Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2015 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual reserves may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com and at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). Total BIIP (143 Bbbls); discovered BIIP (93 Bbbls); commercial discovered BIIP equals the cumulative production (0.1 Bbbls) plus reserves (2.4 Bbbls); sub-commercial discovered BIIP equals economic contingent resources (9.6 Bbbls) plus the unrecoverable portion of discovered BIIP (81 Bbbls); undiscovered BIIP (50 Bbbls); prospective resources (8.5 Bbbls); unrecoverable portion of undiscovered BIIP (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: Mobile Wabiskaw total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). Mobile Wabiskaw development area total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). Immobile Wabiskaw total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Non-GAAP measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Readers are encouraged to review our most recent Management’s Discussion and Analysis, available at cenovus.com for a full discussion of the use of each measure.
Advisory

This presentation contains information in compliance with:

*AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes*

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. The resources estimates contained herein are not reported in accordance with National Instrument 51-101 and are provided solely for the purpose of complying with Alberta regulatory requirements.

Additional information regarding Cenovus Energy Inc., including information regarding contingent resources, is available in our Annual Information Form for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015 at cenovus.com.
Subsection 3.1.1-1) Brief background
# About Cenovus

<table>
<thead>
<tr>
<th>TSX, NYSE</th>
<th>CVE</th>
</tr>
</thead>
<tbody>
<tr>
<td>Enterprise value</td>
<td>C$18 billion</td>
</tr>
<tr>
<td>Shares outstanding</td>
<td>833 million</td>
</tr>
<tr>
<td>2016F production</td>
<td></td>
</tr>
<tr>
<td>Oil sands</td>
<td>151 Mbbls/d</td>
</tr>
<tr>
<td>Conventional</td>
<td>54 Mbbls/d</td>
</tr>
<tr>
<td>Total liquids</td>
<td>205 Mbbls/d</td>
</tr>
<tr>
<td>Natural gas</td>
<td>385 MMcf/d</td>
</tr>
<tr>
<td><strong>Total production</strong></td>
<td><strong>269 MBOE/d</strong></td>
</tr>
<tr>
<td>2015 proved &amp; probable reserves</td>
<td>3.8 BBOE</td>
</tr>
</tbody>
</table>

**Bitumen**
- Economic contingent resources*: 9.3 Bbbls
- Lease rights**: 2.0 MM net acres

**P&NG rights**
- 4.1 MM net acres

**Refining capacity**
- 230 Mbbls/d net

Values are approximate. Forecast production based on February 11, 2016 guidance.

*See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee’s behalf.
Major scheme/project updates

Q1 2000 EUB project approval
Q2 2002 First steam of phase A pilot
Q4 2005 Approval of phase B expansion
Q2 2008 Phase B expansion first steam
Q3 2008 Approval of phase C/D amendment
Q2 2011 Approval of phase E/F/G EIA application
Q2 2011 Phase C expansion first steam
Q2 2012 Phase D expansion first steam
Q4 2012 Approval of phase F and G amendment
Q4 2013 CDE Debottleneck amendment
Q4 2015 Approval of phase H and eastern expansion amendment
Q4 2015 CDE Debottleneck first steam
Recovery process

- The Christina Lake Thermal Project uses the dual-horizontal well SAGD (steam-assisted gravity drainage) process to recover oil from the McMurray formation.

- Two horizontal wells one above the other approximately 5 m apart.

- Steam is injected into the upper well where it heats the oil and allows it to drain into the lower well.

- Oil and water emulsion pumped to the surface and treated.
Drilled SAGD Wells as of March 31, 2016

- **Well pair drilled but not producing**
- **Well pair currently on production**
- **Well current on production**
- **Well drilled but not producing**

*Well using Wedge Well™ technology*
Commercial SAGD Wells as of March 31, 2016

Well pair drilled but not producing
Well pair currently on production
Well* currently on production
Well* drilled but not producing

*Well using Wedge Well™ technology
## Source and Disposal Wells as of March 31, 2016

<table>
<thead>
<tr>
<th>Source and Disposal Wells</th>
<th>Unavailable Wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quaternary Fresh H₂O source (2 wells @ 9-17-76-6W4) (1 well @ 6-16-76-6W4)</td>
<td>Note: MW1 &amp; MW4 are not in use yet, but will be by year end for Phase F</td>
</tr>
<tr>
<td>Local McM. Disposal (2 wells)</td>
<td></td>
</tr>
<tr>
<td>Local McM. Source (1 well)</td>
<td></td>
</tr>
<tr>
<td>MW1 13-7-76-5W4 12-7-76-5W4 (3 well pad)</td>
<td></td>
</tr>
<tr>
<td>CW4 11-36-75-6W4 (2 well pad)</td>
<td></td>
</tr>
<tr>
<td>CW 1 10-34-75-6W4 (3 well pad)</td>
<td></td>
</tr>
<tr>
<td>CW 3 10-27-75-6W4 (3 well pad)</td>
<td></td>
</tr>
<tr>
<td>RD 1 15-35-76-4W4 (6 well pad)</td>
<td></td>
</tr>
<tr>
<td>RD 2 13-34-76-3W4 (7 wells drilled) New piezo installed (Winter 2016) 3 Planned wells</td>
<td></td>
</tr>
<tr>
<td>RD 3 13-03-77-3W4 (1 observation well)</td>
<td></td>
</tr>
</tbody>
</table>

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Subsection 3.1.1 – 2) Geology and Geoscience

Brant Skibsted
Geologist
AER Approved Project Area

Reservoir Properties (project area)

- Reservoir depth: 350m TVD
- Original reservoir pressure: 2500 kPa
- Original reservoir temperature: 12°C
- Average Vertical permeability: 4.2 Darcies
- Average Horizontal permeability: 7.0 Darcies
- Average SAGD pay: 21 meters
- Average porosity ($\phi$): 33%
- Average oil saturation: 80%

Rock Volume: $1,925 \times 10^6$ m$^3$

SOIP: $508 \times 10^6$ m$^3$

Note: CVE Volumetric Estimates, not IQRE estimates

SOIP = Rock Volume in Project area x $\phi$ (.33) x So (.80)
AER Approved Project Area

Reservoir Properties (project area)

- Reservoir depth: 350m TVD
- Original reservoir pressure: 2500 kPa
- Original reservoir temperature: 12°C
- Average Vertical permeability: 4.2 Darcies
- Average Horizontal permeability: 7.0 Darcies
- Average SAGD pay: 21 meters
- Average porosity (Ø): 32%
- Average oil saturation: 70%

Rock Volume: $875 \times 10^6 \text{ m}^3$

SOIP: $196 \times 10^6 \text{ m}^3$

Note: CVE Volumetric Estimates, not IQRE estimates

SOIP = Rock Volume in Project area x phi (.32) x So (.70)
SAGD Pay Iso

Rock Volume: 2,801 x 10^6 m^3

SOIP: 704 x 10^6 m^3

Note: CVE Volumetric Estimates, not IQRE estimates
Stratigraphic wells within PA: 1002
- 2D seismic - 155 km
- 3D seismic - 98 km²
(entire project area now covered by 3D)

2015: 4D - 14.32 km²
2015: 2 strat wells, 39 obs wells

2016: 4D - 14.10 km²
2016: 31 strat wells, 70 obs wells
Analysis:
- Routine core analysis
- Photos

Total cored wells within PA- 310
2016 cored wells within PA- 0
2015 cored wells within PA- 4
Total steam chamber cores- 8

Strat and strat/cored wells are generally abandoned
Some strat and strat/cored wells are cased if they are further used for SAGD observation wells
All abandoned and cased wells are examined for integrity by the completions department prior to SAGD startup
Geological Maps
Composite type log: Phase B

- Pervasive basal mud layer often separates bitumen and McMurray water
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations
Composite type log: Phase CDE

- Pervasive basal mud layer often separates bitumen and McMurray water
- Basal mud is discontinuous and ranges from 0-4 metres in thickness
- Provides a good marker during SAGD operations
Representative Cross Sections
Cross section A-A’ (saturation)
Cross section A-A' (lithology)
Cross section B-B’ (saturation)
Cross section B-B’ (lithology)
Geomechanical and surface heave

- Integrated InSAR (Synthetic Aperture Radar) Land Deformation Monitoring took place between October 2014 – October 2015 by MDA Geospatial Services Inc.
- The measurements were successfully made on 98 active corner reflector (CR) locations installed since April 2008
- In addition to the corner reflectors, the deformation profiles at 19,710 point targets were estimated (coherent target monitoring-CTM). The location of these points coincides directly with pad, pipeline and plant structures

Refer to Appendix 1 for detailed heave data
Corner reflector (CR) locations:

Current Corner Reflectors: 98
Current Reference Corner Reflectors: 11
New Installs: 39 (orange)
• Strain monitoring gauges were installed winter 2016. No data has been acquired yet, but a baseline will be conducted prior to first steam on H03 Pad.

• The strain monitoring data gathered will be used in models and simulations that will improve our understanding of mechanisms that cause casing impairments.
Sample Producer Circulation Completion

- **Surface Casing:** 339.7 mm
- **Production Casing:** 244.5 mm
- **Outer tubing:** 177.8 mm
- **Inner tubing:** 88.9 mm
- **Production Liner:** 177.8 mm
- **Production Casing Annulus Gas Blanket for Pressure Measurement**
- **6 Pt Thermocouple or DTS:** 31.8 mm CT
Sample ESP Producer Completion

Surface Casing: 339.7 mm
Production Casing: 244.5 mm
Production Tubing: 114.3 mm
Bubble Tube: 12.7 mm
Slotted Liner: 177.8 mm
Temperature Instrument String (TC or DTS): 31.7 mm
Sample ESP Producer Completion w/ Tailpipe

Surface Casing: 339.7 mm
Production Casing: 244.5 mm
Production Tubing: 114.3 mm
Bubble Tube: 12.7 mm
Slotted Liner: 177.8 mm
Temperature Instrument String (TC or DTS) 31.7 mm
Tail Pipe: 114.3 mm
Sample Injector Completion

**Surface Casing:**
339.7mm

**Production Casing:**
244.5 mm

**Injector Tubing:**
-139.7 mm to 114.3 mm in horizontal with 2 to 6 steam splitters and open toe

**Slotted Liner:**
177.8 mm
Flow Control Devices

- Currently testing 3 flow control devices
  - 1 liner deployed ICDs
  - 2 tubing deployed ICDs
- Production from wells commenced in 2015
- ICD effectiveness review ongoing

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Well Type</th>
<th>Production Date</th>
<th>Deployment</th>
</tr>
</thead>
<tbody>
<tr>
<td>F01P08</td>
<td>Producer</td>
<td>08/09/2015</td>
<td>Tubing Deployed</td>
</tr>
<tr>
<td>F01P10</td>
<td>Producer</td>
<td>08/03/2015</td>
<td>Tubing Deployed</td>
</tr>
<tr>
<td>B07P10</td>
<td>Producer</td>
<td>12/10/2015</td>
<td>Liner Deployed</td>
</tr>
</tbody>
</table>
Subsection 3.1.1 – 4) Artificial Lift

Mike Ellis
Production Engineer
# Review of artificial lift by well

<table>
<thead>
<tr>
<th>Pad</th>
<th>Start date</th>
<th>Total producers</th>
<th>Total gas lift producer wells</th>
<th>Total ESP producer wells</th>
<th>Total wells using Wedge Well™ technology and ESP</th>
</tr>
</thead>
<tbody>
<tr>
<td>A Pad</td>
<td>2002</td>
<td>10</td>
<td>0</td>
<td>7</td>
<td>3</td>
</tr>
<tr>
<td>A02 Pad</td>
<td>2008</td>
<td>2</td>
<td>0</td>
<td>2</td>
<td>0</td>
</tr>
<tr>
<td>B01 Pad</td>
<td>2008</td>
<td>13</td>
<td>0</td>
<td>7</td>
<td>6</td>
</tr>
<tr>
<td>B02 Pad</td>
<td>2006</td>
<td>8</td>
<td>0</td>
<td>4</td>
<td>4</td>
</tr>
<tr>
<td>B02c Pad*</td>
<td>2013</td>
<td>6</td>
<td>0</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td>B03 Pad</td>
<td>2011</td>
<td>16</td>
<td>0</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>B04 Pad</td>
<td>2011</td>
<td>16</td>
<td>0</td>
<td>8</td>
<td>8</td>
</tr>
<tr>
<td>B05 Pad</td>
<td>2012</td>
<td>18</td>
<td>0</td>
<td>9</td>
<td>9</td>
</tr>
<tr>
<td>B06 Pad</td>
<td>2012</td>
<td>8</td>
<td>0</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>B07 Pad</td>
<td>2012</td>
<td>8</td>
<td>0</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>B07b Pad</td>
<td>2015</td>
<td>11</td>
<td>0</td>
<td>11</td>
<td>0</td>
</tr>
<tr>
<td>B08 Pad</td>
<td>2013</td>
<td>10</td>
<td>0</td>
<td>10</td>
<td>0</td>
</tr>
<tr>
<td>B09 Pad</td>
<td>2014</td>
<td>11</td>
<td>0</td>
<td>11</td>
<td>0</td>
</tr>
<tr>
<td>B11 Pad</td>
<td>2013</td>
<td>12</td>
<td>0</td>
<td>12</td>
<td>0</td>
</tr>
<tr>
<td>F01 Pad</td>
<td>2015</td>
<td>12</td>
<td>0</td>
<td>12</td>
<td>0</td>
</tr>
</tbody>
</table>

*Note: B02C refers to the 6 well pairs on the north side of the B02 Pad Approved Drainage Box, which were drilled at a 50m lateral downhole spacing.
Artificial lift performance

Gas lift (0 current wells):

- Typical operating pressure 4,000 – 5,000 kPag
- No temperature limitations, go as hot as ~263°C
- Average emulsion flow rate ~ 600-1600 m³/d

ESP (150 current wells):

- Majority of wells were converted to ESP after a gas lift phase
- ESP conversion occurs when thief zone intersected or other optimization purposes
- Typical operating pressure 1,800 – 4,000 kPag
- No temperature limitations, go as hot as ~235°C BHT
- Average emulsion flow rate ~ 200-1600 m³/d
Subsection 3.1.1 – 5) Instrumentation

Mike Ellis
Production Engineer
SAGD Well Pressure Instrumentation

At Christina Lake all production wells are equipped with bubble tubes to measure downhole pressures.

Currently there are 2 sizes of bubbles tubes:

- $\frac{3}{8}$ inch
- $\frac{1}{2}$ inch

We are replacing all $\frac{3}{8}$ inch bubble tubes with $\frac{1}{2}$ inch to increase reliability and to accommodate encapsulated thermocouples, where desired.

Fiber pressure gauges have been trialed with poor results. Moving forward bubble tubes will continue to be the pressure instrumentation of choice at Christina Lake.
SAGD Well Temperature Instrumentation

At Christina Lake, production wells currently use 1 of 2 technologies to measure downhole temperatures.

• **Type ‘K’ Thermocouples**
  • Single point installed at the heel
  • 6 point that is installed along the producer horizontal

• **Distributed Temperature Sensing (DTS)**
  • fiber optic instrumentation provides temperature measurement at any point from surface to the toe of the producer horizontal section
Instrumentation in Observation Wells (typical completions)

- Hanging Piezometer
- Hanging Thermocouples
- Cemented Piezometers
- Cemented Piezometers and Hanging Thermocouples

## Observation Well Equipment Reliability

<table>
<thead>
<tr>
<th>Type ‘K’ Thermocouples</th>
<th>Piezometers</th>
<th>Communications</th>
</tr>
</thead>
<tbody>
<tr>
<td>• Reliability has been very good</td>
<td>• Reliability has been good since 2013 when the switch was made to high temperature vibrating wire piezometers rated to 250°C</td>
<td>• Migration to a new radio network has increased reliability substantially</td>
</tr>
<tr>
<td>• Easy to replace if failed</td>
<td>• Cemented piezometers are impossible to replace in kind. Need to install hanging piezometer to replace</td>
<td>• Ongoing upgrades to SCADA equipment increases dependability and lowers future maintenance costs</td>
</tr>
<tr>
<td>• Thermocouple failures arise when the mineral insulated (MI) cable is compromised downhole.</td>
<td>• Have seen failures as a result of improper installation and well securement issues</td>
<td></td>
</tr>
</tbody>
</table>

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June 15, 2016
Observation Wells

Thermocouples

Piezometers

© 2016 Cenovus Energy Inc.
June 15, 2016
Subsection 3.1.1–5c) & d) instrumentation data

Requirements under subsection 3.1.1 5c) and d) are located in Appendices 2 & 3
Subsection 3.1.1 – 6) 4D Seismic

Amin Fardi
Reservoir Engineer
Subsection 3.1.1 – 6) a) seismic lines location map
Subsection 3.1.1 – 6) b)

b) Interpreted steam-affected chamber thickness
Subsection 3.1.1 – 7) Scheme performance

Amin Fardi
Reservoir Engineer
Scheme performance prediction

- Predict well pair performance based on modified Butler’s equation
- Predict well pair CSOR using published CSOR correlations (Edmunds & Chhina 2002)
- Generate overall scheme production performance by adding individual well forecasts over time to honor predicted steam capacity and water treating availability
SAGD summary to date

161 total production wells in operation to date:

- 122 standard well pairs
  - all on ESP, no gas lift

- one offset toe producer well
  - ESP
  - increase recovery from A01-3 well pair

- 38 wells using patented Wedge Well™ technology
  - all on ESP
  - 3 located in A01 pad
  - 1 in between B01 and B02 pad
  - 6 located in B01 pad
  - 3 located in B02 pad
  - 8 located in B03 pad
  - 8 located in B04 pad
  - 9 located in B05 pad
Increase in PWSR due to regional Bottom Water pressure gradients and new pads with slightly elevated Sw.
SAGDable vs. producible OIP (SOIP vs. POIP)

We are presenting two tables
• SAGDable OIP & producible OIP

We define SAGDable OIP as:
• \((\text{Planned length}) \times (\text{Spacing}) \times (\text{Net SAGD pay: Base to top SAGD}) \times (S_o) \times (\varnothing)\)
• Used during the planning phase
• Doesn’t change after well pair plans finalized
• Used to plan additional wells (Wedge Well™ technology, bypassed pay producers, re-drills, new pairs)
• We aim to drill the full planned length (typically 800m), and drill the producer well as low as possible in relation to Base SAGD

We define producible OIP as:
• \((\text{Effective length}) \times (\text{Spacing}) \times (\text{Effective pay: Producer to top SAGD}) \times (S_o) \times (\varnothing)\)
• An “after-drilling” OOIP, based on well pair potential
• Changes with time and interpretation (obs. wells, 4D seismic, MWD error, etc.)
• Used to plan blowdown strategy
• This reflects actual well pair performance
  • incorporates actual overlapping slotted liner lengths initially (including blank sections <100m)
  • incorporates actual elevation of the producing well
  • incorporates lithology

Producible OIP is always < SAGDable OIP
SAGDable vs. producible OIP (definition)

Vertical

SOIP

POIP

Horizontal

Effective length - slotted liner overlap (POIP)

Planned length - ICP to TD (SOIP)
Expect to recover 60-85% of oil in place (OIP) depending on the quality of pay. OIP volumes increased by 10% in 2015 compared to previous year’s estimates. In certain cases significant non-rich pay was added, which has a lower expected ultimate recovery than the original highly rich pay, thus lowering overall expected ultimate recovery.

A02 OIP volumes encompass the entire standard size drainage box intended for 8-12 SAGD production well pairs. Currently only two producing well pairs.

<table>
<thead>
<tr>
<th>Pad</th>
<th>Cumulative Oil Production (Mm³)*</th>
<th>SOIP (Mm³)</th>
<th>SOIP Recovery*</th>
<th>POIP (Mm³)</th>
<th>POIP Recovery*</th>
<th>Ultimate Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>2,198</td>
<td>5,054</td>
<td>43.5%</td>
<td>4,332</td>
<td>50.7%</td>
<td>60-85%</td>
</tr>
<tr>
<td>A02</td>
<td>373</td>
<td>4,056</td>
<td>9.2%</td>
<td>3,583</td>
<td>10.4%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B01</td>
<td>3,323</td>
<td>5,830</td>
<td>57.0%</td>
<td>4,817</td>
<td>69.0%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B02</td>
<td>2,256</td>
<td>3,081</td>
<td>73.2%</td>
<td>2,694</td>
<td>83.8%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B02C</td>
<td>1,229</td>
<td>2,461</td>
<td>49.9%</td>
<td>1,851</td>
<td>66.4%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B03</td>
<td>3,857</td>
<td>7,296</td>
<td>52.9%</td>
<td>5,742</td>
<td>67.2%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B04</td>
<td>4,347</td>
<td>7,369</td>
<td>59.0%</td>
<td>6,295</td>
<td>69.1%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B05</td>
<td>3,359</td>
<td>8,325</td>
<td>40.3%</td>
<td>7,080</td>
<td>47.4%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B06</td>
<td>2,638</td>
<td>5,694</td>
<td>46.3%</td>
<td>4,522</td>
<td>58.3%</td>
<td>60-85%</td>
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<tr>
<td>B07</td>
<td>3,590</td>
<td>8,929</td>
<td>51.8%</td>
<td>6,043</td>
<td>59.4%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B07b</td>
<td>166</td>
<td>6,528</td>
<td>2.5%</td>
<td>5,275</td>
<td>3.1%</td>
<td>60-85%</td>
</tr>
<tr>
<td>B08 Pad</td>
<td>1,751</td>
<td>5,593</td>
<td>31.3%</td>
<td>4,603</td>
<td>38.0%</td>
<td>60-85%</td>
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<tr>
<td>B09 Pad</td>
<td>1,207</td>
<td>7,063</td>
<td>17.1%</td>
<td>5,999</td>
<td>20.1%</td>
<td>60-85%</td>
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<tr>
<td>B11 Pad</td>
<td>2,639</td>
<td>5,887</td>
<td>44.8%</td>
<td>5,266</td>
<td>50.1%</td>
<td>60-85%</td>
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<tr>
<td>F01 Pad</td>
<td>447</td>
<td>5,954</td>
<td>7.6%</td>
<td>4,668</td>
<td>9.6%</td>
<td>60-85%</td>
</tr>
</tbody>
</table>

*As of March 31, 2016

Note: Resource estimates in this table are based on Cenovus volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.
### Average Reservoir Parameters

<table>
<thead>
<tr>
<th>Pad</th>
<th>Well Spacing (m)</th>
<th>Net SAGD Pay (m)</th>
<th>Pad Area</th>
<th>Average ((\phi))</th>
<th>Average ((S_o))</th>
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<tbody>
<tr>
<td>A</td>
<td>116</td>
<td>32</td>
<td>800m x 800m</td>
<td>0.31</td>
<td>0.76</td>
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<tr>
<td>A02</td>
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<td>800m x 800m</td>
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<td>B01</td>
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<td>700m x 850m</td>
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<td>0.80</td>
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<tr>
<td>B02</td>
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<td>0.84</td>
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<td>B02C</td>
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<td>28</td>
<td>300m x 1000m</td>
<td>0.32</td>
<td>0.83</td>
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<tr>
<td>B03</td>
<td>100</td>
<td>43</td>
<td>800m x 800m</td>
<td>0.32</td>
<td>0.84</td>
</tr>
<tr>
<td>B04</td>
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<td>0.31</td>
<td>0.81</td>
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<td>B05</td>
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<td>0.78</td>
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<td>B06</td>
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<td>35</td>
<td>800m x 800m</td>
<td>0.31</td>
<td>0.80</td>
</tr>
<tr>
<td>B07</td>
<td>100</td>
<td>40</td>
<td>800m x 800m</td>
<td>0.31</td>
<td>0.81</td>
</tr>
<tr>
<td>B07b</td>
<td>67*</td>
<td>29</td>
<td>800m x 800m</td>
<td>0.30</td>
<td>0.75</td>
</tr>
<tr>
<td>B08 Pad</td>
<td>67</td>
<td>33</td>
<td>800m x 800m</td>
<td>0.34</td>
<td>0.83</td>
</tr>
<tr>
<td>B09 Pad</td>
<td>67</td>
<td>47</td>
<td>800m x 800m</td>
<td>0.31</td>
<td>0.83</td>
</tr>
<tr>
<td>B11 Pad</td>
<td>67</td>
<td>39</td>
<td>800m x 800m</td>
<td>0.30</td>
<td>0.82</td>
</tr>
<tr>
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<td>67</td>
<td>35</td>
<td>800m x 800m</td>
<td>0.30</td>
<td>0.75</td>
</tr>
</tbody>
</table>

* Pairs 17-19 drilled at 100 m spacing
Two example well pairs provided in Subsection 3.1.1 – 7b) illustrate:

- **B05-6**: High reservoir quality
- **B02-1**: Medium reservoir quality
- **Expect the same ultimate recovery long-term**

Variation in well performance is the result of several years of operational learnings between pad start dates.
Well pair drilled but not producing
Well pair currently on production
Well* currently on production
Well* drilled but not producing

*Well using Wedge Well™ technology
CSOR increase due to adjacent wedge Well start-up
B05-6 Toe
*Rampdown trial at B02-1 interrupted by VFD failure in late 2015, causing steam to be shut-off prematurely.
No baseline data for this well – high water saturations in the pay zone are steam
Five year outlook – pad abandonments

• There are no anticipated pad abandonments for any of the Christina Lake wells in the next five years.
Wellhead steam quality

• Steam quality will be impacted by pipeline size and distance
• Current steam quality injected into all pads is calculated to be greater than 95%
• Currently steam head pressure is operated at 8.5 MPa$_g$ with a corresponding steam temperature of 300°C
• Steam quality is not expected to impact well performance at this time
Subsection 3.1.1 – 7e) Injected fluids

Co-injection and Blowdown Trials
Full-blowdown on A01 pad

• **Full blowdown as of November 2014**
  - November 2014: steam ramp down began on the entire pad
  - February 2015: full steam shut-in to all wells on the pad. Pressure maintenance continued through natural gas injection.
    - current chamber average operating pressure ~ 2,000 kPa_g
    - no negative impact has been observed with the pad operations as a result of full methane injection.
  - average concentration for Jan 2015 - March 2016
    - average methane injection rate 40 e3m3/d
    - CSOR has been maintained at 2.50
B01/B02 pad rampdown/blowdown pilot

Temporary wind-down test on B01 and B02 pads started June 2015

- timeframe: 1 year
- well pairs: B01-1 to B01-4 including WWs 01-03; B02-1 to B02-4 included.
- steam will be brought back on after test is complete

B01-1 to B01-4: Blowdown test (6 month test, extended to 1 year in Jan 2016)

- shut-in steam on all four wells
  - using gas cap (top down blowdown) to maintain pressure
- CSOR has been maintained at 1.67

B02-1 to B02-4: Steam ramp-down test (1 year test)

- cut steam by 25% every 3 months (75%, 50%, 25%, 0%)
- CSOR has been maintained at 1.92

Key learnings thus far:

- Increased gas production observed during blowdown
- Neighboring SAGD pads appear unaffected by blowdown at this time

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June 15, 2016
Subsection 3.1.1 – 7e) Injected fluids
Pre and Post SAP A0202 well - CSOR and Oil Production

- Pre-SAP: CSOR Pre-SAP = 2.37
- SAP: CSOR After SAP = 1.72
- Oil Production:
  - Pre-SAP: 785 bbl/d
  - After SAP: 800.72 bbl/d

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June 15, 2016
A0202 SAP (solvent aided process)

- Started butane co-injection in November 2009
- Cumulative SOR of 1.81
- Cumulative solvent recovery factor of 70.6%
- SAP has shown benefit of oil uplift and reducing SOR
- Acid job on producer well in September 2015
- Planning to stop butane co-injection and operate A0202 on steam in Q2 2016
- Planning to commence NCG co-injection (25 wt.%) in Q3 2016
- A0201 Early SAP injection (planning to inject butane in Q2/Q3 2016)
Subsection 3.1.1 – 7e) Injected fluids

Surfactant Steam Process (SSP) pilot
SSP (Surfactant Steam Process)

C1 → B11P09 (control well 1)  S1 → B11P10 (surfactant 1)  S2 → B11P11 (surfactant 2)  C2 → B11P12 (control well 2)
SSP

- Four wells in SSP trial
- Two wells with different surfactants and two control wells
- First steam in July 2013
- High pressure ESP operation (4000 kPa BHP) in November 2013
- First surfactant co-injection in January 2014
- Low pressure ESP operation (2800 kPa BHP) in June 2014
- Stopped injecting surfactant in Jan/Feb 2015
- Results are inconclusive due to communication with neighboring wells and thief zones
Subsection 3.1.1 – 7f)
2015 key learnings

Operating SAGD with Top Gas, Bottom Water
Operations at Christina Lake

Thief zones:

• B01 to B11 pad are operating under a gas cap
• A01, B01 to B11 and F01 Pads have areas where Regional Bottom Water (BW) present with no shale break separating oil and BW

Well performance of these two situations will be discussed:

• gas cap communication only
• bottom water and gas cap communication
High pressure operations

For high pressure operations, the SAGD chamber has to be isolated from other zones

- no gas cap or bottom water contact
Gas Cap at Christina Lake

SAGD Gas Iso

Section 15 Gas Cap (Currently being repressured with natural gas)

Sections 11-14 Gas Cap (repressured with air)
Gas influx into the steam chamber as evidence from cooling on thermocouples in adjacent monitoring wells. Effects of gas influx into the steam chamber are reversible.
Bottom Water Iso with Mud-Break Overlay

- **Blue** = Bottom Water, 5m contour interval. Data in blue
- **Grey/Black** = Mud Barrier (isolates oil & water zones), 1m CI. Data in red
- Anywhere with blue and no grey: Oil in direct contact with water

No isolation between B06 and B07b Pad. B06 required increased steam rates during B07b startup to combat bottom water influx.
Increase steam to B06 Pad to operate in balance with elevated bottom water pressure during B07b Pad startup. Influence from F01 Pad startup was minimal.
Regional Bottom Water Pressure Influence

- Regional activity from neighboring operators generally caused an increase to bottom water pressure
- Changes in bottom water pressures related to source, disposal, as well as SAGD leak-off / bottom water influx
- CVE reversed local disposal well 1F5/3-16-076-06W4 to a water production well
- Continue to work on an integrated strategy with regional partners to manage bottom water pressures
- Collaboration on a pressure management strategy with offsetting operations has been a success
Regional Bottom Water Pressure Influence

Bottom Water Iso

- Regional activity from neighboring operators generally caused an increase to bottom water pressure
- Changes in bottom water pressures related to source, disposal, as well as SAGD leak-off / bottom water influx
- CVE reversed local disposal well 1F5/3-16-076-06W4 to a water production well 76-3-W4
- Continue to work on an integrated strategy with regional partners to manage bottom water pressures
- Collaboration on a pressure management strategy with offsetting operations has been a success
Subsection 3.1.1 – 7f)
2015 key learnings

Patented Wedge Well™ technology
Well using Wedge Well™ technology

Patented Wedge Well™ Technology Locations

- Well pair drilled but not producing
- Well pair currently on production
- Well* currently on production
- Well* drilled but not producing

*Well using Wedge Well™ technology
Wedge Well™ Learnings

- Better parent well pair operation has reduced the necessity of wells using the Wedge Well™ technology.
- Wedge Well™ technology use may still be justified given the right conditions and will be evaluated on an individual pad basis going forward.
- Wedge Well™ vertical offset in relation to neighboring producers is determined by balancing the accessible incremental oil that can be recovered by the Wedge Well™ with the extent of conductive heating from the existing producing pairs.
Subsection 3.1.1 – 7f) 2015 key learnings
Wabiskaw Zone at Christina Lake
Unexpected Discovery:
steam-core drill in April 2013

6,500kPa Overpressure:
conductive thermal expansion in WBSK
(above 5,400kPa MOP)

4D Seismic Identification

WBSK Producer:
107/06-15, 8,600m³ oil, depressurization

Monitoring:
enhanced observation capabilities in the area
2015-2016 Monitoring Enhancements

- Installed piezometer (00/05-14)
- 4D seismic anomaly NOT overpressure
- Fixed broken thermocouples (03/05-14)
- Fixed broken piezometer (08/06-15)
- Added WBSK thermocouples (02/11-14)
- Shot 4D seismic in Q1 2016
Conclusion

- None of the Wabiskaw is currently observed to be over MOP.
- Monitoring is in place to detect any future over pressuring before it reaches MOP.
- Potential overpressure in 4D seismic in Zone 2 proved to be low pressure, hints at gas accumulation and McMurray/Wabiskaw communication in this area, which reduces overpressure risk.
- Mitigation plans are in place if pressures climb towards MOP.
Subsection 3.1.1 – 7g)
Information requests
Information Requests

No Information requests for 2015
Subsection 3.1.1 – 7h) Pad production plots
Pad production plots

Requirements under subsection 3.1.1 7h) are located in Appendix 4
Subsection 3.1.1 – 8)
Future plans

Amin Fardi
Reservoir Engineer
Resource recovery strategy

Well/pad placement:

• 2016/2017 well pairs will be drilled as per the existing (or future) applications and approvals
• Well spacing/trajectories planned to be submitted for approval prior to construction/drilling

No changes in the overall resource recovery strategy (operating pressure, composition of injected fluid)

Any deviations will be applied for as future amendments
## SAGD Drilling Plans 2016/2017

<table>
<thead>
<tr>
<th>Pad</th>
<th>Pad type</th>
<th>Well count</th>
<th>Timing</th>
</tr>
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<tbody>
<tr>
<td>J07</td>
<td>Production</td>
<td>9 well pairs</td>
<td>Q1 2016</td>
</tr>
<tr>
<td>J09</td>
<td>Production</td>
<td>9 well pairs</td>
<td>Q1 2016</td>
</tr>
<tr>
<td>H09</td>
<td>Production</td>
<td>6 well pairs</td>
<td>Q2 2016</td>
</tr>
<tr>
<td>H07</td>
<td>Production</td>
<td>9 well pairs</td>
<td>Q4 2016</td>
</tr>
<tr>
<td>L02</td>
<td>Production</td>
<td>8 well pairs</td>
<td>Q2 2017</td>
</tr>
<tr>
<td>B12</td>
<td>Production</td>
<td>8 well pairs</td>
<td>Q3 2017</td>
</tr>
<tr>
<td>G11</td>
<td>Production</td>
<td>8 well pairs</td>
<td>Q4 2017</td>
</tr>
</tbody>
</table>
Planned Strat Wells for 2016/17

76-6-W4

76-5-W4

76-4-W4

75-6-W4

75-5-W4

75-4-W4
Steam strategy 2016

- Phase F OTSG adding \( \sim 15,000 \text{ m}^3/\text{d} \) incremental capacity. Two additional pads planned to start up with Phase F OTSG: H01, H03
  - total of 24 well pairs
- The following pads are planned to start up for sustaining production: B06 Wedge Well™ technology, B10, L03, J03, L05, L09, J01, B13
  - total of 93 well pairs and 12 wells using Wedge Well™ technology
- Rampdown/blowdown/co-injection operations:
  - plan to continue blowdown at A01 pad
  - plan to continue at blowdown on B01-1 to B01-4 and rampdown on B02-1 to B02-4
  - Finalize co-injection/blowdown timing on B03, B04, B07 pad
- No steam shortages expected on existing pads
Steam strategy 2017

• The following pads are planned to start up for sustaining production: J09, J07, H09
• total of 24 well pairs
• Blowdown operations:
  • planned to continue at A01 pad
  • Return steam to B01 and B02 and study reversibility following blowdown/rampdown test
  • Commence co-injection/blowdown on mature pads
• No steam shortages expected on existing pads
Appendix 1
Subsection 3.1.1 – 2)
Heave data
Annual vertical deformation rates:
November 16, 2014 – November 11, 2015 (1 year)
Previous Annual vertical deformation rates:
November 21, 2014 – November 16, 2016
Geomechanical and surface heave (Coherent Targets)
Appendix 2
Subsection 3.1.1 – 5d)
Piezometer data
Graph showing pressure (kPa) over time from 2015 to 2016 for the wells 102/03-08-076-06W4. The pressure values range from approximately 2,700 kPa to 3,300 kPa. The graph indicates a general decrease in pressure with minor fluctuations throughout the year.
Broken Downhole
100/15-11-076-06W4

Broken Downhole
102/06-12-076-06W4

Broken Downhole
Broken Downhole
Broken Downhole
Broken Downhole
Appendix 3
Subsection 3.1.1 – 5d)
Observation Well Temperature Data
Appendix 4
Subsection 3.1.1 – 7h)
Pad Production Data
Oil & gas information

The estimates of reserves and contingent resources were prepared effective December 31, 2015 and the estimates of bitumen initially-in-place were prepared effective December 31, 2012. All estimates were prepared by independent qualified reserves evaluators, based on definitions contained in the Canadian Oil and Gas Evaluation Handbook and in accordance with National Instrument 51-101. Additional information with respect to the significant factors relevant to the resources estimates, the specific contingencies which prevent the classification of the contingent resources as reserves, pricing and additional reserves and other oil and gas information, including the material risks and uncertainties associated with reserves and resources estimates, is contained in our AIF and Form 40-F for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015, available on SEDAR at www.sedar.com, EDGAR at www.sec.gov and on our website at cenovus.com.

There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. There is no certainty that any portion of the prospective resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of those resources. Actual resources may be greater than or less than the estimates provided.

Total bitumen initially-in-place (BIIP) estimates, and all subcategories thereof, including the definitions associated with the categories and estimates, are disclosed and discussed in our July 24, 2013 news release, available on SEDAR at sedar.com and at cenovus.com. BIIP estimates include unrecoverable volumes and are not an estimate of the volume of the substances that will ultimately be recovered. Cumulative production, reserves and contingent resources are disclosed on a before royalties basis. All estimates are best estimate, billion barrels (Bbbls). Total BIIP (143 Bbbls); discovered BIIP (93 Bbbls); commercial discovered BIIP equals the cumulative production (0.1 Bbbls) plus reserves (2.4 Bbbls); sub-commercial discovered BIIP equals economic contingent resources (9.6 Bbbls) plus the unrecoverable portion of discovered BIIP (81 Bbbls); undiscovered BIIP (50 Bbbls); prospective resources (8.5 Bbbls); unrecoverable portion of undiscovered BIIP (42 Bbbls). Any contingent resources as at December 31, 2012 that are sub-economic or that are classified as being subject to technology under development have been grouped into the unrecoverable portion of discovered BIIP. Petroleum initially-in-place (PIIP) estimates for Pelican Lake are effective December 31, 2012 and were prepared by McDaniel. All estimates are best estimate discovered PIIP volumes as follows: Mobile Wabiskaw total PIIP (2.11 Bbbls); discovered PIIP (2.11 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0.03 Bbbls); unrecoverable discovered PIIP (1.72 Bbbls); undiscovered PIIP (0 Bbbls). Mobile Wabiskaw development area total PIIP (1.62 Bbbls); discovered PIIP (1.62 Bbbls); cumulative production (0.11 Bbbls); reserves (0.25 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.26 Bbbls); undiscovered PIIP (0 Bbbls). Immobile Wabiskaw total PIIP (1.33 Bbbls); discovered PIIP (1.33 Bbbls); cumulative production (0 Bbbls); reserves (0 Bbbls); contingent resources (0 Bbbls); unrecoverable discovered PIIP (1.33 Bbbls); undiscovered PIIP (0 Bbbls).

Certain natural gas volumes have been converted to barrels of oil equivalent (BOE) on the basis of one barrel (bbl) to six thousand cubic feet (Mcf). BOE may be misleading, particularly if used in isolation. A conversion ratio of one bbl to six Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent value equivalency at the well head.

Non-GAAP measures

Certain financial measures in this document do not have a standardized meaning as prescribed by IFRS such as, Operating Cash Flow, Cash Flow, Operating Earnings, Free Cash Flow, Debt, Net Debt, Capitalization and Adjusted Earnings before Interest, Taxes, Depreciation and Amortization ("Adjusted EBITDA") and therefore are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other issuers. These measures have been described and presented in order to provide shareholders and potential investors with additional measures for analyzing our ability to generate funds to finance our operations and information regarding our liquidity. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. Readers are encouraged to review our most recent Management’s Discussion and Analysis, available at cenovus.com for a full discussion of the use of each measure.

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Advisory

This presentation contains information in compliance with:

AER Directive 054 - Performance Presentations, Auditing, and Surveillance of In Situ Oil Sands Schemes

This document contains forward-looking information prepared and submitted pursuant to Alberta regulatory requirements and is not intended to be relied upon for the purpose of making investment decisions, including without limitation, to purchase, hold or sell any securities of Cenovus Energy Inc. The resources estimates contained herein are not reported in accordance with National Instrument 51-101 and are provided solely for the purpose of complying with Alberta regulatory requirements.

Additional information regarding Cenovus Energy Inc., including information regarding contingent resources, is available in our Annual Information Form for the year ended December 31, 2015 and in our Statement of Contingent and Prospective Resources for the year ended December 31, 2015 at cenovus.com.
## About Cenovus

**TSX, NYSE | CVE**

<table>
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<th>Enterprise value</th>
<th>C$18 billion</th>
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<tr>
<td>Shares outstanding</td>
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### 2016F production

<p>| | |</p>
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</tr>
</thead>
<tbody>
<tr>
<td>Oil sands</td>
<td>151 Mbbls/d</td>
</tr>
<tr>
<td>Conventional</td>
<td>54 Mbbls/d</td>
</tr>
<tr>
<td><strong>Total liquids</strong></td>
<td>205 Mbbls/d</td>
</tr>
<tr>
<td>Natural gas</td>
<td>385 MMcf/d</td>
</tr>
<tr>
<td><strong>Total production</strong></td>
<td><strong>269 MBOE/d</strong></td>
</tr>
</tbody>
</table>

- **2015 proved & probable reserves** | 3.8 BBOE

### Bitumen

- **Economic contingent resources** | 9.3 Bbbls
- **Lease rights** | 2.0 MM net acres
- **P&NG rights** | 4.1 MM net acres
- **Refining capacity** | 230 Mbbls/d net

Values are approximate. Forecast production based on February 11, 2016 guidance.

*See advisory. **Includes an additional 0.5 million net acres of exclusive lease rights to lease on our behalf and our assignee’s behalf.
Subsection 3.1.2 – 1)
 Facilities

Mandy Chen
Sr. Process Engineer
Facility Summary

2nd Stage Blowdown Boiler Start-Up

• Two blowdown boilers were commissioned in September 2015
• Increase steam capacity by 7,280 t/d and minimize blowdown disposal
• Operated on 100% blowdown as feed water

Addition of Heat Exchangers

• Nine heat exchangers were added in August 2015
• Increased cooling capacity by ~3,180 m³/d
Phase C/D/E Process De-oiling
Facility Modifications

• No additional major modifications made to Phase A-E outside of Phase C/D/E optimization already mentioned

• Commissioning of Produced Water / Boiler Feed Water crossover line to enable water sharing across Phase A-E and Phase F expected May 2016

• Commissioning of CL1F expansion expected in August 2016
  ➢ Includes addition of cogeneration

• Addition of three blend coolers and commissioning expected in June 2016
Subsection 3.1.2 – 2) Facility performance

Bailey Gould
Process Engineer
Plant performance

Exceeded design performance:

- Steam plant has achieved higher rates than nameplate design (103%, 50,000 t/d vs nameplate 48,400 t/d)
- Oil treating has achieved higher rates than nameplate design (101%, 25,755 m³/d vs 25,437 m³/d)

Debottlenecking Completed:

- Successful commissioning and start up of CDE Optimization project
- Debottleneck included 2 x OTSGs and additional cooling equipment
Bitumen treatment

Process

• Capacity of 25,437 m³/d, consistently achieving nameplate production in Q1 2016 as new pads ramp up

• Have reduced issues with treating and water quality due to:
  • Further improvements to chemical treating program
  • Improved operating procedures and monitoring programs
  • Modifications to control logic and increased automation

• Continued success of treating program to minimize slop production

• Slop handling is internalized within the facility, with little to no offsite management
Water treatment

De-oiling

• Capacity of 49,146 t/d of water  
• Flowed up to 51,032 t/d of water  
• Issues in de-oiling are:
  • Water cooling at high flow rates
  • Fouling of heat exchangers

Water treatment

• Blowdown recycle into the produced water treatment trains and boiler feed water tank with no adverse impacts up to 50% of total blowdown volumes produced
• Chemical optimization continues to be a focus in water treatment
Steam generation

Steam generation via 17 OTSGs

• Original design capacity of 48,400 m$^3$/d CWE dry steam
• Re-rated design capacity of 50,800 m$^3$/d CWE dry steam
• Have achieved rates in excess of 50,000 m$^3$/d CWE dry steam
• Typical operation: 82% quality
  • Worked with vendor to re-rate CDE OTSGs
  • Rigorous monitoring program including continuous boiler performance monitoring
  • 2 x OTSGs were operated on 100% blowdown as feed water and 75% steam quality for 2 months with slightly higher scaling rate in the radiant section observed
Power usage

*Note – Plot represents monthly power imports. No operating power generation facilities at Christina Lake.
Gas usage
Gas flared

Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.

OTSG trip resulting in flaring off of CDE system.

Production fluids to produced gas slug catcher causing O&G excursion through process, OTSG rates reduced.

Multiple instances of reduced rates to CDE OTSGs due to process issues causing fuel gas imbalance.
Gas vented

Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.

Drastic production cut at end of December due to apportionment resulted in venting.

Phase AB OTSG outages in November resulted in periodic venting.

Multiple OTSG trips resulting in loss of cooling and venting off of process tankage.

Production fluids to produced gas slug catcher causing O&G excursion through process, OTSG rates reduced.
Greenhouse gas emissions

Greenhouse gas emissions are reported to AER on a yearly basis for review.

- Q1 2016 total direct emissions by gas type:
  - CO₂ – 548,976 tonnes CO₂e
  - CH₄ – 5,907 tonnes CO₂e
  - N₂O – 905 tonnes CO₂e

- 2015 total direct emissions by gas type:
  - CO₂ – 1,968,254 tonnes CO₂e
  - CH₄ – 29,843 tonnes CO₂e
  - N₂O – 3,164 tonnes CO₂e

*Note – Only the 2015 GHGs have been verified and submitted, the 2016 numbers are preliminary.
Subsection 3.1.2 – 3) Measurement and reporting (MARP)

Mandy Chen
Sr. Process Engineer
Simplified MARP schematic

Fresh Source from Wells

Saline Source from Wells

Purchased Fuel Gas

Fuel Gas to Field

Truck

Utility to BT

BFW to IF

Fuel Gas to IF

SAGD Production

INV.

LACT

Gas

Oil

Water

Domestic use

Steam to Field

Blow Down to Disp.

PW & Waste to Disp.

ABBT0067303

ABIF0009508
Production Volumes

Bitumen Production

• Estimate by well tests (2 phase test separators with BSW%)
  • 8-12 wells per separator
  • ~10 hour cycles + purges
  • 1 hour of testing for every 40 hours of well operations, or about 2 x 10 hour tests per month

Gas Production

• The produced gas is “measured by difference” based on the gas balance.

• This “measured by difference” monthly volume is used to calculate the facility gas-to-oil ratio (GOR) and then be used to estimate gas production from each well since October 2015.
Injection Volumes

Steam Injection
- Steam to wells measured by nozzles or V-cone
- Prorate well steam to plant steam metered by flow nozzle off steam separators

Gas Co-Injection
- Co-injected gas monitored and reported on a well basis
Water Balance

• Two RD1 disposal water meters were found to be inaccurate due to improper meter configurations in the Distributed Control System (DCS).

• This measurement issue was addressed after the problem was found in December 2014.

• Overall water balance had been improved in 2015. The average monthly water imbalance is 2.99%.

Note:
• Correction factors were applied to disposal volumes reported by the MARP meters. A letter of self disclosure for the water imbalance was submitted to AER in February 2015.
Water Balance

Proration factors

Test rates are used to estimate monthly well production volumes of each product.

Estimated monthly battery production of each product is determined by totalling all wells’ estimated production.

Actual monthly battery production volume of each product is determined by measured delivery and inventory changes.

For each product,
Proration Factor = Actual Battery Production / Estimated Battery Production

For each product for each well,
Actual Monthly Well Production = Estimated Monthly Well Production x Proration Factor

m = Measurement Point

Courtesy of AER
Oil Proration Factor

[Bar chart showing monthly oil proration factors from Jan-2015 to Mar-2016, with a focus on 0.86 for Dec-2015 and Jan-2016, and 0.86 for 2015 YTD AVG and 2016 YTD AVG.]
Water Proration Factor

![Water Proration Factor Chart]

- Jan-2015
- Feb-2015
- Mar-2015
- Apr-2015
- May-2015
- Jun-2015
- Jul-2015
- Aug-2015
- Sep-2015
- Oct-2015
- Nov-2015
- Dec-2015
- 2015 YTD AVG
- Jan-2016
- Feb-2016
- Mar-2016
- 2016 YTD AVG

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Subsections 3.1.2-3b)
June 16, 2016
Steam Proration Factor

![Bar chart showing steam proration factor for various months and years, with some months and years having a value of 1.07, while Jan 2016 has a value of 1.10.](chart.png)
Subsection 3.1.2 – 4) Water production (injection and uses)

Bailey Gould
Process Engineer
Kayley Moule
Production Engineer
Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.

CDE Optimization OTSGs commissioned and operational.

CDE Optimization OTSGs offline.

Steam volumes

Average Monthly Rate (m3/d)

Jan 2015: 40,000
Feb 2015: 41,000
Mar 2015: 42,000
Apr 2015: 43,000
May 2015: 44,000
Jun 2015: 45,000
Jul 2015: 46,000
Aug 2015: 47,000
Sep 2015: 48,000
Oct 2015: 49,000
Nov 2015: 50,000
Dec 2015: 51,000
2015 YTD AVG: 40,603
Jan 2016: 52,000
Feb 2016: 53,000
Mar 2016: 54,000
2016 YTD AVG: 46,002
Produced water to steam ratio

- C Phase OTSG Pigging.
- Start up of F01 pad.
- E Phase OTSG Pigging.
- Start up of B07B pad, start up of CDE Optimization OTSGs.
- CDE Optimization OTSGs Offline.

![Chart showing PWSR (Produced Water to Steam Ratio) over time with key events highlighted.]
Produced water volumes

Average Monthly Rate (m³/d)

<table>
<thead>
<tr>
<th>Month</th>
<th>Avg Rate</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-2015</td>
<td></td>
</tr>
<tr>
<td>Feb-2015</td>
<td></td>
</tr>
<tr>
<td>Mar-2015</td>
<td></td>
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<td>Apr-2015</td>
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<td>May-2015</td>
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<td>Jun-2015</td>
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<td>Jul-2015</td>
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<td>Aug-2015</td>
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<td>Sep-2015</td>
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<td>Oct-2015</td>
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<tr>
<td>Nov-2015</td>
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<tr>
<td>Dec-2015</td>
<td></td>
</tr>
<tr>
<td>2015 YTD AVG</td>
<td>41,497</td>
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<tr>
<td>Jan-2016</td>
<td></td>
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<tr>
<td>Feb-2016</td>
<td></td>
</tr>
<tr>
<td>Mar-2016</td>
<td></td>
</tr>
<tr>
<td>2016 YTD AVG</td>
<td>46,529</td>
</tr>
</tbody>
</table>
Produced-Water Recycle (%) = \[
\frac{(\text{Produced Water In} - \text{Disposal Total})}{\text{Produced Water In}} \times 100
\]
Blowdown recycle

Note: Blowdown recycle rates vary depending on Produced Water:Steam ratio and make-up water demand, in addition to BFW quality.
Brackish water use

Uses:
- Make-up water for steam generation
- Produced water and produced emulsion cooling in Phase ABCDE
- Softened water used for slurry make-up, seal flushes etc.

High brackish make up rates during low PWSR operation.
Brackish water intensity

[Bar chart showing the Brackish water intensity from January 2015 to March 2016, with specific values for each month and averages.]
Fresh water use

Uses:
- Was used for make-up water for steam generation during commissioning and start up of CDE Optimization OTSGs.
- Includes camp and domestic use, utilities, etc. All attempts are made to minimize fresh water usage when not required as make-up water.

Increase in fresh water as make up water during low PWSR operation.

Successful process trial completed to reduce fresh rates to average < 70 t/d when not required for make-up.
Fresh water intensity

![Graph showing fresh water intensity over time]
Total disposal volumes (PW, RW, BD)

Notes: Operating philosophy is to minimize disposal volumes at all times and maximize produced water re-use. Specifically, blowdown recycle, regeneration optimization, and minimizing brackish make-up requirements have been areas of focus to reduce disposal.
Directive 081 disposal limit

- Insulator failure at 25 kV feed, subsequent UPS failure and process issues causing extended 4 day ramp up.
- Multiple process upsets, high PWSR following CDE Optimization OTSGs being taken offline.

Actual Disposal (%) vs Disposal Limit (%)

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Subsection 3.1.2-4e)
June 16, 2016
3-16 well reversal

Reversal of the 3-16 Disposal Well

691,464 m³ produced of the 5,236,500 m³ originally disposed

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June 16, 2016
Fresh and brackish sources

**Fresh wells:**
- Two Quaternary wells (Empress Formation) at 09-17-076-06W4M
- ESRD - Licensed for up to 5,000 m³/day
- TDS = 500-600 mg/L
- 1 Quaternary well (Empress Formation) at 06-16-076-06W4M with TDL of 20,000 m³ for Feb-Sept 2016

**Brackish water source wells:**

- **Historical**
  - 10-34A 1F1/13-34-075-06W4/00 TDS = 7,400 mg/L
  - 10-34B 1F1/13-34-075-06W4/00 TDS = 5,070 mg/L
  - 10-34C 1F1/15-27-075-06W4/00 TDS = 7,780 mg/L
  - 10-3A 1F1/16-03-076-06W4/00 TDS = 4,600 mg/L
  - 10-3B 1F1/02-03-076-06W4/00 TDS = 5,580 mg/L
  - 10-27A 100/04-35-075-06W4/00 TDS = 9,730 mg/L
  - 10-27B 100/13-27-075-06W4/00 TDS = 8,900 mg/L
  - 10-27C 100/02-27-075-06W4/00 TDS = 11,700 mg/L

- **Disposal reversal well**
  - 3-16 1F5/03-16-076-06W4/00 TDS = 6,6200 mg/L

- **2013**
  - CW4-A 1F1/01-35-075-06W4 TDS = 13,200 mg/L
  - CW4-B 1F1/06-01-076-06W4 TDS = 8,800 mg/L

- **New in 2015** (MW1 and MW4 wells-not used until Phase F startup)
  - MW1-A 1F1/07-18-076-05W4 TDS = 16,880mg/L
  - MW1-B 1F1/03-07-076-05W4 TDS = 16,520mg/L
  - MW1-C 1F1/09-07-076-05W4 TDS = 16,420mg/L
  - MW4-A 1F3/11-09-076-06W4 Not sampled yet-expected TDS = >12,000mg/L
  - MW4-B 1F1/04-08-076-06W4 Not sampled yet-expected TDS = >12,000mg/L
  - MW4-C 1F1/16-08-076-06W4 Not sampled yet-expected TDS = >12,000mg/L
Water disposal operations

Injecting into McMurray water sands at 13-34 since April 2015

Approval No. 9712, 10627C and 10627D (Class 1b Disposal)

Sixteen disposal wells (all Class 1b)

• Three disposal wells located near the facility 3-16-1, 4-16, and 7-16 (now abandoned)
• One well located near the facility (3-16-2) has been converted for disposal reversal
• Six disposal wells located at 15-35 utilized for upset scenarios
• Seven disposal wells in service located at 13-34

13-34 disposal is main disposal location with 15-35 and local wells used as back-up
McMurray water disposal wells

Existing Water Disposal Wells
- 100/04-16-76-6W4
- 100/03-16-76-6W4
- Converted to water prod well 1F5/03-16-76-6W4

Existing Water Disposal Wells
RD1 Pad
- 102/15-35-76-4W4
- 103/15-35-76-4W4
- 104/15-35-76-4W4
- 105/15-35-76-4W4
- 106/15-35-76-4W4
- 107/15-35-76-4W4

Existing Disposal Wells
RD2 Pad
- 100/13-34-76-3W4
- 102/13-34-76-3W4
- 103/13-34-76-3W4
- 104/13-34-76-3W4
- 105/13-34-76-3W4
- 100/04-03-77-3W4
- 100/12-34-76-3W4

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Subsection 3.1.2-4g)
June 16, 2016
Disposal well head pressures

Disposal WHP Limit = 5130 kPag

Wellhead Pressure (kPag)

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Subsection 3.1.2.-4h)
June 16, 2016
Christina Lake Disposal Totals

Note: No local disposal occurred in 2015 / Q1 2016
Water Disposal Operations

Bottom Water Pressure

Disposal Volumes moved to 15-35 disposal site

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Subsection 3.1.2.-4h)
June 16, 2016
Water disposal operations cont’d

Regional McMurray Pressures

Pressure (kPa)

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Subsection 3.1.2.-4h)
June 16, 2016
Waste disposal volumes

Reduced slop oil volume due to treating improvements with chemical optimization.

<table>
<thead>
<tr>
<th></th>
<th>2015</th>
<th>2014</th>
<th>2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>Slop Oil / Production Fluids (m³)</td>
<td>31,518</td>
<td>82,241</td>
<td>157,155</td>
</tr>
<tr>
<td>Drilling Waste (m³)</td>
<td>63,664</td>
<td>56,260</td>
<td>37,086</td>
</tr>
<tr>
<td>Lime Sludge (m³)</td>
<td>16,179</td>
<td>15,279</td>
<td>23,759</td>
</tr>
<tr>
<td>Contaminated Soils (m³)</td>
<td>159</td>
<td>187</td>
<td>310</td>
</tr>
<tr>
<td>Spent Scavenger (m³)</td>
<td>6,613</td>
<td>5,346</td>
<td>2,975</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>118,113</strong></td>
<td><strong>159,313</strong></td>
<td><strong>221,285</strong></td>
</tr>
</tbody>
</table>
## Waste disposal sites 2015

<table>
<thead>
<tr>
<th>Facility</th>
<th>Total (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tervita Janvier Landfill</td>
<td>66,951</td>
</tr>
<tr>
<td>Tervita Lindbergh Cavern</td>
<td>20,254</td>
</tr>
<tr>
<td>Cancen New Sarepta Disposal Well</td>
<td>19,382</td>
</tr>
<tr>
<td>Tervita Bonnyville Landfill</td>
<td>8,051</td>
</tr>
<tr>
<td>Newalta Elk Point</td>
<td>2,317</td>
</tr>
<tr>
<td>Newalta Fort McMurray</td>
<td>2,180</td>
</tr>
<tr>
<td>R.B.W. Edmonton</td>
<td>998</td>
</tr>
<tr>
<td><strong>TOTAL (m³)</strong></td>
<td><strong>120,132</strong></td>
</tr>
</tbody>
</table>

Cenovus Christina Lake trucks all disposal waste to licensed third party facilities.
Subsection 3.1.2 – 5) Sulphur production

Bailey Gould
Process Engineer
Scavenger recovery details

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q1 2015</td>
<td>73.8%</td>
</tr>
<tr>
<td>Q2 2015</td>
<td>70.5%</td>
</tr>
<tr>
<td>Q3 2015</td>
<td>73.7%</td>
</tr>
<tr>
<td>Q4 2015</td>
<td>73.3%</td>
</tr>
<tr>
<td>Q1 2016</td>
<td>70.6%</td>
</tr>
</tbody>
</table>
Scavenger uptime details

Plant trip and prolonged ramp up resulted in ~4 days of downtime for both trains.

One train taken offline for cleaning

One train taken offline for cleaning

One train taken offline for cleaning
Sulphur recovery operation

Preventative measures

- Chemical injection continues to be operated in counter current configuration
- Each train is on a 6-12 month PM to be cleaned (contactor, internal distributor, outlet separator demister inspected)
  - Cleaning has been postponed following change in SO₂ emissions limit to daily rather than calendar quarter year average as of Dec 16, 2015.
  - Require Phase F SRU to be operable before a train can be taken down for cleaning to prevent exceeding daily limit.
- Cleaning frequency determined based on process monitoring (pressure drop, spent chemical quality, gas temperature)
SO$_2$ emissions

Limit change to 3.0 t/d on a daily basis as of Dec 16, 2015
Ambient air quality monitoring

Passive exposure monitoring

As per the Approval (Table 3.3), Christina Lake is required to maintain a network of twelve passive monitoring exposure stations to obtain monthly static exposures of H₂S and SO₂.

The passive monitoring results in 2015 did not identify any significant air quality issues related to Plant operations.

Continuous air quality monitoring

CLTP is required in the Approval (Table 3.3) to maintain one continuous ambient air monitoring station 12 months per year to measure ambient levels of SO₂, H₂S, and NO₂ concentrations in addition to wind speed and wind direction.

In 2015, continuous air quality monitoring was conducted from Jan 1 to December 31 by Maxxam Analytics. The continuous ambient air monitoring station is located at 03-16-076-06-W4M. This location is the same as the passive monitoring station C10.

There were no operational issues relating to the ambient air monitoring equipment during the monitoring period.

The continuous ambient air quality monitoring in 2015 did not identify any significant air quality issues related to Plant operations.

No criteria exceedances were noted in either monitoring program
Ambient air monitoring results - sulphur dioxide

2015 Continuous Ambient Sulphur Dioxide Monitoring

- 1-Hour Average Daily Maximum
- AAQO 1-Hour Average Maximum
- 24-Hour Average
- AAQO 24 Hour Average Maximum
Ambient air monitoring results – nitrogen dioxide
Subsection 3.1.2 – 6) Environmental issues

Jesse Wong
Environmental Advisor
## 2015 Compliance issues and amendments

<table>
<thead>
<tr>
<th>Approval number</th>
<th>Amendments</th>
<th>Compliance issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>EPEA Approval 00048522-01-06&amp;07</td>
<td>06 - Phase H approval issued December 16, 2015. 07 – Clerical amendment</td>
<td>No</td>
</tr>
<tr>
<td>EPEA Approval 00298224-00-00</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Water Act Approval 00265924-00-02</td>
<td>02 – Surface Water Run-off Ponds amended to 1:10 yr./24hr duration storm event</td>
<td>No</td>
</tr>
<tr>
<td>Water Act License 00267617-00-02</td>
<td>No</td>
<td>No</td>
</tr>
<tr>
<td>Water Act License 00343057-00-01</td>
<td>Expiry amended to December 12, 2016</td>
<td>No</td>
</tr>
<tr>
<td>Water Act License 00293633-00-00</td>
<td>Water level cut-off elevations modified March 3, 2016</td>
<td>No</td>
</tr>
</tbody>
</table>
## Monitoring programs

<table>
<thead>
<tr>
<th>Monitoring program</th>
<th>Progress and results</th>
</tr>
</thead>
<tbody>
<tr>
<td>Air quality monitoring</td>
<td>Air emissions increased slightly in 2015 due to the commissioning of the blowdown boilers. No significant trends in ambient air monitoring observed.</td>
</tr>
<tr>
<td>Groundwater monitoring</td>
<td>Monitoring Program to be updated to include Phase H.</td>
</tr>
<tr>
<td>Thermal metal mobilization monitoring</td>
<td>Small temperature changes (up to 2°C) detected in the deeper Empress and the Ethel Lake formations in 2015. Groundwater chemistry has been consistent since the start of steaming.</td>
</tr>
<tr>
<td>Wildlife and caribou mitigation and monitoring programs</td>
<td>3 Year comprehensive report completed and sent to AER on May 15th, 2015. Proposed changes to programs being discussed with the AER.</td>
</tr>
<tr>
<td>Wetland monitoring program</td>
<td>Minor changes to program were approved by the AER in April 2016.</td>
</tr>
<tr>
<td>Monitoring program</td>
<td>Progress and results</td>
</tr>
<tr>
<td>--------------------------------------------------------</td>
<td>-----------------------------------------------------------------------------------------------------------------------------------------------------</td>
</tr>
<tr>
<td>Reclamation monitoring Program</td>
<td>Deferred until December 31, 2016. No permanent reclamation has occurred to date, however Cenovus continues to evaluate opportunities for permanent reclamation at the Project, including well pads.</td>
</tr>
<tr>
<td>Wetland reclamation trial program</td>
<td>Deferred until a candidate site becomes available</td>
</tr>
<tr>
<td>Project level conservation, reclamation and closure plan</td>
<td>To be submitted in October 2017, as per Specific Enactment Direction 001 issued March 1, 2016</td>
</tr>
</tbody>
</table>
Environmental initiatives

The regional multi-stakeholder forums that Cenovus was involved with in 2015 include:

- Canadian Oil Sands Innovation Alliance (COSIA): Linear Deactivation Program (LiDEA)

- Alberta Environmental Monitoring, Evaluation and Reporting Agency (AMERA)
  - Wood Buffalo Environmental Association (WBEA)
  - Alberta Biodiversity Monitoring Institute (ABMI)
  - Regional Aquatics Monitoring Program (RAMP)

- Industrial Footprint Reduction Options Group (iFROG)
Subsection 3.1.2 – 7) Statement of compliance

Brent Mitchell
Specialist, Regulatory Applications
2015 Compliance status

Maintain and track compliance

• Incident Management System (IMS)
• Centrac Database for commitment management
• Internal Regulatory Compliance Audit Team
• Dedicated onsite Environmental Monitoring and Stewardship Advisors
• Routine inspections and audits
• Raise awareness through training
• Establish consistent management processes

Cenovus FCCL Ltd. believes existing CLTP operations are in compliance with AER approvals and regulatory requirements.
Subsection 3.1.2 – 8)
Statement of non-compliance

Brent Mitchell
Specialist, Regulatory Applications
## 2015 Non-compliance summary – AER

<table>
<thead>
<tr>
<th>Date</th>
<th>Non compliance/self-disclosure</th>
<th>Follow-up</th>
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</thead>
<tbody>
<tr>
<td>2015-02-03</td>
<td>Unsatisfactory High Risk Drilling Waste Inspection @ 11-22-76-6W4 W0471662</td>
<td>Compliance achieved on Feb 4, 2015</td>
</tr>
<tr>
<td>2015-02-13</td>
<td>Disposal water balance exceedance Approval No. 8591</td>
<td>Compliance achieved on Jul 30, 2015</td>
</tr>
<tr>
<td>2015-07-15</td>
<td>Notice of Noncompliance - Outstanding Non-Abandoned OSE Wells (57 CL wells)</td>
<td>Compliance achieved on Sep 14, 2015</td>
</tr>
<tr>
<td>2016-01-13</td>
<td>Unsatisfactory Low Risk Oil Facility Inspection @ 8-17-76-6W4 F27189</td>
<td>Compliance achieved on Jan 22, 2016</td>
</tr>
</tbody>
</table>
Subsection 3.1.2 – 9)
Future plans
## Major activities and target dates

<table>
<thead>
<tr>
<th>Phase</th>
<th>Regulatory</th>
<th>Production capacity (m³/d)</th>
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<tr>
<td></td>
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<td>Filing</td>
</tr>
<tr>
<td>A</td>
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<td>Q1 1998</td>
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<tr>
<td>B</td>
<td></td>
<td>Q2 2005</td>
</tr>
<tr>
<td>C</td>
<td></td>
<td>Q3 2007</td>
</tr>
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<td>D</td>
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<td>Q3 2007</td>
</tr>
<tr>
<td>E</td>
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<td>G</td>
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<td>FG Amendment</td>
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<td>Q4 2012</td>
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<tr>
<td>CDE 2nd Stage OTSG</td>
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<td>Q4 2012</td>
</tr>
<tr>
<td>H</td>
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<td>Q1 2013</td>
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