Great Divide (10587)

2013 Performance Presentation

Includes the Great Divide (Pod One) and Algar Plants

November 19th 2013
Forward Looking Information and Advisories

This presentation contains forward looking information including expectations for future production, estimates of reserves and future net revenue associated therewith, proposed bitumen capacity expansion at Great Divide and anticipated timing for receipt of regulatory approvals, planned capital spending program for 2012, growth potential at Pod One and Algar, favourable operating results arising from a number of initiatives being undertaken, gas injection efforts at Pod One and general operational and financial performance in future periods.

Forward looking information is based on management’s expectations regarding future growth, results of operations (including production, operating costs, average realized bitumen, crude oil and natural gas prices, average throughput, costs of purchased feedstock and SORs), future capital and other expenditures (including the amount, nature and sources of funding thereof), plans for and results of drilling activity, environmental matters, business prospects and opportunities, future royalty rates, commodity prices and foreign exchange rates and future economic conditions. Estimates regarding future production levels at Pod One and Algar are based on anticipated SORs, reservoir performance and past production performance and unplanned operational upsets based on historical results. Forward looking information involves significant known and unknown risks and uncertainties, which could cause actual results to differ materially from those anticipated. These risks include, but are not limited to: the risks associated with the oil and gas industry (e.g., operational risks in development, exploration, production and start-up activities; delays or changes in plans with respect to exploration or development projects or capital expenditures; actual SORs being different than what was anticipated; unanticipated operational upsets; the uncertainty of reserve and resource estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), the risk of commodity price and foreign exchange rate fluctuations and risks and uncertainties associated with securing and maintaining the necessary regulatory approvals and financing to proceed with the continued expansion of the Great Divide Expansion Project. Additional risks and uncertainties relating to Connacher and its business and affairs are described in further detail in Connacher’s Annual Information Form for the year ended December 31, 2011 which is available at www.sedar.com. Although Connacher believes that the expectations in such forward looking information are reasonable, there can be no assurance that such expectations shall prove to be correct. The forward-looking information included in this presentation is expressly qualified in its entirety by this cautionary statement. Connacher assumes no obligation to update or revise any forward-looking information to reflect new events or circumstances, except as required by law. In addition there can be no assurance that a transaction will result from the strategic review currently being undertaken by the Corporation’s Board of Directors or, if a transaction does materialize, no assurance can be made with respect to the terms or timing associated therewith.

This presentation includes information pertaining to the reserves and the value of future net revenue of the Corporation as at December 31, 2007, 2008, 2009, 2010 and 2011 as evaluated by GLJ Petroleum Consultants Ltd. (“GLJ”) in their reports for the years ended December 31, 2007, 2008, 2009, 2010 and 2011 (the “Year End GLJ Reports”). Statements relating to reserves are deemed to be forward looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and can be profitably produced in the future. Certain information and assumptions relating to the reserves reported herein and the future net revenue associated therewith, including the pricing assumptions used in the Year End GLJ Reports, are set forth in Connacher’s annual information forms for the years ended December 31, 2007, 2008, 2009, 2010 and 2011 which are available at www.sedar.com. There is no assurance that the forecast price and cost assumptions contained in the Year End GLJ Reports will be attained and variances could be material. The estimates of future net revenue disclosed herein do not represent fair value. The reserves estimates of Connacher’s properties described herein are estimates only. The actual reserves on Connacher’s properties may be greater or less than those calculated. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves. The Year End GLJ Reports employ GLJ’s pricing assumptions as at certain specified dates which may differ from the pricing assumptions used in prior reserves evaluations.

All references to barrels of oil equivalent (boe) are calculated on the basis of 6 Mcf:1 bbl (unless otherwise indicated). This conversion ratio is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Boes may be misleading, particularly if used in isolation. Additionally, given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value. In addition, design capacity is not necessarily indicative of the stabilized production levels or steam capacity that may ultimately be achieved at Connacher’s SAGD facilities. Moreover, reported average or instantaneous production levels may not be reflective of sustainable production rates and future production rates may differ materially from the production rates reflected in this presentation due to, among other factors, difficulties or interruptions encountered during the production of bitumen or other hydrocarbons.
### Agenda

#### Subsurface Presentations

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<th>Declan Livesey</th>
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</thead>
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<td>Geology &amp; Geophysics</td>
<td>Gordon Trainor</td>
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<td>Recovery Process &amp; Completions</td>
<td>Colin Germaniuk</td>
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<td>Monitoring</td>
<td>Colin Germaniuk</td>
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<td>Scheme Performance</td>
<td>Colin Germaniuk</td>
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<td>Future Plans (Existing Developments)</td>
<td>Declan Livesey</td>
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#### Surface Presentations

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<th>Background</th>
<th>Declan Livesey</th>
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<tr>
<td>Facilities</td>
<td>Hollis Sylvester</td>
</tr>
<tr>
<td>MARP</td>
<td>Nadir Dantiwala</td>
</tr>
<tr>
<td>Water Management</td>
<td>Nadir Dantiwala</td>
</tr>
<tr>
<td>EH&amp;S</td>
<td>Jennifer Keturakis</td>
</tr>
</tbody>
</table>
Connacher Oil & Gas Assets

- Connacher Oil and Gas Limited is a public, Calgary based exploration, development and production company emphasizing unconventional crude oil projects.

- Primary driver of value is the expansion and continued development of its bitumen production at its Great Divide oil sands operations using in-situ recovery methods.

- Oil sands reserves and resources include 569 MMbbl of 3P reserves, 180 MMbbl high estimate contingent resources and 180 MMbbl high estimate prospective resources (as at 31 December 2012 per GLJ Petroleum Consultants) (1)

(1) See Slide Appendix2 for Reserve Definitions
Great Divide Location Map

Map of the location of the Great Divide Area in relation to Fort McMurray and other SAGD operations. Inset shows the Pod One and Algar Plants, the AER Project Approval Area and the Approved Development Area.
Connacher Great Divide Assets

Pod One Central Processing Facility

Pod One
First Steam September 2007
First Bitumen October 2007

Algar
First Steam May 2010
First Bitumen July 2010

View looking West towards Pod One
### Great Divide Development History

#### Pod One
- **Acquired Lease**: January 2004
- **Application**: August 2005
- **Exploration**: March 2004
- **Approval**: July 2006
- **First Steam**: September 2007
- **Full SAGD**: December 2007
- **Drilled 2 Well Pairs**: January 2010
- **Pad 104 4 Well Pairs Drill & Complete**: March 2013
- **Drill & Complete 4 Infills**: April 2013

#### Algar
- **Acquired Lease**: January 2004
- **Application**: June 2007
- **Drilled 15 Pairs**: June 2007
- **Drilled 17 Well Pairs**: December 2009
- **Commissioned**: May 2010
- **First Steam**: June 2010
- **CoGen Online**: September 2010
- **Full SAGD**: September 2010
- **SAGD+ Ph 1**: July 2011
- **SAGD+ Ph 1.5**: May 2012
- **Redrill Well Pair 202-r01**: February 2013
No Changes to Net Pay and other Geology Maps

Steam Solvent co-injection (SAGD+®) Phase 1 conclusion & Phase 1.5 concluded. Phase 2 Steam/Solvent with ESP’s in Pad 203

4 Infill Wells on production in Pad 102W

Gas re-pressurization for Pad 104. Continuing to maintain the design pressure in the Pod One lean zone & gas cap

Full Field NCG co-injection applied for

Pad 104 - 10 Wells approved, 4 wells pairs drilled and on steam circulation

Pad 101N blowdown

Pod One & Algar Plant - Minor Changes

Well Pair 202-01-R on production

Other
• Pump Performance Update
• HSE & SCVF Updates
• Evaporator Water Recycle Update
• Facilities & MARP Updates

Pad 104 - 10 Wells approved, 4 wells pairs drilled and on steam circulation

Pad 101N blowdown

Pod One & Algar Plant - Minor Changes

Other
• Pump Performance Update
• HSE & SCVF Updates
• Evaporator Water Recycle Update
• Facilities & MARP Updates

Pad 104 - 10 Wells approved, 4 wells pairs drilled and on steam circulation

Pad 101N blowdown

Pod One & Algar Plant - Minor Changes

Other
• Pump Performance Update
• HSE & SCVF Updates
• Evaporator Water Recycle Update
• Facilities & MARP Updates

Pad 104 - 10 Wells approved, 4 wells pairs drilled and on steam circulation

Pad 101N blowdown

Pod One & Algar Plant - Minor Changes

Other
• Pump Performance Update
• HSE & SCVF Updates
• Evaporator Water Recycle Update
• Facilities & MARP Updates
Great Divide - Approval 10587 Detailed Map

Pod One Plant

10587 Approval

Approved Development Area

Algar Plant
Great Divide Current Development

Pod One (19 Well Pairs Producing, 4 Circulating, 4 Infills)
- Pads 101N (5 Well Pairs), 101S (6), 102W (5 WP & 4 Infills), 102S (3), 104 (4)
- Original 15 Wells Pairs Drilled in 2007
- 2 Well Pairs Drilled in 2009 (101S & 102S)
- 2 Wells Pairs Drilled in 2010 (102S)
- Pad 102W Infills & Pad 104 4 Well Pairs drilled in 2013
- First Production October 2007

Algar (18 Well Pairs)
- Pads 201S (6 Well Pairs), 202S (5), 203S (7)
- Original 17 Wells Pairs Drilled in 2009
- Replacement Well Pair 201-01-R drilled 2013
- First Production June 2010

Observation Wells

Pod One
- 100/06-21-082-12W4
- 100/11-21-082-12W4
- 111/05-21-082-12W4
- 111/07-17-082-12W4
- 111/12-16-082-12W4

Algar
- 100/01-24-082-12W4
- 100/04-19-082-11W4
- 100/09-13-082-12W4
- 100/15-13-082-12W4
- 111/16-13-082-12W4
<table>
<thead>
<tr>
<th>Great Divide Summary Stats</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Pod One @ Sept 30, 2013</th>
<th>Algar @ Sept 30, 2013</th>
</tr>
</thead>
<tbody>
<tr>
<td>First Steam</td>
<td>September 2007</td>
<td>May 2010</td>
</tr>
<tr>
<td>First Sales Oil</td>
<td>October 2007</td>
<td>June 2010</td>
</tr>
<tr>
<td>Cumulative Bitumen Produced e³m³</td>
<td>2,083</td>
<td>1,125</td>
</tr>
<tr>
<td>Cumulative Steam Injected e³m³</td>
<td>8,413</td>
<td>5,066</td>
</tr>
<tr>
<td>Cumulative SOR</td>
<td>4.04</td>
<td>4.49</td>
</tr>
<tr>
<td>Number of Producing Well Pairs</td>
<td>19</td>
<td>18</td>
</tr>
<tr>
<td>Number of Circulating Well Pairs</td>
<td>4 (October 2013)</td>
<td>0</td>
</tr>
<tr>
<td>Infill Wells</td>
<td>4</td>
<td>0</td>
</tr>
<tr>
<td>Wells Using Gas Lift</td>
<td>None</td>
<td>12</td>
</tr>
<tr>
<td>Wells Using Downhole Pumps</td>
<td>13 ESP, 5 Rod Pump, 1 PCP &amp; 4 Infill Rod Pumps</td>
<td>3 ESP, 2 Rod Pumps</td>
</tr>
<tr>
<td>Operating Pressure Gas Lift</td>
<td>3,700 - 4500 kPa</td>
<td>3,700 - 4500 kPa</td>
</tr>
<tr>
<td>Operating Pressure Pump</td>
<td>2,200 - 3000 kPa</td>
<td>2,200 - 3000 kPa</td>
</tr>
<tr>
<td>Directive 51 Operating MOP</td>
<td>6,205 kPa Wellhead Injection Pressure</td>
<td>6,205 kPa Wellhead Injection Pressure</td>
</tr>
</tbody>
</table>
Geology
Great Divide Area Type Well

**Great Divide Area Stratigraphy**

- Base Fish Scales
- Viking
- Joli Fou
- Grand Rapids
- Lower Grand Rapids
- Clearwater
- Wabiskaw
- McMurray

**McMurray Gas Zones**
- Top Oil Sand
- McMurray C Bitumen Reservoir
- Paleozoic

**Devonian Carbonates**

**Properties Plot**

- GR (api)
- Density Porosity (dec)
- Neutron Porosity (dec)
- Resistivity (ohmm)
- SP (mV)

**Log Data**

- T.D.: 514.4m
- 1:2000

**Legend**

- 1AA/01-17-082-12W4/00

AER Performance Review November 2013- Connacher Approval 10587 (Pod One & Algar Plants)
Great Divide Area Core & Log Data

Typical Composite Log with Interpretation and core data comparison.

- Log vs Core Comparison
- Analytical interpretation of geophysical logs to determine bitumen saturations (wt%) gives good correlation with core derived bitumen saturations (wt%). Examples shown below.

<table>
<thead>
<tr>
<th>Well</th>
<th>Log NetPay</th>
<th>Core Net Pay</th>
<th>Log Bitumen Wt %</th>
<th>Core Bitumen Wt %</th>
</tr>
</thead>
<tbody>
<tr>
<td>100/08-17-082-12W400</td>
<td>21.3</td>
<td>23.3</td>
<td>13.6%</td>
<td>14.0%</td>
</tr>
<tr>
<td>1AA/03-17-082-12W400</td>
<td>13.2</td>
<td>12.0</td>
<td>11.6%</td>
<td>12.7%</td>
</tr>
<tr>
<td>1AA/03-21-082-12W400</td>
<td>14.9</td>
<td>13.3</td>
<td>10.2%</td>
<td>10.4%</td>
</tr>
<tr>
<td>1AA/07-16-082-12W400</td>
<td>25.9</td>
<td>27.7</td>
<td>11.5%</td>
<td>12.7%</td>
</tr>
<tr>
<td>1AA/10-21-082-12W400</td>
<td>20.8</td>
<td>17.2</td>
<td>13.2%</td>
<td>14.8%</td>
</tr>
</tbody>
</table>
Great Divide Area - 3D Seismic

3D Seismic has been successfully used by Connacher to define edges, sand thickness and paleo structure, and ultimately reduces the drilling costs. No new Seismic was shot during the 2012-13 exploratory season. (4D seismic has been run in Pod One and that is discussed in the monitoring section)
Geology - Great Divide Area Oil Sands Facies and Pay

**Zones**
Defined by Vshale

**Connacher Cut-Offs**
- **Z1** (Sand): 0-10% fines
- **Z2** (Sandy IHS): 10-20% fines
- **Z3** (IHS): 20-50% fines
- **Z4** (Muddy IHS): 50-80% fines
- **Z5** (Mud): 80-100% fines
- **Z6** (Breccia): >10% clasts

**Pay Base Criteria**
- Minimum bitumen grade: 7wt%
- Minimum Net/Gross ratio: 80%
- Maximum included shale interval: 2m
- Minimum zone thickness: 10 m

Core displayed is from a number of separate wells
New Infills and Pad 104 Geology

4 New Well Pairs at Pod One
- Well pairs 104-03, 04, 05 & 06 (West to East)
- Very good reservoir quality with high bitumen saturation.
- Longer horizontal sections (800m) should result in higher production.

Four Infill wells at Pad 102 West (INFO2 - 05; North to South)
- Lateral sections shortened due to rapidly decreasing reservoir thickness at the toes of Pad 102W wells.
Typical Section- Pod One

Pad 101N is characterized by a higher abundance of IHS in the upper part of the reservoir. As seen in well 05 - 21, the sand body gradually thins to the west. In contrast, the reservoir to the south is dominated by lean Z1 sand facies but develops a gas cap with a lean zone above the bitumen pay column.
Overall, Algar reservoir has a higher amount of IHS along with a significant breccia deposit to the north seen in well 100/04-19. Despite poor gamma ray, well 1AB/09-13 confirms high quality reservoir to the east which can be seen on the resistivity curve and has been verified using core. The poor gamma ray thought to be caused by inaccurate log calibration.
Algar New Well 2012 - 2013

- Re-Drilled the poorly performing well pair 202-01.

- Both the producer and injector were placed in a cleaner section of the reservoir.

- The original pair was off-set by approximately 35m.

- Increased the horizontal well length to capture stranded bitumen pay and increase the productivity of the well.
Net Pay Map Great Divide Area

Net Pay (m)

- 10-15m
- 15-20m
- 20-25m
- 25-30m
- >30m

Minimum Criteria:

- Continuous Net Pay >10m
- Saturation 7% Bitumen by Weight
- Porosity >25%

Great Divide Project Approval Area

Great Divide ADA
Original pressure of the gas cap was 2027 kPa in 1988. Subsequent to depletion, the lowest pressure recorded was 746 kPa in 2003.

Estimated BW pressure of 2500 kpa [based on lowest (520m Kb) gage in Algar obs well 100/01-24-082-12W4/ prior to steam injection May 2010]
Geology - Top of Oil Sands Elevation

Top of Oil Sands Elevation (m)
Geology - Base of Oil Sands

Base of Oil Sands Elevation (m)
Geology - Paleo Structure Elevation

Paleo Structure Elevation (m)
The cap-rock in the Great Divide Area consists of a mixture of muddy inclined heterolithic strata (IHS) and a mudstone that average over 10 meters in thickness. The muddy IHS consists of 80% volume of shale that is bio-turbated with mud-lined and sand-filled burrows. Muddy IHS is interpreted to be deposited in a muddy point bar. The light grey mudstone is thinly bedded with the top containing siderite nodules and rootlets. It is interpreted to be deposited in a mud flat to swamp environment. Above are core photos of the cap rock from well 1AA/06-21-82-12W4.
Cap rock Integrity Mini Frac Tests

A Mini Frac test was conducted in well 1AB/14-27-082-12W4 in February 2010. Certain concerns were raised about one test being representative for the whole project area and also the closure pressure determined for the Wabiskaw which could have been influenced by local changes in rock mechanical properties. Consequently a second test was conducted at 1AC/09-22-082-12W4 in April 2013, and this is reported in the table below.

### Results of the 1st Mini Frac at 1AB/14-27-082-12W4

<table>
<thead>
<tr>
<th>Zone Tested</th>
<th>Test Interval (mKb)</th>
<th>BH Fracture Pressure (kPa)</th>
<th>Gradient (kPA/m)</th>
<th>Closure Pressure (kPa)</th>
<th>10% less Than Closure (kPa)</th>
<th>20% Less Than Closure (kPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clearwater Shale</td>
<td>390 - 395</td>
<td>8,463</td>
<td>21.7</td>
<td>5,805</td>
<td>5,225</td>
<td>4,644</td>
</tr>
<tr>
<td>Wabiskaw Shale</td>
<td>417 - 425</td>
<td>10,991</td>
<td>26.3</td>
<td>9,500</td>
<td>8,550</td>
<td>7,600</td>
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<tr>
<td>McMurray Shale</td>
<td>449 - 452</td>
<td>8,583</td>
<td>19.1</td>
<td>6,106</td>
<td>5,495</td>
<td>4,885</td>
</tr>
<tr>
<td>McMurray Oilsand</td>
<td>461 - 466</td>
<td>8,463</td>
<td>17.7</td>
<td>5,805</td>
<td>5,225</td>
<td>4,644</td>
</tr>
</tbody>
</table>

Results for the second test are similar to the first. Although the Wabiskaw measured the highest stress gradient it was reduced from the first test.

### 2nd Mini Frac at 1AC/09-22-082-12W4

<table>
<thead>
<tr>
<th>Zone Tested</th>
<th>Test Interval (mKb)</th>
<th>BH Fracture Pressure (kPa)</th>
<th>Gradient (kPA/m)</th>
<th>Closure Pressure (kPa)</th>
<th>10% less Than Closure (kPa)</th>
<th>20% Less Than Closure (kPa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clearwater Shale</td>
<td>463 - 464</td>
<td>8,635</td>
<td>18.6</td>
<td>6,421</td>
<td>5,779</td>
<td>5,137</td>
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<tr>
<td>Wabiskaw Shale</td>
<td>474 - 475</td>
<td>10,534</td>
<td>22.2</td>
<td>7,917</td>
<td>7,125</td>
<td>6,334</td>
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<tr>
<td>McMurray Shale</td>
<td>481 - 482</td>
<td>8,057</td>
<td>16.7</td>
<td>6,155</td>
<td>5,540</td>
<td>4,924</td>
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<tr>
<td>McMurray Oilsand</td>
<td>517 - 518</td>
<td>6,503</td>
<td>12.6</td>
<td>5,397</td>
<td>4,857</td>
<td>4,318</td>
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</table>

1AC/09-22-082-12W4

AER Performance Review November 2013- Connacher Approval 10587 (Pod One & Algar Plants)
Cap Rock Integrity - Pod One Monthly Average BH Injection Pressure

Directive 51 Maximum Wellhead Injection Pressure = 6,205 kPag
Cap Rock Integrity - Algar Monthly Average BH Injection Pressures

Directive 51 Maximum Wellhead Injection Pressure = 6,205 kPag
Recovery Processes
Great Divide SAGD Recovery Processes

**Basic Process**

![Diagram of oil sands, cap rock, and steam injection]

<table>
<thead>
<tr>
<th>Circulation</th>
<th>Peak SAGD Production</th>
<th>Low Pressure SAGD Production</th>
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</thead>
<tbody>
<tr>
<td>High Pressure</td>
<td>High Pressure</td>
<td>Low Pressure</td>
</tr>
<tr>
<td>~90 days</td>
<td>~12 to 18 months</td>
<td>~4 to 6 years</td>
</tr>
<tr>
<td>Steam Lift</td>
<td>Gas Lift</td>
<td>Pumps</td>
</tr>
</tbody>
</table>

**Additional Processes (discussed below)**

- Pressure Balancing under a gas cap and lean zone (Pod One)
- Pressure Balancing over a water zone (Algar)
- Natural gas Co-injection for intermittent pressure maintenance (full field application submitted)
- Gas Cap Repressurization
- Solvent/Steam Co-Injection SAGD+® (testing at Algar)
- Infill Wells (4 Infills on production in Pad 102W)
## Technologies Developed & Developing

<table>
<thead>
<tr>
<th>Description</th>
<th>Stage</th>
<th>Reason</th>
<th>Approvals</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure Balancing Under a Top Gas &amp; Lean Zone &amp; Bottom Water</td>
<td>Developed</td>
<td>Eliminate steam losses into a gas and lean zone, lower SOR’s and improve productivity. Required the parallel development of reliable on high temperature downhole pumps.</td>
<td>Operated within existing approvals</td>
</tr>
<tr>
<td>Gas Co-injection</td>
<td>Implemented</td>
<td>Natural gas can replace steam to maintain pressure.</td>
<td>Approved at Pad 101N. Full field application submitted for all of Pod One</td>
</tr>
<tr>
<td>Gas Cap Re-Pressurization</td>
<td>Implemented</td>
<td>Reduces the steam losses into the gas cap and lean zone. Effectiveness to be fully assessed as Pad 104 begins SAGD production in Q4 2013</td>
<td>Approved.</td>
</tr>
<tr>
<td>SAGD+ ® Trial</td>
<td>Phase 1 Completed Phase 1.5 Completed</td>
<td>Reduces bitumen viscosity lower than steam alone to improve production rates, SOR, and recovery.</td>
<td>Algar Approved. Application for a SAGD+ ® pilot at Pod One to be submitted 2013 Q4</td>
</tr>
<tr>
<td>Infill Wells</td>
<td>4 Infills on Production in Pad 104</td>
<td>Additional production and reserves at low capital and SOR’s</td>
<td>Application for next 9 infills at Pod One submitted November 2013</td>
</tr>
</tbody>
</table>
Pressure Balancing Under a Top Gas & Lean Zone

**Well Pair 101S-09**

- Temporary production impact during pressure balance
- Improved SOR with low pressure operation
- Pad 104 will be operated in a similar manner except that the re-pressurization is expected to reduce the quantity of steam losses when the steam reaches the lean zone and pumps will be installed earlier

Note: Detailed description of the process provided in the attached technical paper presented by Connacher at the 2011 WHOC.

Link:
Production Optimization at Connacher’s Pod One Oil Sands Project, Johnson et al, World Heavy Oil Congress, Edmonton, Alberta 2011
Pressure Balancing over Bottom Water in Algar

Pressure Balancing with Bottom water in Algar

Production: Well 201-03 - ESP

Installed ESP to balance Inj Pressure with BW Pressure

Installed Steam Diverter

- Allocated Oil (m3)
- Allocated Steam (m3)
- Injector BHP / 1000 (kPa)
- CSOR
• Co-Injection commenced February 2011
• The maximum rate allowed was $5 \times 10^3 \text{m}^3/\text{d}$. The graph to the left shows steam and gas injection on a pad (5 well basis). Only four injectors (101-i1 to i4) received gas injection.
• The addition of gas appears to have had little long term effect on SOR or oil rates
• While NCG does not appear to improve production, it does facilitate pressure maintenance and gas lift while the project is steam constrained and losses to the gas cap are increasing (WSR is <1). It can make a slight improvement to SOR.
• Analysis of the Gas Co-Injection Test was complicated by removal of the metal on metal PCP’s (see Artificial Lift Section) and increasing fluid losses into an overlying gas cap. ESP are not a viable alternative at the wells rates in pad 101N.
• Downturn of gas co-injection between April - August, 2013 due to rod pumps added to four wells in pad 101N during this time
• Because of the poor performance at Pad 101N AER gave approval to remove steam injection from Pad 101N while at the same time injecting gas at the current rates.
Re-Pressure Pod One Gas Cap

The purpose of gas cap re-pressuring is to increase the pressure in the gas cap and lean zone immediately above Pad 104 and institute a more effective pressure balancing process. Simulations had shown long term benefits to production and SOR by re-pressuring to just below the SAGD operating pressures (~2300 kPa in pump mode). Details of this are discussed in detail in the attached paper on Pressure Balancing at Pod One.

- The re-pressuring process is currently underway prior to the start up of Pad 104 in 2013. Methane is injected into the 9-17 well at the injection rates shown in the graph below.

- The gas cap pressure at the 7-17 observation well was approximately 1600 kPa prior to gas injection and the end of September 2013 the pressure in the gas cap was approximately 2400 kPa.

- Currently the well is injecting just enough gas to maintain the pressure.

- The response to gas injection at the 7-17 observation well is shown in the following slide.
Re-Pressure Pod One Gas Cap

The chart below shows the response at various pressure transducers in observation well 7-17 (approximately 600m south of the gas injection at 9-17). The transducers are set at the KB elevations shown on the adjacent log. The interesting observation from this data is the different responses in the gas cap and the lean zone which in this particular well is separated by approximately 3m of shale. The pressure response in the lean zone is noticeably faster than in the gas cap as shown in the lines connecting the chart and the log. From an operational perspective, Connacher is able to pressure the lean zone and gas cap to the target pressure of 2,400 kPa from the 9-17 gas injector.
Phase 1

- In January 2011, ERCB granted approval for a trial of light hydrocarbon - steam co-injection in the seven well pairs of Pad 203.
- Connacher selected two well pairs 203-2 and 203-3 for an initial test (Phase 1) of the process.
- In Phase 1, a commercially available solvent was co-injected with the steam starting in July 2011 at initial rates of approximately 10% by volume and increased to 15% by volume in October 2011. Compared to an April 2011 baseline, daily average per well bitumen production volumes during the months of August 2011 through October 2011 increased approximately 28% percent with a SOR decrease of 16%. The SOR decrease was limited by the necessity to increase steam injection rates to maintain normal operating pressure.
- Phase 1 injection ended November 2011. Solvent was recovered from the Phase 1 wells until April 2012 at which time 89% had been recovered into the dilbit sales stream and the boiler fuel gas.

Phase 1.5

- Phase 1.5 commenced in May 2012 with solvent injection of approximately 10% until August when injection rates were reduced to approximately ~6%, and further reduced in March 2013 to approximately 4%.
- In the 12 months May 2012 through April 2013 bitumen rates increased by approximately 30% compared to the four months prior to the test. The SOR decreased 32% over the same period. The steam rate in the 12 month test was approximately 10% lower than the prior period and the SOR was reduced from an average of 4.5 prior to the test to 3.1 during the test. The final SOR in the month of April 2013 was 2.9.

Note: details of the measurement of solvent injection and recovery are discussed in the attached Steam Solvent SAGD Paper and the Algar MARP.
**SAGD +® and ESPs**

**Current Testing**

The performance of SAGD +® with downhole pumps was evaluated in wells 203-01 and 203-04.

An ESP was installed in well 203-01p in May, 2013. Solvent injection continued at low rates in 203-01 throughout this change to ESPs. Operational issues restricted pump performance and various initiatives are underway to correct this problem. (see graph below)

An ESP was installed in well 203-04p in May, 2013, and solvent injection commenced in July, 2013. Operational issues restricted pump performance and the well was placed back on gas lift when the pump failed in September, 2013. Solvent injection was also terminated in September, 2013, after being injected for three months at an average rate of 8.2 m³/day

---

**SAGD +® Test Trial 203-01 ESP Conversion**

- Bitumen Production (m³/d)
- Steam Injection (m³/d)
- Water Production (m³/d)
- Solvent Injection (m³/d)

*Operational Issues Restrict Volume*

*Based on Registry Volumes to Sept 30, 2013*
Infill Wells Pad 102W

- Infills were drilled shorter than the adjacent well pairs to avoid penetrating the thin channel edge.
- Temperature logs prior to the steam injection indicated wide variations in temperatures along horizontal sections of the infill wells.
- In order to increase temperature in the wells steam cycles were initiated as shown in the graph to the right.
- Infill well 02 received the smallest volume of steam and responded the fastest and also had the highest temperature measured in the pre-steam survey.

Bottom Hole temperature surveys were carried out prior to steaming the infill wells.

Steam into the 102W well pairs was reduced during the steam injection into the infills (as show in the graph to the right). There is a slight reduction in oil rates from the well pairs as a result of the reduced steam volume but this is more than compensated by the average of 55 m$^3$/day produced from each of the infill wells (field allocated volumes).
Completions & Artificial Lift
Typical Injector Completion

Injector Completion Example

**Injection port**
- Allows for an increased volume of steam injection through the long string (hydraulic limitations)
- Promotes more uniform steam distribution throughout the slotted liner
Typical Producer Gas Lift Completion

**Producer (Gas lift)**

**Production port**
- Allows for an increased volume of fluid to move to surface from the toe (due to pressure drop)
- Promotes more uniform steam chamber development (production optimization) due to production of fluid draining in central region of the well bore

Short String
88.9 mm tubing to ? mKB

Long String
88.9 mm tubing to ? mKB

Instrument String
Fiber optic or thermocouple

Gas lift mandrel
25.4 mm landed at heel of long string
Typical Producer Mechanical Lift

Producer (Mechanical Lift)

**ESP development**
- Connacher was the first company to run the high temperature limit ESP
  - Previous temperature limit 218°C
  - Current temperature limit 250°C

**Production tail pipe**
- Allows for an increased volume of fluid to move to surface from the toe
  - Reduces preferential production from the heel (more uniform chamber)
  - Allows for more cooling prior to reaching pump (less steam at pump)

Electronic Submersible Pump
- Metal on metal Progressive cavity pump
- Tubing pump (hydraulic pump jack)
Improved Well Bore Design

Algar Completions

Injector

Short inj string

7" slotted liner

Inj port

Long inj string

Producer

Instrument string

Short prd string

Gas lift coil

7" slotted liner

Prd port

Long prd string
Improved Well Bore Design

Producer (Mechanical Lift)

ESP development
- Connacher was the first company to run the high temperature limit ESP
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  - Current temperature limit 250°C

Production tail pipe
- Allows for an increased volume of fluid to move to surface from the toe
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  - Allows for more cooling prior to reaching pump (less steam at pump)

Electronic Submersible Pump
- Metal on metal Progressive cavity pump
- Tubing pump (hydraulic pump jack)
Typical Infill Well Completion

Updated: June 7, 2013 by Ryan T.

102-INF02

339.7mm, 71.43 kg/m, H-40 ST&C Surface Casing set @ 190 mKB

244.5 mm, 59.53 kg/m, L-80, HYD 563 Production casing set @ 682 mKB

48.3mm ID Guide String to 668 mKB

114.3mm tubing set @ 644 mKB

31.7mm Instrument String to 1230 mKB.
TC’s @ 570m, 700m, 850m, 990m, 1110m, 1230m
Bubble tube depth @ 565 m

88.9 mm TSHP tubing to 1067 mKB

XN Profile Nipple

GDA Steam Splitter - OPEN

Liner Slotting (562m slotted)**
First Slot @ 690 mKB
Last Slot @ 1266 mKB
Avg Liner Depth: ~485 mTVD
Slotting: 0.016” x 0.020”
Reduced slot interval: 0m

**Excludes blanked sections

Pump Seating Nipple set @ 552 mKB

3.25” Insert Pump

114.3mm To 88.9mm Crossover @ 645 mKB

114.3mm Tubing

Slotted Liner Hanger set @ 662 mKB

3.25” Insert Pump

Liner 177.8 mm, 34.2 kg/m, L-80, B.T.L. set @ 1267 mKB
Liner Slotting Programs

Typical Slotting Program

203-3 Profile
Liner Slotting Programs - Recent Experience

Infill well 102-INF02

Re-Drill 202-01-1

Blank in case there is a need to shut off last 1/3 of well if steam breakthrough occurs in this thinner pay

Blanks added to restrict communication to adjacent wellpair
Great Divide Artificial Lift Performance - Pod One

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**Pad 101N**

As steam is removed from this Pad rod pumps are the most practical solution.

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Pads 101S, 102W & 102S

These Pads produce from the core of the oil sands channel and is a good application of ESP’s. The pump history is shown here as an example.

The higher rate wells can accommodate ESP’s whereas lower rate wells and infills operate more efficiently with rod pumps.

Pads 101S and 102S are similar and a detailed history of all the pumps at Great Divide is provide in the additional files accompanying this report.
Great Divide Artificial Lift Performance - Algar

Artificial lift at Algar was based on gas lift for the early stages of production with a later move to lower pressure operation with pumps being considered.

The selection of pumps is based on well productivity and Connacher's experience.

ESP's have been used in three wells in Pad 201. These three wells are in, or close to, a limited bottom water zone and the pumps are required to balance pressure and avoid high steam losses. One of those wells was converted to a rod pump due to sand issues.

Recently and as part of the SAGD+® test ESP have been installed in two well in Pad 203 and are still being evaluated.
Low Pressure SAGD & Pumps

Successful production below a gas cap and lean zone through pressure balance with high temperature ESP pumps.

*Production Optimization at Connacher’s Pod One Great Divide Oil Sands Project, Johnston et al, World Heavy Oil Congress Edmonton Alberta 2011, WHOC11-584*
Low Pressure SAGD & Pumps (2)

Connacher has experienced improved SOR by lowering steam chamber pressures with high temperature ESPs in Pads 102W/101S/102S

SOR reductions with ESP Pump Installations at 101-8, 101-9, 102-3
Pump Experience at 101N

Pad 101N

- All five wells in Pad 101N wells were started on gas lift and in 2009-2010 converted to metal on metal Kudu PCP’s in an attempt to produce at a lower bottom-hole pressure thus improving SOR. Pad 101N was considered a suitable candidate for these pumps as fluid rates were lower than the two other pads and the PCP’s have lower capacity than an ESP at similar down hole conditions.

- Wells P01 and P05 had reasonable run lives but poor efficiency. The first installation of P05 ran for 24 months second is still running at 12 months.

- A rod pump was installed on P03 in September 2011 and after 3 pump replacements, it is running.

- Wells P01, P02, P04 were put back on gas lift which was initially effective at first while reservoir pressure was > 3 MPa but as bottom hole pressures continue to drop (fluid losses and steam capacity required for the high SOR wells) there was insufficient lift to move fluid to surface and production rates are declining and SOR’s increasing. In April 2013 new rod pump were installed on P01, P02, P04.

- As Connacher has had approval to remove steam from this Pad the rod pumps will be an integral part of the blowdown strategy as pressure and temperature reduces and there is less steam available for lift.
Great Divide Gas Migration & Surface Casing Vent Flows

SCVF Tests were conducted on all injectors and producers at Pod One and Algar.

All wells passed the SCVF test with no GM issues except for recently drilled well pairs on Pad 104 and the infill wells on Pad 102W. In these latter twelve wells surface casing is not visible above grade and there is no vent assembly to surface. If vent flow was present, significant elevated methane concentrations would be present in the surface soils in immediate casing area. Typically the casing top is open and filled to surface with water, and will need to be exposed to confirm. SCVF status will be assigned as “inconclusive” pending further inspection below grade.

The information is being audited by AER and the results will be entered in DDS when this is completed. A summary data table is submitted as an additional file to this report.

Connacher believes that it is currently compliant in all SCFV requirements at Great Divide.
Monitoring
Pod One Observations Wells

100/11-21-82-12W4, Operational April 2011
- Monitor North Pad Performance
- Five temperature and five pressure measurements all operational
- Temperature readings suspect - all at original reservoir temperature ~14 °C
- Pressure gauges operational
- Continue collecting data

100/06-21-082-12W4, Operational Dec 2007
- Purpose was to measure rise of steam and to determine if steam moved into any overlying gas caps.
- Operational but readings suspect
- Maximum temperature 20 °C.
- Pressure gauges not operational
- Continue collecting data

111/12-16-82-12W4, Operational Mar 2010
- Provided observations on effects of low pressure operations
- Five temperature and five pressure measurements all operational
- Future monitoring for gas cap pressure maintenance scheme planned for 2011
- Continue collecting data

111/05-21-82-12W4, New Well, Operational Mar 2012
- Drill to acquire information on temperature between well pairs for future infill wells
- Five temperature and three pressure measurements operational
- Continue collecting data

100/07-17-82-12W4, New Well, Operational Mar 2012
- Drill to acquire information on gas cap repressurizing
- Five temperature and five pressure measurements operational
- Continue collecting data
Pod One - Typical Observations Well Configuration

Blue line = Piezometer Cables
Red line = MI Thermocouple Cable

Pres 3 & Temp 5:
430.07mKB

Temp 4: 431.36mKB
Temp 3: 434.05mKB

Pres 2:
456.36mKB
Temp 2:
459.05mKB

Pres 1 & Temp 1:
468.05mKB

Note: As the 3 piezometers are landed within 3m of each other above the heated zone, it is expected that they should read the same temperature to within their range of accuracy.

Hot Zone Top
De-Centralizing Clamps for Piezometer Windows
Hot Zone Bottom

Prepared by Petrospec Engineering Ltd.
Pod One Observations Wells - 111/12-16-82-12W4

Temperature (C)
- SAGD WP
- TC 12/01/10
- 07/01/12 10/01/12 01/01/13
- 04/01/13 07/01/13 10/01/13

Depth (m)

Pressure (kPa)
- SAGD WP
- Gauges 12/01/10
- 07/01/12 10/01/12 01/01/13
- 04/01/13 07/01/13 10/01/13

40 meters from 101S-P10

Oil Sand Top Devonian

111/12-16-82-12W4 [TVD]
Pod One Observations Wells - 111/07-17-82-12W4

111071708212W400 (TVD)

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Temperature (°C)</th>
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</thead>
<tbody>
<tr>
<td>440</td>
<td>0.000</td>
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<tr>
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<td>450</td>
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<tr>
<td>485</td>
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</tr>
<tr>
<td>490</td>
<td>0.000</td>
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</tbody>
</table>

Pressure (kPa)

- SAGD WP
- Guages

33 meters from 104-P03
Pod One Observations Wells - 111/05-21-82-12W4

Temperature (°C)

Depth (m)

Pressure (kPa)

40 m from 102-03
Pod One Observations Wells - 100/11-21-82-12W4

Note:
It appears that all gauges are operational and are showing minor temperature and pressure changes.
Pod One Observations Wells - 100/06-21-82-12W4

Temperature (°C)

Note:
It appears that all gauges are operational (with exception of P at 468 m) and are showing minor temperature and pressure changes.
### Algar Observations Wells

<table>
<thead>
<tr>
<th>Net Pay (m)</th>
<th>10-15m</th>
<th>15-20m</th>
<th>20-25m</th>
<th>25-30m</th>
<th>&gt;30m</th>
</tr>
</thead>
</table>

100/04-19-082-11W4M Operational February 2011
- 6m from Well pair 203-04
- Monitors Pad 202 performance
- Five temperature measurements operational
- Five pressure gauges operational

100/01-24-082-12W4M Operational February 2011
- 20m from Well Pair 203-06
- Five thermocouples operational
- Four pressure gauges operational

100/15-13-082-12W4M Operational February 2011
- 8m from Well Pair 201-04
- Five thermocouples operational
- One pressure gauge operational

100/09-13-082-12W4M Operational February 2011
- 37m from Well Pair 202-04
- Five thermocouples operational

111/16-13-82-12W4W4 Operational March 2012
- 48m from Well Pair 203-05
- Five thermocouples operational
- Five pressure gauges operational

**Cored Wells**
Algar Observations Wells - 100/01-24-82-12W4

Temperature (C)
- SAGD WP
- TC
- 04/01/12
- 07/01/12
- 10/01/12
- 01/01/13
- 04/01/13
- 07/01/13
- 10/01/13

Pressure (kPa)

Depth (m)

TVD
Thermocouple
GM_POROSITY_DEN
Nesial_GM
GR_GM
GM_POROSITY_Neutron
Resist_GM

22 m from 203-06
Algar Observations Wells - 100/04-19-82-11W4

Note:
It appears that all gauges are operational. Connacher expects that isolated zones exist at this location.
Algar Observations Wells - 100/09-13-82-12W4

No pressure recorders working

37m from 202-04
Algar Observations Wells - 100/15-13-82-12W4

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<td>515</td>
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<td>520</td>
<td>2</td>
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<tr>
<td>525</td>
<td>3</td>
</tr>
<tr>
<td>530</td>
<td>4</td>
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</table>

- **SAGD WP**: Yellow squares
- **TC**: Red squares

**100151308212W400 [TVD]**

<table>
<thead>
<tr>
<th>TVD</th>
<th>Thermocouple</th>
<th>GM_POROSITY_DEN</th>
<th>Neutron_GM</th>
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<tbody>
<tr>
<td>0</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
</tbody>
</table>

- **GR_GM**: 150
- **Color fill**: Red

No pressure recorders working
Note:
It appears that all gauges are operational and increasing trend of pressure at 508 m depth is correct. Connacher cannot say conclusively what is causing increase in pressure at this depth.
Pod One & Algar Ground Movement Monitoring

Measurement points generally fixed onto piles or structures tied into piles.

Two maps shown:
- Top for the elevation changes since 2010 to October 2013, and
- Bottom for the changes in the last 12 months.

Elevation changes are lower than estimated in the original Pod One geotechnical report which included a simulation of expected heave.

Measurements reported in the previous report for the period (October 2011 - November 2012) showed subsidence rather than heave. All measurement in the current period show heave.

Data set for annual surveys is in additional files submitted to ERCB.
Pod One 4D Seismic

PP(Base) conventional seismic is the difference between the 2005 and 2010 seismic volumes.

PS(Shear) data shows changes in the shear component - which is an indicator of steam in the rock since 2010.

NRMS (Normalized Root Mean Square of the differences between the 2005 and 2010 surveys) which highlights and confirms change in the reservoir since 2005.

Geological cross section across seismic data.

Geology Net Pay Map
Pod One 4D Seismic (cont’d)

NRMS-normalized root mean square represents the % change in the seismic signal since steaming operations began.

Shear Data - should represent the extend of the steam chamber.

The NRMS represents the percentage change in the reservoir since steaming operations commenced in 2007. This roughly corresponds to produced bitumen and should represent the various steam chambers. The shear data is not affected by steam, gas or bitumen heated above 80°C, as this acts like a liquid. The resulting map should show the current extend of the steam chambers. The two maps should be similar and are not, therefore the results of the 4D seismic are inconclusive. Possible reasons for this include plant and highway noise, and errors resulting from using different geophones at different locations in the two surveys.
Well Performance
Pod One & Algar Well Layout

Shown are the 23 Well Pairs on Pads 101S, 102S, 102W & 104 and four infill wells on Pad 104

Shown are the 18 Well Pairs on Pads 201, 202 & 203.

Note: In order to accommodate similar production & injection start times well pair 11S (shown) was included with Pad 102S for performance plots and resource calculations.
Boiler issues include tube failures and compromised existing boiler tubes due to exposure to extreme heat. Connacher is modifying and repairing boiler tubes.
Pod One Performance - Pad Production & Injection

Gap between steam and produced water (2011-2013) partially due to losses to reservoir and measurement process due to water produced as vapour.
Algar Performance - Pad Production & Injection

Bottom water impacts all five well pairs in Pad 201, well pair 3 in Pad 203 and well pairs 4, 5 & 6 in Pad 203.

The better performance of Pad 203 reflects better quality pay and seven vs five wells in the Pad.
Great Divide Performance - Cum Production by Pad
Great Divide Performance - Cum Production per Well by Pad

Cumulative Bitumen Production (m³/well) vs. Time (2007-2013)


Graph shows the cumulative production trend for different pads and areas from 2007 to 2013.
CSOR by Pad for 101N and 202 appear to be trending similarly (increasing CSOR). Reservoir quantity (IHS & Breccia) is the main contributing factor to this performance. Well Pair 202-01 was completed in poor reservoir and a replacement well pair 202-01r was recently drilled in better reservoir and the full benefits of this are still being realized.
Great Divide Performance - Recovery Steamed OBIP by Pad

The “Steamed OBIP” is an estimate of the Bitumen swept by the steam based on a typical geometry of the SAGD process.
# Pod One Performance - Well Summary

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>Well Pair</th>
<th>Date</th>
<th>Months On</th>
<th>Cum Oil m³</th>
<th>Cum Steam m³</th>
<th>Oil Rate (m³/day)</th>
<th>CSOR</th>
<th>Lift</th>
<th>Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>101N</td>
<td>101-01</td>
<td>Sep-2013</td>
<td>73</td>
<td>79,051</td>
<td>444,545</td>
<td>31</td>
<td>5.6</td>
<td>Rod Pump</td>
<td>North Pad, Channel Edge, Blowdown</td>
</tr>
<tr>
<td>101N</td>
<td>101-02</td>
<td>Sep-2013</td>
<td>73</td>
<td>70,619</td>
<td>441,519</td>
<td>7</td>
<td>6.3</td>
<td>Rod Pump</td>
<td>North Pad, Channel Edge, Blowdown</td>
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<tr>
<td>101N</td>
<td>101-03</td>
<td>Sep-2013</td>
<td>72</td>
<td>58,285</td>
<td>340,416</td>
<td>9</td>
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<td>Rod Pump</td>
<td>North Pad, Channel Edge, Blowdown</td>
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<tr>
<td>101N</td>
<td>101-04</td>
<td>Sep-2013</td>
<td>73</td>
<td>93,564</td>
<td>468,022</td>
<td>46</td>
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<td>Rod Pump</td>
<td>North Pad, Channel Edge, Blowdown</td>
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<tr>
<td>101N</td>
<td>101-05</td>
<td>Sep-2013</td>
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<td>86,554</td>
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<td>Good Well in Good Pay</td>
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<tr>
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<td>73</td>
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<tr>
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<td>Average Well, Crosses Channel</td>
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<td>73</td>
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## Algar Performance - Well Summary

<table>
<thead>
<tr>
<th>Well Pad</th>
<th>Well Pair</th>
<th>Date</th>
<th>Months On</th>
<th>Cum Oil m³</th>
<th>Cum Steam m³</th>
<th>Oil Rate (m³/day)</th>
<th>CSOR</th>
<th>Lift</th>
<th>Comments</th>
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<td>203</td>
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<td>84,191</td>
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<td>203</td>
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<td>Average Well, Near Edge</td>
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<tr>
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<td>Edge Well, Delayed Start Up</td>
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</tbody>
</table>
Pod One - Cumulative Steam In / Water Produced

![Graph showing cumulative steam in and water produced from Sep 2007 to Sep 2013. The graph includes lines for 101N, 101S, 102S, and 102W.]
Algar - Cumulative Steam In / Water Produced

- Cum Steam In / Cum Water Out

May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep

2010 2011 2012 2013

Cum Steam In / Cum Water Out

201 202 203
## Great Divide Performance - Recoverable Bitumen by Pad Pod One

<table>
<thead>
<tr>
<th>Pads</th>
<th>Area (ha)</th>
<th>Avg Porosity (%)</th>
<th>Avg Oil Sat (%)</th>
<th>Avg Net Pay (m)</th>
<th>Pad OBIP e3m³</th>
<th>Est Pad Rec (%)</th>
<th>Est Pad Rec e3m³</th>
<th>Recovery to Sept 2013 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad 101N Post PB</td>
<td>29.6</td>
<td>33%</td>
<td>74%</td>
<td>18.0</td>
<td>1,300</td>
<td>32%</td>
<td>416</td>
<td>30%</td>
</tr>
<tr>
<td>Pad 101S</td>
<td>32.6</td>
<td>33%</td>
<td>80%</td>
<td>20.0</td>
<td>1,720</td>
<td>55%</td>
<td>950</td>
<td>37%</td>
</tr>
<tr>
<td>Pad 102W</td>
<td>31.6</td>
<td>33%</td>
<td>80%</td>
<td>17.0</td>
<td>1,420</td>
<td>50%</td>
<td>710</td>
<td>41%</td>
</tr>
<tr>
<td>Pad 102S</td>
<td>32.7</td>
<td>33%</td>
<td>80%</td>
<td>19.0</td>
<td>1,640</td>
<td>55%</td>
<td>900</td>
<td>27%</td>
</tr>
<tr>
<td>Pad 104</td>
<td>70.9</td>
<td>33%</td>
<td>80%</td>
<td>21.5</td>
<td>4,020</td>
<td>55%</td>
<td>2,210</td>
<td>NA</td>
</tr>
</tbody>
</table>

Notes:

1. Pad 101N is in blowdown and an additional 2% recovery expected.
2. Additional of estimated infill recoveries of approximately 8% for Pads 101S, 102W, 102S, and 104 Infill recoveries not included.
3. Pad 101N injectors were plugged back approximately 1/3 back from well toes.
4. Pad 102S includes four well pairs 101S-11, 102S-12, 102S-13, 102S-12. This simplifies the analysis of the first 15 well pairs drilled and comparisons to well pairs drilled at a later date.
### Great Divide Performance - Recoverable Bitumen by Pad Algar

<table>
<thead>
<tr>
<th>Pads</th>
<th>Area (ha)</th>
<th>Avg Porosity (%)</th>
<th>Avg Oil Sat (%)</th>
<th>Avg Net Pay (m)</th>
<th>Pad OBIP e3m3</th>
<th>Est Pad Rec (%)</th>
<th>Est Pad Rec e3m3</th>
<th>Recovery to Sept 2013 %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pad 201 (5)</td>
<td>41.7</td>
<td>33%</td>
<td>75%</td>
<td>19.0</td>
<td>1,930</td>
<td>55%</td>
<td>1,060</td>
<td>30%</td>
</tr>
<tr>
<td>Pad 202 (6)</td>
<td>45.6</td>
<td>33%</td>
<td>75%</td>
<td>18.0</td>
<td>1,890</td>
<td>55%</td>
<td>1,100</td>
<td>37%</td>
</tr>
<tr>
<td>Pad 203 (7)</td>
<td>56.7</td>
<td>33%</td>
<td>75%</td>
<td>22.0</td>
<td>3,040</td>
<td>55%</td>
<td>1,670</td>
<td>41%</td>
</tr>
</tbody>
</table>

**Notes:**

1. Pad 203 has implemented SAGD+® on a trial basis. Reserves will be adjusted when the commercial project begins. An additional recovery of 10% of the OBIP is estimated.
Future Reservoir Developments
Future Developments - Additional Infill Wells Planned

- On the basis of the good production responses from the 4 new infill wells on Pad 102W Connacher is planning a further 9 infill wells in Pod One.
- Engineering is proceeding and an application will be submitted to AER.
- Six infills are planned for Pad 101 and three for Pad 102.
- An additional test facility is planned for Pad 102.
Future Developments - Great Divide Expansion

- Oil Design Rate 44,000 bbl/d
- Great Divide Plant Remains at current capacity
- Algar Plant Expanded to 34,000 bbl/d
- ERCB Approval October 2012
- Northern Development not in original EIA
Future Developments - Great Divide Expansion (2)
Facilities
Pod One Plant

- 27,000 bbl/d steam generation capacity
- 2.08 m$^3$ (13.1 million bbls) of bitumen produced since December 2007 startup
Algar Plant

- 27,000 bbl/day steam generation capacity
- 1.13 million m³ (7.08 million bbls) of bitumen produced since 2010
**Key Points**

*Design Capacity* ~ 1,600 m³/day bitumen

*Steam Generation*: Drum boilers
  - Operating pressure 6,300 kPa
  - Deliver 4,300 m³/day steam @ 98% + Quality

*Treating*: Diluent addition

*Water Recycle*: IGF, WS Filter, Two vertical tube falling film evaporator towers

*Waste Water*: Waste water shipped to Algar 2nd Stage Evaporators

*Source water*: 3 operating source water wells in the Lower Grand Rapids formation, 1 other source water well approved
Algar Facilities

**Key Points**

Design *Capacity* ~ 1,600 m³/day bitumen

*Steam Generation*: Drum boilers

- Operating pressure 6,700 kPa
- Deliver 4,800 m³/day steam @ 98% + Quality

*Treating*: Diluent addition

*Water Recycle*: IGF, WS Filter, Two vertical tube falling film evaporator towers

*Waste Water*: All water shipped from facility to approved disposal sites

*Source water*: 3 operating source water wells in the Lower Grand Rapids formation, 1 other source water well approved
Great Divide Plant Modifications

Pod One

• Upgraded boiler instrumentation
• Added truck weigh scale
• Addition of well pad 104 to Pod One
• Preventative maintenance on tank berm containment liner
• Added infill wells to Pad 102
• Installation of temporary incinerator for evaporator vent system vapors
• General maintenance

Algar

• Modified and repaired boiler tubes
• Redrilled 202-1 at well pad 202
• Dilbit transfer pump recycle line on pressure control
• Replacing source water line
• Added skirting to dilbit tanks for high density dilbit
• General maintenance
Algar & Pod One Integration

Dilbit

Diluent

Evap Waste
Changes to Pod One and Algar MARP in Reporting Period:

1. Consolidate Algar and Pod One MARP documents into one document
2. General text revisions
3. Updates to secondary water calculations
4. Updates to well pad 104 at Pod One
5. Update to bitumen production calculations
6. Update schematics for operational changes
7. Update to diluent calculations
8. References to Petroleum Registry of Alberta (PRA) changed to Petrinex
9. Update to Pod One and Algar meter tank list
Pod One & Algar Profacs

Pod One uses manual oil cuts however procedures implemented 2012 are clearly showing improved results.

An Agar oil cut meter is installed in Algar and work is progressing on the calibration however oil cuts are still reported from manual cuts.

Improvements to manual cut measurement procedures at Algar have been applied to Pod One.

The profac at Algar is calculated from the interconnect pipeline volumes whereas the Pod One profac is calculated from truck receipts less the Algar pipeline volumes and is subject to typical truck measurement differences.
For the period Oct 1, 2012 to Sep 30, 2013 the steam plant has averaged 98.6% of the original design basis (4,320 m³/day) and 87.5% of the designed total fluid capacity (5,920 m³/day).

The latest 12 month period shows a improvement over the previous 12 month period which were 96.5% for the steam and 87.5% for the total fluid.

Reliability has been maintained in all areas of the operation.

Downtime Hours is the reported downtime for the Well Pairs.
For the 12 months from Oct 1 2012, to the of Sept 30, 2013 the steam plant output has averaged 84.4% of the original design basis (4560 m³/day) and 81.6% of the designed total fluid handling capacity (5995 m³/day).

This performance compares to the previous 12 months which had a steam generation of 86.4% and total fluid throughput of 87.1% of plant design capacity.

Downtime hours is the reported downtime for the Well Pairs.
Pod One Energy Balance

Green House Gas Emissions Reported for 2012 = 227,338.5 t CO₂ equivalent
Algar Energy Balance

Green House Gas Emissions Reported for 2012 = 246,718.6 t CO$_2$ equivalent
Algar Co-Generation Facility

- Designed to produce 13.1 MW electricity from GT and 588 m³/d of steam from the HRSG
- Horse River sub-station on line June 2011
- Running near capacity with power distributed to both Algar and Pod One
- Steam being used at Algar
Water Recycle
Pod One & Algar Evaporator Waste Integration
Pod One & Algar Integrated Water Recycle Scheme

- Evaporators produce high quality boiler feed water efficiently while generating a highly concentrated brine for disposal

- At Algar a **second stage** evaporator further concentrates both the Algar brine and a portion of the Pod One brine to improve water reuse and minimize disposal

- Disposal concentrations are close to crystallizer performance

- Chemical optimization has significantly improved evaporator reliability
Pod One & Algar 2013 YTD Water Recycle Ratio

The series evaporator operation at Algar provides high recycle rates and improved reliability.

The Algar operation accommodates waste from the parallel evaporators at Pod One and brine is shipped from Pod One to Algar.

By treating part of the Pod One blow-down at Algar the average yearly water recycle ratio for both plants is approximately 97%.

Recycle rates decrease in April/May, 2013 due to boiler outages at Algar.

Pod One evaporator waste transfers to Algar were erratic due to operational issues in 2013.

Water Recycle Rate = (Steam Injected – Source (Fresh) Water) * 100
Produced Water

Stream calculations conform to current MARP.

Source water from Lower Grand Rapids (~1900 ppm TDS) and used for boiler feed-water make up and utility water.

Typical Evaporator Chemistry

<table>
<thead>
<tr>
<th>Source Water</th>
<th>Total Hardness ppm</th>
<th>Total TDS Calculated ppm</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>10 - 14</td>
<td>1600 - 1900</td>
</tr>
<tr>
<td>Evaporator Feed</td>
<td>4 - 6</td>
<td>600 - 800</td>
</tr>
<tr>
<td>Evaporator Distillate</td>
<td>&lt;0.5</td>
<td>20 - 60</td>
</tr>
<tr>
<td>Evaporator Sump</td>
<td>280 - 300</td>
<td>40,000-50,000</td>
</tr>
</tbody>
</table>

The TDS after the final Evaporator Stage varies depending on the wasting rate but is approx. 15% or 150,000 ppm.
Pod One Water Balance

Cum Steam In/Cum Water Out

2007 2008 2009 2010 2011 2012 2013

101N 101S 102S 102W
Algar Water Balance

Cum Steam In / Cum Water Out

May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep Oct Nov Dec Jan Feb Mar Apr May Jun Jul Aug Sep

2010 2011 2012 2013

201 202 203
Sulphur Production
Pod One Sulphur Emissions

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Average Sulphur Dioxide Emissions (t/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q4 - 2012</td>
<td>0.347</td>
</tr>
<tr>
<td>Q1 - 2013</td>
<td>0.319</td>
</tr>
<tr>
<td>Q2 - 2013</td>
<td>0.263</td>
</tr>
<tr>
<td>Q3 - 2013</td>
<td>0.416</td>
</tr>
</tbody>
</table>

Algar Sulphur Emissions

<table>
<thead>
<tr>
<th>Quarter</th>
<th>Average Sulphur Dioxide Emissions (t/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Q4 - 2012</td>
<td>0.523</td>
</tr>
<tr>
<td>Q1 - 2013</td>
<td>0.540</td>
</tr>
<tr>
<td>Q2 - 2013</td>
<td>0.540</td>
</tr>
<tr>
<td>Q3 - 2013</td>
<td>0.543</td>
</tr>
</tbody>
</table>

- Pod One EPEA SO₂ emission limit is 1.98 t/day
- Peak SO₂ emissions were 0.72 t/d on July 4, 2013
- Algar EPEA SO₂ emission limit is 1.98 t/day
- Peak SO₂ emissions were 1.03 t/d on October 6, 2012

- Plant Total SO₂ = Flared SO₂ + Steam Generators SO₂
- No significant changes in sulphur production have been observed over the past year of production at Pod One or Algar
- Connacher will continue to monitor produced gas H₂S concentrations, sulphur emissions and evaluate plans for sulphury recovery installations
- SO₂ production is well below emission limits
EH&S Compliance Great Divide
Great Divide Water Wells

Pod One Water Wells
1F1/08-17-082-12W4/00
1F1/09-17-082-12W4/00
1F1/16-17-082-12W4/00

Algar Water Wells
1F2/03-19-082-11W4/00
1F1/04-19-082-11W4/00
1F1/06-19-082-11W4/00

Source Water: Lower Grand rapids 1600 - 1900 ppm TDS
**EH&S Compliance Pod One - Water Withdrawals**

**Water Withdrawals - Pod One Water Wells (m3)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Pod One Water Withdrawals (m³/year)</th>
<th>Licenced Maximum Annual Diversion (m³/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>169,154</td>
<td>292,000</td>
</tr>
<tr>
<td>2011</td>
<td>107,471</td>
<td>292,000</td>
</tr>
<tr>
<td>2012</td>
<td>132,670</td>
<td>292,000</td>
</tr>
<tr>
<td>2013</td>
<td>114,426</td>
<td>292,000</td>
</tr>
</tbody>
</table>

**Water Withdrawals - Algar Water Wells (m3)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Algar Water Withdrawals (m³/year)</th>
<th>Licenced Maximum Annual Diversion (m³/year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>98,139</td>
<td>330,000</td>
</tr>
<tr>
<td>2011</td>
<td>68,222</td>
<td>330,000</td>
</tr>
<tr>
<td>2012</td>
<td>96,164</td>
<td>330,000</td>
</tr>
<tr>
<td>2013</td>
<td>82,403</td>
<td>330,000</td>
</tr>
</tbody>
</table>
## EH&S Compliance Pod One Facility

### Flaring & Venting

<table>
<thead>
<tr>
<th>Date</th>
<th>Cause / Description</th>
<th>Duration (hours)</th>
<th>Volume (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Apr 20, 2013</td>
<td>Maintenance (repair work) on EVC</td>
<td>4.3</td>
<td>0.2</td>
</tr>
<tr>
<td>May 18, 2013</td>
<td>Maintenance, compressor replacement EVC</td>
<td>3.5</td>
<td>0.145</td>
</tr>
<tr>
<td>June 22, 2013</td>
<td>Meter testing</td>
<td>3.0</td>
<td>0.13</td>
</tr>
<tr>
<td>June 30, 2013</td>
<td>Maintenance due to fouling</td>
<td>23.6</td>
<td>2.35</td>
</tr>
<tr>
<td>Sept 29, 2013</td>
<td>Maintenance</td>
<td>5.5</td>
<td>0.4</td>
</tr>
</tbody>
</table>

### Self Disclosures

<table>
<thead>
<tr>
<th>Date</th>
<th>Cause / Description</th>
<th>Corrective Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sept 27, 2012</td>
<td>Late submission of monthly air monitoring report</td>
<td>Reported submitted September 27, 2012</td>
</tr>
<tr>
<td>Oct 10, 2012</td>
<td>Unmetered hydrocarbon receipt</td>
<td>Installation of weigh scale at Pod One trucking terminal</td>
</tr>
<tr>
<td>Oct 18, 2012</td>
<td>Missing passive air monitoring samples</td>
<td>Sample puck replaced, increased monitoring at site to determine cause</td>
</tr>
<tr>
<td>Dec 4-5, 2012</td>
<td>Unmetered off spec product from Algar</td>
<td>Installation of weigh scale at Pod One trucking terminal</td>
</tr>
<tr>
<td>Jan 8, 2013</td>
<td>Late submission of CPP</td>
<td>Report submitted January 8, 2013</td>
</tr>
<tr>
<td>Feb 25, 2013</td>
<td>Erratic water level data</td>
<td>Suspected malfunction of data capture software, installed backup software</td>
</tr>
<tr>
<td>Apr 5, 2013</td>
<td>Missing water level data</td>
<td>Incorrect programming of data capture software, necessary programming completed</td>
</tr>
<tr>
<td>July 4, 2013</td>
<td>Soil erosion and siltation due to flooding</td>
<td>Assessment of all impacted areas completed, restoration of impacted areas underway</td>
</tr>
</tbody>
</table>
## EH&S Compliance Algar Facility

### Flaring & Venting

<table>
<thead>
<tr>
<th>Date</th>
<th>Cause / Description</th>
<th>Duration (hours)</th>
<th>Volume (e³m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dec 5, 2012</td>
<td>Malfunction of pressure safety valve</td>
<td>0.25</td>
<td>0.001</td>
</tr>
<tr>
<td>Jan 18, 2013</td>
<td>Plant upset</td>
<td>6.0</td>
<td>0.024</td>
</tr>
<tr>
<td>Jan 19, 2013</td>
<td>Catastrophic boiler failure</td>
<td>3.0</td>
<td>0.012</td>
</tr>
<tr>
<td>Mar 19, 2013</td>
<td>Boiler tube failure</td>
<td>13.5</td>
<td>0.3</td>
</tr>
<tr>
<td>Apr 22, 2013</td>
<td>Boiler maintenance</td>
<td>5.5</td>
<td>0.5</td>
</tr>
<tr>
<td>Apr 29, 2013</td>
<td>Plant upset</td>
<td>12.0</td>
<td>0.312</td>
</tr>
<tr>
<td>May 17, 2013</td>
<td>Plant upset</td>
<td>2.3</td>
<td>0.034</td>
</tr>
<tr>
<td>May 20, 2013</td>
<td>Plant upset</td>
<td>1.5</td>
<td>0.023</td>
</tr>
<tr>
<td>May 21, 2013</td>
<td>EVC equipment repairs</td>
<td>7.5</td>
<td>0.113</td>
</tr>
<tr>
<td>May 26, 2013</td>
<td>Plant trip</td>
<td>4.0</td>
<td>0.45</td>
</tr>
<tr>
<td>Aug 15, 2013</td>
<td>Power loss (thunderstorm)</td>
<td>3.0</td>
<td>0.337</td>
</tr>
</tbody>
</table>

### Self Disclosures

<table>
<thead>
<tr>
<th>Date</th>
<th>Cause / Description</th>
<th>Corrective Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oct 5, 2012</td>
<td>H₂S exceedance</td>
<td>Exceedance coincided with short term operational upset of boiler, boiler brought back on-line</td>
</tr>
<tr>
<td>Oct 10, 2012</td>
<td>Unmetered hydrocarbon receipt</td>
<td>Installation of weigh scale at Pod One trucking terminal</td>
</tr>
<tr>
<td>Oct 12, 2012</td>
<td>Missing passive air monitoring samples</td>
<td>Sample pucks replaced, increased monitoring at site to determine cause</td>
</tr>
<tr>
<td>Jan 8, 2013</td>
<td>Late submission of CPP</td>
<td>Submitted report January 8, 2013</td>
</tr>
<tr>
<td>May 6, 2013</td>
<td>Potential for flooding</td>
<td>Additional efforts towards controlling melt water, no adverse effects</td>
</tr>
<tr>
<td>May 22, 2013</td>
<td>Damaged passive monitoring station</td>
<td>New pucks installed, continued monitoring of site to determine cause</td>
</tr>
<tr>
<td>June 3, 2013</td>
<td>Damaged passive monitoring station</td>
<td>New pucks installed, continued monitoring of site to determine cause, suspect juvenile black bear</td>
</tr>
<tr>
<td>July 4, 2013</td>
<td>Soil erosion and siltation due to flooding</td>
<td>Assessment of all impacted areas completed and restoration nearly complete</td>
</tr>
<tr>
<td>July 9, 2013</td>
<td>Damaged passive monitoring station</td>
<td>New pucks installed, confirmed black bears involved, installed wildlife deterrents</td>
</tr>
</tbody>
</table>
## EH&S Great Divide - Approvals

### Inspections

<table>
<thead>
<tr>
<th>Date</th>
<th>Agency</th>
<th>Description</th>
<th>Corrective Action</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mar 19, 2013</td>
<td>AER</td>
<td>Oilfield Drilling Waste Audit</td>
<td>Response provided March 27, 2013</td>
</tr>
<tr>
<td>May 24, 2013</td>
<td>AESRD</td>
<td>Public Land Dispositions</td>
<td>Action plan to address housekeeping, erosion, soil management, and interim reclamation submitted October 31, 2013.</td>
</tr>
</tbody>
</table>

### ERCB Amendments

<table>
<thead>
<tr>
<th>Approval Date</th>
<th>Application No.</th>
<th>Licence / Approval No.</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oct 26, 2012</td>
<td>1739682</td>
<td>F41025</td>
<td>Increase max H$_2$S content in Wellpad 201 (D056)</td>
</tr>
<tr>
<td>Oct 26, 2012</td>
<td>1739684</td>
<td>F41026</td>
<td>Increase max H$_2$S content in Wellpad 202 (D056)</td>
</tr>
<tr>
<td>Oct 26, 2012</td>
<td>1739685</td>
<td>F41027</td>
<td>Increase max H$_2$S content in Wellpad 203 (D056)</td>
</tr>
<tr>
<td>Nov 27, 2012</td>
<td>1744953</td>
<td>10587I</td>
<td>Re-drill Well Pair 202-01 on Pad 202, Amend approved development area</td>
</tr>
<tr>
<td>Dec 5, 2012</td>
<td>1744737</td>
<td>10587J</td>
<td>Drill Four Infill Wells from Pad 102 W</td>
</tr>
<tr>
<td>Feb 28, 2013</td>
<td>1755525</td>
<td>54978</td>
<td>Pipeline Licence Amendment - substance change</td>
</tr>
<tr>
<td>Apr 2, 2013</td>
<td>1758377</td>
<td>10587J</td>
<td>Temporary Evaporator Vent Incinerator</td>
</tr>
<tr>
<td>Apr 29, 2013</td>
<td>1760281</td>
<td>F46075</td>
<td>Pad 104 Facility Licence</td>
</tr>
<tr>
<td>June 5, 2013</td>
<td>1756591</td>
<td>10587K</td>
<td>Use of light hydrocarbon with steam on additional ten wells on Pads 201 and 202</td>
</tr>
<tr>
<td>July 24, 2013</td>
<td>1756591</td>
<td>10587L</td>
<td>Request to stop steam injection at Pad 101N</td>
</tr>
<tr>
<td>Pending</td>
<td>1771114</td>
<td>Pending</td>
<td>Co-injection of natural gas with steam into 23 well pairs (Pod One)</td>
</tr>
<tr>
<td>October 25, 2013</td>
<td>1759627</td>
<td>10587L (disposition letter)</td>
<td>Storage of evaporator distillate in source water pond (Algar)</td>
</tr>
</tbody>
</table>
EH&S Compliance Statement

Connacher believes that the Great Divide project and both the Pod One and Algar plants are in full compliance with ERCB approvals and regulatory requirements.
Connacher Involvement on Oil Sands Committees

*Connacher is a member of the following organizations:*

- The Canadian Association of Petroleum Producers (CAPP)
  - Aboriginal Affairs - executive policy group
  - Communication - executive policy group
  - Oil Sands - executive policy group
  - HSE - executive policy group
- Coalition for a Safer 63 and 881 where Connacher sits on the board
- Cumulative Environmental Management Association
- Regional Aquatic Monitoring Program
- Alberta Biodiversity Monitoring Institute
- Wood Buffalo Environmental Association
Appendices
Appendix A - List of Additional Material Submitted

Additional Material Attached to Submission:

Pressure & temperature data form observation wells for Pod One & Algar in prescribed ERCB Format

Energy Usage & Balance for Algar & Great Divide

Electrical Use at Pod One & Algar

SCVF GM Testing Results

Connacher Heave monitoring Data

Pump Histories
Appendix B - Bitumen Reserves and Resources

1) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

2) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

3) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. Possible reserves were 104 million barrels as at Dec 31, 2010 per GLJ. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of the proved plus probable plus possible reserves.

4) 10% Present Value of future net revenue, calculated after deduction of forecast royalties, operating expenses, capital expenditures and well abandonment costs but before corporate overhead or other indirect costs, including interest and income taxes using GLJ Jan 1, 2011 price forecast. Future Net Revenue does not necessarily represent fair market value.

5) Per GLJ Petroleum Consultants Ltd. as at Dec 31, 2010. Refers to gross reserves. Refer to slides 32 and 33 for forward looking information disclaimer and advisories.

6) As at December 31, 2010 per July 2011 Oilweek Magazine. Excludes multinational producers and foreign owned companies operating in Canada.
Appendix C - Individual Well Performance

Individual Well Performance
Pod One Pad 101N Individual Well Performance

Bitumen Production (m³/day)  Steam Inj (m³/day)  Produced Water (m³/day)

101-01  101-03  101-05

101-02  101-04

Return to Main Document
Pod One Pad 101S Individual Well Performance

Return to Main Document
Pod One Pad 102S Individual Well Performance

[Graphs showing Bitumen Production, Steam Inj, and Produced Water for wells 101-11, 102-13, 102-12, and 102-14 over the years 2009 to 2013.]

Return to Main Document
Algar Pad 201S Individual Well Performance

- Bitumen Production (m3/day)
- Steam Inj (m3/day)
- Produced Water (m3/day)

201-01

201-02

201-03

201-04

201-05

Return to Main Document
Algar Pad 202S Individual Well Performance

- Bitumen Production (m3/day)
- Steam Inj (m3/day)
- Produced Water (m3/day)

Return to Main Document
Algar Pad 203S Individual Well Performance

Graphs showing Bitumen Production (m3/day), Steam Inj (m3/day), and Produced Water (m3/day) for wells 203-01 to 203-07 over the years 2010 to 2013.

Return to Main Document
Technical Papers
Pressure Balancing Under a Gas Cap

*Production Optimization at Connacher’s Pod One Oil Sands Project, Johnson et al, World Heavy Congress, Edmonton, Alberta 2011*
Abstract

Connacher’s first oil sands project, the Pod One facility at Great Divide, has been operational since 2007. The successful SAGD project has produced approximately 7 million barrels of bitumen. During the past three and a half years, the impacts of certain predicted reservoir challenges and opportunities have become apparent.

While the quality of the oil sands in this first phase of Pod One is generally good, Pad 101 South in particular has geological zones that affect SAGD operation. This includes a bitumen lean zone, and a gas cap overlying the main bitumen channel/s. Early field results matched with detailed simulations have shown positive results in maximizing well pair production. For the purposes of this paper a lean bitumen zone differs from an aquifer in two ways. The lean zone is not charged, and is limited in size. The operation is also complicated by the fact the gas bearing zone has been depleted through earlier production.

Connacher’s operating practice at Great Divide attempts to achieve a pressure balance between the 3 zones (rich oil sands, lean zone, gas cap) to reduce steam loss and maximize production rates. Reducing the pressure encourages steam chamber development growth horizontally and ensures that steam contacts the highly saturated bitumen areas. How this is achieved with the highest positive impact on well productivity is illustrated with three years of operational data and analysis including the results of simulations that recommended the optimum operating strategies.

Introduction

Pod One’s operational performance to date has been impacted by the overlying depleted McMurray gas cap. Steam chamber communication with the lower pressure zone has occurred on several of the Pad 101 South wells after steam rose to the top of the bitumen portion of the reservoir. This subsequent loss of steam to the gas cap initially reduced well productivity. Currently, Connacher is managing the reservoir challenge by installing down-hole pumps to drop the steam chamber pressures to a value closer to the pressure of the gas cap. This successfully recaptures most of the individual well productivity. Analysis has also shown that re-pressuring the associated McMurray gas cap will reduce steam losses, as well as improve future development potential on known reserves in the southern area of Pod One.

Geological Description

The McMurray formation in the area of Connacher’s Great Divide commercial SAGD project consists of fine to medium sands with generally increasing muddy interbeds that are highly bioturbated toward the top of the reservoir. The basal sediments of the McMurray Formation were deposited in an incised valley and consist of fluvial sediments deposited in high-energy, sand-dominated environments. The upper parts were generated in estuarine to marginal marine environments, resulting in a fining upward sequence of sands and muds. The sequences often include massive cross bedded sands overlain by interbedded sands and shales capped by laminated mudstones. These tight mudstones are considered a barrier to fluid flow and act as a caprock.
The lean zone, is seen in the upper parts of the Great Divide reservoir and interpreted by Connacher to be part of a depleted gas zone. It is a zone of relatively low oil saturation (2-5% bitumen) by weight, with a wireline induction response of ~10-20 ohm*m, whereas, a typical McMurray water wet zone in this area has a wireline induction response of ~6-10 ohm*m (Figure 1). In some instances, the wireline logs will still show crossover in the depleted zone due to some residual gas.

The gas directly above the bitumen resource is termed an associated gas cap. Where present, in Pod One, the associated gas cap is between 1 and 8 m thick. The associated McMurray S Pool was discovered in 1987 by Canadian Worldwide Energy Limited with the 5-16-82-12W4M well. This first well, 5-16, drilled into the reservoir only showed gas above bitumen, while subsequent wells drilled in the area show the development of the lean zone as mapped in Figure 2 and shown in cross-section in Figure 3. As expected, the gas/lean zone contact is also variable throughout the reservoir as gas from various wells was produced at different times.

**Gas Cap Overview**

Volumetric original gas in place (OGIP) is estimated at 129 e³m³ for the McMurray S Pool. 5-16 produced from 1988 to 2004 as detailed in Figure 4 and was the sole source of depletion from this pool cumulating approximately 109 e³m³ natural gas and 986 m³ water. Another well, 10-17-82-12W4, was completed and tested the McMurray S in 1998, however it was not produced from this interval.

Public bottom hole pressure data from 5-16 and 10-17 relating to cumulative gas production is shown in Figure 5. Original pressure of the gas cap was 2,027 kPa in 1988. Subsequent to depletion, the last pressure recording was 746 kPa in 2003 at 5-16 (based on the operating experience at Pod One it is unlikely that the pool pressure was actually this low at the time SAGD operations began and a higher value was used in the simulation work).

Gas over bitumen regulations introduced in Alberta subsequent to the McMurray S pool production prevented further depletion of the associated gas in 2004. There are gas zones in other McMurray sequences above the bitumen resource separated by shale barriers, although at times they had been produced concurrently. Pod One is the only area in Connacher’s existing oil sands land base that has a depleted McMurray gas zone.

**Initial SAGD Operating Strategy**

**101-09 Case History**

101-09, a well pair located beneath the zones of interest, commenced steam circulation in September 2008 and first production was achieved in November 2008 (Figure 6). Production for the first month averaged 75 m³/d bitumen and the initial steam injection rate was 250 t/d. The well was started utilizing lift gas. As the steam chamber developed vertically the steam injection rate increased with chamber growth and production. During the first eight months on SAGD, production increased to 125 m³/d and steam to 350 t/d resulting in an instantaneous steam to oil ratio (ISOR) of approximately 2.8. Once the well achieved peak steam and oil rates and connected to the lower pressure top gas cap, the steam chamber pressure started to decline in April 2009.

In September 2009 the water steam ratio (WSR) and overall fluid production rate started to significantly drop as the well pair produced less of the water that was being injected as steam. At the same time the steam chamber pressure continued to drop, ultimately indicating that steam loss was occurring to a low pressure gas cap located above the bitumen zone. As a result of these steam losses the oil production rate dropped by approximately 50% because the steam that should have been contacting the bitumen within the pay zone was now moving into the gas cap.

In November 2009, an electric submersible pump (ESP) was installed in 101-09 to lower the steam chamber pressure closer to that of the gas cap in an effort to balance pressures and reduce steam losses. Artificial lift was required to operate the SAGD well pair at a pressure below 3000 kPa while maintaining fluid production at a vertical depth of 470 m.

Initial production after the ESP installation improved and within a month the WSR was >1.0. The overall steam injection rate was much lower than before the pump was installed and it was continually adjusted to ensure that the steam chamber pressure was slowly decreasing to match that of the overlying gas cap. This increase in oil production (to 80% of peak rates) and decrease in steam injection also resulted in a decrease of the cumulative SOR.

A comparative well pair without a low pressure gas cap above the bitumen zone would look quite different than 101-09. The initial production growth up to the peak oil rate would be the same, but it would be followed by a gradual decline. Also the steam chamber pressure would likely be constant.

**Surveillance (12-16 Observation Well)**

The performance history of the SAGD production wells provided indirect evidence of the consequences of steam injection into a low pressure gas cap. In order to gain more direct data an observation well, 12-16-82-12W4, was drilled and completed in late February 2010 and started logging pressure and temperature from that point forward. The well is located near the toe of well pairs 101-10 and 101-11. The instrumentation in 12-16 consists of one pressure and one temperature reading from the following depths:

454 mKB – Gas Cap
458 mKB – Lean zone (increased water saturation)
471 mKB – Bitumen
479 mKB – Bitumen
487 mKB – Bitumen

In February of 2010 the majority of the wells located near the 12-16 OBS well had already come into contact with the gas cap and were operating at lower pressures on artificial lift. This resulted in decreased steam chamber pressures (<2,700 kpa) from the initial pressures seen in early production months (>4,300 kpa).

Figure 7 shows the trend of pressure vs depth for five time intervals since March 4, 2010. The 479 and 487 m depths, which are most indicative of the conditions near the producer...
and injector, show decreasing pressure as the steam chamber pressures are strategically being reduced. The 454 and 458 m depths, which are monitoring the gas cap and lean zone, show that the gas cap is slowly increasing in pressure because it is in contact with the higher pressure steam chambers of the injection wells.

Figure 8 shows the trend of temperature vs depth for the same time intervals since March 4, 2010. The 479 and 487 m depths show increasing temperature as the steam chambers slowly extend conductive heat towards the 12-16 OBS well. The 454 and 458 m depths show decreasing temperature as the amount of steam escaping from the steam chambers into the gas cap decreases as the pressures between the steam chambers and the gas cap continue to move towards one another.

**Numerical Simulations**

In order to optimize the production strategy, numerical simulations were completed using the CMG Stars 2010.10 SAGD simulator. Simulations were performed to model the operational impact of the overlying gas/lean zone on a generic SAGD well pair. The simulations involved the following models and operating strategies.

1. 3-D half element SAGD well pair with no overlying gas/lean zone

2. 3-D half element SAGD well pair with overlying gas/lean zone at the toe of the reservoir (shale representing overburden at the heel)
   a. No methane pressure support
   b. Methane injection for pressure support following steam communication
   c. Methane injection for pressure support prior to start-up

The model was loosely based on the well pair 101-09. The size of the overlying gas/lean zone in the model is only a portion of the actual size in an attempt to reduce run time and due to the models comparative application.

**Reservoir Properties for the Models**

1. 3-D half element SAGD well pair with no overlying gas/lean zone

   **Table 1: No overlying gas/lean zone.**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
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</thead>
<tbody>
<tr>
<td>Reservoir top TVD (m)</td>
<td>450</td>
</tr>
<tr>
<td>Reservoir thickness (m)</td>
<td>20</td>
</tr>
<tr>
<td>Vertical permeability (Darcy)</td>
<td>1.9</td>
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<tr>
<td>Horizontal permeability (Darcy)</td>
<td>2.2</td>
</tr>
<tr>
<td>Reservoir pressure (kPaa)</td>
<td>3,400</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>12</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>27</td>
</tr>
<tr>
<td>Oil saturation (S_o)</td>
<td>0.78</td>
</tr>
<tr>
<td>Water saturation (S_w)</td>
<td>0.22</td>
</tr>
</tbody>
</table>

The grid system of the above model was composed of 14,000 blocks (50 x 14 x 20) representing a 50 m width (50 x 1m), 700 m length (14 x 50m) and 20 m thickness (20 x 1 m). The well pair consists of a 700 m injector and underlying producer with 5 meters of separation. The producer is located 0.5 m offset from the base the model.

2. 3-D half element SAGD well pair with overlying gas/lean zone

   **Table 2: With overlying gas/lean zone.**

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
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<td>General</td>
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</tr>
<tr>
<td>Reservoir top TVD (m)</td>
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</tr>
<tr>
<td>Reservoir thickness (m)</td>
<td>28</td>
</tr>
<tr>
<td>Vertical permeability (Darcy)</td>
<td>1.9</td>
</tr>
<tr>
<td>Horizontal permeability (Darcy)</td>
<td>2.2</td>
</tr>
<tr>
<td>Reservoir temperature (°C)</td>
<td>12</td>
</tr>
<tr>
<td>Porosity (%)</td>
<td>27</td>
</tr>
<tr>
<td>Oil saturation (S_o)</td>
<td>0.78</td>
</tr>
<tr>
<td>Water saturation (S_w)</td>
<td>0.22</td>
</tr>
<tr>
<td><strong>Gas zone</strong></td>
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</tr>
<tr>
<td>Thickness (m)</td>
<td>5</td>
</tr>
<tr>
<td>Pressure (kPaa)</td>
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<tr>
<td>Gas saturation (S_g)</td>
<td>0.55</td>
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<tr>
<td>Oil saturation (S_o)</td>
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<tr>
<td>Water saturation (S_w)</td>
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<tr>
<td><strong>Lean zone</strong></td>
<td></td>
</tr>
<tr>
<td>Thickness (m)</td>
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<tr>
<td>Pressure (kPaa)</td>
<td>1,200</td>
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<tr>
<td>Oil saturation (S_o)</td>
<td>0.4</td>
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<tr>
<td>Water saturation (S_w)</td>
<td>0.6</td>
</tr>
</tbody>
</table>

The grid system of the model was composed of 25,200 blocks (50 x 18 x 28) representing a 50 m width (50 x 1m), 2,700 m length (14 x 50m, 1 x 200m, 1 x 400m, 1 x 600m, 1 x 800m) and 28 m thickness (28 x 1 m) (Figure 9). The 20 m of primary oil sands zone extended the full width (50 m) and length (2,700 m) of the model with 700 m well pair at one end of the zone. 15 m above the injector heel at the top of the zone is a 400 m long shale roof (representing lower overburden). The 3 m thick lean zone begins 400 m from the heel of the well (lying above the oil sands zone) and extends 2,300 m horizontally. The 5 m thick gas zone begins 450 m from the heel of the well (lying above the lean zone) and extends 2,250 m horizontally.

The well pair consists of a 700 m injector and underlying producer with 5 meters of separation; located 0.5 m offset from the base the model. The gas injector is located in the gas zone grid, 700 m from the end of the well pair, on the opposite side of the model as the well pair (Figure 10).

**Operational Strategies**

1. 3-D half element SAGD well pair with no overlying gas/lean zone

Heaters were used for a 3 month period to simulate circulation and initiate communication between the injector and producer wells. Initial pressure following start up was maintained at 4,000 kPaa (Constraint 1) utilizing a gradual production increase over a 3 month period. Following this 3 month period a 5 °C subcool (Constraint 1) and production limit of 700/day m3 was utilized. This model was run for a period of 5 years (Figure 11).
2. 3-D half element SAGD well pair with overlying gas/lean zone at the toe of the reservoir (shale representing overburden at the heel)

a. Base gas/lean - No methane pressure support
Heaters were used for a 3 month period to simulate circulation and initiate communication between the injector and producer wells. Initial pressure following start up was maintained at 4,000 kPaa (Constraint 1) utilizing a gradual production increase over a three month period. Following this 3 month period a 5 °C subcool (Constraint 1) and a 700 m3/day production limit was utilized (Constraint 2). Approximately one month after contacting the gas/lean zone the pressure constraint of the steam chamber was dropped to 3,300 kPaa in stages to mimic the initial operating strategy when preparing for an artificial lift install. After two weeks of operating at 3,300 kPaa the pressure of the injection chamber is constrained to 2,500 kPaa to simulate a pump install. The same 700 m3/day production limit is carried forward for the remaining time of the 5 year simulation (Figure 12).

b. Methane injection for pressure support following steam communication with overlying zone
The same operational strategy is followed as the base gas/lean model until the overlying zone is contacted. In this model gas injection commences three months after the steam chamber has been dropped to a 2,500 kPaa pressure constraint. Gas is injected into the gas injection well to maintain a gas injector bottom-hole pressure of 2,300 kPaa, (with a maximum injection rate of 142 c3m3/d) slightly lower than the steam chamber injection pressure. The gas injector constraint is carried forward for the remainder of the simulation. The same 700 m3/day production limit is carried forward for the remaining time of the 5 year simulation (Figure 13).

c. Methane injection for pressure support prior to start-up
In this model gas is injected into the gas injection well to maintain a bottom-hole pressure of 2,300 kPaa (with a maximum injection rate of 142 c3m3/d) prior to circulating (initiating heaters). The same operational strategy is followed as the base gas/lean model for the remaining time of the 5 year simulation (Figure 14).

Simulation results

The models were run to compare the effects of various gas injection schemes versus a base SAGD without an overlying gas/lean zone. All cases compared the same 50% recovery factor of recoverable volume, totaling 238,140 m3 of oil. This is the recoverable volume of the main SAGD oil sands zone that the well pair lies within. Due to the homogeneous nature of the model, the overall rates and lower SOR are slightly more optimistic than reality. A detailed table of results can be found in Table 3 (appendix). A summary of the results is listed here:

<table>
<thead>
<tr>
<th>Run #</th>
<th>Simulation description</th>
<th>Time to 50% (months)</th>
<th>CSOR 50%</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Base SAGD case</td>
<td>27.96</td>
<td>2.58</td>
</tr>
<tr>
<td></td>
<td>Overlying Gas/Lean zone models</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>Base gas/lean case</td>
<td>41.31</td>
<td>3.41</td>
</tr>
<tr>
<td>3</td>
<td>Re-Pressure After</td>
<td>41.28</td>
<td>3.30</td>
</tr>
<tr>
<td>4</td>
<td>Re-Pressure Before</td>
<td>37.27</td>
<td>2.66</td>
</tr>
</tbody>
</table>

Recommendations from modeling

3-D half element SAGD well pair with overlying gas/lean zone at the toe of the reservoir (shale representing overburden at the heel)

a. Base gas/lean - No methane pressure support.
Once communication was established with the overlying gas/lean zone, steam is lost to the zone until some pressure balance is established. The result is an increase in steam volume injected to the max injection constraint as the steam chamber pressure constraint is not being met due to steam loss to the overlying zone (Figure 15). The production rate from the well is immediately affected, and there is a reduction in oil volume for a period of time. SAGD operation is negatively affected until a significant portion of steam injection is once again being utilized by the steam chamber rather than pressure support. It can be seen that for the life of the well a portion of the steam is being lost into the lower pressure zone as the gas injector bottom-hole pressure (gas zone) is slowly building pressure over the entire life of the model.

b. Methane injection for pressure support following steam communication with overlying zone.
This case was run to mimic the wells that are already communicating with the overlying gas/lean zone. In this case the same volume of steam is lost to the reservoir until the time gas injection occurs into the gas injection well. At this time the pressure with the gas injection well is increased to 200 kPaa lower than the SAGD injection chamber pressure. Once this occurs there is an immediate influx of water (Figure 16). From the modeling it was shown that a larger SAGD chamber pressure was crucial in reducing the chance of quenching the steam chamber. The larger this difference the less steam lost and water gained from the overlying zone. The actual pressure difference that should be kept on the SAGD chamber and gas zone will vary from well to well, although the SAGD chamber should always have a higher pressure. Models that had the same steam chamber pressure constraint as the re-pressured gas zone resulted in such a large influx of lean zone water that the steam chamber was quenched.

c. Methane injection for pressure support prior to start-up
In this model the pressure of the gas zone was immediately brought to the point found to be beneficial in the previous model (2,300 kPaa or 200 kPaa less than the steam chamber injection pressure). When the steam chamber began communicating with the overlying gas/lean zone there was some initial loss of steam, although this period and volume was drastically reduced. The overall oil production rate did benefit slightly from the re-pressurization as indicated by the reduction in time to 50% RF, although the major benefit occurred from the reduction in steam loss. The influx of water seen was similar in volume to that of the model ran with post communication injection.
Conclusions

Lowering steam chamber pressures and installing down-hole pumps has proven effective in recovering production losses in bitumen areas underlying the depleted gas cap at Connacher’s Pod One.

From the computer models it can be seen that there is also a substantial benefit to re-pressuring the overlying gas/lean zone, manifested as an SOR reduction. The benefit is apparent for existing well pairs already in communication with the overlying zone, and is increased when the re-pressuring occurs prior to communication with the overlying zone.

In both cases it is crucial the SAGD chamber pressure is slightly greater than the overlying zones in order to minimize the influx of water. Some increased water production may still be expected and the volume of water is based on the pressure difference between the operating SAGD well pair chamber and the overlying gas zone, extent of communication with the zone and the overall gas/lean zone size and thickness.

Connacher plans to pursue re-pressuring at Pod One as part of the area development plan.

Acknowledgement

The authors wish to thank Connacher Oil and Gas Limited for permission to publish this paper.

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2. CENOVUS ENERGY INC., ERCB In Situ Progress Reports, Chistina SAGD 8591, ERCB website, 2005-2010 Annual Reports.
Figure 1: Type Log of 1AA/13-16-82-12W4 showing gas, lean, and oil zones at Great Divide
Figure 2: Great Divide Associated Gas Pay and Lean Zone Isopach Maps.
Figure 3: Structural cross section showing initial gas well and subsequent wells with gas and lean zone
Figure 4: 5-16 Historical Gas Production Data.

Figure 5: Bottom Hole Pressure Data from 5-16 and 10-17.
Figure 6: 101-09 Historical Production and Injection Data.
Figure 7: 12-16 Observation Well Pressure Data.
Figure 8: 12-16 Observation Well Temperature Data.
Figure 9: CMG builder $S_n$ cross section.

Figure 10: CMG builder 3D $S_n$ showing half element schematic of SAGD injector/producer and Gas injector.
Figure 11: Results for base SAGD case.

Figure 12: Results for base gas/lean zone case.
Figure 13: Results for re-pressuring gas cap after communication with gas cap.

Figure 14: Results for re-pressuring gas cap before start up.
Table 3: Detailed Simulation Results.

<table>
<thead>
<tr>
<th>Run #</th>
<th>Simulation description</th>
<th>50% RF Oil (m³)</th>
<th>Time to 50% (months)</th>
<th>CSOR 50%</th>
<th>Cumulative oil (₇³m³)</th>
<th>CSOR m³/m³</th>
</tr>
</thead>
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<tr>
<td></td>
<td></td>
<td></td>
<td></td>
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<td>Year 1</td>
<td>Year 3</td>
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<td>Base SAGD case</td>
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<td>27.96</td>
<td>2.58</td>
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<td>149</td>
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<td>Overlying Gas/Lean zone models</td>
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<td>2</td>
<td>Base gas/lean case</td>
<td>238140</td>
<td>41.34</td>
<td>3.41</td>
<td>38</td>
<td>105</td>
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<tr>
<td>3</td>
<td>Re-Pressure after steam comm</td>
<td>238140</td>
<td>41.28</td>
<td>3.30</td>
<td>38</td>
<td>104</td>
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<td>Re-Pressure before SAGD begins</td>
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<td>37.27</td>
<td>2.66</td>
<td>40</td>
<td>116</td>
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</tbody>
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Figure 15: CMG Results 3D temperature image of steam chamber moving into overlying gas zone in both the X and Y direction.
Figure 16: CMG Results 3D Water saturation image of water moving from the overlying lean zone into the producing SAGD well pair following gas injection.
Steam Solvent (SAGD+)

History Matching Field Results from a SAGD / Light Hydrocarbon Process (SAGD+™), Lau et al, World Heavy Oil, Congress, Aberdeen, Scotland 2012
History Matching Field Results from a SAGD / Light Hydrocarbon Process (SAGD+™)

E.C. LAU, M.D. JOHNSON, T. LAU
Connacher Oil & Gas Limited

This paper has been selected for presentation and/or publication in the proceedings for the 2012 World Heavy Oil Congress [WHO12]. The authors of this material have been cleared by all interested companies/employers/clients to authorize dmg events (Canada) inc., the congress producer, to make this material available to the attendees of WHO12 and other relevant industry personnel.

Abstract
Connacher Oil & Gas Limited is presently operating two SAGD projects at its Pod One and Algar sites, about 80 km southwest of Fort McMurray, Alberta, Canada. The total approved steam injection capacity is 57,000 barrels per day. Connacher is committed to enhance the performance of its current projects and future expansion sites by developing drilling, lifting and recovery technologies. Amongst these, SAGD with light hydrocarbon co-injection (SAGD+™) is one of the most promising methods.

In July 2011, Connacher initiated the first field trial at two Algar well pairs. Shortly after the light hydrocarbon (or solvent) co-injection, increases in bitumen production and solvent recovery were observed. In mid-November, the solvent injection was suspended and the well pairs reverted to the normal SAGD operating mode. The residual effects of solvent injection were monitored until February 2012.

This paper describes the selection of the well pairs, the modifications to the injection and production facilities and the design of the monitoring program. It also describes how the geological, wellbore and production information was used in a thermal simulation model to simulate the recovery behavior. By matching the production history, Connacher gained significant insights into the reservoir recovery and well flow mechanisms. Furthermore, Connacher was able to identify areas of improvement and applied them in the subsequent SAGD+™ field trials.

Introduction
Connacher operates two SAGD plants in the Great Divide Area of Alberta. The older of these two plants, Pod One, has been producing bitumen since 2007. The Algar plant, which is 6 km from Pod One, came on stream in 2010 (Figure 1). Both plants use a steam assisted gravity drainage (SAGD) process 1 to produce bitumen from horizontal well pairs 500 to 800 m long and drilled in an oil sands zone that is up to 25 m thick. The average thickness of the bitumen bearing sand at Pod One is approximately 21 m and the average at Algar 20 m. Successful bitumen production from this resource requires the application of the very latest SAGD technology. Conventional SAGD requires two horizontal wells drilled along the base of the bitumen pay with the upper well, the injector, placed approximately 5m above the producing well. Production is initiated by circulating steam in both wells. Once communication is established between the wells, steam is injected at relatively high rates into the injector to form a steam chamber and the bitumen is produced by gravity drainage along the edges of the chamber and into the lower producer. Various techniques have already been advanced at the Pod One facility to enhance the basic SAGD process including the use of high temperature downhole pumps and pressure balancing under a gas cap 2.

Algar presented different geological challenges than Pod One. While there was no gas cap present, the average reservoir quality was slightly lower and the geology more complex. In order to improve production rates and reduce steam/oil ratios, enhancements to the basic SAGD process were considered. The processes evaluated were infill wells, steam with a surfactant additive and steam with a solvent additive. Infill wells will be tested in the near future in Pod One and field tests of a steam and surfactant additive commenced December 2011, also in Pod One. Algar was a better candidate for SAGD+™ a steam/light hydrocarbon (or solvent) co-injection process, as the reservoir was early in the development life and had few thief zones (e.g. a gas cap, a high water saturated zone) that could contribute to the loss of the injected solvent.
Background

Algar Facilities, Wells and Project History

Currently there are 17 well pairs producing at Algar (Figure 1). With the exception of one pair, all horizontal well pairs commenced steam injection in May 2010 and first production was in the following month. At the end of April 2012, the Algar project had produced 604,018 m³ of bitumen and injected 2,856,251 m³ of steam (cold water equivalent) for a thermal efficiency based on a steam/oil ratio of 4.46. Producing well peak bitumen rates were approximately 80 m³/day and ranged between 49 and 120 m³/day. The average bitumen production rate as of April 2012 was 57.3 m³/day/well and the average steam injection rate was 274.5 m³/day/well (Figure 2).

The bitumen at this facility is produced predominately as a bitumen-in-water emulsion with bitumen content of 15% to 25%. The product sold from the facility is “dilbit”, a mixture of bitumen and light hydrocarbon (diluent).

Reasons for the SAGD+™

The main reason for injecting solvent together with the steam is to deliver solvent to the edges of the SAGD steam chamber. At these cooler chamber edges the steam and light hydrocarbon condense; steam delivers its latent heat to the bitumen and the solvent dissolves and diffuses into the bitumen. Both mechanisms reduced bitumen viscosity.

Prior to this reported field test, Connacher carried out simulations (not reported here) of the steam / light hydrocarbon process with a typical light hydrocarbon (hexane) at concentrations of up to 15% by volume and at reservoir pressures between 2,000 and 4500 kPa. These simulations indicated that additional productivity, incremental recovery and improved thermal efficiency would result from the addition of simple solvents.

Reduction of bitumen viscosity using solvents has been reported in the literature and used in the field a number of times, though not necessarily in association with the SAGD process. Many laboratory-based experiments using steam and solvents to recover bitumen from the oil sands have been reported. The work of Redford and McKay 4 made it quite clear that in the laboratory the addition of most solvents to steam under a number of different conditions always improved oil recovery. The Redford and McKay work and a subsequent patent 4 showed that heavier solvents are generally better. When considering the practicalities of handling the solvent prior to and downstream of the wells, heavier solvents have a distinct advantage.

Based on PVT data, heavier solvents can also reduce reservoir losses. An important requirement of the SAGD™ process is to recover as much of the injected solvent as possible and recycle it or include it with the sales oil, or dilbit (at Algar this is a mixture of bitumen ~75% and diluent ~25%). Minimal solvent losses are a critical aspect of the project economics as the injected solvent is more expensive than the produced bitumen.

While many technical papers and patents discuss the use of more specific (pure) hydrocarbons, practical reasons make their use uneconomic in the Athabasca Oil Sands, especially when solvent losses into the reservoir are taken into account.

A critical part of the treating process at the Algar plant, and nearly all other SAGD operations, is the addition of a diluent in the 680 to 730 kg/m³ density range. This diluent is added to the produced emulsion together with other chemicals to reduce viscosity and promote separation of the bitumen from the water. Injecting a solvent that is compatible with the diluent used in the treating system makes operational sense.

Field Trial

Connacher’s first SAGD+™ field trial was initiated to determine if previous simulation and laboratory work 3 could be duplicated in a practical manner in the field. The field trial was also intended to provide real-world data that could be used in a reservoir simulation model.

A commercially available solvent was co-injected with the steam starting in July 2011 at initial rates of 10% by volume and increased to 15% by volume in October 2011. The solvent injection was terminated in mid-November 2011. The two well pairs selected for the SAGD+™ trial reported in this paper were 203-02 and 203-03 (Figure 1). Details of the trial are discussed below.

Compared to an April 2011 baseline, daily average bitumen production volumes during the months of August 2011 and September 2011 increased 23 percent. This was also accompanied by an average SOR decrease of 15 percent (Figure 12 & 13). The SOR decrease was limited by the necessity to maintain high steam injection rates so that downhole pressures were high enough for the successful operation of the gas lift system used in the producing wells. This requirement will not be necessary in the future when the company installs downhole pumps and transitions its Algar operations to low pressure SAGD.

Geological Description

The McMurray Formation in the area of the Algar SAGD project consists of a complex clastic assemblage of fine to medium sands with generally increasing muddy interbeds that are highly bioturbated toward the top of the reservoir which is capped with a mudstone. This facies sequence is defined by shale volume (Vsh). It often includes massive cross bedded sands (Z1) overlain by IHS, a laterally accretive, interbedded sands and shales (Z2-4) capped by laminated mudstones (Z5). These tight mudstones are considered a barrier to fluid flow and act as a local caprock. Whereas, intermittently, there is a brecciated facies (Z6) with various size clasts that are interpreted to be storm slump deposits and considered a baffle to fluid flow (Figure 3). The basal sediments of the reservoir are incised valley sediments deposited in a high-energy, sand-dominated environment. The upper parts were generated in estuarine to marginal marine environments, resulting in a fining upward sequence of sands and muds. The tight mudstones capping the reservoir are mudflat/swamp deposits.
Within the reservoir, there is presence of a bottom water interval. A typical McMurray water wet zone in this area has a petrophysical induction response of approximately 6-10 ohm*m (Figure 4).

Geostatistical models were generated to help understand the facies, grade and connectivity relationships within the complex McMurray reservoir in Algar. The model was generated with petrophysical log and core data from all vertical delineation wells and lateral well pairs drilled to date. Using high resolution petrophysical logs and cores, an accurate correlation of facies were determined for all vertical wells. In addition, petrophysical analysis was performed to calculate Vsh, porosity, effective permeability, grade (weight percent bitumen) and oil, gas, and water saturations (Figure 5). Regional geology, core sedimentary structure analysis and seismic were also used to help map sand body geometries. Stochastic realizations using variograms were then computed and validated (Figure 6). Validation was done by intentionally creating the model without certain key wells and observing the predictive capacity of the model. Further validation was done with new wells drilled this past winter.

Field Trial Design

Wells and Injection Facilities

The 203-02 and 203-03 well pairs were chosen because of their relatively simple and similar geology, and the fact that both wells had reached peak production and entered into a stable operational phase.

The downhole completions for the two well pairs are shown in Figures 7 (203-03 injector) and Figure 8 (203-03 producer). Each well was completed with a slotted liner and two tubing strings. The wellhead and tubing arrangements were designed such that a well shut-in was not required between the circulation and SAGD phases. The same well designs were also used at well pair 203-02.

Solvent and steam were injected into the long and short steam lines just prior to the injector wellheads (Figure 9). There is a flow control for steam and solvent on each string. Solvent was added downstream of the steam flow control to attain the required solvent concentrations. During the test period, steam rates were varied as required to maintain bottomhole pressure.

Fluid production from the long and short strings in the producing wells was controlled by gas lift rates and surface chokes. Generally, the wells were operated with a relatively low subcool of between 0°C and 5°C. The definition of subcool is the value by how much the steam saturation temperature, (corresponding to well buttonhole pressure) exceeds the temperature of the produced water. The water balance for the well pairs (i.e. the water produced / steam injected) was also used as a guide for production control.

Solvent Composition and Rate

There were five requirements for selecting the solvent used at Algar:

1. The solvent should be heavy enough so that a significant fraction will condense with the steam and be produced with the bitumen-water emulsion.
2. The solvent must be compatible with the bitumen and not cause adverse reaction such as the precipitation of asphaltene.
3. The solvent must be compatible with the diluted bitumen (dilbit) that is shipped from the facility to heavy oil upgraders.
4. The solvent must be commercially available in substantial quantities and at a price that will make it cost effective in reducing bitumen viscosity in spite of the reservoir losses.
5. The solvent should be easy to handle with normal oil field facilities and so a solvent that is a liquid at standard temperatures and pressures is preferred.

The solvent selected by Connacher which meets many of the above requirements was a commercially available condensate with C4-C8 components and a density between 675 and 695 kg/m³. The solvent injection volume of 10% to 15% of the steam volume (cold water equivalent) was selected for the first trial based on findings from Connacher’s initial simulation studies. This volume ratio is also a practical range. Firstly, the solvent concentration is a small portion of the injection stream and it should not significantly change the carrier steam temperature. The resulting low partial pressure of the solvent vapour should be able to keep even the heavier solvent molecules in their vapour form. Secondly, the solvent recovered with the bitumen should approximately equate to the amount of diluent required for blending the bitumen into dilbit.

Solvent Recovery Facilities

At the injector bottomhole, the solvent vapors rise into the steam chamber, contact the bitumen, condense and drain to the producer along with bitumen and water. The wellhead fluids at the producer bottom-hole are produced through the long and short strings with the aid of gas lift. The produced fluids are then directed either to the test or the group separators (Figure 10). The solvent, which was mainly in a vapour phase, was produced to the central processing facility where it was recovered and recycled (Figure 11).

A small amount of solvent is produced along with bitumen in the produced emulsion which is processed along with additional diluent in the CPF treaters to separate the bitumen and water. The solvent in the vapours coming from the well group headers (Figure 11) is condensed along with steam and recycled to the treaters. Solvent that is not condensed enters the fuel gas system and is burnt in the boilers. The diluted bitumen from the treaters is cooled and shipped as dilbit.

Measurement of Recovered Solvent

It was very important that adequate measurements be obtained to quantify the production increase, SOR improvement, and the solvent recovery to demonstrate the effectiveness of the SAGD™ process. The solvent balance for the test was based on the fact that the solvent was

3
composed primarily of C4-C8 components and there was little overlap with the bitumen produced or with the lift gas used to produce the bitumen. All produced C4-C8 components were attributable to the injected solvent. Measurements were done through a combination of flow meters and sampling to obtain the solvent fraction through simulated distillations and density.

The calculation of solvent recovered in the process required measurement of solvent in both the emulsion and gas streams. This was done by sampling those streams and analyzing the composition and density of the emulsion and the composition of the vapour.

**Individual Wells**

The solvent balance for individual wells was obtained by directing the production through the test separator as shown in the production system schematic (Figure 10).

For each well pair:

\[
\text{Solvent Injected} = \text{FTI201+FTI203} \quad (\text{Figure 9})
\]

(FT\# refers to the volume meters on the plant drawings in Figures 9 to 11)

\[
\text{Solvent Produced} = \text{Solvent in Vapour + Solvent in Liquid}
\]

\[
\text{Solvent Produced} = S1 \times \text{FT14912} + S2 \times \text{FT14919}(1-W) \quad (\text{Figure 10})
\]

S1 (Solvent Fraction) was determined by sampling the vapours off the test separator and determining the solvent components. S2 (Solvent Fraction in liquid Phase) was determined by separating the oil and water (W = Water Cut) and analyzing the oil for solvent components.

**Battery**

A solvent balance for the whole Algar production facility (battery) was also calculated so that errors could be proportionally allocated to the individual wells. The accuracy of fluid measurement at Algar was generally within 10%. This battery balance was calculated from the meters shown in Figure 10. The treating facilities operate at a temperature of approximately 125°C.

For the Battery:

\[
\text{Total Solvent Injected} = \text{FT10401}
\]

\[
\text{Solvent Produced} = \text{Solvent in Vapour + Solvent in Liquid}
\]

\[
\text{Solvent Produced in Vapours} = \text{Solvent Recovered in Vapours + Solvent Losses to Fuel Gas}
\]

\[
= S5 \times \text{FT11216} + S4 \times \text{FT11213}
\]

\[
\text{Solvent Produced} = S5 \times \text{FT11216} + S4 \times \text{FT11213} + S3 \times \text{FT1311}(1-W)
\]

Where, S3 is the solvent in the bitumen emulsion measured at the test separator. S4 is the solvent measured in the gas directed steam boilers. S5 is the condensed solvent recovered from the inlet vapour separator. The solvent measured at S5 (only components less than C9 are included) is returned to central processing plant FWKO/separator and aids in the treating process.

The amount of solvent in the bitumen produced is calculated from:

\[
\text{Solvent in Bitumen} = S4 \times \text{FT11213} + S3 \times \text{FT1311}(1-W)
\]

**Reservoir Losses = Solvent Injected – Solvent Produced**

**Field Results**

**Bitumen Production Prior to Solvent Injection**

Bitumen production and steam injection for the two well pairs since the start of steam injection in May 2010, is shown in Figure 12. In the months prior to solvent injection (July 2011), the two test well pairs, 203-02 and 203-03 had produced 25,687 and 20,044 m³ of bitumen respectively. This volume is approximately 12% of the original volume of bitumen in the well-pair drainage areas. During the same period, the well pairs had injected 95,084 m³ and 84,647 m³ of steam (cold water equivalent). Monthly peak bitumen rates prior to the trial were approximately 100 m³/day for well pair 203-02 and 70 m³/day for 203-03. Total bitumen production rates for the two wells averaged 79 m³/day/well in April 2012, and average steam injection rates were 282 m³/day/well. There was a plant turnaround in May 2012 so April is used as a pre-trial reference for production changes.

**Measured Steam, Bitumen and Solvent Volumes during the Trial**

The combined performance for the two well pairs during the SAGD+™ trial is shown in Figure 13. This graph also shows the injection, recovery and losses of solvent from the two well pairs.

Connacher’s steam and solvent technology, SAGD+™, demonstrated favourable results during the 2011 field trial. Increases in production and lower steam / oil ratios were measured and a solvent recovery rate was achieved that is high enough to be economic in full scale project. Compared to April 2011 (baseline), the daily average bitumen production volumes during the months of August 2011 and September 2011 increased by 23 percent. This was also accompanied by an average SOR decrease of 15 percent during the same period (Figures 12 & 13). The SOR decrease was limited by the necessity to maintain high steam injection rates so that downhole pressures were high enough for the successful operation of the gas lift system used in the producing wells. This requirement will not be necessary in the future when the company installs downhole pumps and transitions its Algar operations to low pressure SAGD.
During the solvent injection trial, most of the solvent was recovered from the vapour separator (V-112, see Figure 11). The sampling results showed that significant amounts of solvent were also recovered through the emulsion and produced gas streams. The total solvent recovery was estimated to be over 85%. The current method of measuring solvent recovery has some inherent inaccuracies but we estimated that the results are within +/- 10%.

Further testing is required and as of May 2012, Connacher commenced a second test on one other well pair in the same Pad 203 at Algar. A number of refinements have been incorporated into the second trial including a more efficient solvent recovery scheme.

Numerical Simulation

Approach

A history match study of the SAGD+™ trial was started soon after the initiation of solvent co-injection at the 203-02 and 203-03 injectors. Geological information used in the model was an upscaled SAGD grid based on a 3-D geostatistical model that had been created in a commercial software package. This model used well pairs 203-02, 203-03 and an adjoining well pair, 203-04. The geostatistical model creates a number of realizations of the geology but for simulation purposes the most likely realization was selected.

The SAGD grid model was imported into a dynamic reservoir simulator and the model was downsized from three well pairs to one well pair for test runs (i.e. 203-04, to simulate SAGD only). Through several initial runs, the model thickness, facies descriptions, petrophysical properties, grid sizes, relative perm abilities, fluid properties, thermal properties, wellbore parameters and numerical parameters were examined to ensure that they were in the practical ranges. When satisfactory SAGD match results were obtained from 203-04, the model was expanded laterally into a dual well pair model to include one of the SAGD+™ well pairs 203-02/203-03.

Reasonable matches were obtained and with the experience gained, the geology and wellbore sections were modified to set up a new model for well pairs 203-02 and 203-03. The simulation process was repeated.

Without significant changes, good history matches were obtained for the 203-03 and the 203-02 well pairs. The repeatability indicates that the model parameters were valid. Subsequently, the history match run was updated periodically with new production data to further verify its validity. For the purpose of the current paper only the 203-02/03 model results up to mid-May 2012 are presented.

Input

The model has a length of 800 m and a width of 200 m. It has a range of thicknesses from 35 m to 40 m (McMurray C to the Devonian). This thickness was chosen such that adjacent secondary and/or lean zones were included. Although these zones were of low quality and were not expected to contribute significantly to the bitumen production, they were important for simulating any "thief-zone" effects. Table 1 shows a summary of the model parameters.

Grid dimensions of 2m (width) by 1m (thick) by 50m (length) were selected based on a comparison study conducted during the early runs.

Three sets of input data were used to describe the specific reservoir and operational settings: geological parameters, wellbore configurations and well constraints.

To obtain a realistic geological description, Connacher used advanced geomodelling software to provide 3D descriptions of the reservoir. As discussed in the Geological Description section, the model takes into account all geological features observed in the vertical delineation and horizontal SAGD wells and applies a statistical technique to populate the model with facies and petrophysical information.

To simulate the wellbore effects, a coupled reservoir simulator was used that was capable of simulating the wellbore dynamics. The casings, liners, long and short injection tubings and long and short gas lift tubings were described based on the actual wellbore trajectories and configurations. It was decided that only the horizontal portions of the SAGD wells would be modeled because the incorporation of vertical/slant sections would slow down the runs and introduce other simulation uncertainties.

The following are the daily operational constraints specified at the injectors and producers:

**During Steam Circulation:**

- Long tubing steam rate
- Heel annulus pressure

**During SAGD and SAGD+™:**

- Injector short tubing steam/solvent rate
- Injector long tubing steam/solvent rate
- Producer heel annulus pressure
- Producer heel tubing pressure (estimated from the annulus pressure by assuming a tubing pressure drop)

These were the key parameters that were controlled either directly or indirectly by field operators on an on-going basis. While the steam rates were directly controlled, the producer wellbore pressures were indirectly controlled through the lift gas rate and choke back pressure.

During the early runs, an investigation was performed to compare two input methods: daily data and 5-day averaged data. The daily data case was found to provide more meaningful predictions and numerically more efficient than the 5-day averaged case. The daily method was therefore adopted.
Objective of the History Match

The objective of this simulation was to tune the reservoir properties and process parameters so that the model was capable of predicting field performance. At Algar, the closely monitored field performance parameters were:

**Bitumen/water production volumes**

In this study, the production rates, trends and cumulative volumes are considered to be equally important. A higher priority has been given to the bitumen production because (i) bitumen prediction is the primary concern, and (ii) the bitumen volumes are more accurately measured than the other flow volumes.

**Injector Bottom-hole Pressure**

At Algar, the injector heel pressures are determined from the injector blanket gas pressures. This is one of the most routinely monitored well pressure parameter. It is an indication of the steam chamber pressure.

**Solvent Recovery Volume**

The target solvent recovery for the history match was 85% based on field data.

**Key Process Variables**

A large number of sensitivities were conducted by varying the following reservoir and process parameters:

- Horizontal permeability
- Vertical permeability
- Initial oil and water saturation
- Critical water saturation
- Residual oil saturation to gas
- Residual oil saturation to water
- Relative permeability to water
- Relative permeability to gas
- Thermal capacity rock
- Thermal conductivity of rock
- Solvent k value
- Solvent viscosity
- Steam quality

Table 2 provides a brief summary of the observed sensitivities of each variable.

**Simulation Results**

Figure 16 and 17 show the rate and pressure matches for well pair 203-02. As of May 13, 2012, the predicted cumulative bitumen and water volumes are 55,828 and 178,751 m³, respectively. These are equivalent to 103% and 97% of the measured field production volumes, respectively. With no solvent injection, the model predicted that the bitumen production would be reduced by 4,565 m³. Thus, the model predicted that the incremental bitumen production from SAGD+™ would be 5.9 m³ of bitumen for each cubic metre of unrecovered solvent (18% as discussed below).

Figures 20 and 21 show the solvent injection and recovery rate comparisons. The model predicted 50 to 70% of solvent recovery during the injection period and an additional recovery of about 25% after the termination of solvent injection. The predicted cumulative recoveries from the 203-02 and 203-03 well pairs are 82% and 80%, respectively. These are slightly lower than the field estimate of 85%.

The above results are also summarized in Tables 3 and 4.

**Discussion**

The results presented in this paper represent the first field trial of Connacher's SAGD+™ process. The satisfactory volume and pressure matches indicate that the model is capable of simulating the recovery mechanisms. It also verifies that a relatively small amount of solvent can improve the performance of a conventional SAGD process.

The hydrocarbon solvent vapour is carried in the steam chamber at very low concentrations, and is greatly concentrated at the chamber edges where steam condenses (Figure 22). As the mole fractions of different hydrocarbon components increase, their corresponding partial pressures also increase. When the partial pressure of a hydrocarbon component reaches that of its saturation pressure, it starts to condense. The reduction in concentration of this component in turn causes the remaining molecules to reach their saturation pressures and thus trigger a chain of mole fraction changes in the vapour system. Eventually, all condensable molecules are condensed by cooling at the steam chamber edges. A comparison of the vapour solvent mole distributions in Figure 22 and the liquid solvent mole distributions in Figure 23 indicates that all solvent condensations occur within a short distance of the chamber edges.

Among the reservoir variables considered in this study, the relative permeability end points (see Table 5) and the thermal properties (see Table 6) are the most sensitive. They appear to be highly interdependent of each other and suggest that the mechanisms are very complex. In this study, relatively low water and gas end point relative permeability curves have been used. Low relative permeability values of water and gas are often seen in laboratory tests of heavy oil and oil sands cores.

The liquid phase viscosity of solvent shows a strong effect on the bitumen productivity. This is an area that needs further laboratory testing.

The history match model was used to provide predictions for subsequent SAGD+™ trials. It was also modified into a
simpler semi-homogeneous model for an optimization study of the process.

Conclusion
1. The first trial of Connacher's SAGD+™ project was successfully completed and favourable field results, including increased production and improved steam / oil ratios, were obtained from both well pairs. The results were sufficient to justify another trial and commercial evaluation.
2. A 3D geostatistics model was developed to provide valuable information for the assessment and visualization of the Algar reservoir.
3. A reservoir simulation model coupled with the wellbore was developed from the geomodel. A history match study was conducted to assess the SAGD+™ process. Satisfactory results were obtained.

Acknowledgement
The authors wish to thank Connacher Oil and Gas Limited for permission to publish this paper, Glenn Murdoch for providing valuable geological and geomodelling input and Declan Livesey for providing valuable engineering input to the study.

References
2. JOHNSON, M.D., HANSEN, L.A., LAU, T, PHENIX, T.J., BREEN, S.P., Production Optimization at Connacher's Pod One (Great Divide) Oil Sands Project; World Heavy Oil Congress, Edmonton, Alberta 2011, WHOC11-584

Table 1: 3D Model Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Top of McMurray C (m)</td>
<td>480 - 485</td>
</tr>
<tr>
<td>Top of Oil sand (m)</td>
<td>485 - 495</td>
</tr>
<tr>
<td>Bottom of Oil sand (m)</td>
<td>510 - 520</td>
</tr>
<tr>
<td>Average Porosity of Oil sand Pay</td>
<td>30%</td>
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<tr>
<td>Average Oil Saturation of Oil sand Pay</td>
<td>80%</td>
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<td>Top Gas (m)</td>
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<td>Bottom Water (m)</td>
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<tr>
<td>Average Horizontal Permeability (mD)</td>
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<tr>
<td>Average Vertical Permeability (mD)</td>
<td>454</td>
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<td>Initial Reservoir Pressure (kPa)</td>
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<td>Initial Reservoir Temperature (°C)</td>
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<tr>
<td>Initial Solution Gas-Oil Ratio (m³/m³)</td>
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Table 2: Summary of Variable Sensitivities

<table>
<thead>
<tr>
<th>Mode of Operation</th>
<th>Key Sensitive Variables</th>
<th>Comments</th>
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<tbody>
<tr>
<td>Steam Circulation</td>
<td>Critical water saturation</td>
<td>This parameter determines the amount of mobile water in the reservoir and thus affects the water leak off rate during steam circulation.</td>
</tr>
<tr>
<td></td>
<td>Thermal properties</td>
<td>This set of properties affect how fast the injector and producer communicates during steam circulation.</td>
</tr>
<tr>
<td></td>
<td>Steam quality</td>
<td>During the circulation period, steam delivered at the heels have lower qualities than during SAGD due to the heat transfers between injection and production tubings. The steam quality has a strong influence on how much of the reservoir is heated.</td>
</tr>
<tr>
<td></td>
<td>Vertical permeability</td>
<td>The vertical transmissibility was varied to match the fluid communication timing between the injector and producer. It also affects the injection pressure during ramp up.</td>
</tr>
<tr>
<td></td>
<td>Critical water saturation</td>
<td>This parameter has a strong effect on the amount of water produced.</td>
</tr>
<tr>
<td></td>
<td>Residual oil saturation to gas</td>
<td>This parameter determines the residual oil saturation in the steam chamber.</td>
</tr>
</tbody>
</table>
Residual oil saturation to water
This parameter, together with relative permeability end point, affects the bitumen rate and production stability.

Relative permeability to water
This parameter has a strong influence on the bitumen rate and production stability.

Relative permeability to gas
This parameter also has a strong influence on the bitumen rate and production stability.

Thermal properties
The thermal properties have a strong influence on the heat distribution and thus are significant in obtaining the steam-oil ratio match.

Steam quality
Steam is generated at 100% at the generators. Certain losses are anticipated. The steam quality is another variable used to match the steam-oil ratio.

Solvent
Solvent k value
The k value appears to have an inverse relationship with the solvent return. For the type of solvent studied, there is little influence on the incremental bitumen production.

Solvent viscosity
This parameter contributes significantly to the incremental bitumen recovery.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Field Measurement</th>
<th>Model Prediction</th>
<th>Prediction Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Bitumen Volume (m³)</td>
<td>53991</td>
<td>55828</td>
<td>103.4%</td>
</tr>
<tr>
<td>Cumulative Water Volume (m³)</td>
<td>185002</td>
<td>178751</td>
<td>96.6%</td>
</tr>
<tr>
<td>Cumulative Solvent Injection (m³)</td>
<td>4299</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Cumulative Solvent Recovery (m³)</td>
<td>3654 +/- 10%</td>
<td>3526</td>
<td>82.0%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Field Measurement</th>
<th>Model Prediction</th>
<th>Prediction Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cumulative Bitumen Volume (m³)</td>
<td>46569</td>
<td>52217</td>
<td>112.1%</td>
</tr>
</tbody>
</table>

Table 4: Simulation Estimates of Incremental Bitumen

<table>
<thead>
<tr>
<th>Case</th>
<th>Cumulative Bitumen Volume (m³)</th>
<th>Cumulative Solvent Injection (m³)</th>
<th>Cumulative Solvent Recovery (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>History Match Case</td>
<td>55828</td>
<td>4268</td>
<td>3628 +/- 10%</td>
</tr>
<tr>
<td>Steam Only Case</td>
<td>51263</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Incremental Bitumen due to Solvent Co-Injection (m³)</td>
<td>4565</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Solvent Loss in History Match Case (m³)</td>
<td>773</td>
<td>-</td>
<td>-</td>
</tr>
<tr>
<td>Incremental Bitumen to Solvent Loss Ratio (m³/m³)</td>
<td>5.9</td>
<td>6.1</td>
<td></td>
</tr>
</tbody>
</table>

Table 5: Summary of History Match Variables

<table>
<thead>
<tr>
<th>Variable</th>
<th>Values</th>
</tr>
</thead>
<tbody>
<tr>
<td>Horizontal permeability (mD)</td>
<td>2361</td>
</tr>
<tr>
<td>Vertical permeability (mD)</td>
<td>1136</td>
</tr>
<tr>
<td>Thermal capacity of rock (J/m³·C)</td>
<td>1.70E+06</td>
</tr>
<tr>
<td>Thermal conductivity of rock (J/m·day·C)</td>
<td>7.56E+05</td>
</tr>
<tr>
<td>Thermal conductivity of oil (J/m·day·C)</td>
<td>1.30E+04</td>
</tr>
<tr>
<td>Thermal conductivity of water (J/m·day·C)</td>
<td>5.44E+04</td>
</tr>
<tr>
<td>Steam quality during circulation</td>
<td>2892</td>
</tr>
<tr>
<td>Steam quality during SAGD/Solvent</td>
<td>50%</td>
</tr>
</tbody>
</table>

Table 6: Summary of End Points

<table>
<thead>
<tr>
<th>Facies</th>
<th>Critical water sat.</th>
<th>Residual oil sat. to gas</th>
<th>Residual oil sat. to water</th>
<th>Water relative perm.</th>
<th>Gas relative perm.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clean Sand</td>
<td>10.0%</td>
<td>12.5%</td>
<td>12.5%</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>Sandy IHS</td>
<td>15.0%</td>
<td>20.0%</td>
<td>20.0%</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>IHS</td>
<td>25.0%</td>
<td>30.0%</td>
<td>30.0%</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>Muddy IHS</td>
<td>30.0%</td>
<td>40.0%</td>
<td>40.0%</td>
<td>0.01</td>
<td>0.04</td>
</tr>
<tr>
<td>Breccia</td>
<td>10.0%</td>
<td>15.0%</td>
<td>15.0%</td>
<td>0.01</td>
<td>0.04</td>
</tr>
</tbody>
</table>

Table 3: Measured Versus History Match Volume
Figure 1: Algar Horizontal Well pair Trajectory

Figure 2: Algar Project Injection & Production
### Zones Defined by VSh

<table>
<thead>
<tr>
<th>Zone</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Z1</td>
<td>(Sand): 0-10% fines</td>
</tr>
<tr>
<td>Z2</td>
<td>(Sandy IHS): 10-20% fines</td>
</tr>
<tr>
<td>Z3</td>
<td>(IHS): 20-50% fines</td>
</tr>
<tr>
<td>Z4</td>
<td>(Muddy IHS): 50-80% fines</td>
</tr>
<tr>
<td>Z5</td>
<td>(Mud): 80-100% fines</td>
</tr>
<tr>
<td>Z6</td>
<td>(Breccia): &gt;10% clasts</td>
</tr>
</tbody>
</table>

**Figure 3: Connacher McMurray Facies Definition**
Figure 4: Algar Type Log Showing Bottom Water
Figure 5: Petrophysical Analysis of Key Algar Well

Figure 6: Geomodel Sections Showing Grade
Figure 7: 203-03 Injector Configuration

Figure 8: 203-03 Producer Configuration
Figure 9: Algar Solvent Injection System

Figure 10: Algar Well Pad Production System
Figure 11: Algar Solvent Recovery System

Figure 12: Performance Results of SAGD+™ Well Pairs
Figure 13: Solvent Injection & Recovery Results

Figure 14: Cross Section of Model Along 203-02 Well Pair
Well Pair 203-03

Figure 15: Cross Section of Model Along 203-03 Well Pair

Figure 16: Well Pair 203-02 Rate Comparisons

Figure 17: Well Pair 203-02 Pressure Comparisons
Figure 22: Model Cross-Section Showing the Mole Fraction Distribution of Vapour Solvent

Figure 23: Model Cross-Section Showing the Mole Fraction Distribution of Liquid Solvent

Figure 24: Model Cross-Section Showing Mole Fraction Distribution of Liquid Solvent
Cap Rock Integrity - Actual Injection Pressure Pod One
Cap Rock Integrity - Actual Injection Pressure Algar

Recovery Processes
Great Divide SAGD Recovery Processes
Pressure Balancing Under a Top Gas & Lean Zone
Pressure Balancing over Bottom Water in Algar

Developing Technologies
Gas Co-Injection
Re-Pressure Pod One Gas Cap
Re-Pressure Pod One Gas Cap
SAGD +TM

Completions & Artificial Lift
Injector Completion
Producer Gas Lift Completion
Producer Mechanical Lift
Improved Well Bore Design
Improved Well Bore Design
Injector Wellbore Cup Tool
Liner Slotting Programs

Great Divide Artificial Lift Performance
Low Pressure SAGD & Pumps
Pump Experience at 101N

Great Divide Gas Migration & Surface Casing Vent Flows
Monitoring
Pod One Observations Wells
Pod One - Typical Observations Well Configuration
Pod One Observations Wells - Gas Cap Monitoring

Algar Observations Wells
Algar Temperature Observation 9-13-82-12W4
Algar Temperature Observation 15-13-82-12W4
Algar Pressure Observation 4-19-82-11W4
Algar Pressure Observation 1-24-82-12W4
Algar Pressure Observation 16-13-82-12W4
Pod One & Algar Ground Movement Monitoring
Pod One 4D Seismic
Pod One 4D Seismic (contd)
Well Performance
Pod One & Algar Well Layout
Pod One Performance
Algar Performance
Pod One Performance - Pad Production & Injection
Algar Performance - Pad Production & Injection
Great Divide Performance - Cum Production by Pad/Well
Great Divide Performance - CSOR by Pad
Great Divide Performance - Recovery OBIP by Pad
Great Divide Performance - Well Summary
Great Divide Performance - Steam In / Water Produced
Great Divide Performance - Recoverable Bitumen by Pad
Future Reservoir Developments
Future Developments - Pad 104
Future Developments Infill Wells Pad 102W
Future Developments - Great Divide Expansion
Future Developments - Great Divide Expansion (2)
Facilities
Pod One Plant
Algar Plant
Pod One Facilities
Algar Facilities
Great Divide Plant Modifications
Pod One Process Schematic
Algar Process Schematic
Pod One Plant Layout
Algar Plot Plan
Algar & Pod One Integration
Pod One MARP
Appendix C - Algar Geological Sections

Geology - Algar Layout & Sections
Geology - Algar Pad 201 East
Geology - Algar Pad 201 West
Geology - Algar Pad 202 East
Geology - Algar Pad 202 West
Geology - Algar Pad 203 East
Geology - Algar Pad 203 West

Appendix D - Individual Well Performance

Individual well Performance
Pod One Pad 101N Individual Well Performance
Pod One Pad 101S Individual Well Performance
Pod One Pad 102S Individual Well Performance
Pod One Pad 102W Individual Well Performance
Algar Pad 201S Individual Well Performance
Algar Pad 202S Individual Well Performance
Algar Pad 203S Individual Well Performance

Appendix D - Great Divide Artificial Lift Performance

Technical Papers

Pressure Balancing Under a Gas Cap
Steam Solvent (SAGD)