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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.



Disclosure Advisories

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MEG Energy Corp.

Meeting Agenda

Overview Sachin Bhardwaj

Geosciences Greg Helman

Reservoir
 Kejia Xi

OperationsBill Mazurek

• Water Scott Rayner

Compliance & Environment Mike Robbins

Future Plans
 Sachin Bhardwaj



MEG Energy Corp.

Who We Are

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





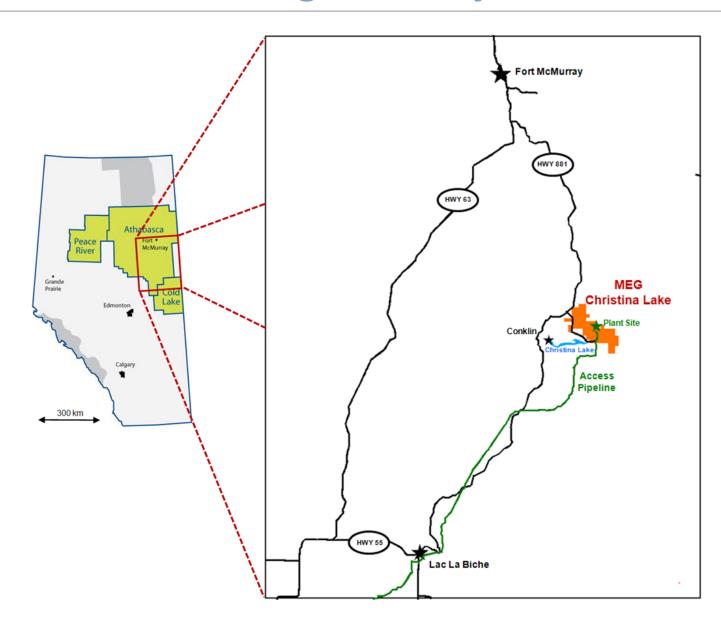
MEG Energy Corp.

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



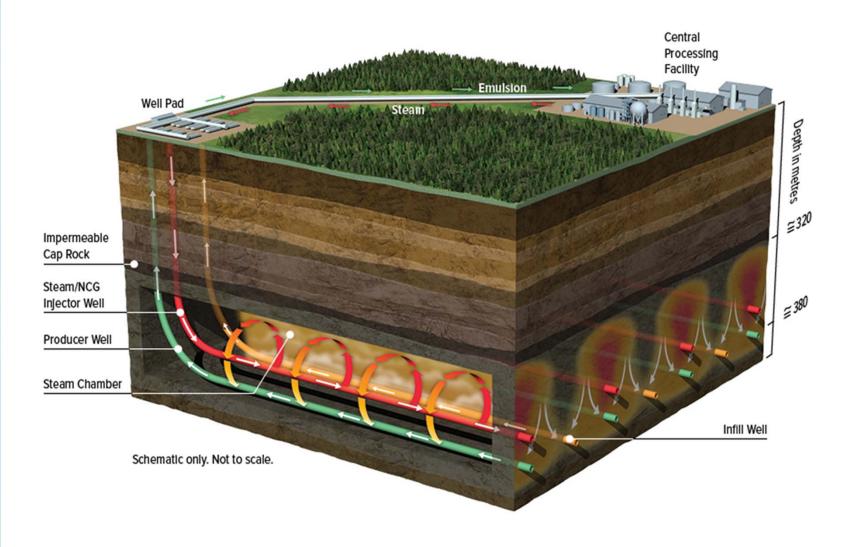






Steam-Assisted Gravity Drainage (SAGD)

An Efficient Technology





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

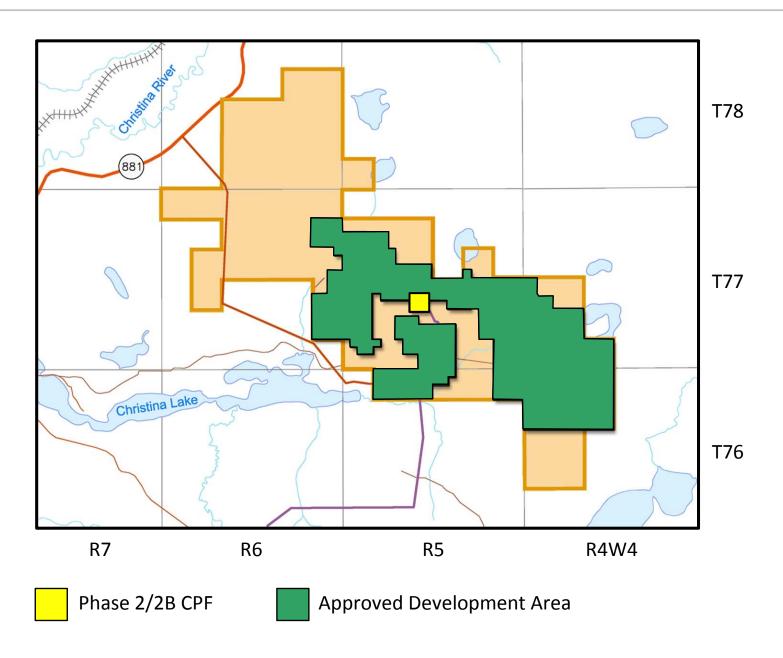


2017-2018 Operating Highlights

- 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

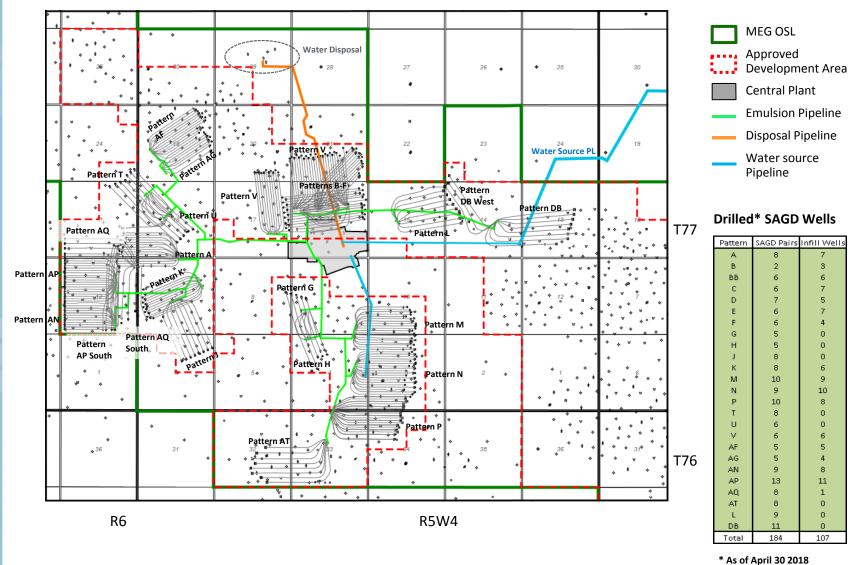








Active Development Area (ADA)





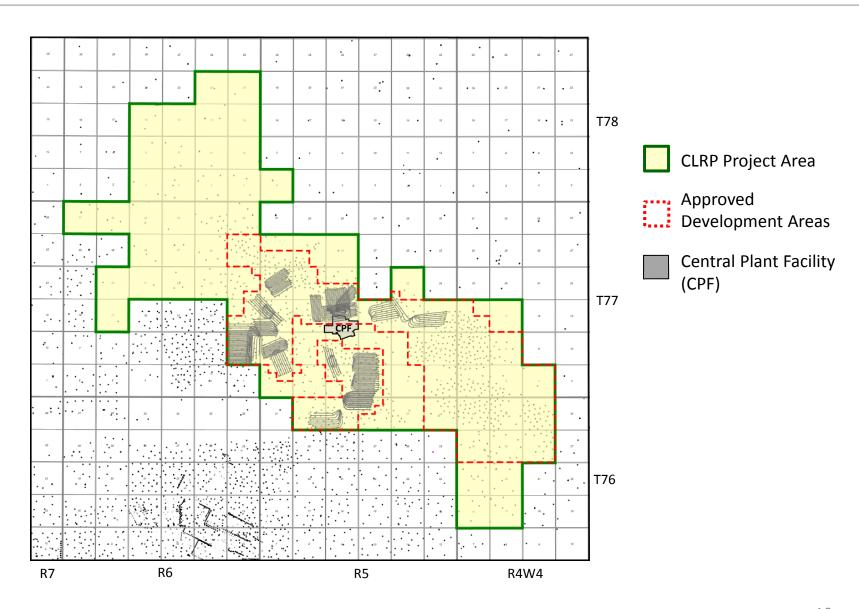


Geoscience Review

- 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

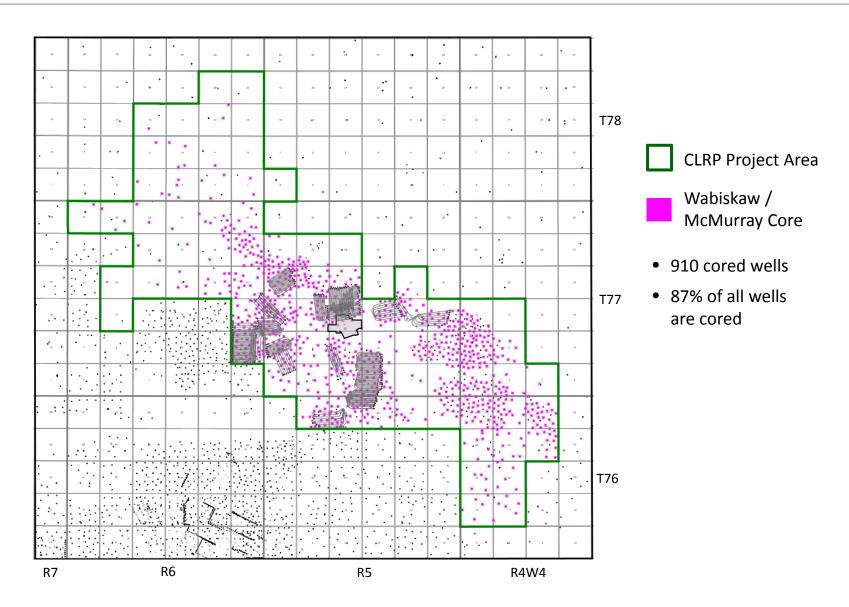


Christina Lake Regional Project (CLRP)



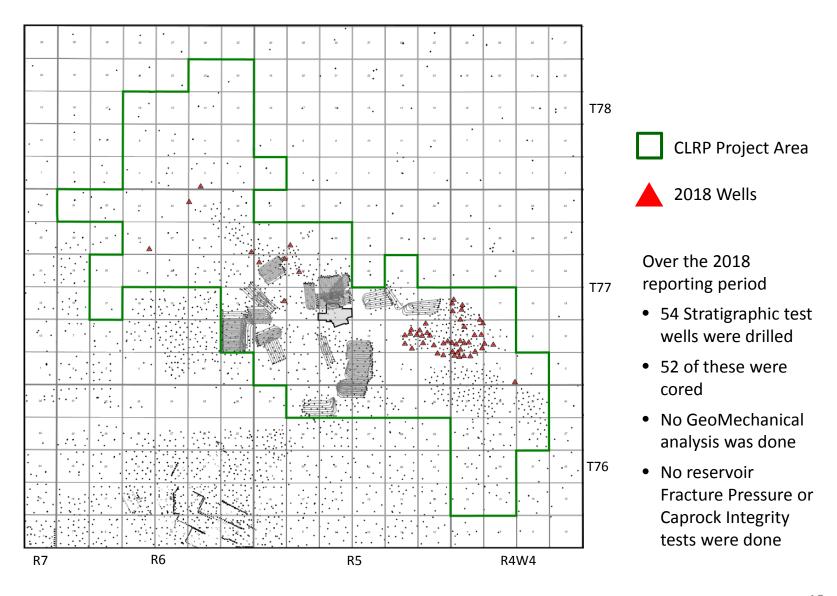


Wabiskaw / McMurray Cores



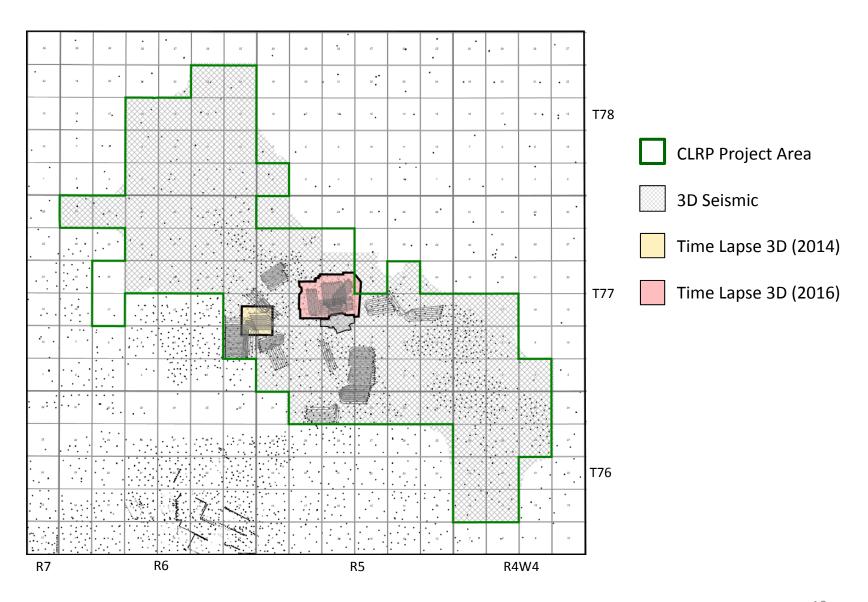


2016 Stratigraphic Test Wells



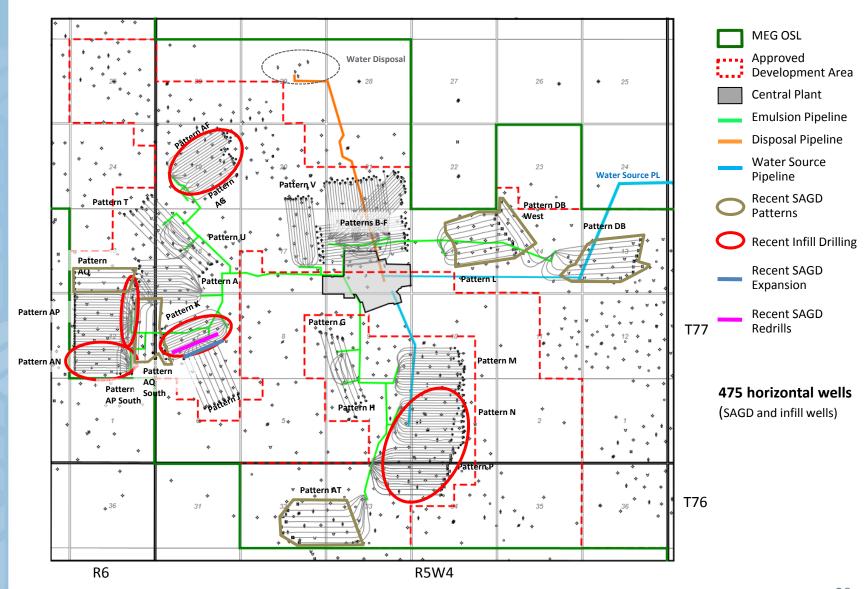


3D Seismic





Active Development Area (ADA)

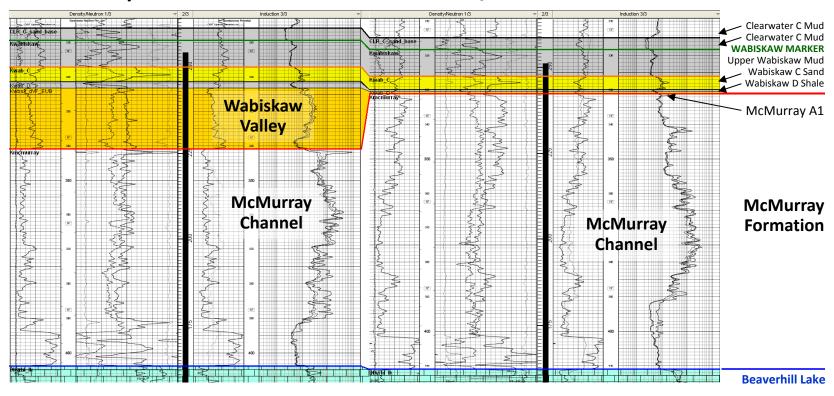




Wabiskaw/McMurray Stratigraphy

1AA/13-18-77-05W4

1AC/10-07-77-05W4



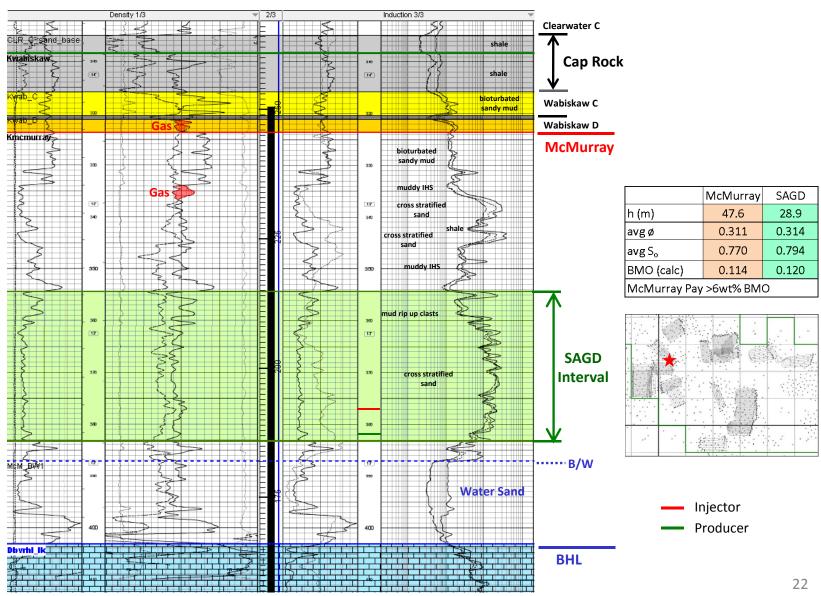
Stratigraphic Unit	Facies Association
lower Clearwater C	offshore mud
upper Wabiskaw	offshore / lower shoreface mud
Wabiskaw C	shoreface sand
Wabiskaw D Shale	bay mud
Wabiskaw D Valley	bay sand and mud
McMurray A1	shoreface sand / coal
upper McMurray Channel	tidal flat / creek sand and mud
lower McMurray 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 SAGD Pay Parameters

SAGD Pay

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

R_t = Deep Induction

 $\emptyset_{\text{density}} \ge 25\%$

- parameters for S_o calculation

 S_o (bitumen saturation) $\geq 50\%$

Gas and coal excluded



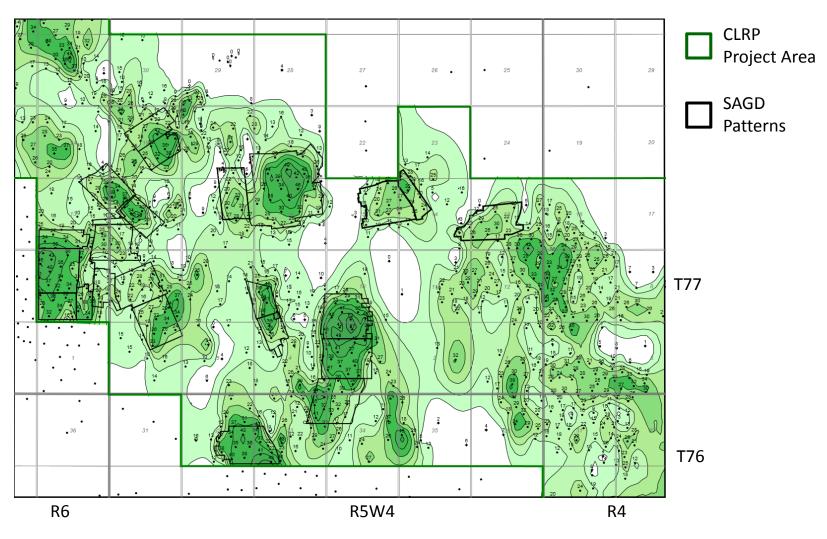
McMurray Reservoir Properties

Average Pay (m)	18.7
Average Depth to reservoir top (mTVD)	359
Porosity range (Frac)	0.30-0.36
Water Saturation Range (frac)	0.15-0.30
Average K _h (Darcies)	5,000
Average K _v (Darcies)	2,500
Initial Reservoir Pressure (Kpag)	2,100
Reservoir temperature (°C)	13

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



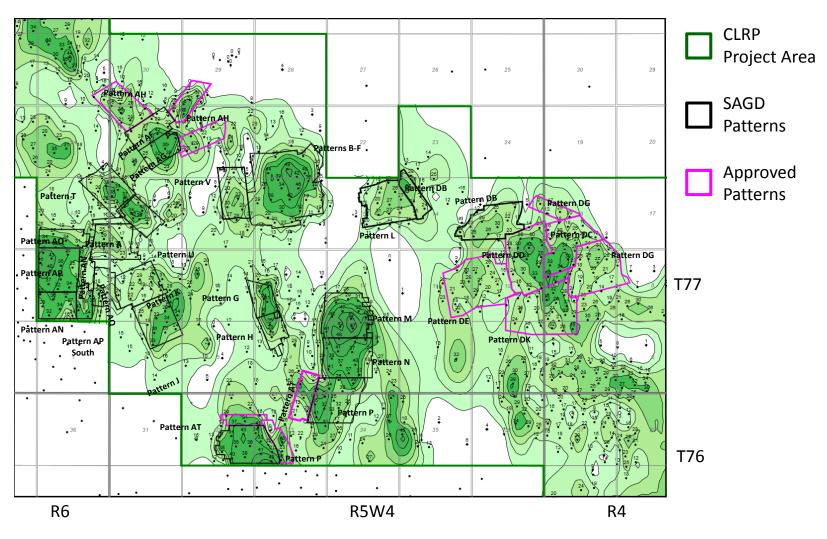
SAGD Pay Cutoffs:

- 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



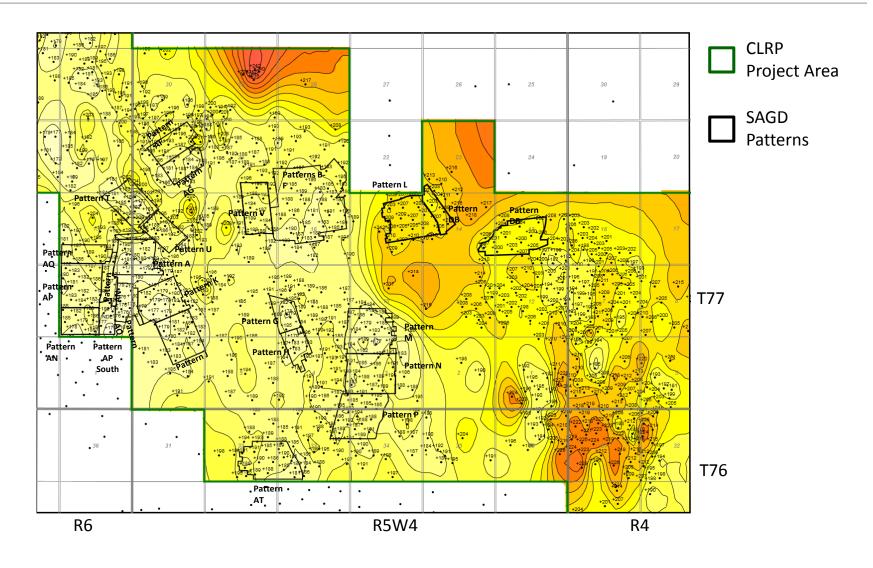
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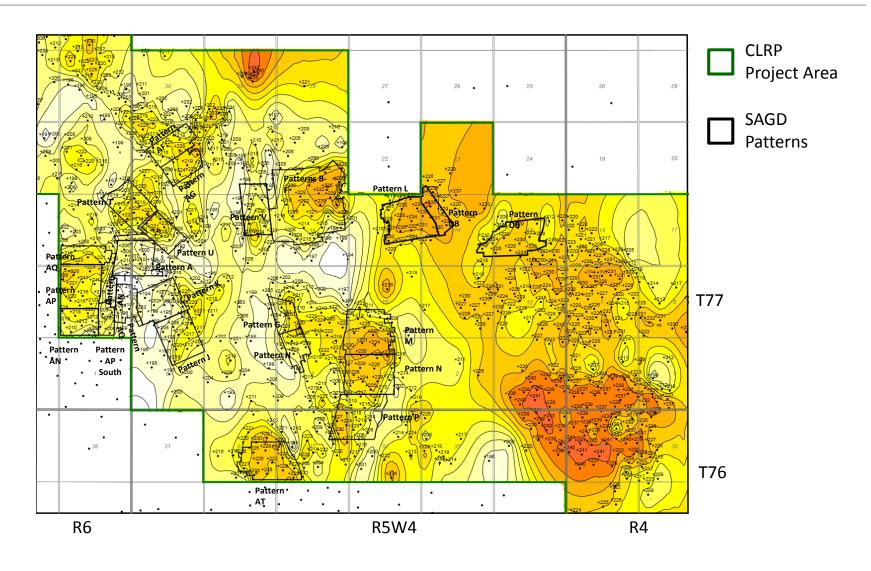
ADA Base SAGD Pay Structure



Contour interval = 5 m



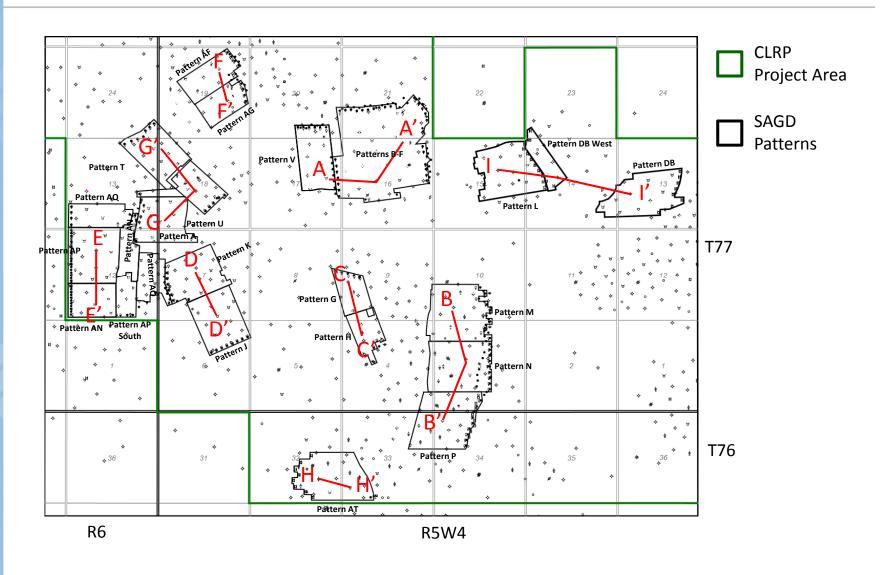
ADA Top SAGD Pay Structure



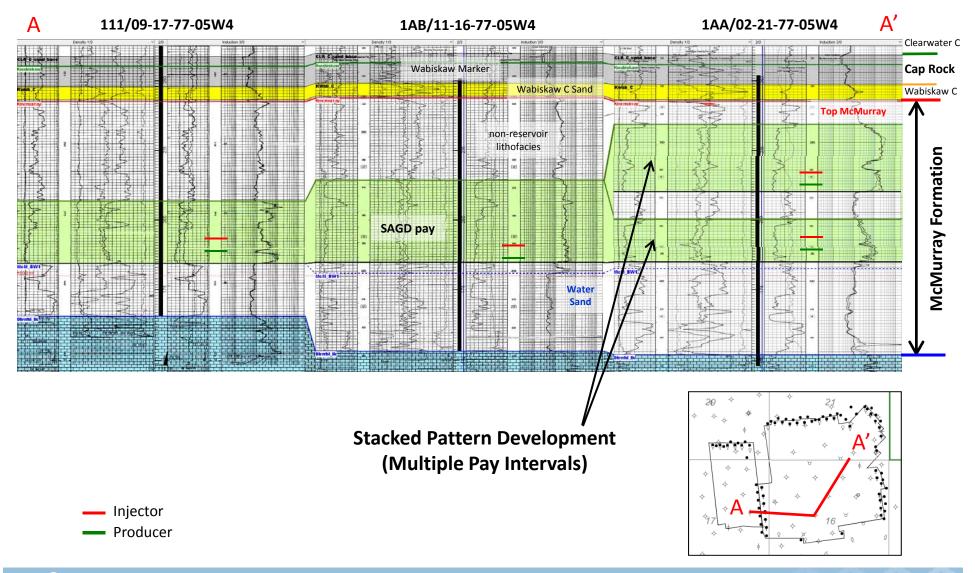
Contour interval = 5 m



Cross Sections for Scheme Area

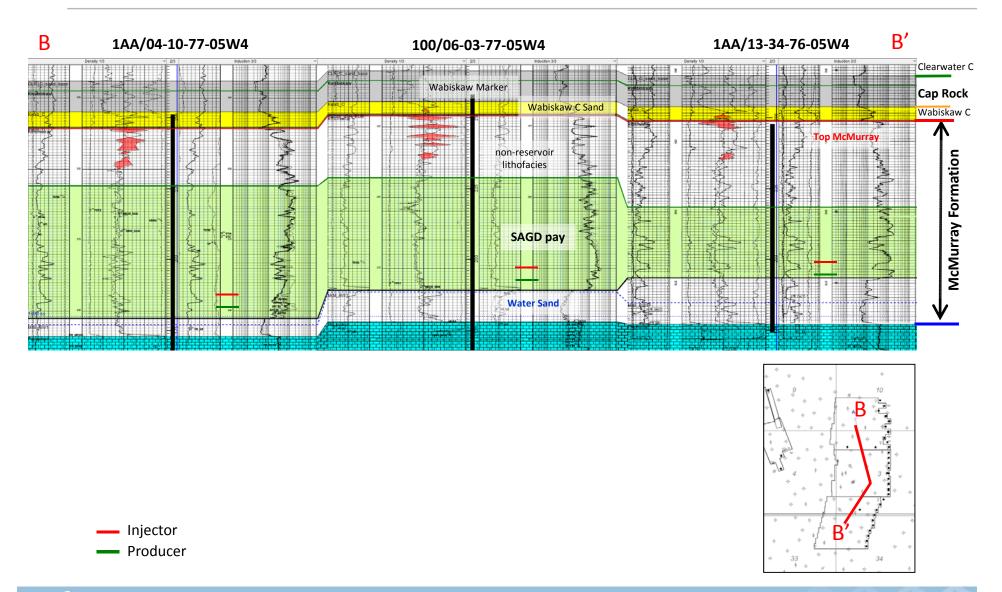


Structural Cross Section A-A'



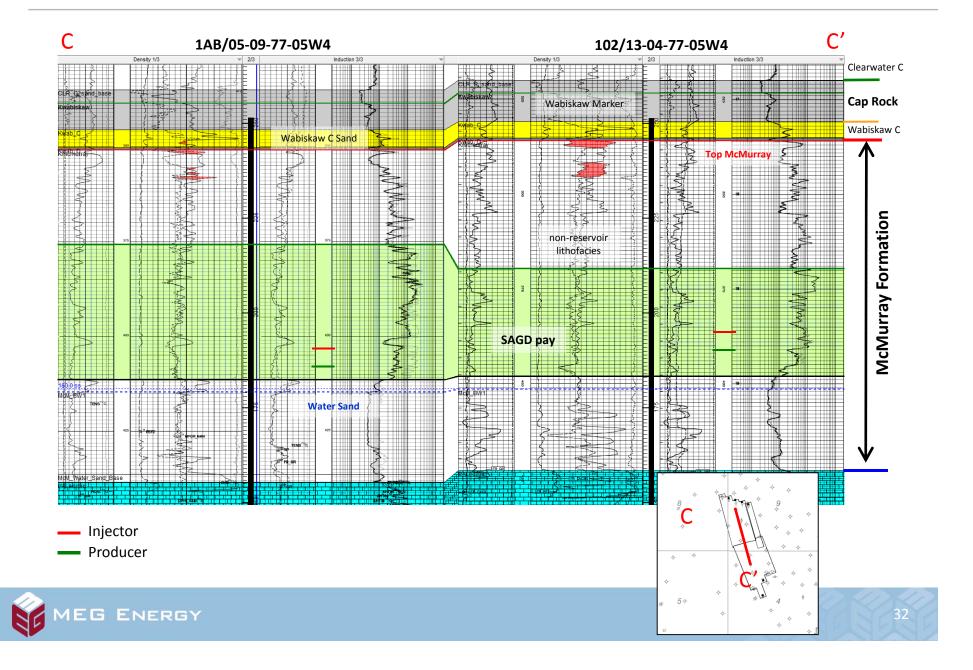


Structural Cross Section B-B'

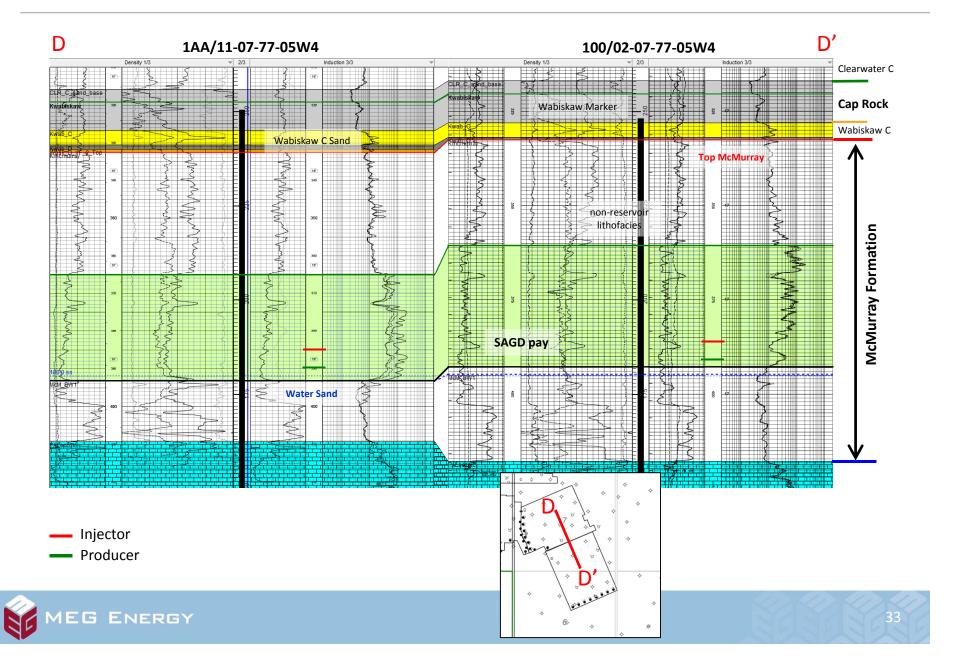




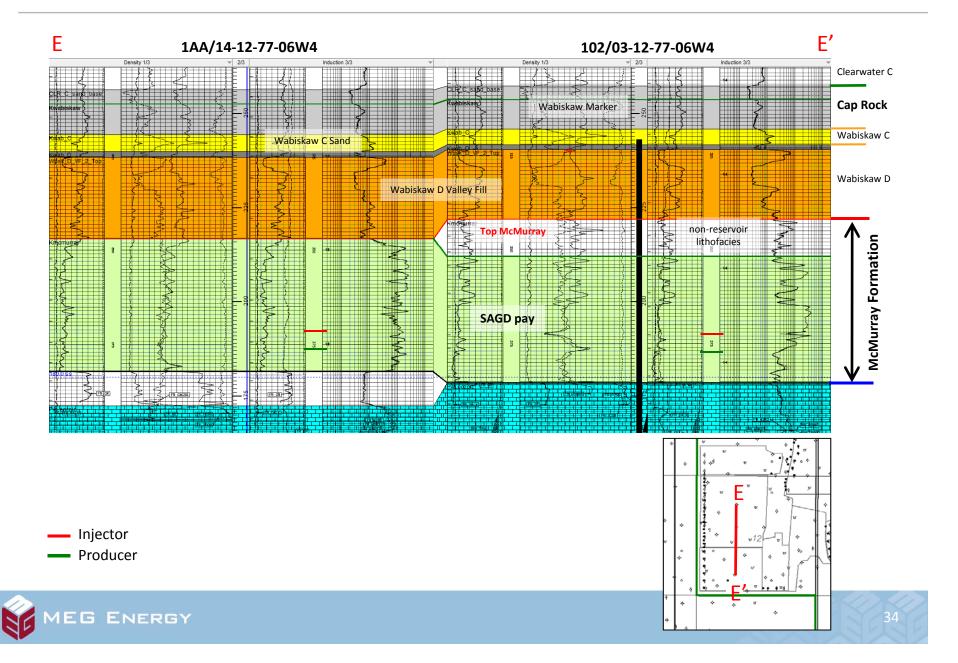
Structural Cross Section C-C'



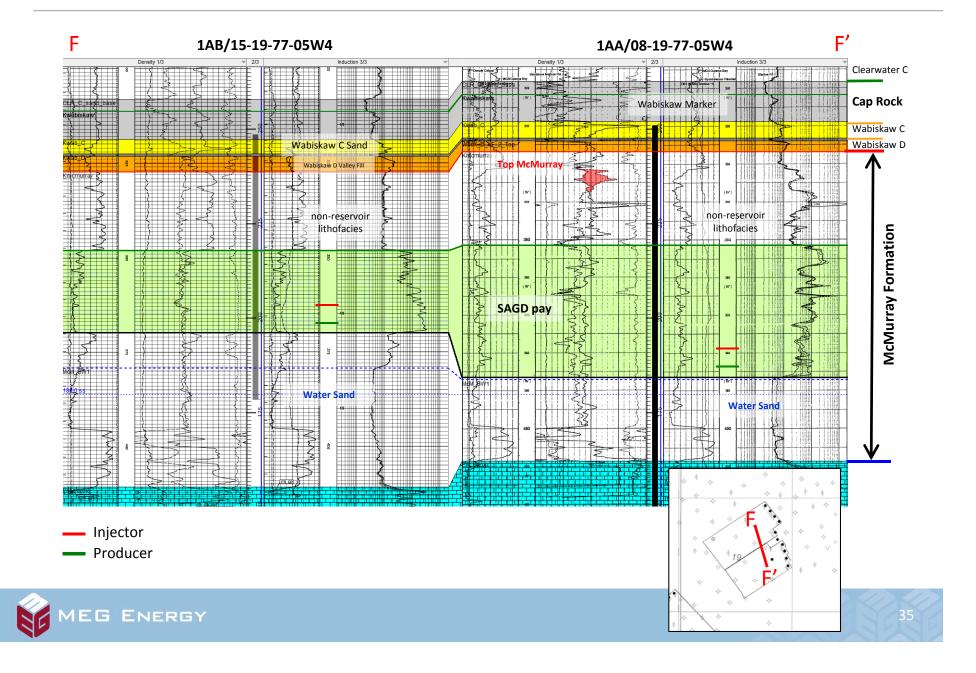
Structural Cross Section D-D'



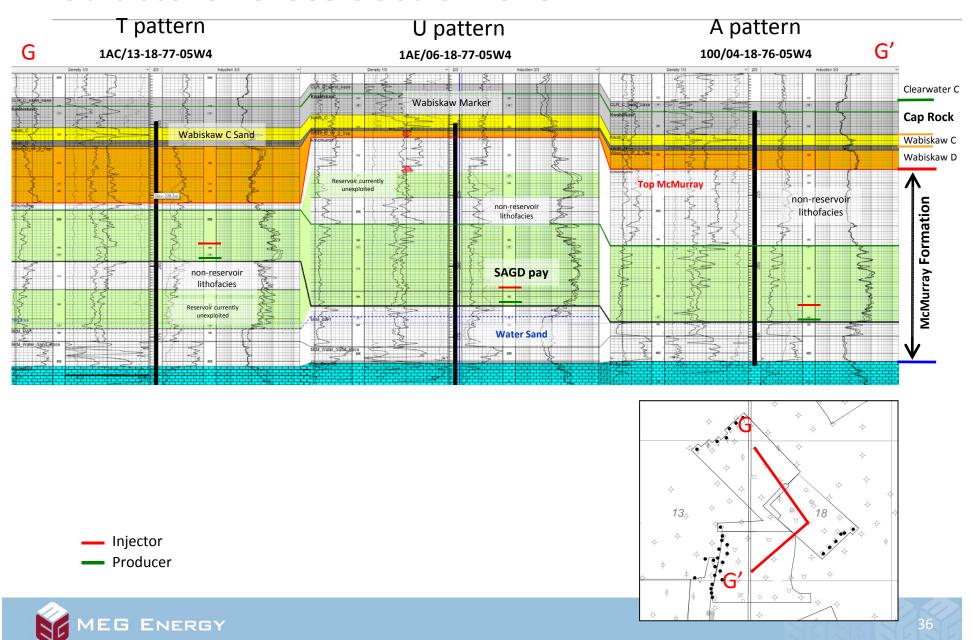
Structural Cross Section E-E'



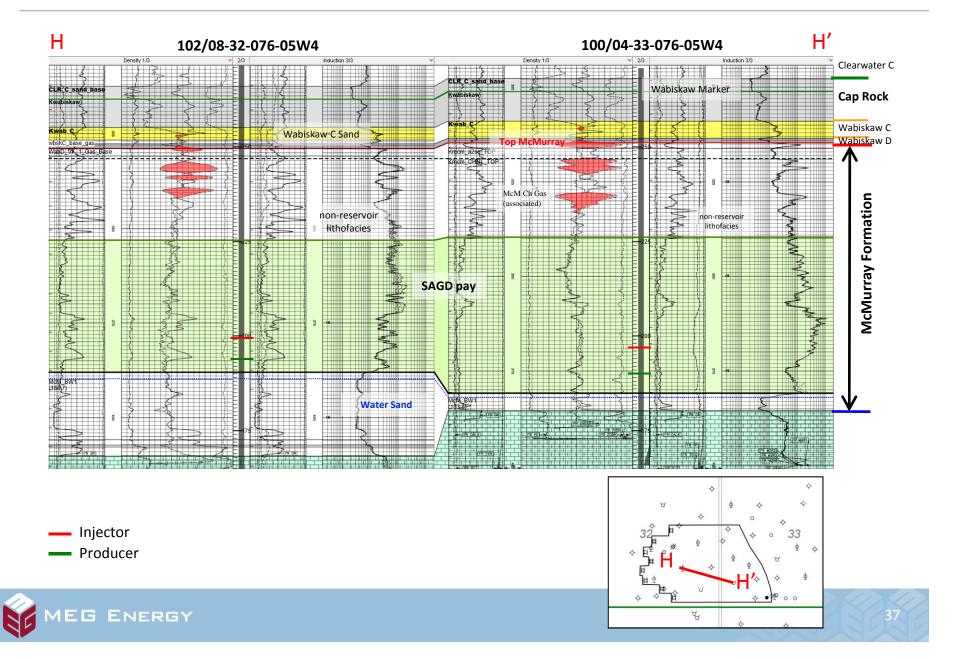
Structural Cross Section F-F'



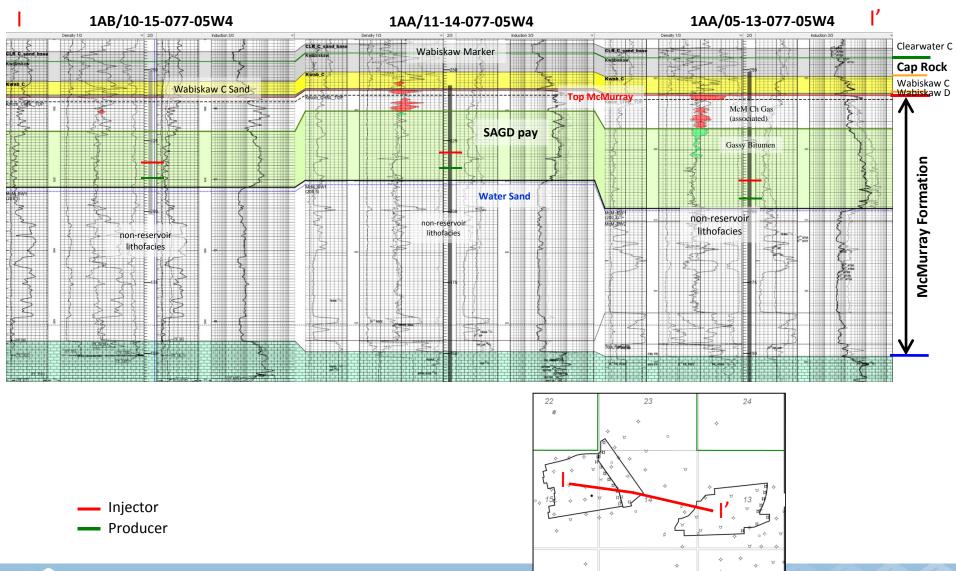
Structural Cross Section G-G'



Structural Cross Section H-H'



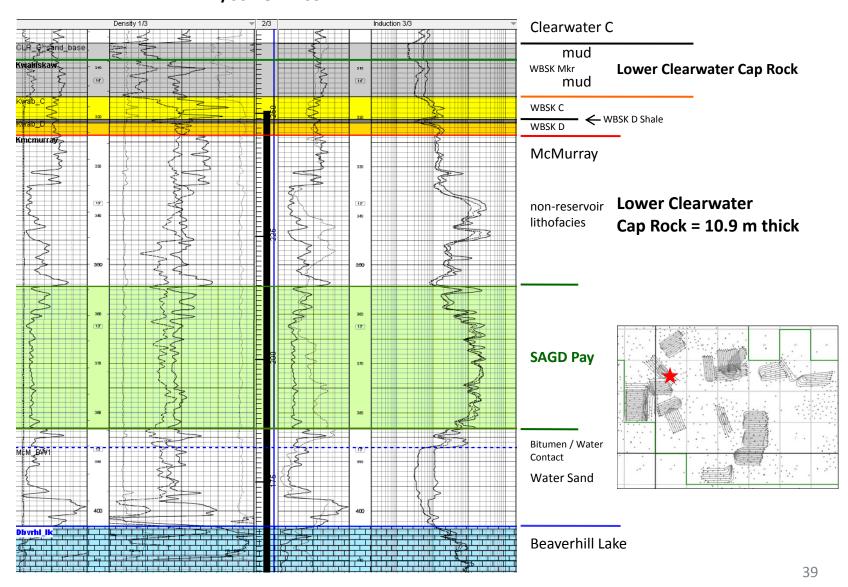
Structural Cross Section I-I'



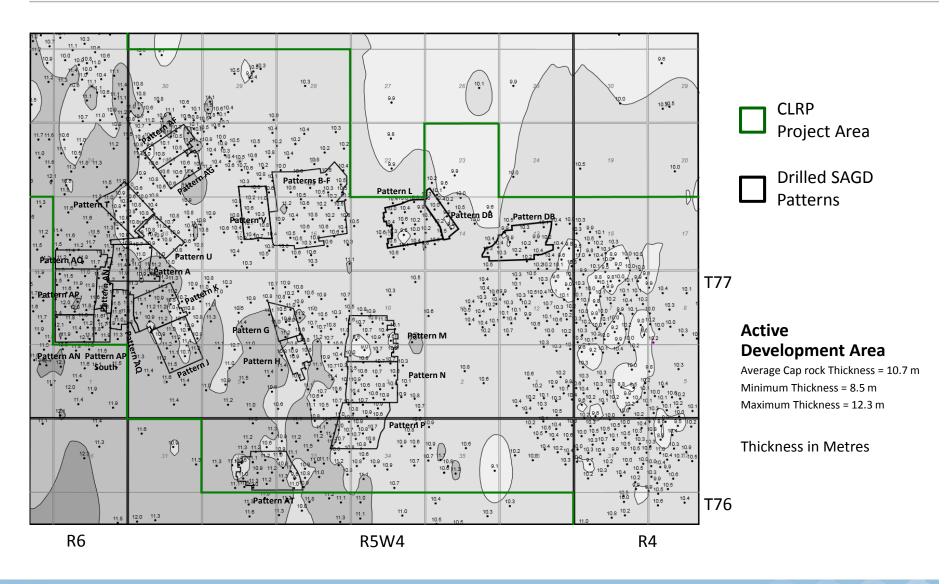


Lower Clearwater Cap Rock

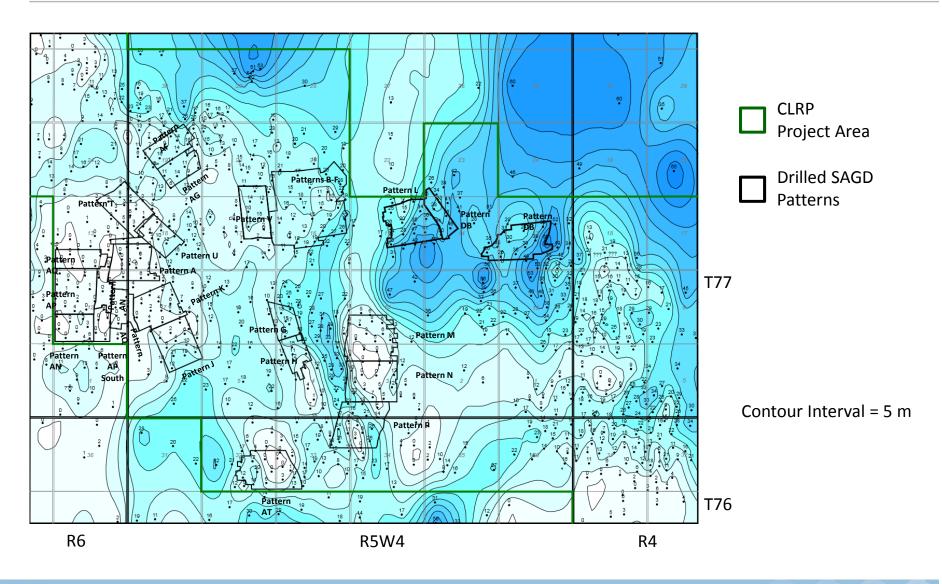
1AE/06-18-77-05W4



ADA Lower Clearwater Cap Rock



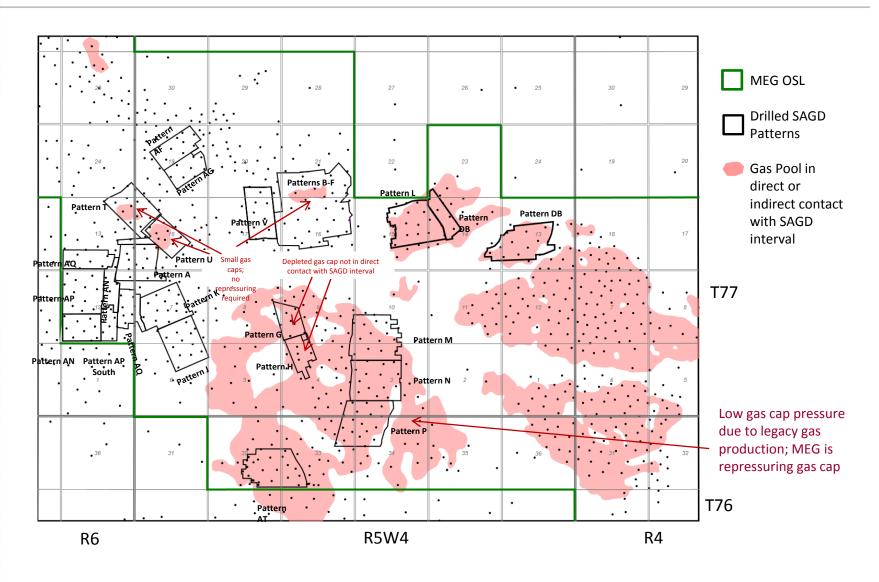
ADA Basal McMurray Net Water Isopach







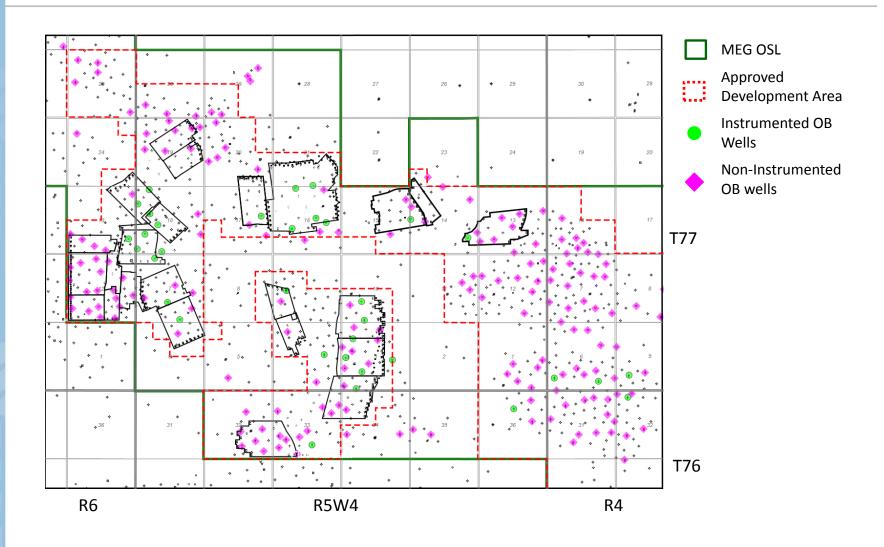
ADA Associated McMurray Gas Pools



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



ADA OB and Cased Wells





Well Spacing

	O	A Consider Bh	A Sanasian
	Operating	Average Spacing Between	Average Spacing
Pattern	Wellpairs	SAGD Pairs (m)	Between SAGD Pair to Infill (m)
Α	8	100	50
В	2	100	50
BB+D7	7	100	50
C+D6	7	110	55
D-D6-D7	5	100	50
E+F1	7	100	50
F-F1	5	100	50
V	6	100	50
G	4	100	NA
Н	3	100	NA
J	8	100	NA
K	7	100	50
M	10	100	50
N	9	100	50
Т	8	100	NA
U	6	100	NA
AP West	10	100	50
AP South	3	112	65
ΔF	5	100	50
AG	5	100	50
AN	8	100	50
Р	10	100	50
AQ North	4	105	NA
AQ South	4	120	NA
Total	163		



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 Review

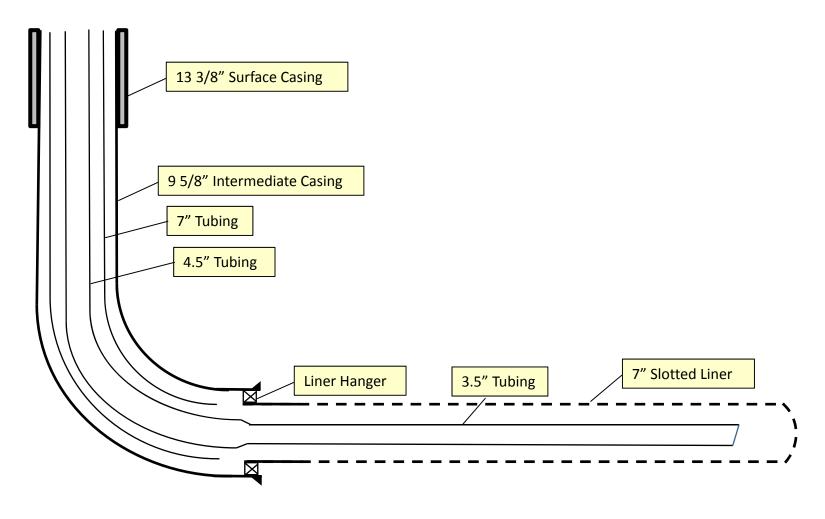
- Wells
 - Schematics
 - Well Integrity Management
 - Artificial Lift
- Scheme Performance
 - Field performance
 - Pattern performance
 - Cased hole logs
- eMSAGP update
- Associated gas cap re-pressuring



Wells



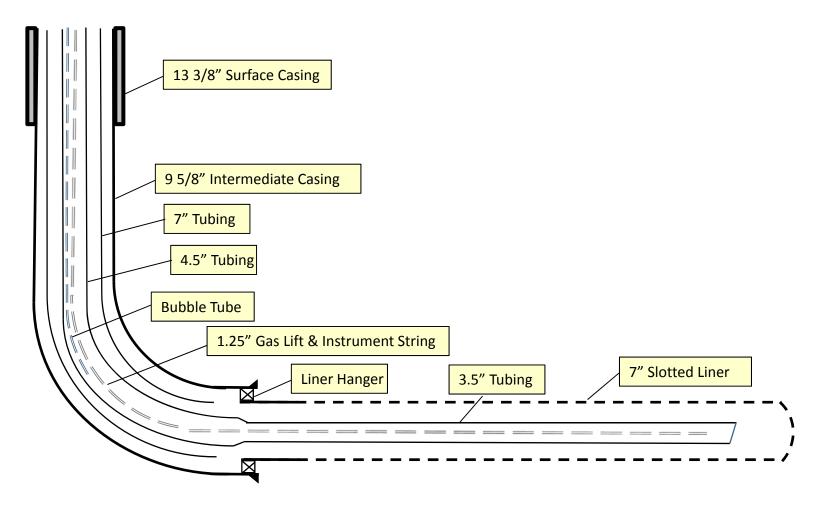
Well Completions – SAGD Injector



- Steam injected into both long tubing and short tubing
- Blanket gas on annulus



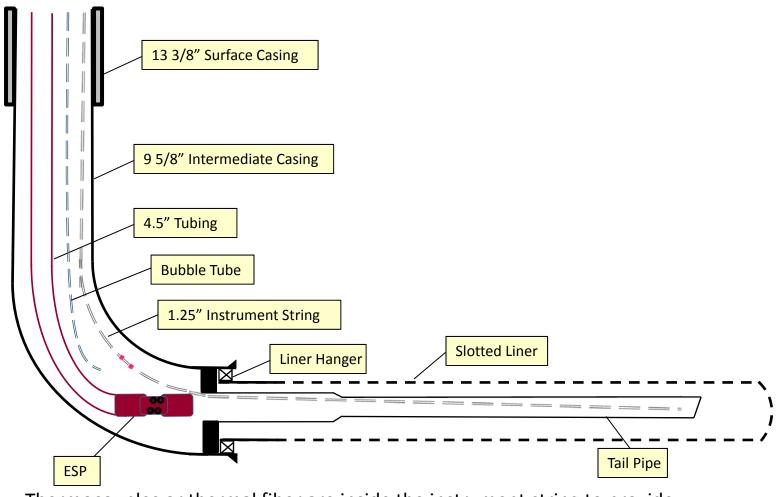
Well Completions – SAGD Producer (Gas Lift)



• Thermocouples are inside the instrument string to provide temperature measurements at selected locations



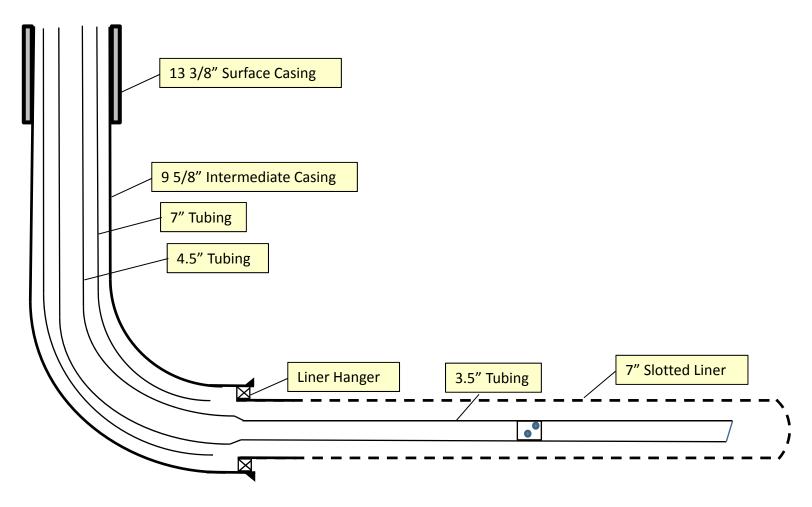
Well Completions – SAGD Producers (ESP)



- 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



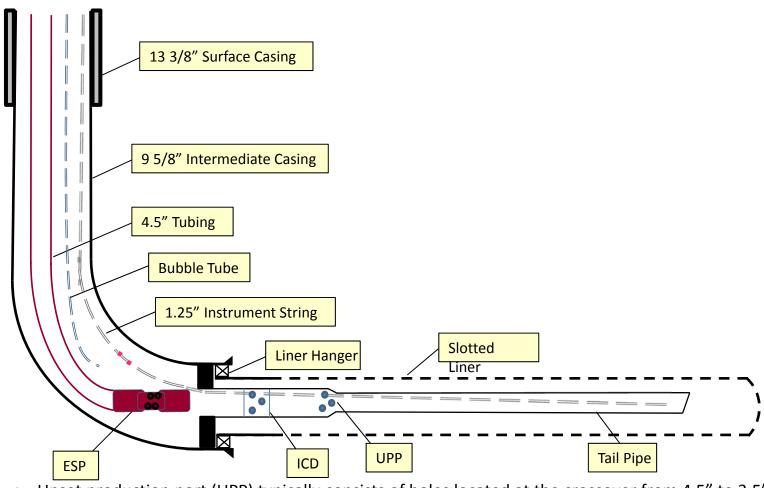
Well Completions – Outflow Control Devices



- 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



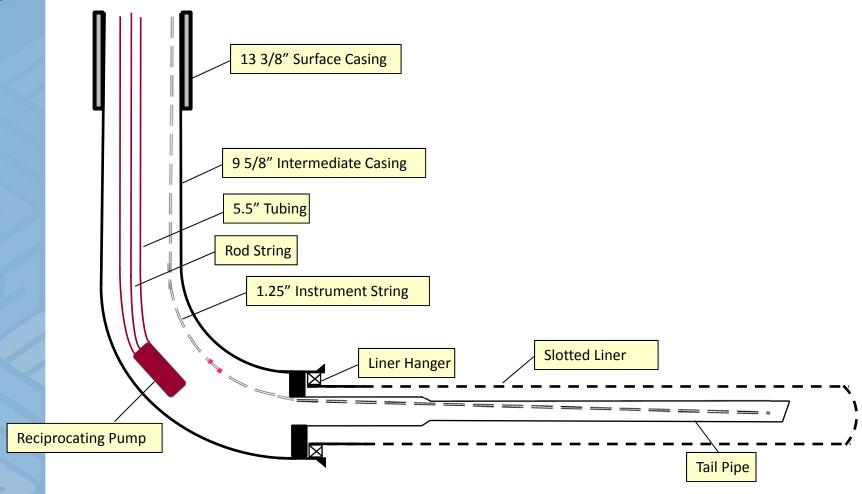
Well Completions – Inflow Control Devices



- 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



Well Completions – Infill Producers



- 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

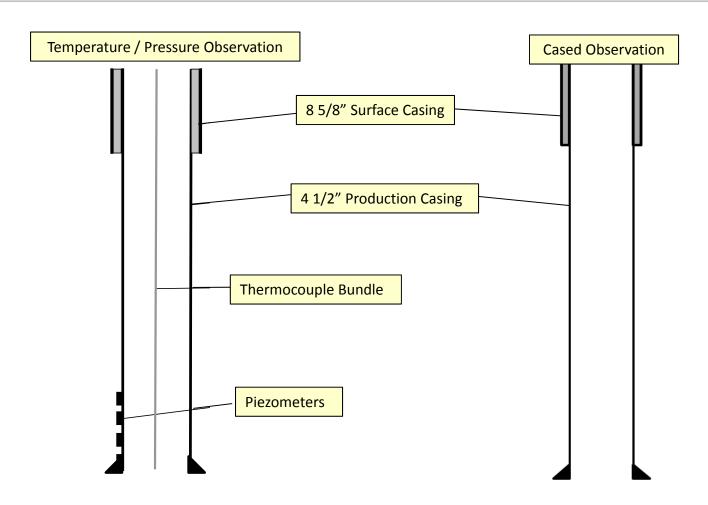


Temperature Measurement

- 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



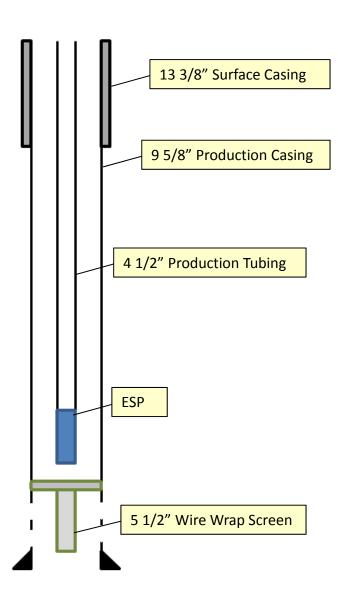
Observation Wells



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

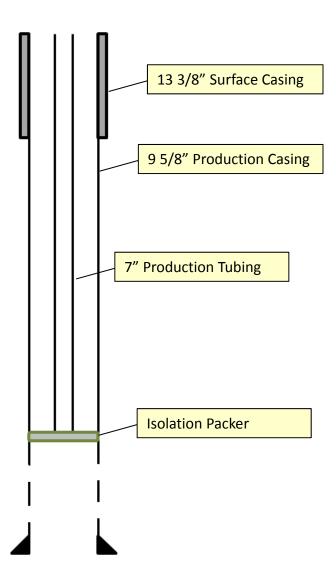


Water Source Wells





Water Disposal Wells





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)



CLRP Well Integrity - Liners

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



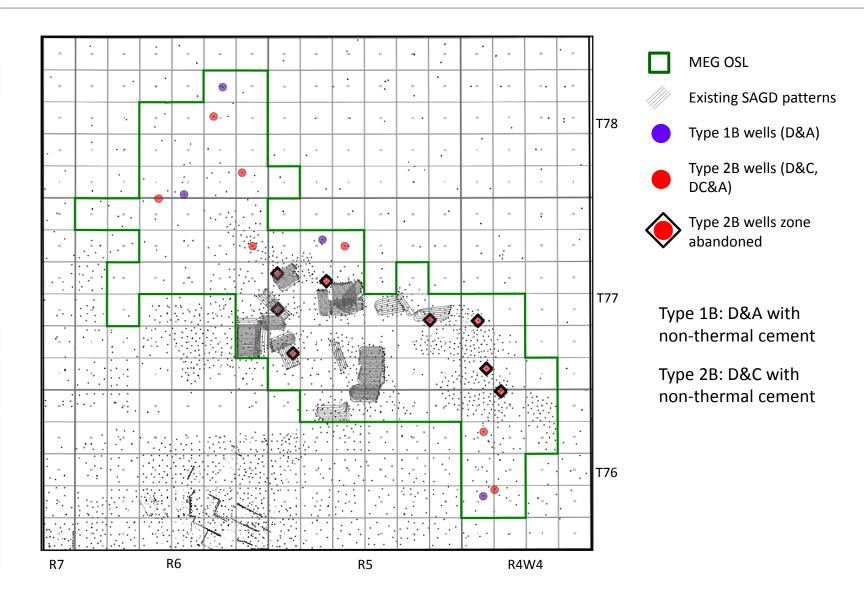
Directive 013 and IWCP

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





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

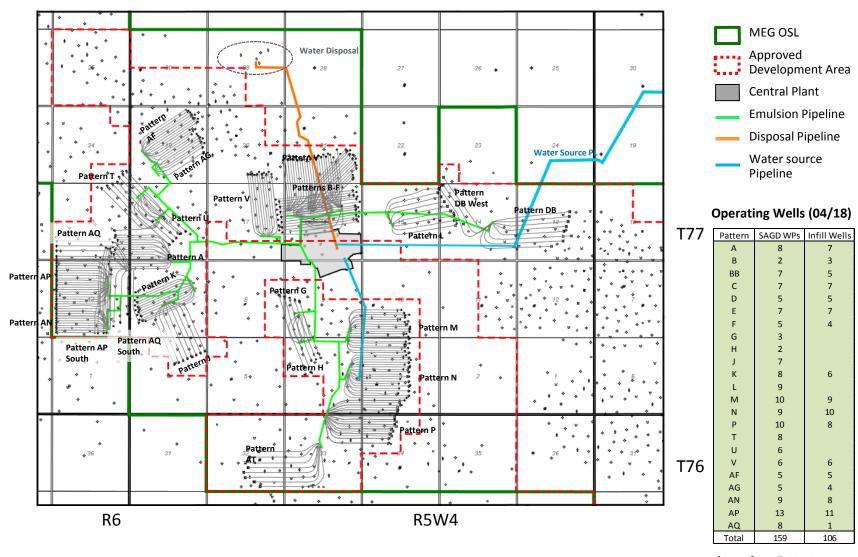
- Operating pressures range from 2,000-2,500 kPag
- Design fluid rates 100-500 m³/d



Scheme Performance



Pattern Layout



^{*} As of April 30 2018

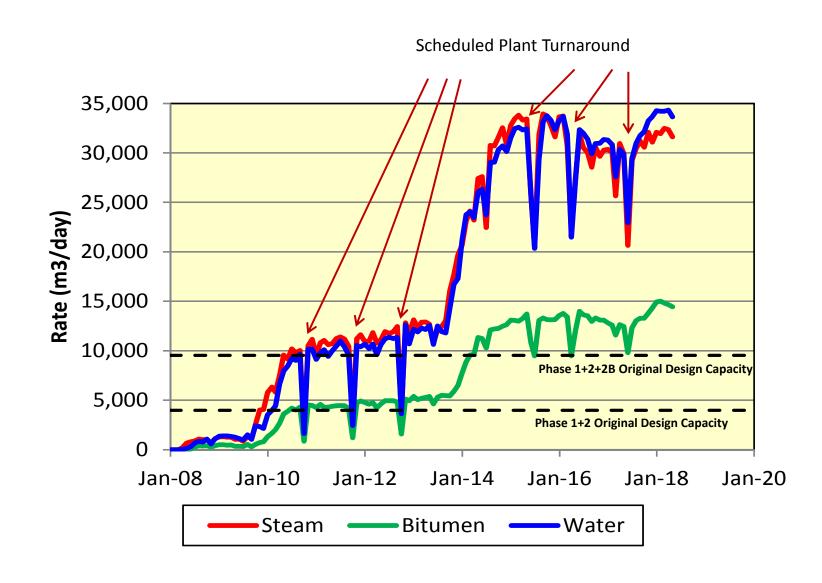


Reservoir Performance

- 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

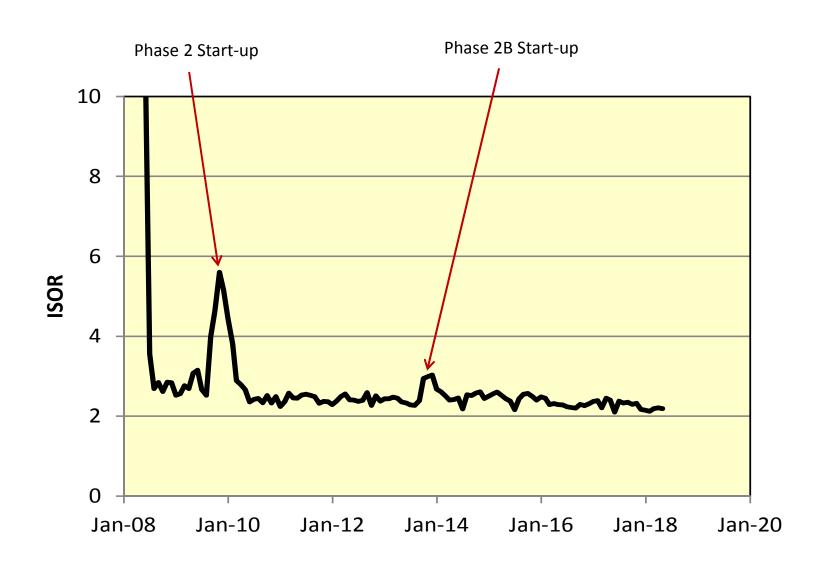


Production Performance



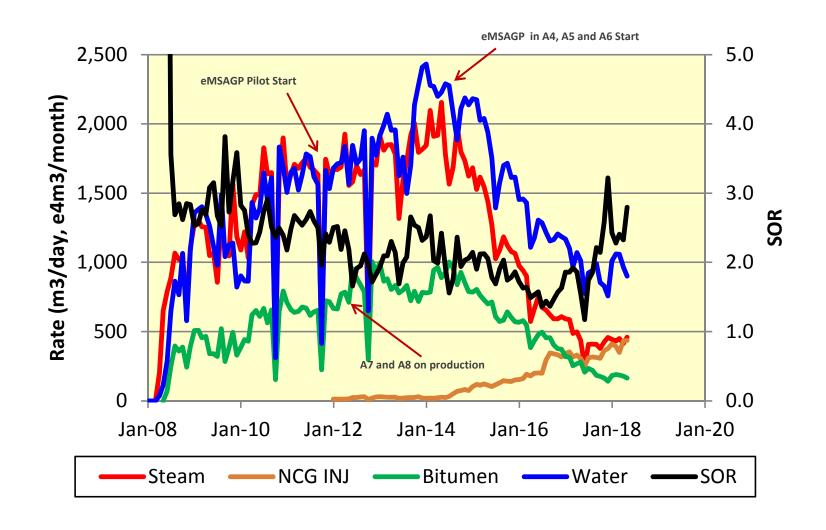


Performance – SOR of All Patterns



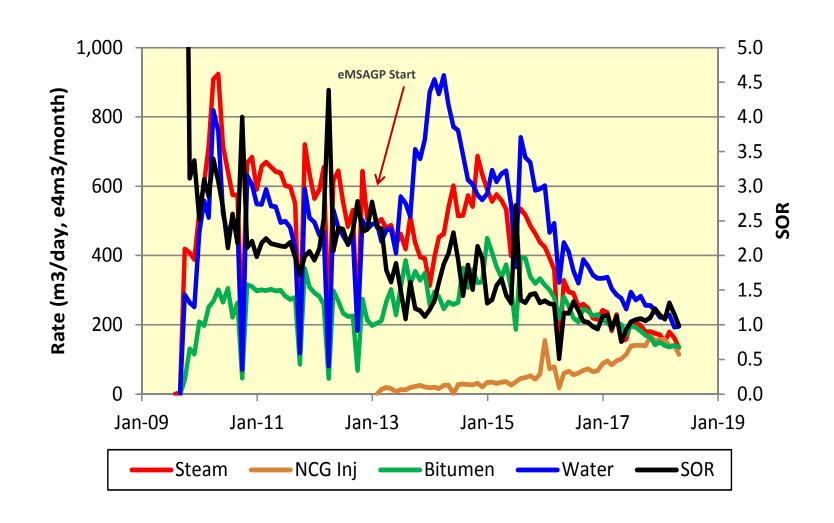


Pattern A Performance



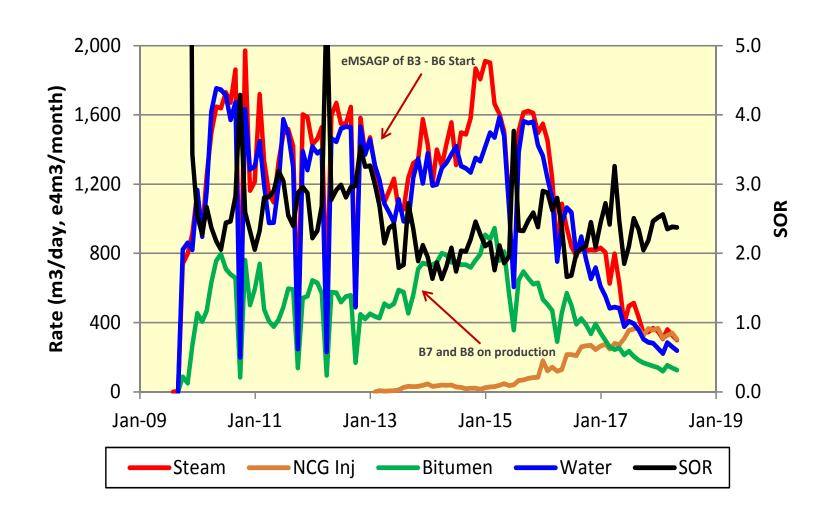


Pattern B Performance



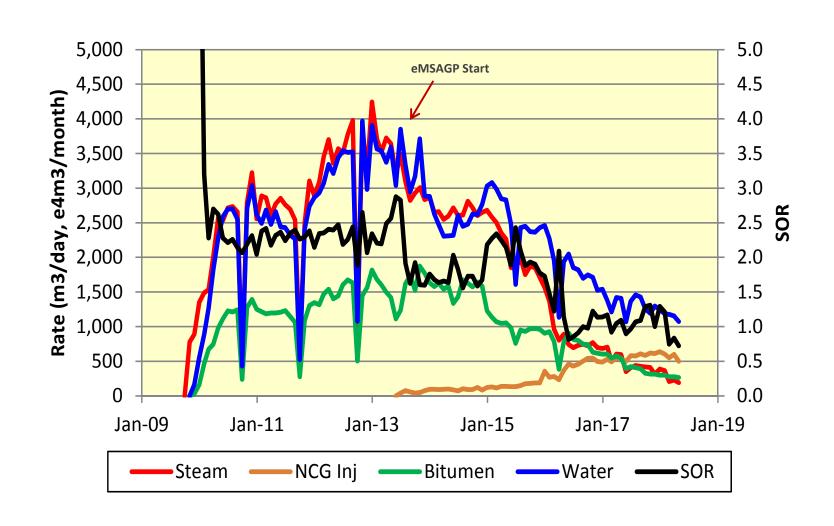


Pattern BB Performance



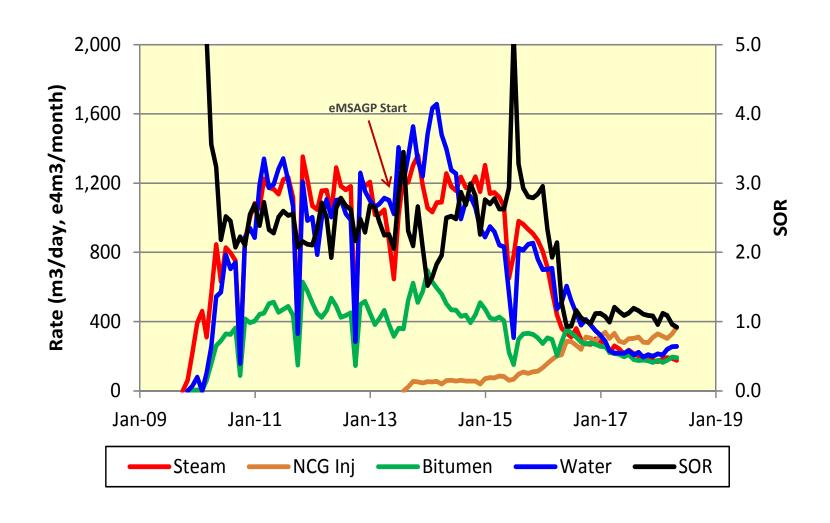


Pattern C Performance



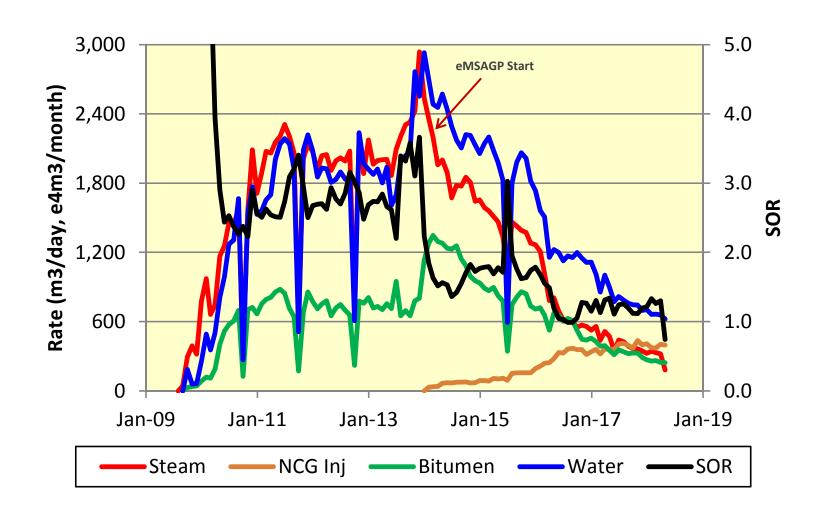


Pattern D Performance



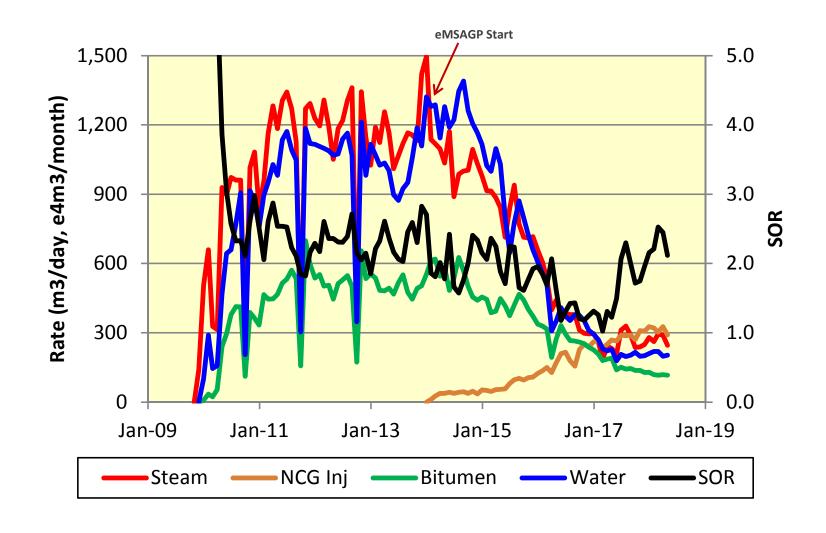


Pattern E Performance



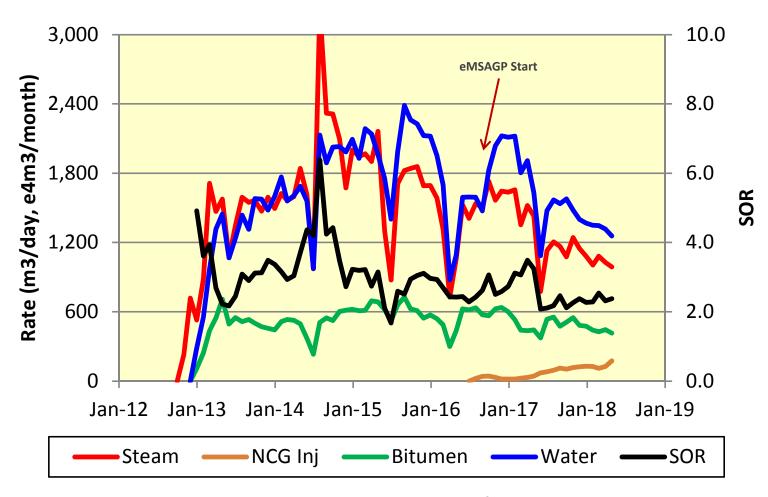


Pattern F Performance





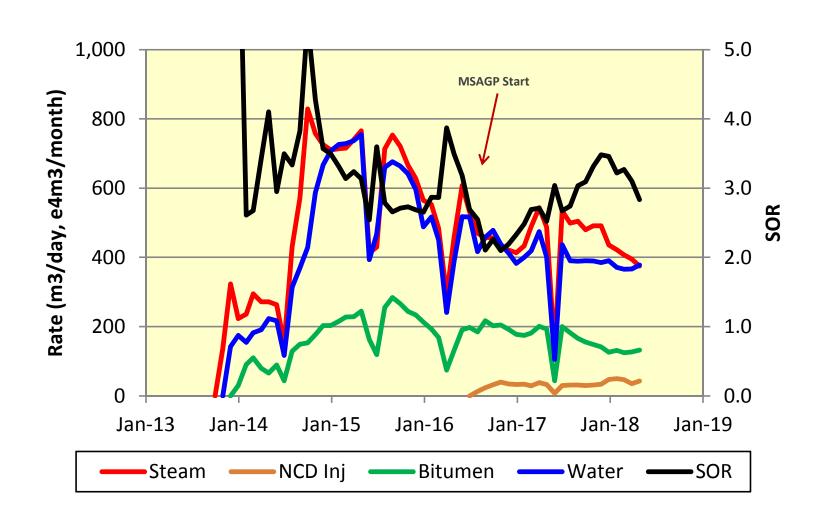
Pattern V Performance



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

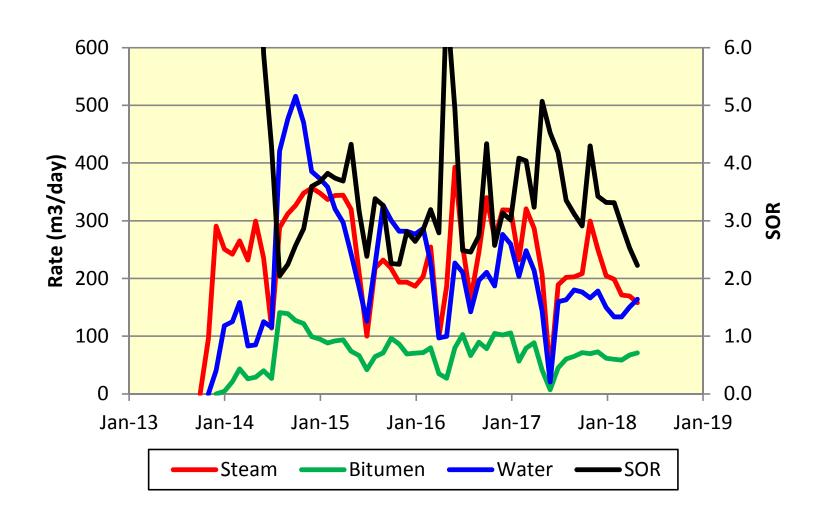


Pattern G Performance



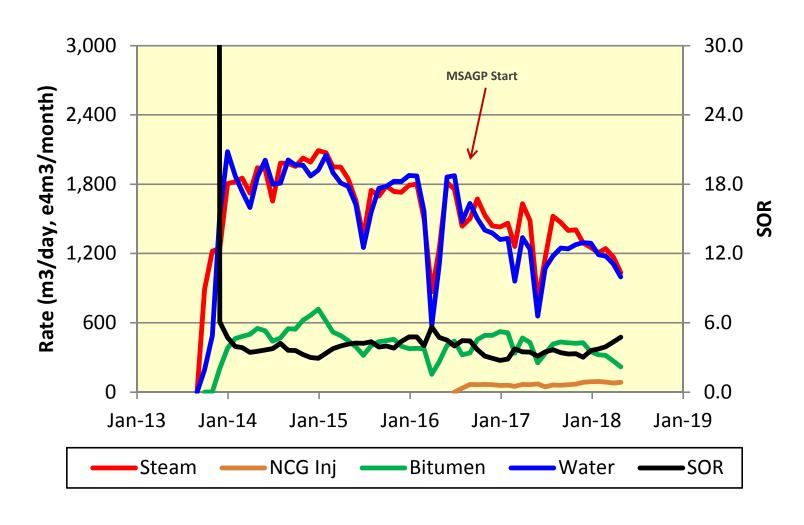


Pattern H Performance





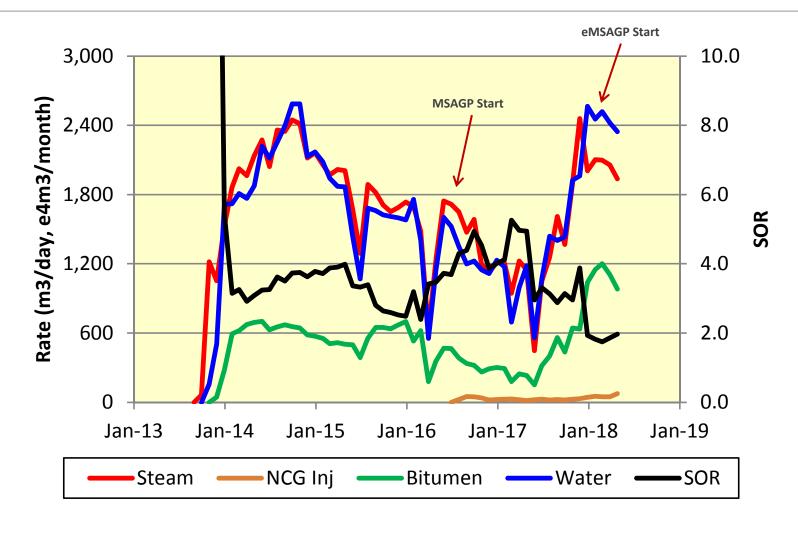
Pattern J Performance



Drop in production in 2015 largely due to liner impairment on J4



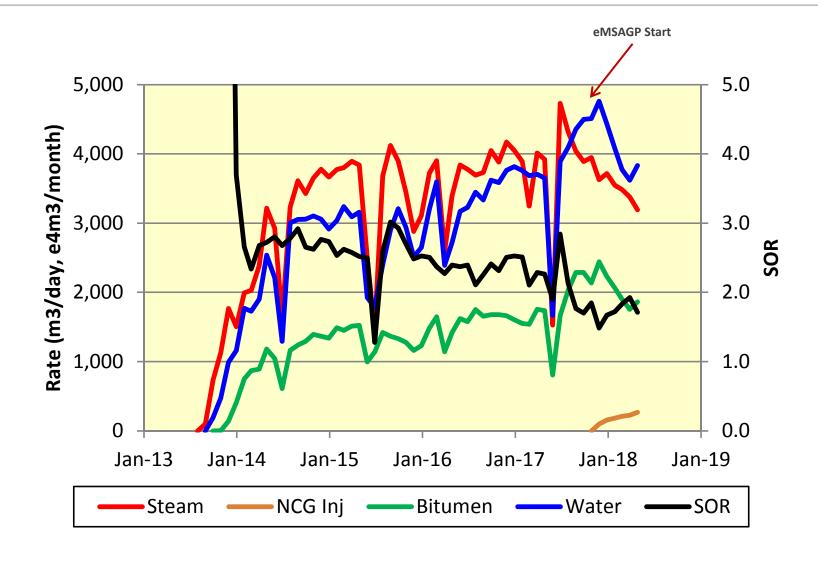
Pattern K Performance



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.

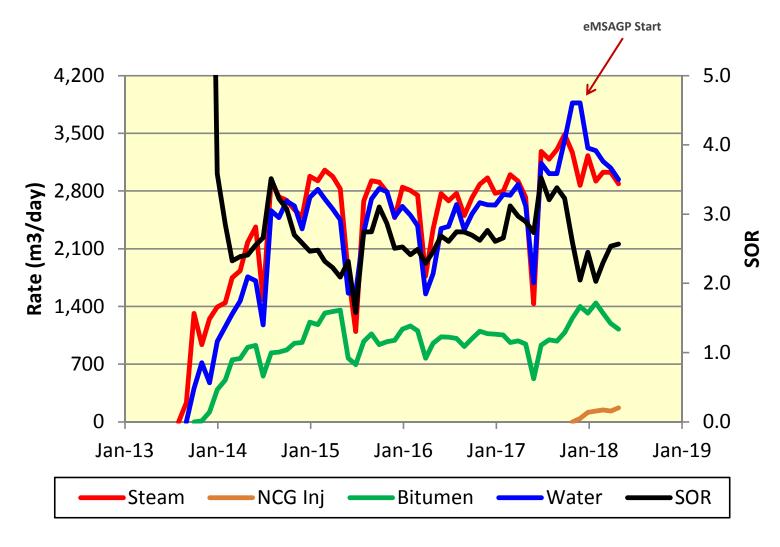


Pattern M Performance





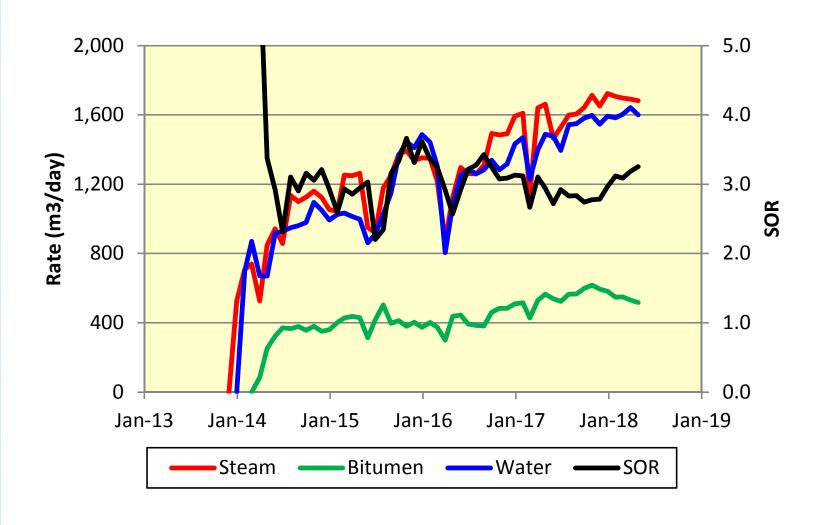
Pattern N Performance



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.

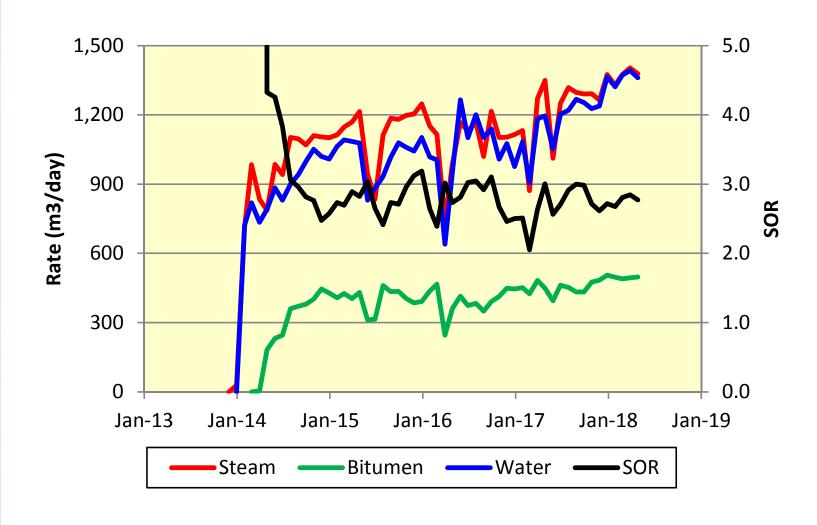


Pattern T Performance



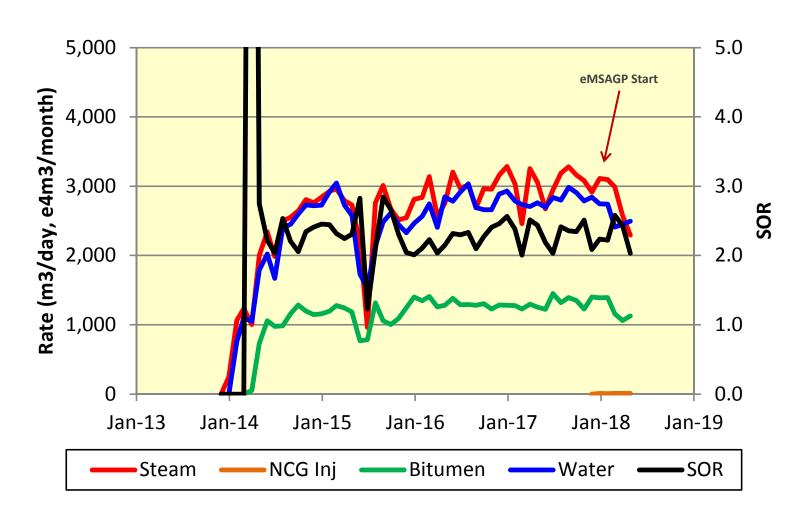


Pattern U Performance





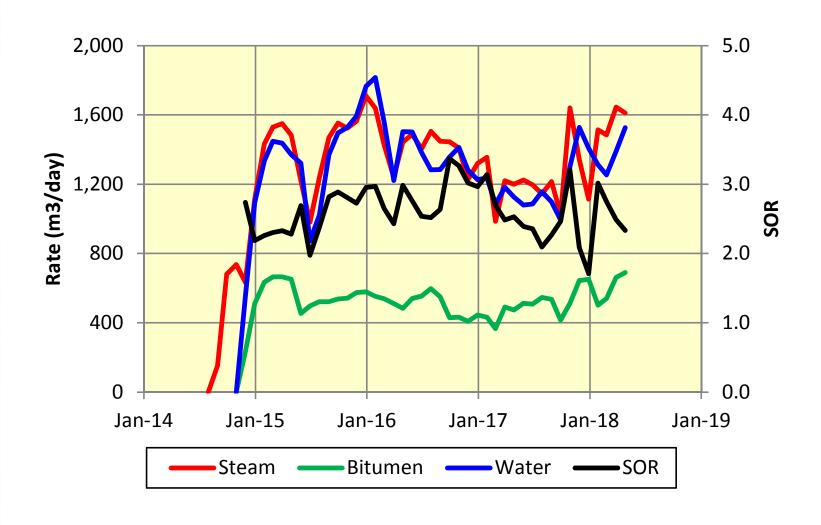
Pattern AP Performance



Note: excludes wells under Experimental Scheme No. 12528

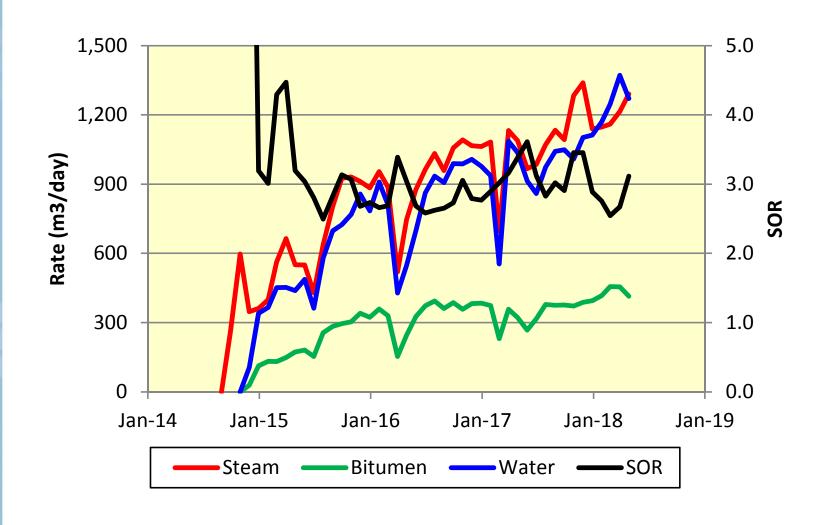


Pattern AF Performance



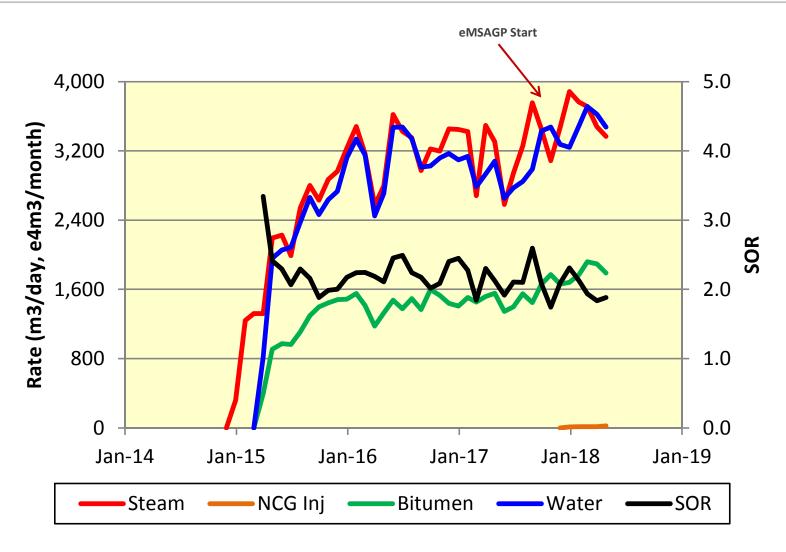


Pattern AG Performance





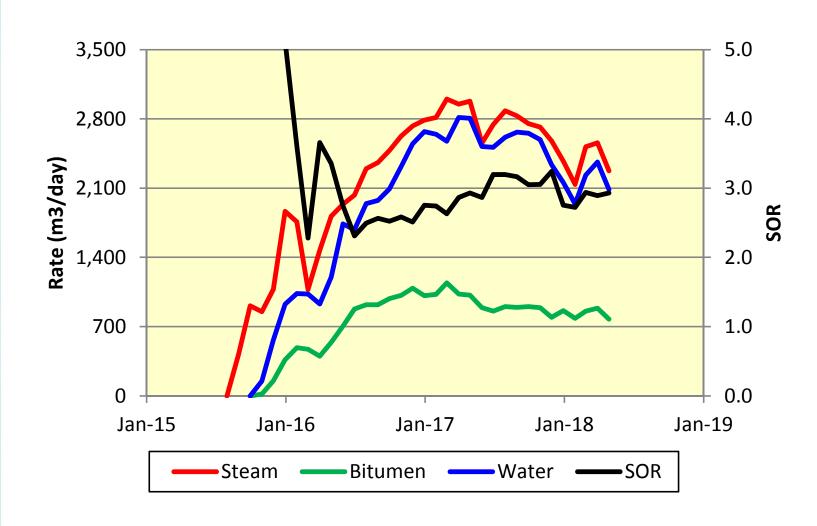
Pattern AN Performance



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.

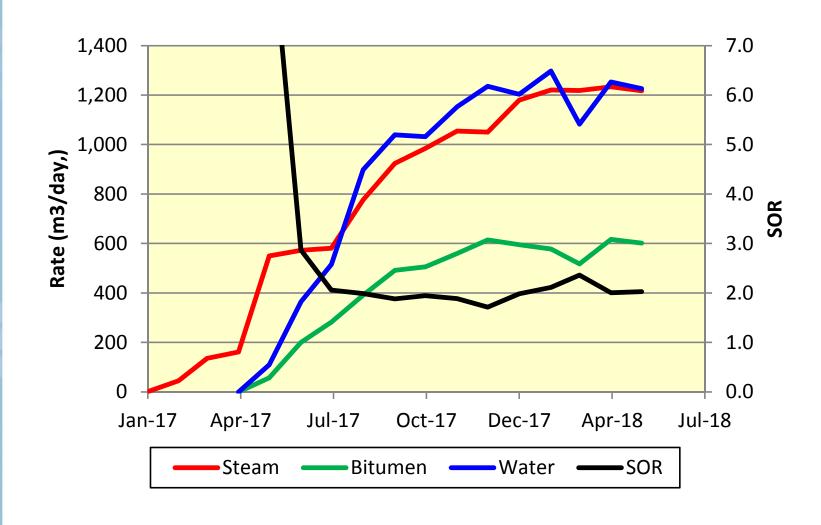


Pattern P Performance



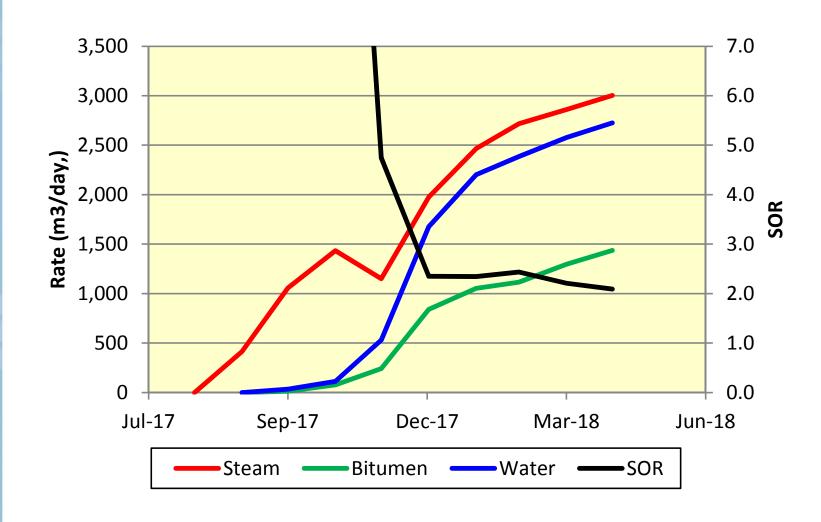


Pattern AP South Performance



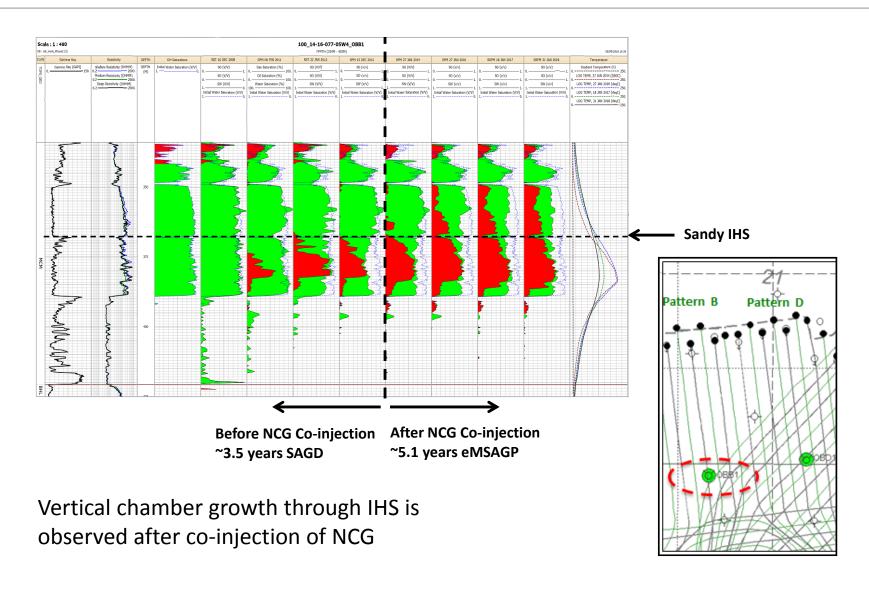


Pattern AQ Performance



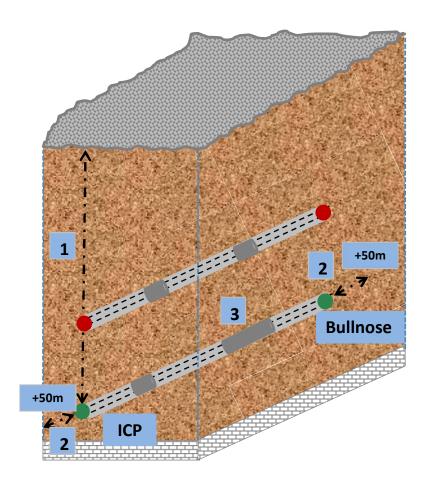


OBB1 Logging Results





Original Bitumen in Place



• SAGDable Bitumen In Place

- 1 Calculate pay height above producer.
- Add 50m effective drainage length past first and last slots, unless poor reservoir is encountered.
- 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

	•	1		1	1	
Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	OBIP (m³)
А	8	22	874	0.33	0.76	3,752,000
В	2	32	744	0.33	0.83	1,300,000
BB+D7	7	20	808	0.32	0.83	3,006,000
C+D6	7	30	841	0.33	0.75	4,687,000
D-D6-D7	5	21	678	0.34	0.81	1,952,000
E+F1	7	23	866	0.33	0.77	3,520,000
F-F1	5	22	776	0.33	0.78	2,148,000
V	6	26	1084	0.32	0.74	3,926,000
G	4	17	759	0.33	0.71	1,237,000
Н	3	17	692	0.33	0.72	836,000
J	8	21	986	0.33	0.76	4,191,000
K*	8	16	955	0.33	0.74	3,000,000
М	10	30	998	0.32	0.75	7,185,000
N	9	26	1054	0.33	0.8	6,634,000
Т	8	15	952	0.32	0.82	2,970,000
U	6	19	882	0.30	0.80	2,414,000
AP West	10	31	918	0.34	0.82	7,760,000
AP South	3	23	727	0.33	0.79	1,485,000
AF	5	23	972	0.32	0.82	2,862,000
AG	5	22	836	0.33	0.77	2,234,000
AN*	9	23	870	0.33	0.81	4,744,000
P*	10	21	957	0.32	0.76	4,742,000
AQ**	8	19	973	0.33	0.80	4,404,000
Total	153					80,989,000

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

Lis liner length (including blanks) with 50m added to each end where appropriate

*Updated in May 2018

**New 2018



Bitumen Recovery – Mature Patterns

Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	SAGDable BIP (m³)	Cumulative Production (m³)	Recovery to Date (%SAGDable)	Estimated Final Recovery (%SAGDable)
Α	8	20	874	0.32	0.76	3,501,000	2,079,028	59%	65%
В	2	26	744	0.33	0.84	1,078,000	805,569	75%	83%
BB+D7	7	18	808	0.32	0.82	2,680,000	1,570,066	59%	61%
C+D6	7	26	841	0.33	0.76	4,090,000	3,247,700	79%	83%
D-D6-D7	5	18	678	0.34	0.81	1,686,000	1,093,909	65%	76%
E+F1	7	19	866	0.33	0.77	2,940,000	2,049,961	70%	74%
F-F1	5	19	776	0.33	0.78	1,867,000	1,155,564	62%	65%
Total						17,842,000	12,001,797	67%	72%

Note: Cumulative Production to April, 2018

h is net pay: SAGD top- Producer

Lis 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

Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	SAGDable BIP (m³)	Cumulative Production (m³)	Recovery to Date (%SAGDable)
V	6	24	1084	0.31	0.73	3,479,000	1,026,416	30%
G	4	14	759	0.33	0.71	1,025,000	266,971	26%
Н	3	12	692	0.32	0.74	598,000	113,942	19%
J	8	18	986	0.33	0.76	3,592,000	699,000	19%
K*	8	15	955	0.33	0.74	2,788,000	879,195	32%
М	10	27	998	0.32	0.75	6,469,000	2,387,875	37%
N	9	23	1054	0.33	0.81	5,887,000	1,612,580	27%
Т	8	13	952	0.31	0.81	2,550,000	667,326	26%
U	6	16	882	0.30	0.80	2,033,000	608,594	30%
AP West	10	27	918	0.33	0.83	6,813,000	2,645,954	39%
AP South	3	21	727	0.33	0.79	1,362,000	182,609	13%
AF	5	18	972	0.32	0.82	2,278,000	672,155	30%
AG	5	20	836	0.33	0.77	2,095,000	389,755	19%
AN*	9	20	870	0.33	0.82	4,165,000	1,658,661	40%
P*	10	17	957	0.32	0.76	3,961,000	743,669	19%
AQ**	8	17	973	0.33	0.80	3,935,000	183,131	5%
Total	153					53,030,000	14,737,835	28%

Note: Cumulative Production to April, 2018

h is net pay: SAGD top- Producer

Lis 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

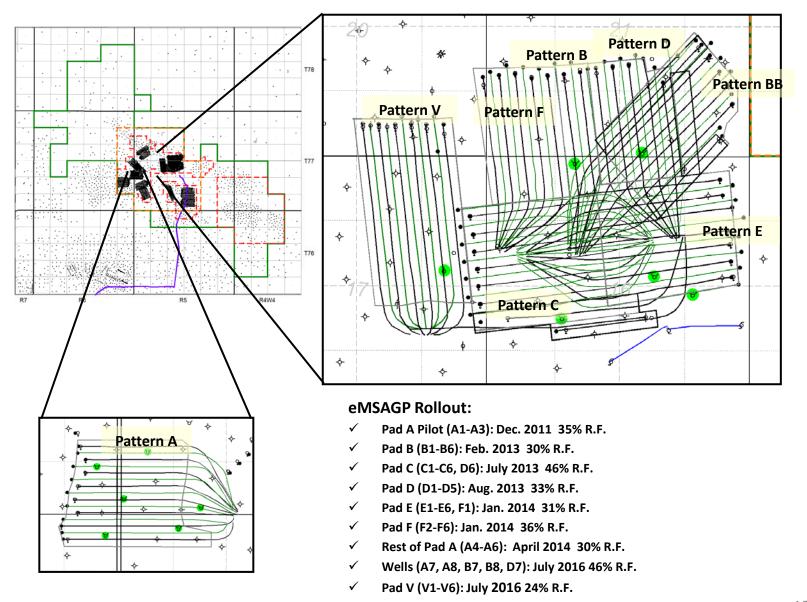
- The mature patterns are connected to new patterns that are projected to produce beyond five years
- At this point, there is no plan to abandon any surface pads for potential needs of pressure maintenance



enhanced Modified Steam and Gas Push

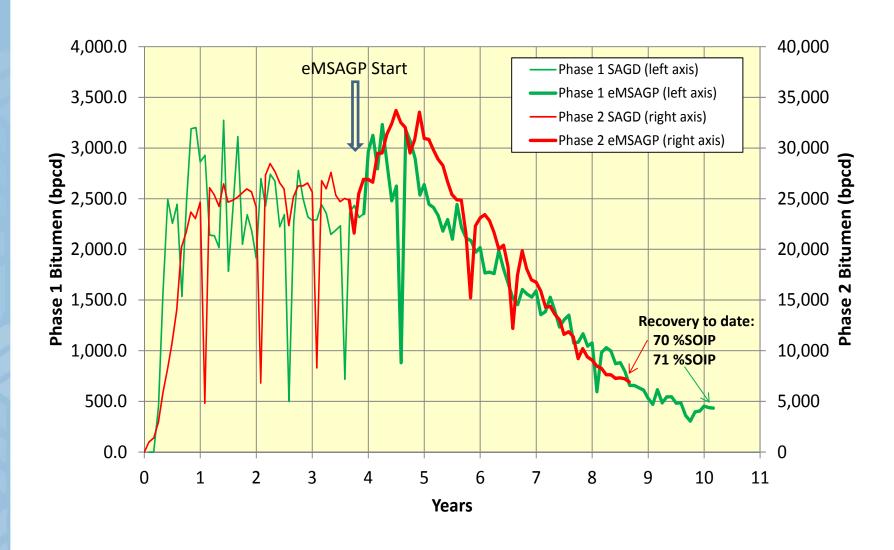


Phase 1 and Phase 2 Pad Layout



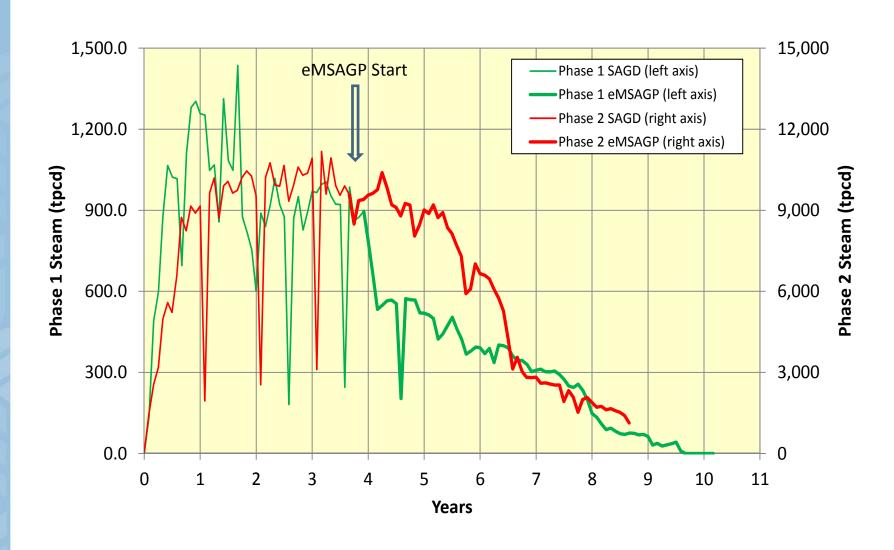


Bitumen Rates for Phases 1 and 2



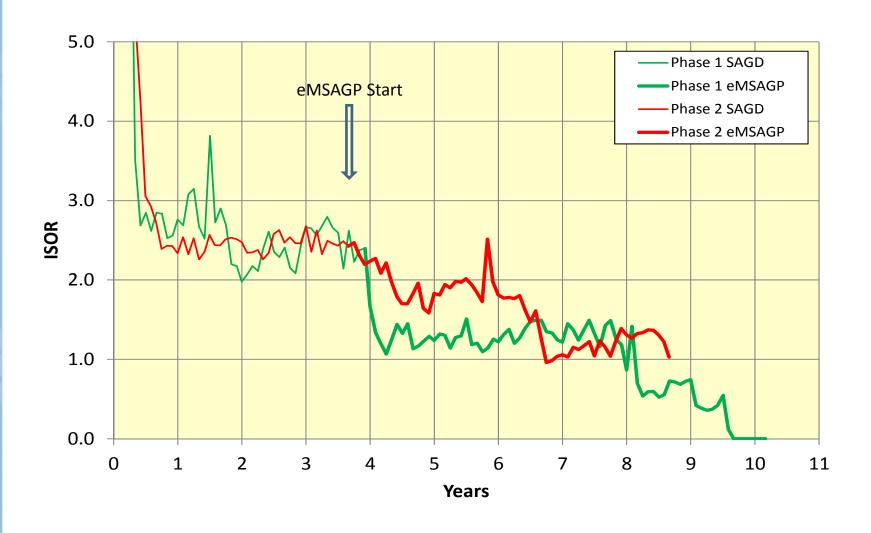


Steam Rates for Phases 1 and 2





SOR for Phases 1 and 2





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

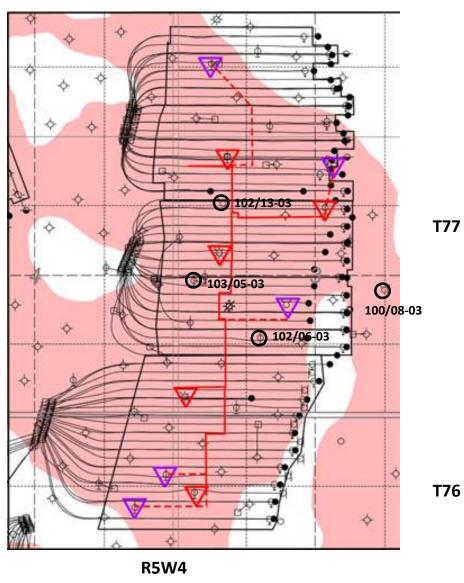


Gas Cap Re-Pressuring Project Update

- 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)



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

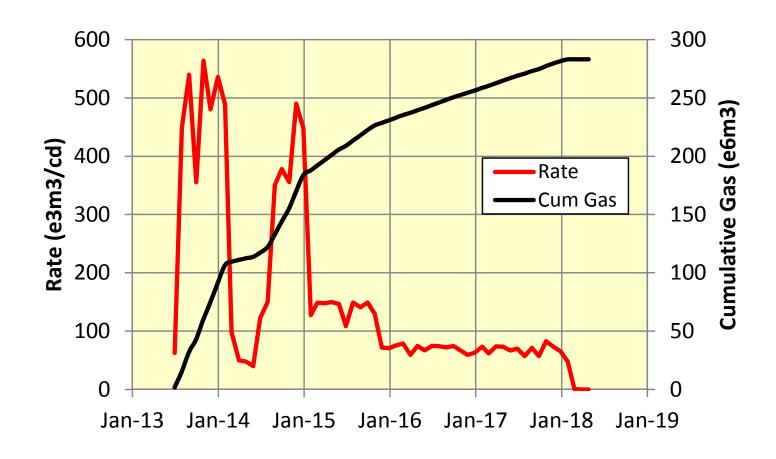
Note:

Not all SAGD intervals in the pool wells are directly connected to associated gas

T76

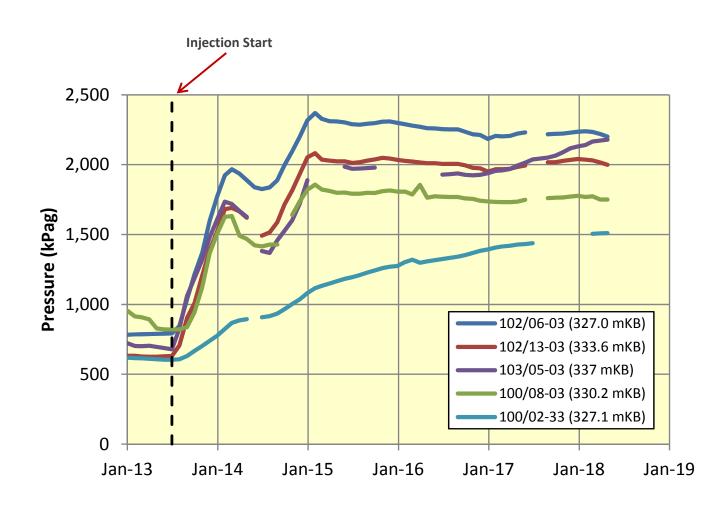


Total Gas Injection





Observation Well Pressure Readings



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



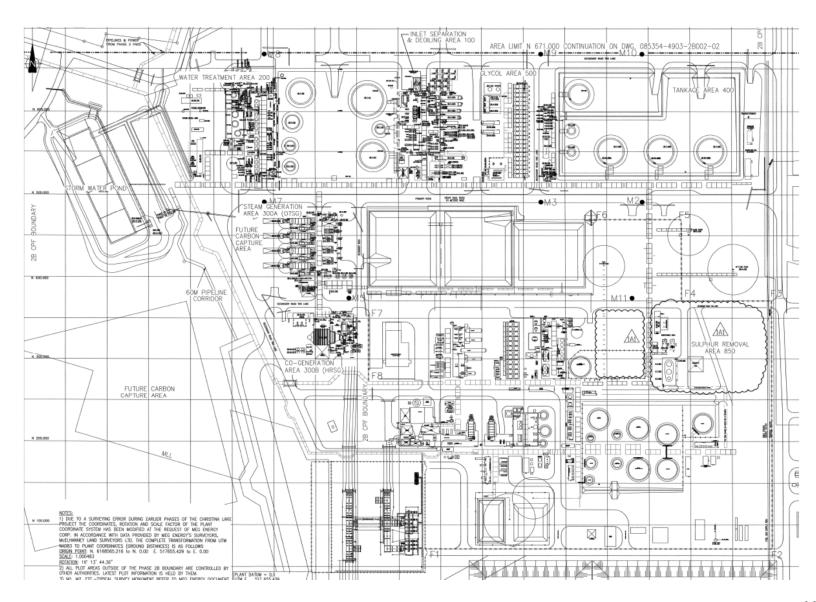


Operations Overview

- Operation Overview
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage

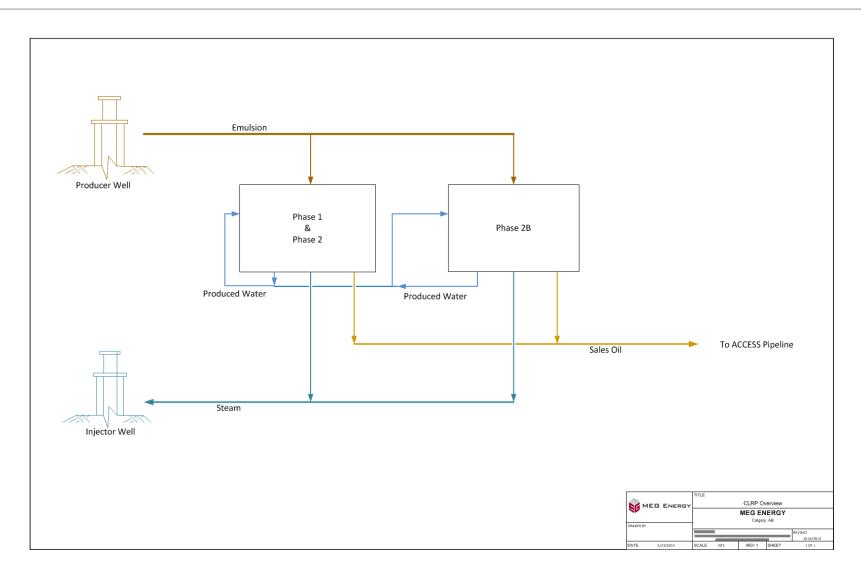


CPF Site Plan



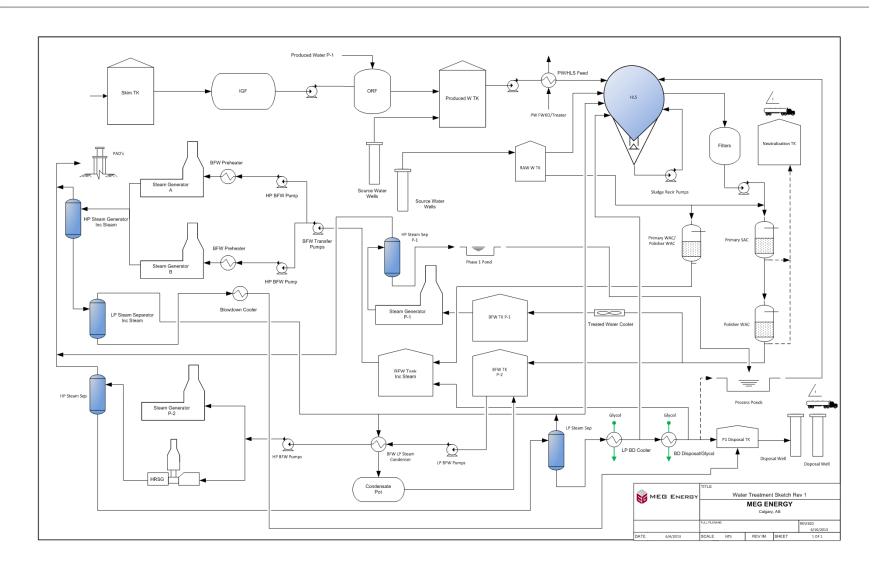


Integrated Distribution/Gathering System



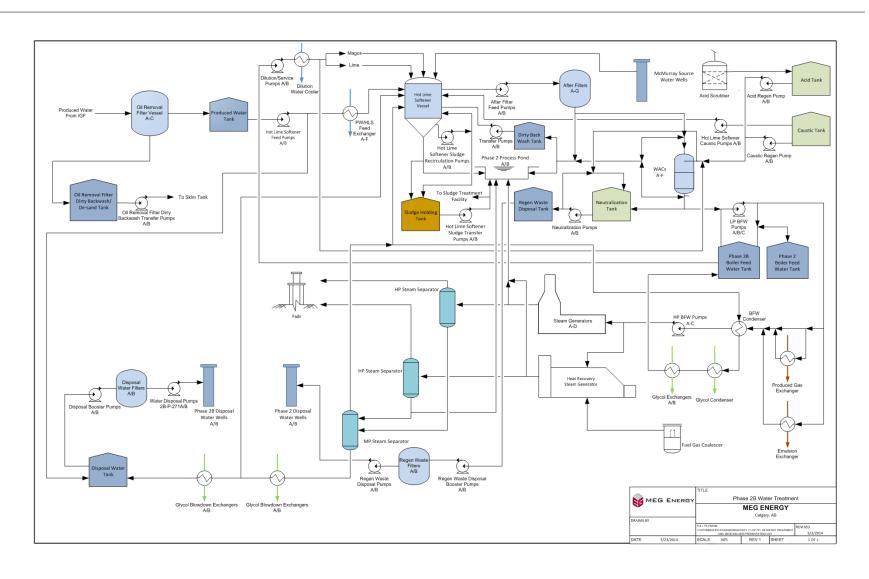


Water and Steam Process Overview Phase 1 and 2



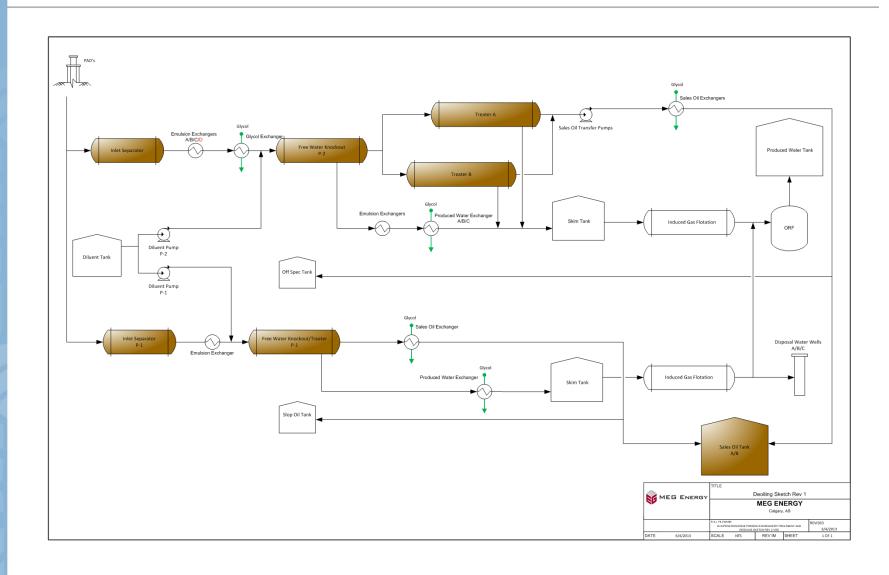


Water and Steam Process Overview Phase 2B



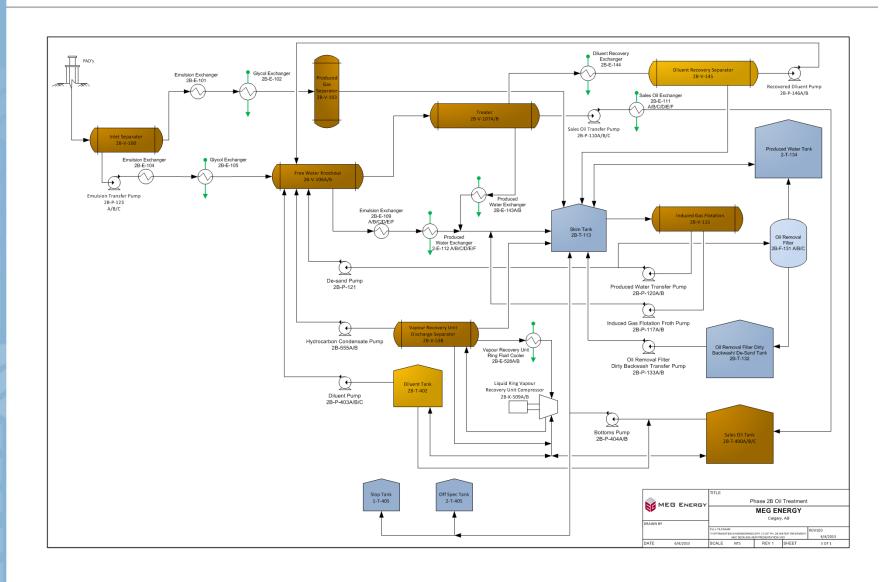


Oil Treatment Overview Phase 1 and 2





Oil Treatment Overview Phase 2B



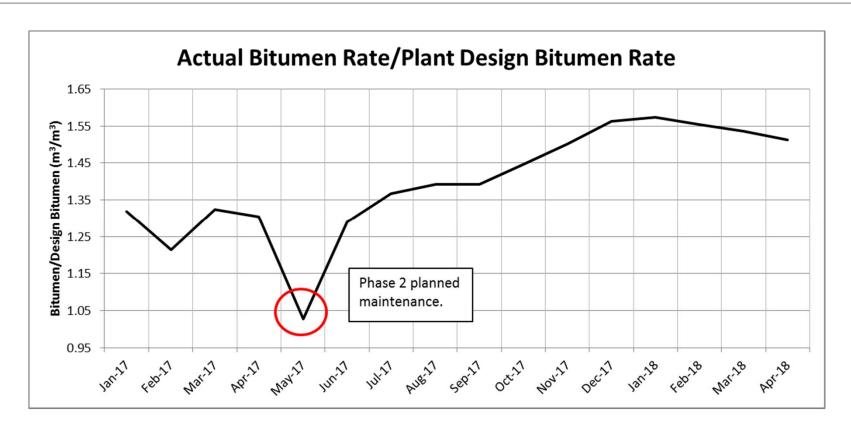


Additions/Modifications

 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



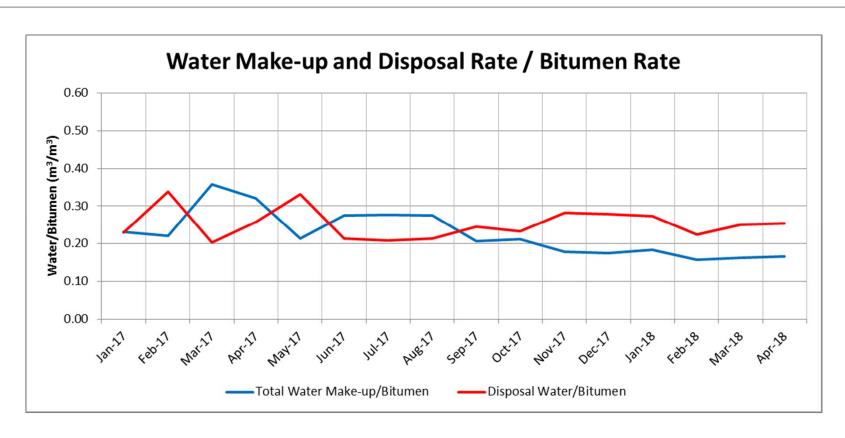
Facility Performance: Bitumen Treatment

Future Actions

- Installation of enhanced interface level measurement in Phase 2B FWKOs 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





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



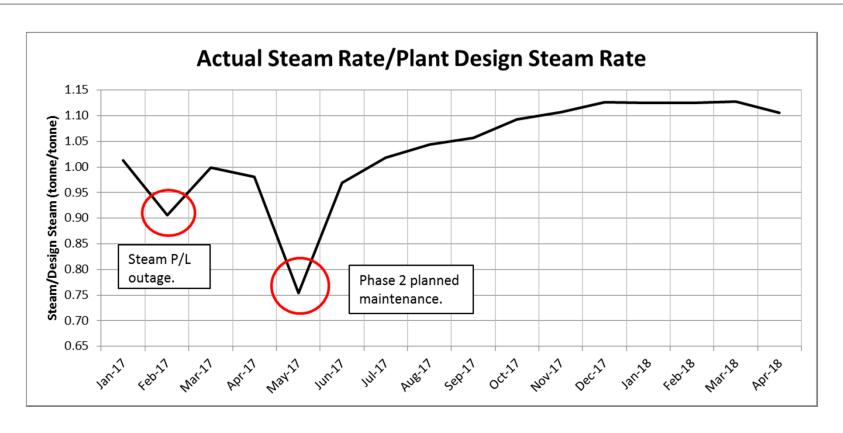
Facility Performance: Water Treatment

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





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



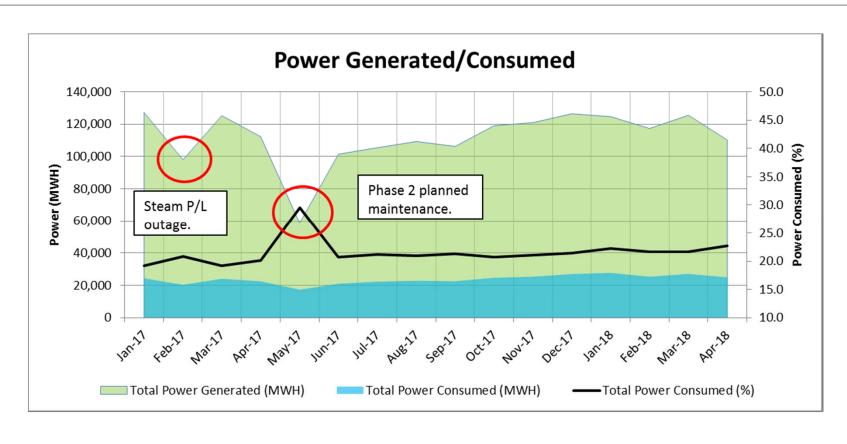
Facility Operations: Steam Generation

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

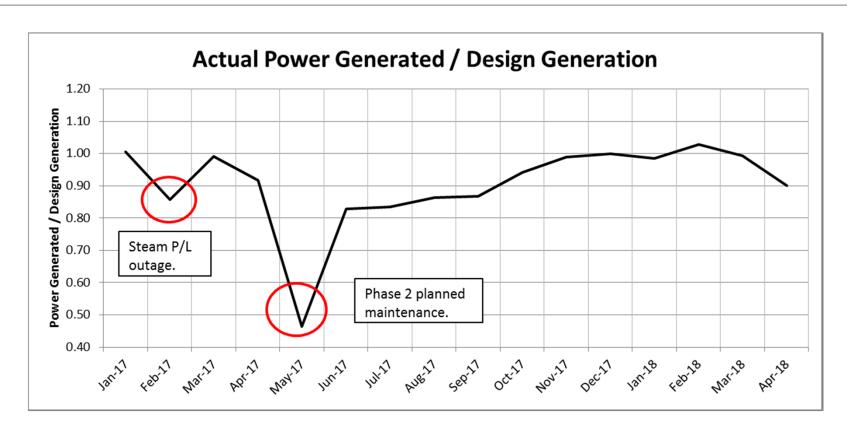


Facility Performance: Power Generation





Facility Performance: Power Generation





Facility Performance: Power Generation

Successes

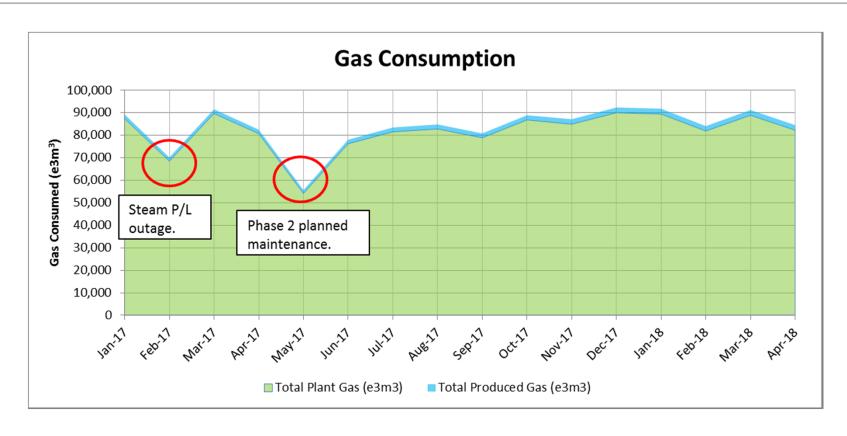
Stable operation throughout the year

Issues Being Addressed

No significant issues

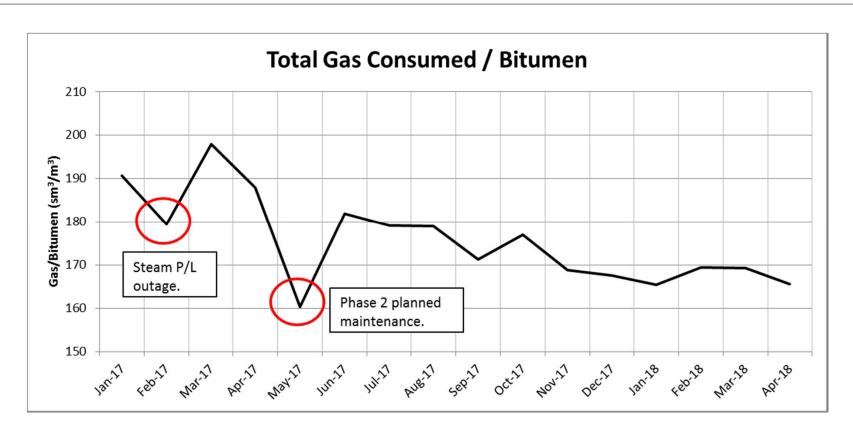


Facility Performance: Gas Usage





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

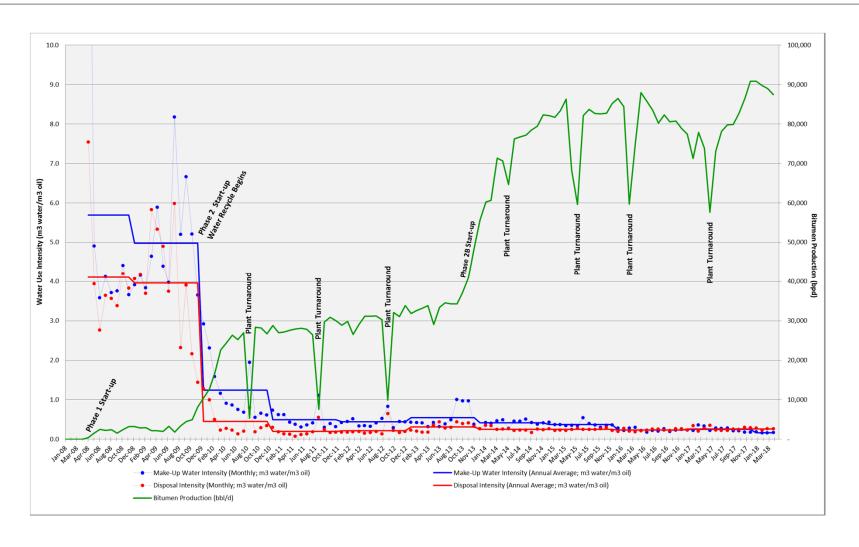
Field Steam Measurement

 Electronic diagnostics on smart vortex steam meters (Rosemount 8800D) have improved safe operations and reduced O&M costs



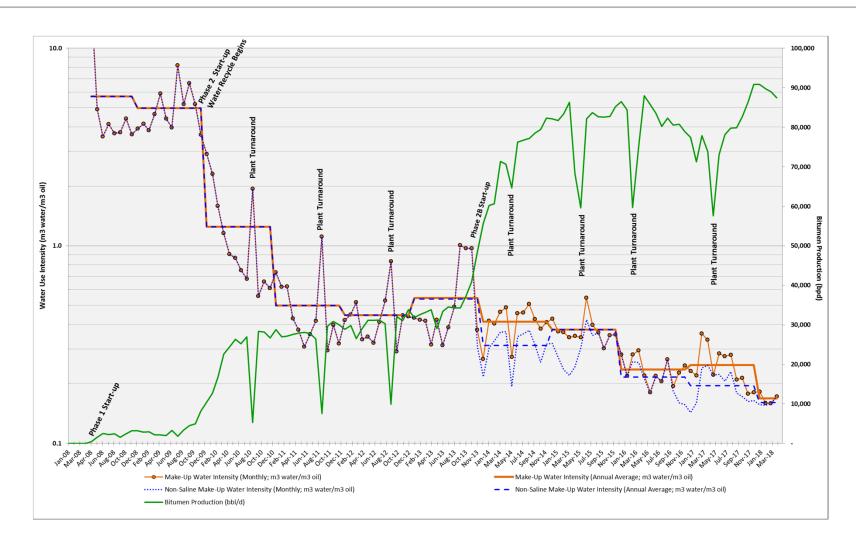


Water Use Intensity





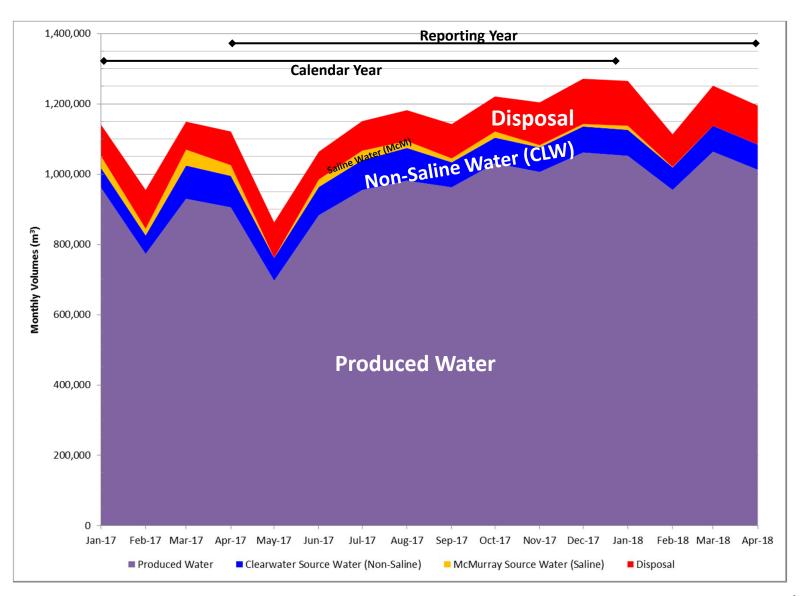
Non-Saline Water Use Intensity



*2017 had lowest non-saline water use intensity in CLRP operations history (0.20)

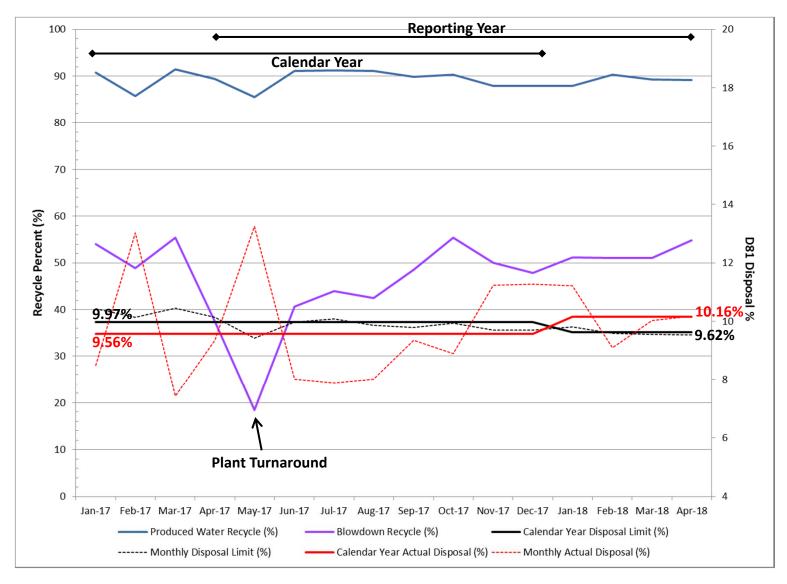


Monthly Water Volumes



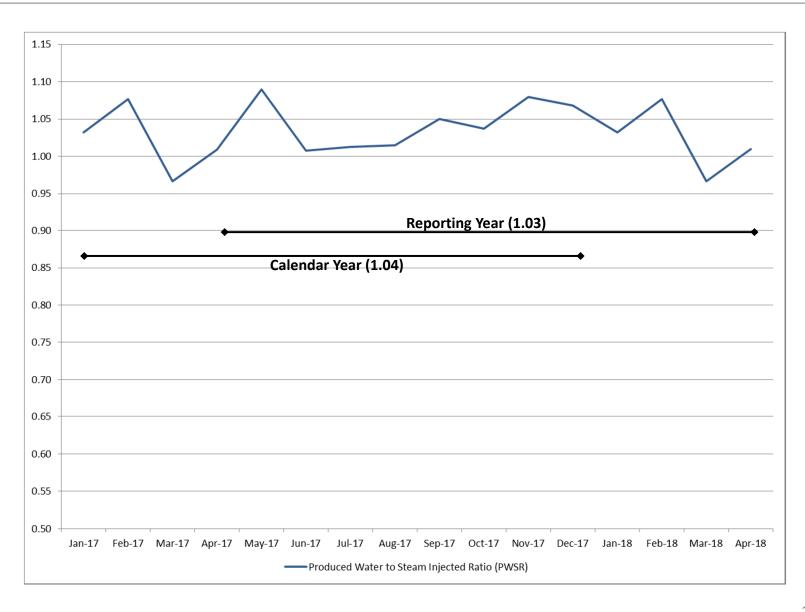


Water Recycle and D81 Limits



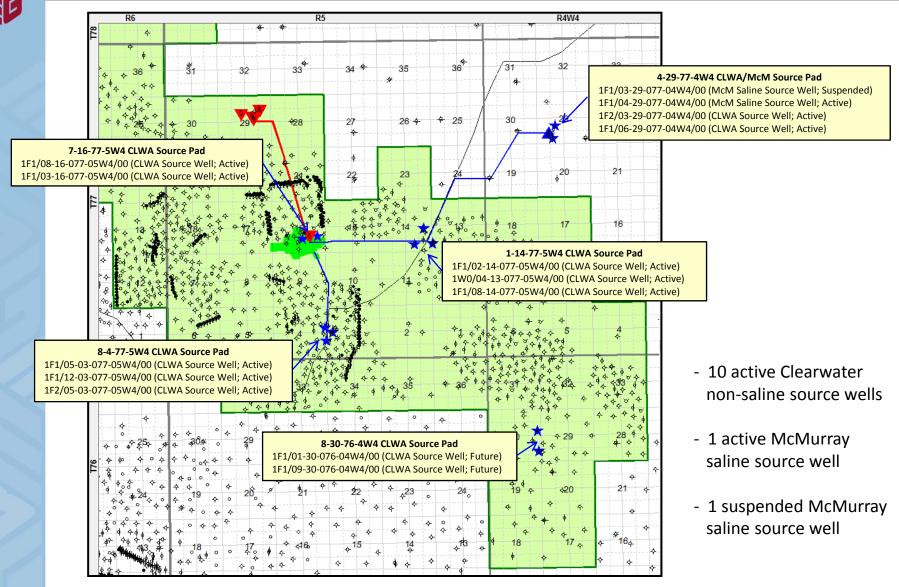


Produced Water to Steam Injected Ratio



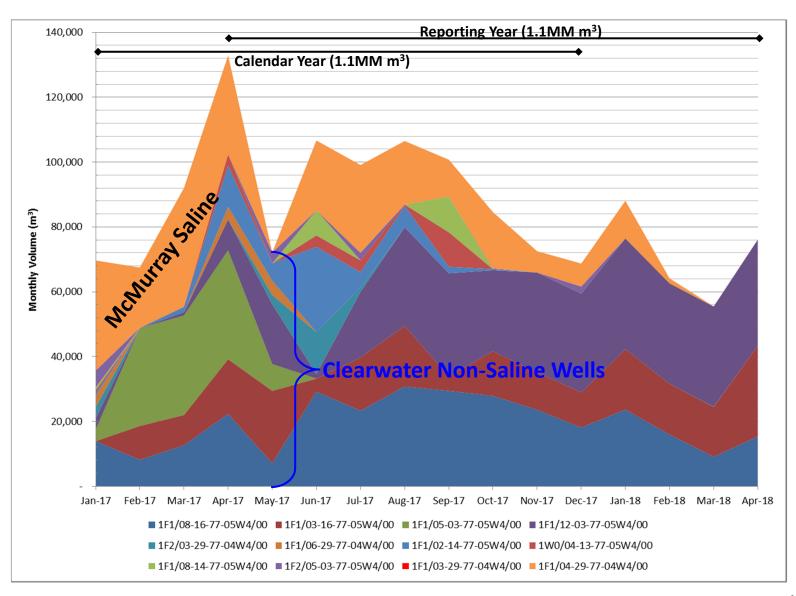


Source Water Well Locations



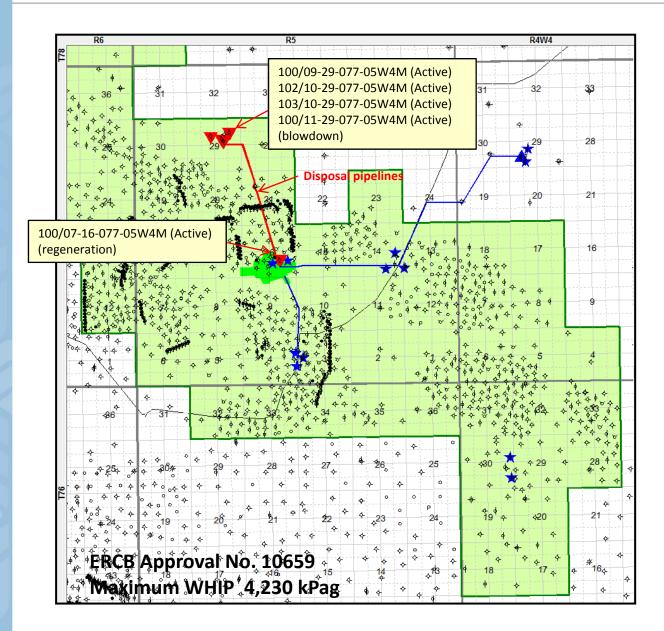


Source Well Production





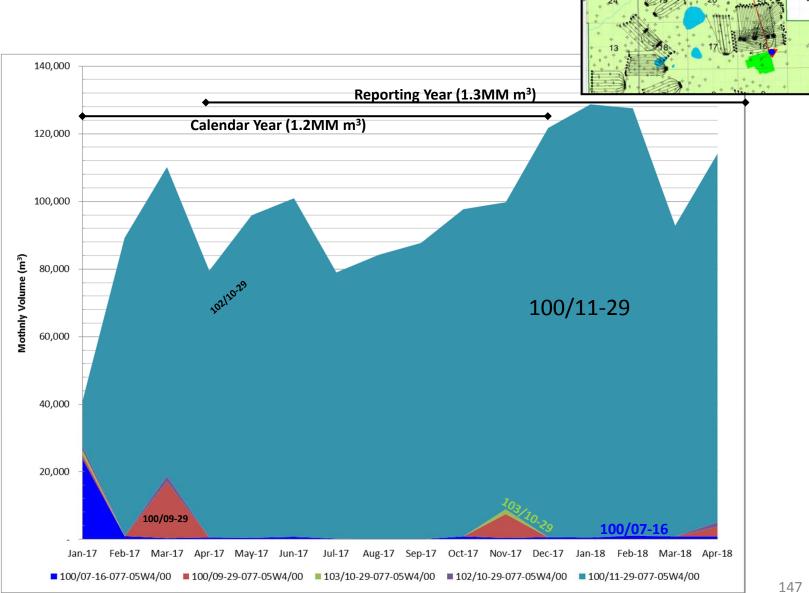
McMurray Disposal Wells



5 active McMurray disposal wells

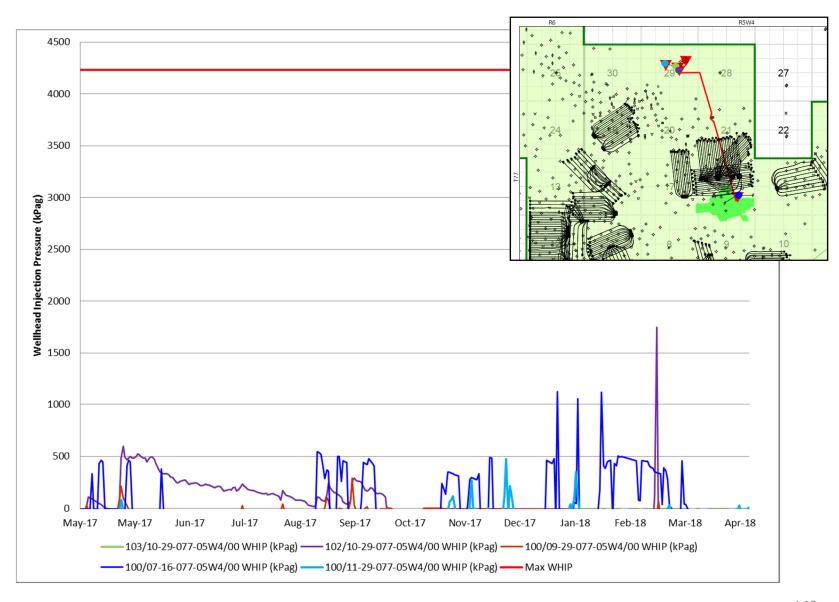


Disposal Summary

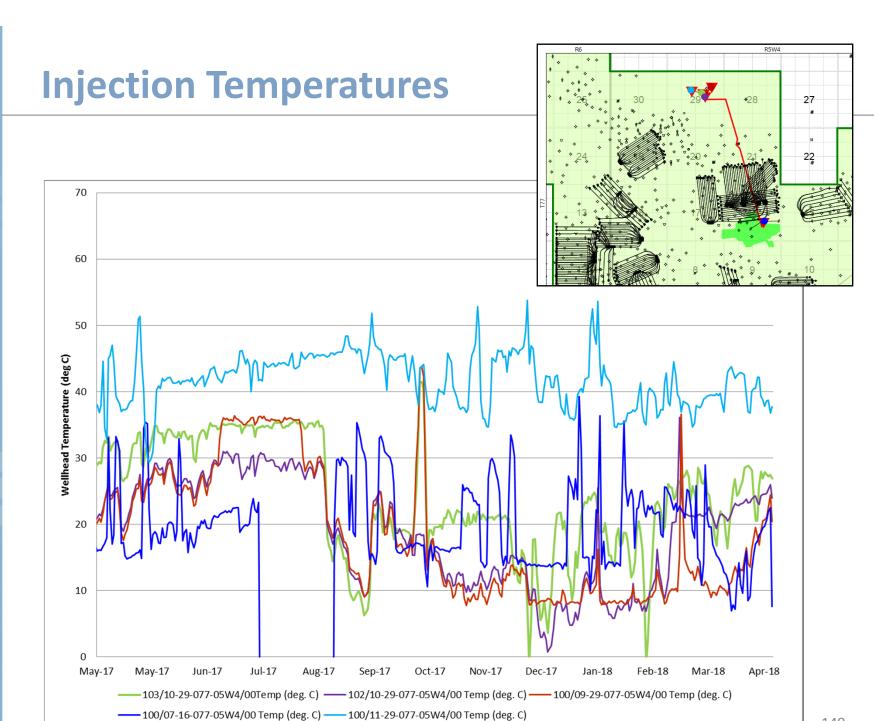




Wellhead Injection Pressures

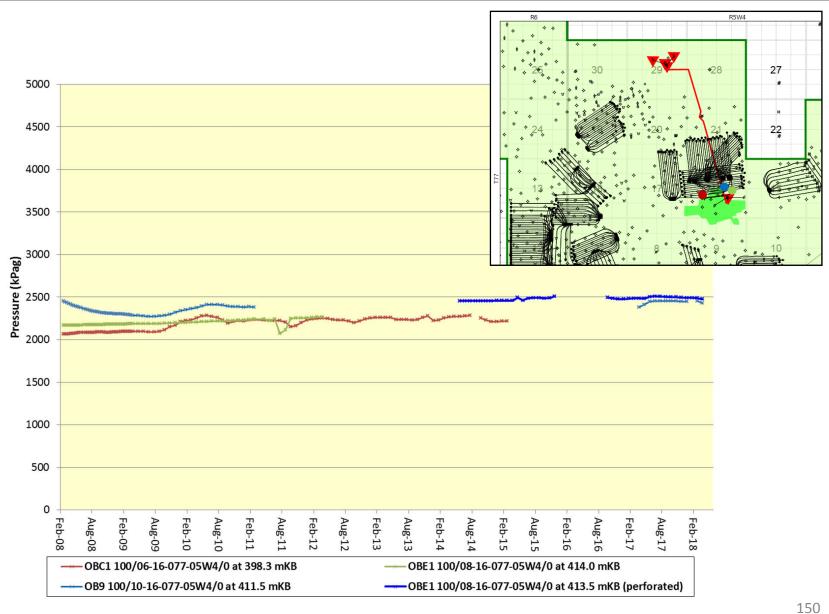








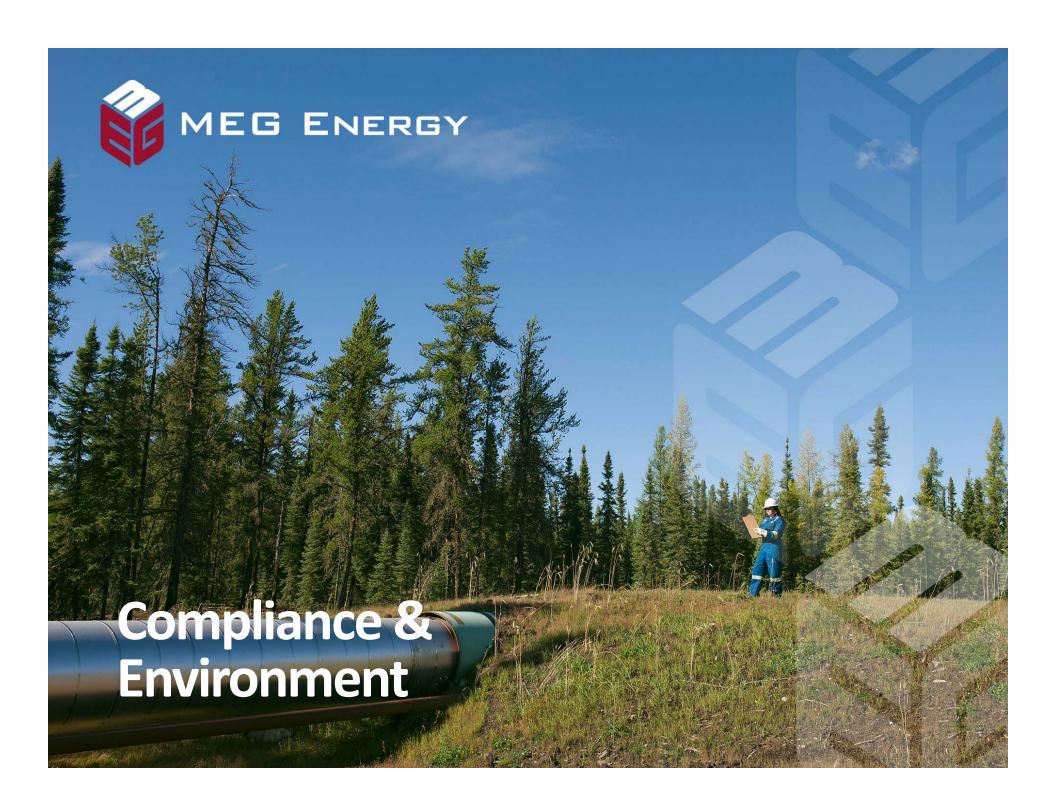
Basal McMurray Water Sand Pressure Monitoring





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





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



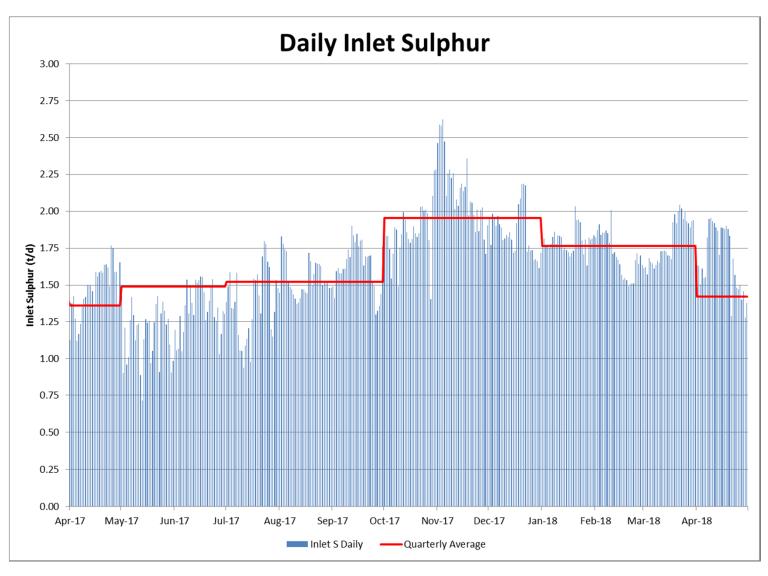
Environmental Initiatives

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



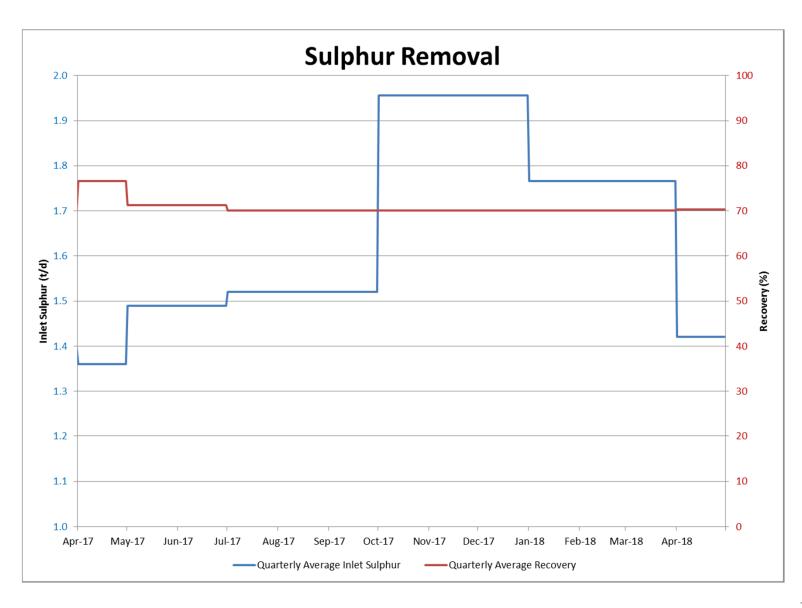
Daily Inlet Sulphur



Average inlet sulphur surpassed 1 t/d in 2014 triggering scheme sulphur recovery requirements

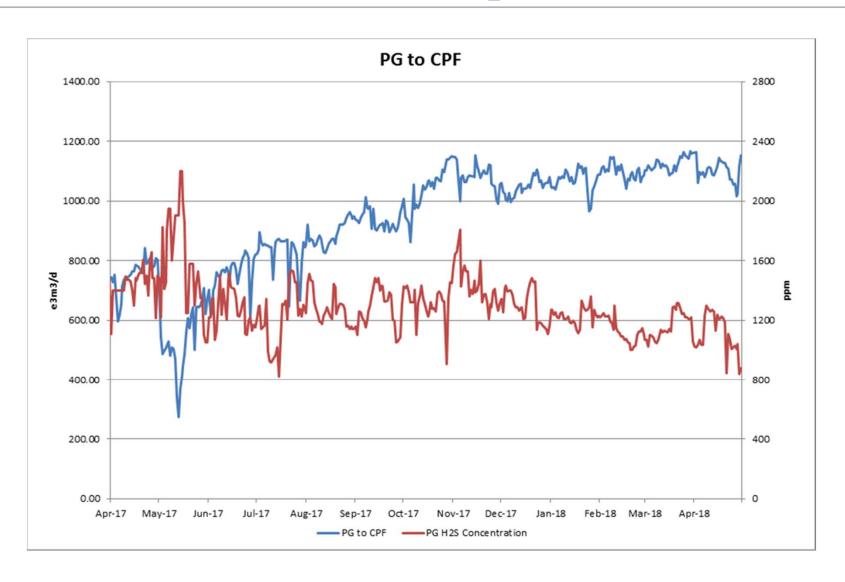


Sulphur Removal





Produced Gas Rates and H₂S Concentration



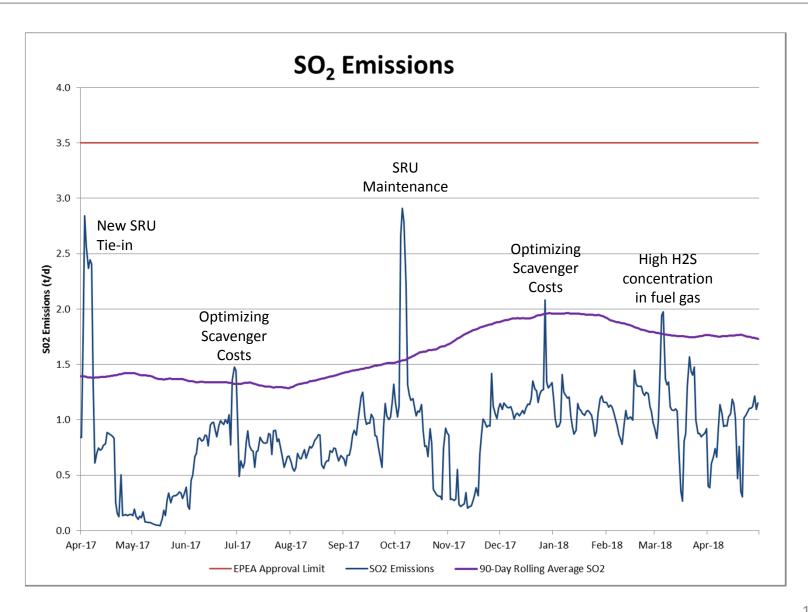


Produced Gas Recycle Project

- 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





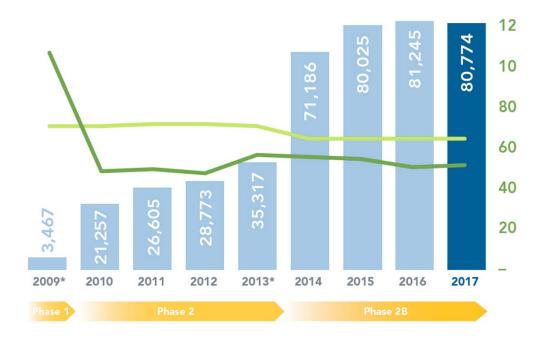
Sulphur Recovery Unit (SRU)

- 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



Greenhouse Gas (GHG) Management

NET GHG INTENSITY PERFORMANCE



- 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).

- Bitumen Production (bpd)
- MEG Net GHG Intensity** (t CO₂e/bbl)
- Industry Average GHG Intensity (t CO₂e/bbl)

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

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



Compliance Summary

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.



Compliance Summary

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



Ambient Air Quality Monitoring

Continuous Ambient Air Monitoring Trailer and Passive Sampling

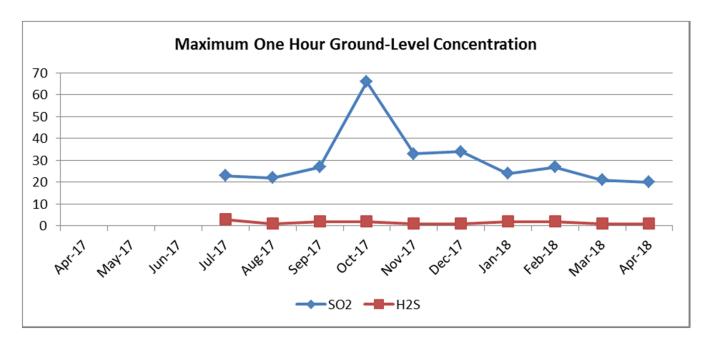
- MEG employed the use of a continuous ambient air monitoring trailer from January to June 2016 for phases 1, 2 and 2B as required by our approval
- Four passive monitors are installed around the CLRP site for the measurement of H₂S and SO₂ with readings taken on a monthly basis



Ambient Air Quality Monitoring

Continuous Monitoring Results

	Maximum Reading (ppbv)	Month of Maximum Reading	Limit (ppbv)
SO2	66	October 2017	172
H2S	3	July 2017	10



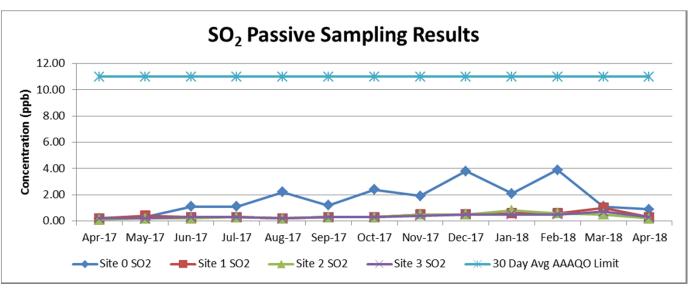
There were no exceedances of Ambient Air Quality Objectives during the reporting period.

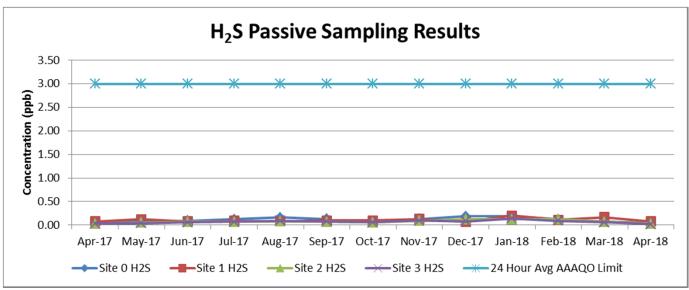
Continuous ambient air monitoring was conducted from July 2017 to April 2018, and will continue until June 2018.



Ambient Air Quality Monitoring

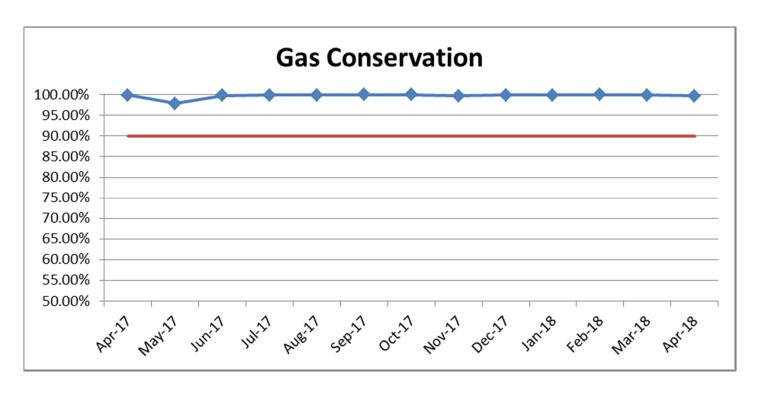
Passive Sampling Results







Gas Usage



- 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

- 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

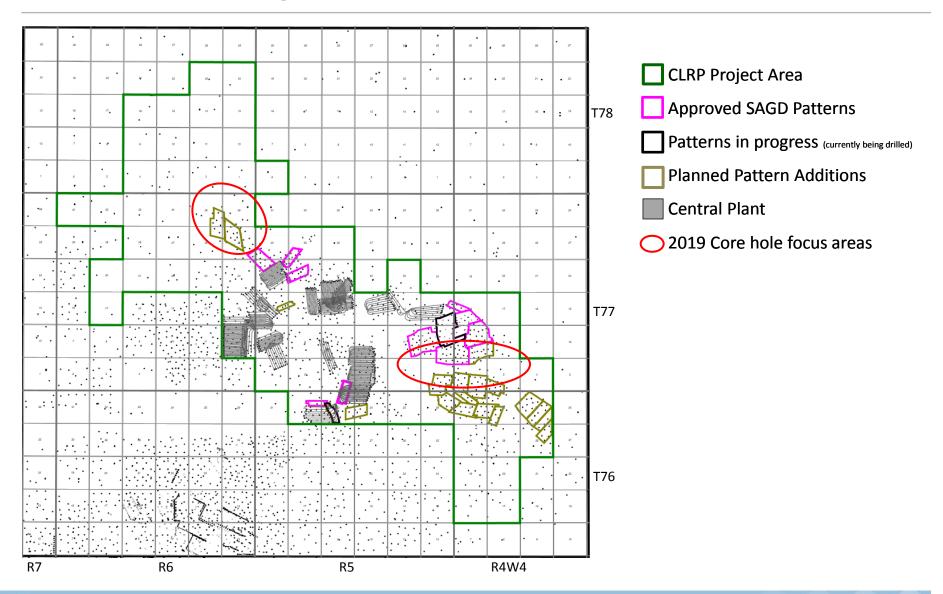
April 2017 - April 2018

- 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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