Christina Lake Regional Project

2013/2014 Performance Presentation

June 17 & 18, 2014
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Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs and transportation costs from such amount.
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In particular, this presentation contains forward-looking statements pertaining to the following: the reserve and resource potential of MEG’s assets; the bitumen production and production capacity of MEG’s assets; MEG’s growth strategy and opportunities; MEG’s capital expenditure programs and future capital requirements; the estimated quantity of MEG’s proved reserves, probable reserves and contingent resources; MEG’s projections of commodity prices, costs and netbacks; MEG’s estimates of future interest and foreign exchange rates; MEG’s environmental considerations, including water usage and greenhouse gas emissions; MEG’s blending capability for its bitumen diluent blend; the timing and size of certain of MEG’s operations and phases, including its planned bitumen development projects, and the levels of anticipated production; supply and demand fundamentals for crude oil, bitumen blend, natural gas, condensate and other diluents; MEG’s access to adequate pipeline capacity; MEG’s access to third-party infrastructure; industry conditions including with respect to project development; potential future markets for MEG’s products; the planned construction of MEG’s facilities, including the Stonefell Terminal and the Access Pipeline expansion; MEG’s drilling plans; MEG’s plans for, and results of, exploration and development activities; the use of the proceeds of the public offering; the expected application timeframe for the Surmont Project and for the Growth Properties; the timing for receipt of various regulatory approvals, including receipt of various regulatory approvals for the Christina Lake Project, Surmont Project and Growth Properties; MEG’s treatment under governmental regulatory and royalty regimes and tax laws; and MEG’s future general and administrative expenses.

The forward-looking statements contained in this presentation are based on certain assumptions including: future crude oil, bitumen blend, natural gas, condensate and other diluents prices; MEG’s ability to obtain qualified staff and equipment in a timely and cost-efficient manner; the regulatory framework governing royalties, taxes and environmental matters in the jurisdictions in which MEG conducts and will conduct its business; MEG’s ability to market production of bitumen blend successfully to customers; MEG’s future production levels; the applicability of technologies for the recovery and production of MEG’s reserves and resources; the recoverability of MEG’s reserves and resources; operating costs; future capital expenditures to be made by MEG; future sources of funding for MEG’s capital programs; MEG’s future debt levels; geological and engineering estimates in respect of MEG’s reserves and resources; the geography of the areas in which MEG is conducting exploration and development activities; the impact of increasing competition on MEG; and MEG’s ability to obtain financing on acceptable terms.

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Meeting agenda

- Overview  
  Simon Geoghegan
- Geosciences  
  Ian Perry
- Reservoir  
  Lisa MacKenzie/Kejia Xi
- Operations  
  Ted Lamb
- Water  
  Scott Rayner
- Compliance & Environment  
  Simon Geoghegan
- Future Plans  
  Simon Geoghegan
MEG Energy Corp. (MEG) is a public Calgary-based energy company focused on the development and recovery of bitumen and the generation of power in northeast Alberta.
MEG Energy Corp.

Who We Are

• Established in 1999
• Utilize steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands
• Operating Area—Christina Lake Project Phases 2 (includes Phase 1) and 2B
• 50%-ownership of the Access Pipeline
Steam-Assisted Gravity Drainage (SAGD)

An Efficient Technology
Christina Lake Regional Project

Project history

Phase 1
• Approved in February 2005 for bitumen production of 477 m³/d (3,000 bpd)
• Sustained steaming commenced March 2008

Phase 2
• Approved in March 2007 for total production of 3,975 m³/d or 25,000 bpd (incremental 3,523 m³/d or 22,000 bpd)
• First steam Q3 2009

Phase 2B
• Plant expansion to 9,540 m³/d or 60,000 bpd (incremental 5,540 m³/d or 35,000 bpd)
• First steam Q3 2013

Phase 3
• Approval granted January 2012, expansion to 33,390 m³/d or 210,000 bpd
Christina Lake Regional Project

2013-2014 Operating Highlights

• 2013 bitumen production from both Phase 2 and 2B facilities averaged 35,317 bpd

• Q1 2014 bitumen production of 58,643 bpd and field wide SOR of 2.5

• Achieved nameplate production in February 2014, with a ramp-up that surpassed Phase 2 performance
Christina Lake Regional Project (CLRP)

Phase 2/2B CPF

Approved Development Area

Access Pipeline
Christina Lake Regional Project (CLRP)

Central Plant Overview
CLRP Active Development Area (ADA)

Drilled SAGD Wells

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD well pairs</th>
<th>Infill wells</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>7</td>
</tr>
<tr>
<td>B</td>
<td>2</td>
<td>3</td>
</tr>
<tr>
<td>BB</td>
<td>6</td>
<td>6</td>
</tr>
<tr>
<td>C</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>D</td>
<td>7</td>
<td>5</td>
</tr>
<tr>
<td>E</td>
<td>6</td>
<td>7</td>
</tr>
<tr>
<td>F</td>
<td>6</td>
<td>4</td>
</tr>
<tr>
<td>G</td>
<td>5</td>
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<td>H</td>
<td>5</td>
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</tr>
<tr>
<td>J</td>
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</tr>
<tr>
<td>K</td>
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<tr>
<td>M</td>
<td>10</td>
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<tr>
<td>N</td>
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<tr>
<td>T</td>
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<td>V</td>
<td>6</td>
<td>0</td>
</tr>
<tr>
<td>AF</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>AG</td>
<td>5</td>
<td>0</td>
</tr>
<tr>
<td>AP</td>
<td>10</td>
<td>0</td>
</tr>
<tr>
<td><strong>total</strong></td>
<td><strong>125</strong></td>
<td><strong>39</strong></td>
</tr>
</tbody>
</table>
Geosciences
CLRP Geoscience Review

- Well and Seismic Data
- Stratigraphic Framework
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
- SAGD Patterns
- McMurray Water Resources
- Cap Rock Geology
- Active Development Area Associated Gas Resources
- Legacy Wells Thermal Compatibility
Christina Lake Regional Project (CLRP)

- CPF = Central Plant Facility
- CLRP Project Area
- Approved Development Areas
- Access Pipeline
CLRPMabiskaw / McMurray Cores

- 827 cored wells
- 85% of all wells are cored
CLRP 2014 Stratigraphic Test Wells

80 wells drilled and cored
CLRP Active Development Area (ADA)

289 horizontal wells (SAGD & Infill wells)
CLRP: Wabiskaw/McMurray Stratigraphy

<table>
<thead>
<tr>
<th>Stratigraphic Unit</th>
<th>Facies Association</th>
</tr>
</thead>
<tbody>
<tr>
<td>lower Clearwater C</td>
<td>offshore mud</td>
</tr>
<tr>
<td>upper Wabiskaw</td>
<td>offshore / lower shoreface mud</td>
</tr>
<tr>
<td>Wabiskaw C</td>
<td>shoreface sand</td>
</tr>
<tr>
<td>Wabiskaw D Shale</td>
<td>bay mud</td>
</tr>
<tr>
<td>Wabiskaw D Valley</td>
<td>bay sand and mud</td>
</tr>
<tr>
<td>McMurray A1</td>
<td>shoreface sand / coal</td>
</tr>
<tr>
<td>upper McMurray Channel</td>
<td>tidal flat / creek sand and mud</td>
</tr>
<tr>
<td>lower McMurray Channel</td>
<td>fluvial / estuarine channel sand and mud</td>
</tr>
<tr>
<td>Beaverhill Lake</td>
<td>carbonate mudstone</td>
</tr>
</tbody>
</table>

McMurray stratigraphy after ERCB RGS 2003
**CLR P: Wabiskaw / McMurray Reference Well**

**1AE/06-18-77-05W400**

<table>
<thead>
<tr>
<th>Parameter</th>
<th>McMurray</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>h (m)</td>
<td>47.6</td>
<td>30.3</td>
</tr>
<tr>
<td>avg Ø</td>
<td>0.311</td>
<td>0.314</td>
</tr>
<tr>
<td>Avg S_o</td>
<td>0.770</td>
<td>0.794</td>
</tr>
<tr>
<td>BMO (calc)</td>
<td>0.114</td>
<td>0.120</td>
</tr>
</tbody>
</table>

McMurray Pay ≥ 6 wt% BMO

**Interval**

- Cap Rock
- Wabiskaw C
- Wabiskaw D
- McMurray
- SAGD
- Water Sand
- B/W
- BHL

McMurray Pay ≥ 6 wt% BMO
### CLRP: McMurray Reservoir Properties

<table>
<thead>
<tr>
<th>Property</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average pay (m)</td>
<td>18.7</td>
</tr>
<tr>
<td>Average depth to reservoir top (mTVD)</td>
<td>359</td>
</tr>
<tr>
<td>Average porosity (frac)</td>
<td>0.32</td>
</tr>
<tr>
<td>Average $S_w$ (frac)</td>
<td>0.25</td>
</tr>
<tr>
<td>Average $K_h$ (Darcies)</td>
<td>5,000</td>
</tr>
<tr>
<td>Average $K_v$ (Darcies)</td>
<td>2,500</td>
</tr>
<tr>
<td>Initial reservoir pressure (kPag)</td>
<td>2,100</td>
</tr>
<tr>
<td>Reservoir temperature ($^\circ$C)</td>
<td>13</td>
</tr>
</tbody>
</table>
CLRP: McMurray SAGD Pay Parameters

**SAGD Pay**

≥ 10 m continuous pay (defined from cores, images and well logs)

\[ R_t = \text{Deep Induction} \]

\[ \phi_{\text{density}} \geq 25\% \]

\[ S_o \text{ (bitumen saturation)} \geq 50\% \]

gas and coal excluded

parameters for \( S_o \) calculation
CLRP ADA Total McMurray SAGD Pay ≥ 10 m

SAGD Pay Cutoffs:
- continuous bitumen pay ≥ 10 m (defined by logs, images and core)
- So ≥ 50% (~6 wt% bulk mass oil)
- Porosity (density) ≥ 25%

contour interval = 5 m
CLRPA DA Base SAGD Pay Structure

contour interval = 5 m

CLRPA Project Area
SAGD Patterns

R6  R5W4

T77
CLRP ADA Top SAGD Pay Structure

contour interval = 5 m

CLRP Project Area
SAGD Patterns
SAGD Pattern A Map View
SAGD Pattern A Map View

- SAGD Well Pair
- Infill Well
- SAGDP ICP
- Infill ICP
- Start of Slots
- SAGD Drainage
- OB Well

T77

R6 400 m R5W4
CLRP Pattern A SAGD Development

- **1AC/01-13-77-06W4**
  - Clearwater C
  - Wabiskaw
  - Wabiskaw D valley fill
  - Wabiskaw C Sand
  - SAGD pay
  - mud
  - non-reservoir lithofacies
  - Top McMurray
  - limestone

- **1AB/04-18-77-05W4**
  - Injector
  - Producer
  - Cap Rock
  - Wabiskaw Marker

- **1AA/03-18-77-05W4**
  - Cap Rock
  - Wabiskaw Member
  - McMurray Formation

- **Beaverhill Lake**
- **Wabiskaw**
- **Cap Rock**
- **Clearwater C**
CLRP Phase 2 SAGD and Infill Wells Map View
CLRP Stacked SAGD Pay

100/14-16-77-05W4 OBB1

100/02-21-77-05W4 OBD1

Single Pattern Development (Single Pay Interval)

Stacked Pattern Development (Multiple Pay Intervals)

Piezometers
CLRP Phase 2 SAGD and Infill Wells Map View
CLRPR Pattern B SAGD Development

- 1AA/06-21-77-05W4
- 100/14-16-77-05W4 OBB1

- Clearwater C
- Cap Rock
- Wabiskaw C

- McMurray
- Devonian

- SAGD Pay
- Non-Reservoir Lithofacies
- Water Sand
- Gas
- Piezometers

- Bitumen / Water Contact
- Water Sand
- Non-Reservoir Lithofacies
CLRP Pattern BB SAGD Development

100/02-21-77-05W4 OBD1

1AB/01-21-77-05W4

Clearwater C
Cap Rock
Wabiskaw C
McMurray
Devonian

Piezometers
CLRP Pattern C SAGD Development

1AB/12-16-77-05W4

1AA/12-16-77-05W4

Clearwater C

Cap Rock

Wabiskaw C

Mcmurray

Devonian

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Gas
CLRDP Pattern D SAGD Development

1AB/07-21-77-05W4

Cap Rock

Clearwater C

Wabiskaw C

McMurray

Devonian

“Tiger Stripes” = interbedded water sand and bitumen sand

100/02-21-77-05W4 OBD1

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Gas

Piezometers

Bitumen / Water Contact

Water Sand

Non-Reservoir Lithofacies

SAGD Pay
CLRP Pattern E SAGD Development

“Tiger Stripes” = interbedded water sand and bitumen sand
CLRP Pattern F SAGD Development

1AA/05-21-77-05W4

1AA/13-16-77-05W4

Clearwater C

Cap Rock

McMurray

Devonian

Gas

Non-Reservoir Lithofacies

SAGD Pay

Bitumen / Water Contact

Water Sand

SAGD Pay

Water Sand
CLRP Pattern D6/D7 SAGD Development

100/06-16-77-05W4 OBC1

1AA/07-16-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Non-Reservoir Lithofacies

Bitumen / Water Contact

Piezometers

SAGD Pay

SAGD PP

D7

D6
CLRP Pattern V SAGD Development

1AA/10-17-77-05W4

1AA/15-17-77-05W4

- Cap Rock
- Wabiskaw C
- McMurray

- Gas
- Non-Reservoir Lithofacies
- SAGD Pay
- Water Sand
- Bitumen / Water Contact
- Water Sand

Devonian
CLRP G & H SAGD Development

- SAGD Well Pair
- ▲ SAGD Prod ICP
- □ SAGD Drainage
- ★ Legacy Well (abandoned zone)
- Green OB Well
- Purple Cased Well

T77

R5W4 400 m
CLRPG & H SAGD Development

- SAGD Well Pair
- ▲ SAGD Prod ICP
- □ SAGD Drainage
- ★ Legacy Well (abandoned zone)
- ▶ OB Well
- ♦ Cased Well

R5W4

400 m
CLRP Pattern G SAGD Development

1AB/05-09-77-05W4

1AA/04-09-77-05W4
CLR P Pattern H SAGD Development

1AA/13-04-77-05W4

1AB/13-04-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Gas

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Non-Reservoir Lithofacies

SAGD Pay

Water Sand
CLRP J & K SAGD Development

- SAGD Well Pair
- ▲ SAGD Prod ICP
- SAGD Drainage
- ★ Legacy Well (zone abandoned)
- ● OB Well
- ★★ Cased Well

T77

R5W4

400 m
CLRJ & K SAGD Development
CLRPM Pattern J SAGD Development

1AA/02-07-77-05W4

1AA/16-06-77-05W4

Cap Rock
Wabiskaw C
McMurray

Non-Reservoir Lithofacies
SAGD Pay
Gas

Non-Reservoir Lithofacies
SAGD Pay

Devonian

Sand

Bitumen / Water Contact

Water
CLRDP Pattern K SAGD Development

1AF/06-07-77-05W4

1AD/10-7-77-05W4

Cap Rock

Wabiskaw C

McMurray

Devonian

Non-Reservoir Lithofacies

SAGD Pay

Water Sand

Bitumen / Water Contact

Water Sand

Non-Reservoir Lithofacies

Non-Reservoir Lithofacies
CLRP M & N SAGD Development

Pattern M

Pattern N

OBM1

OBM2

OB 13-3

OB 15

OBN1

OBN2

M10

M1

N9

N1

T77

R5W4

400 m

SAGD Well Pair

SAGD Prod ICP

SAGD Drainage

Legacy Well (zone abandoned)

OB Well

Cased Well

MEG Energy
CLRP Pattern M SAGD Development

1AA/04-10-77-05W4

1AA/03-10-77-05W4

- Cap Rock
- Wabiskaw C
- McMurray
- Devonian
- SAGD Pay
- Non-Reservoir Lithofacies
- Water Sand
- Bitumen / Water Contact
CLRP T & U SAGD Development

- **SAGD Well Pair**
- **SAGD Prod ICP**
- **SAGD Drainage**
- **Legacy Well (zone abandoned)**
- **OB Well**
- **Cased Well**

Pattern T

Pattern U

Pattern A

R6

400 m

R5W4

T77
Lower sands to be developed at a later date
CLR Pattern U SAGD Development

102/12-18-77-05W4

1AA/07-18-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

SAGD Pay

Gas

SAGD Pay

Gas

Non-Reservoir Lithofacies

Wabiskaw D

Water Sand

Devonian

Bitumen / Water Contact
CLRP AF & AG SAGD Development

- SAGD Well Pair
- SAGD Prod ICP
- SAGD Drainage
- Legacy Well (zone abandoned)
- OB Well
- Cased Well

400 m
R5W4

Pattern AF
Pattern AG

T77
CLRP AF & AG SAGD Development

- SAGD Well Pair
- ▲ SAGD Prod ICP
- SAGD Drainage
- ☆ Legacy Well (zone abandoned)
- ♂ OB Well
- ✿ Cased Well

MAP

- Pattern AF
- Pattern AG

T77
R5W4
400 m
CLRP Pattern AF SAGD Development

1AB/11-19-77-05W4

1AB/15-19-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

Gas

SAGD Pay

Bitumen / Water Contact

Water Sand

SAGD Pay
CLRP Pattern AG SAGD Development

1AB/06-19-77-05W4

1AA/08-19-77-05W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

SAGD Pay

Gas

Gas

Bitumen / Water Contact

Water Sand

SAGD Pay

McMurray
CLRP AP SAGD Development

- SAGD Well Pair
- SAGD Prod ICP
- SAGD Drainage
- Cased Well

Pattern AP

OSL Boundary

400 m

R6W4
CLRP AP SAGD Development

- SAGD Well Pair
- SAGD Prod ICP
- SAGD Drainage
- Cased Well

Pattern AP

- T77

R6W4

400 m
CLRP Pattern AP SAGD Development

1AB/12-12-77-06W4

100/11-12-77-06W4

Cap Rock

Wabiskaw C

Wabiskaw D

McMurray

Devonian

Bitumen / Water Contact

SAGD Pay

Water Sand

SAGD Pay
CLRP ADA Basal McMurray Net Water Isopach

Contour Interval = 5 m

CLRP Project Area
Drilled SAGD Patterns
Low gas cap pressure due to legacy gas production; MEG is repressuring the gas cap.

Local gas cap contact with SAGD interval; ~20% depletion from original pressure; no repressuring required.

Small gas cap; no repressuring required.

Depleted gas cap not in direct contact with SAGD interval.

Drilled SAGD Patterns
- Gas Pool in direct and indirect contact with SAGD interval
- MEG OSL

Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas.
CLRP Lower Clearwater Cap Rock

1AE/06-18-77-05W4

Clearwater C

WBSK Mkr

mud

Lower Clearwater Cap Rock

WBSK C

mud

WBSK D Shale

McMurray

non-reservoir lithofacies

Lower Clearwater Cap Rock = 10.9 m thick

SAGD Pay

Bitumen / Water Contact

Water Sand

Beaverhill Lake
Active Development Area
Average Cap rock Thickness = 10.8 m
Minimum Thickness = 8.6 m
Maximum Thickness = 13.1 m
The measured minimum *in situ* principal stress gradient in the Clearwater cap rock is approximately 20 kPa/m. This gradient coincides with the weight of the overburden as derived from density logs indicating the minimum principal stress is in the vertical direction, i.e., if fracturing were to occur, it is likely in the horizontal direction.

For a typical cap rock depth of 320 m in the CLRP area, the minimum principal stress is 6,400 kPa. This is more than twice the anticipated steady state SAGD operating pressure.

The measured minimum *in situ* principal stress gradient in the McMurray oil sands is slightly lower at approximately 18 kPa/m. This indicates the minimum principal stress is likely in the horizontal direction, i.e., if fracturing were to occur, it is likely in the vertical direction.

Quote from BitCan Geosciences & Engineering Inc.:

> “...if a vertical fracture inadvertently propagated out of the payzone into the caprock, it would eventually turn horizontal. This is due to the *in-situ* stress regime in the caprock favoring horizontal fractures. Therefore, the vertical fracture extending upwards from the payzone is arrested in the caprock and does not propagate further upwards, i.e., it cannot form the hydraulic conduit connecting the payzone and aquifers.”

MEG’s measurements are consistent with other operators’ mini-frac results in the Christina Lake area.
Regional Cap Rock Mini-Frac Test Results

- CVE Christina Lake data: 2010 CVE Christina Lake ERCB Annual Update, June 2010
- CVE Narrows Lake data: CVE Narrows Lake Application to ERCB, Appendix 1-VII (Cap Rock Study), June 2010
- Harvest BlackGold data: Application for Approval of the BlackGold Expansion Project, Volume 1, December 2009
- Devon Jackfish data: 2011 Devon Jackfish ERCB Annual Update, October 2011
CLRP Legacy Wells

- **Type 1B wells (D&A)**: D&A with non-thermal cement
- **Type 2B wells (D&C, DC&A)**: D&C with non-thermal cement

Legend:
- MEG OSL
- Existing SAGD patterns
- Type 1B wells (D&A)
- Type 2B wells (D&C, DC&A)
- Type 2B wells zone abandoned

Type 1B: D&A with non-thermal cement
Type 2B: D&C with non-thermal cement
Legacy Well Thermal Compatibility

• Thermal compatibility addressed on a pad by pad basis in conjunction with IDA amendment applications.

• Specific D-20 abandonment applications have been filed and approved for requisite wells within the ADA and 3 zonal abandonments have been completed in the past year.

• A general thermal compatibility program has been drafted by MEG and reviewed by AER staff. The program includes:
  – A detailed assessment of compatibility of existing all wellbores within the CLRP project area
  – General abandonment approach
  – Monitoring plans

• Submission of the CLRP thermal compatibility program planned for Q3 2014.
Reservoir
CLRP Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Work overs
  - Artificial Lift

- Current Performance
  - Field performance
  - Pattern performance
  - eMSAGP update
  - OB well cased-hole logging
  - Time lapsed seismic

- Associated gas cap re-pressuring
Wells
Well Completions – SAGD Injector

- Steam injected into both long tubing and short tubing
- Blanket gas on annulus
Well Completions – SAGD Producer (Gas Lift)

- 13 3/8” Surface Casing
- 9 5/8” Intermediate Casing
- 7” Tubing
- 4.5” Tubing
- 1.25” Gas Lift & Instrument String
- Liner Hanger
- 3.5” Tubing
- 7” Slotted Liner

- Thermocouples are inside the instrument string to provide temperature measurements at selected locations
Thermocouples are inside the instrument string to provide temperature measurements at selected locations.
Thermocouples are inside the instrument string to provide temperature measurements at selected locations.
• Thermocouples are landed over expected steam zone
• Piezometers are placed in areas of geological interest (gas, bitumen, water zones and potential pay breaks)
Water Source Wells

- 13 3/8” Surface Casing
- 8 5/8” Production Casing
- 4 1/2” Production tubing
- ESP
- 5 1/2” Wire Wrap Screen
Water Disposal Wells

- 13 3/8” Surface Casing
- 9 5/8” Production Casing
- 7” Production Tubing
- Isolation Packer

Water Disposal Wells

82
Developing Well Integrity Best Practices for CLRP

• Includes: SAGD, Infill, Observation, Gas-Repressure, Core-Holes, Legacy Gas, Source and Disposal Wells

The Well Integrity Program includes:

• Risk management – Well health matrix
• Well Integrity Management System (well tracking and monitoring)
• Targeted selection casing integrity checks and Well Servicing support
• Casing design and failure mechanism identification
• AER commitments and reporting
Issue

• Liner impairment on N2P
• Identified while pulling coil during investigation of instrumentation coil check during wellpair circulation September 2013

Implications

• The coil tubing was parted and long tubing cut in attempt to pass the impairment with work coil (unsuccessful)
• Ran impression block and conducted N2 foam cleanout to confirm the impairment was impassable
• Identified impairment approximately at the halfway point of the horizontal

Actions

• Set two wireline retrievable plugs in the well for redrill
• Successfully completed sidetrack redrill from existing N2P intermediate section April 2014
• Reintroduced steam May 2014 - Circulation
Issue

• Liner impairment on N3P
• Identified parted coil and long tubing string during ESP conversion October 2013

Implications

• The coil tubing and long string were both parted
• Tubing irretrievable in the liner suggested unpassable
• Identified impairment approximately at the halfway point of the horizontal

Actions

• 116 m of the liner was retrieved for analysis
• Set two wireline retrievable plugs in the well for redrill
• Analysis conducted of the parted long tubing; no signs of corrosion/erosion
• Successfully completed sidetrack redrill from existing N3P intermediate section April 2014
• Reintroduced steam May 2014 - Circulation
Issue
- Liner impairment on M7P
- Identified damaged tubing during ESP conversion December 2013

Implications
- The long tubing string was bent and showed collar damage; unable to pass the impairment with a drift
- Identified impairment approximately midway between the liner hanger and the liner halfway point of the horizontal

Actions
- Retrieved 6 joints of liner from near the heel for analysis
- Set two wireline retrievable plugs in the well for redrill
- Successfully completed sidetrack redrill from existing M7P intermediate section March 2014
- Reintroduced steam April 2014 - Circulation
**Issue**

- In-zone isolated liner impairments on 4 SAGD producer wells in 2013

**Highlights**

- The impairments developed during circulation and were not production induced
- These wells had an average lateral length of about 1000 metres
- All 4 wells were successfully re-drilled utilizing the existing intermediate section and have since resumed SAGD operation

**Optimization**

- Analysis has suggested the impairments may be a result of thermal induced deformation in longer lateral wells
- Based on our assessment, these effects are not widespread at CLRP
- Slotted liner design has been adjusted on future wells
- Investigating higher weight casing, different grades and connection designs to mitigate these potential thermal effects

Intermediate casing integrities confirmed and no issues with well containment
• All MEG SAGD well pairs are initially completed with gas lift capabilities
• 103 Electric submersible pumps (ESP) in operation
  – Approximately 65% ESPs rated to 220°C and 35% rated to 250°C
  – Operating pressures range from 2,100-3,000kPag
  – Design fluid rates 200-1200m³/d
  – Run-time between pulls is 625-675 days

• 38 rod pumps installed in the infill wells
  – Operating pressures range from 2,000-2,500kPag
  – Design fluid rates 100-500m³/d
Scheme
Performance
### CLRP Pattern Layout

#### April 2014 Wells

**SAGD Well Pairs:**
- Operating: 102
- Circulating: 1
- Standing: 22
- Total: 125

**Infill:**
- Operating: 37
- Standing: 2
- Total: 39
• First steam into Phase 1 (3 WPs) effectively started in March 2008
• First steam into Phase 2 wells started in August 2009
• First steam into Phase 2B wells started in Q3 2013
• Wells were started up in stages, dictated by steam availability
• Current steam chamber pressure is between 2,000 and 2,900 kPag for Phases 1 and 2, between 2,300 and 3,400 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present.
• The combined bitumen production from Phases 1 and 2 reached the design capacity of 3,975 m³/d (25,000 bopd) by late April 2010.
• Phase 2B production ramp-up bettered that of Phase 2. Total production from all phases reached 11,340 m³/d (71,300 bopd) in Q2 2014, exceeded the combined initial design capacity of 9,539 m³/d (60,000 bopd).
The SOR of CLRP has ranged from 2.3 to 3.0 over the last 12 months and averaged 2.6, a slight increase over previous year due to new well start-ups.

The Phase 1 eMSAGP pilot was initiated in December 2011, which has shown very successful results. Commercial application of eMSAGP has been expanded to wells A4, A5, A6 and patterns B, C, D, E and F.

The SOR of the eMSAGP wells (36 SAGD WP’s and 37 infill wells) averaged 2.0 relative to the design level of 2.8 in the period, which allowed MEG to utilize the freed up steam to bring more wells on production.

In Q1 2014, MEG achieved record quarterly production of 58,643 bopd, an 80% increase over the same period of 2013. April production averaged over 71,300 bopd.
CLRP Production Performance

Scheduled Plant Turnaround

Phase 1+2+2B Design Capacity

Phase 1+2 Design Capacity

Rate (m³/day)

Steam Injection
Water
Bitumen

0 5,000 10,000 15,000 20,000 25,000 30,000

1/1/08 12/31/08 12/31/09 12/31/10 12/31/11 12/31/12 12/31/13 12/31/14

- Red: Steam Injection
- Blue: Water
- Green: Bitumen
CLRP Performance – Phases 1 & 2 Pattern SOR
CLRP Performance – Phase 2B Pattern SOR
CLRP Performance – SOR of All Patterns

Phase 2 Start-up

Phase 2B Start-up
Increased water to steam ratio noted recently was mostly from two edge SAGD well pairs (A6 and A8), a result of edge or bottom water incursion.
Increased water to steam ratio noted recently was due to lower steam chamber pressures in two SAGD well pairs (B1 and B2) that caused bottom water incursion.
CLRP Performance – Pattern C

![Graph showing CLRP Performance Pattern C](image-url)

- **SOR Rate (m3/day, e3m3/month)**
- **Steam**
- **Water**
- **Bitumen**
- **Co-injection**
- **ISOR**

**eMSAGP of C1 – C6 Start**
Increased water to steam ratio noted recently was due to lower steam chamber pressures in four SAGD well pairs (D1 to D4) that caused bottom water incursion.
Increased water to steam ratio noted recently was mostly from two edge SAGD well pairs (E1 and F1), a result of edge or bottom water incursion.
CLRP Performance – Pattern F

eMSAGP Start

Rate (m³/day, e³m³/month)

- Steam
- Water
- Bitumen
- Co-injection
- ISOR
CLRP Performance – Pattern V

![Graph showing performance data for CLRP Pattern V over time with different rates for Steam, Water, Bitumen, and ISOR.](image-url)
CLRP Performance – Pattern J

![Graph showing CLRP Performance for Pattern J]

- **Rate (m$^3$/day)**
- **SOR**
- **Dates:** 1/1/13 to 1/1/15
- **Lines:**
  - Red: Steam
  - Blue: Water
  - Green: Bitumen
  - Black: ISOR
CLRP Performance – Pattern M

![Graph showing performance over time with different rates for Steam, Water, Bitumen, and ISOR.](image-url)
CLRP Performance – Pattern N

![Graph showing CLRP Performance Pattern N with SOR rate vs. time for Steam, Water, Bitumen, and ISOR.]

- **SOR Rate (m³/day)**
- **1/1/13 to 7/2/13 to 1/1/14 to 7/2/14 to 1/1/15**
- **Y-axis:** Rate (m³/day) from 0 to 3,500
- **X-axis:** Time from 1/1/13 to 1/1/15

Lines:
- **Red:** Steam
- **Blue:** Water
- **Green:** Bitumen
- **Black:** ISOR
## Original Oil in Place

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average h (m)</th>
<th>Average L (m)</th>
<th>Average Porosity</th>
<th>Average Oil Saturation</th>
<th>OOIP (m$^3$)</th>
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Note: h is net Pay: SAGD base to SAGD Top

L is Liner length (including blanks) with 50m added to each end (100m total)
## Oil Recovery

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<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average h (m)</th>
<th>Average L (m)</th>
<th>Average Porosity</th>
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<th>Recovery (% SAGDable)</th>
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Note: Production volume and number of operating wellpairs are as of April 2014
h is net pay above the producer
L is Liner length (including blanks) with 50m added to each end (100m total)
Cumulative production includes associated infill wells
Update on enhanced Modified Steam and Gas Push (eMSAGP)
Phase 1 and Phase 2 Pad Layout

- Pattern A
- Pattern B
- Pattern C
- Pattern D
- Pattern E
- Pattern F
- Pattern V
- Pattern BB

**eMSAGP Rollout:**
- Pad B (B1-B6): Feb. 2013
- Pad C (C1-C6, D6): July 2013
- Pad D (D1-D5): Aug. 2013
- Pad E (E1-E6, F1): Jan. 2014
- Pad F (F2-F6): Jan. 2014
- Rest of Pad A (A4-A6): April 2014
eMSAGP Pilot in Pattern A

- The eMSAGP pilot involves 3 SAGD well pairs (A1, A2 and A3) and 3 infill wells (initially A1N and A2N, later also 0.5*A3N and 0.5*A7N). Non-condensable gas (NCG) and steam are injected into SAGD injectors; production is through SAGD producers and infill wells.

- Co-injection commenced in December 2011. The first two infill wells were brought on production in January 2012 after steam stimulation. A3N and A7N were put on production in January 2014.

- Over ~2.5 years, steam injection has been reduced by about 60%.
  - NCG injection reduces steam requirement while maintaining steam chamber pressure.
  - Combined bitumen production is consistently better than that expected from SAGD alone.
  - SOR has dropped from ~2.5 to ~1.3, resulting in more wells being brought on and proportionally lower emissions and water usage.

- To-date, pilot performance has been very satisfactory.
Performance of eMSAGP Pilot

![Graph showing the performance of eMSAGP Pilot. The graph plots the rate (m³/day) against time (from 1/1/10 to 1/1/15) with three different lines representing Steam, Bitumen, and NCG Co-injection. The graph indicates variations in rates over time, with notable changes at specific dates.]
SOR of eMSAGP Pilot

Before

After

Pilot Start

1/1/10 1/1/11 1/1/12 12/31/12 12/31/13 1/1/15

SOR

1/1/10 1/1/11 1/1/12 1/1/12 12/31/12 12/31/13 1/1/15

Before After

- Black line represents 'Before' data.
- Green line represents 'After' data.

Legend:
- Black line: Before
- Green line: After
Performance of eMSAGP Wells

Pilot Start
Commercial Start

Rate (m³/day)
Co-injection Rate (e³m³/day)

1/1/10 1/1/11 1/1/12 12/31/12 1/1/14 1/1/15

Steam Injection
Bitumen
NCG Co-injection
SOR of eMSAGP Wells

The diagram illustrates the SOR (Saturation Oil to Gas) of eMSAGP Wells over time, with two distinct phases: Pilot Start and Commercial Start. The SOR values decrease significantly after the Pilot Start, reaching a steady state by 12/31/12. The Commercial Start is marked by a further decrease in SOR, stabilizing around 1/1/15.

Key Dates:
- Pilot Start: 1/1/10
- Commercial Start: 12/31/12

The chart shows two lines representing ISOR (Initial SOR) and CSOR (Current SOR), with ISOR starting higher and CSOR showing a more gradual decline.
• After 2.5 years, the eMSAGP pilot has demonstrated consistent and very satisfactory performance. Higher bitumen production rate was achieved at a much lower SOR, averaging 1.3 over the period.

• Following the success of the pilot, commercial application of eMSAGP has been implemented in patterns B, C, D, E, F and 3 more wells in Pattern A (A4 to A6).

• Performance to date strongly suggests repeatable performances from pattern to pattern.

• Freed up steam has been redeployed to start new SAGD and infill wells.

• Since the initiation of B Pattern eMSAGP in Feb 2013, the bitumen production rate for Phases 1 and 2 has increased by 7,000 bpd and ISOR has come down from 2.4 to 1.8, keeping the overall steam injection rate approximately constant.
OB wells have pressure and temperature instrumentation.
OB4 is 39 m from the A4 SAGD well pair

Cased hole saturation logs showing steam chamber development with time

Approximate position of production and injection wells from directional surveys while drilling
OB6 is 2.5 m from the A2 SAGD well pair

Cased hole saturation logs indicated increased gas saturation and reduced oil saturation in the steam chamber

Potential baffles and barriers

- mud clasts
- 27 cm thick mud parting
- >5 cm thick mud partings

Approximate position of production and injection wells from directional surveys while drilling
Cased hole saturation logs and temperature surveys indicate chamber development in the lower pay zone and the start of drainage from the upper.

Approximate position of production and injection wells from directional surveys while drilling.

OBB1 is 1 m from B1.
Cased hole saturation logs and temperature surveys indicate steam chamber development in both upper and lower reservoirs.

Approximate position of production and injection wells from directional surveys while drilling.

OBD1 is 11 m from B4 and 17.5 m from D3.
Cased hole saturation logs and temperature surveys indicate lateral steam chamber development and bitumen saturation in the bottom water zone.

Approximate position of production and injection wells from directional surveys while drilling.

OB9 is approximately 30 m from the E2 SAGD well pair.
Time Lapse 3D Seismic (Pattern A)

- SAGD Well Pair
- Infill Well
- SAGDP ICP
- Infill ICP
- Start of Producer Slots
- Start of Injector Slots
- SAGD Drainage
- OB Well
- 3D Seismic (2014)
Time Lapse 3D Seismic (Pattern A)

- SAGD Well Pair
- Infill Well
- SAGDP ICP
- Infill ICP
- Start of Producer Slots
- Start of Injector Slots
- SAGD Drainage
- OB Well
- Seismic Cross Section Along A2 Well Pair

3D Seismic (2014)
Time Lapse 3D Seismic (Pattern A)

Projected A2 Well Pair

Cased Hole Gas Saturation Log

Top Steam / Gas

Wabiskaw

BHL

Elevation m ASL
Time Lapse 3D Seismic (Pattern A)

Elevation of Steam / Gas Top

Seismic Cross Section along A2 Well Pair
CLRP Gas Cap
Re-pressuring
Gas Cap Re-pressuring Project Update

- The AER approval was granted in November 2012
- Natural gas injection into 5 wells commenced in June 2013
- Total injection to date was 112.5 e6m3 (~4 BCF), with an average injection rate of 350 e3m3/day (12.4 mmscf/day) over the period
- Pressure responses have been observed in all 5 monitoring wells
- Estimated gas zone pressure above the active SAGD patterns (M & N) was about 1,500 kPag.
- Performance to date indicates faster pressure increase over the active SAGD area which allows for a lower gas injection rate.
- Pressures of gas and SAGD zones are being monitored closely. Plan is to add continuous temperature monitoring in 1 or 2 OB wells.
- Plan is to restore the gas cap pressure on top of the active SAGD area close to the repressuring target of 2,250 kPa and then inject at a rate to maintain that pressure.
Observation Well Pressure Readings

The 100/02-33 well is roughly 1,600 meters away from the active injection/SAGD area.
CLRPGas Cap Re-pressure Scheme (Patterns M & N)

- **Gas injection wells**
- **Gas injection wells (future)**
- **Gas pipeline**
- **Gas pipeline (future)**
- McMurray Channel Gas Pool in direct and indirect contact with SAGD interval
- **Observation Wells**

**Note:**
Not all SAGD intervals in the pool wells are directly connected to associated gas
CLRP Future Development

- CLRP Project Area
- Approved SAGD Patterns
- Future SAGD Patterns
Operations
Operations Overview

- Operation Overview
- Bitumen Treatment
- Vapour Recovery
- Water Treatment
- Steam Generation
- Power Generation
- Measurement and Reporting
- Future Activities
Oil Treatment Overview Phase 1 and 2
Operational Summary

• MEG’s commercial operation continues to exceed expectations.

• Key accomplishments:
  – Successful implementation of Phase 1 and 2 debottleneck projects
  – Successful ramp up of Phase 2B
  – Continuous usage of Saline Water
  – Noted fugitive emissions reduction from VRU improvements in 2012
  – Implementation of new steam safety system for common steam distribution pipeline
Facility Operations: Bitumen Treatment

Successes

- Oil processing Phase 1 and 2 on spec > 99% for the last year
- Consistently over nameplate in Phase 1 and 2
- Very successful ramp up of Phase 2B
- Zero BS&W excursions on the sales pipeline for the last year.
- Phase 1 and 2 Debottlenecking projects completed in Q2 - Q3 2013
  - Additional produced water cooling
  - Additional ORF vessel
  - Sales Oil cooler / Diluent pre-heater
- Injecting recovered diluent into sales oil to minimize diluent losses in the plant.

Issues

1. Exchanger fouling
2. Glycol cooling system is limited during summer months
3. Gathering system instability on plant trips
4. Slop oil handling
Facility Operations: Bitumen Treatment

Actions & Resolutions

1. Expand produced water cooling in Phase 2B and chemical trials to reduce produced water exchanger fouling.

2. Cleaning of Phase 2 Glycol Aerial Coolers and evaluating ways to reduce air recirculation to improve efficiency of Phase 2 Glycol Aerial Coolers

3. Emulsion gathering control philosophy

4. Slop oil treating and reduction initiatives
Facility Operations: Vapour Recovery

- Phase 2 Vapour recovery compressor maintained a 98% availability.
- Phase 2B has 2 VRU packages, each with 2 liquid ring type compressors and higher design pressure tanks.

Issues
- First stage compressor replacement in Phase 2
- Phase 2B commissioning, seal ring issues resulted in lower availability for the first months

Implications
- Flaring of gas during Phase 2 compressor repairs
- Flaring in Phase 2B until compressors lined out
Gas Conservation

Volume (e3m3)

% Conservation

- 0.00%

2B Ramp up Gas Lift

PROD (total Produced Gas)  FLARE (flared produced gas)  % Gas Conservation
Facility Operations: Water Treatment

Successes

• Phase 1 and 2 water treatment plant operating consistently above nameplate capacity
• Phase 2B averaged 45.5% of nameplate during reporting period and has achieved 100% capacity
• Boiler feedwater on spec 95% (yearly average)
• Continue recycling high blowdown volumes (steam and liquid) average recycle rate for April 1, 2013 – May 1, 2014 of 60%
• Continuous use of saline water from end of November 2013 onward
• New HLS sludge processing for all water treatment facilities operational August 2013

Issues

1. Process ponds liner – West pond re-lining planned for Q3 2014
2. Dry chemicals (lime and magox) feeding issues
Actions & Resolutions

1. Pond liner repair Q2-Q3 2014
2. Lime and MagOx upgrades underway
## Water Treatment – Quality Parameters

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Clearwater Well</th>
<th>Saline Water</th>
<th>Produced Water</th>
<th>Boiler Feed Water Phase 2</th>
<th>Boiler Feed Water Phase 2B</th>
</tr>
</thead>
<tbody>
<tr>
<td>TDS (as mg/l)</td>
<td>2,095</td>
<td>13,172</td>
<td>2008</td>
<td>4010</td>
<td>3735</td>
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<tr>
<td>SiO₂ (as mg/l)</td>
<td>8.1</td>
<td>12</td>
<td>210</td>
<td>50</td>
<td>75</td>
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<tr>
<td>Cl (as mg/l)</td>
<td>694.5</td>
<td>7,248</td>
<td>962.4</td>
<td>1890</td>
<td>1860</td>
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<tr>
<td>Na (as mg/l)</td>
<td>844</td>
<td>5,010</td>
<td>789</td>
<td>1,440</td>
<td>1440</td>
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<tr>
<td>K (as mg/l)</td>
<td>3.5</td>
<td>59.2</td>
<td>16</td>
<td>29</td>
<td>29</td>
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<tr>
<td>Ca (as mg/l CaCO₃)</td>
<td>1.45</td>
<td>63.2</td>
<td>3.57</td>
<td>0.093</td>
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<td>Total Alkalinity (as mg/l CaCO₃)</td>
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<td>1,160</td>
<td>355.8</td>
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<td>pH</td>
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<tr>
<td>Fe (as mg/l)</td>
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<td>Trace</td>
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<td>0.01</td>
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<tr>
<td>Total Hardness (as mg/l CaCO₃)</td>
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<td>542</td>
<td>16.04</td>
<td>0.4</td>
<td>0.12</td>
</tr>
</tbody>
</table>
Target is 6000 ppm but boiler limits are 12,000 ppm.
Target is 6000 ppm but boiler limits are 12,000 ppm.
Facility Operations: Steam

Successes

• Very stable operation throughout the year
• Average steam quality 78%
• Maintenance of individual steam generators completed without full plant outage
• Maintained full steam capacity through Phase 2B ramp-up
• Online economizer cleaning on Incremental OTSGs

Issues

1. Continued fouling of incremental steam economizers.
2. Phase 2 HRSG transition section damage
3. Phase 2 OTSG blower issues
4. Phase 2B HP BFW pump issues during start-up
5. Carryover and deposition of boiler blowdown
Facility Operations: Steam

Actions & Resolutions

1. Supply hot BFW to Incremental OTSGs to reduce economizer fouling
2. Phase 3 design used for transition piece for Phase 2 HRSG
3. Upgraded shroud on Phase 2 OTSG blower
4. Phase 2B HP BFW pumps, upgraded bearing material
5. New blowdown diffusers at pond for Phase 2 HRSG and wind fence trial at pond to reduce blowdown plume
Boiler Availability Phase 1 and 2

% Availability

1-Apr 1-May 1-Jun 1-Jul 1-Aug 1-Sep 1-Oct 1-Nov 1-Dec 1-Jan 1-Feb 1-Mar 1-Apr

- P2 HRSG
- P2 OTSG
- P1 OTSG
- Increm 1
- Increm 2
- P2 GTG
Boiler Availability Phase 2B

![Boiler Availability Phase 2B Graph](image-url)
Successes

• Consistent Phase 2 GT operation (availability >97.5%)
• Successful start-up of Phase 2B GT
• Successfully operated Phase 2 GT islanded from grid through AESO outage in May 2013

Issues

1. Salting of transformers and insulators due to blowdown carryover
2. Instability during grid isolation at full load - resolved
3. Bird strikes in summer 2013 tripped entire facility
Actions & Resolutions

1. Logic changes to minimize Phase 2B MP Steam vent opening, planned upgrade of Phase 2 blowdown diffusers at pond, and wind fence trial at pond
2. Redundant power line installed by AltaLink from Black Spruce
3. Reduced bird strikes by turning out lights in substation, installed insulator covers on poles which are high risk for bird strikes, and consulted avian specialist on bird strike risk
Power Generation, Sales and Usage (MW-h)

The chart shows the power generation, sales, and usage over time from April 2013 to April 2014. The data includes:
- **Power Sold (MWh)**
- **Power Generated (MWh)**
- **Power Purchased (MWh)**
- **Power Used (MWh)**
Energy Intensity

(power and fuel usage per m3 of bitumen production)

*Excludes fuel usage for power generation
CoGen GTG Availability

% Availability

Phase 2  Phase 2B

Facility Operations: Gas Usage

Successes
• Stable operation

Issues
• Low supply pressure due to TCPL rupture and de-rate, December, 2013

Actions
• Gas shedding philosophy developed to optimize operations in the event of a gas supply interruption
Facility Operations: Measurement and Reporting

Successes

• Started up all MARP meters for Phase 2B successfully
• The overall steam from CPF to the well pad steam meters balance within tolerance
• Flare gas reporting procedures revised to include Phase 2B
• Second year of well testing at the source water wells confirm minimal gas at the source water wells. Operational balances for source water to group meters have been within tolerance.
• The 2B well pad steam meters have experienced fewer failures due to buildup than Phase 2 well pad steam meters
• Water cut analyzers at pads D, F, J, and K have received final calibrations from manufacturers, pads M and N will be completed following the Phase 2 shutdown
• New water wells, including two brackish, were drilled and are in operation
Issues

1. Test separator gas meters sized for gas lift and are oversized for ESP operation.
2. Missing gas sample taps in Phase 2B will need to be installed during the next shutdown.
3. Secondary steam measurement will need to be installed in Phase 2B at the next shutdown.
Future Actions

1. Install smaller gas meter on affected test separators that provides acceptable turndown.

2. Projects have been kicked off to install the missing gas sample taps.

3. Secondary steam flow meters will be installed during the next Phase 2B scheduled shutdown in May 2015. As an interim measure using balance of Phase 1, Phase2, and Phase 2B CPF steam to sum of all well pad steam distributions to validate steam measurement.
Well Testing and Measurement

- Existing design has 2 to 12 producing wells through a single test separator. Pads with more than 12 wells have the incremental wells under continuous test using conditioning orifice meters.
- MEG has had reliability issues with the orifice meters and the following is being done to improve their performance and reliability:
  - Investigating different sizes/types of meters where the measured rate is outside the accuracy envelope of the meter
  - Improved insulation to limit freezing issues
- Bitumen Proration Factors ranged from 0.92 – 1.15
- Steam Proration Factors ranged from 0.97 – 1.02
Future Activities

- Ongoing plant de-bottleneck projects
- RISER initiative
- West Pond liner replacement
- Emulsion system control philosophy
Water Management
Water Management

- Water Use and Volumes
- Water Source
- Water Disposal
- Water Use Forecast
- Water Use Optimization
Produced Water to Steam Injected Ratio

- 2013 PWSR = 93%
- 2014 YTD PWSR = 99%
CLRP Source Water Well Locations

- 10 active Clearwater non-saline source wells
- 1 active McMurray saline source well
Source Well Production

~9000 m$^3$/d peak non-saline rate

~2800 m$^3$/d peak saline rate

McMurray Saline
Source Water Management

- Saline McMurray groundwater production ongoing since November 2013
- Non-saline Clearwater A groundwater production and pressure monitored in accordance with *Water Act* licenses
- Utilized 59% of the licensed volume in 2013
- Clearwater and McMurray water sands are responding to pumping as expected
CLRP McMurray Disposal Wells

- 5 active McMurray disposal wells

Maximum WHIP: 4,230 kPag

ERCB Approval No. 10659

Disposal pipelines

100/09-29-077-05W4M (Active)
102/10-29-077-05W4M (Active)
103/10-29-077-05W4M (Active)
100/11-29-077-05W4M (Active) (blowdown)
100/07-16-077-05W4M (Active) (regeneration)
Wellhead Injection Pressures

*100/07-16-077-05W4/00 well on vacuum during operation
Basal McMurray Water Sand Pressure Monitoring
Water Use Performance (Directive-81)

- 2013 disposal limit = 8.75%
  - Actual = 10.63%
  - Primarily due to Phase 2B start-up
  - Self-disclosure submitted December 2013
- 2014 YTD disposal limit = 9.97%
  - Actual = 10.43%
  - Forecasting to be below disposal limit for 2014
Disposal % vs. AER D81 Limits.

Phase 2B Commissioning/Ramp-up

- Actual Disposal
- Disposal Limit
Water Use Forecast
Water Use Optimization

- MEG continues to optimize blowdown recycle (exceeding design and adjusting to operational limitations) >60%
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for make-up.
- Technology advancement to reduce SOR (eMSAGP)
- Blowdown evaporator planned for 2015 to further improve water recycle capabilities
- Ongoing water conservation initiatives within Phase 2 and 2B facilities
Compliance and Environment
Compliance & Environment

• Flaring/Gas Conservation
• Sulphur Production and Emissions
• Greenhouse Gas Management
• Compliance
Monthly Flare Volumes

- Overall gas conservation >99%
Sulphur Production and Emissions

- MEG is conducting active monitoring of produced gas $\text{H}_2\text{S}$ concentrations on a weekly basis.

- EPEA $\text{SO}_2$ emissions limit for CLRP is 2.0 t/d, daily $\text{SO}_2$ emissions have averaged 0.914 t/d (April 1, 2013 to April 30, 2014).

- Sulphur increases as a result of Phase 2B ramp up and increased production.

- Sulphur scavenger system planned to be available in Q3 2014 if required.
Inlet sulphur has increased with production, but remains below 1 t/day approval limits.

Sulphur recovery facilities will be commissioned by Q3 2014.
MEG CLRPM continues to produce one of the lowest net GHG intensity barrels in the *in situ* industry.

- Q1 2014 performance of ~0.0544 T/bbl CO$_2$e vs an industry average of 0.071T/bbl CO$_2$e, despite ongoing Phase 2B ramp-up.
- GHG performance is attributed to continued low SORs, use of co-generation technology for steam generation, and ongoing reservoir efficiency initiatives (ie. eMSAGP).
Regulatory Compliance

Inspections

• 3 inspections were conducted from April 2013 to April 2014, all of which were satisfactory.
  – 2 AER Satisfactory Well Site Inspection
  – Ground Disturbance Investigation
Self-Disclosures

MEG reported 7 self-disclosures to the AER during the reporting period:

• **April 18, 2013: Steam Injection Rate Reduction**
  
  – Non-compliance on reduction in the steam injection rate to one injector well that exceeded the 30% threshold stated in scheme approval 10773. The injection rate was reduced due to limited capacity of a common steam line. Future occurrences of the non-compliance are not anticipated as the common line now has adequate capacity.

• **June 13 and July 12, 2013: Breaches of F Pad Berm**
  
  – In both instances, uncharacteristically high rainfall volumes resulted in water accumulation on lease that washed out a section of the berm. MEG will permanently reconstruct the washed out berm per AER Directive 55 requirements. Further, MEG has initiated a review of all pads to ensure suitable grade and berm stability.

• **June 29, 2013: Water Diversion Location Error**
  
  – Water was diverted from the wrong legal location due to incorrectly installed signage. Upon becoming aware of the issue, MEG immediately suspended diversion activities and reported the non-conformance to AESRD. Site signage was installed at the correct location and staff and contractors were made aware of the issue. The remaining diversion on the license was conducted at the correct location. The correct location and the source location inadvertently used were roadside ditches similar in appearance and in proximity to each other.

• **September 4, 2013: Steam Pipeline Condensate Drain Tank Lease Dikes**
  
  – Non-conformance regarding installation of lease dikes on condensate drains associated with above ground steam lines at the CLRP. Future lease dikes will be sized so that any reasonable potential release from top of tank will be captured within the containment. Where feasible, MEG will attempt to incorporate the lease dike into existing wellpad lease dikes.
Self-Disclosures (continued)

• December 5, 2013: West Lime Sludge/Process Pond Primary Liner Failure
  – An increase in chloride values in the interstitial space indicated a failure of the primary liner in the west process pond. MEG will continue to complete monthly leak detection monitoring and ground water monitoring in the area to ensure no impacts to ground water are observed as a result of the loss of liner integrity. The corrective action plan to address process pond leakage was submitted to AESRD and includes a leak scan and potential repair of the East Pond liner as well as a full replacement of the West Pond liner.

• December 17, 2013: Directive 081 Disposal Rate Non-Compliance
  – MEG self-disclosed to the AER an annual disposal rate higher than the facility limit. The non-compliance is attributed to the CLRP Phase 2B start-up as described above. MEG met with the AER and presented a corrective action plan to reach compliance with D81 by the end of 2014.

• February 6, 2014: Voluntary Self Disclosure of Well Test Frequency
  – Supplementary information was provided on February 21, 2014 in response to a letter received from the AER regarding MEG’s testing results for all wells were not compliant with the AER’s measurement requirements (AER Directive 017). The compliance issue arises when a single test separator is used to measure production rates from more than twelve producing wells. As MEG has added infill wells to certain pads, the 12 producer limit was exceeded. To address this issue, MEG installed (with AER approval) calibrated orifice meters to estimate production from wells that do not receive enough operating hours through the test separator.
Flaring and Venting

- MEG reported 39 flaring/venting notifications to the AER including exceedances and outages.

Incident Reporting

- July 6, 2013: High Risk Non-Compliance – Ground Disturbance

  - On July 7, 2013 contact with a non-commissioned water pipeline occurred during ground disturbance activities. The AER Bonnyville Field Centre was notified of this incident on July 10, MEG was issued a Notice of High Risk Noncompliance as MEG failed to immediately notify the appropriate Field Centre of contact with a pipeline. MEG was also not in compliance in that mechanical equipment was used within 60 cm of a pipeline without direct onsite supervision by a representative of the licensee. A single high risk non-compliance covering both violations was issued by the AER.

  - The AER attended the site to carry out its own investigation on July 15, 2013. The repair of the damaged pipelines resumed on July 16, 2013. During the investigation, the AER Bonnyville Field Centre determined that there was no impact to public health and safety, environment, resource conservation or stakeholder confidence in the regulatory process. MEG was able to immediately correct or take action to rectify the noncompliant event. An action plan to prevent a reoccurrence of a similar risk was developed and submitted to the AER Bonnyville Field Centre.
Spills

- 59 reportable spills occurred at MEG from April 2013 to April 2014. All reports were filed with the AER and remediation has been completed. MEG’s 2013/14 spill intensity ranks well below CAPP industry average.
Compliance

• To the best of MEG’s knowledge, the Christina Lake Regional Project is in compliance with all conditions and regulatory requirements related to Approval No. 10773.
CLRP
Future Plans
Regulatory Amendments

Amendments approved April 2013 - April 2014

• Phase 2, 2B, and 3 Facility modifications related to cogeneration and evaporators
• Expansion of NCG co-injection to Pads B, C & D, E & F and additional wells on pad A
• Approval/amendments for patterns L, P, AJ, AN, AQ
• Facilities amendment related to facilities relocation (Phase 2B4X)
CLRP Future Plans

- Ongoing de-bottlenecking of Phase 2B facilities
- Commissioning of sulphur recovery at Phase 2B facility
- Construction and commissioning of evaporator at Phase 2B
- Approval and construction of Phase 2B4X facilities
- Ongoing pattern additions within CLRP development area
- Finalization and submission of thermal compatibility program
- Continued development of eMSAGP within Active Development Area
- Ongoing resource assessment