Long Lake Kinosis Oil Sands Project Annual Performance Presentation

April 2017

This presentation contains information to comply with Alberta Energy Regulator’s Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

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Forward Looking Statements

This document was prepared and submitted pursuant to Alberta regulatory requirements. It contains statements relating to reserves which are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves exist in the quantities predicted or estimated, and can be profitably produced in the future. There is no certainty that the reserves exist in the quantities predicted or estimated or that it will be commercially viable to produce any portion of the reserves described in this document.

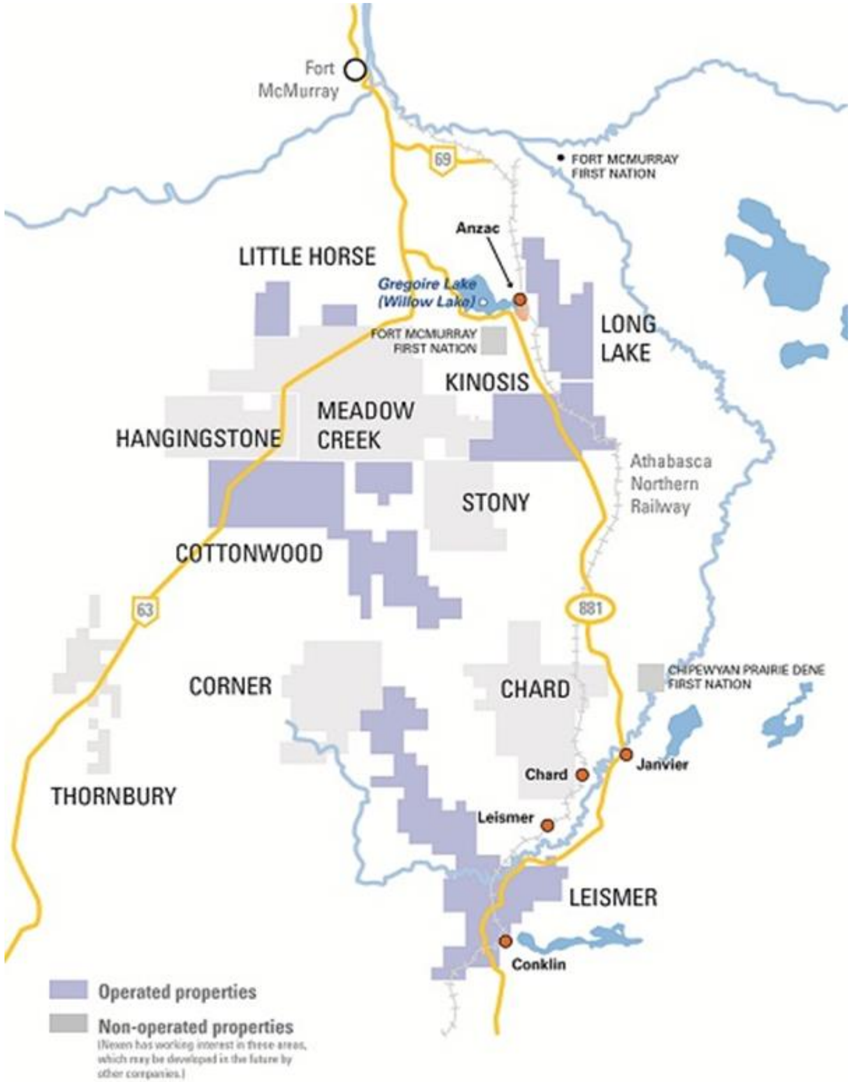
Corporate Ownership

- Nexen Energy ULC (Nexen) is an upstream oil and gas company responsibly developing energy resources in the UK North Sea, offshore West Africa, the United States and Western Canada.

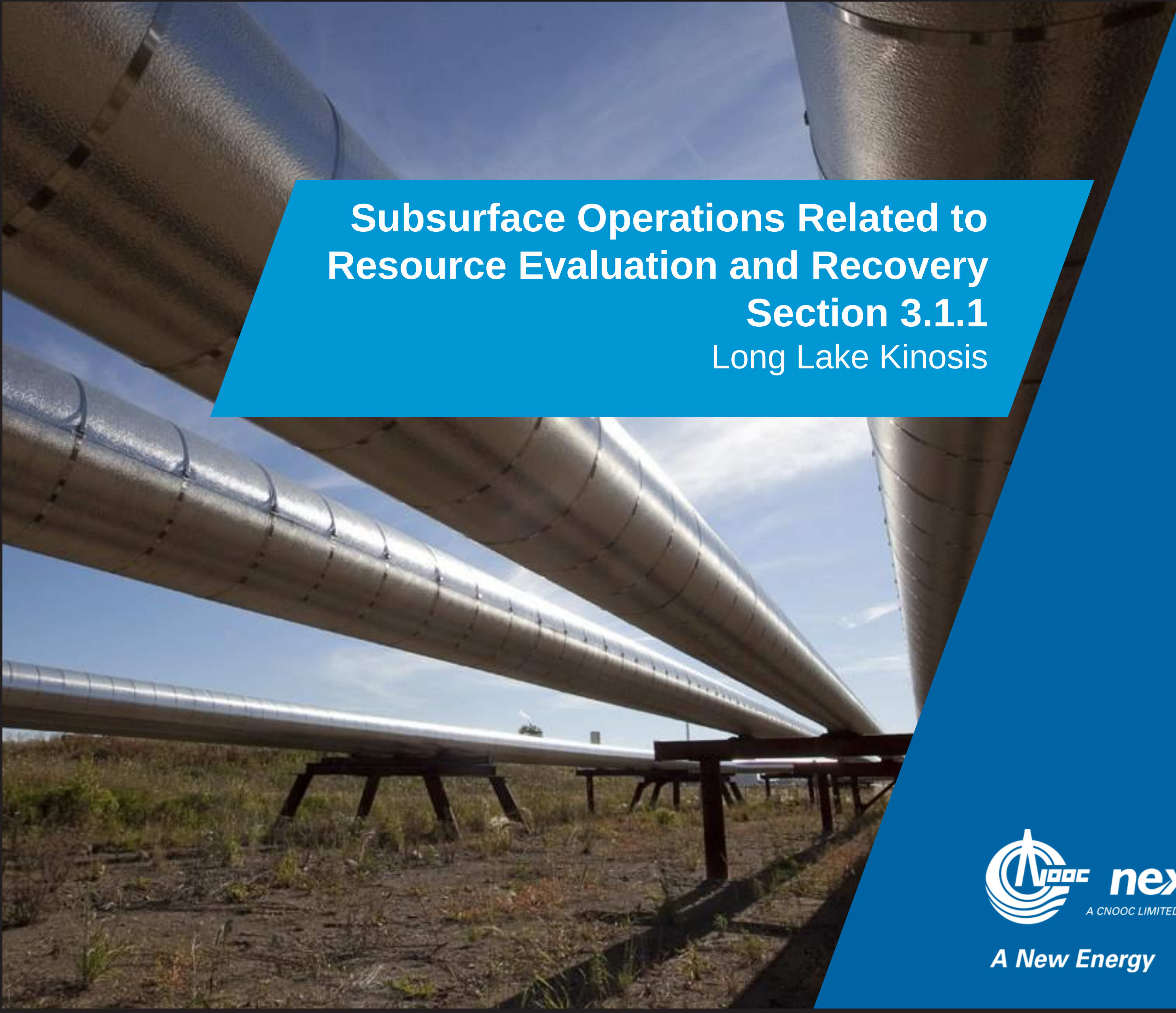
- Nexen is a wholly-owned subsidiary of the China National Offshore Oil Company (CNOOC) Limited.

- Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.

Nexen Oil Sands



Contents



Subsurface Operations Related to Resource Evaluation and Recovery Section 3.1.1

Long Lake Kinosis

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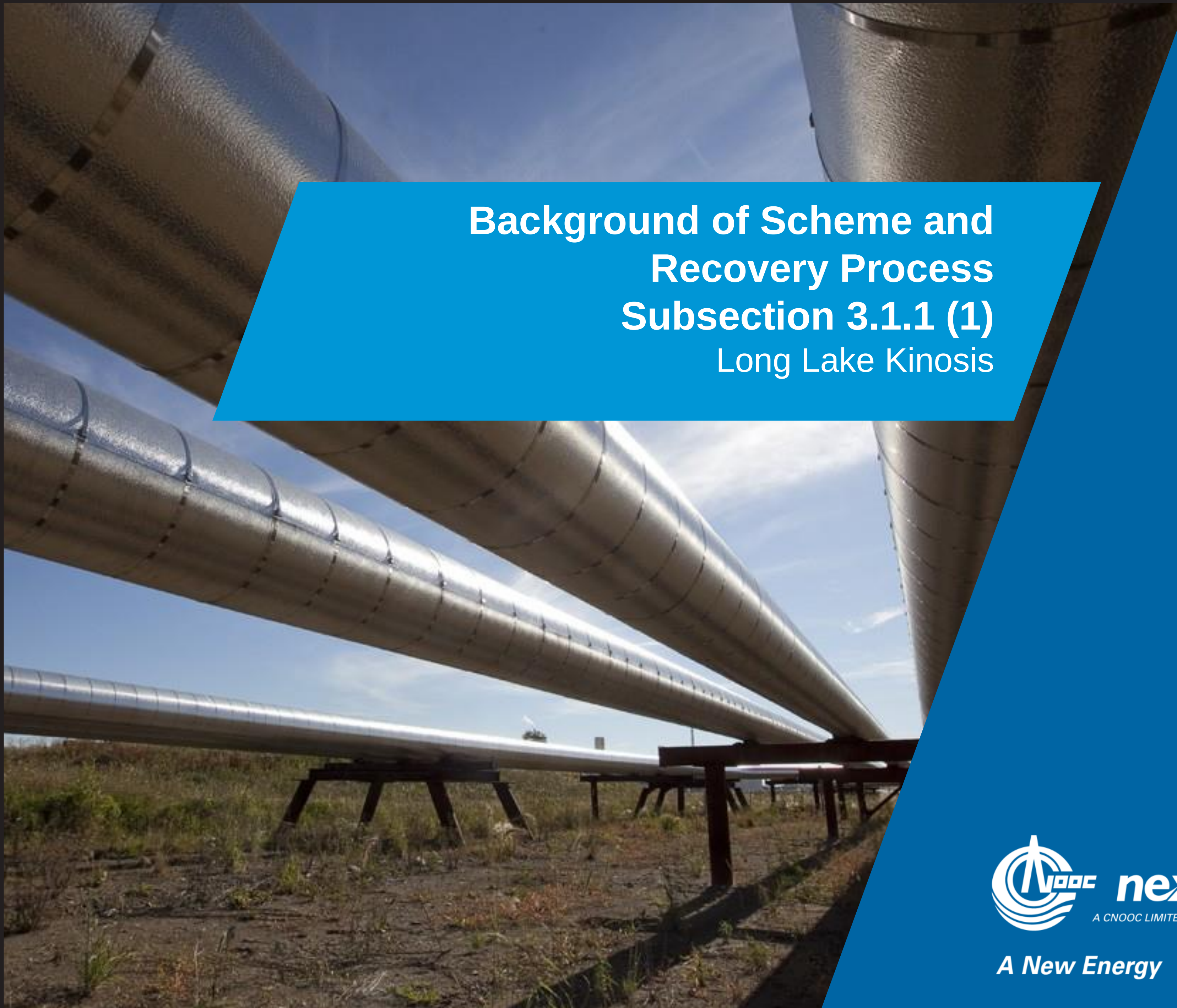

Background of Scheme and Recovery Process Subsection 3.1.1 (1)

Long Lake Kinosis

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Long Lake Scheme Description

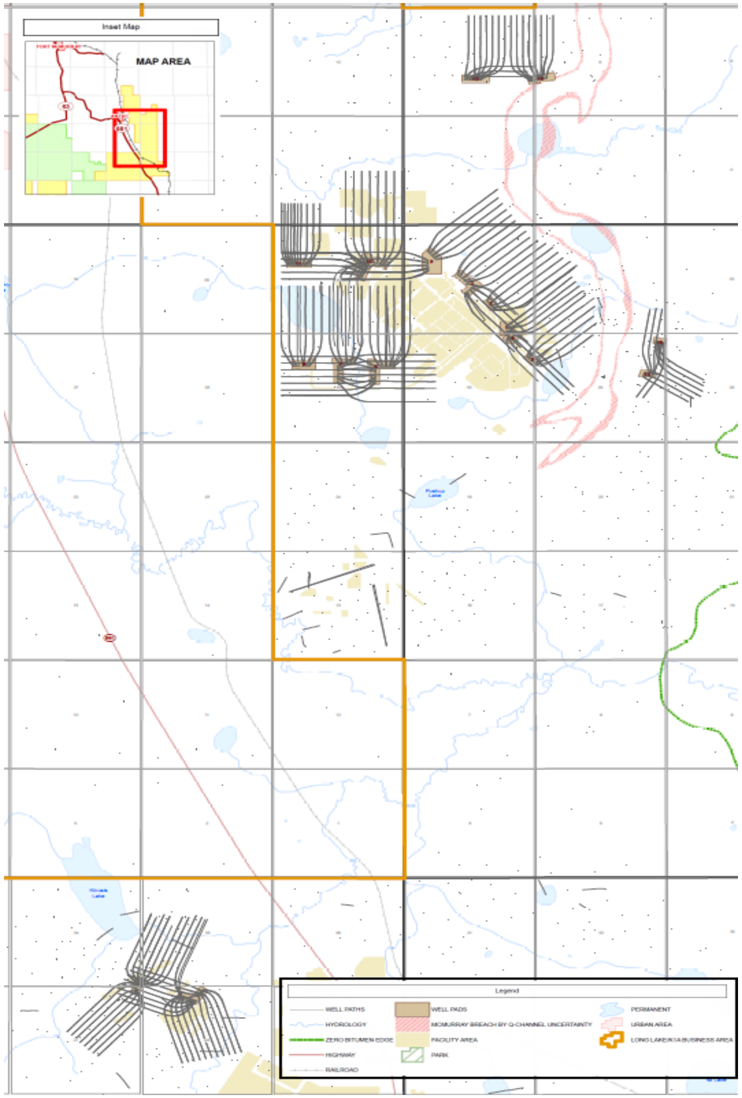
- Located approximately 40 km southeast of Fort McMurray.

- An integrated SAGD and Upgrader oil sands project producing from the Wabiskaw-McMurray deposit.

	Design (LLK) m³/d	bbl/d
Bitumen	11,130	70,000
Steam	37,000	233,000
SOR	3.3	

	Design (K1A*) m³/d	bbl/d
Bitumen	3,180	20,000
Steam	9,540	60,000
SOR	3.0	

*K1A – First 20K of 70K which is Phase 1A of Kinosis

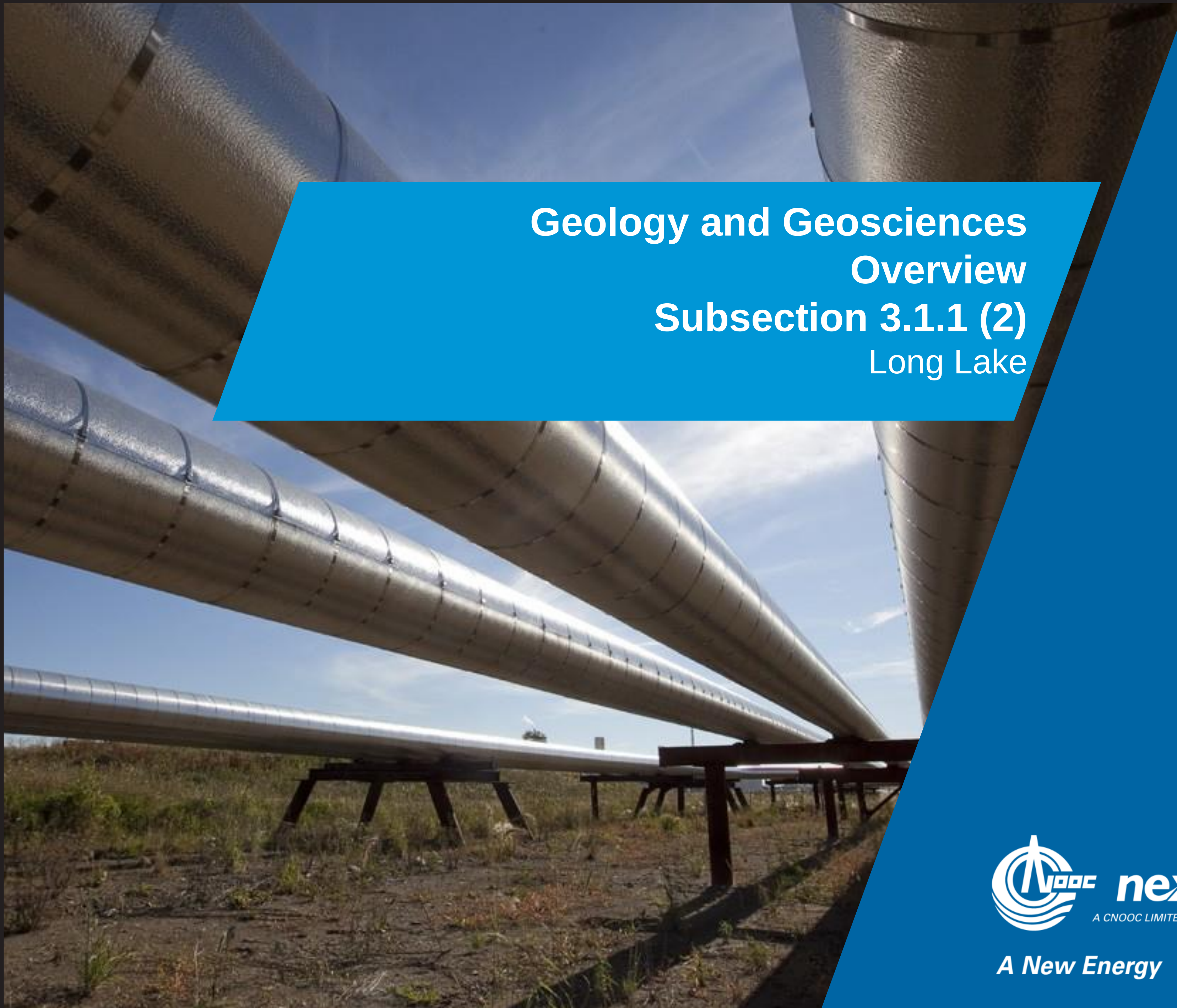


CHRONOLOGY OF OIL SANDS OPERATIONS

Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility (LLK)
2003	Regulatory approvals for the commercial LLK Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial LLK Facility
2006	Regulatory amendments, including Pad 11
2007	Start of commercial bitumen production for the Long Lake Facility
2007	Regulatory submissions for Long Lake South (development of Kinosis lease)
2009	Regulatory approvals issued for K1A (First 20k bbls of Phase 1 of 2 of Kinosis (formerly Long Lake South))
2009	Start of operation of the LLK Upgrader
2010	Regulatory approvals for Pads 12 and 13
2012	First production from Pads 12 and 13
2012	Major turnaround for maintenance at Central Processing Facility (CPF) and Upgrader
2012	Regulatory approvals and construction begins for Pads 14, 15 and K1A Pads 1 and 2
2013	Increased production from LLK well pads, begin circulation at Pad 14
2014	K1A Pads 1, 2 and Pads 14, 15 start production
2015	Diluent Recovery Project Start up; Pipeline leak ceases production at K1A
2016	Hydro-Cracker Unit (HCU) Incident; Wildfire shut down Long Lake operations for ~2 months

2016 Summary

- LLK operated at minimum rates following HCU incident.
- LLK experienced approximately two month shutdown due to Wildfires in Wood Buffalo region.
- LLK pads exhibited strong ramp up performance after dewatering and re-pressurization phase.
- Lifting of LLK Pipeline Suspension Order (Nov. 10, 2016).
- Approval for Pad 14/15 4D Seismic deferral and amendment to MOP granted.



Geology and Geosciences Overview
Subsection 3.1.1 (2)

Long Lake

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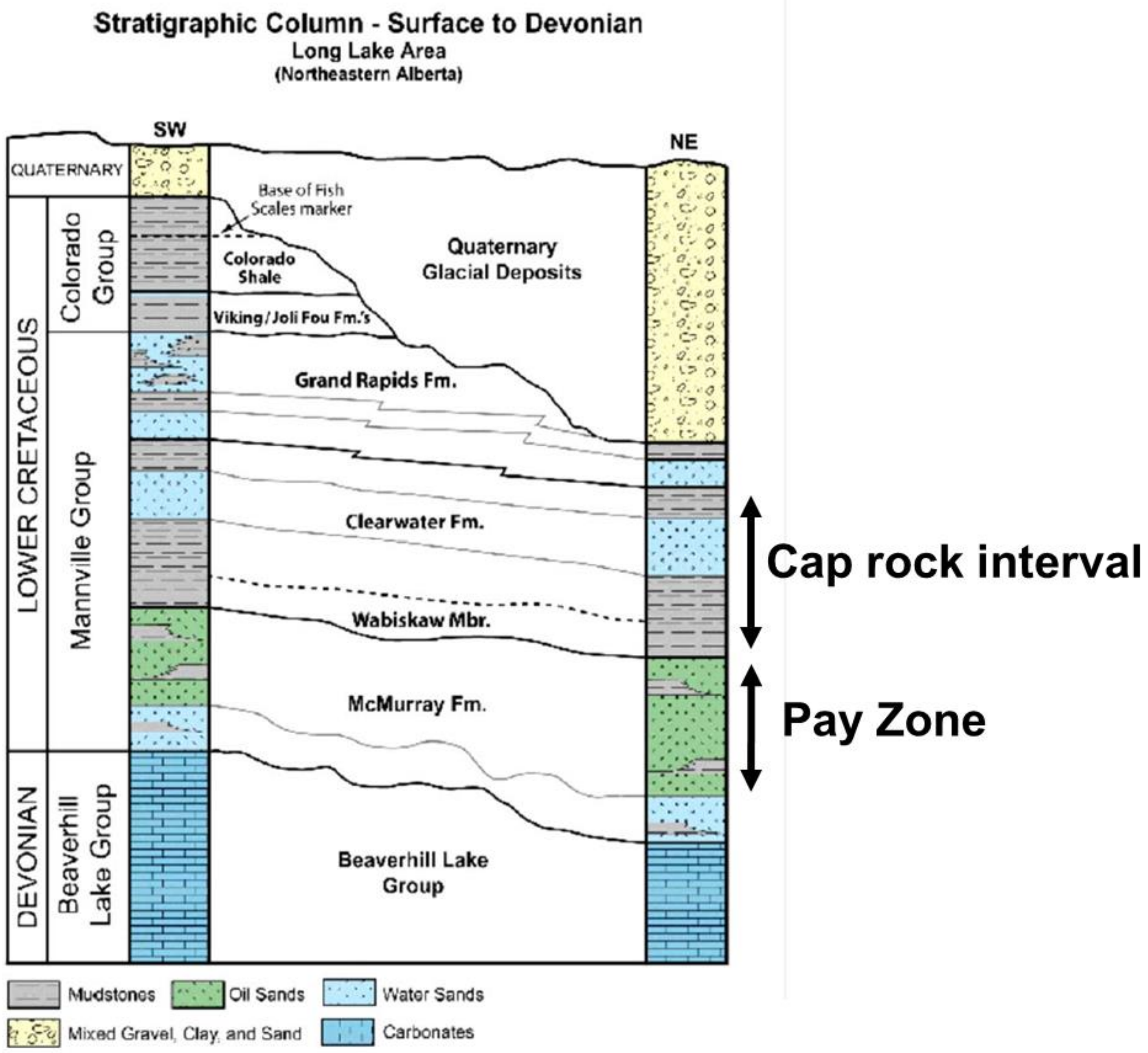
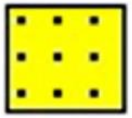
Stratigraphy

Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.



Nexen Facies Codes



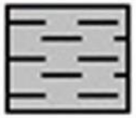
Sandstone .... Facies 1:
- clean crossbedded sandstone
- VSH 0 - 10%
- estuarine sands

Sandy IHS .... Facies 2:
- inclined interbedded sandstone, and mudstone
- VSH 10 - 30%
- point bar facies

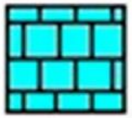
Breccia .... Facies 3:
- mud clast breccia
- sand supported and mud clast supported
- channel base facies

Muddy IHS .... Facies 4:
- inclined interbedded sandstone, and mudstone
- VSH 30 - 80%
- point bar facies

Mudplug .... Facies 5:
- muds and silts
- abandoned channel muds
- point bar facies



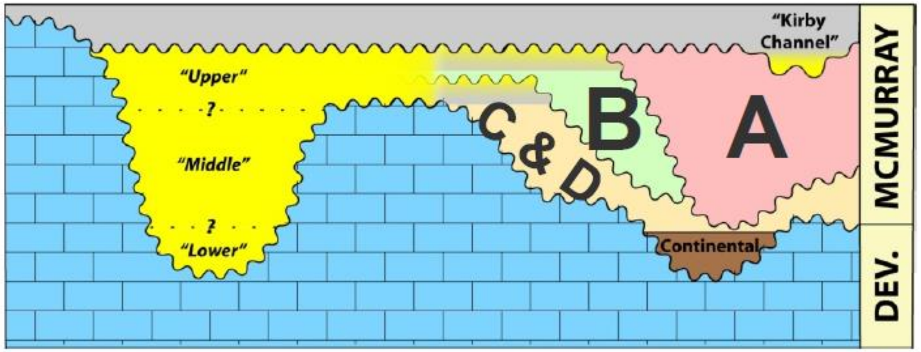
Mudstone .... Facies 6:
- flood plain deposits



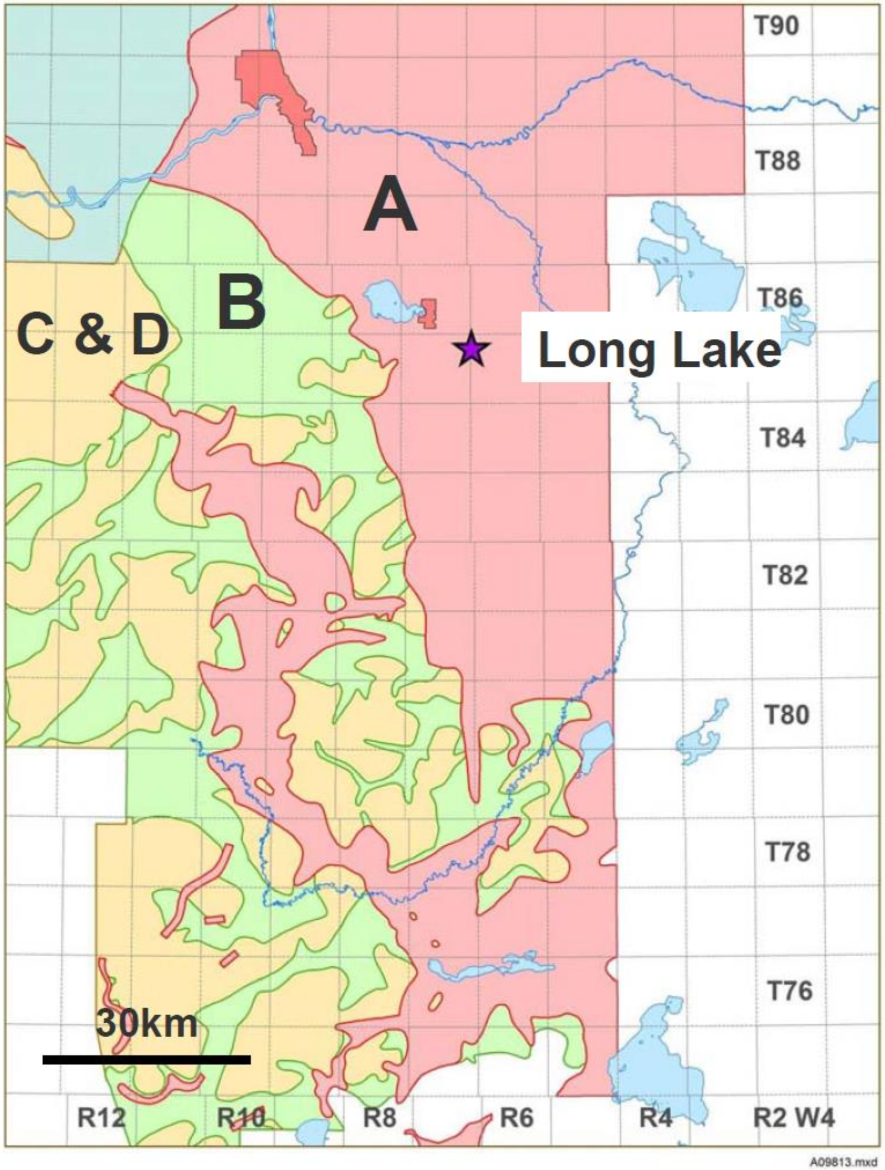
Limestone .... Facies 7:
- Devonian carbonates

Nexen's Regional Model

- Multiple valleys:
  - C & D valleys (oldest)
  - A valley (youngest)
- In terms of sequence stratigraphy, it was a low-accommodation setting
- Compound incised-valley system hung from several surfaces in the McMurray



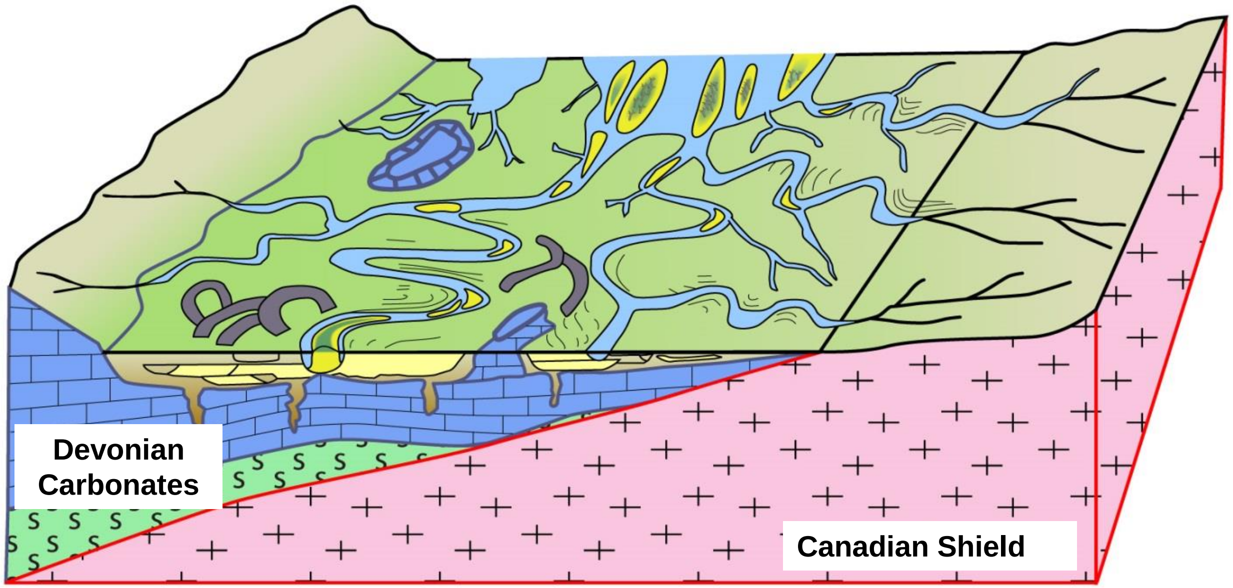
Jervey, 2003



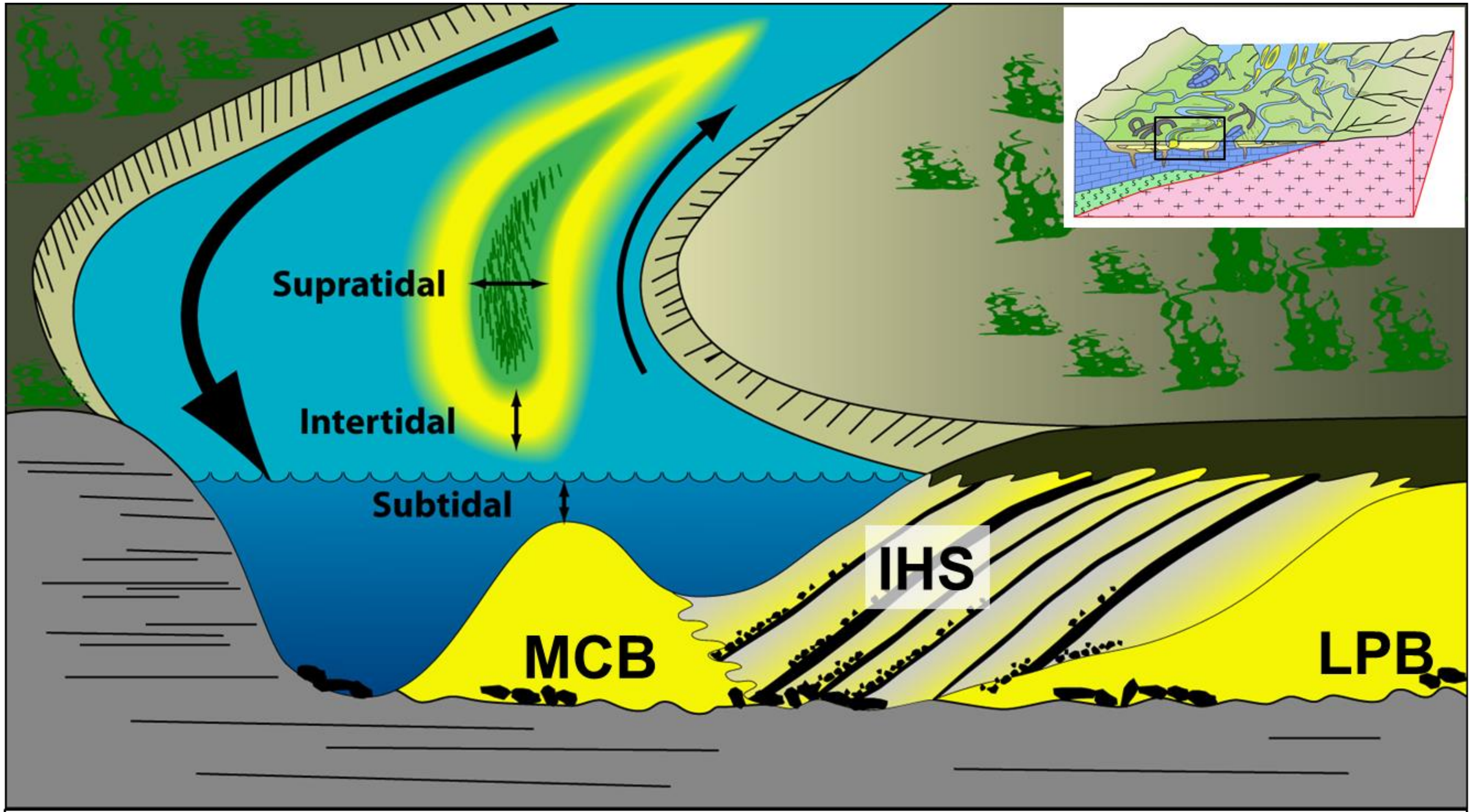
Regional Depositional Model

- Tidal-Fluvial/Estuarine Complexes
  - Stacked channel systems including:
    - Mid-channel bars
    - Channel-tidal shoal complexes
    - Channel-point bar complexes
    - Mud plugs

- Estuarine/brackish water environment



McMurray Geological Model and Reservoir Facies



MCB = mid channel bar	Facies 1 & Facies 3
LPB = lower point bar	Facies 1 & Facies 3
IHS = inclined heterolithic stratification	Facies 2 & Facies 3 & Facies 4

Long Lake Devonian Structure with Karst and Salt Dissolution Features

Legend

MAP DATA

- 2014/2015 CORE OBS WELLS
- ZERO BITUMEN EDGE
- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

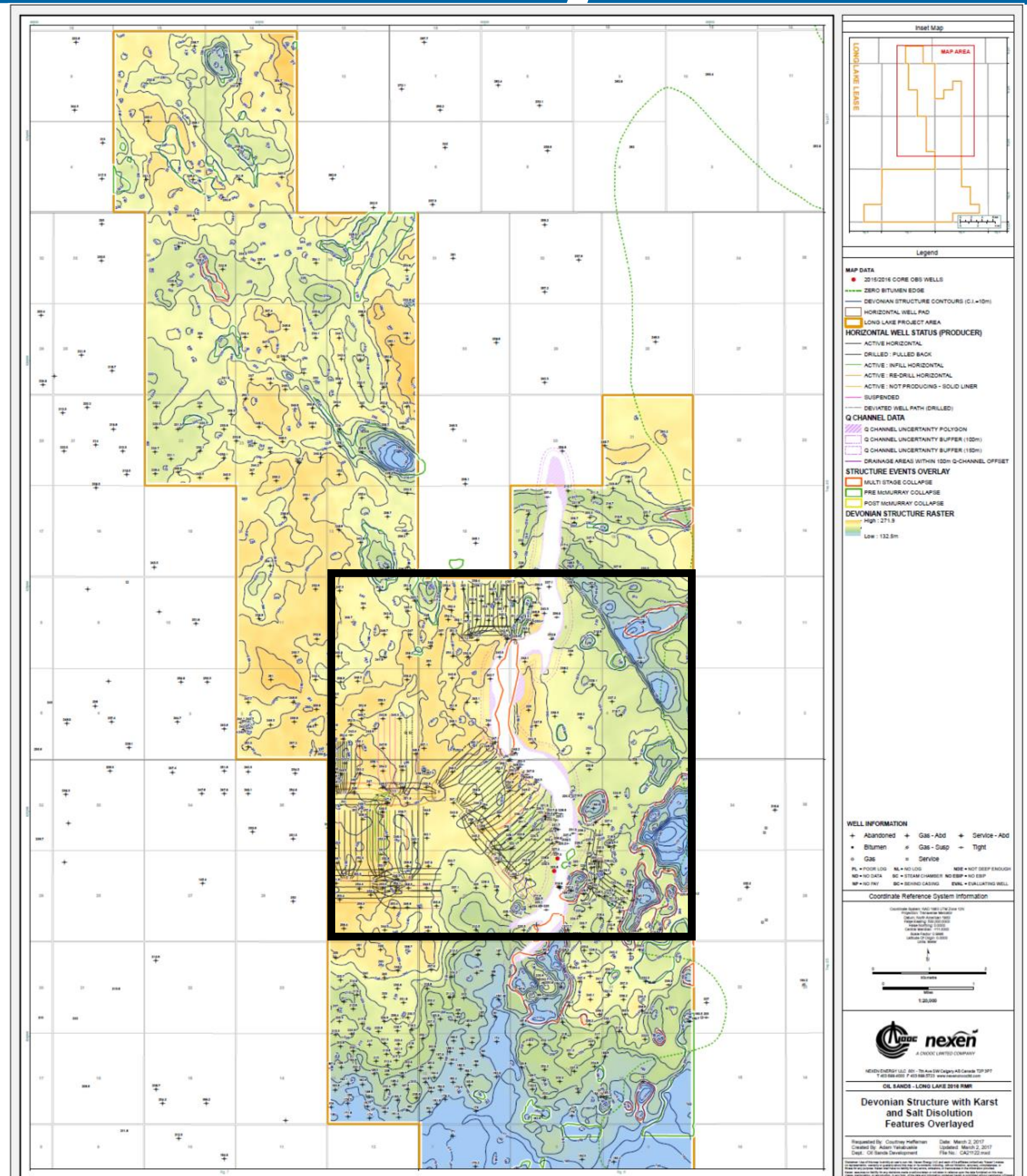
STRUCTURE EVENTS OVERLAY

- MULTI STAGE COLLAPSE
- PRE McMURRAY COLLAPSE
- POST McMURRAY COLLAPSE

DEVONIAN STRUCTURE RASTER

High : 271.9

Low : 132.5m



Long Lake Devonian Structure with Karst and Salt Dissolution Features

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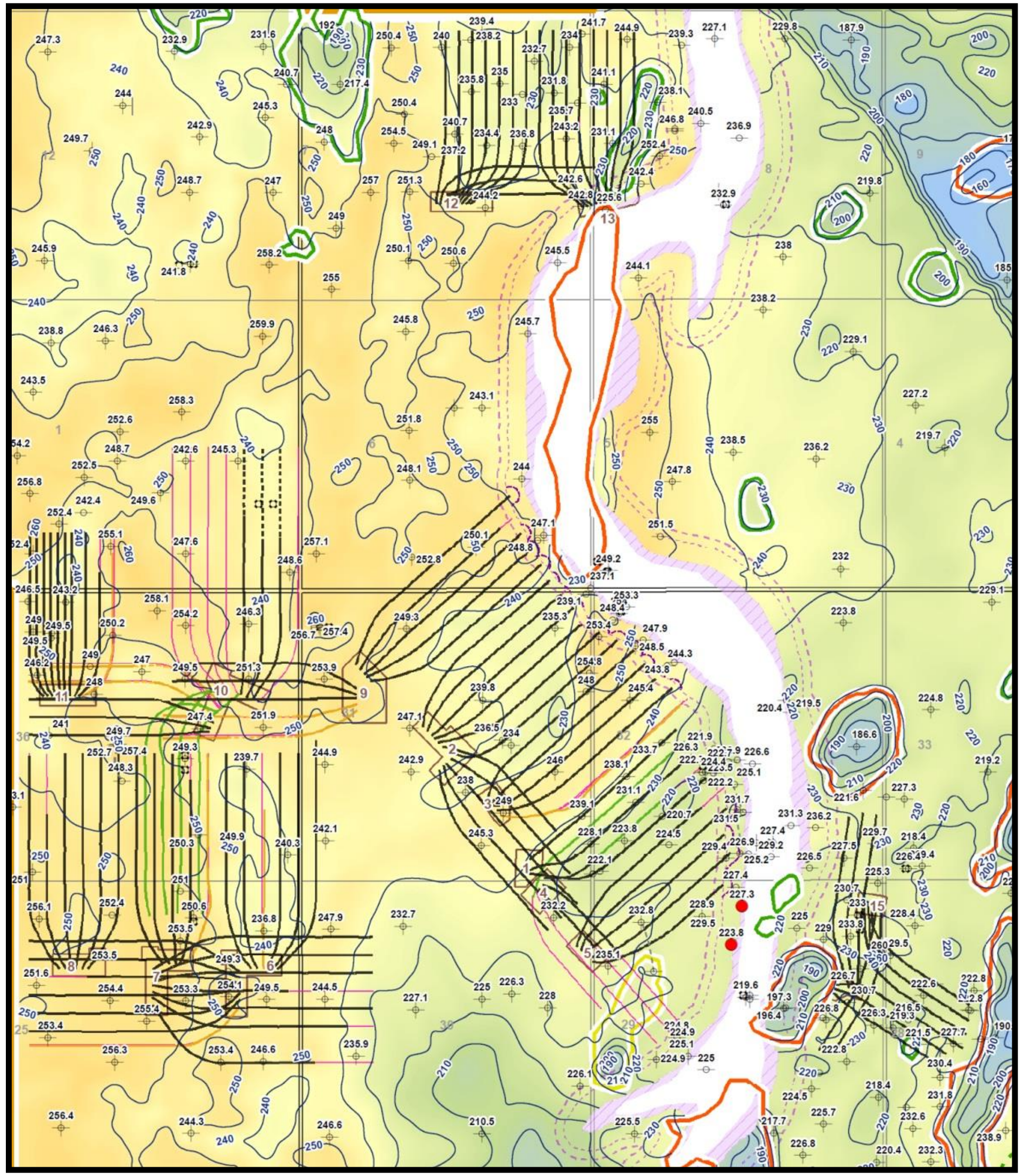

- Relatively flat below current SAGD development areas
- Lows related to collapse features (karst and dissolution) and erosion

Long Lake McMurray Structure

MAP DATA

- 2015/2016 CORE OBS WELLS
- ZERO BITUMEN EDGE
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
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Q CHANNEL DATA

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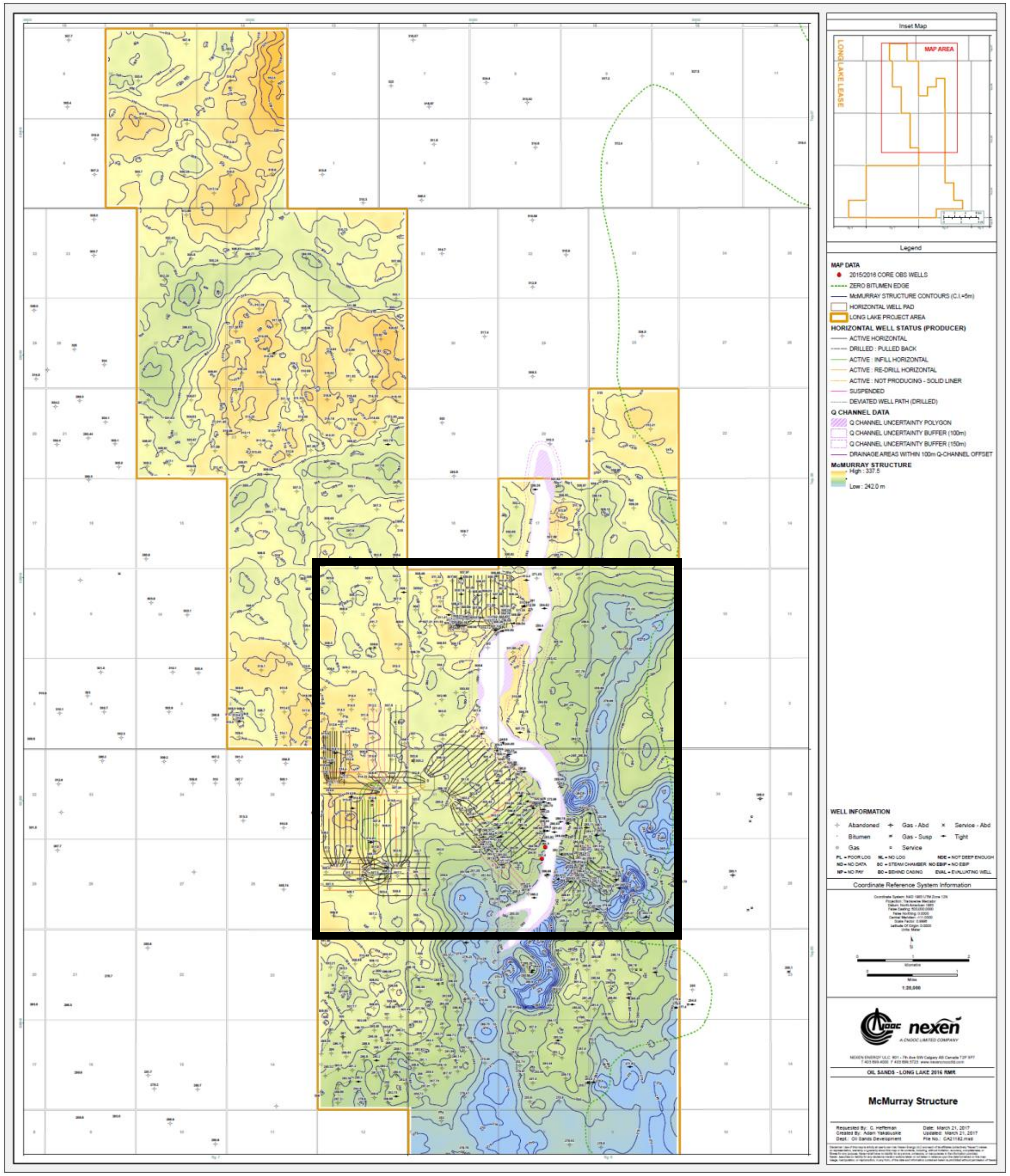
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

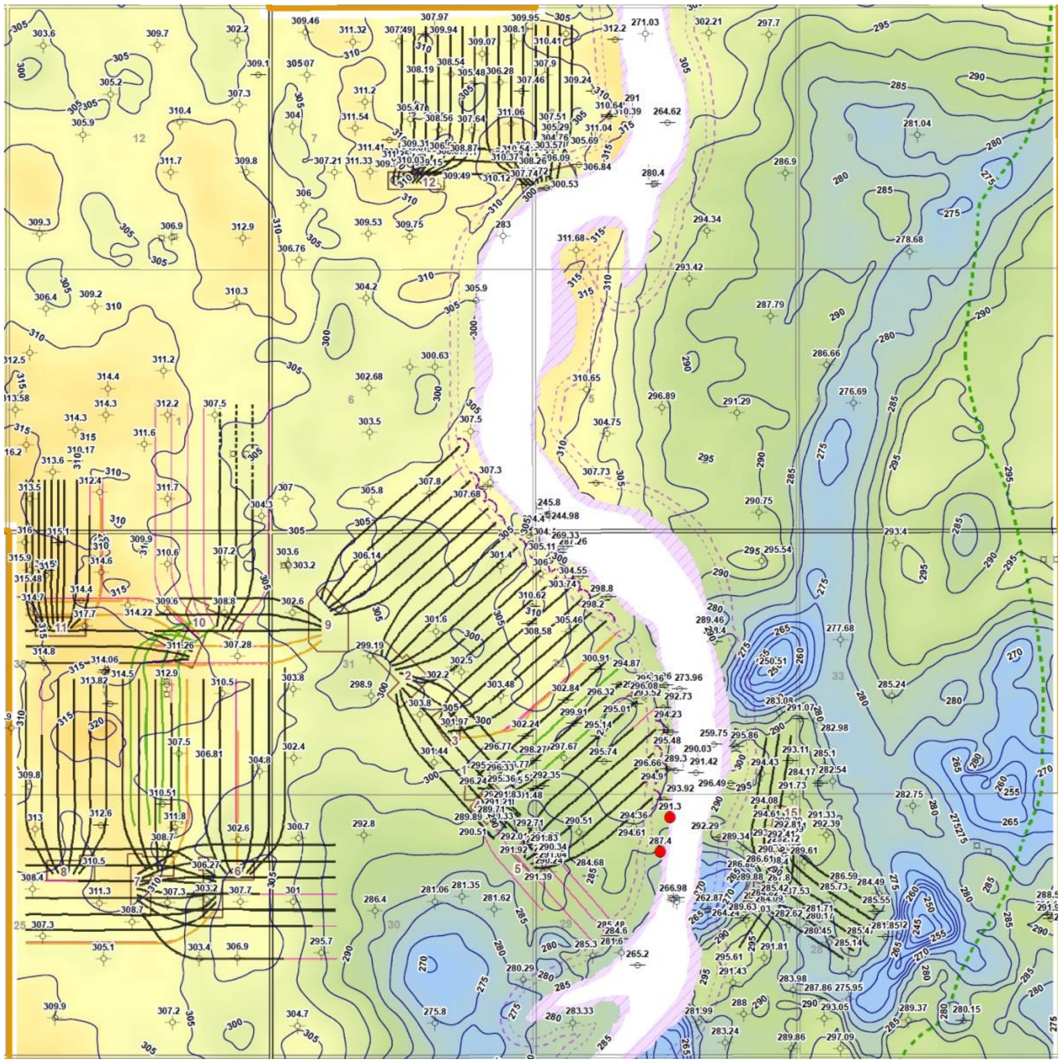
McMURRAY STRUCTURE

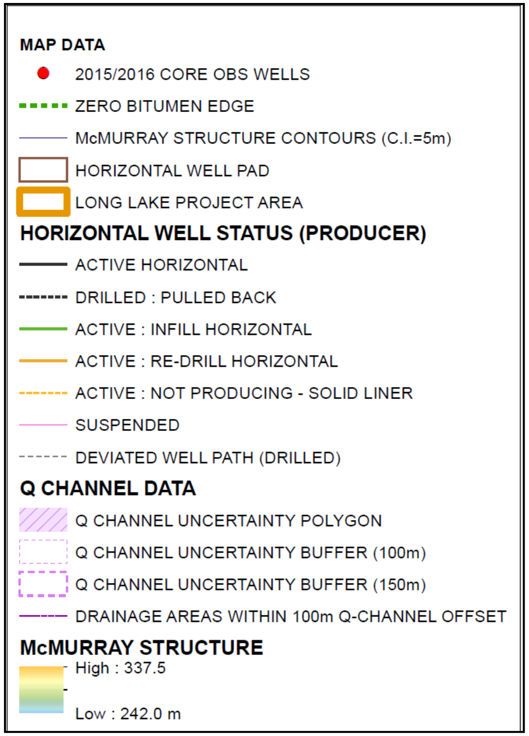
High : 337.5

Low : 242.0 m



Long Lake McMurray Structure





- Relatively flat
- Blue-shaded areas are lows related to salt dissolution
- Subtle structural influences related to karsting, erosion on Devonian and differential compaction over muddier McMurray deposits

Long Lake McMurray Isopach

Legend

MAP DATA

- 2015/2016 CORE OBS WELLS
- McMURRAY ISOPACH CONTOURS (C.I.=10m)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

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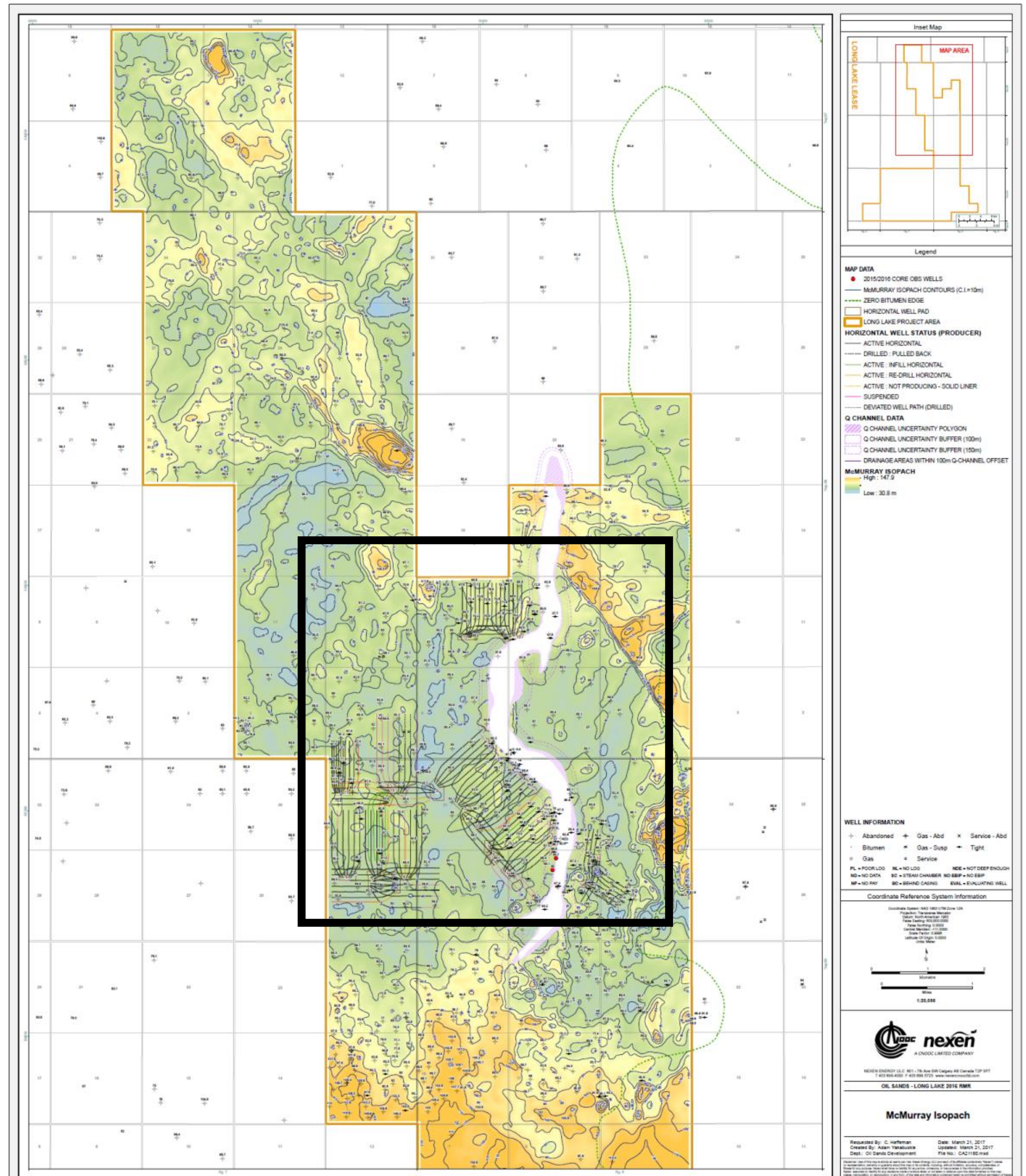
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

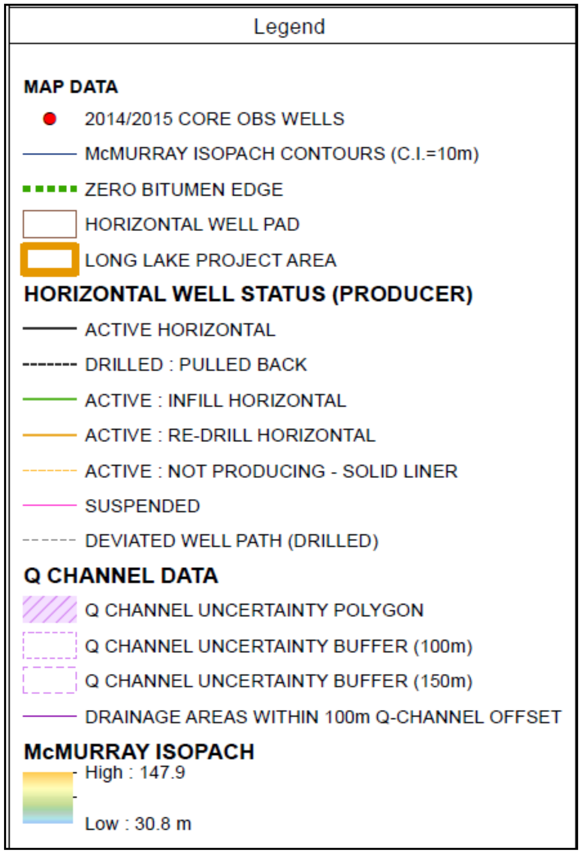
McMURRAY ISOPACH

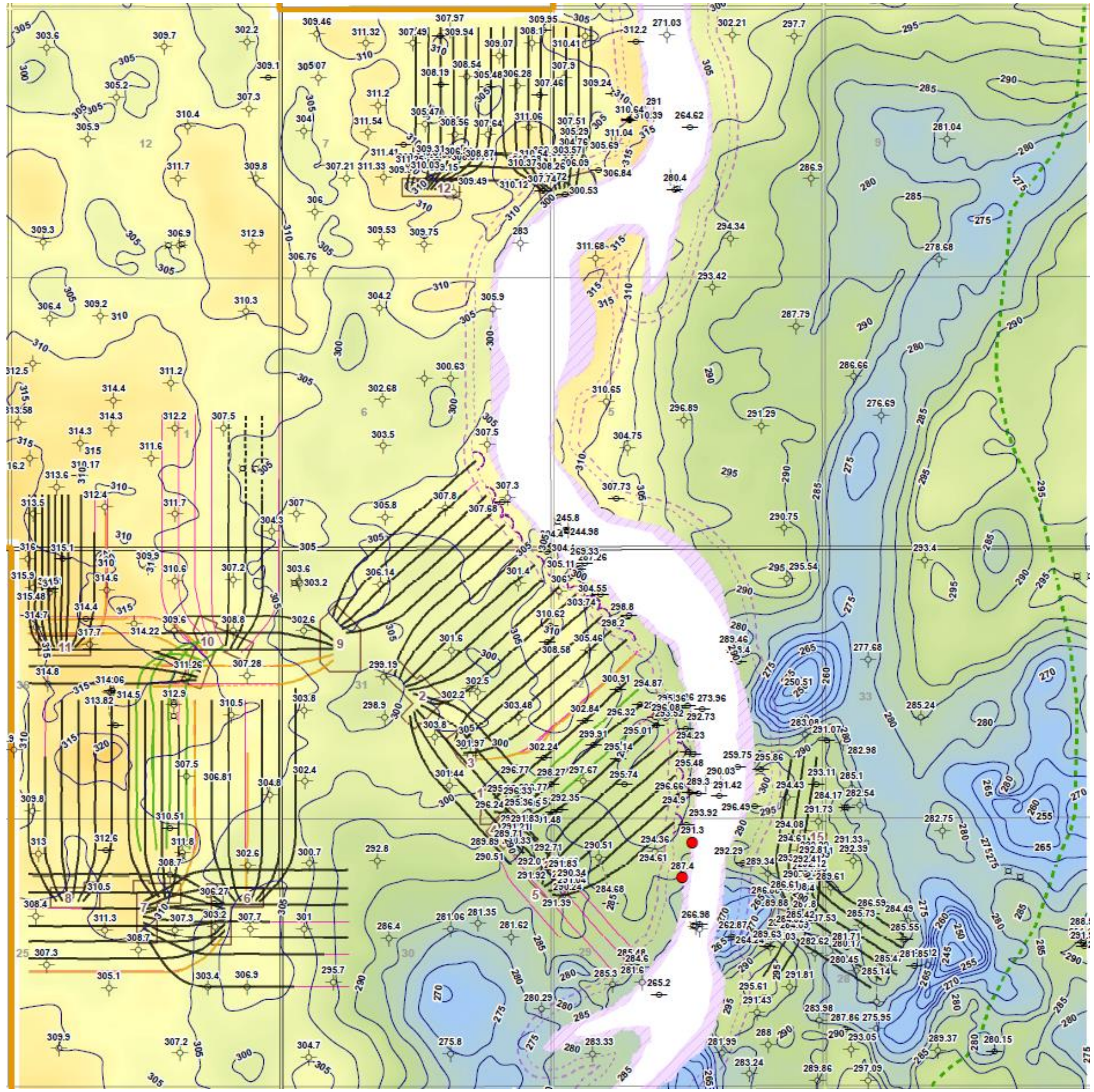
High : 147.9

Low : 30.8 m



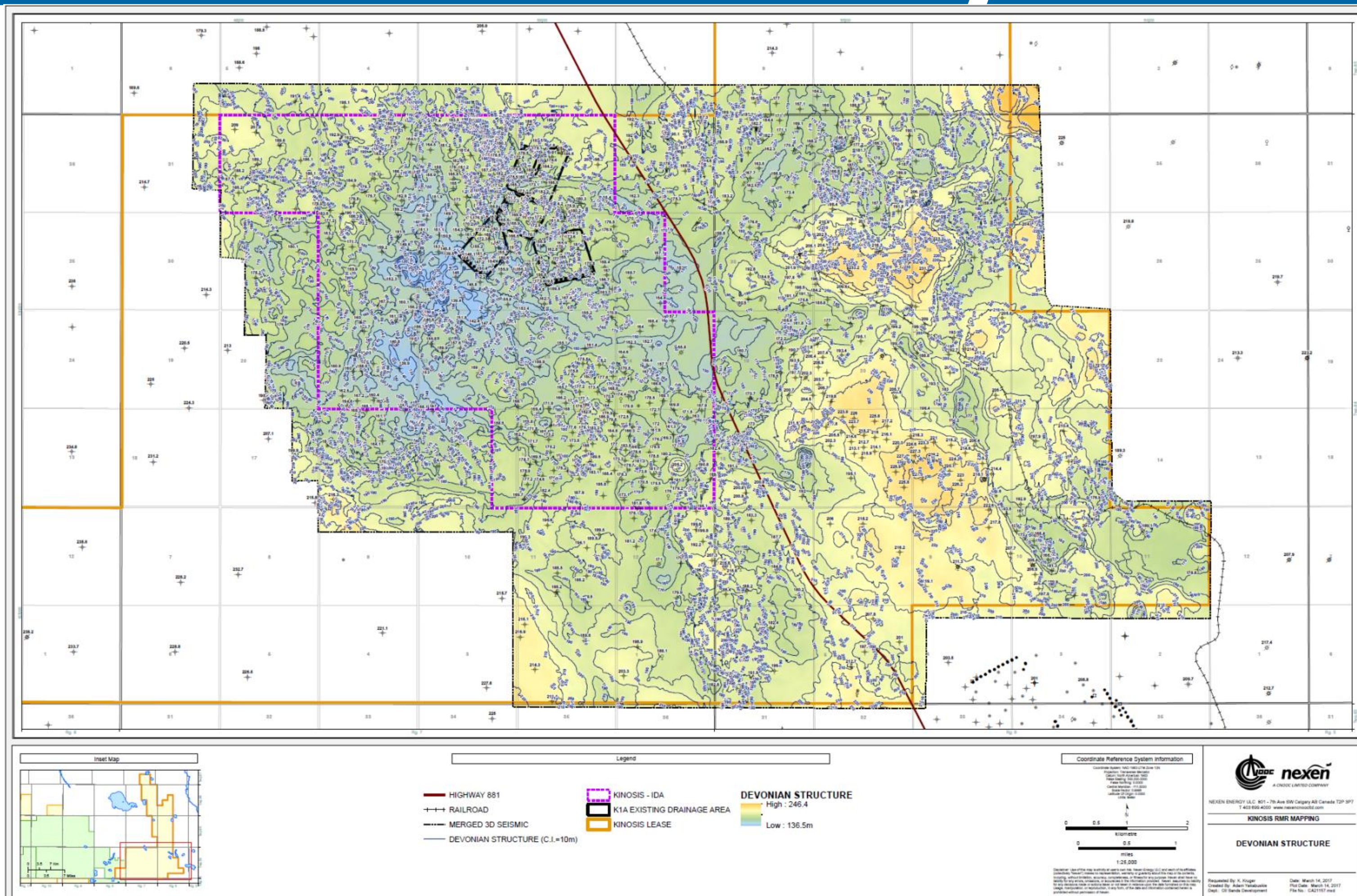
Long Lake
McMurray Isopach





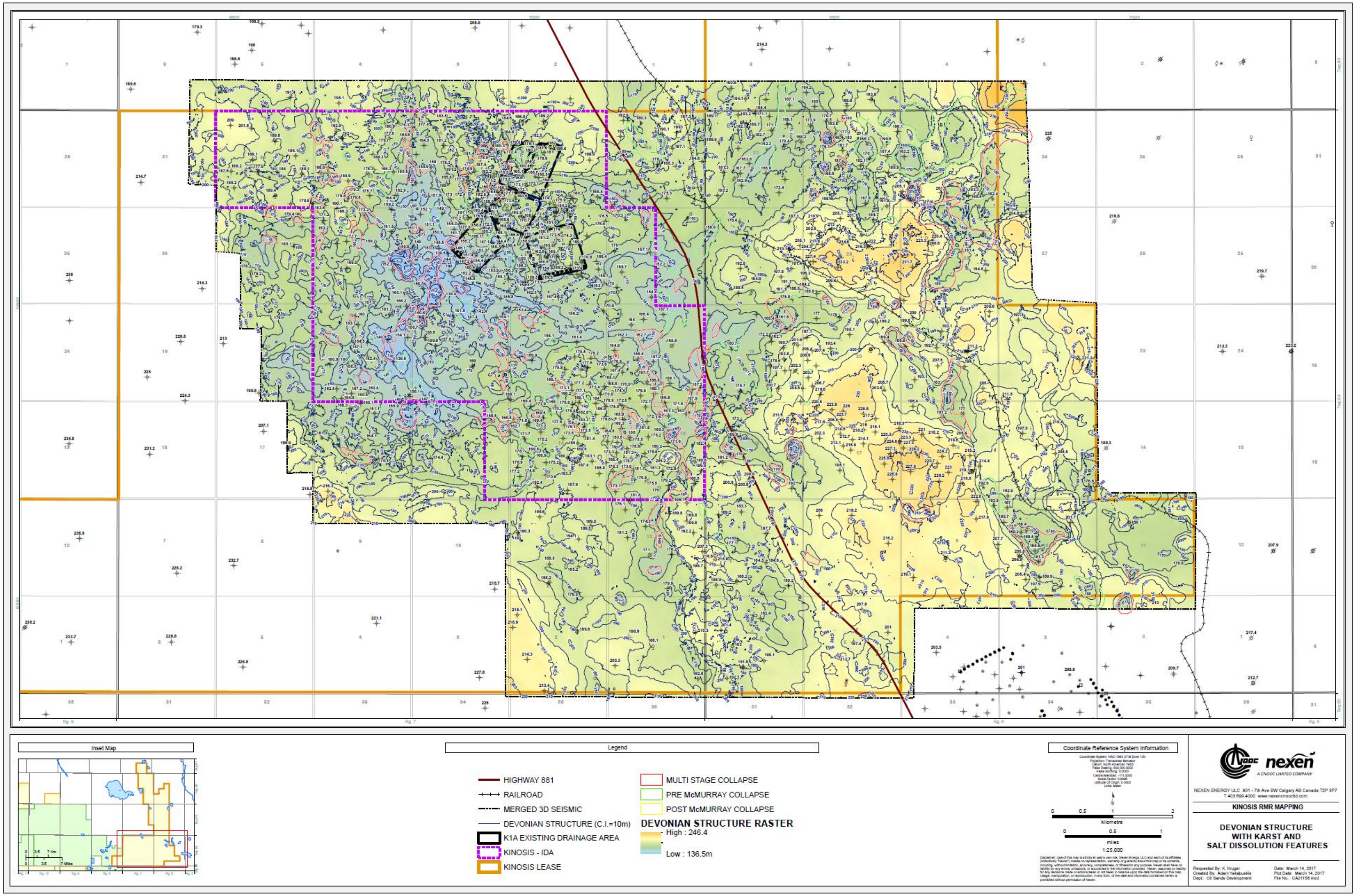
- Relatively consistent isopach (50-70m)
- Thick areas associated with Devonian lows

Kinosis Structure - Top of Devonian

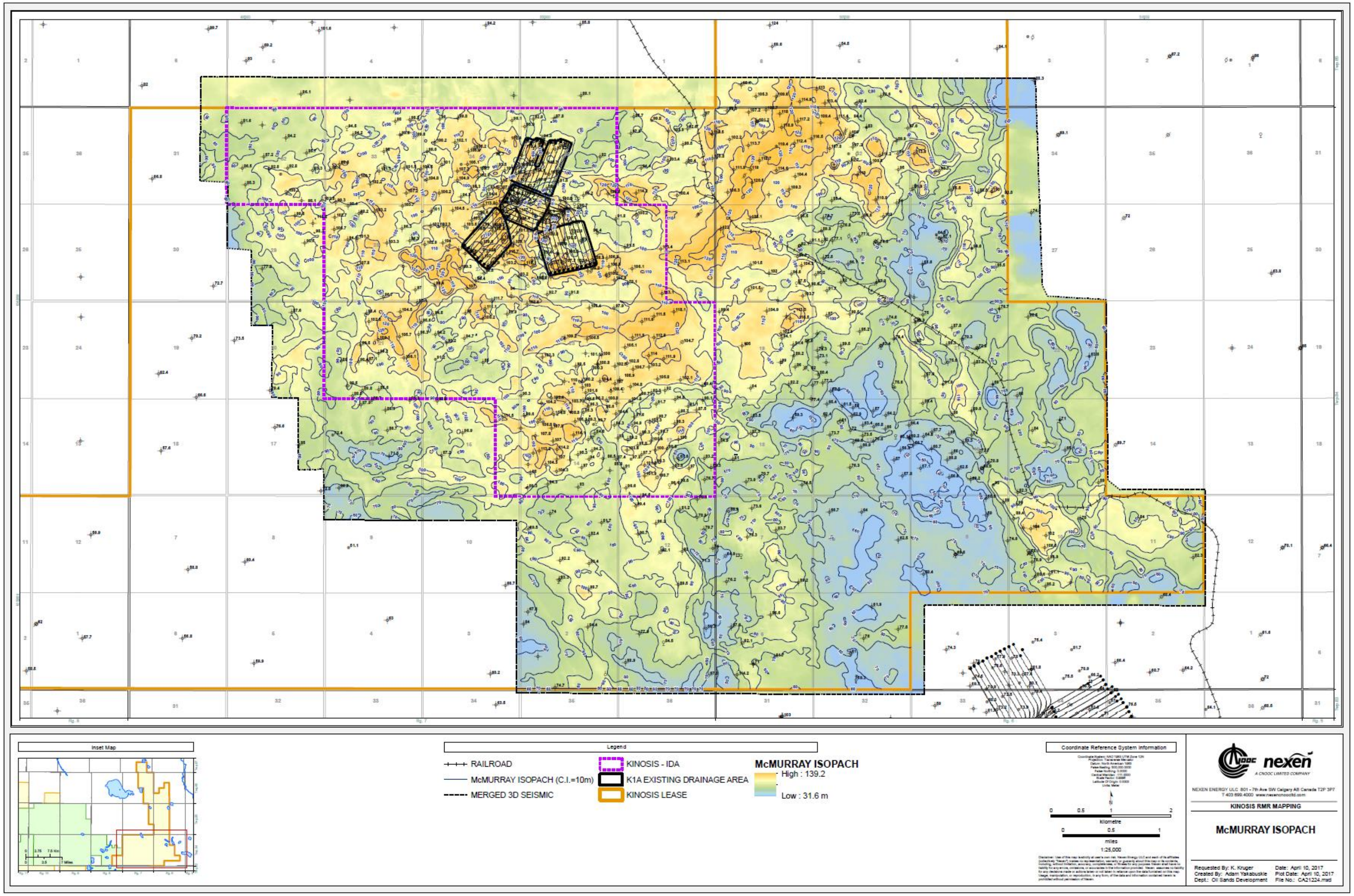


- Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts
- Has a significant effect on base of pay structure and bottom water contacts
- Timing of salt solutioning was pre-McMurray, syn-McMurray and post-McMurray
- Minor karsting on Devonian surface

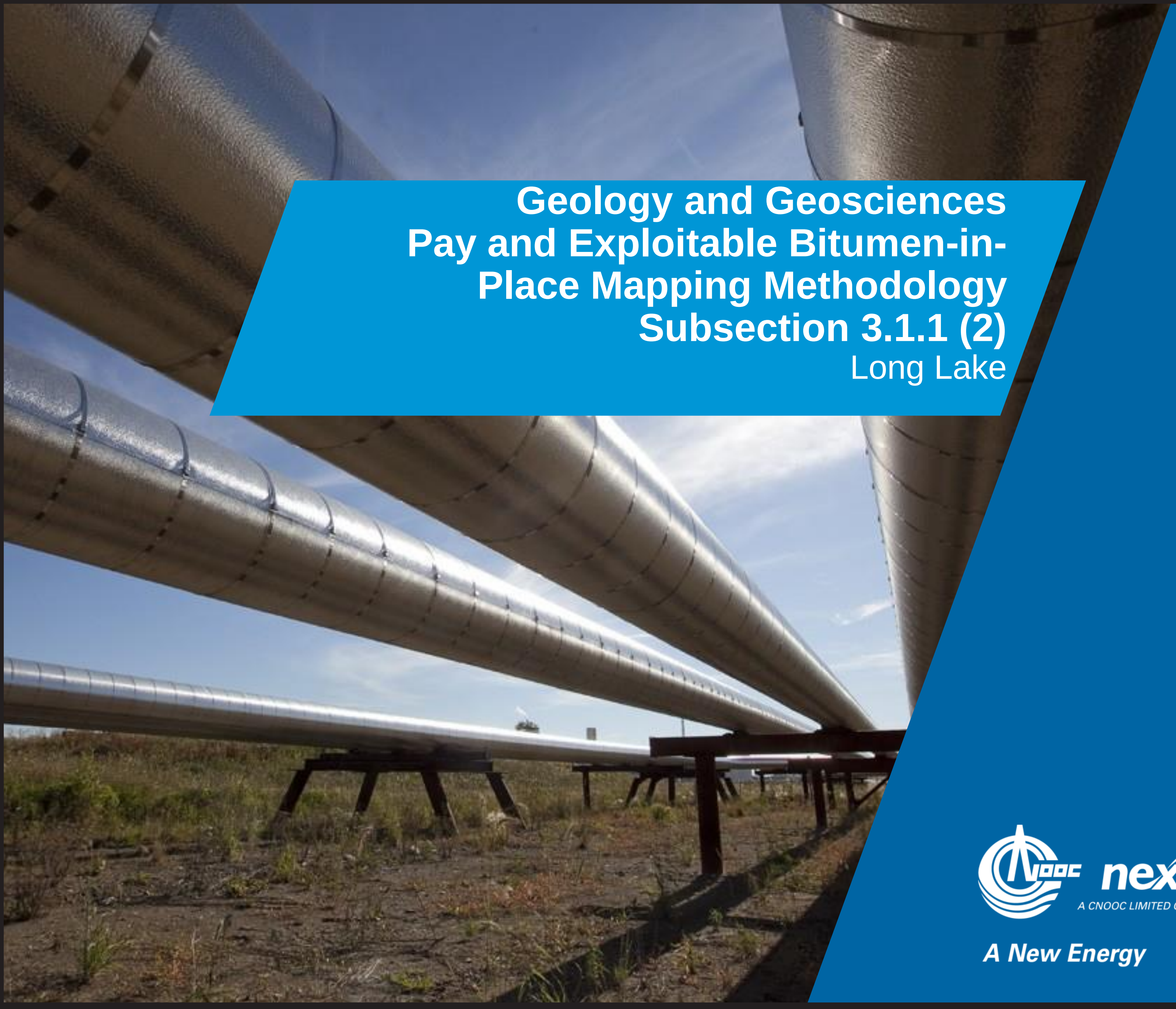
Kinosis Devonian Structure with Karst and Salt Dissolution Features



Kinosis Structure - Top of McMurray



- Influenced by depositional elements that result in differential compaction
- Influenced by Devonian salt collapse



Geology and Geosciences
Pay and Exploitable Bitumen-in-Place Mapping Methodology
Subsection 3.1.1 (2)

Long Lake

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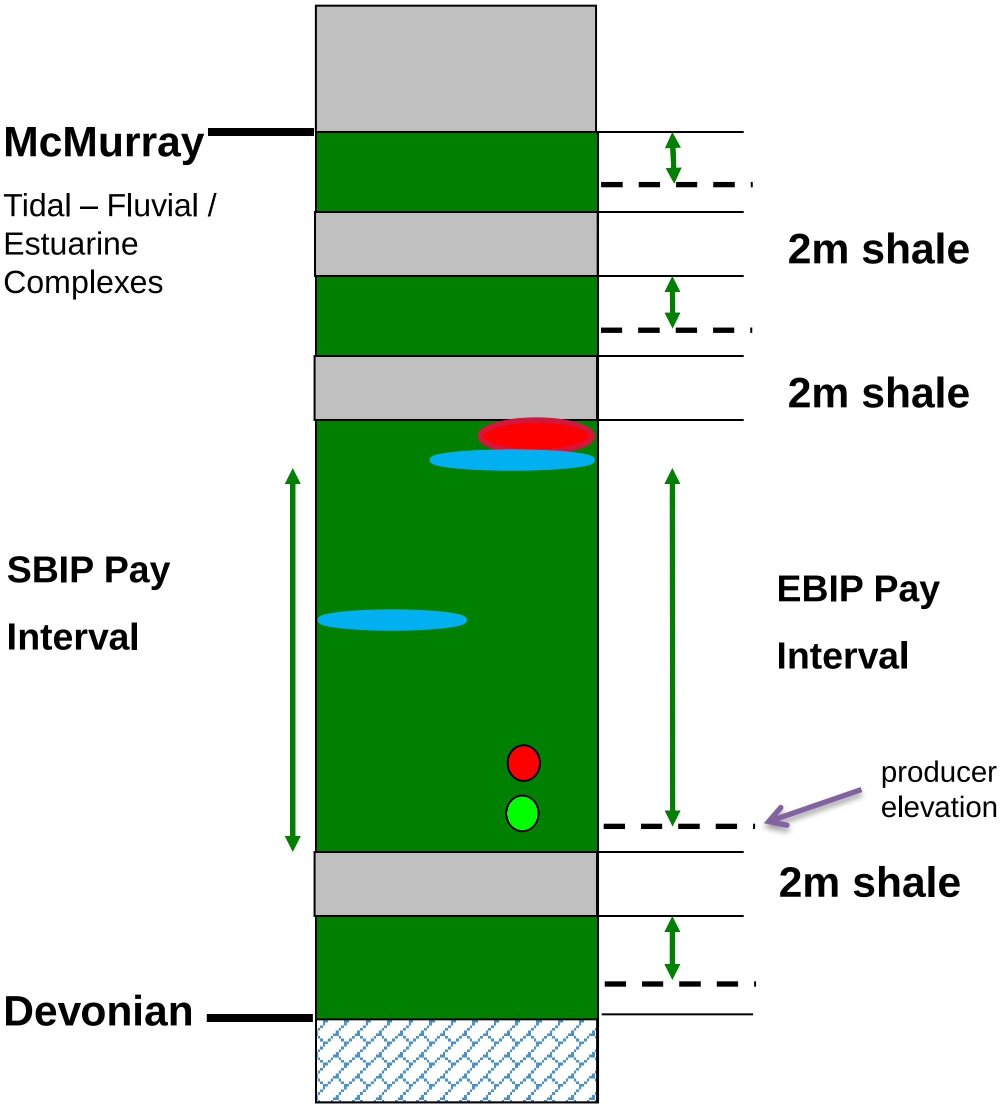
Pay and Exploitable Bitumen-in-Place Mapping Methodology

- Pay cut-offs:
  - Top of pay interval is a 2m shale with >30%V_{shale}
  - Focus on low V_{shale} intervals with thinner and fewer shale beds
  - Account for standoff from bottom water or non-reservoir
- Top of EBIP/SBIP Pay Interval:
  - Single shale interval (> 30% V_{shale}) of 2m
  - Cumulative shale interval (> 30% V_{shale}) of 4
- Base of SBIP Pay Interval:
  - Base of bitumen pay/reservoir rock
- Base of EBIP Pay Interval:
  - Depth of an existing or planned horizontal well pair (EBIP pay base = producer well depth)
  - Stand-off from bitumen/water contact or non-reservoir
- Gas Interval(s) Associated with EBIP/SBIP Pay Interval
  - Gas identified by neutron/density crossover
- High Water Saturation Interval(s) Associated with EBIP/SBIP Pay Interval
  - > 50% Swe (effective water saturation) and < 30% V_{shale}
- EBIP will be calculated from a hydrocarbon pore volume height (HPVH) map.

- Reservoir Rock
  - Sand
  - Breccia
  - IHS with < 30% V_{shale}
- High Water Saturation Interval
  - > 50% Swe (effective water saturation) and < 30% V_{shale}
- Minimum EBIP HPVH and Pay Interval Contour
  - 3 m^3/m^2 EBIP HPVH = 12m EBIP Pay Interval

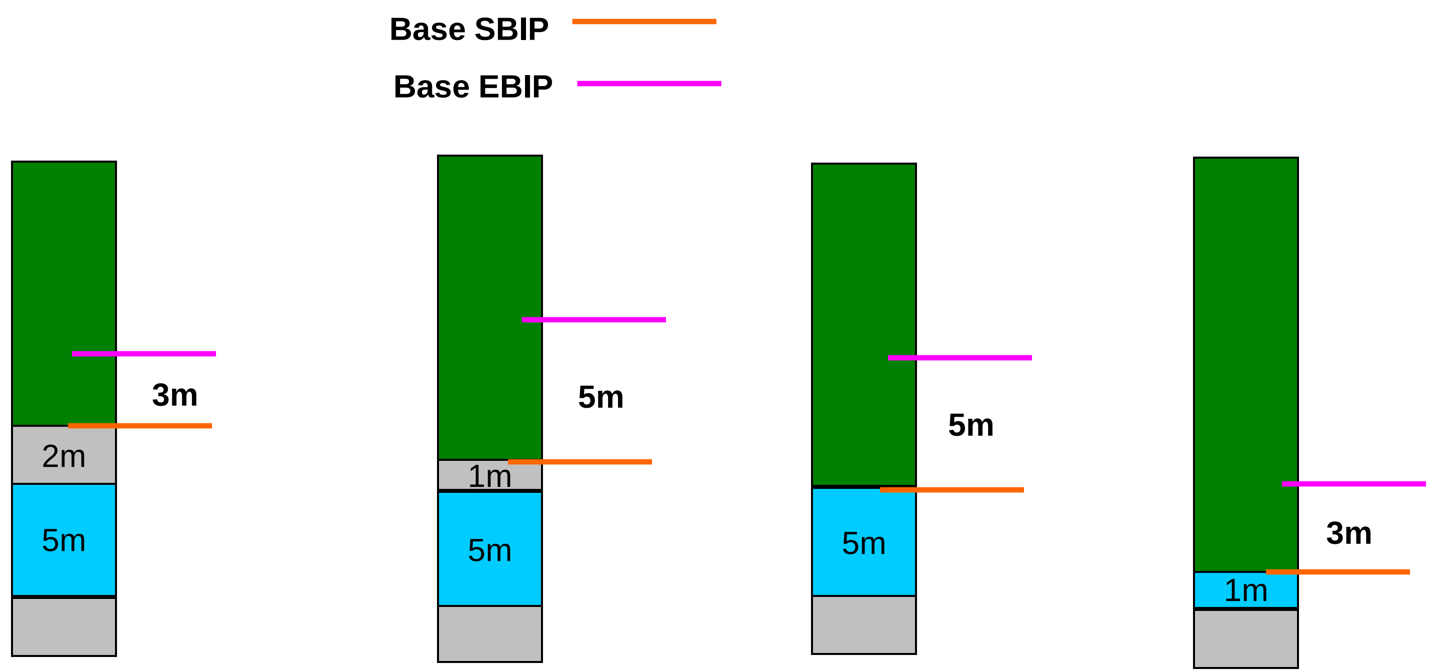
Pay and Bitumen-in-Place Mapping Methodology



- **SBIP Pay Interval:**
  - < 30% V_{shale}
  - < 50% Swe
- May have associated:
  - gas interval(s)
  - high water saturation interval(s)
- Primary zone defined as the thickest pay interval <u>unless</u>:
  - an existing (or planned) horizontal well pair is within an interval
  - geologists have interpreted continuity of an interval across an area

Pay and Exploitable Bitumen-in-Place Mapping Methodology

- Base of EBIP Pay Interval:
  - Depth of an existing or planned horizontal well pair (EBIP Pay Interval base = producer well depth)
  - 3m stand-off if no bottom water (minimum shale of 2m thickness)
  - 5m stand-off if in contact with bottom water (minimum bottom water thickness of 2m)



Pay and Exploitable Bitumen-in-Place Mapping Methodology

Base of EBIP Pay Interval

- In areas where reserves are mapped but future well pairs have not been laid out, a 3m or 5m stand-off from the mapped base of the reservoir is applied when estimating EBIP.
- Applying these stand-offs attempts to account for the volume of resource that may not be recoverable by future SAGD producer wells due to the following assumptions:
  - Wells will be placed at elevations that optimize the well pair extent through high quality reservoir;
  - Maintaining a flat trajectory;
  - Avoiding production risk due to bottom water where it occurs.
- **3m** stand-off is applied above the base-of-reservoir where the base of reservoir is in contact with non-reservoir strata.
  - Attempt to account for resource that will likely remain unproduced due to irregularities on the base-of-reservoir surface structure.
- Stand-off is increased to **5m** where the base of the reservoir is mapped as being in contact with bottom water.
  - "Contact" is considered to occur where there is less than a 2m shale interval between the top of bottom water and the base of the bitumen reservoir.
- 5m stand-off from the bottom water contact attempts to mitigate the following concerns:
  - Maintain sufficient stand-off between the producer and the bottom water surface to avoid early communication.
  - Attempts to account for the uncertainty in the nature of the contact between the base-of-reservoir and bottom water.
  - Uncertainty in the elevation of the bottom water contact.
  - Allows steam chamber development along the entire length of the horizontal well pair during the early SAGD ramp up phase and should act as a baffle.
- Once a SAGD well pair location is proposed for an area, the actual elevation of the producer well will then define the EBIP base.

Producer Vertical Depth

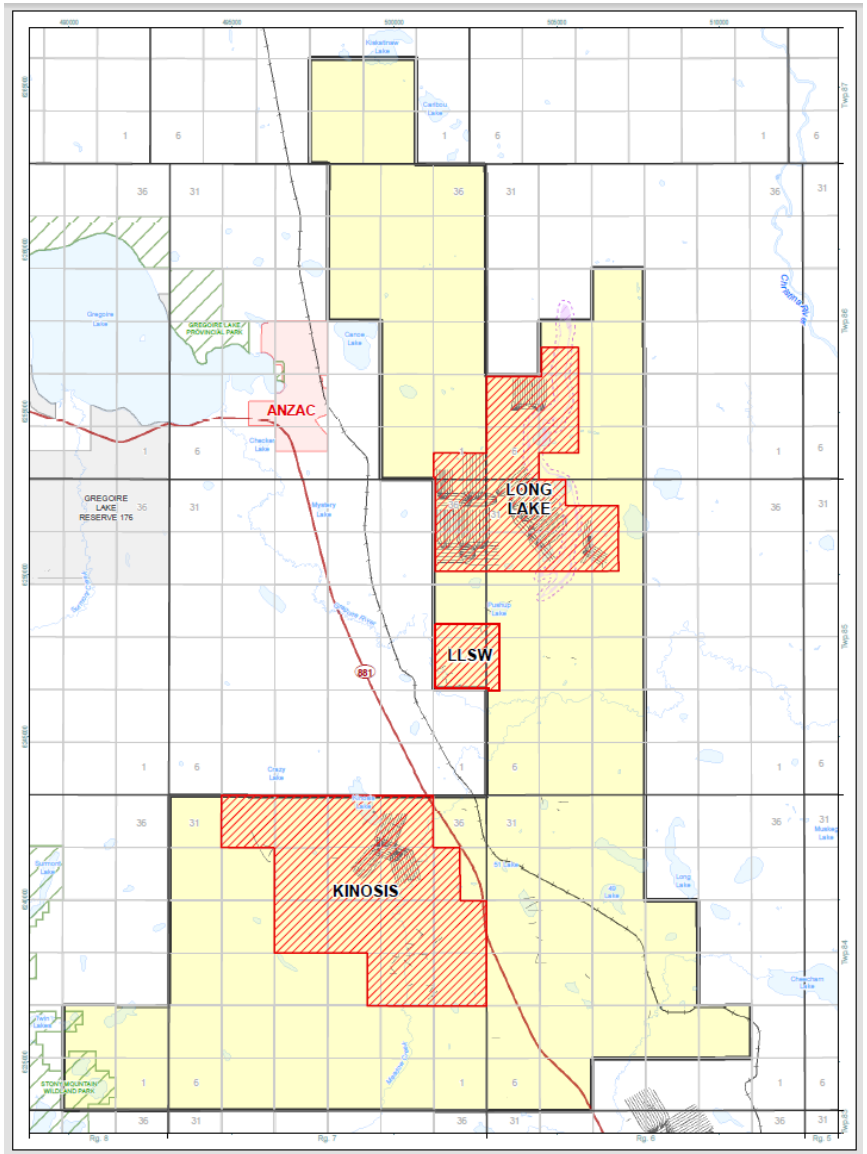
Considerations:

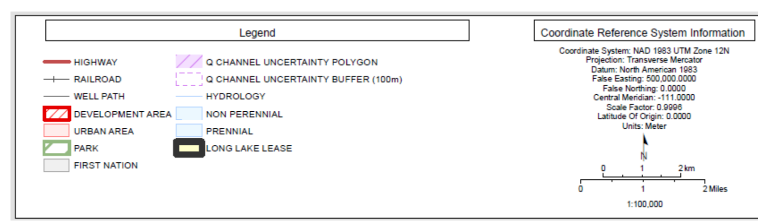
- Target high quality resource - preferably staying above mud clast breccia
- Plan horizontal well pair orientation so as to minimize stranded pay and/or preserve secondary development opportunities
- Maintain a flat trajectory as much as possible

Constraints:

- Minimum of 5m stand-off from bottom water (if present) to minimize the risk of a pressure sink coming in contact with the higher pressure steam chamber
- Max. elevation change between adjacent horizontal wells 15m/100m
- 3 to 5m vertical deviation from intermediate casing point (ICP)
- Approximate maximum rise or dip rate 1m/50m

Lease: Development Areas





Long Lake Development Area EBIP and Average Reservoir Parameters

Long Lake (including Long Lake SW) Development Area EBIP

Long Lake EBIP (E^6m^3)	119

Nexen Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

$$HPVH = \sum_{pay\ bs}^{pay\ tp} (S_o * \Phi)$$

HPVH is calculated from petrophysical logs calibrated to Dean Stark analysis.

Long Lake EBIP Average Reservoir Parameters

- Measured Depth (top) 200 mKB
- Thickness 22 m
- Effective Porosity 31.2 %
- V_{shale} 10.1 %
- Permeability – Historical Plug Data
  - k_{max} 5,565 mD
  - k_{vert} 4,491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure:

  ~1,000 – 1,100kPa @ 230m AMSL

Effective porosity, effective water saturation, and V_{shale} are calculated every 10 cm over the EBIP interval, and the average is derived.

Kinosis Development Area EBIP and Average Reservoir Parameters

Kinosis Development Area EBIP

Kinosis IDA	
EBIP (E^6m^3)	206

Nexen Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

$$HPVH = \sum_{\text{pay bs}}^{\text{pay tp}} (S_o * \Phi)$$

HPVH is calculated from petrophysical logs calibrated to Dean Stark analysis.

Pay Average Reservoir Parameters

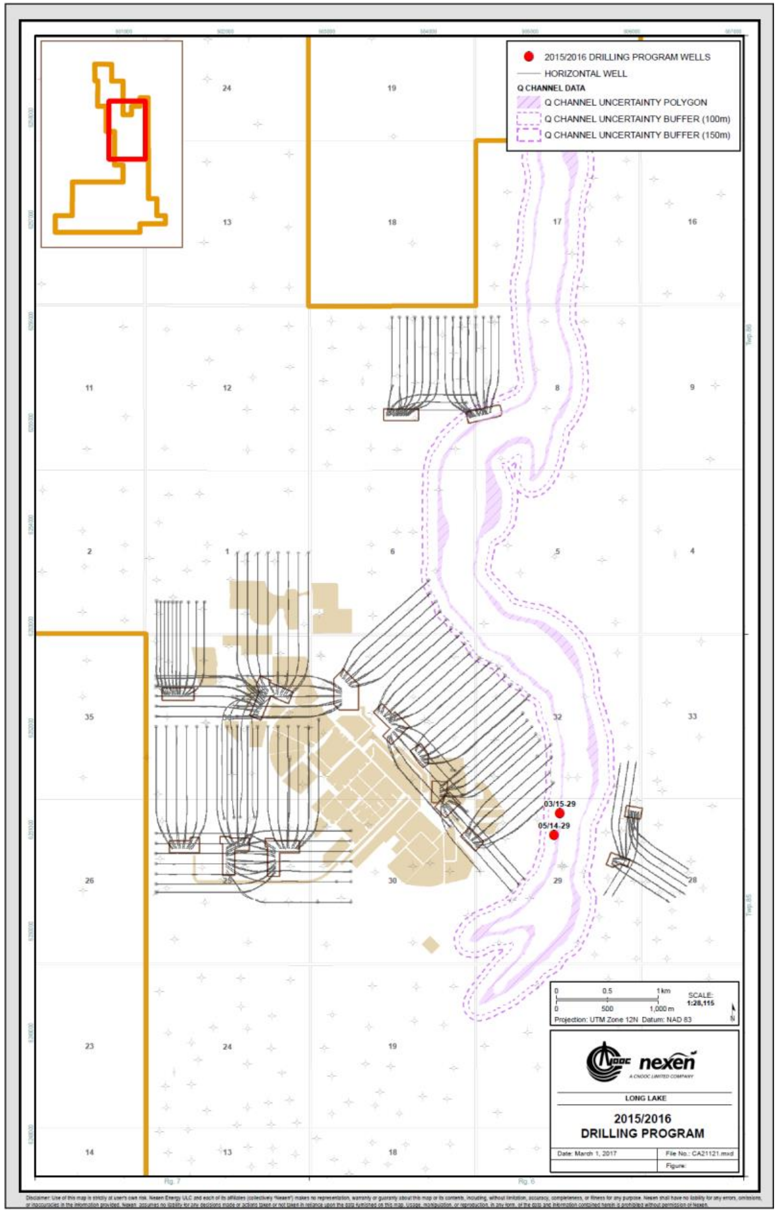
- Measured Depth (top) 280 mKB
- Thickness 34 m
- Effective Porosity 31 %
- Permeability From Core Plugs
  - k_{max} 4,030 mD
  - k_{vert} 2,347 mD
- Effective Water Saturation 26 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure
  - ~1,100 – 1,300 kPa

Effective porosity and effective water saturation are calculated every 10cm over the Pay interval, and the average is derived.

Long Lake
2016 Winter Program

2016 Program

- **2** new Q-Channel Monitoring Wells



Long Lake
2016 Program

UWI	Well Name	Well License #	Core Collected
105142908506W400	NEU CNOOC OBS VWPTC NEWBY 14-29-85-6	0478465	YES
103152908506W400	NEU CNOOC OBS VWPTC NEWBY 15-29-85-6	0478464	YES

Long Lake
SBIP Pay Interval Isopach

Legend

- ● 2015/2016 CORE OBS WELLS
- SBIP ISOPACH (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

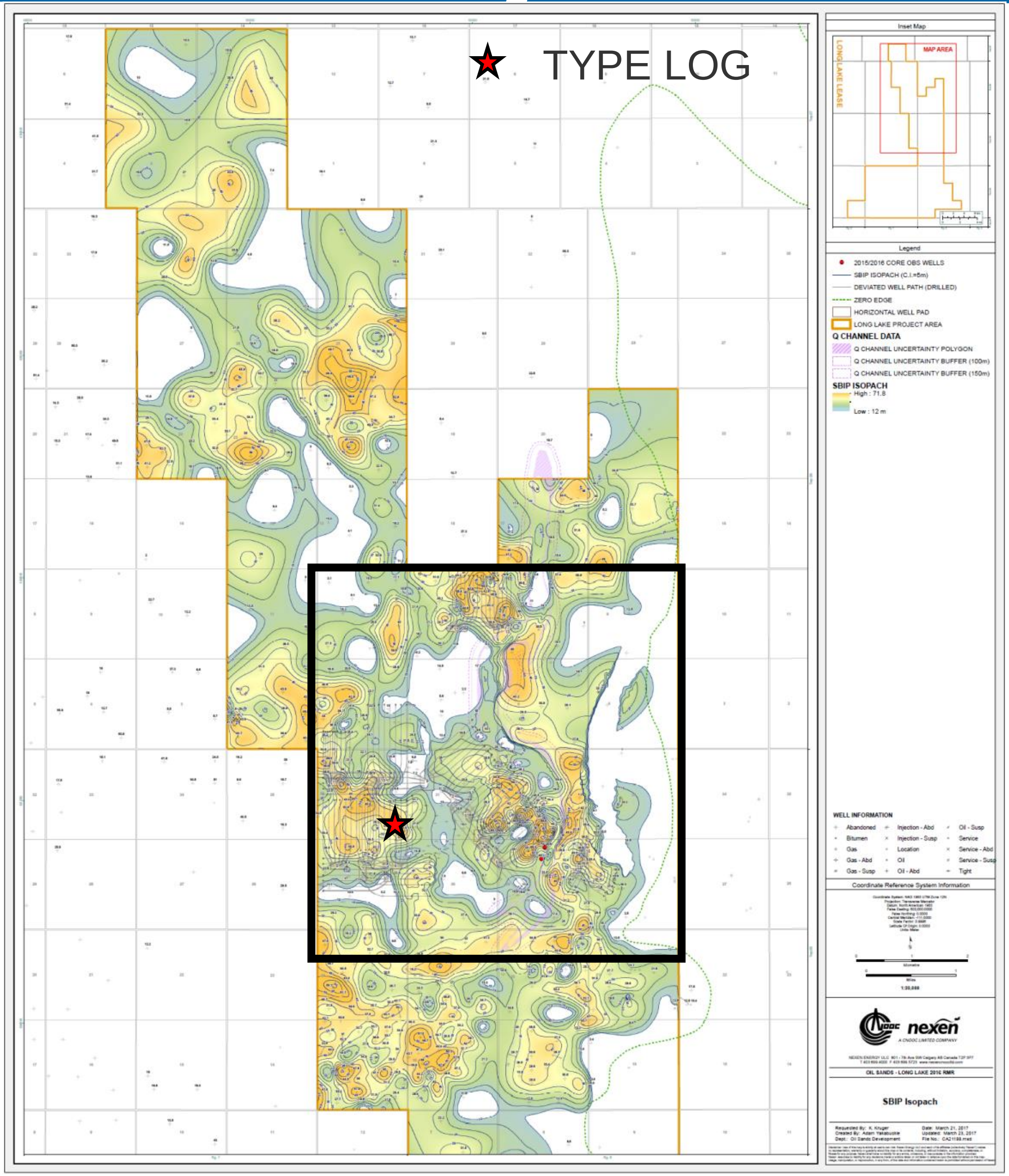
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP ISOPACH

High : 71.8

Low : 12 m



Long Lake
SBIP Pay Interval Isopach

Legend

- ● 2015/2016 CORE OBS WELLS
- SBIP ISOPACH (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

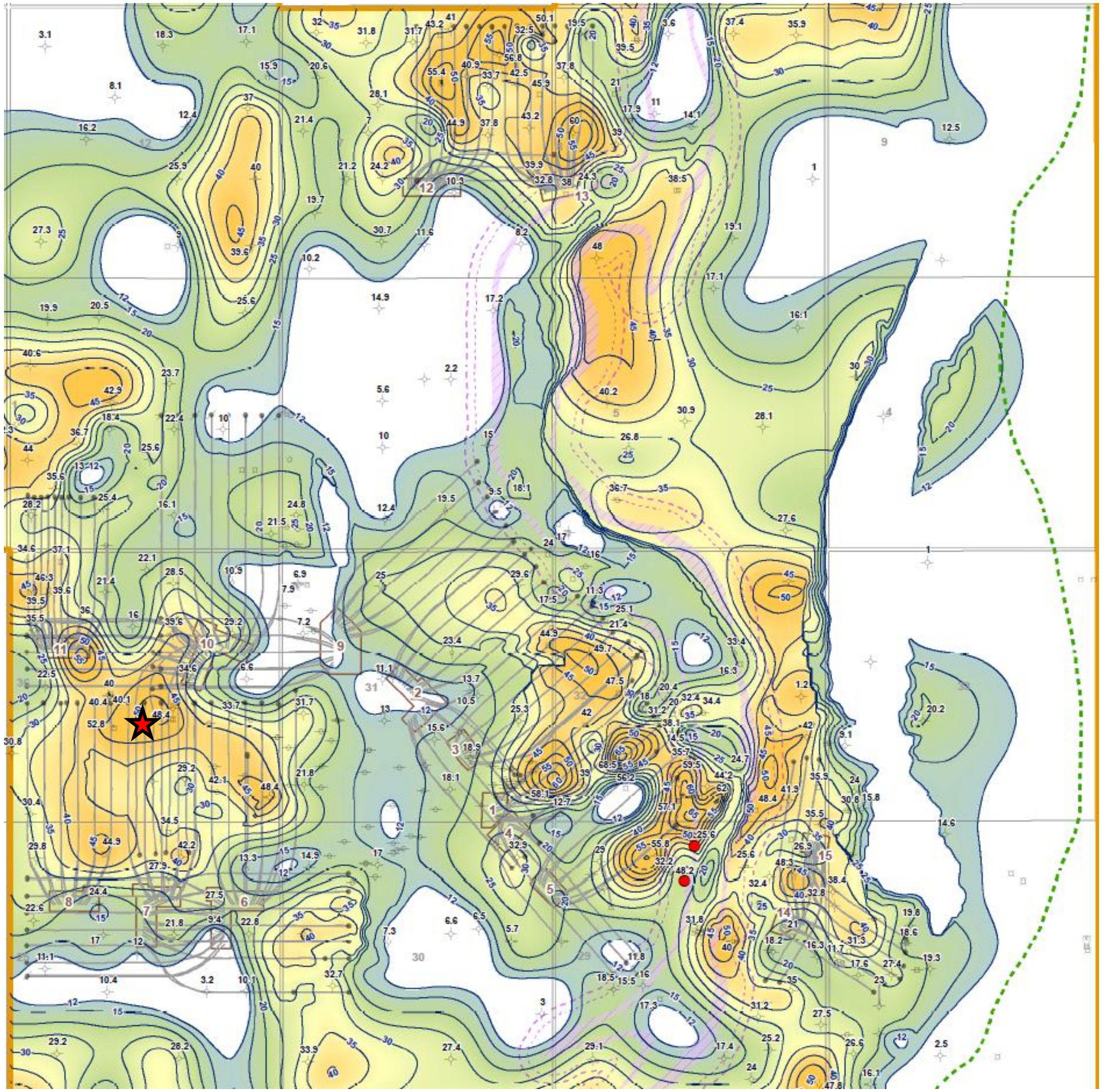
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP ISOPACH

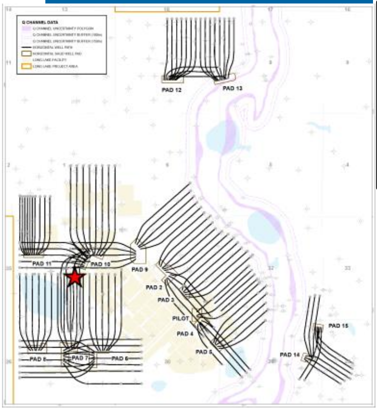
High : 71.8

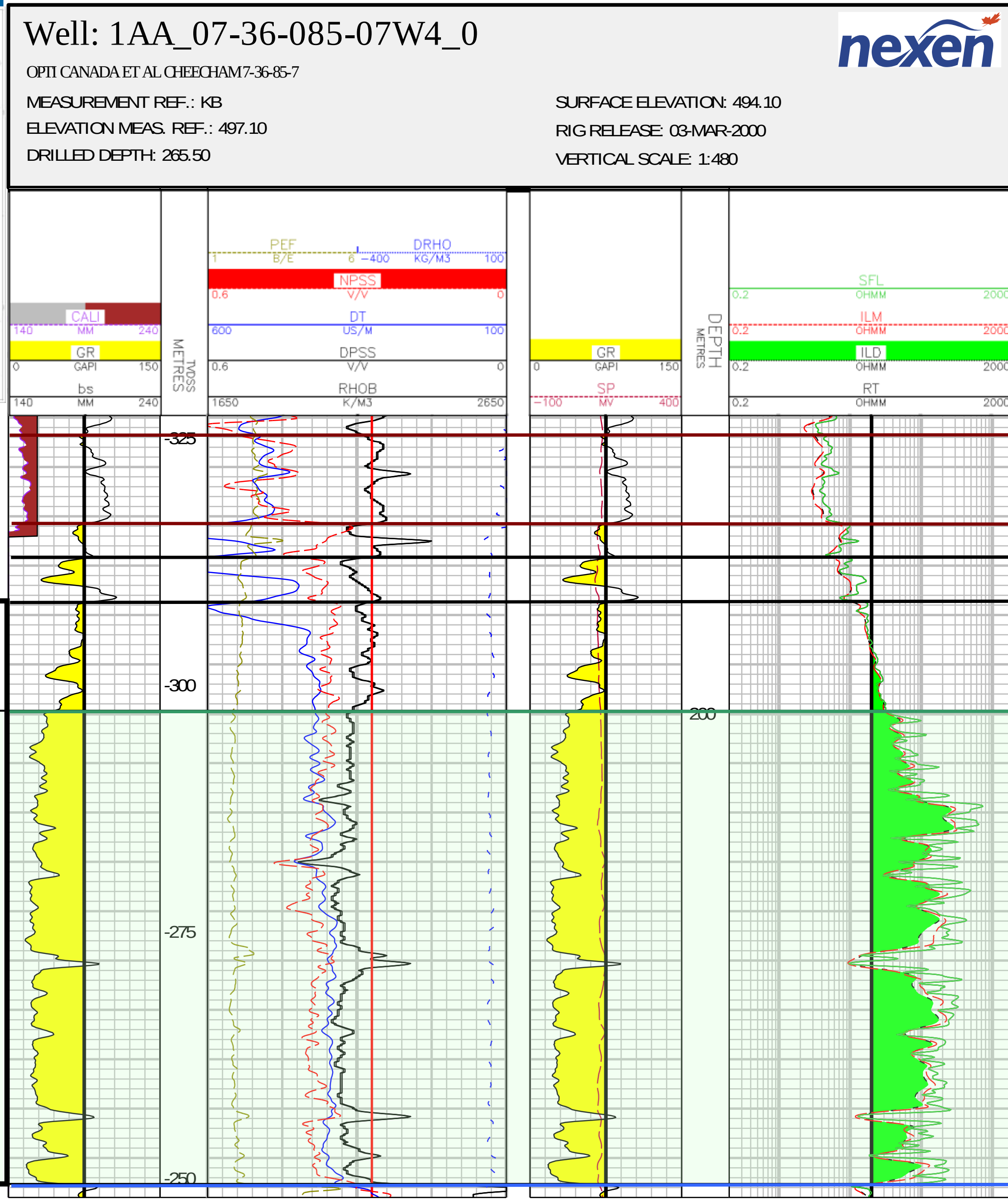
Low : 12 m



★ TYPE LOG

SBIP Type Log – 1AA/07-36-085-07W4





Wabiskaw

Wabiskaw 'C'

McMurray

McMurray A1

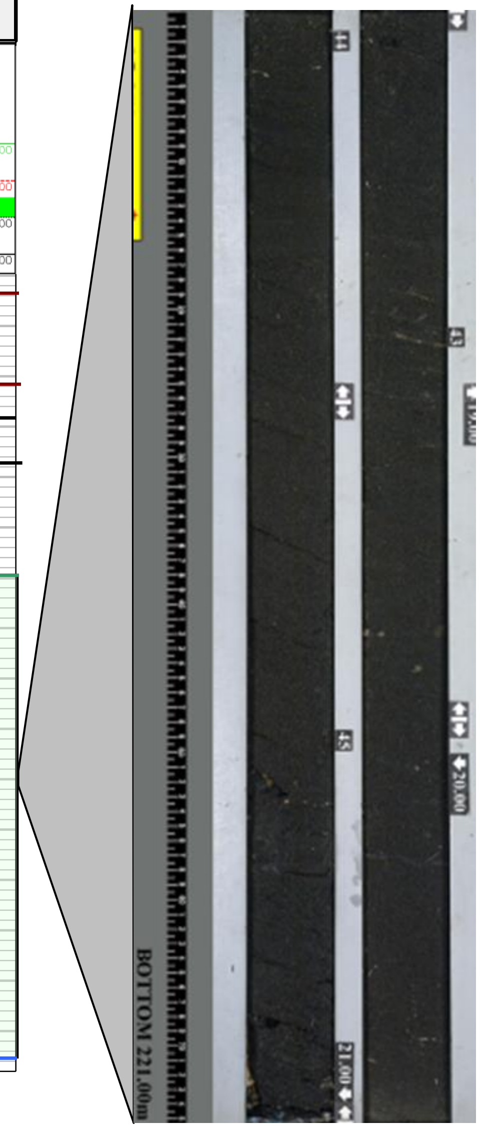
Tidal-Fluvial Estuarine Complexes

Top of Pay

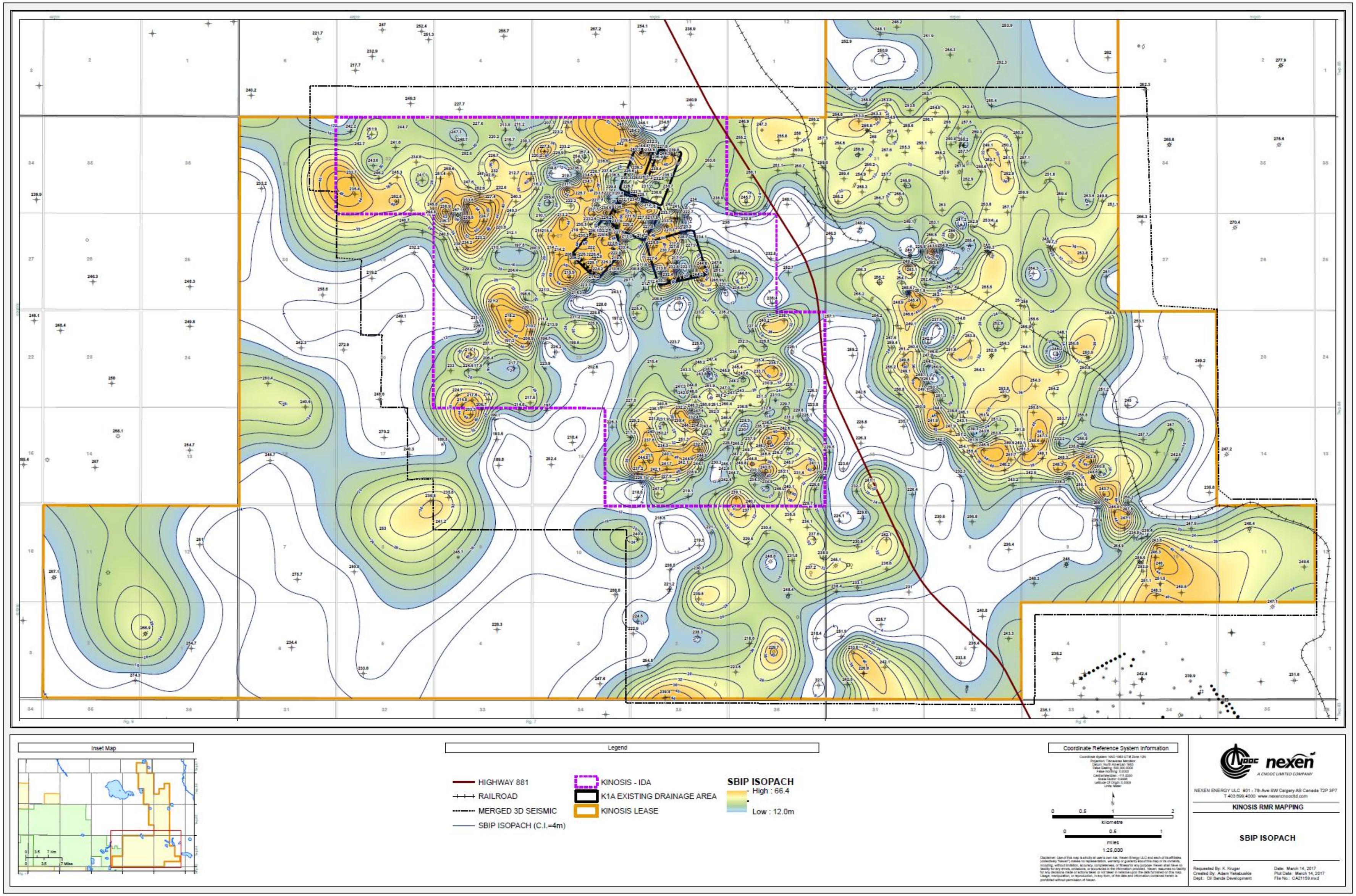
SBIP Pay Interval

Base of Pay

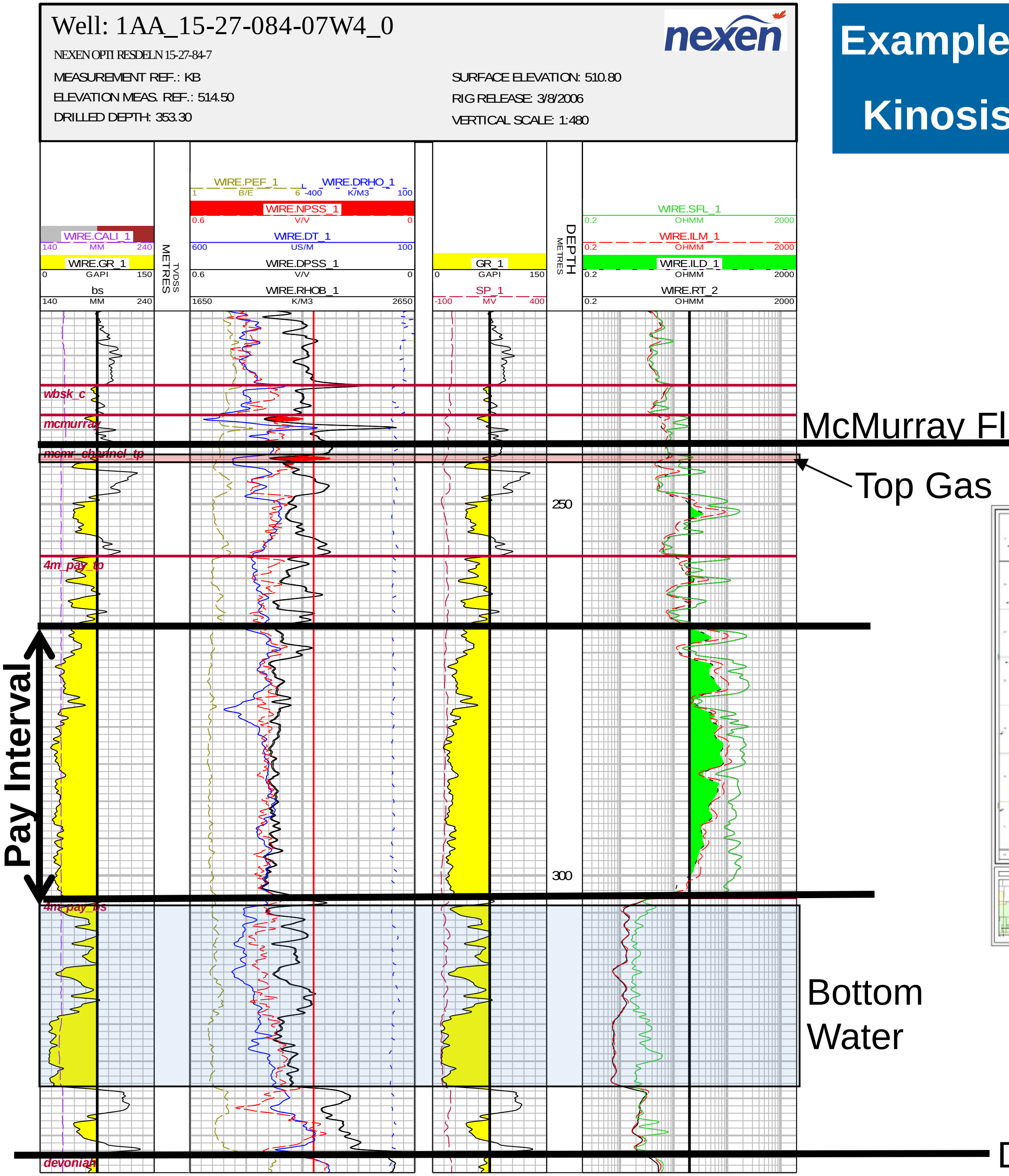
Devonian

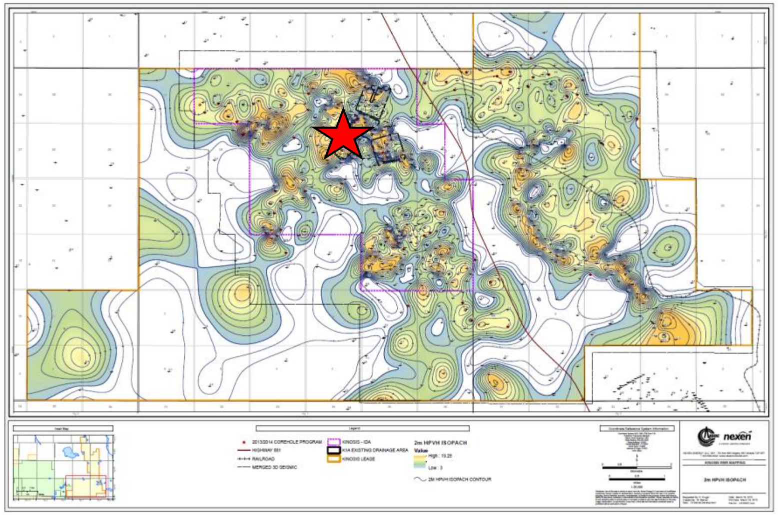


Kinosis
SBIP Pay Interval Isopach



Example Log: Kinosis KIA





Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.

Long Lake
SBIP Pay Interval Base Structure

Legend

MAP DATA

- 2015/2016 CORE OBS WELLS
- SBIP BASE STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

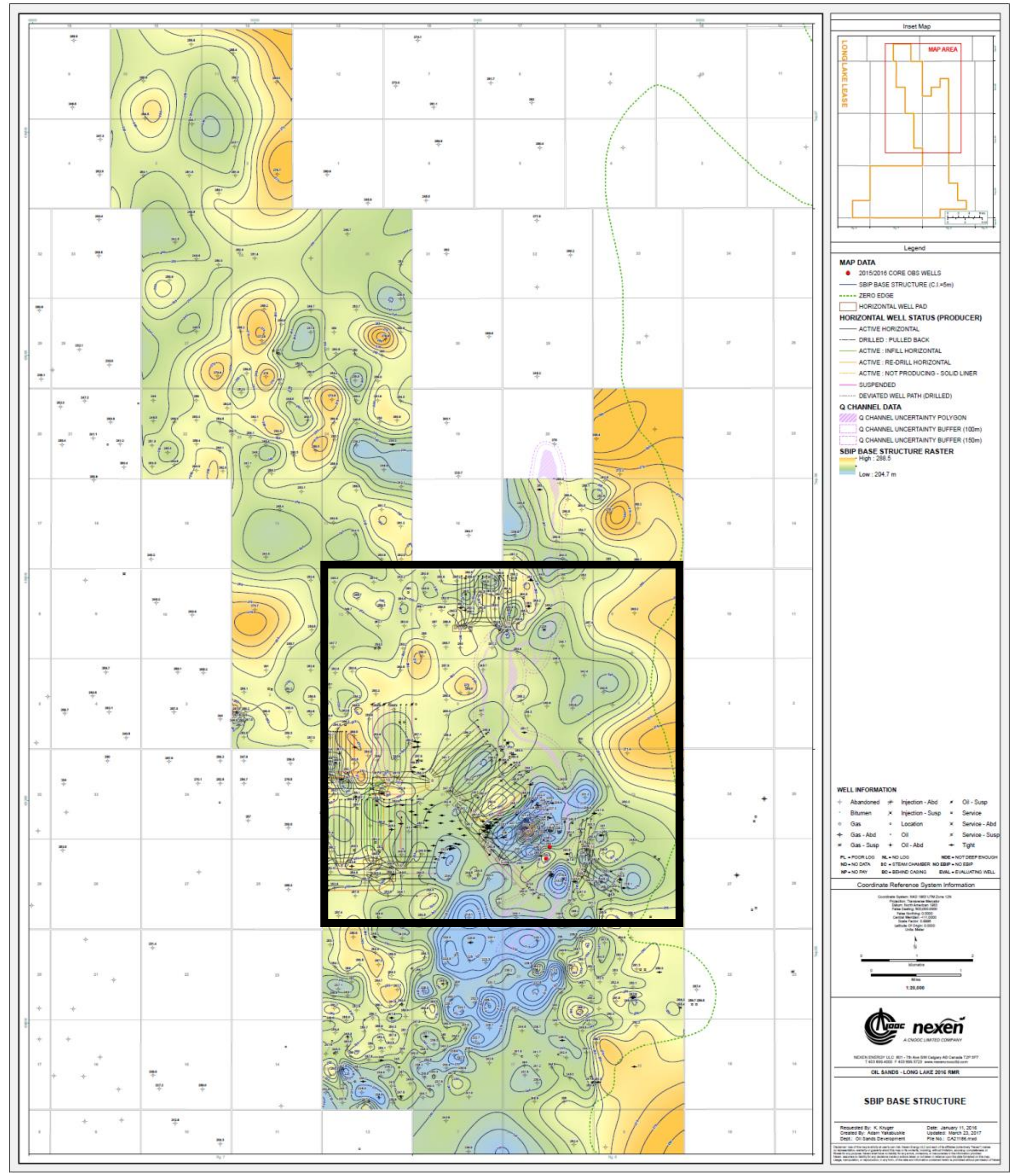
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP BASE STRUCTURE RASTER

High : 288.5

Low : 204.7 m



Long Lake
SBIP Pay Interval Base Structure

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Legend

MAP DATA
- 2015/2016 CORE OBS WELLS
- SBIP BASE STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD

HORIZONTAL WELL STATUS (PRODUCER)
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- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
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- ACTIVE : NOT PRODUCING - SOLID LINER
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- DEVIATED WELL PATH (DRILLED)

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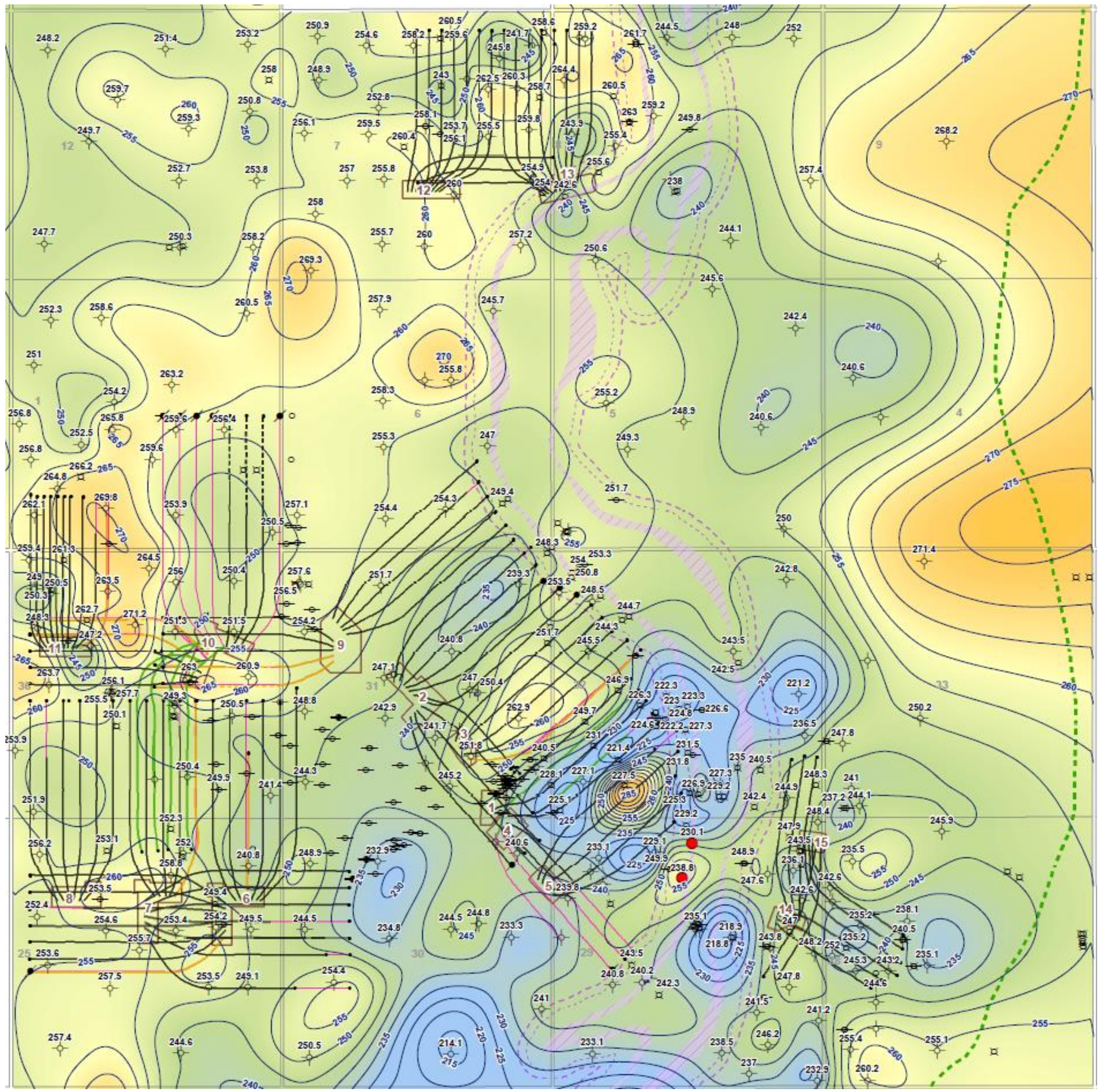
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP BASE STRUCTURE RASTER
High : 288.5
Low : 204.7 m



- Base of SBIP Pay Interval influenced by facies changes, karsting, erosion, salt dissolution, and bottom water

Long Lake
SBIP Pay Interval Top Structure

Legend

MAP DATA

- 2015/2016 CORE OBS WELLS
- SBIP TOP STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

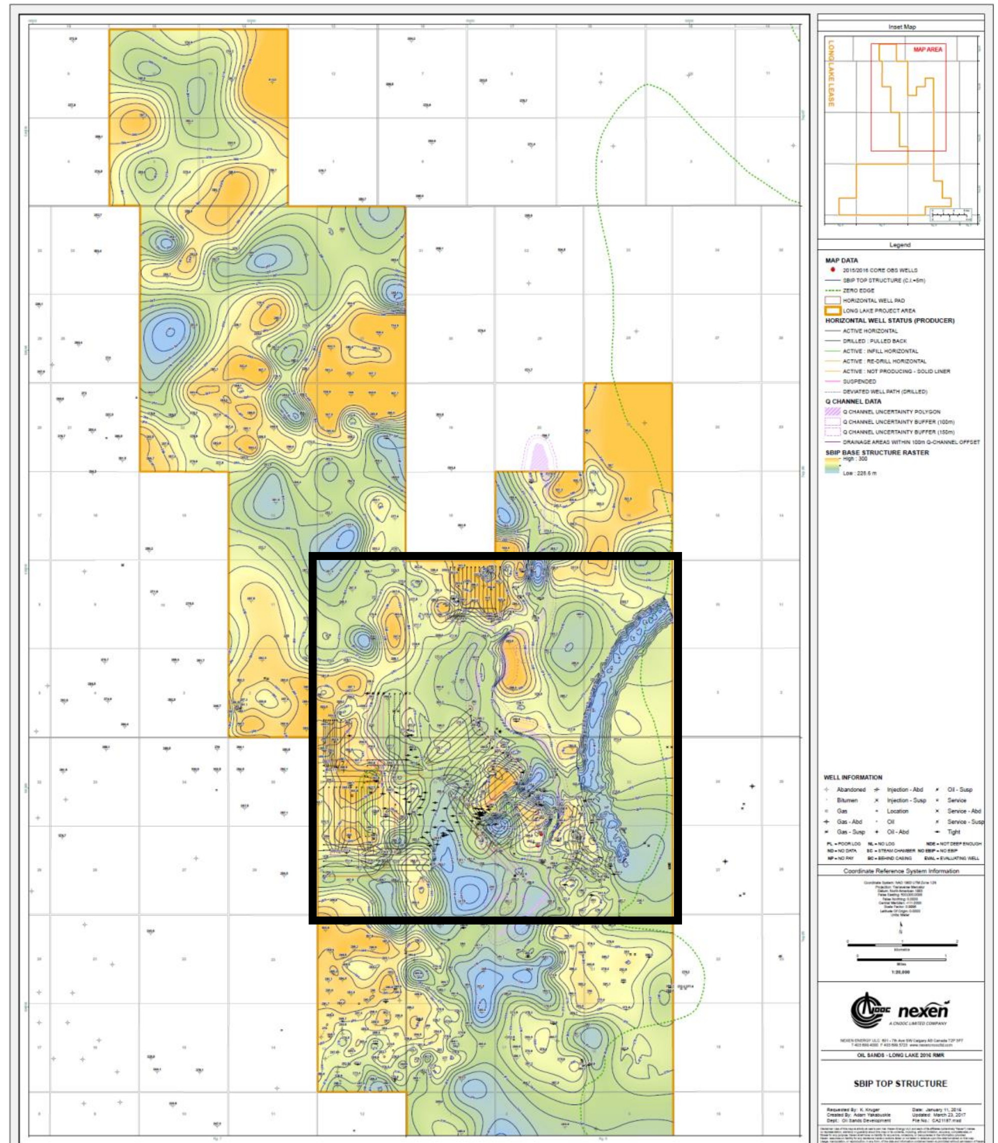
Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP BASE STRUCTURE RASTER

High : 300

Low : 228.6 m



Long Lake
SBIP Pay Interval Top Structure

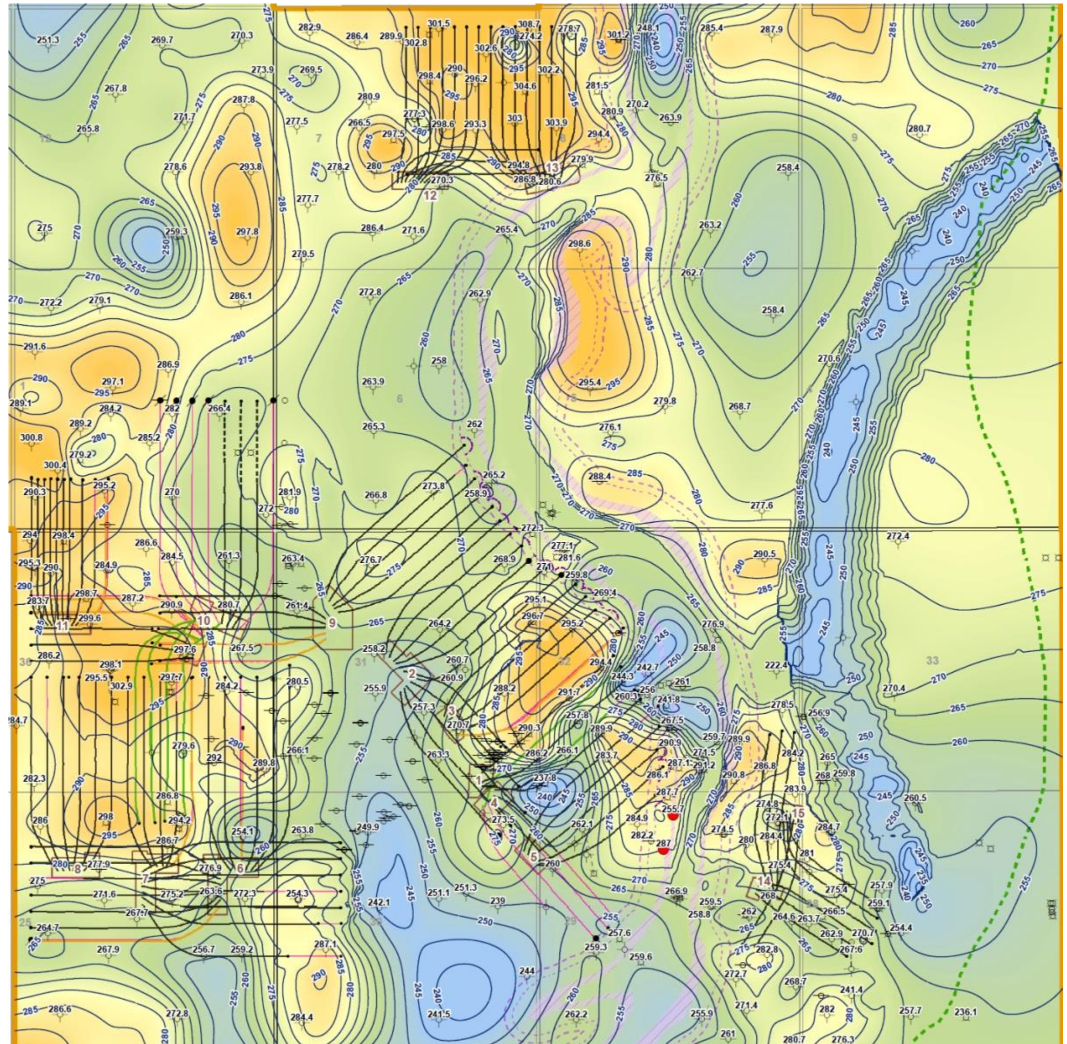
Legend

MAP DATA
- 2015/2016 CORE OBS WELLS
- SBIP TOP STRUCTURE (C.I.=5m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

SBIP BASE STRUCTURE RASTER
- High : 300
- Low : 228.6 m



- Top of SBIP Pay Interval:
  - base of 2m or thicker shale
  - cumulative 4m shale
  - base of top gas
  - base of top water
  - top of McMurray tidal-fluvial estuarine complexes
- Bitumen in regional McMurray shorefaces and the McMurray A1 are not considered pay

Kinosis
Structure of SBIP Base

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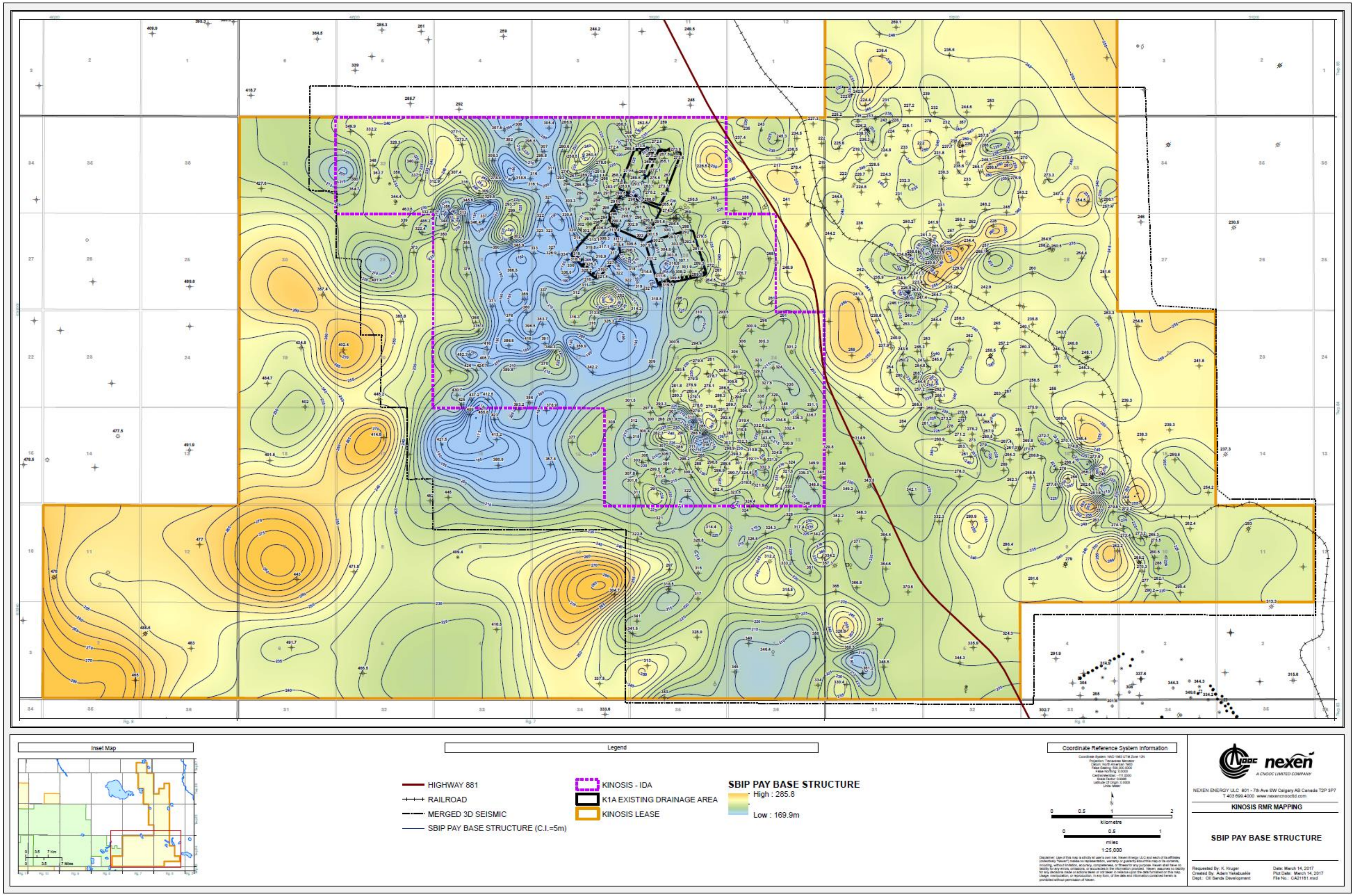
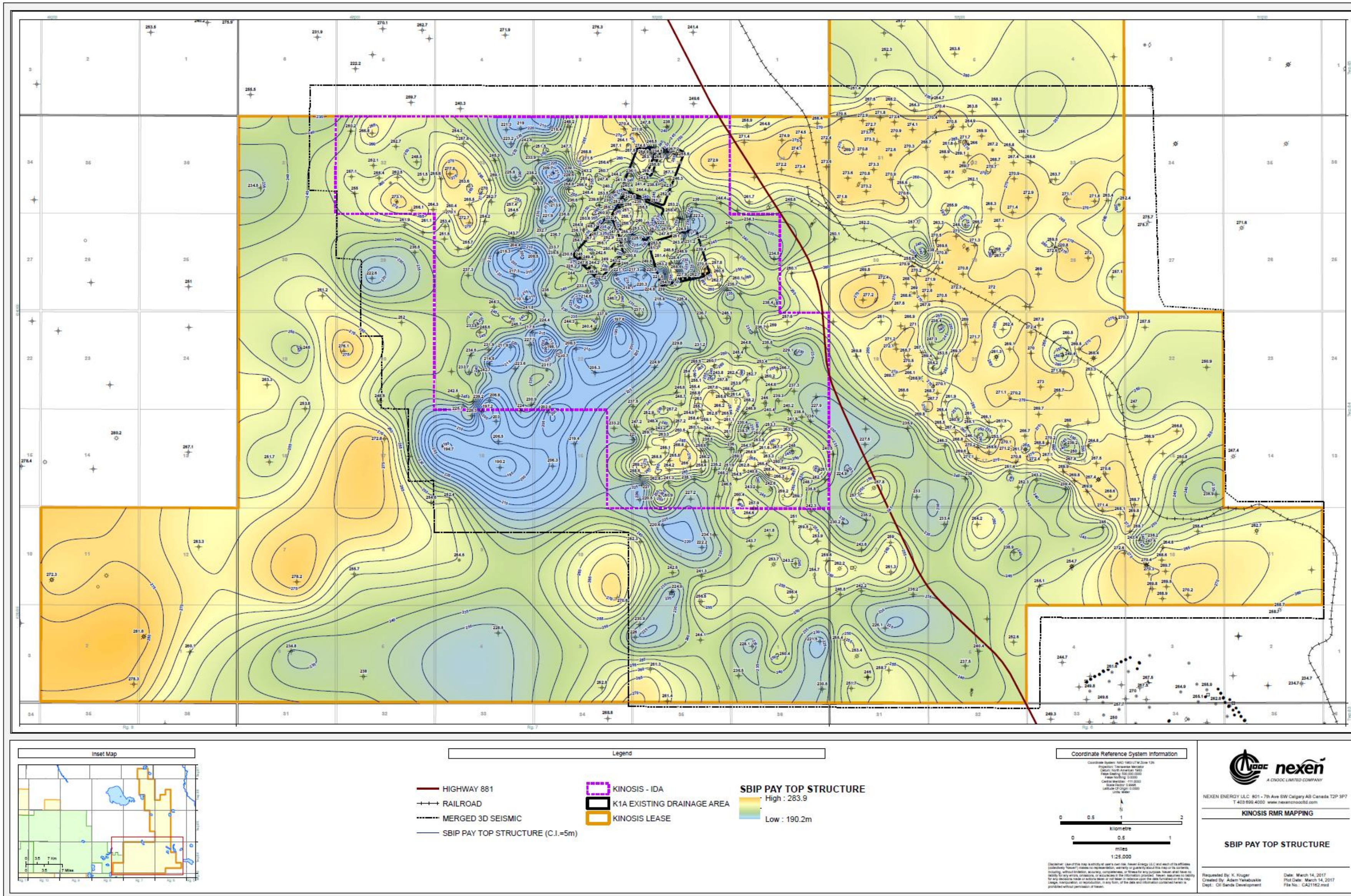


Kinosis
Structure of SBIP Top



Long Lake
HPVH Isopach over SBIP Pay Interval

Legend

- 2015/2016 CORE OBS WELLS
- SBIP HPVH ISOPACH (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

- K1A PROSPECT

Q CHANNEL DATA

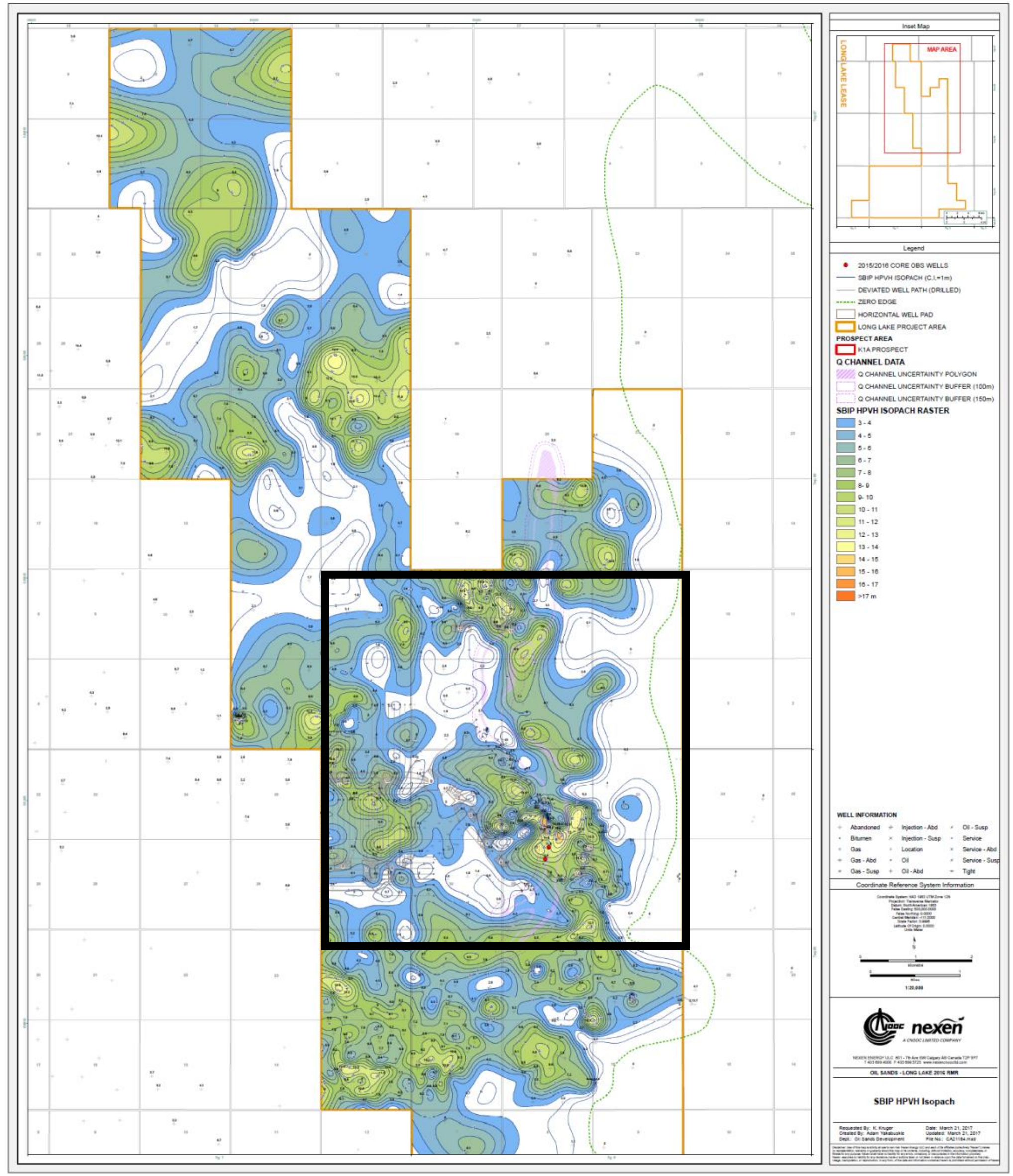
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP HPVH ISOPACH RASTER

- 3 - 4
- 4 - 5
- 5 - 6
- 6 - 7
- 7 - 8
- 8- 9
- 9- 10
- 10 - 11
- 11 - 12
- 12 - 13
- 13 - 14
- 14 - 15
- 15 - 16
- 16 - 17
- >17 m

$$HPVH = \sum_{\text{Min pay bs}}^{\text{Min pay tp}} (So^{*}\Phi)$$

- Colour shading : > $3m^3/m^2$ HPVH



Long Lake
HPVH Isopach over SBIP Pay Interval

Legend

- 2015/2016 CORE OBS WELLS
- SBIP HPVH ISOPACH (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

PROSPECT AREA

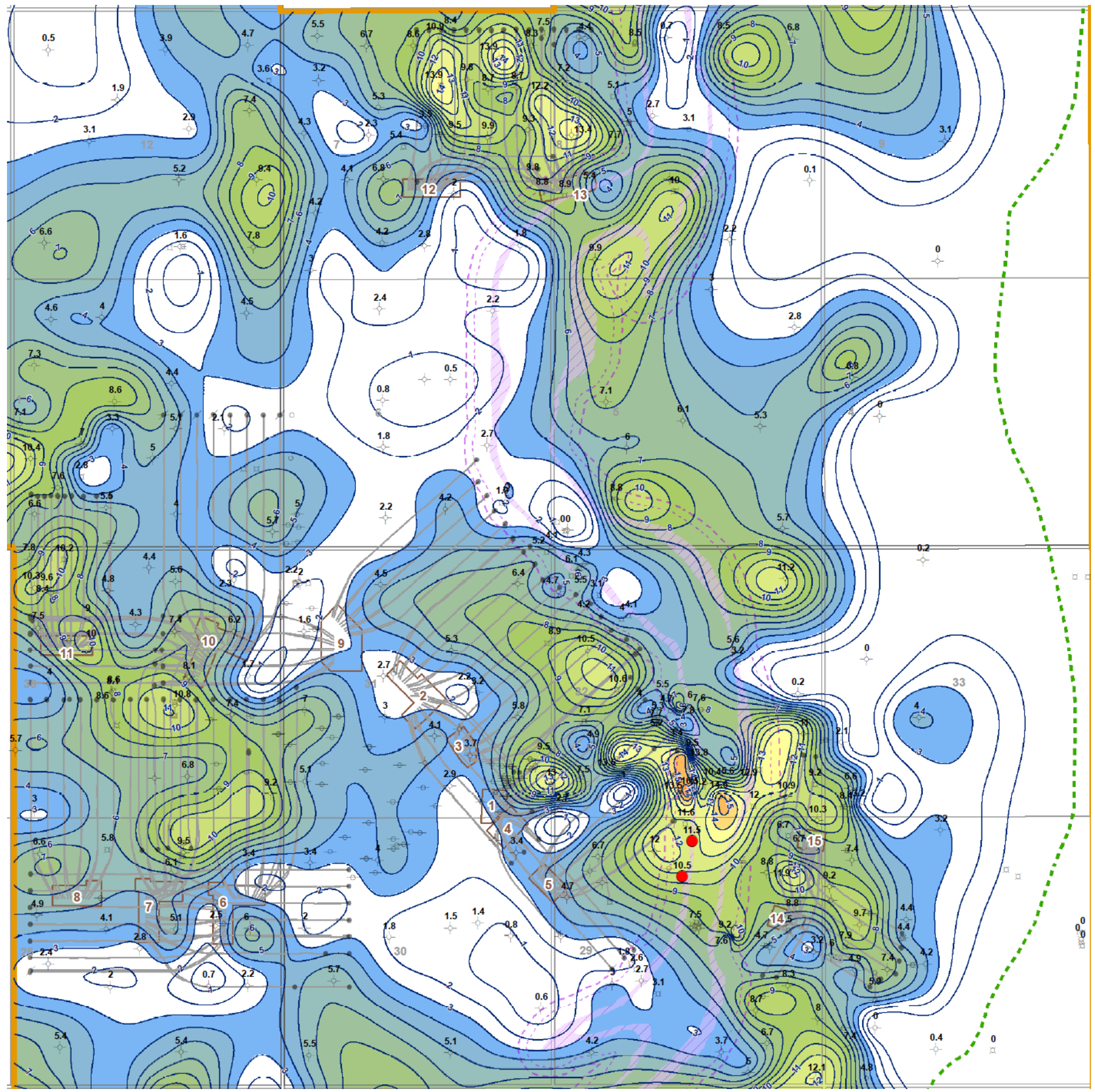
- K1A PROSPECT

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

SBIP HPVH ISOPACH RASTER

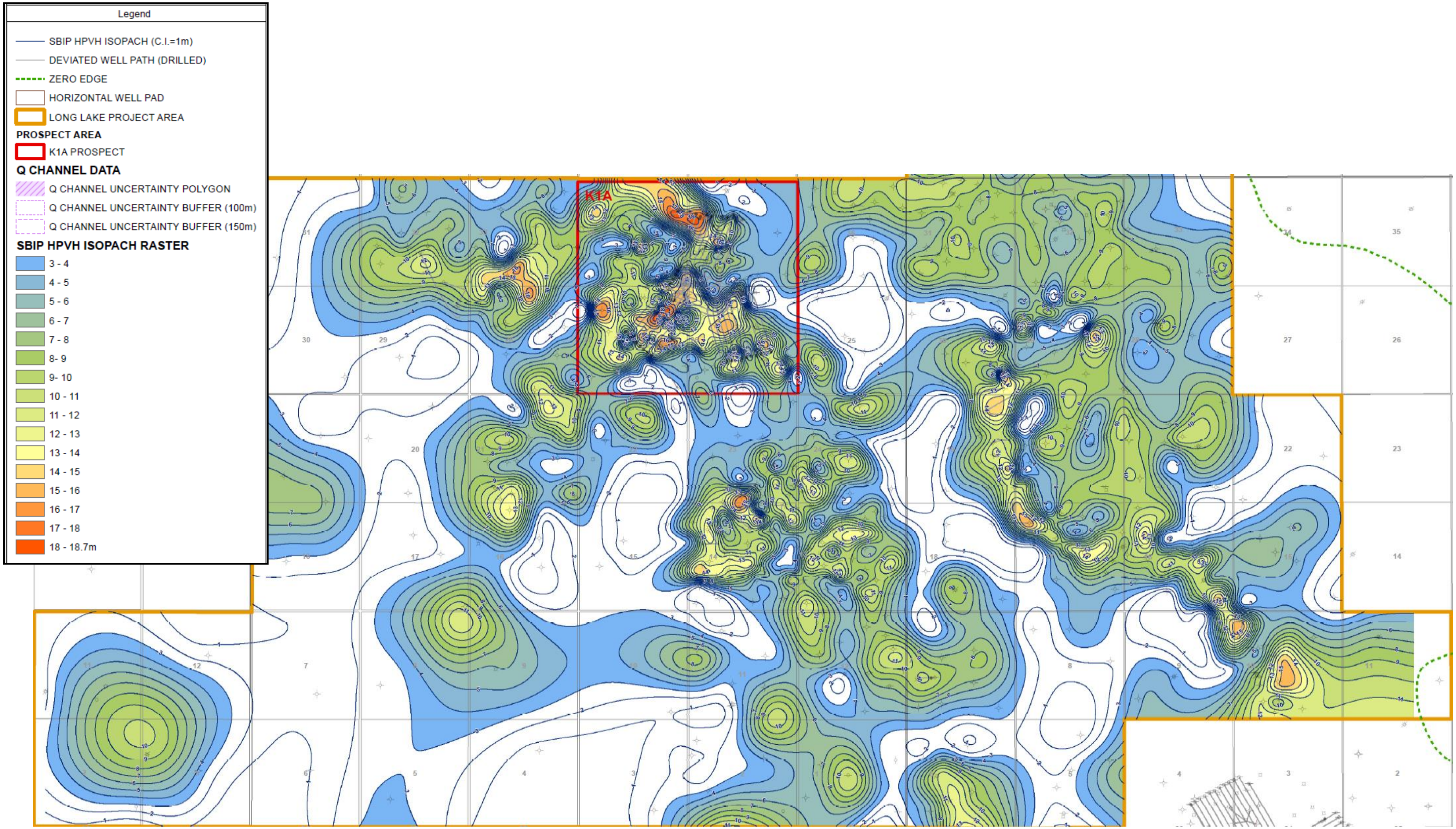
- 3 - 4
- 4 - 5
- 5 - 6
- 6 - 7
- 7 - 8
- 8- 9
- 9- 10
- 10 - 11
- 11 - 12
- 12 - 13
- 13 - 14
- 14 - 15
- 15 - 16
- 16 - 17
- >17 m



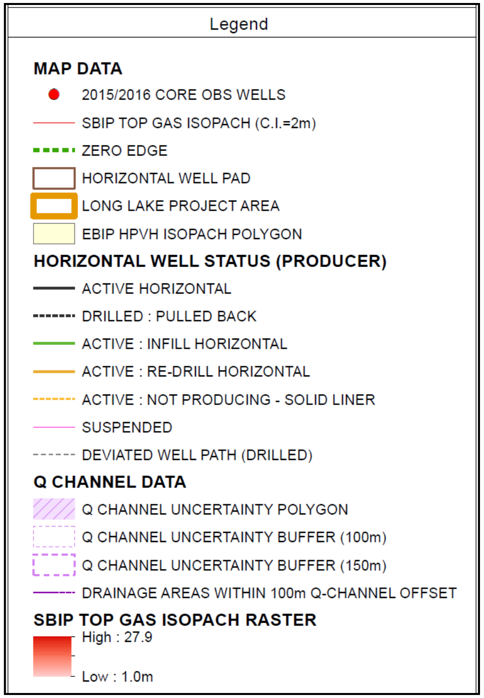
$$HPVH = \sum_{\text{Min pay bs}}^{\text{Min pay tp}} (So*\Phi)$$

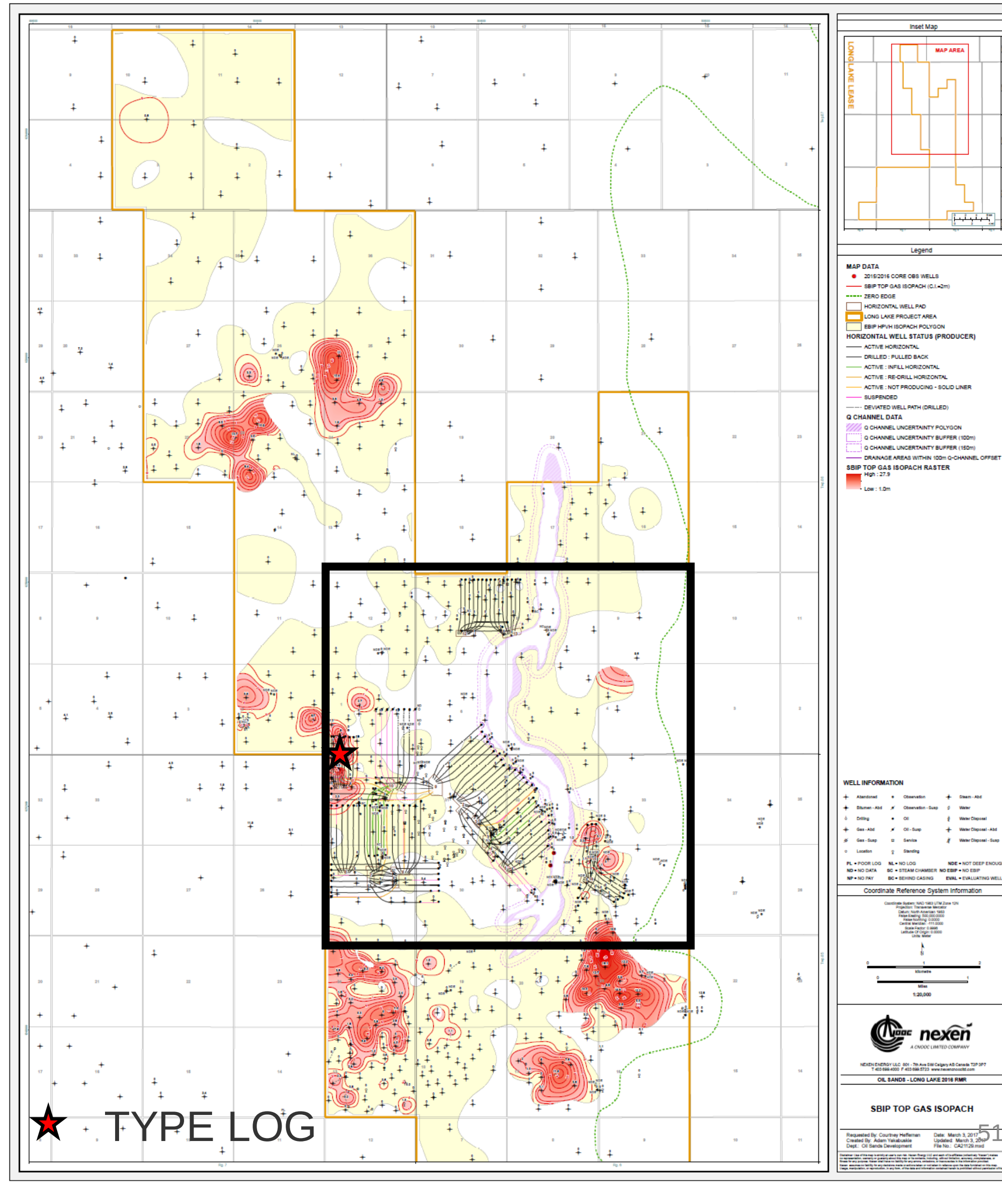
- Colour shading : > $3m^3/m^2$ HPVH

Kinosis
HPVH Isopach over SBIP Interval



Long Lake Total Gas: Gas Interval(s) within and in contact with SBIP Interval





- Gas identified by neutron/density crossover
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to $3m^3/m^2$ HPVH SBIP contour

Long Lake Total Gas: Gas Interval(s) within and in contact with SBIP Interval

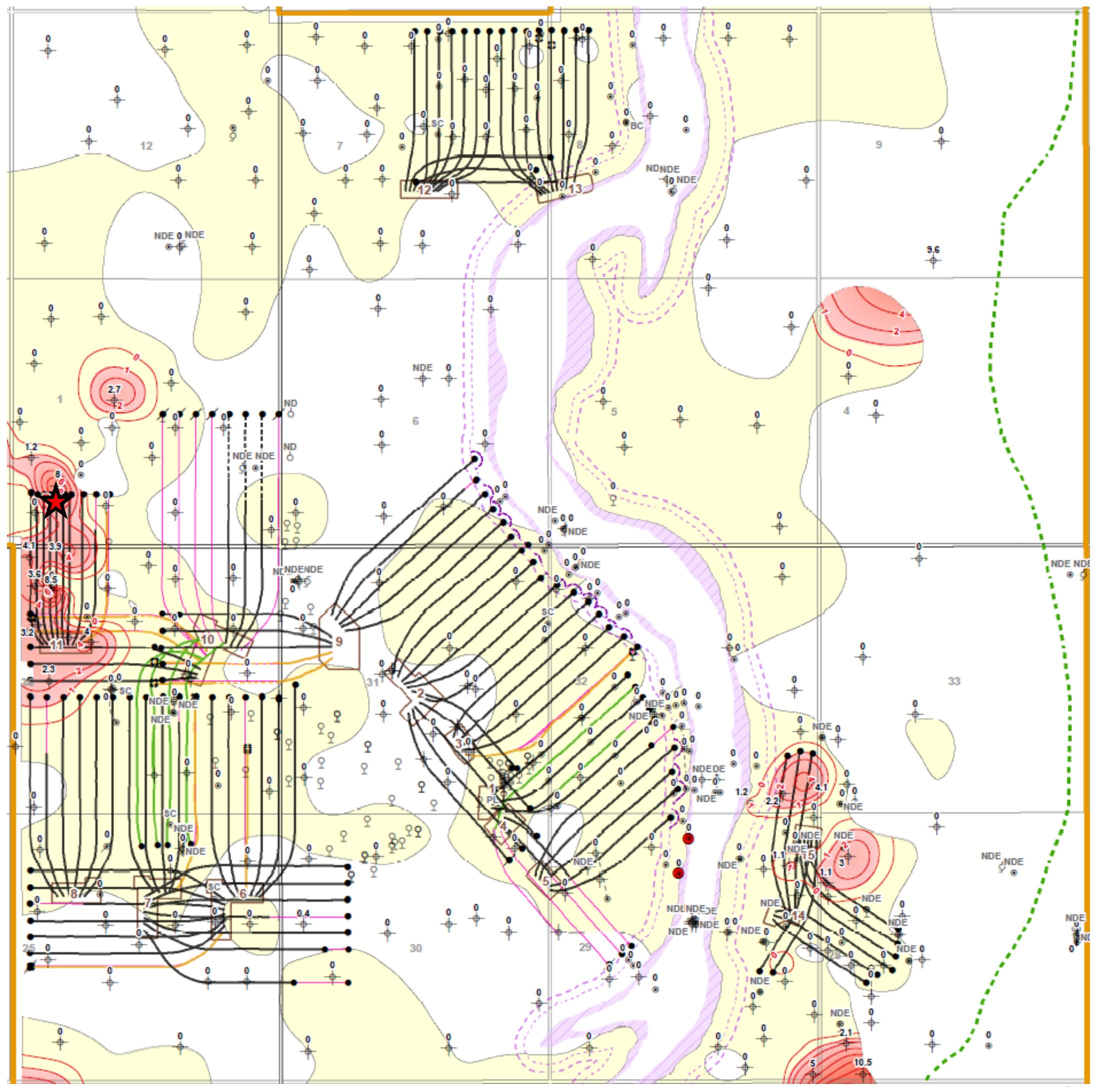
Legend

MAP DATA
- 2015/2016 CORE OBS WELLS
- SBIP TOP GAS ISOPACH (C.I.=2m)
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- EBIP HPVH ISOPACH POLYGON

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

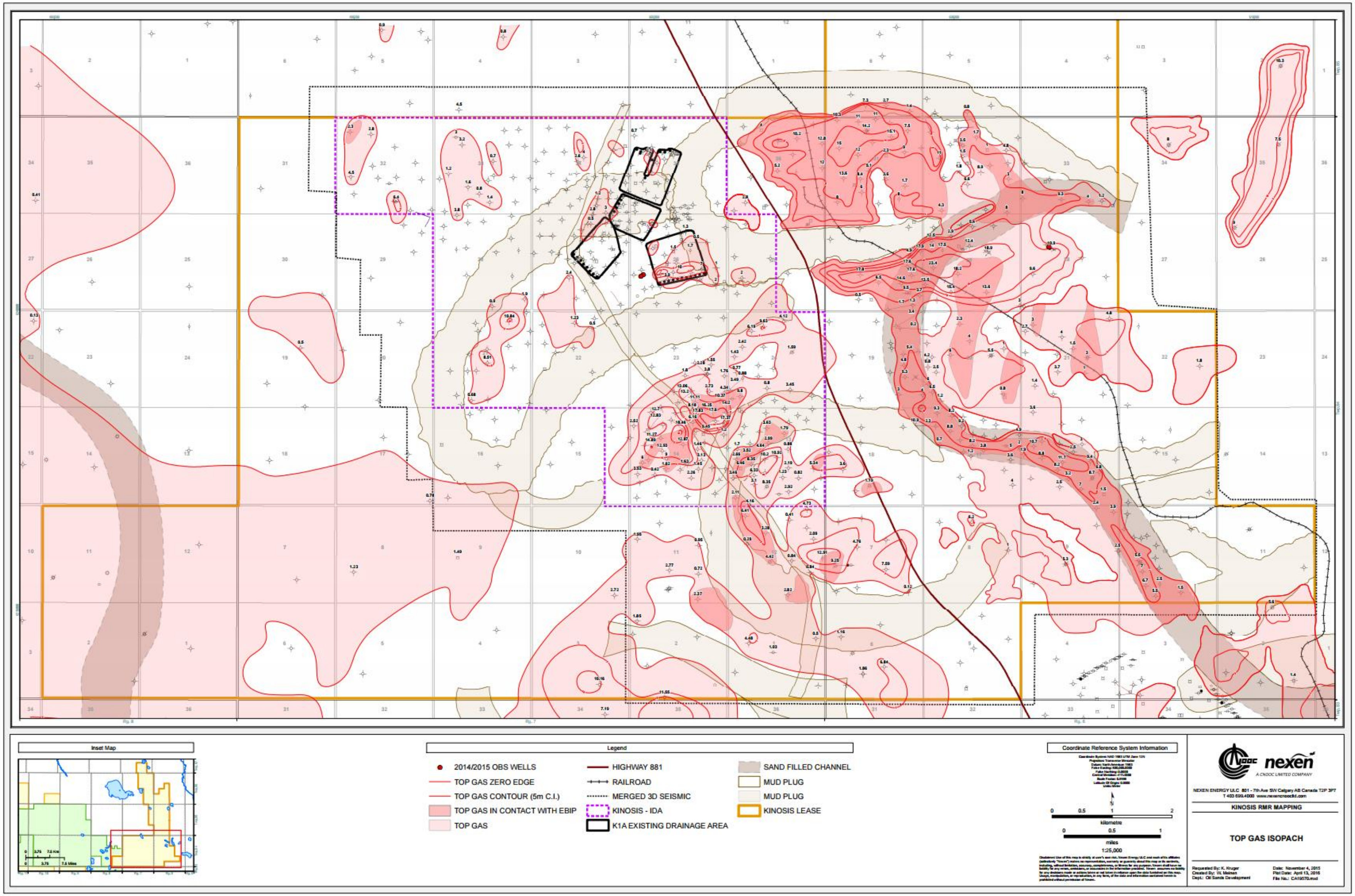
SBIP TOP GAS ISOPACH RASTER
- High : 27.9
- Low : 1.0m



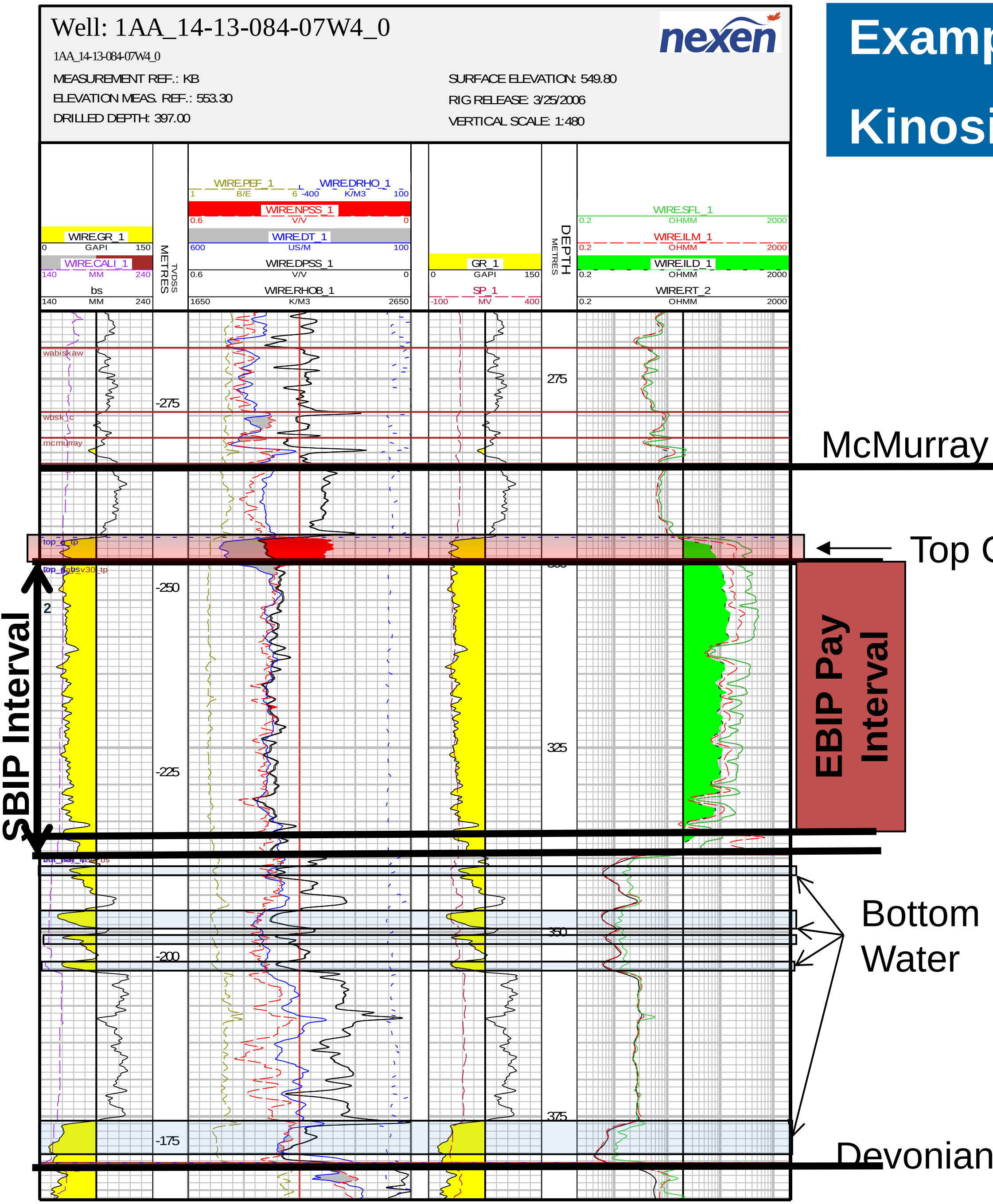
- Gas identified by neutron/density crossover
- Gas associated with SBIP Interval;
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to 3m³/m² HPVH SBIP contour

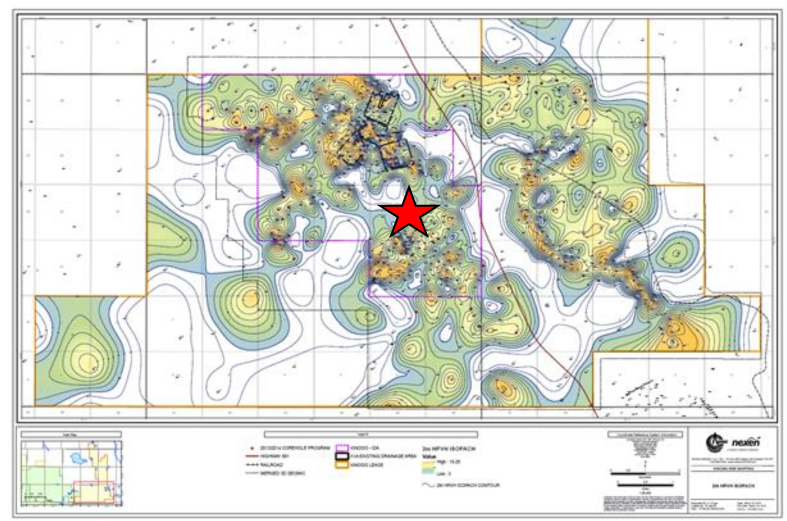
★ TYPE LOG

Kinosis
Top Gas in the McMurray

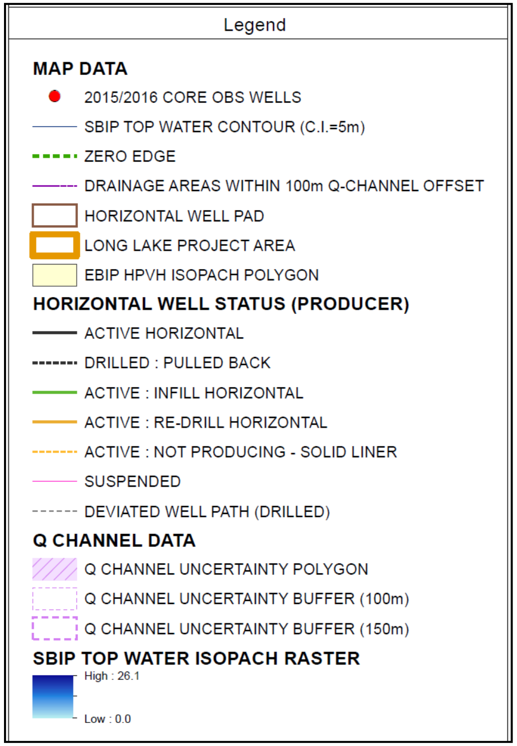


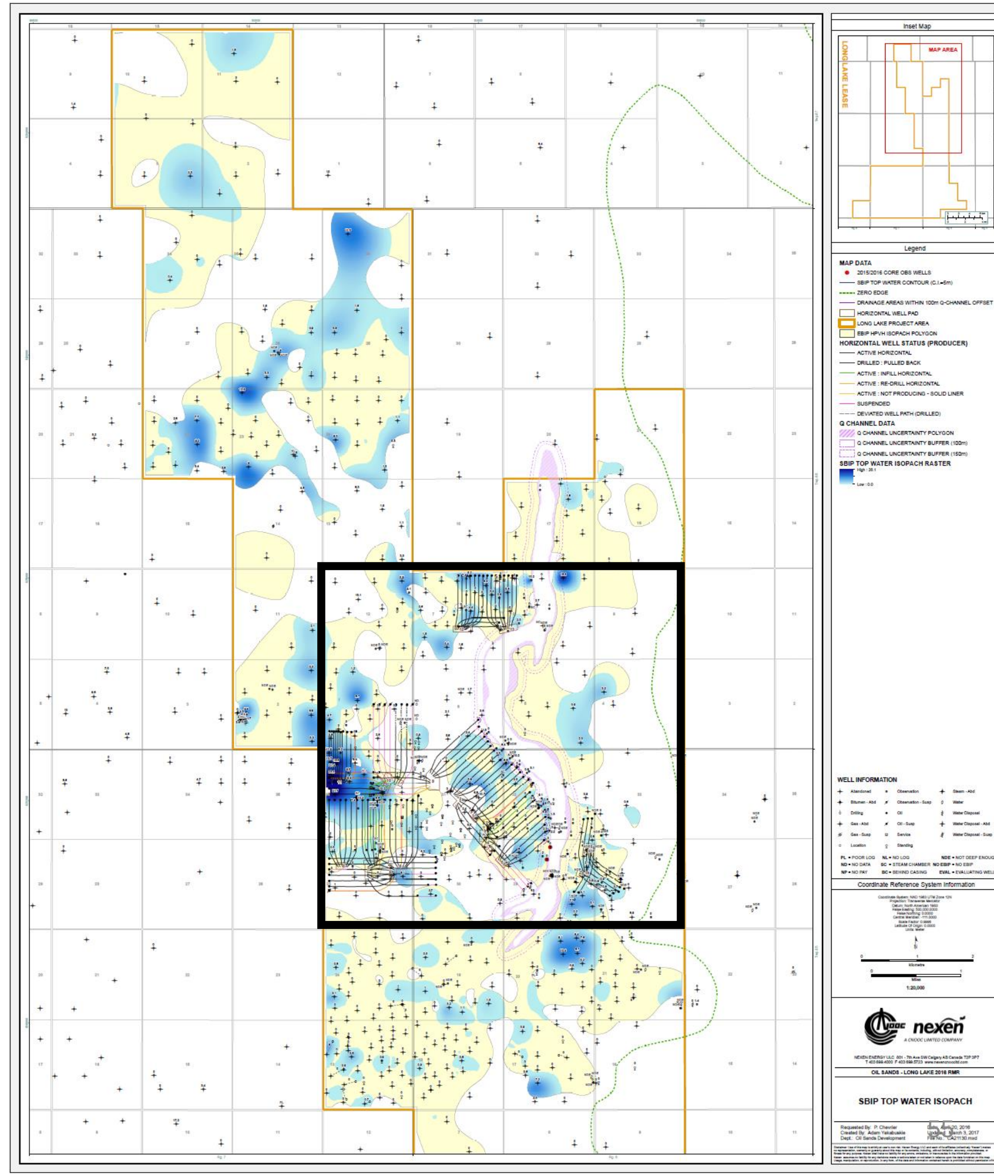
Example Log: Kinosis IDA





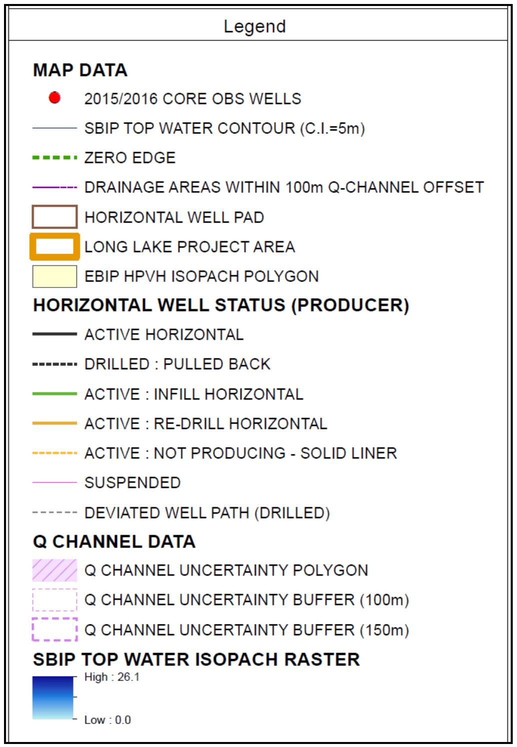
Long Lake
Top Water Associated with SBIP Interval

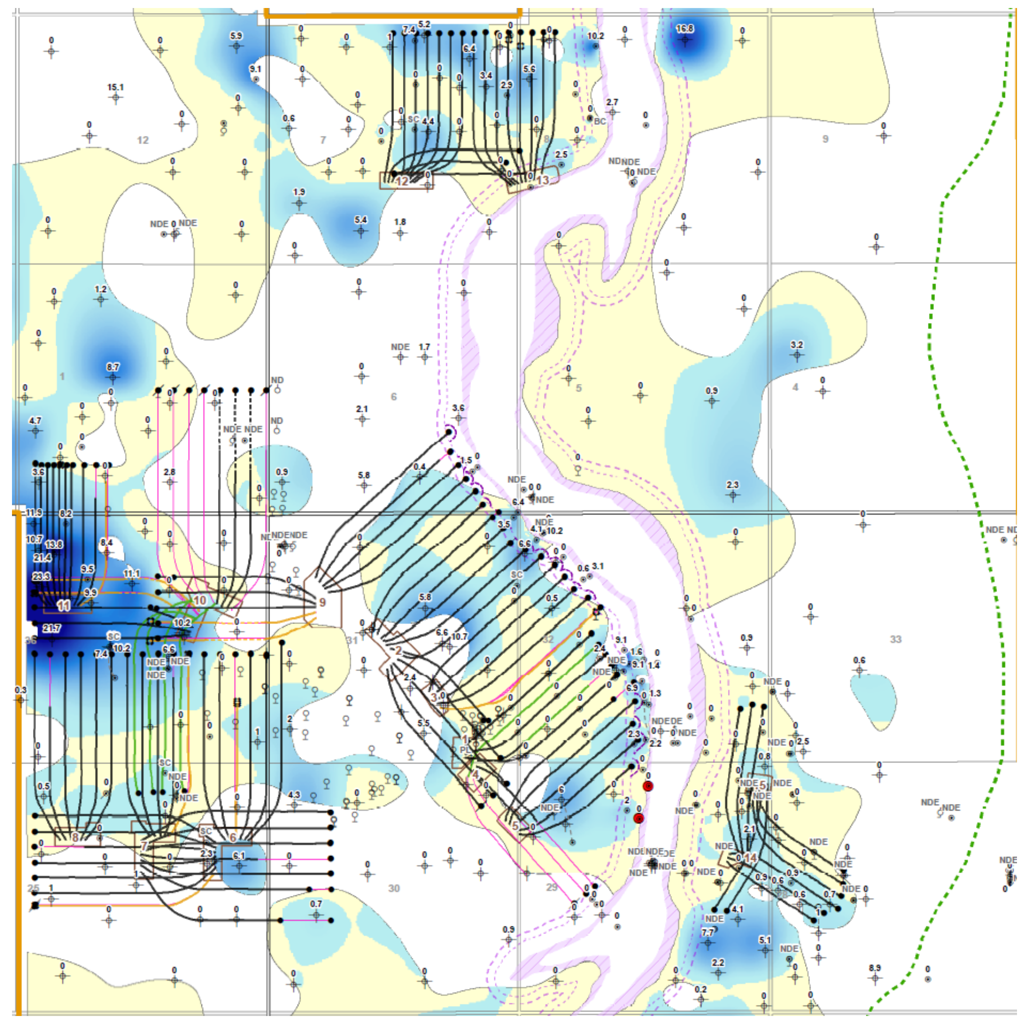




- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3 m^3/m^2$ HPVH SBIP contour

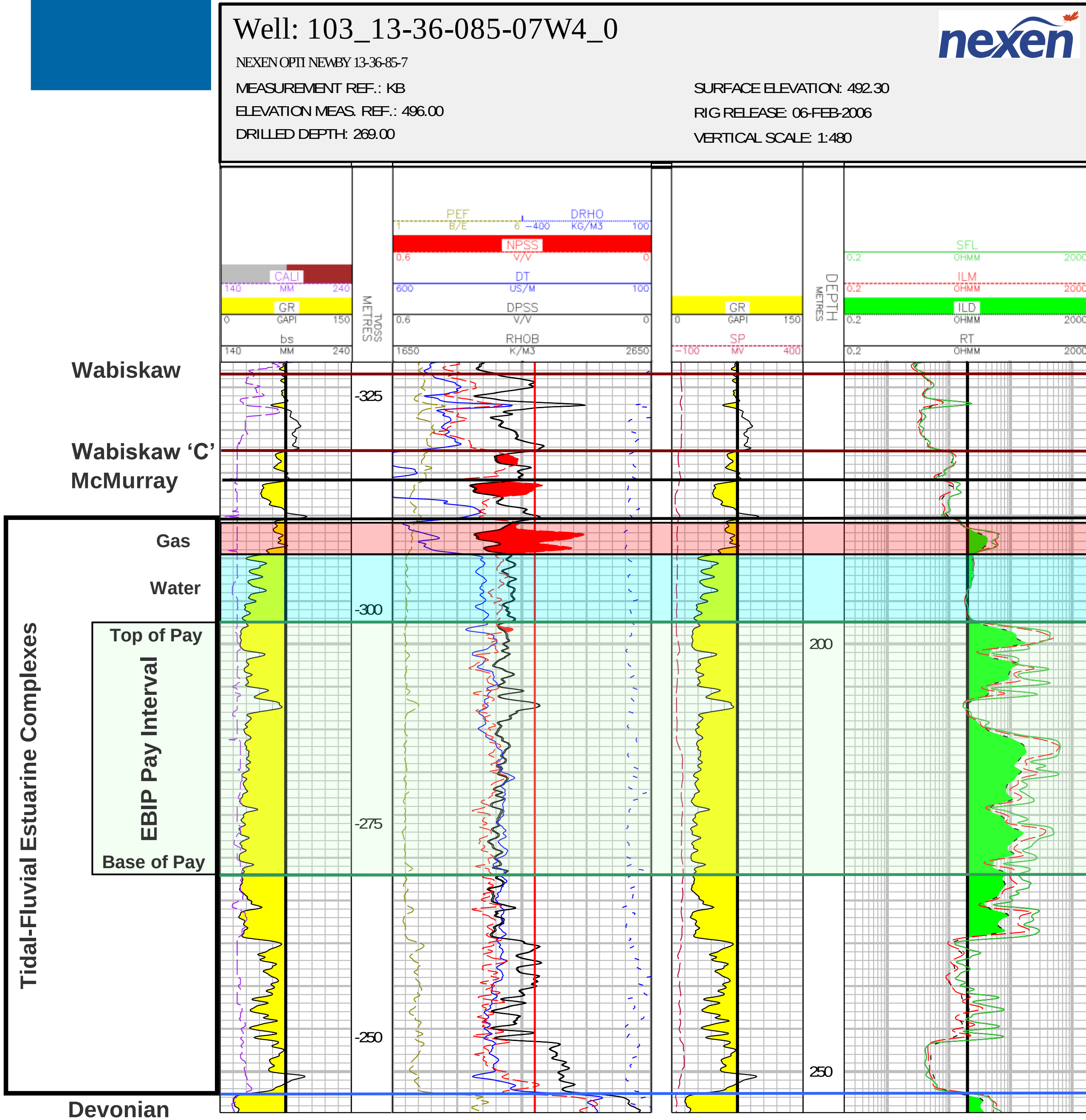
Long Lake
Top Water Associated with SBIP Interval

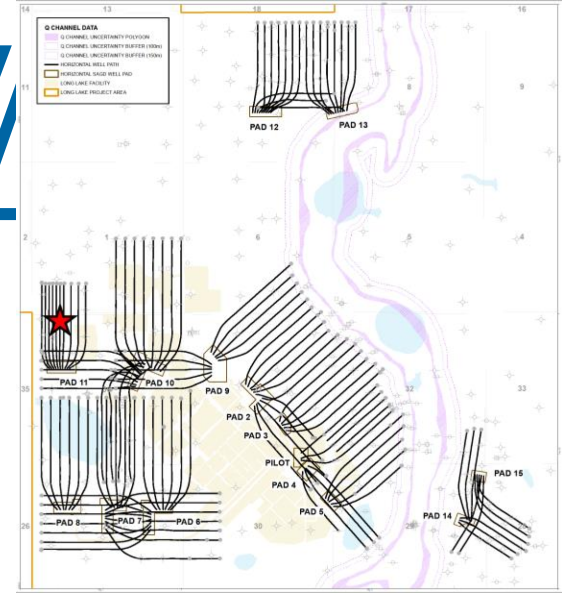


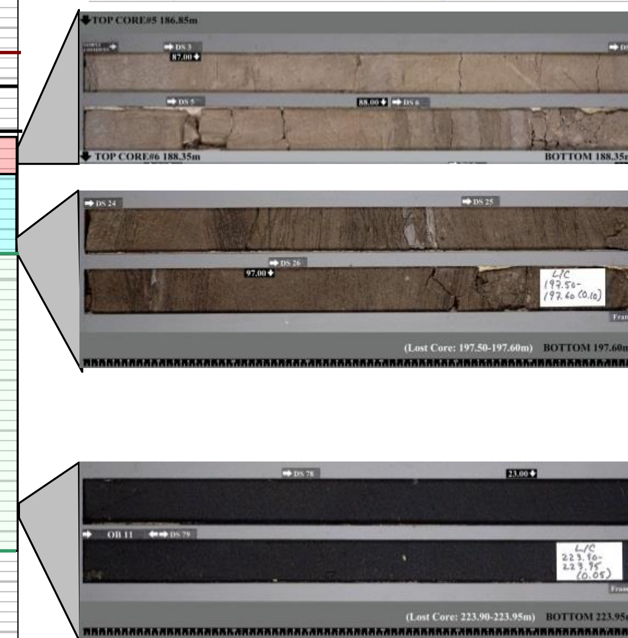


- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH SBIP contour

Top Impairment Type Log – 103/13-36-085-07W4







Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval

Legend

- ● 2015/2016 CORE OBS WELLS
- SBIP HWSI TOTAL ISOPACH (C.I.=5m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- EBIP_HPVH_POLYGON_RMR2015_QCH

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA

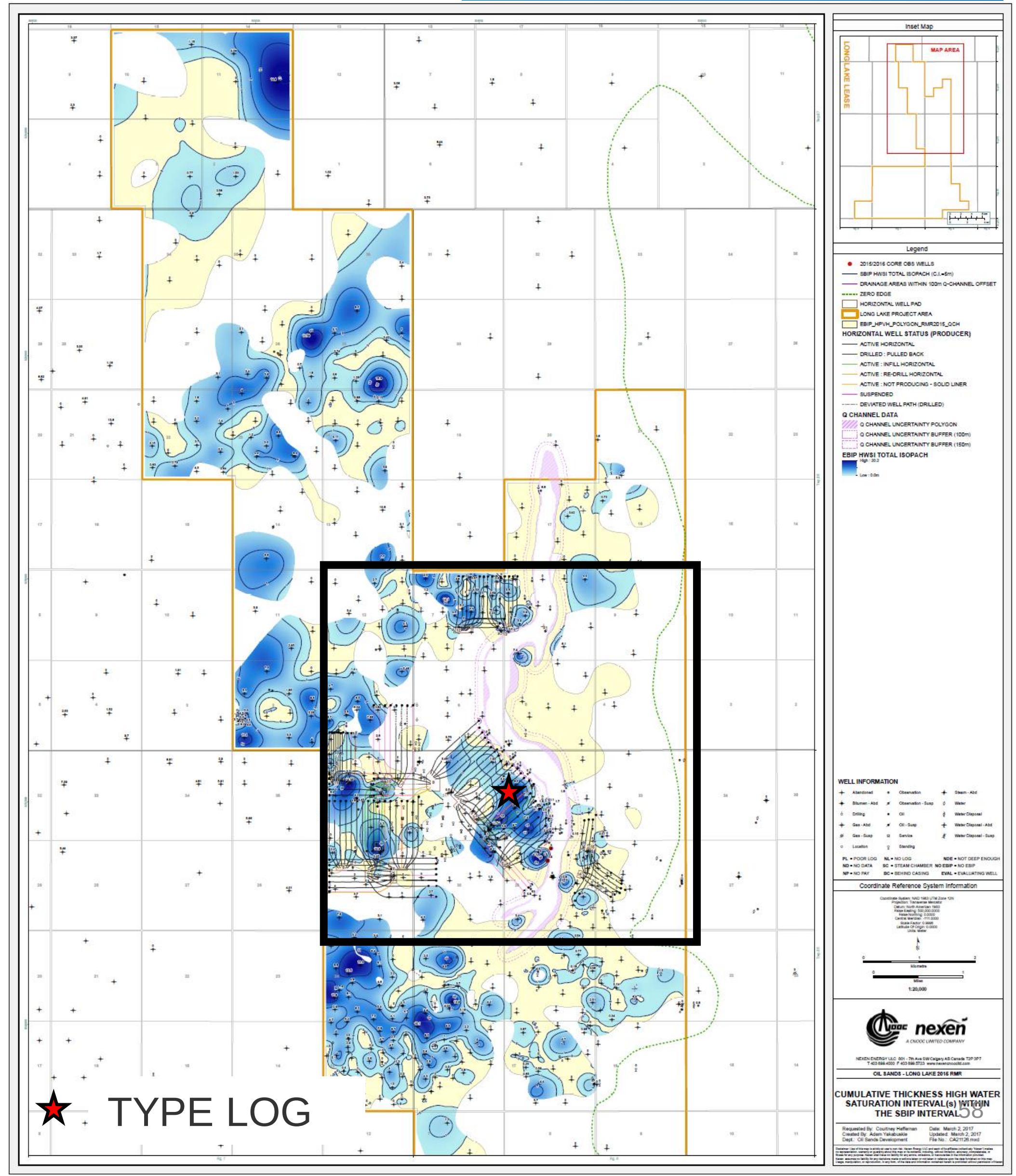
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

EBIP HWSI TOTAL ISOPACH

High : 20.2

Low : 0.0m

- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour



Long Lake Cumulative Thickness of High Water Saturation Interval(s) within EBIP Interval

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Legend

- 2015/2016 CORE OBS WELLS
- SBIP HWSI TOTAL ISOPACH (C.I.=5m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- EBIP_HPVH_POLYGON_RMR2015_QCH

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
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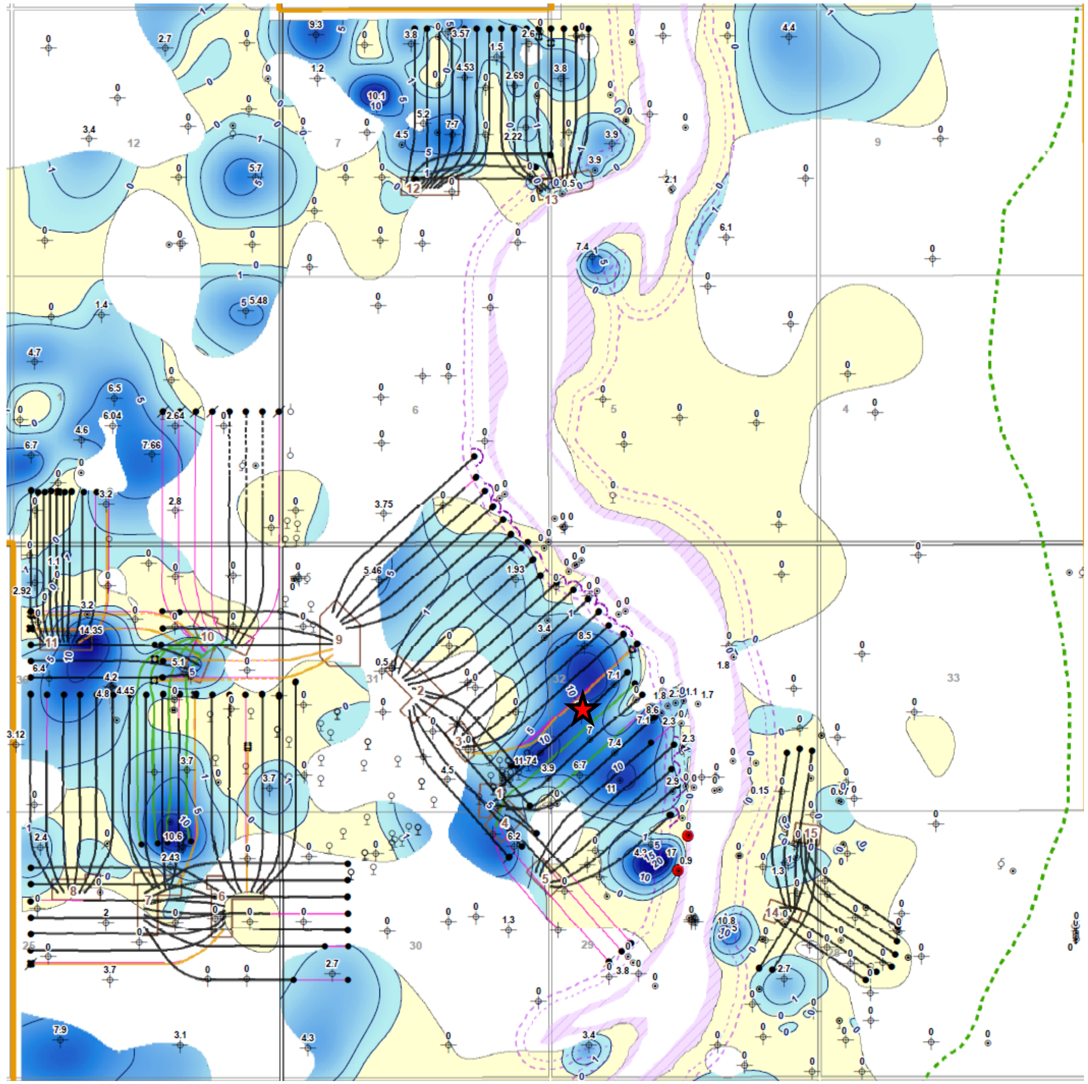
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

EBIP HWSI TOTAL ISOPACH

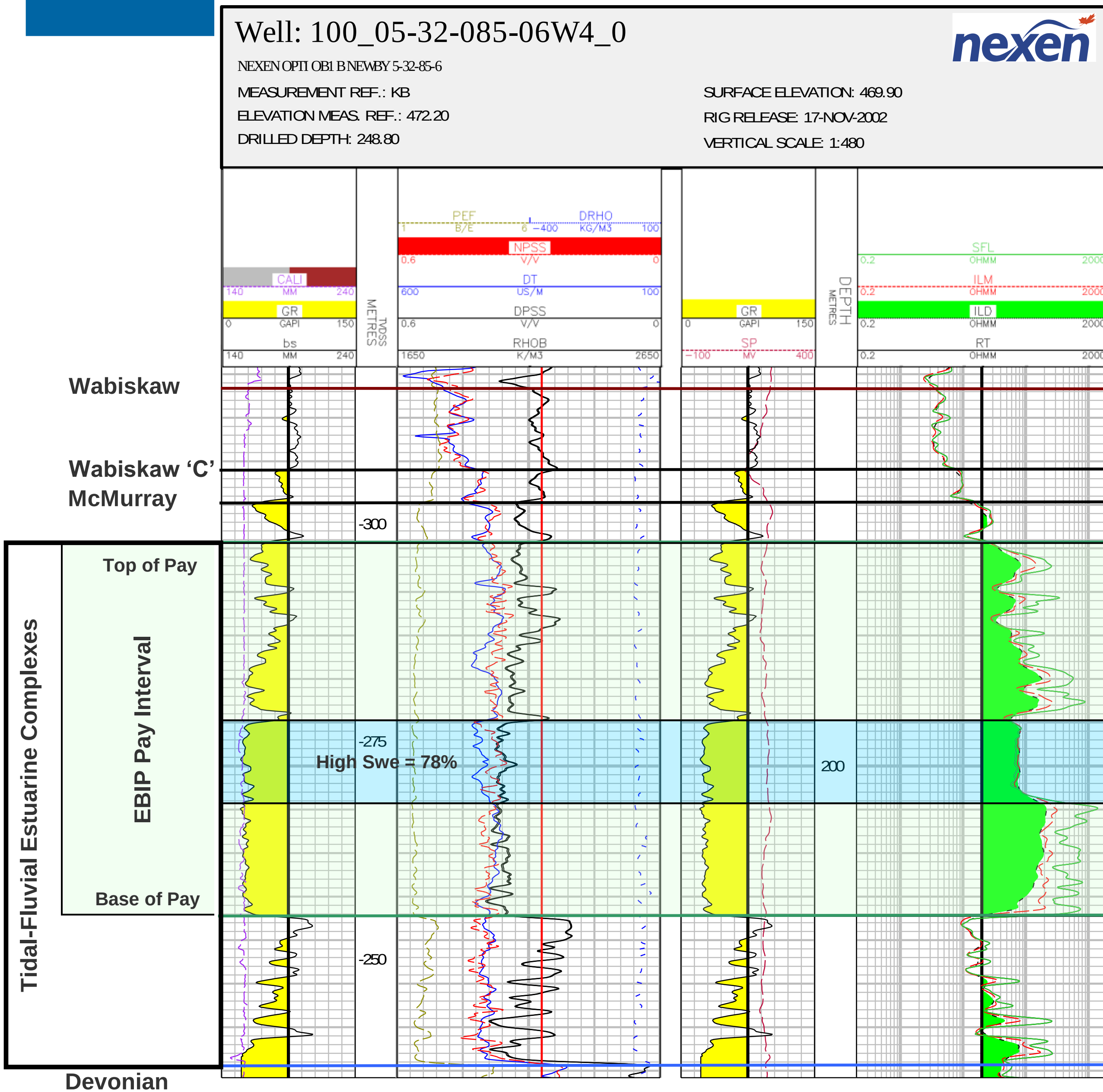
High : 20.2
Low : 0.0m

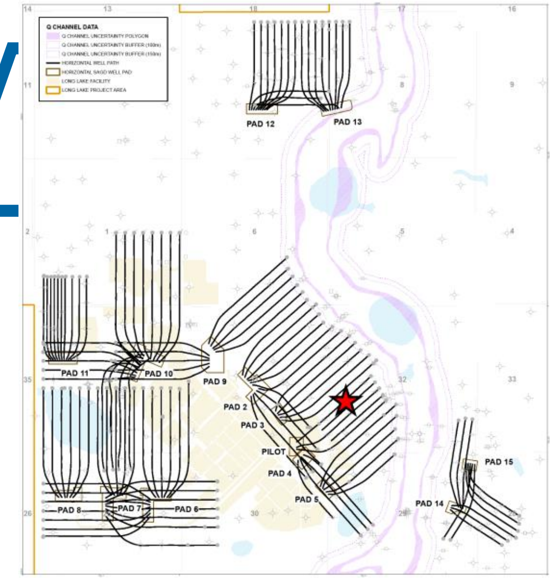


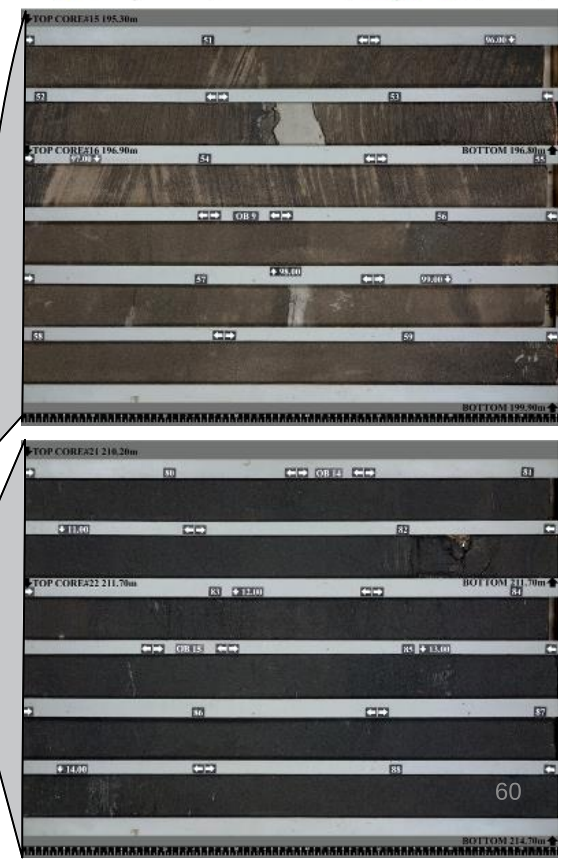
- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to 3m^3/m^2 HPVH EBIP contour

★ TYPE LOG

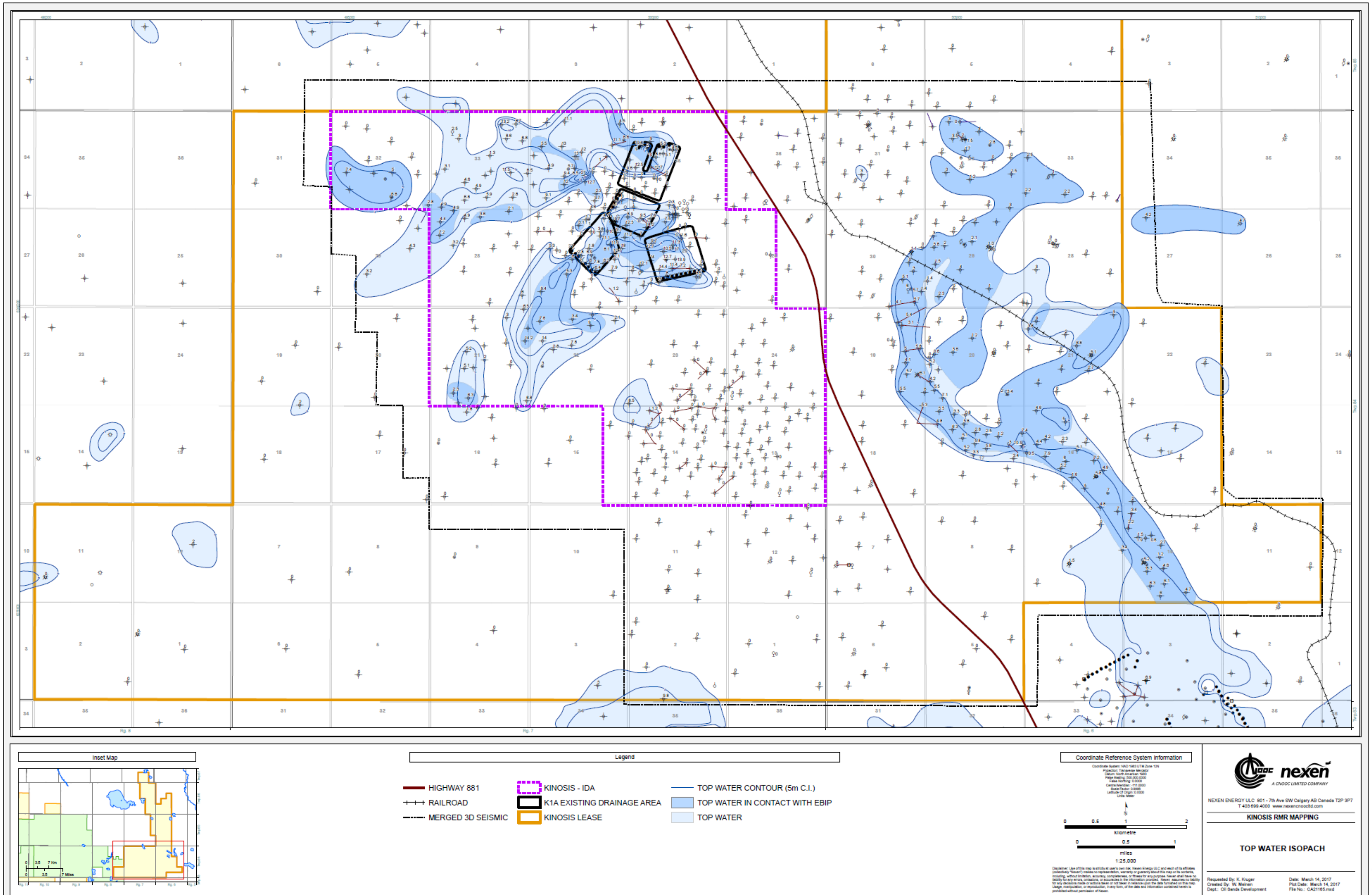
High Water Saturation Type Log 100/05-32-085-06W4



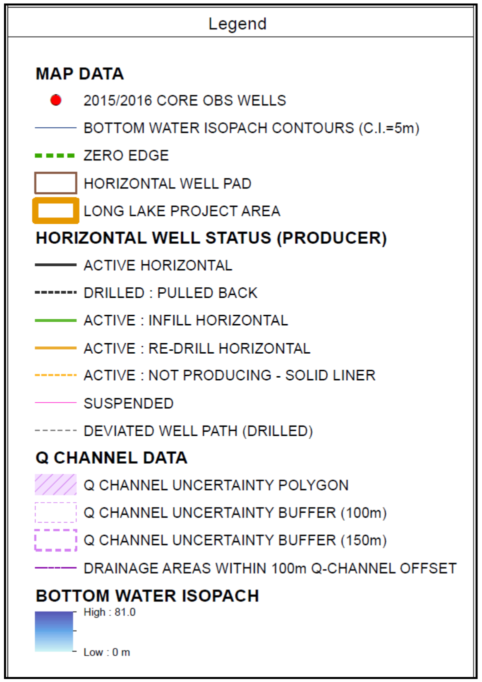


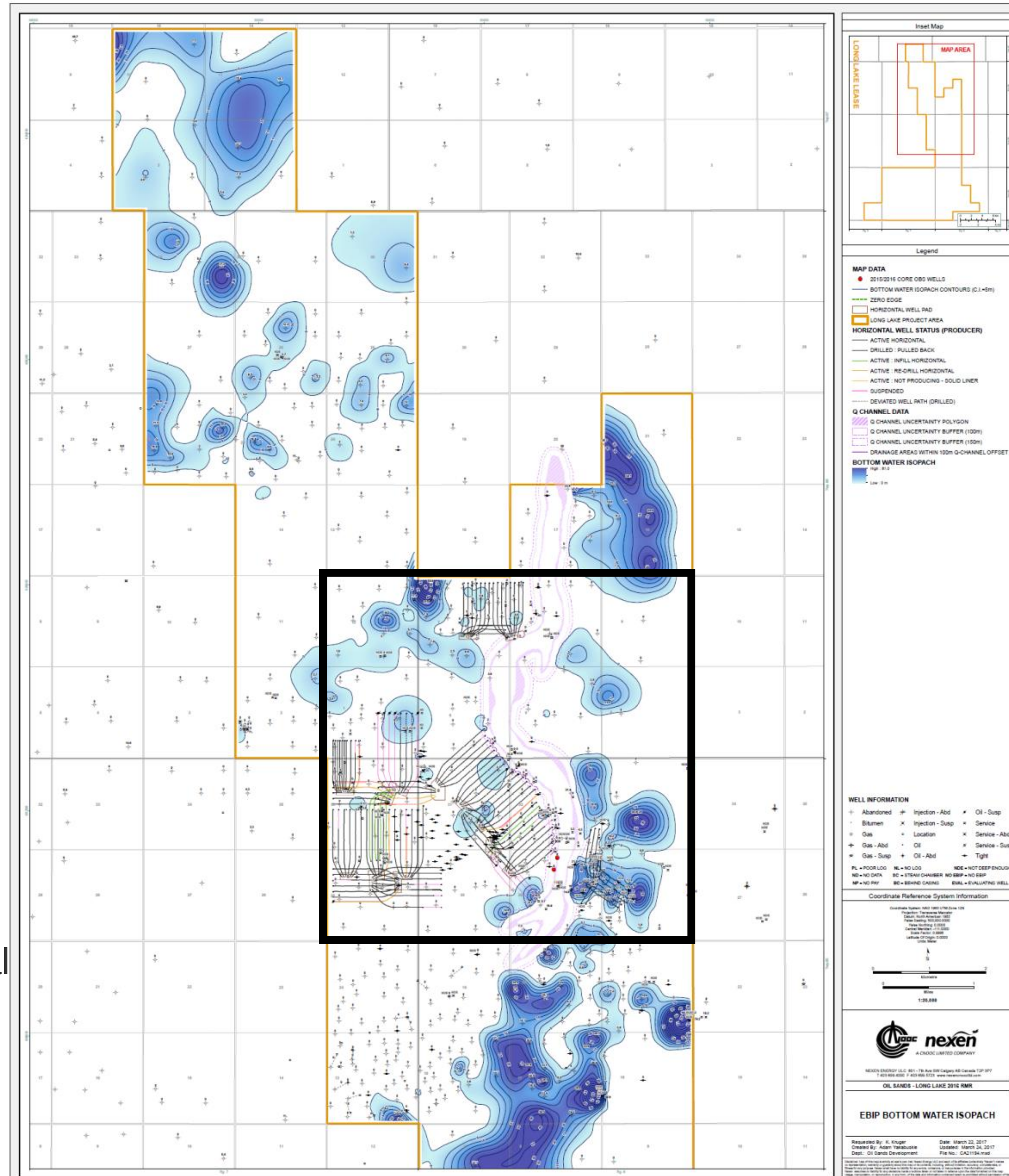


Kinosis
Top Water in the McMurray



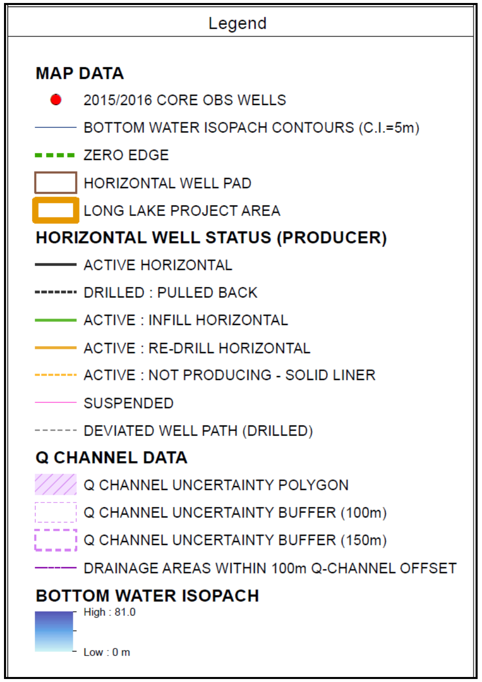
Long Lake
Bottom Water Associated with EBIP Interval

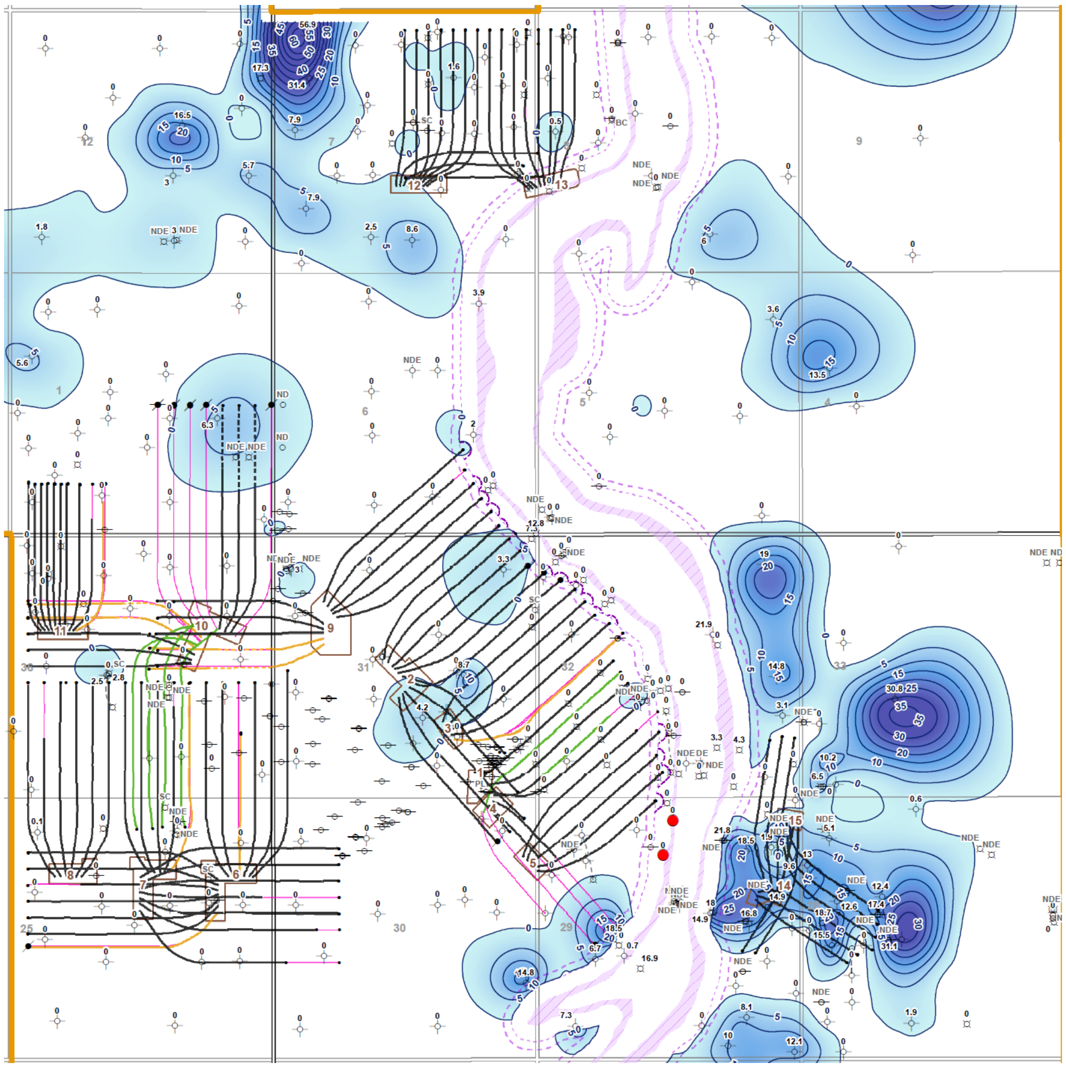




- > 50% Swe and < 30% V_{shale}.
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

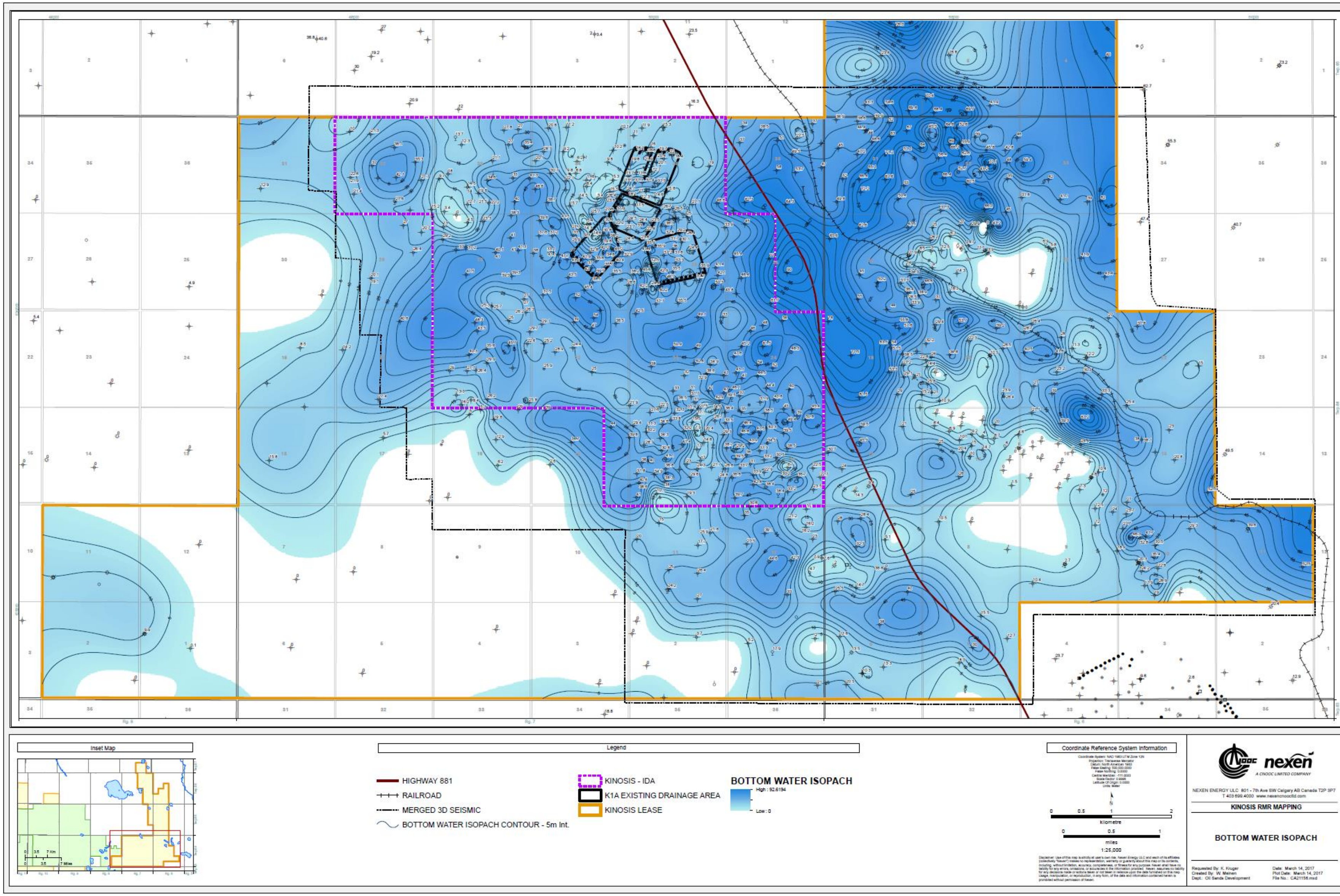
Long Lake
Bottom Water Associated with EBIP Interval



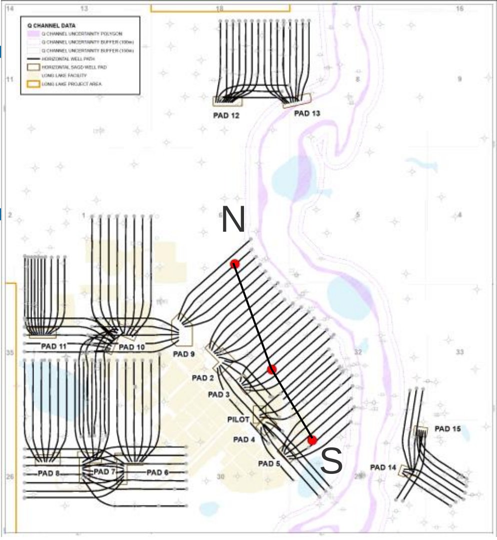


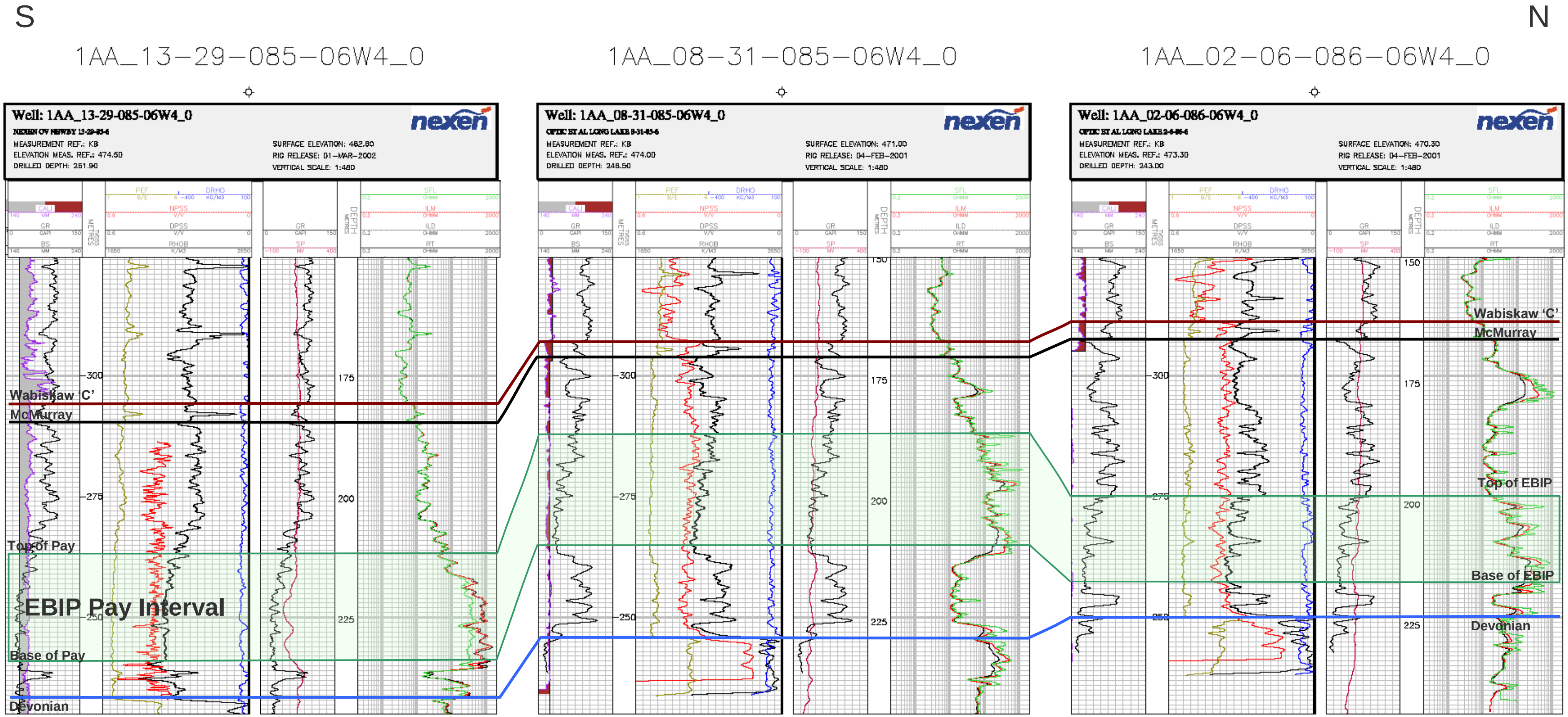
- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

Kinosis
Bottom Water in the McMurray

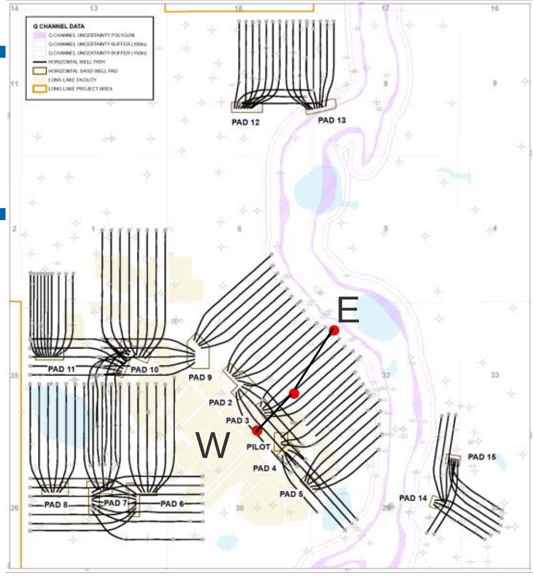


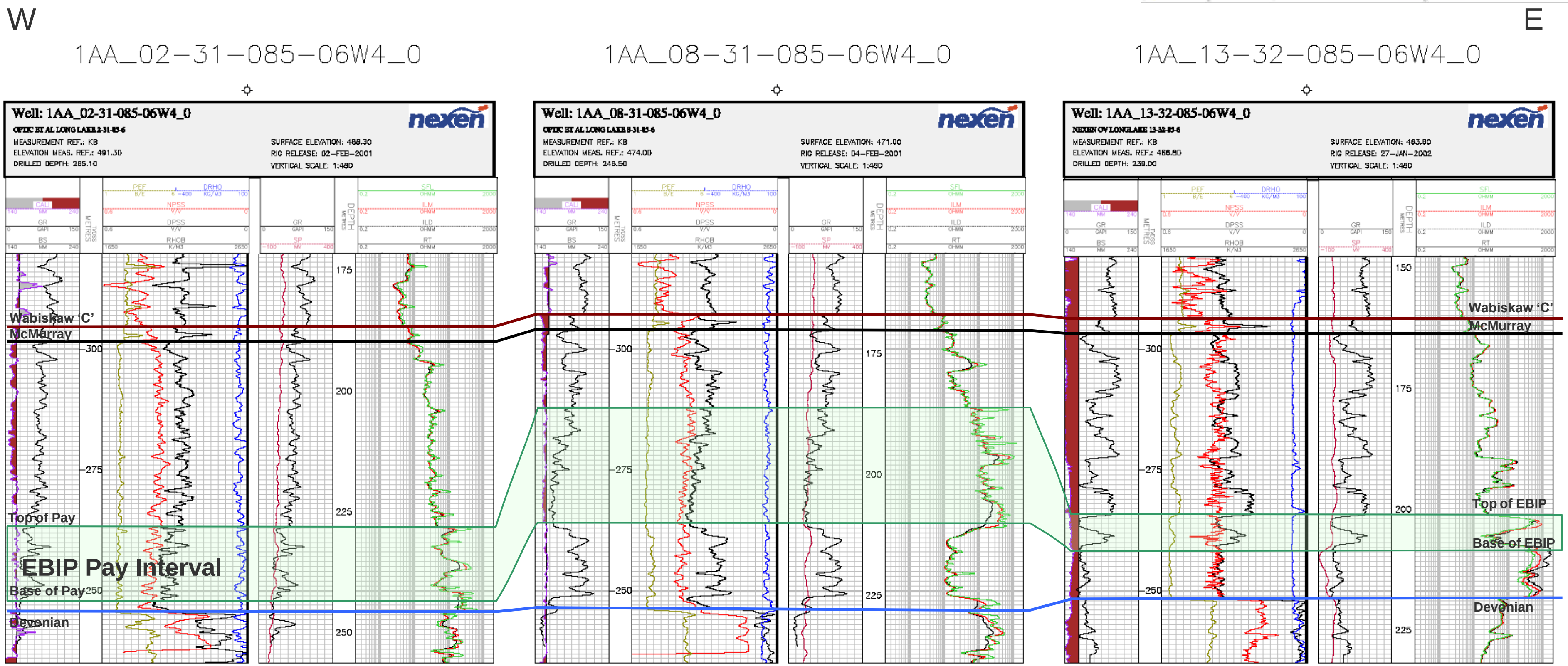
Representative structural cross-section of the East Side of Long Lake (South - North)



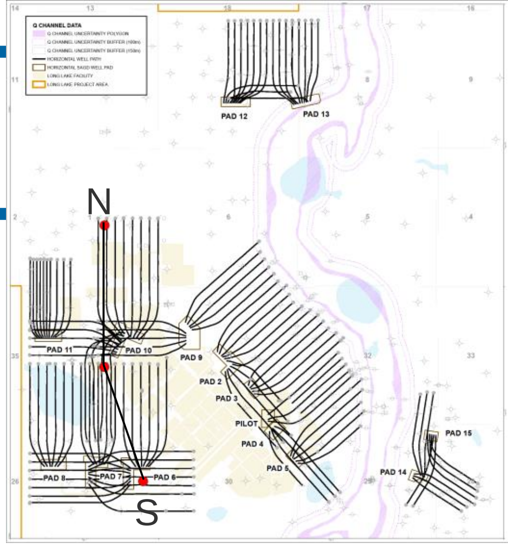


Representative structural cross-section of the East Side of Long Lake (West - East)





Representative structural cross-section of the West Side of Long Lake (South - North)



S N

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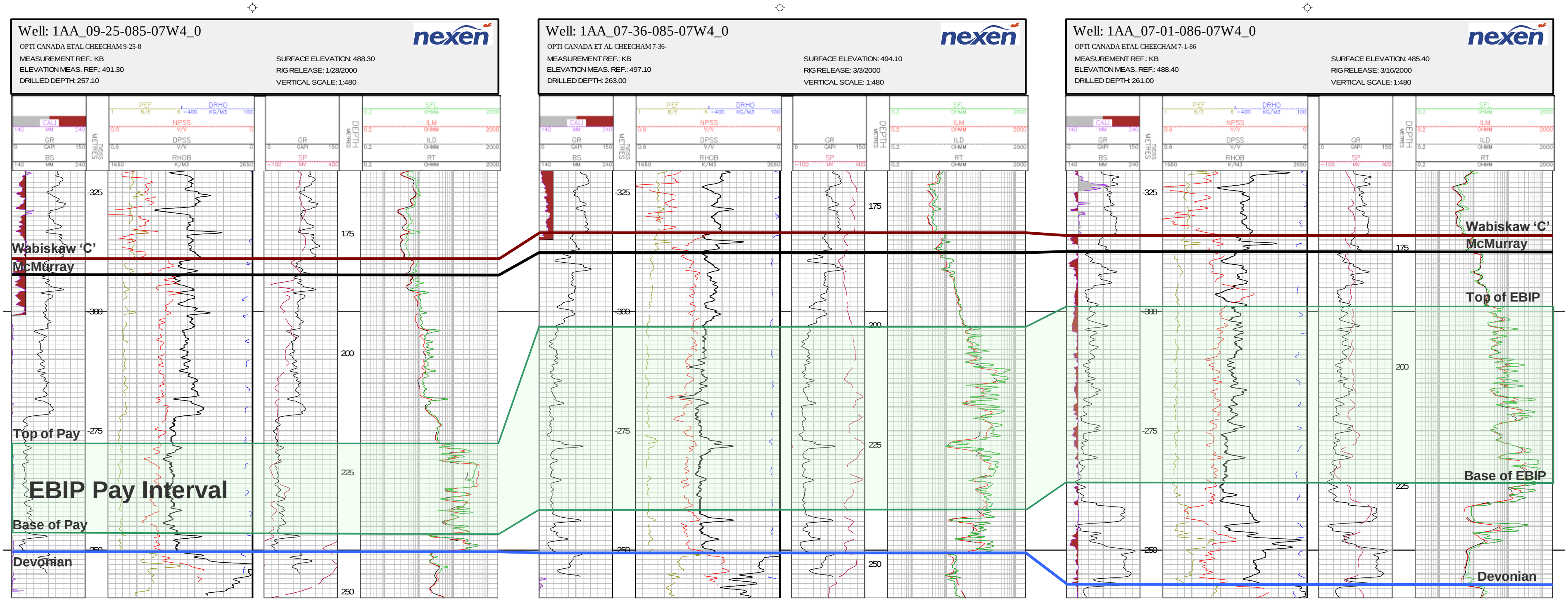

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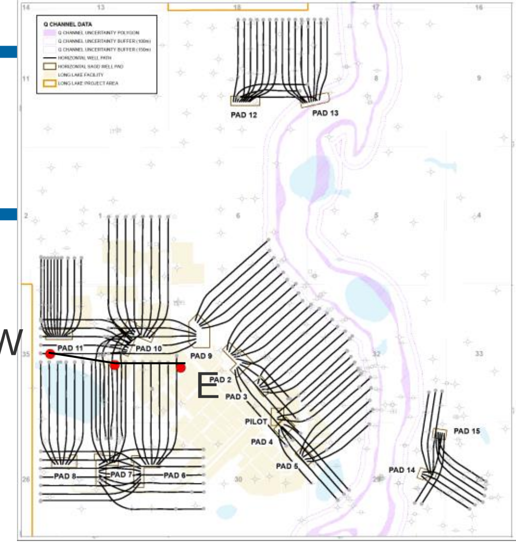
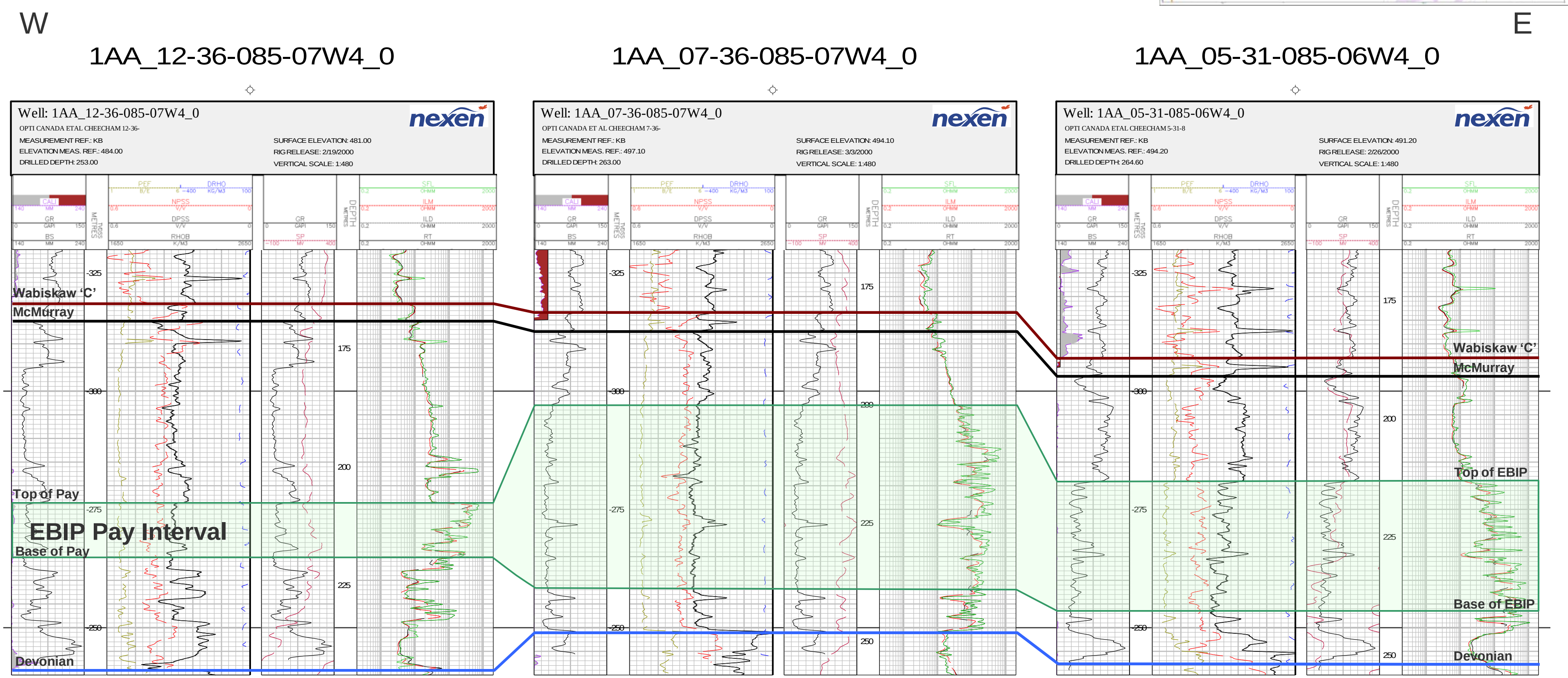
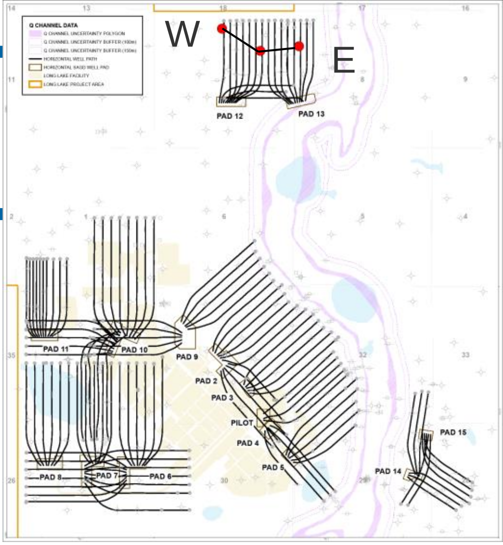
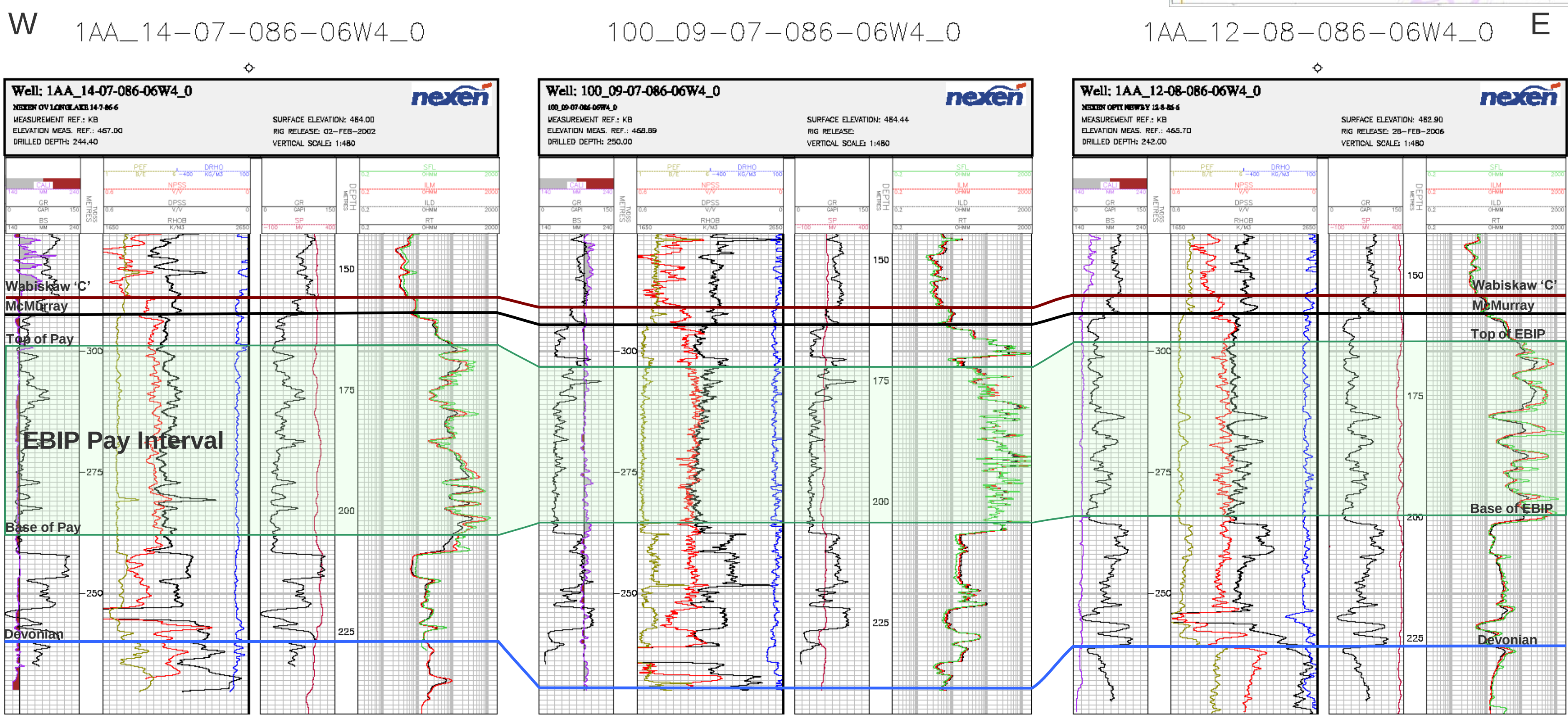




Representative structural cross-section of Pads 12 and 13





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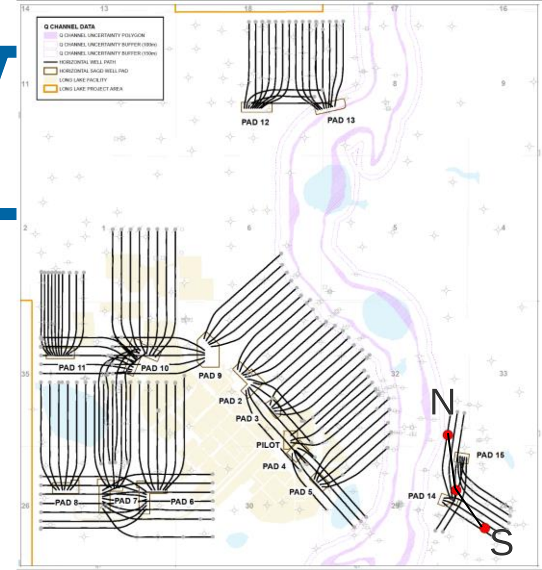
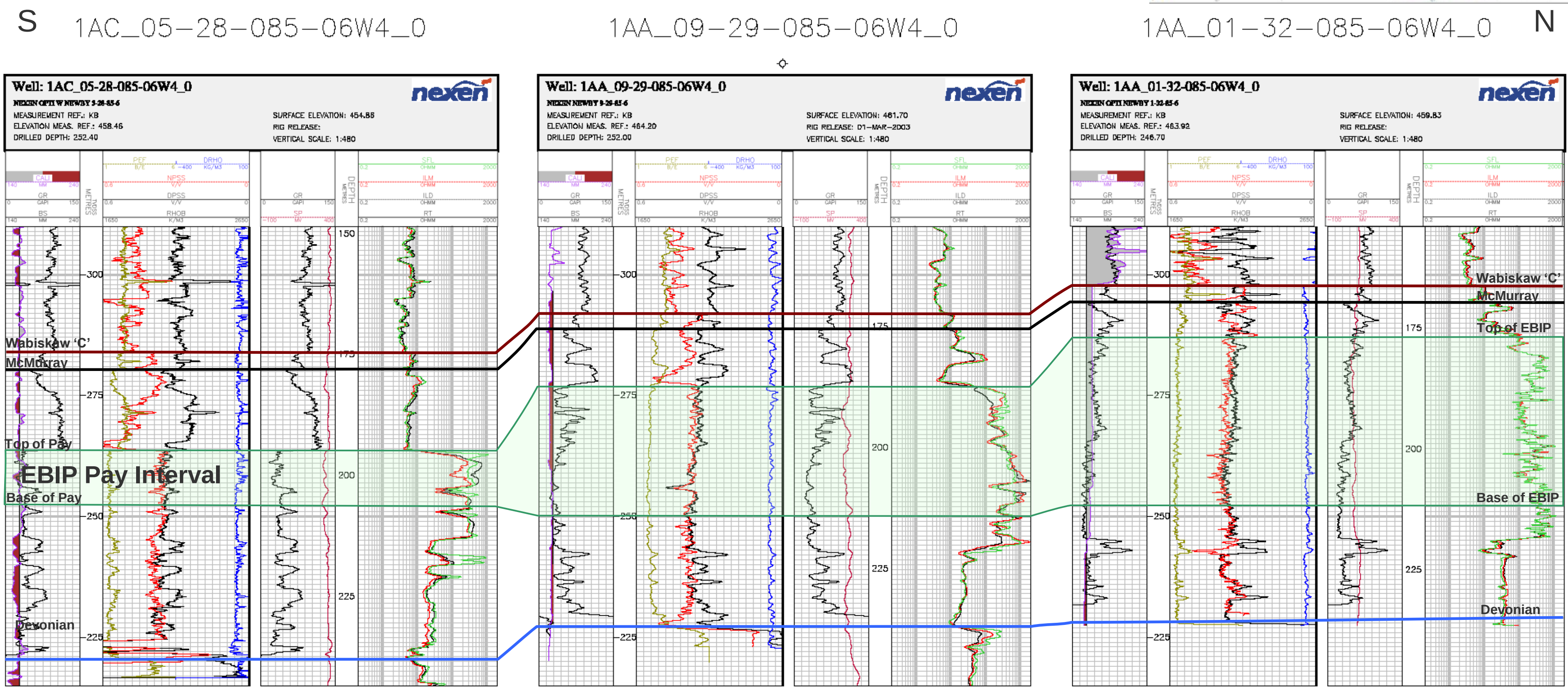
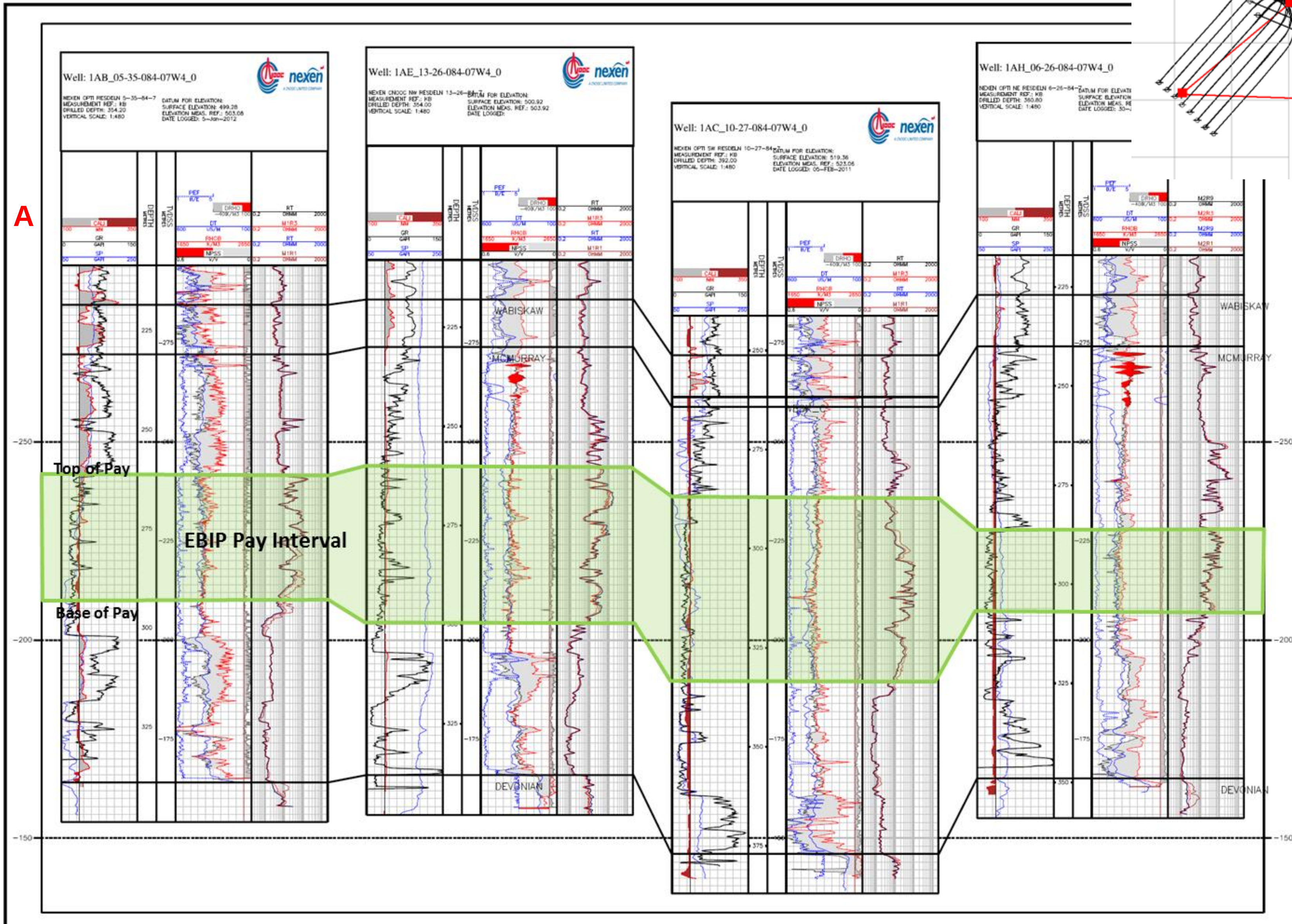
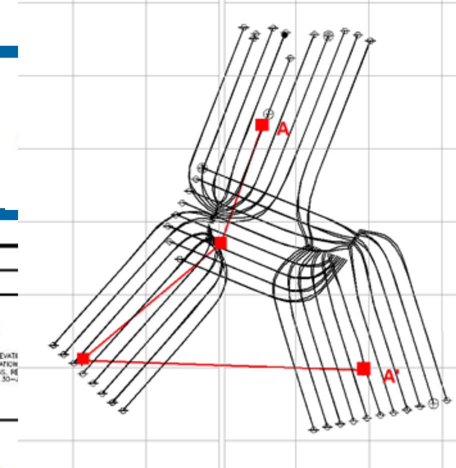




Representative structural cross-section of K1A

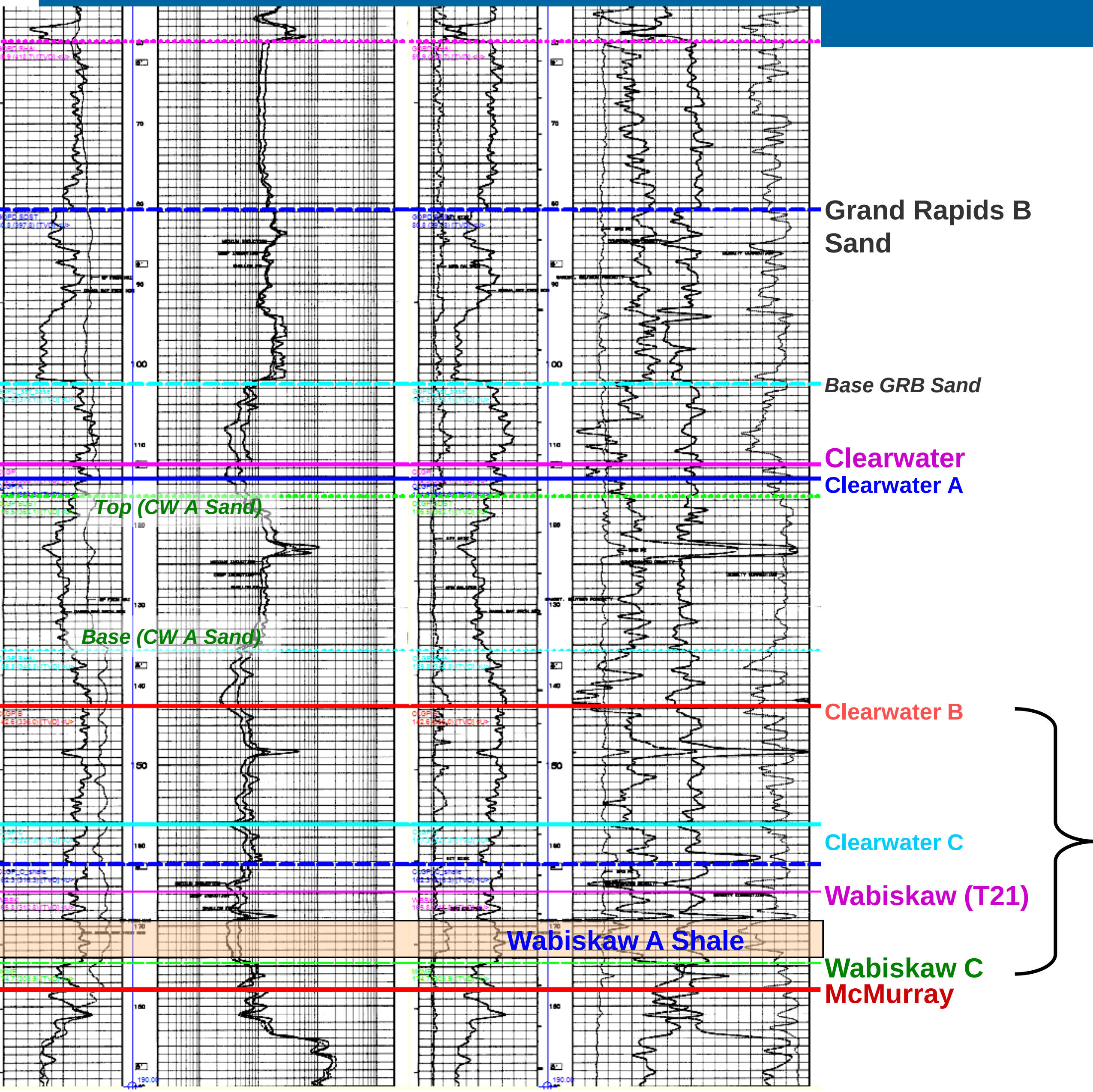




Long Lake Cap Rock Type Log

AA/08-20-085-06W4/0

KB: 478.6 m RR: 2001-01-09
TD: 255.0 m [TVD] FormTD: BHL
Mode: Abnd Fluid: N/A
OPTIC ET AL LONG LAKE 8-20-85-6



Cap rock defined as top of Clearwater B to top of Wabiskaw C sand

Long Lake Cap Rock Evaluation

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TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB082908506W400
XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
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CAPROCK CORE
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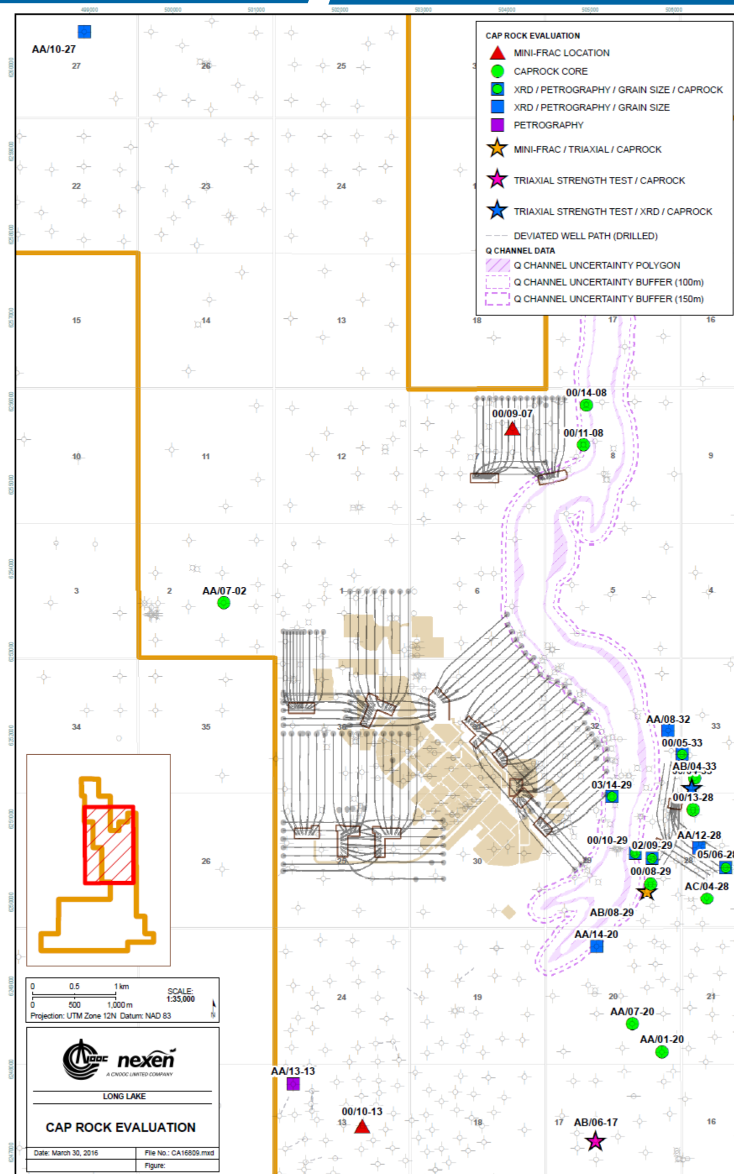
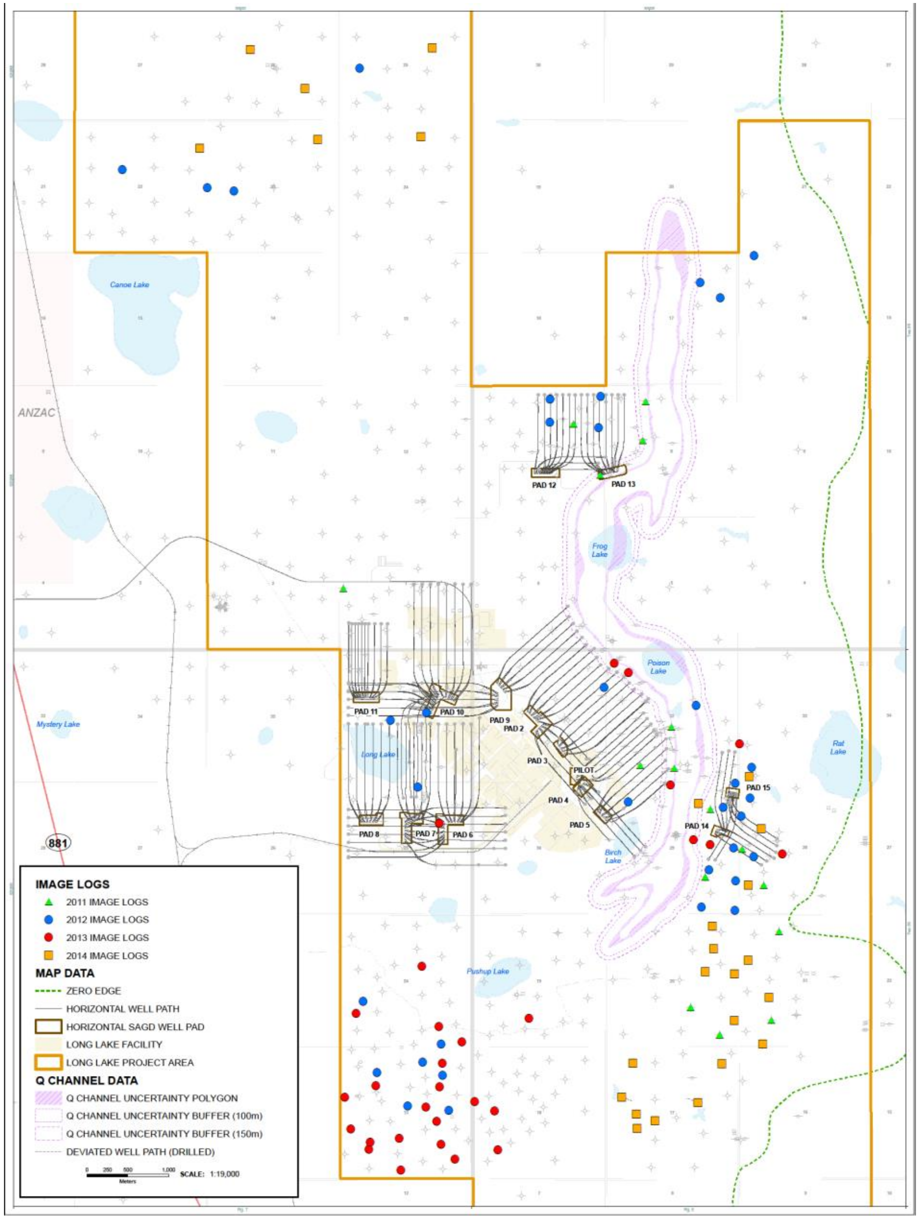


Long Lake
Cap Rock Evaluation Image Logs



Long Lake
Cap Rock Evaluation Image Logs

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Long Lake
Cap Rock Evaluation Image Logs

UWI	Well Name	Well License	Year
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Long Lake
Cap Rock Evaluation Image Logs

UWI	Well Name	Well Licence	Year
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100043308506W400	NEU CNOOC VWP S NEWBY 4-33-85-6	461840	2014
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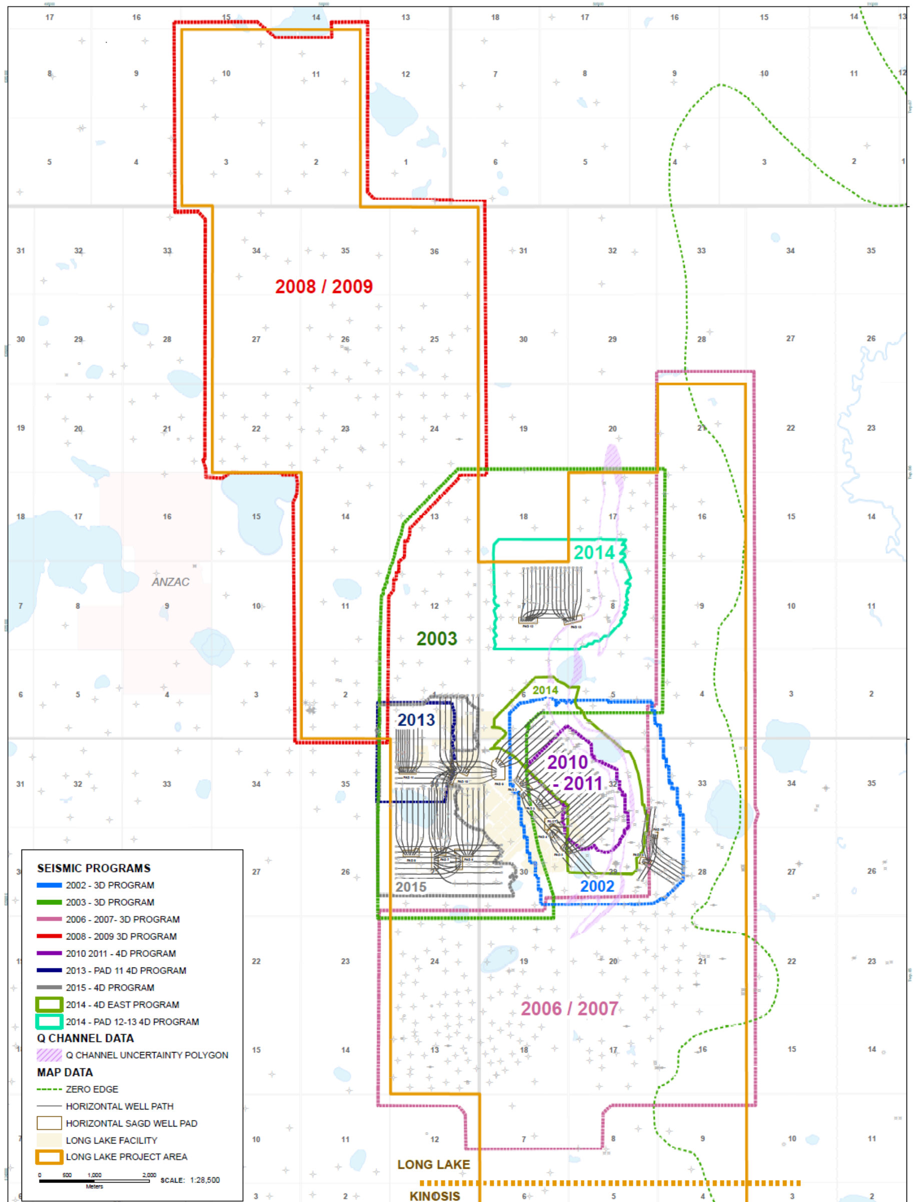
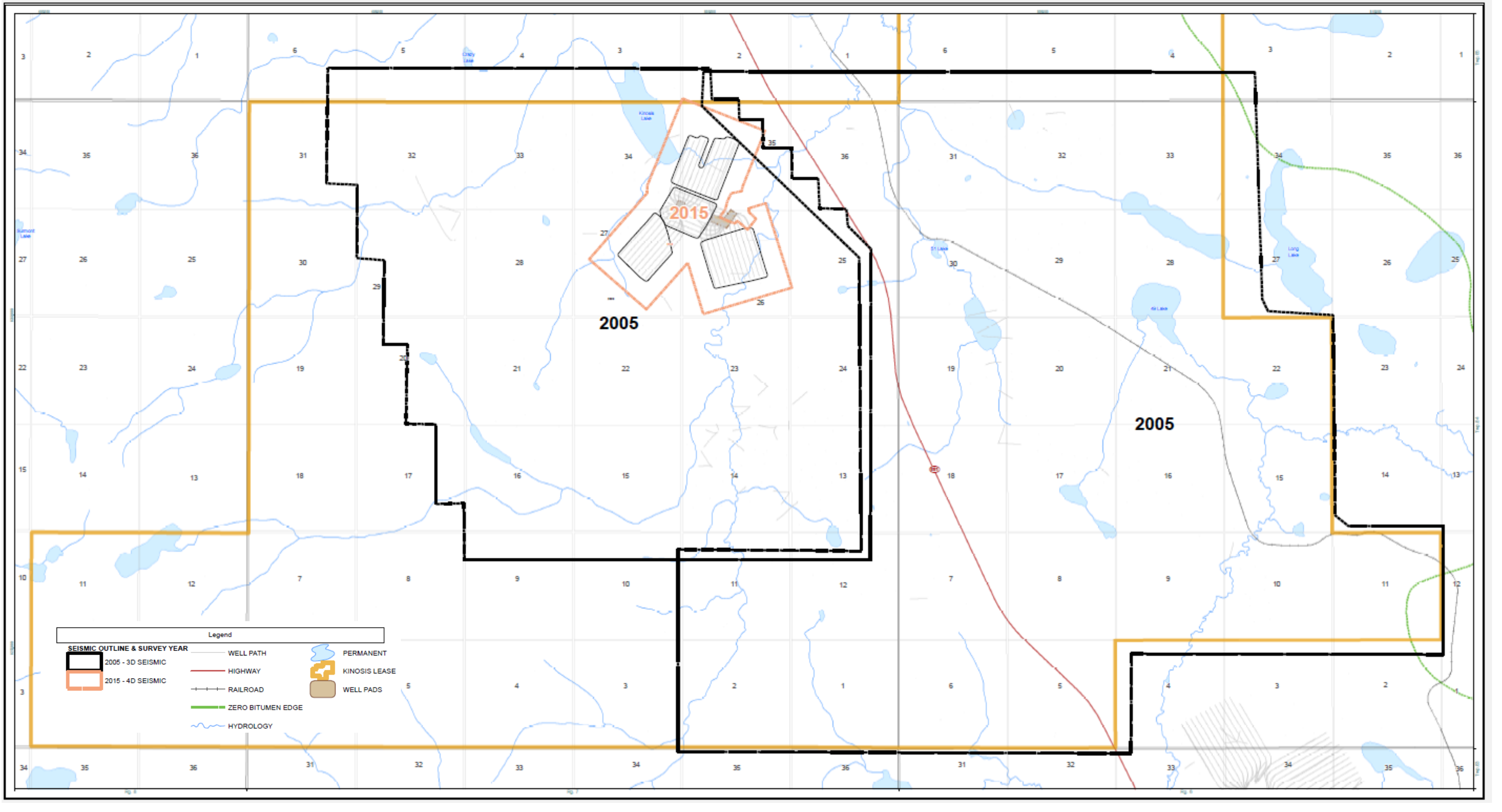
Long Lake Seismic
No 4D in 2016



Kinosis Seismic
No 4D in 2016

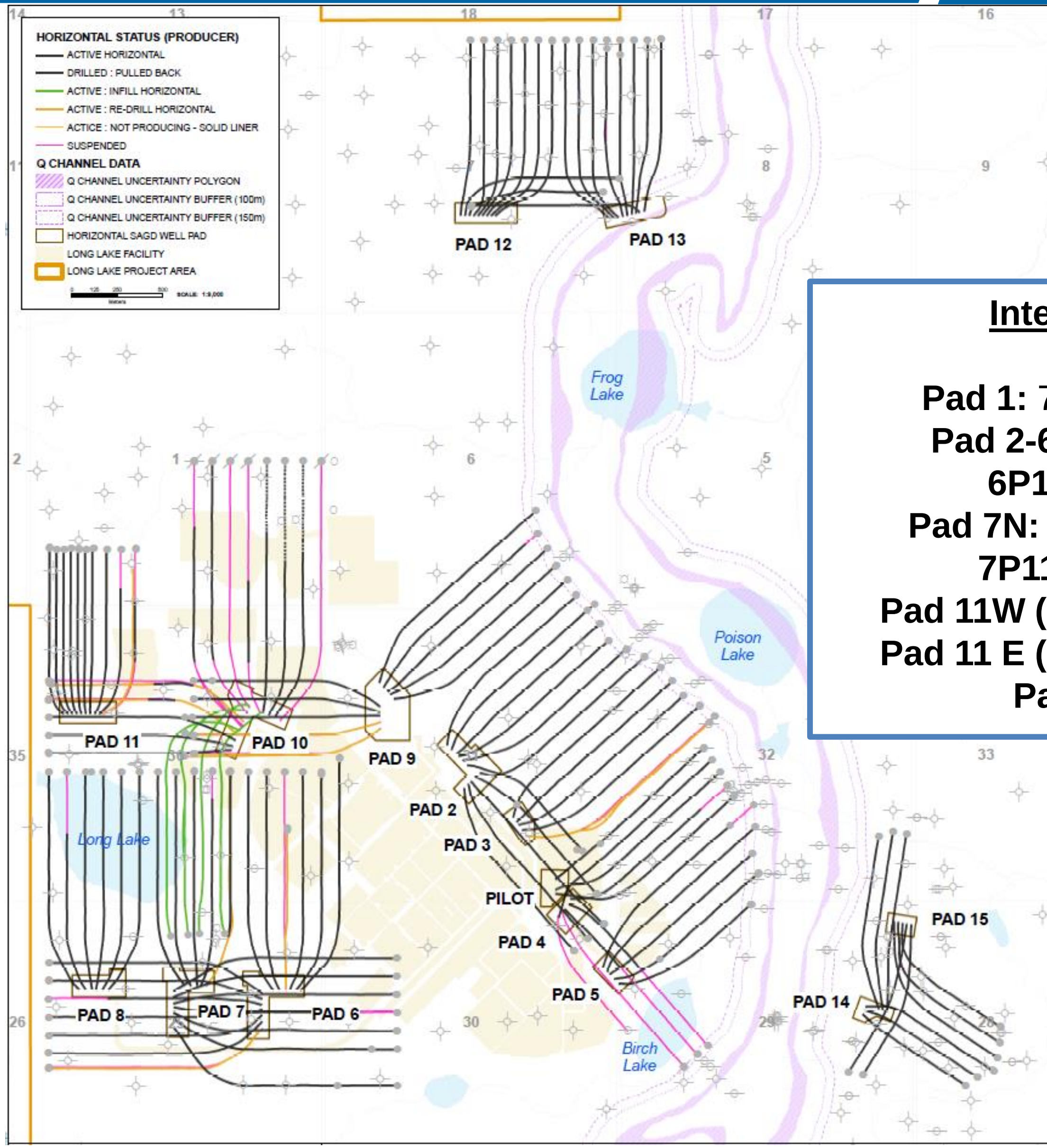


Drilling and Completions, Artificial Lift and Instrumentation Subsection 3.1.1 (3, 4, 5)

Long Lake

A New Energy

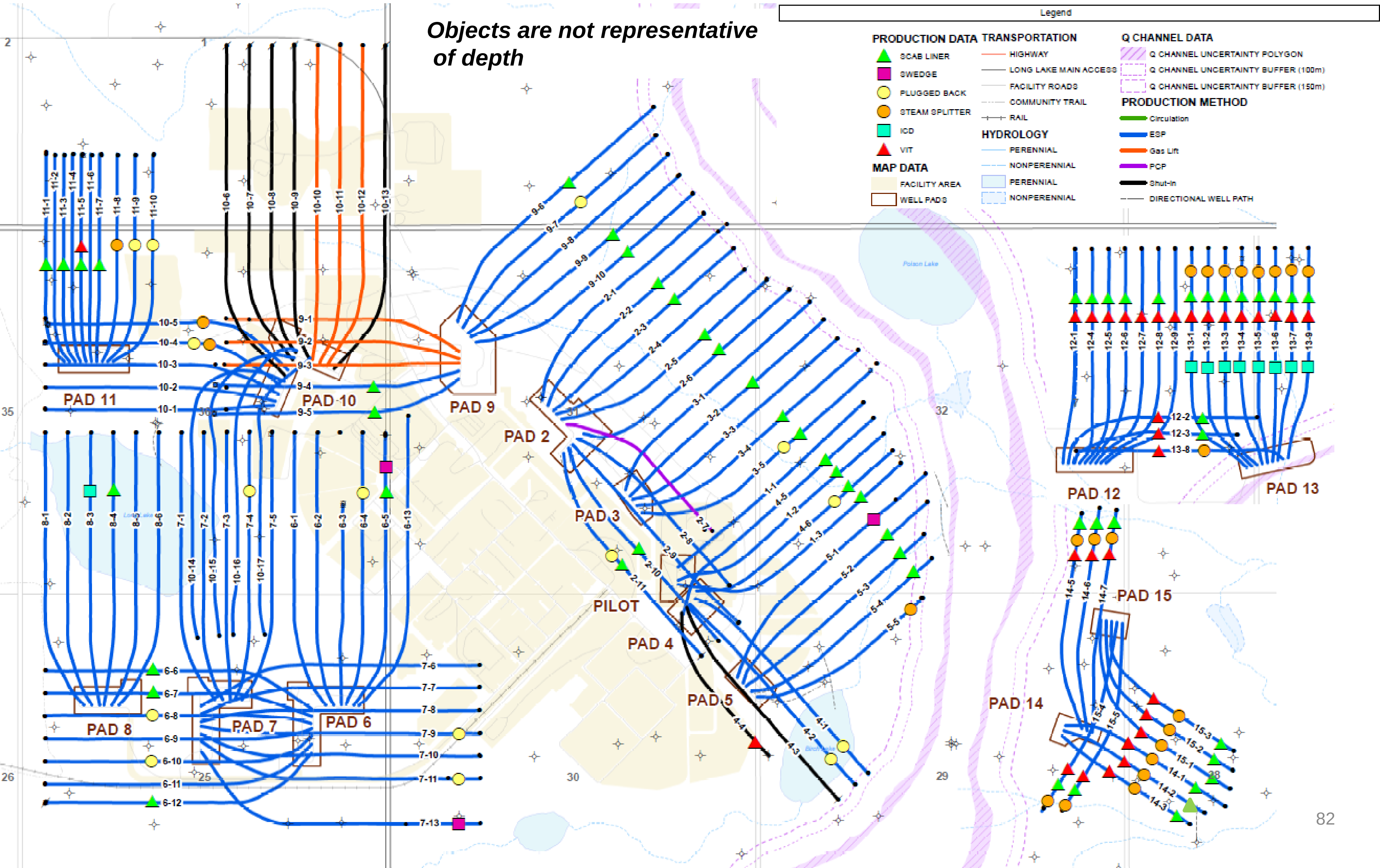
Long Lake
Horizontal Well Locations



Inter-well Spacing

Pad 1: 75m (with infill pairs)
Pad 2-6, Pads 8-10: 100m
6P11 to 6P12: 75m
Pad 7N: 50m (with infill wells)
7P11 to 7P12: 200m
Pad 11W (11P01 to 11P06): 40m
Pad 11 E (11P07 to 11P10): 80m
Pad 12-15: 75m

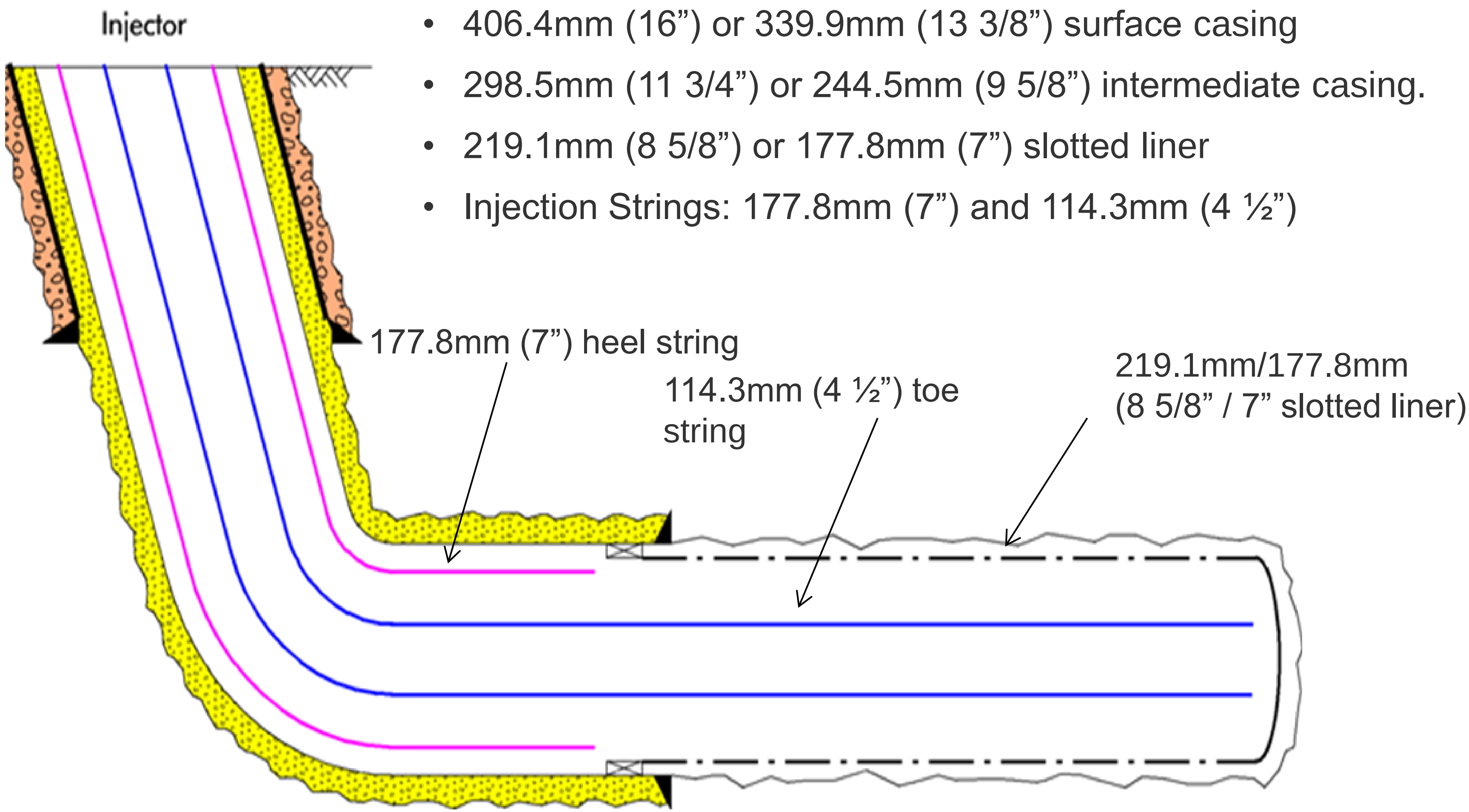
Long Lake Well Pair Completions Map 2016



Typical Injector Completion

Concentric:

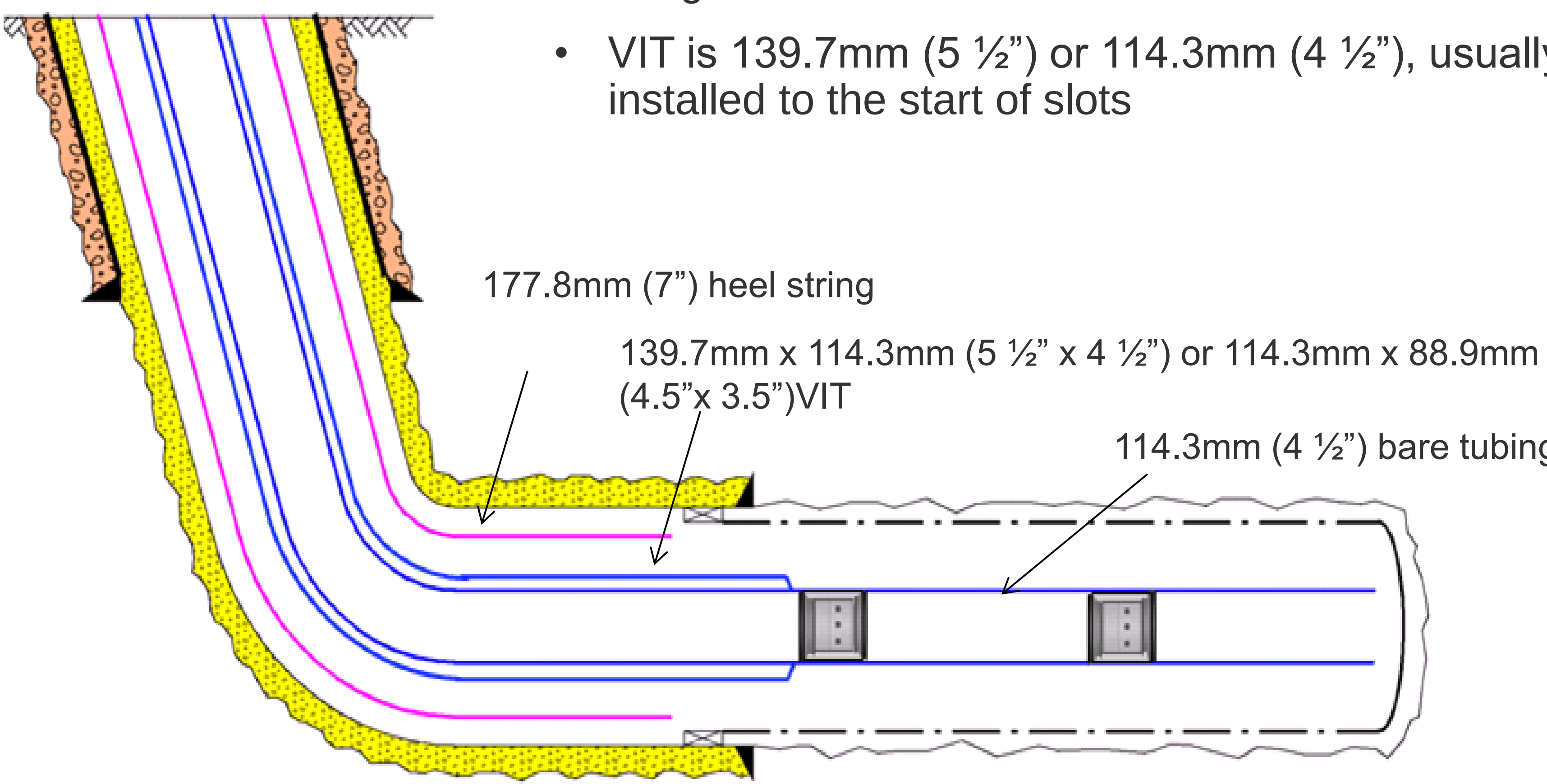
- Majority of Long Lake's design
- 406.4mm (16") or 339.9mm (13 3/8") surface casing
- 298.5mm (11 3/4") or 244.5mm (9 5/8") intermediate casing.
- 219.1mm (8 5/8") or 177.8mm (7") slotted liner
- Injection Strings: 177.8mm (7") and 114.3mm (4 ½")



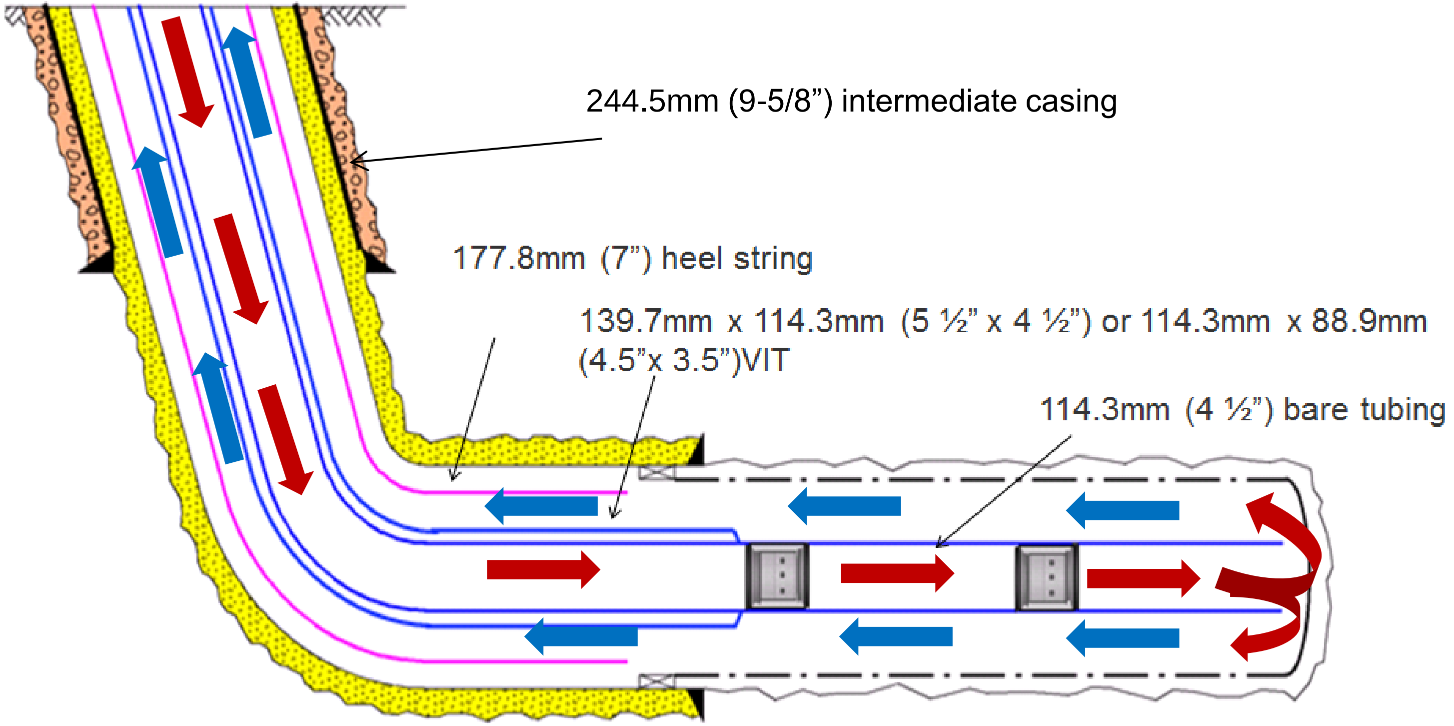
Vacuum Insulated Tubing (VIT) Injector Completion

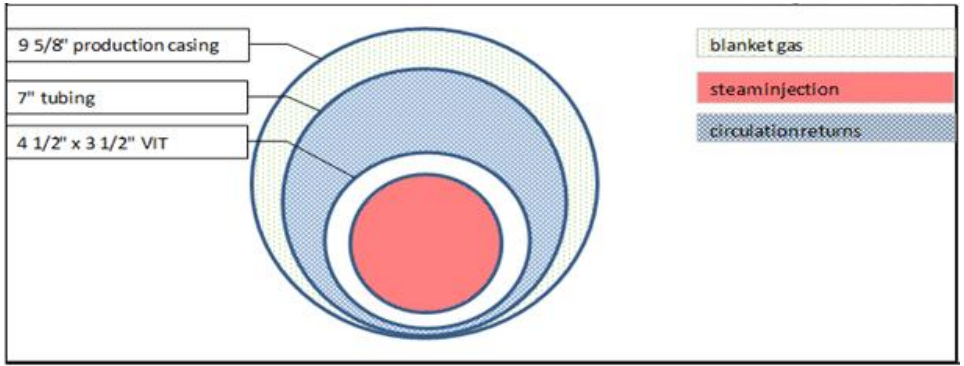
- All Kinosis wells, and a few Long Lake pads are completed with steam splitters in the long injection string
  - Results showing improved temperature conformance in Long Lake wells
- VIT is 139.7mm (5 ½”) or 114.3mm (4 ½”), usually installed to the start of slots

Injector



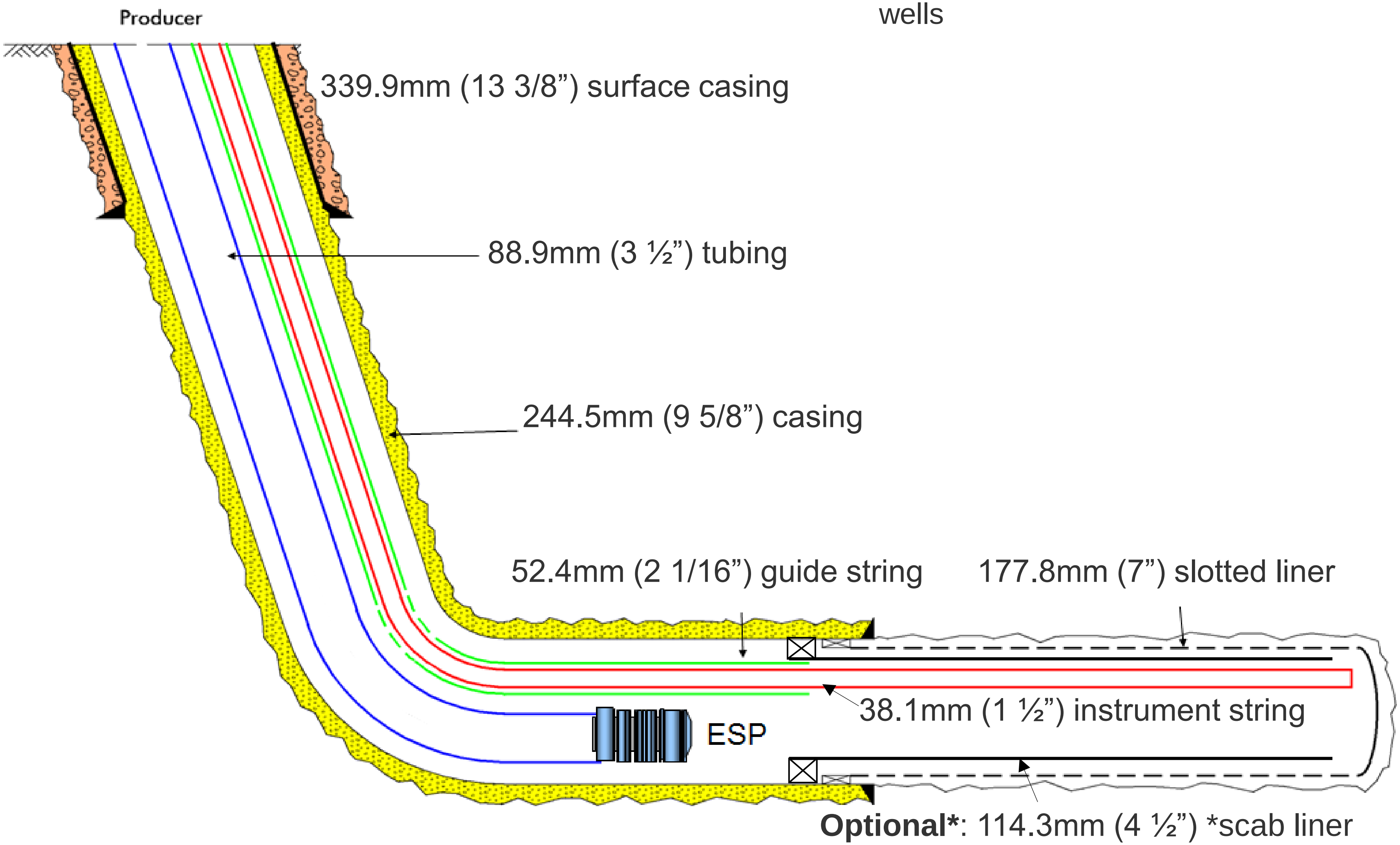
Typical Injector Circulation



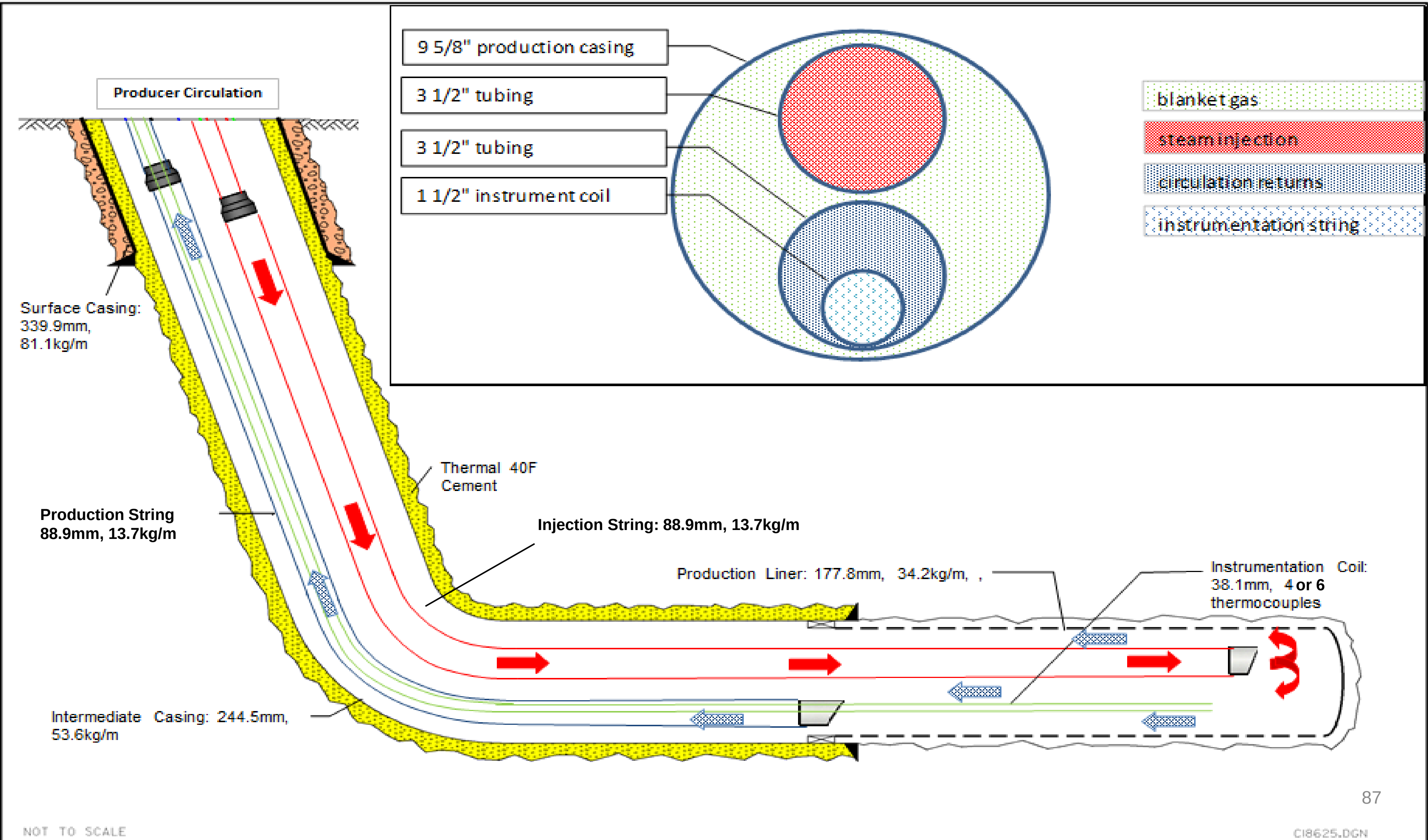


Typical Producer Completions – ESP

*Scab liners installed in some producer wells



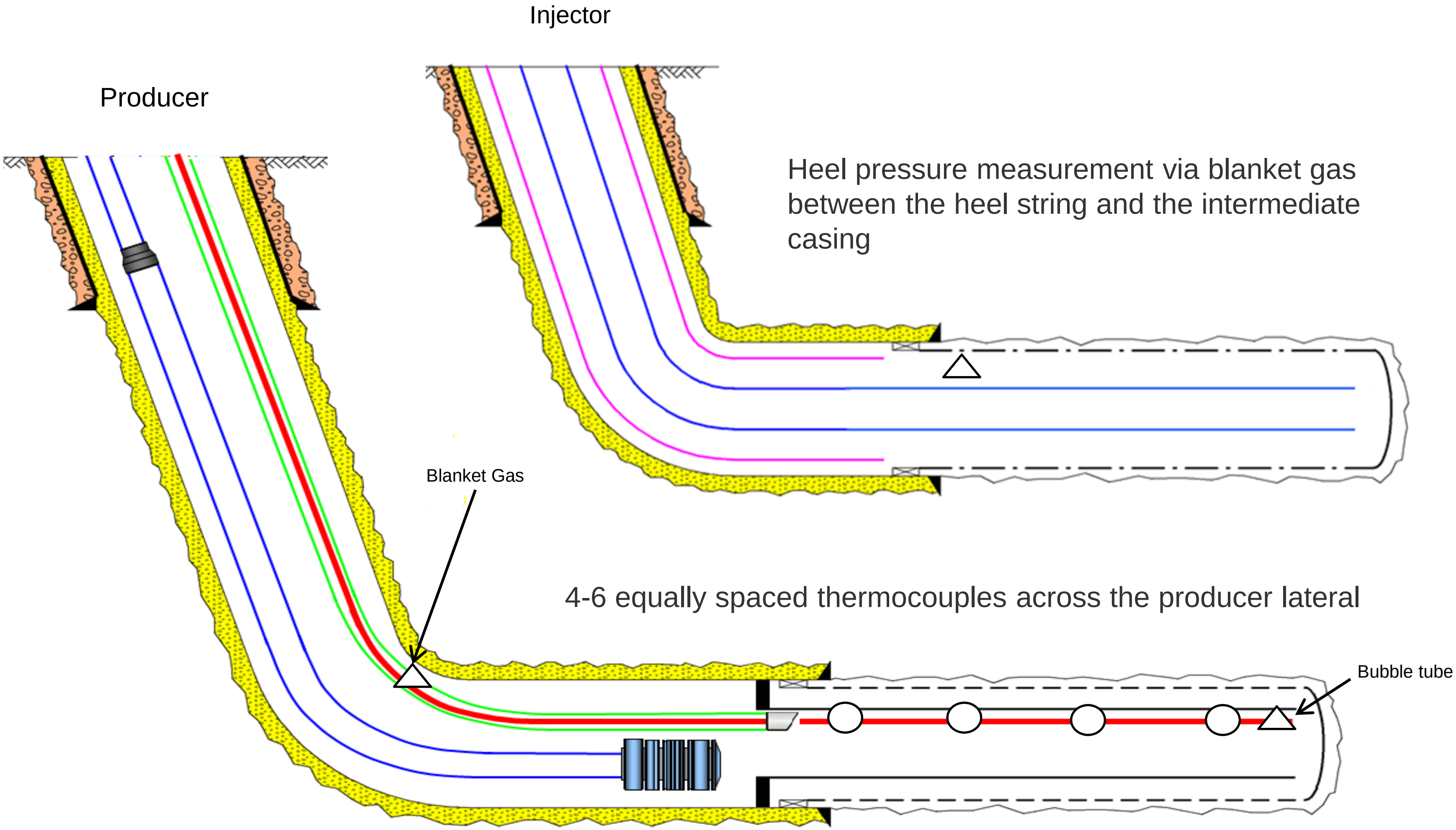
Typical Producer Circulation



Artificial Lift Performance

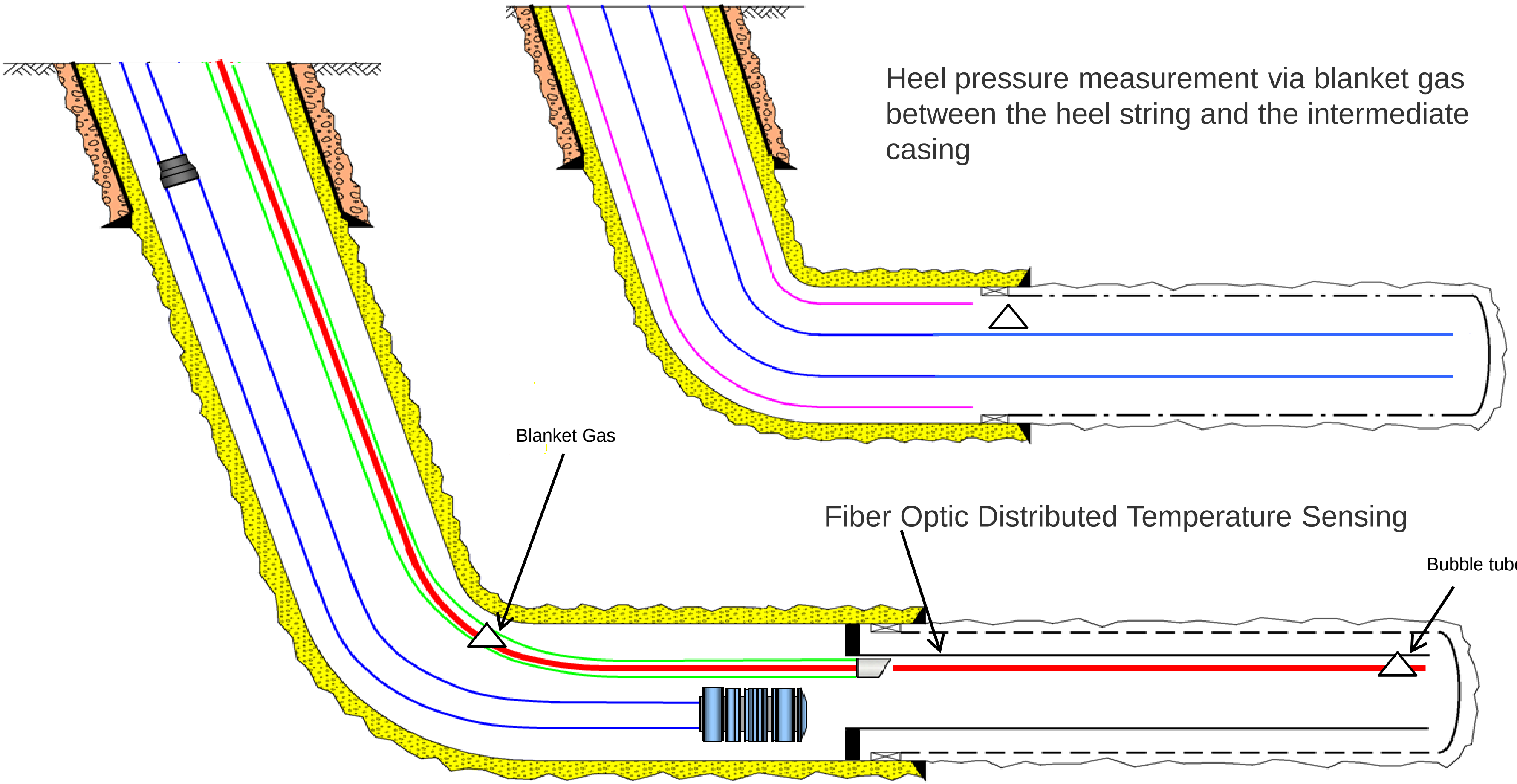
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers to allow production at lower steam chamber pressures.
  - 6 wells currently are on gas lift production.
- ESPs installed in 109 SAGD wells:
  - Pump performance (at Dec. 31, 2016):
    - Average Run Time: 516 days
    - Mean Time to Failure (cumulative): 847 days
    - Mean Time to Failure (720 running average): 1,590 days
  - Operating temperatures have reached 215ºC.
  - Pumps operate at pressures between 1,000 and 1,500 kPa (Producer).
  - Fluid production rates range from 75 – 1,100 m^3/d.
- Active member of ESP Reliability Information and Failure Tracking System JIP
- Currently running 1 Progressive Cavity Pump (PCP) in 02P07.
  - Kudu 1100-MET-750 metal stator and rotor installed Mar-2014 (intermittent operations since)
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates.

SAGD Instrumentation



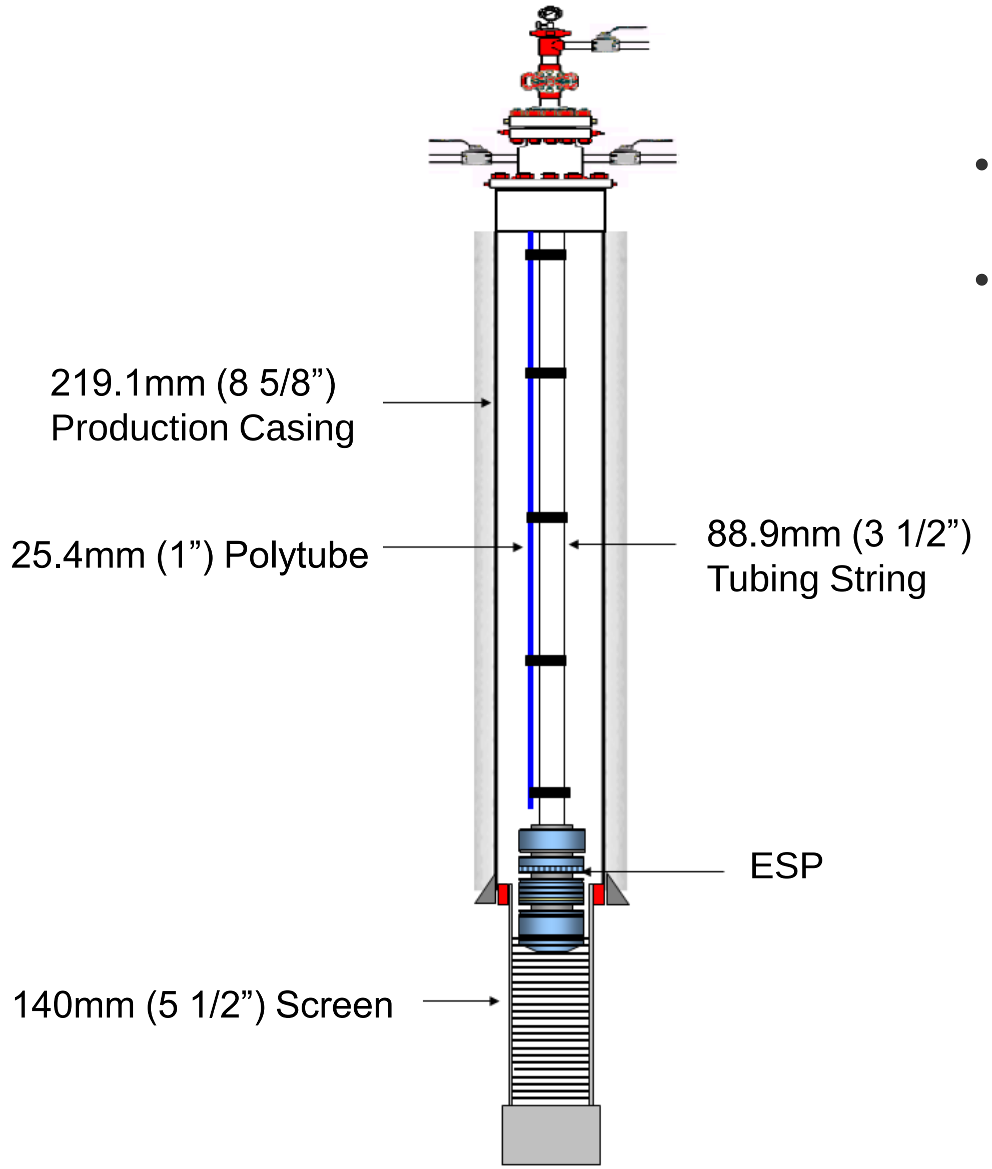
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Alternate SAGD Instrumentation



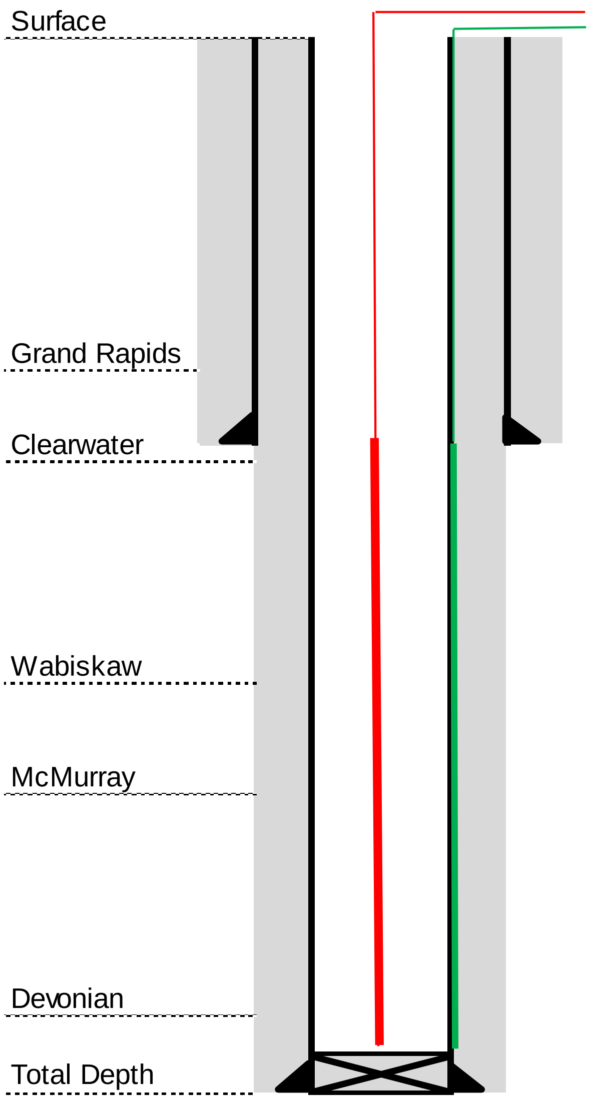
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Typical Water Source Well



- ESP intake landed above the top of the water formation
- 18.3mm probe run through polytube and landed above the ESP
  - Monitors water level in casing

Current Design and Practices



- Cement with Thermal 40 EXP cement
- Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
- Thermocouple strings (red) provide temperature measurements
- Run a CBL on well with pressure pass if required

Drilling and Completions, Artificial Lift and Instrumentation Subsection 3.1.1 (3, 4, 5)

K1A

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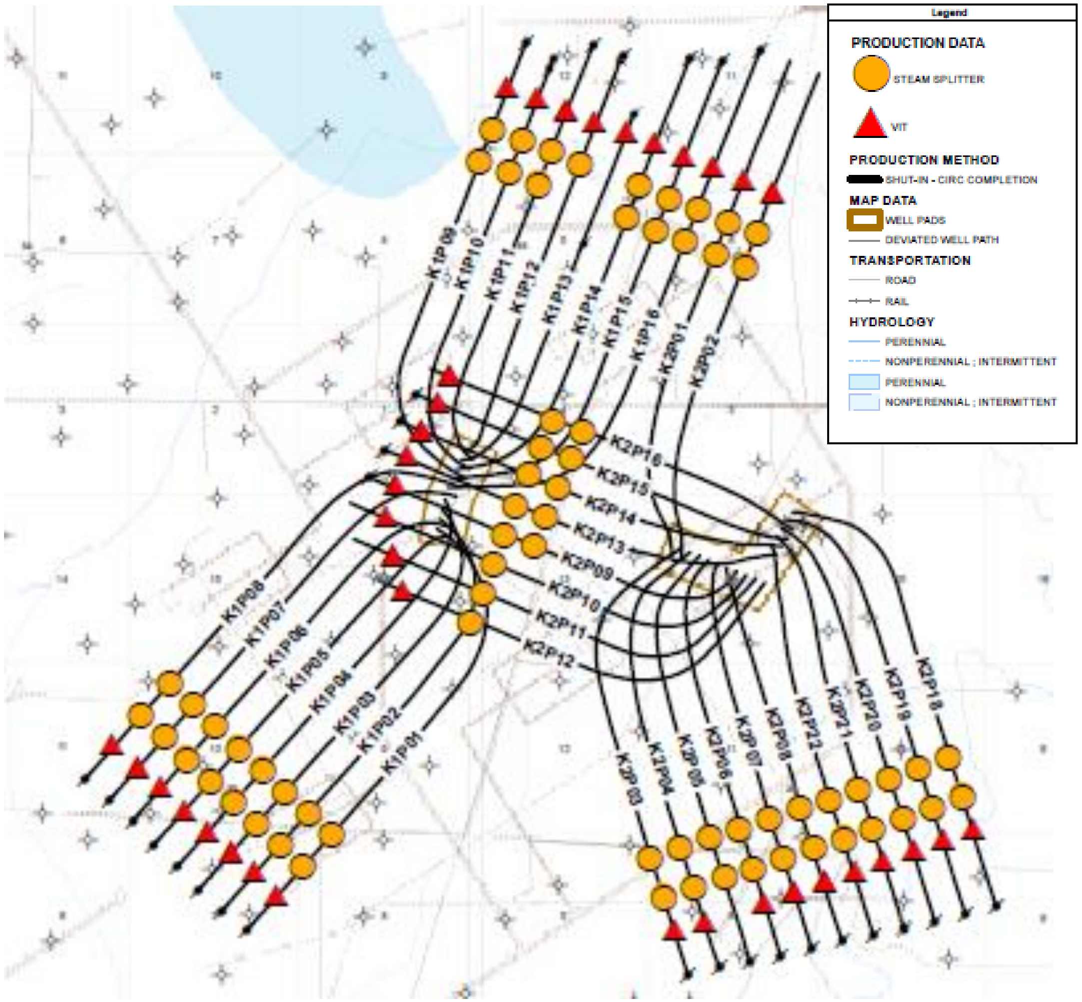
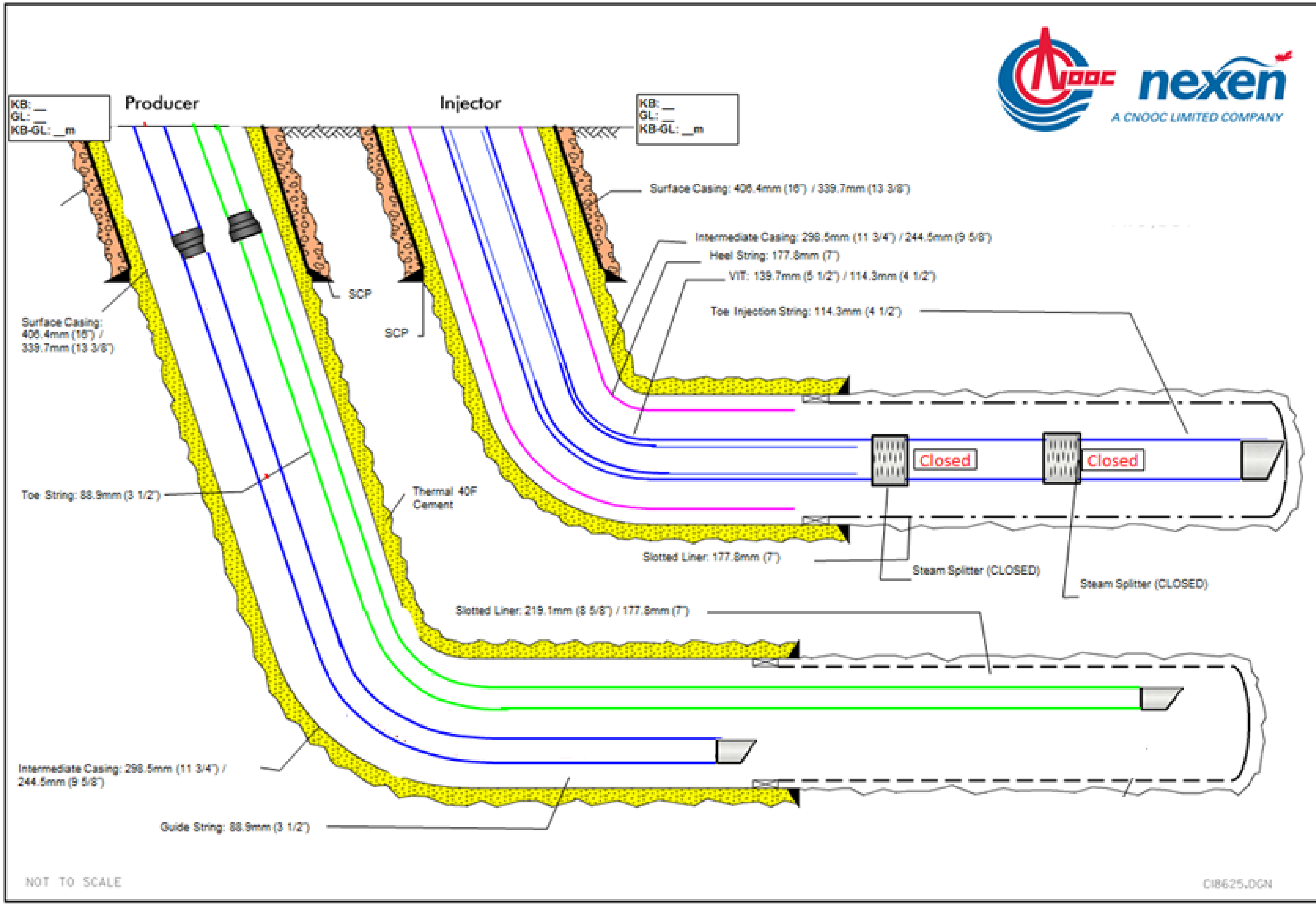
K1A Well Pair Completions Map as of Dec 31, 2016

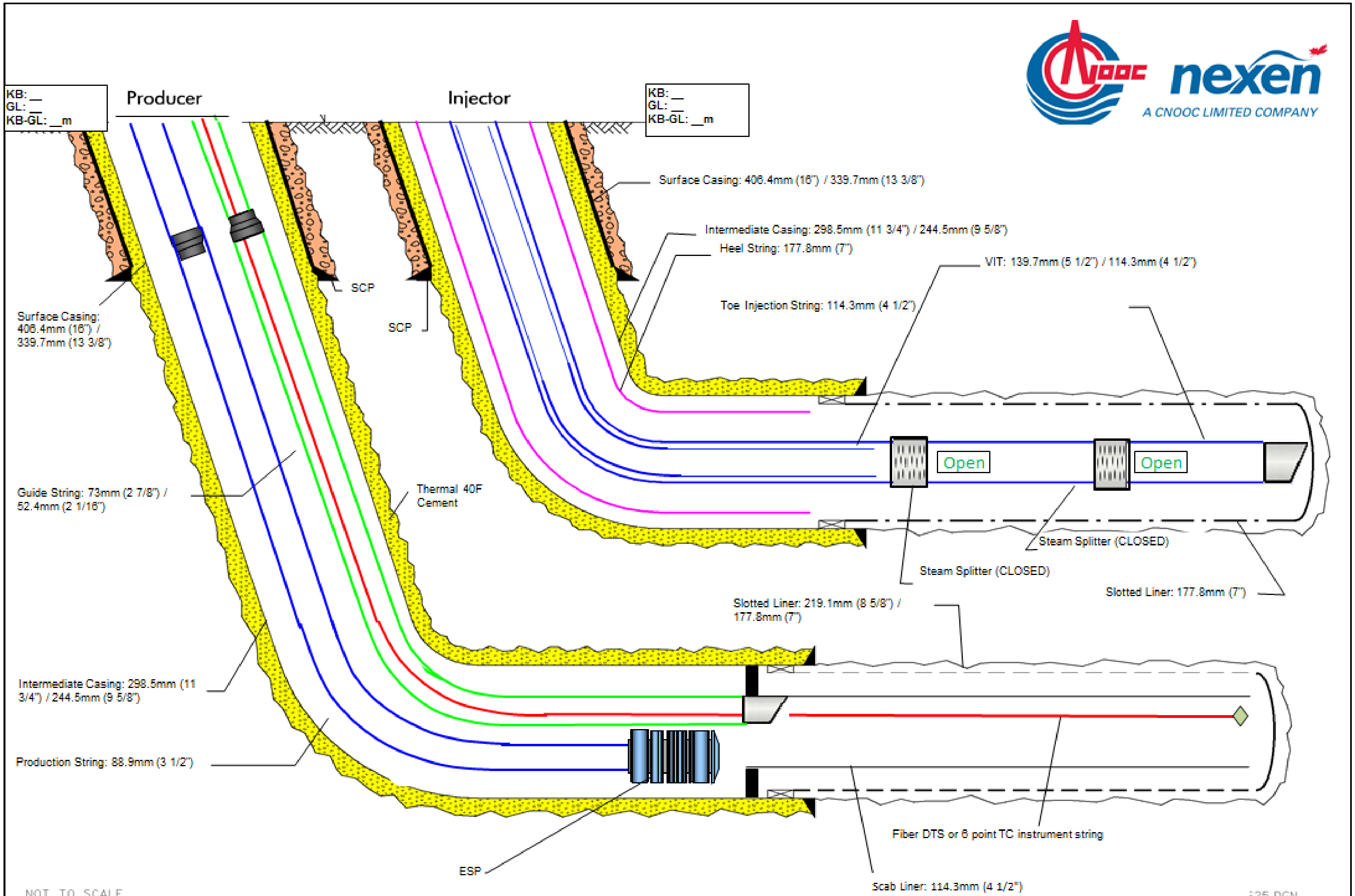


- On Jul. 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF.
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down.
- Status of wells as of Dec. 31, 2016:
  - 36 well pairs remain suspended however are ready for circulation.

Typical K1A Completion Schematic Circulation



Typical K1A Completion Schematic SAGD



Scheme Performance
Section 3.1.1 (7)
Long Lake

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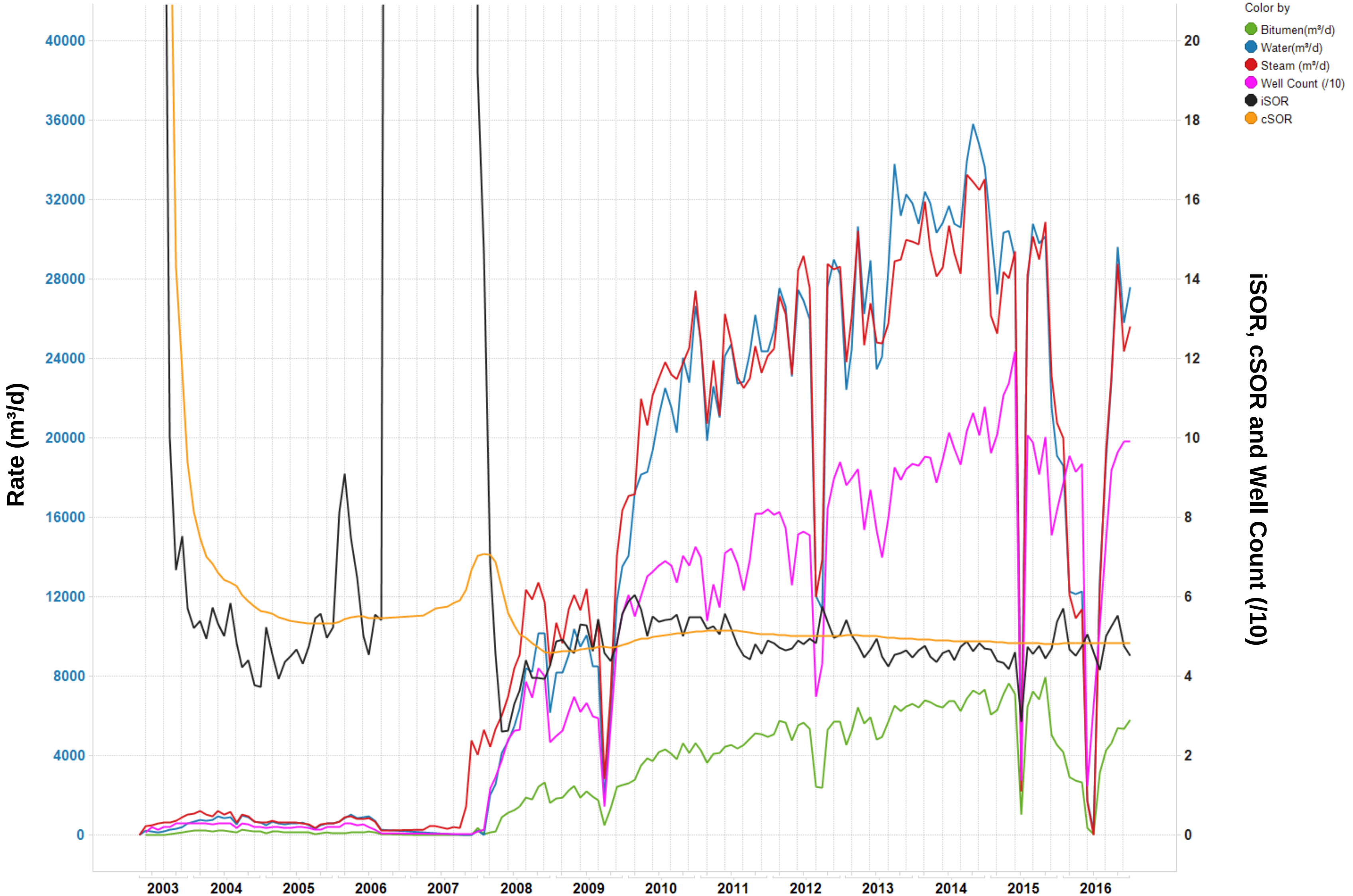
Long Lake 2016 Performance

- Commercial SAGD:
  - LLK: 15 pads,120 well pairs; 105 active producing wells at year end
  - K1A: 2 pads, 37 well pairs; 0 active producing wells at year end
- Majority of LLK wells throttled for first half of year due to HCU incident on Jan.15, 2016
- LLK operations ceased for approximately two months due to Wildfires in the region, May-Jun. 2016
  - Safe restart of field following thorough PSSRs on wells and facility
  - LLK pads continuing to deliver strong ramp up performance after dewatering and depressurization phase
    - Downhole injection pressure varies throughout the field, ranges from 1,350 to 2,250 kPa
- Restarted steam injection on south half of Pad 5 following results of new observation wells (103/15-29 and 105/14-29)

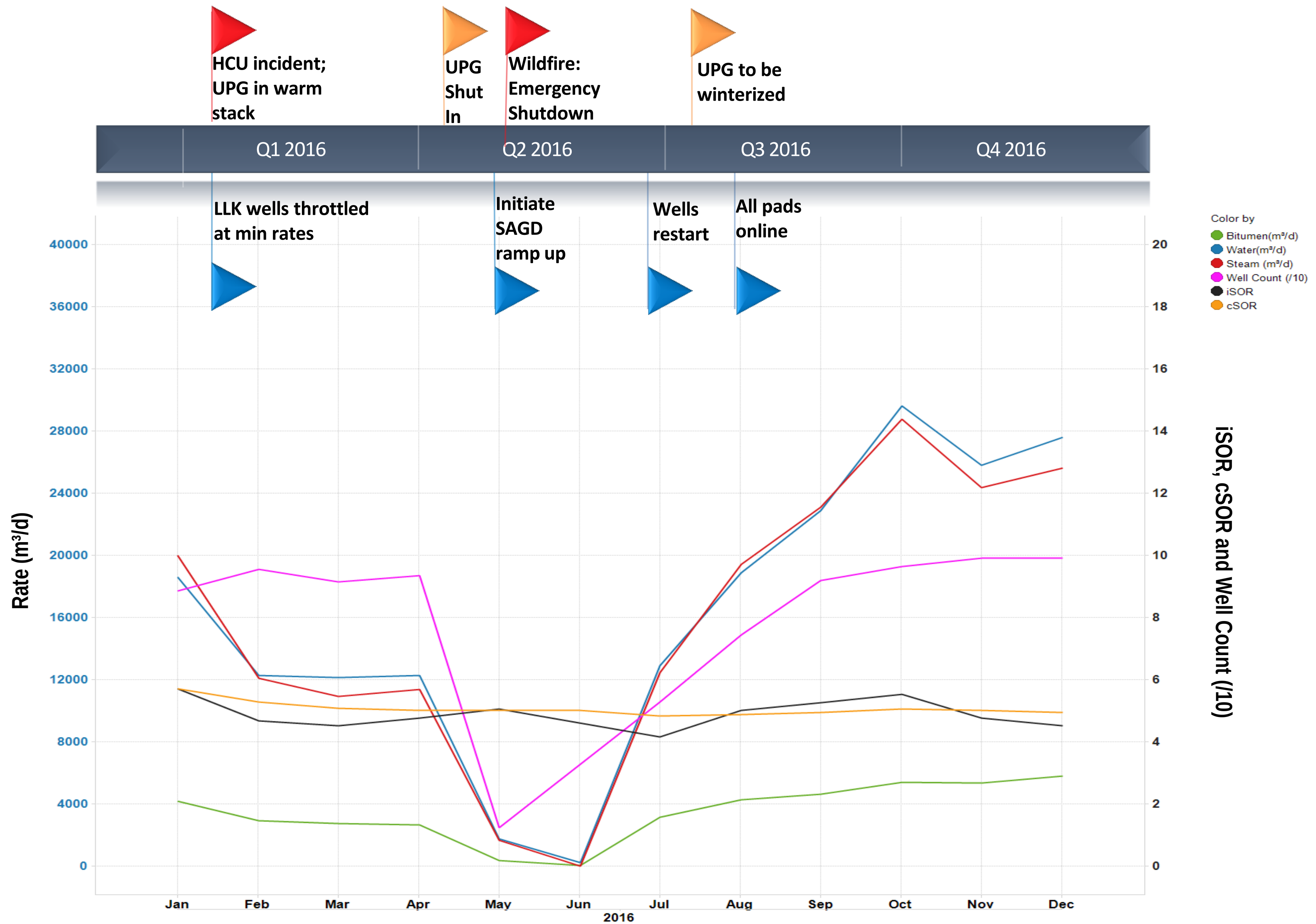
Scheme Performance
Field Level



*Graph includes K1A

Scheme Performance

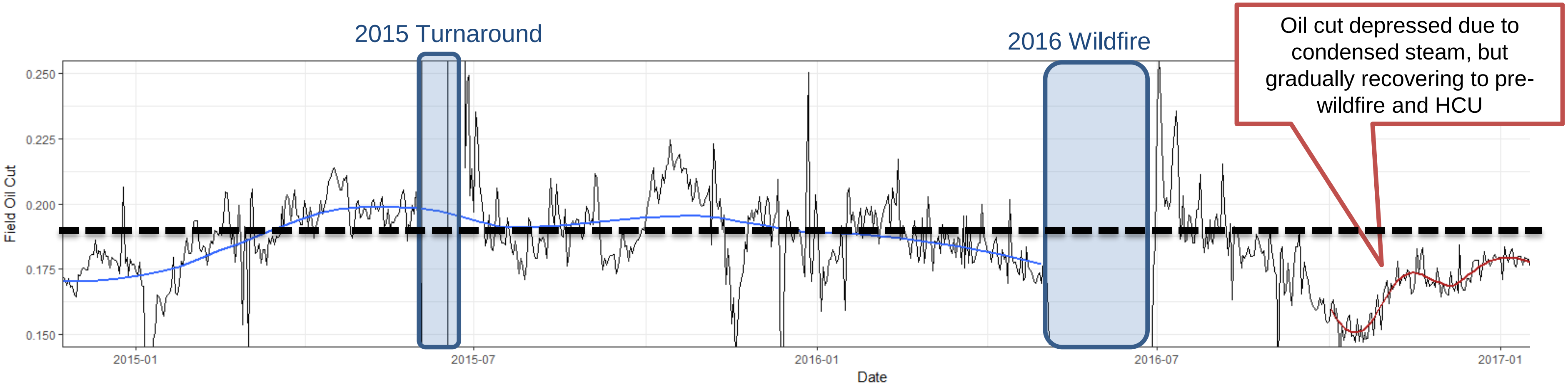
2016 Field Level Highlights



Scheme Performance

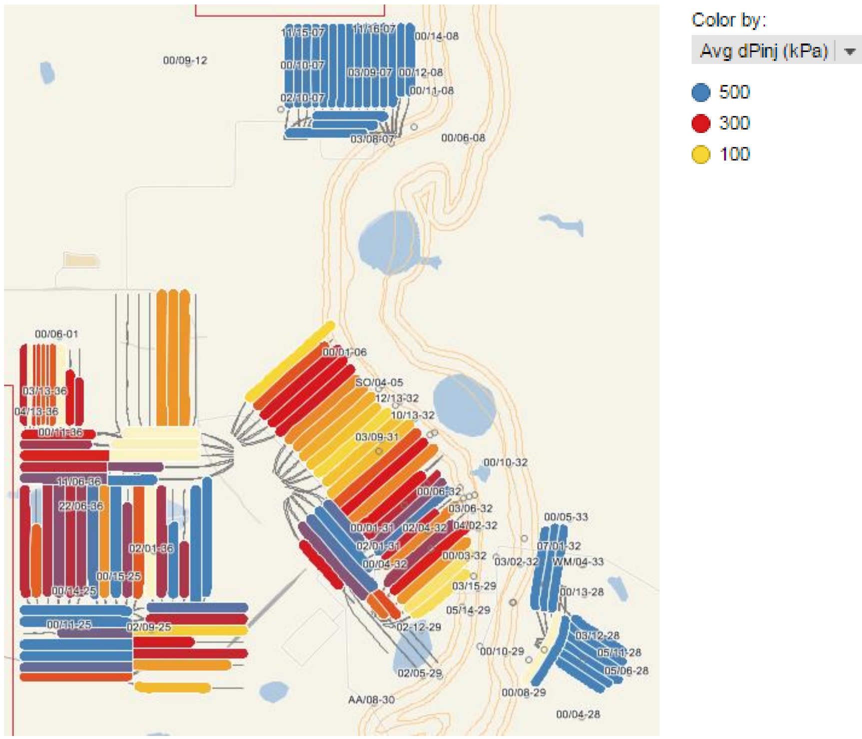
2016 Wildfire Impact

- Long Lake wells experienced ~3 month throttled period followed by a ~2 month shut-in
  - Significant amounts of condensed steam (water) built up in the reservoir; needs to be removed before can return to “optimized” reservoir conditions
  - Various plant constraints are limiting ability to produce this water out at a quick pace

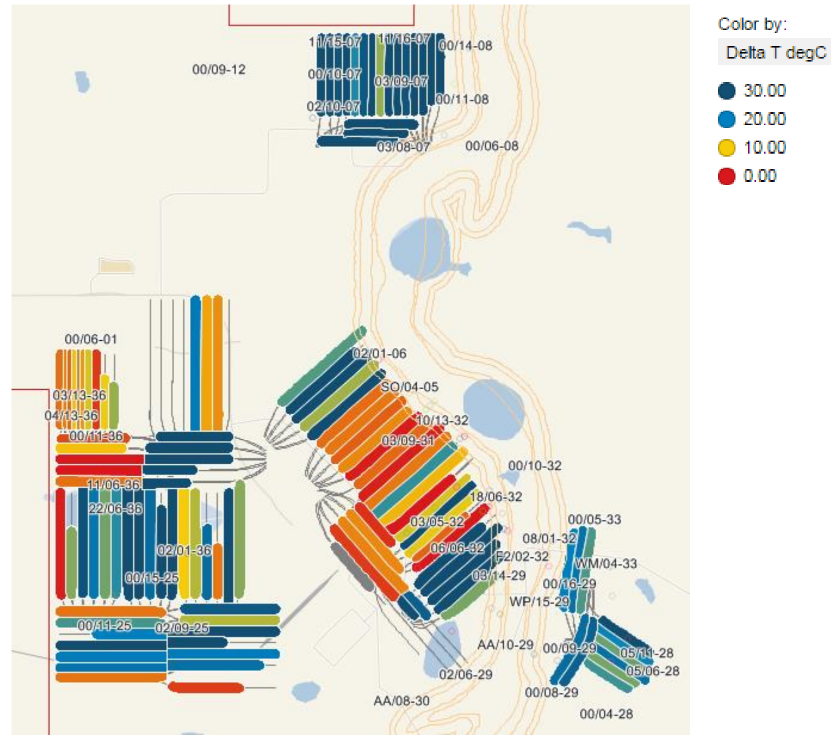


Impact of Throttle / Wildfire Outage
Wellbore data

Injector Pressure
dP (Jan. - Jul. 2016)



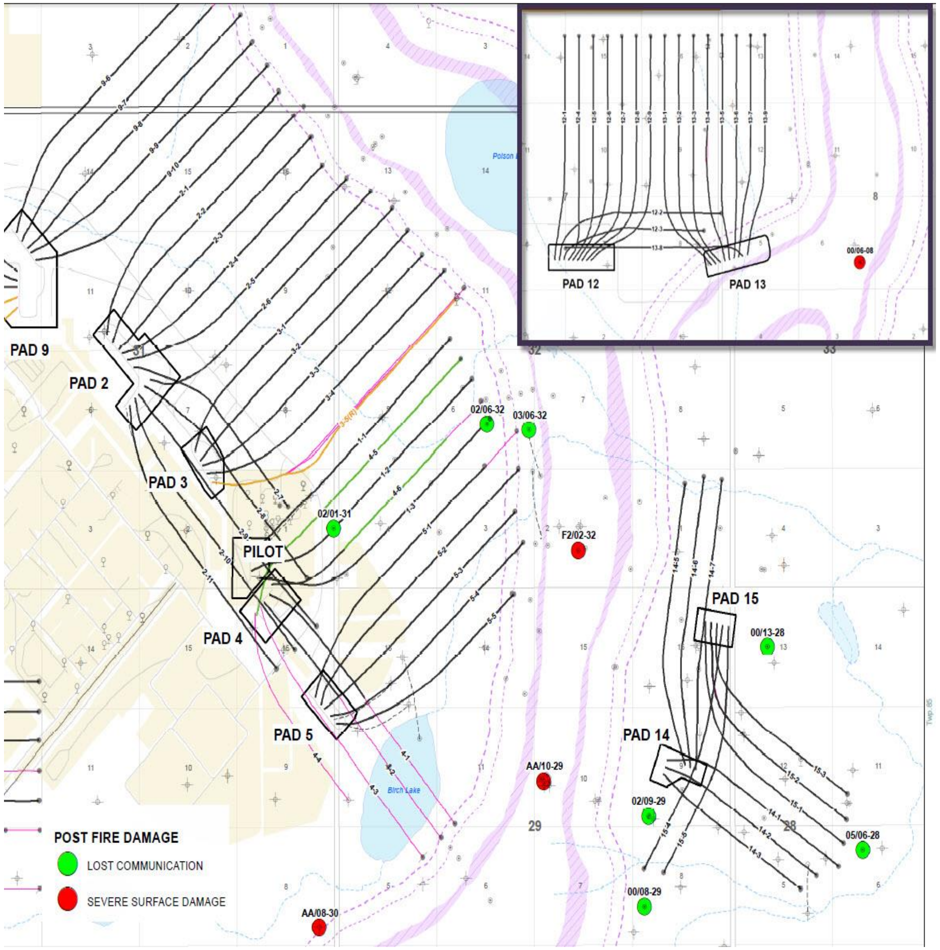
Producer Temperature
dT (May - Jul., 2016)



- Pressure and temperatures decreases observed during period of reduced rates, followed by shut-in
- Field is continuing to build pressures
  - *Observation wells still exhibit steam chamber pressures in the reservoir of 50-300 kPa less than prior optimized state*

2016 Wildfire Impact
Observation Well Damage

- Lost communication with 11 observation wells after wildfire
  - Severe surface damage occurred at four (4) wells
  - Seven (7) wells lost communication and data during wild fire
- Modified monitoring approvals were granted temporarily prior to well start up
- All regulatory wells were inspected and repaired prior to September 10, 2016
- Suspended Gas well 100/9-17-084-06W4 wellhead was damaged by the fire. Wellhead was repaired in July 2016 and well abandonment was completed March 2017.



2016 Wildfire Impact
Observation Well Damage

- Examples of two observation wells severely damaged at surface
- Both wells repaired and properly communicating

Scheme Performance
Recoverable Bitumen

Pad	Well Count	Cumulative Production, YE 2016 (e6m3)	EUR (e6m3)	EBIP (e6m3)	SBIP (e6m3)	EBIP		SBIP	
						Current RF	Estimated Ultimate RF	Current RF	Estimated Ultimate RF
LL-001	5	1.0	1.5	2.1	1.8	46%	71%	53%	83%
LL-002NE	6	0.7	1.1	2.4	3.1	30%	44%	24%	34%
LL-002SE	5	0.3	0.4	1.1	1.6	26%	38%	17%	25%
LL-003	5	1.1	1.5	2.5	3.7	44%	60%	30%	40%
LL-004	2	0.1	0.1	0.2	1.1	55%	60%	9%	10%
LL-005	5	1.3	1.8	3.2	3.1	41%	56%	41%	57%
LL-006N	6	0.8	1.3	2.9	3.8	26%	44%	20%	34%
LL-006W	7	0.8	1.1	1.8	2.7	44%	60%	29%	40%
LL-007E	7	0.7	1.1	1.4	1.9	51%	76%	37%	55%
LL-007N*	9	1.9	2.5	3.3	3.9	56%	74%	47%	63%
LL-008	6	1.1	1.7	3.2	3.2	34%	53%	34%	54%
LL-009NE	5	0.2	0.4	1.1	2.0	21%	40%	12%	22%
LL-009W	5	0.4	0.7	1.6	1.9	27%	45%	23%	38%
LL-010N	3	0.2	0.3	1.1	1.1	22%	31%	21%	29%
LL-010W	5	0.6	1.1	2.0	2.6	31%	54%	24%	43%
LL-011	10	1.1	1.4	2.2	2.8	51%	65%	40%	51%
LL-012	9	0.6	1.6	3.4	4.8	17%	46%	12%	32%
LL-013	9	0.7	1.6	3.3	4.3	23%	49%	17%	38%
LL-014	6	0.3	1.2	1.9	4.2	15%	61%	7%	28%
LL-015	5	0.2	0.9	1.4	2.2	12%	61%	8%	39%
K1A-A	9	0.0	2.5	4.4	6.6	0%	56%	0%	37%
K1A-B	8	0.0	2.2	3.9	4.8	0%	57%	0%	46%
K1A-C	8	0.1	3.0	5.1	6.4	2%	58%	2%	47%
K1A-D	11	0.0	3.0	5.4	6.9	1%	56%	1%	44%
Total	**156**	**14.3**	**33.9**	**61.0**	**80.8**	**23%**	**56%**	**18%**	**42%**

* Includes 4 infill producers

Scheme Performance

December 2016 Average Injector Pressures

Drainage Area/ Pad	Average Injector Pressure (kPag)
LL-001	1,353
LL-002NE	1,247
LL-002SE	1,168
LL-003	1,339
LL-004	1,332
LL-005	1,406
LL-006N	1,736
LL-006W	1,588
LL-007E	1,755
LL-007N	1,644
LL-008	1,647
LL-009NE	1,290
LL-009W	1,725
LL-010N	1,993
LL-010W	1,707
LL-011	1,373
LL-012	1,847
LL-013	1,770
LL-014N	2,242
LL-014E/015E	2,244
LL-015S	1,783

Scheme Performance
Methodology for Predicting Performance

- Future performance predictions are developed for each wellpair using a combination of multiple forecasting tools:
    - Analytical tools (modified Butler models)
    - Simulation
    - Analogue data

- Probabilistic forecasts for each wellpair are combined and aggregated to a field level forecast.

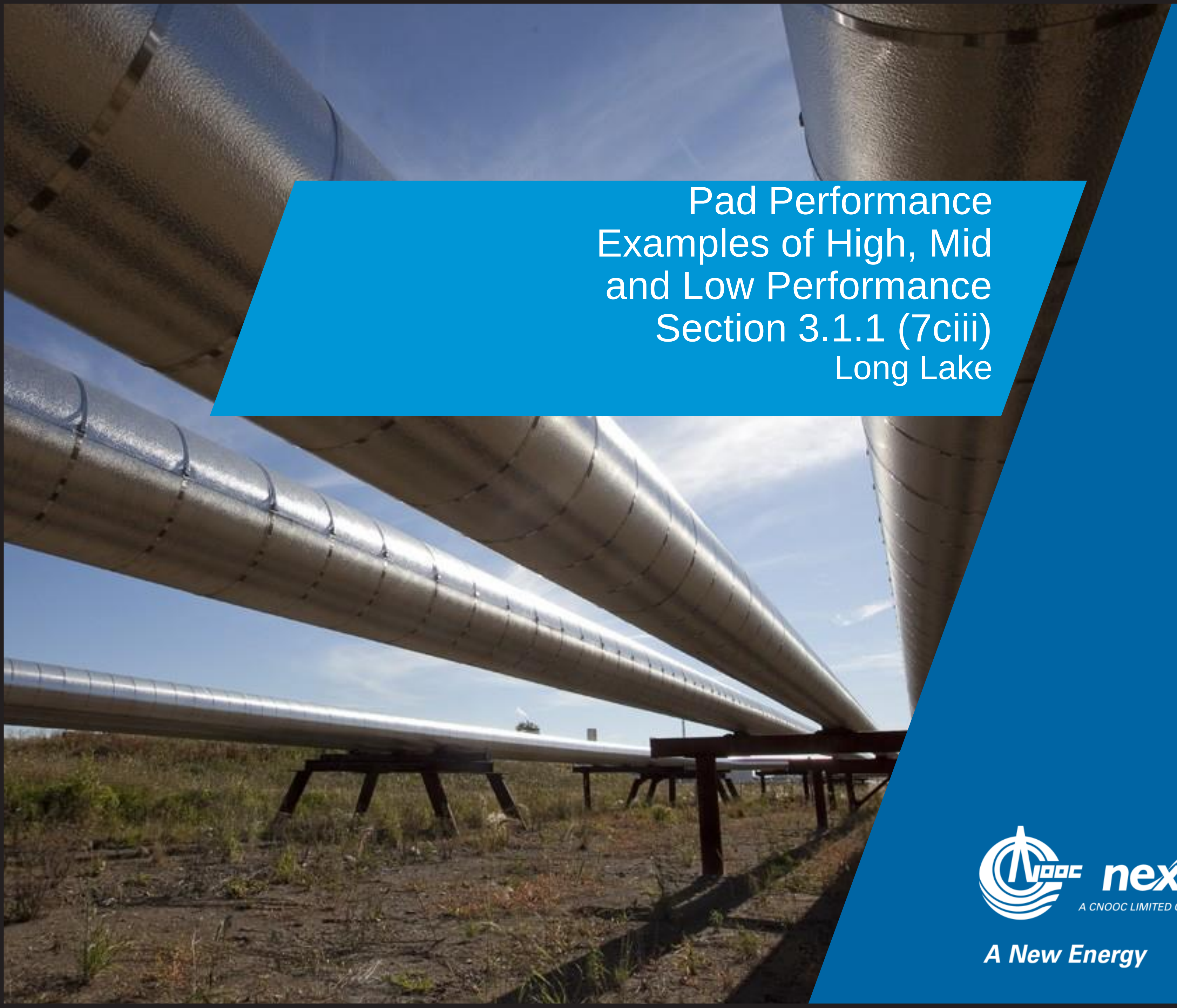
- Constraints and field assumptions are applied:
    - Plant constraints (steam, bitumen, water)
    - Planned & unplanned downtime:
        - Plant turnarounds
        - Steam outages
        - Well downtime (ESP failures, etc)

Scheme Performance

Injection Steam Quality

- Injection steam quality is estimated at 95% at the wellhead.
- To validate, a HYSYS model of the steam injection header system from the CPF to Pads 12/13 has been run, based on the following parameters:
  - HP steam at the CPF HP separator at 9,000 kPa and 100% quality;
  - HP steam at the Pad 12/13 wellheads at 4,500 kPa;
  - No driplegs/steam traps modeled in HYSYS – conservative.
- As per the HYSYS model, HP steam quality at the injector wellhead is 92% (assuming no driplegs/steam traps).
- The Nexen steam injection header system operates with driplegs/steam traps, therefore estimate of 95% steam quality at the wellhead is reasonable.
- Steam quality will be affected by injection header length. Pads 12/13 were modeled as these Pads represent the greatest header length from the CPF.
- No impact is expected on the bitumen recovery mechanism due to steam quality.

Pad Performance
Examples of High, Mid and Low Performance
Section 3.1.1 (7ciii)
Long Lake



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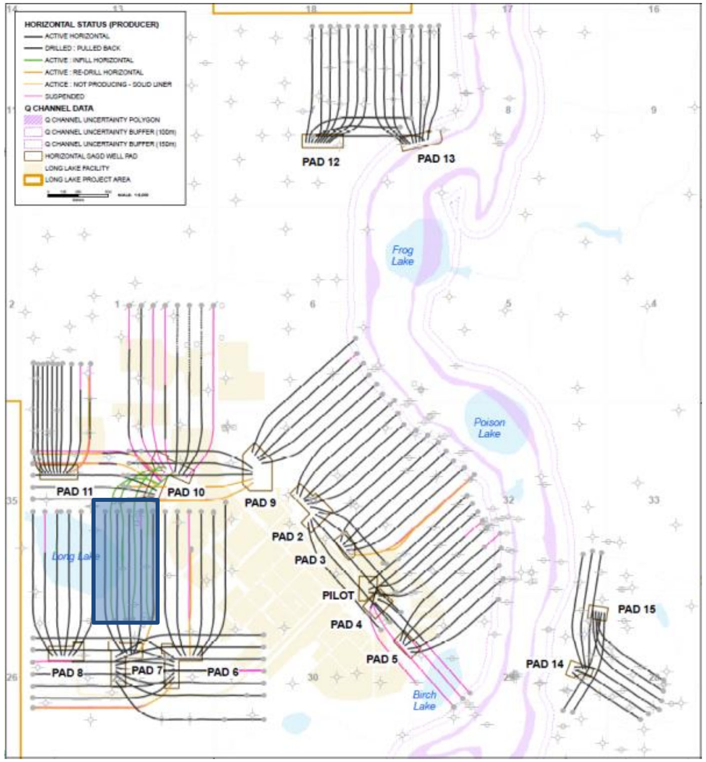
Examples of High, Mid, Low Recovery
High level comparison

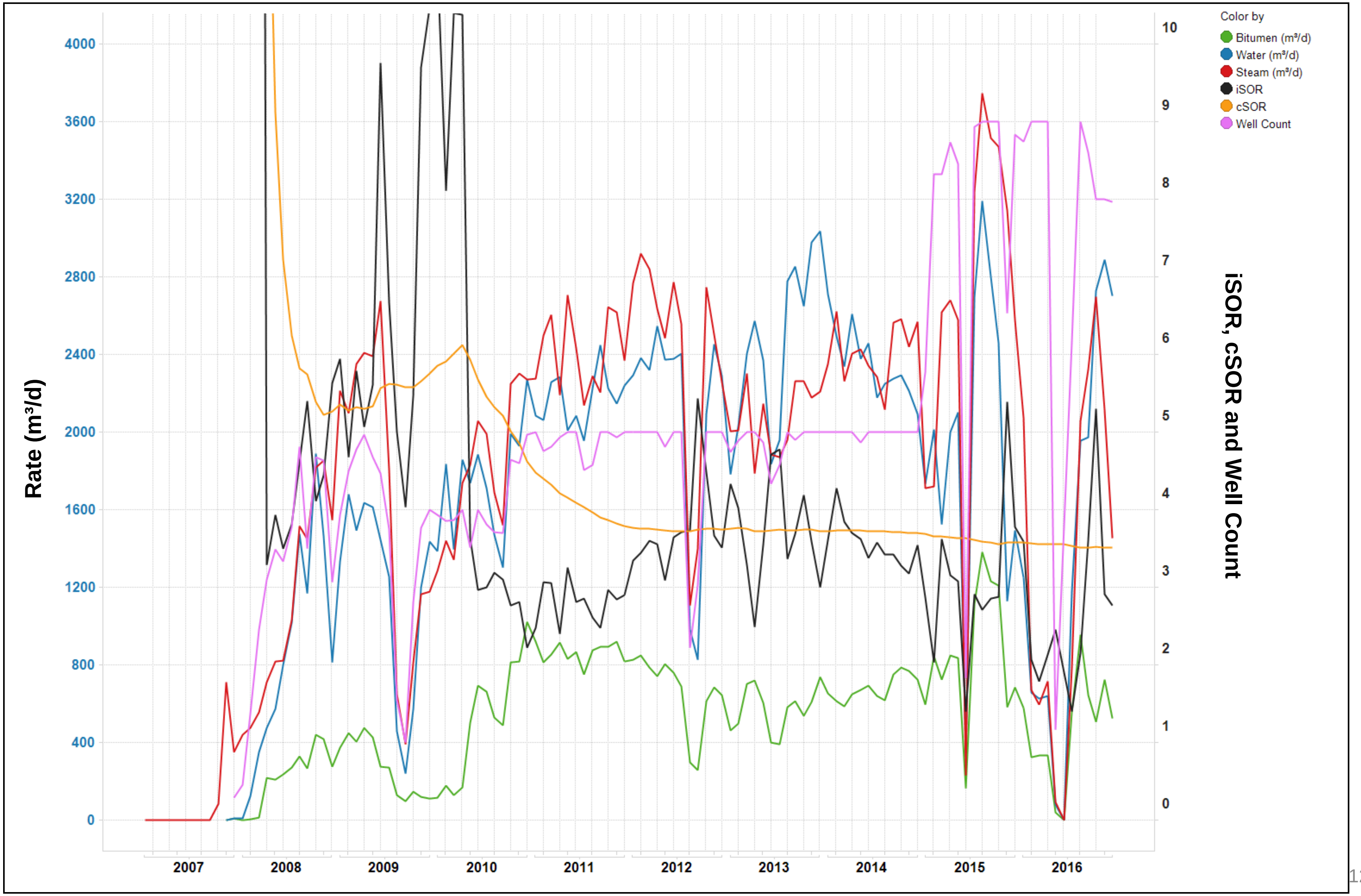
	Resource Quality	Performance	Operating Strategy
Pad 7N *High*	EBIP thickness: 32m Swe: 0.31	Well Peak Rate: 320 m^3/d Current Pad RF: 57%	4 Infill wells
Pad 1 *Mid*	EBIP thickness: 33m Swe: 0.39	Well Peak Rate: 320 m^3/d Current Pad RF: 46%	Original pilot pad 2 infill pairs added
Pad 9NE *Low*	EBIP thickness: 13m Swe: 0.40	Well Peak Rate: 110 m^3/d Current Pad RF: 21%	Low priority Not operated consistently

Example of High Recovery
Pad 7N

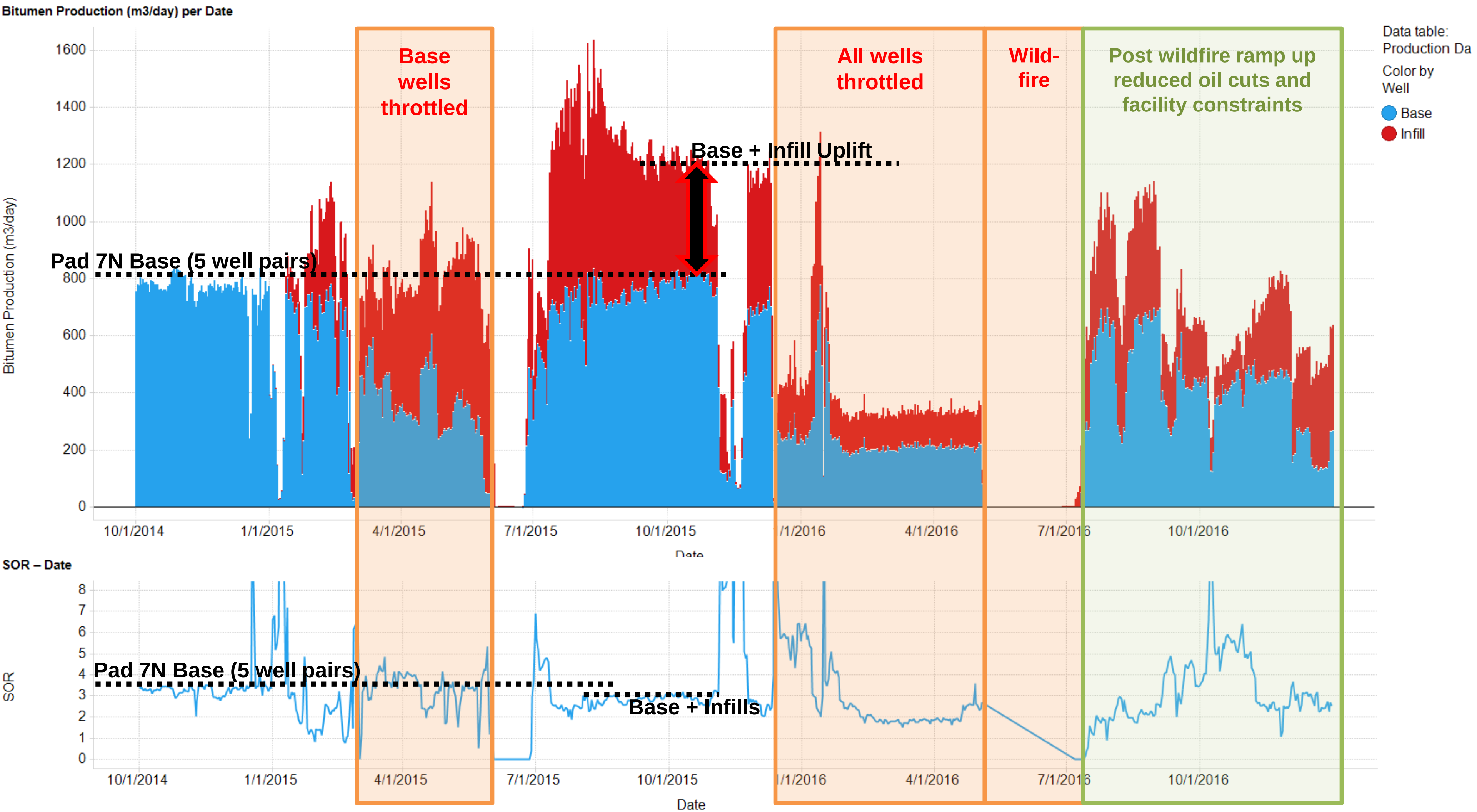
- 5 base wellpairs and 4 infill wells, all equipped with ESPs:
  - Conversion to SAGD beginning Q1 2008
  - ESP failure on 7P01 in Sep. 2016
- Wildfire recovery ongoing:
  - Oil cuts are lower post-wildfire
  - Attempting to produce out as much of the flush as possible and increase pressure to 1,800 kPa
- 4D seismic and thermocouple data indicates excellent chamber development and conformance along wells
- Projecting incremental pad recovery from infills with impact to parent wells yet to be seen:
  - YE 2016 RF: 57%



Example of High Recovery
Pad 7N



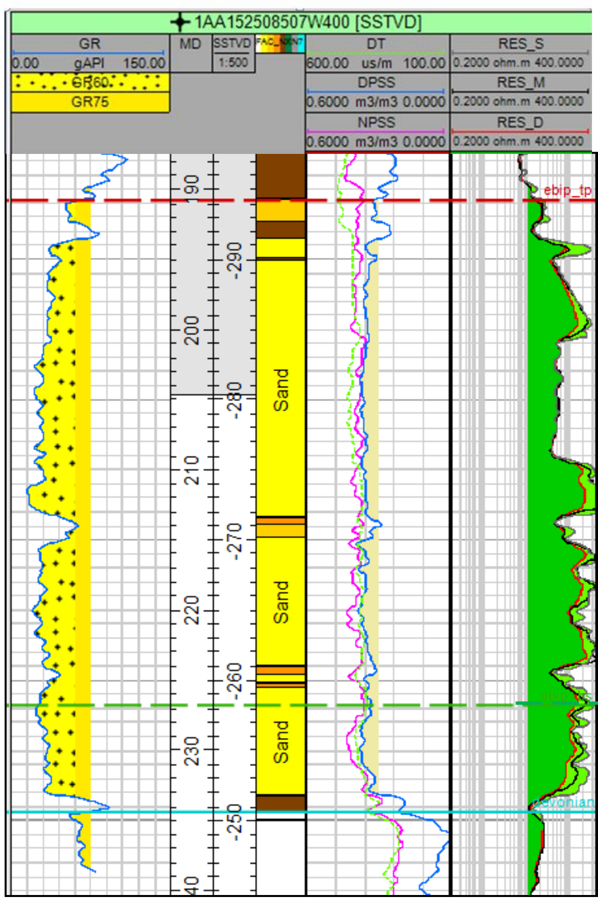
Example of High Recovery
Pad 7N – Infill Performance

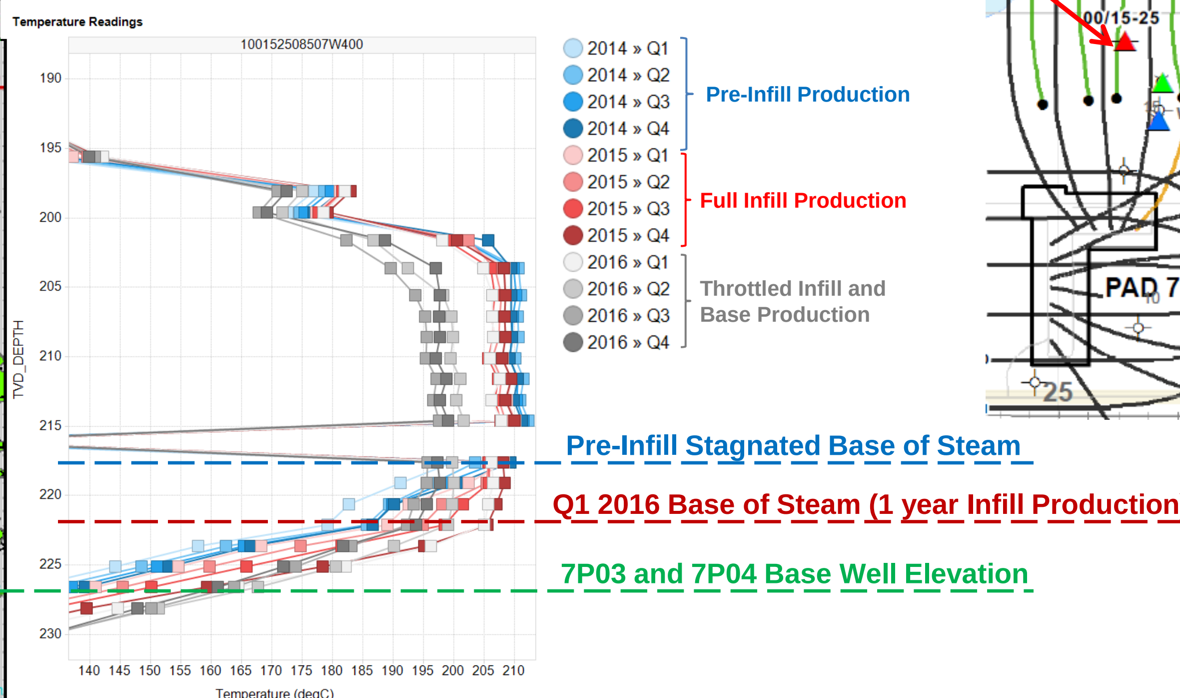


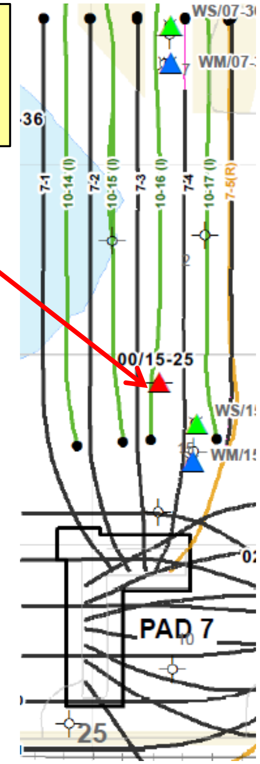
Example of High Recovery
Pad 7N – Infill Performance

- Observation well between 7P03 and 7P04 showing additional chamber development at the base since infill production started.

00/15-25 located:
46m east of 7P03
55m west of 7P04

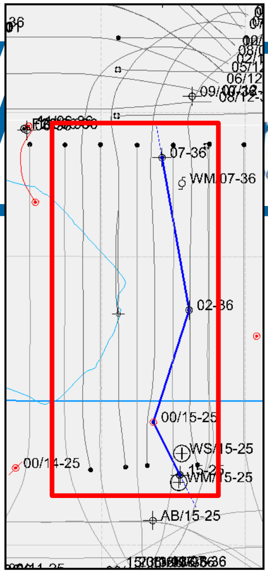


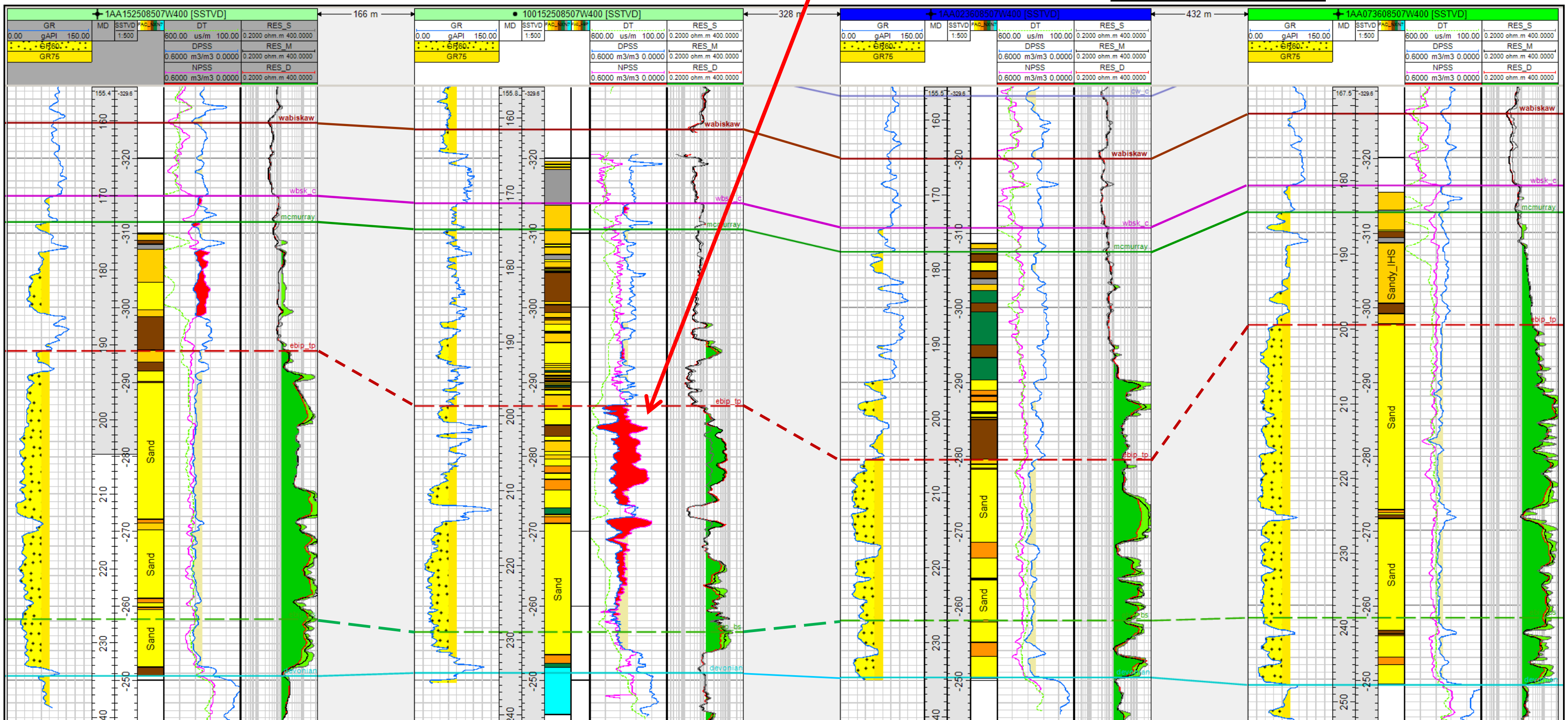




Example of High Recovery
Pad 7N – Geology

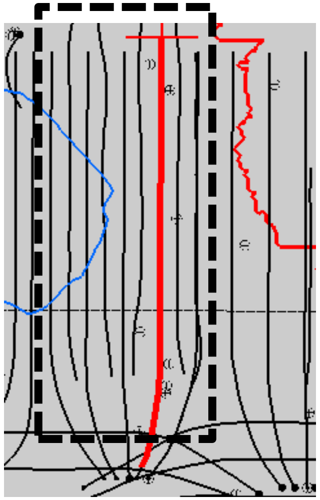
- Thick, clean sand with shallow mudplug across the middle of the laterals

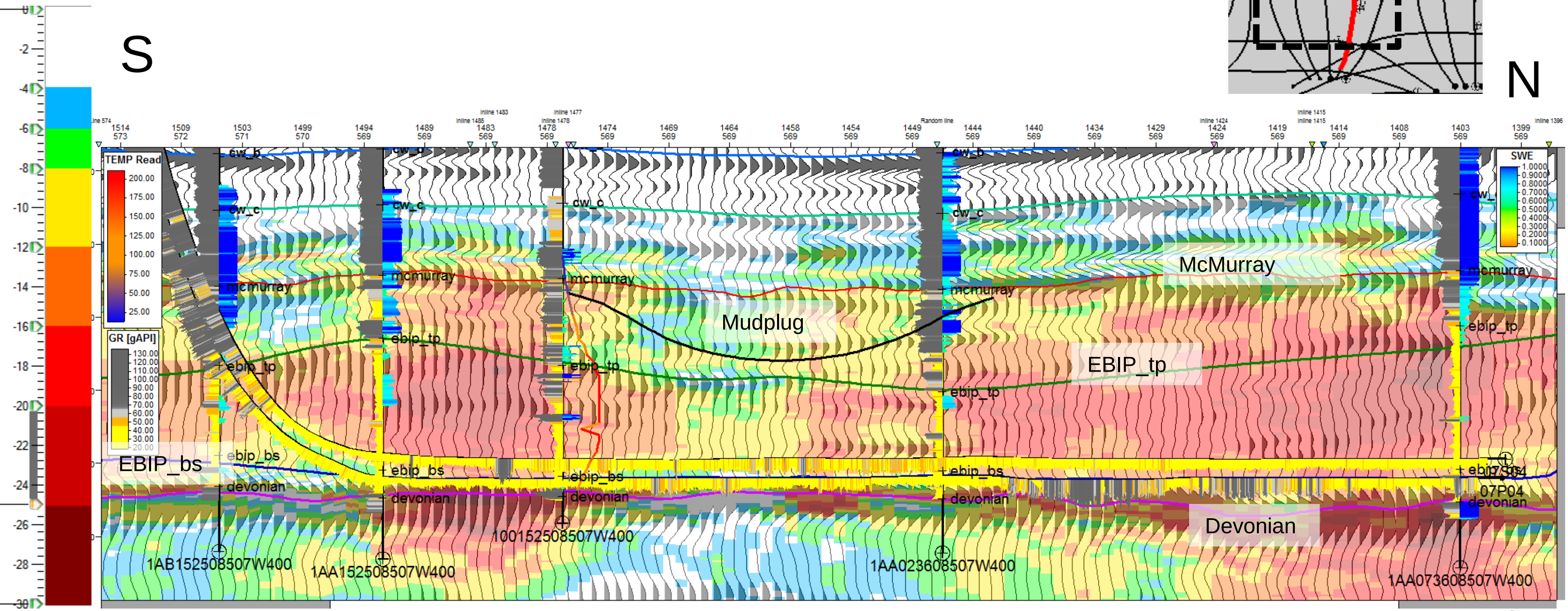




Example of High Recovery
Pad 7N – 4D Seismic

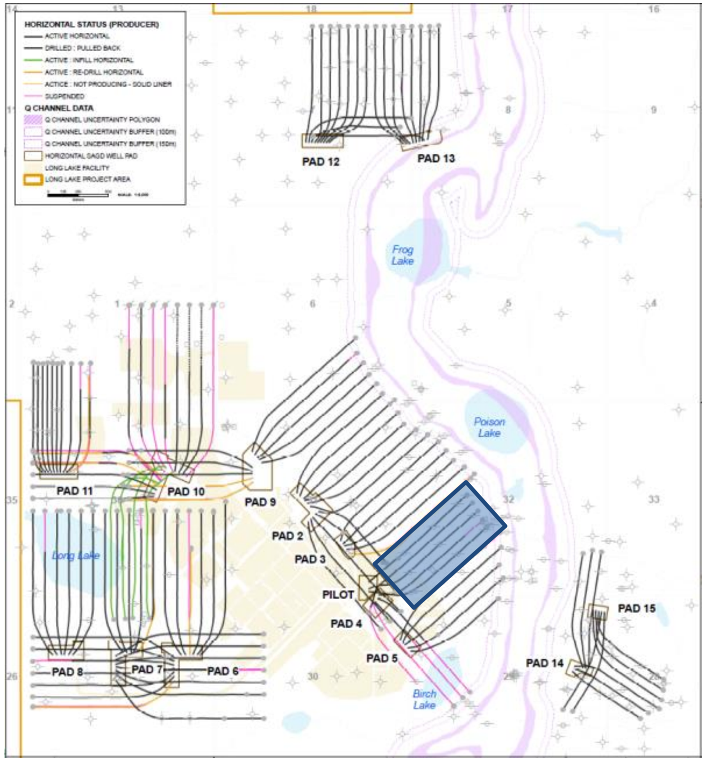
- 4D seismic from 2015 (impedance percentage change) along 7P04
- Good conformance along wellbore and development to EBIP top (better towards toes of 7N base wells)
- Large anomaly observed in top water at the toes





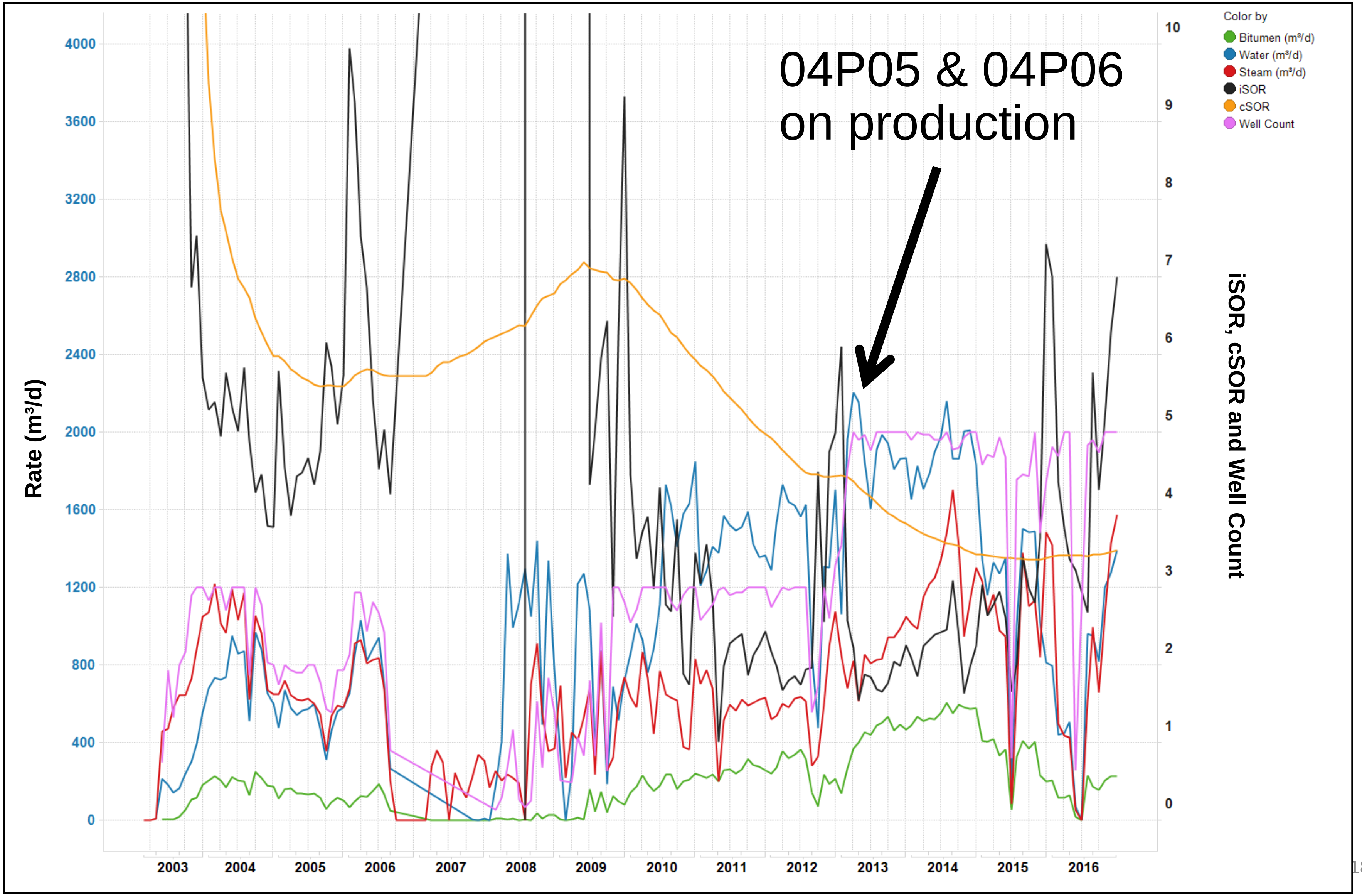
Example of Mid Recovery
Pad 1

- 5 well pairs:
  - All wells equipped with ESPs
- Original pilot pad drilled in 2003 had 3 well pairs with 150m well spacing
- 2 infill pairs were drilled in 2012 (04P05, 04P06)
  - Reduced well spacing to 75m
- Due to presence of lean zones, pad sees long recovery time after extended shut-ins
  - High watercut and withdrawal rates prior to seeing bitumen rate recovery
  - Similar performance impact observed after wildfire
- Historically operated at lower bottom hole pressures compared to surrounding pads:
  - Q-Ch constraints
  - Managing steam efficiency with lean zones
- YE 2016 RF is 43%



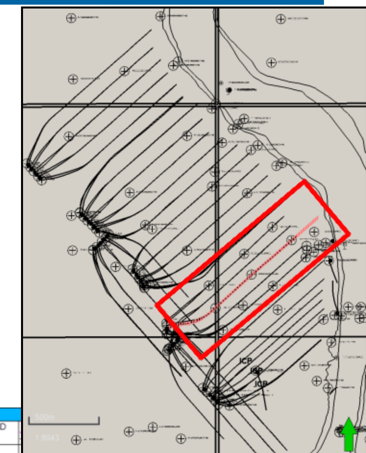
Example of Mid Recovery

Pad 1

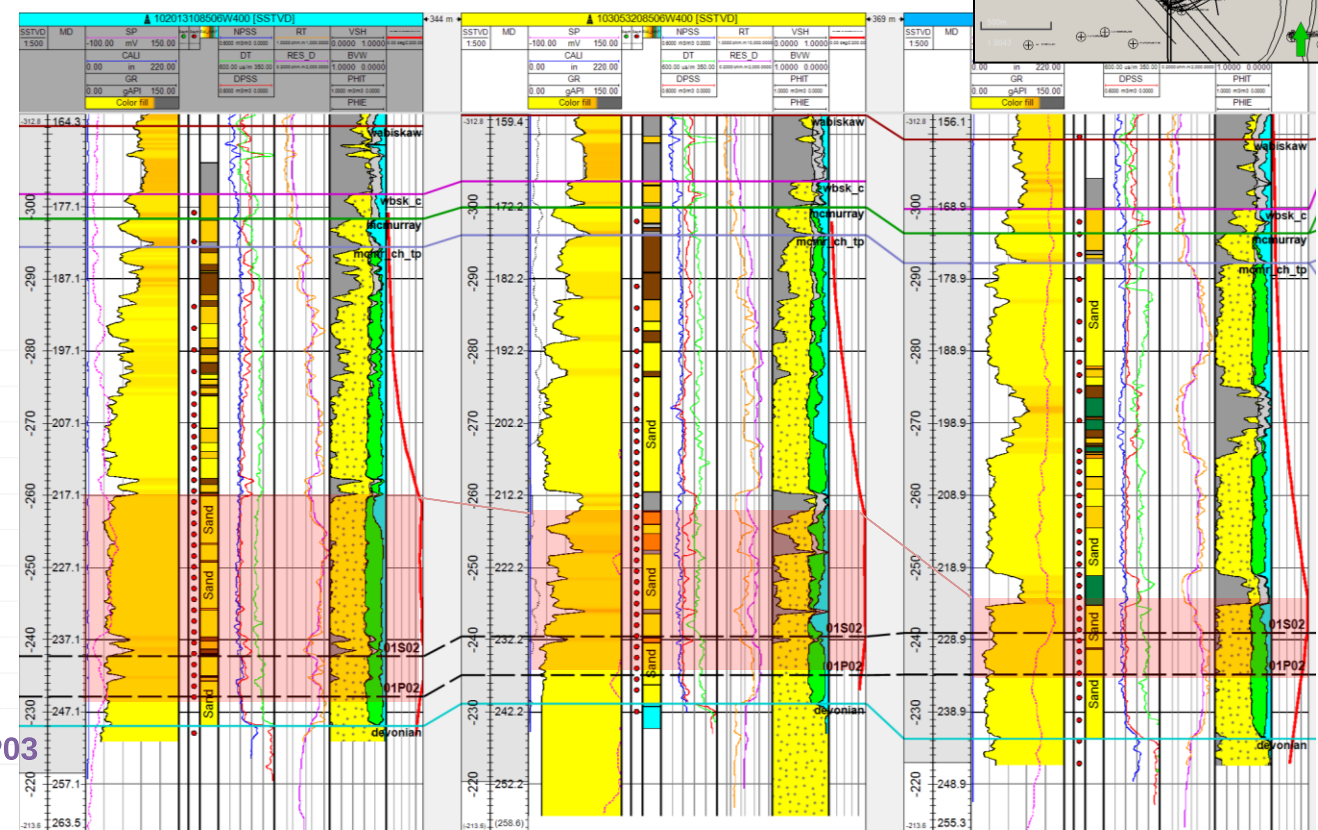


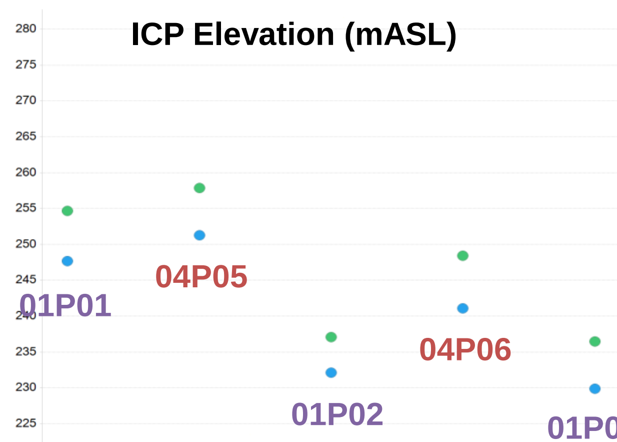
Example of Mid Recovery
Pad 1

- Good quality reservoir (~50m of pay)
- Multiple high saturation intervals (lean zones)
- Observation wells show vertical steam chamber growth impacted by heterogeneity
- Infill pairs (04P05 & 04P06) drilled at higher elevation to access stranded pay



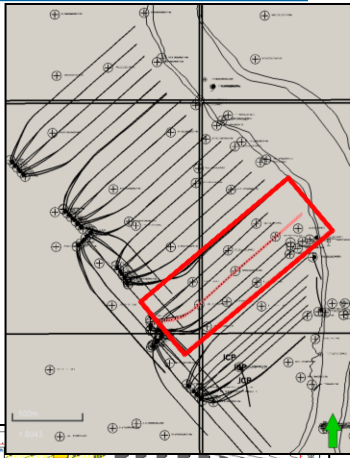
Steam Chamber

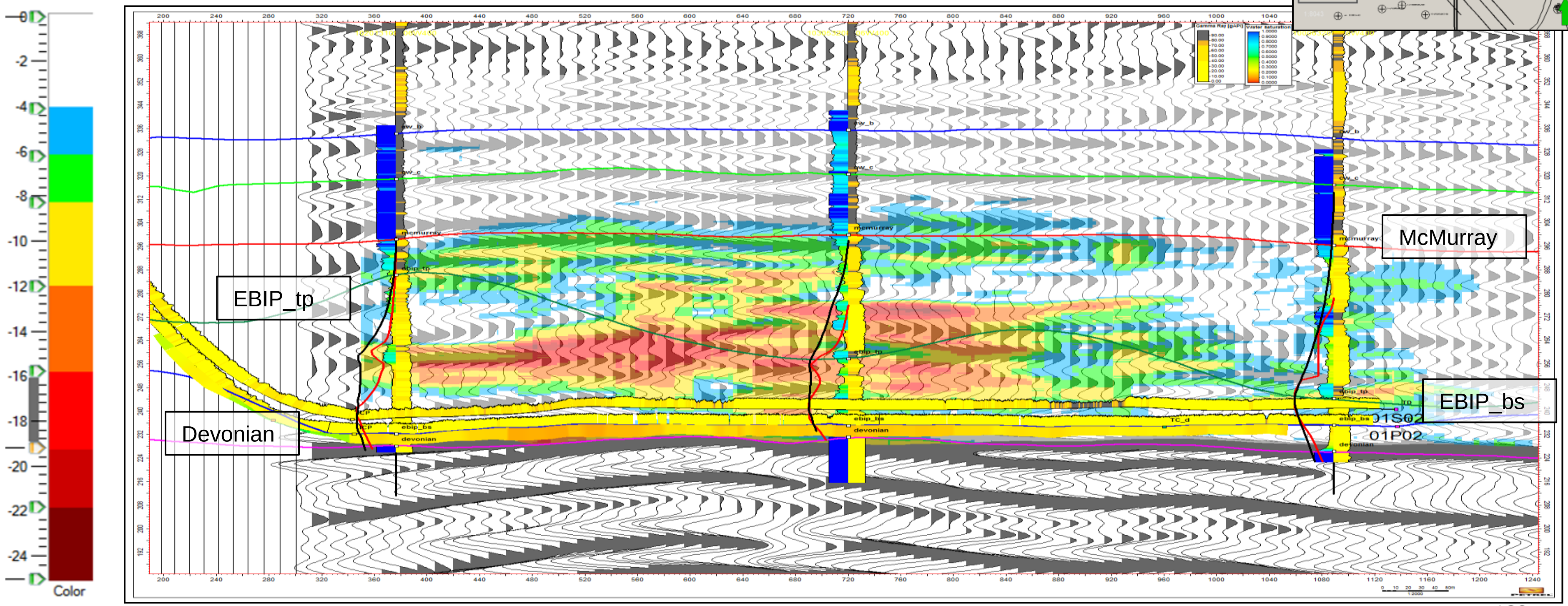




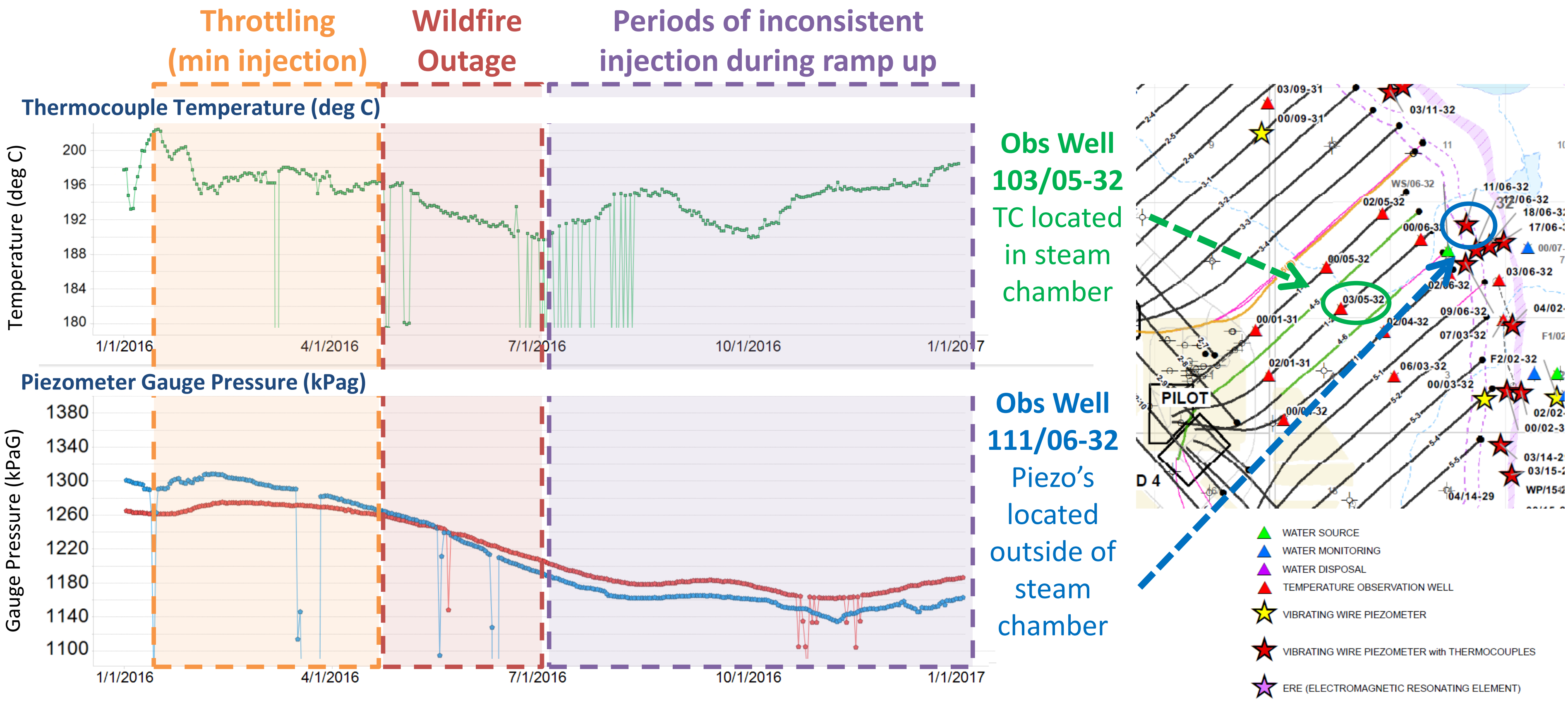
Example of Mid Recovery
Pad 1 - 4D Seismic

- 2014 4D seismic (impedance % change) along 1P02
- Anomalies show inconsistent steam chamber development:
  - Limited development at the toe – no toe injection since Q1 2013
  - Un-accessed resource at the heel due to baffle / barrier
- 4D development aligns with temperature data from observation wells : Jan 2014 (Red), Nov 2016 (Black)





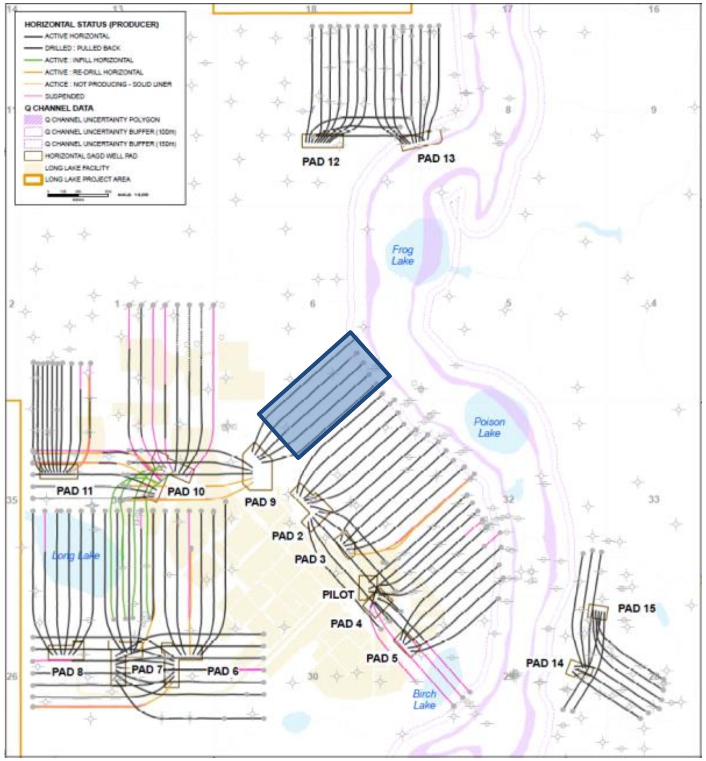
Example of Mid Recovery
Pad 1



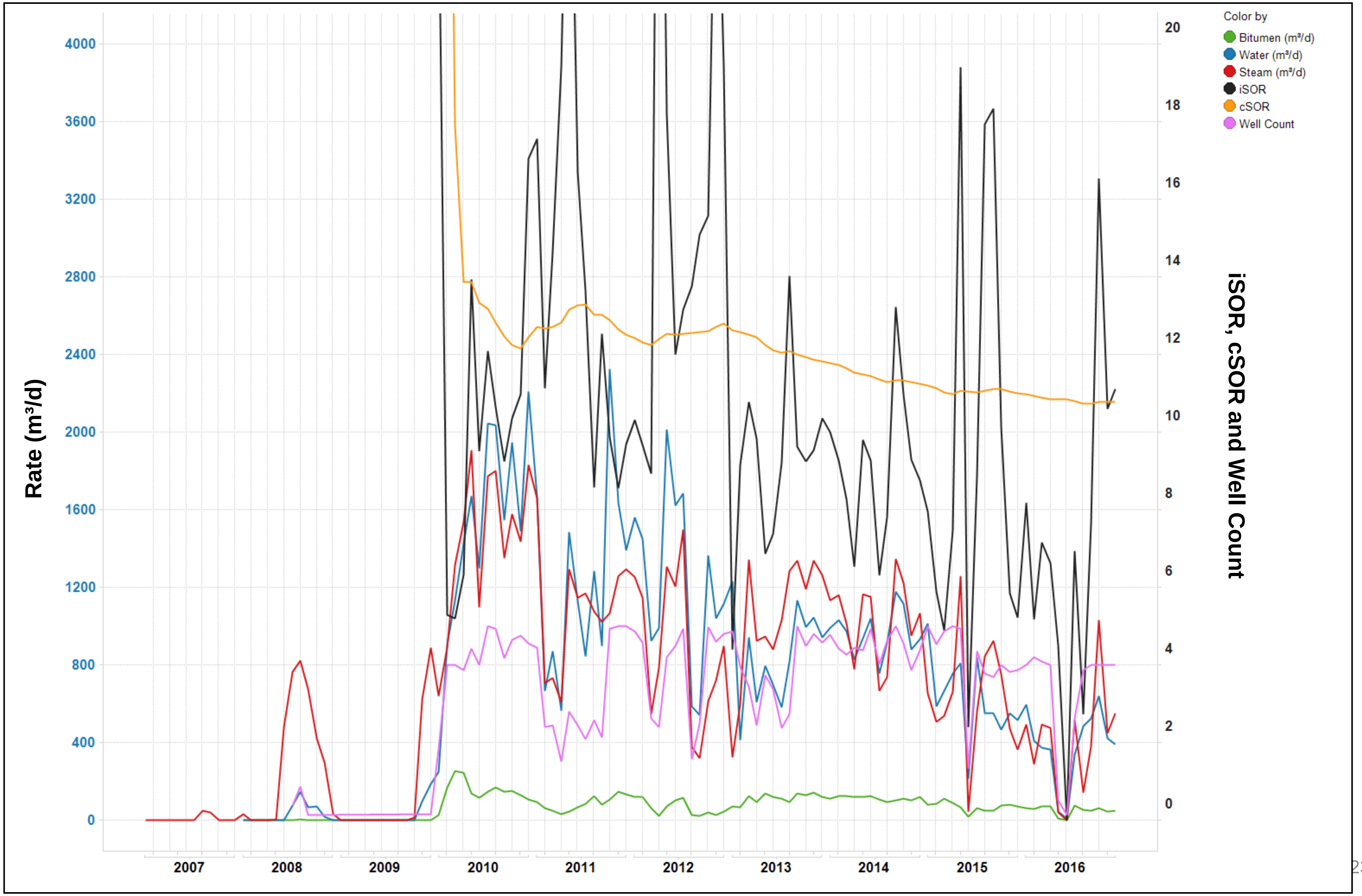
- Observation wells show temperature and pressure drop during throttling and wildfire outage
- Pressure response seen in obs wells outside of steam chamber is more muted compared to within chamber

Example of Low Recovery
Pad 9NE

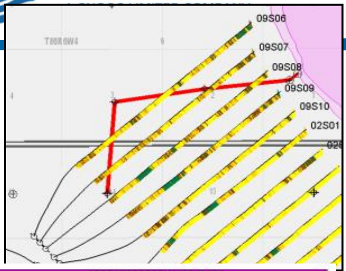
- 5 well pairs:
  - All wells equipped with ESPs
  - 9P06 long term shut in due to low flow at ESP
  - 9P07 toe is plugged back due to liner failure
- First oil production Q1 2010:
  - 6 years of production, Inconsistent steam injection
- Wells are all low on priority list due to poor quality and performance, therefore they get heavily impacted with facility restrictions
- SOR's are historically high due to inconsistent operating strategy:
  - Wells have had excess steam injected when facility is steam long
  - Minimum rates have been injected when facility is steam short
- Post Wildfire Production Performance:
  - Initial increase in oil volumes due to flush production during start up
  - Low connectivity to neighboring pad. Wells maintained bottom hole pressure during shut in, and easily achieved target pressure during ramp up
  - Oil cuts continue to decrease and have yet to reach pre-wild fire percentages
- 2016 YE Recovery Factor 22%



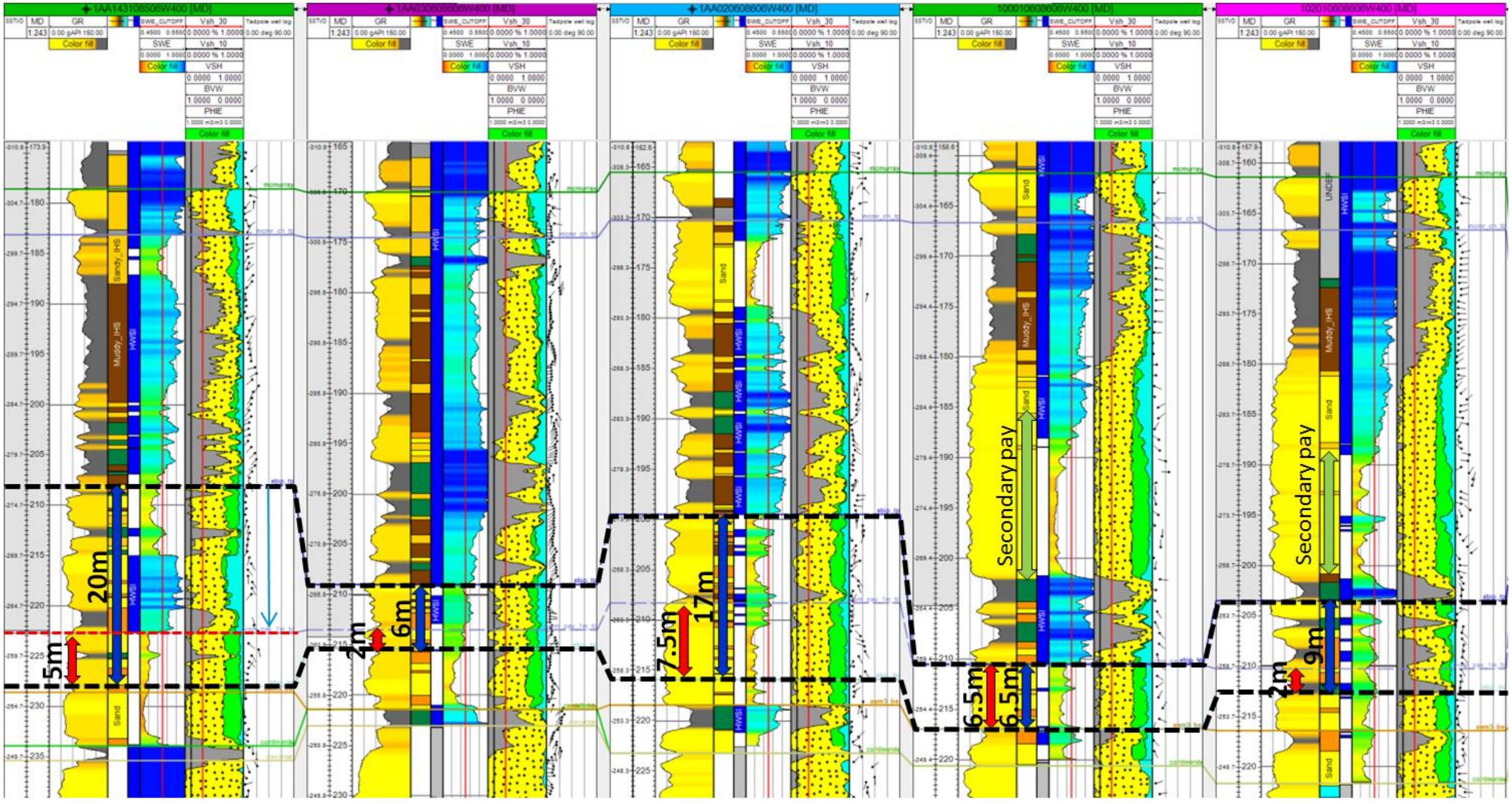
Example of Low Recovery
Pad 9NE

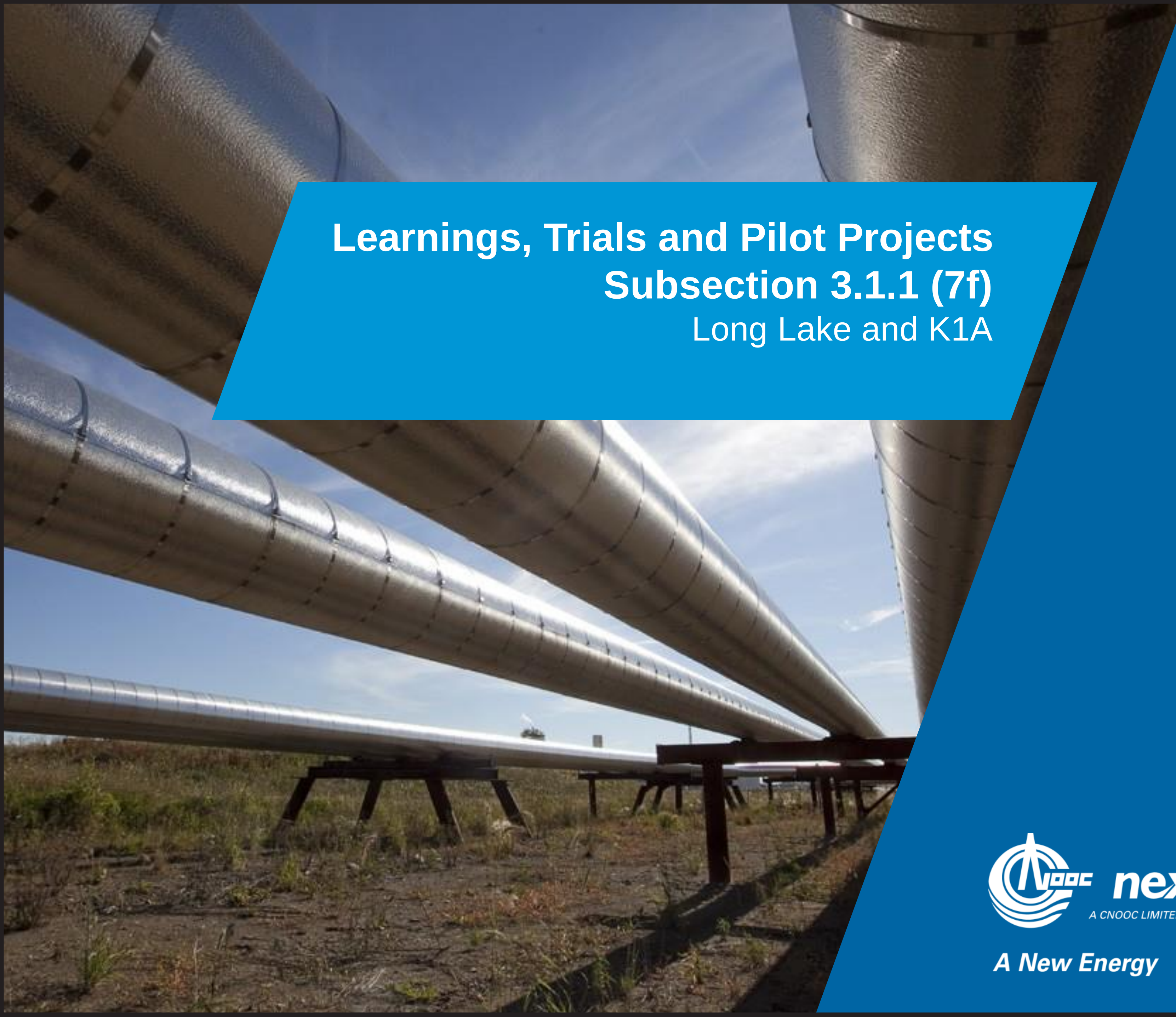


Example of Low Recovery
Pad 9NE



- Wellpairs are located within thin, poor quality pay, resulting in poor production performance:
  - Two separate complexes occur over Pad 9NE, which impacts reservoir quality
  - Pay height decreases towards the toes of well pairs





Learnings, Trials and Pilot Projects
Subsection 3.1.1 (7f)

Long Lake and K1A

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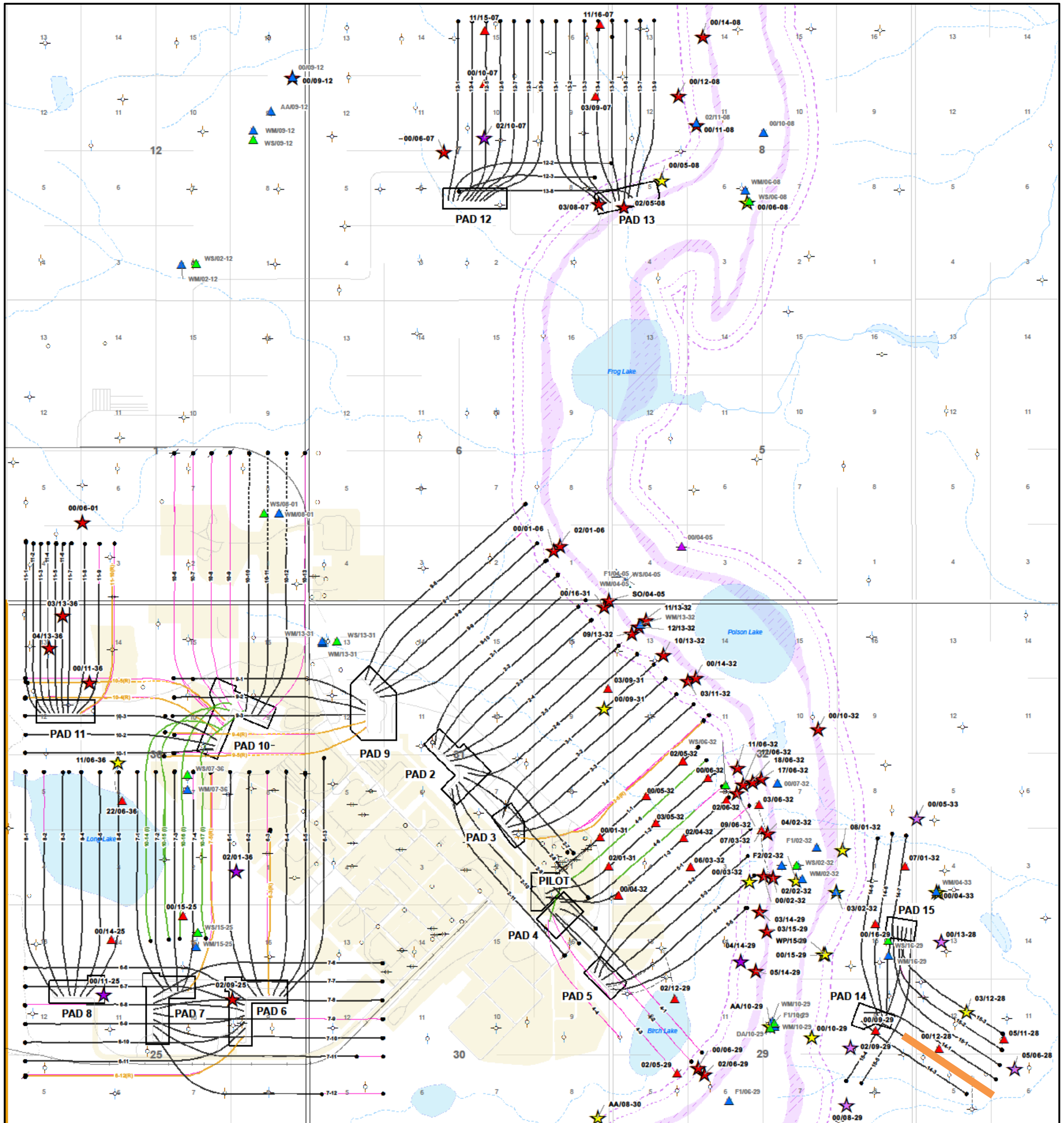
2016 Liner Failures



- 1 liner failure in 2016
- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled:

- None

Wells Repaired:

- 14P02 – liner failure Q3, packer assembly

Wells Shut In – Ongoing Evaluation:

- None

Well Re-drilled
Well Repaired
Well Shut in

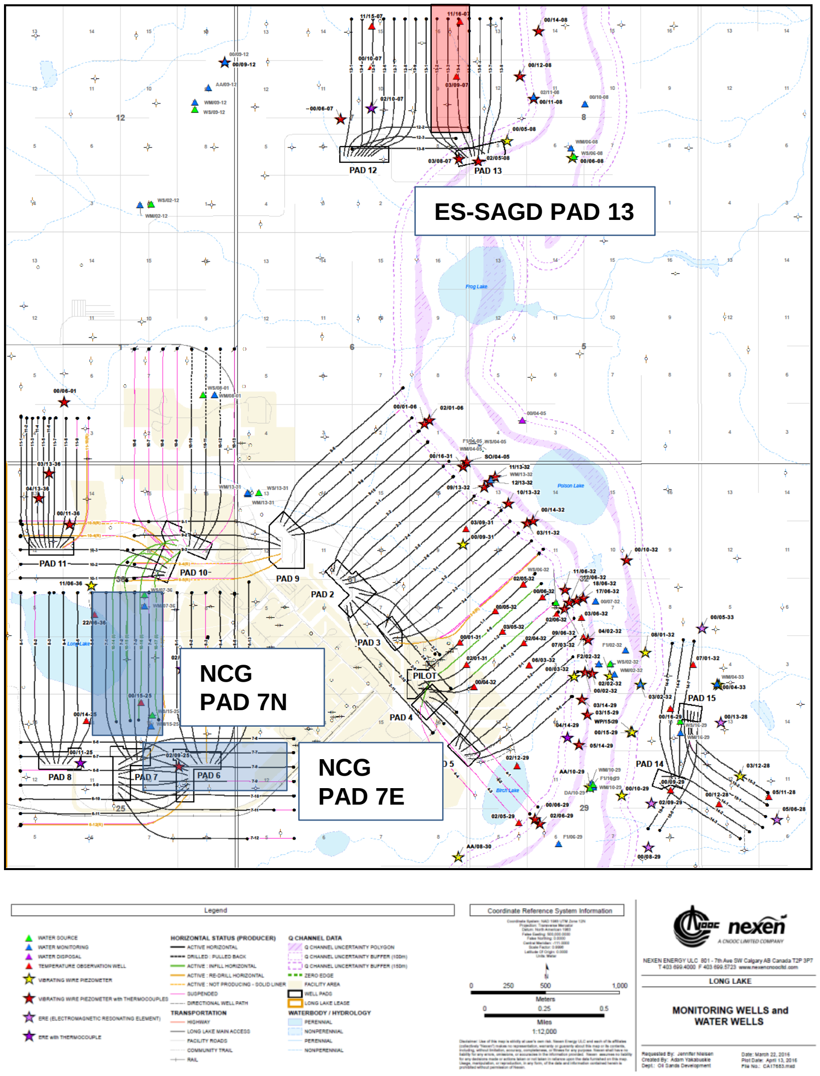
Liner Failures History

Well	Well Pair ID	Failure Date (Year)	Repair Action
2P11	LL-002-11	2013	Plugback
2P11	LL-002-11	2014	None - well shut-in
3P05	LL-003-05	2012	Re-Drill
3S05	LL-003-05	2013	Re-Drill
3P05	LL-003-05	2014	Re-Drill
6P03	LL-006-03	2010	Re-Drill
6S03	LL-006-03	2011	Re-Drill
6P04	LL-006-04	2014	Plugback
6P08	LL-006-08	2011	Plugback
6P08	LL-006-08	2012	Plugback
6P09	LL-006-09	2014	None
6P10	LL-006-10	2014	Plugback
6P12	LL-006-12	2012	Re-Drill
6P12	LL-006-12	2014	None - well shut-in
7P04	LL-007-04	2011	Plugback
7P04	LL-007-04	2011	Plugback
7P07	LL-007-07	2015	Packer Assembly
7P09	LL-007-09	2012	Plugback
7P11	LL-007-11	2012	Packer Assembly
7P11	LL-007-11	2014	Plugback / Packer Assembly
7P13	LL-007-13	2014	Packer Assembly
7P13	LL-007-13	2015	None - well shut-in
8S06	LL-008-06	2015	Long string could not be pulled, cut string; well shut-in
9P07	LL-009-07	2012	Plugback
9P07	LL-009-07	2014	Plugback
10P04	LL-010-04	2014	Plugback
11P02	LL-011-02	2015	Packer Assembly
11P05	LL-011-05	2011	Re-Drill
11P10	LL-011-10	2013	Re-Drill
13P08	LL-013-08	2015	Packer Assembly
14P02	LL-014-02	2016	Packer Assembly

2016 Other Well Integrity Actions

- IWCP D13 Compliance:
  - Within Year 2 of program (Apr. 2016 - Apr. 2017):
    - 45 wells still out of compliance - Target quota of 12 to bring into compliance
    - 19 wells brought into compliance in Year 2 of program as at Dec. 31, 2016 with additional work completed in Q1 2017
    - Intention to have all 26 additional wells compliant in Years 2 & 3
- 01P03A - Re-abandonment:
  - Non Routine well abandonment completed in Oct. 2016
  - Cut and capped well prior to Mar. 31, 2017
  - No SCVF observed during abandonment operations
  - Gas Migration program will be put in place to monitor well

Update on Co-Injection Projects



PAD 13 Solvent Co-Injection Pilot (2 years):

- Application approval 9485U was received in Q2 2013
- Injected solvent being used is gas condensate (mostly C5 to C6 composition)
- Solvent co-injection started Q4 2014 at 13S3 and 13S4
- Solvent suspended in late 2015 due to inconsistent operations at Pad 13 caused by surface constraints
- Continuing to monitor solvent recovery
- Re-evaluating pilot plans in light of surface interruptions

PAD 7E NCG Pilot:

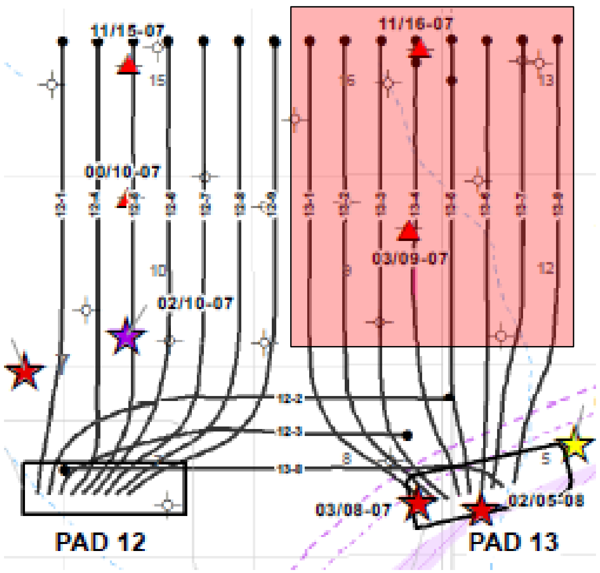
- Application approval 9485R received in Q3 2012
- Injected gas being used is natural gas
- Gas injection started Q4 2014 at 7P7 – 7P9
- Gas injection suspended after 2015 turnaround
- Timing for pilot re-start being evaluated

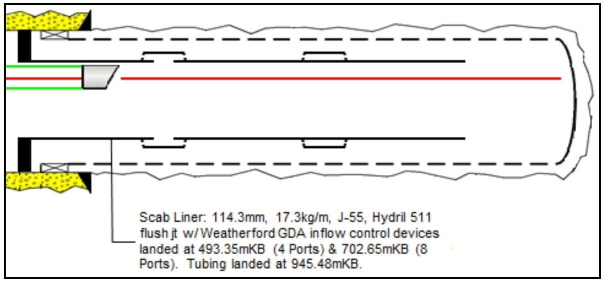
PAD 7N NCG Pilot:

- Application approval 9485CC received in Q2 2014
- Injected gas to be used is natural gas
- Construction of co-injection surface facilities complete Q2 2015 on 5 well pairs planned
- Timing for pilot startup being evaluated

ICD Performance

- Simple Inflow Control Devices (liner ports) were installed in the Pad 13 producer scab liners to promote “more even” production of fluid along the wellbore with expected benefits of:
  - Reduced pressure drop along the producer
  - Better conformance along the well
- Majority of wells with ICDs have been consistently good producers since SAGD conversion and are meeting production expectations:
  - Wells show good conformance
  - All ICDs remain in operation with no current plans to close, alter or remove the devices





ICD Performance Cont'd

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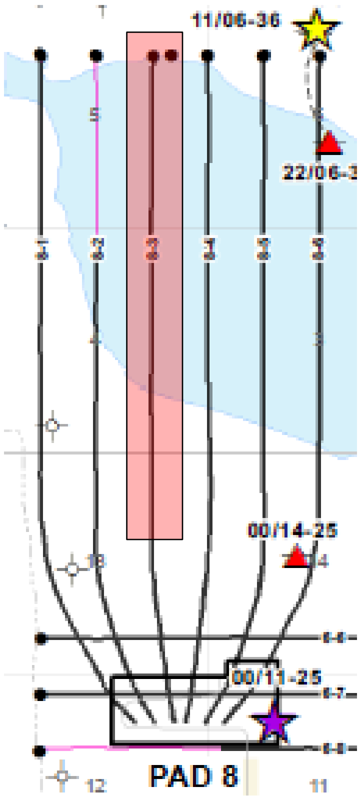
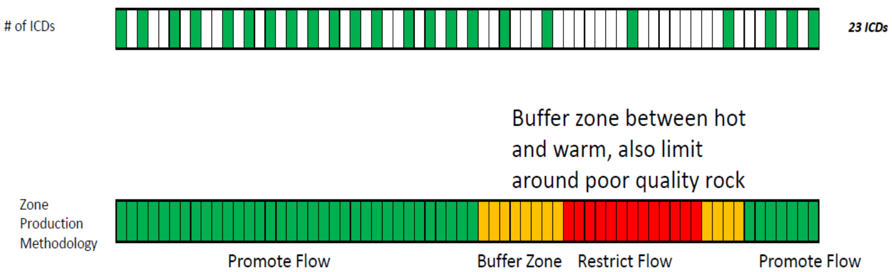
- More rigorous ICD design and installation was completed at 08P03
- Well had a history of poor performance due to a hot spot associated with poor reservoir quality near the mid-section of the well
- Production string installed consisting of 23 ICD devices with device geometry designed to limit steam coning and promote hydrocarbon production
- Devices spaced to equalize flow along the length of the wellbore accounting for differences in reservoir quality



- Since ICD installation, well has shown improved temperature conformance and an increase in total fluid rate



Observation Wells
Subsection 3.1.1 (7)
Long Lake

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Long Lake Observation Wells

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LEGEND

- WATER SOURCE
- WATER MONITORING
- WATER DISPOSAL
- TEMPERATURE OBSERVATION WELL
- VIBRATING WIRE PIEZOMETER
- VIBRATING WIRE PIEZOMETER with THERMOCOUPLES
- ERE (ELECTROMAGNETIC RESONATING ELEMENT)
- ERE with THERMOCOUPLE
- PROPOSED OBSERVATION WELLS

HORIZONTAL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DIRECTIONAL WELL PATH

TRANSPORTATION

- HIGHWAY
- LONG LAKE MAIN ACCESS
- FACILITY ROADS
- COMMUNITY TRAIL
- RAIL

Q CHANNEL DATA

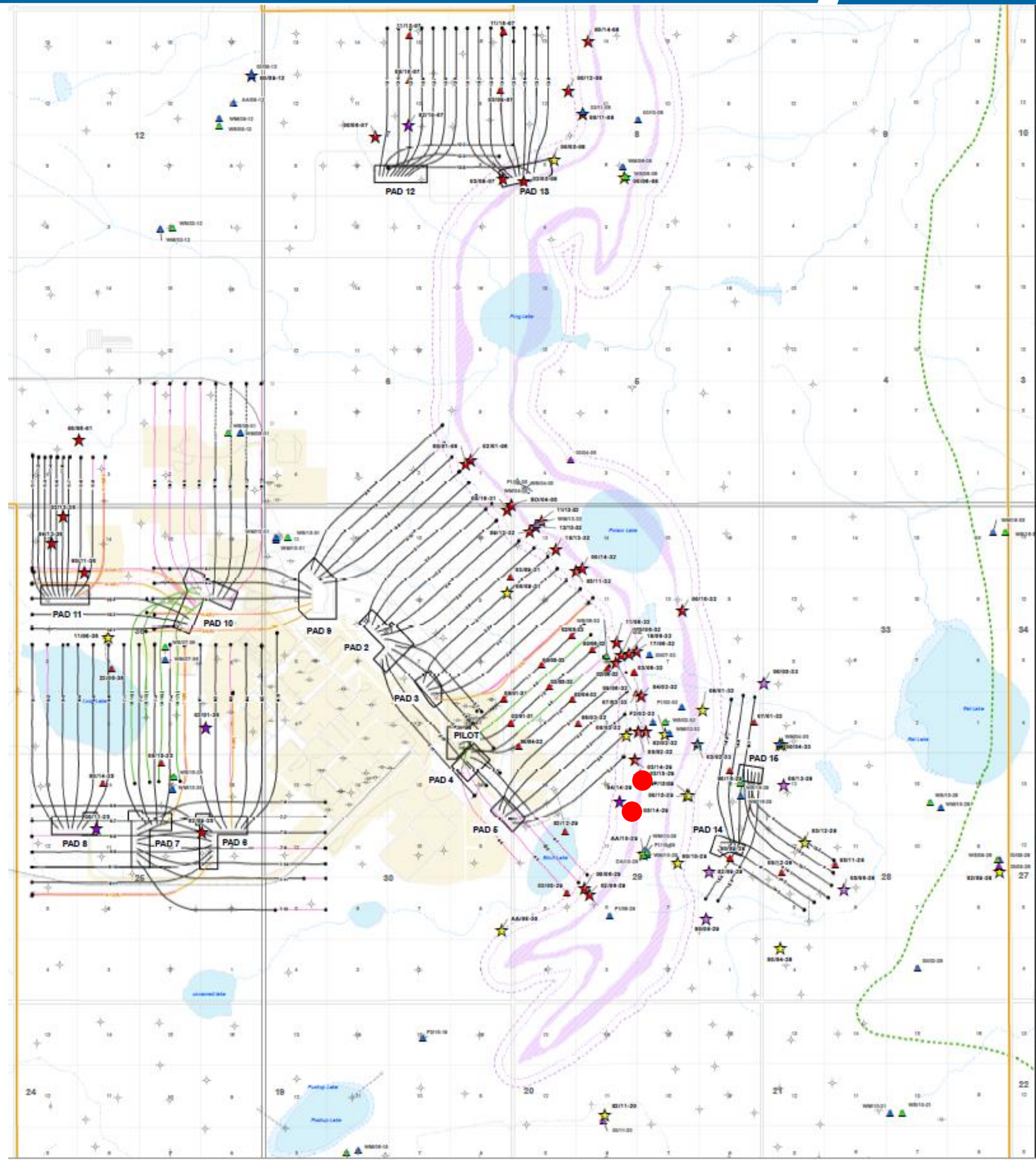
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

MAP DATA

- ZERO EDGE
- FACILITY AREA
- WELL PADS
- LONG LAKE LEASE

HYDROLOGY

- PERENNIAL
- NONPERENNIAL ; INTERMITTENT
- PERENNIAL
- NONPERENNIAL ; INTERMITTENT



Observation Wells – Long Lake

N/A – Greater than 300m to Q-channel or closest well pair

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel	
			(Max Edge)	(Min Edge)
100010608606W400	LL-009-09	69	45	70
100013108506W400	LL-001-01	1	N/A	N/A
100023208506W400	LL-005-04	51	29	44
100033208506W400	LL-005-04	7	103	120
100042808506W400	LL-014-03	297	N/A	N/A
100043208506W400	LL-001-03	12	N/A	N/A
100043308506W400	LL-014-07	219	N/A	N/A
100050808606W400	LL-013-09	115	68	87
100053208506W400	LL-001-01	3	N/A	N/A
100053308506W400	LL-014-07	109	N/A	N/A
100060108607W400	LL-011-08	118	N/A	N/A
100060708606W400	LL-012-01	67	N/A	N/A
100060808606W400	LL-013-09	N/A	87	50
100062908506W400	LL-004-02	52	97	145
100063208506W400	LL-001-02	4	283	N/A
100081708506W400	LL-014-03	N/A	N/A	N/A
100082908506W400	LL-015-04	128	236	N/A
100091208607W400	LL-012-01	N/A	N/A	N/A
100092908506W400	LL-015-04	10	N/A	N/A
100093108506W400	LL-003-01	3	N/A	N/A
100100708606W400	LL-012-05	5	N/A	N/A
100102908506W400	LL-014-03	279	99	140
100103208506W400	LL-005-01	N/A	7	42
100110808606W400	LL-013-09	230	109	138
100112508507W400	LL-006-07	46	N/A	N/A
100113608507W400	LL-010-05	4	N/A	N/A
100120808606W400	LL-013-09	132	179	213
100122808506W400	LL-014-01	32	N/A	N/A
100132808506W400	LL-015-05	164	N/A	N/A
100140808606W400	LL-013-09	263	23	33
100141708606W400	LL-013-09	N/A	41	8
100142508507W400	LL-008-06	28	N/A	N/A
100143208506W400	LL-003-03	135	3	42
100152508507W400	LL-010-16	17	N/A	N/A
100152908506W400	LL-014-05	203	100	113
100162908506W400	LL-014-06	18	286	N/A
100163108506W400	LL-002-03	97	46	57
102010608606W400	LL-009-09	112	10	27
102012108506W400	LL-014-01	N/A	N/A	N/A
102013108506W400	LL-001-02	1	N/A	N/A
102013608507W400	LL-006-01	35	N/A	N/A
102023208506W400	LL-005-04	101	20	7
102042208506W400	LL-014-01	N/A	N/A	N/A
102043208506W400	LL-001-03	4	N/A	N/A
102050808606W400	LL-013-06	36	4	28
102052908506W400	LL-004-05	2	N/A	N/A
105142908506W400	LL-005-05	281	12.8	55.6
103152908506W400	LL-005-05	161	14.3	13.2

UWI	Closest Wellpair	Distance to Wellpair	Distance to Q channel	
			(Max Edge)	(Min Edge)
102053208506W400	LL-001-01	1	N/A	N/A
102062908506W400	LL-004-02	100	53	98
102063208506W400	LL-001-03	6	217	235
102092508507W400	LL-007-08	7	N/A	N/A
102092808506W400	LL-015-03	N/A	N/A	N/A
102092908506W400	LL-015-04	77	N/A	N/A
102100708606W400	LL-012-05	11	N/A	N/A
102112008506W400	LL-004-03	N/A	N/A	N/A
102122908506W400	LL-005-04	25	N/A	N/A
102152908506W400	LL-014-05	193	110	123
103023208506W400	LL-014-05	175	31	73
103053208506W400	LL-001-02	5	N/A	N/A
103063208506W400	LL-005-01	51	48	78
103080708606W400	LL-013-01	8	80	115
103090708606W400	LL-013-04	13	N/A	N/A
103093108506W400	LL-002-06	38	N/A	N/A
103113208506W400	LL-003-03	92	40	81
103122808506W400	LL-015-03	6	N/A	N/A
103133608507W400	LL-011-06	6	N/A	N/A
103142908506W400	LL-005-05	69	30	55
104023208506W400	LL-005-01	38	60	90
104133608507W400	LL-011-04	9	N/A	N/A
104142908506W400	LL-005-05	192	103	139
105062808506W400	LL-015-01	82	N/A	N/A
105112808506W400	LL-015-03	33	N/A	N/A
106033208506W400	LL-005-01	42	N/A	N/A
107013208506W400	LL-014-07	18	N/A	N/A
107033208506W400	LL-005-04	72	7	27
108013208506W400	LL-014-05	175	33	87
109063208506W400	LL-001-03	47	156	169
109133208506W400	LL-002-05	96	21	40
110133208506W400	LL-003-01	75	33	80
111063208506W400	LL-001-02	123	121	136
111063608507W400	LL-010-01	48	N/A	N/A
111133208506W400	LL-002-06	190	77	65
111150708606W400	LL-012-05	9	N/A	N/A
111160708606W400	LL-013-04	9	N/A	N/A
112063208506W400	LL-001-03	105	110	122
112133208506W400	LL-002-05	148	28	12
117063208506W400	LL-005-01	157	10	21
118063208506W400	LL-005-01	130	60	72
122063608507W400	LL-008-06	47	N/A	N/A
1AA083008506W400	LL-004-04	N/A	161	247
1AA102908506W400	LL-004-01	N/A	113	66
1F2023208506W400	LL-005-04	227	146	133
1S0040508606W400	LL-002-02	126	11	15
1WM043308506W400	LL-014-07	204	N/A	N/A

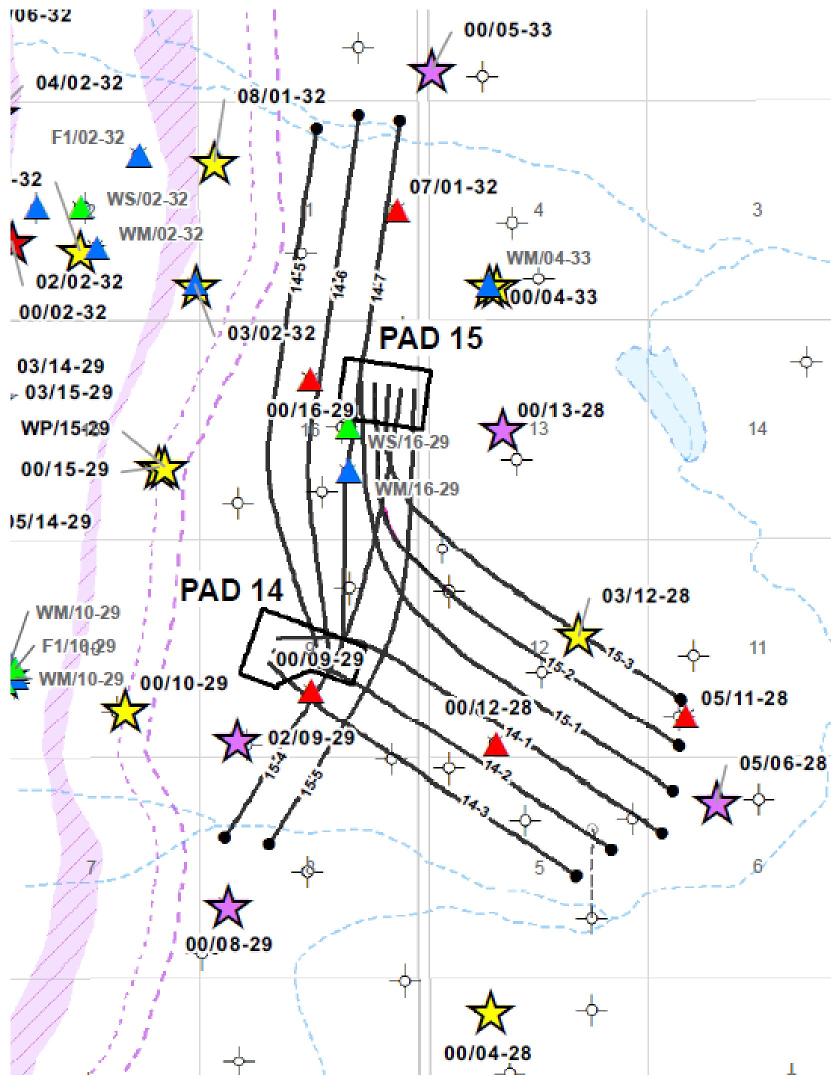
Pad 14/15 Observation Wells Caprock Monitoring

Pad 14 Baseline and Current Values

Well Name	Sensor Depth (mKB)	Sensor Elev. (mASL)	Formation	Base Line Pressure kPa_a	Current Pressure* kPa_a
100/04-28	126	335.6	CLWT A	1,015	1,020
100/05-33	119	341.2	CLWT A	980	992
100/13-28	116	341.9	CLWT A	1,000	1,006
102/15-29 (WP/15-29)	127	344.3	CLWT A	990	1,002
WM/04-33	115	343.8	CLWT A	970	957
	115.5	343.3	CLWT A	980	974

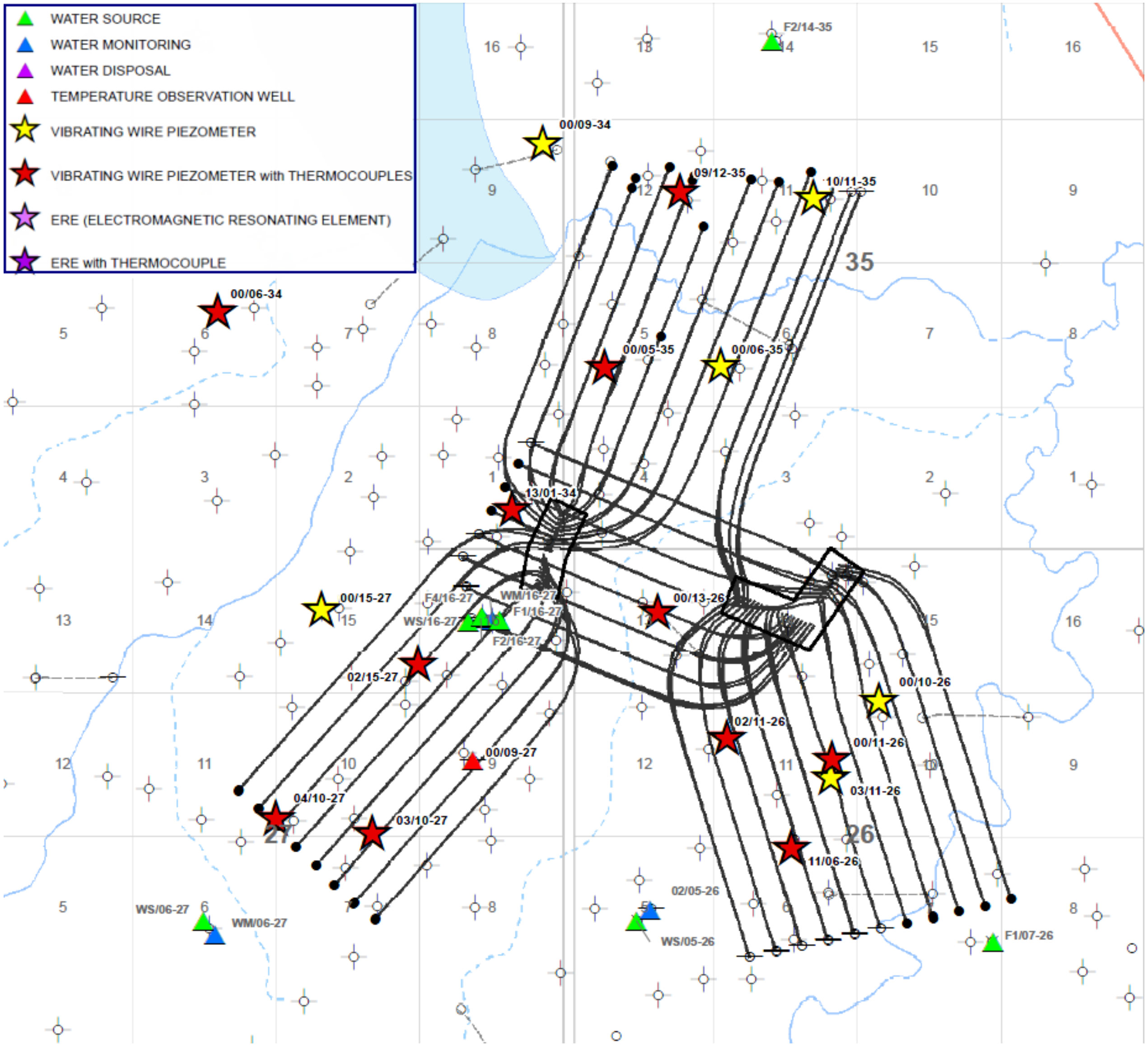
Pad 15 Baseline and Current Values

Well Name	Sensor Depth (mKB)	Sensor Elev. (mASL)	Formation	Base Line Pressure kPa_a	Current Pressure* kPa_a
105/06-28	122.5	336.4	CLWT A	1,100	1,113
100/08-29	118.5	349.2	CLWT A	930	929
102/09-29	126.5	339.6	CLWT A	1,020	1,030
103/12-28	121.5	340.5	CLWT A	1,040	1,029

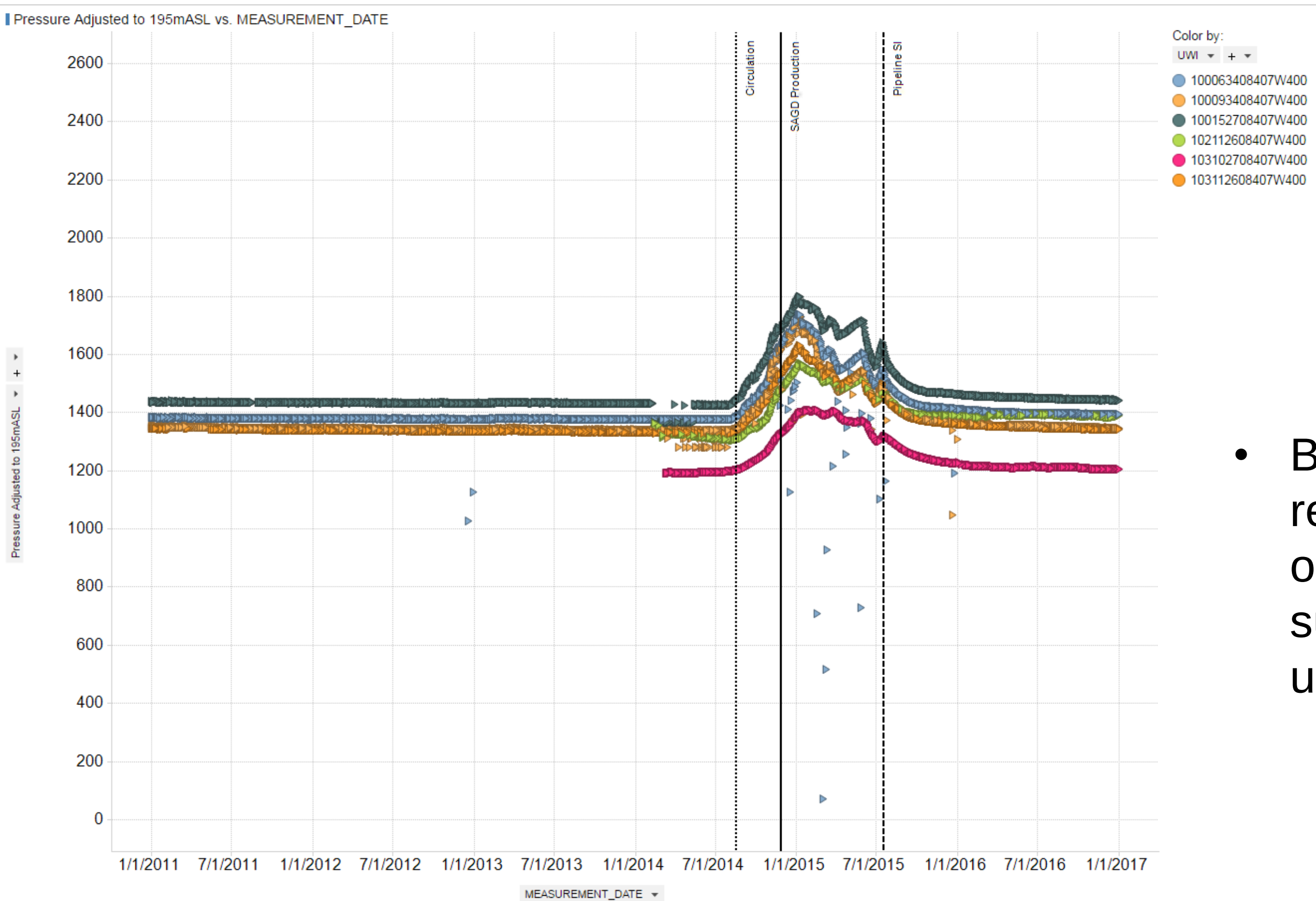


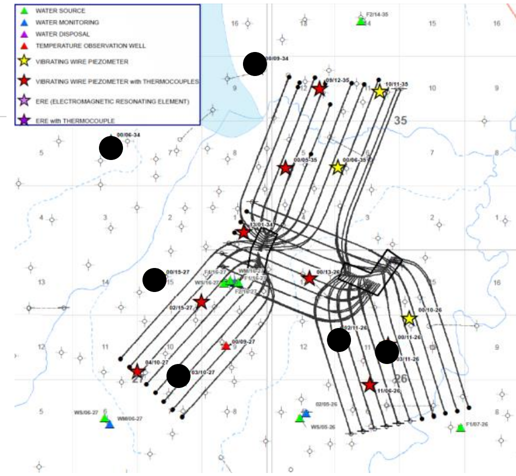
* December 2016

K1A Observation Wells



Bottom Water Pressure





- Bottom water pressure response to initial operations and subsequent decrease upon suspension

Observation Well Challenges

- Multiple issues can impact the quality and confidence of observation well data.
- This can cause low confidence in the data set or invalid data all together. Causes can include, but are not limited to:
  - Power supply to the well, primarily during winter months;
  - Mechanical issues such as battery failures;
  - Ambient temperature fluctuations;
  - Surface connection issues;
  - Downhole corrosion of sensors;
  - DCS polling frequency and daylight savings programming;
  - Surface logger firmware;
  - Force majeure (eg: Fort McMurray wildfire).
- There are sensors that are also considered to be of low confidence as the pressure readings are suspect; they are not collaborated by adjacent sensors and do not correlate with subsurface operations.

Observation Well Challenges

- Nexen continuously works with various vendors to increase reliability in both well operations and data quality which includes:
  - Utilizing different technologies (ERE gauges, GORE thermocouple bundles);
  - Regular inspections of surface equipment;
  - Alternative completions designs;
  - Redundant instrumentation (eg: Fluid mini troll sensor placed within a VWP monitoring well).
- Systems are in place to monitor observation well data daily to track and identity potential issues.
- Nexen performs integrated reviews with data and subsurface personnel.
- Vendor and maintenance crews are scheduled routinely to address issues.
- In 2016 Nexen:
  - Discovered and addressed a firmware defect that caused wells to sporadically shutdown;
  - Adjusted polling frequencies to conserve power;
  - Had wells destroyed by the wildfire that had to be re-instrumented;
  - Proactively removed damaged subsurface equipment prior to full failure;
  - Replaced old thermocouples with new technology GORE bundles for increased reliability.

Future Plans
Subsection 3.1.1 (8)
Long Lake and Kinosis

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Future Plans – Producing areas

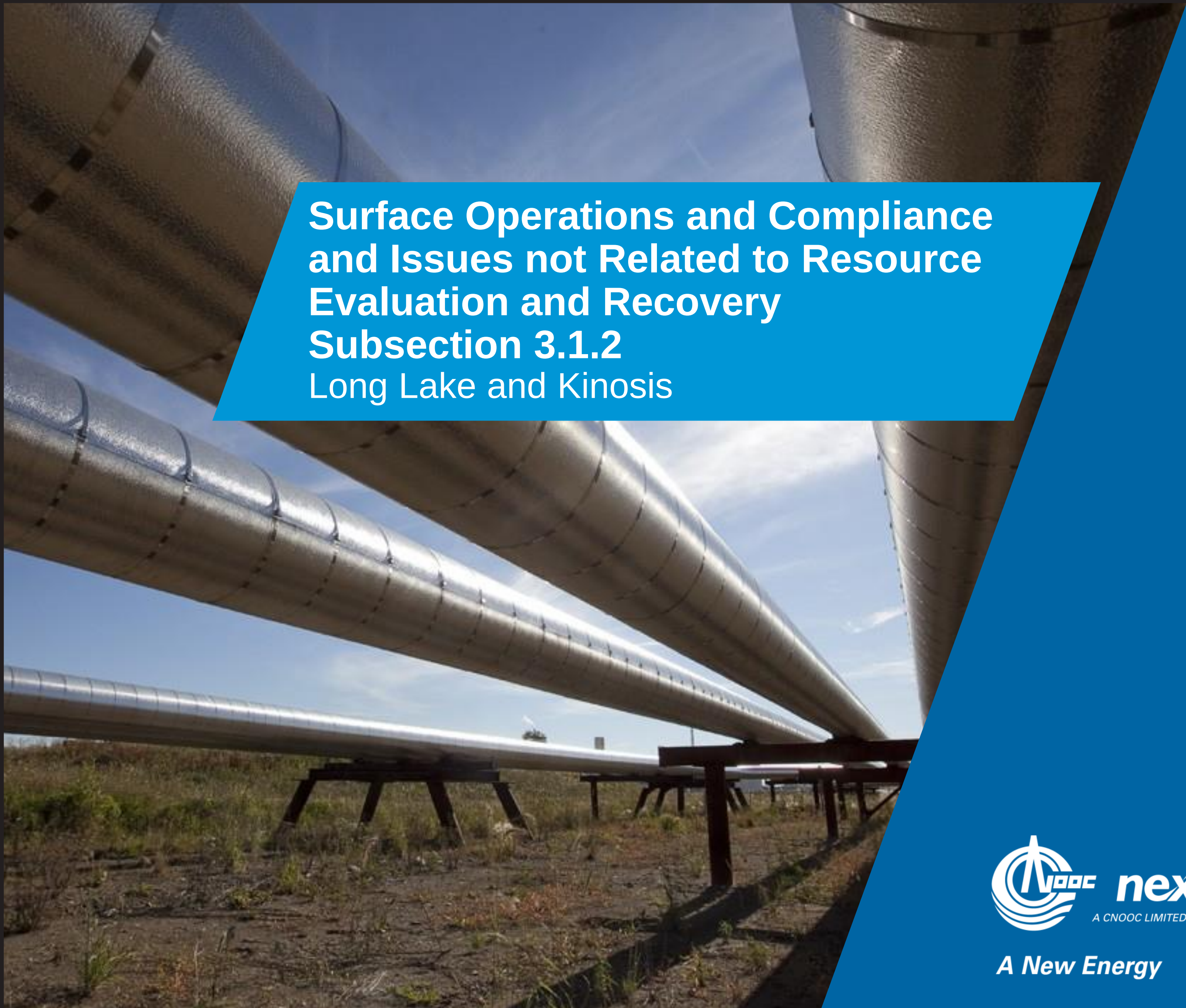
- Continue to manage SAGD production according to surface constraints and capacity.
- Advance plans for K1A recovery:
  - Working on final recommendation of repair versus replace.
- Production opportunities:
  - Continue to progress future infills at Long Lake:
    - 7 wells sanctioned in Q2 2017.
  - Evaluate additional well pairs off existing well pads at Long Lake.
- Install Casing Jet Pump at 13P01 (Pad 13):
  - Evaluate pump performance improvements by reducing casing pressure.
  - Sliding sleeve installed Q3 2016 with pump installation planned for Q1 2017.
- Dispose of Unresolved Emulsion (Rag layer) into active injector:
  - Approval granted for injection at 02S10.
- Respond to Supplemental Information Requests to Proposed Groundwater Management Plan application (2016):
  - Pending EPEA approval, implement strategic injection initiative.

Future Plans - New Development

- LLK:
  - LLSW (Pads 16 to 18):
    - Pending internal sanction
- Kinosis:
  - Planning for future projects significantly slowed down due to commodity prices:
    - Gas re-pressurization project on hold

Future Plans – Pad Abandonments

- There are no anticipated pad abandonments for any of the Long Lake or K1A pads in the next five years.



Surface Operations and Compliance and Issues not Related to Resource Evaluation and Recovery Subsection 3.1.2

Long Lake and Kinosis

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Facilities
Subsection 3.1.2 (1)
Long Lake and Kinosis

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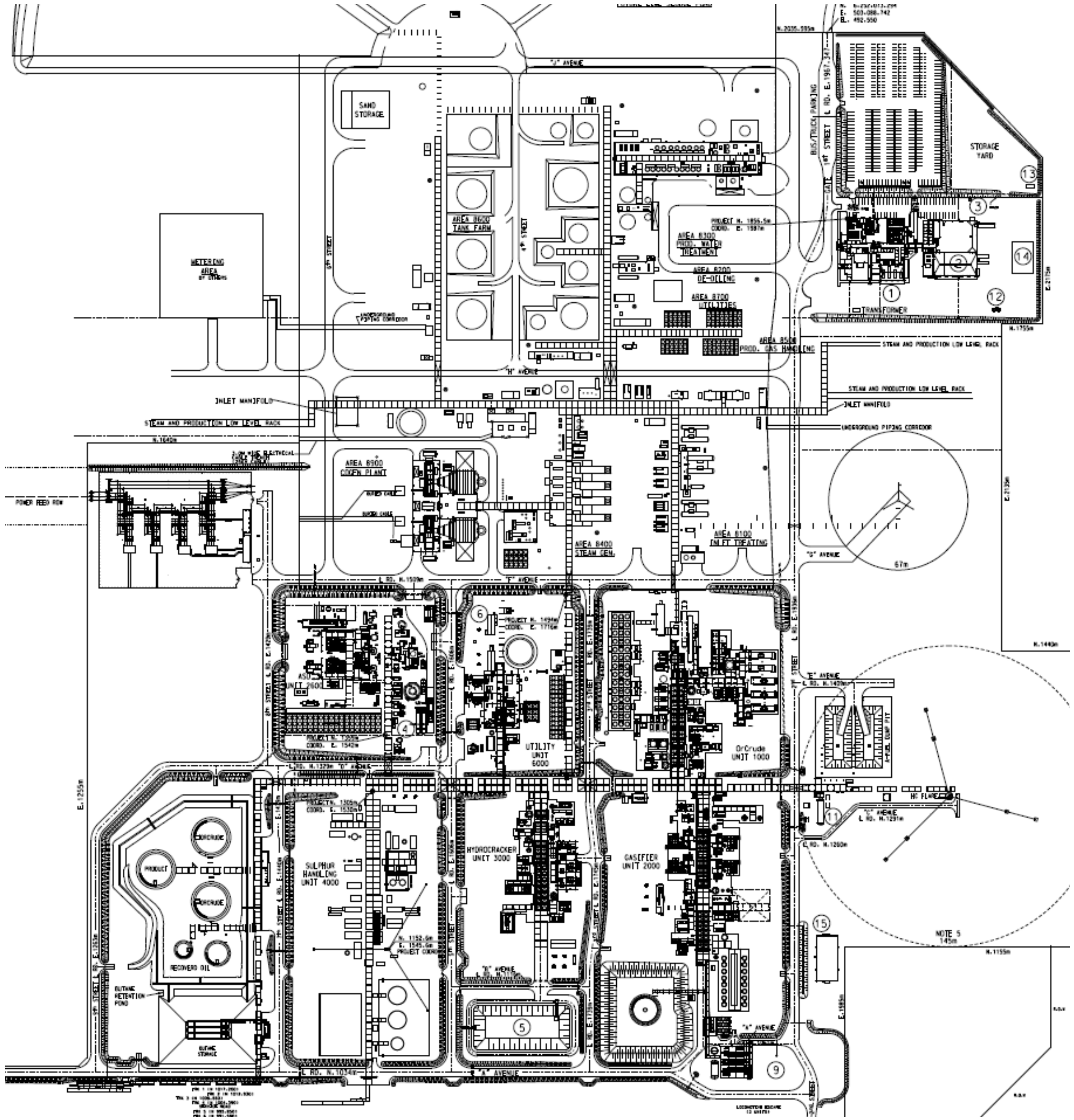
Long Lake Facilities

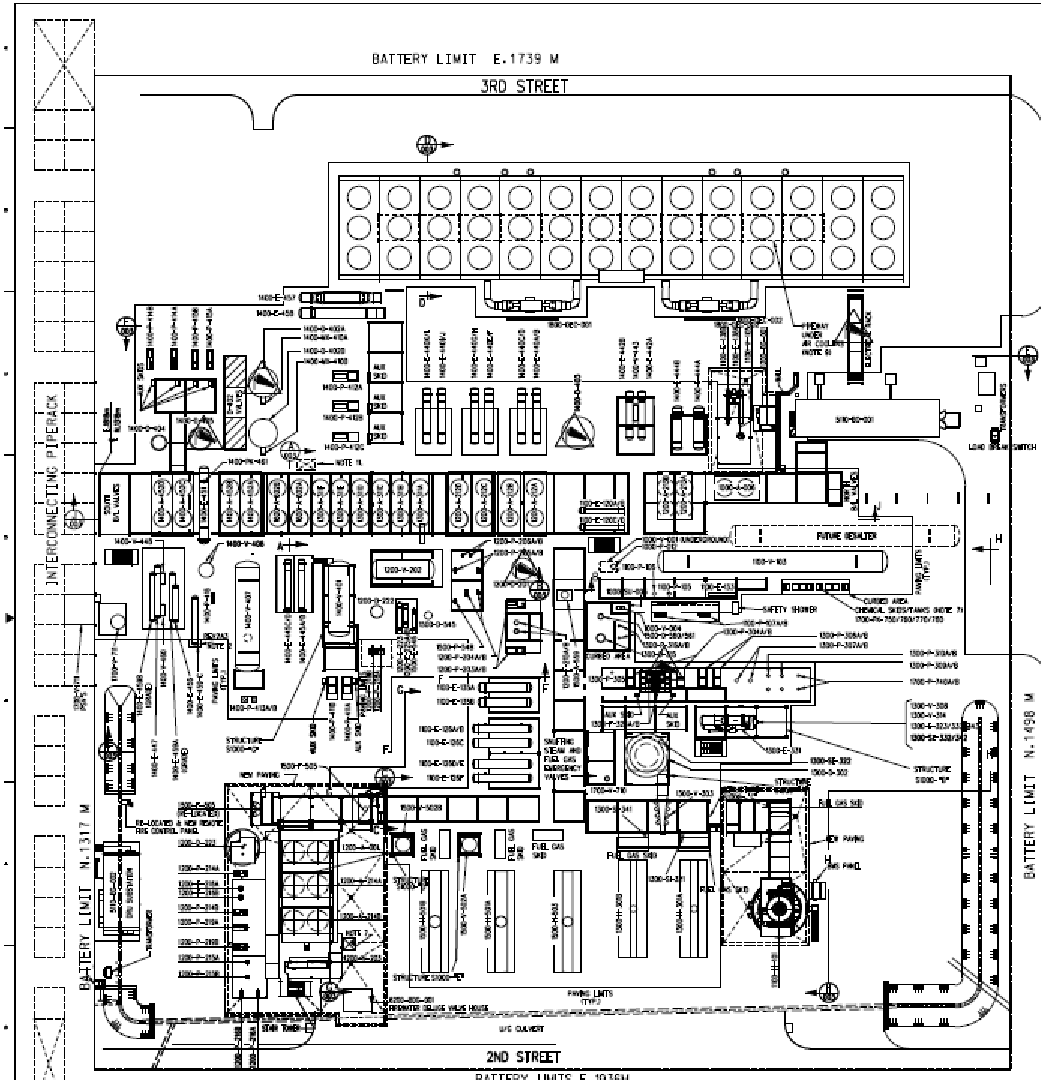
Long Lake overview with new DRU construction activities– October 22, 2014

Long Lake Plot Plan



Subsection 3.1.2 (1a)

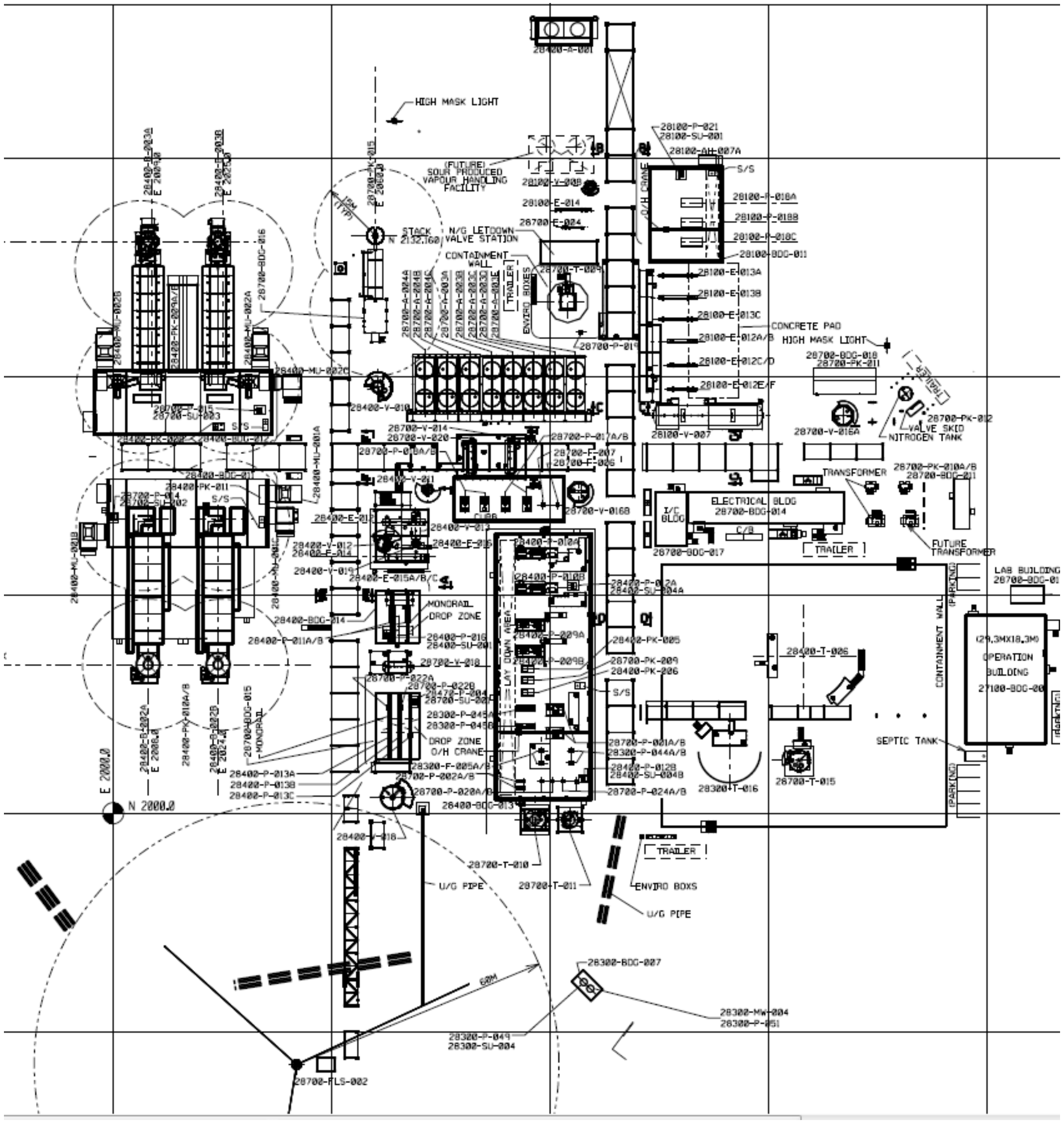
Diluent Recovery Unit Plot Plan



Kinosis Phase 1 (K1A)

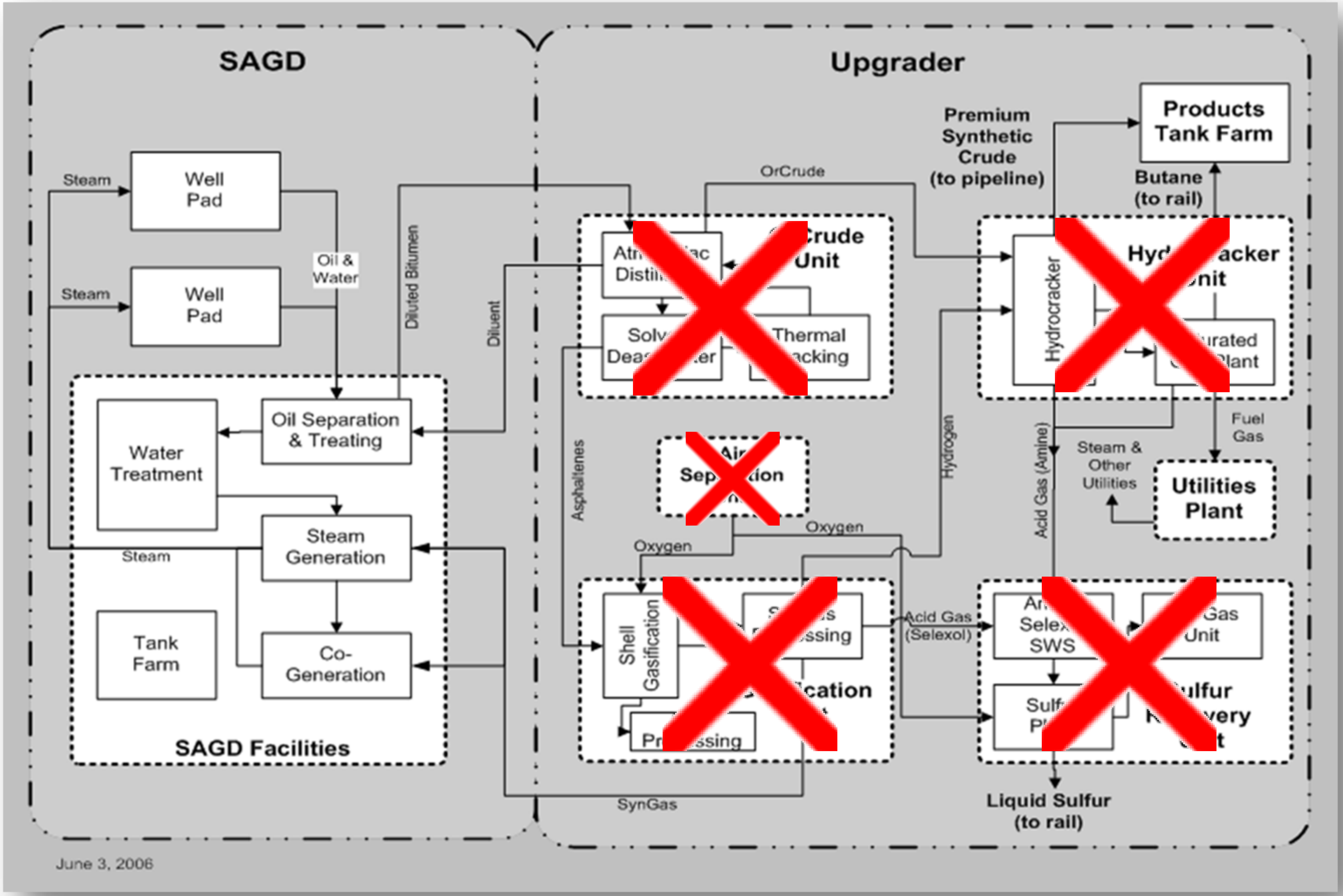
Aerial of Nexen's K1A Steam Generation Facility with Well Pad 2 in background – Oct., 2014

Kinosis Phase 1A (K1A) Plot Plan

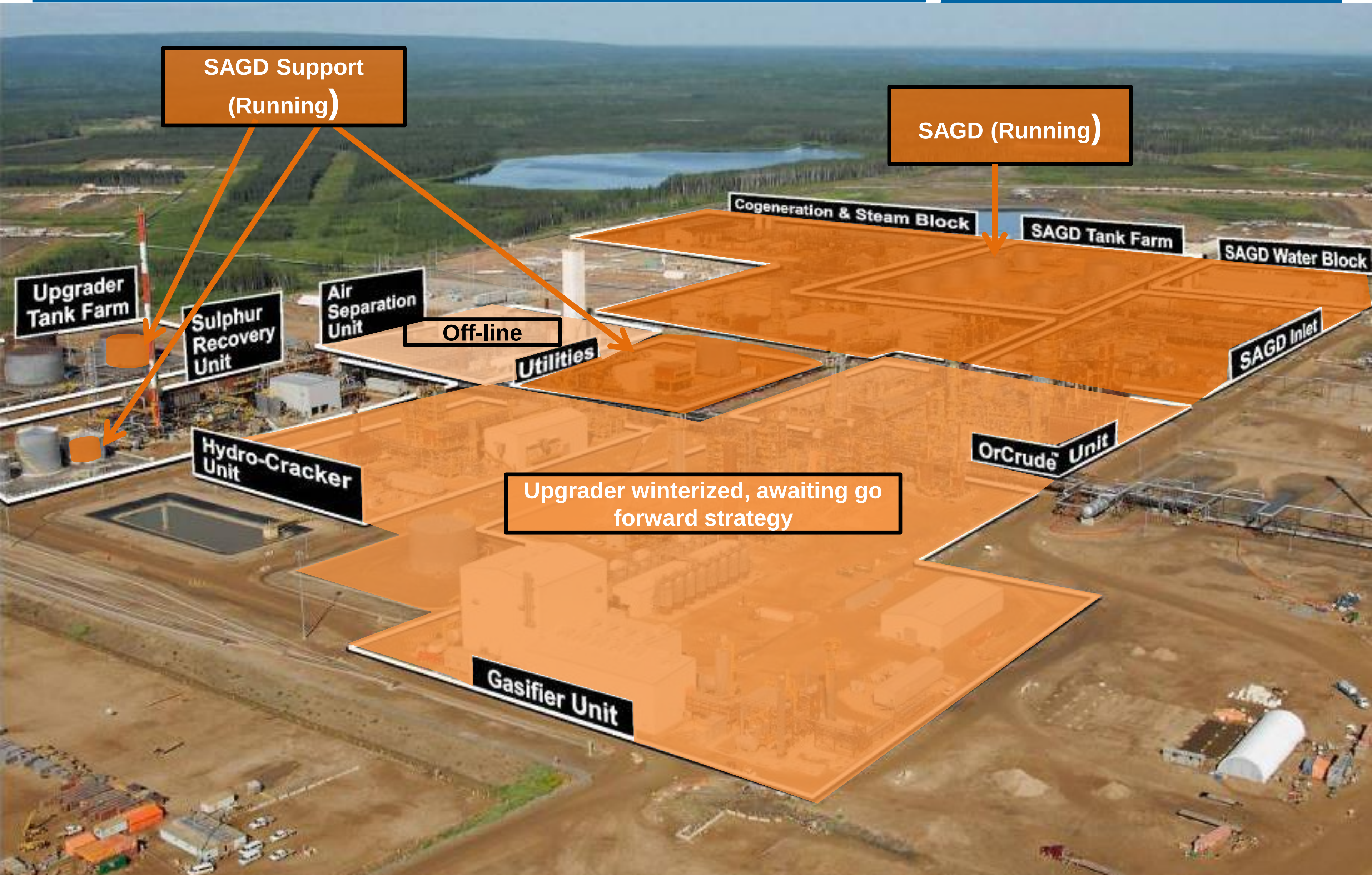


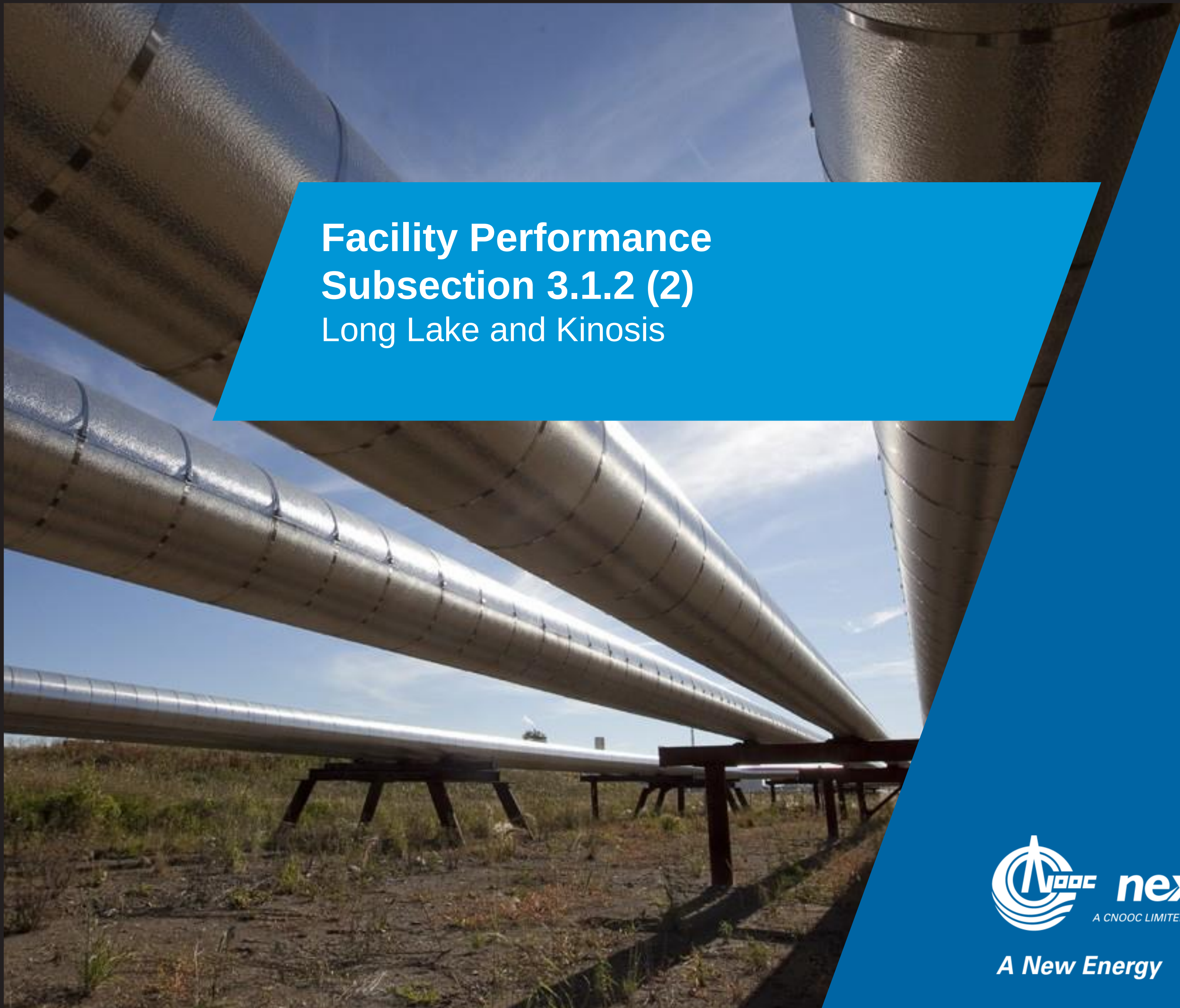
Subsection 3.1.2 (1a)

Current Plant Schematic



Current LLK Operations





Facility Performance
Subsection 3.1.2 (2)
Long Lake and Kinosis

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Facility Performance

Subsection 3.1.2 (2)

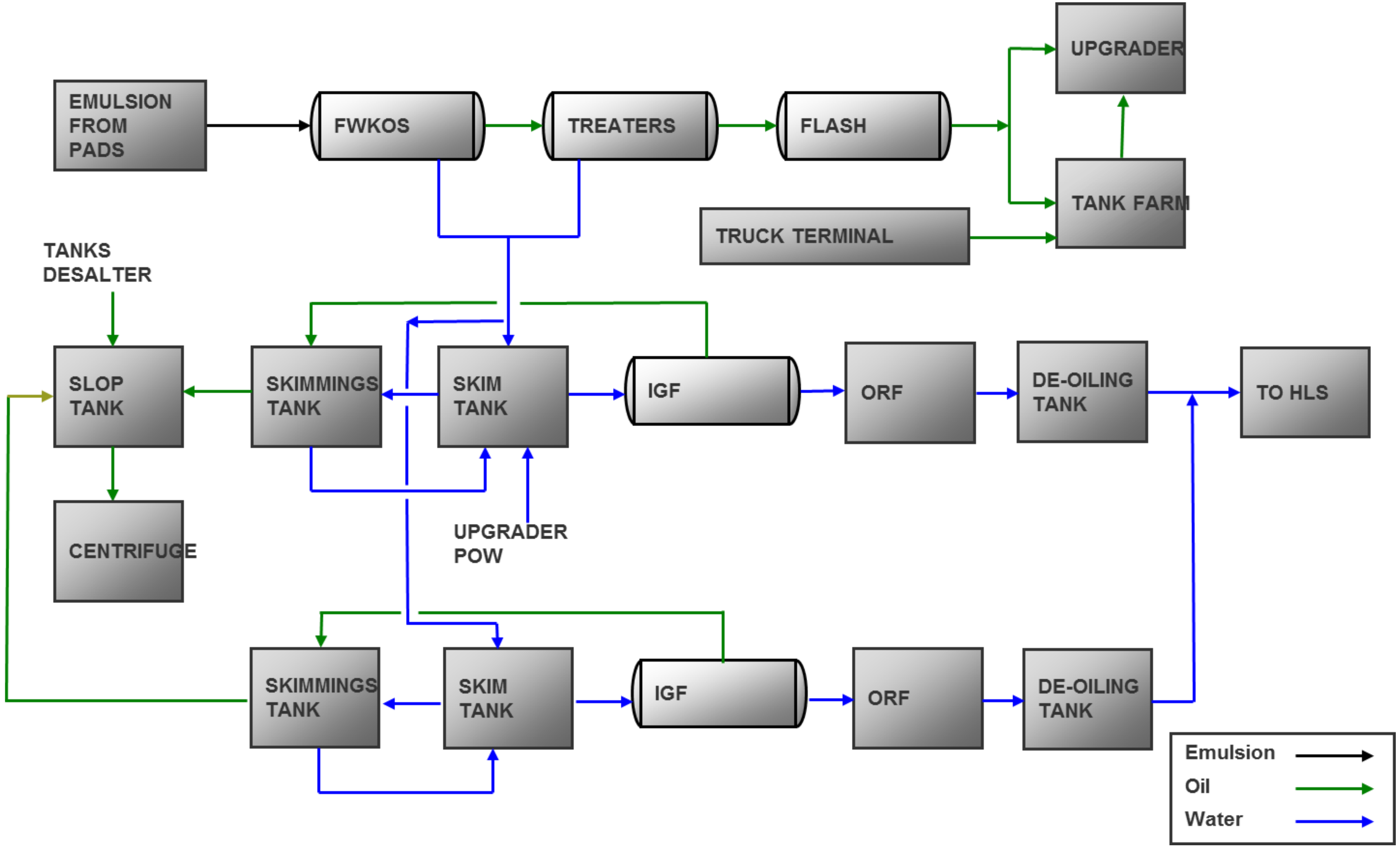
Long Lake Operations Summary

- On Jan.15, 2016 there was an explosion, at the Hydrocracker Unit Compressor Building, in the Upgrader area of Nexen's Long Lake Facility.
- This incident resulted in a temporary shut-in of the Upgrader at Long Lake.
- In addition to the shut-in of the Upgrader, the Horse River Wildfire (Wildfire) also impacted operations at Long Lake in May and Jun., 2016.
- The Wildfire caused a forced evacuation of Fort McMurray on May 3, 2016 and a complete evacuation and shut down of Long Lake on May 4, 2016.
- Some units in the Upgrader were brought back online in Jun. 2016 to support SAGD operations while others remain shut-in.

Long Lake Operations Summary

- Winterization of the Upgrader was completed in September 2016.
- The Upgrader will remain shut-in until a decision on the repair/start-up is made.
- Despite the operational upsets and suspension of SAGD operations in May and Jun. 2016, Long Lake SAGD operations were restarted and production has continued to increase throughout the remainder of 2016.
- SAGD Operations has experienced a high level of plant reliability since the Upgrader shutdown.
- K1A Operations remain down while decisions on the pipeline repair or replace options are pending.

Bitumen Treatment



Inlet and De-Oiling

General Comments:

- The plant switched to a synthetic crude for diluent supply due to the Upgrader shut down.
- With the shutdown of the SRU the amine treatment in the produced gas was lost. A waiver was granted by the AER on Jan. 20, 2017 to authorize Nexen to operate in this mode until Dec. 31, 2017.
- Complete emergency plant shutdown due to the wildfire was performed. Additional cleaning and facility integrity checks were completed prior to start-up.
- Oil accumulation in De-Oiled Tanks as a result of sample taps unavailability due to plugging caused intermittent oil-in-water excursions.

Chemical Injection

- A trial was conducted in late 2016 in order to test the transitions to chemical supplied by a new vendor.

Inlet and De-Oiling

Tank Venting

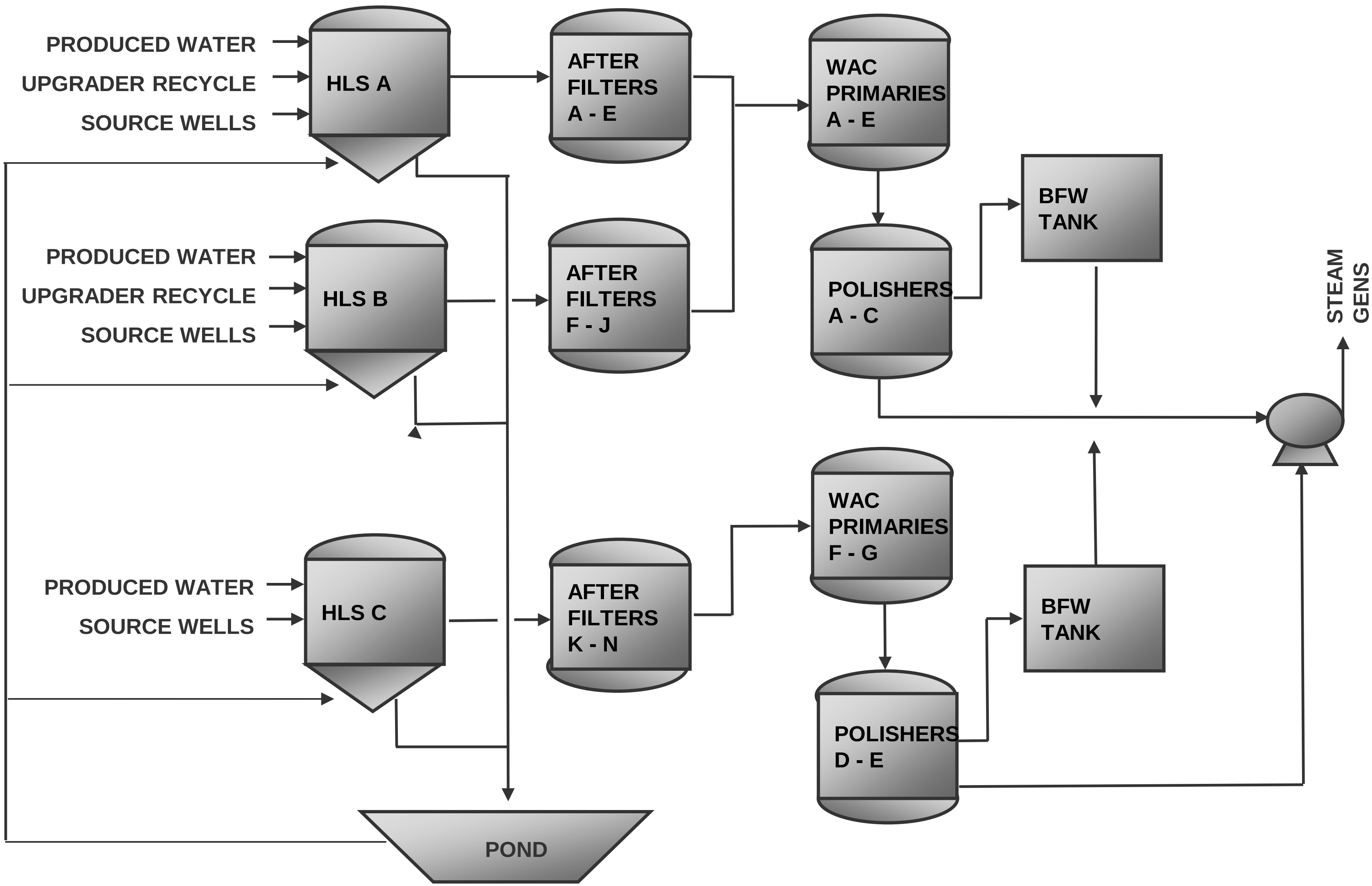
- Several venting incidents in 2016 led to:
  - Changes in operating philosophy to maintain steady flow into the tanks by avoiding direct truck offloading and proactively adjusting chemical injection in preparation for potential foulant increase during heat exchanger switching process;
  - Implementation of field modifications in order to handle light ends generated in the process efficiently by rerouting them to the Mixed Fuel gas header;
  - Optimization of the response of the Vapor Recovery System (VRU) by implementing changes to the process control strategy; and
  - Identification of venting events is determined by the PSV set point versus the practice of visual confirmation which resulted in an increase in reporting.
- Nexen is currently using gas monitors to set up at the PSVs to determine if actual venting occurs when the set point in met.

Subsection 3.1.2 (2)

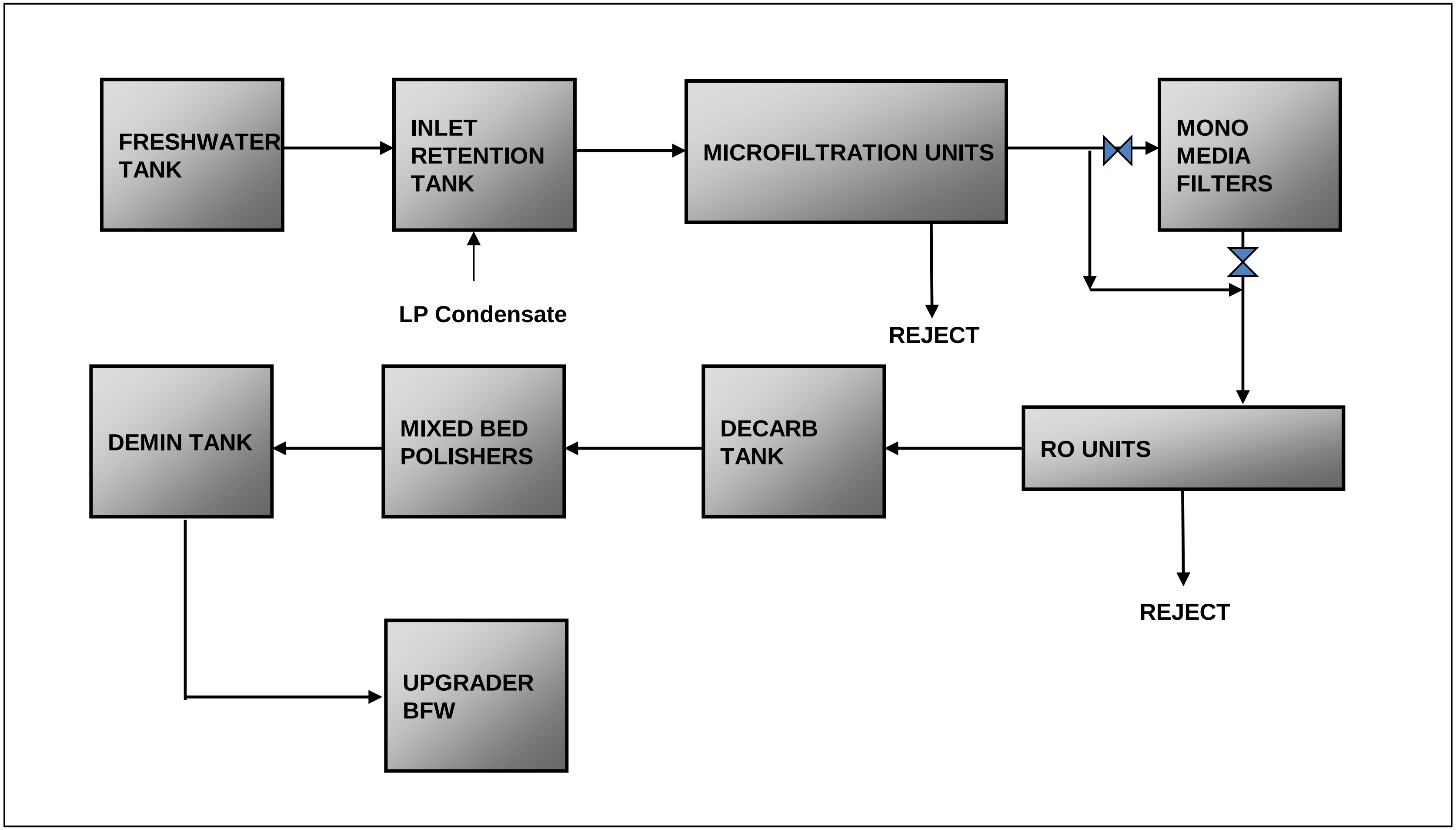
Water Treatment

Subsection 3.1.2 (2b)

Produced Water Treatment



High Quality Water System



Water Treatment

Micro Filtration (MF) System

- High Quality Water System (HQWS) is now able to treat water with only the mono media filters when running at low rates, so the micro filtration system is no longer required and temporary equipment has been de-mobbed.

Weak Acid Cation (WAC) Unit Monitoring

- Optimized proactive monitoring program to improve reliability of the WAC exchanger unit

Chemical Usage Optimization

- Specialty chemical vendor change in 2016 for water and steam and Nexen continues to work with the vendor to optimize chemical usage

Water Treatment

Sludge Carry Over from HLSs

- Monitoring the sludge profile was a challenge due to sample taps plugged.
- Optimizated proactive monitoring of chemicals for effective control of HLS performance.

Regen Waste Header Repair

- Regen waste header is heavily corroded at the point where the waste regen stream ties into the header.
- Additional monitoring was implemented by operations resultung in more effective pH control of the regen waste before dumping to the pond.

Water Treatment

Brackish Water

- The brackish system was not in use in 2016 as the operation was water long and brackish make-up was not required.
- Brackish header was drained in preparation for winter to protect the integrity of the system.

Continued Fresh Water Use with Upgrader Down

Due to the design of the LLK facility, brackish water cannot be used in place of fresh water despite the Upgrader being largely "shut in". Fresh water is used within the LLK facility for the following purposes:

- HQWS – with the Upgrader down, the HQWS primarily supplies water to be used as NOx control steam. As noted on slide 162, the feed for the HQWS is a combination of fresh water and LP condensate. The system is not designed to treat brackish water.

- Inlet Heat Exchanger – with the Upgrader down, HQWS demand has been greatly reduced. Due to minimum turndown on the system, it no longer runs continuously. Despite this, there is an inlet heat exchanger that uses the fresh water flow to the HQWS as its cooling medium. This heat exchanger must always remain in service, so when the HQWS is down, the fresh water supply to the HQWS flows through this heat exchanger and is then diverted to the Injection Facility (IF) pond. The heat exchanger is not designed to use brackish water as a cooling medium.

- IF Chemical Blending – fresh water is used to blend chemicals in the injection facility for use in the HLS. The high hardness/salinity of brackish water would cause issues in the chemical system.

- Utility water in the Battery, IF – end users of utility water (pump seals, VRU) cannot handle the high hardness and salinity of brackish water.

Long Lake 2016 Water Balance

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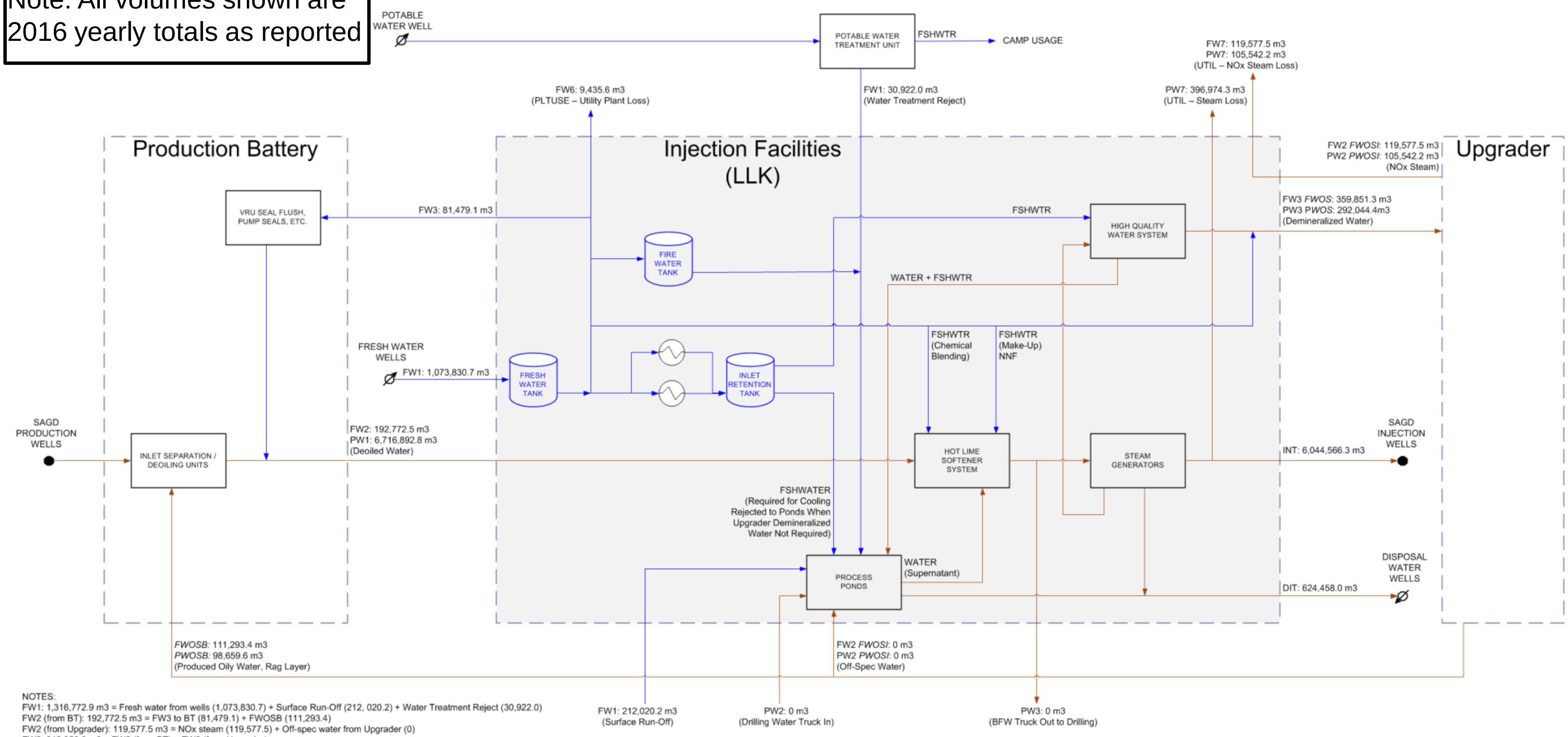
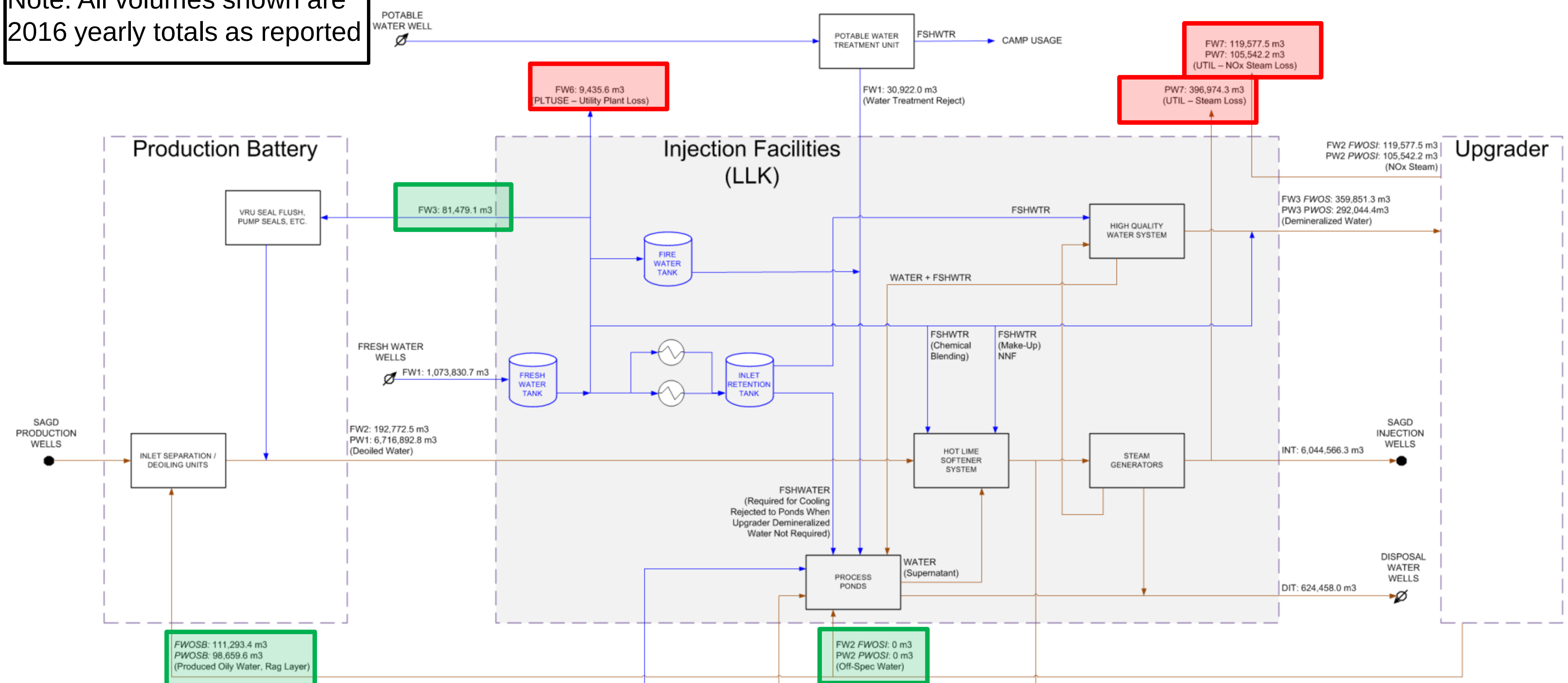
Note: All volumes shown are 2016 yearly totals as reported



NOTES:
FW1: 1,316,772.9 m3 = Fresh water from wells (1,073,830.7) + Surface Run-Off (212, 020.2) + Water Treatment Reject (30,922.0)
FW2 (from BT): 192,772.5 m3 = FW3 to BT (81,479.1) + FWOSB (111,293.4)
FW2 (from Upgrader): 119,577.5 m3 = NOx steam (119,577.5) + Off-spec water from Upgrader (0)
FW2: 312,350.0 m3 = FW2 (from BT) + FW2 (from Upgrader)
PW1: 6,719,892.8 m3 = Total Deoiled Water (6,909,665.3) – FW2 from BT (192,772.5)
PW2: 105,542.2 m3 = NOx steam (105,542.2) + Off-spec water from Upgrader (0) + Drill Water Truck In (0)
FW3: 441,330.4 m3 = Demineralized (359,851.3) + Utility Water to Upgrader (0) + VRU Seal Flush to BT (81,479.1)
PW3: 292,044.4 m3 = Demineralized Water to Upgrader (292,044.4) + BFW Truck Out to Drilling (0)
PW7: 502,516.5 m3 = NOX Stream (105,542.2) + Utility Steam process loss (396,974.3)

Long Lake 2016 Water Balance

Note: All volumes shown are 2016 yearly totals as reported



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Utility/process water streams lost

Utility/process water streams recycled for use in SAGD

Long Lake 2016 Water Balance

2016 INJECTION FACILITY WATER BALANCE			
FW1			1,316,772.9
	Fresh Water from Wells	1,073,830.7	
	Surface Run-Off	212,020.2	
	Water Treatment Reject	30,922.0	
FW2			312,520.4
	FW3: VRU Seal Flush, Chem Blending to BT	81,649.5	
	FWOSB: POW from Upgrader	111,293.4	
	FWOSI: NOx Steam from Upgrader	119,577.5	
	FWOSI: Off-Spec Water from Upgrader	-	
FW4	Fresh Water Opening Inventory		6,695.5
PW1			6,716,722.4
	Total Deoiled Water	6,909,665.3	
	Net of FW3 and FWOSB	- 192,942.9	
PW2			105,542.2
	PWOSI: NOx Steam from Upgrader	105,542.2	
	PWOSI: Off-Spec Water from Upgrader	-	
	Drilling Water Truck In	-	
PW4	Produced Water Opening Inventory		358,013.3
TOTAL WATER IN			**8,816,266.7**
INT	Steam Injection to SAGD Wells		6,044,566.3
DIT	Water to Disposal		624,458.0
FW3			441,500.8
	VRU Seal Flush, Chem Blending to BT	81,649.5	
	FWOS: Demineralized Water to Upgrader	359,851.3	
	FWOS: Utility Water to Upgrader	-	
FW5	Fresh Water Closing Inventory		6,736.3
FW7	UTIL - NOx Steam Loss		119,577.5
PW3			292,044.4
	PWOS: Demineralized Water to Upgrader	292,044.4	
	BFW Truck Out to Drilling	-	
PW5	Produced Water Closing Inventory		375,696.5
FW6	PLTUSE: Utility Water Loss		9,435.6
PW7			502,516.5
	UTIL - NOx Steam Loss	105,542.2	
	UTIL - Process Steam Loss	396,974.3	
TOTAL WATER OUT			**8,416,531.9**
IMBALANCE			399,734.8
IMBALANCE / TOTAL WATER OUT			**4.75%**

Note: All volumes shown are 2016 yearly totals as reported

- Water imbalance around the LLK Injection Facility for 2016 was ~400,000 m^3 or 4.75%.
- “Water in” was higher than “Water out”.
- Despite the Upgrader being “shut-in” for the majority of the year, total of ~652,000 m^3 of demineralized water was sent from the IF to the Upgrader in 2016:
  - Large portion of this volume was used for preservation activities within the upgrader in the first 4 months of 2016.
  - Generation of utility steam for NO_x control throughout the year.
- Detailed exercise to identify sources of imbalance has not been conducted since the Upgrader was shut down.
- Total fresh water inlet meter volume for 2016 is 1,070,347 m^3 (not shown in chart, good agreement with Fresh Water from Wells)

PW7: Discrepancy and Go Forward

- While Nexen was reviewing the LLK water balance for the D54 presentation follow-up, it became apparent that our reporting of some volumes as PW7 was inconsistent with how those volumes are actually used in our facility. This PW7 volume is outlined in red on the diagram in following slide.

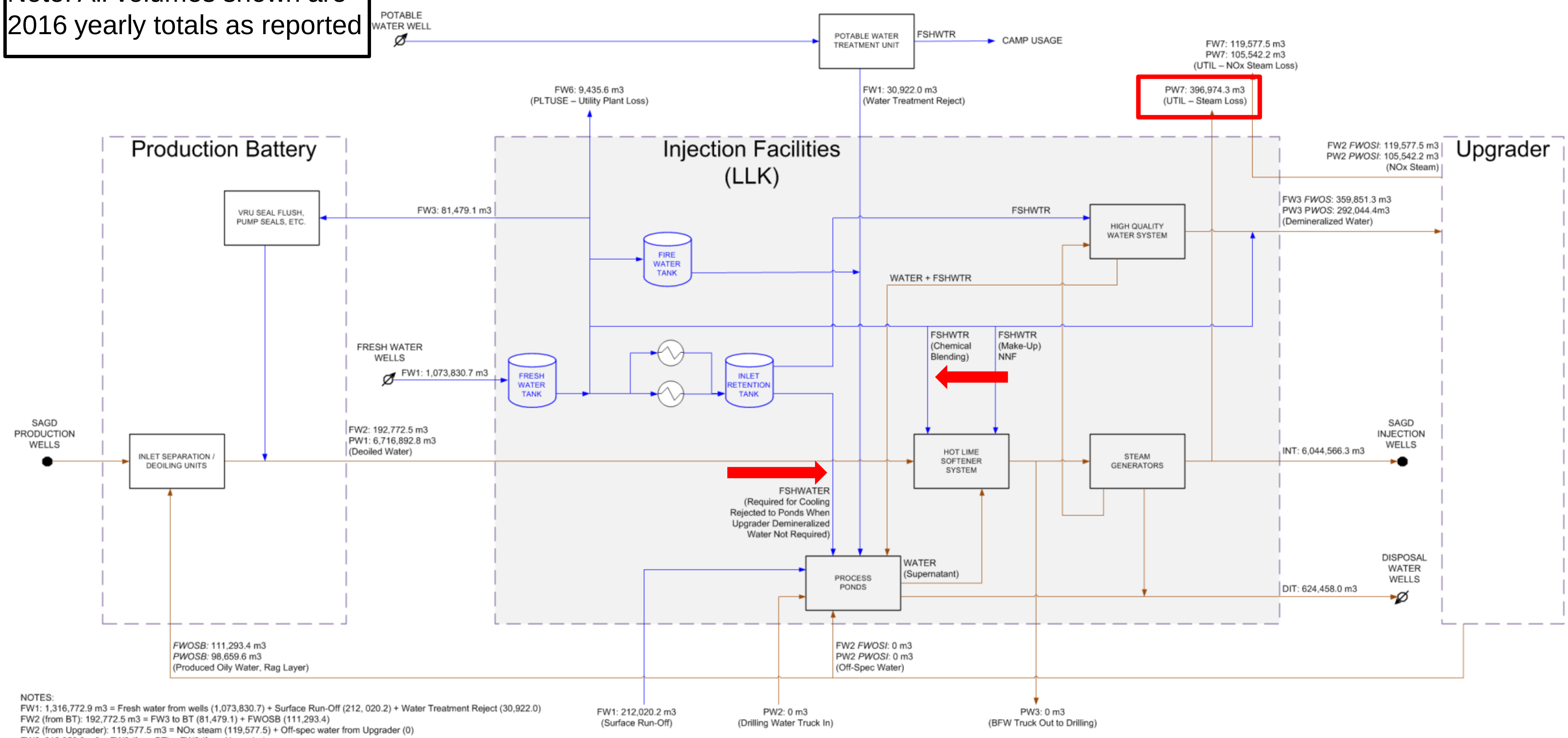
- Since the Upgrader ceased operation, Nexen believes that a large portion of the volume reported as PW7 (utility steam loss) was actually fresh water that is being used within the injection facility. This happens either via chemical blending to the HLS or flow to the pond when the HQWS was not in service. Both these streams are marked with red arrows in the following slide.

- Nexen intends to remove these streams from PW7 reporting starting in 2017. They will no longer show up in any D81/IF Water Balance streams as they are internal use within the IF.

- The use of this fresh water will be accurately reflected in the water use report (WUR) for 2016.

PW7: Discrepancy and Go Forward

Note: All volumes shown are 2016 yearly totals as reported



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Typical Water Quality (Produced and Disposal)

	pH	Conductivity (us/cm)	Turbidity (NTU)	Dissolved Hardness	Silica	Iron
RO (reject water 2nd stage)	n/a	4.000-12,000 average 6,900	0-4 average 1.7	n/a	n/a	n/a
Produced Water	7-9 average 7.3	1,500-3,000 average 2000	100-900 average 150	5-20 average 13	50-250 average 140	n/a
Supernatant Water	9-10, average 9.5	5,000-15,000 average 7,500	50-1,000 average 200	50-100 average 80	30-150 average 83	n/a
Fresh Water	7-8.5 average 7.8	2,000-3,000 average 2,118	0-8 average 4	n/a	n/a	0-2.5 average 1.3

- No brackish water chemistry in 2016.
- In 2016 POW changed to mostly boiler blowdown and data is captured as part of boiler monitoring in the Upgrader.

Steam and Power Generation

Subsection 3.1.2 (2c, d)

Steam Generation

Fuel Consumption

- Syngas is no longer being used due to the shutdown of the Upgrader.
- Produced gas is no longer sweetened due to the shutdown of the SRU and the amine system. Sour produced gas is blended with pipeline natural gas for use as fuel gas in the boilers.

HRSG Duct Burner Fouling

- In 2016, duct burners were supplied with only natural gas. Duct burner fouling reduced significantly.
- Repairs of the previously damaged HRSG roof panels will be completed in 2017. HRSG roof panel integrity has stabilized since going to natural gas only operation.

Boiler Reliability

- High reliability of boilers in 2016 due to stabilized fuel supply.

Steam Generation

Glycol Monitoring

- Increased monitoring/maintenance on various exchangers has greatly reduced glycol losses from previous years.

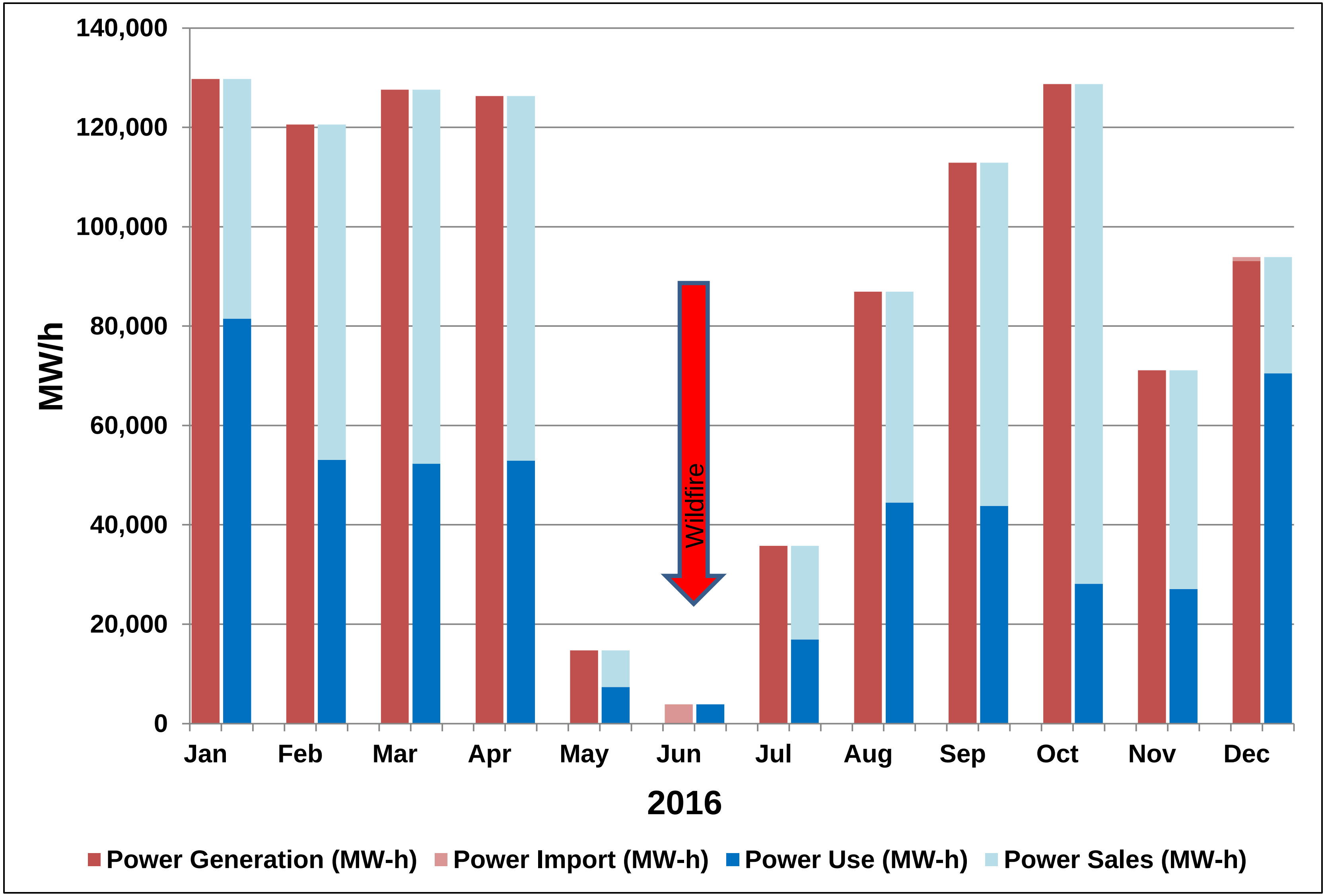
E-013 Exchangers (Blowdown/MP Steam Condensers)

- E-013 A & C tube side material upgrades to duplex stainless steel has improved reliability of the reboilers in 2016. Upgrades on E-013B will be completed in 2017.

Power Generation

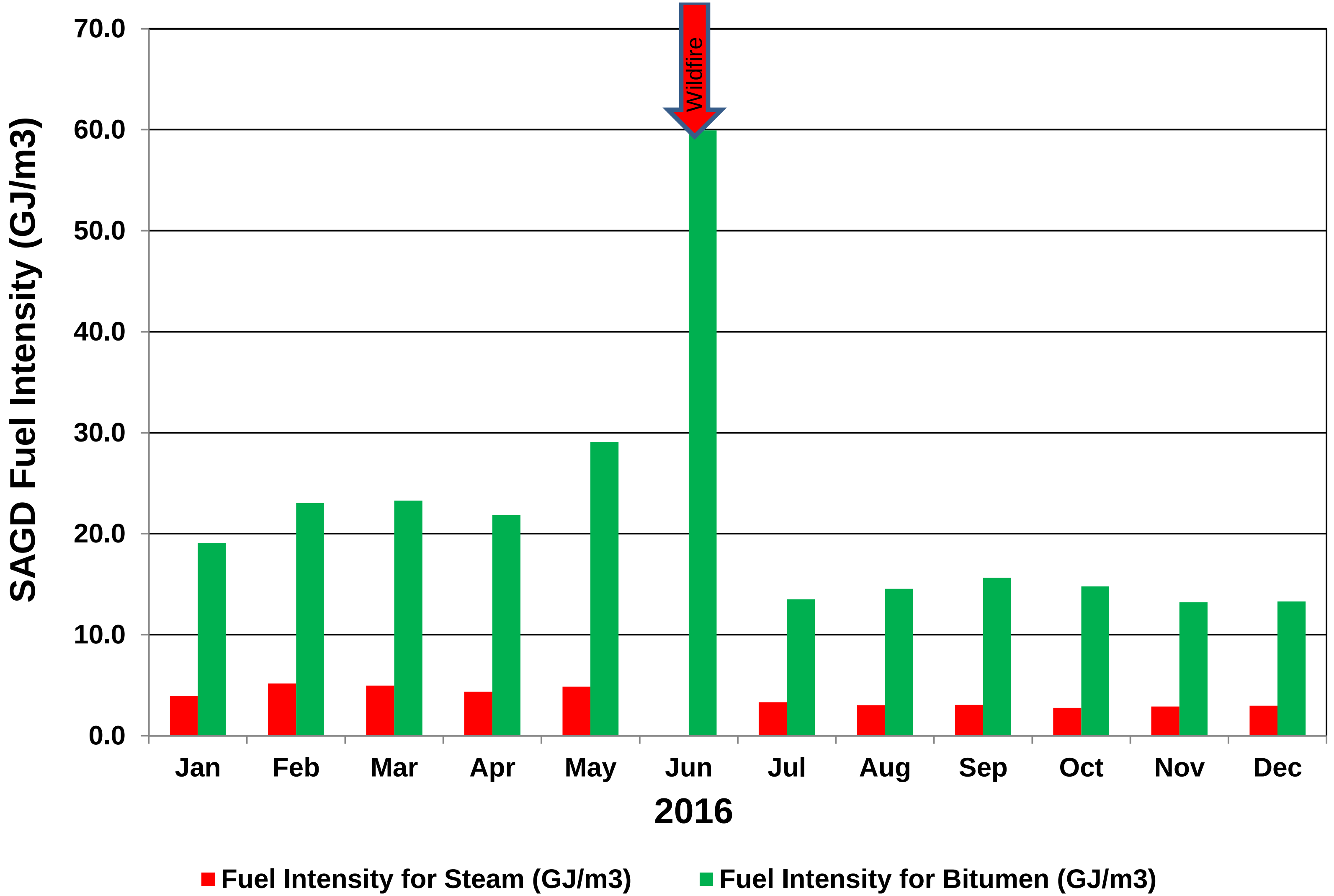
- **Emergency Power Supply**
  - Increased efforts have been made to improve reliability of the emergency generators and standby air compressors by utilizing external vendors to correct any deficiencies and implement PM's (preventative maintenance) schedule on our behalf.

Total Power Usage

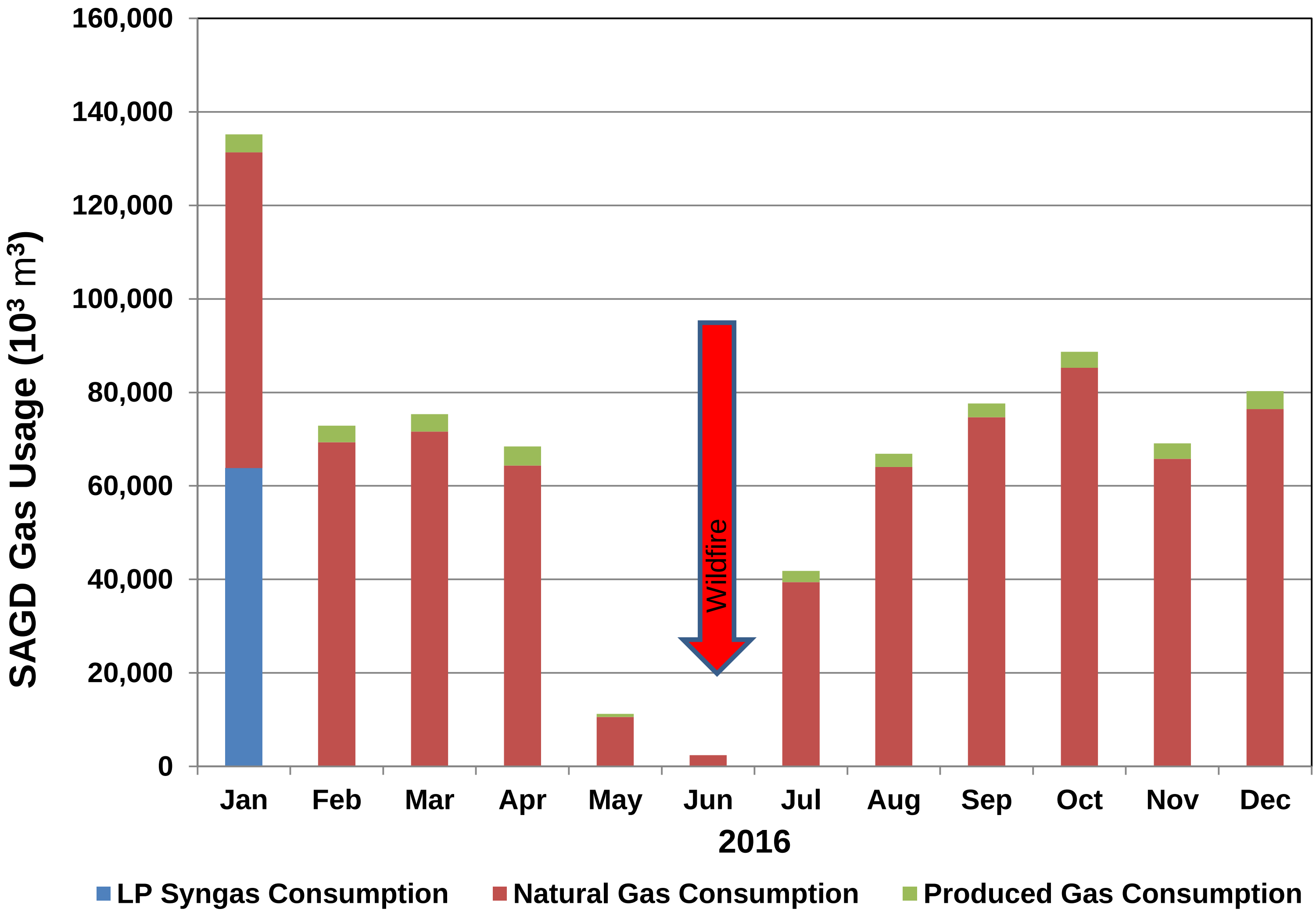


Subsection 3.1.2 (2d)

SAGD Energy Intensity (adjusted for power generation)



Total Gas Consumed (Purchased and Produced)



Subsection 3.1.2 (2e)

Total Gas Vented and Flared

Month (2016)	Total Vented Volume (Sm^3)	Total Gas Flared (Sm^3)
Jan	1,092	14,686
Feb	0	32,207
Mar	2	9,790
Apr	2,549	12,679
May	86	17,255
Jun	0	76,777
Jul	34,990	81,575
Aug	1,303	12,771
Sep	14,770	23,224
Oct	15,679	26,288
Nov	3,355	20,106
Dec	6,826	11,171
Total	**80,652**	**338,529**

Greenhouse Gas Emissions

- Long Lake's GHG intensity is generally trending downwards
  - Generally, lower GHG intensity is associated with lower SORs, improved reliability, and efficient operations
  - In 2016, lower emissions are associated with lower production and no syngas combustion after the upgrader incident

Year	2010	2011	2012	2013	2014	2015	2016
Kilotonnes (kT) CO_2e Emissions	3,229	3,191	3,613	4,139	4,384	3,547	1,582
GHG intensity (kg CO_2e/bbl bitumen produced)	361	307	317	310	280	250	199

- Long Lake's GHG compliance costs are derived from a baseline of 2010-12 performance data
  - Long Lake's baseline includes the facility's three major products – bitumen, premium synthetic crude and electricity
- Compliance is being met through reducing Long Lake's GHG intensity, the use of offsets from Nexen's Soderglen wind farm asset, and contributions to the technology fund
- Current GHG regulations (known as SGER) have risen in stringency, with 2017 being its final year
  - In 2017, SGER's target is a 20% reduction in baseline emissions, with a carbon price of $30 per tonne CO_2
- Regulations are being developed for a new carbon tax on large GHG emitters beginning in 2018
  - The new carbon tax is expected to account for all the emissions from Long Lake and deduct credits for bitumen production, power generation, and upgraded crude production (if the upgrader is operational)

Measurement and Reporting
Subsection 3.1.2 (3)

Long Lake

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Produced Bitumen Measurement

- Ten two-phase test separators with up to 12 well pairs for Pads 1-10, 12 & 13:
  - Currently testing two wells per day per separator. 12 hour test duration, with a minimum of one test per week per well.
  - Wells with ESPs are equipped with wellhead coriolis meters for daily optimization, which allows a longer well test duration for monitoring S&W profiles.
  - Bitumen cuts are based on an inline water cut analyzer (AGAR OW-201 meter) and manual cuts are taken for confirmation.
  - All ten wells on Pad 11 receive continuous well testing via individual coriolis flow measurement and AGAR water cut meters.
- Multiphase flow meters installed on Pads 14 & 15 were operational for 2016. K1A pads were not in service for 2016.

Produced Bitumen Measurement

- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab and 3rd Party lab to determine density as requested by Department of Energy.
- Improvements to MARP maintenance program is ongoing.
- Significant increase in 2016 in compliance to the annual MARP as a result of implementation of EPAP audit findings.

Proration Factors

LLK Proration Factors 2016

MONTH	OIL	WATER
Jan	0.82	1.01
Feb	0.83	1.07
March	0.81	1.06
April	0.83	1.05
May	0.84	1.10
June	1.39	0.86
July	0.86	0.95
August	0.84	1.01
Sept	0.86	1.03
October	0.85	0.97
November	0.96	0.95
December	1.08	0.92

Heavy Oil Battery
Thermal recovery operations
(Petrinex subtypes 344 and 345)

- Oil = 0.81 - 1.39
- Water = 0.86 - 1.10
- Per D017 Section 12.3.3 Gas Measurement:
- A battery level GOR is used to determine well gas production.
- Therefore, the gas proration is 1.00000.

Steam Production Measurement

- The two V-cone meters installed for steam measurement at CPF during 2012 Turnaround (8400-FIT-510,8400-FIT-518) are still out of service.
- A project is ongoing to have these meters replaced. In the interim a steam calculation method for total plant steam production and net steam to pads is used.

Total Steam Production (TSP) = OTSG (Sum_p) + HRSG (Sum_p)

OTSG = Once through steam Generators (840X-B-001 A-F) x = 1 to 6

OTSGs (8401-B-001A-F) will be producing steam based on three criteria (otherwise the value is zero).

$$\text{Steam Production} = \frac{\text{Boiler Feed Water Flow } (Sm^3/h) \times \text{Steam Quality } (\%)}{100}$$

$$= Sm^3/h$$

$$= Sm^3/h \times 24$$

$$= Sm^3/d$$

Steam Production Measurement

HRSGs - Heat Recovery Steam Generators (890X-B-001, X = 1&2)

HRSGs will be producing steam based on three criteria (otherwise the value is zero).

$$\text{Steam Production} = \frac{\text{Boiler Feed Water Flow } (Sm^3/h) \times \text{Steam Quality } (\%)}{100}$$

$$= Sm^3/h$$

$$= Sm^3/h \times 24$$

$$= Sm^3/d$$

Steam Injection Measurement

- Steam injection is measured at the wellhead (estimating steam quality of 97% at the wellhead).
  - Nexen measures the total steam at the individual well heads on each pad through the use of vortex meters and does not use a common meter to prorate HP steam to the wells. Through 2016 these meters were inspected, cleaned and calibrated. All wellhead meters have a preventative maintenance schedule to maintain the accuracy as per MARP.
- As part of the revised plant production calculation the net steam to pads will be:

Net Steam (SAGD well pads) = TSP – HP to LP Letdown + LP steam vent

TSP =Total Steam Production

HP to LP Letdown = 8400-PV-553A & 563A

LP Steam vent = 8400-PV-553B & 563B

Water Production, Injection and Uses Subsection 3.1.2 (4)

Long Lake

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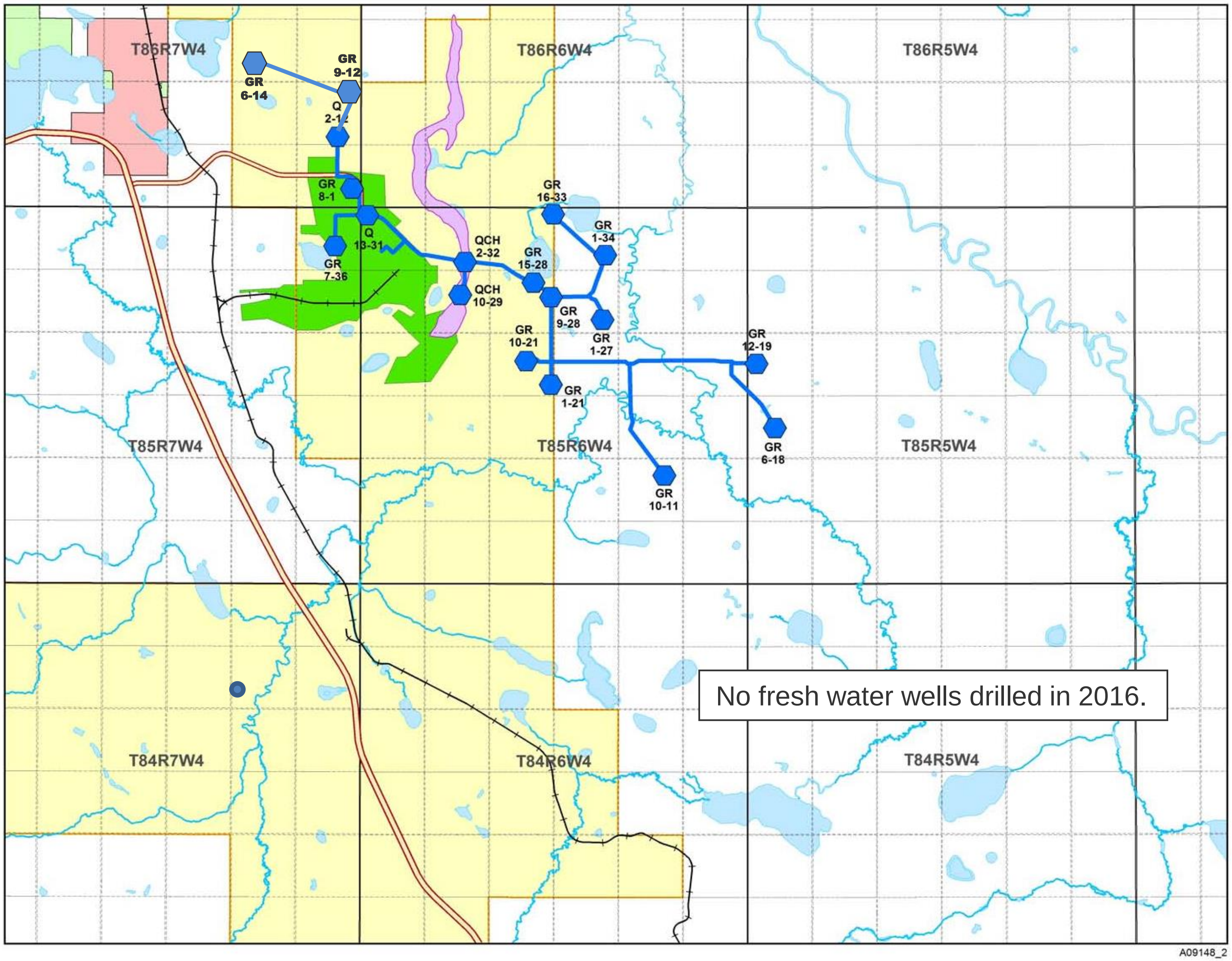
Freshwater Pipelines



Subsection 3.1.2 (4a)

Freshwater Pipelines (CONT'D)

Plant Operations	AENV# 235895-01-00		Total Dissolved Solids		Jan-Dec 2016	
Location	Formation	Fresh?	Sample Date	Concentration (mg/L)	Total (m^3)	Annual avg. (m^3/cd)
01-21-85-06W4M	Grand Rapids	Y	08-Nov-16	1,600	67,246	184
01-27-85-06W4M	Grand Rapids	Y	08-Nov-16	1,300	103,526	283
01-34-85-06W4M	Grand Rapids	Y	08-Nov-16	1,200	46,756	128
02-12-86-07W4M	Quaternary	Y	1-Oct-15	680	154,512	422
02-32-85-06W4M	Gregoire Channel	Y	18-Dec-12	1,800	0	0
06-14-86-07W4M	Grand Rapids	Y	10-Nov-16	1,300	94,782	259
06-18-85-05W4M	Grand Rapids	Y	22-Sep-09	1,000	0	0
07-36-85-07W4M	Grand Rapids	Y	09-Nov-16	940	113,835	311
08-01-86-07W4M	Grand Rapids	Y	9-Sep-14	888	0	0
09-12-86-07W4M	Grand Rapids	Y	09-Nov-16	640	113,850	311
09-28-85-06W4M	Grand Rapids	Y	08-Nov-16	1,300	96,285	263
10-11-85-06W4M	Grand Rapids	Y	10-Nov-16	3,300	47,058	129
10-21-85-06W4M	Grand Rapids	Y	08-Nov-16	1,600	78,814	215
10-29-85-6W4M	Gregoire Channel	Y	14-Dec-16	950	4,084	11
12-19-85-05W4M	Grand Rapids	Y	29-Sep-15	2,400	34,532	94
13-31-85-06W4M	Quaternary	Y	08-Jul-16	540	30,922	85
15-28-85-06W4M	Grand Rapids	Y	09-Nov-16	1,600	77,411	212
16-33-85-06W4M	Grand Rapids	Y	09-Nov-16	1,200	37,057	101
License Allocation 3,285,000 m^3 (annual daily average of 9,000 m^3/d)		TOTAL			1,100,670	3,007

Potable	AENV# 235895-01-00				Jan-Dec 2016	
Location	Formation	Fresh?			Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M	Quaternary	Y	08-Jul-16	540	42,372*	116

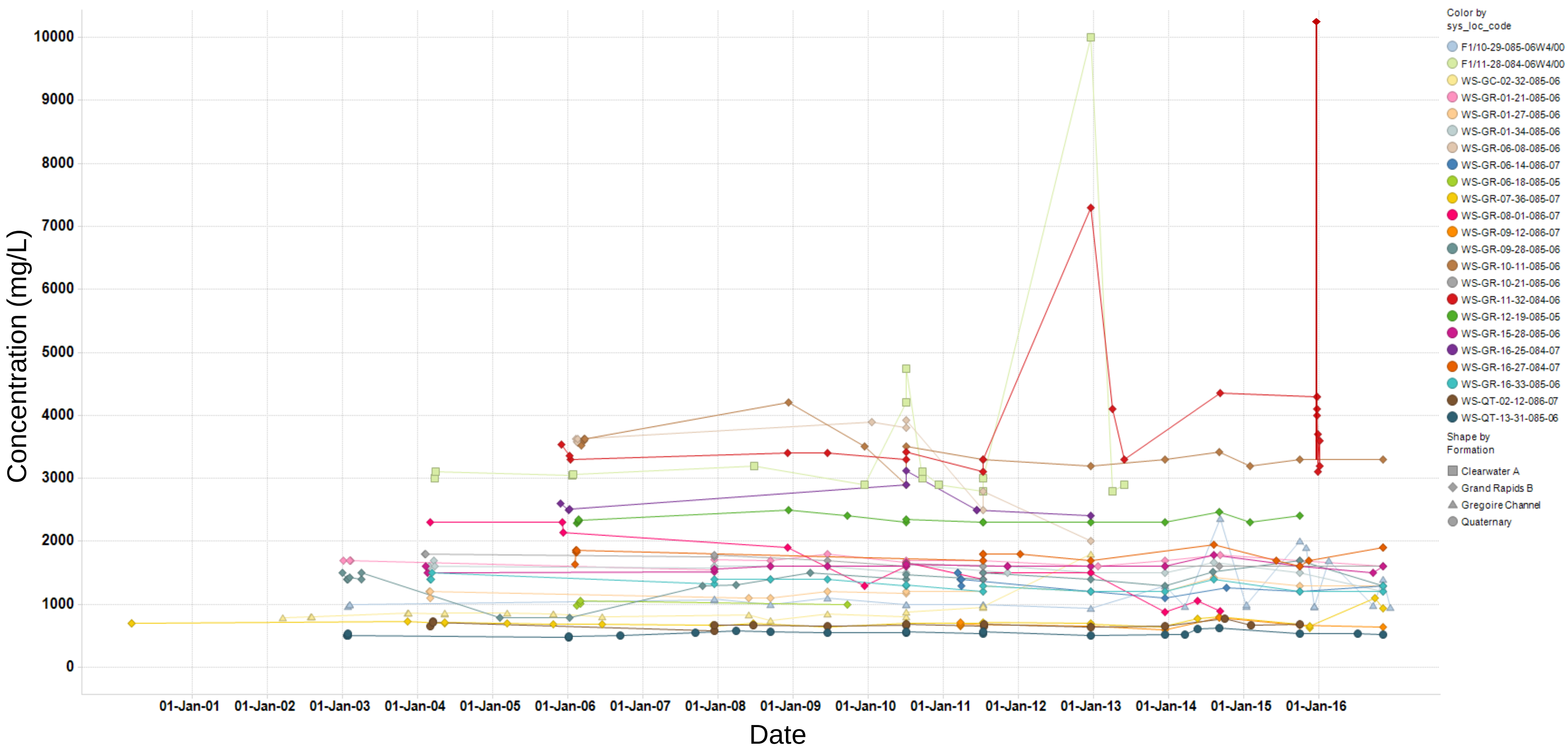
Other	AENV# 235895-01-01 (was 250344-01-00)				Jan-Dec 2016	
Location	Formation	Fresh?			Total (m^3)	Annual avg. (m^3/cd)
07-36-85-07W4M	Grand Rapids	Y	09-Nov-16	940	0	0

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water.
- Groundwater samples are collected if source wells are diverted during the year.

*Difference reported compared with annual Water Use Report reporting is 7,521 m^3 because treatment plant meter doesn't agree with Nexen flow meter from WS QT 13-31

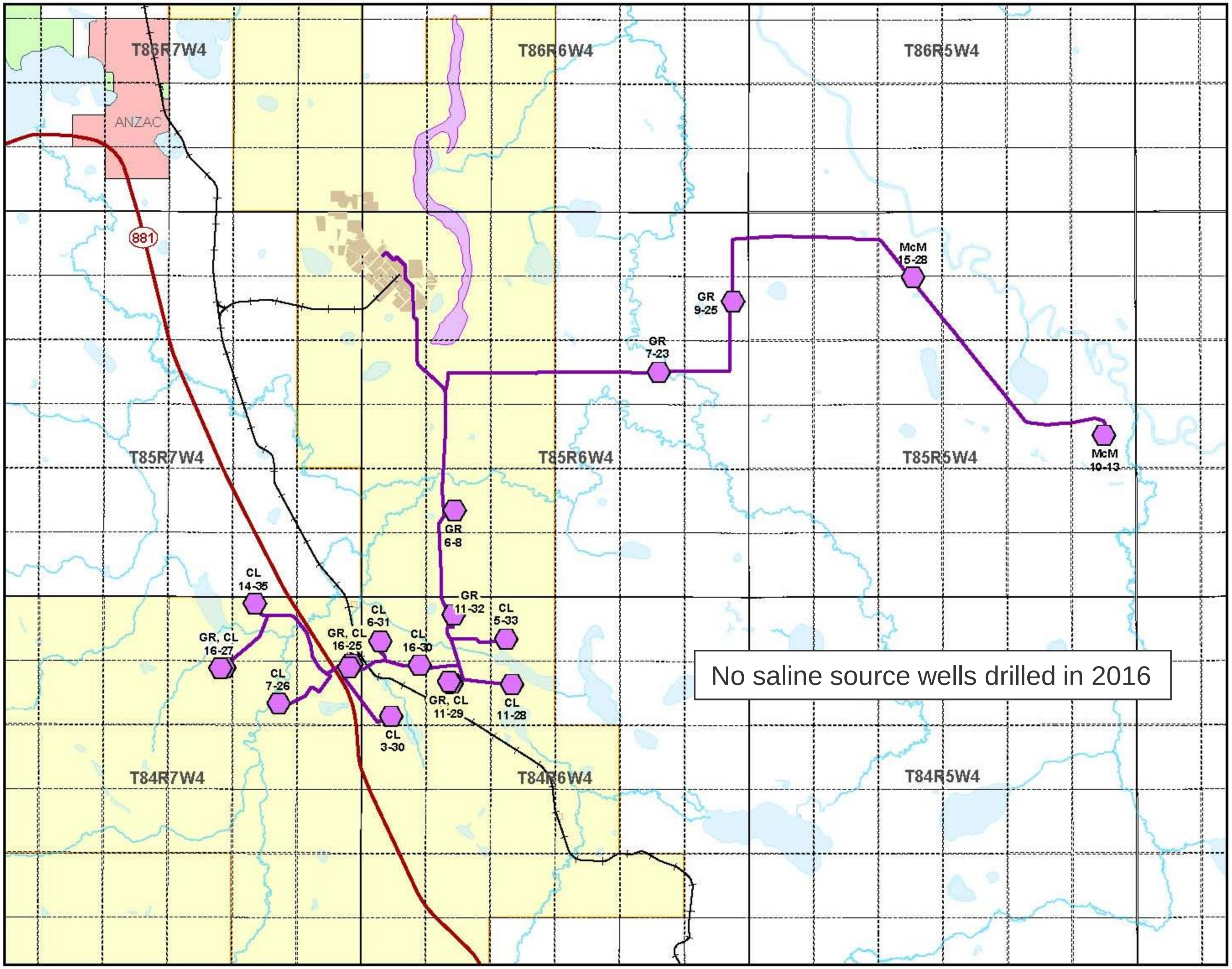
Subsection 3.1.2 (4a,b)

Fresh Water Source Wells Water Quality TDS



- Groundwater quality at WS-GR-11-32-084-06W4M was returned to baseline, confirmatory sample collected Jan. 5, 2016.
- Groundwater quality at F1/10-29-085-06W4M was returned to baseline, confirmatory sample collected Dec. 14, 2016.
- Could not collect samples in 2016 at wells WS-QT-02-12-086-07W4M and WS-GR-12-19-085-05W4M because of power issues post wildfire.

Saline Water Pipelines



Subsection 3.1.2 (4a)

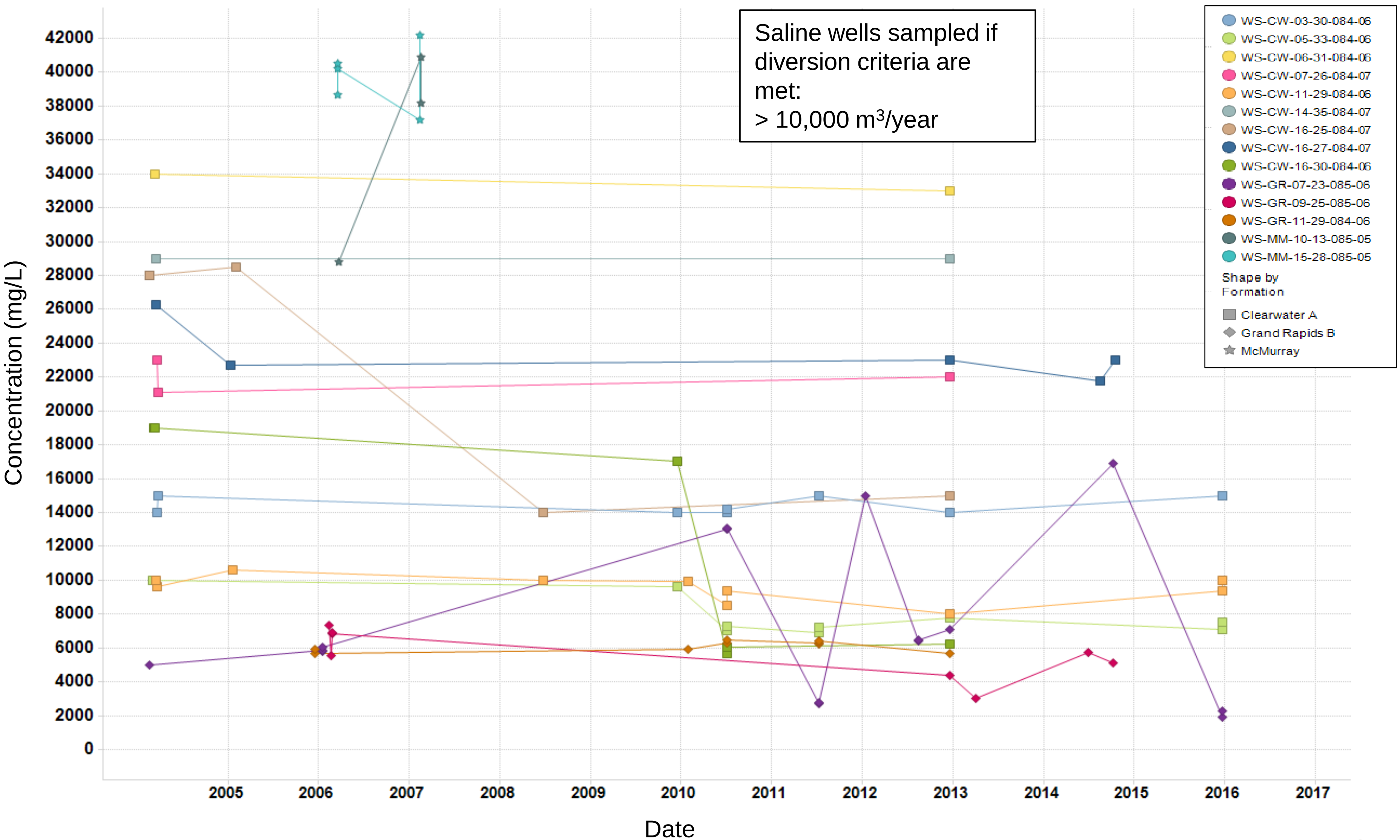
Saline Water Pipelines (CONT'D)

Plant Operations			Total Dissolved Solids		Jan-Dec 2016	
Location	Formation	Saline?	Sample Date	Concentration (mg/L)	Total (m3)	Annual avg. (m3/cd)
1F2/03-30-084-06W4	Clearwater	Y	22-Dec-15	15,000	0	0
1F1/05-33-084-06W4	Clearwater	Y	22-Dec-15	7,500	0	0
1F1/06-31-084-06W	Clearwater	Y	19-Dec-12	33,000	0	0
07-23-85-06W4	Grand Rapids	Y	22-Dec-15	2,300	0	0
1F1/07-26-084-07W4	Clearwater	Y	19-Dec-12	22,000	0	0
09-25-85-06W4	Grand Rapids	Y	9-Oct-14	5,130	0	0
1F1/10-13-085-05W4	McMurray	Y	18-Feb-07	38,200	0	0
1F1/11-29-084-06W4	Clearwater	Y	22-Dec-15	10,000	0	0
11-29-84-06W4	Grand Rapids	Y	19-Dec-12	5,700	0	0
1F1/14-35-084-07W4	Clearwater	Y	19-Dec-12	29,000	0	0
1F1/15-28-085-05W4	McMurray	Y	14-Feb-07	42,200	0	0
1F1/16-27-084-07W4	Clearwater	Y	16-Oct-14	23,000	0	6
1F1/16-25-084-07W4	Clearwater	Y	19-Dec-12	15,000	0	0
1F1/16-30-084-06W4	Clearwater	Y	19-Dec-12	6,200	0	0
Subtotal Saline Diverted Volume					0	0
06-08-85-06W4M	Grand Rapids	N	19-Dec-12	2,000	0	0
1F1/11-28-084-06W4	Clearwater	N	30-May-13	2,900	0	0
11-32-84-06W4M	Grand Rapids	N	05-Jan-16	3,600	4,082	11
16-25-84-07W4M	Grand Rapids	N	19-Dec-12	2,400	0	0
16-27-84-07W4M	Grand Rapids	N	11-Nov-16	1,900	0	0
Subtotal Non-Saline Diverted Volume					**6,252**	**17**
TOTAL VOLUME DIVERTED					**6,252**	**17**

- 19 wells tied in.
- 5 fresh wells tied into saline pipeline (SAGD startup, plant upsets, feed to HQWS).
- Isolation valves are installed on freshwater wells on the saline water pipeline.
- Saline wells are sampled if diversion criteria are met: > 10,000 m^3/year

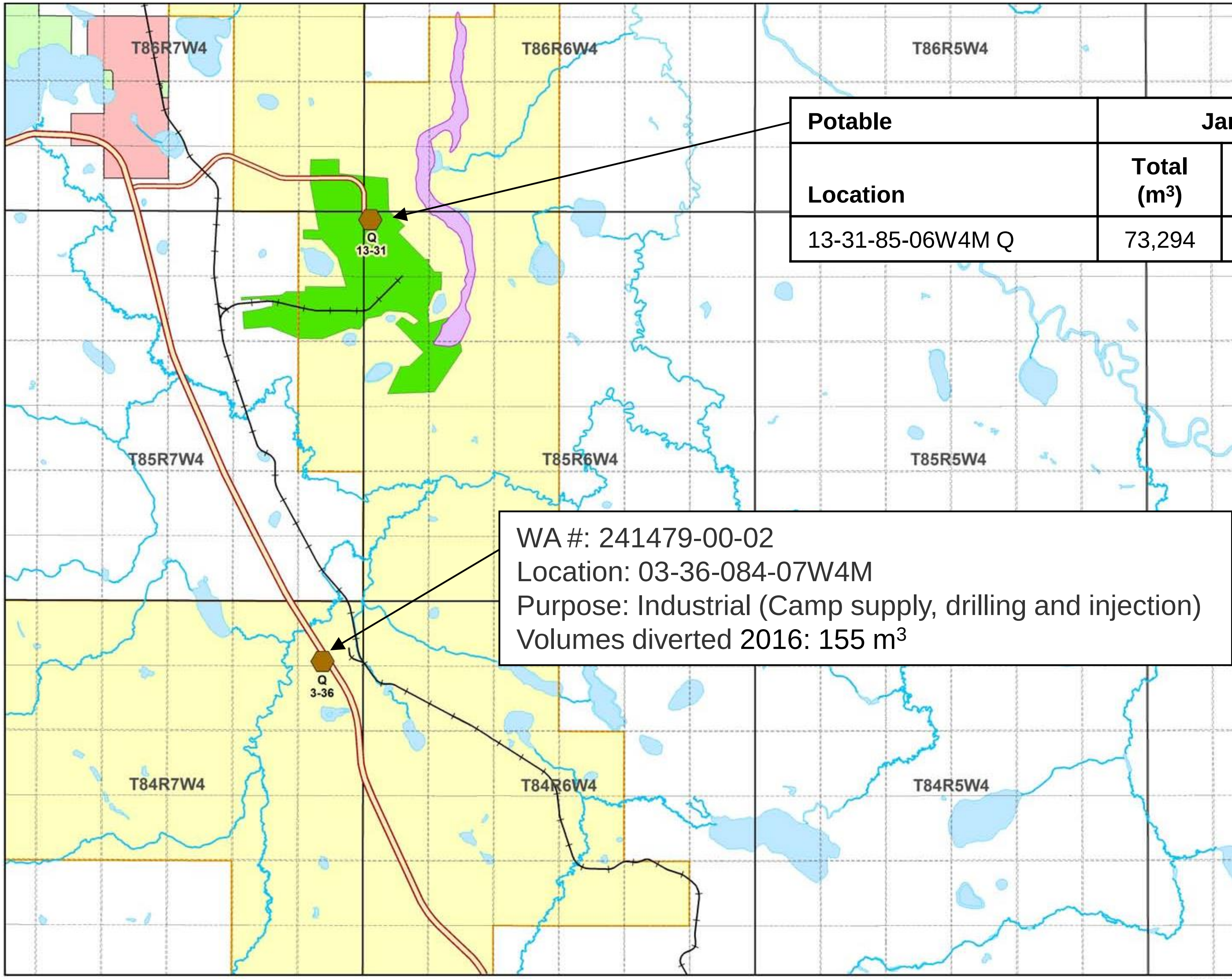
Subsection 3.1.2 (4a,b)

Saline Source Wells Water Quality TDS



Subsection 3.1.2 (4a)

Potable Well



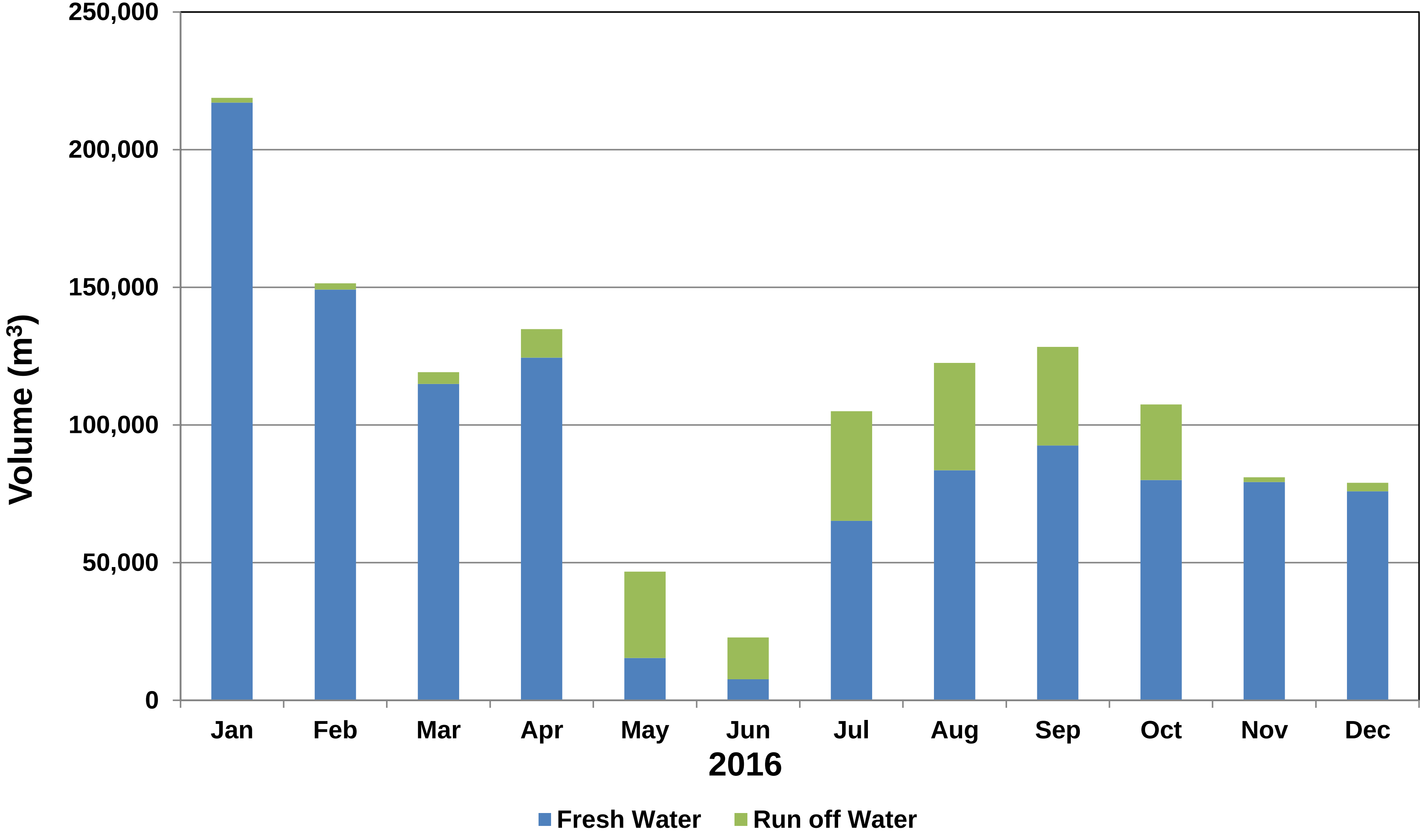
Potable	Jan-Dec 2016	
Location	Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M Q	73,294	200

WA #: 241479-00-02
Location: 03-36-084-07W4M
Purpose: Industrial (Camp supply, drilling and injection)
Volumes diverted 2016: 155 m^3

Other Water Sources

- Surface runoff to lime sludge ponds (00247843-00-00):
  - 2016: 212,020 m^3 (estimate).
- Well drilling:
  - Various TDLs: 1,420 m^3 in 2016.
- K1A Emulsion Line Clean-Up and Remediation Activities:
  - TDL No. 376956 for water reuse: 4,649 m^3 in 2016.

Fresh Water Use Volumes



Water Make-up

- Use of freshwater make-up (in decreasing amounts)
  1. Demineralized water make-up (UPG and cogens)
  2. Utility and plant use (UPG and SAGD)
  3. SAGD steam make-up
  4. Potable
  5. Others (incl. drilling)

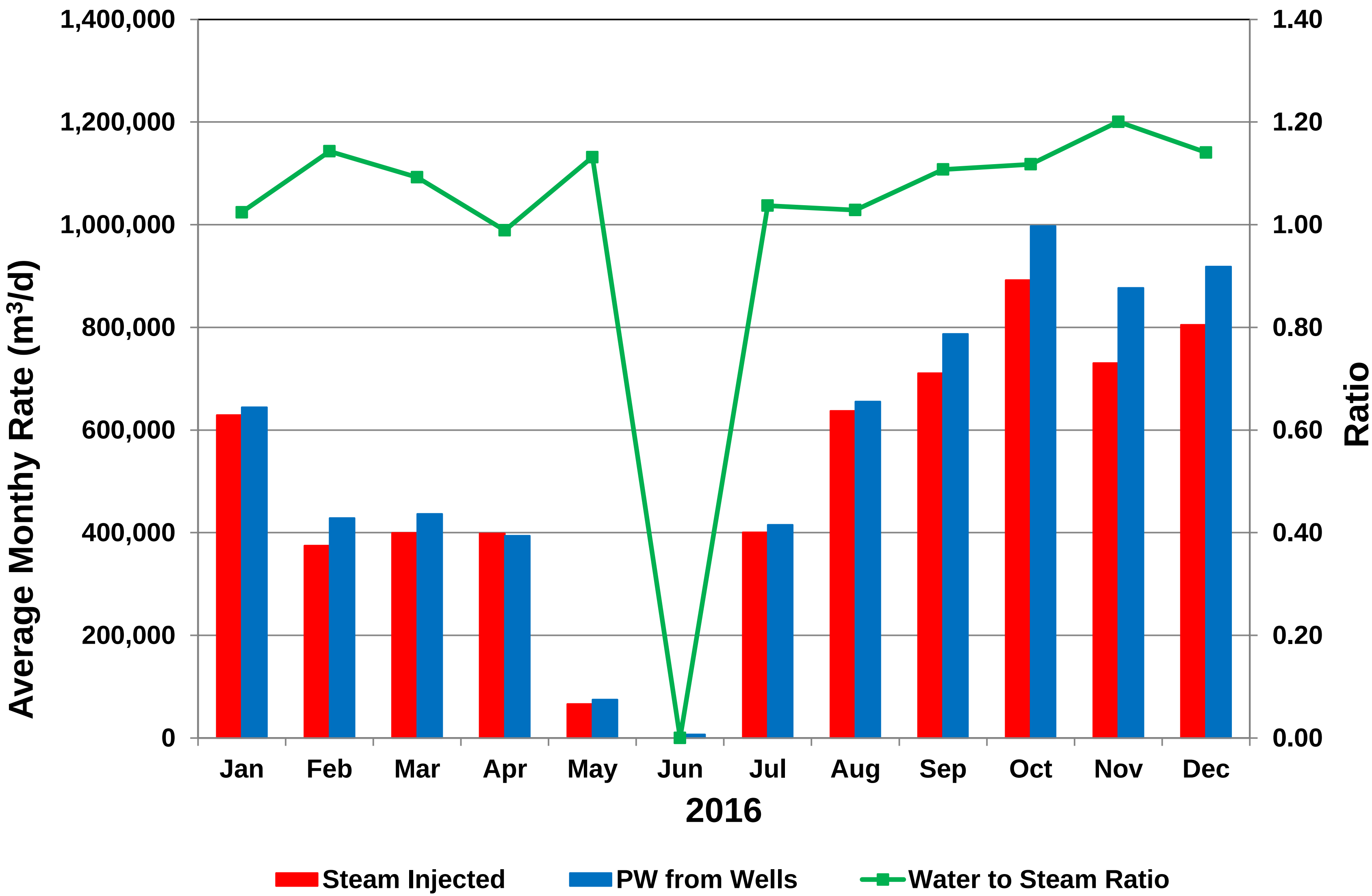
	Freshwater Uses in 2016 (m³)			
	Total	**Domestic**	**SAGD**	**Process**
Main groundwater license (235895-01-00 as amended)	1,139,604	42,372	839,463	257,769
Surface runoff to ponds (includes K1A)	212,020		212,020	
SAGD drilling	0			
Winter drilling program (Long Lake and Kinosis)	1,420			
Potable trucked to Long Lake	0			
TOTAL	**1,353,044**			

* Volume of fresh water to SAGD was calculated according to D081 and includes the volume of water re-used from utilities and process.

- Saline water make-up:

  0 m³ in 2016 for steam make-up (HLS's)

Produced Water and Steam Injected Volumes

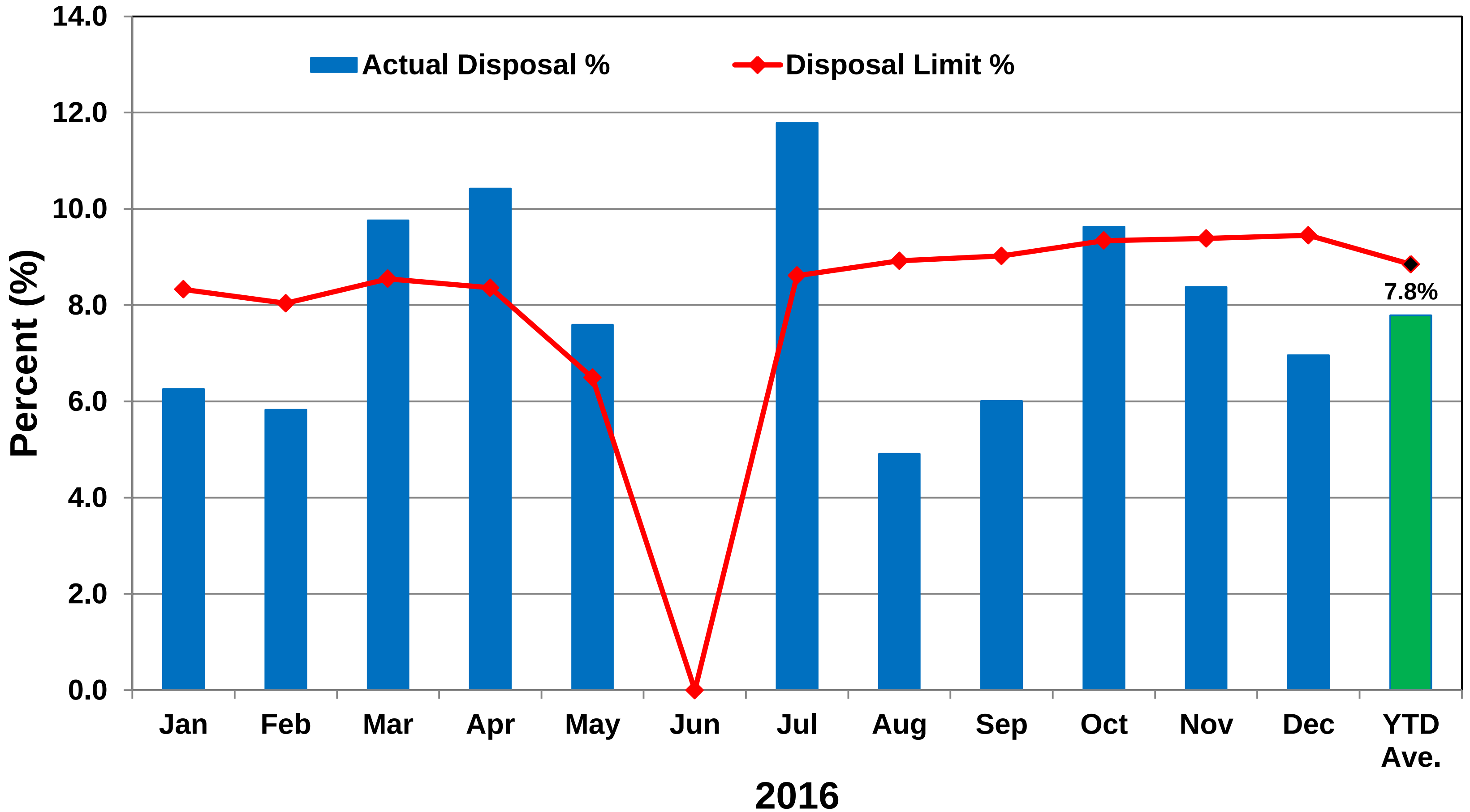


Subsection 3.1.2 (4c,d)

Water Management

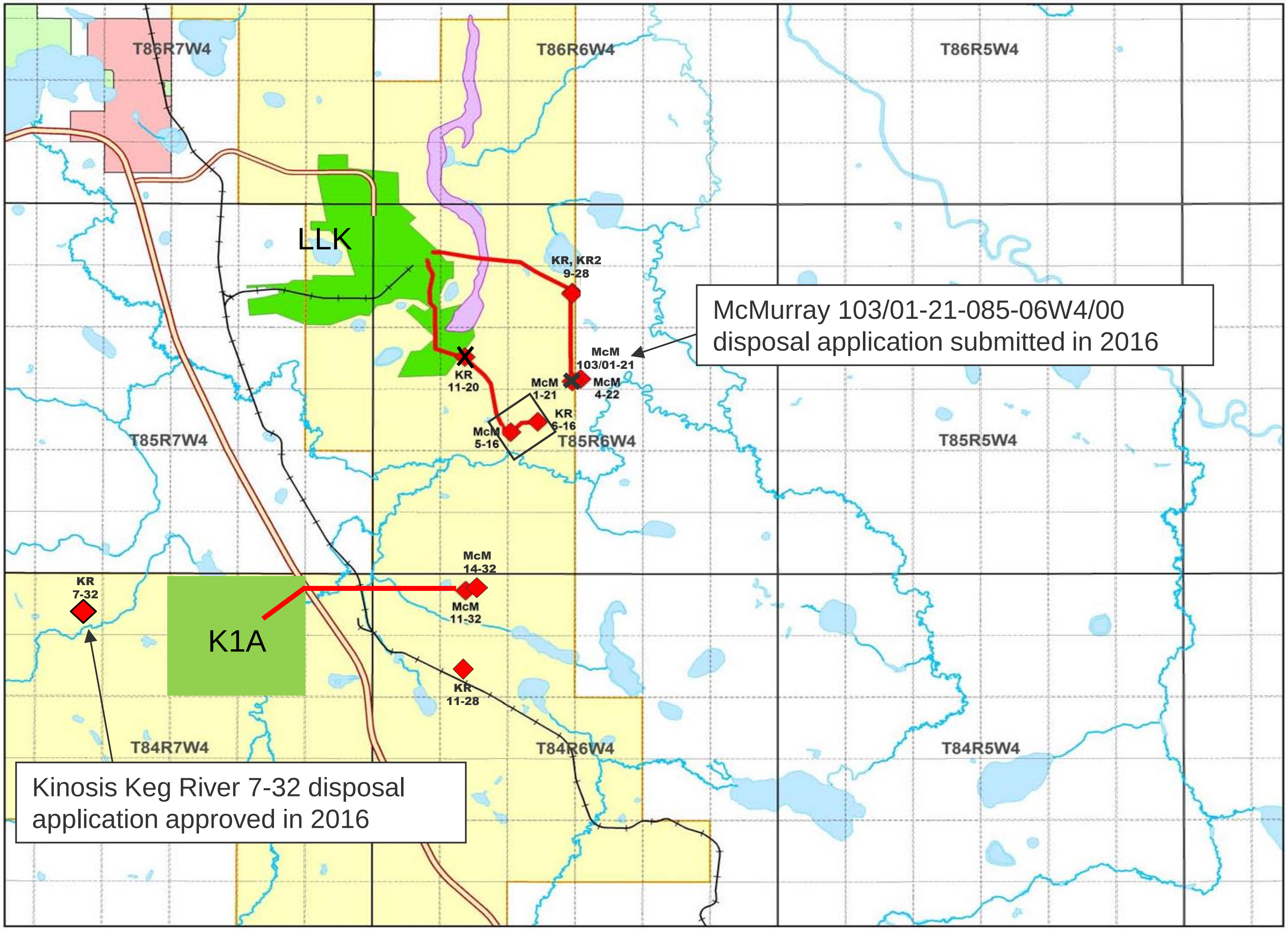
Nexen's disposal rate includes freshwater demand to the upgrader

$$\text{Disposal limit (\%)} = \frac{[(\text{Freshwater In}*0.03) + (\text{Brackish water In }*0.35) + (\text{Produced water In}*0.1)]}{[(\text{Freshwater In}) + (\text{Brackish water In}) + (\text{Produced water In})]}*100$$



Subsection 3.1.2 (4e,f)

Disposal Wells



Subsection 3.1.2 (4g)

Disposal Wells (CONT'D)

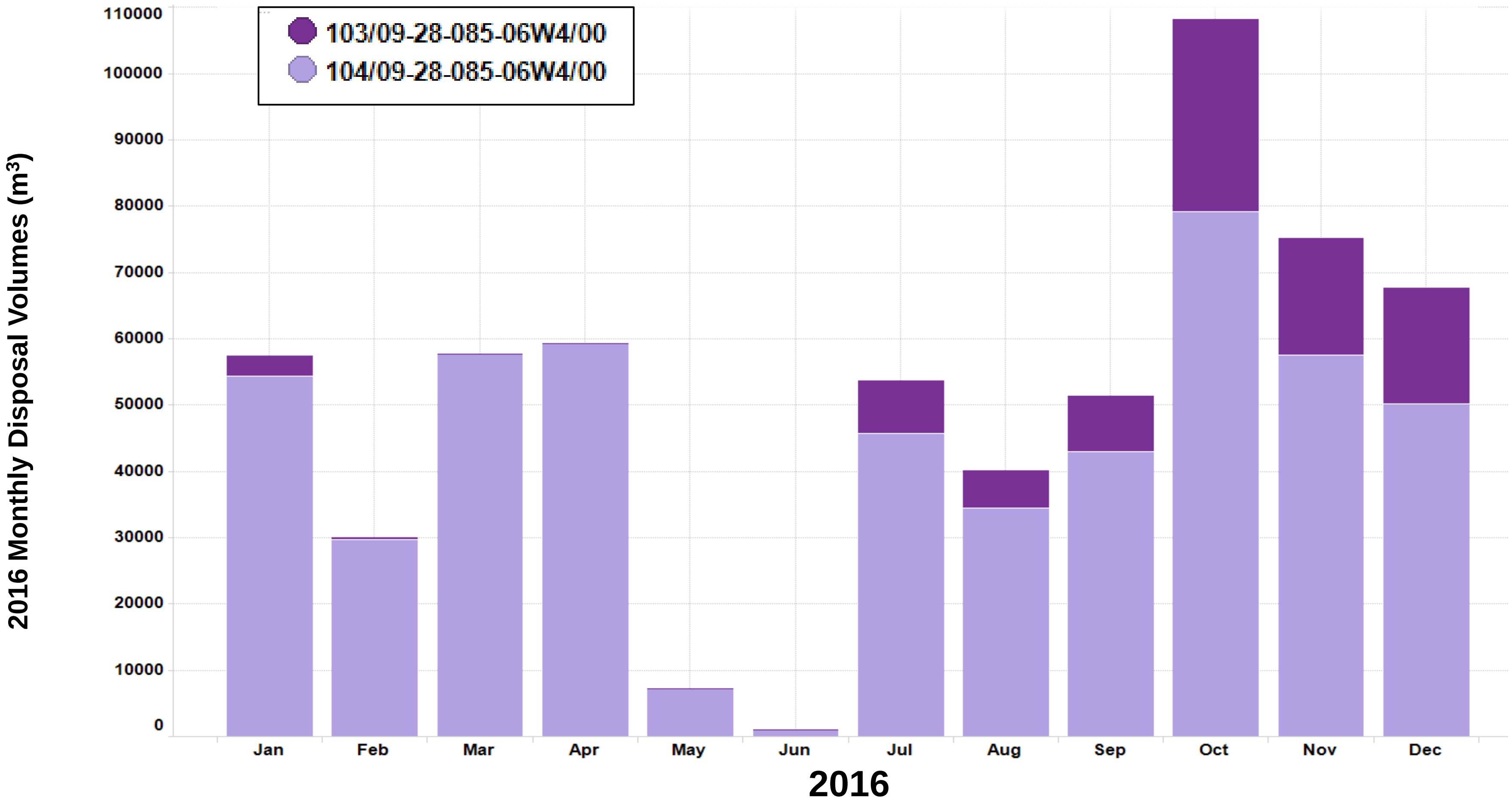
AER Approval # 10023G	Class 1b	January - December 2016		
Disposal Well		**Max. WHP (kPag)**	****Total (m^3)**	**Annual avg. (m^3/cd)**
104/09-28-085-06W4/00 KR	Blowdown	1,107	542,312	1,482
103/09-28-085-06W4 KR	Blowdown	821	82,146	224
100/04-22-085-06W4 McM	Blowdown	-	-	-
100/11-32-084-06W4 McM	Blowdown	-	-	-
100/14-32-084-06W4 McM	Blowdown	-	-	-
100/11-28-084-06W4/00 KR	Drilling fluids	-	-	-
TOTAL			**624,458**	**1,706**

AER Approval # 11611	Class 1a	January - December 2016		
Disposal Well		**Max. WHP (kPag)**	**Total (m^3)**	**Annual avg. (m^3/cd)**
100/06-16-085-06W4 KR*	-	-	-	-
100/05-16-085-06W4 McM*	-	-	-	-

*Well is suspended

- Disposal capacity is adequate.
- Disposal fluid temperature ~60°C.
- All wells passed annulus pressure test
- Data Loss Notification wells (Clause 7 from Approval No. 10023H) :
  - 1F2/02-32-085-06W4/00 and 1AA/10-29-085-06W4/00 → May 5 – July 23, 2016 (wildfire)
  - 102/09-28-085-06W4/00 → Dec. 11, 2016 – Jan. 25, 2017 (data was recovered)

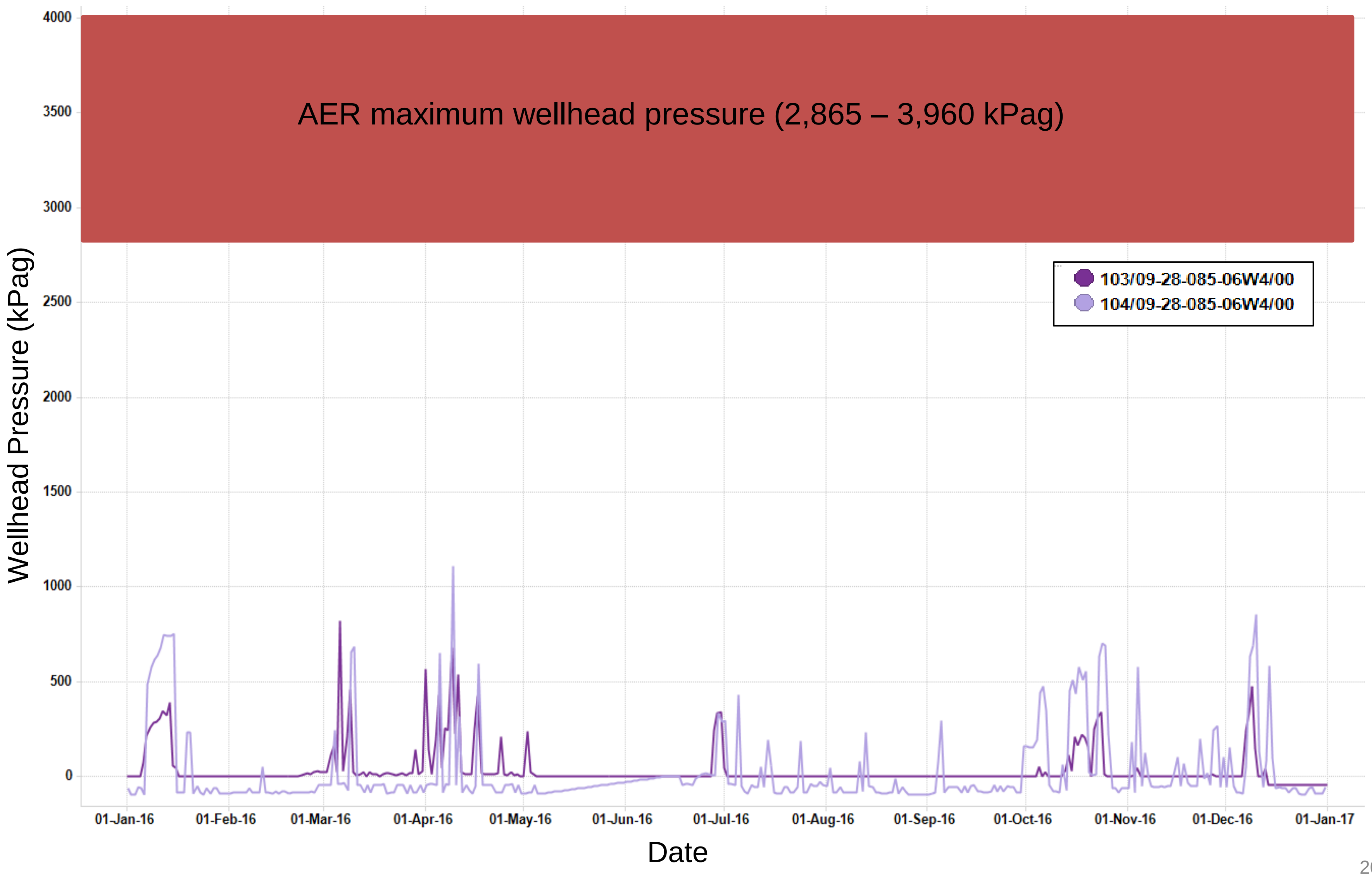
Disposal Well Volumes - Class 1b



- 2016 disposal only to Keg River wells 103/ and 104/09-28-085-06W4/00

Subsection 3.1.2 (4h)

Disposal Well - Well Head Pressures



Sulphur Production and Air Emissions

Subsection 3.1.2 (5)

Long Lake

nexen

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Sulphur Recovery Overview

The Long Lake sour gas processing system is located in the Upgrader area but is an integrated facility for treating sour gas produced from both the SAGD CPF and Upgrader. There are six subsystems in this unit:

1. **Amine Regeneration Subsystem**
   - The Amine Regeneration Subsystem is designed to remove H2S and CO2 from rich amine and produce lean amine for re-use in the OrCrude™, Hydrocracker Unit, AGU, SRU Subsystem, and SAGD;
2. **Selexol Regeneration Subsystem**
   - The Selexol Regeneration Subsystem is designed to remove H2S and CO2 from rich Selexol and produce lean Selexol for re-use in the Selexol Absorbing System;
3. **Sour Water Stripping Subsystem**
   - The Sour Water Stripping Subsystem is designed to strip H2S and NH3 from sour water coming from the OrCrude™, Hydrocracker Unit, AGU, and the SRU Subsystem. Stripped water is returned to the SAGD CPF and Upgrader for re-use and the acid gas exiting this system flows to the SRU subsystem;

Sulphur Recovery Overview Continued

4. **SRU Subsystem**
   - The SRU Subsystem converts Sulphur contaminants (mainly H_2S) flowing from the Amine Regeneration, Selexol Regeneration, and Sour Water Stripping Subsystems into liquid Sulphur. The subsystem is also designed to destroy ammonia;
5. **Tail Gas Treating Unit (TGTU) Subsystem**
   - The TGTU Subsystem is designed to convert any Sulphur contaminants in the tail gas flowing from the SRU Subsystem back into H_2S so that the H_2S can be removed by amine solution in the TGTU Absorber. Any remaining Sulphur contaminants in the tail gas are oxidized in the incinerator before it is released to atmosphere; and
6. **Miscellaneous Utilities Subsystem**
   - The Miscellaneous Utilities Subsystem contains the acid gas flare and associated equipment, a natural gas heater, and various condensate collection drums, condensate blowdowns, flash drums, etc., that are necessary for the operation of the Sulphur recovery systems.

Sulphur Recovery Rates & Uptimes

	Items	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Average
Claus Units	% of Month Processing AG	48.0%	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	**48.0%**
Sulphur Recovery	Monthly Recovery Rate (%)	99.5%	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	**99.5%**
	Quarterly Recovery Rate (%)	**99.5%**			**O/S**			**O/S**			**O/S**			**99.5%**
	Average Inlet Sulphur (Tonnes/day)	155.9	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	**155.93**
	Average Monthly Sulphur Production (Tonnes/day)	155.1	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	O/S	**155.08**

Month	% Time TGTU in Operation with SRU Trains	% Time Train 1 in Operation	% Time Train 2 in Operation
Jan-16	48.0%	48.0%	47.5%
Feb-16	0.0%	0.0%	0.0%
Mar-16	0.0%	0.0%	0.0%
Apr-16	0.0%	0.0%	0.0%
May-16	0.0%	0.0%	0.0%
Jun-16	0.0%	0.0%	0.0%
Jul-16	0.0%	0.0%	0.0%
Aug-16	0.0%	0.0%	0.0%
Sep-16	0.0%	0.0%	0.0%
Oct-16	0.0%	0.0%	0.0%
Nov-16	0.0%	0.0%	0.0%
Dec-16	0.0%	0.0%	0.0%

- Claus Units were in service until the HCU incident. Sulphur compounds were removed from the systems firing Natural Gas in the reaction furnaces.
- TGTU was immediately shutdown after the HCU incident.

Subsection 3.1.2 (5a) i, ii)

Acid Gas Flaring Events Summary

Year 2016						
Month	AG Sources			SWAG Sources		
	Duration (h)	Volume (Sm^3)	SO_2 (Tonnes)	Duration (h)	Volume (Sm^3)	SO_2 (Tonnes)
January	1.8	2,033	0.3	386.8	266,625	20.2
February	4.1	151	0.0	696.0	381,632	14.1
March	0.1	26	0.0	744.0	234,195	0.0
April	2.4	5,845	0.3	744.0	173,998	0.0
May	0.0	0	0.0	0.0	0	0.0
June	0.0	0	0.0	0.0	0	0.0
July	0.0	0	0.0	0.0	0	0.0
August	0.0	0	0.0	0.0	0	0.0
September	0.0	0	0.0	0.0	0	0.0
October	0.0	0	0.0	0.0	0	0.0
November	0.0	0	0.0	0.0	0	0.0
December	0.0	0	0.0	0.0	0	0.0
2016 Total	**8.4**	**8,054**	**0.6**	**2,570.7**	**1,056,451**	**34.2**

AG : Acid Gas
SWAG : Sour Water Acid Gas

- Total SO_2 emissions due to acid gas flaring were 34.2 tonnes
- Acid Gas Flaring Events are part of the monthly air report submitted to Alberta Environment & Parks (AEP).
- Sour Water Stripper operated at low stripping conditions to prevent freezing issues after the HCU incident. It was completely shutdown on Feb. 9th after reducing at minimum levels H_2S and NH_3 in sour water.

Sulphur Production

	Quarter	Total (tonnes)	Average (tonnes/day)	Limit (tonnes/day)
Commercial Plant	1st	177.48	1.95	*1.0 (18.5)
	2nd	8.29	0.09	
	3rd	5.98	0.06	
	4th	7.51	0.08	
SRU Incinerator Stack	1st	47.97	0.53	15.6
	2nd	4.56	0.05	
	3rd	0.00	0.00	
	4th	0.00	0.00	

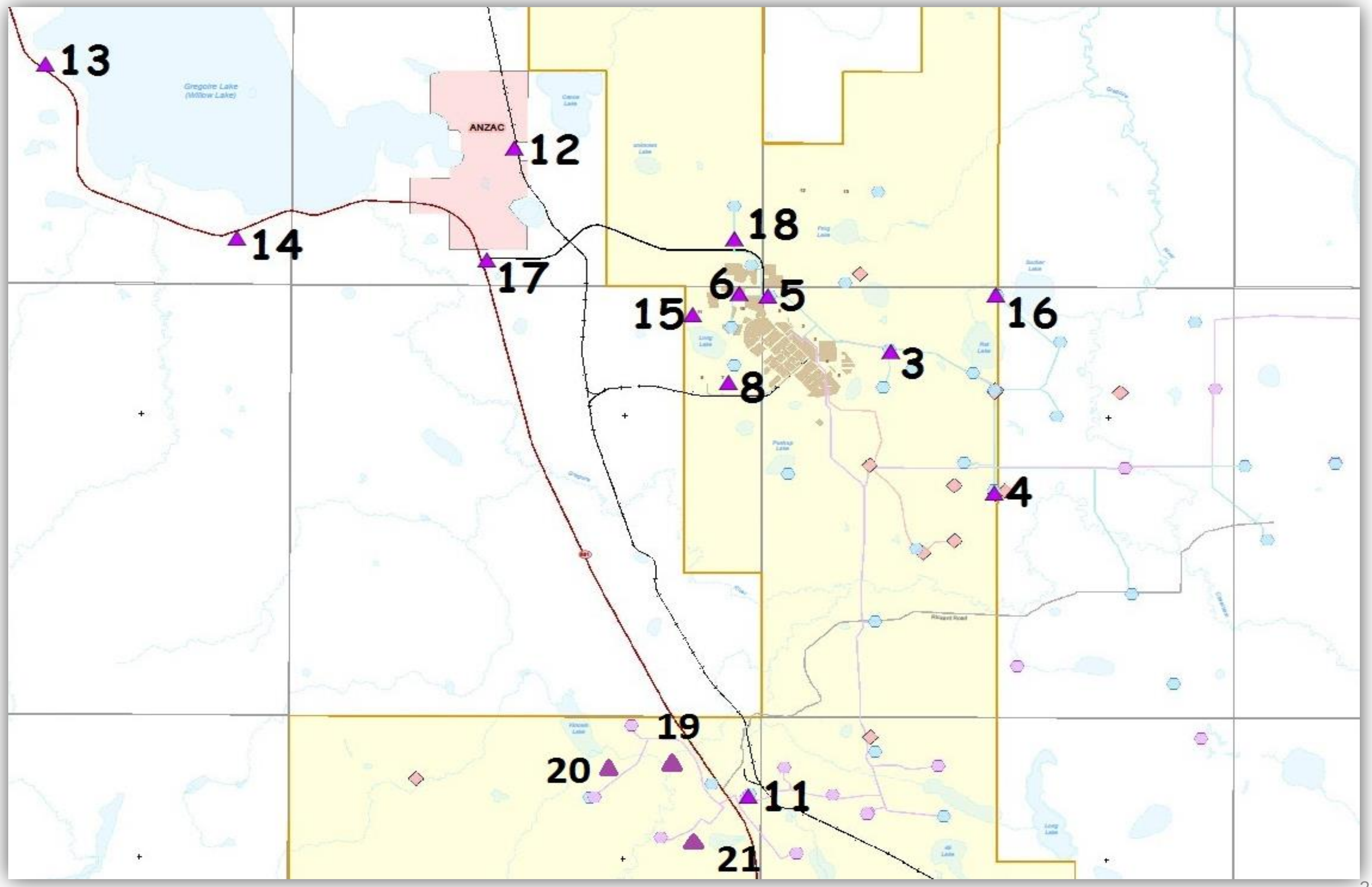
- *Sulphur Recovery Unit (SRU) shut-in post Jan. 16/16.
- Operations are under 1 tonne/day on a quarterly average.

Ambient Air Monitoring

- The Long Lake continuous air monitoring station is located approximately 35 km southeast of Fort McMurray on the northern edge of the hamlet of Anzac and is operated by the Wood Buffalo Environmental Association (WBEA).
- The Anzac Station contains analyzers that continuously measure SO_2, O_3, TRS, THC, NO, NO_2, NO_X, PM 2.5, wind speed and direction, and temperature.
- There were 20 events in 2015 which exceeded the Alberta Ambient Air Quality Objectives (AAAQO). All of these events were attributed to forest fires burning in the region.

Date / Time	Parameter	Concentration (ppb or µg/m³)	Limit	Exceedance Period	AER Reference #
5/5/16 23:00	O_3	138.0		1hr	311081
5/6/16 0:00	PM2.5	223.0	30 µg/m³ 24 hr avg	24hr	311080
5/14/16 0:00	PM2.5	267.0		24hr	311658
5/15/16 0:00	PM2.5	267.0		24hr	311441
5/16/16 0:00	PM2.5	42.0		24hr	311492
5/17/16 0:00	PM2.5	52.0		24hr	311552
5/18/16 0:00	PM2.5	67.0		24hr	311608
5/19/16 0:00	PM2.5	50.0		24hr	311680
5/20/16 0:00	PM2.5	40.0		24hr	311731
5/21/16 0:00	PM2.5	46.0		24hr	311748
5/22/16 0:00	PM2.5	60.0		24hr	311825
5/23/16 0:00	PM2.5	73.0		24hr	311877
5/24/16 0:00	PM2.5	84.0		24hr	311926
5/5/16 22:00	TRS	42.0		1hr	311080
5/5/16 23:00	TRS	12.0		1hr	311080
5/15/16 0:00	TRS	4.1		24hr	311422
5/15/16 3:00	TRS	11.0		1hr	311422
5/15/16 4:00	TRS	12.0		1hr	311422
5/15/16 5:00	TRS	15.0		1hr	311422
5/6/16 22:00	NO_2	291.0		1hr	311080

Passive Air Monitoring Locations Long Lake & K1A



Subsection 3.1.2 (5d)

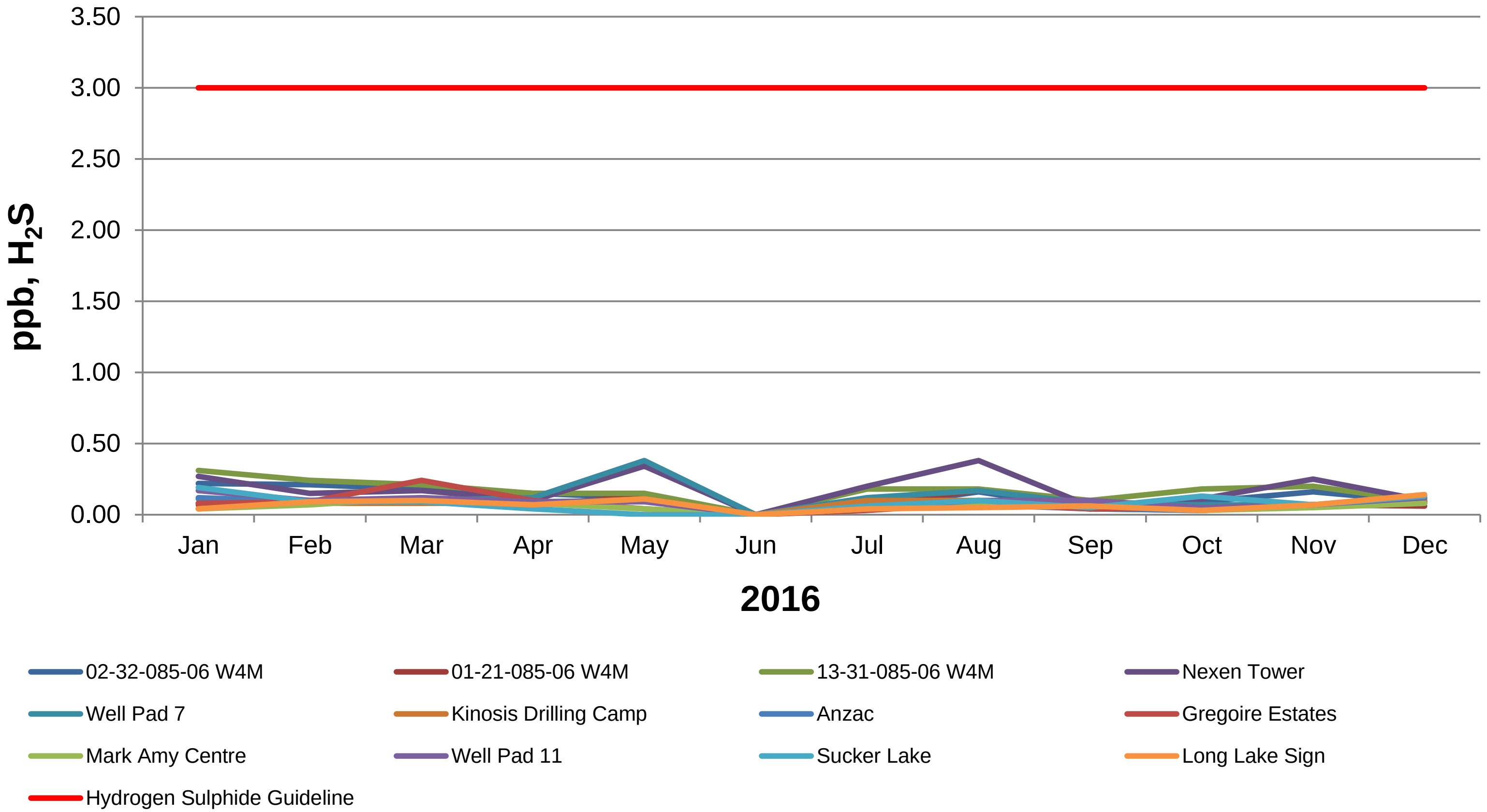
Passive Air Monitoring Station Status

Station Number	Station Location	Status
1	SAGD Pilot Site SE- near Pilot flare stack	Discontinued in December 2010
2	SAGD Pilot Site NW Rear of the Pilot	Discontinued in December 2010
3	02-32-085-06 W4M Source Well	Active
4*	01-21-085-06 W4M Source Well	Active
5	13-31-085-06 W4M Source Well	Active
6	Nexen Tower	Active
7	Well Pad 9	Discontinued in January 2010
8	Well Pad 7	Active
9	Electrical Substation	Discontinued in December 2010
10	Beside Tankyard	Discontinued in December 2010
11*	Kinosis Drilling Camp	Active
12	Anzac	Active
13	Gregoire Estates	Active
14	Mark Amy Centre	Active
15	Well Pad 11	Active
16	Sucker Lake	Active
17	Long Lake Sign	Active
18	02-12-85-06 W4M Source Well	Discontinued in May 2014
19*	K1A Camp	Active as of June 2014
20*	K1A Pad 1	Active as of June 2014
21*	Surerus Laydown	Active as of June 2014

* K1A Passive Stations

Long Lake H_2S Passive Monitoring

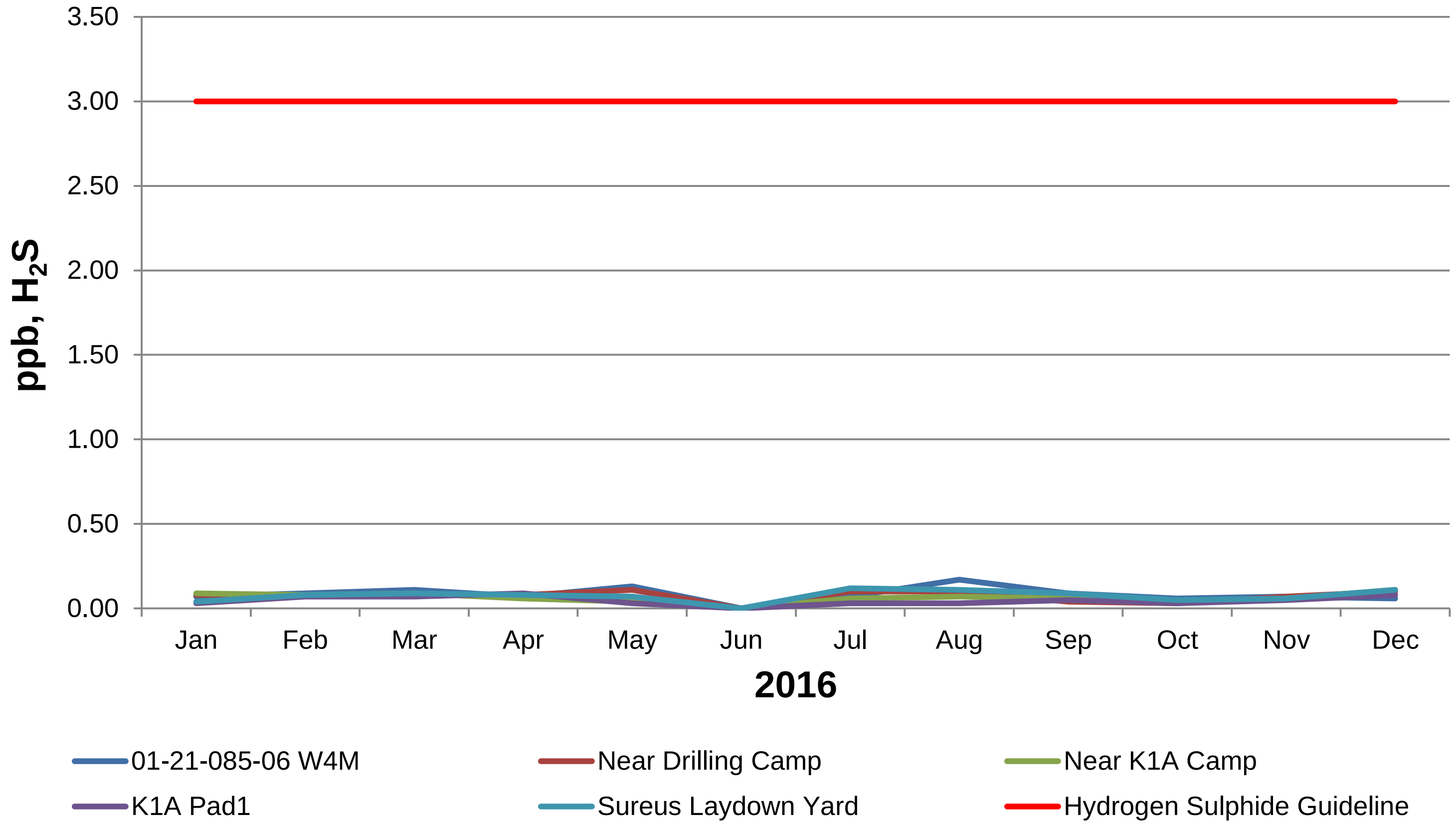
- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv. No stations exceeded this limit in 2016.



Subsection 3.1.2 (5d)

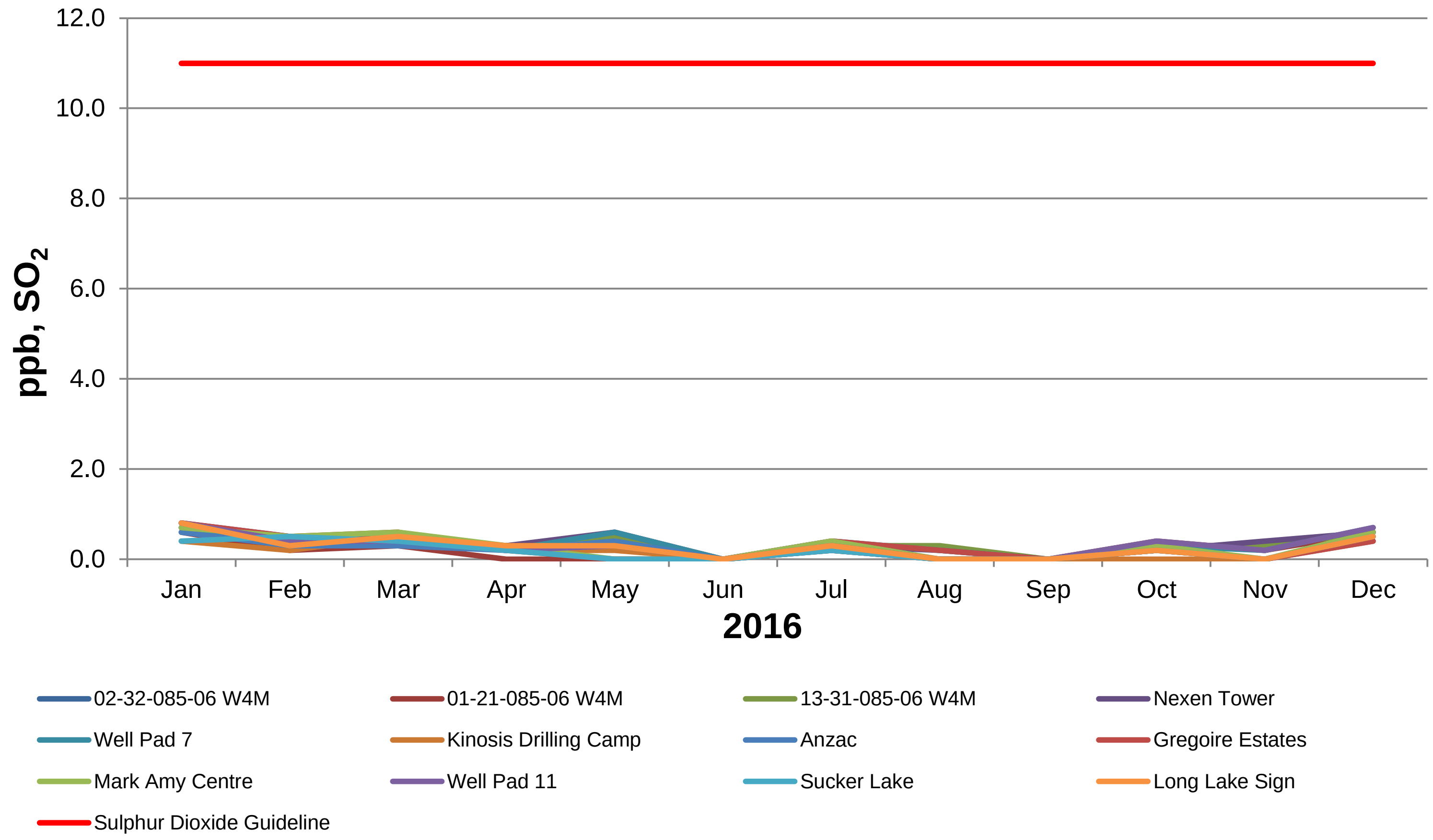
K1A H_2S Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3 ppbv. No stations exceeded this limit in 2016.



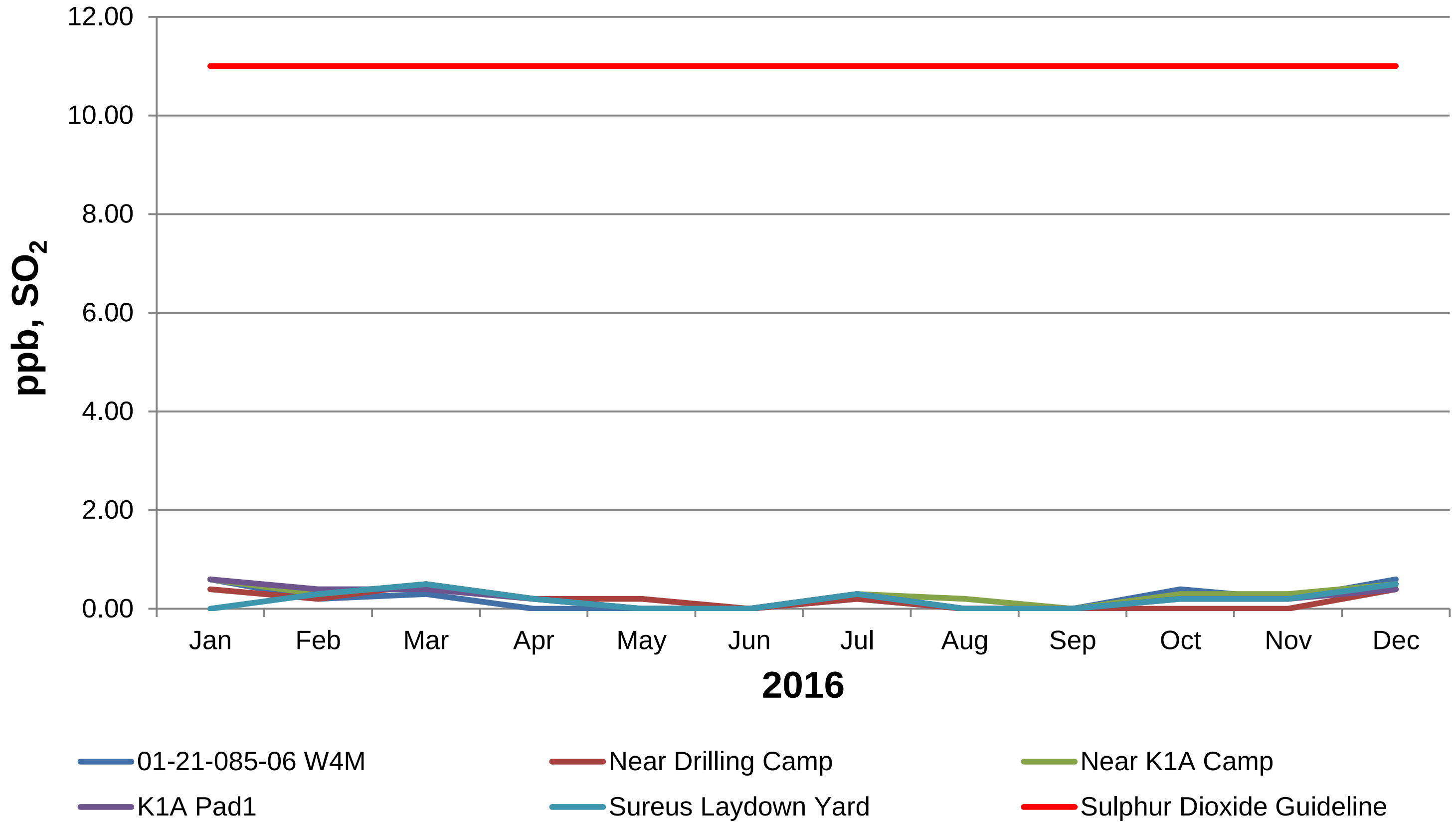
Long Lake SO_2 Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2016.



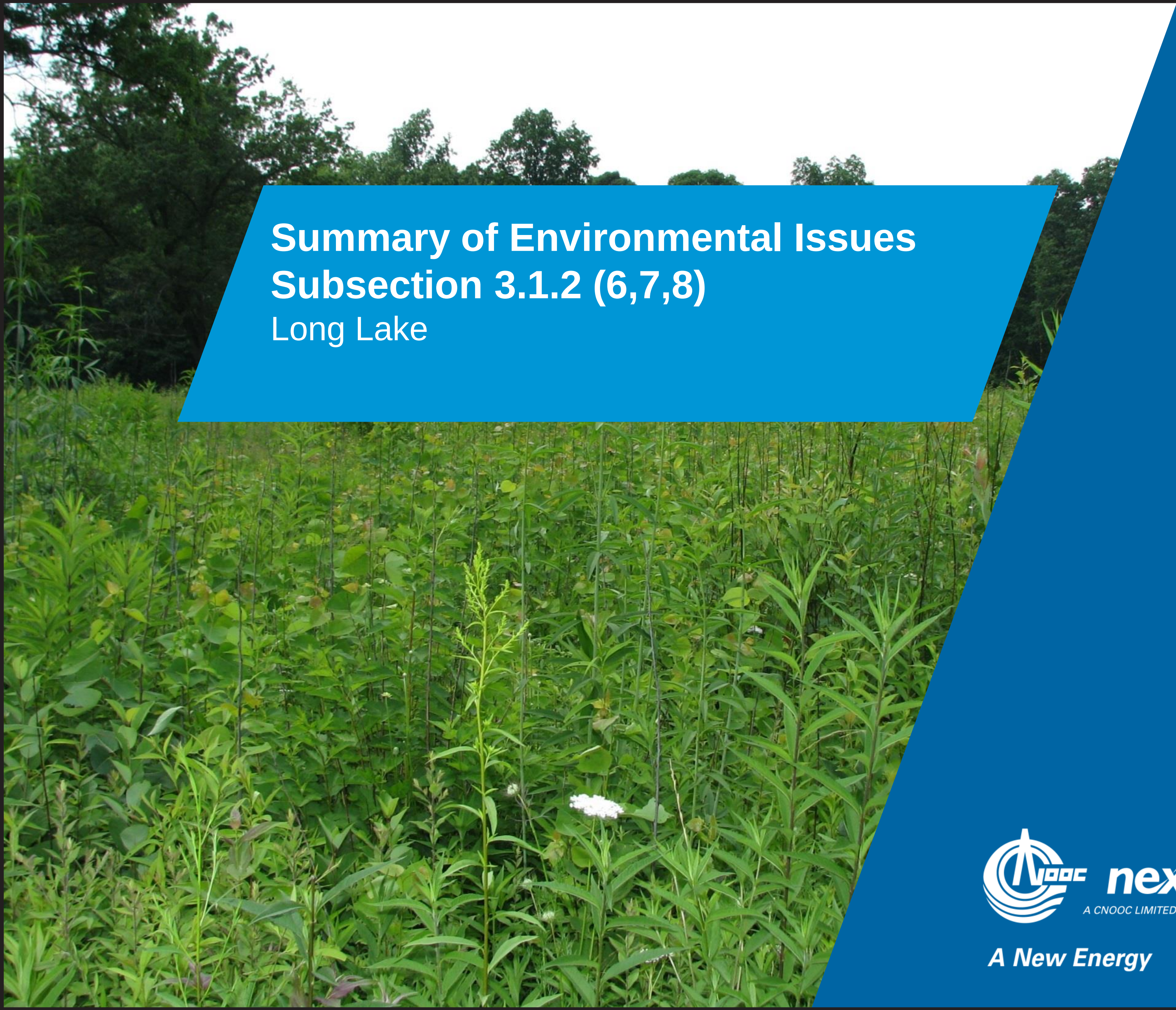
K1A SO_2 Passive Monitoring

- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2016.



Summary of Environmental Issues Subsection 3.1.2 (6,7,8)

Long Lake



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Compliance Statement

- To the best of Nexen's knowledge, the Long Lake Project is compliant with the conditions of its approvals and regulatory requirements subject to the items listed non-complaint in the summaries that follow.

Regulatory Compliance

- Inspections (23)
  - Satisfactory Inspections (22)
  - Unsatisfactory Inspections (1)
    - Waterworks approval (AEP)
- Voluntary Self Disclosures (4)
- Regulatory Notifications (6)
  - Pipeline Suspension Order Lifted (Nov. 10, 2016)

Compliance Discussion

Notification	Events that led to the non-compliance	Nexen action plan	Status
Notice of Noncompliance D013- Suspension requirements for 102/7-32-84-7W4 well May 5, 2016	Failure to downhole suspend a medium risk well by compliance deadline.	To bring this well into compliance Nexen decided to convert this disposal well to an observation well for the Keg River formation by landing a mini troll downhole. The Petrinex Well Status was updated accordingly on August 11, 2016 and No AER well licence amendment was required.	Compliance achieved August 15, 2016 – letter submitted to AER via email confirming corrective action taken.
Notice of Noncompliance D013 - Suspension requirements for 00/16-30-085-06W4 well June 3, 2016	Failure to submit inactive well inspection by the compliance deadline.	Nexen performed and submitted the inspection in the DDS system .	Compliance achieved June 25, 2016
Notice of Noncompliance D013 - Suspension requirements for 100/2-15-080-10W4 well March 15, 2016	Failure to submit inactive well inspection and classification by the compliance deadline.	Nexen submitted the inspection and classification in the DDS system.	Compliance achieved April 4, 2016
Notice of Noncompliance D013 - Suspension requirements for various wells April 29, 2016	Failure to bring 45 wells into compliance - with the IWCP program Nexen must bring 12 into compliance by March 17, 2017.	Nexen has brought more than 12 wells into compliance.	Compliance achieved February 1, 2016
AER issued an investigation letter on small fire at well 10-20-84-06W4 Lic # 0165412 to better understand the details on well control and a gas release due to the Alberta Wildfires that swept through the area, Nexen reported a gas release and a well incident (FIS 20161682). June 24, 2016	Naturally occurring wildfires.	Nexen conducted the required inspections and provided all requested data to the AER.	Compliance achieved July 13, 2016

Compliance Discussion - VSDs

Voluntary Self Disclosure	Events that led to the non-compliance	Nexen action plan	Status
VSD submitted for 5 K1A Pipelines not having been discontinued after 12 months of no active service, contrary to section 82(1) of the Pipeline Rules.	Events that led to the non-compliance include: a failure to properly identify and action the regulatory requirement to formally discontinue the flowlines from service; contractor evaluation and technical review of proposed chemical cleaning strategy; decision to evaluate the need for emulsion system cleaning via third party review; and wildfires.	Nexen completed the work to discontinue the pipelines.	Compliance achieved January 16, 2017
June 16, 2016 Nexen advised the AER of unauthorized perforations above the Base of Ground Water Protection (BGWP) at the well 100/05-07-084-06W4 Lic# 0195119 that were unknown to Nexen and were discovered as a result of a D13 review. On August 16, 2016 Nexen submitted a VSD of the findings.	Nexen acquired this well from another operator and discovered the un-reported downhole work and casing failure while trying to suspend the well under IWCP.	Nexen will abandon the well in accordance with Directive 020 by February 28, 2017. Legacy well data and casing failure incident submitted to AER July 2016. AER granted extension for casing failure repair until March 31, 2017.	March 7, 2017 - Casing Failure Resolution. March 16, 2017 - Well Abandoned in accordance with Directive 020.
June 21, 2016 Nexen notified the AER of its failure to obtain the appropriate Directive 056 well licence on a phantom well 100/5-32-85-6W4.	Oversight of required documentation when skidding to a new well.	Submit well licence application in accordance with Directive 056 by July 25, 2016. File all required well data to the AER in accordance with Directive 059.	Compliance achieved July 25, 2016
October 28, 2016 Nexen formally advised the AER of a non-compliance situation in which a historical Oil Sands core hole at 1AA/15-27-084-07W4 Lic # 0348171 was physically equipped and converted to an observation well. Nexen did not file a license amendment as required by Directive 056. Nexen also determined that the well data filed to the AER was incorrect .	Oversight when converting the well from core hole to observation	Submit well licence amendment application in accordance with Directive 056 no later than November 28, 2016. Upon receipt of the well licence amendment, submit the lahee re-classification request and all required well data to the AER. Update Well Status to observation in Petrinex. .	Compliance achieved November 24, 2016.

Environmental Regulatory Compliance

Permit Violations Summary	2013	2014	2015	2016
	98	52	47	83

- Identification of venting events is determined by the PSV set point versus the practice of visual confirmation which resulted in an increase in reporting.
- A number of non-compliances were incurred as a result of the 2016 wildfire.

Reportable Spill Summary	2013		2014		2015		2016	
	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)
	20	548	17	1551	26	5937	7	**120**

- Total number of reportable spills are down from previous years and the volume released from reportable spills are down.

*Volumes include liquid and solid reportable releases

Reportable Spills

- Jan.28, 2016 - 70 m^3 Boiler feed water leak.
- Feb. 6, 2016 - 0.4 m^3 Disposal Water leak at a pigging station at the pilot plant (pipeline leak).
- Feb. 18, 2016 – 30 l Citric Acid leak from 10" Chiller return line after cleaning of chiller water system (refined product).
- Apr. 8, 2016 – 10 m^3 fitting on discharge of lime sludge pump broke, spilling water/lime sludge mixture to grade.
- Jun. 28, 2016 – 400 l poly spill out side of 8200 IGF building.
- Aug. 30, 2016 - Seal failure at the fresh water pump building caused ~5 m^3 fresh water spill .
- Nov. 25, 2016 -10 m^3 during troubleshooting on 9-12 WSW flow transmitter 9351-FIT-100 internals came out of the live process line, resulting in release of fresh water to grade (off lease).

Other Non-Compliances

Section 2.2 of the Nexen Water Act License 00235895-01-00: The Licensee shall not deposit or cause to be deposited any substance in, on or around the source of water that has or may have the potential to adversely affect the source of water.

- In recent years Nexen has reported multiple events where, due to faulty check valves, fresh water wells have experienced backflow from the common header into individual fresh water wells.
- Although there was only one backflow event in 2016, a trend has shown that the integrity of the current equipment used to prevent backflow was starting to show failure. In response to the backflow issues on the fresh water system, Nexen is working to complete a documented review of the status of all the fresh water wells in order to eliminate the need to isolate the valves when they are not operating. Nexen will replace all faulty check-valves (2 per well) on the fresh water system and evaluate the others to determine a path forward. Nexen has also initiated a preventative maintenance schedule that will have all check valves replaced every 5 years (current valves are approximately 10 years old). Until all faulty check valves are replaced any wells with known valve leaks that remain outstanding for replacement will be isolated at the block valves when the well is purposely down or if the wells trip and the CRO is unable to restart the well for any reason.

AER Scheme Approval

- Amendments Approved in 2016:
  - Long Lake Southwest Modifications - approved Mar. 31, 2016.
  - Request for Temporary Modification of Pads 12, 13, 14, and 15 Monitoring Program as a Result of Wildfire – approved Jun. 28, 2016.
  - Thermal Compatibility Review Well Pads 5 and 8 – approved Sep. 22, 2016.
  - Pad 14 and 15 Monitoring Plan Modifications (4D seismic deferral and maximum bottomhole pressure tapered schedule extension) – approved Nov. 16, 2016.

AER Scheme Applications

- Applications Under Review in 2016:
  - Application Pad 14 and 15 Maximum Bottomhole Injection Pressure Tapered Schedule Extension Request (approved Jan. 12, 2017).
  - Exception to Sulphur Recovery Clause (approved Jan. 30, 2017).
  - Application for Q-Channel Groundwater Management Plan (approved Mar. 8, 2017).
  - Application for Injection of Residual Emulsion (approved Mar. 22, 2017).

Environmental Summary
Monitoring Programs

- All monitoring programs were conducted in accordance with regulatory approvals and most plans have been updated in 2016 with the issuance of the new approval.
  - Groundwater monitoring
  - Hydrology and water quality monitoring
  - Soil monitoring
  - Wildlife monitoring
  - Wetland monitoring
  - Source emission and ambient air monitoring
  - Conservation and reclamation plans

Environmental Summary
Monitoring Programs

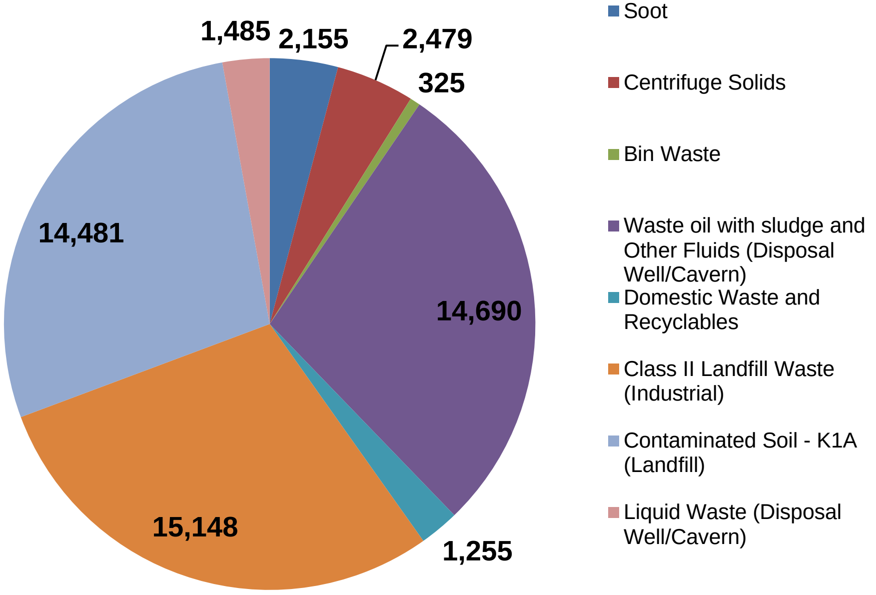
- Funded the regional Joint Oil Sands Monitoring (JOSM).
- Participation in regional stakeholder committees:
  - WBEA;
  - Alberta Biodiversity Monitoring Institute (ABMI);
  - Ecological Monitoring Committee for the Lower Athabasca (EMCLA).

Environmental Summary: Innovation, Research & Reclamation Initiatives

- Continued leadership in Canada's Oil Sands Innovation Alliance (COSIA) to accelerate the pace of environmental performance improvement.
  - Participation in the Land, Water, and Greenhouse Gas Environmental Priority Areas as well as the Monitoring working group.
  - Leading multiple Joint Industry Projects including caribou habitat restoration, reclamation practice studies, and wildlife monitoring technologies.

Waste Disposal

Hazardous Waste	tonnes
Soot	2,155
Centrifuge Solids	2,479
Bin Waste	325
Disposal Well/Cavern	14,690
Total	**19,649**
Non-Hazardous Waste	
Domestic Waste and Recyclables	1,255
Class II Landfill Waste (Industrial)	15,148
Contaminated Soil - K1A Spill (Landfill)	14,481
Disposal Well/Cavern	1,485
Total	**32,370**
Grand Total (Hazardous/DOW + Non-Hazardous/Non-DOW Waste)	**52,019**



Future Plans - Surface

- As a result of the Pipeline release and the Upgrader explosion Nexen is currently evaluating operating options which include:
  - SAGD only;
  - SAGD with an Upgrader; or
  - SAGD with modifications to the Upgrader.

- Options are also being evaluated in relation to repairing or replacing the K1A pipeline.

- Plans in place to replace the rental centrifuge with Nexen’s own centrifuge.

Appendix

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Well Pad Performance
Subsection 3.1.7(h)
Long Lake

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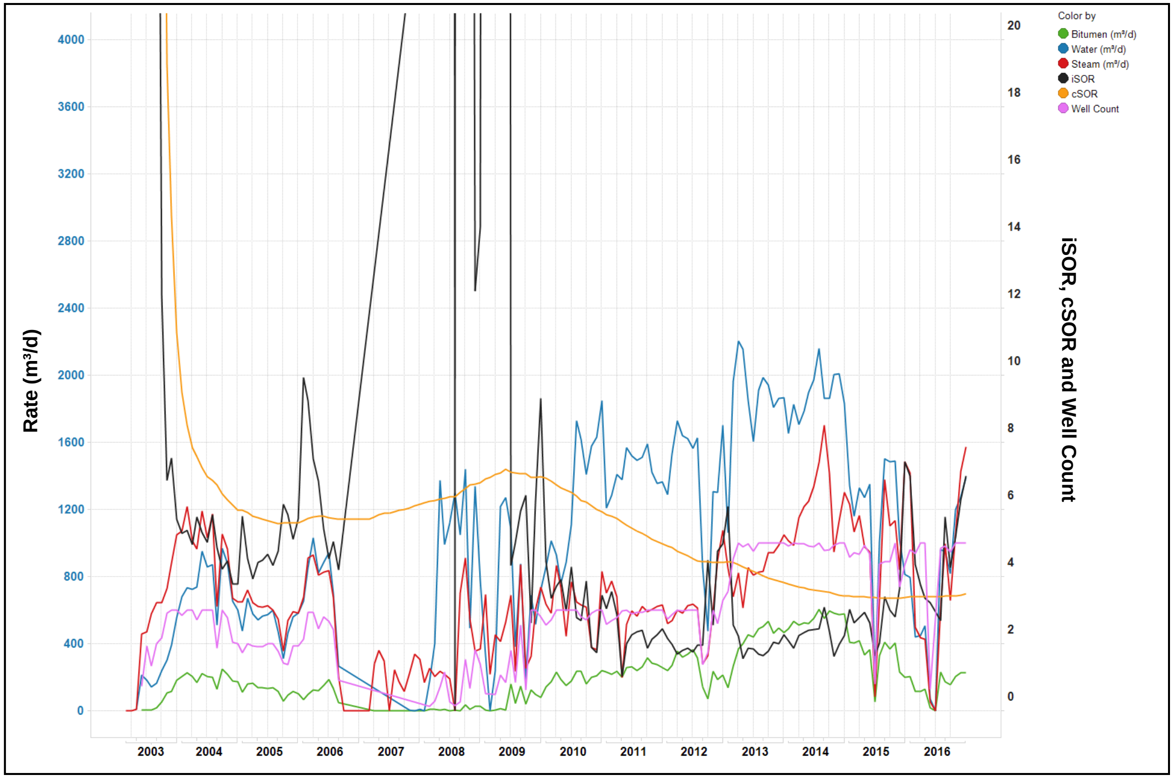
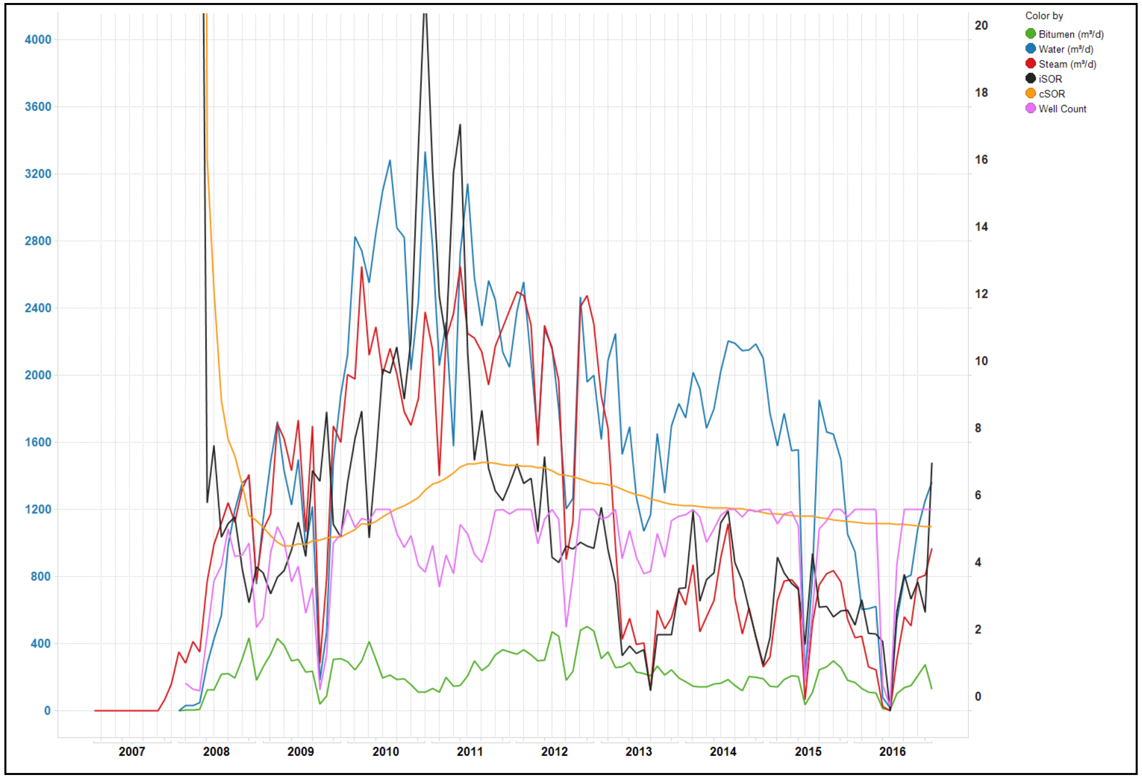
Pad 1 Production Summary



- All 5 wells on ESP
- Impact of inconsistent operating conditions on production performance as continuing to ramp up after wildfire outage at YE
- At YE, injection pressures were ~1,275-1,550 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 971 E^3m^3 (RF 43%)

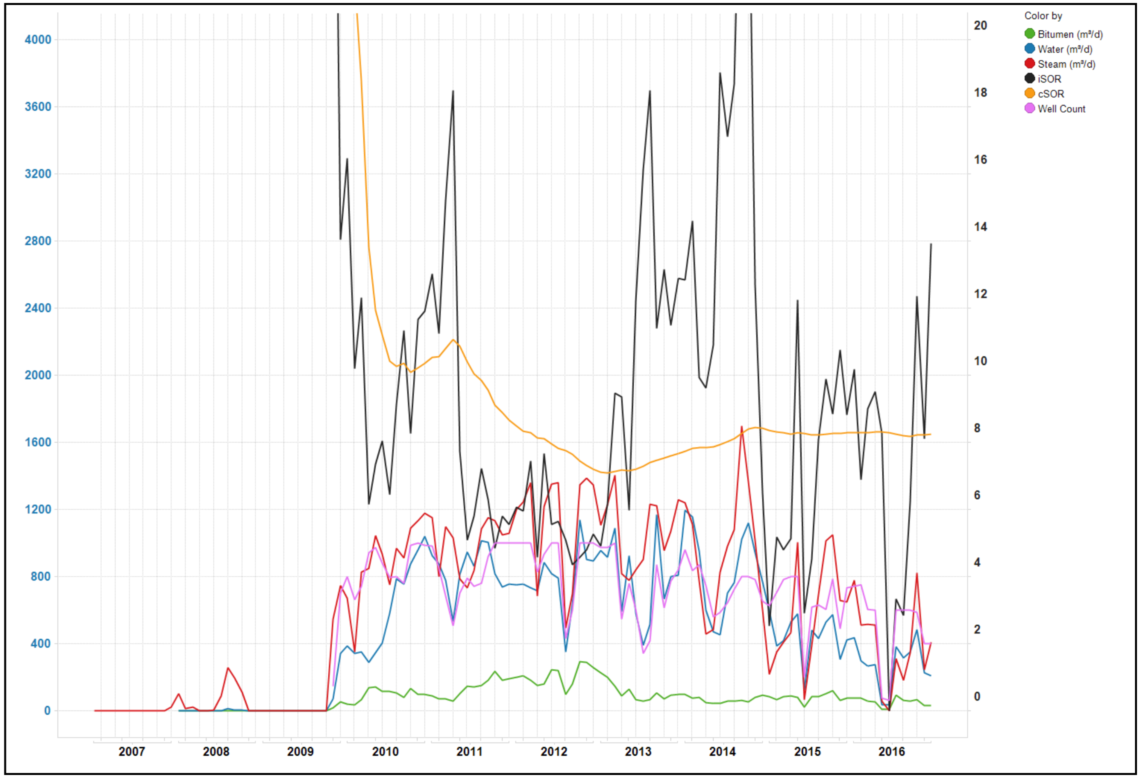
Pad 2NE Production Summary



- Six well pairs (02P01 to 02P06)
- Cumulative production of 727E^{3}m^3 (RF 29%)

- All 6 wells on ESP
- Steam SI to 02S04, 02S05 and 02S06 since Q1 2013
- Impact of inconsistent operating conditions on production performance as continuing to ramp up after wildfire outage at YE
- At YE, injection pressures were ~930 – 1,460 kPa

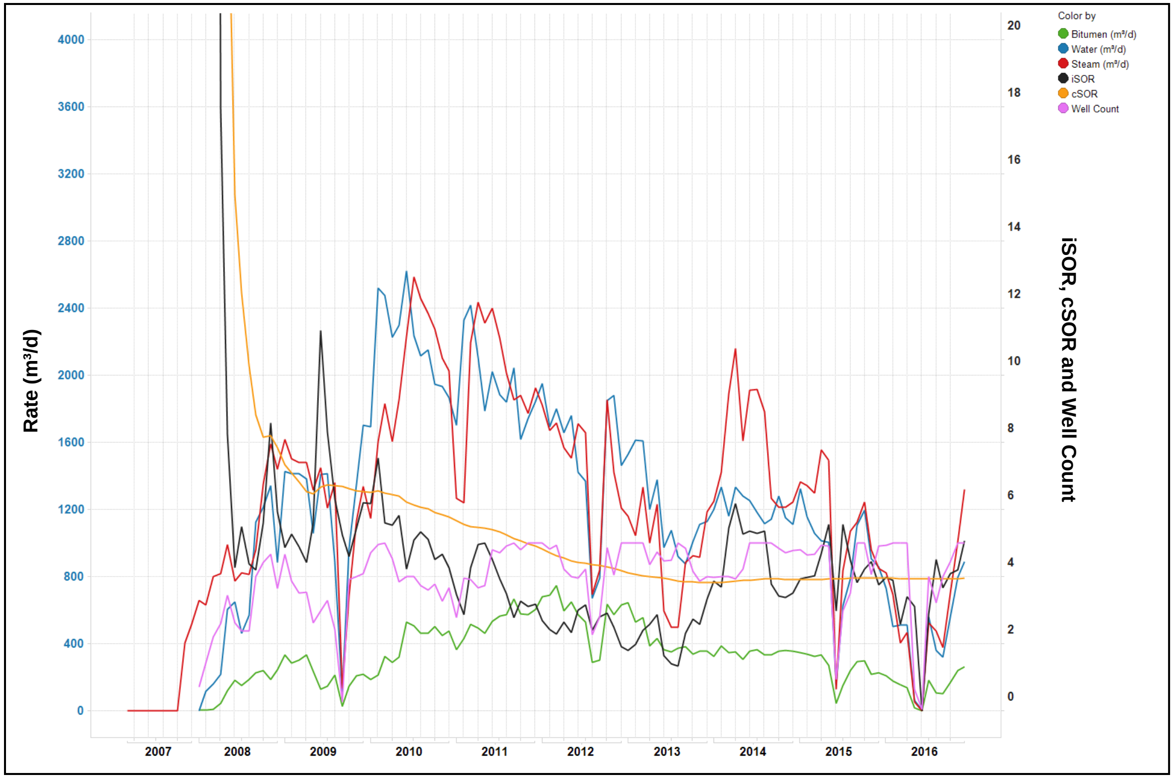
Pad 2SE Production Summary



- 2P8 - 2P10 on ESP
- 2P07 on PCP
- 02Pair11 SI due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,175 – 1,640 kPa

- Five well pairs (02P07 to 02P011)
- Cumulative production of $276E^3m^3$ (RF 23%)

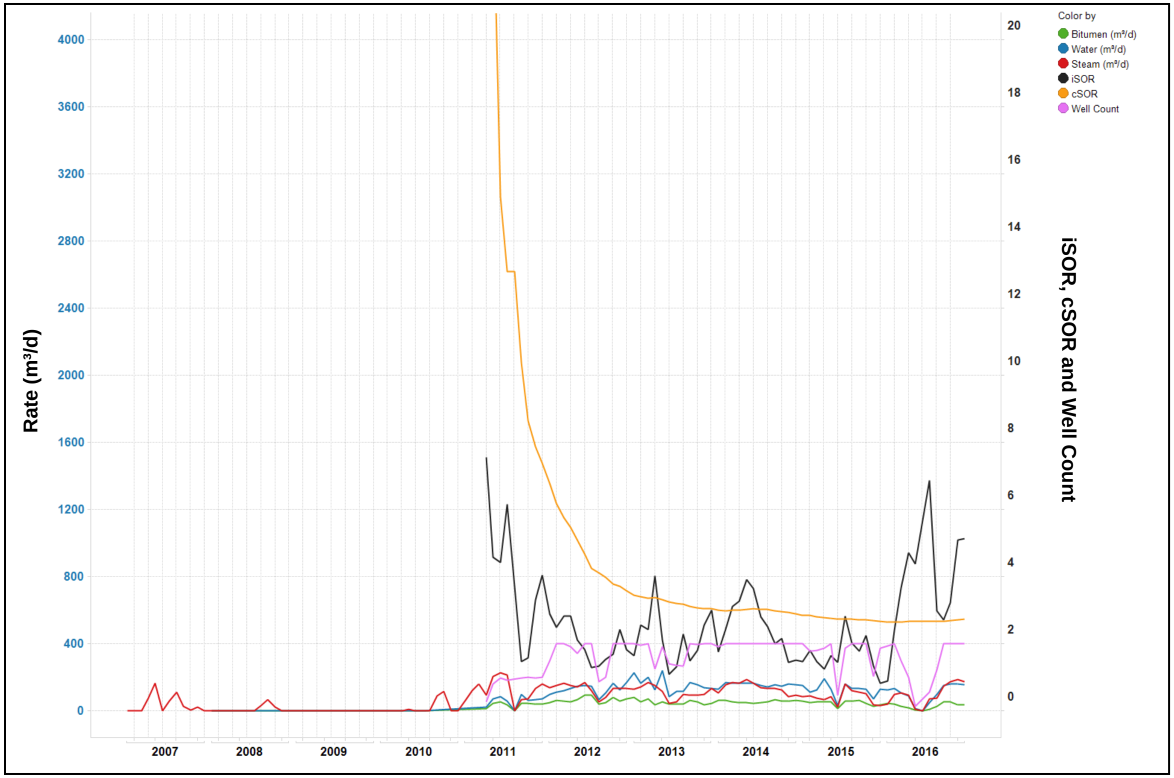
Pad 3 Production Summary



- All 5 wells on ESP
- Producers are showing strong performance as the pad continues to ramp up after wildfire outage
- At YE, injection pressures were ~1,270-1,500 kPa

- Five well pairs (03P01 to 03P05)
- Cumulative production of 1,102 E^3m^3 (RF 44%)

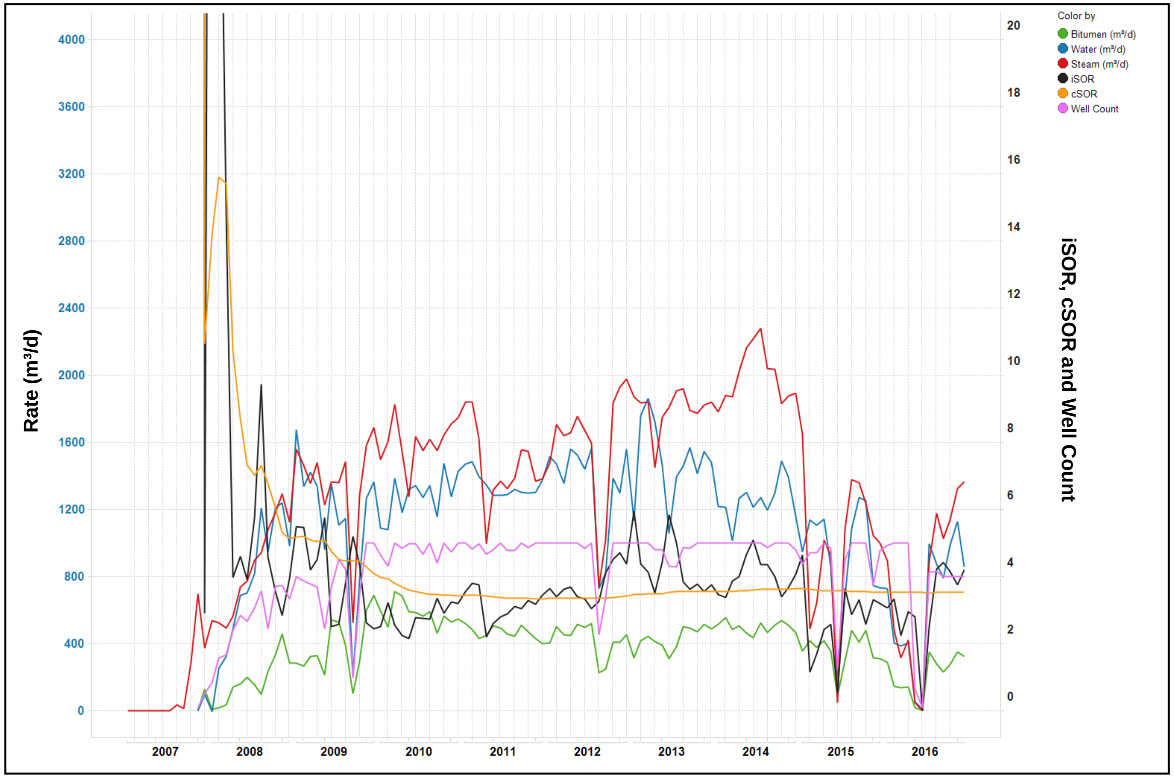
Pad 4 Production Summary



- All 2 wells on ESP
- Stable operation helped maintain production after wildfire outage
- At YE, injection pressures were ~1,175 – 1,425kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 100 E^3m^3 (RF 54%)

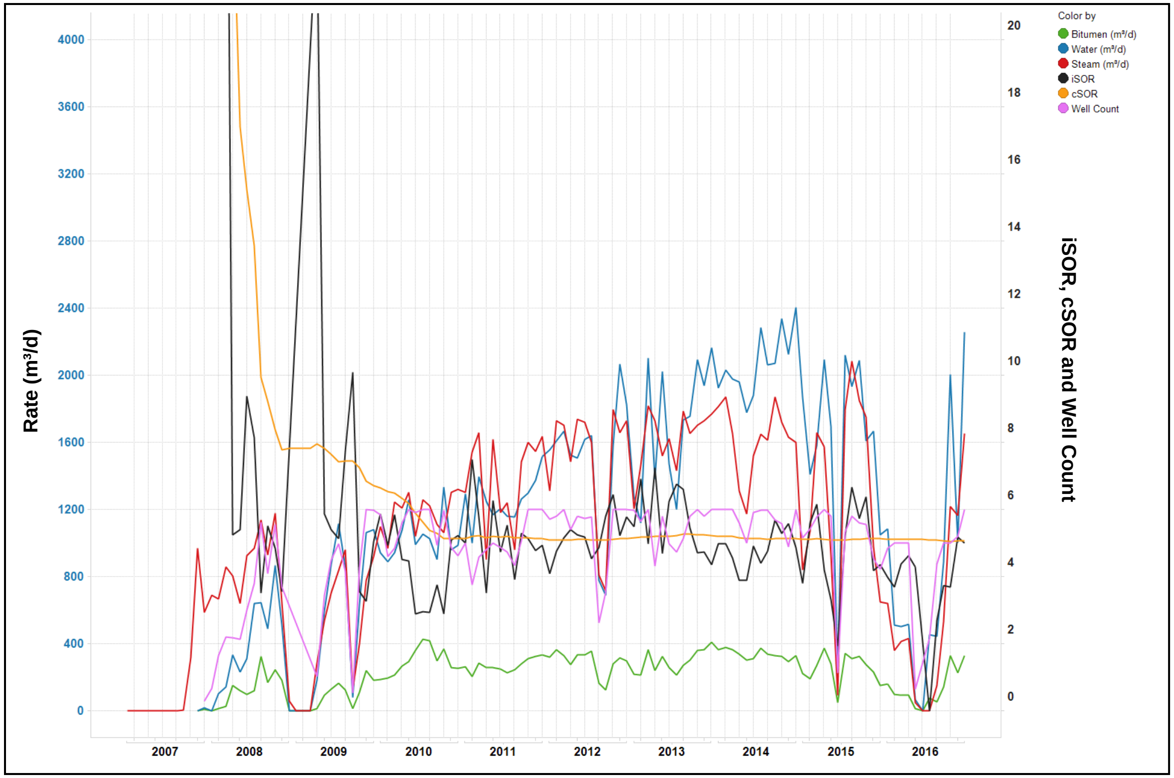
Pad 5 Production Summary



- Five well pairs (05P01 to 05P05)
- Cumulative production of 1,291 E³m³ (RF 41%)

- All 5 wells on ESP
- Steam was re-started to 05S04 and 05S05 in Q2 2016
- Producers are showing strong performance as the pad continues to ramp up after wildfire outage
- At YE, injection pressures were ~1,230–1,500kPa

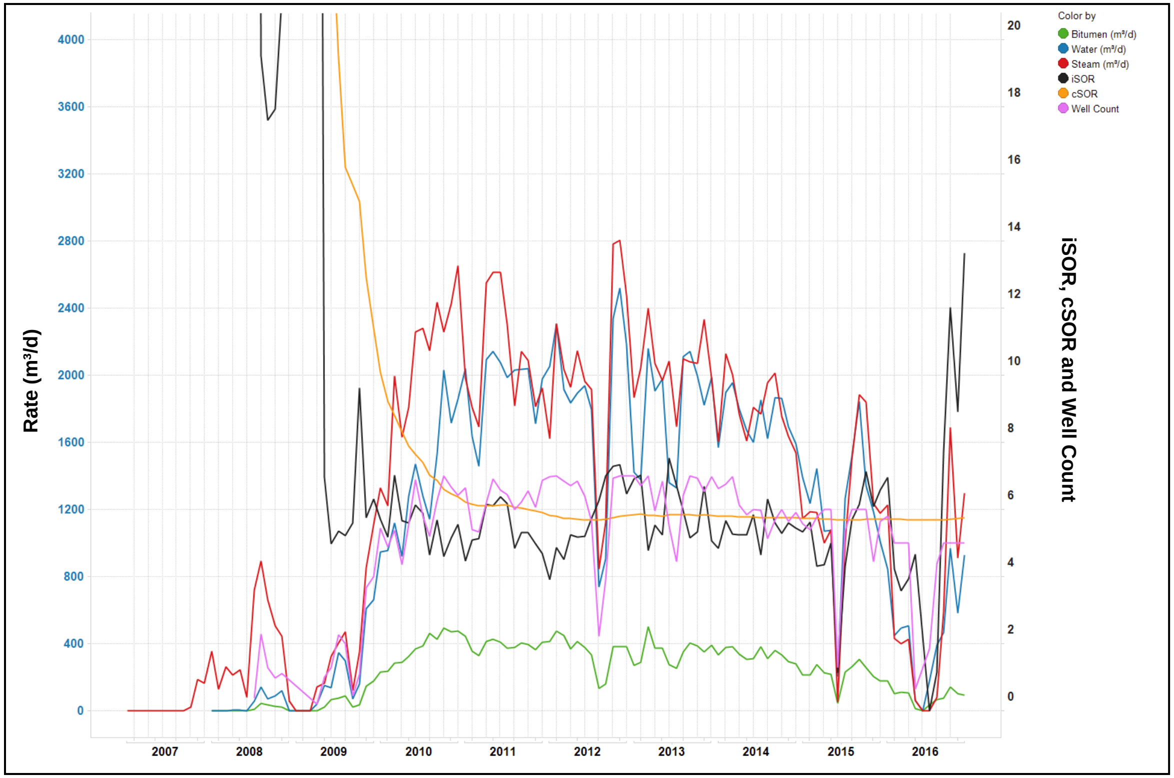
Pad 6N Production Summary



- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 762 E^3m^3 (RF 26%)

- All wells on ESP
- 3 wells with inconsistent operating strategy in 2016 (6S1,6S3 and 6P4)
- 6P4 plugged back due to poor reservoir quality at toe
- At YE, injection pressures were ~1,700–1,800kPa

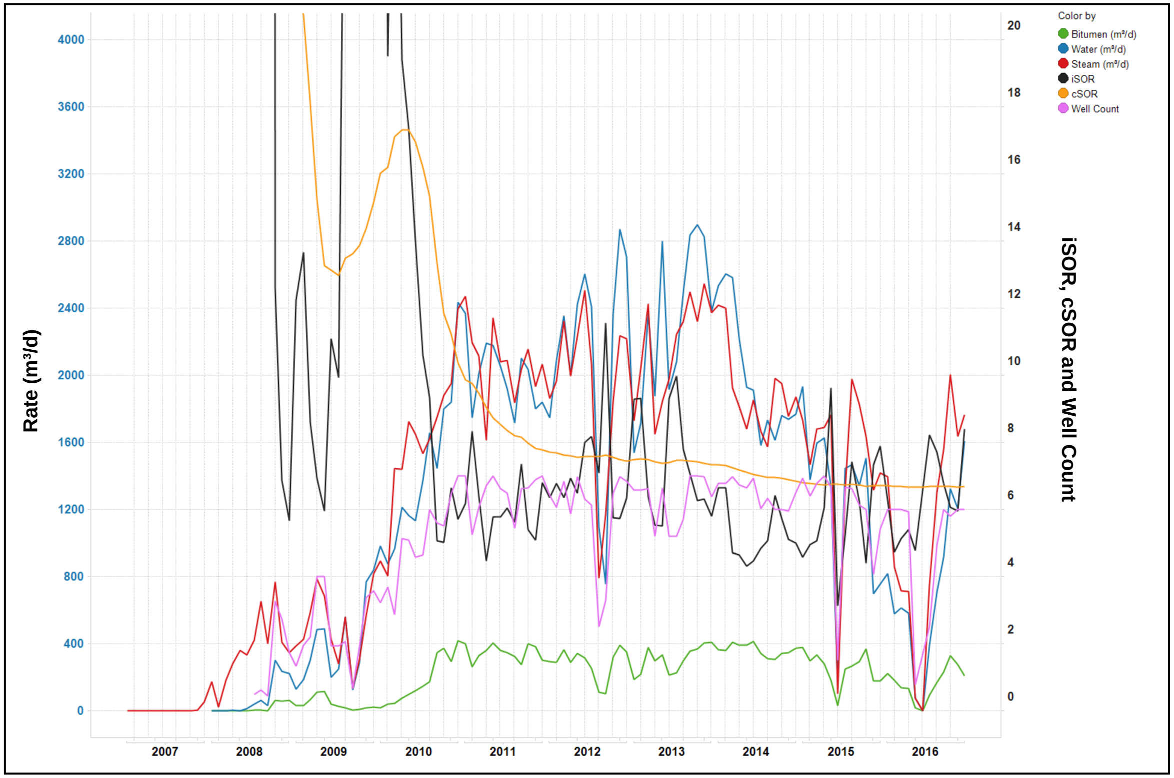
Pad 6W Production Summary



- Seven well pairs (06P06 to 06P12)
- Cumulative production of 795E³m³ (RF 42%)

- All 7 wells on ESP
- 6P06 shut in for ESP failure during 2016, replacement planned in Q1 2017
- Several liner failures historically
- 6P12 shut in due to potential liner failure in April 2014
- At YE, injection pressures were ~1,470–1,975 kPa

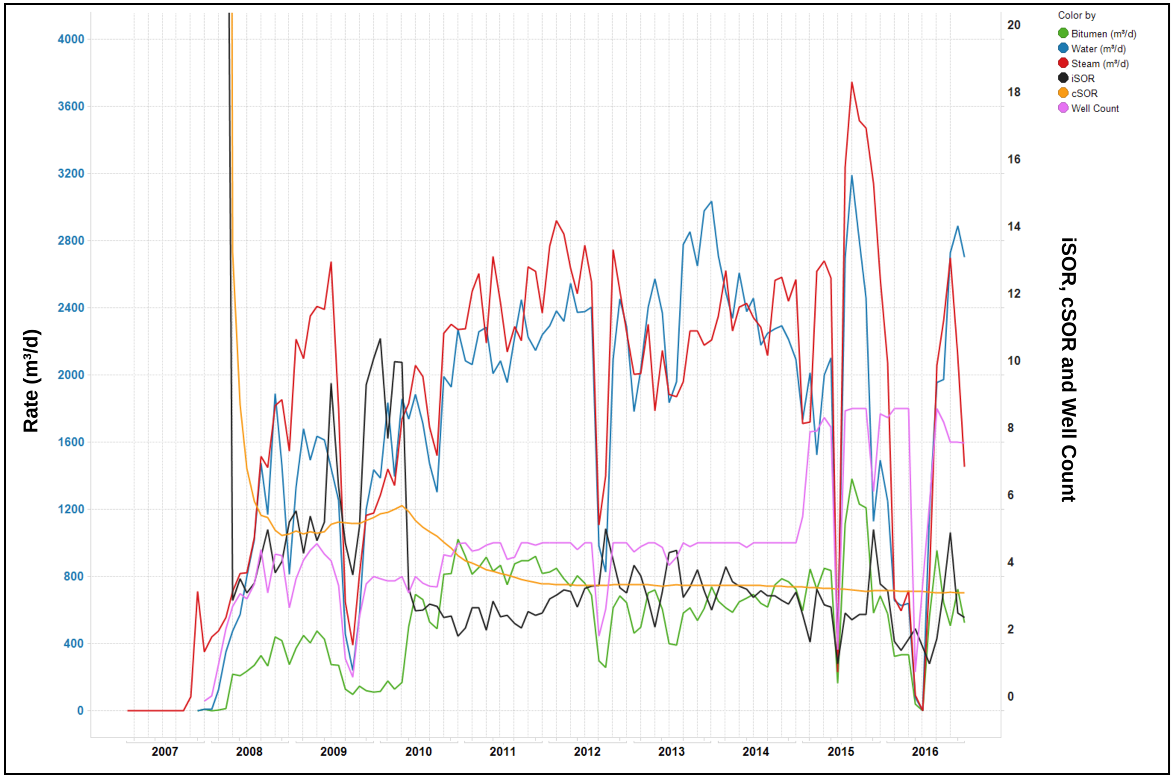
Pad 7E Production Summary



- All 7 wells on ESP
- Stable operation
- Continuing to see strong performance from northern well pairs
- NCG co-injection has not been restarted since 2015 turnaround
- 07P12 shut in due to potential liner failure
- At YE, injection pressures were ~1,425–2,050 kPa

- Seven well pairs (07P06 to 07P12)
- Cumulative production of 715E^3m^3 (RF 39%)

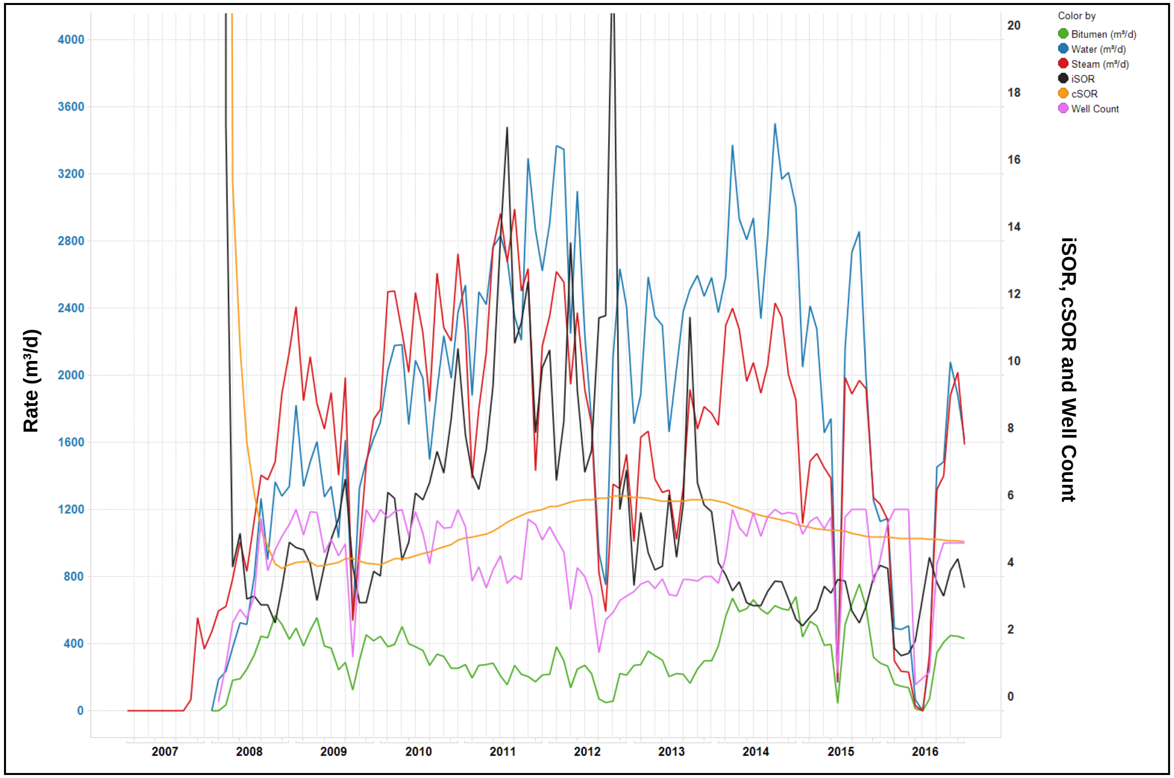
Pad 7N Production Summary



- Five well pairs (07P01 to 07P05)
- Four infill producer wells (10P14 to 10P17)
- Cumulative production of 1,862 E^3m^3 (RF 57%)

- All 9 wells on ESP
- Infill producer wells (drilled in 2014) ramped up after steam squeeze – one well started up without steam squeeze
- Strong performance from infill producer wells
- Completed construction for proposed NCG co-injection pilot project
- NCG co-injection being reassessed
- Increased steam injection to support infill producer wells and neighboring Pad 8
- At YE, injection pressures were ~1,600 – 1,775 kPa

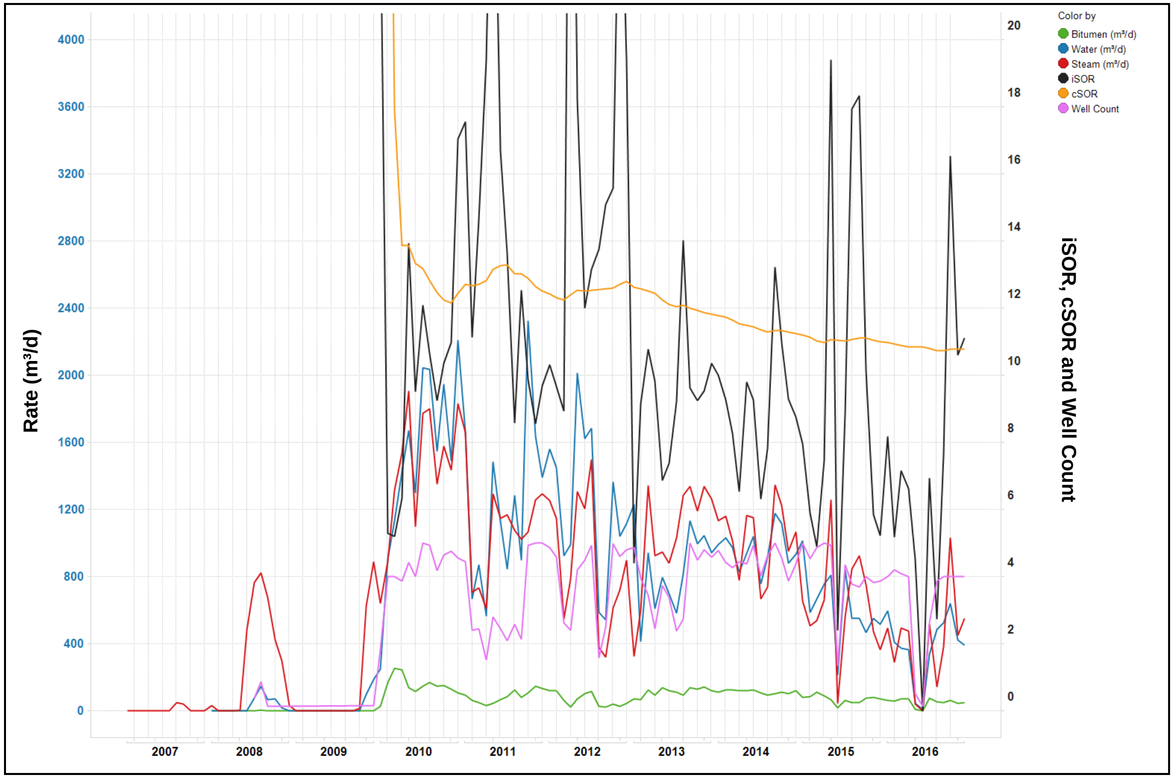
Pad 8 Production Summary



- All 6 wells on ESP
- 08S06 shut in after potential liner failure
- No observed negative impact to 08P06 production
- Increased injection on 08S05 to support 08P06
- ICD's installed on 08P03
- At YE, injection pressures were ~1,550–1,775 kPa

- Six well pairs (08P01 to 08P06)
- Cumulative production of 1,096 E^3m^3 (RF 34%)

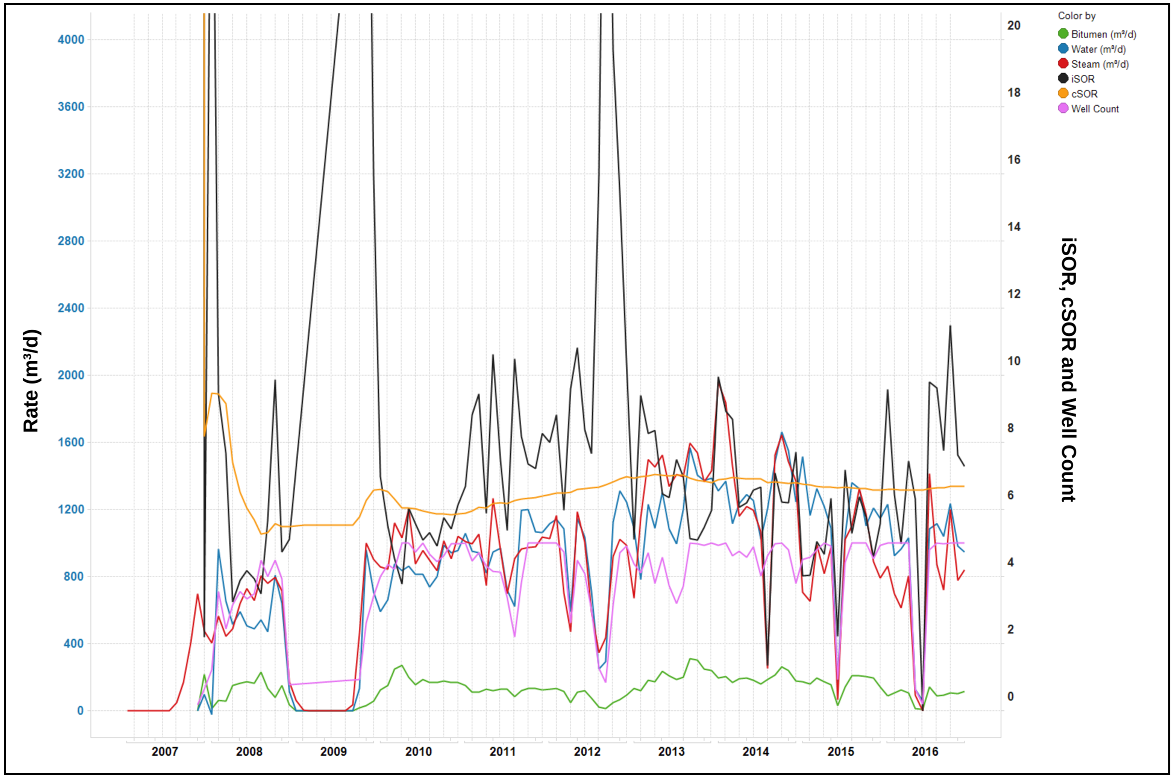
Pad 9NE Production Summary



- All 5 wells on ESP
- 9P07 plugged back at toe due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,225 – 1,325 kPa

- Five well pairs (09P06 to 09P10)
- Cumulative production of $235E^3m^3$ (RF 19%)

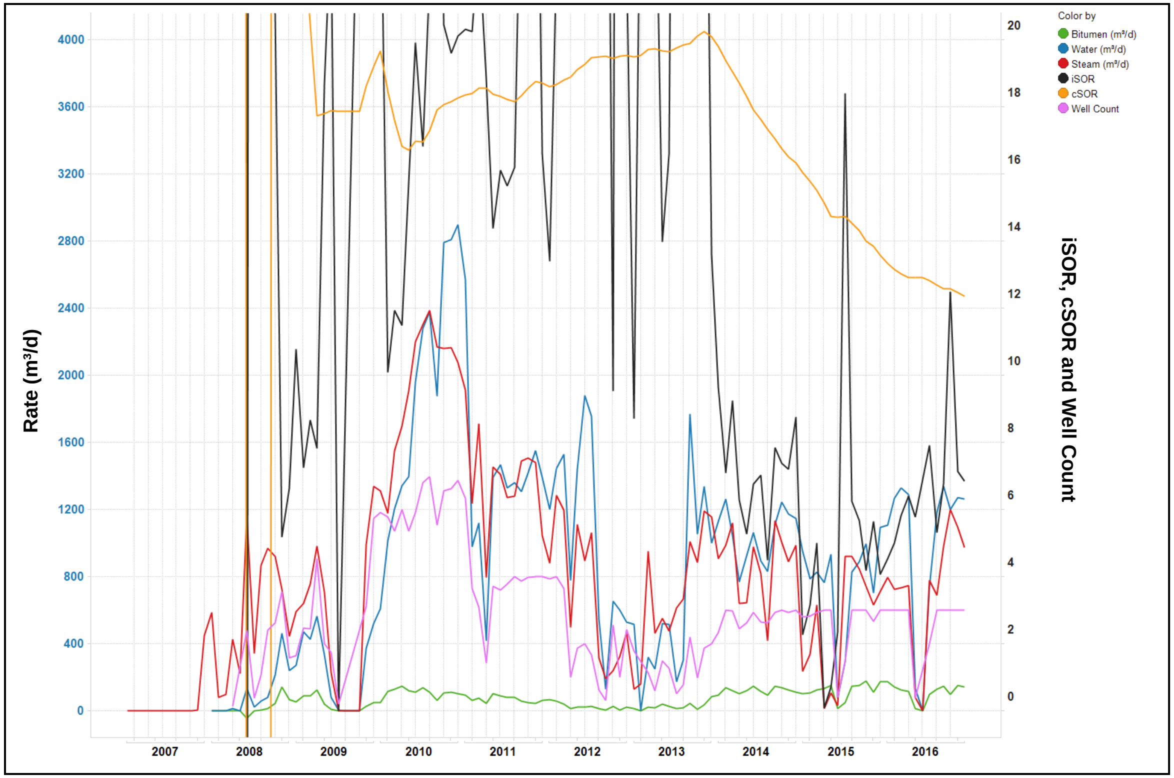
Pad 9W Production Summary



- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- Oil rate declined after AGAR calibration
- Unstable operation due to low priority on 9P4 and 9P5
- At YE, injection pressures were ~1,650 - 1,800 kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 438 E^3m^3 (RF 27%)

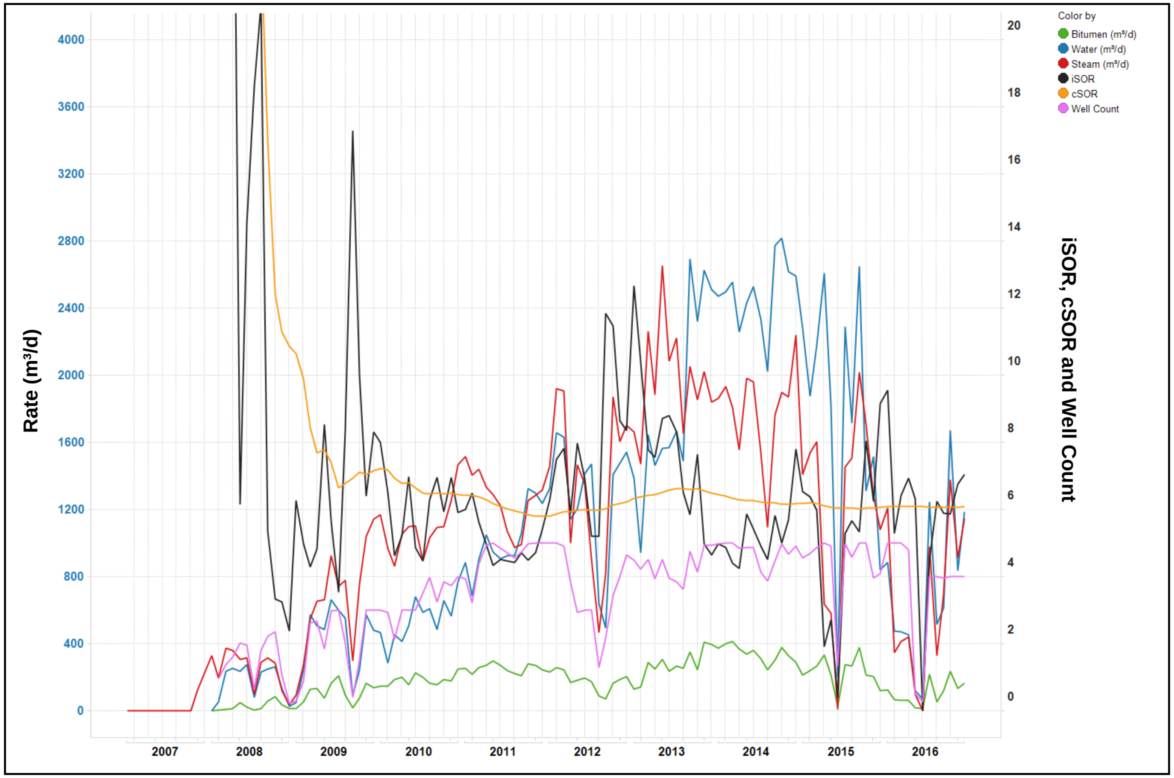
Pad 10N Production Summary



- All wells on gas lift
- Oil cut has improved steadily throughout the lives of the wells, resulting in improved bitumen production
- At YE, injection pressures were ~2,000 kPa

- Three well pairs producing (10P10 to 10P12)
- Cumulative production of 190E^{3}m^3 (RF 19%)

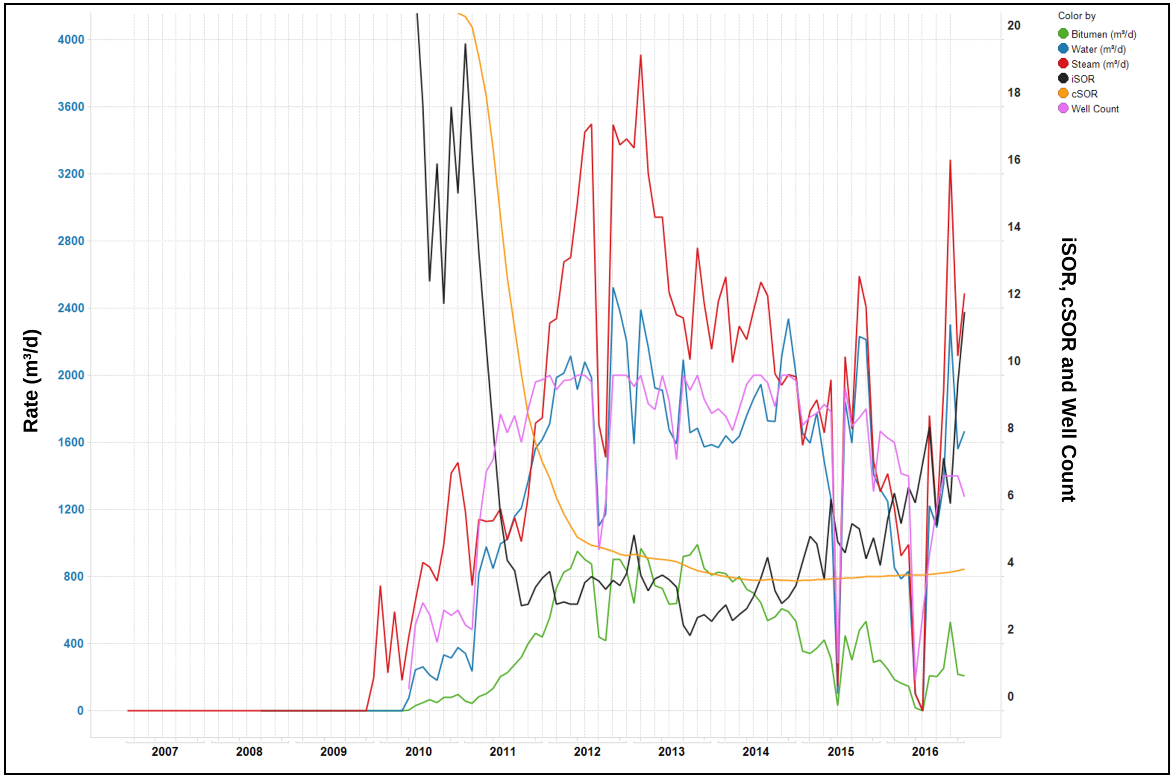
Pad 10W Production Summary



- All 5 wells on ESP
- Stable operation
- Performance impacted by top water WSR > 1.0
- At YE, injection pressures were ~1,675–1,750 kPa

- Five well pairs (10P01 to 10P05)
- Cumulative production of 620E^{3}m^3 (RF 28%)

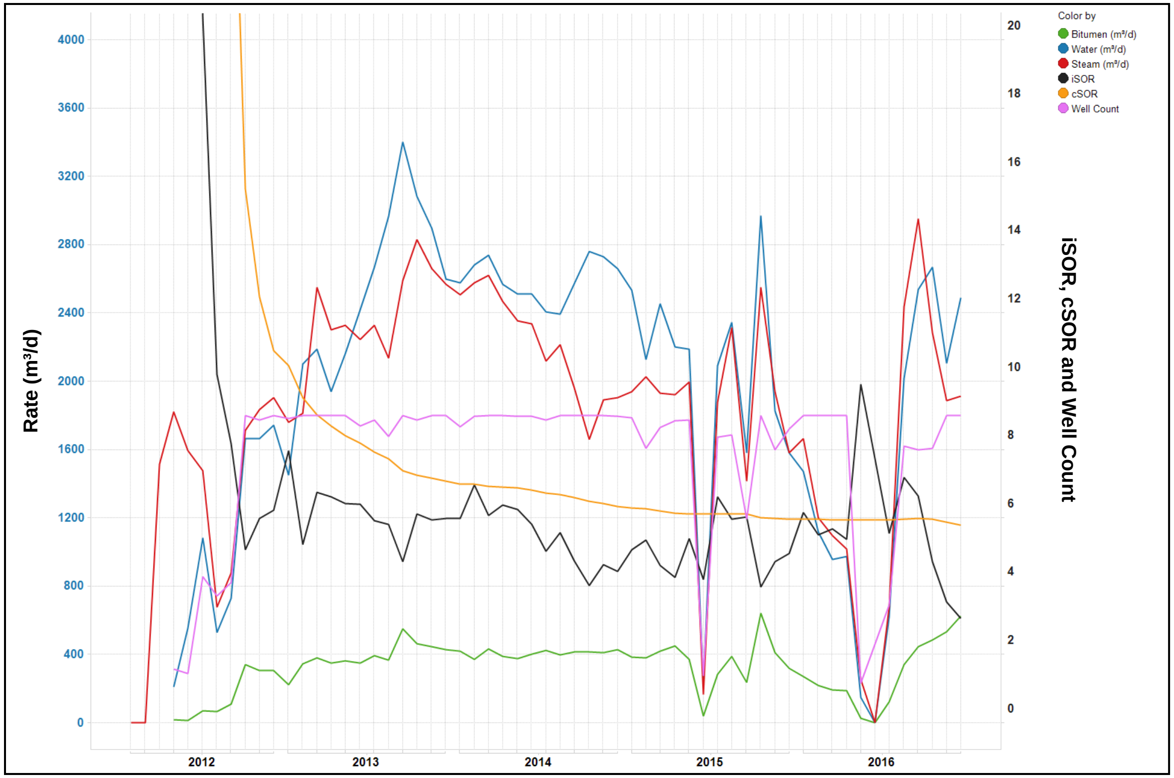
Pad 11 Production Summary



- Ten well pairs (11P01 to 11P10)
- Cumulative production of 1,122E³m³ (RF 49%)

- All 10 wells are on ESP
- Pad in possible decline phase
- 11S08 shut in since steam kick during workover in Q3
- Liner failure on 11P02 repaired with liner and packer assembly
- At YE, injection pressures were ~1,675–1,800 kPa

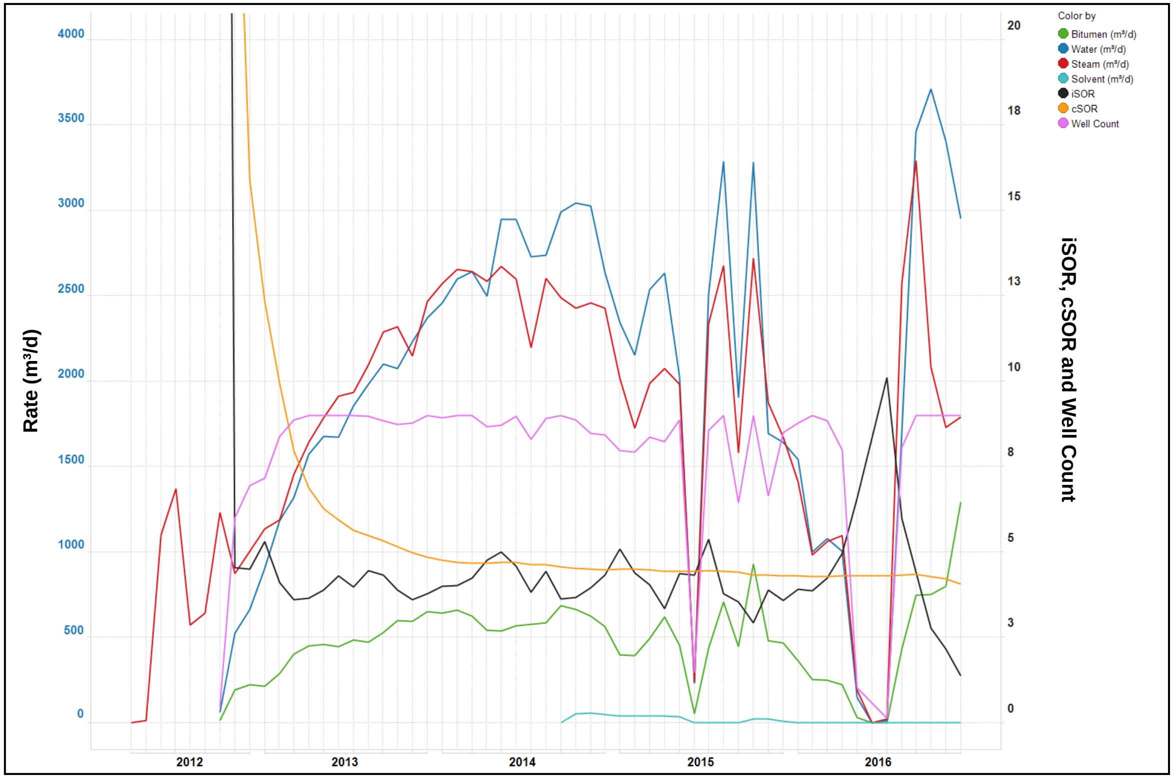
Pad 12 Production Summary



- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- At YE, injection pressures were ~1,750–1,875 kPa

- Nine well pairs (12P01 to 12P09)
- Cumulative production of $564E^3m^3$ (RF 17%)

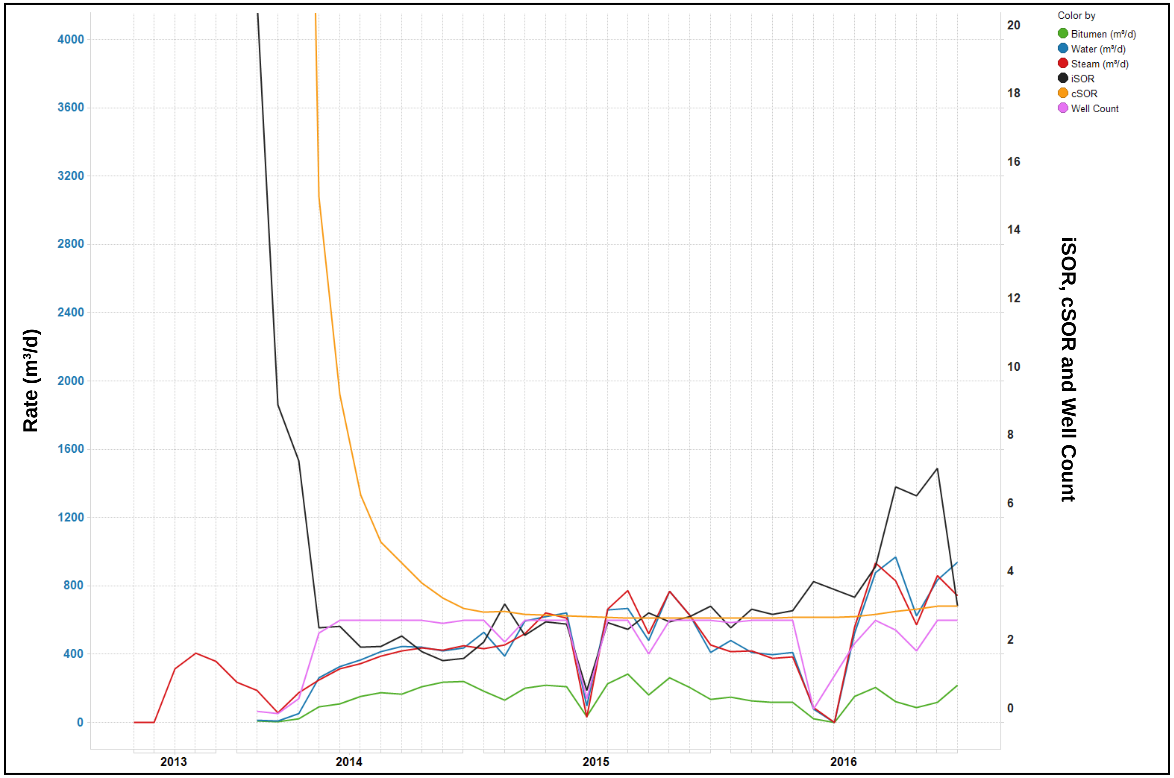
Pad 13 Production Summary



- Nine well pairs (13P01 to 13P09)
- Cumulative production of 741E^{3}m^3 (RF 23%)

- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone and facility constraints
- Initiated ES-SAGD project at wells 13P3 and 13P4 in October, 2014. Limited solvent injection following 2015 Turnaround due to facility constraints
- At YE, injection pressures were ~ 1,700–1,800 kPa

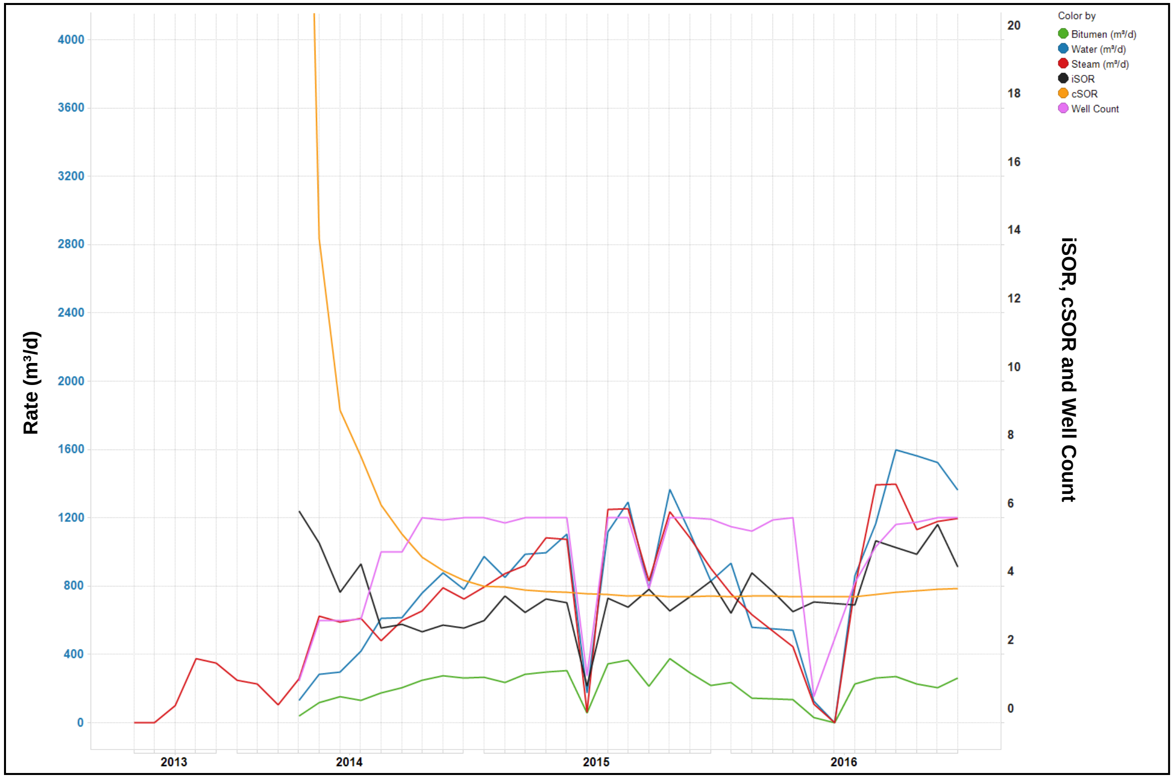
Pad 14N Production Summary



- All 3 wells on ESP
- All wells on ramp-up
- At YE, injection pressures were ~ 2,250kPa

- Three well pairs (14P05 to 14P07)
- Cumulative production of 156 e^3m^3 (RF 11%)

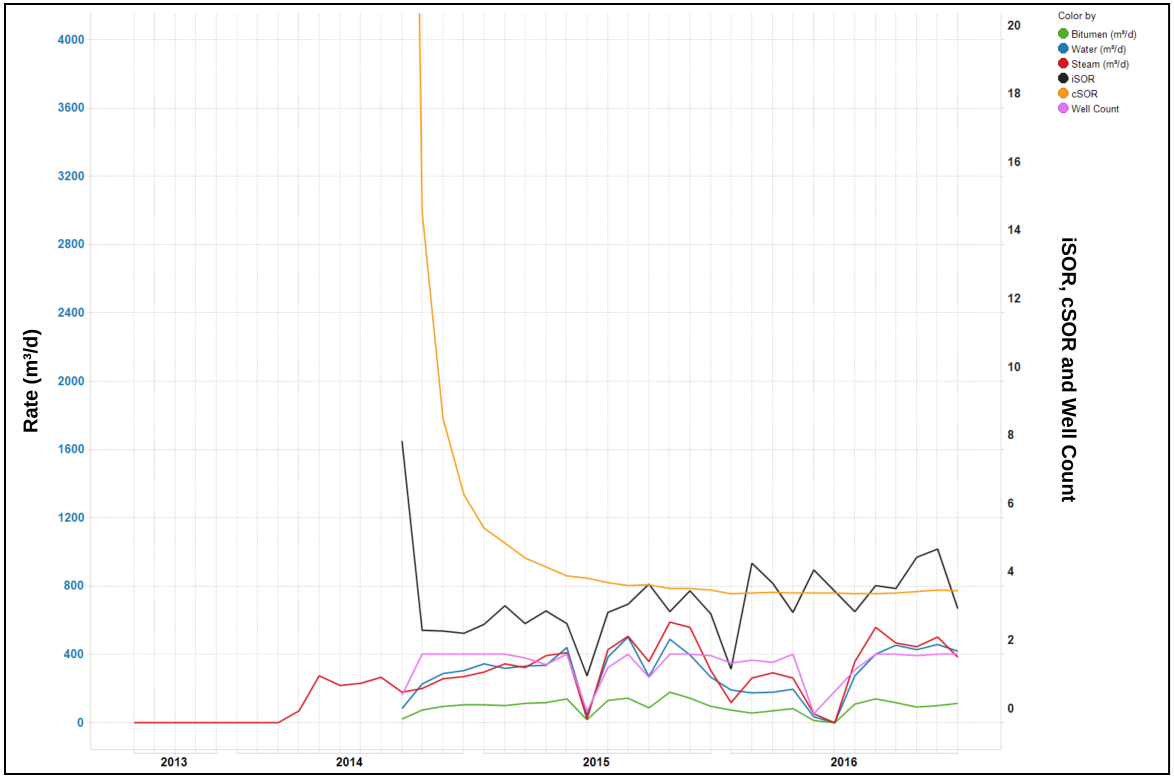
Pad 14/15E Production Summary



- All 6 wells on ESP
- 14P02 liner failure in 2016
- Wells demonstrating ramp up or plateau
- At YE, injection pressures were ~2,250kPa

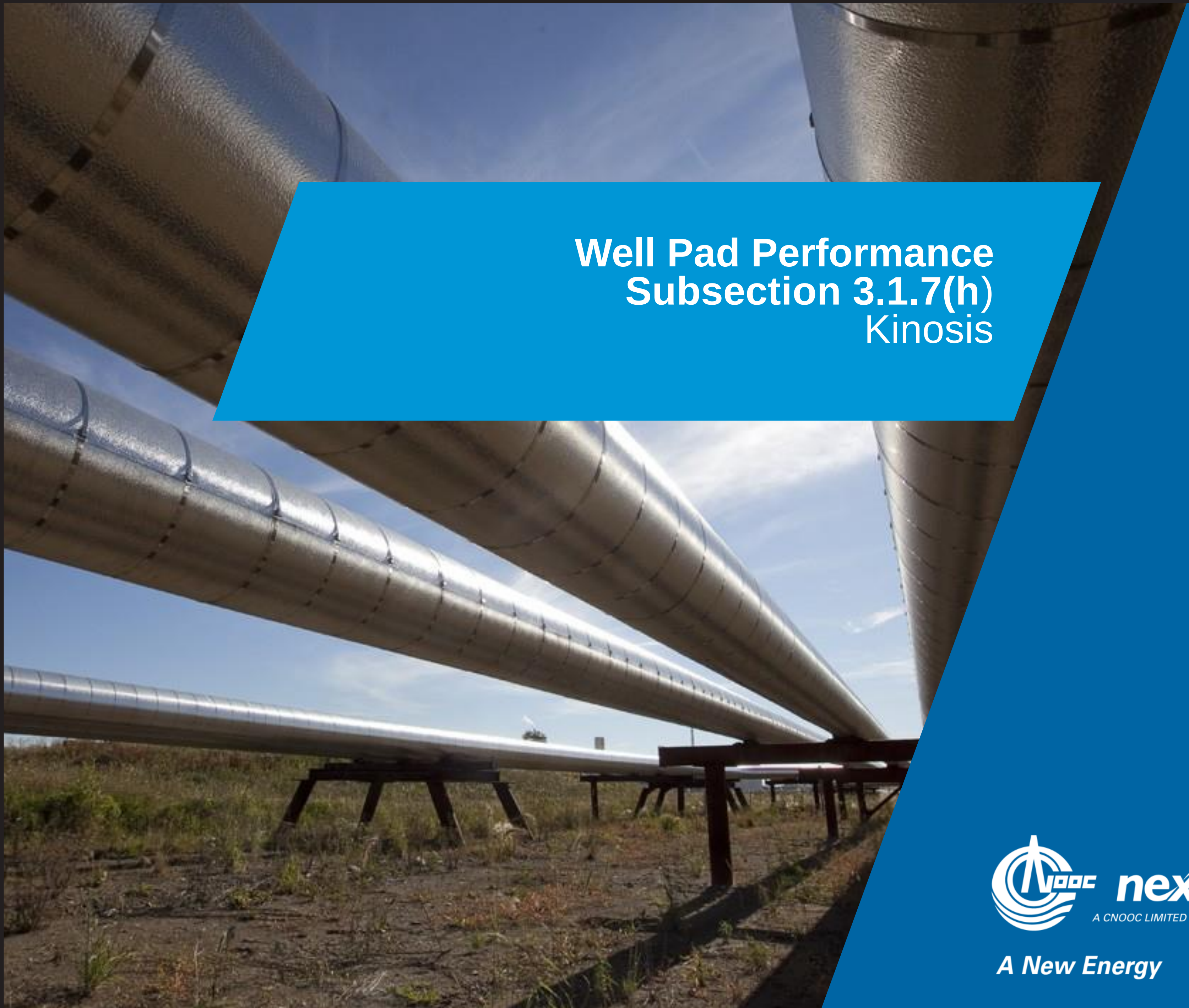
- Six well pairs (14P01 to 14P03 and 15P01 to 15P03)
- Cumulative production of 215 e^3m^3 (RF 17%)

Pad 15S Production Summary



- Both wells on ESP
- All wells on ramp-up and continuing to build to target pressure following wildfire
- At YE, injection pressures were ~ 1725 - 1,775kPa

- Two well pairs (15P04, 15P05)
- Cumulative production of 81 e^3m^3 (RF 12%)



Well Pad Performance
Subsection 3.1.7(h)
Kinosis

nexen
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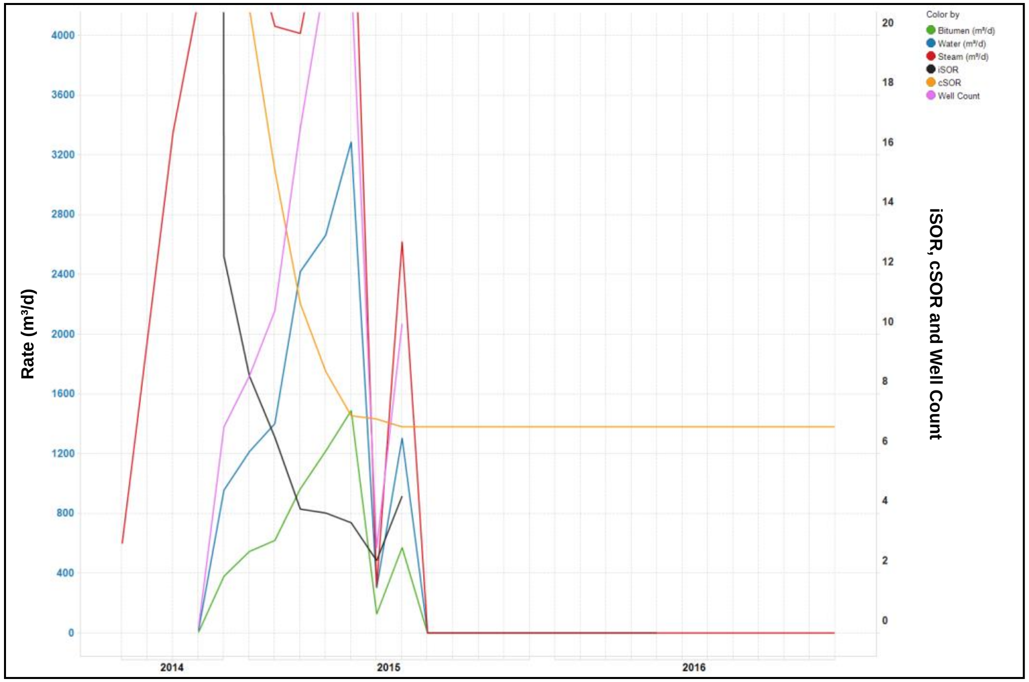
K1A Production Summary



- All wellpairs inactive
- K1P09 shut-in

- 22 well pairs
- Cumulative production of 181 e^3m^3 (RF 1%)