This presentation contains information to comply with Alberta Energy Regulator’s Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes.
Nexen is an upstream oil and gas company responsibly developing energy resources in the UK North Sea, offshore West Africa, the United States and Western Canada.

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.
SAGD WELLS & CENTRAL PROCESSING FACILITY
AN INTEGRATED SAGD AND UPGRADER
<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>EIA and regulatory submissions for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003</td>
<td>Regulatory approvals for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2003 - 2007</td>
<td>Production at the Long Lake SAGD Pilot Plant</td>
</tr>
<tr>
<td>2004</td>
<td>Construction begins for the commercial Long Lake Facility</td>
</tr>
<tr>
<td>2006</td>
<td>Regulatory amendments, including Pad 11</td>
</tr>
<tr>
<td>2007</td>
<td>Start of commercial bitumen production for the Long Lake Facility</td>
</tr>
<tr>
<td>2007</td>
<td>Regulatory submissions for Long Lake South (development of Kinosis lease)</td>
</tr>
<tr>
<td>2009</td>
<td>Regulatory approvals issued for Long Lake South</td>
</tr>
<tr>
<td>2009</td>
<td>Start of operation of the Long Lake Upgrader</td>
</tr>
<tr>
<td>2010</td>
<td>Regulatory approvals for Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>First production from Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>Major turnaround for maintenance at CPF and Upgrader</td>
</tr>
<tr>
<td>2012</td>
<td>Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)</td>
</tr>
<tr>
<td>2012</td>
<td>Construction begins for K1A and Pads 14 and 15</td>
</tr>
<tr>
<td>2013</td>
<td>Increased production from Long Lake well pads, begin circulation at Pad 14</td>
</tr>
</tbody>
</table>
GEOLOGY AND GEOSCIENCE
Reservoir: McMurray Fm.

Cap rock: Wabiskaw & Clearwater Fm.
**NEXEN FACIES CODES**

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

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

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

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

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

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

- **Limestone**
  - Facies 7:
    - Devonian carbonates
NEXEN’S REGIONAL MODEL

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

Jervey, 2003
• 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**

<table>
<thead>
<tr>
<th>Acronym</th>
<th>Explanation</th>
<th>Facies Coarse</th>
<th>Facies Fine</th>
</tr>
</thead>
<tbody>
<tr>
<td>MCB</td>
<td>mid-channel bar</td>
<td>Facies 1 &amp; Facies 3</td>
<td>Facies 1 &amp; Facies 3</td>
</tr>
<tr>
<td>LPB</td>
<td>lower point bar</td>
<td>Facies 1 &amp; Facies 3</td>
<td>Facies 1 &amp; Facies 3</td>
</tr>
<tr>
<td>IHS</td>
<td>inclined heterolithic stratification</td>
<td>Facies 2, Facies 3, &amp; Facies 4</td>
<td>Facies 2, Facies 3, &amp; Facies 4</td>
</tr>
</tbody>
</table>
DEVONIAN STRUCTURE
WITH KARST AND SALT DISSOLUTION FEATURES

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA (C.I.=10m)

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

STRUCTURE EVENTS
- MULTI STAGE COLLAPSE
- PRE McMURRAY COLLAPSE
- POST McMURRAY COLLAPSE

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
- DEVONIAN STRUCTURE RASTER
  - High: 270.3
  - Low: 124.5m
DEVONIAN STRUCTURE
WITH KARST AND SALT DISSOLUTION FEATURES

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

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA (C.I.=5m)
- McMURRAY STRUCTURE

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED: PULLED BACK
- ACTIVE: INFILL HORIZONTAL
- ACTIVE: RE-DRILL HORIZONTAL
- ABANDONED: 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

McMURRAY STRUCTURE RASTER
- High: 337.2
- Low: 115.4m
• 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

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA (C.I.=5m)
- McMurRAY STRUCTURE

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
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- Q CHANNEL UNCERTAINTY BUFFER (150m)
- DRAINAGE AREAS WITHIN 100m Q-CHANNEL OFFSET

MAP DATA
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

McMURRAY ISOPACH RASTER
- High : 147.5
- Low : 17.2m
• Relatively consistent isopach (50-60m)
• Thick areas associated with Devonian lows
PAY AND EXPLOITABLE BITUMEN-IN-PLACE MAPPING METHODOLOGY
Pay cut-offs

• Top of pay interval is a 2 m shale (> 30% $V_{\text{shale}}$)

Top of EBIP Pay Interval

• Single shale interval (> 30% $V_{\text{shale}}$) of 2 m
• Cumulative shale interval (> 30% $V_{\text{shale}}$) of 4 m

Base of EBIP Pay Interval

• Depth of an existing or planned horizontal well pair
• Standoff from bitumen/water contact or non-reservoir

Reservoir Rock

• Sand
• Breccia
• IHS with < 30% $V_{\text{shale}}$
• < 50% Swee (effective water saturation) and < 30% $V_{\text{shale}}$
• 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% Swee (effective water saturation) and < 30% $V_{shale}$

• EBIP will be calculated from a hydrocarbon pore volume height (HPVH) map
### EBIP AND AVERAGE RESERVOIR PARAMETERS (LONG LAKE AND K1A)

#### Long Lake and K1A

<table>
<thead>
<tr>
<th></th>
<th>EBIP ($E^6 m^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Long Lake</strong></td>
<td>334.55</td>
</tr>
<tr>
<td><strong>K1A</strong></td>
<td>69.57</td>
</tr>
<tr>
<td><strong>Total EBIP</strong></td>
<td>404.12</td>
</tr>
</tbody>
</table>

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

Hydrocarbon Pore Volume Height

$$HPVH = \sum (S_o \cdot \Phi)_{pay\ bs}$$

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 Average Reservoir Parameters

- Measured Depth (top) 200 m KB
- Thickness 22 m
- Effective Porosity 31.0%
- $V_{shale}$ 10.3%
- Permeability – Historical Plug Data
  - $K_{max}$ 5565 mD
  - $K_{vert}$ 4491 mD
- Effective Water Saturation 31.6%
- Temperature 6 – 8 °C
- Initial Reservoir Pressure ~1000 - 1100 kPa @ 230m AMSL
• Colour shading: >12m EBIP Interval
• Contours clipped to 3m³/m² HPVH EBIP contour

LONG LAKE
EBIP PAY INTERVAL
ISOPACH
LONG LAKE
EBIP PAY INTERVAL ISOPLACH

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP HPVH ISOPLACH CONTOUR (C.I. = 4m)

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)

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- 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

EBIP ISOPLACH RASTER
- High: >12m
- Low: 12.0m

• Colour shading: >12m EBIP Interval

★ TYPE LOG
<table>
<thead>
<tr>
<th>Depth</th>
<th>Tidal-Fluvial Estuarine Complexes</th>
<th>Devonian</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>McMurray 'C'</td>
<td></td>
</tr>
<tr>
<td>275</td>
<td>McMurray A1</td>
<td></td>
</tr>
<tr>
<td>300</td>
<td>Top of Pay</td>
<td></td>
</tr>
<tr>
<td></td>
<td>EBIP Pay Interval</td>
<td></td>
</tr>
<tr>
<td></td>
<td>Surface Elevation: 494.10</td>
<td></td>
</tr>
<tr>
<td></td>
<td>RIG RELEASE: 03-MAR-2000</td>
<td></td>
</tr>
<tr>
<td></td>
<td>VERTICAL SCALE: 1:480</td>
<td></td>
</tr>
</tbody>
</table>
• Colour shading: >12m EBIP Interval
• Contours clipped to 3m³/m² HPVH EBIP contour
LONG LAKE
EBIP PAY INTERVAL ISOPACH

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP HPVH ISOPACH CONTOUR (C.l = 4m)

HORIZONTAL WELL STATUS (PRODUCER)
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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

EBIP ISOPACH RASTER
- High : 67.3
- Low : 12.0m

• Colour shading : >12m EBIP Interval

★ TYPE LOG
LONG LAKE
EBIP PAY INTERVAL BASE
STRUCTURE

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP BASE STRUCTURE (C.I.=5m)

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

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

MAP DATA
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

EBIP BASE STRUCTURE RASTER
- High : 303.6
- Low : 205.0m
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 BASE
STRUCTURE

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP TOP STRUCTURE (C.I.=5m)

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)

MAP DATA
- ZERO EDGE
- HORIZONTAL WELL PAD
- LONG LAKE PROJECT AREA

EBIP TOP STRUCTURE RASTER
- High : 322.6
- Low : 217.5m
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

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP HPVH ISOPACH CONTOUR (C.I.=1m)

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED : PULLED BACK
- ACTIVE : INFILL HORIZONTAL
- ACTIVE : RE-DRILL HORIZONTAL
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- DEViated WELL PATH (DRILLED)

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- 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

EBIP HPVH ISOPACH RASTER
- High : 15.0
- Low : 3.0m

Min pay tp
HPVH = \sum_{min \text{ pay ts}} (So*\Phi)

- Colour shading : > 3m³/m² HPVH
LONG LAKE
HPVH ISOPACH OVER EBIP PAY INTERVAL

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA
- EBIP HPVH ISOPACH CONTOUR (C.I=1m)

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

Q CHANNEL DATA
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- 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
- EBIP HPVH ISOPACH RASTER

Min pay to

\[
\text{HPVH} = \sum (\text{So} \times \Phi)
\]

Min pay bs

- Colour shading : > 3m$^3$/m$^2$ HPVH
- 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 3m³/m² HPVH EBIP contour
LONG LAKE
TOTAL GAS: GAS INTERVAL(S) WITHIN & IN CONTACT WITH EBIP INTERVAL

- 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
• > 50% Swe and < 30% $V_{\text{shale}}$
• High water saturation intervals above and in contact with EBIP
• Contours clipped to 3m$^3$/m$^2$ HPVH EBIP contour
LONG LAKE
HIGH WATER SATURATION INTERVAL(S) IN CONTACT WITH TOP EBIP INTERVAL ISOPACH

- > 50% Swe and < 30% $V_{\text{shale}}$
- 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

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA (C.I.=2m)
- CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(S) WITHIN THE EBIP INTERVAL
- 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
- LONG LAKE 2013 EBIP AREA

CUMULATIVE THICKNESS HIGH WATER SATURATION INTERVAL(S) WITHIN THE EBIP INTERVAL
- High : 29.6
- Low : 0.0m

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

- Cumulative thickness of high water saturation interval(s) within EBIP interval
- Contours clipped to $3\text{m}^3/\text{m}^2$ HPVH EBIP contour

**LONG LAKE**

**CUMULATIVE THICKNESS OF HIGH WATER SATURATION INTERVAL(S) WITHIN EBIP INTERVAL**
LONG LAKE BOTTOM WATER ASSOCIATED WITH EBIP INTERVAL

2013/2014 DRILLING PROGRAM
- OBSERVATION WELLS
- CORE HOLE WELLS
- STRAT WELLS
- BOTTOM HOLE LOCATIONS

CONTOUR DATA (C.I.=5m)
- BOTTOM WATER IN CONTACT WITH EBIP ISOPACH

HORIZONTAL WELL STATUS (PRODUCER)
- ACTIVE HORIZONTAL
- DRILLED: PULLED BACK
- ACTIVE: INFILL HORIZONTAL
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- 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
- LONG LAKE 2013 EBIP AREA

BOTTOM WATER IN CONTACT WITH EBIP ISOPACH

- > 50% Swe and < 30% $V_{\text{shale}}$
- Base of Bottom Water
  - top of a > 2m > 30% $V_{\text{shale}}$ shale interval
- Contours clipped to 3m$^3$/m$^2$ HPVH EBIP contour
LONG LAKE
BOTTOM WATER ASSOCIATED WITH EBIP INTERVAL

• > 50% Swe and < 30% $V_{\text{shale}}$
• Base of Bottom Water
  - top of a > 2m > 30% $V_{\text{shale}}$ 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 PADS 12 AND 13

Well: 1AA_14-07-086-06W4_0
Surface Elevation: 484.89
Measurment Ref.: V.E.
Drilled Depth: 3026.60
Well: 100_09-07-086-06W4_0
Surface Elevation: 484.44
Measurment Ref.: V.E.
Drilled Depth: 3006.00
Well: 1AA_12-08-086-06W4_0
Surface Elevation: 485.83
Measurment Ref.: V.E.
Drilled Depth: 2925.00

Top of Pay
Wabiskaw 'C'
McMurray

EBIP Pay Interval
Base of Pay
Devonian
Caprock defined as top of Clearwater B to top of Wabiskaw C sand
LONG LAKE
CAP ROCK EVALUATION

MINI-FRACT LOCATION
10009070866W400
1AB08290856W400

CAP ROCK CORE

XRD / PETROGRAPHY / GRAIN SIZE
1AA08320856W400
1AA10270860W400
1AA12280856W400
1AA14208506W400
10005308506W400
10506208506W400
102902908506W400
100102908506W400
103142908506W400

TRIAXIAL STRENGTH & DIRECT SHEAR TESTING
1AB08290856W400

XRD, PETROGRAPHY, & GRAIN SIZE ANALYSIS
10005308506W400
100082908506W400
10011080866W400
100132808506W400
10014080866W400
1AA01208506W400
1AA07020860W400
1AA07208506W400
1AB04308506W400
1AB082908506W400
1AC042808506W400

CAP ROCK CORE
10005308506W400
100082908506W400
10011080866W400
100132808506W400
10014080866W400
1AA01208506W400
1AA07020860W400
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LONG LAKE
CAP ROCK EVALUATION
IMAGE LOGS

IMAGE LOGS
- 2011 IMAGE LOGS
- 2012 IMAGE LOGS
- 2013 IMAGE LOGS
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CAP ROCK EVALUATION IMAGE LOGS

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<th>Well Name</th>
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Evaluation Wells Completed
• Cored Vertical Wells: **29**
• Non-cored Vertical Wells: **7**
• Non-cored Deviated Wells: **8**
• Total = **44**

Observation Wells
• 4 initial development area
• 4 Pads 14 and 15
• 3 wells drilled in Sec13-085-07W4
• Total = **11**

Total = **55** wells
### PAD 14 & 15 OBSERVATION WELLS (23 WELLS)

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<tr>
<th>Obs. Well Count</th>
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<td>8</td>
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<td>108/01-32-085-06W4M, 103/02-32-085-06W4M, 100/10-29-085-06W4M, 100/15-29-085-06W4M, 1F2/02-32-085-06W4M, 1AA/10-29-085-06W4M, 1F1/02-32-085-06W4M, 1F1/06-29-085-06W4M</td>
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</table>
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.

Amendments to Scheme Approval No. 9485 for Kinosis Phase 1A (K1A) Project approved in 2012:

- Well Pads 1 and 2 Relocation - Feb 28th
- Steam Generation Facility – March 26th
- Well Pair Amendment – August 16th

Construction ongoing for K1A.

Kinosis 2 gas re-pressurization approved by AER February 2014.
KINOSIS
2013 ACTIVITY & 3D SEISMIC OUTLINE

- Complete drilling 37 SAGD wellpairs at K1A
- 8 obs wells drilled in K1A
- 62 delination wells drilled:
  - 37 West of HWY 881
  - 25 East of HWY 881
- No additional seismic activity in 2013
Kinosis IDA

EBIP

<table>
<thead>
<tr>
<th>Kinosis IDA</th>
<th>204</th>
</tr>
</thead>
</table>

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

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.

Pay Average Reservoir Parameters

- Depth: 280 m KB
- Thickness: 34 m
- Effective Porosity: 31%
- Permeability From Core Plugs
  - $K_{max}$: 4030 mD
  - $K_{vert}$: 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 10 cm over the Pay interval, and the average is derived.
KINOSIS
STRUCTURE - TOP OF DEVONIAN

• Structure controlled by Pre-Cretaceous erosion and dissolution of the Prairie Evaporite, Lotsberg and Cold Lake salts.

• Minor karsting on Devonian surface

• 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
DEVONIAN STRUCTURE
WITH KARST AND SALT DISSOLUTION FEATURES

MAP DATA
- 2012/2013 DRILLING PROGRAM
- DEVONIAN CONTOUR (Em C.L.)

STRUCTURE EVENTS
- Multi-stage Collapse
- Pre-McMurray Collapse
- Post-McMurray Collapse

Value
- High: 259.8
- Low: 105.4

TRANSPORTATION
- Highway
- Railroad

DRAINAGE AREA
- KIA Drainage Area

SEISMIC
- Merced 3D Seismic

LEASE DATA
- Kinosis Lease

Data: May 7, 2014
File No.: CA17026.mxd
• Influenced by depositional elements that results in differential compaction.
• Can determine timing of some dissolution features, areas of thick and thin sand sections.
KINOSIS STRUCTURE ON EBIP BASE KINOSIS

MAP DATA
- 2012 / 2013 DRILLING PROGRAM
- PAY BASE (EBIP) CONTOUR (6m OIL)

Value
- High: 250.6
- Low: 140.3

TRANSPORTATION
- HIGHWAY
- RAILROAD

DRAINAGE AREA
- K1A DRAINAGE AREA
- SEISMIC
- MERGED 3D SEISMIC

LEASE DATA
- KINOSIS - IDA
- KINOSIS LEASE

Projection: UTM Zone 12N Datum: NAD 83
Date: February 21, 2014
Note: Resistivity gradient is due to salinity changes. Core used to confirm oil saturations.
KINOSIS
CAP ROCK DATA COLLECTED IN 2013
KINOSIS
TOP GAS IN THE MCMURRAY
• Application for the Kinosis 2 Gas Re-Pressurization Amendment submitted December 5, 2013 and approved by AER in February 2014

• Nexen is proposing to re-pressurize associated Wabiskaw-McMurray gas pools by injecting natural gas in the Kinosis 2 Project Area (see figure below)

• Historical gas production has depleted the reservoir pressure in the associated gas zones from an original pressure of approximately 1,000 kPa to a current pressure of 600 - 650 kPa

• Re-pressurizing the associated gas caps will improve future development potential of the bitumen resource which is currently being delineated

• This project will primarily utilize the existing gas gathering infrastructure, which will be repaired and upgraded as required for gas injection
Nexen is planning a multi-phased development of Kinosis IDA. The first Phase is K1A

- Project expectations
  - 15-25,000 b/d peak bitumen rates
  - SAGD drilling commenced in 2012
- Two wellpads (4 drainage areas) of 16 and 21 well pairs
- 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

K1A Scope (shaded area)
• Drilling commenced September 2012 on K1A Pad 1 and finished June 2013
• Drilling commenced January 2013 on K1A Pad 2 and finished October 2013
• Began completions activities in 2013 and will finish by Q2 2014
  – Pad 1 Producers completed July/Aug 2013, Pad 2 producers completed Oct/Nov 2013 (circulation tubulars)
  – Pad 1 Injectors completed Dec 2013 to Jan 2014
  – Pad 2 Injectors completed Q1/Q2 2014
Most wells came in as expected

Re-interpretation of bottom water completed while drilling after one well drilled encountered water

Elevation adjustments made on well elevations based on new oil water contact interpretation

Six producer wells encountered water, and two wells had to be shortened as a result

Tables on next two slides show adjustments on wells

Drainage Area EBIP communicated in July 2012 amendment updated based on 2012 corehole results (40 wells) and well adjustments

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<th>Volume (E3M3)</th>
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<td>K1A EBIP Application 1732244 (July 2012)</td>
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<tr>
<td>EBIP Changes – Delineation Data</td>
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<tr>
<td>EBIP Changes – SAGD Well Adjustments</td>
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<tr>
<td>K1A EBIP Total Updated (Dec 2013)</td>
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% Change: +5.2%
### Pad 1 Planned vs Actual Drilling

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*Long Lake Commercial Scheme Approval No. 9485, as amended
Application for Kinosis K1A Modifications (Aug 16, 2012)
**Pad 2 Planned vs Actual Drilling**

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</tbody>
</table>

*Long Lake Commercial Scheme Approval No. 9485, as amended
Application for Kinosis K1A Modifications (Aug 16, 2012)*
KINOSIS 2014 FUTURE PLANS

• K1A – 5 additional observation wells drilled
• Other locations are oil sand evaluation wells
• Gas re-pressurization to commence in 2014 in Kinosis 2 area
• Future phases being evaluated
DRILLING AND COMPLETIONS, ARTIFICIAL LIFT, AND INSTRUMENTATION
LONG LAKE & KINOSIS
LONG LAKE
HORIZONTAL WELL LOCATIONS
WELL PAIR COMPLETIONS MAP THROUGH 2013
KINOSIS
HORIZONTAL WELL LOCATIONS

MAP DATA
- Surveyed Well Trajectory
- Hydrology
- Proposed Well Pad
- K1A Drainage Area
- KINOSIS K1A MAP AREA
- KINOSIS LEASE

WELL SYMBOLS
- Abandoned
- Gas - Sweep
- Gas - Standing
- Gas - Ab incredient
- Water Well
- 210 Deviated Well IC (HEEL)
- 218 Deviated Well FTP (TOE)
- 218 Point of Elevation Change

PAD 1
K02P15

PAD 2
K02P13
K02P14
K02P12
K02P11
K02P10
K02P09
K02P08
K02P07
K02P06
K02P05
K02P04
K02P03
K02P02
K02P01

INSET MAP

LONG LAKE
TIM 87 MAM
KINOSIS
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”)
- Swedge injector string design remains in select wells to help mitigate steam breakthrough between the injector and producer heel
  - If cooler temperatures are seen near the heel and are not desired, swedge design is removed
• All Kinosis wells, Long Lake Pad 13 wells, 05S05 and 11S08 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 first steam splitter
TYPICAL INJECTOR CIRCULATION

Injector Circulation

Surface Casing: 339.9mm, 81.1kg/m
Intermediate Casing: 298.5mm, 80.36kg/m, K-55, Tenaris Blue
Heel Inj. String: 177.8mm, 34.2kg/m

269.9 mm Hz Hole

Toe Inj. String: 114.3 x 88.9mm vacuum insulated tubing with steam splitters
Injection Liner: 177.9mm, 34.2kg/m

9 5/8" production casing
7" tubing
4 1/2" x 3 1/2" VIT
blanket gas
steam injection
circulation returns
TYPICAL PRODUCER COMPLETIONS – ESP

- Scab liners installed in many of the producing wells in an effort to achieve optimal temperature conformance across the wellbore
• Experimenting with 2 7/8” return strings in some Kinosis wells
• Original gas lift completions have been converted to artificial lift via Electric Submersible Pumps (ESP) in most SAGD producers
  − 9 wells currently are on gas lift production
  − Conversions completed to allow production at lower steam chamber pressures (between 1400-2200 kPa)

• ESP’s installed in 92 wells
  − Pump performance:
    • Average Run Time: 382 running days
    • Mean Failure Time: 703 running days
  − Operating temperatures have reached 210ºC
  − Pumps operate at pressures between 1000 and 1500 kPa (Producer)
  − Fluid production rates range from 50 - 1100 m³/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 May-2011 (continuous operations since)
  − Efficiency slowly declining but still meeting well deliverability so no need for replacement

• ESP’s 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
- 4-6 equally spaced thermocouples across the producer lateral with one redundant thermocouple at the toe.
- Heel pressure measurement via blanket gas between heel string and intermediate casing
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

219.1mm (8 5/8”) Production Casing
25.4mm (1”) Polytube
88.9mm (3 1/2”) Tubing String
140mm (5 1/2”) Screen

ESP
TYPICAL OBSERVATION WELLS

- Vibrating wire piezometer sensors (green) are strapped outside the production string providing pressure and temperature measurements
  - 2 and 3 string casing designs have been used
- Thermocouple strings (red) provide temperature measurements
• Thermal Cement To McMurray From Above Original Well PBTD
  – 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
LONG LAKE WELL PADS
## RECOVERABLE BITUMEN

<table>
<thead>
<tr>
<th>Pad</th>
<th>Num Wells</th>
<th>EBIP $E^6 m^3$</th>
<th>Estimated Ultimate RF</th>
<th>Recoverable Bitumen $E^6 m^3$</th>
<th>Cum Production Dec. 2013 $E^3 m^3$</th>
<th>RF</th>
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<td>9</td>
<td>3.1</td>
<td>50%</td>
<td>1.6</td>
<td>183</td>
<td>6%</td>
</tr>
<tr>
<td>14 and 15</td>
<td>11</td>
<td>3.4</td>
<td>50%</td>
<td>1.7</td>
<td>0</td>
<td>0%</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>121</strong></td>
<td><strong>40.9</strong></td>
<td><strong>52%</strong></td>
<td><strong>21.4</strong></td>
<td><strong>8351</strong></td>
<td><strong>20%</strong></td>
</tr>
</tbody>
</table>

- Exploitable Bitumen In Place (EBIP) is the bitumen volume from the producer to the top of the pay interval
• Commercial Steam Assisted Gravity Drainage (SAGD)
• Downhole injection pressure varies throughout the field, ranges from 1,400 kPa to 2,400 kPa
• Steam generation stability from facility improved 2013
• 15 pads and 121 well pairs, 101 producing wells at year end
• Began circulating Pads 14 (6 wells) Q3, 2013
• Waiting to circulate Pad 15 (5 wells)

<table>
<thead>
<tr>
<th></th>
<th>Design</th>
<th></th>
<th>Dec-13</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>m³/d</td>
<td>bbl/d</td>
<td>m³/d</td>
</tr>
<tr>
<td>Bitumen</td>
<td>11,130</td>
<td>70,000</td>
<td>6,623</td>
</tr>
<tr>
<td>Steam</td>
<td>37,000</td>
<td>233,000</td>
<td>29,880</td>
</tr>
<tr>
<td>SOR</td>
<td>3.3</td>
<td></td>
<td>4.5</td>
</tr>
</tbody>
</table>
2013 PERFORMANCE

- Oil has increased from the beginning of the year from ~4,550 to ~6,600 m³/d at year end
- SOR has dropped slightly from 5.2 to 4.5 at year end
- WSR has increased to above 1 at year end; most likely due to maximizing well withdrawals
- Operating reliability improved production performance
- Production slow down (June-July 2013) due to Enbridge pipeline rupture

Well Status (December 2013)

<table>
<thead>
<tr>
<th>Status</th>
<th>Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Shut in</td>
<td>9</td>
</tr>
<tr>
<td>Circulation</td>
<td>6</td>
</tr>
<tr>
<td>SAGD</td>
<td>101</td>
</tr>
<tr>
<td>Waiting for Circulation</td>
<td>5</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>121</strong></td>
</tr>
</tbody>
</table>
- All 5 wells on ESP
- Converted 04P05 and 04P06 to ESP
- Stable operation helped achieve higher production
- Steam injection increased after the start up of 04P05 and 04P06
- At YE, injection pressures were ~1,320-1,580 kPa

- Five well pairs (01P01 to 01P03, 04P05 and 04P06)
- Cumulative production of 601 E³m³ (RF 27%)
PAD 2NE PRODUCTION SUMMARY

- Six well pairs (02P01 to 02P06)
- Cumulative production of 556 E^3 m^3 (RF 24%)

- All 6 wells on ESP
- Steam SI to 02S04, 02S05 and 02S06
- Operational instability and steam reductions have lead to inconsistent production performance
- At YE, injection pressures were ~1,250 – 1,650 kPa
Five well pairs (02P07 to 02P11)

Cumulative production of 205 E³m³ (RF 21%)

- 3 wells on ESP
- 02P07 on PCP
- 02P10 on gas lift
- 02P11 SI Oct to Dec 2013 due to potential well failure:
  - installed bridge plug and converted to ESP
- Operational instability leads to inconsistent production performance
- At YE, injection pressures were ~1,660 – 2,100 kPa
PAD 3 PRODUCTION SUMMARY

- Five well pairs (03P01 to 03P05)
- Cumulative production of 837 E³m³ (RF 36%)
- All 5 wells on ESP
- Short-term mid year steam SI to 03S01, 03S02, and 03S03
- Re-drilled 03PAIR05 late 2013/early 2014
- Decline in bitumen rates can be attributed to steam reductions and the downtime associated with 03P05
- At YE, injection pressures were ~1,400-1,750 kPa
PAD 4 PRODUCTION SUMMARY

- Two well pairs (04P01 to 04P02)
- Cumulative production of 53 $E^3m^3$ (RF 35%)
- Both wells on ESP
- At YE, injection pressures were ~1,150 – 1,250 kPa

![Graph showing production rates and SOR across years from 2006 to 2013.](image)
PAD 5 PRODUCTION SUMMARY

- Five well pairs (05P01 to 05P05)
- Cumulative production of 900 E³m³ (RF 37%)

- All 5 wells on ESP
- Stable operation helped achieve higher production and lower SOR
- At YE, injection pressures were ~1,450–1,775kPa
PAD 6N PRODUCTION SUMMARY

- Six well pairs (06P01 to 06P05 plus 06P13)
- Cumulative production of 502 E$^3$m$^3$ (RF 17%)
- All 6 wells on ESP
- Total produced fluid increased due to stable production and maximizing fluid withdrawals
- At YE, injection pressures were ~2,000 – 2,100 kPa
PAD 6W PRODUCTION SUMMARY

- All 7 wells on ESP
- Steam injection rates were decreased at 6P07, 6P10 and 6P12 due to operational issues
- At YE, injection pressures were ~1,675 – 2,000 kPa

- Seven well pairs (06P06 to 06P12)
- Cumulative production of 567 E³m³ (RF 30%)
• Five well pairs (07P01 to 07P05)
• Cumulative production of 1,139 E$^3$m$^3$ (RF 37%)

- All 5 wells on ESP
- 07P01-07P03 in possible decline phase
- Proposed NCG project
- At YE, injection pressures were ~2,100 kPa
- Seven well pairs (07P06 to 07P12)
- Cumulative production of 431 E³m³ (RF 31%)

- All 7 wells on ESP
- Proposed NCG pilot location:
  - Candidate wells are 07S07, 07S08 and 07S09
  - Targeting Q3 2014 start date
  - Drilled an observation well for NCG monitoring
- At YE, injection pressures were ~2,100 – 2,400 kPa
• Six well pairs (08P01 to 08P06)
• Cumulative production of 624 E³m³ (RF 23%)

• All 6 wells on ESP
• 08P01, 02 production shut-in mid 2012 as wells were uneconomic due to high SOR. Reviewing for potential start-up in Q1 2014
• At YE, injection pressures were ~2,100 kPa
PAD 9W PRODUCTION SUMMARY

- Five well pairs (09P01 to 09P05)
- Cumulative production of 267 E^3 m^3 (RF 16%)
- All 5 wells on gas lift
- 09PAIR04 and 09PAIR05 re-drilled into higher quality reservoir in 2012
  - Production increased from an average of 30m^3/d to 90m^3/d
- High steam rates injected to 09P05 due to losses to Pads 6N and 7N
- Targeting a WSR of 1.0
- At YE, injection pressures were ~2,200 kPa
• Five well pairs (09P06 to 09P10)
• Cumulative production of 151 E³m³ (RF 14%)

• All 5 wells on ESP
• Operational instability has lead to inconsistent production performance and high SOR
• At YE, injection pressures were ~1,775 - 1,950 kPa
PAD 10W PRODUCTION SUMMARY

- Five well pairs (10P01 to 10P05)
- Cumulative production of 375 E³m³ (RF 16%)

- All 5 wells are on ESP
- 10PAIR04 and 10PAIR05 re-drilled into higher quality reservoir in 2012
  - 10P04 production increased from an average of 45m³/d to 65m³/d
  - 10P05 production increased from an average of 30m³/d to 130m³/d
- Performance impacted by top water WSR > 1.0
- At YE, injection pressures were ~2,050 kPa
• Three well pairs producing (10P10 to 10P12)
• Cumulative production of 107 E³m³ (RF 9%)
• 10P10, 11 and 12 are on gas lift
• 10P06, 07, 08, 09 shut in as currently uneconomic due to high SOR
• 10P13 shut in as injector well is non-operational (tubulars stuck during workover)
• Significant IHS intervals within reservoir may limit steam chamber growth
• At YE, injection pressures were ~2,200 kPa
PAD 11 PRODUCTION SUMMARY

- Ten well pairs (11P01 to 11P10)
- Cumulative production of $681 \times 10^3 \text{m}^3$ (RF 32%)
- All 10 wells are on ESP
- All well pairs converted to SAGD in 2011
- Production ramping up as expected
- Reduced operating pressure from 2,300 to 2,100 kPa, reduced SOR from 4 to 3
- Proposed NCG project
- At YE, injection pressure was 2,100 kPa
PAD 12 PRODUCTION SUMMARY

- Nine well pairs (12P01 to 12P09)
- Cumulative production of $172\ E^3\ m^3$ (RF 5%)
- All 9 wells on ESP
- At YE, injection pressures were ~1,900 kPa
PAD 13 PRODUCTION SUMMARY

- Nine well pairs (13P01 to 13P09)
- Cumulative production of 183 E$^3$m$^3$ (RF 6%)
- All 9 wells on ESP
- Proposed ES-SAGD project
- At YE, injection pressures were ~1,850 – 2,000 kPa
PADS 14 AND 15 PRODUCTION SUMMARY

• Pad 14
  – Drilling finished in January 2013
  – Six well pairs (14P01 to 14P03, 14P05 to 14P07)
  – First steam on October 2, 2013
  – First oil anticipated for Q1 2014

• Pad 15
  – Drilling finished in November 2012
  – Five well pairs (15P01 to 15P05)
  – First steam anticipated for Q1 2014
  – First oil anticipated for Q3 2014
LEARNINGS

• Pad 12 & 13 enhanced start-up
• Application of saturation logging
• Maximizing fluid withdrawals by minimizing subcool
• Reduction in pressure in a leaky reservoir
• VIT (~1/3 of the injector horizontal length):
  – Positive impact on circulation as higher quality steam reaches the toe of well
  – Negative impact on SAGD as the heel temperature may remain colder than the rest of the wellbore of producer

• Steam Splitter and ICD (Inflow Control Device):
  – Still under investigation

• Solvent Soak Experimentation:
  – Solvent soaking in cold system was experimented with in several SAGD well pairs
  – Production responses and observed circulation durations showed no measurable impact as a result of solvent soaking in the cold system
• Xylene injection (70m³) 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

• The results show positive impact on production after conversion to SAGD
### Pad 12

<table>
<thead>
<tr>
<th>Well Pair</th>
<th>Xylene Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>12P01</td>
<td>57.6</td>
</tr>
<tr>
<td>12P02</td>
<td>58.8</td>
</tr>
<tr>
<td>12P03</td>
<td>59.2</td>
</tr>
<tr>
<td>12P04</td>
<td>58.4</td>
</tr>
<tr>
<td>12P05</td>
<td>0.0</td>
</tr>
<tr>
<td>12P06</td>
<td>57.8</td>
</tr>
<tr>
<td>12P07</td>
<td>59.4</td>
</tr>
<tr>
<td>12P08</td>
<td>0.0</td>
</tr>
<tr>
<td>12P09</td>
<td>57.4</td>
</tr>
</tbody>
</table>

### Pad 13

<table>
<thead>
<tr>
<th>Well Pair</th>
<th>Xylene Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13P01</td>
<td>60.7</td>
</tr>
<tr>
<td>13P02</td>
<td>30.2</td>
</tr>
<tr>
<td>13P03</td>
<td>30.1</td>
</tr>
<tr>
<td>13P04</td>
<td>60.0</td>
</tr>
<tr>
<td>13P05</td>
<td>60.1</td>
</tr>
<tr>
<td>13P06</td>
<td>60.3</td>
</tr>
<tr>
<td>13P07</td>
<td>0.0</td>
</tr>
<tr>
<td>13P08</td>
<td>61.0</td>
</tr>
<tr>
<td>13P09</td>
<td>62.9</td>
</tr>
</tbody>
</table>
• Interpretation indicates vapor / steam phase sits on the liquid phase
• Potential flooding around wellbore
Maximizing fluid withdrawal on Pad 7N has increased overall bitumen production.

All Long Lake wells are currently using this optimization:
- Some wells have doubled in production in December relative to October rates.
REDUCTION IN OPERATING PRESSURE FOR LEAKY RESERVOIRS

• Pad 11:
  • Operating pressure before July 2013 = 2,300kPa: SOR = 4.0m$^3$/m$^3$
  • Operating pressure after July 2013 = 2,100kPa: SOR = 3.0m$^3$/m$^3$
• Pads 1, 2NE, 3, 4, 5, and 9NE have observation wells placed approximately 50 m and 100 m off the toes of the horizontal SAGD wells
  – The 50 and 100 m wells are used to monitor temperature and pressure off the toes of the pads
  – The 100 m well is maintained at or below the Q Channel pressure to ensure fluids cannot possibly enter the higher pressured channel

• Pad 1 has 9 observation wells within the SAGD horizontal wells that collect temperature
  – For each well pair
    • 3 observations well located at heel, mid-point and toe

• Pad 13 monitoring wells are located between Pad 13 SAGD wells and Q-channel
PAD 1 OBSERVATION WELLS

<table>
<thead>
<tr>
<th>Pair</th>
<th>Heel A</th>
<th>Mid B</th>
<th>Toe C</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pair 1</td>
<td>1.2</td>
<td>7.2</td>
<td>6.8</td>
</tr>
<tr>
<td>Pair 2</td>
<td>1.9</td>
<td>2.1</td>
<td>2</td>
</tr>
<tr>
<td>Pair 3</td>
<td>14.6</td>
<td>8.5</td>
<td>11.2</td>
</tr>
</tbody>
</table>
OBSERVATION WELLS (ALONG 01P01)
OBSERVATION WELLS (ALONG 01P02)
OBSERVATION WELLS (ALONG 01P03)
OBSERVATION WELL SUMMARY

- Designated monitoring wells located 50 and 100 m off the toes of Pads 2NE, 3, 4, 5 and 9NE between SAGD operations and Q Channel
  - Located to monitor any possible steam chamber growth towards the Q Channel
  - No temperature effects due to SAGD activity
  - Operating strategy is to adjust SAGD operations so that the 100m observation wells are at pressures equal to or below the Q Channel pressure
- Monitoring wells located off the toe of 01P03
  - Operating strategy has stabilized temperature at 12/06-32
- Monitoring well located off the toe of 02P05 (109/13-32)
  - Drilled into 210C (~ 2,000 kPag) at 185 mKB
  - Operating strategy has reduced the temperature to 169C (~1,170 kPaG) at 185mKB
- Pad 13 monitoring wells
  - Operating strategy is to adjust SAGD operations so that the observation wells are operating at pressures equal to or below the Q Channel pressure
SUMMARY AND FUTURE PLANS
2013 SUMMARY

- Field bitumen rate continued to ramp up and SOR trending downwards
  - Increased volumes of produced water from reservoir increased challenges with water management
- 107 out of 121 well pairs on operation at year end (9 shut - in, 5 waiting on circulation)
- Continued to optimize Pads 12 and 13
- Started Pad 14 wells on circulation
- Successfully drilled K1A wells and progressed facility construction on schedule
- Drilled 79 delineation wells and 17 observation wells in 2013/2014 winter program
Evaluation Wells Completed

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

Observation Wells

- 4 Pads 14 and 15
- 1 Additional Well (15-29 E)
- 3 East Asset Obs Wells
- Total = 8 Wells

Total = 45 wells
FUTURE PLANS – EXISTING PADS

• Continue to optimize wells throughout the field and increase production
  – Evaluate infills to accelerate and maximize recovery

• Assess opportunities to apply enhanced SAGD technologies
  – Advance NCG co-injection trial at Pad 7E, target implementation Q3, 2014
  – Evaluate NCG implementation on Pads 7N and 11, pending approvals
  – Advance ES-SAGD implementation trial on Pad 13, target implementation Q3, 2014

• Evaluate results of the 2013/2014 corehole program and incorporate into overall interpretation

• Select poor wells for shut-in or wind down and allocate steam to Pads 14 and 15 and K1A
Long Lake

• Pads 14 and 15
  – Move into SAGD production, continue ramping up of wells
  – Advance development of 4 additional well pairs, pending approvals

• Long Lake SW (Pads 16-18)
  – Proceed with development plans, pending approvals

Kinosis

• K1A
  – Complete construction and tie-ins
  – Target first steam in Q2 2014, SAGD conversion starting Q3 2014

• Future developments
  – Advance gas re-pressurization project

Continue to assess area for exploitation opportunities
This presentation contains information to comply with Alberta Energy Regulator’s Directive 054 – Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes.
• 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.
<table>
<thead>
<tr>
<th>Year</th>
<th>Activity</th>
</tr>
</thead>
<tbody>
<tr>
<td>2000</td>
<td>EIA and regulatory submissions for the commercial Long Lake Project</td>
</tr>
<tr>
<td>2003</td>
<td>Regulatory approvals for the commercial Long Lake Project</td>
</tr>
<tr>
<td>2003-2007</td>
<td>Production at the Long Lake SAGD Pilot Plant</td>
</tr>
<tr>
<td>2004</td>
<td>Construction begins for the commercial Long Lake Project</td>
</tr>
<tr>
<td>2006</td>
<td>Regulatory amendments, including Pad 11</td>
</tr>
<tr>
<td>2007</td>
<td>Start of commercial bitumen production for the Long Lake Project</td>
</tr>
<tr>
<td>2007</td>
<td>Regulatory submissions for Long Lake South (development of Kinosis lease)</td>
</tr>
<tr>
<td>2009</td>
<td>Regulatory approvals issued for Long Lake South</td>
</tr>
<tr>
<td>2009</td>
<td>Start of operation of the Long Lake Upgrader</td>
</tr>
<tr>
<td>2010</td>
<td>Regulatory approvals for Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>First production from Pads 12 and 13</td>
</tr>
<tr>
<td>2012</td>
<td>Major turnaround for maintenance at CPF and Upgrader</td>
</tr>
<tr>
<td>2012</td>
<td>Regulatory approvals for Pads 14 and 15 and K1A (formerly Long Lake South)</td>
</tr>
<tr>
<td>2012</td>
<td>Construction begins for K1A and Pads 14 and 15</td>
</tr>
<tr>
<td>2013</td>
<td>Increased production from Long Lake well pads, begin circulation at Pad 14</td>
</tr>
</tbody>
</table>
PROCESS OVERVIEW
LONG LAKE PLOT PLAN
FOCUS AREAS IN 2013

Slop Oil Management

- On site slop oil facility did not have the capacity to manage all slop oil which resulted in having to truck oil off site as well as cause production limitations. In 2014, centrifuges were installed within the plant proper that have been working well. The new system is equipped with a VRU eliminating venting and odours. Nexen is looking at additional centrifuges that could potentially eliminate the existing facility.

Vapour Recovery Unit

- The VRU continued to offer challenges due to capacity restrictions. In response Nexen initiated a specialized team to analyze all aspects of the VRU. Many recommendations have been made and are currently under evaluation.

Lime and Magox Injection Limitations

- Lime and Magox injection limitations continue to cause production losses with multiple events of high hardness and silica. Projects for Lime and Magox feed re-design to HLS-A/B/C implementation in progress. This should improve reliability and capacity for dry and slurry injection of Lime and Magox to HLS-A/B/C.
Steam Flow Transmitters

- Main CPF and DB steam flow transmitters upgraded to V-Cone meters during the 2012 outage. These are not functioning properly as there appears to be some design issues. Technical is currently identifying and fixing these issues.

OTSG “E” Overpressure Incident

- On June 17, 2013 OTSG-E had a furnace overpressure event caused by too much combustible fuel gas within the furnace due to an abrupt increase (3.25 times) in heating value of the fuel gas to OTSG–E.

- In response to the overpressure event Nexen halted syngas usage in all boilers until modifications to the system could be made. This resulted in syngas flaring as a safety precaution until October.

Recycle Rate

- Although achievements were made, Nexen experienced challenges that resulted in not reaching the target recycle rate for Long Lake. Nexen continues to work with AER in order to come to a resolution in the future.
OIL SEPARATION AND TREATMENT

Diagram showing the flow of processes:
- Emulsion from pads
- FWKOS
- Treaters
- Flash
- Uplgrader
- Tank farm
- Truck terminal
- Slop tank
- Skimmings tank
- Skim tank
- Upgrader pow
- Centrifuge
- Skimmings tank
- Skim tank
- IGF
- ORF
- De-oiling tank
- To HLS

Legend:
- Emulsion
- Oil
- Water
CONTROLLED DILBIT QUALITY

Control of Dilbit Quality (density, BS&W, interface)

Oil-water interface measurement

- Nucleonic profilers installed in FWKO’s, continue to provide accurate measurement resulting in continued good quality control.

Chemical injection; re-location of chemical injection, upgraded pump with VFD control and bulk storage facilities

- No change in 2013 with the chemical injection remaining at the east and west edges of CPF which continue to provide good results with ease of handling and monitoring for operators.
- The De-emulsifier “Oil Soluble” Unit (DMO) continue to provide excellent results.
- A bulk storage project underway as part of K1A will support CPF as well resulting in efficiency improvements in our chemical addition.

Improved reliability of Upgrader to provide Naphtha as diluent results in improved treating

- Upgrader reliability continues to improve as well as throughput resulting in increased stability of naphtha supply throughout 2013. Diluent Recovery Unit Project was initiated in 2013.
- Naphtha having a lighter density than Premium Synthetic Crude provides better oil-water separation thus improved treating.
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. This has resulted in improved FWKO separation performance.

FWKO Internal Modifications (Baffles)

- We have modified the internal baffle in each FWKO (increased the height) to allow for an increased liquid level to provide extended residence time which has resulted in improved performance.

FWKO Rapid Response Team (RRT)

- Under support from a third party engineering firm initiated a process of RRT’s and ran one for FWKO over 12 weeks resulting in identifying operational changes that increased the throughput on the FWKO’s to meet facility rated throughput.
Build-up of silt, drilling mud and clays in Treaters

- Current use of DMO helps in consolidation of fines in the interface in FWKOs and treaters. We have seen no change in 2013.

- Fines separated out in the interface are removed by rag draws to slop tank. We have seen no change in this process for 2013.

- After partial separation in slop tank, rag is trucked to onsite centrifuge facilities for separation into oil, water and solids streams. Oil is returned to dilbit tanks, water to sludge pond and solids are shipped offsite.

- Vendor contracted in late 2013 to install 3rd centrifuge in early 2014.

- Some fines accumulate in the treaters and have to be cleaned out every 18 months. We have seen no change in 2013.
Electrostatic grid treating

- 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.

- A study conducted with vendor assistance proved the ineffectiveness of the grids. The study determined, for electrostatic grids to be effective, there should be 5 – 10% water carryover from FWKOs to treaters. The FWKOs at our facility provide almost dry feed to the treaters.

- A trial is proposed for 2014 to inject up to 10% produced water into the feed of one of the treaters. This may help the electrostatic grids to function per design and help remove salts and solids along with water.

Vessel cleaning without production loss

- At current rates a treater can be taken offline without production impact. At higher rates, treater cleaning would be aligned with HLS outages.
Optimization Opportunities

**Produced Water Exchanger Fouling**

- Due to increased production, exchanger fouling has increased and is managed effectively by a combination of steam and chemical cleaning. In 2013, no exchanger was mechanically cleaned except for regulatory inspection.

**Chemical Treatment Optimization**

- Chemical injection rates have been optimized and continue to perform well in 2013.
Slop Management

• Slop tank receives rag from FWKOs, treaters, Upgrader desalter and skim oil from skimmings tanks
• Oil and water are separated and recycled to front end
• Rag is sent out to the onsite centrifuge facility for further separation
• Proposed relocation of onsite centrifuge facility can enable integration with CPF
  – No intention to move existing slop oil facility but late 2013 had plans in place to bring in another vendor and integrate their centrifuge into our CPF.
  – Anticipate throughputs up to 150 m3/day processing on trial and if successful bring in another integrated unit and remove current facility.
Oil Removal Filters (ORF) units underwent a review of logic controls to optimize backwashing and water volumes in 2012 & 2013 and continue to provide good results.

Walnut shell media used in ORFs having a high affinity for oil was removed, fines removed, cleaned and replaced in the vessels then topped up with new.

ORFs provide final polishing of de-oiled water by removing oil as well as turbidity.

De-oiling plant and ORFs are performing very well. Oil in de-oiled water supplied to HLS is less than 5ppm consistently (generally <2ppm) against a target of 10ppm and off spec at 20ppm. No change in 2013.

On occasion we have experienced soot excursions into the ORF’s from the Area 3 Filter Press system carried over to SAGD in the POW water. This was managed through backwashing the ORF’s and monitoring chemical injection.
The two VRU liquid ring compressors in the CPF and in the debottlenecking unit compress the vapour generated in tanks of the respective tank farms.

Vapour recovery system continues to offer us challenges due to capacity restrictions associated with piping configurations and size.

To address VRU challenges a specialized team was formed and analyzed all aspects of the VRU performance and recommendations are being evaluated.

Any operational activity resulting in weeping/venting is given very high priority to resolve. All materials have been inventoried and stored and scaffolding for access remains in place. No change in 2013.
WATER TREATMENT
Hot Lime Softener Fouling

- Modifications were made to HLS-C downcomer, collector ring and DA compartment during 2013 outage to reduce fouling and improve unit performance. Similar modifications were completed for HLS-A/B during the 2012 Turnaround and performance of the unit is currently under evaluation.

- Additional sludge taps were installed on HLS-C and the commissioning will be completed in 2014.

Hot Lime Softener chemical addition systems

- Separate coagulant injection to HLS-A/B tie-ins were completed and final implementation will be done in 2014.

- New pH an turbidity meters were proposed for HLS-A/B/C and final changes will be completed in 2014.

- Capital projects for Lime and Magox feed re-design to HLS-A/B/C implementation in progress. This should improve reliability and capacity for dry and slurry injection of Lime and Magox to HLS-A/B/C.

Afterfilter Performance and Backwash Efficiency

- Reduced backwash usage from 4500m3/day to 1500m3/day – Automation for the change was completed.
TOTAL DISSOLVED HARDNESS IN BFW

![Graph showing total dissolved hardness from Jan-13 to Dec-13. The CPF BFW line is shown in orange, the DB BFW line is shown in blue, and the limit line is shown in yellow. The CPF BFW and DB BFW lines stay below the limit throughout the year.]

- CPF BFW
- DB BFW
- Limit
HIGH QUALITY WATER SYSTEM

FRESHWATER TANK → INLET RETENTION TANK → MICROFILTRATION UNITS → MONO MEDIA FILTERS

DEMIN TANK → MIXED BED POLISHERS → DECARB TANK → RO UNITS

LP Condensate → REJECT

UPGRADER BFW
Monomedia Filters

• Sequence improvements implemented

Reverse Osmosis membrane life extension

• Chemical feed issues – improvements to feed systems implemented

• Implementation in progress for capital project to install additional analyzers and automation to optimize chemical usage and mitigate fouling of the RO system

• Replaced filming amine with neutralizing amine as treatment for MP and LP steam condensate fed to HQWS. Implementation was on-going

Trials to reduce Fresh Water intake to HQWS

• Increased RO recovery to 80% - No positive results due to increased RO fouling and demin water production decrease

• Replaced fresh water with supernatant for the FWKO desanding

• New RO cleaner identified and to be tested in 2014

Mixed Beds

• Mechanical design to be reviewed in 2014
STEAM GENERATION
OTSG OPTIMIZATION

Flame Optimization

- There is a plan in place to modify the OTSG B burner cone the same as the other units to improve flame shape in May 2014 outage.

Combustion Fan Corrosion

- Dew-point corrosion damaging combustion fan louvers and shrouds. Plan to replace in all OTSGs with epoxy-coated shrouds, linkages and dampers, and monitor improvement. This modification has been implemented in three out of six OTSGs and results are positive. Nexen set hard sulphur limits for syngas, and if exceeded syngas is pulled.

Tube Temperature Measurement

- Installed additional T/C’s in OTSG B for a trial. Trial results being compiled. The results are inconclusive due to unreliable thermocouple readings, therefore, no plan to install in other OTSGs.

OTSG A-F Re-Rating

- Re-rating of OTSGs A-F to increase wet steam production capacity by 8 Sm3/h each (Total 48 Sm3/h) by the end of May 2014 is in progress.
HRSG – Duct Burner Fouling

- It was found that syngas contributed to duct burner fouling in the HRSGs. Procedures are being reviewed to see if risk can be mitigated. Nexen has had success with six hour duct burner purging with LP nitrogen and now progressing towards duct burners auto purge system with HP Nitrogen up to 1850 Kpag. The auto purge system will not impact steam production.
Natural Gas Separate Supply to OTSG D and HRSG 1 and 2

- Project is in progress to install a separate supply of Natural Gas to OTSG D and HRSG 1 and 2 to burn LP Syngas in these units instead of venting when sufficient supply of LP Syngas is not available to consume in all OTSGs and HRSGs.

Individual Natural Gas Header to Each OTSG and HRSG

- The economic evaluation of a project (individual natural gas header to each OTSG and HRSG) is in progress.

Syngas Challenges

- Stopped utilizing syngas in OTSG E/F after June overpressure incident. Syngas utilization was halted in OTSG A-D and HRSGs for steam production for more than three months.

- GT #1 and GT #2 were commissioned for syngas operation. Currently Nexen is only injecting syngas into GT #2 since the 2012 Turnaround. GTG #1 is not available to run on syngas due to a failed valve and the logic is to be modified to run both GTGs on syngas. Both issues are planned to be resolved during the 2014 Cogen Outage.

- Tested HP syngas injection into GT’s successful. Modifications being made to control logic to allow HP and LP syngas injection at the same time.
Control Strategy Improvements

• Improvements are being made to increase performance and reduce tripping during transition between syngas and natural gas. Many modifications were completed in the fuel gas system after the OTSG E incident in June. OTSG E/F were modified to run with produced gas and natural gas only, while OTSG A-D would run either natural gas or syngas. The live transition of fuel to OTSG A-D would only be from natural gas to syngas.
• Automation of Safe Park for Syngas fuel upsets has been implemented and has greatly improved the frequency of boiler trips. Procedures have been developed for live transition from the natural gas to syngas with very good success.

Air to Fuel Optimization

• Issue has been identified with high CO on start-up of boilers. Air to fuel ratio modifications are being made to reduce CO on start-up. All of these modifications were completed by 2\textsuperscript{nd} quarter of 2012. All boilers can now meet MCR on Syngas. Completed and operating without high CO issues since then.
8400-E-013-C Damaged Tube Bundle Replacement

- 8400-E-013-C damaged tube bundle was replaced with a new bundle without shutting down the debottleneck steam plant. Monitoring the bundles was also improved. This not only saved steam production impact, but also improved water recycle ratio.

OSTG and HRSG Pigging

- 24 month pigging results are showing no negative impact to date. OTSGs E/F are being trialed on a 3 year interval. A performance monitoring tool has been developed for assessment.

HP/MP/LP Steam Separator’s Blow Down Control Valve Re-Sizing

- Project of re-sizing HP/MP/LP steam separator’s blow down control valves was completed in 2013 and since then HP steam separators flooding has not been observed.
Blowdown Tank

• Control logic to limit steam and water flow to the blowdown tank is in process. Potential high risk limitations are being assessed by the project group. Mechanical repairs to OTSG blowdown valve actuators being addressed to go live. The target for implementation of this control logic is set for 2014.

Steam Flow Transmitters

• Main CPF and DB steam flow transmitters upgraded to V-Cone meters during the 2012 outage. These are not functioning properly as there appears to be some design issues. Technical is currently identifying and fixing these issues.
SAGD INTENSITY GRAPH

SAGD Fuel Intensity (GJ/m³)

Fuel Intensity for Steam (GJ/m³)  Fuel Intensity for Bitumen (GJ/m³)
SAGD NATURAL GAS & SYNGAS USAGE

SAGD Gas Usage (e³m³/d)

LP Syngas Usage (e³m³/d)

Natural Gas Usage (e³m³/d)
LONG LAKE GHG SUMMARY

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

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kilotonnes (kT) CO₂e Emissions</td>
<td>3,229</td>
<td>3,191</td>
<td>3,613</td>
<td>4,122</td>
</tr>
<tr>
<td>GHG intensity (kg CO₂e/bbl bitumen produced)</td>
<td>361</td>
<td>307</td>
<td>317</td>
<td>309</td>
</tr>
</tbody>
</table>

• Long Lake’s use of ‘syngas’ and our reservoir challenges have made the GHG intensity of SAGD higher than average

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>SAGD - kT CO₂e Emissions</td>
<td>2,330</td>
<td>2,527</td>
<td>2,881</td>
<td>2,825</td>
</tr>
<tr>
<td>GHG intensity (kg CO₂e/bbl bitumen produced)</td>
<td>261</td>
<td>243</td>
<td>254</td>
<td>213</td>
</tr>
</tbody>
</table>

• Upgrader GHG emission intensity was high in 2013 as ~40% of syngas production was flared as a safety precaution following an incident

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upgrader – kT CO₂e Emissions</td>
<td>899</td>
<td>664</td>
<td>732</td>
<td>1,298</td>
</tr>
<tr>
<td>GHG intensity (kg CO₂e/bbl SCO produced)</td>
<td>132</td>
<td>79</td>
<td>84</td>
<td>137</td>
</tr>
</tbody>
</table>

• Nexen currently does not yet have an AESRD approved baseline for the SGER
  – Nexen has proposed a baseline for Long Lake that follows SGER and the technical guidance – we believe a baseline using the emissions intensities from 2010-12 is representative of the facility
  – Nexen remains supportive of the SGER and its historic baseline approach
  – Talks with the AESRD on this issue are ongoing
VOLUME MEASUREMENT AND REPORTING
PRODUCED BITUMEN & WATER MEASUREMENT

• Ten two-phase test separators with up to 13 well pairs.
• Currently testing two wells per day per separator. 12 hour test duration, with a minimum of one test per week per well.
  - Wells with ESP’s are equipped with wellhead coriolis meters for daily optimization, which allows the well test a longer duration for monitoring S&W profiles.
  - Produced gas has been measured through a system designed for gas lift. This is oversized for wells producing with ESP’s and accurate measurement has not been possible.
• 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.
• 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.
• Multiphase flow meter was installed on Pad 14 prior to production.
Bitumen and water are prorated to total battery production. The average 2013 bitumen proration factor was 0.8867 and produced water proration factor was 0.8903, while Produced gas proration factor was 6.1226.

<table>
<thead>
<tr>
<th>Month</th>
<th>Oil</th>
<th>Gas</th>
<th>Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>0.8568</td>
<td>7.4331</td>
<td>0.8963</td>
</tr>
<tr>
<td>Feb</td>
<td>0.8928</td>
<td>6.6296</td>
<td>0.8721</td>
</tr>
<tr>
<td>Mar</td>
<td>0.9162</td>
<td>6.0147</td>
<td>0.8534</td>
</tr>
<tr>
<td>Apr</td>
<td>0.8820</td>
<td>6.4226</td>
<td>0.8837</td>
</tr>
<tr>
<td>May</td>
<td>0.8059</td>
<td>5.5141</td>
<td>0.8546</td>
</tr>
<tr>
<td>Jun</td>
<td>0.8626</td>
<td>6.4072</td>
<td>0.8459</td>
</tr>
<tr>
<td>Jul</td>
<td>0.8663</td>
<td>5.1914</td>
<td>0.8493</td>
</tr>
<tr>
<td>Aug</td>
<td>0.8579</td>
<td>4.6882</td>
<td>0.9230</td>
</tr>
<tr>
<td>Sep</td>
<td>0.9009</td>
<td>5.8250</td>
<td>0.8992</td>
</tr>
<tr>
<td>Oct</td>
<td>0.9386</td>
<td>6.1419</td>
<td>0.9319</td>
</tr>
<tr>
<td>Nov</td>
<td>0.9530</td>
<td>6.8099</td>
<td>0.9138</td>
</tr>
<tr>
<td>Dec</td>
<td>0.9074</td>
<td>6.3933</td>
<td>0.9609</td>
</tr>
<tr>
<td><strong>Average</strong></td>
<td><strong>0.8867</strong></td>
<td><strong>6.1226</strong></td>
<td><strong>0.8903</strong></td>
</tr>
</tbody>
</table>
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 2013 these meters were inspected, cleaned and calibrated. All well head meters have preventative maintenance schedule to maintain the accuracy as per MARP.

- Two V-cone meters installed for steam measurement at CPF during 2012 turnaround still have metering issues, vendors are involved in resolving issues.

- Disposal well volumes validated by group meter.

- All the turbine meters at water wells have been bench proved for 2013.
MEASUREMENT & REPORTING

Successes in 2013

• EPAP renewed plan was submitted in December of 2013.
• Continue to follow S-23 plan for Upgrader volume reporting.
• MARP for 2013 was submitted on February 28, 2014.
• VX- MPF meter at Pad 14 was installed.
• All well pad emulsion flow meters at test separators have been calibrated.
• Electronic calibrations of all AGAR analyzers have been completed for 2013.
• All MARP and S-23 meters are being addressed regarding calibration and algorithm methodology based on unit availability.
**POTABLE WELL**

---

**Potable**

<table>
<thead>
<tr>
<th>Location</th>
<th>Jan-Dec 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Total (m$^3$)</td>
</tr>
<tr>
<td>13-31-85-06W4M Q</td>
<td>194,558</td>
</tr>
</tbody>
</table>

---

Never been used for potable (used for SAGD drilling in 2013)
No drilling of fresh source wells in 2014
### Plant Operations

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Fresh?</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>01-21-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>128,636</td>
<td>352</td>
</tr>
<tr>
<td>01-27-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>260,053</td>
<td>712</td>
</tr>
<tr>
<td>01-34-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>120,577</td>
<td>330</td>
</tr>
<tr>
<td>02-12-86-07W4M Q</td>
<td>Quaternary</td>
<td>Y</td>
<td>410,780</td>
<td>1,125</td>
</tr>
<tr>
<td>02-32-85-06W4M QC</td>
<td>Gregoire Channel</td>
<td>Y</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>06-14-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>107,424</td>
<td>294</td>
</tr>
<tr>
<td>06-18-85-05W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>07-36-85-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>330,905</td>
<td>907</td>
</tr>
<tr>
<td>08-01-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>68,880</td>
<td>189</td>
</tr>
<tr>
<td>09-12-86-07W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>254,484</td>
<td>697</td>
</tr>
<tr>
<td>09-28-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>44,576</td>
<td>122</td>
</tr>
<tr>
<td>10-11-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>361,610</td>
<td>991</td>
</tr>
<tr>
<td>10-21-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>87,497</td>
<td>240</td>
</tr>
<tr>
<td>10-29-85-6W4M QC</td>
<td>Gregoire Channel</td>
<td>Y</td>
<td>55,616</td>
<td>152</td>
</tr>
<tr>
<td>12-19-85-05W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>200,641</td>
<td>550</td>
</tr>
<tr>
<td>13-31-85-06W4M Q</td>
<td>Quaternary</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>15-28-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>157,023</td>
<td>430</td>
</tr>
<tr>
<td>16-33-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>63,035</td>
<td>173</td>
</tr>
</tbody>
</table>

**License Allocation 3,285,000 m³ (annual daily average of 9,000 m³/d)**

<table>
<thead>
<tr>
<th>Jan-Dec 2013</th>
<th>TOTAL</th>
<th>7,245</th>
</tr>
</thead>
</table>

- Total of 18 wells tied in.
- WS Q 13-31-085-06W4 also used for potable water
No drilling of saline source wells in 2014
### Plant Operations

<table>
<thead>
<tr>
<th>Location</th>
<th>Formation</th>
<th>Saline?</th>
<th>Total (m³)</th>
<th>Annual avg. (m³/cd)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F2033008406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>4,317</td>
<td>12</td>
</tr>
<tr>
<td>1F1053308406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>8,393</td>
<td>23</td>
</tr>
<tr>
<td>1F1063108406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>4,007</td>
<td>11</td>
</tr>
<tr>
<td>07-23-85-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>60,746</td>
<td>166</td>
</tr>
<tr>
<td>1F1072608407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>2,754</td>
<td>8</td>
</tr>
<tr>
<td>09-25-85-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1101308505W400</td>
<td>McMurray</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1112908406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>8,492</td>
<td>23</td>
</tr>
<tr>
<td>11-29-84-06W4 GR</td>
<td>Grand Rapids</td>
<td>Y</td>
<td>3,772</td>
<td>10</td>
</tr>
<tr>
<td>1F1143508407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1152808505W400</td>
<td>McMurray</td>
<td>Y</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>1F1162708407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>2,423</td>
<td>7</td>
</tr>
<tr>
<td>1F1162508407W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>207</td>
<td>1</td>
</tr>
<tr>
<td>1F1163008406W400</td>
<td>Clearwater</td>
<td>Y</td>
<td>4,667</td>
<td>13</td>
</tr>
<tr>
<td><strong>Subtotal Saline</strong></td>
<td></td>
<td></td>
<td><strong>99,777</strong></td>
<td><strong>273</strong></td>
</tr>
<tr>
<td>06-08-85-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>2,066</td>
<td>6</td>
</tr>
<tr>
<td>1F1112808406W400</td>
<td>Clearwater</td>
<td>N</td>
<td>1,179</td>
<td>3</td>
</tr>
<tr>
<td>11-32-84-06W4M GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>5,801</td>
<td>16</td>
</tr>
<tr>
<td>16-25-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>5,254</td>
<td>14</td>
</tr>
<tr>
<td>16-27-84-07W4 GR</td>
<td>Grand Rapids</td>
<td>N</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td><strong>Subtotal Fresh</strong></td>
<td></td>
<td></td>
<td><strong>14,301</strong></td>
<td><strong>39</strong></td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td></td>
<td></td>
<td><strong>114,079</strong></td>
<td><strong>312</strong></td>
</tr>
</tbody>
</table>

- 19 wells tied in
- 5 fresh wells tied into saline pipeline (SAGD startup, plant upsets, feed to HQWS)
FRESHWATER SOURCE WELLS WATER QUALITY TDS
Note:
- Saline source wells have not been produced very much (yet)
- Wells not sample in 2013 due to extreme cold and equipment malfunction
Surface runoff to lime sludge ponds (00247843-00-00)

- 2013: 231,611 m³ (estimate)

Corehole and SAGD drilling

- Various TDLs: 84,588 m³ in 2013 (estimate includes 100% of water used in 2013 calendar year)
- WS Q 03-36-084-07W4 (-00-00): 32,826 m³ in 2013
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)

Saline water make-up:
- 99,777 m³ in 2013 for steam make-up (HLS’s)
RECYCLE % = \[
\frac{\text{steam injection to the reservoir – freshwater make-up-other uses of freshwater}}{\text{produced water from the reservoir}}\] \times 100

• 2013 recycle rate = 78%

• Achievements
  - Small amounts of freshwater to SAGD for steam generation.
  - Re-boiler repairs improving boiler blowdown recovery.

• Challenges:
  - Reservoir gains correlate with recycle rate.

• Nexen is committed to prudent water use and to achieving the highest water recycle rate practical.
DISPOSAL WELLS

- Class 1a Wells (2)
  - Withdrawn
- Class 1b Wells (5)
  - K1A McM disposal well 14-32 application submitted
  - McM disposal well 1-21 suspended
  - LLK backup KR disposal well 9-28 application pending
  - K1A McM disposal well 14-32 application submitted
  - TDL at KR disposal well 11-28 for 2013/14 drilling fluids
- Kinosis KR 7-32 disposal well drilling in 2014
Reservoirs (McMurray and Keg River) performing well

Average temperature of disposal water is ~50°C

All wells passed annulus pressure test; no WHP exceedences

<table>
<thead>
<tr>
<th>Approval # 10023E</th>
<th>Class 1b</th>
<th>January - December 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Disposal Well</td>
<td>Total (m³)</td>
<td>Annual avg. (m³/cd)</td>
</tr>
<tr>
<td>103/09-28-085-06W4 KR</td>
<td>1,019,722</td>
<td>2,794</td>
</tr>
<tr>
<td>100/09-28-085-06W4 McM</td>
<td>462,093</td>
<td>1266</td>
</tr>
<tr>
<td>100/01-21-085-06W4 McM</td>
<td>3,991</td>
<td>11</td>
</tr>
<tr>
<td>100/04-22-085-06W4 McM</td>
<td>28,832</td>
<td>79</td>
</tr>
<tr>
<td>100/11-32-084-06W4 McM</td>
<td>16,936</td>
<td>46</td>
</tr>
<tr>
<td>100/11-28-084-06W4 KR</td>
<td>760</td>
<td>2</td>
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<tr>
<td><strong>TOTAL</strong></td>
<td>1,514,638</td>
<td><strong>4,150</strong></td>
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<th>Approval # 11611</th>
<th>Class 1a</th>
<th>January - December 2013</th>
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<tr>
<td>Disposal Well</td>
<td>Total (m³)</td>
<td>Annual avg. (m³/cd)</td>
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<tr>
<td>100/06-16-085-06W4 KR</td>
<td>0</td>
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<tr>
<td>100/05-16-085-06W4 McM</td>
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<tr>
<td><strong>TOTAL</strong></td>
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DISPOSAL WELL – WELLHEAD PRESSURES

ERCB maximum wellhead pressures (3000 - 3950 kPag)

WHP (kPag)

McM 1-21
McM 4-22
McM 9-28
KR 9-28

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;
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.
## SO₂ EMISSIONS

### SO₂ Emissions & Sulphur Recovery

<table>
<thead>
<tr>
<th>Month</th>
<th>Total tonnes of SO₂</th>
<th>Incinerator Stack (t SO₂)</th>
<th>SAGD Boilers (t SO₂)</th>
<th>Total Flare (t SO₂)</th>
<th>Upgrader Flare (t SO₂)</th>
<th>Sour Gas Flare (t SO₂)</th>
<th>SAGD Flare (t SO₂)</th>
<th>Avg. daily Incinerator Emissions (t SO₂)</th>
<th>Avg. daily Plant Emissions (t SO₂)</th>
<th>Sulphur Recovery Efficiency (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>206.37</td>
<td>41.37</td>
<td>2.90</td>
<td>162.10</td>
<td>86.00</td>
<td>75.97</td>
<td>0.130</td>
<td>1.33</td>
<td>6.66</td>
<td>99.20</td>
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<tr>
<td>February</td>
<td>298.19</td>
<td>43.23</td>
<td>12.76</td>
<td>242.20</td>
<td>211.60</td>
<td>30.09</td>
<td>0.510</td>
<td>1.54</td>
<td>10.65</td>
<td>99.40</td>
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<tr>
<td>March</td>
<td>459.66</td>
<td>46.99</td>
<td>62.04</td>
<td>350.63</td>
<td>74.14</td>
<td>272.70</td>
<td>3.790</td>
<td>1.41</td>
<td>14.72</td>
<td>98.60</td>
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<tr>
<td>April</td>
<td>211.12</td>
<td>38.93</td>
<td>34.65</td>
<td>137.54</td>
<td>118.37</td>
<td>18.79</td>
<td>0.380</td>
<td>1.30</td>
<td>7.04</td>
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<td>280.30</td>
<td>51.68</td>
<td>28.37</td>
<td>200.25</td>
<td>16.36</td>
<td>183.73</td>
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<td>137.61</td>
<td>49.39</td>
<td>29.13</td>
<td>59.09</td>
<td>15.65</td>
<td>43.44</td>
<td>0.004</td>
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<td>July</td>
<td>131.64</td>
<td>33.62</td>
<td>1.12</td>
<td>96.90</td>
<td>47.81</td>
<td>49.02</td>
<td>0.070</td>
<td>1.08</td>
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<td>August</td>
<td>152.75</td>
<td>53.60</td>
<td>4.91</td>
<td>94.24</td>
<td>88.30</td>
<td>5.90</td>
<td>0.044</td>
<td>1.79</td>
<td>4.93</td>
<td>99.80</td>
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<td>134.01</td>
<td>31.01</td>
<td>2.80</td>
<td>100.20</td>
<td>96.90</td>
<td>3.12</td>
<td>0.175</td>
<td>1.00</td>
<td>4.32</td>
<td>99.90</td>
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<tr>
<td>October</td>
<td>256.25</td>
<td>62.91</td>
<td>22.82</td>
<td>170.52</td>
<td>72.90</td>
<td>97.34</td>
<td>0.276</td>
<td>2.03</td>
<td>8.27</td>
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<td>November</td>
<td>265.65</td>
<td>22.19</td>
<td>43.77</td>
<td>199.69</td>
<td>196.09</td>
<td>3.50</td>
<td>0.104</td>
<td>0.74</td>
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<td>December</td>
<td>184.50</td>
<td>45.07</td>
<td>31.21</td>
<td>108.22</td>
<td>30.46</td>
<td>77.58</td>
<td>0.175</td>
<td>1.50</td>
<td>6.15</td>
<td>99.30</td>
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<tr>
<td>Total</td>
<td>2718.05</td>
<td>519.99</td>
<td>276.48</td>
<td>1921.58</td>
<td>1054.58</td>
<td>861.18</td>
<td>5.82</td>
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<td>964.22</td>
<td>131.59</td>
<td>77.70</td>
<td>754.93</td>
<td>371.74</td>
<td>378.76</td>
<td>4.43</td>
<td>1.43</td>
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<td>2nd Quarter</td>
<td>629.04</td>
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<td>150.38</td>
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<td>3rd Quarter</td>
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<td>8.83</td>
<td>291.34</td>
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<td>1.29</td>
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<tr>
<td>4th Quarter</td>
<td>706.40</td>
<td>130.17</td>
<td>97.80</td>
<td>478.43</td>
<td>299.45</td>
<td>178.42</td>
<td>0.56</td>
<td>1.42</td>
<td>7.76</td>
<td>99.47</td>
</tr>
</tbody>
</table>

- The sulphur recovery rate averaged 99.2% during 2013
- Incinerator Stack Quarterly Average SO₂ Limit = 15.6 tonnes per day
- Plant Annual Average SO₂ Limit = 18.42 tonnes per day
- 2013 Average SO₂ well below limits
### SULPHUR RECOVERY RATES AND UNIT UPTIMES

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<thead>
<tr>
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<tbody>
<tr>
<td>Claus Units % of Month Processing AG</td>
<td>90.0%</td>
<td>90.2%</td>
<td>99.2%</td>
<td>98.4%</td>
<td>92.8%</td>
<td>93.7%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>100.0%</td>
<td>88.6%</td>
<td>100.0%</td>
<td>88.4%</td>
<td>95.1%</td>
</tr>
<tr>
<td>Sulphur Recovery Monthly Recovery Rate (%)</td>
<td>99.2%</td>
<td>99.4%</td>
<td>98.6%</td>
<td>99.7%</td>
<td>98.7%</td>
<td>99.5%</td>
<td>99.8%</td>
<td>99.9%</td>
<td>99.2%</td>
<td>99.9%</td>
<td>99.3%</td>
<td>99.4%</td>
<td></td>
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<tr>
<td>Quarterly Recovery Rate (%)</td>
<td>99.0%</td>
<td>99.3%</td>
<td></td>
<td>99.7%</td>
<td></td>
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<td></td>
<td>99.5%</td>
<td></td>
<td>99.4%</td>
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<tr>
<td>Average Inlet Sulphur (Tonnes/day)</td>
<td>240.8</td>
<td>233.5</td>
<td>362.6</td>
<td>343.8</td>
<td>289.5</td>
<td>288.2</td>
<td>288.7</td>
<td>304.8</td>
<td>366.4</td>
<td>331.1</td>
<td>320.8</td>
<td>268.3</td>
<td>303.2</td>
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<tr>
<td>Average Monthly Sulphur Production (Tonnes/day)</td>
<td>239.0</td>
<td>232.2</td>
<td>357.5</td>
<td>342.9</td>
<td>285.7</td>
<td>286.7</td>
<td>287.4</td>
<td>304.2</td>
<td>365.9</td>
<td>328.6</td>
<td>320.3</td>
<td>266.3</td>
<td>301.4</td>
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<th>Month</th>
<th>% Time TGU in Operation</th>
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<tr>
<td>Jan-13</td>
<td>97.6</td>
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<tr>
<td>Feb-13</td>
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<tr>
<td>Mar-13</td>
<td>98.7</td>
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<tr>
<td>Apr-13</td>
<td>99.6</td>
</tr>
<tr>
<td>May-13</td>
<td>94</td>
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<tr>
<td>Jun-13</td>
<td>92.7</td>
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<tr>
<td>Jul-13</td>
<td>100</td>
</tr>
<tr>
<td>Aug-13</td>
<td>100</td>
</tr>
<tr>
<td>Sep-13</td>
<td>99.9</td>
</tr>
<tr>
<td>Oct-13</td>
<td>93</td>
</tr>
<tr>
<td>Nov-13</td>
<td>100</td>
</tr>
<tr>
<td>Dec-13</td>
<td>99.4</td>
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</table>
ACID GAS FLARE EVENTS SUMMARY

- Total SO$_2$ flaring for 2013 was 861.18 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 2013 was due to unplanned Upgrader trips and restarts.

### Table: ACID GAS FLARE EVENTS SUMMARY

<table>
<thead>
<tr>
<th>Month</th>
<th>AG Sources</th>
<th>SWAG Sources</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Duration (h)</td>
<td>Volume (Sm3)</td>
</tr>
<tr>
<td>January</td>
<td>76.2</td>
<td>95536</td>
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<tr>
<td>February</td>
<td>66.2</td>
<td>73214</td>
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<tr>
<td>March</td>
<td>16.3</td>
<td>160910</td>
</tr>
<tr>
<td>April</td>
<td>4.0</td>
<td>8921</td>
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<tr>
<td>May</td>
<td>65.5</td>
<td>93441</td>
</tr>
<tr>
<td>June</td>
<td>47.1</td>
<td>28718</td>
</tr>
<tr>
<td>July</td>
<td>0.0</td>
<td>0</td>
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<tr>
<td>August</td>
<td>19.7</td>
<td>542</td>
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<td>September</td>
<td>2.0</td>
<td>1667</td>
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<tr>
<td>October</td>
<td>86.9</td>
<td>27426</td>
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<tr>
<td>November</td>
<td>3.1</td>
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<tr>
<td>December</td>
<td>88.5</td>
<td>31346</td>
</tr>
<tr>
<td>2013 Total</td>
<td>475.4</td>
<td>524741</td>
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**Note:** SWAG - Sour Water Acid Gas  
AG - Acid Gas
REGULATORY COMPLIANCE AND ENVIRONMENTAL PERFORMANCE
Inspections:

- August 2013 Inspection: Follow-up on produced water release from tank
- October 2013 Inspection: Scheduled visit of In-Situ Surveillance Group

Compliance Actions:

- High Risk Enforcement Action was received in August of 2013 regarding an unsatisfactory spill clean-up. Compliance was achieved and incident requirements were addressed with the AER in October.
AER APPROVALS

Approvals:

- Solvent Co-injection at Pad 13 – approved April 24, 2013
- Multi-Phase Flow Meters at Pads 14 and 15 and K1A – approved May 9, 2013
- Pads 14 and 15 Well Compatibility – approved July 26, 2013
- Pads 14 and 15 Circulation Phase Operation Pressures – October 2, 2013
- Pad 3 Pair 5 Wellbore Re-entry – approved October 25, 2013
- Pads 14 and 15 Vertical Fluid Containment Monitoring – approved January 2014
- K1A Well Compatibility – approved January 2014
- Revised Gregoire Channel Edge Interpretation – approved February 2014
- Gas Re-pressurization Project at Kinosis – approved February 2014
- Pads 16, 17 & 18 – approved March 2014

In Review:

- Field Trial Co-Injection of NCG with Steam at Pad 7N
- Field Trial Co-Injection of NCG with Steam at Pad 11
- Pads 14 and 15 Extension Wells
During 2013 Long Lake had a total of 97 permit violations and 20 reportable spills previously reported to AER or ESRD.

### Spills

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<tr>
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<td>3</td>
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### Permit Violations

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<td>Material Released</td>
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<tr>
<td>Water - Produced</td>
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<td>A PSV on a heat exchanger popped and overflowed the catch tray spilling produced water. Spill was contained on lease.</td>
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<tr>
<td>Oil (Premium Synthetic Crude)</td>
<td>15</td>
<td>A leak in the fin fan coolers developed due to freezing inside of tubes on the inlet pass. Spill was contained on lease.</td>
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<td>Bitumen Emulsion</td>
<td>2.5</td>
<td>Failed AGAR probe bleed valve on treater. Spill was contained on lease.</td>
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<tr>
<td>Lime Sludge</td>
<td>20</td>
<td>Sludge recirculation pump discharge isolation valve failed. Spill was contained on lease.</td>
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<tr>
<td>Selexol</td>
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<td>A leak developed in one of the filter cannisters within the lean selexol filter skid. Spill was contained on lease.</td>
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<tr>
<td>Water - Boiler Blowdown</td>
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<td>Steam plant tripped resulting in blow down tank overflow. Spill was contained on lease.</td>
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<td>Emulsion</td>
<td>40</td>
<td>Faulty level indicator on flow line tank resulted in overfilling of pop tank, majority of which was captured by secondary containment. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Diluted Bitumen</td>
<td>3</td>
<td>Tank overflowed due to faulty level indication as well as miscommunication between operators. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Selexol</td>
<td>7.25</td>
<td>Lean selexol pump developed a leak on a 2&quot; vent from the piping on the lean selexol suction header. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Water - Industrial Wastewater</td>
<td>200</td>
<td>Backflow of upgrader stormwater pond into ditches due to high levels. Spill was contained on lease.</td>
<td></td>
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</tr>
<tr>
<td>Water - Industrial Wastewater</td>
<td>30</td>
<td>Plant ditches filled with process water and breached the containment weir at the end of the ditch releasing the water to the natural environment.</td>
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</tr>
<tr>
<td>Diesel Fuel</td>
<td>0.35</td>
<td>Malfunctioning float switch caused transfer pumps to overflow tank. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Material Released</td>
<td>Volume</td>
<td>Incident Description</td>
<td></td>
<td></td>
<td></td>
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</tr>
<tr>
<td>Drilling Mud - Water Based</td>
<td>50</td>
<td>Drilling mud from a directional drill on the Kinosis/Long Lake pipeline corridor, spilled and migrated to the moat on well pad 6. Spill was contained on lease.</td>
<td></td>
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</tr>
<tr>
<td>Drilling Mud - Water Based</td>
<td>10</td>
<td>A frac out occurred while horizontally directionally drilling the pilot hole for the installation of the boiler feed water line, releasing drilling mud to surface. Spill was contained on lease.</td>
<td></td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Drilling Mud - Water Based</td>
<td>2.5</td>
<td>A frac out occurred while horizontally directionally drilling the pilot hole for the installation of the 16&quot; emulsion line, releasing approximately 3 m3 drilling mud to surface. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Drilling Mud - Water Based</td>
<td>8</td>
<td>While reaming for the 24&quot; emulsion line, a frac out occurred on the P/L ROW (PLA121312) releasing 8-10 m3 of drilling mud to surface. Spill was contained on lease.</td>
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</tr>
<tr>
<td>Drilling Mud - Water Based</td>
<td>2</td>
<td>While drilling the Kinosis Creek crossing for the 12&quot; BFW line, drilling fluid migrated through overburden to surface resulting in release of 2m3. Spill was contained on lease.</td>
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<td></td>
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</tr>
<tr>
<td>Water - Run-off</td>
<td>60</td>
<td>K1A site runoff combined with pumping out an excavation on site caused a release of sediment into Robert Creek.</td>
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<td></td>
<td></td>
</tr>
<tr>
<td>Water - Industrial Wastewater</td>
<td>71</td>
<td>Workers cut into a storm line that was thought to be empty, releasing oily water into an excavation. Spill was contained on lease.</td>
<td></td>
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</tr>
<tr>
<td>Water - Steam Condensate</td>
<td>4</td>
<td>Steam silencer at Pad 15 overflowed leading to release of 4 m3 of steam condensate on the well pad. Spill was contained on lease.</td>
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</tr>
</tbody>
</table>
There were 53 hours (some during the same reportable event) during 2013 where approval limits were found to be exceeded based upon values measured by the CEMS units. These hours are summarized in the following table:

<table>
<thead>
<tr>
<th>Exceedances</th>
<th>Stack Name</th>
<th>UnitNo.</th>
<th>Jan</th>
<th>Feb</th>
<th>Mar</th>
<th>Apr</th>
<th>May</th>
<th>June</th>
<th>July</th>
<th>Aug</th>
<th>Sept</th>
<th>Oct</th>
<th>Nov</th>
<th>Dec</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>Temp</td>
<td>Infiltrator Stack</td>
<td>4320-H-000</td>
<td>0</td>
<td>0</td>
<td>10</td>
<td>2</td>
<td>7</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>23</td>
</tr>
<tr>
<td>SO2</td>
<td>Infiltrator Stack</td>
<td>4320-H-001</td>
<td>0</td>
<td>1</td>
<td>3</td>
<td>1</td>
<td>10</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>21</td>
</tr>
<tr>
<td>NOx</td>
<td>Utility Boiler A</td>
<td>6500-B-001A</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>NOx</td>
<td>Utility Boiler B</td>
<td>6500-B-001B</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>NOx</td>
<td>OTSG C</td>
<td>8400-B-001C</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
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<td>0</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>NOx</td>
<td>OTSG E</td>
<td>8400-B-001E</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>1</td>
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<td>0</td>
<td>0</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>3</td>
</tr>
<tr>
<td>NOx</td>
<td>Cogen 1</td>
<td>8901-B-001</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>2</td>
</tr>
<tr>
<td>NOx</td>
<td>Cogen 2</td>
<td>8902-B-001</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>1</td>
<td>0</td>
<td>2</td>
<td>2</td>
</tr>
<tr>
<td>Total</td>
<td></td>
<td></td>
<td>0</td>
<td>4</td>
<td>13</td>
<td>6</td>
<td>19</td>
<td>2</td>
<td>0</td>
<td>2</td>
<td>0</td>
<td>4</td>
<td>3</td>
<td>0</td>
<td>53</td>
</tr>
</tbody>
</table>

Of the total of 97 permit violations, events mainly occurred in the Sulphur Recovery Unit for Long Lake Operations (48 events). These events were generally related to $\text{SO}_2$ flaring and stack temperature excursions.

Flaring and venting within Inlet Treating resulted in the bulk of SAGD permit violations.

OTSG “E” overpressure incident in June resulted in syngas flaring as a safety precaution until October while a root cause analysis was completed.
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. The elevation of the monitoring station is approximately 1624 ft. (495 m) above sea level.

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.

This air station is operated by the Wood Buffalo Environmental Association.
PASSIVE AIR MONITORING – THIRTEEN LOCATIONS
<table>
<thead>
<tr>
<th>Station Number</th>
<th>Station Location</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>SAGD Pilot Site SE- near Pilot flare stack</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>2</td>
<td>SAGD Pilot Site NW Rear of the Pilot</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>3</td>
<td>02-32-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>4</td>
<td>01-21-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>5</td>
<td>13-31-085-06 W4M Source Well</td>
<td>Active</td>
</tr>
<tr>
<td>6</td>
<td>Nexen Tower</td>
<td>Active</td>
</tr>
<tr>
<td>7</td>
<td>Well Pad 9</td>
<td>Discontinued in January 2010</td>
</tr>
<tr>
<td>8</td>
<td>Well Pad 7</td>
<td>Active</td>
</tr>
<tr>
<td>9</td>
<td>Electrical Substation</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>10</td>
<td>Beside Tank yard</td>
<td>Discontinued in December 2010</td>
</tr>
<tr>
<td>11</td>
<td>Near Kenosis Drilling Camp</td>
<td>Active</td>
</tr>
<tr>
<td>12</td>
<td>Anzac</td>
<td>Active</td>
</tr>
<tr>
<td>13</td>
<td>Gregoire Estates</td>
<td>Became Active in February 2010</td>
</tr>
<tr>
<td>14</td>
<td>Mark Amy Centre</td>
<td>Became Active in January 2010</td>
</tr>
<tr>
<td>15</td>
<td>Well Pad 11</td>
<td>Became Active in December 2010</td>
</tr>
<tr>
<td>16</td>
<td>Sucker Lake</td>
<td>Became Active in December 2010</td>
</tr>
<tr>
<td>17</td>
<td>Long Lake Sign</td>
<td>Became Active in December 2010</td>
</tr>
<tr>
<td>18</td>
<td>02-12-85-06 W4M Source Well</td>
<td>Became Active in December 2010</td>
</tr>
</tbody>
</table>
2013 H₂S Passive Results


3 (2-32)
4 (1-21)
5 (13-31)
6. NEXEN TOWER
8. PAD 7
11. DRILLING CAMP
12. ANZAC
13. GREGOIRE LAKE EST
14. MARK AMY
15. PAD 11
16. SUCKER LAKE
17. LONG LAKE SIGN
18. (2-12)
SO\textsubscript{2} PASSIVE MONITORING

2013 SO\textsubscript{2} Passive Results

STATIC SULPHUR DIOXIDE AENV GUIDELINE

GUIDELINE = 11 ppbv
WASTE DISPOSAL

- Total tonnes in 2013 – 136,870
- Slop Oil hauled to Tervita Approved Disposal Facility. 11680 tonnes (total volume).
- Soot and Centrifuge solids disposed of in Clean Harbour’s Class I landfill, 34,016 tonnes.
- Lime Sludge from Pond Dredging 40,218 tonnes.
- Waste totals include Upgrader wastes.
• Programming was modified on the distributed control system (DCS), to provide a proactive warning system for Nexen operators based on a prediction of total loading for every hour of operating.

• Nexen upgraded the analyzer hard drive on the SRU Continuous Emissions Monitoring System (CEMS), as well as the software for all seven CEMSs on site for greater reliability.

• Started installation of a new centrifuge operated by a third party. This unit will improve the water and slop-oil re-use at Long Lake. Once fully functional the unit will have a VRU capable of controlling venting (and odours) associated with the facility.

• Submitted renewal application for Long Lake EPEA approval 137467-00-00 as amended and received one year extension on current approval. New expiry date is October 31, 2014.
ENVIRONMENTAL INITIATIVES
RESEARCH & DEVELOPMENT

• Founding partner in Canada’s Oil Sands Innovation Alliance (COSIA) to accelerate the pace of environmental performance improvement.
  – Participation in the Land, Water, and Greenhouse Gas Environmental Priority Areas.
  – Leading multiple Joint Industry Projects including caribou habitat reclamation practice studies, and wildlife monitoring technologies.

• Supporter of Joint Oil Sands Monitoring (JOSM) including the following sub-groups:
  – Participation in the Regional Aquatics Monitoring Program (RAMP).
  – Participation in the Wood Buffalo Environmental Association (WBEA).
  – Participation in the Ecological Monitoring Committee of the Lower Athabasca (EMCLA).
  – Supporter of the Alberta Biodiversity Monitoring Institute (ABMI).

• Groundwater isotope tracing study with Alberta Innovates Technology Futures (AITF).
• Participation in the Cumulative Environmental Management Association (CEMA).
FUTURE PLANS
Reliability

• **Excellence Initiatives:**
  – Continue work on a multiyear initiative to implement the elements of Reliability Excellence (RE) and to integrate RE into Operations Excellence and Maintenance Excellence. This is an ongoing process of improvement. We have established teams to move these forward.
  – Improve Procurement and Inventory Management processes to improve support for Maintenance and Project activity. This carried over into 2013 and is ongoing.

• **Production**
  – Installation of Diluent Recovery Unit (2016 commissioning)
  – Begin processing production from Pads 14 and 15 and K1A