2013 PRIMROSE, WOLF LAKE, AND BURNT LAKE ANNUAL PRESENTATION TO THE AER

SUBSURFACE ISSUES RELATED TO RESOURCE EVALUATION AND RECOVERY

January 2014
Directive 54: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

January 29, 2014

3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery

January 30, 2014

3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery
# Outline - Subsurface Issues Related to Resource Evaluation and Recovery

<table>
<thead>
<tr>
<th>Section</th>
<th>Page(s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Geology and Seismic</td>
<td>4-33</td>
</tr>
<tr>
<td>Surface Movement</td>
<td>34</td>
</tr>
<tr>
<td>Reservoir Performance</td>
<td>35</td>
</tr>
<tr>
<td>PAW Artificial Lift Summary</td>
<td>36</td>
</tr>
<tr>
<td>Various Thermal Subsurface Well Design</td>
<td>37-38</td>
</tr>
<tr>
<td>PAW Steam Quality</td>
<td>39</td>
</tr>
<tr>
<td>SAGD Scheme Description</td>
<td>40-47</td>
</tr>
<tr>
<td>SAGD Reservoir Detail and Performance</td>
<td></td>
</tr>
<tr>
<td>Wolf Lake SAGD</td>
<td>48-70</td>
</tr>
<tr>
<td>Burnt Lake SAGD Pilot</td>
<td>71-73</td>
</tr>
<tr>
<td>CSS Scheme Description</td>
<td>74-89</td>
</tr>
<tr>
<td>CSS Reservoir Detail and Performance</td>
<td></td>
</tr>
<tr>
<td>Primrose/Wolf Lake: Clearwater</td>
<td>90-112</td>
</tr>
<tr>
<td>2014 Steam Schedules</td>
<td>113</td>
</tr>
<tr>
<td>Primrose East 2013 Update</td>
<td>114-124</td>
</tr>
<tr>
<td>Investigation Updates</td>
<td>125-132</td>
</tr>
<tr>
<td>Key Learning's</td>
<td>133-136</td>
</tr>
<tr>
<td>Primrose Next Developments</td>
<td>137-140</td>
</tr>
<tr>
<td>CSS Summary</td>
<td>141</td>
</tr>
<tr>
<td>Follow Up Process to CSS</td>
<td>142-148</td>
</tr>
</tbody>
</table>
Development History for PAW

Orange/Blue Sand (Primrose South and North)
- 1992 (Amoco): CDD Pilot Phase 5 Horizontal Well Steam Drive
- 1993-1999 (Amoco): Phase 1-20 Horizontal Well CSS
- 1996 (Amoco): Phase 2-3 MWSDD Steam Drive Drainage Pilot
- 1998 (Amoco): BD-18 SAGD Pilot
- 2000 (CNRL): Phase 21 Horizontal Well HPCSS
- 2003-2013: Phase 60, 61, 64, 65, 68 Horizontal Well HPCSS

Yellow Sand (Primrose East)
- 1996 (Suncor): Burnt Lake Pilot SAGD
- 2007-2008 (CNRL): Phase 74, 75, 77, 78 Horizontal Well HPCSS
- 2011-2012: Phase 90-95 Horizontal Well HPCSS

Valley Fill (Wolf Lake)
- 1988 (BP): Z8 Vertical Well CSS
- 1989 (Amoco): HWP1 SAGD Pilot
- 2005 (CNRL): Z13 Vertical Well CSS

C3 Sand (Wolf Lake)
- 1966 (BP): Phase A Vertical Well Steam and Combustion Pilots
- 1980-1985 (BP): Wolf Lake 1 West Vertical Well CSS
- 1980-1985 (BP): Wolf Lake 1 East Vertical Well CSS
- 1994 (Amoco): Wolf Lake 1 East Horizontal MWSDD
- 1996 (Amoco): Wolf Lake 1 West Horizontal MWSDD
- 1999-2000 (CNRL): Phase E2 and N Horizontal CSS

B10 Sand (Wolf Lake)
- 1989 (BP): E14 Vertical Well CSS Pilot
- 1997 (Amoco): D2 Pair 1 SAGD
- 2000 (CNRL): D2 Pair 2-6 SAGD
- 2000-2001: SD9 SAGD
- 2001: S1A SAGD
- 2004: S1A SAGD re-drill
- 2010: S1B SAGD

McMurray Sand (Wolf Lake)
- 2010 (CNRL): MCI SAGD
Primrose and Wolf Lake (PAW) OBIP within Approval Area 9140R

Total PAW OBIP: 911 Million m³

OBIP numbers include McMurray, Clearwater and Grand Rapids pay

Pay criteria for each area and formation shown in subsequent slides

Average PAW Clearwater Reservoir Characteristics

- Oil saturation: 0.6
- Bitumen weight: 9%
- Pay thickness: 11m
- Porosity: 32%
- Horizontal permeability: 3,000mD
- Vertical permeability: 900mD
- Viscosity: 100,000cP (at 15°C)
Regional Stratigraphy

McMurray: Estuarine to shoreface deposits
Clearwater Formation:
- Compound incised valley system
- Estuarine deposit vary from valley to valley
- Valley specific reservoir facies assemblages
Grand Rapids B10: Shoreface deposits
Representative Stratigraphic Cross Section
### Clearwater Net Pay Isopach

#### Regional Clearwater Net Pay Isopach

- **Primrose**
  - Blue Valley: bitwt >6%, >7m, (FAA has no Berthierine and <10% mud)
  - Orange Valley: bitwt >6%, >7m (O30 <10% mud)

- **Primrose East**
  - Yellow Valley: bitwt >6%, >7m (FA3 <10% mud, vertically continuous)

- **Wolf Lake**
  - C3 sand: bitwt >6%, (>10m, >8 ohm)
  - Valley Fill: bitwt >6%
Clearwater Formation Structure

- Clearwater reservoir base is the start of continuous deposits with bitwt >6% and <10% mud beds
- Clearwater reservoir top is the termination of continuous deposits with bitwt >6% and <10% mud beds
Reservoir Characteristics

- Reservoir: FAB & FAA
- Avg. oil saturation: 0.62
- Avg. bitumen weight: 9.3%
- Max. net pay thickness: 23 m
- Avg. porosity: 32%
- Avg. horizontal permeability: 3,000mD
- Avg. vertical permeability: 900mD
- Avg. viscosity: 100,000cP (at 15°C)
Blue Sand (Primrose South and North) Reservoir

• Reservoir is defined as FAA & FAB which are made up of a mix of bioturbated beds and clasts
  – FAB: Consists of a mixture of bioturbated muds beds (similar to FAA) and mud clasts within a sand matrix
  – FAA: Consists of bioturbated mud beds
Orange Sand (Primrose South)

Reservoir Characteristics

Reservoir: O10
Avg. oil saturation: 0.65
Avg. bitumen weight: 9.8%
Max. net pay thickness: 20m
Avg. porosity: 32%
Avg. horizontal permeability: 3,000mD
Avg. vertical permeability: 900mD
Avg. viscosity: 100,000cP (at 15°C)
Orange Sand (Primrose South) Reservoir

- Reservoir is defined as O10:
  - O10: fine grained, x-bedded sandstone with abundant mud clasts and occasional (<10%) mud drapes. Interpreted as tidal channel deposits.
Yellow Sand (Primrose East)

Reservoir Characteristics

Reservoir: FA7, FA8 & FA9
Avg. oil saturation: 0.63
Avg. bitumen weight: 9.5%
Max. net pay thickness: 29 m
Avg. porosity: 32%
Avg. horizontal permeability: 3,000mD
Avg. vertical permeability: 900mD
Avg. viscosity: 70,000cP (at 15°C)
Yellow Sand (Primrose East) Reservoir

- Reservoir consists of FA7, FA8 & FA9.
  - FA9:
    - Composed of clean sand
  - FA8:
    - Relatively muddy facies but when thin enough (less than approximately 1m) it is included in as pay as it is situated stratigraphically between the clean FA7 and FA9 facies.
  - FA7
    - Dominant reservoir facies in Yellow sand
    - Clean sand with wispy mud beds
Valley Fill (Wolf Lake)

Reservoir Characteristics

Reservoir: CS80  
Avg. oil saturation: 0.57  
Avg. bitumen weight: 8.9%  
Max. net pay thickness: 42 m  
Avg. porosity: 33%  
Avg. horizontal permeability: 3,000mD  
Avg. vertical permeability: 200 mD  
Avg. viscosity: 100,000 cP (at 15°C)
Valley Fill (Wolf Lake) Reservoir

- Reservoir is defined as Facies B, C and D in CS80.
  - Facies B: Fine grained x-bedded sand matrix with approximately 20-50% mud clasts (cm-dm scale)
  - Facies C: fine grained, current ripple laminated sand with up to 50% thin discontinuous, wavy mud lamiae/beds
  - Facies D: fined grained, x-bedded sand, rare <10% mud clasts and mud laminae. Extensive “lean zones” present within this facies.
C3 Sand (Wolf Lake)

Reservoir Characteristics

Reservoir: C3-20 & C3-30
Avg. oil saturation: 0.50
Avg. bitumen weight: 7.8%
Max. net pay thickness: 17 m
Avg. porosity: 33%
Avg. horizontal permeability: 2,000mD
Avg. vertical permeability: 200 mD
Avg. viscosity: 100,000 cP (at 15°C)
C3 Sand (Wolf Lake) Reservoir

- Reservoir is defined as facies C3-20 & C3-30. An overall cleaning upwards reservoir.
  - C3-30: X-bedded very fine grained sand with rare (<10%), bioturbated mud laminae
  - C3-20: Interbedded very fine grained sand and mud (<20%), mud lamiae/beds mm-cm scale and moderately bioturbated.
Grand Rapids B10 Pay Isopach

Grand Rapids B10
Shoreface Sand

- Laterally continuous sand in FA4 & FA5, >30 ohm·m (Net Pay >10m for development)
- All 4 B10 SAGD Pads highlighted as black wells.
Grand Rapids B10 Structure

SAGD pay defined as clean sand in FA4 and FA5
- Average bitumen weight 11.5%
Wolf Lake SAGD B10 Sand Reservoir Characteristics

Reservoir Characteristics

- Reservoir: FA5 & FA4
- Average oil saturation: 0.75
- Average bitumen weight: 11.5%
- Maximum net pay thickness: 16 m
- Average porosity: 33%
- Average HZ permeability: 3,200 mD
- Average Vertical Permeability: 2,500 mD
- Viscosity: 100,000cP (at 15°C) but variable
- No connected bottom water
Grand Rapids (Wolf Lake) B10 Reservoir

- Reservoir defined as FA4 and FA5:
  - Cleaning upwards shoreface. FA4 grades upwards into FA5
    - FA4
      - Very fine to fine grained sand with rare mud laminations and contains mud lined burrows
    - FA5
      - Very fine grained sand, void of mud interbeds or laminations and contains mud lined burrows.
McMurray Sand

- Laterally continuous sand
  Bitwt >10%, >6 ohm·m, >5 m
- Net Pay >10 m for development
- Proposed 2014 strat wells ✭

Contour Interval = 1 m
• SAGD Pay defined by continuous clean sand and breccia. IHS is not included.
• Base of reservoir, above bottom water, corresponds to bitumen weight 10% and 6 ohm·m.
Reservoir Characteristics

Reservoir: FA5
Average oil saturation: 0.73
Average bitumen weight: 11.9%
Maximum net pay thickness: 19 m
Average porosity: 34%
Average HZ permeability: 6,000 mD
Average Vertical Permeability: 5,000 mD
Cut-off for pay: 6 ohm·m
Viscosity: 100,000cP (at 15°C) but variable
MC1 (Wolf Lake) McMurray Formation Reservoir

- Reservoir defined as FA5. Interpreted as estuarine channel deposits. Comprised of fine to medium grained, x-bedded sand (<10% mud beds) and breccia.
Wolf Lake McMurray Bottom Water Isopach

- McMurray Bottom Water Isopach
  - cut-offs are less than 6 ohm·m
  - isopach represents a gross water interval
  - Bottom water at MC1 shows no response from the source water wells located in the McMurray
Progress in 2013 → Plans for 2014

2013
- 29 stratigraphic wells drilled
- 8 off pad observation wells drilled
- 132 CSS production wells drilled
- 43 Delineation FTS wells

2014
- 70 stratigraphic wells planned
- 3 observation wells planned
- 12 CSS production wells planned
- The planned re-drills of two CSS production wells are a result of poor cement jobs in the build portions of the wells
- Flow to Surface investigation wells ongoing
Cored Wells Within PAW

Total wells cored: 991
2013 wells cored: 38
Wells with caprock core: 798
3-D Seismic Wolf Lake - TWP 65/66 R 5/6

Wolf Lake Seismic

- 2009 Wolf Lake I
- 2009 Wolf Lake II
- 2011 Wolf Lake III
- 2012 Wolf Lake IV
- 2012 Primrose North XIII
**3-D Seismic: Primrose East**

- **2013 3D Coverage**
- **2012 3D Coverage**
- **2011 3D Coverage**
- **2010 4D Coverage**
- **Post Steam Area 1**
- **2010 3D Coverage**
- **2009 4D Coverage**
- **Post Steam Area 1**
- **2008 3D Coverage**
- **2004 3D Coverage**

**All pre-steam seismic has been merged in 2012**
3D Seismic: Primrose North and South Township 67 & 68-04W4

- Primrose North & South
  - 06-II-3D
  - 09-IV-3D
  - 09-V-3D
  - 10-VIII
  - 10-VI-3D
  - 10-VII
  - 12-XIV-3D
  - 12-XIII-3D
  - 13-XVII-3D

- Primrose East (Adjacent)
  - 12-XVII-3D
    - (Merged Volume)
Historical Surface Movement – Jan 2012 to July 2013

- Interferometric synthetic aperture radar (InSAR) from RADARSAT-2 imagery
- Black regions are water bodies or areas that cannot be imaged
- No heave monuments
Reservoir Performance

- Artificial Lift Summary
- Thermal Subsurface Well Design
- Steam Quality
- SAGD Recovery Process Basics
- SAGD Typical Well Schematics
- Wolf Lake SAGD
- Burnt Lake SAGD Pilot
- CSS Recovery Process Basics
- CSS Typical Well Schematics
- Wolf Lake CSS
- Primrose CSS
- Primrose Follow-Up Processes
### Artificial Lift Type & Distribution as at Dec. 15, 2013

<table>
<thead>
<tr>
<th>Operating Area</th>
<th>Rod Insert</th>
<th>Tubing Pump</th>
<th>PCP</th>
<th>ESP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Primrose South</td>
<td>541</td>
<td>2</td>
<td>3</td>
<td>1</td>
</tr>
<tr>
<td>Primrose North</td>
<td>307</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Primrose East</td>
<td>194</td>
<td>1</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Burnt Lake</td>
<td>3</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wolf Lake CSS</td>
<td>42</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Wolf Lake SAGD</td>
<td>7</td>
<td>17</td>
<td>0</td>
<td>5</td>
</tr>
<tr>
<td>Primrose brackish</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>9</td>
</tr>
<tr>
<td>Wolf Lake Brackish</td>
<td>0</td>
<td>0</td>
<td>5</td>
<td>2</td>
</tr>
<tr>
<td>Fresh Water (10-66-5W4)</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>6</td>
</tr>
</tbody>
</table>

#### Rod Pump Lift Capacity Range

<table>
<thead>
<tr>
<th>Pump Size</th>
<th>Pump Jack</th>
<th>Stroke Length</th>
<th>Efficiency</th>
<th>SPM</th>
<th>m3/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>2&quot;</td>
<td>160</td>
<td>86&quot;</td>
<td>80%</td>
<td>9</td>
<td>45</td>
</tr>
<tr>
<td>2.5&quot;</td>
<td>456</td>
<td>120&quot;</td>
<td>80%</td>
<td>9</td>
<td>100</td>
</tr>
<tr>
<td>2.5&quot;</td>
<td>456</td>
<td>144&quot;</td>
<td>80%</td>
<td>9</td>
<td>120</td>
</tr>
<tr>
<td>3.25&quot;</td>
<td>456</td>
<td>120&quot;</td>
<td>80%</td>
<td>9</td>
<td>170</td>
</tr>
<tr>
<td>3.25&quot;</td>
<td>456</td>
<td>144&quot;</td>
<td>80%</td>
<td>9</td>
<td>200</td>
</tr>
<tr>
<td>3.25&quot;</td>
<td>1280</td>
<td>240&quot;</td>
<td>80%</td>
<td>9</td>
<td>340</td>
</tr>
<tr>
<td>3.75&quot;</td>
<td>Rotoflex</td>
<td>288&quot;</td>
<td>80%</td>
<td>5</td>
<td>300</td>
</tr>
<tr>
<td>4.75&quot;</td>
<td>Rotoflex</td>
<td>288&quot;</td>
<td>80%</td>
<td>5</td>
<td>480</td>
</tr>
<tr>
<td>5.5&quot;</td>
<td>Rotoflex</td>
<td>288&quot;</td>
<td>80%</td>
<td>5</td>
<td>650</td>
</tr>
</tbody>
</table>

#### ESP Capacity Range

- Operating temperature range: 50°C to 330°C
- Operating differential pressure range: 1 kPa to 6500 kPa
Thermal Subsurface Well Design

CSS
- Phase 1-21: Dual pad layout, 160m spacing, 600m length, 16-20 horizontals per pad
- Phase 29-31, 51-55: Superpad, 188m spacing, 1200m length, 16-20 hz’s, 8-10 deviated
- Phase 27: Single pad, 160m spacing, 1400m length, 9 horizontals per pad
- Phase 28N/S: Single pad, 75m spacing, 1000m length, 10 horizontals per pad
- Phase 74-75, 77-78: Single pad, 60m spacing, 900m length, 20 horizontals per pad
- Phase 22-24, 58-68: 80m spacing, 1000-1700m length, 18-20 horizontals per pad
- Phase 90-95: Single pad, 60&80m spacing, 800-1600m length, 10-25 horizontals per pad
- Phase 25-26; Single pad, 60&80m spacing, 600-1700m length, 15-20 horizontals per pad
- Phase 40-43: Single pad, 74m spacing, 86 wells @ 1700m length; 10 wells @ 800 – 1000m length, 24 horizontals per pad

SAGD
- Lateral Spacing ranges from 75-140m Spacing
- Lateral lengths range from 650-1000m
- Number of well pairs per pad range from 3-8
Well Spacing Throughout PAW

Phase 1-21, 27: 160 m spacing
  – Old standard spacing
Phase 29-31, 51-55: 188 m
  – Super pad standard spacing
Phase 28: 75 m spacing
  – Reduced to test increased recovery factor
Phase 58,59,62,63,66,67: 80 m spacing
  – Reduced to increase recovery factor
Phase 74-75, 77-78, 90-95: 60&80 m spacing
  – Reduced to implement future gravity drainage and increase recovery factor
Phase 22-24, 60-61,64-65, 68: 80 m spacing
  – Current standard spacing
Phase 25A/B,26, 60&80 m spacing
  – Current standard spacing and reduced for thin pay trial
Phase 40-43: 74m spacing
  – Current standard spacing (spacing required to allow for 24 wells)
The steam quality at most pads is between 0.5 and 1.0 percent lower than the quality at the plant (the furthest pads may be up to 4 percent lower).

Quality change varies depending on the operating pressure, operating flow rates, line size and distance between the plant and the pad.
SAGD Basics – Well Warm Up

• For both wells of SAGD pair
  – Inject steam down tbg. string to toe
  – Produce water and steam via 2\textsuperscript{nd} tbg. string from heel

• Continue steam circulation for 2 to 4 months
  – Duration determined by temp. and performance observations
  – Typical wellhead pressures of 1 to 7 MPa

• Measure and monitor injection and returned volumes, pressures and temperature
SAGD Basics – Injection / Production

• Inject steam into upper well
  – Balance between toe and heel
  – Control based on reservoir response and temperature observations in producer

• Pump fluid from lower well with artificial lift
  – Monitor bottomhole pressure data for both injection and production wells
  – Bottomhole temperature observations influence how wells are operated
  – Generally withdrawal rates exceed steam injection rates
  – Typical fluid production rates vary from 250 m³/d to 600 m³/d
Wolf Lake SAGD Location Map
Sample Parallel String Injector Completion

- Intermediate casing: 9-5/8"
- Injection Tubing: 3-1/2"
- Slotted Liner: 7"
Sample Single String Injector Completion

- Intermediate casing: 9-5/8"
- Injection Tubing: 4-1/2"
- Slotted Liner: 7"
- Steam Distribution Device
Sample Producer with Rod Pump Completion

- Instrumentation String
  - 1-9/10"
  - 10 thermocouple points or fiber

- Production Tubing
  - 4-1/2"

- Intermediate casing
  - 9-5/8"

- Slotted Liner
  - 7"

- Oversized Tubing Pump
  - 1-1/4" corod
Sample Producer with Scab Liner Completion

- Intermediate casing - 9-5/8”
- Production Tubing - 4-1/2”
- Instrumentation Coil - 1-1/4” Fibre
- Slotted Liner - 7”
- Scab Liner - 5”
- Guide String - 1-9/10”
- ESP

New pump intake point (at toe)
Sample Observation Well Completion

Temperature Only

- Casing: 4-1/2"
- Tubing: 2-3/8"
- Thermal Fiber

Temperature and Pressure

- Casing: 5-1/2"
- Tubing: 2-3/8"
- Thermal Fiber
- Pressure Gauge
- Packer
Wolf Lake SAGD Summary

<table>
<thead>
<tr>
<th></th>
<th>D2 (B10)</th>
<th>SD9 (B10)</th>
<th>S1A (B10)</th>
<th>S1B (B10)</th>
<th>B10 Total</th>
<th>MC1 (MCM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Active Wellpairs</td>
<td>4</td>
<td>6</td>
<td>8</td>
<td>6</td>
<td>24</td>
<td>6</td>
</tr>
<tr>
<td>2013 Bit Prod, e3m3</td>
<td>2.5</td>
<td>37.5</td>
<td>49.6</td>
<td>88.9</td>
<td>178.5</td>
<td>119.7</td>
</tr>
<tr>
<td>2013 Avg. SOR (*dry steam)</td>
<td>12</td>
<td>5.6</td>
<td>4.9</td>
<td>3.4</td>
<td>4.5</td>
<td>3.4</td>
</tr>
<tr>
<td>Cumm Bit, e3m3</td>
<td>329.7</td>
<td>856.8</td>
<td>945.3</td>
<td>162.7</td>
<td>2,294.5</td>
<td>307.8</td>
</tr>
<tr>
<td>Cumm SOR (*dry steam)</td>
<td>4.7</td>
<td>3.8</td>
<td>3.9</td>
<td>4.1</td>
<td>4.0</td>
<td>3.5</td>
</tr>
<tr>
<td>OBIP, e3m3</td>
<td>1,877</td>
<td>1,819</td>
<td>2,682</td>
<td>1,971</td>
<td>8,349</td>
<td>1,443</td>
</tr>
<tr>
<td>2013 YE RF, %</td>
<td>17.6</td>
<td>47.1</td>
<td>35.2</td>
<td>8.3</td>
<td>27.5</td>
<td>21.3</td>
</tr>
</tbody>
</table>

- Current production is from B10 Grand rapids & MCMR
- D2 has many operational challenges, all options are being considered
- SD9 recovery is approaching 50%, considering options for blowdown
- S1A has had a positive response to stimulations
- S1B has had a positive response to stimulations
- MC1 reservoir heterogeneities are causing operational challenges
Wolf Lake SAGD
Operational Strategy

• Operate wells based on a target steam chamber pressure and target sub-cool
• There is a temperature limitation at surface dictated by the pressure at the facility inlet. Fluid temperature must stay below saturated conditions at this pressure which may dictate the achievable temperature (sub-cool) in the wellbore. The older pads chamber pressures are therefore lowered to operate within surface constraints
• Steam chamber pressure is measured by annulus gas pressure in the injector and is controlled by the steam injection rate
  – Target pressure for SD9 is 2200kPa
  – Target pressure for S1A is 2500kPa
  – Target pressure for S1B is 3000kPa
  – Target pressure for MC1 is 3100kPa
• Sub-cool is determined based on the difference between the saturated temperature of the steam chamber pressure and the highest temperature along the producer lateral
  – Target to maintain a minimum 20-30°C sub-cool
Wolf Lake SAGD Performance

WL SAGD Production

- **Oil** (green line)
- **Water** (blue line)
- **Steam** (red line)
- **CSOR** (black line)

Key Events:
- **D2 P1**: 1997
- **D2 P2-P6**: Oct/2000
- **SD9 Jul/2001**
- **D2 & SD9 perforated late 2003/early 2004**
- **S1A Aug/2004**
- **MC1 and S1B 2011**

**Notes:**
- Wolf Lake SAGD Performance
- MC1 and S1B perforated late 2003/early 2004
- S1A perforated Aug/2004
Wolf Lake SAGD
B10 Pad S1B – Low Recovery

- SAGD well pair: 6
- ERCB Approval: Jul 08, 2010
- Completed Drilling: Oct. 2010
- First Steam: Aug. 2011
- Hz section length: 900 m
- Inter-well-pair spacing: 100 m
- Avg. net pay: 12 m
- Avg. So: 75%
- Avg. porosity: 36%
- Ultimate RF: 45%
- Current RF: 8.3%
Wolf Lake SAGD
S1B Pad Performance

WL SAGD B10 Production - S1B Pad

Stimulations Annotated

Oil Water Steam CSOR

Rates (m3/d)

CSOR

Stimulations:
- 1L and 5L
- 2L
- 3L
- 4L
- 6L

Timeline:
- Jul-11
- Oct-11
- Jan-12
- Apr-12
- Jul-12
- Oct-12
- Jan-13
- Apr-13
- Jul-13
- Oct-13
Historical E14 CSS Production

• S1B pad affected by old E14 CSS production
  – Perforated in Grand Rapids formation
  – Abandoned CSS wells prior to drilling S1B

• Enhanced mobility pathway from the injector to producer resulting in hot heels and cold toes

• S1B-1 is not affected by E14 wells

• Installed tailpipes to the toe of the producer laterals in S1B pairs 2, 3, 5, & 6
  – Effective in heating up producer toes

• A learning for exploiting a pad with known highly permeable channels is to blank off these areas
S1B Stimulations

• Due to the E-14 wells operating strategy, there are hot spots along the laterals which limit production

• Tail pipes have been used to pull hot fluid past the colder spots in an attempt to get the full length of the lateral to contribute

• All of the wells have now been stimulated with acid or perforations with positive results. The change in the temperature profile shows improved conformance across the lateral on pairs 3-6. Pairs 1 and 2 did not improve.
S1B Chamber Pressures
S1B Learnings

- Increased pad pressure to 4000 kPa to increase heat in the chamber and encourage flow from cold sections of the lateral. Increased pump efficiency but no change in conformance along the lateral

- Lowered pad pressure to 3000 kPa for current operation

- Stimulations have had positive results and production is increasing
  - Plugging mechanism has not been determined, all stimulations have had some level of success
Wolf Lake McMurray SAGD
Pad MC1 – Medium Recovery

- SAGD well pair: 6
- ERCB Approval: Feb 16, 2010
- Completed Drilling: Aug. 2010
- First Steam: May 2011
- Hz section length: 900 m
- Inter- well-pair spacing: 70 m
- Avg. net pay: 12 m
- Avg. So: 73%
- Avg. porosity: 34%
- Ultimate RF: 40%
- Current RF: 21.3%
WL SAGD
MC1 Pad Performance

WL SAGD McMurray Production - MC1 Pad

- Oil
- Water
- Steam
- CSOR

Installing ESP’s
Installing single string with 2 steam distribution devices
OBS 4 – Data collection errors from pressure monitoring equipment, investigating cause and making efforts to return to operation. This well was drilled to monitor bottom water however logs do not show bottom water extending to this area.
MC1 Obs Well 1 (Located 16 m from 6L)
MC1 Obs Well 3 (Located 32 m from 4L)
Trend shows the inability to get an accurate bottom water reading from obs 1 due to its close proximity to the steam chamber of pair 6.
MC1 Pair 1 Re-drill

• Started re-drill in October 2013

• Producer
  – Circulation issues while drilling
  – Drilled to planned TD, liner became stuck during installation and could not free, re-drilled through the stuck liner and completed with 5” liner to TD

• Injector
  – A risk assessment was done following the producer issues and decided to extend existing lateral instead of drilling a new lateral
  – BHA became stuck at the end of liner, could not free, left in hole
MC1 Learnings

- 2L premium screen slimhole has proven to produce high rates with a low pressure differential

- Bottom water pressure trends with chamber pressures due to observation well being too close to the steam chamber

- Lateral lengths are highly breciated and muddy which decreases the effective contributing length
  - Obs well data shows that breccia is not distributing any heat and mud streaks are limiting chamber growth
  - Steam distribution and scab liners were installed to selectively produce higher quality reservoir at the toes of pad
Wolf Lake SAGD
B10 Pad SD9 – High Recovery

- SAGD well pair: 6
- Completed Drilling: Apr 2001
- First Steam: Jul 2001
- Hz section length: 950 m
- Inter-well-pair spacing: 90 m
- Avg. net pay: 13 m
- Avg. So: 76%
- Avg. porosity: 33%
- Est. RF: 45%
- Current RF: 47.1%
Wolf Lake SAGD
SD9 Pad Performance

WL SAGD B10 Production - SD9 Pad

- Oil
- Water
- Steam
- CSOR

Perforated SD9
Steam separator installed
Blowdown Strategy

- High recovery factor and declining rates make this pad a candidate for a blowdown strategy

- Steam and withdrawal rates have been declining over the last 4 years due to a facility constraint at surface limiting wellhead temperatures.

- Currently investigating pressure/temperature responses and reservoir modelling to determine strategy
5 Yr. Outlook – Pad Abandonments

• SD9 is approaching 50% recovery
  – A blowdown strategy is being investigated

• D2 is currently uneconomic to produce
  – Investigating pad performance to determine if there is an opportunity to economically continue production or request to abandon
Wolf Lake SAGD - 2014 Plan

• Continue operation and evaluation of SAGD performance

• Investigate blowdown strategy at SD9

• Investigate redrill/infill possibilities from existing pad locations
Burnt Lake SAGD Performance Summary

2013 Performance

<table>
<thead>
<tr>
<th>Burnt Lake SAGD Pilot Production</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Active Well Pairs</td>
<td>3</td>
</tr>
<tr>
<td>2013 Bitumen Production (m³)</td>
<td>38,191</td>
</tr>
<tr>
<td>2013 Average SOR</td>
<td>4.9</td>
</tr>
<tr>
<td>Cumulative Bitumen Production (m³)</td>
<td>875,951</td>
</tr>
<tr>
<td>Cumulative SOR</td>
<td>4.0</td>
</tr>
<tr>
<td>OBIP (m³)</td>
<td>1,493,000</td>
</tr>
<tr>
<td>Recovery Factor (%)</td>
<td>58.7</td>
</tr>
</tbody>
</table>

2013 Optimization Highlights:
- Continued the LP SAGD operation at ~ 1,600 kPa.
- Balanced steam in with water production on all well pairs.

2014 Future Plans:
- Continue steaming and evaluating late recovery
Burnt Lake SAGD Performance

Burnt Lake Clearwater SAGD Production

- Oil
- Water
- Steam
- CSOR

Production & Injection Rate (m³/d)
Cumulative SOR

01-Jan-87 to 01-Jan-14

CNQ | PREMIUM VALUE | DEFINED GROWTH | INDEPENDENT
Burnt Lake Observation Well temperature Profiles (CS2/CP2: Horizontal length 1000 m)
Cyclic Steam Stimulation Overview

• CSS Basics
  – Steaming
  – Geomechanics
  – Depletion
  – Well Design
  – OBIP
  – Recovery

• Wolf Lake Update
  – Valley Fill
  – C3 Sands

• Primrose Update
  – Oil, Water, Steam
  – Current and Potential Recoveries
  – Performance Variation
  – 2014 Steam Schedule
  – Investigation Updates
  – Key Learning’s 2013
  – 2014 Development
CSS Basics - Steaming

• Steam Generation - Quality of ~75%, ~15 MPa.

• Inject steam to dilate reservoir
  – Typical vertical stress gradient is 21 kPa/m. (@500 m TVD, dilate at 10.5 MPa)

• Wave steam strategy through majority of wells
  – Alternate steam strategies implemented where interwell communication & CLWTR dilation profile require

• Reservoir pressure management
  – Fill up infront of wave to increase reservoir pressure ahead of post fill-up wells (2-5 wells ahead)
  – Soak wells 3+ rows behind steam injection to reduce leak off on post fill-up wells

• Rate and volumes are dependent on well geometry and cycle number
  – Each cycle required to reheat volume of steam-affected reservoir back to saturated steam temperature conditions and grow to contact previously non-contacted bitumen
  – Steam volume growth focused on optimizing volume over fill-up (VOF)
• Injection of steam volume over fill-up (VOF) has evolved since 2005

  – VOF targets incorporate wellbore design, cycle and reservoir
    - Liner lengths
    - Well spacing
    - Reservoir quality and thickness
    - Cycle or pore volume steam (PV steam) injected to date

  – In 2013, VOF targets varied based on these factors

• Post July 2013, early cycle VOF targets significantly reduced as part of the modified steam strategy
CSS Basics - Steaming
Modified Steam Injection Strategy

• Canadian Natural believes in continuous improvement to steam strategies to maximize recovery and reduce risk, and continues to examine cycle performance

• Since the July 2013 steam restriction implemented due to flow to surface events, the modified steam strategy includes low volume commissioning cycles followed by reduced volume commercial cycles
  – Commissioning cycle 1 → ~10,000m³/well (~9,000 m³/well VOF)
  – Commissioning cycle 2 → ~17,000m³/well (~15,000 m³/well VOF)
  – Commercial cycle 1 → ~25,000m³/well (~22,000 m³/well VOF)

• Goal of initial steam injection is to increase the horizontal stress by increasing poro-elastic and thermal elastic stresses which leads to horizontal fractures

• Commissioning cycle evaluation demonstrated smaller pause required between cycles than expected
  – Pad 91 lower DI in cycle 1 did not appear to impact cycle 2 performance
CSS Basics – Steaming
Relationship of Cycle Volumes to Cycle and Ultimate Recovery

• Early cycle steam volumes have little to no impact on the cycle thermal efficiency
  – Performance is dependent on near well bore reservoir quality
  – Evaluating performance of multiple cycles with no steam volume growth

• Mid to late life reduced cycle volumes have an impact on performance
  – Increases number of cycles a well receives during its life to inject the same amount of pore volume steam
    ▪ Increasing casing integrity risk
    ▪ Reduces thermal efficiency (reheating water within reservoir)
    ▪ Increases risk of inter-well communication with multiple pressure cycles through a given area (reducing thermal efficiency)

• Ultimate recovery is believed to be improved by increased cycle volumes due to improved thermal efficiencies and reservoir conformance
CSS Basics - Steaming
Proactive Reservoir Pressure Management

- Inter-well communication has been shown to reduce reservoir performance. Risk managed by controlling pressure gradients around steam wave.

- Front of Wave
  - Design for a fill-up steam bank ahead of wave which establishes a controllable pressure gradient ahead of the wave

- Behind Wave
  - Soaking wells
    - Use stress to confine steam injection
  - Flow back wells
    - Design a flow back rate that balances production while keeping reasonable pressure differentials (dPs) between wells

Depletion Index = “DI” = Total Fluid Produce/Steam Injected

- 1.7 MPa reduced per 0.1 DI
- 1.5 MPa reduced per 0.1 DI
Flow back rate affected by:

- **Steam slug size**
  - Larger steam slugs will have smaller dP’s at the same flow back rate

- **Design maximum dP’s between rows**
  - Larger maximum dP’s between rows allows for a higher flow back rate
  - Approximately 1MPa between rows has been targeted
  - Larger dP’s have higher risk for interwell communication

- **Wave speed**
  - The faster the wave, the higher the flow back rate can be without going over the max dP between rows

- **Depletion state (i.e. life of well)**
Geomechanics Horizontal Fractures Dominate

- Initial Clearwater stress state favours vertical fracturing
- Initial, $\sigma_{\text{vertical}} > \sigma_{\text{horizontal,min}}$
- Injection of steam increases the horizontal stresses such that horizontal fractures are induced, $\sigma_{\text{vertical}} < \sigma_{\text{horizontal}}$

Clearwater shale has been proven to be a competent barrier for CSS

Colorado Group is considered the regional seal in the Cold Lake region protecting the Quaternary aquifers

Stress state is affected by Temperature and Pressure

$$\Delta \sigma_h = \alpha \frac{1 - 2\nu}{1 - \nu} \Delta p$$

$$\Delta \sigma_h = \alpha \frac{E}{1 - \nu} \Delta T$$
# Geomechanical Stress Test Results

<table>
<thead>
<tr>
<th>Well Alias</th>
<th>UWI</th>
<th>MPP mTVD</th>
<th>Pclosure kPa</th>
<th>Pisp kPa</th>
<th>Gradient kPa/m</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>244.0</td>
<td>N/A</td>
<td>6,300</td>
<td>25.8</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>284.0</td>
<td>N/A</td>
<td>8,600</td>
<td>30.3</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>325.0</td>
<td>N/A</td>
<td>8,300</td>
<td>25.5</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>386.0</td>
<td>N/A</td>
<td>6,300</td>
<td>16.3</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>408.5</td>
<td>N/A</td>
<td>7,500</td>
<td>18.4</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>WL 05-15</td>
<td>100/05-15-66-05W4</td>
<td>439.8</td>
<td>N/A</td>
<td>8,100</td>
<td>18.4</td>
<td>Test Performed Sept-2000</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>172.0</td>
<td>3,517</td>
<td>N/A</td>
<td>20.4</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>221.4</td>
<td>3,966</td>
<td>N/A</td>
<td>17.9</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>271.5</td>
<td>6,730</td>
<td>N/A</td>
<td>24.8</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>313.5</td>
<td>8,647</td>
<td>N/A</td>
<td>27.6</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>336.5</td>
<td>10,660</td>
<td>N/A</td>
<td>31.7</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>473.6</td>
<td>11,313</td>
<td>N/A</td>
<td>23.9</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-11</td>
<td>100/11-11-67-03W4</td>
<td>481.7</td>
<td>9,753</td>
<td>N/A</td>
<td>20.2</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-12</td>
<td>100/11-12-67-03W4</td>
<td>317.5</td>
<td>8,523</td>
<td>N/A</td>
<td>26.8</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-12</td>
<td>100/11-12-67-03W4</td>
<td>385.0</td>
<td>6,553</td>
<td>N/A</td>
<td>17.0</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-12</td>
<td>100/11-12-67-03W4</td>
<td>414.5</td>
<td>8,602</td>
<td>N/A</td>
<td>20.8</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRE 11-12</td>
<td>100/11-12-67-03W4</td>
<td>495.7</td>
<td>13,760</td>
<td>N/A</td>
<td>27.8</td>
<td>Test Performed Mar-2009</td>
</tr>
<tr>
<td>PRN 11-14</td>
<td>100/11-14-68-04W4</td>
<td>231.5</td>
<td>6,317</td>
<td>N/A</td>
<td>27.3</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 11-14</td>
<td>100/11-14-68-04W4</td>
<td>287.0</td>
<td>8,767</td>
<td>N/A</td>
<td>30.5</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 11-14</td>
<td>100/11-14-68-04W4</td>
<td>463.0</td>
<td>9,533</td>
<td>N/A</td>
<td>20.6</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 11-14</td>
<td>100/11-14-68-04W4</td>
<td>481.0</td>
<td>10,800</td>
<td>N/A</td>
<td>22.5</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 3-14</td>
<td>100/03-14-68-04W4</td>
<td>233.5</td>
<td>7,070</td>
<td>N/A</td>
<td>30.3</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 3-14</td>
<td>100/03-14-68-04W4</td>
<td>278.0</td>
<td>8,300</td>
<td>N/A</td>
<td>29.9</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 3-14</td>
<td>100/03-14-68-04W4</td>
<td>452.0</td>
<td>9,500</td>
<td>N/A</td>
<td>21.0</td>
<td>Test Performed Jan-2010</td>
</tr>
<tr>
<td>PRN 3-14</td>
<td>100/03-14-68-04W4</td>
<td>473.0</td>
<td>11,840</td>
<td>N/A</td>
<td>25.0</td>
<td>Test Performed Jan-2010</td>
</tr>
</tbody>
</table>
CSS Basics - Depletion

- CSS consists of 3 depletion stages
  1) Trickle Producing/Steaming
     - Keeps casing hot without depleting reservoir pressure
  2) Flow back – reservoir pressure > static head of fluid + group line pressure
  3) Pumping – reservoir pressure <= (static head of fluid + group line pressure)
     - Rate is initially limited by pump capacity
Typical Horizontal CSS Well

- **Surface Casing**: Thermally cemented, 340mm, set between 30m and 120m depending on surrounding area.
- **Kick-Off Point**: ~130m to 220m.
- **Intermediate Casing**: Thermally cemented, 244.5mm, 59.5kg/m, metal to metal seal connections, L80 or PS80.
- **Centralizers**: Used for proper placement of casing.
- **Continuous Rod**: 177.8mm, 34.2kg/m or 168.3mm, 29.76kg/m.
- **Slotted Liner**: 114.3mm.
- **Production Tubing**: 114.3mm.
- **Fluid Production**.
- **Burst Pup Joint**: Approx. 1100-2000m.
- **Approx. 800-1600m**.
- **Approx. 1100-2000m**.
CSS Basics – Observation Wells

Grand Rapids Monitoring  Ground Level  Passive Seismic Monitoring

Thermal Fibre
Fibre Optics & Heater Strings

Packer

Lower Grand Rapids
Pressure and Temperature
Sensor

Geophones:
Cemented into place

Spacers
Formation Integrity
Thermal Fibre & Passive Seismic Monitoring

• Passive Seismic surveillance is an effective tool for detecting casing failures, especially in the build section of the wellbore
  – 98% detection rate of out of zone (up hole) casing failures since 2009.

• Thermal fibre gives us the ability to monitor for fluid migration attributed to inferior cement jobs
  – Focuses on detection of horizontal fractures intersecting observation well

• Thermal fibre is Canadian Natural’s preferred method for fluid monitoring within the Colorado Shales
  – Monitoring to date has shown no issues during steaming or production
Formation Integrity
Lower Grand Rapids Pressure Monitoring

- Lower Grand Rapids (LGR) pressure monitoring has proven to be an effective observation system regarding formation integrity surveillance during CSS
  - Under certain circumstances it can be difficult to distinguish heave from fluid invasion based on LGR pressure alone
    - Pressure anomalies in the LGR must be examined in conjunction with all available data to determine pressure response sources:
      - Passive seismic, thermal fiber, injectivity plots, production data
  - Continue to obtain data to quantify the poro-elastic heave pressures in the LGR during CSS steaming
  - Primrose East, Primrose North, Primrose South Phases 28-31 and Phases 22-26 all are currently equipped with LGR monitoring equipment
    - All new pads are equipped with LGR pressure monitoring
  - Canadian Natural shall notify the ERCB if a B12 pressure increase/decrease is greater than 200 kPa/day
CSS Basics - OBIP Assumptions

OBIP = Area × Net Pay × Porosity × Oil Saturation

- Area is 1 well spacing wide by length of well plus ½ spacing on each end
- Net pay is as previously defined in the Geology section
- Oil saturation is determined from Bitumen Weight percentage assuming a sand/shale density of 2650 kg/m³, water/oil density of 1000 kg/m³, and 32% porosity
CSS Basics - Recovery

- CSS life is dictated by the economic limits (SOR)
- Typical economic SOR limit 6-10
  - Oil/Gas price ratio dependant
  - Current SOR economic limit is >14
- Forecasting is based on a type curve
- Recovery is a function of amount of steam injected
- Goal of steam scheduling is to maximize rates and recovery
- Type curve uncertainty exists for greater than 15% recovery at 160m spacing
## 2013 Performance Summary

### Wolf Lake Valley Fill CSS Performance Summary

<table>
<thead>
<tr>
<th>Phase</th>
<th>Z8 &amp; HWP</th>
<th>Z13</th>
<th>VF Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSS Well Count</td>
<td>20</td>
<td>21</td>
<td>41</td>
</tr>
<tr>
<td>2013 Steam Injection (m3)</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2013 Bitumen Production (m3)</td>
<td>7,400</td>
<td>49,600</td>
<td>57,000</td>
</tr>
<tr>
<td>Cumulative Bitumen Production (m3)</td>
<td>691,000</td>
<td>415,000</td>
<td>1,106,000</td>
</tr>
<tr>
<td>Cumulative SOR</td>
<td>3.9</td>
<td>4.5</td>
<td>4.1</td>
</tr>
</tbody>
</table>
Z13 Casing Failure Update

- 8 producing wells
- 13 failed wells – root cause still under investigation
  - Comparison of Z8 (1 failure) vs. Z13

<table>
<thead>
<tr>
<th>Well</th>
<th>Year Failed</th>
<th>Status</th>
</tr>
</thead>
<tbody>
<tr>
<td>Z13-1</td>
<td>2011</td>
<td></td>
</tr>
<tr>
<td>Z13-2</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-3</td>
<td>2011</td>
<td></td>
</tr>
<tr>
<td>Z13-4</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-5</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-6</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-7</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-8</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-9</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-10</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-11</td>
<td>2011</td>
<td></td>
</tr>
<tr>
<td>Z13-12</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-13</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-14</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-15</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-16</td>
<td>2013</td>
<td></td>
</tr>
<tr>
<td>Z13-17</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-18</td>
<td>Producing</td>
<td></td>
</tr>
<tr>
<td>Z13-19</td>
<td>2011</td>
<td></td>
</tr>
<tr>
<td>Z13-20</td>
<td>2011</td>
<td></td>
</tr>
<tr>
<td>Z13-21</td>
<td>2011</td>
<td></td>
</tr>
</tbody>
</table>
Wolf Lake Valley Fill CSS, All Pads

- HWP1 Oct/1993
- Z13 Nov/2005
- Z8 Nov/1988
Wolf Lake C3 Sand CSS

2013 Performance Summary
- Injected 127,000 m³/well
- Reduced steam volume into E2_I

Wolf Lake Valley Fill CSS Performance Summary

<table>
<thead>
<tr>
<th>Phase</th>
<th>E2 &amp; D2D</th>
<th>N</th>
<th>C3 Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>CSS Well Count</td>
<td>6</td>
<td>5</td>
<td>11</td>
</tr>
<tr>
<td>2013 Steam Injection (m³)</td>
<td>526,900</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2013 Bitumen Production (m³)</td>
<td>5,100</td>
<td>6,100</td>
<td>11,200</td>
</tr>
<tr>
<td>Cumulative Bitumen Production (m³)</td>
<td>536,500</td>
<td>401,200</td>
<td>937,700</td>
</tr>
<tr>
<td>Cumulative SOR</td>
<td>5.0</td>
<td>6.2</td>
<td>5.5</td>
</tr>
</tbody>
</table>
## Wolf Lake 2013 / Potential Recoveries

<table>
<thead>
<tr>
<th>Wolf Lake Area</th>
<th>OBIP (e3m³)</th>
<th>2013 cum oil (e3m³)</th>
<th>RF (%)</th>
<th>Estimated Recovery (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Valley Fill</td>
<td>6,600</td>
<td>1,100</td>
<td>16.7</td>
<td>21-26%</td>
</tr>
<tr>
<td>C3 Sand</td>
<td>21,500</td>
<td>5,600</td>
<td>26.2</td>
<td>26-28%</td>
</tr>
</tbody>
</table>
Primrose Oil, Water, Steam, and SOR

Primrose North, South, and East
31 Day Average

Primrose North

Primrose East
Wolf Lake Oil, Water, Steam, and SOR

Wolf Lake CSS and SAGD
31 Day Average

- Z8 – Nov 1988 Steam Start
- HWP – Oct 1993 Steam Start
- E2 – Oct 2000 Steam Start
- N – Nov 2000 Steam Start
- Z13 – Nov 2005 Steam Start
- Aug 2011 SAGD Steam Only

Flow Rate (m³/d)

Cumulative SOR
Primrose Current Recoveries - 2013
## Primrose Current / Potential Recoveries

<table>
<thead>
<tr>
<th>Area 1:</th>
<th>OBIP (MMbbl)</th>
<th>Area (mi²)</th>
<th>Pay Thickness (ft)</th>
<th>Porosity (%)</th>
<th>Cum Oil (MMbbl)</th>
<th>Current Recovery</th>
<th>Potential Recovery Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5,730</td>
<td>2,049,000</td>
<td>14.1</td>
<td>32</td>
<td>1,285</td>
<td>22%</td>
<td>30.35%</td>
</tr>
<tr>
<td>2</td>
<td>3,851</td>
<td>1,639,000</td>
<td>12.5</td>
<td>32</td>
<td>957</td>
<td>15%</td>
<td>24.30%</td>
</tr>
<tr>
<td>3</td>
<td>3,001</td>
<td>1,702,000</td>
<td>13.5</td>
<td>32</td>
<td>759</td>
<td>15%</td>
<td>26.52%</td>
</tr>
<tr>
<td>4</td>
<td>3,552</td>
<td>1,486,000</td>
<td>13.1</td>
<td>32</td>
<td>817</td>
<td>12%</td>
<td>26.32%</td>
</tr>
<tr>
<td>5</td>
<td>4,377</td>
<td>1,489,000</td>
<td>15.4</td>
<td>32</td>
<td>438</td>
<td>12%</td>
<td>26.32%</td>
</tr>
<tr>
<td>6</td>
<td>3,377</td>
<td>1,489,000</td>
<td>13.1</td>
<td>32</td>
<td>410</td>
<td>12%</td>
<td>27.28%</td>
</tr>
<tr>
<td>7</td>
<td>3,056</td>
<td>444,000</td>
<td>3.7</td>
<td>32</td>
<td>99</td>
<td>7%</td>
<td>15.24%</td>
</tr>
<tr>
<td>8</td>
<td>5,202</td>
<td>2,860,000</td>
<td>13.8</td>
<td>32</td>
<td>240</td>
<td>12%</td>
<td>21-27%</td>
</tr>
<tr>
<td><strong>Subtotal Area 1:</strong></td>
<td><strong>5,735</strong></td>
<td><strong>2,049,000</strong></td>
<td><strong>14.1</strong></td>
<td><strong>32</strong></td>
<td><strong>1,285</strong></td>
<td><strong>22%</strong></td>
<td><strong>30.35%</strong></td>
</tr>
<tr>
<td>Area 2:</td>
<td>OBIP (MMbbl)</td>
<td>Area (mi²)</td>
<td>Pay Thickness (ft)</td>
<td>Porosity (%)</td>
<td>Cum Oil (MMbbl)</td>
<td>Current Recovery</td>
<td>Potential Recovery Range</td>
</tr>
<tr>
<td>1</td>
<td>3,221</td>
<td>1,836,000</td>
<td>9.9</td>
<td>32</td>
<td>506</td>
<td>12%</td>
<td>21-27%</td>
</tr>
<tr>
<td>2</td>
<td>996</td>
<td>896,000</td>
<td>6.0</td>
<td>32</td>
<td>185</td>
<td>10%</td>
<td>20-22%</td>
</tr>
<tr>
<td>3</td>
<td>1,291</td>
<td>888,000</td>
<td>9.5</td>
<td>32</td>
<td>70</td>
<td>8%</td>
<td>15-22%</td>
</tr>
<tr>
<td>4</td>
<td>5,825</td>
<td>2,048,000</td>
<td>13.6</td>
<td>32</td>
<td>757</td>
<td>13%</td>
<td>20-30%</td>
</tr>
<tr>
<td>5</td>
<td>5,870</td>
<td>2,048,000</td>
<td>13.9</td>
<td>32</td>
<td>947</td>
<td>17%</td>
<td>23-30%</td>
</tr>
<tr>
<td>6</td>
<td>5,870</td>
<td>2,048,000</td>
<td>13.9</td>
<td>32</td>
<td>863</td>
<td>17%</td>
<td>21-27%</td>
</tr>
<tr>
<td>7</td>
<td>5,268</td>
<td>2,048,000</td>
<td>13.9</td>
<td>32</td>
<td>851</td>
<td>17%</td>
<td>23-30%</td>
</tr>
<tr>
<td>8</td>
<td>5,616</td>
<td>2,048,000</td>
<td>13.9</td>
<td>32</td>
<td>951</td>
<td>17%</td>
<td>23-30%</td>
</tr>
<tr>
<td>9</td>
<td>5,735</td>
<td>2,860,000</td>
<td>13.5</td>
<td>32</td>
<td>1,016</td>
<td>15%</td>
<td>25-32%</td>
</tr>
<tr>
<td>10</td>
<td>5,068</td>
<td>1,020,000</td>
<td>13.5</td>
<td>32</td>
<td>717</td>
<td>14%</td>
<td>22-26%</td>
</tr>
<tr>
<td>11</td>
<td>5,070</td>
<td>1,020,000</td>
<td>14.3</td>
<td>32</td>
<td>723</td>
<td>14%</td>
<td>26-30%</td>
</tr>
<tr>
<td>12</td>
<td>5,112</td>
<td>1,020,000</td>
<td>13.8</td>
<td>32</td>
<td>733</td>
<td>13%</td>
<td>21-27%</td>
</tr>
<tr>
<td><strong>Subtotal Area 2:</strong></td>
<td><strong>5,645</strong></td>
<td><strong>2,049,000</strong></td>
<td><strong>14.1</strong></td>
<td><strong>32</strong></td>
<td><strong>1,285</strong></td>
<td><strong>22%</strong></td>
<td><strong>30.35%</strong></td>
</tr>
<tr>
<td>Area 3:</td>
<td>OBIP (MMbbl)</td>
<td>Area (mi²)</td>
<td>Pay Thickness (ft)</td>
<td>Porosity (%)</td>
<td>Cum Oil (MMbbl)</td>
<td>Current Recovery</td>
<td>Potential Recovery Range</td>
</tr>
<tr>
<td>1</td>
<td>5,772</td>
<td>2,860,000</td>
<td>11.2</td>
<td>32</td>
<td>1,146</td>
<td>30%</td>
<td>24-30%</td>
</tr>
<tr>
<td>2</td>
<td>5,582</td>
<td>2,860,000</td>
<td>10.9</td>
<td>32</td>
<td>1,229</td>
<td>32%</td>
<td>23-50%</td>
</tr>
<tr>
<td>3</td>
<td>5,725</td>
<td>2,860,000</td>
<td>13.8</td>
<td>32</td>
<td>1,116</td>
<td>25%</td>
<td>24-30%</td>
</tr>
<tr>
<td>4</td>
<td>7,065</td>
<td>3,072,000</td>
<td>11.2</td>
<td>32</td>
<td>1,141</td>
<td>18%</td>
<td>21-27%</td>
</tr>
<tr>
<td><strong>Subtotal Area 3:</strong></td>
<td><strong>24,142</strong></td>
<td><strong>2,860,000</strong></td>
<td><strong>11.2</strong></td>
<td><strong>32</strong></td>
<td><strong>1,146</strong></td>
<td><strong>30%</strong></td>
<td><strong>24-30%</strong></td>
</tr>
<tr>
<td>Area 4:</td>
<td>OBIP (MMbbl)</td>
<td>Area (mi²)</td>
<td>Pay Thickness (ft)</td>
<td>Porosity (%)</td>
<td>Cum Oil (MMbbl)</td>
<td>Current Recovery</td>
<td>Potential Recovery Range</td>
</tr>
<tr>
<td>1</td>
<td>10,294</td>
<td>4,175,104</td>
<td>10.4</td>
<td>32</td>
<td>1,827</td>
<td>9%</td>
<td>20-30%</td>
</tr>
<tr>
<td>2</td>
<td>10,303</td>
<td>4,175,104</td>
<td>10.4</td>
<td>32</td>
<td>1,805</td>
<td>7%</td>
<td>20-30%</td>
</tr>
<tr>
<td>3</td>
<td>11,134</td>
<td>4,175,104</td>
<td>11.3</td>
<td>32</td>
<td>2,000</td>
<td>15%</td>
<td>21-27%</td>
</tr>
<tr>
<td><strong>Subtotal Area 4:</strong></td>
<td><strong>32,189</strong></td>
<td><strong>4,175,104</strong></td>
<td><strong>10.4</strong></td>
<td><strong>32</strong></td>
<td><strong>1,827</strong></td>
<td><strong>9%</strong></td>
<td><strong>20-30%</strong></td>
</tr>
<tr>
<td>Area 5:</td>
<td>OBIP (MMbbl)</td>
<td>Area (mi²)</td>
<td>Pay Thickness (ft)</td>
<td>Porosity (%)</td>
<td>Cum Oil (MMbbl)</td>
<td>Current Recovery</td>
<td>Potential Recovery Range</td>
</tr>
<tr>
<td>1</td>
<td>4,028</td>
<td>2,725,000</td>
<td>8.3</td>
<td>32</td>
<td>947</td>
<td>15%</td>
<td>23-30%</td>
</tr>
<tr>
<td>2</td>
<td>7,050</td>
<td>300,000</td>
<td>11.3</td>
<td>32</td>
<td>706</td>
<td>14%</td>
<td>47-50%</td>
</tr>
<tr>
<td>3</td>
<td>2,503</td>
<td>300,000</td>
<td>11.3</td>
<td>32</td>
<td>555</td>
<td>24%</td>
<td>42-48%</td>
</tr>
<tr>
<td><strong>Subtotal Area 5:</strong></td>
<td><strong>5,730</strong></td>
<td><strong>2,725,000</strong></td>
<td><strong>8.3</strong></td>
<td><strong>32</strong></td>
<td><strong>947</strong></td>
<td><strong>15%</strong></td>
<td><strong>23-30%</strong></td>
</tr>
<tr>
<td>Area 6:</td>
<td>OBIP (MMbbl)</td>
<td>Area (mi²)</td>
<td>Pay Thickness (ft)</td>
<td>Porosity (%)</td>
<td>Cum Oil (MMbbl)</td>
<td>Current Recovery</td>
<td>Potential Recovery Range</td>
</tr>
<tr>
<td>1</td>
<td>14,533</td>
<td>4,817,342</td>
<td>15.1</td>
<td>32</td>
<td>1,497</td>
<td>15%</td>
<td>13-18%</td>
</tr>
<tr>
<td>2</td>
<td>14,247</td>
<td>4,817,342</td>
<td>14.5</td>
<td>32</td>
<td>1,120</td>
<td>9%</td>
<td>13-18%</td>
</tr>
<tr>
<td>3</td>
<td>14,000</td>
<td>4,817,342</td>
<td>15.0</td>
<td>32</td>
<td>1,150</td>
<td>8%</td>
<td>13-18%</td>
</tr>
<tr>
<td>4</td>
<td>15,585</td>
<td>4,817,342</td>
<td>15.7</td>
<td>32</td>
<td>1,748</td>
<td>11%</td>
<td>13-18%</td>
</tr>
<tr>
<td><strong>Subtotal Area 6:</strong></td>
<td><strong>59,165</strong></td>
<td><strong>4,817,342</strong></td>
<td><strong>15.1</strong></td>
<td><strong>32</strong></td>
<td><strong>1,497</strong></td>
<td><strong>15%</strong></td>
<td><strong>13-18%</strong></td>
</tr>
<tr>
<td><strong>Primary Total</strong></td>
<td><strong>378,963</strong></td>
<td><strong>49,959</strong></td>
<td><strong>13%</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Primrose Performance Variation

- Predictable performance up to 15% recovery factor
Early Recovery - Phase 26 Type Curve

Average Reservoir Parameters
- Net Pay 7m
- Oil Saturation 65%
- Porosity 32%

Above Average Performance
- Thin reservoir
- 20 wells at 60 m spacing
  - Gas cap on NE corner of pad

Too early in life to predict actual recovery at 40% PV steam
- 3 CSS cycles complete
- C4 Steam underway
Early Recovery - Phase 26
Production History

Cycle 2 and 3 steam volumes fill-up only due to non-remediated Dome AEC legacy well in area

- Expected performance for early life mini cycles
  - Re-stimulation of near wellbore region with benefit of voidage created Cycle 1
  - Little to no impact to long term recovery when minis conducted early life (PV Steam < 0.1)

Post cycle 1 mini steam cycles successful in early life recovery
Mid Recovery - Phase 53
Type Curve

Average Reservoir Parameters
- Net Pay 16m
- Oil Saturation 61%
- Porosity 32%

Below Average Performance
- No steam growth last cycle

16 horizontal wells at 160 m spacing (average)

Forecasting <15% actual recovery at 40% PV steam

Cycle 3 prematurely steamed resulting in more energy to reheat excess water in the reservoir

Subsequent cycles show that with proper pump time, performance is parallel to the type curve
Mid Recovery - Phase 53
Production History

Cycle 5 steam volumes reduced significantly from Cycle 4 volumes
- Avg steam/well C4: 113k m³ vs. Avg steam/well C5: 44k m³

Poorest performance in mid-life wells when significant steam volume reduction from cycle to cycle
Late Recovery - Phase 27 Type Curve

Average Reservoir Parameters
- Net Pay 8 m
- Oil Saturation 64%
- Porosity 32%

Average Performance
- Slightly lower than average thickness, average quality reservoir

8 horizontal wells at 165m spacing (average)
Forecasting 15% actual recovery at 40% PV steam
Late Recovery - Phase 27
Production History

Type curve performance achieved

- Cycle duration (time) is a function of well life (i.e. older wells need longer pump time)

![Graph showing production history for Phase 27 with notes 9C27 steamed with Ph28]
Tight Spacing Well Performance
Type Curves for T68, Pad 28 and Primrose East (PRE) Phase 1

- CSS wells recovering similar amount of bitumen regardless of well spacing

- Tight well spacing actual recovery factors on track to double wide well spacing

**TYPE CURVE RECOVERY**

**ACTUAL RECOVERY**

Normalized values calculated by using recoveries from 60-80m spacing but increasing the drainage area to have 160m spacing.
Tight Spacing Well Performance
CSS Well Spacing Concept

• Heat transfer occurs over a finite distance before its efficiency drops below the economic limit

• Optimum well spacing will yield maximum recovery, reserves and NPV

• Affected by reservoir quality and commodity prices

• Field example:
  – Primrose South Phase 1
    ▪ 80 m vs. 160 m Spacing
Tight Spacing Well Performance
Primrose South Phase 1

Pads that are in the same reservoir but at different well spacing

C1 & B1 160 m
D1 80 m
### Comparison of D1 (80 m spacing) with C1 and B1 (160 m Spacing) Wells

<table>
<thead>
<tr>
<th>Cum. Steam (m³)</th>
<th>Cum. Oil (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>200,000</td>
<td></td>
</tr>
<tr>
<td>400,000</td>
<td></td>
</tr>
<tr>
<td>600,000</td>
<td></td>
</tr>
<tr>
<td>800,000</td>
<td></td>
</tr>
<tr>
<td>1,000,000</td>
<td></td>
</tr>
<tr>
<td>1,200,000</td>
<td></td>
</tr>
</tbody>
</table>

- **C1 Wells (160 m)**
- **D1 Low Wells (80 m)**
- **D1 High Wells (80 m)**
- **B1 Wells (160 m)**

Production data indicates wells have a similar performance profile regardless of spacing.
Tight Spacing Well Performance

Conclusions

• Tighter spacing wells perform with similar normalized thermal efficiency as larger spacing wells
  • Similar cumulative oil volume vs steam volume performance per well regardless of spacing
  • This results in a higher actual recovery for a densely spaced pad of the same area
    • Currently on track to approximately double the recovery

• Tighter well spacing will increase ultimate oil recovery for CSS

• 60-80m spacing is currently standard for Canadian Natural’s PAW area
2014 Steam Schedules

### Primrose North

<table>
<thead>
<tr>
<th>Month</th>
<th>Steam Start Date</th>
<th>Steam Volume/Well (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>Phase 55</td>
<td>115,000</td>
</tr>
<tr>
<td>Feb-14</td>
<td>Phase 60, 64, 68</td>
<td>10,000</td>
</tr>
<tr>
<td>Mar-14</td>
<td>Phase 61, 65</td>
<td>10,000</td>
</tr>
<tr>
<td>Apr-14</td>
<td>Phase 60, 64, 68</td>
<td>17,000</td>
</tr>
<tr>
<td>May-14</td>
<td>Phase 61, 65</td>
<td>17,000</td>
</tr>
<tr>
<td>Jun-14</td>
<td>Phase 60, 64, 68</td>
<td>25,000</td>
</tr>
<tr>
<td>Jul-14</td>
<td>Phase 61, 65</td>
<td>25,000</td>
</tr>
<tr>
<td>Aug-14</td>
<td>Phase 60, 64, 68</td>
<td>25,000</td>
</tr>
<tr>
<td>Sep-14</td>
<td>Phase 60, 64, 68</td>
<td>25,000</td>
</tr>
<tr>
<td>Oct-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov-14</td>
<td>Phase 61, 65</td>
<td>25,000</td>
</tr>
<tr>
<td>Dec-14</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Primrose South

<table>
<thead>
<tr>
<th>Month</th>
<th>Steam Start Date</th>
<th>Steam Volume/Well (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>Phase 25-26</td>
<td>25,000</td>
</tr>
<tr>
<td>Feb-14</td>
<td>Phase 23-24</td>
<td>70,000</td>
</tr>
<tr>
<td>Mar-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Apr-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>May-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jun-14</td>
<td>Phase 25-26</td>
<td>30,000</td>
</tr>
<tr>
<td>Jul-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aug-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sep-14</td>
<td>Phase 40-43</td>
<td>10,000 &amp; 17,000</td>
</tr>
<tr>
<td>Oct-14</td>
<td>(Orange Sands)</td>
<td></td>
</tr>
<tr>
<td>Nov-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Dec-14</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Primrose East

<table>
<thead>
<tr>
<th>Month</th>
<th>Steam Start Date</th>
<th>Steam Volume / Well (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Feb-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Mar-14</td>
<td>Phase 74-78</td>
<td>Steamflood (~400 CDSR)</td>
</tr>
<tr>
<td>Apr-14</td>
<td>Phase 90</td>
<td>17,000</td>
</tr>
<tr>
<td>May-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jun-14</td>
<td>Phase 91</td>
<td>7,000</td>
</tr>
<tr>
<td>Jul-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aug-14</td>
<td>Phase 92-93</td>
<td>13,000 &amp; 16,000</td>
</tr>
<tr>
<td>Sep-14</td>
<td>Phase 94-95</td>
<td>9,500 &amp; 15,000</td>
</tr>
<tr>
<td>Oct-14</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Nov-14</td>
<td>Phase 90-91</td>
<td>20,000 &amp; 8,100</td>
</tr>
<tr>
<td>Dec-14</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Primrose East Area 1 Update

• 2013 Activity
  – Last steamed from West to East during Q2-Q3 2012
    ▪ On pumping production for all of 2013
  – FTS discovered at 2 new locations when area was depressured
    ▪ Investigation on-going

• 2014 Plans
  – Steamflood
    ▪ Meets original application intent for follow-up process
      ▪ Majority of area within desired recovery range to convert
        • Recovery factor ~17%
    ▪ Operation strategy → bottomhole pressure stays below hydrostatic
Primrose East Area 1 – Current Cycle Performance

- Better SOR performance in the thicker pay (P75,77)
  - Longer pump time contributes to higher DI and lower SOR
    - Calendar Day Steam Rate Range: 80-55 m3/day/well

*Actual performance data as of Jan. 9th, 2012*
FUP – Scope of Proposed PR-E Steamflood

- Implement steamflood throughout all of Primrose East Area 1
  - 38 injectors / 39 producers

- Target reservoir pressure <4.5 MPa
  - Operate above bubble point
  - Increase heat transfer to oil sand
  - Minimize gas interference in pumps
  - Balance thermal efficiency with steam & oil rates
  - Mitigate risk underneath FTS investigation

- 1:1 producer/injector ratio

- Target injection rates <1,500 m³/d
  - 800-1500 m³/d during fill-up
  - 200-800 m³/d at target pressure
Primrose East Area 2 - 2013 Update

- CSS Cycle 2 through PRE A2
  - Started December 2012 on Pad 91, 92 (Fault above liners) → Block Steam
  - Started December 2012 on Pad 92 small block → 27,000 m³ steam per well
  - Started December 2012 on Pad 93 Gas Cap Fill-Up and Wave Steamed across 93, 95, 92
    - 120m buffers used on pads 92, 93 and 94 and were successful in mitigating but not eliminating inter-well communication
    - Performance on pads 92 & 93 exceeded expectations
  - Started June 2013 on Pad 90
    - Block steam strategy was implemented in order to eliminate inter-well communication and excessive well soaking
    - Due to discovery of bitumen at surface, PRE steam ended in June 2013 and P90 cycle 2 steam volumes were cut short
    - Useful data for PRE A2 CSS analog
PRE Area 2 Features & Steam Strategy

PRE A2 Features
- Varying well spacing/lengths
  - 60-86.5m spacing
  - 500m-1450m liner lengths
- Burnt Lake Proximity
- P93,94,95 Gas Caps
- P91 Fault

PRE Area 2 Features
- Varying well spacing/lengths
  - 60-86.5m spacing
  - 500m-1450m liner lengths
- Burnt Lake Proximity
- P93,94,95 Gas Caps
- P91 Fault
Steaming stopped June 2013 due to FTS

- Pad 90, 91 was on steam → reduced cycle volumes

Note: Non-GC are referring to wells that are not used for CLWTR gas cap compression
PRE Area 2 Cycle 2 - Performance to Date

Performance variances from forecast due to steam plant shut in and better than expected results from reservoir pressure management

- Inter-well communication observed on all wave-steamed pads, however steam strategies were able to minimize the negative affects of this

Pad 91 is shut in since wells were too cold to continue pumping

*Performance data as of January 6th, 2014*
PRE Area 2
Pad 91 Fault – Block Steam Cycle 1 and 2

10k m³ steam per well into P91 in Cycle 1
- 1-26 and 13-24 monitoring wells near fault showed similar response to steam injection throughout PRE A2
  - Pressure increases during initial cycle injection

30k m³ steam per well into P91 in Cycle 2
- In addition to LGR surveillance, passive seismic and thermal fiber was added to 1-26 and 13-24 observation wells
- LGR pressures observed during Cycle 1 were reduced magnitude during Cycle 2
- Seismic anomalies have been observed during production, believed to be associated with reservoir subsidence
- P91 fault steaming continues to be an important point of research in CSS development
PRE Area 2 Cycle 2
Gas Cap Update - Background

- Three gas caps are present in the Clearwater Formation above phases 93, 94 and 95.
- Phase 93 saw 8 wells connect with the gas cap in cycle 1
  - Thermal efficiency impacts
- 17A93 and 11A94 were perforated on pads 93 and 94 to inject directly into the respective gas caps (see highlighted)
- Phase 95 did not connect with gas cap after cycle 2 steaming
  - Buffer distance: ~160m

### Gas Cap Estimated Pore Volumes

1. Pad 93: 215,000 m³
2. Pad 94: 130,000 m³
3. Pad 95: 375,000 m³
PRE Area 2
Pad 93 Gas Cap Learnings

After communication was established in cycle 1, performance suffered
  – Gas cap compression required to dilate reservoir
  – Production depleted volumes previously used to compress gas cap
    ▪ Reduced oil cut

Prior to cycle 2 steam, 17A93 was perforated to directly inject into the gas cap.
  – Preferentially compresses the gas cap with 1 wellbore
  – Improves offsetting wellbores conformance by minimizing leak-off to gas cap

Steam-Oil Ratios for the wells under the gas cap improved from 9.7 to 8.5
  – Despite improved SOR, gross production was very similar cycle 1 to cycle 2
    ▪ Oil cuts were still low (~20% both cycles)

Gas cap single well injector improved performance, however the gas cap effects still impacted the performance when compared to non-gas cap wells.
PRE Area 2
Pad 93 Gas Cap – Monitoring Fill-Up

Reduced steam volume injected into CLWTR to compress gas cap
PRN Area 1
Phase 54 Steaming – 15-19 Wellbore Event

• Pressure increase observed on wellbore, which was monitoring open Colony perforations.
  – Faulty suspension, with cement top at 461mkb, likely began to influence the Colony zone
  – No other colony monitoring well observed an increase in pressure

• Steam injection was at the fill-up stage on Phase 54 during the reaction.
  – A 3 row buffer from steam was created by producing rows 7 and 8 (6 was not steamed)

• Surface access has been established and well servicing investigation to begin Q1 2014
PRN Area 1
Phase 54 & 55 Steaming (in progress)

• Pad 54 steam completed
• Pad 55 currently block steaming

Pad 54: 92,000 m³ average per well
Pad 55: 102,000 m³ average per well
PRN Area 2
Pad 66 Multi-Well Injectivity Event Learning

- Multi-well injectivity event occurred on P66 on June 11, 2013
  - Injectivity observed with corresponding pressure decrease on 5 wells on Pad 66
  - A known Clearwater FAE gas cap exists above these wells in the area.

- All affected wellbores on Pad 66 were taken down to trickle steam rates

- Observation well response indicated a redistribution of fluid within the Clearwater zone as fluid migrated into voidage areas of the Phase 66 drainage box

- As a precaution steaming operations were buffered to the North of wellbore 10A66
  - A two row buffer to high pressure steam was utilized.

- The steam wave was then completed as the observation wells showed recovery from the event
PRN Area 2
12-14-068-04-W4 Investigation

• Oil found in 12-14-68-4W4 Colony gas well on March 1, 2012
  – Oil sample analysis identified as steam affected Clearwater oil
  – Follow up logging commenced in Q1 2013 upon gaining winter access

• 12-14 Logging investigation findings:
  – Temperature, Bond, and RST logs were run
  – Casing failure found within Clearwater sand interval
  – Data suggests poor wellbore is responsible for Colony response

• Recompleted as Lower Grand Rapids Observation wells
  – 12-14 completed as B12 observation well
Phase 25-26 Update

- Phase 25A/B & 26
  - Pads 25A/B
    - 15 wells at 80 m spacing
  - Pad 26
    - 20 wells at 60 m spacing
  - Total of 50 wells
  - 650-1650m laterals
  - Steam-in date: Q2 2013
  - Cycle 1 CSS
    - Steam-In Date: Q2 2013
    - ~23,000 m³/well
  - Cycle 2 & 3 Mini CSS
    - Steam-in Date: Q3 2013
  - Cycle 4 CSS (Upcoming)
    - Steam-in Date: Q1 2014
    - ~ 23,000 m³/d
PRS
Phase 26/25 Gas Cap Summary

• Clearwater FAE gas caps located above Phases 25 & 26
• CD Muds separate majority of reservoir from the FAE gas cap
  – Observing limited connectivity to the FAE gas cap
  – Gas cap predominantly filled with water (low gas saturation)
• No significant impact to operations
Primrose Flow to Surface Events

• In May and June 2013, three bitumen releases, (flow to surface [FTS] sites), were identified within Primrose East:
  – 10-01-067-03 W4M (10-1)
  – 10-02-067-03 W4M (10-2)
  – 02-22-067-03 W4M (2-22)

• On June 24, 2013 an additional bitumen FTS was identified within Primrose South:
  – 09-21-067-04 W4M (9-21)

• To date the seepages are contained and cleanup is complete on all three Primrose East terrestrial sites and is ~80% (as of today) complete at 9-21.
Primrose Flow to Surface Events

- Canadian Natural is working diligently with the AER and ESRD to investigate and remediate the affected locations and investigate the cause.
Key Learning – Dome AEC Legacy Wells

- Drilled 1981-1984 by Dome AEC
- Abandoned without confirmation of cement tops and gaps between plug 2 and 3 across the Colorado Shale group
- Open conduits across the Colorado Shale group are seen as potential pathways for fluid migration to upper horizons and possibly surface.
- Wellbores were classified as thermal compliant with the documented cement tops
- All wellbores will be investigated and remediated prior to conducting steaming within the area

Open Conduit in Colorado Shale group
Key Learning – Dome AEC Legacy Wells

- 7 of 25 wells remediated
Key Learning – Liner Re-Drill Learnings

• Re-entries drilled in PAW to overcome lost horizontal liner access or suspected poor wellbore placement
  – Primrose North: 4A58, 7A58, 3A66, 8A66
  – Wolf Lake: S1A-2L, MC1-1L

• 3A66 re-drill unsuccessful due to difficulties drilling in unconsolidated sands with existing voidage and low bottomhole pressure
  – Lost circulation issues
  – Hole collapse leading to trapped liner and drill pipe
Developing Learning – Thin Pay Pilot On-Track

- Thin pay trail on Phases 25-26
  - Pay thickness range: 5.5-7.0m
- Performance is meeting/exceeding type curve expectations so far
  - One CSS cycle followed by two mini cycles
  - Currently on steam
Primrose Next Development
Primrose North Development

Primrose North Area 3 (60-68)

- 5 Pads with 20 wells/pad
  - 100 wells total
  - 80 m well spacing
- 895 - 1700 m laterals
- Steam in date scheduled for Q1 2014
- Steam wave injection volumes
  - 10,000 m³/well Commissioning 1
  - 17,000 m³/well Commissioning 2
- Drilling and Construction Complete
Primrose South Development

Phases 40-43 (Orange Sand)

- Canadian Natural’s first development in Orange Sand Valley
- 4 Pads with 24 wells, 74m spacing
  - Total of 96 wells
- 700-1700m laterals
- Drilling complete Q2 2014
- Steam-in date: Q3 2014
- Steam wave injection volumes (nominal)
  - 10,000 m³/well Commissioning 1
  - 17,000 m³/well Commissioning 2
Other Development Plans

• PRN Development – Proposed Application Date Q1 2014
  – Canadian Natural plans to apply for new pads with ~120-130 horizontal CSS wells in the Clearwater Formation; wells in Primrose North (68-4W4, 68-5W4) would be steamed from PRN Plant
    ▪ Drilling in Q1 2015
    ▪ Steam in late 2016

• PRS Development – Proposed Application Date Q1 2014
  – Canadian Natural plans to apply for new pads with ~72 horizontal CSS wells in the Clearwater Formation; wells in Primrose South (67-4W4) would be steamed from PRS Plant
    ▪ Drilling in Q1 2015
    ▪ Steam in late 2016

• WL Development
  – One steam generator to be added to WL Plant – Proposed Application Date Q1 2014
  – WL Pad Adds in 66-5W4 - Proposed Application Date Q2 2014,
    ▪ Drilling Q2 2015
    ▪ Steam in late 2016
  – Z13 Re-drills, currently developing scope
  – MC1 Step-outs, currently developing scope
CSS Summary

• Re-entries/infills are an excellent way to capture reserves stranded by early cycle liner problems and/or too large of spacing however difficulties arise when drilling in a depleted, low pressure reservoir

• For a given drainage area, the use of smaller spaced wells achieves a higher ultimate recovery
  – Normalized type curves are the same for a more densely spaced pad

• PAW strategy change and wellbore investigation and remediation to mitigate risk going forward
  – Reduced steam volumes with multiple commissioning cycles
  – Increased Grand Rapids monitoring
  – Tighter alarm criteria
FUP – Follow Up Process to CSS

- The proposed FUP strategy based on infill wells operated as dedicated injectors and mature wells operated as dedicated producers

- Repeated Cyclic Drive (CD) cycles required to establish good inter-well communication, followed by Steamflood (SF)
FUP – Potential Scope in Primrose South/North

- FUP requires extensive infill drilling to reduce well spacing from current 160-190 m to 80-95 m
- Scope of potential infill program depends on success of field trials
  - C17: cyclic drive (CD)
  - D1: steamflood (SF)
- Targeting commercial application in Primrose South/North by 2017-2019
- PR-S Phases 1-21 OBIP ~675 MMbbl
  - Current average CSS RF ~17%
- Significant incremental recovery potential based on preliminary CD/SF performance forecasts
  - Ultimate Ph1-21 CSS RF = 26%
  - Ultimate Ph1-21 CD/SF RF >35%
FUP – Impact of Continued CSS in PR-S

- Need to pressure up mature wells prior to first infill cycle to achieve horizontal orientation of infill fractures, key requirement for good interwell communication
  - Another CSS cycle would increase steam volumes required to change stress state
  - Recommend no further CSS cycles due to negative impact on infill economics
FUP – Status of Cyclic Drive Trial at C17

- 2012 CD cycle operated at while 2011 CD cycle operated below fracture pressure
  - Performance directionally encouraging, improved SOR/CDOR vs. WDI trends
  - Apparent reduction in achievable WDI at comparable CDSR, likely due to off-pattern fluid migration in Clearwater
FUP – Status of Steamflood Trial at D1
Meeting Simulation Results → Looks Promising

- Dedicated injection into 2/4/6/8D1 and dedicated production from 1/3/5/7D1+1C2 since June 2012
  - Performance generally meets simulation based expectations
  - Reservoir pressure 0.5-1.0 MPa
  - Production 20-30% lower than initially expected due to persistent sand control issues on a few wells
FUP – Steamflood in Primrose East A1

- Encouraging D1 trial performance to date suggests steamflood is a viable FUP to CSS in Clearwater reservoir
  - extensive numerical simulation supports application of steamflood technology on Phases 74-78 (A1)
- Significant D1 gas production limits pump efficiency and hence CDSR
  - Minimize gas interference by targeting $P_{\text{reservoir}} \geq P_{\text{bubble}}$
- High degree of interwell communication supports expansion of SF technology
- RF: PR-E A1 = 17% vs. D1 at start of SF trial = 35.3% (excl. buffers)
- PR-E A1 has thicker pay, tighter well spacing and lighter oil than D1
FUP – Scope of Proposed PR-E Steamflood

- Implement steamflood throughout all of Primrose East Area 1
  - 38 injectors / 39 producers
- Target reservoir pressure <4.5 MPa
  - Operate above bubble point
  - Increase heat transfer to oil sand
  - Minimize gas interference in pumps
  - Balance thermal efficiency with steam & oil rates
  - Mitigates risk underneath FTS investigation
- 1:1 producer/injector ratio
- Target injection rates <1,500 m³/d
  - 800-1500 m³/d during fill-up
  - 200-800 m³/d at target pressure
Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. Forward-looking statements are identified by the words "believe," "may," "will," "would," "could," "should," "project," "forecast," "estimate," "plan," "intend," "expect," "tend," "continue," "likely," "expect," "strategy," "outlook," "opportunity," "goal," "target," "objective," "schedule," "intend," "may," "potential," "predict," "should," "will," "objective," "project," "forecast," "goal," "guidance," "outlook," "effort," "seeks," "schedule," "proposed" or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this Annual Information Form ("AIF") constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansion, Septimus Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia and the construction and future operations of the North Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, which speak as of the date such forward-looking statements are made or of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company's products; political conditions and international relations; the fiscal and monetary policies of governing authorities; the commodity price risk; the impact of existing and proposed legislation and regulations regarding the environment; the results of legal proceedings; the costs of seismic, drilling and other equipment; the ability of the Company and its subsidiaries to obtain adequate capital; the ability of the Company and its subsidiaries to implement its business strategy, including exploration and development activities; the effects of inflation; the cost of financing; the ability of the Company and its subsidiaries to replace and expand its reserves; the ability of the Company and its subsidiaries to accurately evaluate the potential of new exploration and development activities; the success of exploration activities; and the success of operations and development projects. Certain factors that could cause actual results to differ materially from current expectations include, but are not limited to, the uncertainty of estimates and reserves; the timing and cost of development; the success of exploration and production activities; the ability of the Company and its subsidiaries to predict future commodity prices; the availability of supplies; the availability of capital; the ability of the Company and its subsidiaries to implement its business strategy; the ability of the Company and its subsidiaries to obtain adequate capital; the ability of the Company and its subsidiaries to implement its business strategy, including exploration and development activities; the effects of inflation; the cost of financing; the ability of the Company and its subsidiaries to replace and expand its reserves; the ability of the Company and its subsidiaries to accurately evaluate the potential of new exploration and development activities; the success of exploration activities; and the success of operations and development projects. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to the Company or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, of the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.
Reporting Disclosures

Special Note Regarding Currency, Production and Reserves
In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This document, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators (“Evaluators”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2012 and a preparation date of February 11, 2013. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission (“SEC”) requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report targeted to be released in late March 2013.

Resources Other Than Reserves
The contingent resources other than reserves (“resources”) estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101. No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2012. The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures
This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations, cash production costs, and net asset value. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company’s performance. No non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS in the “Financial Highlights” section of the Company’s MD&A which is incorporated by reference into this document. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A which is incorporated by reference into this document.

The volumes shown are Company share before royalties unless otherwise stated.
THE PREMIUM VALUE DEFINED GROWTH INDEPENDENT
2013 PRIMROSE, WOLF LAKE, AND BURNT LAKE ANNUAL PRESENTATION TO THE AER

SURFACE OPERATIONS, COMPLIANCE AND ISSUES NOT RELATED TO RESOURCE EVALUATION AND RECOVERY

January 2014
Directive 54: Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

• January 29, 2014

  3.1.1 Subsurface Issues Related to Resource Evaluation and Recovery

• January 30, 2014

  3.1.2 Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery
Outline - Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery

- Facilities
  - Plot Plans, Simplified Plant Schematic, Modifications and Updates
  - Facility Performance
    - Oil & Water Treatment, Steam & Power Generation, Gas Usage, Greenhouse Gas Emissions
    - Water Imbalances
    - FTS Facility Performance Operating Impacts
- Measurement & Reporting
  - Well Production Estimates, Proration factors, Test Durations, New Measurement Technology
- Water Production, Injection, and Uses
  - UWIs, Water Uses and Water Quality
  - Fresh, Brackish, Steam and Produced Water Volumes & Forecasts
  - Brackish Water Supply
  - UWIs & Disposal Well Compliance
  - Wolf Lake Disposal & Water Storage Volumes
  - Wolf Lake Waste Disposal
<table>
<thead>
<tr>
<th>Outline - Surface Operations, Compliance, and Issues Not Related to Resource Evaluation and Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>• Sulphur Production</strong></td>
</tr>
<tr>
<td>▪ Summary and Discussion of Emissions</td>
</tr>
<tr>
<td>Page</td>
</tr>
<tr>
<td><strong>• Environmental Summary</strong></td>
</tr>
<tr>
<td>▪ Compliance Issues &amp; Amendments</td>
</tr>
<tr>
<td>▪ Monitoring Programs</td>
</tr>
<tr>
<td>▪ Reclamation</td>
</tr>
<tr>
<td>▪ Regional Initiatives</td>
</tr>
<tr>
<td>▪ Groundwater Monitoring</td>
</tr>
<tr>
<td>Page</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td><strong>• Abandonments</strong></td>
</tr>
<tr>
<td>Page</td>
</tr>
<tr>
<td><strong>• Approval Condition Compliance</strong></td>
</tr>
<tr>
<td>▪ Approvals (9140R, 9108, 8186A, 8672A, 8673, 3929A, 4128D, 9792A)</td>
</tr>
<tr>
<td>Page</td>
</tr>
<tr>
<td><strong>• Discussion of Non-Compliance Items</strong></td>
</tr>
<tr>
<td>▪ Self Disclosures</td>
</tr>
<tr>
<td>Page</td>
</tr>
<tr>
<td><strong>• Future Plans</strong></td>
</tr>
<tr>
<td>Page</td>
</tr>
</tbody>
</table>
Facilities

• Detailed Site Survey Plans - refer to included drawings:
  – Wolf Lake Plant Plot Plan
  – Primrose Plant Plot Plans (South, North, East)
  – Typical Pad Plot Plan (Primrose East)

• Simplified Plant Schematic - refer to included drawings:
  – Wolf Lake / Primrose Simplified Plant Facilities Schematic

• Summary of Modifications:
  – Wolf Lake Non-Saline Water Reduction
    • Construction started in 2013 to lower non-saline water usage. Partial commissioning completed at the end of 2013. Construction and commissioning to continue into 2014.
  – Wolf Lake Unit 3 DCS Upgrade
    • Replaced obsolete control system in Wolf Lake Plant Unit 3 (part of multi-year program)
Facilities

• Summary of Modifications (continued)
  – Added Nuclear Density Array on Unit 2 Treater
    ▪ Monitors oil density in the Treater for interface level management
    ▪ Provides more stable operations with less carryover/carryunder
  – Wolf Lake Slop Oil Treatment System
    ▪ Commissioning and troubleshooting the centrifuge
  – Wolf Lake Salt Cavern
    ▪ Installed a new pump and a rental filter package
  – Unit 2 Sales Oil Debottleneck
    ▪ Installed a new pump
  – Unit 2 IGF Retrofit
    ▪ Installed 2 pumps and new eductors as part of an upgrade to the IGF system in Unit 2 at Wolf Lake to match Unit 8 and improve performance
Facilities

• Summary of Modifications (continued)
  – D1 Steam Drip Leg Installation
    ▪ Liquid dropout piping to improve steam qualities
  – HRSG Repairs
    ▪ Completed major repairs and replacement of the failed module. Modules upgraded to be fully piggable and constructed of P22 material. System fully commissioned and now running at full rates. Optimization and testing on-going.
  – Primrose East Plant Steam Plant Modifications
    ▪ OTSG modifications to use as a feedwater pre-heater to allow warmer BFW to mix with colder emulsion from Primrose East Area 1 and Area 2
Specific Project Update

• Wolf Lake Non-Saline Water Reduction
  – Project to reduce non-saline water consumption to 3,000 m³/d
  – Plant upgrades include:
    ▪ Conversion of ion exchange package from non-saline water to saline water
    ▪ 2 new glycol fan bays
    ▪ new glycol pumps and building
    ▪ 3 new glycol coolers
    ▪ New slurry feed pumps
    ▪ Piping modifications to allow saline heating in 114-E
  – Project construction nearing completion. Some systems partially commissioned.
Primrose East Sulphur Treatment

- Temporary produced gas sweetening at Primrose East
  - Sweetening package was re-started on August 8, 2013
  - Some produced gas was conserved by sending it to Primrose South as sweet fuel gas
  - Flaring due to compressor issues/servicing, Primrose South outages and undersized package for current field size
    - Was intended for use during initial plant outage when Primrose East Area 1 were the only pads in operation
    - Not sized for both Primrose East Area 1 and Area 2
    - Maximum flow rate of sweetened gas that can be sent from Primrose East to Primrose South ~7,300 m$^3$/h
      - Primrose South unable to utilize additional gas without flaring
  - Total sulphur removed: ~ 84 tonnes (Aug 8 – Dec 31, 2013)
  - Total sulphur flared: ~ 164 tonnes (June 7 – Dec 31, 2013)
Facility Performance

• Bitumen and Water Treatment
  – Overall water quality and oil treating targets were met:
    ▪ Set saline water make-up and oil treating records
    ▪ Production temperatures from Primrose East depressurizing were challenging to handle properly, from initially very hot to a gradual cooling down.
  – Disposal system pushed to assist in depressurizing the FTS areas
    ▪ Disposal system limited due to the reliability of the entire system due to age
      ▪ passing valves, well injectivity issues, salt cavern disposal pump issues and disposal pump reliability issues
    ▪ Several projects on-going to minimize these problems
  – Successfully completed Units 10/11, Unit 2 (deoiling only) and Unit 3 turnarounds this year
Facility Performance

• Steam Generation:
  – Primrose North achieved 90.1% of budget injected steam volumes
  – Primrose South achieved 90.4% of budget injected steam volumes
  – Primrose East steam plant was shut down on June 7 due to the FTS
  – Temporary cut backs at both Primrose South and Primrose North due to the FTS in Primrose East
  – Two HRSG module replacements in November due to failure in 2012
Facility Performance

- Power generation/consumption on a monthly basis
- Net consumption high in Sept/Oct due to HRSG turnaround

<table>
<thead>
<tr>
<th>Month</th>
<th>Power Generation MWh</th>
<th>Power Consumption MWh</th>
<th>Net MWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>64,672</td>
<td>76,814</td>
<td>-12,142</td>
</tr>
<tr>
<td>February</td>
<td>57,879</td>
<td>66,943</td>
<td>-9,064</td>
</tr>
<tr>
<td>March</td>
<td>64,576</td>
<td>72,528</td>
<td>-7,952</td>
</tr>
<tr>
<td>April</td>
<td>60,502</td>
<td>65,467</td>
<td>-4,965</td>
</tr>
<tr>
<td>May</td>
<td>58,494</td>
<td>62,631</td>
<td>-4,137</td>
</tr>
<tr>
<td>June</td>
<td>55,743</td>
<td>54,159</td>
<td>1,584</td>
</tr>
<tr>
<td>July</td>
<td>57,340</td>
<td>53,825</td>
<td>3,515</td>
</tr>
<tr>
<td>August</td>
<td>56,237</td>
<td>56,497</td>
<td>-260</td>
</tr>
<tr>
<td>September</td>
<td>4,753</td>
<td>50,451</td>
<td>-45,698</td>
</tr>
<tr>
<td>October</td>
<td>24,920</td>
<td>54,290</td>
<td>-29,369</td>
</tr>
<tr>
<td>November</td>
<td>60,752</td>
<td>59,818</td>
<td>934</td>
</tr>
<tr>
<td>December</td>
<td>65,667</td>
<td>62,029</td>
<td>3,368</td>
</tr>
</tbody>
</table>
### Facility Performance

**Gas Usage on a monthly basis**

<table>
<thead>
<tr>
<th>Month</th>
<th>Total Purchased Gas e3m³</th>
<th>Total Solution Gas Conserved e3m³</th>
<th>Total Gas Vented E3m³</th>
<th>Total Solution Gas Flared e3m³</th>
<th>Solution Gas Conserved %</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>124,157</td>
<td>35,596</td>
<td>0.9</td>
<td>77</td>
<td>99.8%</td>
</tr>
<tr>
<td>February</td>
<td>106,325</td>
<td>30,223</td>
<td>1.3</td>
<td>746</td>
<td>97.6%</td>
</tr>
<tr>
<td>March</td>
<td>121,090</td>
<td>29,832</td>
<td>1.3</td>
<td>48</td>
<td>99.8%</td>
</tr>
<tr>
<td>April</td>
<td>107,110</td>
<td>27,751</td>
<td>0.6</td>
<td>136</td>
<td>99.5%</td>
</tr>
<tr>
<td>May</td>
<td>111,261</td>
<td>29,447</td>
<td>2.1</td>
<td>121</td>
<td>99.6%</td>
</tr>
<tr>
<td>June</td>
<td>94,474</td>
<td>25,409</td>
<td>22.2</td>
<td>4,631</td>
<td>84.6%</td>
</tr>
<tr>
<td>July</td>
<td>84,554</td>
<td>25,530</td>
<td>0.6</td>
<td>10,846</td>
<td>70.2%</td>
</tr>
<tr>
<td>August</td>
<td>68,408</td>
<td>31,977</td>
<td>3.7</td>
<td>13,414</td>
<td>70.4%</td>
</tr>
<tr>
<td>September</td>
<td>57,266</td>
<td>25,492</td>
<td>5.8</td>
<td>8,151</td>
<td>75.8%</td>
</tr>
<tr>
<td>October</td>
<td>60,821</td>
<td>25,748</td>
<td>1.7</td>
<td>7,006</td>
<td>78.6%</td>
</tr>
<tr>
<td>November</td>
<td>81,717</td>
<td>24,187</td>
<td>0.7</td>
<td>6,038</td>
<td>80.0%</td>
</tr>
<tr>
<td>December</td>
<td>90,916</td>
<td>28,290*</td>
<td>3.7*</td>
<td>4,656*</td>
<td>85.9%</td>
</tr>
</tbody>
</table>

*Total purchased gas does not include gas from site gas wells

*Solution gas flared volumes are corrected to remove purchased gas to flare

*Total gas vented includes brackish water associated vent gas. Volumes in June due to Unit 1 turnaround.

*Solution gas conserved, vent gas and solution gas flared based on yearly average – data unavailable
Facility Performance

• Flaring & Solution Gas Conservation Compliance
  – All Primrose and Wolf Lake facilities are equipped for gas conservation except one pilot well, 15BM – granted exemption in 2004
  – New pads (since 2004) are built with VRUs or are linked to a neighboring pad’s VRU

• Solution Gas Flare Volumes
  – Conserved ~ 88% of total Primrose and Wolf Lake solution gas in 2013

• Facility Venting Compliance
  – Unit 1 turnaround resulted in higher than normal venting rates from the brackish tank
  – No routine venting in the field
  – No routine venting at Primrose North, South or East plants
  – Vapour recovery on all major sources of solution gas at Wolf Lake
Facilities – Greenhouse Gas Emissions

- PAW Greenhouse Gas Emissions

<table>
<thead>
<tr>
<th>Month</th>
<th>2013 (tCO2e)</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>321,034</td>
</tr>
<tr>
<td>February</td>
<td>275,932</td>
</tr>
<tr>
<td>March</td>
<td>303,210</td>
</tr>
<tr>
<td>April</td>
<td>272,463</td>
</tr>
<tr>
<td>May</td>
<td>283,920</td>
</tr>
<tr>
<td>June</td>
<td>245,038</td>
</tr>
<tr>
<td>July</td>
<td>226,550</td>
</tr>
<tr>
<td>August</td>
<td>204,470</td>
</tr>
<tr>
<td>September</td>
<td>170,085</td>
</tr>
<tr>
<td>October</td>
<td>179,728</td>
</tr>
<tr>
<td>November</td>
<td>217,957</td>
</tr>
<tr>
<td>December</td>
<td>234,664</td>
</tr>
<tr>
<td>Year Total</td>
<td>2,935,051</td>
</tr>
</tbody>
</table>
Water Imbalances

• Primrose East
  – A large water imbalance at Primrose East Plant was reported for August 2013
  – This was a data entry error that was corrected on Dec. 18, 2013.

• Primrose South
  – Large water balances at Primrose South Plant were reported for August to November 2013.
  – Errors occurred due to in-proper data entry of steam volumes going to Primrose North phases from Primrose South plant and errors occurred in the steam blowdown flow calculation.
  – These errors have been corrected and are now within 5%.
FTS Facility Performance Operating Impacts

• Primrose East Plant
  – Flaring – After the steam plant was shut in the sweetening package was re-commissioned to transfer as much as possible of the produced gas to Primrose South Plant for use in their steam gens
  – The sweetening package and compressor was sized previously for Primrose East Area 1 production only
  – Sweet gas only is used for firing the Primrose East Plant OTSG running as a feedwater pre-heater due to concerns with possible damage from condensing of the exhaust gas. Also sweet gas is required to help with flame stability at these low firing rates.
  – 1 steam gen (1 standby) at Primrose East Plant is operating as a feedwater pre-heater so that hot BFW can combine with cold emulsion production from Primrose East Area 1 and Area 2 for two reasons:
    ▪ To ensure the Primrose East Plant booster pumps can pump properly
    ▪ To allow Wolf Lake to treat this emulsion properly. Wolf Lake is not capable of treating cold emulsion.
FTS Facility Performance Operating Impacts

• Heat Integration
  – This summer PAW heat integration was a challenge as less saline water was being used due to low steam demand
  – PAW uses saline water cooling, glycol systems, and steam plant BFW/emulsion exchangers to manage and optimize heat
  – Transferring and mixing inlet heat to the inlets U2 and U8 is currently possible at Wolf Lake. However, transferring heat from U10 to U2 or U8 is currently not possible under all circumstances. At low rates this is partially achievable. Significant piping modifications would be required to improve inlet temperature balancing. Production from Primrose East preferentially flows to the U10 inlet.
FTS Facility Performance Operating Impacts

• Produced Water Recycle
  – Due to FTS the produced water recycle ratio was significantly effected
  – With Primrose East steam plant shutdown and with depressuring of the Primrose East field more water was being produced then steam created. This resulted in high water disposal rates.
  – Canadian Natural is confident we will meet Directive 081 by November 2015.

• Saline Water Cooling System
  – With decreased saline makeup rates a large cooling load was removed from the overall heat balance.
  – To compensate more load was shifted to the steam plant heat exchangers and the Wolf Lake glycol systems.
FTS Facility Performance Operating Impacts

• Water Make-up Adjustments
  – Due to the current operating conditions associated with FTS non-saline make-up water has been lowered to minimum rates and saline water was reduced to very low rates based on steam demand and cooling requirements.
  – This has resulted in a poor 2013 saline water to non-saline water ratio as saline water rates can be turned down to almost zero whereas non-saline water currently has a minimum rate to supply the various utility users.
Measurement and Reporting

• Measurement, Accounting & Reporting Plan (MARP) for Wolf Lake / Primrose Thermal Bitumen Scheme Approved May 1st, 2007. Annual updates in March.

• Methods for estimating well production and injection volumes reported to Petrinex

  – Produced emulsion from the scheme is commingled at the battery. Bitumen and water production from the battery is prorated to each well using monthly proration test data and proration factors.

    ▪ Total Battery Oil (Water) / Total Test Oil (Water) at Wells = Oil (Water) Proration Factor

    ▪ Oil (Water) Proration Factor * Each Well Test Oil (Water) Volume = Oil (Water) Allocated to Each Well
Measurement and Reporting (con’t)

- Gas allocated to each well is determined by GOR (gas oil ratio) for the battery
  - Total Solution Gas Produced / Total Battery Oil = Gas Oil Ratio
  - Gas Oil Ratio * Oil Allocated to Each Well = Gas Allocated to Each Well
- Injected volumes of steam and water are not estimated, they are continuously measured at wellhead
- Some pads have capability to take steam from Primrose South or Primrose North. Combined proration factor for both plants used for steam transfer volume estimation.
• Test Durations
  – Canadian Natural field operations has identified the test durations, gross fluid rates and BS&W results required to obtain valid proration test data for each well
  – Most wells have 4 hour proration test durations; however some wells may be tested from 1 to 6 hours depending on their unique operating conditions and cycle maturity
  – Each well is tested each month and may be tested several times throughout the month
Measurement and Reporting – Proration Factors
Measurement and Reporting

• New Measurement Technology
  – Installed multi-phase flow metering technology.
    ▪ Conducting field tests since mid-2012. Tests will be continued into 2014.
    ▪ Objective is to identify a multi-phase flow meter which provides adequate performance and accuracy to replace the traditional test separator system for multiple wells
  – Installed a new nuclear level technology for interface control on two inlet separator vessels at Wolf Lake for improved interface level control. Testing and optimization in progress.
### Water Production, Injection, and Uses

- Primrose & Wolf Lake Project Water Well UWI Listing
  - ESRD non-saline water well license renewed in 2012
  - Primrose non-saline water wells are utility use only
  - McMurray brackish water well 1F3/10-03-67-4W4M was abandoned in 2013

<table>
<thead>
<tr>
<th>Non-saline WSW</th>
<th>Brackish WSW</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wolf Lake</strong></td>
<td><strong>Primrose</strong></td>
</tr>
<tr>
<td>1F1/12-10-066-05W4M (E3)</td>
<td>1F1/10-05-67-04W4</td>
</tr>
<tr>
<td>1F2/12-10-066-05W4M (ML)</td>
<td>1F1/14-05-67-04W4</td>
</tr>
<tr>
<td>1F2/06-10-066-05W4M (ML)</td>
<td>04-14-67-03W4</td>
</tr>
<tr>
<td>1F1/13-10-066-05W4M (ML)</td>
<td>NW 08-068-04W4</td>
</tr>
<tr>
<td>1F2/13-10-066-05W4M (E3)</td>
<td>NW 08-068-04W4</td>
</tr>
</tbody>
</table>

ML – Muriel Lake Formation  
E3 – Empress 3 Formation

ML – Muriel Lake Formation  
E3 – Empress 3 Formation
Water Production, Injection, and Uses

• Non-saline water uses
  – Utility water, utility steam, seal flush and gland water, slurry make-up, dilution water, filter backwash, quench water, miscellaneous – ends up as boiler feedwater
  – Water softener regenerations – some of this water is recycled as boiler feedwater and some is used as cavern wash and then sent to disposal
  – Non-saline water may also be used for boiler feedwater make-up as required
  – Further non-saline water reduction below existing reduction targets would be challenging due to the size and age of the facility. Additional saline water treatment systems, water source wells and infrastructure would be required to provide water to a wide range of small users (pumps, seals, utility stations, etc.)

• Brackish water uses
  – De-sand quench, filter backwash – ends up as boiler feedwater
  – Boiler feed water make-up supply

• Water Quality Assessment
  – Quaternary Water Source Wells (6)
    ▪ Empress Unit 3 & Muriel Lake Formations
    ▪ Average TDS = 625 mg/L, TDS ranges from 593 to 647 mg/L
  – Grand Rapids Fm. Water Source Wells (7)
    ▪ Average TDS = 9,721 mg/L, TDS ranges from 8,900 to 10,300 mg/L
  – McMurray Fm. Water Source Wells (10)
    ▪ Average TDS = 7,276 mg/L, TDS ranges from 6,470 to 8,570 mg/L
  – Produced Water Quality
    ▪ Typical parameters: TDS = 7,102 mg/L, Cl = 3,700 mg/L, pH 7.3, hardness = 99 mg/L
## Water Production, Injection, and Uses

### Primrose and Wolf Lake - 2013 Monthly Water and Steam Volumes

<table>
<thead>
<tr>
<th>Month</th>
<th>Surface Water</th>
<th>Non-Saline Groundwater</th>
<th>Saline Water</th>
<th>Produced Water</th>
<th>Steam Injection</th>
<th>PW Recycled</th>
<th>PW Recycled Bulletin 2006-11</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>m³/day</td>
<td>m³/d</td>
<td>m³/d</td>
<td>m³/d</td>
<td>m³/d</td>
<td>%</td>
<td>%</td>
</tr>
<tr>
<td>January</td>
<td>732</td>
<td>10,427</td>
<td>29,034</td>
<td>40,118</td>
<td>72,916</td>
<td>98.8</td>
<td>154.8</td>
</tr>
<tr>
<td>February</td>
<td>654</td>
<td>8,171</td>
<td>24,424</td>
<td>40,799</td>
<td>69,552</td>
<td>97.0</td>
<td>148.8</td>
</tr>
<tr>
<td>March</td>
<td>677</td>
<td>9,039</td>
<td>27,715</td>
<td>38,732</td>
<td>68,536</td>
<td>99.0</td>
<td>152.5</td>
</tr>
<tr>
<td>April</td>
<td>974</td>
<td>15,242</td>
<td>16,659</td>
<td>40,633</td>
<td>65,931</td>
<td>98.6</td>
<td>124.2</td>
</tr>
<tr>
<td>May</td>
<td>1,081</td>
<td>13,286</td>
<td>19,174</td>
<td>42,150</td>
<td>68,124</td>
<td>99.2</td>
<td>128.7</td>
</tr>
<tr>
<td>June</td>
<td>3,115</td>
<td>8,030</td>
<td>9,985</td>
<td>47,319</td>
<td>56,603</td>
<td>90.3</td>
<td>102.3</td>
</tr>
<tr>
<td>July</td>
<td>1,899</td>
<td>7,874</td>
<td>4,023</td>
<td>43,893</td>
<td>44,370</td>
<td>88.0</td>
<td>85.8</td>
</tr>
<tr>
<td>August</td>
<td>1,011</td>
<td>7,311</td>
<td>1,412</td>
<td>36,799</td>
<td>40,049</td>
<td>92.4</td>
<td>87.6</td>
</tr>
<tr>
<td>September</td>
<td>632</td>
<td>5,504</td>
<td>6,604</td>
<td>32,041</td>
<td>38,134</td>
<td>91.4</td>
<td>102.3</td>
</tr>
<tr>
<td>October</td>
<td>671</td>
<td>5,433</td>
<td>4,403</td>
<td>31,600</td>
<td>36,687</td>
<td>78.3</td>
<td>90.8</td>
</tr>
<tr>
<td>November</td>
<td>745</td>
<td>6,053</td>
<td>7,510</td>
<td>40,561</td>
<td>45,526</td>
<td>83.8</td>
<td>99.8</td>
</tr>
<tr>
<td>December</td>
<td>778</td>
<td>7,907</td>
<td>6,097</td>
<td>38,706</td>
<td>53,121</td>
<td>92.1</td>
<td>104.4</td>
</tr>
</tbody>
</table>

* Surface water is effluent diversion from Cold Lake fish hatchery and surface water runoff
* Non-saline ground water from Wolf Lake water source wells
* Saline water is from McMurray and Grand Rapids aquifers
* Blowdown recycle from Wolf Lake Steam Separator is 100%

\[
\text{PW Recycled} = \frac{(\text{Total PW} - \text{PW to Disposal})}{\text{Total PW}}
\]
Water Production, Injection, and Uses

- PAW water volume summary for 2013
  - Wolf Lake Non-saline Water - Average 8,716 m³/d
  - Grand Rapids Brackish Water - Average 454 m³/d
  - McMurray Brackish Water - Average 12,638 m³/d
  - Burnt Lake Pilot Water – Cold Lake Fish Hatchery Effluent Diversion - Average 779 m³/d
  - Plant Runoff Water – Average 305 m³/d

No runoff data before 2006
• Brackish to Non-Saline Groundwater Ratio
  – Decrease in brackish use compared to 2012 (13,092 vs. 19,065 m³/d)
  – Average brackish to non-saline groundwater ratio was 1.50 in 2013 (2.02 in 2012)
  – Non-saline water was increased and saline usage decreased in 2013 due to:
    ▪ Execution of two major turnarounds
    ▪ FTS forcing a major reduction in saline water demand

Excludes Cold Lake Fish Hatchery Effluent Volumes
• Long term make-up yearly requirements approximately 35,000 to 40,000 m³/d
• Reduction of non-saline groundwater use – down to 3,000 m³/d by mid-2016

Excludes Runoff Water and Cold Lake Fish Hatchery Effluent Volumes
McMurray Brackish Water Supply – Existing

- Producing wells
  - 3 horizontal and 6 vertical wells
  - 3 vertical wells brought online in 2012
  - 1F3/10-03-67-4W4M abandoned Q3 2013
- 2013 production
  - average – 12,638 m³/d
  - maximum – 32,382 m³/d
- Drawdown of 54 m in obs well 6-30 (6 km from pumping centre)

McMurray Fm Basal Aquifer Isopach Map - targeted due to prolific nature of aquifer
McMurray Brackish Water Supply – Phase 2 Expansion

• Phase 2 Expansion
  – Additional development in existing pumping centre (PC1)
    ▪ add one horizontal water well (WSW122)
  – Develop new pumping centre in NW67-3 and SW68-3 (PC2)
    ▪ add four horizontal water wells
    ▪ following basal aquifer fairway north of existing pumping centre (PC1)
    ▪ constrained by geology, thermal development, target circle and mineral and surface rights
McMurray Brackish Water Supply – Phase 2 Expansion

• Project Schedule
  – Pumping Centre 1
    ▪ Drilling of horizontal water well started January 2014
    ▪ WSW122 schedule to be tied-in by end of Q1 2014
  – Pumping Centre 2
    ▪ Originally planned to be operational by Q2 2014 in order to meet commitment to decrease non-saline water use to 3,000 m³/d
    ▪ Road/pipeline construction and drilling activities have been delayed by objections raised during the surface land disposition and well licence regulatory process
    ▪ PC2 is expected to be operational by Q2 2016 if all approvals are granted by October 2014
  – May require additional make-up water from alternate sources.
## Water & Waste Disposal Wells, Landfill Waste UWI List & Disposal Compliance

**• Primrose & Wolf Lake Project Disposal Water Well UWI Listing**

- Wells shown in bold are active, (Wolf Lake - WDW#1 and WDW#9 are zonally abandoned)

<table>
<thead>
<tr>
<th>Wolf Lake</th>
<th>Primrose South</th>
<th>Primrose East</th>
</tr>
</thead>
<tbody>
<tr>
<td>Well</td>
<td>Formation</td>
<td>Well</td>
</tr>
<tr>
<td>WDW#1 - 100090806605W400</td>
<td>Precambrian</td>
<td>103100506704W400</td>
</tr>
<tr>
<td>WDW#2 - 100100806605W400</td>
<td>Precambrian</td>
<td></td>
</tr>
<tr>
<td>WDW#4 - 100050806605W400</td>
<td>Precambrian</td>
<td></td>
</tr>
<tr>
<td>WDW#5 - 100150706605W400</td>
<td>Precambrian</td>
<td></td>
</tr>
<tr>
<td>WDW#9 - 100140506605W400</td>
<td>Precambrian</td>
<td></td>
</tr>
</tbody>
</table>

**• Wolf Lake (WDW #2, 4, & 5)**

- Disposal scheme was amended on June 16/10 to allow injection into WDW #4 (Approval 8672A). Maximum wellhead injection pressures decreased from 17,500 kPa to 13,770 kPa; with the ability to inject at 17,500 kPa for a maximum time period of 24 hrs.
  - Injection pressures have not exceeded 13,770 kPa for a 24 hour period in 2013.

**• Primrose South**

- Injected 0 m³ fluid in 2013.

**• Primrose East**

- 3-11 zonally abandoned in the McMurray formation.
- 11-2 continued discussions regarding potential abandonment options with AER.
Water & Waste Disposal Wells, Landfill Waste
Wolf Lake Disposal Volumes
• Water is stored in the C3 Formation
  – Converted two wells to injectors in June 2003

• Injected 555,370 m³ total
  – 303,992 m³ to M2-S
    ▪ 114,907 m³ in 2013
  – 251,378 m³ to M2-E
    ▪ 92,208 m³ in 2013

• M2-E and M2-S are currently configured for summer operations
## Wolf Lake Water Storage Volumes

<table>
<thead>
<tr>
<th>Year</th>
<th>Month</th>
<th>M2_E Gross (m³/d)</th>
<th>M2_E Oil (m³/d)</th>
<th>M2_E Water (m³/d)</th>
<th>M2_E Water Inj (m³/d)</th>
<th>M2_S Gross (m³/d)</th>
<th>M2_S Oil (m³/d)</th>
<th>M2_S Water (m³/d)</th>
<th>M2_S Water Inj (m³/d)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2003</td>
<td>Jan</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></td>
<td>Feb</td>
<td>0.36</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0.36</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Mar</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></td>
<td>Apr</td>
<td>92.3</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></td>
<td>May</td>
<td>203.71</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></td>
<td>Jun</td>
<td>147.27</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></td>
<td>Jul</td>
<td>775.45</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></td>
<td>Aug</td>
<td>535.81</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></td>
<td>Sep</td>
<td>529.93</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></td>
<td>Oct</td>
<td>516.87</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></td>
<td>Nov</td>
<td>204.21</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></td>
<td>Dec</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>
</tbody>
</table>
Water & Waste Disposal Wells, Landfill Waste
Wolf Lake Water Storage Compliance

- **Formation Integrity and Pressure Monitoring**
  - Offset well reservoir pressures never exceeded the 2.5 MPa allowable during injection periods
  - M2-E injection packer successfully passed packer isolation test on June 25, 2013
  - M2-S injection packer successfully passed packer isolation test on June 25, 2013
  - No wellbore integrity issues encountered

- **Wolf Lake Water Storage – Reservoir**
  - M2 & N2 Cumulative DI = 1.27
    - Cumulative Gross Production = 12,625,452 m³
    - Cumulative Oil Production = 1,547,430 m³
    - Cumulative Steam Injected = 9,915,737 m³ CWE
    - Cumulative Water Injected = 555,370 m³
  - M2 & N2 Remaining Voidage = 2,154,345 m³

\[
DI = \frac{\text{Total Fluid Produced (Bitumen + Water)}}{\text{Total Steam Injected (CWE)}}
\]
• From the outlined area (M2 wells and N2-F)
  ▪ Total Injected Water = 555,370 m³ since Jan ’03
  ▪ Total Produced Water = 630,951 m³ since Jan ’03
  ▪ Difference = 75,581 m³

• Expect to utilize M2 storage in 2014
Injectors appear to communicate readily with offset wells.

No problems anticipated when pumping out injected water.

Intend to maintain two wells for injection.

Expect to utilize water storage as required in 2014.

Investigating high volume lift alternatives for 2014.

M2-E and M2-S are classified as disposal wells on S-4 forms.
• Waste to Tervita Landfill
  ▪ 6,240.9 tonnes – Contaminated soil
  ▪ 77,190.7 tonnes – Lime waste

• Waste to Terivata Cavern
  ▪ 10,214.5 m³ – Sludge hydrocarbons, wastewater and sand

• Waste to RBW
  ▪ 1,016.01 m³ solid waste – contaminated soils, plastics, filters, asbestos, batteries, glycol, fluorescent tubes, caustics

• Waste to NewAlta
  ▪ 4,111 m³ – sludge hydrocarbons and co-emulsion
Sulphur Production

• EPEA approval limits for SO$_2$:
  – PSP + WLP = 6.7 t/d
  – PNP = 2.0 t/d
  – PEP = 2.0 t/d

• CEMS values are used for reporting at all steam plants
  – PNP from September 1, 2010 onward
  – PEP, PSP, and WLP from April 1, 2011 onward

• Quarterly averages for all steam plants < 1.0 t/d sulphur

• Contingency for compliance with ID 2001-3 is currently to restrict/delay production to maintain sulphur level below 1 t/d quarterly average
Sulphur Production

2013 Primrose & Wolf Lake Sulphur Emissions

- Primrose North
- PSP Calendar Quarter
- Primrose East
- Wolf Lake
- PNP Calendar Quarter
- WLP Calendar Quarter
- Primrose South
- PEP Calendar Quarter
- ERCB Quarterly Limit
Sulphur Production

• To maintain sulphur levels below 1 t/d, production from the following wells/pads were held back in Q1/Q2 2013:
  – Feb 9 – May 6: Primrose North held back 18,444 m³ of oil
Environmental Summary
Compliance & Amendments

• Compliance Issues
  – EPEA Approval: Air Related
    ▪ Daily SO$_2$ exceedance Primrose North Plant 14-08-68-04-W4M (March 18, 2013)
    ▪ Hourly NOx exceedance Primrose South Plant HRSG 10-67-04-W4M (May 14, 2014)
  – Water Related:
    ▪ WL WSW 01 and 05 water level measurements missing (August 7, 2013)
Environmental Summary
Monitoring Programs

- Environmental Monitoring Programs currently underway include:
  - Wildlife Monitoring Program
  - Wildlife Mitigation Plan
  - Wildlife Habitat Enhancement Program
  - Wetlands and Hydrology Monitoring Program
Environmental Summary
Monitoring Programs

• Objectives of Wildlife Monitoring Program
  – To determine if the PAW project has an influence on the abundance and
distribution of wildlife species;
  – The effectiveness of crossing structures; and
  – Distribution and movement of caribou.

• Wildlife Monitoring/Mitigation Program activities for 2013:
  – Breeding songbird surveys
    ▪ 87 standard point count surveys were completed
  – Winter track surveys
    ▪ 22 transects were surveyed along aboveground pipelines
    ▪ 58 transects were surveyed (February, March and November 2013)
Environmental Summary
Monitoring Programs

• Wildlife Monitoring/Mitigation Plan activities in 2013
  – Woodland caribou cameras
    ▪ 41 remote cameras deployed for 8 weeks each in spring and early summer along eastern and northern boundaries of Project Area to capture seasonal movement of caribou in the fall.
    ▪ Photos captured in spring 2013 recorded 180 caribou detections in addition to 11 other mammal species.
  – Remote Camera Monitoring of Above-Ground Pipeline
    ▪ 30 remote cameras deployed along AGP to record wildlife behaviour and confirm wildlife movement under the AGP
    ▪ 30 remote cameras deployed along game trails or cutlines near remote camera areas on the AGP to record wildlife occurrence and behaviour as animals approach the pipeline
Environmental Summary
Monitoring Programs

• Wildlife Habitat Enhancement Program
  – Nest Box Program
    ▪ 18 bird boxes and 2 bat boxes were maintained to confirm use during the breeding season. Three bird boxes had nesting materials present and two others showed evidence of use.
  – Approvals for site treatment (site mounding prior to planting) were not received thus limiting the availability of candidate sites for tree planting
    ▪ Eight sits planted with seedling where site preparation was completed the previous year or deemed unnecessary
    ▪ Planted sites covered a linear distance of 2,650 m
    ▪ 23 previously planted sites were monitored
Environmental Summary
Monitoring Programs

• Hydrology, Wetlands and Water Quality Monitoring Program 2013

  – Wetland Monitoring Component
    ▪ Preliminary observations indicate that there were only minor differences in overall species richness among monitoring and reference sites compared to previous years

  – Hydrology Monitoring Component
    ▪ All lakes appeared to exhibit hydrological regimes similar to those of past years.
    ▪ Lake levels were typically dominated by spring runoff events and various preceptation.

  – Water Quality Component
    ▪ Based on results from Burnt Lake and Sinclair Lake there were no large deviations observed in the analytical results when compared with those from previous years.
Environmental Summary
Monitoring Programs

• Preliminary Results
  – Hydrology Program
    ▪ Looseman Lake and North Reference Lake experienced average lake levels lower than the August 1, 2007 reference level. This may be attributed to changing outlet conditions or lower seasonal inputs.
  – Wetland Monitoring Program
    ▪ 2012 re-measurement of wetland sites indicates only small differences in species richness among monitoring and reference sites.
  – Water Quality Program
    ▪ To-date, no large deviation was observed for surface water quality samples from Burnt Lake and Sinclair Lake.
    ▪ Phenol concentrations at Burnt Lake were at or above guideline concentrations in a majority of samples.
    ▪ Total phosphorus at or above guideline concentrations at Sinclair Lake.
    ▪ Continued monitoring will determine if these results are indicative of a trend.
Environmental Summary
Reclamation Programs

• Reclamation activities in 2013:
  – Re-vegetation Program consisted of reforesting 33.88 ha
  – Approximately 65,330 tree and shrub seedlings were planted.
    ▪ Planting on borrows accounted for 24.98 ha
      ▪ total of 50,510 tree and shrub seedlings
    ▪ In-fill planting on borrows and clearings accounted for 8.90 ha
      ▪ 14,820 tree and shrub seedlings.

• Proposed activities in 2014:
  – Reforestation of 23.3 ha of borrow pits in Primrose North.
  – Planting of 5.2 ha linear disturbances and 0.8 ha of non linear disturbances as part of the habitat Enhancement Program.
    ▪ This is work that was not completed in 2013 due to problems with obtaining a TFA for the work.
Environmental Summary
Regional Initiatives

• LICA Airshed Zone
  – The LICA Airshed Zone is responsible for operating a regional air monitoring network for part of the Lakeland and adjacent area inclusive of passive and continuous monitoring networks.
  – In addition to posting the air monitoring network results to the LICA website, the LICA Airshed Zone also posts real time air monitoring results for the regional Alberta Quality health Index (AQHI)
  – The Joint Canada-Alberta Oil Sands Monitoring agency (JOSM) has engaged the LICA Airshed Zone to fulfill their regional air monitoring needs.
Environmental Summary
Regional Initiatives

• Beaver River Watershed Alliance (BRWA):
  – The Beaver River Watershed Alliance (BRWA) serves as the Watershed Planning and Advisory Council (as set out by Alberta Environment and Sustainable Resource Development) for the Beaver River watershed.
  – The BRWA has completed the final draft of their State of the Watershed Report which provides a snapshot of regional watershed health and will act as the guiding document for development of their upcoming Watershed Management Plan as part of Alberta’s Water for Life Strategy.
  – The BRWA has recently become engaged in discussion with JOSM representatives.
Environmental Summary
Arsenic Mobility Investigation

• Arsenic Mobility Research Program Description
  – Long-term research program at Z8 Pad ongoing since 2001.
  – Evaluating the liberation of arsenic associated with elevated groundwater temperatures from steaming a thermal pad.
  – Thirty-three groundwater monitoring wells installed primarily in shallow and deep Quaternary aquifers (Empress, Bonnyville and Sand River).
  – Monitoring temperature, chemistry and water level data in all wells to complete temporal assessments associated with steaming with a focus on the Empress.

• Research Program Highlights from 2013
  – Empress aquifer results consistent with historical findings
    ▪ thermal and arsenic plumes are migrating downgradient of the pad.
    ▪ arsenic concentrations continue to decrease near thermal pad (no steam since 2005).
  – Additional Sand River aquifer monitoring wells installed and included in research program.
Environmental Summary
Groundwater Monitoring and Management

• Shallow and Deep Groundwater Monitoring Programs
  – Completed as per terms and conditions outlined in EPEA Amending Approval 11115-03-04, Section 4.6 and Table 4.7-A
    ▪ shallow groundwater monitoring at plant facilities
    ▪ deep groundwater monitoring of source and regional monitoring wells
  – Annual EPEA Groundwater Monitoring Report submitted by March 31
  – Annual Water Act Groundwater Monitoring Report submitted by February 28
  – Additional deep wells added to regional monitoring network
    ▪ twenty-five wells drilled and installed in Primrose
    ▪ water level monitoring and semi-annual sampling as per EPEA approval
Environmental Summary
Groundwater Monitoring and Management

• Pad 74 Risk Management Plan
  – Ongoing application of the Pad 74 Risk Management Plan including monitoring, sampling and monthly reporting to regulators.
  – Monitoring and sampling results are reported annually to ESRD via EPEA Approval since March 2012.
  – Elevated chloride and dissolved hydrocarbon concentrations are present but currently neither exceed Tier 1 criteria.

• Primrose flow to surface sites (2-22, 10-2, 10-1 and 9-21)
  – Geology and Regional Groundwater Delineation, Monitoring and Remediation Plan approved by ESRD December 2013
  – Drilling groundwater monitoring wells will start once construction complete
Groundwater Monitoring at E14 Pad

• A groundwater monitoring well was installed at E14 Pad (16-32-065-05W4M) as per the amendment to the Commercial Scheme Approval 9140I for SIB Pad
  – Installed on the south side of the pad in July 2010 to monitor for changes in the basal quaternary aquifer associated with SIB operation
  – Completed into the basal aquifer identified as the Muriel Lake (121 to 127 metres below ground surface)
  – Instrumented to monitor water levels and temperatures
  – Sampled semi-annually as part of regional groundwater monitoring program
Groundwater Monitoring at E14 Pad

- Groundwater Monitoring Results for groundwater monitoring well 16-32a
  - Anomalous water levels and chemistry not noted (comparable to regional results Muriel Lake Formation)
  - In-situ groundwater temperature at 7°C
Well Pads and Abandonments

• There were two wells abandoned in 2013:
  – 100/03-10-067-04W4: not cut and capped (suspended w/ cement plugs
    ▪ 1C17 - Horizontal CSS well
  – 100/03-26-067-04W4: casing issues. Cut and capped
    ▪ 3B29 – Deviated “B-Column” well
Approval 9140R – Oil Sands Primrose Wolf Lake
• Original Approval – August 2002
• Amendment A - Approved October 2003
  ▪ Approval to conduct Gas and Gas Solvent enhanced recovery pilot
• Amendment B - Approved January 2004
  ▪ Approval to develop PRN and decrease production volume to 14,000 m3/d
• Amendment C - Approved March 2007
  ▪ Approval for PRE and increase production volume to 19,000 m3/d
  ▪ Approval for Orange Valley Sand Phases 41-50 and Blue Valley Sand Phases 8, 9, 11, 12 (West)
• Amendment D - Approved March 2007
  ▪ Approval to expand the development area to include 67-5W4M
  ▪ Approval 6804 (Burnt Lake rescinded)
• Amendment E - Approved March 2008
  ▪ Pads 58, 62, 66 modification to development plan
• Amendment F - Approved August 2008
  ▪ Pads 59, 63, 7 modification to development plan
• Amendment G - Approved February 2010
  ▪ Approval for McMurray MC1 SAGD Pad
• Amendment H - Approved July 2010
  ▪ Approval for Grand Rapids S1B SAGD Pad
• Amendment I - Approved September 2010
  ▪ Approval for PRS Phases 22-24
Approval 9140R – Oil Sands Primrose Wolf Lake

- Amendment J - Approved November 2010
  - Approval for PRE Development Area 2
- Amendment K - Approved December 2010
  - Approval for Trim Treating during PEP Steam Outage
- Amendment L - Approved August 2011
  - Approval for modification of PRE Phases 90/91 drainage boxes
- Amendment M - Approved October 2011
  - Approval for PRS Phases 25/26
  - Approval for PRN Phases 60, 61, 64, 65 & 68
- Amendment N - Approved February 2012
  - Approval for PRS D1 Steamflood Trial
- Amendment O - Approved May 2012
  - Approval for Wolf Lake Sparky B8 Trial
- Amendment P - Approved November 2012
  - Approval for Primrose South Phases 40-43
- Amendment Q - Approved April 2013
  - Approval to Approval to amend development of Primrose South Phases 40, 41, 42 and 43
- Amendment R - Approved May 2013
  - Approval to add an Algae Carbon Capture (ACC) Pilot Plant at the Primrose South Processing Plant
Annual Report
(a) Summary of monthly injected and produced volumes/well
(b) Well/Formation Integrity
(c) Reservoir Water Storage remaining
(d) Water Balance, Bitumen Volumes and Incremental Recovery
(e) Overall performance and 2012 plans
(f) Discussion of produced water utilization & fresh water reductions
• Approval Compliance Requirements
  - Directive 51 Compliance
  - Maximum Injection Pressures (kPa)
    - F1/11-02-067-03W4/0 = 7800
    - 00/03-11-067-03W4/0 = 5500

• Injection packer isolation test failed on 11-2 in 2008
  - Well currently shut-in
  - Work in progress

• No disposal in 2012 as water is now recovered and re-used
• Approval Compliance Requirements Directive 51 Compliance
• Operational injection pressure limit 13,770 kPa
• Maximum injection pressure 17,500 kPa for a 24 hour period
• Disposal wells are:
  - WDW#1 - 00/09-08-066-05W4/0
  - WDW#2 - 00/10-08-066-05W4/0
  - WDW#4 - 00/05-08-066-05W4/0
  - WDW#5 - 00/15-07-066-05W4/0
  - WDW#9 - 00/14-05-066-05W4/0
• Approval Compliance Requirements
  – Monitoring Maximum Injection Pressures
    ▪ 3 exceedances of maximum allowable injection pressure during non-routine operations.
    ▪ Disposal system modifications in progress to prevent this from occurring
  – Annual Report
    ▪ 2012 Report Submitted
    ▪ 2013 Report will be prepared following annual cavern sounding

• Salt Cavern 1 – 118/12-8-66-5W4
  – Cavern volume (as of April 2013 sounding) 192,723 m³
  – Wash water 2,998 m³
  – Oily waste (bitumen) 333 m³
  – Solid waste 0 m³
  – Next Cavern sounding expected in April 2014

*Note: all salt cavern volumes are from sounding to sounding.
Approval 8673 – Cavern Disposal
Approved October 2000

• Salt Cavern 2 - 119/12-8-66-5W4 – Washing Only
  – Cavern volume (as of April 2013 sounding) 54,502 m³
  – Wash water 14,903 m³
  – Next Cavern sounding expected in April 2014
Approval 3929A – Primrose Class 1b Disposal Amended September 2011

• Approval Compliance Requirements
  - Originally approved 1983
  - Transferred to Canadian Natural from Dome Petroleum – September 2011
  - Directive 51 Compliance
  - Maximum Wellhead Injection Pressures (kPa)
    - 03/10-05-067-04W4/0 = 6,000
• Approval No. 4128D – Class II Disposal
  ▪ Transferred to Canadian Natural from Dome Petroleum – September 2011
  ▪ Directive 51 Compliance
  ▪ 02/10-05-067-04W4/0 = 16,000 kPA

• Approval No. 9792A– Class II Disposal
  ▪ 00/14-02-065-08W4/0 has been abandoned and the approval was rescinded September 2011
Compliance Disclosures

• Reportable spills
  – 29 reportable spills were reported in 2013 including; 2 gylcol, 13 emulsion, 4 FTS bitumen, 2 bitumen, 1 regen wastewater, 1 boiler feedwater, 1 hydrated lime, 1 oil, 1 brackish water, 2 produced water, and 1 diesel fuel.

• Digital Data Submissions (DDS)
  – Notifications/Submissions were entered into the DDS as per Directives in 2012.
Non-Compliance

- ERCB Scheme Approval 9140
  - None
Future Plans

• Wolf Lake Plant Control System & Electrical Upgrades
  – Significant work ongoing to upgrade equipment and infrastructure
• Wolf Lake Unit 2 Improvements
  – Desand and VRU system upgrades
• Produced Water Debottlenecking
  – Various changes being reviewed to increase water handling capability
• Disposal System Improvements
  – Minor changes to increase overall system reliability
• Wolf Lake Steam Generation Capacity Increase
  – Minor modifications to the existing steam gens to increase capacity
• Wolf Lake Steam Generation Capacity Increase
  – Reviewing addition of steam generation for future SAGD steam demand
Future Plans

• Surface Facilities Associated with PE A1 Steamflood Conversion  
  – Primrose East A1 Pad 74/75/77/78 piping and artificial lift modifications

• Primrose East Heat Integration  
  – Re-piping inlet heat exchangers to optimize heat transfer

• Primrose South Steam Generator Economizer Upgrades  
  – Replace damaged equipment and improve efficiency, 2 OTSG’s targeted for 2014

• Various small sustaining capital projects  
  – To replace aging infrastructure and equipment  
  – To reduce operating costs  
  – To improve environmental performance
Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the "Company") in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as "forward-looking statements") within the meaning of applicable securities legislation. "Forward-looking statements" include the words: "may", "could", "will", "would", "should", "could", "will", "can be", "anticipated", "expected", "believe", "estimate", "forecast", "project", "plan", "seek", "schedule", "target", "intend", "may", "potential", "goal", "objective", "initiative", "strategy", "outlook", "effort" and "schedule" and similar expressions. Forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, and are subject to inherent risks and uncertainties. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on assessments made by the Company on the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions; the impact of market prices of the Company’s products; changes in the Company’s capital structure; capital expenditures; interest and inflation rates; commodity prices; environmental risks; the Company’s ability to develop projects; the Company’s ability to compete; the Company’s successful compliance with environmental and other regulatory requirements; the Company’s ability to attract and retain key people; the Company’s ability to access capital; the Company’s success in integrating acquired businesses; the impact of government regulations; and management’s ability to manage risks inherent in the industry. The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions; the impact of market prices of the Company’s products; changes in the Company’s capital structure; capital expenditures; interest and inflation rates; commodity prices; environmental risks; the Company’s ability to develop projects; the Company’s ability to compete; the Company’s successful compliance with environmental and other regulatory requirements; the Company’s ability to attract and retain key people; the Company’s ability to access capital; the Company’s success in integrating acquired businesses; the impact of government regulations; and management’s ability to manage risks inherent in the industry. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of risks and uncertainties is not exhaustive and is not the only factors that may affect the Company’s operations and results of operations, and should not be construed as exhaustive or as a guarantee that the Company’s expectations will be realized. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on the information available to it and the assumptions made by the Company in using such information, there can be no assurances that the plans, initiatives or expectations upon which they are based will be achieved. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions; the impact of market prices of the Company’s products; changes in the Company’s capital structure; capital expenditures; interest and inflation rates; commodity prices; environmental risks; the Company’s ability to develop projects; the Company’s ability to compete; the Company’s successful compliance with environmental and other regulatory requirements; the Company’s ability to attract and retain key people; the Company’s ability to access capital; the Company’s success in integrating acquired businesses; the impact of government regulations; and management’s ability to manage risks inherent in the industry. For additional information refer to the "Risks Factors" section of the AIF. Readers are cautioned that the foregoing list of risks and uncertainties is not exhaustive and is not the only factors that may affect the Company’s operations and results of operations, and should not be construed as exhaustive or as a guarantee that the Company’s expectations will be realized. Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on the information available to it and the assumptions made by the Company in using such information, there can be no assurances that the plans, initiatives or expectations upon which they are based will be achieved. In addition, statements relating to "reserves" are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (NGLs) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.
Reporting Disclosures

Special Note Regarding Currency, Production and Reserves
In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent ("BOE"). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This document, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators ("Evaluators"). Sproule Associates Limited and Sproule International Limited (together as "Sproule") and GLJ Petroleum Consultants Ltd. ("GLJ"), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2012 and a preparation date of February 11, 2013. Sproule evaluated the North America and International light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101") requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission ("SEC") requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report targeted to be released in late March 2013.

Resources Other Than Reserves
The contingent resources other than reserves ("resources") estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101. No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2012. The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures
This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations, cash production costs, and net asset value. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS in the “Financial Highlights” section of the Company’s MD&A which is incorporated by reference into this document. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A which is incorporated by reference into this document.

The volumes shown are Company share before royalties unless otherwise stated.
PRIMROSE/WOLF LAKE CYCLIC STEAM STIMULATION (CSS)

2013 WELL INTEGRITY ANNUAL PRESENTATION
CNRL’s Well Integrity Goals

1. Develop a further understanding of well failure mechanisms.

2. Ensure monitoring resources are applied effectively to minimize risk to HSE and resource recovery.

3. Prolong well life through improved well design and operational practices.
Agenda

1. Review 2013 Casing Failure Statistics
2. Review On-Going Well Integrity Initiatives
3. Discuss Future Initiatives
4. Conclusions and Take Away Items
Part 1 Failure Statistics - Summary

• Out of zone casing failure rate has increased in 2013
  – Majority of failures were concentrated on 2 pads which have had a high number of previous well failures (WL Z13 and Primrose Pad 52)
• In zone (Clearwater) casing failure rate has decreased in 2013

• CNRL has implemented many CSS well design changes in 2013 to enhance well integrity in order to reduce casing failures
  – Intermediate casing connection change
  – Limited rotation during casing installation/cementing
  – Modified cementing practices

• A reduction in CNRL’s out of zone failure rate for CSS wells as a result of the improved well design is not expected to until pads drilled in 2013 reach cycle 4 in 2017
Part 1 Failure Statistics - Summary

• Failure count vs:
  – Cycle
    ▪ Most out of zone failures occur during and after cycle 4 in 2013
  – Geological Formation
    ▪ Majority of out of zone well failures occur in the Belle Fourche, Fish Scales and Westgate formations
  – Operating Stage
    ▪ Majority of failures occur in production phase when casing is cooled and in tension – One out of zone failure did occur during steam injection in 2013

• Method of detection
  – Passive seismic has a 100% detection rate for out of zone casing failures in 2012-2013 on pads equipped with function equipment
Definition of well failure location

• Near Surface Failure – 0m – 25 m TVD
  – CNRL has not had any near surface casing failures to date

• Out of Zone Failure – Failure depth is between 25 m TVD and the interface of the Grand Rapids/Clearwater formation
  – Includes failures within the Grand Rapids, Colorado and Quaternary formations

• In Zone Failure – Occurs within the Clearwater formation
  – Includes failures within the Clearwater capping shale
1.8% of total wells drilled at Primrose had an out of zone failure in 2013.
14 of the out of zone well failures occurred on 2 pads
- Wolf Lake Z13
  (7 well failures)
- Primrose North Pad 52
  (7 well failures)

These two pads have already had a high number of casing failures during previous years

Wolf Lake Z13
- Some of the failures may have occurred in 2012 as PS not available on the pad
Well Integrity – 2013 Casing Failures

• Primary Out of Zone Casing Failures – 23 wells with out of zone casing failures

Majority of the failures occurred on Wolf Lake Z13 and Primrose North pad 52

On pads where Passive Seismic is used - all out of zone well failures were detected

<table>
<thead>
<tr>
<th>Well</th>
<th>Well Type</th>
<th>UWI</th>
<th>Lics #</th>
<th>Area</th>
<th>Detection Method</th>
<th>Confirmation Date</th>
<th>Measured Depth (m)</th>
<th>Total Vertical Depth (m)</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>23A92</td>
<td>HZ</td>
<td>102/01-27-067-03W4/0</td>
<td>432925</td>
<td>PRE</td>
<td>PS</td>
<td>16-Jan-13</td>
<td>543.0</td>
<td>443.96</td>
<td>LOWER GR</td>
</tr>
<tr>
<td>10A74</td>
<td>HZ</td>
<td>104/01-02-067-03W4/0</td>
<td>380838</td>
<td>PRE</td>
<td>PS</td>
<td>15-Feb-13</td>
<td>264.4</td>
<td>263.33</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>4C51</td>
<td>HZ</td>
<td>100/06-04-068-04W4/0</td>
<td>309855</td>
<td>PRN</td>
<td>PS</td>
<td>27-Mar-13</td>
<td>312.8</td>
<td>311.11</td>
<td>VIKING</td>
</tr>
<tr>
<td>16A58</td>
<td>HZ</td>
<td>105/06-10-068-04W4/0</td>
<td>396762</td>
<td>TWP 68</td>
<td>PS</td>
<td>16-Apr-13</td>
<td>254.2</td>
<td>252.84</td>
<td>FISH SCALES</td>
</tr>
<tr>
<td>7B51</td>
<td>SRL</td>
<td>100/14-05-068-04W4/0</td>
<td>309864</td>
<td>PRN</td>
<td>PS</td>
<td>10-May-13</td>
<td>246.7</td>
<td>245.34</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>14A58</td>
<td>HZ</td>
<td>100/06-10-068-04W4/0</td>
<td>396760</td>
<td>TWP 68</td>
<td>PS</td>
<td>15-May-13</td>
<td>254.0</td>
<td>253.55</td>
<td>FISH SCALES</td>
</tr>
<tr>
<td>8B52</td>
<td>SRL</td>
<td>102/14-08-068-04W4/0</td>
<td>317148</td>
<td>PRN</td>
<td>PS</td>
<td>2-Jun-13</td>
<td>245.9</td>
<td>243.12</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>1C53</td>
<td>HZ</td>
<td>100/03-16-068-04W4/0</td>
<td>318907</td>
<td>PRN</td>
<td>PS</td>
<td>23-Jul-13</td>
<td>248.0</td>
<td>246.97</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>7B52</td>
<td>SRL</td>
<td>103/11-08-068-04W4/0</td>
<td>317122</td>
<td>PRN</td>
<td>PS</td>
<td>7-Sep-13</td>
<td>176.0</td>
<td>176.00</td>
<td>LEA PARK</td>
</tr>
<tr>
<td>8A52</td>
<td>HZ</td>
<td>102/14-07-068-04W4/0</td>
<td>317152</td>
<td>PRN</td>
<td>PS</td>
<td>26-Sep-13</td>
<td>277.0</td>
<td>276.82</td>
<td>WEST GATE</td>
</tr>
<tr>
<td>2A52</td>
<td>SRL</td>
<td>102/14-08-068-04W4/0</td>
<td>317127</td>
<td>PRN</td>
<td>PS</td>
<td>3-Oct-13</td>
<td>309.9</td>
<td>303.13</td>
<td>WEST GATE</td>
</tr>
<tr>
<td>5A52</td>
<td>HZ</td>
<td>102/11-07-068-04W4/0</td>
<td>317150</td>
<td>PRN</td>
<td>PS</td>
<td>21-Oct-13</td>
<td>251.1</td>
<td>251.20</td>
<td>FISH SCALES</td>
</tr>
<tr>
<td>4A52</td>
<td>HZ</td>
<td>102/06-07-068-04W4/0</td>
<td>317128</td>
<td>PRN</td>
<td>PS</td>
<td>22-Oct-13</td>
<td>298.2</td>
<td>297.61</td>
<td>WEST GATE</td>
</tr>
<tr>
<td>13-Z13*</td>
<td>DEV/DIR</td>
<td>104/05-27-066-05W4/0</td>
<td>327258</td>
<td>WL CSS</td>
<td>PIT</td>
<td>30-Oct-13</td>
<td>234.6</td>
<td>234.32</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>4-Z13*</td>
<td>DEV/DIR</td>
<td>104/04-27-066-05W4/0</td>
<td>327246</td>
<td>WL CSS</td>
<td>PIT</td>
<td>31-Oct-13</td>
<td>233.14</td>
<td>229.02</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>5-Z13*</td>
<td>DEV/DIR</td>
<td>102/03-27-066-05W4/0</td>
<td>327248</td>
<td>WL CSS</td>
<td>PIT</td>
<td>5-Nov-13</td>
<td>241.54</td>
<td>235.80</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>6-Z13</td>
<td>DEV/DIR</td>
<td>100/03-27-066-05W4/0</td>
<td>327244</td>
<td>WL CSS</td>
<td>PIT</td>
<td>8-Nov-13</td>
<td>289.03</td>
<td>283.71</td>
<td>WEST GATE</td>
</tr>
<tr>
<td>12-Z13*</td>
<td>DEV/DIR</td>
<td>106/05-27-066-05W4/0</td>
<td>327254</td>
<td>WL CSS</td>
<td>PIT</td>
<td>13-Nov-13</td>
<td>279.03</td>
<td>278.92</td>
<td>WEST GATE</td>
</tr>
<tr>
<td>4C52</td>
<td>HZ</td>
<td>102/06-09-068-04W4/0</td>
<td>317119</td>
<td>PRN</td>
<td>PS</td>
<td>23-Nov-13</td>
<td>454.0</td>
<td>441.70</td>
<td>LOWER GR</td>
</tr>
<tr>
<td>19A58</td>
<td>HZ</td>
<td>100/11-10-068-04W4/0</td>
<td>396765</td>
<td>TWP 68</td>
<td>PS</td>
<td>2-Dec-13</td>
<td>251.2</td>
<td>248.63</td>
<td>BELLE FOURCHE</td>
</tr>
<tr>
<td>1A66</td>
<td>HZ</td>
<td>100/12-01-068-04W4/0</td>
<td>396916</td>
<td>TWP 68</td>
<td>PS</td>
<td>21-Dec-13</td>
<td>252.4</td>
<td>249.14</td>
<td>BELLE FOURCHE</td>
</tr>
</tbody>
</table>

*Denotes wells with multiple failures
Well Integrity – 2013 Casing Failures

- Primary Out of Zone Casing Failures – 23 wells with out of zone casing failures

<table>
<thead>
<tr>
<th>Well</th>
<th>Tubular OD</th>
<th>Failure In:</th>
<th>Cycle of Failure</th>
<th>Well Phase During Failure</th>
<th>Repair Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>23A92</td>
<td>244.5</td>
<td>CONN</td>
<td>1</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
<tr>
<td>10A74</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>WKO</td>
<td>Slimhole</td>
</tr>
<tr>
<td>4C51</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>WKO</td>
<td>Patch</td>
</tr>
<tr>
<td>16A58</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
<tr>
<td>7B51</td>
<td>177.8</td>
<td>CONN</td>
<td>4</td>
<td>WKO</td>
<td>Patch</td>
</tr>
<tr>
<td>14A58</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
<tr>
<td>8B52*</td>
<td>177.8</td>
<td>CONN</td>
<td>4</td>
<td>WKO</td>
<td>Patch</td>
</tr>
<tr>
<td>1C53</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>7B52</td>
<td>177.8</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>8A52</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>2A52*</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>5A52</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>4A52*</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>13-Z13*</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>4-Z13*</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>15-Z13*</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>5-Z13*</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>6-Z13</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>12-Z13*</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>16-Z13</td>
<td>139.7</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Zonal Suspension</td>
</tr>
<tr>
<td>4C52</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
<tr>
<td>19A58</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>1A66</td>
<td>244.5</td>
<td>CONN</td>
<td>5</td>
<td>Pump</td>
<td>Patch</td>
</tr>
</tbody>
</table>

- Most well failures occur during the latter stages of production (pump, workover) when the wellbore is cool and the casing is in tension
- Minimal HSE risk as wellbore fluid level is well below break location
- All of the CSS well failures were at the casing connection

One well failure occurred during steam injection in 2013 (Grand Rapids Formation)
Well Integrity – 2013 Casing Failures

- In Zone Casing Failures:
  - Current status of 2013 in-zone casing failures

<table>
<thead>
<tr>
<th>Well</th>
<th>Well Type</th>
<th>UWI</th>
<th>Lics #</th>
<th>Area</th>
<th>Detection Method</th>
<th>Confirmation Date</th>
<th>Measured Depth (m)</th>
<th>Total Vertical Depth (m)</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>9A92</td>
<td>HZ</td>
<td>100/06-23-067-03W4/00</td>
<td>432911</td>
<td>PRE</td>
<td>PS</td>
<td>2-May-13</td>
<td>727.80</td>
<td>517.2</td>
<td>CLWTR</td>
</tr>
<tr>
<td>5C52</td>
<td>HZ</td>
<td>100/11-09-068-04W4/00</td>
<td>317153</td>
<td>PRN</td>
<td>PS</td>
<td>7-Aug-13</td>
<td>511.2</td>
<td>459.3</td>
<td>CLWTR</td>
</tr>
<tr>
<td>1B30</td>
<td>SRL</td>
<td>100/11-26-067-04W4/00</td>
<td>284593</td>
<td>PRS</td>
<td>PIT</td>
<td>20-Sep-13</td>
<td>730.40</td>
<td>465.5</td>
<td>CLWTR CAP</td>
</tr>
<tr>
<td>5C31</td>
<td>HZ</td>
<td>100/04-01-068-04W4/03</td>
<td>301757</td>
<td>PRS</td>
<td>PIT</td>
<td>1-Dec-13</td>
<td>528.4</td>
<td>471.50</td>
<td>CLWTR CAP</td>
</tr>
<tr>
<td>11A59</td>
<td>HZ</td>
<td>105/03-16-068-04W4/00</td>
<td>401746</td>
<td>TWP68</td>
<td>PS</td>
<td>29-Dec-13</td>
<td>534.3</td>
<td>469.26</td>
<td>CLWTR CAP</td>
</tr>
</tbody>
</table>

One well failure occur during steam injection in 2013

<table>
<thead>
<tr>
<th>Well</th>
<th>Tubular OD</th>
<th>Failure In:</th>
<th>Cycle of Failure</th>
<th>Well Phase During Failure</th>
<th>Repair Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>9A92</td>
<td>244.5</td>
<td>CONN</td>
<td>2</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>5C52</td>
<td>244.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Patch</td>
</tr>
<tr>
<td>1B30</td>
<td>177.8</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>ZONAL W CEMENT</td>
</tr>
<tr>
<td>5C31</td>
<td>245.5</td>
<td>CONN</td>
<td>4</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
<tr>
<td>11A59</td>
<td>244.5</td>
<td>CONN</td>
<td>3</td>
<td>Pump</td>
<td>Slimhole</td>
</tr>
</tbody>
</table>
Out of Zone Failures by Cycle

Majority of out of zone failures occurred in cycle 4+ in 2013
In Zone Failures by Cycle

Failure rate decreased in 2013
Phases 59, 63 and 67 were not steamed in 2013
Failure by Geological Zone – Out of Zone Failure

- Majority of the out of zone horizontal well casing failures occur in the Belle Fourche, Base of Fish Scales and Westgate geological formations.
Out of Zone Failure vs Wellbore Pressure

Majority of failures occur while the reservoir is under low pressure
- High Pressure – Failed during steam, soak, trickle production, flow back
- Low Pressure – Failed during pumping or while well is shut in
- No Pressure – Failed during a work over

One out of zone failure occurred while well was on steam in 2013 – 4C52
Failure Vs. Operating Stage

Out of zone failures primarily occur during the production/shut in phases
- Tensile parting due to thermal affects is the ultimate failure mechanism

Pad 52 had two failures while well was on steam
- 4C52 - Out of Zone
- 5C52 - In Zone
On pads equipped with passive seismic, detection rate of out of zone well failures is 98% - Over the past two years the detection rate has been 100%
Part 2 Outline – Current Initiatives

• Understanding Failure Mechanisms

• Thermal Well Design
  – Thermal Casing Connections
    ▪ Connection fatigue test qualification

• Thermal Well Construction
  – Review of Changes to CNRL’s Cementing Procedures for CSS wells

• External Corrosion
  – Phase 16 Intermediate Casing Replacement

• Phase 52 and Z13 failure analysis
Part 2 Outline – Current Initiatives

• Understanding Failure Mechanisms

• Thermal Well Design
  – Thermal Casing Connections
    ▪ Connection fatigue test qualification

• Thermal Well Construction
  – Review of Changes to CNRL’s Cementing Procedures for CSS wells

• External Corrosion
  – Phase 16 Intermediate Casing Replacement

• Phase 52 and Z13 failure analysis
Thermal Well Design

Understand casing failure mechanism
- Load path (tensile, compressive, out of plane loading)
- Fatigue
- Buckling
- SSC
- Stress/Strain localization

Analyze Well Design, Well Construction and Well Operation Practices

Implement Improvements to Reduce Well Failures
Understanding Failure Mechanisms

• Cumulative Damage
  – Total damage caused by a number of stress cycles is equal to the sum of damages caused by the individual stress cycles
• The following mechanisms will cumulatively reduce casing fatigue life:
  – Installation loads
    ▪ Fatigue damage caused by pipe movement
  – Cyclic loading during operation
    ▪ Fatigue caused by cyclic formation movement and cyclic thermal loading
  – Environmental Cracking
    ▪ Sulphide Stress Cracking (SSC)/Caustic Cracking (CSCC)

To define casing integrity, the cumulative effect of all mechanisms must be considered
Contributing Mechanism - Casing Fatigue During Installation

- Casing Rotation - Bending during installation produces cyclic tensile and compressive stresses
  - Bending stress is a function of dogleg severity and casing outside diameter

Traditional fatigue testing focuses within the high cycle fatigue range
Rotation at a high bending stress is considered low cycle fatigue
Contributing Mechanism - Formation Movement

- Formation flexing is caused by
  - Dilation of the reservoir during steam injection imposing heave and a bending stress on the overburden
  - Compaction of the reservoir during production reverses the effect (fatigue)

Formation Slip can occur if the bending (shear) stress exceeds the formation shear strength

Formation Movement - Low Cycle Fatigue

• The pipe is very tolerant to lateral movement in the magnitude of 15mm-30mm over a 1m interval*
  – Bending strain in pipe body is typically < 1%
  
  *Lateral movement and bending strain is interpreted from cased hole log analysis

• Casing connections in close proximity to the formation movement are not as tolerant
  – Low or ultra low cycle fatigue may be induced as strain in the connection thread roots is plastic
  – Cracks can form and propagate in the connection in the area of high strain localization
    ▪ Contributes to cumulative damage
  – Space casing connections out from known weak formations
Contributing Mechanism
Thermal Cycling – Low Cycle Fatigue

• Undamaged casing connections subjected to thermal service typically can withstand ~100 thermal cycles
  – Validated though finite element analysis (FEA)/Full scale testing

• *Damaged* casing connections can fail within 10 thermal CSS cycles
  – Strain concentration in the connection likely ≥10%
  – As casing cycles between tension and compression, cracks propagate, ultimately leading to failure
Camera Run – Down Hole Connection Failure

95% of CNRL’s CSS casing failures to date are at the connection
Parting occurs at the last thread confirmed through multi-finger caliper log interpretation
Well Failure Mechanisms

- Casing failures result from cumulative damage during installation and operation
  - **Installation:**
    - Establish a limit to the number of casing rotations
    - Evaluate the casing connections’ resistance to fatigue
  - **Operation:**
    - Fatigue caused by formation movement
    - Fatigue induced through thermal cycling
  - **Mitigation/Inspection:**
    - Reduce bending strain (Well planning, DLS controls)
    - Establish guidelines for inspection in the event of aggressive rotation
    - Space casing connection out from weak planes

Casing failures can be reduced through proper well design, construction and operating practices
Part 2 Outline – Current Initiatives

• Understanding Failure Mechanisms

• Thermal Well Design
  – Thermal Casing Connections
    ▪ Connection fatigue test qualification

• Thermal Well Construction
  – Review of Changes to CNRL’s Cementing Procedures for CSS wells

• External Corrosion
  – Phase 16 Intermediate Casing Replacement

• Phase 52 and Z13 failure analysis
Fatigue Testing

• In response to the fatigue failure during installation in 2012 the CNRL/Casing manufacturer conducted fatigue testing of the two different types of casing connections used at Primrose
  – Fatigue testing simulating high bending stress had not been conducted by the manufacturer
    ▪ Unknown if fatigue performance at high bending stress will match the manufacturer’s fatigue prediction curve

• Outcome of the fatigue testing:
  – Validate the number of rotations until crack initiation
  – Verify what impact CNRL’s well construction (and operational) practices have on casing integrity
Fatigue Testing

Cyclic load is applied to the end of the pipe at a frequency close to the resonant frequency of the pipe.

Strain Gauges are mounted on the pipe body to confirm the accuracy of deflection.

Cyclic Load - Eccentric weight is rotated at 20-22 Hz by a motor to simulate required deflection.
Fatigue Testing - Cycles to Crack Initiation

- Results of testing show that fatigue cracks initiate after cycling for 50% of the estimated fatigue life
  - Micro-cracks were observed to form on the thread root of the last thread on casing connection (pin end)
  - CNRL observed cracking within the last thread when casing strings were pulled after excessive rotation during installation in 2012

Maximum casing rotation limit is 2000 revolutions during installation
No fatigue crack initiation
Part 2 Outline – Current Initiatives

• Understanding Failure Mechanisms

• Thermal Well Design
  – Thermal Casing Connections
    ▪ Connection fatigue test qualification

• Thermal Well Construction
  – Review of Changes to CNRL’s Cementing Procedures for CSS wells

• External Corrosion
  – Phase 16 Intermediate Casing Replacement

• Phase 52 and Z13 failure analysis
Problem Statement

• Maintaining pipe movement throughout cement placement
  – Rotation is lost on 30% of all wells with ICP>1100m
    ▪ Sample size - ph 60-68, ph 90-95, ph 40-43
  – Generally pipe rotation is lost prior to cement displacement resulting in poor placement

Scenario 1: Torque out prior to getting cement on outside of casing

Scenario 2: Torque out during displacement

\[ h_c = \text{height of cement in annulus} \]
\[ h_n = \text{height of cement left to displace} \]
Previous Cementing Practice

• Casing was rotated only during cement placement
  - Casing is prone to differential sticking when rotated without linear movement
    - As cement displaces the drilling fluids, horizontal section of casing sticks to low side of hole
  - Torque required to rotate wells with ICP>1100m is above the recommended make-up torque of the casing connection. Imposes additional strain on casing connections
    - Limit to rate of rotation due to the high torque output requirement
Primrose Well 2A42 - 21 MPa Pressure Pass - ICP 1206m

- Torqued out prior to getting cement on outside of shoe

Colorado Shale Top - 2A42 182 – 202 mKB

Grand Rapids Top 2A42 405-425 mKB

Clearwater Top 2A42 788-808 mKB

2A42 – Bond log infers no hydraulic isolation within the Colorado Shale
Changes to Cementing Practices

• New practice is to rotate (~10 rpm) and reciprocate (2m stroke length) casing using the rig top drive
  – No occurrence of loss of rotation prior to displacing cement since changing the cementing practice
    ▪ Max length of ICP ~1300m
  – Torque during rotation has lowered on average by ~35%
    ▪ Reducing stress/strain on the connection
    ▪ Within top drive system torque rating
      ▪ Special equipment no longer required
  – Limit total casing rotations to 2000 revolutions
    ▪ Reduces fatigue damage to the connection

Pipe movement can now be maintained throughout the critical section of the cement job
Changes to Cementing Practices

• Modified pump and displacement rates
  – Reduced pumping and displacement rates to plug flow conditions for improved hole cleaning & cement placement

• Use of batch mixer to improve cement blend consistency

• Cement squeeze used for final stage of displacement
  – Final volume is pumped at very low rates allowing cement to thicken and fill void in the annulus
1A42 - 21 MPa Pressure Pass - ICP 1265m – Rotated and Reciprocated

Colorado Shale Top - 190 mKB

Grand Rapids Top - 415 mKB

Clearwater Top - 1045 mKB

Cement bond drastically improves using new cement practices
Part 2 Outline – Current Initiatives

• Understanding Failure Mechanisms

• Thermal Well Design
  – Thermal Casing Connections
    ▪ Connection fatigue test qualification

• Thermal Well Construction
  – Review of Changes to CNRL’s Cementing Procedures for CSS wells

• External Corrosion
  – Phase 16 Intermediate Casing Replacement

• Phase 52 and Z13 failure analysis
External Corrosion Initiatives

• External corrosion preventative measures
  – Bentonite top ups are done on a routine basis
  – Surface casing extends above grade on all new pads
    ▪ Prevents ground water from accumulating in the casing

• To date below grade corrosion monitoring (vertilog or equivalent) have not detected any casing failures due to corrosion

• Above proactive initiatives are effective for preventing near surface well failures
External Corrosion – Phase 16

• In preparation for steam on Phase 16, corrosion logs and pressure tests were conducted

• Corrosion logs detected external corrosion near surface

<table>
<thead>
<tr>
<th>Date</th>
<th>Well</th>
<th>Corrosion (%)</th>
<th>Depth from Ground Level (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>13-Jul</td>
<td>4A16</td>
<td>42</td>
<td>1.9</td>
</tr>
<tr>
<td>13-Jul</td>
<td>1B16</td>
<td>60</td>
<td>1.37</td>
</tr>
<tr>
<td>13-Jul</td>
<td>4B16</td>
<td>74</td>
<td>1.82</td>
</tr>
<tr>
<td>13-Jul</td>
<td>5B16</td>
<td>81</td>
<td>1.2</td>
</tr>
<tr>
<td>13-Jul</td>
<td>3B16</td>
<td>29</td>
<td>0.68</td>
</tr>
<tr>
<td>13-Jul</td>
<td>5A16</td>
<td>54</td>
<td>1.18</td>
</tr>
<tr>
<td></td>
<td>1A16</td>
<td></td>
<td>No DVERT log run, assumed unacceptable corrosion based on adjacent wells. These wells are all to be remediated.</td>
</tr>
<tr>
<td></td>
<td>2A16</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3A16</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>2B16</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

• As a preventative measure - Casing was cutout and replaced on all wells with near surface corrosion greater than 40% of nominal wall thickness
External Corrosion

• Three sections were sent for further analysis at a third party facility

• General surface corrosion was found around the circumference of the pipe corresponding to where ground water would have accumulated at the cement top

• Root cause: Pad drilled prior to 2004 (Phases 1-21, Wolf Lake) did not have surface casing originally completed above grade.
  – Prior to steaming these areas, further corrosion logging shall be conducted to evaluate external corrosion
Part 2 Outline – Current Initiatives

- Understanding Failure Mechanisms

- Thermal Well Design
  - Thermal Casing Connections
    - Connection fatigue test qualification

- Thermal Well Construction
  - Review of Changes to CNRL’s Cementing Procedures for CSS wells

- External Corrosion
  - Phase 16 Intermediate Casing Replacement

- Phase 52 and Z13 failure analysis
Phase 52 Casing Failures

- 16 confirmed well failures out of 24 wells
  - 4 wells with multiple casing failures

Majority of failures occurred in Colorado Shale

<table>
<thead>
<tr>
<th>Pad 52 - Formation of Casing Failures</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lea Park</td>
</tr>
<tr>
<td>----------</td>
</tr>
<tr>
<td>1</td>
</tr>
</tbody>
</table>

Majority of failures occurred in Colorado Shale
4C52 – High Pressure Casing Failure

- Casing has shifted at the location of break in the Grand Rapids formation (454 mMD; 442 mTVD)
  - Two additional connections breaks are in the Colorado formation
- Rotated for ~2600 revolutions at a 14°/30m dogleg
  - Fatigue life prediction for the type of connection used is approximately 3500 revolutions at a 14°/30m
  - ~70% of the casing connections fatigue life consumed during installation
  - Fatigue cracks were likely in the connection prior to failure
- Likely failure mechanisms
  - Cumulative damage resulting from fatigue caused by installation, formation movement and thermal cycling
- Well Status: Repaired – Cemented Liner (Slimhole)
Phase 52 Casing Failures

Belle Fourche/Fish Scales -
- Casing impairments are all ~4m above top of Fish Scales formation

Collar Break

Impairments

Casing Break TVD From Top of Fish Scales

<table>
<thead>
<tr>
<th>1C52</th>
<th>7A52</th>
<th>1A52</th>
<th>7C52</th>
<th>3A52</th>
<th>4C52</th>
</tr>
</thead>
<tbody>
<tr>
<td>3</td>
<td>2.5</td>
<td>2</td>
<td>3</td>
<td>3</td>
<td>2.5</td>
</tr>
</tbody>
</table>

- 1C52
- 7A52
- 1A52
- 7C52
- 3A52
- 4C52
Phase 52 Casing Failure

- **Failure Mechanism**
  - Formation movement at weak overburden layer
    - Significant contrast in Young’s Modulus between shale and weak seam
      - 25-50 times difference in strength
  - Highly localized formation flex-slip occurs along weak seam during steam injection and production
    - Predicted that a seam exists ~4 meters above top of Fish Scales formation (Location of impairments from caliper log interpretation)


CNRL Sample Core – Primrose South - Colorado Shale – Belle Fourche
Phase 52 Casing Failure

• Casing in area of localized geological movement is subjected to high strain ultra-low cycle fatigue
  – Cracks form and propagate in the area with the highest strain localization in the casing connection
• Connection failures often occur during late cycle production
  – As casing cools the tensile stress in the connection increases causing cracks to further propagate causing failure due to parting

Cracks form in the last thread of the connection
Z13 Casing Failures

- 13 total well failures – 6 detected in 2011; 7 detected in 2013
  - Failures are all in the Colorado Shale

2011 Casing Failure
2013 Casing Failure
Passed PIT
Z13 Break vs. Formation

Well Failures tend to group around geological markers
- Fish Scales
- Base of the Westgate
- Top of the Jolifou

Formation movement potentially present at these intervals
Z13-6 – Shifted at Break-Formation Shear

Break Surface

Top View – Downhole Camera

Side View of Break

Top of Break

Milled through casing below break
During well diagnostics, 121mm gauge ring tagged break in 139.7mm casing
  - MFC shows no sign of a reduced diameter at break

3D processing of log shows lateral shift close to break location

Cause of failure
  - Cumulative Damage
    - Low cycle fatigue caused by bending/shear at the connection
    - Ultimate connection failure occurred by tensile parting during production
Z13 Failures – Root Cause

• Failures of vertical deviated wells are a result of cumulative damage resulting from dilation/compaction induced formation flexing combined with thermal cycling

• Preventative measures to be considered to reduce casing failures
  – Select casing connections that are resistant to high strain / low cycle fatigue
  – Space connections out from known weak overburden layers
  – Investigate the effectiveness of a geomechanical model to predict magnitude of formation flexing and shear slip imposed on the reservoir during the steam cycles
    ▪ Optimize resource recovery while preventing fatigue induced casing failures
Section 3 - Future Initiatives

• Qualification of casing connections for thermal service
  – Finite Element Analysis of 244.5 mm casing connection
  – Full Scale Physical Test

• Further investigation of the casing failure mechanisms

• Update Well Integrity Protocol
  – Work on protocol continues in 2014
    ▪ Refinement of targeted selection process
    ▪ Test frequency requirements prior to steam in

• CSS horizontal liner installation practices
Section 4 Outline

• Conclusion
  – CNRL continues to obtain a further understanding of well failure mechanisms
  – In 2013 CNRL implemented changes to well construction practices to prolong well life
    ▪ Pads equipped with new design changes with see cycle 4 steam ~2017
  – Future initiatives are in place in 2013 to improve well design, construction and operating practices

• Questions/Comments?
Forward Looking Statements

Certain statements relating to Canadian Natural Resources Limited (the “Company”) in this document or documents incorporated herein by reference constitute forward-looking statements or information (collectively referred to herein as “forward-looking statements”) within the meaning of applicable securities legislation. Forward-looking statements can be identified by the words “believes,” “expects,” “plan,” “continue,” “could,” “intend,” “may,” “potential,” “predict,” “should,” will “objective,” “project,” “forecast,” “goal,” “guidance,” “outlook,” “effort,” “seeks,” “schedule,” “proposed,” or expressions of a similar nature suggesting future outcome or statements regarding an outlook. Disclosure related to expected future commodity pricing, forecast or anticipated production volumes, royalties, operating costs, capital expenditures, income tax expenses, and other guidance provided throughout this Annual Information Form (“AIF”) constitute forward-looking statements. Disclosure of plans relating to and expected results of existing and future developments, including but not limited to the Horizon Oil Sands operations and future expansion, Septimus Primrose thermal projects, Pelican Lake water and polymer flood project, the Kirby Thermal Oil Sands Project, construction of the proposed Keystone XL Pipeline from Hardisty, Alberta to the US Gulf Coast, the proposed Kinder Morgan Trans Mountain pipeline expansion from Edmonton, Alberta to Vancouver, British Columbia and the construction and future operations of the North West Redwater bitumen upgrader and refinery also constitute forward-looking statements. This forward-looking information is based on annual budgets and multi-year forecasts, and is reviewed and revised throughout the year as necessary in the context of targeted financial ratios, project returns, product pricing expectations and balance in project risk and time horizons. These statements are not guarantees of future performance and are subject to certain risks and the reader should not place undue reliance on these forward-looking statements as there can be no assurances that the plans, initiatives or expectations upon which they are based will occur.

In addition, statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of proved and proved plus probable crude oil and natural gas and natural gas liquids (“NGLs”) reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary significantly from reserve and production estimates.

The forward-looking statements are based on current expectations, estimates and projections about the Company and the industry in which the Company operates. Forward-looking statements made on the date such statements were made are based on information available as of the date of the report or document in which they are contained, and are subject to known and unknown risks and uncertainties that could cause the actual results, performance or achievements of the Company to be materially different from any future results, performance or achievements expressed or implied by such forward-looking statements. Such risks and uncertainties include, among others: general economic and business conditions which will, among other things, impact demand for and market prices of the Company’s products and services; the effectiveness and efficiency with which the Company’s capital spending and expenditures are managed, and in particular, the funds and investment returns related to the Company’s current guidance is based; economic conditions in the countries and regions in which the Company conducts business; political uncertainty, including actions of or against terrorists, insurgent groups or other conflict including conflict between states; industry capacity; ability of the Company to implement its business strategy, including exploration and development activities; impact of competition; the Company’s defense of lawsuits; availability and cost of seismic, drilling and other equipment; ability of the Company and its subsidiaries to complete capital programs; the Company’s and its subsidiaries ability to secure adequate transportation for its products; unexpected disruptions or delays in the resumption of the mining, extracting or upgrading of the Company’s bitumen products; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; ability of the Company to attract the labor required to build its thermal and oil sands mining projects; operating hazards and other difficulties inherent in the exploration for and production and sale of crude oil and natural gas and in mining, extracting or upgrading the Company’s bitumen products; availability and cost of financing; the Company’s and its subsidiaries success of exploration and development activities and their ability to replace and expand crude oil and natural gas reserves; timing and success of integrating the business and operations of acquired companies; production levels; imprecision of reserve estimates and estimates of recoverable quantities of crude oil, natural gas and NGLs; not currently classified as proved; actions by governmental authorities; government regulations and the expenditures required to comply with them (especially safety and environmental laws and regulations and the impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company’s course of action would depend upon its assessment of the future considering all information then available. For additional information refer to the “Risks Factors” section of the AIF. Readers are cautioned that the foregoing list of factors is not exhaustive. Unpredictable or unknown factors not discussed in this report could also have material adverse effects on forward-looking statements.

Although the Company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, are expressly qualified in their entirety by these cautionary statements. Except as required by law, the Company assumes no obligation to update forward-looking statements, whether as a result of new information, future events or other factors, of the foregoing factors affecting this information, should circumstances or Management’s estimates or opinions change.
Reporting Disclosures

Special Note Regarding Currency, Production and Reserves
In this document, all references to dollars refer to Canadian dollars unless otherwise stated. Reserves and production data are presented on a before royalties basis unless otherwise stated. In addition, reference is made to crude oil and natural gas in common units called barrel of oil equivalent (“BOE”). A BOE is derived by converting six thousand cubic feet of natural gas to one barrel of crude oil (6Mcf:1bbl). This conversion may be misleading, particularly if used in isolation, since the 6Mcf:1bbl ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In comparing the value ratio using current crude oil prices relative to natural gas prices, the 6Mcf:1bbl conversion ratio may be misleading as an indication of value.

This document, herein incorporated by reference, have been prepared in accordance with IFRS, as issued by the International Accounting Standards Board.

For the year ended December 31, 2012 the Company retained Independent Qualified Reserves Evaluators (“Evaluators”), Sproule Associates Limited and Sproule International Limited (together as “Sproule”) and GLJ Petroleum Consultants Ltd. (“GLJ”), to evaluate and review all of the Company’s proved and proved plus probable reserves with an effective date of December 31, 2012 and a preparation date of February 11, 2013. Sproule evaluated the North America and international light and medium crude oil, primary heavy crude oil, Pelican Lake heavy crude oil, bitumen (thermal oil), natural gas and NGLs reserves. GLJ evaluated the Horizon SCO reserves. The evaluation and review was conducted in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (“COGE Handbook”) and disclosed in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) requirements. In previous years, Canadian Natural had been granted an exemption order from the securities regulators in Canada that allowed substitution of U.S. Securities Exchange Commission (“SEC”) requirements for certain NI 51-101 reserves disclosures. This exemption expired on December 31, 2010. As a result, the 2011 and 2012 reserves disclosure is presented in accordance with Canadian reporting requirements using forecast prices and escalated costs.

The Company annually discloses net proved reserves and the standardized measure of discounted future net cash flows using 12-month average prices and current costs in accordance with United States Financial Accounting Standards Board Topic 932 “Extractive Activities - Oil and Gas” in the Company’s Form 40-F filed with the SEC in the “Supplementary Oil and Gas Information” section of the Company’s Annual Report targeted to be released in late March 2013.

Resources Other Than Reserves
The contingent resources other than reserves ("resources") estimates provided in this presentation are internally evaluated by qualified reserves evaluators in accordance with the COGE Handbook as directed by NI 51-101. No independent third party evaluation or audit was completed. Resources provided are best estimates as of December 31, 2012. The resources are evaluated using deterministic methods which represent the expected outcome with no optimism or conservatism.

Resources, as per the COGE Handbook definition, are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but are not currently considered commercially viable due to one or more contingencies. There is no certainty that it will be commercially viable to produce any portion of these resources.

Due to the inherent differences in standards and requirements employed in the evaluation of reserves and contingent resources, the total volumes of reserves or resources are not to be considered indicative of total volumes that may actually be recovered and are provided for illustrative purposes only.

Crude oil, bitumen or natural gas initially-in-place volumes provided are discovered resources which include production, reserves, contingent resources and unrecoverable volumes.

Special Note Regarding non-GAAP Financial Measures
This document includes references to financial measures commonly used in the crude oil and natural gas industry, such as cash flow from operations, adjusted net earnings from operations, cash production costs, and net asset value. These financial measures are not defined by IFRS and therefore are referred to as non-GAAP measures. The non-GAAP measures used by the Company may not be comparable to similar measures presented by other companies. The Company uses these non-GAAP measures to evaluate its performance. The non-GAAP measures should not be considered an alternative to or more meaningful than net earnings, as determined in accordance with IFRS, as an indication of the Company’s performance. The non-GAAP measures adjusted net earnings from operations and cash flow from operations are reconciled to net earnings, as determined in accordance with IFRS in the “Financial Highlights” section of the Company’s MD&A which is incorporated by reference into this document. The derivation of cash production costs is included in the “Operating Highlights – Oil Sands Mining and Upgrading” section of the Company’s MD&A which is incorporated by reference into this document.

The volumes shown are Company share before royalties unless otherwise stated.
THE PREMIUM VALUE DEFINED GROWTH INDEPENDENT

PROVEN  EFFECTIVE  STRATEGY