Presenters

- Gary Shaner  Geology
- Haejin Kim  Exploitation
- Duilio Raffa  Reservoir Engineering
- Jason Augustin  Production Operations
- Jean-Michel Wan  Regulatory & Environment
- Neal Gartner  Facilities
Agenda – Subsurface

1. Overview
2. Geology / Geoscience
3. Drilling and Completions
4. Artificial Lift
5. Scheme Performance
6. Future Plans
Agenda – Surface

1. Facilities and Facility Performance
2. Measurement and Reporting
3. Waste Water Disposal
4. Water Source Use
5. Sulphur Emissions
6. Environmental Issues
7. Compliance Statement
8. Future Plans
Subsurface
Overview – Location

- Northeast Alberta near Bonnyville.
- Cold Lake Oil Sands Area.
Overview – Scheme Area

- Cold Lake Oil Sands Area.
- Township 60, Range 3, W4M.
- General Petroleum formation.
Overview – SAGD Development

Gemini Phase One

- Using Steam Assisted Gravity Drainage (SAGD) to recover bitumen from the General Petroleum formation.
- Single 600 m well pair, length matched to 50 MMBtu steam facility.
## Overview – Approval History

<table>
<thead>
<tr>
<th>Application Number</th>
<th>Project Summary</th>
<th>Approval No. and Date</th>
<th>Expiry Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>1741545</td>
<td>Application to change the operator to Baytex Energy Ltd.</td>
<td>11789B November 1, 2012</td>
<td>N/A</td>
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<tr>
<td>1734633</td>
<td>Response to Condition 2 of ERCB Decision (Plan to mitigate the potential impacts to surface water bodies from wells and facilities associated with Pads 101 and 103)</td>
<td>11789A September 5, 2012</td>
<td>N/A</td>
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<td>1617225</td>
<td>Application for a Commercial Thermal Project at Gemini</td>
<td>11789 March 30, 2012</td>
<td>261830-00-00 April 19, 2012</td>
</tr>
</tbody>
</table>
Geology/Geoscience – Reservoir Properties

Reservoir Attributes | Approval Area | Operating Area
--- | --- | ---
Area (ha) | 682 | 4.6
avgRes Depth (m) | 398mTVD (+176mSS) | 392mTVD (+177mSS)
Viscosity (cp) | 50,000 to 280,000 | 50,000 to 280,000
Initial Reservoir T(°C) / P(kPa) | 17 / 3000 | 17 / 3000
avgKmax (md) | 2,800 to 6,400 | 2,800 to 6,400
avgH (m) | 21.7 | 25.0
avgSo (frac) | 0.8 | 0.8
avgPhi (frac) | 0.33 | 0.33
OBIP (e³m³) | 4,042* | 277.2*

- OBIP = Area x Height x So x Phi
- * >10m Height (Net Bitumen Pay)
Geology/Geoscience – Net pay map

- GP age incised valley system
  - Approximately 1,100m wide.

- GP bitumen saturated sandstone
  - Approximately 300m wide, 3,600m long.

- Net pay cutoffs
  - Gamma ray <60 API
  - Density porosity >30%
  - Deep resistivity >10ohm.m
Top bitumen structure falls off to the Southwest.

Subtle drape / differential compaction at depositional edges.
Geology/Geoscience – Structure Map

• Base bitumen structure relatively flat in and along channel axis.

• Steep structure along edges reflective of discrete deposition.
• Thick, 32m of bitumen saturated GP sandstone.

• 9m marine shale caprock directly overlying bitumen.
Geology/Geoscience – Strat/Core Wells

- 11 cored wells over the General Petroleum in the Project area.
- 1AA/04-13-060-03W4 with cap rock integrity analysis.
Geology/Geoscience – Cross section

General Petroleum Structural Cross Section
Geology/Geoscience – Seismic Coverage

- 3.376km² 3D seismic within approved area.
Geomechanics

- 100/04-13-060-03W4 Mini Frac.
Geomechanics

- 100/04-13-060-03W4 Measured Frac Pressures.
  - Reservoir: 5,847 – 5,956 kPa (average gradient 14.3 kPa/m)
  - Caprock: 6,030 – 6,527 kPa (average gradient 16.0 kPa/m)
Drilling and Completions

Producer Completion

- 3-55 surface casing
- L-80 production casing
- Outer tubing 139.7 mm tubing
- Instrument string 31.75 mm coil
- Inner tubing 73.0 mm tubing
- Inner hanger
- Liner 177.8 mm
Artificial Lift

- Using gas lift, no major issues with performance.
  - Minor issue of undersized inlet flash when well slugs.
Instrumentation In Wells

- **Injector:**
  - Casing gas blanket for bottom hole pressure measurement.

- **Producer:**
  - Lift gas blanket for bottom hole pressure measurement.
  - Thermocouple string for bottom hole temperature measurement.
Scheme Performance

- Circulation:
  - Established circulation into producer on Jan 24, 2014 and into injector on Feb 13, 2014.
  - Circulated for total of 96 days, 79 operating days with 17 days downtime.
  - Converted to SAGD mode May 1, 2014.

- SAGD Mode:
  - Production ramping up as expected.
  - Subcools 0 – 10 °C.
Scheme Performance

Oil Water Steam Rate (m3/d)

CSOR, CWSR (v/v)
Scheme Performance

As of Sept 30, 2014:

- 19,487 m$^3$ cumulative oil production
  - OBIP $\sim$ 600m x 25m x 70m x 0.80 So x 0.33 por = 277.2 e$^3$m$^3$
  - recovery factor $\sim$ 7.0 %.

- 2.76 cumulative steam oil ratio ( 2.06 instantaneous ).
• SAGD operating average 3,960 kPa (May – Oct 2014).

Bottomhole Pressures (kPa)
Operating Pressures

- Monthly Average Bottomhole Pressures (kPa).

<table>
<thead>
<tr>
<th>Month</th>
<th>Pressure (kPa)</th>
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<tr>
<td>Jan-14</td>
<td>3,733</td>
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<tr>
<td>Feb-14</td>
<td>2,916</td>
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<tr>
<td>Mar-14</td>
<td>3,272</td>
</tr>
<tr>
<td>Apr-14</td>
<td>3,334</td>
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<tr>
<td>May-14</td>
<td>4,001</td>
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<tr>
<td>Jun-14</td>
<td>3,998</td>
</tr>
<tr>
<td>Jul-14</td>
<td>3,898</td>
</tr>
<tr>
<td>Aug-14</td>
<td>3,980</td>
</tr>
<tr>
<td>Sep-14</td>
<td>3,832</td>
</tr>
<tr>
<td>Oct-14</td>
<td>4,057</td>
</tr>
</tbody>
</table>
Steam Properties

- Injecting dry steam.
  - 100% wellhead quality, short distance from facility.

- Maximum 4,200 kPag BHP.
  - Steam saturation temperature ~ 253 °C.
Future Plans

- Evaluating current design and performance for future development:
  - Liner – slots vs wire-wrapped screen.
  - Lifting – gas lift vs tubing pump vs ESP.

- No drilling or changes to the current steam strategy is planned for the remainder of the year.

- Scheme Amendment:
  - Baytex plans to submit an application to reduce the size of the commercial facility from 1,600 m$^3$/d to 800 m$^3$/d.
  - The Amendment will also include addition of Project Areas (Pod 2 and Pod 3).
Surface
Facilities – SE ¼-14-60-03 W3M Plot Plan
Facility Schematic
Facility Performance

- Facility started making sales specification oil August, 2014. Initially the facility was unable to meet water content requirement, but changes to chemical program and treating pressure allowed 0.5% BS&W to be consistently achieved.

- OTSG had high pressure drop which caused numerous shutdowns and needed to be run below design flow rate. OTSG was mechanically cleaned in August and excessive scale was found inside economizer tubes (from previous owner operation). Boiler now runs as per design.

- Makeup water treatment uses SAC water softeners and consistently produces BFW specification water.

- 2 x 400 kW power generators with natural gas engine drivers. Generators had multiday outage due to failed rotor/winding.

- Facility experienced numerous freezing problems on mixed fuel gas and emulsion lines during January and February, 2014. Insulation and heat trace has been repaired/upgraded in preparation for coming winter.
Facility Performance - Gas

- Gas volumes $\text{e}^3 \text{m}^3$

<table>
<thead>
<tr>
<th>Month</th>
<th>Produced</th>
<th>Purchased</th>
<th>Vent</th>
<th>Flare</th>
<th>Solution Gas Recovery %</th>
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<tr>
<td>Jan-14</td>
<td>0</td>
<td>208.3</td>
<td>0</td>
<td>24</td>
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<tr>
<td>Feb-14</td>
<td>0</td>
<td>478.6</td>
<td>0</td>
<td>12.7</td>
<td>-</td>
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<tr>
<td>Mar-14</td>
<td>0</td>
<td>469.4</td>
<td>0</td>
<td>5.1</td>
<td>-</td>
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<td>Apr-14</td>
<td>107.8</td>
<td>225.9</td>
<td>0</td>
<td>0.7</td>
<td>99.3</td>
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<tr>
<td>May-14</td>
<td>87.5</td>
<td>509.2</td>
<td>0</td>
<td>1.7</td>
<td>98.1</td>
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<tr>
<td>Jun-14</td>
<td>90.1</td>
<td>702.1</td>
<td>0</td>
<td>3.6</td>
<td>96.1</td>
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<tr>
<td>Jul-14</td>
<td>61.5</td>
<td>719.3</td>
<td>0</td>
<td>0.2</td>
<td>99.6</td>
</tr>
</tbody>
</table>

- Produced gas is recovered and consumed at OTSG.
Greenhouse Gas

<table>
<thead>
<tr>
<th>Month</th>
<th>CO₂ (tonnes)</th>
<th>CH₄ (tonnes)</th>
<th>N₂O (tonnes)</th>
<th>CO₂e (tonnes)</th>
</tr>
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<tbody>
<tr>
<td>02-14-60-03-W4M</td>
<td></td>
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<td></td>
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<tr>
<td>January 2014</td>
<td>445</td>
<td>0.009</td>
<td>0.008</td>
<td>448</td>
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<tr>
<td>February 2014</td>
<td>941</td>
<td>0.018</td>
<td>0.017</td>
<td>947</td>
</tr>
<tr>
<td>March 2014</td>
<td>909</td>
<td>0.018</td>
<td>0.017</td>
<td>915</td>
</tr>
<tr>
<td>April 2014</td>
<td>641</td>
<td>0.012</td>
<td>0.012</td>
<td>644</td>
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<tr>
<td>May 2014</td>
<td>1143</td>
<td>0.022</td>
<td>0.021</td>
<td>1150</td>
</tr>
<tr>
<td>June 2014</td>
<td>1526</td>
<td>0.029</td>
<td>0.028</td>
<td>1535</td>
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<td>July 2014</td>
<td>1497</td>
<td>0.029</td>
<td>0.027</td>
<td>1506</td>
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<tr>
<td>August 2014</td>
<td>1848</td>
<td>0.036</td>
<td>0.034</td>
<td>1859</td>
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<tr>
<td>Total</td>
<td>8950</td>
<td>0.17</td>
<td>0.16</td>
<td>9004</td>
</tr>
</tbody>
</table>

- The CPF was in start-up mode between January and end of April 2014.
3) Measurement and Reporting
Measurement and Reporting

MARP approved May 7, 2013
• Annual update submitted Feb 28, 2014.

Production Volumes
• Single well battery – no proration or well tests required
• Bitumen & Produced Water determined by Dispositions – Inventory Change – Receipts
• Produced Gas: Measured VRU, Treater, and Separator Gas Streams.

Injection Volumes
• Steam: Measured BFW – Blowdown.
Measurement and Reporting – Water Balance

<table>
<thead>
<tr>
<th>Month</th>
<th>ABIF 0130103 Water Balance %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>0</td>
</tr>
<tr>
<td>Feb-14</td>
<td>0</td>
</tr>
<tr>
<td>Mar-14</td>
<td>0</td>
</tr>
<tr>
<td>Apr-14</td>
<td>6.00%</td>
</tr>
<tr>
<td>May-14</td>
<td>2.30%</td>
</tr>
<tr>
<td>Jun-14</td>
<td>0.10%</td>
</tr>
<tr>
<td>Jul-14</td>
<td>1.60%</td>
</tr>
</tbody>
</table>

- Annual MARP meter inspections and calibration as per MARP and Directive 17.
4) Water Production and Usage
Source Water

- Non Saline water source well.
  - 102/02-14-060-03W4M.
  - AB WS 0131002.

- Water from the Empress Channel aquifer.

- Produced water is not recycled.

- Source Water Quality.
  - 789 ppm TDS 2013-01-02.
Source Water Volumes
Water and Steam Volumes

- Produced Water and Steam Injection Volumes ($m^3$).

<table>
<thead>
<tr>
<th>Month</th>
<th>Produced Water</th>
<th>Injected Steam</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>345</td>
<td>345</td>
</tr>
<tr>
<td>Feb-14</td>
<td>4,688</td>
<td>4,688</td>
</tr>
<tr>
<td>Mar-14</td>
<td>5,590</td>
<td>5,589</td>
</tr>
<tr>
<td>Apr-14</td>
<td>3,498</td>
<td>2,976</td>
</tr>
<tr>
<td>May-14</td>
<td>5,393</td>
<td>6,131</td>
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<tr>
<td>Jun-14</td>
<td>8,503</td>
<td>9,055</td>
</tr>
<tr>
<td>Jul-14</td>
<td>9,088</td>
<td>9,252</td>
</tr>
</tbody>
</table>
Water and Waste Disposal

- **Baytex Gemini 100/02-14-060-03W4.**
  - Disposing into the Clearwater formation; Approval 12173.
  - Class II disposal well, application submitted to relicense as Class 1B (Oct 19, 2014).
  - ABIF 0130103.
  - Injection Pressure 4,300 kPa, Injection Temp 70 °C.

- **Baytex Gemini 102/04-13-060-03W4.**
  - Disposing into the Clearwater formation; Approval 12288.
  - Class 1B disposal well.
  - ABIF 0130103.
  - Injection Pressure 4,300 kPa, Injection Temp 70 °C.

- **Baytex Ardmore 100/15-18-062-3W4/2.**
  - ABIF 0081235.

- **Baytex Ardmore 100/11-18-062-4W4.**
  - ABIF 0091739.

- **Baytex Sugden 100/06-07-062-08W4.**
  - ABIF 0089706.

- **Tervita Lindbergh 05-26-056-05W4.**
  - ABWP 0000557.

- **Four Winds Hillmond 04-29-051-26W3.**
  - SKIF 0005884.
Produced Water Disposal Volumes

- Gemini Pilot uses less than 500,000 m$^3$ per year of make up water and does not recycle the produced water as per allowance in Directive 081, section 5.
5) Sulphur Production
SO₂ Quarterly Emissions (t) at Gemini CPF

- The CPF was in start-up mode between January and end of April 2014
### Monthly Sulphur Balance¹

<table>
<thead>
<tr>
<th>Measurement Location</th>
<th>All Oil Sands Wells on Pad (kg S)</th>
<th>TANK VRU (kg S)</th>
<th>Flared Gas (kg S)</th>
<th>Total Gas from Plant (kg S)</th>
<th>Water Source Well Casing Gas (kg S)</th>
<th>Total Monthly Sulphur emitted (kg S)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan-14</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Feb-14</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>Mar-14</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
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<tr>
<td>Apr-14</td>
<td>1.5</td>
<td>0.0</td>
<td>0.0</td>
<td>1.5</td>
<td>0.0</td>
<td>1.5</td>
</tr>
<tr>
<td>May-14</td>
<td>1.2</td>
<td>0.0</td>
<td>0.0</td>
<td>1.2</td>
<td>0.0</td>
<td>1.2</td>
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<tr>
<td>Jun-14</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
<td>0.0</td>
</tr>
<tr>
<td>Jul-14</td>
<td>77.4</td>
<td>0.0</td>
<td>0.3</td>
<td>77.7</td>
<td>0.0</td>
<td>77.7</td>
</tr>
<tr>
<td>Aug-14</td>
<td>45.5</td>
<td>5.0</td>
<td>0.0</td>
<td>50.5</td>
<td>0.0</td>
<td>50.5</td>
</tr>
</tbody>
</table>

¹ – Sulphur release values are based on metered flowrates and the H₂S content from a gas analysis sample taken from the produced gas effluent stream. The emission estimate assumes 100% of the H₂S is converted into SO₂ and released into the atmosphere.
SO₂ Max Daily Emissions (t/d)

- SO₂ emissions: no exceedances of EPEA Approval limit.

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<tbody>
<tr>
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<td>0.0000</td>
<td>0.0000</td>
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<td>0.0000</td>
<td>0.0052</td>
<td>0.0036</td>
<td>0.75</td>
</tr>
</tbody>
</table>

- The CPF was in start-up mode between January and end of April 2014.
Spills and Clean-Up

- October 20, 2014: Baytex reported an onsite crude oil spill FIS# 20142352.

- All areas impacted by the 7m$^3$ spill have been fully remediated and confirmed clean via a third party sampling program.

- The Remediation Closure Report will be submitted to the AER in November 2014.
Passive Monitoring

- No exceedances of $\text{SO}_2$ concentration objective.

<table>
<thead>
<tr>
<th>Passive Monitoring Stations Maximum Monthly Concentrations</th>
</tr>
</thead>
<tbody>
<tr>
<td>--------</td>
</tr>
<tr>
<td>$\text{H}_2\text{S}$ Pad 1</td>
</tr>
<tr>
<td>$\text{SO}_2$ Pad 1</td>
</tr>
</tbody>
</table>

AAAQO is ESRD 30-day objective

Concentrations in ppbv

- The values collected for $\text{H}_2\text{S}$ represent a time-weighted average based on the exposure time (1 month). Currently only 1hr and 24hr limits are available for $\text{H}_2\text{S}$ under the AAAQO guidelines. Data is presented for trend analysis only
Continuous Air Monitoring

- SO₂, NO₂ and H₂S concentrations (ppbv): no exceedances.

### Continuous Monitoring Stations SO₂ Concentrations

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<thead>
<tr>
<th></th>
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</tr>
</thead>
<tbody>
<tr>
<td>Max Hourly</td>
<td>2</td>
<td>3</td>
<td>5</td>
<td>4</td>
<td>39</td>
<td>10</td>
<td>5</td>
<td>2</td>
<td>2</td>
<td>1</td>
<td>2</td>
<td>2</td>
<td>2</td>
<td>172</td>
<td></td>
</tr>
<tr>
<td>Max Daily</td>
<td>0.8</td>
<td>1.1</td>
<td>1.3</td>
<td>2.0</td>
<td>7.0</td>
<td>1.9</td>
<td>2.5</td>
<td>0.7</td>
<td>0.3</td>
<td>0.2</td>
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<td>0.6</td>
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<tr>
<td>Average Monthly</td>
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<td>-</td>
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<td>-</td>
<td>1.1</td>
<td>1.0</td>
<td>0.6</td>
<td>0.08</td>
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<td>0.03</td>
<td>0.09</td>
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### Continuous Monitoring Stations H₂S Concentrations

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<tr>
<td>Max Hourly</td>
<td>28</td>
<td>51</td>
<td>74</td>
<td>39</td>
<td>62</td>
<td>41</td>
<td>81</td>
<td>63</td>
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<td>18</td>
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<td>Max Daily</td>
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<td>0.7</td>
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### Continuous Monitoring Stations NO₂ Concentrations

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</tr>
</thead>
<tbody>
<tr>
<td>Max Hourly</td>
<td>28</td>
<td>51</td>
<td>74</td>
<td>39</td>
<td>62</td>
<td>41</td>
<td>81</td>
<td>63</td>
<td>28</td>
<td>18</td>
<td>64</td>
<td>61</td>
<td>159</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

- The CPF was in start-up mode between January and end of April 2014
• Hourly temperatures and water levels are recorded using Level TROLLs in monitoring wells that are less than 35 metres to the east and to the north of the steam injection wells.

• No thermal effects observed on groundwater immediately adjacent to the steam injection wells.

• As there is no observed effect in the monitoring wells, of which some are completed in the Marie Creek Formation, and the Formation is continuous between the steam injection site and Angling Lake, there are no expected thermal effects on Angling Lake.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Temperature (°C)</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sand River and Surficial aquifer</td>
<td>4 - 7</td>
<td>Seasonal variation related to air and ground temperature changes</td>
</tr>
<tr>
<td>Ethel Lake</td>
<td>4.8 - 4.9</td>
<td>Stable</td>
</tr>
<tr>
<td>Marie Creek</td>
<td>4.9 – 5.1</td>
<td>Stable</td>
</tr>
<tr>
<td>Muriel Lake</td>
<td>4.8</td>
<td>Stable in the OBS well (variation in the WSW due to pump heating)</td>
</tr>
</tbody>
</table>
Groundwater Monitoring Program

- Baseline data collected by Matrix in 2013 and early 2014.

- Monitoring of all surficial aquifers for temperature, water levels and chemistry.

- Groundwater Monitoring to be completed 3 times in 2014:
  - April and August events are complete.
  - November/December event: To be conducted.

- Elevated dissolved metals at 2 locations in April 2014 and 2 different locations in August 2014.
  - Interpreted to be due to suspended particles present in these samples despite sample being field filtered and preserved.
  - Sites to be resampled in November/December to verify metals concentrations.

- Annual report will be prepared for submission in April 2015.
Domestic Well and Surface Water (Angling Lake) Monitoring Program

- Field verified water well survey conducted in 2013 by Matrix.
- Domestic well monitoring was conducted in August 2014.
- Results currently being analyzed and will be included in 2014 annual report.
- Angling Lake monitoring currently being completed.
Soil Monitoring Program

- Soil monitoring program completed 1\textsuperscript{st} week of September 2014.

- Laboratory analytical results obtained on Sept 29, 2014. Preliminary interpretation did not identify any issues.

- 2014 soil monitoring report currently underway.
Authorizations and Approvals:

- April 29, 2014: Requested authorization to increase the maximum well head injection pressure at 00/02-14-060-03W4/0 from 3000 kPag to 4320 kPag. Approval (12173A) received on July 30, 2014.


- April 2014: Requested authorization to install two tank burners. Granted in April 2014. Amendment to Approval (Scheme and EPEA) not required by the AER.

- June 2014: Requested authorization to install a third tank burner. Granted in June 2014. Amendment to Approval (Scheme and EPEA) not required by the AER.

- October 1, 2014: Received Water Act approval for a permanent diversion licence of up to 229,950 m³/yr from the Quaternary Muriel Lake Aquifer. Current draw for Gemini pilot: ~450 m³/d (max allowed is 630 m³/d).
Voluntary Self Disclosure (VSD):

- Submitted VSD to the AER on Jan 17, 2014.

- Brief MAWP exceedance of disposal well 100/02-14-060-03W4 during start up operations.

- VSD was accepted by the AER on Apr 7, 2014.
Regulatory Summary (continued)

Voluntary Self Disclosure (VSD):

- Submitted VSD to the AER on Sept 16, 2014.

- Between Aug 11–Sept 9, 2014, OTSG blowdown waste (~1248m³) was disposed of into well 100/02-14-060-03W4 (Class II Disposal). The deficiency was immediately corrected by diverting the blowdown waste to a separate tank for offsite disposal.

- VSD was accepted by the AER on Sept 30, 2014.

- Long-term solution is for Baytex to re-license the 100/02-14 well appropriately as this was the original purpose of the well.

Compliance

- To the best of our knowledge, the Baytex Gemini SAGD Project is currently in compliance with all conditions of its approvals and associated regulatory requirements.
Future Plans

• Scheme Amendment:
  • Baytex plans to submit an application to reduce the size of the facility from 1,600 m$^3$/d to 800 m$^3$/d.
  • The Amendment will also include addition of Project Areas (Pod 2 and Pod 3) as shown on the next page.

• Commercial Phase:
  • Baytex plans to proceed with 800 m$^3$/d Commercial Project based on results from Pilot performance along with market performance and capital availability.
Future Plans – Project Area Addition
Advisory

Forward-Looking Statements

In the interest of providing interested parties with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements made by the presenter and contained in these presentation materials (collectively, this "presentation") are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). The forward-looking statements contained in this presentation speak only as of the date of this presentation and are expressly qualified by this cautionary statement. The information contained in this presentation does not purport to be all-inclusive or to contain all information that potential investors may require.

Specifically, this presentation contains forward-looking statements relating to, but not limited to: our business strategies, plans and objectives; and our Gemini SAGD Pilot Project, including development and operational plans, completion strategies, our assessment of the performance of the project, our interpretation of geology, project life, original bitumen in place volumes, expected recovery factors and steam-oil ratios, the annual volume of make up water used by the project, and our plans to file an application to amend the currently approved project. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

Cash dividends on our common shares are paid at the discretion of our Board of Directors and can fluctuate. In establishing the level of cash dividends, the Board of Directors considers all factors that it deems relevant, including, without limitation, the outlook for commodity prices, our operational execution, the amount of funds from operations and capital expenditures and our prevailing financial circumstances at the time. Although Baytex believes that the expectations and assumptions upon which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because Baytex can give no assurance that they will prove to be correct.

These forward-looking statements are based on certain key assumptions regarding, among other things: our ability to execute and realize on the anticipated benefits of the acquisition of the Eagle Ford assets; petroleum and natural gas prices and pricing differentials between light, medium and heavy gravity crude oils; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; the amount of future cash dividends that we intend to pay; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated. Readers are cautioned that such assumptions, although considered reasonable by us at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: failure to realize the anticipated benefits of the acquisition of the Eagle Ford assets; declines in oil and natural gas prices; risks related to the accessibility, availability, proximity and capacity of gathering, processing and pipeline systems; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; uncertainties in the credit markets may restrict the availability of credit or increase the cost of borrowing; refinancing risk for existing debt and debt service costs; a downgrade of our credit ratings; the cost of developing and operating our assets; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in government regulations that affect the oil and gas industry; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects or expansion of our activities; risks related to heavy oil projects; changes in environmental, health and safety regulations; the implementation of strategies for reducing greenhouse gases; depletion of our reserves; risks associated with the ownership of our securities, including the discretionary nature of dividend payments and changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These risk factors are discussed in Baytex's Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2013, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.
Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The above summary of assumptions and risks related to forward-looking statements in this presentation has been provided in order to provide potential investors with a more complete perspective of our current and future operations and as such information may be not appropriate for other purposes. There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Oil and Gas Information

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved and probable reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery. The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts, including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods, is required to properly use and apply reserves definitions.

The recovery and reserves estimates described herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves and future production from such reserves may be greater or less than the estimates provided herein. The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation. For complete NI 51-101 reserves disclosure, please see our Annual Information Form for the year end December 31, 2013 dated March 25, 2014.

When converting volumes of natural gas to oil equivalent amounts, Baytex has adopted a conversion factor of six million cubic feet of natural gas being equivalent to one barrel of oil, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Oil equivalent amounts may be misleading, particularly if used in isolation.
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