Long Lake Kinosis Oil Sands Project Annual Performance Presentation

April 2018

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

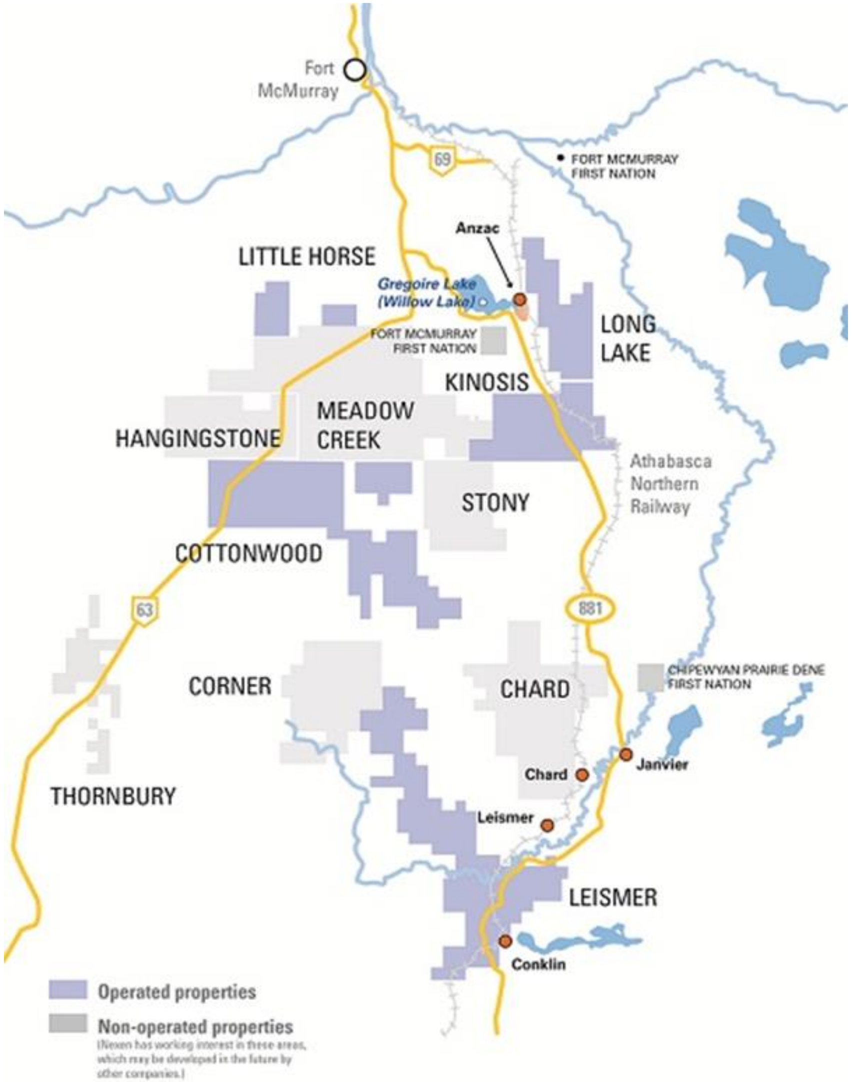
This document was prepared and submitted pursuant to Alberta regulatory requirements. It contains statements relating to reserves which are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the described reserves exist in 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

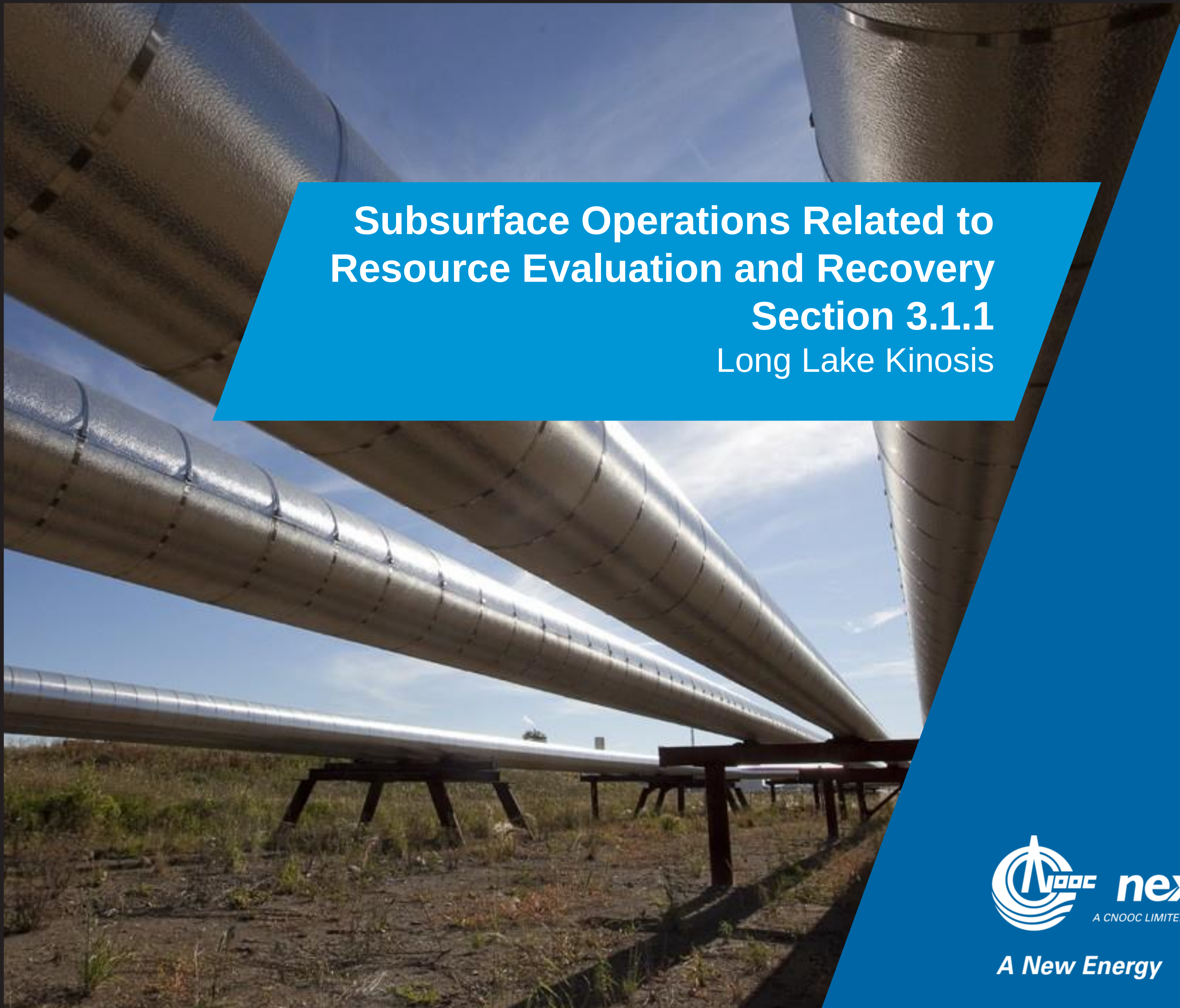
- Nexen Energy ULC (Nexen) is an upstream oil and gas company responsibly developing energy resources in the UK North Sea, offshore West Africa, the United States and Western Canada.

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

Nexen Oil Sands



Contents



Subsurface Operations Related to Resource Evaluation and Recovery Section 3.1.1

Long Lake Kinosis

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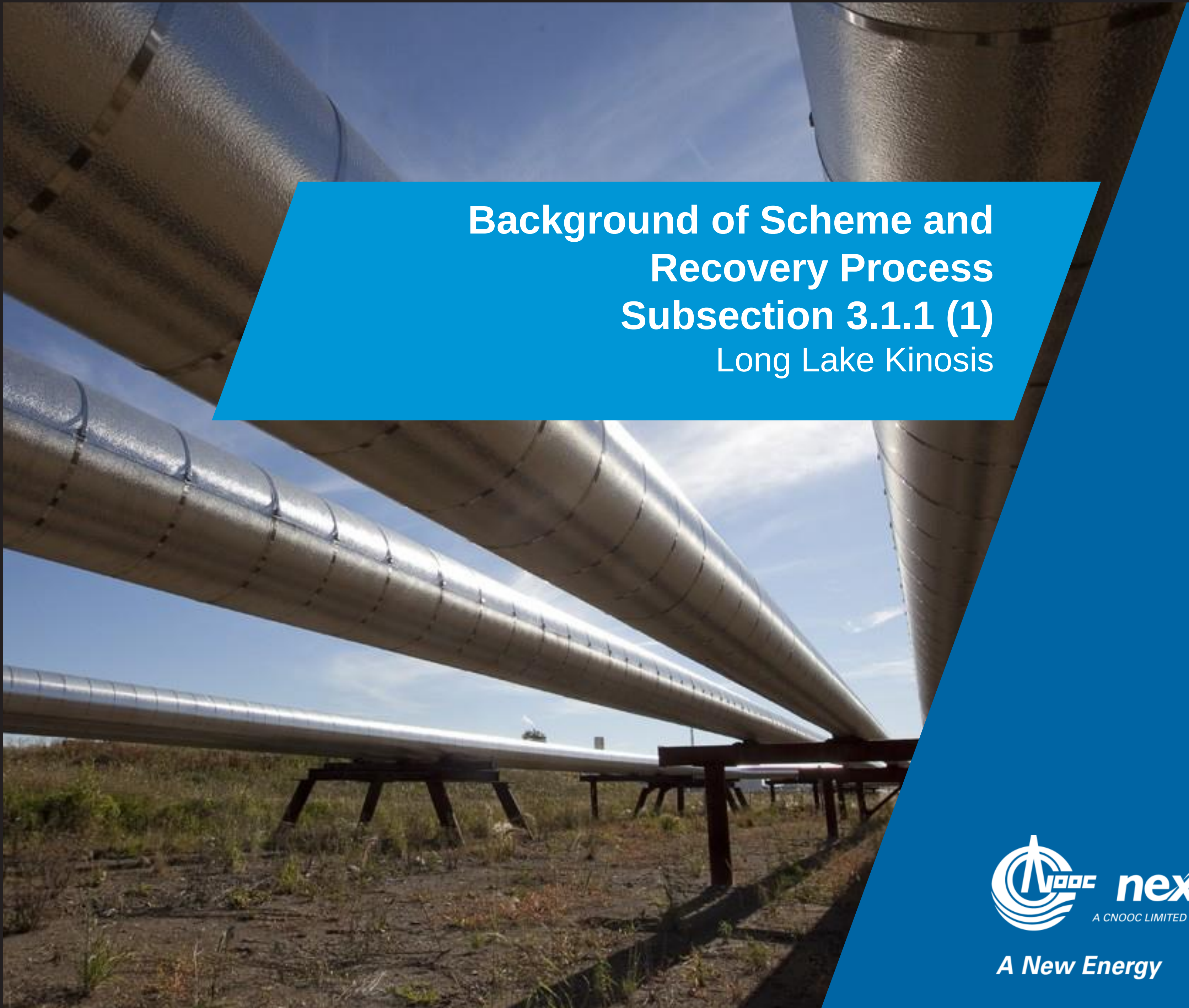

Background of Scheme and Recovery Process Subsection 3.1.1 (1)

Long Lake Kinosis

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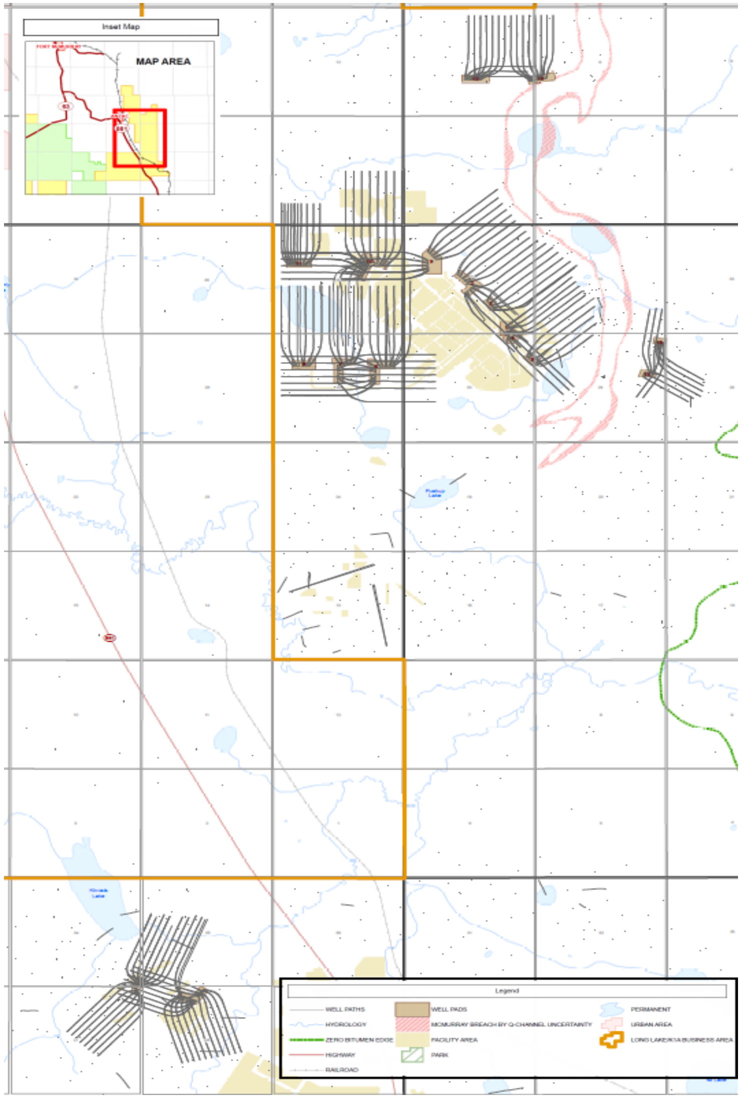
Long Lake Scheme Description

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

	Design (K1A*) m³/d	Design (K1A*) 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

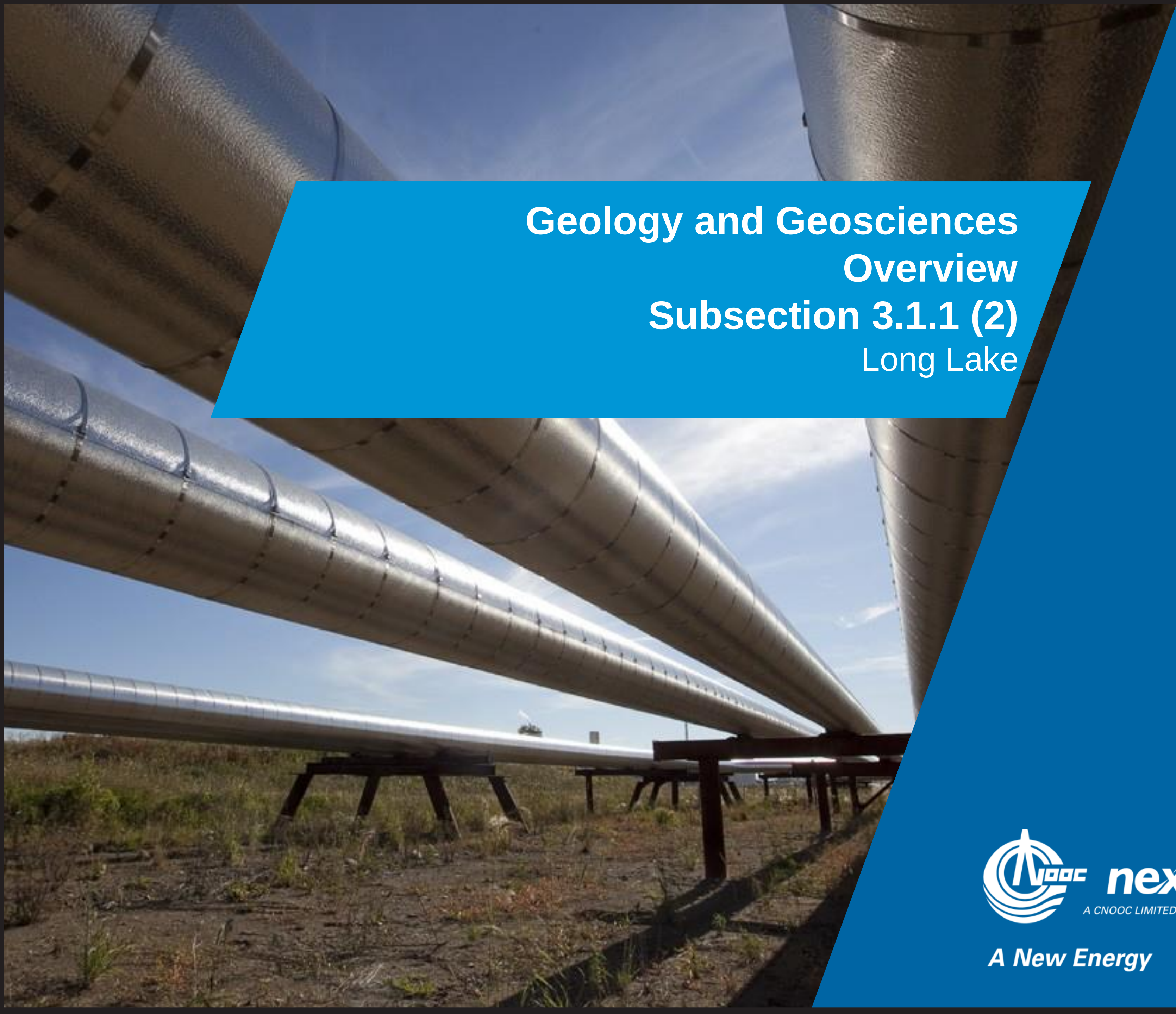
Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility (LLK)
2003	Regulatory approvals for the commercial LLK Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial LLK Facility
2006	Regulatory amendments, including 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; 7N Infills on production
2016	Hydro-Cracker Unit (HCU) Incident; Wildfire shut down Long Lake operations for ~2 months
2017	Commenced drilling Infills on Pads 5, 8

2017 Summary

- Long Lake pads exhibited strong and stable performance throughout the year.
- OSCA Scheme Amendment for Q-Channel Monitoring - Approved March 2017.
- EPEA Groundwater Management Plan (GMP) - Approved August 2017.

Geology and Geosciences Overview
Subsection 3.1.1 (2)

Long Lake



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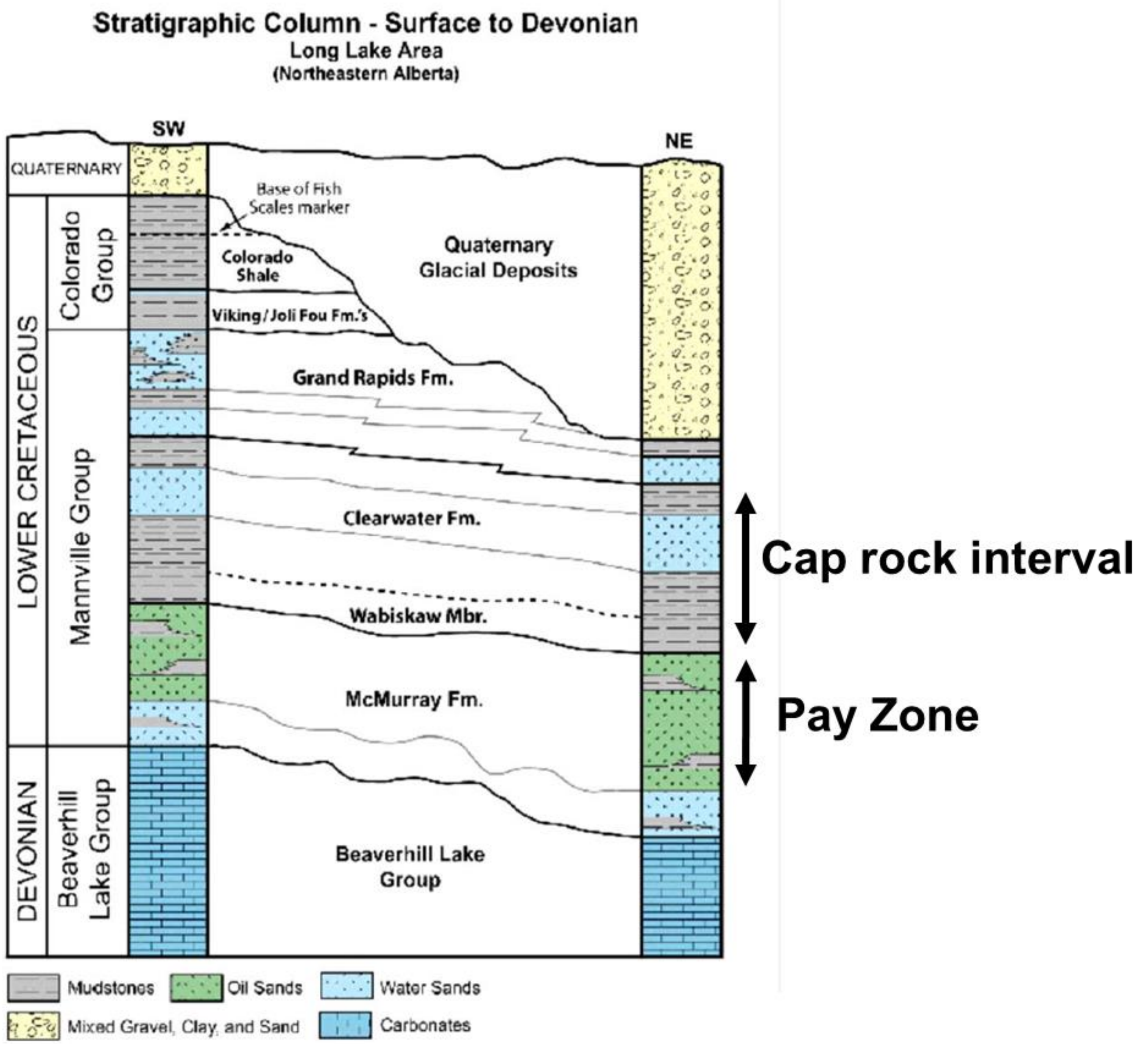
Stratigraphy

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

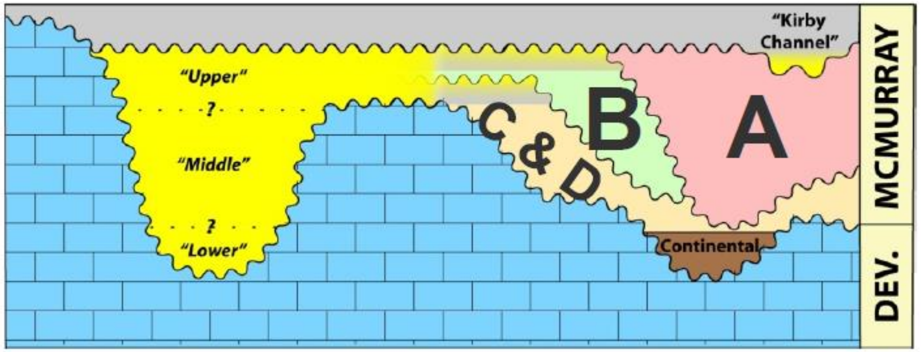
Mudplug .... **Facies 5:**
- muds and silts
- abandoned channel muds
- point bar facies

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

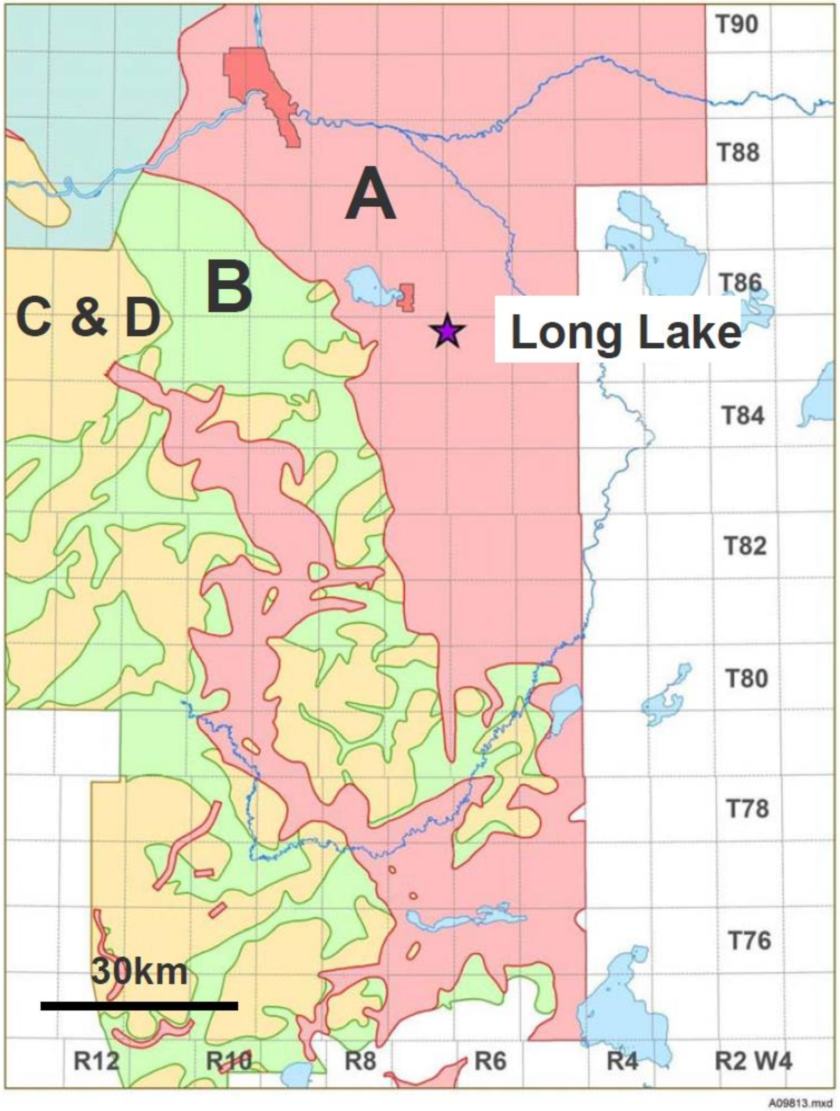
Limestone .... **Facies 7:**
- Devonian carbonates

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

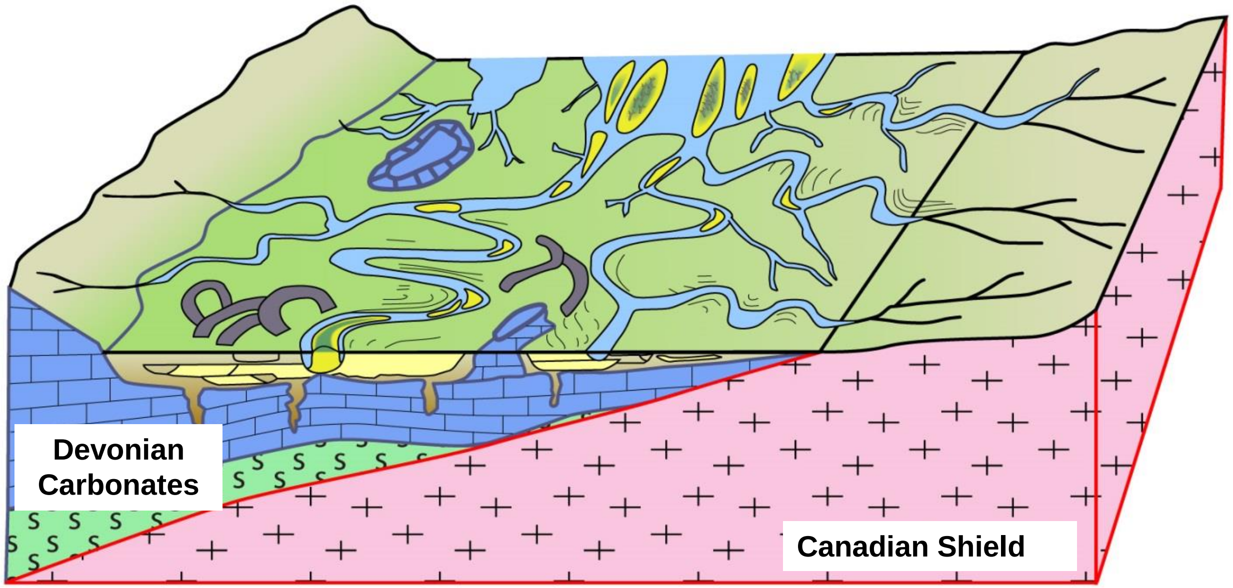


Jervey, 2003

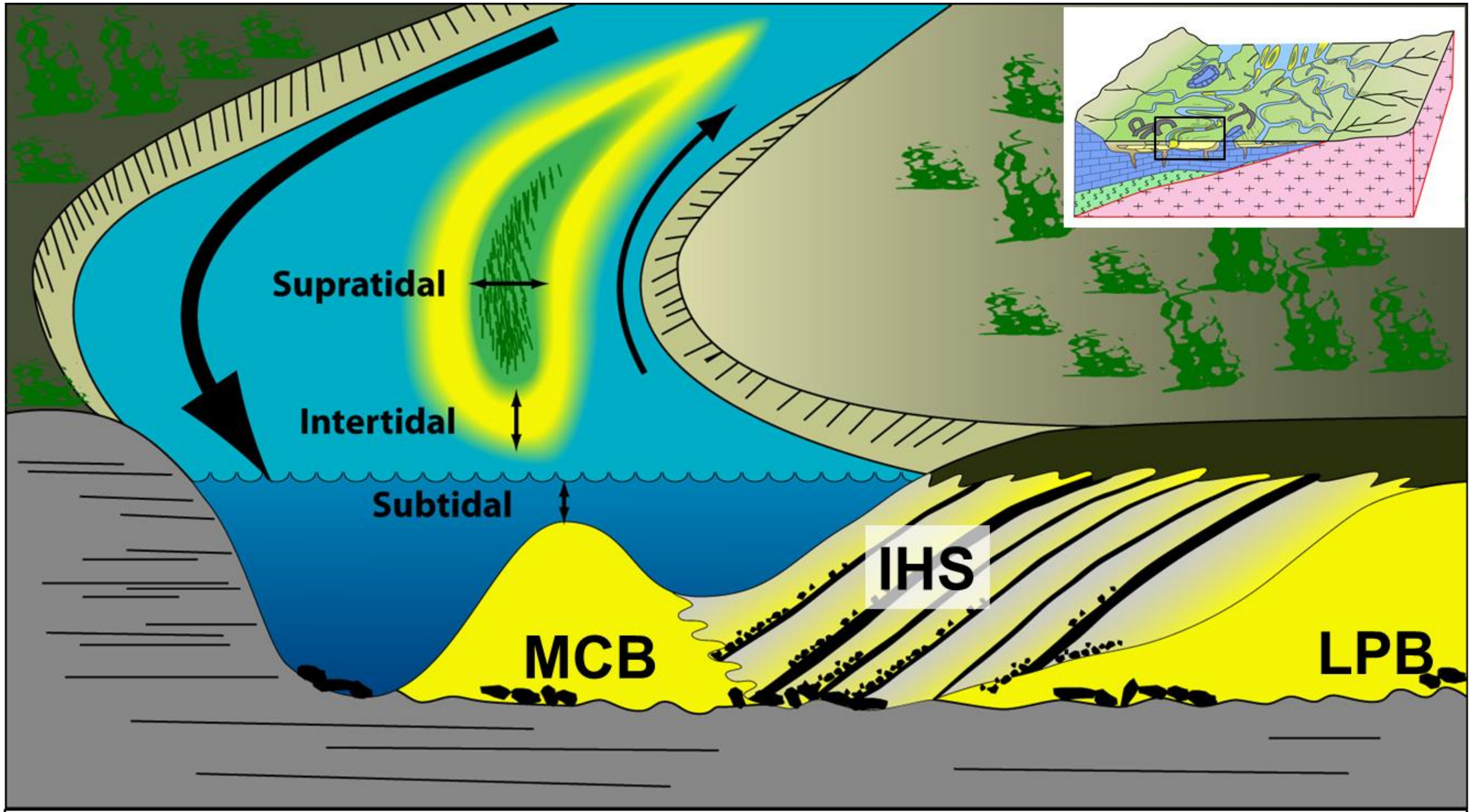


Regional Depositional Model

- 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

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Legend

- HIGHWAY
- RAILROAD
- DEVONIAN STRUCTURE (C.I.=10m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

HORIZONTAL WELL STATUS (PRODUCER)

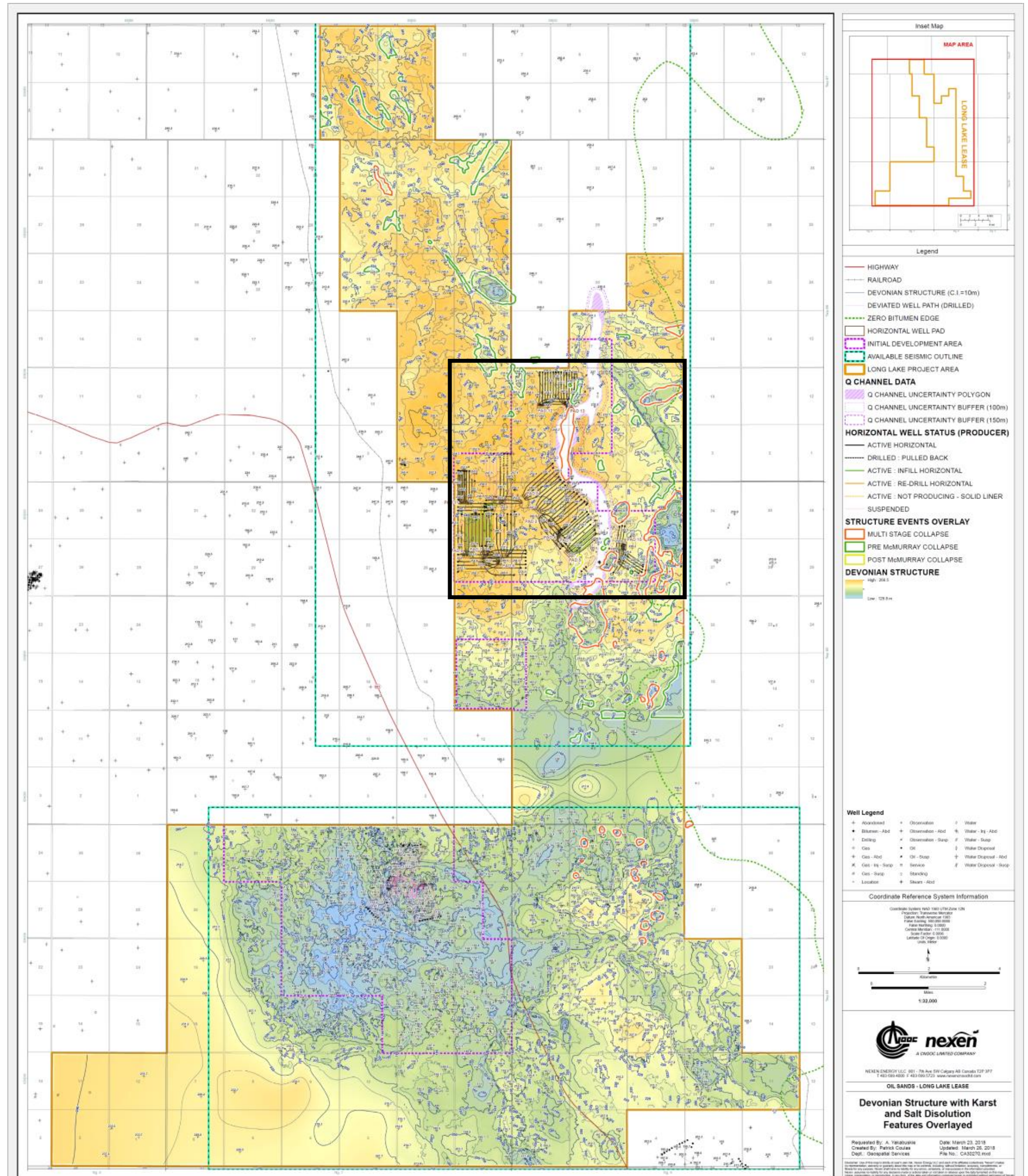
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

STRUCTURE EVENTS OVERLAY

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

DEVONIAN STRUCTURE

- High : 268.5
- Low : 129.8 m



Long Lake Devonian Structure with Karst and Salt Dissolution Features

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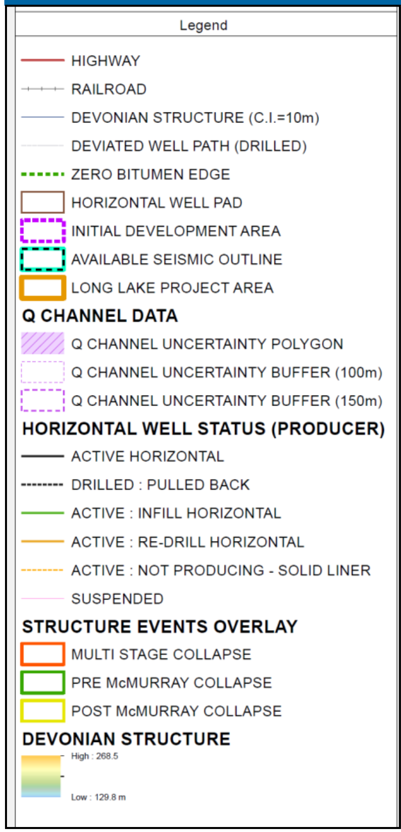

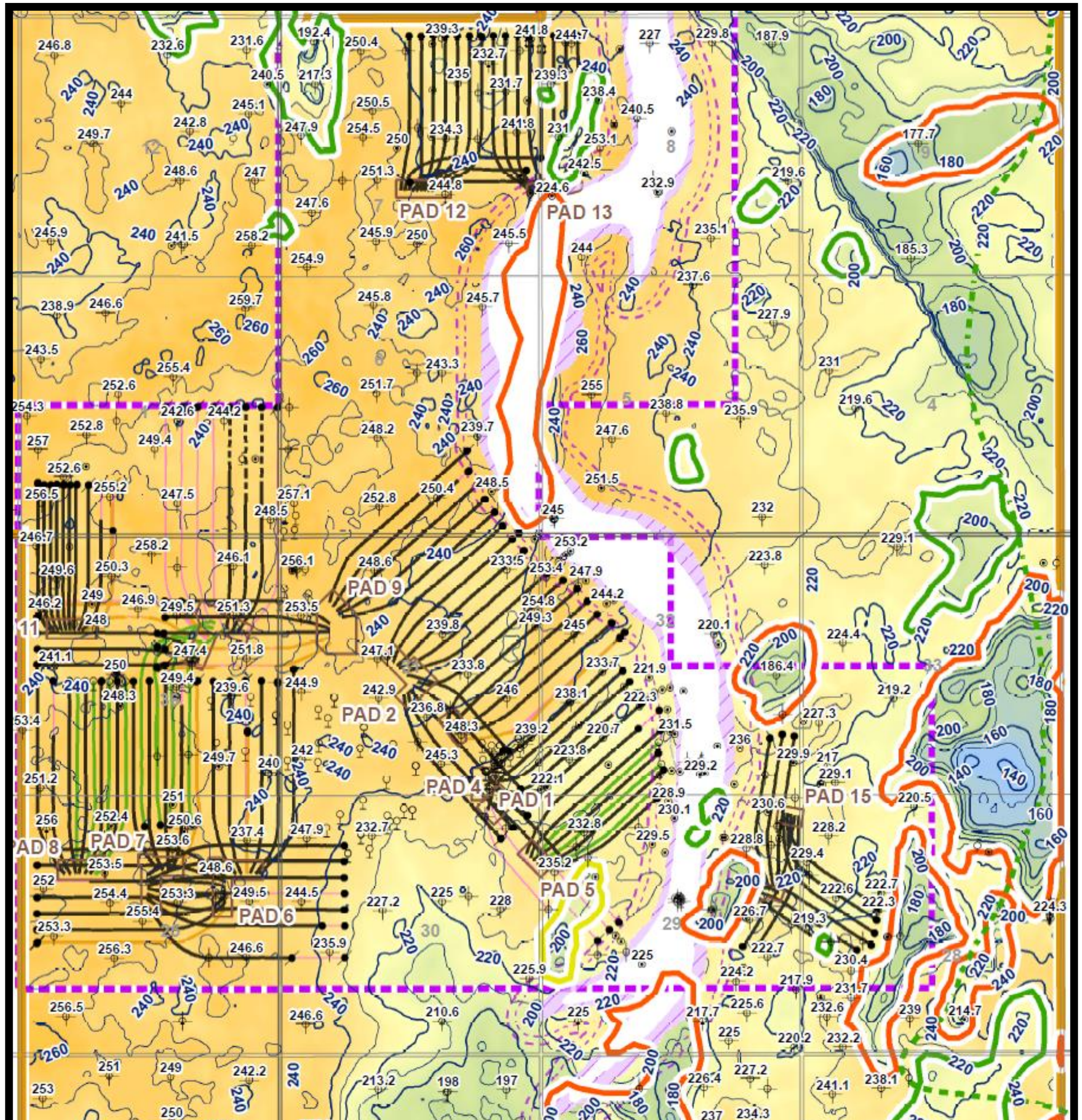

- Relatively flat below current SAGD development areas
- Lows related to collapse features (karst and dissolution) and erosion

Long Lake
McMurray Structure

Legend

- HIGHWAY
- RAILROAD
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
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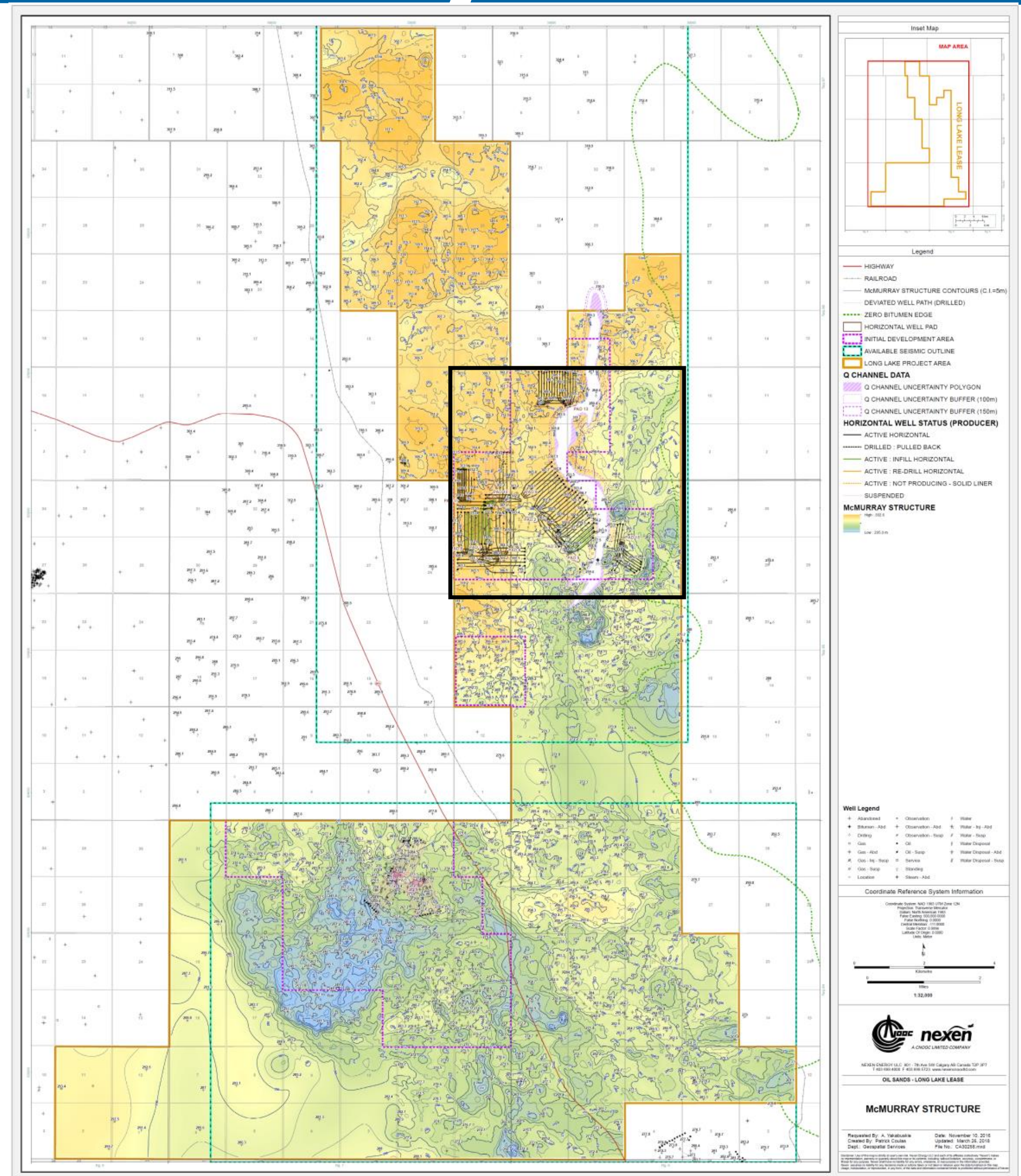
McMURRAY STRUCTURE

High : 332.6

Low : 235.3 m



Long Lake
McMurray Structure

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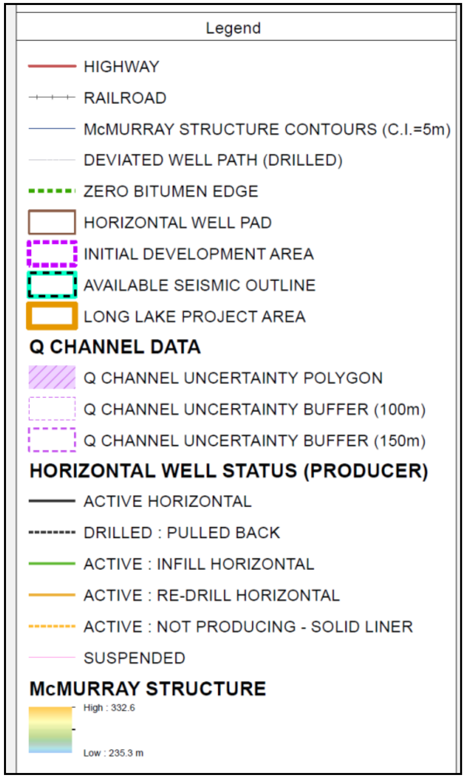

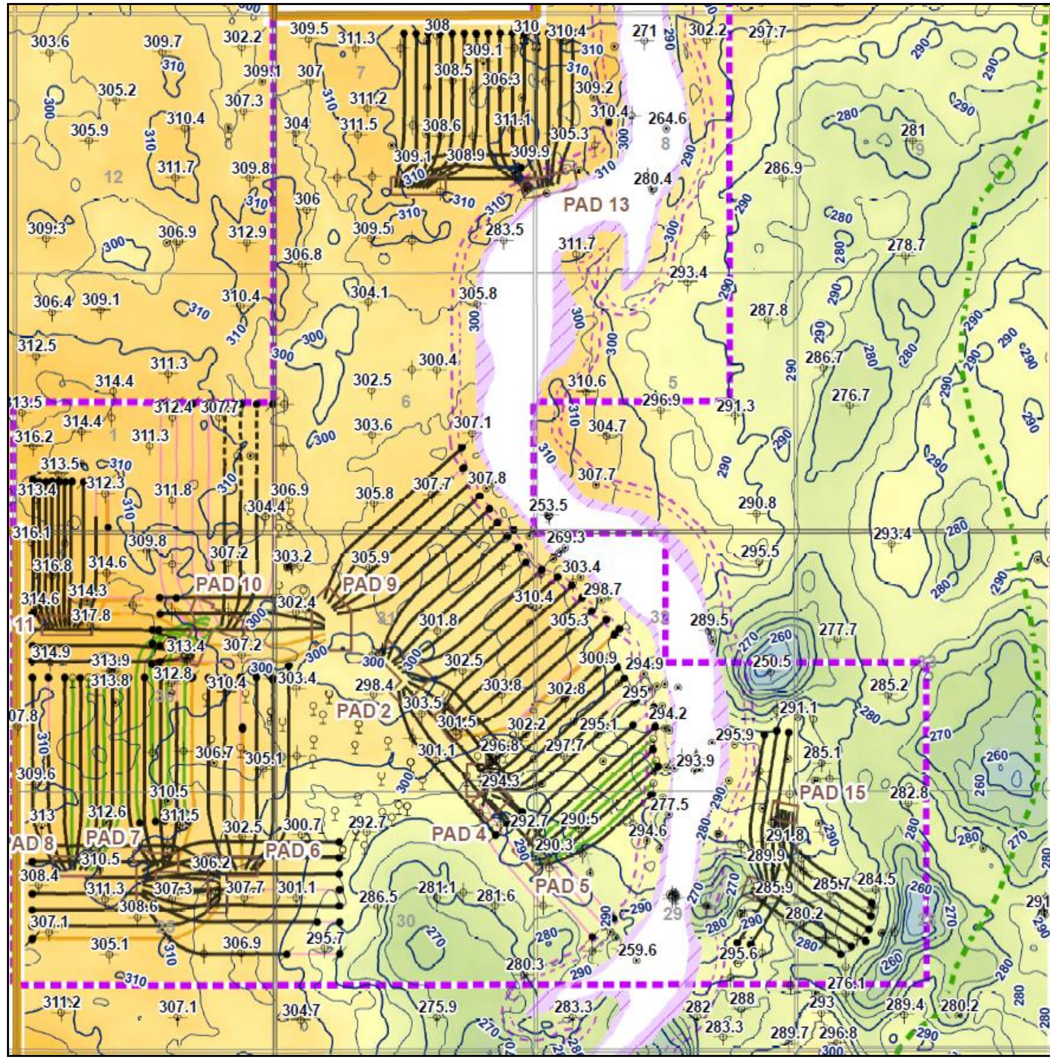

- Blue/Green-shaded areas are lows related to salt dissolution
- Subtle structural influences related to karsting, erosion on Devonian and differential compaction over muddier McMurray deposits

Long Lake
McMurray Isopach

Legend

- McMURRAY ISOPACH CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
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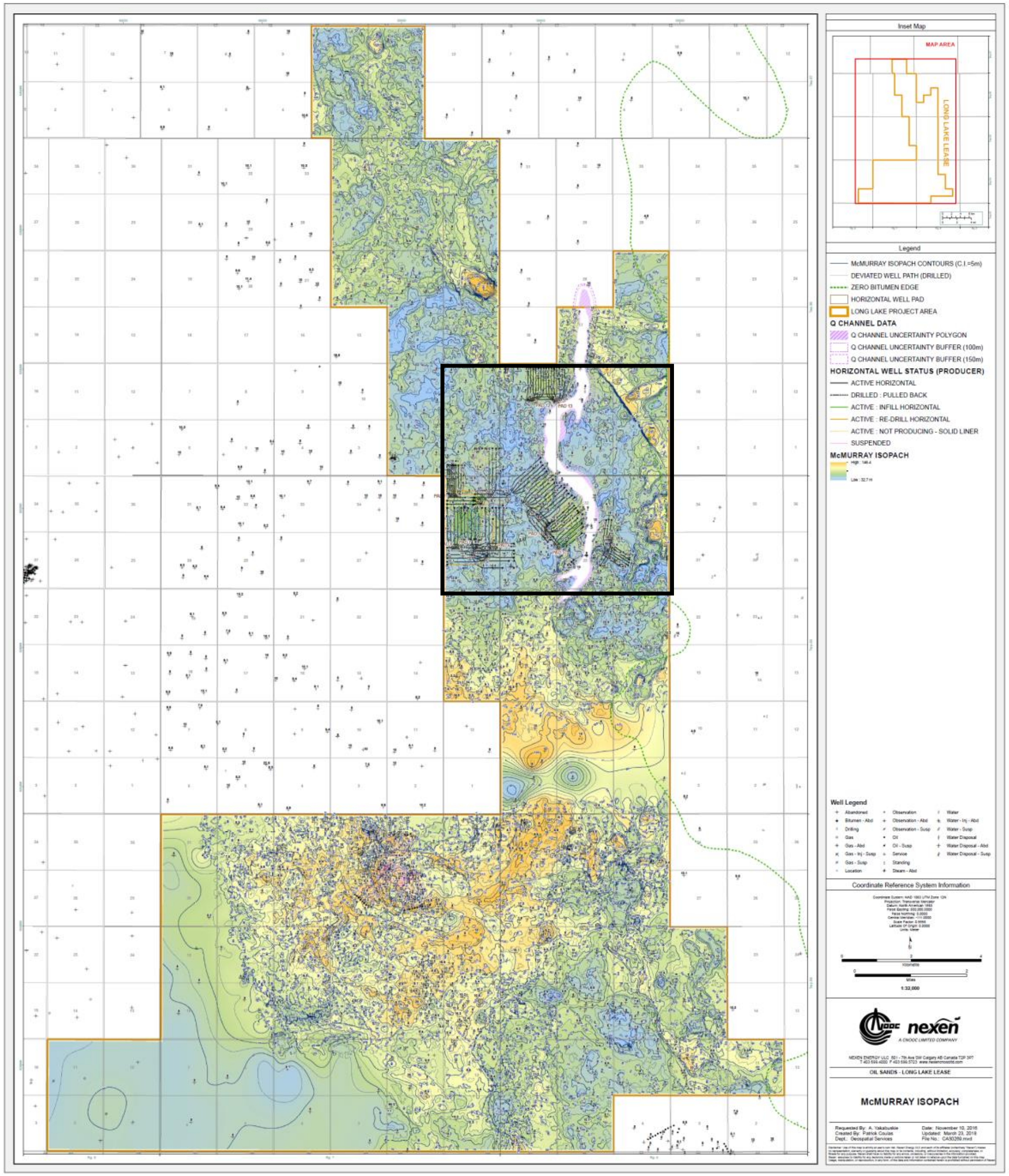
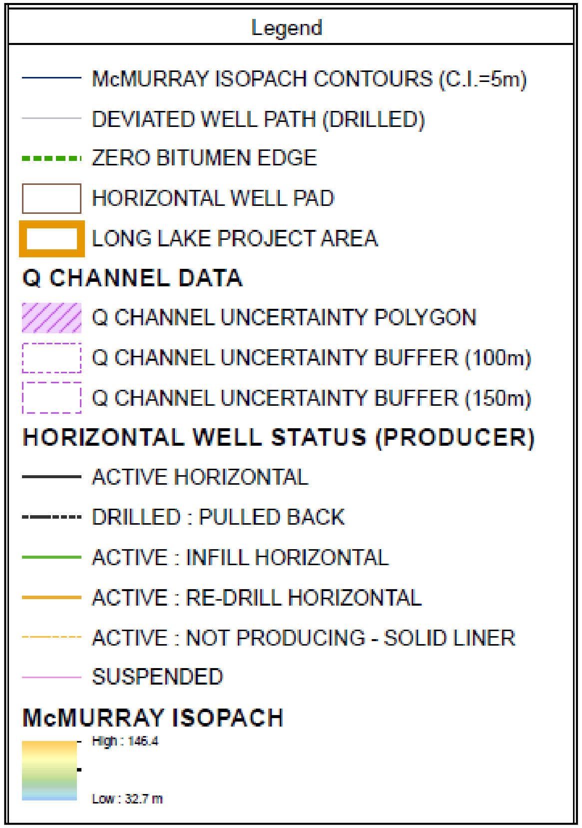
McMURRAY ISOPACH

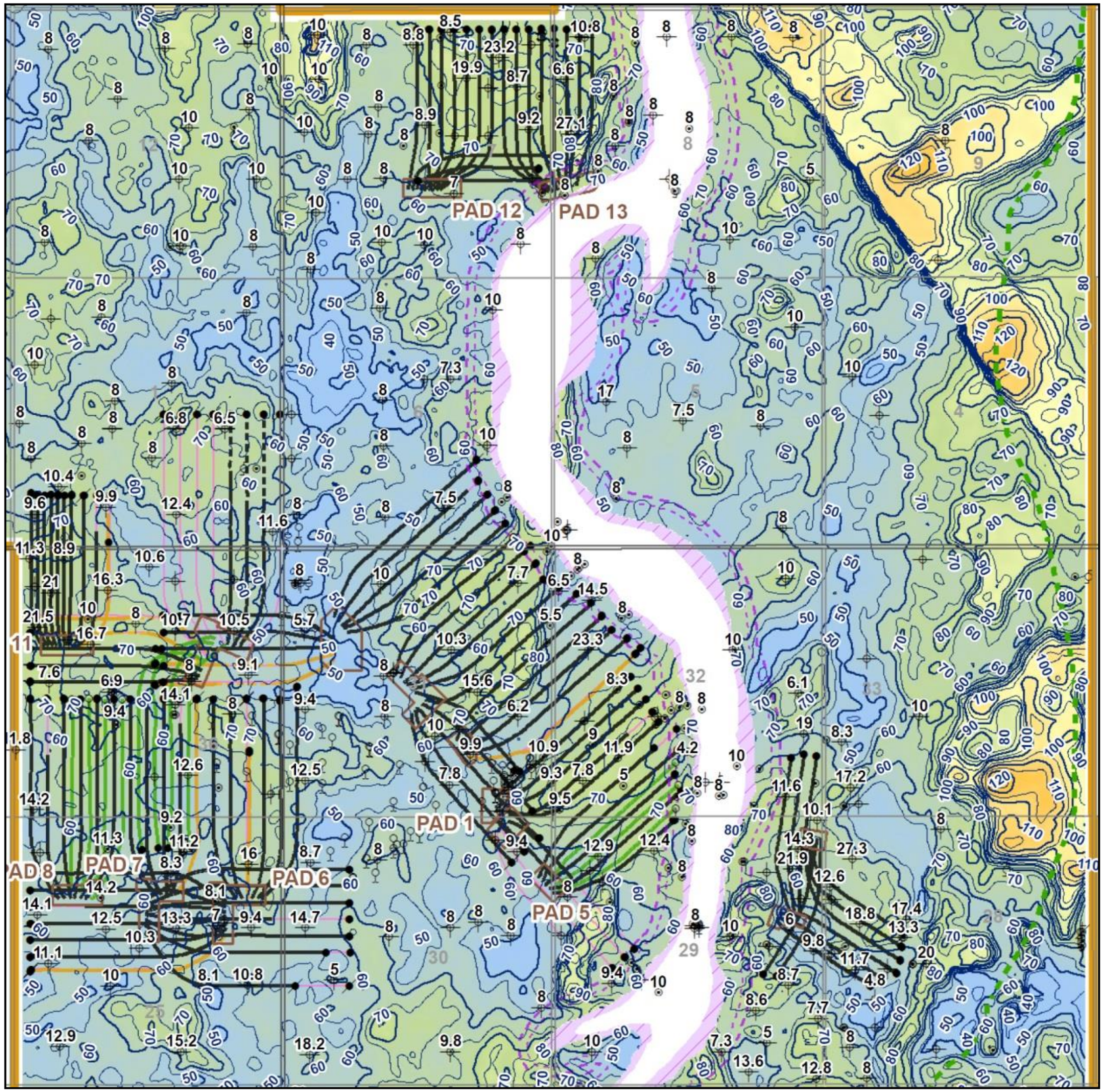
High : 146.4

Low : 32.7 m



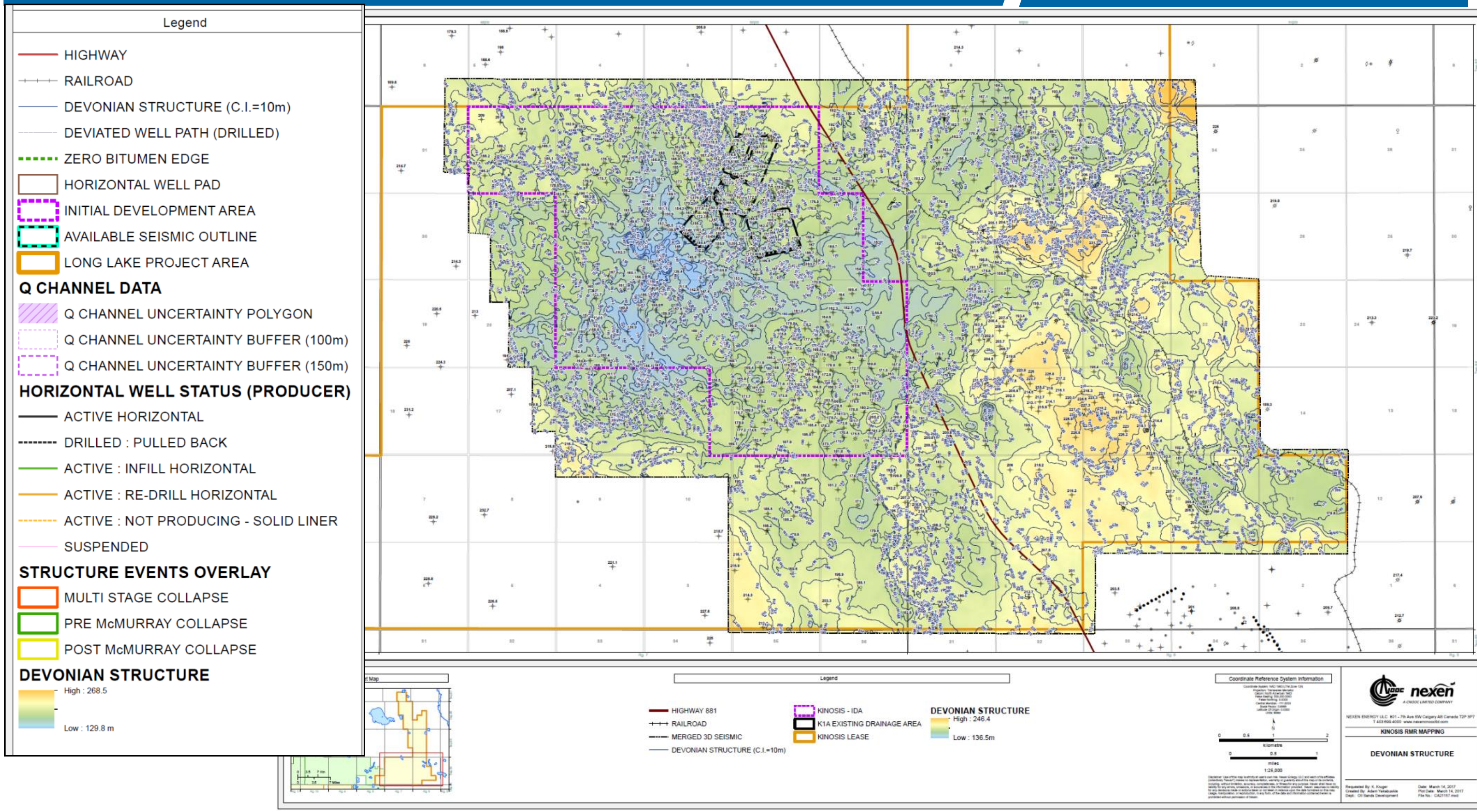
Long Lake McMurray Isopach





- 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

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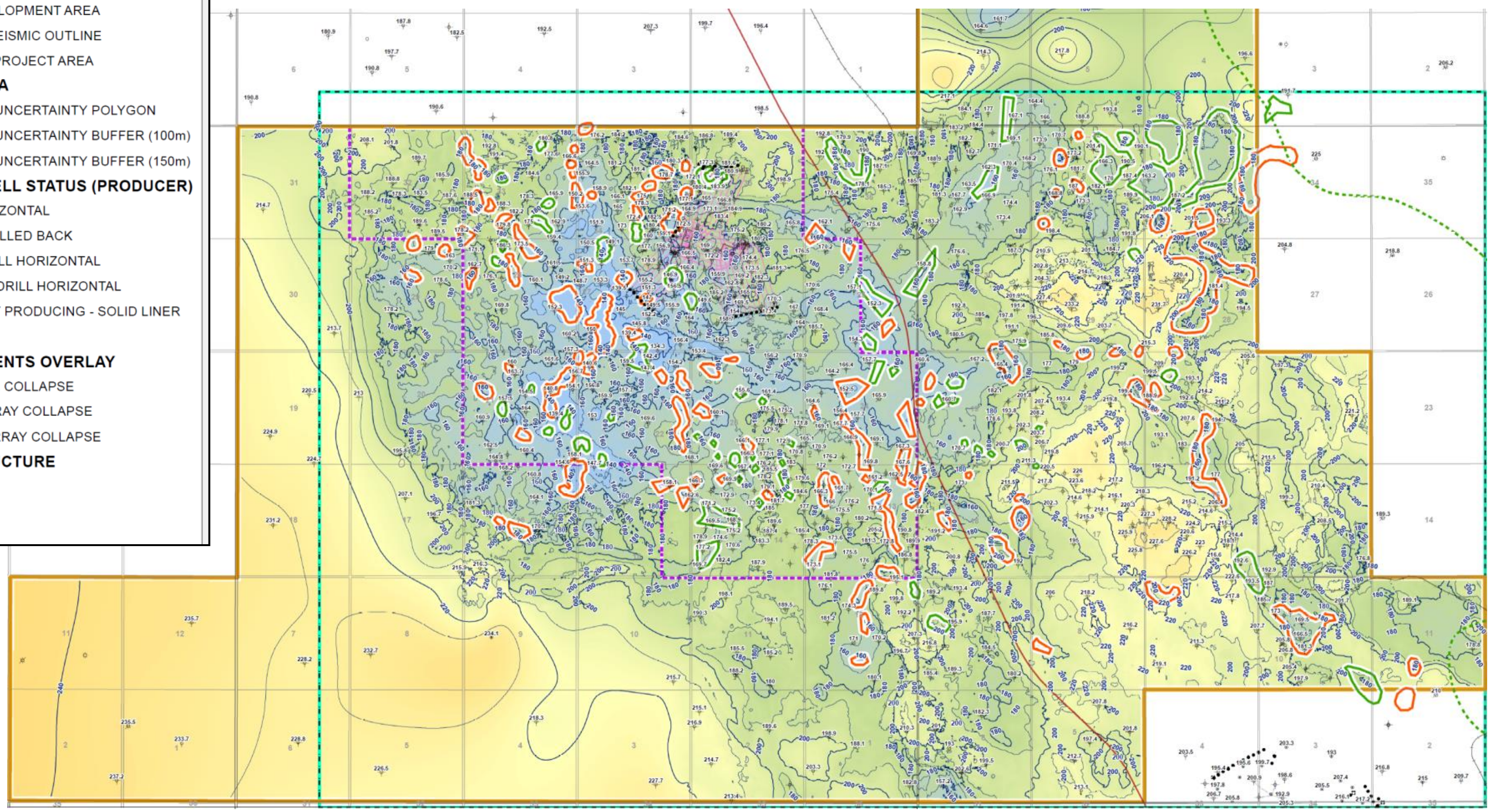
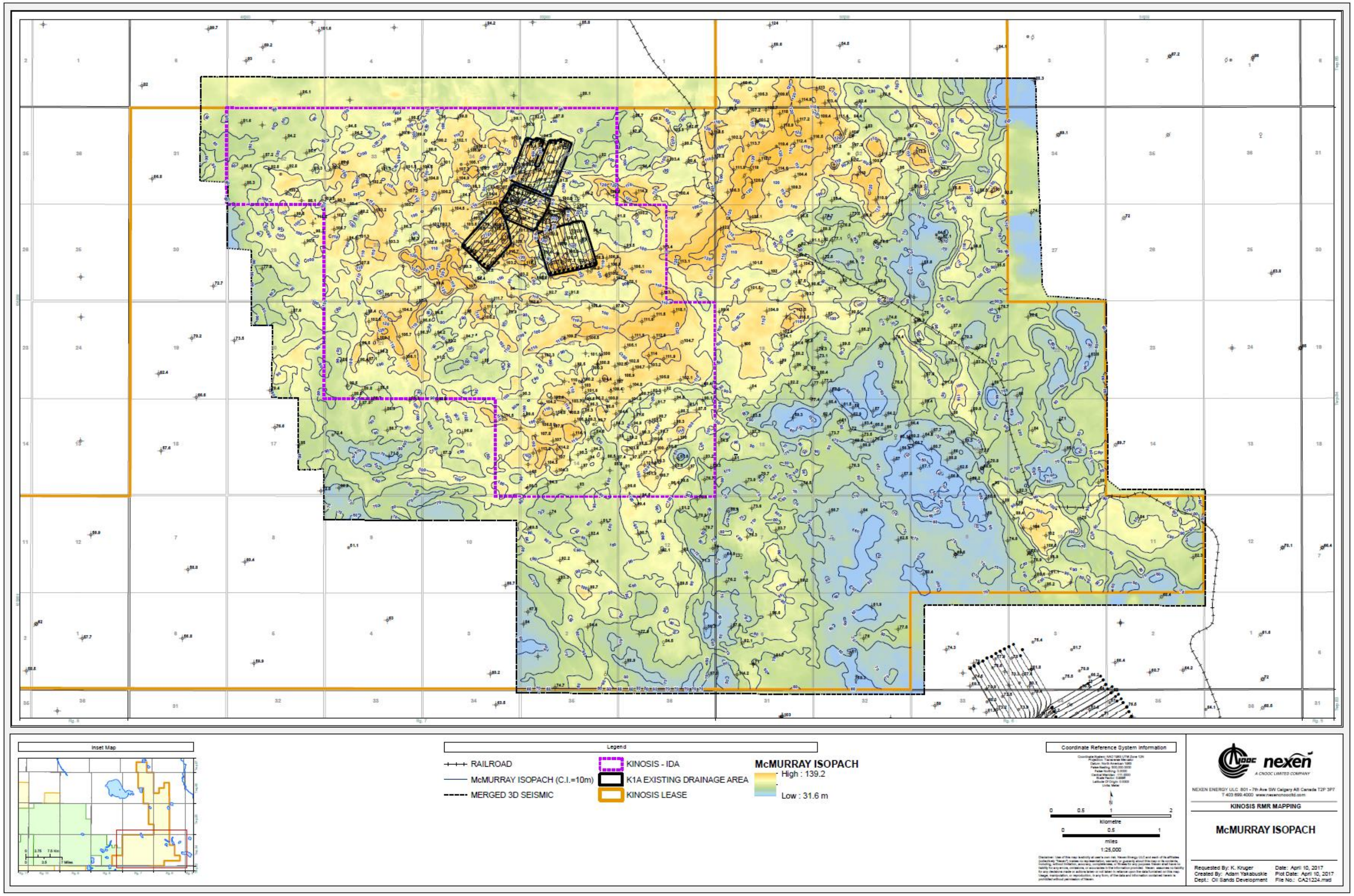
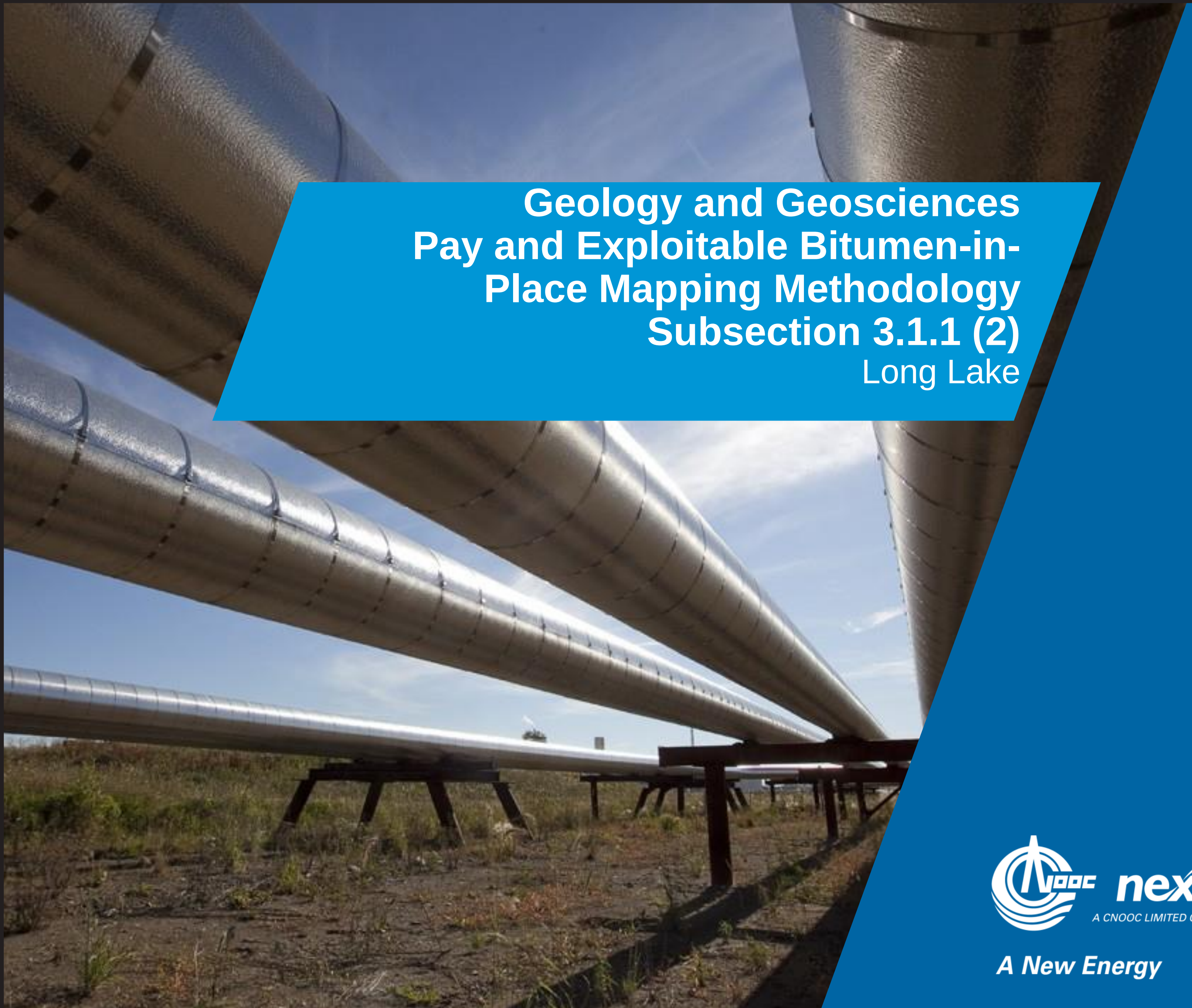


Kinosis Structure - Top of McMurray



- 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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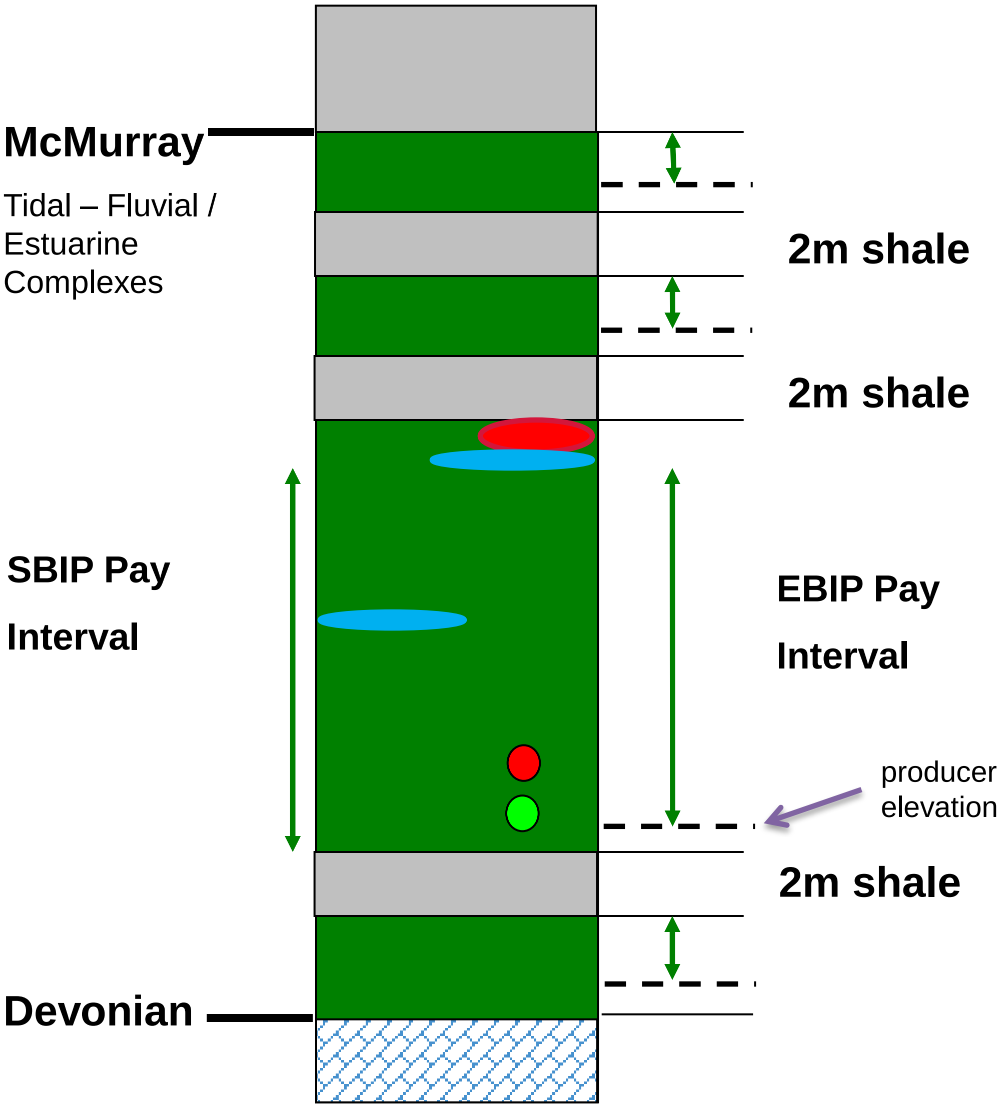
Pay and Exploitable Bitumen-in-Place Mapping Methodology

- 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 4m
- 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% S_{we} (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% S_{we} (effective water saturation) and < 30% V_{shale}
- Minimum EBIP HPVH and Pay Interval Contour
  - $3m^3/m^2$ EBIP HPVH = 12m EBIP Pay Interval

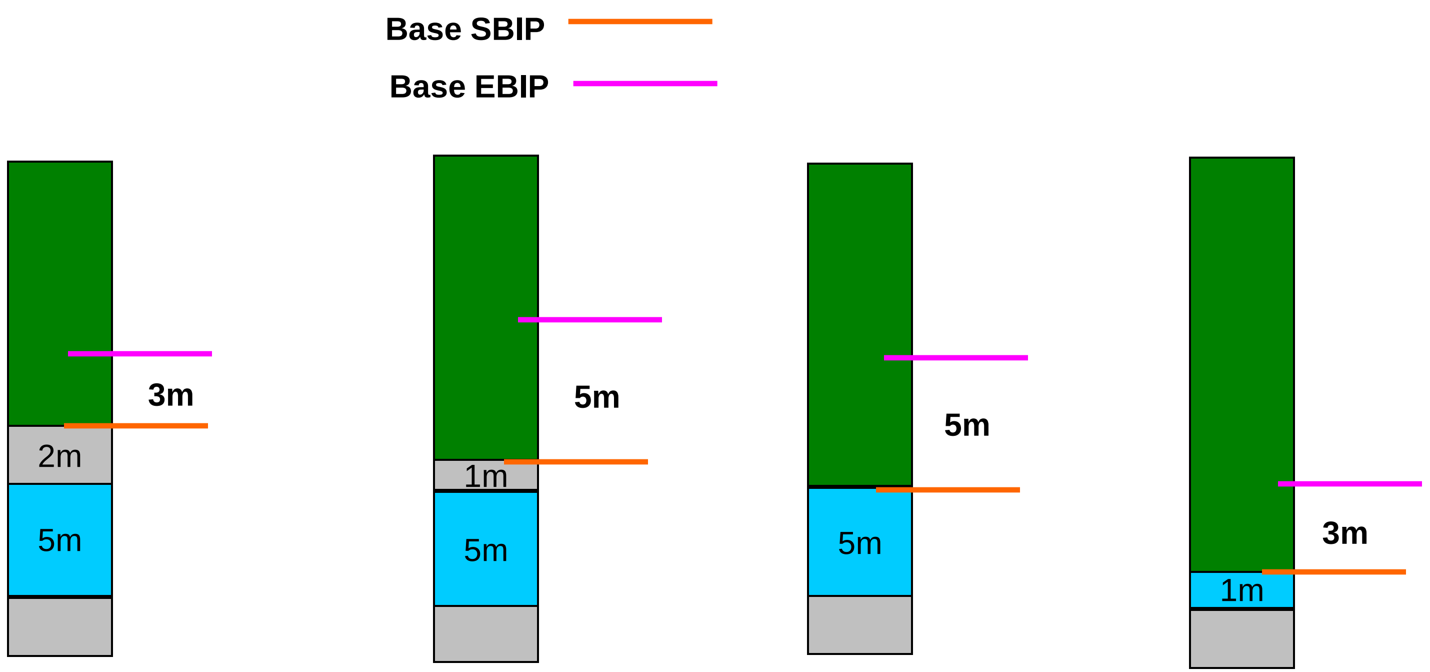
Pay and Bitumen-in-Place Mapping Methodology



- **SBIP Pay Interval:**
  - < 30% V_{shale}
  - < 50% S_{we}
- May have associated:
  - gas interval(s)
  - high water saturation interval(s)
- Primary zone defined as the thickest pay interval unless:
  - 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:

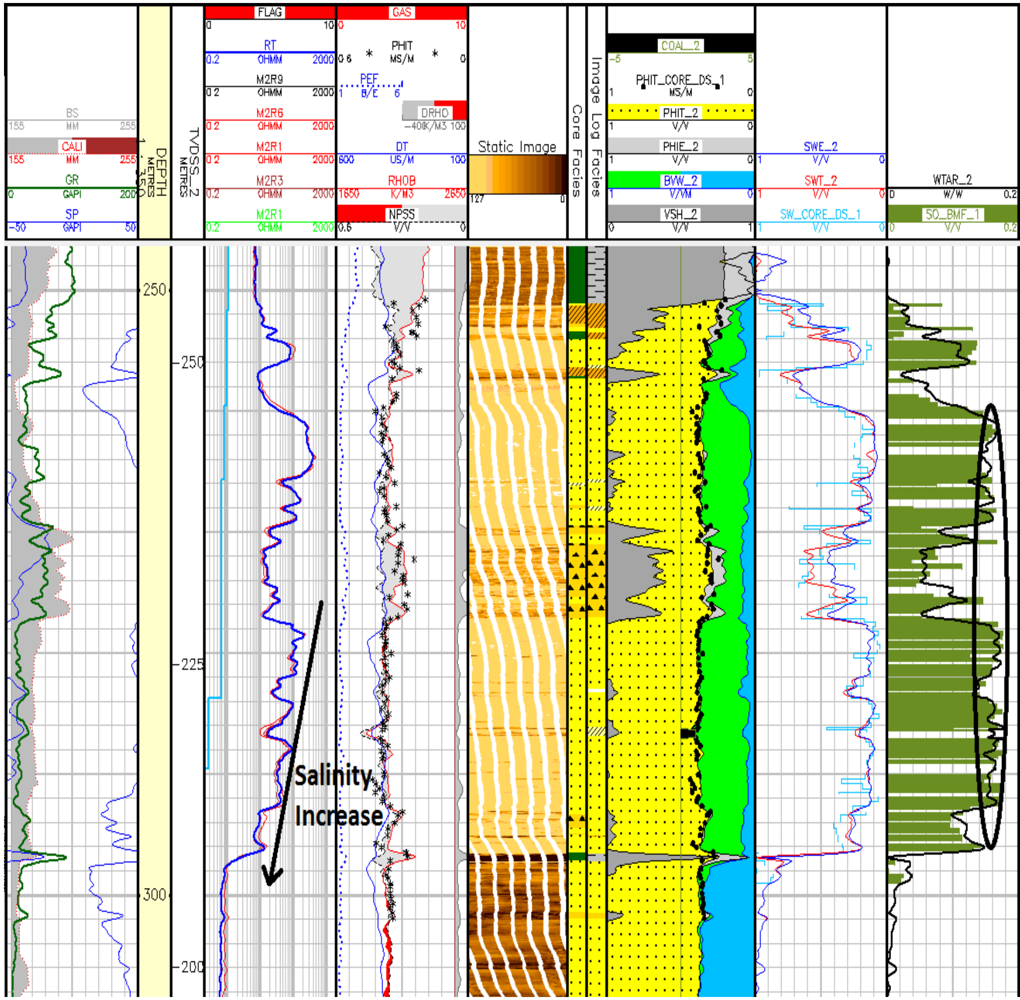
- Minimum of 5m stand-off from bottom water (if present) to minimize the risk of a pressure sink coming in contact with the higher pressure steam chamber.
- Max. elevation change between adjacent horizontal wells 15m/100m.
- 3 to 5m vertical deviation from intermediate casing point (ICP).
- Approximate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

Formation Water Resistivity – R_w

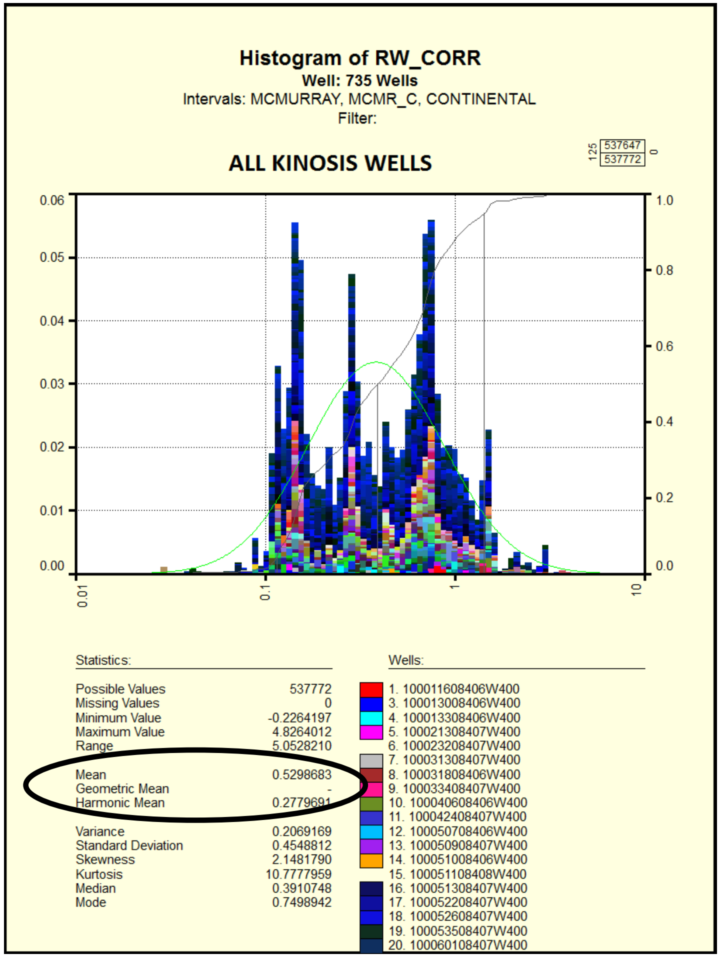
- R_w can change drastically, spatially and vertically within the reservoir.
- The shallow McMurray to the North and areas that are exposed to surface water and quaternary channels will have fresh water sources.
- McMurray in the South region has a great deal of variaton, with salinity often increasing with depth.
- The saline water is associated with salt dissolution from the underlying Prairie Evaporite and can be correlated with collapse features from the salt dissolution.
- Kinosis has a great deal of salt dissolution features.
- Long Lake also has some salt dissolution features as well as a fresh water source from the quaternary channel in the East.

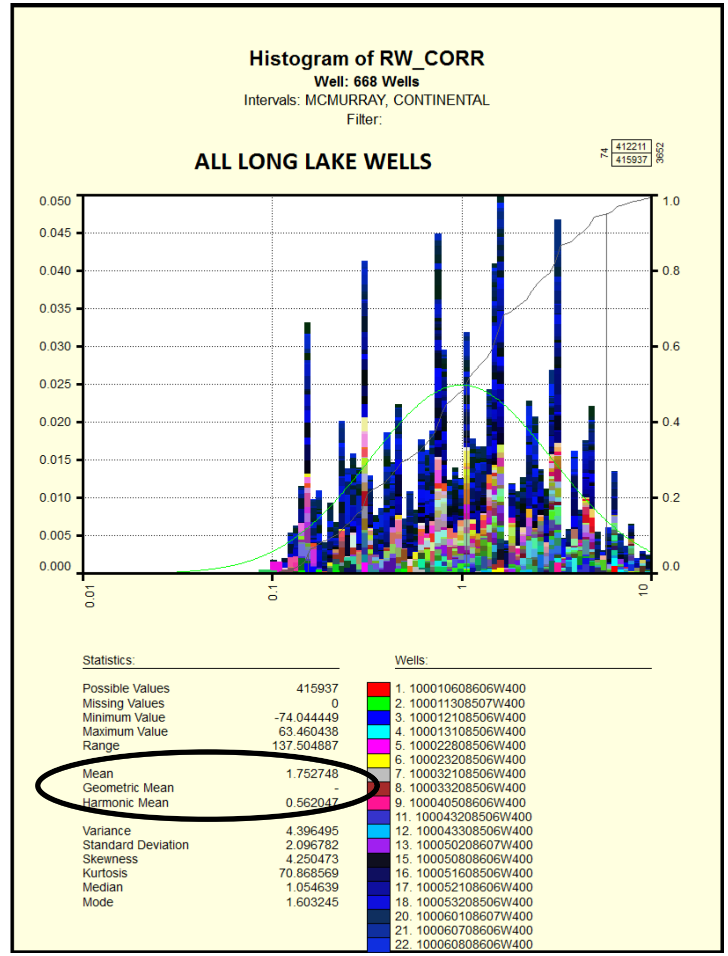
Salinity Increasing example

- Example well with resistivity decreasing with depth, but the bitumen content remains consistent form dean stark core analysis and log analysis.
- This indicates formation water salinity is increasing with depth.

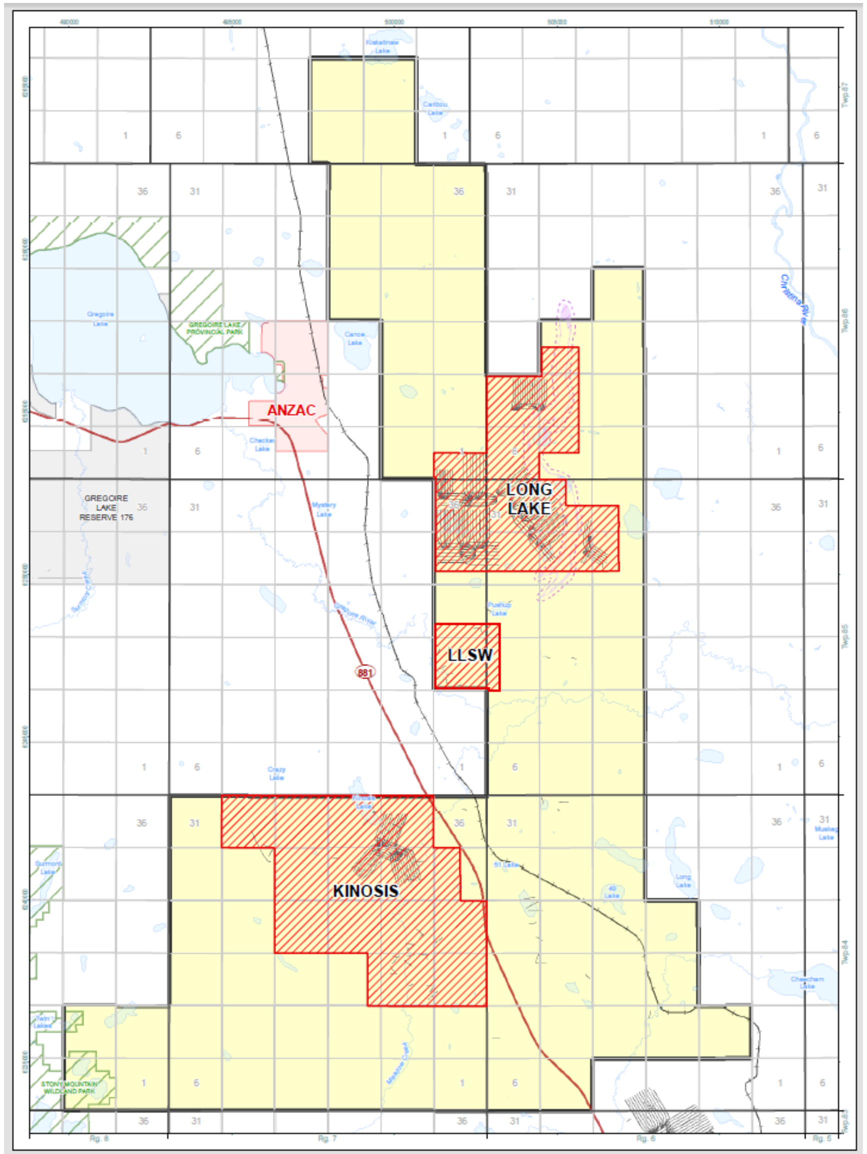


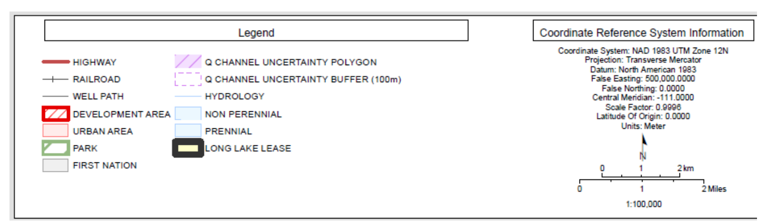
R_w Distributions from Petrophysics





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)	124

Nexen Cutoffs: HPVH > 3 m

Hydrocarbon Pore Volume Height

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

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)	177

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 33 m
- Effective Porosity 32 %
- 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
2017 Winter Program

- No core holes were drilled in 2017

Long Lake
SBIP Pay Interval Isopach

Legend

- HIGHWAY
- RAILROAD
- SBIP ISOPACH CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

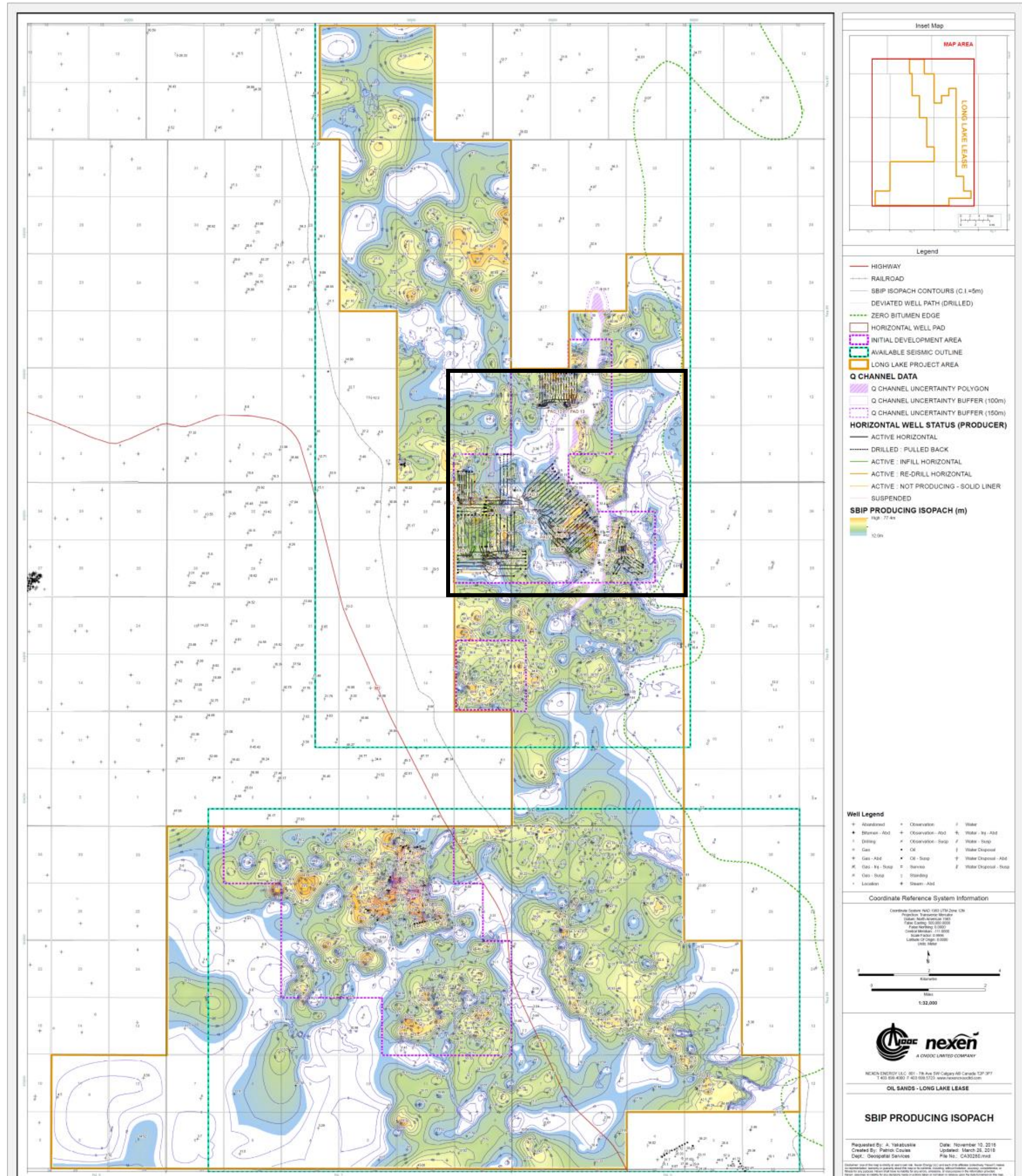
HORIZONTAL WELL STATUS (PRODUCER)

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

SBIP PRODUCING ISOPACH (m)

High : 77.4m

12.0m



Long Lake
SBIP Pay Interval Isopach

Legend

- HIGHWAY
- RAILROAD
- SBIP ISOPACH CONTOURS (C.I.=5m)
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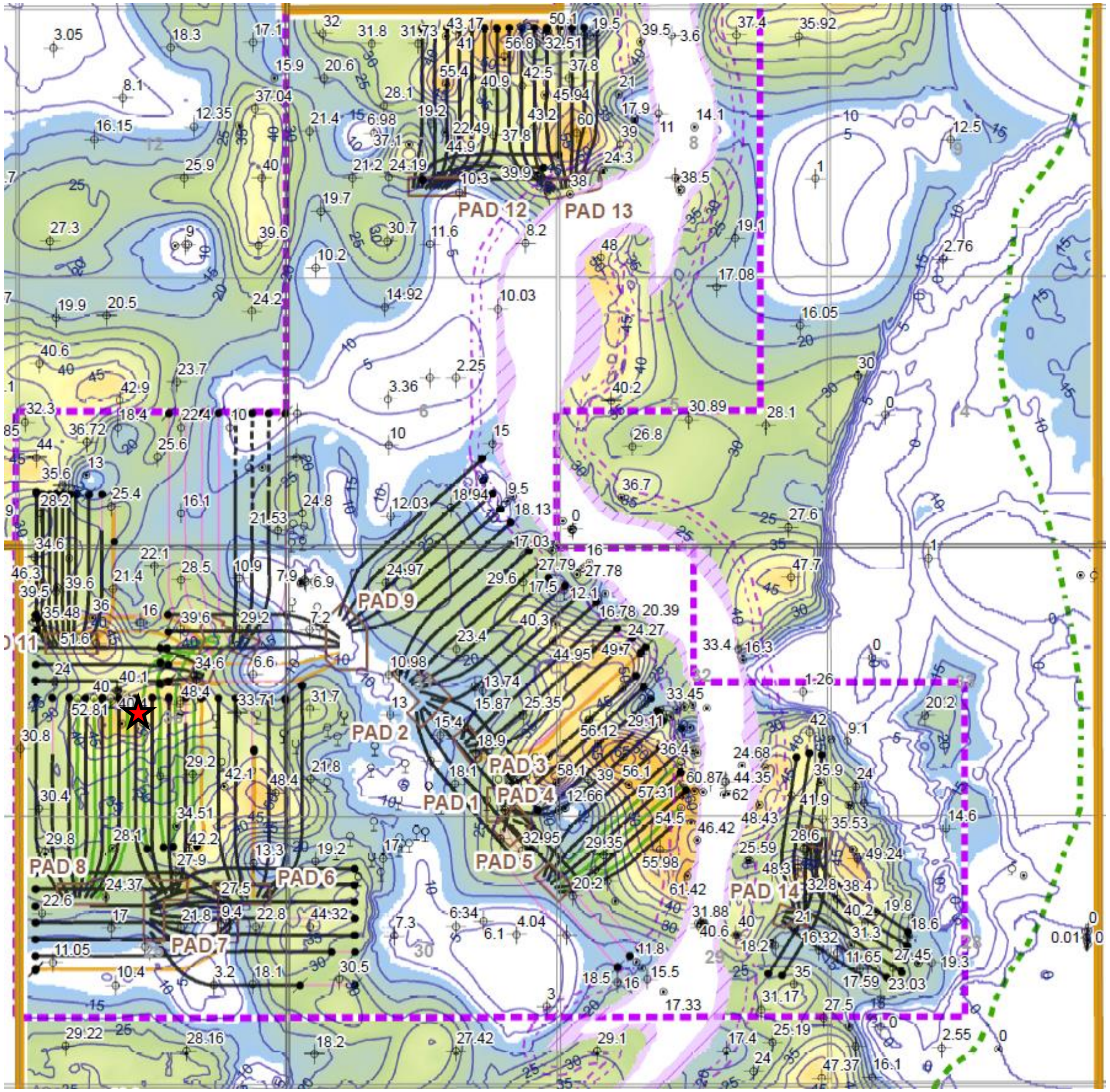
SBIP PRODUCING ISOPACH (m)

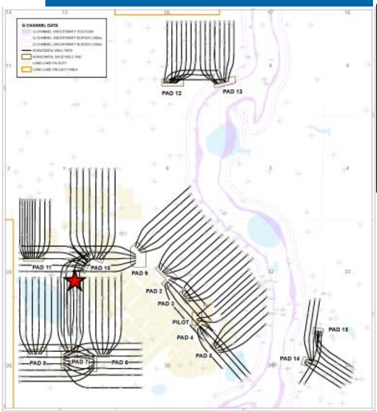
High : 77.4m

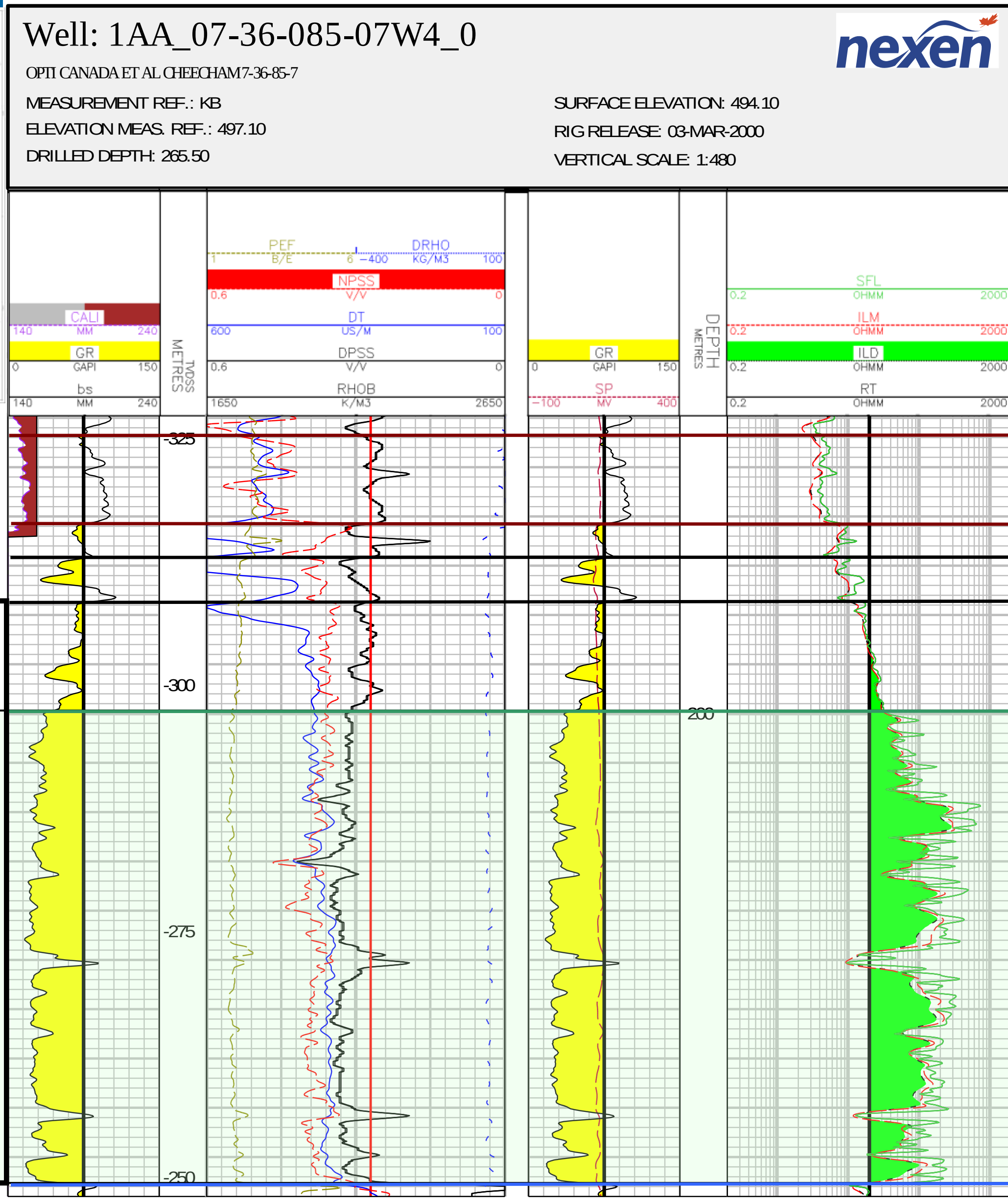
12.0m

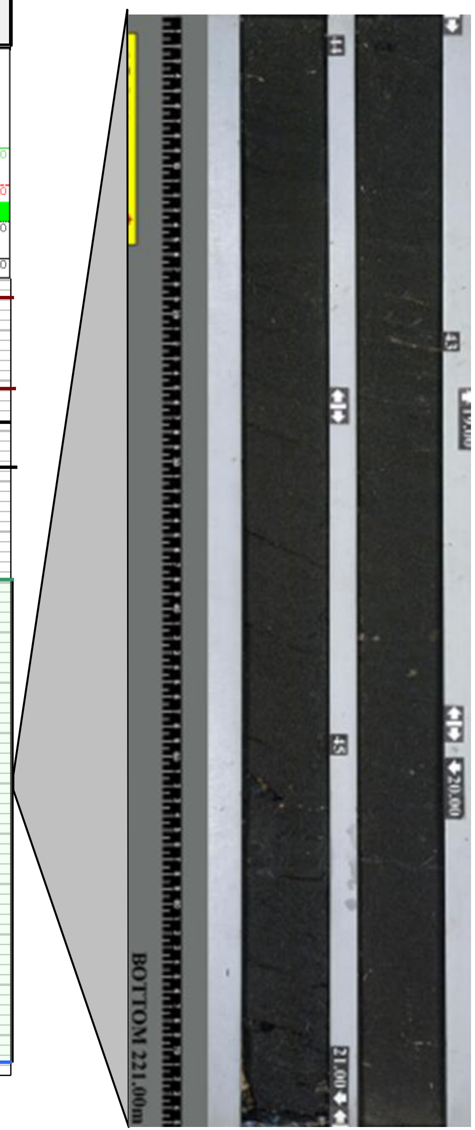


★ TYPE LOG

SBIP Type Log – 1AA/07-36-085-07W4







Kinosis
SBIP Pay Interval Isopach

Legend

- HIGHWAY
- RAILROAD
- SBIP ISOPACH CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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HORIZONTAL WELL STATUS (PRODUCER)

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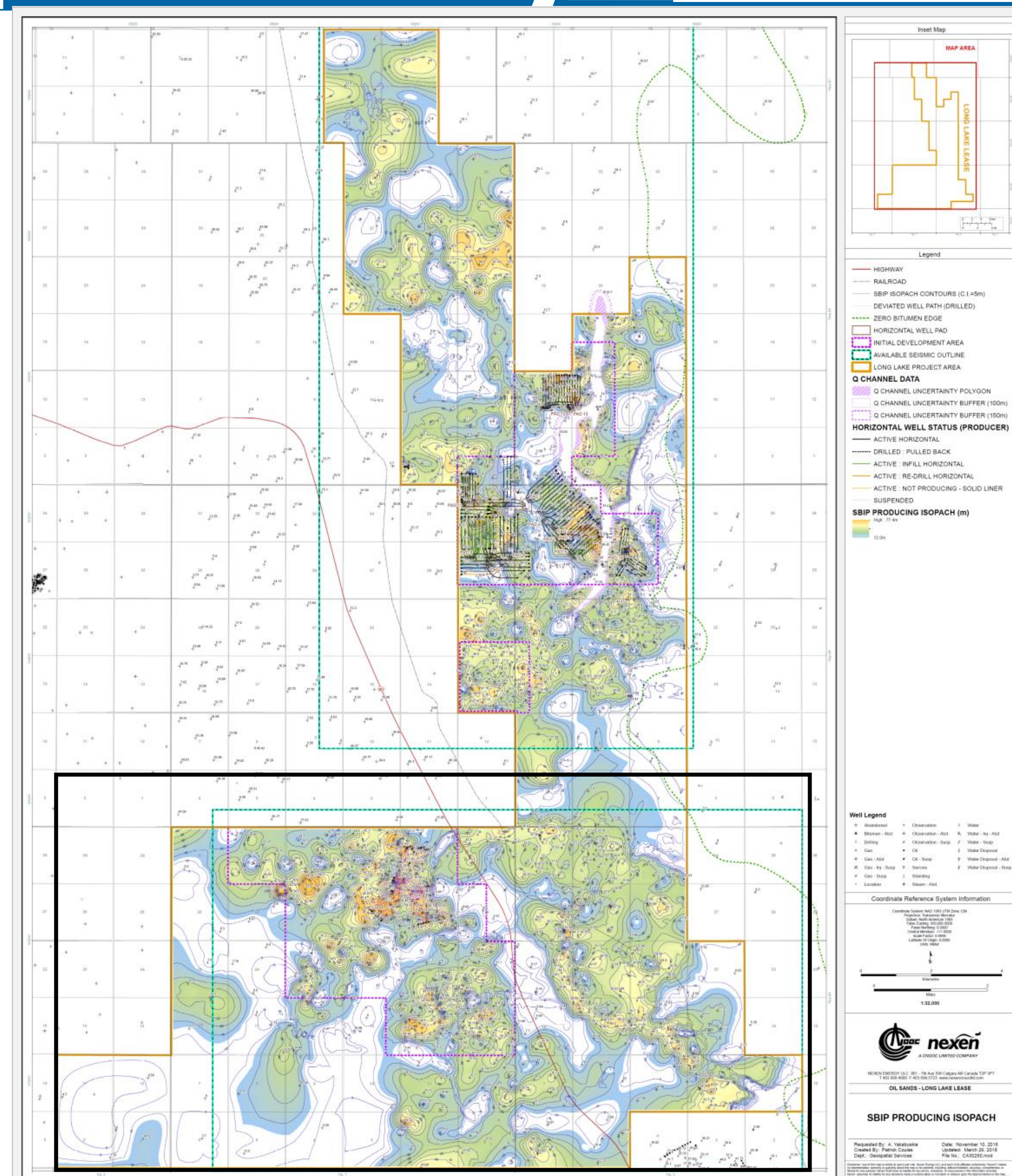
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

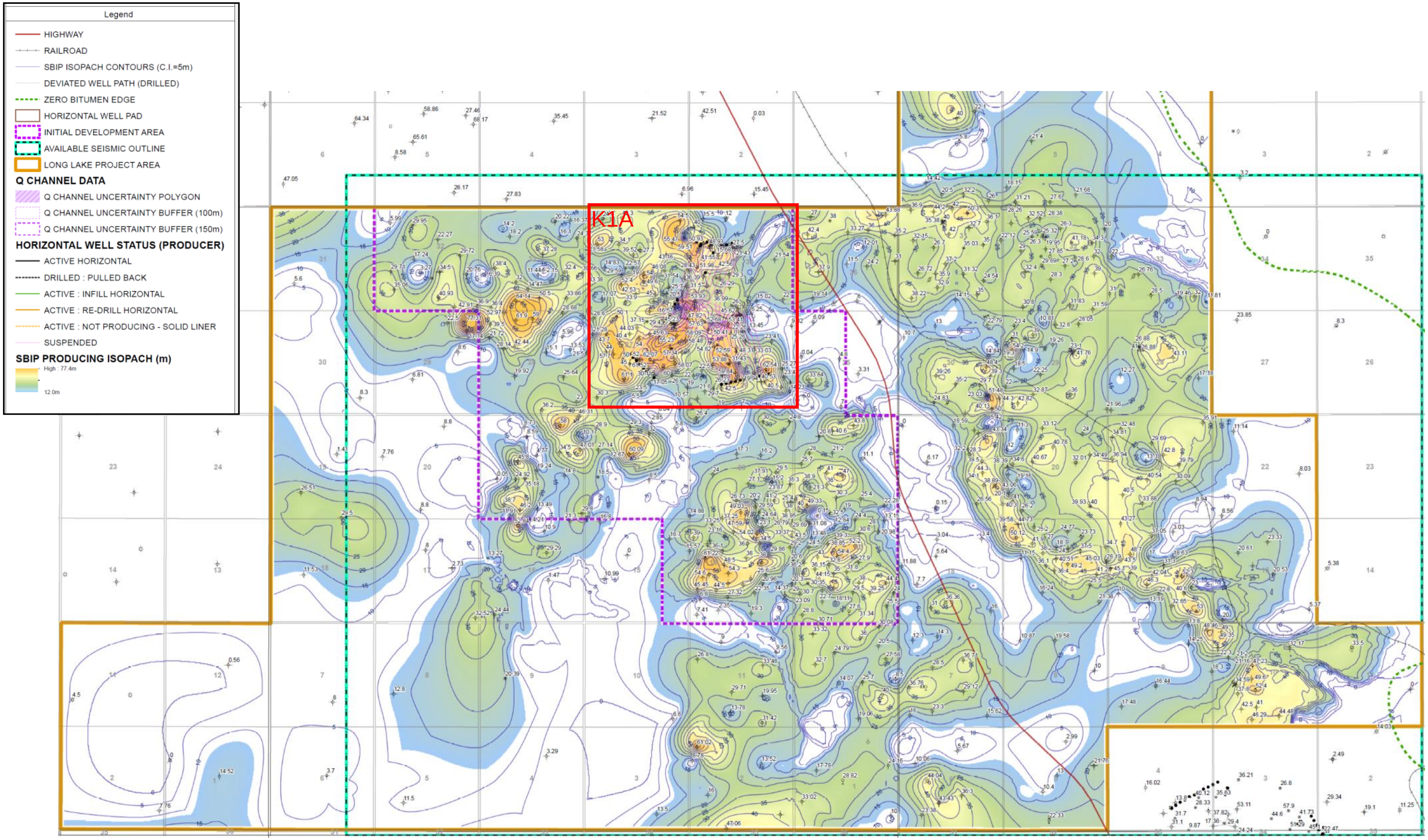
SBIP PRODUCING ISOPACH (m)

High : 77.4m

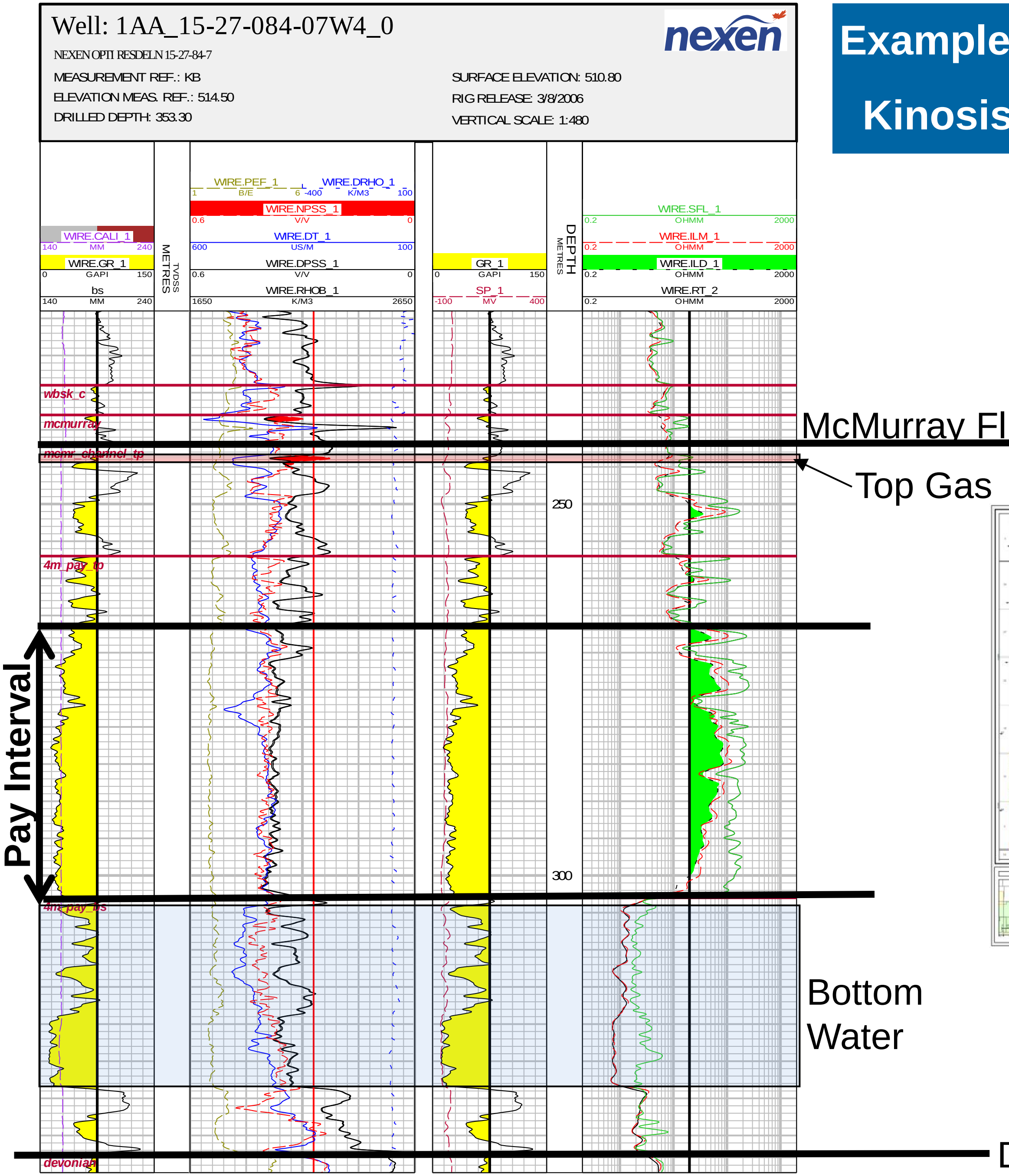
12.0m

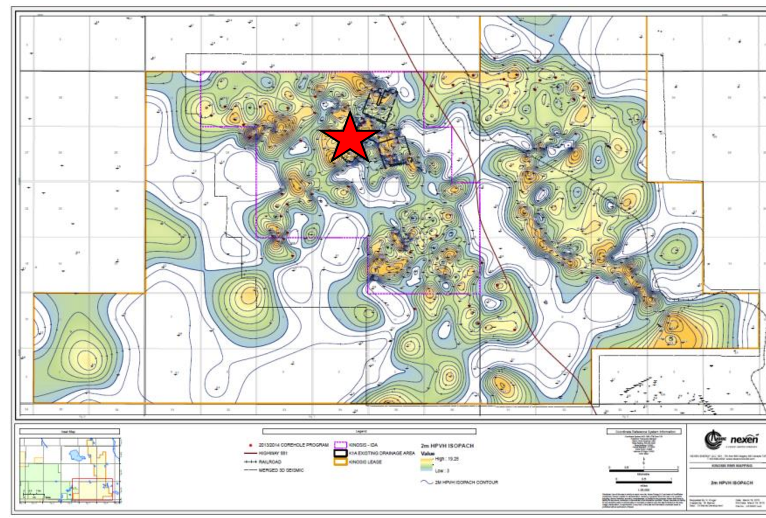


Kinosis
SBIP Pay Interval Isopach



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

nexen
A CNOOC LIMITED COMPANY

Legend

- HIGHWAY
- RAILROAD
- SBIP BASE CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

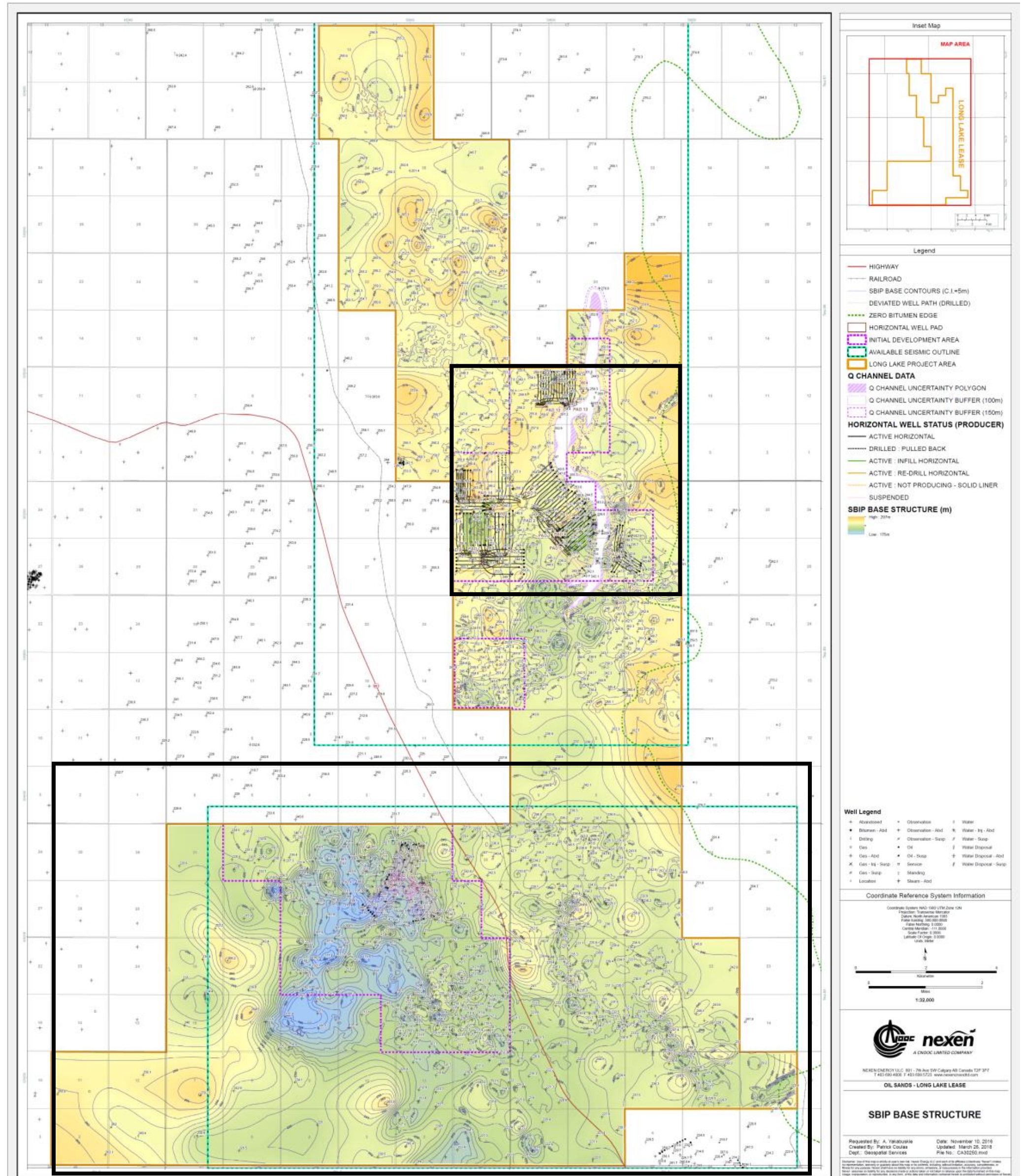
HORIZONTAL WELL STATUS (PRODUCER)

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

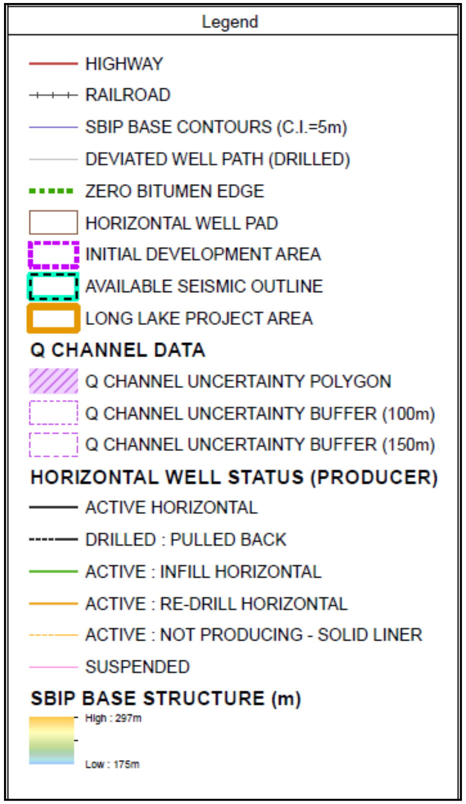
SBIP BASE STRUCTURE (m)

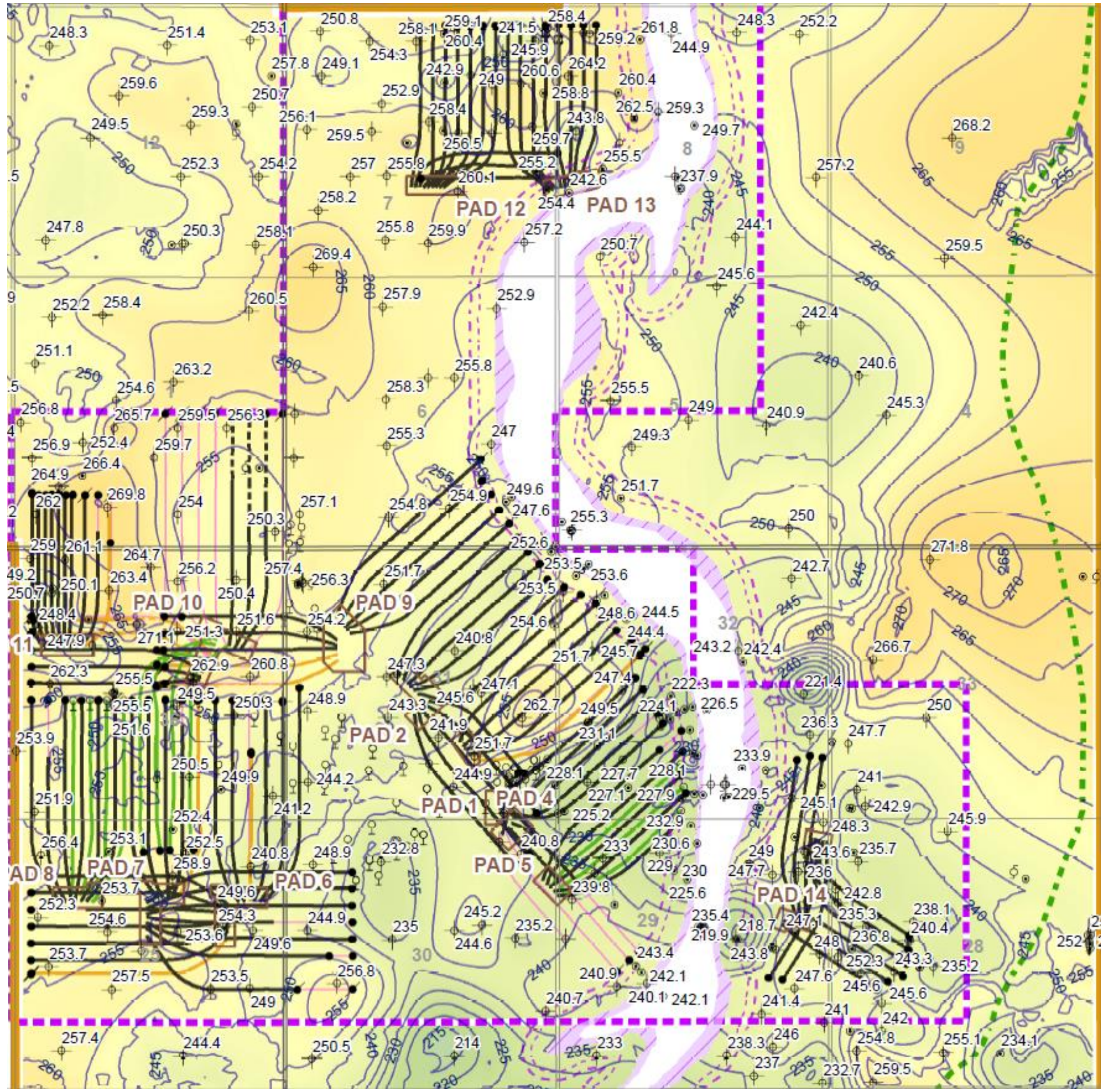
High : 297m

Low : 175m



Long Lake
SBIP Pay Interval Base Structure





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

Kinosis
SBIP Pay Interval Base Structure

Legend

- HIGHWAY
- RAILROAD
- SBIP BASE CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
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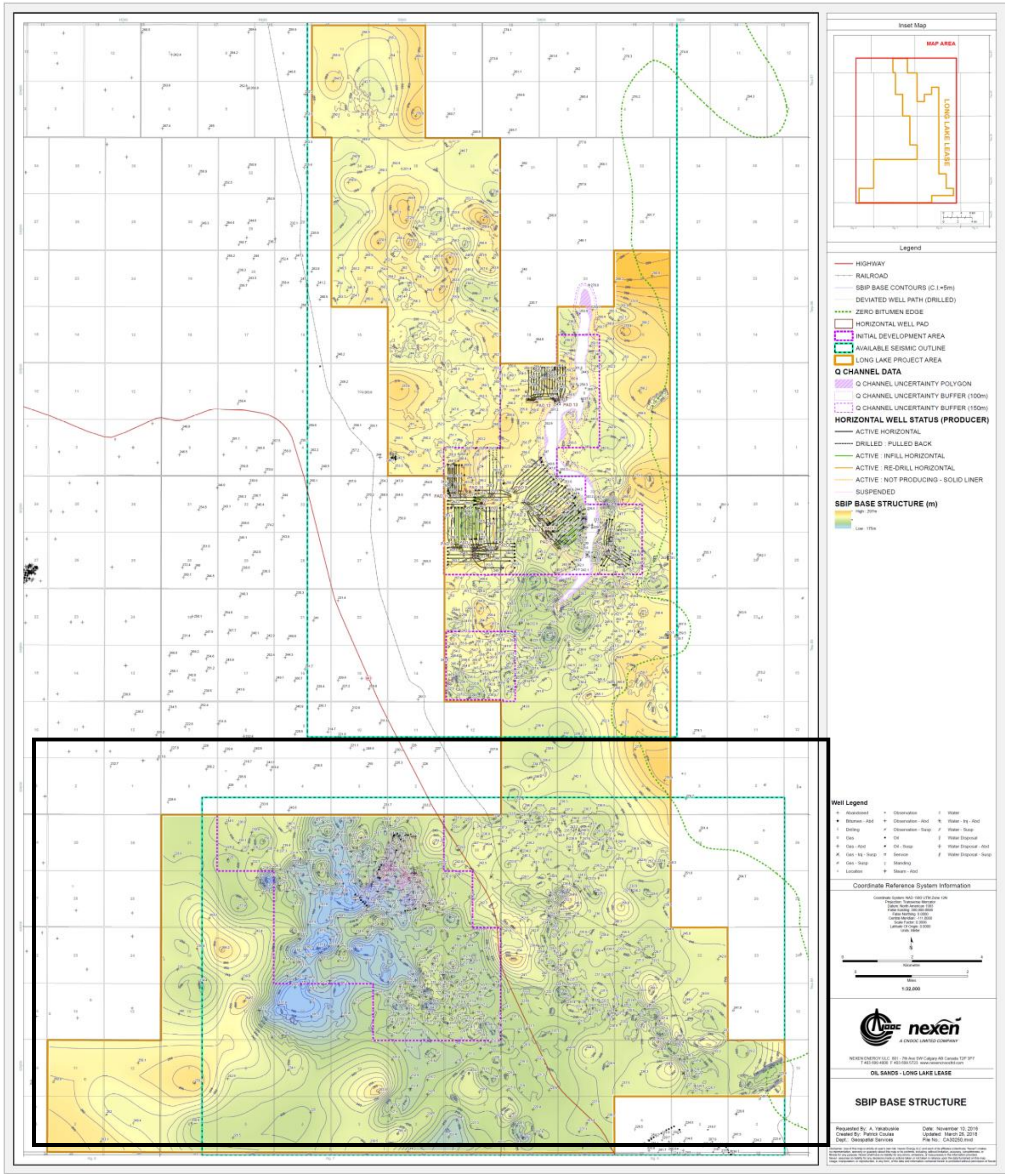
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

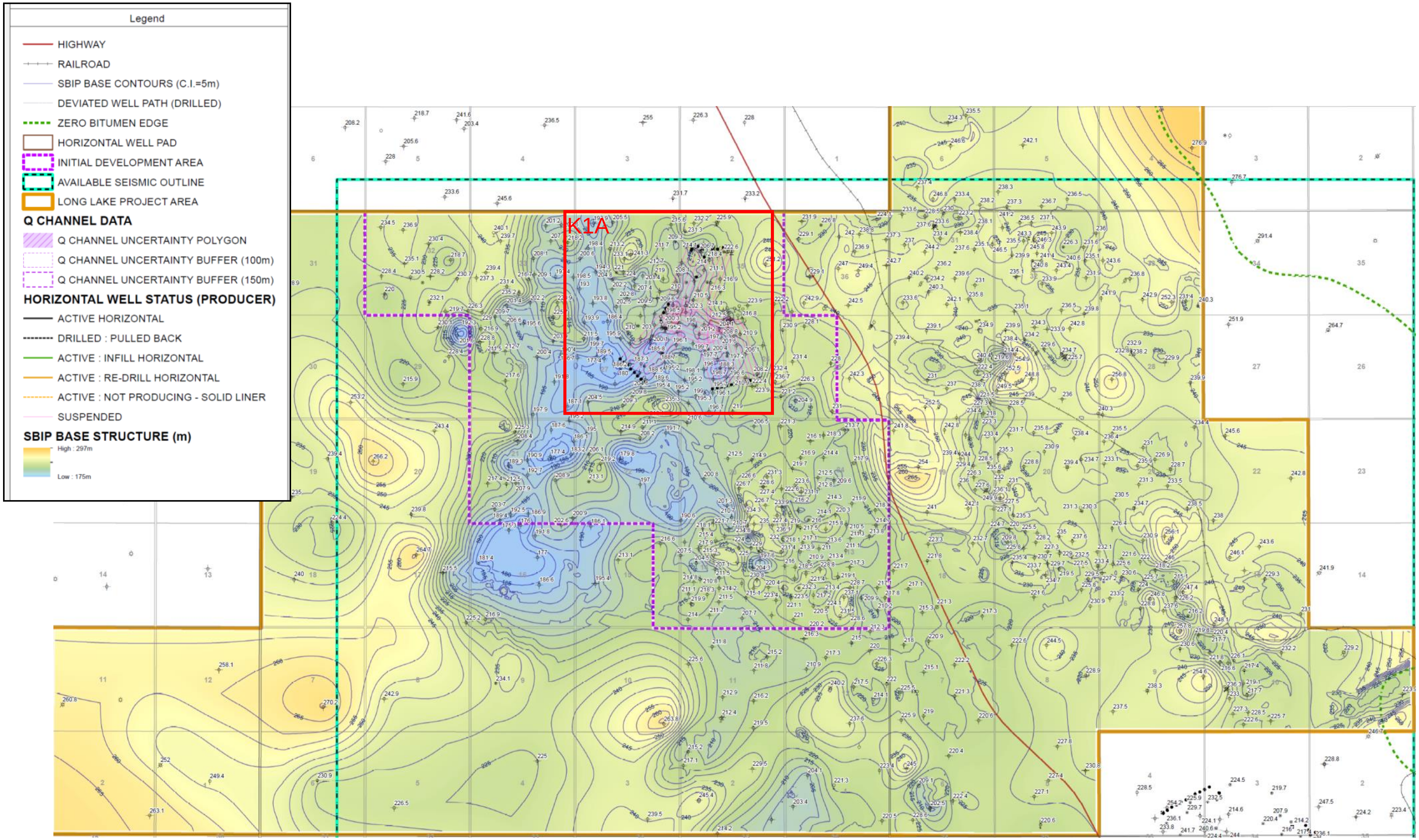
SBIP BASE STRUCTURE (m)

High : 297m

Low : 175m



Kinosis
Structure of SBIP Base



Long Lake
SBIP Pay Interval Top Structure

A CNOOC LIMITED COMPANY

Legend

- HIGHWAY
- RAILROAD
- 2m PAY TOP CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

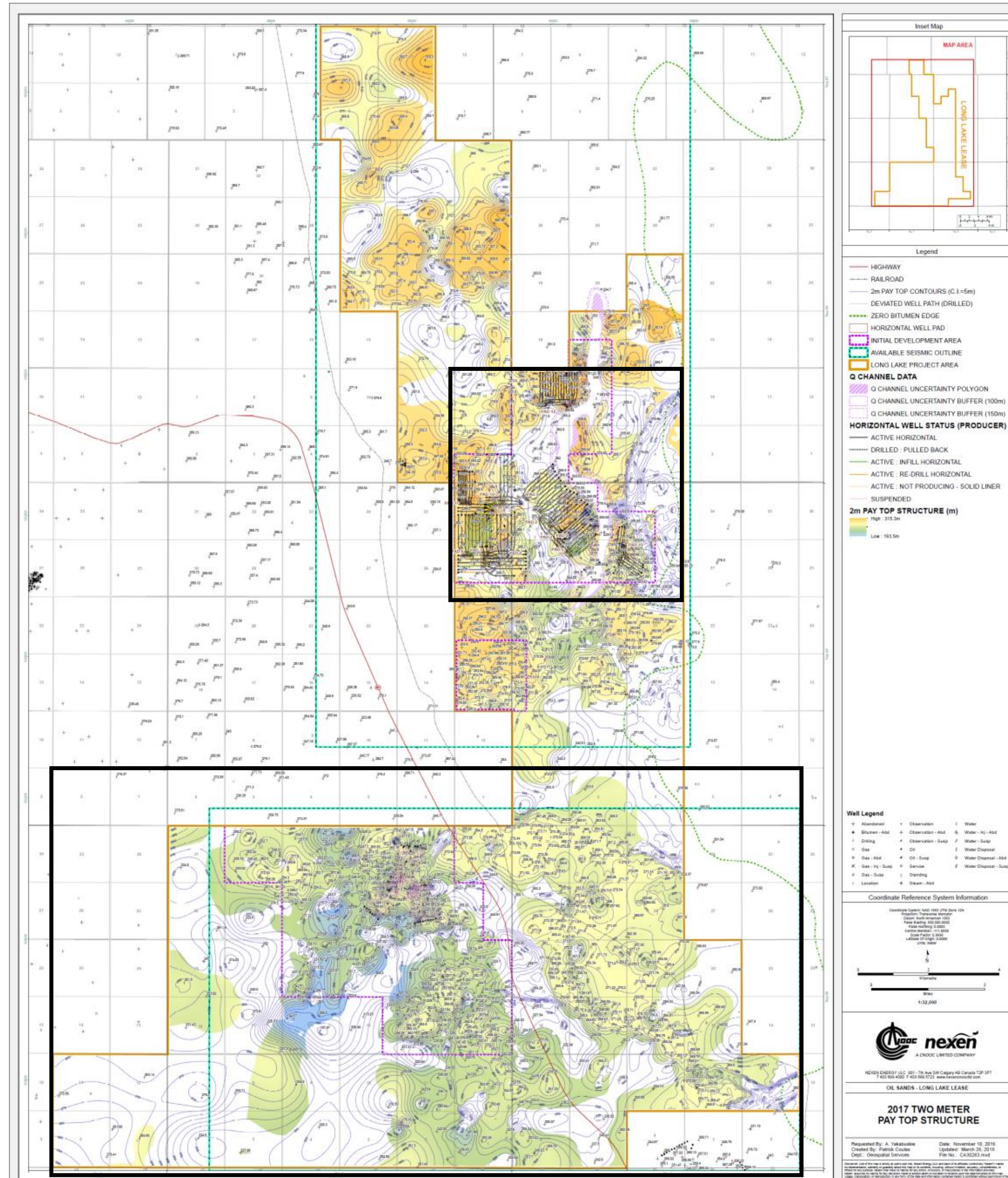
HORIZONTAL WELL STATUS (PRODUCER)

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

2m PAY TOP STRUCTURE (m)

High : 315.3m

Low : 193.5m



Long Lake
SBIP Pay Interval Top Structure

A CNOOC LIMITED COMPANY

Legend

- HIGHWAY
- RAILROAD
- 2m PAY TOP CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

HORIZONTAL WELL STATUS (PRODUCER)

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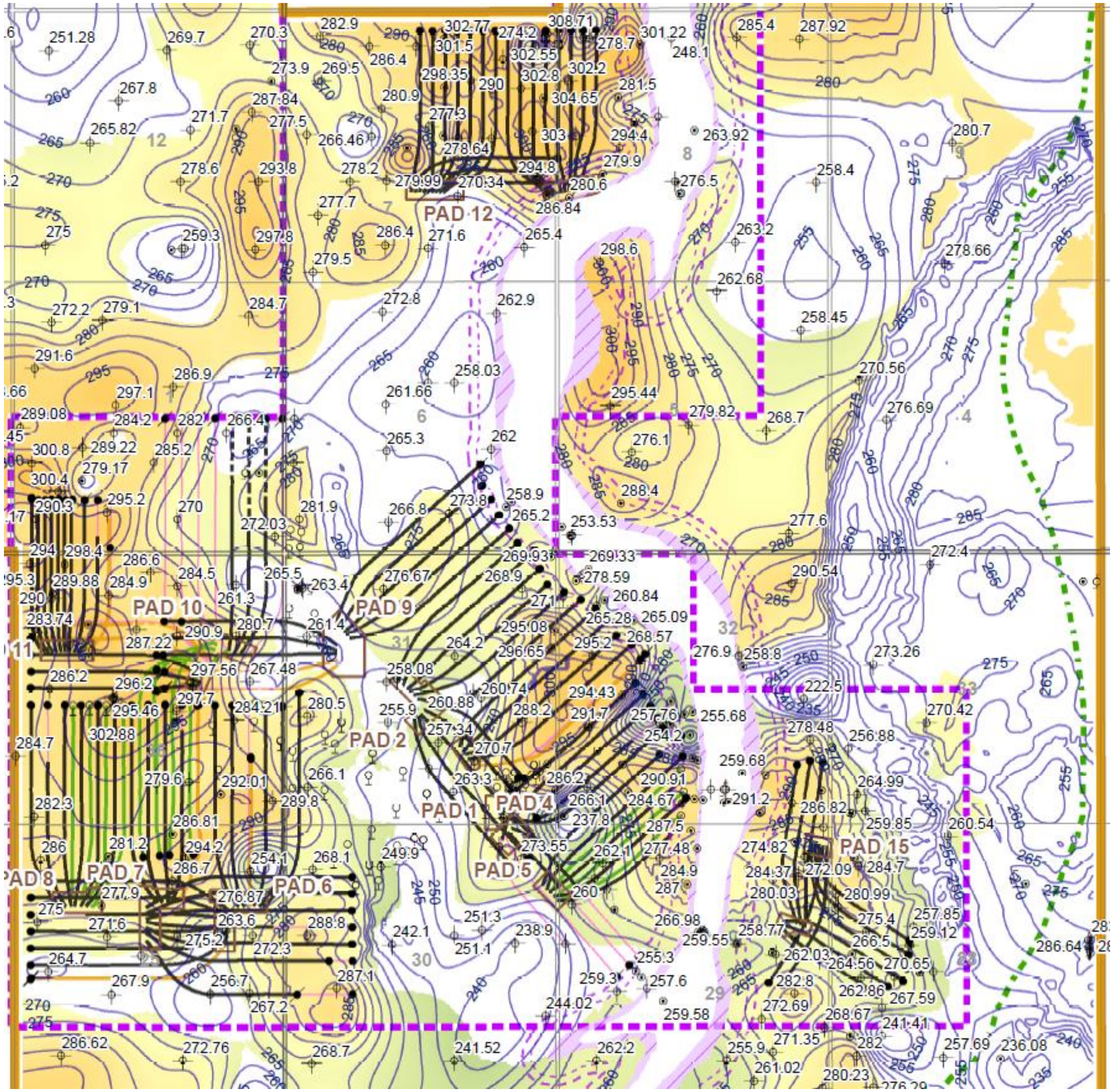
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

2m PAY TOP STRUCTURE (m)

High : 315.3m

Low : 193.5m



- 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
SBIP Pay Interval Top Structure

Legend

HIGHWAY

RAILROAD

2m PAY TOP CONTOURS (C.I.=5m)

DEVIATED WELL PATH (DRILLED)

ZERO BITUMEN EDGE

HORIZONTAL WELL PAD

INITIAL DEVELOPMENT AREA

AVAILABLE SEISMIC OUTLINE

LONG LAKE PROJECT AREA

Q CHANNEL DATA

Q CHANNEL UNCERTAINTY POLYGON

Q CHANNEL UNCERTAINTY BUFFER (100m)

Q CHANNEL UNCERTAINTY BUFFER (150m)

HORIZONTAL WELL STATUS (PRODUCER)

ACTIVE HORIZONTAL

DRILLED : PULLED BACK

ACTIVE : INFILL HORIZONTAL

ACTIVE : RE-DRILL HORIZONTAL

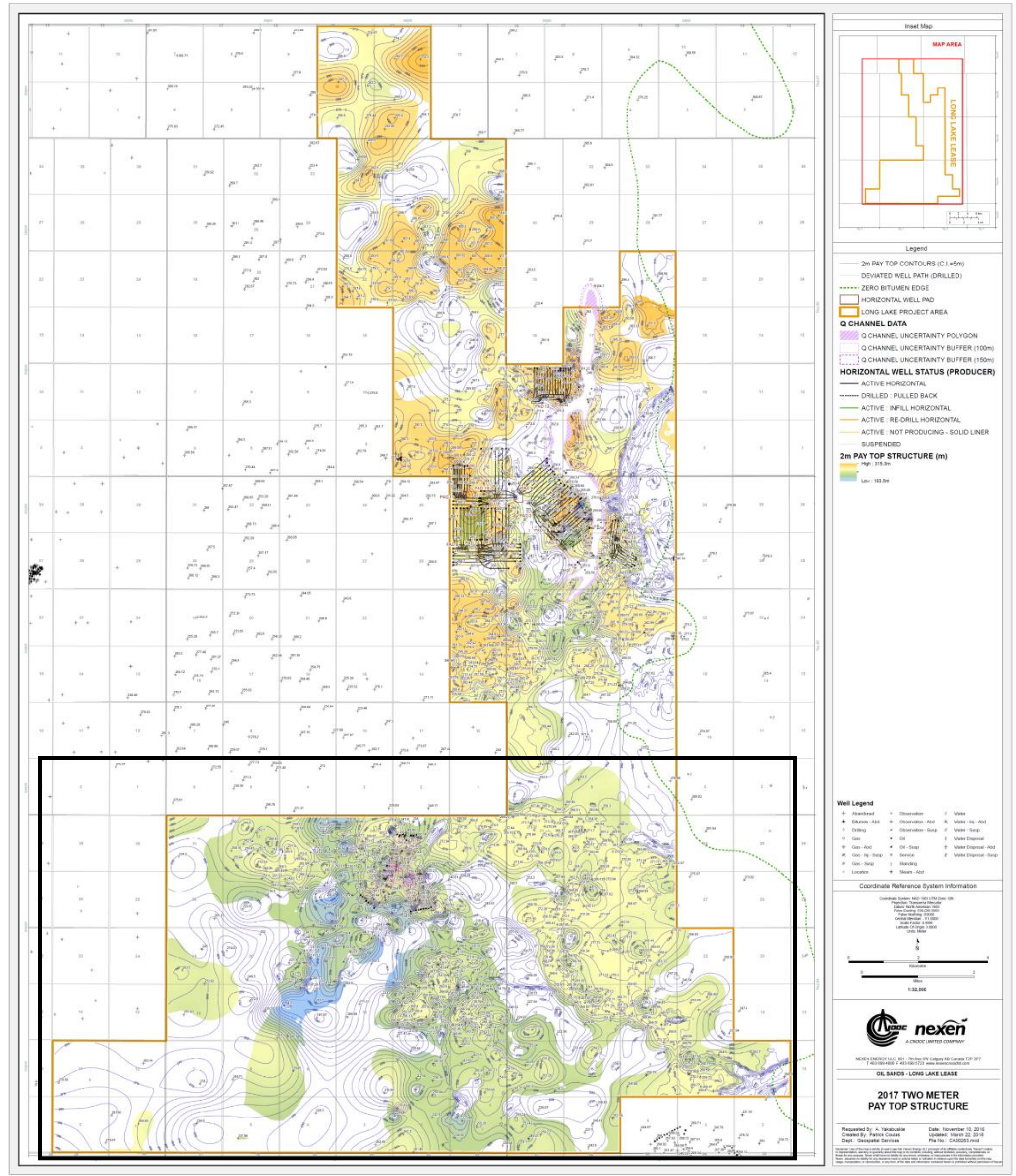
ACTIVE : NOT PRODUCING - SOLID LINER

SUSPENDED

2m PAY TOP STRUCTURE (m)

High : 315.3m

Low : 193.5m



Kinosis
Structure of SBIP Top

Legend

- HIGHWAY
- RAILROAD
- 2m PAY TOP CONTOURS (C.I.=5m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

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

HORIZONTAL WELL STATUS (PRODUCER)

- ACTIVE HORIZONTAL
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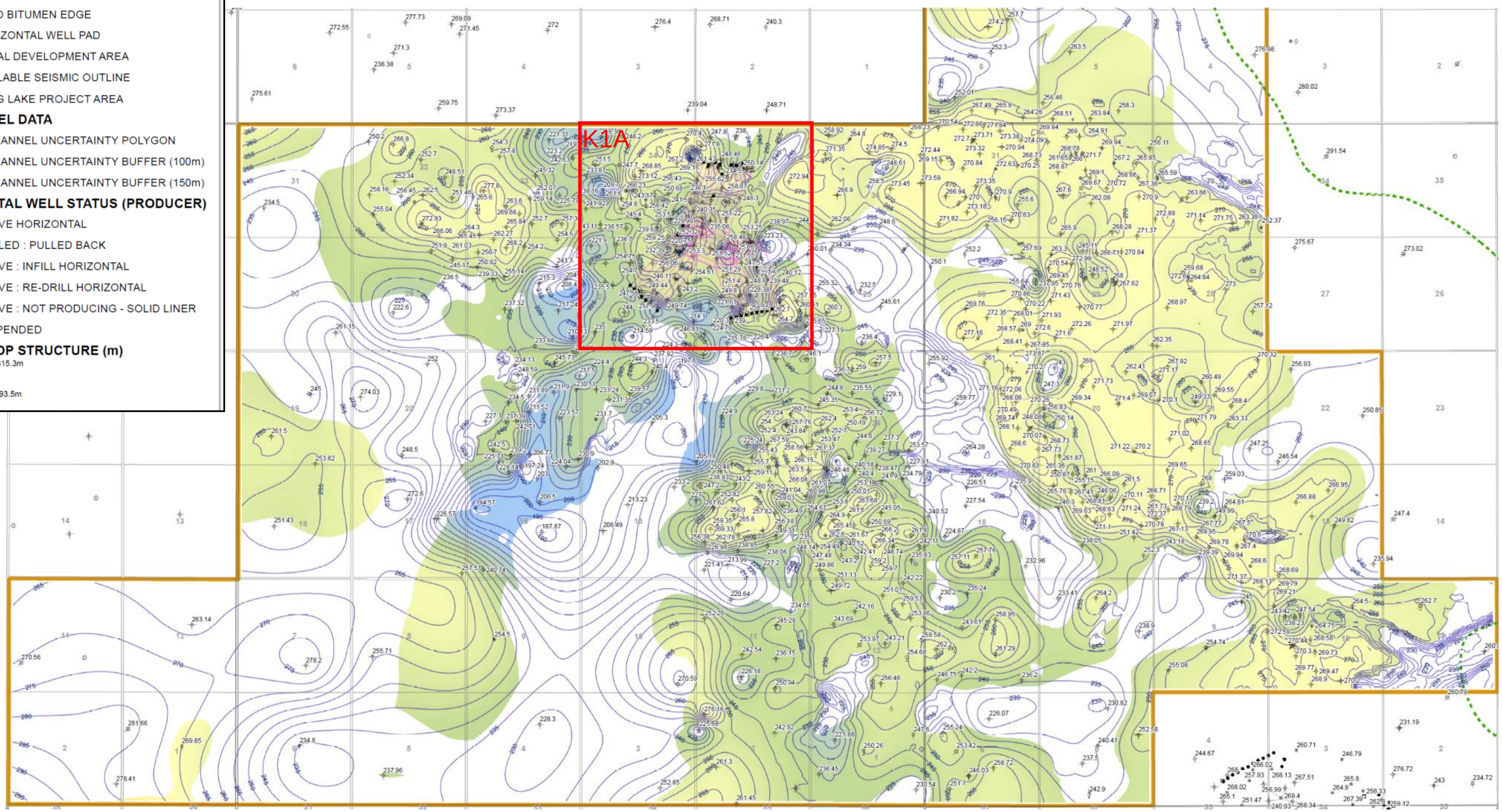
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

2m PAY TOP STRUCTURE (m)

High : 315.3m

Low : 193.5m



Long Lake
HPVH Isopach over SBIP Pay Interval

Legend

- HIGHWAY
- RAILROAD
- SBIP HPVH CONTOURS (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
- LONG LAKE PROJECT AREA

Q CHANNEL DATA

- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
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HORIZONTAL WELL STATUS (PRODUCER)

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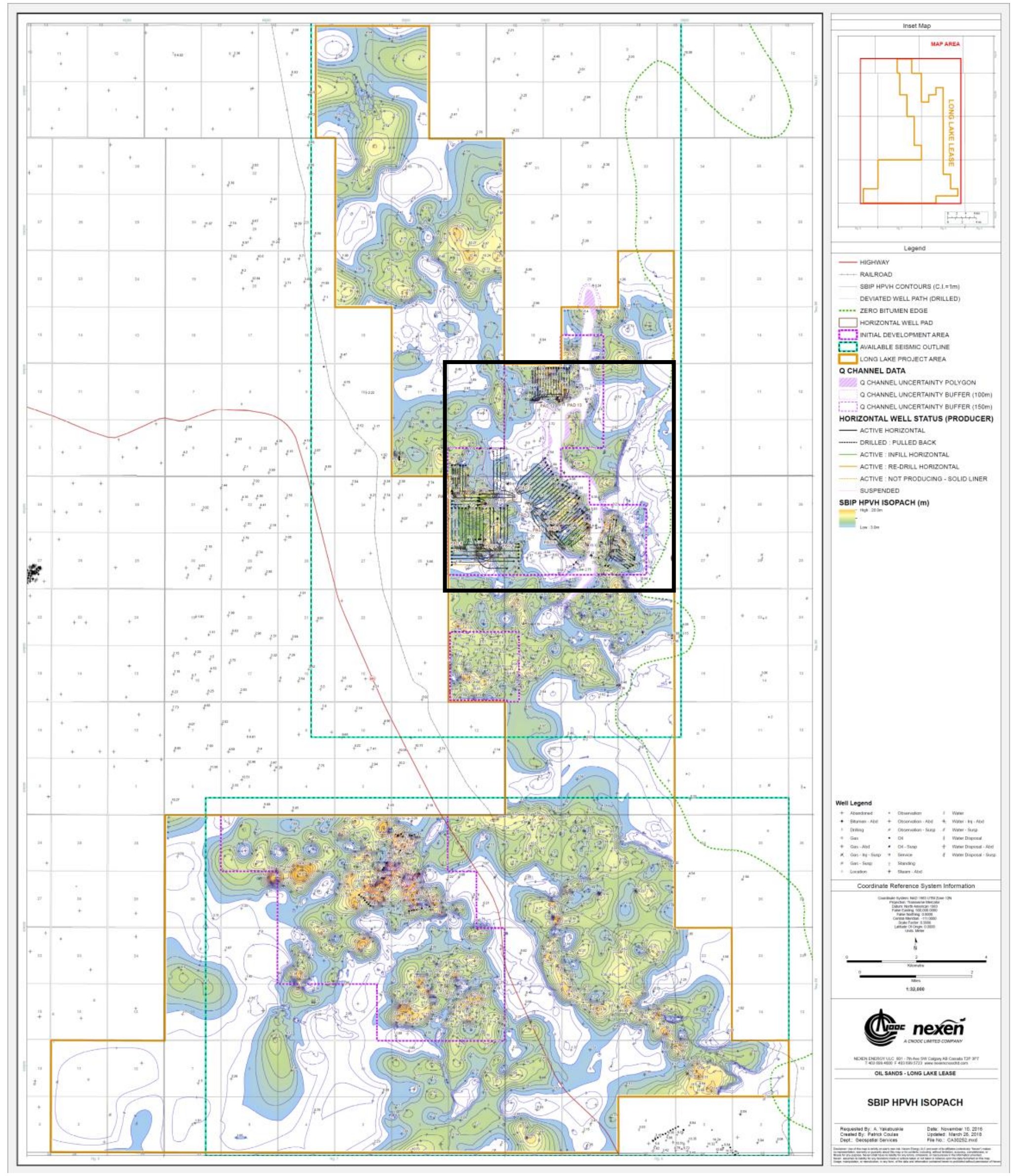
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

SBIP HPVH ISOPACH (m)

High : 20.0m

Low : 3.0m

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



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

Long Lake
HPVH Isopach over SBIP Pay Interval

Legend

- HIGHWAY
- RAILROAD
- SBIP HPVH CONTOURS (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
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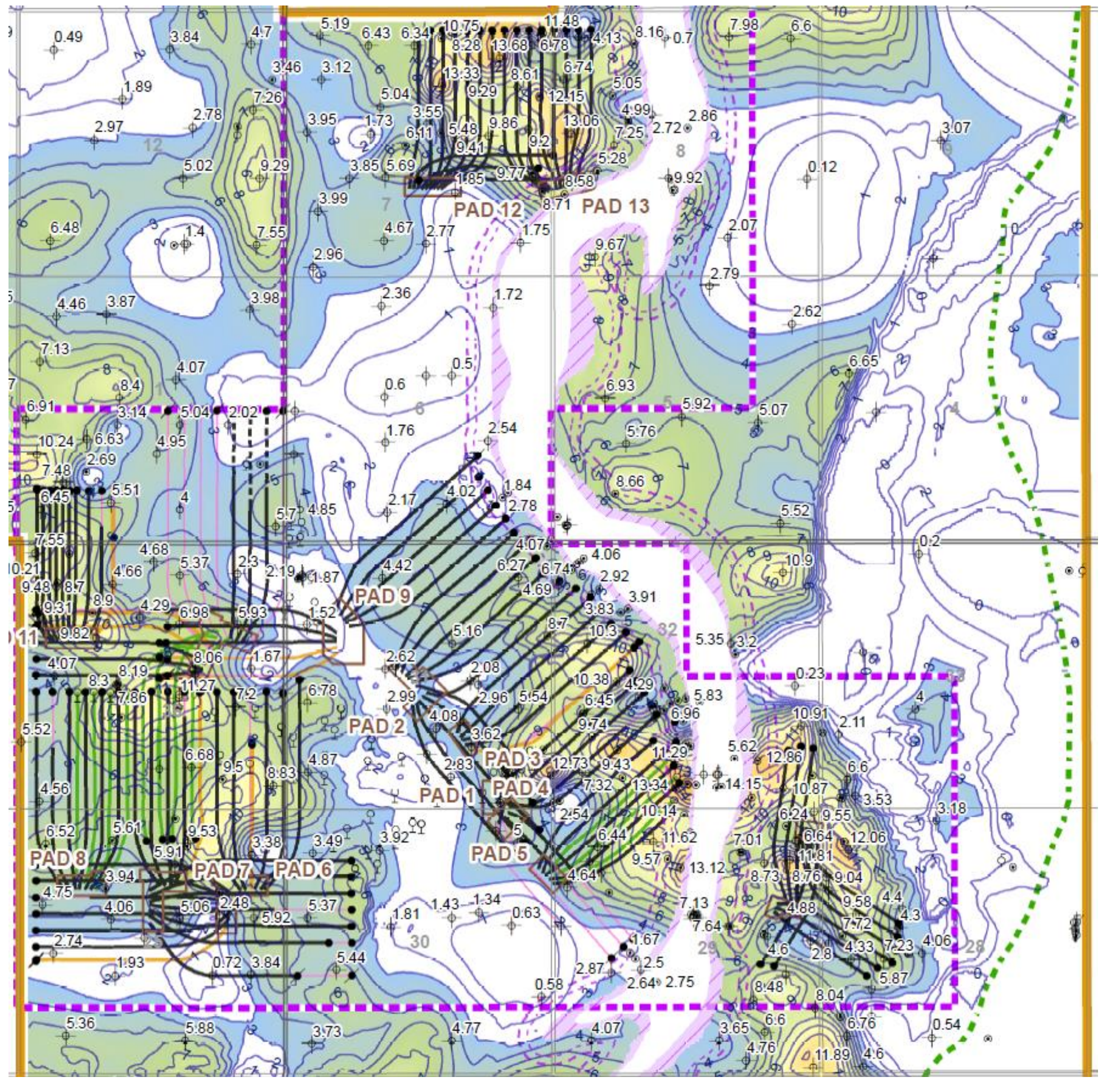
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

SBIP HPVH ISOPACH (m)

High : 20.0m

Low : 3.0m



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

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

Kinosis
HPVH Isopach over SBIP Pay Interval

nexen
A CNOOC LIMITED COMPANY

Legend

- HIGHWAY
- RAILROAD
- SBIP HPVH CONTOURS (C.I.=1m)
- DEVIATED WELL PATH (DRILLED)
- ZERO BITUMEN EDGE
- HORIZONTAL WELL PAD
- INITIAL DEVELOPMENT AREA
- AVAILABLE SEISMIC OUTLINE
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- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

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- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED

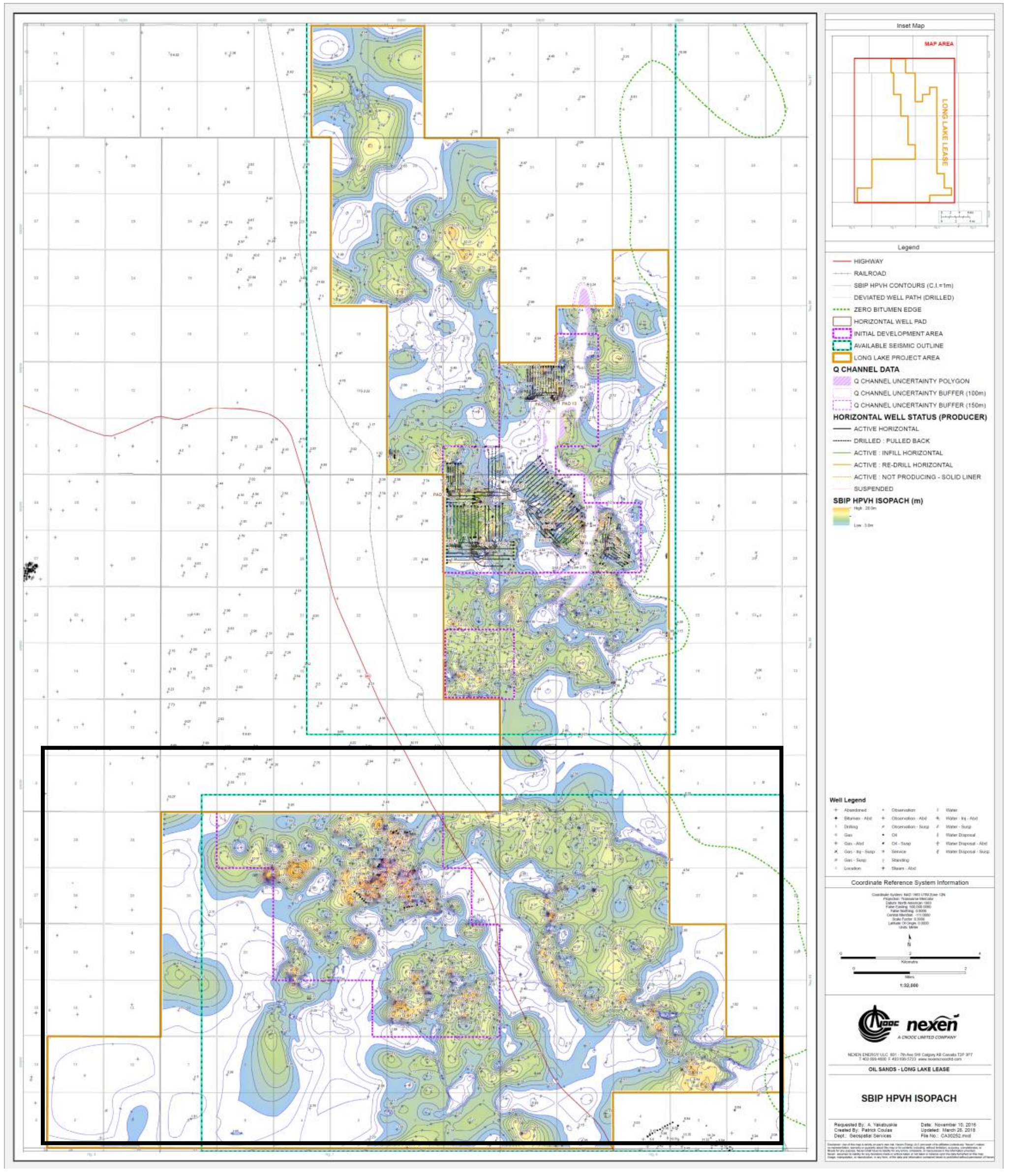
SBIP HPVH ISOPACH (m)

High : 20.0m

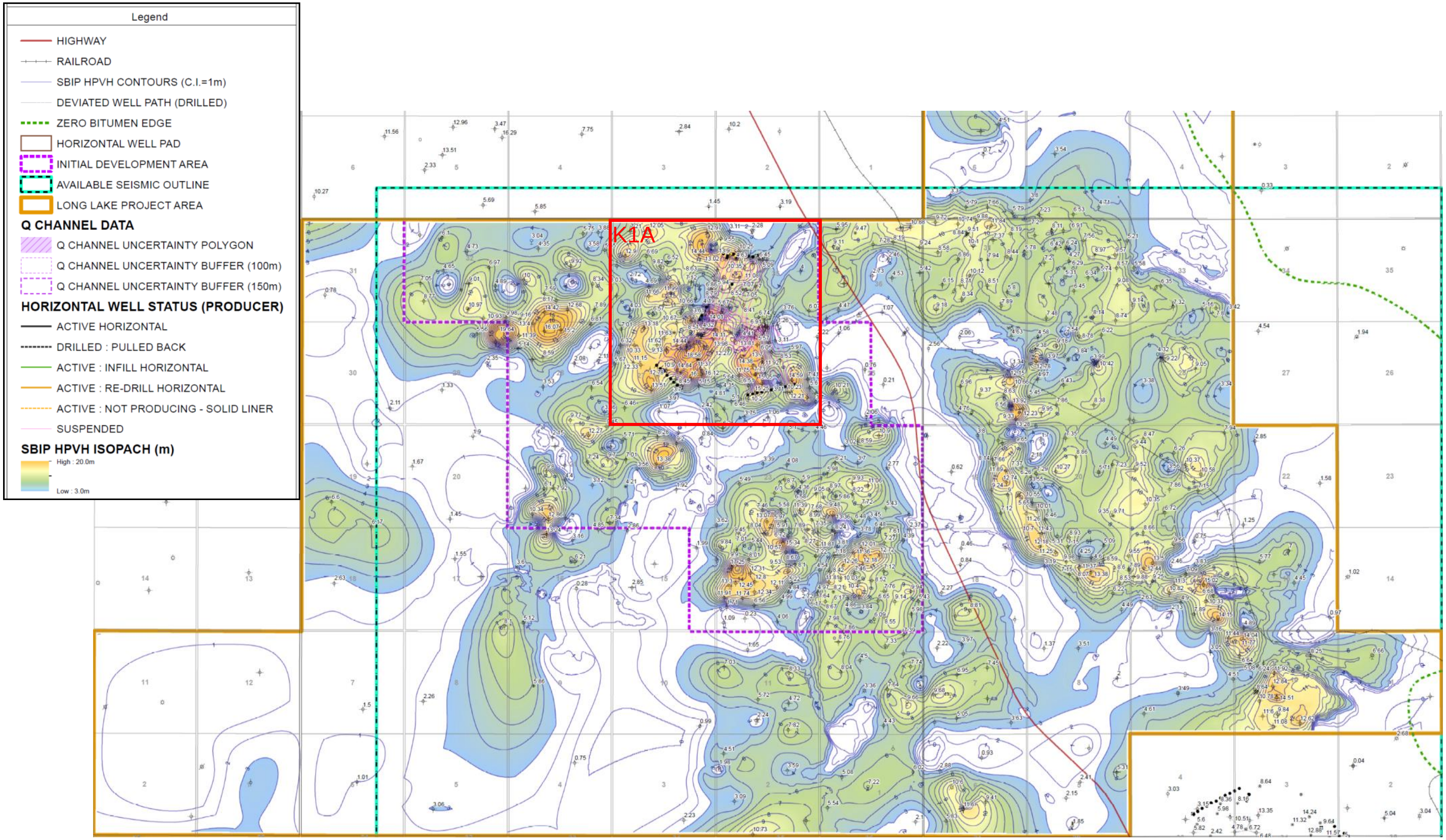
Low : 3.0m

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

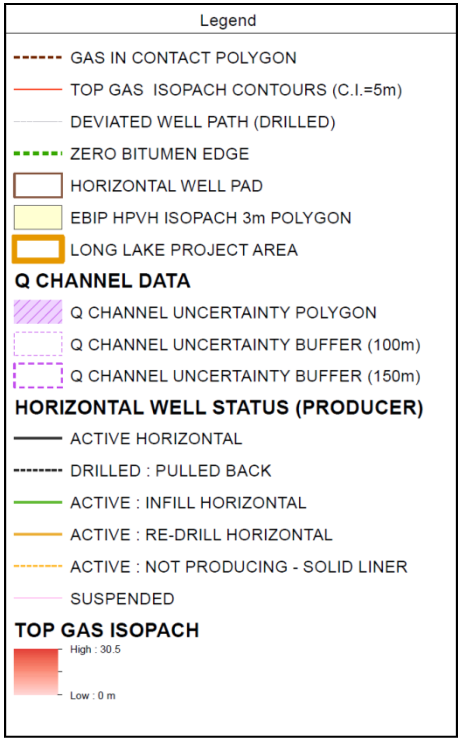
- Colour shading : > $3m^3/m^2$ HPVH



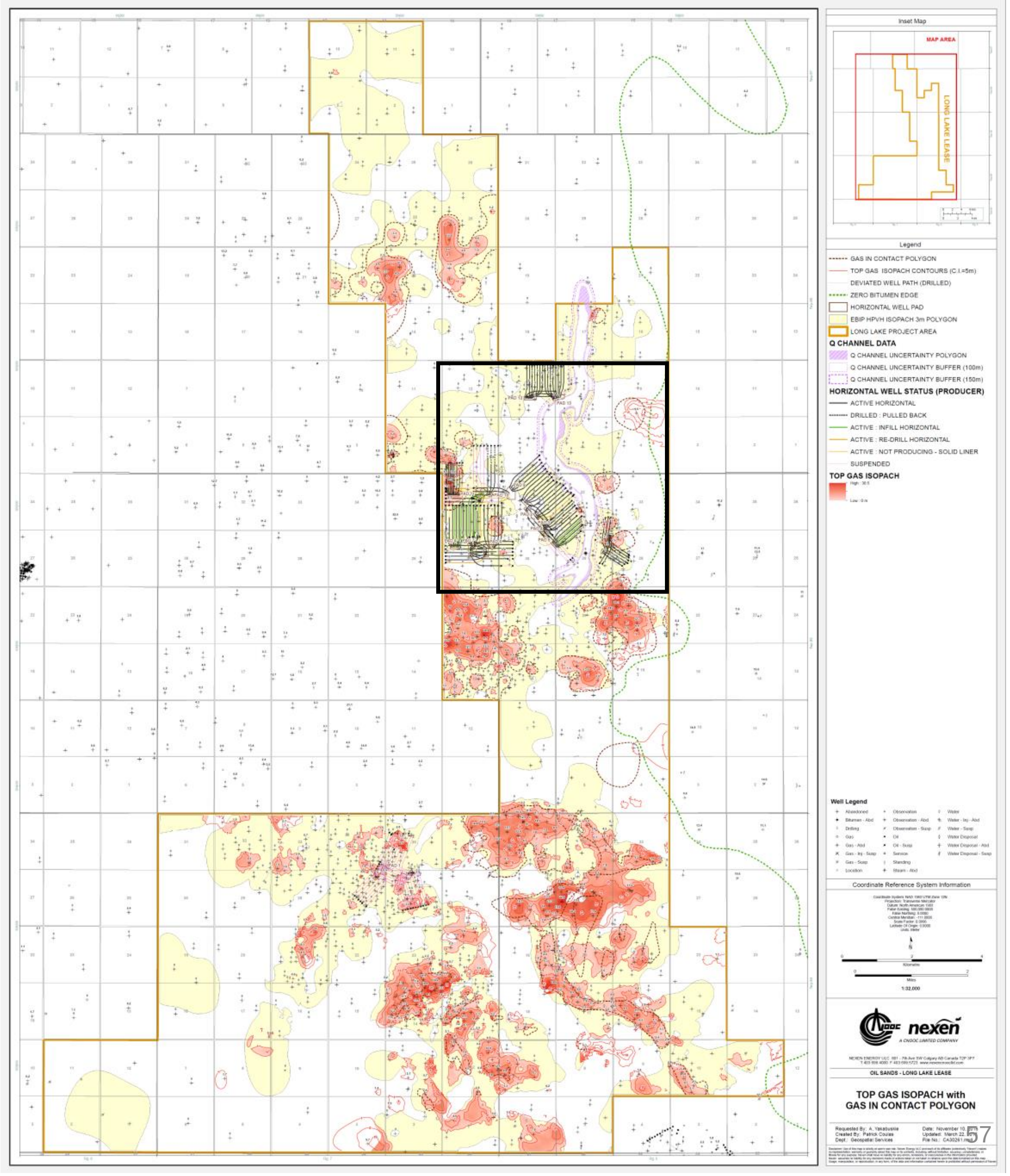
Kinosis
HPVH Isopach over SBIP Interval



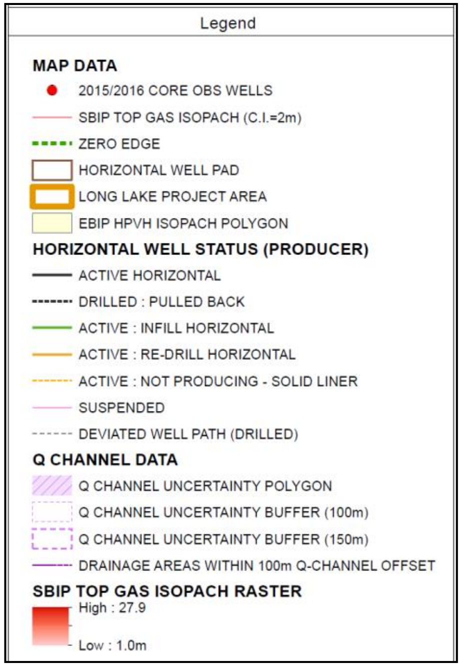
Long Lake Gas: Gas Interval(s) within and in contact with SBIP Interval

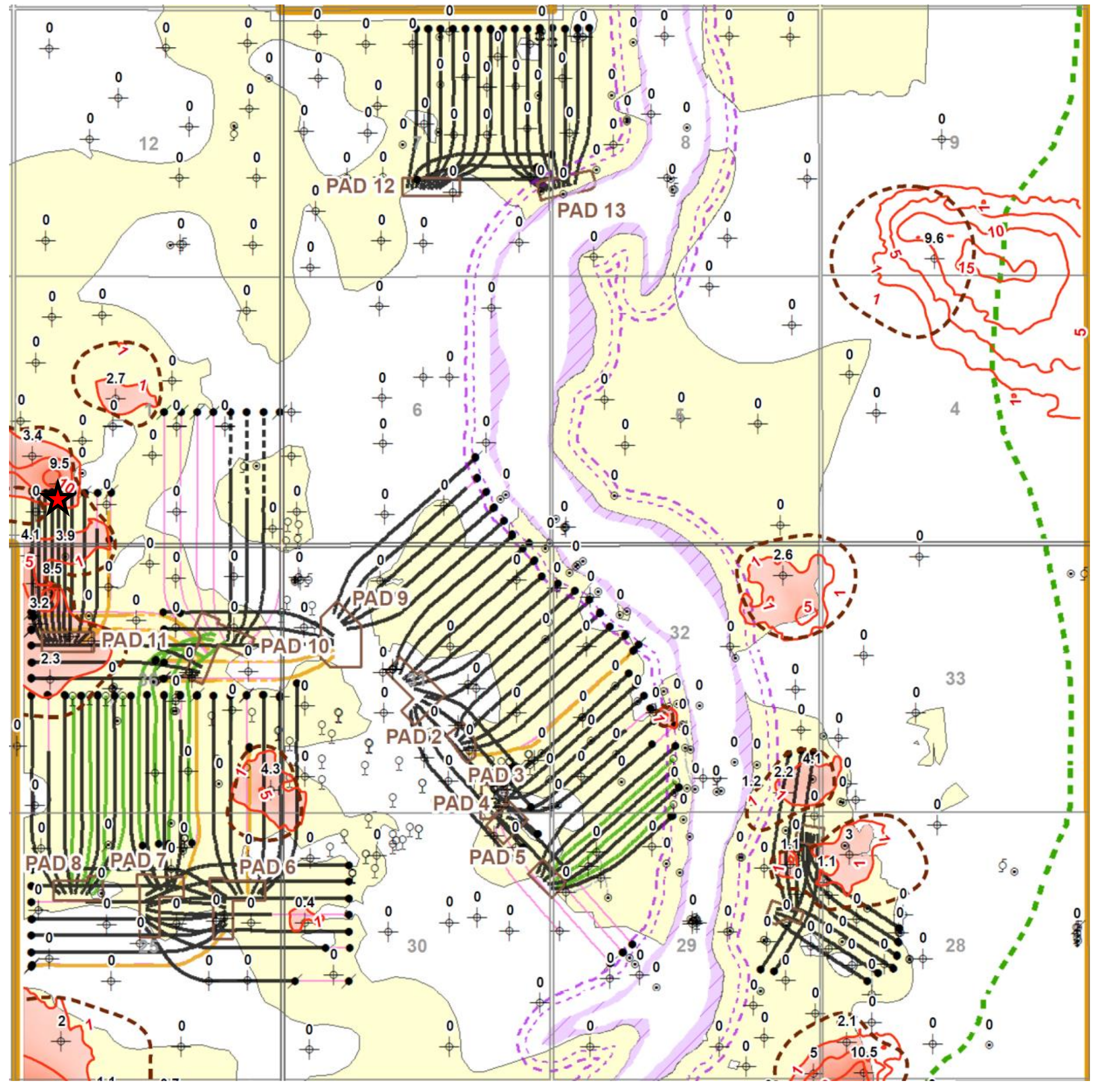


- Gas identified by neutron/density crossover.
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to $3m^3/m^2$ HPVH SBIP contour



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

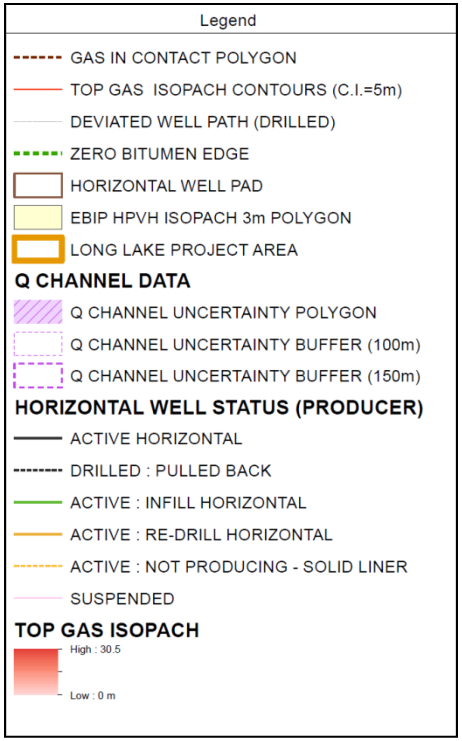


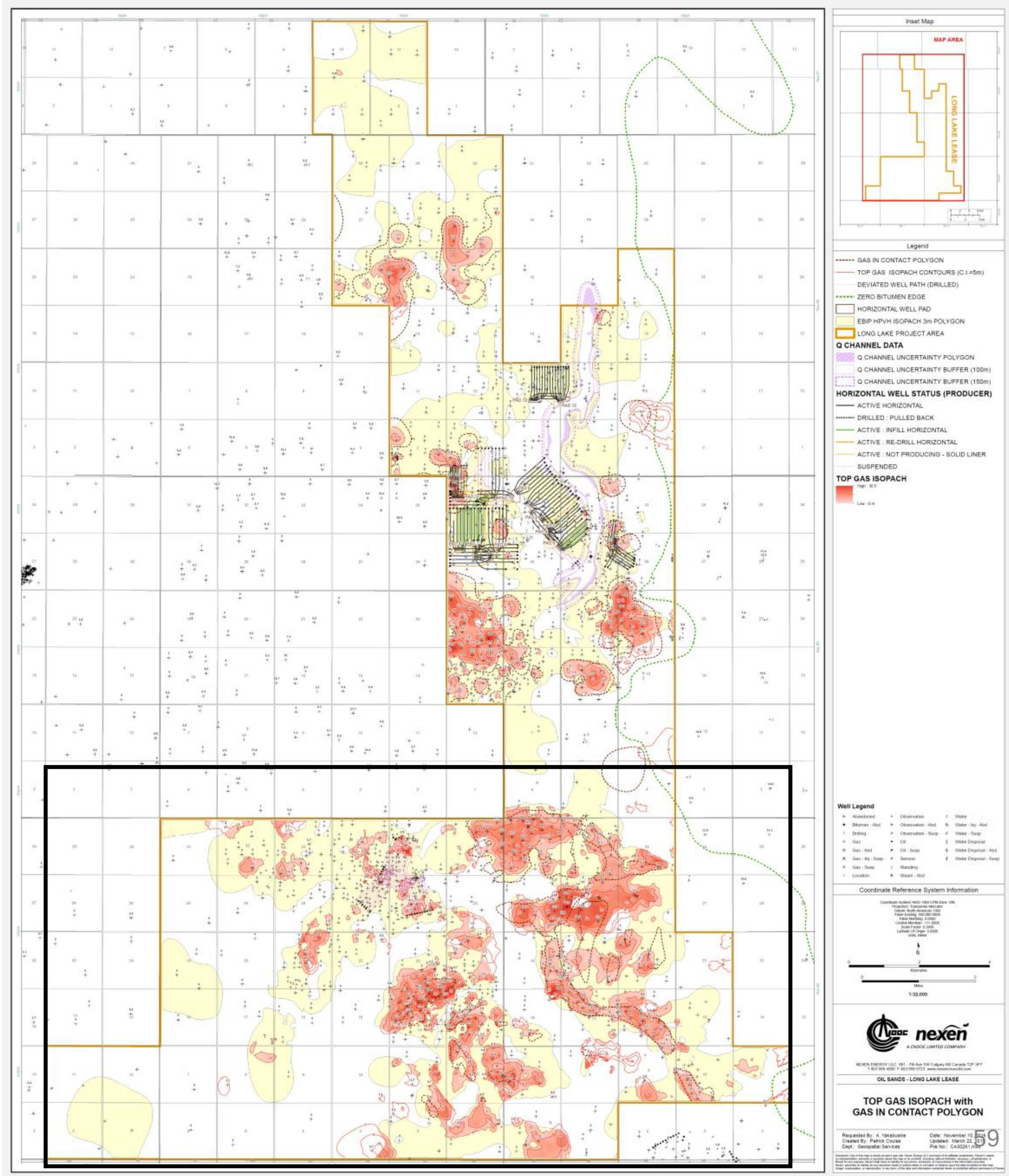


- Gas identified by neutron/density crossover.
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to $3m^3/m^2$ HPVH SBIP contour

★ TYPE LOG

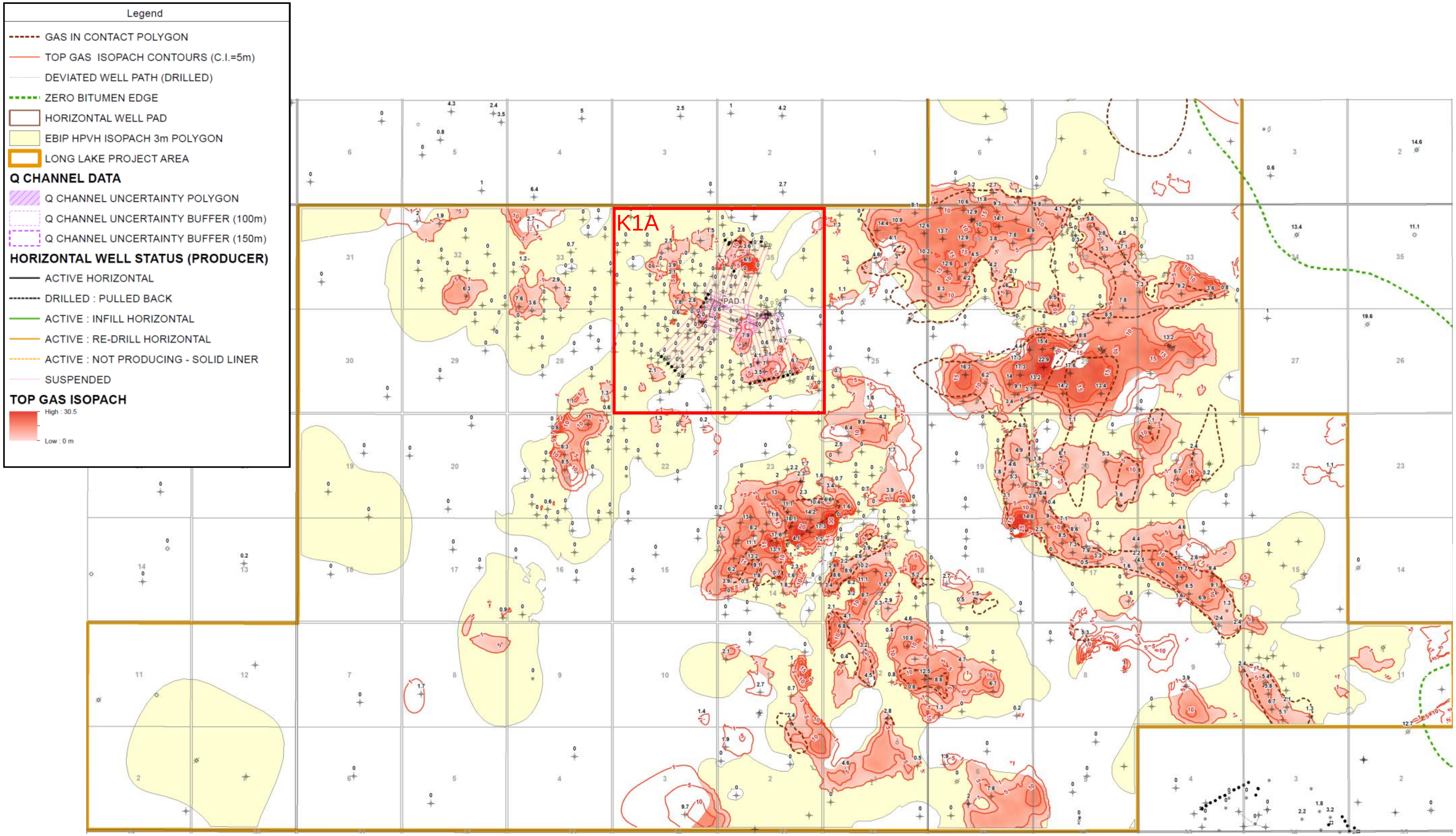
Kinosis Gas: Gas Interval(s) within and in contact with SBIP Interval



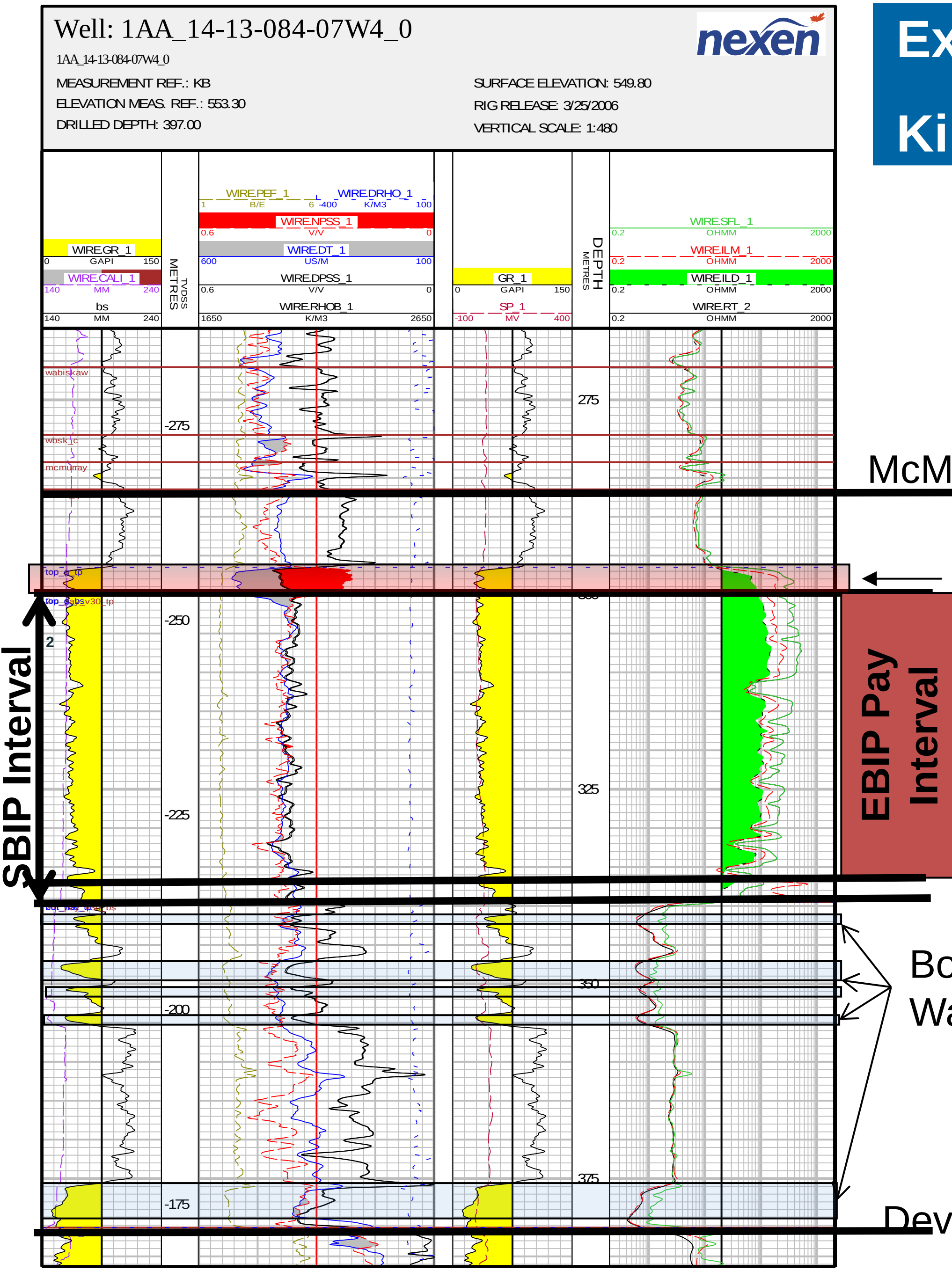


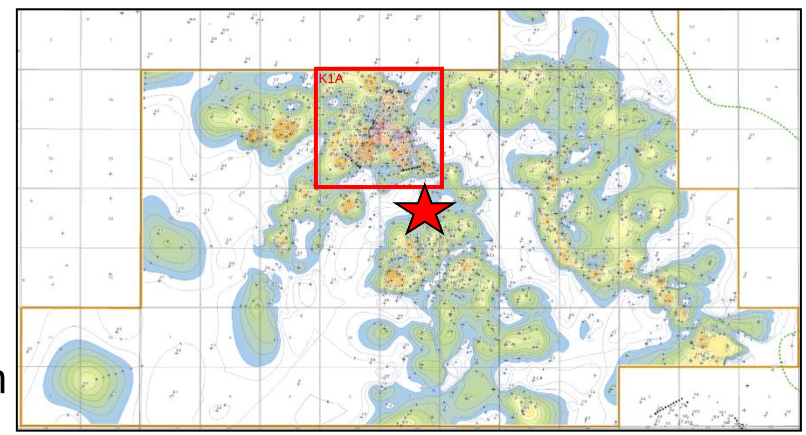
- Gas identified by neutron/density crossover.
- Gas associated with SBIP Interval:
  - within SBIP Interval
  - directly in contact with top water or top of SBIP interval
  - contours clipped to $3m^3/m^2$ HPVH SBIP contour

Kinosis
Top Gas in the McMurray



Example Log: Kinosis IDA





Long Lake
Top Water Associated with SBIP Interval

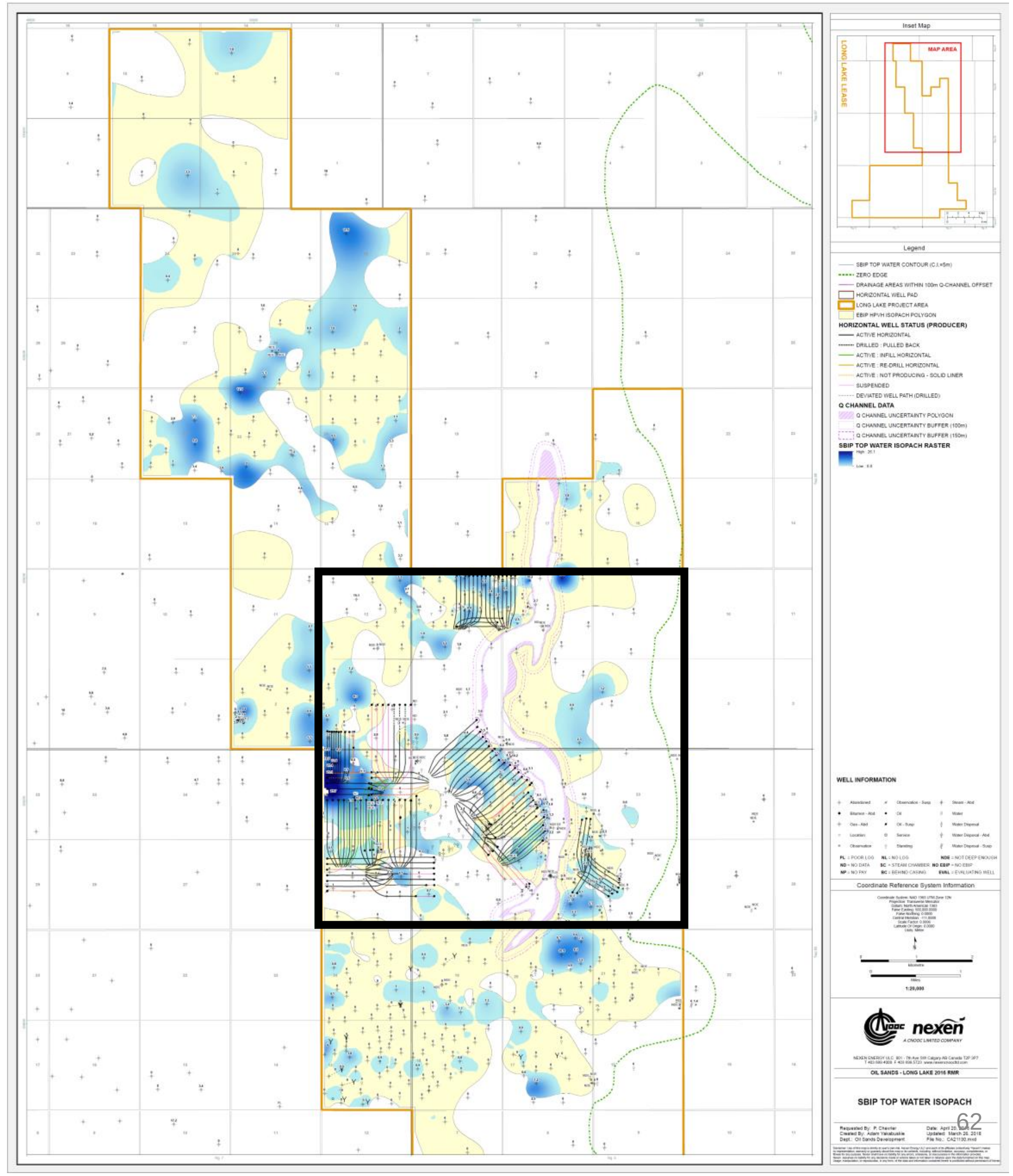
Legend

MAP DATA
- 2015/2016 CORE OBS WELLS
- SBIP TOP WATER CONTOUR (C.I.=5m)
- ZERO EDGE
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET
- 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)

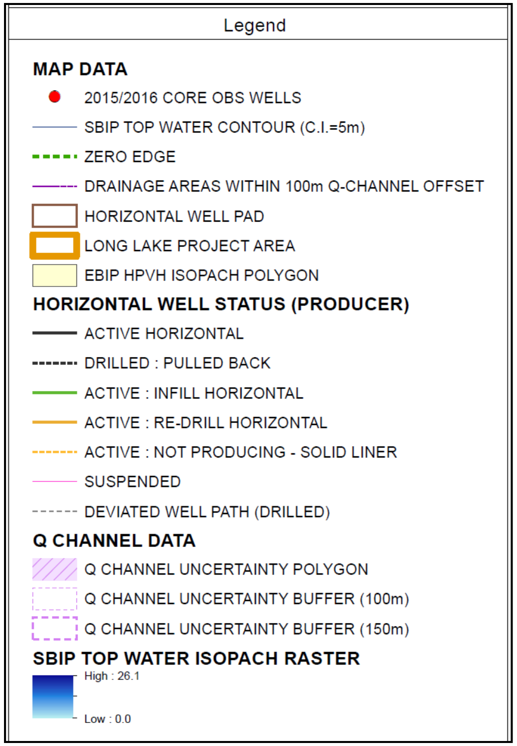
Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

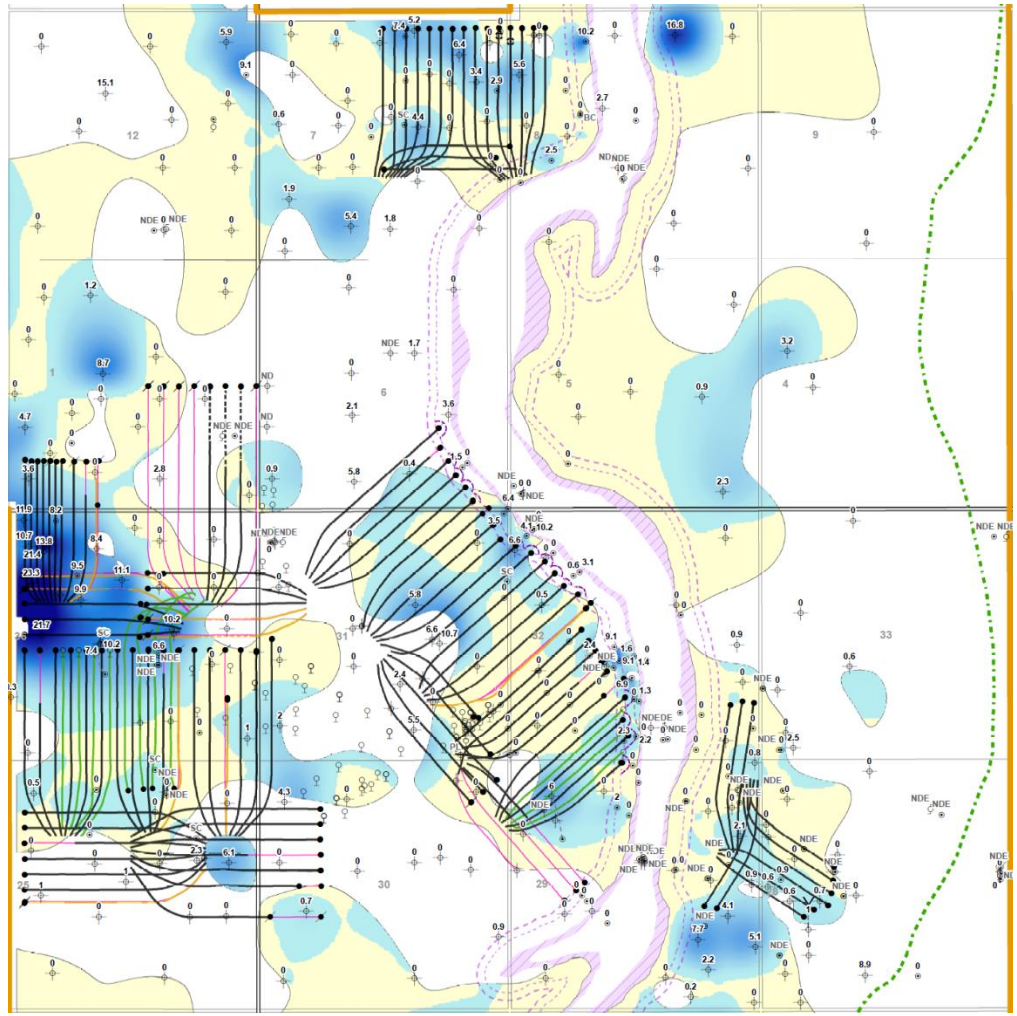
SBIP TOP WATER ISOPACH RASTER
- High : 26.1
- Low : 0.0



- > 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

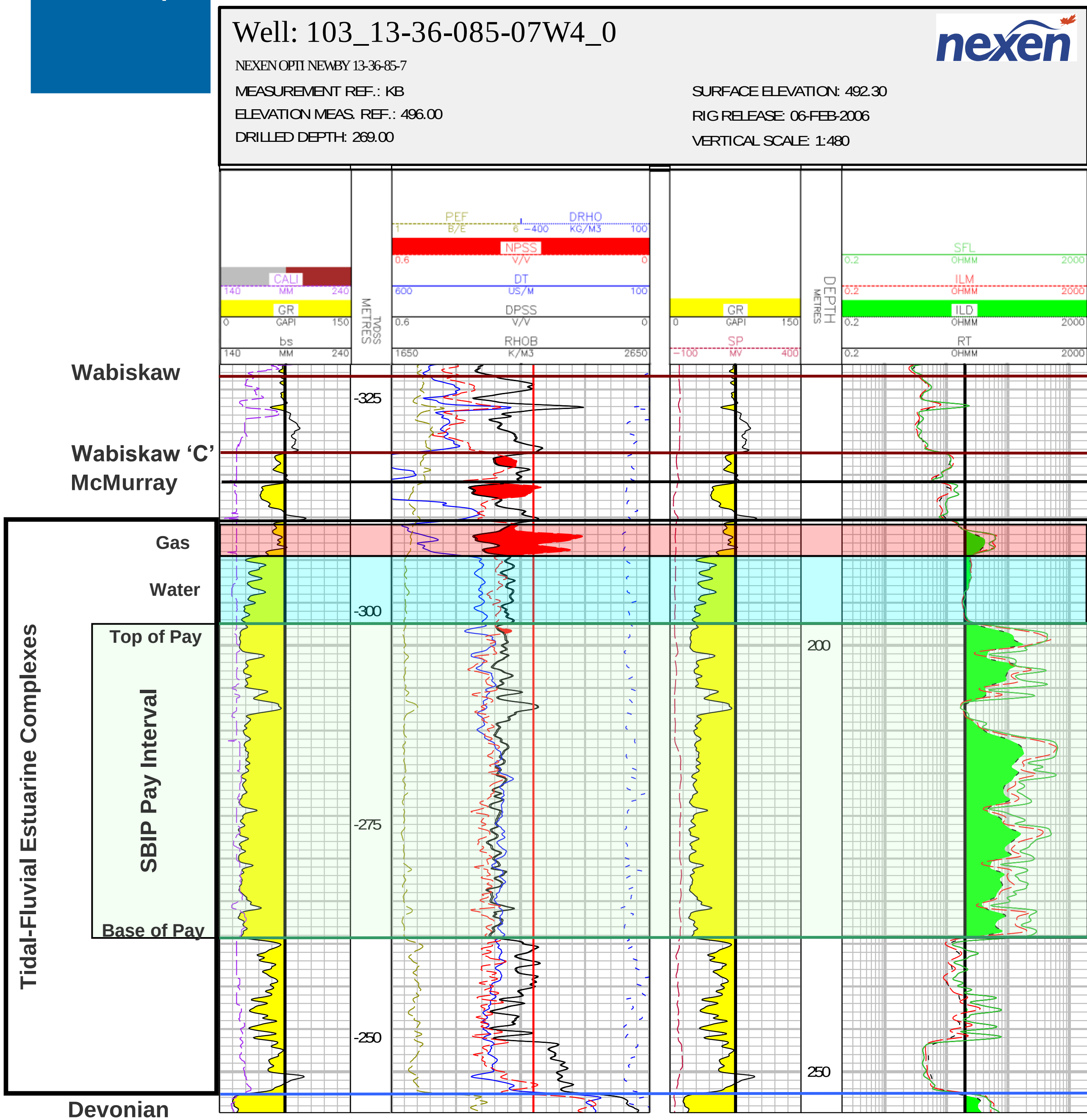
Long Lake
Top Water Associated with SBIP Interval

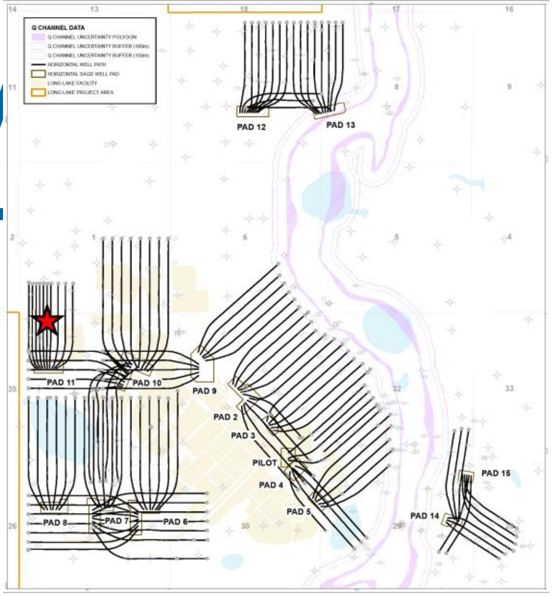


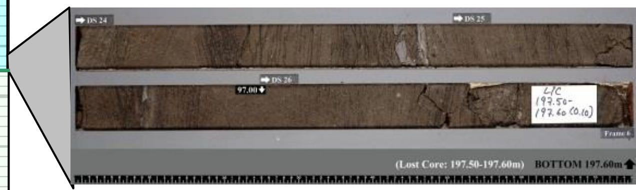


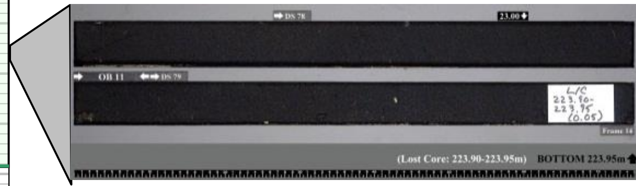
- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH SBIP contour

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









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

nexen
A CNOOC LIMITED COMPANY

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

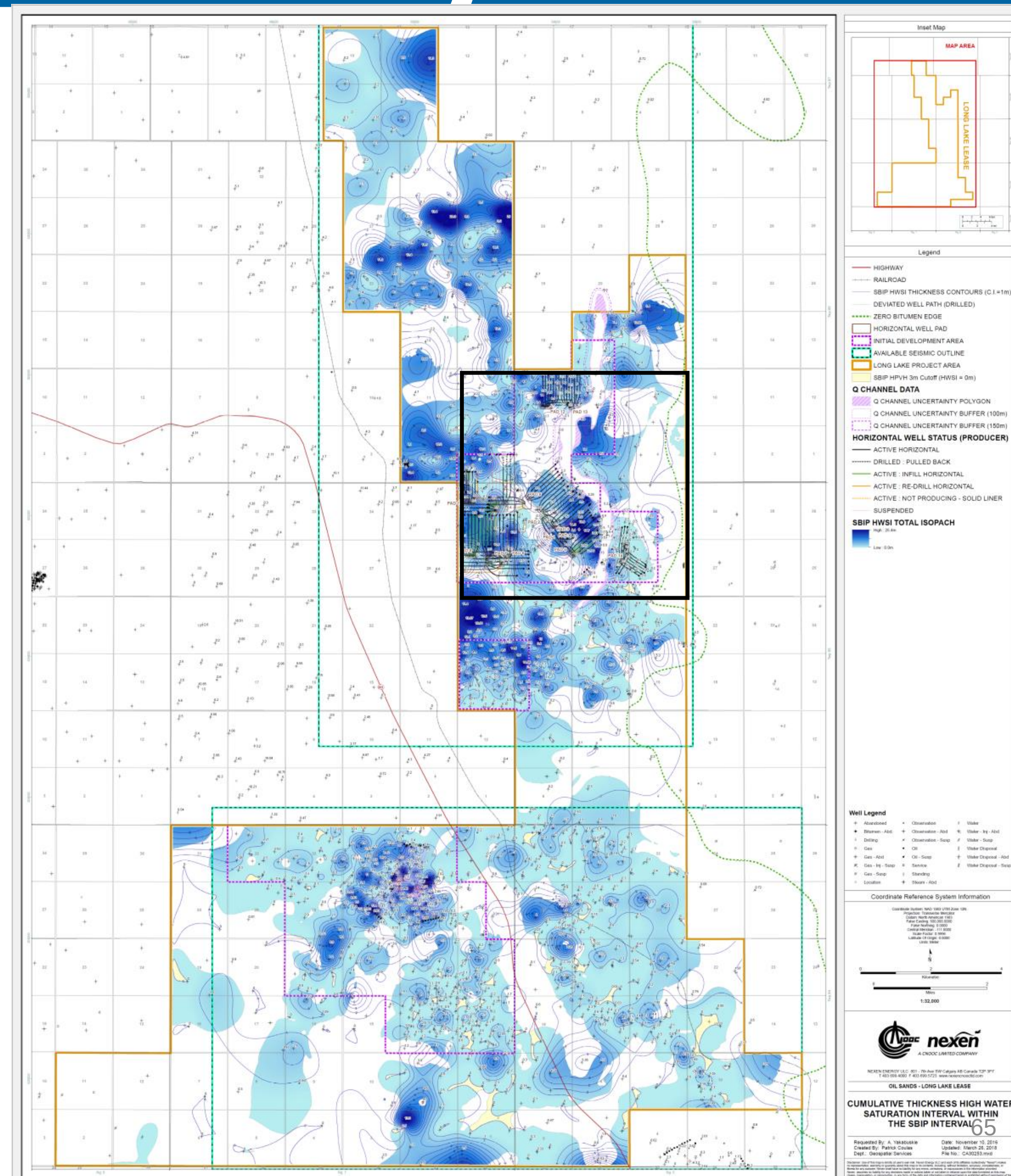
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)

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 SBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour



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

Legend

- 2015/2016 CORE OBS WELLS
- SBIP HWSI TOTAL ISOPACH (C.I.=5m)
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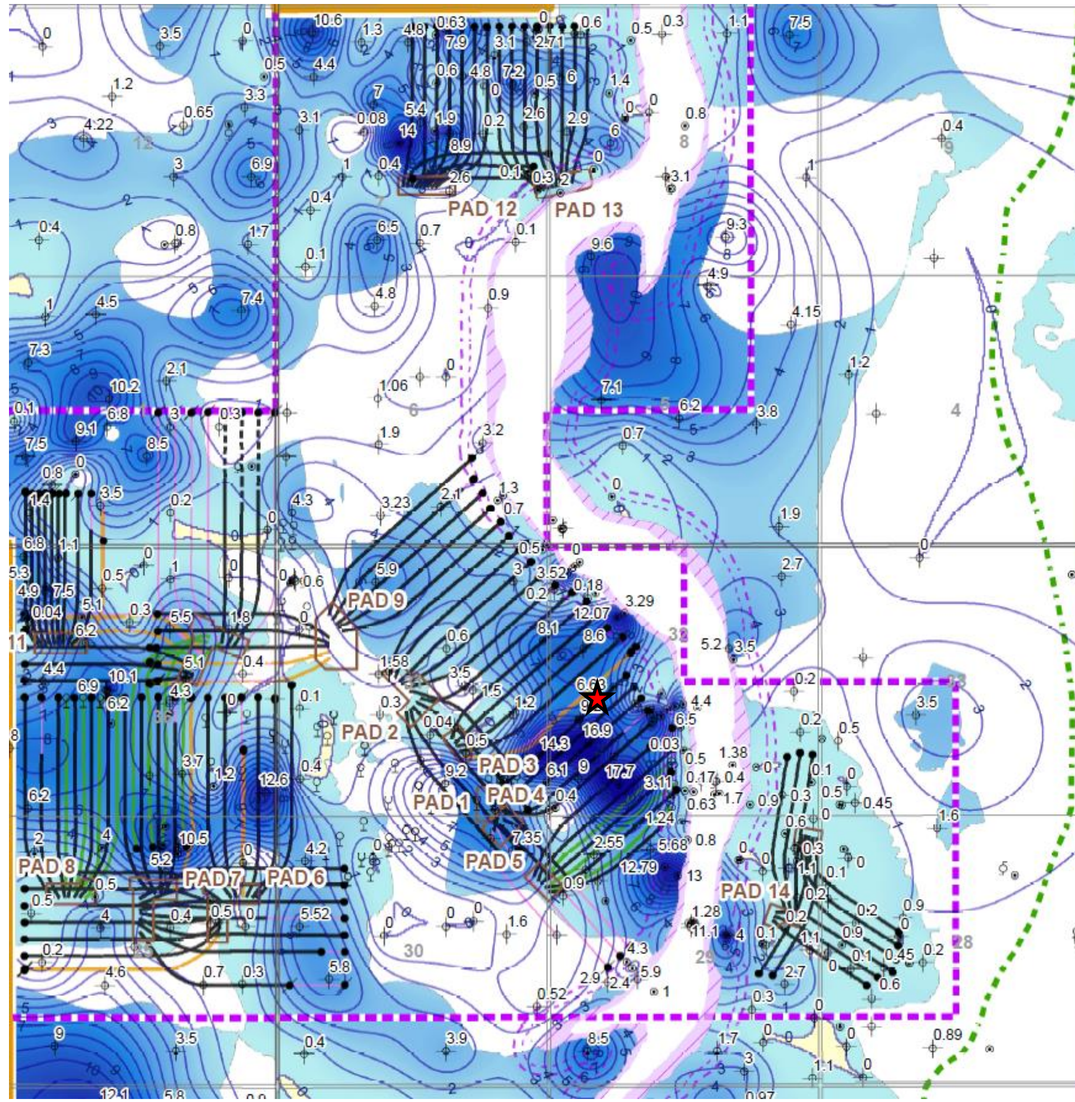
EBIP HWSI TOTAL ISOPACH

High : 20.2

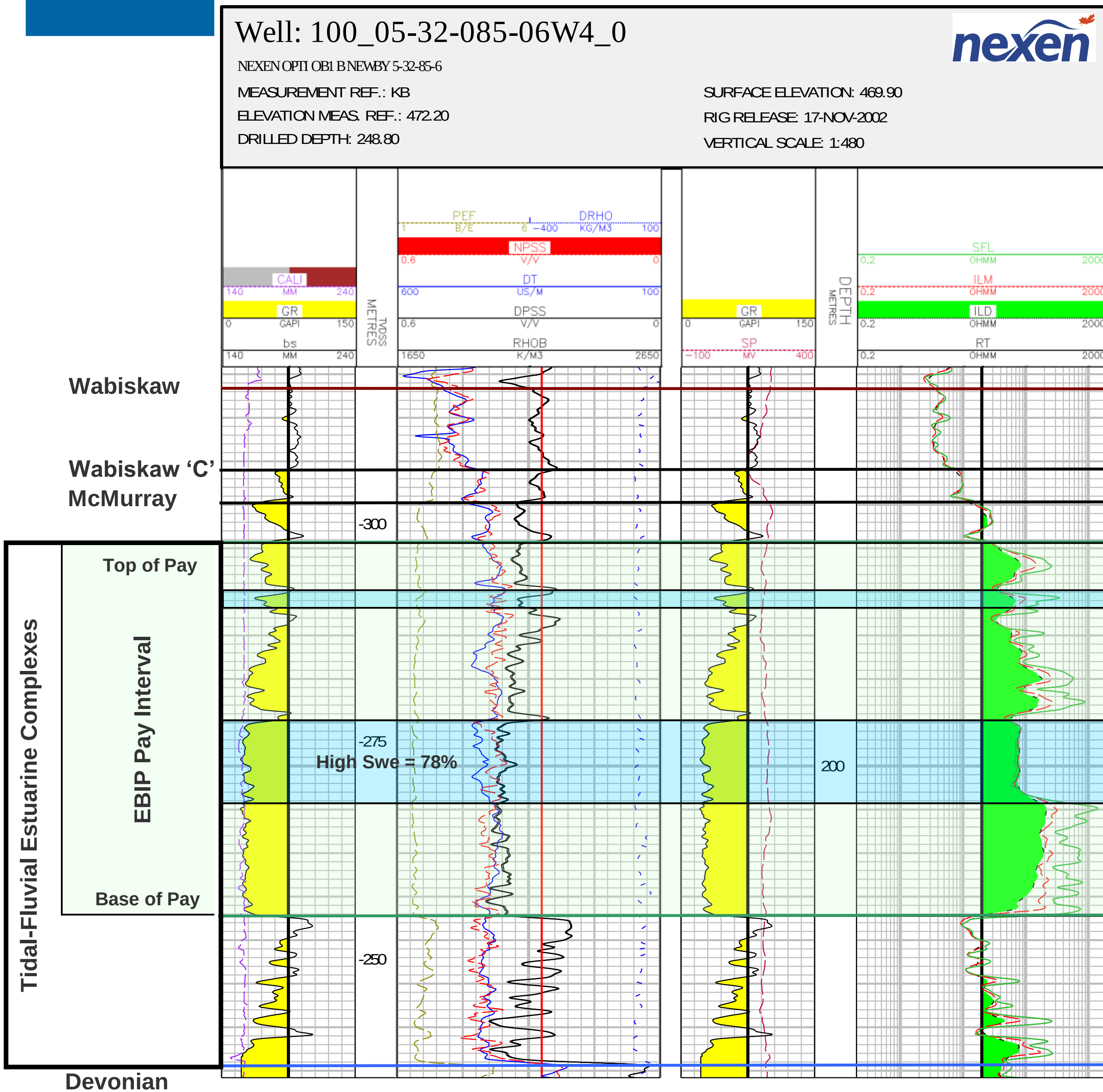
Low : 0.0m

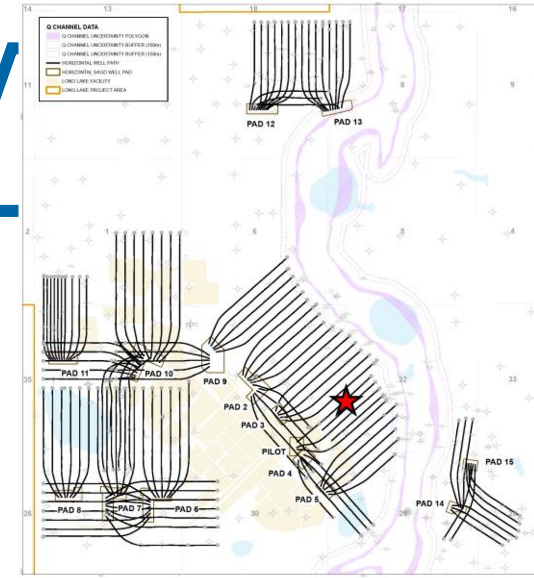


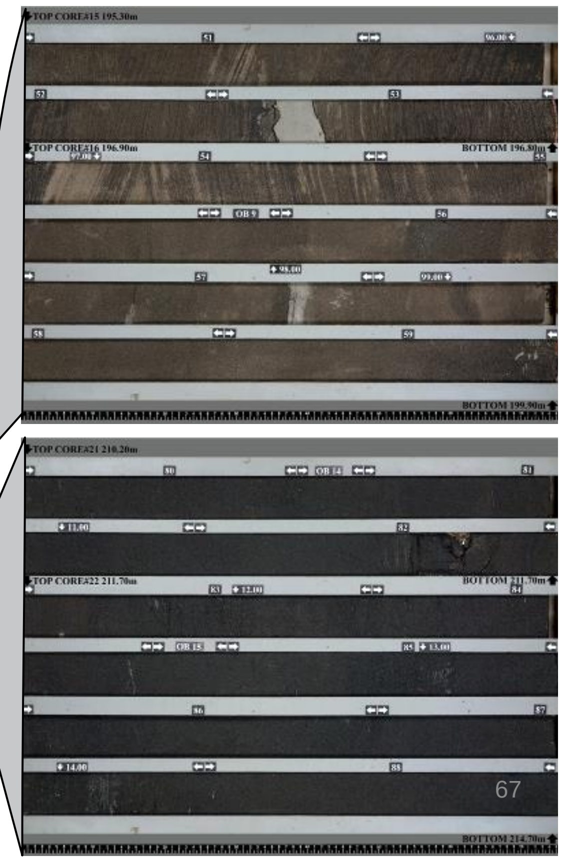
- > 50% Swe and < 30% V_{shale}
- Cumulative thickness of high water saturation interval(s) within SBIP interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

★ TYPE LOG

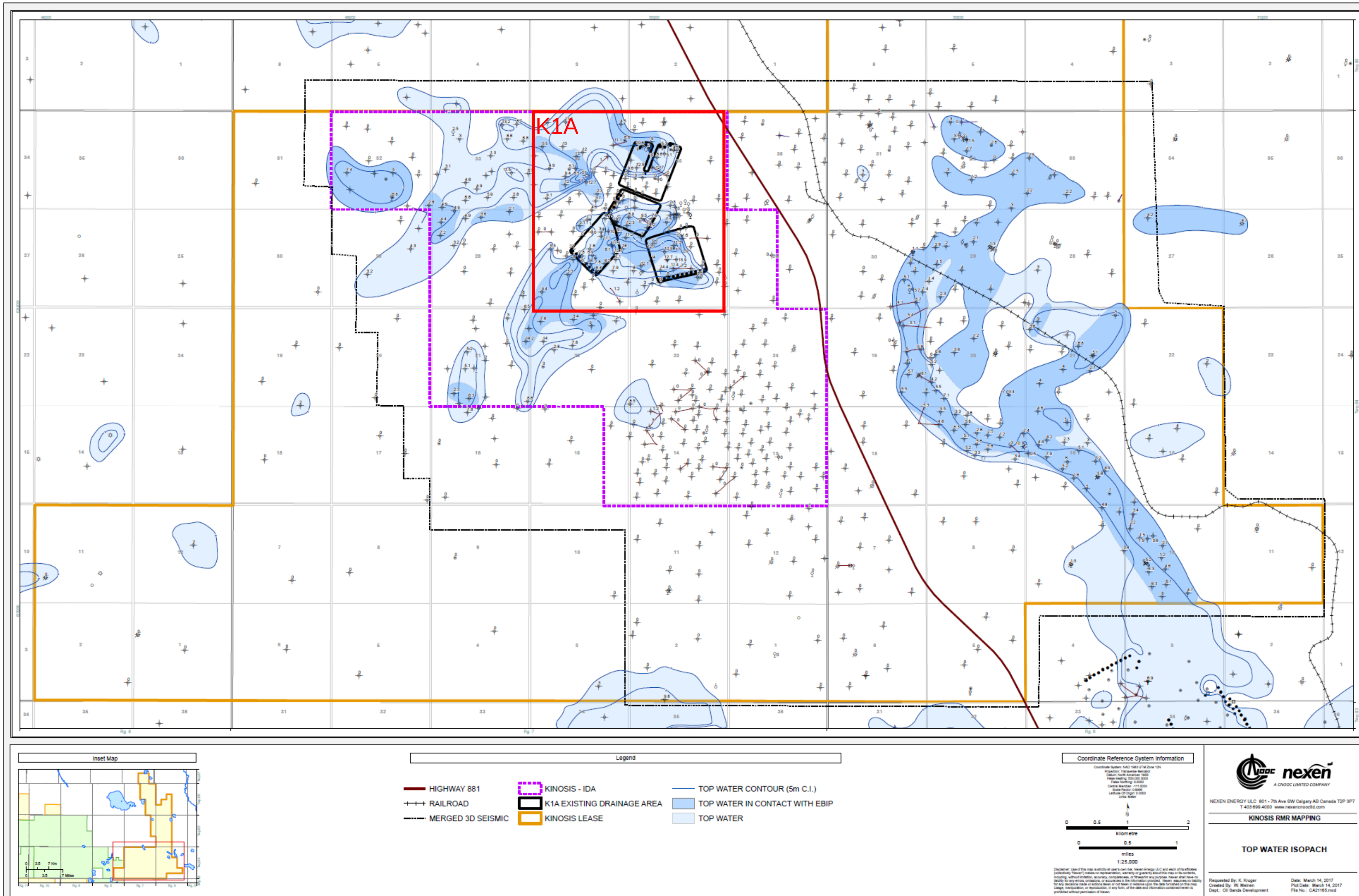
High Water Saturation Type Log
100/05-32-085-06W4



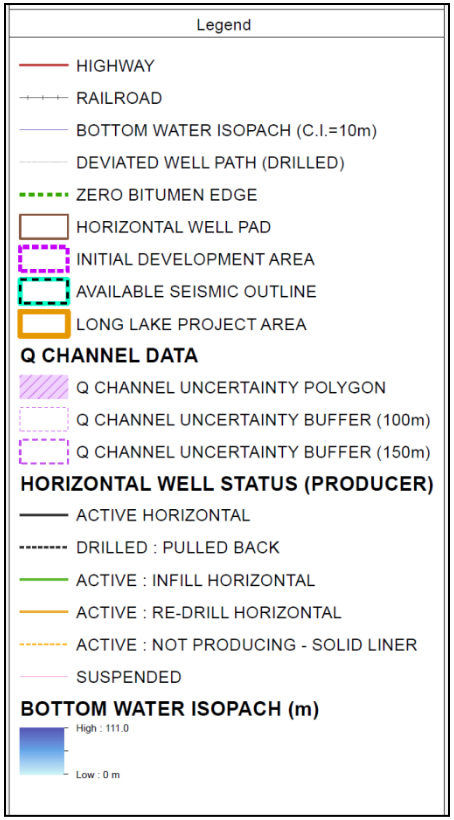


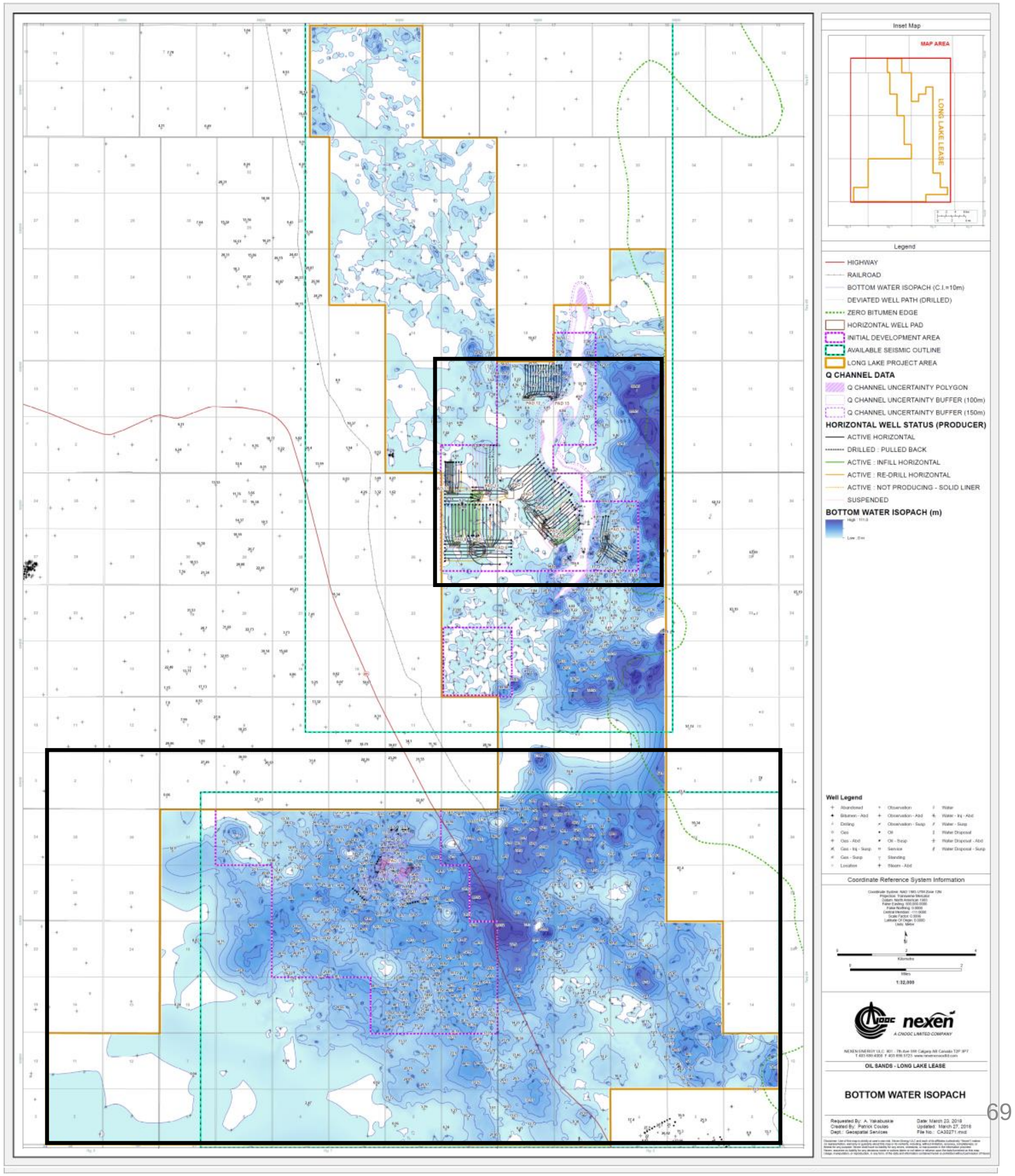


Kinosis
Top Water in the McMurray



Long Lake
Gross Bottom Water in McMurray





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

Long Lake
Gross Bottom Water in McMurray

Legend

HIGHWAY
RAILROAD
BOTTOM WATER ISOPACH (C.I.=10m)
DEVIATED WELL PATH (DRILLED)
ZERO BITUMEN EDGE
HORIZONTAL WELL PAD
INITIAL DEVELOPMENT AREA
AVAILABLE SEISMIC OUTLINE
LONG LAKE PROJECT AREA

Q CHANNEL DATA

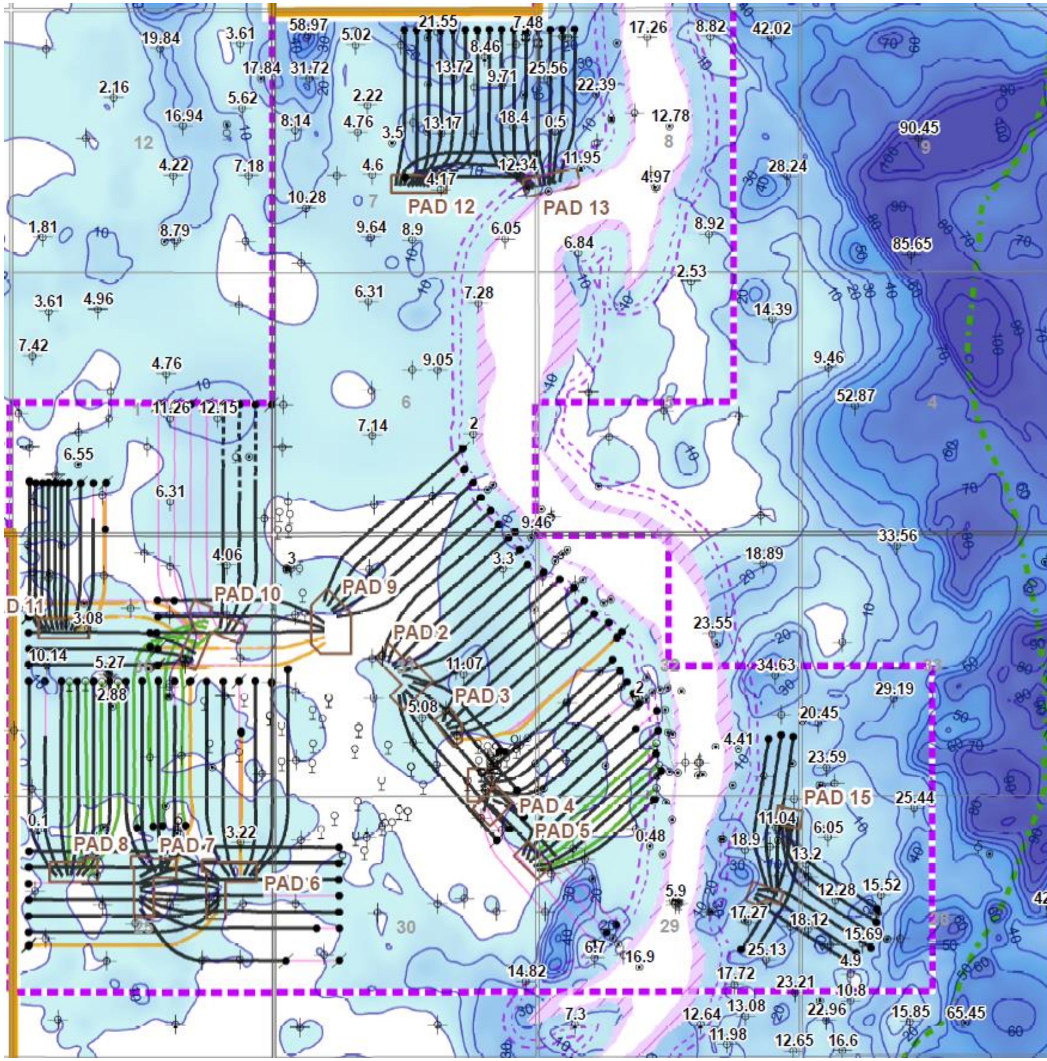
Q CHANNEL UNCERTAINTY POLYGON
Q CHANNEL UNCERTAINTY BUFFER (100m)
Q CHANNEL UNCERTAINTY BUFFER (150m)

HORIZONTAL WELL STATUS (PRODUCER)

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

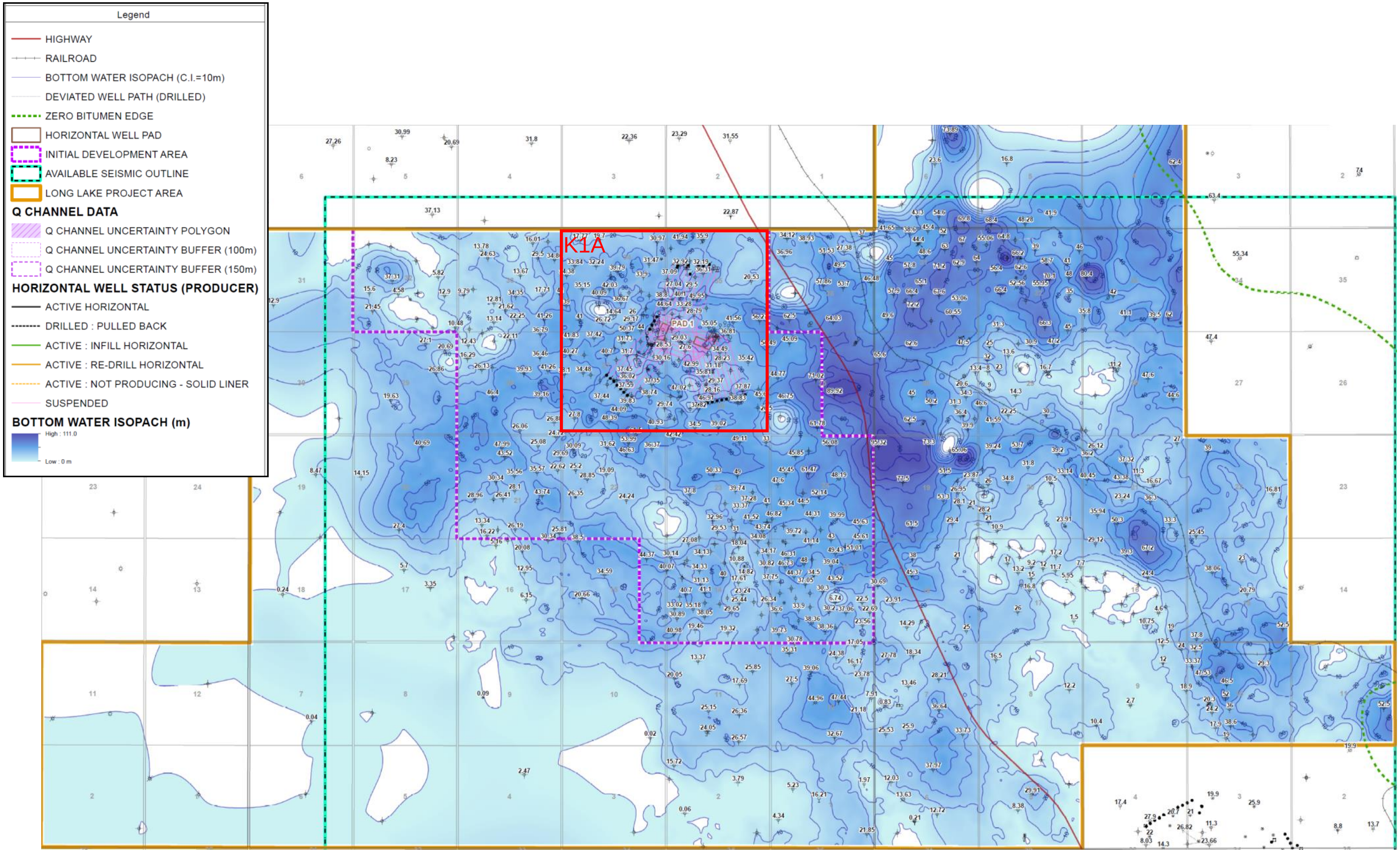
BOTTOM WATER ISOPACH (m)

High : 111.0
Low : 0 m

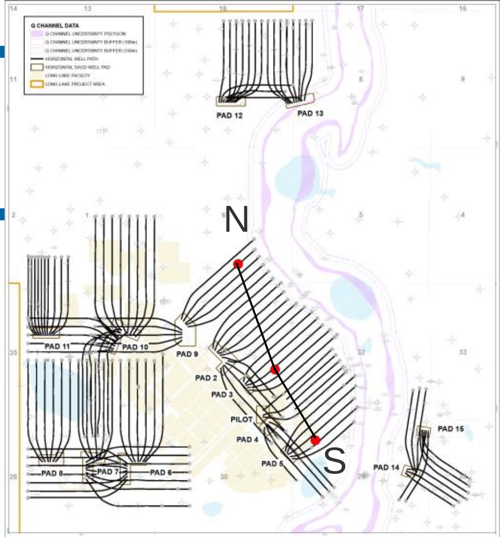


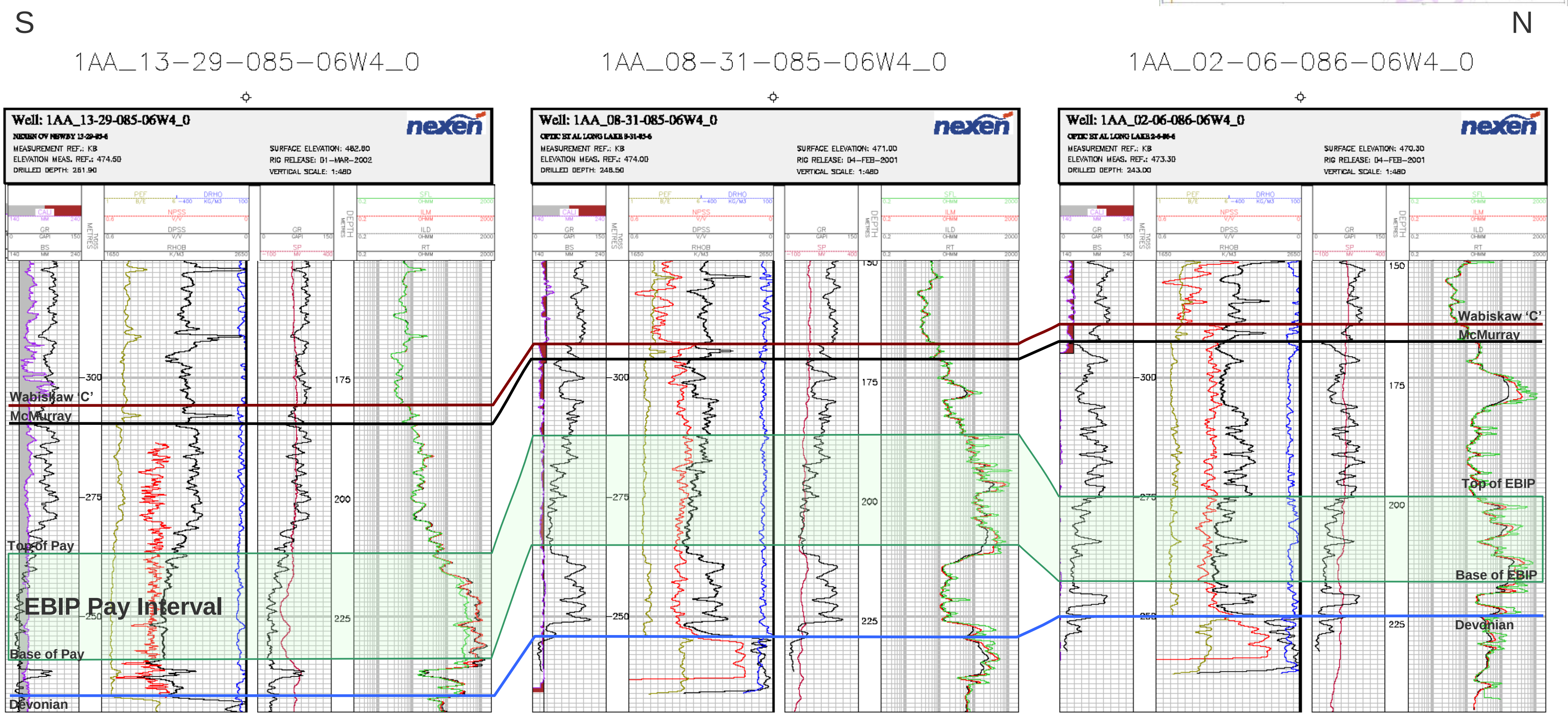
- > 50% S_{we} and < 30% V_{shale}
- Top of Bottom Water:
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

Kinosis
Gross Bottom Water in the McMurray

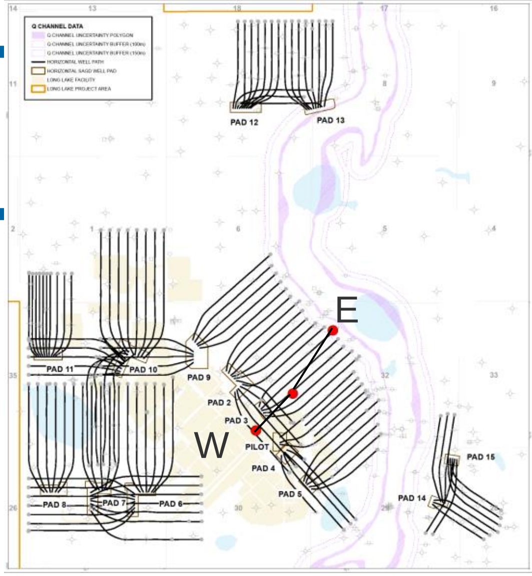


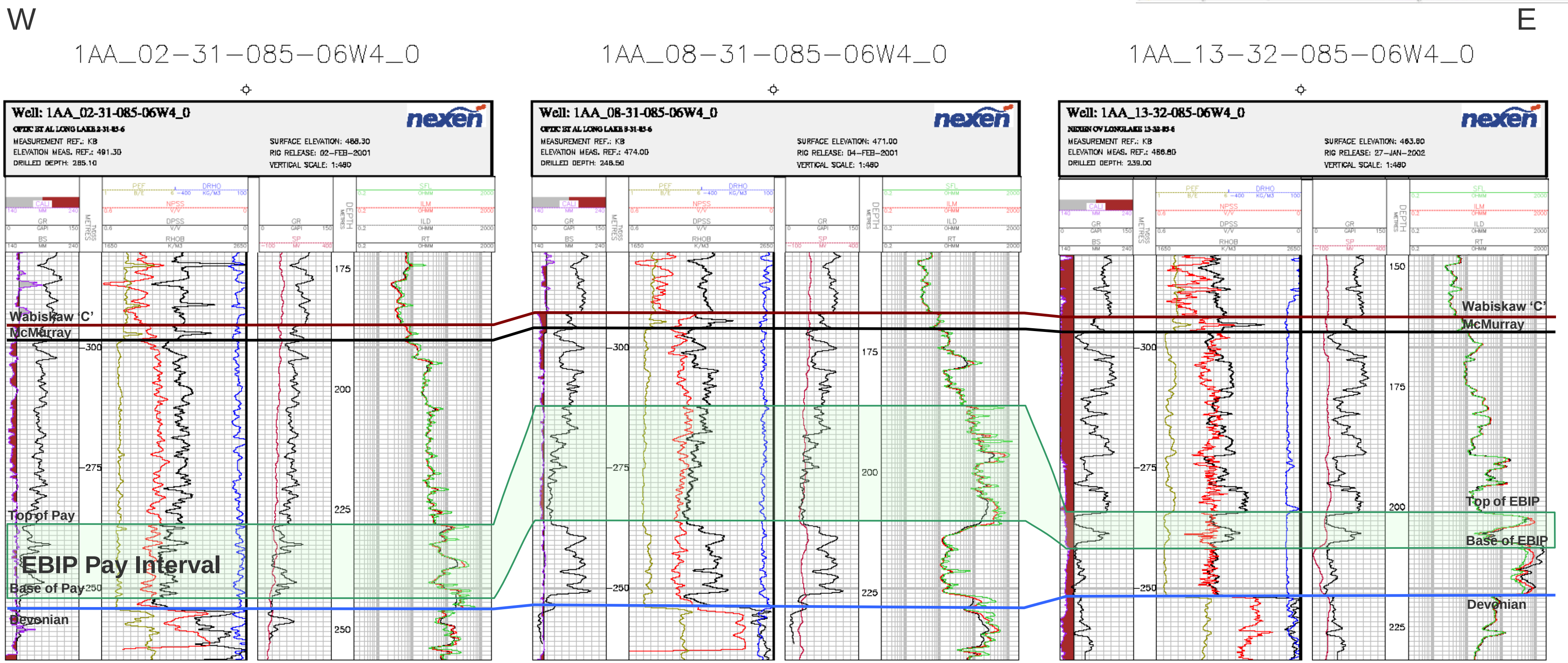
Representative structural cross-section of the East Side of Long Lake (South - North)



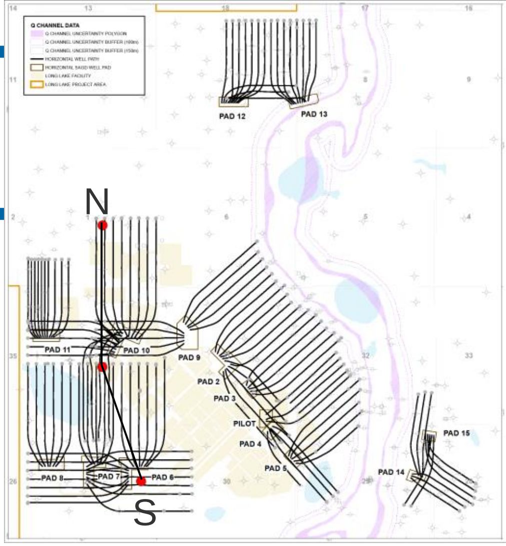


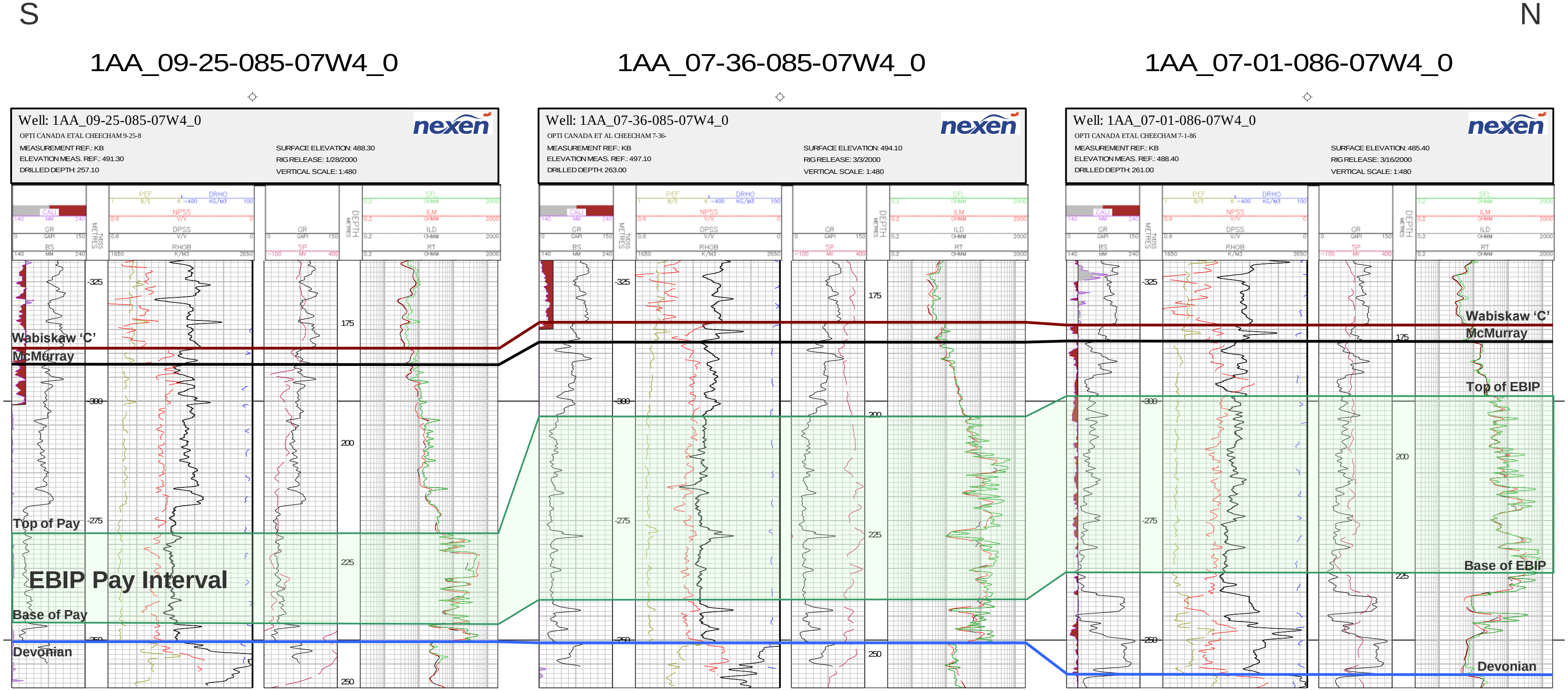
Representative structural cross-section of the East Side of Long Lake (West - East)



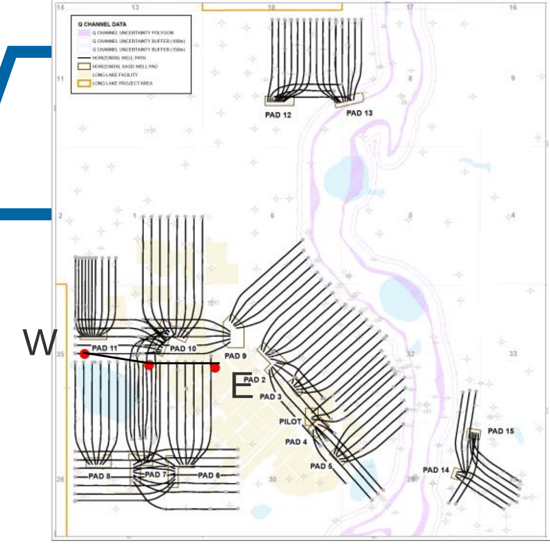


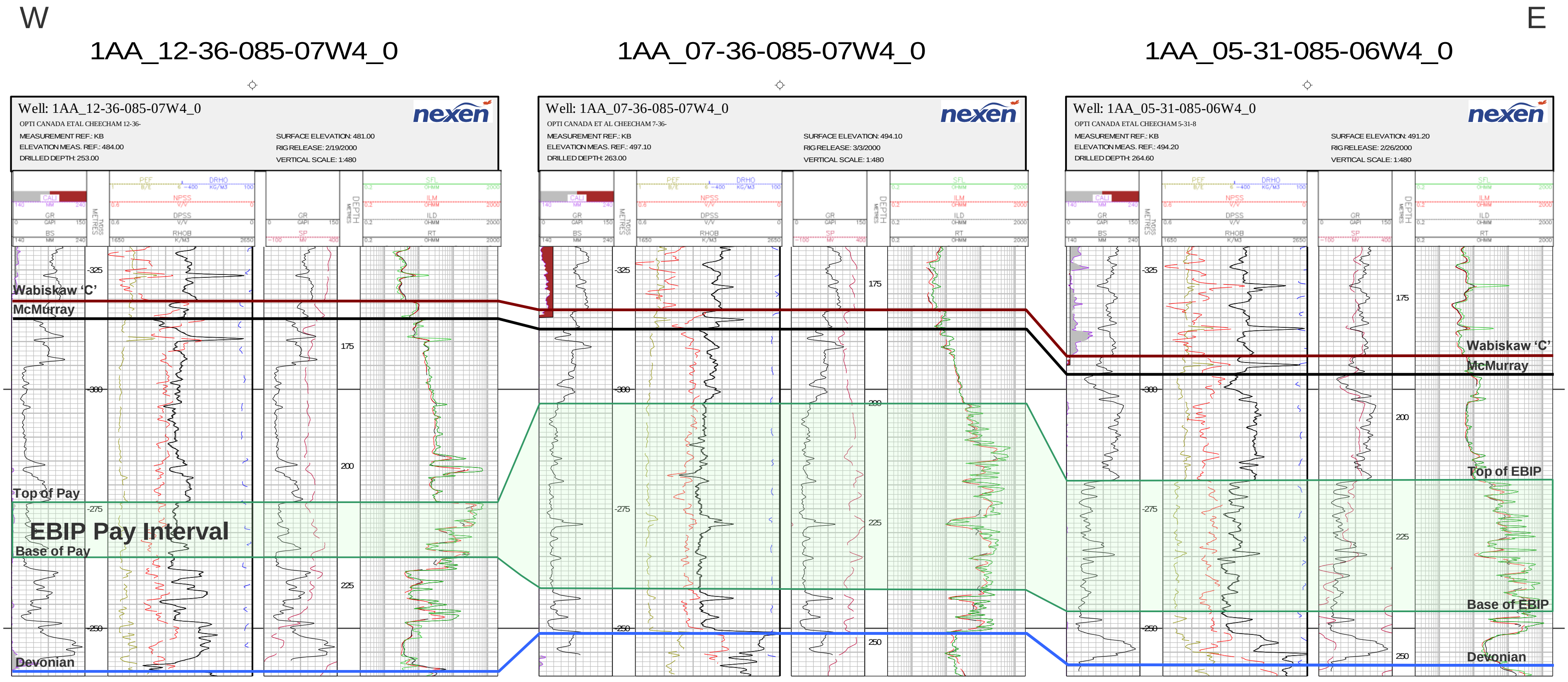
Representative structural cross-section of the West Side of Long Lake (South - North)



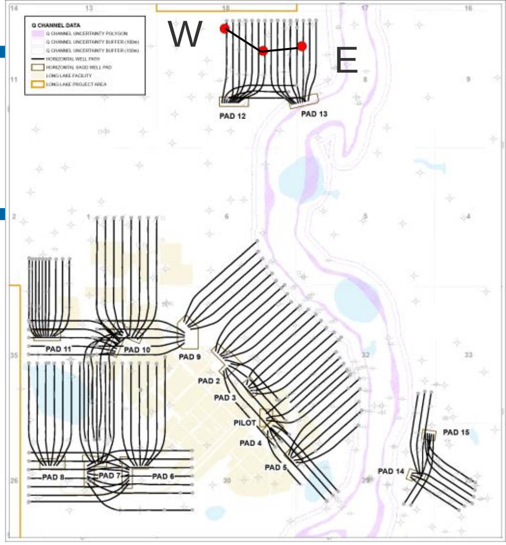


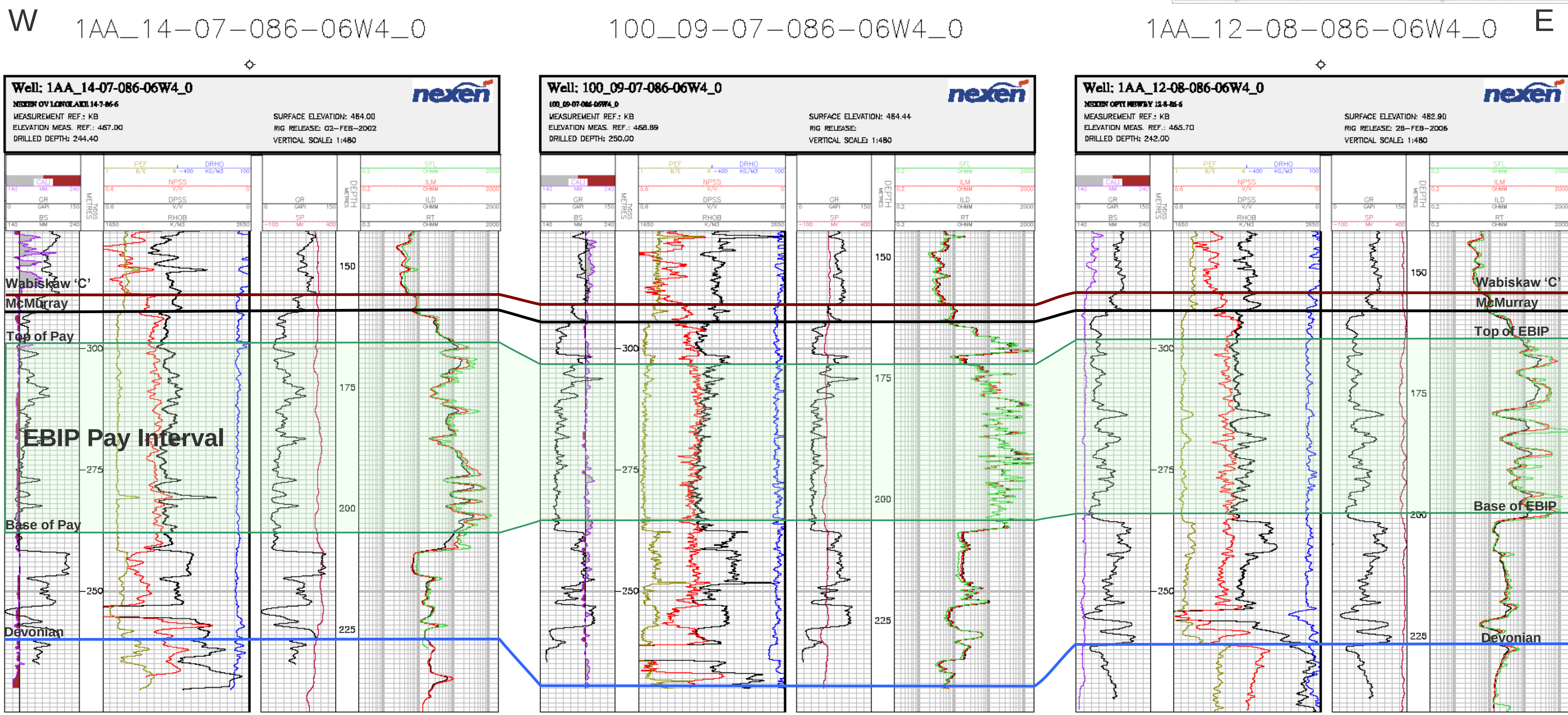
Representative structural cross-section of the West Side of Long Lake (West - East)



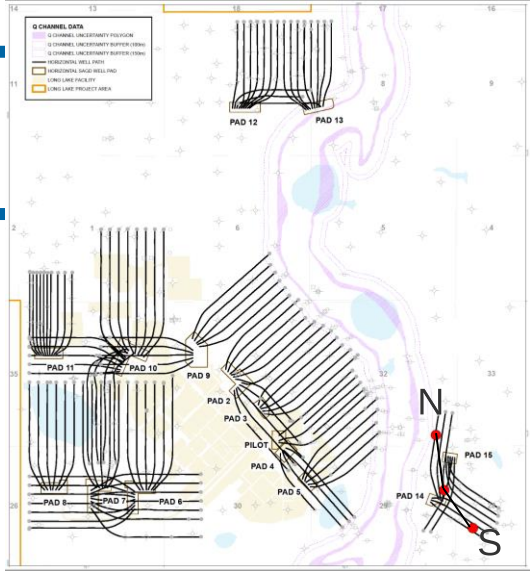


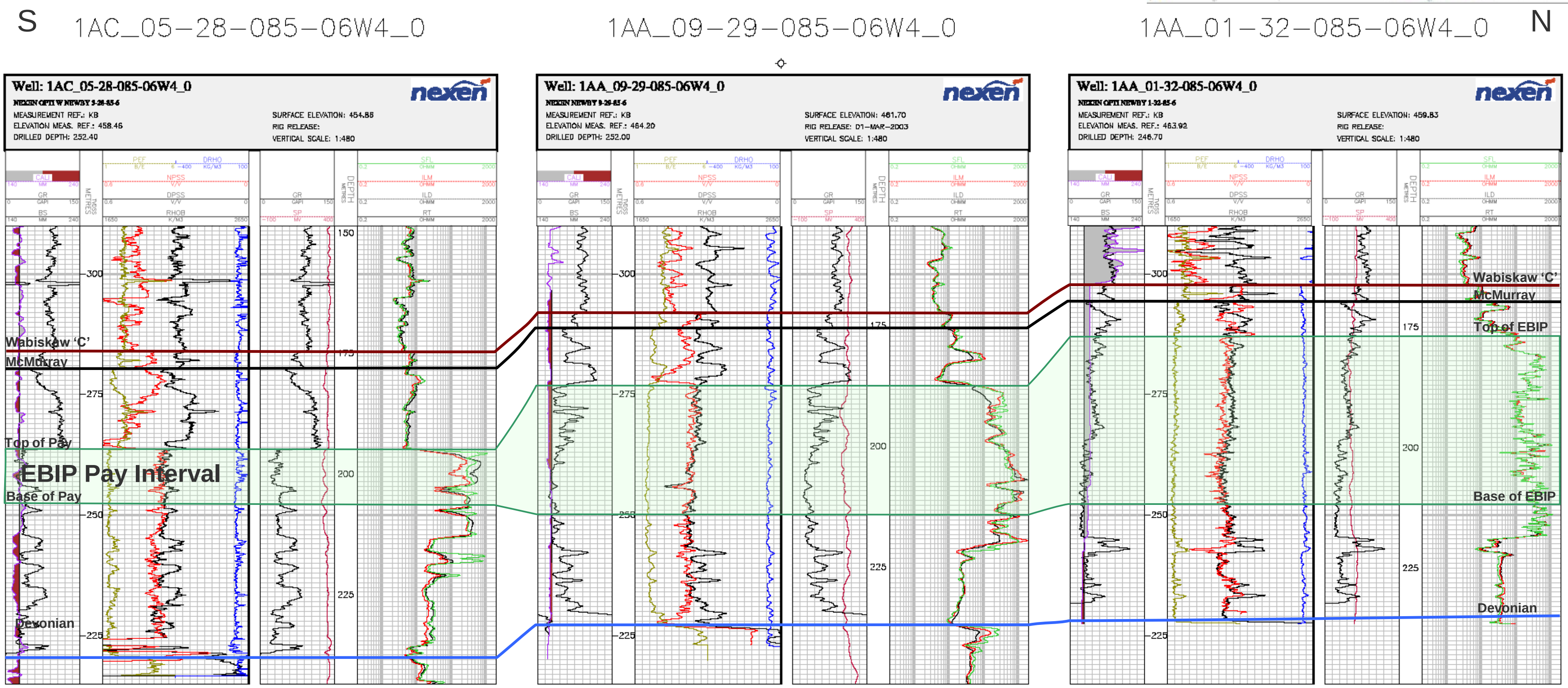
Representative structural cross-section of Pads 12 and 13



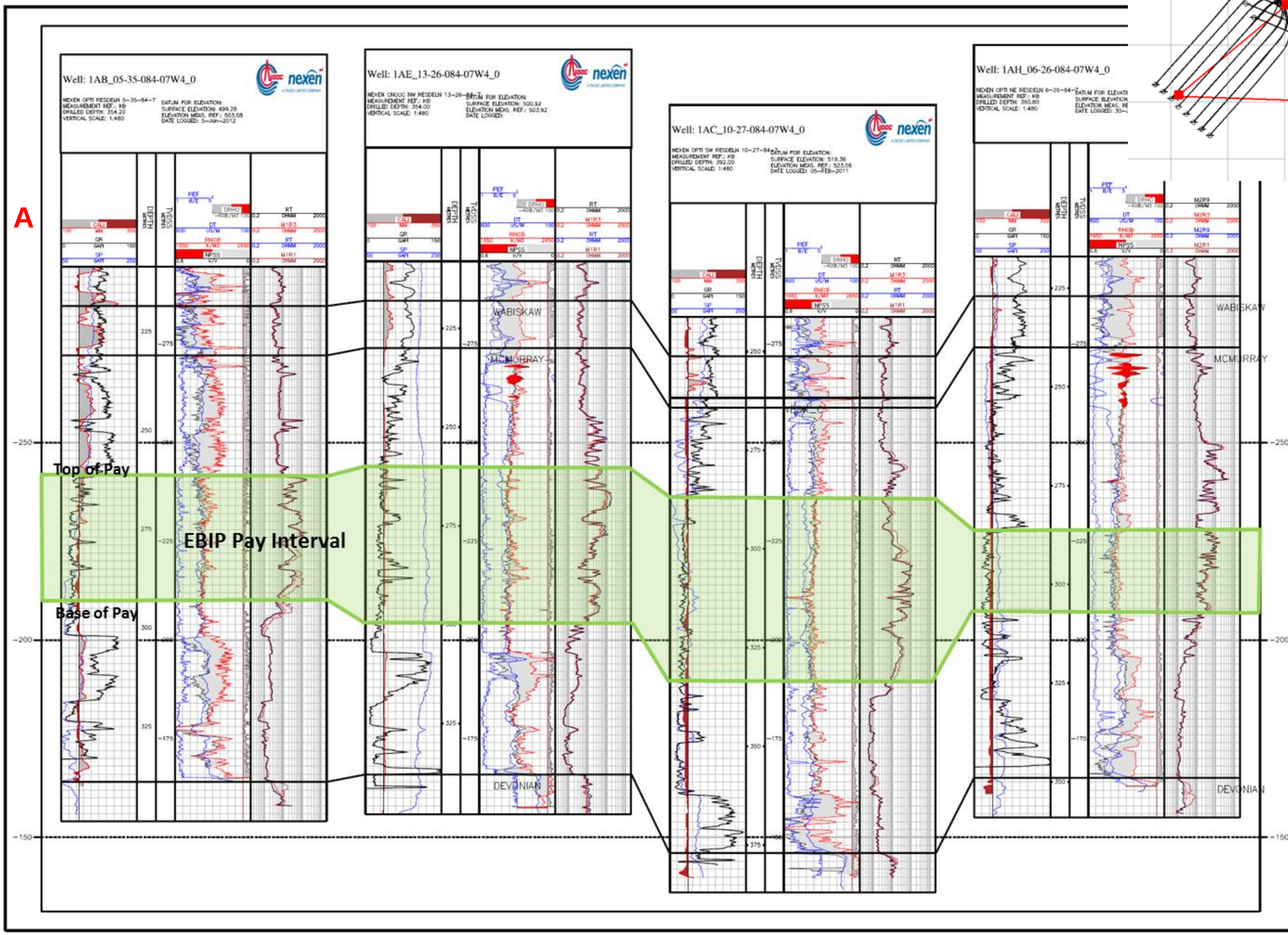


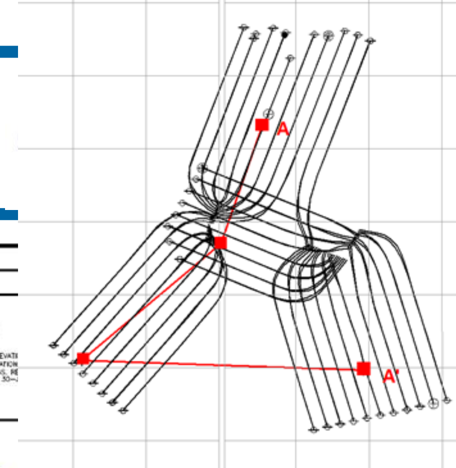
Representative structural cross-section of Pads 14 and 15





Representative structural cross-section of K1A





Long Lake Cap Rock Type Log

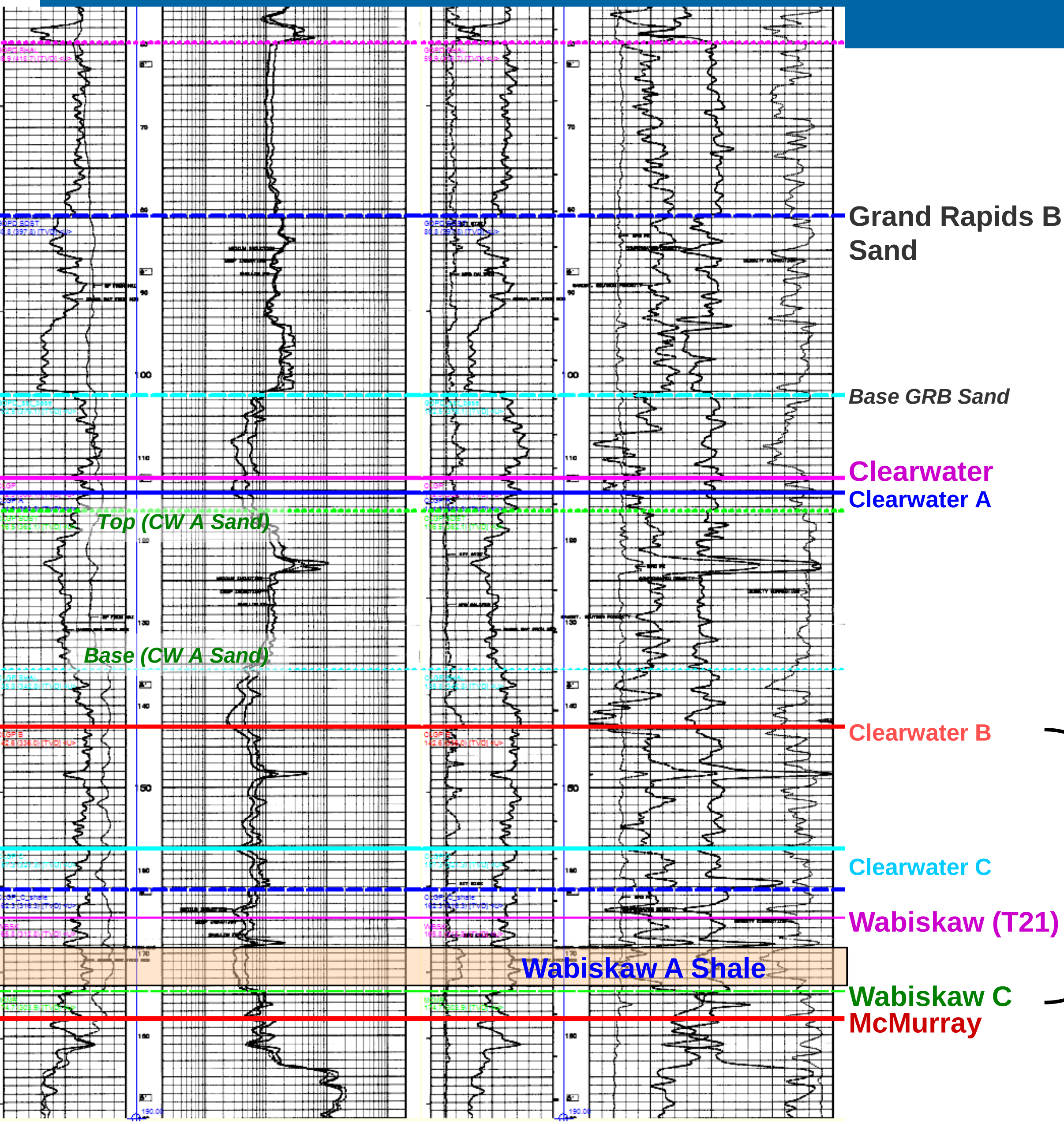
AA/08-20-085-06W4/0

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

MINI-FRAC LOCATIONS
100090708606W400
1AB082908506W400
TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB082908506W400
XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
1AA083208506W400
1AA102708607W400
1AA122808506W400
1AA142008506W400
100053308506W400
105062808506W400
102092908506W400
100102908506W400
103142908506W400
CAPROCK CORE
100053308506W400
100082908506W400
100110808606W400
100132808506W400
100140808606W400
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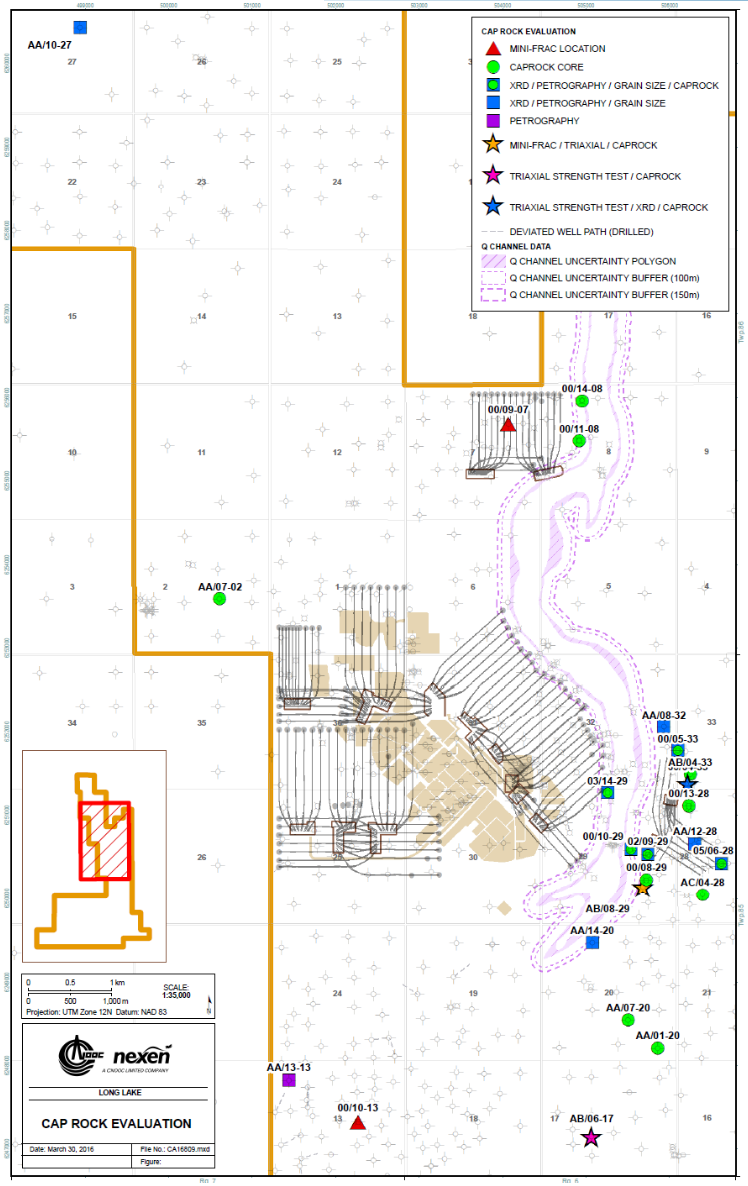
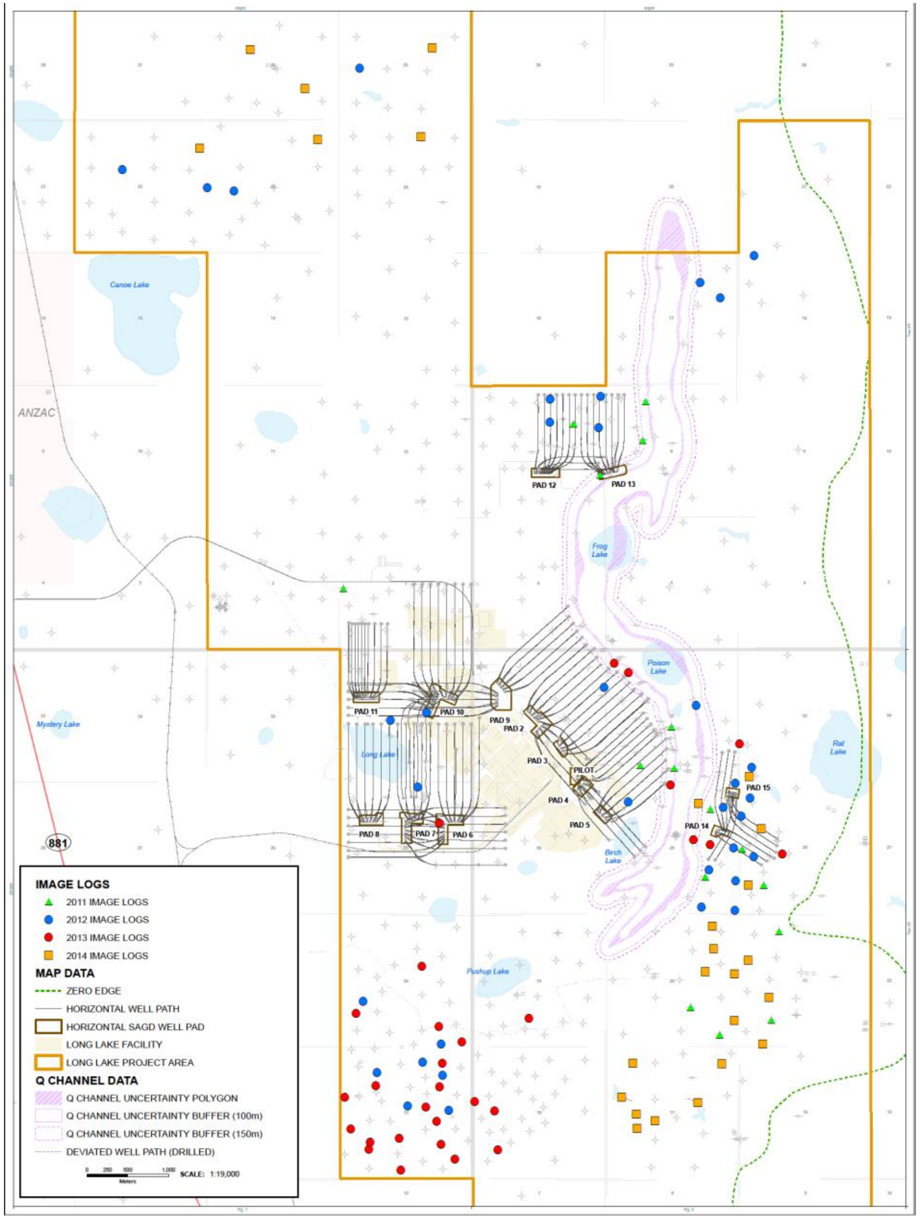
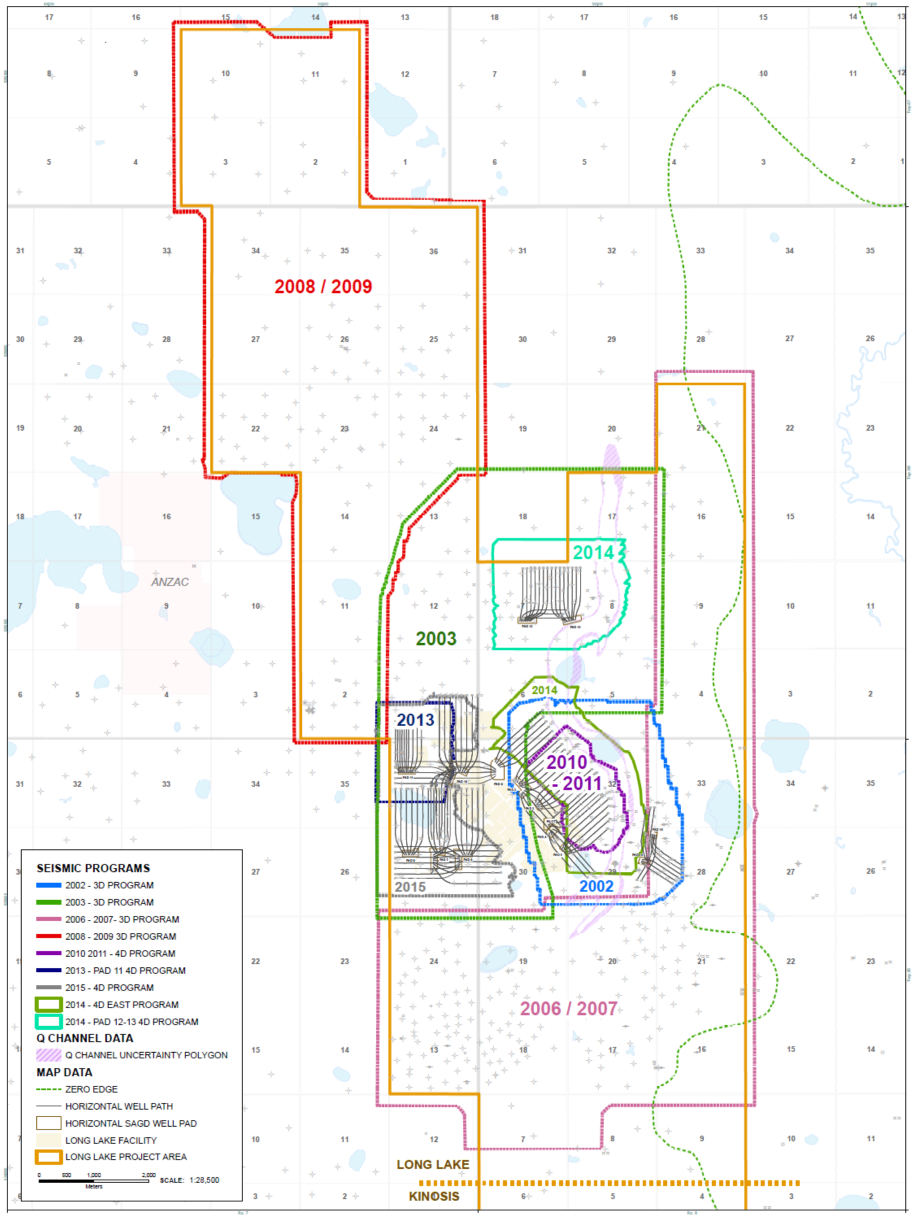


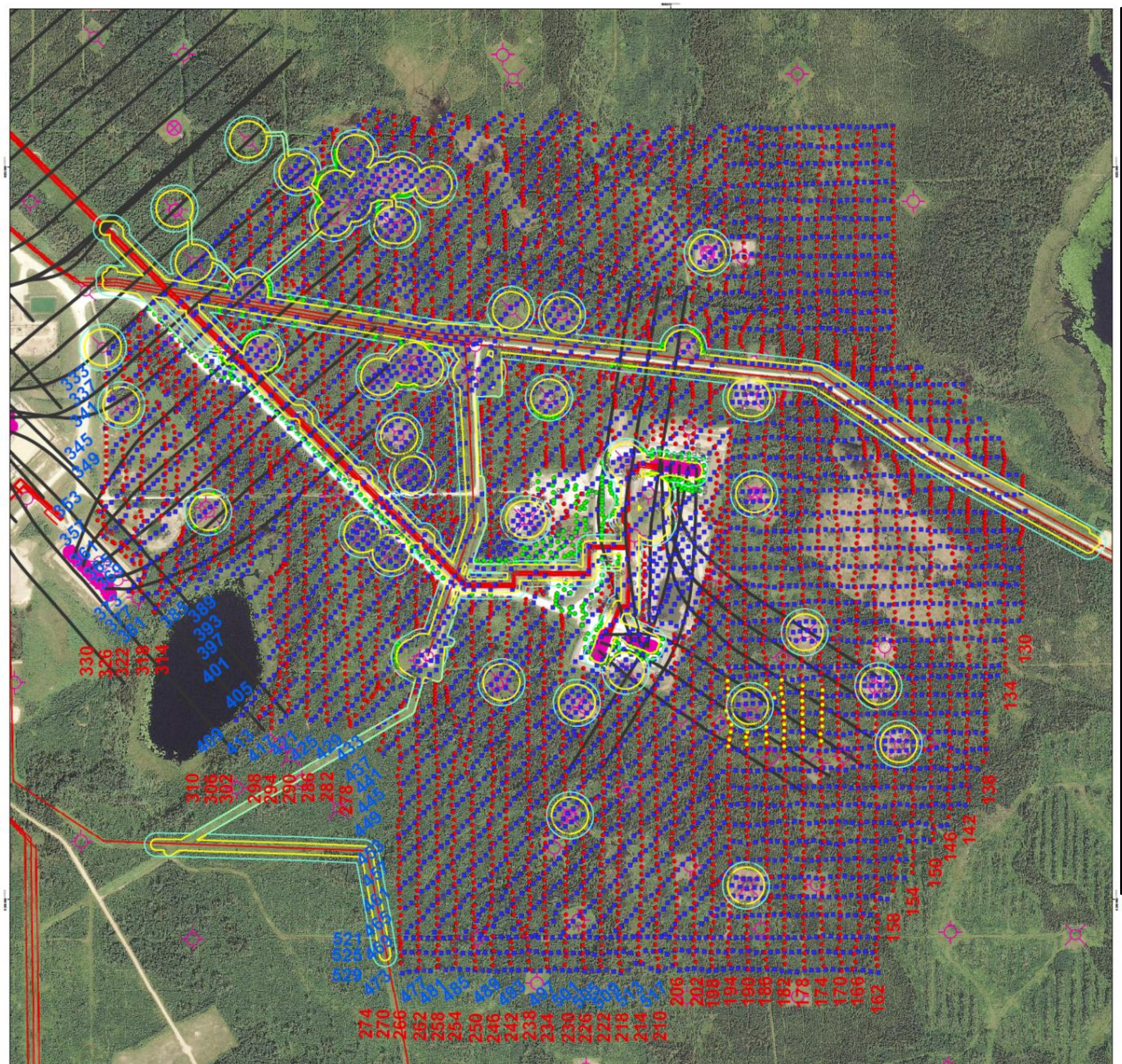
Long Lake
Cap Rock Evaluation Image Logs

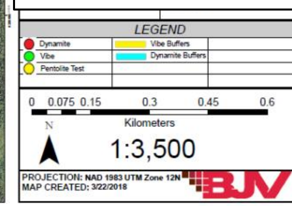


Long Lake Seismic
No 4D in 2017



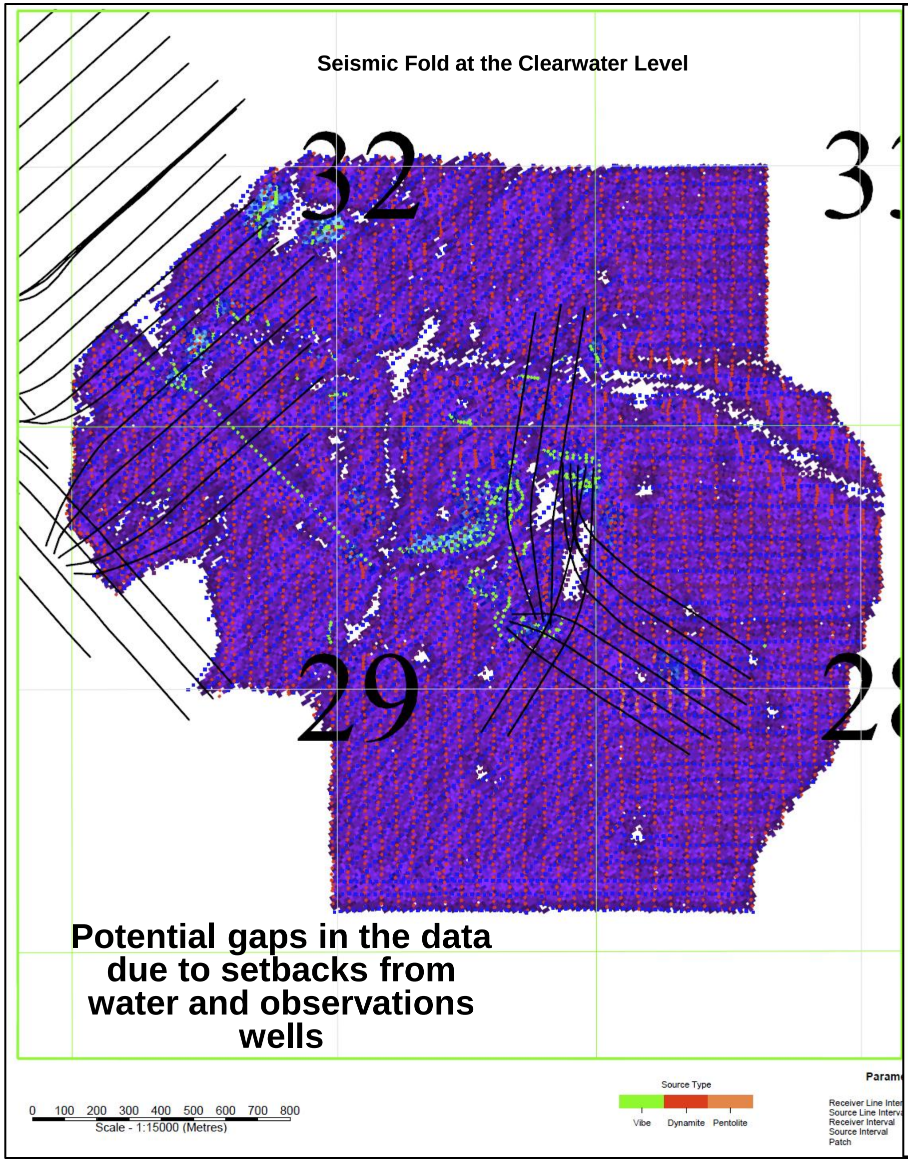
2018 4D Monitor Survey Acquisition Pads 14 & 15

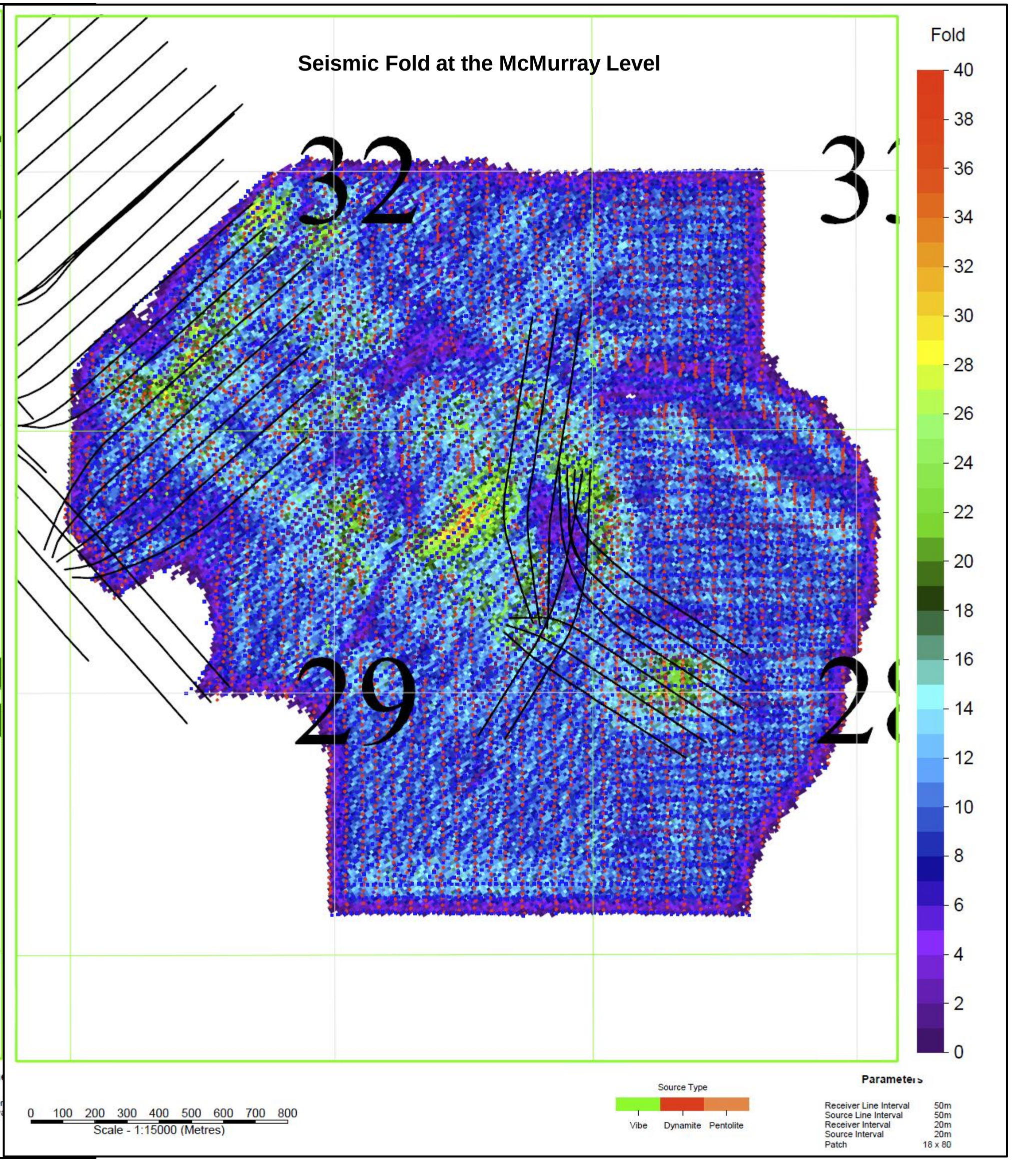




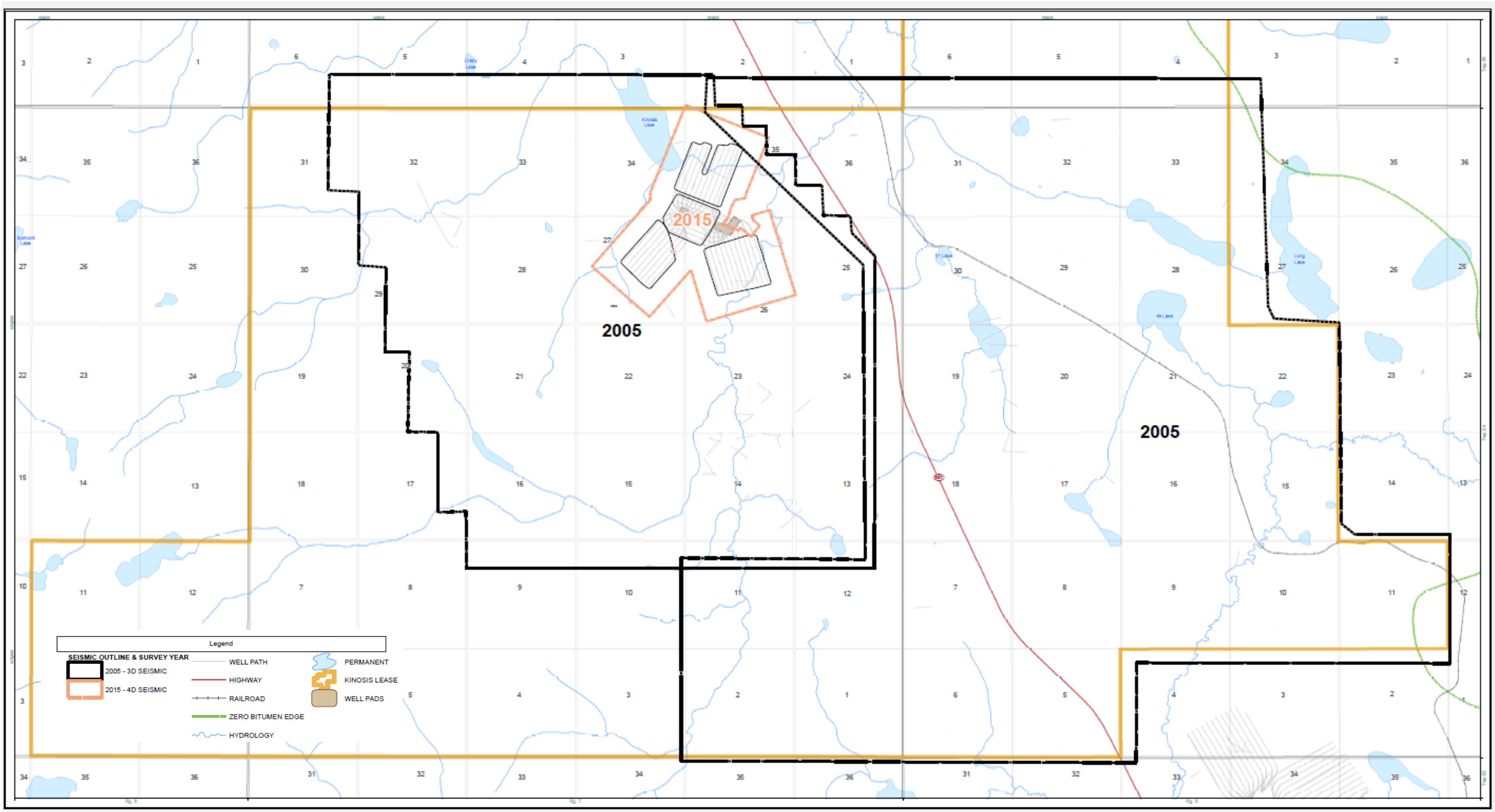
- 4D Monitor survey over Pads 14/15 was completed in mid-February 2018 as per the Pads 14/15 Commercial Scheme Approval 9485N.
- Data is currently being processed with an interpretation to follow.
- Exploration Directive ED2006-15 requires a large setback from water wells and observation wells (64m for dynamite charges <12kg). 1/8kg charge was used.
- All wells in the survey area owned by Nexen.
- Given the numerous water and observation wells in the area, the set back requirements had a negative impact on the program.
    - Data gaps/reduced quality
    - Increased costs to comply with directive

Design Fold Plots of 4D Program





Kinosis Seismic
No 4D in 2017



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

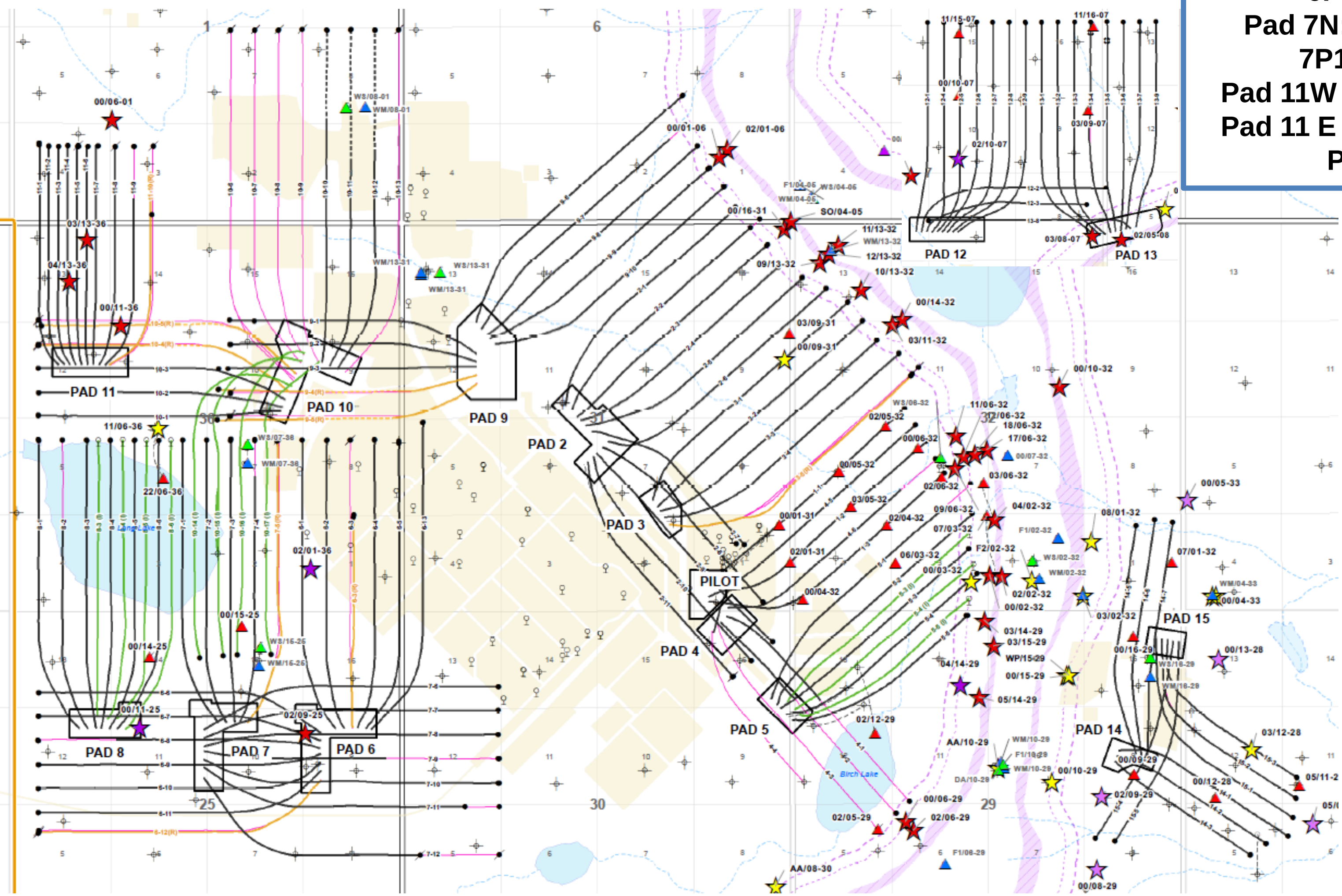
Long Lake

A New Energy

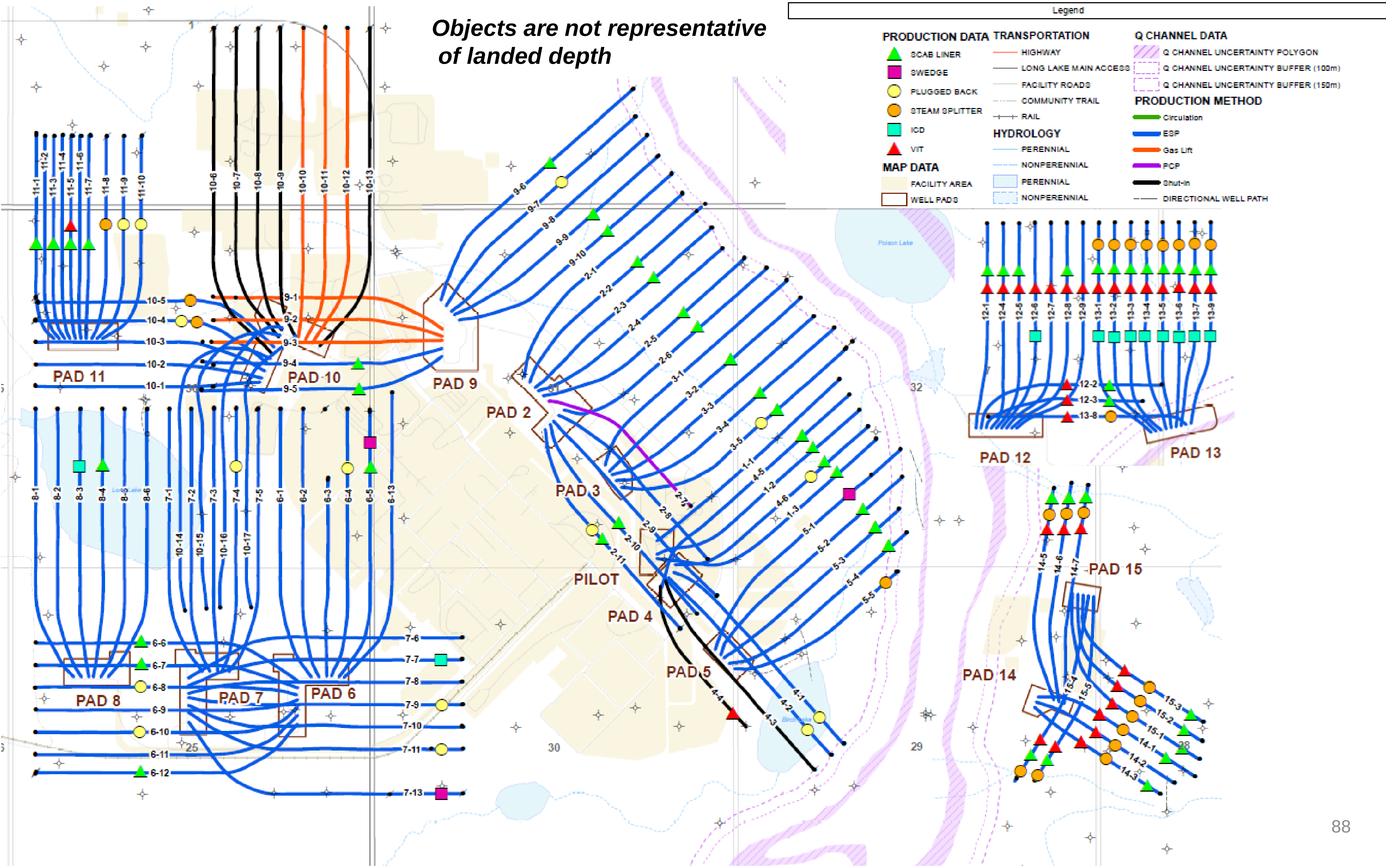
Long Lake
Horizontal Well Locations

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



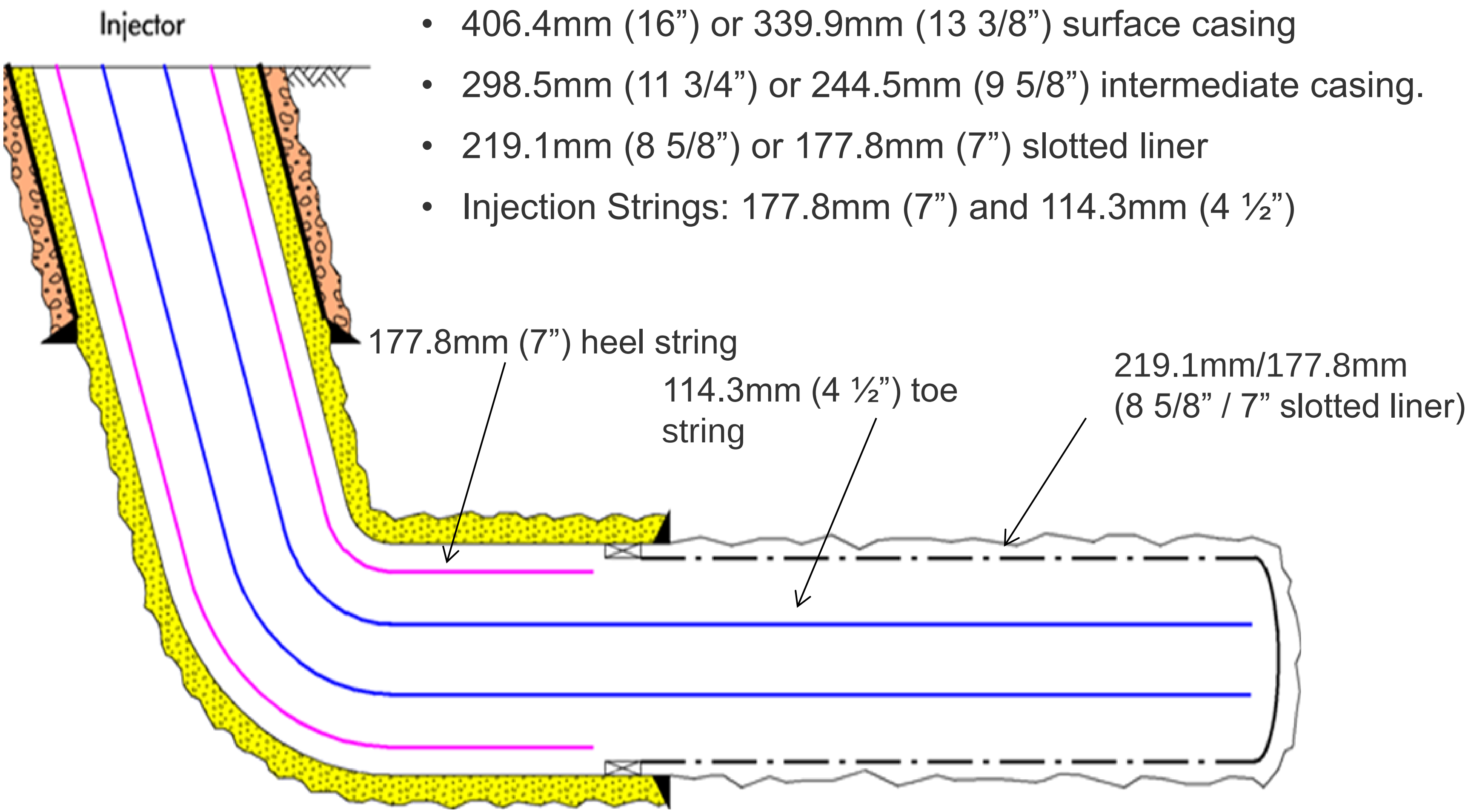
Long Lake Well Pair Completions Map 2017



Typical Injector Completion

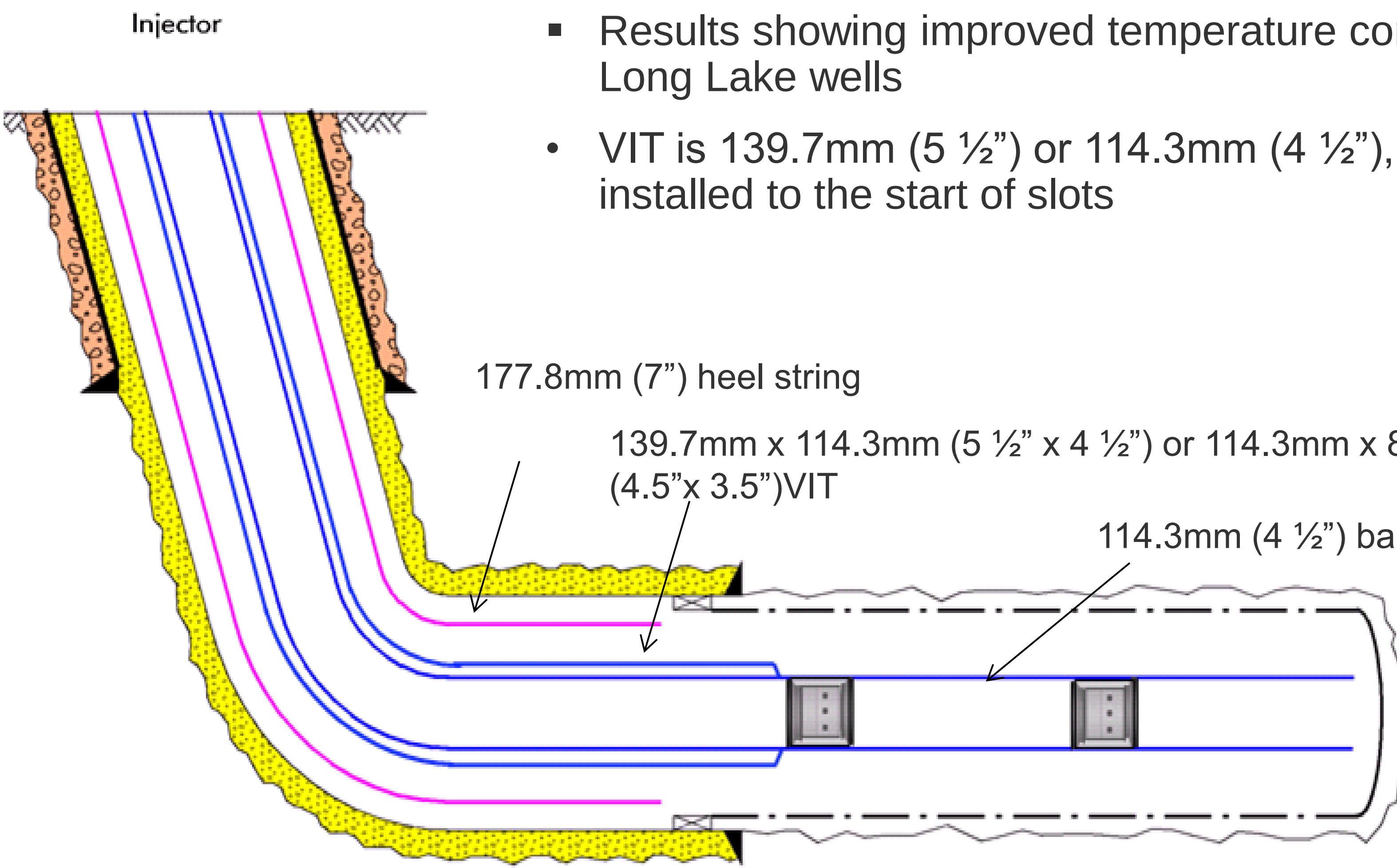
Concentric:

- 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")

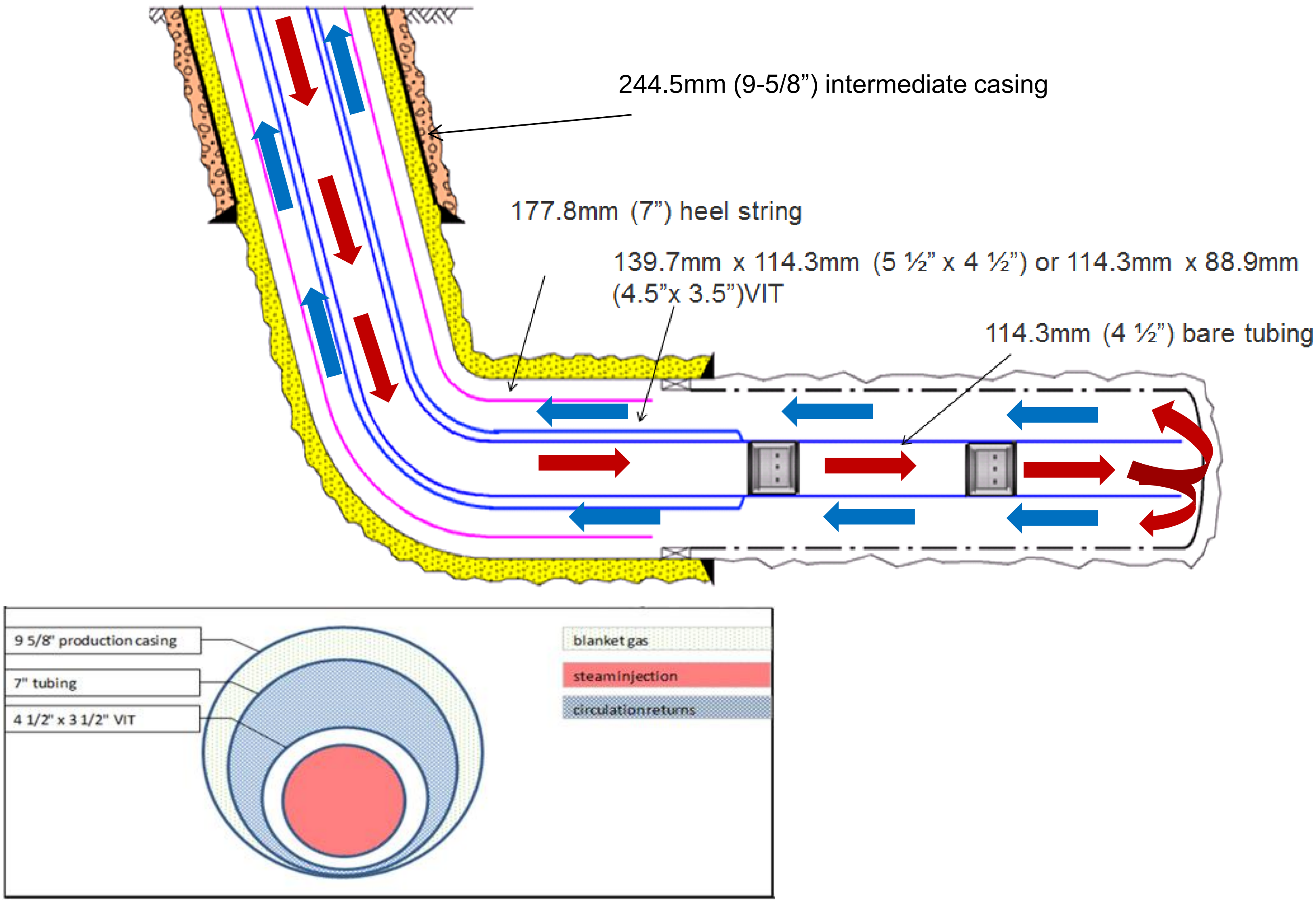


Vacuum Insulated Tubing (VIT) Injector Completion

- 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

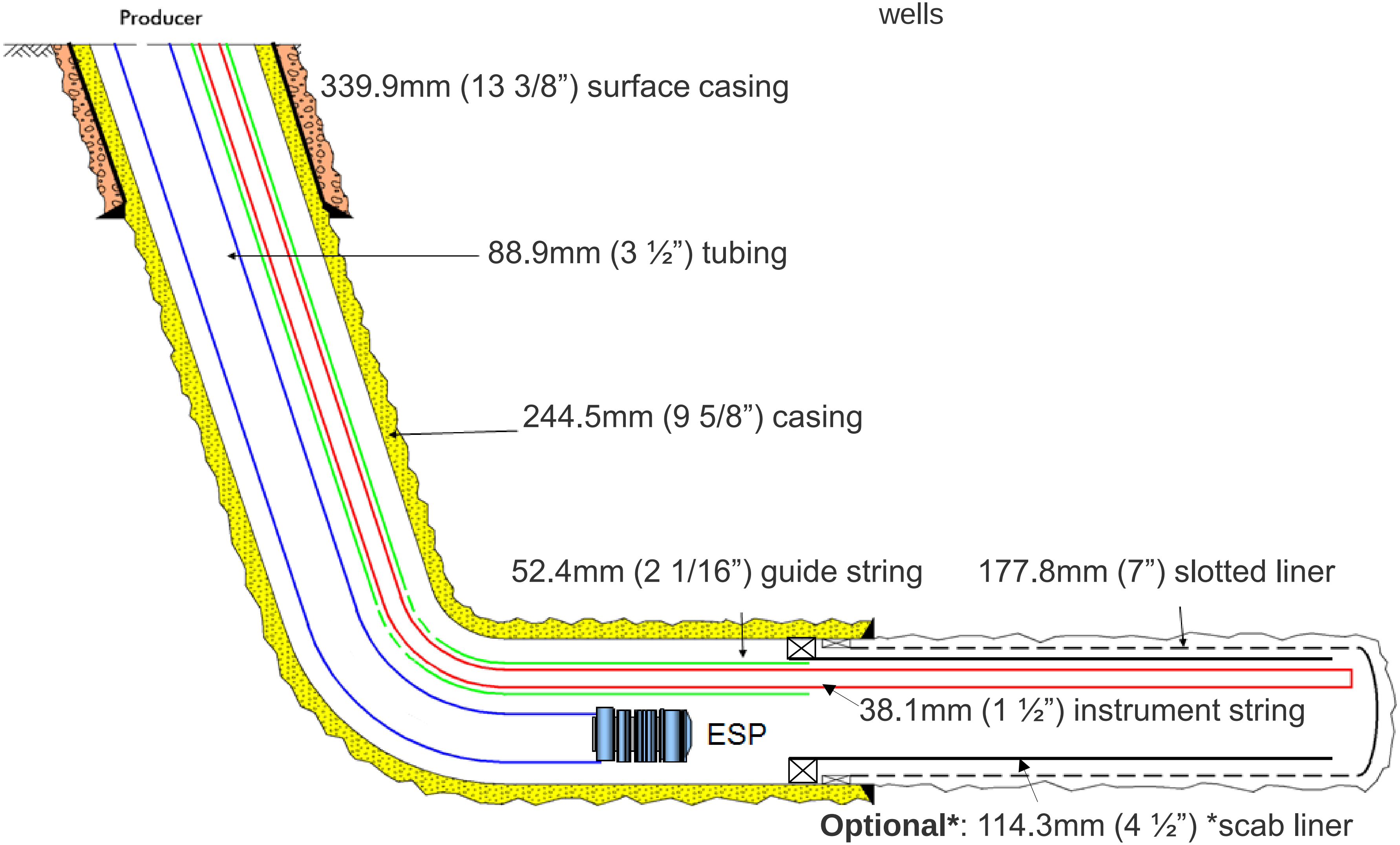


Typical Injector Circulation

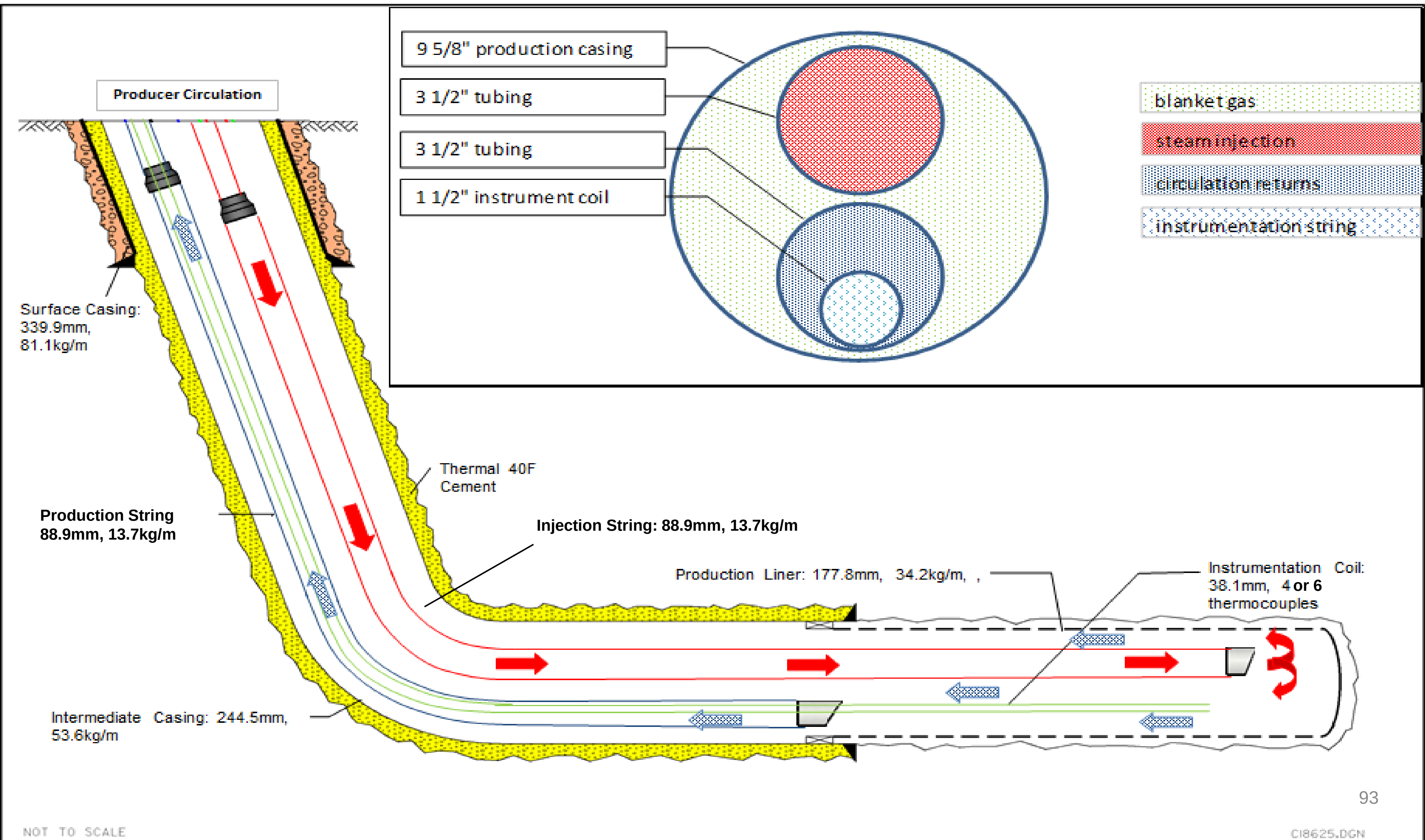


Typical Producer Completions – ESP

*Scab liners installed in some producer wells



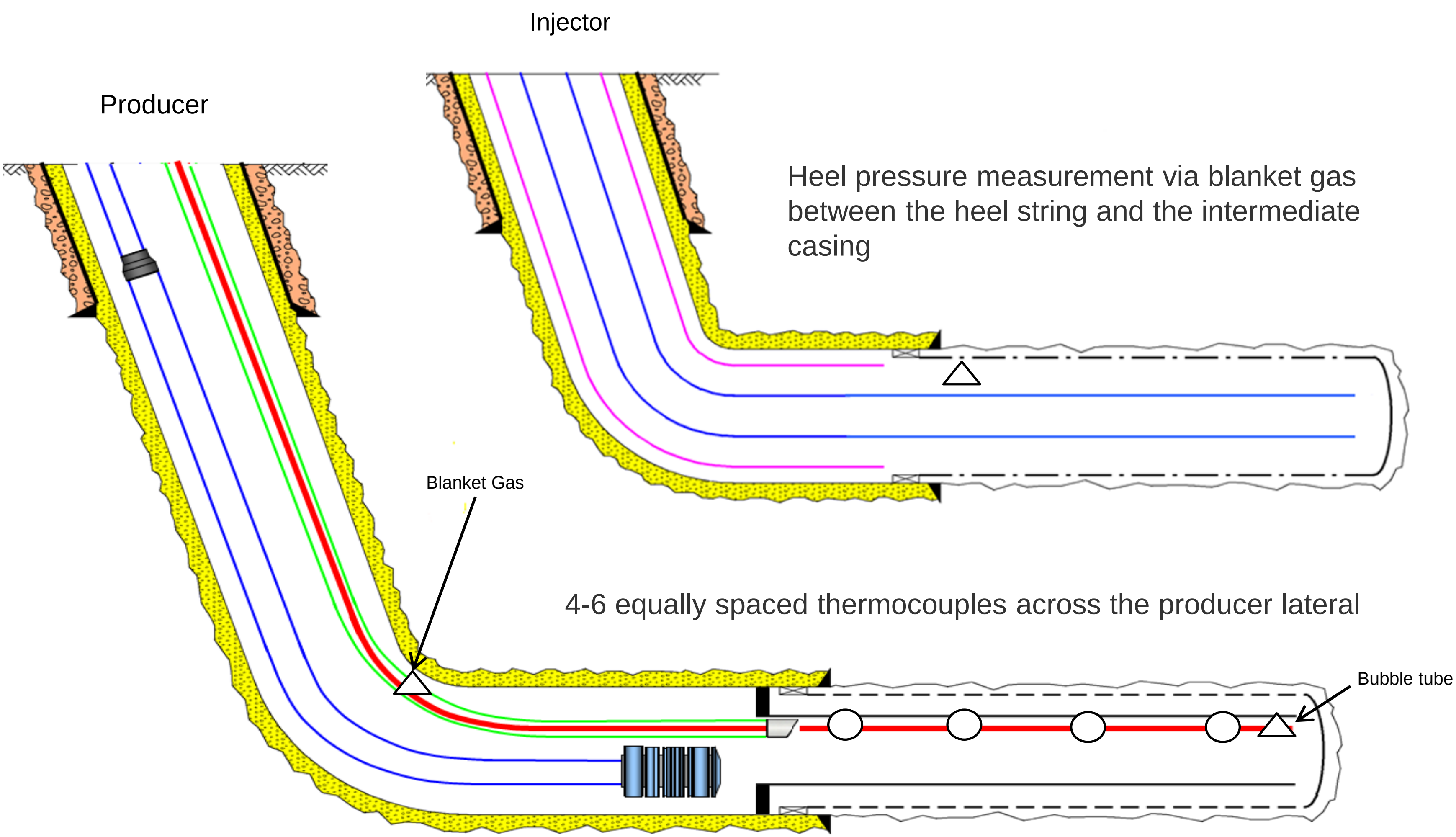
Typical Producer Circulation



Artificial Lift Performance

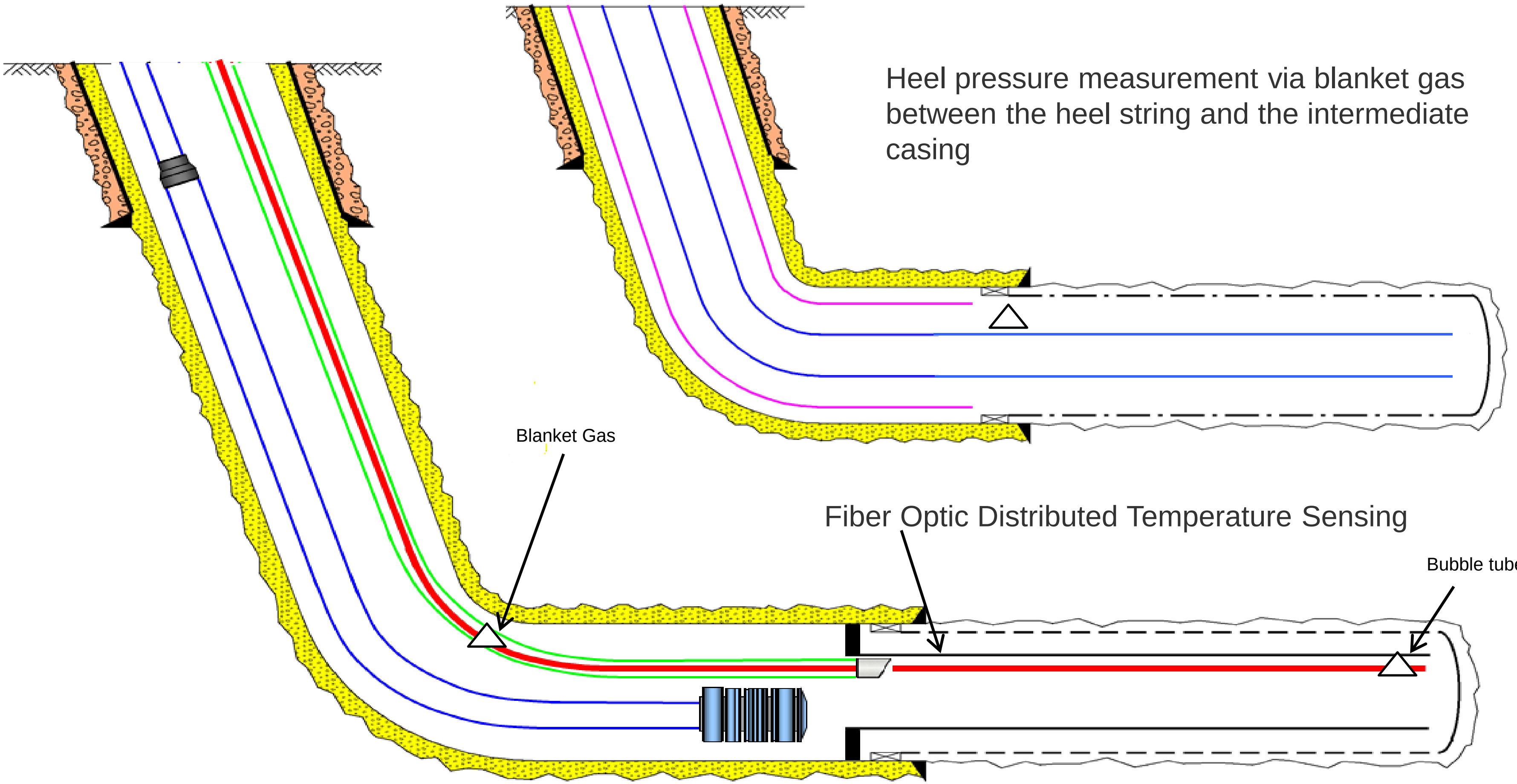
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers to allow production at lower steam chamber pressures.
  - 6 wells currently are on gas lift production
  - Currently running 1 Progressive Cavity Pump (PCP) in 02P07
    - Kudu 1100-MET-750 metal stator and rotor installed Mar-2014 (intermittent operations since)
- ESPs installed in 109 SAGD wells:
  - Pump performance (at Dec 31, 2017):
    - Average Run Time: 565 days
    - Mean Time to Failure (cumulative): 904 days
    - Mean Time to Failure change (Dec 2016 – Dec 2017): +7%
  - 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
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates.

SAGD Instrumentation



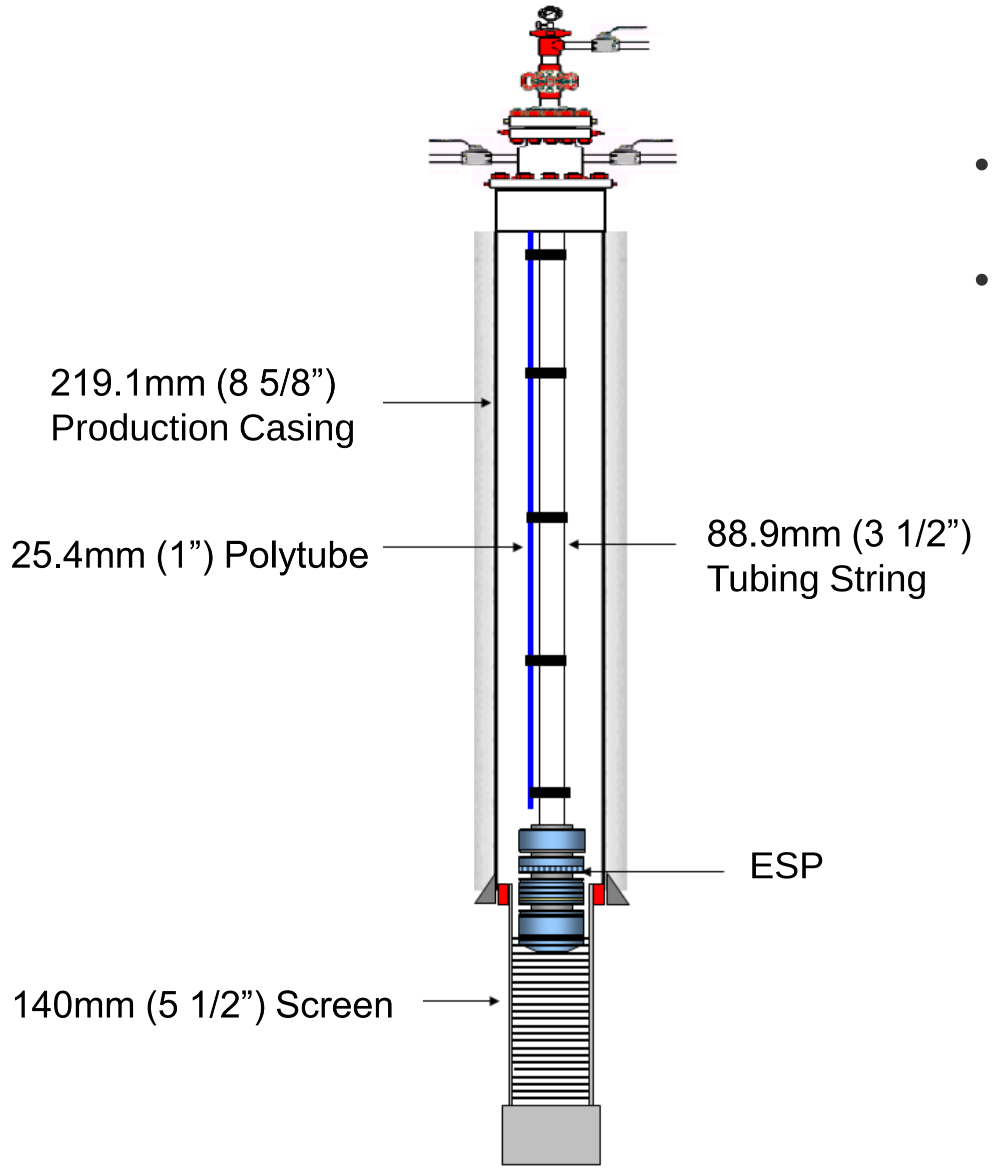
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Alternate SAGD Instrumentation



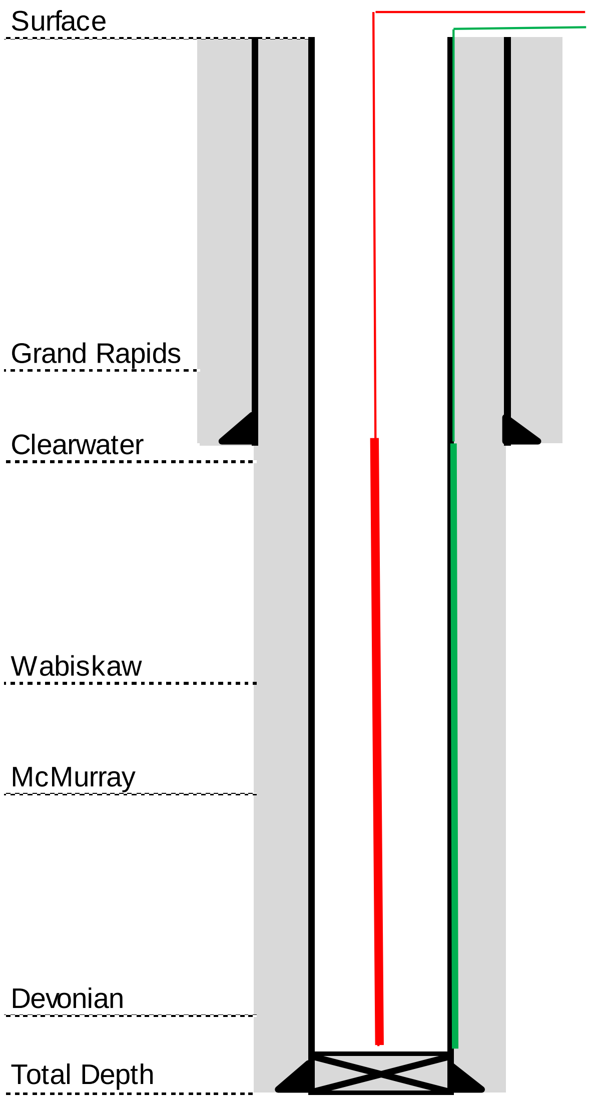
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

Typical Water Source Well



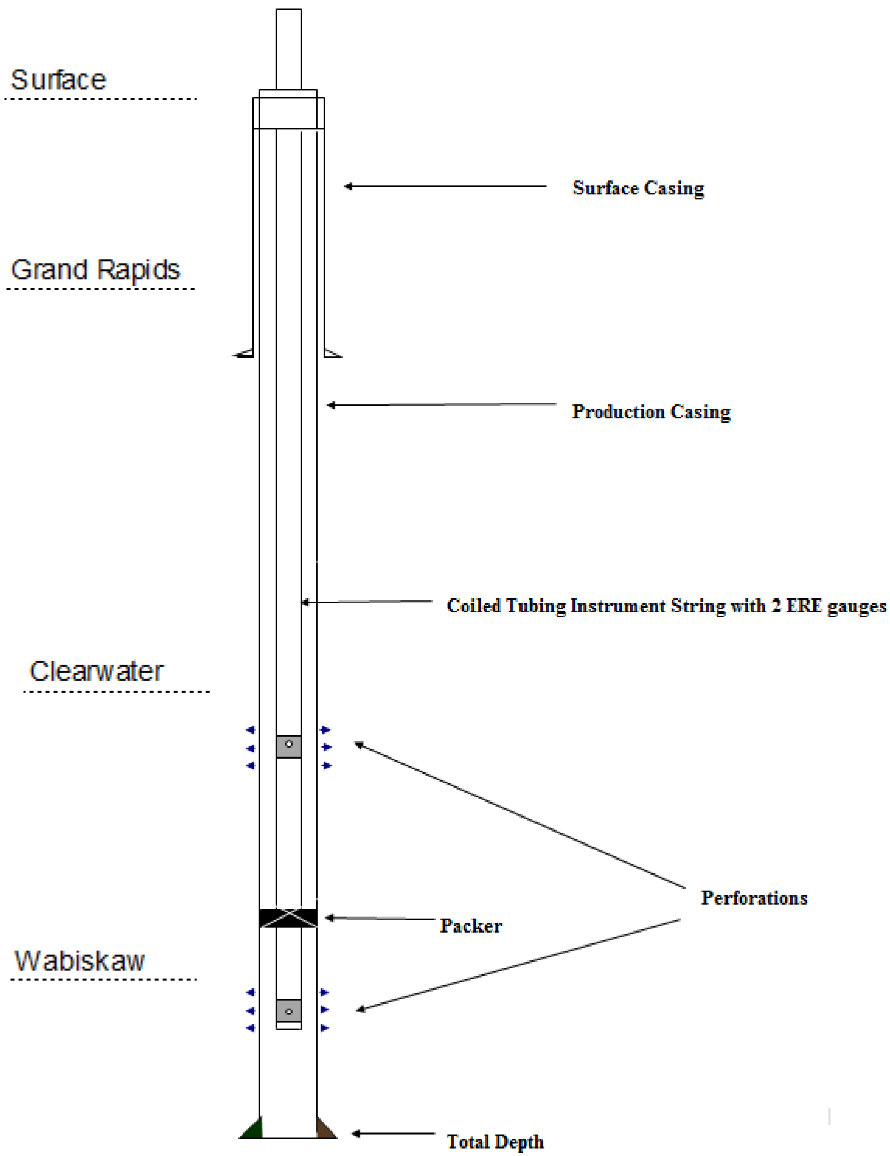
- ESP intake landed above the top of the water formation
- 18.3mm probe run through polytube and landed above the ESP
  - Monitors water level in casing

Typical Observation Well Current Design and Practices

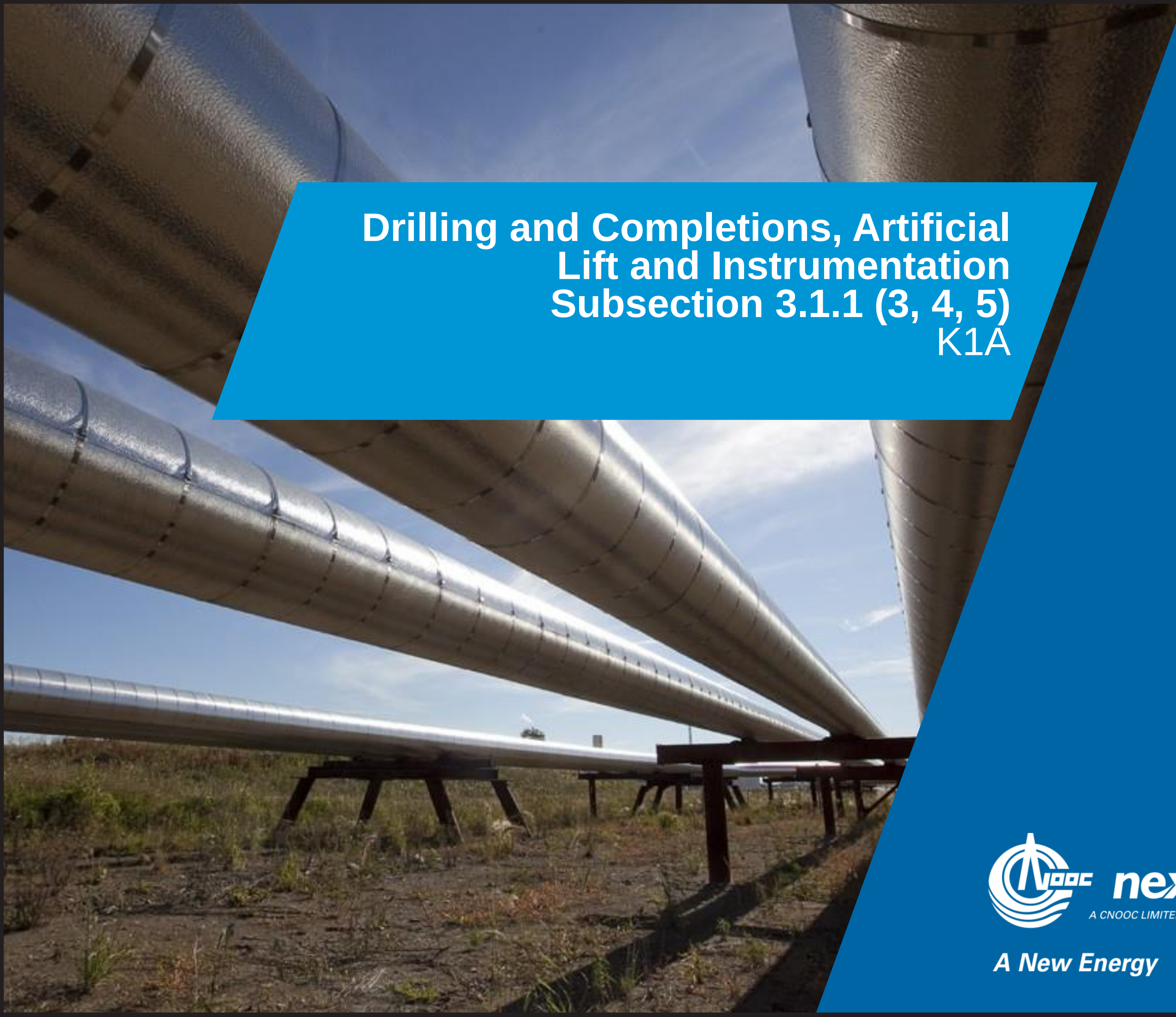


- Cement with Thermal 40 EXP cement
- Vibrating wire piezometer sensors (green) are strapped outside the production casing providing pressure and temperature measurements
- Thermocouple strings (red) provide temperature measurements
- Run a CBL on well with pressure pass if required

Alternative Observation Well Recompletion Design



- Perforated vertical wells with a packer isolating multiple zones to ensure monitoring over low permeability intervals (eg: Clearwater for caprock surveillance)
- Electromagnetic Resonating Elements (ERE) gauges are contained within coil tubing instrument string inside the production casing providing pressure and temperature measurements



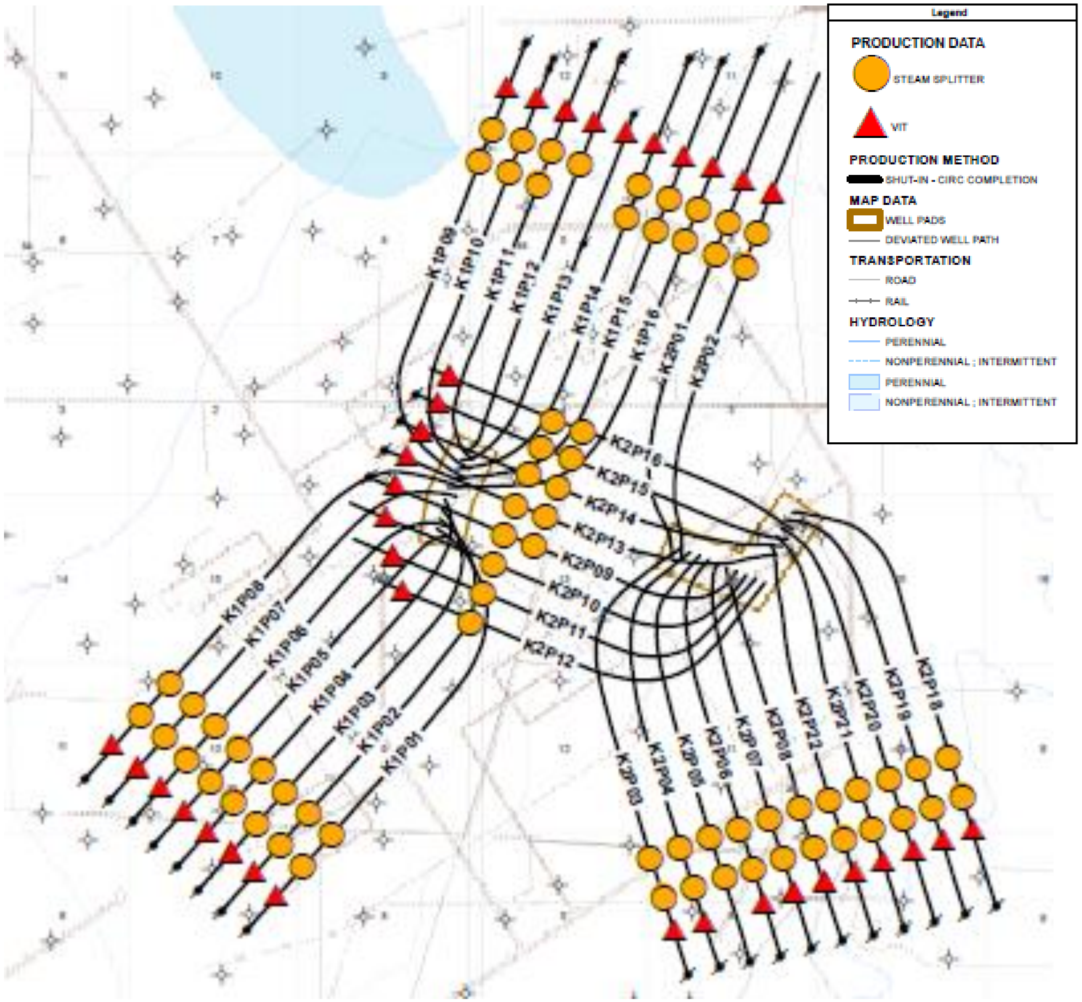
Drilling and Completions, Artificial Lift and Instrumentation Subsection 3.1.1 (3, 4, 5)

K1A

nexen
A CNOOC LIMITED COMPANY

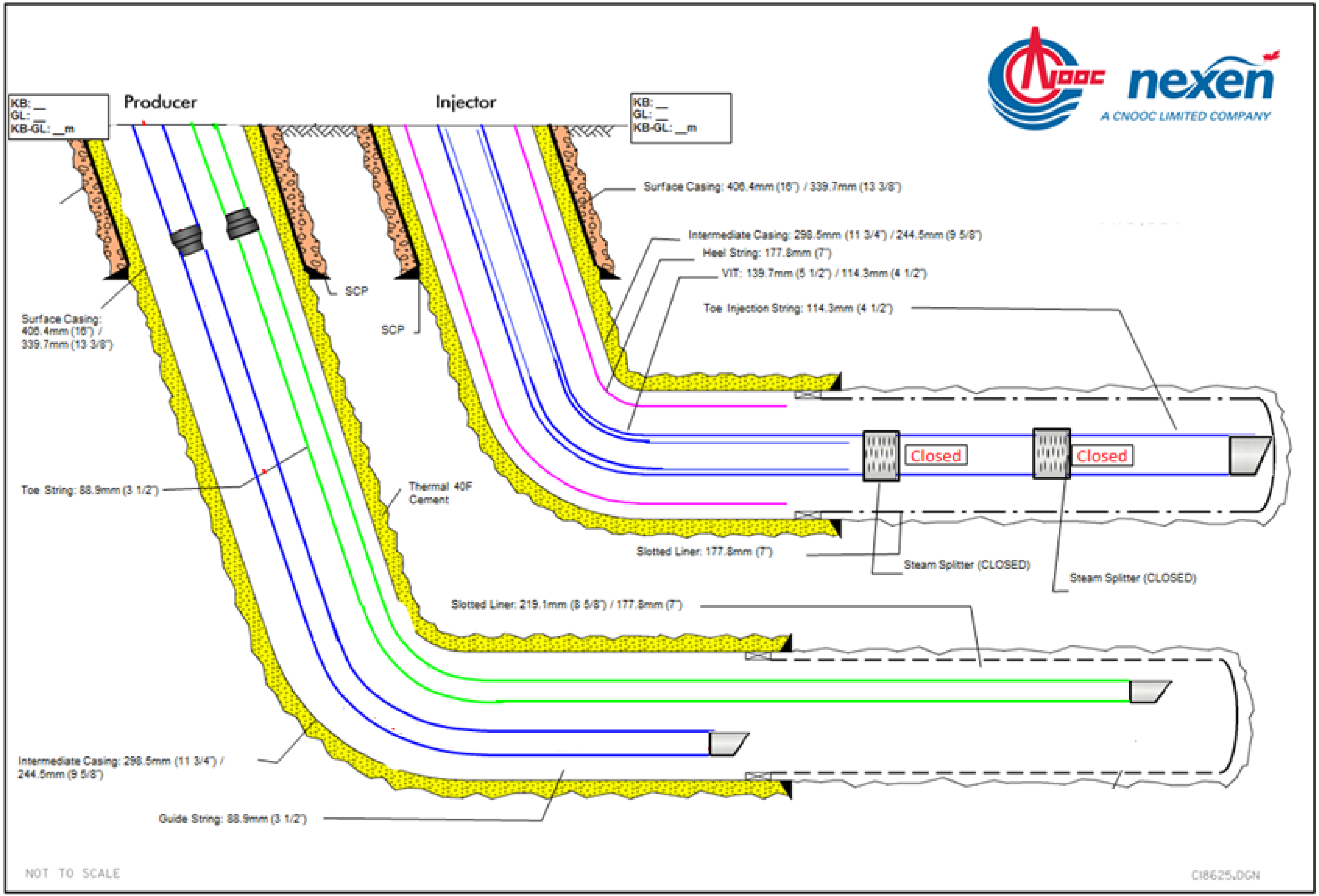
A New Energy

K1A Well Pair Completions Map as of Dec 31, 2017

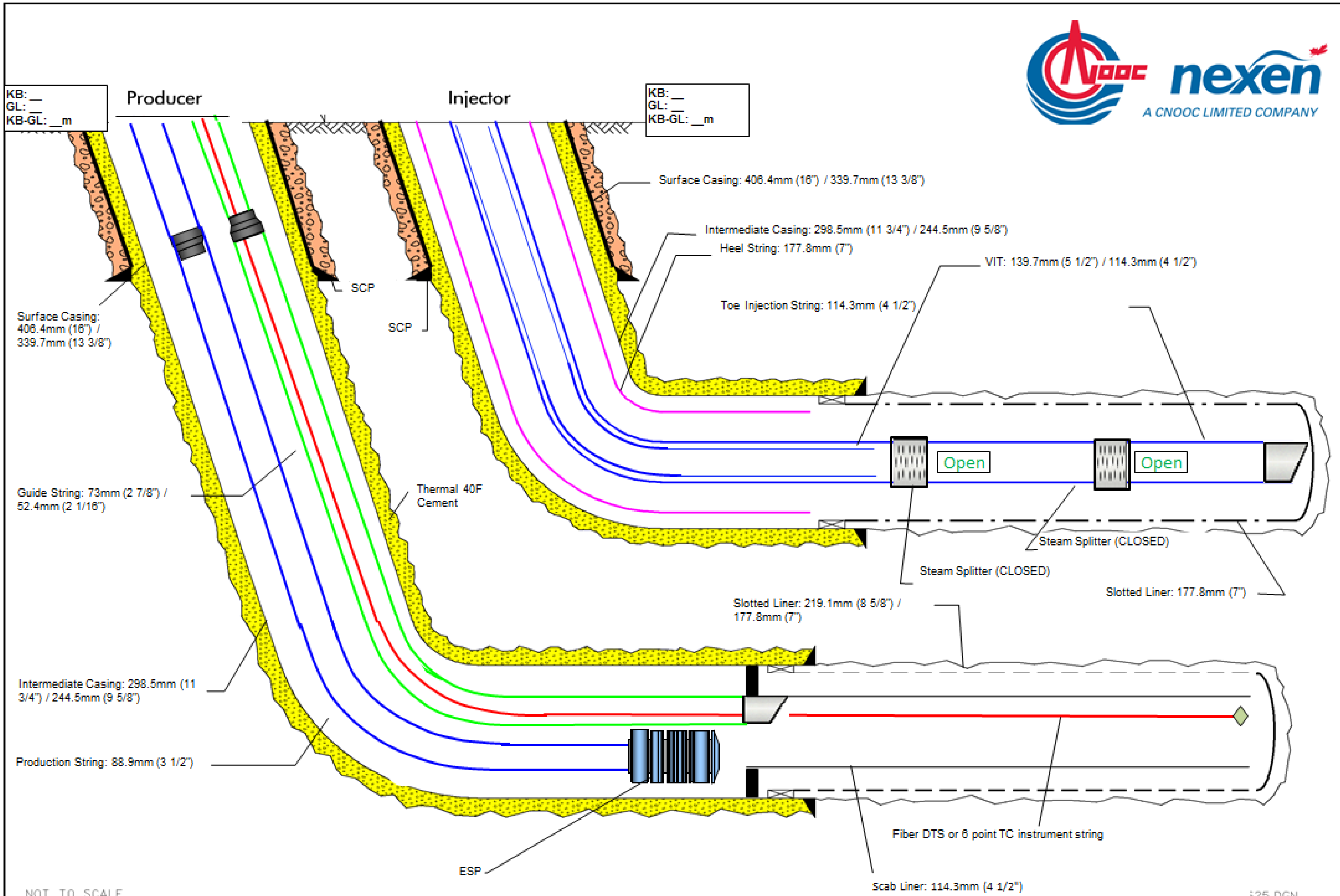


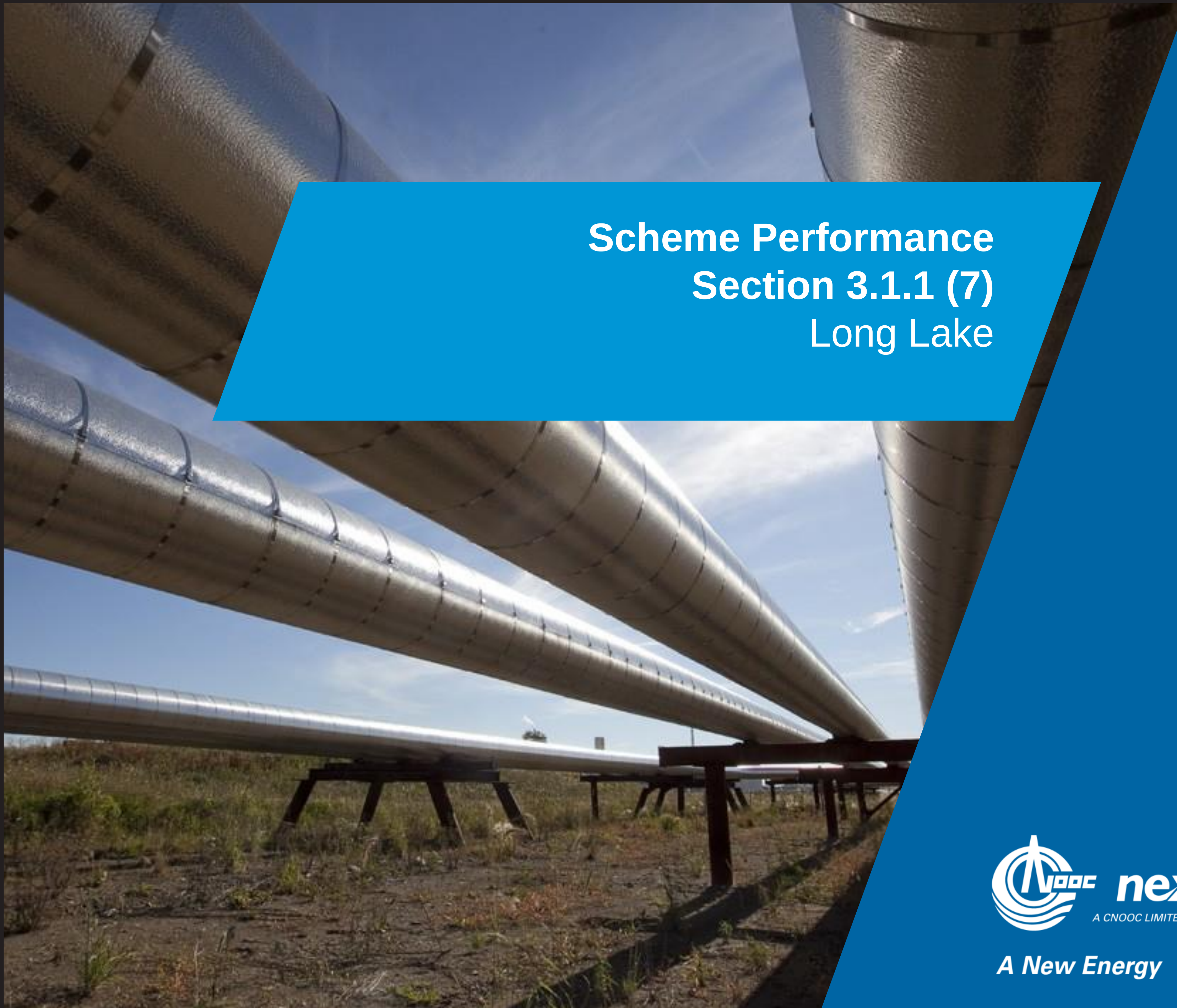
- On Jul. 15, 2015 a line rupture was discovered on the K1A produced emulsion line tie-back to Long Lake CPF.
  - Operations of both the remote steam generation facility (SGF) and well pairs at K1A were subsequently ceased and remain down.
- Status of wells as of Dec. 31, 2017:
  - 36 well pairs remain suspended, however are equipped for circulation.

Typical K1A Completion Schematic Circulation



Typical K1A Completion Schematic SAGD





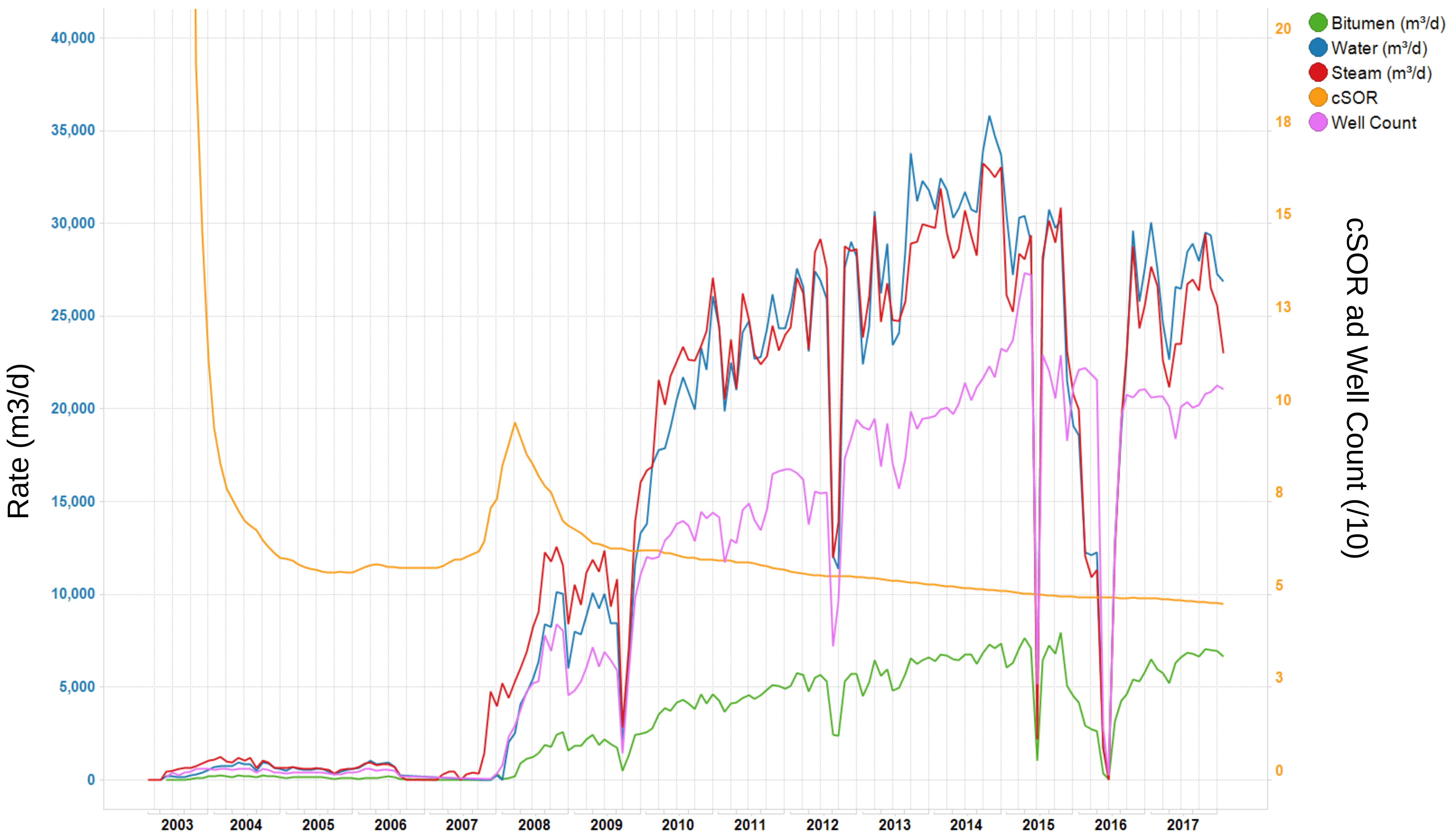
Scheme Performance
Section 3.1.1 (7)
Long Lake

A New Energy

Long Lake 2017 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
- Strong, steady performance exhibited throughout the year
- Approval of GMP enabled re-introduction of steam to four wells:
  - 2P04, 2P05, 2P06, 3P01

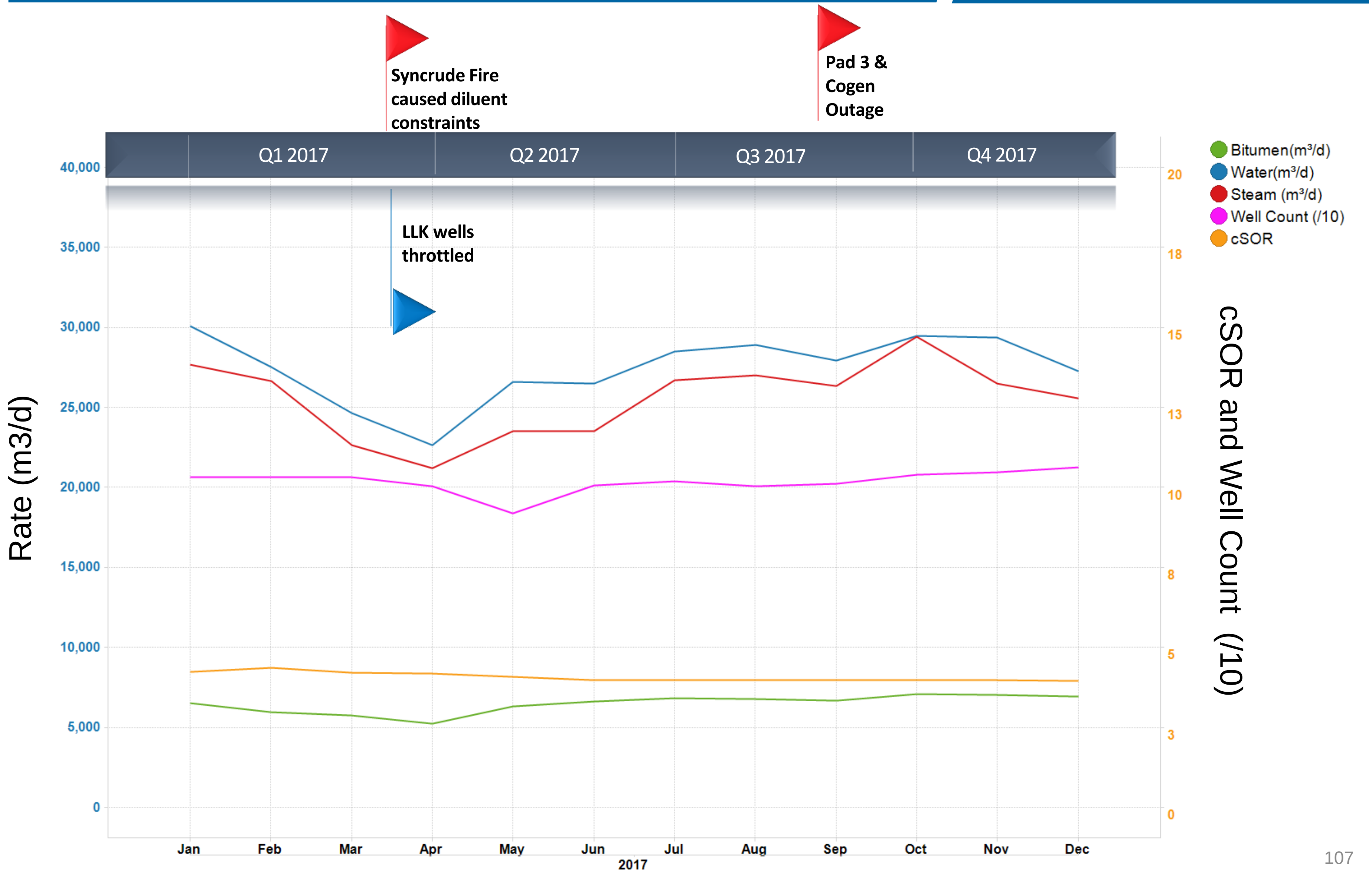
Scheme Performance
Field Level



*Graph includes K1A

Scheme Performance

2017 Field Level Highlights



Scheme Performance

Recoverable Bitumen

Pad	Well Count	Cumulative Production, YE 2017 (e6m3)	EUR (e6m3)	EBIP (e6m3)	SBIP (e6m3)	EBIP		SBIP	
						Current RF	Estimated Ultimate RF	Current RF	Estimated Ultimate RF
LL-001	5	1.1	1.5	2.2	2.8	48%	66%	38%	52%
LL-002NE	6	0.8	1.1	2.3	2.7	34%	47%	30%	41%
LL-002SE	5	0.3	0.4	1.1	1.6	28%	35%	18%	23%
LL-003	5	1.2	1.7	2.6	3.4	48%	65%	36%	49%
LL-004	2	0.1	0.1	0.2	0.2	62%	62%	48%	48%
LL-005	5	1.4	2.0	2.9	3.5	49%	69%	40%	57%
LL-006N	6	0.8	1.3	3.1	3.9	26%	42%	21%	33%
LL-006W	7	0.8	1.0	1.7	2.6	49%	58%	33%	39%
LL-007E	7	0.8	1.0	2.1	2.8	37%	48%	27%	36%
LL-007N	9	2.2	3.0	3.2	3.8	69%	95%	58%	80%
LL-008	6	1.3	2.0	2.9	3.4	46%	70%	39%	60%
LL-009NE	5	0.3	0.3	1.2	1.7	21%	28%	15%	19%
LL-009W	5	0.5	0.5	1.7	1.9	27%	30%	24%	26%
LL-010N	8	0.3	0.5	2.8	3.5	11%	18%	8%	14%
LL-010W	5	0.7	1.1	2.2	2.7	31%	52%	26%	43%
LL-011	10	1.2	1.6	2.3	2.7	55%	69%	46%	57%
LL-012	9	0.8	1.9	3.4	4.5	24%	55%	18%	41%
LL-013	9	1.1	2.0	3.3	4.3	33%	61%	25%	46%
LL-014/15E	6	0.3	0.8	1.3	1.8	25%	59%	18%	41%
LL-014N	3	0.3	0.8	1.4	1.8	18%	55%	15%	44%
LL-015S	2	0.1	0.3	0.6	0.7	19%	51%	17%	44%
K1A-A	9	0	2.5	4.8	5.8	0%	52%	0%	43%
K1A-B	8	0	2.2	3.9	4.4	0%	56%	0%	50%
K1A-C	8	0.1	3	5.1	6.3	2%	59%	2%	47%
K1A-D	11	0	3	5.3	6.9	1%	56%	1%	43%
Total	**161**	**16.6**	**35.6**	**63.7**	**80.0**	**26%**	**56%**	**21%**	**45%**

* Includes 4 infill producers

Scheme Performance

Dec 2017 MOP & Average Injector Pressures

Drainage Area/ Pad	MOP (kPag)	Average Injector Pressure (kPag)
LL-001	2950, Infills = 2500	1,558
LL-002NE	2950	1,542
LL-002SE	2950	1,265
LL-003	2950	1,555
LL-004	2950	1,372
LL-005	2950	1,602
LL-006N	2950	1,890
LL-006W	2950	1,689
LL-007E	2950	1,730
LL-007N	2950	1,818
LL-008	2950	1,710
LL-009NE	2950	1,625
LL-009W	2950	1,948
LL-010N	2950	2,081
LL-010W	2950	1,778
LL-011	2950	1,584
LL-012	2250	1,840
LL-013	2250	1,777
LL-014N	2300*	2,149
LL-014E/015E	2300*	1,867
LL-015S	2300*	1,621
K1A-A	2000	0
K1A-B	3000	0
K1A-C	3000	0
K1A-D	3000	0

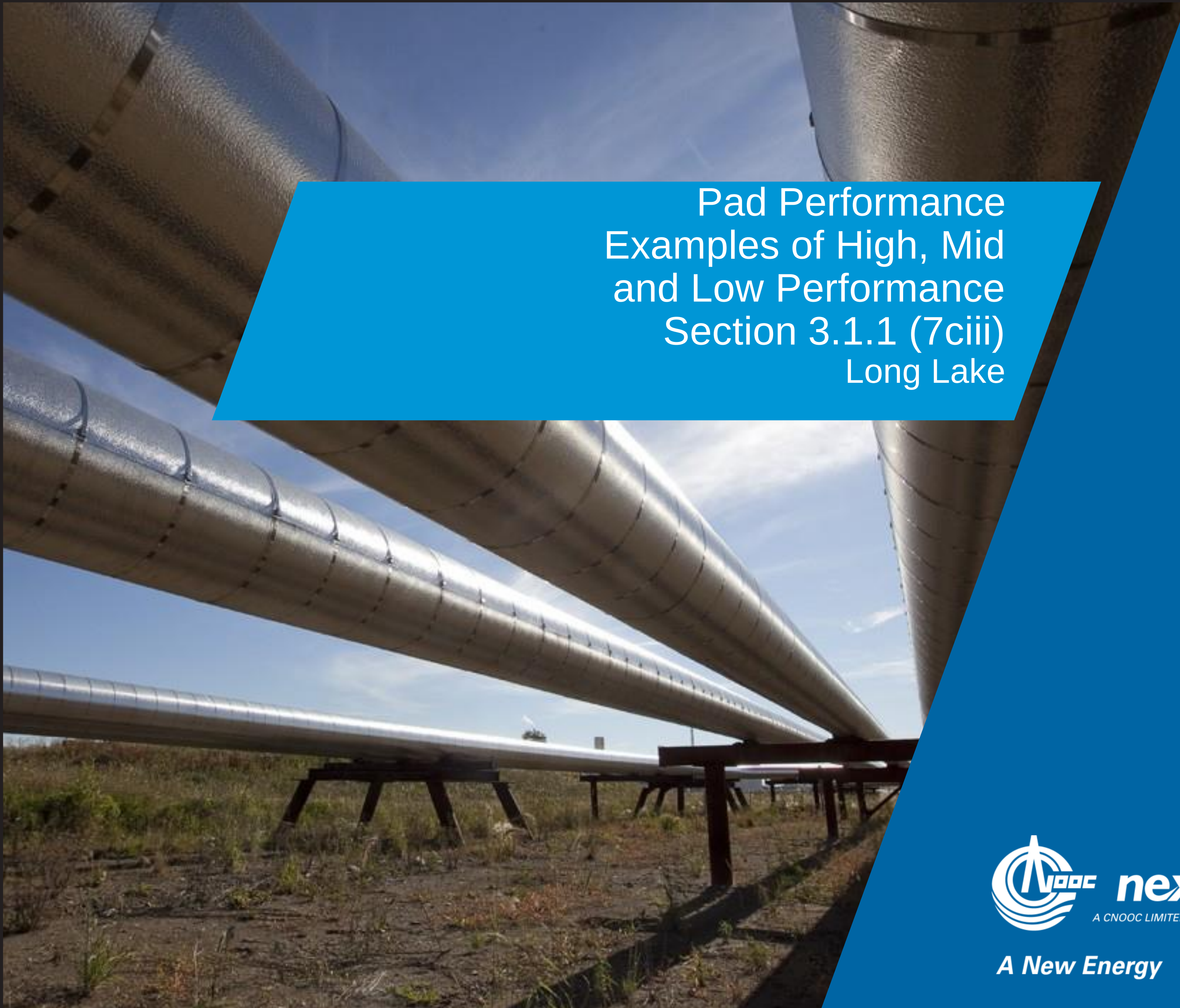
* Tapered MOP

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 well pair 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.



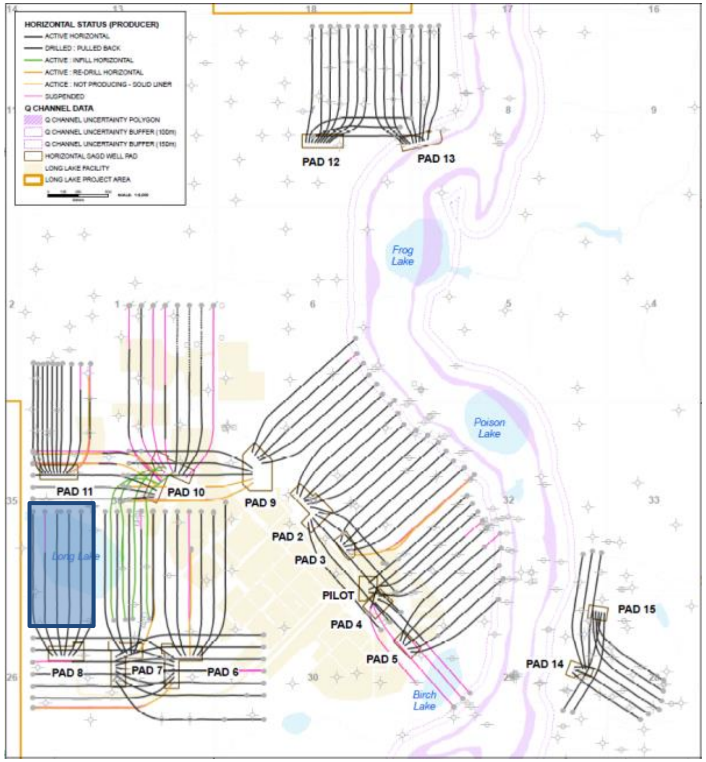
Pad Performance
Examples of High, Mid and Low Performance
Section 3.1.1 (7ciii)
Long Lake

Examples of High, Mid, Low Recovery
High level comparison

	Resource Quality (mapped average)	Performance	Operating Strategy
Pad 8 *High*	EBIP thickness: 31m S_{we}: 0.39	Well Peak Rate: 308m³/d Current Pad RF: 39%	Infills drilled in Q1 2018
Pad 14N *Mid*	EBIP thickness: 23 m S_{we}: 0.22	Well Peak Rate: 141m³/d Current Pad RF: 15%	Sustaining Pad, Tapered pressure strategy
Pad 10N *Low*	EBIP thickness: 13 m S_{we}: 0.25	Well Peak Rate: 92m³/d Current Pad RF: 8%	Low priority, Not operated consistently

Example of High Recovery
Pad 8

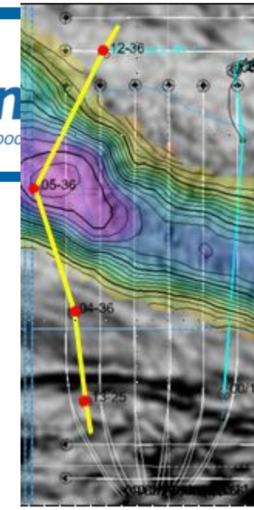
- 6 base wellpairs, all equipped with ESPs
  - Conversion to SAGD beginning Q1 2008
  - 8P03 has been producing with ICDs since Dec 2015
  - 8P06 producing without an injector since Apr 2015
- Four infill wells drilled in Q1 2018
  - Steam injection was reduced in Q4
- Limited seismic data available due to surface lake
- Pad 8 is impacted by top water and lean zone; current operating pressure is lower than pressure in top water and lean zone
  - Significant amount of water was produced from this region in the first 5 years
  - An aggressive operating strategy enabled production benefit to be realized in the last 5 years
  - Oil cut recovered well and stabilized post wildfire
- YE 2017 SBIP RF is 39%



Example of High Recovery
Pad 8

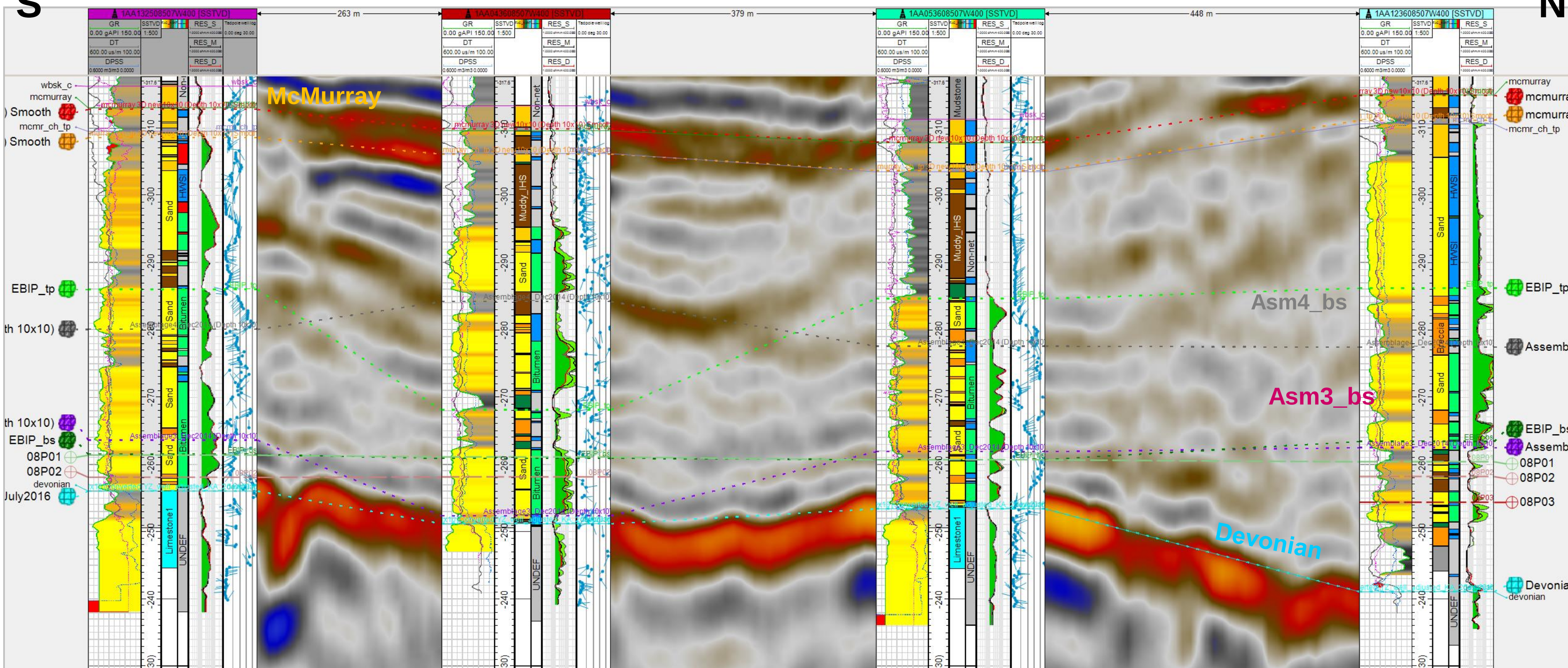
Example of High Recovery
Pad 8 – Geology

- Reservoir quality gets better from west to east on Pad 8
- Regional G&G study helps on Devonian structure interpretation in the area with no or unreliable seismic data
- Limited stranded pay below producers



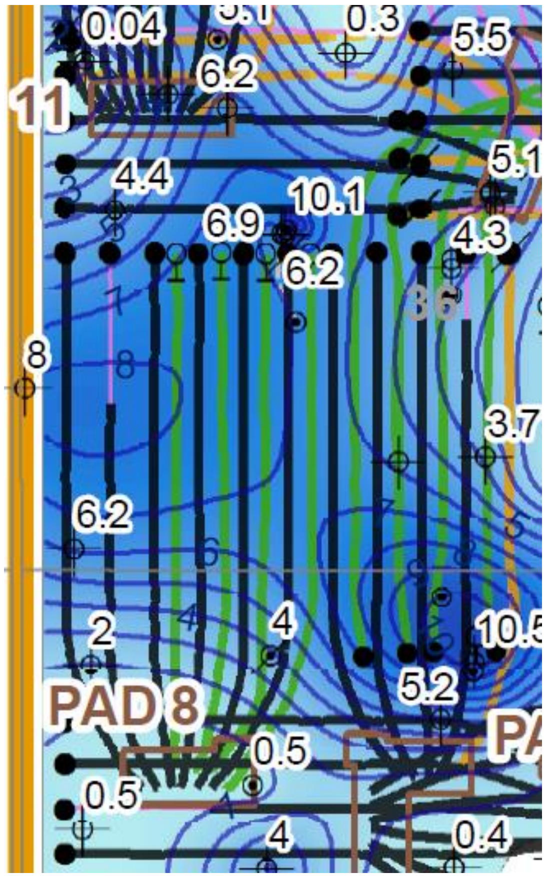
S

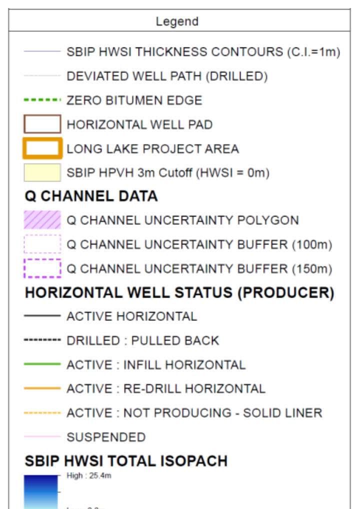
N

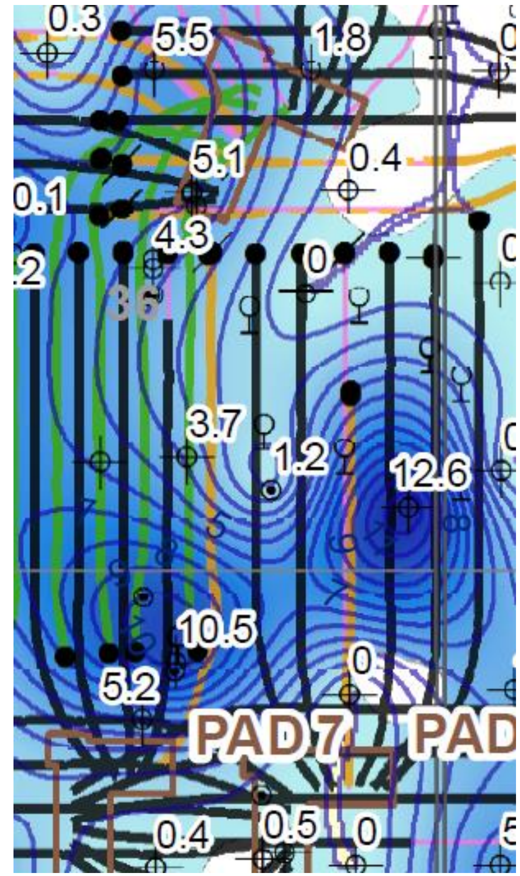


Example of High Recovery
Pad 8 – Geology

- Pad 8 toes are in connection with extensive water saturated intervals
- Top water is truncated by the mudplug cutting across Pads 8 and 7N





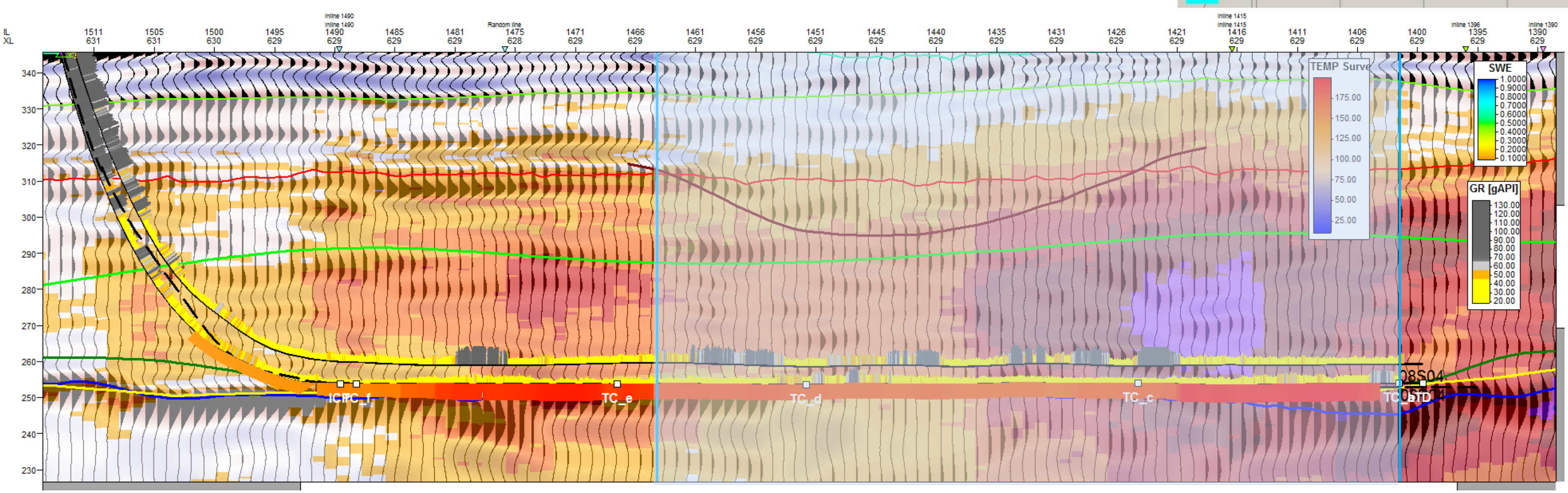


Top Water Associated with SBIP Interval

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

Example of High Recovery
Pad 8 – 4D Seismic

- 4D seismic from 2015 (impedance percentage change) along 8P04
- Limited data available due to surface lake
- Good conformance along wellbore and development to EBIP top



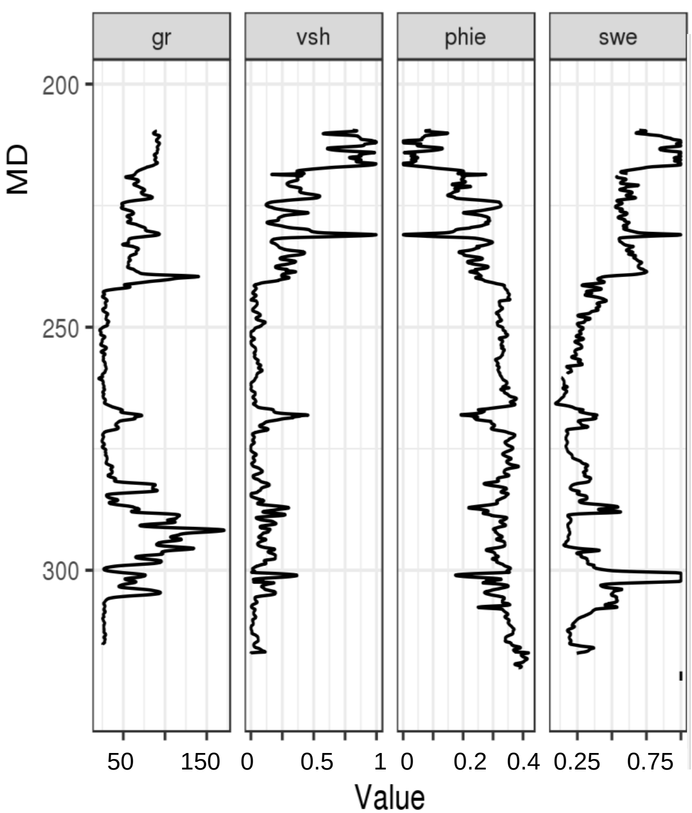
Surface Lake

Example of High Recovery
Pad 8 – Monitoring

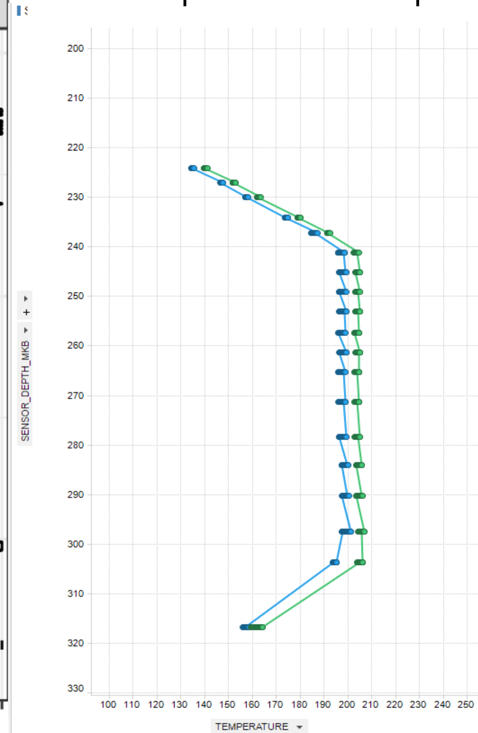
- There are 3 OBS wells in vicinity of Pad 8
- OBS 122/06-36
  - Deviated well drilled to avoid the surface lake

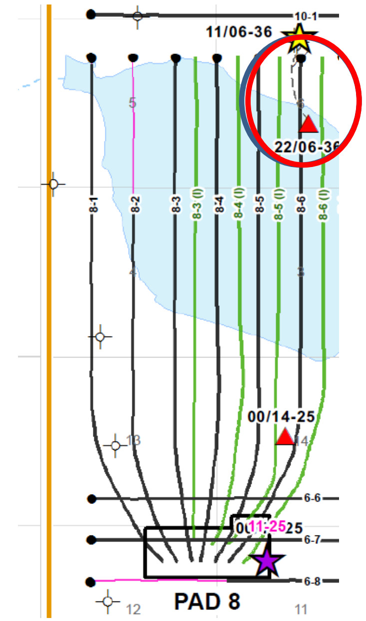
122/06-36 (08P06 offset)

Log Data



Sensor Depth MKB vs Temp

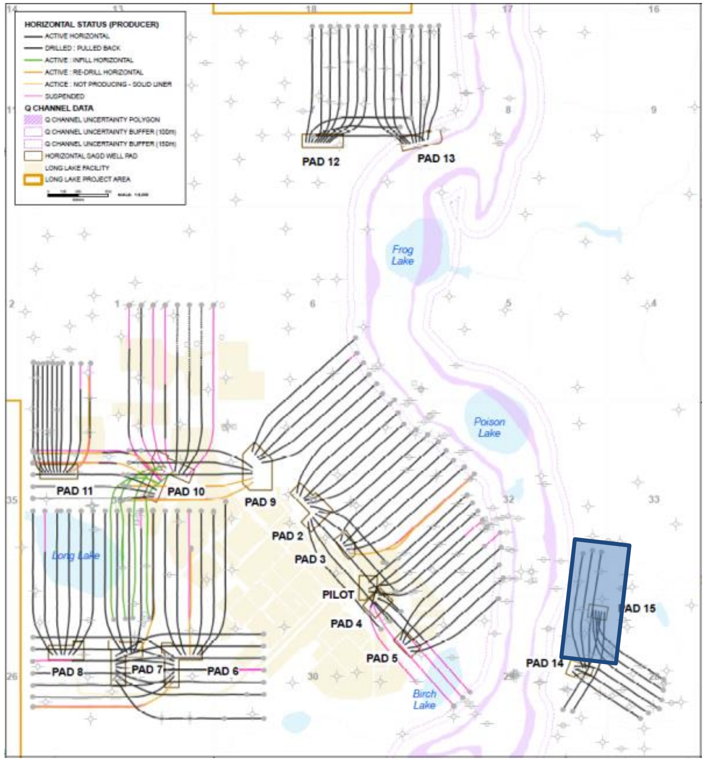




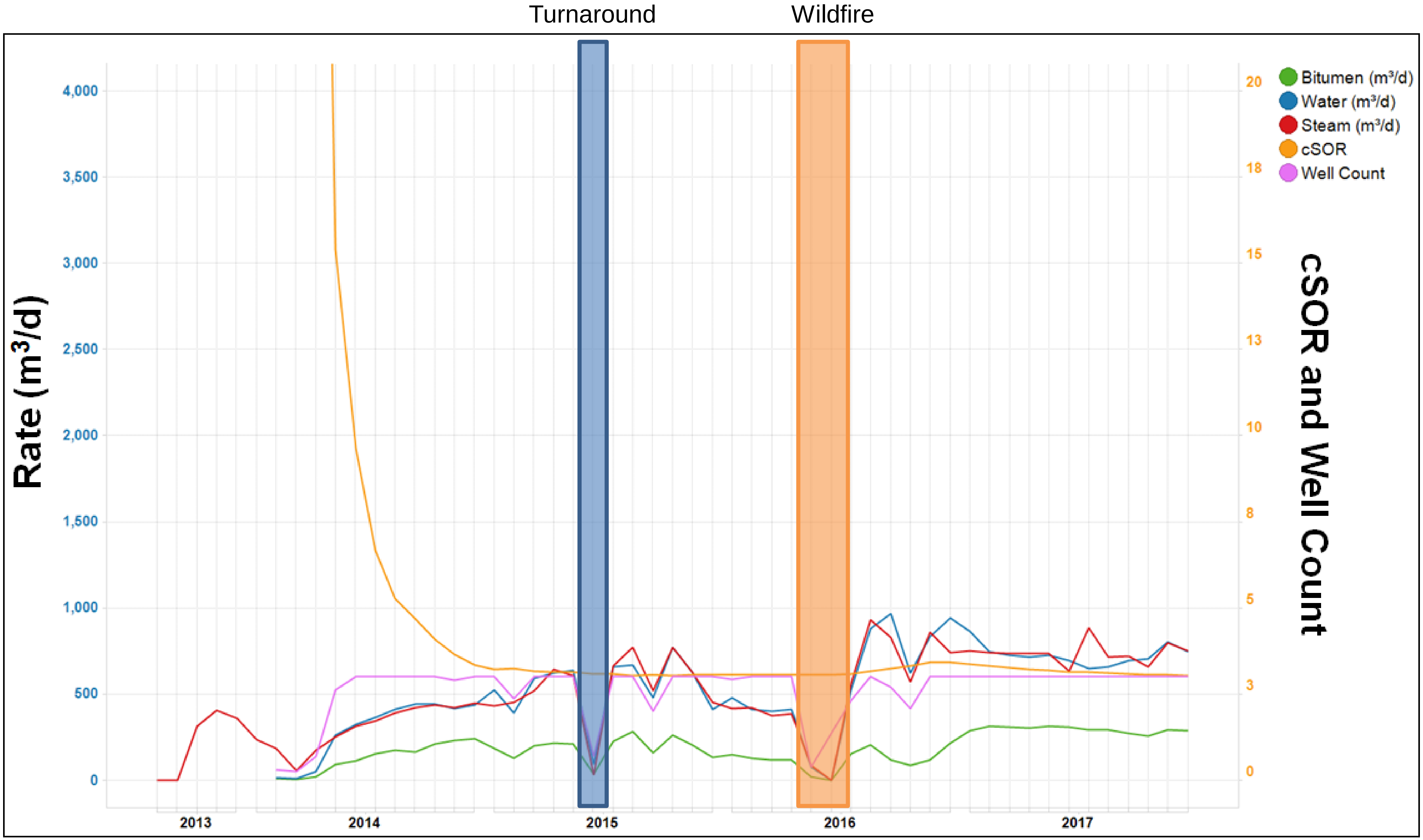
- 2016 Valid McMurray Sensors
- 2017 Valid McMurray Sensors

Example of Mid Recovery
Pad 14N

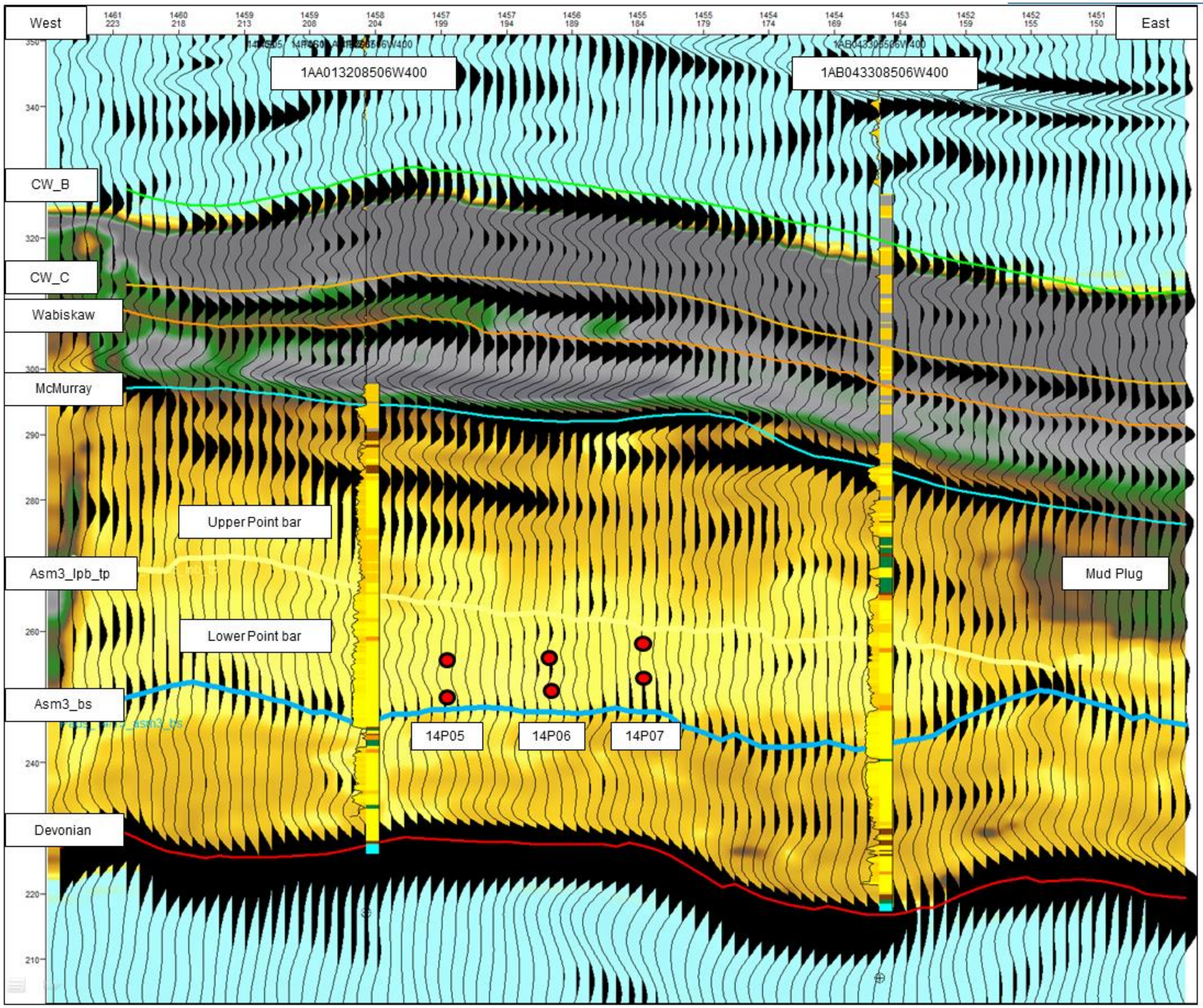
- Sustaining well pad, drainage area with 3 well pairs:
  - All wells equipped with ESPs
  - 75m spacing
  - Sand control trial
- First oil production Q1 2014
- Due to complex reservoir, pad is operated in accordance with tapered pressure schedule and at/below Q-channel pressure
- Stable production rates seen post-Wildfire
- YE 2017 SBIP RF is 15%

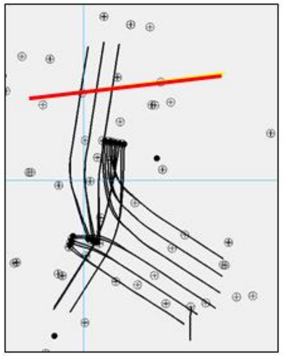


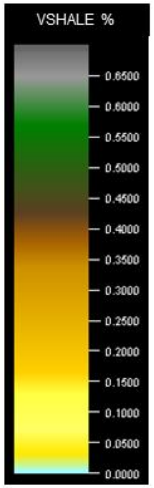
Example of Mid Recovery
Pad 14N



Example of Mid Recovery
Pad 14N - Geology

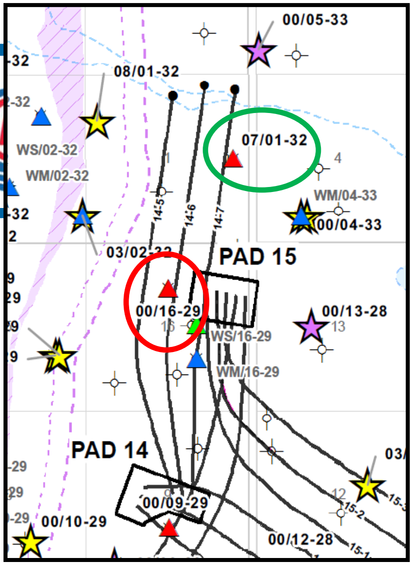




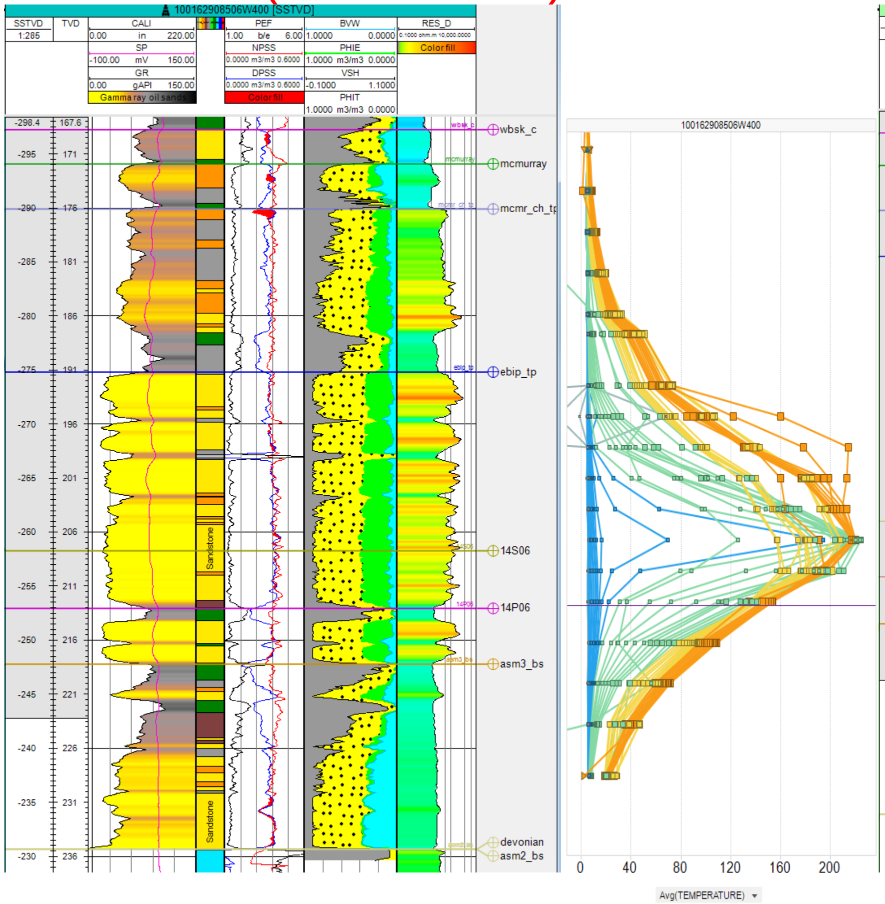


Example of Mid Recovery
Pad 14N

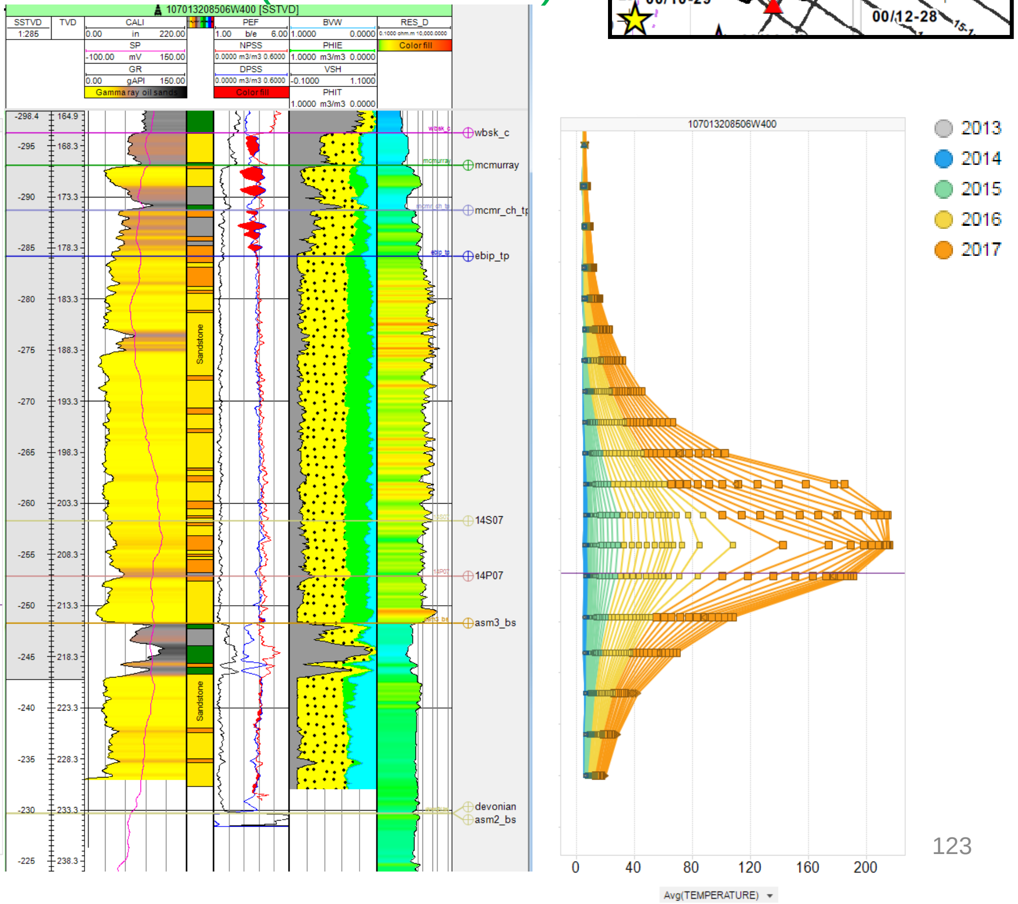
- Good quality reservoir
- Observation wells show vertical steam chamber growth impacted by local heterogeneity



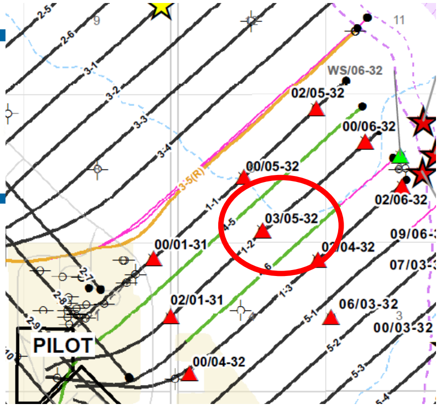
100/16-29 (14P06 offset)



107/01-32 (14P07 offset)



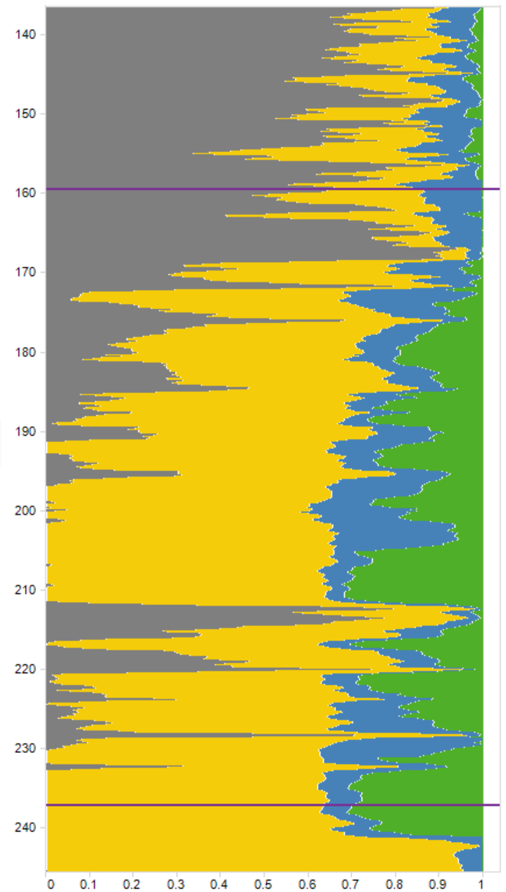
Example of restrained steam chamber growth



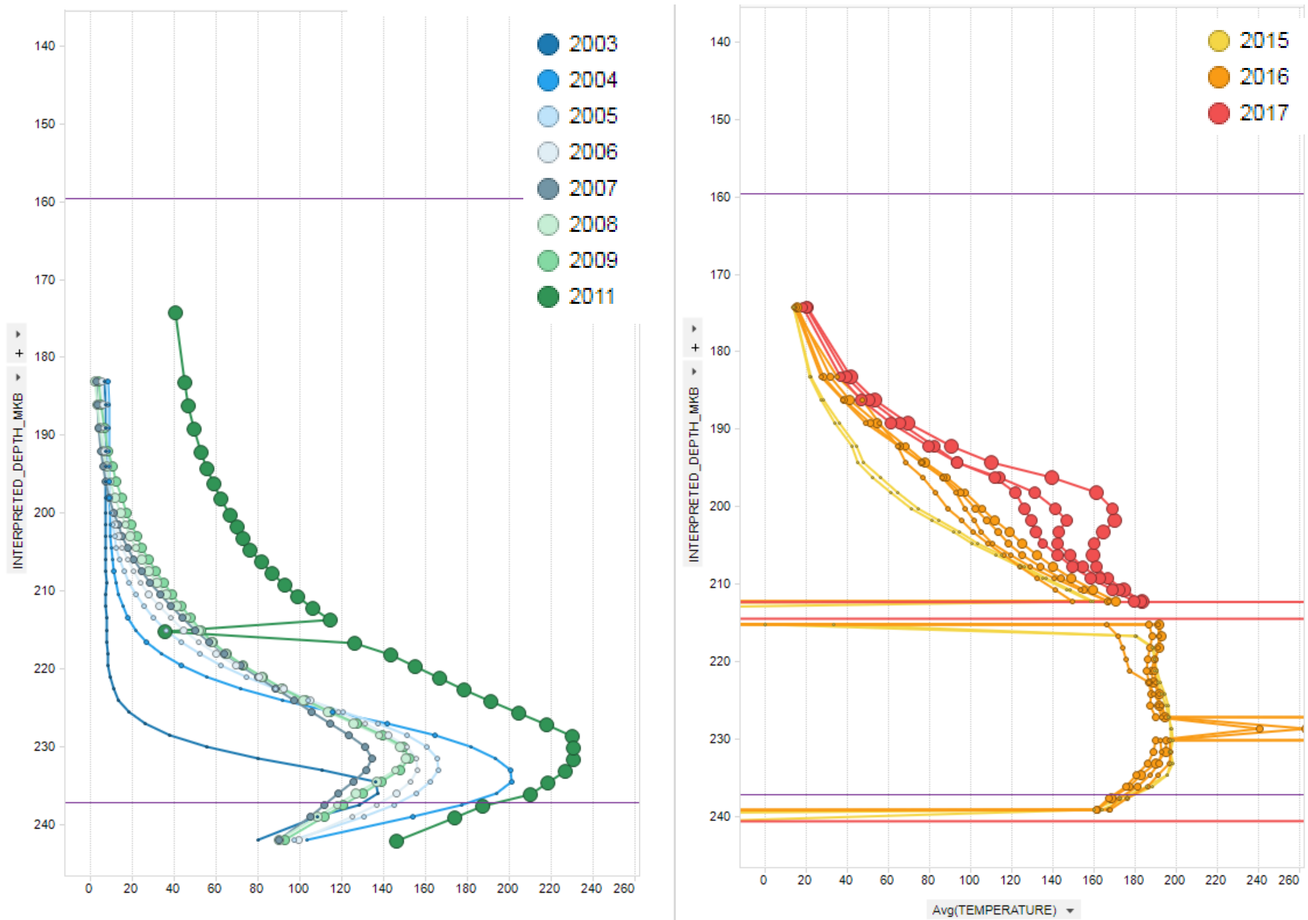
- Observation well in Pad 1 with vertical steam chamber growth impacted over production history by heterogeneity (multiple baffles)

103/05-32 (01P02 offset)

Log Data

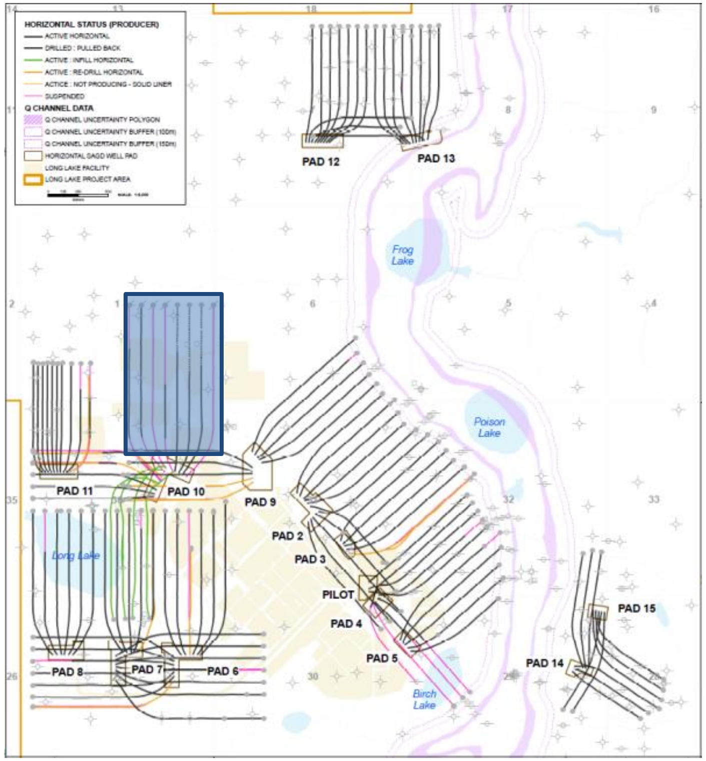


Sensor Depth MKB vs Temperature (degC)

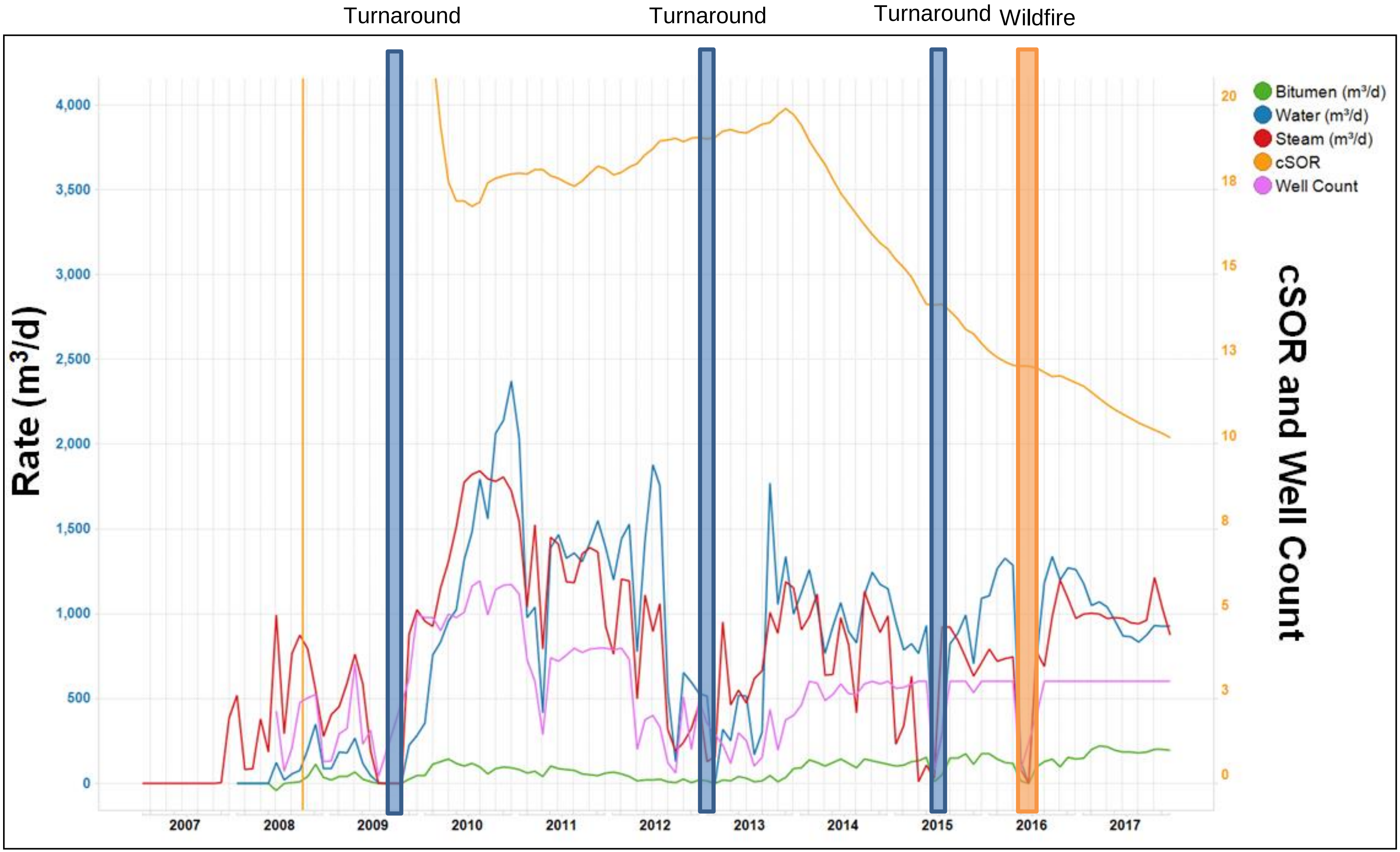


Example of Low Recovery
Pad 10N

- 8 well pairs:
  - 3 wells currently operational, equipped with gas lift
  - 10P6-9 and 10P13 long term shut in due to consistent poor performance
- First oil production March 2010
- EBIP is generally very thin, <15m over most of the pad
- Long horizontal wells, pulled back in 2011 to focus on better reservoir
- Gas lift wells moved up on the priority list and have had stable operation resulting in stronger relative performance
- 2017 YE Recovery Factor 8% (SBIP)



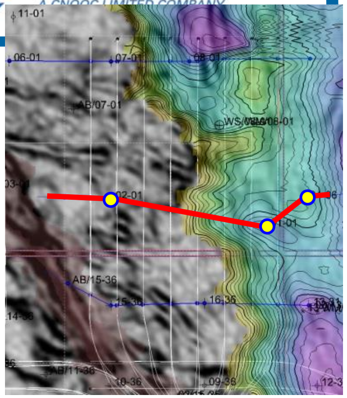
Example of Low Recovery
Pad 10N



PAD 10N – X-section (W-E)

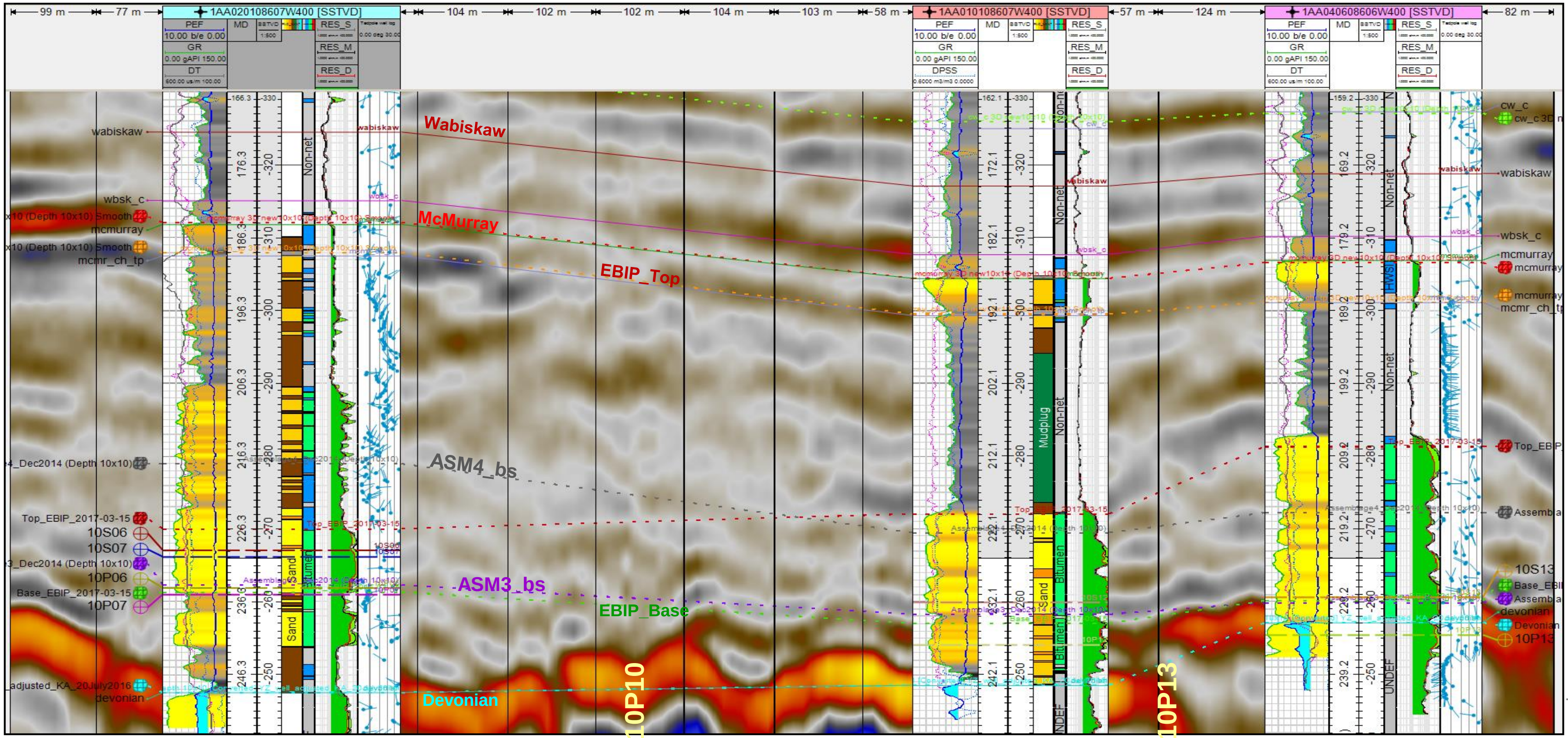
(across middle of wells)

- Erosional Feature across western edge of pad and thick and wide mudplug along eastern edge of pad
- Upper McMurray (Assemblage 4) is part of the pointbar complex bounded by Erosional Feature in the west and thick and wide mudplug in the east
- Dominant dipping direction of IHS is to the east/northeast



10N_W-E_xsec_Mids

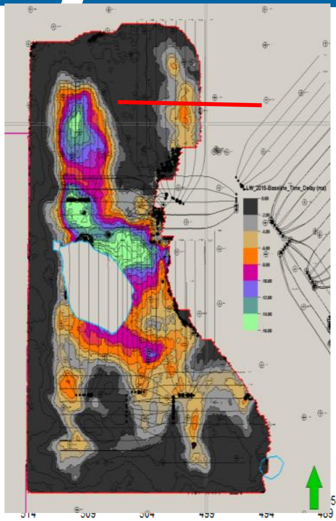
W

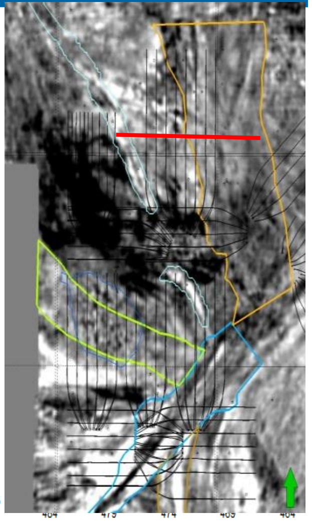


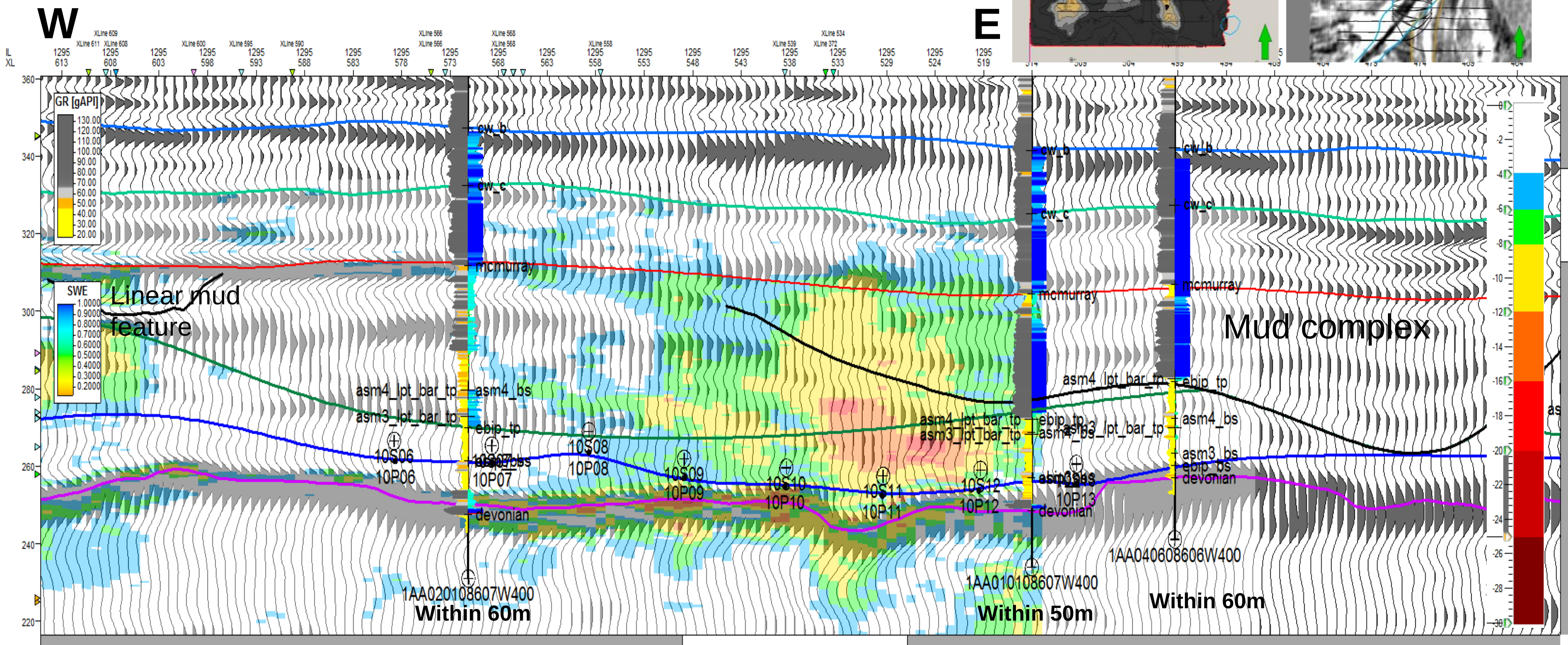
E

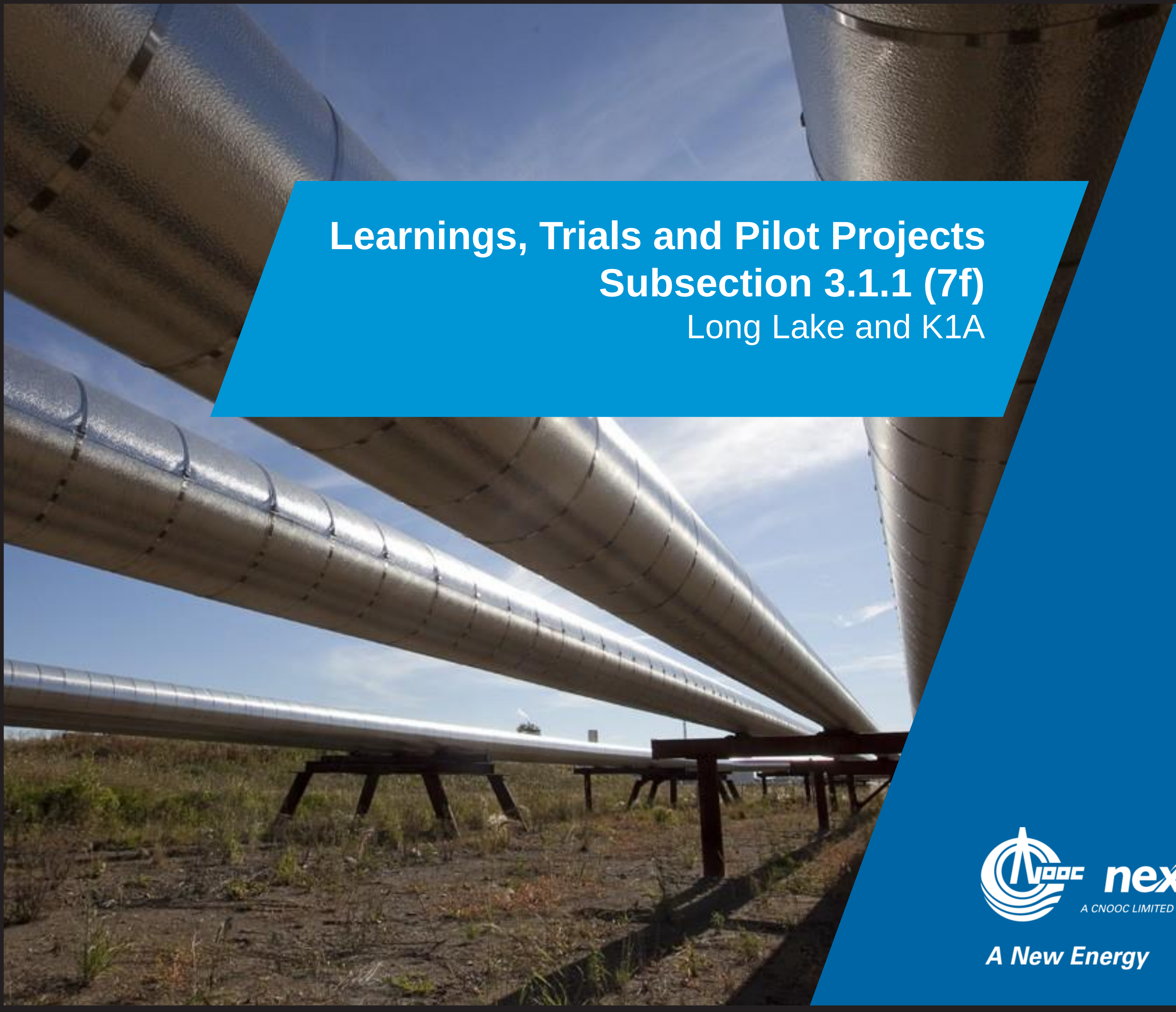
PAD10N cross section in the middle (W-E) with 4D anomaly

- Good steam chamber development in the mid section







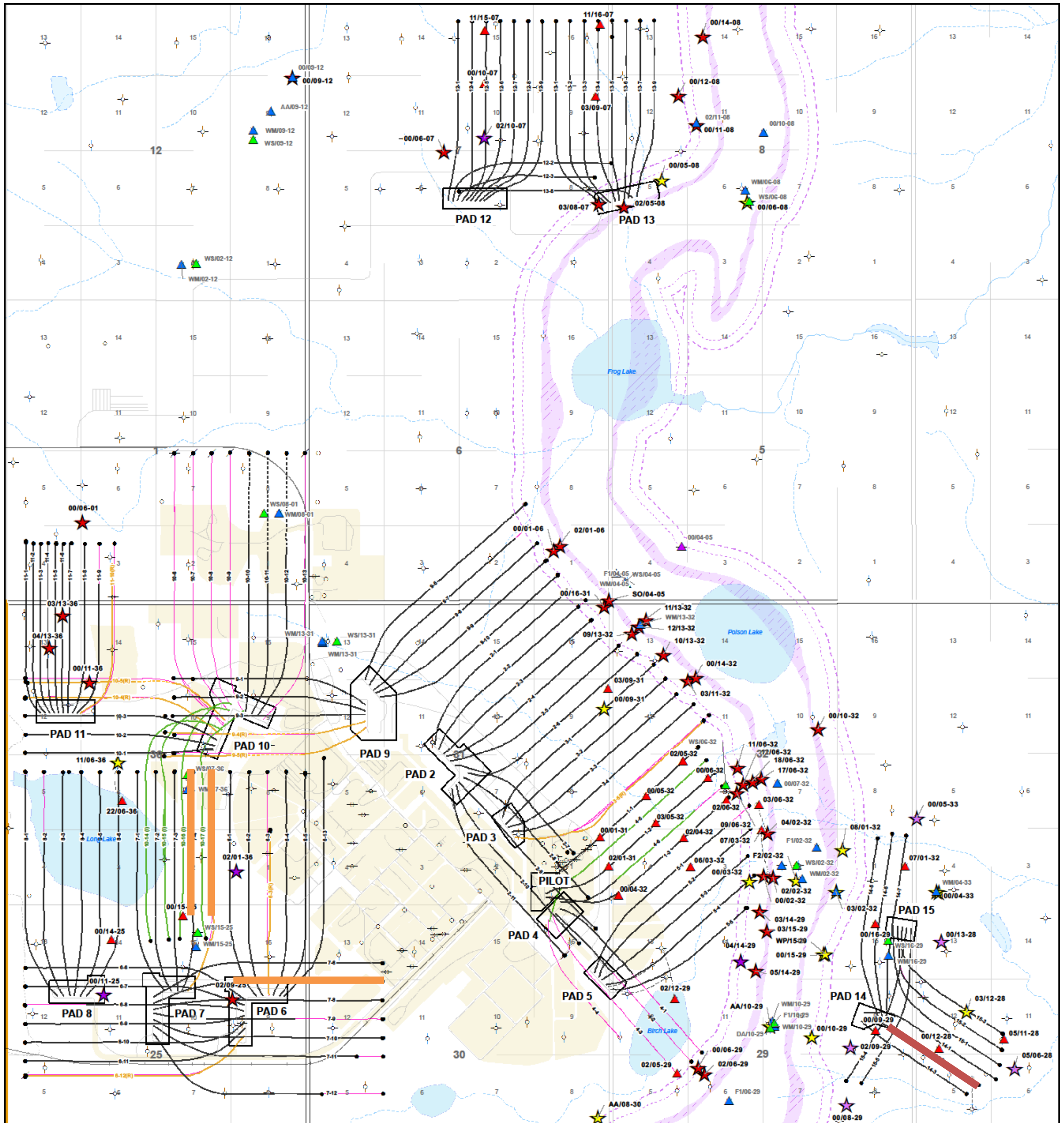


Learnings, Trials and Pilot Projects
Subsection 3.1.1 (7f)

Long Lake and K1A

A New Energy

2017 Liner Failures



- 4 liner failures in 2017
- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled:

- None

Wells Repaired:

- 07P05 – liner failure, most likely due to steam jetting, repaired Q1 w/packer assembly
- 07P04 – liner failure, most likely due to steam jetting, repaired Q3 w/bridge plug
- 07P07 – liner failure, most likely due to steam jetting, repaired Q3 w/packer assembly and ICD's

Wells Shut In – Ongoing Evaluation:

- 14P02 – suspected liner failure Q4, workover not yet conducted

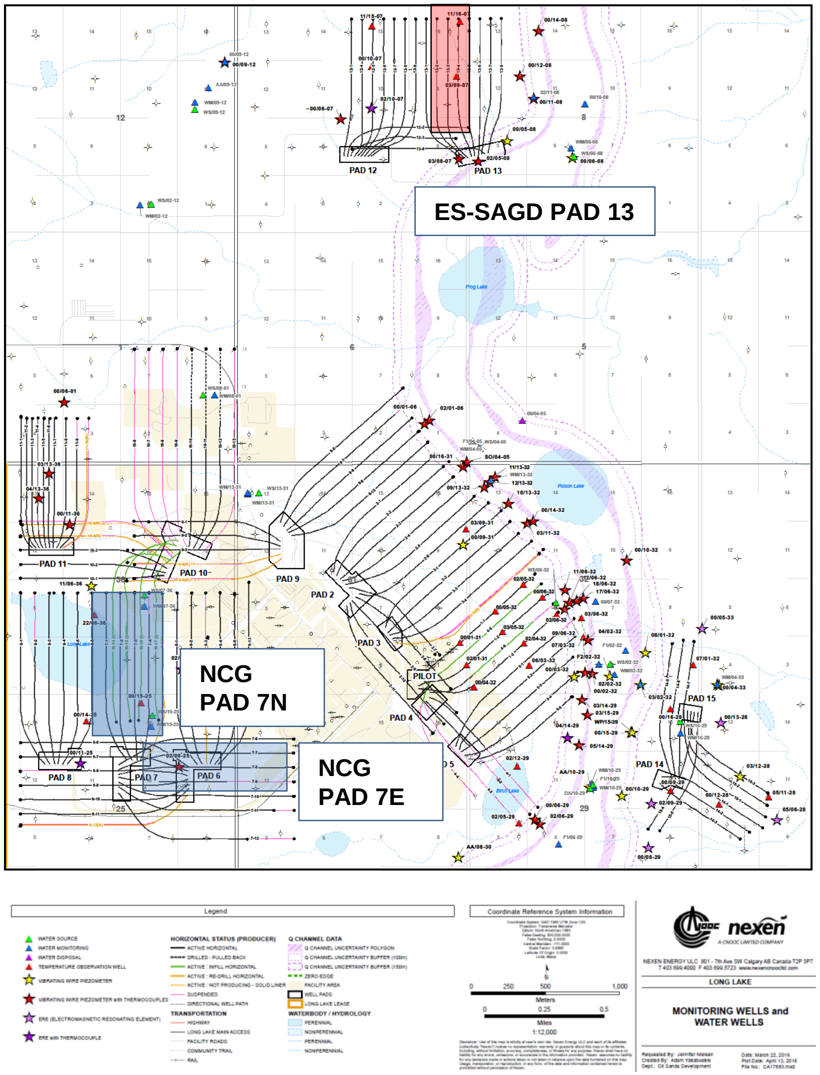
Well Re-drilled
Well Repaired
Well Shut in

2017 Other Well Integrity Actions

Inactive Well Compliance Program (IWCP) D13 Compliance:

- Initially 281wells were in the IWCP program.
- In year 3 (2017), 17 wells from the IWCP were deemed non-compliant.
  - Target was 10 and are now at 0.
- IWCP program has 84 wells left and all 84 are compliant.
- The current “inactive well list” has 176 wells in total.
  - 92 are new on the inactive well list with 1 well listed as non-compliant.

Update on Co-Injection Projects



PAD 13 Solvent Co-Injection Pilot:

- Application approval 9485U was received in Q2 2013
- Injected solvent was gas condensate (mostly C5 to C6 composition)
- Solvent co-injection started Q4 2014 at 13S3 and 13S4
- Solvent injection ended Jan. 2016
- Total solvent injected 11,902 m^3
- Total solvent recovered 7,920 m^3 or 67% to Dec. 2016
- ES-SAGD pilot monitoring ended Dec. 2016

PAD 7E NCG Pilot:

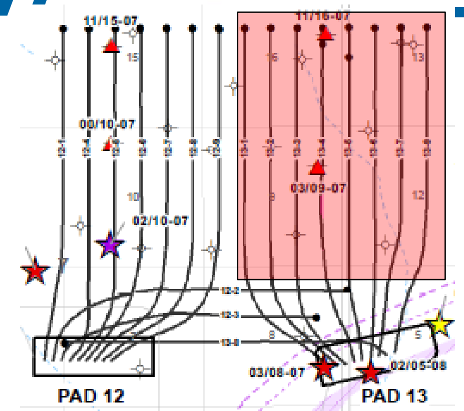
- Application approval 9485R received in Q3 2012
- Natural gas injection started Q4 2014 at 7P7 – 7P9
- Gas injection suspended after 2015 turnaround.
- No NCG injection through 2017

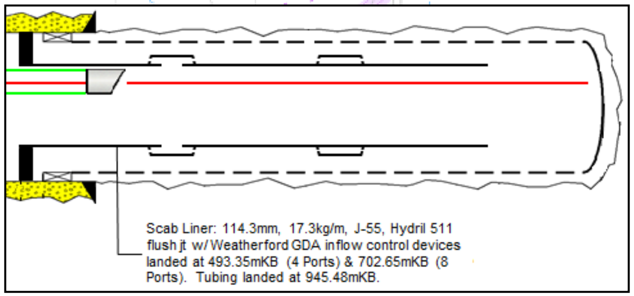
PAD 7N NCG Pilot:

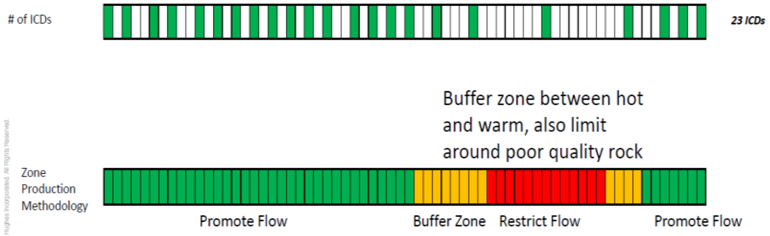
- Application approval 9485CC received in Q2 2014
- Construction of co-injection surface facilities complete Q2 2015 on 5 well pairs planned
- Short term NCG injection around 2015 facility turnaround
- No NCG injection through 2017

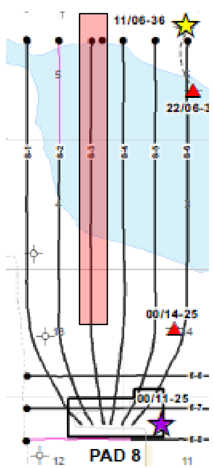
ICD Performance

- Simple Inflow Control Devices (liner ports) were installed in the Pad 13 producer scab liners during initial completion 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:
  - Wells show good conformance.
  - All ICDs remain in operation with no current plans to close, alter or remove the devices.
- More rigorous ICD design and installation was completed at 08P03 (Dec. 2015) (slide 132):
  - Since ICD installation, well has shown improved temperature conformance and an increase in total fluid rate.



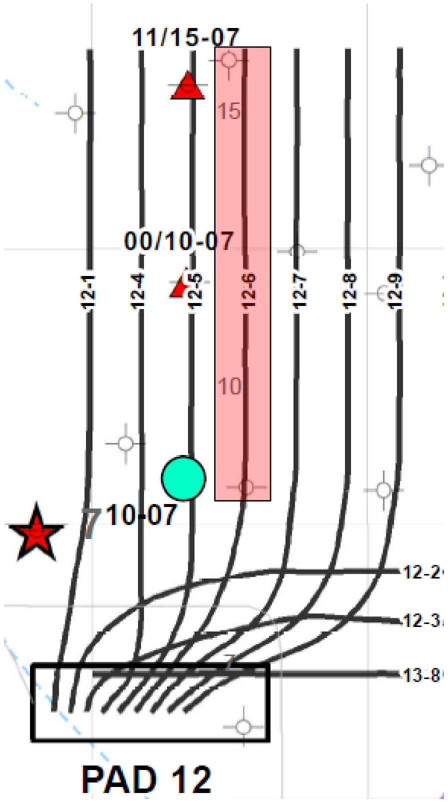


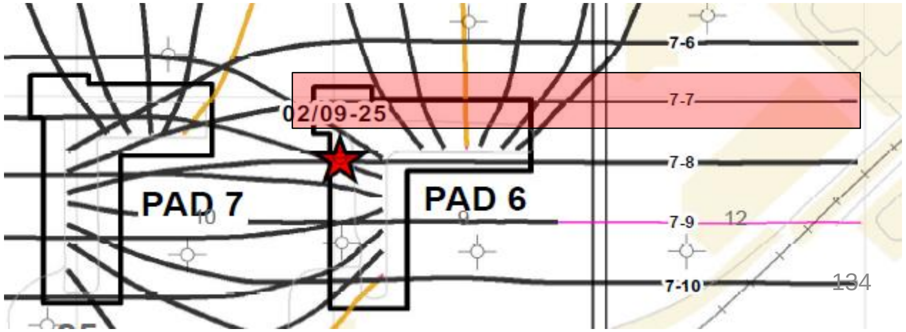




ICD Performance Cont'd

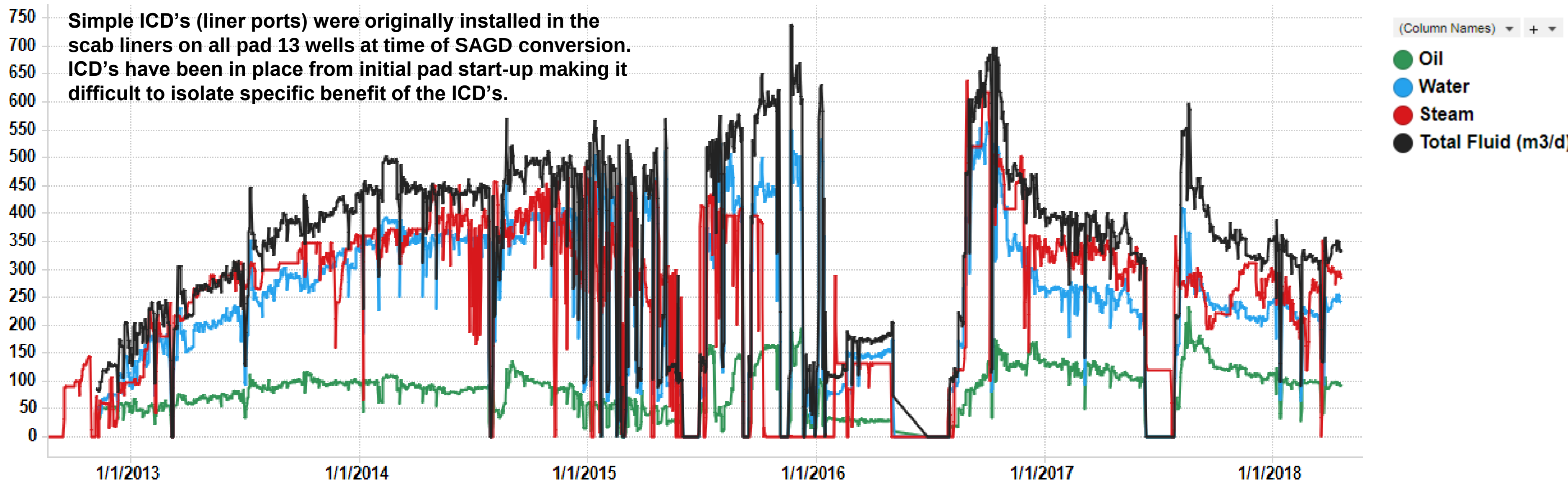
- More rigorous ICD designs and installations have also been completed at 12P06 and 07P07 in Aug 2017 and Dec 2017 respectively.
- 12P06 production string installed consisting of 29 ICD devices with device geometry designed to limit steam coning and promote hydrocarbon production.
  - 12P06 has shown improved conformance and increased total fluid rate since ICD installation.
  - Production currently limited due to surface restrictions.
- 07P07 production string installed consisting of 28 ICD devices & 16 packers with device geometry & packer isolation designed to limit steam coning and promote hydrocarbon production.
  - ICD performance is still being evaluated at 07P07 given the recent installation.
- As ICD complexity increases, additional time and attention is required during the workover to properly condition the well to ensure successful installation of the completion string.

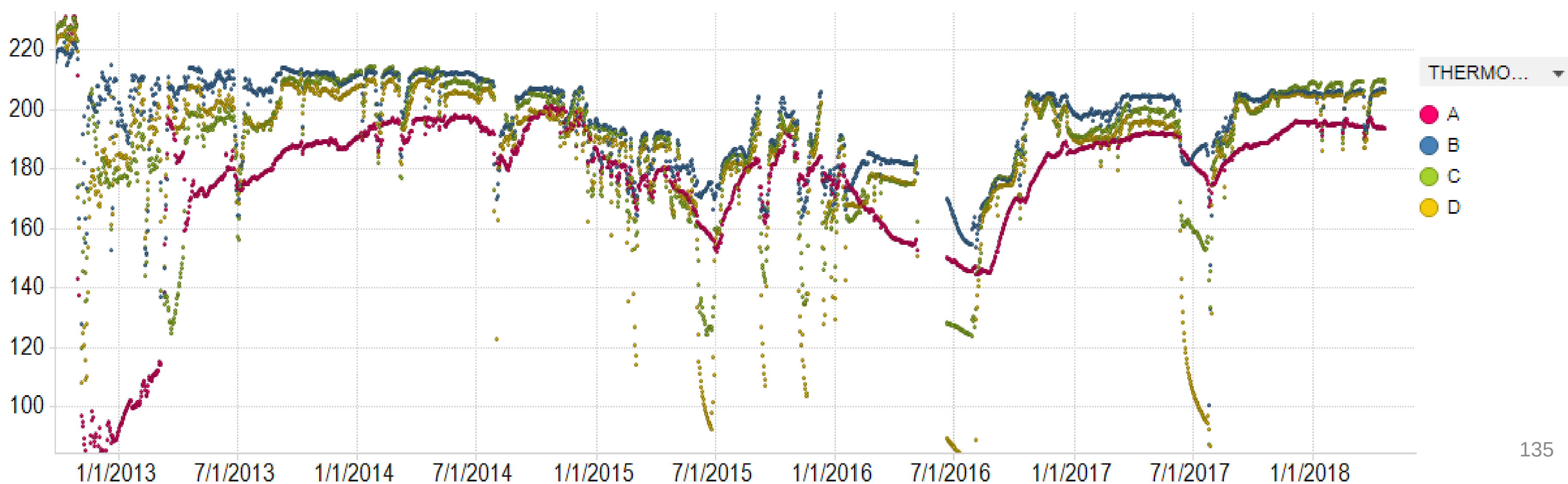




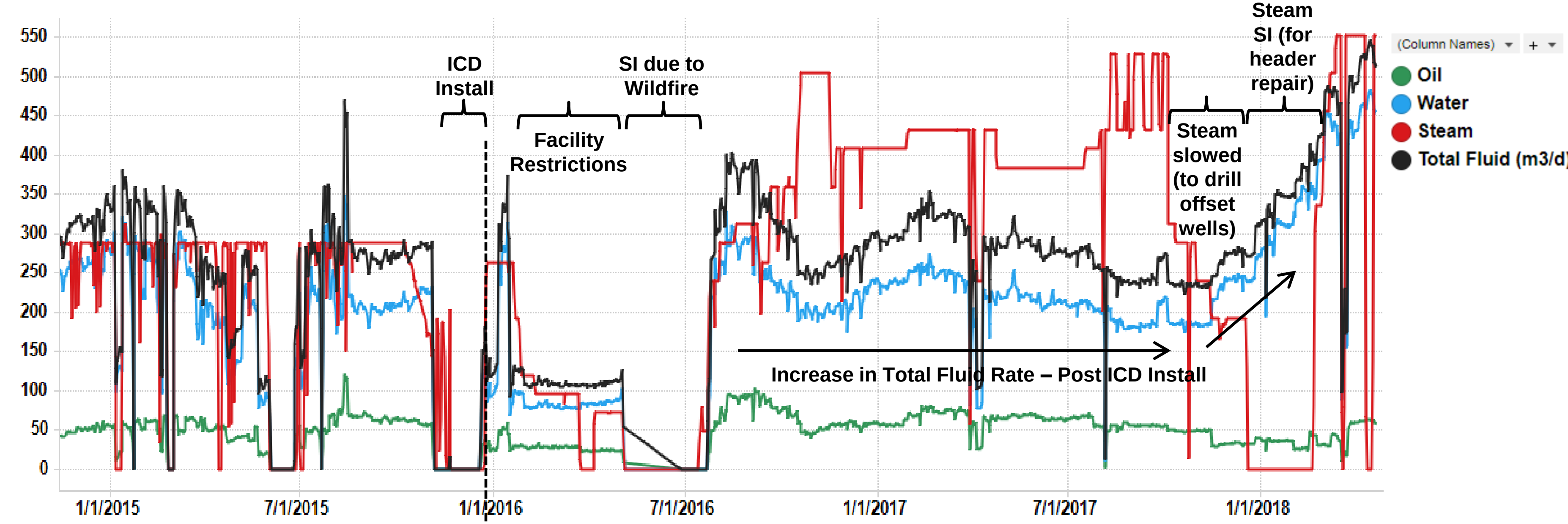
ICD Performance – 13P06

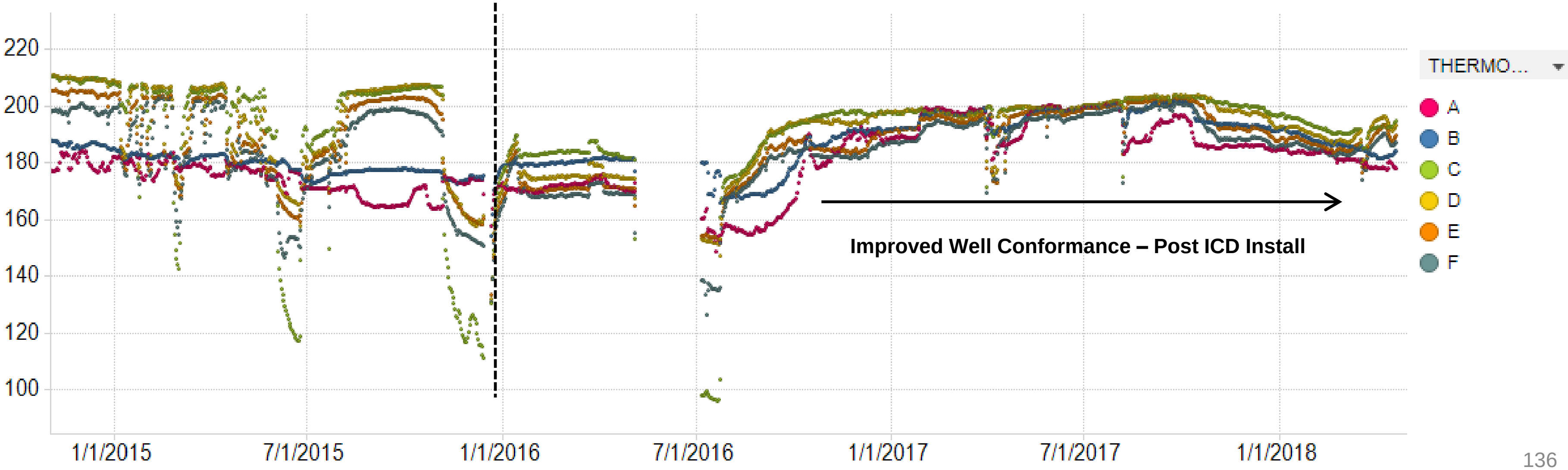
Simple ICD's (liner ports) were originally installed in the scab liners on all pad 13 wells at time of SAGD conversion. ICD's have been in place from initial pad start-up making it difficult to isolate specific benefit of the ICD's.





ICD Performance – 08P03

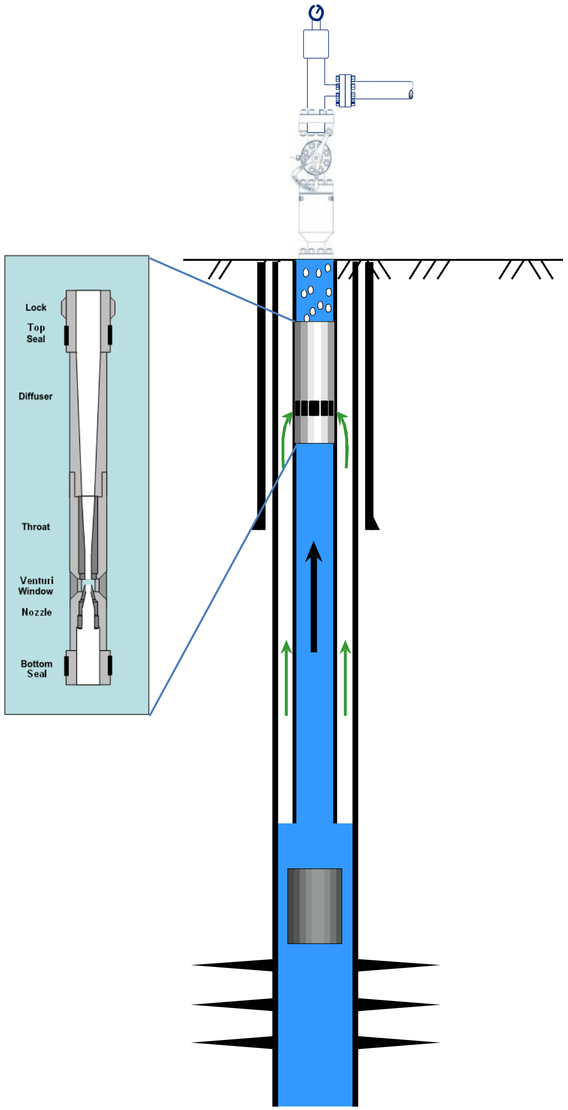




Casing Jet Pump (CJP) Trial

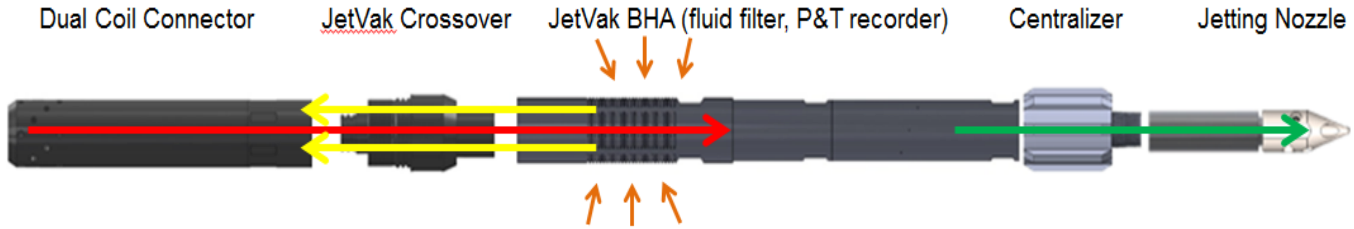
How CJP Can Help?

- Working principle: Jet nozzle creates a low pressure zone (lower than casing pressure) and draws gas from the casing side of the well into the production tubing string via sliding sleeve ports in the production tubing string.
- Inverted Jet pump installed inside the sliding sleeve on the production tubing, 1 joint below the wellhead.
- CJP deployed on 13P01 producer during trial, with sliding sleeve shifted to the open position.
- CJP in operation from Jan 2017 to Sept. 2017.
- Field trial did not deliver desired results.
  - Additional field/lab work is required to determine appropriate jet-pump nozzle sizing.



JetVak Liner Cleanouts

- Majority of LLK wells are completed with slotted liners.
  - Loss of sand control leads to sand influx and eventually ESP failure.
- Well has to be cleaned out before it can be repaired.
  - Typically requires multiple bailer runs with the service rig that can take 5 to 10 days resulting in high workover costs.
- Cleanout with JetVak dual coil tubing tool fluidizes solids in the well (using jetting tool), venturi section of tool creates a suction to lift fluids to surface.
- Technology was trialed on one Long Lake well in August 2017 to clean-out a failed liner.

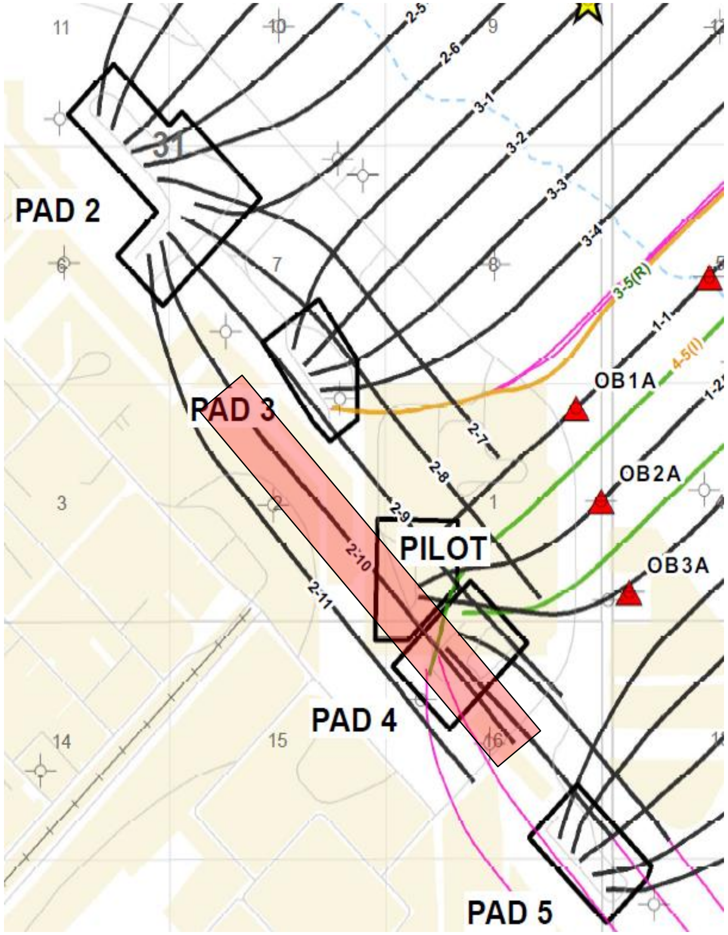


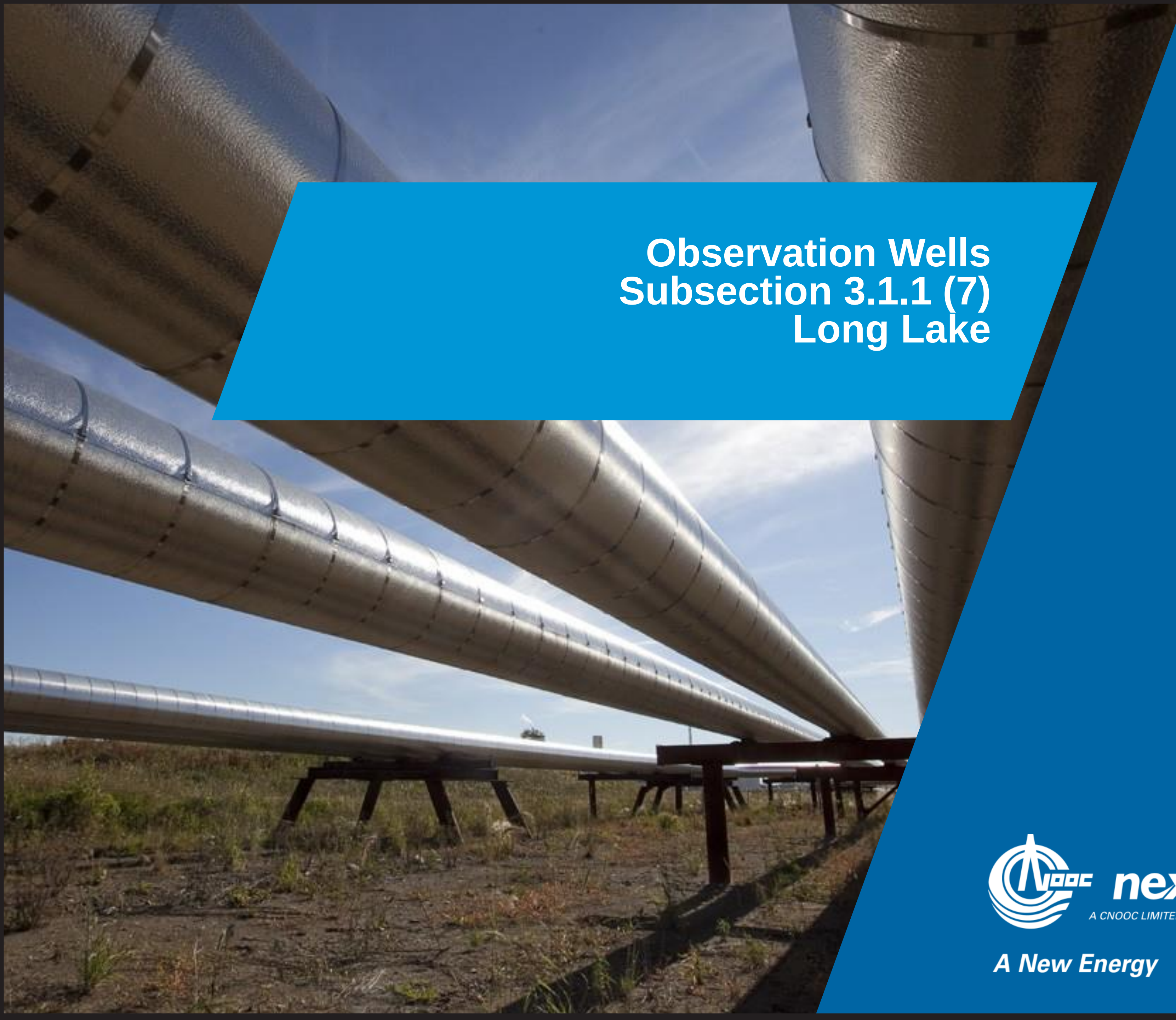
Results of JetVak Clean-out

- The workover was a partial success. The well was cleaned to TD within the time frame estimated and recovered 3m^3 of sand. However, when logging tools were deployed they could not reach TD due to sand.
- The service rig was required to run the sand bailer (traditional method) to clean to TD. The rig was unsuccessful in getting through the sand bridge.

Unresolved (Slop Oil) Emulsion Injection Trial

- Trial to inject unresolved emulsion into active injector at 02S10 location.
- Intent of trial is to reduce costs of offsite trucking and 3rd party disposal.
- Injected 55 m^3 of unresolved emulsion during injection campaigns in May and September, with steam shut-in during injection operations.
- Experienced some increase in Injectivity Index and Delta-P between injector and producer which moderated over time following re-initiation of steam injection.
- With current design, can only inject small volumes of unresolved emulsion relative to the volumes produced.
- Trial approval expires March 31, 2018 and there is currently no plan to extend the trial.





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
- ACTICE : 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)	Distance to Q channel (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)	Distance to Q channel (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

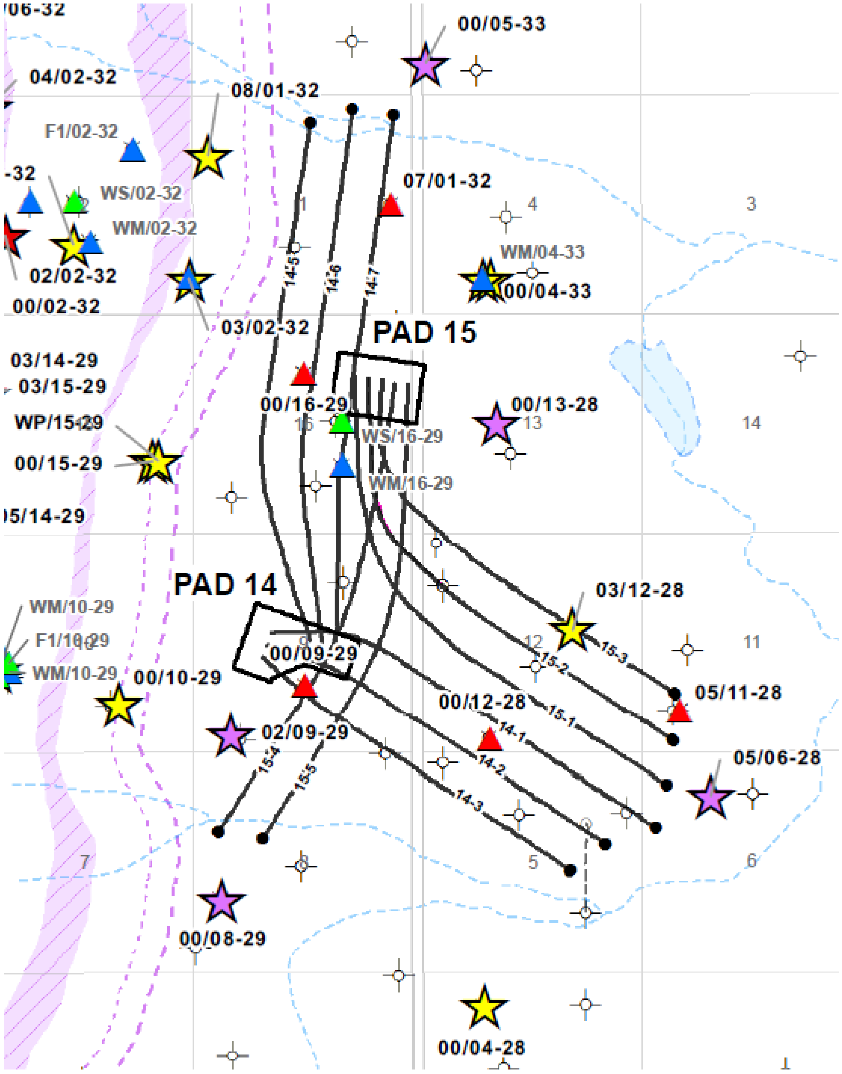
Pad 14/15 Observation Wells Caprock Monitoring

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	1016
100/05-33	119	341.2	CLWT A	980	1,002
100/13-28	116	341.9	CLWT A	1,000	1,009
102/15-29 (WP/15-29)	127	344.3	CLWT A	990	998
WM/04-33	115	343.8	CLWT A	970	965
	115.5	343.3	CLWT A	980	981

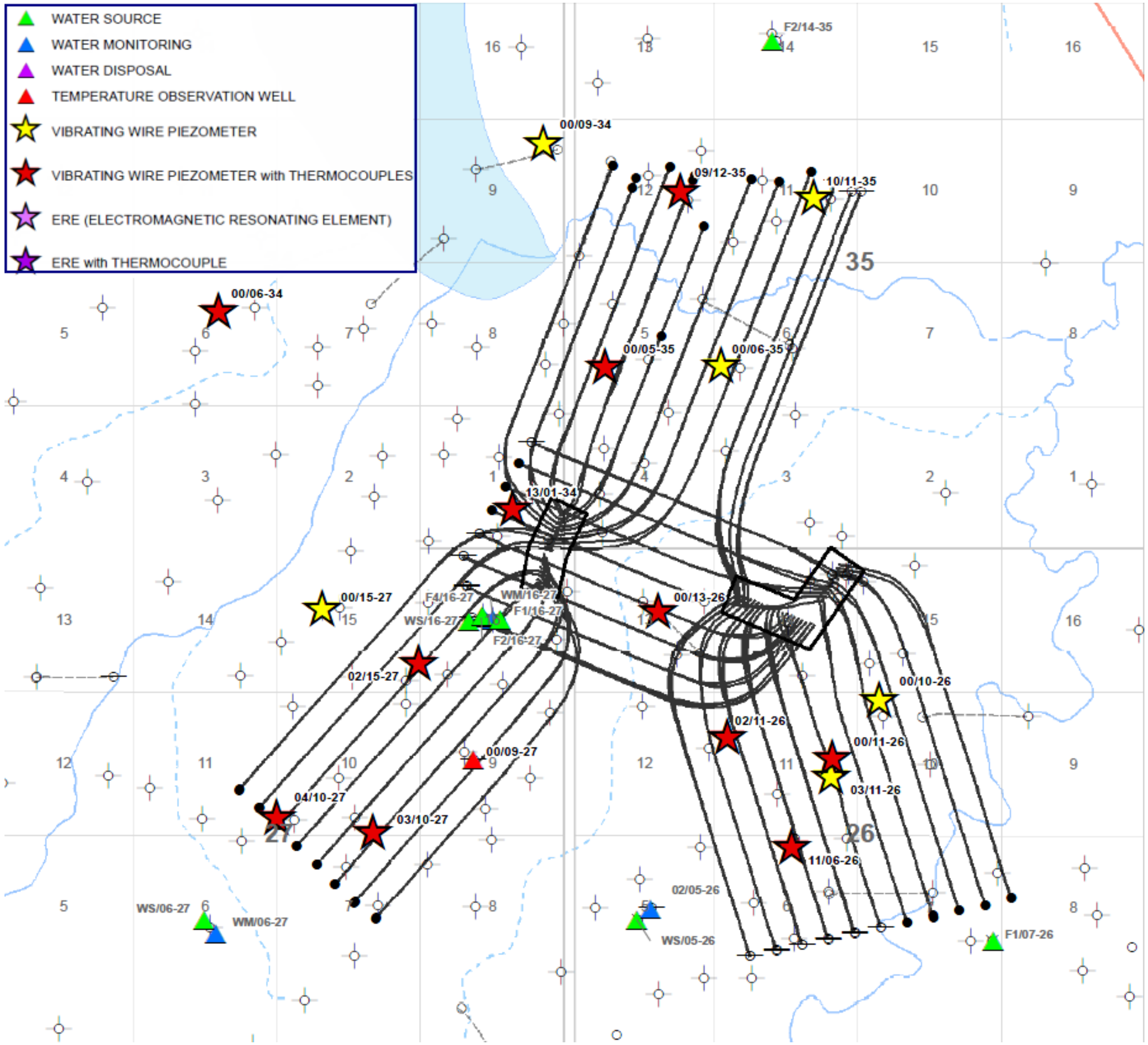
Pad 15 Baseline and Current Values

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	1,111
100/08-29	118.5	349.2	CLWT A	930	951
102/09-29	126.5	339.6	CLWT A	1,020	1,024
103/12-28	121.5	340.5	CLWT A	1,040	1,032



** December 2017*

K1A Observation Wells



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;
    - Extreme persistent winter conditions were experienced in 2017 in excess of -50°C with wind chill.
  - Mechanical issues such as battery failures;
  - Ambient temperature fluctuations;
  - Surface connection issues;
  - Downhole corrosion of sensors;
  - Expected run life of downhole sensors; and
  - Suspected defective sensor vintages.
- 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);
    - Thus far, we have had good success with these new technologies.
  - Regular inspections of surface equipment; and
  - Regular inspections of downhole sensors.
- 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.
- Thermocouple strings and piezometers are tested at the well to determine data validity (Loop resistances, internal resistances).

Groundwater Management Plan
Long Lake

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Groundwater Management Plan
Operating Guidelines Pre and Post Approval

Original Q-Channel Operating Guidelines	Groundwater Management Plan Guidelines
• Temperatures to remain below 100°C [(1)] at any observation well in Area B [(2)] (AER Scheme Approval for Long Lake #9485 Clause #23). • SAGD well pairs to be operated such that pressures measured at the 100m observation wells will be less than or equal to Q-Channel (Q-Ch) pressure at the equivalent depth.	• New groundwater management plan (GMP) reflects planned regulatory changes and technical evaluation based on risk. • Updated directive allows a shift in objective from considering the Q-Ch as a receptor to identifying specific receptors (surface water bodies and Grand Rapids B aquifer). • Receptors are protected by managing conditions within a defined area of the Q-Ch referred to as the Aquifer Management Unit (AMU). • The plan includes staged responses triggered by pressure, temperature and chemistry thresholds. • SAGD well pairs continue to be operated such that pressures measured at the pressure monitoring wells will be less than or equal to Q-Ch pressure at the equivalent depth.

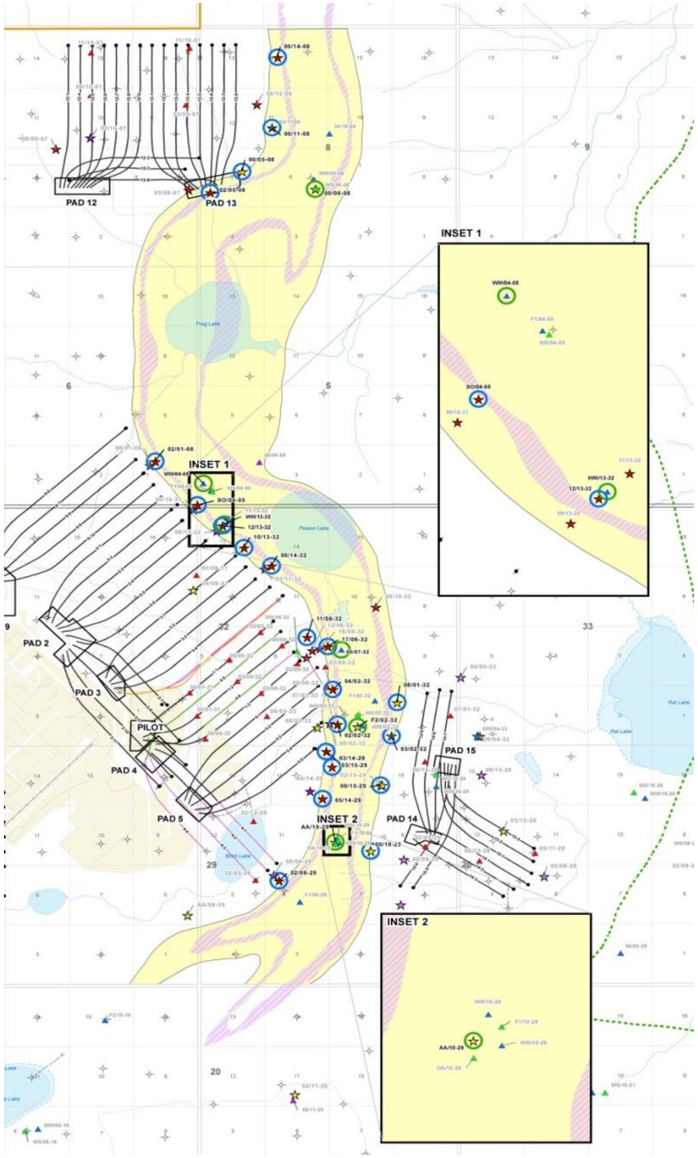
- The Q-Ch GMP report is submitted annually with the EPEA approval requirements.

[(1)] Q-Channel 100°C temperature clause in the Long Lake Scheme Approval is arbitrary.

[(2)] Area B is defined as any well between the toe of the SAGD well pairs and where the Q-Ch breaches the top of the McMurray.

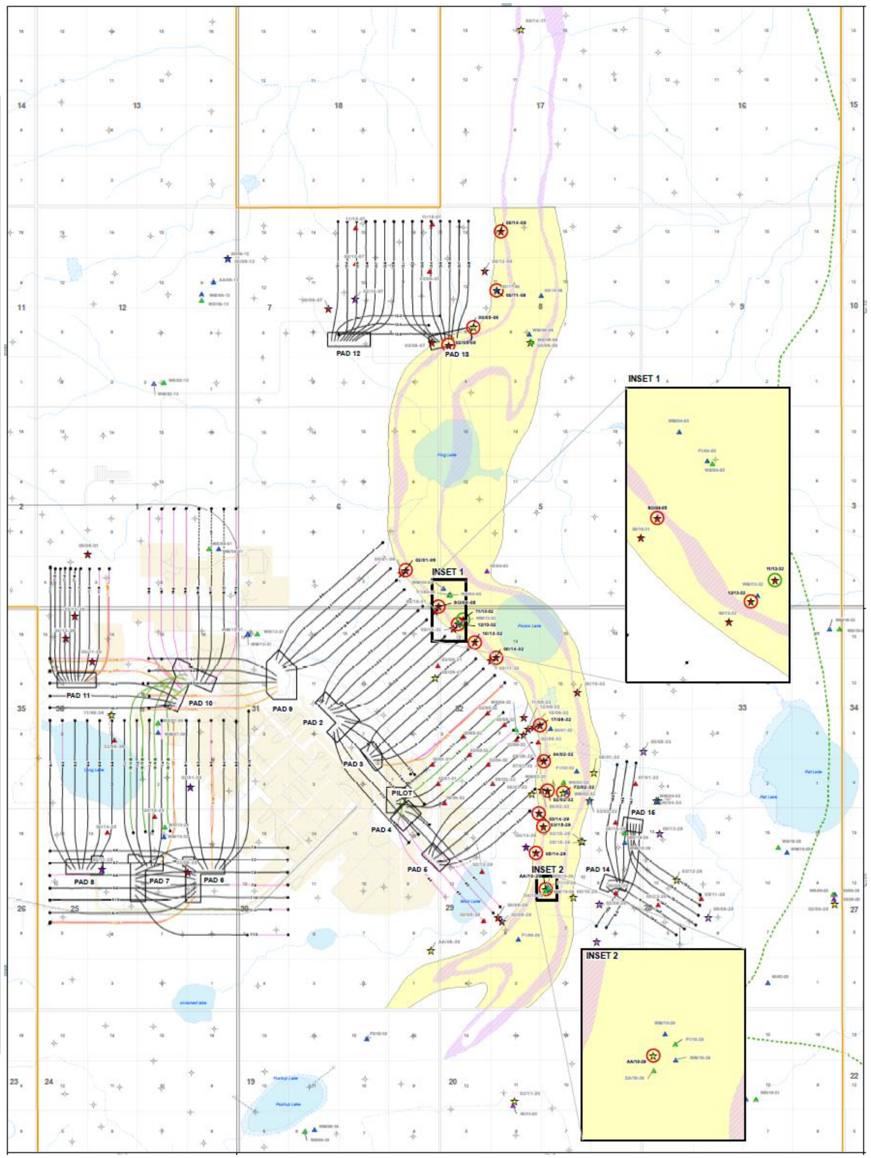
Pressure Monitoring Network

UWI	Abbreviation	Type	Parameters for Control / Management
100/05-08-086-06W4/00	00/05-08	Control	Pressure
100/10-29-085-06W4/00	00/10-29	Control	Pressure
100/11-08-086-06W4/00	00/11-08	Control	Pressure
100/14-08-086-06W4/00	00/14-08	Control	Pressure
100/14-32-085-06W4/00	00/14-32	Control	Pressure
100/15-29-085-06W4/00	00/15-29	Control	Pressure
102/01-06-086-06W4/00	02/01-06	Control	Pressure
102/02-32-085-06W4/00	02/02-32	Control	Pressure
102/05-08-086-06W4/00	02/05-08	Control	Pressure
102/06-29-085-06W4/00	02/06-29	Control	Pressure
103/02-32-085-06W4/00	03/02-32	Control	Pressure
103/14-29-085-06W4/00	03/14-29	Control	Pressure
103/15-29-085-06W4/00	03/15-29	Control	Pressure
104/02-32-085-06W4/00	04/02-32	Control	Pressure
105/14-29-085-06W4/00	05/14-29	Control	Pressure
108/01-32-085-06W4/00	08/01-32	Control	Pressure
110/13-32-085-06W4/00	10/13-32	Control	Pressure
111/06-32-085-06W4/00	11/06-32	Control	Pressure
112/13-32-085-06W4/00	12/13-32	Control	Pressure
117/06-32-085-06W4/00	17/06-32	Control	Pressure
1S0/04-05-086-06W4/00	S0/04-05	Control	Pressure
100/06-08-086-06W4/00	00/06-08	Monitoring	Pressure
1AA/10-29-085-06W4/00	AA/10-29	Monitoring	Pressure
1F1/02-32-085-06W4/02	F1/02-32	Monitoring	Pressure
1WM/04-05-086-06W4/00	WM/04-05	Monitoring	Pressure
1WM/13-32-085-06W4/00	WM/13-32	Monitoring	Pressure



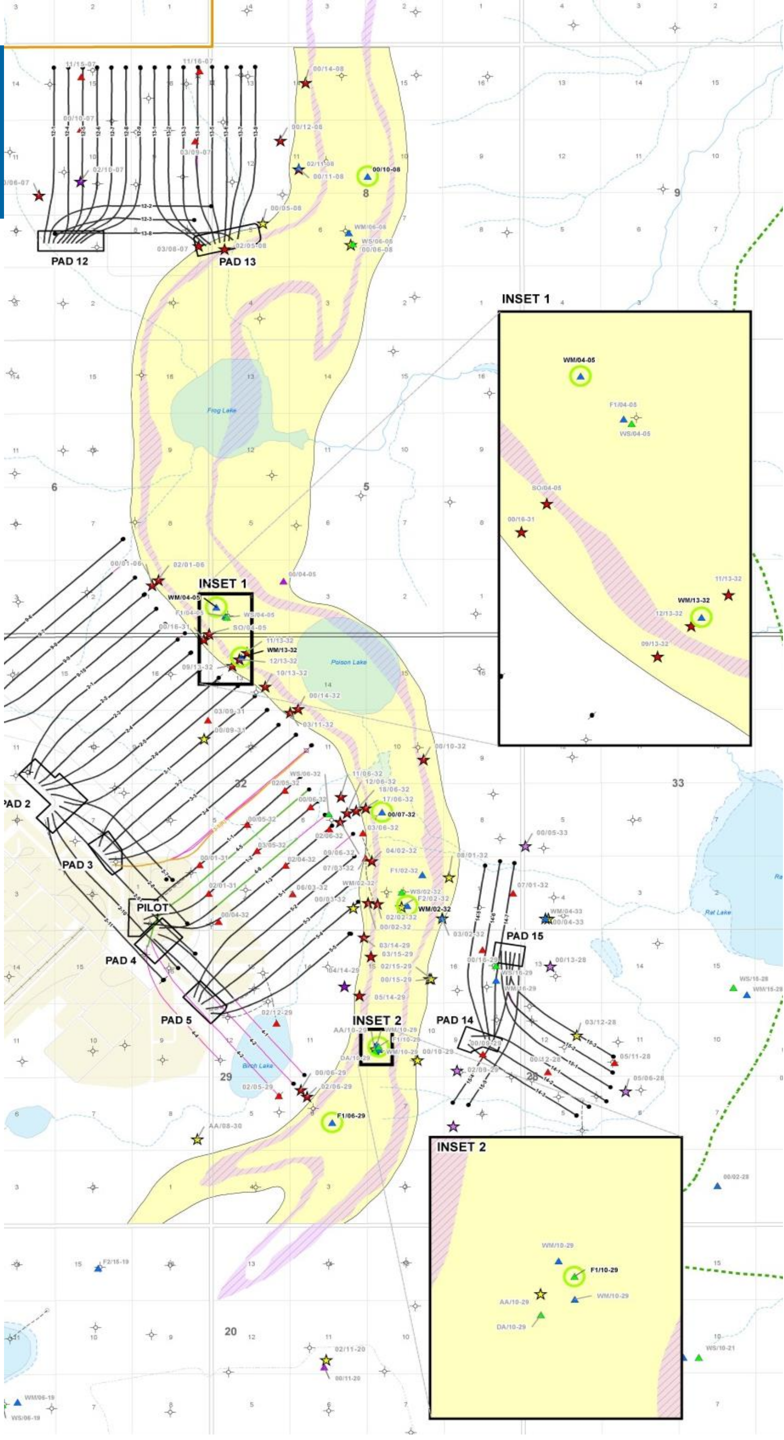
Temperature Monitoring Network

UWI	Abbreviation	Type	Parameters for Control / Management
100/05-08-086-06W4/00	00/05-08	Monitoring	Temperature
100/11-08-086-06W4/00	00/11-08	Monitoring	Temperature
100/14-08-086-06W4/00	00/14-08	Monitoring	Temperature
100/14-32-085-06W4/00	00/14-32	Monitoring	Temperature
102/01-06-086-06W4/00	02/01-06	Monitoring	Temperature
102/02-32-085-06W4/00	02/02-32	Monitoring	Temperature
102/05-08-086-06W4/00	02/05-08	Monitoring	Temperature
103/14-29-085-06W4/00	03/14-29	Monitoring	Temperature
103/15-29-085-06W4/00	03/15-29	Monitoring	Temperature
104/02-32-085-06W4/00	04/02-32	Monitoring	Temperature
105/14-29-085-06W4/00	05/14-29	Monitoring	Temperature
110/13-32-085-06W4/00	10/13-32	Monitoring	Temperature
112/13-32-085-06W4/00	12/13-32	Monitoring	Temperature
117/06-32-085-06W4/00	17/06-32	Monitoring	Temperature
1S0/04-05-086-06W4/00	S0/04-05	Monitoring	Temperature
1AA/10-29-085-06W4/00	AA/10-29	Monitoring	Temperature
1F2/02-32-085-06W4/00	F2/02-32	Monitoring	Temperature
111/13-32-085-06W4/00	11/13-32	PoM	Temperature



Chemistry Monitoring Wells

UWI	Abbreviation	Type	Parameters for Control / Management
100/07-32-085-06W4/00	00/07-32	Monitoring	Chemistry
100/10-08-086-06W4/00	00/10-08	Monitoring	Chemistry
1F1/02-32-085-06W4/02	F1/02-32	Monitoring	Chemistry
1F1/06-29-085-06W4/00	F1/06-29	Monitoring	Chemistry
1F1/10-29-085-06W4/00	F1/10-29	Monitoring	Chemistry
1WM/04-05-086-06W4/00	WM/04-05	Monitoring	Chemistry
1WM/13-32-085-06W4/00	WM/13-32	Monitoring	Chemistry



Application of GMP Monitoring Plan Operational Updates

- Re-introduction of steam to Pad 2NE and 3P01:
  - Pressure/temperature increases in reservoir as expected.
  - Emulsion and oil rates back to pre shut-in rates at Pad 2NE and 3P01.
- Pressure, Temperature and Chemistry are stable in monitoring wells.
  - Pressures at Control Wells maintained below reference Q-Ch pressures.
  - Temperature at Temperature monitoring well 112/13-32 has remained unchanged.
    - Stable Temperature at 112/13-32 stable in 2017 (~16C).
  - Temperature at Temperature Point of Management (PoM) no change.
  - Chemistry in Q-Ch remains stable at baseline.

Future Plans
Subsection 3.1.1 (8)
Long Lake and Kinosis

A New Energy

Future Plans – Producing areas

- Continue to manage SAGD production according to surface constraints and capacity.
- Acquisition of 4D seismic on Pads 14/15 (completed Q1 2018).
- Production opportunities:
  - Startup Phase1 infills: 7 wells drilled in late 2017/Q1 2018 on Pad 5 and 8.
  - Progress future infills
  - Evaluate additional well pairs off existing well pads at Long Lake.
- Advance plans for K1A recovery:
  - Progressing pipeline replacement.

Future Plans - New Development

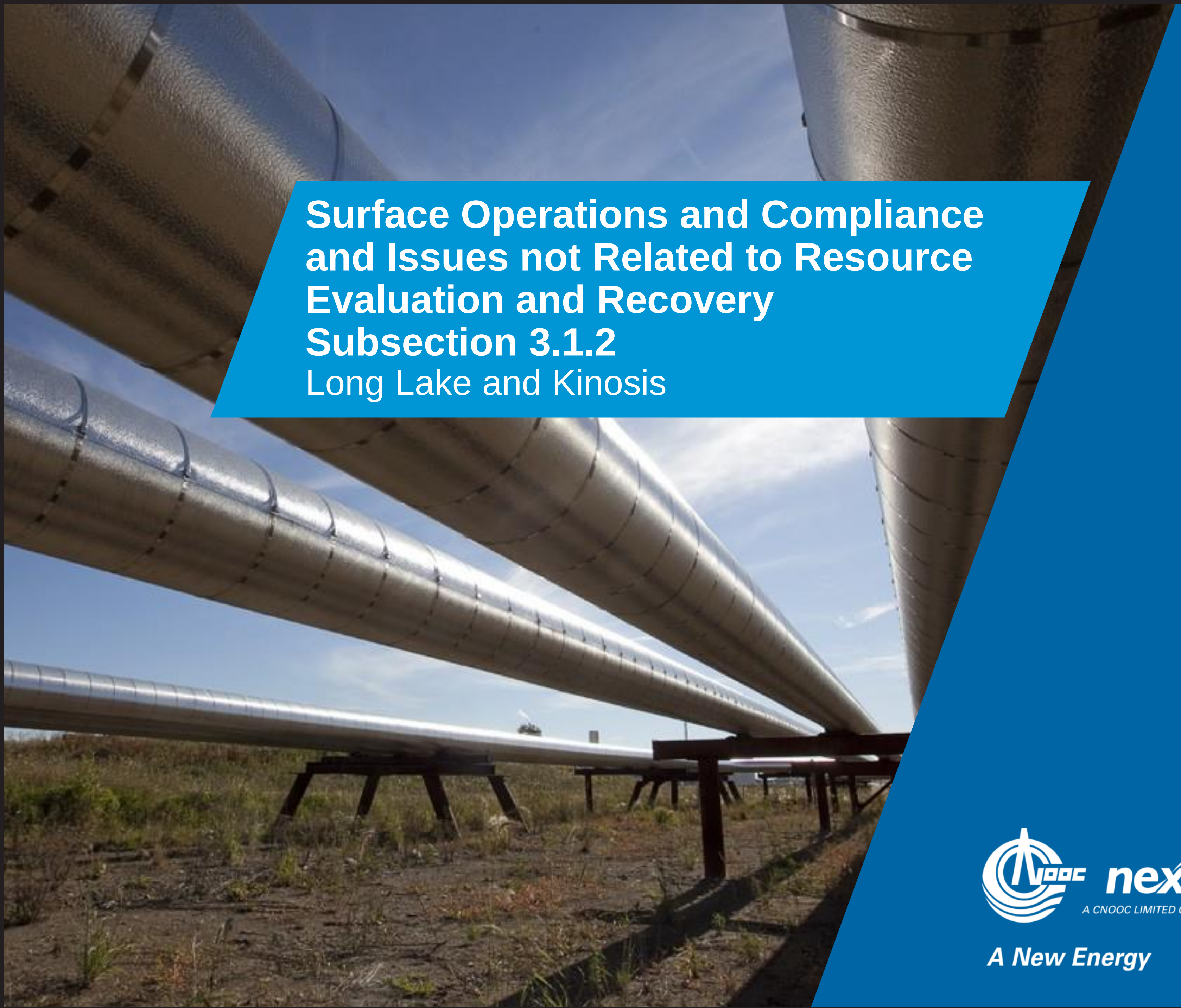
- Long Lake:
  - LLSW (Sustaining Pads 16 to 18):
    - Pending internal sanction.
- Kinosis:
  - Planning for future projects significantly slowed down due to commodity prices:
    - Gas re-pressurization project on hold.

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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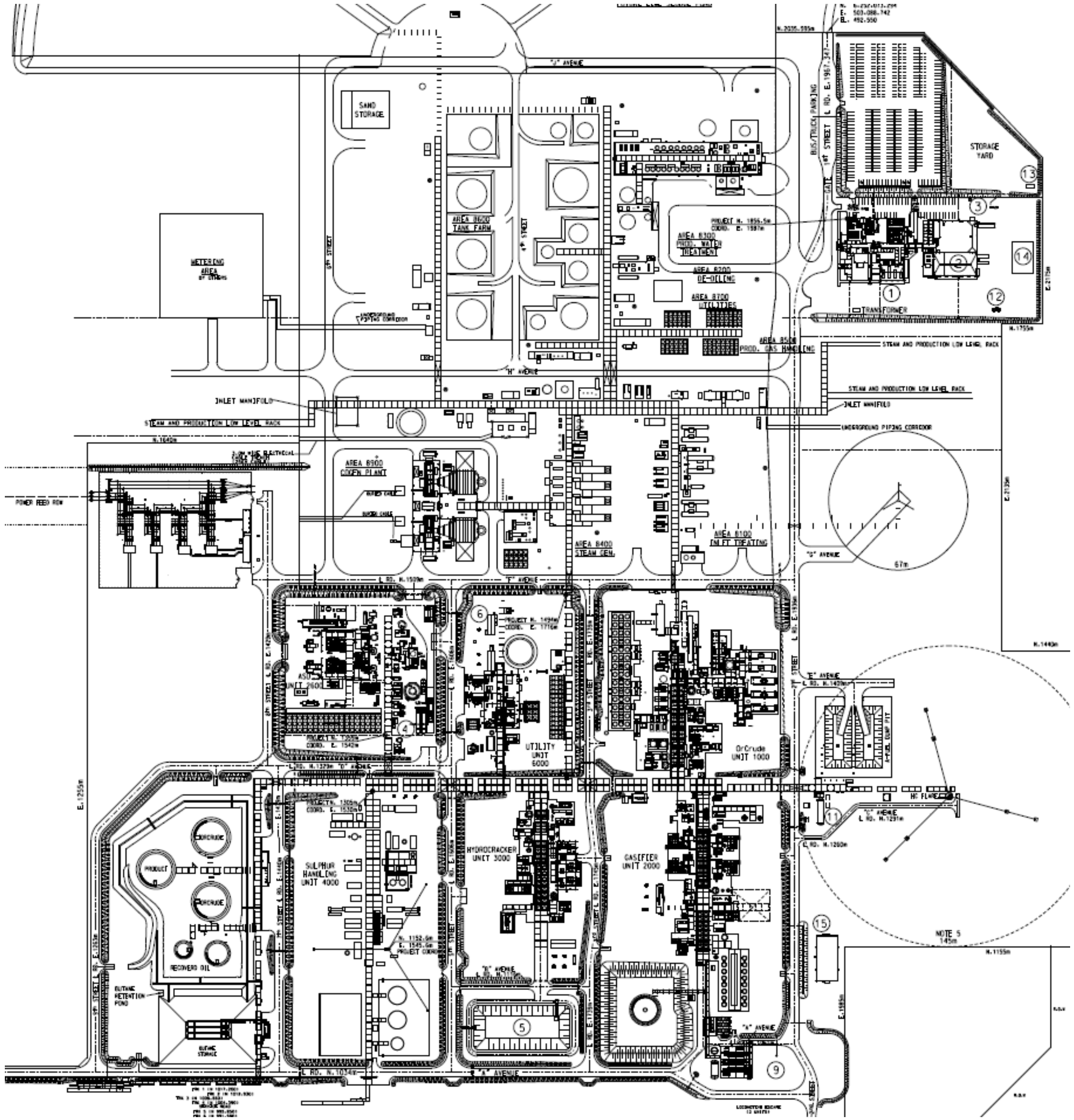
Facilities
Subsection 3.1.2 (1)
Long Lake and Kinosis

A New Energy

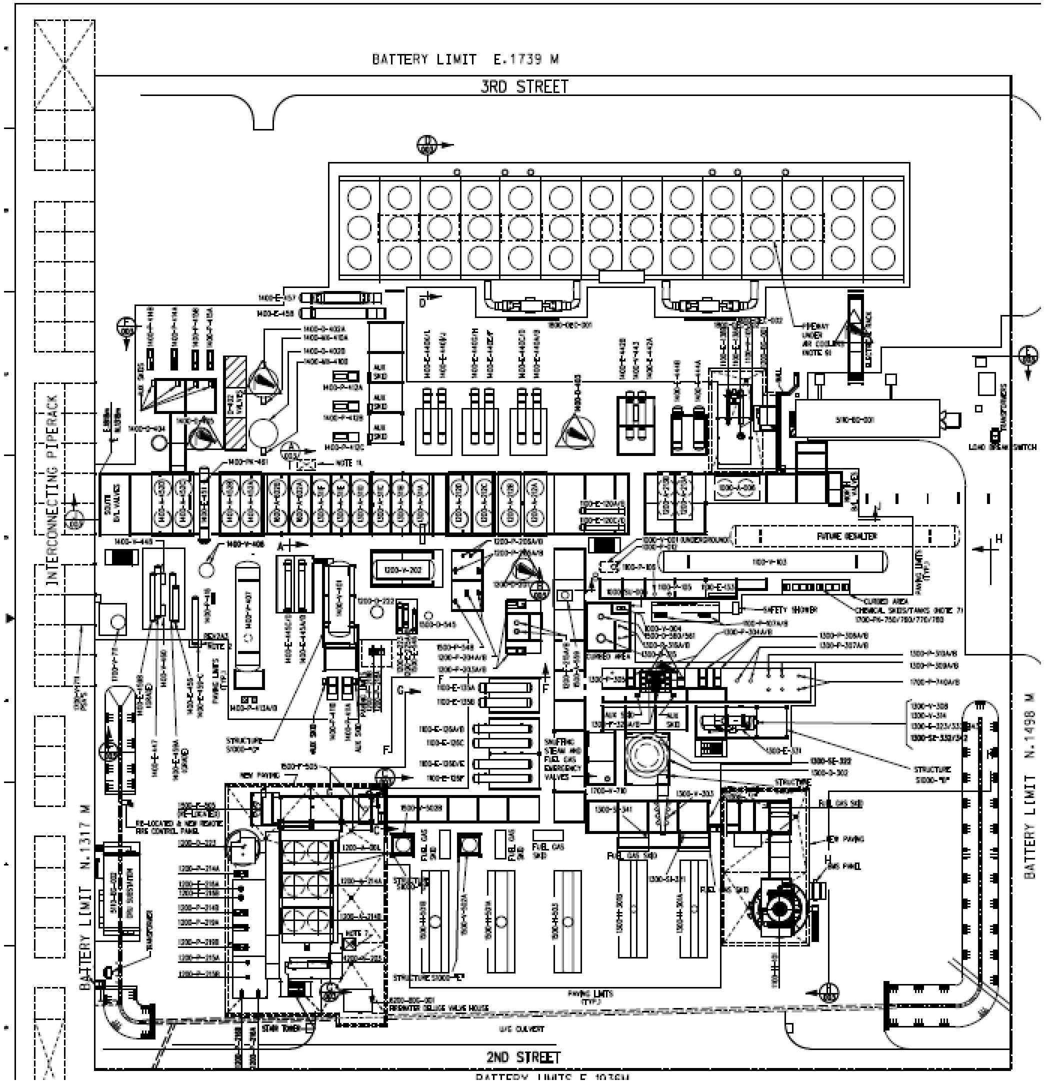
Long Lake Facilities

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

Long Lake Plot Plan



Diluent Recovery Unit Plot Plan

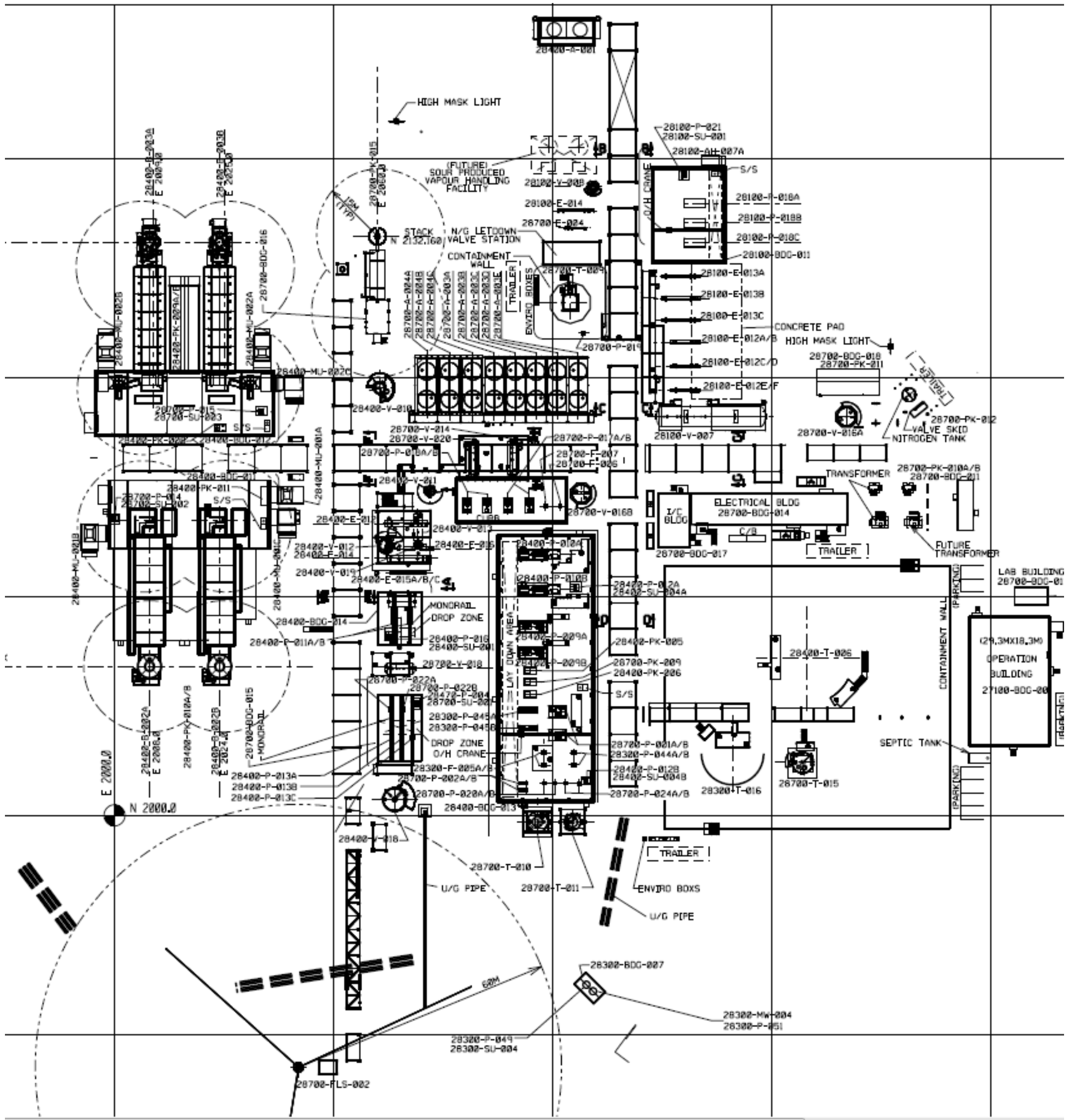


Subsection 3.1.2 (1a)

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

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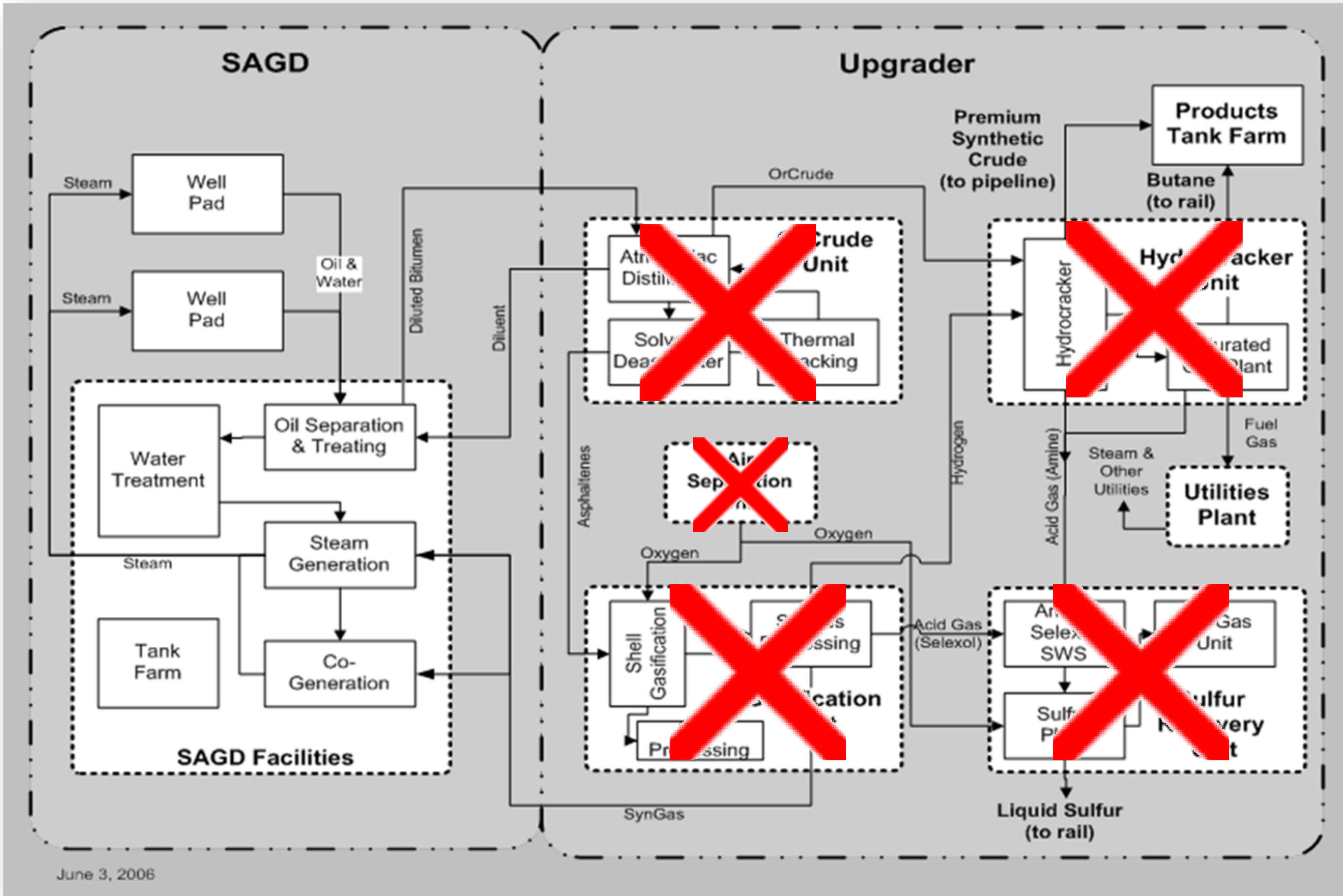
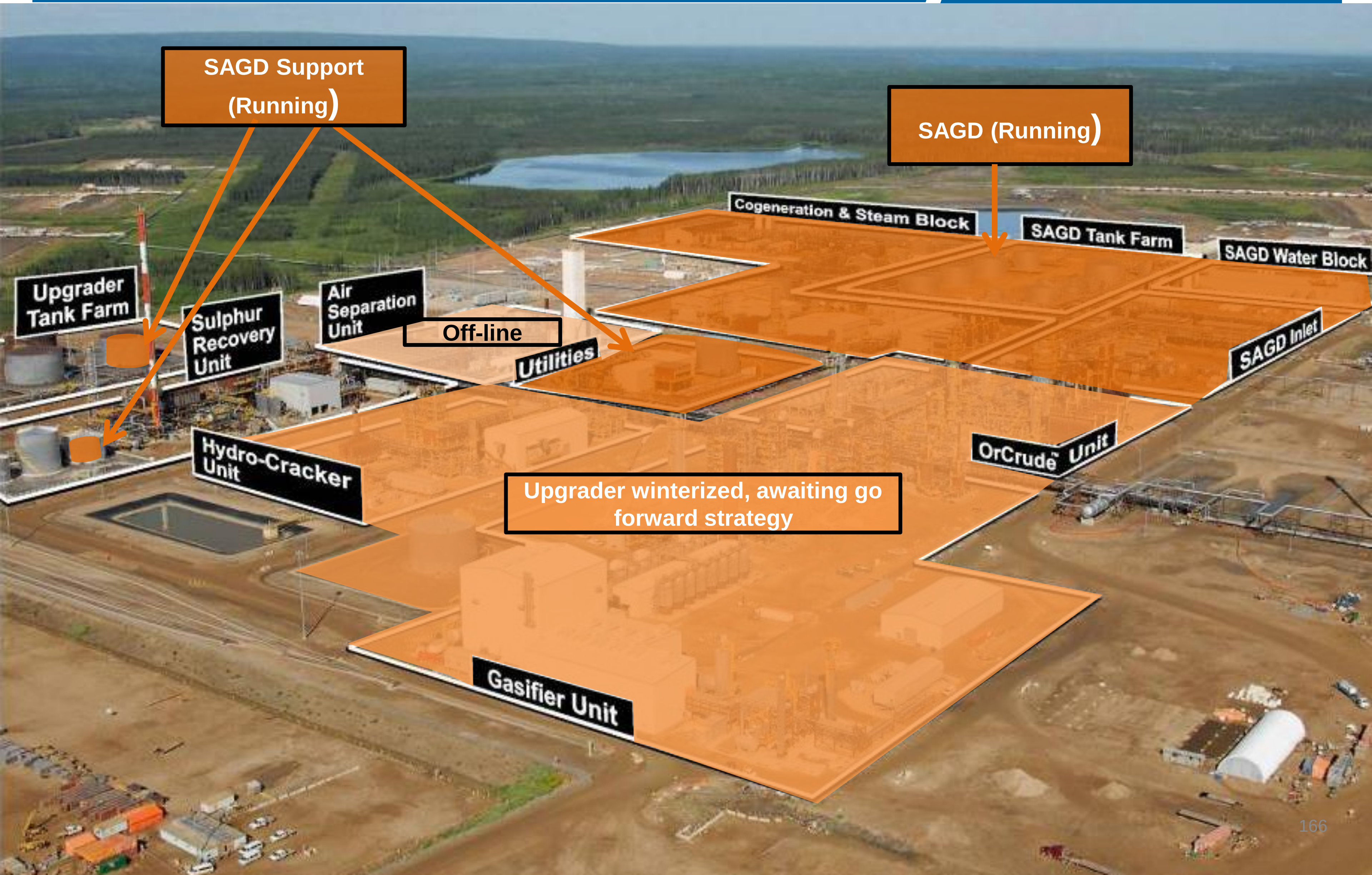
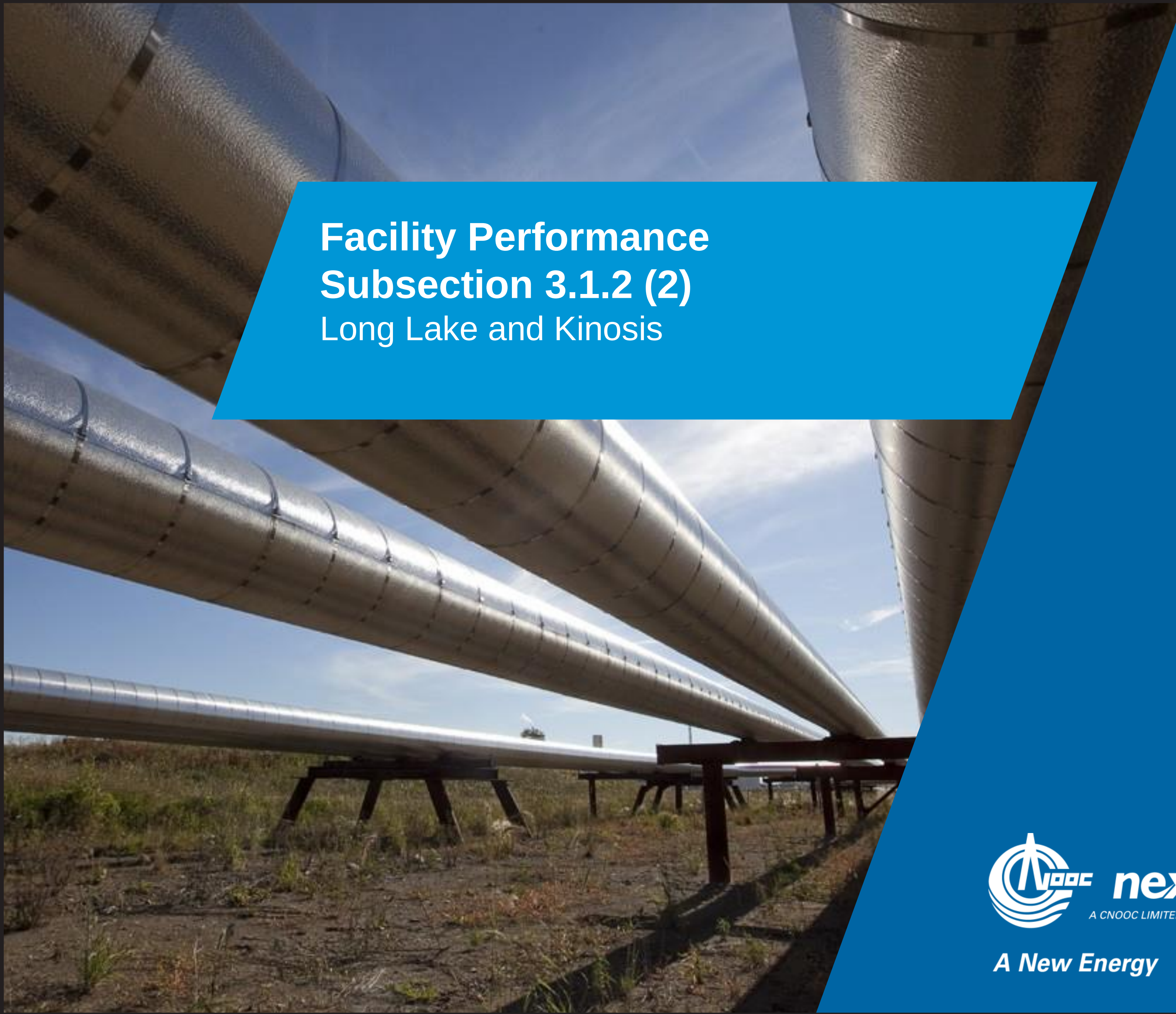


Current LLK Operations





Facility Performance
Subsection 3.1.2 (2)

Long Lake and Kinosis

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Facility Performance

Subsection 3.1.2 (2)

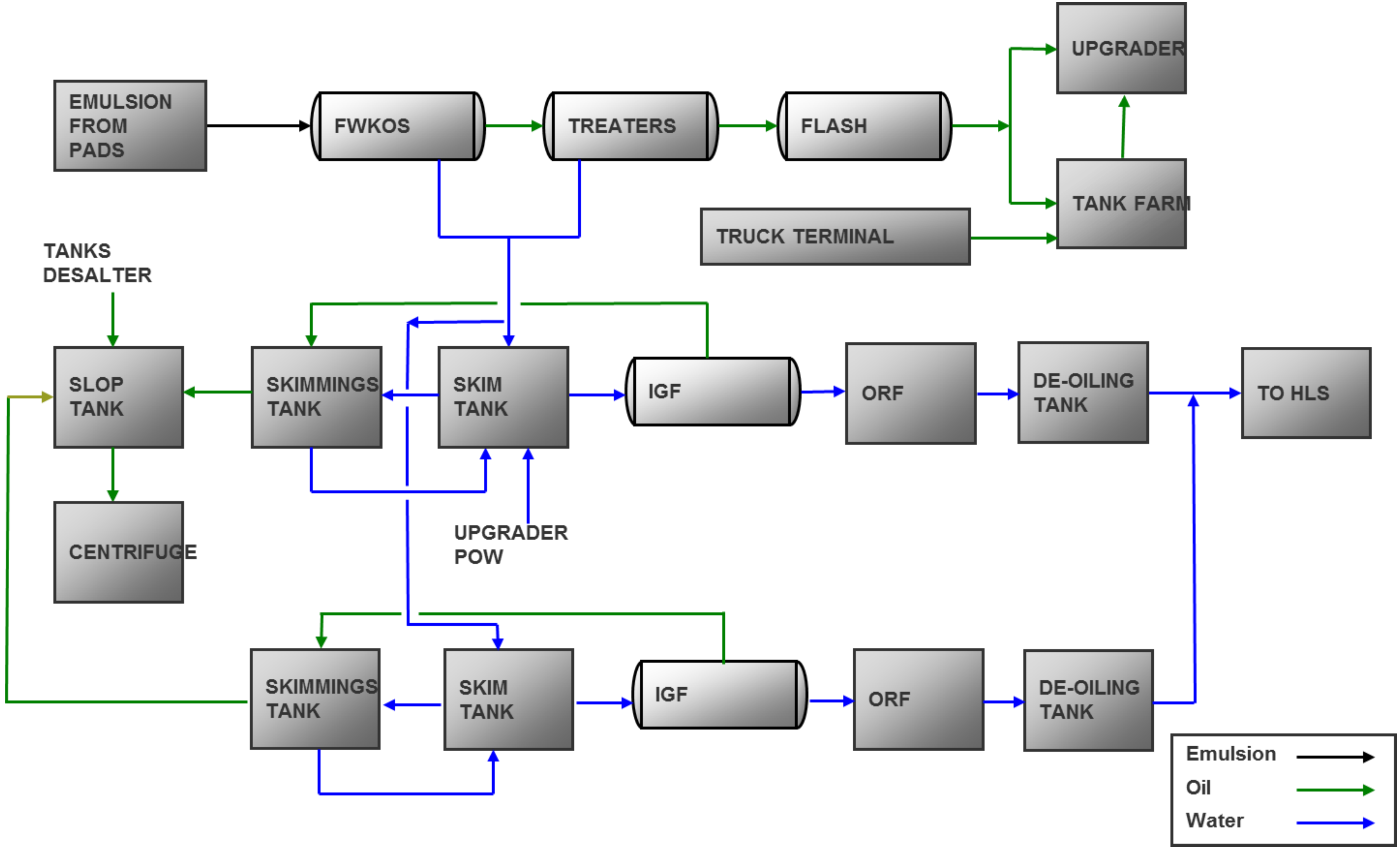
Long Lake Operations Summary

- In 2017, Long Lake continued to operate in SAGD mode only.
- The Upgrader area that is still in service is the Utility & Offsite unit to supply superheated steam for the gas turbines, diluent for dilbit production and flaring.
- During 2017, the SAGD only operation has been stable and reliable.
- Switched inlet treatment and de-oiling chemical vendor in February 2017.
- Trials were conducted in inlet treatment to evaluate performance with lighter diluent blends with the intent to reduce diluent usage and evaluate the equipment separation performance at higher density.
- Switched marketing strategy to focus on PDH sales vs PSH
- Completed the switching of chemicals for water treatment and steam generation to a new vendor.
- Directive 081 Disposal Limit variance from 10% to 15% was granted starting October 1, 2017 until October 31, 2020.
- Replaced Slop Oil Rental Centrifuge with Nexen's own centrifuge.
- Installation of a rental dilbit chiller is underway.
- The Upgrader will remain shut-in until final decision on the repair/start-up is made.
- K1A Operations will remain down until pipeline is replaced.

Rental Dilbit Chiller Project Status

- Rental Dilbit chiller installation:
    - has received all rental equipment;
    - the module assembly is on track;
    - piping installation is continuing at site; and
    - the anticipated start-up date is May 1, 2018.

Bitumen Treatment



Inlet and De-Oiling

General Comments:

- The plant switched to CFT/OSN and CFT/SYN blend diluents for normal operation.
- Successfully completed new vendor Chemical Trials, Diluent Blend Trials (CFT/OSN, CFT/SYN, CRW/SYN), High Density Inlet Separation Treatment Trial.
- The plant has been operated consistently above 40,000 BPD from the start of 2017 and reached a record high production of 46,764 BPD in October.
- AER indicated that a sulfur recovery waiver is not required as long as the SAGD sulphur inlet is <1 tonne/day.

Chemical Injection

- Switched chemicals supplier for inlet and De- oiling system in 2017.

Inlet and De-Oiling

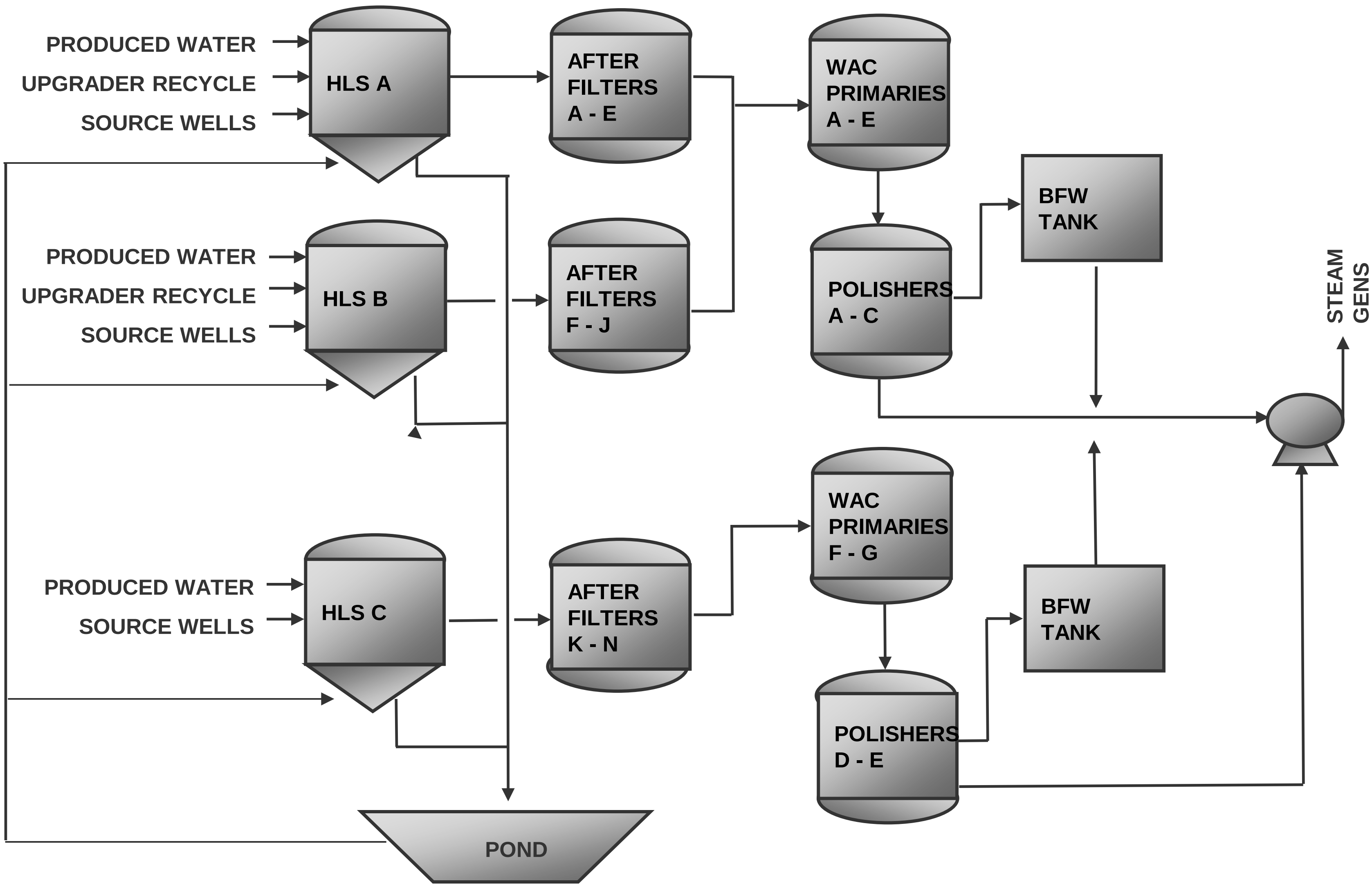
Tank Venting

- Several venting incidents in 2017 led to the following actions to prevent re-occurrence:
  - Procedure put in place to ensure no process fluid off loading to Backwash and Slop Tank was strictly adhered to which reduced the number of venting incidents from these tanks.
  - 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;
  - Dispersion model study was conducted from various tanks during venting incidents at various scenarios to determine that there were no adverse effects as required by AER.
  - Identified Immediate, mid and long term strategies in improving the VRU systems to handle vapour loads effectively; and
  - Also working with chemical vendor to improve treatment chemistry in inlet, to reduce off spec water going to de-oiling which results in venting incidents.
- Reporting criteria have been finalized and rolled out.
  - Future work will include dispersion modelling of multiple tank venting scenarios.

Water Treatment

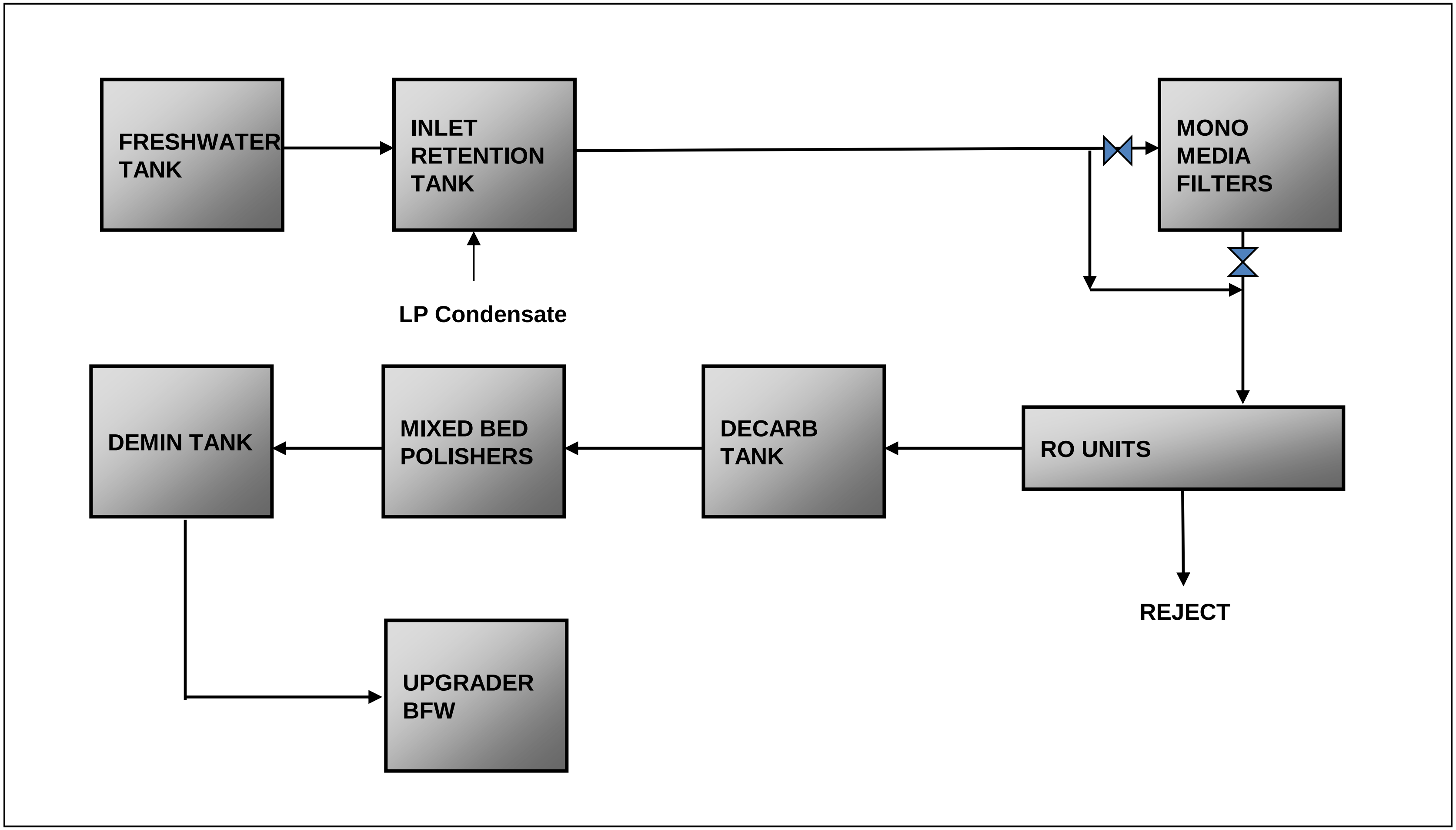
Subsection 3.1.2 (2b)

Produced Water Treatment



Subsection 3.1.2 (2b)

High Quality Water System



Water Treatment

Hot Lime Softener (HLS) operation

- Coagulant dosage to HLS increased significantly in June 2017 due to the deoiled produced water quality change. This also resulted in accelerated fouling of the HLS. Issues arose with respect to the HLS sludge blowdown line plugging.

Weak Acid Cation (WAC) Unit Monitoring

- Optimized WAC resin usage by extending the service time between regeneration.
- WAC resin compaction has been observed and is being mitigated after resuming the nitrogen scour step as part of the transfer in resin regeneration sequence.

Chemical Usage Optimization

- Chemical vendor fully transitioned to GE.
- Reduced acid/caustic usage after extending the WAC service length.

Water Treatment

Sludge Carry Over from HLSs

- Experience difficulties to maintain HLS outlet turbidity due to deoiled produced water quality issues. Monitoring the sludge profile was a challenge due to sample taps plugged.
- More frequent fouling of after filters has been observed due to turbidity carry over from HLSs, routine chemical cleaning on after filter media was carried out based on filters proactive monitoring.

Pond A/B

- In 2017, operating with only one of the two lime sludge ponds (pond B) for the entire year, pond A still out of service.
- Pond B was dredged in 2017. A significant improvement in supernatant to HLSs water quality after dredging.
- The liner leakage rate has been controlled within regulatory limit by maintaining level in the Pond.

Water Treatment

Brackish Water

- The brackish system was not in use in 2017 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.

Water Treatment

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 shutdown. Fresh water is used within the LLK facility for the following purposes:

- High quality water system was running during most of 2017, fresh water is used as water source to produced boiler feed water for the utility boilers in the Upgrader. The water is converted to intermittent pressure superheated steam (IPSH) for the gas turbines to control NOx emission
- In December 2017, the IPSH line ruptured due to failed steam trap, which caused the HQW to shut down, and gas turbines had to reduce rates to meet NOx emission target.
- Since Upgrader was shutdown, the fresh water usage reduced significantly. Majority of the fresh water is used to produced NOx steam.
- Fresh water is also used as cooling medium for Inlet treatment Produced Vapour heat exchangers and VRU compressors seal, to blend chemicals in the injection facility for use in the HLS.
- Utility water in the Battery, IF – end users of utility water (pump seals, VRU) cannot handle the high hardness and salinity of brackish water. The brackish water would cause issues in the chemical system as well.

Typical Water Quality (Produced and Disposed)

	pH	Conductivity (us/cm)	Turbidity (NTU)	Dissolved Hardness	Silica	Iron
RO (reject water 2nd stage)	n/a	4.000 - 12,000 average 6,500	average 7.5	n/a	n/a	n/a
Produced Water	7-9 average 7.6	1,500 - 3,000 average 1,900	100 - 900 average 228	5 - 20 average 14	50 - 250 average 150	n/a
Supernatant Water	9 -1 0, average 9.7	5,000 - 15,000 average 8,140	50 - 1,000 average 362	50 - 100 average 120	30 - 150 average 88	n/a
Fresh Water	7 - 8.5 average 8.0	2,000 - 3,000 average 2,003	0 - 12 average 8	n/a	n/a	0 - 2.5 average 1.5
Disposal Water	10 - 12, average 11.5	9,000 - 25,000 average 19,147	n/a	1 - 10 average 6.8	250 - 700 average 421	1 - 4 average 2.5

- No brackish water chemistry in 2017.

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.
- Seeing corrosion on the Once Through Steam Generators' flue gas recirculation line, increased frequency of repairs.

HRSG Duct Burner Fouling

- In 2016, duct burners were supplied with only natural gas. Duct burner fouling reduced significantly.
- HRSG roof repaired in 2017, combustion has been stable due to cleaner fuel.

Boiler Reliability

- High reliability of boilers in 2017 due to stabilized fuel supply.

Steam Generation

Glycol Monitoring

- Increased monitoring/maintenance on various exchangers has greatly reduced glycol losses from previous years.
- Repaired produced water heat exchangers E-006 C/D floating gasket to stop glycol leak in 2017.

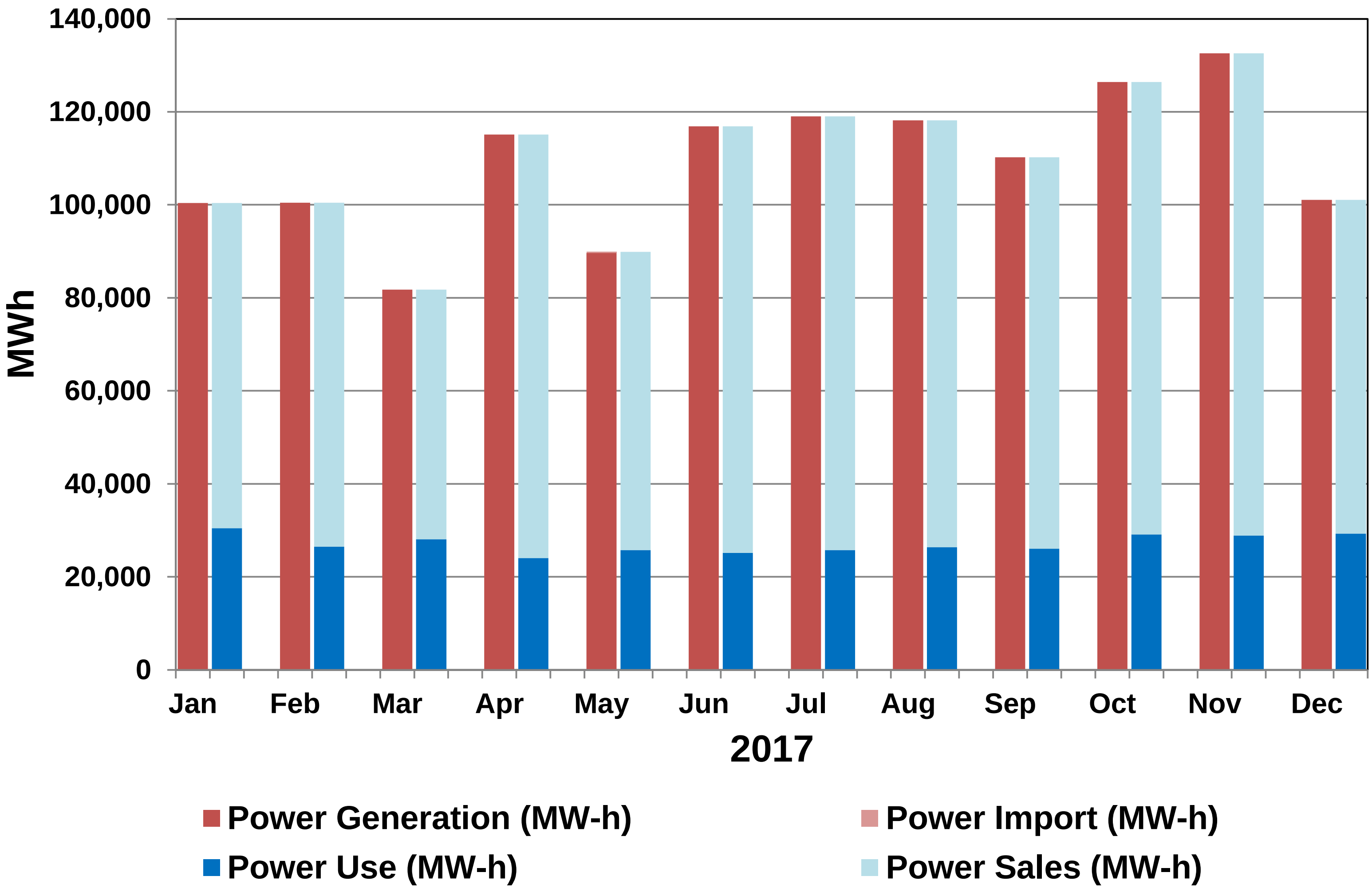
E-013 Exchangers (Blowdown/MP Steam Condensers)

- E-013B material upgrade completed in 2017.
- Monitoring E-013 heat transfer performance to minimize low pressure blowdown to disposal.

Power Generation

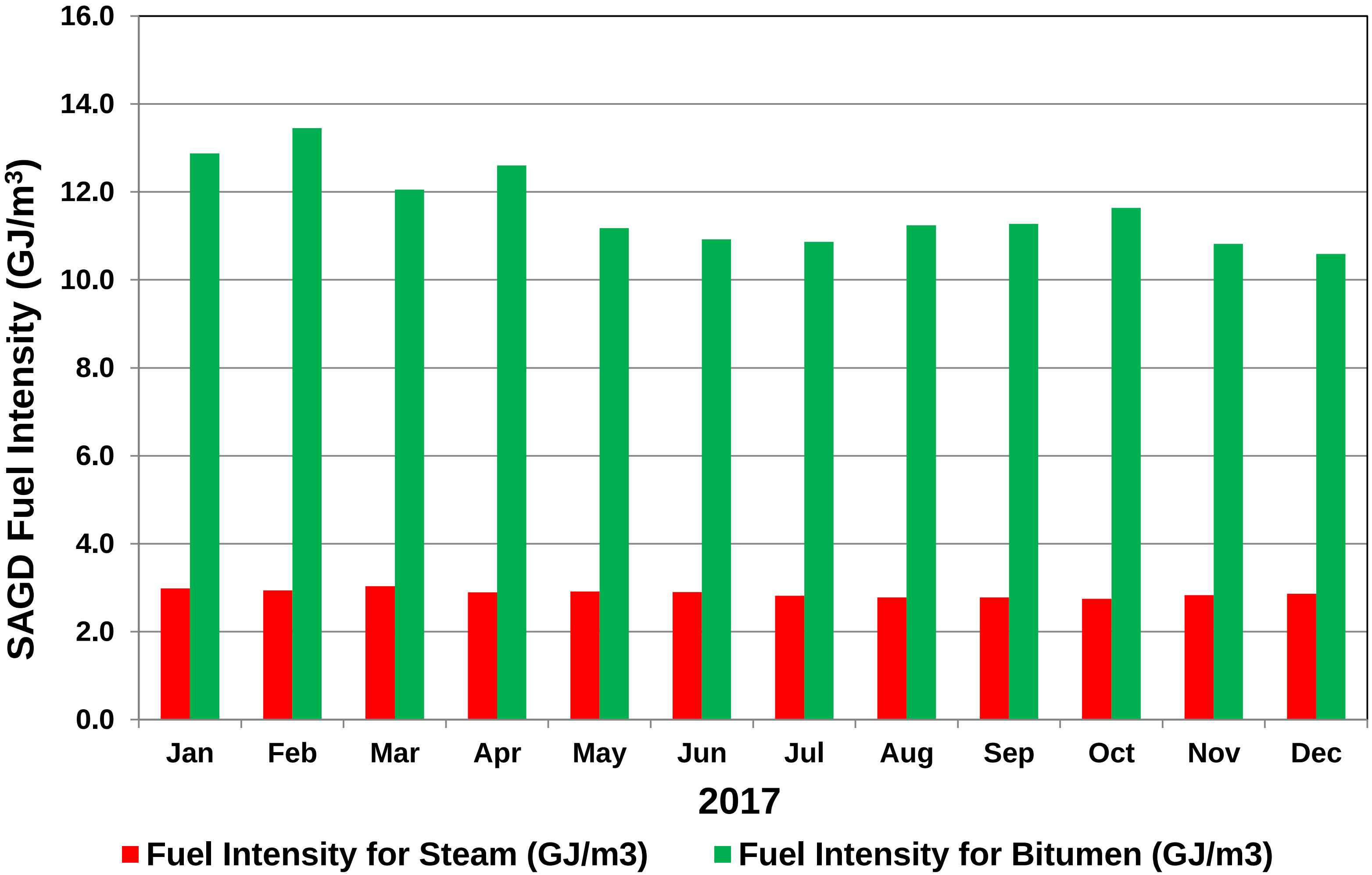
- **Emergency Power Supply**
  - Increased efforts have been made to improve reliability of the emergency generators and standby air compressors by utilizing external vendors to correct any deficiencies and implement preventative maintenance (PM) schedule on our behalf.

Total Power Usage

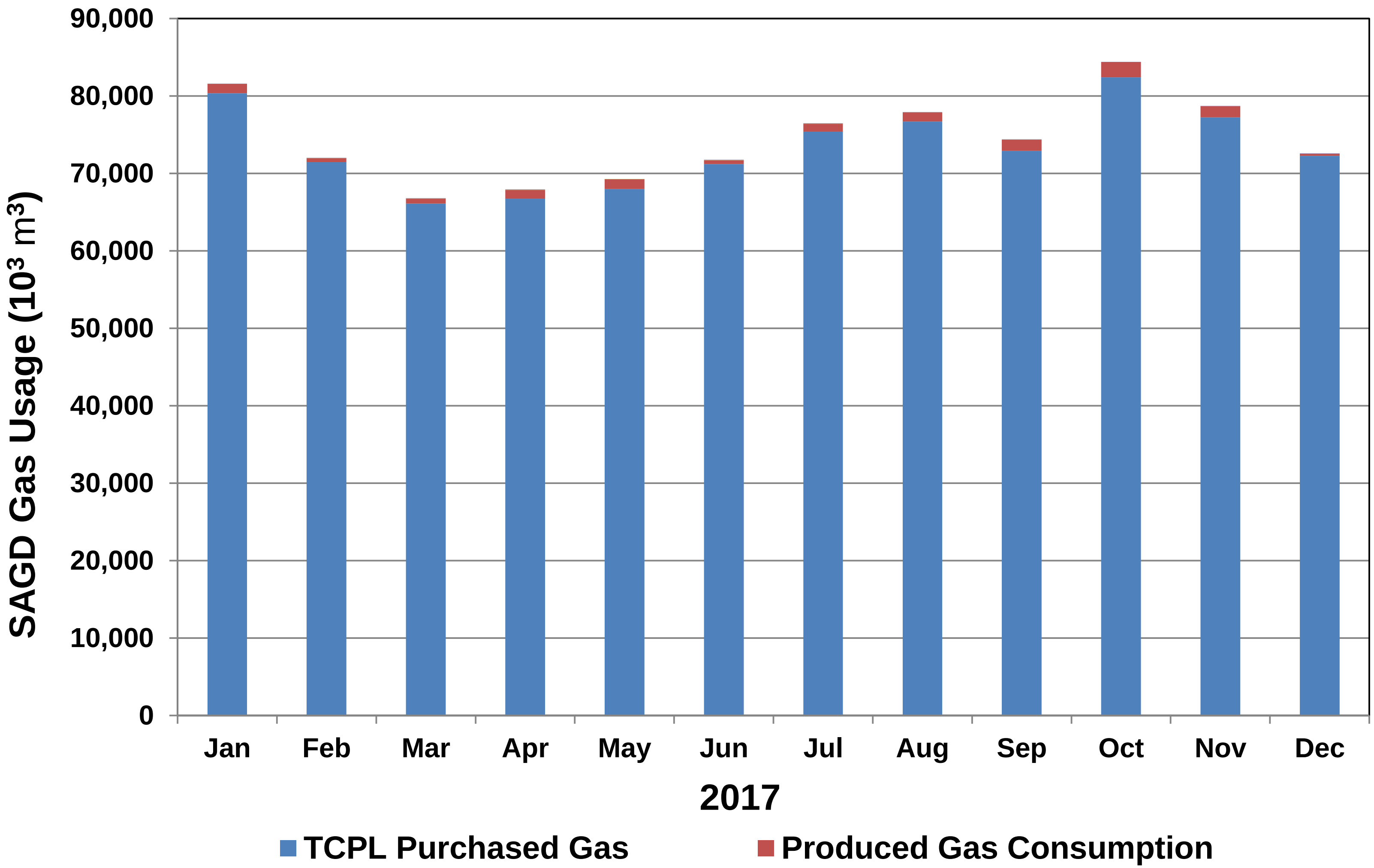


Subsection 3.1.2 (2d)

SAGD Energy Intensity (adjusted for power generation)



Total Gas Consumed (Purchased and Produced)



Total Gas Vented and Flared

Month (2017)	Total Vented Volume (10^3m^3)	Total Gas Flared (10^3m^3)
Jan	0.5	12.7
Feb	0.1	14.2
Mar	12.8	26.7
Apr	0.3	15.6
May	1.6	9.8
Jun	1.1	19.1
Jul	0.2	20.1
Aug	0.2	15.6
Sep	0.2	18.1
Oct	13.9	4.8
Nov	54.9	1.9
Dec	0.5	12.7
Total	85.8	158.6

Greenhouse Gas Emissions

- Long Lake's GHG intensity is trending downwards
  - The lower GHG intensity is associated with lower SORs, improved reliability, and efficient operations.

Year	2010	2011	2012	2013	2014	2015	2016	2017
Kilotonnes (kT) CO_2e Emissions	3,228	3,189	3,613	4,139	4,384	3,547	1,582	1,869
GHG intensity (kg CO_2e/bbl bitumen produced)	361	307	316	310	280	249	199	126

- Long Lake's GHG compliance costs are derived from a 2010-2012 baseline.
  - Long Lake's baseline includes the facility's three major products – bitumen, premium synthetic crude and power.
- Compliance is being met through reducing Long Lake's GHG intensity, using offsets from Nexen's Soderglen wind farm asset, and contributions to the technology fund.
- Current GHG regulations (SGER), which end in 2017, have risen in stringency.
  - In 2017, SGER's target is a 20% reduction in baseline emissions, with a carbon price of $30 per tonne CO_2.
- The new Carbon Competitiveness Incentive Regulation came into effect in 2018.
  - The new regulation replaces the SGER baseline system with common, output based allocations by product type.

Measurement and Reporting Subsection 3.1.2 (3)

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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.
- The multiphase flow meter installed on Pad 14 was operational until November 2017. The test data is validated daily via the Coriolis and water cut meter on the test loop piping. MARP approval will happen in 2018.
- A new multiphase flow meter installed on Pad 15 was operational in 2017.
- K1A pads were not in service for 2017.

Produced Bitumen Measurement

- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab to determine density as requested by Department of Energy.
- Continued increase in 2017 compliance to the annual MARP as a result of implementation of EPAP audit findings.

Proration Factors

LLK Proration Factors 2017

MONTH	OIL	WATER
Jan	1.10	0.91
Feb	1.02	0.92
March	1.01	0.91
April	1.00	0.93
May	1.04	0.92
June	1.03	0.89
July	1.07	0.91
August	1.06	0.89
Sept	1.05	0.87
October	1.04	0.89
November	1.06	0.95
December	1.04	0.91

Heavy Oil Battery
Thermal recovery operations
(SAGD subtype 345)

- Oil = 1.0 - 1.1
- Water = 0.87 – 0.95
- Per D017 Section 12.3.3 Gas Measurement a battery level GOR is used to determine well gas production

Subsection 3.1.2 (3b)

Steam Production Measurement

Approval to use steam calculation method for total plant steam production and net steam to pads was granted in 2017. This is the primary methodology for steam production reporting.

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

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

OTSGs (8401-B-001A-F) will be producing steam based on three criteria

(otherwise the value is zero).

Steam Production = <u>Boiler Feed Water Flow (Sm^3/h) x Steam Quality (%)</u>

100

= Sm^3/h

= Sm^3/h x 24

= Sm^3/d

Subsection 3.1.2 (3a)

Steam Production Measurement

<u>HRSGs - </u>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 2017 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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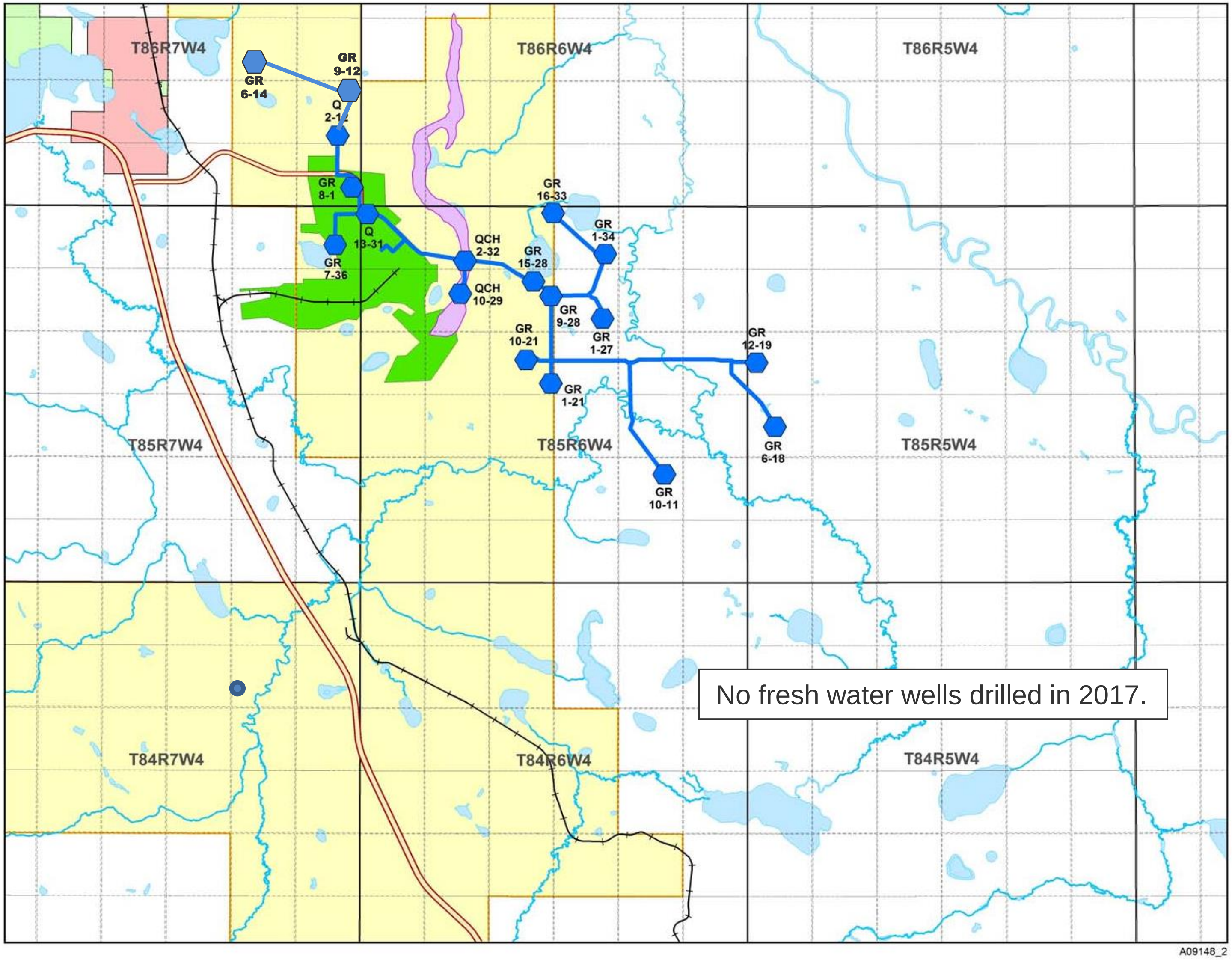
Freshwater Pipelines



No fresh water wells drilled in 2017.

Freshwater Pipelines (CONT'D)

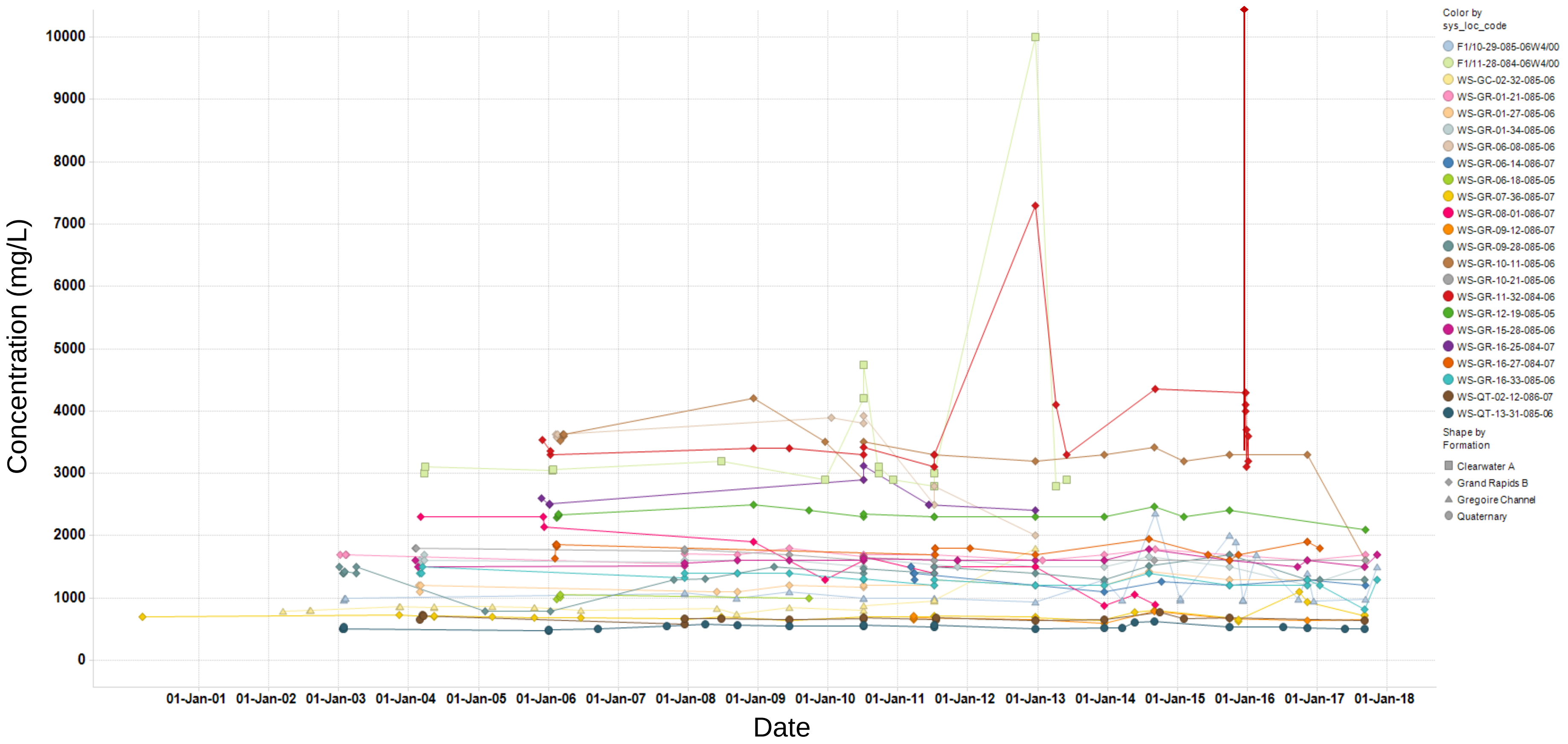
Plant Operations	AENV# 235895-01-00		Total Dissolved Solids		Jan-Dec 2017	
Location	Formation	Fresh?	Sample Date	Concentration (mg/L)	Total (m^3)	Annual avg. (m^3/cd)
01-21-85-06W4M	Grand Rapids	Y	08-Sept-17	1,700	63,585	174
01-27-85-06W4M	Grand Rapids	Y	07-Sept-17	1,300	27,013	74
01-34-85-06W4M	Grand Rapids	Y	07-Sept-17	1,500	39,168	107
02-12-86-07W4M	Quaternary	Y	07-Sept-17	640	93,066	255
02-32-85-06W4M	Gregoire Channel	Y	18-Dec-12	1,800	0	0
06-14-86-07W4M	Grand Rapids	Y	09-Sept-17	1,200	142,465	390
06-18-85-05W4M	Grand Rapids	Y	22-Sep-09	1,000	0	0
07-36-85-07W4M	Grand Rapids	Y	07-Sept-17	720	33,809	93
08-01-86-07W4M	Grand Rapids	Y	9-Sep-14	888	0	0
09-12-86-07W4M	Grand Rapids	Y	07-Sept-17	660	84,362	231
09-28-85-06W4M	Grand Rapids	Y	07-Sept-17	1,300	97,254	266
10-11-85-06W4M	Grand Rapids	Y	11-Sept-17	1,600	33,030	90
10-21-85-06W4M	Grand Rapids	Y	08-Nov-16	1,600	96,061	263
10-29-85-6W4M	Gregoire Channel	Y	11-Nov-17	1,500	451	1
12-19-85-05W4M	Grand Rapids	Y	11-Sept-17	2,100	0	0
13-31-85-06W4M	Quaternary	Y	08-Sept-17	500	28,806*	79
15-28-85-06W4M	Grand Rapids	Y	11-Nov-17	1,700	70,223	192
16-33-85-06W4M	Grand Rapids	Y	11-Nov-17	1,300	86,322	236
License Allocation 3,285,000 m^3 (annual daily average of 9,000 m^3/d)		TOTAL			895,615	2,454

Potable	AENV# 235895-01-00				Jan-Dec 2017	
Location	Formation	Fresh?			Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M	Quaternary	Y	08-Sept-17	500	26,233	72

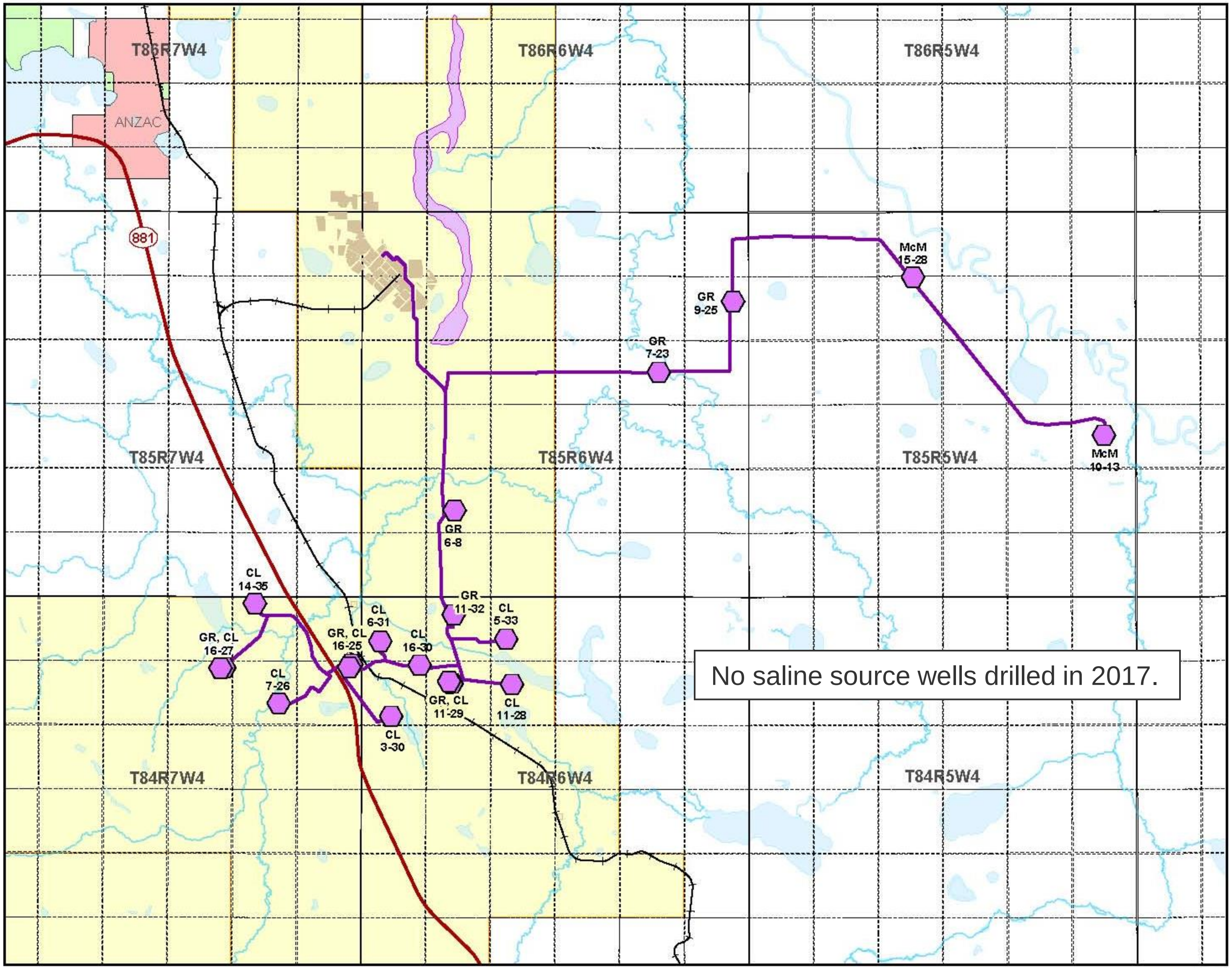
- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water.
- Groundwater samples are collected if source wells are diverted during the year.
- Well 1F1/10-29-085-06W4/00 only turned on for sampling

*Note: A total volume of 55,039 m^3 was diverted from well WS-QT-13-31-085-06W4 for the intended purpose of potable use. The volume of water rejected from the potable facility (28,806 m^3) was re-used in the plant operations rather than being sent to disposal.

Fresh Water Source Wells Water Quality TDS

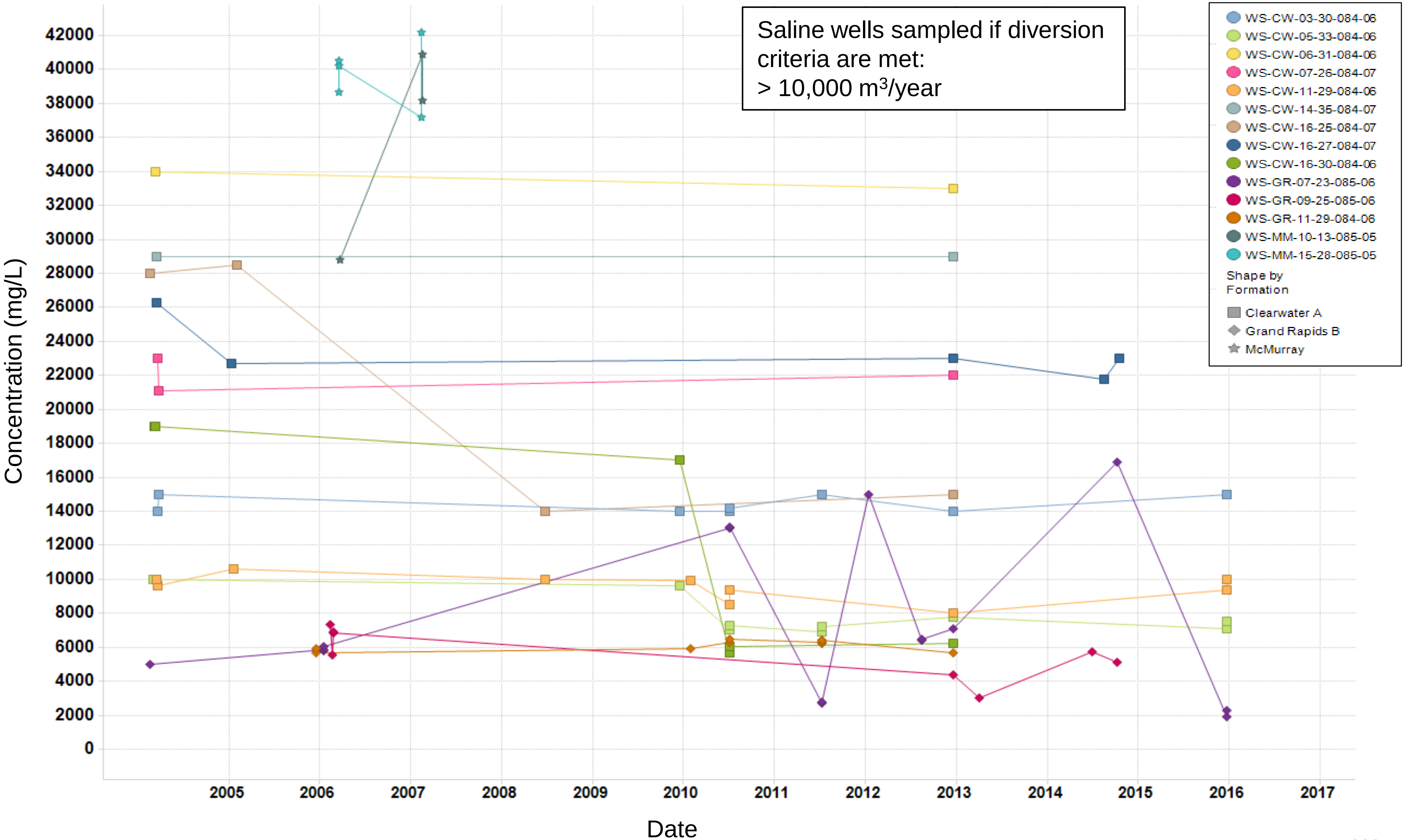


Saline Water Pipelines



No saline source wells drilled in 2017.

Saline Source Wells Water Quality TDS



Subsection 3.1.2 (4a)

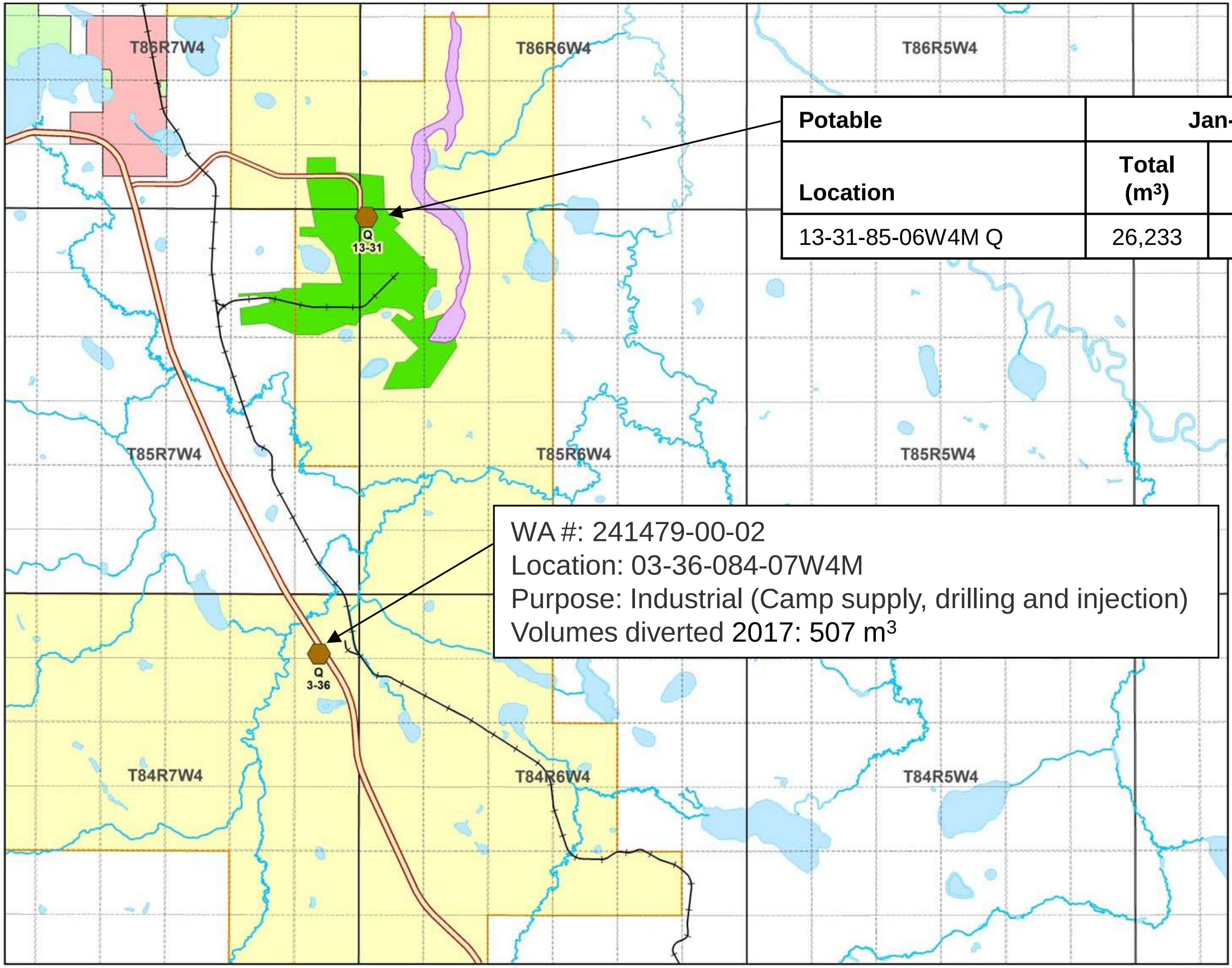
Saline Water Pipelines (CONT'D)

Plant Operations			Total Dissolved Solids		Jan-Dec 2017	
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	0	0
16-25-84-07W4M	Grand Rapids	N	19-Dec-12	2,400	0	0
16-27-84-07W4M	Grand Rapids	N	13-Jan-17	1,800	284	-
Subtotal Non-Saline Diverted Volume					**284**	**-**
TOTAL VOLUME DIVERTED					**284**	**-**

- 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
- Saline system not used in 2017.
- Minor volume used from WS-GR-16-27 to clean K1A system.

Subsection 3.1.2 (4a,b)

Potable Well



Potable	Jan-Dec 2017	
Location	Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M Q	26,233	72

WA #: 241479-00-02
Location: 03-36-084-07W4M
Purpose: Industrial (Camp supply, drilling and injection)
Volumes diverted 2017: 507 m^3

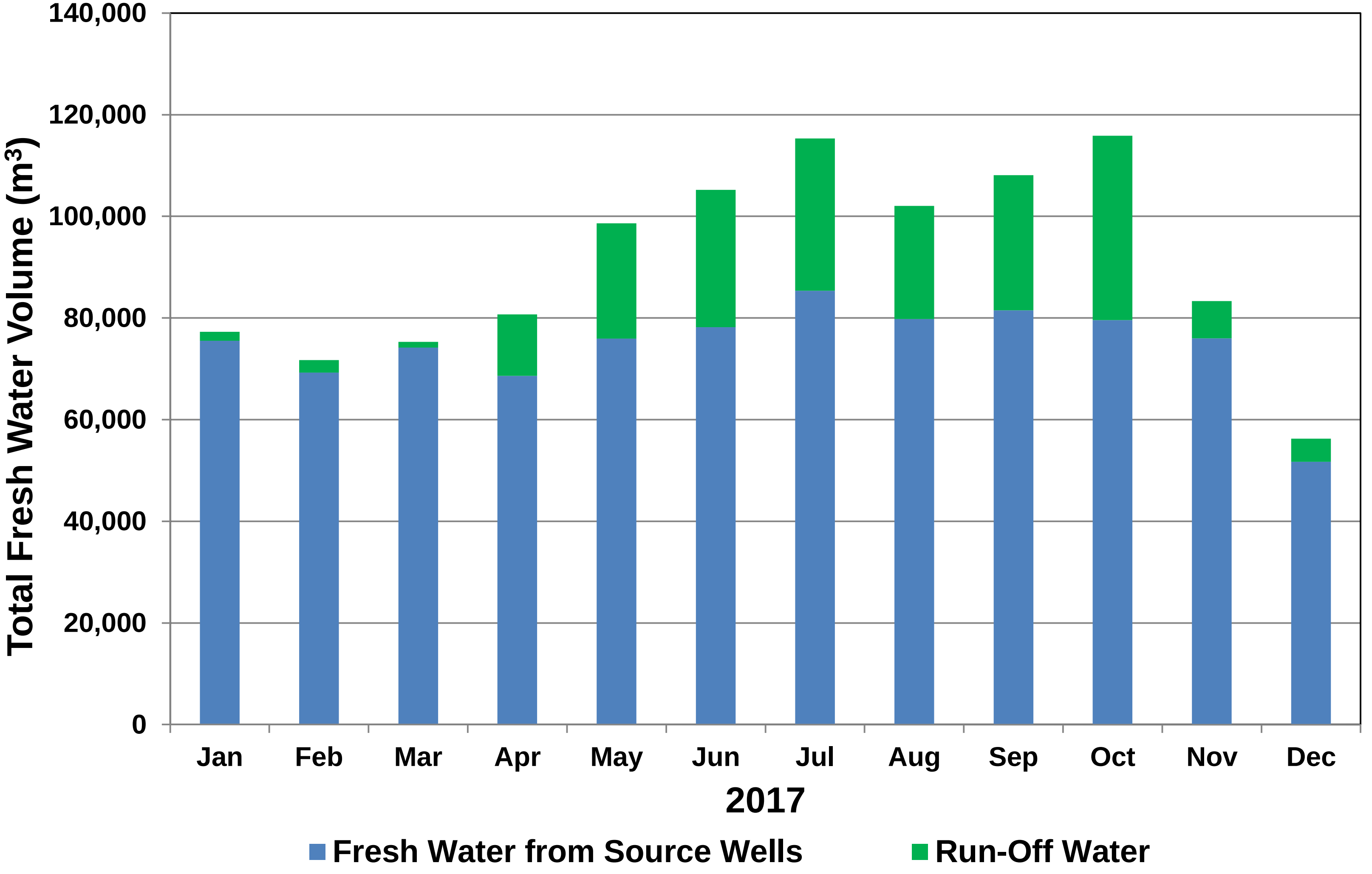
Subsection 3.1.2 (4a)

Other Water Sources

- Surface runoff to lime sludge ponds (00247843-00-00):
  - 2017: 194,117 m^3 (estimate).

- Well drilling:
  - Various TDLs: 2,653 m^3.

Fresh Water Use Volumes



* Excludes domestic water use of 26,233 m^3

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. Potable
  4. Others (incl. drilling)

	Freshwater Uses in 2017 (m^3)			
	Total	Domestic	SAGD*	Process
Main groundwater license (235895-01-00 as amended)	921,898	26,233	669,057	226,608
Surface runoff to ponds (includes K1A)	194,117		194,117	
SAGD drilling**	3,343			
Winter drilling program (Long Lake and Kinosis)	0			
Potable trucked to Long Lake	0			
TOTAL	**1,119,358**			

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

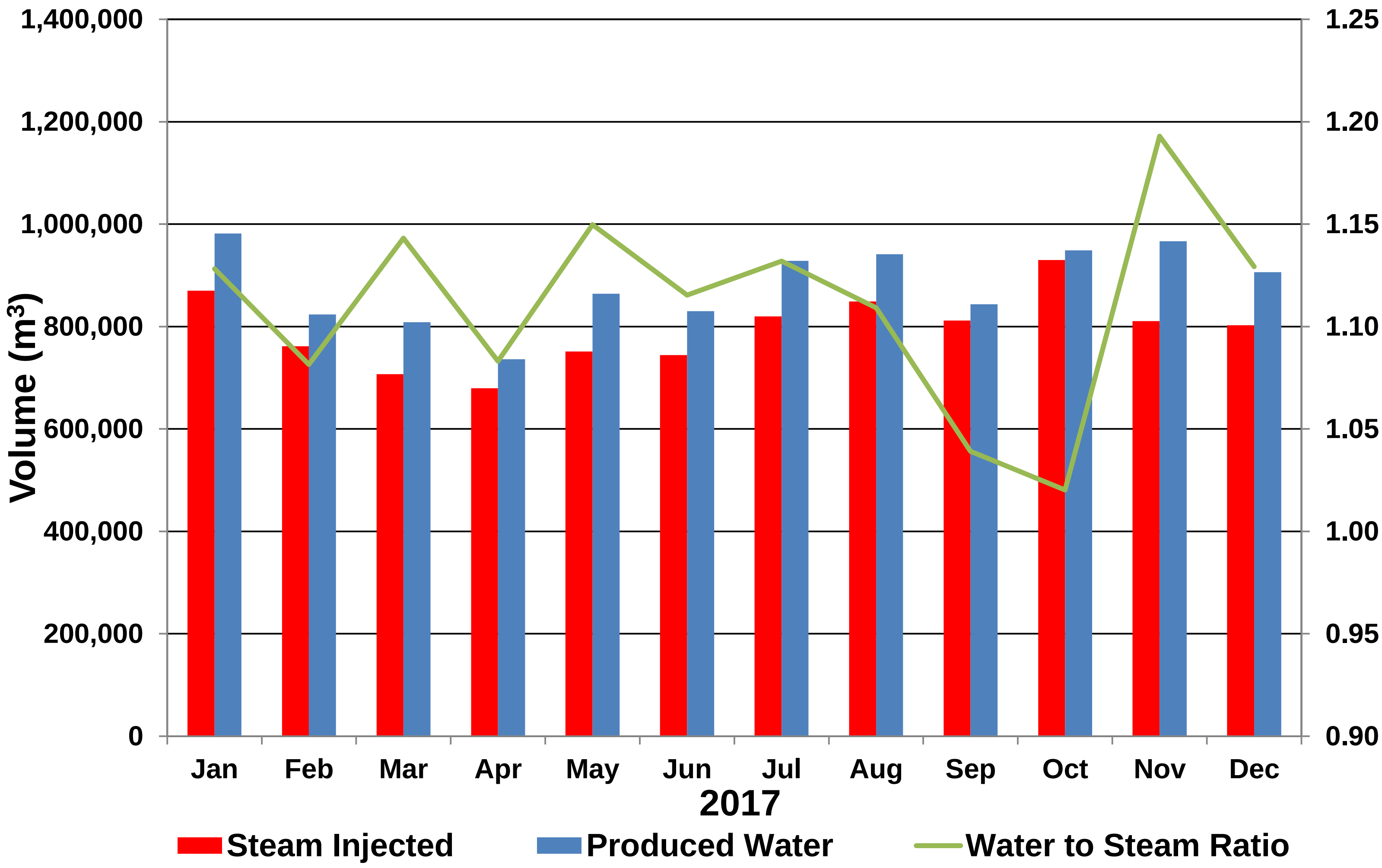
** Infill program

- Saline water make-up:

  0 m^3 in 2017 for steam make-up (HLS's)

Subsection 3.1.2 (4b)

Produced Water and Steam Injected Volumes

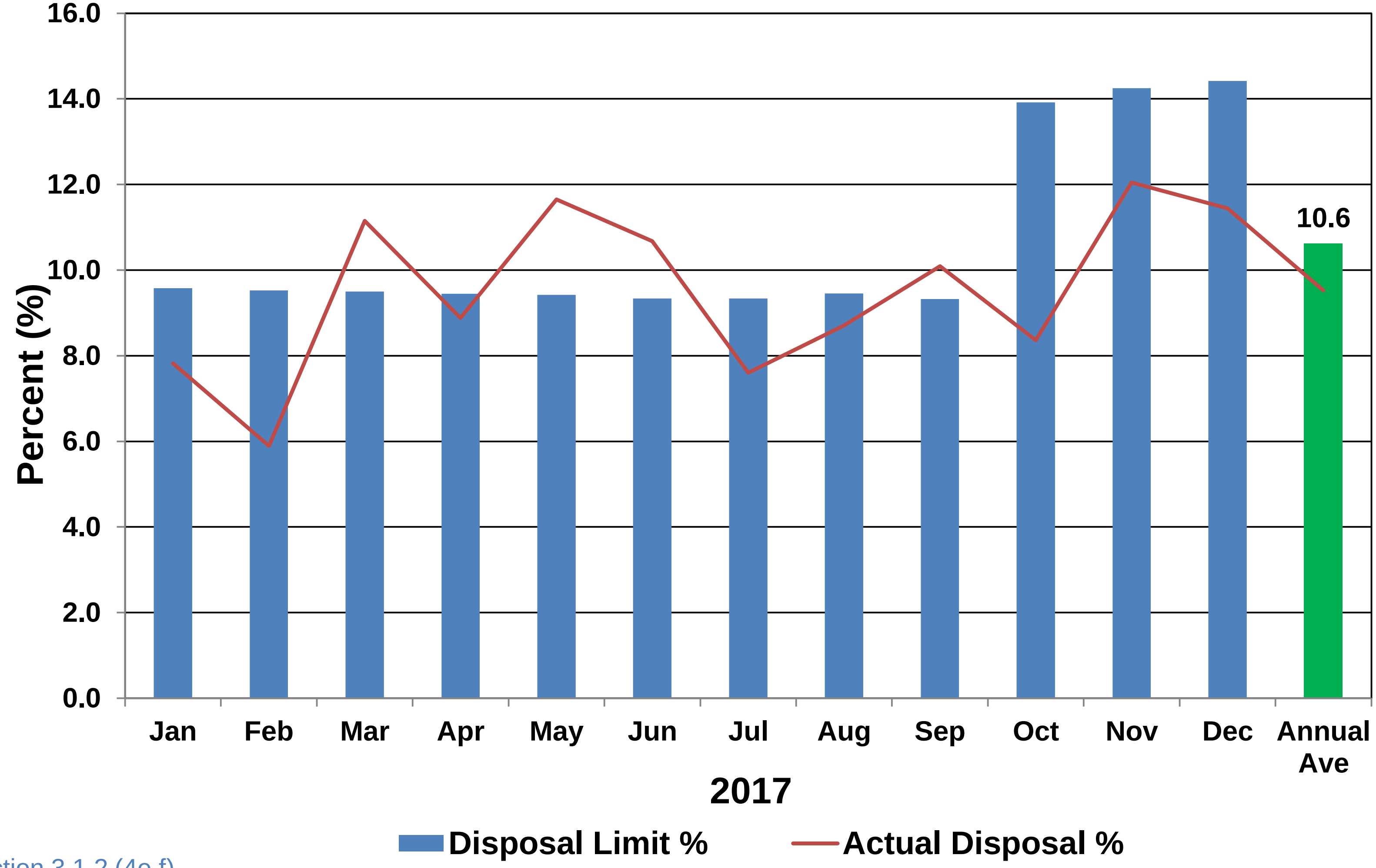


Subsection 3.1.2 (4c,d)

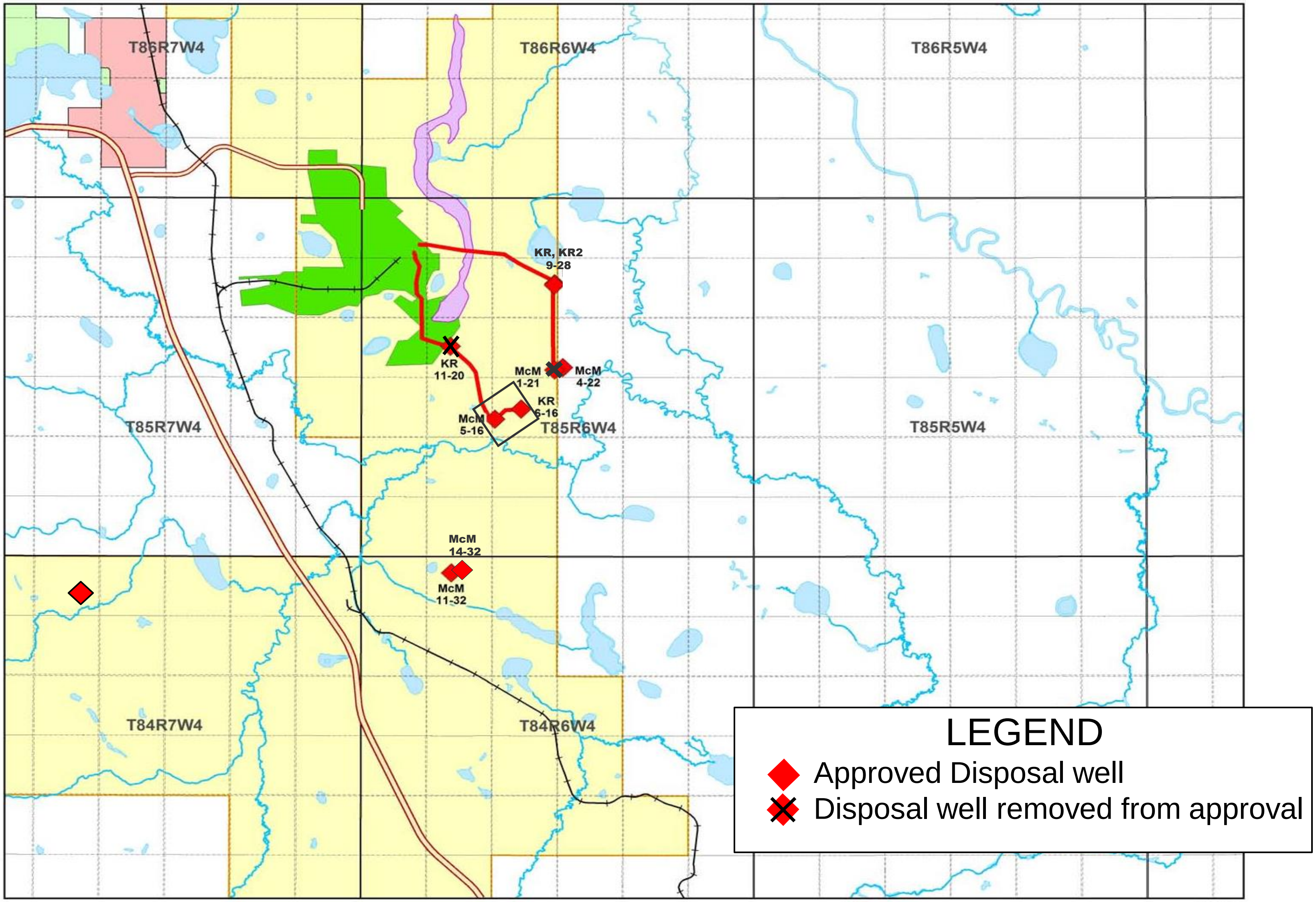
Water Management

Disposal limit (%) = $\frac{[(\text{Freshwater In}^*D_f) + (\text{Brackish water In }^*D_b + (\text{Produced water In}^*D_p)]^*100}{[(\text{Freshwater In}) + (\text{Brackish water In}) + (\text{Produced water In})]}$

Note: Nexen received approval to have produced water disposal factor increased from 0.10 to 0.15 effective Oct 1, 2017.



Disposal Wells



Subsection 3.1.2 (4g)

Disposal Wells (CONT'D)

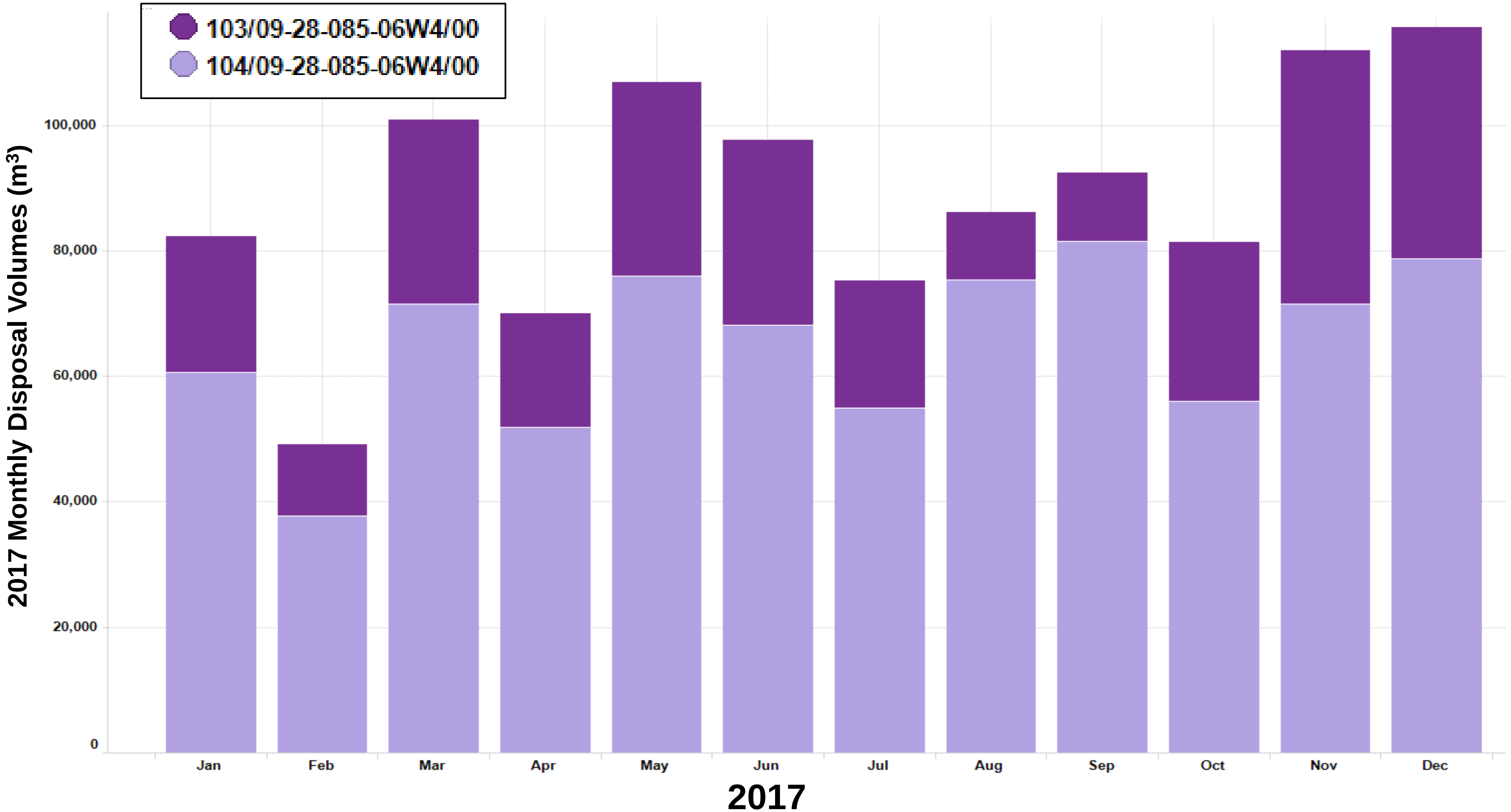
AER Approval # 10023J	Class 1b	January - December 2017		
Disposal Well		**Max. WHP (kPag)**	**Total (m^3)**	**Annual avg. (m^3/cd)****
104/09-28-085-06W4/00 KR	Blowdown	1,630	782,572	2,162
103/09-28-085-06W4 KR	Blowdown	1,674	296,458	921
100/04-22-085-06W4 McM*	Blowdown	-	-	-
100/11-32-084-06W4 McM*	Blowdown	-	-	-
100/14-32-084-06W4 McM*	Blowdown	-	-	-
100/11-28-084-06W4/00 KR*	Drilling fluids	-	-	-
102/07-32-084-07W4/00 KR	Blowdown	-	-	-
103/01-21-085-06W4/02 McM	Blowdown	-	-	-
TOTAL			**1,079,030**	**3,083**

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
**Excluding days of no disposal

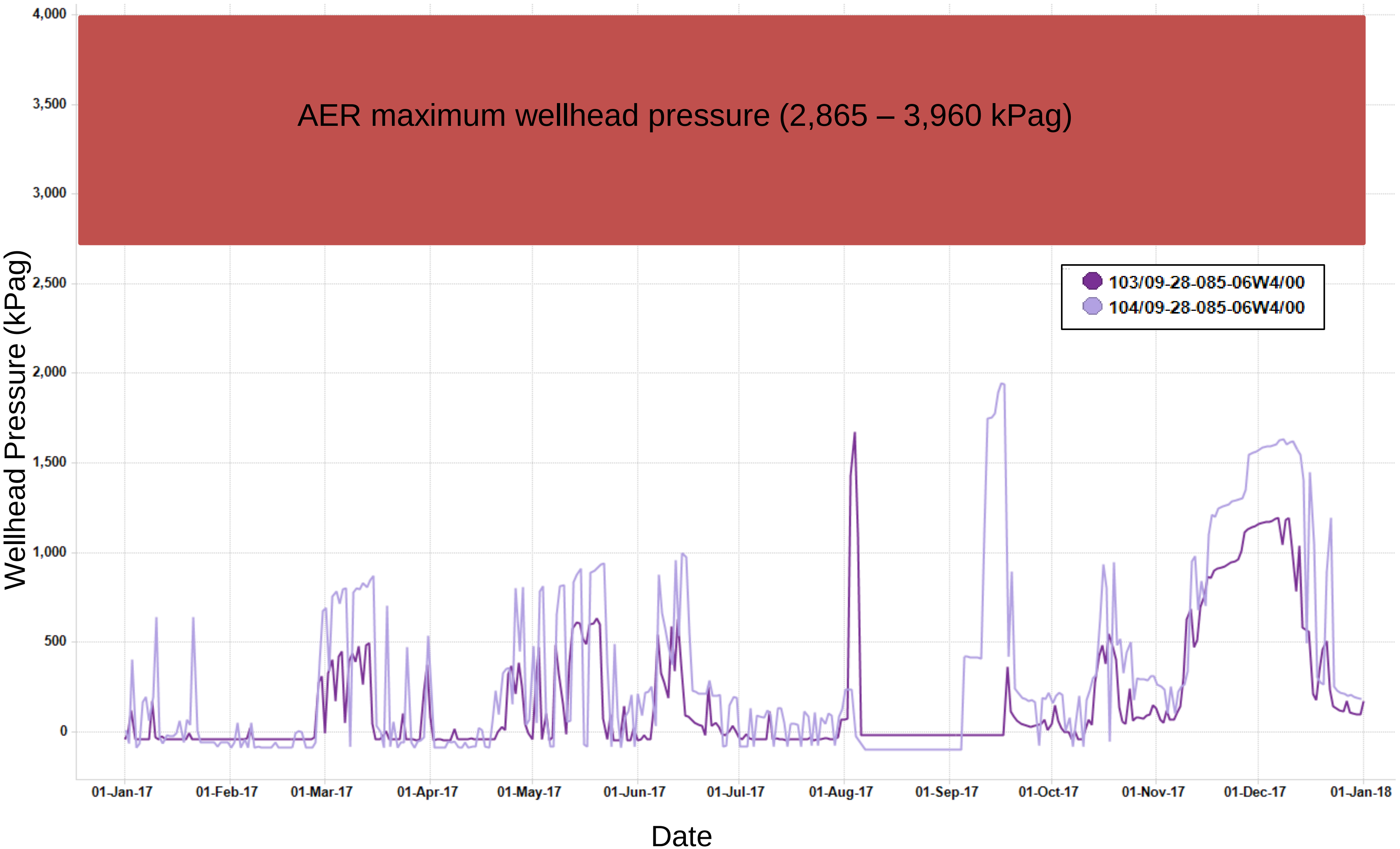
- Disposal capacity is adequate.
- Disposal fluid temperature ~60°C.
- All wells passed annulus pressure test

Disposal Well Volumes - Class 1b



- 2017 disposal only to Keg River wells 103 and 104/09-28-085-06W4/00

Disposal Well - Well Head Pressures



Subsection 3.1.2 (4h)

Sulphur Production and Air Emissions

Subsection 3.1.2 (5)

Long Lake

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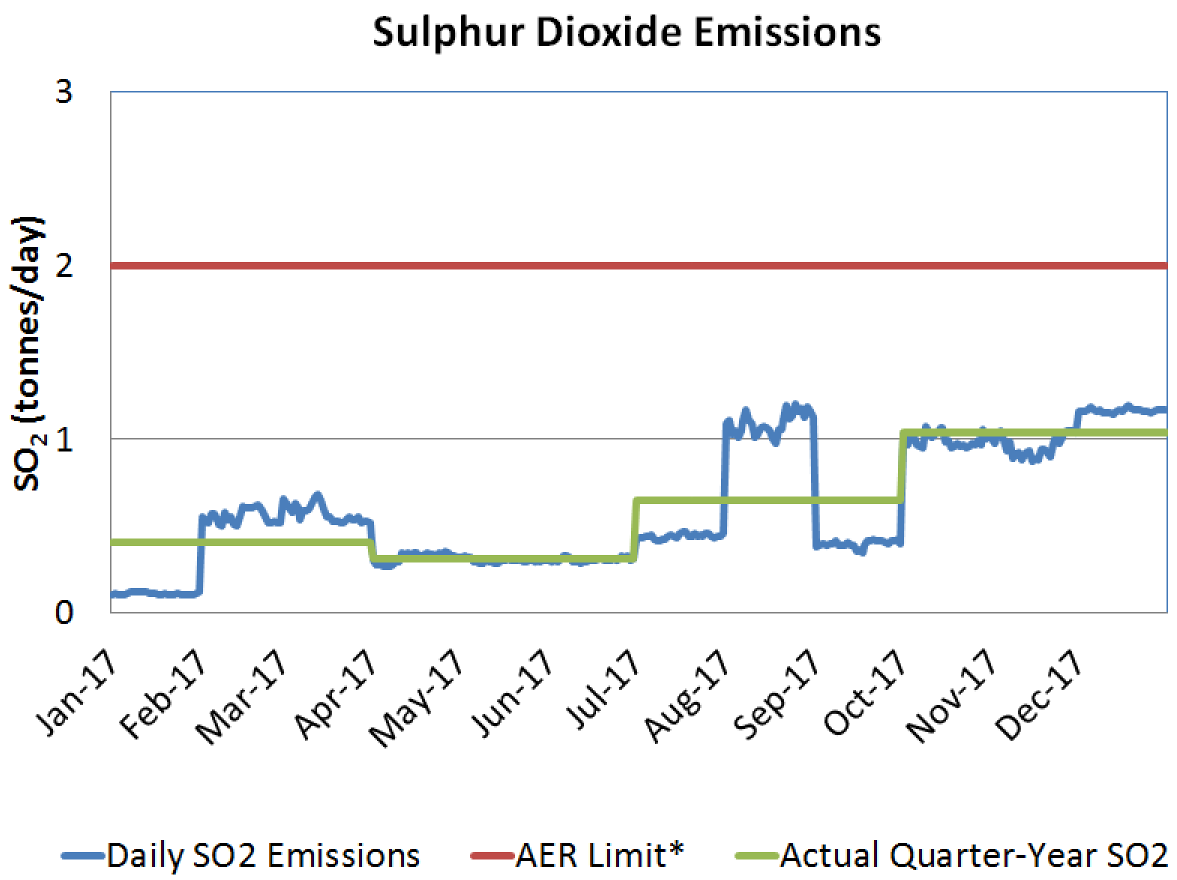
Sulphur Production

- Sulphur was not recovered at Long Lake in 2017.
- The annual average sulphur inlet was under 1 tonne/day and corresponding SO_2 emissions were under 2 tonne/day.

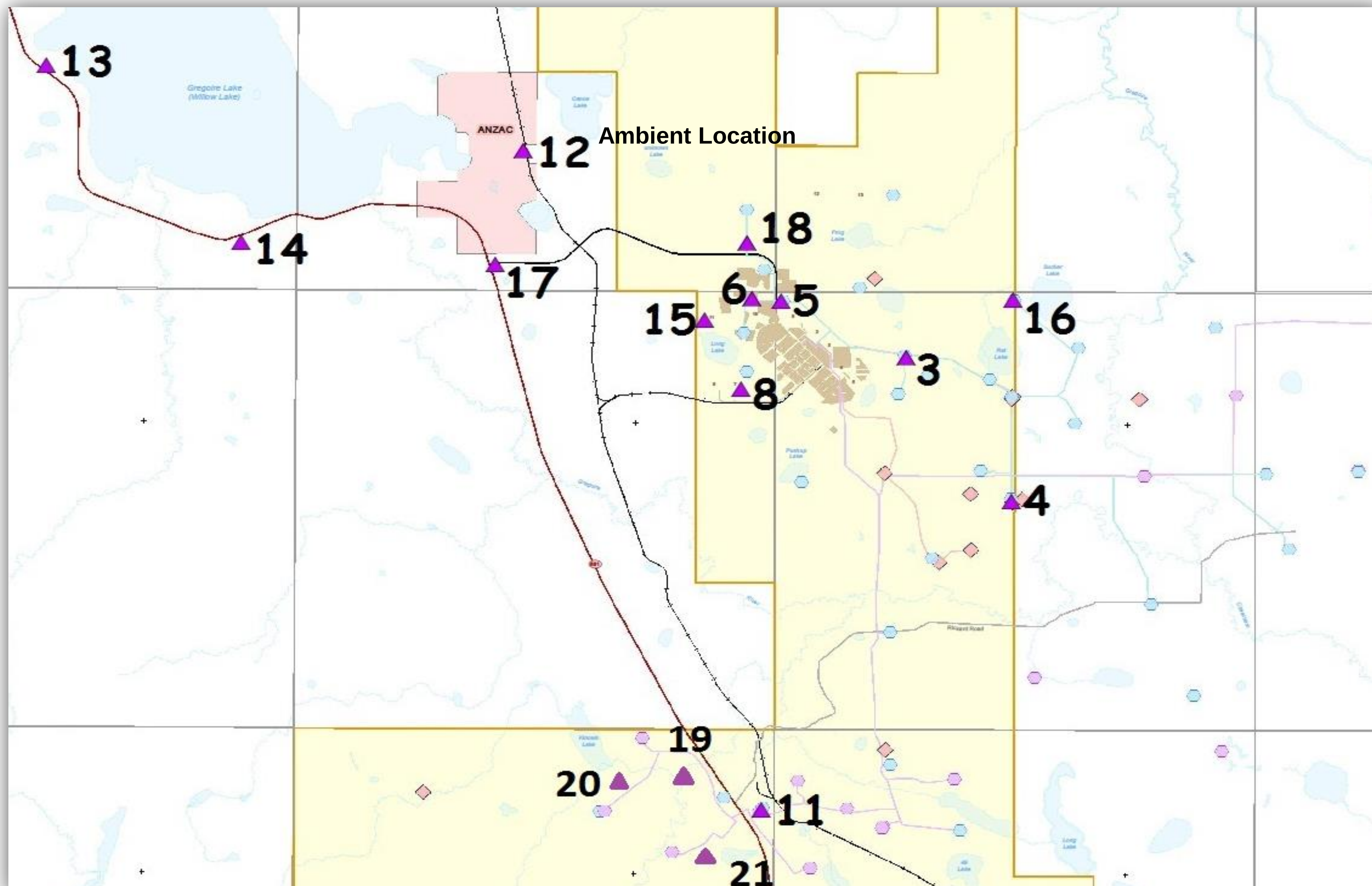


Subsection 3.1.2 (5b)

Air Monitoring

- Passive air monitoring for SO_2, H_2S, and NO_2 was conducted around the Long Lake facility in accordance with the EPEA.
- Continuous emissions of NO_2 were monitored using Continuous Emissions Monitoring (CEMS) as required by the EPEA. Relative Accuracy Test Audits and Manual Stack Surveys were completed as part of the performance testing requirements.
- Ambient Air Monitoring was conducted by WBEA at the Anzac Ambient Air Monitoring Station on behalf of Long Lake operations. Continuous and intermittent data was submitted to the Director by the WBEA.
- Emissions of SO_2 and NO_2 from the Long Lake facility were summarized in the monthly and annual Air Emission Reports.

Passive Air Monitoring Locations
Long Lake & K1A



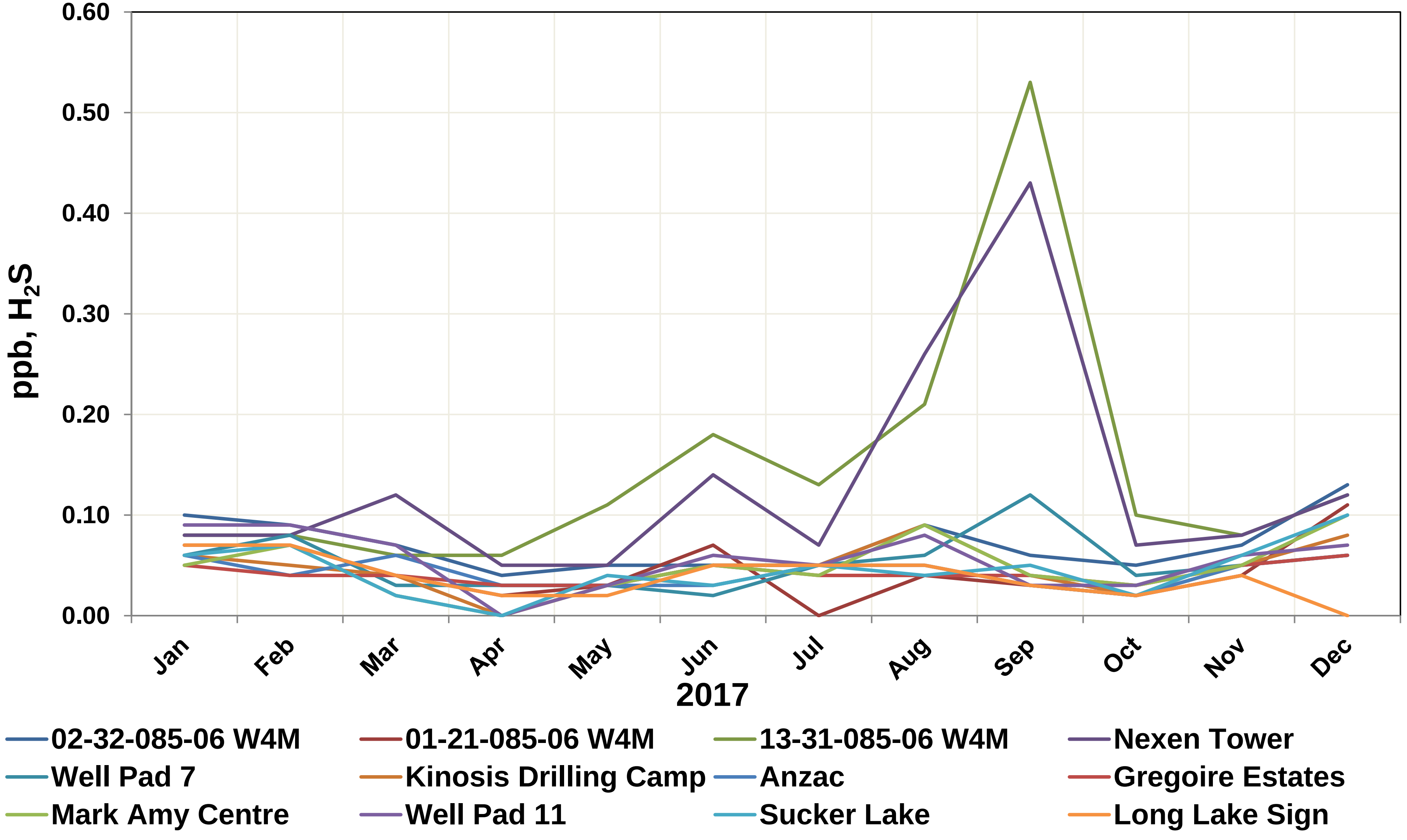
Subsection 3.1.2 (5d)

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

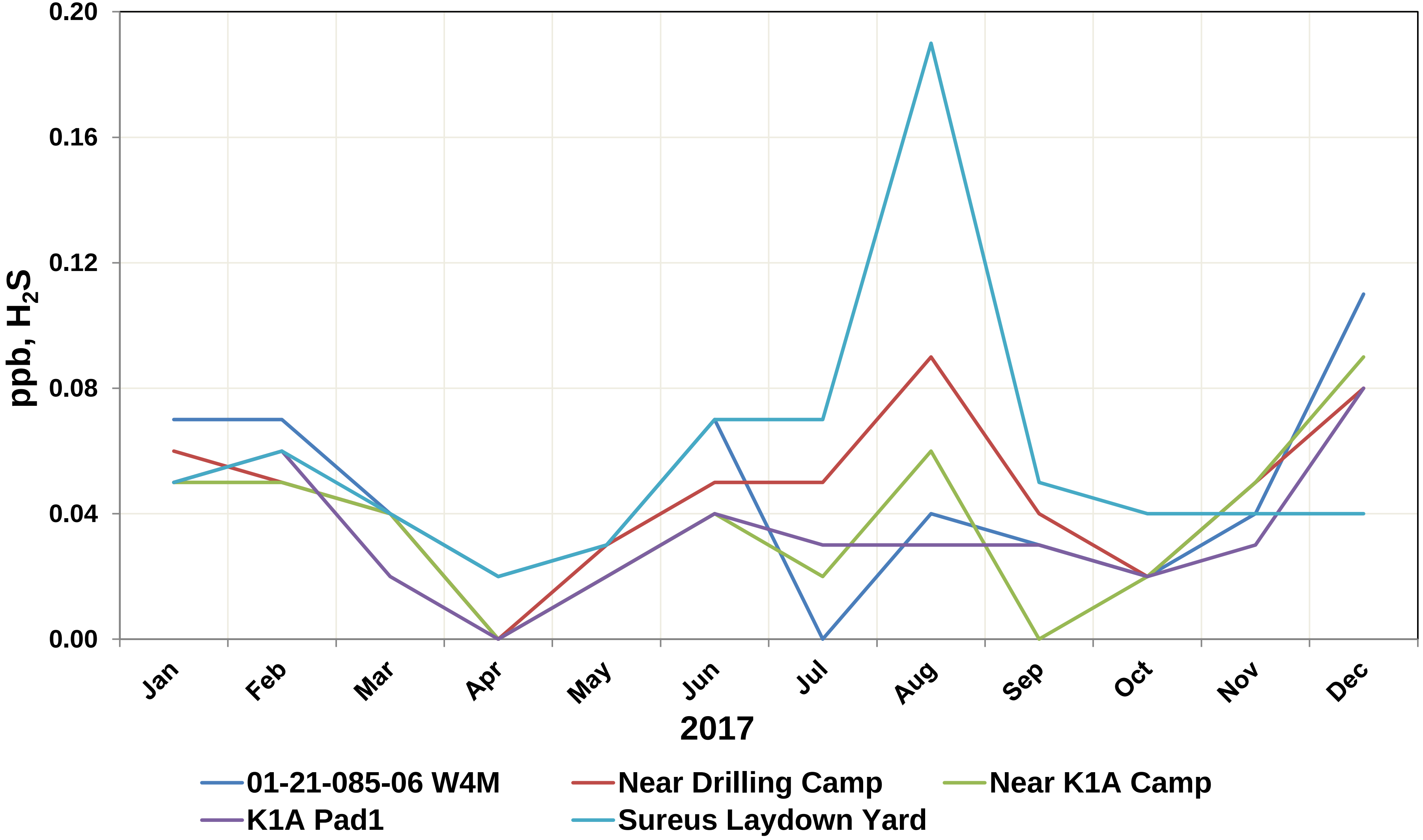
* K1A Passive Stations

Long Lake H_2S Passive Monitoring



Subsection 3.1.2 (5d)

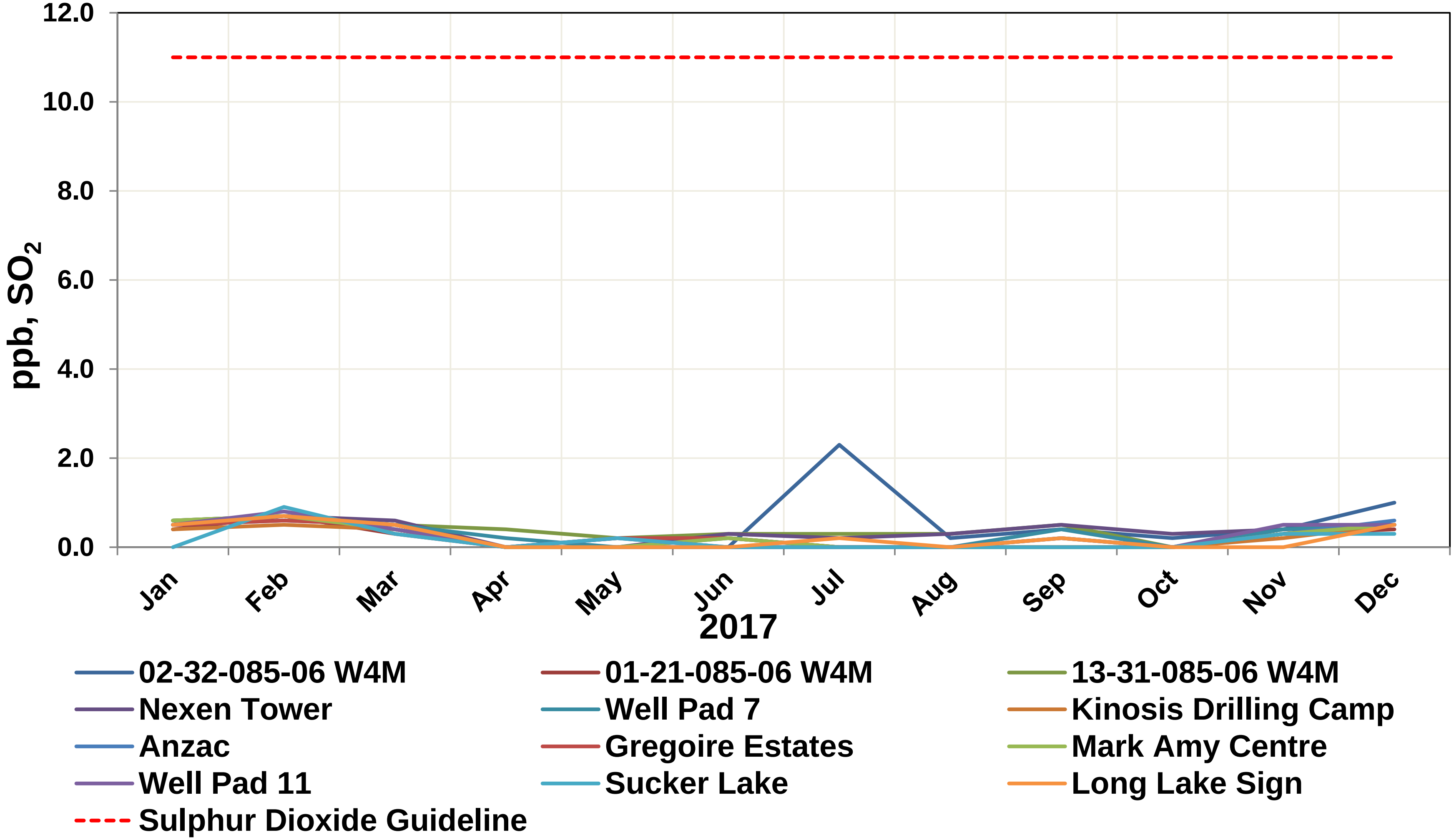
K1A H_2S Passive Monitoring



Subsection 3.1.2 (5d)

Long Lake SO_2 Passive Monitoring

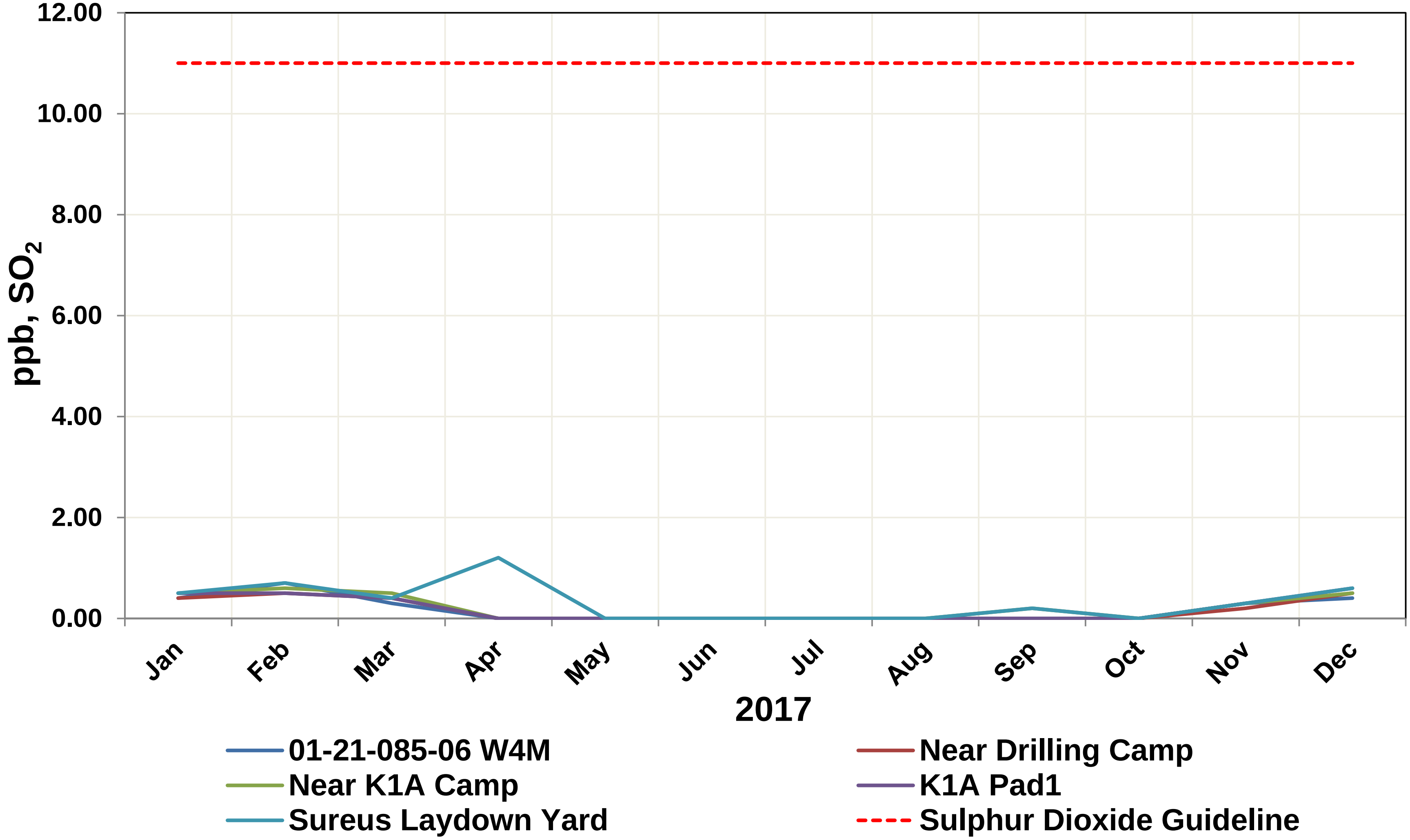
- The AAAQO set out by the AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. No stations exceeded this limit in 2017.



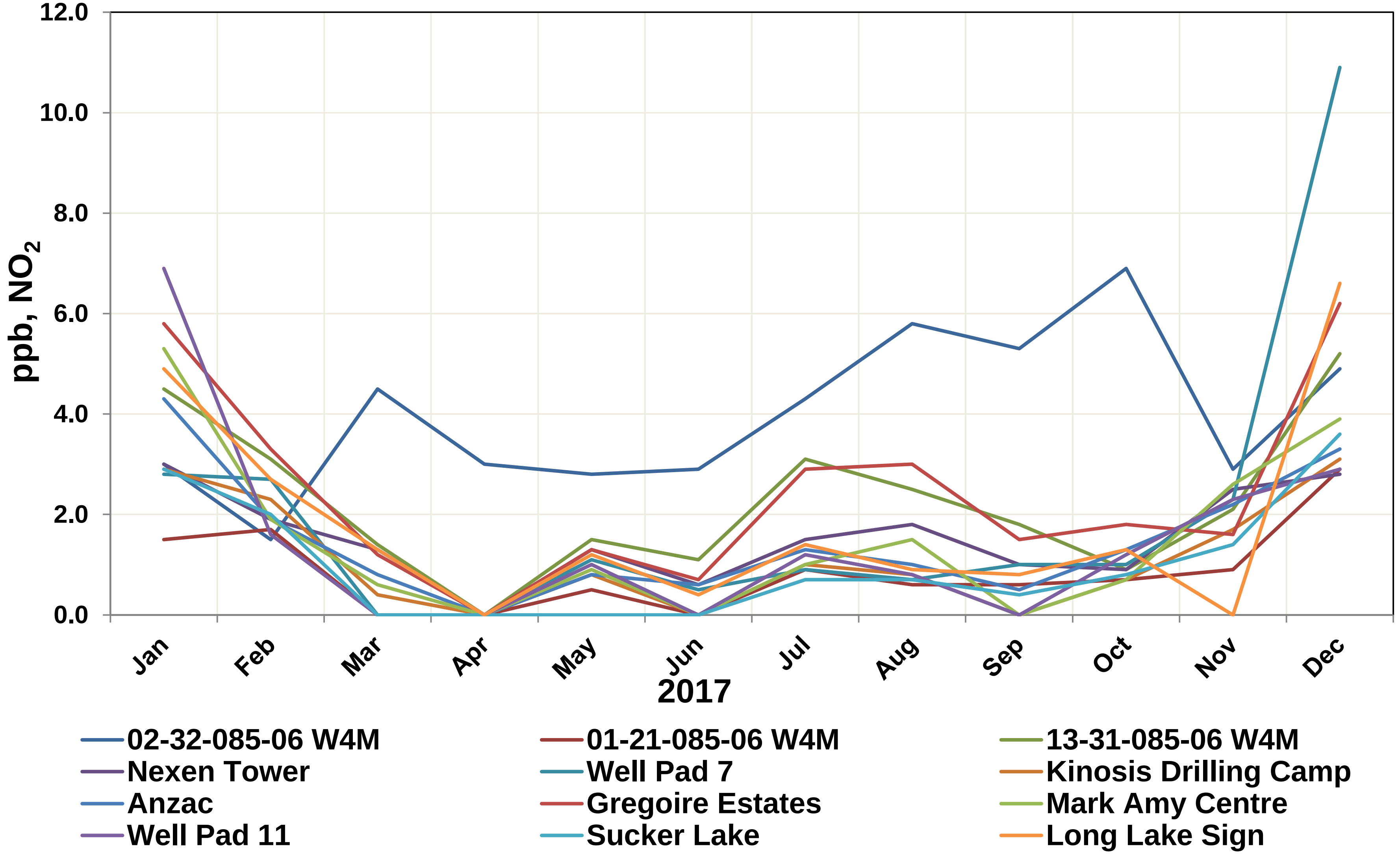
Subsection 3.1.2 (5d)

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 2017.

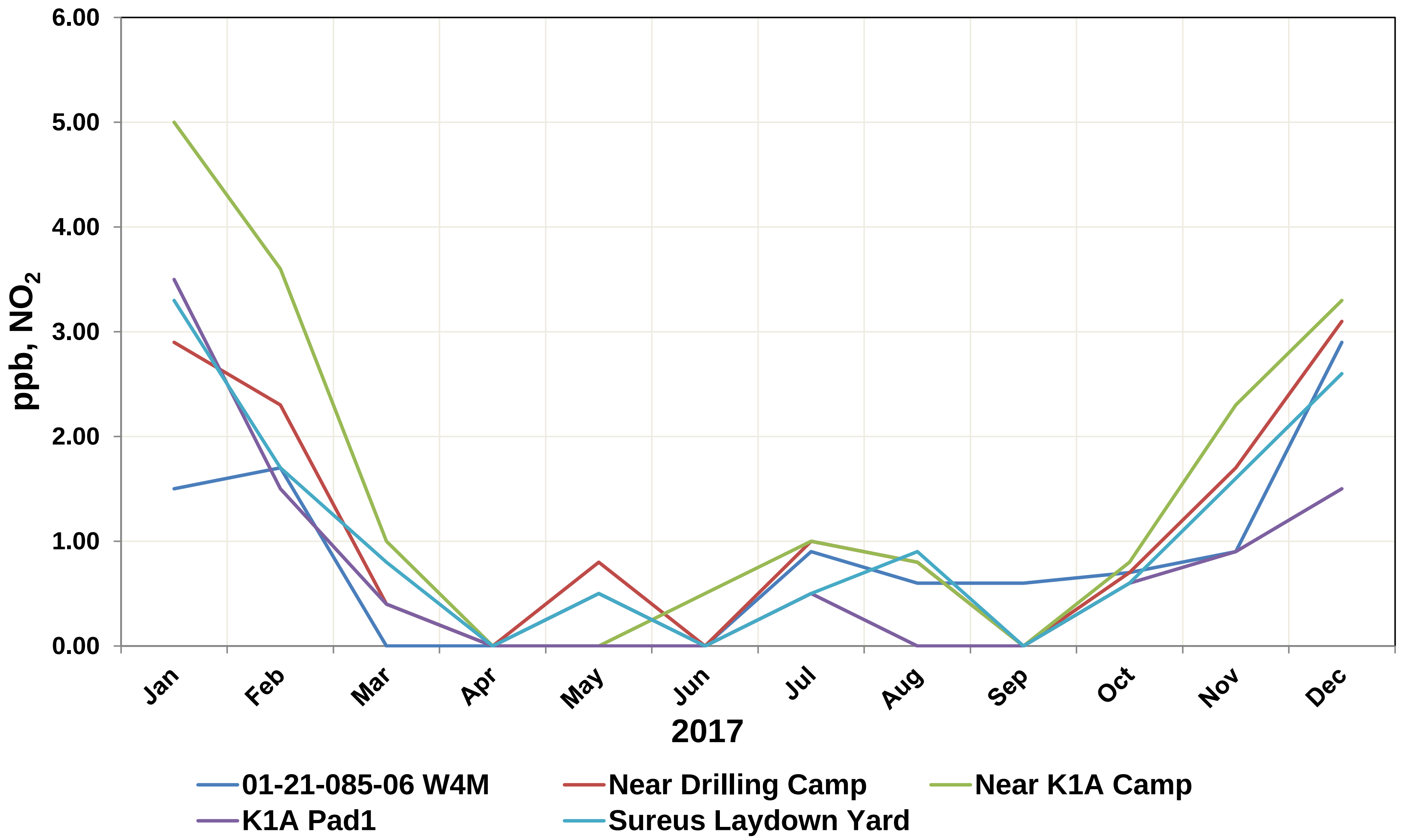


Long Lake NO_2 Passive Monitoring



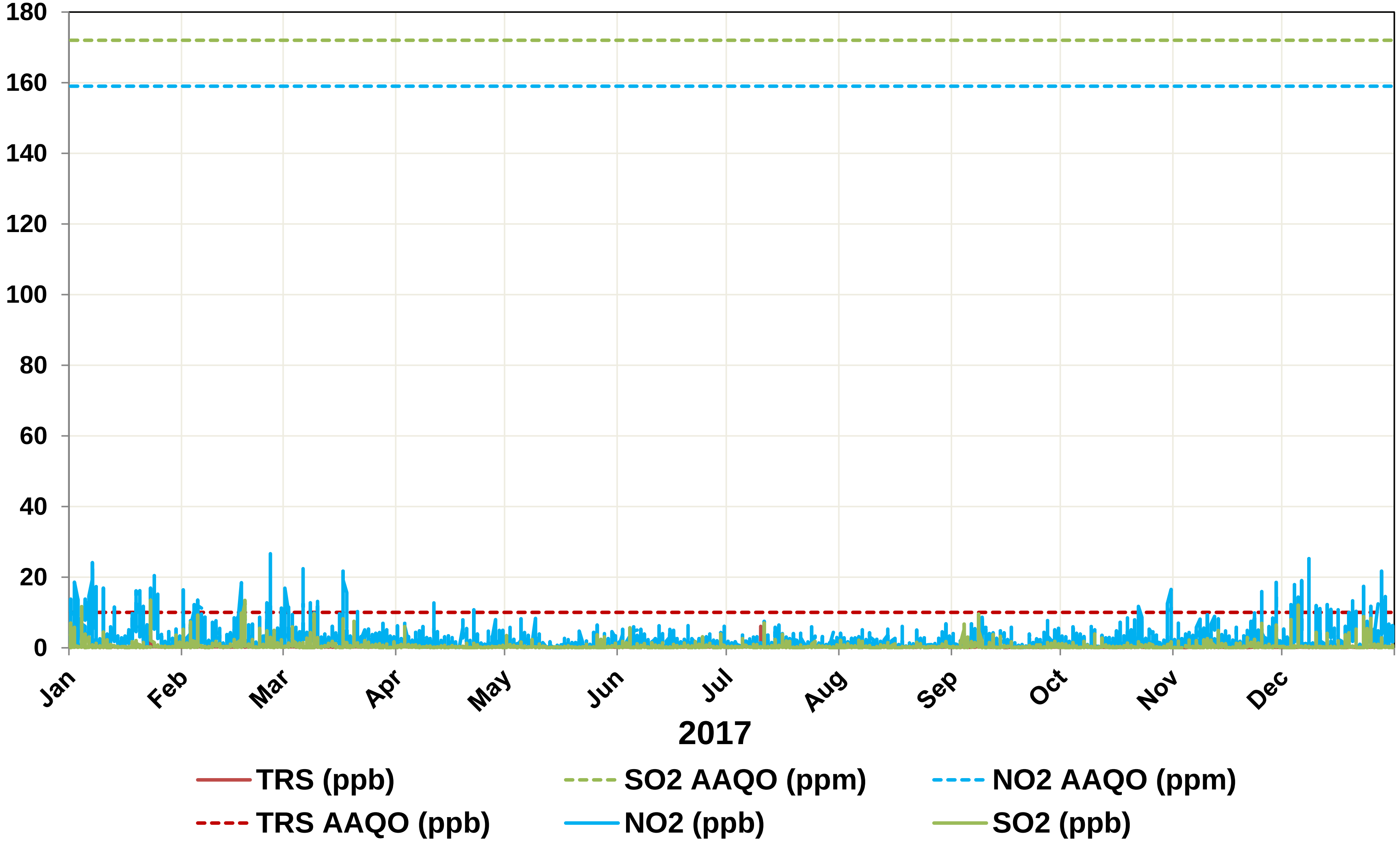
Subsection 3.1.2 (5d)

K1A NO_2 Passive Monitoring

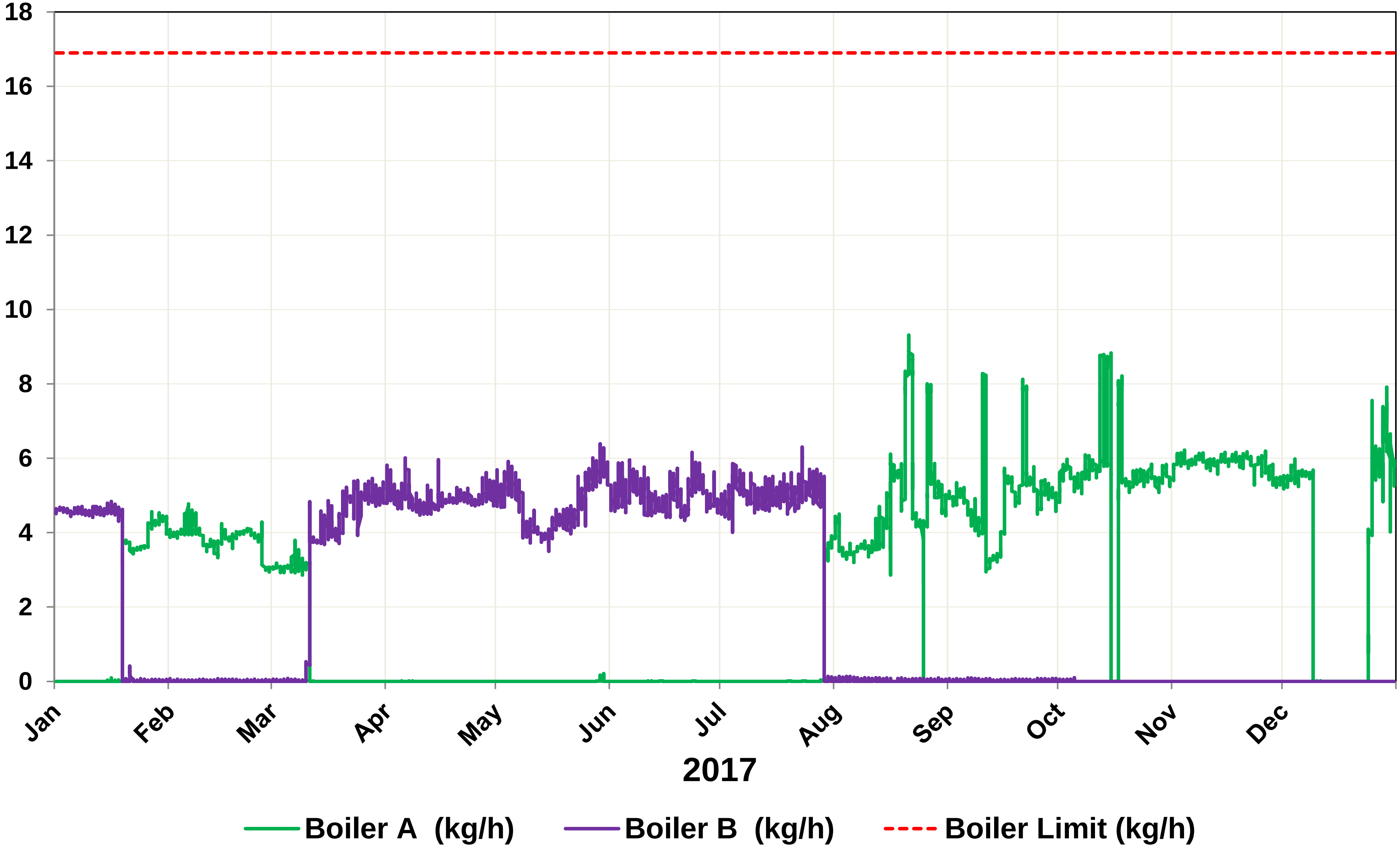


Subsection 3.1.2 (5d)

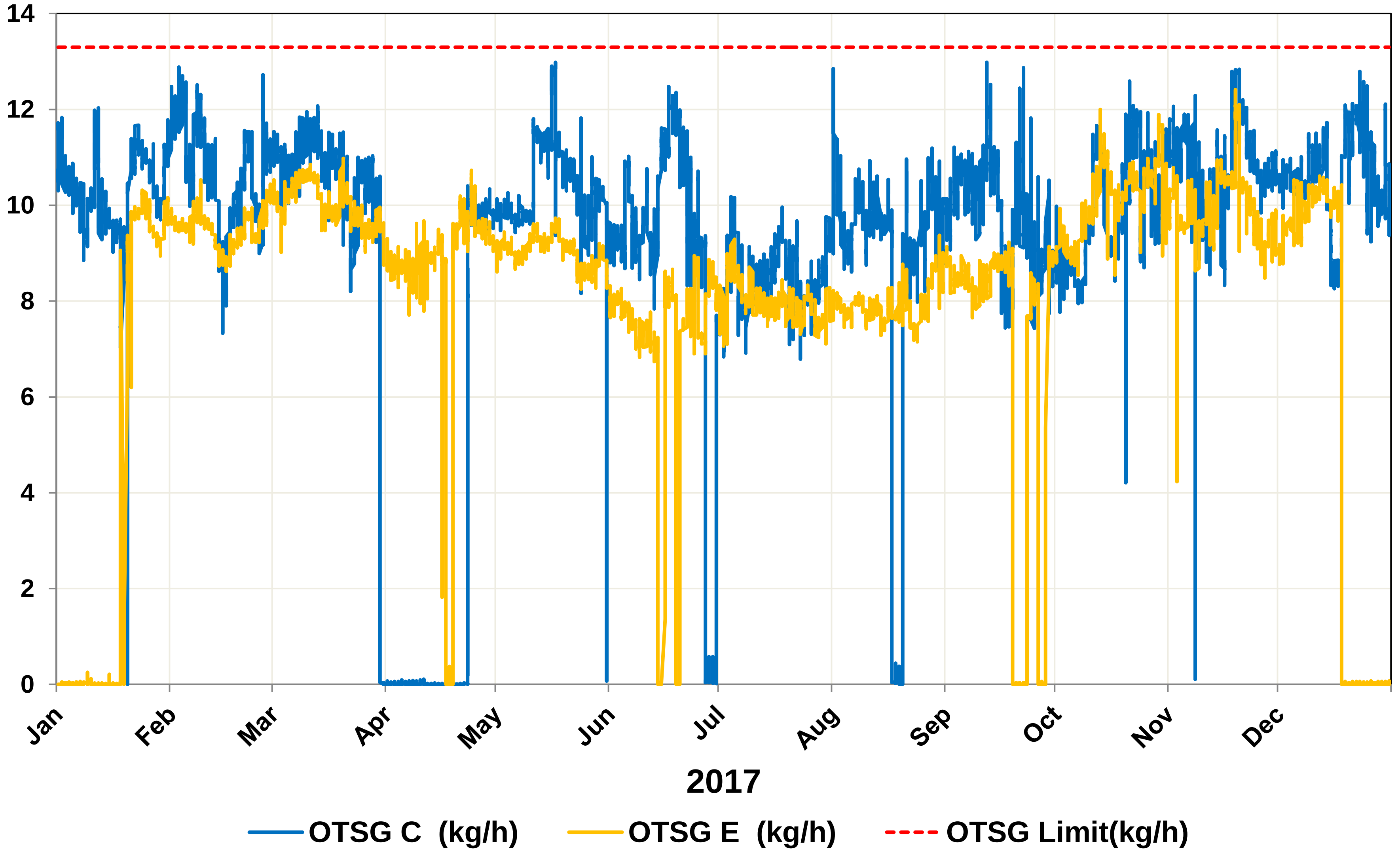
Anzac Ambient Monitoring
NO2, SO2, TRS Hourly Maximum



Hourly CEMS NOx - Boilers

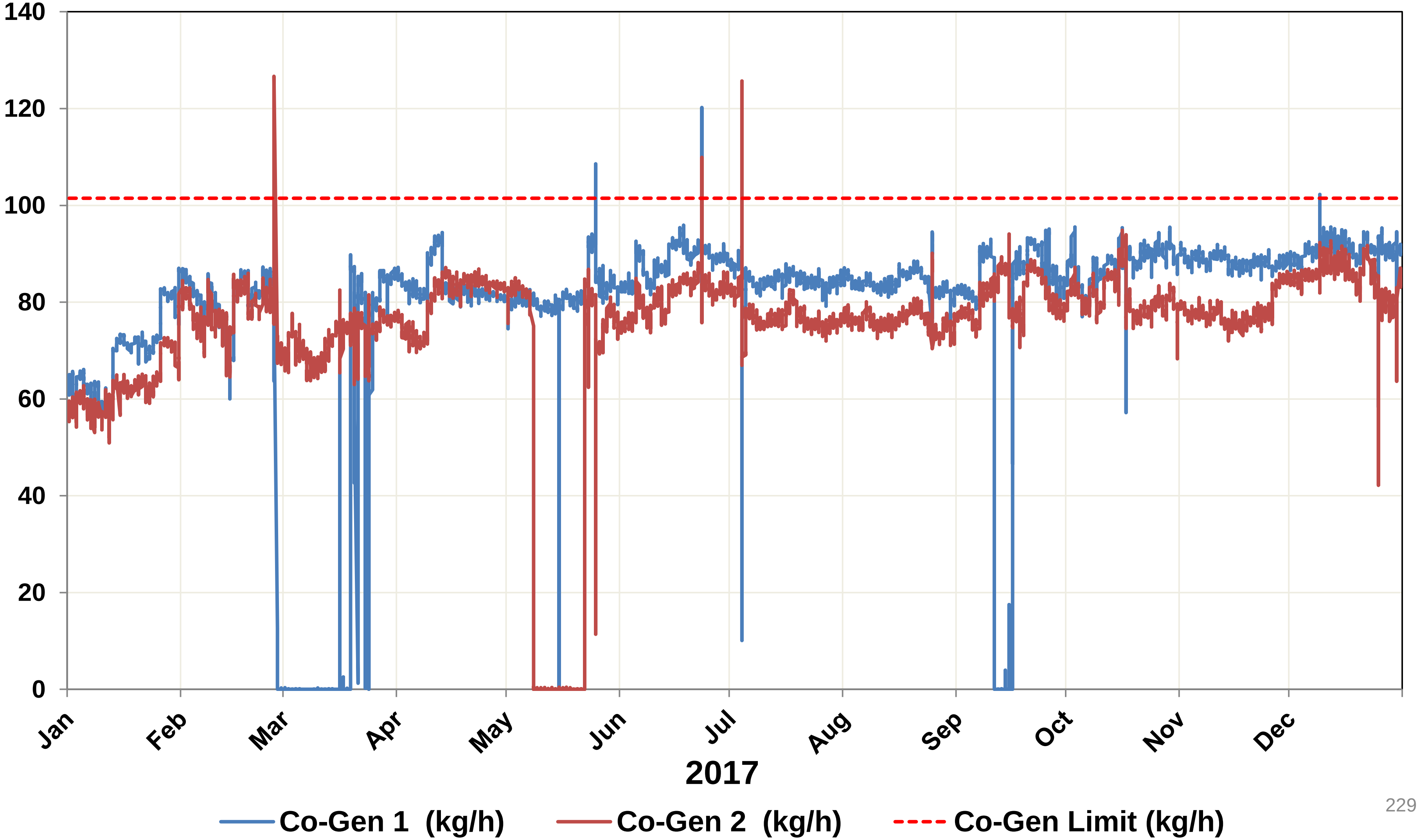


Hourly CEMS NOx – OTSG's



Hourly CEMS NOx – Co-Gen's

- IPSH steam was experiencing an upset during the1-hr readings above the limit. After a 4-hr avg was applied during his time, NO_X emissions were not in contravention of the approval.



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 (12)
  - Satisfactory Inspections (6)
  - Unsatisfactory Inspections (6):

Unsatisfactory Inspection Findings	Status
February 8, 2017 - AER performed an Oil Facility site inspection, location 10-36-85-7W4. INSP ID 459781. Inspection resulted in an unsatisfactory rating. Deficiencies were noted under Manual 001: Facility and Well Site Inspections.	Compliance achieved August 3, 2017
February 13, 2017 - AER performed a Well Site site inspection, location 100/9-12-86-7W4/00 Lic# 0349621. INSP ID 459658. Inspection resulted in an unsatisfactory rating. February 22, 2018 - inspection deficiency was moved under the water act results tree instead of the water measurement. February 13, 2017 - AER performed a well site site inspection, location 104/9-28-85-6W4/00 Lic# 0460151. INSP ID 459670. Inspection resulted in an unsatisfactory rating. Deficiencies were noted under Manual 001: Facility and Well Site Inspections. February 13, 2017 - AER performed a well site site inspection, location 103/9-28-85-6W4/00 Lic# 0282523. INSP ID 459674. Inspection resulted in an unsatisfactory rating. Deficiencies were noted under Manual 001: Facility and Well Site Inspections.	Compliance achieved March 14, 2017
December 5, 2017 - AER performed an inspection on facility 7-31-85-6W4 F32978 INSP #469483, relevant to Nexen reporting vented volumes that had increased in H2S concentration in May 2017 compared to prior reporting. The inspection received an unsatisfactory rating due to a non-compliance issue in the vented vapor not being representative of the actual concentrations of the release per EPEA regulations.	Compliance achieved February 1, 2018 Action plan submitted to AER via email
December 18, 2017 - A low risk unsatisfactory inspection finding was issued by the AER for late notification of the fresh water leak on discharge header on November 22, 2017.	Compliance achieved February 15, 2018

- Audit (1)
  - November 17, 2017 - AER selected to audit the Technical supporting documentation for the licence application of well 05P03 108/03-32-085-06W4/00 Lic# 0486030. The technical audit covered section 7.12.3 to section 7.13.4 of the Directive 56 section 7. The audit completion was confirmed on January 23, 2018.

Compliance Discussion

Notices of Non-Compliance and Voluntary Self Disclosures	Status
Notice of Noncompliance Late reporting of Benzene Dehydrator Inventory List (AER) May 5, 2017.	Compliance achieved May 17, 2017
Notice of Noncompliance On December 13, 2017 the Alberta Energy Regulator (AER) issued Nexen a notice of Non-compliance under Directive 013: Suspension Requirements for Wells; for failure to perform the required downhole work to suspend well 109/07-01-086-07W4/0 Lic# 0340666; within the required 12 month period.	Compliance achieved March 27, 2018
Voluntary Self Disclosure On March 29, 2017, Nexen requested an extension to bring 16 pipelines that had previously been part of the AER Suspension Order, issued August 29, 2015, into compliance. In addition, on the same day, Nexen voluntarily self-disclosed that 36 additional inactive pipeline segments were non-compliant. The 52 lines were non-compliant under AER's Manual 005 (Pipeline Inspections) and require abandonment or suspension work and associated licence amendments to bring them into compliance.	Nexen remains on track to complete the associated work by July 2018, as agreed with the AER, and is, in the meantime, providing monthly status reports to the AER.

Environmental Regulatory Compliance

Regulatory/Permit Violations Summary	2013	2014	2015	2016	2017
	98	52	47	83	62

- 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 venting release incidents incurred in 2017 as a result of the condensate, chemical trails conducted.

Reportable Spill Summary	2013		2014		2015		2016		2017	
	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)	Events	Volume (m^3)
	20	548	17	1,551	26	5,937	7	120	5	37.6

- 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

- February 3, 2017 - 11.6 m^3 Low Pressure Steam condensate leak.
- August 8, 2017 - 2 m^3 Glycol leaking in Central Processing Facility.
- September 11, 2017 – 4 m^3 Steam condensate leak.
- November 22, 2017 – 12 m^3 Fresh Water leak from 8100-E-009/12.
- December 1, 2017 – 8 m^3 Steam condensate leak from line rupture.

AER Scheme Approval

- Amendments Approved in 2017:
  - Pad 14 and 5 MOP Injection Pressure and Tapered Schedule Extension – January 12, 2017.
  - Q-Channel Groundwater Management Plan - March 8, 2017.
  - Pad 6 and 10 Infill Well and Commingling Application - March 8, 2017.
  - Residual Emulsion Trial - March 22, 2017.
  - Pad 5 Infill Well Extensions for 3 wells - April 7, 2017.
  - Thermal Compatibility Review Pad 3, 6 and 10 - May 26, 2017.
  - Tapered MOP Pads 14 and 15 – September 13, 2017.
  - Variation to Directive 081 - Water Disposal Limits - October 30, 2017.
  - Long Lake Southwest Modifications - December 8, 2017.

Subsection 3.1.2 (6b)

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
  - Wildlife monitoring
  - Wetland monitoring
  - Source emission and ambient air monitoring
  - Conservation and reclamation plans

- Exception: Soil monitoring extension granted by AER to November 2018.

Subsection 3.1.2 (6c)

Environmental Summary Monitoring Programs

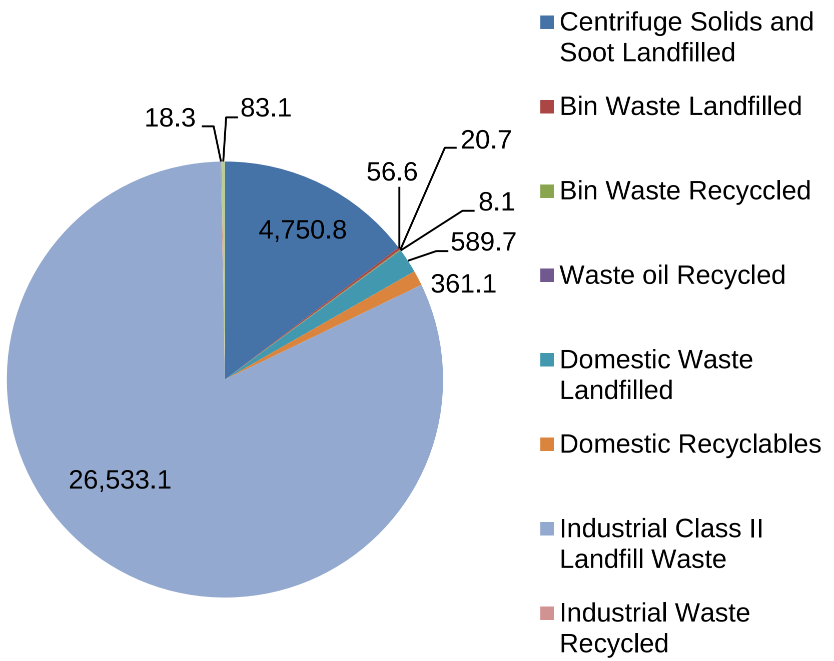
- Funded the regional Joint Oil Sands Monitoring (JOSM).
- Participation in regional stakeholder committees:
  - WBEA;
  - Alberta Biodiversity Monitoring Institute (ABMI);
  - Ecological Monitoring Committee for the Lower Athabasca (EMCLA).

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
Centrifuge Solids and Soot Landfill	4,751
Bin Waste Landfill	57
Bin Waste Recycled	21
Waste oil Recycled	8
Total	**4,836**
Non-Hazardous Waste	
Domestic Waste Landfill	590
Domestic Recyclables	361
Industrial Class II Landfill Waste	26,533
Industrial Waste Recycled	18
Liquid Waste (Disposal Well/Cavern)	83
Total	**27,585**
Grand Total (Hazardous/DOW + Non-Hazardous/Non-DOW Waste)	**32,421**



Similar to the previous years, the quantity of the water disposed down Nexen Long Lake Class Ib disposal wells is not included as it is reported in separate slides.

Future Plans - Surface

- The Upgrader will remain shut-in until final decision on the repair/start-up is made.
- Engineering is progressing on K1A pipeline replacement.

Appendix

Well Pad Performance
Subsection 3.1.7(h)
Long Lake

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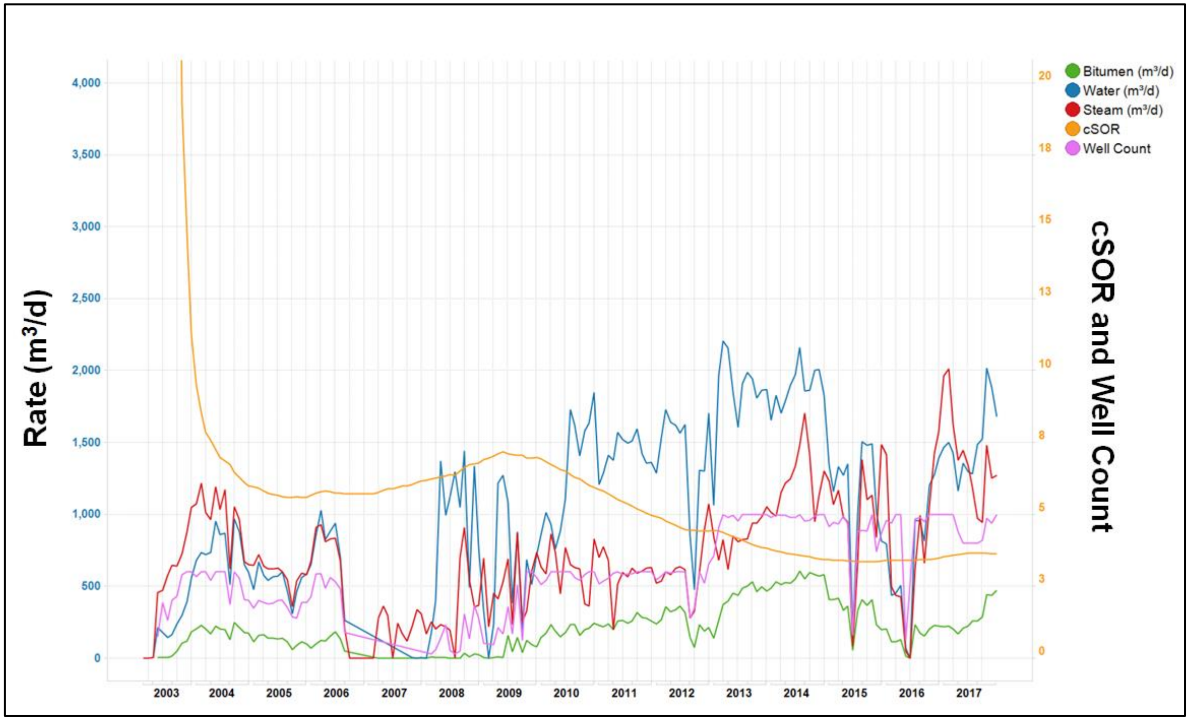
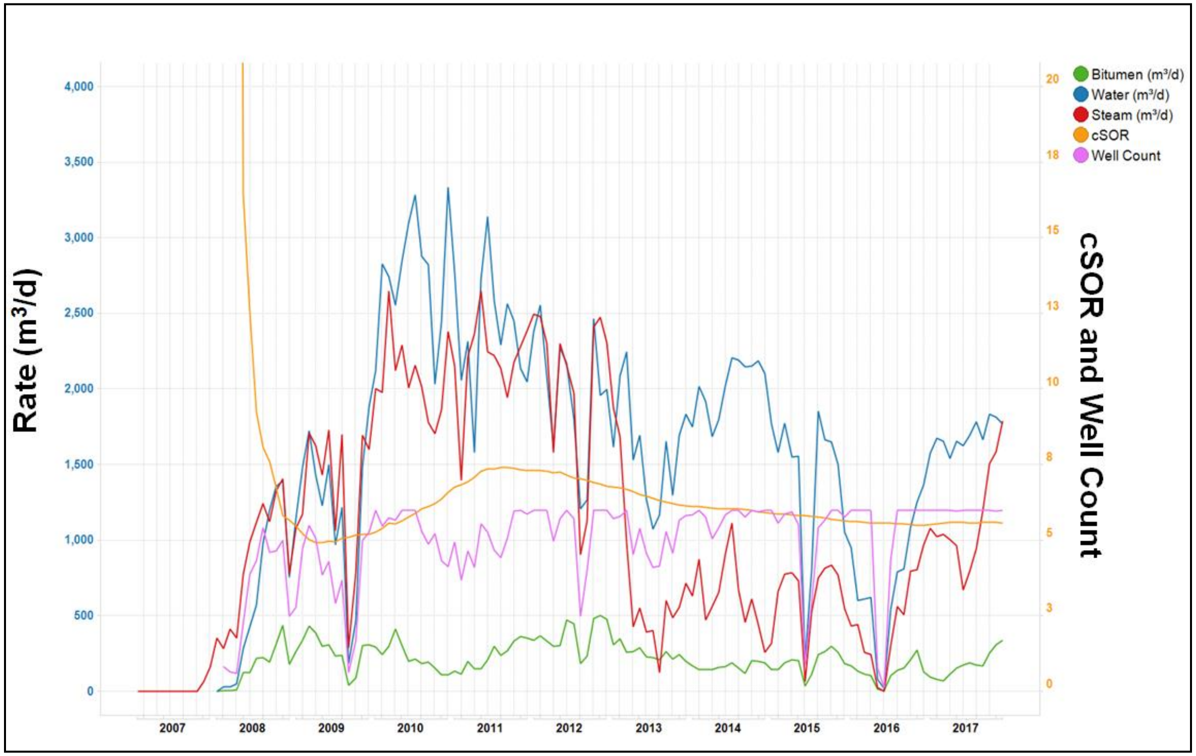
Pad 1 Production Summary



- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 1075 E^3m^3 (RF 38%)

- All 5 wells on ESP
- Producers are showing strong performance after:
  - Increasing emulsion withrdrawal to the pre-wildfire rates
  - Increasing oil rate due to stable operations and improving oil cut in base wells
- cSOR is stable
- At YE, injection pressures were ~1,480-1,600 kPa

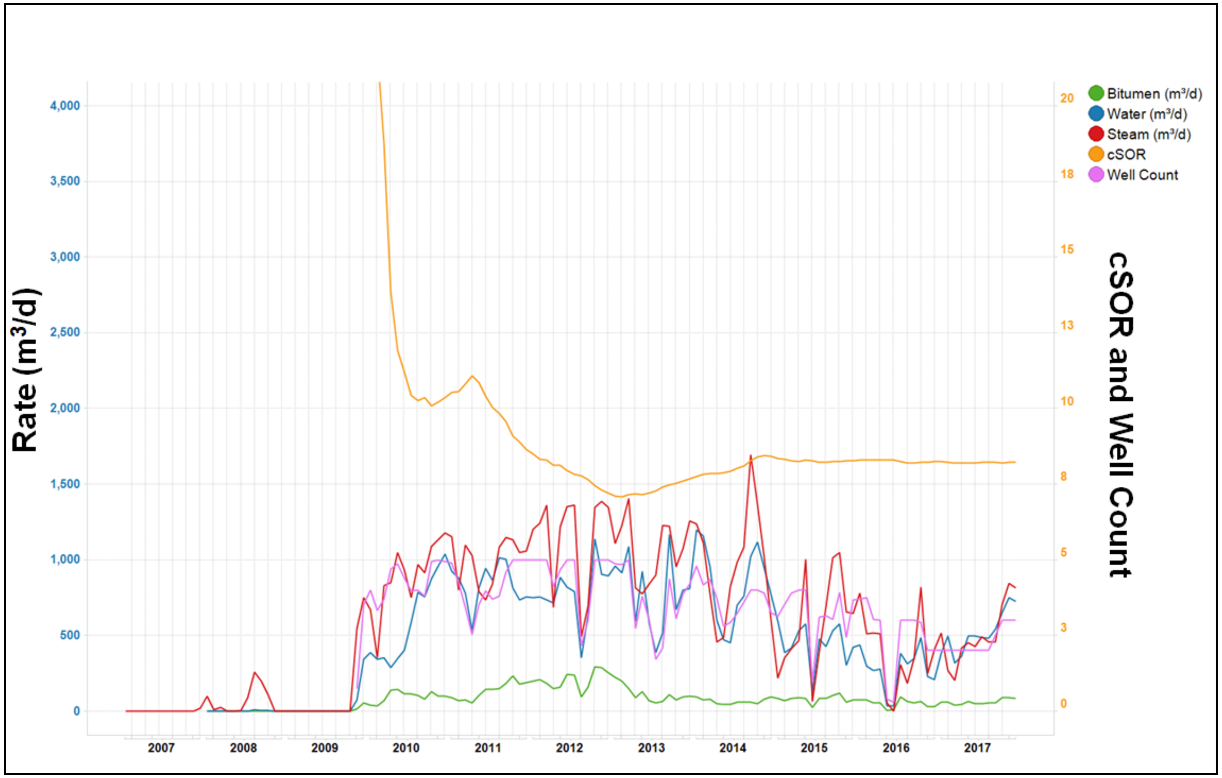
Pad 2NE Production Summary



- All 6 wells on ESP
- Steam injection resumed on 02S04, 02S05, and 02S06 in late 2017
- Production rates increasing in late 2017 due to steam reintroduction on the aforementioned well pairs
- At YE, injection pressures were ~1,450 – 1,600 kPa

- Six well pairs (02P01 to 02P06)
- Cumulative production of 792 E^3m^3 (RF 30%)

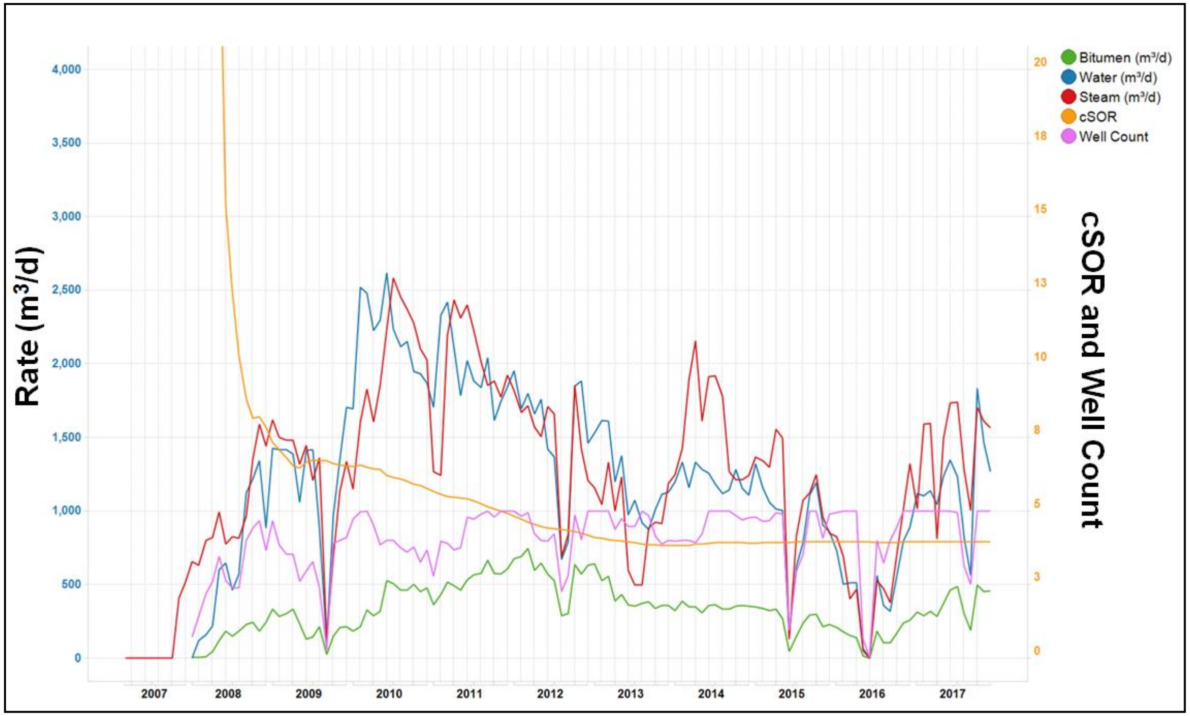
Pad 2SE Production Summary



- Five well pairs (02P07 to 02P011)
- Cumulative production of 298 E^3m^3 (RF 18%)

- 2P08 - 2P10 on ESP
- 2P07 on PCP and currently SI due to worn pump
- 02P11 SI due to liner failure in 2014
- Injection of residual emulsion occurred on 2S10 in 2017
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,550 – 1,575 kPa

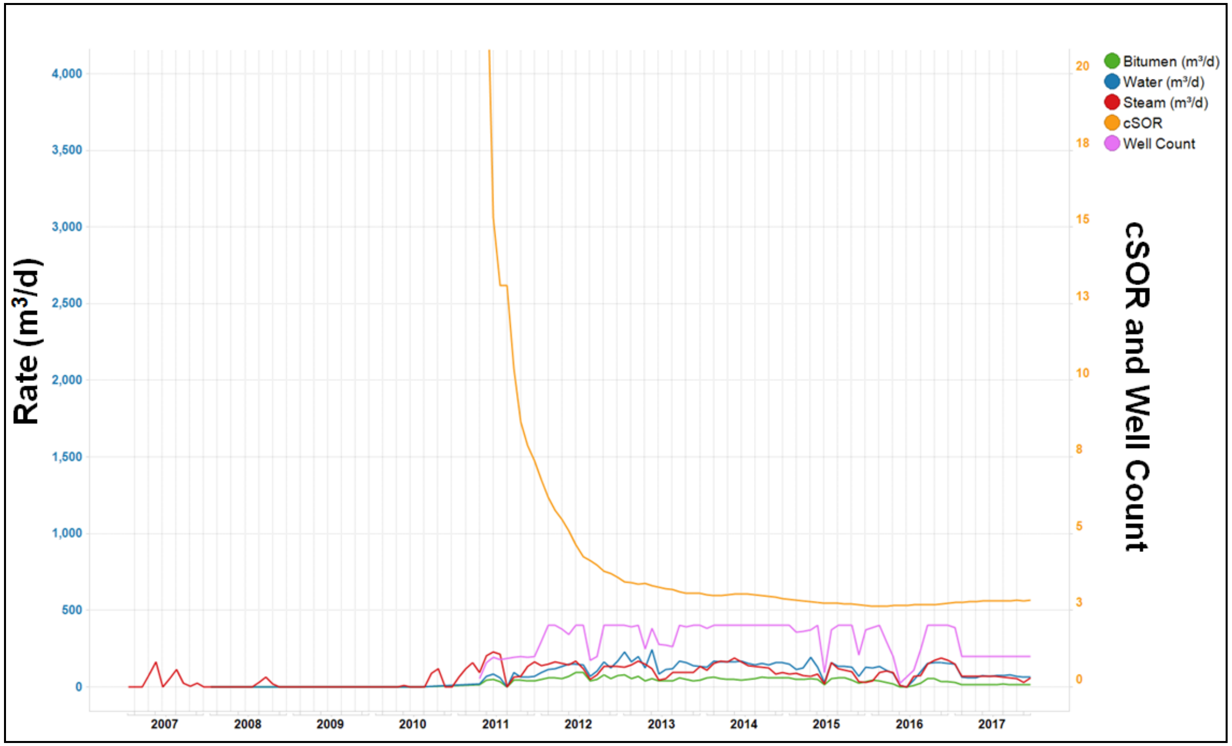
Pad 3 Production Summary



- Five well pairs (03P01 to 03P05)
- Cumulative production of 1,237 E^3m^3 (RF 36%)

- All 5 wells on ESP
- Producers are showing strong performance and emulsion and oil rates have been improving in 2017
- Slight improvement has been observed in Cumulative Steam Oil Ratio due to applying optimization plans in a stable operating condition.
- At YE, injection pressures were ~1,490-1,600 kPa

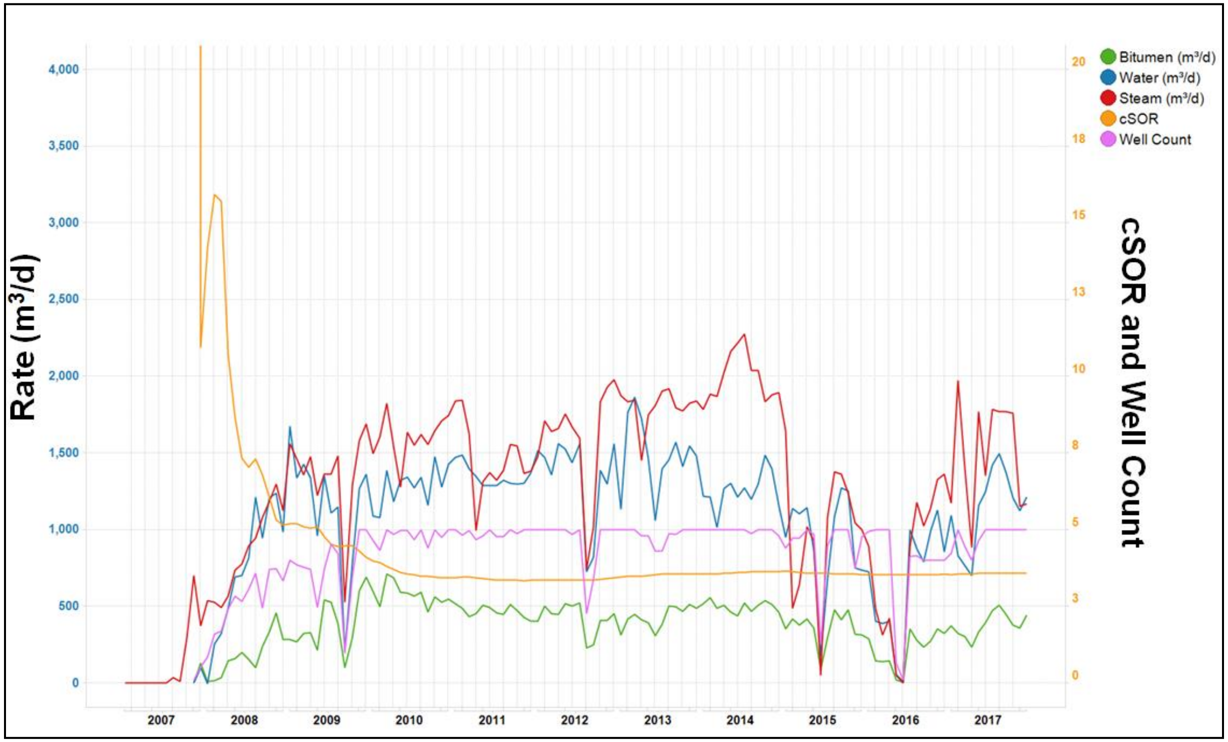
Pad 4 Production Summary



- 1 well on ESP (4P01)
- ESP was failed in 4P02 in January 2017. ESP replacement is not currently economically justifiable due to low oil production rate.
- Production performance of 4P01 has remained unchanged in 2017.
- At YE, injection pressures were ~1,425kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 106 E^3m^3 (RF 53%)

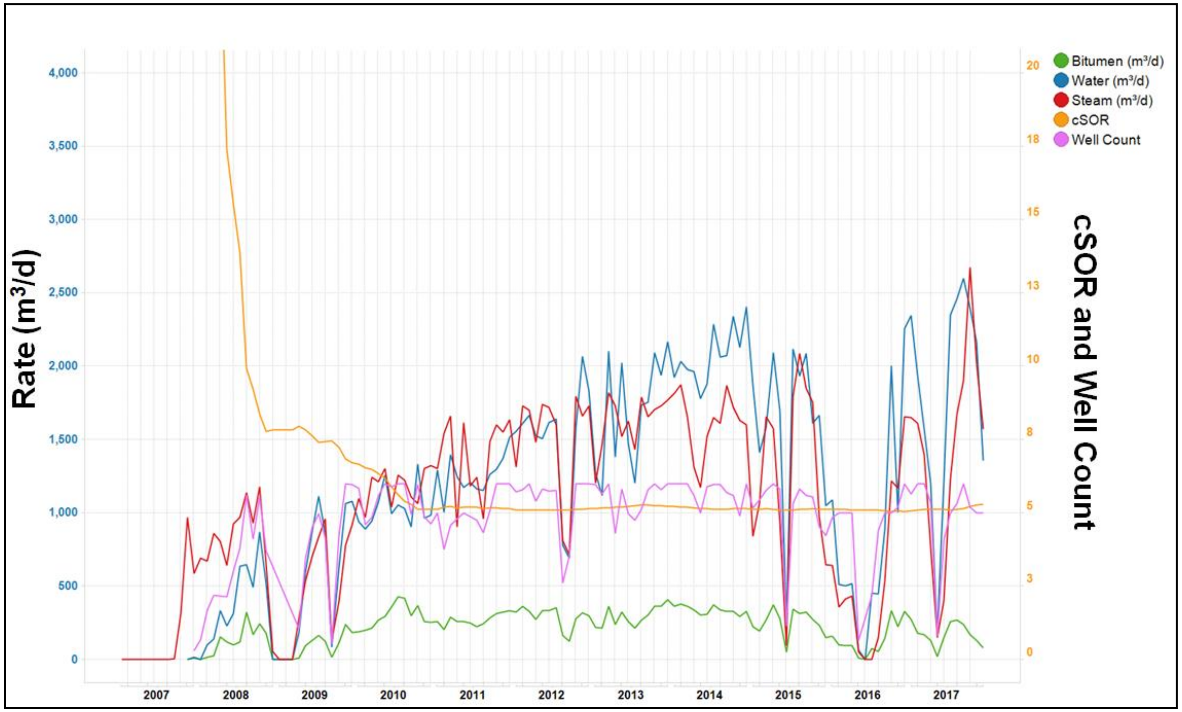
Pad 5 Production Summary



- All 5 wells on ESP
- Producers are showing strong performance after maximizing emulsion rates resulting overall strong performance in 2017.
- At YE, injection pressures were ~1,600-1,650 kPa

- Five well pairs (05P01 to 05P05)
- Cumulative production of 1,431 E^3m^3 (RF 41%)

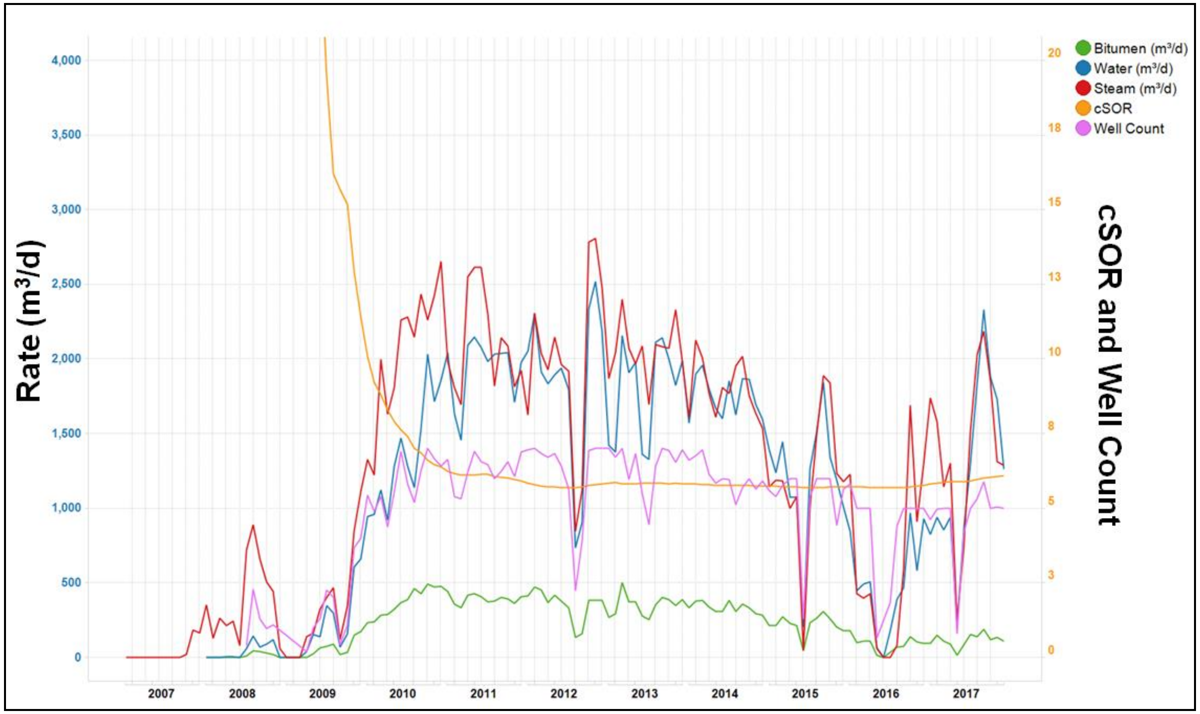
Pad 6N Production Summary



- All wells on ESP
- Pad Outage for Group Separator/Pop Tank Inspection from May 5 to Jun 7, 2017
- Unbalanced operation strategy after wildfire outage has impacted production
- At YE, injection pressures were ~1,710–1,915 kPa

- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 825 E^3m^3 (RF 21%)

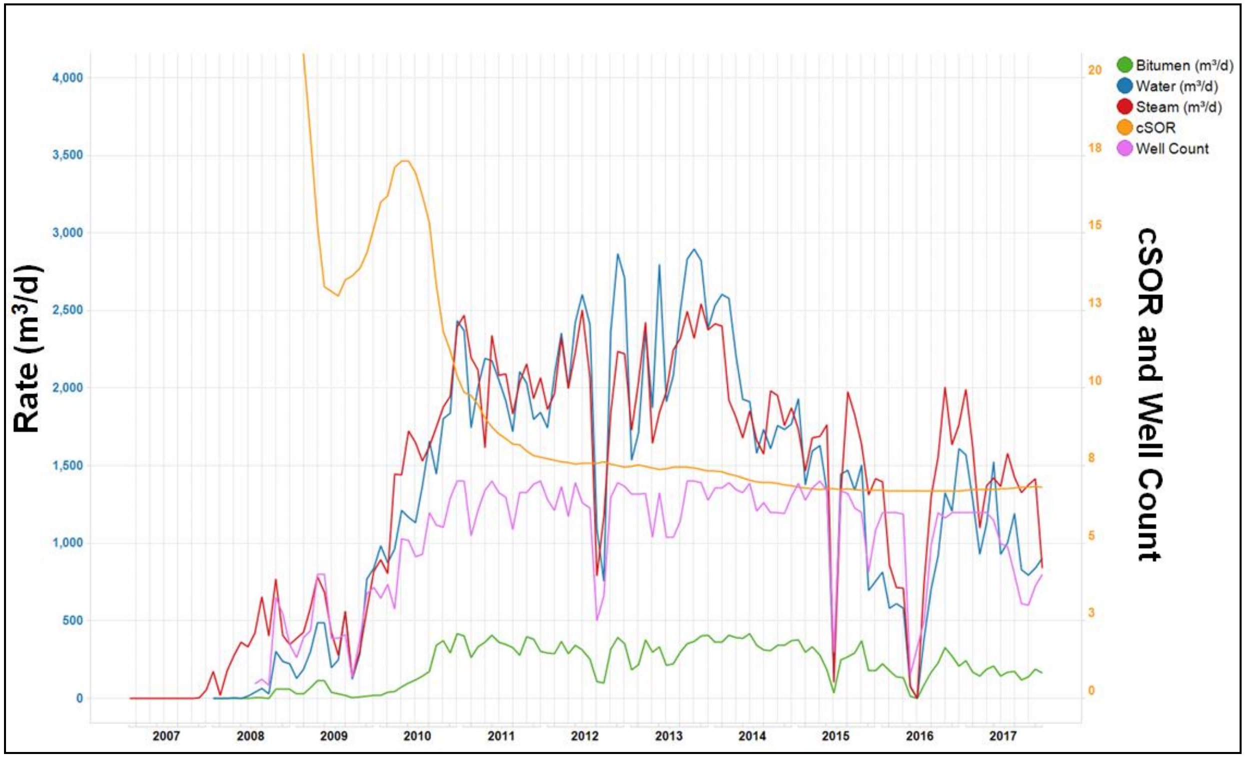
Pad 6W Production Summary



- Seven well pairs (06P06 to 06P12)
- Cumulative production of 837 E^3m^3 (RF 33%)

- All 7 wells on ESP
- Pad Outage for Group Separator/Pop Tank Inspection from May 5 to Jun 7, 2017
- 2017 ESPs replacements occurred as campaigns, therefore some wells were shut-in 1 - 5 months
- Several liner failures historically
- 6P12 shut in due to liner failure in 2014
- At YE, injection pressures were ~1,515–1,850 kPa

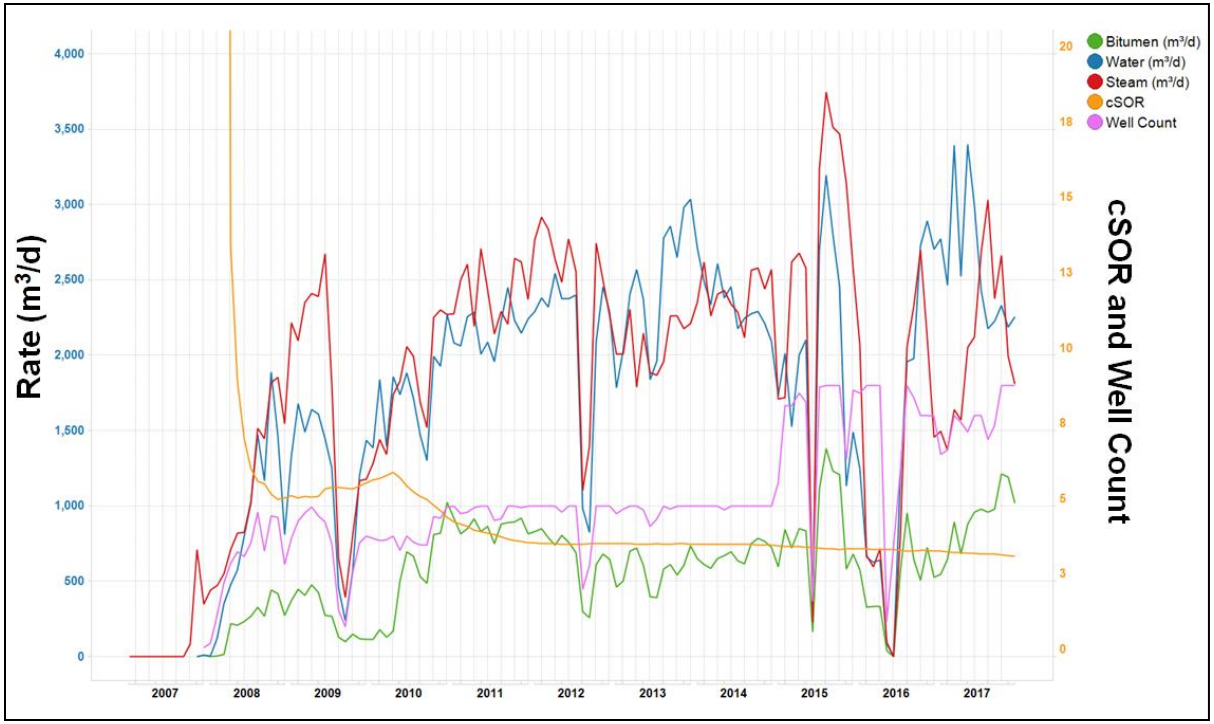
Pad 7E Production Summary



- Seven well pairs (07P06 to 07P12)
- Cumulative production of 778 E^3m^3 (RF 27%)

- 6 wells on ESP
- 7P07 liner failure, installed ICD in Dec2017
- 7P12 shut in due to liner failure
- NCG co-injection has not been restarted since 2015 turnaround
- At YE, injection pressures were ~1,560–1,960 kPa

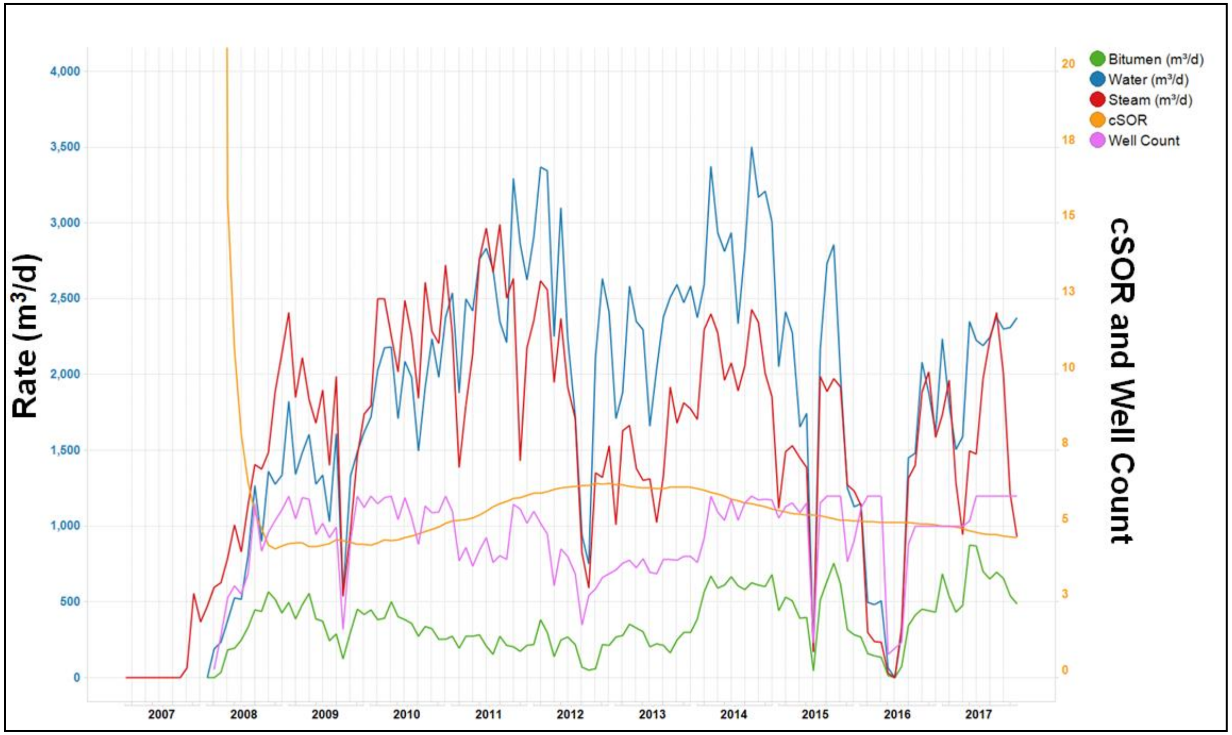
Pad 7N Production Summary



- Five well pairs (07P01 to 07P05)
- Four infill producer wells (10P14 to 10P17)
- Cumulative production of 2,196 E^3m^3 (RF 58%)

- All 9 wells on ESP
- Infill producer wells ramped up in Q1 2015 and have exhibited strong performance
- Oil cut recovered back to pre 2016 wild fire level
- 7P4 plugged back by ~240m due to a liner failure in 2017
- Increased steam injection to support infill producer wells and neighboring Pad 8
- At YE, injection pressures were ~1,670 – 1,950 kPa

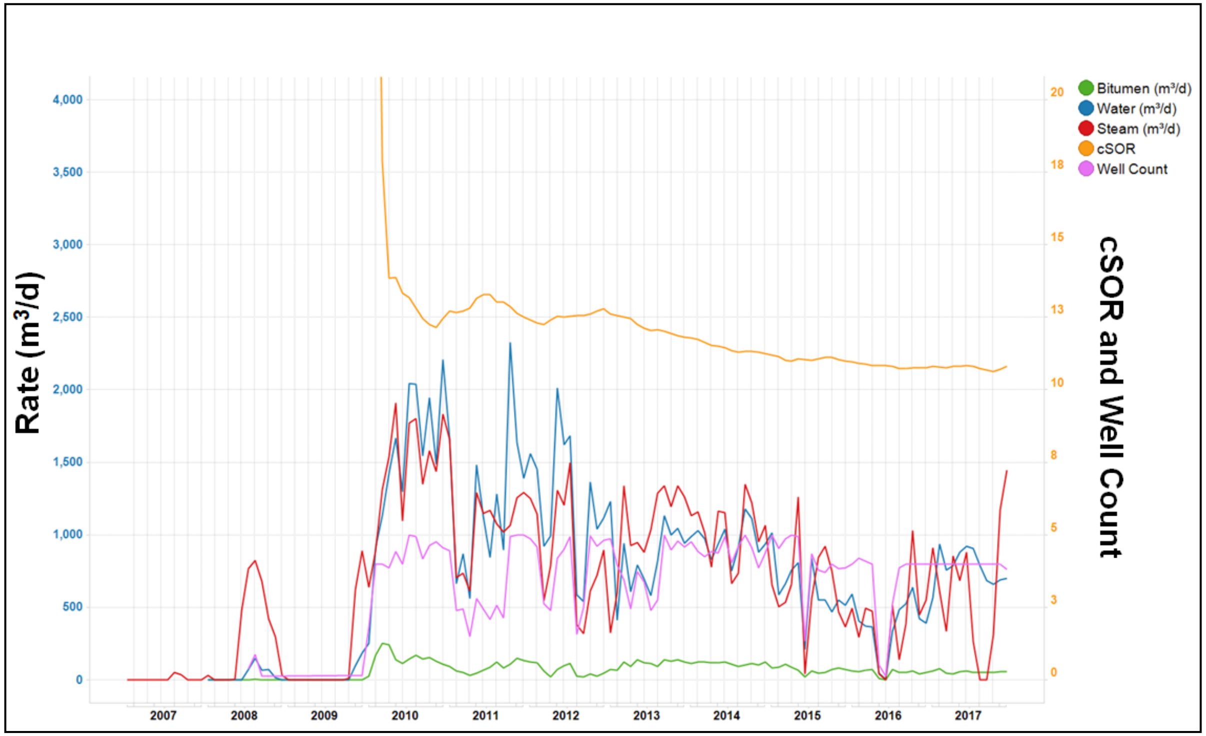
Pad 8 Production Summary



- Six well pairs (08P01 to 08P06)
- Cumulative production of 1,328 E^3m^3 (RF 39%)

- All 6 wells on ESP
- 08S06 failed in 2015, no observed negative impact to 08P06 production
- ICD's installed on 08P03 in 2015
- Steam injection reduced in account for material balance
- 4 infill wells drilled in Q4 2017
- At YE, injection pressures were ~1,650–1,730 kPa

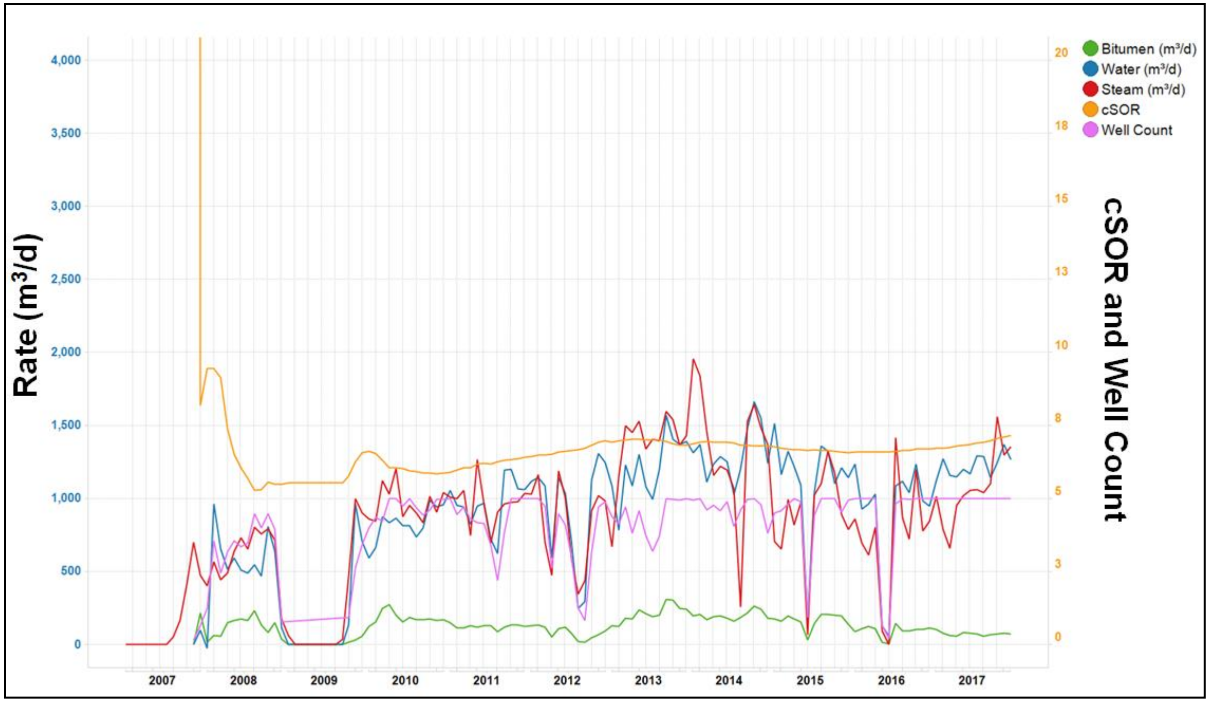
Pad 9NE Production Summary



- Five well pairs (09P06 to 09P10)
- Cumulative production of 256 E^3m^3 (RF 15%)

- All 5 wells on ESP
- 9P06 SI due to insufficient inflow with current reservoir pressure
- Production rates impacted by pressure blowdown trial
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,635 – 1,650 kPa

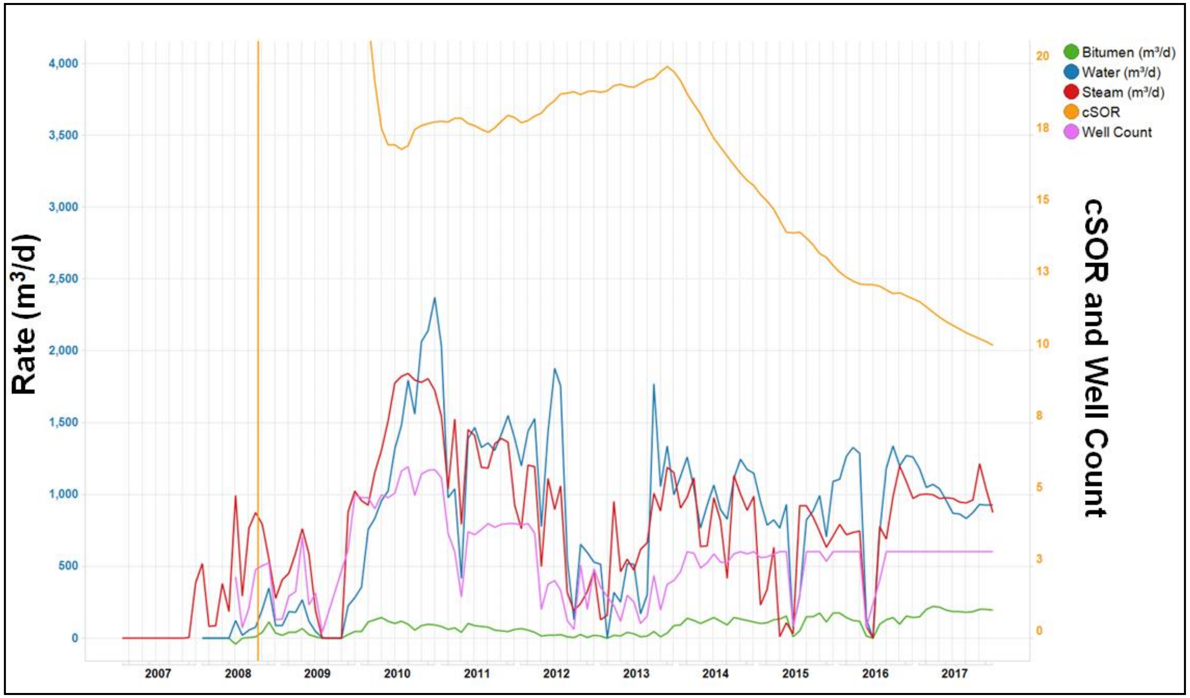
Pad 9W Production Summary



- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- Oil rate declined after Wildfire outage
- Unstable operation on 9P4 and 9P5 due to low priority
- At YE, injection pressures were ~1,840 - 1,980kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 465 E^3m^3 (RF 24%)

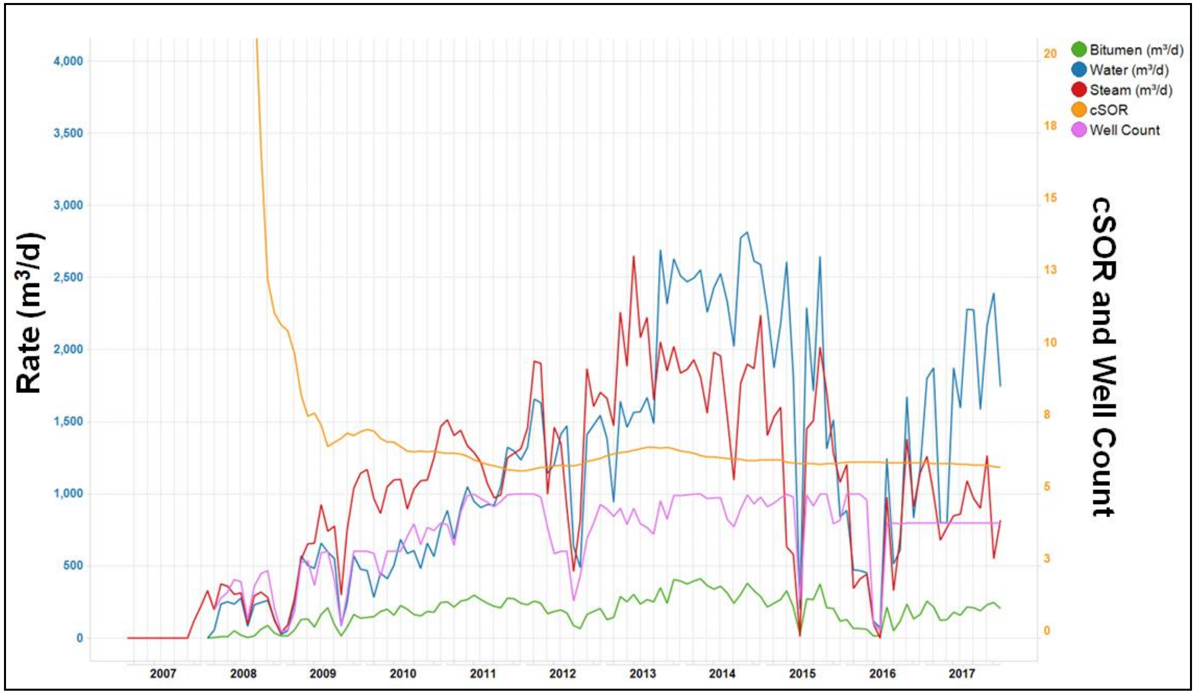
Pad 10N Production Summary



- All producing wells on gas lift
- Steady operation strategy got with a stable production performance
- At YE, injection pressures were ~2,000 kPa

- Three well pairs producing (10P10 to 10P12)
- Cumulative production of $190E^3m^3$ (RF 8%)

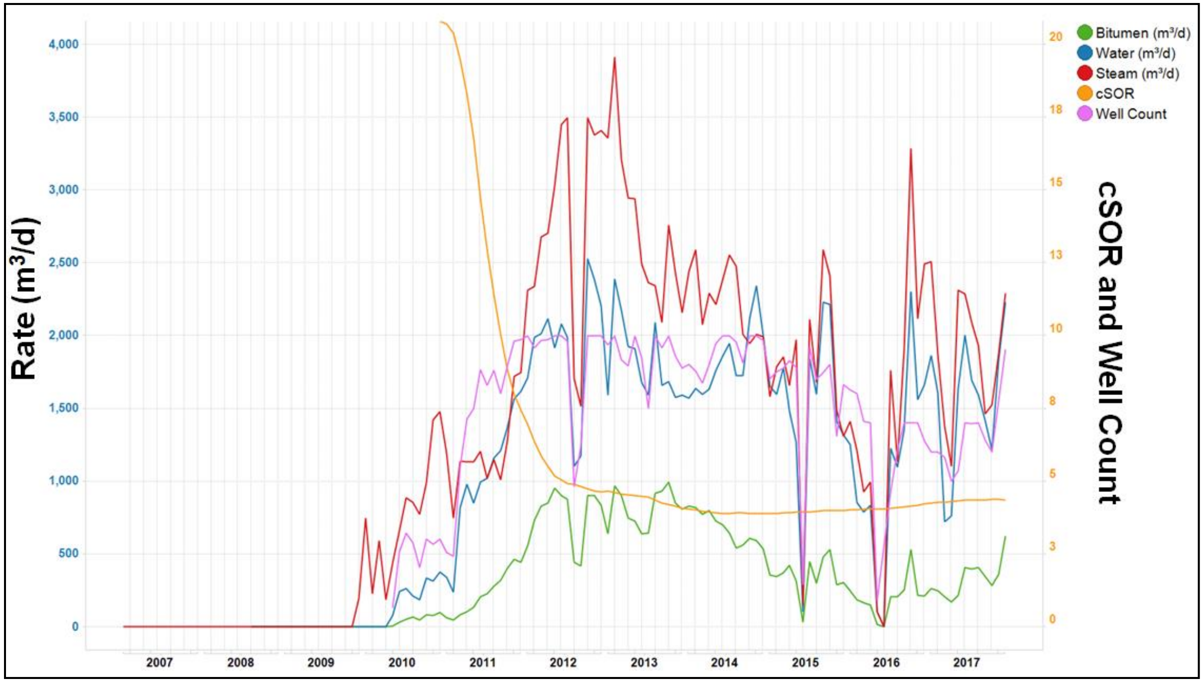
Pad 10W Production Summary



- Pad continued to be impacted by top water
- 10P04 was plugged back in 2014, currently shut in as potential re-failure
- At YE, injection pressures were ~1,745–1,850 kPa

- Five well pairs (10P01 to 10P05)
- Cumulative production of 692 E^3m^3 (RF 26%)

Pad 11 Production Summary



- All 10 wells are on ESP
- 11P08 restarted in 2017 and ramp back up to its pre shut in rate
- Failed ESPs replaced for 11P02, 110P3, 11P09, and 11P10 in 2017
- At YE, injection pressures were ~1,750–1,805 kPa

- Ten well pairs (11P01 to 11P10)
- Cumulative production of 1,242 E^3m^3 (RF 46%)

Pad 12 Production Summary

- All 9 wells are on ESP
- Strong performance post wildfire
- Surface pad constraints exist
- At YE, injection pressures were ~1,750 – 1,900 kPa

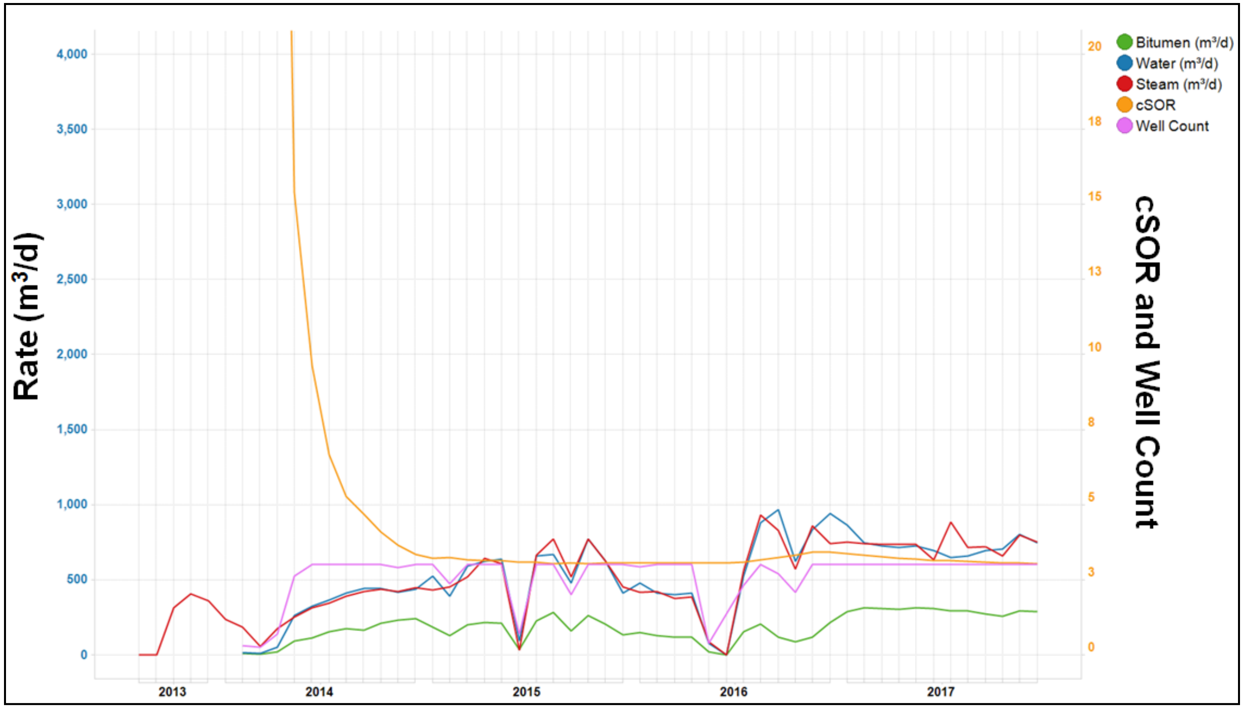
- Nine well pairs (12P01 to 12P09)
- Cumulative production of 800 E^3m^3 (RF 18%)

Pad 13 Production Summary

- All 9 wells are on ESP
- Strong performance post wildfire
- Surface pad constraints exist
- ES-SAGD project not currently operational
- At YE, injection pressures were ~1,700 –1,825 kPa

- Nine well pairs (13P01 to 13P09)
- Cumulative production of 1093 E^3m^3 (RF 25%)

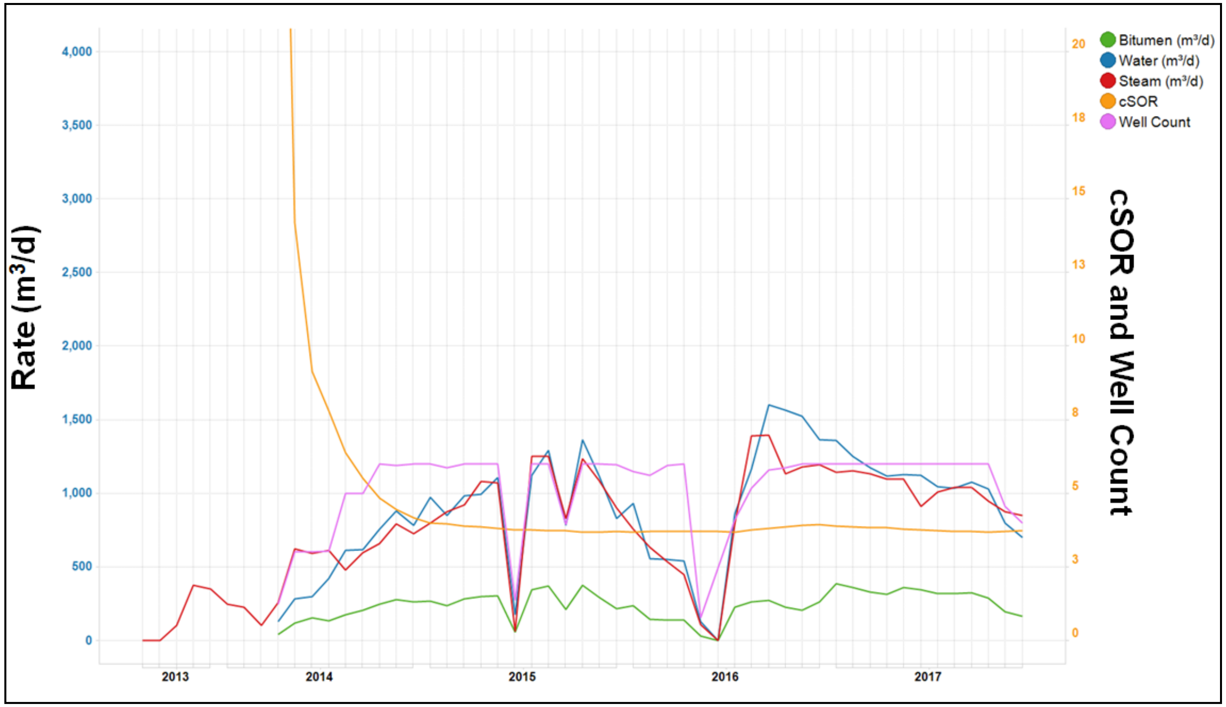
Pad 14N Production Summary



- All 3 wells on ESP
- Wells are stable, on plateau
- At YE, injection pressures were ~ 2,150kPa

- Three well pairs (14P05 to 14P07)
- Cumulative production of 262 E^3m^3 (RF 15%)

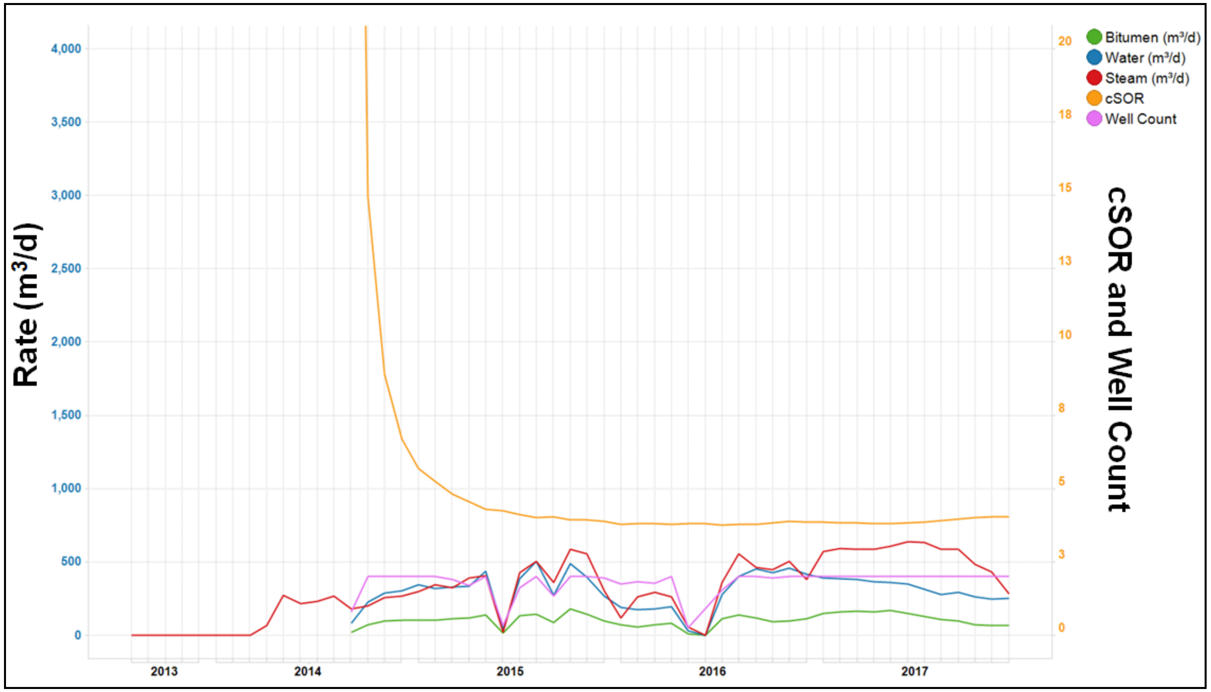
Pad 14/15E Production Summary



- All 6 wells on ESP
- 14P02 liner failure in 2017
- Wells demonstrating plateau
- At YE, injection pressures were ~1,880–2,100 kPa

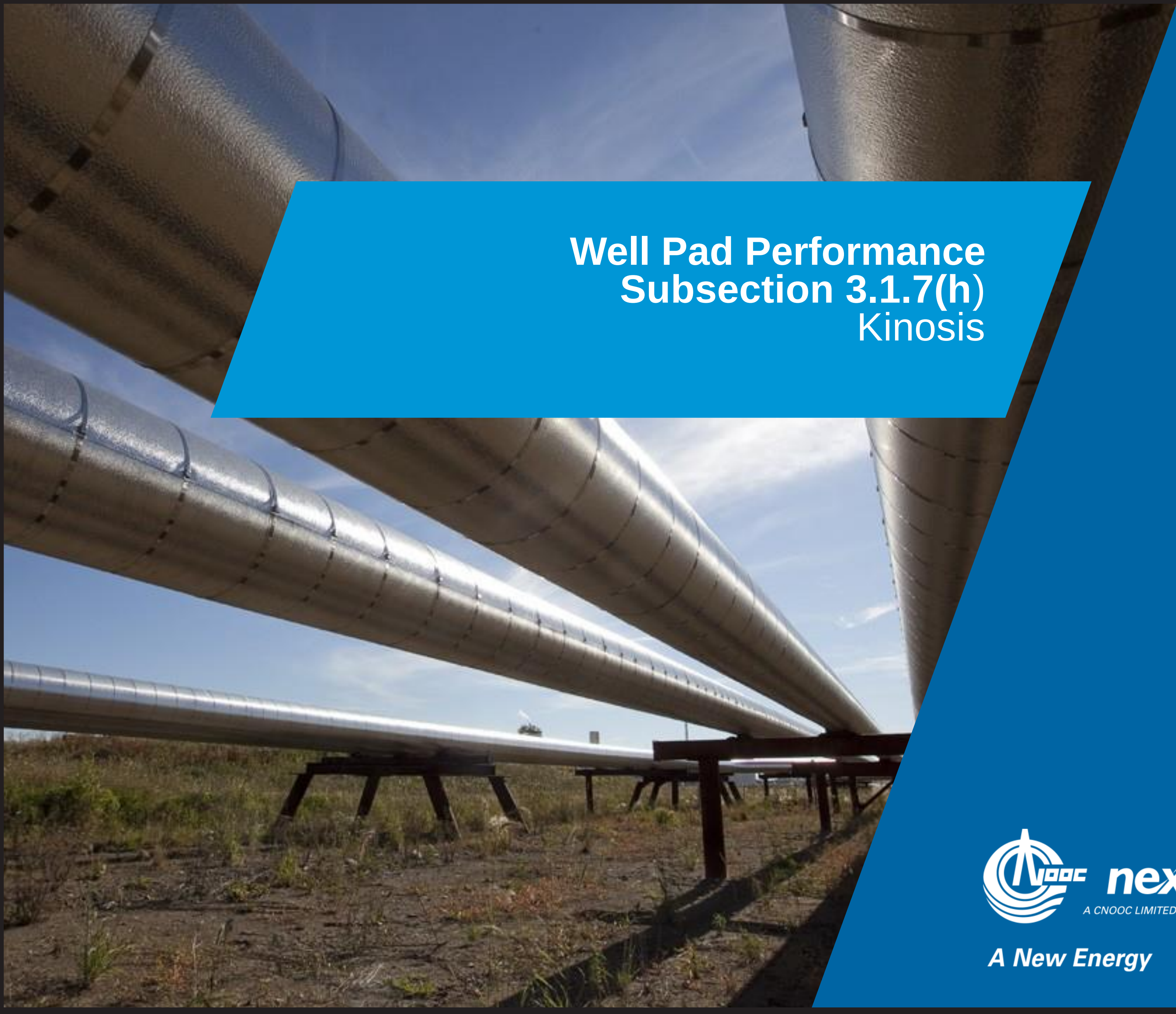
- Six well pairs (14P01 to 14P03 and 15P01 to 15P03)
- Cumulative production of 326 e^3m^3 (RF 18%)

Pad 15S Production Summary



- Both wells on ESP
- In Q4, wells impacted by workovers on offset wells
- At YE, injection pressures were ~ 1635 - 1,660kPa

- Two well pairs (15P04, 15P05)
- Cumulative production of 126 e^3m^3 (RF 17%)



Well Pad Performance
Subsection 3.1.7(h)
Kinosis

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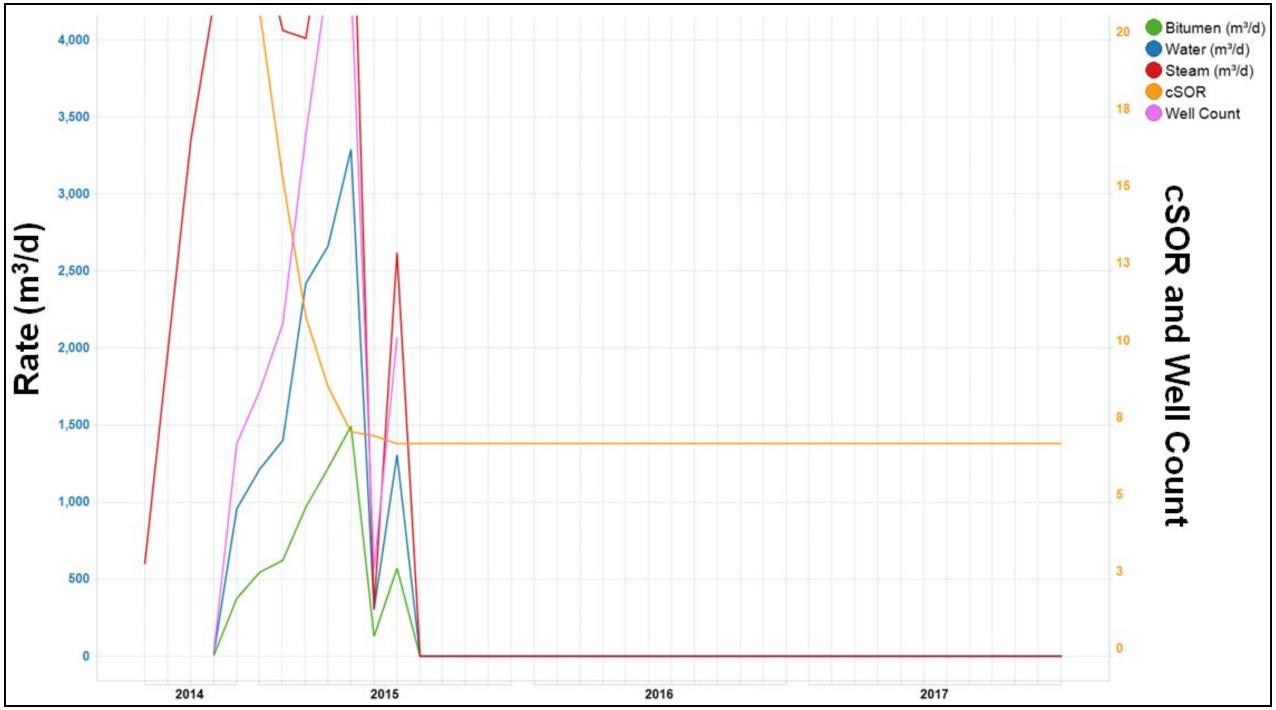
K1A Production Summary



- All wellpairs inactive
- K1P09 shut-in

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

Nexen 2017 AER RMR Presentation
P06860

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Role:

Date: