Annual Surmont SAGD Performance Review Approvals 9426, 11596, and 9460

April 28, 2015

Calgary, Alberta, Canada
• Introduction, Overview and Highlights
• Subsurface Resource Evaluation and Recovery
• Surface Operations and Compliance - Phase 1
• Future Plans
• Surface Operations and Compliance - Pilot Project
Introduction, Overview and Highlights
Ownership and Approvals

Ownership

• The Surmont In Situ Oil Sands Project is a 50/50 joint venture between ConocoPhillips Canada Resources Corp. and TOTAL E&P Canada Ltd; Operated by ConocoPhillips

Project History

• 1997 - First steam at pilot project
• 2007 - First steam at Phase 1
• 2010 - Construction start at Phase 2

Approval Update - AER Approval No. 9426

• Amendments 9426Y and 9426Z
  • Geological Cross-Sections for Well Pads 262-1, 262-2, 266-2
• Amendments 9426AA and 9426BB
  • Sustaining Well Pads 104 and 267
• Amendments 9426BB and 9426CC
  • Outboard Wells for Well Pads 264, 265, 266
  • Buffer Well and Fishbone Well for Well Pad 266-2
• Application 1800069
  • Surmont Phase 3
Surmont Overview

Phase 1 is focused on improving well & facility uptime and steam quality.

Surmont combined approved capacity is 21,624 m³/d (136,000 bbl/cd)*
*(Phase 1 - 4,293 m³/d, Phase 2 - 17,331 m³/d)
2014 Highlights

- Continuous improvement results in record production
  - Steam deliverability and uptime
  - ESP Run Time and Optimization
  - Total system concept to shelter volumes

- Phase Two Operational Readiness
  - Leveraging learnings from Phase 1 and other operators
  - Developing startup plans and procedures
  - Rehearsals/walkthroughs/etc

- Sustaining pads
  - Pad 101-24/25/26 deferred to 2016
  - Pad 103 start-up planned for 2015

- Additional steam deferred to 2017
  - May re-think this strategy in current economic environment
**Surmont 1 Performance**

### Historical Steam Injection and Bitumen Production

- **MBPD**
  - Steam (cwebpd)
  - Oil (boepd)

#### 2007-2008
- Unstable Ramp-Up

#### 2009
- Steam Gen Issues
- 2009 Steady Operations

#### 2010-2012
- Stable operations reaching “capacity”

#### 2013+
- Continuous Improvement

### Average Steam Uptime

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<tr>
<th>Year</th>
<th>Uptime</th>
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<td>2009</td>
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<td>2013</td>
<td>96%</td>
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<td>2014</td>
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### SOR and WOR

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<th>Year</th>
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<td>2008</td>
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<td>2014</td>
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#### Key Issues

- **2007 Key Issues**
  - Commissioning
  - Manpower
  - Off-spec product
  - Freezing
  - Minimum Turndown

- **2008 Key Issues**
  - Freezing
  - Off-spec product
  - Plant Instability
  - Well Integrity
  - Well Constraints

- **2009 Key Issues**
  - OTSG integrity
  - Front-end treatment
  - 1st turnaround
  - Well Constraints

- **2010-2012 Key Issues**
  - ESP installations/repair
  - OTSG maintenance
  - 2011 Turnaround
  - Well Constraints

- **2013+ Key Issues**
  - ESP installations/repair
  - OTSG maintenance
  - 2014 Turnaround
  - Well & Facility Optimization
2014 Loss Production Rollup

Losses Avg. History

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<th>Year</th>
<th>Losses Avg.</th>
<th>1,220 bpd exc. T/A</th>
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<td>3,737 bpd</td>
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<td>2013</td>
<td>2,164 bpd</td>
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<td>2012</td>
<td>2,437 bpd</td>
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<tr>
<td>2011</td>
<td>3,376 bpd</td>
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83% Facilities (incl. T/A and weather) 17% Wells

Oil Losses Categories

- Facilities
- Wells

2,976 857 570 0
1,249 1,621 1,407 3,465
2,952 361 1,920 0
Subsurface Resource Evaluation and Recovery

Subsection 3.1.1 (2) Geology and Geophysics
2014-2015 Delineation Campaign and Well Density

Subsection 3.1.1 (2f)

Delineation Wells - Surmont Lease

- 1372 existing wells – 96 new
- 96 new vertical wells (as of Jan 31, 2015)

Phase 1 and Phase 2
Development Area
Drainage Areas
Surmont lease
Focus on Surmont Phase 1 sustaining pad locations as well as delineation of Phase 3
(only wells that penetrate the McMurray)

- **Existing wells**
- **New vertical wells (as of Jan 31, 2015)**
- **Phase 1 and Phase 2 Development Area**
- **Drainage Areas**
- **Surmont lease**
2014-2015 Delineation Campaign and Core Density

- 1372 wells total
- 520 existing core wells
- 35 new core wells (as of Jan 31, 2015)
- Phase 1 and Phase 2 Development Area
- Drainage Areas
- Surmont lease
Existing wells
Existing cored wells
New core wells (as of Jan 31, 2015)
Phase 1 and Phase 2 Development Area
Drainage Areas
Surmont lease
2014-2015 Delineation Campaign and FMI/CMI Logs

1372 wells total
993 existing FMI/CMI wells
95 new FMI/CMI wells (as of Jan 31, 2015)

Phase 1 and Phase 2 Development Area
Drainage Areas

McMurray FMI Wells - Surmont Lease

100% Coverage of FMI/CMI Data in 2014/2015 program
• Important for breccia identification

1372 wells total
993 existing FMI/CMI wells
95 new FMI/CMI wells (as of Jan 31, 2015)
100% Coverage of FMI/CMI Data in 2014/2015 program

- Important for breccia identification

- Existing wells
- Existing FMI wells
- New FMI wells (as of Jan 31, 2015)
- Phase 1 and Phase 2 Development Area
- Drainage Areas
- Surmont lease
Delineation across Phase 1, 2, and 3

Delineation Well Density Map - Jan 2014

Delineation Well Density Map - Jan 2015

McMurray penetrated wells only

Symbol Legend
- 1 well
- 2-5 wells
- 6-10 wells
- 11-20 wells
- 21-50 wells
- Development Area
- Dunmore Lease

Kilometers
Increased Formation Micro Imaging density with latest drilling

2014-2015 Delineation Campaign and FMI Logs

FMI Well Log Density Map – Jan 2014

FMI Well Log Density Map – Jan 2015

McMurray penetrated wells only
2014-2015 Delineation Campaign and Well Density

Increased core density with latest drilling

Cored Wells Density Map - Jan 2014

Cored Wells Density Map - Jan 2015

McMurray penetrated wells only

Subsection 3.1.1 (2f)
### Reservoir Characteristics

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<th>101N</th>
<th>101S</th>
<th>102N</th>
<th>102S</th>
<th>Lease</th>
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<td>Phie in NCB</td>
<td>32.8%</td>
<td>33.6%</td>
<td>33.1%</td>
<td>31.7%</td>
<td>32.33%</td>
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<td>So in NCB</td>
<td>81.8%</td>
<td>83%</td>
<td>81.6%</td>
<td>73.5%</td>
<td>78.61%</td>
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<tr>
<td>KH in NCB</td>
<td>4425 mD</td>
<td>5306 mD</td>
<td>4538 mD</td>
<td>3801 mD</td>
<td>4569 mD</td>
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<td>KV in NCB</td>
<td>3670 mD</td>
<td>4452 mD</td>
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<td>Initial Pressure (KPA)</td>
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<td>~1000</td>
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<td>Temperature (°C)</td>
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Subsection 3.1.1 (2b)

**Surmont lease**

**Drainage areas**
McMurray Gross Isopach

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

Subsection 3.1.1 (2c)
McMurray Net Gas Isopach

Net Top Gas thickness = sands have deep resistivity \( \geq 10 \, \Omega \cdot m \) and \( Vsh < 65\% \)

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area

Phase 1 & 2 Drainage Areas

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation
McMurray Net Top Water Isopach

Net Top Water thickness = sands have deep resistivity <10 $\Omega$-m and Vsh <45%

2014/2015 Delineation Program Update
- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation
McMurray Top Continuous Bitumen Structure

TCB = The uppermost limit of good reservoir, bitumen-bearing sands.

2014/2015 Delineation Program Update
- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

Phase 1 & 2 Development Area
Phase 1 & 2 Drainage Areas
3D seismic areas used for mapping (all 12 volumes)
Surmont lease

Top Continuous Bitumen Structure
McMurray Base Continuous Bitumen Structure

BCB = First occurrence of good reservoir, bitumen-bearing sands.

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area
Phase 1 & 2 Drainage Areas

2014/2015 Delineation Program Update
- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

Base Continuous Bitumen Structure
McMurray Net Continuous Bitumen Pay

Subsection 3.1.1 (2c)

Net continuous bitumen = sands have deep resistivity > 40 Ω·m and Vsh <33%, and no shale greater than 3 m thick

Phase 1 & 2 Development Area

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Net continuous bitumen = sands have deep resistivity > 40 Ω·m and Vsh <33%, and no shale greater than 3 m thick

2014/2015 Delineation Program Update

- December 2014 – minor changes due to:
  - Re-evaluated/unified geologic picks
  - Improved Seismic Interpretation

Subsection 3.1.1 (2d)
Surmont Lease OBIP

3D seismic areas used for mapping (all 12 volumes)

Surmont lease

Phase 1 & 2 Development Area
Phase 1 & 2 Drainage Areas

<table>
<thead>
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<th>Properties</th>
<th>Development Area</th>
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<tr>
<td>NCB Thickness Range</td>
<td>0 to Greater than 30 m</td>
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<tr>
<td>Phie in NCB</td>
<td>32.33%</td>
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<td>So in NCB</td>
<td>78.61%</td>
</tr>
<tr>
<td>OOIP in NCB &gt; 18m</td>
<td>3362.23 MMbbls Deterministic</td>
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OBIP = Thickness x Phie x So x Area

Subsection 3.1.1 (2a, 2b, 2c)
Phase 1 Type Log Well Pad 101

Example Log 100161408307w400

McMurray
Continuous Bitumen
High Sw
Devonian

Phase 1 Area

Pad 101
Type Log

Subsection 3.1.1 (2e)
Phase 2 Type Log – Well Pad 264-2

Example Log 100162208306w400

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McMurray
Top Gas
High Sw

Continuous Bitumen

Devonian

Phase 2 Area
Objectives

- Characterize vertical and lateral variance in viscosity at different temperatures
- Model the variance in bitumen properties and its implications for bitumen production rates during SAGD
- Characterize relationship between viscosity, density and geochemical composition

No change in 2014.
Viscosity increases with depth in the McMurray Formation.

51 existing viscosity sample wells

Delineated Wells - Surmont
Representative Structural Cross Section

- Surmont 1 Pad 102
- Surmont 1 Pad 101
- Pilot
- Surmont 2 Initial DA
- Lower Grand Rapids
- Clearwater Shale
- Clearwater Marker
- Wabiskaw / McMurray Marker
- Devonian Unconformity

10:1 vertical exaggeration
A well at 4-3-84-6 W4M intersected a raised bitumen/water contact, the contact is ~12 m higher than the nearest offset.

The well also intersected a small gas pool under the bitumen.

The presence of basal water becomes a risk on Well Pad 262-1.
**INSAR Surface Deformation Monitoring**

- Interferometric Synthetic Aperture Radar Images
  - Data is collected every 24 days
- Data acquisition initiated after first steam in 2008
  - Data used for Geomechanical Model Calibration
- CRs 1 to 20 installed March 2008
- CRs 21 to 47 installed March 2010
- CRs 48 to 72 installed March 2012
- CRs 226 to 244 installed March 2014

- Deformation currently in line with expectations
- Maximum deformation seen in CRs 29-33, over pad 101N.
- Several CRs were replaced in Spring 2014, including CR14 which was affected by frost heave.

**Location Map of CR Points**

**Cumulative Deformation April 2012 to December 2014**
Conclusions from the study:

- The best seals within the cap rock interval are the deeper water deposits occurring on maximum flooding surfaces.
- These muds can be over 80% clay and are correlated throughout and beyond the Surmont lease.

7 new cap rock cores in 2015

Cap rock interval investigation included:
- Core description and analyses
- Log interpretation and correlation
- Seismic interpretation and correlation

Analytical methods included:
- Visual core examination,
- Reflected light microscopy,
- Laser particle size analysis,
- Biostratigraphic analyses,
- X-ray diffraction for clay species,
- QEMSCAN (quantitative mineralogy),
- Chemostratigraphy (bulk geochemistry) and
- MICP (mercury injection capillary pressure) analyses to determine seal capacity
Conclusions from the study:

- In the 2011 testing, despite the varying conditions tested, the retained minimum stress gradient of the cap rock at 18.4 kPa/m was further validated.
- The recommended MOP gradient is 15 kPa/m (@SF=1.2) which is lower than previous by applying a higher factor of safety.

- Three mini-frac tests targeted the most structurally complex features currently identifiable across the lease based on mapped structures of the Devonian, McMurray, cap rock, and overburden.
- All of the 2011 test locations were proposed to, and reviewed by the AER prior to execution of the tests. The locations include variability in other features such as proximity to gas depletion, overburden, karsting and other structural variability.
- Other Maximum Operating Pressure (MOP) supporting data, includes cap rock core samples subjected to tri-axial testing, log data, FMI interpretations, seismic, etc., combined with the overall cap rock characterization, reservoir simulation and geomechanical modeling.
Based on the cap rock integrity studies, ConocoPhillips has proposed a maximum pressure of 15kpa/m.

Circulation optimization including dilation is an area of ongoing study.

Pace of pressure drops will be largely driven by:
- Specific, local reservoir properties,
- Thief zone interactions,
- Economics,
- ESP installations,
- Plant capacity, and
- Global steam optimization.

ConocoPhillips continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated MOP on one side and economic achievable pressures on the low side.
Subsection 3.1.1 (3)
Drilling and Completions
Well Summary

- 6 drainage areas
  - Pilot
  - 101 North
  - 101 South
  - 102 North
  - 102 South
  - Pad 103

- 56 well pairs, 4 infill producers

Pilot (3 well pairs)
Phase 1A (21 drilled – 20 completed)
Phase 1A redrills (3 wells)
Phase 1B (7 drilled – 7 completed)
Phase 1C (8 drilled well pairs – 8 completed)
Pad 101 South 2011-2012 Infills
Pad 103 (12 pairs drilled – 2 inj. wells completed)
Pad 101 Plot Plan

<table>
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<tr>
<th>Surface Well Name</th>
<th>Downhole Well Name</th>
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<tbody>
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<td>101-26</td>
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Subsection 3.1.1 (3a)
2014 update:
- Infill Pairs 24, 25, and 26 are drilled and completed, but not producing
- 101-P20 converted to Electric Submersible Pump (ESP)
Subsection 3.1.1 (3b)

2014 Update:
• Infill producers 21 and 22 Completed

Pad 102 Completions

- Mechanical Lift Completion Well
- Concentric Completion Well
- Parallel Completion Well

Phase 1B

P22

P21

Phase 1B
## Pad 101 & 102 Well Completions

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<th>Well Identifier Surface (Downhole)</th>
<th>Producer Completion</th>
<th>Injector Completion</th>
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<td>101-22 (11INF)</td>
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**Notes:**
- This well is not online.

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<td>Concentric</td>
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<tr>
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<td>ESP</td>
<td>Concentric</td>
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<td>102-21 (INF)</td>
<td>PCP</td>
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<tr>
<td>102-22 (INF)</td>
<td>PCP</td>
<td>N/A</td>
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</tbody>
</table>
Phase 1 Typical Parallel Injector

11 3/4” Intermediate Casing
4 1/2” Heel String
2 7/8” Toe String
8 5/8” slotted liner

No change in 2014
Phase 1 Typical Concentric Injector

11 3/4” Intermediate Casing

7” Heel String

16” Conductor Pipe

8 5/8” Slotted Liner

4” Toe String

No change in 2014
Phase 1 Typical Concentric Producer

5/8” TC Bubble Tube Instrument Control Line Clamped to the Outside of Toe Tubing

- 13 3/8” Conductor Pipe
- 1” G/L Coil
- 9 5/8” Intermediate casing
- 7” Heel String
- ¼” Bubble Tube
- 4” Toe String
- 7” Slotted Liner

No change in 2014
Phase 1 Typical PCP Producer

- 9 5/8" Intermediate Casing
- 3.5" Production Tubing
- 3/8" Bubble Tube + 2x ¼" Encapsulated F.O. P/T Instrumentation Cables Clamped (Intake)
- Sucker Rod / CoRod
- Progressive Cavity Pump (PCP)
- 7" Slotted Liner
- 40pt Fibre Optic Temp Coil
- 2 1/16" x 3-1/2" Guide String / Steam Warm-up line
- No change in 2014
Phase 1 Typical ESP Producer

- **9 5/8” Intermediate casing**
- **3.5” Production Tubing**
- **3/8” Bubble tube + power cable + 2x ¼” encapsulated F.O. P/T instrumentation cables clamped (intake/discharge)**
- **2 1/16” Guide string**
- **Liner Hanger**
- **40pt Fibre Optic Temp Coil**
- **7” slotted liner**
- **ESP (landed at Well Tangent)**
- **Single Point Fiber P/T**

No change in 2014
2013 Infills on Pad 101 & Pad 102 have Flow Control Devices Installed

Typical Flow Control Device

Producer - Circulation & GL Modes

Injector - Circulation & GL Modes
Typical Flow Control Device Completion

Short and long tubing strings during SAGD production:

• During initial circulation a toe tubing string is required, however due to the equalizing character of the FCDs a toe tubing string is not required.

• This concept was tested in the pilot well pair, 102-06, which showed that we could pull back the toe strings to the heel and still have good steam and production performance. However, depending on the injected steam rates, the toe presence of the toe string may not add significant pressure drop along the lateral in the case of the injector well and may not warrant the workover to pull back or remove the string.

• The option exists and can be evaluated on a well or pad level.

• The similar option exists for the producer well and the lateral instrumentation could be run on a separate coil. Again, this option could be evaluated on a well or pad level.
Subsection 3.1.1 (4)
Artificial Lift
Gas Lift

- Gas lift is effective with bottomhole operating pressures >3,000 kPa.
- Current production rates range from 100 m³/d to 700 m³/d of emulsion targeting 3,500 kPa

Electric Submersible Pump (ESP)

- ESP for thermal SAGD applications can be sized to meet the specific deliverability of the well.
- High temperature ESPs can operate at bottom hole temperatures up to 275 ºC.

Progressive Cavity Pumps (PCP)

- Generally PCPs have been used for low deliverability wells and where potential solids may be produced.*

* ConocoPhillips initial strategy for PCPs was to use them on low deliverability wells where the current ESP designs are deemed less appropriate. However, installation of larger PCP are being considered for wells that may produce relatively “cold” viscous fluid for some time.
Artificial Lift Strategy

The artificial lift mode selection is reliant on the pressure strategy for any given well, or drainage area (DA).

- Phase 1A & C wells utilized Gas Lift (GL) and then converted to ESP after steam chamber coalescence.
- Only 2 wells in Pad 101 remain on GL at the end of 2014. The wells are scheduled for ESP conversion in 2015.
- PCP have been selected on wells where the initial deliverability may be low due to technology trials, such as the infill fishbones producers on Pad 102. These wells may be converted to ESP after further on-stream evaluation.
Artificial Lift Performance

Population (on production):
- 34 ESP wells,
- 4 Infill PCP (101-10INF1, 101-11INF1, 102-21, 102-21)*,
- 1 PCP after GL (102-03)*, and
- 2 Gas Lift wells (101-02, 101-03)*

2014 Key Decisions:
- Installation of “Slim” ESP on two wells
  - (102-14, 102-16)*.
- Installation of GE ESP.

Update:
- 9 ESP failures total
- 2 ESP Proactive replacements
- ESP Average Runtime failed = 13 months
- ESP Mean Time To Failure: 27.9 months
- PCP Average Runtime failed = 1 month
- PCP Mean Time To Failure: 25.6 months

* Down hole locations
Subsection 3.1.1 (5)
Instrumentation in Wells
SAGD Well Instrumentation

Newly converted wells in 2014
- Pad 101 – 101-20 (16 INF)
- Pad 102 – 102-10

- All ESP/PCPs are equipped with 40 point fiber optic
  - 101-03 and 101-05 are the only ESP conversions equipped with thermocouples (first ESP completions) with 5 points
- Heel instrumentation includes a bubble tube
Soft cable Thermocouple (TC) strings were replaced by hard cable TC strings for improved well integrity

- Example thermocouple and piezometer (101-07-OBA)
- Typically 30 TC (1.5 m spacing)
- 2-3 piezometers placed at varying intervals

Subsection 3.1.1 (5a, 5b)
**Typical ESP Well Configuration**

- **13-3/8” Conductor**
- **1/4” Bubble Tube Coil (in power cable)**
- **3/8” Instrumentation for motor Temp gauge (clamped)**
- **¼” encapsulated instrumentation line for LxData P/T sensor (clamped)**
- **40 point LxData Instrumentation (Fiber Optics inside of 1.25” Coil)**
- **9-5/8” Intermediate casing**
- **7.0” Slotted Liner or 6-5/8” Equalizer Liner**
- **2-1/16” Guide String**
- **Liner hanger top**
- **Production String 3 ½”**
- **P/T Sensor** clamped to 2-3/8” pup joint
• Lateral instrumentation is key to ensure proper well performance monitoring and integrity (for slotted liners).

• Pressure monitoring redundancy/backup in ESP wells is needed to avoid significant production losses or unnecessary ESP pulls.

• For circulation optimization, fibre optic pressure measure at the toe of the well will be incorporated in new well completions.
Subsection 3.1.1 (6)
4D Seismic
4D Seismic Location Map

Phase 1 Area

Pilot
- Buried analog single component geophones
- Cased dynamite shots (1/4 Kg) @ 9 m
- 13th monitor acquired in September 2014

Pad 101N
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 6th and 7th monitor acquired in March and September 2014

Pad 101S
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 8th monitor acquired in March 2014

Pad 102N
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 8th monitor acquired in April 2014

Pad 102S
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 5th monitor acquired in April 2014

Pads 103 and 104
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- Baseline acquired in April 2012
### Phase 1 4D Seismic Program

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<th>2013</th>
<th>2014</th>
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<tr>
<td>104</td>
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</table>

**Legend:**
- B: Baseline
- M: Monitor
4D Seismic Workflow

- Cross-plot of 4D anomaly volumes versus allocated SAGD oil production volumes from select Phase 1 well pairs.

Because of seismic resolution there are some discrepancies between the total oil produced and the volume of 4D anomalies.
Well Pad 07/08/09, without a true baseline. For the rest of Well Pairs the 4D anomaly volumes have increased. Good conformance, especially at the heel. Well Pads 02/03 are E-SAGD pilot.

4D anomaly volumes have increased. Continued conformance improvement along Well Pad 10, 11, 16, 17.

Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.
4D anomaly volumes have increased. Improve conformance along well pairs 1 to 9.

4D anomaly volumes have increased. Improved conformance along well pairs 10 to 18.
2014 4D Seismic Results Pilot

- Poor SAGD conformance in middle of well pair “C”
- Coalescence between well pair B/A and C
Problem:
- Well pair 101-P16 lacking good conformance along well pair

Action:
- Increase pressure of steam injection at toe

Results:
- Conformance improved at toe

Seismic Examples: 101-P16 Conformance (Toe)
Seismic Examples: 102-04 OBA Baffle Breakthrough (Heel)

- April 2014 4D survey with RST showing steam breakthrough through mudstone

- 2009 RST and 4D surveys confirmed recovery above mudstone
- Operating pressure reduced to manage thief zone interactions
• Objectives - Top water and gas thief zone interaction.
• Poor SAGD conformance in middle of well pair “C”
• Coalescence between WP B/A and C
• 4D seismic has proven very useful in monitoring and optimizing conformance and pressure strategy.

• 4D correlates with observation well data.

• Continuing to optimize heel/toe production/injection splits using 4D results.

• Ongoing efforts to history match reservoir models using 4D seismic.
Subsection 3.1.1 (7)
Scheme Performance
Scheme Performance

Pilot

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<tr>
<th>Bitumen Production bbl/d (m³/d)</th>
<th>Steam Injection bbl/d (m³/d)</th>
<th>ISOR v/v</th>
<th>WOR v/v</th>
<th>RWR %</th>
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Phase 1

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<th>Steam injection bbl/d (m³/d)</th>
<th>ISOR v/v</th>
<th>WOR v/v</th>
<th>RWR %</th>
<th>Water Recycle %</th>
<th>Opp. Efficiency %</th>
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<td>3,446</td>
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<td>3,856</td>
<td>9,450</td>
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<td>2.37</td>
<td>2.39</td>
<td>-1%</td>
<td>88.2%</td>
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</table>

Pilot

- Performance impacted by ESP and subcool target in 2014

Phase 1

- ESP installations in 2013 allowed for a drawdown of liquid levels in 2014 resulting in strong performance
- Benefited from high operating efficiency
- Conducted a successful turnaround in September
- Reservoir Water Retention (RWR) stabilizing with maturity of the steam chambers
- Operating pressures continuing to decline at approximately 250kPa/year
Subsection 3.1.1 (7a,ii)

Moderate performance in 2014 due to pump limitations and operating pressure

Data through Jan 31, 2015

<p>| | |</p>
<table>
<thead>
<tr>
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<tbody>
<tr>
<td>Plant CSOR</td>
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<tr>
<td>Plant CWSR</td>
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<tr>
<td># Well Pairs Started (incl. infill producers)</td>
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<tr>
<td>2014 iSOR avg. (v/v)</td>
<td>4.20</td>
</tr>
</tbody>
</table>
Pilot Performance History

Data through Jan. 31, 2015

- Wellpair A cSOR = 4.32
- Wellpair A cWSR = 1.40
- Recovery Factor: 40.5%

- Wellpair B cSOR = 3.71
- Wellpair B cWSR = 2.27
- Recovery Factor: 48.4%

- Last production 19Jan2014
- Recovery Factor: 7.8%
Deviation from capacity due to:

- Reservoir pressure limiting steam requirement and corresponding production
- P3 pump had failed shutting in production from this well
Status on January 31, 2015

- **Pilot:**
  - 2 well pairs on SAGD
  - Well pair C shut in pending evaluation

- **Phase 1:**
  - 37 well pairs on SAGD
  - 2 infill producers
  - 2 infill fishbone producers
  - 4 cold well pairs

- Surmont Phase 1’s first sustaining Pad planning to start injection/production in 2015

- 5 year outlook - no expected pad abandonments
## Well Lists

<table>
<thead>
<tr>
<th>Alias</th>
<th>Phase</th>
<th>Alias</th>
<th>Phase</th>
<th>Alias</th>
<th>Phase</th>
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<td>101-P01 (10DH)</td>
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<td>101-P15 (15DH)</td>
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<td>102-P22</td>
<td>Infill Well</td>
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</table>
Phase 1 Performance History

- Good performances due to stable operations and well availability
- Stable iSOR for the past three years around 2.5
Deviation from capacity due to:

- Planned / Unplanned power outages
- Well availability:
  - 2 ESP Conversions + 11 ESP Replacements
  - 1 SAGD Conversion (ESP Day1)
  - September Turnaround
### Observation Well Distances to Nearest Well Pair

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<th>UWI</th>
<th>Alias</th>
<th>Distance to Wellpair (m)</th>
<th>UWI of Closest Well</th>
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<table>
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<th>Distance to Wellpair (m)</th>
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<td>OB20</td>
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<td>OB21(Abandoned)</td>
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<td>1.6</td>
<td>1AA042408307W400</td>
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<td>103112408307W400</td>
<td>OB41</td>
<td>16.0</td>
<td>106052408307W400</td>
</tr>
</tbody>
</table>
OBS 36: Heat keeps progressing above breccia

Pilot Well Pair A: OBS36 (Mid)

Subsection 3.1.1 (7b)
- Operated at 1600 kPa for 5-6 years with significant surface area of contact of chamber with thief zone
- Saturated steam temperatures observed in thief zone at OBS22 since 2009
- Gas pressure zones approximately 400kPa below steam chamber pressure
Top Gas Monitoring

**OBS-23 (103/12-24-083)**
- Tested 2 samples in early 2010 from McMR Gas Cap
- Lab gas chromatography with thermal conductivity detector (TCD GC) indicated H₂S conc. ~ 1.09% and 0.28%
- Well currently abandoned due to well integrity issues

**OBS-41 (103/11-24-083)**
- Onsite field test on 6 samples in 2011, 2 samples in 2012, 2 samples in 2013 and 6 samples in 2014 and 3 samples in January 2015
- H₂S con. measured (highest values): 0.61% (2011), 0.42% (2012) and 0.47% (2013)
- Considered representative sample and closest analog for Pad 101
- Most recent samples for H₂S concentrations:
  - Feb 5th, 2014
    - Maximum of 6 samples: Field Observations: 0.42% (4216ppm); Lab Observations: 0.23% (2314ppm)
  - Jan 10th, 2015
    - Maximum of 3 samples: Field Observations: 0.27% (2711ppm); Lab Observations: 0.16% (1632ppm)

**OBS (102/02-24-083)**
- Drilled in Feb 2013 for gas observation
- Onsite field test on 2 samples in 2013; Field Observation 0% (0ppm)
- Most recent samples for H₂S concentrations:
  - Feb 6th, 2014
    - Maximum of 7 samples: Field Observations: 0.00% (0ppm); Lab Observations: 0.00% (<.1ppm)
  - Jan 12th, 2015
    - Maximum of 2 samples: Field Observations: 0.00% (0ppm); Lab Observations: 0.00% (1ppm)
Temperature Measurement

- Thermocouple string installed
- Horizontal observation well with fiber optic
- No temperature monitoring

Pressure Measurement

(as planned after hard cable TC string installation)

Piezos in:
- Bitumen
- Top water
- Bitumen and top water
- Top gas
- Top gas, bitumen and top water
- E-SAGD observation wells with 10 piezometers per well monitoring:
  - bitumen zones
  - high water saturation zones
  - thief zone (water / gas)
  - cap rock
- No piezometer installed

No change in 2014
4D seismic anomaly observed in top of Clearwater formation around Observation Well 22 in 2013

- Anomaly confirmed in subsequent 2014 seismic data and voluntarily self-disclosed to AER
- Root cause confirmed to be thermal siphoning due to a casing leak
  - Casing leak caused water influx into well bore
  - Boiling column of water heated Clearwater formation sufficiently near well bore to break gas out of solution, appearing as an anomaly in 4D seismic analysis
  - Data acquisition and modeling confirmed thermal siphoning condition as root cause
  - Water test well 1F1/12-24-083-07 W4M samples confirmed no impact to Clearwater aquifer
- Observation Well 22 abandoned February, 2015 as per AER approvals
  - Thermal siphoning condition eliminated with abandonment of well
Well pair 101-10(03) (Pad 101 North)

- Start-up in Feb 2011
Steam Chamber Development Well Pair 101-03

Temperature Monitoring

101-03-OBB

101-03-OBC

Subsection 3.1.1 (7b)
Steam Chamber Development Well Pair 101-03

WELL PAIR 101-10 (03)

S1 - Point Bar

McMurray

Secondary Mud Ch

Basal Shale

McMurray Lower Channels

Devonian Unconformity

Map View

Monitor 7 September 2014

Subsection 3.1.1 (7b)

= 4D anomaly
~60 deg C Isotherm
Steam Chamber Development  Well Pair 101-03

- Pressure Monitoring
  - Lower piezometers follow exactly 101-I03 BHP injection trend
  - Pressure response ahead of the temperature front – Most likely through mobile initial water
OBIP and Recovery Factor

Average porosity = 33%
Average So = 80%
OBIP = bulk volume x Φ x So

No change in 2014
NCB = producer to Vsh cutoff of 33%

Minimized resource below producer

125 m
40 m
850 m
1 = No thief zone, highest recovery, 45%+
2 = Limited thief zone, medium recovery, 40%+
3 = Thief zone, lowest recovery, 30%+

* Recoveries based on simulations and in-house proxy tool

No change in 2014
OBIP and Recovery Factor (Jan 31, 2015)

Pilot and Phase 1 Recovery

<table>
<thead>
<tr>
<th>Drainage area</th>
<th>OBIP (e3m3)</th>
<th>Avg Phi %</th>
<th>Avg So %</th>
<th>Expected Rf %</th>
<th>Cum Prod (e3m3)</th>
<th>Current Rf %</th>
</tr>
</thead>
<tbody>
<tr>
<td>101N</td>
<td>7,296</td>
<td>32.5%</td>
<td>80.0%</td>
<td>50%</td>
<td>1,293</td>
<td>17.7%</td>
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<tr>
<td>101S</td>
<td>10,396</td>
<td>33.3%</td>
<td>80.3%</td>
<td>50%</td>
<td>2,353</td>
<td>22.6%</td>
</tr>
<tr>
<td>102N</td>
<td>7,379</td>
<td>32.7%</td>
<td>80.6%</td>
<td>50%</td>
<td>1,831</td>
<td>24.8%</td>
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<tr>
<td>102S</td>
<td>7,353</td>
<td>31.3%</td>
<td>74.2%</td>
<td>50%</td>
<td>2,842</td>
<td>38.6%</td>
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<tr>
<td>Pilot A</td>
<td>608</td>
<td>32.3%</td>
<td>82.9%</td>
<td>50%</td>
<td>247</td>
<td>40.6%</td>
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<tr>
<td>Pilot B</td>
<td>598</td>
<td>32.6%</td>
<td>83.1%</td>
<td>50%</td>
<td>289</td>
<td>48.4%</td>
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<tr>
<td>Pilot C</td>
<td>1,216</td>
<td>33.1%</td>
<td>84.8%</td>
<td>N/A</td>
<td>95</td>
<td>7.8%</td>
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<tr>
<td>Pilot A&amp;B</td>
<td>1,205</td>
<td>32.4%</td>
<td>82.9%</td>
<td>50%</td>
<td>536</td>
<td>44.4%</td>
</tr>
</tbody>
</table>

OBIP = Thickness x Phi x So x Area
Thickenss = Calculated from the top of continuous bitumen to the producer depth
Area = Polygons around each well pair of 125 m x length of lateral section

• *Expected ultimate recovery dependent on blowdown timing and operating strategy*
• Low Recovery Pad Example – Pad 101 North
  – 11 well pairs drilled
  – Low recovery essentially due to late start-up:
    • 3 well pairs started in 2007
    • 6 well pairs started end 2010 / beginning 2011
      – 2 well pairs scheduled for ESP conversion middle of this year (Q3/2015)
    • 2 infill well pairs deferred to 2017 (101-25 & 26)
• Low Recovery Pad Example – Pad 101 North
  – 4D seismic monitoring – September 2014
  – Low recovery to date but still in the early time
  – Fairly good steam chamber conformance

Well Pairs started in 2011
• Medium Recovery Pad Example – Pad 102 North
  – 9 well pairs drilled (2 cold fishbone infill producers)
  – Medium recovery at 32.7%
OBIP and Recovery Factor (Jan 31, 2015)

- Medium Recovery Pad Example – Pad 102 North
  - 4D seismic monitoring – September 2014 monitor
  - Good steam chamber development over mature wells
• High Recovery Pad Example – Pad 102 South
  – 9 well pairs drilled
  – High performance well pairs
• High Recovery Pad Example – Pad 102 South
  – 4D seismic monitoring – April 2014 monitor
  – Good steam chamber development over mature wells

Well Pairs converted into SAGD in 2012 – 102-10 & 102-11
Top Steam Chamber Monitoring (4D Isocontours)

Pad 101 North

Steam chamber pressures have declined to 1,800 – 2,300 kPa

- ESP Converted
- To be converted to ESP in 2015

Latest available Phase 1 4D ~60°C isocontours
Steam chamber pressures have declined to 1,400 – 2,300 kPa.

Latest available Phase 1 4D ~60°C isocontours

ESP Converted
Operating on PCP
√ Converted to ESP in 2014
Latest available Phase 1 4D ~60°C isocontours

Steam chamber pressures have declined to 1,800 – 2,400 kPa

Pad 102 North (Monitor April 2014)

ESP Converted

To be operated on PCP
Latest available Phase 1 4D ~60°C isocontours

Pad 102 South

Steam chamber pressures have declined to 1,700 – 2,300 kPa
Latest available Phase 1 4D ~60°C isocontours

Pilot operating pressure decreased to 1600 kPa for the last 5 years.
Phase 1: Operating Pressure

- Operating Pressure
  - Progressively decrease operating pressure to manage interaction with top reservoir / thief zones
  - Well pairs converted to ESP to operate at lower pressure
  - 101 North at higher pressure due to ongoing technology trial
Phase 1: Pad 101 - Top Abandoned Mud Channel

- Pad 101: Abandoned mud channel overlaying bitumen interval
Phase 1: Pad 101 North - Top Water

- Top water: Extension of Pilot top water above Pad 101 North but limited
Phase 1: Pad 101 North - Top Water

- Top water: Limited extension of Pilot top water above Pad 101 North
Phase 1: Pad 102 - Top Abandoned Mud Channel

Abandoned mud channel
Phase 1: Pad 102 North - Top Water

Abandoned mud channel

Subsection 3.1.1 (7g)
Phase 1: Pad 101 North - Top Water

- Pad 101 North - Top water:
  - Development of the steam chamber towards top of reservoir – Monitor 7th Sept 2014

Perpendicular Section: Cumulative M7 (September 2014)

Map View

= 4D anomaly
~60 deg C Isotherm
Phase 1: Pad 101 North - Top Water

- Pad 101 North - Top water:
  - Decrease operating pressure to manage interaction with top water and coalescence between well pairs
  - Well performances not impaired by top water
  - Stable pressure through 2014
Phase 1: Pad 101 South - Top Abandoned Mud Channel

- Pad 101 South - Top abandoned mud channel:
  - Development of the steam chamber towards top of reservoir
Phase 1: Pad 101 South Top Abandoned Mud Channel

- Pad 101 South (101-10/11/12/13/14)
  - June 2009: 101-12 steam chamber development up to the top reservoir. WP shut down. Restarted February 2010.
  - 101-12/13/14: ESP conversion in Aug/Sept 2010. Operating pressure decreased to manage interaction with the top of the reservoir
  - Stable performance since ESP conversion
Phase 1: Pad 101 South - Infill Producer Performance

- Infill producers 101-P21 and 101-P22
  - Drilled in 2012
  - Open-hole hook in P21 and cased-hole hook in P22
  - Completed with PCP and started in Sept 2012
  - Steam injection through the guide string stopped in August 2014
  - Average daily bitumen rate ~38-47m³/d (per well)
Infill Well Pair 101-P19 (16INF) and 101-P20 (17INF)
- Drilled in 2012
- Completed with concentric VIT in the injectors and concentric non-VIT in the producers
- Completed with ESP Day1
- Average daily bitumen rate ~400-700bbl/d (per well)
Key Milestones

- Drilled in Q3, 2013
- 1st fishbone well configuration ever in SAGD operations
- Successfully drilled 102-21 and 102-22 multilateral open-hole fishbone wells with approx. 14 ribs
- Successfully deployed flow control device (equalizer liner) in both fishbone wells
- 102-21 started in June 2014 and restarted in November after turnaround
- 102-22 started in November 2014
- No significant oil production to date (cold wellbore temperature)
Solvent Soak Trial

Key Milestones

- **Type of Solvent = Xylene**
- **Expected Injection Volume**
  - Equivalent to 1 wellbore volume which is about 30 to 40 m³ of solvent per well (i.e., 60 to 80 m³ per well pair).
- **AER Amendment Approval – 9426T**
  - Received: July 17th, 2013
  - Trial deferred to 2016
Cumulative Oil (bbl)

Pad 102N Individual Well Performance

cSOR

Key Milestones

- Circulation Oct 2008
- First FCD deployed in Surmont
- Cumulative production of 1.95 MMbbl as of Jan 31\textsuperscript{st} 2015
- Cumulative SOR of 2.46 as of Jan 31\textsuperscript{st} 2015
• Reasons for higher vertical placement
  - 101-09(01) Drilled in Q4 2008
  - Drilled high to avoid low quality reservoir
  - Outboard infill wellpairs 101-25/26 drilled to recovery stranded resource
• Strong production performance in 2014 with record low iSOR

• History matching complete on new geo-model. This assists greatly in reservoir management and understanding steam chamber development.
  • Provides a greater understand of the pay zone, specifically with regards to thief zone interaction
  • Has helped to optimize the operating strategy to mitigate the thief zone interaction impact on performance
  • Aids in understand the steam chamber development in order to optimize well pad performance

• A greater understanding of the impact the Vacuum Insulated Tubing completion has on circulation was gained through the startup of wellpair 101-20.

• A Subsurface Containment Group was created to improve the geo-mechanical understanding and serve as a single point of contact for all containment questions and concerns.
• Subcool monitored in SAGD producer to avoid steam flashing through the liner and preserved its integrity

• Wellbore subcool:
  - Saturated temperature at producer BHP – Hottest Temperature in Prod
  - Used in ESP / PCP wells
  - Target is 8°C

• Reservoir subcool:
  - Saturated temperature at injector BHP – Hottest Temperature in Prod
  - Used in Gas Lift wells
  - Target is increased to 20°C to take into account uncertain ∆P between the injector and the producer
Phase 1: Pad 101 North Performance

![Graph showing the performance of Pad 101 North Phase 1 with data points and markers for Bitumen production, Steam injection, Water production, CSOR, ISOR, and the number of well pairs started. The graph covers the period from January 2014 to February 2015.](image-url)
Phase 1: Pad 101 South Performance
Phase 1: Pad 102 North Performance

[Graph showing performance metrics over time from January 2014 to February 2015 with labels for Bitumen production, Steam injection, Water production, CSOR, ISOR, and # Well pair started.]
Phase 1: Pad 102 South Performance

The graph illustrates the performance of Pad 102 South over a period from January 2014 to February 2015. The x-axis represents the months from January 14 to February 15, and the y-axis represents the rate of production in m3/d. The graph includes lines for Bitumen production, Steam injection, Water production, CSOR, ISOR, and the number of Well pairs started. The data shows fluctuations in production rates and the introduction of steam injection and water production efforts over time.
Pad Performance Proration

- Stable proration factors
- Recurrent water cut metering calibration maintains consistency in SOR measurements and allocation calculations
Surface Operations and Compliance
Phase 1 Approval 9426

Facilities
Subsection 3.1.2 (1)
Phase 1 Plot Plan - CPF

Plant optimization focus for Phase 1 CPF in 2013
Artificial Lift Program added 1 new ESP wells in 2014
Artificial Lift Program added 2 PCP & 1 ESP well in 2014
Multiphase Flow Meter
Continued Focus on Construction and Commissioning at Surmont 2
2014 – Capital Projects

- Dresser Coupling Replacement: Replaced 26 Dresser couplings on Sales Oil and Diluent tank to more robust design
- Diluent Agitator: Agitator installed in the diluent tank to create more uniform blend
- New Economizer box: Built new economizer box with upgraded materials and additional monitoring capabilities
- Surmont 2 over 80% construction completed
- S1 Debottleneck: Added Glycol Trim Heater, Instrument Air Compressor, 500 area MCC, and a fifth Steam Gen (All of this equipment is not currently tied in or operational – this is to occur at a future date)

2014 – Optimization Focus Overview

- Steam optimization
  - Improve steam quality control.
  - Steam production and delivery development: Optimize Firing control to minimize steam production losses due to BFW temperature swings.
  - Steam quality control improvement trial on SG-531 C.
    - Step one of the trial completed (Firing 105% at 80% steam quality)
    - Step two will be firing 107% at 83%
Facility Performance
Subsection 3.1.2 (2)
Facility Performance: Bitumen Treatment

![Graph showing Facility Performance: Bitumen Treatment](image-url)
Facility Performance: Water Treatment

- Water Treatment plant operating as per design.

- Minor WLS operational challenges throughout the year, primarily in controlling turbidity swings leaving the warm lime softener.

- Sludge Pond dredged successfully in July 2014.

- Turnaround completed in October. Repairs conducted on roof of warm lime softener resulting from exterior corrosion.
Facility Performance: Water Treatment

Turbidity variation leaving the Warm Lime Softener
(Jan 31, 2014 to Jan 31, 2015)
Facility Performance: Water Treatment

Boiler Feed Water Quality (Jan 31, 2014 to Jan, 31, 2015)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>BFW Specification</th>
<th>Avg. Value</th>
<th>% of time on Spec</th>
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<tbody>
<tr>
<td>Hardness (Dissolved), mg/L</td>
<td>&lt;0.3</td>
<td>0.10</td>
<td>99.4</td>
</tr>
<tr>
<td>Silica, as SiO2, mg/L</td>
<td>&lt;50</td>
<td>21.8</td>
<td>99.4</td>
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<tr>
<td>Bitumen in Water, ppm</td>
<td>&lt;3.0</td>
<td>0.39</td>
<td>100</td>
</tr>
<tr>
<td>Turbidity, NTU</td>
<td>&lt;3.5</td>
<td>2.42</td>
<td>98.8</td>
</tr>
</tbody>
</table>
Facility Performance: Steam Generation

2013 Issue:
Steam Generator Fouling minimized due to BDR reduction
Max rate 71.2 bpd
Average: 65.8 bpd

2014
Operating BDR @ 25%
Max rate 73.1 bpd (No T/A)
Average: 69.2 bpd (No T/A)

Turnaround
Facility Performance: Steam Generation (Pigging Frequency)

Average OTSG Throughput and Days Between Pigging

- Increased combined days between pigging

Date
- 1-Jan-12
- 1-Mar-12
- 1-May-12
- 1-Jul-12
- 1-Sep-12
- 1-Nov-12
- 1-Jan-13
- 1-Mar-13
- 1-May-13
- 1-Jul-13
- 1-Sep-13
- 1-Nov-13
- 1-Jan-14
- 1-Mar-14
- 1-May-14
- 1-Jul-14
- 1-Sep-14
- 1-Nov-14

Volume (m3, days)
- 52 days
- 43 days
- 41 days
- 28 days
- 37 days
- 23 days
- 67 days
- 66 days
- 66 days
- 109 days
- 109 days
- 110 days
- 265 days
- 288 days

Subsection 3.1.2 (2c)
Electricity consumption has increased as wells are moved from gas lift to artificial lift.
### Facility Performance: Gas

<table>
<thead>
<tr>
<th>Total Gas Imports (TCPL)</th>
<th>2007</th>
<th>2008</th>
<th>2009</th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>Units</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>42,999</td>
<td>160,095</td>
<td>183,933</td>
<td>223,447</td>
<td>228,344</td>
<td>250,412</td>
<td>254,883</td>
<td>241,276</td>
<td>10³m³</td>
</tr>
<tr>
<td>Total Gas Flared</td>
<td>4,640.6</td>
<td>6,438.7</td>
<td>3,962.0</td>
<td>705.0</td>
<td>624.8</td>
<td>217.6</td>
<td>117.3</td>
<td>277.3</td>
<td>10³m³</td>
</tr>
<tr>
<td>Solution Gas Recovery Rate</td>
<td>60.6%</td>
<td>93.6%</td>
<td>94.5%</td>
<td>98.5%</td>
<td>99.2%</td>
<td>98.0%</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### S1/S2 Produced Gas Interconnect
- Completed in 2014.
  - Will send all Produced Gas to Surmont 2 for sulfur removal.
  - Phase I Steam Generators will begin burning 100% TCPL gas.
Facility Performance: Greenhouse Gas

Greenhouse Gas Emission Intensity

Exceeded Specified Gas Emitters Regulation Reduction Target of 8% for 2014
Measurement and Reporting
Subsection 3.1.2 (3)
Well Allocation Oil Production = Estimated Monthly Well Oil Production x Oil Proration Factor

Where:

- Estimated Production = Accepted well test / duration of test * on-stream hours
- Oil Proration Factor = Actual battery production / estimated battery production
- Actual Battery Production
  = Dispositions + Tank Inventory – Receipts + Shrinkage + External Shipments
  + (Load Oil to Wells inventories)

Where:

- Dispositions = Sales Oil shipped to Enbridge + Diluent send to Surmont Pilot
- Tank Inventory = Sales Oil tanks volume changes + Diluent tank volume changes
  + Slop tank oil inventory + Skim tank oil inventory
- Receipts = Sales Oil received from Surmont Pilot + Diluent received from Enbridge
- Shrinkage = Shrinkage adjustment
- External Shipment = Oil from slop trucked out to external facility

Sales Oil: Could be Dilbit or Synbit

Surmont MARP Rev 10 (SUR2-A0A-00-OPM-OPN-0045) – Submitted February 2015
Well Allocated Water Production = Estimated Monthly Well Water Production x Water Proration Factor

Where:

Estimated Water Production = Accepted well test / duration of test * on-stream hours
Water Proration Factor = Produced water (PW) volume / estimated water production
PW Volume = Dispositions + PW\text{tanks} – Receipts + Load Water (LW) Inventory

Where:

Dispositions: Battery PW Disposition to Injection Facility + Pilot Plant + Other
PW\text{tanks}: Battery PW Inventory, including net water content in oil storage tanks
Receipts: PW received from other sources, including Injection Facility
LW Inventory: Battery LW Inventory
Well Allocated Gas Production

Well Allocation Gas Production = Well Allocated Oil Production x Calculated Gas-Oil Ratio

Where:

Calculated Gas-Oil Ratio (GOR) = Gas Production / Battery Bitumen Production
Gas Production = Dispositions – Receipts

Where:

Dispositions = Metered Flared Gas + Metered Steam Gen Fuel Gas + Utilities Fuel Gas + Gas for purging system
Receipts = Fuel Gas Receipts from TCPL + eSAGD Produced Gas
**Estimated Volume of Injected Steam** = Sum of Injected Steam to Wells x Steam Proration Factor

Where:

Steam Proration Factor = Steam Produced / Steam Measured

Steam Produced:  Total Steam Meter to Well Pads – Steam Condensate Dropped Out
– Steam Recovered at Pipeline – Steam to eSAGD wells

Steam Measured:  Steam Injection to Heel and Toe String of each well

Surmont MARP Rev 10 (SUR2-A0A-00-OPM-OPN-0045) – Submitted February 2015
Production Proration Factors

Target Range: 0.85 - 1.15

Sept. Turn-Around

Oil
Water
Emulsion

Subsection 3.1.2 (3a)
Average Steam Proration for year 2014 = 1.0063
Well Testing

- CPC continues to assess well test performance, to optimize each individual well’s test duration

- Phase Dynamic Water Cut Meter trial to ensure proper performance
  - Establish proper sampling procedures for meter calibration
  - Execute calibration per well
  - Perform meter validation after every calibration

- In preparation for the large number of Surmont 2 wells, CPC developed and tested an In-House program to automatically accept or reject well test results based defined criteria to ensure reporting compliance
Water Production, Injection, and Uses
Subsection 3.1.2 (4)
Water Source Wells Non-Saline

**Surmont Pilot**

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1082508307W400</td>
<td>1AJ082508307W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1072508307W400</td>
<td>100072508307W400</td>
<td>Clearwater</td>
</tr>
</tbody>
</table>

**Surmont Phase 1**

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1021808306W400</td>
<td>1F2021808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1041808306W400</td>
<td>102041808306W400</td>
<td>Lower Grand Rapids</td>
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<tr>
<td>1F1011908306W400</td>
<td>100011908306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1032308307W400</td>
<td>100032308307W400</td>
<td>Lower Grand Rapids</td>
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</table>

**Surmont Phase 2**

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
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<tbody>
<tr>
<td>1F1022108306W400</td>
<td>100022108306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1022608306W400</td>
<td>100022608306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1052808306W400</td>
<td>100052808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1070308306W400</td>
<td>1F2070308306W400</td>
<td>Lower Grand Rapids</td>
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<tr>
<td>1F1101408306W400</td>
<td>1F1111408306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1130508306W400</td>
<td>100130508306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1153408307W400</td>
<td>1F2153408307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

**Notes**

- All water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use)
- Phase 2 source wells licenced December 14, 2012, only used for hydro testing
Water Production and Steam Injection Volumes

- ** Produced water (m³) **
- ** Steam Injection (CWE, m³) **

Subsection 3.1.2 (4d)
Continuous optimization and improvements:

- Measurement
- Material balance for water systems
- Energy balance across steam generation
- Enhanced steam quality

<table>
<thead>
<tr>
<th>Year</th>
<th>WRR, %</th>
</tr>
</thead>
<tbody>
<tr>
<td>2012</td>
<td>81.9</td>
</tr>
<tr>
<td>2013</td>
<td>87.1</td>
</tr>
<tr>
<td>2014</td>
<td>88.2</td>
</tr>
</tbody>
</table>
Surmont achieved *Directive 81* facility water imbalance compliance in 2014;
Continuous improvement towards closing the water imbalance gap;
Challenging to keep metering imbalance within 5% when performing large maintenance/repair projects (Feb-May 2014, Sept 2014)
Surmont achieved *Directive 81* disposal limit compliance in 2014 (9.1% actual vs. 9.2% disposal limit) after completing blowdown recycle rate trials in 2013.

Average boiler blowdown recycle rate at Surmont 1 in 2014 was 53-58%.
### Water Disposal Wells

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>AER Disposal Approval No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>102/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>103/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>103/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>100/09-25-083-07W4/0</td>
<td>Keg River</td>
<td>6000</td>
<td>Water Disposal</td>
<td>9573C</td>
</tr>
<tr>
<td>100/01-16-083-05W4/0</td>
<td>McMurray</td>
<td>2700</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/07-22-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/08-10-083-05W4/0</td>
<td>McMurray</td>
<td>2300</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/01-11-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/04-21-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/01-04-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/01-09-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/10-15-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/08-23-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/16-24-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
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<tr>
<td>100/08-27-083-05W4/0</td>
<td>McMurray</td>
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<td>10044H</td>
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<td>100/01-28-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
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<tr>
<td>102/15-15-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>102/08-21-083-05W4/0</td>
<td>McMurray</td>
<td>3400</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
</tbody>
</table>

**Notes**
- Disposal to 100/09-25-083-07W4/0 ended December 2011
- As of December 2011, water transferred to Phase 1 via pipeline
- Disposal to 100/09-25-083-07W4/0 recommenced August 2014
Water Disposal Wells Well Head Pressure (McMurray)

Approval Max. WHP for 01-16: 2700 kPa
Approval Max. WHP for 07-22, 01-11, and 04-21: 2500 kPa
Approval Max. WHP for 08-10: 2300 kPa

Subsection 3.1.2 (4b)
Water Disposal Well 100/01-16-083-05 W4M
Observation Well Pressure (McMurray)

- 102/01-16 Piezo 3 (McMurray Gas, 238 mKB)
- 102/01-16 Piezo 2 (McMurray Water, 263 mKB)
- 102/01-16 Piezo 1 (McMurray Water, 289 mKB)
Water Disposal Well 100/08-10-083-05 W4M
Observation Well Pressure (McMurray)

- 102/08-10 Piezo 3 (McMurray Gas, 203 mKB)
- 102/08-10 Piezo 2 (McMurray Water, 228 mKB)
- 102/08-10 Piezo 1 (McMurray Water, 253 mKB)

Subsection 3.1.2 (4h)
# Typical Water Analysis

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Raw Makeup Water (mg/L)</th>
<th>Produced Water (mg/L)</th>
<th>Disposal Water (mg/L)</th>
</tr>
</thead>
<tbody>
<tr>
<td>pH</td>
<td>8.5</td>
<td>7.5</td>
<td>8.8</td>
</tr>
<tr>
<td>Total Dissolved Solids (TDS)</td>
<td>1,400</td>
<td>1,800</td>
<td>22,000</td>
</tr>
<tr>
<td>Chloride</td>
<td>200</td>
<td>650</td>
<td>8,000</td>
</tr>
<tr>
<td>Hardness as CaCO$_3$</td>
<td>&lt;0.5</td>
<td>10</td>
<td>5</td>
</tr>
<tr>
<td>Alkalinity as CaCO$_3$</td>
<td>900</td>
<td>300</td>
<td>2,650</td>
</tr>
<tr>
<td>Silica</td>
<td>8</td>
<td>240</td>
<td>200</td>
</tr>
<tr>
<td>Total Boron</td>
<td>6</td>
<td>40</td>
<td>250</td>
</tr>
<tr>
<td>Total Organic Carbon</td>
<td>15</td>
<td>450</td>
<td>2,000</td>
</tr>
<tr>
<td>Oil Content</td>
<td>&lt;1</td>
<td>50</td>
<td>30</td>
</tr>
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</table>
## Waste Disposal

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Tonnes)</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dangerous Oilfield Waste</td>
<td>5,683</td>
<td></td>
</tr>
<tr>
<td>Hydrocarbon/Emulsion Sludge</td>
<td>1,219</td>
<td>Cavern</td>
</tr>
<tr>
<td>Crude Oil/Condensate Emulsions</td>
<td>4,432</td>
<td>Oilfield Waste Processing Facility</td>
</tr>
<tr>
<td>Various</td>
<td>30</td>
<td>Landfill</td>
</tr>
<tr>
<td>Non-Dangerous Oilfield Waste</td>
<td>18,480</td>
<td></td>
</tr>
<tr>
<td>Lime Sludge</td>
<td>18,329</td>
<td>Landfill</td>
</tr>
<tr>
<td>Various</td>
<td>151</td>
<td>Landfill</td>
</tr>
<tr>
<td>Well Fluids</td>
<td>66</td>
<td>Cavern</td>
</tr>
</tbody>
</table>

The Surmont 1 lime sludge pond was dredged in 2014
## Waste Recycling

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (Tonnes)</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil</td>
<td>39</td>
<td>Used Oil Recycler</td>
</tr>
<tr>
<td>Empty Containers</td>
<td>22</td>
<td>Recycling Facility</td>
</tr>
<tr>
<td>Fluorescent Light Tubes</td>
<td>10</td>
<td>Recycling Facility</td>
</tr>
<tr>
<td>Batteries</td>
<td>7</td>
<td>Recycling Facility</td>
</tr>
</tbody>
</table>
Sulphur Production
Subsection 3.1.2 (5)
Sulphur emissions were below the AER limit of 0.94 tonnes/day.
Monthly Sulphur Emissions

Sulphur Emissions (tonnes/month)

Subsection 3.1.2 (5a)
SO$_2$ Emissions are well below the EPEA approval limit of 2 tonnes/day.

Subsection 3.1.2 (5a)
Passive ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2014.
Continuous ambient air monitoring - all Alberta Ambient Air Quality Objectives were met in 2014.
Environmental Issues
Subsection 3.1.2 (6)
Environmental Approval Contraventions

- Failure to submit 2013 Industrial Wastewater Report (Reference No. 289347).
  - Report is now submitted
- Ambient air quality monitoring trailer operated less than 90% of the time (Reference No. 289438)
  - This occurred during turnaround when electricity to the trailer was lost (no action required), still met all air monitoring requirements in 2014
- Failure to properly dispose of hydrotest fluids (Surmont 2 new lines) (Reference 289488)
  - Spill of hydrotest fluids containing biocide to ground. Area was monitored and biocide naturally attenuated.
Environmental Monitoring

Groundwater Monitoring Program

- 2014 results within historical/background concentrations

Integrated Wetlands Monitoring Program

- 2014 results within historical/background concentrations

Reclamation Programs

- No reclamation in 2014

Wildlife Monitoring Program

- Monitoring of above-ground pipeline completed in 2014

Participated in joint industry environmental monitoring committees in 2014 (WBEA, RAMP, JOSM, etc.)

Groundwater and Integrated Wetland Monitoring Programs extended to Surmont 2
Compliance Confirmation
Subsection 3.1.2 (7) + (8)
ConocoPhillips is in regulatory compliance for 2014 with the exception of the following:

- **Bulletin 2006-11 Water Recycle Rate**
  - Self disclosure issued to AER in January 2015 (88.2% vs. 90%)

- **Directive 81 Injection Facility Water Imbalance**
  - Self disclosure issued to AER in May 2014
  - Exceeded 5% imbalance for 4-month period coincident with lime sludge pond dredging (Feb – May 2014)
  - In compliance since June 2014

- **Legacy wells**
  - Being treated as routine abandonments with proper abandonment operations in progress
Subsection 3.1.1 (8), 3.1.2 (9)
Future Plans
Future Plans – Phase 1

- Continued research into OTSG fouling: evaluating chemical treatment
- 102-21/22 fish bone infill wells in 102N remained cold on startup. Evaluating alternative start-up plan.
- CPF Debottleneck including one OTSG addition is being reassessed.
- Phase 1 Infill Program: 101-24/25/26 alternative start-ups have been delayed to Q1 2016. Work remains to tie in wells.
- Pad 103 start-up and ramp-up
2015 plans for ~ 10 near Hwy & S1 Control Reflectors (CR) installed February/March 2014

CR Installs in 2014

<p>| | |</p>
<table>
<thead>
<tr>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>S2 DA</td>
<td>80</td>
</tr>
<tr>
<td>Hwy and Pipeline ROW</td>
<td>8</td>
</tr>
<tr>
<td>Pad 104</td>
<td>16</td>
</tr>
<tr>
<td>Pad 102</td>
<td>2</td>
</tr>
<tr>
<td>Pad 101</td>
<td>1</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>107</strong></td>
</tr>
</tbody>
</table>

- existing CR
- new CR on well lease
- new CR in clearing
- new CR along highway

CR Points occurring on an existing well lease can proceed. Additional approvals required for all other locations

- Installing 12m pipe with pile driver vs. auger in previous years

Subsection 3.1.2 (9a-d)
S2 Project Execution Update

Execution Status

- Project to Date (End February) TRR 0.30
  - Best in industry
- Facilities Construction Progress
  - 92% construction completion
- Commissioning Progress
  - 75% Train A CPF commissioning progress
  - 58% commissioning progress
- First Steam target Q2 2015

- Drilling on complete on 10 of the initial pads, 119 of 129 well pairs, on plan
  - Drilling on last pad deferred to 2016 in line with projected well need
  - Well completions ongoing

S2 CPF January 2015

S2 SAGD Drilling Results

SAGD Drilling deferred to 2016
S2 Ramp-up

- Start-up Key Milestones
  - OTSG Testing
  - Bitumen Treating

- Pad 103 – Planned for Mid April, steamed from S1 to warm up lines

- Production expectations and the corresponding construction schedule for the project were based on Phase 1 experience and benchmarking against other operators.

- Well pads 264-1 and 264-2 brought online first (in parallel)
  - To be followed by 263-2 and 263-1
  - Long term pad order driven by construction schedule

- The well start up base plan is primarily based on a conventional circulation pre-heat period of 90 days

Subsection 3.1.2 (9a-d)
Liquid Scavenger Solution

• Intro to Liquid Scavenger
  • Required to treat additional sulfur compounds in the produced gas stream
    - Mercaptans
  • Replaces the Sulfurox unit
  • 2 Skid system with tanks for new solution and spent solution
  • Spent solution is disposed offsite

• Schedule
  • Start Execution 30-July-15
  • Skid 1 RFO 1-Nov-15
  • Skid 2 RFO 15-Jan-16

• Status
  • PO’s for both Skids placed
  • Detailed engineering at 55%
  • Preparing to file for construction permit
Future Developments

Subsection 3.1.2 (9a-d)
Surface Operations and Compliance
Pilot Project Approval 9460

Facilities
Subsection 3.1.2 (1)
Site Survey Plan

Subsection 3.1.2 (1a)

2014 Work

9-25 Disposal Well Reactivation

P1 ESP Replacement
GT Trial Completed in 2014
Facility Performance
Subsection 3.1.2 (2)
Pilot Plant Performance Bitumen Production

Average Production in 2013 = ~560 bbl/d

Average Production 2014 = ~356 bbl

P3 Pump Failure

P1 Pump Replacement
Pilot Plant Performance Steam Generation

Steam Injection

Steam (bpd CWE) vs Date

- Steam Injection from 1/1/2014 to 12/17/2014
- Steady decline in steam production
- P1 Pump Replacement noted on the chart

Subsection 3.1.2 (2c)
Deviation from capacity due to:

- Reservoir pressure limiting steam requirement and corresponding production
- P3 pump failed shutting in production from this well
- ESP and subcool targets
### Pilot Plant Performance Gas Usage

<table>
<thead>
<tr>
<th></th>
<th>2010</th>
<th>2011</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015-01</th>
<th>units</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Total Gas Imports</strong> (TCPL)</td>
<td>11,224</td>
<td>12,334</td>
<td>9,728</td>
<td>11,828</td>
<td>10,351</td>
<td>690</td>
<td>$10^3$m³</td>
</tr>
<tr>
<td><strong>Solution Gas</strong></td>
<td>53.2</td>
<td>1,347.3</td>
<td>2,961.6</td>
<td>3,229.2</td>
<td>1,152.0</td>
<td>55.6</td>
<td>$10^3$m³</td>
</tr>
<tr>
<td><strong>Total Gas Vented</strong></td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>$10^3$m³</td>
</tr>
<tr>
<td><strong>Total Gas Flared</strong></td>
<td>0.9</td>
<td>2.8</td>
<td>2.5</td>
<td>85.4</td>
<td>31.7</td>
<td>0.9</td>
<td>$10^3$m³</td>
</tr>
<tr>
<td><strong>Solution Gas Recovery</strong></td>
<td>98.3</td>
<td>99.8</td>
<td>99.9</td>
<td>97.4</td>
<td>97.2</td>
<td>98.4</td>
<td>%</td>
</tr>
</tbody>
</table>
Measurement and Reporting
Subsection 3.1.2 (3)
Battery Actual Bitumen Production = \[
\text{Closing Inventories} - \text{Opening Inventories (Oil portion of Sales and Slop)} / \text{Shrinkage Factor} - \text{Diluent Received} + \text{Closing Inventories} - \text{Opening Inventories (Diluent)} + \text{Closing} - \text{Opening (Injected Fluids into Producers)} + \text{Sales Shipped to S1 and Trucked}
\]

Battery Estimated Bitumen Production = Well bitumen production is calculated from well tests (pro-rated battery)
Water Production = [Closing inventories – Opening Inventories (Water portion of Sales, Slop, Flash, Skim and Produced Water)] – Water Content of Received Diluent or Oil + [Closing – Opening (Injected Fluids into Producers)] + Produced Water + Produced Water Truck Tickets + Water Content of Sales Oil

Battery Estimated Water Production = Well water production is calculated from well tests (pro-rated battery)
Measurement and Reporting Methods

Production Gas

- Total battery gas production estimated from inlet of FKOD, Scrubber and P3 usage
- Well gas production calculated from well oil production and GOR
- GOR is the battery gas production / the battery bitumen production
- Gas proration factor = total battery gas production / well test gas production

Steam

- Steam injection metered individually at each well and allocated using the group steam injection meter

Well Testing

- One well on test at a time
- Target at least two tests per well per month (24 hours in length)
- All well pairs tests regularly tested to meet minimum monthly target

No modifications in accounting formula
Water Production, Injection, and Uses
Subsection 3.1.2 (4)
Water Source Wells Non-Saline

### Surmont Pilot

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
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</thead>
<tbody>
<tr>
<td>1F1082508307W400</td>
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<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1072508307W400</td>
<td>100072508307W400</td>
<td>Clearwater</td>
</tr>
</tbody>
</table>

### Surmont Phase 1

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1021808306W400</td>
<td>1F2021808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1041808306W400</td>
<td>102041808306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1011908306W400</td>
<td>100011908306W400</td>
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</tr>
<tr>
<td>1F1032308307W400</td>
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<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

### Surmont Phase 2

<table>
<thead>
<tr>
<th>Source Well</th>
<th>Observation Well</th>
<th>Formation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1F1022108306W400</td>
<td>100022108306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1022608306W400</td>
<td>100022608306W400</td>
<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1052808306W400</td>
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</tr>
<tr>
<td>1F1070308306W400</td>
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</tr>
<tr>
<td>1F1101408306W400</td>
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<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1130508306W400</td>
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<td>Lower Grand Rapids</td>
</tr>
<tr>
<td>1F1153408307W400</td>
<td>1F2153408307W400</td>
<td>Lower Grand Rapids</td>
</tr>
</tbody>
</table>

### Notes
- All water currently used at the Surmont project is non-saline and non-potable (i.e., waters not readily or economically treatable for potable, domestic, agricultural or livestock use).
- Phase 2 source wells licenced December 14, 2012, only used for hydro testing.

Subsection 3.1.2 (4a)
Subsection 3.1.2 (4b)
## Water Disposal Wells

<table>
<thead>
<tr>
<th>Well</th>
<th>Zone Approved for Disposal</th>
<th>Maximum Wellhead Injection Pressure (kPa)</th>
<th>Well Status</th>
<th>AER Disposal Approval No.</th>
</tr>
</thead>
<tbody>
<tr>
<td>INACTIVE</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>102/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>103/03-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>103/10-31-083-06W4/0</td>
<td>McMurray</td>
<td>3600</td>
<td>Abandoned</td>
<td>9573C</td>
</tr>
<tr>
<td>100/09-25-083-07W4/0</td>
<td>Keg River</td>
<td>6000</td>
<td>Water Disposal</td>
<td>9573C</td>
</tr>
<tr>
<td>100/01-16-083-05W4/0</td>
<td>McMurray</td>
<td>2700</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/07-22-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/08-10-083-05W4/0</td>
<td>McMurray</td>
<td>2300</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/01-11-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
<tr>
<td>100/04-21-083-05W4/0</td>
<td>McMurray</td>
<td>2500</td>
<td>Water Disposal</td>
<td>10044H</td>
</tr>
</tbody>
</table>

| INACTIVE              |                            |                                          |               |                            |
| 100/01-04-083-05W4/0  | McMurray                   | 2500                                     |               | 10044H                     |
| 100/01-09-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 100/10-15-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 100/08-23-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 100/16-24-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 100/08-27-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 100/01-28-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 102/15-15-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |
| 102/08-21-083-05W4/0  | McMurray                   | 3400                                     |               | 10044H                     |

### Notes
- Disposal to 100/09-25-083-07W4/0 ended December 2011
- As of December 2011, water transferred to Phase 1 via pipeline
- Disposal to 100/09-25-083-07W4/0 recommenced August 2014
Pilot Water Disposal Well 100/09-25-083-07 W4M
Well Head Pressure (Keg River)

Approval Max. WHP for 100/09-25: 6000 kPa
Pilot Disposal Water to S1
### Waste Disposal & Recycling

#### Solid Waste

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Weight (kg)</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Recycled Materials</td>
<td>970</td>
<td>Recycled</td>
</tr>
<tr>
<td>Dangerous Oilfield Waste</td>
<td>1,118</td>
<td>Landfill</td>
</tr>
<tr>
<td>Non-Dangerous Oilfield Waste</td>
<td>693</td>
<td>Landfill</td>
</tr>
</tbody>
</table>

#### Fluid Waste

<table>
<thead>
<tr>
<th>Waste Description</th>
<th>Disposal Volumes (m³)</th>
<th>Disposal Method</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dangerous Oilfield Waste</td>
<td>352</td>
<td>Cavern</td>
</tr>
<tr>
<td>Non-Dangerous Oilfield Waste</td>
<td>288</td>
<td>Cavern</td>
</tr>
</tbody>
</table>
Sulphur Production
Subsection 3.1.2 (5)
Monthly Sulphur Emissions

Subsection 3.1.2 (5b)
Subsection 3.1.2 (5c)

SO₂ emissions well below daily limit of 0.08 t/d
Alberta Ambient Air Quality Objectives were met in 2014.
Environmental Issues
Subsection 3.1.2 (6)
Compliance

• 2013 Industrial Waste Water Report not submitted on site (Reference 289346)

Groundwater Monitoring

• 2014 results within historical/background concentrations

Soil Monitoring

• 2014 results within historical/background concentrations

Reclamation Programs

• No reclamation in 2014
Compliance Confirmation
Subsection 3.1.2 (7)
ConocoPhillips is in compliance in all areas of the regulations for all of 2014 with the exception of minor flare events exceeding the regulated time limit.
Noncompliance Issues
Subsection 3.1.2 (8)
Noncompliance

Flaring Events

• Thirteen flaring events sustained over four hours within 24 hour period.
  • Reported to Bonnyville field office and entered into DDS system without issues.
  • No events exceeded the $30 \times 10^3 \text{m}^3$ daily volume limit.
Future Plans
Subsection 3.1.2 (9)
Future Plans

The pilot is licensed until 2019
- Thief zone pressure management
- Blowdown case studies
- Pilot shutdown
- Gas cap monitoring