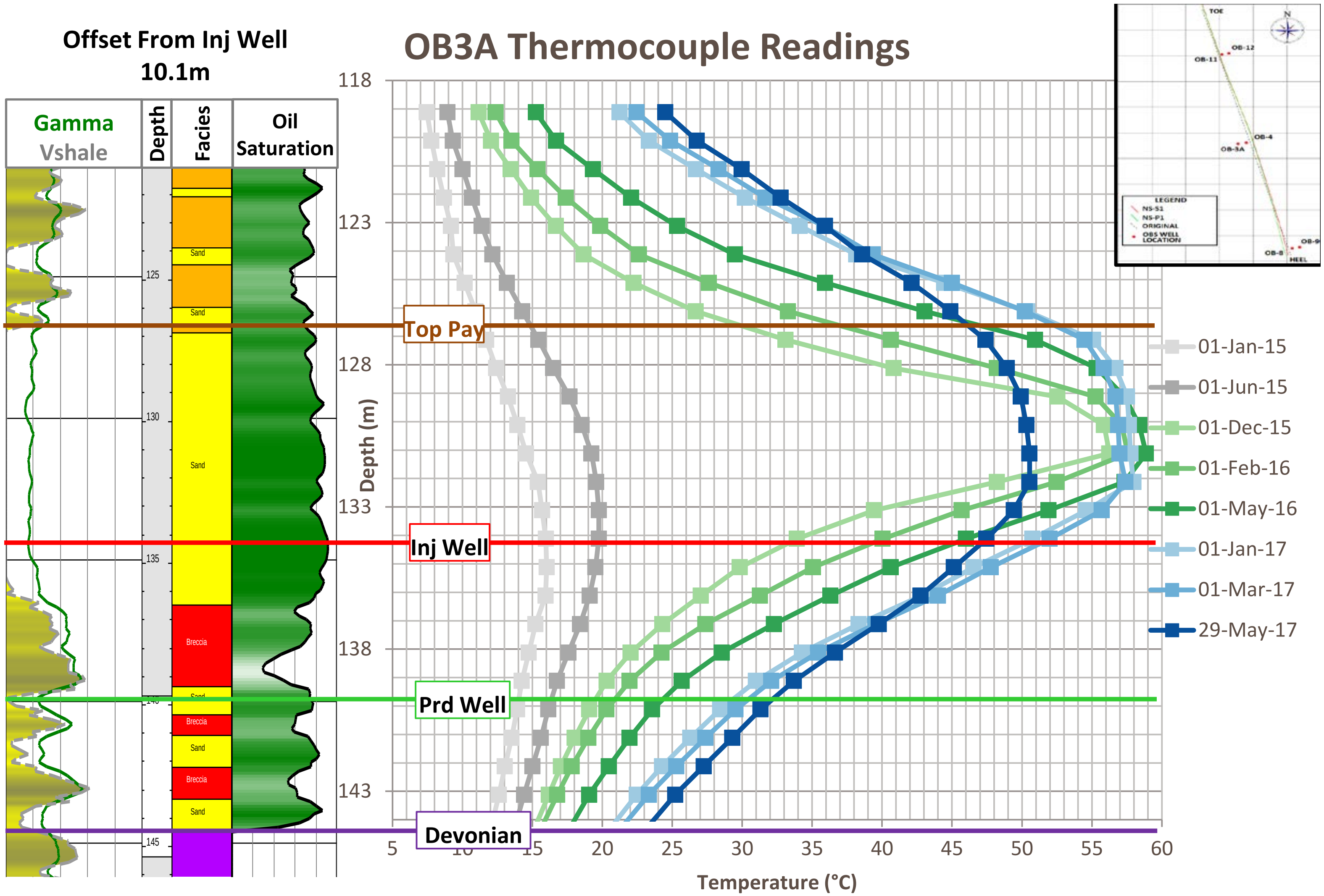
Scheme Performance – Chamber Growth



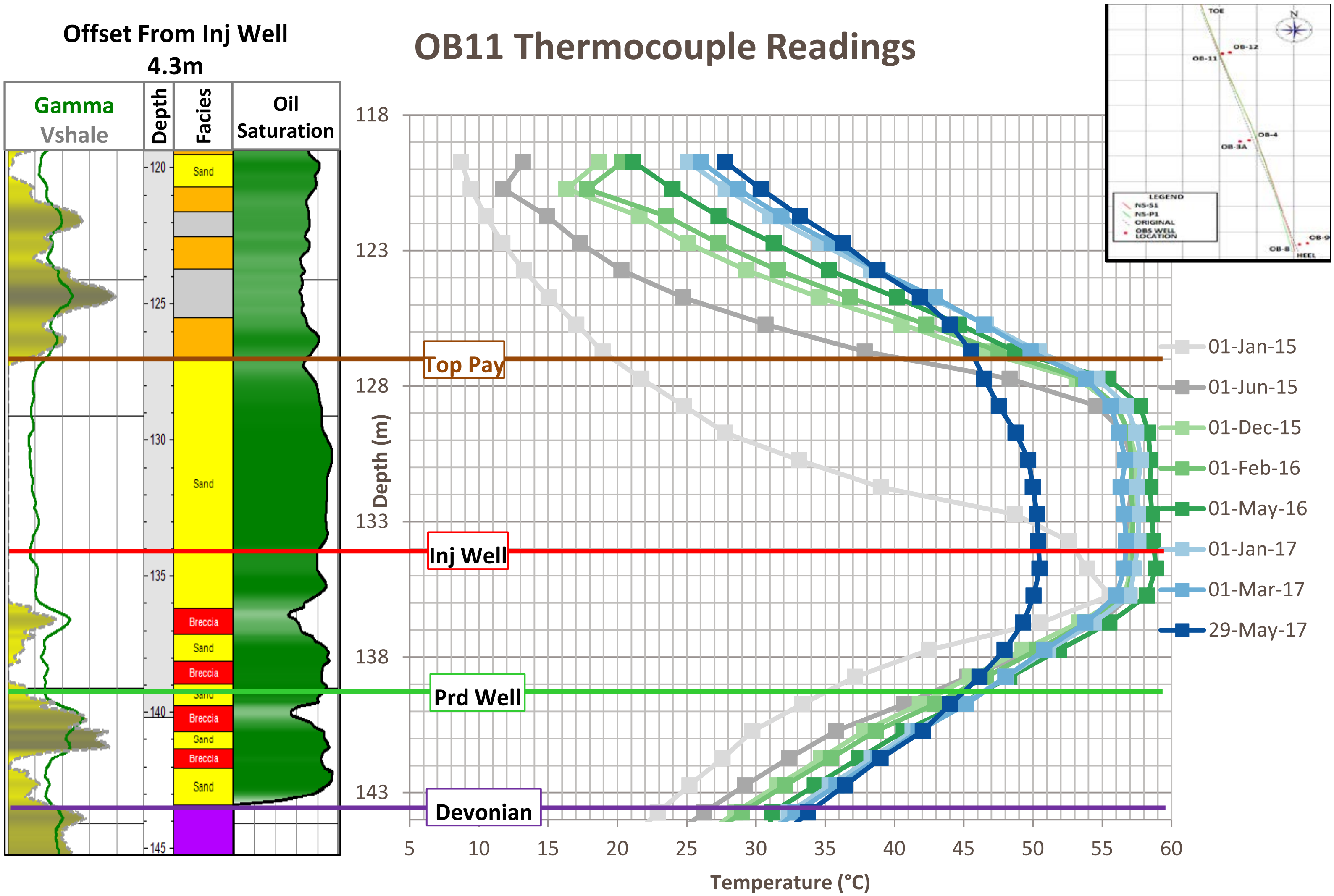
Scheme Performance – Chamber Growth



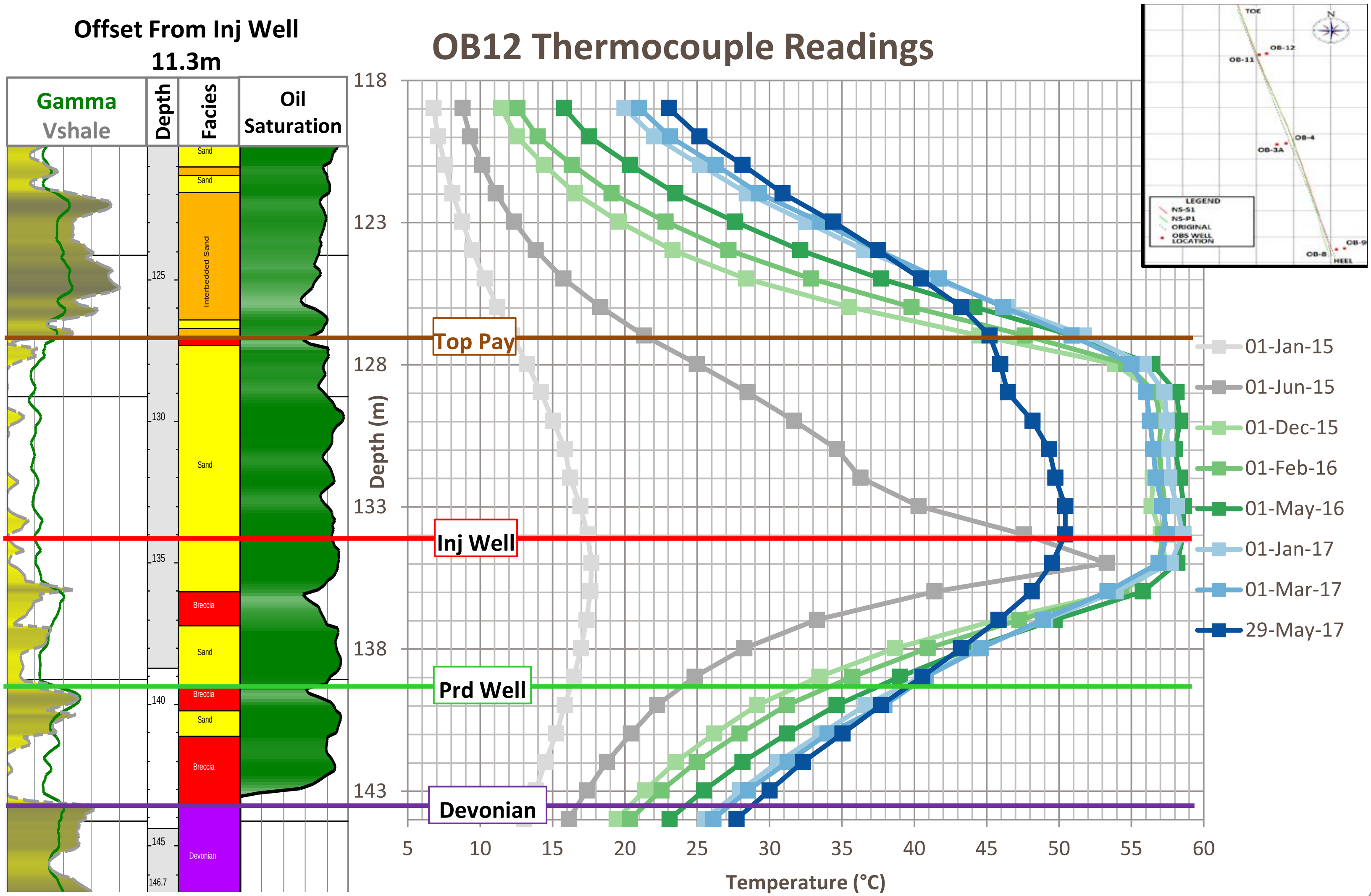
Scheme Performance – Chamber Growth



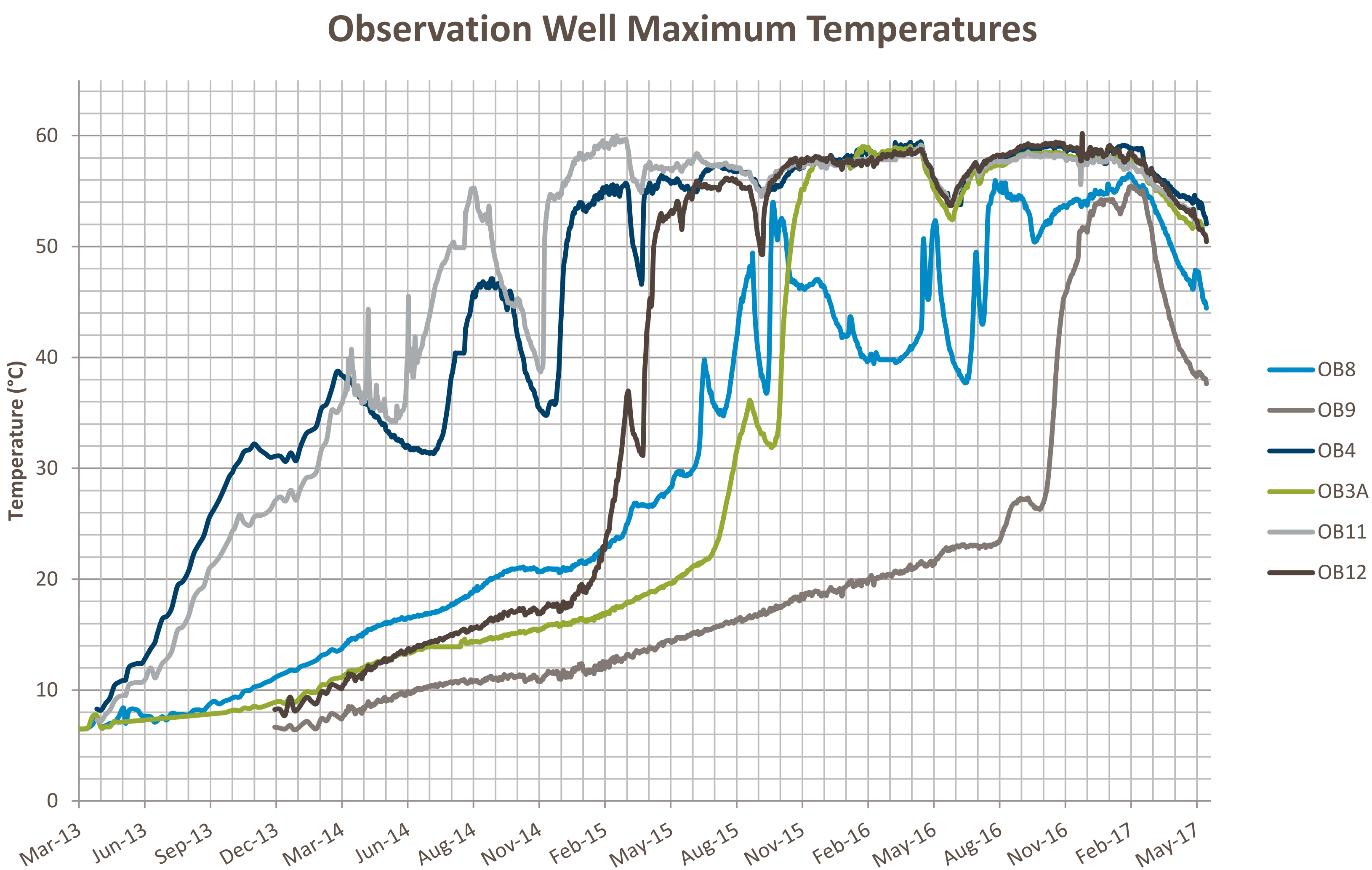
Scheme Performance – Chamber Growth



Scheme Performance – Chamber Growth



Scheme Performance – Chamber Growth



Reservoir Saturation Tool Results (RST Logs)

RST Log Series

March 2015

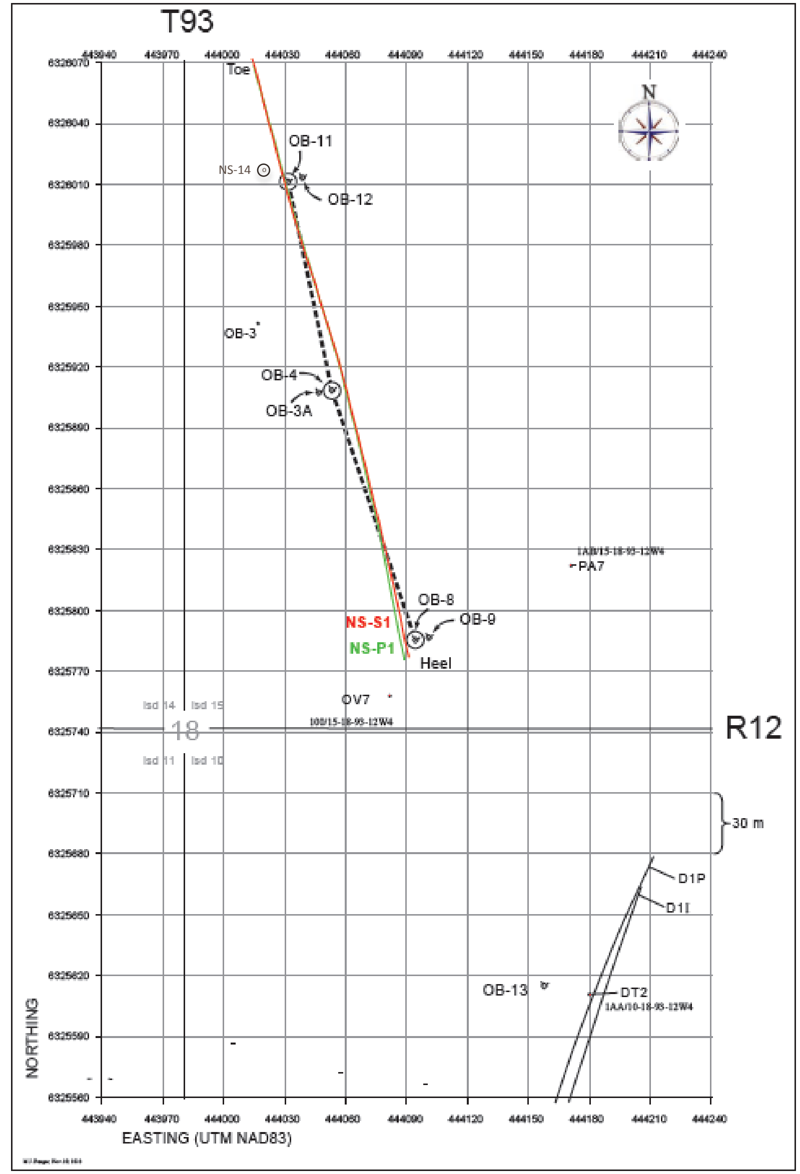
- OB11, OB4, OB8

March 2016

- OB11, OB4, OB8

January 2017

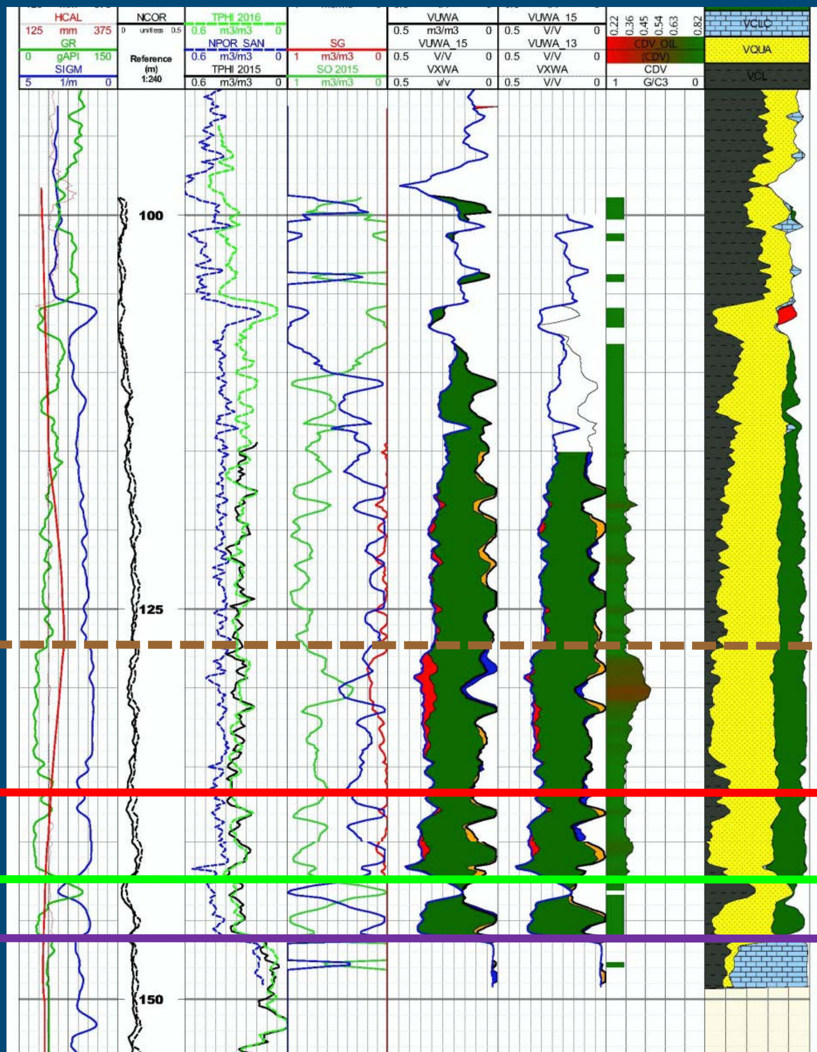
- OB11, OB12, OB4, OB3A, OB8, OB9, OB13, and NS14



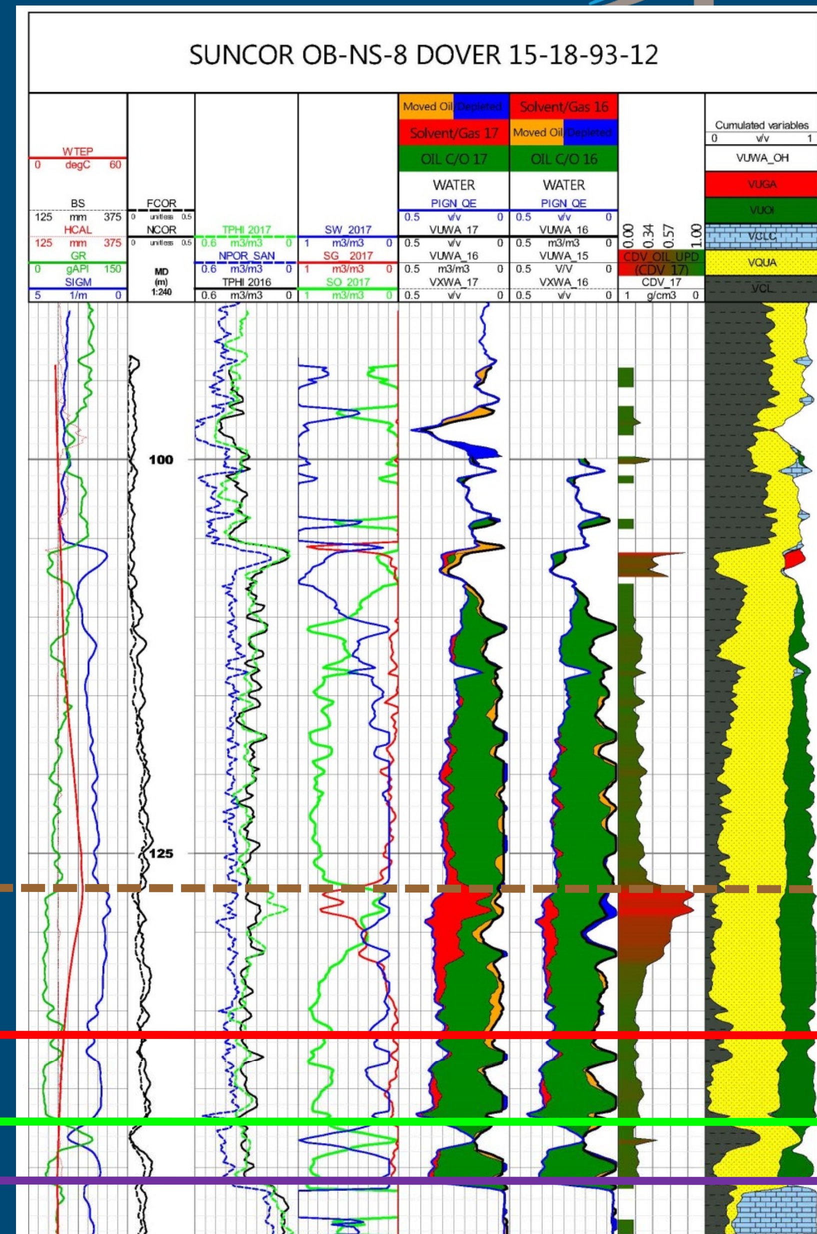
OB-08

Approximately 4.5m of vapour chamber developed below top of pay with ~ 2m of transition zone below chamber.

2016



2017

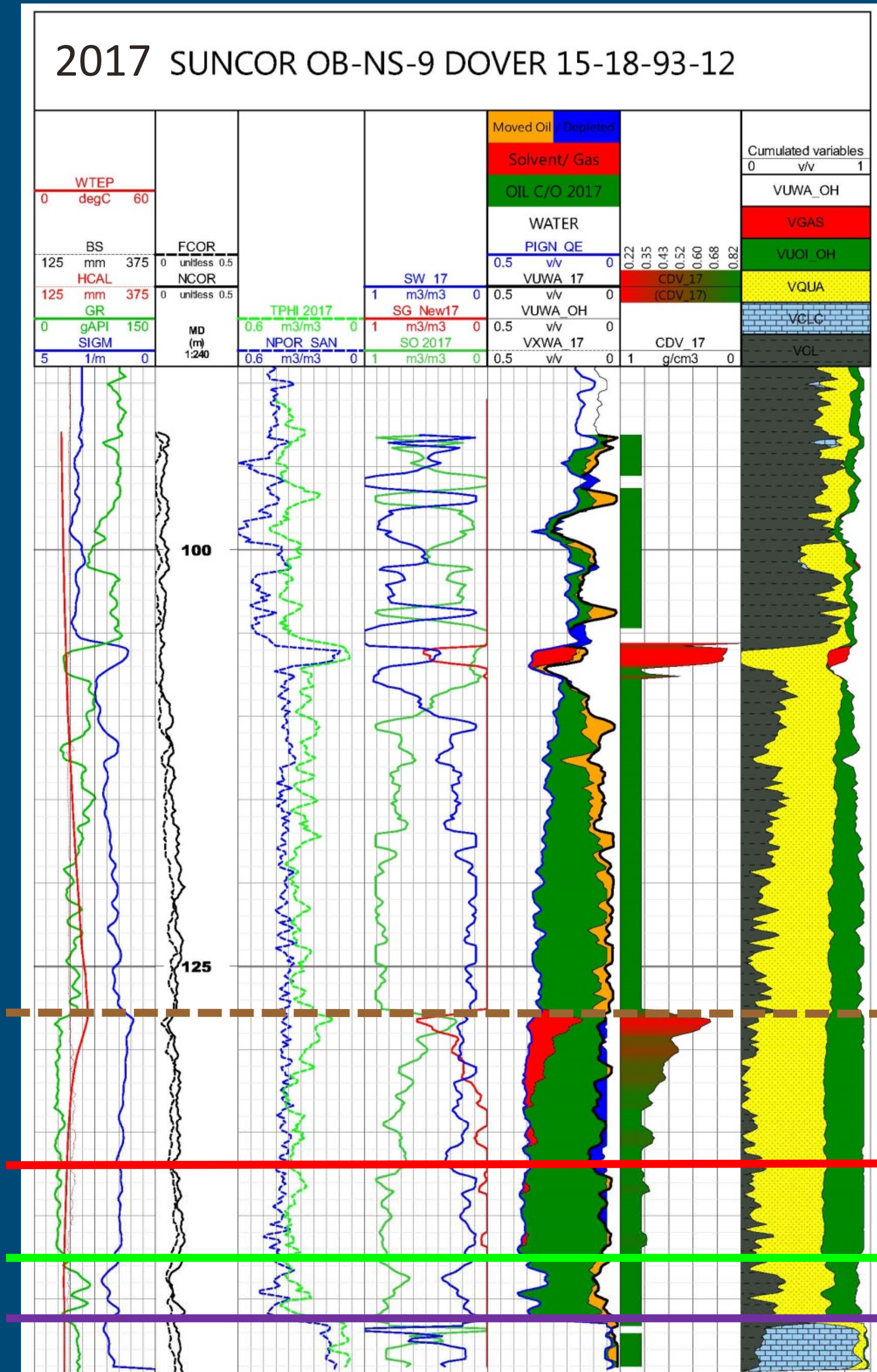


Top of Pay

Injector

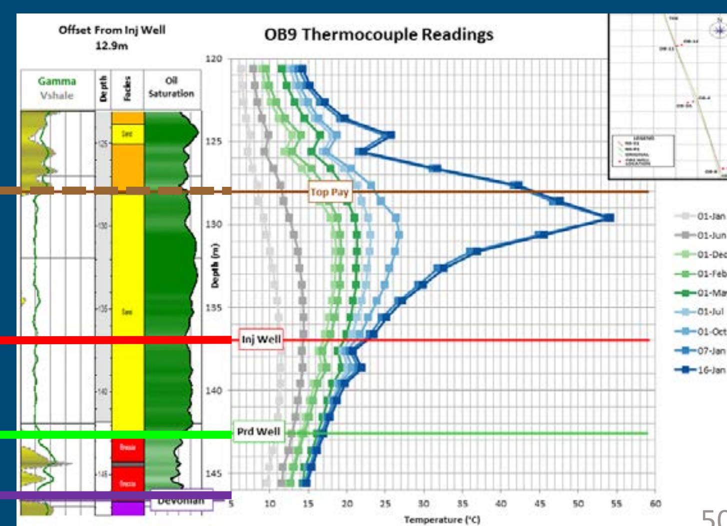
Producer

Devonian



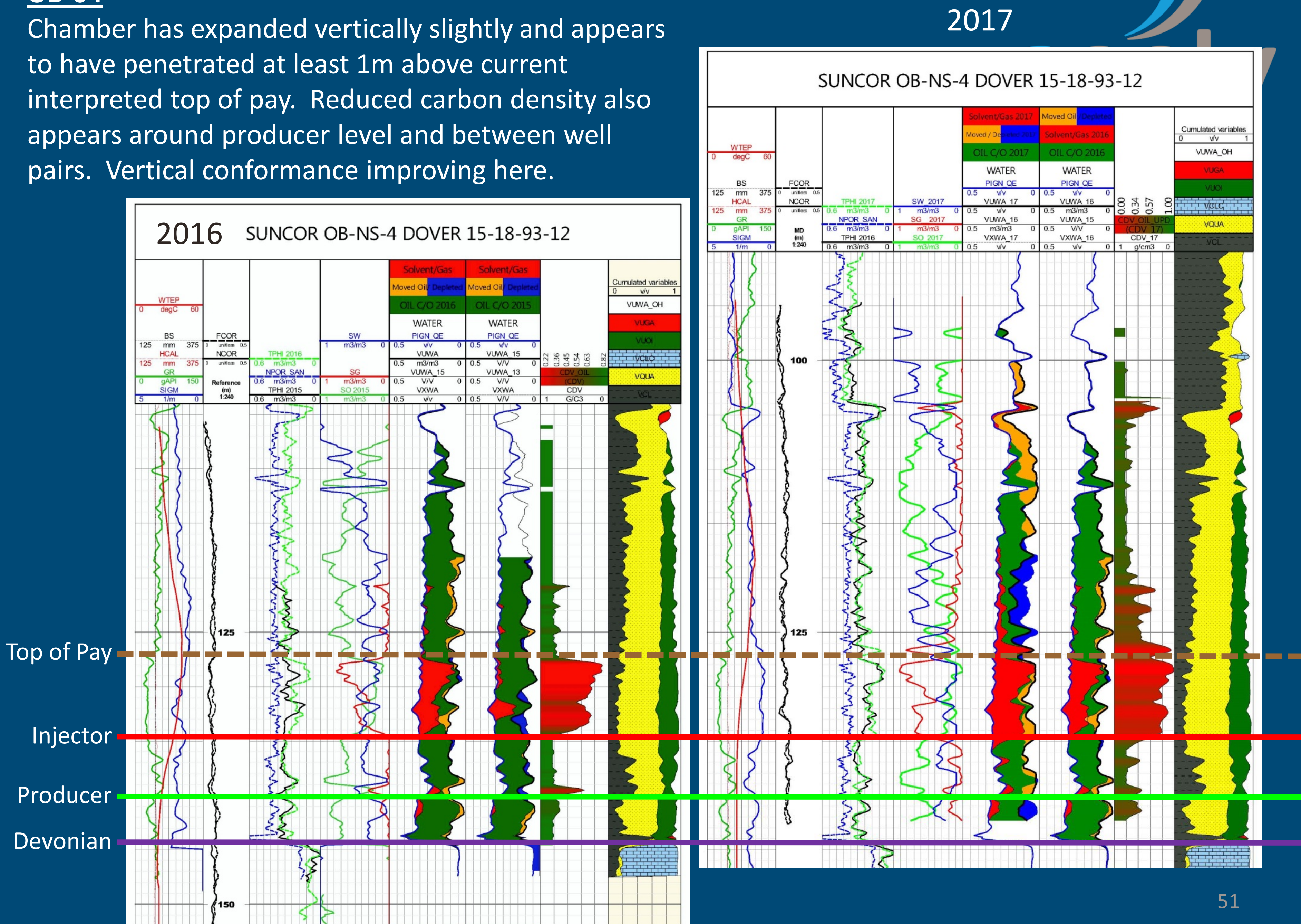
OB-09

Chamber developing below top of pay. Approximately 1m thick with a 4m transition zone below back to native bitumen.

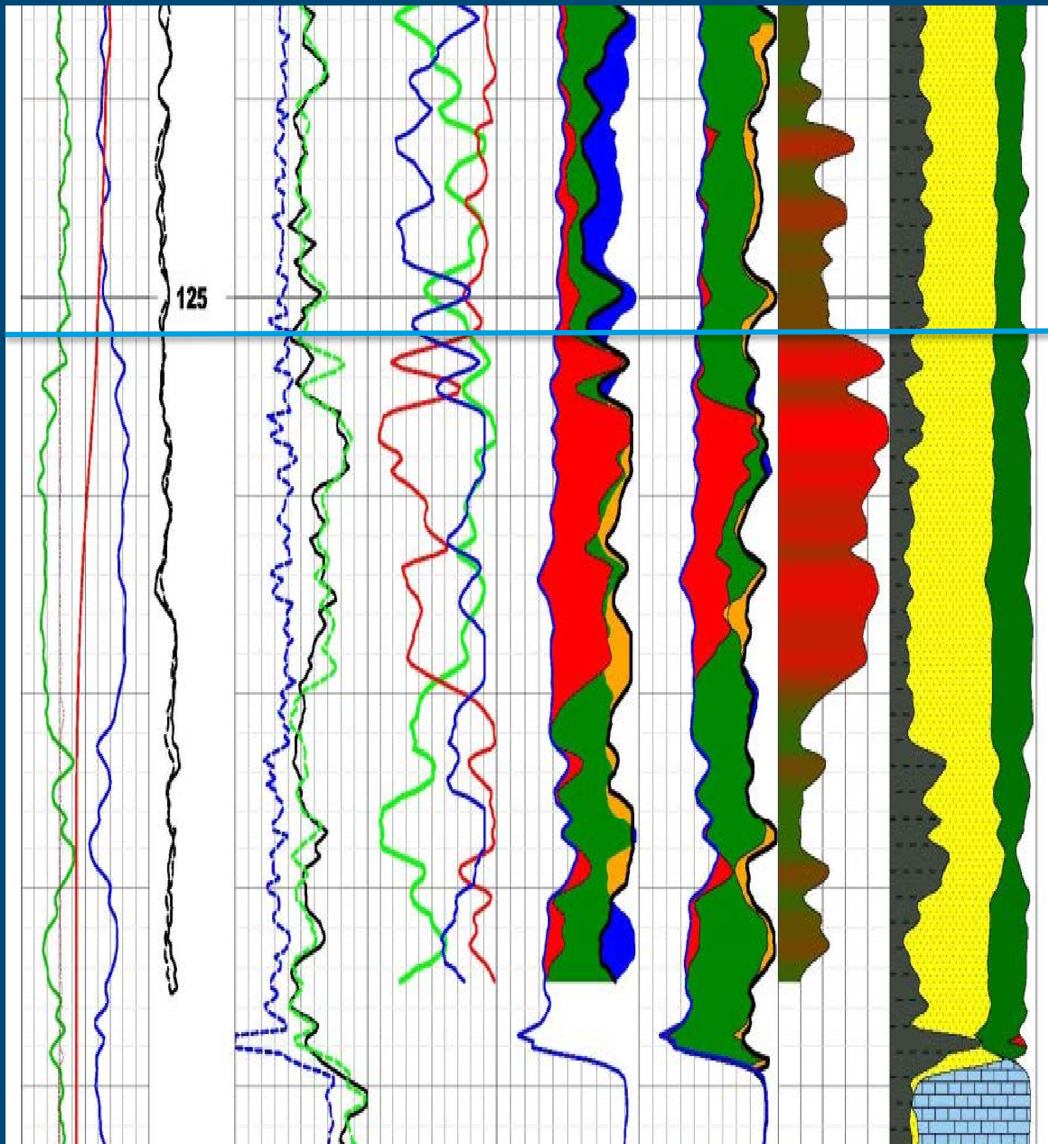


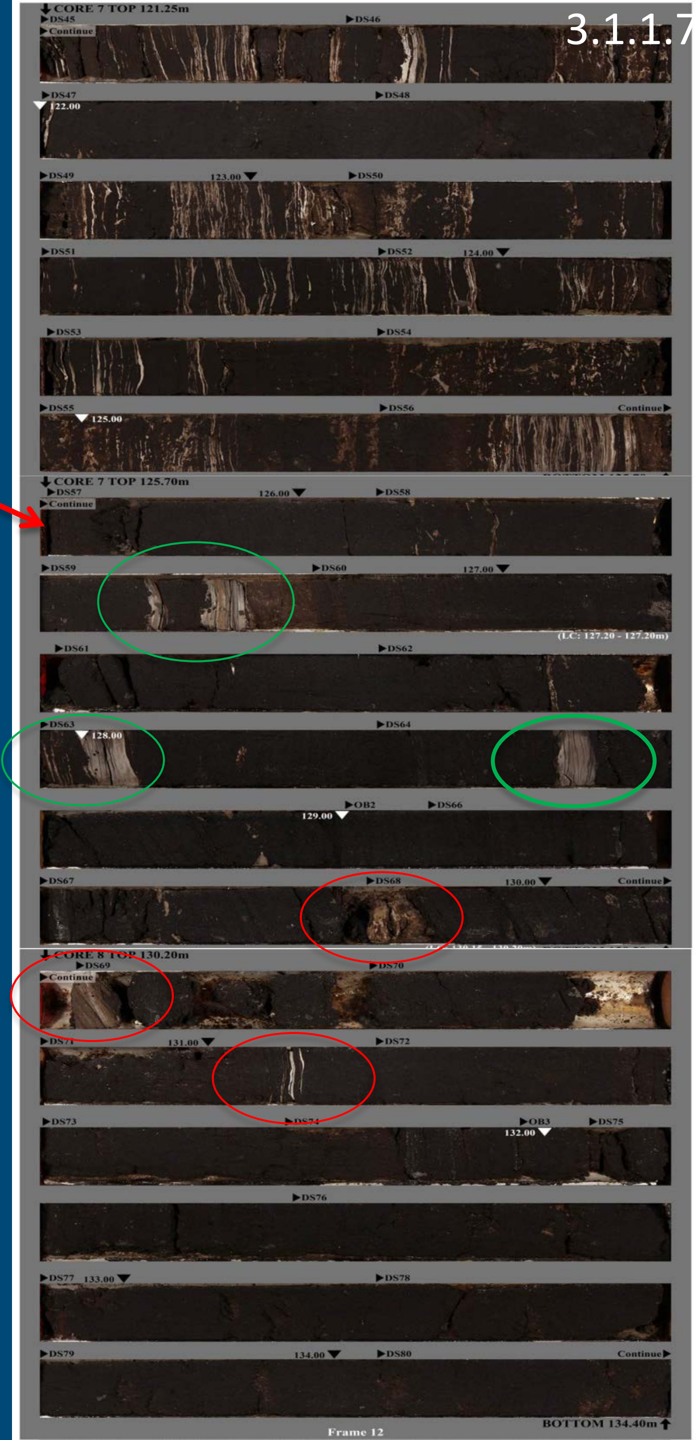
OB-04

Chamber has expanded vertically slightly and appears to have penetrated at least 1m above current interpreted top of pay. Reduced carbon density also appears around producer level and between well pairs. Vertical conformance improving here.

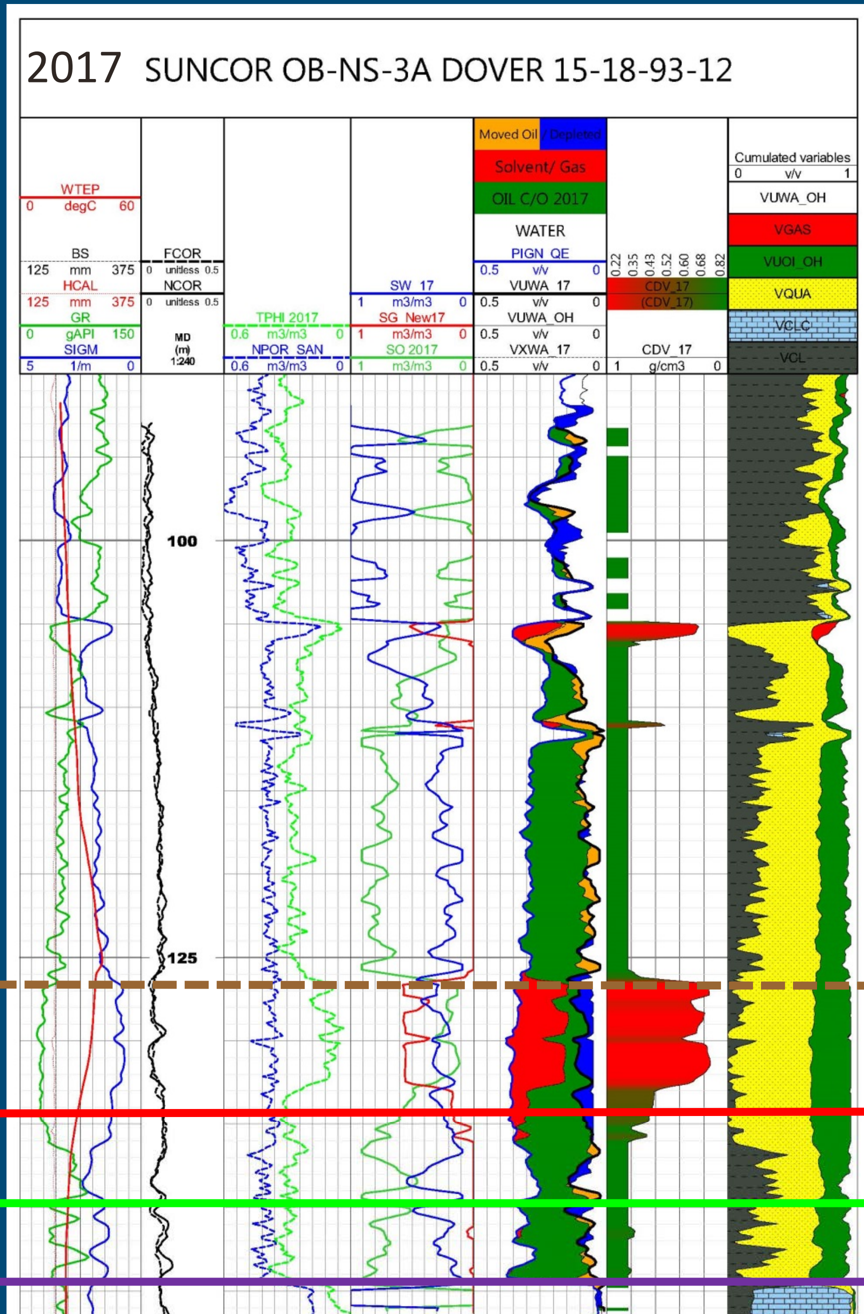


OB-04 IHS Penetration





The solvent chamber has penetrated up to a depth of ~126m. The first significant shale bed appears at 128.6m with a couple of minor ones below that.



OB-3A

Well developed 6.5m thick chamber immediately below top of pay. No IHS penetration apparent.

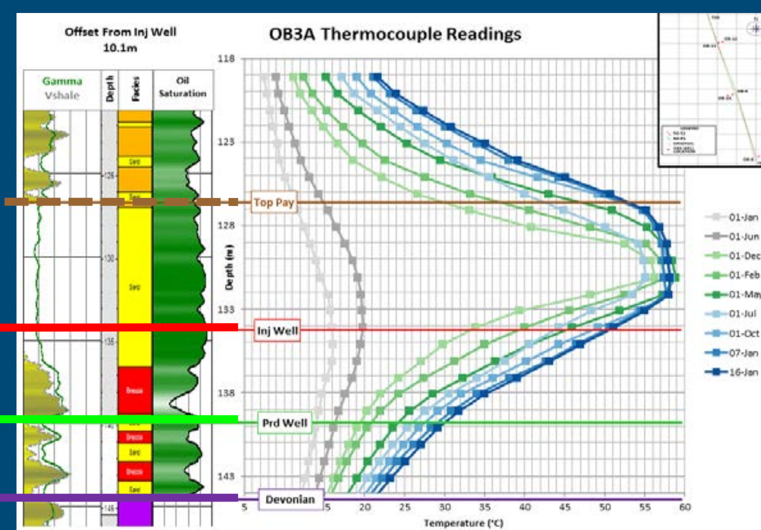
3m thick transition zone below chamber.

Top of Pay

Injector

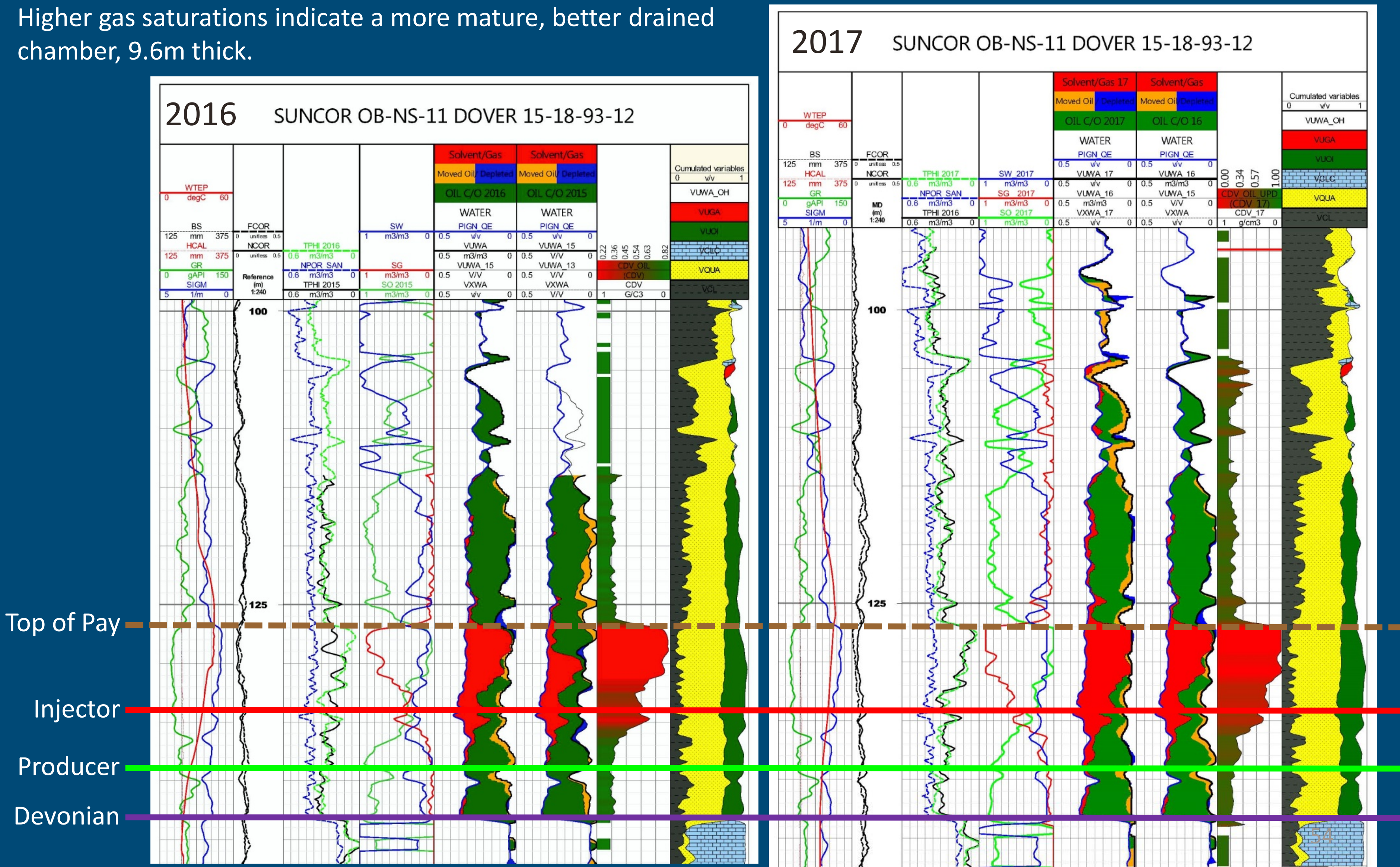
Producer

Devonian



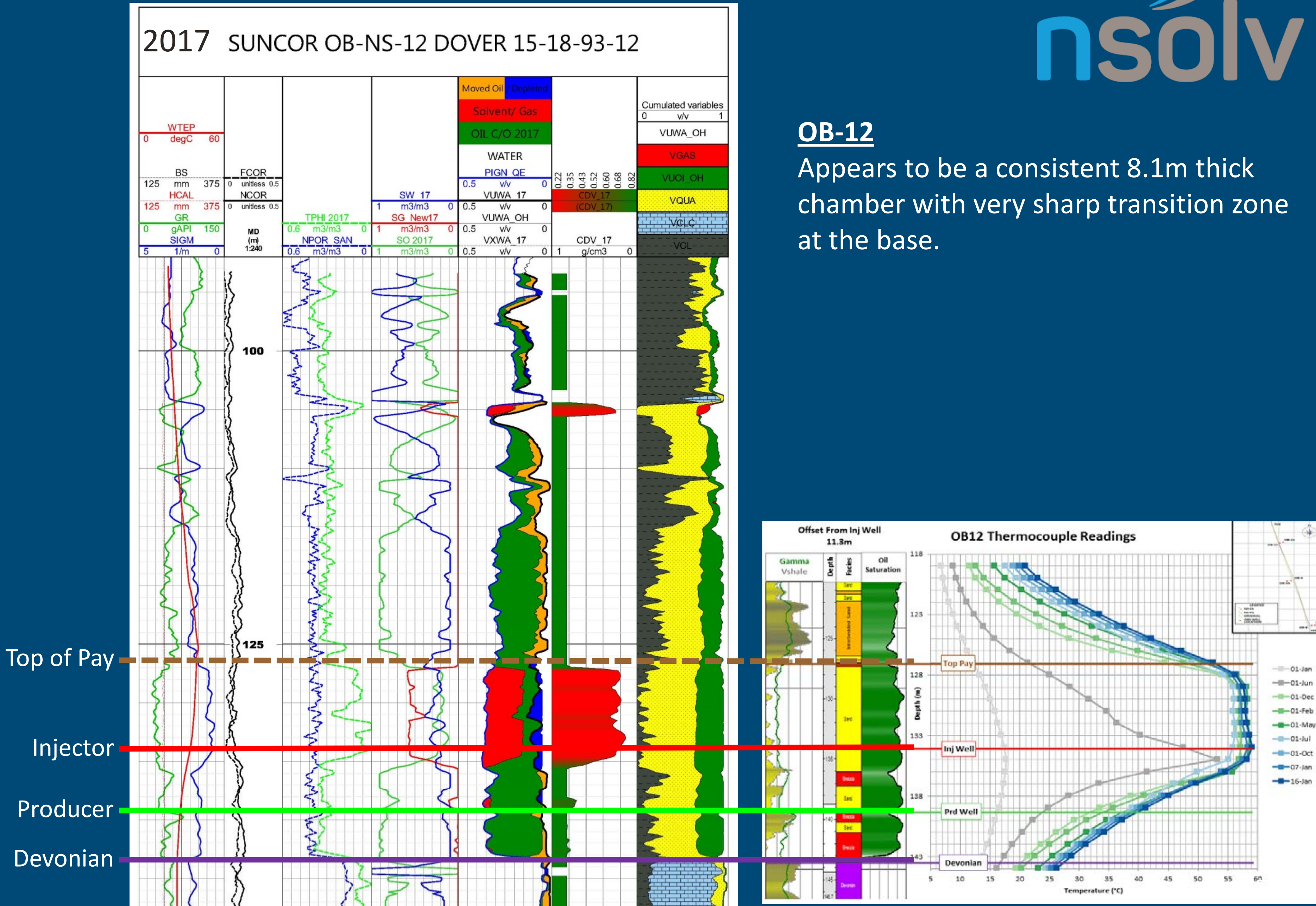
OB-11

Slight increase in gas saturation above the top of pay.
Gas saturation has increased above injector indicating more efficient sweep of this area.
Lower carbon density around producer.
Higher gas saturations indicate a more mature, better drained chamber, 9.6m thick.



OB-12

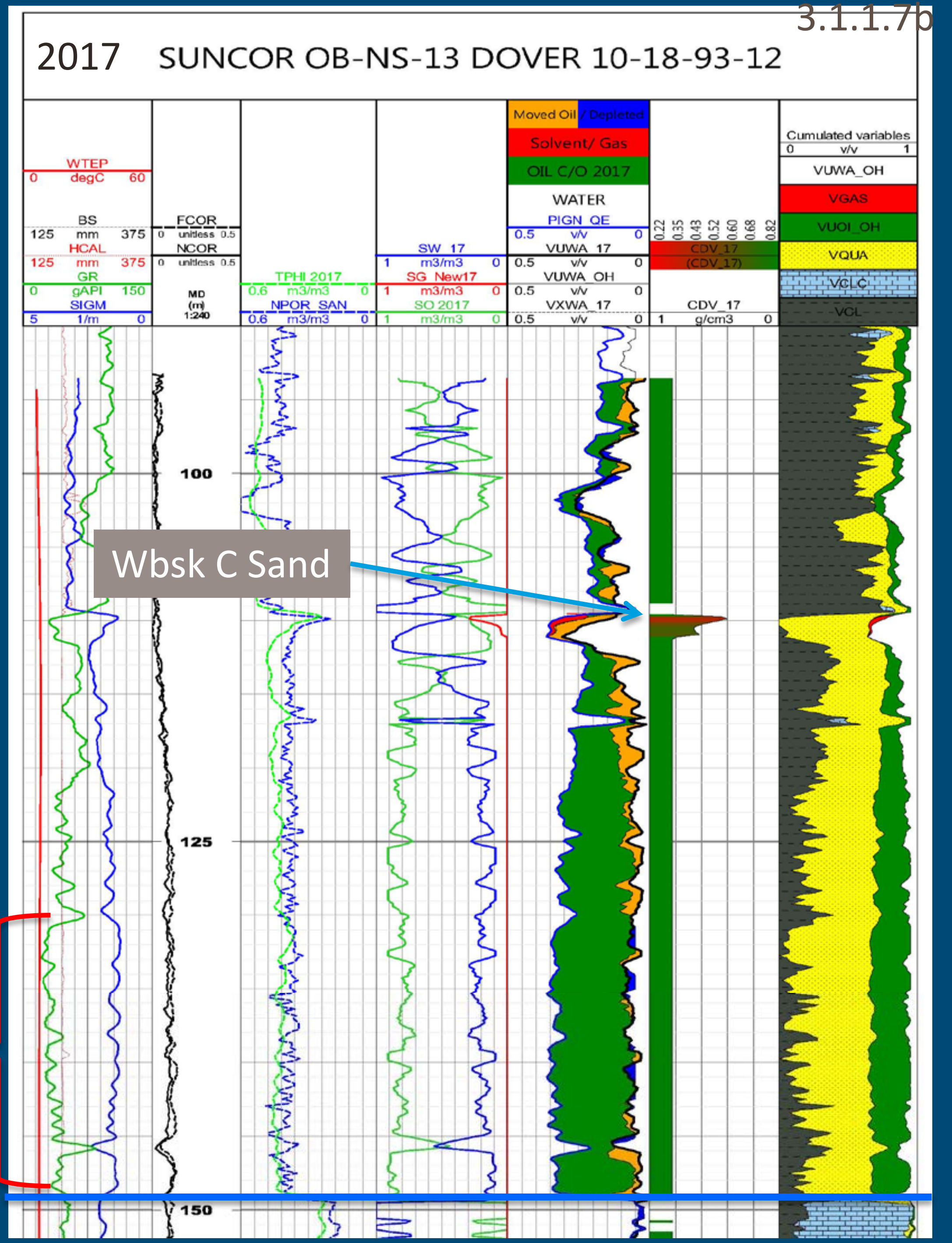
Appears to be a consistent 8.1m thick chamber with very sharp transition zone at the base.



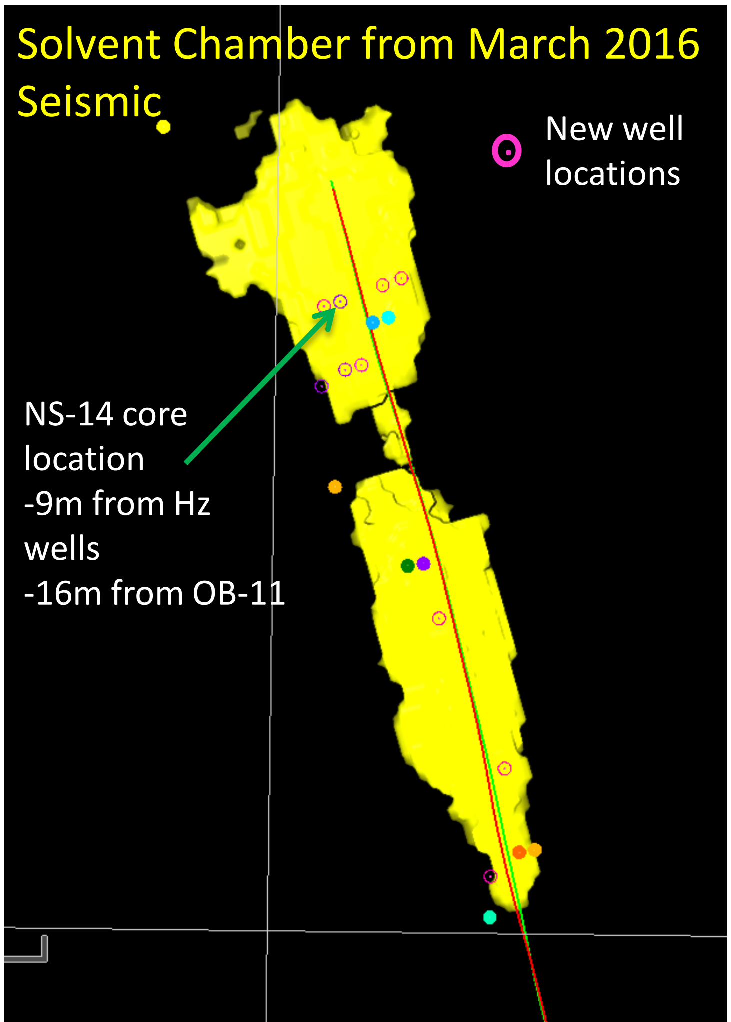
OB-13

This observation well is located ~180m south from the heel of the Nsolv wells and was put in place to monitor for solvent migration from the Nsolv chamber to any existing depleted SAGD chambers in the area.

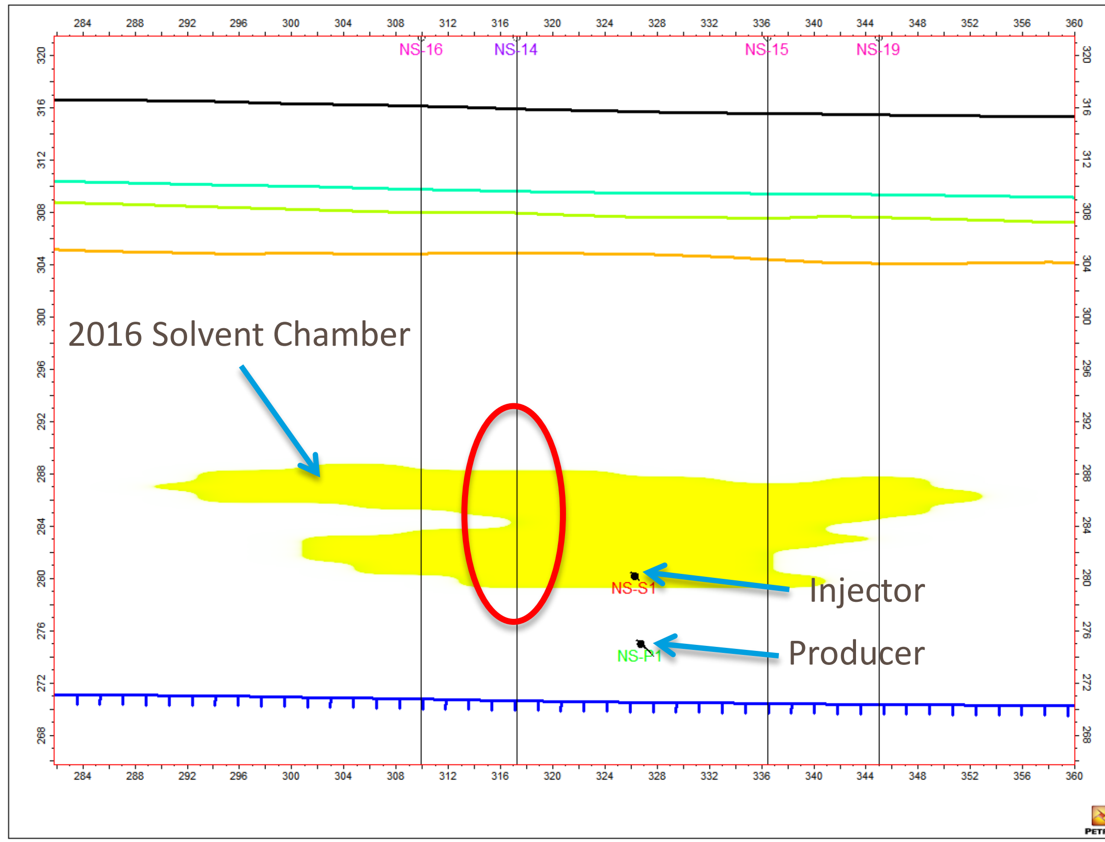
No indication of any solvent migration is present in OB-13



Post Solvent Coring



NS-14 chosen as it had the thickest intersection of the proposed well locations.



NS-14 was cored from March 21st to Mar 29th, 2017

Coring Overview

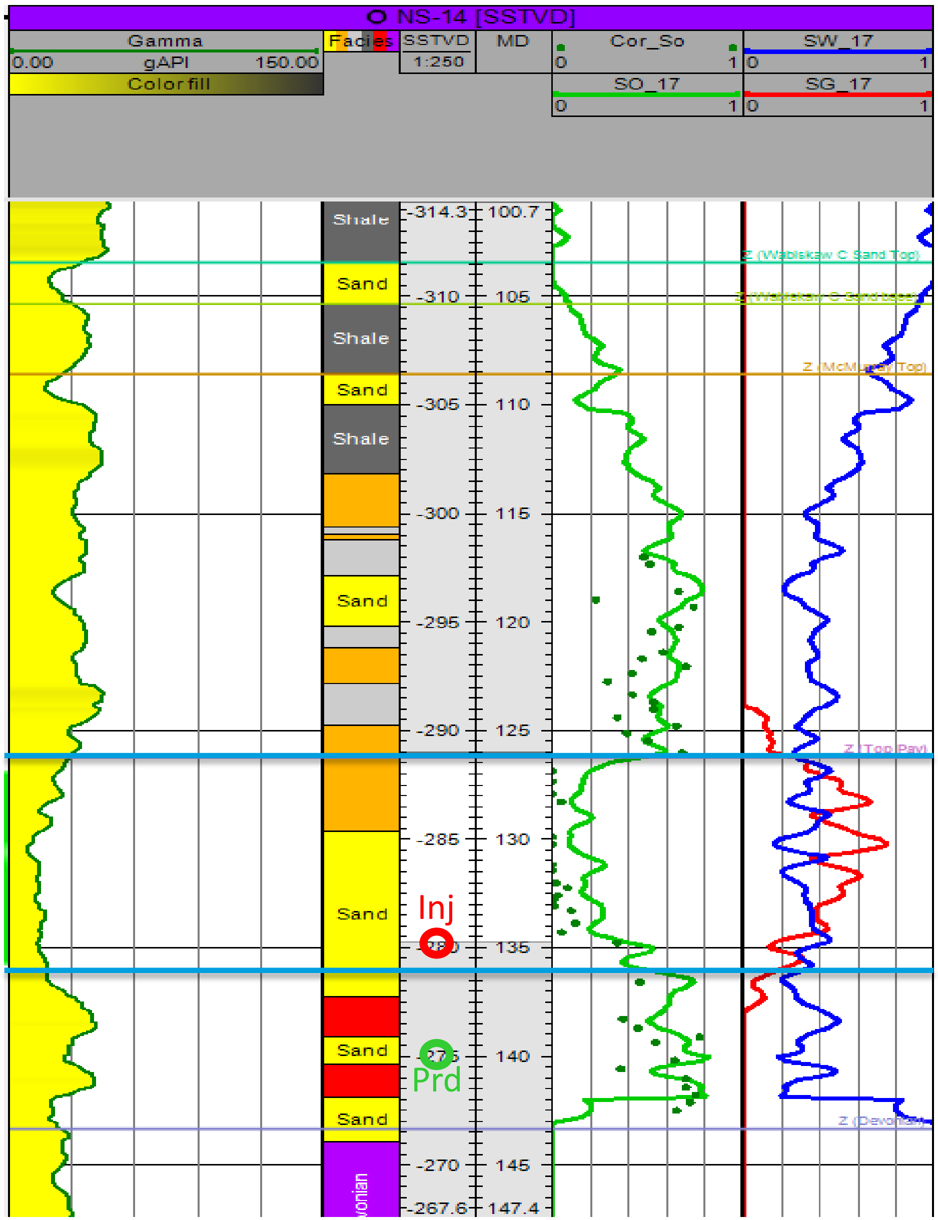
- Coring program intended to use a sonic rig for core recovery
  - Sonic coring was expected to perform well with respect to core recovery in unconsolidated sands void of bitumen (similar to water sands)
  - Sonic coring does not use a mud system, therefore a more pristine core was anticipated to be recovered
- The sonic rig encountered difficulty once it reached the solvent chamber to penetrate the formation with core recovery and integrity suffering. The sonic rig was subsequently swapped out for a conventional rotary rig, which did not encounter the same issues
- Coring into a live solvent chamber
  - No safety issues arose due to coring through the vapour chamber
  - No butane was detected at surface at any point during coring operations

Core Analysis Summary

The following core analysis has been carried out on NS-14:

- Dean Stark for the entire core interval
- 8 PSD samples to calibrate hyperspectral imaging
- 2 Permeability samples
- Core photos
- 6 SARA analyses and 2 simulated distillation from outside the swept zone
- 1 SARA and 1 Simulated distillation from the swept zone
- Visual core description
- 18 GCMS samples for biomarker analysis (baffles and barriers within the reservoir)
- Numerous binocular microscope photos
- 6 thin section samples and descriptions
- Hyperspectral imaging
    - Raw data file
    - Interpreted oil saturation, porosity, water saturation, grain size, sorting, and permeability
    - Core photos
    - Sedimentary texture imagery
- X-Ray Fluorescence
    - 5cm sampling interval
    - Mineralogy, source indicators, bitumen analysis and stratigraphy
    - Spectral gamma, major elements
    - Clay mineralogy
    - Mechanical properties
- PNX logs (Reservoir saturation tool, wireline logs)
- CT Scans of core

Residual Oil Saturation



Chamber Interval

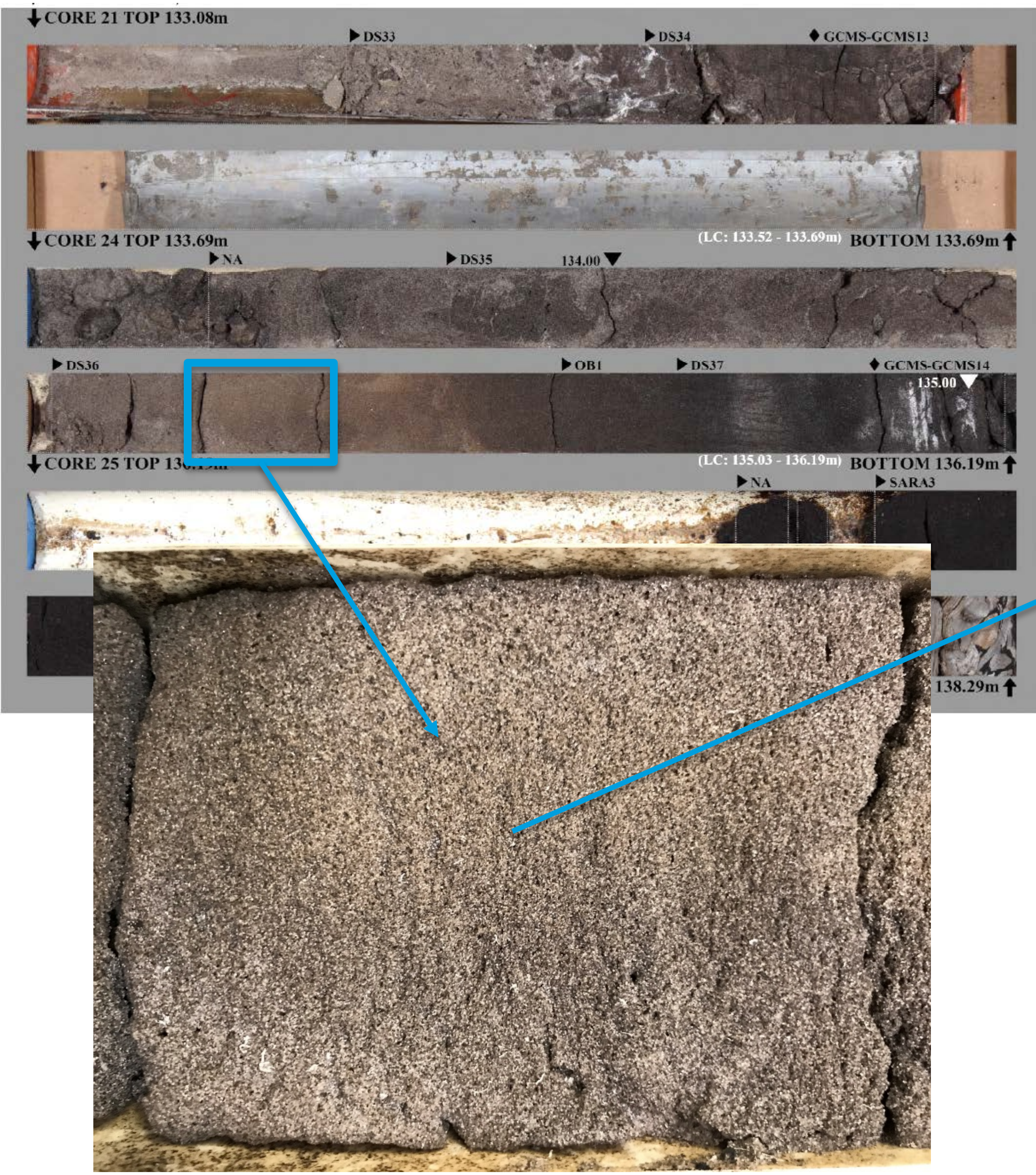
Average oil saturation over the identified chamber region from 126m to 136m is 8.2 vol %. From Dean Stark results.

Top of chamber

PNX log detects the butane in this region and reads slightly higher oil saturation than the DS results suggest. PNX average is 23% So.

Base of chamber

Photo Example



Dean stark reports 4.8%* residual oil saturation at base of chamber for this particular sample.

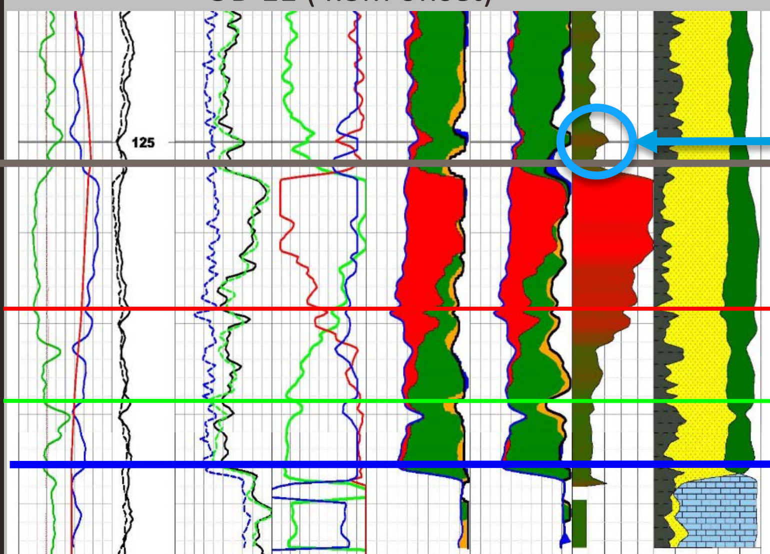
*not an average value, excludes some insoluble components

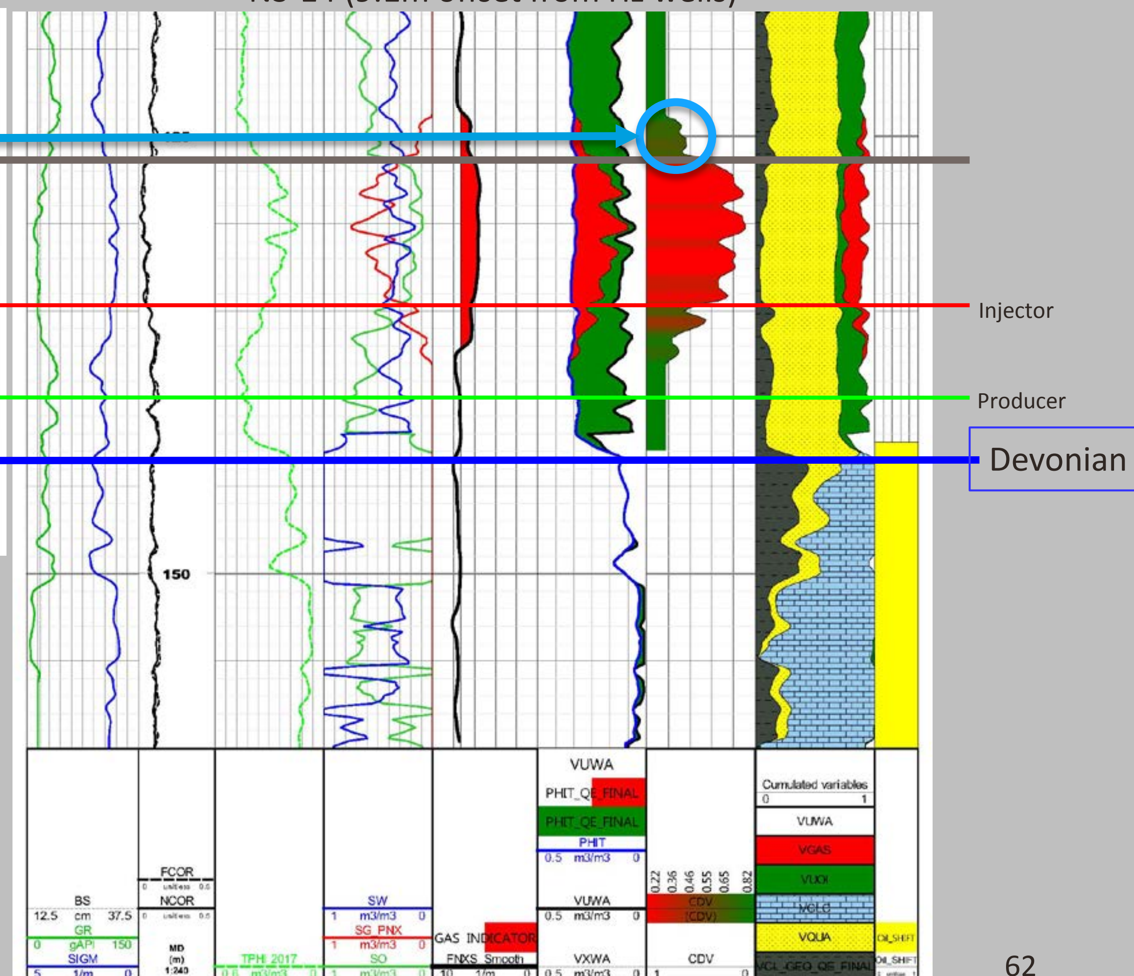
PNX Log Summary

16.9m between wells

OB-11 (4.3m offset)

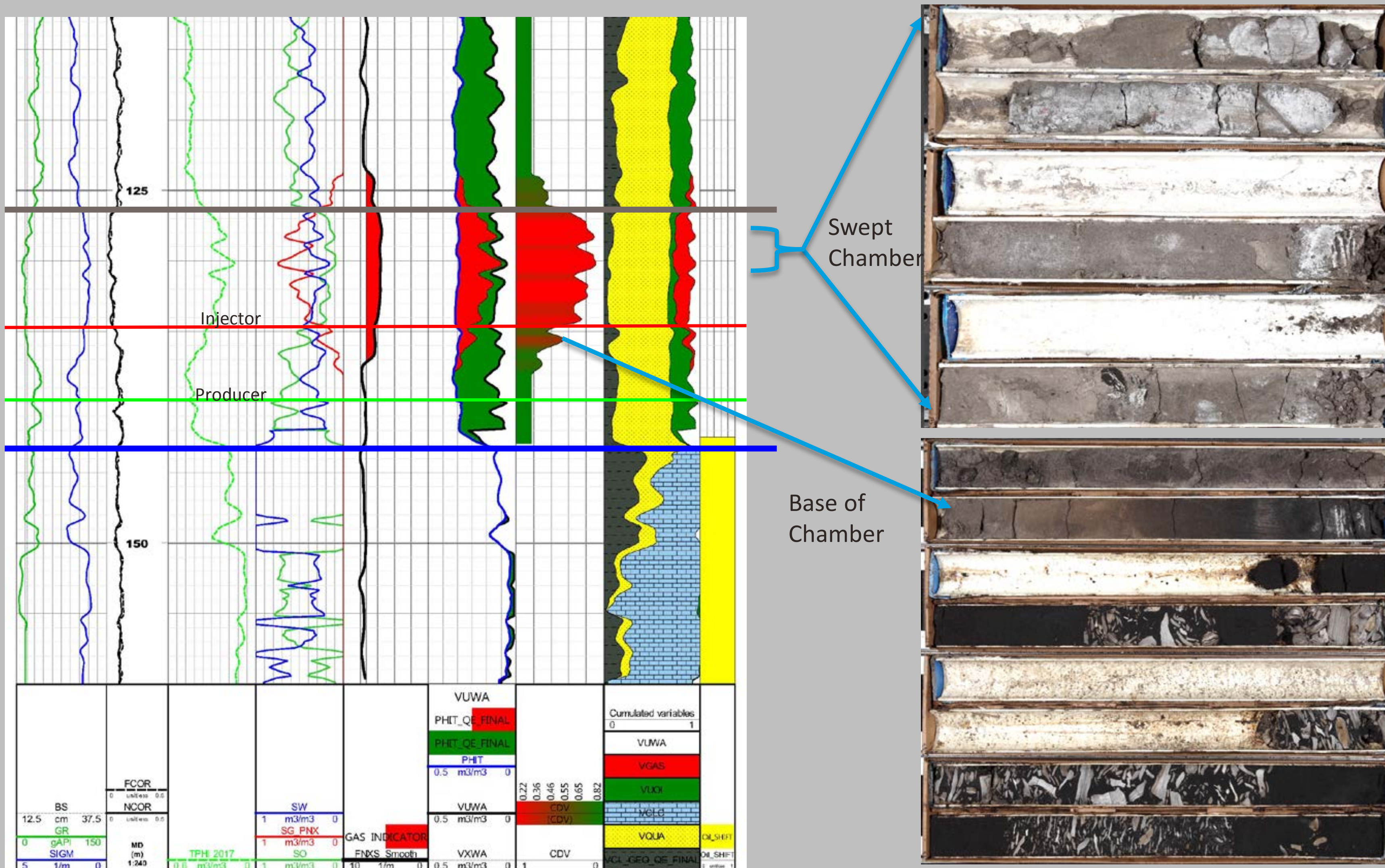
NS-14 (9.1m offset from Hz wells)





IHS penetration in NS-14 appears slightly more pronounced than in OB-11. Both NS-14 and OB-4 are located updip relative to the horizontals which could explain the more advanced IHS penetration despite the slightly dirtier top of reservoir.

PNX Log Summary



Post Solvent Core Findings

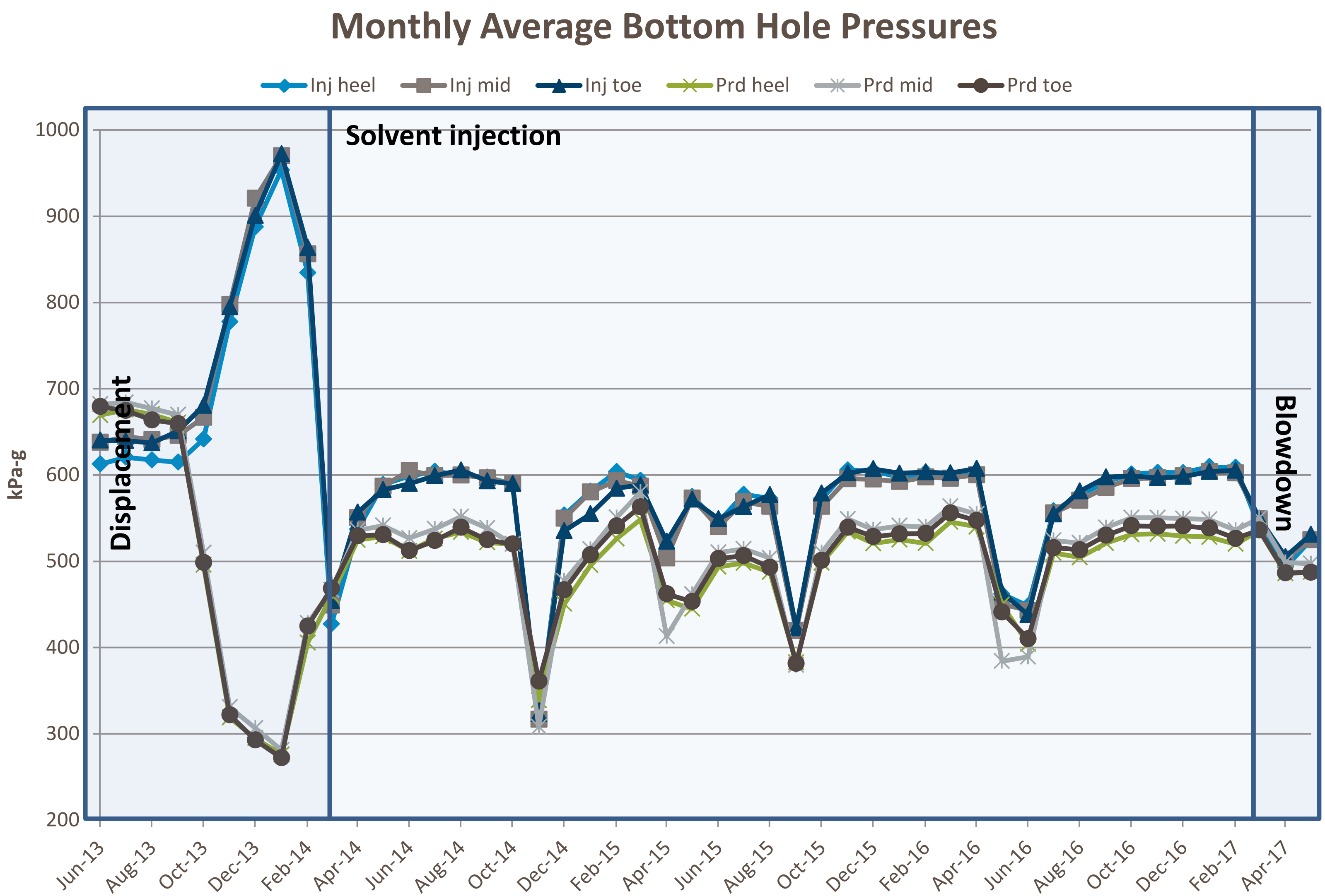
nsolv

- Dean stark results show very low residual So values of around 8% by volume
- Residual oil may have trace amounts of insoluble components that were not measured in the DS analysis
- Thin section and microscope photos indicate asphaltene precipitation appears to occur on grains and remain in place

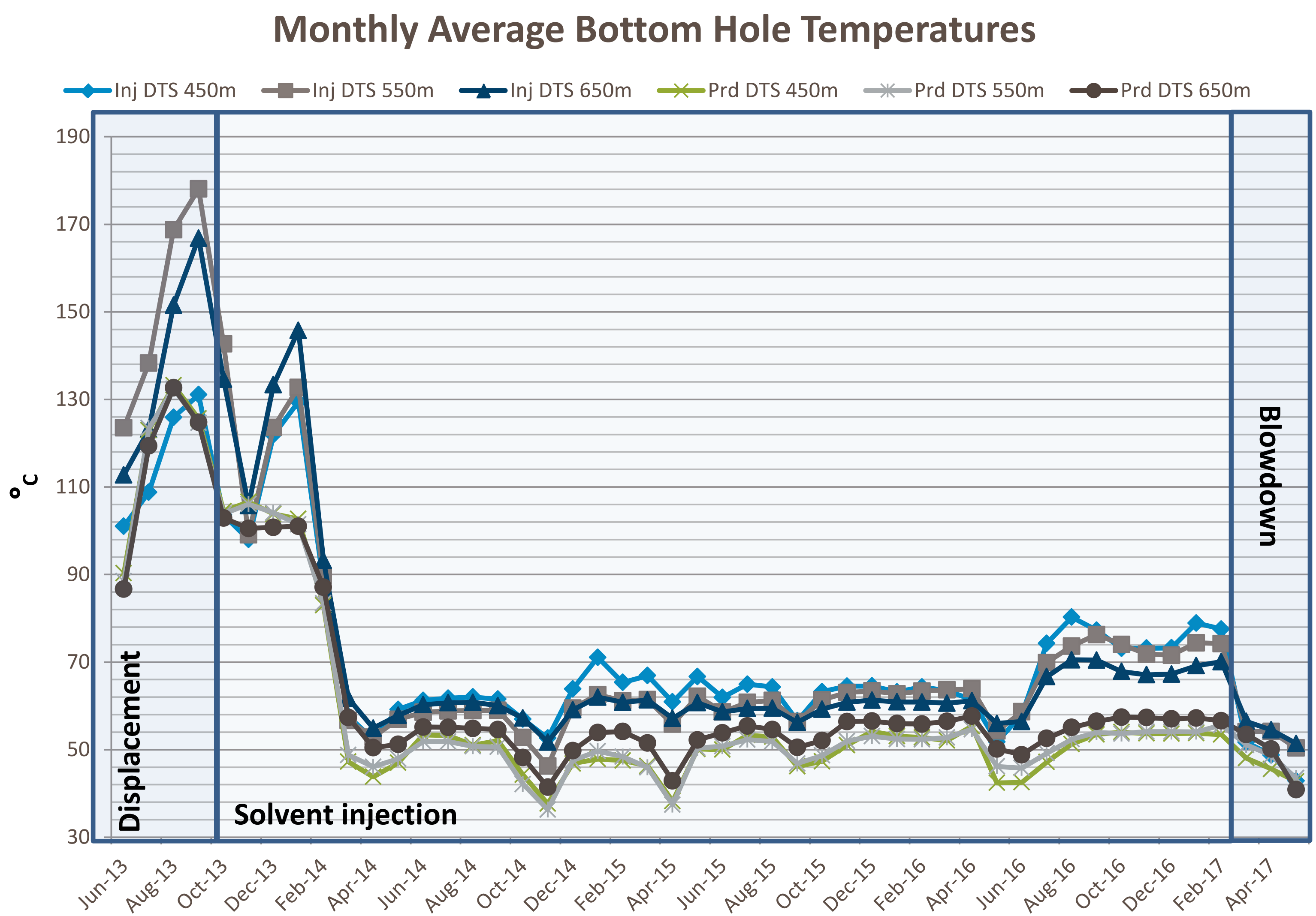
Scheme Performance – Solvent delivery

- Operating solvent chamber 570-610 kPag and 55-59 ˚C
- Solvent vapourizer temperature setpoint is adjusted to target vapour conditions downhole
  - Elevated Injector temperature to test impact on solvent demand
- Solvent purity, non-condensables (C1 and C2) injection targeted below 0.2 mol %
- Ran a 3 month NCG injection test towards the end of Solvent Injection and through Wind-down
  - Allowed NCG to content to rise to 0.15 mol%
  - No significant change in process performance observed
  - Duration too short to provide conclusive results, modeling indicates it may take up to a year for any significant accumulation and measurable impact due to the large chamber size

Scheme Performance – Bottom Hole Pressures



Scheme Performance – Bottom Hole Temperatures

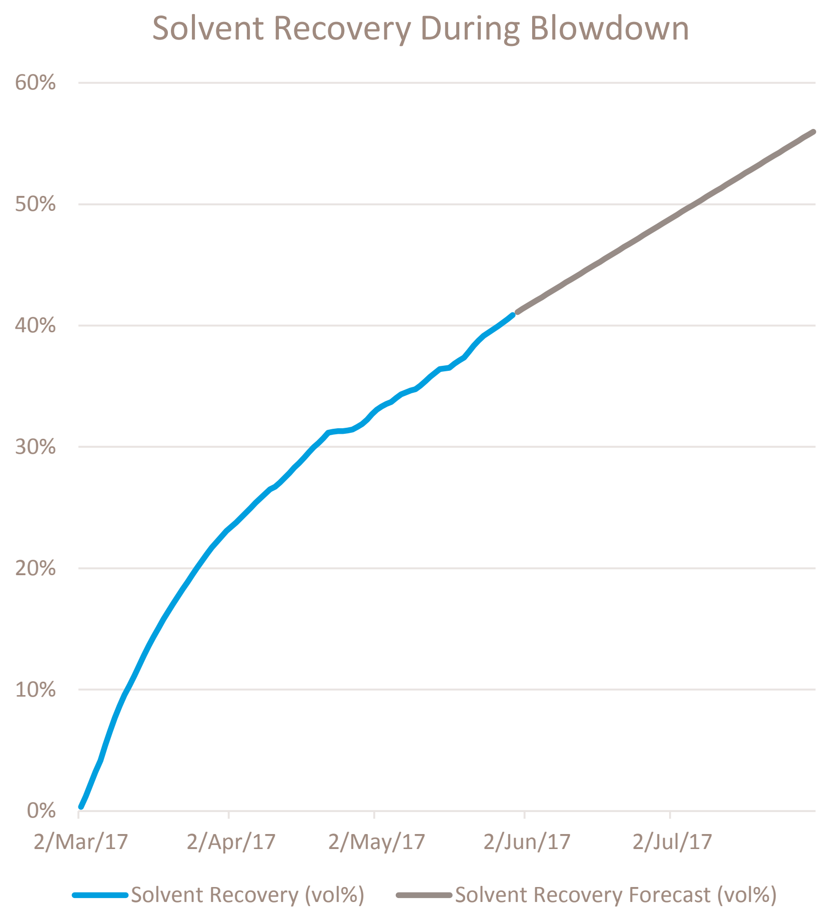


Key Learnings

- Elevated bottom hole temperature provided a meaningful reduction in instantaneous SvOR and Solvent Holdup
- Shortened wind-down phase showed that the recovery process could continue without any make-up solvent for an extended period without issue

Key Learnings

- Brief blowdown phase prior to shut-down showed significant recovery of held-up solvent over a very short period of time
- More than 40% in only 3 months, with daily recovery rates still high at shut-in
- Results support solvent recovery prediction of over 70% for mature well pairs on commercial projects



Key Learnings

- Blowdown phase also contributed to a meaningful reduction in cumulative SvOR for the wellpair by the project's end, as anticipated, as oil production continued during blowdown
- Solvent recycle % also increased during the brief blowdown phase as more held-up solvent was recovered, exceeding 96% for the project
- Pressure support during blowdown via NCG injection for the last few weeks of blowdown was helpful from a stability point of view
- Artificial lift – excellent overall performance; components in the hole for over 2 years

Future Plans

- Continue to compile and review the significant amount of technical data that was gathered over the life of the project
- Submission of an updated Conservation & Reclamation Plan to the AER
- Abandonment and reclamation of the project wells (timing TBD)
- Abandonment and reclamation of the facility site (timing TBD)

AER Directive 054 - 2015 Performance Presentation

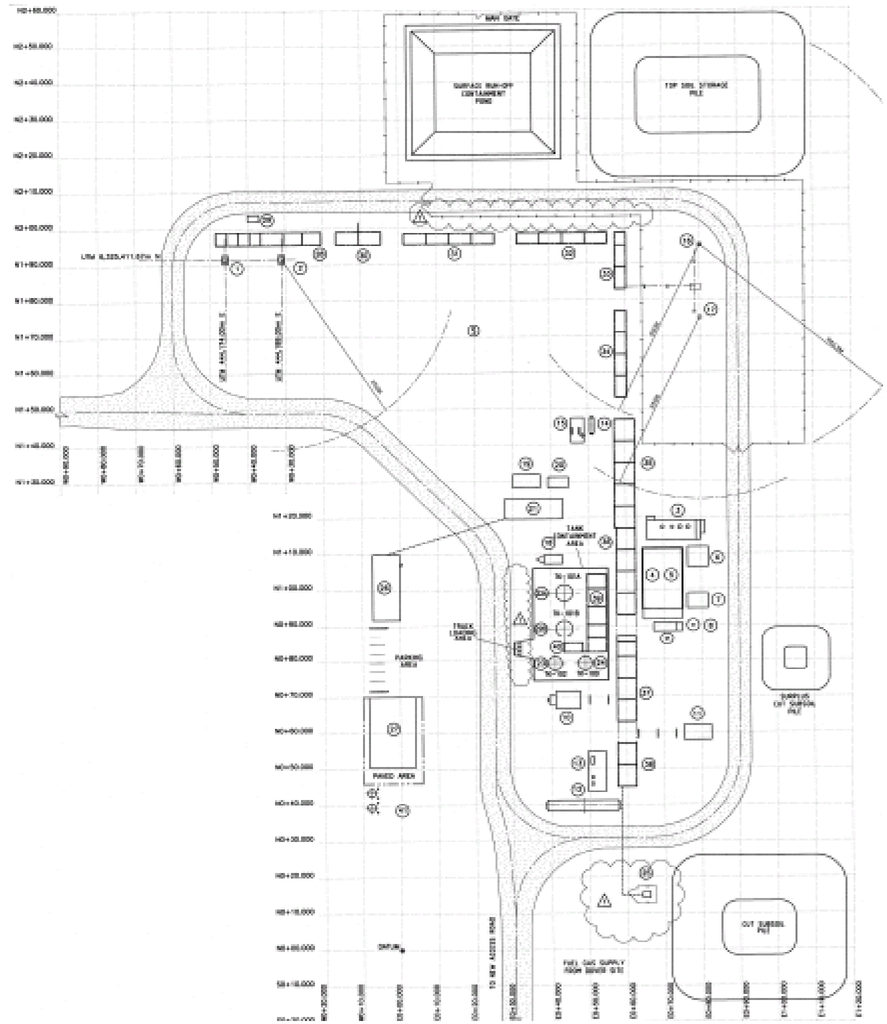
Section 3.1.2

Surface Operations, Compliance, and Issues not related to Resource Evaluation and Recovery

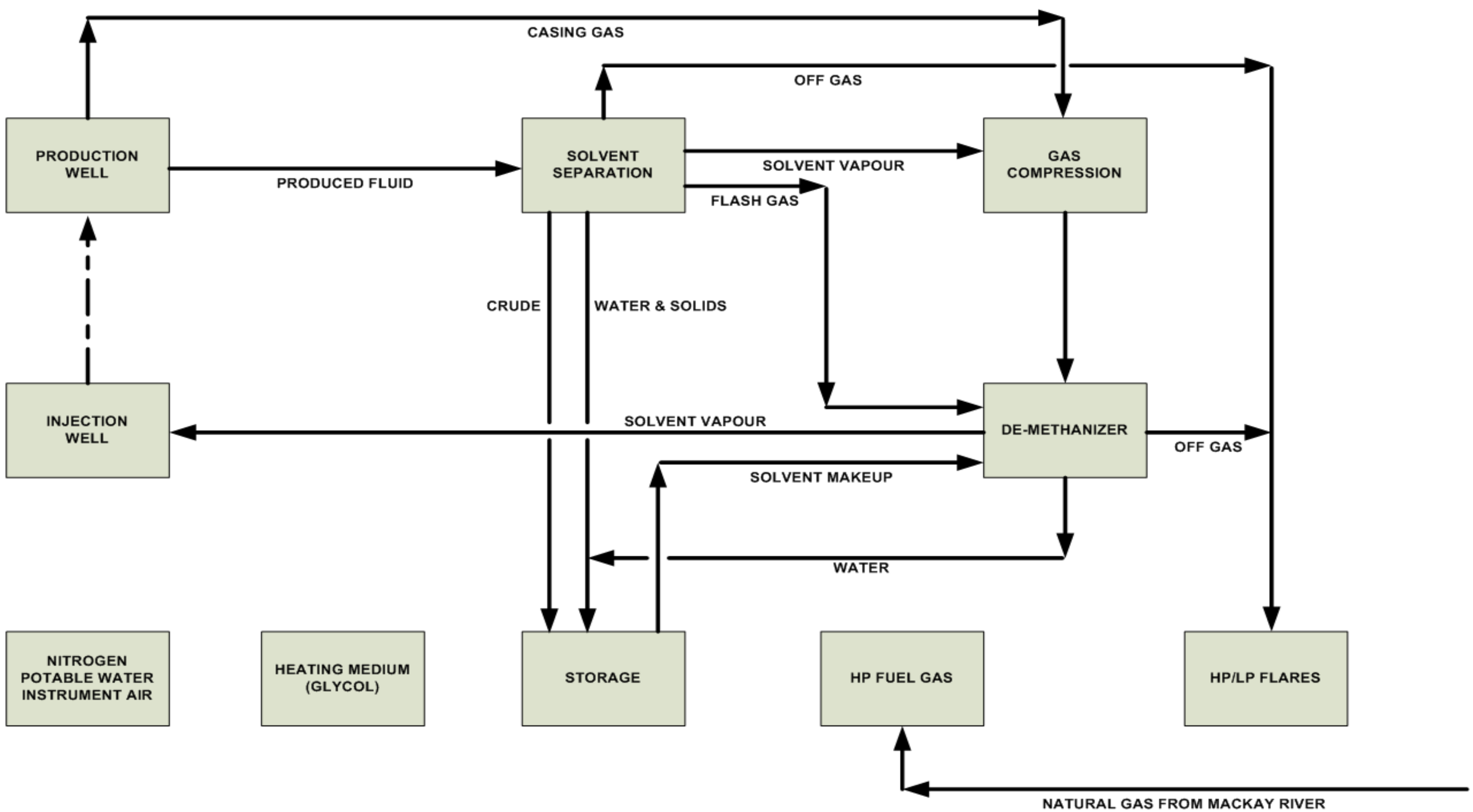
Table of Contents

- Facilities
- Central Processing Facility (CPF) Performance
- Measurement and Reporting
- Water, Production, Injection and Use
- Sulphur Production
- Environmental Performance
- Future Plans

Facilities – Plot Plant



Facilities – Production Schematic



Facilities Modification

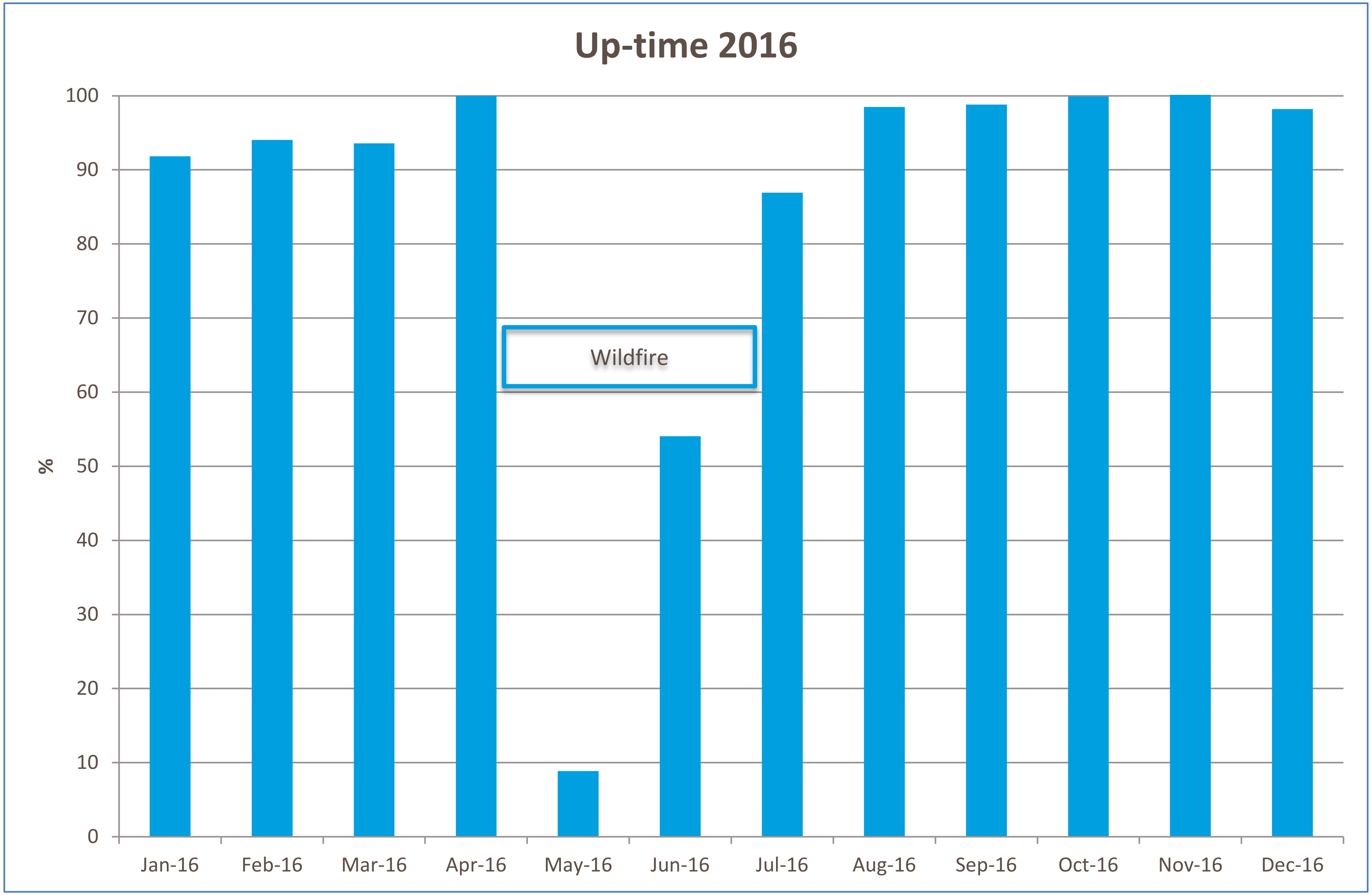
2017

- Modest alterations for Blowdown operation
- Reversed flow in the Solvent Makeup system
- Added temporary aerial cooler to prepare solvent for offloading

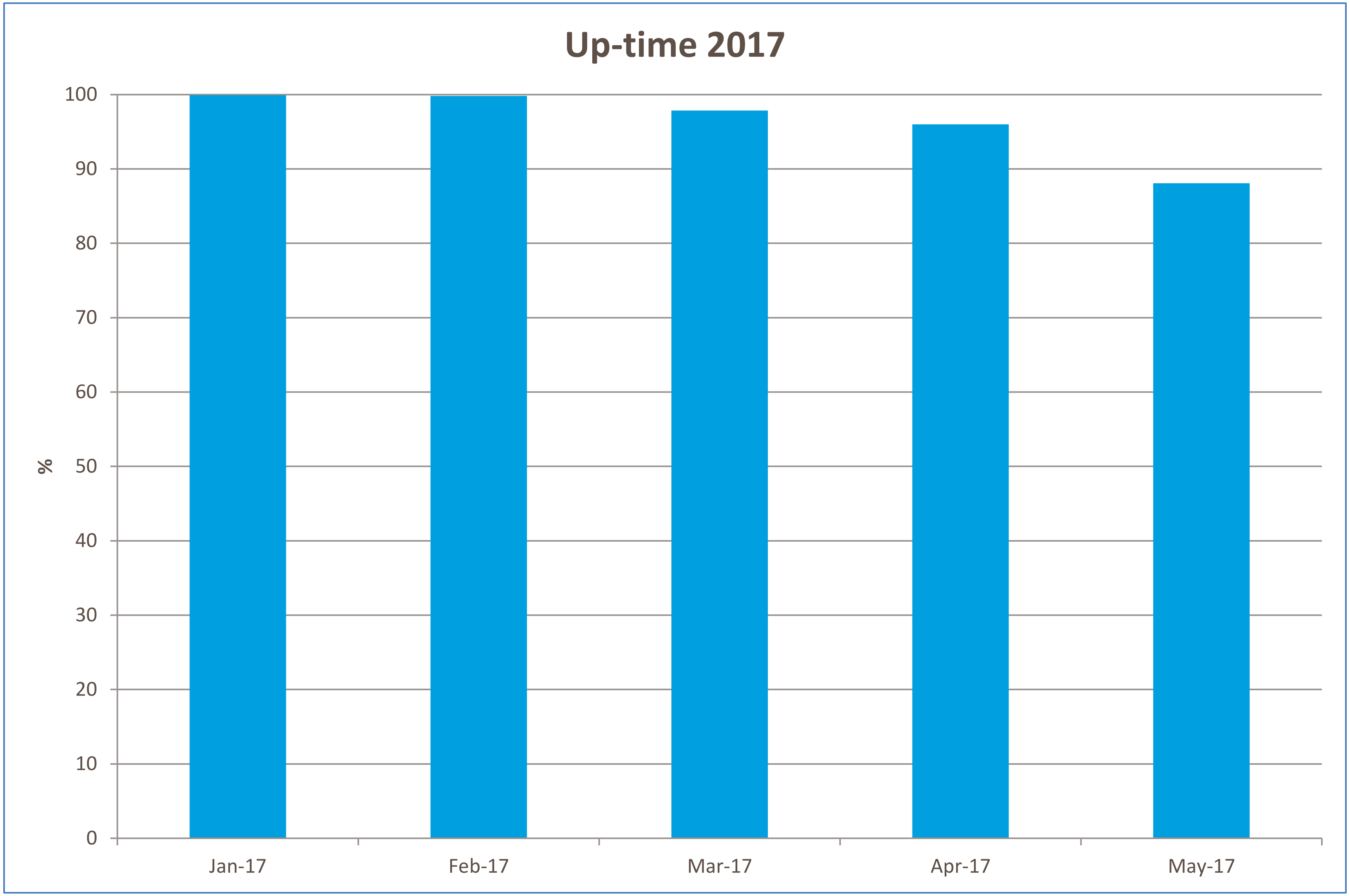
CPF Performance

- Facility is operating very well
- Able to maintain an average up-time of 97.7% since August 2016, excluding workover and the wildfire, despite limited redundancy
- Fluid separation without chemicals
  - Oil with only trace water
  - Very clean produced water
- No issues maintaining solvent purity

CPF Performance



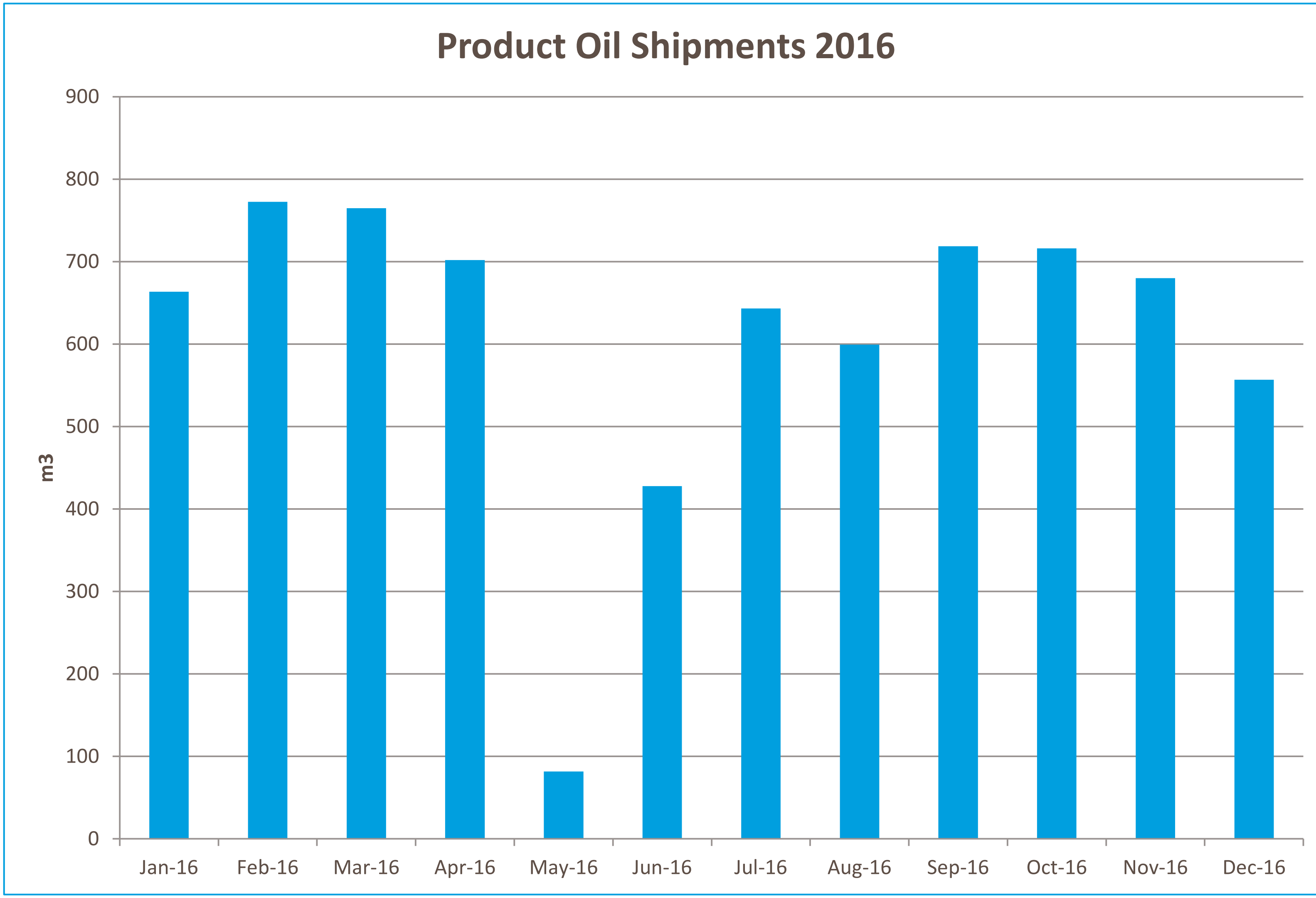
CPF Performance



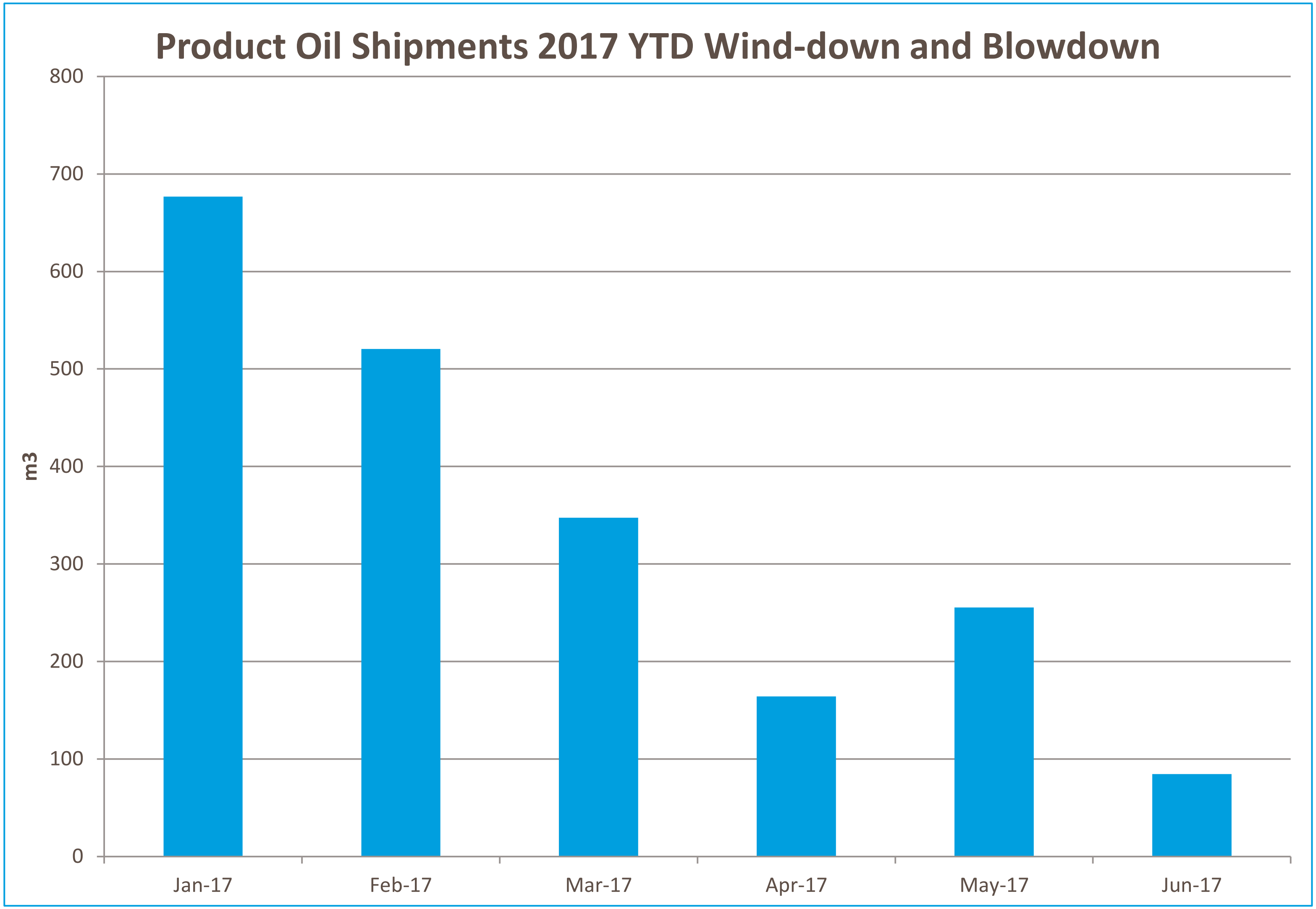
CPF Performance – Bitumen Treatment

- Able to produce dry oil without use of separation chemicals or external diluent

CPF Performance – Bitumen Treatment



CPF Performance – Bitumen Treatment



CPF Performance – Water Treatment

- No water treatment required on-site
- Residual oil is recovered in the Skim Tank

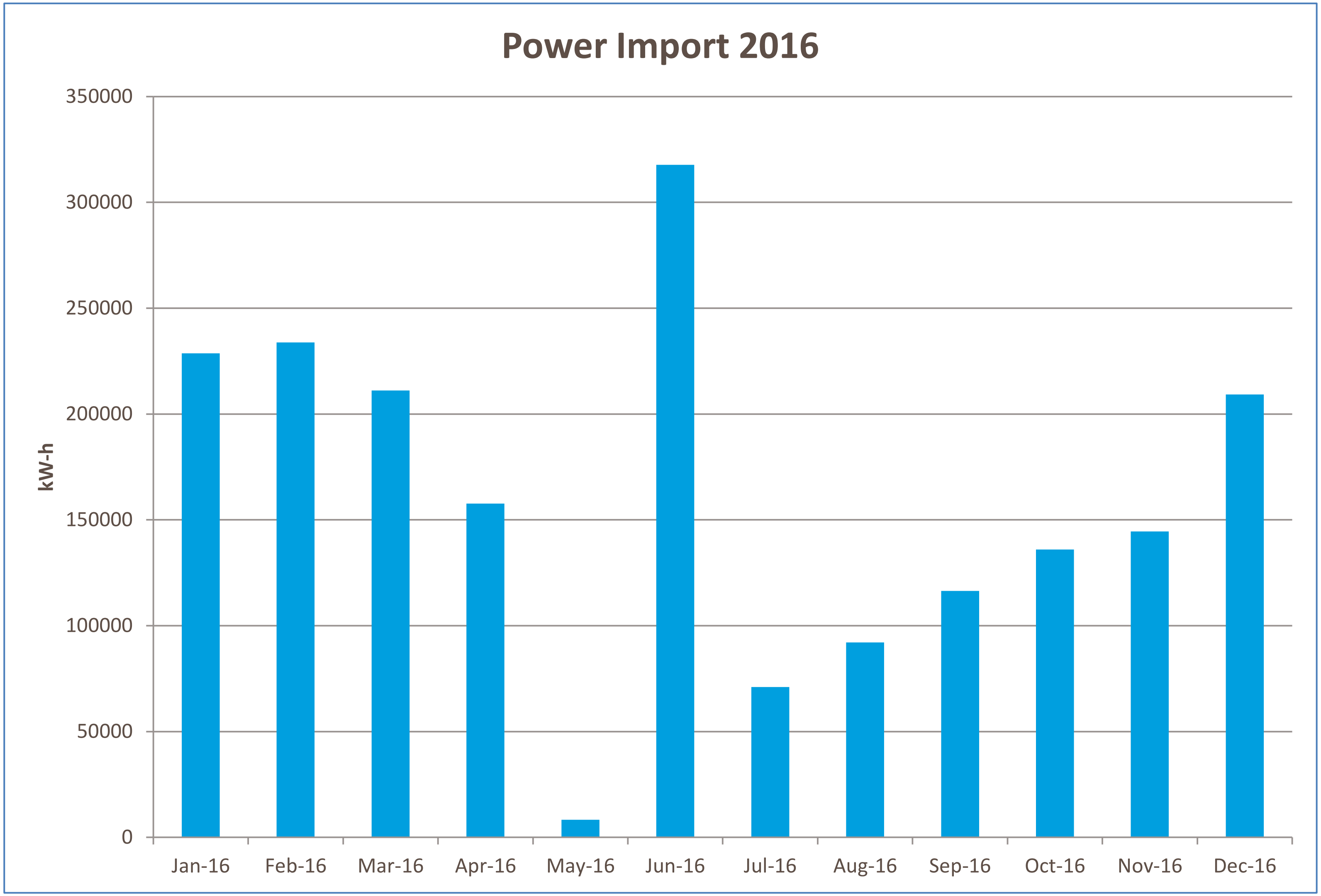
CPF Performance – Solvent Treatment

- Solvent purity is critical to the Nsolv process
  - Defined in terms of non-condensables (C1, C2) mol%
  - C3 to C5+ is considered solvent
- Solvent is purified in a distillation column
  - Target non-condensables mol%: < 0.03
  - Relaxed to 0.20 mol% in last months of operation

CPF Performance – Power

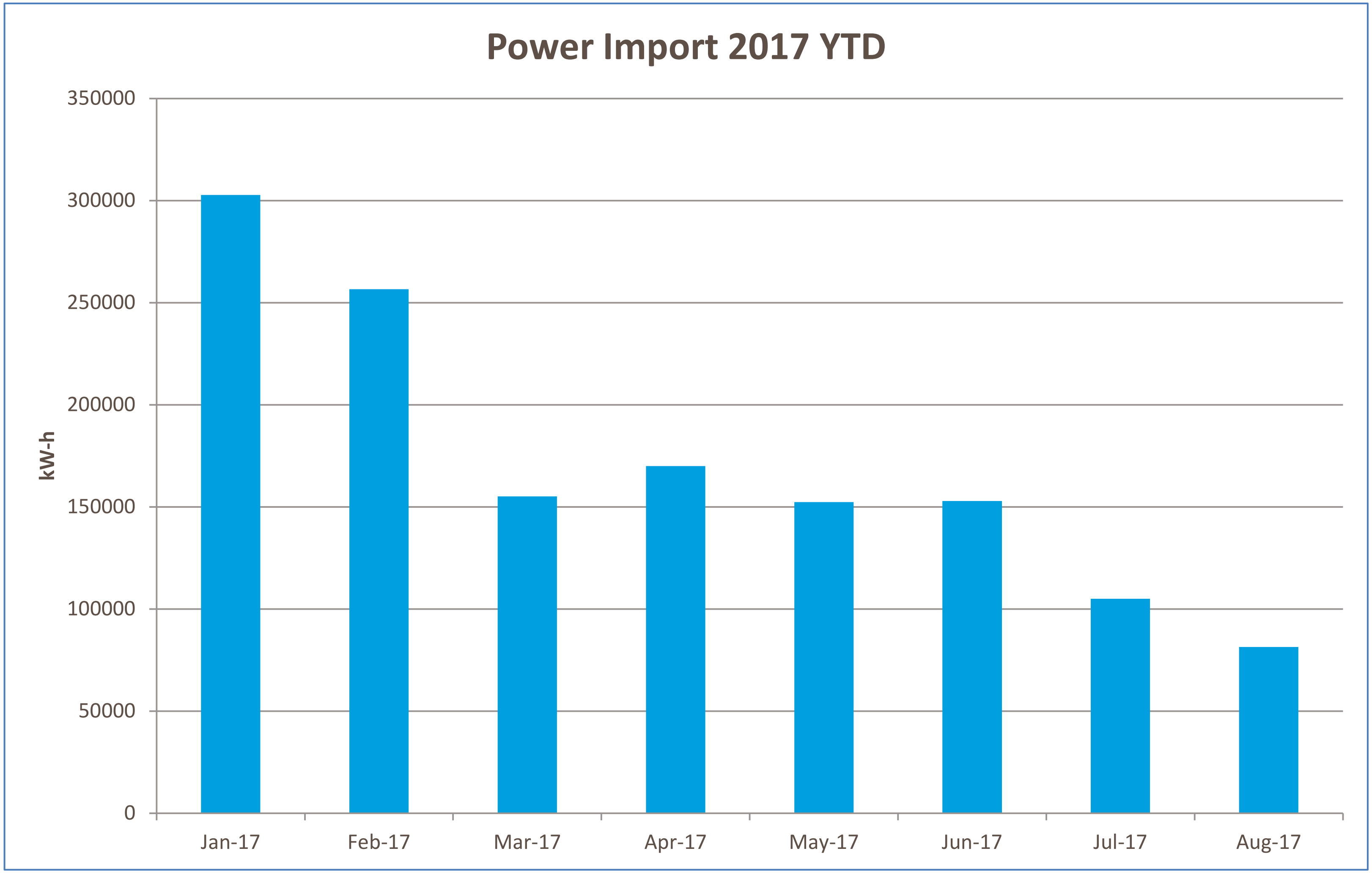
- Power imported from ATCO
- Emergency backup provided by 500 kW generator

CPF Performance – Power



CPF Performance – Power

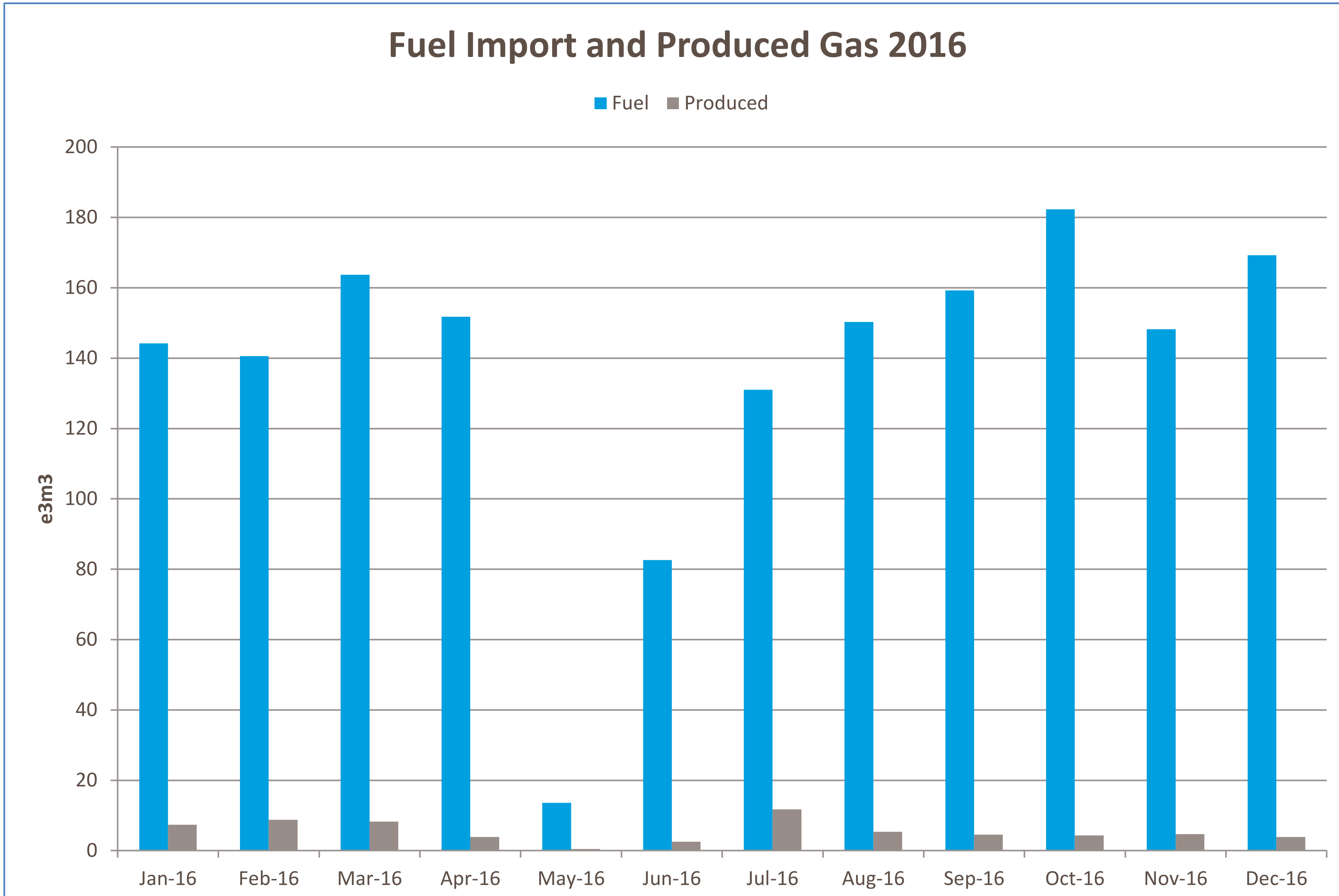
nsolv



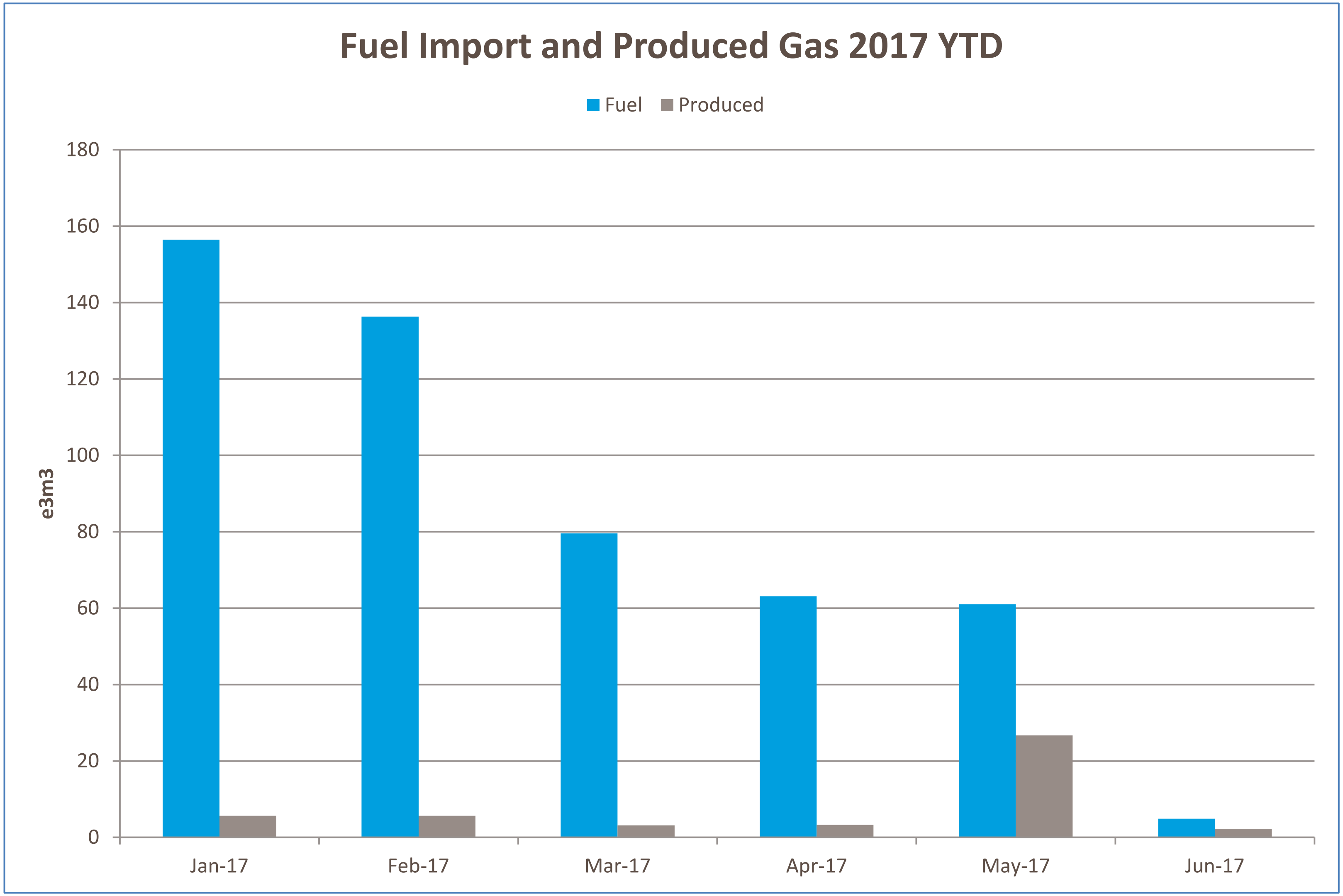
CPF Performance – Gas

- Fuel gas imported from Suncor
- Produced solution gas is flared
- Solution gas production commenced with recycle of injected solvent on 5th April 2014
- Fuel gas import is high for pilot plant due to solution gas flaring and other pilot plant flowsheet simplifications

CPF Performance – Gas



CPF Performance – Gas

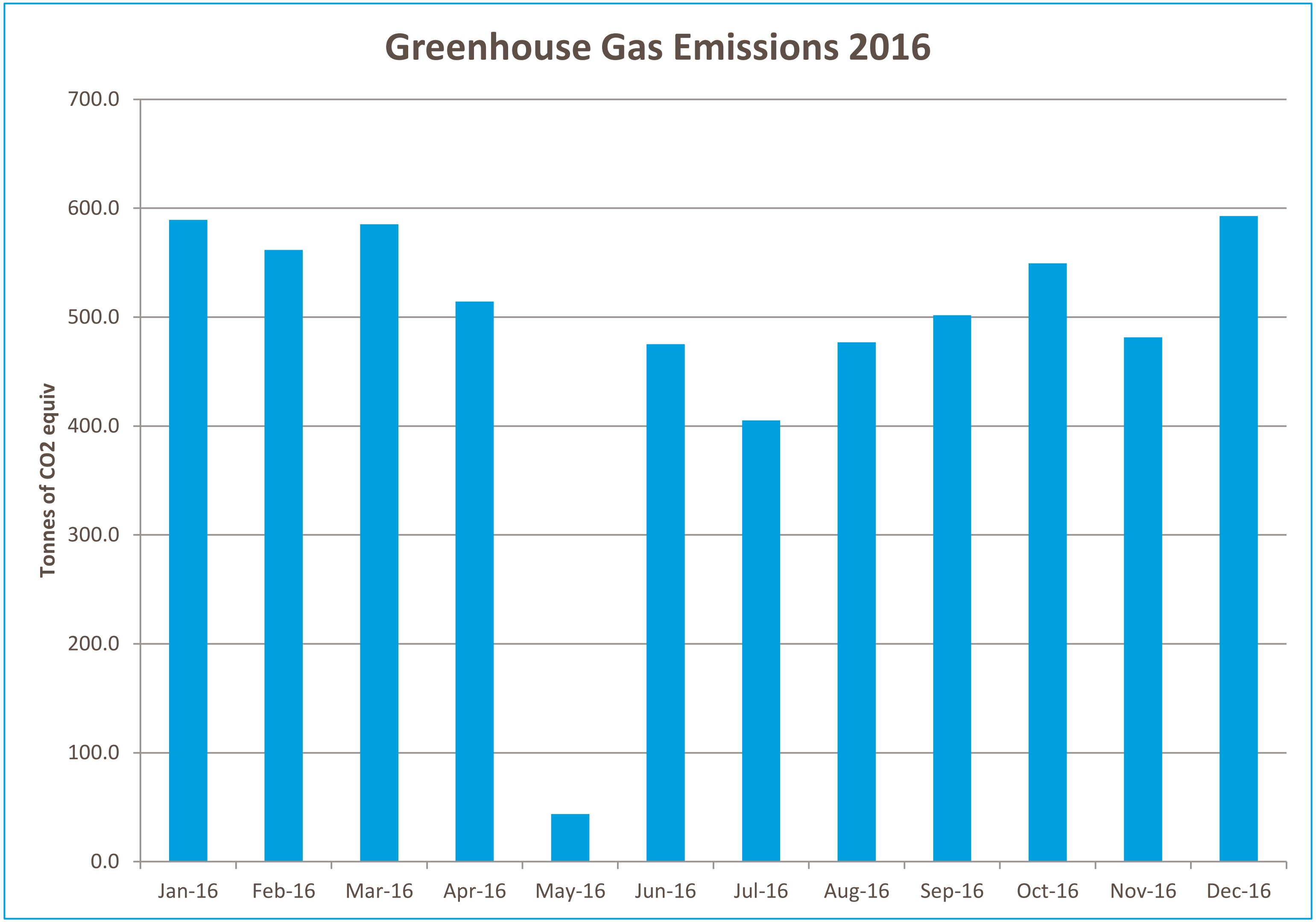


CPF Performance – Green House Gas Emissions

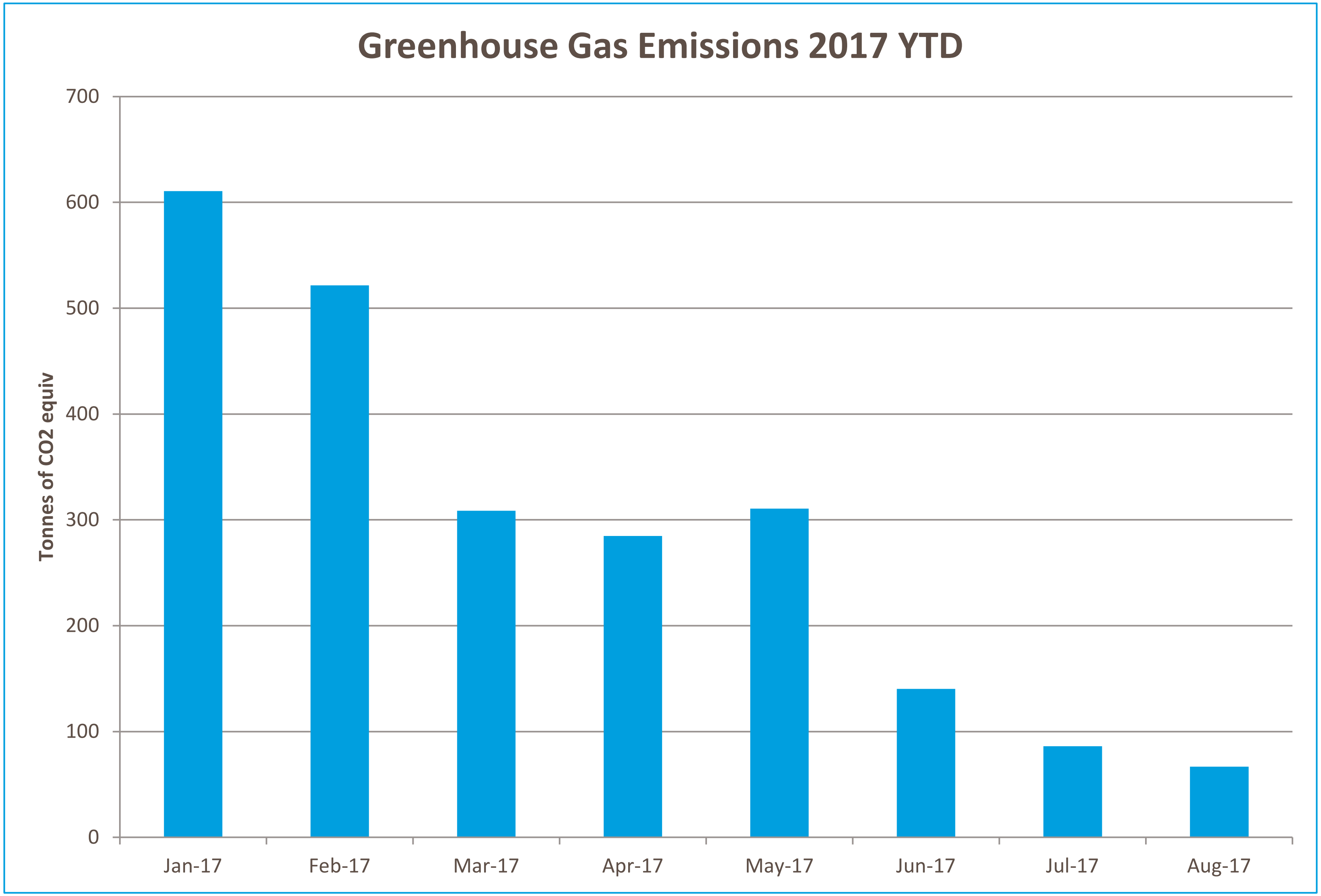
- CO_2 emissions YTD: 2,330 Tonnes CO_2 equiv.
- Total CO_2 emissions: 20,479 Tonnes CO_2 equiv.
- GHG factors:
  - Power: 820 kg/MWh
  - Fuel gas combustion: 1.91 kg/m^3
  - Fuel gas production and transport: 0.29 kg/m^3
  - Solvent production and trucking: 121 kg/m^3
  - Solvent flaring: 1.91 kg/m^3

CPF Performance – Green House Gas Emissions

nsolv



CPF Performance – Green House Gas Emissions



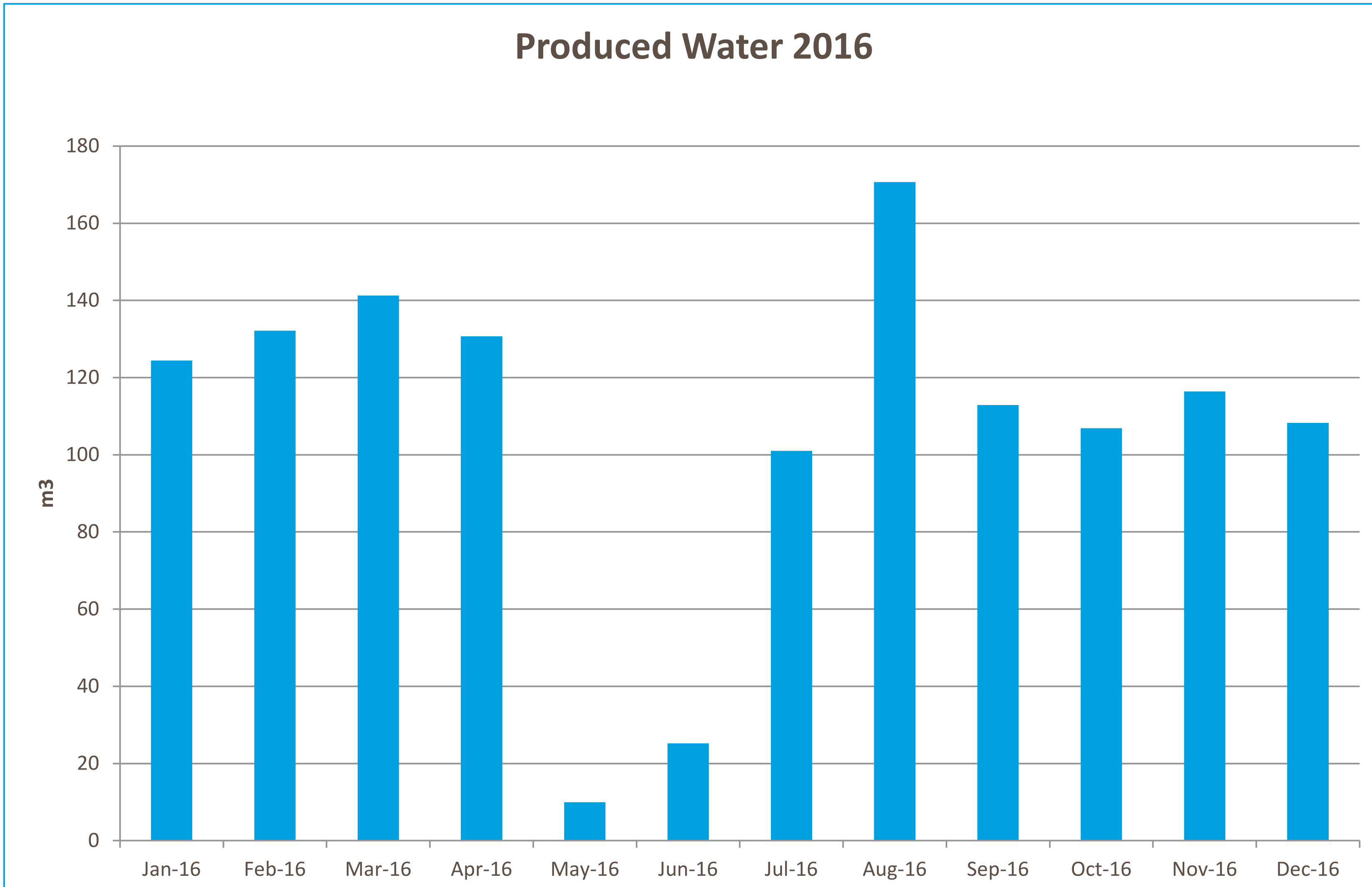
Measurement & Reporting

- Single well pair facility:
  - All production attributed to the production well
  - No individual well testing required
- Facility Codes associated with Suncor BEST Approval 11825:
  - AB BT0126919
  - AB IF0126920

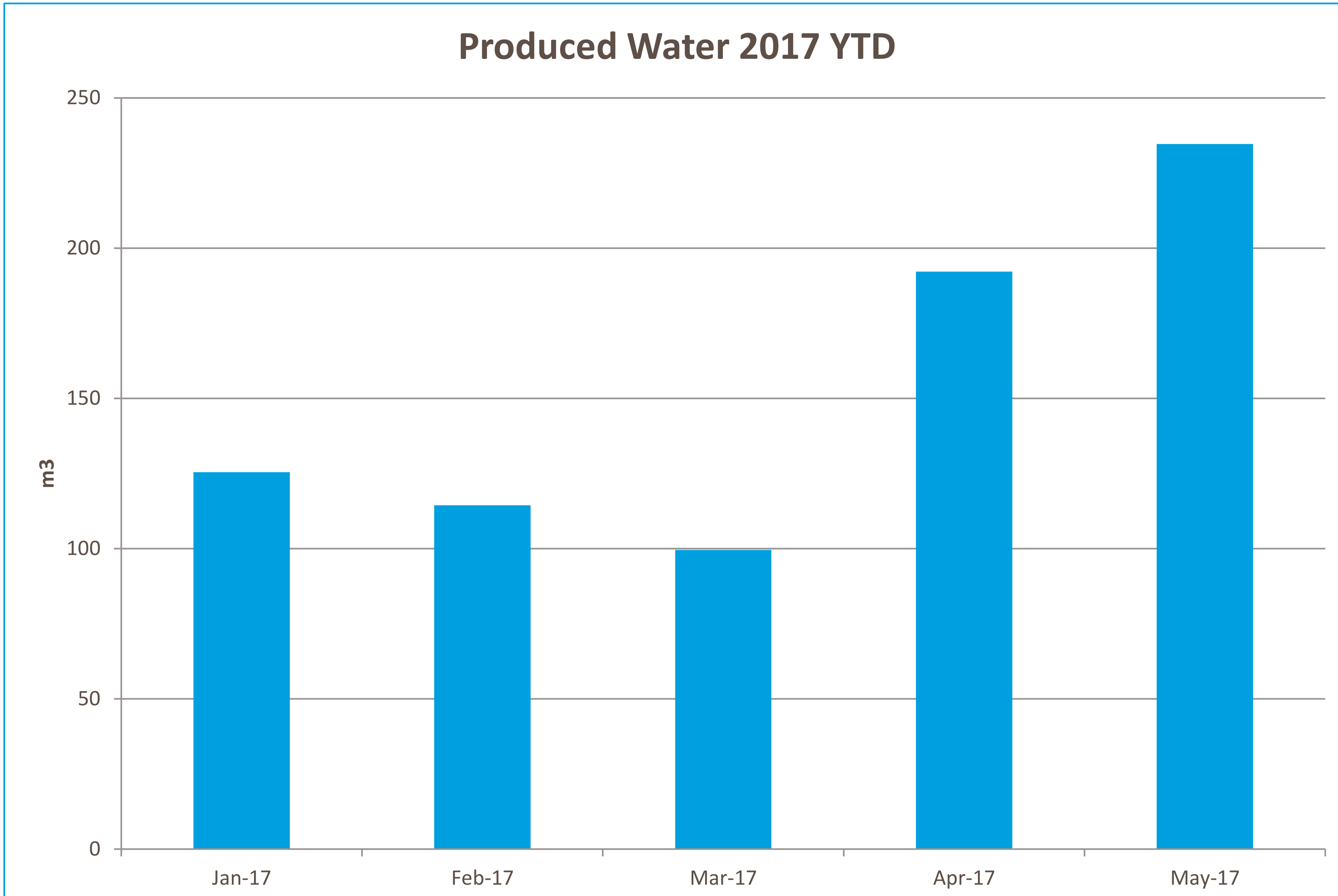
Water Production

- 21% water cut on average
- Water is hauled off-site to disposal at Newalta facility:
  - ABWP0000688
- Produced water is sampled and analyzed by third party lab:
  - Avg. TDS: 15,742 mg/L
  - Avg. pH: 8.07
  - Avg. Na: 5,748 mg/L
  - Avg. Cl: 8,831 mg/L
  - HCO_3: 1,388 mg/L

Water Production



Water Production



Sulphur Production

- Produced gas is sampled and analyzed by third party lab
- H2S is below measurable limits

BEST Regulatory Summary

- AER Experimental Scheme Approval No. 11825 issued May 8, 2012
- EPEA Amending Approval No. 705-02-01 issued May 17, 2012
- Measurement, Accounting & Reporting Plan approved September 29, 2012
- Facility License F-45241 issued October 12, 2012
- Well License 0445932 (NS-S1) issued May 16, 2012
- Well License 0445946 (NS-P1) issued May 17, 2012
- RMWB Development Permit 2012-DP-00991 issued August 3, 2012
- AER Directive 051 approval for both wells issued February 7, 2013
- Production of Surface Casing Vent Flow Approval issued July 29, 2014

Suncor Energy Inc. is in compliance with all regulatory approvals, decisions, regulations and conditions as described in Experimental Scheme Approval 11825

SUNCOR

BEST Environmental Summary

- Disturbance: no new disturbance in current reporting period
- Stormwater: surface run-off from the project is contained on the site through the use of a stormwater pond. Water is sampled & released if it meets EPEA requirements.
- Domestic Wastewater: wastewater is contained & trucked to an approved treatment facility
- Spill Containment: consists of storage & secondary containment that complies with Directive 055 requirements. Other measures include: collection of surface run-off; spill prevention & loss control systems; groundwater monitoring; proper maintenance, operating procedures & inspections; spill contingency & response plans.
- Air Emissions: monitoring & sampling as per the EPEA approval requirements
- Groundwater: monitoring & sampling as per the EPEA approval requirements
- No reportable releases or enforcement actions are associated with the project to date.

Information Request:

Can Suncor provide a summary of the groundwater monitoring at the site(BEST), i.e. location of groundwater observation wells and an overview of the sampling results?

- Based on the 2016 monitoring and sampling results, the following is concluded:
  - Two monitoring and sampling events were conducted in June 2016 and September 2016. The first planned event in April was forgone due to the Fort McMurray wildfires.
  - The monitoring well network (BT-MW-506, BT-MW-507, BT-MW-510, and BT-MW-511) was in good condition in 2016 and did not require any repairs.
  - The groundwater elevations at BT-MW-506 (shallow well) in 2016 show meteoric influence and were consistent with historical observations.
  - The groundwater elevations in the deep groundwater monitoring wells (i.e., BT-MW-507, BT-MW-510, and BT-MW-511) were consistent with historical observations. The groundwater flow direction was southeast in both in June 2016 and September 2016, consistent with historical results.
  - Field electrical conductivity and temperature were consistent with historical results. Field pH values were compared to laboratory pH and are consistent with historical results.
  - Analytical results of routine parameters were below their respective guidelines in 2016 except for total dissolved solids, chloride, sodium, sulphate, and nitrite (as N). Any exceedances were consistent with historical observations.

Information Request continued

- Analytical results of dissolved metals were below the guidelines except for manganese, boron, and mercury:
  - Boron naturally occurs at concentrations above the guideline and is found naturally occurring within the Clearwater Formation.
  - Analytical results of manganese were above the guideline in BT-MW-506, BT-MW-510, and BT-MW-511. The manganese shows a decreasing trend and is either naturally occurring or within laboratory margin of error.
  - The mercury exceedance at one well at such a low concentration could be within laboratory's margin of error and should be further confirmed in 2017.

Information Request continued

- The oxidation of groundwater dissolves nitrate (NO3-) from organic material. Additionally, oxidation will lead to the precipitation of manganeseoxide (MnO) from the groundwater which will result in a reduction in dissolved manganese. It is concluded that the decreasing manganese and increasing nitrate trends observed in 2016 result from naturally occurring processes and not related to the facility operations.

- There were no detectable concentrations of hydrocarbons or naphthenic acids in 2016.

- Phenols were not detected at concentrations above the method detection limits at BT-MW-507 (0.0019 mg/L) and BT-MW-511 (0.0018 mg/L) in June 2016.

- Based on the 2016 and historical analytical results, it is concluded that facility processes have not affected the groundwater quality.

Information Request continued: BEST Monitoring well locations

Information Request continued: Groundwater elevation contour map (Sept, 2016)