HANGINGSTONE 2013

Thermal In-Situ Scheme Progress Report

Approval Nos. 8788I (Demonstration)
11910A (Expansion)

Presented On: February 5, 2014
1. Background - Hangingstone
   - Demonstration
   - Expansion

2. Subsurface
   - Geology – Net Pay & Reservoir Structure
   - Seismic & Geomechanical Learnings
   - Well Design & Instrumentation
   - Reservoir Performance

3. Surface Operations
   - Facility Design
   - Facility Performance
   - Measurement & Reporting
   - Water:
     - Source
     - Disposal
   - Other wastes
   - Sulphur emissions
   - Environmental (included but not presented)
   - Compliance Statement & Approvals
   - Future Plans

4. Discussion
Demo Scheme No. 8788I Background

**Plant 1**
- On original PCEJ CSS Site
- Startup 1999 – 2,000 bbl/day (320 m³/day)

**Plant 2**
- Phase 2 Facility, startup 2000 - 4,000 bbl/day (640 m³/day)
- Phase 3 Facility, startup in 2002 - 4,000 bbl/day (640 m³/day)

**Wells & Pads**
- Pad 1: A, B (startup 1999)
- Pad 2: C, D, E (startup 2000)
- Pad 5: T (startup 2007); R, S (2008); U startup Nov 2010; V&W drilled in 2011; (W started circulation in May 2013 and put on SAGD in August 2013)
- Pad 6: X started in May 2010 (ESP started in Dec); Y started circulation Nov/11 (Y well ESP started in Feb 2013)

- Project located 50 km south of Fort McMurray
- Approved demonstration project area: 3.75 sections
- Approved production capacity: 11,000 bbl/day (1,760 m³/day)
Expansion Scheme No. 11910 Background

- Scheme Approval – Nov/2012
- EPEA Approval – Jan/2013
- Approved Capacity – 30k bpd
- Commenced early civil works – Feb 26/2013
- Commenced drilling – Aug 27/2013
- Drilling progress to date – WP01: 5 well pairs; WP03: 3 well pairs
- Start of mechanical construction – Feb/2014 (piperack piling)
- Start Up (first steam) – scheduled for Q2 2016
Geosciences
Demo - Well & 3D Seismic Data
Net Pay Thickness > 15 m
Average Phi = 30%
Average So = 85%
Demo - Base Reservoir Structure
Demo - Top Reservoir Structure
Demo - Composite Well Log

AA/02-34-84-11W4
KB: 563.3m
Expansion - Well & Seismic Data

- DEMO PROJECT AREA
- PROJECT AREA
- APPROVED DEVELOPMENT AREAS
- 3D SEISMIC SURVEY AREAS
- 2008 3D SURVEY
- 2007 3D SURVEY
- McMurray Core
- 2012-2013 OV

HANGINGSTONE LEASE BOUNDARY

HANGINGSTONE EXPANSION PROJECT
Expansion – Base Reservoir Structure
Expansion – Top Reservoir Structure
Expansion – Type Well (1)

DEPLETION AREA B1
1AA/02-22-84-11W4M

- Wabiskaw Member
- Wabiskaw Sand
- MCMURRAY FM
  - MCM A1
  - MCM A2
  - MCM B1
  - MCM B2
  - MCM C
- Nonreservoir Interval
- SAGD Reservoir Interval
- WATERWAYS FM

Legend:
- Clean Sand
- Sandy IHS
- Muddy IHS
- Shale
- Mud-Clast Breccia

17
DEPLETION AREA BE-N
1AA/04-24-84-11W4M

- Wabiskaw Member
- Wabiskaw Sand
- MCMURRAY FM
- Nonreservoir Interval
- SAGD Reservoir Interval
- WATERWAYS FM

Legend:
- Clean Sand
- Sandy IHS
- Muddy IHS
- Shale
- Mud-Clast Breccia
Geology – Future Plans

27 Well Pairs Drilled
2014 - Q1 2015
Geomechanical Related Issues and Learnings

• Initial determination of injection pressures was based on mini-frac tests in 1980s
• 2010 Mini-frac test for Hangingstone Expansion (HE) Project Cap Rock Integrity Study shows consistent results

<table>
<thead>
<tr>
<th>Depth, m</th>
<th>Min. stress</th>
<th>Vert. stress</th>
<th>Stress regime</th>
</tr>
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<tbody>
<tr>
<td></td>
<td>MPa</td>
<td>kPa/m</td>
<td>MPa</td>
</tr>
<tr>
<td>McM Sands</td>
<td>327.0</td>
<td>5.59</td>
<td>17.09</td>
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<td>McM Shale</td>
<td>314.5</td>
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<tr>
<td>WBSK Shale</td>
<td>297.0</td>
<td>6.17</td>
<td>20.77</td>
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<tr>
<td>CWTR shale</td>
<td>272.0</td>
<td>5.39</td>
<td>19.82</td>
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</table>

• HE Project Cap Rock Study concluded 5 MPa to be a safe operating pressure (80% of fracture pressure)
• No cap rock integrity issues have been observed at Demo since 1999 start up
• Ongoing sand production in some wells, but manageable through:
  - Stable operation
  - Higher subcool
• Bottom pressure is regularly measured by purging the annulus with gas; utilizing it as a bubble tube and recording the pressure.
Surface Heave

Network of 54 monuments

Maximum heave during period 2012-2013: 29.3 mm

Cumulative Heave 1999-2013: 332 mm
Max Slope: 0.066%

- Modeling predicted max heave of 400mm over the life of the project; max slope 0.12%
  - within structural design tolerances for surface facilities
- Measured heave thus far within predicted limits
- No concerns observed
- 24 active well pairs
  - “oldest” wells A/B, started up in July 1999
  - “youngest” wells V and W, started up in July 2012 and May 2013 respectively
- F-Well abandoned in July 2003
- W-Well was started up Q2-2013 (delayed due to steam constraints)
### SAGD Well Completions

#### Typical Injector
- 406 mm (16") Conductor Casing
- 245 mm (9 5/8") Intermediate Casing
- 177.8 mm (7") Tie-Back Casing
- 177.8 mm (7") Liner w/ Screens
- 114.3 mm (4 1/2") Tubing

#### Typical Producer
- 406 mm (16") Conductor Casing
- 245 mm (9 5/8") Intermediate Casing
- 177.8 mm (7") Tie-Back Casing
- 177.8 mm (7") Liner w/ Screens
- 114.3 mm (4 1/2") Tubing

### Well Completions Table

<table>
<thead>
<tr>
<th>Wellpair</th>
<th>Tie-Back</th>
<th>Liner Size</th>
<th>Screen Type</th>
<th>4-1/2&quot; Tubing</th>
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<tr>
<td></td>
<td>Yes/No</td>
<td>7&quot;</td>
<td>8-5/8&quot;</td>
<td></td>
</tr>
<tr>
<td>A</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
</tr>
<tr>
<td>B</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
</tr>
<tr>
<td>C</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
</tr>
<tr>
<td>D</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
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<tr>
<td>E</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
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<td>H</td>
<td>Yes</td>
<td>P</td>
<td>I</td>
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<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
</tr>
<tr>
<td>J</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
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<td>K</td>
<td>No</td>
<td>VP</td>
<td>-</td>
<td>I/P</td>
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<td>L</td>
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<td>VP</td>
<td>-</td>
<td>I/P</td>
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<td>O</td>
<td>Yes</td>
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<td>VP</td>
<td>-</td>
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<tr>
<td>V</td>
<td>Yes</td>
<td>P</td>
<td>I</td>
<td>Failed Liner - 4-1/2&quot;WWS</td>
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<td>P</td>
<td>I</td>
<td>-</td>
</tr>
<tr>
<td>X</td>
<td>Yes</td>
<td>VP</td>
<td>-</td>
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<tr>
<td>Y</td>
<td>Yes</td>
<td>-</td>
<td>I/P</td>
<td>Failed Liner - 5-1/2&quot;WWS</td>
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<tr>
<td>Z</td>
<td>No</td>
<td>P</td>
<td>I</td>
<td>SCVF - 7&quot; Cement to Surface</td>
</tr>
</tbody>
</table>

I = Injector Well
P = Producer Well

**Note:** The table entries include various combinations of Yes/No for Tie-Back, Liner Size options, and Screen Type options for the 4-1/2" Tubing. The Typical Producer configurations also feature additional details regarding specific liner types and tubing options.
SAGD Well Completions

- 1999-2004 MeshRite/wire wrap – Limited technology available for “SAGD” applications
  - Isolated cases of sand production

- 2005-2010 Slotted Liner – Commercial emergence of technology, lower cost alternative
  - Good sand control
  - High pressure drops

- Hangingstone Expansion design – Straight cut slots on injectors / MeshRite and wire wrap on producers
  - Decision based on
    - Operating experience at DEMO operations
    - Thorough testing program and strength evaluations
    - Cost analysis
• SAGD start-up in Feb 2012
• Liner failure (sand production / plugged well off) Nov 2012
• Well Workover Dec 2012 – Jan 2013
  – Installed scab liner w/ 0.005” Wire-Wrapped-Screen
• Well back on production w/o any solids production
SAGD Well Completions – HZZP SCVF Repair/ Workover

- SAGD start-up in Nov 2008
- SCVF (Well shut in) Nov 30, 2012
- Well Workover Jan – Feb 2013
  - CASTM-CBLM & Temp logging, Perforate 9-5/8” Intermediate casing and Cement Squeeze, 7” casing cemented to surface, Liner cleanout to toe, Re-complete well.
• SAGD start-up in July 2012
• Liner failure (sand production / plugged well off) June 2013
  - Evidence of washed out liner; hole in tubing string, caliper log on liner showed deformation at the same point of the tubing failure
• Well Workover Aug – Oct 2013
  - Installed one 7” casing patch, issues with casing patch setting tool
  - Installed scab liner w/ 0.005” Wire-Wrapped-Screen
  - Scheduled startup Q1/Q2 2014
Contributing factors which resulted in “challenging” workovers

• JACOS DEMO operates at high injection pressures (≈4500kPa) resulting in downhole pressures higher than hydrostatic head

• Failed wells are in communication with adjacent wells making it difficult/impossible to de-pressure the reservoir

• Specialized brine (up to 1.5 density) was required to weight-up the column to preform workover
  - Well control was difficult due to fluctuating downhole pressures; well took kill fluid
Artificial Lift

- **HZXP** – Schlumberger Hotline 550 (218°C)
  - 1\(^{st}\) ESP pump installed Dec/10 – April/12 (Run Time 487D, Surface Connector Failure).
  - 2\(^{nd}\) ESP system installed May/12– June/13 (Run Time 381D, Surface Connector / Electrical Cable Failure).
  - 3\(^{rd}\) ESP pump installed July/13.
    - Operating Temperatures up to 170°C
    - Pump Pressure – 2000-2300kPa
    - Production rate \(\approx 200\text{m}^3/\text{D}\)
    - SOR \(\approx 2.5\)

- **HZYP** – Schlumberger Hotline SA3 (250°C)
  - Pump installed Jan 2013, online Feb 2, 2013
    - Operating Temperatures up to 175°C
    - Pump Pressure – 2000-2800kPa
    - Production rate \(\approx 120\text{m}^3/\text{D}\) (Reduced rates due to high \(\Delta P\))
    - SOR \(\approx 3.1\)
HZXP/HZYP ESP trial was initiated to test downhole pumps at the DEMO Operations.

The location of the wells was chosen due to the fact the wells are relatively isolated from the adjacent high pressure wells. The adjacent well (W) was the last well to be brought on stream.

Eventually when X/Y steam chamber coalesces with W-Well, X/Y will be converted to “natural lift” SAGD wells.
Thermocouple Placement on SAGD Wells

Instrumentation in Wells

Wells A, B
Injector

Wells C, H
Injector

Wells D, E, I
Injector

Wells J, K, L, M, N, O, P, Q, R, S, T
Injector

NO THERMOCOUPLES

Wells U, V, W, Y
Injector

NO THERMOCOUPLES
Instrumentation in HZX (ESP) Well

- HZXI – 6 Thermocouples
- HZXP – 40 Point LX-Data Temperature, LX-Data Pressure
- ESP – Single Point LX-Data Temperature, LX-Data Pressure
• T/Cs provide comparable temperature trend with a non-uniform profile similar to that from the high definition LX-Data
• T/Cs miss high points between TC#2 / TC#3 and TC#4 / TC#5
• With two points of injection and one point of production the response to both temperature profiles would be the same; reduce injection to toe, potentially move position of scab liner (intake point)
Reservoir
Reservoir Performance Summary

- Currently producing 24 SAGD well pairs
- 2013 average bitumen rate ~ 5,944 bbl/day (945 m³/day)
- Cumulative bitumen produced from project startup to 12/31/2013 ~ 30.6 million bbl (4.9 million m³)
- Cumulative SOR to 12/31/2013 ~ 3.7
- OBIP for the developed area is 78 million bbl (12 million m³)
- Recoverable bitumen is estimated at 48 million bbl (7.6 million m³) (61% Ultimate Recovery)
Generic Production Curve Method for bitumen production

- SAGD well life consists of build up period, plateau period and decline period.
- Plateau rate is calculated as a function of effective net thickness.
Typical Performance of Bitumen Rate

- **Buildup Period**
- **Plateau Period**
  - End of Plateau Period = \( \frac{1}{2} \) of Reserves Recovered
- **Decline Period**

Cumulative production = Reserves

Production Period (Years)
Well performance prediction (SOR)

- A linear trend is adopted to describe the SOR performance.
- The initial SOR in the demo area has been evaluated as a function of effective net thickness. The initial SOR is classified into four categories of net thickness.
  - 10, 15, 20, 25m
- The increasing ratio with time is from simulation results.
  - 0.025/month
- The actual trend is close to this prediction.
Typical Performance of Instantaneous SOR

Buildup Period

Plateau Period

Linear Trend

Decline Period

Production Period (Years)
Typical Performance of Bitumen Rate

Wells with History

End of Plateau Period = ½ of Reserves Recovered

Cumulative production = Reserves

Production Period (Years)

Bitumen Rate

History ↔ Forecast

Wells with History
**Typical Performance of Bitumen Rate**

**Wells with History**

- **History** ↔ **Forecast**

Update decline based on actual trend

**Cumulative production = Reserves**
Typical Performance of Instantaneous SOR

Wells with History

Well Life is based on the Performance of Bitumen Rate

Instantaneous SOR

Production Period (Years)

History

Forecast

Linear Trend
• Decline method
  – Adopted to well groups (A to Q pairs) that have enough production history to estimate the decline
  – The steam chambers from the well pairs in this group have merged or will merge in the future (Steam chamber between J well and O well have a communication since 2011.)
  – Though there is no observation well between A & M well pairs, the calculated drainage areas (inverted cone) based on cumulative bitumen production showed communication (drainage areas overlap – shown on slide 15)
  – A trend that reflects the stable operating period in both bitumen production and SOR is picked for the forecast with assumption that reservoir pressure will be relatively constant (fluctuation in pressure may exist due to marketing of bitumen and gas supply)
Production forecast for A - Q patterns – Decline Methodology

- Decline predicted from A – Q well pair production history

Bitumen and Instantaneous SOR Forecast : A-Q Pairs

These data are production rate in steady production condition. The data which were measured during turn around or other production interruption event are eliminated production rate.
## Cumulative Reservoir Statistics (to 12/31/2013)

<table>
<thead>
<tr>
<th>Start Year</th>
<th>Well Pair</th>
<th>Original Bitumen in Place (Mm3)</th>
<th>Cumulative Bitumen Produced (Mm3)</th>
<th>Current Recovery (%)</th>
<th>Ultimate Recovery (%)</th>
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<tbody>
<tr>
<td>1999</td>
<td>A, B, C, D and E</td>
<td>2,990</td>
<td>1,750</td>
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<td>2002</td>
<td>H, I, J and K</td>
<td>2,150</td>
<td>1,370</td>
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<td>2004</td>
<td>L, M and N</td>
<td>1,500</td>
<td>730</td>
<td></td>
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<td>2005</td>
<td>O, P and Q</td>
<td>1,230</td>
<td>460</td>
<td></td>
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<td>2007</td>
<td>S and T</td>
<td>1,130</td>
<td>260</td>
<td>23%</td>
<td>58%</td>
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<tr>
<td>2008</td>
<td>R and Z</td>
<td>850</td>
<td>180</td>
<td>21%</td>
<td>44%</td>
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<tr>
<td>2010</td>
<td>U and X</td>
<td>990</td>
<td>90</td>
<td>9%</td>
<td>55%</td>
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<tr>
<td>2012</td>
<td>Y and V</td>
<td>940</td>
<td>20</td>
<td>2%</td>
<td>54%</td>
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<tr>
<td>2013</td>
<td>W</td>
<td>570</td>
<td>3</td>
<td>1%</td>
<td>55%</td>
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<tr>
<td><strong>Total</strong></td>
<td></td>
<td><strong>12,350</strong></td>
<td><strong>4,863</strong></td>
<td><strong>39%</strong></td>
<td><strong>58%</strong></td>
</tr>
</tbody>
</table>
Net Pay Map

M-well estimated Drainage area (Cumulative Bitumen: 370Mm3)

A-well estimated Drainage area (Cumulative Bitumen: 600Mm3)
OBIP Calculation methodology and assumptions

- OBIP = Bulk volume x Porosity x Oil Saturation (So)
- Bulk volume = Net Pay Thickness x Chamber Width x Chamber Length
- Chamber Length = Well Length + 50-60m at each end of well
- Average porosity = 30%
- Average So = 85%
- Chamber Width (W) = 100-190m
- Chamber Length (L) = 540-850m
- Net Pay Thickness (H) = 15.5-26.0m
Bitumen and Steam outlook in next 5-year
Example of the well performance (high performance)

Recovery factor at the end of 2013: 62.2%

B-well: Shut-in
B-well: Re-production

Well Performance History [AB Wells]

Bitumen, Steam, Water Rate (m³/D)

SOR

Jan-99 Jan-00 Jan-01 Jan-02 Jan-03 Jan-04 Jan-05 Jan-06 Jan-07 Jan-08 Jan-09 Jan-10 Jan-11 Jan-12 Jan-13 Jan-14
Comments for A and B wells

- These wells have approximately 13 years history and still maintain economic performance.
- These two wells produced ~ 5.4 MMbbl (0.86 million m³) of bitumen and CSOR ~ 3.7
- The steam chambers for the A and B wells have been communicating since late 2001.
- The injection pressure of B is usually maintained higher than A, thereby sweeping bitumen from B to A. B well is a steam donor.
- A pair is unbounded on the west side. Most of the bitumen in this area is expected to be recovered through the sweep between M and A wells. (M at higher pressure)
- NCG co-injection on A, B, and C - E well pairs has been conducted since Jun. 2012.
Example of the well performance (medium performance)

Recovery factor at the end of 2013: 48.3%
Comments for J well

- J pair has maintained good performance over the past year.
- The bitumen production profile appears to be following the typical build up, plateau, and decline periods.
- Well produced ~ 2.1 MMBBL and CSOR ~ 3.0
- The decline rate has moderated in the last 1-3 years.
- The J pair is in communication with the I pair to the south.
- The J pair started communication with the O pair in 2011 to the north and some steam is provided to the O well from J.
Example of the well performance (low performance)

Recovery factor at the end of 2013: 27.5%
Comments for N well

- Actual bitumen production is lower than expected (150m$^3$/d).
- Well produced ~ 0.7 MMBBL and CSOR ~ 3.6
- Potential reasons for this low productivity are:
  - The reservoir along the HZ well contains clast facie and the facie prevents the steam chamber growth. Thermocouple data in the producer indicates that steam chamber growth on toe side is poor; likely due to clast facies at the toe end.
  - Steam corning induced sand production. This well has been controlled by production rate which prevents sand in flux. This option enables the N well to produce steadily.
Example of the well performance with ESP

Well Performance History [X Wells]

Recovery factor at the end of 2013: 10.9%
Comments for X well

- First well with ESP test in the field.
- Well produced ~ 0.4 MMBBL and SOR ~ 2.7
- X pair has maintained good performance since an ESP was installed to operate at low pressure (in December, 2010).
  - Maintained bitumen production
  - Reduced steam rate, which was free to be redeployed into other wells to maximize the total bitumen production from the facility, providing a very efficient way of adding low cost barrels.
  - Reduced SOR
- The second ESP failed in June 2013 (398 days in service) due to control line failure resulting in a short. The third ESP has been installed and running since July 2013. (Ref. : First ESP life : 487 days)
HZYP Production History

- SAGD start-up in Feb 2012
- Sand production observed early in production life
- Liner failure (sand production / plugged well off) Nov 2012, well workover
- Rate control to minimize sand production, flow between toe and heel attempted
- Slowly ramping up production from the well
Drilled and completed in August 2011
Started steaming May 2012
Circulation took place over 2.5 months
Normal production started in Oct 2012

Ramp-up phase was as expected
Severe sand production observed in early February 2013. Well shut-in by mid February 2013 due to severe sand production.
A look back showed temperature spike occurred in Dec 20\textsuperscript{th}, 2012
Location of the liner breach was at 694 md, below the IHS penetrated by the injector.
W Well Summary

Drilled and completed in August 2011
Started steaming May 2013
Circulation took place over 2.5 months
Normal production started in August 2013

Ramp-up phase was carefully monitored based on V well learning
Temperature spike occurred at thermo-couple TC2 (810 md), which is below the IHS penetrated by the injector.
Operation of this well is carefully monitored to prevent severe coning into the well
Non-condensable Gas Co-injection to A - E Well Pairs

- NCG co-injection commenced in June 2012.

- Target NCG rate is around 1 mol% for each well pair.
  A,E Well: 1500 (sm$^3$/D)
  C Well: 2500 (sm$^3$/D)
  B,D Well: 4000 (sm$^3$/D)

- NCG co-injection was occasionally interrupted due to surface facility operational problems, including:
  - Low supply pressure on the fuel gas line (Trans Canada)
  - Production cutback due to transportation issues
  - Plant turnaround
Non-condensable Gas Co-injection to ABCDE Well Pairs

NGC Co-injection Performance (Jan 2013 - Jan 2014)

- NCG Co-injection
- TCPL Gas Supply Disruption

Graph showing:
- Total Steam
- Total Prod Fluid
- Total Bit
- Total injection gas
- Weight ave Inj Press (kPa)

Rate (T/D)

Time:
- Jan-13
- Feb-13
- Mar-13
- Apr-13
- May-13
- Jun-13
- Jul-13
- Aug-13
- Sep-13
- Oct-13
- Nov-13
- Dec-13
Non-condensable Gas Co-injection to ABCDE Well Pairs

A-E NCG Co-Injection History (Injection and Recovery rate)

- **NCG Injected**
- **NCG Recovered**
Non-condensable Gas Co-injection Plan to ABCDE Well Pairs

- Short Term Plan
  - Stop NCG Injection to A-E
    - The recovery of TransCanada gas pipeline which is restricting some supply gas rate to JACOS
    - Getting base line (stable CH4/CO2 component without NCG Injection, those are used to estimate the ratio of NCG recovered in total produced gas from reservoir) for the preparation of A-Q NCG Co-Injection
  - A-Q NCG Co-Injection
    - Waiting for AER approval to commence H-Q NCG Co-Injection

<table>
<thead>
<tr>
<th></th>
<th>A</th>
<th>B</th>
<th>C</th>
<th>D</th>
<th>E</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam Rate [T/D]</td>
<td>220</td>
<td>230</td>
<td>140</td>
<td>170</td>
<td>130</td>
</tr>
<tr>
<td>Steam Injection Pressure [kPa]</td>
<td>4710</td>
<td>4680</td>
<td>4670</td>
<td>4700</td>
<td>4680</td>
</tr>
</tbody>
</table>

- Long Term Plan
  - Target NCG rate is around 1 mol% for each well pair
    - A,E Well: 1500 (sm³/D)
    - C Well: 2500 (sm³/D)
    - B,D Well: 4000 (sm³/D)

History from Dec-2013 to Jan-2014
Heat conduction continuously occurs above the steam chamber (TC1-TC13) and below injector (TC 19-24) – Temp. keeps increasing. Cooling at top of steam chamber (TC14) observed during gas co-injection period due to partial pressure effect.
TCs located at top of the steam chamber show partial pressure effect (chamber top temperature (TC14) dropped 4°C).
Learning from Non-condensable Gas Co-injection to A-E well

- Able to maintain injection pressure with less steam.

- A portion of the injected NCG remained at the top of the steam chamber during the injection period, acting as an insulation layer, and reducing the heat loss to the overburden.

- Bitumen production was on the natural decline trend, no evidence of impairment to bitumen production due to gas accumulation at the top of the steam chamber.

- The amount of saved steam was evaluated to be in the range of 100~150m$^3$/D at an injection rate of 13,500m$^3$/D, and steam injection fluctuate the NCG co-injection period.
  - Saved steam was used to start new wells (W well) to maximize the total bitumen production from the facility.

- From steam cost point of view, equivalent steam calculation shows that gas co-injection is cost neutral.
  - Lower emission as a result of lower steam consumption is also beneficial.
• Phases 3 & 4 are thermally matured
  – Production from phase 3 wells started in December 2001
  – Production from the last wells in phase 4 started in August 2005
  – Temperature observation wells show full steam chamber development
  – Fluid communication between the wells observed between the phases 3 & 4 and presented below.
Communication Phases 3 & 4 Examples

- **J pair – O pair**
  - O-well steam injection pressure started increasing from Mar-2010 along with net fluid due to the inflow from J-well

- **H pair – K pair**
  - K-well steam rate decreased when H-well steam injection became higher than K-well in Aug-2008, as pressure increased in both pairs (production started in 2002)

- **O pair – P pair**
  - P-well production rate increased after cutback of O-well production rate from Apr-2012; support from J pair

- **L pair – N pair**
  - N-well steam injection rate was lower (should be higher) with increased injection pressure; N-well production rate was stable though steam injection rate was lower and fluid imbalance observed in L-well. These phenomenon suggest the flow from L-pair to N-pair (production started in 2004)
• Phases 3 & 4 are thermally matured – fluid communications observed
• Based on the positive experience from A-E co-injection, JACOS would like to expand the NCG co-injection to the thermally matured area of the fields (i.e. phases 3 & 4).
• Application was submitted last year and is still pending with the board
Steam Injection (Temperature, Pressure, Quality)

Daily Average
Pressures and Temperatures
2013

<table>
<thead>
<tr>
<th>Well</th>
<th>Pressure (kPa)</th>
<th>Temperature (°C)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A Well</td>
<td>4580</td>
<td>259</td>
</tr>
<tr>
<td>B Well</td>
<td>4665</td>
<td>261</td>
</tr>
<tr>
<td>C Well</td>
<td>4618</td>
<td>260</td>
</tr>
<tr>
<td>D Well</td>
<td>4680</td>
<td>261</td>
</tr>
<tr>
<td>E Well</td>
<td>4623</td>
<td>260</td>
</tr>
<tr>
<td>H Well</td>
<td>4775</td>
<td>262</td>
</tr>
<tr>
<td>I Well</td>
<td>4791</td>
<td>262</td>
</tr>
<tr>
<td>J Well</td>
<td>4678</td>
<td>261</td>
</tr>
<tr>
<td>K Well</td>
<td>4701</td>
<td>262</td>
</tr>
<tr>
<td>L Well</td>
<td>4819</td>
<td>262</td>
</tr>
<tr>
<td>M Well</td>
<td>4682</td>
<td>260</td>
</tr>
<tr>
<td>N Well</td>
<td>4643</td>
<td>259</td>
</tr>
<tr>
<td>O Well</td>
<td>4479</td>
<td>259</td>
</tr>
<tr>
<td>P Well</td>
<td>4319</td>
<td>256</td>
</tr>
<tr>
<td>Q Well</td>
<td>4244</td>
<td>256</td>
</tr>
<tr>
<td>R Well</td>
<td>4860</td>
<td>263</td>
</tr>
<tr>
<td>S Well</td>
<td>4729</td>
<td>262</td>
</tr>
<tr>
<td>T Well</td>
<td>4798</td>
<td>263</td>
</tr>
<tr>
<td>U Well</td>
<td>4750</td>
<td>261</td>
</tr>
<tr>
<td>V Well</td>
<td>4124</td>
<td>259</td>
</tr>
<tr>
<td>W Well</td>
<td>4303</td>
<td>254</td>
</tr>
<tr>
<td>X Well</td>
<td>2854</td>
<td>234</td>
</tr>
<tr>
<td>Y Well</td>
<td>3495</td>
<td>245</td>
</tr>
<tr>
<td>Z Well</td>
<td>4201</td>
<td>254</td>
</tr>
<tr>
<td>Average</td>
<td>4475</td>
<td>259</td>
</tr>
</tbody>
</table>

100% Steam Quality* @:
HZA, HZB, HZC, HZD, HZE
Average Steam quality for the remaining wells ~ 97%

* Steam Traps @ Phase 1&2 Wellheads
Future Plans

- Lower pressure operation
- NCG Injection for the next group of thermally matured well pads once approval is obtained.
Surface Operations
Facility Performance
2013 Service Factor – 91%

Operations interruptions are described in two categories

- Planned Plant Turnarounds
  - Major – April 2013
    - Vessel inspections, PSV maintenance, process equipment cleaning, meter calibration/checks, boiler pigging, various repairs
  - Minor – October 2013
    - Boiler pigging, HTS cleaning, corrosion coupon installation
- Contributed 4% of downtime
- Transportation/Utility Restrictions
  - Limitations in the following
    - Markets
    - Road access
    - Natural gas supply
- Contributed 5% of downtime
Facility Performance

- Bitumen Treatment
  - HTS and LPS
    - Bitumen off HTS contains about 1-2% water, remaining water is flashed off in LPS

- De-oil Train
  - Consists of Skim tank, IGF, and Oily Water Filters
    - Each stage should remove 90% of the oil content

- Vapor Recovery
  - Produced gas from all SAGD wells and Plant II HTS/LPS recovered and utilized for fuel gas
  - Fuel gas used for purge in the tank farms is recovered at the VRU (Vapor Recovery Unit) and utilized for fuel gas
Facility Performance

- Zero liquid discharge
  - not able to produce salt due to produced water organics
  - disposing some concentrated brine offsite & blowdown to disposal wells

- Higher SOR than designed
  - has limited the bitumen production capacity (plant is steam limited)

- Higher GOR than designed
  - have upgraded vapor header from wells & installed gas recovery

- Heat exchanger efficiency
  - lower than design, resulting in lower BFW temperature

- Water quality
  - dissolved organics not anticipated in design
  - lower steam quality and less blowdown recycle than designed
Water treatment at JACOS's two plants performed well and met the boilers' requirements in 2013. The boiler feed water had an average quality of TDS, silica and hardness as shown as in the table below.

O2 Measurement in BFW – 15ppb

Average Rate / Design through HLS in 2013 was 106%.

![Table 1. Tested water treatment performance and boiler feed water quality in 2013](image)
**Steam Generation**

- Plant 1 – B-201A/B – 50MMBtu Boilers
- Plant 2 – B510/520 – 180MMBtu Boilers
  - B540 – 50MMBtu Boiler

<table>
<thead>
<tr>
<th></th>
<th>2013 Steam Volume (m³)</th>
<th>2013 Steam Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>B-201A/B</td>
<td>B-510/520</td>
</tr>
<tr>
<td>January</td>
<td>25,697</td>
<td>83,782</td>
</tr>
<tr>
<td>February</td>
<td>25,362</td>
<td>92,823</td>
</tr>
<tr>
<td>March</td>
<td>27,340</td>
<td>107,196</td>
</tr>
<tr>
<td>April</td>
<td>26,383</td>
<td>51,637</td>
</tr>
<tr>
<td>May</td>
<td>26,295</td>
<td>99,656</td>
</tr>
<tr>
<td>June</td>
<td>24,510</td>
<td>94,298</td>
</tr>
<tr>
<td>July</td>
<td>25,916</td>
<td>98,190</td>
</tr>
<tr>
<td>August</td>
<td>27,569</td>
<td>106,265</td>
</tr>
<tr>
<td>September</td>
<td>25,925</td>
<td>102,717</td>
</tr>
<tr>
<td>October</td>
<td>28,244</td>
<td>94,957</td>
</tr>
<tr>
<td>November</td>
<td>26,927</td>
<td>92,038</td>
</tr>
<tr>
<td>December</td>
<td>26,565</td>
<td>84,437</td>
</tr>
<tr>
<td>Total</td>
<td>316,733</td>
<td>1,107,998</td>
</tr>
<tr>
<td>Daily Average</td>
<td>865</td>
<td>3,027</td>
</tr>
<tr>
<td>Design Capacity</td>
<td>1,206</td>
<td>5,444</td>
</tr>
</tbody>
</table>

Note: The slight variance between the boiler steam volumes and steam injected into the wells is caused by the fact there are steam traps on A-E wells where condensed steam is sent back to the CPF.
# Power & Energy Intensity

## Power (kWh&MW) & Intensity [Natural Gas ($10^3$ m$^3$ & GJ)/Bitumen (m$^3$)]

<table>
<thead>
<tr>
<th>Year</th>
<th>Power (kWh)</th>
<th>Power (MW)</th>
<th>Natural Gas* ($10^3$ m$^3$)</th>
<th>Bitumen (m$^3$)</th>
<th>Intensity (m$^3$/m$^3$)</th>
<th>Nat gas heating value (GJ/$10^3$m$^3$)</th>
<th>Intensity** (GJ/m$^3$)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan</td>
<td>2,640,184</td>
<td>3.5</td>
<td>9,252</td>
<td>27,875</td>
<td>332</td>
<td>39.09</td>
<td>13.0</td>
</tr>
<tr>
<td>Feb</td>
<td>2,361,262</td>
<td>3.5</td>
<td>9,412</td>
<td>27,767</td>
<td>339</td>
<td>38.83</td>
<td>13.2</td>
</tr>
<tr>
<td>Mar</td>
<td>2,641,609</td>
<td>3.6</td>
<td>10,726</td>
<td>32,143</td>
<td>334</td>
<td>39.27</td>
<td>13.1</td>
</tr>
<tr>
<td>Apr</td>
<td>2,101,370</td>
<td>2.9</td>
<td>6,624</td>
<td>19,720</td>
<td>336</td>
<td>39.40</td>
<td>13.2</td>
</tr>
<tr>
<td>May</td>
<td>2,396,229</td>
<td>3.2</td>
<td>10,653</td>
<td>30,460</td>
<td>350</td>
<td>39.06</td>
<td>13.7</td>
</tr>
<tr>
<td>Jun</td>
<td>2,342,663</td>
<td>3.3</td>
<td>9,999</td>
<td>27,586</td>
<td>362</td>
<td>38.52</td>
<td>14.0</td>
</tr>
<tr>
<td>Jul</td>
<td>2,375,941</td>
<td>3.2</td>
<td>10,246</td>
<td>30,059</td>
<td>341</td>
<td>38.76</td>
<td>13.2</td>
</tr>
<tr>
<td>Aug</td>
<td>2,402,372</td>
<td>3.2</td>
<td>10,402</td>
<td>31,524</td>
<td>330</td>
<td>39.18</td>
<td>12.9</td>
</tr>
<tr>
<td>Sep</td>
<td>2,374,542</td>
<td>3.3</td>
<td>9,980</td>
<td>31,041</td>
<td>322</td>
<td>39.91</td>
<td>12.8</td>
</tr>
<tr>
<td>Oct</td>
<td>2,484,913</td>
<td>3.3</td>
<td>9,735</td>
<td>29,390</td>
<td>331</td>
<td>39.38</td>
<td>13.0</td>
</tr>
<tr>
<td>Nov</td>
<td>2,547,286</td>
<td>3.5</td>
<td>9,029</td>
<td>29,422</td>
<td>307</td>
<td>39.35</td>
<td>12.1</td>
</tr>
<tr>
<td>Dec</td>
<td>2,672,392</td>
<td>3.6</td>
<td>8,579</td>
<td>27,771</td>
<td>309</td>
<td>39.40</td>
<td>12.2</td>
</tr>
<tr>
<td>TOTAL</td>
<td>29,340,763</td>
<td>3.3</td>
<td>114,637</td>
<td>344,757</td>
<td>333</td>
<td>39.40</td>
<td>12.5</td>
</tr>
</tbody>
</table>

* - Total natural gas to plant  
** - Using monthly net gas heating values
## Natural/Produced Gas Summary - 2013

<table>
<thead>
<tr>
<th></th>
<th>Purchased Gas</th>
<th>Produced Gas</th>
<th>Flared Gas</th>
<th>Produced Gas Recovery</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>9,252</td>
<td>387</td>
<td>28</td>
<td>93%</td>
</tr>
<tr>
<td>February</td>
<td>9,412</td>
<td>503</td>
<td>24</td>
<td>95%</td>
</tr>
<tr>
<td>March</td>
<td>10,726</td>
<td>459</td>
<td>27</td>
<td>94%</td>
</tr>
<tr>
<td>April</td>
<td>6,624</td>
<td>203</td>
<td>35</td>
<td>83%</td>
</tr>
<tr>
<td>May</td>
<td>10,653</td>
<td>316</td>
<td>34</td>
<td>89%</td>
</tr>
<tr>
<td>June</td>
<td>9,999</td>
<td>413</td>
<td>33</td>
<td>92%</td>
</tr>
<tr>
<td>July</td>
<td>10,246</td>
<td>480</td>
<td>36</td>
<td>93%</td>
</tr>
<tr>
<td>August</td>
<td>10,402</td>
<td>413</td>
<td>38</td>
<td>91%</td>
</tr>
<tr>
<td>September</td>
<td>9,980</td>
<td>433</td>
<td>38</td>
<td>91%</td>
</tr>
<tr>
<td>October</td>
<td>9,735</td>
<td>515</td>
<td>35</td>
<td>93%</td>
</tr>
<tr>
<td>November</td>
<td>9,029</td>
<td>423</td>
<td>31</td>
<td>93%</td>
</tr>
<tr>
<td>December</td>
<td>8,579</td>
<td>358</td>
<td>33</td>
<td>91%</td>
</tr>
<tr>
<td>TOTAL</td>
<td>114,637</td>
<td>4,904</td>
<td>392</td>
<td>92%</td>
</tr>
</tbody>
</table>

Note: The flared gas is produced gas originating from the Plant 1 High Temperature Separator.
Measurement and Reporting
• 15 out 24 SAGD well pairs have individual metered wellhead separators; produced fluid rates are continuously measured and recorded

• Two Group/Test separators
  – P / Q / Z Wells
  – R / S / T / U / V / W Wells

• Bitumen cut determined as follows
  – Phase 5 Wells (R→W) – Online Cut Meter (Phase Dynamics)
  – All other wells – Manual bitumen cut measurement (twice a month)

• Steam injection rates are continuously measured at each and every wellhead and prorated to high-pressure steam meters
• Total daily bitumen production is determined with total metered volume trucked out, compensating for the inventory level in sales tanks. The trucked volume is prorated to the custody transfer meter from the receivers trucking terminals. $\sum$Individual wellhead bitumen is measured/calculated and prorated to the plant production. The average proration factor in 2013 was 0.9129.

• Produced water from each well is calculated with the following formula
  - $PW = \text{Produced Fluid} - \text{Bitumen}$

• Total produced water from all the wells is prorated to the total metered de-oiled produced water steam. This volume includes all condensed produced steam which is not measured off the liquid leg of the well head separators.

• The average produced water proration factor for 2013 was 1.091
### Measurement and Reporting – Water Balance

The chart below summarizes the water balance for 2013.

<table>
<thead>
<tr>
<th>2013</th>
<th>IN</th>
<th>OUT</th>
<th>(ABS) Δ(%)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Produced Water</td>
<td>Raw Water</td>
<td>Total</td>
</tr>
<tr>
<td>January</td>
<td>110,661</td>
<td>20,413</td>
<td>131,074</td>
</tr>
<tr>
<td>February</td>
<td>126,498</td>
<td>13,446</td>
<td>139,944</td>
</tr>
<tr>
<td>March</td>
<td>144,025</td>
<td>14,900</td>
<td>158,924</td>
</tr>
<tr>
<td>April</td>
<td>80,115</td>
<td>12,392</td>
<td>92,506</td>
</tr>
<tr>
<td>May</td>
<td>131,612</td>
<td>15,011</td>
<td>146,623</td>
</tr>
<tr>
<td>June</td>
<td>118,428</td>
<td>18,620</td>
<td>137,048</td>
</tr>
<tr>
<td>July</td>
<td>127,067</td>
<td>17,893</td>
<td>144,961</td>
</tr>
<tr>
<td>August</td>
<td>139,662</td>
<td>17,716</td>
<td>157,378</td>
</tr>
<tr>
<td>September</td>
<td>140,106</td>
<td>16,407</td>
<td>156,512</td>
</tr>
<tr>
<td>October</td>
<td>133,597</td>
<td>17,075</td>
<td>150,672</td>
</tr>
<tr>
<td>November</td>
<td>134,151</td>
<td>13,573</td>
<td>147,724</td>
</tr>
<tr>
<td>December</td>
<td>128,364</td>
<td>12,772</td>
<td>141,136</td>
</tr>
<tr>
<td>Total</td>
<td>1,514,285</td>
<td>190,217</td>
<td>1,704,502</td>
</tr>
</tbody>
</table>

Note: The water balance (Nov-Dec) is currently under investigation. The data indicates there is a measurement issue with the Produced Water IN.
Optimization of test duration

- Optimization of test duration
  - Weak returning pressure well and unstable operation well maximize isolation.

- Test period and frequency
  - Minimum test period: 36 hours per month
  - Test frequency: Target 2 per month
New to JACOS 2013 MARP
(as required by ERCB Directive 017 – Sept 2012)

• **Bitumen Measurement**
  - Density measurement
  - Water/Solids cut

• **Water/Steam Primary and Secondary Measurement**
  - Identify secondary measurement point/meter
  - Monthly balance within 5%
Injection facility water balance
(monthly imbalance must not exceed 5.0% for three consecutive months)

Disposal Limit
(2013 Disposal Limit – 9.0%)
Water Source, Production, Injection, and Disposal
Wells - DQ02-2 & DQ06-7
SE 11-084-11W4M

Water Source – fresh groundwater, no brackish water use; no surface water

Licensed withdrawal - 438,000 m3/yr.
Max pumping rate - 1200 m3/day

Source water is required to makeup for reservoir loss (~5%), evaporation & disposal

All makeup used for steam generation – introduced at wellheads and plant as “quench” water

HE Use – Hangingstone Expansion water loading station withdrawal, for construction and drilling.
Produced Water

- Produced Water Recycle = (Steam Injection – Fresh Water) / Produced Water
- Reservoir Loss = 1 - (Produced Water / Steam Injection)

<table>
<thead>
<tr>
<th></th>
<th>Fresh Water</th>
<th>Produced Water Volume</th>
<th>Steam Injection Volume</th>
<th>Produced Water Recycle</th>
<th>Reservoir Loss</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>20,413</td>
<td>110,661</td>
<td>123,789</td>
<td>93%</td>
<td>10.6%</td>
</tr>
<tr>
<td>February</td>
<td>13,446</td>
<td>126,498</td>
<td>132,468</td>
<td>94%</td>
<td>4.5%</td>
</tr>
<tr>
<td>March</td>
<td>14,900</td>
<td>144,025</td>
<td>150,391</td>
<td>94%</td>
<td>4.2%</td>
</tr>
<tr>
<td>April</td>
<td>12,392</td>
<td>80,115</td>
<td>87,714</td>
<td>94%</td>
<td>8.7%</td>
</tr>
<tr>
<td>May</td>
<td>15,011</td>
<td>131,612</td>
<td>140,326</td>
<td>95%</td>
<td>6.2%</td>
</tr>
<tr>
<td>June</td>
<td>18,620</td>
<td>118,441</td>
<td>132,709</td>
<td>96%</td>
<td>10.8%</td>
</tr>
<tr>
<td>July</td>
<td>17,893</td>
<td>127,067</td>
<td>138,739</td>
<td>95%</td>
<td>8.4%</td>
</tr>
<tr>
<td>August</td>
<td>17,716</td>
<td>139,662</td>
<td>148,332</td>
<td>94%</td>
<td>5.8%</td>
</tr>
<tr>
<td>September</td>
<td>16,407</td>
<td>140,106</td>
<td>142,836</td>
<td>90%</td>
<td>1.9%</td>
</tr>
<tr>
<td>October</td>
<td>17,075</td>
<td>133,597</td>
<td>138,019</td>
<td>91%</td>
<td>3.2%</td>
</tr>
<tr>
<td>November</td>
<td>13,573</td>
<td>134,151</td>
<td>131,743</td>
<td>88%</td>
<td>-1.8%</td>
</tr>
<tr>
<td>December</td>
<td>12,772</td>
<td>128,364</td>
<td>124,359</td>
<td>87%</td>
<td>-3.2%</td>
</tr>
<tr>
<td>Total</td>
<td>190,217</td>
<td>1,514,298</td>
<td>1,591,425</td>
<td>93%</td>
<td>4.8%</td>
</tr>
</tbody>
</table>
Waste Water Disposal

JACOS CLASS 1b WELLS
(Approval No. 8640C)

- WS2-23 F1/02-23-084-11W4/0
- WD-3 00/15-14-084-11W4/0
- WD-4 00/01-23-084-11W4/0 (abandoned)
- WD-5 00/16-14-084-11W4/0 (abandoned)

OFFSITE BRINE DISPOSAL
Absolute 10-17-053-23W4
Worthington Business Park Edmonton

<table>
<thead>
<tr>
<th>Rate Summary</th>
<th>2013 Avg Rate (m³/D)</th>
</tr>
</thead>
<tbody>
<tr>
<td>WD-3</td>
<td>9</td>
</tr>
<tr>
<td>WS2-23</td>
<td>72</td>
</tr>
<tr>
<td>Total disposal to JACOS wells</td>
<td>80</td>
</tr>
<tr>
<td>Brine to offsite disposal well</td>
<td>10</td>
</tr>
<tr>
<td>TOTAL DISPOSAL</td>
<td>90</td>
</tr>
</tbody>
</table>
## Waste Water Disposal Volumes

### Monthly Disposal Volumes

<table>
<thead>
<tr>
<th></th>
<th>Trucked Out</th>
<th>WD-3</th>
<th>WS2-23</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>313.3</td>
<td>297.0</td>
<td>2407.9</td>
</tr>
<tr>
<td>February</td>
<td>226.3</td>
<td>183.0</td>
<td>1758.4</td>
</tr>
<tr>
<td>March</td>
<td>313.6</td>
<td>272.9</td>
<td>2432.1</td>
</tr>
<tr>
<td>April</td>
<td>312.5</td>
<td>227.4</td>
<td>2357.9</td>
</tr>
<tr>
<td>May</td>
<td>352.5</td>
<td>250.3</td>
<td>2194.5</td>
</tr>
<tr>
<td>June</td>
<td>268.7</td>
<td>316.7</td>
<td>1796.6</td>
</tr>
<tr>
<td>July</td>
<td>312.5</td>
<td>169.2</td>
<td>2054.3</td>
</tr>
<tr>
<td>August</td>
<td>234.4</td>
<td>0.0</td>
<td>1999.5</td>
</tr>
<tr>
<td>September</td>
<td>314.6</td>
<td>221.7</td>
<td>2449.4</td>
</tr>
<tr>
<td>October</td>
<td>311.4</td>
<td>310.6</td>
<td>2283.7</td>
</tr>
<tr>
<td>November</td>
<td>272.4</td>
<td>490.8</td>
<td>2207.8</td>
</tr>
<tr>
<td>December</td>
<td>273.2</td>
<td>447.8</td>
<td>2214.6</td>
</tr>
</tbody>
</table>
Types of Solid Waste

- Lime Sludge
- Sand
- Spent filter media

SOLID WASTE DISPOSAL
15.06 tonne/day
Class II Oilfield Landfills:
Tervita Janvier SE-03-081-06W4M
Sulphur Dioxide Emissions

- The average SO$_2$ emission rate in 2013 was 0.56 T/d
- Lower emissions towards the end of April and in mid-October were due to plant turnarounds
- Higher emissions in July were due to increased produced gas, as wells were ramped up after significant cutbacks
- Higher emissions near the end of September were due to increased gas returns associated with well troubleshooting
Future Plans

MVR Evaporator (Water Treatment)

- Application – Submitted Jan 2014
- Construction – Q3 2014
- Targeted Start-up – Q4 2014
Environmental
Environmental

- **AESRD Compliance Inspection – Jan 22/13**
  - Focused on air emissions/quality conditions of approval
  - In compliance with all approval conditions

- **Active Ambient air monitoring program:**
  - Data collected from January 1\textsuperscript{st} to June 30, 2013 (6 months in 2013) as per approval; in compliance with all AAAQO

- **Routine Annual monitoring programs:**
  - Six passive ambient air monitoring stations collected SO\textsubscript{2} and H\textsubscript{2}S data during 2013 – no exceedences noted.
  - Groundwater - spring/fall sampling completed; increasing trends in parameters noted at ENV98-1A and ENV08-9. Follow-up actions outlined in report being drafted.
  - Fugitive emission survey (LDAR). Repairs made during site visit, in compliance with CCME.
  - Water Use - report in draft; updates to AESRD Water Use Reporting registry ongoing.
  - Soil Management - spring/fall soil sampling completed. Several areas identified for excavation and improved management practices.
Regional Initiative Involvement:

<table>
<thead>
<tr>
<th>ABMI</th>
<th>OSDG/CAPP</th>
<th>CEMA</th>
</tr>
</thead>
<tbody>
<tr>
<td>RAMP</td>
<td>iFROG</td>
<td>JOSM</td>
</tr>
<tr>
<td></td>
<td>(wetland monitoring research group)</td>
<td>(Joint Oil Sands Monitoring program)</td>
</tr>
</tbody>
</table>

Remediation and Reclamation Progress:

- In 2013, 44 OSE sites were surface reclaimed, and 30 were planted (spruce, pine)
- Follow-up monitoring by the UofA took place at 10 year old upland reclamation trial plots
- Pine and spruce were planted at 04-36 / Balsam poplar and spruce were planted at 14-21 (former remote sumps)
- Reclamation applications filed: 5&6-27-84-11, 4-27-84-11, 7-27-84-11, 10&15-26-84-11
- 2D and 3D seismic programs signed off by AESRD (63.82 ha)
- Phase 2 ESAs: 10&11-34-84-11, 10-34-84-11, 13-13-84-11, 13-21-84-11, 3&4-27-84-11, 5-27-84-11, 102/02-23-84-11, 100/02-23-84-11, 100/01-23-84-11
- Surface reclamation activities (lime application) conducted at 100/01-23-84-11
“Removing the Wellsite Footprint” (iFROG Program) – Partial Road Removal Project

• **Work completed:**
  - The partial removal of the road fill material in winter 2011.
  - Three excavations along the road as re-vegetation treatment plots.
  - Moss, tree, & shrub species planted in 2011 and 2012.
  - Re-vegetation and hydrologic communication assessed in 2013.

• **Work planned:**
  - Monitor success of re-vegetation and hydrologic communication until the fall of 2014 (final monitoring year).
Facility Repairs and Upgrades:

**Surface Run-off Modifications & Repairs:**
- Plants 1 and 2 were surveyed to generate an elevation profile of the site.
- Survey to guide 2014 construction activities to modify all run-off control systems.
- Surface run-off ponds at Plants 1 and 2 were modified to original specifications – to increase pond volume and facilitate run-off water management and control.
- Repairs included re-grading the Plant 2 run-off pond.

**Secondary Containment Repair:**
- Secondary containment repair and replacement work continued in 2013.
- Repair and modification work to continue in 2014 as previously outlined.
Ambient Air Quality Monitoring – Passive Stations

2013 Ambient Air Quality from Passive Monitoring Stations
Total Sulphur Dioxide

Limit = 11 ppb (30-day average)
Ambient Air Quality Monitoring – Passive Stations

2013 Ambient Air Quality from Passive Monitoring Stations
Hydrogen Sulphide

Limit = 3 ppb (24-hour average)

H2S Equivalent (mg/SO3/day/100cm2)

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

Station 1
Station 2
Station 3
Station 4
Station 5
Station 6
AAAQO
2013 Ambient Air Quality from Active Monitoring Station
Sulphur Dioxide (SO2)

Limit = 172 ppb (1-hour average)

Limit = 48 ppb (24-hour average)
Ambient Air Quality Monitoring - Active Station

Limit = 10 ppb (1-hour average)

Limit = 3 ppb (24-hour average)

Minimum reporting threshold (1 ppb)
Compliance Statement & Approvals
• JACOS is in compliance with all conditions of their approval and regulatory requirements

  - Pipeline Operations Inspection – Feb 20/13
    - Received notice of high-risk non-compliance on Feb 25/13 - documentation and inspection gaps.
    - Implemented corrections and achieved compliance on Mar 28/13

  - Release of runoff from unauthorized locations – Apr 17/13
    - Runoff pumped or released from areas other than two licensed runoff ponds on two main plant pads
    - Training and operating procedures implemented to ensure runoff is pumped only from licensed ponds
    - Culverts that allowed uncontrolled release of runoff from plant pads have been plugged or removed. Soil testing on discharge showed no contamination; passed criteria.
    - Runoff system remediation work is ongoing & will maintain diligence during spring runoff to manage water

• No amendments to Scheme Approval 8788I in 2013
  - Filed amendment application (Application No. 1764015) for NCG co-injection – still under review
  - Filed amendment application to strike minimum recycle rate clause (JACOS complies with D081) (Jan 2014)

  - MVR application filed - 2014

• MARP: 2013 Update submitted and accepted

• EPAP: Filed 2013 Declaration – achieved approval on Jan 16/14
• No self-disclosures were reported by JACOS in 2013.

• Greenhouse Gas Emissions:
  – JACOS submitted its annual SGER report to AESRD and NPRI GHG report to Environment Canada.
  – Total direct emissions for 2013 (as of Nov, 2013) is 247,641 tonnes of CO₂ equivalent
  – Total emissions for 2013 will be reported to AESRD.
  – Approved baseline emission intensity remains 0.4724 tonne CO₂-e/m3

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Requirement</th>
<th>Actual</th>
</tr>
</thead>
<tbody>
<tr>
<td>Solution Gas Recovery</td>
<td>&gt; 90%</td>
<td>94.1%</td>
</tr>
<tr>
<td>SO₂ Emissions</td>
<td>&lt; 1.63 T/d</td>
<td>0.56 T/d</td>
</tr>
<tr>
<td>Water Recycle Ratio</td>
<td>&gt; 90%</td>
<td>92.5%</td>
</tr>
<tr>
<td>Plant 2 B-520 NOₓ</td>
<td>&lt; 7.60 kg/hr</td>
<td>2.94 kg/hr</td>
</tr>
</tbody>
</table>
### Reported Spills/ Releases

<table>
<thead>
<tr>
<th>Name</th>
<th>Date</th>
<th>Legislation and Permit/Approval number</th>
<th>Description</th>
<th>Report submitted</th>
<th>Regulatory follow-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plant 2 flare outage</td>
<td>03-Jan-13</td>
<td>EPEA - 1604-02</td>
<td>Outage for 2.5 hrs due to issues with the auto-ignition system.</td>
<td>08-Jan-13</td>
<td>No</td>
</tr>
<tr>
<td>On site drilling fluid spill</td>
<td>14-Feb-13</td>
<td>EPEA - 1604-02</td>
<td>Release of 0.3m3 of drilling fluid from the circulating tee being left open.</td>
<td>21-Feb-13</td>
<td>No (Spill was cleaned up immediately)</td>
</tr>
<tr>
<td>Plant 2 flare outage</td>
<td>07-Mar-13</td>
<td>EPEA - 1604-02</td>
<td>Fluctuation in the natural gas flow is expected to have cause an outage, delayed by mechanical auto-ignitor failure.</td>
<td>14-Mar-13</td>
<td>No</td>
</tr>
<tr>
<td>Uncontrolled off lease release of surface runoff water</td>
<td>17-Apr-13</td>
<td>EPEA - 1604-02</td>
<td>Release of an unspecified volume of surface runoff water due to flooding (excessive precipitation) at Plant 1.</td>
<td>23-May-13</td>
<td>No (JACOS initiated surface runoff control measure repairs/modification)</td>
</tr>
<tr>
<td>Uncontrolled off lease release of surface runoff water</td>
<td>09-Jun-13</td>
<td>EPEA - 1604-02</td>
<td>Release of an unspecified volume of surface runoff water due to flooding (excessive precipitation) at Plant 1.</td>
<td>13-Jun-13</td>
<td>No (JACOS initiated surface runoff control measure repairs/modification)</td>
</tr>
<tr>
<td>Process gas flaring event (Plant 2)</td>
<td>14-Aug-13</td>
<td>n/a</td>
<td>3,641.67 m3 release of process gas ws flared due to power outage (August 14, 2013).</td>
<td>14-Aug-13</td>
<td>No (Incident reported through the DDS)</td>
</tr>
<tr>
<td>Process gas flaring event (Plant 2)</td>
<td>03-Sep-13</td>
<td>n/a</td>
<td>Flaring event (3.1x10³m3 volume) for 7 hours due to unexpected power outage.</td>
<td>03-Sep-13</td>
<td>No (Incident reported through the DDS)</td>
</tr>
<tr>
<td>Process gas flaring event (Plant 2)</td>
<td>22-Sep-13</td>
<td>n/a</td>
<td>Flaring event (3.96x10³m3 volume) for 9.5 hours due to unexpected power outage.</td>
<td>22-Sep-13</td>
<td>No (Incident reported through the DDS)</td>
</tr>
<tr>
<td>Off lease spill of bitumen</td>
<td>30-Sep-13</td>
<td>EPEA - 1604-02</td>
<td>Release of approximately 0.05m3 of bitumen from a bitumen tanker truck which came off the road.</td>
<td>03-Oct-13</td>
<td>No (Spill was cleaned up immediately, and RCMP were notified)</td>
</tr>
<tr>
<td>On lease spill of glycol</td>
<td>21-Oct-13</td>
<td>EPEA - 1604-02</td>
<td>Release of approximately 1.9m3 of glycol at the Plant 1 process water treatment area due to mechanical pump failure.</td>
<td>28-Oct-13</td>
<td>YES (Requested report on spill clean up. Report delivered, working to clean site - final confirmation due to AESRD)</td>
</tr>
<tr>
<td>Process gas flaring event (Plant 2)</td>
<td>11-Dec-13</td>
<td>EPEA - 1604-02</td>
<td>Flaring event (2.014x10³m3 volume) for 5 hours due to unexpected power outage.</td>
<td>11-Dec-13</td>
<td>No (Incident reported through the DDS)</td>
</tr>
</tbody>
</table>
**Compliance Statement & Approvals – Scheme No. 11910A**

- JACOS is in compliance with all conditions of their approval and regulatory requirements

- Amendment ‘A’ to Scheme Approval 11910:
  - Well pad updates & minor well trajectory changes

- Submitted amendment application:
  - Highway 63 Crossing

### Reported Incidents

<table>
<thead>
<tr>
<th>Name</th>
<th>Date</th>
<th>Contravention number</th>
<th>Legislation and Permit/Approval number</th>
<th>Description</th>
<th>Report submitted</th>
<th>Regulatory follow-up</th>
</tr>
</thead>
<tbody>
<tr>
<td>Clearing trespass</td>
<td>01-Mar-13</td>
<td>n/a</td>
<td></td>
<td>Trespass due to surveying error</td>
<td>5-Mar-13</td>
<td>No</td>
</tr>
<tr>
<td>Failure to submit construction notification</td>
<td>03-Apr-13</td>
<td>n/a</td>
<td></td>
<td>Late notification of construction start to AER</td>
<td>n/a</td>
<td>No</td>
</tr>
<tr>
<td>Soil handling - EPEA Approval</td>
<td>10-May-13</td>
<td>269992</td>
<td>EPEA - 153105-00-01</td>
<td>Approximately 360m³ of topsoil and subsoil admixed in stockpile</td>
<td>17-May-13</td>
<td>No</td>
</tr>
<tr>
<td>Water use without licence</td>
<td>11-May-13</td>
<td>270017</td>
<td>Water Act - no Licence</td>
<td>Water diversion without a Water Act Licence</td>
<td>17-May-13</td>
<td>No</td>
</tr>
<tr>
<td>Culvert installation - water across road</td>
<td>10-Jun-13</td>
<td>271065</td>
<td>EPEA - 153105-00-01</td>
<td>Water flowing across road in possible contravention of Water Act, EPEA Approval and Fisheries Act. Environment Canada, DFO and AESRD were contacted regarding this incident.</td>
<td>17-Jun-13</td>
<td>Yes - 11-Aug-13 and 18-Oct-13</td>
</tr>
<tr>
<td>Rock truck clay spill</td>
<td>01-Jul-13</td>
<td>272084</td>
<td>EPEA - 153105-00-01</td>
<td>Load of clay across lease boundary due to rock truck box tipping over.</td>
<td>8-Jul-13</td>
<td>Yes - 18-Oct-13</td>
</tr>
<tr>
<td>Pad 3 Soil management</td>
<td>01-Aug-13</td>
<td>273394</td>
<td>EPEA - 153105-00-01</td>
<td>Clay pad installed without salvaging subsoil</td>
<td>8-Aug-13</td>
<td>No</td>
</tr>
<tr>
<td>Soil in snow pile</td>
<td>11-Mar-13</td>
<td>274207</td>
<td>EPEA - 153105-00-01</td>
<td>Topsoil present in snow pile</td>
<td>27-Aug-13</td>
<td>No</td>
</tr>
<tr>
<td>Clay berm on subsoil - CPF</td>
<td>25-Jun-13</td>
<td>274471</td>
<td>EPEA - 153105-00-01</td>
<td>Clay pad installed without salvaging subsoil</td>
<td>25-Jun-13</td>
<td>No</td>
</tr>
<tr>
<td>Construction start without submitting C&amp;R plan</td>
<td>03-Sep-13</td>
<td>274780</td>
<td>EPEA - 153105-00-01</td>
<td>Commence construction without submitting Conservation and Reclamation Plan</td>
<td>10-Sep-13</td>
<td>No</td>
</tr>
<tr>
<td>Over-use of water on TDL</td>
<td>02-Sep-13</td>
<td>274892</td>
<td>Water Act - TDL 0032983</td>
<td>Water use after licence limit had been reached</td>
<td>13-Sep-13</td>
<td>Yes - 15-Nov-13</td>
</tr>
<tr>
<td>Error in water diversion location on TDL</td>
<td>06-Sep-13</td>
<td>277577</td>
<td>Water Act - TDL 00336866</td>
<td>Error on water diversion location on licence</td>
<td>21-Nov-13</td>
<td>No</td>
</tr>
<tr>
<td>Mud spill at SAGD pad 1</td>
<td>07-Dec-13</td>
<td>20132467</td>
<td>EPEA - 153105-00-01</td>
<td>Mud spill during SAGD drilling</td>
<td>13-Dec-13</td>
<td>No</td>
</tr>
</tbody>
</table>
Future Plans – Hangingstone Overview

Demo:
• MVR Evaporator (Water Treatment)

Expansion:
• Drilling of 27 well pairs on 5 well pads
• Commence mechanical construction of CPF, Utilities & Infrastructure, Field Facilities construction in Q1-2014
Observation Well Temperature OBA4 (A Pair)

* Depths of TC and distances to injector and producer are based on a location matching study which was conducted using temperature rising data during steam circulation. Last Data was captured on May 6, 2003. After Workover, Data from April 9, 2004. NOTE: NO DATA FROM OCTOBER 4-25, 2007. DATA IS UP-TO-DATE FROM OCTOBER 26, 2007 FOR ALL POINTS EXCEPT POINT #8 WHICH IS NOT WORKING. NO DATA on 7/1/11 and 9/1/11. NO DATA FOR #1-8; 17-24 SINCE AUGUST 2011 - 11/25/11. NO DATA ON 7/22/12 AND 7/25/12. NO DATA FROM 8/11/2012 - PRESENT.

Top of the Reservoir (279.5)
Top of Devonian Lst.
Injector (4.5m west from OB)
Producer (4.5m west from OB)

TC 1/1/2012
2/1/2012
3/1/2012
4/1/2012
5/1/2012
6/1/2012
7/1/2012
8/1/2012
9/1/2012
10/1/2012
11/1/2012
12/1/2012
1/1/2013

NOTE: NO DATA FROM OCTOBER 4-25, 2007. DATA IS UP-TO-DATE FROM OCTOBER 26, 2007 FOR ALL POINTS EXCEPT POINT #8 WHICH IS NOT WORKING. NO DATA on 7/1/11 and 9/1/11. NO DATA FOR #1-8; 17-24 SINCE AUGUST 2011 - 11/25/11. NO DATA ON 7/22/12 AND 7/25/12. NO DATA FROM 8/11/2012 - PRESENT.
Observation Well Temperature - OBC4 (C Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. TC's back into the ground on January 30, 2004. Data is up-to-date. During DCS Upgrade from March 15-May 4, 2007 data was lost. NO DATA FOR JULY 22, 2012. REPEATED DATA FROM AUGUST 1, 2012 - PRESENT.
Observation Well Temperature - OBD2 (E Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Before Workover, the data was last captured on February 18, 2003. TC’s back into the ground on February 21, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
* Depths of TC are the planned depth. Distances to injector and producer are based on Drilling Final Report. Data captured from on March 9, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. There was no data recorded from February 20 - June 17, 2003. Data captured again from June 18, 2003. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Observation Well Temperature - OBE3 (E Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Last data was captured on February 19, 2003 before Workovers. Data captured again from February 21, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.

LEGEND

TF
CH
PB2
PB1
LST

Top of the Reservoir (278m)

Injector (3.2m east from OB)

Producer (3.8m east from OB)

Top of Devonian Lst.
Observation Well Temperature - OBH1 (H Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on Drilling Final Report. Thermocouples out from the ground on February 20, 2003. Back in the ground on December 12, 2003. Data captured for all TC’s on January 20, 2004 and thereafter on February 8, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Observation Well Temperature - OBH3 (H Pair)

Top of the Reservoir (280m)

Injector (4.8m south from OB)

Producer (6.1m south from OB)

Top of Devonian Lst.

* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Last data captured on February 20, 2003. Workover done on this well, TC back into the ground on March 5, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Observation Well Temperature - OBH4 (H Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on Drilling Final Report. Last data before workover was captured on May 6, 2003. TC back in the ground on March 5, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Observation Well Temperature - OBI1 (I Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Last data captured before workover on May 6, 2003. TC's back into the ground on March 5, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Before workover, last data was captured on May 6, 2003. TC's back into the ground on March 4, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.
Observation Well Temperature - OBI3 (I Pair)

* Depths of TC are the planned depth. Distances to injector and producer are based on Drilling Final Report. Last data before workover was captured on May 6, 2003. TC’s back into the ground on March 4, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.

Legend:
- TF
- CH
- PB2
- PB1
- LST

Top of the Reservoir (277m)
Injector (.5.8m south from OB)
Producer (6.8m south from OB)
Top of Devonian Lst.
* Depths of TC are the planned depth. Distances to injector and producer are based on the Drilling Final Report. Last data captured on May 6, 2003 before workover. TC’s back into the ground on March 9, 2004. During DCS Upgrade from March 15-May 4, 2007 data was lost.