Long Lake – Annual Performance Presentation in accordance with Directive 054 (Subsurface)

April 8, 2015

Overview

- Overview
- Geology and Geosciences
  - Slides 8 to 66
- Kinosis Geology and Geosciences
  - Slides 67 to 89
- Drilling and Completions
  - Slides 90 to 105
- Scheme and Pad Performance
  - Slides 106 to 124
- Learnings, Trials, and Pilots (Slides 125 to 142)
  - Liners – Redrill and Repairs
  - Infill Projects – Learnings and Future Plans
- Observation Wells
  - Slides 143-146
- Future Plans

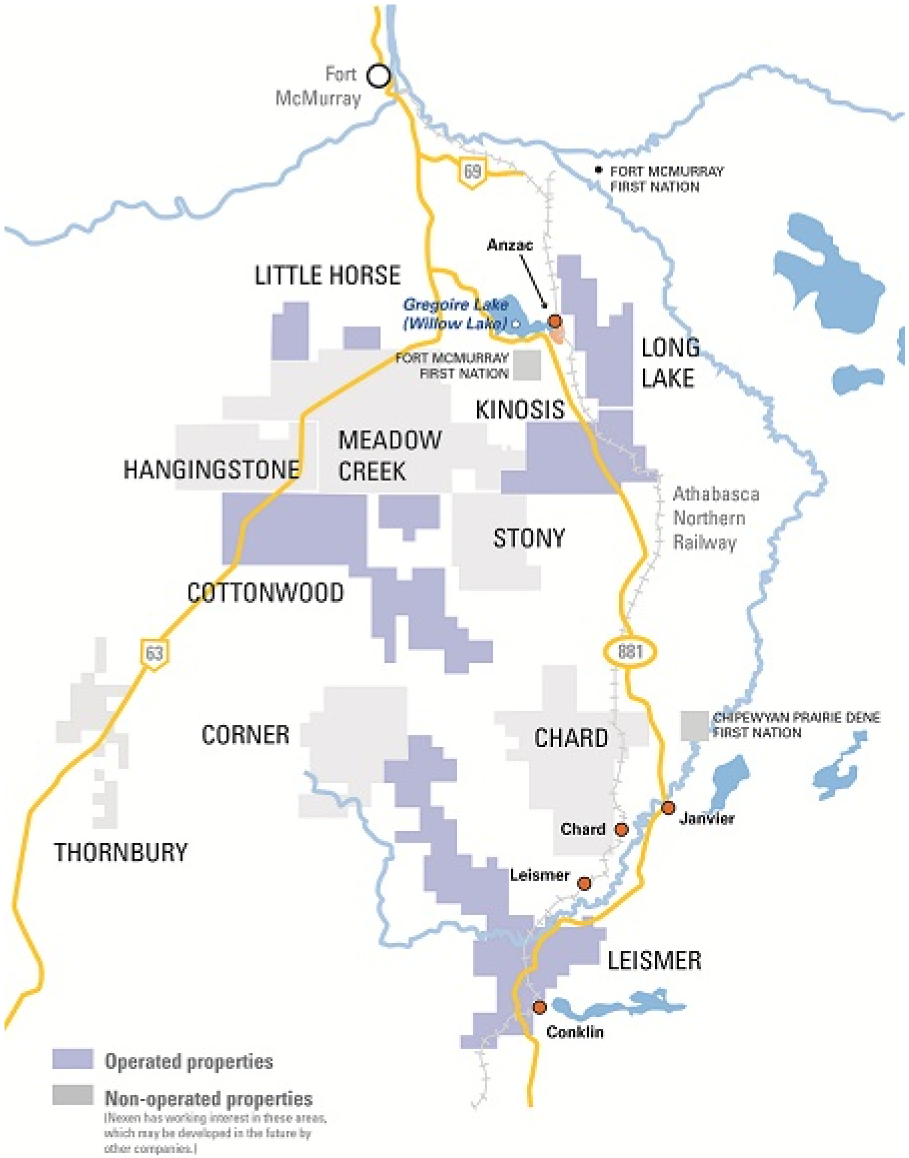
Purpose

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

Corporate Ownership

- Nexen Energy ULC 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.
- In February 2013, Nexen became a wholly-owned subsidiary of Chinese National Offshore Oil Company (CNOOC) Limited.
- Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.

Nexen Oil Sands Leases



Chronology of Oil Sands Operations

Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility
2003	Regulatory approvals for the commercial Long Lake Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial Long Lake 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 Long Lake South
2009	Start of operation of the Long Lake Upgrader
2010	Regulatory approvals for Pads 12 and 13
2012	First production from Pads 12 and 13
2012	Major turnaround for maintenance at CPF and Upgrader
2012	Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)
2012	Construction begins for K1A and Pads 14 and 15
2013	Increased production from Long Lake well pads, begin circulation at Pad 14
2014	K1A and Pads 14 and 15 started production

2014 Summary

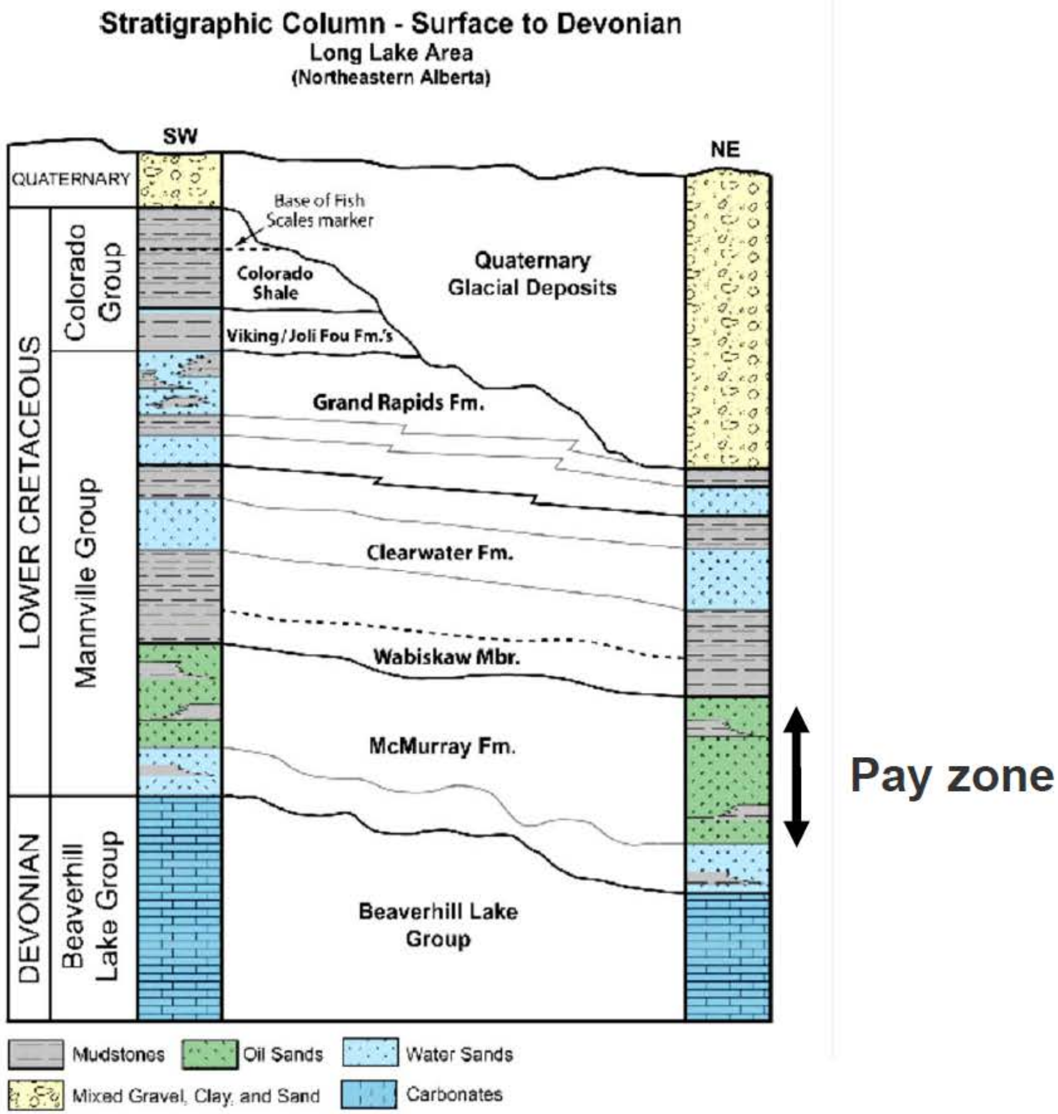
- Most successful year at Long Lake
  - Best ever safety record
  - Record production (42,900 bpd average) and significant increase over 2013
    - Improved plant reliability
    - Optimization of existing wells
    - Pads 14/15 ramping up above expectation
  - K1A completion and start-up
  - Completion and start-up of first Long Lake infill wells

Geology and Geosciences

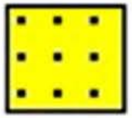
Stratigraphy

Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.



Nexen's Facies Code



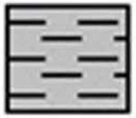
Sandstone .... Facies 1:
- clean crossbedded sandstone
- VSH 0 - 10%
- estuarine sands

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

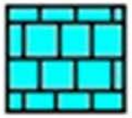
Breccia .... Facies 3:
- mud clast breccia
- sand supported and mud clast supported
- channel base facies

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



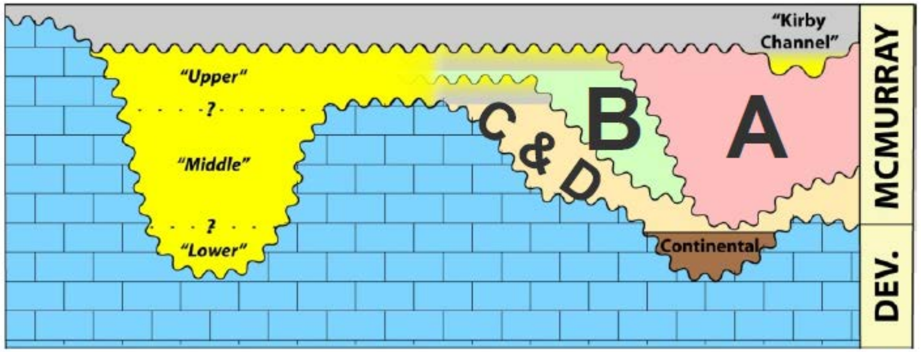
Mudstone .... Facies 6:
- flood plain deposits



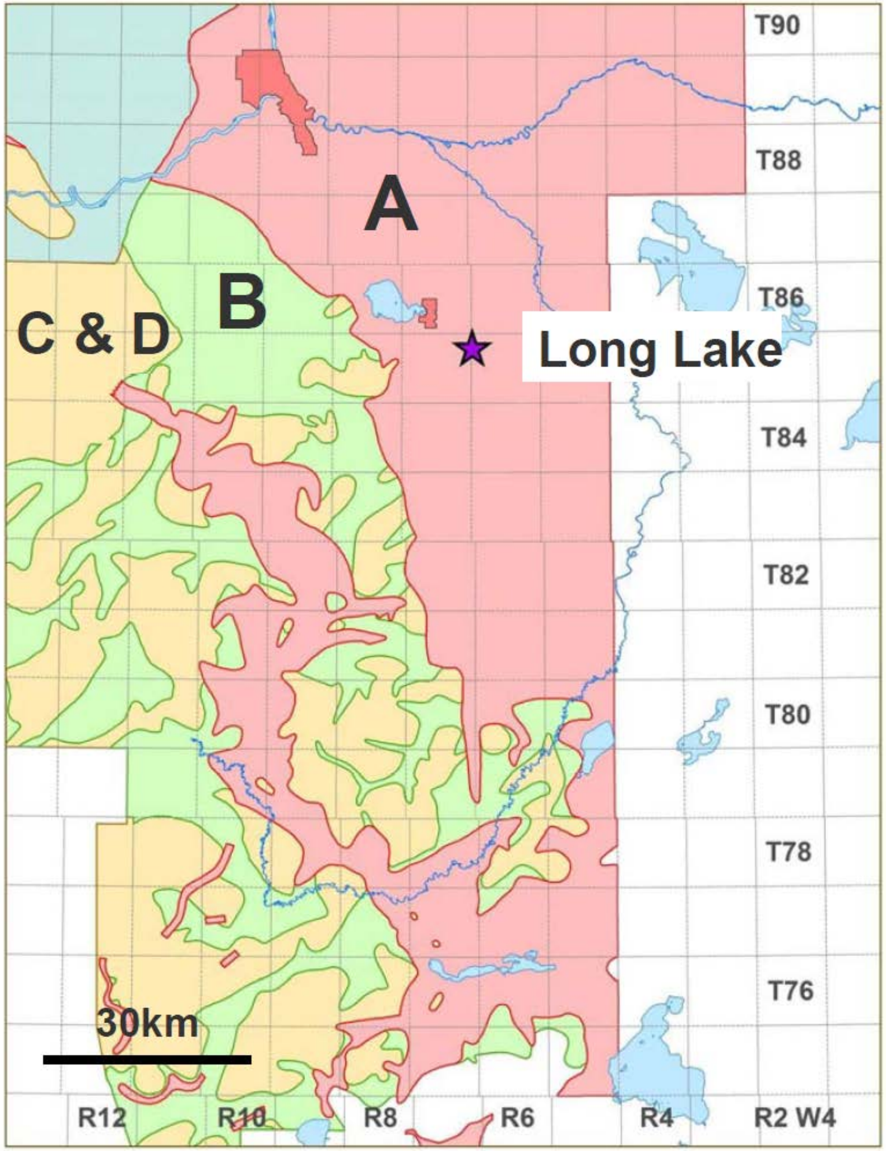
Limestone .... Facies 7:
- Devonian carbonates

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

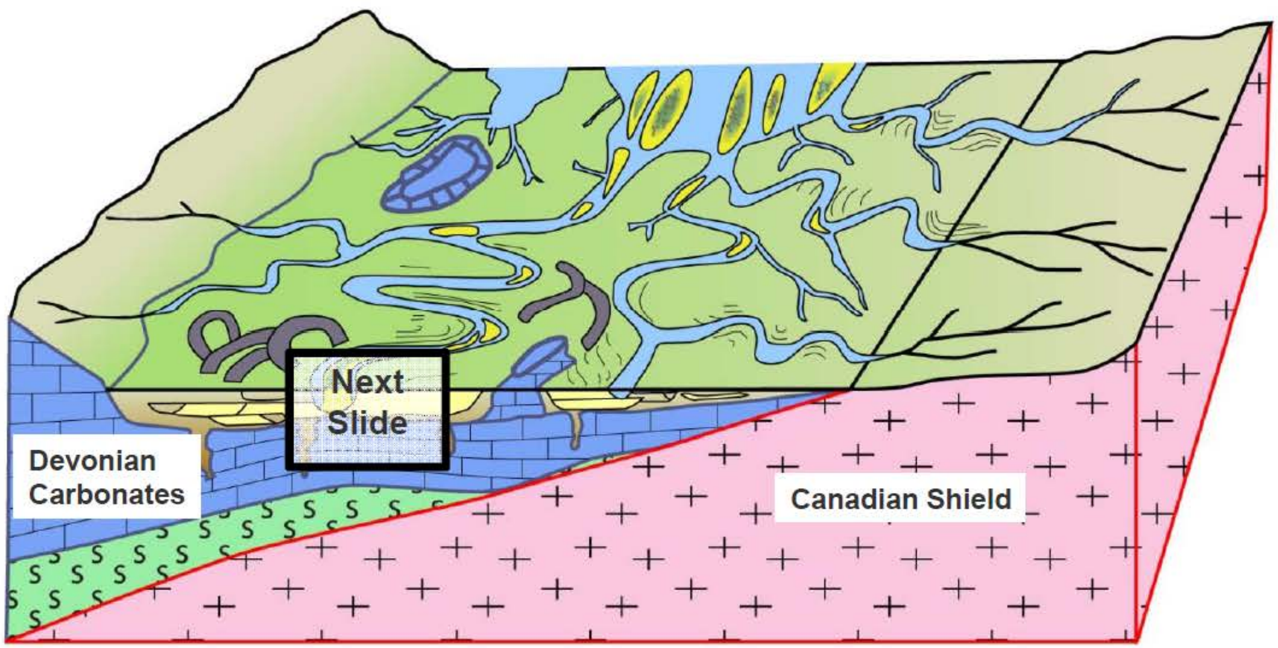


Jervey, 2003

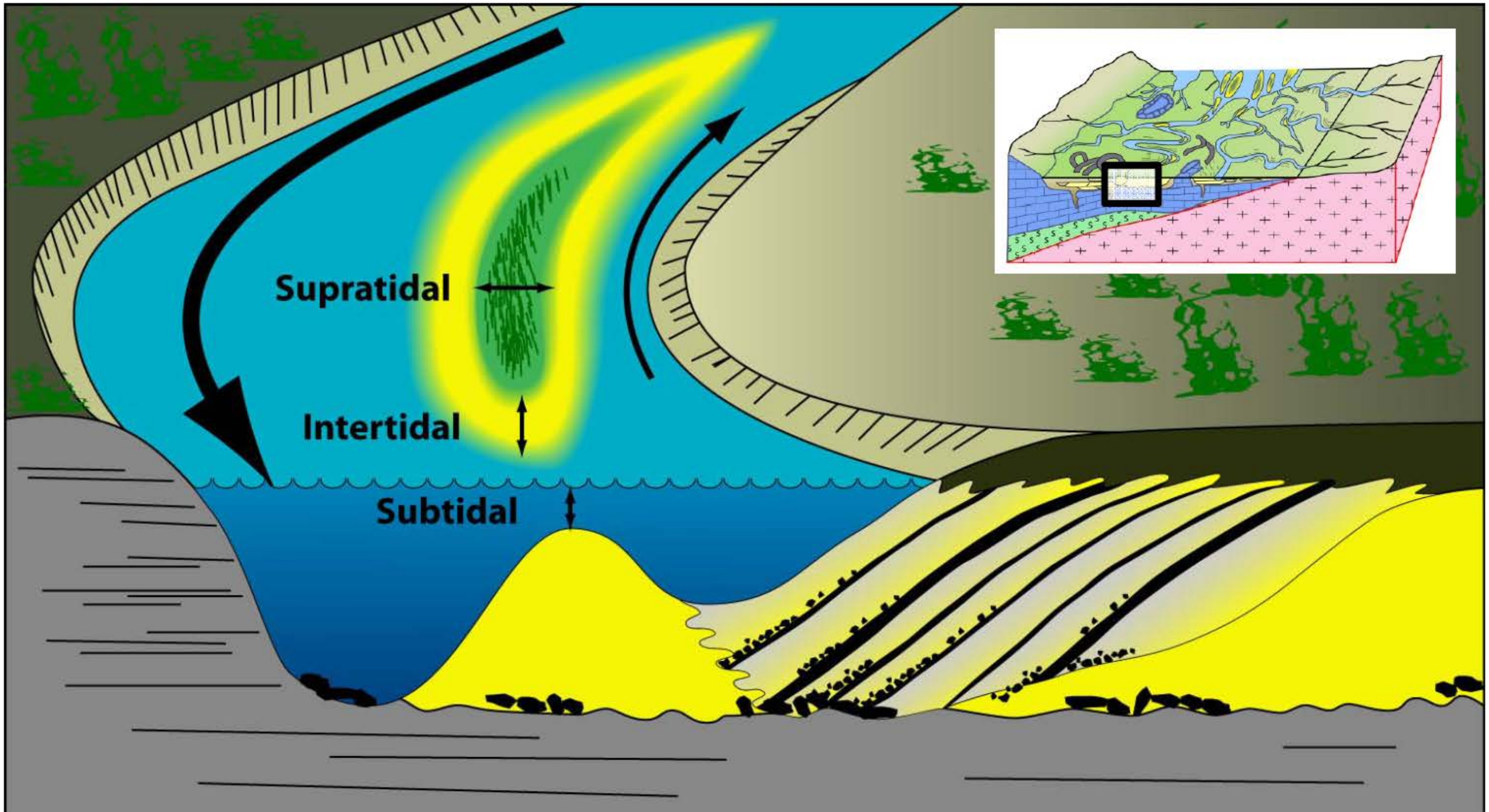


Regional Depositional Model

- 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

Devonian Structure
with Karst and Salt Dissolution Features

MAP DATA

- ZERO EDGE
- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

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

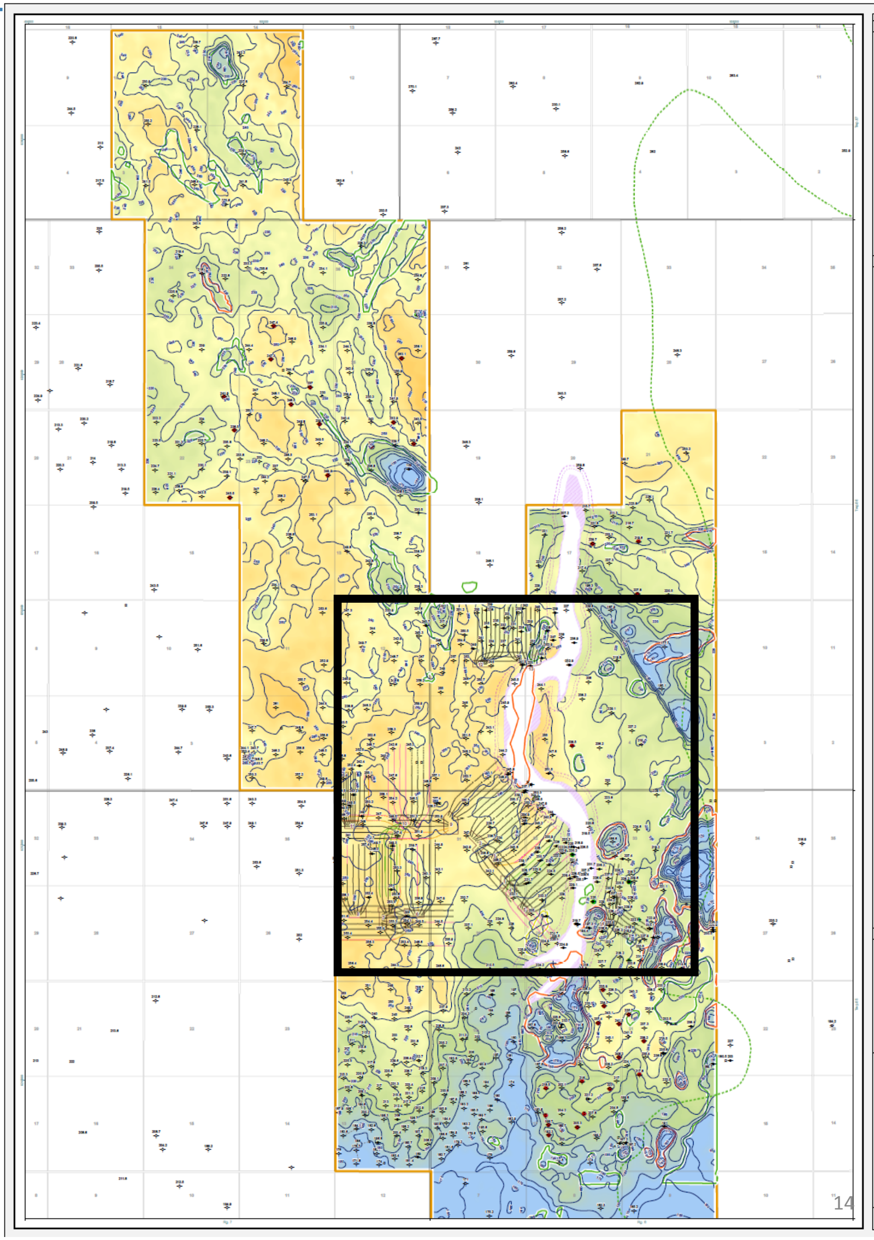
STRUCTURE EVENTS OVERLAY

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

DEVONIAN STRUCTURE RASTER

High : 267.8

Low : 139.3m



Devonian Structure
with Karst and Salt Dissolution Features

MAP DATA

- ZERO EDGE
- DEVONIAN STRUCTURE CONTOURS (C.I.=10m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

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

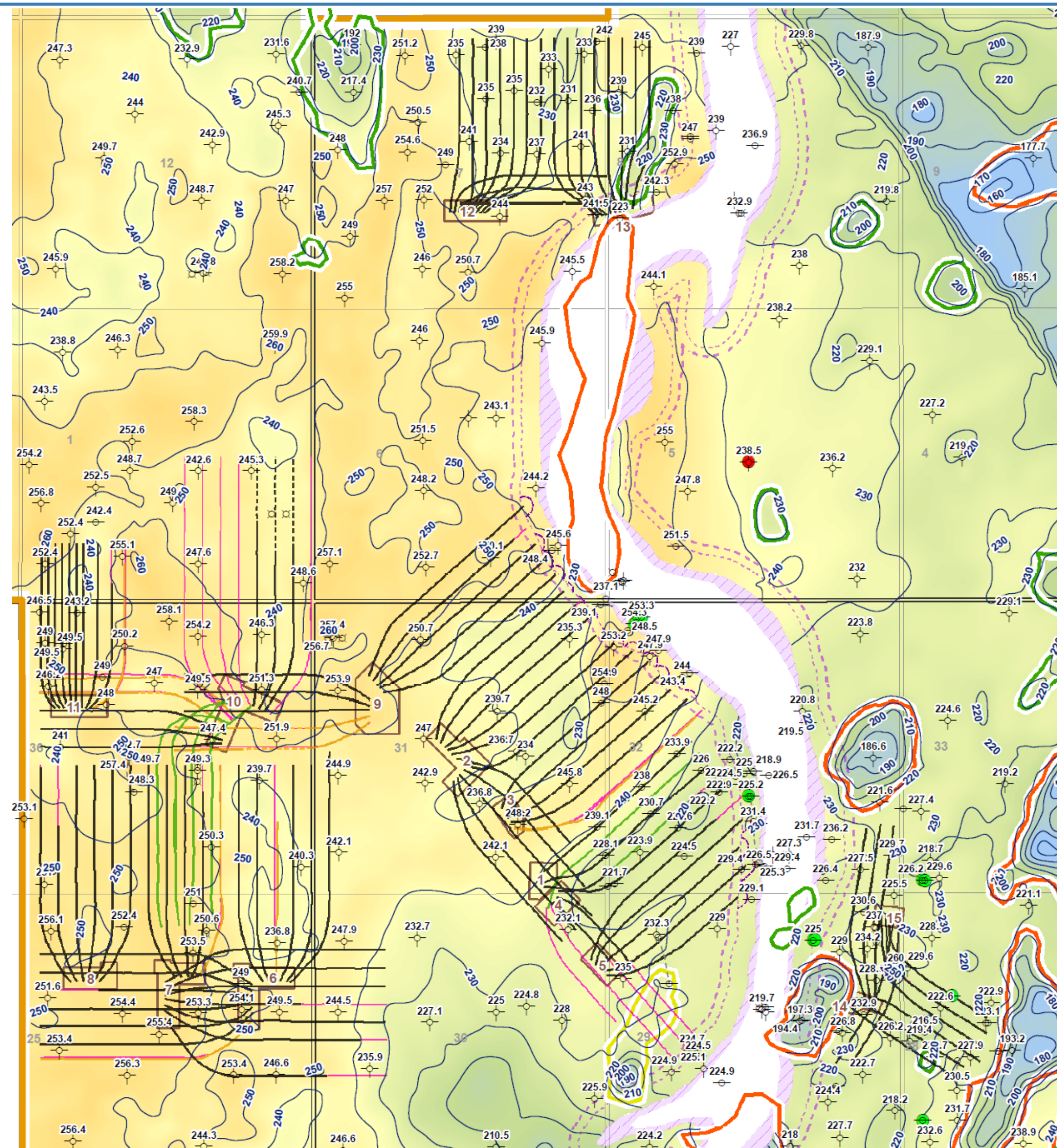
STRUCTURE EVENTS OVERLAY

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

DEVONIAN STRUCTURE RASTER

High : 267.8

Low : 139.3m



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

Long Lake
McMurray Structure

MAP DATA

- ZERO EDGE
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

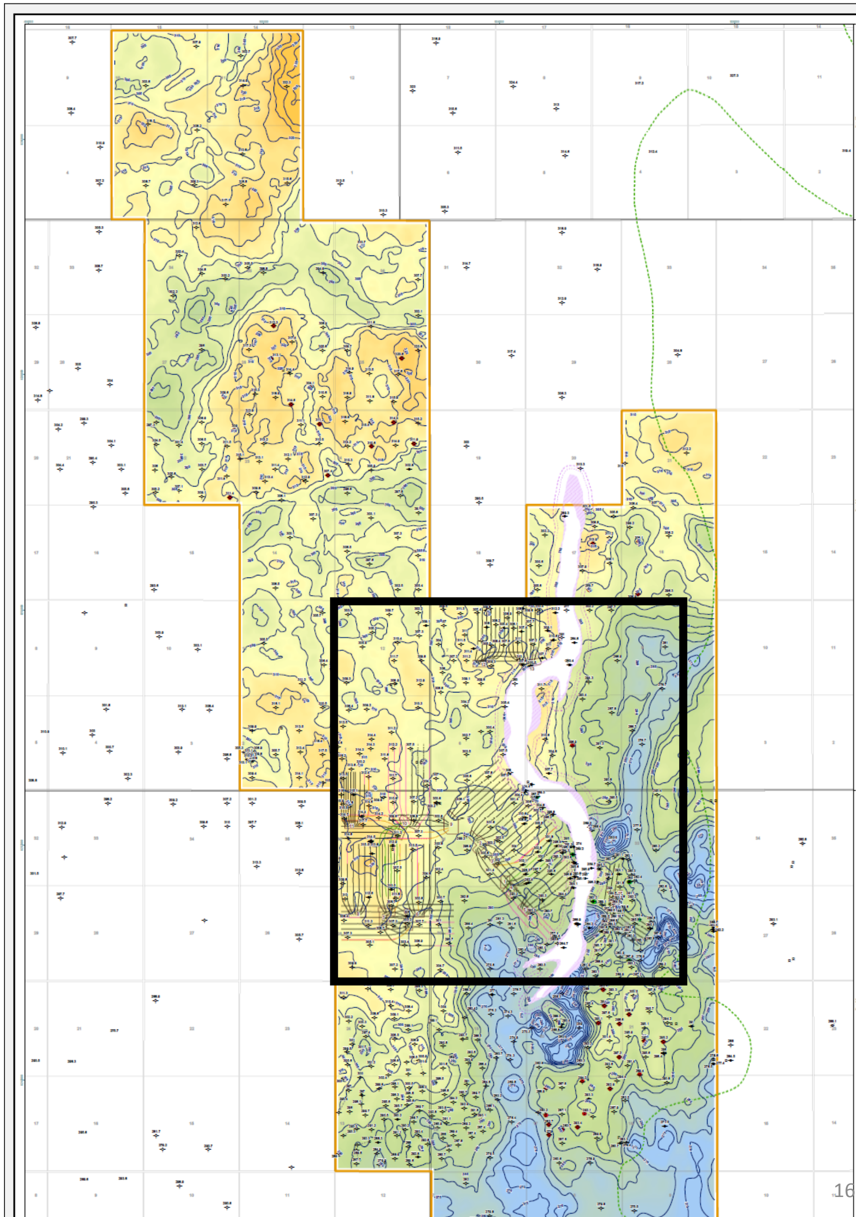
Q CHANNEL DATA

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

McMURRAY STRUCTURE RASTER

High : 334.2

Low : 245.1 m



Long Lake
McMurray Structure

MAP DATA

- ZERO EDGE
- McMURRAY STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

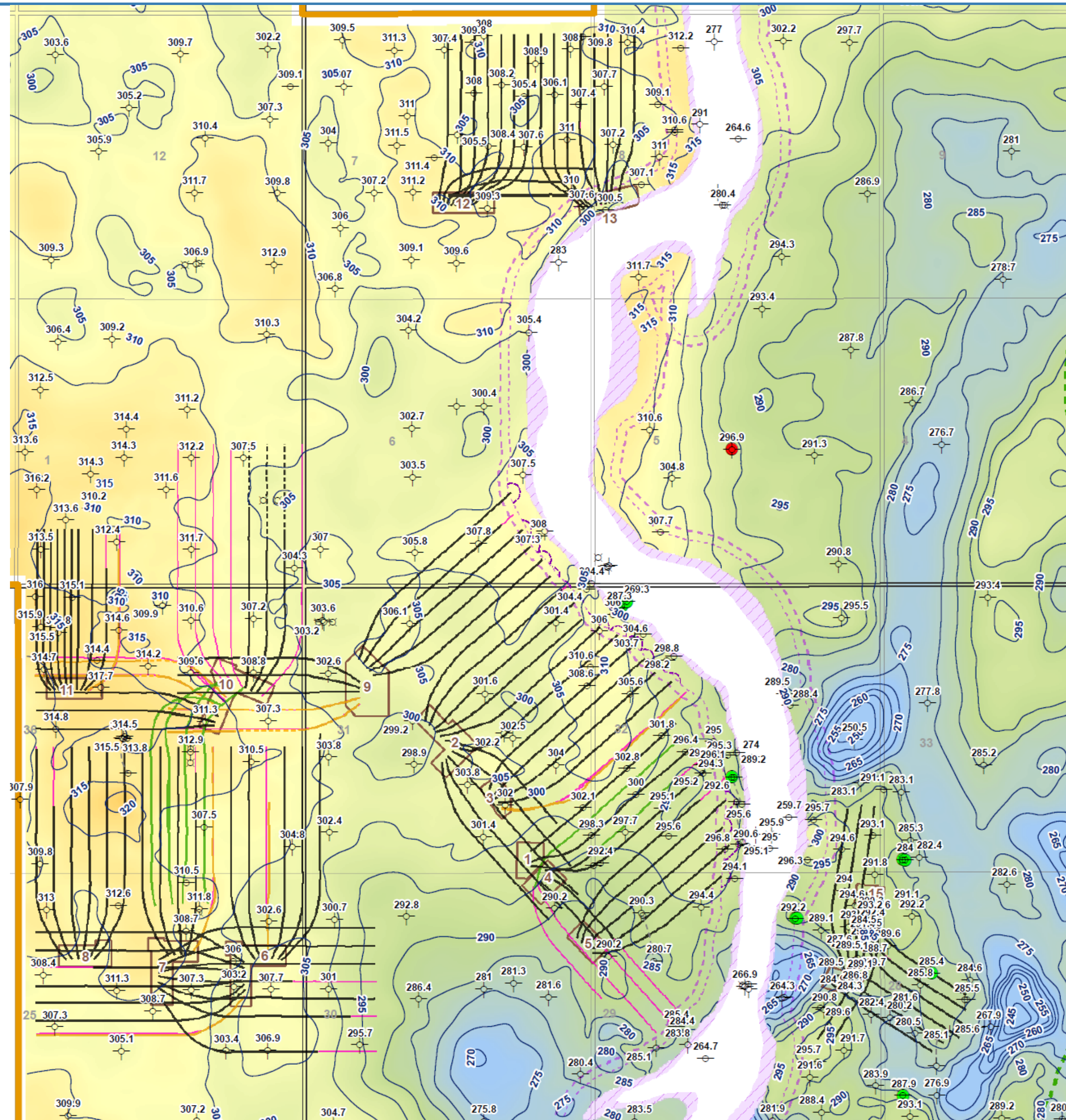
Q CHANNEL DATA

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

McMURRAY STRUCTURE RASTER

High : 334.2

Low : 245.1 m



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

Long Lake McMurray Isopach

MAP DATA

- ZERO EDGE
- McMURRAY ISOPACH CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

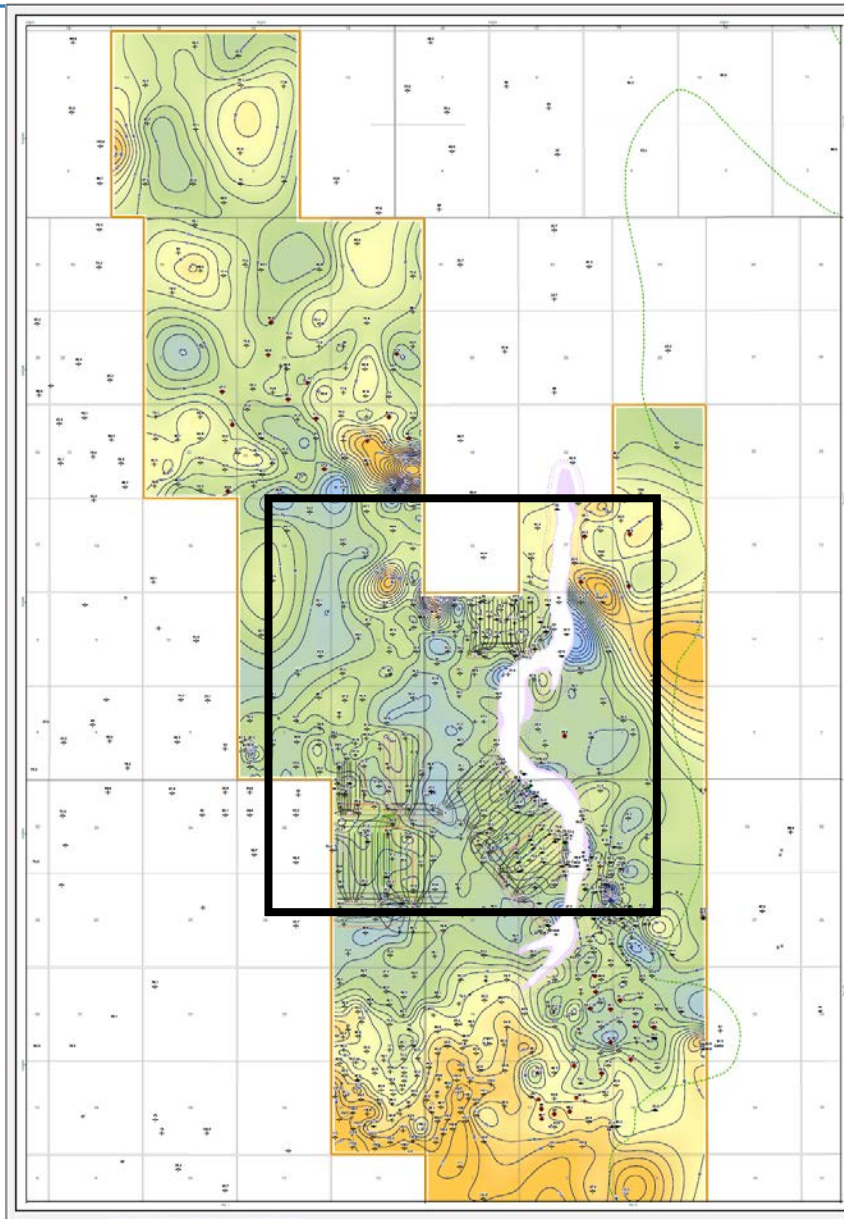
Q CHANNEL DATA

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

McMURRAY ISOPACH RASTER

High : 159.9

Low : 16.9m



Long Lake
McMurray Isopach

MAP DATA

- ZERO EDGE
- McMURRAY ISOPACH CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

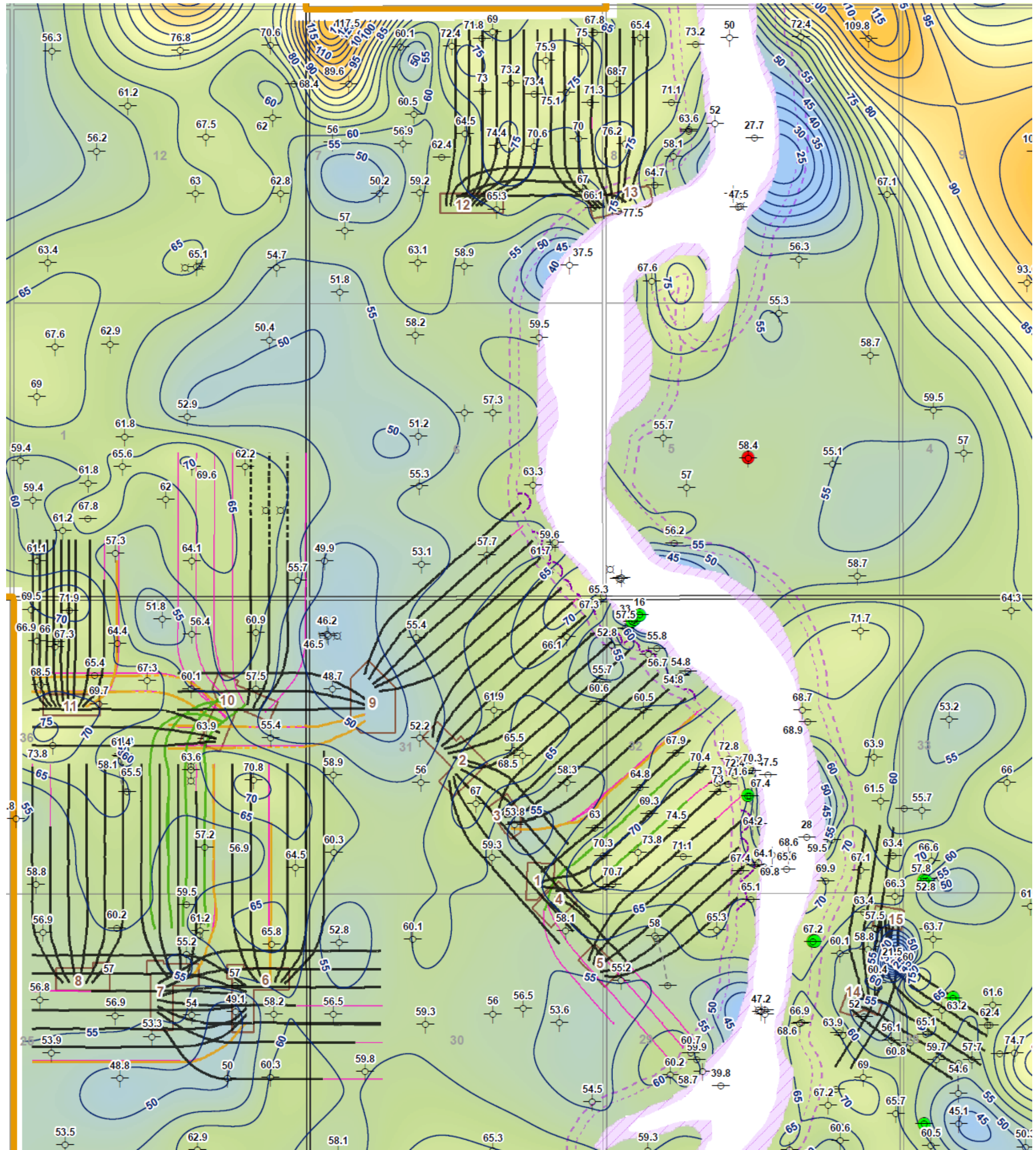
Q CHANNEL DATA

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

McMURRAY ISOPACH RASTER

High : 159.9

Low : 16.9m



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

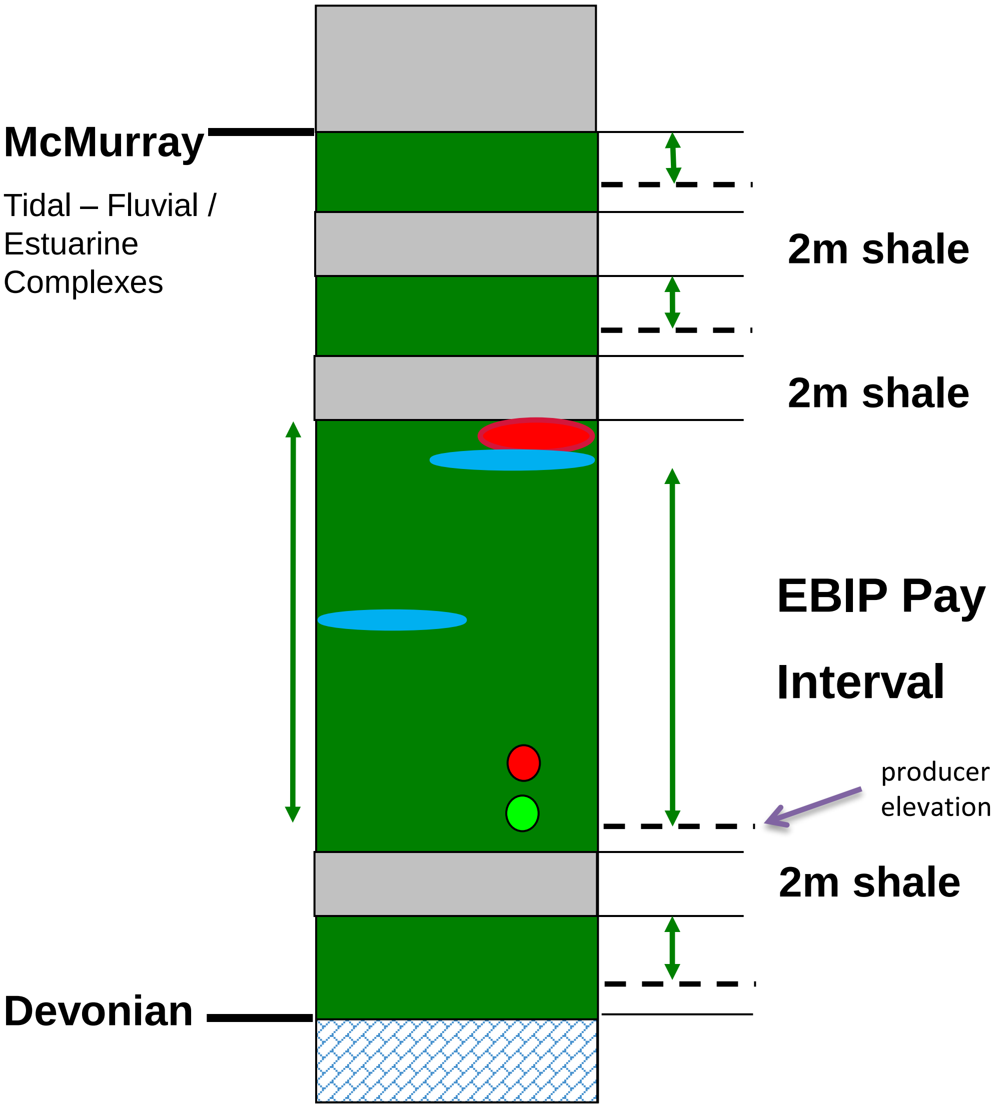
Pay and Exploitable Bitumen-in-Place Mapping Methodology

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 Pay Interval:
  - Single shale interval (> 30% V_{shale}) of 2m
  - Cumulative shale interval (> 30% V_{shale}) of 4m
- 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 Pay Interval
  - Gas identified by neutron/density crossover
- High Water Saturation Interval(s) Associated with EBIP Pay Interval
  - > 50% Swe (effective water saturation) and < 30% V_{shale}
- EBIP will be calculated from a hydrocarbon pore volume height (HPVH) map

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

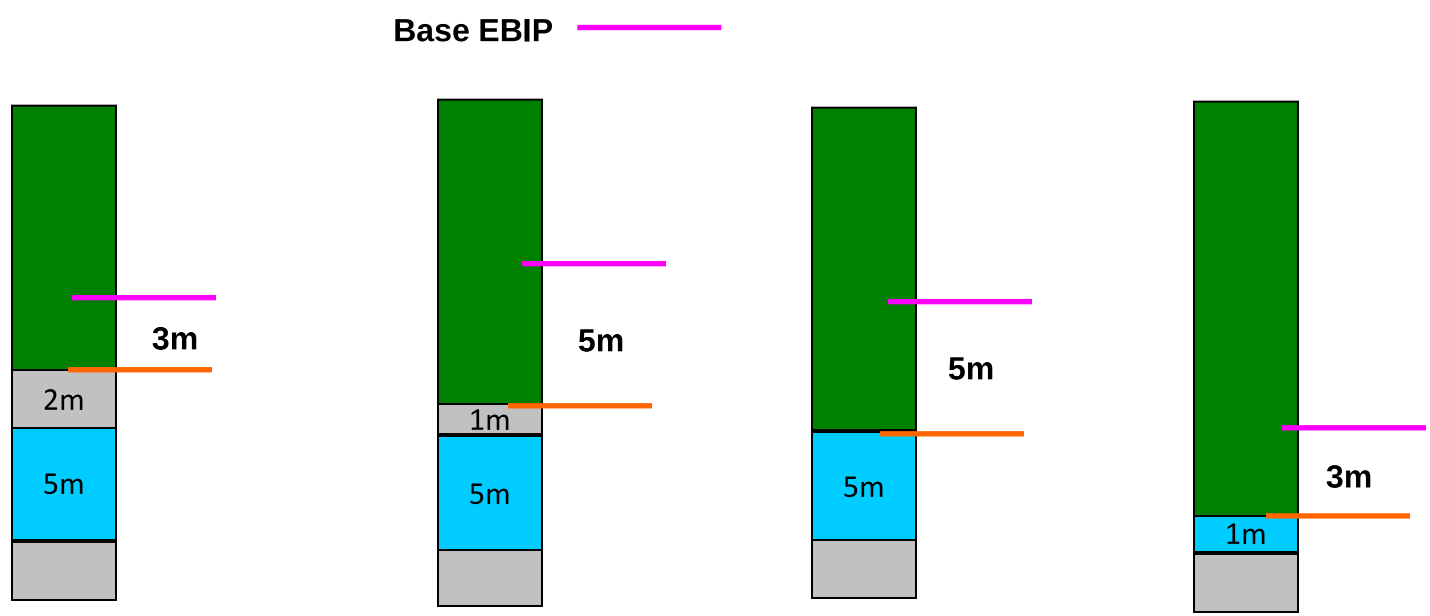
Pay and Exploitable Bitumen-in-Place Mapping Methodology



- **EBIP Pay Interval**
  - < 30% V_{shale}
  - < 50% Swe
- may have associated
  - gas interval(s)
  - high water saturation interval(s)
- Primary zone defined as the thickest pay interval unless:
  - an existing (or planned) hz 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 hz 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

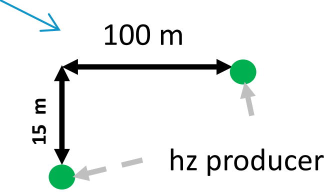
Producer Vertical Depth

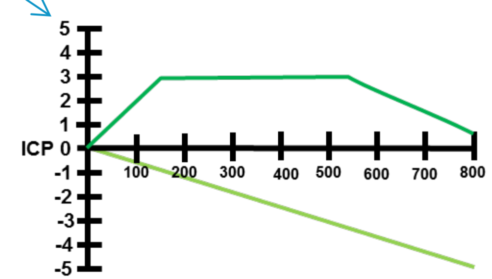
Considerations

- Target high quality resource - preferentially 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 horizontal wells 15 m/100 m
- 3 to 5 m vertical deviation from intermediate casing point (ICP)
- Approximate maximum rise or dip rate 1m/50m





EBIP and Average Reservoir Parameters (Long Lake, not including K1A)

Long Lake EBIP (E^6m^3)	330.65

Nexen Cutoffs: h > 12m or HPVH > 3 m

Hydrocarbon Pore Volume Height

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

Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Long Lake EBIP Average Reservoir Parameters

- Measured Depth (top) 200 m KB
- Thickness 22 m
- Effective Porosity 31.2 %
- V_{shale} 10.1 %
- Permeability – Historical Plug Data
  - Kmax 5565 mD
  - Kvert 4491 mD
- Effective Water Saturation 31.2 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure:

  ~1000 - 1100kPa @ 230m AMSL

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

Long Lake
EBIP Pay Interval Isopach

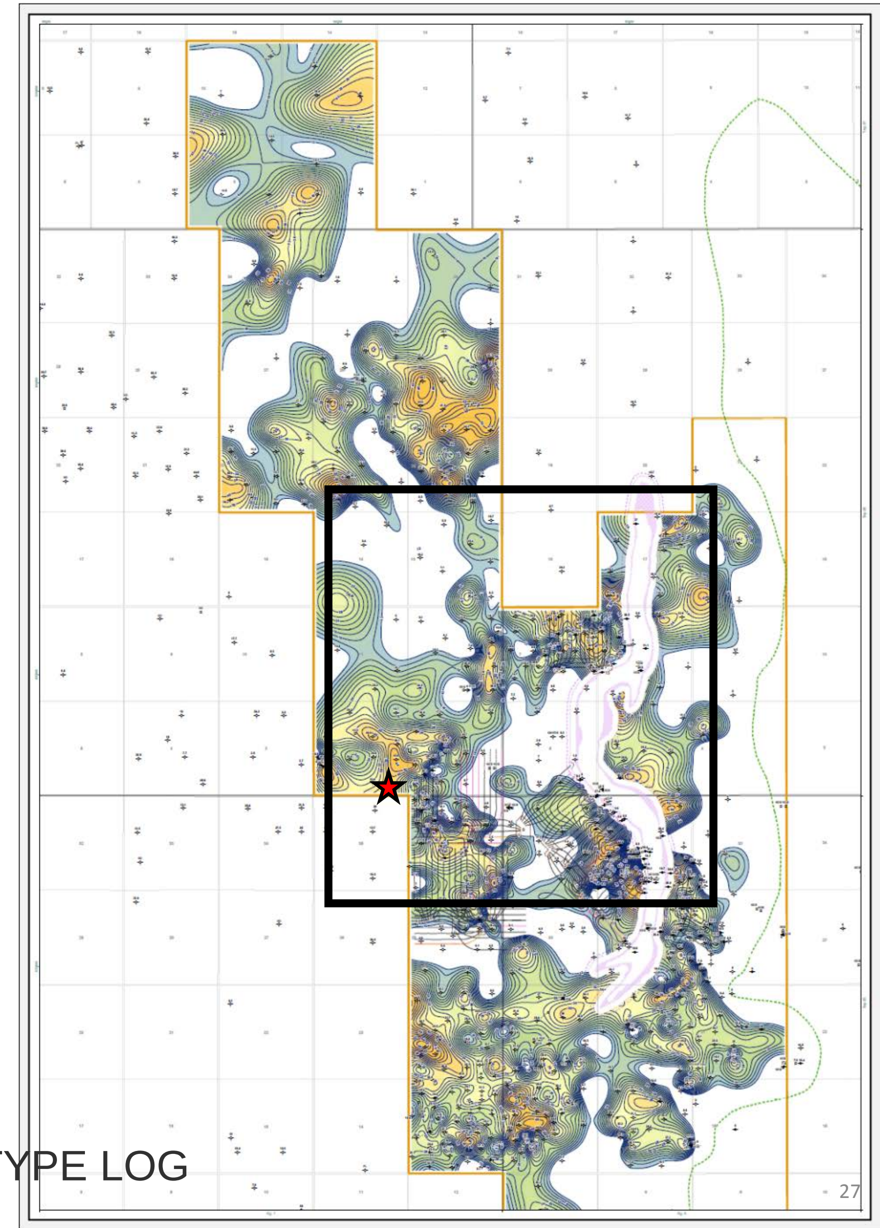
MAP DATA
- ZERO EDGE
- EBIP ISOPACH (C.I.=2m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

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

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

EBIP ISOPACH RASTER
- High : 72.2
- Low : 12.0m

- Colour shading : >12m EBIP Interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour



★ TYPE LOG

Long Lake
EBIP Pay Interval Isopach

MAP DATA
- ZERO EDGE
- EBIP ISOPACH (C.I.=2m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

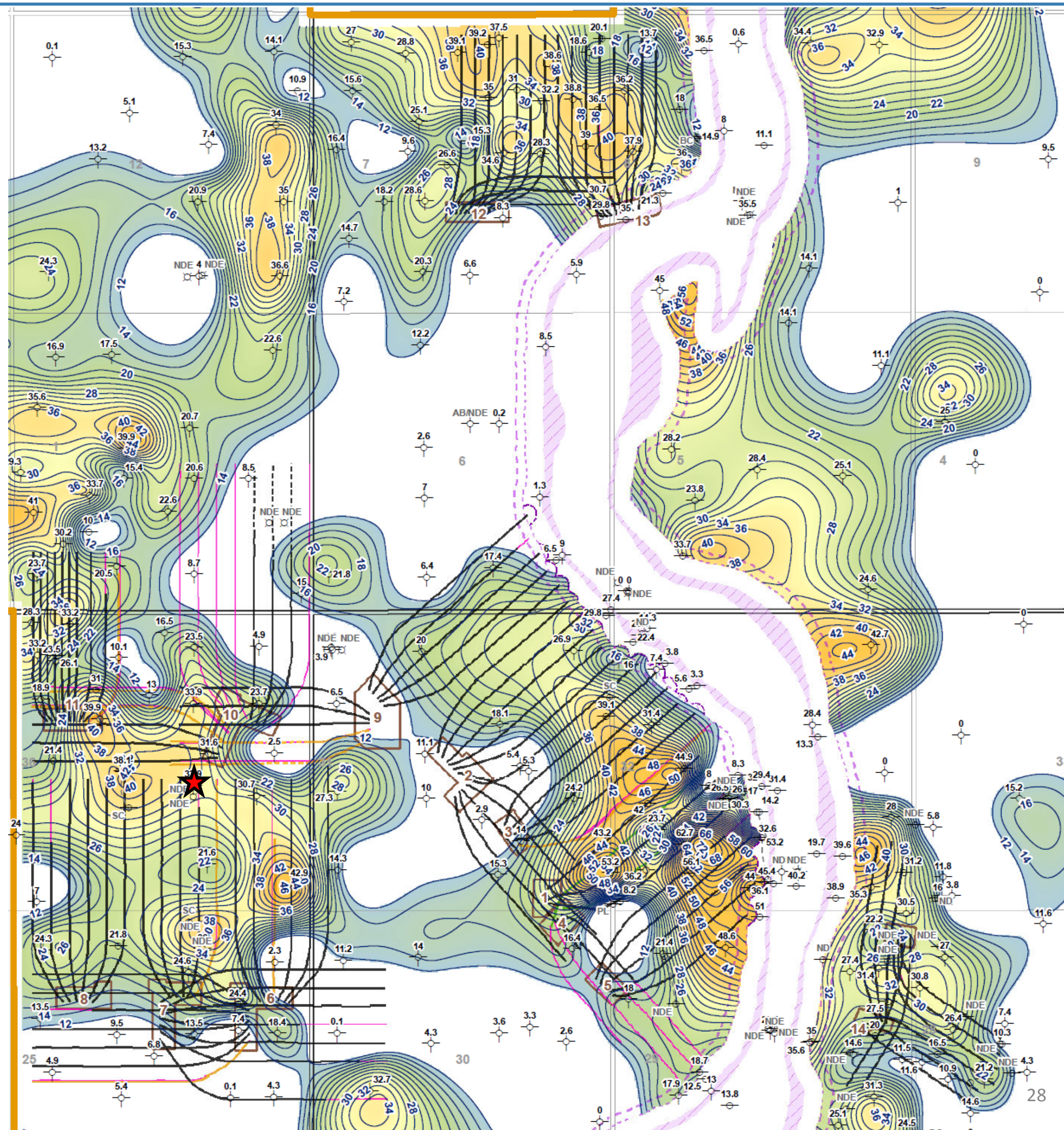
HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

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

EBIP ISOPACH RASTER

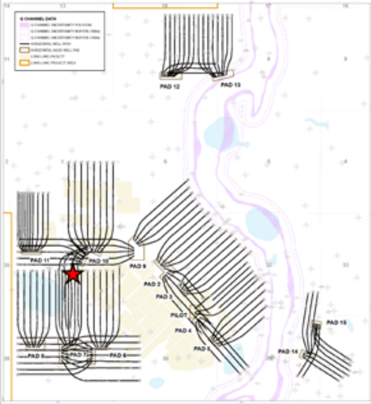
High : 72.2

Low : 12.0m



- Colour shading : >12m EBIP Interval

★ TYPE LOG

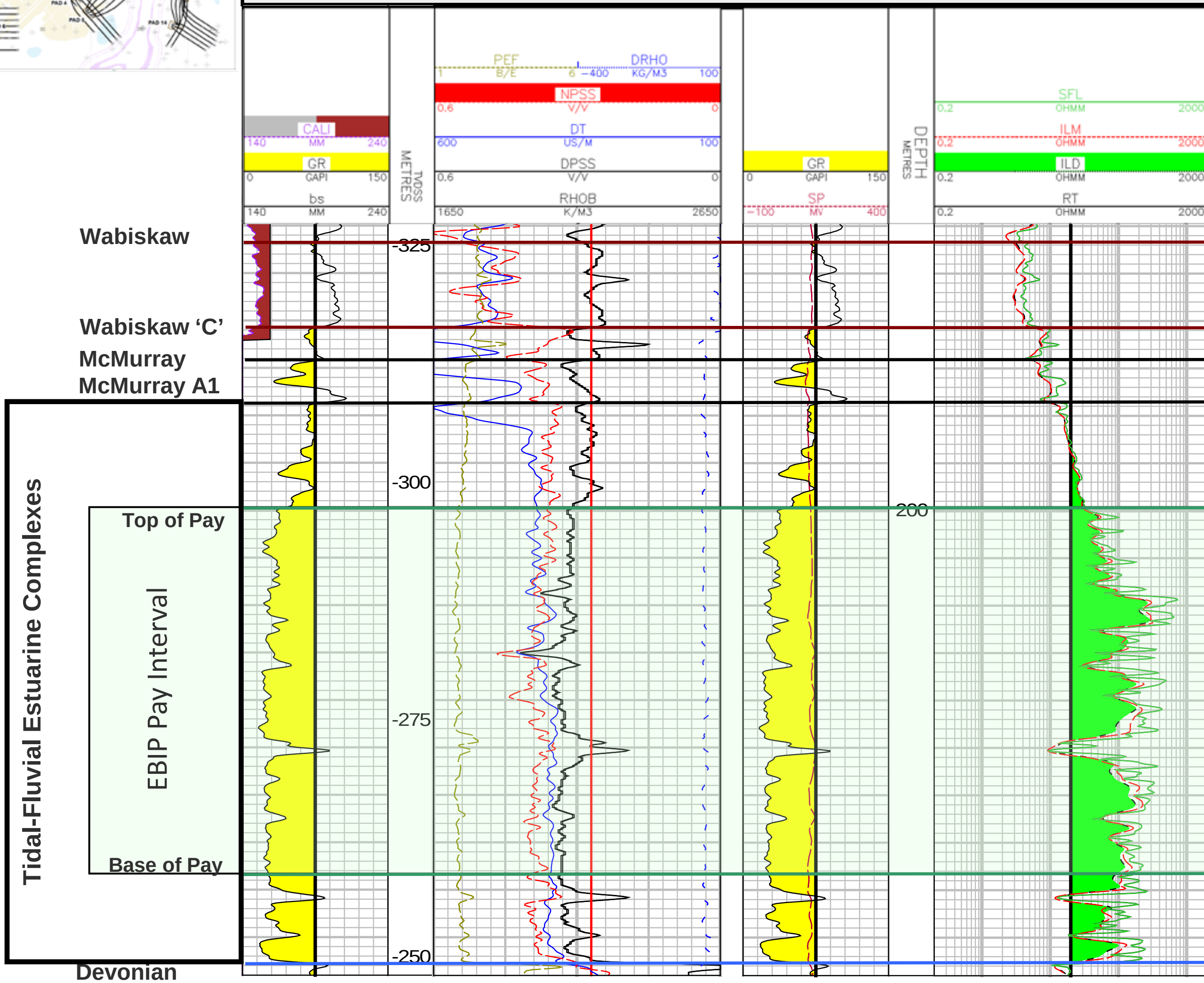


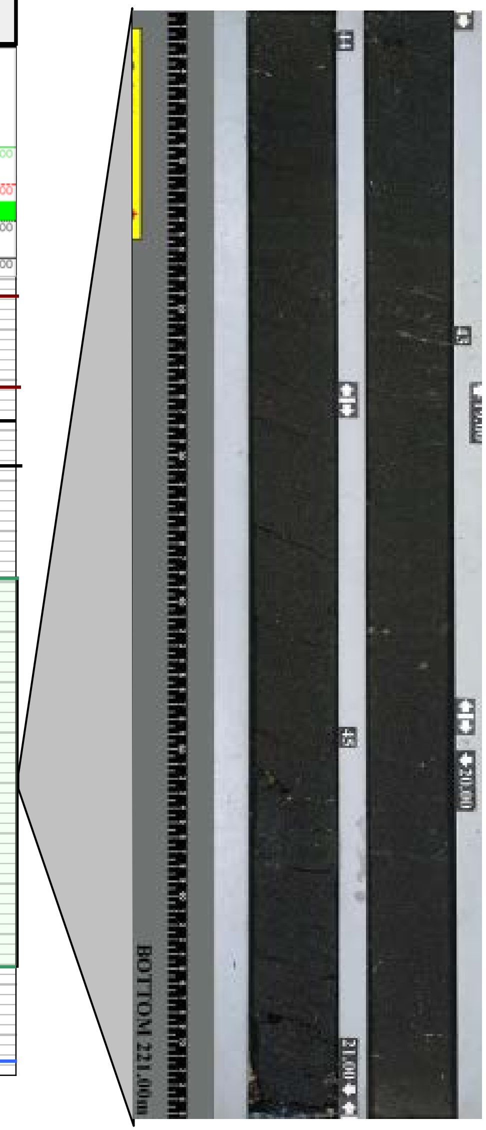
Type Log – 1AA/07-36-085-07W4

Well: 1AA_07-36-085-07W4_0

OPTI CANADA ET AL CHEECHAM 7-36-85-7

MEASUREMENT REF.: KB	SURFACE ELEVATION: 494.10
ELEVATION MEAS. REF.: 497.10	RIG RELEASE: 03-MAR-2000
DRILLED DEPTH: 265.50	VERTICAL SCALE: 1:480





Long Lake
EBIP Pay Interval Base Structure

MAP DATA

- ZERO EDGE
- EBIP BASE STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

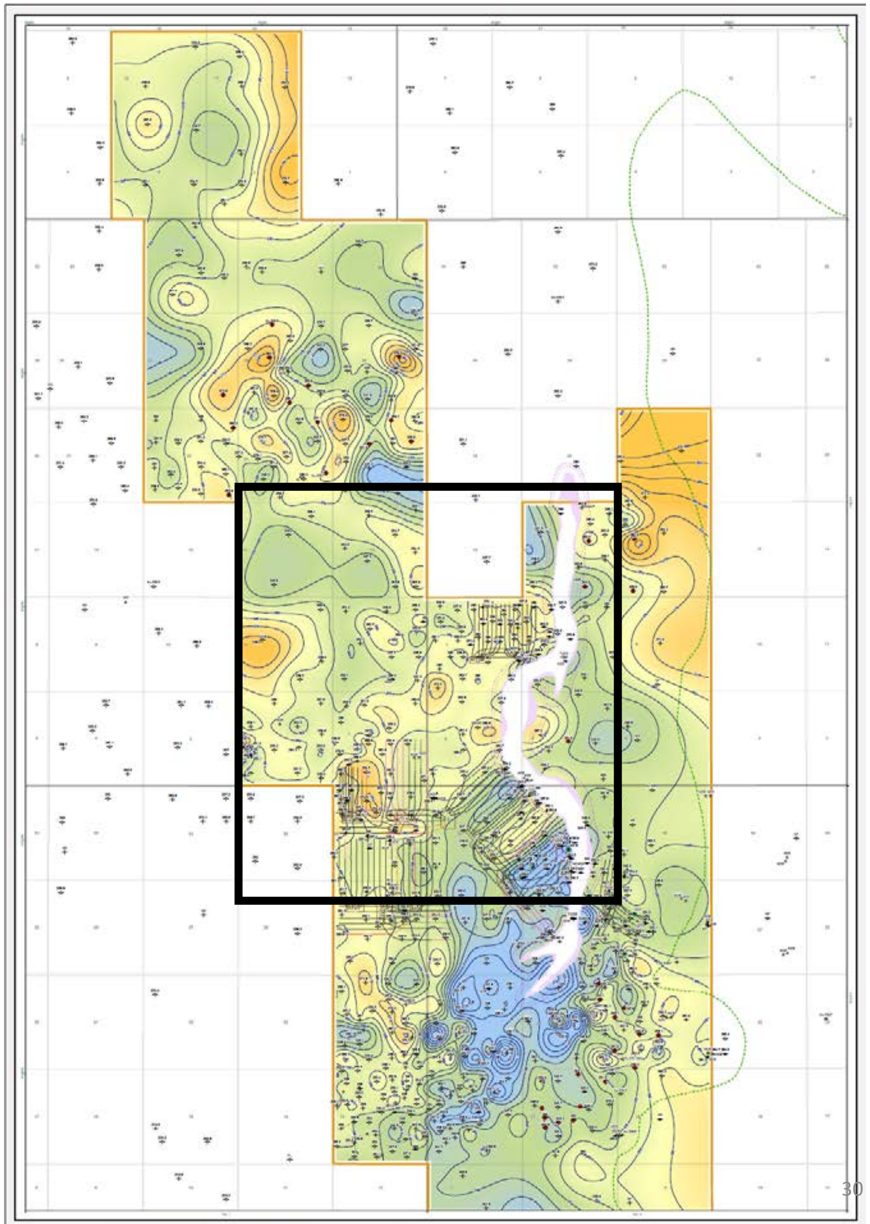
Q CHANNEL DATA

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

EBIP BASE STRUCTURE RASTER

High : 300.0

Low : 208.4m



Long Lake
EBIP Pay Interval Base Structure

MAP DATA

- ZERO EDGE
- EBIP BASE STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

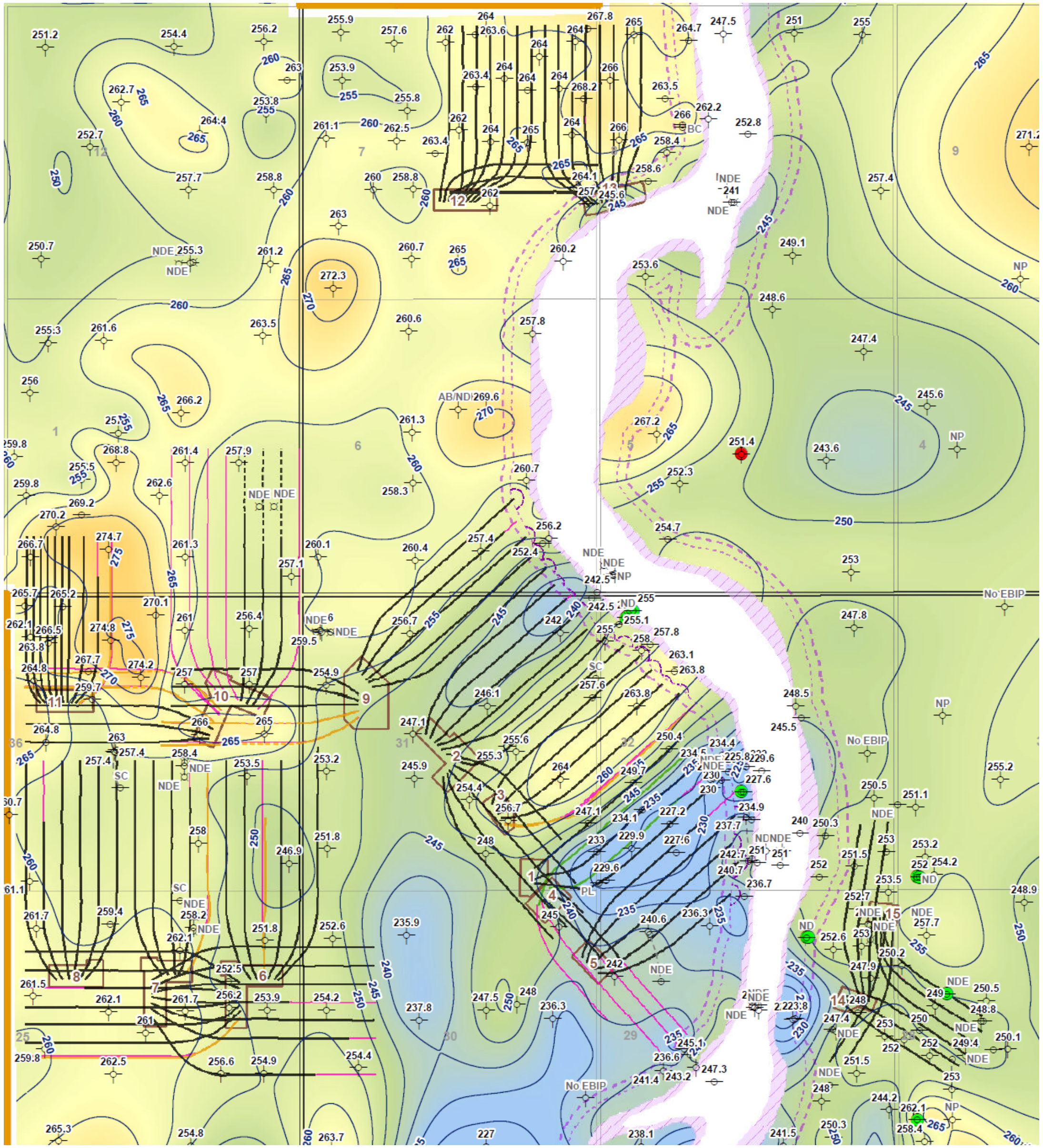
Q CHANNEL DATA

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

EBIP BASE STRUCTURE RASTER

High : 300.0

Low : 208.4m



- Base of EBIP Pay Interval influenced by facies changes, karsting, erosion, salt dissolution, and bottom water
- Base EBIP is equal to the producer depth

Long Lake
EBIP Pay Interval Top Structure

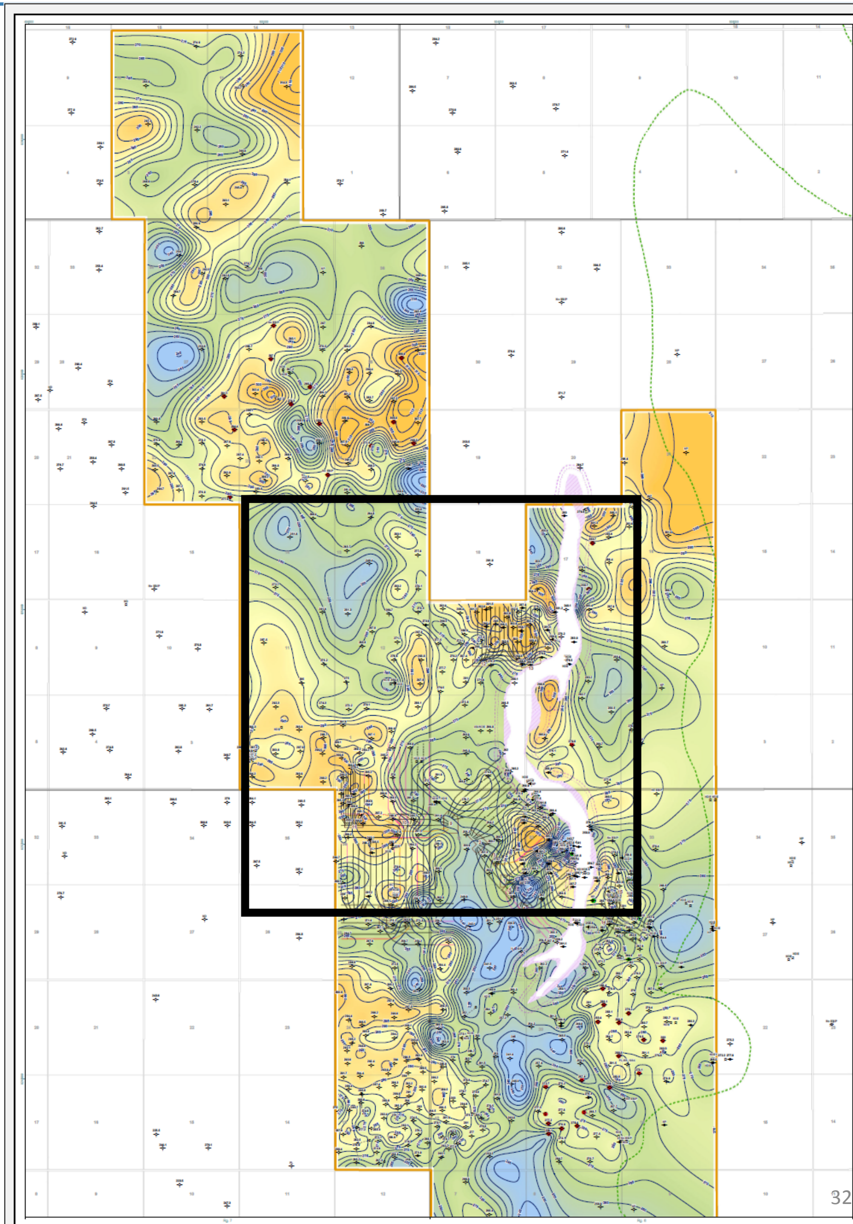
MAP DATA
- ZERO EDGE
- EBIP TOP STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

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

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

EBIP TOP STRUCTURE RASTER
- High : 324.7
- Low : 225.7m



Long Lake
EBIP Pay Interval Top Structure

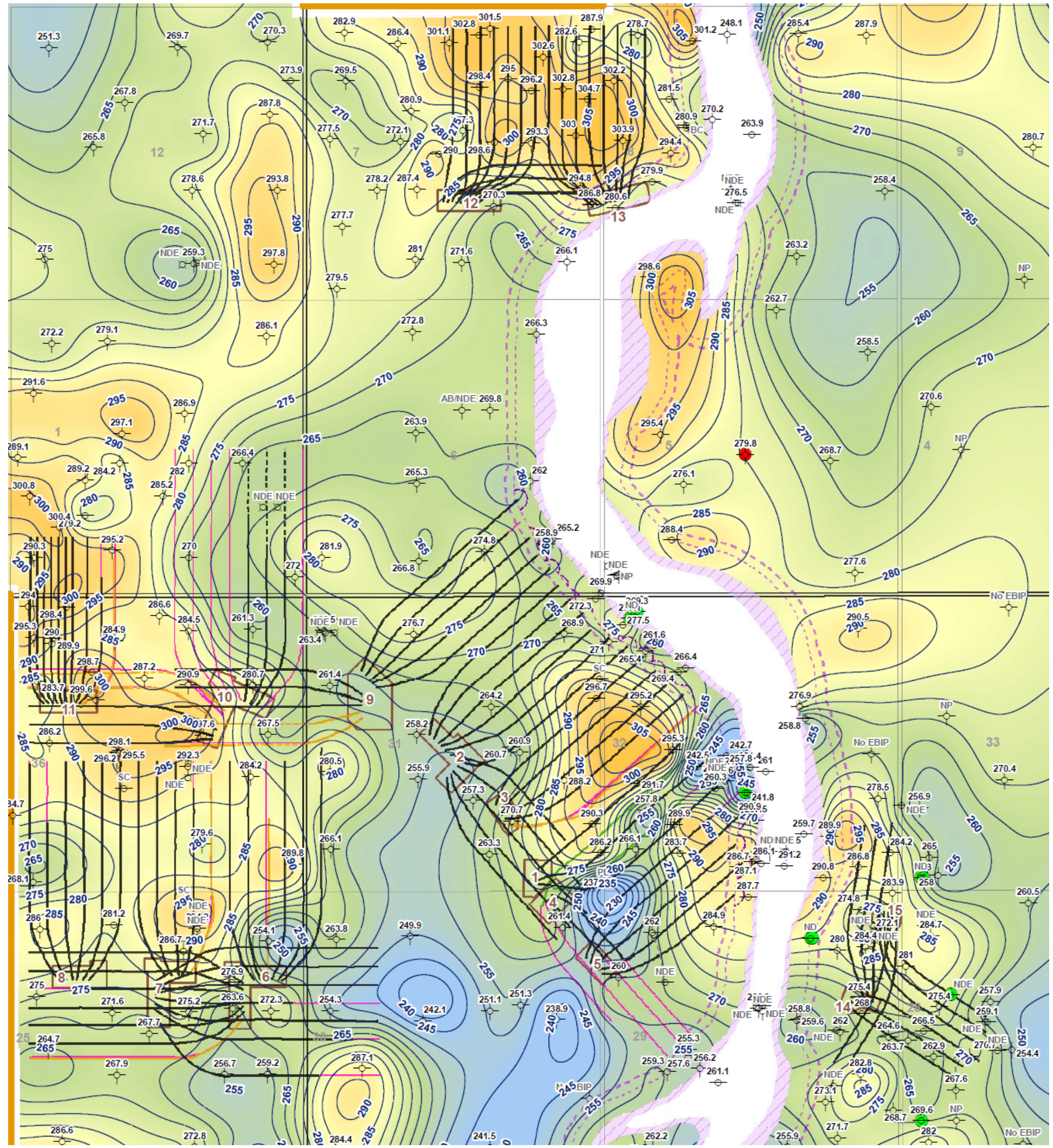
MAP DATA
- ZERO EDGE
- EBIP TOP STRUCTURE CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

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

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

EBIP TOP STRUCTURE RASTER
High : 324.7
Low : 225.7m



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

Long Lake
HPVH Isopach over EBIP Pay Interval

MAP DATA

- ZERO EDGE
- EBIP HPVH ISOPACH (C.I.=1m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

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

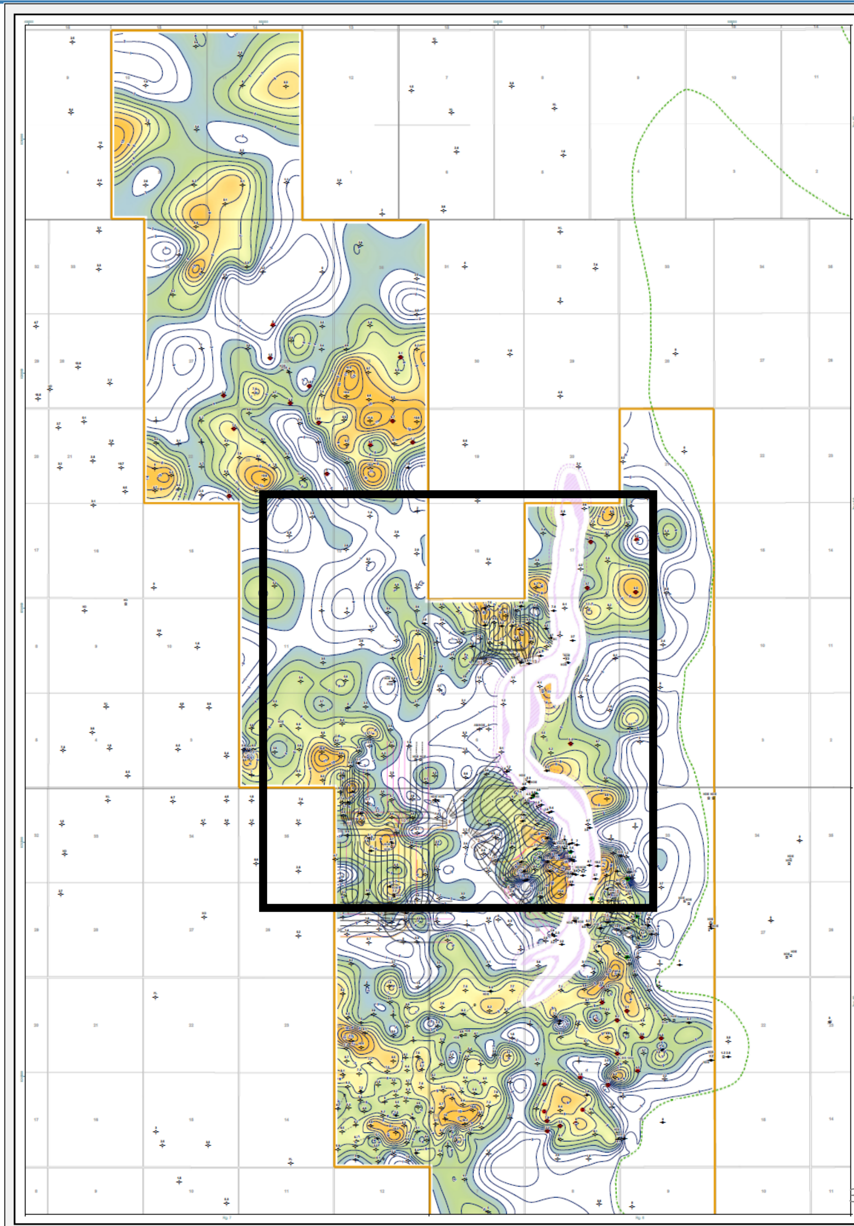
EBIP HPVH ISOPACH RASTER

High : 15.5

Low : 3.0m

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

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



Long Lake
HPVH Isopach Over EBIP Pay Interval

MAP DATA

- ZERO EDGE
- EBIP HPVH ISOPACH (C.I.=1m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

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

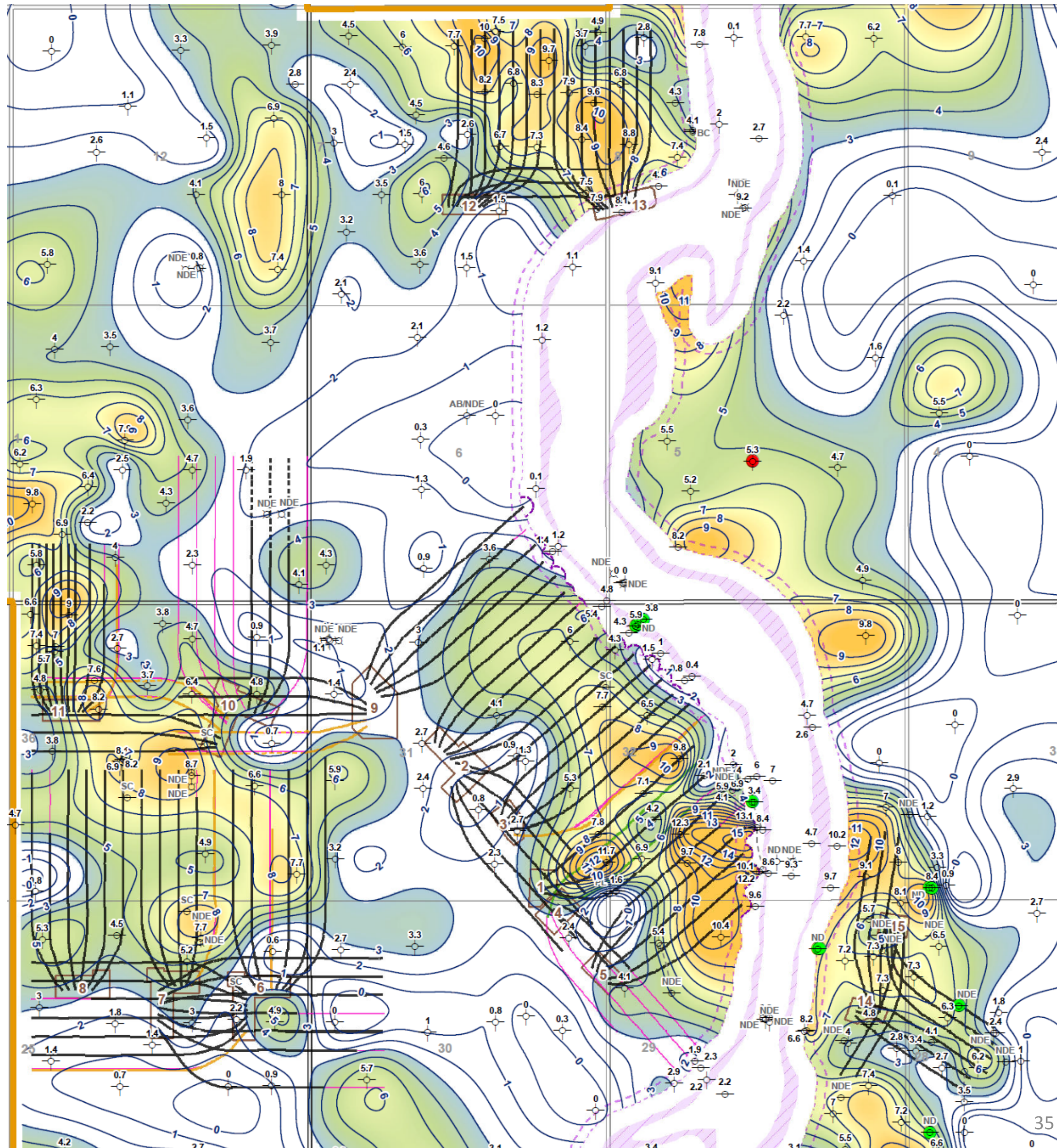
EBIP HPVH ISOPACH RASTER

High : 15.5

Low : 3.0m

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

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



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

MAP DATA

ZERO EDGE

EBIP TOTAL GAS ISOPACH (C.I.=2m)

LLK 2014 EBIP HPVH ISO POLYGON

HORIZONTAL WELL PAD

LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

CORE HOLE LOCATION

OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

ACTIVE HORIZONTAL

DRILLED : PULLED BACK

ACTIVE : INFILL HORIZONTAL

ACTIVE : RE-DRILL HORIZONTAL

ACTIVE : NOT PRODUCING - SOLID LINER

SUSPENDED

DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA

Q CHANNEL UNCERTAINTY POLYGON

Q CHANNEL UNCERTAINTY BUFFER (100m)

Q CHANNEL UNCERTAINTY BUFFER (150m)

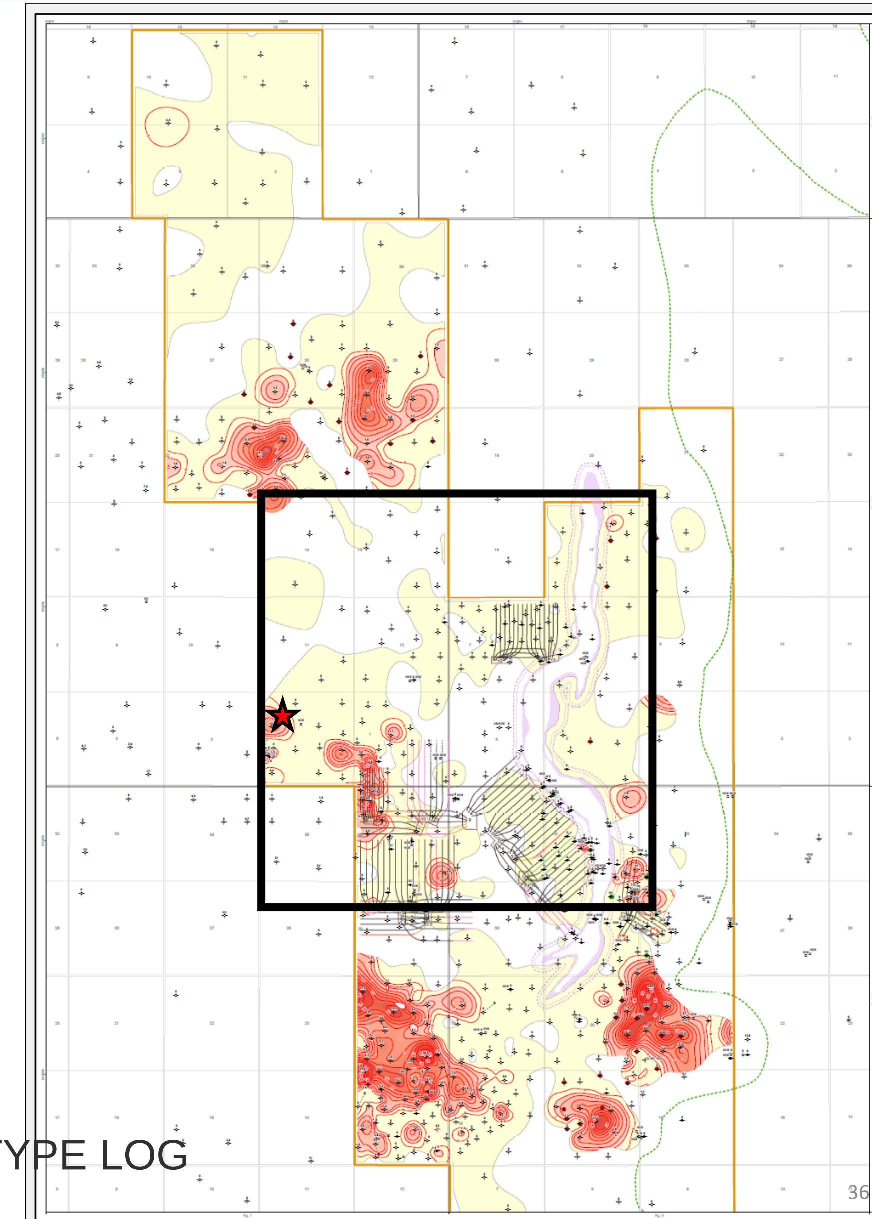
DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

EBIP TOTAL GAS ISOPACH RASTER

High : 25.8

Low : 1.0 m

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



★ TYPE LOG

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

MAP DATA

- ZERO EDGE
- EBIP TOTAL GAS ISOPACH (C.I.=2m)
- LLK 2014 EBIP HPVH ISO POLYGON
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

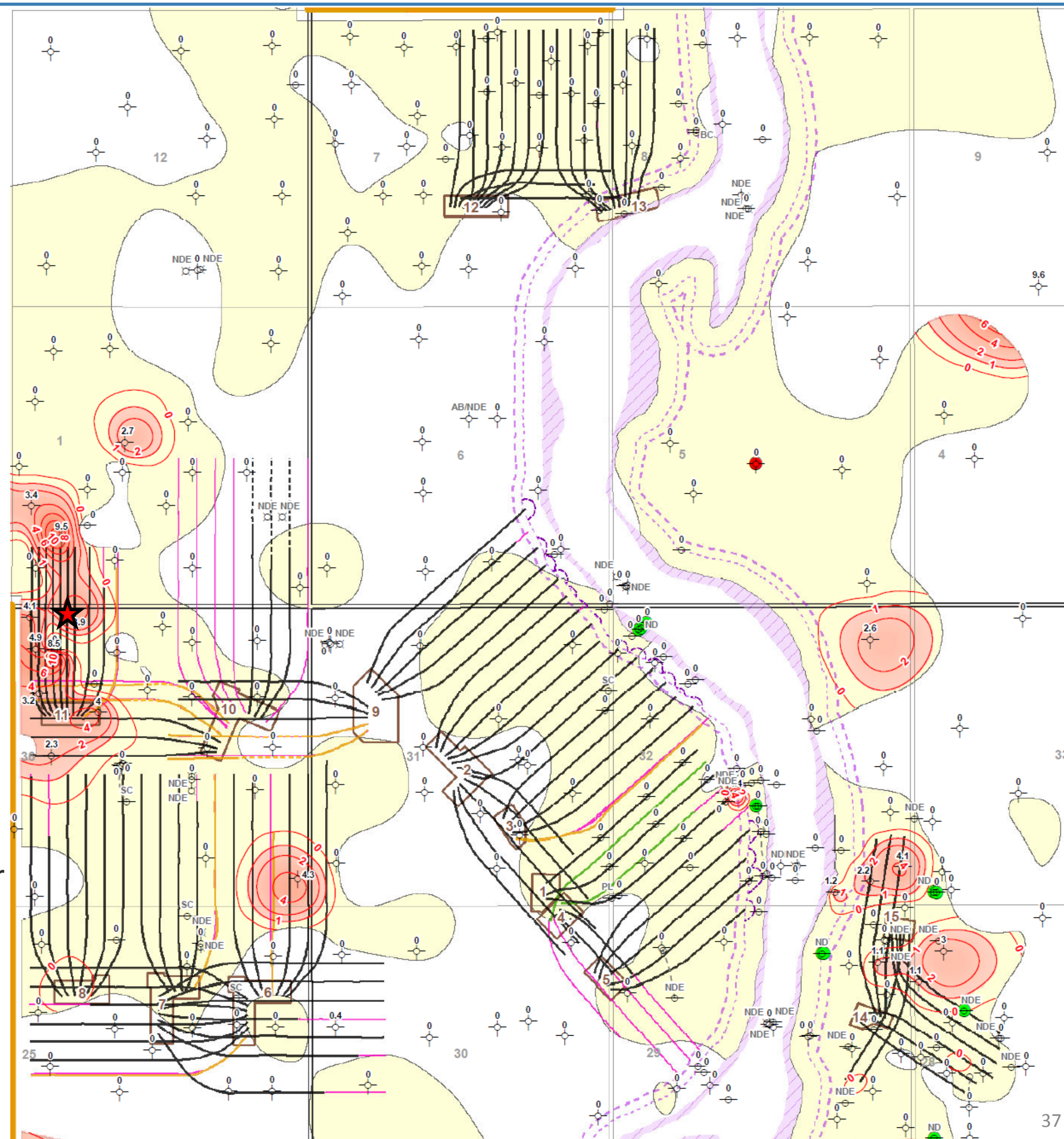
Q CHANNEL DATA

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

EBIP TOTAL GAS ISOPACH RASTER

High : 25.8

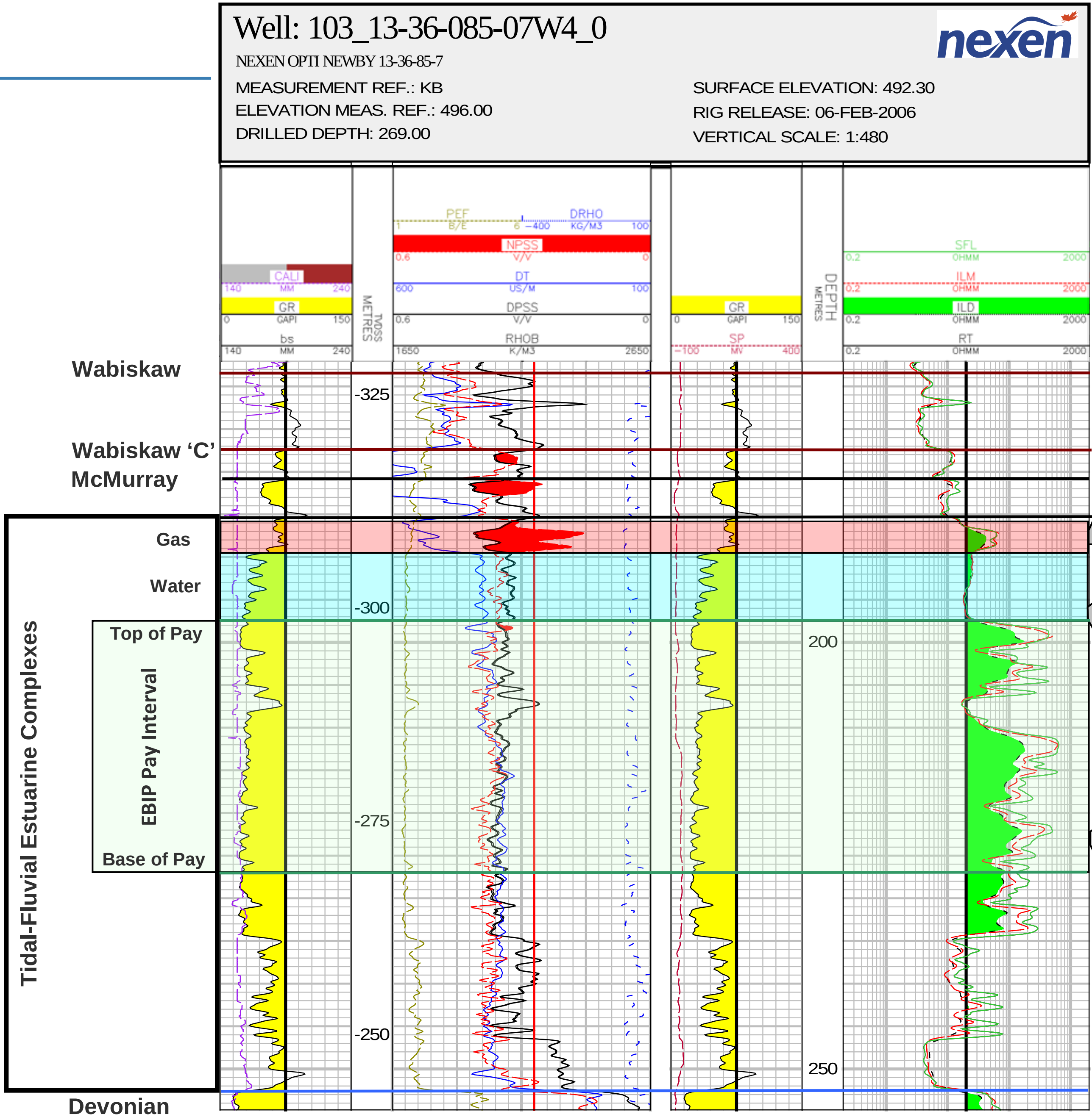
Low : 1.0 m

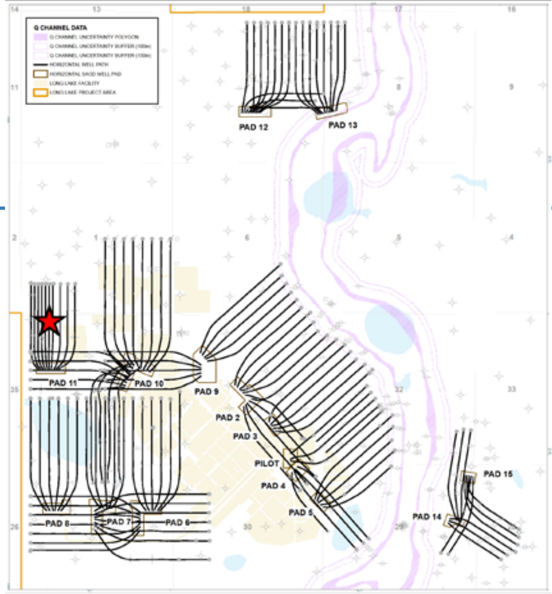


- Gas identified by neutron/density crossover
- Gas associated with EBIP Interval
  - within EBIP Interval
  - directly in contact with top water or top of EBIP interval
  - contours clipped to $3m^3/m^2$ HPVH EBIP contour

★ TYPE LOG

Type Log – 103/13-36-085-07W4





Long Lake High Water Saturation Interval(s) in contact with Top EBIP Interval Isopach

CONTOUR DATA (C.I.=5m)

HIGH WATER SATURATION INTERVAL(s) ABOVE AND IN CONTACT WITH EBIP INTERVAL ISOPACH

2013/2014 DRILLING PROGRAM

CORE HOLE LOCATION

OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

ACTIVE HORIZONTAL

DRILLED : PULLED BACK

ACTIVE : INFILL HORIZONTAL

ACTIVE : RE-DRILL HORIZONTAL

ACTIVE : NOT PRODUCING - SOLID LINER

SUSPENDED

DEVIATED WELL PATH (DRILLED)

Q CHANNEL DATA

Q CHANNEL UNCERTAINTY POLYGON

Q CHANNEL UNCERTAINTY BUFFER (100m)

Q CHANNEL UNCERTAINTY BUFFER (150m)

DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

MAP DATA

ZERO EDGE

HORIZONTAL WELL PAD

LONG LAKE PROJECT AREA

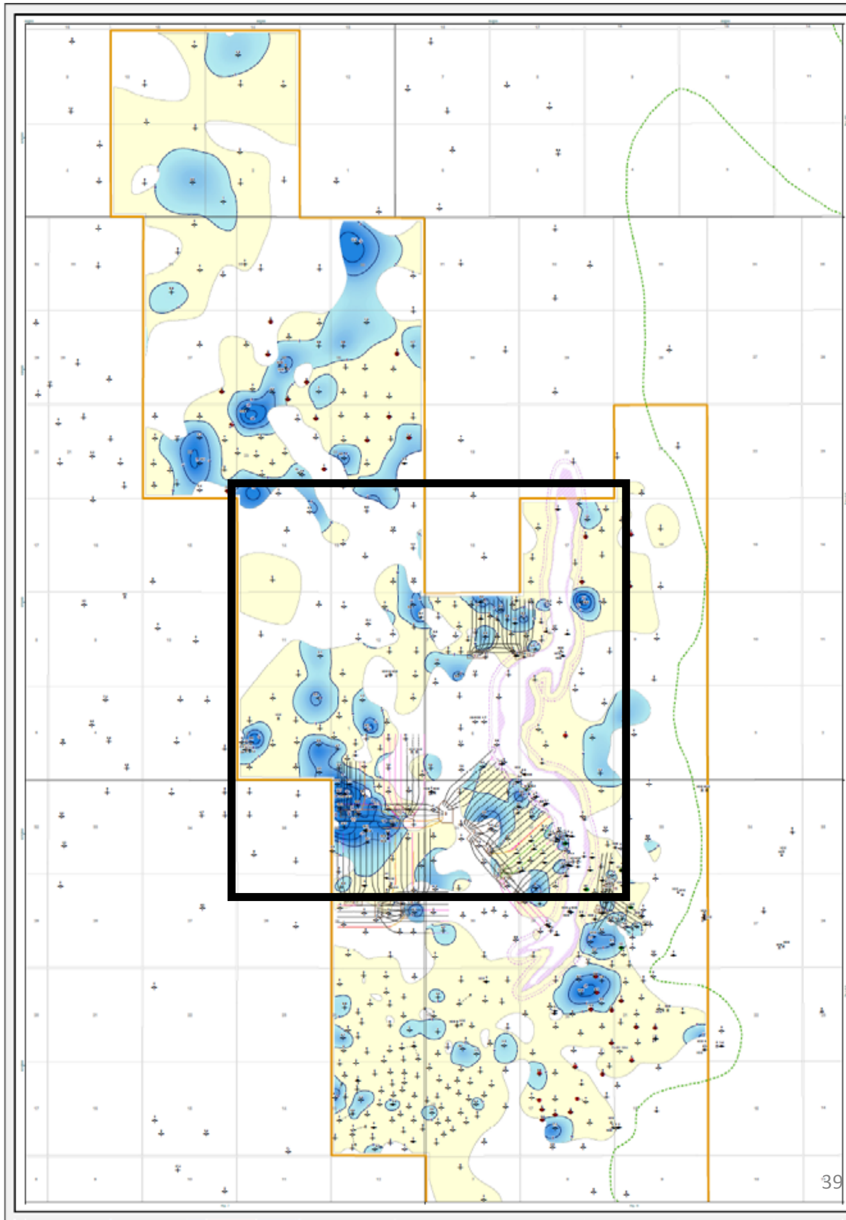
LLK 2014 EBIP HPVH ISO POLYGON

HIGH WATER SATURATION INTERVAL(s) ABOVE AND IN CONTACT WITH EBIP INTERVAL ISOPACH

High : 27.4

Low : 0.0m

- > 50% Swe and < 30% V_{shale}
- High water saturation intervals above and in contact with EBIP
- Contours clipped to $3 m^3/m^2$ HPVH EBIP contour



Long Lake High Water Saturation Interval(s) in contact with Top EBIP Interval Isopach

CONTOUR DATA (C.I.=5m)
- HIGH WATER SATURATION INTERVAL(s) ABOVE AND IN CONTACT WITH EBIP INTERVAL ISOPACH

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

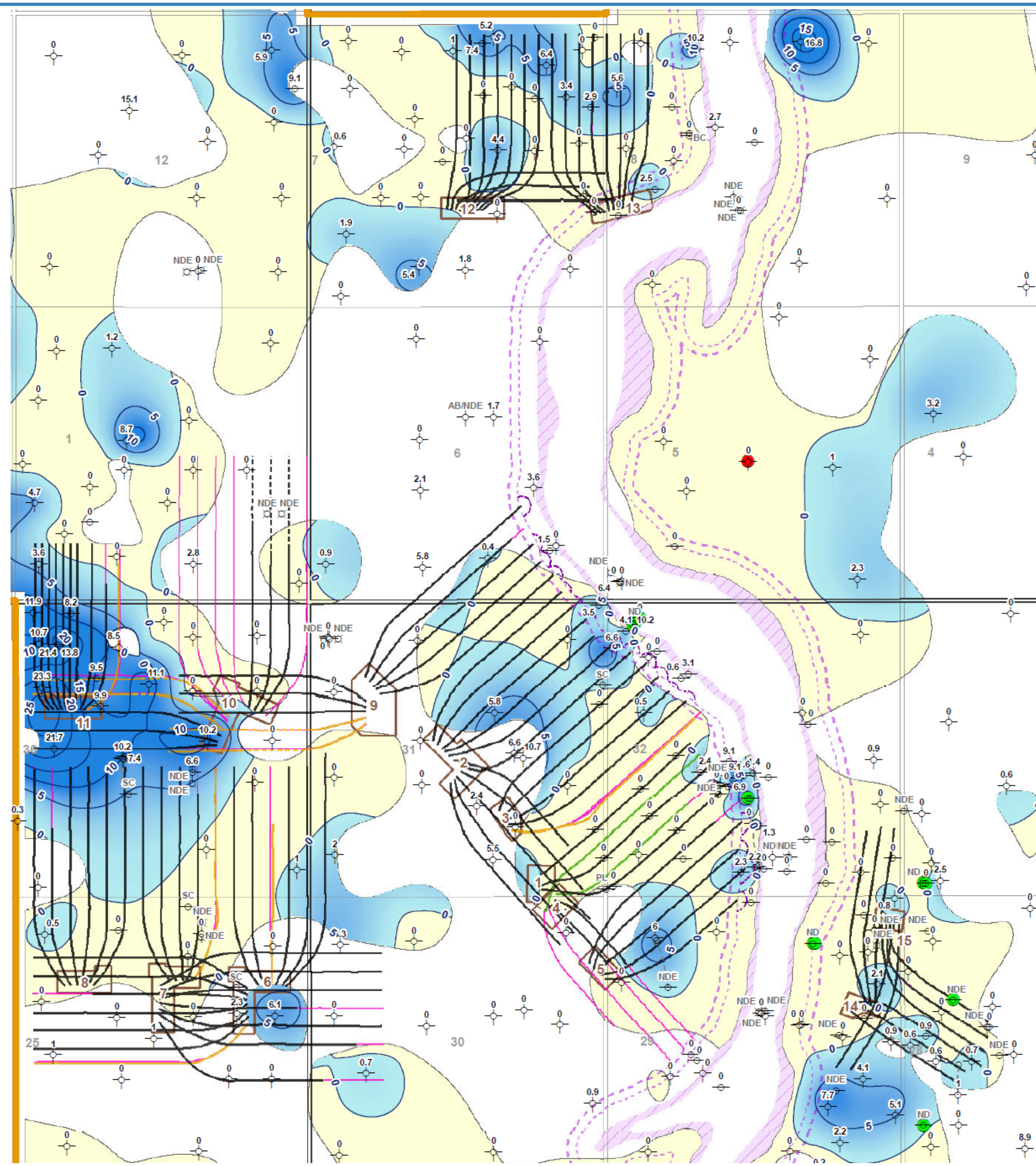
HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

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

MAP DATA
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- LLK 2014 EBIP HPVH ISO POLYGON

HIGH WATER SATURATION INTERVAL(s) ABOVE AND IN CONTACT WITH EBIP INTERVAL ISOPACH
- High : 27.4
- Low : 0.0m

- > 50% Swe and < 30% V_{shale}
- High water saturation intervals above and in contact with EBIP
- Contours clipped to 3m^3/m^2 HPVH EBIP contour



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

CONTOUR DATA (C.I.=2m)

- CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(s) WITHIN THE EBIP INTERVAL

2013/2014 DRILLING PROGRAM

- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

HORIZONTAL WELL STATUS (PRODUCER)

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

Q CHANNEL DATA

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

MAP DATA

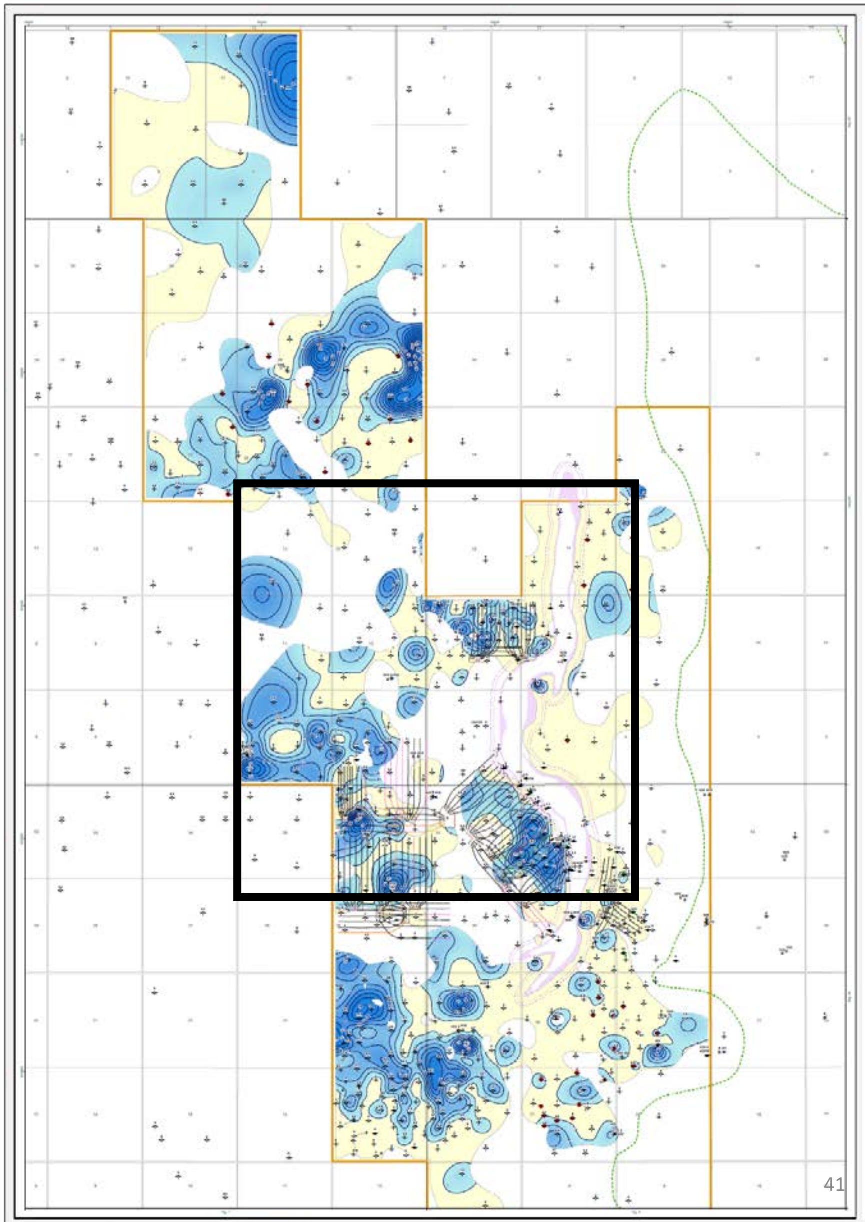
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- LLK 2014 EBIP HPVH ISO POLYGON

CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(s) WITHIN THE EBIP INTERVAL

High : 32.2

Low : 0.0m

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



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

nexen
A CNOOC LIMITED COMPANY

CONTOUR DATA (C.I.=2m)
- CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(s) WITHIN THE EBIP INTERVAL

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

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

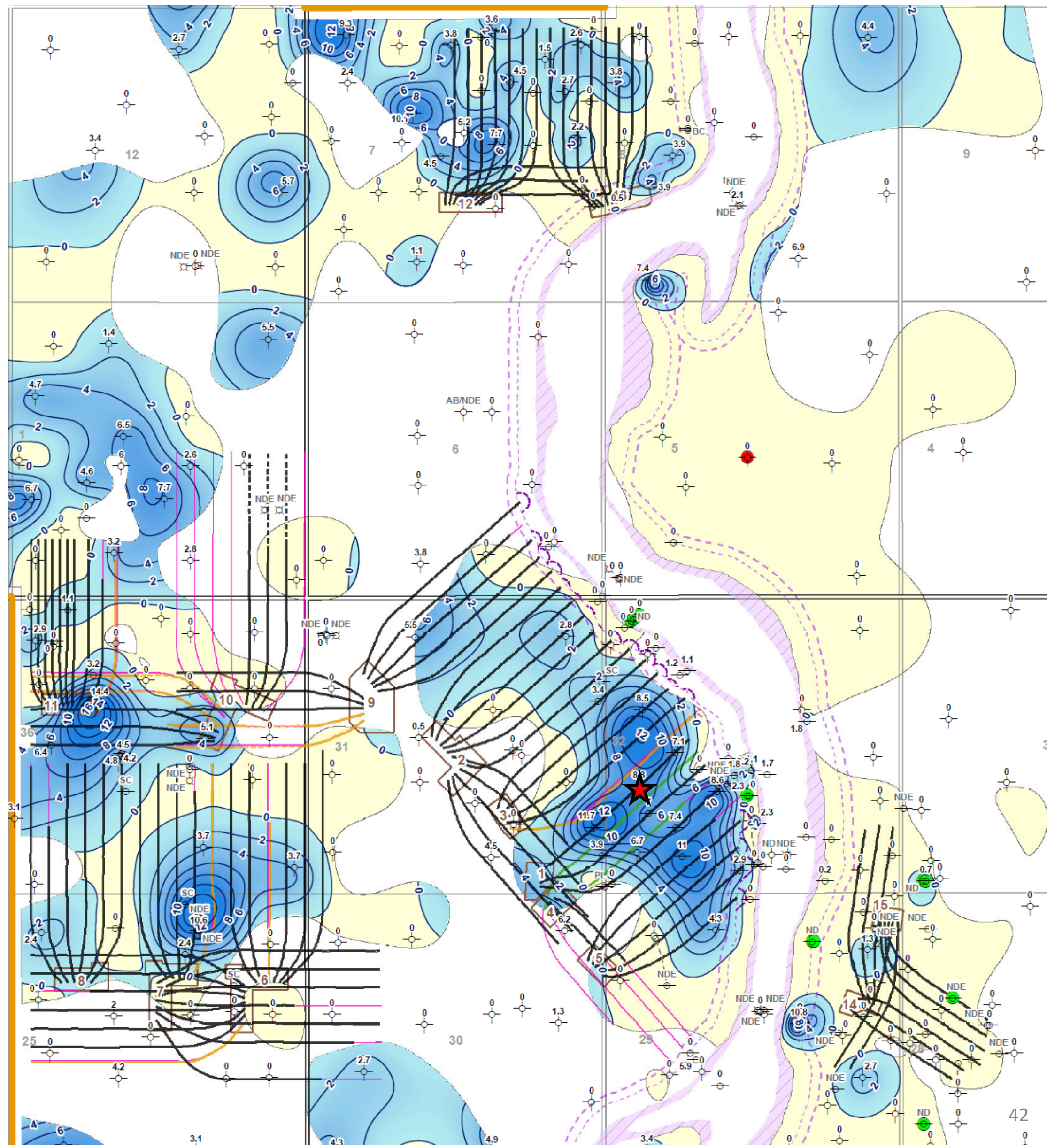
Q CHANNEL DATA
- Q CHANNEL UNCERTAINTY POLYGON
- Q CHANNEL UNCERTAINTY BUFFER (100m)
- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

MAP DATA
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA
- LLK 2014 EBIP HPVH ISO POLYGON

CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(s) WITHIN THE EBIP INTERVAL
- High : 32.2
- Low : 0.0m

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

★ TYPE LOG



Type Log – 100/05-32-085-06W4

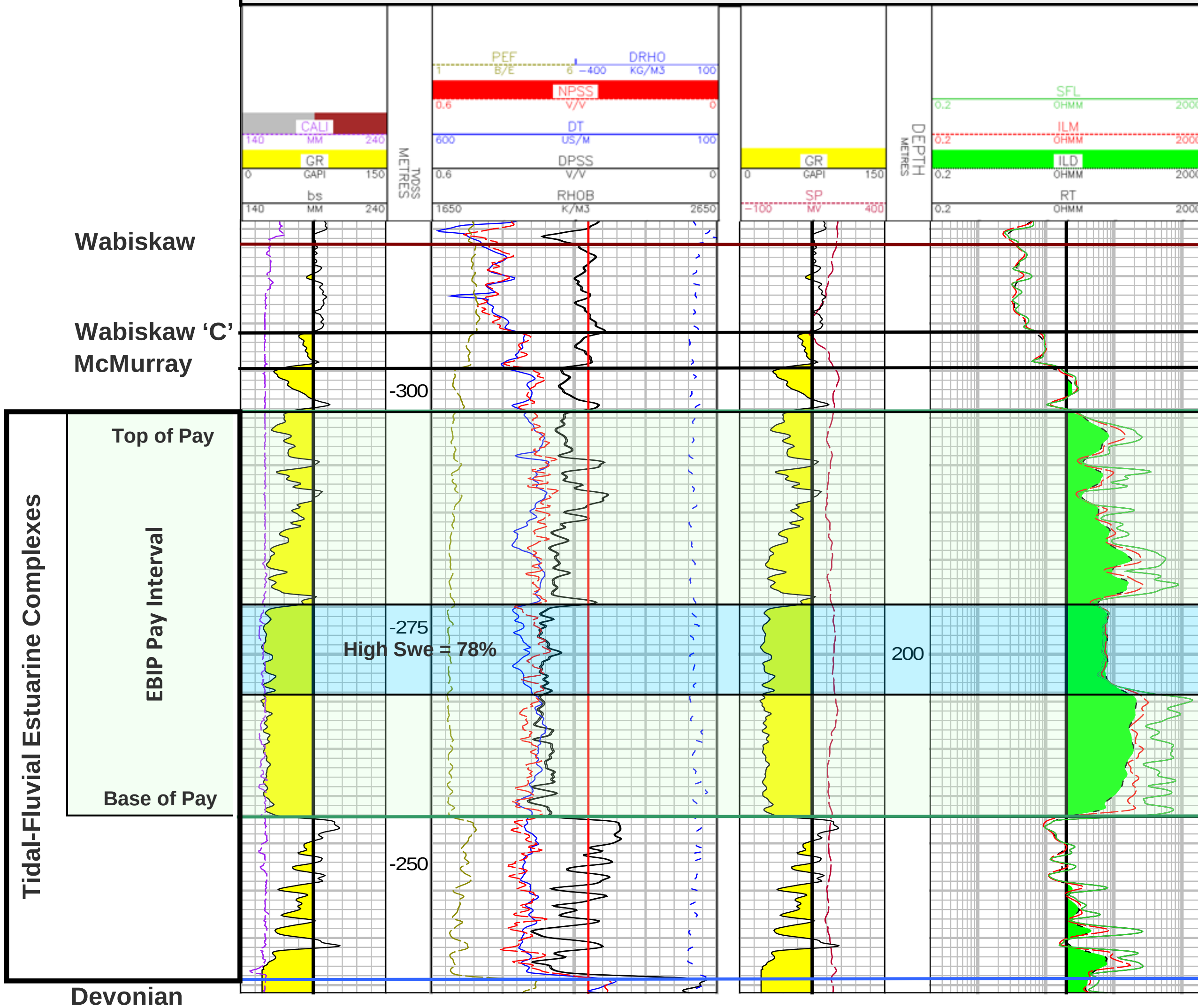
Well: 100_05-32-085-06W4_0

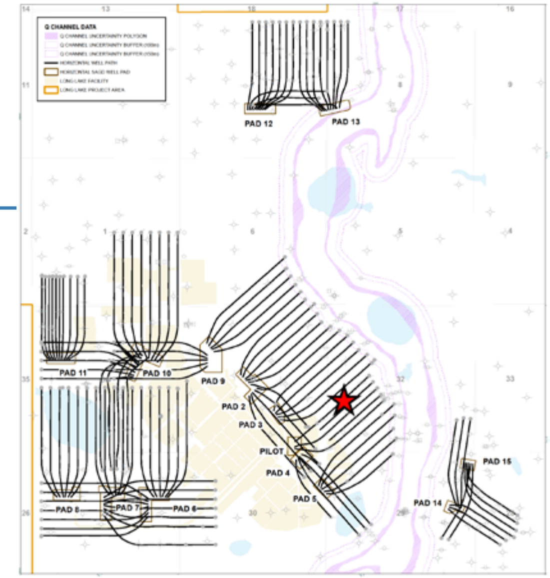
nexen

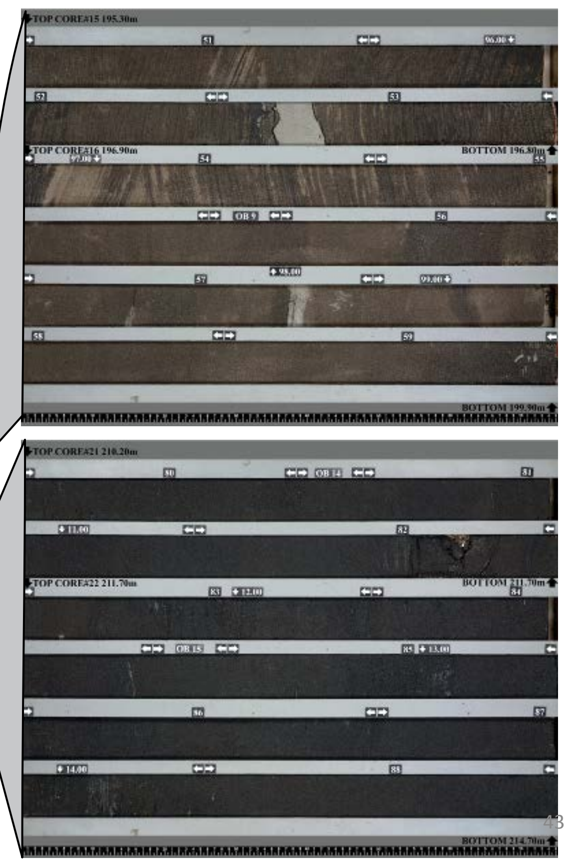
NEXEN OPTI OB1 B NEWBY 5-32-85-6

MEASUREMENT REF.: KB
ELEVATION MEAS. REF.: 472.20
DRILLED DEPTH: 248.80

SURFACE ELEVATION: 469.90
RIG RELEASE: 17-NOV-2002
VERTICAL SCALE: 1:480







Long Lake
Bottom Water Associated with EBIP Interval

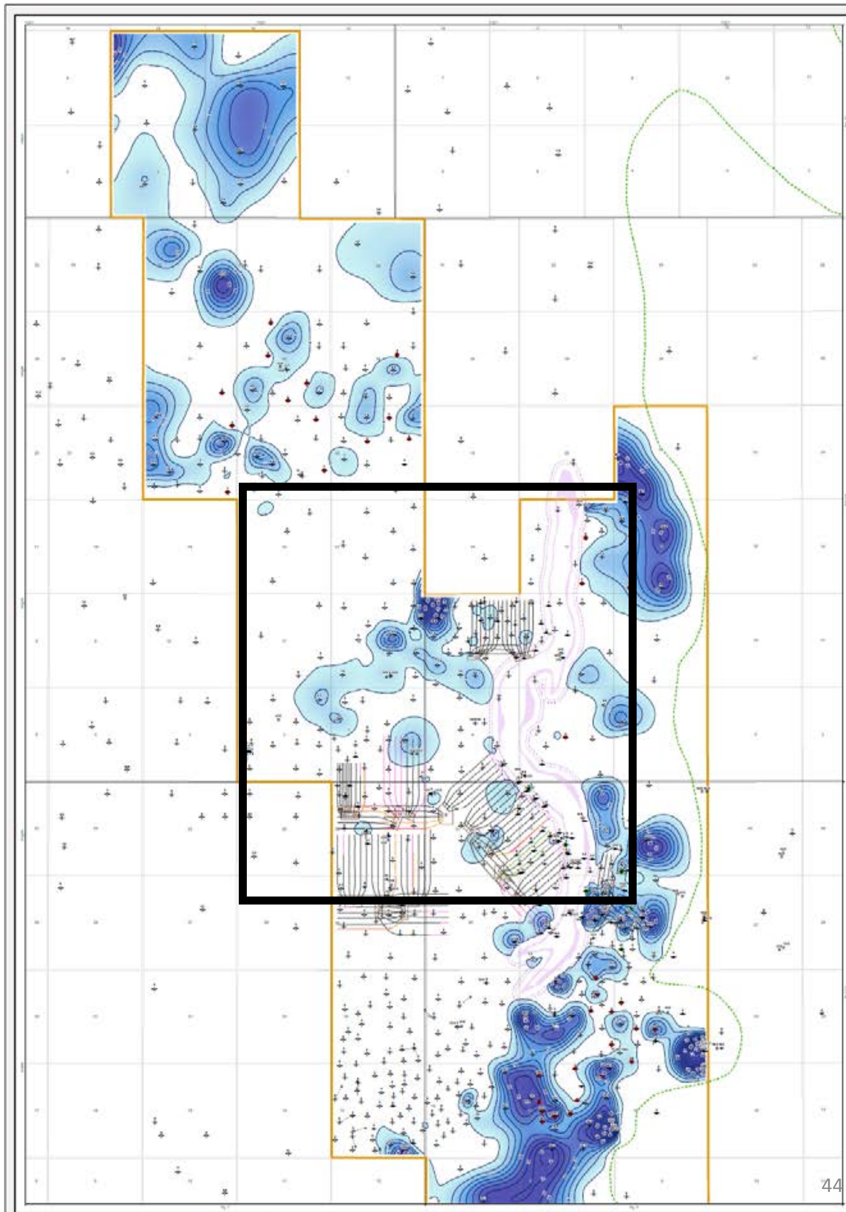
MAP DATA
- ZERO EDGE
- BOTTOM WATER ISOPACH CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

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

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

BOTTOM WATER ISOPACH RASTER
- High : 81.0
- Low : 0 m



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

Long Lake
Bottom Water Associated with EBIP Interval

MAP DATA
- ZERO EDGE
- BOTTOM WATER ISOPACH CONTOURS (C.I.=5m)
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

2013/2014 DRILLING PROGRAM
- CORE HOLE LOCATION
- OBSERVATION WELL LOCATION

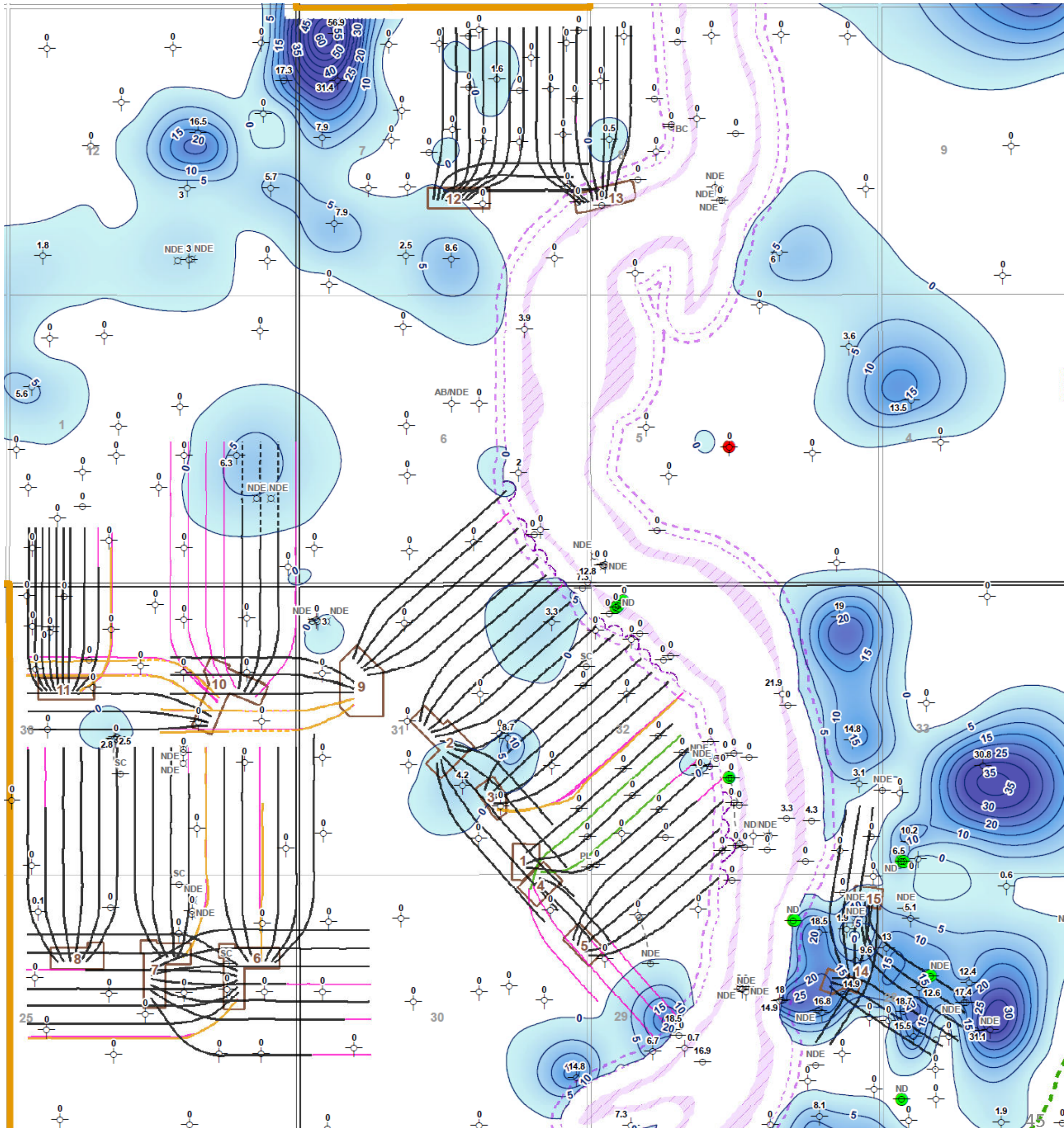
HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
- ACTIVE : NOT PRODUCING - SOLID LINER
- SUSPENDED
- DEVIATED WELL PATH (DRILLED)

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

BOTTOM WATER ISOPACH RASTER

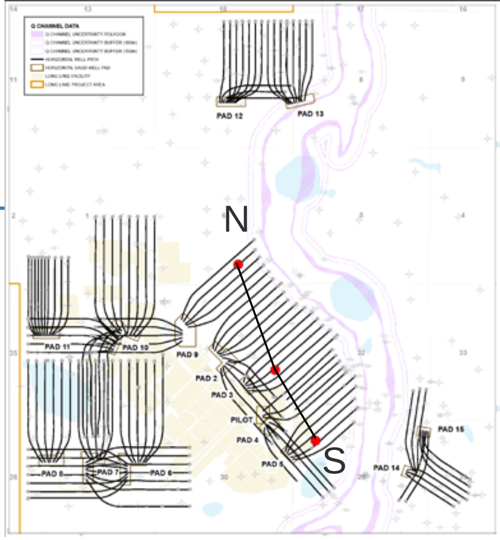
High : 81.0

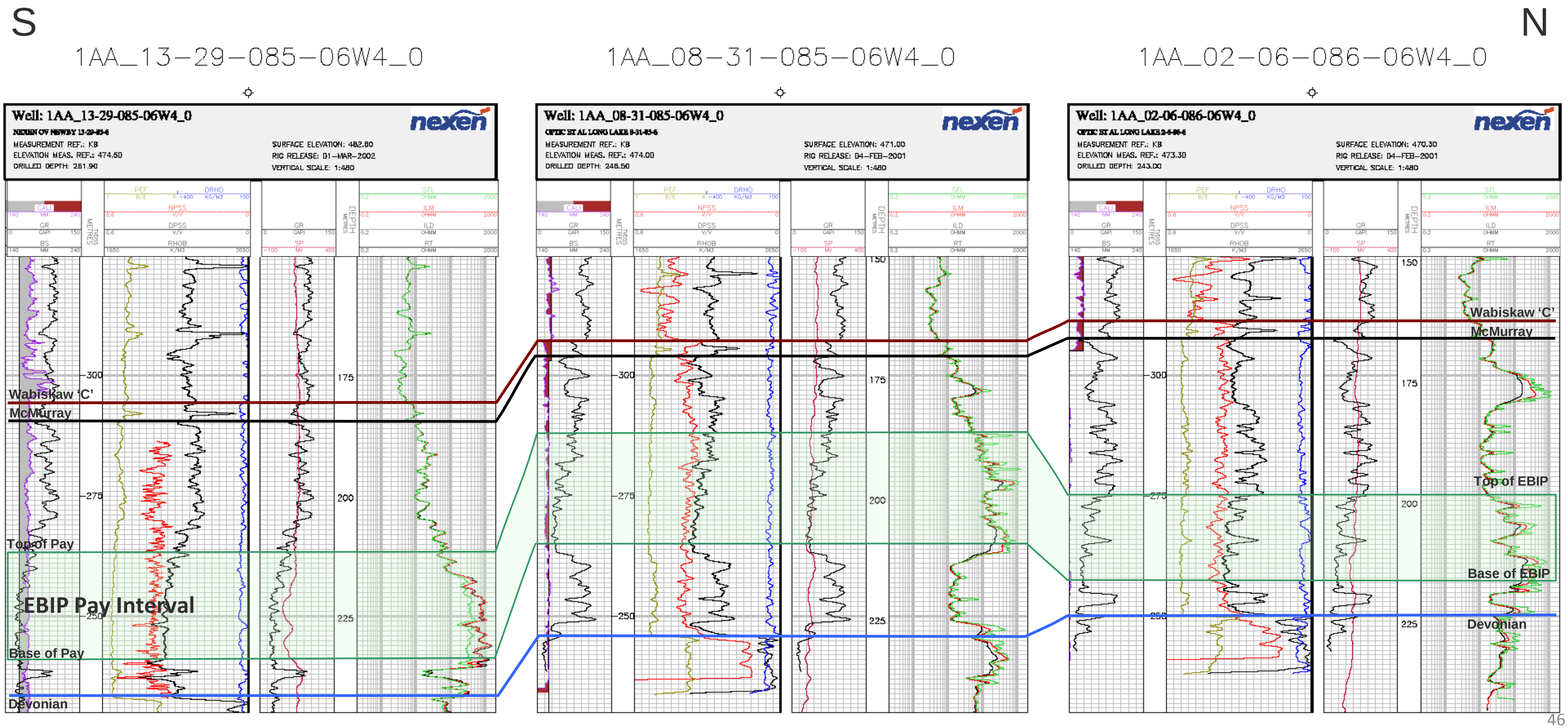
Low : 0 m



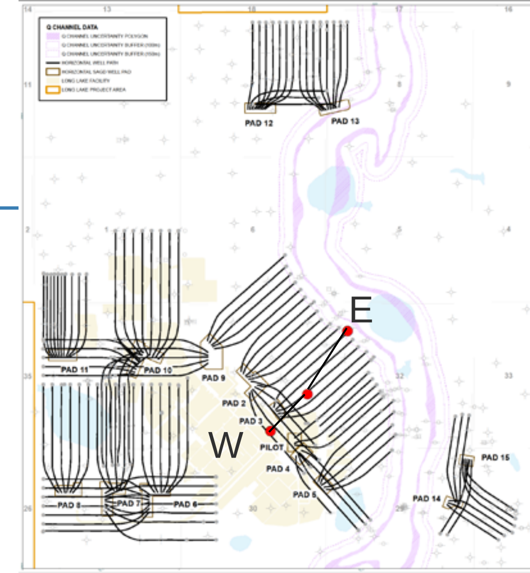
- > 50% Swe and < 30% V_{shale}
- Base of Bottom Water
  - top of a > 2m > 30% V_{shale} shale interval
- Contours clipped to $3m^3/m^2$ HPVH EBIP contour

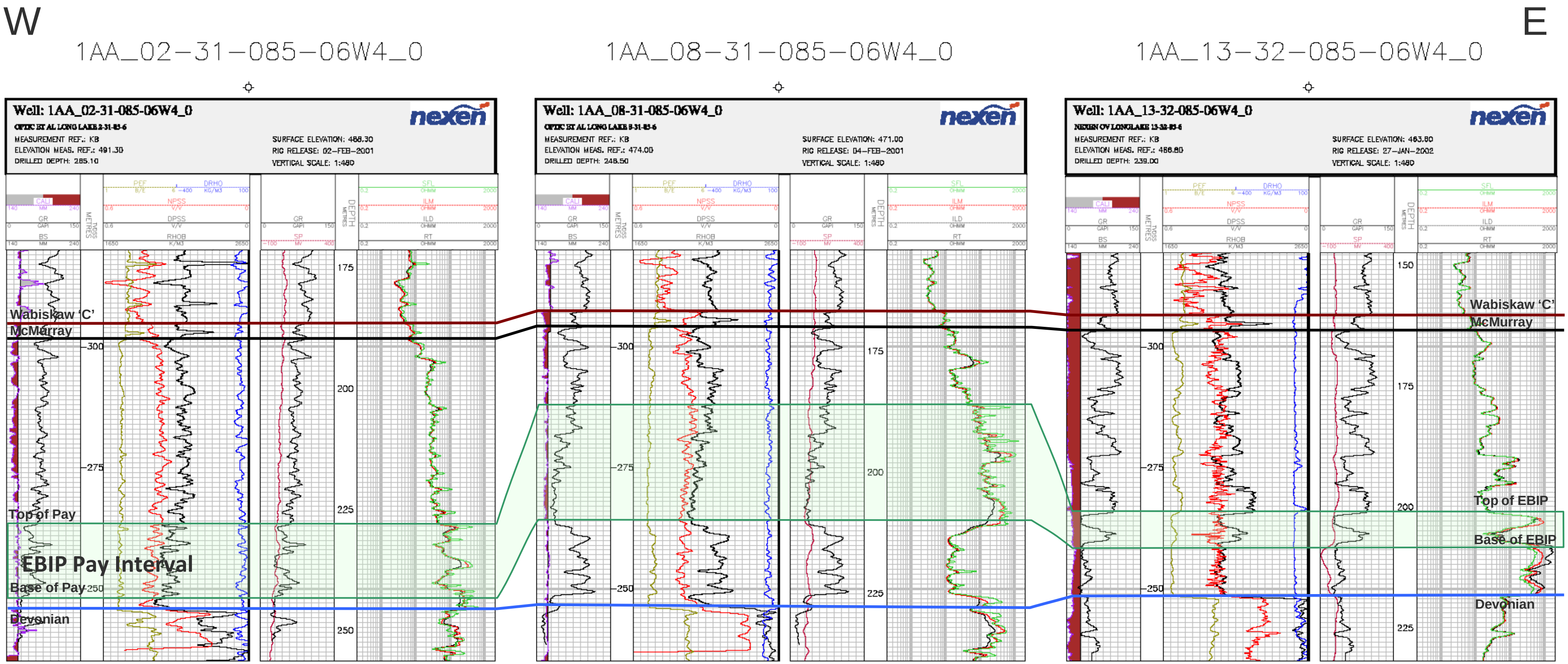
Representative structural cross-section of the East Side of Long Lake (South - North)



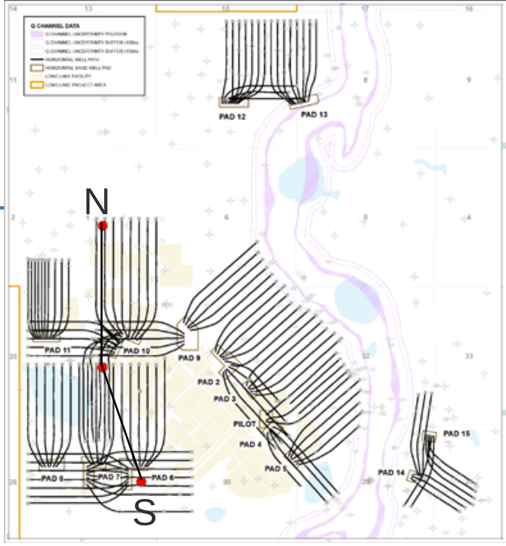


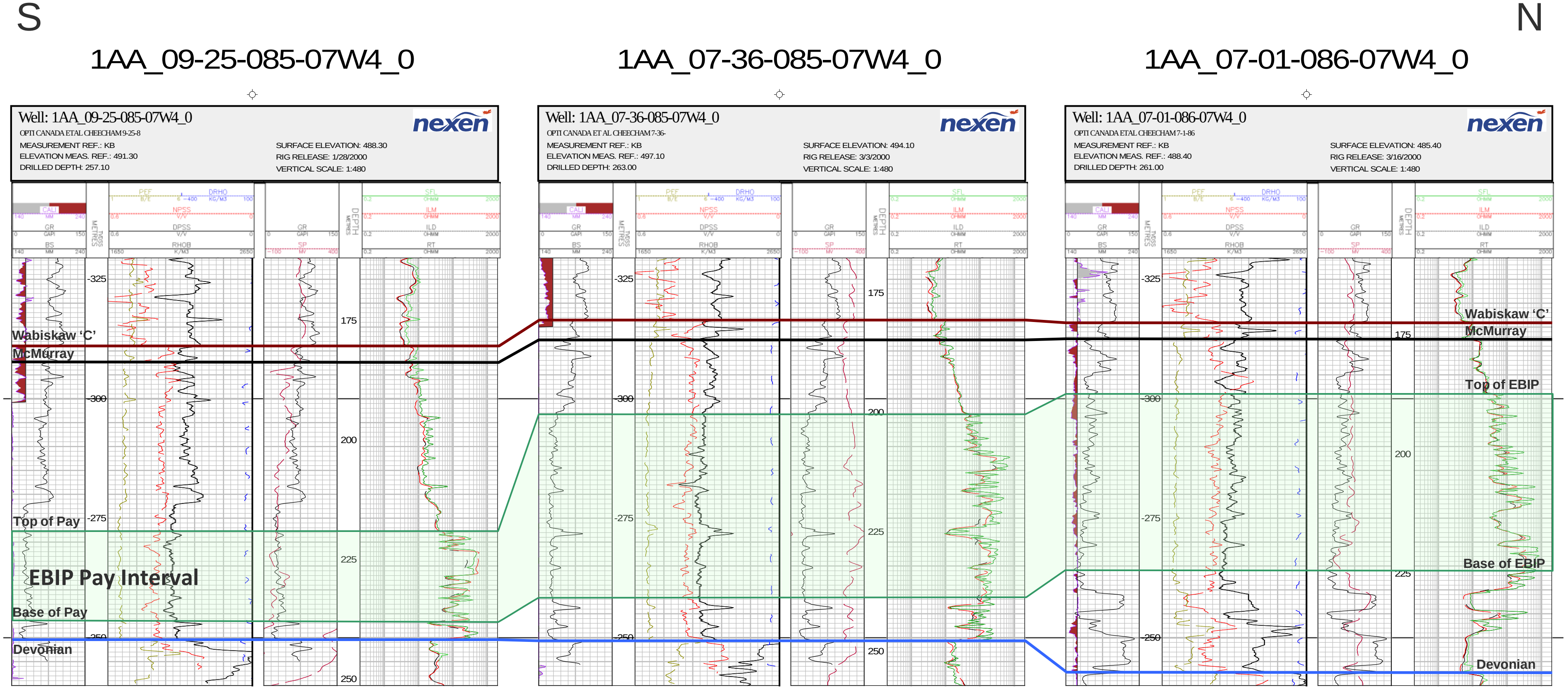
Representative structural cross-section of the East Side of Long Lake (West - East)



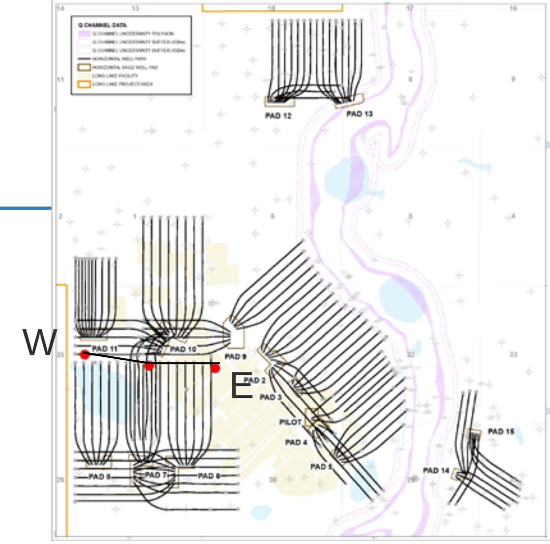


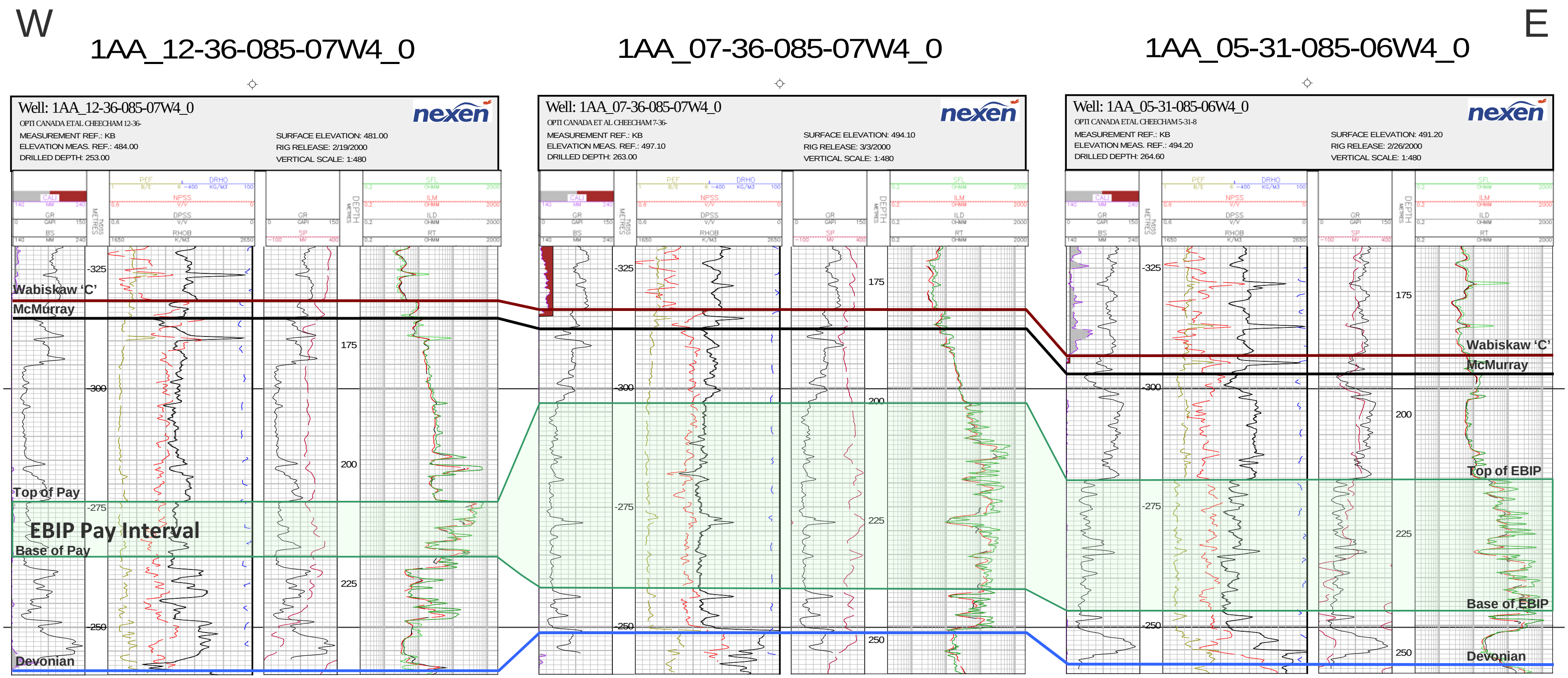
Representative structural cross-section of the West Side of Long Lake (South - North)



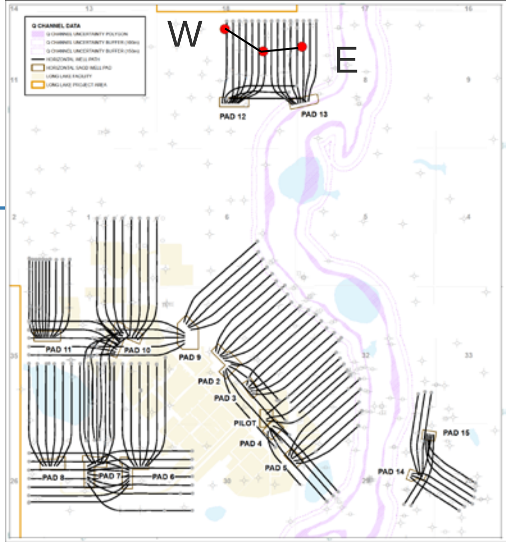


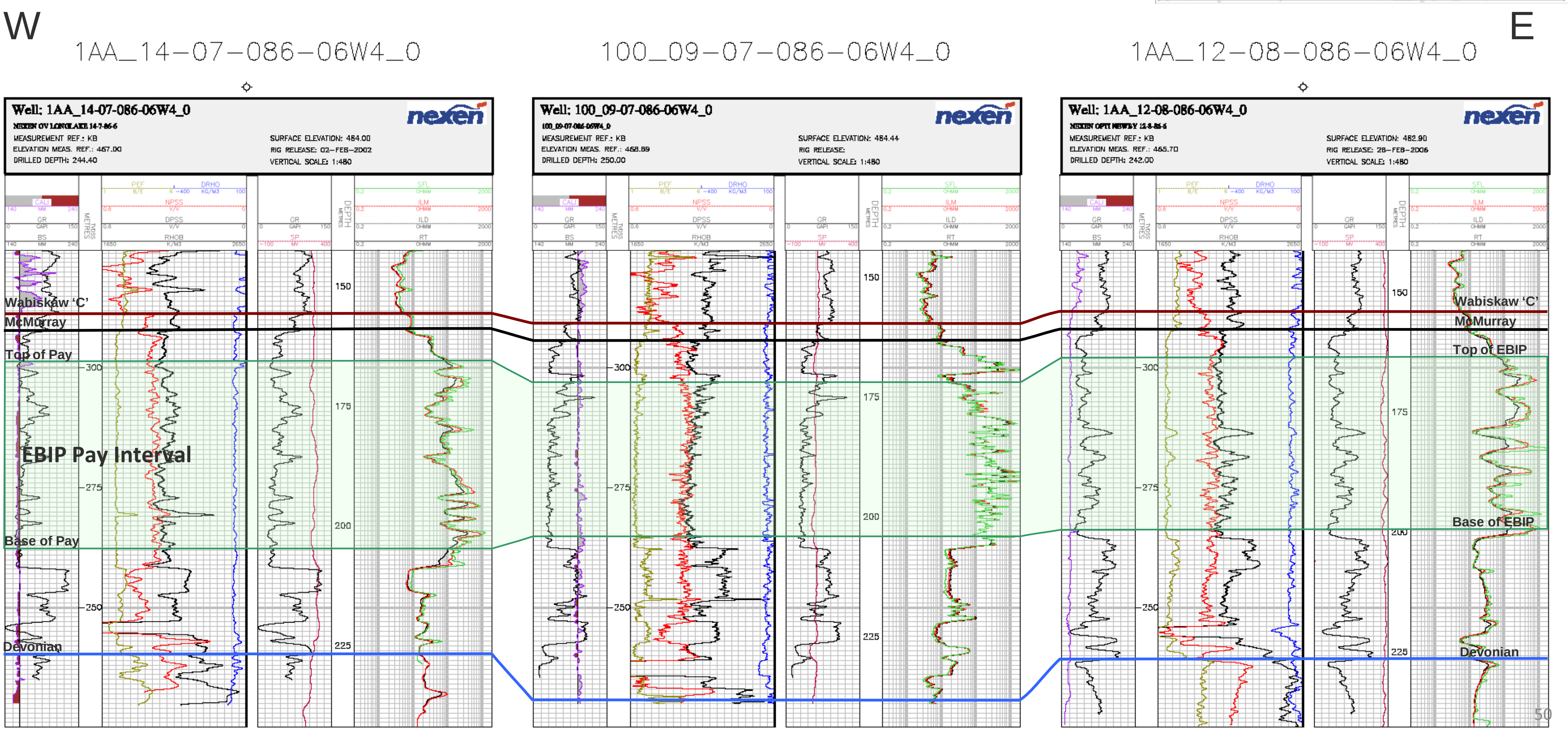
Representative structural cross-section of the West Side of Long Lake (West - East)



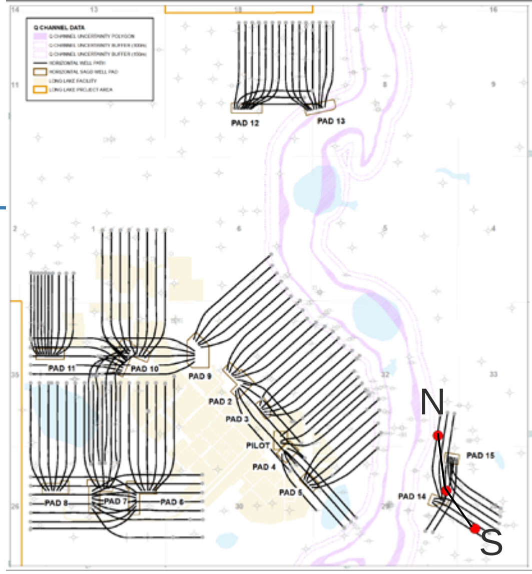


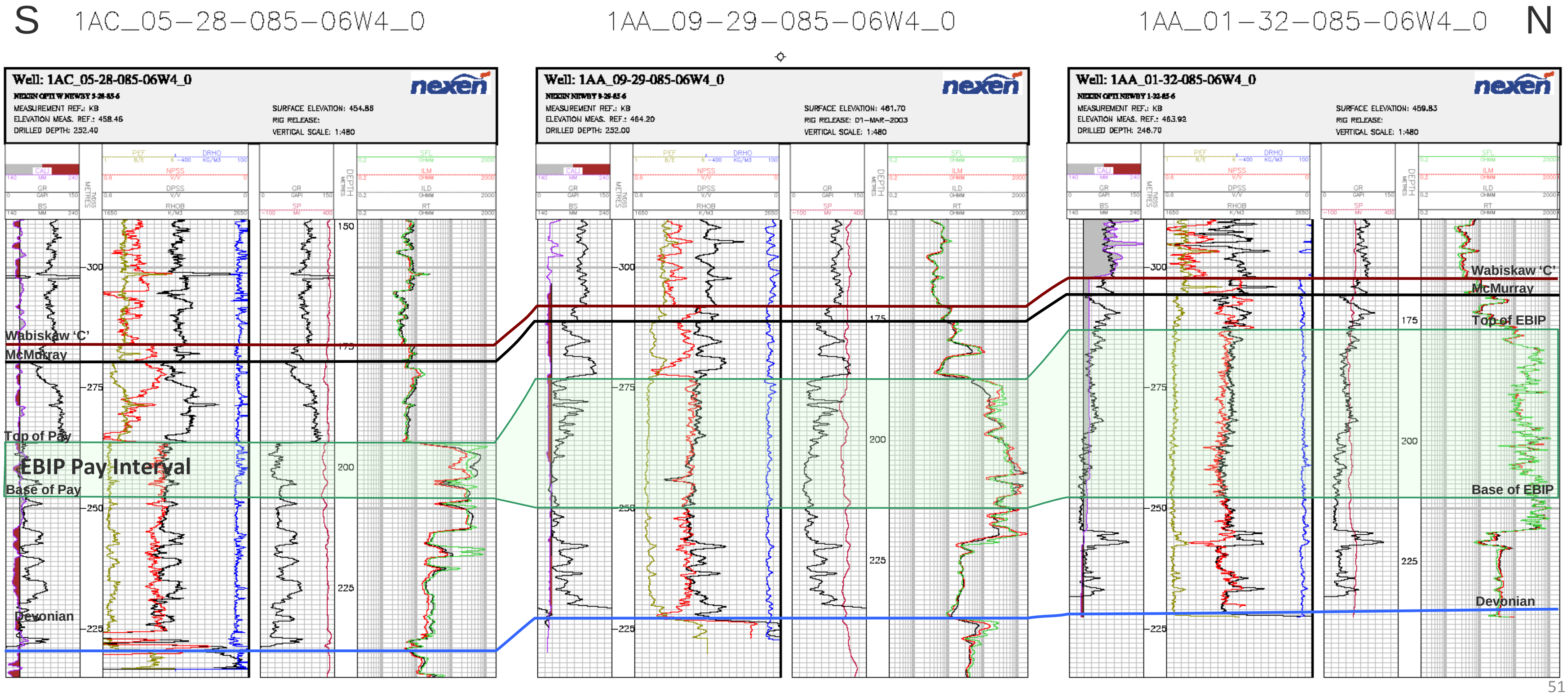
Representative structural cross-section of Pads 12 and 13





Representative structural cross-section of Pads 14 and 15

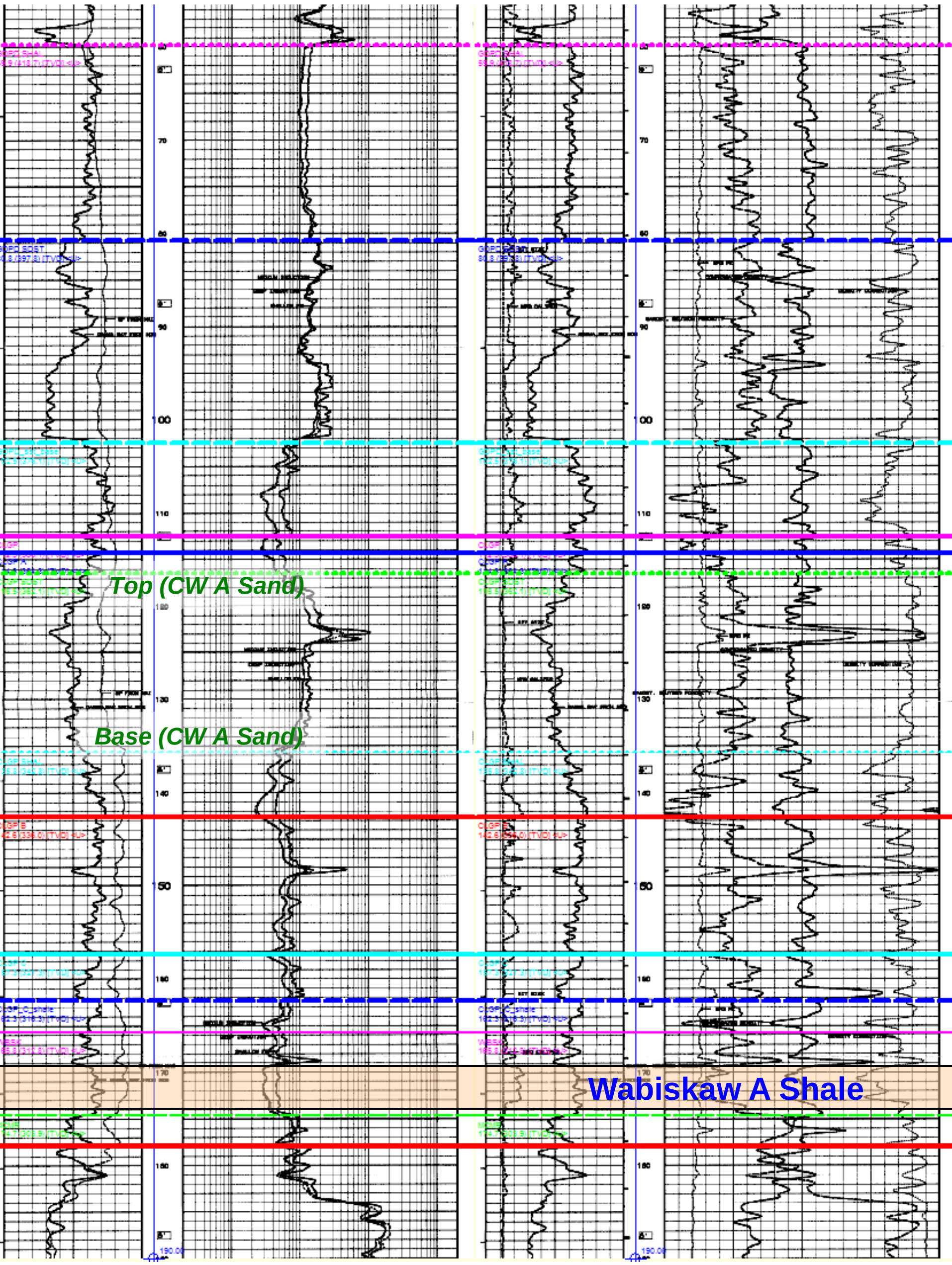




AA/08-20-085-06W4/0

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

Long Lake
Cap Rock Type Log



Grand Rapids B Sand

Base GRB Sand

Clearwater

Clearwater A

Clearwater B

Clearwater C

Wabiskaw (T21)

Wabiskaw C

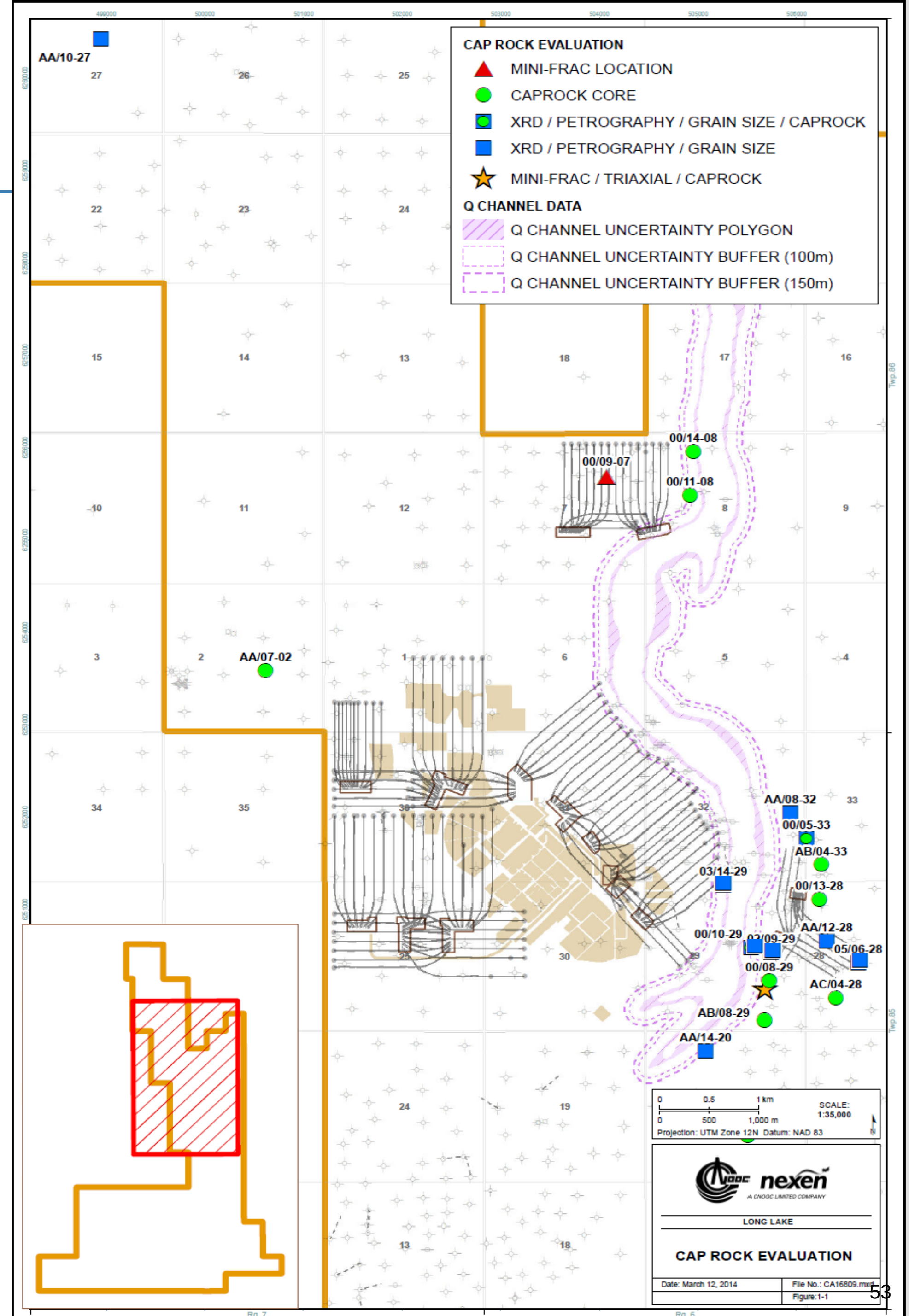
McMurray

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

Long Lake Cap Rock Evaluation - Pre-2014

- MINI-FRAC LOCATION
- CAPROCK CORE
- XRD / PETROGRAPHY / GRAIN SIZE
- MINI-FRAC / TRIAXIAL / CAPROCK
- McMURRAY BREACH by Q-CHANNEL UNCERTAINTY

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
1AA012008506W400
1AA070208607W400
1AA072008506W400
1AB043308506W400
1AB082908506W400
1AC042808506W400

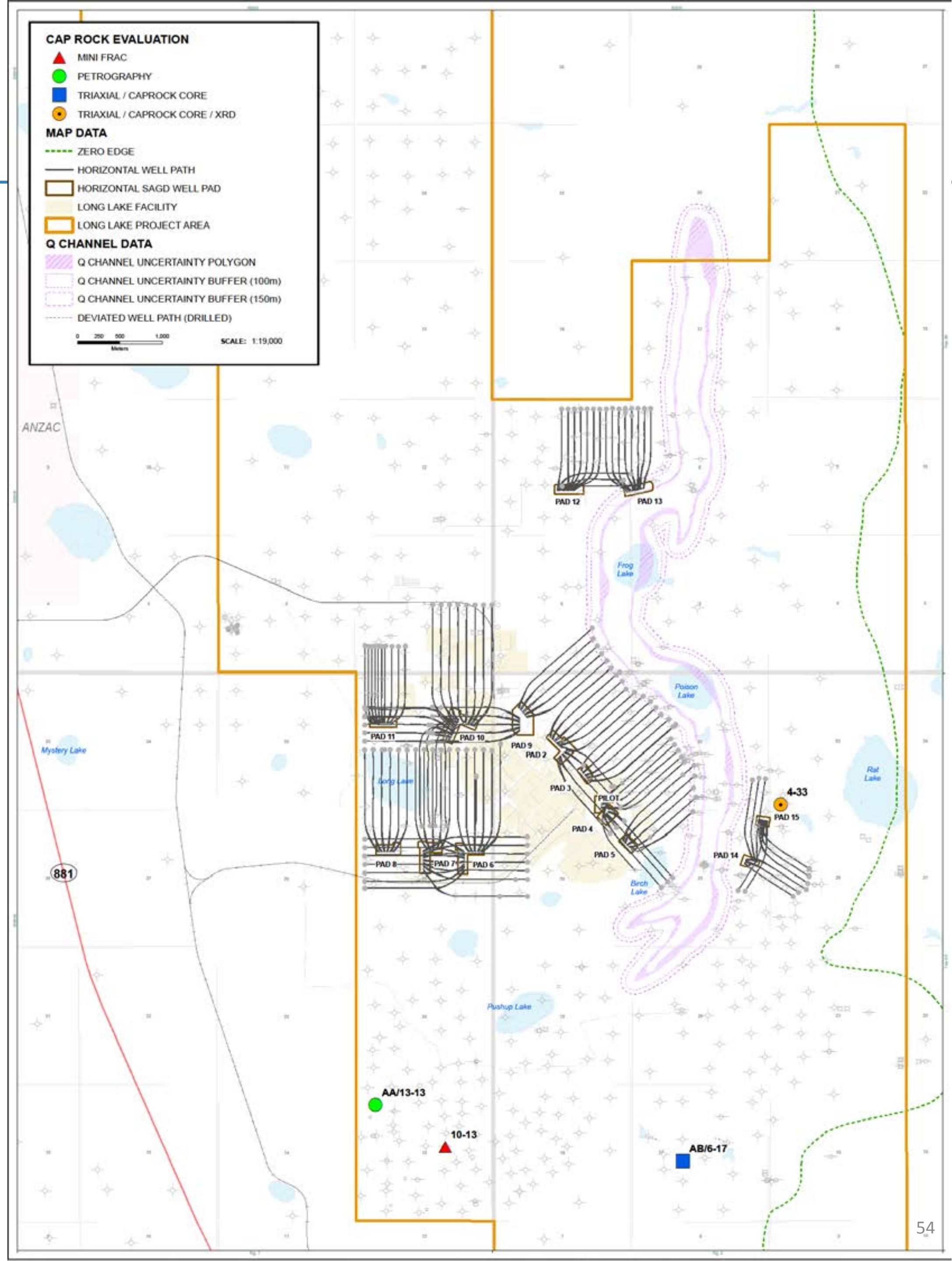


Long Lake Cap Rock Evaluation - 2014

CAP ROCK EVALUATION

- ▲ MINI FRAC
- ● PETROGRAPHY
- ■ TRIAXIAL / CAPROCK CORE
- ⊙ TRIAXIAL / CAPROCK CORE / XRD

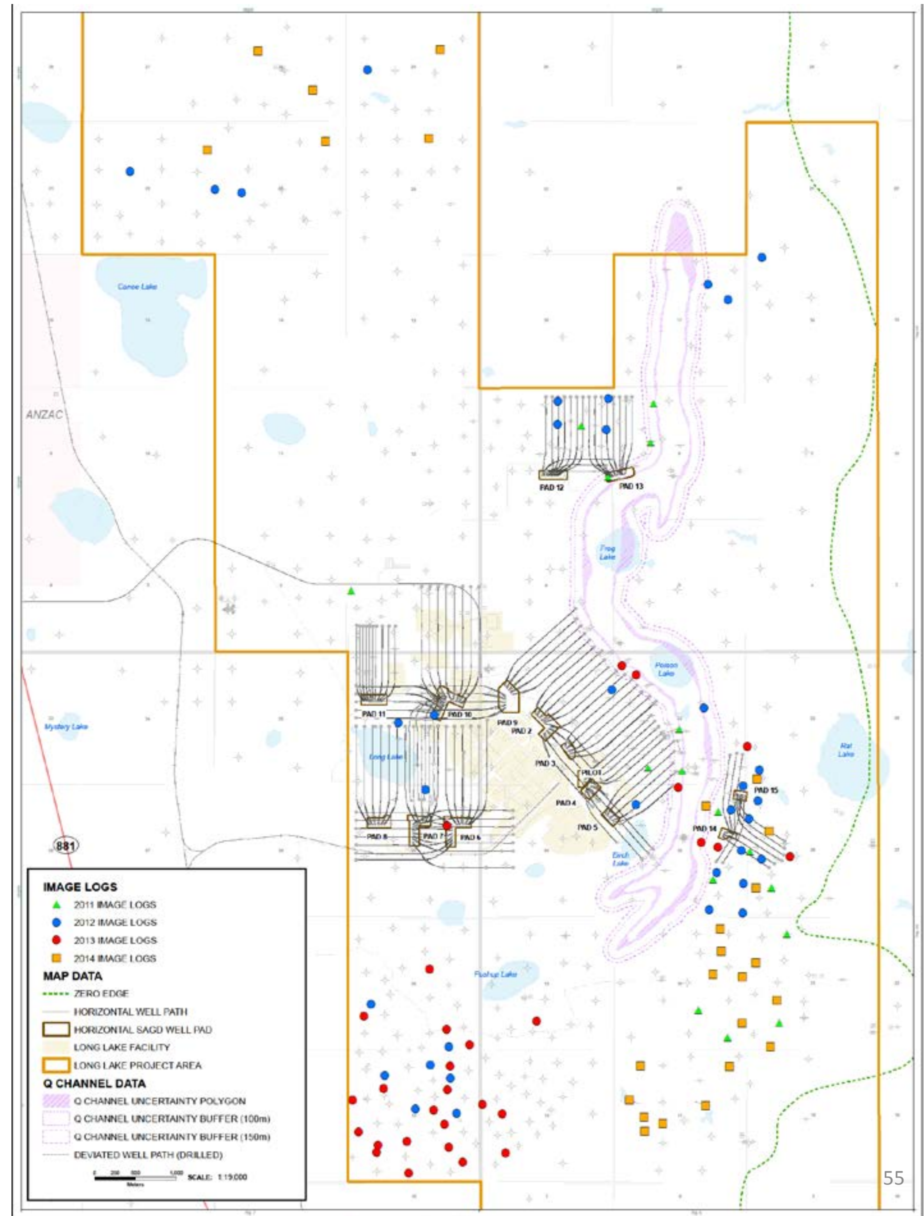
MINI-FRAC LOCATION
100101308506W400
TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB061708506W400
100043308506W400
XRD
100043308506W400
PETROGRAPHY
1AA131308507W4/00
CAPROCK CORE
1AB061708506W400
100043308506W400



Long Lake
Cap Rock Evaluation Image Logs

IMAGE LOGS

- ▲ 2011 IMAGE LOGS
- ● 2012 IMAGE LOGS
- ● 2013 IMAGE LOGS
- ■ 2014 IMAGE LOGS



Long Lake
Cap Rock Evaluation Image Logs

UWI	WELL_NAME	Licence No.	Year
103080708606W400	Nexen OPTI VWP Newby 8-7-86-6	0428037	2011
1AB052808506W400	Nexen OPTI Newby 5-28-85-6	0427602	2011
107033208506W400	Nexen OPTI OBS E Newby 3-32-85-6	0430940	2011
100140808606W400	Nexen OPTI VWP Newby 14-8-86-6	0429890	2011
1AB042108506W400	Nexen OPTI Newby 4-21-85-6	0427525	2011
117063208506W400	Nexen OPTI VWP E Newby 6-32-85-6	0428454	2011
1AA072008506W400	Nexen OPTI Newby 7-20-85-6	0427523	2011
1AB050108607W400	Nexen OPTI Newby 5-1-86-7	0426907	2011
1AB082908506W400	Nexen OPTI Newby 8-29-85-6	0427605	2011
1AB142108506W400	Nexen OPTI Newby 14-21-85-6	0427599	2011
100090708606W400	Nexen OPTI OBS Newby 9-7-86-6	0429878	2011
100110808606W400	Nexen OPTI VWP Newby 11-8-86-6	0429631	2011
1AB162908506W400	Nexen OPTI Newby 16-29-85-6	0427928	2011
1AA012008506W400	Nexen OPTI Newby 1-20-85-6	0427522	2011
1AC042808506W400	Nexen OPTI NE Newby 4-28-85-6	0427601	2011
106033208506W400	Nexen OPTI OBS W Newby 3-32-85-6	0429976	2011
100082908506W400	Nexen CNOOC OBS SW Newby 8-29-85-6	0443963	2012
100100708606W400	Nexen CNOOC OBS Newby 10-7-86-6	0443868	2012
109103608507W400	Nexen OPTI OBS Newby 10-36-85-7	0442823	2012
103093108506W400	Nexen CNOOC OBS E Newby 9-31-85-6	0444540	2012
1AD162908506W400	Nexen OPTI S Newby 16-29-85-6	0439561	2012
1AB101308507W400	Nexen OPTI SW Newby 10-13-85-7	0440277	2012
1AB161308507W400	Nexen OPTI SW Newby 16-13-85-7	0440283	2012
111150708606W400	Nexen CNOOC OBS Newby 15-7-86-6	0443869	2012
1AA052508607W400	Nexen OPTI Newby 5-25-86-7	0439592	2012
1AA091708606W400	Nexen OPTI Newby 9-17-86-6	0439575	2012

UWI	WELL_NAME	Licence No.	Year
1AC082908506W400	Nexen OPTI NE Newby 8-29-85-6	0439559	2012
100093608507W400	Nexen OPTI OBS Newby 9-36-85-7	0442997	2012
1AA052308607W400	Nexen CNOOC NE Newby 5-23-86-7	0443298	2012
1AA112208607W400	Nexen OPTI Newby 11-22-86-7	0439583	2012
122063608507W400	Nexen OPTI OBS W Newby 6-36-85-7	0429990	2012
100103208506W400	Nexen CNOOC OBS Newby 10-32-85-6	0443946	2012
1AB012408507W400	Nexen OPTI SW Newby 1-24-85-7	0440291	2012
1AB043308506W400	Nexen OPTI W Newby 4-33-85-6	0439562	2012
1AC012908506W400	Nexen OPTI NE Newby 1-29-85-6	0439557	2012
1AC052808506W400	Nexen OPTI W Newby 5-28-85-6	0439554	2012
1AB141308507W400	Nexen OPTI SW Newby 14-13-85-7	0440280	2012
1AA052408507W400	Nexen OPTI Newby 5-24-85-7	0440293	2012
1AB131608606W400	Nexen OPTI N Newby 13-16-86-6	0439574	2012
102122908506W400	Nexen OPTI OBS Newby 12-29-85-6	0438758	2012
1AB012908506W400	Nexen OPTI SE Newby 1-29-85-6	0439556	2012
1AB122808506W400	Nexen OPTI NW Newby 12-28-85-6	0439555	2012
111160708606W400	Nexen CNOOC OBS Newby 16-7-86-6	0444078	2012
1AB052308607W400	Nexen CNOOC NW Newby 5-23-86-7	0443299	2012
1AB022908506W400	Nexen OPTI SE Newby 2-29-85-6	0439558	2012
1AC162908506W400	Nexen OPTI NE Newby 16-29-85-6	0439560	2012
100132808506W400	Nexen CNOOC OBS W Newby 13-28-85-6	0443942	2012
1AA151708606W400	Nexen OPTI SE Newby 15-17-86-6	0439576	2012
103090708606W400	Nexen CNOOC OBS NE Newby 9-7-86-6	0444368	2012
100152508507W400	Nexen CNOOC OBS Newby 15-25-85-7	0444147	2012
1AB091308507W400	Nexen OPTI SW Newby 9-13-85-7	0440276	2012
1AA151308507W400	Nexen OPTI Newby 15-13-85-7	0440282	2012

Long Lake
Cap Rock Evaluation Image Logs

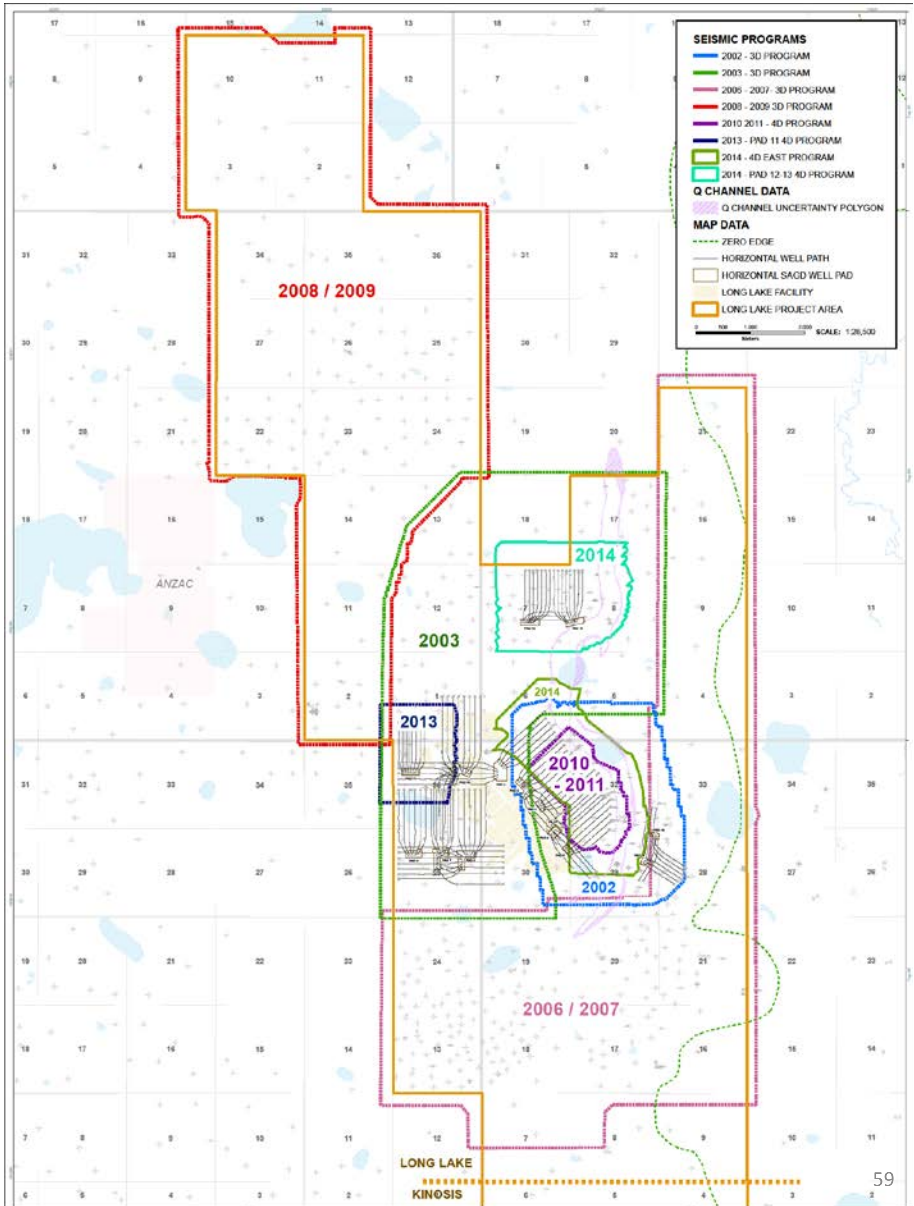
UWI	Well Name	Well License	Year
1AB121808506W400	Nexen CNOOC S Newby 12-18-85-6-4	452419	2013
1AE121808506W400	Nexen CNOOC W Newby 12-18-85-6-4	452786	2013
1AB071308507W400	Nexen CNOOC Newby 7-13-85-7-4	452444	2013
1AC081308507W400	Nexen CNOOC SW Newby 8-13-85-7-4	452446	2013
1AC091308507W400	Nexen CNOOC NW Newby 9-13-85-7-4	452447	2013
1AC161308507W400	Nexen CNOOC W Newby 16-13-85-7-4	452406	2013
1AB052408507W400	Nexen CNOOC SW Newby 5-24-85-7-4	452408	2013
1AA102408507W400	Nexen CNOOC Newby 10-24-85-7-4	452410	2013
1AD041308507W400	Nexen CNOOC DD E Newby 4-13-85-7-4 (BH)	452682	2013
1AB051308507W400	Nexen CNOOC DD NW Newby 5-13-85-7-4 (BH)	452683	2013
1AC051308507W400	Nexen CNOOC DD SE Newby 5-13-85-7-4 (BH)	452872	2013
1AB111308507W400	Nexen CNOOC DD NW Newby 11-13-85-7-4 (BH)	452685	2013
1AC012408507W400	Nexen CNOOC DD SE Newby 1-24-85-7-4 (BH)	452686	2013
1AD012408507W400	Nexen CNOOC DD NE Newby 1-24-85-7-4 (BH)	452873	2013
100101308507W400	Nexen CNOOC OBS Newby 10-13-85-7	453792	2013
102092508507W400	Nexen CNOOC OBS Newby 9-25-85-7	451050	2013
100053308506W400	Nexen OPTI OBS W Newby 5-33-85-6	444781	2013
105062808506W400	Nexen CNOOC OBS Newby 6-28-85-6	453531	2013
100102908506W400	Nexen CNOOC VWP S Newby 10-29-85-6	453585	2013
100011308507W400	Nexen CNOOC S Newby 1-13-85-7	0453603	2013
103061308507W400	Nexen CNOOC OBS SE Newby 6-13-85-7	0453571	2013
1AB031308507W400	Nexen CNOOC DD SE Newby 3-13-85-7	0452681	2013
1AB041808506W400	Nexen CNOOC NE Newby 4-18-85-6	0452427	2013
1AB121308507W400	Nexen CNOOC DD W Newby 12-13-85-7	0452684	2013
110133208506W400	Nexen CNOOC VWP SE Newby 13-32-85-6	0453560	2013
109133208506W400	Nexen CNOOC VWP W Newby 13-32-85-6	0453540	2013
103142908506W400	Nexen CNOOC VWP Newby 14-29-85-6	0453532	2013
102092908506W400	Nexen CNOOC OBS SW Newby 9-29-85-6	0453581	2013
1AB031908506W400	Nexen CNOOC NE Newby 3-19-85-6	0452424	2013

Long Lake
Cap Rock Evaluation Image Logs

UWI	Well Name	Well Licence	Year
100042808506W400	NEU CNOOC VWP NEWBY 4-28-85-6	461719	2014
100043308506W400	NEU CNOOC VWP S NEWBY 4-33-85-6	461840	2014
100152908506W400	NEU CNOOC VWP NEWBY 15-29-85-6	462042	2014
103122808506W400	NEU CNOOC VWP NEWBY 12-28-85-6	461749	2014
1AA022608607W400	NEU CNOOC NE NEWBY 2-26-86-7	462081	2014
1AA102508607W400	NEU CNOOC NEWBY 10-25-86-7	461064	2014
1AA112608607W400	NEXEN CNOOC NEWBY 11-26-86-7	462083	2014
1AA152408607W400	NEU CNOOC NEWBY 15-24-86-7	461063	2014
1AA162208607W400	NEU CNOOC NEWBY 16-22-86-7	462076	2014
1AA162308607W400	NEU CNOOC NEWBY 16-23-86-7	462078	2014
1AB012008506W400	NEU CNOOC NEWBY 1-20-85-6	461037	2014
1AB051708506W400	NEU CNOOC NEWBY 5-17-85-6	461031	2014
1AB052108506W400	NEXEN CNOOC NEWBY 5-21-85-6	461083	2014
1AB061708506W400	NEU CNOOC NEWBY 6-17-85-6	461614	2014
1AB092008506W400	NEU CNOOC NW NEWBY 9-20-85-6	461079	2014
1AB101708506W400	NEU CNOOC DD NEWBY 10-17-85-6	461065	2014
1AB121708506W400	NEU CNOOC DD NEWBY 12-17-85-6	461066	2014
1AB122108506W400	NEU CNOOC NEWBY 12-21-85-6	461085	2014
1AB131708506W400	NEU CNOOC NEWBY 13-17-85-6	461034	2014
1AB161708506W400	NEU CNOOC NEWBY 16-17-85-6	461036	2014
1AB162008506W400	NEU CNOOC NEWBY 16-20-85-6	461081	2014
1AC042108506W400	NEU CNOOC NEWBY 4-21-85-6	461082	2014
1AC051708506W400	NEU CNOOC S NEWBY 5-17-85-6	461032	2014
1AC092008506W400	NEU CNOOC SW NEWBY 9-20-85-6	461080	2014
1AD092008506W400	NEU CNOOC SE Newby 9-20-85-6	461709	2014

Long Lake Seismic

- 3-D seismic as of 2014
- Pads 4 and 5 & Pads 12 and 13 4-D seismic acquired in 2014



Long Lake
Seismic

Project Objectives and Expectations:

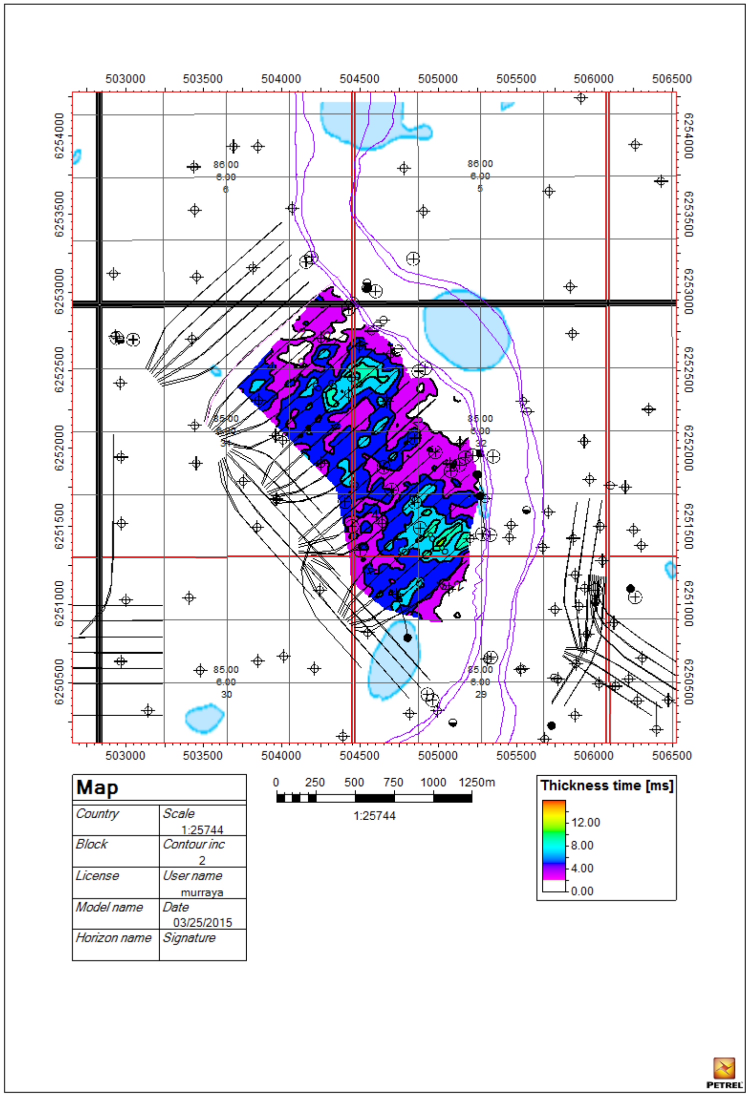
- Use 4D (time-lapse) seismic techniques to detect areas of the reservoir that have been influenced by steam injection
- Potential to monitor steam conformance along a well pair and image thief zones

Three different areas were examined in 2014

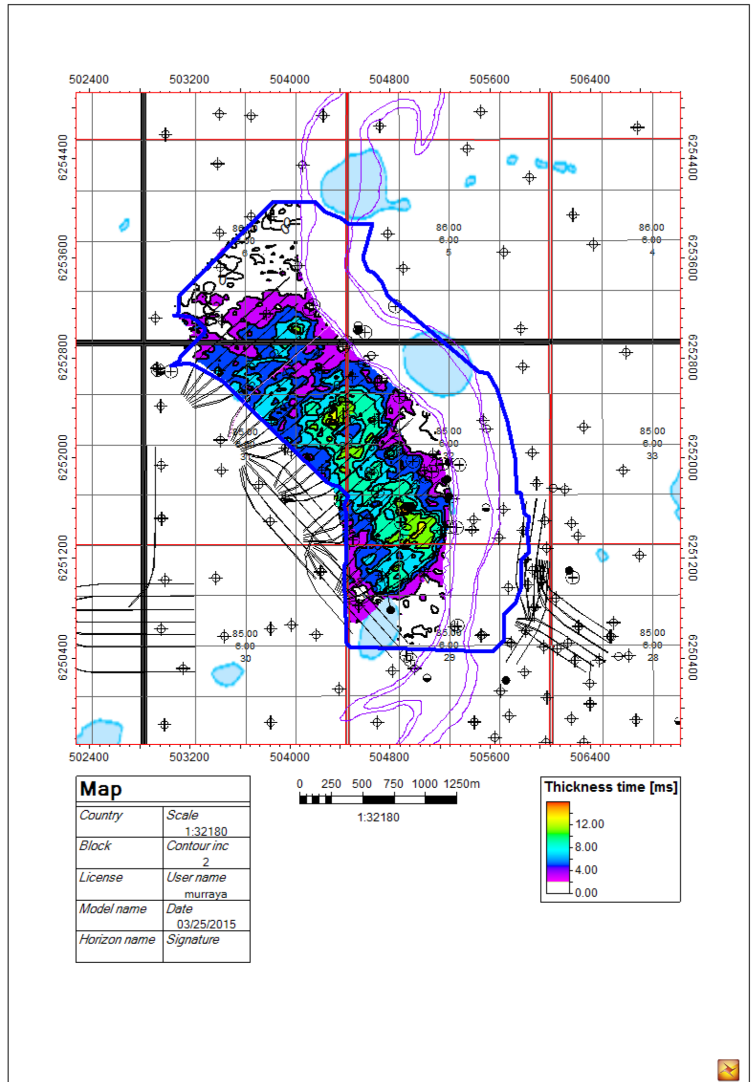
- 2014 4D survey covering Pads 1, 3, 5 and a portion of Pad 2NE
- 2014 4D survey covering Pads 12 and 13
- 2013 4D survey covering Pads 10W & 11

Long Lake
Seismic – East Asset Time Delay

2011 4D TIME DELAY



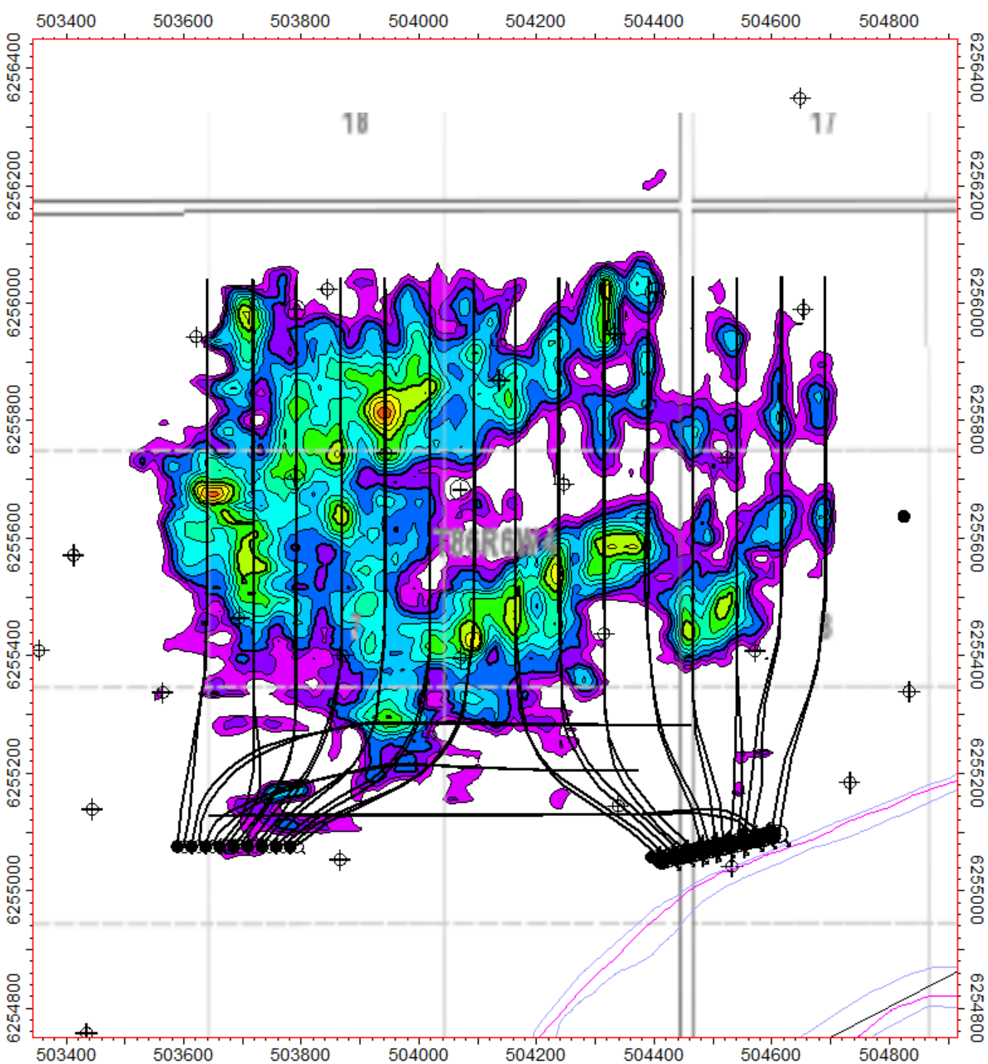
2014 4D TIME DELAY



Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2011 and 2014.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

Long Lake
Seismic – East Asset Time Delay

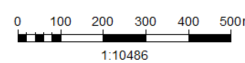


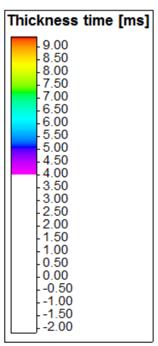
Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2013.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

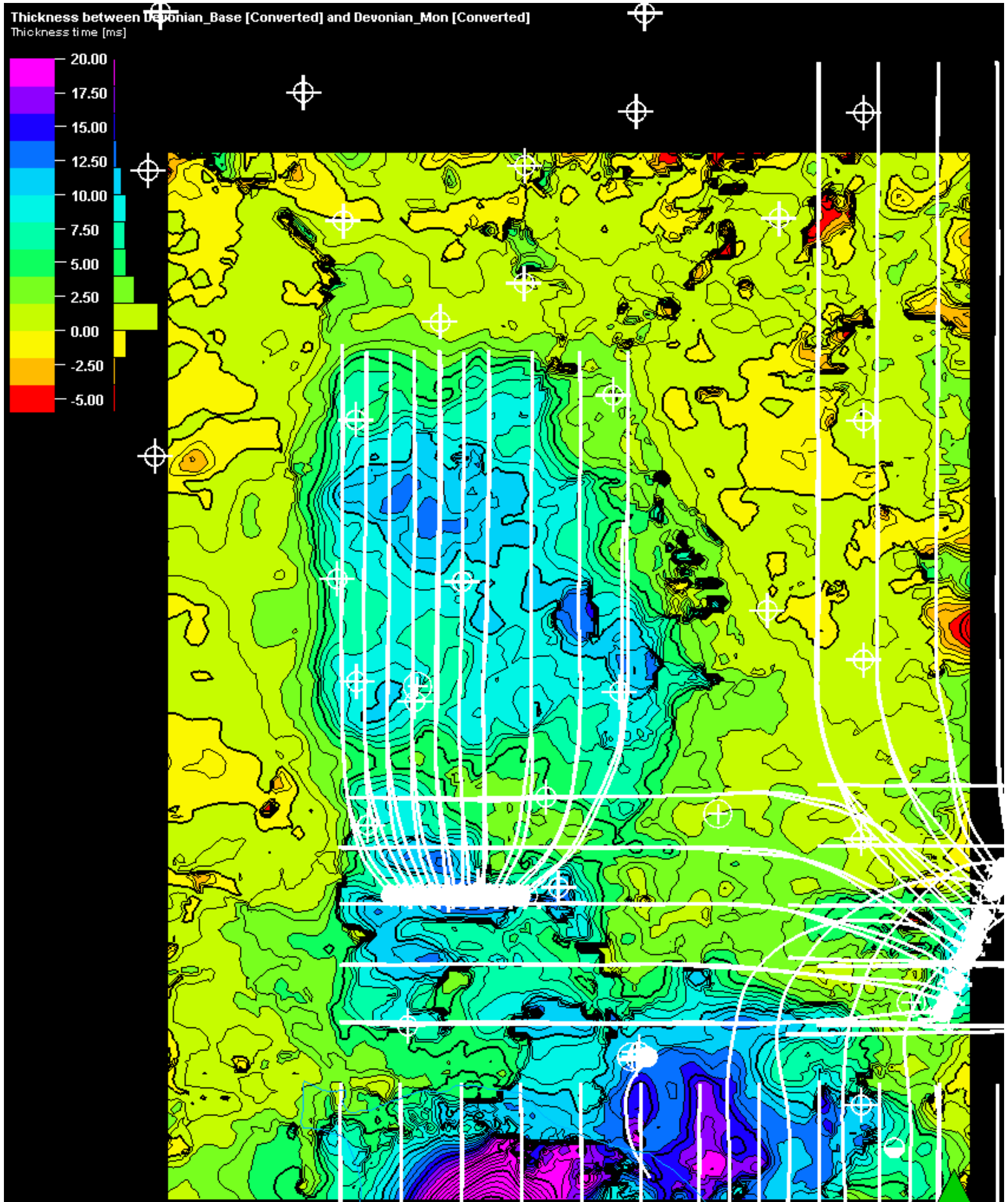
This is the first monitor seismic survey that has been shot over these pads.

Map	
Country	*Scale* 1:10486
Block	*Contour inc* 0.5
License	*User name* wagnerk
Model name	*Date* 03/26/2015
Horizon name	*Signature*





Long Lake
Seismic – Pad 10W & 11 Time Delay



Time Delay anomalies are the difference between the Devonian surface on the 2002 baseline seismic survey and the monitor seismic surveys in 2013.

These time delays generally represent steam chamber growth but also any changes in gas occurrence.

This is the first monitor seismic survey that has been shot over these pads.

Long Lake
2014 Winter Program

Evaluation Wells Completed

- Cored Vertical Wells: **17**
- Non-cored Vertical Wells: **17**
- Non-cored Deviated Wells: **2**
- Total = **36**

Observation Wells

- **3** Water Monitoring Wells
- **4** Q-Channel Monitoring Wells
- **3** Pad 14/15 Wells
- Total =**10**

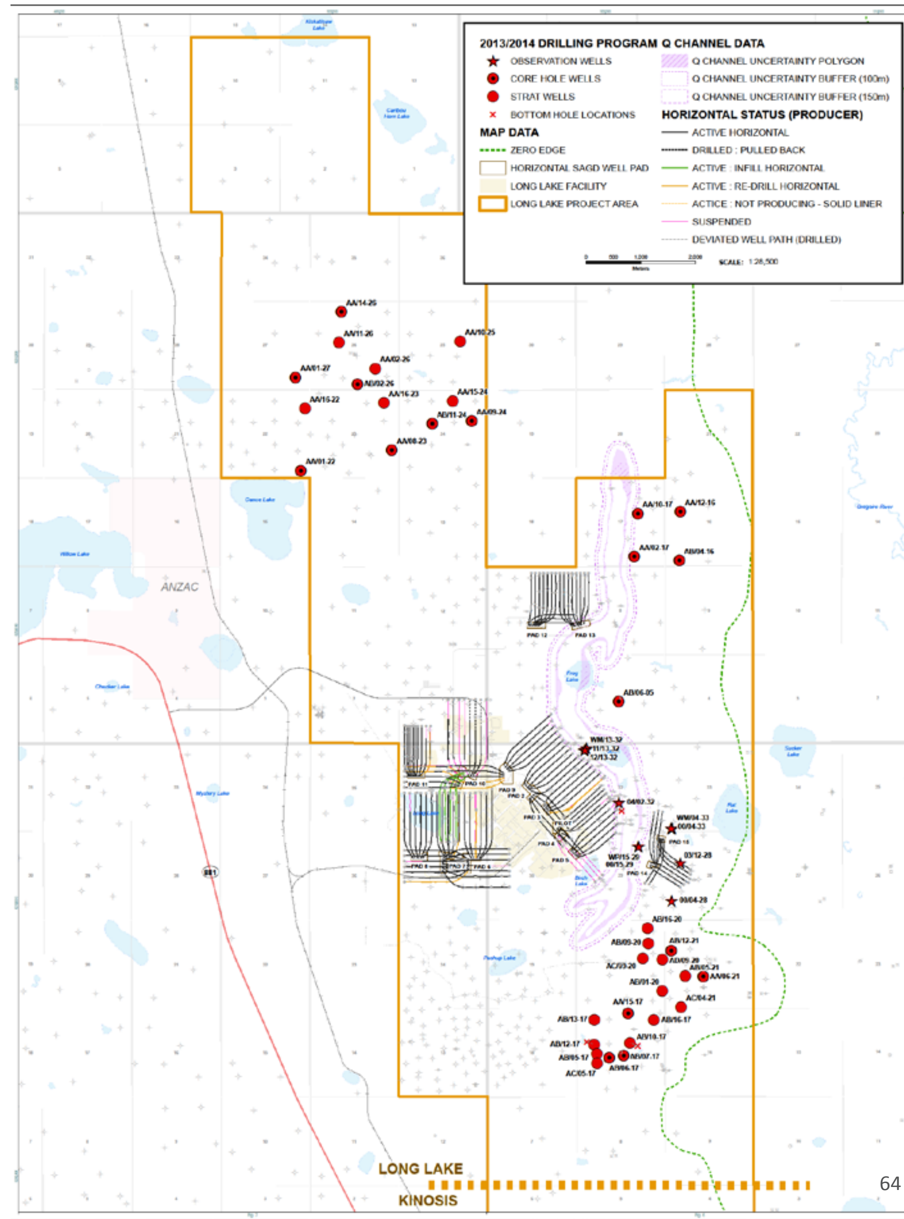
Infill Wells

- **4** wells drilled on Pad 7

Re-Drills

- **3** wells re-drilled (03P05 & 03S05 & 11P10)

Total = **53** wells



Long Lake 2014 Core Hole Program (17 Wells)

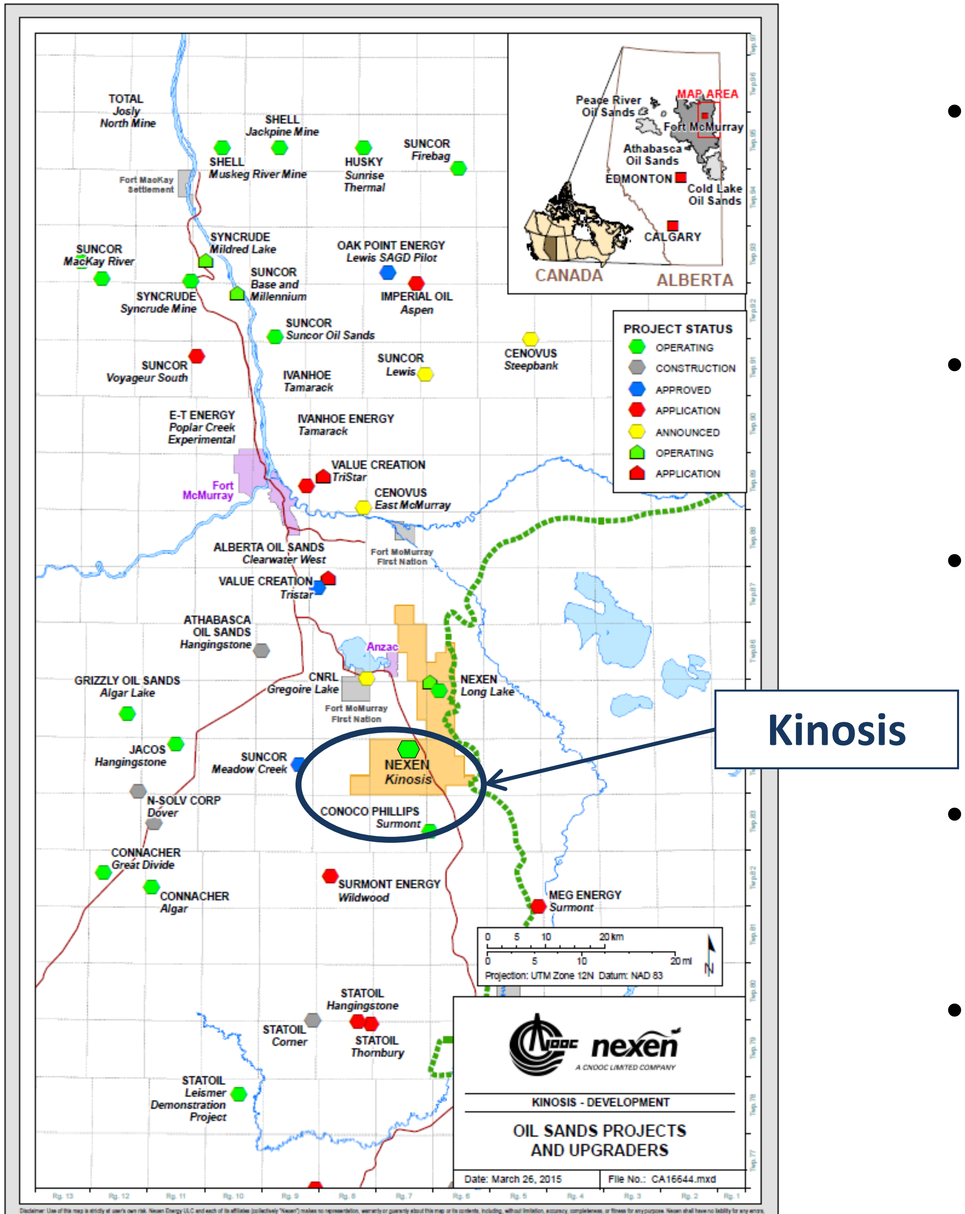
UWI	Well Name	Well License #
1AA151708506W400	NEU CNOOC NEWBY 15-17-85-6	461035
1AB071708506W400	NEU CNOOC NEWBY 7-17-85-6	461033
1AA062108506W400	NEU CNOOC NEWBY 6-21-85-6	461084
1AB122108506W400	NEU CNOOC NEWBY 12-21-85-6	461085
1AB061708506W400	NEU CNOOC NEWBY 6-17-85-6	461614
1AA012208607W400	NEU CNOOC NEWBY 1-22-86-7	462075
1AA082308607W400	NEU CNOOC NEWBY 8-23-86-7	462077
1AA092408607W400	NEU CNOOC NEWBY 9-24-86-7	462079
1AB112408607W400	NEU CNOOC NEWBY 11-24-86-7	462080
1AB022608607W400	NEU CNOOC SW NEWBY 2-26-86-7	462082
1AA142608607W400	NEU CNOOC NEWBY 14-26-86-7	462084
1AA012708607W400	NEU CNOOC NEWBY 1-27-86-7	462085
1AB041608606W400	NEU CNOOC NEWBY 4-16-86-6	461059
1AA121608606W400	NEU CNOOC NEWBY 12-16-86-6	461060
1AA101708606W400	NEU CNOOC NEWBY 10-17-86-6	461062
1AA021708606W400	NEU CNOOC NEWBY 2-17-86-6	461061
1AB060508606W400	NEU CNOOC NEWBY 6-5-86-6	461058

Long Lake 2014 Observation Well Program (10 Wells)

UWI	Well Name	Well License #
1WM043308506W400	NEU CNOOC VWP WM NEWBY 4-33-85-6	NL-00209
1WM133208506W400	NEU CNOOC WM G C NEWBY 13-32-85-6	NL-00208
112133208506W400	NEU CNOOC VWP N B NEWBY 13-32-85-6	463737
111133208506W400	NEU CNOOC WM N C NEWBY 13-32-85-6	463680
103122808506W400	NEU CNOOC VWP NEWBY 12-28-85-6	461749
100152908506W400	NEU CNOOC VWP NEWBY 15-29-85-6	462042
1WP152908506W400	NEU CNOOC VWP NEWBY 15-29-85-6 R	NL-00207
100042808506W400	NEU CNOOC VWP NEWBY 4-28-85-6	461719
100043308506W400	NEU CNOOC VWP S NEWBY 4-33-85-6	461840
104023208506W400	NEU CNOOC VWP SD NEWBY 2-32-85-6	461851

Kinosis
Geology and Geoscience

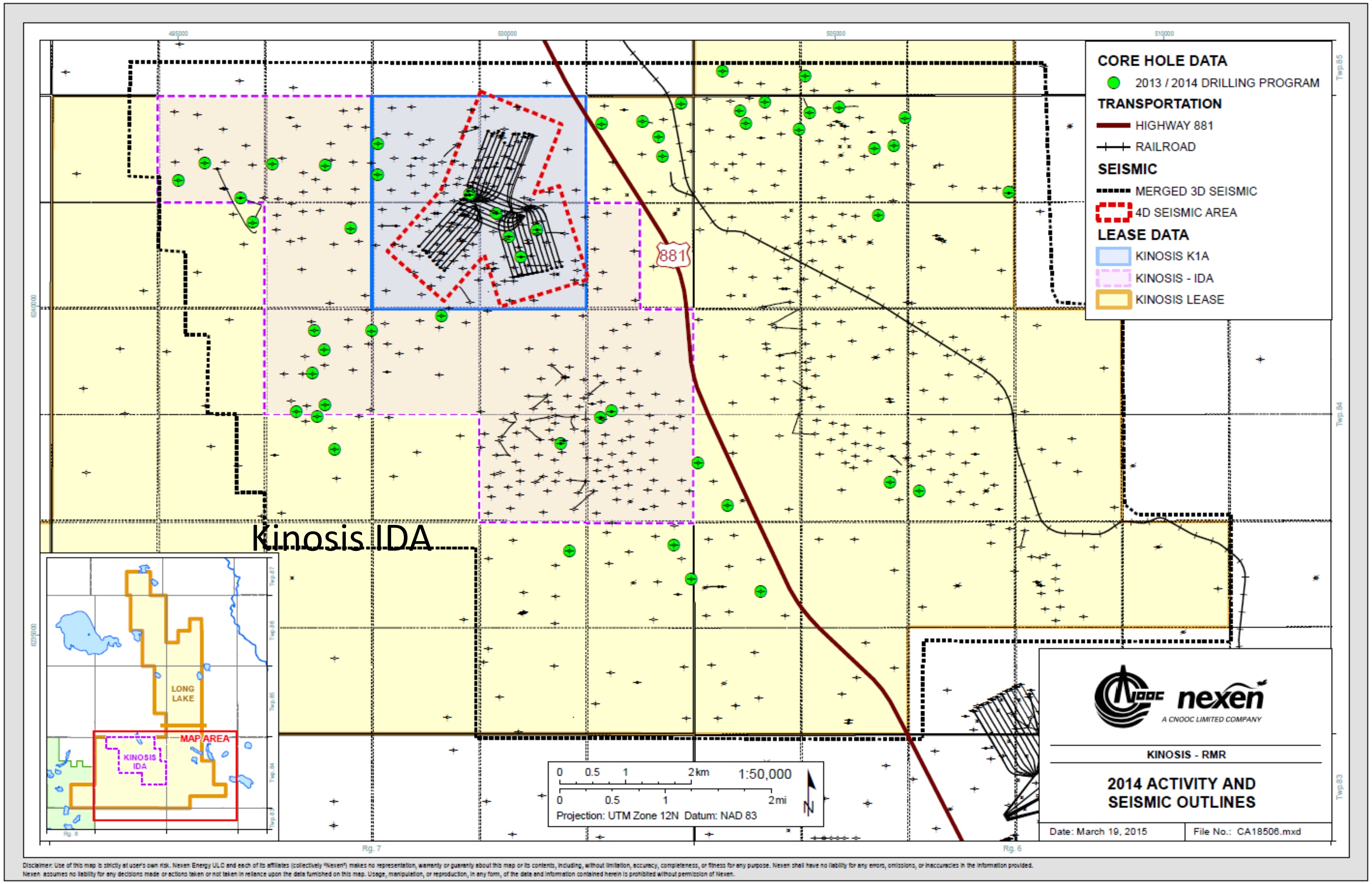
Kinosis Location



- Nexen's Kinosis property is located approximately 50km SE of Fort McMurray
- Located between Long Lake and ConocoPhillips Surmont
- ERCB Approval No. 9485F was granted in 2009 for development of Kinosis in a portion of T84R7W4
- First steam achieved Aug 2014, first oil achieved Nov 2014
- Kinosis 2 Gas Re-pressurization commenced

Kinosis – 2014 Activity and 3D Seismic Outline

- 5 OBS wells drilled in K1A
- 47 delineation wells drilled
- 27 West of HWY 881
- 20 East of HWY 881



Kinosis IDA EBIP and Average Reservoir Parameters

Kinosis IDA EBIP

Kinosis IDA	
EBIP (E^6m^3)	204

Nexen Cutoffs: h > 12m or HPVH > 3 m

Hydrocarbon Pore Volume Height

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

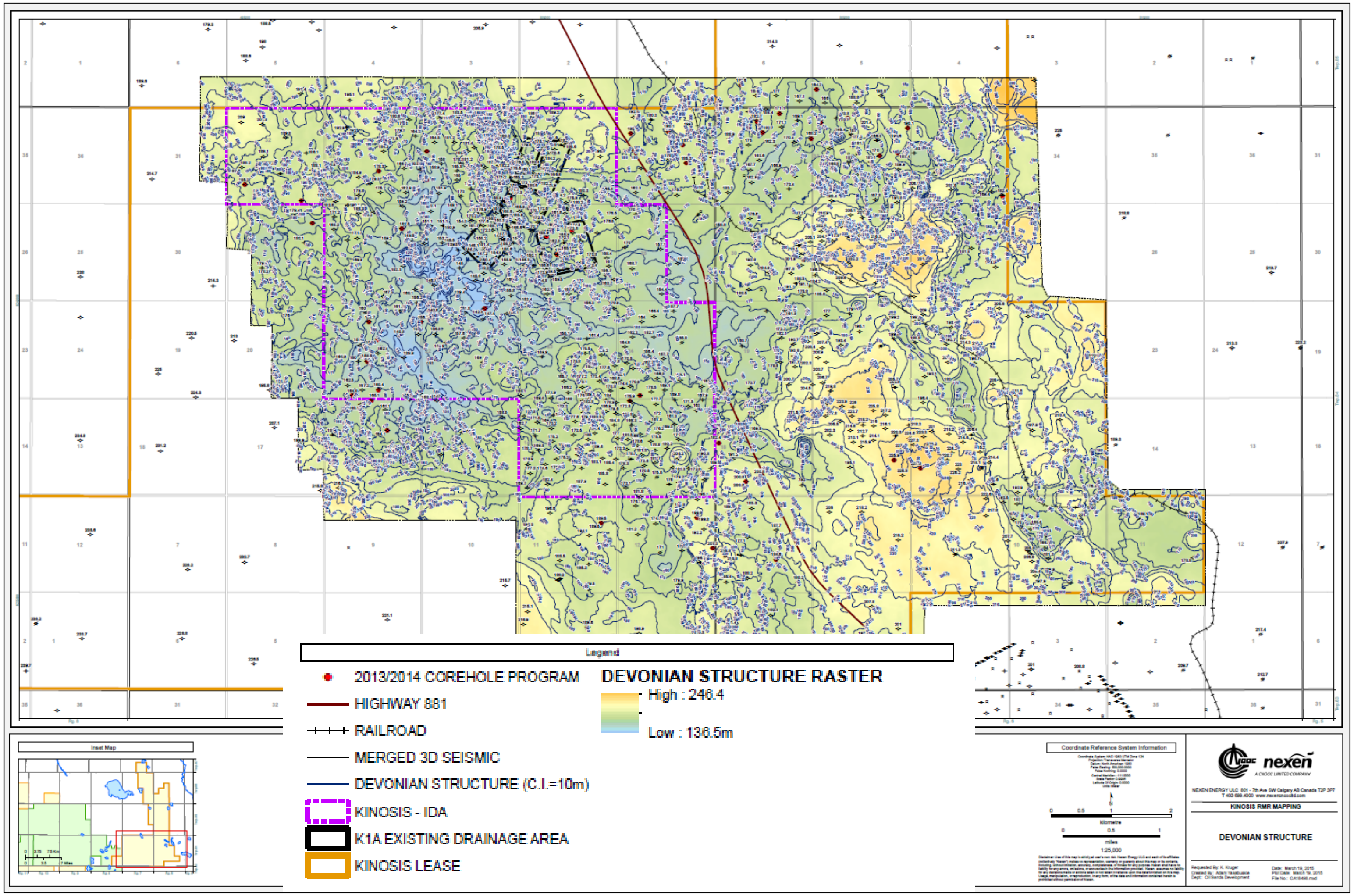
Hydrocarbon Pore Volume Height (HPVH) is calculated from petrophysical logs calibrated to Dean Stark analysis.

Pay Average Reservoir Parameters

- Depth 280 m KB
- Thickness 34 m
- Effective Porosity 31 %
- Permeability From Core Plugs
  - Kmax 4030 mD
  - Kvert 2347 mD
- Effective Water Saturation 26 %
- Temperature 6 – 8 °C
- Initial Reservoir Pressure
  - ~1100 - 1300 kPa

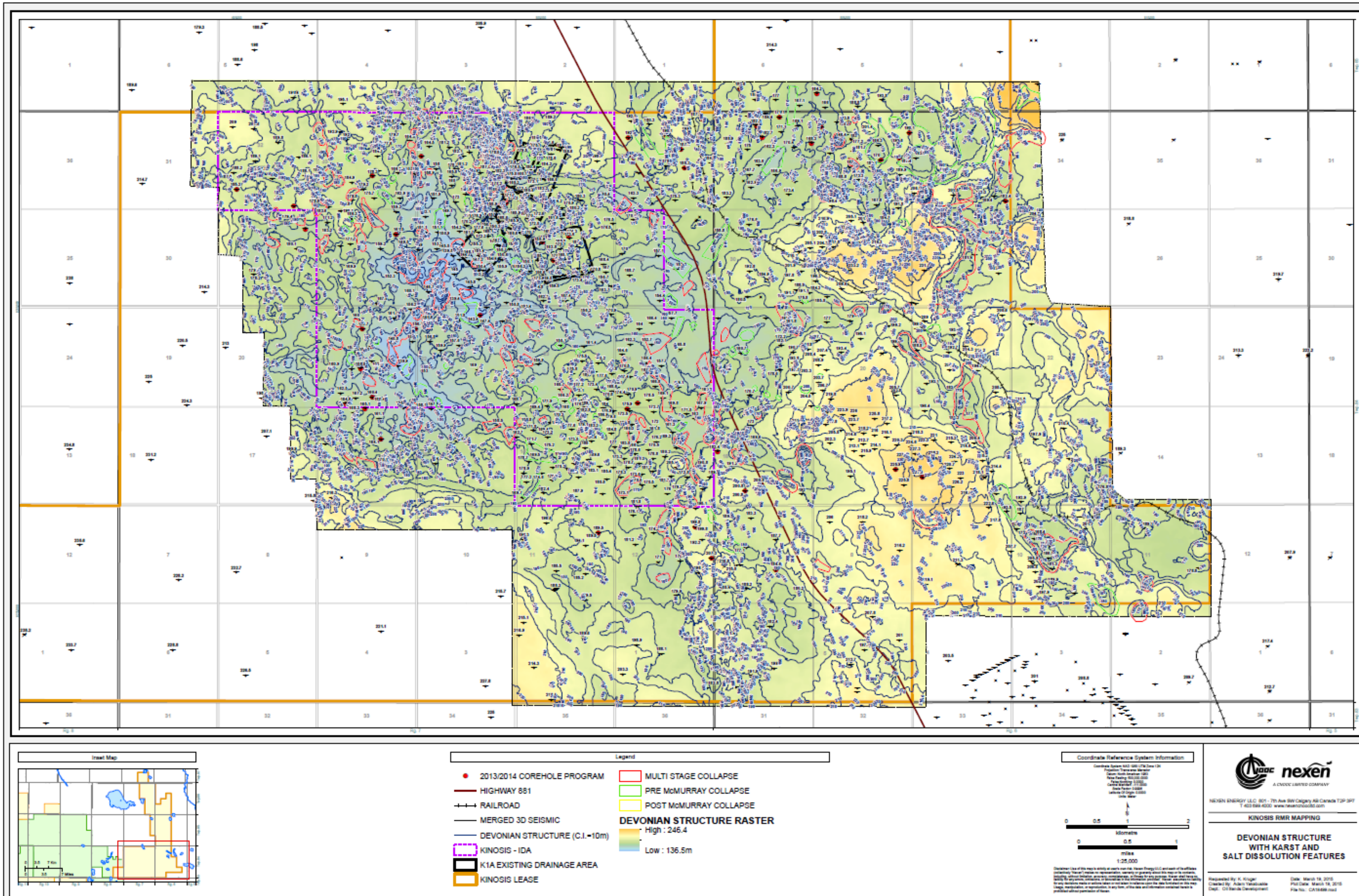
Effective porosity and effective water saturation are calculated every 10cm over the Pay interval, and the average is derived.

Structure - Top of Devonian

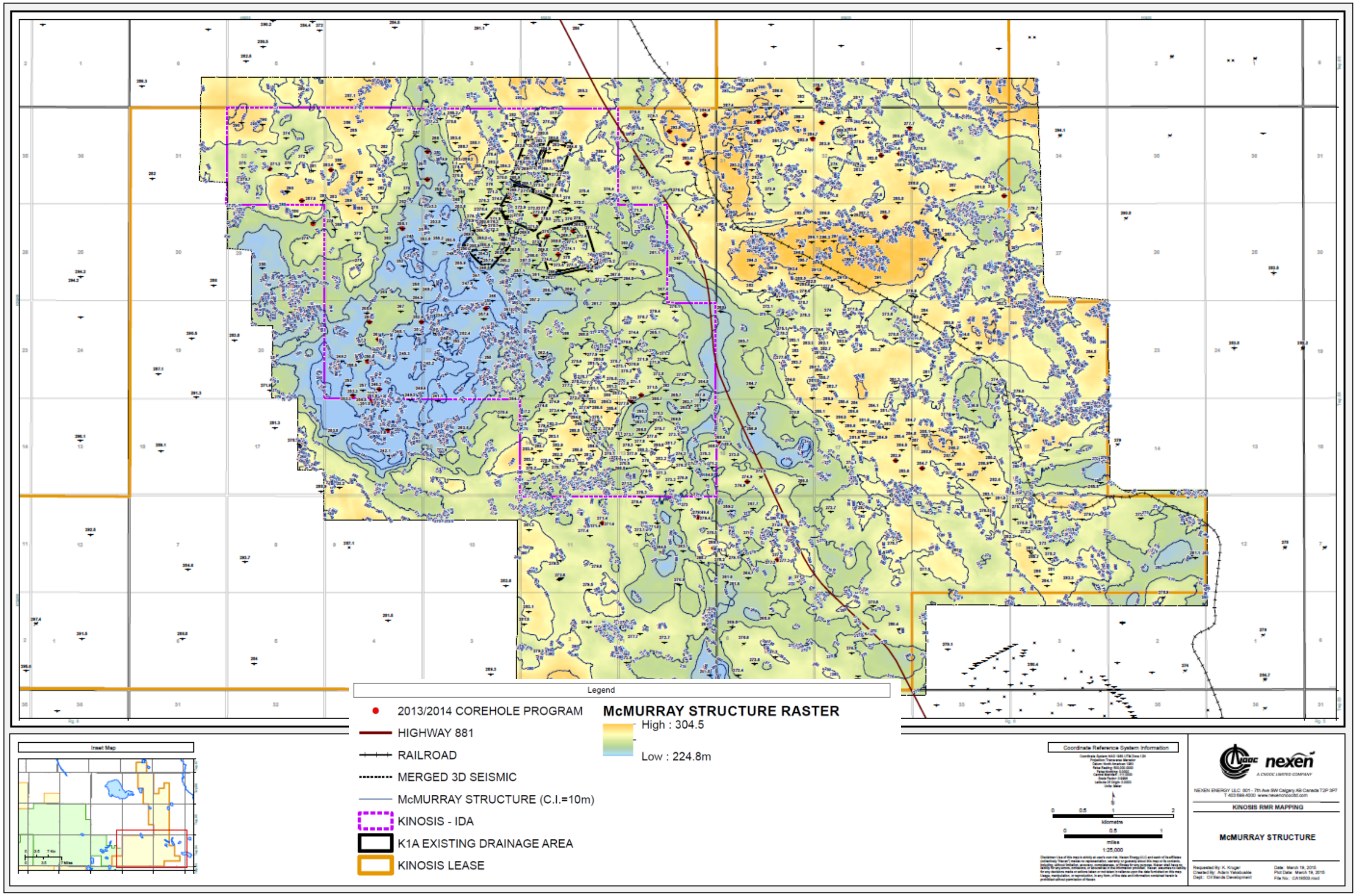


- Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts.
- Has a significant effect on base of pay structure and bottom water contacts.
- Timing of salt solutioning was pre-McMurray, syn-McMurray and post-McMurray
- Minor karsting on Devonian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

Devonian Structure with Karst and Salt Dissolution Features

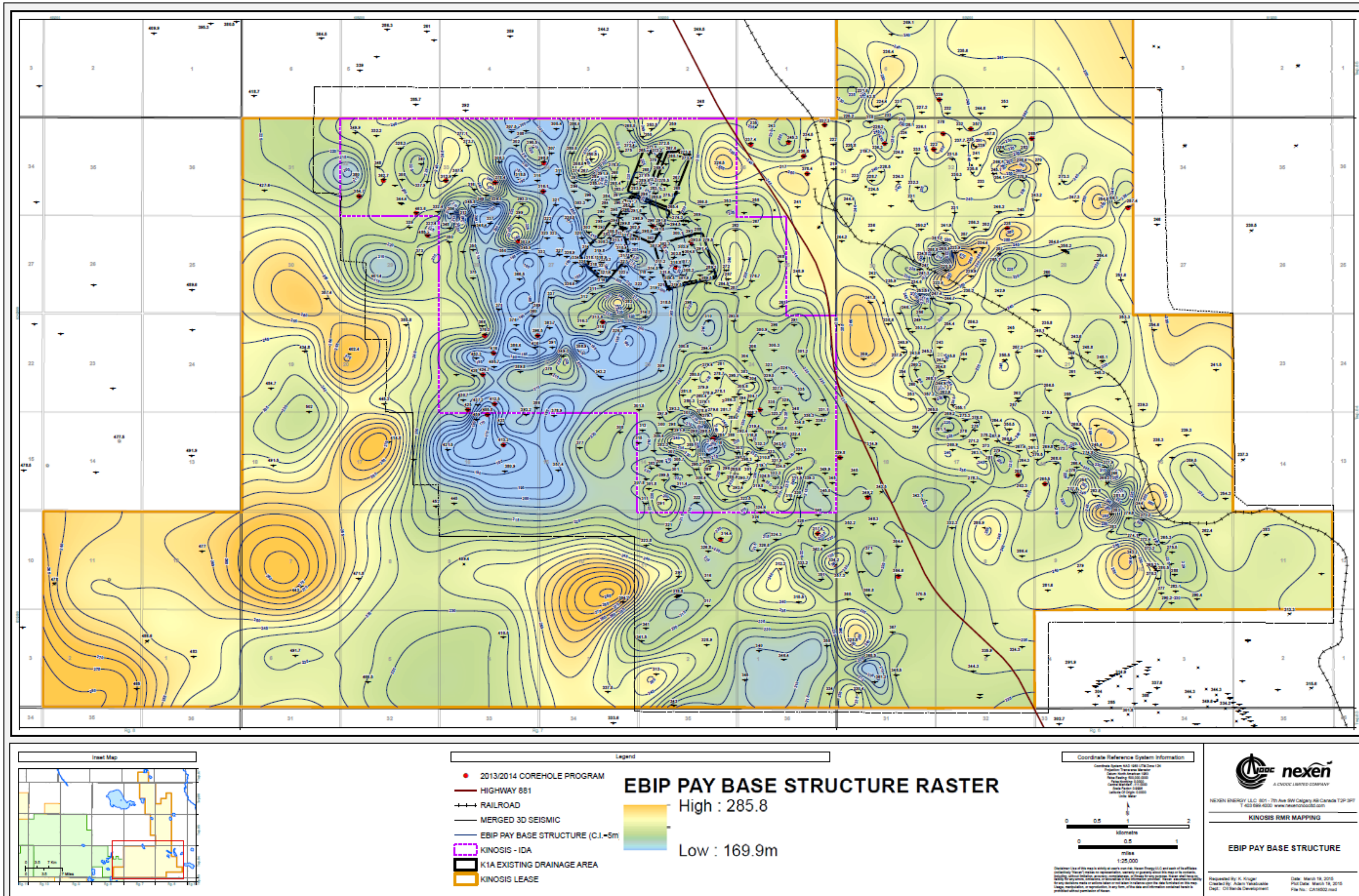


Structure - Top of McMurray

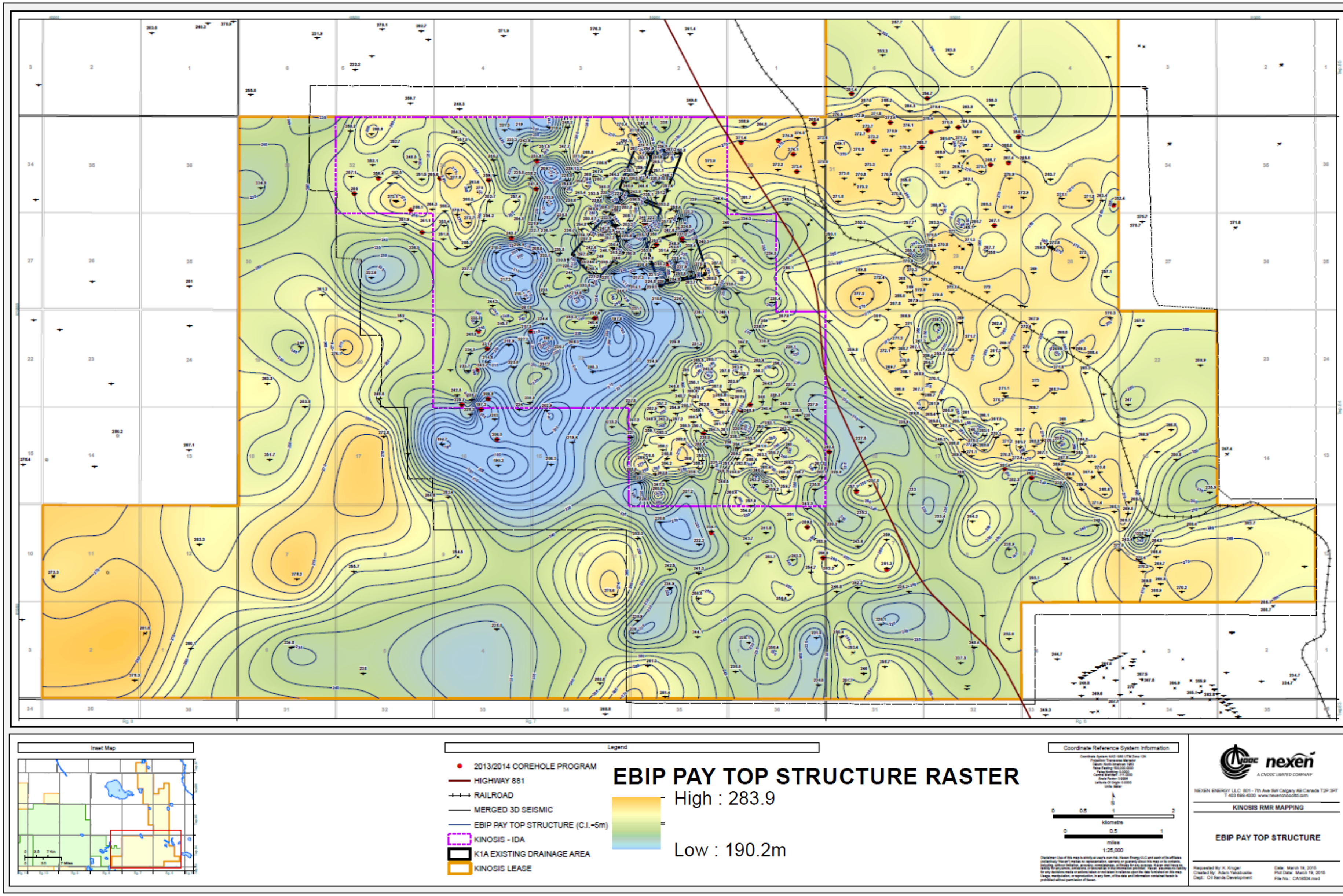


- Influenced by depositional elements that results in differential compaction.
- Can determine timing of some dissolution features, areas of thick and thin sand sections.

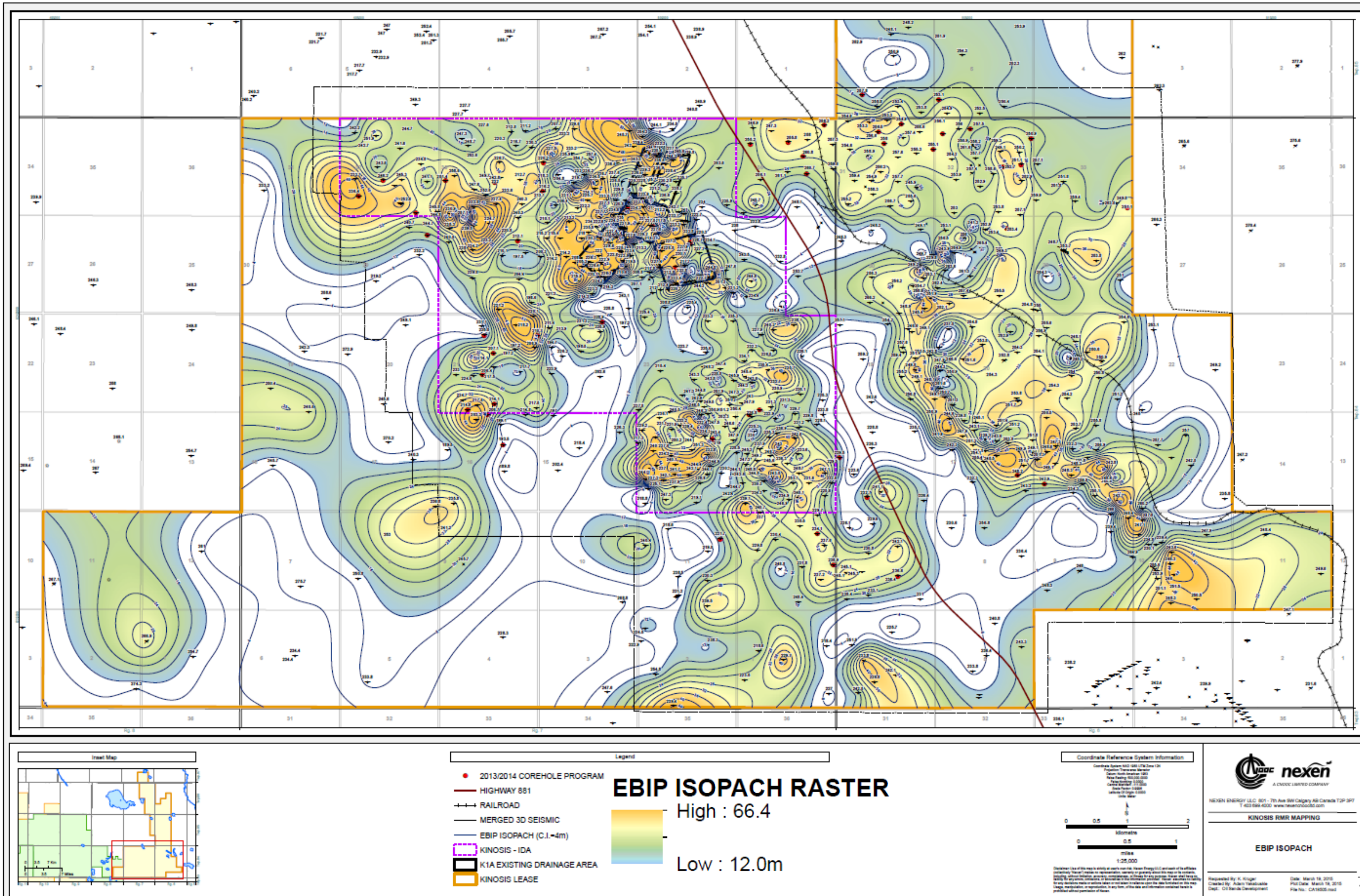
Structure - EBIP Base Kinosis



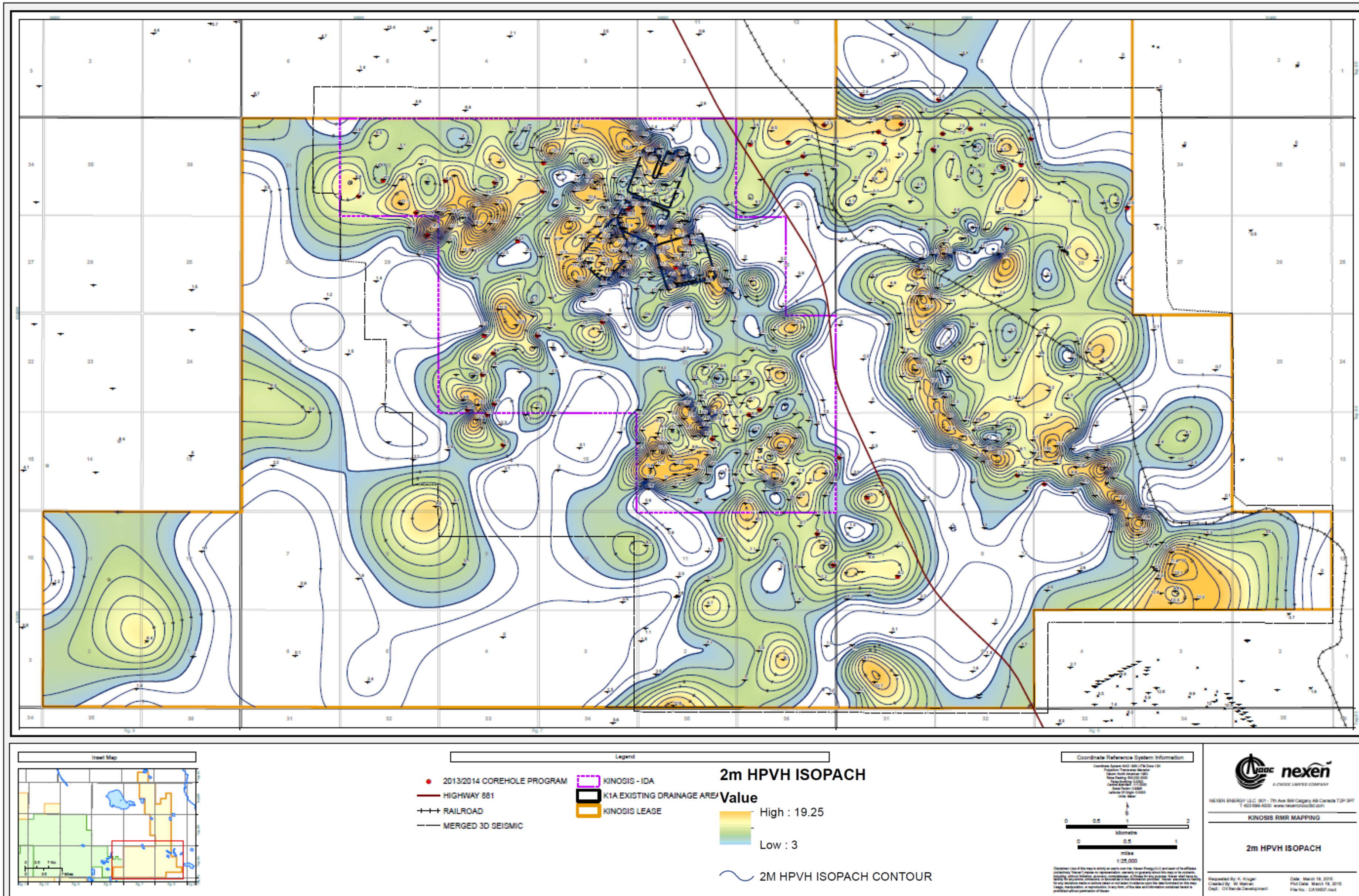
Structure - EBIP Top Kinosis

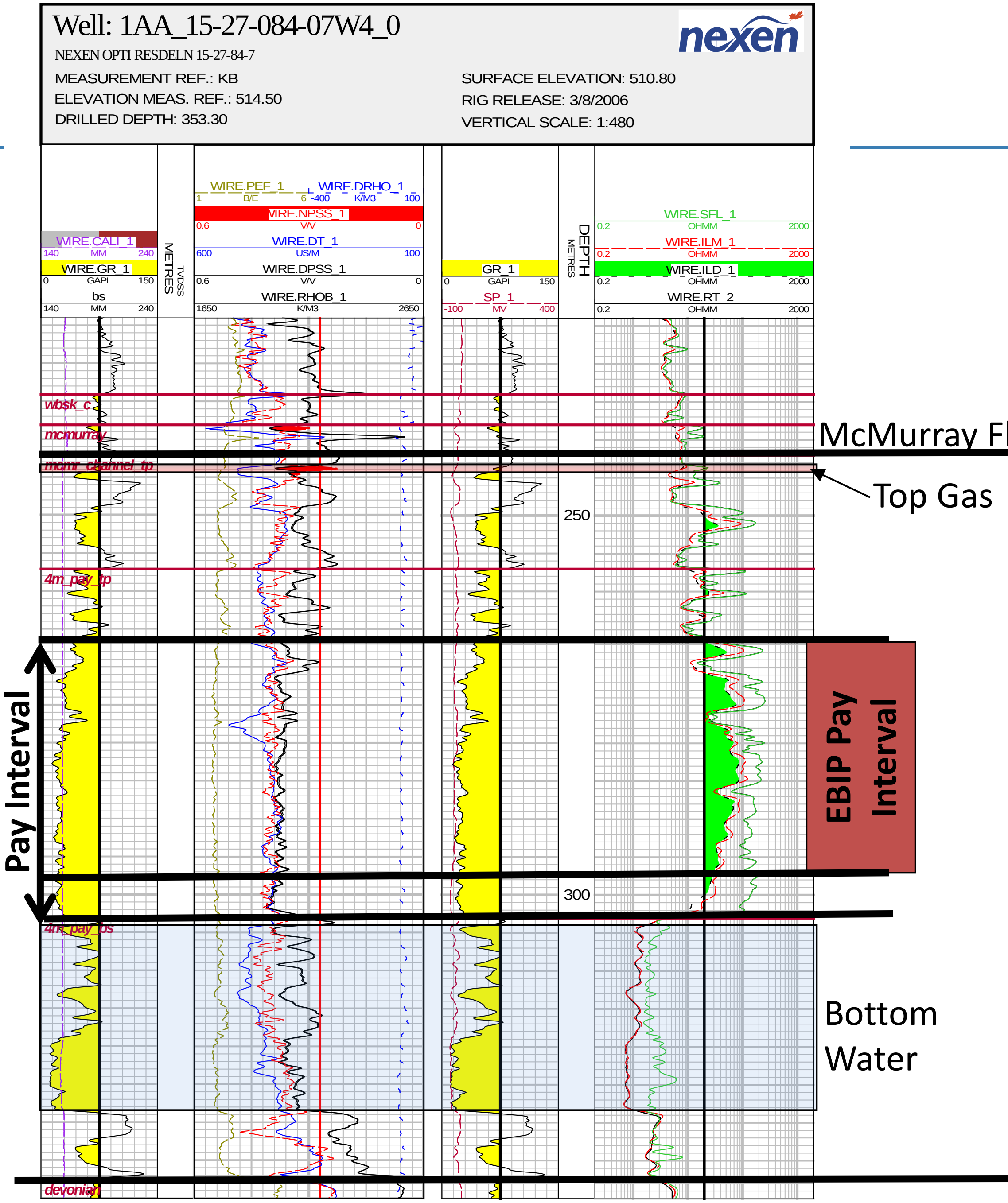


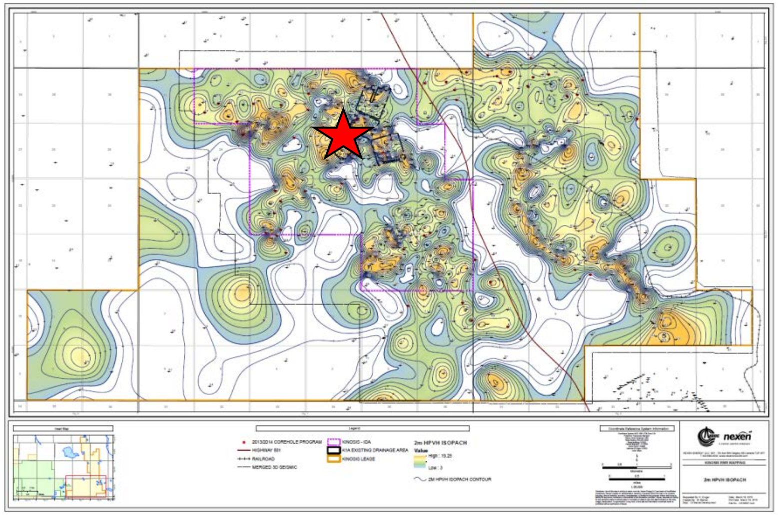
Kinosis EBIP Isopach



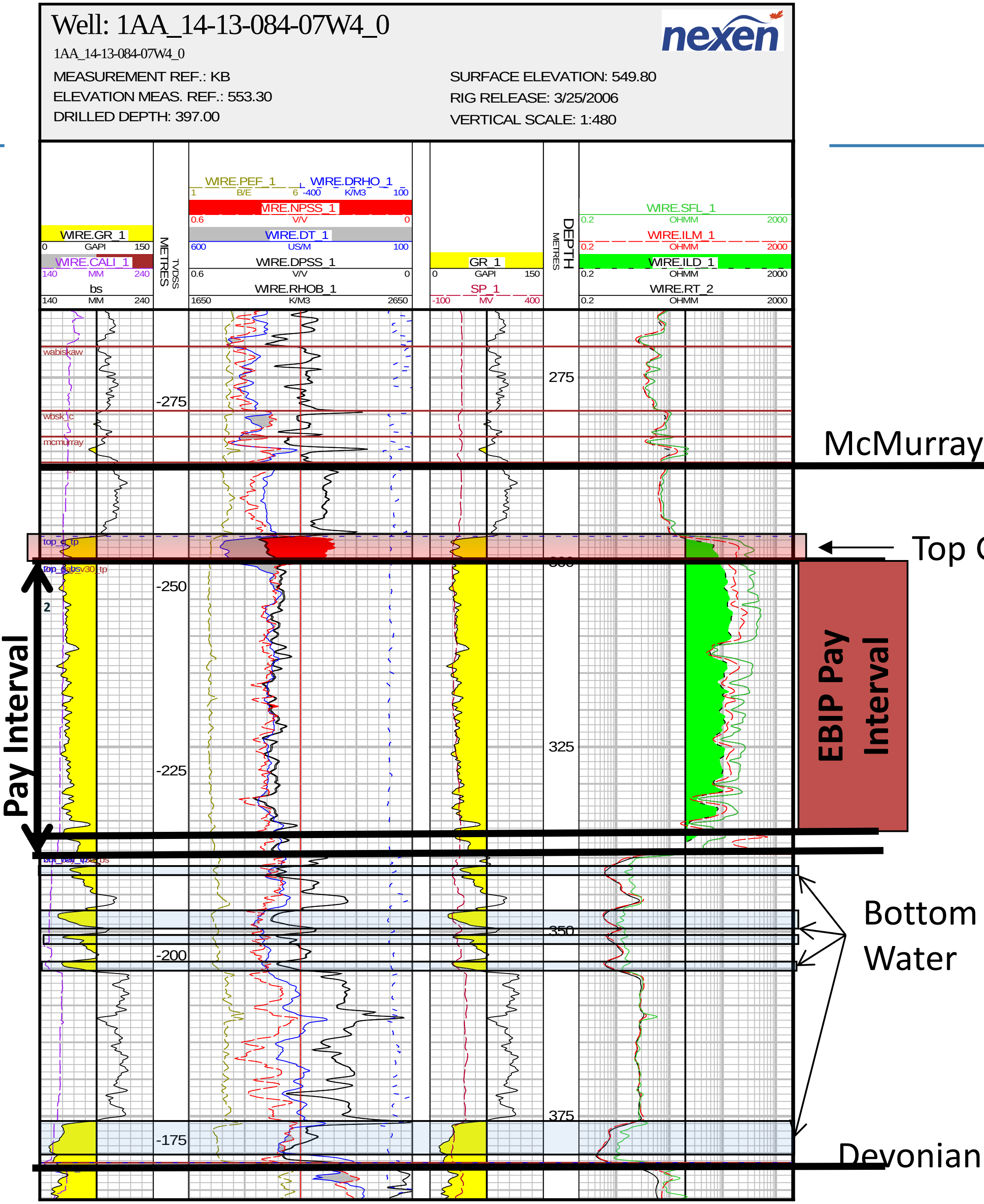
HPVH Isopach over EBIP Interval
Kinosis

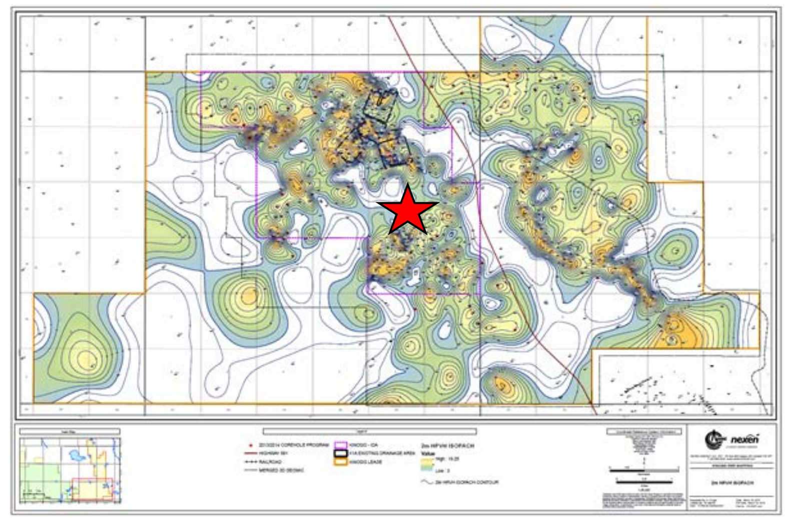




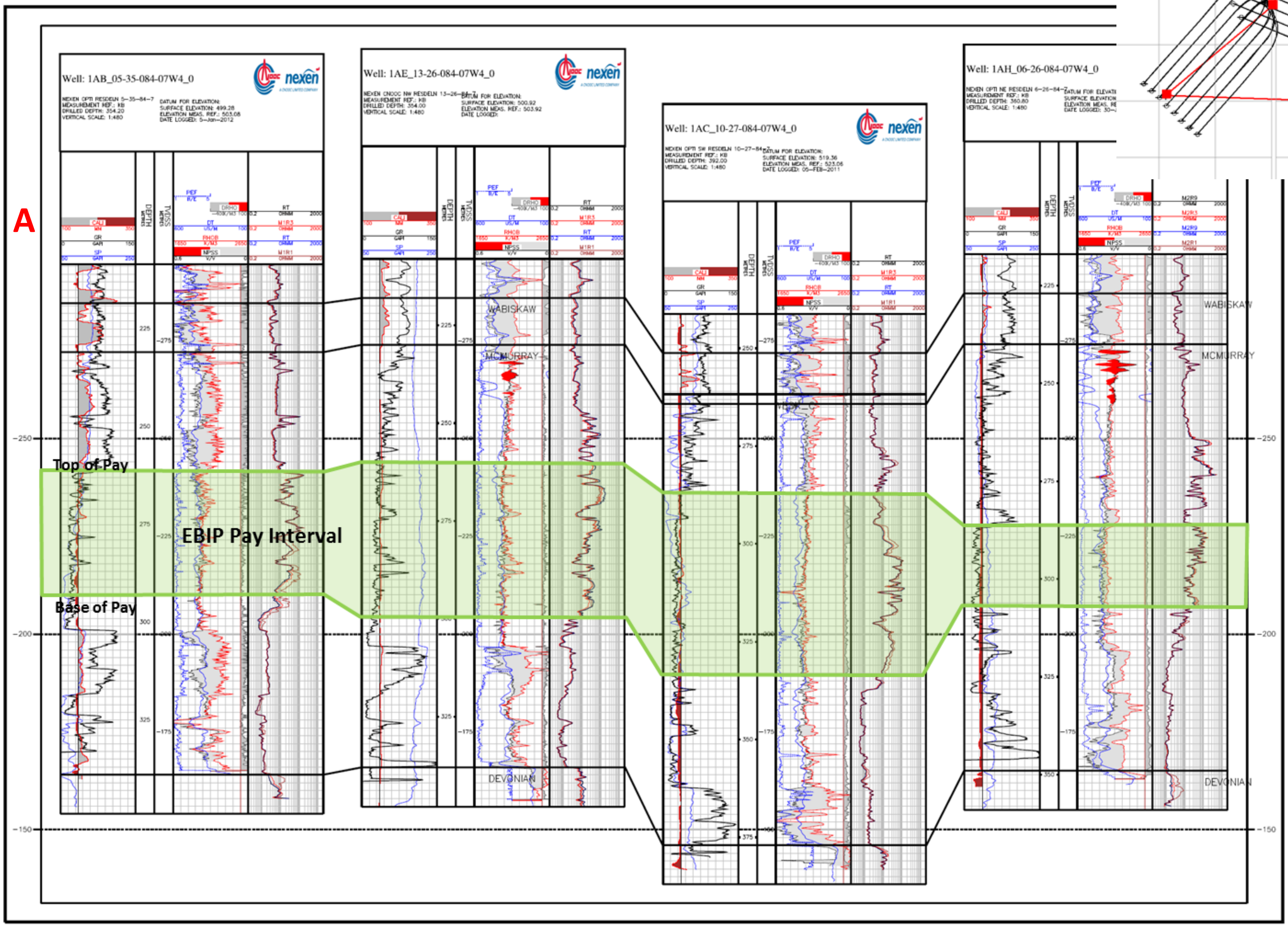


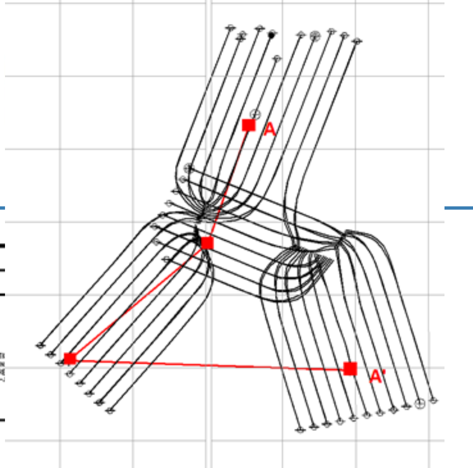
Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.


Well: 1AA_14-13-084-07W4_0
1AA_14-13-084-07W4_0
MEASUREMENT REF.: KB
ELEVATION MEAS. REF.: 553.30
DRILLED DEPTH: 397.00
SURFACE ELEVATION: 549.80
RIG RELEASE: 3/25/2006
VERTICAL SCALE: 1:480
WIRE.GR_1
WIRE.CALI_1
bs
TVDSS METRES
WIRE.PEF_1
WIRE.DRHO_1
WIRE.NPSS_1
WIRE.DT_1
WIRE.DPSS_1
WIRE.RHOB_1
GR_1
SP_1
DEPTH METRES
WIRE.SFL_1
WIRE.ILM_1
WIRE.ILD_1
WIRE.RT_2
wabiskaw
mcmurray
275
325
350
375
-275
-250
-225
-200
-175
McMurray Fluvial Estuarine Complex top
Top Gas
Pay Interval
EBIP Pay Interval
Bottom Water
Devonian

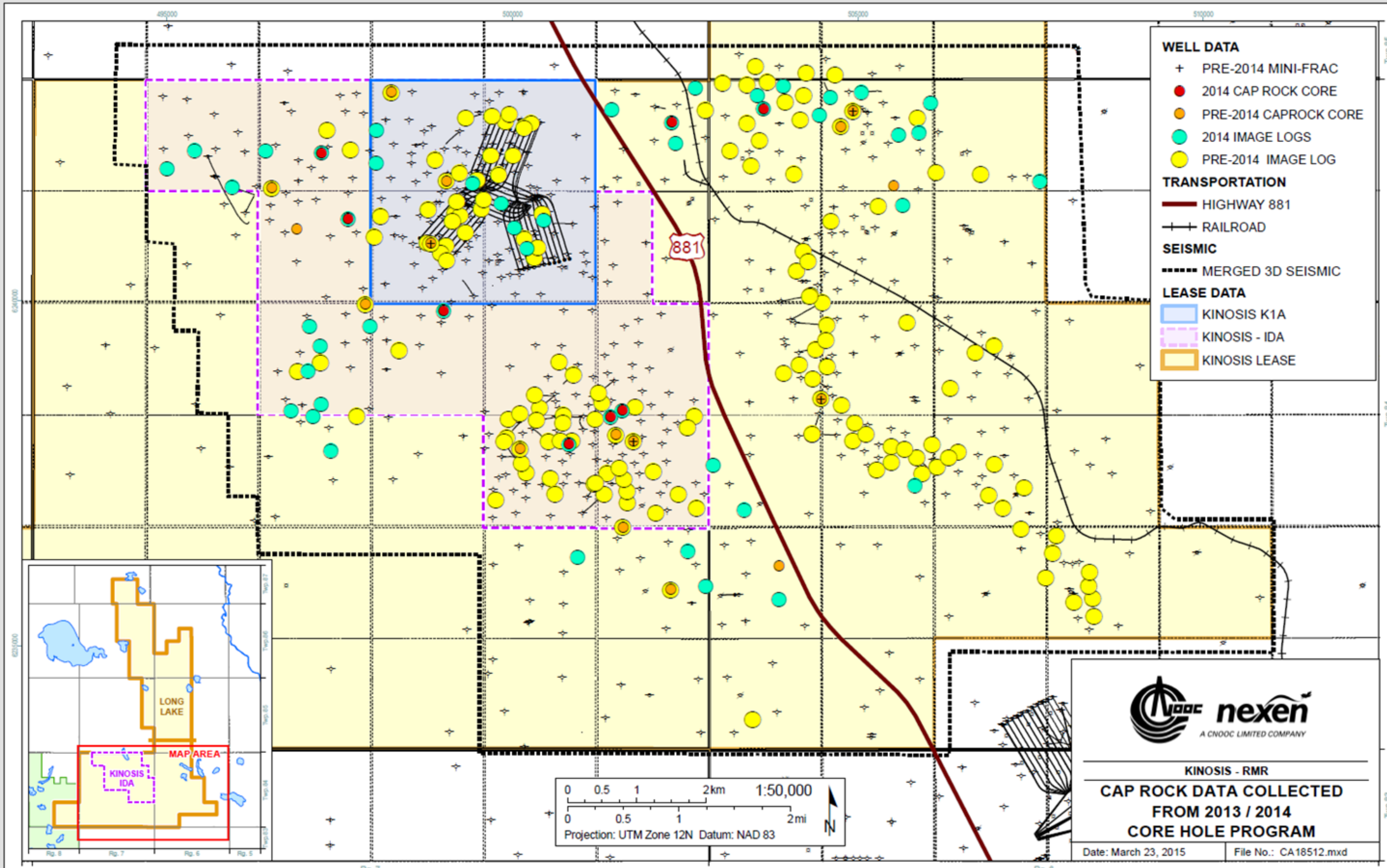


Representative structural cross-section of K1A

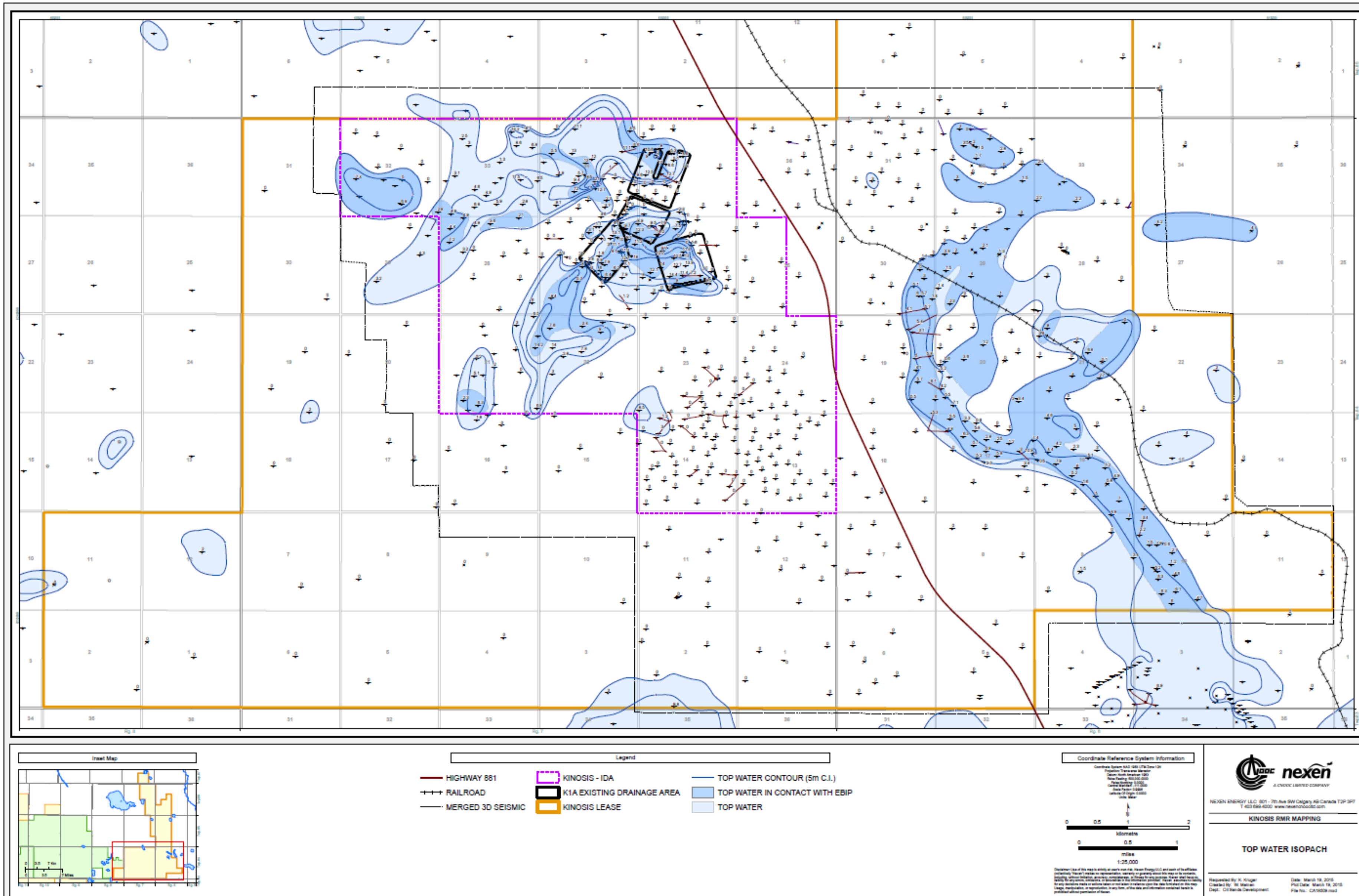




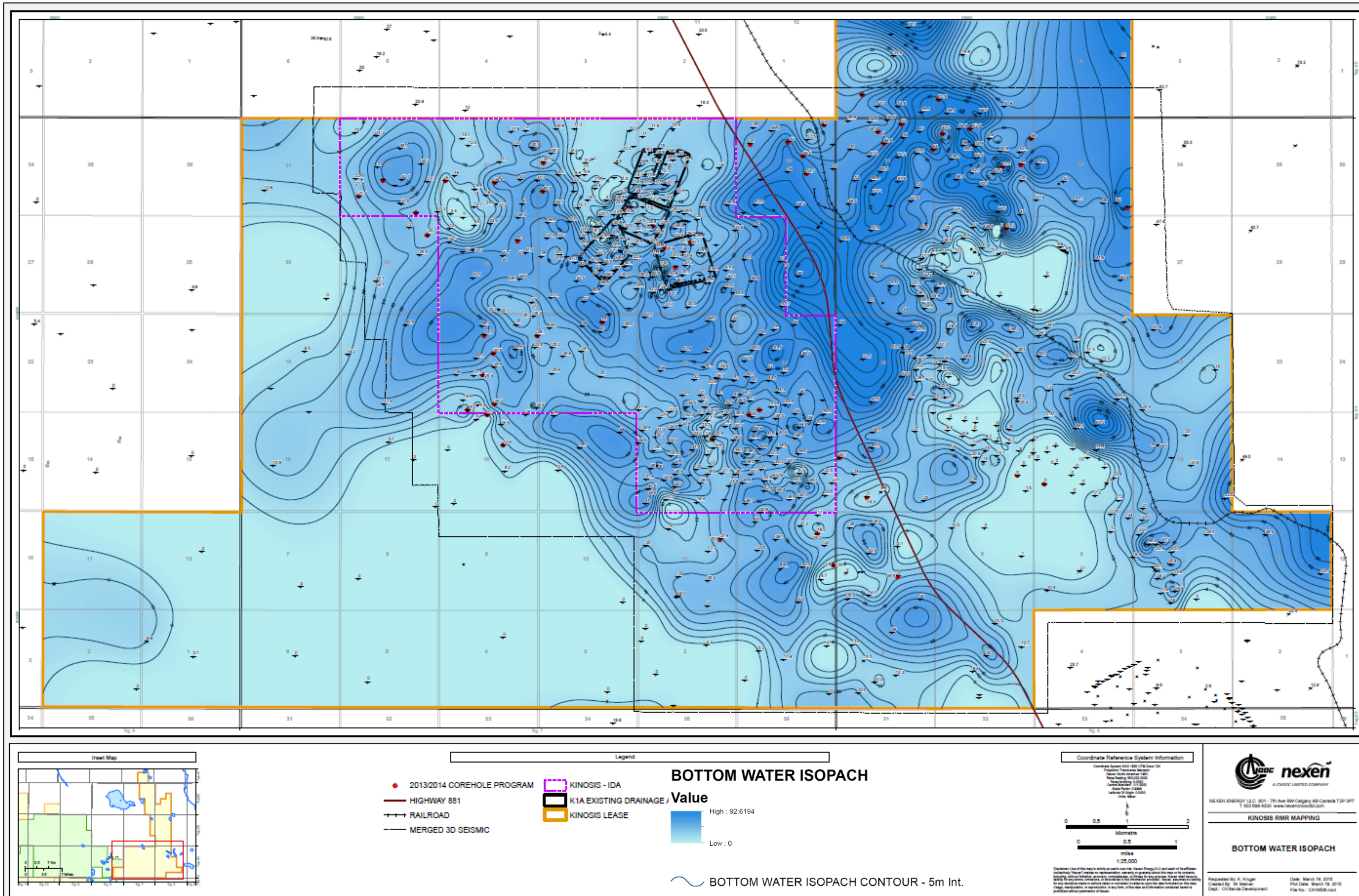
Cap Rock data collected in 2014



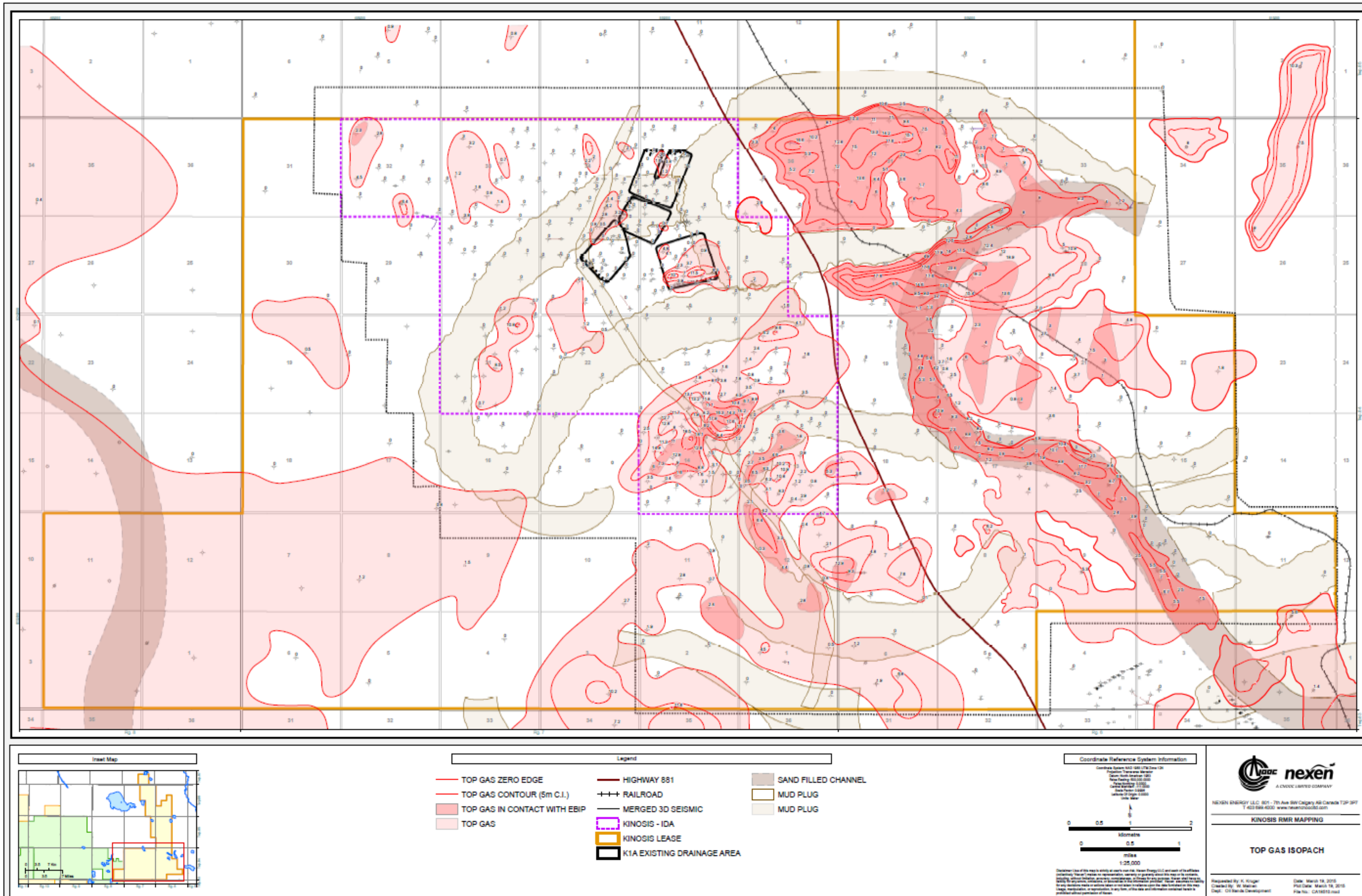
Top Water in the McMurray - Kinosis



Bottom Water in the McMurray - Kinosis

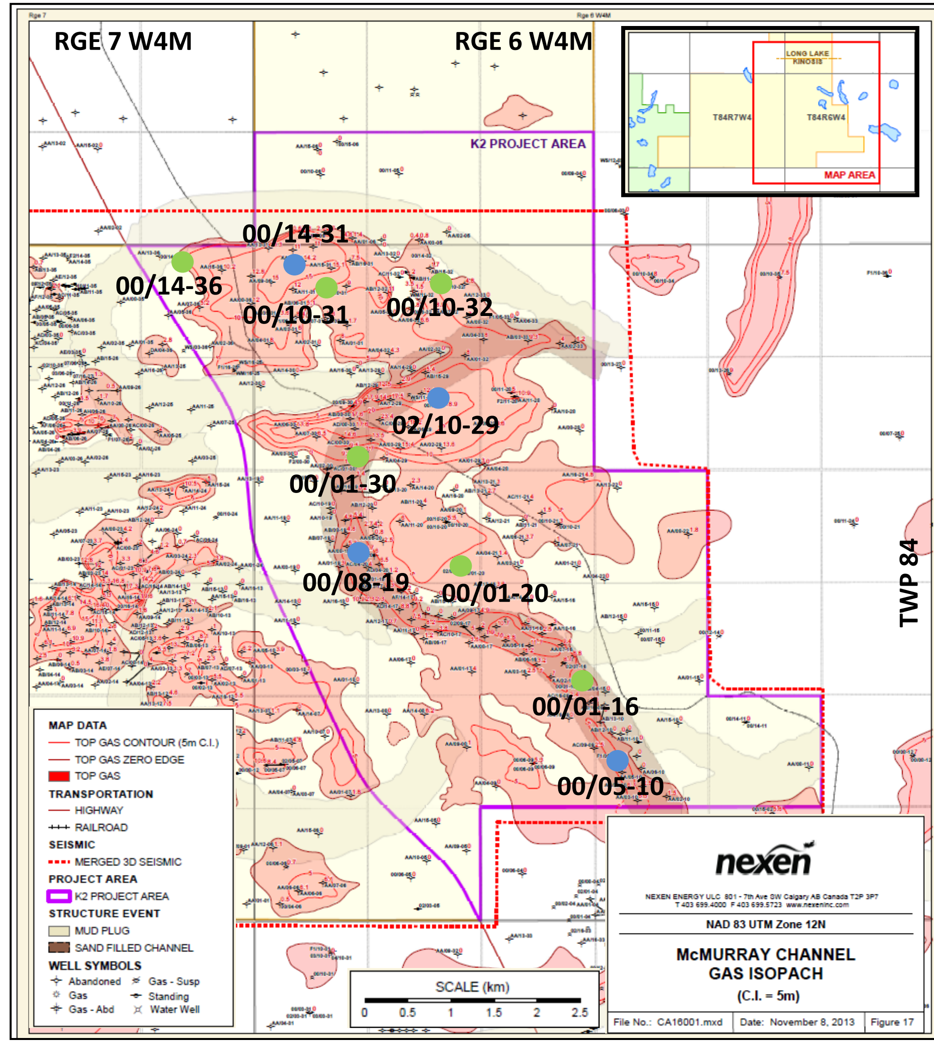


Top Gas in the McMurray - Kinosis



Kinosis 2 Gas Re-pressurization Update

- Received approval in February 2014 to repressure Kinosis 2 gas pool with natural gas
- Natural gas injection started in August 2014
- Total injected gas volume: 1.2 sBcf (~12% of total McMurray gas produced from Kinosis 2 gas pool)
- Average pressure within Kinosis 2 gas pool increased from 560 kPag to 615 kPag
- The minimum pressure target is 1100kPa to establish a pressure equilibrium within the system as bottom water pressure in the Kinosis 2 area is ~ 1100kPa



Gas Injection Well

Pressure Observation Well

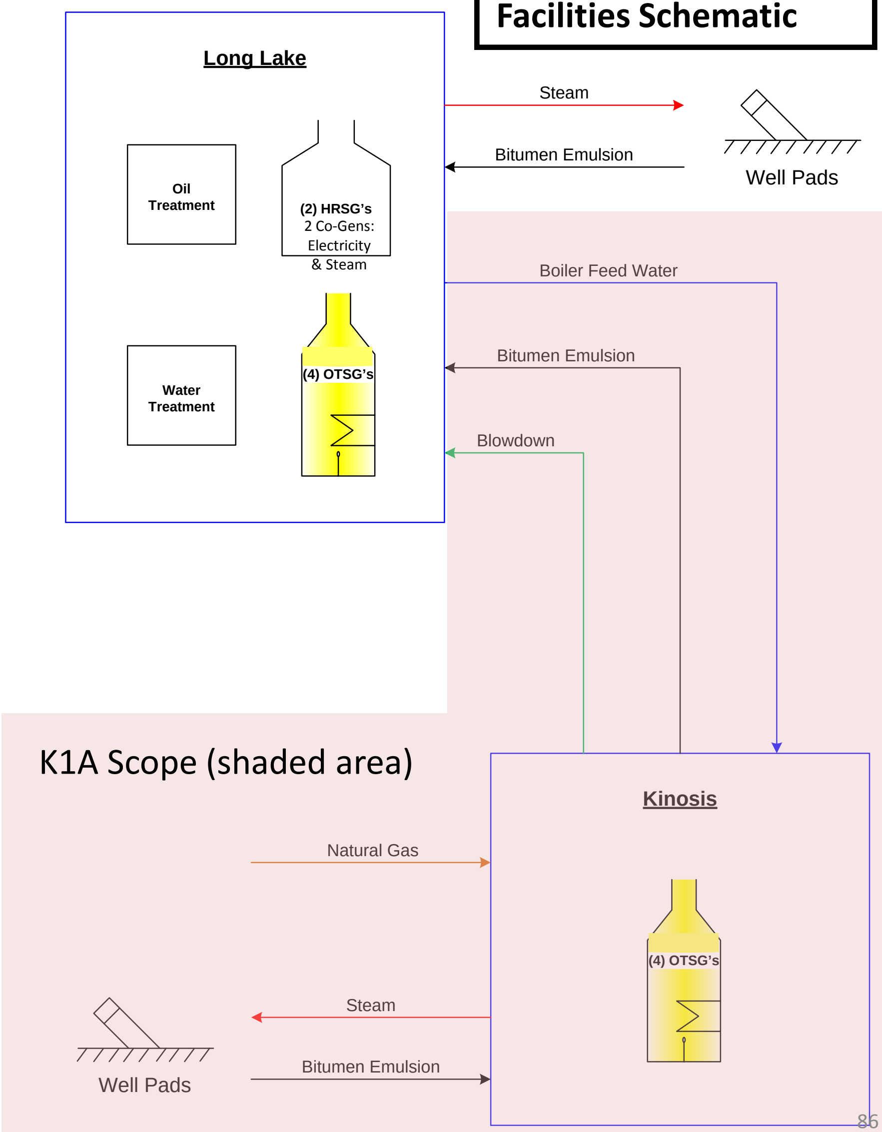
Kinosis - K1A Project Scope

Nexen planning a multi-phased development of Kinosis IDA.

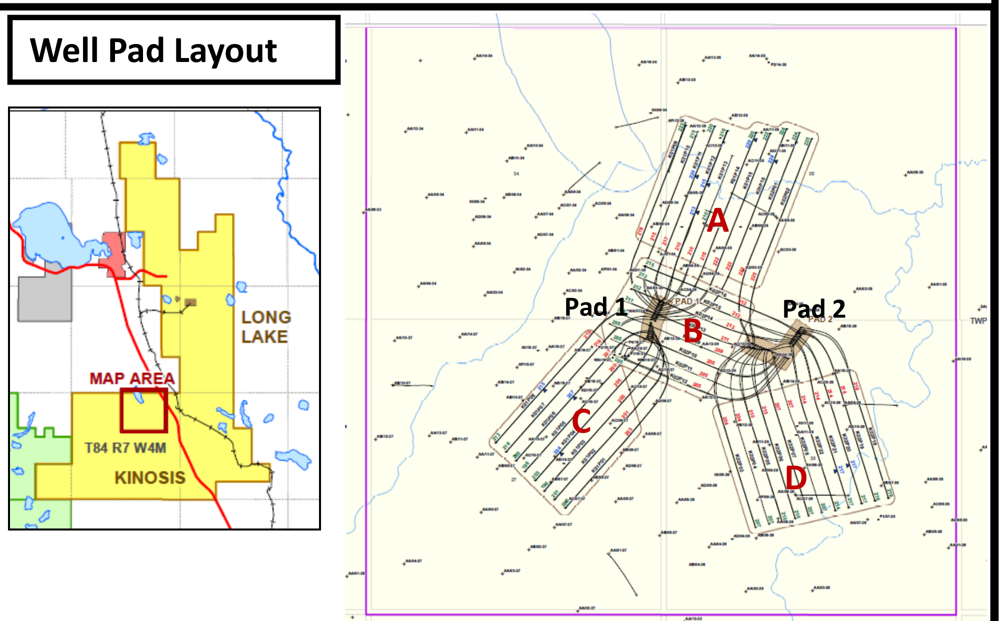
The first Phase is K1A – First Steam Achieved Aug 2014

- Project expectations
  - 15-25,000 b/d peak bitumen rates
  - SAGD drilling commenced in 2012, First Steam Aug 2014, First Oil Nov 2014
- Two wellpads (4 drainage areas) of 16 and 21 well pairs at 75m spacing
- Steam Generation Facility (4 OTSG's)
- Pipelines connecting the facilities to Long Lake
  - Boiler feed water from Long Lake, emulsion to Long Lake
- Tie-ins and support infrastructure required at Long Lake
- Support utilities

Facilities Schematic

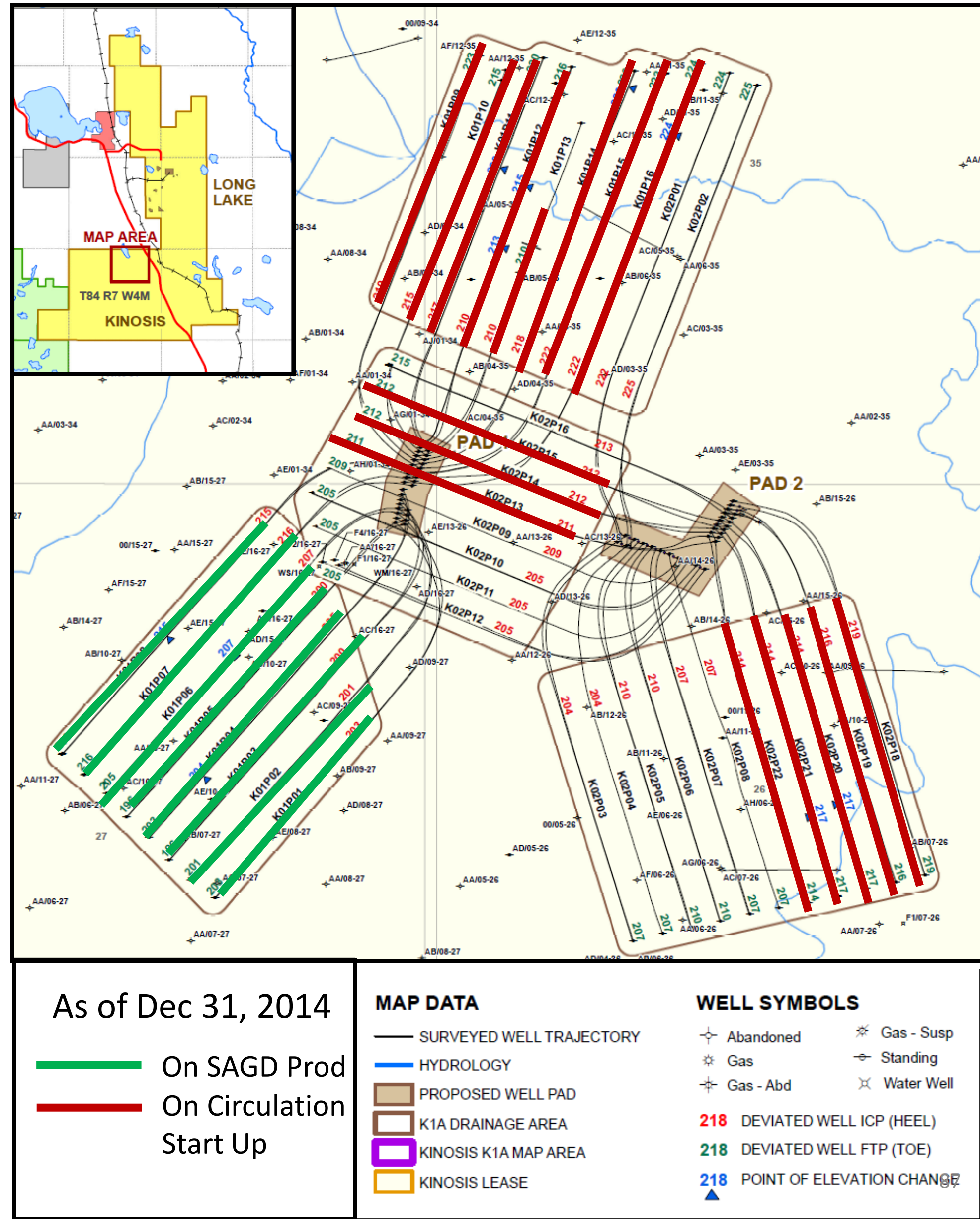


Well Pad Layout



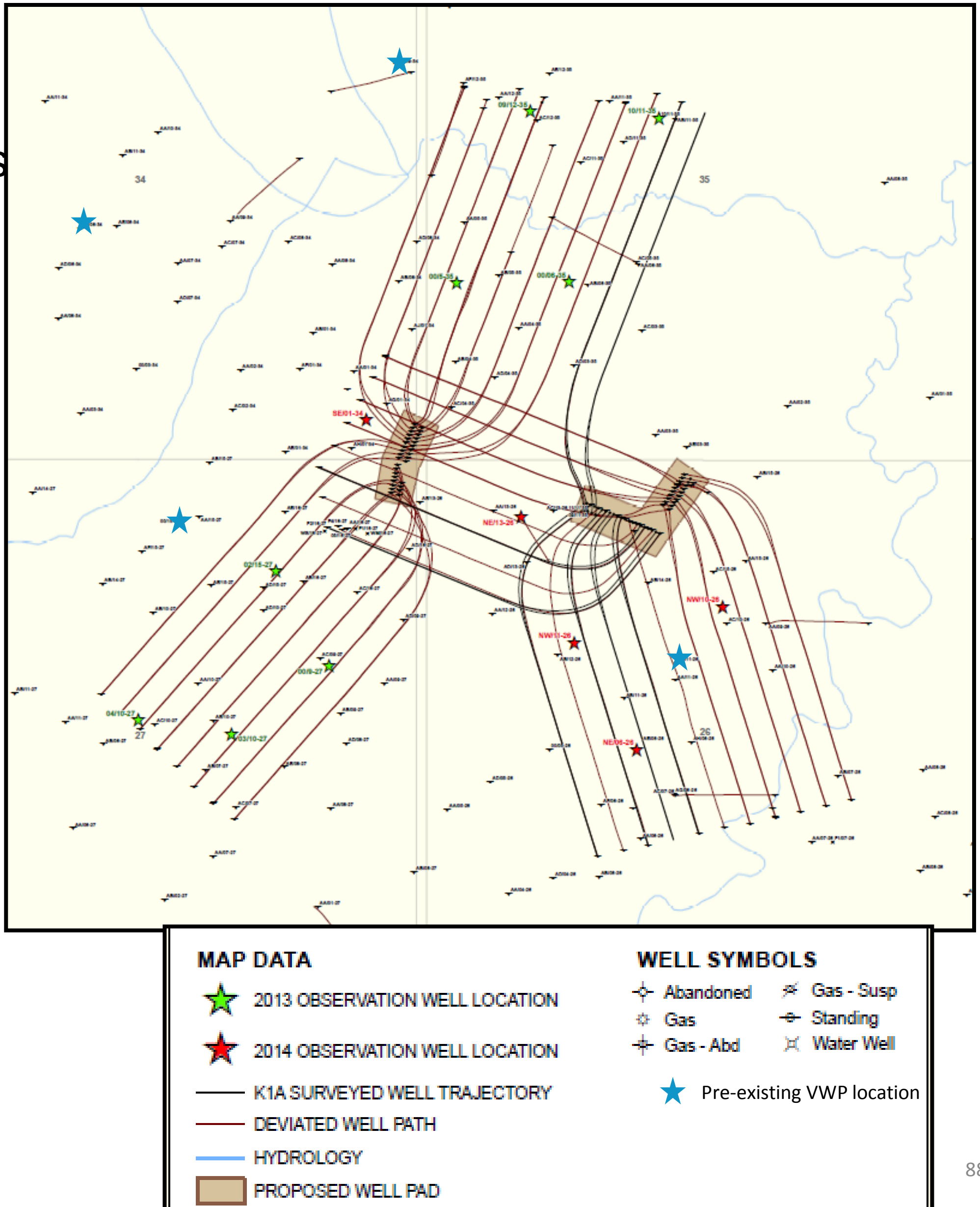
K1A – Operations Update as of Dec 31, 2014

- First steam commenced Aug 2014
  - 8 wells on circulation first on Pad 1 – Drainage Area C, K1P01 to K1P08
  - 8 more wells placed on circulation over Aug to Nov 2014, Drainage Area A, K1P09 to K1P16 as room in start up circulation facilities allowed
  - 8 Wells on Pad 2 placed on circulation Oct 2014
    - Drainage Area B: K2P13 to K2P15
    - Drainage Area D: K2P18 to K2P22
- Well conversions from Circulation to SAGD Production with ESPs commenced in Nov 2014
  - 8 wells converted in Drainage Area C, K1P01 to K1P08

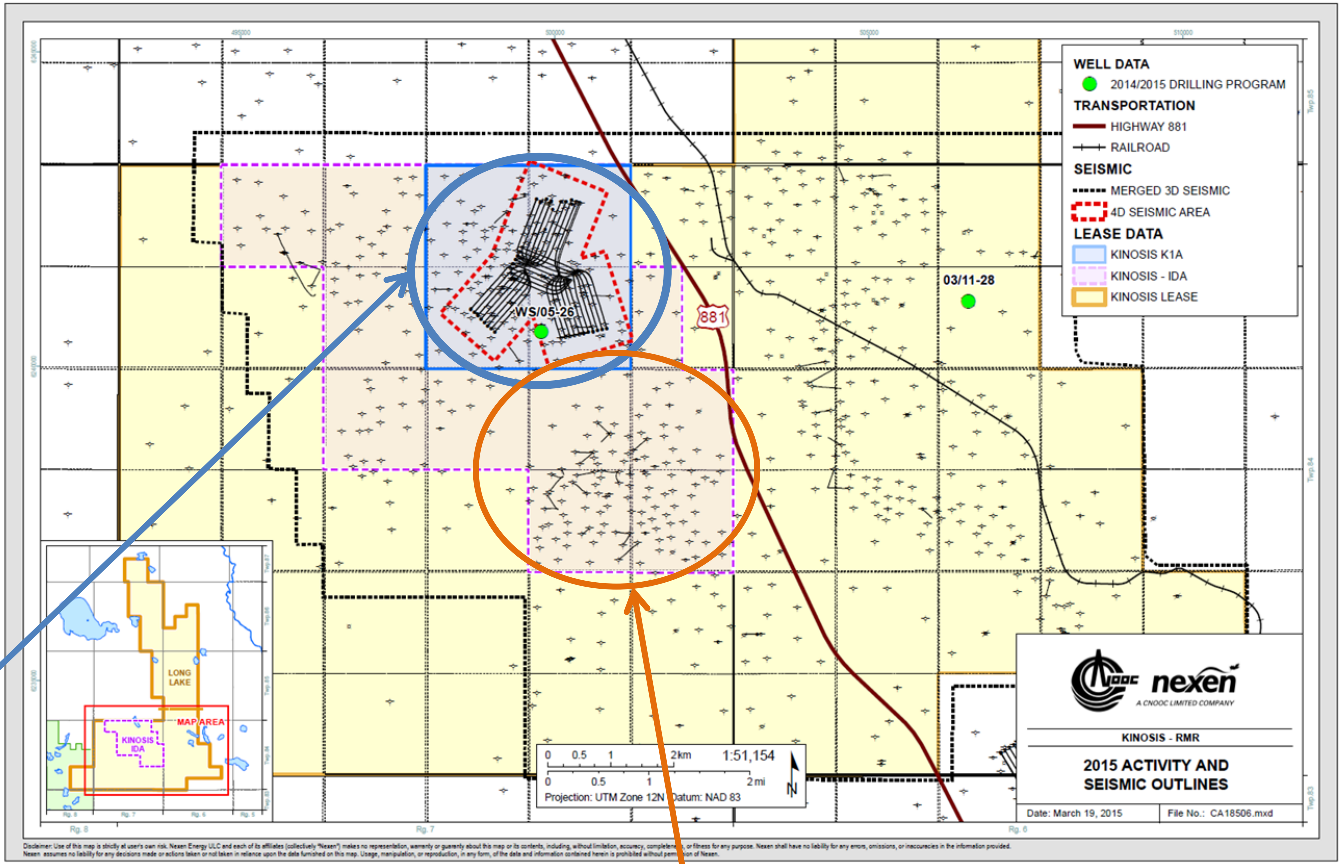


Kinosis 1A Observation Wells

- 2013:
  - Installed eight (8) wells with VWP's (vibrating wire piezometer)
- 2014:
  - Installed five (5) wells with VWP's
  - Installing 10 thermocouple strings for monitoring temperature
- Purpose:
  - Monitor temperature and steam chamber development and bottom water interaction (where applicable) over time
  - Monitor temperature and pressure for cap rock monitoring



Kinosis 2015 Future Plans

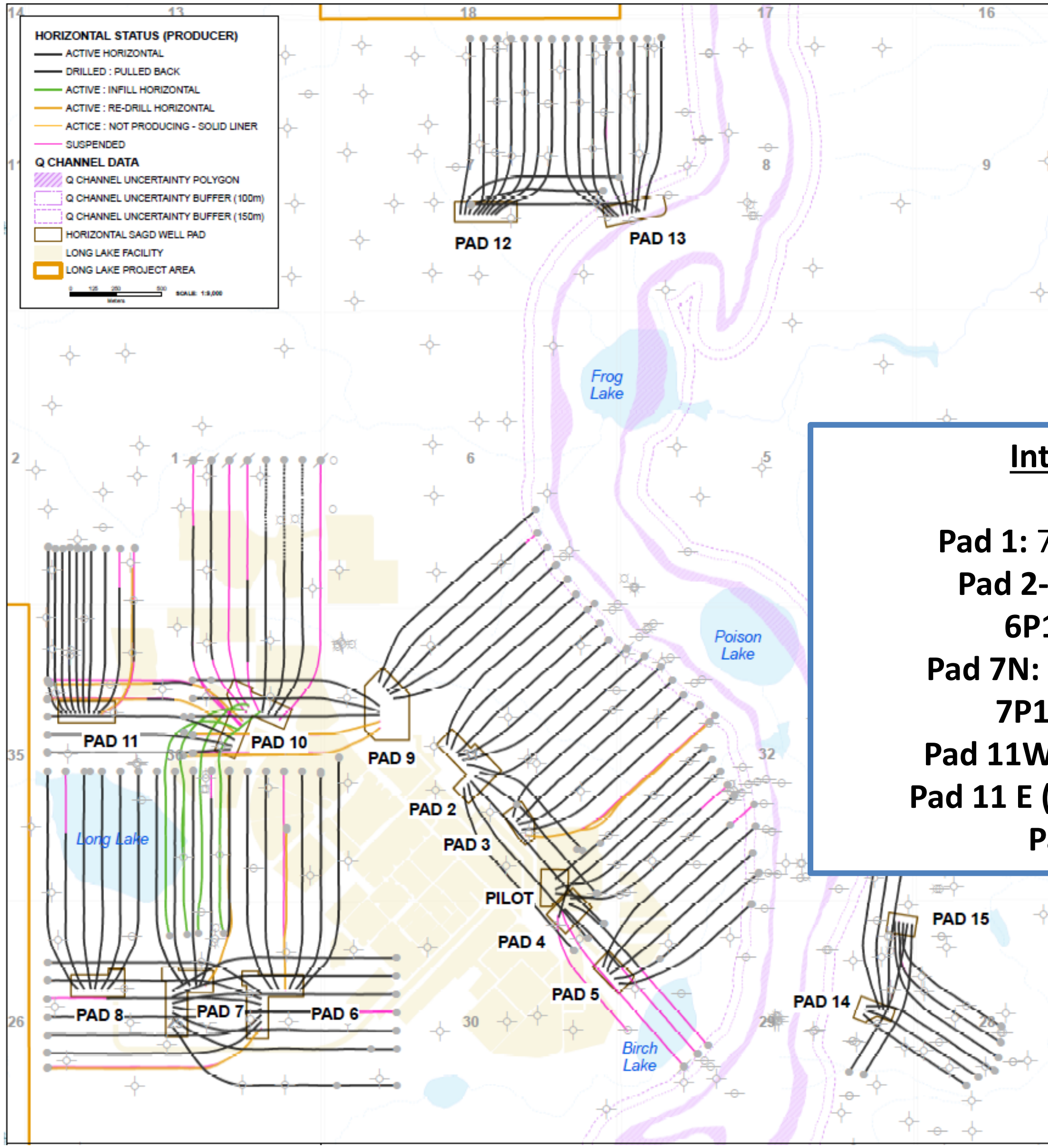


- K1A – 4D Seismic to be shot over 3 Drainage Areas (A, C and D).
  - No 4D survey at Drainage Area B because of surface constraints of the Kinosis facilities (Pad 1, flowlines and roadway) preventing the placement of dynamite holes and/or buried geophones
  - The edges of the Drainage Areas A & C surveys overlap over Drainage B, however the data quality is low and likely not suitable for interpretation at Drainage B.

- 3 K1A OBS wells to have thermocouple strings installed, one well re-outfitted with new T/C string
- 2 OBS wells drilled for water source and disposal monitoring purposes
- Future phases being evaluated–
  - K1B regulatory applications submitted

Drilling and Completions, Artificial Lift, and Instrumentation
Long Lake & Kinosis

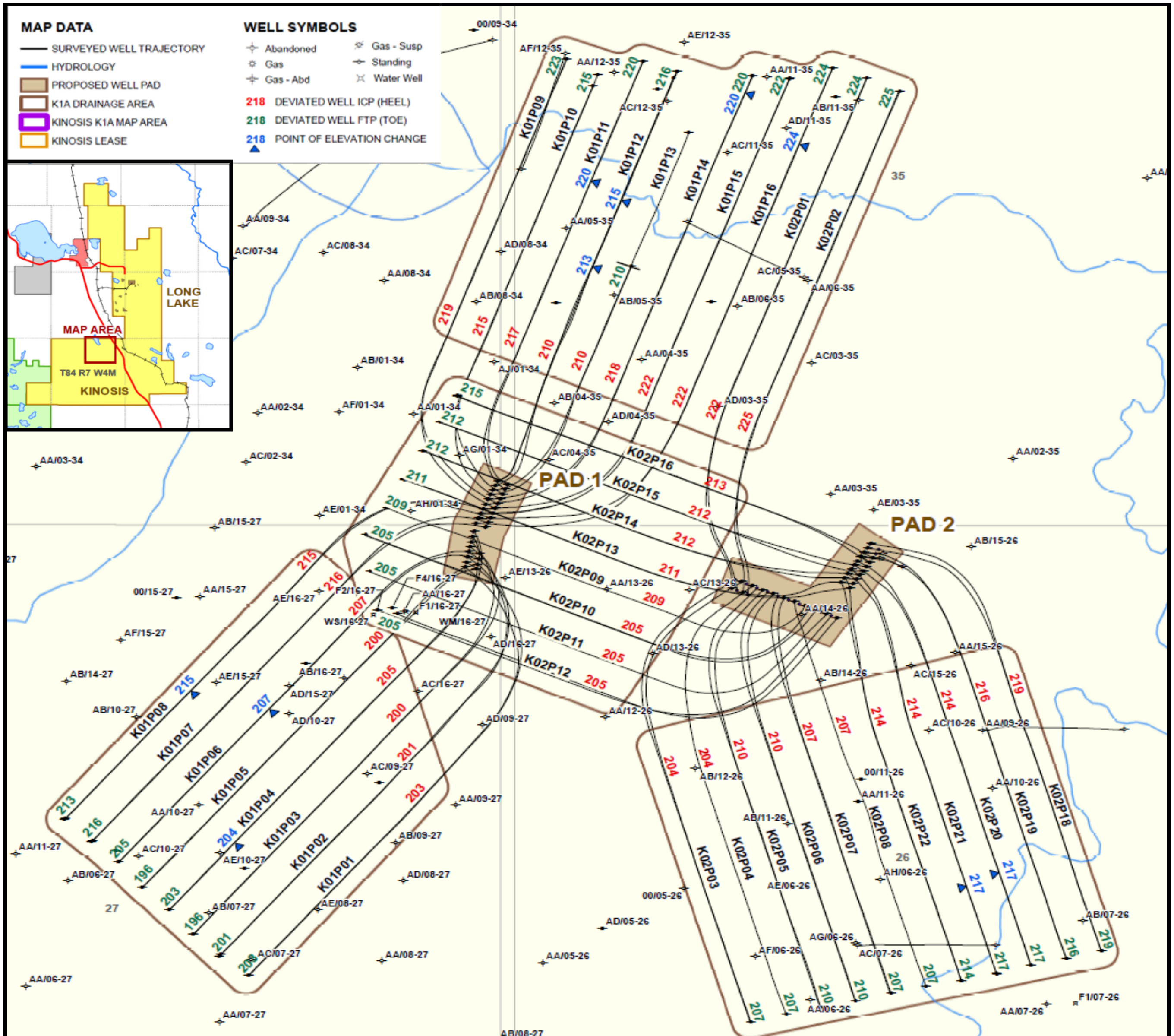
Long Lake
Horizontal Well Locations



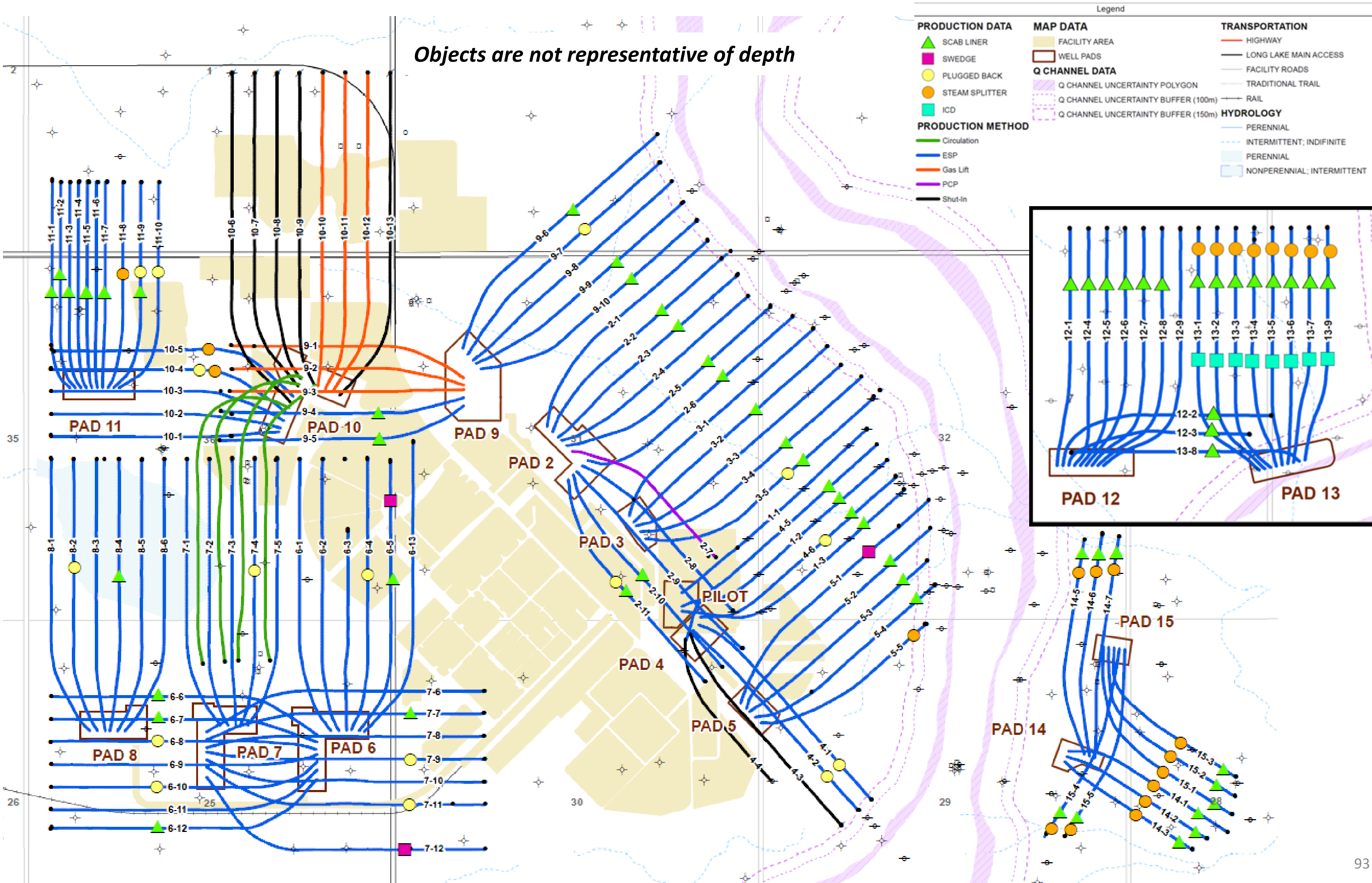
Inter-well Spacing

Pad 1: 75m (with infill wells)
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 P06): 40m
Pad 11 E (11P07 to 11P10): 80m
Pad 12-15: 75m

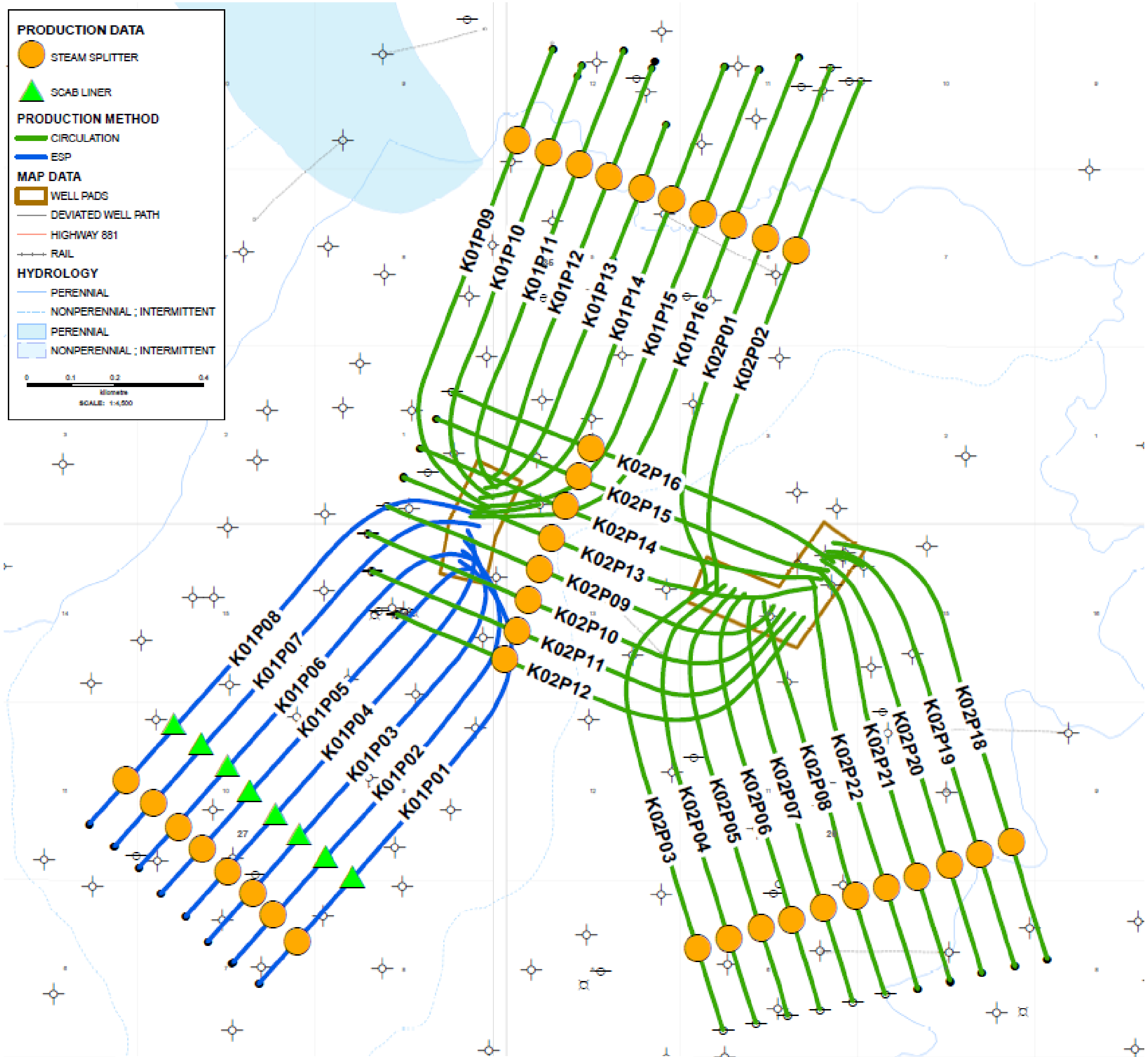
Kinosis
Horizontal Well Locations



Long Lake Well Pair Completions Map through 2014

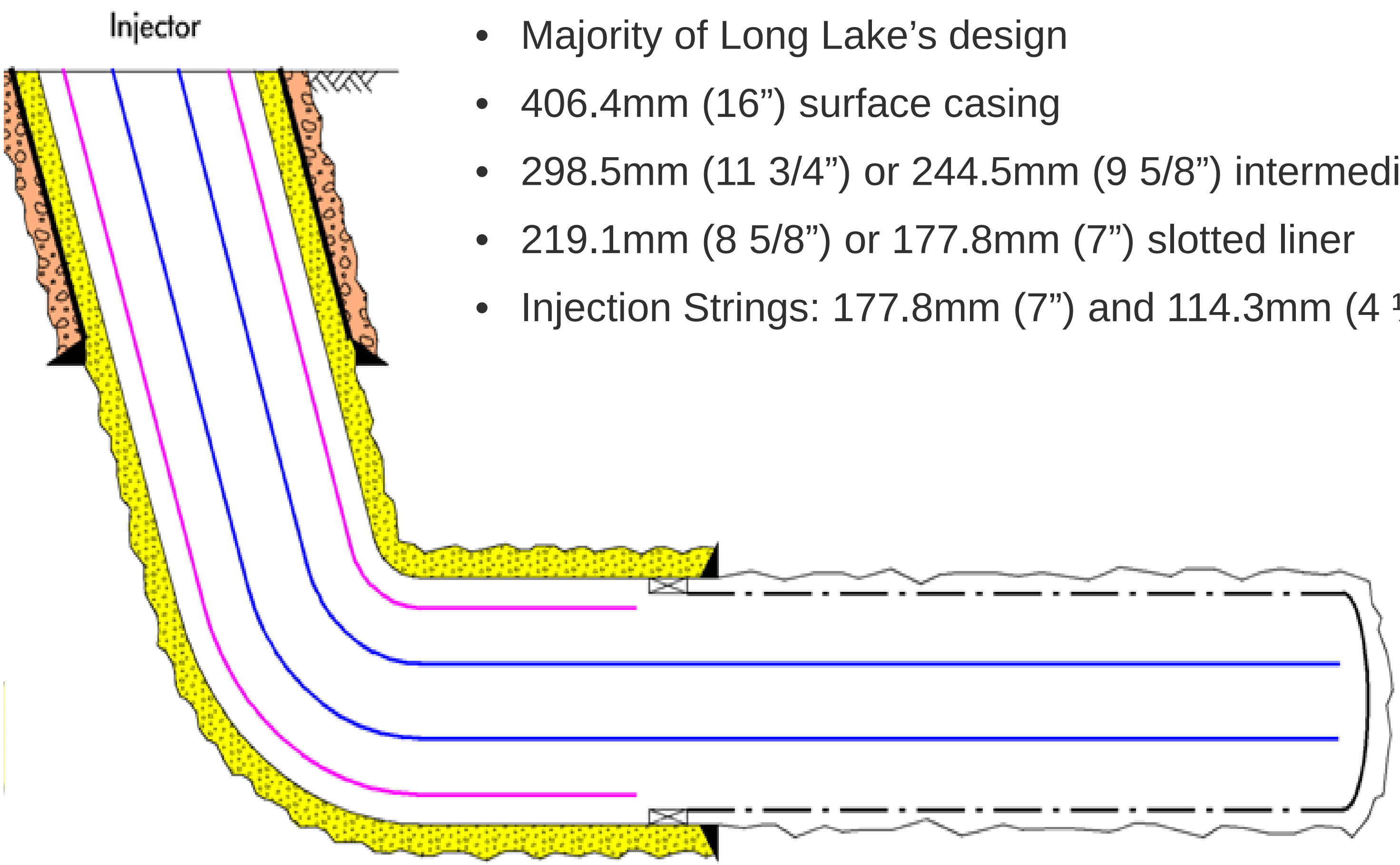


Well Pair Completions Map through 2014



Objects are not representative of depth

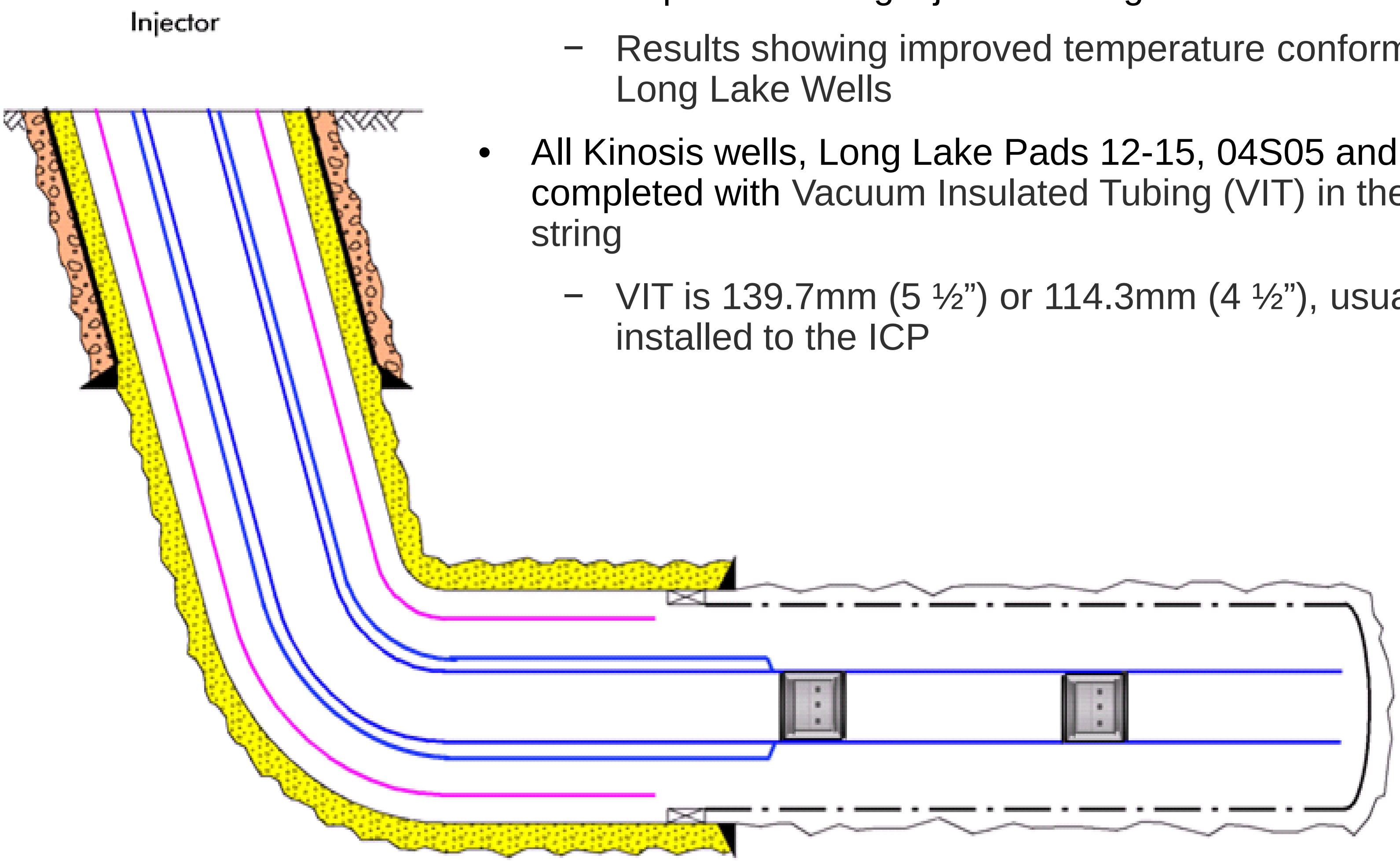
Typical Injector Completion



Concentric

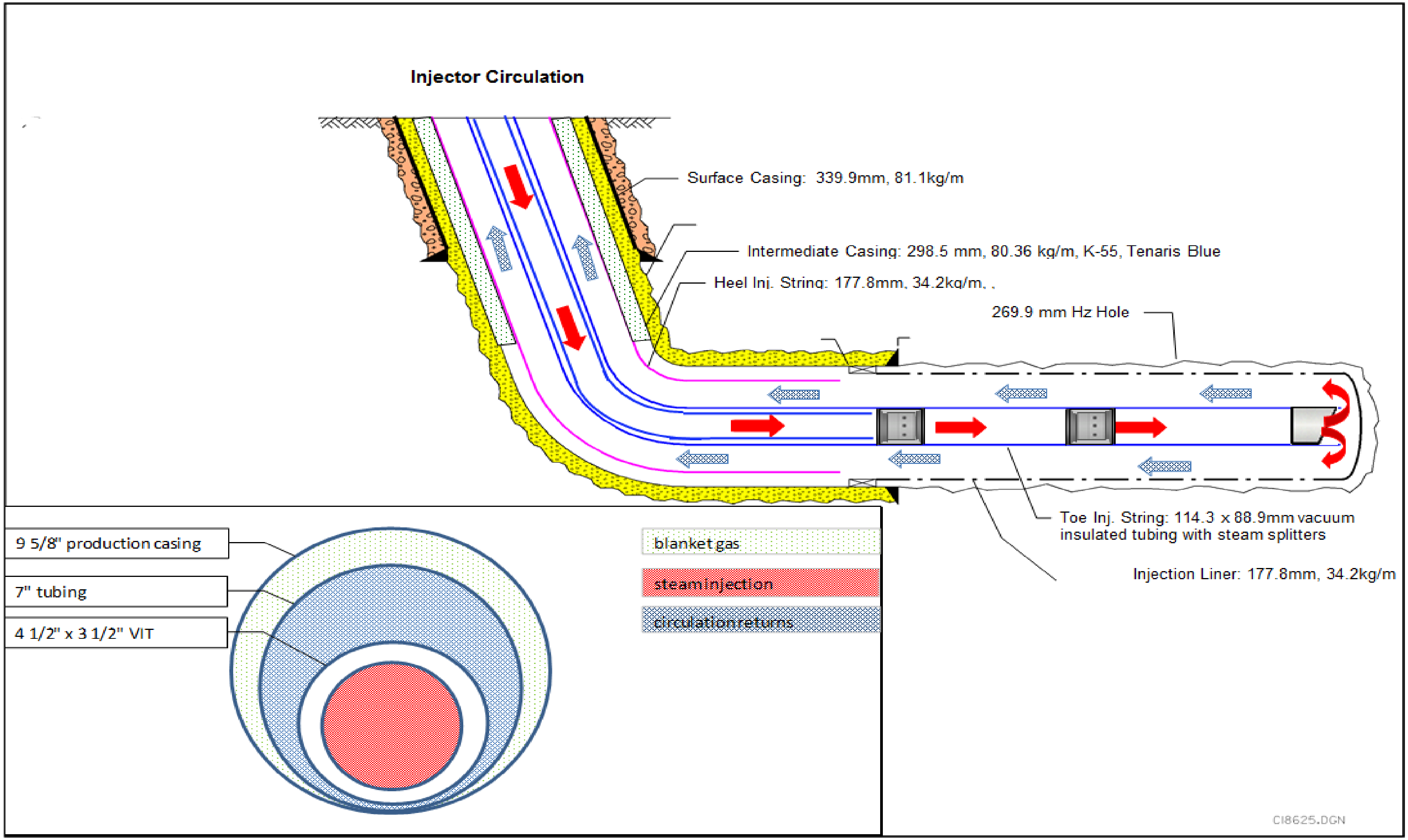
- Majority of Long Lake's design
- 406.4mm (16") surface casing
- 298.5mm (11 3/4") or 244.5mm (9 5/8") intermediate casing
- 219.1mm (8 5/8") or 177.8mm (7") slotted liner
- Injection Strings: 177.8mm (7") and 114.3mm (4 ½")

Alternative Injector Completion

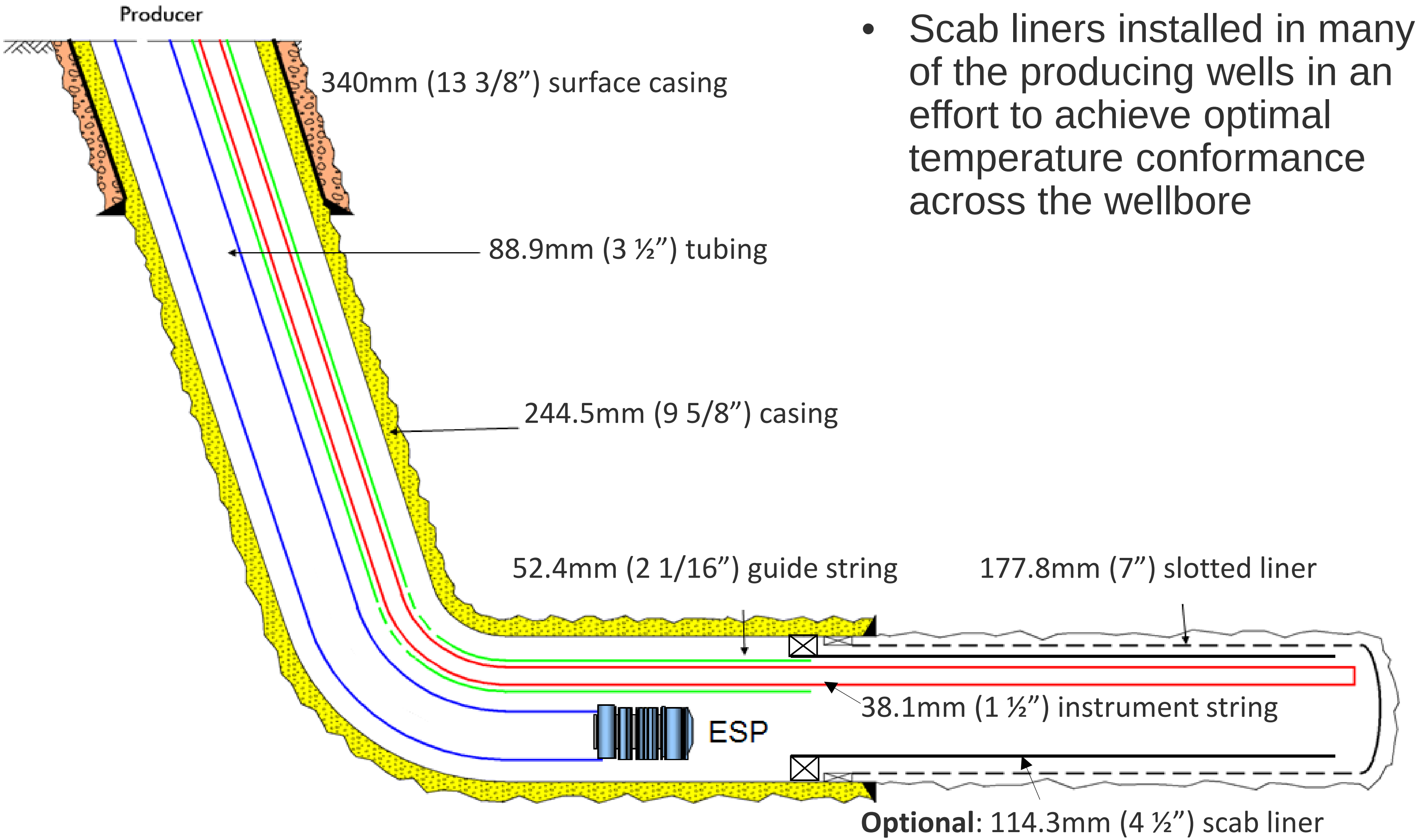


- All Kinosis wells, and a few Long Lake wells completed with steam splitters in long injection string
  - Results showing improved temperature conformance in Long Lake Wells
- All Kinosis wells, Long Lake Pads 12-15, 04S05 and 11S05 completed with Vacuum Insulated Tubing (VIT) in the long string
  - VIT is 139.7mm (5 ½") or 114.3mm (4 ½"), usually installed to the ICP

Typical Injector Circulation

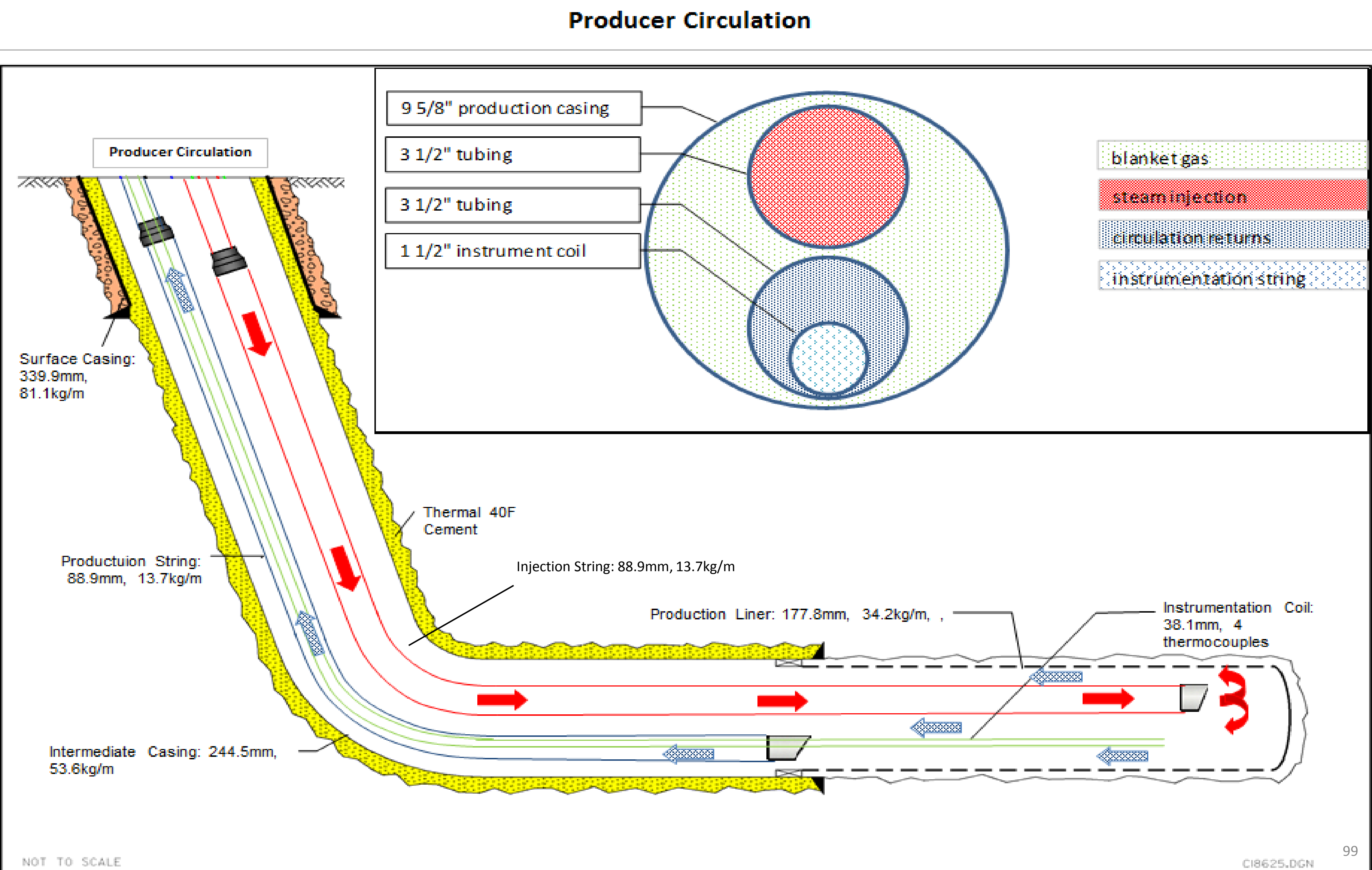


Typical Producer Completions – ESP



- Scab liners installed in many of the producing wells in an effort to achieve optimal temperature conformance across the wellbore

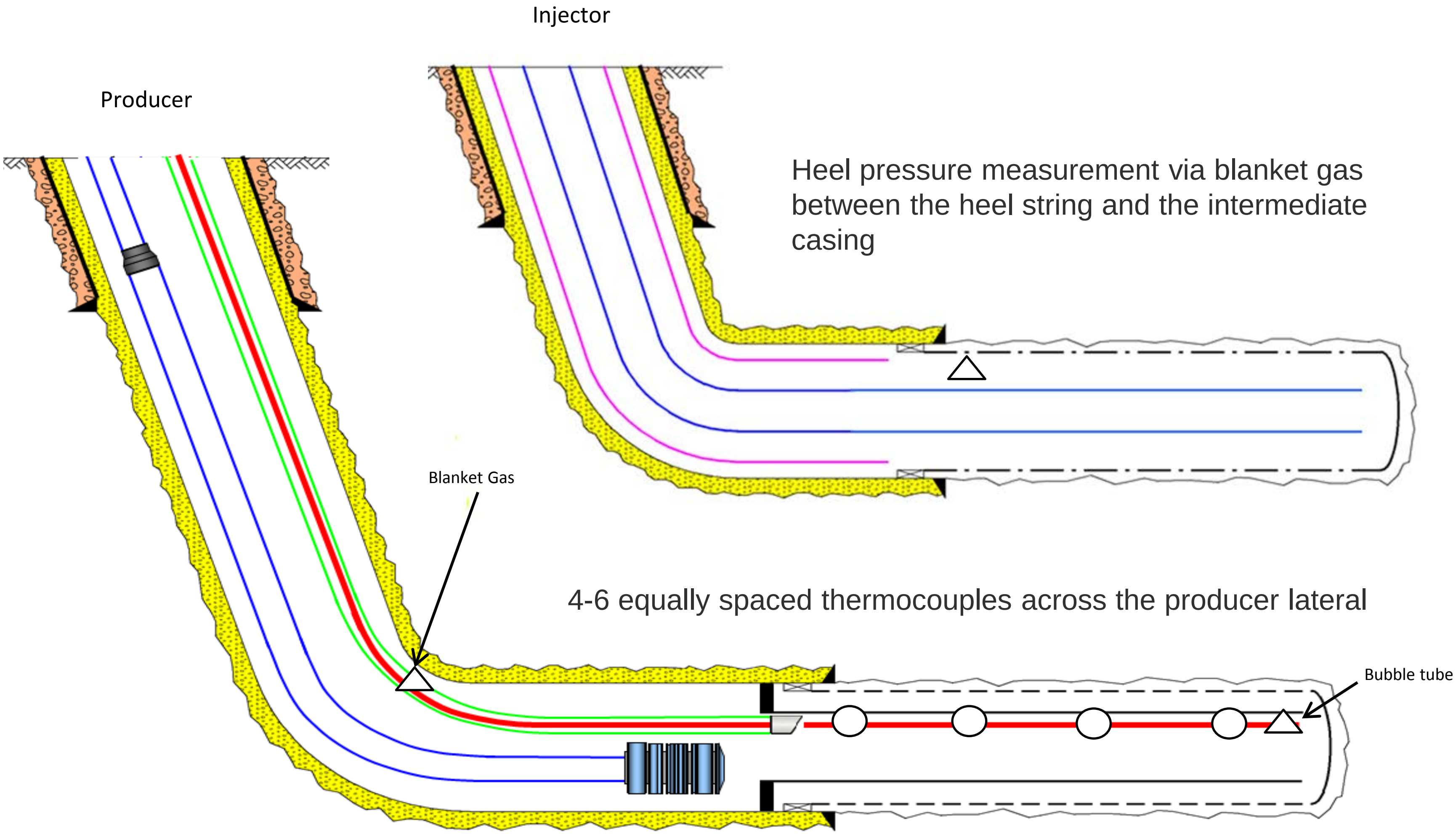
Typical Producer Circulation



Artificial Lift Performance

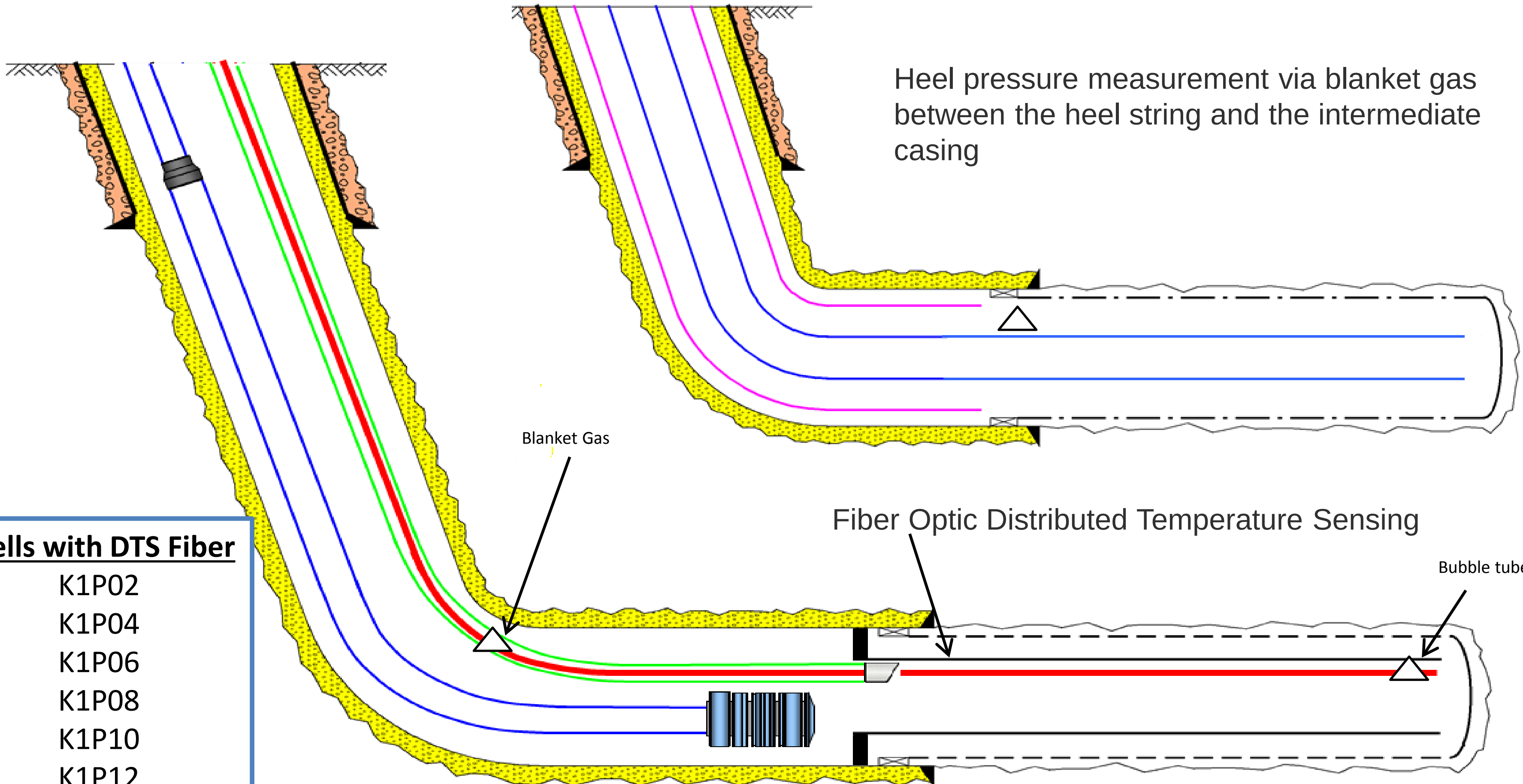
- Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers
  - 6 wells currently are on gas lift production
  - Conversions completed to allow production at lower steam chamber pressures (between 1400-2200 kPa)
- ESPs installed in 109 wells
  - Pump performance:
    - Average Run Time: 372 running days
    - Mean Failure Time: 682 running days
  - Operating temperatures have reached 215ºC
  - Pumps operate at pressures between 1000 and 1500 kPa (Producer)
  - Fluid production rates range from 75 - 1100 m^3/d
- Active member of ESP Reliability Information and Failure Tracking System JIP
- Currently running 1 Progressive Cavity Pump (PCP) in 02P07
  - Kudu 1100-MET-750 metal stator and rotor installed Mar-2014 (continuous operations since)
- ESPs and PCP use Variable Frequency Drive (VFD) to control pump speed and production rates

SAGD Instrumentation



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

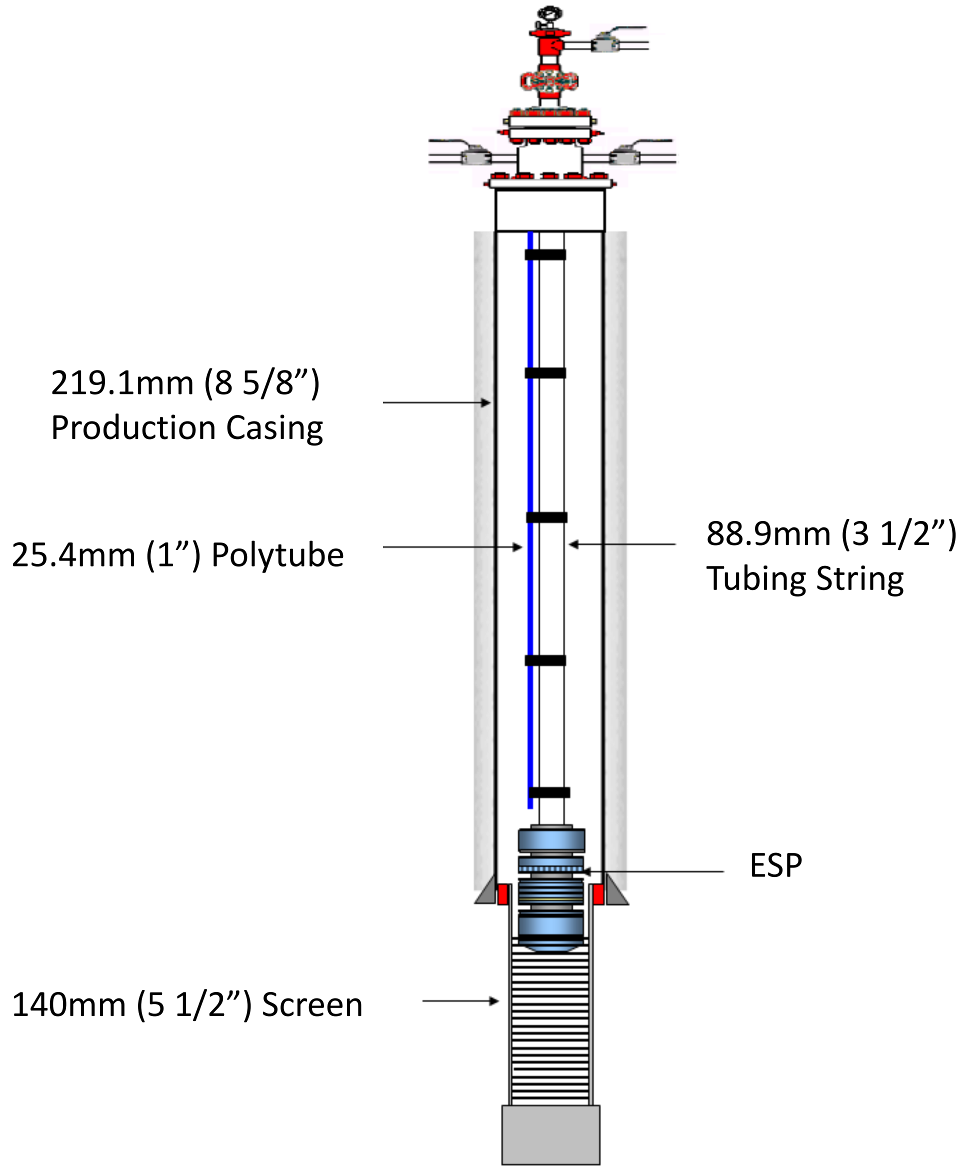
Alternate SAGD Instrumentation



Wells with DTS Fiber
K1P02
K1P04
K1P06
K1P08
K1P10
K1P12
K1P14
K1P16

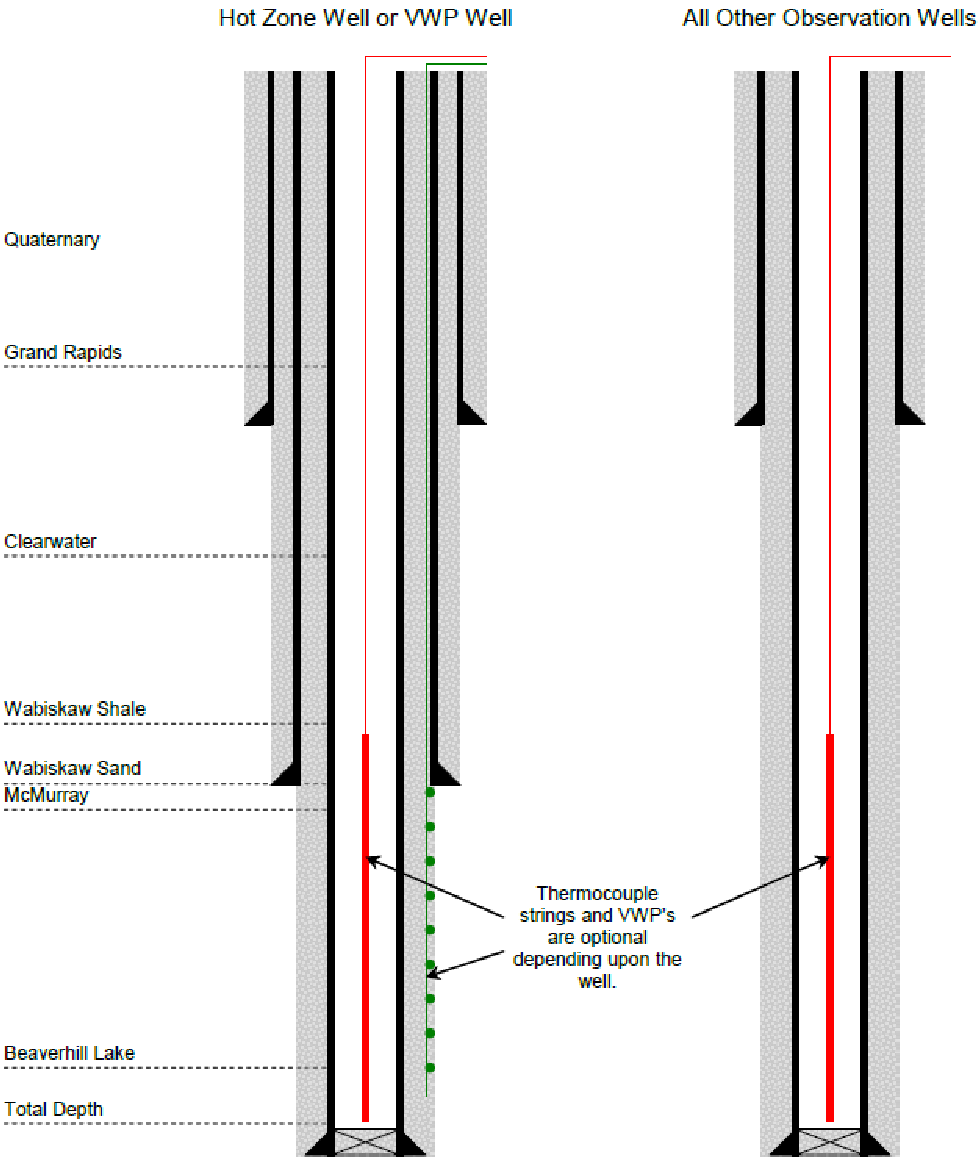
- Heel pressure measurement via blanket gas injection between guide string and instrument string
- Toe pressure measurement via blanket gas injection into bubble tube

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

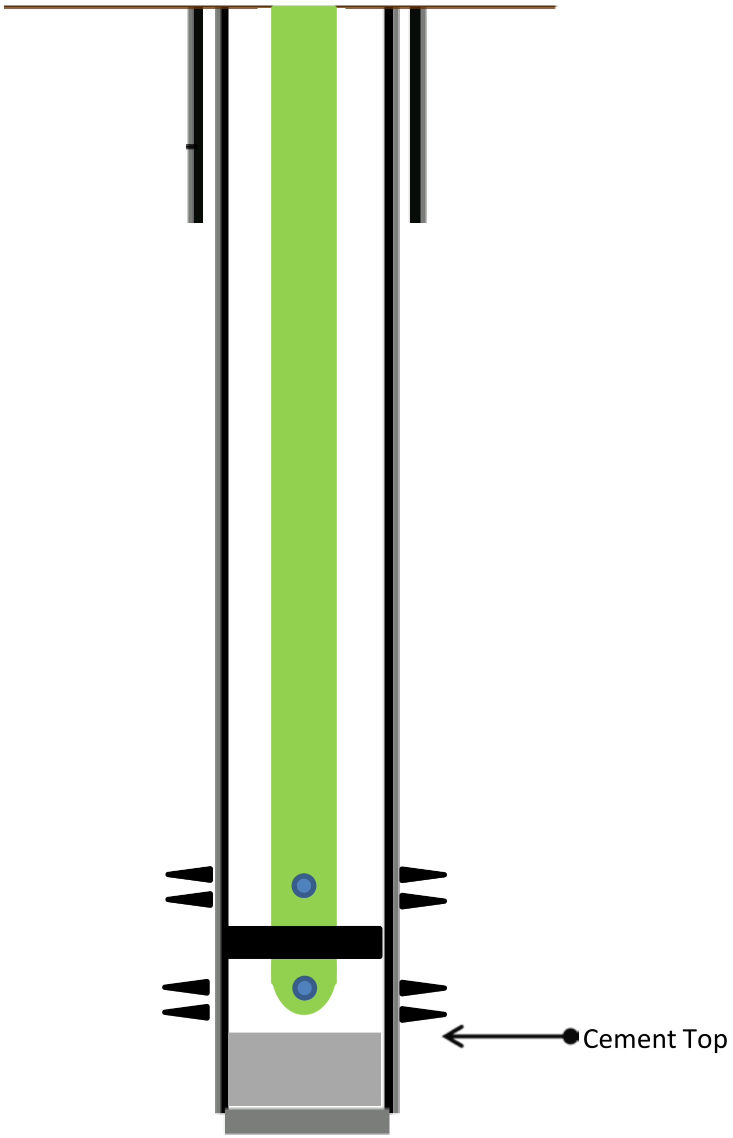
Typical Observation Wells



- Vibrating wire piezometer sensors **(green)** are strapped outside the production casing providing pressure and temperature measurements
  - 2 and 3 string casing designs have been used
- Thermocouple strings **(red)** provide temperature measurements

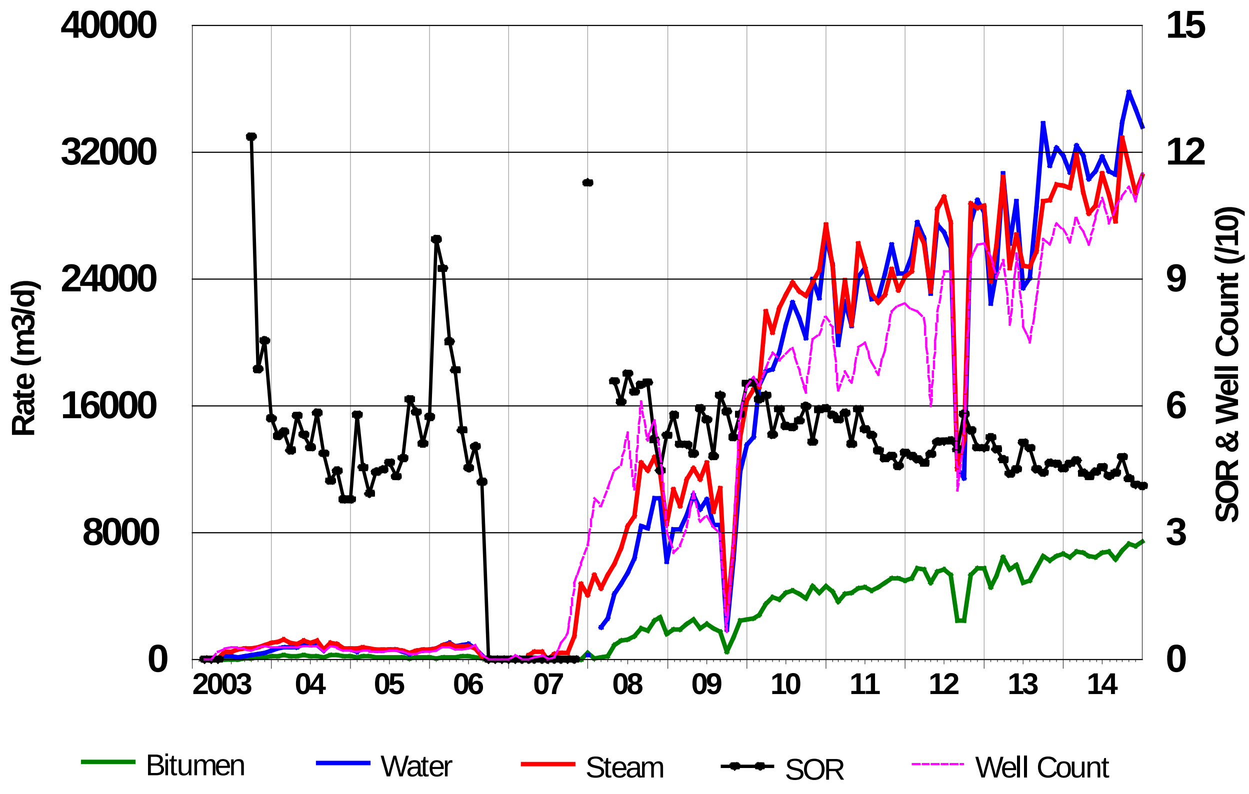
Alternative Observation Well Pads 14 & 15

- Thermal Cement from PBTD to the top of the McMurray
  - To prevent heating from McMurray
- Perforated Upper and Lower Cap Rock Intervals
  - Clearwater B
  - Wabiskaw C
- Full Bore Permanent Packer Between Perforations
- 1.5” Pressure/Temperature Coil String Stabbed Into Packer
  - Complete with 2 isolated pressure/temperature gauges monitoring each perforated cap rock zone



Scheme Performance

2014 Performance (Long Lake + K1A)



Performance

- Commercial Steam Assisted Gravity Drainage (SAGD)
- Downhole injection pressure varies throughout the field, ranges from 1,400 kPa to 2,400 kPa
- Converted remaining wells on Pad 15 from circulation to SAGD production with ESPs in April 2014
- Began circulating K1A well pairs in August 2014. 8 wells converted from circulation to SAGD production with ESPs in Nov 2014
- 17 pads and 153 well pairs, 119 producing wells at year end
  - Long Lake : 15 pads and 116 well pairs, 111 producing wells at year end
  - K1A : 2 pads and 37 well pairs, 8 producing wells at year end
- Reduced injection pressures on several pads throughout Long Lake
  - Material balance - Improved efficiency (lower SOR and/or higher WSR)
  - Trialing different strategies for pads with high water saturation intervals
  - Q-channel

	Design		Dec-2014	
	m^3/d	bbl/d	m^3/d	bbl/d
Bitumen	11,130	70,000	7,431	46,762
Steam	37,000	233,000	30,516	192,029
SOR	3.3		4.1	

Recoverable Bitumen

Pad	Num Wells	EBIP E^6 m^3	Estimated Ultimate RF	Recoverable Bitumen $E^6 m^3$	Cum Production Dec. 2014 E^3 m^3	RF
1	5	2.1	60%	1.2	797	36%
2NE	6	2.4	51%	1.2	611	25%
2SE	5	1.0	33%	0.3	228	23%
3	5	2.4	60%	1.4	955	39%
4	2	0.2	66%	0.1	72	52%
5	5	3.2	60%	1.9	1082	34%
6N	6	2.7	48%	1.3	621	22%
6W	7	2.0	60%	1.2	683	36%
7E	7	1.3	69%	0.9	563	43%
7N *	5	3.1	66%	2.0	1383	46%
8	6	2.5	57%	1.4	844	34%
9NE	5	1.1	52%	0.6	192	17%
9W	5	1.5	50%	0.8	345	22%
10N	3	2.2	25%	0.5	150	14%
10W	5	2.2	57%	1.3	498	24%
11	10	2.2	62%	1.4	922	42%
12	9	3.4	55%	1.9	330	10%
13	9	3.2	54%	1.7	404	13%
14	6	1.8	49%	0.9	82	4%
15	5	1.3	53%	0.7	21	1%
K1A	37	19.9	53%	10.6	12	0%
TOTAL	**153**	**61.6**	**54%**	**33.3**	**10795**	18%

* Pad 7N estimated ultimate RF and recoverable bitumen volumes do not include expected additional recovery from infill wells drilled in 2014

December 2014 Average Injection Pressures

Drain Area/Pad	Average Injector Pressure (kPa)
K1A-A	1828
K1A-B	2725
K1A-C	2549
K1A-D	2800
LL-001	1675
LL-002NE	1337
LL-002SE	1594
LL-003	1538
LL-004	1368
LL-005	1731
LL-006N	2018
LL-006W	1777
LL-007E	1905
LL-007N	2046
LL-008	1722
LL-009NE	1663
LL-009W	2098
LL-010N	1659
LL-010W	2036
LL-011	1867
LL-012	1606
LL-013	1836
LL-014	2325
LL-015	2280

PAD Performance

Examples of Low, Mid, High Recovery

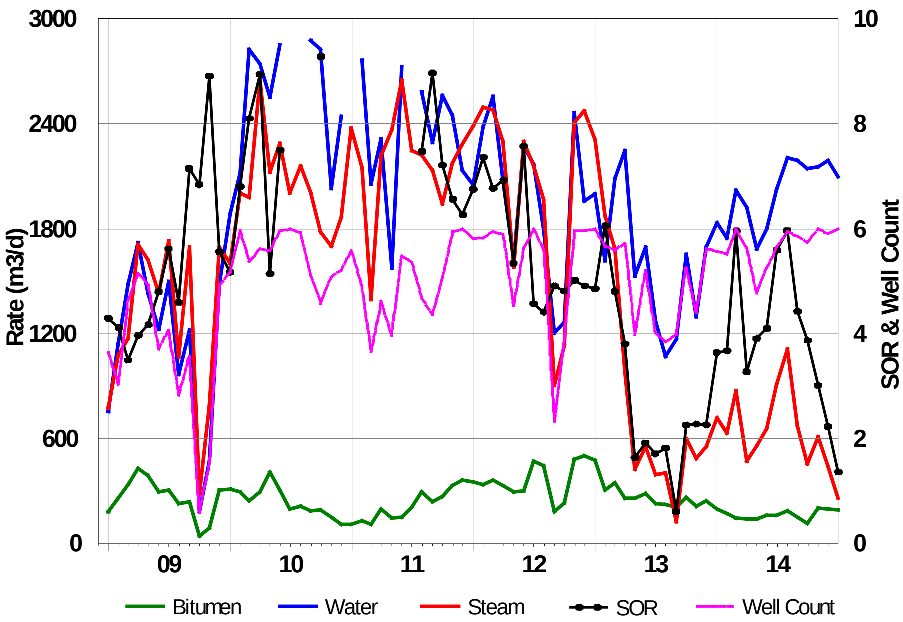
Examples of Low, Mid, High Recovery

- Low Recovery
  – Pad 2NE

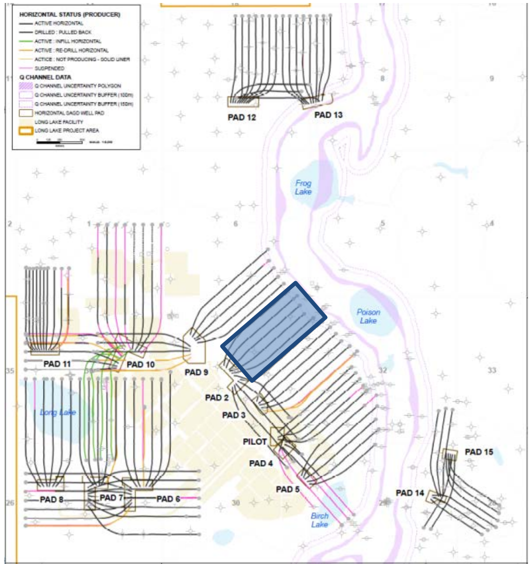
- Mid Recovery
  – Pad 8

- High Recovery
  – Pad 11

PAD 2NE Production Summary



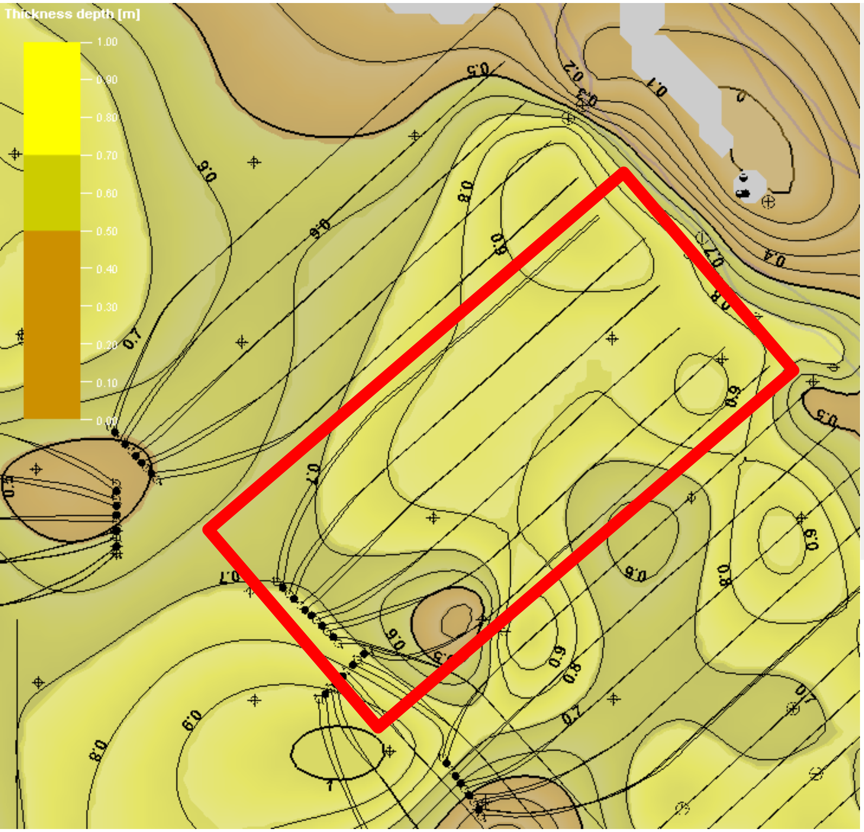
Well	EBIP (m3)	Dec 2014 Cumulative Bitumen (m3)	Dec 2014 RF (%)	Final EUR (m3)	Final RF (%)
02P01	375	65	17%	225	60%
02P02	395	68	17%	237	60%
02P03	450	86	19%	270	60%
02P04	434	108	25%	174	40%
02P05	349	125	36%	139	40%
02P06	393	158	40%	177	45%
Pad 2NE	**2396**	**611**	**25%**	**1222**	**51%**

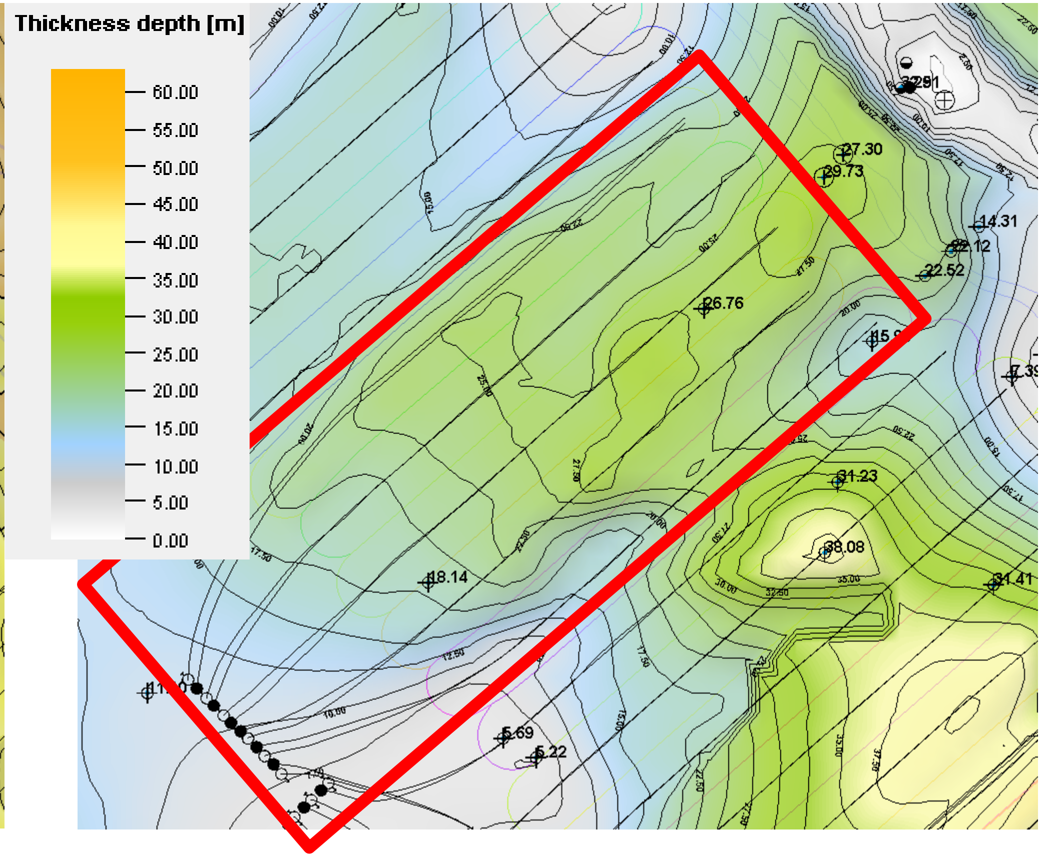


- Steam SI to 02S04, 02S05 and 02S06 since Q1 2013 due to Q-channel
- Reduction in production rates due to less energy being injected into the system
- Short term steam reductions due to plant or surface constraints have lead to inconsistent production performance
- At YE, injection pressures were ~1,275 – 1,485 kPa
- Stepped pressure outwards from the shut in injectors to reduce cross-flow

PAD 2NE - Geology

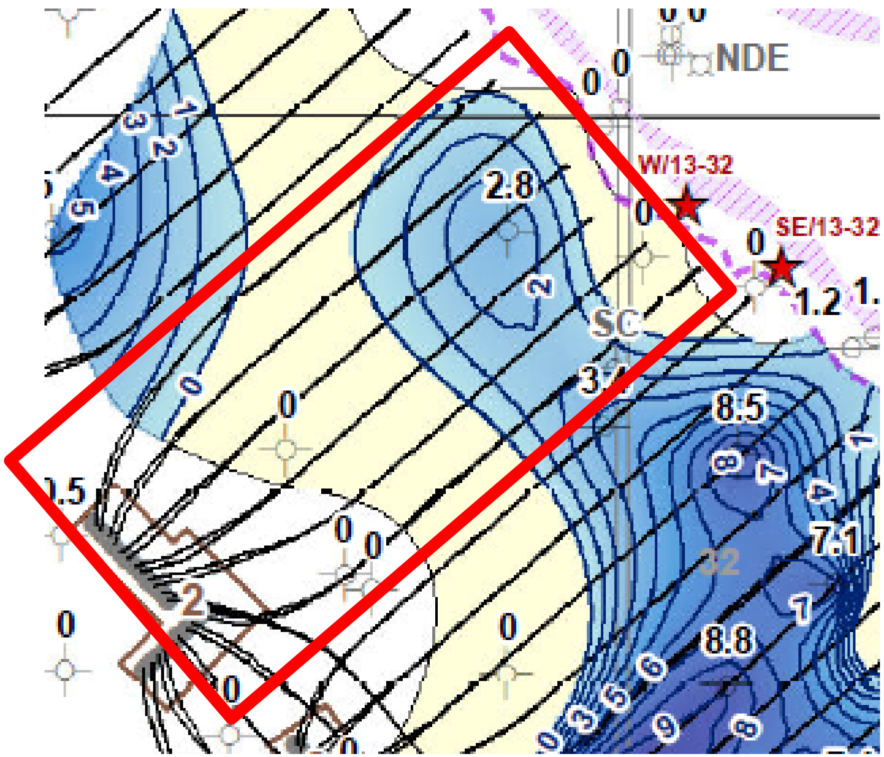
- Sand Facies
- EBIP Interval



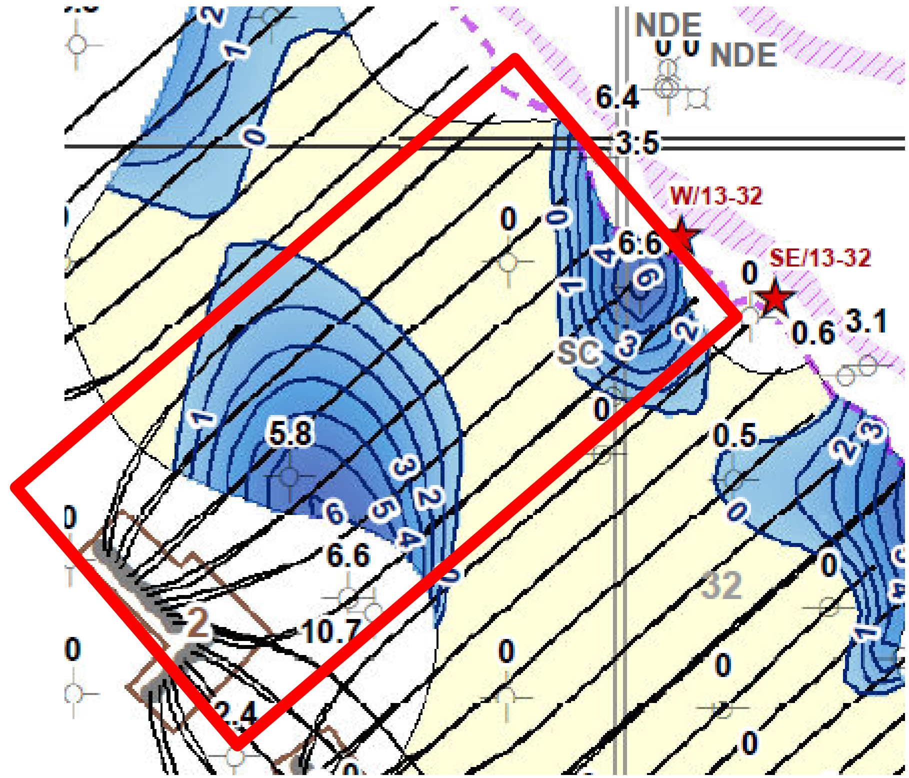


PAD 2NE - Geology

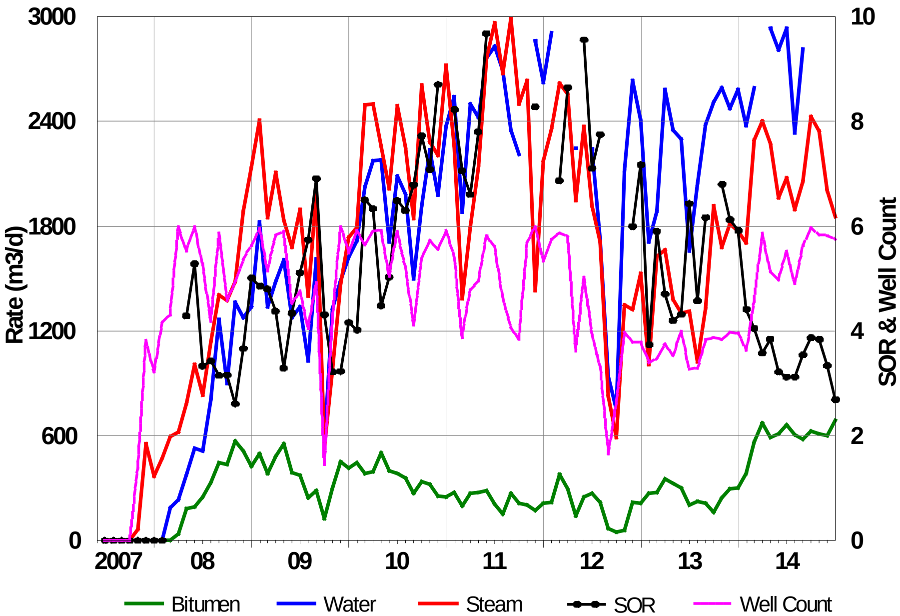
- Cumulative “lean zone” within EBIP interval



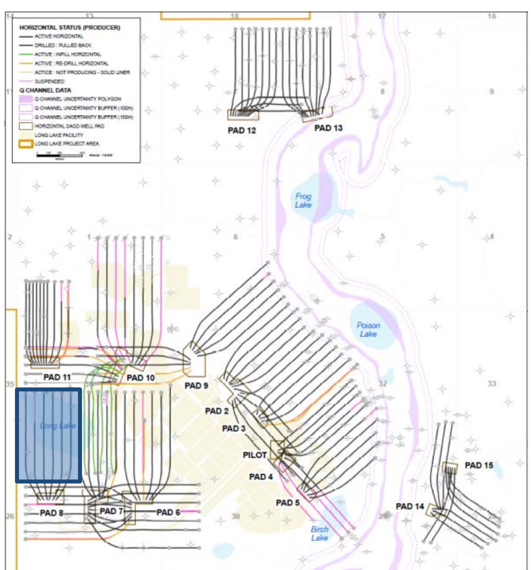
- Top Water in contact with EBIP interval



PAD 8 Production Summary



Well	EBIP (m3)	Dec 2014 Cumulative Bitumen (m3)	Dec 2014 RF (%)	Final EUR (m3)	Final RF (%)
08P01	302	41	14%	136	45%
08P02	183	61	33%	82	45%
08P03	429	98	23%	193	45%
08P04	488	160	33%	293	60%
08P05	516	260	50%	361	70%
08P06	555	223	40%	333	60%
Pad 8	**2473**	**843**	**34%**	**1399**	**57%**

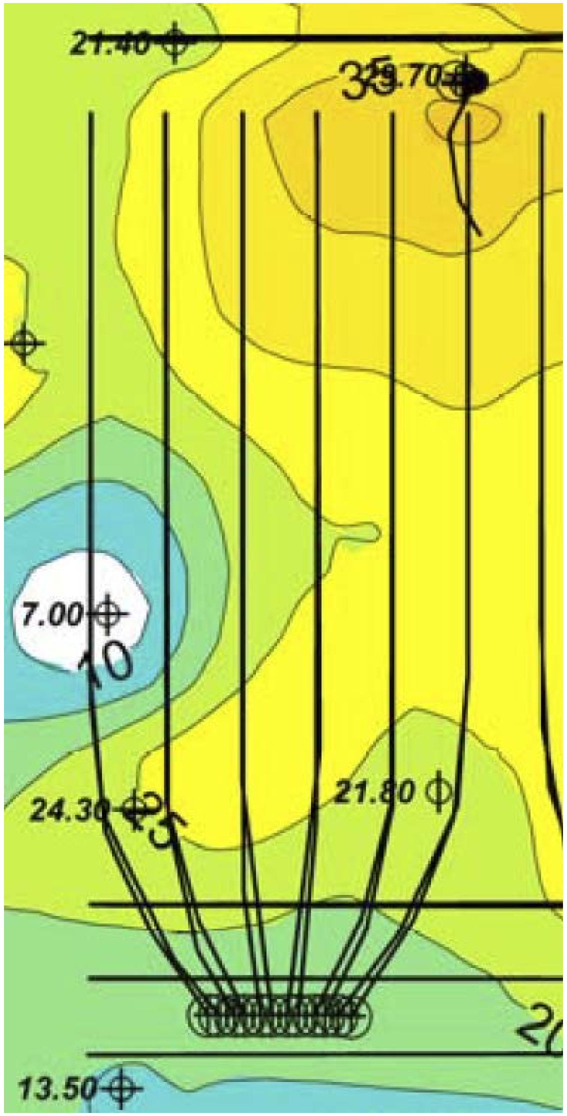


- Oil cut dropping in late 2013 - changed production strategy to focus on increased emulsion rates
  - Improved oil cut – improved oil production
  - Improved temperature distribution along laterals
- Brought 08P01 & 08P02 online in February 2014 after being shut in since 2012

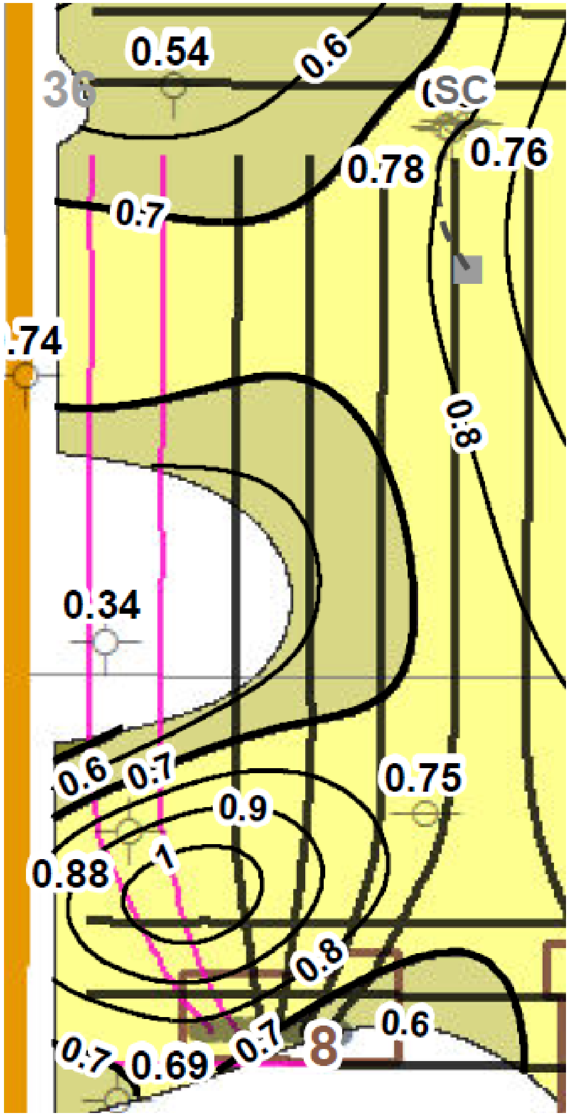
PAD 8 – Geology

- Reservoir quality improves from east to west

EBIP ISOPACH

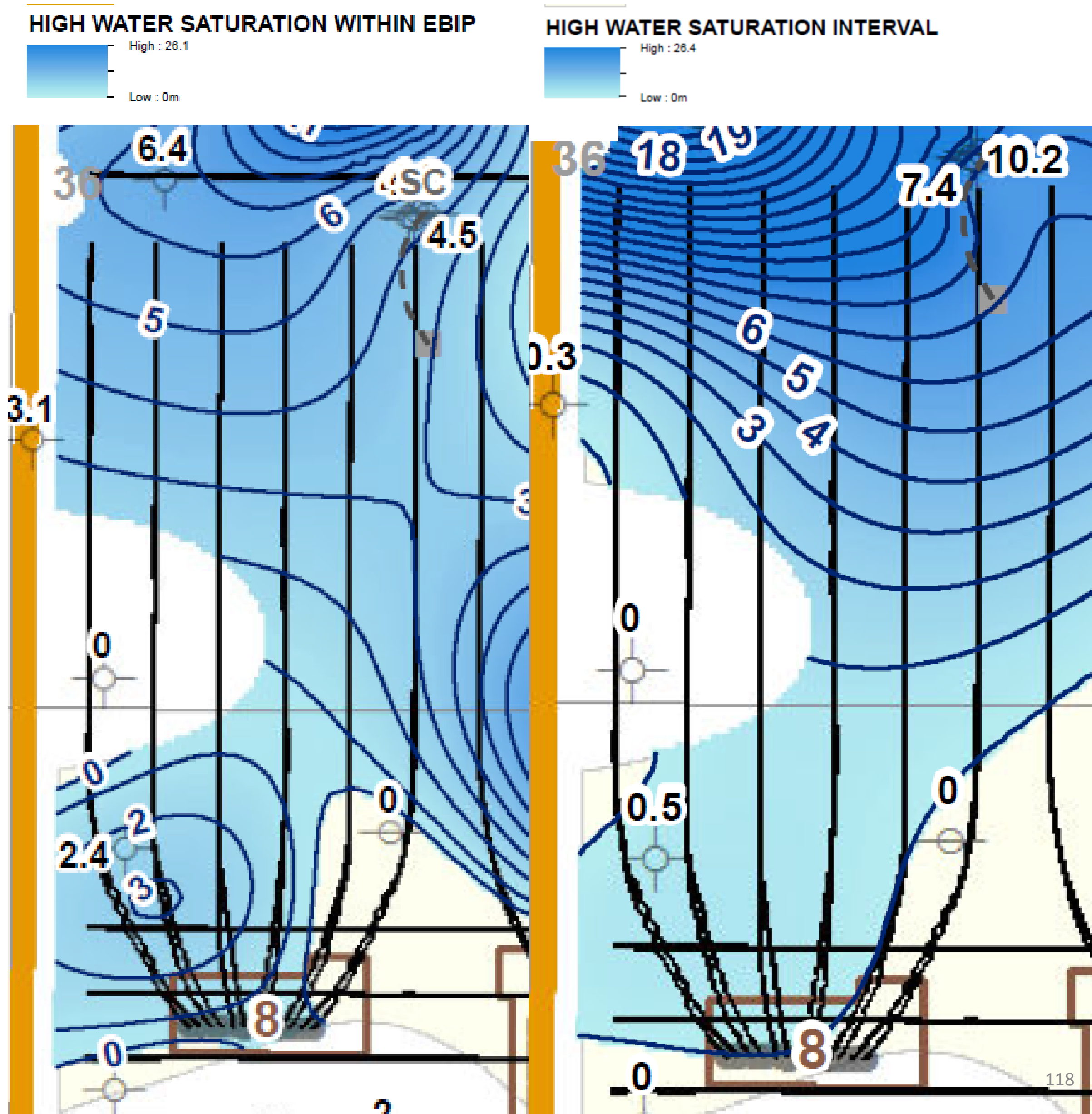


SAND FACIES PERCENTAGE



PAD 8 – Geology

- Lean zones throughout pad
- Top water at toes connected to extensive top water body on Pad 10W and Pad 11



PAD 8 Performance

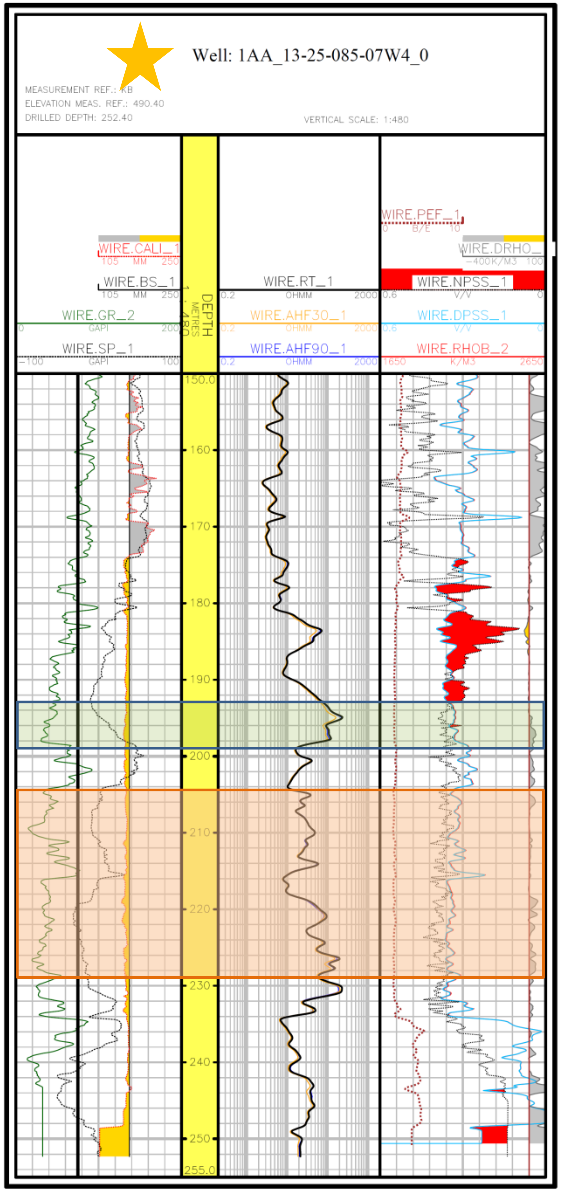
Some similar characteristics throughout pad:

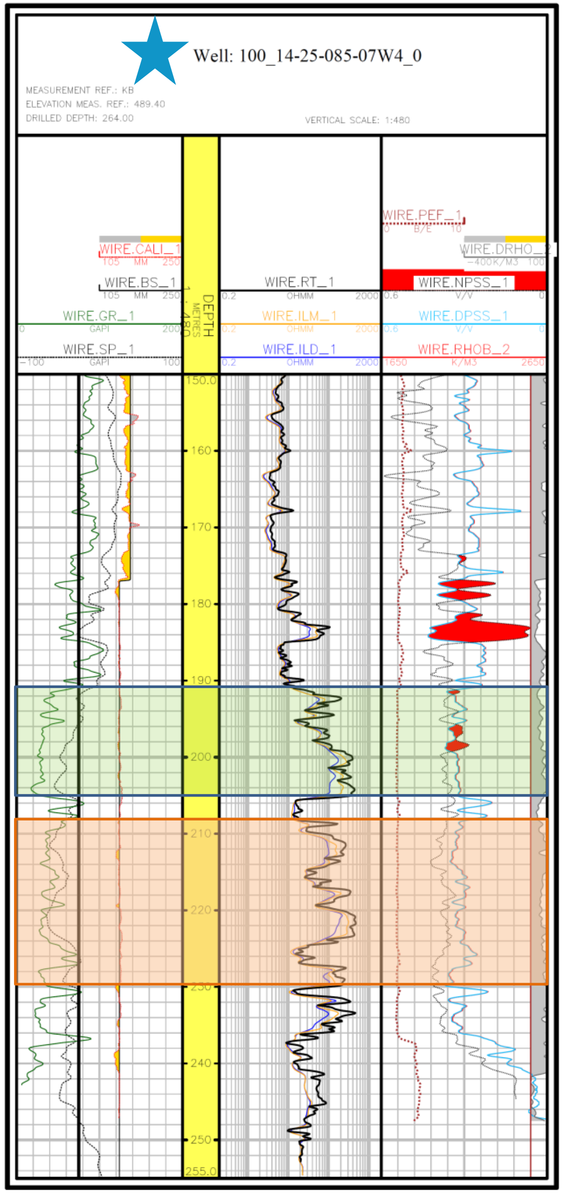
- Large top water influence – high produced water volumes
  - Upsized pump capacity in late 2013 / early 2014 to produce higher volumes
- Limited seismic and core hole data due to lake covering pad area
- Large secondary zone above primary EBIP – separated by shale barrier
- Scab liners installed in several wells to encourage temperature development at the toes

Pad can be split into 2 groups:

- 08P01, 08P02, 08P03 – low recovery
  - Lower quality reservoir
  - Thin pay – dominated by mud plug
- 08P04, 08P05 & 08P06 – high recovery
  - High quality reservoir
  - Thicker pay
  - Increased emulsion production resulted in improved contribution from the toe sections

PAD 8 – Secondary Zone

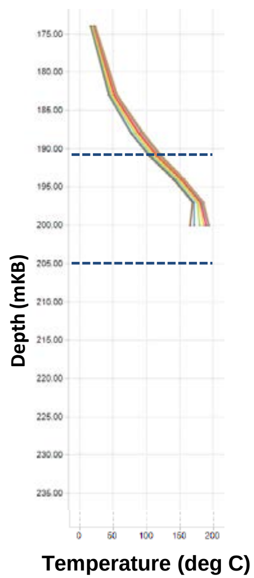


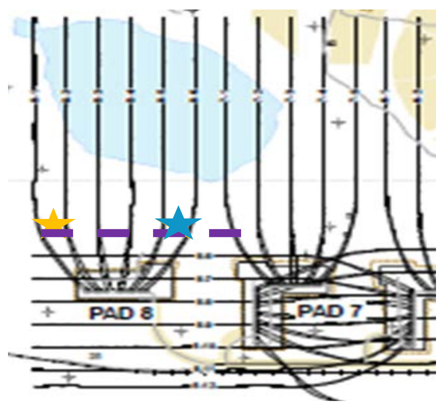


Continuing to investigate whether secondary zone has started contributing

- Potentially 8-12 m of pay
- Temperature profile on 100/14-25 obs well
- RST on 100/14-25 observation well in Q1 2015
- 4D seismic over Long Lake West in Q1 2015
- New observation well on Pad 6W in Q1 2015

Observation Well 100/14-25-085-07W4





Secondary Zone

Primary EBIP

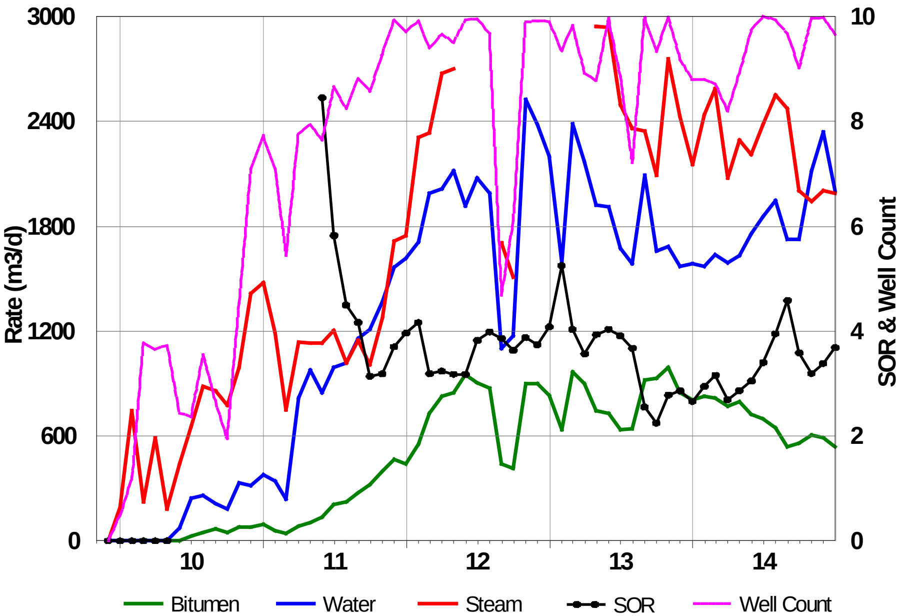
PAD 8 – Restarting 08P01 & 08P02

- Producers shut in Q2 2012 due to high water cut
  - Question of whether 0% oil cut readings were accurate
- Injectors continued to get occasional steam when excess was available
- Successfully restarted ESPs in Q1 2014 without any issues
- Significant improvement in performance (rates below are combined for 08P01 & 08P02)

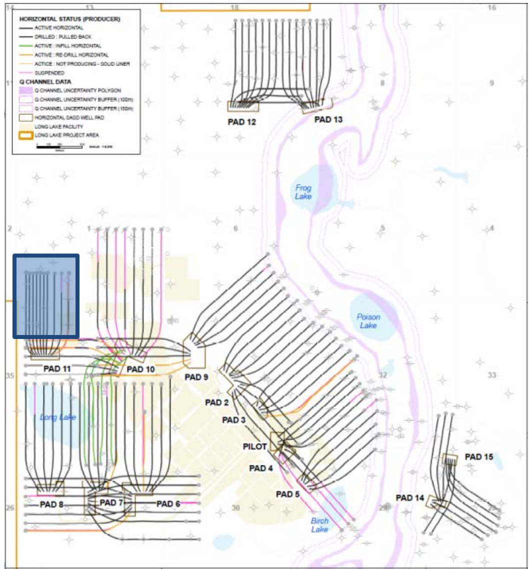
Case	Oil Rate (m3/day)	Total Fluid Rate (m3/day)	Oil Cut (%)
April 2011 Average	10	1200	<1%
Dec 2014 Average	115	1250	9%

- Similar strategy to the rest of the pad– focus on withdrawing fluid
- Lower priority compared to higher performing wells in the field due to high water cut
  - inconsistent production & injection
- Temperatures along wellbores continuing to heat up

PAD 11 Production Summary



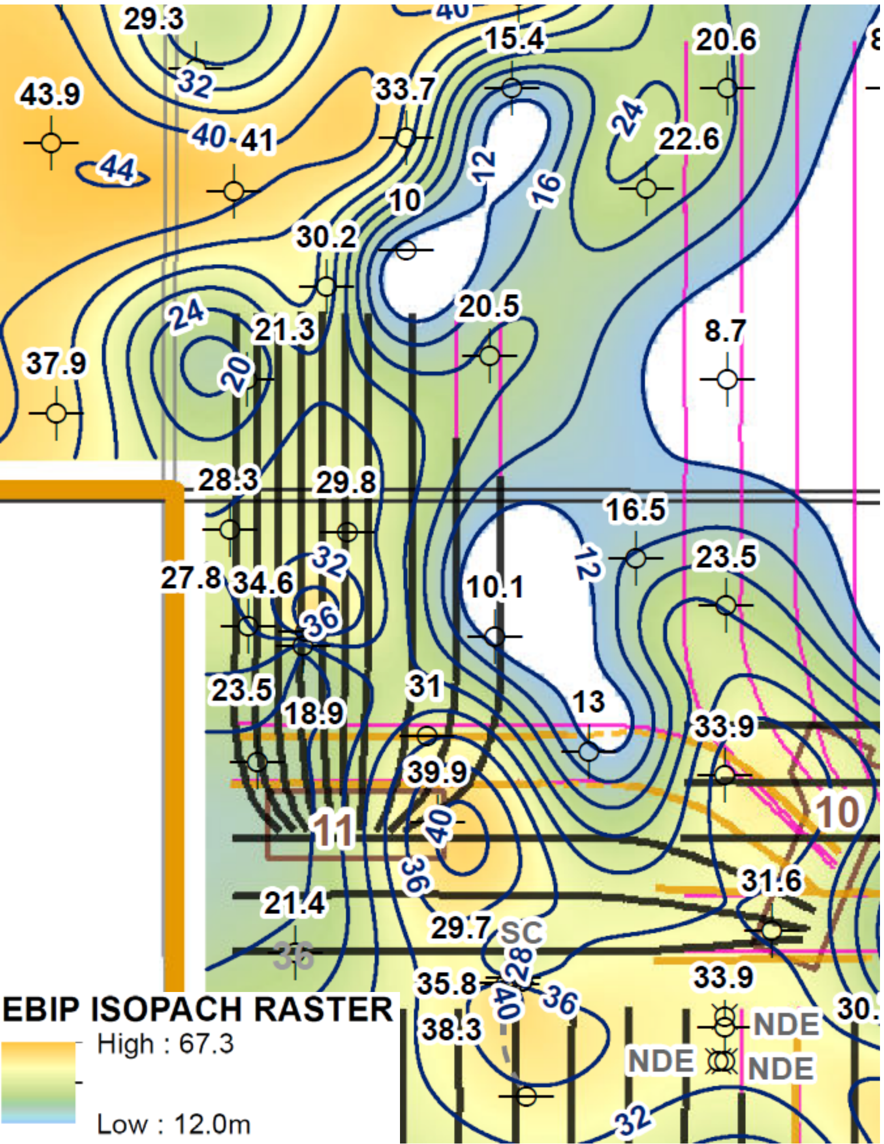
Well	EBIP (m3)	Dec 2014 Cumulative Bitumen (m3)	Dec 2014 RF (%)	Final EUR (m3)	Final RF (%)
11P01	322	130	40%	193	60%
11P02	181	74	41%	109	60%
11P03	182	106	58%	124	68%
11P04	185	80	43%	111	60%
11P05	197	62	32%	118	60%
11P06	201	86	43%	120	60%
11P07	279	108	39%	167	60%
11P08	316	119	38%	190	60%
11P09	189	117	62%	144	76%
11P10	158	39	25%	95	60%
Pad 11	**2209**	**922**	**42%**	**1370**	**62%**



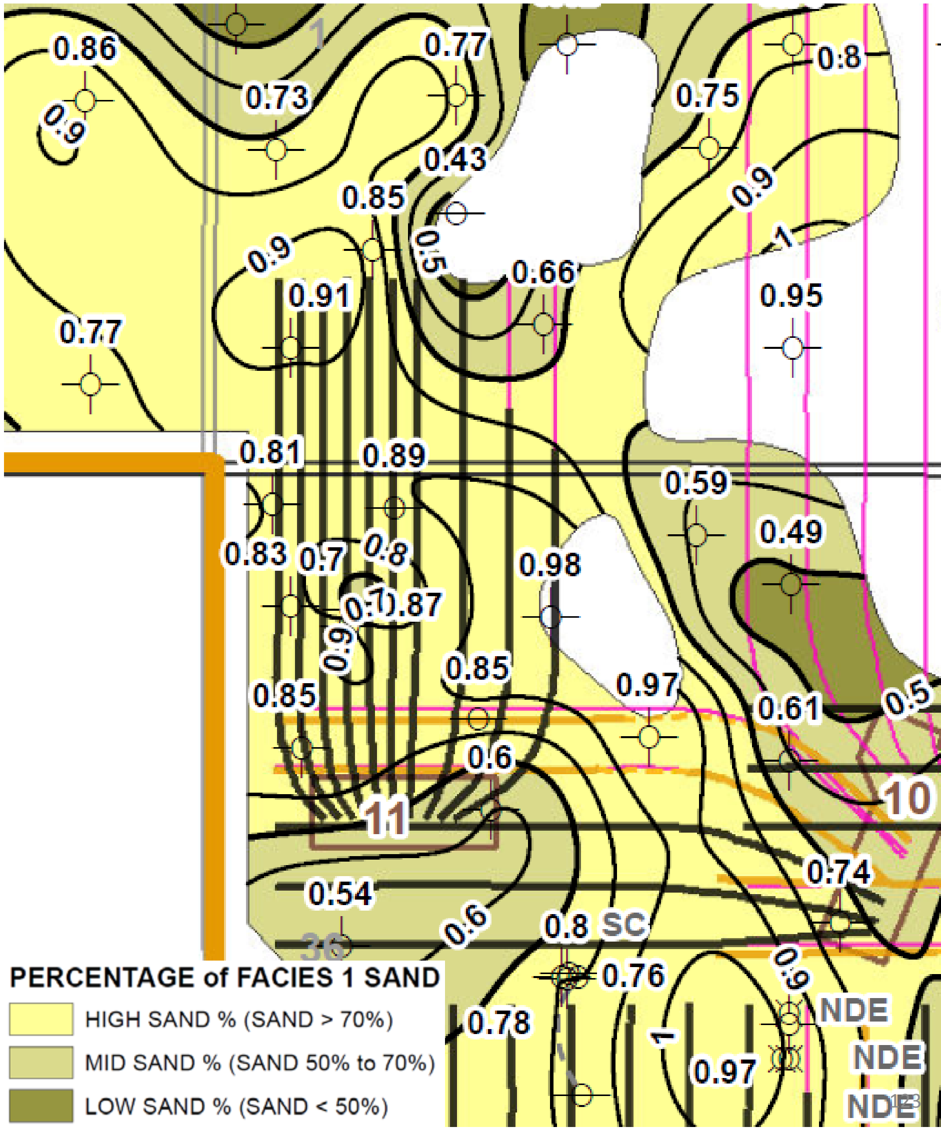
- All 10 wells are on ESP
- Tighter well spacing on west side of pad (40m vs 80m)
- Thick, relatively clean sand package with top water
- 2013 4D has improved interpretation of IHS bedding and steam chamber development
- 11P10 re-drilled due to liner failure
- Decline in bitumen rates can be attributed to top water effect
- Reduced operation pressure from 2100 to 1850 kPa
- At YE, injection pressures were ~1,850–1,920 kPa

PAD 11 - Geology

EBIP ISOPACH

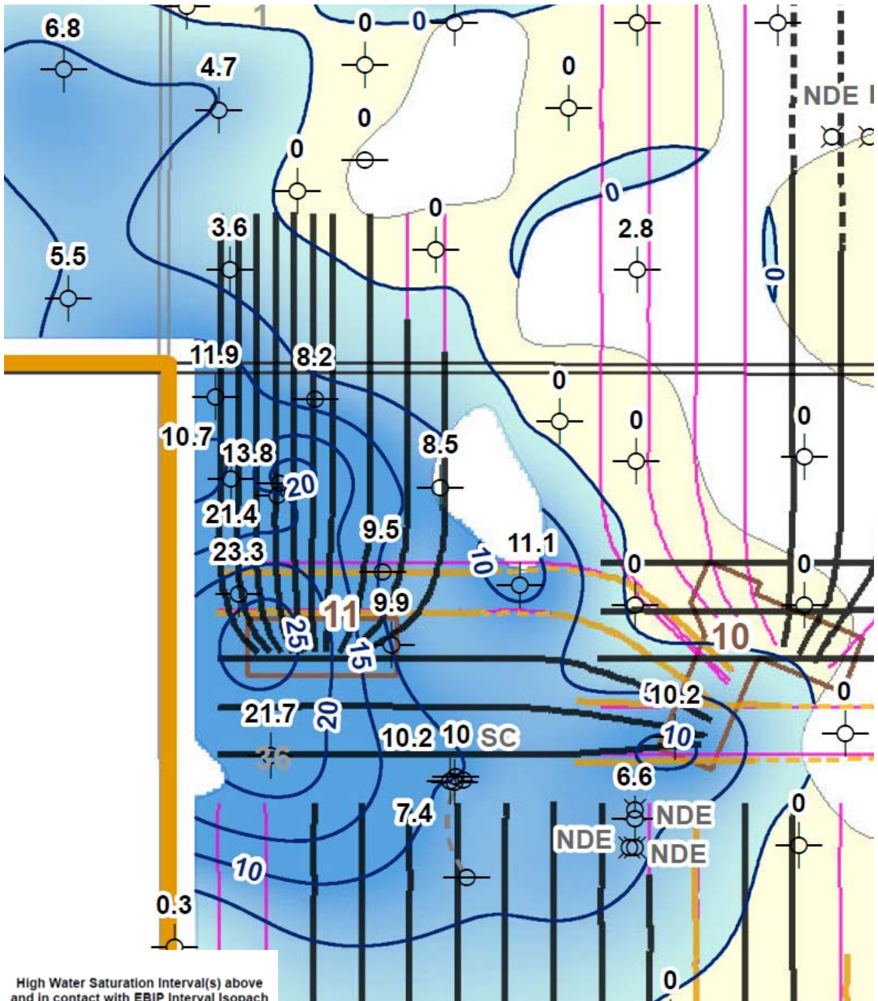


SAND FACIES PERCENTAGE

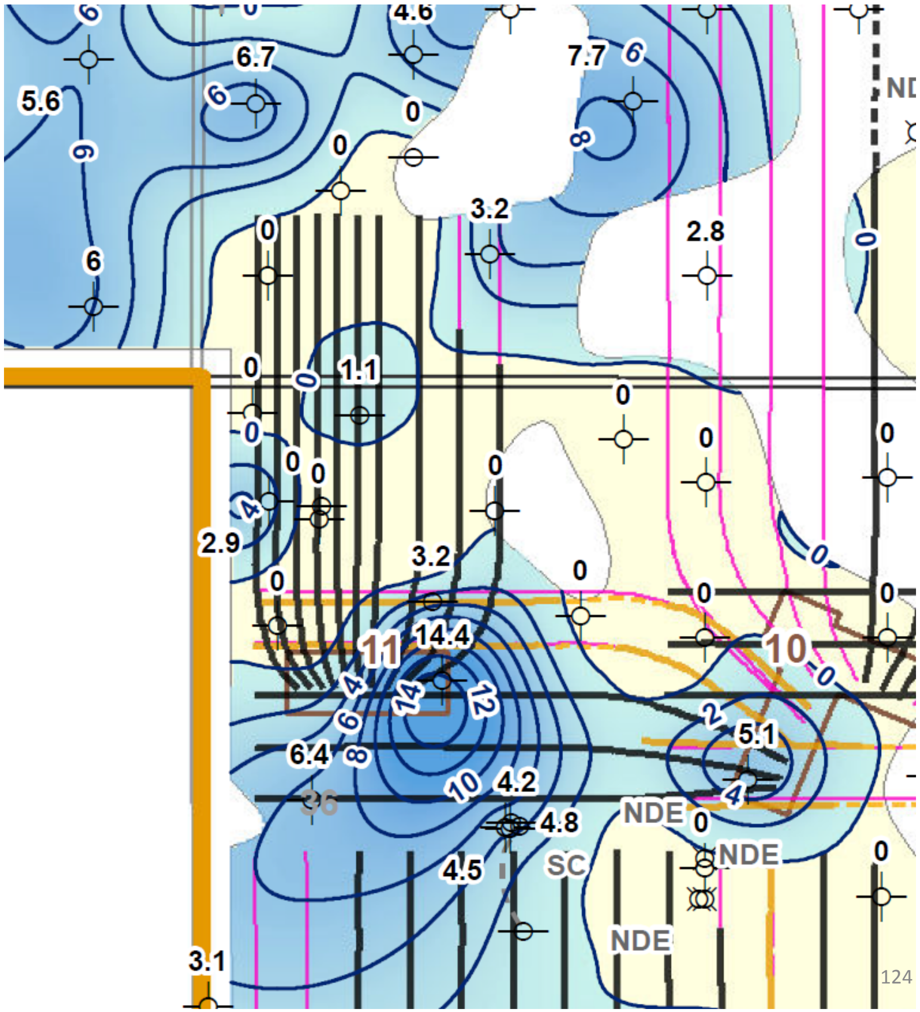


PAD 11 - Geology

HWS Interval above and in contact with EBIP – Top Water



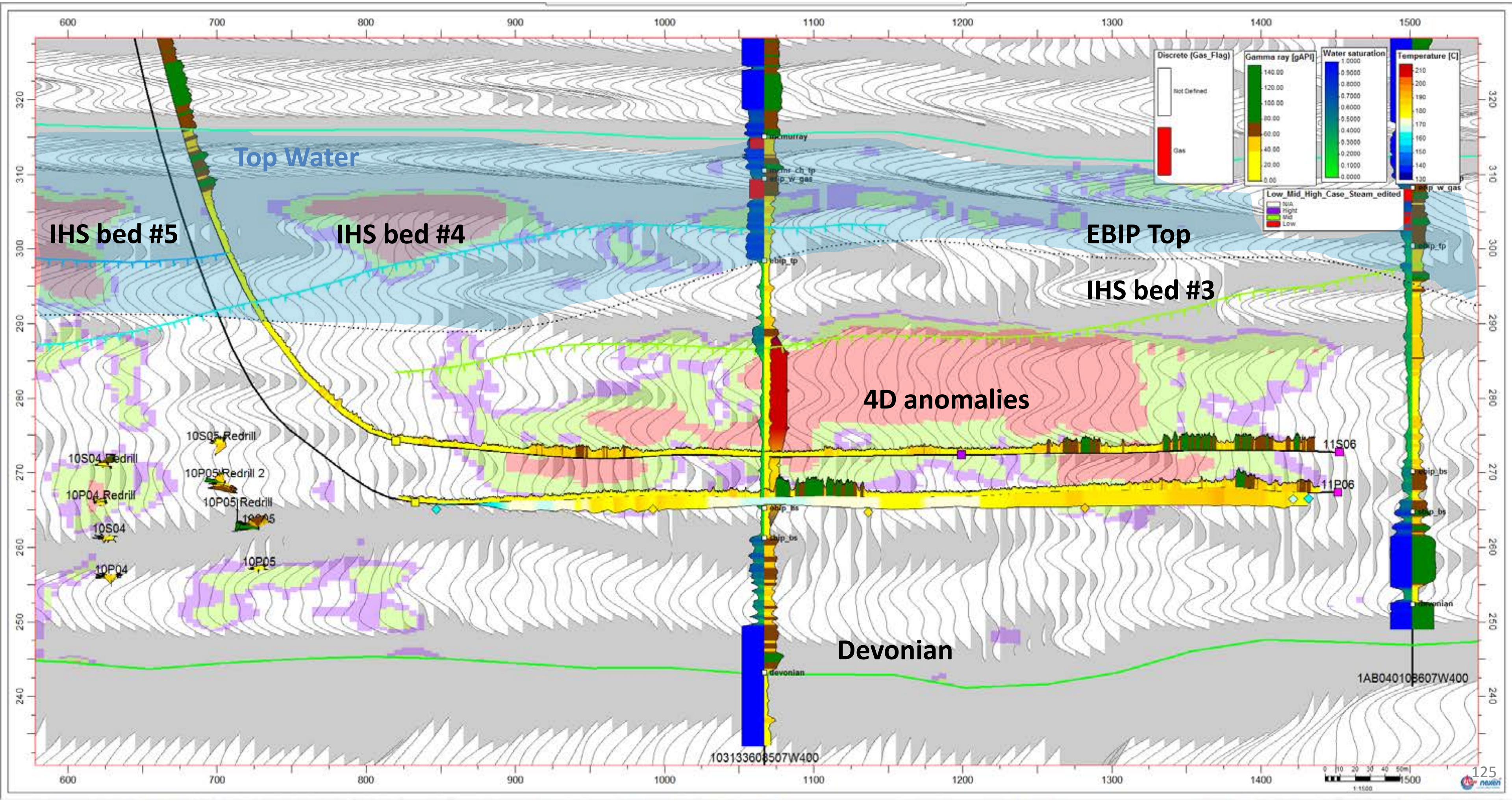
Cumulative Thickness HWS Interval within the EBIP –lean zone



Pad 11 – Example of cross section

Combining production history with 4D data:

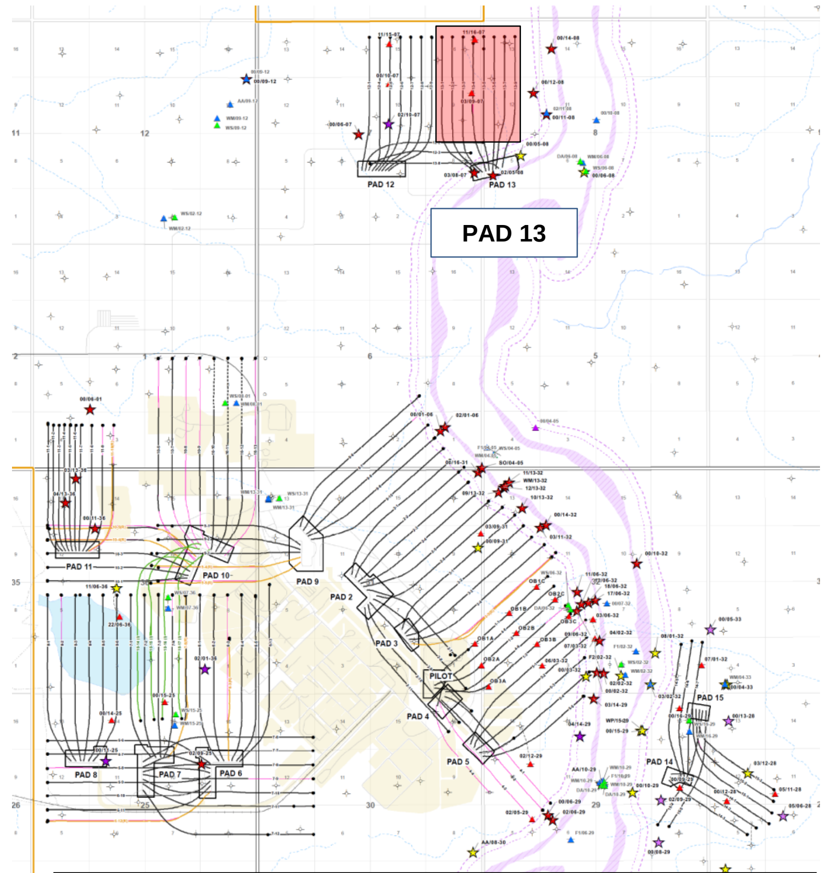
- 4D used to define IHS in top water not seen on logs or in core– changes interpretation of top water zones and operating strategy
- 4D anomalies confirmed by temperatures seen on Observation well

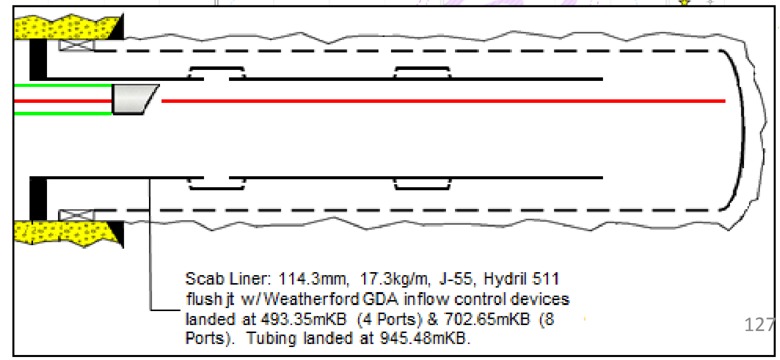


Learnings, Trials, and Pilot Projects

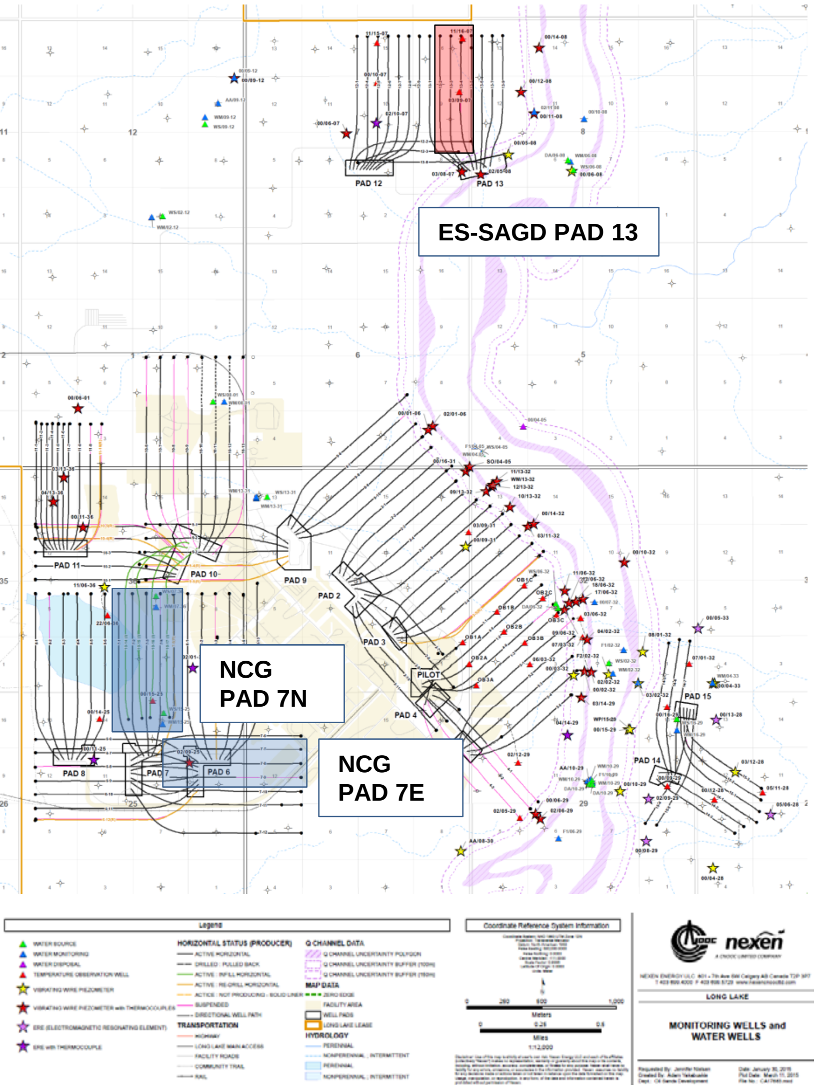
ICD Performance – PAD 13

- In-flow control devices were installed in the producer scab liners with the intent to promote "more even" production of fluid along the wellbore with the expected benefits:
  - Reduced pressure drop along the producer
  - Better conformance along the well
  - Allow more representative temperature measurement from down-hole thermocouples
- Majority of wells with ICDs have been consistent good producers since SAGD conversion and are meeting production expectations
- All ICDs remain in operation with no current plans to close, alter or remove the devices
- 11 producers have 2 fixed sleeve ICDs (4 and 8 or 3 and 9 ports) and 2 have 1 fixed sleeve ICD (7 ports) installed along the lateral
- Wells are showing good conformance





Pilot Projects Update



- PAD 13 Solvent Co-Injection Pilot Test (2 years)
  - Application approval 9485U was received in April, 2013
  - Solvent co-injection started October, 2014 at 13S3 and 13S4.
  - Preliminary indications of production uplift seen despite lean zone impairment in the pilot area.
  - Solvent recovery in line with simulation prediction as of year end 2014.
- PAD 7E NCG Pilot Test
  - Application approval 9485R received in September, 2012.
  - Gas injection started Oct., 2014 at 7P7 – 7P9.
  - Early indications of iSOR reduction however results not yet conclusive.
  - Gas injection stable at 10 E3M3/D with minimal operational issues. No detrimental impact seen on bitumen production.
- PAD 7N NCG Pilot Test
  - Application approval 9485CC received in May, 2014.
  - NCG co-injection in 5 well pairs planned.
  - Pilot start up planned for 2015.

Solvent Soak – Pad 12 & 13

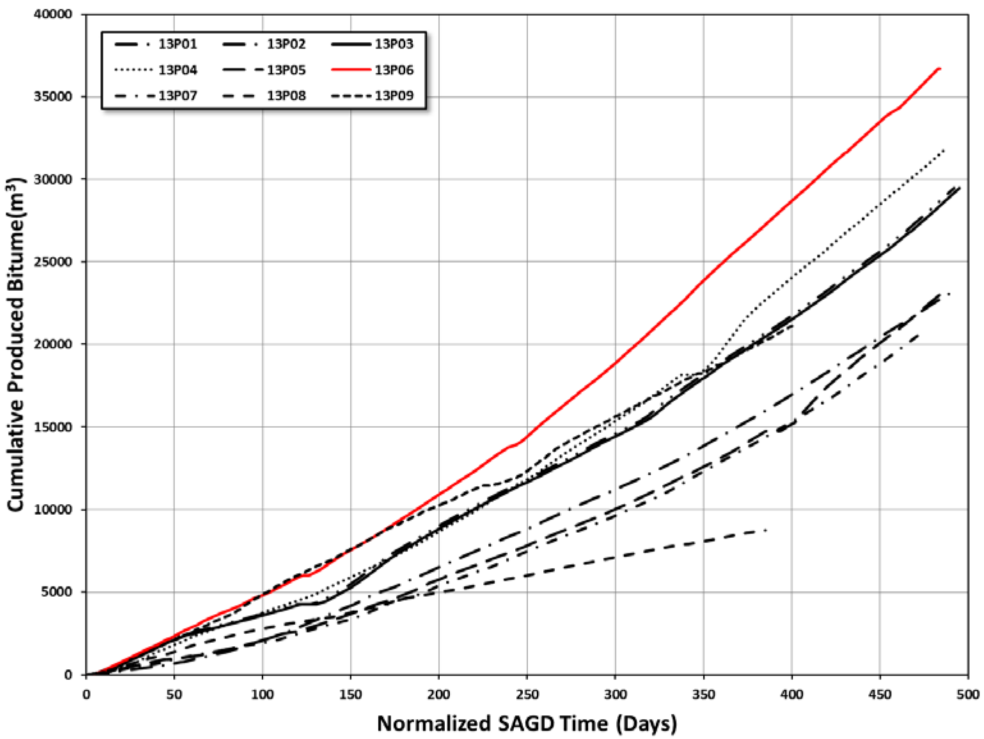
- Solvent soaking in cold system prior to circulation was experimented with in several SAGD well pairs
- Production responses and observed circulation durations showed no measureable impact as a result of solvent soaking in the cold system

Pad 12	
Well Pair	**Xylene Volume (m^3)**
12P01	57.6
12P02	58.8
12P03	59.2
12P04	58.4
12P05	0.0
12P06	57.8
12P07	59.4
12P08	0.0
12P09	57.4

Pad 13	
Well Pair	**Xylene Volume (m^3)**
13P01	60.7
13P02	30.2
13P03	30.1
13P04	60.0
13P05	60.1
13P06	60.3
13P07	0.0
13P08	61.0
13P09	62.9

Solvent Soak – Pad 12 & 13

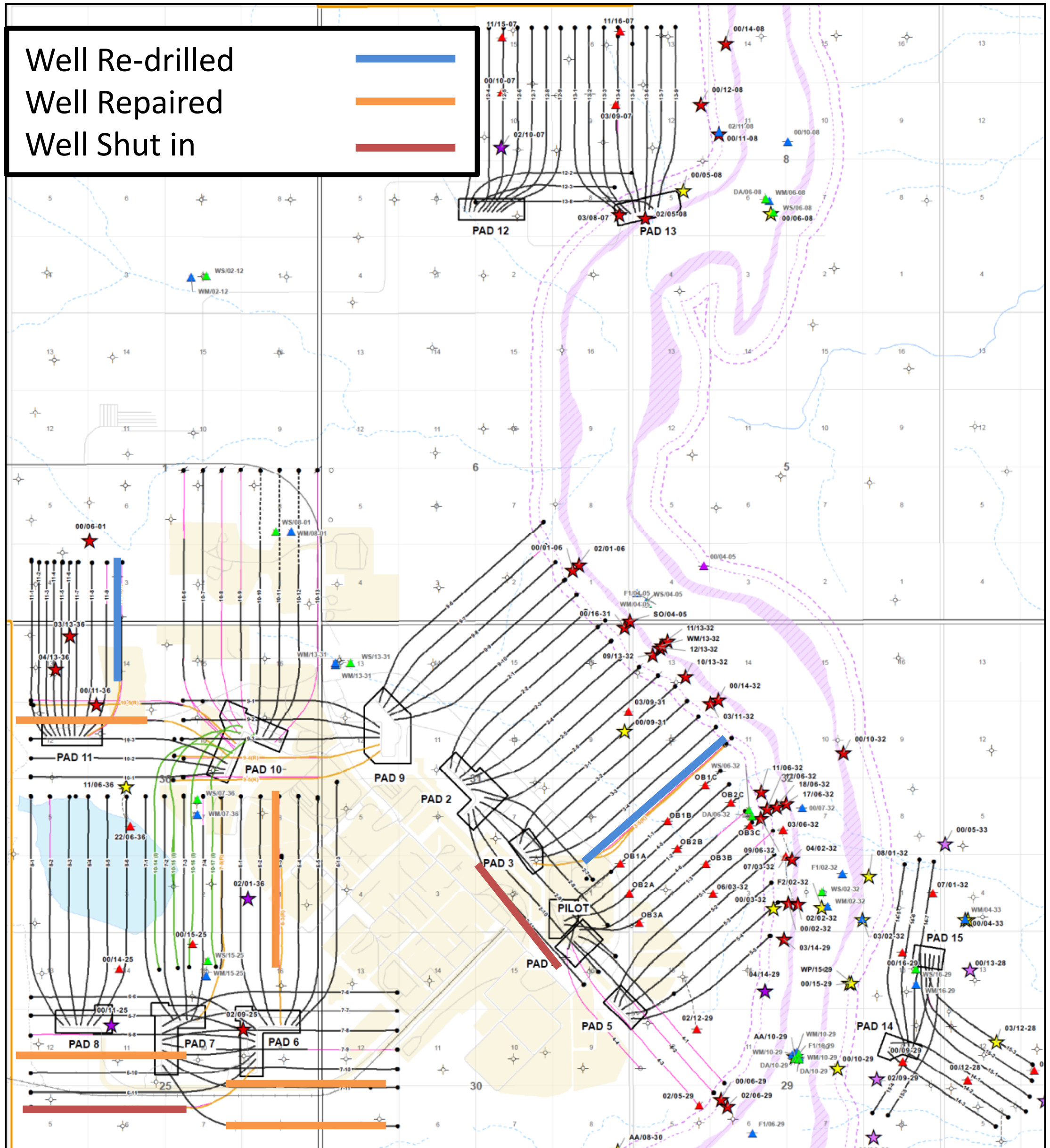
- Xylene injection in a warm system was experimented with in 13P06 once the well pair demonstrated hydraulic communication after circulation of both injector and producer at balanced pressures.
- After xylene injection, the well was left to soak during turnaround and then circulation was resumed for 1 month.
  - Volume injected : 70m3
  - Wellbore temperature : 120 deg C
  - Time left shut in : 1 month



- The results show positive impact on production after conversion to SAGD

Liner Failures – Redrill and Repairs

2014 Liner Failures



- 9 liner failures in 2014
- Evaluated case by case to determine whether to repair, re-drill or shut in

Wells Re-drilled

- 3P05/03S05 - liner failure Q3 2013, first oil Q2 2014
- 11P10 - liner failure Q4 2013, first oil Q2 2014

Wells Repaired

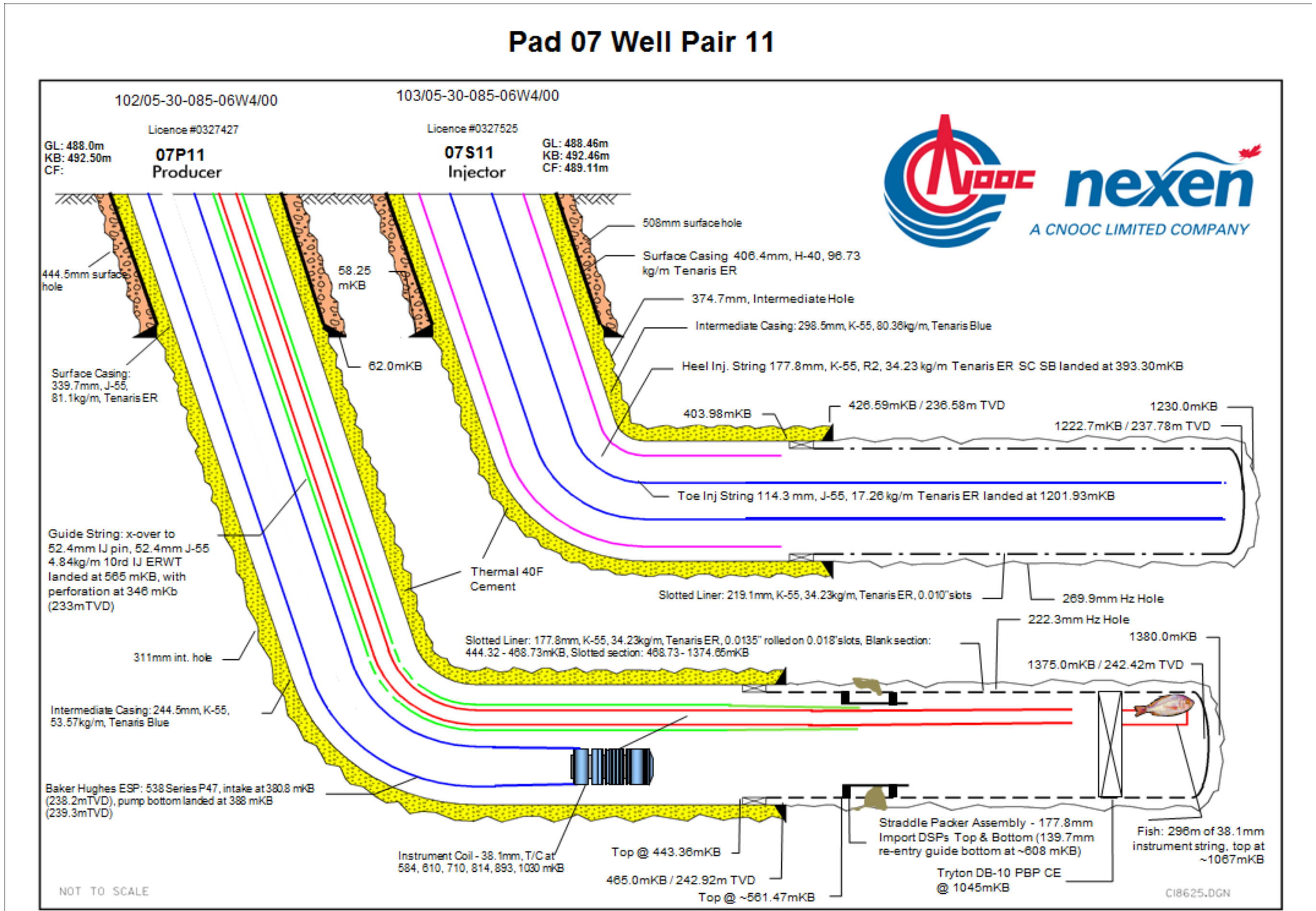
- 6P04 - liner failure Q2, plugged back
- 6P10 - liner failure Q3, plugged back
- 7P11 - liner failure Q3, heel scab
- 7P12 - liner failure Q3, heel scab
- 10P04 - liner failure Q3, plugged back

Wells Currently Shut In – Ongoing Evaluation

- 6P12 – liner failure Q1
- 2P11 – liner failure Q2

2014 Liner Failures

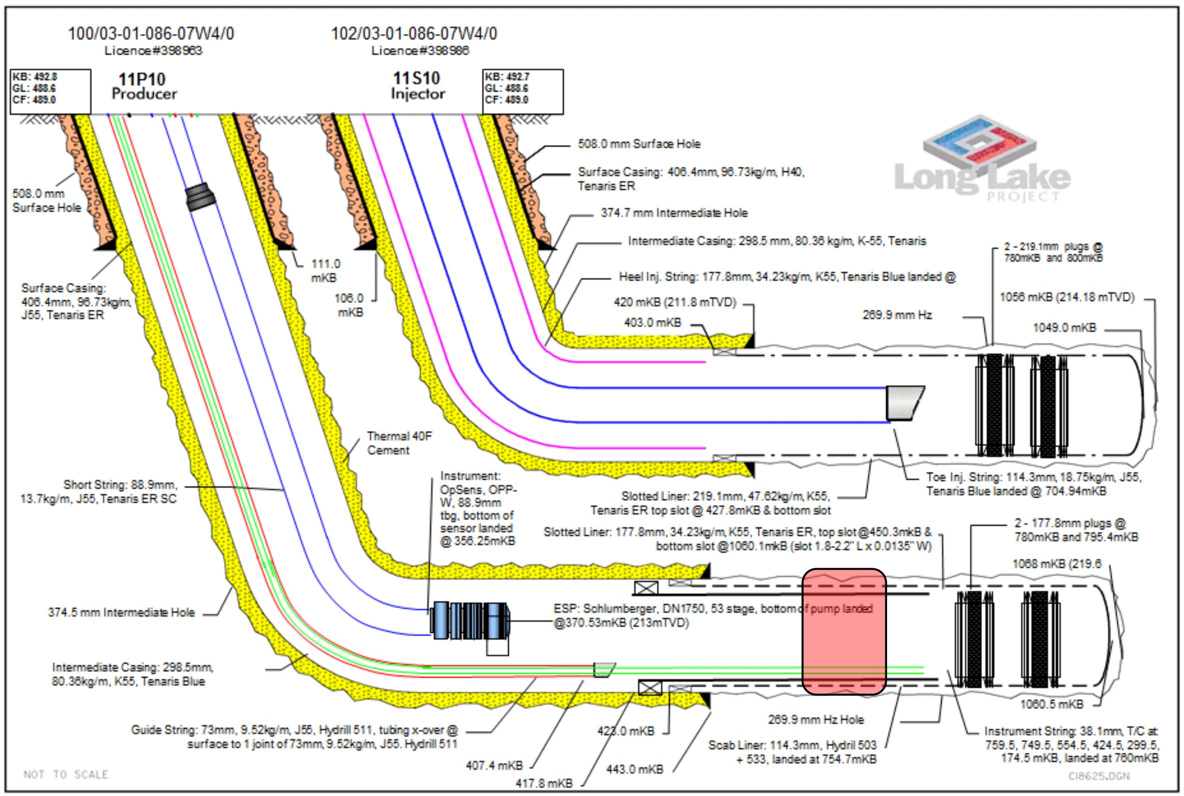
- Trialing a different repair design on 2 well pairs (07P11, 07P12)
  - Straddle packer assembly with 2 packers and blank pipe
- Isolate damaged section of liner without losing access to the rest of lateral
- On production since Q3 2014 without issues



2014 Redrill Lookback– 11P10

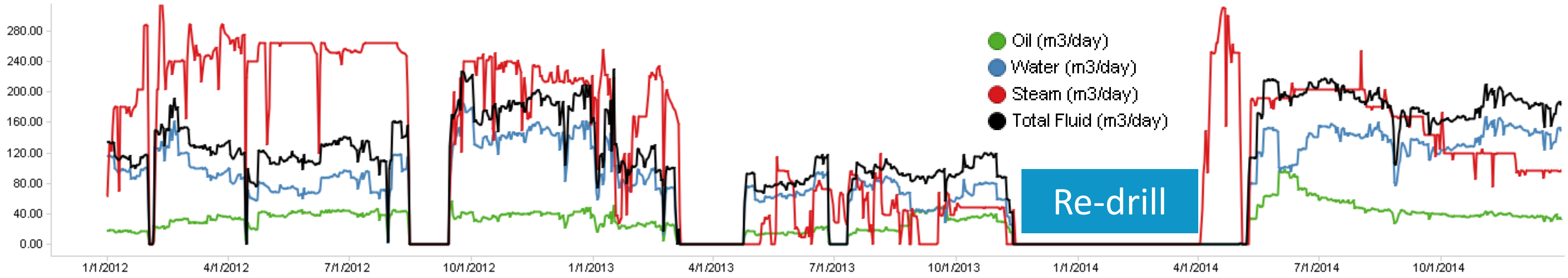
- Suspected liner failure at ~600mKB
- Unsuccessfully attempted to clean out wellbore to verify failure location
- Could not use other repair options such as plug back due to location of failure and debris in the lateral

Pad 11 Well Pair 10 (11P10 & 11S10): As ran Schematic September 5, 2011



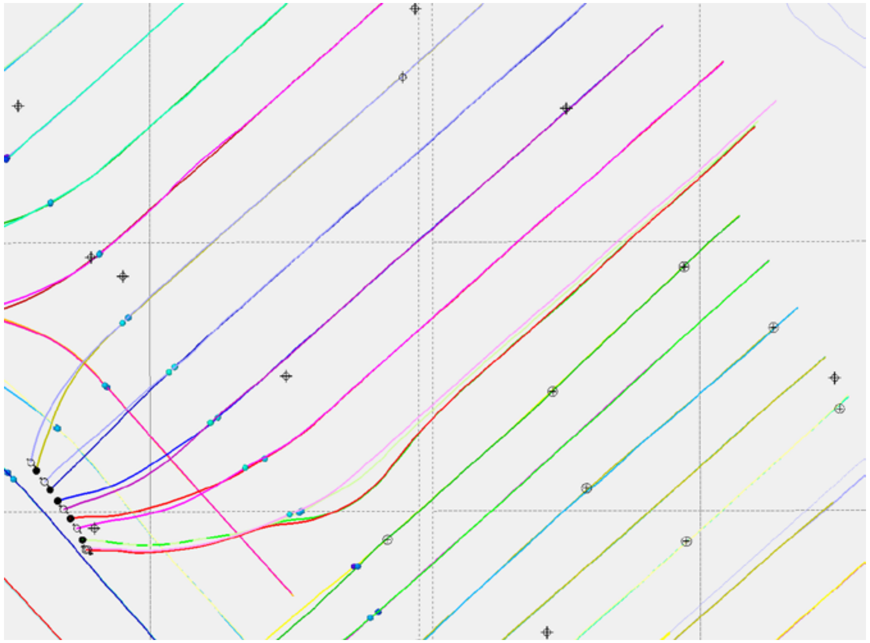
2014 Redrill Lookback– 11P10

- Re-drilled in Q1 2014 – side track from original well
  - 6m offset
  - Shortened lateral to match plugged back depth of original producer
- Re-drilled well is performing well with higher water and total emulsion rates compared to prior to re-drill



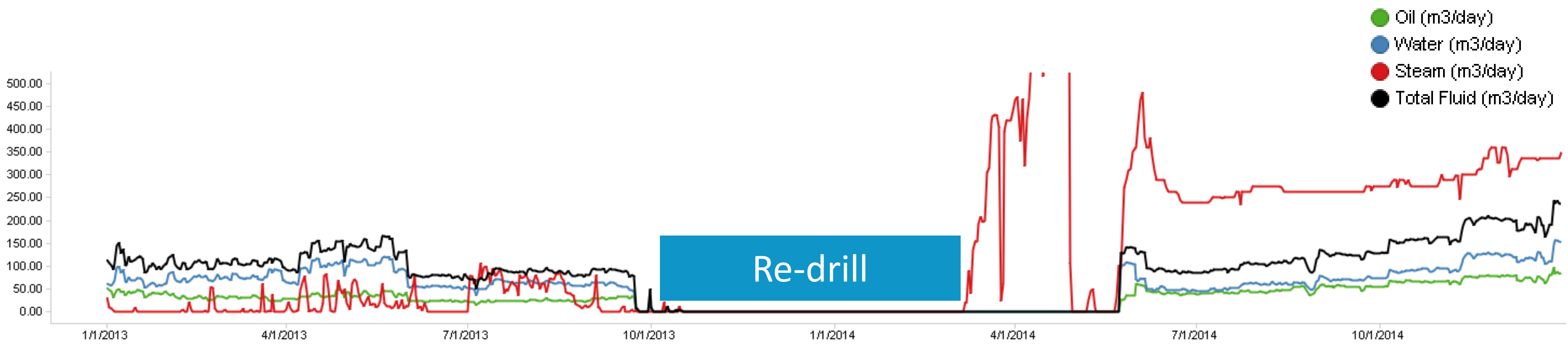
2014 Redrill Lookback– 03P05

- Liner failure in both injector and producer
- New trajectories
  - Stayed 25m away from the previous failure area at the heel of the well
  - Increased well offset to 7m at the heel to limit risk or re-failing wells
  - Toe-up trajectories were drilled to avoid poor geology at the toes of the wells
  - Drilled a bit shorter to maintain 150m buffer with Q-Channel edge



2014 Redrill Lookback– 03P05

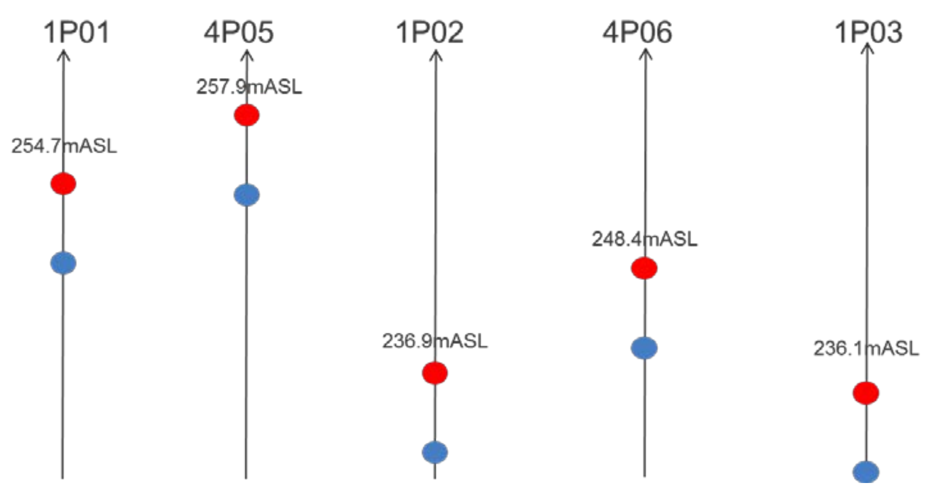
- Improvement in production after re-drill
- Re-drilled in Q1 2014 – side track from original injector and producer

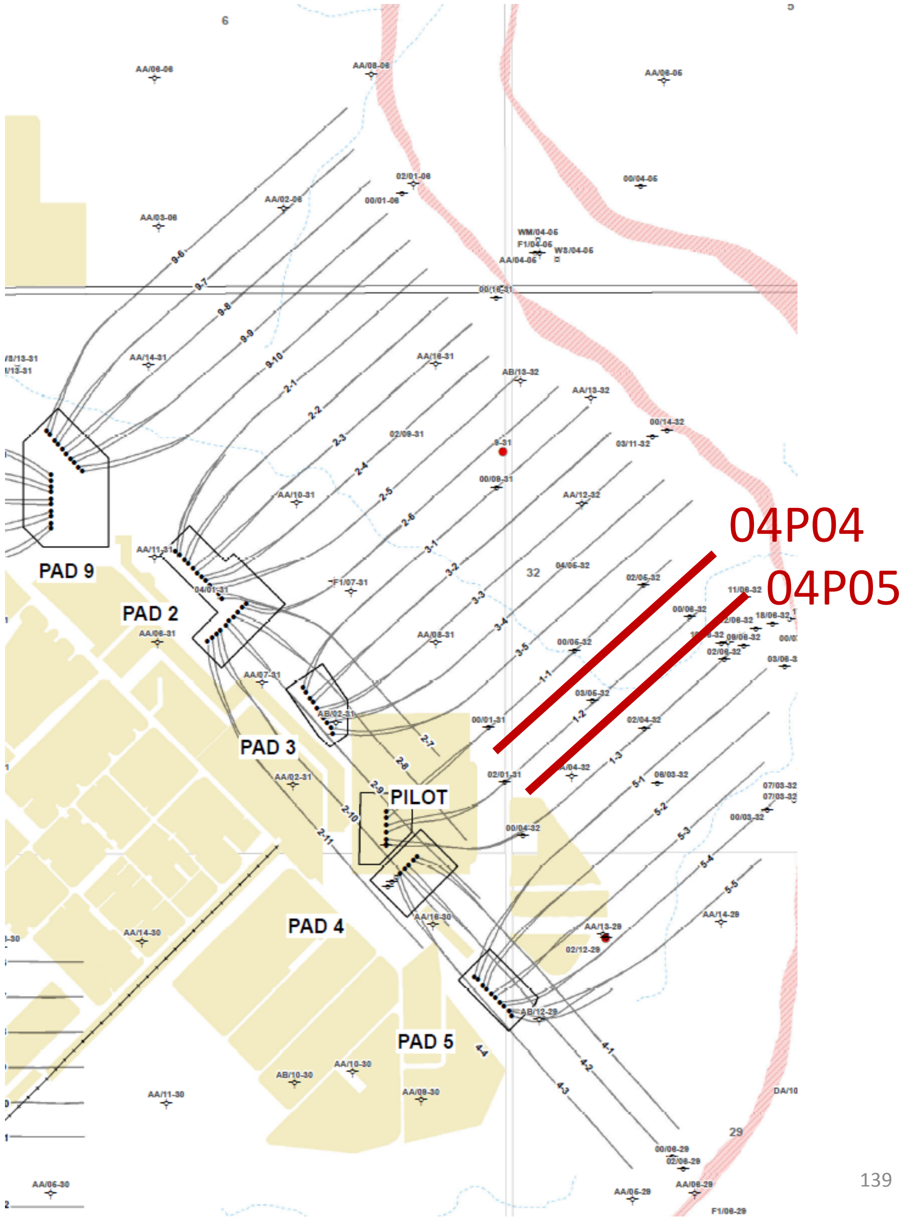


Infill Projects – Learnings and Future Plans

PAD 1 Infill Project Lookback

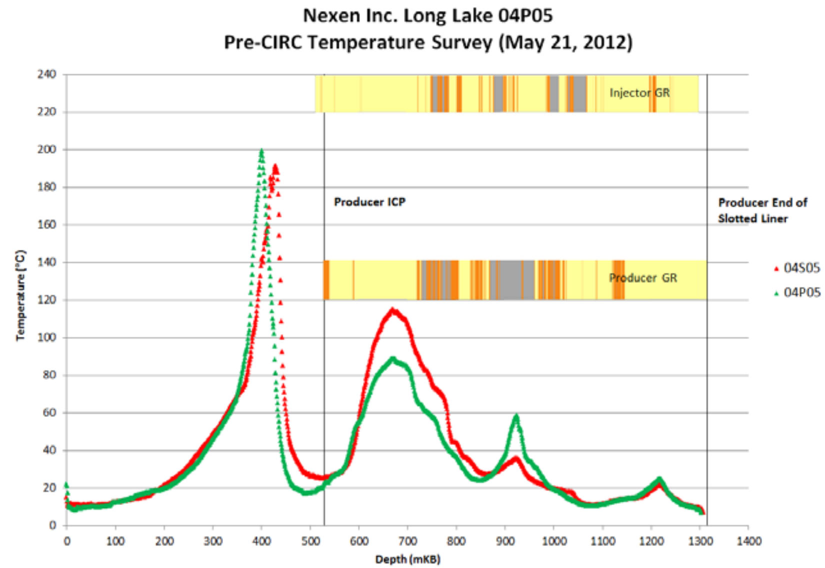
- 2 well pairs (injector + producer) drilled in 2012. Circulated for 3 months prior to starting SAGD in Q1 2013
- Original well pairs on Pad 1 had 150m well spacing
- Infill well pairs were placed in different sand packages to target undrained reserves

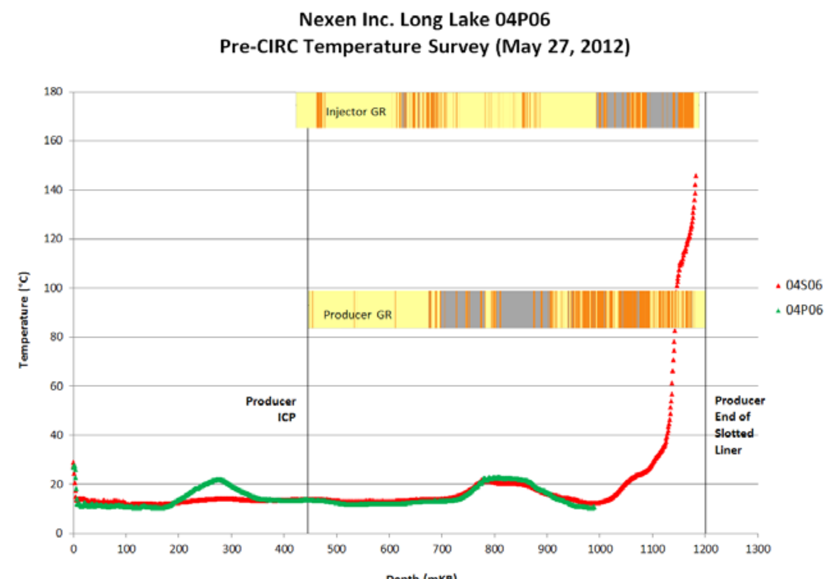


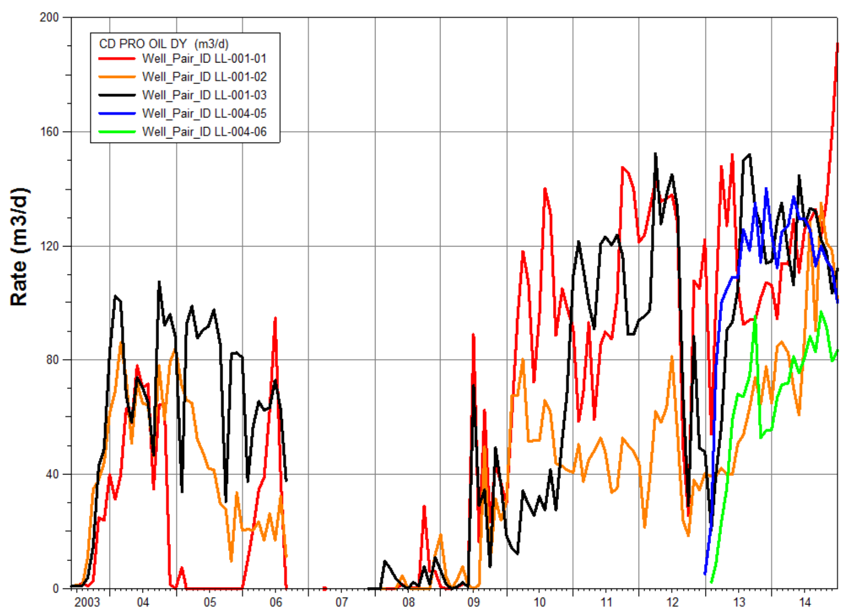


PAD 1 Infill Project Lookback

- Temperature survey after drilling infill wells showed inconsistent temperature development
  - Confirmed that injectors were required instead of only producer wells
- Infill wells have been successful in increasing both production and estimated recoverable reserves from Pad 1

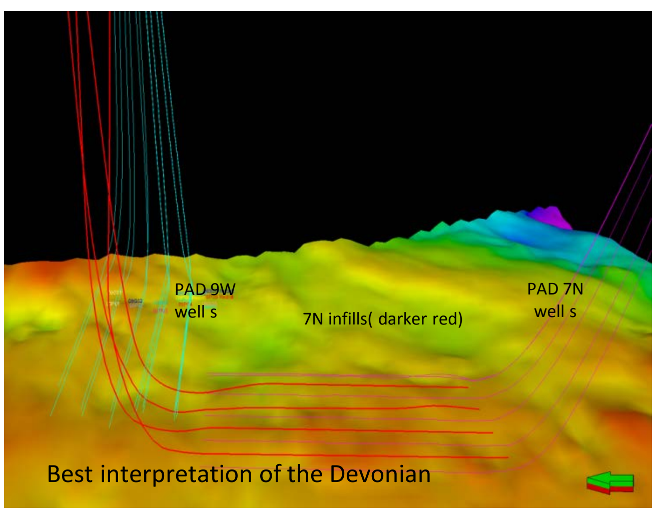


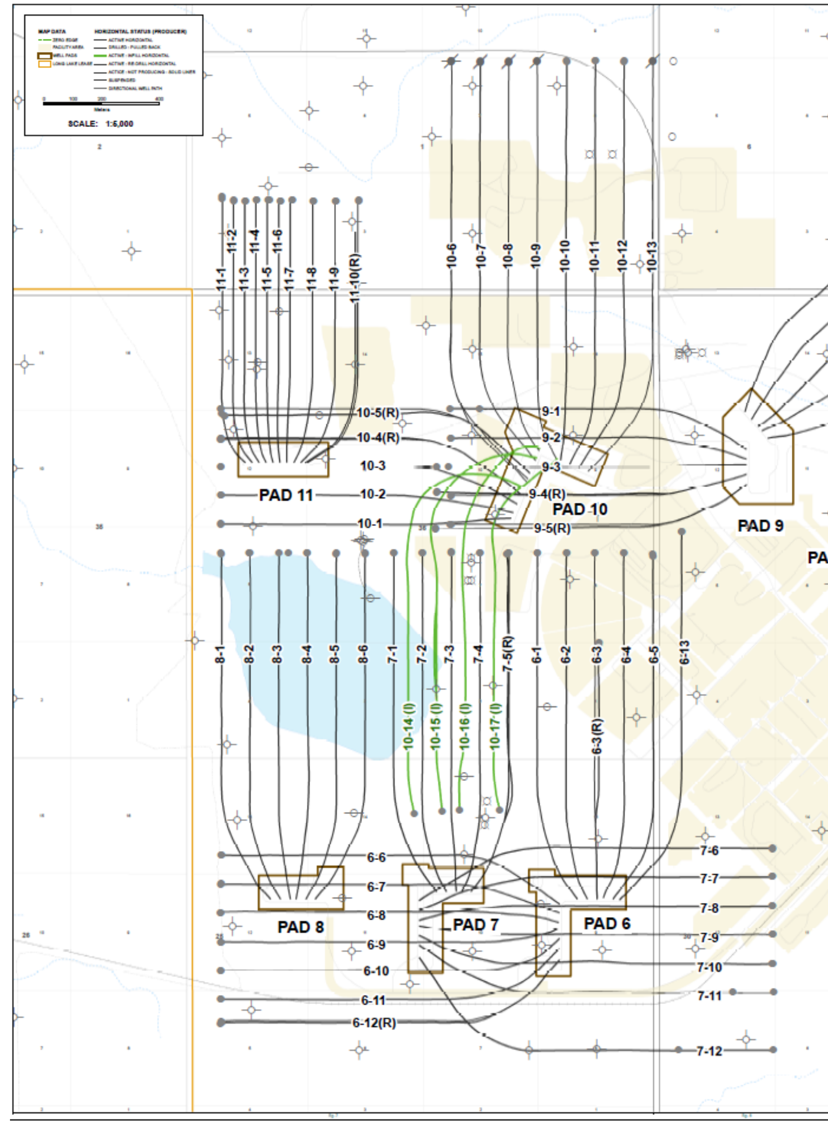




PAD 7N Infill Project Summary

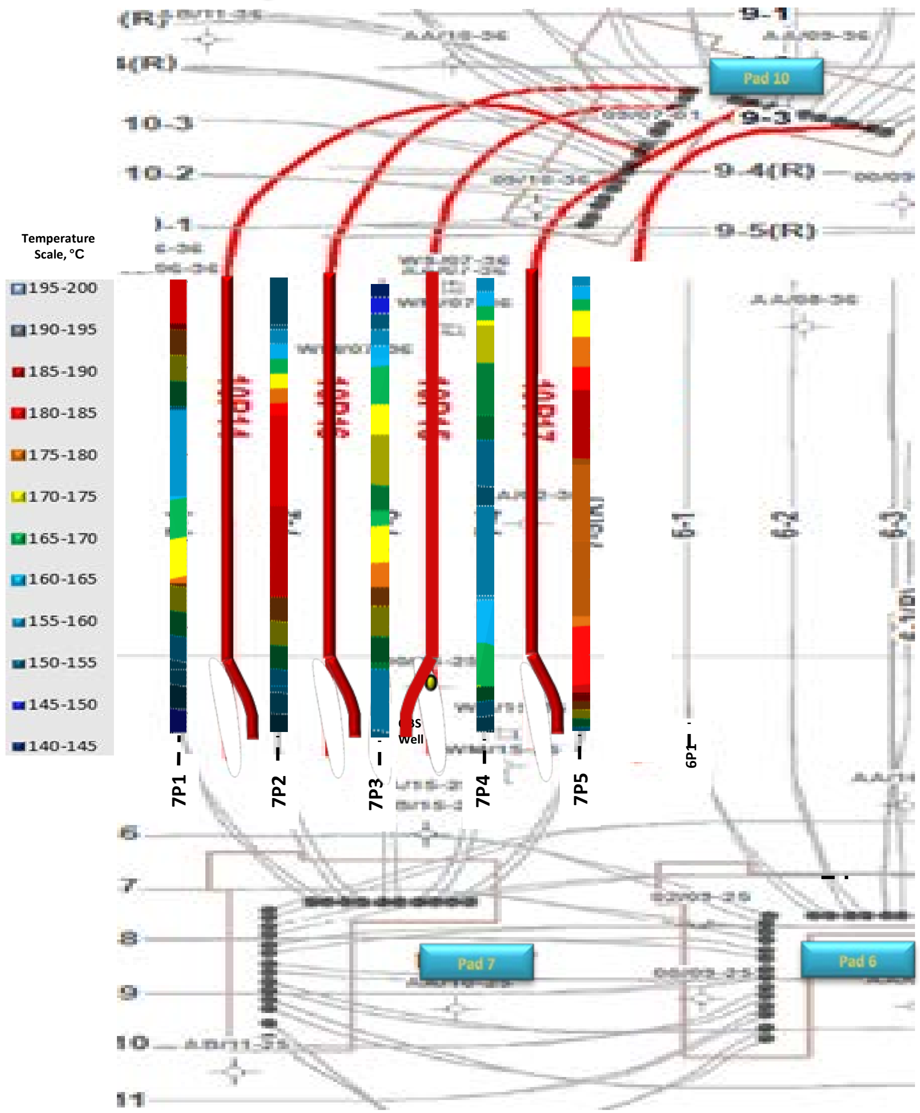
- Infill program of 4 producer wells in 7N, upgrading surface facilities in Pad 10.
  - ESP artificial lift
  - Drilling spud time in mid-August 2014
  - Small NCG modifications in surface facilities (PAD) 10, for future implementation of NCG.
  - 1st vertical spud in Long lake
    - Fastest well drilled was 10P17 (Vertical Spud)
    - Performance on 10P17 clearly shows that well design concept changes (e.g. vertical vs slant spud) has potential of reducing overall drilling costs/time.
  - Early identification of Devonian risk collision in some wells
  - First oil in Q1 2015





PAD 7N Infill Project Learnings

Drilling Orientation



Drilling Trajectories:

- Used Temperature Fall off analysis to help guide well trajectories
- 10P15/10P17
  - » to avoid collision with the existing OBS well →10P15
  - » get ~ 30 m closer to existing chamber
  - » Observed higher temperature closer to the toes of the infill wells
- At YE, were evaluating 10P16 start up without pre-heating (estimated ~ 10% likelihood of this happening in one well)
- Other 3 wells planned only steam injection (1-1.5 months) instead of 3 months
- Horizontal infill producer elevations were planned to be at the same TVD as the offsetting producer wells. However, due to unintended intersection of the Devonian, the elevation of three infill producers were adjusted, on average 5m upwards. As a result, these new infill producers are above the original producer wells.

PAD 7N Infill Project Learnings: Drilling Risks and Results

- Robust drilling risk assessment and implementation of risk mitigation options directly contributed to successful wells' delivery

- Penetration into the Devonian strata occurred on 10P15
  - The primary cause of this unintended penetration was uncertainty in determining the elevation of the Devonian surface using 3D seismic in the vicinity of the well.
  - The Devonian was penetrated for 45 meters (MD) in the lateral section of the well.
  - Following communication DOE, the lateral section was subsequently plugged back with cement. As a result, there is no contact between the drilled Devonian section and any open wellbore.
  - The well was then sidetracked at a higher elevation and reached total depth (TD) entirely within the McMurray Formation

- Penetration into the Devonian strata occurred on 10P16
  - The primary cause of this unintended penetration was uncertainty in determining the elevation of the Devonian surface using 3D seismic in the vicinity of the well.
  - An additional factor was the narrow drilling window that was available for the well to avoid collision with existing suspended SAGD wells.
  - The Devonian was penetrated for 8 meters of measured depth (MD) in the build section of the well.
  - Following communication with the DOE, the proper corrective measures were taken

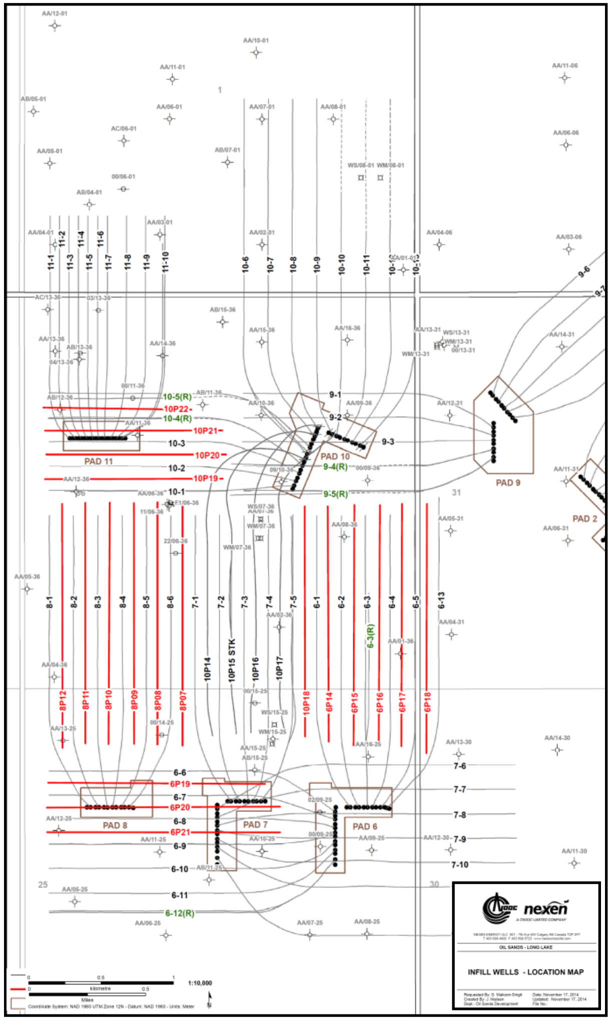
PAD 7N Infill Project Learnings: Drilling Risks and Mitigation

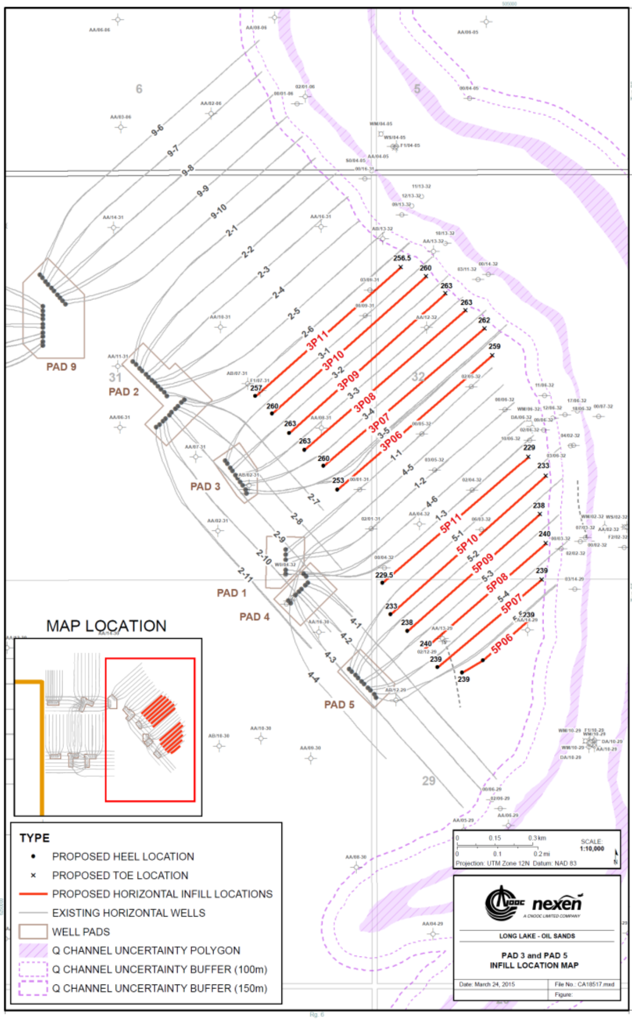
- Options for reducing risks of Devonian collision while maximizing pay, in future infills are being evaluated
  - Evaluate the benefit of acquiring seismic while drilling to identify Devonian surface and avoid trespass before the next well program
  - Try image Devonian under the lake using Refraction Statics
  - Integration of 4D (planned to be shot in 2015)
  - Further TVD uncertainty analysis in drilling depth during well planning
  - Work with survey vendor(s) to understand better ways of reducing TVD uncertainty: (Independent gyros, Ranging, re-processing of existing surveys, fluid pressure measurements, etc.)

- Despite these efforts, the risk of Devonian trespass cannot be eliminated
  - Limited seismic data quality and well data leading to uncertainty in seismic surface
  - Drilling uncertainty on depth
  - Continue to have early communication with DOE to explain potential issues prior to the program

Future Infill Project Opportunities

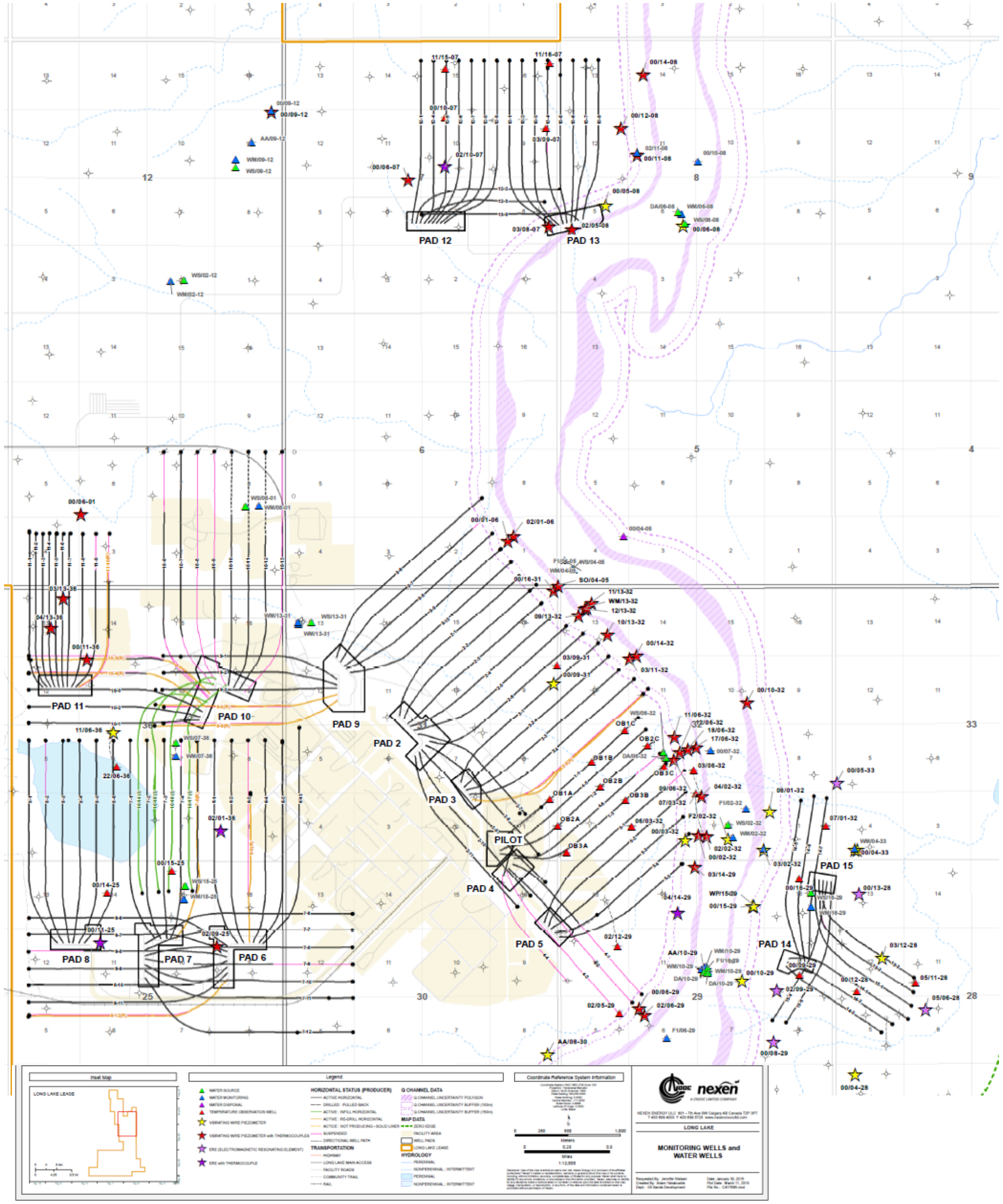
- Asset teams have identified opportunities for infill well locations throughout Long Lake
- Pads 3, 5, 6N, 6W, 8, and 10W
- Planning to continue evaluation of proposed locations throughout 2015 and submit corresponding approval applications





Observation Wells

Long Lake Well Pads and Observation Wells



Observation Wells – Long Lake

N/A – Greater than 250m to Q-channel or closest well pair

UWI	Closest Wellpair	Distance to Wellpair (m)	Distance to Q channel (m)	
			(Max Edge)	(Min Edge)
100010608606W400	LL-009-09	69	45	70
100013108506W400	LL-001-01	1	N/A	N/A
100023208506W400	LL-005-04	51	29	44
100033208506W400	LL-005-04	7	103	120
100042808506W400	LL-014-03	N/A	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	N/A	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	N/A	99	140
100103208506W400	LL-005-01	N/A	7	42
100110808606W400	LL-013-09	230	109	138
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	N/A	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	N/A	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
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
102053208506W400	LL-001-01	1	N/A	N/A

UWI	Closest Wellpair	Distance to Wellpair (m)	Distance to Q channel (m)	
			(Max Edge)	(Min Edge)
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
102112008506W400	LL-004-03	N/A	N/A	N/A
102122908506W400	LL-005-04	25	N/A	N/A
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
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	447	161	247
1AA102908506W400	LL-004-01	394	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
1WP152908506W400	LL-014-05	193	110	123

Pad 14/15 Obs Wells Baseline Values

Pad 14 Baseline Values

(as of March 31, 2015)

Well Name	Sensor Depth (m)	Formation	Base Line Pressure kPa_a	Current Pressure kPa_a
04-28	126	CLWT A	TBD	1020
05-33	119	CLWT A	980	985
100_04-33	123.1	CLWT A	1110	Will be removed
	126.1	CLWT A	1185	
13-28	116	CLWT A	1000	1005
1WP_15-29	127	CLWT A	TBD	990
WM_04-33	115	CLWT A	970	960
	115.5	CLWT A	980	975

Pad 15 Baseline Values

(as of March 31, 2015)

Well Name	Sensor Depth (m)	Formation	Base Line Pressure kPa_a	Current Pressure kPa_a
105_06-28	122.5	CLWT A	1100	1105
08-29	118.5	CLWT A	930	925
102_09-29	126.5	CLWT A	1020	1020
103_12-28	121.5	CLWT A	TBD	1020

- DCS alarm is triggered +75kPa above baseline (Hi alarm) and DCS steam shut-in is triggered +100kPa (Hi-Hi alarm).
- Need to set baseline for 04-28, WP15-29, 03/13-28

Future Plans

Long Lake 2014/2015 Evaluation Program

- Long Lake
  - 4 observation wells drilled (2 cored); 3 for reservoir optimization and future infill placement and 1 for Q-Channel monitoring
  - 4D shot over Long Lake West

- Kinosis
  - 3 water wells (1 source and 2 monitoring)
  - baseline 3D seismic survey over K1A IDA

2015 Plans – Existing Pads

- Long Lake: continue to optimize wells and increase production
- K1A: continue with SAGD conversions and production ramp-up
- Assess Opportunities to apply enhanced SAGD technologies
  - Monitor NCG Co-injection trial at Pad 7E to assess capability to reduce steam requirements
  - Advance NCG Co-injection trial at Pad 7N, target implementation 2015
  - Monitor ES-SAGD solvent co-injection pilot at Pad 13 with respect to production uplift and solvent recovery and assess commercial feasibility of process
- Review opportunity for 5 additional well pairs on Pads 14 and 15
- Continue to evaluate infills at Long Lake
  - Monitor and optimize LL Pad 7N infills
  - Further evaluate infills in Long Lake area
  - Submit regulatory applications

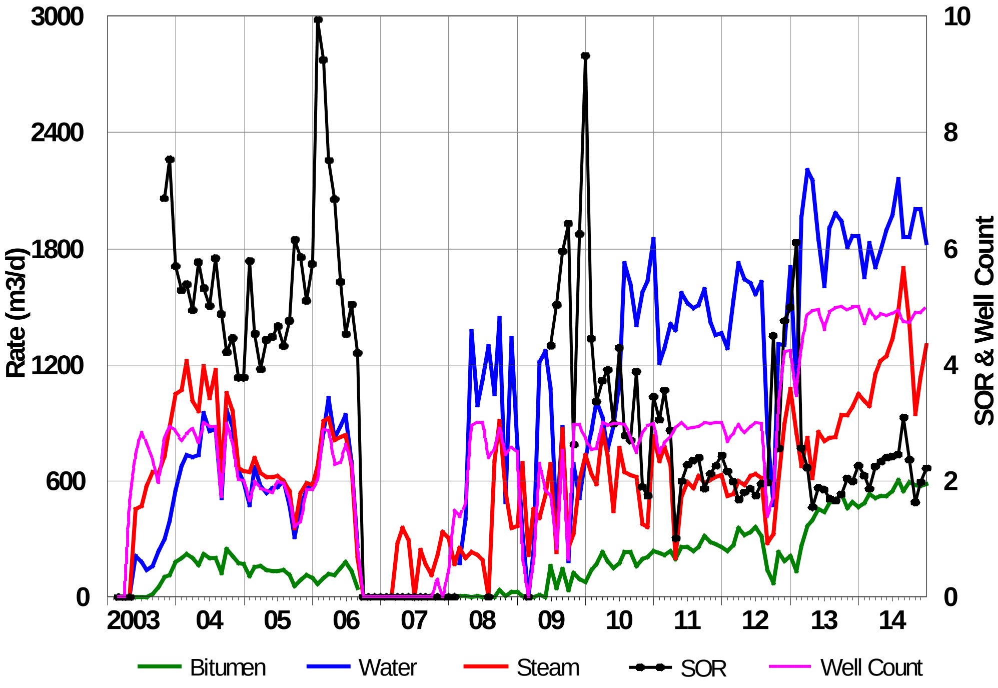
2015 Plans – New Developments

- Long Lake
  - Long Lake SW (Pads 16 to 19)
    - Proceed with development planning at a reduced pace
    - Regulatory approval received for Pads 16 to 18; submitted Q4 2014 for Pad 19
- Kinosis
  - K1B
    - Proceed with development planning at a reduced pace
    - Regulatory application submitted in Q1 2015
  - K2
    - Evaluate results from gas re-pressurization
- Continue to assess the area for exploitation opportunities

Scheme Performance

Pad Level

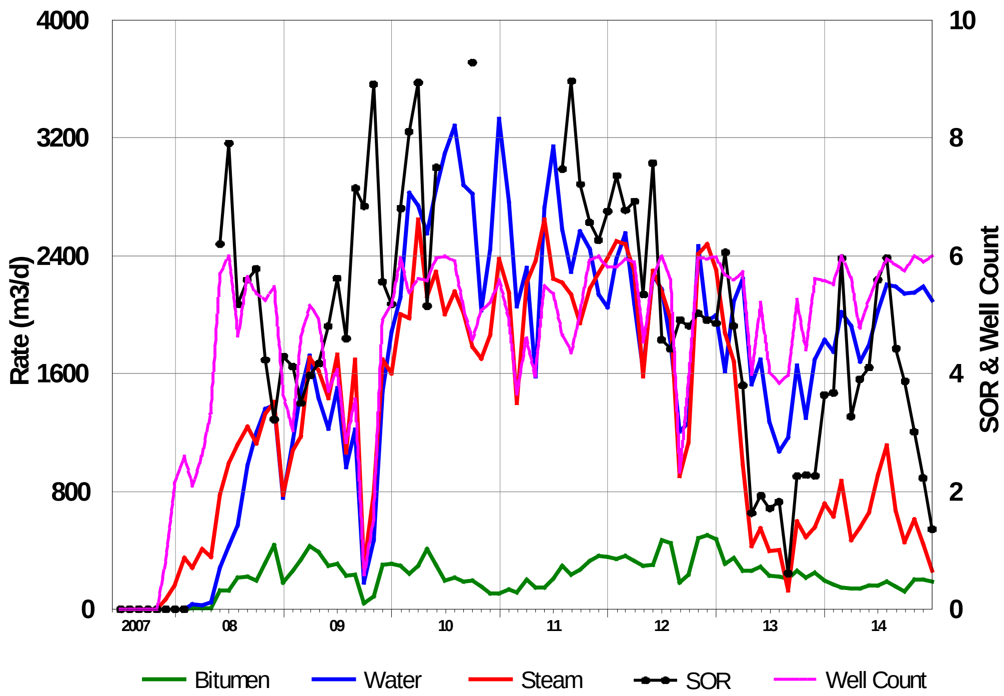
PAD 1 Production Summary



- All 5 wells on ESP
- Stable operation and increased steam injection helped achieve higher production
  - 1S01 toe steam was restarted mid year
- At YE, injection pressures were ~1,600-1,750 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 797 E^3m^3 (RF 36%)

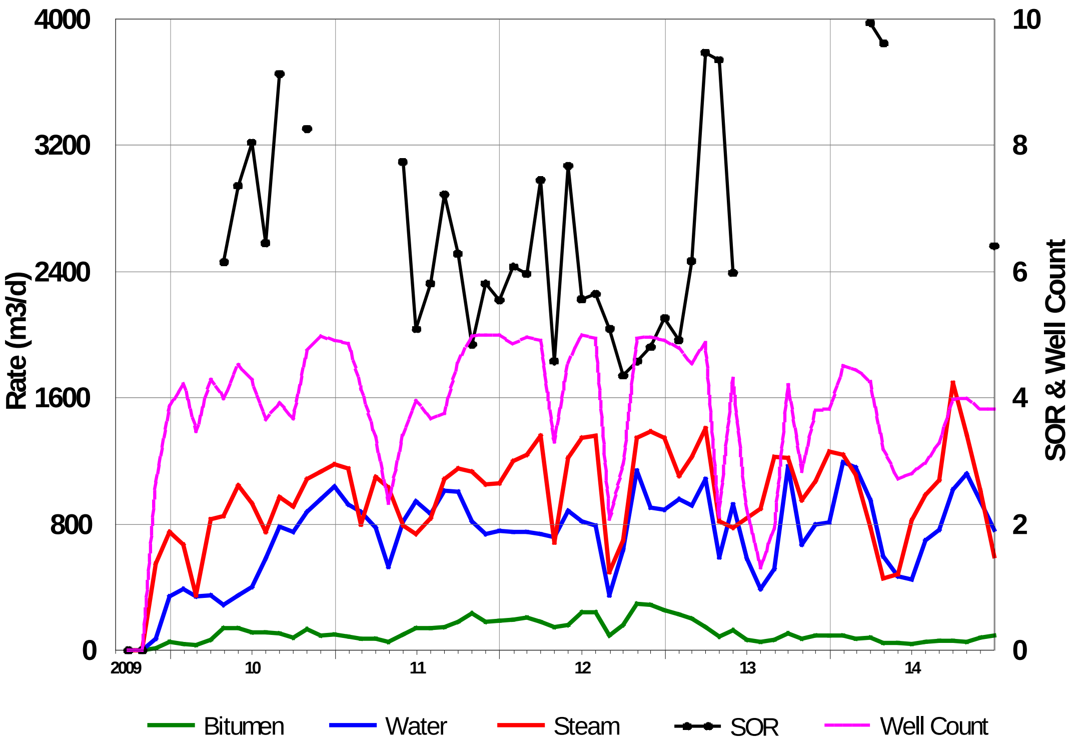
PAD 2NE Production Summary



- All 6 wells on ESP
- Steam SI to 02S04, 02S05 and 02S06
- Short term steam reductions have lead to inconsistent production performance
- At YE, injection pressures were ~1,275 – 1,485 kPa

- Six well pairs (02P01 to 02P06)
- Cumulative production of 611 E^3m^3 (RF 25%)

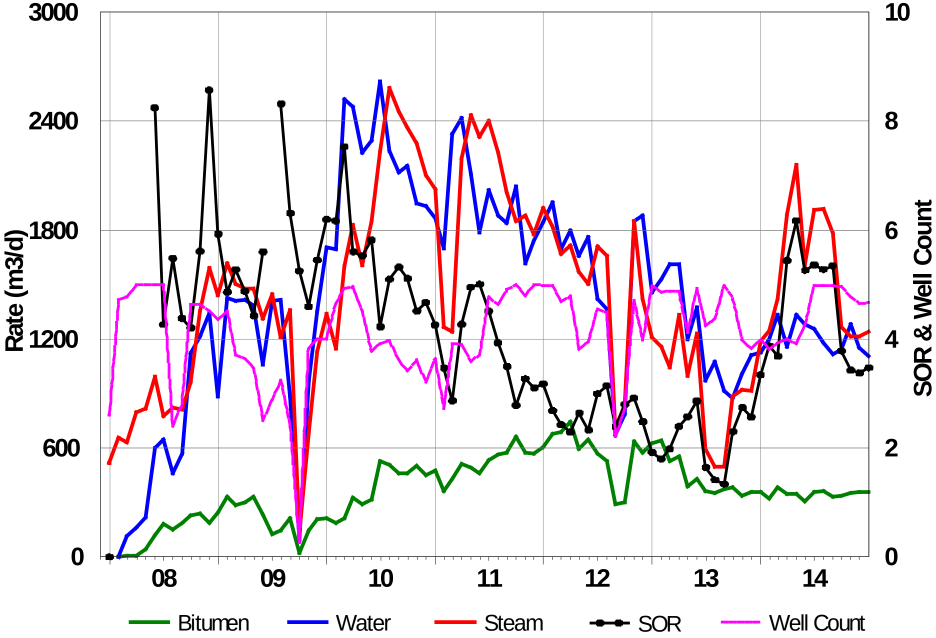
PAD 2SE Production Summary



- Five well pairs (02P07 to 02P011)
- Cumulative production of 228 E^3m^3 (RF 23%)

- 2P8 - 2P10 on ESP
- 2P07 on PCP
- 02Pair11 SI due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,350 – 1,900 kPa

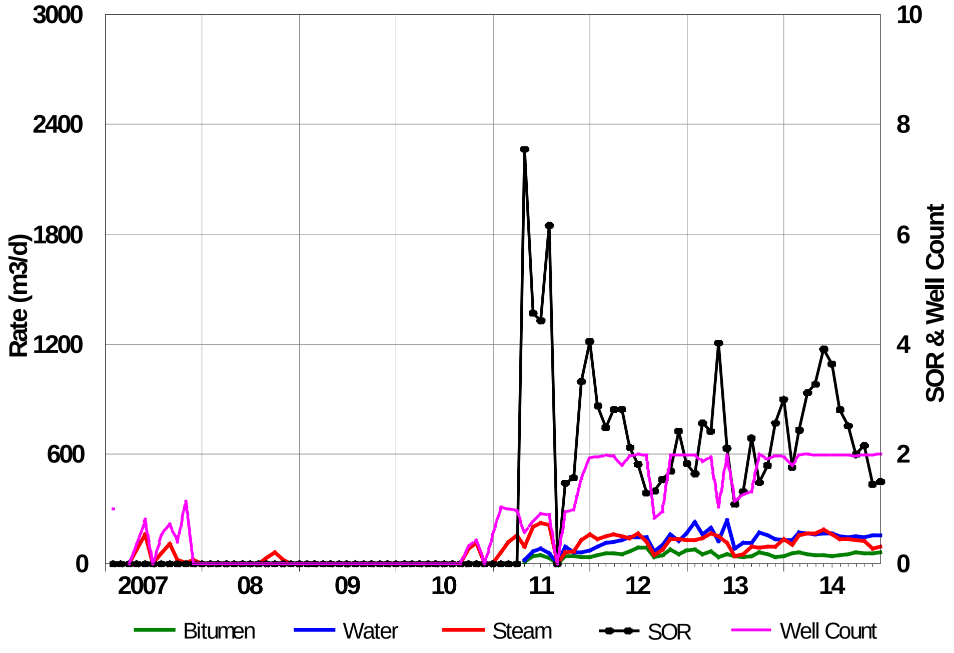
PAD 3 Production Summary



- All 5 wells on ESP
- Short-term steam reductions to 03S01, 03S02, and 03S03
- 03PAIR05 ramping up after redrill
- At YE, injection pressures were ~1,285-1,800 kPa

- Five well pairs (03P01 to 03P05)
- Cumulative production of 955 E^3m^3 (RF 39%)

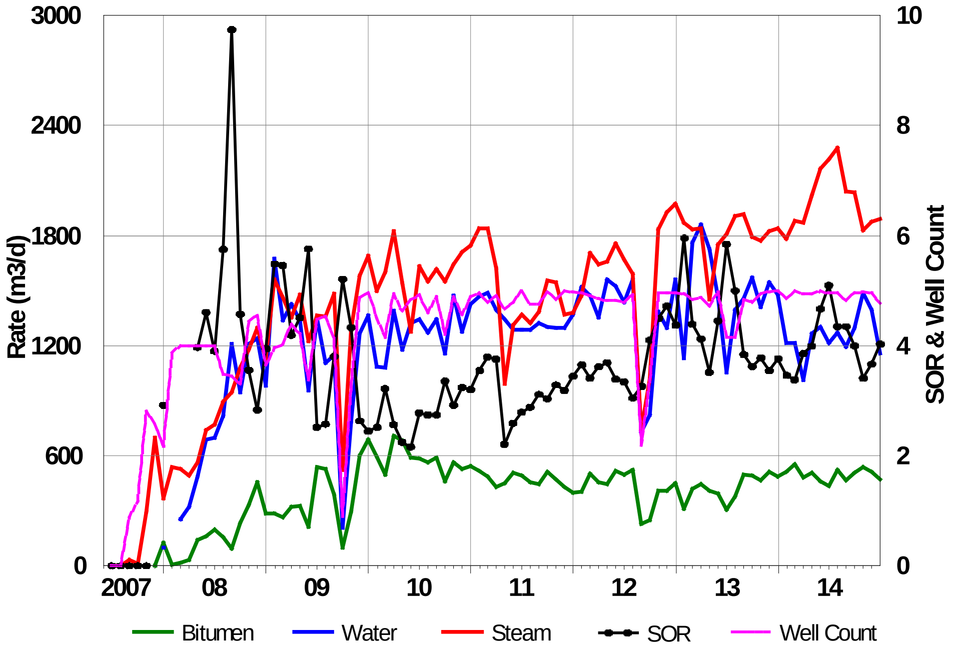
PAD 4 Production Summary



- All wells on ESP
- Stable operation helped maintain production
- At YE, injection pressures were ~1,260–1,515kPa

- Two well pairs (04P01 to 04P02)
- Cumulative production of 72 E^3m^3 (RF 52%)

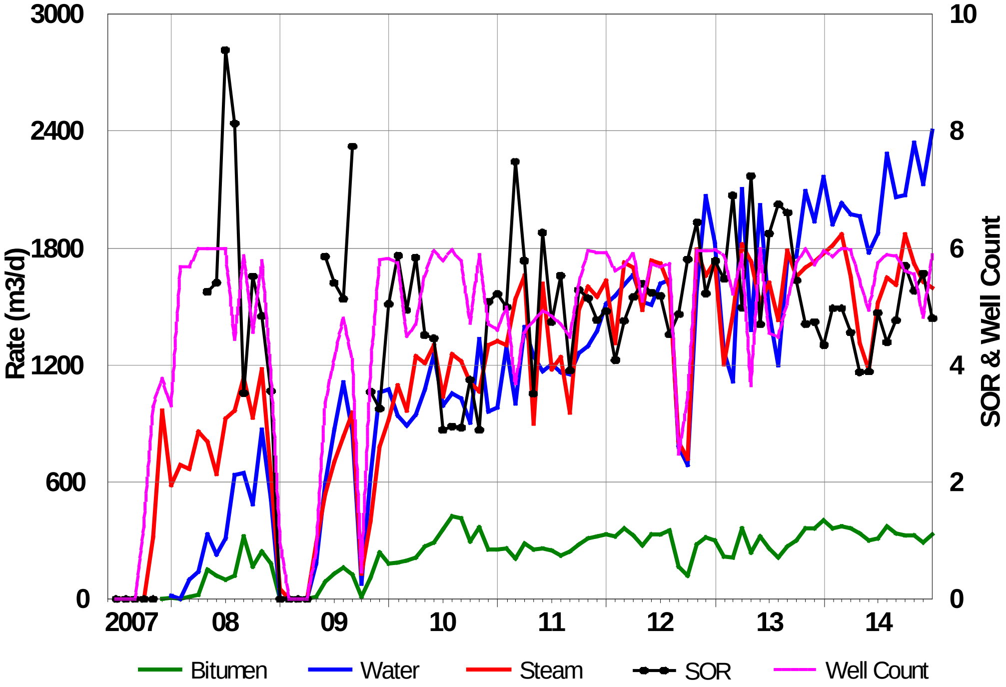
PAD 5 Production Summary



- All 5 wells on ESP
- Stable operation and increased steam helped maintain production
  - 5S02 toe steam was restarted in Q3
- At YE, injection pressures were ~1,650–1,825kPa

- Five well pairs (05P01 to 05P05)
- Cumulative production of 1082 E^3m^3 (RF 34%)

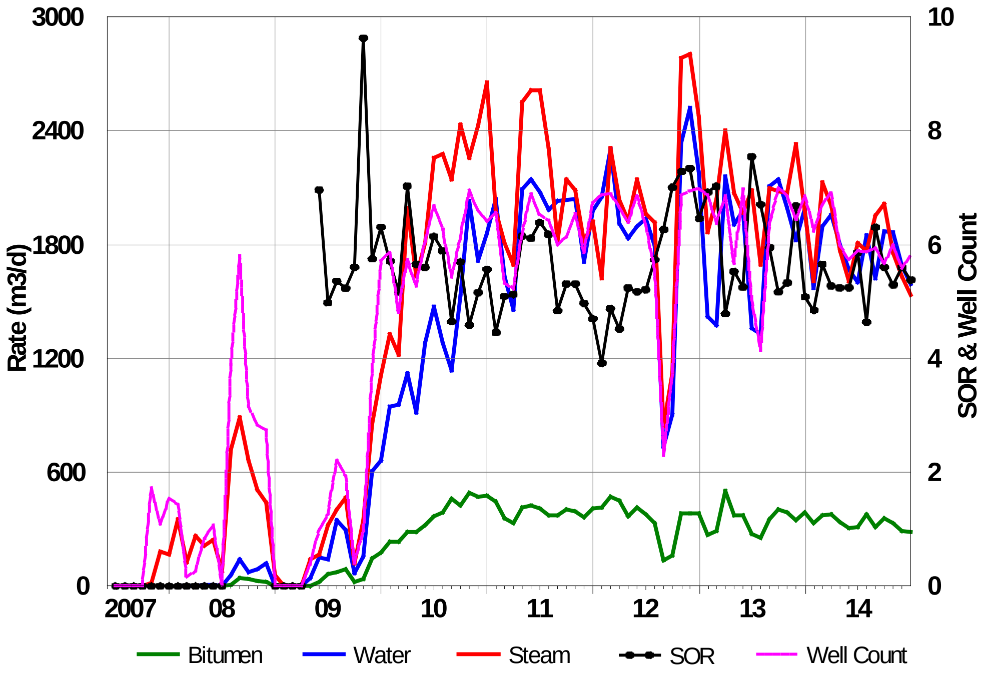
PAD 6N Production Summary



- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 621 E^3m^3 (RF 22%)

- All wells on ESP
- Higher water production as a result of maximizing withdrawals
- 6P4 plugged back due to poor reservoir quality at toe
- At YE, injection pressures were ~1,750–1,850kPa

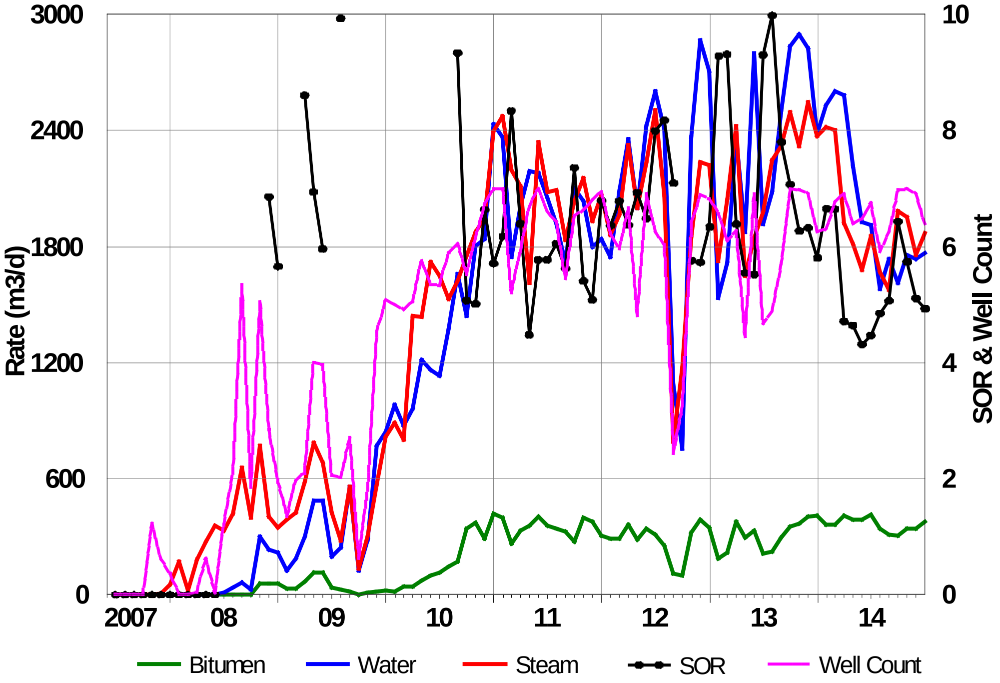
PAD 6W Production Summary



- All 7 wells on ESP
- Stable operation
- 6P12 shut in due to potential liner failure
- At YE, injection pressures were ~1,700–1,950 kPa

- Seven well pairs (06P06 to 06P12)
- Cumulative production of 683 E^3m^3 (RF 36%)

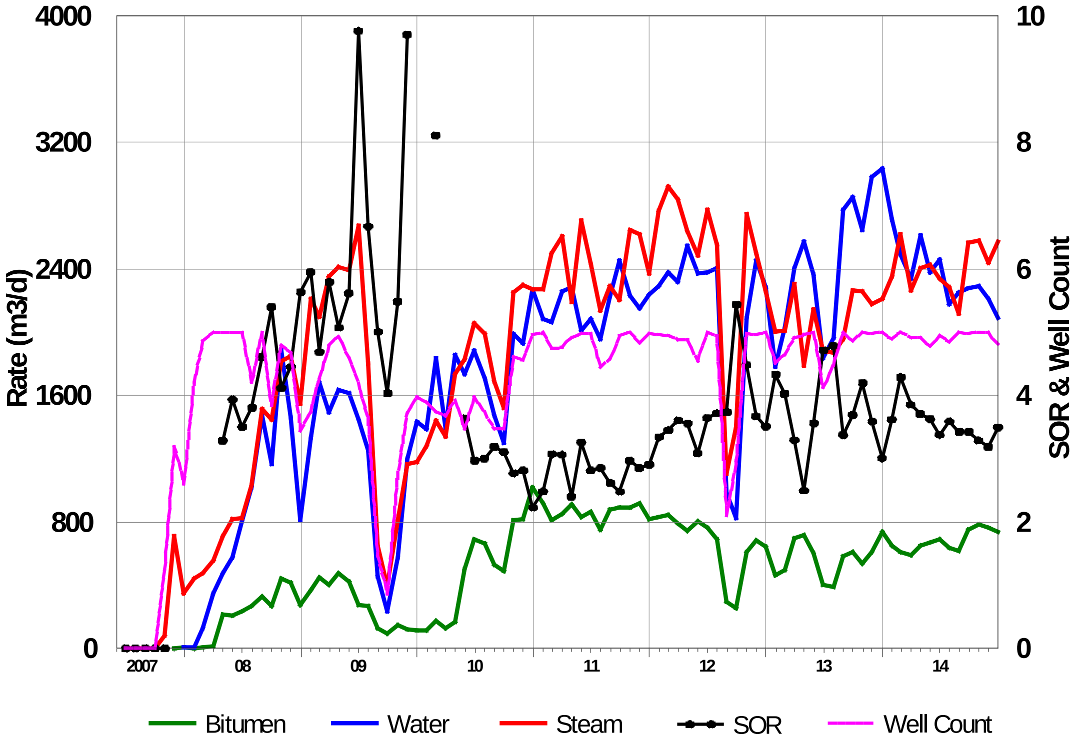
PAD 7E Production Summary



- Seven well pairs (07P06 to 07P12)
- Cumulative production of 563 E^3m^3 (RF 43%)

- All 7 wells on ESP
- Stable operation
- At YE, injection pressures were ~1,850–2,100 kPa
- NCG injection started October 2014 on 07P07, 07P08, 07P09
- Liner failures on 07P11 and 07P12 repaired with liner and packer assembly

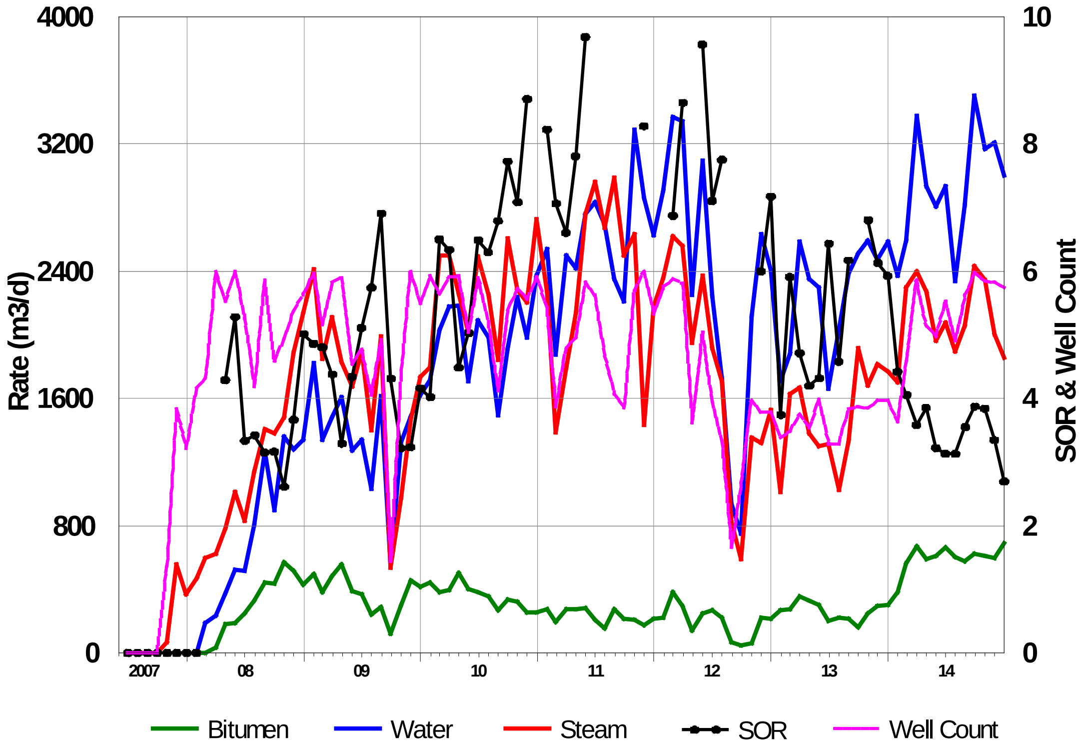
PAD 7N Production Summary



- Five well pairs (07P01 to 07P05)
- Cumulative production of 1383 E^3m^3 (RF 46%)

- All 5 wells on ESP
- 07P01-07P03 in possible decline phase
- Proposed NCG pilot project
- Increased steam injection and maximized withdrawals helped achieve higher production
- 4 infill producer wells were drilled in 2014
- At YE, injection pressures were ~2,000 - 2,100 kPa

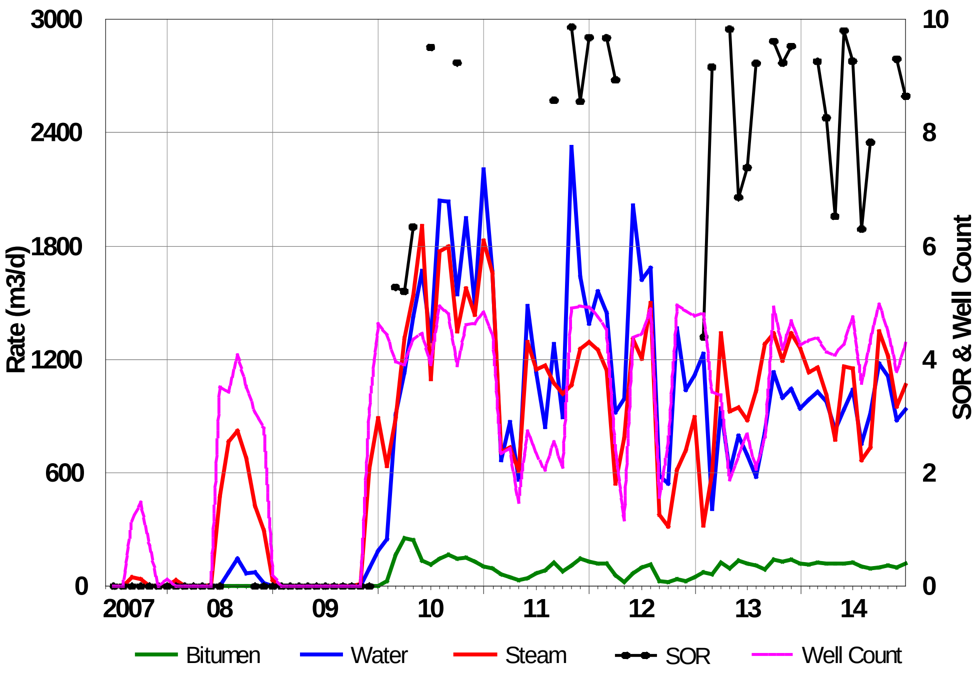
PAD 8 Production Summary



- Six well pairs (08P01 to 08P06)
- Cumulative production of 844 E^3m^3 (RF 34%)

- All 6 wells on ESP
- Increased emulsion rates in late 2013 and saw improved performance
- Brought 08P01 & 08P02 online in February 2014 after being shut in since 2012
  - No issues re-starting ESPs
- At YE, injection pressures were ~1,850–2,100 kPa

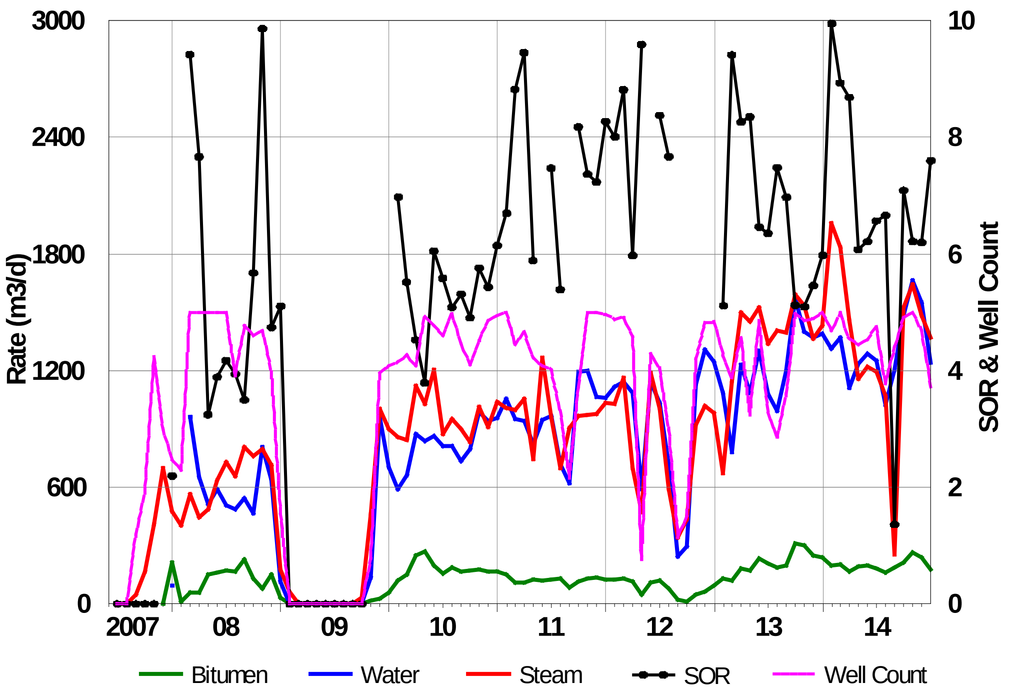
PAD 9NE Production Summary



- All 5 wells on ESP
- 9P07 plugged back at toe due to liner failure
- Poor reservoir quality and unstable operation impacting performance
- At YE, injection pressures were ~1,350 – 1,900 kPa

- Five well pairs (09P06 to 09P10)
- Cumulative production of 192 E^3m^3 (RF 17%)

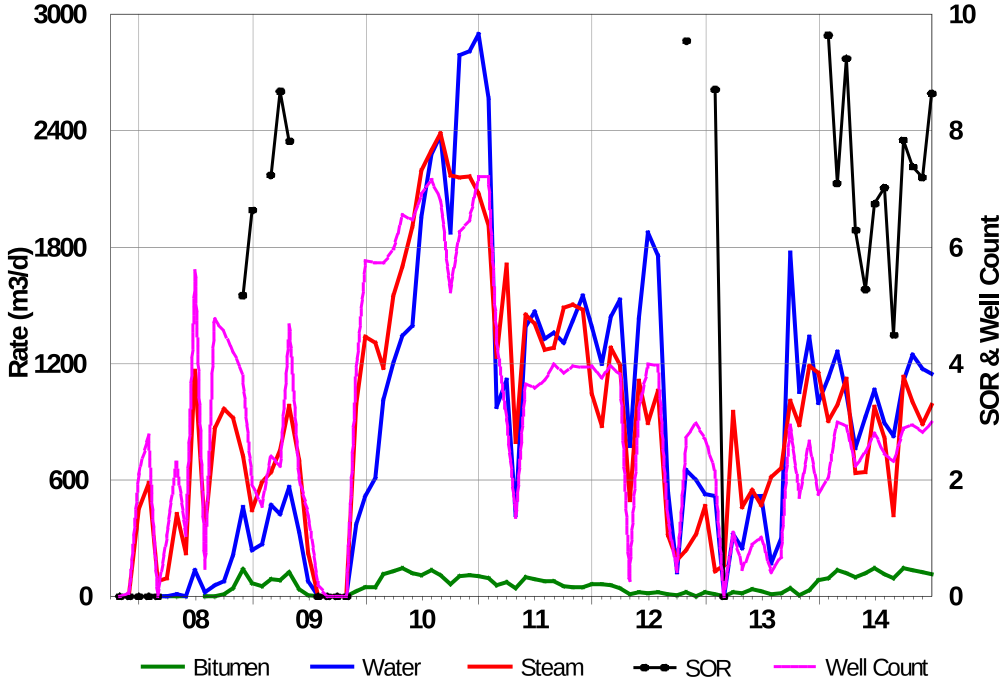
PAD 9W Production Summary



- 9P1-9P3 on gas lift
- 9P4 & 9P5 on ESP
- Stable operation
- 9P5 in possible decline phase
- At YE, injection pressures were ~2,000 - 2,100 kPa

- Five well pairs (09P01 to 09P05)
- Cumulative production of 345 E^3m^3 (RF 22%)

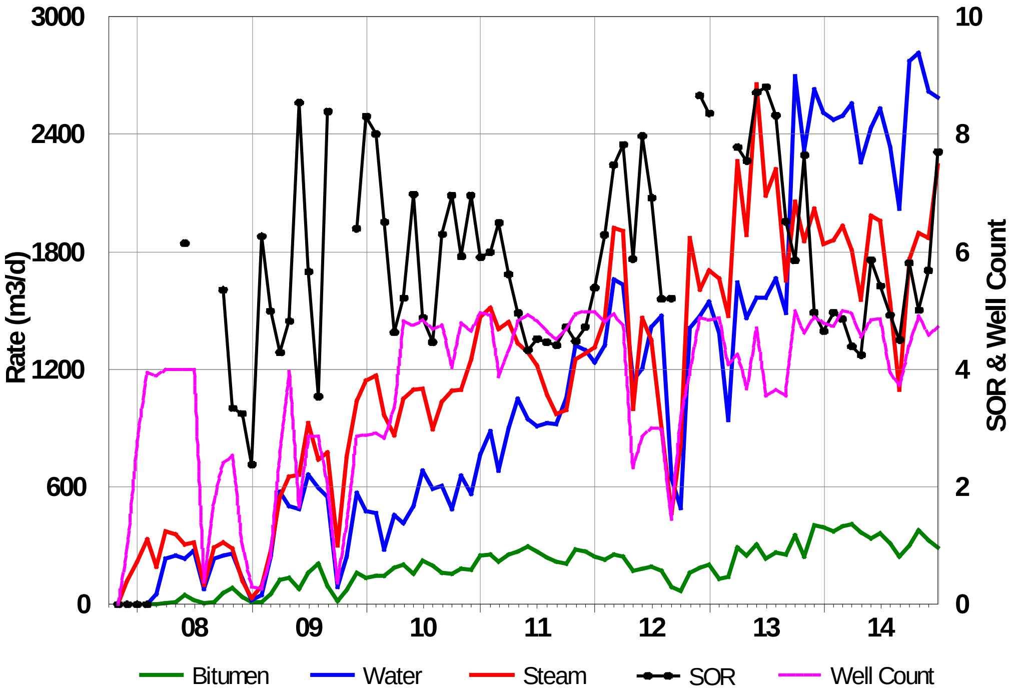
PAD 10N Production Summary



- All wells on gas lift
- Increased run time led to higher production and lower SOR
- At YE, injection pressures were ~1,700 – 1,900 kPa

- Three well pairs producing (10P10 to 10P12)
- Cumulative production of 150 E^3m^3 (RF 14%)

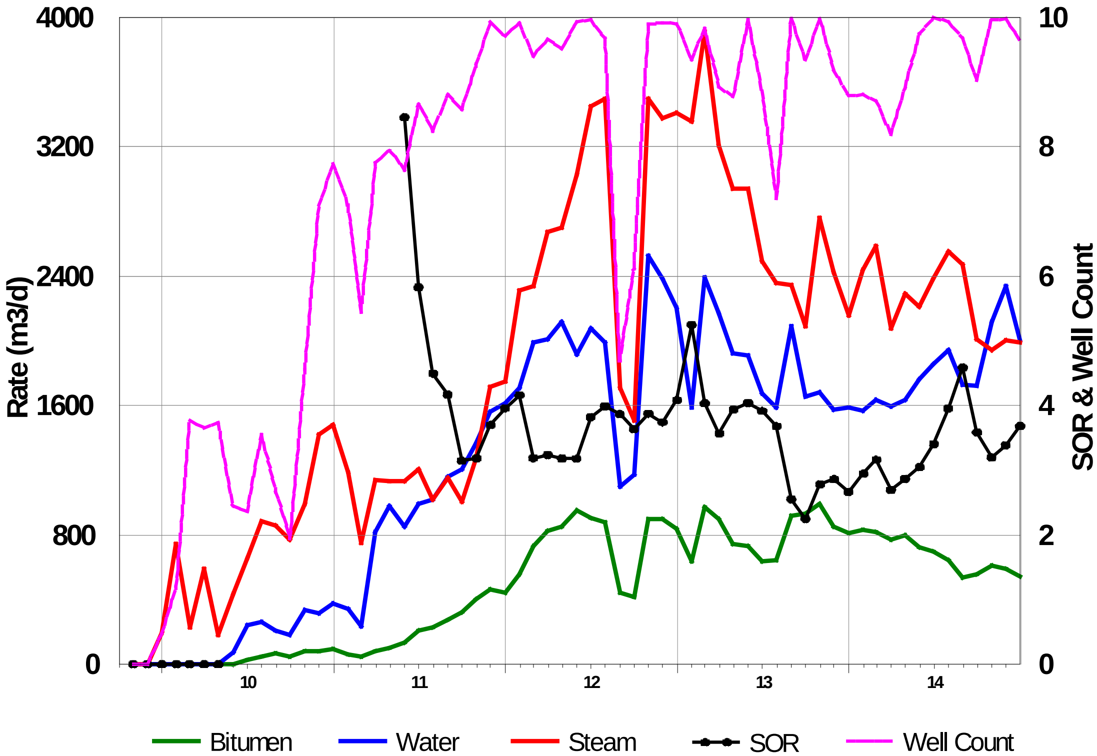
PAD 10W Production Summary



- All 5 wells on ESP
- Stable operation
- Performance impacted by top water WSR > 1.0
- At YE, injection pressures were ~1,950–2,100 kPa

- Five well pairs (10P01 to 10P05)
- Cumulative production of 498 E^3m^3 (RF 24%)

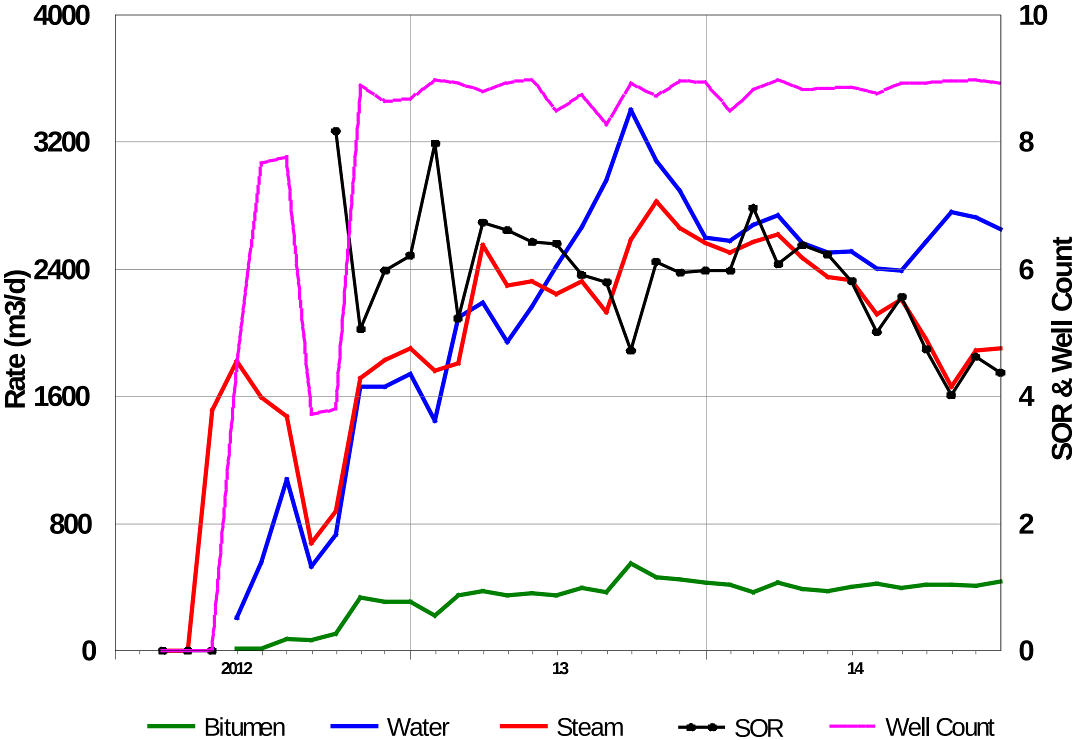
PAD 11 Production Summary



- Ten well pairs (11P01 to 11P10)
- Cumulative production of 922 E^3m^3 (RF 42%)

- All 10 wells are on ESP
- Pad in possible decline phase
- 11P10 re-drilled due to liner failure
- Decline in bitumen rates can be attributed to top water effect
- Reduced operation pressure from 2100 to 1850 kPa
- At YE, injection pressures were ~1,850–1,920 kPa

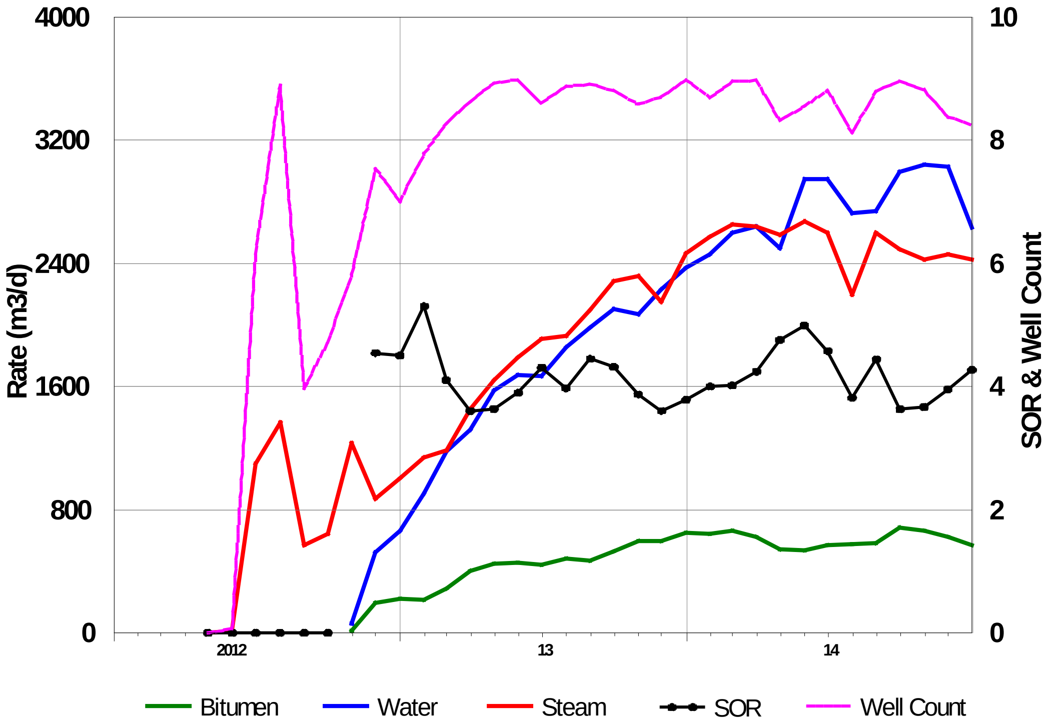
PAD 12 Production Summary



- Nine well pairs (12P01 to 12P09)
- Cumulative production of 330 E^3m^3 (RF 10%)

- All 9 wells are on ESP
- Flat bitumen rate attributed to lean zone
- Reduced pressure on west side of pad in attempt to promote water production
- Reduced operational pressure from 1,900 to 1,600 kPa
- At YE, injection pressures were ~1,300–1,875 kPa

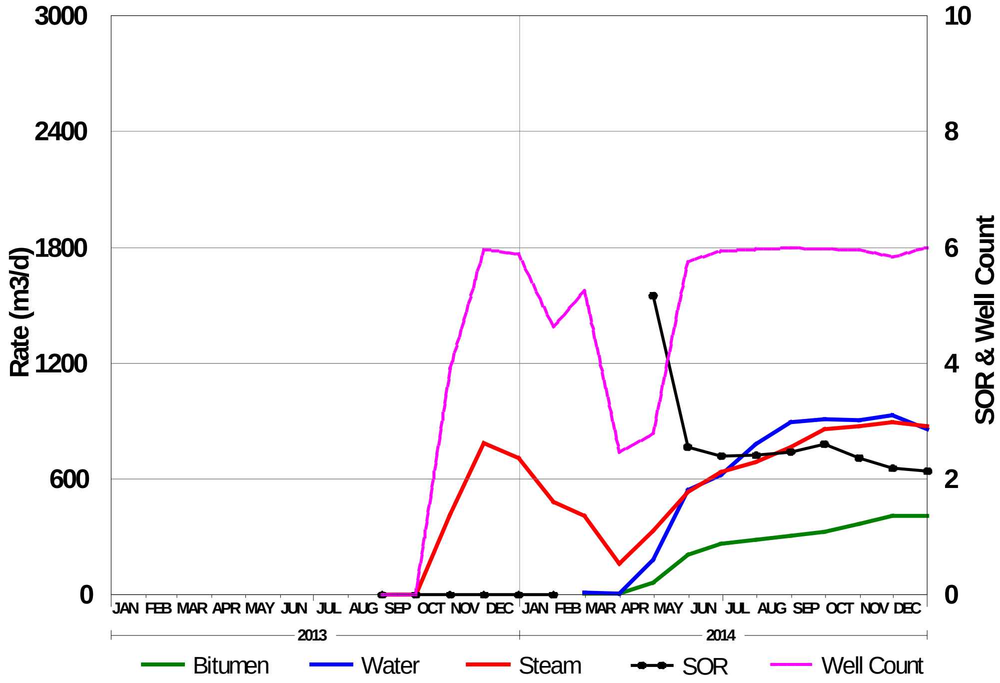
PAD 13 Production Summary



- Nine well pairs (13P01 to 13P09)
- Cumulative production of 404 E^3m^3 (RF 13%)

- All 9 wells are on ESP
- Initiated ES-SAGD project at wells 13P3 and 13P4 in October
- Flat bitumen rate attributed to lean zone and facility constraints
- Reduced operational pressure from 1,975 to 1,825 kPa
- At YE, injection pressures were ~1,800–1,875 kPa

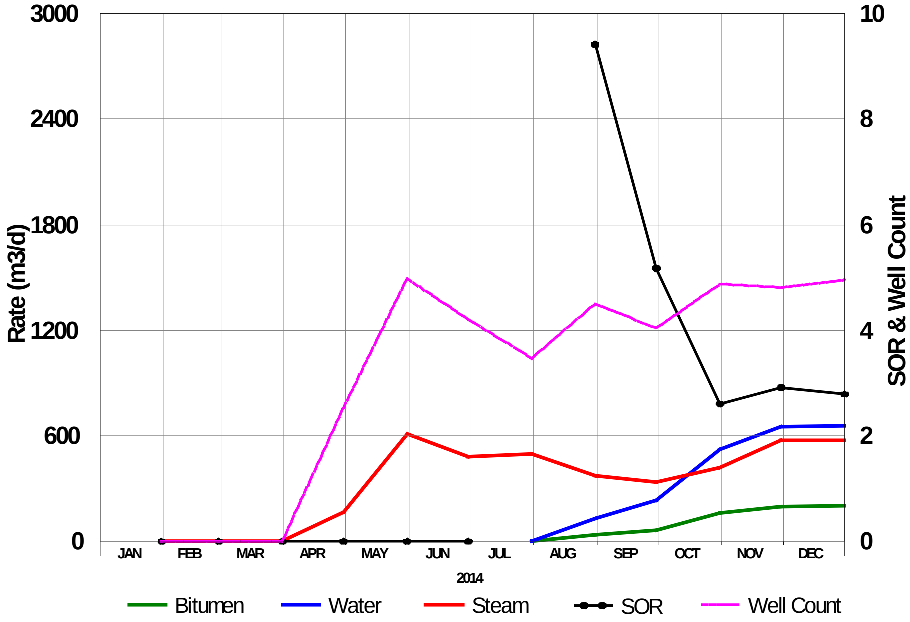
PAD 14 Production Summary



- All 6 wells on ESP
- SAGD conversion in Q2 2014
- All wells on ramp-up
- At YE, injection pressures were ~2,300 - 2,500kPa

- Six well pairs (14P01 to 14P03 and 14P05 to 14P07)
- Cumulative production of 82 E^3m^3 (RF 4%)

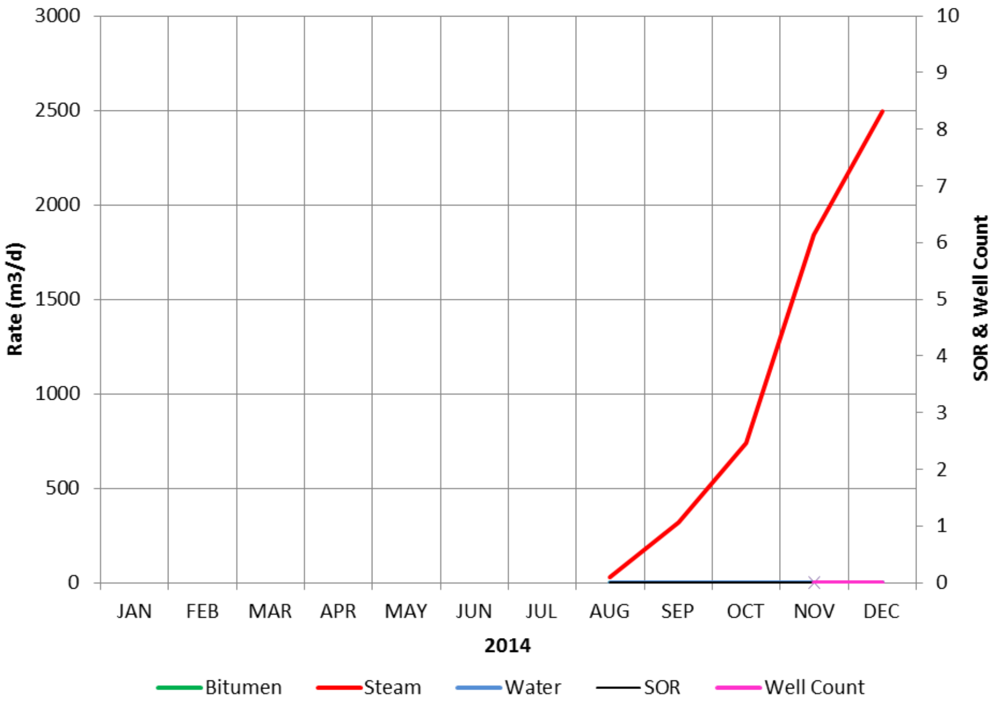
PAD 15 Production Summary



- All 5 wells on ESP
- Last well converted to SAGD in Q4 2014
- All wells on ramp-up
- At YE, injection pressures were ~ 2,300 - 2,500kPa

- Five well pairs (15P01 to 15P05)
- Cumulative production of 21 E^3m^3 (RF 1%)

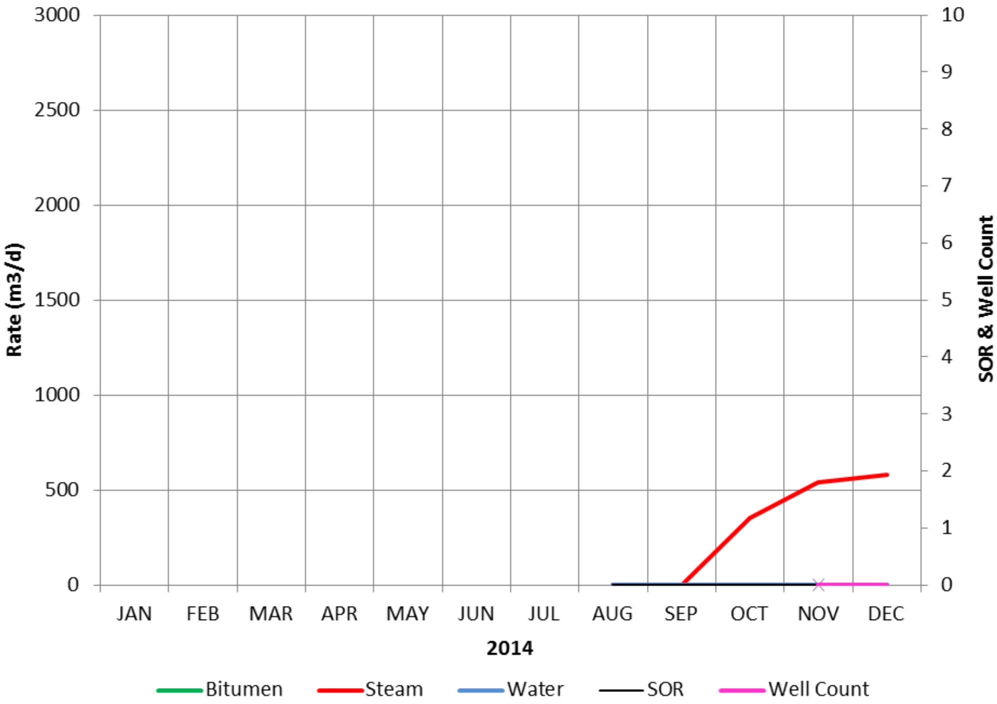
K1A-A Production Summary



- Ten well pairs (K1P09 to K1P16 and K2P01 to K2P02)
- Cumulative production of 0 E^3m^3 (RF 0%)

- 8 Pairs on circulation at YE
  - K1P09 to K1P16
  - Circulation Pressures from 1200 to 2800 kPa
  - Leaky Wells circulated closer to bottom water pressure
- Anticipate conversion to production in 2015
- K2P01 & K2P02 scheduled for circulation start up in Q3 2015

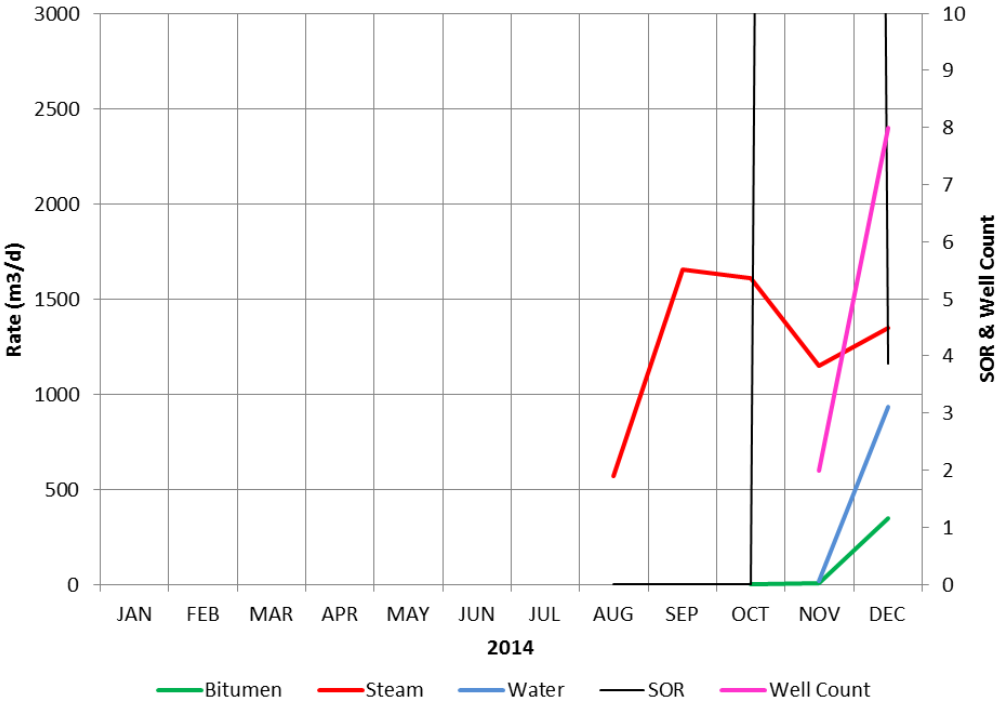
K1A-B Production Summary



- Eight well pairs (K2P09 to K2P16)
- Cumulative production of 0 E^3m^3 (RF 0%)

- 3 of 8 pairs on circulation in Oct 2014
  - K2P13 - K2P15
  - Circulation Pressures of 2,500 to 2,800 kPag
- Anticipate conversion to production in 2015
- K2P09 – K2P12 & K2P16 scheduled for circulation start up through 2015
- Solvent Assisted start up trial on K2P14 – injected $38m^3$ Solvent (Diluent) in late Dec

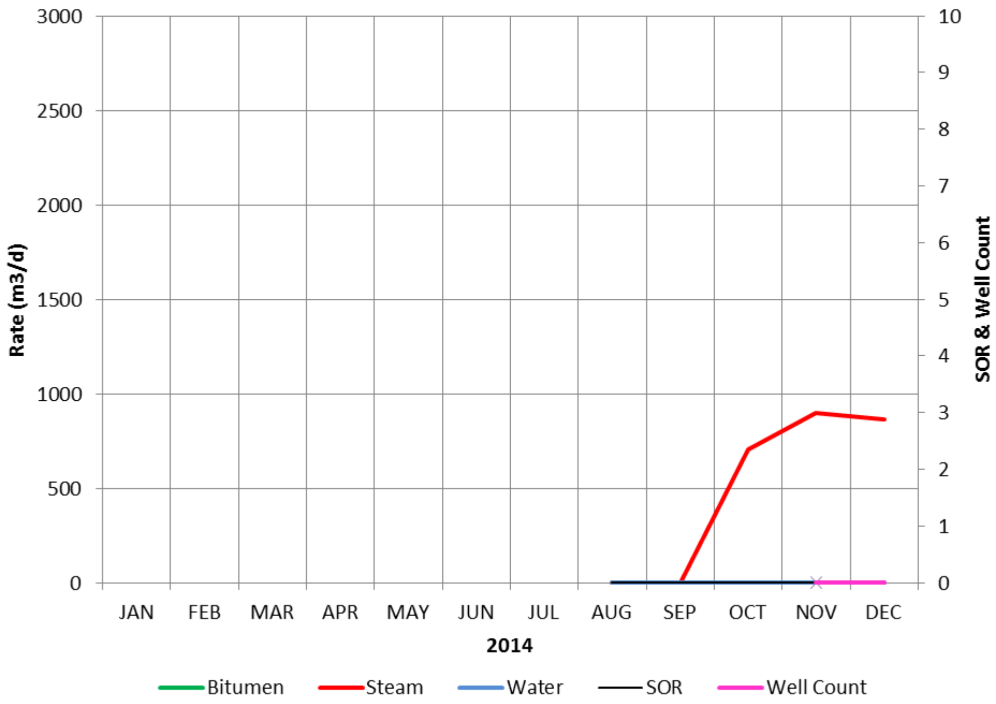
K1A-C Production Summary



- Eight well pairs (K1P01 to K1P08)
- Cumulative production of 12 E^3m^3 (RF 0.2%)

- 8 of 8 pairs on circulation in Aug 2014
- Circulation Pressures from 2,500kPa to 2,800 KPa
- Conversion to Production Started in Nov 2015 through Dec 2014
- Operating Pressure of 2,500 to 2,800 kPa

K1A-D Production Summary



- Eleven well pairs (K2P03 to K2P08 and K2P18 to K2P22)
- Cumulative production of 0 E^3m^3 (RF 0%)

- 5 of 11 pairs on circulation in Oct 2014
  - K2P18 - K2P22
  - Circulation Pressures of 2,800kPa
- Anticipate conversion to Production in 2015
- K2P03 – K2P08 scheduled for circulation start up through 2015
- Solvent Assisted start up trial on K2P19 – injected $38m^3$ Solvent (Diluent) in late Dec

Long Lake – Annual Performance Presentation in Accordance with Directive 054 (Surface Facilities)

April 9, 2015

Overview

- Overview
- Field Infrastructure and Inlet Treating
  - Slides 14-19
- Steam and Power Generation
  - Slides 20-30
- Water Treatment
  - Slides 31-38
- Volume Measurement and Reporting
  - Slides 39-42
- Water Production, Injection and Uses
  - Slides 43-57
- Sulphur Recovery
  - Slides 58-63
- Regulatory Compliance & Environmental Performance
  - Slides 64-83
- Future Plans
  - Slides 84-85

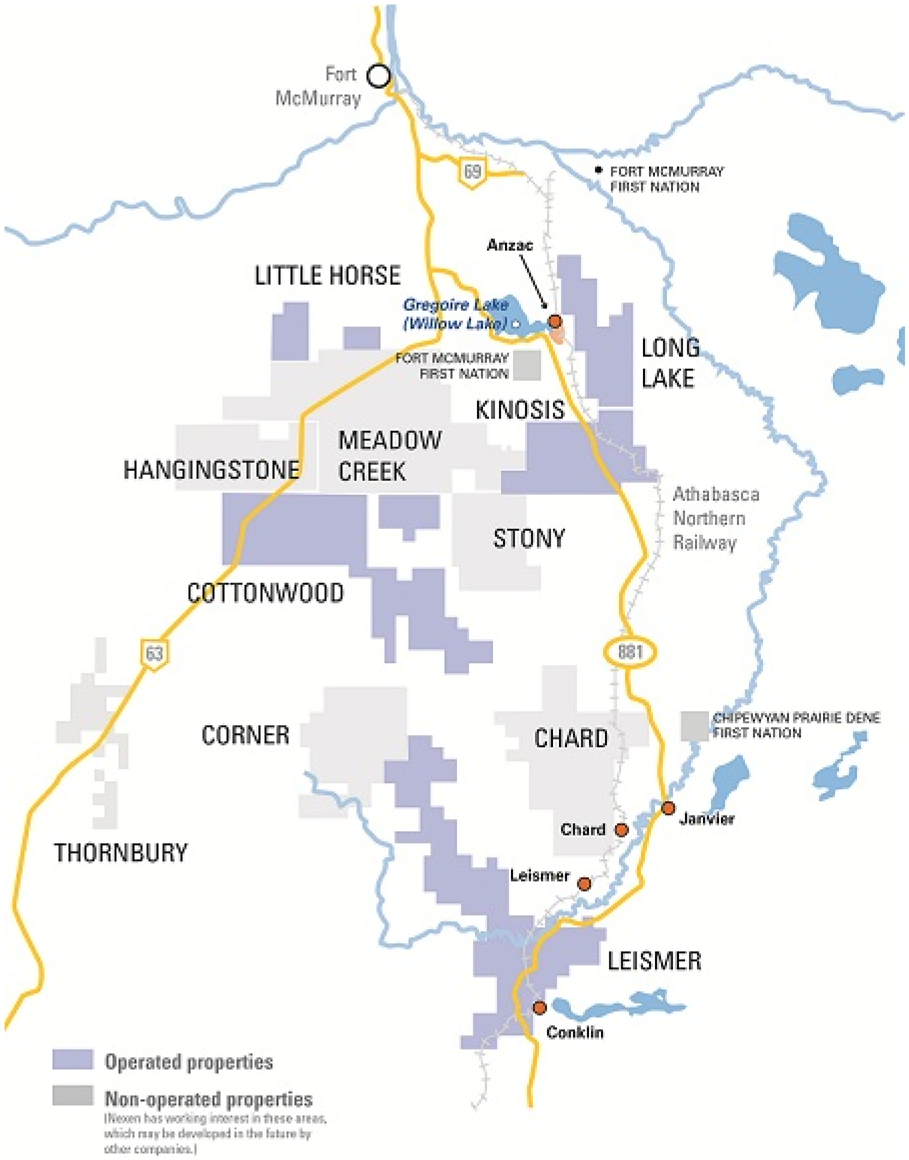
Purpose

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

Corporate Ownership

- Nexen Energy ULC 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.
- In February 2013, Nexen became a wholly-owned subsidiary of Chinese National Offshore Oil Company (CNOOC) Limited.
- Nexen has three principal businesses: conventional oil and gas, oil sands and shale gas.

Nexen Oil Sands Leases



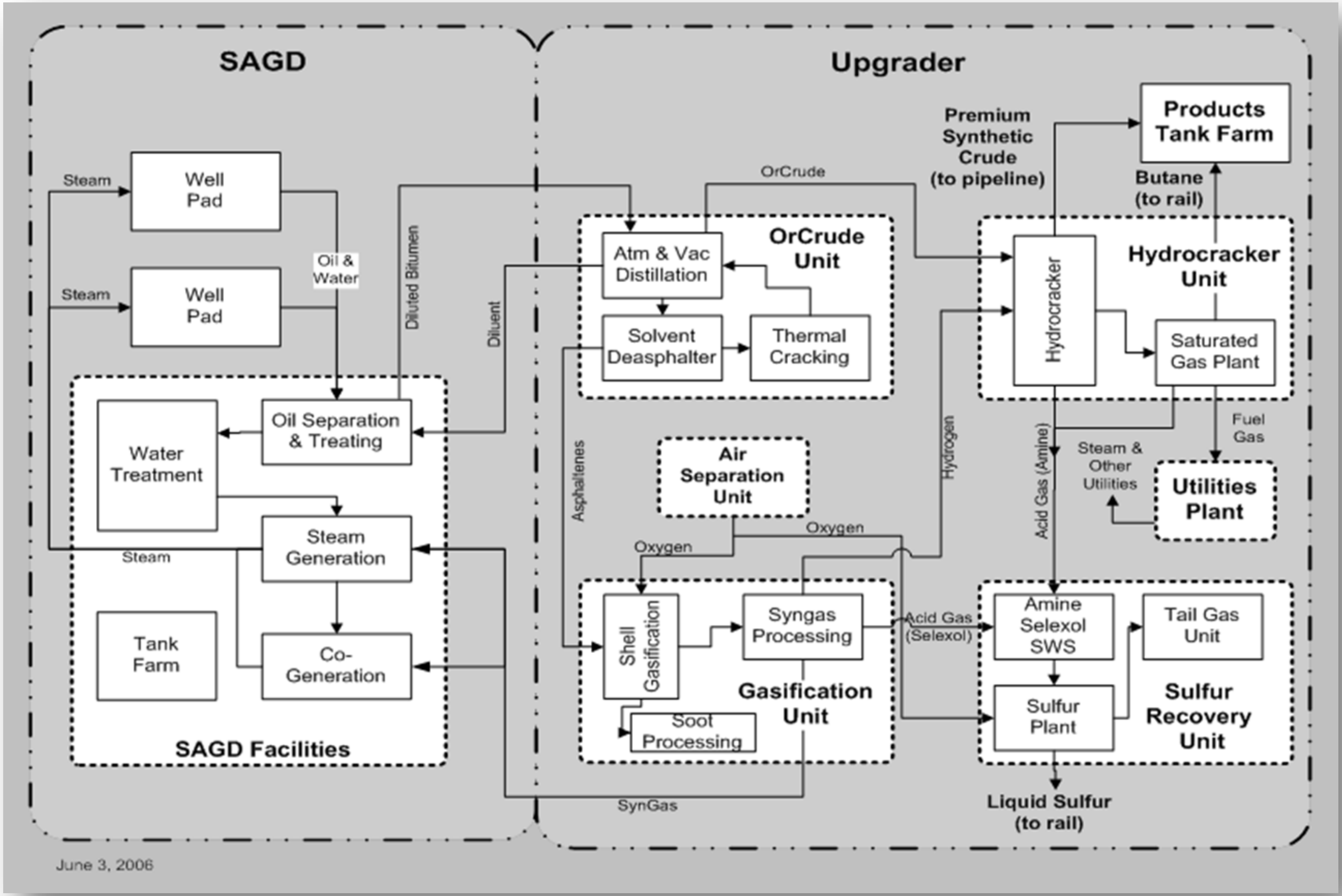
Chronology of Oil Sands Operations

Year	Activity
2000	EIA and regulatory submissions for the commercial Long Lake Facility
2003	Regulatory approvals for the commercial Long Lake Facility
2003 - 2007	Production at the Long Lake SAGD Pilot Plant
2004	Construction begins for the commercial Long Lake 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 Long Lake South
2009	Start of operation of the Long Lake Upgrader
2010	Regulatory approvals for Pads 12 and 13
2012	First production from Pads 12 and 13
2012	Major turnaround for maintenance at CPF and Upgrader
2012	Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)
2012	Construction begins for K1A and Pads 14 and 15
2013	Increased production from Long Lake well pads, begin circulation at Pad 14
2014	K1A and Pads 14 and 15 started production

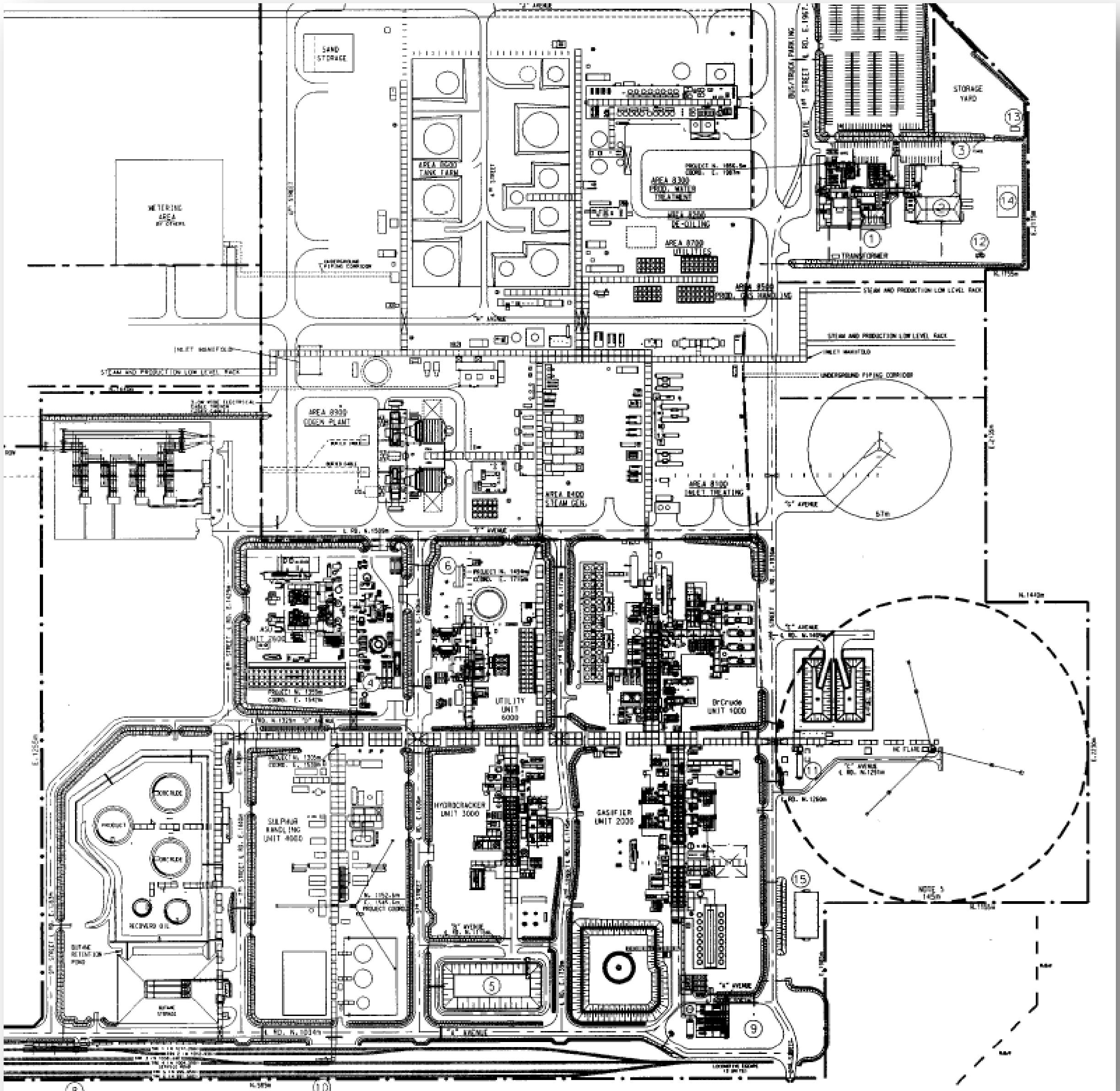
2014 Summary

- Most successful year at Long Lake
  - Best ever safety record
  - Record production (42,900 bpd average) and significant increase over 2013
    - Improved plant reliability
    - Optimization of existing wells
    - Pads 14 & 15 ramping up above expectation
  - K1A completion and start-up
  - Completion and start-up of first Long Lake infill wells

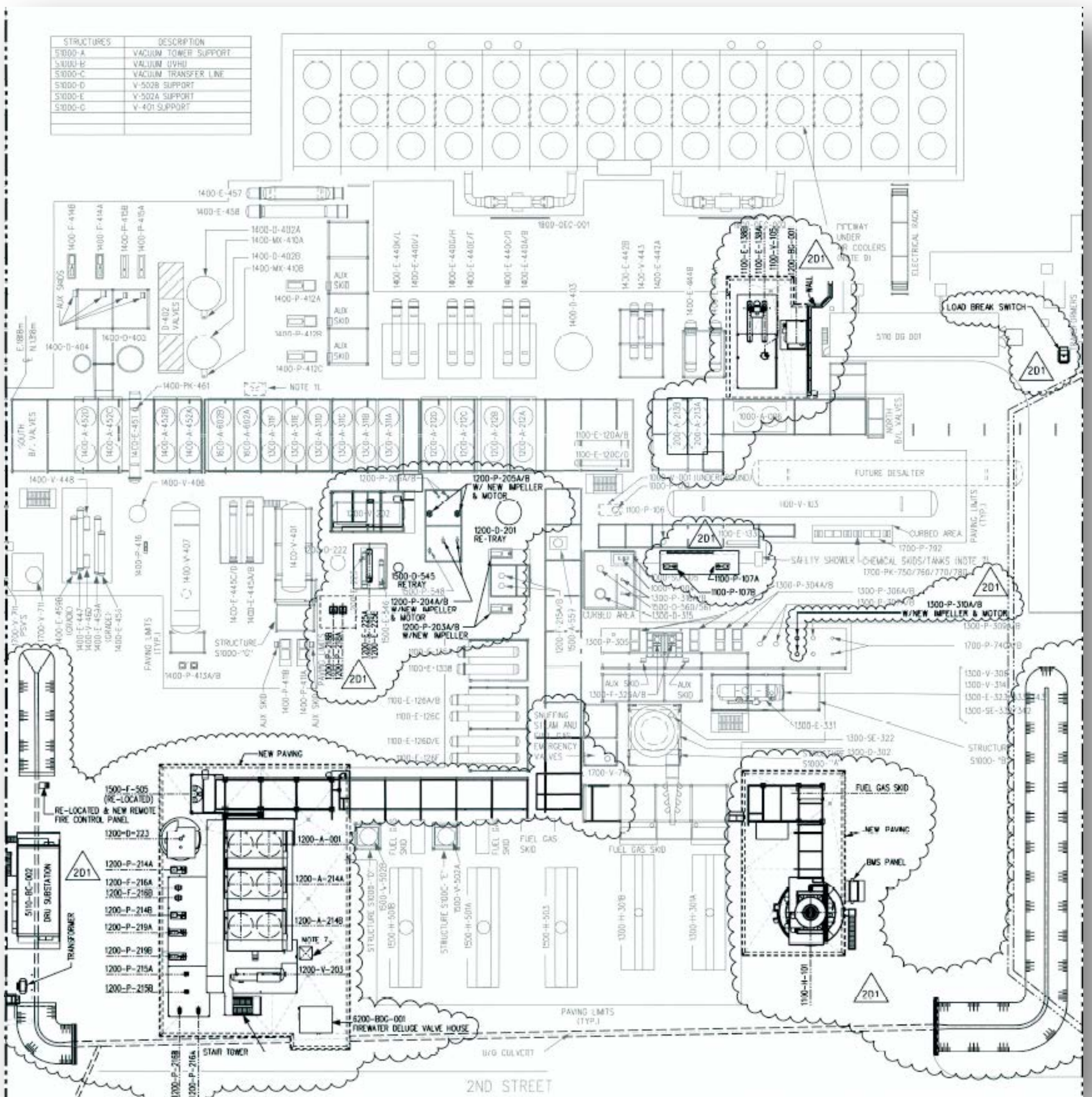
Process Overview

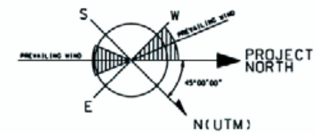


Long Lake Plot Plan

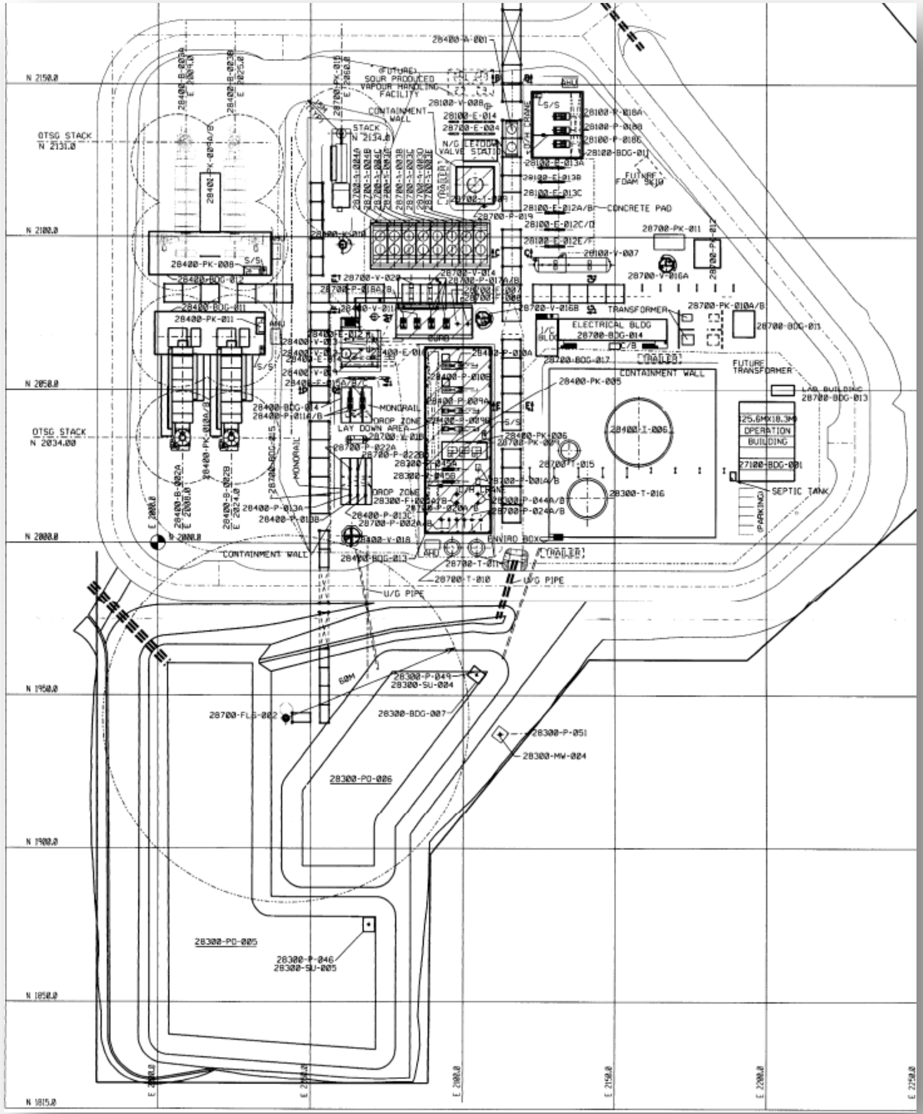


DRU Plot Plan





Kinosis Phase 1A (K1A) Plot Plan



Long Lake

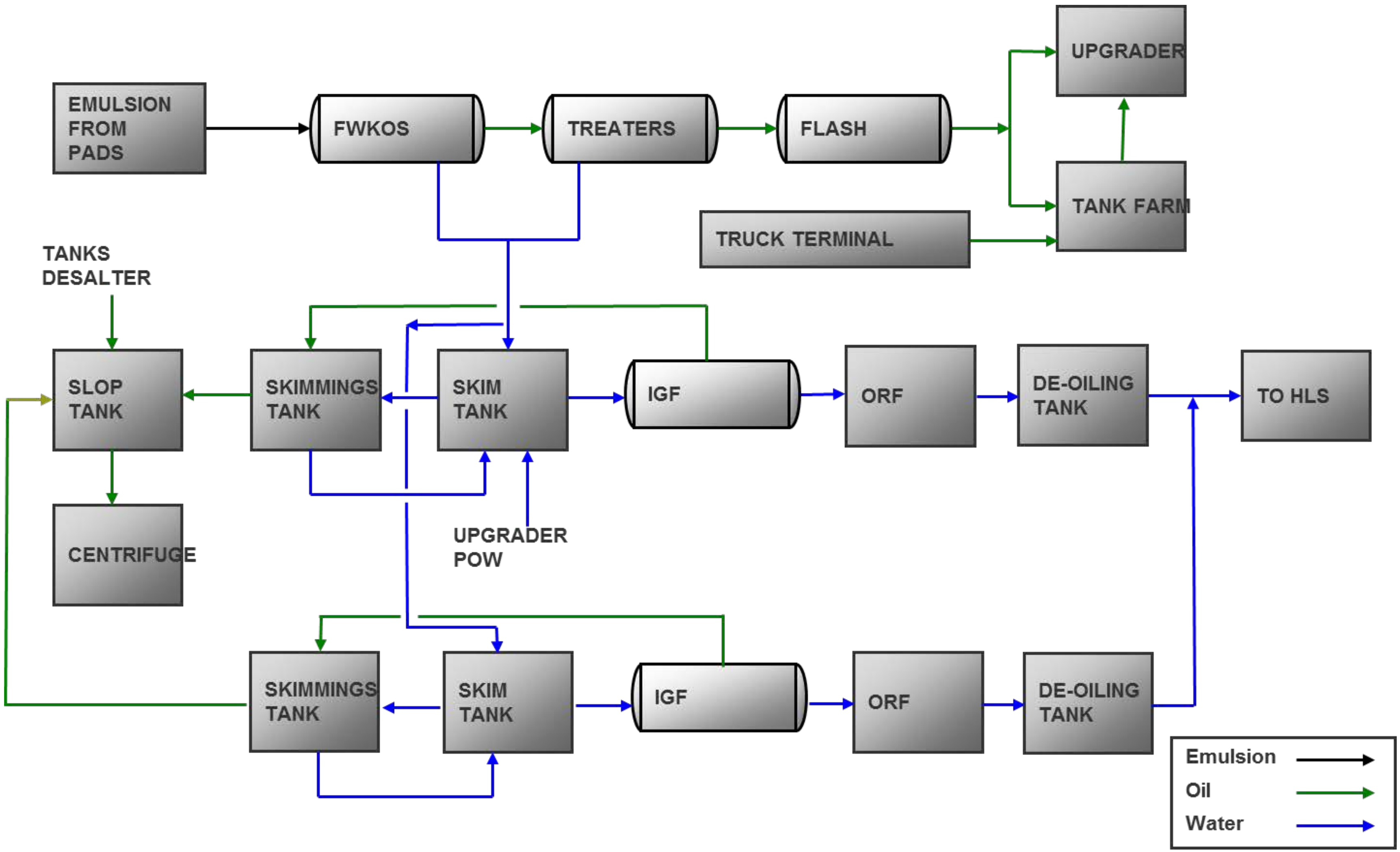
Long Lake overview with new DRU construction activities– October 22, 2014

Kinosis Phase 1 (K1A)

Aerial of Nexen's K1A Steam Generation Facility with Well Pads 2 in background – October 15, 2014

Field and Inlet Treating

Field and Inlet Treating



Field and Inlet Treating - Successes

- **Chemical injection – re-location of chemical injection, upgraded pump with VFD control and bulk storage facilities**
  - Existing chemicals continue to provide good performance with regular monitoring
  - The bulk storage project as part of K1A has been commissioned and supports CPF and is showing the efficiency improvements as expected. The new DMO trial was postponed in 2014 but is on target for early 2015.

- **FWKO Desand Line Modification Project**
  - Modified desand lines on the FWKO's allow us to dump clean water from FWKO's front end and route it through the Produced Water exchangers.

- **Exchanger Performance**
  - Nexen determined that the fully open desand lines on the FWKO were impacting fouling on the PW exchangers due to high throughput rates and oil carryover.
  - After blocking in the desands on the front end it was noticeable that the fouling frequency in the exchangers was dropping and allowing longer run times.

Field and Inlet Treating – Successes Continued

- **Rag / Slop Management**
  - Brought in a second centrifuge to process slop which increased our capability from 200m3/day to approximately 800m3/day
  - Old philosophy of batching tanks or providing separation discarded for 100% slop processing which has yielded very good results and long haul truck hauling ceased
  - Slop recycle to front end FWKO stopped as not required with centrifuge capacity
  - Desand dumps on FWKO front end closed in to prevent excessive oil and water carryover into de-oiling system having a positive impact on rag formation
  - DMO trials planned to improve any rag formation tendencies by emulsion from K1A

- **K1A**
  - Production in 2014
  - Early performance shows it is exceeding expectations for production rates

Field and Inlet Treating – Updates Continued

- **High Exchanger Temperatures & Tank Pressures**
  - With higher production rates Nexen is experiencing higher Produced Oily Water (POW) and Produced Water (PW) temperatures that result in higher exchanger outlet temperatures and subsequently higher tank pressures
  - This places a higher load on the Vapor Recovery Compressors (VRU)
  - The newly installed FWKO desand lines as well as increased throughput rates have allowed more oily water and solids to route through the exchangers causing increased fouling and subsequent higher frequency of chemical cleaning
  - Generally this is a steaming process followed by a caustic solution flush to remove heavy material
  - The additional load of bringing on K1A has had an extra burden
  - Although they have their own bank of exchangers the overall loading in the Inlet process has gone up and challenges have been encountered managing all the water
  - The exchanger design flow rates for PW is near or at the upper limit of 36,000m3

Field and Inlet Treating – Updates Continued

- **Electrostatic Grids in Treaters**
  - The treaters are designed to remove residual water in the oil phase from the FWKOs utilizing electrostatic grids. The grids have not been as effective in removing water as expected. There was no change in 2014 and they were not in service.
  - It has been proposed to install sonar probes to establish proper levels to control PW injection properly and get the grids working. On hold as of December 2014.

- **VRU Performance and "Rapid Results Team"**
  - Since the tanks operate at only a slight positive pressure they cannot be connected to the flare system.
  - Vapor recovery system continues to offer us challenges due to capacity restrictions associated with piping configurations and size.
  - Rebuild of one complete unit with parts on hand already which has been completed.
  - Increased pressure on Flash Vessel and Diluent Condensate Separator resulting in VRU load reduction. Completed this with good results for 4 day period and unable to repeat due to other process factors.
  - ORC diluent stripper control improved to provide less light ends in diluent resulting in VRU load reduction
  - Any operational activity resulting in weeping/venting trigger a very high priority to resolve. All materials have been inventoried in stores and scaffolding for access remains in place. No change in 2014.

Steam and Power Generation

Steam and Power Generation - Successes

- **Steam Production**
  - The remainder of the ABSA requirements for the OTSG re-rates have been submitted for final approval. These re-rates allow for increased steam production.
    - Approval was received for the re-rate of the OTSG's
    - The TIWW PSV's were received
    - All six OTSG's are now re-rated to 154m3/h from 146 m3/h
  - No longer mixing Syngas and Natural gas
    - Fewer trips of the OTSG's and HRSG's, especially OTSG's E and F that run on Natural gas only
    - Less complications from heating value fluctuation
  - More reliable steam production due to fewer trips results in improved bitumen production

- **Condensate Quality**
  - Continuing to use filming Amine injection for LP, MP and HP steam

Steam and Power Generation – Successes Continued

- **E-013 Exchangers**
  - 8400-E-013 A and C tube bundles have been replaced with bundles made of different metallurgy intended for longer life before failure

- **Automated Safe Park function on DCS**
  - cuts qualities and fuel gas to OTSGs and HRSG's and transitions GTG's to Natgas from Syngas
  - Now automatically occurs during a PSA trip or a Gasifier train trip (Upgrader trips)

- **Procedure for use of HP Syngas**
  - Procedure for use of high pressure syngas in the GTGs was completed
  - HP Syngas is now successfully being used in the GTGs when available which offsets natural gas usage

Steam and Power Generation – Successes Continued

- **Duct Burner Fouling**
  - Procedure for purging and cleaning of HRSG duct burners completed February 2014
  - Operations can now complete cleaning of duct burners while unit is online which has increased syngas usage and steam output on an annual basis

- **Air Extraction Unit**
  - Commissioned and tested the Air Extraction Unit for GTGs, which will increase power output
  - More work required

- **Blowdown Tank**
  - No Blowdown Tank (8400-T-002) overflows
  - Improved procedure contributed to this milestone
  - Work on logic changes ongoing

Steam and Power Generation - Updates

- **Emergency Power Supply**
  - Total plant power outage determined weaknesses with SAGDs E-gen power supply
  - Team is working with the AIT group for re-design of the system to mitigate the risk to the operation

- **E-013 Exchangers**
  - 8400-E-013-B exchanger found internally leaking after only 6 months of operation, affecting site water balance
  - Changes to metallurgy is expected to extend life to two years

Steam and Power Generation – Updates Continued

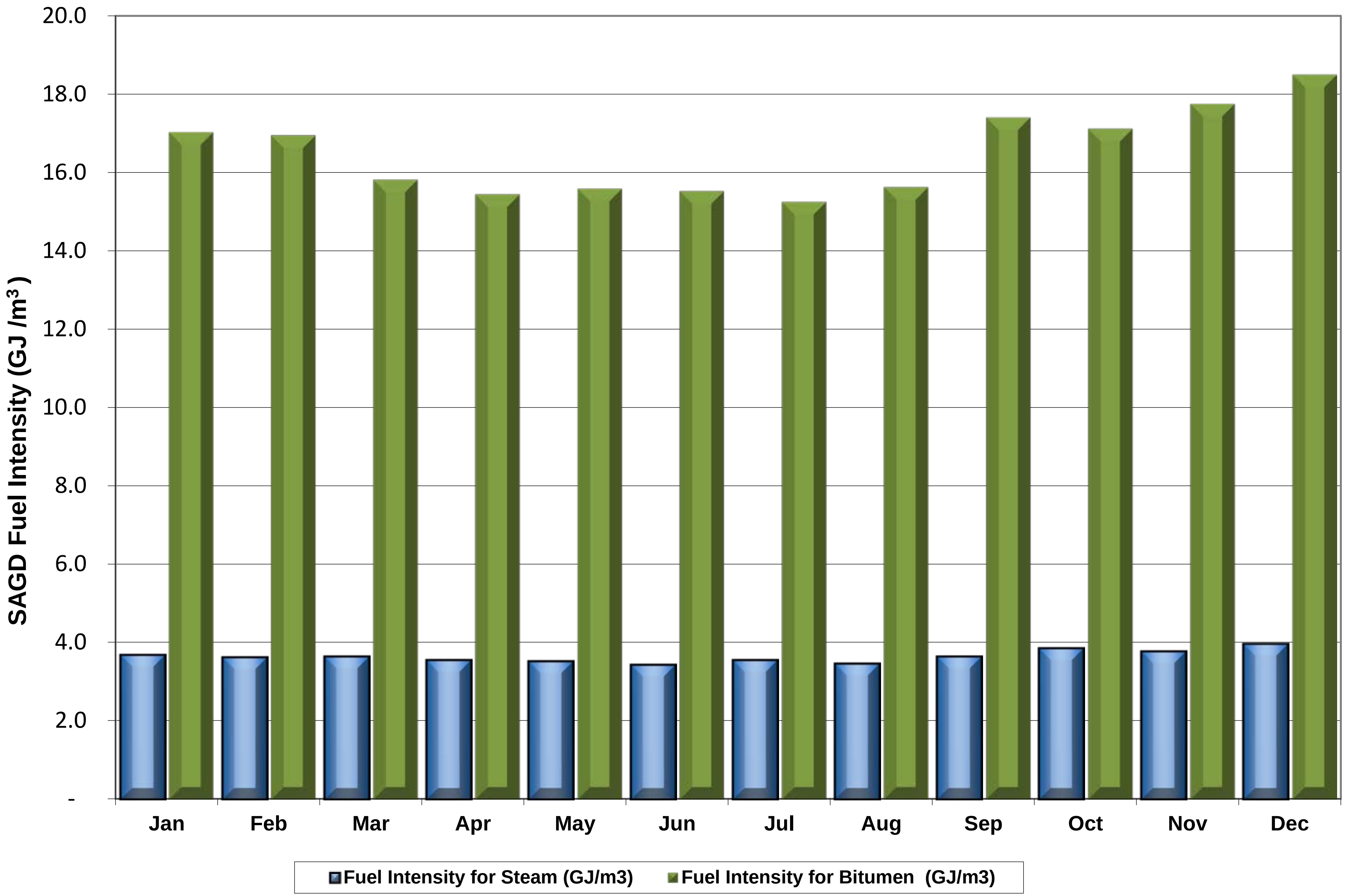
- **Duct Burner Fouling**
  - causing reduced steam production from HRSGs 1 and 2
    - Nitrogen purging effective but requires 6 hours and fouling returns quickly
    - Looking into different ways to clean the duct burners that do not require a full outage

- **PSA Reliability (Upgrader)**
  - Inconsistent Syngas pressure from the Upgrader causes OTSGs and HRSGs to trip when pressure swings are too large
  - Team has been established to review and correct PSA issues

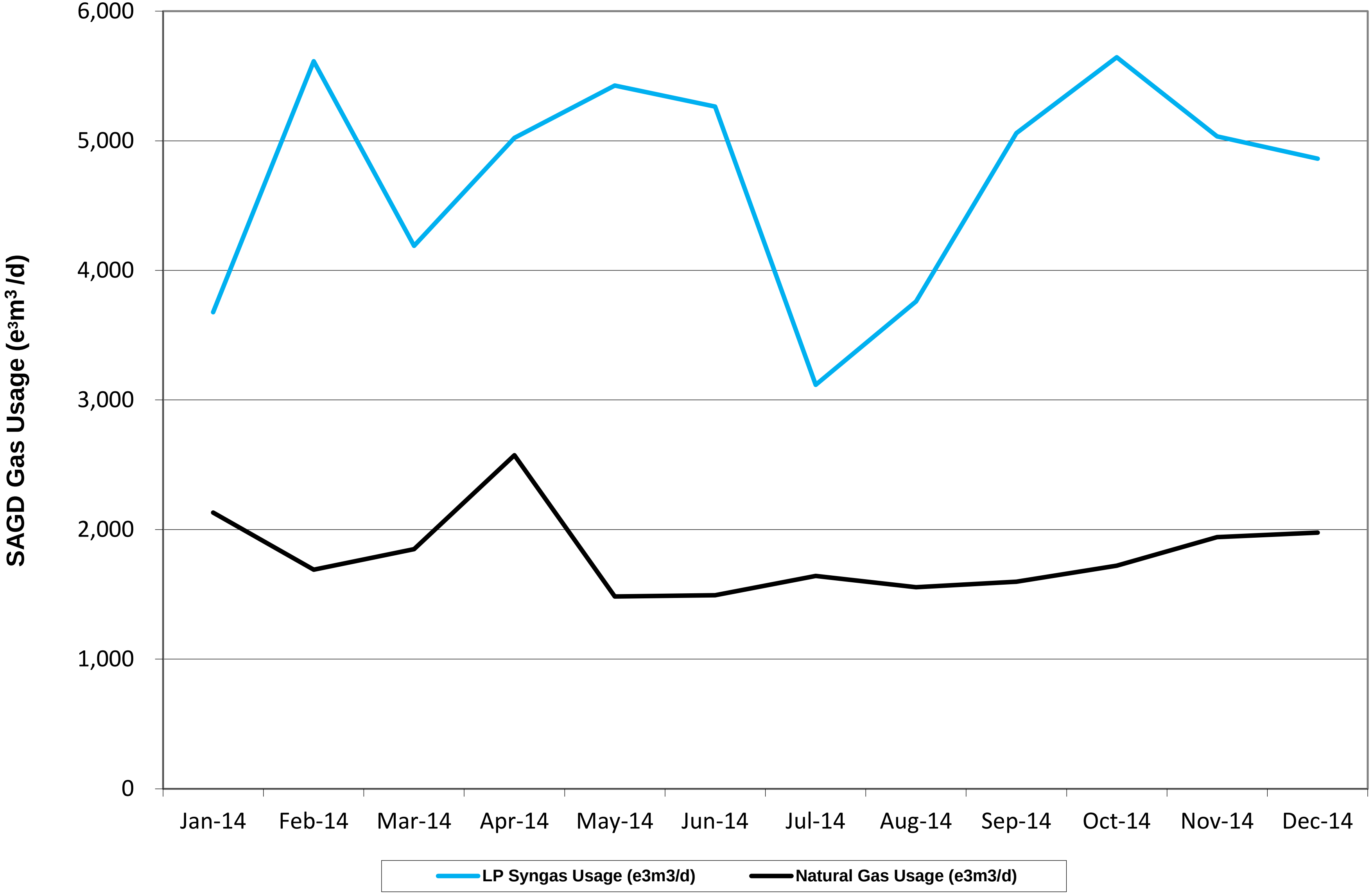
Steam and Power Generation – Updates Continued

- **Fuel Gas Configurations**
  - OTSGs A-D and HRSGs 1 and 2 must run on the same fuel as per the current configuration
  - When Syngas supply from the Upgrader is low, these boilers must be run at lower rates, or the choice must be made to switch all over to natural gas
    - Natural gas tie-in to HRSG's 1 and 2 design complete, and scheduled for June 2015
    - Will allow multiple options for utilizing available fuels on any steam generators

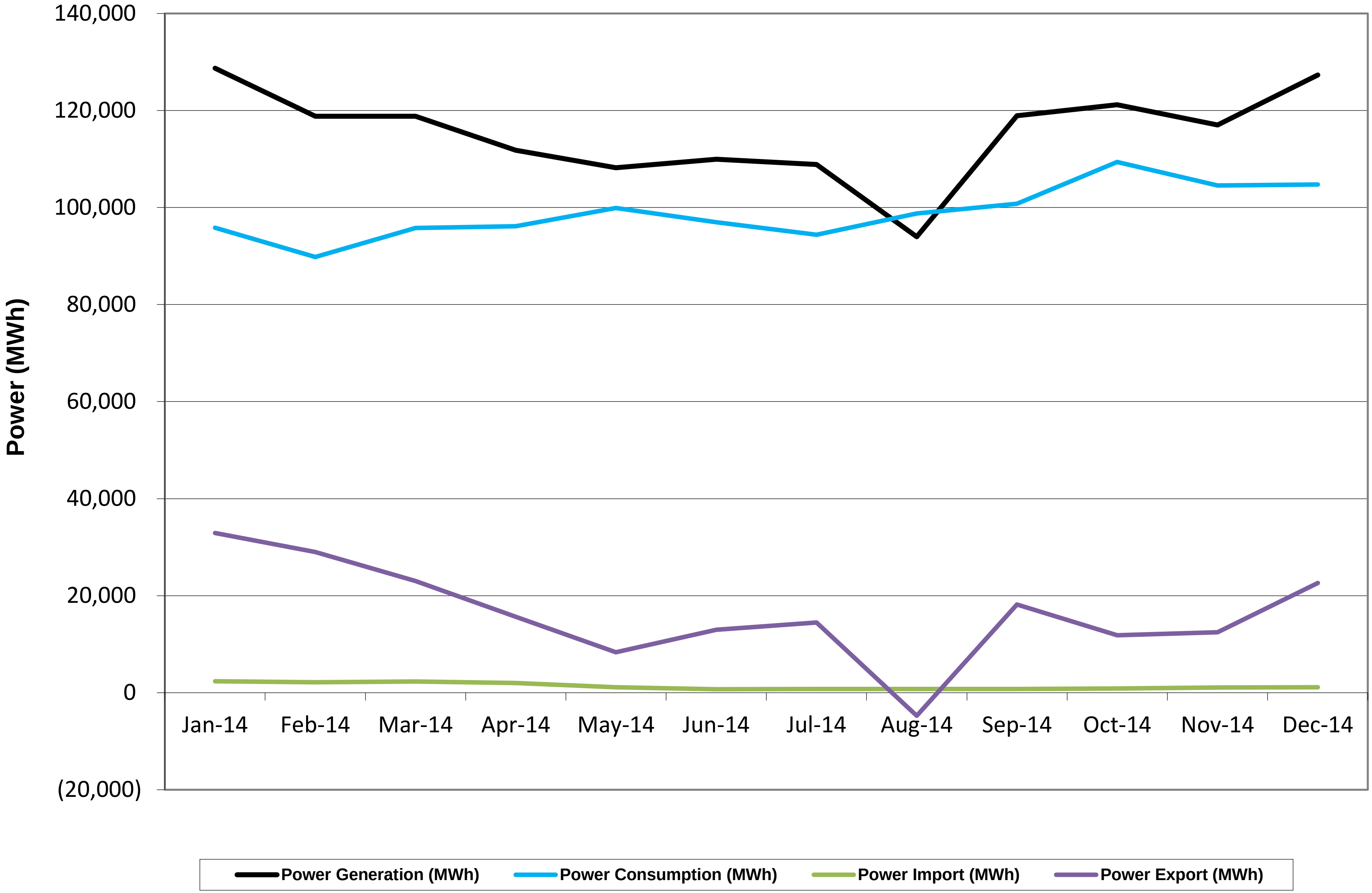
SAGD Energy Intensity



SAGD Natural Gas and Syngas Usage



Total Power Usage



Greenhouse Gas Emissions

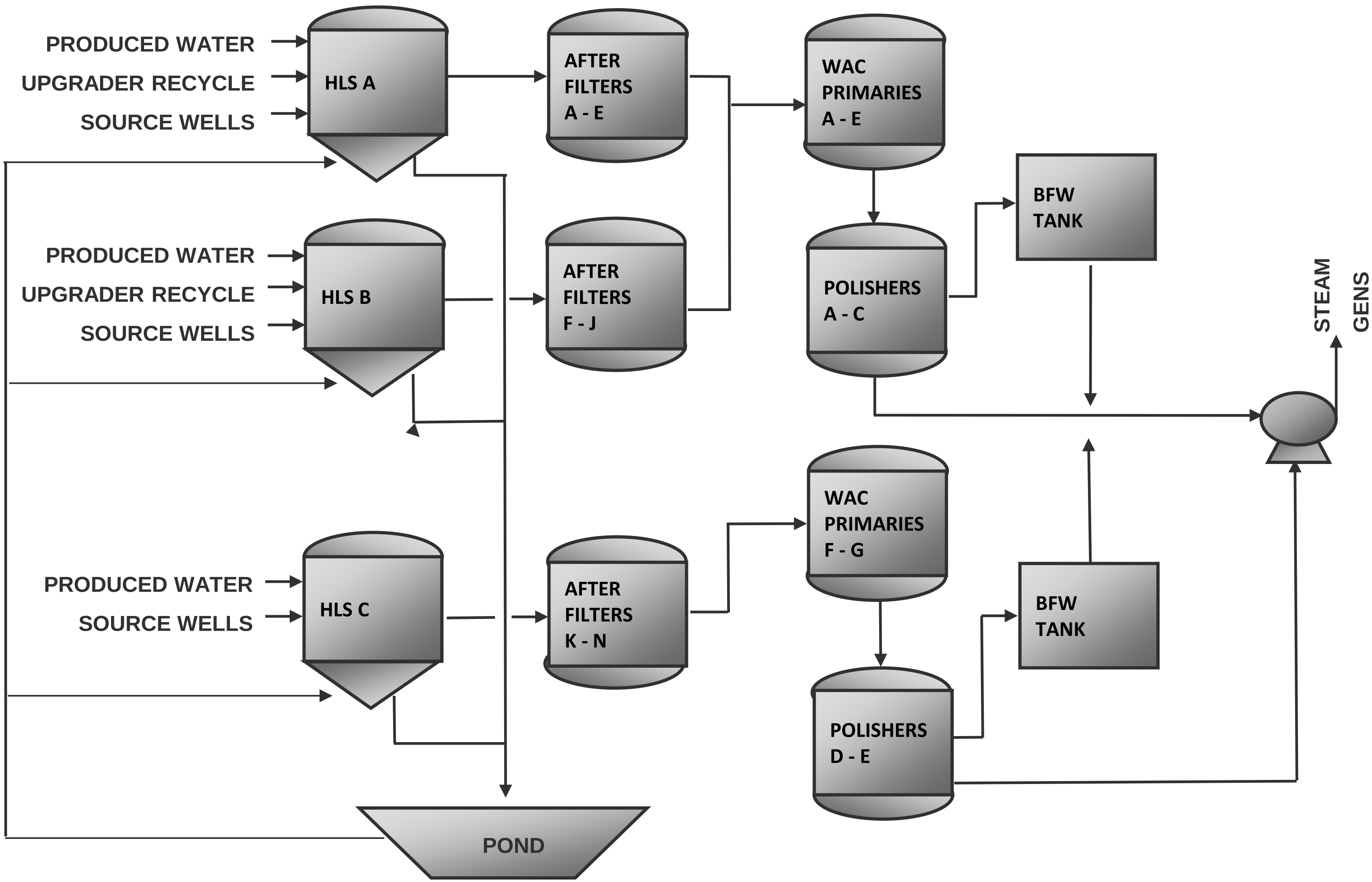
- Long Lake's absolute GHG emissions have been rising with increasing production, but intensity is trending downwards

Year	2010	2011	2012	**2013**	**2014**
Kilotonnes (kT) CO_2e Emissions	3,229	3,191	3,613	4,139	**4,758**
GHG intensity (kg CO_2e/bbl bitumen produced)	361	307	317	310	**304**

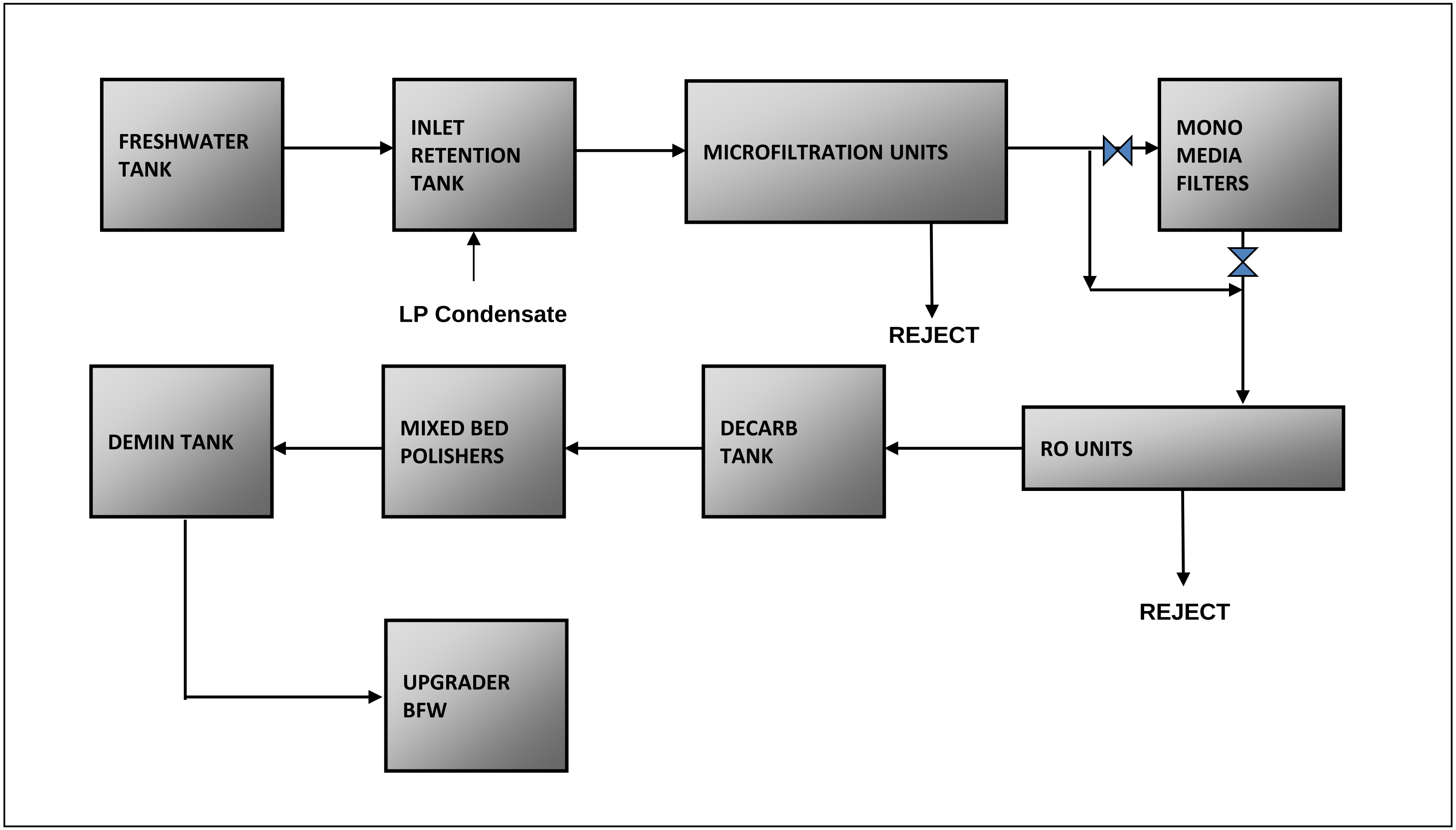
- Nexen and the AESRD resolved negotiations around Long Lake's baseline in July 2014, Long Lake now has an approved baseline based on 2010-12 performance
  - Long Lake's GHG baseline is divided among the facility's three major products – bitumen, PSC and electricity
- Long Lake's compliance is being met through reducing Long Lake's GHG intensity, the use of offsets from Nexen's Soderglen wind farm asset, and contributions to the technology fund
- Current GHG regulations (known as SGER) are set to expire in June 2015
  - Nexen is monitoring the development of these regulations

Water Treatment

Produced Water Treatment



High Quality Water System



Water Treatment - Successes

- **After Filters**
  - After filters backwash sequence implemented
  - Backwash volume significantly reduced

- **Chemical injection modifications**
  - Chemical injection modifications for Produced Water (PW) were completed
    - Separate coagulant injection to HLSs A/B started up, allowing proper adjustment during upset conditions
    - New flocculant injection system installed (pumps and pre-mixer dilution drums)

- **Capacity Test**
  - SAGD Water Treatment Capacity test conducted
  - Throughput increased after HLS internal modifications completed on 2012-2013 and WAC primaries/polishers adjusted differential pressure within safe limit

- **E-013 Exchangers**
  - E-013 bundles replaced
  - Improvement of the LP condensate quality and recovery, increasing the usage as feed to HQWS and reducing fresh water requirements

Water Treatment – Successes Continued…

- **High Quality Water System**
  - Fresh water heater E-002 bundle replaced
  - better control on the HQWS inlet temperature, allowing more stable temperature supply to ROs
  - Microfiltration membranes replaced in 2 of 3 trains, improving water feed quality to Reverse Osmosis Membranes (RO)
  - Mixed beds enhanced performance. Resin replaced and scour step added to improve separation and regeneration of the anion and cation resins
  - RO low fouling membranes trial was started to evaluate the impact of high TOC on low fouling membranes; this continued into 2015
  - Lime sludge from HLS blowdown is now being centrifuged and disposed of to landfill and water returned to the produced water system which will eliminate costly dredging and will contribute to pond integrity
  - More SAGD low pressure steam condensate into the HQWS feed, less fresh water use from source wells

Water Treatment - Updates

- **SAGD BFW treatment for hardness and silica**
  - Improvements required for the Lime/Magox systems
  - Brackish water used during K1A start up, difficult to treat
  - Higher Backwash and regeneration volumes for After filters and Weak Acid Cation Exchangers (WAC) required
  - High fouling rate with online pH meters, unreliable
  - WAC primary and polisher resin losses due to passing valves

- **Sludge carry over from HLSs**
  - Additional sludge taps on HLSs not preforming as designed
  - High fouling rate with online pH meters, unreliable
  - New pumps installed for better flocculent injection control
  - Periodical issues with HLS blowdown valves, doing manual blow downs

- **WAC primary and polisher resin fouling**
  - causing high differential pressures
  - Result of poor de-oiled water quality and over feeding chemicals

Water Treatment – Updates Continued…

- **Difficulties in controlling De-Aerator compartment level for HLS restricting feed to HLS A/B**
  - WAC primary and polisher inlet valves not working
  - WAC feed pumps/recirculation valves fouling

- **High Quality Water System**
  - Mono media filters low run time
  - Rapid fouling on RO's membranes
  - Trial with more foulant resistant membranes started

- **Fresh Water Leak**
  - Fresh Water leak at the common header from source wells to plant
  - Repair plan issued
  - A temporary repair has been completed with final repair to be completed during the 2015 Turnaround

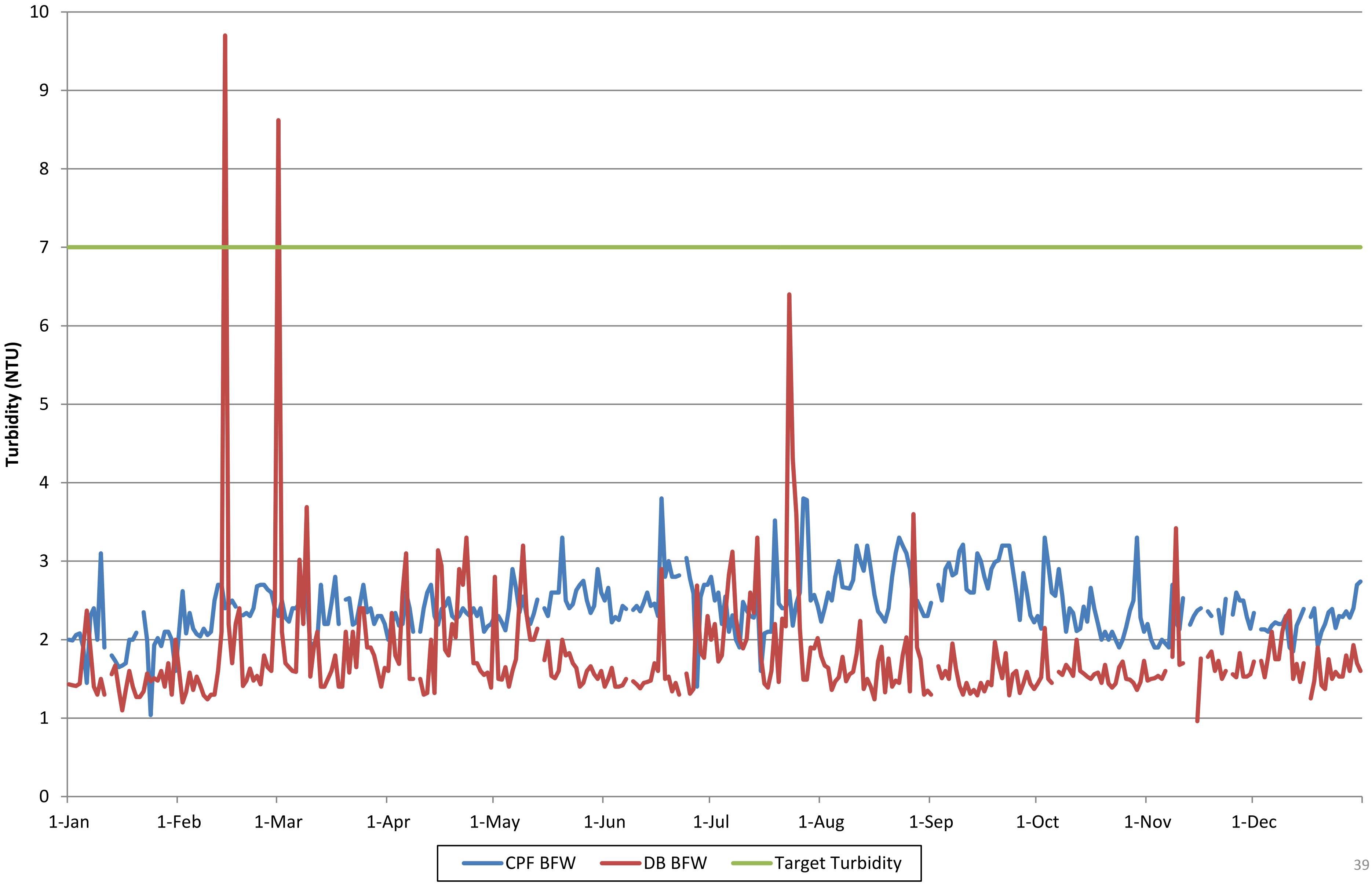
Water Treatment – Updates Continued…

- **Micro-Filtration**
  - Micro filtration unit performance issues
  - Membranes replaced in 2 of 3 trains in 2014
  - All are complete at time of report

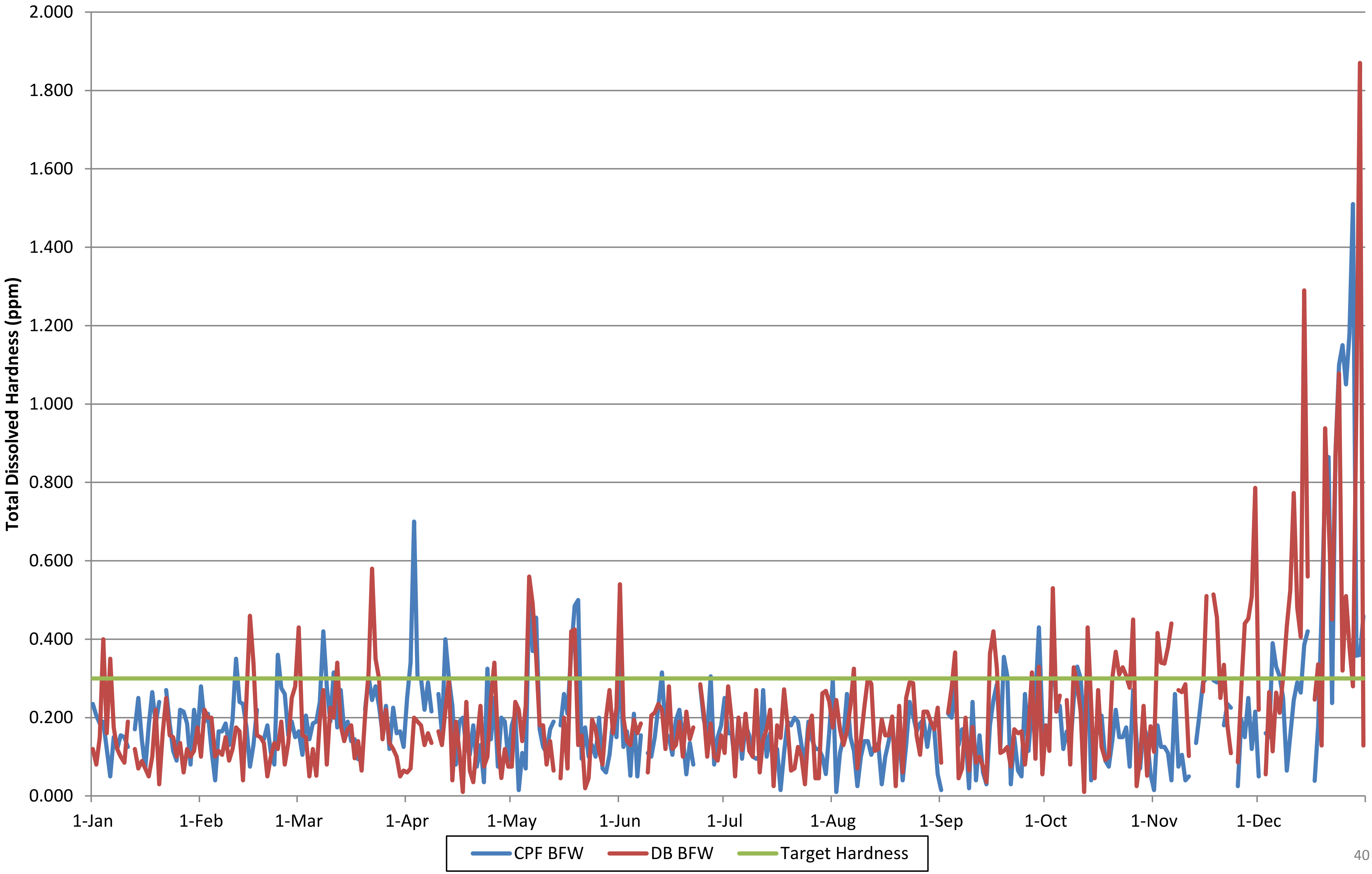
- **Mixed Bed Polishers**
  - Mixed bed polishers internal damage on interface laterals causing resin losses
  - Temporary repair complete to reduce resin losses; project in progress to install new interface laterals for permanent fix during 2015 Turnaround

- **HQWS Analyzers**
  - Additional analyzers installed in HQWS to better control chemical injection and improve feed to RO
  - Commissioning and automation for the HQWS analyzers to be completed in future

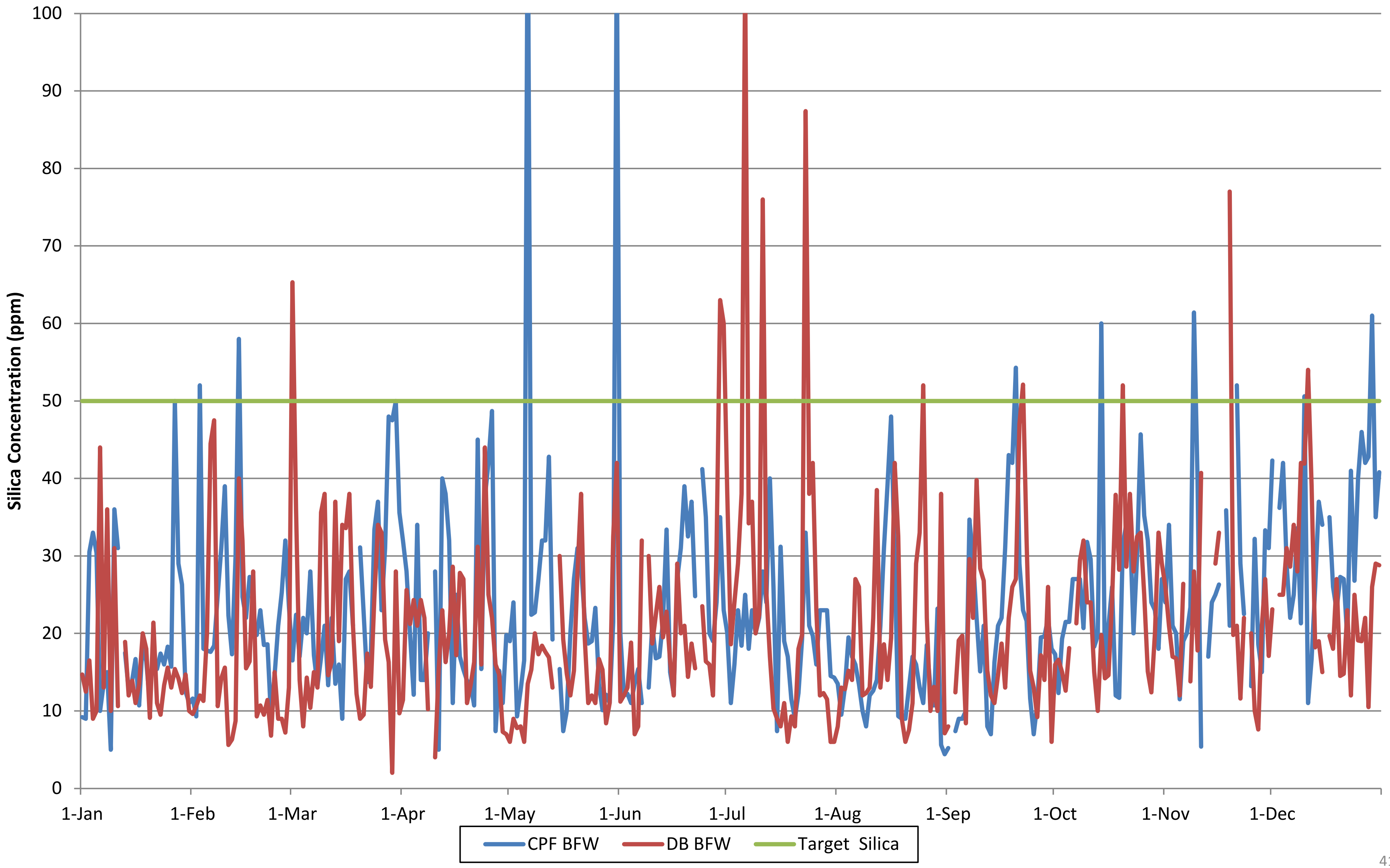
Turbidity in Boiler Feed Water



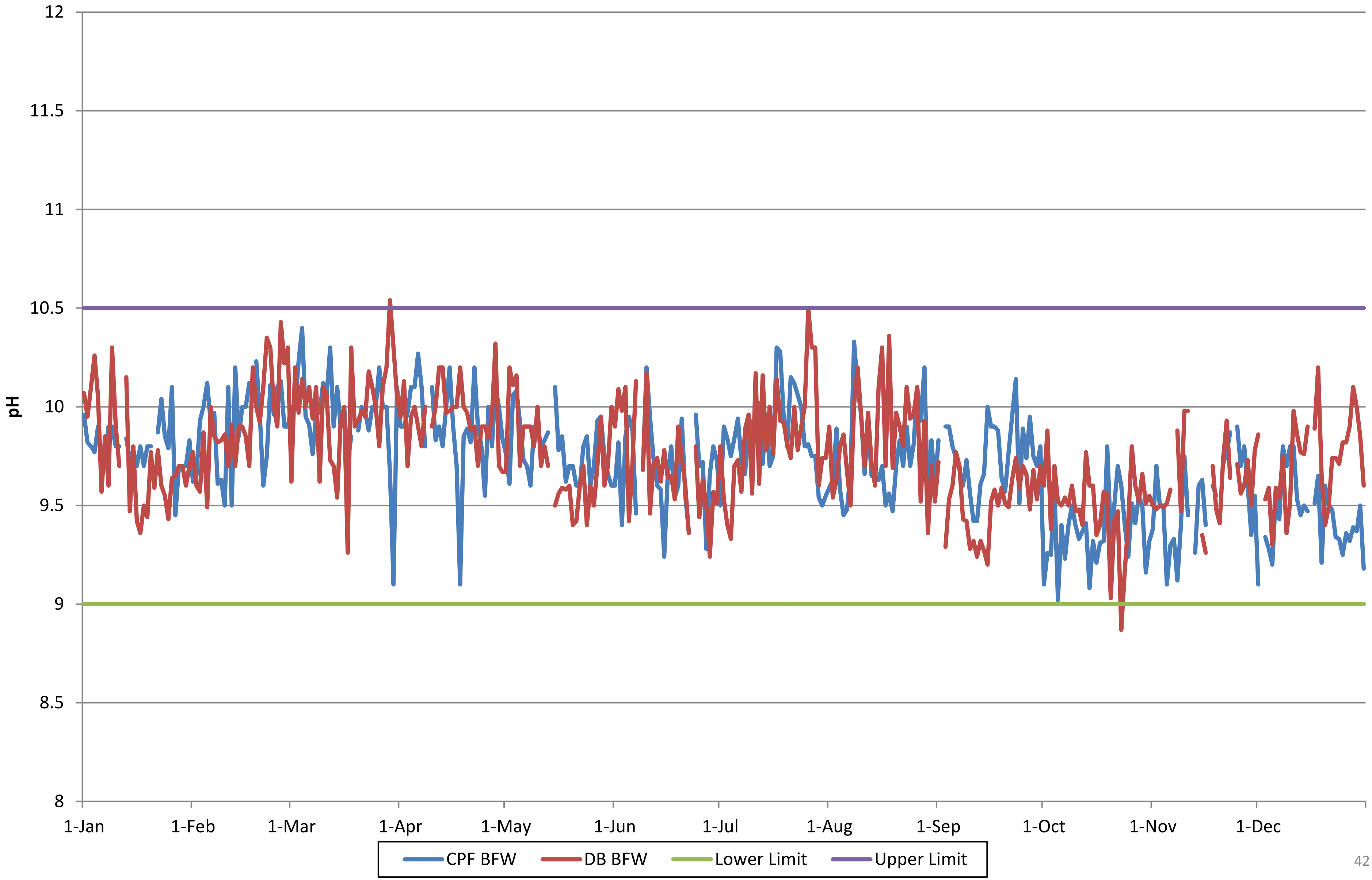
Total Dissolved Hardness In Boiler Feed Water



Silica In Boiler Feed Water



pH for Boiler Feed Water



Volume Measurement and Reporting

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 the well test a longer duration for monitoring S&W profiles.
  - Bitumen cuts are based on an inline water cut analyzer (AGAR meter) and manual cuts are taken for confirmation.
- All ten wells on Pad 11 receive continuous well testing via individual coriolis flow measurement and AGAR water cut meters.
- Multiphase flow meters installed on Pads 14 & 15 and K1A.
- Bitumen samples collected from emulsion line are analyzed by Long Lake Lab and 3rd Party lab to determine density as requested by Department of Energy.

Steam Injection Measurement

- Steam injection is measured at the wellhead (estimating steam quality of 95% at the wellhead).
  - Nexen accurately 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. These vortex meters with a steam condensate trap upstream have given the most accurate trend of actual plant output. Through 2014 these meters were inspected, cleaned and calibrated. All wellhead meters have preventative maintenance schedule to maintain the accuracy as per MARP.
- Two V-cone meters were installed for steam measurement at CPF during 2012 turnaround (8400-FIT-510,8400-FIT-518).

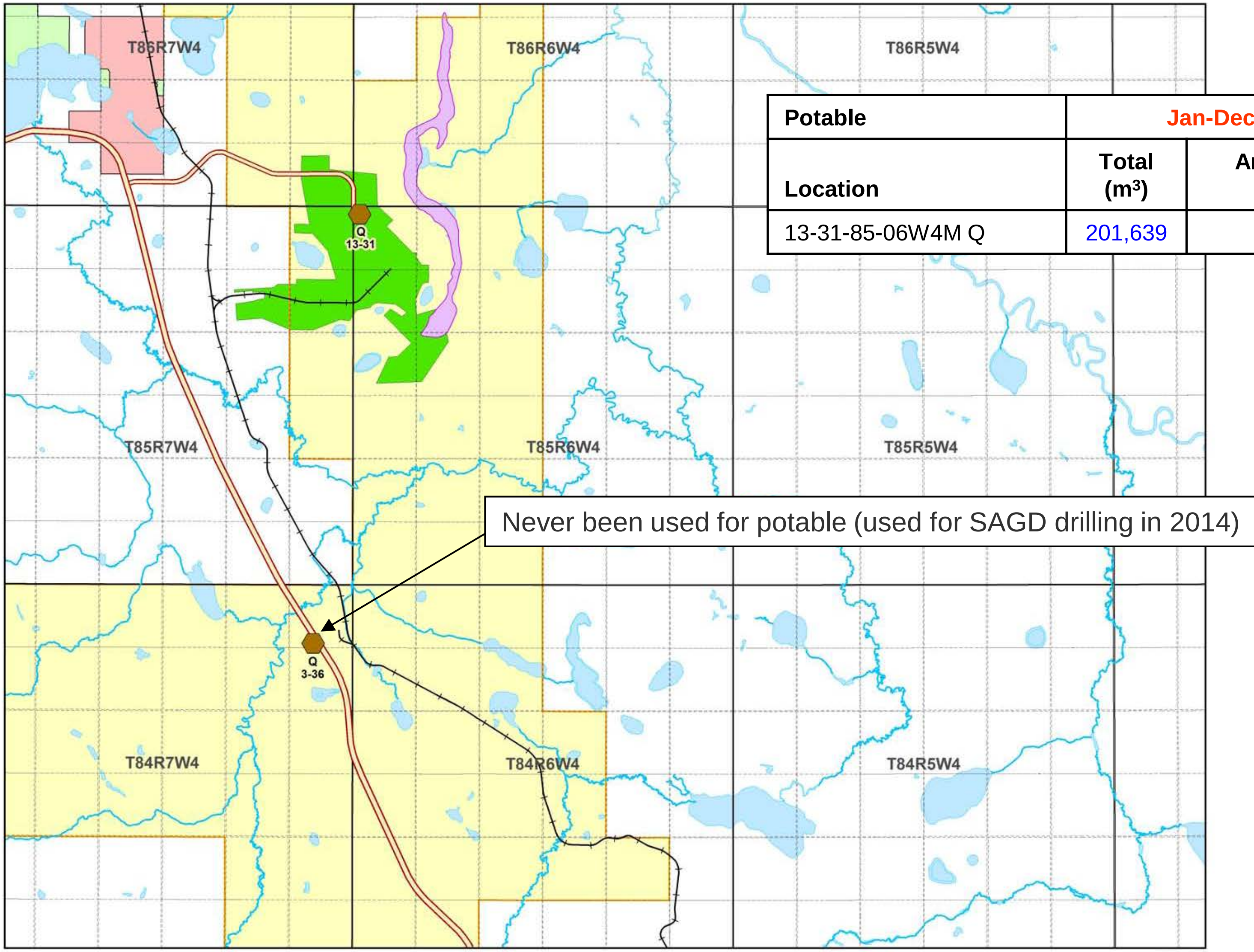
Produced Bitumen and Water Measurement

Proration Factors

	OIL	GAS	WATER
Jan	0.88862	6.11645	0.92670
Feb	0.92045	8.13304	0.88479
March	0.90985	6.42687	0.88804
April	0.87712	5.46922	0.90581
May	0.84712	5.57744	0.91318
June	0.87523	5.25845	0.94228
July	0.88836	5.69410	0.94814
August	0.85256	6.94934	0.90956
Sept	0.92527	7.15486	0.90103
October	0.88353	6.03378	0.97200
November	0.85216	3.13596	0.97422
December	0.85402	4.02812	1.01620

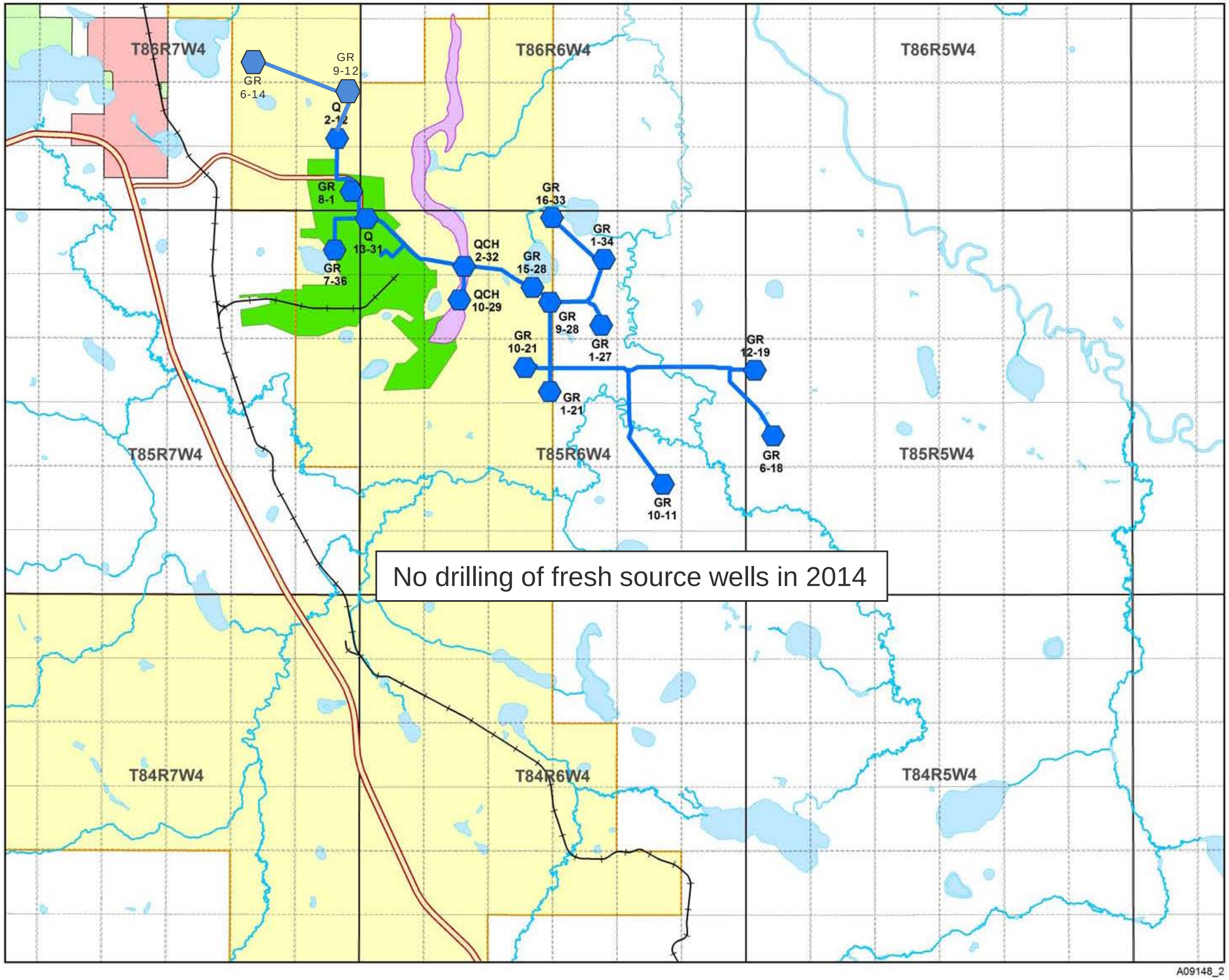
Water Production, Injection & Uses

Potable Well



Potable	Jan-Dec 2014	
Location	Total (m^3)	Annual avg. (m^3/cd)
13-31-85-06W4M Q	201,639	552

Freshwater Pipeline

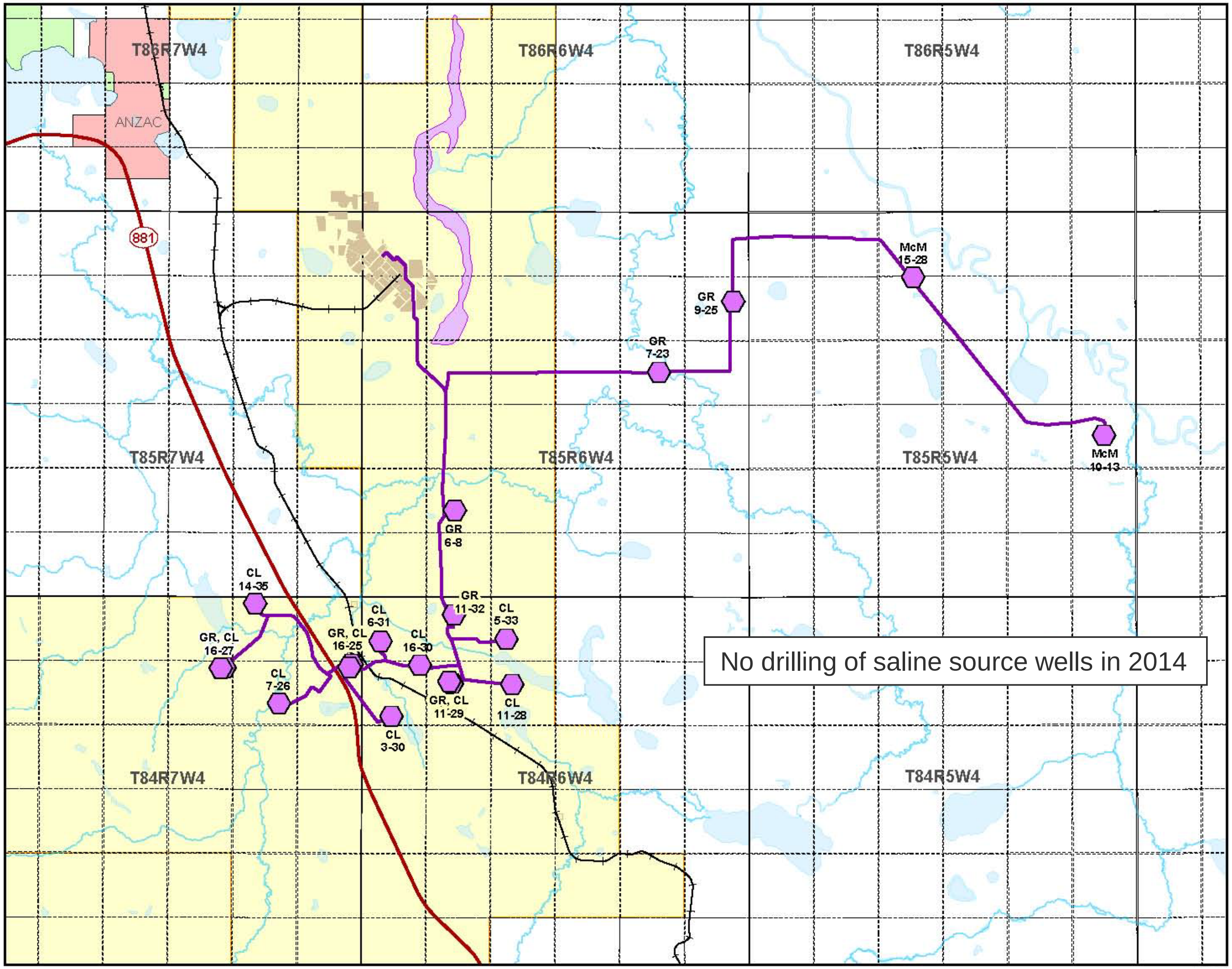


Freshwater Pipeline (CONT'D)

Plant Operations	AENV# 235895-01-00		Jan-Dec 2014	
Location	**Formation**	**Fresh?**	**Total (m3)**	**Annual avg. (m3/cd)**
01-21-85-06W4M GR	Grand Rapids	Y	125,729	344
01-27-85-06W4M GR	Grand Rapids	Y	207,022	567
01-34-85-06W4M GR	Grand Rapids	Y	117,392	322
02-12-86-07W4M Q	Quaternary	Y	315,144	863
02-32-85-06W4M QC	Gregoire Channel	Y	0	0
06-14-86-07W4M GR	Grand Rapids	Y	108,464	297
06-18-85-05W4M GR	Grand Rapids	Y	0	0
07-36-85-07W4M GR	Grand Rapids	Y	334,418	916
08-01-86-07W4M GR	Grand Rapids	Y	3	0
09-12-86-07W4M GR	Grand Rapids	Y	230,686	632
09-28-85-06W4M GR	Grand Rapids	Y	29,191	80
10-11-85-06W4M GR	Grand Rapids	Y	345,935	948
10-21-85-06W4M GR	Grand Rapids	Y	83,172	228
10-29-85-6W4M QC	Gregoire Channel	Y	35,873	98
12-19-85-05W4M GR	Grand Rapids	Y	165,898	455
13-31-85-06W4M Q	Quaternary	Y	0	0
15-28-85-06W4M GR	Grand Rapids	Y	159,211	436
16-33-85-06W4M GR	Grand Rapids	Y	53,124	146
License Allocation 3,285,000 m3 (annual daily average of 9,000 m3/d)		**TOTAL**	2,311,262	6,315

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water.

Saline Water Pipeline

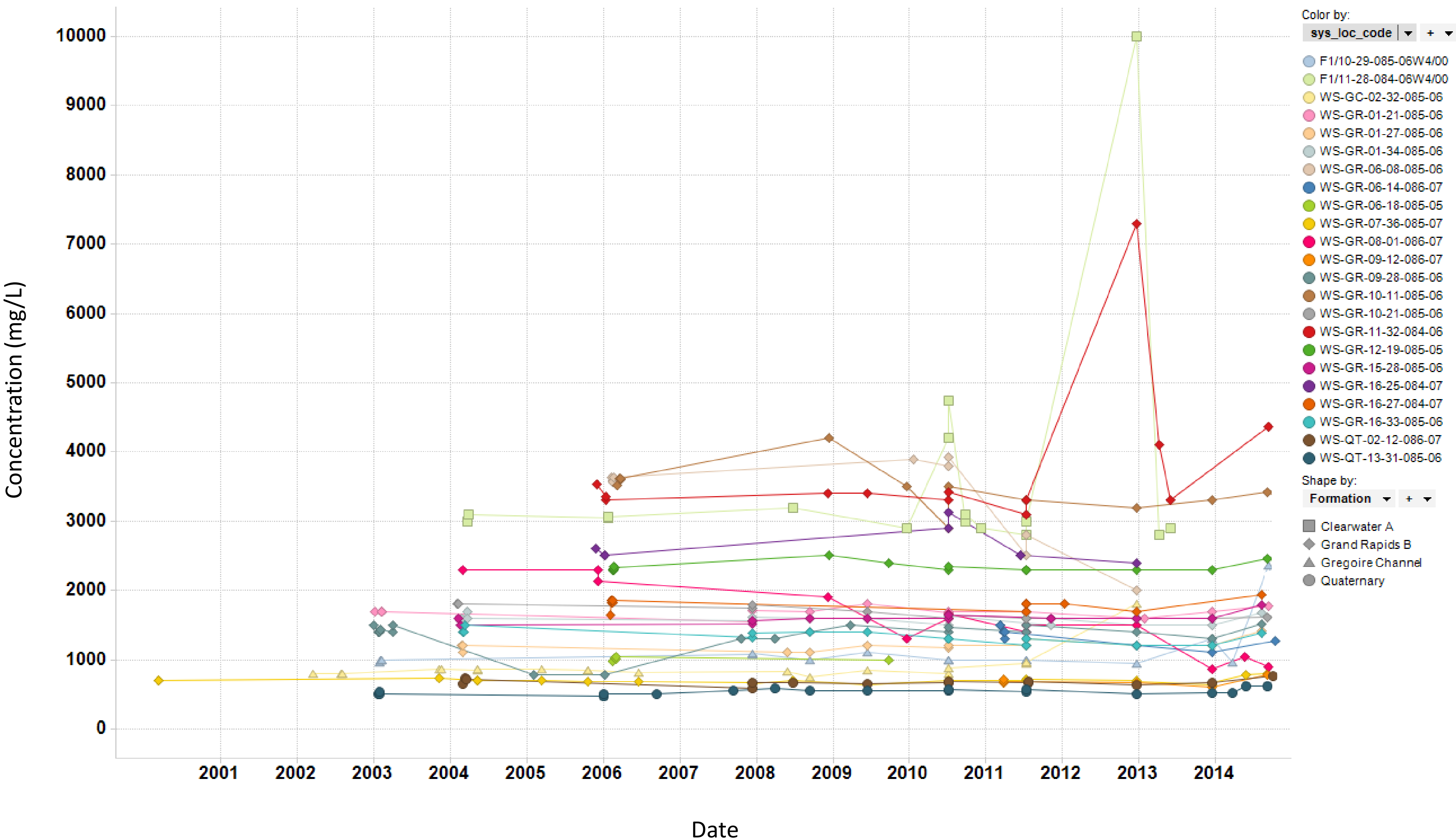


Saline Water Pipeline (CONT'D)

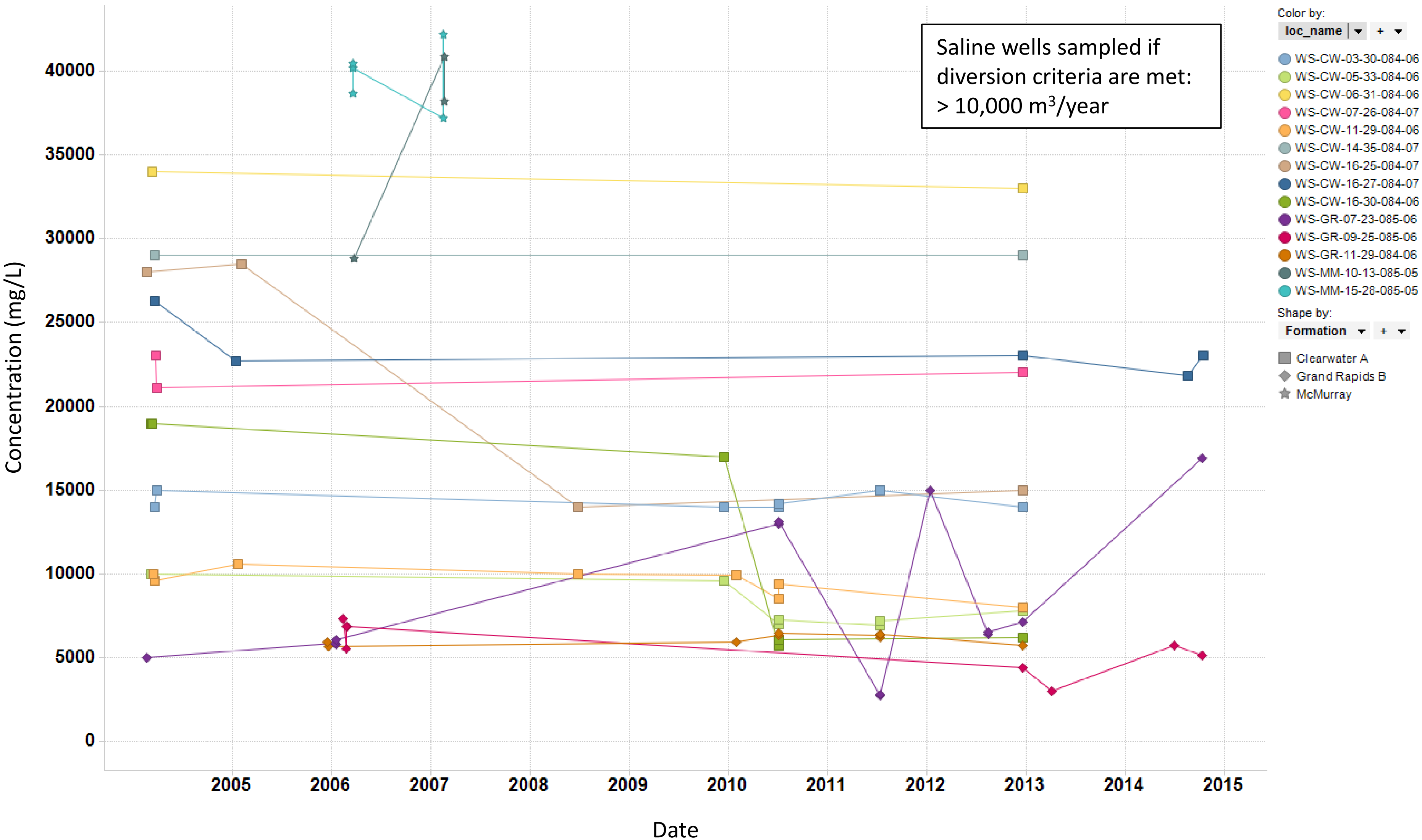
Plant Operations			Total Dissolved Solids		Jan-Dec 2014	
Location	**Formation**	**Saline?**	**Sample Date**	**Concentration (mg/L)**	**Total (m3)**	**Annual avg. (m3/cd)**
1F2033008406W400	Clearwater	Y	19-Dec-12	14,000	15,109	41
1F1053308406W400	Clearwater	Y	19-Dec-12	7,800	8,584	24
1F1063108406W400	Clearwater	Y	19-Dec-12	33,000	0	0
07-23-85-06W4 GR	Grand Rapids	Y	09-Oct-14	16,900	6,825	19
1F1072608407W400	Clearwater	Y	19-Dec-12	22,000	39,925	109
09-25-85-06W4 GR	Grand Rapids	Y	09-Oct-14	5,130	0	0
1F1101308505W400	McMurray	Y	18-Feb-07	38,200	0	0
1F1112908406W400	Clearwater	Y	19-Dec-12	8,000	11,264	31
11-29-84-06W4 GR	Grand Rapids	Y	19-Dec-12	5,700	0	0
1F1143508407W400	Clearwater	Y	19-Dec-12	29,000	0	0
1F1152808505W400	McMurray	Y	14-Feb-07	42,200	0	0
1F1162708407W400	Clearwater	Y	16-Oct-14	23,000	163	0
1F1162508407W400	Clearwater	Y	19-Dec-12	15,000	1,388	4
1F1163008406W400	Clearwater	Y	19-Dec-12	6,200	9,465	26
				Subtotal Saline Diverted Volume	*92,721*	*253*
06-08-85-06W4M GR	Grand Rapids	N	19-Dec-12	2,000	0	0
1F1112808406W400	Clearwater	N	30-May-13	2,900	20	0
11-32-84-06W4M GR	Grand Rapids	N	09-Sept-14	4,360	1,095	3
16-25-84-07W4 GR	Grand Rapids	N	19-Dec-12	2,400	0	0
16-27-84-07W4 GR	Grand Rapids	N	07-Aug-14	1,940	2,288	6
				Subtotal Fresh Diverted Volume	*3,403*	9
				TOTAL VOLUME DIVERTED	96,125	263

- 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.

Fresh Water Source Wells Water Quality TDS



Saline Source Wells Water Quality TDS



Other Water Sources

- Surface runoff to lime sludge ponds (00247843-00-00)
  - 2014: 201,725 m^3 (estimate)

- Corehole and SAGD drilling
  - Various TDLs: 102,128 m^3 in 2014
    - Includes volumes from WS Q 03-36-084-07W4: 1,390 m^3 in 2014
    - Estimate includes 100% of water used in 2014 calendar year

Water Make-up

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

	Freshwater Uses in 2014			
	total	domestic	SAGD	UPG
main groundwater license (235895)	2,509,480	201,639	587,026	1,720,815
Surface runoff to ponds	201,725		201,725	
SAGD drilling	2,320		2,320	
Winter drilling program (Long Lake and Kinosis)	99,808		99,808	
Potable trucked to Long Lake	2,160		2,160	
TOTAL	**2,815,493**	**201,639**	**893,039**	**1,720,815**

- Saline water make-up:

  99,777 m^3 in 2014 for steam make-up (HLS's)

Water Management Metrics

WATER RECYCLE

- RECYCLE % $\frac{\text{[steam injection to the reservoir – freshwater portion of that steam injection]}}{\text{(produced water from the reservoir)}}$ *100

- 2014 recycle rate: 76.4%

- Small amounts of freshwater to SAGD for steam generation.
- Continued implementation of water conservation practices.
- Reservoir gains correlate with recycle rate.
- Nexen is committed to prudent water use and to achieving the highest water recycle rate practical.

WATER DISPOSAL

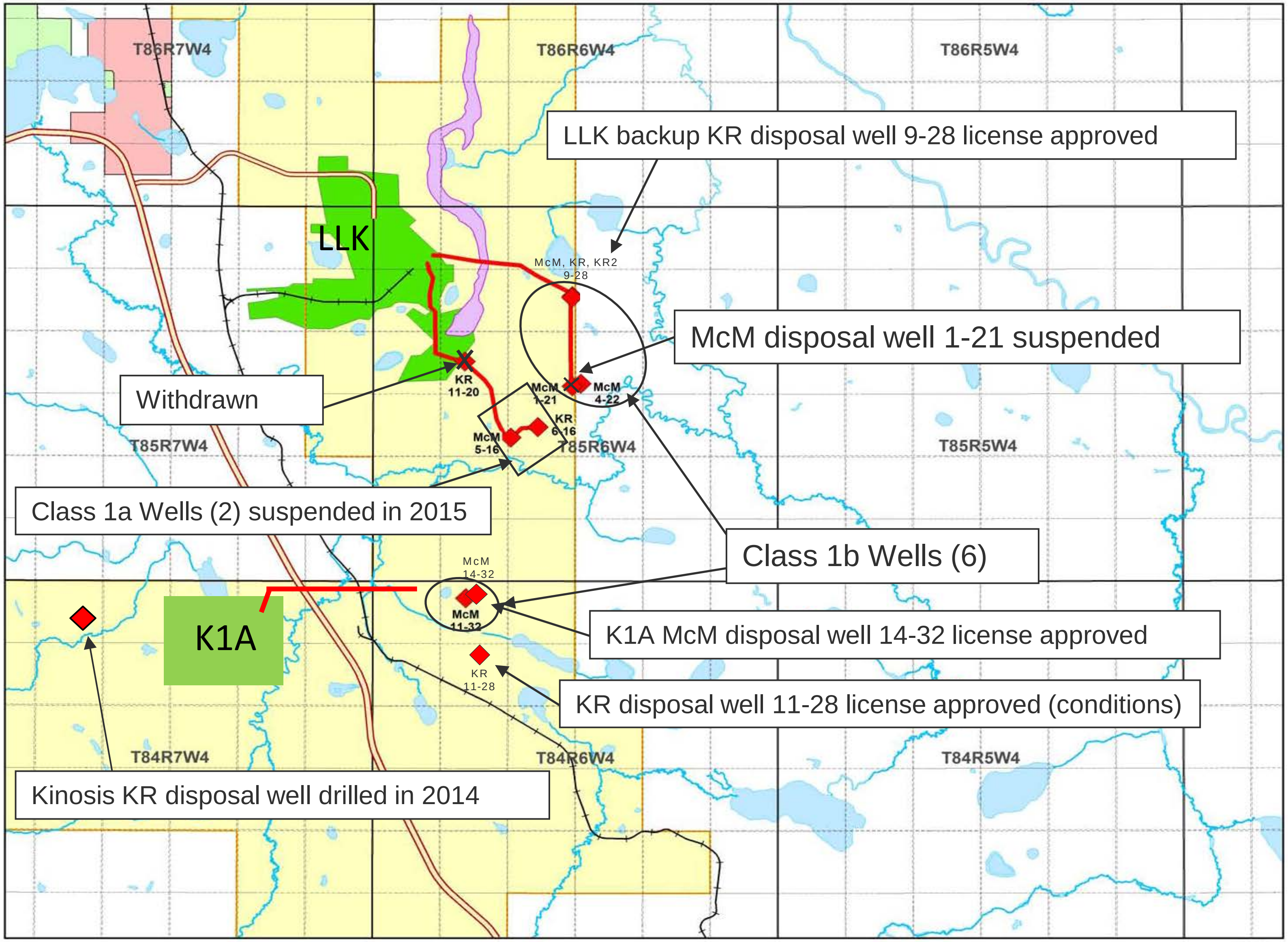
- Disposal limit (%) = $\frac{\text{[(Freshwater In*0.03) + (Brackish water In *0.35) + (Produced water In*0.1)]}}{\text{[(Freshwater In) + (Brackish water In) + (Produced water In)]}}$*100

- Disposal limit = 9%
- 2014 disposal rate = 10.4%
- Nexen's disposal rate includes freshwater demand to the upgrader

WATER TO STEAM RATIO (WSR)

- 2014 WSR = 1.11; monthly WSR ranged from 1.06 to 1.16

Disposal Wells



Disposal Wells (CONT'D)

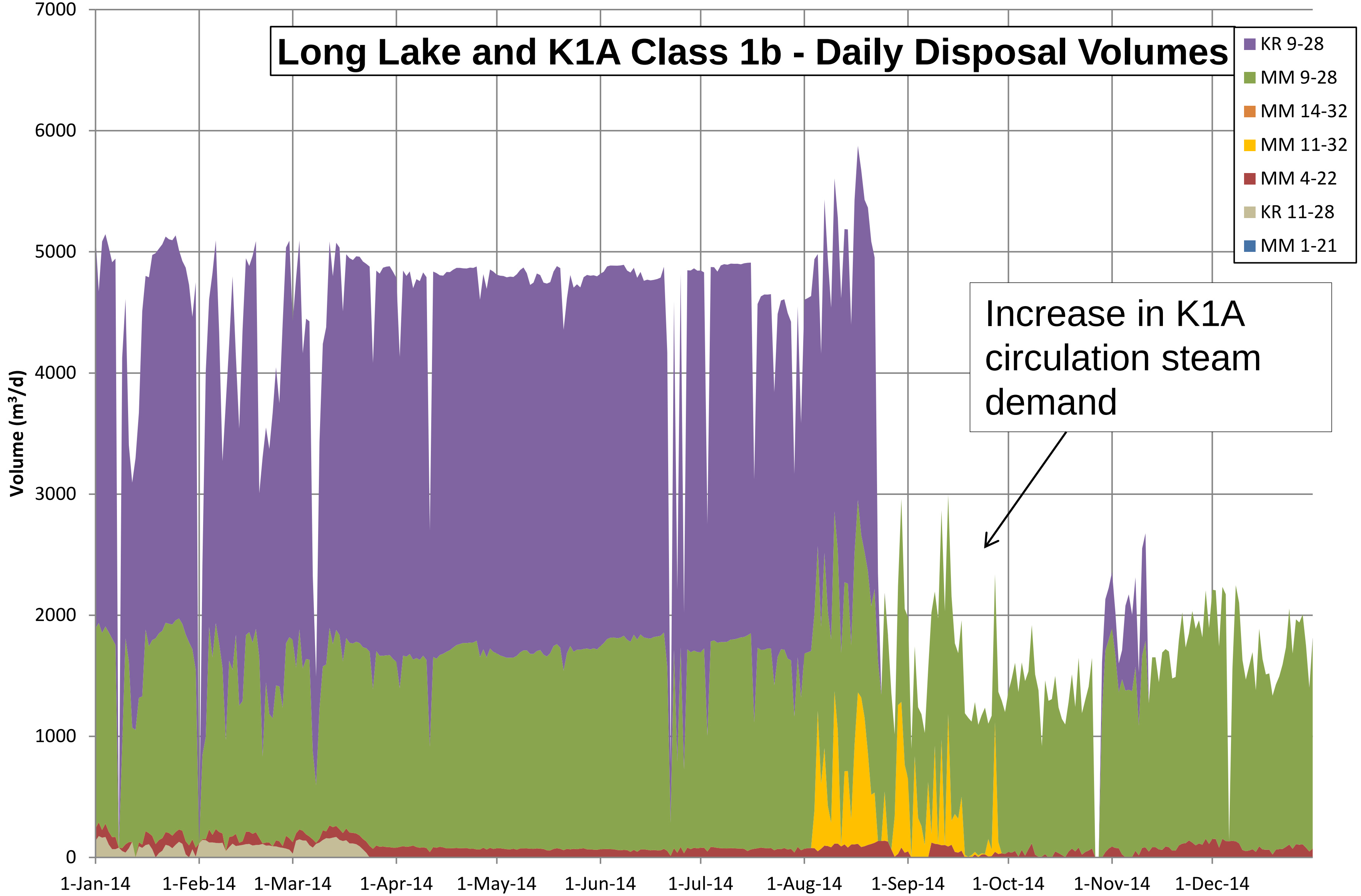
Approval # 10023F	Class 1b	January - December 2014		
Disposal Well		Total (m^3)	Annual avg. (m^3/cd)	WHP (kPag)
103/09-28-085-06W4 KR	Blowdown	682,411	1,869	1,247
100/09-28-085-06W4 McM	Blowdown	544,817	1,492	2,110
100/01-21-085-06W4 McM*	Blowdown	0	0	-
100/04-22-085-06W4 McM	Blowdown	25,531	70	2,569
100/11-32-084-06W4 McM	Blowdown	25,129	69	Est. 3,500
100/14-32-084-06W4 McM	Blowdown	0	0	-
100/11-28-084-06W4/00 KR	Drilling fluids	8,160	22	2,890
	Total	1,286,048	3523	
Approval # 11611	**Class 1a**	January - December 2014		
Disposal Well		Total (m^3)	Annual avg. (m^3/cd)	WHP (kPag)
100/06-16-085-06W4 KR**	-	0	0	-
100/05-16-085-06W4 McM**	-	0	0	-
	Total	0	0	-

*Well is suspended

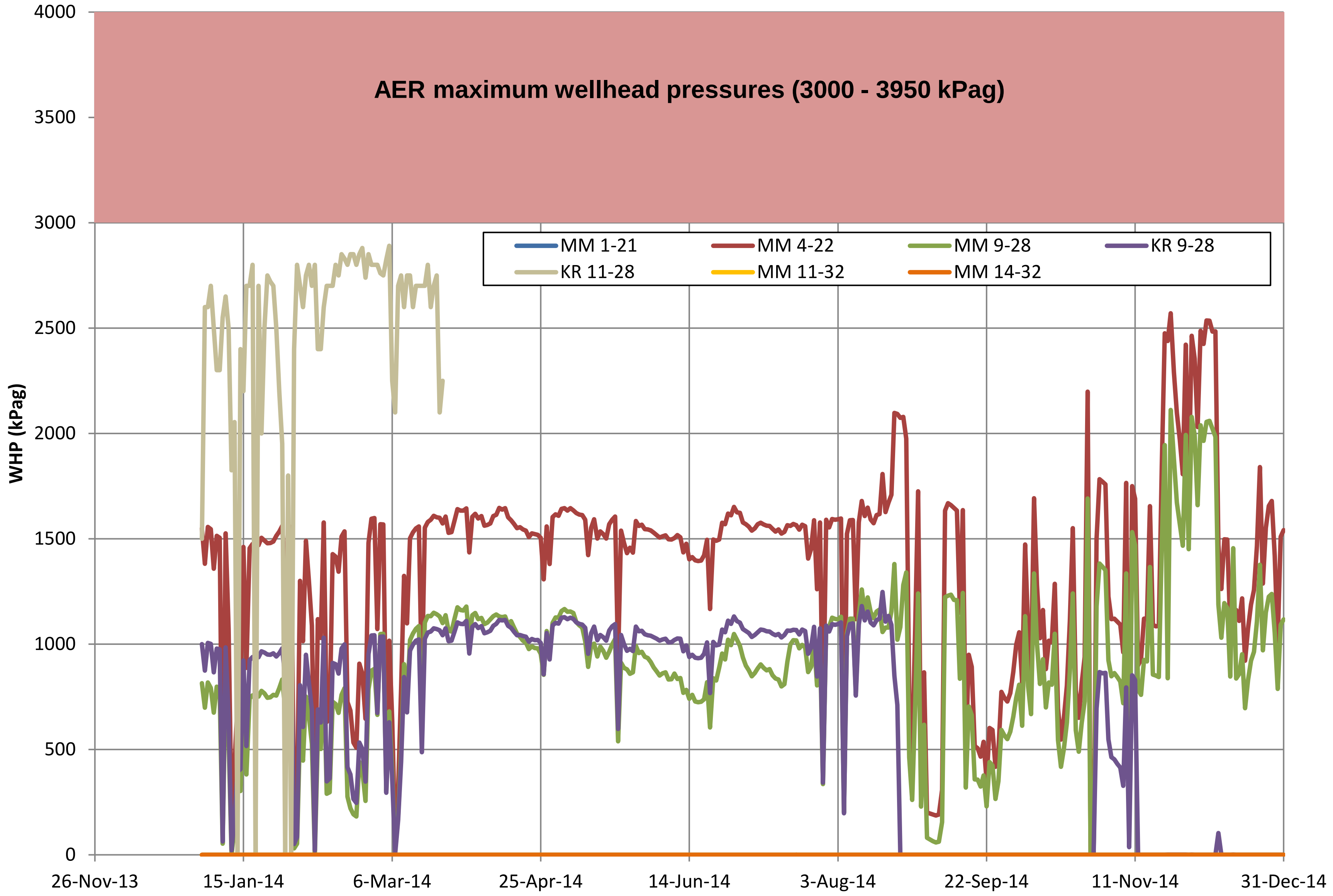
**Well is suspended in 2015

- Reservoirs (McMurray and Keg River) performing well
- Average temperature of disposal water is ~50°C
- All wells passed annulus pressure test

Disposal Well Volumes



Disposal Well - Well Head Pressures



Sulphur Recovery

Sulphur Recovery Overview

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

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

Sulphur Recovery Overview (Continued)

4. **SRU Subsystem**
   - The SRU Subsystem converts sulphur contaminants (mainly H2S) flowing from the Amine Regeneration, Selexol Regeneration, and Sour Water Stripping Subsystems into liquid sulphur. The subsystem is also designed to destroy ammonia;
5. **Tail Gas Treating Unit (TGTU) Subsystem**
   - The TGTU Subsystem is designed to convert any sulphur contaminants in the tail gas flowing from the SRU Subsystem back into H2S so that the H2S can be removed by amine solution in the TGTU Absorber. Any remaining sulphur contaminants in the tail gas are oxidized in the incinerator before it is released to atmosphere; and
6. **Miscellaneous Utilities Subsystem**
   - The Miscellaneous Utilities Subsystem contains the acid gas flare and associated equipment, a natural gas heater, and various condensate collection drums, condensate blowdowns, flash drums, etc., that are necessary for the operation of the sulphur recovery systems.

SO_2 Emissions

2014 SO2 Emissions (tonnes)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
FLARE													
SAGD													
SAGD Flare	0.160	0.086	0.125	0.200	0.098	0.106	0.100	0.113	0.048	0.027	0.271	0.198	
SAGD Total	0.160	0.086	0.125	0.200	0.098	0.106	0.100	0.113	0.048	0.027	0.271	0.198	1.532
Upgrader													
Upgrader Hydrocarbon Flare	163.000	13.770	37.380	19.863	14.110	26.118	38.610	27.121	5.630	7.070	89.430	129.250	
Upgrader Acid Gas Flare	28.850	4.590	159.110	8.130	0.000	19.500	486.360	12.660	0.000	0.000	0.000	0.040	719.240
Upgrader Total	191.850	18.360	196.490	27.993	14.110	45.618	524.970	39.781	5.630	7.070	89.430	129.290	1290.592
Total Flare	192.010	18.446	196.615	28.193	14.208	45.724	525.070	39.894	5.678	7.097	89.701	129.488	1292.124
POWER HOUSE & BOILER STACKS													
SAGD													
Cogen 1	4.990	22.560	10.160	5.040	6.270	6.620	4.200	11.830	5.440	11.900	6.600	6.930	
Cogen 2	7.470	25.550	20.570	10.760	16.210	9.320	5.660	5.580	10.160	8.560	7.100	6.640	
OTSG A	3.860	15.920	8.380	4.910	5.000	5.960	3.110	4.940	3.650	5.050	3.940	3.770	
OTSG B	3.840	15.310	8.290	4.780	4.920	5.920	3.180	5.000	3.500	4.250	3.900	3.680	
OTSG C	3.840	15.970	8.510	4.040	7.120	5.910	3.150	5.040	3.510	4.960	3.860	3.750	
OTSG D	0.080	0.090	0.080	0.100	0.110	0.100	0.080	0.080	0.100	0.100	0.100	0.100	
OTSG E	2.320	1.940	1.930	2.770	3.640	1.480	1.050	1.600	1.420	1.560	1.500	1.180	
OTSG F	2.320	1.940	1.980	1.810	3.680	1.710	1.170	1.660	1.340	1.620	1.440	1.210	
SAGD Total	28.720	99.280	59.900	34.210	46.950	37.020	21.600	35.730	29.120	38.000	28.440	27.260	486.230
Upgrader													
N/A													
Upgrader Total	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Power House and Boiler Stacks Total	28.720	99.280	59.900	34.210	46.950	37.020	21.600	35.730	29.120	38.000	28.440	27.260	486.230
SRU INCINERATOR STACK	40.570	28.810	58.120	64.850	22.320	35.910	75.920	42.310	58.530	26.670	24.530	72.370	550.910
Grand Total	261.300	146.536	314.635	127.253	83.478	118.654	622.590	117.934	93.328	71.767	142.671	229.118	2329.264

- The sulphur recovery rate averaged 99.2% during 2014
- Incinerator Stack Quarterly Average SO_2 Limit = 15.6 tonnes per day
- Plant Annual Average SO_2 Limit = 18.42 tonnes per day
- 2014 Average SO_2 well below limits

	Quarter	Total (tonnes)	Average (tonnes/day)	Limit (tonnes/day)
Plant Annual Average	ALL	2329.264	6.382	18.42
SRU Incinerator Stack	1st	127.500	1.397	15.6
	2nd	123.080	1.349	
	3rd	176.760	1.937	
	4th	123.570	1.354	

Sulphur Recovery Rates and Unit Uptimes

	Items	Jan-14	Feb-14	Mar-14	Apr-14	May-14	Jun-14	Jul-14	Aug-14	Sep-14	Oct-14	Nov-14	Dec-14	Average
Claus Units	**% of Month Processing AG**	90.6%	100.0%	80.8%	95.2%	100.0%	94.0%	92.2%	85.3%	100.0%	100.0%	100.0%	100.0%	94.8%
Sulphur Recovery	**Monthly Recovery Rate (%)**	99.6%	99.9%	98.8%	99.7%	99.9%	99.8%	96.4%	99.6%	99.7%	99.9%	99.9%	99.7%	99.4%
	Quarterly Recovery Rate (%)	99.5%			99.8%			98.6%			99.8%			99.4%
	Average Inlet Sulphur (Tonnes/day)	286.8	415.2	283.3	382.8	396.9	374.4	253.8	241.7	318.5	381.4	371.1	367.9	339.5
	Average Monthly Sulphur Production (Tonnes/day)	285.6	414.6	279.8	381.6	396.5	373.5	244.6	240.8	317.5	381.0	370.7	366.7	337.7

Month	% Time TGTU in Operation
Jan-14	90.4%
Feb-14	100.0%
Mar-14	80.1%
Apr-14	92.2%
May-14	100.0%
Jun-14	93.8%
Jul-14	89.6%
Aug-14	84.1%
Sep-14	100.0%
Oct-14	100.0%
Nov-14	100.0%
Dec-14	100.0%

Acid Gas Flare Events Summary

Month	AG Sources			SWAG Sources		
	Duration (h)	Volume (Sm3)	SO2 (Tonnes)	Duration (h)	Volume (Sm3)	SO2 (Tonnes)
January	72.1	9510	11.7	74.4	140819	17.2
February	0.0	0.0	0.0	16.7	3008	4.6
March	149.4	97454	95.9	162.9	78136	63.2
April	35.7	3487	5.1	34.6	3581	3.1
May	0.0	0.0	0.0	0.0	0.0	0.0
June	45.9	9623	12.2	22.8	8512	7.3
July	71.6	25790	34.4	377.7	529582	451.9
August	120.0	11808	10.9	120.0	178196	1.7
September	0.0	0.0	0.0	0.0	0.0	0.0
October	0.0	0.0	0.0	0.0	0.0	0.0
November	0.0	0.0	0.0	0.0	0.0	0.0
December	0.0	0.0	0.0	120.0	178196	1.7
2014 Total	**494.6**	**157672**	**170.2**	**929.1**	**1120029**	**550.7**

Note: SWAG - Sour Water Acid Gas
AG - Acid Gas

- Total SO_2 flaring for 2014 was 720.9 tonnes.
- Acid Gas Flaring Events are part of the monthly report submitted to Alberta Environment and Sustainable Resource Development (AESRD).
- The leading cause for the major flaring events in 2014 was due to unplanned Upgrader trips and restarts.

Regulatory Compliance and Environmental Performance

Regulatory Compliance

- **Inspections:**
  - February 13, 2014 Follow-up to the Pad 14/15 pipeline failure
  - March 5, 2014 Follow-up to a spill reported by Nexen in the DRU
  - March 5, 2014 Follow-up to a uncontrolled run-off spill and Pad 14 flow line
  - August 15, 2014 Follow-up to the Pad 14/15 pipeline failure
  - August 15, 2014 Follow-up to the Pad 14/15 pipeline failure subsequent spill
  - December 20, 2014 Follow-up inspection in response to odour complaints from Anzac
  - December 22, 2014 Follow-up inspection in response to a spill/release incident which occurred on November 24 (fresh water line failure)

- **Compliance Actions:**
  - No compliance actions in 2014

Compliance Continued

- **Voluntary Self Disclosures:**
  - May 15, 2014
    - Nexen did not complete a DDS notification 48 hours prior to hydrotesting two pipelines as part of the commissioning activities for the Kinosis lease. Corrective action – Nexen informed AER of the event prior to activity and conducted additional education for staff .
  - June 1, 2014
    - Nexen reported to the AER an incident in which a hydrostatic pressure test of a new 14" steam pipeline resulted in the release of water into a containment tray. No release into the environment.
  - August 15, 2014
    - Nexen notified the AER of a downhole pressure exceedance in the toe producer of 14P03. Corrective action – steam injection decreased, alarms set on production well pressure.

Compliance Continued

- **Voluntary Self Disclosures Continued**
  - September 2, 2014
    - Nexen notified the Alberta Department of Energy and the AER of a penetration of Devonian mineral rights that occurred during the 2014 infill drilling program while drilling well 102/15-25-085-07W4. Alberta Energy waived the fine for trespass on the basis of complex geology. AER confirmed the matter was brought into compliance.
  - September 9, 2014
    - Nexen notified the Alberta Department of Energy and the AER of a penetration of Devonian mineral rights that occurred during the 2014 infill drilling program while drilling well 104/15-25-085-07W4/0. Alberta Energy waived the fine for trespass on the basis of complex geology. AER confirmed the matter was brought into compliance.
  - December 4, 2014
    - Nexen notified the AER of a downhole pressure exceedance in 15P02 producer. Corrective action– new procedure to reduce freezing of pressure gauges, redundant alarms set on injection and producer pressures.

AER Scheme Approval

- **Amendments received in 2014:**
  - Pad 11 Producer 10 Wellbore Re-entry – approved January 17, 2014
  - Pad 14/15 Monitoring Program – approved January 23, 2014
  - Well compatibility Pad 1& 2 at K1A – approved January 23, 2014
  - Gas Re-Pressurization Project at K2 – approved February 25, 2014
  - Pads 16, 17 and 18 – approved March 12, 2014
  - Long Lake Pad 7N Infill – approved May 16, 2014
  - Field Trial Co-Injection of NCG with Steam at Pat 7N – approved May 29, 2014
  - Field Trial Co-Injection of NCG with Steam at Pat 11– approved May 29, 2014
  - Kinosis Phase 1A - Well Compatibility Update – approved July 24, 2014
  - Trial Solvent Enhanced Circulation at Kinosis K1A – approved August 5, 2014
  - Long Lake Diluent Tank Project – approved October 21, 2014
  - Revised Gregoire Channel Edge Interpretation – approved February 26, 2014
  - Diluent Tank Project – approved October 21, 2014
- **Applications in review:**
  - Pad 19

Environmental Reportable Incidents

SPILLS		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Operations	1	0	1	0	0	2	0	1	1	1	3	2	**12**
	Projects	1	0	3	0	0	0	0	0	0	1	0	0	**5**
	Total	**2**	**0**	**4**	**0**	**0**	**2**	**0**	**1**	**1**	**2**	**3**	**2**	**17**

PERMIT VIOLATIONS		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
	Operations	3	4	6	1	1	0	5	2	2	2	3	4	**33**
	Projects	0	0	1	1	0	0	0	0	0	2	0	0	**4**
	Total	**3**	**4**	**7**	**2**	**1**	**0**	**5**	**2**	**2**	**4**	**3**	**4**	**37**

- During 2014 Long Lake and K1A had a total of 37 permit violations and 17 reportable spills previously reported to the AER.
- There was a significant decline in 2014 (37) as compared to 2013 (97) for total permit violations and this is largely due to the creation of a tool for control room operators to identify any potential risk of violating the limits and make changes in the process to eliminate that risk.

Reportable Spill Summary Operations

Material Released	Quantity (m3)	Brief Description
Water - Supernatant	3	Supernatant was spilled when the hose on the trash pump to the brackish header failed.
Magnesium Oxide	5	Faulty level transmitter caused Magox Slurry tank to overflow
Diesel Fuel	1.2	400 bbl tank set up near Pad 10 had diesel soaking in the bottom of the tank, diesel leaked from a manway that was not secured properly resulting in diesel being spilled
Water - Boiler Feed	19	A Pressure Safety Valve related to two Boiler Feedwater Coolers (8300-E001-A/B) released 19m3 of boiler Feedwater. Approximately 17m3 overflowed secondary containment and was captured by the onsite collection system and diverted to the Lime Sludge Pond.
Oil & Water Emulsion	3	Process Oily Water spill at Encanex centrifuge
Water - Boiler Feed	5	PSV on 8300-E-001 lifted and overflowed the containment, spilling boiler Feedwater on the ground
Water - Utility	17.1	WS-6-31 Brackish water well found with passing valve and leaking gasket on flange.
Diesel Fuel	0.513	Contractor forgot to close the air bleed valve of a fuel truck after purging the hose. When he resumed filling the second tank the diesel came out of the bleed line and flowed down the diesel tank.
Water - Boiler Feed	9.375	Heat tracing failure on HLS-C sample line caused the pipe to freeze and a gasket to leak.
Water - Boiler Feed	12	Overflow at Encanex centrifuge while worker was filling polymer mix tank.
Water - fresh groundwater	1425.6	Water was found bubbling up from the ground near water source well lines at plant boundary. Break was discovered after investigation.
Water - Produced	8	During a WAC Regen, water was found flowing out of the nitrogen vent.

Reportable Spill Summary
Project Development and Execution

Material Released	Quantity (m3)	Brief Description
Oil & Water Emulsion	7	During steam heating of ruptured line, 7m3 of oily water was released to ground.
Propane	0.12	Propane tank shifted from thawing ground conditions and caused a supply line to crack and release approximately 120L of propane for 30-60min into the atmosphere.
Hydraulic Fluid (mineral based)	0.01	While checking on the overflow pond on pad, employee noticed a puddle of hydraulic oil on the ground which in turn spilled on the surface of the pond. (Approximately 10L). Reported to AER based on adverse effect to surrounding run-off water.
Oil & Water Emulsion	2.5	Release of 5 m3 of produced fluid due to circulation valve failure in SUS building
Water - Steam Condensate Water - Boiler Blowdown	13 20	13m3 of LP Condensate and 20m3 of Concentrated Blowdown from the LP Steam Condensate Drum spilled to the ground and migrated into the storm water pond due to a leaking 6" valve.

Permit Violation Summary

- There were 17 hours (some during the same reportable event) during 2014 where stack approval limits were found to be exceeded based upon values measured by the CEMS units. These hours are summarized in the following table:

	OTSG C	OTSG E	Cogen 1	Cogen 2	Boiler A	Boiler B	SRU	SRU
	NOx	NOx	NOx	NOx	NOx	NOx	SO2	Temperature
January	0	0	0	0	0	0	0	6
February	0	0	0	0	0	2	0	2
March	0	1	0	0	1	2	0	1
April	0	0	0	0	0	0	0	0
May	0	0	0	0	0	0	0	0
June	0	0	0	0	0	0	0	0
July	0	0	0	0	0	0	0	1
August	0	0	0	0	0	0	0	0
September	0	0	0	0	0	0	0	0
October	0	0	0	0	0	0	0	0
November	0	0	0	0	0	0	0	0
December	1	0	0	0	0	0	0	0
Total	1	1	0	0	1	4	0	10

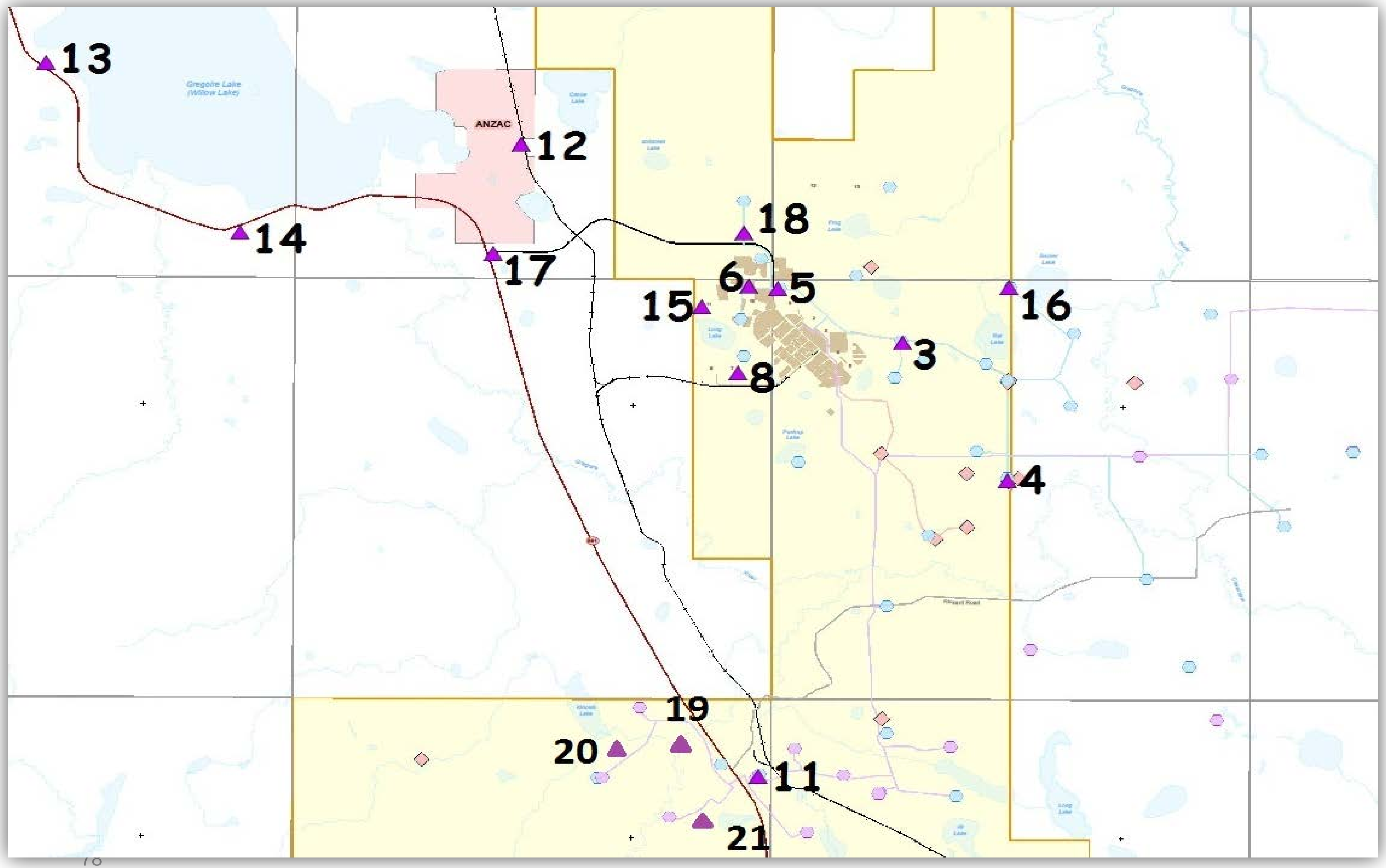
- The permit violations can commonly be attributed to stack temperature excursions in the SRU and NOx exceedances in Boiler B.

Continuous Air Monitoring

- The Long Lake continuous air monitoring station is located approximately 35 km southeast of Fort McMurray on the northern edge of the hamlet of Anzac and is operated by the Wood Buffalo Environmental Association.
- The Anzac Station contains analyzers that continuously measures SO_2, O_3, TRS, THC, NO, NO_2, NO_X, PM 2.5, wind speed and direction, and temperature.
- There were 4 events that exceeded the Alberta Ambient Air Quality Objectives (AAAQO). All of the events described below were attributed to the forest fires that were burning in the region at that time and did not require follow-up reports.

Date	Parameter	Concentration	Limit	AER Ref #
July 20, 2014	PM 2.5	40 µg/m3	30 µg/m3 24 hr avg	521043
July 21, 2014	PM 2.5	34 µg/m3		287108
July 22, 2014	PM 2.5	32 µg/m3		287170
August 5, 2014	PM 2.5	66 µg/m^3		287894

Passive Air Monitoring – Long Lake and K1A

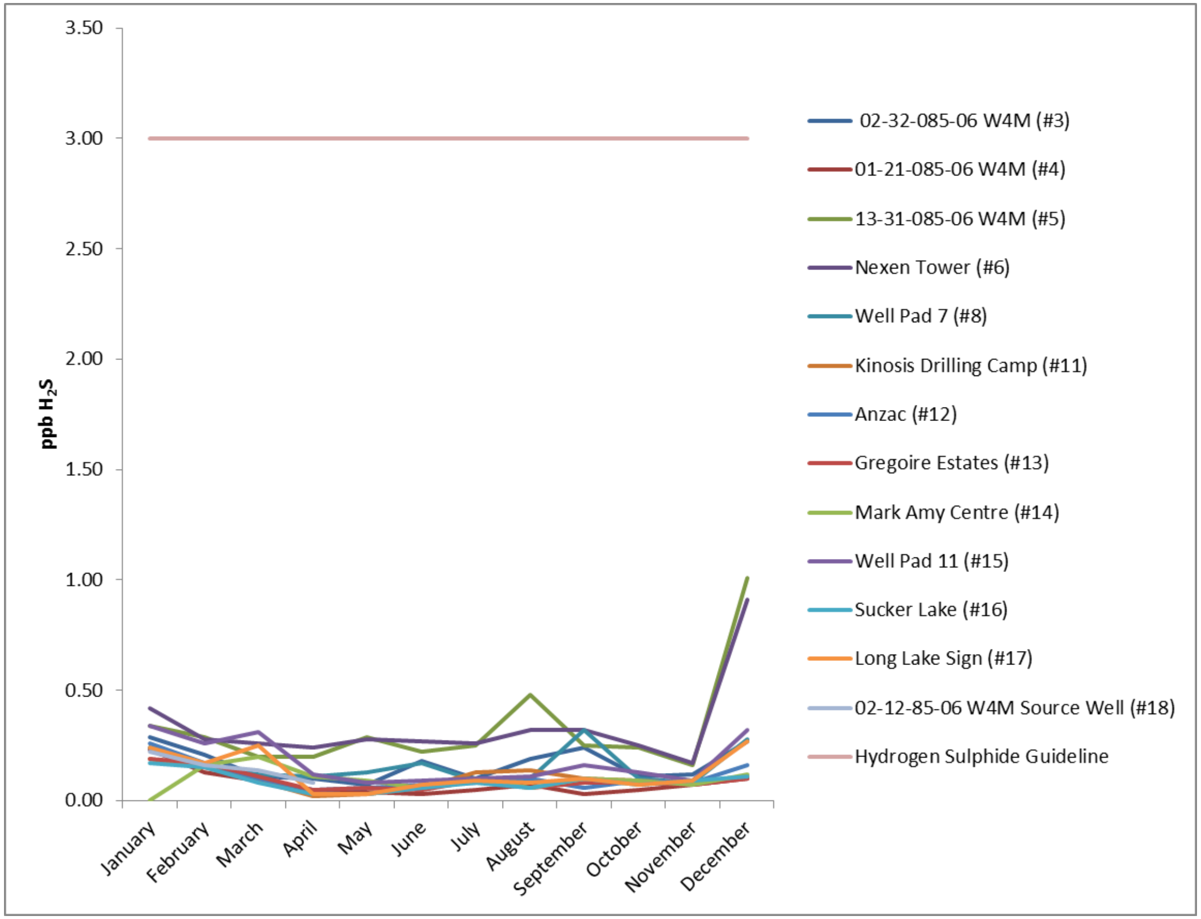


Passive Air Monitoring Station Summary

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

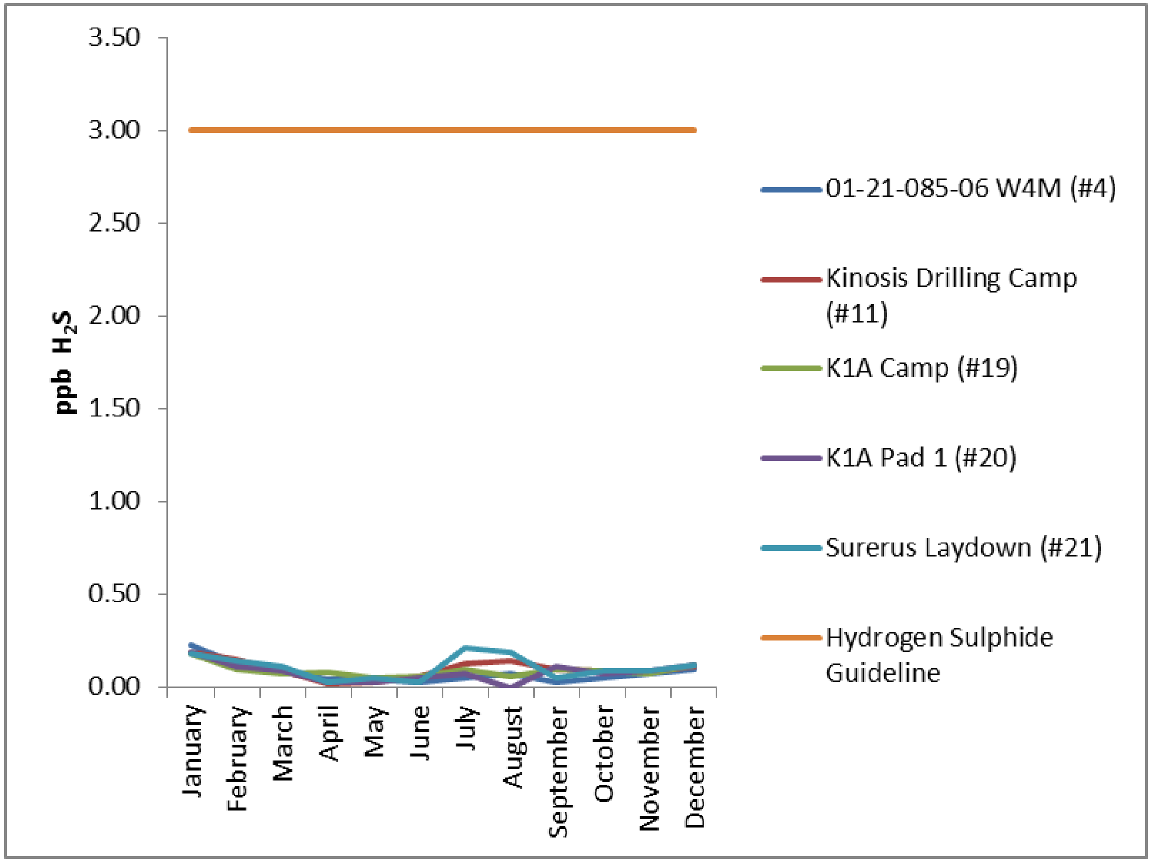
* K1A Passive Stations

Long Lake H_2S Passive Monitoring



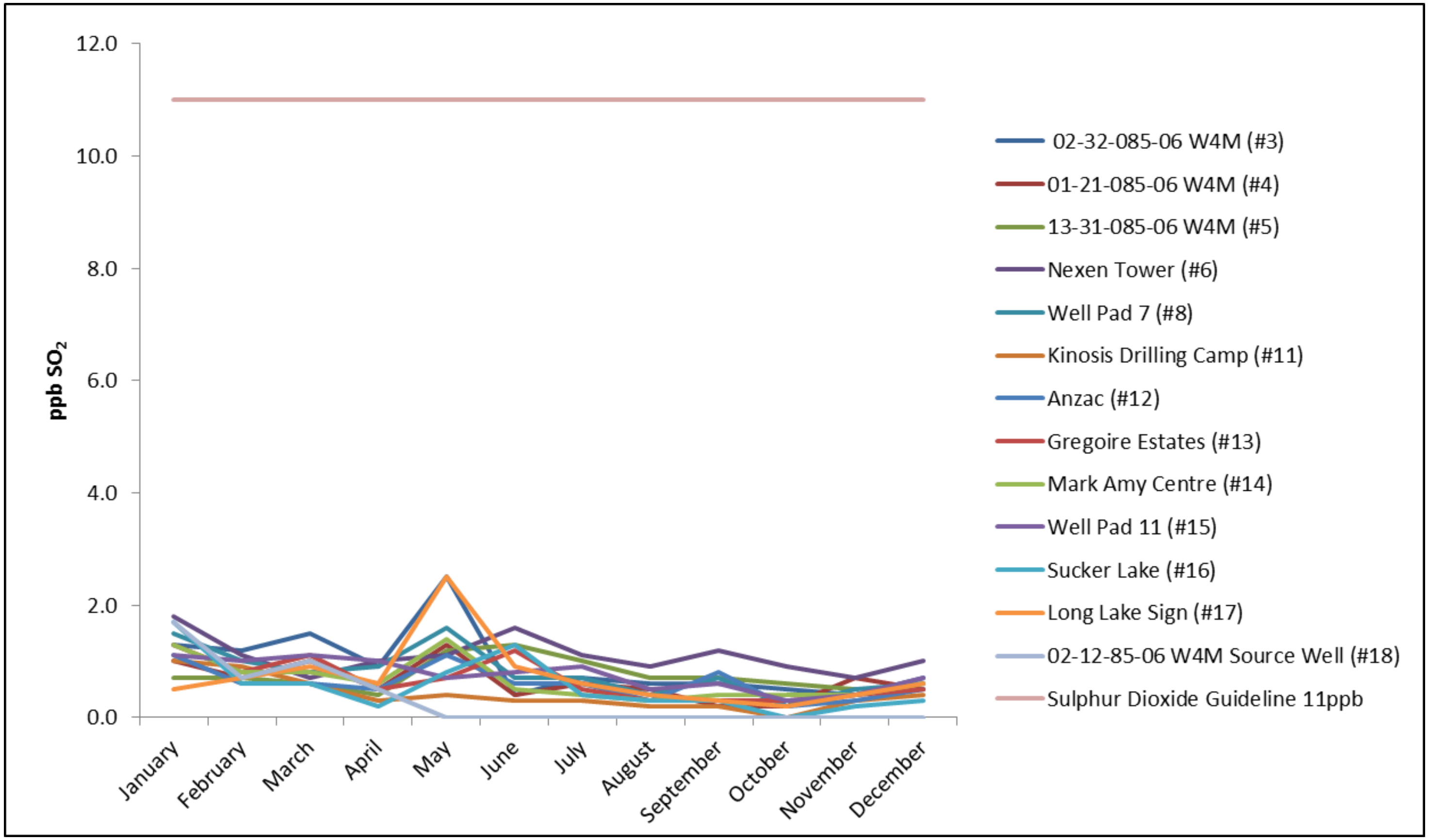
- The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.

K1A H_2S Passive Monitoring



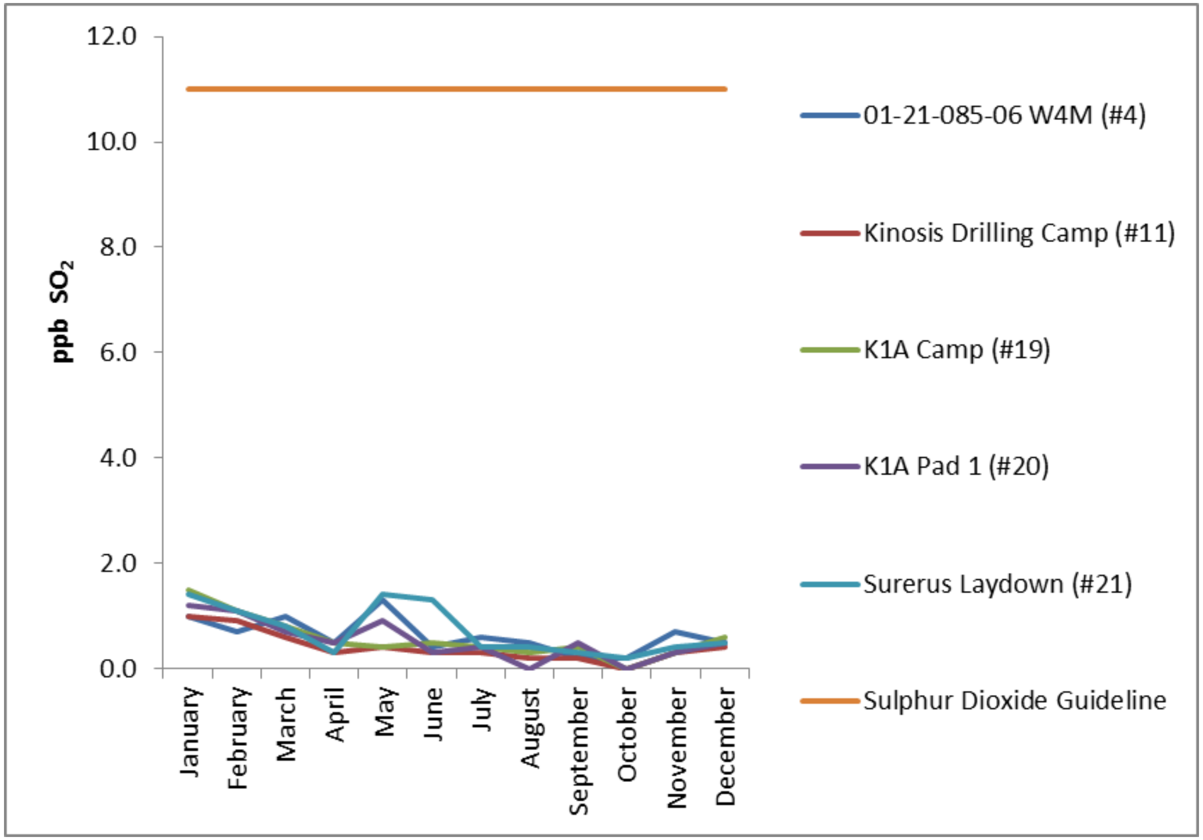
- The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.

Long Lake SO_2 Passive Monitoring



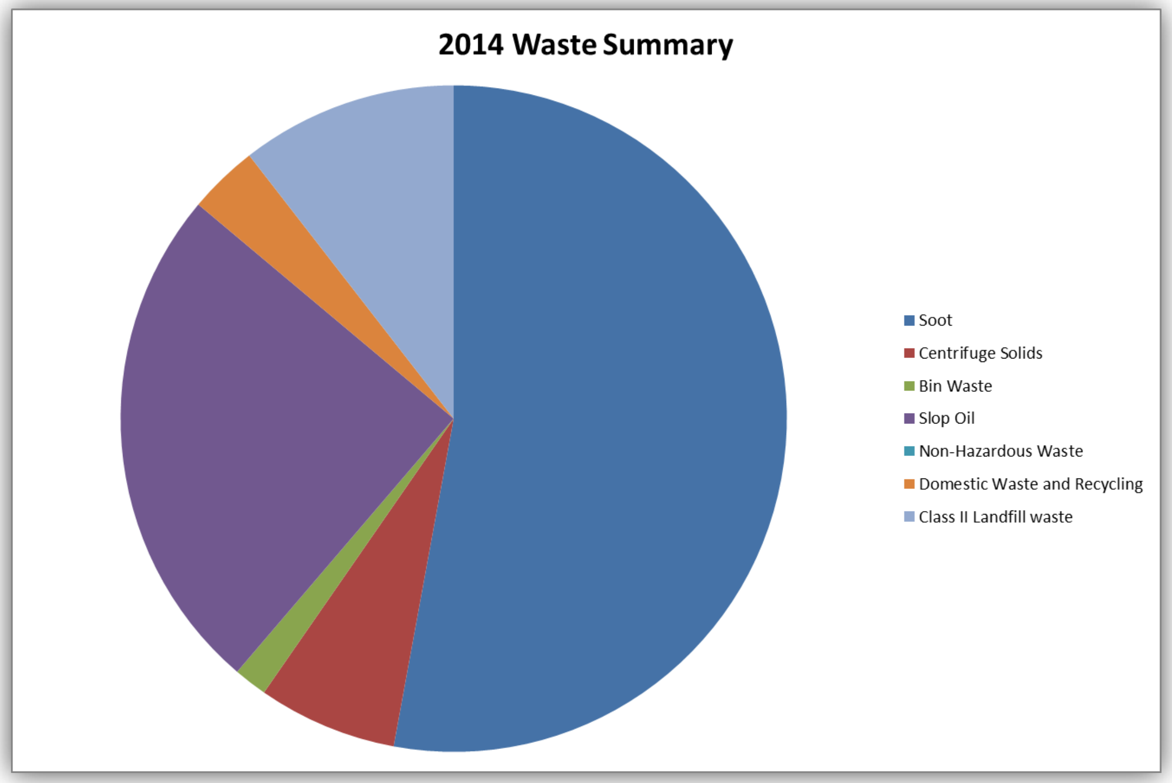
- The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.

K1A SO_2 Passive Monitoring



- The AAAQ Guidelines set out by AER for a 30-day average Static Sulphur Dioxide is 11 ppbv. In the absence of a 30 day average guideline for Hydrogen Sulphide Nexen uses, the Static Hydrogen Sulphide 24-hour average guideline of 3ppbv.

Waste Disposal



Hazardous Waste	tonnes
Soot	36110
Centrifuge Solids	4614
Bin Waste	1107
Slop Oil	16957
Total	**58788**
Non-Hazardous Waste	
Domestic Waste and Recycling	2312
Class II Landfill waste	7178
Total	**9490**
Grand Total	**68278**

Environmental Summary
Operational Initiatives

- Provided environmental event investigation and analysis support, which increased operation personnel's understanding of regulatory requirements and event causes.

- A change to Teflon gaskets to reduce potential odour issues
  - An investigation found tank PRV's and PVSV's wisping and repairs were initiated
  - The root cause analysis of the high frequency of failures determined that the gasket material on the PRVs was not compatible with naphtha
  - Nexen had been using both Naphtha and PSC as diluent and the standard had not been updated when Nexen switched to 100% naptha diluent
  - Teflon will be used in all on-going repairs and during the 2015 Turnaround Nexen will change out every gasket regardless of integrity

- Began shutting down the Sour Water Systems after Upgrader upsets or trips to reduce the amount of Sour Water Acid Gas sent to the flare. This action is only implemented from April to October when ambient temperature are above -5°C. A number of exceedances have been prevented with this action.

Environmental Summary
Monitoring Programs

- Conducted in accordance with regulatory approvals:
  - Groundwater monitoring
  - Hydrology and water quality monitoring
  - Soil monitoring
  - Wildlife monitoring
  - Wetland monitoring
  - Source emission and ambient air monitoring
  - Conservation and reclamation plans
- Funded the regional Joint Oil Sands Monitoring (JOSM)
- Participation in regional stakeholder committees:
  - Cumulative Environmental Management Association (CEMA)
  - Participation in the Wood Buffalo Environmental Association (WBEA)
  - Regional Aquatics Monitoring Program (RAMP)

Environmental Summary
Innovation, Research and 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 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.

- The Algar Restoration Pilot Project, a Nexen-led project through COSIA, won the Emerald Awards' Shared Footprints Award.
  - The project represents a collaboration between six oil sands companies, the province of Alberta and the local forestry industry and is actively restoring important caribou habitat.

Future Plans

Future Plans

- 2015 Turnaround
- Permanent lime centrifuge scheduled for installation and commissioning in second half of 2015
- Diluent Recovery Project (DRU) Start-up

Nexen Energy ULC
UPGRADER PERFORMANCE PRESENTATION

Purpose

This presentation contains information to comply with:

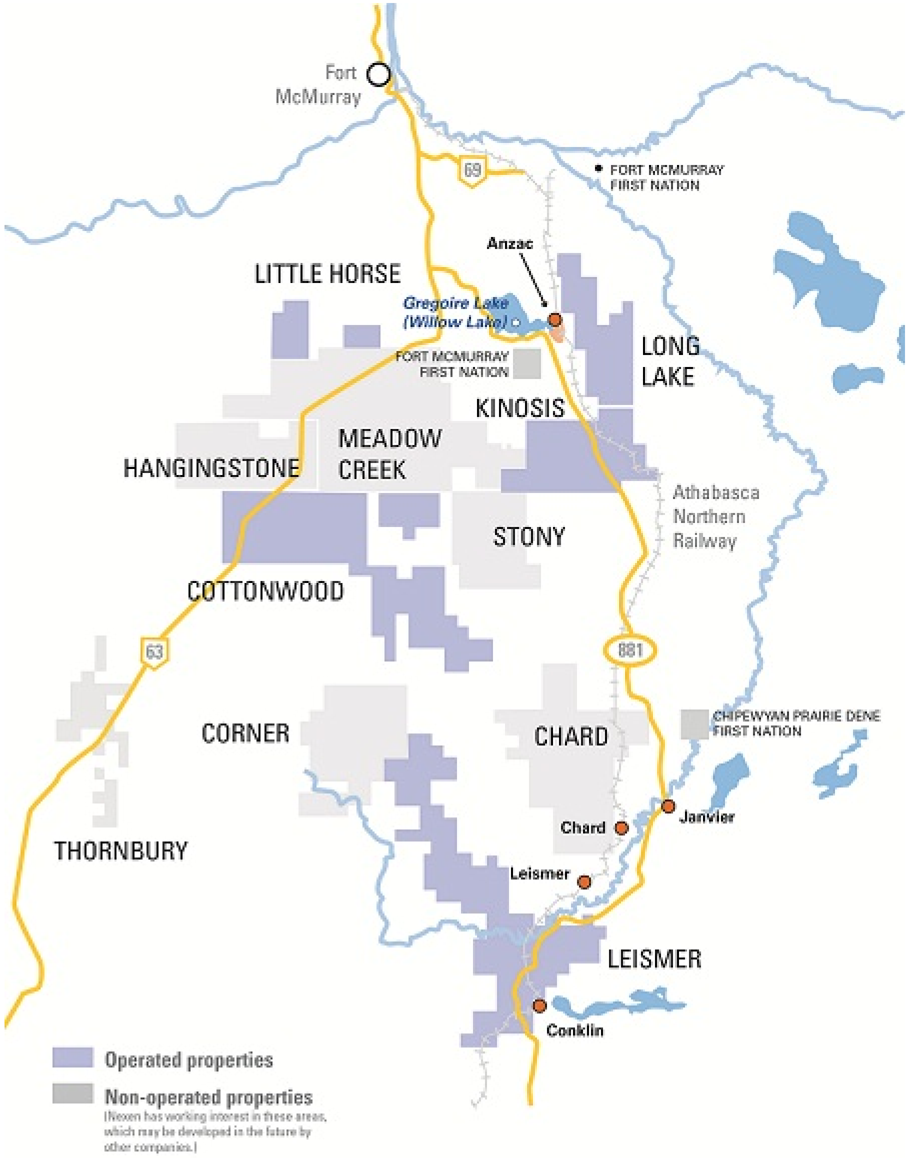
AER Scheme Approval No. 9485 (as amended)
Approval Condition No. 20

1. Discuss product yields and qualities and energy efficiency as compared with the design expectation
2. Results of any studies undertaken to identify opportunities for improved yield and energy efficiency
3. Description of any modifications made to improve yield and energy efficiency
4. Schedule to add facilities to convert the upgrader product (A-fuel) to sweet syngas for use as a replacement for natural gas in the Scheme.
5. Performance of the A-fuel gasification facilities and comparison with design expectations.

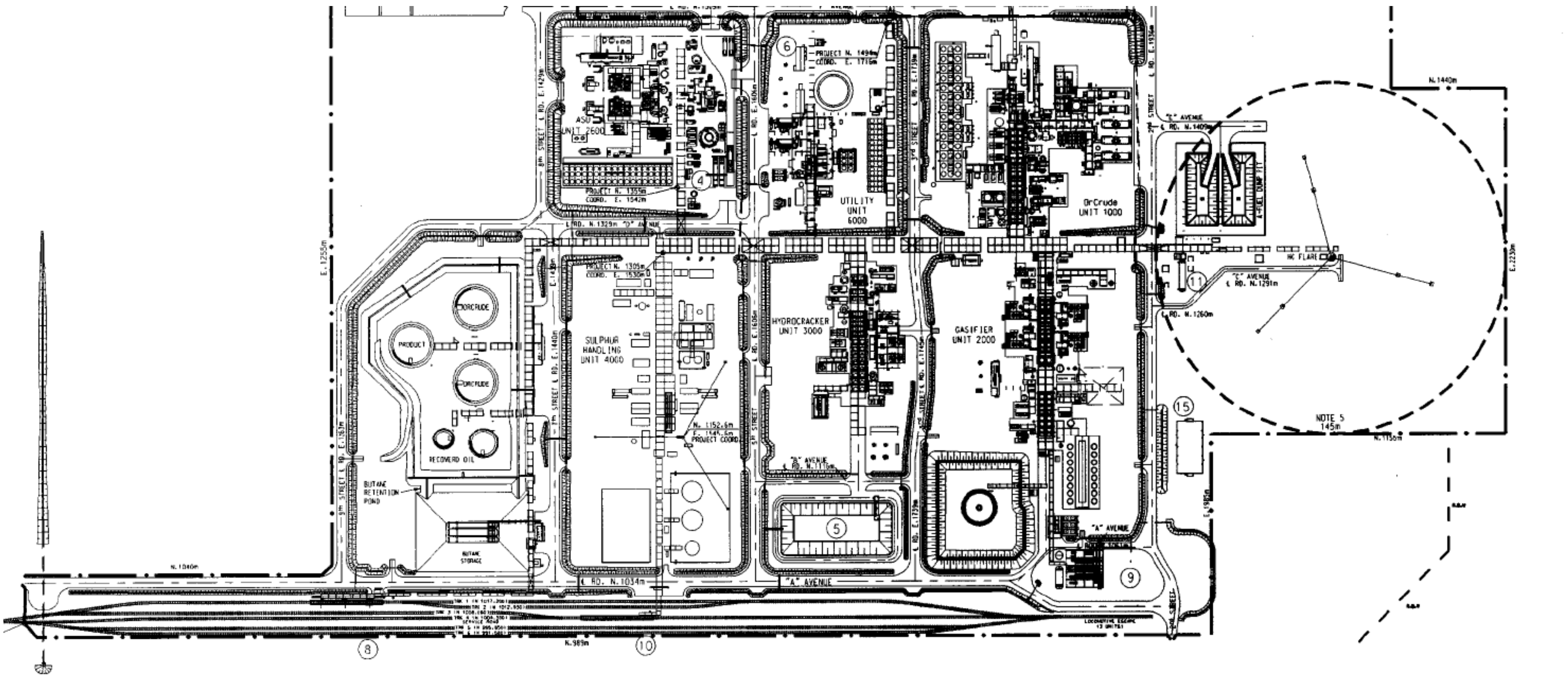
Background

- Long Lake is an integrated oil sands project and the first to combine a Steam Assisted Gravity Drainage (SAGD) scheme for the production of bitumen from the Wabiskaw-McMurray deposit with an Upgrader.
- Long Lake is located approximately 40 km southeast of Fort McMurray in the Athabasca Oil Sands.

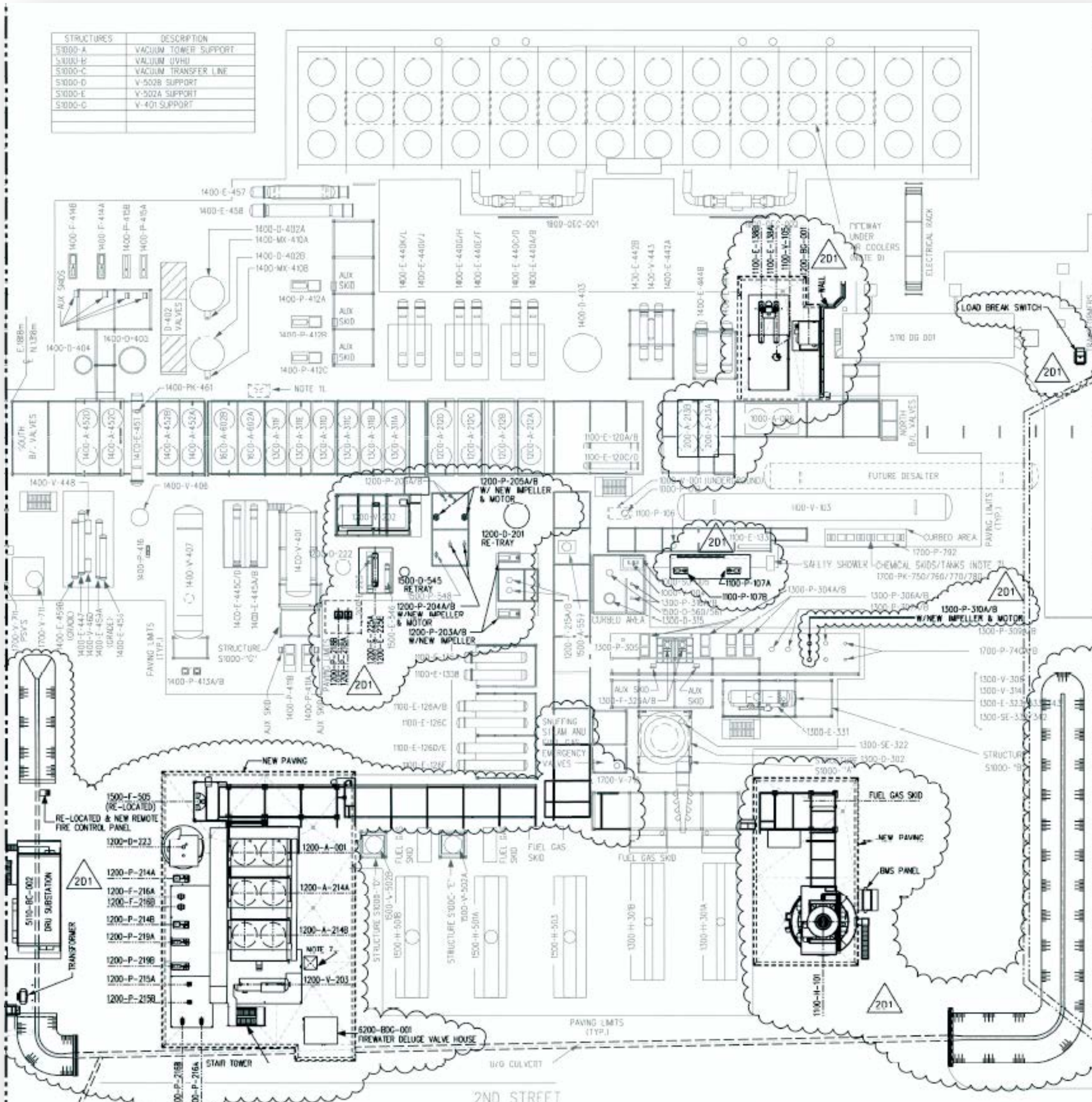
Nexen Oil Sands Leases

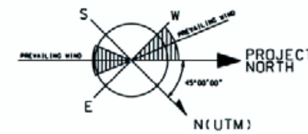


Upgrader Plot Plan

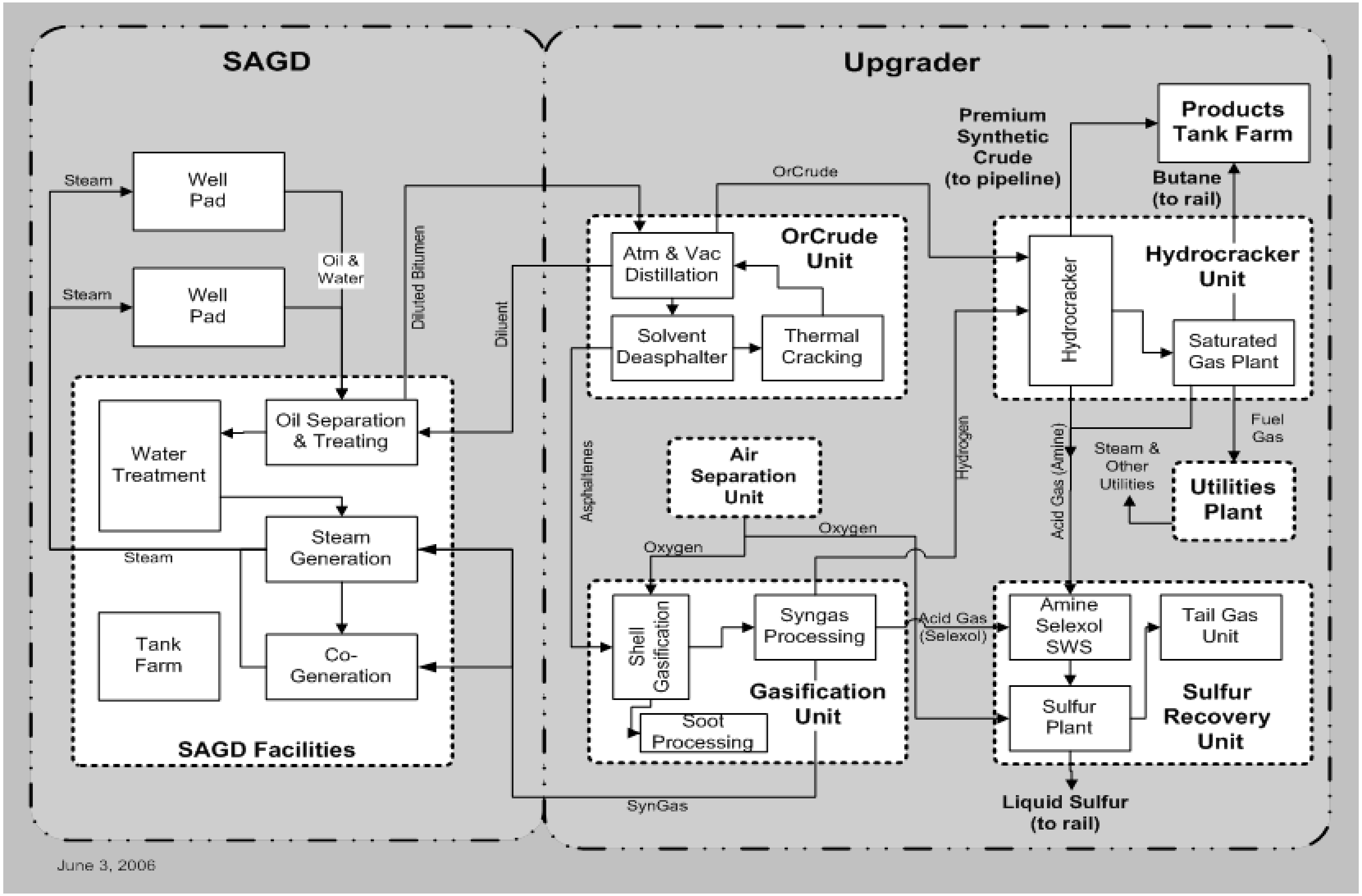


DRU Plot Plan





Integration between SAGD and Upgrader



Long Lake Upgrader and Central Processing Facility

2013 & 2014 Summary of Upgrader Performance

- Priority in 2013 and 2014 were to:
  - Increase reliability of the Upgrader
  - Standardize monitoring tools to help analyze failures (Meridium)
- Fewer upsets = fewer incidents and odor complaints
- Zero Based Analysis of our failures has changed our perception of what is important and where to focus our energy.
- Annual production rates increased over the previous reporting period, but full capacity has not yet been reached
- Scheduled and executed outages to improve reliability through repairs, upgrades and redundancy.

Product Yields

- The design yield objective for the Upgrader is 79% to 83% (original regulatory application, OPTI 2000), dependent on feed quality
  - Yield determined by (SCO production - Diluent for further processing) / Bitumen for further processing
- The average yield achieved over 2013 & 2014 was 73%

Monthly Product Yields

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sept	Oct	Nov	Dec
2013 Instantaneous Balanced Yield	62%	70%	73%	76%	72%	71%	72%	69%	69%	75%	75%	75%
2014 Instantaneous Balanced Yield	74%	73%	73%	74%	76%	76%	73%	77%	74%	74%	75%	72%

- The yield is determined from S-23 Manual calculations and is further described in the Long Lake Upgrader's Bi-Annual Report of Operations.
- Lower yields were realized during 2013 due to unscheduled shutdowns of the Solvent De-Ashphaltene Unit for issues such as pump failures and water entrainment caused by level instrument malfunction

Initiatives to Improve Yield & Energy Efficiency

- Reliability initiatives such as:
  - Vacuum tower study
  - Installed upgraded valves and redundant instrumentation in the PSA to help improve reliability of Hydrogen production
  - Converter bed catalyst in the SRU was replaced with metal traps in order to capture undesirable deposits, keep the differential pressure across the beds under control and extend the run lengths from 10 to 12 months to at least 18 months.
  - Initiated a project to increase the feed processing capacity of each Gasifier train so that at nameplate capacity, Nexen can still operate with 3 Gasifiers, allowing flexibility for maintenance
  - Installing key redundant transmitters to minimize repeat trips
  - Aggressive preventative maintenance program for our Soot handling equipment

- Advance work on Diluent Recovery Unit. Commissioning is expected after 2015 Turnaround.

Unit Availability

Unit	2013 (%)	2014 (%)
OrCrude™ Unit	99.0	100.0
Hydrocracker	98.0	99.0
Air Separation Unit	93.0	99.0
Asphaltene Gasification Unit	66.0	64.0
Sulphur Recovery Unit	95.0	100.0
Utilities & Offsites	100.0	100.0

OrCrude^{TM} Unit

- This area of the operation has been focusing on increasing yield and equipment reliability, specifically pumps.
- In the latter part of 2014 OrCrude^{TM} experienced issues with vacuum tower fouling which will be addressed as part of the 2015 Turnaround.
- Also in TA 2015 the new plant unit (Named DRU) will be commissioned, and additional cleaning and equipment repairs will be completed to allow Nexen to consistently operate until the next planned turnaround in 2016.

Hydrocracker Unit (HCU)

- The operation of the HCU during 2013 and 2014 was oriented to maximizing yield while meeting product specifications for customers and shipping companies. Test runs were performed to optimize HCU catalyst operation and liquid product recovery in the Saturation Gas Plant located downstream of the HCU reactors.
- Low feed rates as compared to design were attributed to low feed rates from the OrCrude™ Unit due to the vacuum tower fouling
- Reduced Yield was due to low hydrogen availability from the PSA due to mechanical availability of the Pressure Swing Absorption (PSA) plant and Gasifier reliability.

Asphaltene Gasification Unit

- Consists of four identical Gasifier Trains
  - Operating plan is to run at least three units at present bitumen production rates
- Work on Gasifier reliability is ongoing.
  - Nexen has installed upgraded valves and redundant instrumentation to help improve reliability;
    - Work continues as outage schedules dictate until all 4 have been completed.
  - Normal pigging (cleaning of internal piping) is scheduled up to two times per year on each train, depending on the soot fouling of the equipment.
  - Nexen is working on a project to increase the feed processing capacity of each Gasifier train so that at nameplate capacity, Nexen can still operate with 3 Gasifiers, leaving one for maintenance and upgrades. A revised metallurgy is also part of this project to improve on the reliability of the operation.

Ash Processing Unit

- The Ash Processing Unit (APU) is not in operation.
- The soot byproduct from the APU continues to be shipped to Clean Harbours' landfill in Ryley, AB
  - During this reporting period off-site soot disposal for Nexen amounted to 28577 tonnes in 2013 and 36110 tonnes in 2014.
  - Nexen continues to evaluate other disposal options.

Sulphur Recovery Unit

- The Claus units have been able to run more than 18 months and processed more than four times the acid gas per kilogram of catalyst compared to previous runs after replacing one third of the first converter bed catalyst with metal traps in 2012 Turnaround.

- Modifications to the reaction furnace burners were also implemented in 2012 in order to improve acid gas combustion and reduce particle formation which may reduce sulphur recovery and contribute to fouling.

- Performance evaluations of the Claus units and the Tail Gas Treating Unit (TGTU) were conducted by a third party company. Final reports showed that the activity of the hydrogenation catalyst is decaying and will be replaced during the turnaround in 2016.

Sulphur Recovery

- The average sulphur recovery rates in 2013 and 2014 were 99.4% calculated using the methodology outlined in the S-23 Report as (Total Produced Sulphur - Total Sulphur Flared or Wasted)/Total Produced Sulphur*100.

- The total sulphur flared or wasted was reduced significantly in 2013 and 2014 compared with 2011 and 2012 performances.

- These results were credited to:
  - A lower number of operational upsets in the Upgrader,
  - Improvements in reaction furnace burners.
  - Installation of metal traps which improves Claus catalyst performance.
  - Developed a software predictor to minimize flaring incidents.
  - Implementation of additional alarms to warn operators.

- Redesign of reaction furnaces mirror walls to ensure proper burner alignment and improvements in acid gas feed quality are key recommendations to further extend run lengths.

2013 Sulphur Recovery and Emissions

	Q1	Q2	Q3	Q4	Total
Sulphur Production (tonnes)					
Sulphur Produced	26405.8	28029.2	28641.1	33388.1	116464.2
Sulphur Flared	254.2	190.9	74.9	154.2	674.2
Sulphur Delivered	23396	30302.2	27034.6	30695.4	111428.2
Sulphur Recovery %	**99.0%**	**99.3%**	**99.7%**	**99.5%**	**99.4%**
SO_2 Emissions (tonnes)					
Total Incinerator Stack	131.6	140.0	118.2	130.2	520.0
Total Flare SO_2 Emissions	754.9	396.9	291.3	478.4	1921.6
Total Power Stack and Boilers	77.7	92.2	8.8	97.8	276.5
Total SO_2 Emissions	964.2	629.0	418.4	706.4	2718.0

2014 Sulphur Recovery and Emissions

	Q1	Q2	Q3	Q4	Total
Sulphur Production (tonnes)					
Sulphur Produced	30,136.7	35,657.2	30,528.6	26405.8	122728.3
Sulphur Flared	160.2	74.10	341.1	61.0	636.4
Sulphur Delivered	33529.2	35431.6	30254.0	38782.4	137997.2
Sulphur Recovery %	**99.5%**	**99.8%**	**98.6%**	**99.8%**	**99.4%**
SO_2 Emissions (tonnes)					
Total Incinerator Stack	127.5	123.1	176.8	123.6	550.9
Total Flare SO_2 Emissions	407.1	88.1	570.6	226.3	1292.1
Total Power Stack and Boilers	187.9	117.8	87.0	93.7	486.3
Total SO_2 Emissions	722.4	329.0	834.4	443.6	2329.4

Future Plans

Continued Focus on improving reliability

- 2015 and 2016 Turnaround.
- Expand the use of Meridian for down time/slowdown tracking.
- Zero Based Analysis of failures & slowdowns (number and severity)
  - Reduction of repeat failures.
  - Reduction of one time failures.
- Improved proactive monitoring program.
- Improved Threat Management tool.