In Situ Oil Sands Progress Presentation

Orion 10103

May 1st, 2014
# Today’s Agenda

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Directly south of Imperial Oil Mahkeses

- 8 sections – 20.7 km²
- 100% Shell
- Hilda Lake SAGD Pilot operating since 1997
- 21 well pairs on-stream
- 106-P4 abandoned, 106-I4 shut in
Phase 1&2 Project Area Base Map
History/Timeline

Hilda Lake Pilot Plant
- Hilda Pilot 1 first steam - 1997
- Hilda Pilot 3 first steam - 2000

Orion Phase 1
- Commercial development application - Aug 2001
- EUB Commercial Scheme approval - Jan 2005
- Construction - Mar 2006
- Shell acquires Black Rock Ventures Inc (BVI) - Jun 2006
- Commissioning and Start-up - Aug 2007
- First M2M PC pump installation - Oct 2009
- Increased steam availability and ramp up to 22 well pairs on stream - 2010
- Field-wide implementation of EDTA stimulations - 2011
- First slotted liner perforation - May 2012
- Reached historical monthly production record as a result of high system reliability and 6 additional liner perforations - 2013
Phase 1 Initial Field Development
Phase I Start-up Update – Surface

- August 2007- water treatment facility started up
- September 2007- oil treatment facility started up
- First steam in the ground Sep 14/07 (Pad 107)
- Steaming restriction lifted April 2/08
  - Steam generation was restricted to 40 t/h per boiler (1920 t/d total) pending resolution of odour concerns
- In 2009 continuation of steam system constraints (evaporators & boiler maintenance etc) resulted in reduced steam availability. High pressure differentials developing between injector/producer well pairs
- In 2010, heat integration (produced gas exchangers, glycol system), noise mitigation issues and evaporator reliability issues addressed. Steady increase in steam availability, combined with well interventions, resulted in increased bitumen production and reducing steam oil ratios.
- In 2011, continued optimisation of wells and evaporators resulted in increased steam/bitumen
- In July-Sept 2012, the two boilers had to be repaired due to leaks
- In Dec 2013 the field reached a historical monthly-average production record of 963 m$^3$/d with an SOR of 4 T/m$^3$. 
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Well Proposal and Drilling Background:
- Proposed 3 wells for P106
  - one del well,
  - one bitumen producer
  - one steam injector
- Del well – confirm the SAGD base
- SAGD pair
  - A hole in intermediate casing
  - P106-I4P4 below SAGD base
  - Test the production rate
Data Acquisition During Drilling

Drilled 3 wells for P106 from Jan 10 to Feb 20 2014

- **Del well**
  - LWD logs include GR-NEUT-DENS-Resistivity and AFR Borehole Image from 400mMD to 590mMD
  - GR from 30m to TD for three wells
  - Drilling samples were collected every 5m from 300mMD to 590mMD TD
  - gas detector from 140mMD to TD

- **Producer P106-P5**
  - GR-NEUT-DENS-Resistivity from 673mMD (ICP) to 1395mMD TD
  - GR from 30m to TD for three wells
  - Drilling samples were collected every 10m from 330mMD to 1395mMD TD
  - gas detector from 140mMD to 1395mMD TD

- **Injector P106-I5**
  - Drilling samples were collected every 10m from 330mMD to 1389mMD TD
  - gas detector from 148mMD to 1389mMD TD
Heated zone has low resistivity below cut-off (10 ohms);
In clean sand interval, 6 ohms resistivity is still good reservoir;
Reservoir Interval in P106 Toe Area
Overburden in P106 Area (HZ Wells Cross-Section)

- Total overburden interval >= 240m
- Colorado Shaley interval 130 - 160m
- Grand Rapid interbeded sand shale interval ±110m
## Drilling Results

<table>
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<tr>
<th>Formation</th>
<th>P106 Del-0816</th>
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<th>P106-P5</th>
<th></th>
<th>P106-I5</th>
<th></th>
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<tr>
<td></td>
<td>Proposed (m)</td>
<td>Actual (m)</td>
<td>Proposed (m)</td>
<td>Actual (m)</td>
<td>Proposed (m)</td>
<td>Actual (m)</td>
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<tr>
<td>SSTVD</td>
<td>Thickness</td>
<td>SSTVD</td>
<td>Thickness</td>
<td>SSTVD</td>
<td>SSTVD</td>
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<tr>
<td>Shale Top</td>
<td>171.0</td>
<td>169.9</td>
<td>172.0</td>
<td>171.6</td>
<td>172.0</td>
<td>173.5</td>
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<tr>
<td>Clearwater Sandstone Top</td>
<td>163.0</td>
<td>164.3</td>
<td>168.0</td>
<td>167.3</td>
<td>168.0</td>
<td>168.3</td>
</tr>
<tr>
<td>SAGD Top</td>
<td>163.3</td>
<td>161.9</td>
<td>164.9</td>
<td>164.6</td>
<td>164.4</td>
<td>165.4</td>
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<tr>
<td>SAGD Base</td>
<td>147.0</td>
<td>144.8</td>
<td>xx</td>
<td>xx</td>
<td>xx</td>
<td>xx</td>
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<tr>
<td>HZ section and TD</td>
<td></td>
<td></td>
<td>150.0</td>
<td>150.2</td>
<td>156.0</td>
<td>156.0</td>
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</table>
Composite Well Log

102151706403W400

Waste zone

Clearwater Shale

“Waste zone”

Productive zone

Wabiskaw Shale

Gas

CLGP Flooding Surface

Bitumen

Water
102161706403W4: Upper Reservoir Facies

Top @ 413.21m

Bottom @ 417.70m
1AA051606403W4: Lower Reservoir Facies
Cross Sections - Locations

[Diagram of cross sections with labels A, B, B', A', and annotations for area with regulatory approval and Orion acreage.]
Structural Cross Section (W-E)
Structural Cross Section (N-S)
Bitumen Isopach

Clearwater Formation

---

**Area with regulatory approval**

**Orion acreage**

---

**SHELL CANADA**

**ORION**

Net bitumen isopach, Clearwater

Depth (m)

Scale: 1:50000

Author: Lindsay Mueller

Date: 01/04/2012

Copyright 2005 SIEP B.V.
Bitumen Isopach

Productive Zone

SHELL CANADA
ORION
Net bitumen isopach, Productive Zone
Depth (m)
Scale: 1:25000

Area with regulatory approval
Orion acreage
Structure Map – Base Productive Zone

Elevation (TVDSS)

---

SHELL CANADA
ORION
Structure Map, Base Productive Zone
Depth (m)

Area with regulatory approval
Orion acreage

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Copyright 2005 SIEP B.V.
Clearwater Sand Property Map – Average Vsh

Wabiskaw to Clearwater Flooding Surface

Area with regulatory approval
Orion acreage

Orion acreage

S:\SCProj11\pr_Petrel\ORION\Working_Projects\PETREL\ORION\PROJECTS\Clear_ATS41_GridNorth_2011.pet --- "Model name" ---     "3D-Grid name"
Wabiskaw to Clearwater Flooding Surface

Clearwater Sand Property Map – Average Porosity
Clearwater Sand Property Map – Average KV/KH

Wabiskaw to Clearwater Flooding Surface

Area with regulatory approval
Orion acreage

SHELL CANADA

ORION
Property Map, Average KV/KH

Ratio

Author: Lindsay Mosher
Date: 01/04/2012

Copyright 2005 SIEP B.V.
Orion SAGD – Well Placement

IP1&3

107 Pad

105 Pad

103 Pad

104 Pad

106 Pad

Predominantly Sand Facies
Predominantly Mud Facies

High Performance Pads:
Hilda P1, Hilda P3 and 103

Average Performance Pads:
105 and 107

Low Performance Pads:
104 and 106
OBIP

- Volumetric input:
  - GRV based on maps (top to base of interpreted “Productive Zone”)
  - POR, So, N:G and Bo based on well/core data

- The formula used is: \( \text{OBIP} = \text{GRV} \times \text{NTG} \times \text{PHI} \times \text{So} / \text{Bo} \)

- OBIP in Approval Area
  - OBIP: \( 43.2 \times 10^6 \text{ m}^3 \)
  - GRV: \( 215 \times 10^6 \text{ m}^3 \)
  - Height: 20.6 m
  - POR: 33%
  - So: 68%
  - N:G: 91.6%

- OBIP in Operating Area
  - OBIP: \( 8.52 \times 10^6 \text{ m}^3 \)
  - GRV: \( 40.8 \times 10^6 \text{ m}^3 \)
  - Height: 21.6 m
  - POR: 33%
  - So: 70%
  - N:G: 90.4%
## OBIP/Average Properties per Pad

### Wabiskaw to Clearwater Flooding Surface

<table>
<thead>
<tr>
<th>Pads / Pilot</th>
<th>OBIP (e3m³)</th>
<th>POR (%)</th>
<th>So (%)</th>
<th>N:G (%)</th>
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<tbody>
<tr>
<td>11P1</td>
<td>567</td>
<td>33</td>
<td>62</td>
<td>93.3</td>
</tr>
<tr>
<td>13P3</td>
<td>594</td>
<td>33</td>
<td>63</td>
<td>93.6</td>
</tr>
<tr>
<td>Pad103</td>
<td>1334</td>
<td>33</td>
<td>62</td>
<td>95.3</td>
</tr>
<tr>
<td>Pad104</td>
<td>1416</td>
<td>33</td>
<td>64</td>
<td>87.7</td>
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<tr>
<td>Pad105</td>
<td>1446</td>
<td>32</td>
<td>66</td>
<td>92.4</td>
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<tr>
<td>Pad106</td>
<td>1705</td>
<td>33</td>
<td>56</td>
<td>89.9</td>
</tr>
<tr>
<td>Pad107</td>
<td>1451</td>
<td>32</td>
<td>66</td>
<td>85.0</td>
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Reservoir Property Ranges:

- **Horizontal Permeability**: 100 – 5000 mD
- **Vertical Permeability**: 80 – 4000 mD
- **Viscosity**: 30,000 – 3,000,000 cSt
- **Initial Reservoir Temp**: 16 °C
- **Initial Reservoir Pressure**: 3200 kpa
Petrographic Study – Sand Mineralogy

5-Well Petrographic Study
October 2006
Figure 6: Authigenic clay zones, represented by colored boxes, colored by amount of total clay.
SCL OR10 DELO Cold Lk 3-12-64-3W4 selected for analysis.

Special core analysis measurements set out to improve understanding of three areas:

- **Formation Damage**
  - Critical Salinity: permeability significantly reduced after introduction of fresh water indicating strong sensitivity to salinity of injection water.
  - Fines Migration: formation fines sensitive to injection rate. Formation damage will occur at higher flow rates if fines move further into the reservoir and accumulate.
  - SEM: fluid rock sensitivity concerns include fines migration of kaolinite and water sensitivity of smectite.

- **Fluid saturations on native state samples under reservoir conditions**
  - Residual fluid saturations measured on 4 native state samples. Results slightly lower or close to initial water saturation measured from Dean Stark strip samples. Indicates small amount of moveable water may be present.
Conclusion

- Geologic modeling study was completed to better understand Pad-to-Pad production performance differences.
- Placement of wells in poorer quality facies reduces well production.
- No “geologic barriers” found that would cause the high $\Delta P$ between the injector and the producer. The high $\Delta P$ appears to have been caused by scaling around liners.
- Freshwater and injection rate affect the reservoir permeability.
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Geophysics – Repeat 2D Seismic

- Hilda Lake 3D: Feb-Mar 2005 (1.75 sq. km)
- 2D seismic, Blackrock, 2005
- Orion Baseline 2D Swath: Summer 2007 (50 km)
- Orion 3D: April 2009 (8.35 sq. km)
- Orion First Repeat 2D Swath: Fall 2009 (50 km)
- Orion Second Repeat 2D Swath: Feb 2011 (40 km)
- Orion Third Repeat 2D Swath: Feb 2014 (~34.5 km)
Pad 103 Repeat 2D Seismic

2009

2011
Objective is to use measurements of surface deformation and micro-seismic activity as indicators to determine what impact (if any) that IOL’s CSS operations might have on Orion’s SAGD operations.

Surface deformation is measured using Satellite InSAR techniques based primarily on analysis of returns from specially constructed permanent corner reflectors.

Micro-seismic data is recorded in two monitor wells, the Hilda Lake 11 OB4 (operated by Shell) and the IOL 2-20 (monitored by Imperial).

Pressure data in the Clearwater Gas cap is monitored by pressure gauges in the Hilda Lake 11 OB3 monitor well in the 2-20 monitor well.

Shell and Imperial have agreed to share the information gathered in this project.
Since August, 2010 the OB4 and 2-20 monitor wells have recorded micro-seismic activity associated with 5 injection cycles of the T14 pad, 4 injection cycles of the T15 pad, and 3 cycles for V13 pad.
Greater surface uplift is seen on the Orion lease due to nearby high pressure steam injection at Imperials Cold Lake operations.
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**Hilda Lake Injector Schematic**

**Hilda I1 (1997)**
- 406 mm surface casing
- 298.5 mm Intermediate casing
- 219.1 mm liner
- 89 mm tubing short string
- 89 mm tubing Long string
- 1000 m horizontal length

**Hilda I3 (2000)**
- 340 mm surface casing
- 245 mm Intermediate casing
- 178 mm liner
- 82.6 mm coil tubing short string
- 82.6 mm coil tubing Long string
- 1000 m horizontal length
Hilda Lake Typical Producer Schematic

- 340 mm surface casing
- 245 mm Intermediate casing
- 178 mm liner
- Tubing string with artificial lift
- Guide String with fibre optic temperature instrumentation
Orion Typical Injector Schematic

- 339 mm surface casing
- 245 mm Intermediate casing
- 178 mm slotted liner
- 73 mm short tubing string
- 89 mm long tubing string
- 750m horizontal length
- 339 mm surface casing
- 245 mm Intermediate casing
- 178 mm slotted liner
- 73 mm tubing string
- 89 mm tubing string with fibre optic instrument string in 18/22 of the producers
Orion M2M PCP Completion

**ORION**

**SAGD Well**

| 9-5/8" x 7" & 3-7/8" x 2-7/8" |

Production Well – Artificial Lift

---

**508 mm (20")** 78 kg/m
Conductor at ~20 mKKB

**339.7 mm (13-3/8")** 71.4 kg/m, K-55
Surface Casing at 200 mKKB

**52.4 mm (2")** 4.84 kg/m, J-55, 1J
Guide String at 177 mKKB

**88.9 mm (3-7/8")** 13.84 kg/m, J-55, EUE
Production Casing at 544 mKKB

**244.5 mm (9-5/8")** 59.53 kg/m K-55, TS
Blue Production Casing at 630 mKKB

**177.8 mm (7")** 34.3 kg/m K-55, TS Blue
0.020" bottom 0.014" Slotted Liner from 611 - 1350 mKKB

---

244.5 x 177.8 mm Liner Hangar
No seal, sand tight only

700 m
Orion ESP Completion

Surface Casing:
- Size: 208.7 mm, 71.4 kgf/m, H-18, 3rd, STAC
- Depth: 92 = MD 92 = TVD

Intermediate Casing:
- Size: 244.5 mm, 99.6 kgf/m, L-80
- Depth: 563 = MD 423 = TVD

ESP Cable:
- Type: Field Lead 5 kV flat EH1BE-NS GSF Cable
- Conductor: 4 AVG Solid (0.244" Dia) Conductor
- Connector: Metalllok Surface Feedthrough Connector

Thermocouple Cable:
- Type: 1/8" Duplex Type K with points at 575.5 & 576.5 mMD

Production String:
- Size: 88.9 mm, 12.94 kgf/m, J-95, BUE, Range 2
- Depth: 582 = MD 414 = TVD

ESP Cable and Thermocouple Cable secured to production string with Cannon clamps (mid-joint and cross-coupling clamps)

Guide String:
- Size: 68.3 mm, 6.0 kgf/m, J-56, 1st, Range 2
- Depth: 514 = MD 417 = TVD

Instrumented Coil (with cap line for pumping fibre and TCs pre-installed)
- Size: 31.8 mm, 2.93 kgf/m, Q7-700, Coil
- Other 2 x 6.4 mm, 0.9 mm wall, 316 SS cap lines, with termcoupled sub
- Depth: 1041.0 = MD 422 = TVD

Liner End:
- Size: 178.6 mm, 38.7 kgf/m, LB1BE-76, LTC
- Top: 517.4 = MD 422 = TVD
- Bottom: 1445.6 = MD 422 = TVD

Production Liner:
- Size: 172.8 mm, 36.7 kgf/m, LB1BE-76, LTC
- Top: 517.4 = MD 422 = TVD
- Bottom: 1445.6 = MD 422 = TVD

CLP Hydraulically Liner Hanger
- Depth: 585.9 = MD 423 = TVD
3/4 Valves still working, 1st valve requires maintenance & has been closed since August 22, 2013 (~30-50 valve cycles to date)

- All downhole P/T sensors have failed
- Injection test program saw positive results in steam conformance
- Shell does not plan to install more ICV's in future injectors, as the project is cost prohibitive.
  - However, Shell may trial the installation of a steam diverter with bi-directional high temperature cups as a “poor boy ICV”

---

Pad-106 11 Injector ICV completion

- Casing Shoe: 616.0 MD, mKh, ~414.07 m TVD
- Production Liner
- Horizontal Section: 746.1 m
- Liner end: 1347.0
- PT Sensors
- PT Sensor + DTS end
- Tail Pipe
- Interval Control Valve (ICV)
- Barrier Cups

Liner top 600.1 mKh

8 lines strapped to 4-1/2” tubing OD
Scab Liner Installations

2010
- 103 P2 single packer
- 105 P3 single packer
- 105 P4 single packer
- 107 P3 double packer
- 107 P4 double packer

2011
- 107 P2 double packer

2013
- 105 P3 changed to double packer
- 105 P4 changed to double packer
Liner Perforations

- A total of seven wells were perforated
- Low differential pressure achieved, < 250 kPa
- During and after flow back, samples were collected. Insignificant sand production was observed for majority of wells. (traces)
- Tagged sand in one well after perforating. Tried to bail sand and put well back on production
- Typical TCP guns design at Orion:
  - 114.3mm carrier @ 20spm or 39spm
  - 79mm carrier @ 20spm
  - 23 grade HMX charges, deep penetration
Liner Perforations

- A total of seven wells were perforated
  - 103P1 (95% of total liner length)
  - 105P1 (66% of total liner length)
  - 105P2 (80% of total liner length)
  - 104P2 (60% of total liner length)
  - 103P3 (87% of total liner length)
  - 107P2 (62% of total liner length)
  - 107P1 (59% of total liner length)

- There are already 4 wells that have been perforated in Q1 2014, 103P2, 103 P4, 107 P3 and 107 P4.

- Additional candidates are being assessed for Q3 2014. wells TBD
Feb 2013 - Feb 2014 Well modifications

**Well Suspensions:**

104/09-16-064-03W4/00    (May 2013)

**Well Abandonments:**

104/09-16-064-03W4/00    (Dec 2013 - Jan 2014)

- Permanent bridge plug & cement on top
- Cement retainer & squeeze

**Conversion:**

103/16-17-064-03W4/00 completed from disposal well to brackish water well
(May 2013)
2011-2012 Well modifications
Well 16-17 disposal well was drilled in 1997

History shows problem with sand. Sand was bailed, a plug landed at 451 mKB and well suspended in November 2011.

Injected Fluids:
- 219 000 m$^3$ of boiler blow down had been injected pre 2011
- 900 L of CCRW inhibitor & XC 370 biocide injected in Nov 2011

Completed in the McMurray aquifer

Recompleted with ESP pump in May 2013 to test as a potential back-up brackish-water source well
**16-17 Brackish Water Well** *(103/16-17-064-03W4/00)*

- **Benefits:**
  - Redundancy
  - Can be used after shutdowns

- **Completed Testing:**
  - Temporary 3” CS piping used as a tie-in for the test line
  - Well Test #1: Aug 14 – 21, 2013
  - Well Test # 2: Sept 16 – 20, 2013
  - Tested up to ~ 650 m³/d (27 m³/hr)

- **Typically Brackish Water Used ~55% of overall runtime**

- **Next Steps:**
  - After obtaining regulatory approvals from AER and Alberta DOE, permanently tie in the well to the steam facility.
Concentric design was used to prevent the loss of steam quality for the injected steam.

Long string steam quality loss would be minimized up to the bottom of the short tubing with the concentric design.
Orion Artificial Lift History

- **2005**
  ESP installed on Hilda Pilot P3

- **2009**
  Hilda Pilot 1 converted from rod pump to ESP (July)
  4 ESP and 4 PCP installs on Phase 1 wells
  ESP: 106 P2 and P4, 107 P1 & P4
  PCP: 105 P1, 106 P3, 107 P2 and P3

- **2010**
  3 ESP to PCP conversion: 106 P4 & 107 P4 & Hilda Pilot 1
  3 new PCP installs: 103 P2, 105 P3&P4

- **2011**
  2 ESP failures replaced with High Temperature ESP: 106 P2 and 107 P1

- **2012**
  1 ESP failure replaced with High Temperature ESP: Hilda Pilot 3
  2 High Temperature ESP failure replaced with single tubing completion: 106 P2 and 107 P1

- **2013**
  ESP Replacements: Hilda Pilot 3
  PCP Replacements: Hilda Pilot 1, 103 P2, 105 P1, 105 P4, 106 P3, 107 P1, 107 P2
Orion Artificial Lift Reliability

Artificial Lift Run Time

- **Current PCP Run Time**
- **Current ESP Run Time**
- **Avg Run Time of Replaced ESPs**
- **Avg Run Time of Replaced PCPs**

### # of Installs

<table>
<thead>
<tr>
<th>Station</th>
<th>PCP</th>
<th>ESP</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pilots</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>103 WP2</td>
<td>5</td>
<td>5</td>
</tr>
<tr>
<td>105</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>106</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>107</td>
<td>10</td>
<td>5</td>
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</tbody>
</table>
Artificial Lift – Orion Wells

<table>
<thead>
<tr>
<th>Natural Lift SAGD</th>
<th>11 wells</th>
</tr>
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<tbody>
<tr>
<td>PCP SAGD</td>
<td>10 wells</td>
</tr>
<tr>
<td>ESP SAGD</td>
<td>1 well</td>
</tr>
<tr>
<td>Abandoned</td>
<td>1 well</td>
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</table>

### Operating Temperature Range

<table>
<thead>
<tr>
<th>ESP</th>
<th>All Metal PCP</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 C</td>
<td>350 C</td>
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</table>

### Rate

<table>
<thead>
<tr>
<th>Rate</th>
<th>ESP</th>
<th>All Metal PCP</th>
</tr>
</thead>
<tbody>
<tr>
<td>280–450 m3/d, 40–60 Hz</td>
<td>100–370 m3/d, 100–350 RPM</td>
<td></td>
</tr>
</tbody>
</table>
Failure Modes in Orion

ESP

Run life
- Range 5-46 months
- Average 12 months

Failure causes
- Water finds its way to the motor due to;
  - shaft seal wear, thermal expansion, well deviation & vibration
- Exceeding temperature limit (218°C); melting the winding material
- Two failures from solid precipitation inducing shaft seal failures

All metal PCP

Run life
- Range 10-43 months
- Average 25 months

Failure causes
- Rod coupling failure (design has been modified)
- Steam erosion from well steam breakthrough
Artificial Lift Advantages

**All metal PCP**
- Resilient to well stimulation
- Resilient to steam
- Ease of operation
- Downhole pump assembly simplicity
- Lower CAPEX and OPEX than ESP

**ESP**
- Widely used technology
- Higher lift capacity
- Higher flow capacity
Orion Clearwater Observation Well Location Map

Hilda Lake OB4, OB3, OB2, OB1

29 m 1 m 31 m 7 m

14.65 m

P103- OB1 and OB2

8.07 m 9.76 m

11.78 m

P107-OB1

14.13 m

P107-OB2

9.89 m

15.47 m

P106- OB1 and OB2

9.79 m

P104-OB1

P105-OB1

Pad # of Observation wells

<table>
<thead>
<tr>
<th>Pad</th>
<th># of Observation wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pilot I1P1</td>
<td>4 (one equipped with pressure sensor)</td>
</tr>
<tr>
<td>Pad 103</td>
<td>3</td>
</tr>
<tr>
<td>Pad 104</td>
<td>1</td>
</tr>
<tr>
<td>Pad 105</td>
<td>1</td>
</tr>
<tr>
<td>Pad 106</td>
<td>2</td>
</tr>
<tr>
<td>Pad 107</td>
<td>2</td>
</tr>
<tr>
<td>TOTAL</td>
<td>13</td>
</tr>
</tbody>
</table>
Hilda Pilot 11P1 Observation Wells

Hilda Lake OB4, OB3, OB2, OB1

Hilda Lake OB1 and OB2:

Fibre optic temperature instrumentation string deployed on 38 mm tubing string
Hilda Pilot 1IP1 Observation Wells Completions

**Hilda Lake OB3**

Pressure and Temperature Monitoring

- 5 1/2” casing
- Inside diameter 122.5 mm, 4.825”
- Fiber Cable
- Perforation in gas cap 423.15-426.85mKB
- Fluid in tubing and casing
- 38.1 mm, 1.5” coil tubing - land 430 mKB
- Tubing 73 mm, J55”
- DTS Fiber
- Packer-405 mKB
- Packer tailpipe Land 435 mKB
- Clearwater Sand
- Fiber Optic Pressure Gauge

**Hilda Lake OB4**

- DTS Fiber strapped to the outside of tubing inside 0.25” capline
- 5 1/2” casing
- Inside diameter 122.5 mm, 4.825”
- Geophone array from 150 to 450m TVD
- Bottom Geophone 51 mm, 2”
- Gas
- Clearwater Sand
- Cement in tubing
- tubing 42 mm, 1.66”
Typical Phase 1 Observation well

Fibre optic temperature instrumentation suspended with sinkerbar
Production casing in thermal cement (40% silica flour)
Orion Phase 1 Observation Well Data

2010: added another observation well on Pad 103 south of well #4 (2m)

2011-2012

- 107 OB1: Surface repair due to a mouse nest built in the junction box
- 106 OB1
  - Capline replacement on 106 OB1 due to radigans closure
  - Casing pressure test executed on 106 OB1 at time of capline replacement
  - Capline and fiber replaced February 2012
- 103 OB2: Capline and fiber replaced July 2012

2013- Feb 2014

- Hilda OB2: Thermocouple data verified Feb 2014
Orion Phase 1 Observation Well Data

2013 – 2014
Pinnacle (Halliburton) DTS installation and replacement campaign

- Several observation wells to be retrofitted with thermocouples to improve calibration:
  - 103OB1
  - 103OB2
  - 105OB1 (No valid data, May 2013 – Jan 2014)
  - 106OB1
  - 107OB1 (Calibrated)
  - 107OB2 (No valid data, May 2013 – Jan 2014)

- All observation wells functional as of January 2014
2013 Orion SAGD Temperature Data Summary

- Orion Phase 1 Producer Instrumentation strings in place
  - 17 out of 20 producers
  - 13 out of 17 have currently functional fibre
  - Permanent down-hole monitoring system upgrade began January 2014, project includes fibre replacements, recalibration and the installation of four new instrumented coil tubings

- Purpose:
  - To evaluate steam breakthrough point during static condition
  - To evaluate steam conformance with producer’s dynamic temperature profile
  - To evaluate liquid level
  - To evaluate sub-cool for a given well pair
  - To evaluate steam front’s location during the initial start-up of SAGD (circulation)
Orion Well Integrity

- Yearly valve maintenance and integrity tests
  - More than 200 valves tested
    - 22 valves did not pass pressure test, and were replaced
  - Incorporated new valve design in 2013
    - Trial on 103-P2 and 103-P3
- Feb 2013 – Feb 2014
  - 5 caliper logs completed, 5 casing pressure tests completed, 4 cement bond logs completed. All logs showed positive well integrity, with the exception of 106P4 which was abandoned in Dec 2013.
- Orion Arsenic Management Plan
  - Completed casing integrity check on all eight wells on Pad 105 as part of Orion Arsenic Management Plan. Test results were all positive.
## Today’s Agenda

<table>
<thead>
<tr>
<th>Topic</th>
<th>Presenter</th>
</tr>
</thead>
<tbody>
<tr>
<td>Introductions and Background</td>
<td>Ivan Gonzalez</td>
</tr>
<tr>
<td><strong>Subsurface Issues Related to Resource Evaluation and Recovery</strong></td>
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<tr>
<td>Geology/Geoscience</td>
<td>John Zhao</td>
</tr>
<tr>
<td>Geophysics</td>
<td>Yue Wu</td>
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<tr>
<td>Drilling and Completions</td>
<td>Chris Jang</td>
</tr>
<tr>
<td>Artificial Lift</td>
<td>Chris Jang</td>
</tr>
<tr>
<td>Instrumentation in Wells</td>
<td>Chris Jang</td>
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<tr>
<td>Scheme Performance</td>
<td>Laura Mislun</td>
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<td>Future Plans</td>
<td>Hong Yang</td>
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<tr>
<td><strong>Surface Operations, Compliance &amp; Issues</strong></td>
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<tr>
<td></td>
<td>Grant Zellweger</td>
</tr>
<tr>
<td></td>
<td>Derek Parker</td>
</tr>
</tbody>
</table>
Production/Injection Start-Up History

- Hilda Lake I1/P1 started in September 1997
  - PCP installed in February 2003.
- I3/P3 started in September 2000
- Pad107 started in September 2007
  - Pumps installed in Oct-Nov 2009 (2 ESP and 2 PCP).
- Pad106 started in October 2007
  - ICVs installed on Well pair 1 injector in Dec 2009,
  - Well pair 2-4 on artificial lift, installed in Oct-Nov 2009 (2 ESP, 1 PCP).
  - Well pair 4 abandoned due to casing integrity issue in 2013. Redrilled as 106 WP5 in Q1 2014.
- Pad105 started in May 2008, shut-in in August 2008 (Boiler Outage), restarted in October 2008
  - Well pair 1 converted to AL mode in 2009 (PCP),
  - Well pairs 3 and 4 converted to AL mode in November 2010 (PCP).
- Pad104 started in October 2007 with multiple shut-ins due to steam shortages
  - All in steam lift mode
- Pad103
  - Well pairs 1, 2 and 3 converted to SAGD mode in March-April 2010,
  - Well pair 2 on artificial lift since December 2010 (PCP),
  - Well pair 4 started up in July 2010 and converted to SAGD mode in October 2010.
Currently injecting steam at max the wells will take, less than max plant capacity (~ 4800 m³/d)

Plant T/A

Boiler Outage

Phase 1 wells start up

I1P1 start up

I1P1 : PCP installed

I3P3 : ESP installed

I3P3 start up
Production/Injection History - Last 3 Years

**Orion - Yearly Average Oil Production**

- 2011: 642 m³/d
- 2012: 699 m³/d
- 2013: 870 m³/d

**Orion - Yearly Average Water Production**

- 2011: 3112 m³/d
- 2012: 3121 m³/d
- 2013: 3796 m³/d

**Orion - Yearly Average Steam Injection**

- 2011: 3073 m³/d
- 2012: 3099 m³/d
- 2013: 3769 m³/d

**Orion - Yearly SOR**

- 2011: 5.27
- 2012: 4.79
- 2013: 5.06

- **CSOR**: 4.43
- **SOR**: 4.33

*Note: CSOR stands for Cold Solution Oil Recovery, and SOR stands for Steady Oil Recovery.*
Production/Injection History - Last 3 Years

2013 Snapshot
- Average Oil: 870 m³/d
- Average Water: 3,796 m³/d
- Average Steam: 3,769 m³/d CWE
- CSOR: 4.87
- ISOR: 4.33
Pad 107 & Pad 106 started up

I1P1 started up

Start up Pad 105, 104

Start up Pad 103

I3P3 started up

Start up Pad 107 & Pad 106

Production/Injection History- Total Cumulative

<table>
<thead>
<tr>
<th>Production/Injection History</th>
<th>Oct. 2007 - Feb 28, 2014</th>
<th>Average Orion rate to date</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>578 m3/d</td>
<td></td>
</tr>
<tr>
<td>Water</td>
<td>2,956 m3/d</td>
<td></td>
</tr>
<tr>
<td>Steam</td>
<td>2,901 m3 CWE/d</td>
<td></td>
</tr>
<tr>
<td>CSOR</td>
<td>4.8</td>
<td></td>
</tr>
</tbody>
</table>

Cumulative Prod/Inj Volume (m3)

Start up Pad 103

Start up Pad 105, 104

Start up Pad 107 & Pad 106

I3P3 started up

I1P1 started up
- **Phase I approved capacity:** 1590 m³/d (10,000 bbl/d)
  - Based on 205 t/h steam and 3.0 SOR
- **Average bitumen production rate increased from 699 m³/d (4.4 kbbl/d) in 2012 to 870 m³/d (5.5 k bbl/d) in 2013**
  - Annual average steam production at 157 t/h (Boilers/Evaporator Maintenance)
  - cSOR improved from 5.1 in 2012 to 4.8 in 2013, with 9 well pairs still in steam lift mode.
  - There was a total of 21 well pairs (including the 2 pilot well pairs) producing at January 31, 2014
  - The heterogeneity of the reservoir is better understood after an Integrated Study done in 2011. Surveillance and performance analysis in 2013 corroborate current understanding.
  - Phase I wells were drilled into more moderate quality reservoir compared to the pilot’s. This is determining not as good Phase I earlier performance.
  - Precipitation and scaling around liners impaired the productivity of the wells, and it is being successfully mitigated with chemical stimulations and perforations
2 Well pairs:
- I1/P1 started in 1997
- I3/P3 started in 2000

- ~1000 m long
- 100 m spacing
- Different designs / Lateral offset
- 420 m TVD
Pilot Performance - Hilda Lake Pilot - I1P1

2013 Snapshot
- Average Oil: 46 m³/d
- Average Water: 231 m³/d
- Average Steam: 203 m³/d CWE
- SOR: 4.42

High Performance well pair

Pilot 1

2013 Snapshot
- Average Oil: 46 m³/d
- Average Water: 231 m³/d
- Average Steam: 203 m³/d CWE
- SOR: 4.42

Pump replace
PCP installed

Steam-to-Oil Ratio (m³/m³)

Oil Production (m³/d) Steam Injection (m³/d)
Pilot Performance - Hilda Lake Pilot - I1P1

Average to date since startup:
(as of Feb 28, 2014)
- Oil: 44 m3/d
- Water: 196 m3/d
- Steam: 164 m3/d CWE
- CSOR: 3.7
- RF: 44.4%

- Reduced steam injection rate
- Converted to artificial lift mode

Cumulative Production and Injection (m³/d)

Steam-to-Oil Ratio (m³/m³)

Graph showing the cumulative production and injection over time, with annotations for reduced steam injection rate and conversion to artificial lift mode.
PILOT OB1

- Steam chamber at the heel has intersected the observation well with a temperature of 235°C.
- Signal attenuation observed since December 2012.
Pilot Performance - Hilda Lake Pilot - I1P1

<table>
<thead>
<tr>
<th>Obs Well</th>
<th>Hz Distance from heel</th>
<th>Distance to I1/P1</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>65</td>
<td>7</td>
</tr>
<tr>
<td>2</td>
<td>325</td>
<td>31</td>
</tr>
<tr>
<td>3</td>
<td>660</td>
<td>1</td>
</tr>
<tr>
<td>4</td>
<td>865</td>
<td>29</td>
</tr>
</tbody>
</table>

PILOT OB2

- There was cooling of about 20 °C in the section between the injector and producer due to 21-day shut off during end of July 2012. Temperature has increased since.
Pilot Performance - Hilda Lake Pilot - I1P1

<table>
<thead>
<tr>
<th>Obs Well</th>
<th>Hz Distance from heel</th>
<th>Distance to I1/P1</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>65</td>
<td>7</td>
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<tr>
<td>2</td>
<td>325</td>
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<tr>
<td>3</td>
<td>660</td>
<td>1</td>
</tr>
<tr>
<td>4</td>
<td>865</td>
<td>29</td>
</tr>
</tbody>
</table>

Hilda OB4 (29 m to P1)

PILOT OB4

Toe Chamber shows good growth rate in 2013
High Performance well pair

**Pilot Performance - Hilda Lake Pilot - I3P3**

**2013 Snapshot**
- Average Oil: 45.2 m³/d
- Average Water: 226 m³/d
- Average Steam: 206 m³/d
- SOR: 4.8

**Pilot 3**

- Oil increase in Aug 2013 due to installation of new ESP pump

Graph showing oil production, steam injection, and other parameters over time.
Pilot Performance - Hilda Lake Pilot - I3P3

Average to date since startup:
(As of Feb 28, 2014)
- Oil: 46 m³/d
- Water: 186 m³/d
- Steam: 183 m³/d CWE
- CSOR: 4.0
- RF: 40.0%

Pump installed
Orion Pads Performance – Hilda Lake Pilots

Current Pad Average Operating Chamber Pressure = 3878 kPa

Hilda Pilot Injection Pressures

Pressure [kPa]


PILOT1 Injector Casing Pressure
PILOT3 Injector Casing Pressure
Orion Pads Performance – Pad 103

2013 Snapshot
- Average Oil: 208 m³/d/pad
- Average Water: 816 m³/d/pad
- Average Steam: 810 m³/d/pad
- SOR: 3.9

High Performance well pair
Orion Pads Performance – Pad 103

Average to date since startup:
(as of Feb 28, 2014)

- Oil: 154 m³/d/pad
- Water: 699 m³/d/pad
- Steam: 669 m³/d/pad
- CSOR: 4.34
- RF: 17.5%
Orion Pads Performance – Pad 103

Current Pad Average Operating Chamber Pressure = 3883 kPa
103 P1 Chemical Stimulation and Perforation Performance

- Chemical Stimulation
- Liner Perforation

**Daily Fluids (m³/day)**
- Total Steam
- Oil

**Pressure Differential (kPa)**
- 0 to 3,600

**Timeline**
- 11-2010 to 03-2013
There is good hydraulic communication between injectors and producers.

Reservoir average temperature increased since January 2013 from 26 C to 30 C signaling moderate chamber growth around mid well area in well pair 103 WP1.
Orion Pads Performance – Pad 103

There is good hydraulic communication between injectors and producers.

Fibre was replaced in June 2012 but is still not calibrated correctly. Best estimate of steam chamber growth is from October 2012 Welltech Log.

Fibre to be re-calibrated in Q3 2014.
Orion Pads Performance – Pad 103

- There is good hydraulic communication between injectors and producers.
- Temperature split confirms the presence of a nodule between the well pair and the observation well.
- Very good chamber development around the mid area of well pair PAD103WP4.

103 OB3
Orion Pads Performance – Pad 105

**2013 Snapshot**
- Average Oil: 221 m³/d/pad
- Average Water: 750 m³/d/pad
- Average Steam: 730 m³/d/pad
- SOR: 3.3

**Average Performance well pair**

![Graph showing oil, water, and steam production over time, with key performance indicators highlighted.]
Orion Pads Performance – Pad 105

Average to date since startup:
(as of Feb 28, 2014)
- Oil: 141 m³/d/pad
- Water: 651 m³/d/pad
- Steam: 625 m³/d/pad
- CSOR: 4.44
- RF: 21.5 %
Orion Pads Performance – Pad 105

Current Pad Average Operating Chamber Pressure = 3996 kPa
Orion Pads Performance – Pad 105

105 P1 Liner Perforation Performance

105 P2 Chemical Stimulation and Liner Perforation Performance
Orion Pads Performance – Pad 105

- Faster Steam chamber growth compared to pads 106 and 107. Shows the greatest peak temperature in the field.
- Fiber shows progressive signal attenuation across the bottom half of the reservoir. Fiber to be replaced in 2014
Orion Pads Performance – Pad 107

2013 Snapshot
- Average Oil: 191 m³/d/pad
- Average Water: 725 m³/d/pad
- Average Steam: 658 m³/d/pad
- SOR: 3.5

Pad 107

Average Performance well pair

Conversion to artificial lift
Scab liner
Turn Around
Liner Perfs

Oil Production (m³/d) vs Steam Injection (m³/d)

Steam-to-Oil Ratio (m³/m³)
Orion Pads Performance – Pad 107

Average to date since startup:
(as of Feb 28, 2014)
- Oil: 116 m$^3$/d/pad
- Water: 557 m$^3$/d/pad
- Steam: 528 m$^3$/d/pad
- CSOR: 4.6
- RF: 19.5%

Pad 107

Conversion to artificial lift
Conversion to artificial lift

Scab liner installation

Liner Perorations

Steam-to-Oil Ratio (m$^3$/m$^3$)

Cumulative Production and Injection (m$^3$/d)

Oct-07 Jan-08 Apr-08 Jul-08 Oct-08 Jan-09 Apr-09 Jul-09 Oct-09 Jan-10 Apr-10 Jul-10 Oct-10 Jan-11 Apr-11 Jul-11 Oct-11 Jan-12 Apr-12 Jul-12 Oct-12 Jan-13 Apr-13 Jul-13 Oct-13 Jan-14

Steam Inj Oil Water CSOR
Current Pad Average Operating Chamber Pressure = 3904 kPa

Injection pressure was greater at this well during this time to boost production as the well did not have a pump and was struggling to produce after steam outage. Pump installed Q3 2013

Pressures at the wellhead never exceeded 6 MPA during this time.
Orion Pads Performance – Pad 107

107 OB1

- Limited conductive heat sensed by OB1 (28°C). Consistent with seismic interpretation and operating strategy.
- Fibre Failed June 2013. To be replaced in 2014
Orion Pads Performance – Pad 107

107 OB2

- Limited conductive heat sensed by OB2 (40°C) by the toe of well pair 107WP2.
- Fibre to be recalibrated in 2014
Orion Pads Performance - Pad 106

2013 Snapshot
- Average Oil: 77 m3/d/pad
- Average Water: 494 m3/d/pad
- Average Steam: 548 m3/d/pad
- SOR: 7.1

Pad 106

Steam decrease due to shutting in injector 4 and decreasing steam to injector 3 during wellpair 5 drilling.
Orion Pads Performance - Pad 106

Average to date since startup:
(as of Feb 28, 2014)
- Oil: 73 m³/d/pad
- Water: 464 m³/d/pad
- Steam: 536 m³/d/pad
- CSOR: 7.35
- RF: 13.5 %
Orion Pads Performance – Pad 106

Current Pad Average Operating Chamber Pressure= 3040 kPa

Diverted steam to I2 when I4 was shut in for drilling. Observation well data show less steam chamber height growth at OB1 so decided to concentrate steam injection at I2 assuming this steam chamber is in better communication with upper reservoir and will keep oil flowing to P1,2,3 during drilling.
Orion Pads Performance – Pad 106

106 OB1

- Steam chamber showing good shape.
- Profile seems to be logical, however, the magnitude are abnormally high. Recalibration is needed (to be re-calibrated in Q3 2014)
Orion Pads Performance – Pad 106

Steam chamber showing good lateral and vertical growth.

Rapid increase in conductive heating during last months of 2012 (+14°C); this is caused by a gradual increase in steam injection in 106_I2 after 2012 mid year outage.
Orion Pads Performance – Pad 104

2013 Snapshot
- Average Oil: 85 m³/d/pad
- Average Water: 553 m³/d/pad
- Average Steam: 612 m³/d/pad
- SOR: 7.2

Low Performance well pair

Pad 104

![Graph showing oil production, steam injection, and steam-to-oil ratio over time with key events marked: Turn Around, Boiler outage, Liner Perforation.]

- Steam Inj
- Oil
- Water
- iSOR
- CSOR
Orion Pads Performance – Pad 104

Average to date since startup:
[as of Feb 28, 2014]
- Oil: 66 m³/d/pad
- Water: 480 m³/d/pad
- Steam: 487 m³/d/pad
- CSOR: 7.46
- RF: 10.1 %
Orion Pads Performance – Pad 104

Current Pad Average Operating Chamber Pressure = 3778 kPa

Pad 104 Injection Pressures

- Blue: Pad 104 Injector 1 Casing Pressure
- Red: Pad 104 Injector 2 Casing Pressure
- Green: Pad 104 Injector 3 Casing Pressure
- Purple: Pad 104 Injector 4 Casing Pressure

Date range: 1/1/2012 to 1/1/2014
Orion Pads Performance – Pad 104

104 OB1

- Wells were placed in a moderate quality reservoir hindering early communication between injector and producer and limiting steam chamber growth.

- Reverse SAGD operation improved communication between injector and producer of well pair 1 and well pair 4.

- Positive response to stimulation jobs, but not comparable to 105 wells.

- Production improvement attributed to constant steam supply and optimized operating strategies.
Orion Pads Performance – Pad Pressures
OBIP per Pad

- OBIP calculated by volumetric method
- The inter well spacing at Orion is 100 m, horizontal well section at 660 m on average
- The formula used is:
  - \( OBIP = GRV \times NTG \times PHI \times So / Bo \)

<table>
<thead>
<tr>
<th>Pads / Pilot</th>
<th>OBIP (e3m3)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I1P1</td>
<td>593</td>
</tr>
<tr>
<td>I3P3</td>
<td>566</td>
</tr>
<tr>
<td>Pad103</td>
<td>1447</td>
</tr>
<tr>
<td>Pad104</td>
<td>1391</td>
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<tr>
<td>Pad105</td>
<td>1431</td>
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<tr>
<td>Pad106</td>
<td>1270</td>
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<tr>
<td>Pad107</td>
<td>1391</td>
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</table>
## Recovery Factors

<table>
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<tr>
<th>Pads / Pilot</th>
<th>Cum. Production (Feb 2014, e³m³)</th>
<th>RF % (Jan 2014)</th>
<th>Ultimate Recovery (e³m³)</th>
<th>Expected RF (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>I1P1</td>
<td>263.4</td>
<td>44.4</td>
<td>305</td>
<td>51</td>
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<tr>
<td>I3P3</td>
<td>226.5</td>
<td>40.0</td>
<td>260</td>
<td>46</td>
</tr>
<tr>
<td>Pad103</td>
<td>252.9</td>
<td>17.5</td>
<td>662</td>
<td>46</td>
</tr>
<tr>
<td>Pad104</td>
<td>141.0</td>
<td>10.1</td>
<td>328</td>
<td>24</td>
</tr>
<tr>
<td>Pad105</td>
<td>307.5</td>
<td>21.5</td>
<td>670</td>
<td>47</td>
</tr>
<tr>
<td>Pad106</td>
<td>170.9</td>
<td>13.5</td>
<td>455</td>
<td>36</td>
</tr>
<tr>
<td>Pad107</td>
<td>271.9</td>
<td>19.5</td>
<td>646</td>
<td>46</td>
</tr>
</tbody>
</table>
None of the Orion Pads or the Pilot wells will be abandoned in the upcoming five years.
Scheme Performance Prediction

Performance forecast

- Volumetric estimation of OBIP
- Early performance of SAGD gives reasonable prediction on later performance
- CSOR vs. reservoir properties correlation

RF

- 50% expected RF on productive intervals (facies with good reservoir quality)
- 25% RF from low-productive intervals (facies with lower reservoir quality)
Actual Injection Conditions vs. Approved Design

- Original approved wellhead injection pressure of 5 MPa, approval increased to 6 MPa on Sept 18, 2008.

- Most wells operated at 3-4 MPa bottom hole pressure (4 to 5.9 MPa at surface).

- Highest bottom hole pressure of 3.9 MPa (Pad 105 and 107), equivalent to ~5.5 MPa surface pressure.

- Clearwater bottom hole fracture pressure estimated at ~9 MPa

- 100% quality steam is generated at the central facilities

- Estimated wellhead steam quality ~ 95% (impacted by the injection rate, insulation quality and distance from boilers)
Initial performance is dependent on well pair placement within the high quality resource. Future wells will incorporate this knowledge in order to improve their SAGD efficiency.

Well pairs placed within the moderate quality resource showed lower deliverability at early stages but are eventually improving oil production as their steam chambers evolve with more continuous injection.

Differential pressure between injectors and producers and oil production improve significantly after chemical stimulations. Chemical stimulations are done on producers only, injectors do not show scale build up.

Pilot producers are not historically impacted by skin building, hence, no stimulations were needed to improve their deliverability.

The effect of steam breakthrough is successfully mitigated by installation of scab liners.

There was a noticeable improvement in SORs after artificial lift installations.

Liner perforation campaign significantly reduces differential pressure between injectors and producers (dP reduces to ~250 kPa), and looks like it may be maintained for the life of the well.

2013 showed an improvement in plant and field reliability.
## Today’s Agenda

<table>
<thead>
<tr>
<th>Topic</th>
<th>Presenter(s)</th>
</tr>
</thead>
<tbody>
<tr>
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<tr>
<td><strong>Subsurface Issues Related to Resource Evaluation and Recovery</strong></td>
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<td></td>
<td>Grant Zellweger</td>
</tr>
<tr>
<td></td>
<td>Derek Parker</td>
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</table>
Future Plans – Field Development

- Short term: Shell is planning to drill 2 SAGD well pairs from an existing pad in 2014/2015 in order to increase the production.

- Long term: Shell is also planning to fill the Phase 1 plant production by drilling additional SAGD wells when the steam is available in future after depletion of current wells.
New Pad (P108) Proposal for 2014 to 2015 Drilling
P108 Well Trajectory

P108 -- I2P2 Intersection

[Graph showing well trajectory data]
Steam Strategy Plan
## Today’s Agenda

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Shell Orion
Complex Plot Plan

Install Process Line

Reclamation

Pad 105

Groundwater Well Installation
Surface Facility Process Flow

- **SAGD WELLS**
- **PRODUCTION PADS**
- **PRODUCED GAS**
- **PRODUCED GAS SEPARATOR**
- **VAPOR RECOVERY UNIT**
- **SKIM TANK**
- **SKIM OIL**
- **SALES OIL**
- **SALES OIL**
- **DE-OILING**
- **INDUCED STATIC FLotation**
- **OIL REMOVAL FILTER**
- **OIL**
- **OIL**
- **OIL**
- **OIL ENTO**
- **LACT**
- **PIPELINE**
- **STEAM GENERATION**
- **WATER TREATMENT**
- **BOILER**
- **BOILER FEEDWATER**
- **VAPOUR SEPARATOR**
- **EVAPORATOR**
- **GENERATOR**
- **NATURAL GAS MAKE UP**
- **HP FLARE**
- **LP FLARE**
The central processing facility has two conventional drum boilers to generate steam to inject into the reservoir to heat the bitumen.

The crude emulsion is three phases: bitumen, water and small amounts of gas. The emulsion is sent via pipeline to the central processing facility for separation.

The small amount of gas separated from the bitumen, along with purchased natural gas and Vapor Recovery Unit (VRU) gas is burned as fuel in the boilers.

The water treatment facilities clean and treat the produced water so that it can be re-used to generate steam. The process allows us to reuse more than 90% of produced water. Brackish water is the primary source of industrial makeup water.

The waste produced during the water recycling and treatment process is trucked offsite to an AER approved waste disposal facility.
Well Pad Facilities

- The facility has 5 well pads with a total of 23 well pairs, including 106-WP4 whose producer was abandoned in December 2013.
- Typical well pad configuration of a well pad is 4 well pairs, which consist of 4 injector wells and 4 producer wells.
The Bitumen treating system allows for three phase separation (Oil, Water, Gas) of the produced emulsion fluid. Primary equipment consists of:

- Diluent injection system for emulsion separation requirements and sales oil blending specifications
- Chemical injection for emulsion separation requirements
- 3 Phase separation equipment; Free Water Knock Out and Treater (the treater is equipped with an electrostatic grid)
- Heat exchange equipment; shell and tube for bitumen coolers and produced water cooling. Heat rejected is consumed in both the Glycol and BFW systems to aid in heat integration
- Diluent recovery system
- Bitumen storage and blending for transport via pipeline
- Bitumen quality (Sales Oil) is < 0.5 BS&W
The vapour recovery system allows for collection, compression and complete utilization of produced vapours. All recovered vapour is used as fuel in the steam generation system:

- Evaporator vent recovery
- 10 tanks
- Diluent recovery system
- Induced Gas Floatation

The vapour recovery system is integrated with the LP flare system. If the vapour recovery system is not available the recovered vapour is diverted to the LP flare system.

The vapour recovery system reliability was 95.21 %. Downtime was largely attributed to boiler down time.
Produced Water from the Production Treating Train is Deoiled using the following equipment

- Skim Tank – Designed to maximize retention time
- Induced Gas Floatation Vessel – Micro-Bubble Floatation
  - Hydrocarbon Content < 10ppm oil/water
- Oil Removal Filters – Walnut Deep Bed Filtration
Evaporator technology is utilized to generate boiler feedwater

- Produce BFW that meets or exceeds the water criteria set out by ASME
- Generate a concentrated brine waste stream that is disposed of at an AER approved facility
- Design of 95% conversion rate of feed to distillate
Monthly Steam Production - 2013

Design Capacity
~ 144,500 m³/month
Monthly Gas Usage – 2013

The chart shows the monthly gas usage from January to December 2013. The bars represent the total gas usage in cubic meters (m³) for each month, with separate segments for produced gas and purchased gas.
Challenges/Limitations

- AER Facility Licence Amendment
- TDS Anomaly - Management Plan
  - Pad 105 TDs Anomaly
  - Pad outage December 2012 – February 2013 to complete well casing integrity testing
Plant Additions/Modifications

- Upgrade the well test sampling stations, installed BS & W online analyzer
- Pad106 Well Pair 4 – abandoned
- New Well Pair – Pad 106 Well Pair 5
- Installed Slop Oil line to Sales Oil system
Future Plant Additions/Modifications

- Submitted Alberta Energy Resources application to convert the McMurray disposal well into a brackish water source well
- Submitted two Scheme amendments
  - Two SAGD well pairs
  - Additional produced gas cooler to increase cooling capacity
approved MARP

Annual revision submitted February 25, 2014

Preventive Maintenance program in place to manage calibrations and servicing of reporting and accounting meters
# Orion Measurement, Accounting & Reporting Plan (MARP)

## Production Well Testing

<table>
<thead>
<tr>
<th>Pad</th>
<th>Separator</th>
<th>Purge Time</th>
<th>Test Durations</th>
<th>Test Frequency</th>
<th>BS&amp;W Samples</th>
<th>AER Requirements</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pads (5 Pads with 4 Well Pairs/Pad plus Hilda with 2 Well Pairs)</td>
<td>2 Phase Separator</td>
<td>&lt; 0.5 hours</td>
<td>• 4-6 Hours – Optimization Well Tests &amp; 12-18 Hours – AER Reporting Well Tests</td>
<td>4-6 Hours – Optimization Well Tests – 3X/Week (During Weekdays) 12-18 Hours – AER Reporting Well Tests – 1X/Week (During Weekends)</td>
<td>Twice per week to determine Well Pair Producer BS&amp;W, which is used to calculate Oil and Water Rates. Samples are taken near the end of Well Tests to ensure maximum purge time.</td>
<td>Proration Well Testing Schedule. Class 1 - &lt; 30 m3/d Oil production. Required Testing - minimum 3 Well Tests / month for a minimum of 12 hour duration and a minimum of 5 days between Well Tests.</td>
</tr>
</tbody>
</table>
Bitumen Proration is determined as follows

- PF = Produced Bitumen / Estimated Bitumen

- Produced Bitumen consists of
  - Dilbit Sales from Orion to IPF
  - Tank inventories (Density correction is applied)
  - Diluent received

- Estimated Bitumen as follows
  - Totalized test separator emulsion meter less the water
Produced Water Proration is determined as follows

- PF = Battery Water Production / Estimated Produced Water

- Battery Water Production consists of
  - $\sum \text{Dispositions} - \sum \text{Receipts}$
    - Dispositions as follows
    - Waters from the FWKO, Treater, Produced Gas Sep, Diluent Recovery, and Mixed Gas Drum
    - Receipts as follows
    - Recycled product from T-2000, Evaporator Wash Water, Recycle from IGF, Odor Control to Slop

- Estimated Produced Water consists of
  - Totalized Test Sep Emulsion * WC% + Water In Gas phase
Produced Gas Proration is determined as follows

- PF = Battery Gas Production / Estimated Produced Gas

- Battery Gas Production = Dispositions + Fuel + Flare - Receipts
  - Dispositions = \( \sum \) Gas to Boilers
  - Fuel = Pilot Gas to Flare Stacks (calculated)
  - Flare = \( \sum \) Flare meters

- Estimated Produced Gas consists of
  - Well Test Bitumen Production * Facility GOR

  GOR is calculated as follows; Battery Gas Production / Battery Bitumen Production (calculated on a monthly basis)
Water Balance / Recycle Rate is Calculated as follows:

- \( \frac{\text{Steam Injected} - \text{(Fresh Water)}}{\text{Produced Water}} \times 100 \)

Diluent is metered prior to injection for treating and for pipeline viscosity/density specifications.

Purchased gas is measured upstream of mixed gas drum.
Water Proration Factors – 2013

0.60

0.80

1.00

1.20

Proration Factor

0.85% to 1.15 % range

0.00 0.20 0.40 0.60

Proration Factor

January  February  March  April  May  June  July  August  September  October  November  December
Orion draws fresh water from water source well (WSW) 13-16-64-3W4 as per Alberta Environment and Water, License to Divert Water Approval #242090-00-00

Water diversion volume for 2013

- 1798 m³, 7.5% of the total allowable diversion of 23,725 m³
- Total Dissolved Solids – 720 mg/L

The license to divert water is for the following industrial purposes:

- Utility water supply for the administration buildings
- Eye wash and emergency showers
- Evaporator pump seals (converted to distillate water)
Brackish Water Usage - 2013

- Brackish water is taken from the McMurray formation and used as industrial make up
- AER Licensed Water Source Wells
  - 102/11-16-64-3W4M
    Converted into an observation well
  - 100/15-16-64-3W4M
    2013 usage = 76,292 m³
    Total Dissolved Solids = 11,000 mg/L
- Brackish water usage 2013
  Total 2013 usage = 76,292 m³
Water Disposal Limits 2013

Graph showing disposal limits and actual disposal volumes for each month. The graph includes columns for disposal volume limit (m3), disposal limit (%), and actual disposal (%). The disposal limits and actual disposals are compared over the months from January to December.
On-site Water Disposal – 2013

- License permits produced water and recovered steam condensate to be disposed of into the Granite Wash and McMurray Formations, respectively. Disposal Approval #8175

- Granite Wash water disposal well – produced water
  AER licence # 0192346  02/16-17-064-03W40
  - Normal operating pressure 9,000 kPa. The disposal system is protected by a high pressure shutdown limit of 13,950 kPa.
  - Normal disposal temperature 75°C
  - 2013 Disposal Volume 1,439 m³

- McMurray water disposal well – steam condensate/softener regen
  AER licence # 0196880  03/16-17-064-03W40
  - Suspended November 2011
Off-site Waste Disposal – 2013

- Tervita – Lindbergh (LSD 05-26-056-05W4)
  - Treatment, Recovery & Disposal (TRD) Facility
  - Evaporator Brine waste (Waste Corrosive Liquid - WSTCLQ) total volume 71,043 m³

- NewAlta Corporation – Elk Point (LSD 03-15-55-06W4)
  - Petroleum waste oil (Crude Oil/Condensate Emulsion - COEMUL) total volume 50 m³

- RBW Waste Management
  - Recycling or disposal at the Edmonton facility
  - Solid waste contaminated with hydrocarbons (Waste Corrosive Misc. – WSTMIS) total volume
Domestic Waste Disposal – 2012

- Domestic wastewater
  - The domestic waste water system consists of the administrative office restrooms and kitchen. They are collected once per week by a commercial septic service.
  - No problems or irregularities in the performance of the sewage system and associated equipment
  - The total volume of domestic wastewater hauled to the Town of Bonnyville municipal waste facility was 2,345 m$^3$

- Paper/Cardboard Recycle
  - Paper and cardboard recycle program
Flare Volumes – 2013

Flare Volume (e3m3)
GHG Emissions – 2013

Total Direct Emissions (t CO₂e/month)
Air Monitoring Program

- The monthly and annual Air Emissions and Monitoring reports were submitted to Alberta Environment and Sustainable Resource Development.
- Shell Canada has continued operating the passive monitoring network to maintain historical monitoring and to continue stakeholder monitoring commitments.
- The ambient air monitoring requirements for Alberta Environment and Sustainable Resource Development Approval #141258-00 is satisfied through the Lakeland Industry and Community Association LICA Airshed Network.
- Active funding member of Lakeland Industry Community Association (LICA). Shell Canada has an industry representative on the Board of Directors (Secretary – Treasurer) and Airshed Committee.
- The Annual Fugitive Emission and Leak Detection Program was conducted in December 2013 in which four leaks were identified. All repairs are scheduled for repair during the facility outage in June 2014.
Soil Monitoring Program

- The 2nd Soil Monitoring Proposal Program was submitted to Alberta Environment and Sustainable Resource Development in January 2014. The 2nd Soil Monitoring activities are tentatively scheduled for Q2/Q3 2014.

- There were no soil management program activities. An informational letter update was submitted to Alberta Environment and Sustainable Resource Development in March 2014.
Groundwater Monitoring

- The Annual Groundwater Monitoring Program and reporting for Orion continued through 2013. The annual report was submitted to Alberta Environment and Sustainable Resource Development in March 2014.

- The Arsenic Groundwater Monitoring Program continued and now consists of 23 monitoring wells with the incorporation of three additional monitoring well installed nearby Pad 105.

- Identify and determine the source of a TDS anomaly observed in the Empress 3 aquifer (Well MW07-11) located near Pad 105. Shell Orion operations and surveillance staff worked collaboratively with Alberta Environment and Sustainable Development Resources and Alberta Energy Regulator (previously the Energy Resource and Conservation Board).
Groundwater Monitoring

The TDS Anomaly Management Program initially focused on the Orion Pad 105 well integrity and observed groundwater monitoring well (MW07-11) anomalies. Shell endeavored to provide scientific proof of the “source and cause” in the Empress 3 groundwater aquifer. Shell completed several activities to demonstrate Pad 105 well casing integrity.

- Nitrogen depression testing,
- Well Casing Pressure Integrity Campaign – Completed integrity testing on 8 wells,
- Temperature data logs - discussion with respect to the cement bond log quality and the interpretation of each well log.
In conjunction with the well integrity activities, Shell implemented the following groundwater monitoring activities;

- Increase the sampling frequency at MW07-11 from biannually to monthly;
- Added water temperature and water level monitoring equipment;
- And installed four additional groundwater monitoring wells.

It was determined that the “The chemical changes occurring in Empress 3 Formation beneath Pad 105 are related to release of saline water from upper bedrock or rafted sections of upper bedrock deposited within the Empress Formation” (J. Fennel, 2013)
Casing Pressure Actual temperature profile and its magnitude observed in the Empress 3 aquifer (MW-07-11) could be reproduced using a 3D layer-cake model.

The model confirms that the temperature propagation observed around the water monitoring well MW-07-11 is due to wellbore conduction and aquifer flow convection.
Groundwater Monitoring - Evaluation

- Evaluation of mobilization of Arsenic associated with increased groundwater temperatures since 2007
- Temperature and elevated arsenic observed in Empress 3 unit
- Point of management and point of compliance in place
- Very good likelihood that some aquifers are disconnected; no direct pathway to receptors
- Distance to receptors and GW flow velocities indicate low risk from thermal mobilization
- Current monitoring program sufficient; modeling to be updated as required.
Wildlife Monitoring Program

- The Wildlife Monitoring Program continued and reported to Alberta Environment and Sustainable Resource Development in March 2014.

- As a component of the Wildlife Monitoring Program, we are submitting application to continue the Above Ground Pipeline remote camera monitoring in lieu of manual tracking surveys.
The Annual Industrial Wastewater and Runoff report was submitted to Alberta Environment and Sustainable Resource Development in February 2014 with no anomalies.

The Annual Conservation and Reclamation report was submitted to Alberta Environment and Sustainable Resource Development in March 2014.
Environmental - Initiatives

Continued the residential water well testing – conducted biannually at two locations
Shell Canada Energy did not receive or amend any Alberta Environment and Sustainable Resource Development Approvals associated with the Orion facility.
To the best of Shell’s knowledge, operations are consistent with all conditions of the Orion approvals and regulatory requirements.