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The information concerning petroleum reserves and resources appearing in this document was derived from a report of GLJ Petroleum Consultants Ltd. dated effective as of December 31, 2017, which has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-101 entitled Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) at that time. The standards of NI 51-101 differ from the standards of the SEC. The SEC generally permits U.S. reporting oil and gas companies in their filings with the SEC, to disclose only proved, probable and possible reserves, net of royalties and interests of others. NI 51-101, meanwhile, permits disclosure of estimates of contingent resources and reserves on a gross basis. As a consequence, information included in this presentation concerning our reserves and resources may not be comparable to information made by public issuers subject to the reporting and disclosure requirements of the SEC.

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Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs, transportation costs and realized commodity risk management gains/(losses) from such amount.
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This document may contain forward-looking information including but not limited to: expectations of future production, revenues, expenses, cash flow, operating costs, steam-oil ratios, regulatory approvals, pricing differentials, reliability, profitability, emission intensity and capital investments; estimates of reserves and resources; the anticipated reductions in operating costs as a result of optimization and scalability of certain operations; and the anticipated sources of funding for operations and capital investments. Such forward-looking information is based on management’s expectations and assumptions regarding future growth, results of operations, production, future capital and other expenditures, plans for and results of drilling activity, environmental matters, regulatory processes, business prospects and opportunities.

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MEG Energy Corp.

Meeting Agenda

- Overview               Sachin Bhardwaj
- Geosciences            Greg Helman
- Reservoir              Kejia Xi
- Operations             Bill Mazurek
- Water                  Scott Rayner
- Compliance & Environment Mike Robbins
- Future Plans           Sachin Bhardwaj
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
- Use steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands
- Operating Christina Lake Project Phases 2 (includes Phase 1) and 2B
Christina Lake Regional Project
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 or 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
• First steam Q3 2009

Phase 2B
• Approved in March 2009 for total production of 9,540 m³/d or 60,000 bpd
• First steam Q3 2013

Phases 3A/B/C/D
• Approved in February 2012 for total production of 33,390 m³/d or 210,000 bpd

Phase 2B4X
• Approved in June 2014 to re-locate Phase 3B to Phase 2/2B CPF
Christina Lake Regional Project

2017-2018 Operating Highlights

- 2017 Bitumen Production Averaged 80,775 bpd
- Q1 2018 Bitumen Production of 93,306 bpd
- Q1 2018 Average Field-wide SOR of 2.17
- Expanded Implementation of eMSAGP
Christina Lake Regional Project

Phase 2/2B CPF

Approved Development Area
Active Development Area (ADA)

Drilled* SAGD Wells

* As of April 30 2018
Geoscience Review

- Well and Seismic Data
  - Core hole update
  - SAGD Drilling update

- Stratigraphic Framework
  - Geologic Overview
  - Type log

- Reservoir and Pay Parameters

- Active Development Area Bitumen Pay
  - Developable pay Isopach map (with approved and near future undrilled patterns)
  - Top and Base pay Structure maps
  - Structure Sections over exploited area

- Cap Rock Geology
- Basal Aquifer Net sand Isopach
- Active Development Area Associated Gas Resources
- Observation Wells
- SAGD Well Spacing
Christina Lake Regional Project (CLRP)
Wabiskaw / McMurray Cores

- 910 cored wells
- 87% of all wells are cored
2016 Stratigraphic Test Wells

Over the 2018 reporting period:

- 54 Stratigraphic test wells were drilled
- 52 of these were cored
- No GeoMechanical analysis was done
- No reservoir Fracture Pressure or Caprock Integrity tests were done
3D Seismic

- CLRP Project Area
- 3D Seismic
- Time Lapse 3D (2014)
- Time Lapse 3D (2016)
Active Development Area (ADA)

475 horizontal wells (SAGD and infill wells)
Wabiskaw/McMurray Stratigraphy

Stratigraphic Unit | Facies Association
------------------|------------------
lower Clearwater C | offshore mud
upper Wabiskaw     | offshore / lower shoreface mud
Wabiskaw C         | shoreface sand
Wabiskaw D Shale   | bay mud
Wabiskaw D Valley  | bay sand and mud
McMurray A1        | shoreface sand / coal
upper McMurray Channel | tidal flat / creek sand and mud
lower McMurray Channel | fluvial / estuarine channel sand and mud
Beaverhill Lake    | carbonate mudstone

McMurray stratigraphy after ERCB RGS 2003
Wabiskaw / McMurray Reference Well

1AE/06-18-77-05W400

**McMurray**

- Clearwater C
- Cap Rock
- Wabiskaw C
- Wabiskaw D
- McMurray

**SAGD Interval**

<table>
<thead>
<tr>
<th></th>
<th>McMurray</th>
<th>SAGD</th>
</tr>
</thead>
<tbody>
<tr>
<td>h (m)</td>
<td>47.6</td>
<td>28.9</td>
</tr>
<tr>
<td>avg #</td>
<td>0.311</td>
<td>0.314</td>
</tr>
<tr>
<td>avg S°</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 >6wt% BMO
McMurray SAGD Pay Parameters

**SAGD Pay**

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

$R_t = \text{Deep Induction}$

$\phi_{\text{density}} \geq 25\%$

$S_o$ (bitumen saturation) ≥ 50%

Gas and coal excluded

parameters for $S_o$ calculation
### 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>Porosity range (Frac)</td>
<td>0.30-0.36</td>
</tr>
<tr>
<td>Water Saturation Range (frac)</td>
<td>0.15-0.30</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 (°C)</td>
<td>13</td>
</tr>
</tbody>
</table>

Note: Resource values in this table are based on MEG Energy volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.
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%;

Min contour = 10 m
Contour interval = 5 m
OBIP Approved Development Areas

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

Min contour = 10 m
Contour interval = 5 m
Contour interval = 5 m
ADA Top SAGD Pay Structure

Contour interval = 5 m
Cross Sections for Scheme Area

- SAGD Patterns
- Project Area

Grids: T77, T76, R6, R5W4
Structural Cross Section A-A’

Stacked Pattern Development (Multiple Pay Intervals)
Structural Cross Section B-B’

- **Clearwater C**
- **Cap Rock**
- **Wabiskaw C**
- **Top McMurray**
- **McMurray Formation**

**Legend**
- Red: **Injector**
- Green: **Producer**

**Key Points**
- **Wabiskaw Marker**
- **Wabiskaw C Sand**
- **non-reservoir lithofacies**
- **SAGD pay**
- **Water Sand**

**Well Locations**
- **B**
  - 1AA/04-10-77-05W4
- **B’**
  - 1AA/13-34-76-05W4
Structural Cross Section C-C’

- **Producer**: 102/13-04-77-05W4
- **Injector**: 1AB/05-09-77-05W4

- **Wabiskaw C Sand**
- **Wabiskaw Marker**
- **Top McMurray**
- **non-reservoir lithofacies**
- **SAGD pay**
- **Water Sand**
- **Clearwater C**
- **Cap Rock**
- **Wabiskaw C**
- **McMurray Formation**

**Legend**:
- Red: Injector
- Green: Producer

MEG Energy

32
Structural Cross Section E-E’

- **Clearwater C**
- **Cap Rock**
- **Wabiskaw C**
- **Wabiskaw D**

**McMurray Formation**

**Top McMurray**

**SAGD pay**

**Wabiskaw C Sand**

**Wabiskaw D Valley Fill**

**Wabiskaw Marker**

**non-reservoir lithofacies**

**Injector**

**Producer**
Structural Cross Section F-F’

- **F** and **1AB/15-19-77-05W4**
- **1AA/08-19-77-05W4** and **F’**

Key Features:
- **Clearwater C**
- **Cap Rock**
- **Wabiskaw Marker**
- **Wabiskaw C Sand**
- **McMurray Formation**
- **SAGD pay**
- **Non-reservoir lithofacies**
- **Water Sand**
- **Injector**
- **Producer**

Legend:
- Red: Injector
- Green: Producer

Map inset: **F** and **F’**

Company Logo: MEG Energy
Structural Cross Section G-G’

T pattern
1AC/13-18-77-05W4

U pattern
1AE/06-18-77-05W4

A pattern
100/04-18-76-05W4

- Clearwater C
- Cap Rock
- Wabiskaw C
- Wabiskaw D
- McMurray Formation
- Wabiskaw Marker

- Top McMurray
- SAGD pay
- Water Sand
- Reservoir currently unexploited
- Non-reservoir lithofacies

Injector
Producer

MEG Energy
Structural Cross Section H-H’

- McMurray Formation
- Clearwater C
- Cap Rock
- Wabiskaw C
- Wabiskaw D
- Water Sand
- SAGD pay
- Top McMurray
- non-reservoir lithofacies
- Producer
- Injector

Diagram showing the structural cross section with layers and facies identification.
Lower Clearwater Cap Rock

1AE/06-18-77-05W4

Clearwater C mud

WBSK Mark

Lower Clearwater Cap Rock mud

WBSK C

WBSK D ← WBSK D Shale

McMurray

non-reservoir lithofacies

Lower Clearwater Cap Rock = 10.9 m thick

SAGD Pay

Bitumen / Water Contact

Water Sand

Beaverhill Lake
**ADA Lower Clearwater Cap Rock**

*Active Development Area*
- Average Cap rock Thickness = 10.7 m
- Minimum Thickness = 8.5 m
- Maximum Thickness = 12.3 m

*Thickness in Metres*

![Map showing CLRP Project Area and Drilled SAGD Patterns]
Contour Interval = 5 m

CLRP
Project Area

Drilled SAGD
Patterns

T77

T76

ADA Basal McMurray Net Water Isopach
Note: Not all SAGD intervals in the pool wells are directly connected to associated gas.
ADA OB and Cased Wells

- MEG OSL
- Approved Development Area
- Instrumented OB Wells
- Non-Instrumented OB wells
# Well Spacing

<table>
<thead>
<tr>
<th>Pattern</th>
<th>Operating Wellpairs</th>
<th>Average Spacing Between SAGD Pairs (m)</th>
<th>Average Spacing Between SAGD Pair to Infill (m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>B</td>
<td>2</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>BB+D7</td>
<td>7</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>C+D6</td>
<td>7</td>
<td>110</td>
<td>55</td>
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<tr>
<td>D-D6-D7</td>
<td>5</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>E+F1</td>
<td>7</td>
<td>100</td>
<td>50</td>
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<tr>
<td>F-F1</td>
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<td>100</td>
<td>50</td>
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<tr>
<td>G</td>
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<td>5</td>
<td>100</td>
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<td>AN</td>
<td>8</td>
<td>100</td>
<td>50</td>
</tr>
<tr>
<td>P</td>
<td>10</td>
<td>100</td>
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<tr>
<td>AQ North</td>
<td>4</td>
<td>105</td>
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</tr>
<tr>
<td>AQ South</td>
<td>4</td>
<td>120</td>
<td>NA</td>
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<tr>
<td><strong>Total</strong></td>
<td><strong>163</strong></td>
<td></td>
<td></td>
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</tbody>
</table>
Geoscience Summary

• 2018 Winter core program was successful in finalizing more subsurface patterns

• Better understanding and survey control allowed for longer wells and difficult well placement with respect to anti-collision
  – MEG is successfully extending drill length allowing for more patterns reached from individual surface pads

• SAGD well spacing becoming further optimized
Reservoir
Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Artificial Lift

- Scheme Performance
  - Field performance
  - Pattern performance
  - Cased hole logs

- eMSAGP update

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

- Steam injected into both long tubing and short tubing
- Blanket gas on annulus
Thermocouples are inside the instrument string to provide temperature measurements at selected locations.
Thermocouples or thermal fiber are inside the instrument string to provide temperature measurements at selected locations.

Bubble tube is landed near ESP to provide pressure measurement for SAGD producer.
Well Completions – Outflow Control Devices

- Consists of several holes placed mid-way of the long tubing to distribute steam at the middle of the well in addition to the heel and toe
- Current installation are V1I and M4I and results to date have been positive
• Upset production port (UPP) typically consists of holes located at the crossover from 4.5” to 3.5” tubing and is always open
• Inflow control device typically consists of a sliding sleeve with holes that is initially closed and later opened when the well is mature
• To date, MEG has only utilized ICDs in the production tubing and not on the liner
Thermocouples or thermal fiber are inside the instrument string to provide temperature measurements at selected locations.

Bottom hole pressure is estimated from fluid level measurement.
Temperature Measurement

• Have historically relied on six/four-point thermocouple strings in all SAGD and infill wells due to proven accuracy

• Currently have installed thermal fibre on V, AP and AN infill wells, AF, P and AQ Pad SAGD producers, and re-drills on AP and M Pads (AP4P, M3P, M4P, M6P, M9P)

• Recent fibre installations have demonstrated improved data quality, reliability, and cost, and thermal fiber is expected to be the technology for future pads
Observation Wells

- Thermocouples are landed over expected steam zone
- Piezometers are placed in areas of geological interest (gas, bitumen, water zones and potential pay breaks)
Water Disposal Wells

13 3/8” Surface Casing

9 5/8” Production Casing

7” Production Tubing

Isolation Packer
Well Integrity Management

Well Integrity Program for CLRP

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

The Well Integrity Program includes:

- Well Integrity Management System (well tracking and monitoring)
- Targeted proactive casing integrity checks and well servicing support
- Casing design
- Compliance assurance, AER commitments and reporting
- Directive 013 and Inactive Well Compliance Program management
Well Integrity Management System

Highlights

• Select and prioritize SAGD wells for intermediate casing integrity inspections based on risk based evaluation criteria

• Conduct follow-up inspections as needed

• Incorporate learnings from the Well Integrity Management model into well design
CLRP Well Suspensions

- 6 SAGD well pairs are suspended on Pads G, H, and J
  - 2 pairs are suspended due to high production of fine sand
  - 1 pair suspended after operating issues (poor injector – producer communication)
  - 3 pairs have not yet started on production
- Suspended 1 infill well on Pad B due to high production of fine sand
- Suspended 7 SAGD producer wells on Pads B, K, M, and AP that have been re-drilled. All re-drills are now the active producers.
  - 4 due to liner plugging issues (high pressure drop)
  - 1 due to high production of fine sand
  - 2 due to liner impairments (2011 and 2016)
K7N is the only well shut-in due to suspected liner integrity concerns within the 2017-2018 reporting period

**Issue**
- Suspected K7N has in-zone liner impairment after observing pressure increase during second steam cycle on infill well (Jan 2018)

**Implications**
- Unable to pass the impairment with a work string or flush through the impairment
- Thermal fiber data shows that no steam can pass through impairment during subsequent steam cycles
- Identified impairment is close to the heel portion of the liner

**Actions**
- Analysis suggests that the impairment formed during the second steam cycle as a result of thermally induced deformation
- Currently assessing remedial/re-drill options for this well
- Slotted liner design has been adjusted on future wells for improved strength
Directive 013 and IWCP

Program Highlights

• Achieved 20% compliance quota for IWCP Years 1, 2 and 3

• Staging abandonments geographically for efficient reclamation and caribou habitat restoration

• Leveraging winter access to undertake abandonment of associated inactive pipeline and surface facilities, where applicable

• Program focused in Christina Lake in 2018

• Successfully completed 4 non-routine zonal abandonments to mitigate thermal compatibility concerns in future SAGD development areas
Legacy Wells

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 Directive 20 abandonment applications have been filed and approved for requisite wells within the Approved Development Area
- MEG has developed a thermal compatibility program which has been reviewed by AER staff. The program includes:
  - A detailed assessment of compatibility of existing wellbores within the CLRP project area
  - General abandonment strategies to ensure well integrity thermal development areas
  - Monitoring and surveillance plans
Artificial Lift

- **149 electric submersible pumps (ESP) in operation**
  - Approximately 62% ESPs rated to 250°C and 38% rated to 220°C
  - Operating pressures range from 2,100-3,450 kPag
  - Design fluid rates 200-1200 m³/d
  - Run-time between pulls is approximately 900 days and improvements have been made by utilizing higher temperature rated equipment, as required

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

Operating Wells (04/18)

<table>
<thead>
<tr>
<th>Pattern</th>
<th>SAGD WPs</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>
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</tbody>
</table>

Total 159 106

* As of April 30 2018
Reservoir Performance

- 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
- The combined bitumen production from Phases 1 and 2 reached the original design capacity of 3,975 m³/d (25,000 bpd) by late April 2010
- Phase 2B production ramp-up bettered Phase 2. Total production reached 11,340 m³/d (71,300 bpd) in Q2 2014, far exceeded the combined original design capacity of 9,539 m³/d (60,000 bpd)
- Production averaged 80,775 bpd in 2017. In Q1 2018, MEG achieved quarterly production of 93,306 bpd. April production averaged 90,793 bpd
- The SOR of CLRP has ranged from 2.1 to 2.4 over the last 12 months and averaged 2.2 with new well start-ups
- Current steam chamber pressure is between 2,125 and 2,390 kPag for Phases 1 and 2, between 2,140 and 3,640 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present
Production Performance

Scheduled Plant Turnaround

Rate (m³/day)

Jan-08  Jan-10  Jan-12  Jan-14  Jan-16  Jan-18  Jan-20

0  5,000  10,000  15,000  20,000  25,000  30,000  35,000

Steam  Bitumen  Water

Phase 1+2+2B Original Design Capacity
Phase 1+2 Original Design Capacity
Performance – SOR of All Patterns

- Phase 2 Start-up
- Phase 2B Start-up

ISOR

Jan-08 Jan-10 Jan-12 Jan-14 Jan-16 Jan-18 Jan-20

0 2 4 6 8 10
Pattern A Performance

![Graph showing performance of Pattern A with various labels, including: Steams, NCG INJ, Bitumen, Water, and SOR. Key points include eMSAGP Pilot Start, eMSAGP in A4, A5, and A6 Start, and A7 and A8 on production.]
Pattern B Performance

[Graph showing rates and SOR over time]

- Steam
- NCG Inj
- Bitumen
- Water
- SOR
Pattern BB Performance

- **Rate (m³/day, e4m³/month)**
- **SOR**

- **eMSAGP of B3 - B6 Start**
- **B7 and B8 on production**

Legend:
- Red: Steam
- Orange: NCG Inj
- Green: Bitumen
- Blue: Water
- Black: SOR
Pattern C Performance

![Graph showing the performance of Pattern C with various lines representing different factors such as Steam, NCG Inj, Bitumen, Water, and SOR over time from Jan-09 to Jan-19. The graph highlights the eMSAGP Start event.]
Pattern D Performance

[Graph showing the performance of Pattern D with different rates and SOR over time from Jan-09 to Jan-19.]

- **Rate (m³/day, e⁴m³/month)**
- **SOR**
- **Legend**: Red = Steam, Orange = NCG Inj, Green = Bitumen, Blue = Water, Black = SOR

The graph also highlights the eMSAGP Start event.
Pattern E Performance

![Graph showing the performance of different fluids over time, with peaks and valleys indicating changes. The graph includes lines for Steam, NCG Inj, Bitumen, Water, and SOR (Steam Oil Ratio). There is a note indicating the start of eMSAGP.]
Pattern F Performance

- **Rate (m³/day, e4m³/month)**
- **SOR**

The graph shows the performance of various injection methods over time, with peaks and troughs indicating changes in rate and SOR. Notable events include eMSAGP Start, which is marked on the graph.
For this reporting period, there was no disposal activities of unresolved emulsion into V6I, largely due to better processing efficiency at the CPF and very low volumes of this emulsion.
Pattern G Performance

MSAGP Start

Rate (m³/day, e4m³/month)

Jan-13 Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19

0 100 200 300 400 500

0.0 1.0 2.0 3.0 4.0 5.0

- Red: Steam
- Orange: NCD Inj
- Green: Bitumen
- Blue: Water
- Black: SOR
Pattern H Performance

![Graph showing performance metrics over time, with lines for Steam, Bitumen, Water, and SOR rate (m3/day) from Jan-13 to Jan-19. The x-axis represents dates from Jan-13 to Jan-19, and the y-axis represents rate (m3/day) and SOR values.]
Drop in production in 2015 largely due to liner impairment on J4
**Pattern K Performance**

**Low Performance Pad (last year):** Due primarily to injectors being drilled lower than planned making it difficult to control vapor production near heel. Well work-overs to isolate the heel section of the injectors and new wells have turned this pad around.
Pattern M Performance

The chart shows the performance of Pattern M with different rates and SOR (Steam Oil Ratio) over time from Jan-13 to Jan-19. Key points include:

- **Rate (m³/day, e4m³/month)**: The x-axis represents the months from Jan-13 to Jan-19.
- **SOR**: The y-axis represents the SOR from 0.0 to 5.0.
- **Lines**:
  - **Red**: Steam
  - **Orange**: NCG Inj
  - **Green**: Bitumen
  - **Blue**: Water
  - **Black**: SOR

An arrow points to the eMSAGP Start, indicating a significant event in the performance timeline.
**Medium Performance Pad:** SAGD pay is under an associated gas cap and above bottom water. There has been no particular challenge in operating this pad to date.
Pattern T Performance

- Rate (m$^3$/day)
- SOR

Graph showing the performance of Pattern T with data points for steam, bitumen, water, and SOR from January 2013 to January 2019.
Pattern U Performance

![Graph showing performance data for steam, bitumen, water, and SOR over a period from January 2013 to January 2019.](image)

- **Rate (m^3/day)**: The x-axis represents the rate in cubic meters per day, with increments from 0 to 1,500.
- **SOR**: The y-axis represents the SOR (Steam Oil Ratio), with increments from 0 to 5.0.

Legend:
- **Red**: Steam
- **Green**: Bitumen
- **Blue**: Water
- **Black**: SOR
Pattern AP Performance

Note: excludes wells under Experimental Scheme No. 12528
Pattern AF Performance

![Graph showing the performance of different fluids over time. The x-axis represents the months from January 2014 to January 2019, and the y-axis represents the rate in m³/day. The graph includes lines for Steam, Bitumen, Water, and SOR. The SOR values range from 0.0 to 5.0.](image-url)
Pattern AG Performance

Rate (m³/day)

Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19

SOR

Steam  Bitumen  Water  SOR

0  100  200  300  400  500  600  700  800  900  1,000  1,100  1,200  1,300  1,400  1,500  1,600  1,700  1,800  1,900  2,000  2,100  2,200  2,300  2,400  2,500  2,600  2,700  2,800  2,900  3,000  3,100  3,200  3,300  3,400  3,500  3,600  3,700  3,800  3,900  4,000  4,100  4,200  4,300  4,400  4,500  4,600  4,700  4,800  4,900  5,000
High Performance Pad: High production associated with good reservoir quality and no impairments. There has been no particular challenge in operating this pad to date.
Pattern P Performance

Graph showing the performance of different fluids over time:

- **Rate (m³/day)**
  - X-axis: Jan-15 to Jan-19
  - Y-axis: 0 to 3,500

Legend:
- Red: Steam
- Green: Bitumen
- Blue: Water
- Black: SOR
Pattern AP South Performance

The graph shows the performance of different rates and SOR over the period from January 2017 to July 2018. The rates are measured in m3/day, while the SOR is shown on the right axis. The graph includes four different rates: Steam, Bitumen, Water, and SOR. The data trends indicate an increase in all rates and SOR over the observed period.
OBB1 Logging Results

Vertical chamber growth through IHS is observed after co-injection of NCG
• **SAGDable Bitumen In Place**

1. Calculate pay height above producer.

2. Add 50m effective drainage length past first and last slots, unless poor reservoir is encountered.

3. For blank sections >100m, only include 100m for effective length. Expect to access 50m from either side.

• **Total Bitumen In Place**

Use full pay height
**Total Bitumen 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>OBIP (m³)</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>8</td>
<td>22</td>
<td>874</td>
<td>0.33</td>
<td>0.76</td>
<td>3,752,000</td>
</tr>
<tr>
<td>B</td>
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<td>32</td>
<td>744</td>
<td>0.33</td>
<td>0.83</td>
<td>1,300,000</td>
</tr>
<tr>
<td>BB+D7</td>
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<td>20</td>
<td>808</td>
<td>0.32</td>
<td>0.83</td>
<td>3,006,000</td>
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<tr>
<td>C+D6</td>
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<td>0.33</td>
<td>0.75</td>
<td>4,687,000</td>
</tr>
<tr>
<td>D-D6-D7</td>
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<td>678</td>
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<td>0.81</td>
<td>1,952,000</td>
</tr>
<tr>
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Note: Resource estimates in this table are based on MEG Energy volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.

Note: h is net Pay: SAGD base to SADG Top
L is liner length (including blanks) with 50m added to each end where appropriate
*Updated in May 2018
**New 2018
## Bitumen Recovery – Mature Patterns

<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>SAGDable BIP (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery to Date (%SAGDable)</th>
<th>Estimated Final Recovery (%SAGDable)</th>
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<tbody>
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<td>65%</td>
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<td>83%</td>
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<td>65%</td>
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<td><strong>Total</strong></td>
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<td><strong>12,001,797</strong></td>
<td><strong>67%</strong></td>
<td><strong>72%</strong></td>
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</table>

**Note:** Cumulative Production to April, 2018  
- h is net pay: SAGD top- Producer  
- L is liner length (including blanks) with 50m added to each end (100m total)

**Note:** Resource estimates in this table are based on MEG Energy volumetric calculations, and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.
# Bitumen Recovery – New Patterns

<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>SAGDable BIP (m³)</th>
<th>Cumulative Production (m³)</th>
<th>Recovery to Date (%SAGDable)</th>
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</thead>
<tbody>
<tr>
<td>V</td>
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<td>1084</td>
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<td>0.73</td>
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<td>598,000</td>
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<td>18</td>
<td>986</td>
<td>0.33</td>
<td>0.76</td>
<td>3,592,000</td>
<td>699,000</td>
<td>19%</td>
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<tr>
<td>K*</td>
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<td>955</td>
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<td>0.74</td>
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<tr>
<td>AP West</td>
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<td>0.83</td>
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<td>AP South</td>
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<td>727</td>
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<td>AN*</td>
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<td>0.32</td>
<td>0.76</td>
<td>3,961,000</td>
<td>743,669</td>
<td>19%</td>
</tr>
<tr>
<td>AQ**</td>
<td>8</td>
<td>17</td>
<td>973</td>
<td>0.33</td>
<td>0.80</td>
<td>3,935,000</td>
<td>183,131</td>
<td>5%</td>
</tr>
<tr>
<td>Total</td>
<td>153</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td>53,030,000</td>
<td>14,737,835</td>
<td>28%</td>
</tr>
</tbody>
</table>

Note: Cumulative Production to April, 2018

h is net pay: SAGD top- Producer
L is liner length (including blanks) with 50m added to each end (100m total)
*Updated in May 2018
**New 2018

Estimated final recovery (%SAGDable) for new patterns ranges from 50% to 70%

Note: Resource estimates in this table are based on MEG Energy volumetric calculations., and are not in accordance with National Instrument 51-101 guidelines. They are provided solely for the purpose of complying with Alberta regulatory requirements.
Pad Abandonment

- The mature patterns are connected to new patterns that are projected to produce beyond five years.
- At this point, there is no plan to abandon any surface pads for potential needs of pressure maintenance.
enhanced Modified Steam and Gas Push
**Phase 1 and Phase 2 Pad Layout**

**eMSAGP Rollout:**
- Pad B (B1-B6): Feb. 2013 30% R.F.
- Pad C (C1-C6, D6): July 2013 46% R.F.
- Pad D (D1-D5): Aug. 2013 33% R.F.
- Pad E (E1-E6, F1): Jan. 2014 31% R.F.
- Pad F (F2-F6): Jan. 2014 36% R.F.
- Rest of Pad A (A4-A6): April 2014 30% R.F.
- Wells (A7, A8, B7, B8, D7): July 2016 46% R.F.
- Pad V (V1-V6): July 2016 24% R.F.
Bitumen Rates for Phases 1 and 2

Recovery to date:
70 %SOIP
71 %SOIP

Phase 1 SAGD (left axis)
Phase 1 eMSAGP (left axis)
Phase 2 SAGD (right axis)
Phase 2 eMSAGP (right axis)
Steam Rates for Phases 1 and 2

![Steam Rates Graph]

- **Phase 1 SAGD (left axis)**
- **Phase 1 eMSAGP (left axis)**
- **Phase 2 SAGD (right axis)**
- **Phase 2 eMSAGP (right axis)**

**Legend:**
- Green line: Phase 1 SAGD (left axis)
- Green and red line: Phase 1 eMSAGP (left axis)
- Red line: Phase 2 SAGD (right axis)
- Red line: Phase 2 eMSAGP (right axis)

**Graph Details:**
- **Phase 1 Steam** (tpcd)
- **Phase 2 Steam** (tpcd)
- **Years**
- **eMSAGP Start**
SOR for Phases 1 and 2

- Phase 1 SAGD
- Phase 1 eMSAGP
- Phase 2 SAGD
- Phase 2 eMSAGP
Summary of eMSAGP Development

- In 7.5 years of eMSAGP (11 years total), the Pad A pilot demonstrated consistent and very satisfactory performance
  - Higher bitumen production and recovery were achieved at a much lower SOR, averaging 0.16 over the period
  - Recovery to April 2018 was 71% of SAGDable OOIP

- From the initiation of B Pattern eMSAGP in Feb 2013, Phase 2 eMSAGP showed repeatable performance
  - ISOR over the reporting period was 1.32
  - Bitumen recovery reached 70% of SAGDable OOIP

- Overall, eMSAGP has demonstrated better performance than SAGD with Higher recoveries with significant SOR reductions
  - Infill wells are drilled at a pattern recovery of about 30%SOIP.
  - NCG co-injection starts when infill wells demonstrate steady production and pattern pressure is about the original formation pressure
  - Steam freed up from eMSAGP process has been redeployed to new SAGD wells to increase overall production beyond original nameplate capacity
  - eMSAGP has been applied to Phase 2B pads: K, M, N, and part of the AN and AP pads. Performance data will be presented in the future
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 283 e6m3 (~10.0 BCF), with an average injection rate of 49 e3m3/day (~1.8 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 & P) was about 2,000 kPag, about the same level as the initial gas cap pressure
- Performance to date indicates faster pressure increase over the active SAGD area which allows for a lower gas injection rate and volume to maintain gas cap pressure
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely
- Negative thief zone effect of the gas cap has not been observed to date
- A new project was commenced in the L pad gas cap in April 2018
Gas Cap Re-pressure (Patterns M, N & P)

Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas.
Total Gas Injection

- **Cumulative Gas (e6m³)**
- **Rate (e3m³/cd)**

Graph showing gas injection rates and cumulative gas over time from Jan-13 to Jan-19.
The 100/02-33 well is roughly 600 meters away from the active injection/SAGD area.
Unresolved Emulsion Injection
Unresolved Emulsion Overview

- Pilot project extended on September 27, 2017 (Approval No. 10773QQ) until September 30, 2018
  - Approval allows for the injection of unresolved emulsion into an active steam chamber limited to well pair V6
  - Unresolved emulsion is a mixture of produced water, oil & fine clay particles which cannot be treated with the processing trains currently in use at the CLRP
  - V6I selected because of low oil production rate and poor reservoir quality, which limits the risk of any potential production impacts

- Rates of unresolved emulsion at CLRP have been reduced resulting in the trial being put on hold
  - Largely due to better processing efficiency at the CPF
  - No unresolved emulsion has been injected to the reservoir since April 2017
  - No current plans to re-start injection of unresolved emulsion
Operations
Operations Overview

- Operation Overview
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage
CPF Site Plan
Integrated Distribution/Gathering System

- Producer Well
- Phase 1 & Phase 2
- Phase 2B
- Produced Water
- Produced Water
- Emulsion
- Sales Oil
- To ACCESS Pipeline
- Steam
- Injector Well
Water and Steam Process Overview Phase 1 and 2
Water and Steam Process Overview Phase 2B
Oil Treatment Overview Phase 1 and 2
Additions/Modifications

• No significant additions or modifications have been made to the Central Processing Facilities in the last 12 months
Facility Performance: Bitumen Treatment

- Performance over original design primarily due to operation with naphtha diluent and equipment design factors.
Facility Performance: Bitumen Treatment

Successes

• Installed solids removal equipment in the Phase 2 oil treating vessels with positive results
• Alternate chemical treating formulation to reduce fouling in the produced water exchangers in all phases continues to be successful
• Modified Phase 2 diluent tank inlet to promote mixing of tank contents to reduce the impact of daily variations in diluent composition on the sale oil storage tanks

Issues Being Addressed

• Diluent mixing in Phase 2B storage tank
• Vapor recovery optimization in tank farms
Facility Performance: Bitumen Treatment

Future Actions

• Installation of enhanced interface level measurement in Phase 2B FWKO and Treaters
• Modifications to FWKO and Treater internal baffle design
• Various plant debottlenecking projects in Phase 2B
• Continue optimization of chemical treatment program
• Continue plant testing to establish ultimate capacity as bottlenecks are eliminated
Facility Performance: Water Treatment

Water Make-up and Disposal Rate / Bitumen Rate

- Total Water Make-up/Bitumen
- Disposal Water/Bitumen

Graph showing water make-up and disposal rates from January 17 to April 18.
Facility Performance: Water Treatment

Successes

• Conversion of afterfilters from multi media to mono media
• Successfully re-routed Phase 2 water treatment SAC/WAC regeneration waste from blowdown pond to spent lime sludge holding tank for processing through centrifuge
• Use of Inductively Coupled Plasma (ICP) apparatus to track boiler silica transport across boilers along with statistical data analysis of process data allowed BFW silica level to be increased, reducing the magnesium oxide requirements

Issues Being Addressed

• Balance boiler blowdown recycle against produced water usage to optimize disposal water volume
• Cleaning of solidified sludge from the Phase 2B HLS to improve operation and reliability
Facility Performance: Water Treatment

**Future Actions**

- Increase dryness of processed HLS sludge from centrifuge to reduce disposal volumes
- Various chemical treatment initiatives to optimize chemical usage
- Plant testing to determine bottlenecks to future growth
Facility Performance: Steam Generation

*Actual Steam Rate/Plant Design Steam Rate*

- Steam P/L outage.
- Phase 2 planned maintenance.
Facility Performance: Steam Generation

Successes

• Stable operation throughout the year
• Successfully completed repairs on two 50 MMBtu/hr OTSGs
• Implemented enhanced steam pipeline condensate removal at one location in distribution system
• Modeling of steam generator fouling showing promising results

Issues Being Addressed

• Continue to implement improved steam pipeline condensate removal facilities at high value locations
• Overall control and protection of the HP steam distribution being reviewed to enhance operability
Future Actions

• Continue optimization of steam generator fouling to examine impact on efficiency and runtime

• Installation of fuel gas heating value analyzer in Phase 2B to allow increased accuracy of steam generator efficiency tracking and optimization
Facility Performance: Power Generation

Power Generated/Consumed

- Steam P/L outage.
- Phase 2 planned maintenance.

- Total Power Generated (MWH)
- Total Power Consumed (MWH)
- Total Power Consumed (%)

January 2017 to April 2018
Facility Performance: Power Generation

![Graph showing actual power generated vs. design generation with key events marked: Steam P/L outage in May 2017, Phase 2 planned maintenance in June 2017.](image-url)
Facility Performance: Power Generation

**Successes**
- Stable operation throughout the year

**Issues Being Addressed**
- No significant issues
Facility Performance: Gas Usage

![Gas Consumption Graph]

- **Steam P/L outage.**
- **Phase 2 planned maintenance.**

Legend:
- Green: Total Plant Gas (e3m3)
- Blue: Total Produced Gas (e3m3)
Facility Performance: Gas Usage
Facility Measurement

Well Tests

• Well tests used to determine bitumen and water production rates for each well
  – Pads are equipped with test separators
  – Each production well receives 1 testing hour per 40 hours in operation
  – Test durations shall be optimized to obtain as many representative production well tests as possible for each month
  – Reservoir GOR = 5; Gas Proration Factor = 1

• Water cuts via in-line meters or spot samples with manual S&W measurement
  – Using alternative S&W method using emulsion density

Field Steam Measurement

• Electronic diagnostics on smart vortex steam meters (Rosemount 8800D) have improved safe operations and reduced O&M costs
Water Use Intensity
Non-Saline Water Use Intensity

*2017 had lowest non-saline water use intensity in CLRP operations history (0.20)*
Water Recycle and D81 Limits

D81 Compliant in 2017

*2018 calendar year disposal limit/actual percentages are YTD to April 30
Produced Water to Steam Injected Ratio

Calendar Year (1.04)

Reporting Year (1.03)
Source Water Well Locations

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

- **Clearwater Non-Saline Wells**

- **McMurray Saline**

### Reporting Year (1.1MM m³)

### Calendar Year (1.1MM m³)
McMurray Disposal Wells

- 5 active McMurray disposal wells

ERCB Approval No. 10659
Maximum WHIP 4,230 kPag
Disposal Summary

Calendar Year (1.2MM m³)

Reporting Year (1.3MM m³)

100/07-16

100/09-29

100/10-29

100/11-29
Wellhead Injection Pressures
Injection Temperatures
Basal McMurray Water Sand Pressure Monitoring
Water Management Summary

- 2017 had lowest non-saline water use intensity in CLRP operations history
  - MEG planning to execute a project to replace non-saline water for backwash with produced water. This will further decrease the non-saline water use intensity.
- D81 compliant in 2017
- High produced water to steam ratios have increased 2018 year-to-date disposal rates. Forecasting to be D81 compliant in 2018 with the implementation of the backwash project and commencement of steaming and production at new pads.
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for steam generation make-up
- Non-saline Clearwater A and Ethel Lake groundwater production and pressure monitored in accordance with Water Act licenses
- Ethel Lake, Clearwater and McMurray aquifers are responding to pumping as expected
- Technology advancement to reduce SOR and increase overall water use efficiency
- Blowdown evaporator planned to be online in 2019 to further improve water recycle capabilities
MEG Energy

Compliance & Environment
Compliance & Environment

Reporting Year Highlights

• Monitoring Programs
• Sulphur Production and Removal
• Greenhouse Gas Management
• Compliance Summary
• Reclamation
MEG’s Extensive Monitoring

Detecting any changes that may occur due to our developments

**Air**
Chemical analysis and flow rates for all fuel streams and stack emissions. We also monitor ambient air quality around our facilities.

**Groundwater**
Check water quantities and quality. This includes our groundwater use as well as leak detection systems for our recycling ponds, waste management facility and tank farms.

**Regional Monitoring**
MEG participates in a number of regional monitoring initiatives and groups such as the Alberta Biodiversity Monitoring Institute, the Wood Buffalo Environmental Association, and the Alberta, Canada, Joint Oil Sands Monitoring program.

**Soil**
Soil analysis and laboratory testing for any chemical changes or contaminations

**Surface Water/Wetlands**
Monitor surface water quantity and quality in nearby water bodies and watercourses

**Wildlife**
Winter tracking, monitoring wildlife corridors using remote cameras, and employee wildlife sighting cards

**Vegetation**
Monitor species composition and abundance
Monitoring Program Updates

In compliance with EPEA Approval 216466-01-01, the following Monitoring Program Proposals were submitted to the AER

- August 31, 2017: CLRP Woodland Caribou and Wildlife Mitigation Plan and Monitoring Program Proposal
- August 31, 2017: MEG CLRP Wetland and Water Body Monitoring Proposal
- August 31, 2017: Project Level Conservation, Reclamation and Closure Plan (PLCRCP)
- December 31, 2017: Updated Project Specific Wetland Reclamation Trial
MEG participates in the following environmental initiatives:

- **Industrial Footprint Reduction Options Group (iFROG)**
  - University of Alberta led research collaboration focused on enhancing construction and wetlands reclamation practices in boreal Alberta

- **Regional Industry Caribou Collaboration (RICC/COSIA)**
  - A group of companies from the oil sands and forestry sectors collaborating with the Government of Alberta and other institutions to address caribou conservation and recovery in NE Alberta

- **Faster Forests (COSIA)**
  - The COSIA Faster Forests program is a reclamation research collaboration amongst seven oil & gas operators designed to identify reclamation techniques which can accelerate re-vegetation of sites disturbed by exploration activities

- **Wood Buffalo Environmental Association (WBEA)**
  - WBEA monitors the environment of the Regional Municipality of Wood Buffalo in north-eastern Alberta
Average inlet sulphur surpassed 1 t/d in 2014 triggering scheme sulphur recovery requirements
Produced Gas Rates and H$_2$S Concentration
Produced Gas Recycle Project

• Produced Gas Recycle Project will manage higher than expected produced gas returns to the CPF
  – Packages are installed
  – Piping is 50% complete
  – Electrical & instrumentation installation underway
• Regulatory application filed on February 9, 2018
  – Scheme approval and EPEA approval amendment applications approved on March 29, 2018
• Project expected to be operational in Q3 2018
SO₂ Emissions

SO₂ Emissions

- New SRU Tie-in
- SRU Maintenance
- Optimizing Scavenger Costs
- High H₂S concentration in fuel gas

SO₂ Emissions (t/d)

- EPEA Approval Limit
- SO₂ Emissions
- 90-Day Rolling Average SO₂
• **October 2017** – SRU was removed from service for maintenance and MEG complied with approval limits for Sulphur emissions during the outage

• **Sulphur Recovery Guideline Variance** – On December 21, 2017 MEG received approval for a variance of the Alberta Sulphur Recovery Guidelines (ID 2001-03) from the AER
  – Compliance with ID 2001-03 is based on the days within the calendar quarter during which the non-regenerative SRU is operational
  – Excludes periods of planned maintenance or unplanned outages
  – Requires that a 95% operational uptime is maintained within the calendar year
  – The variance is valid through to the end of 2018
• MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.

• GHG performance is attributed to reservoir performance (low SORs), use of cogeneration technology for steam generation, and ongoing reservoir efficiency technologies (i.e., eMSAGP).

Sources: MEG’s net GHG data from 2010-2016 has been third-party verified. 2017 data is preliminary. In situ industry average estimate is calculated based on the most recent reported data to Environment Canada, Alberta Energy Regulator, and Alberta Electric System Operator.

* Phase start-up: higher steam requirements with low initial production
** Net GHG intensity includes the associated benefits of cogeneration
## Audit/Inspection Summary

<table>
<thead>
<tr>
<th>Date</th>
<th>Audit/Inspection</th>
<th>Area</th>
<th>Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>May 1, 2017</td>
<td>AER Water Act Audit</td>
<td>Temporary Water Use Reporting Audit</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>May 16-17, 2017</td>
<td>AER Drilling Inspection</td>
<td>Pipeline Multiple locations</td>
<td>Satisfactory</td>
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<tr>
<td>May 16, 2017</td>
<td>AER Drilling Inspection</td>
<td>Akita 27</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>May 16, 2017</td>
<td>AER Drilling Inspection</td>
<td>Akita 21</td>
<td>Satisfactory</td>
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<td>May 30, 2017</td>
<td>AER Pipeline Inspection</td>
<td>License 46441 (Steam)</td>
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<tr>
<td>July 17, 2017</td>
<td>AER Drilling Waste Audit</td>
<td>Licence No. 4822440</td>
<td>Satisfactory</td>
</tr>
<tr>
<td>September 26, 2017</td>
<td>AER Manual 001</td>
<td>Winnifred South Compressor</td>
<td>Unsatisfactory Low Risk. Issues addressed and resolved by MEG.</td>
</tr>
<tr>
<td>September 26, 2017</td>
<td>AER Manual 001</td>
<td>Wellsite Licence No. 484169</td>
<td>Satisfactory</td>
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<tr>
<td>September 26, 2017</td>
<td>AER Source Water Inspection</td>
<td>Borrow Pit 6 Water Diversion location</td>
<td>Satisfactory</td>
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<tr>
<td>October 21, 2017</td>
<td>AEP Ambient Air Trailer Audit</td>
<td>CLRP – EPEA 216466-01-01</td>
<td>Satisfactory</td>
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<tr>
<td>November 20, 2017</td>
<td>AER Pipeline Inspection</td>
<td>License No. 46441 (35, 36) (steam) and 46442 (40), (emulsion)</td>
<td>Satisfactory</td>
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<tr>
<td>November 21, 2017</td>
<td>AER Drilling Inspection</td>
<td>Akita 27</td>
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</tr>
<tr>
<td>February 20, 2018</td>
<td>AER Pipeline Inspection</td>
<td>Wildlife Crossing Compliance</td>
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<td>March 21, 2018</td>
<td>AER Drilling Waste Inspection</td>
<td>Waste Handling and Storage</td>
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<tr>
<td>April 2, 2018</td>
<td>AER Drilling Waste Audit</td>
<td>Drilling Waste Management and Documentation</td>
<td>Satisfactory</td>
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</table>
Self-Disclosures & Non-Compliances

• **Voluntary Self Disclosures:**
  - February 2017, the infill well, MEG A3N HARDY 115/01-13-077-06 W4/00 was deficient in test hours.

• **Non-Compliances:**
  - AER Winifred South Inspection - On September 26, an AER inspection at the inactive Winifred South compressor station resulted in an unsatisfactory low risk result. Unsatisfactory AER findings include: faded “out of service” signs on the tanks, underground tanks not blinded from equipment, and housekeeping deficiency related to construction debris not stored properly.

• **AER Follow up to Enforcement Initiative:**
  - September 7, 2017 - Follow-Up to the Enforcement Action associated with Surface Water Diversion exceedance and Administrative Penalty issued February 6, 2015.
    - All commitments outlined in the administrative penalty have been successfully implemented. MEG received notice of closure from the AER on November 20, 2017.
MEG reported 5 EPEA approval contraventions to the AER during the reporting period:

- **Emergency Generator Emissions Approval Contravention (AER CIC#332334)** – MEG identified that a P2B Emergency Generator was excluded from the CLRP EPEA Approval, as an emissions source. EPEA Approval was amended to include this equipment.

- **Passive Sample Station Missing (AER CIC#331801)** – One of the four air monitoring passive stations was identified as missing and was not available for analysis for October 2017.

- **P2 Cogen 90% Availability Exceedance (AER CIC#333221)** – MEG did not meet the 90% uptime limit for the month of December as required by EPEA Approval Section 3.9.

- **Industrial Runoff Release (AER CIC#327442)** – On July 24, water levels increased on AP pad due to heavy rains and began to overflow the SW corner of the pad berm. The industrial runoff water release was uncontrolled and sampling was not able to be completed before the release to confirm whether runoff water parameters met EPEA approval requirements.

- **P2 Skim Oil Tank Venting (AER CIC#329568)** – On September 9th a vacuum truck was transferring fluids from the P1 slop tank (1-T-405) to the P2 skim oil tank (2-T-118). The P2 tank over pressured due to the high tank levels during fluid transfer, causing the PVSV to open and release vapors to atmosphere.
Clearwater Pressure Monitoring

Contravention Details (CIC#330970)

- Clearwater was being withdrawn from the 3-16-77-5W4(S2; Licence# 352705) and 8-16-77-5W4(S3; Licence #352706) source water wells. Pressure monitoring equipment failed and pressure data was not available to calculate the daily water levels. Pressure data was lost from August 1, 2017 to October 1, 2017
- Lost data resulted from the Promore unit (converts downhole data to pressure) failing and shorting out the Modbus loop, resulting in communications failing back to the DCS

Description of Environmental Impact

- No environmental impact as the electronic submersible pumps (ESP's) associated with the source water wells are landed above the perforation intervals and screens. There would be minimal risk of exceeding 100% drawdown in the well

Corrective Actions

- Alarms were initiated to notify Field Production Engineer if pressure monitoring equipment fails
- Developed and implemented an internal procedure: *Clearwater Source Water and Observation Well Monitoring and Management of Pressure Data Loss Events*
  - If a pressure monitoring outage could result in daily pressure data not being recorded operations will switch to another source water well with functioning pressure monitoring or initiate field operations to complete secondary pressure monitoring of down hole liquid level shots with an echometer
- Implementing training on the procedure to applicable staff managing water diversion and pressure monitoring
Continuous Ambient Air Monitoring Trailer and Passive Sampling

- MEG employed the use of a continuous ambient air monitoring trailer from January to June 2016 for phases 1, 2 and 2B as required by our approval
- Four passive monitors are installed around the CLRP site for the measurement of H$_2$S and SO$_2$ with readings taken on a monthly basis
Continuous Monitoring Results

<table>
<thead>
<tr>
<th>Maximum Reading (ppbv)</th>
<th>Month of Maximum Reading</th>
<th>Limit (ppbv)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SO2 66</td>
<td>October 2017</td>
<td>172</td>
</tr>
<tr>
<td>H2S 3</td>
<td>July 2017</td>
<td>10</td>
</tr>
</tbody>
</table>

There were no exceedances of Ambient Air Quality Objectives during the reporting period.

Continuous ambient air monitoring was conducted from July 2017 to April 2018, and will continue until June 2018.
Ambient Air Quality Monitoring

Passive Sampling Results

SO$_2$ Passive Sampling Results

H$_2$S Passive Sampling Results
• Overall gas conservation >95%

• MEG reported 13 flaring and 1 venting notifications to the AER from April to December 2017 including exceedances and outages

• MEG reported 3 flaring and 0 venting notifications to the AER from January to April in 2018 including exceedances and outages
Conservation & Reclamation

Reporting Year Highlights

Wetland Reclamation Trial Program
- Completed second year of monitoring at Borrow Pit 7 WRT
- Submitted Wetland Reclamation Trial Proposal for partial pad removal/peat replacement trial in December 2017

Borrow Pit Reclamation
- Borrow Pit 8
  - Finalized soil re-contouring/reclamation and re-vegetation occurred in Q2 2017
  - Canadian Toad Protected Habitat established
- Borrow Pit 3
  - Area not overlapped by new Pad AT was reclaimed and planted in November 2017
- Borrow Pit 4A
  - ~2 hectares of western edge of water body contoured and reclaimed

Ongoing Research and Monitoring Programs
- MEG’s Woodland Caribou Mitigation and Monitoring Program
- COSIA Faster Forest Program
- COSIA iFrog Program (Industrial Footprint Reduction Options Group)
- COSIA RICC Program (Regional Industry Caribou Collaboration)

Project Level Conservation, Reclamation, and Closure Plan
- PLCRCP submitted to AER for review in December 2017
Linear Disturbance Deactivation/Caribou Habitat Restoration

- As required by MEG’s EPEA Caribou Mitigation and Monitoring Plan, linear restoration activities continued in townships 077-03 and 077-04 W4M in the spring of 2017 and winter of 2018
  - The 2017 spring project occurred from May 26 to June 7, 2017
    - 5.82 km of ripped seismic line completed in the 2017 winter program was planted.
    - 317 m of line that had been mounded but not planted during the winter were planted
    - 180 m of seismic line that had received no previous treatment was planted
  - The 2018 winter project occurred from January 29 to March 4
    - Total of 24.1 km of linear features were treated
    - Total lines restored in 2016 - 2018: 61.1 km
OSE Reclamation

Reporting Year Highlights:

Ongoing OSE Reclamation, Assessments and Reclamation Certification

• Annual Field Program executed, including:
  – 2017 Program Aerial Assessments
  – CLRP 110074 Groundtruthing
  – Surmont 110076 Groundtruthing
  – CLRP 120080 Groundtruthing
  – Kirby 120075 Groundtruthing
  – Surmont 120086 Groundtruthing
  – May River 110062 Groundtruthing
  – Thornbury 110075 Groundtruthing
  – Surmont Storm Wells Aerial Assessments

• OSE Wellsite Reclamation Certification received for:
  – CLRP 090045
  – CLRP 100089
  – Surmont 050045
  – Surmont 070004
  – Surmont 100069
  – Thornbury 100070

• OSE Program revegetation completed on 5 cut/fill locations
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.
  – For the period of April 1, 2017 to March 31, 2018, MEG Energy has no unaddressed non-compliant events
Future Plans
Future Plans

- Continued development of eMSAGP within Active Development Area
- Ongoing progress of brownfield development within existing facility footprint
- Ongoing pattern addition within CLRP development area
- Ongoing resource assessment
Regulatory Activity

April 2017 - April 2018

- Directive 56 licenses and amendments for well pads and field facilities
- Sub-surface reconfiguration scheme amendments for patterns AH and P
- Scheme amendment applications for sustaining patterns including DE, DG, and DK

April 2018 - April 2019

- Field wide expansion of NCG Co-Injection (eMSAGP)
- Scheme amendment applications for sustaining patterns
Future Development
Environment and Regulatory

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