MEG ENERGY

Christina Lake Regional Project

2016/2017 Performance Presentation
Commercial Scheme Approval No. 10773

June 13, 2017

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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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Meeting Agenda

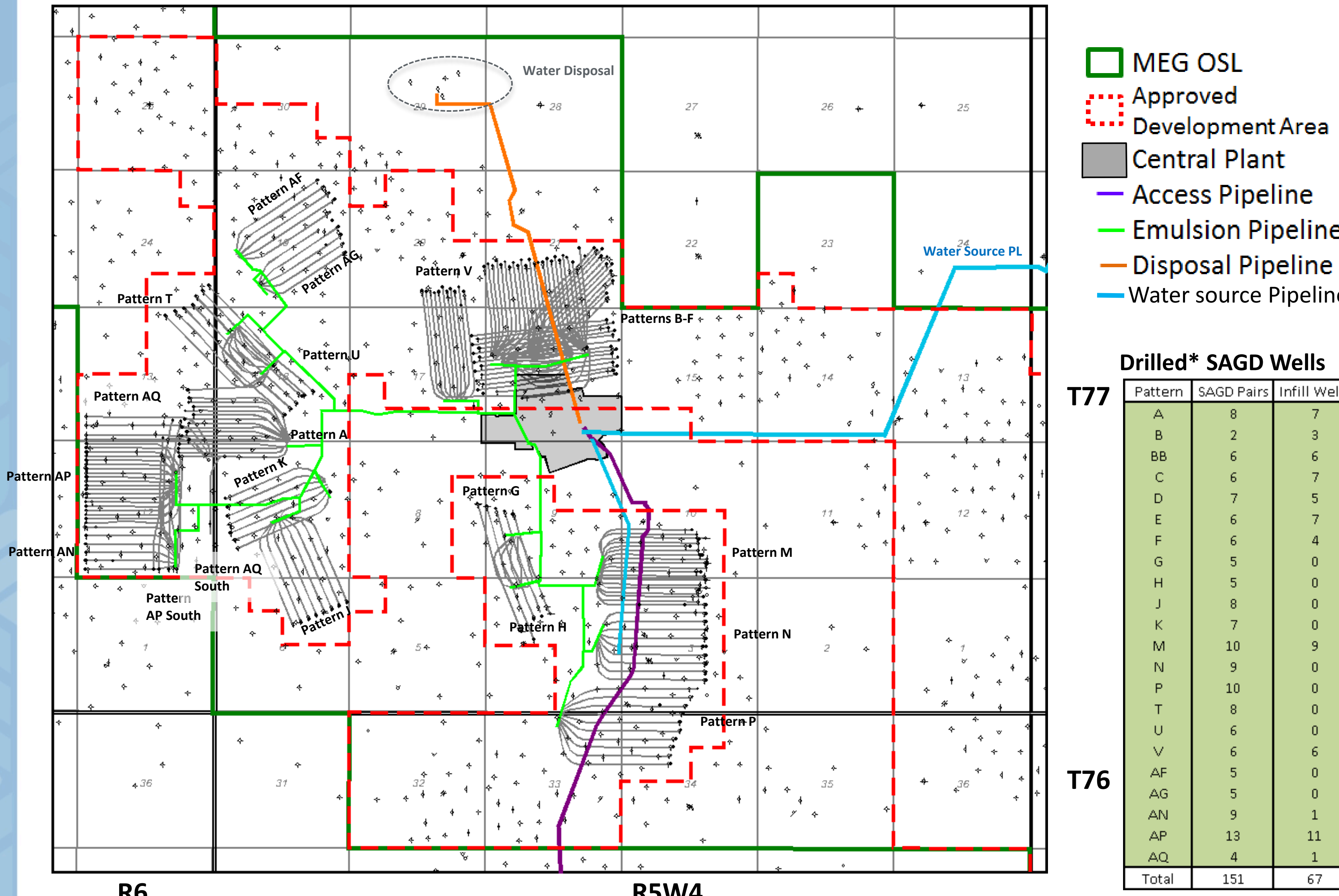
• **Overview**	Sachin Bhardwaj
• **Operations**	Bill Mazurek
• **Water**	Scott Rayner
• **Compliance & Environment**	Mike Robbins
• **Geosciences**	Greg Helman
• **Reservoir**	Kejia Xi
• **Future Plans**	Sachin Bhardwaj

Christina Lake Regional Project

2016-2017 Operating Highlights

- 2016 bitumen production averaged 81,245 bpd
- Q1 2017 Bitumen Production of 77,309 bpd
- Q1 2017 Average Field-wide SOR of 2.36
- Expanded implementation of eMSAGP

Active Development Area (ADA)



Drilled* SAGD Wells

Pattern	SAGD Pairs	Infill Wells
A	8	7
B	2	3
BB	6	6
C	6	7
D	7	5
E	6	7
F	6	4
G	5	0
H	5	0
J	8	0
K	7	0
M	10	9
N	9	0
P	10	0
T	8	0
U	6	0
V	6	6
AF	5	0
AG	5	0
AN	9	1
AP	13	11
AQ	4	1
Total	151	67

* As of April 30 2017

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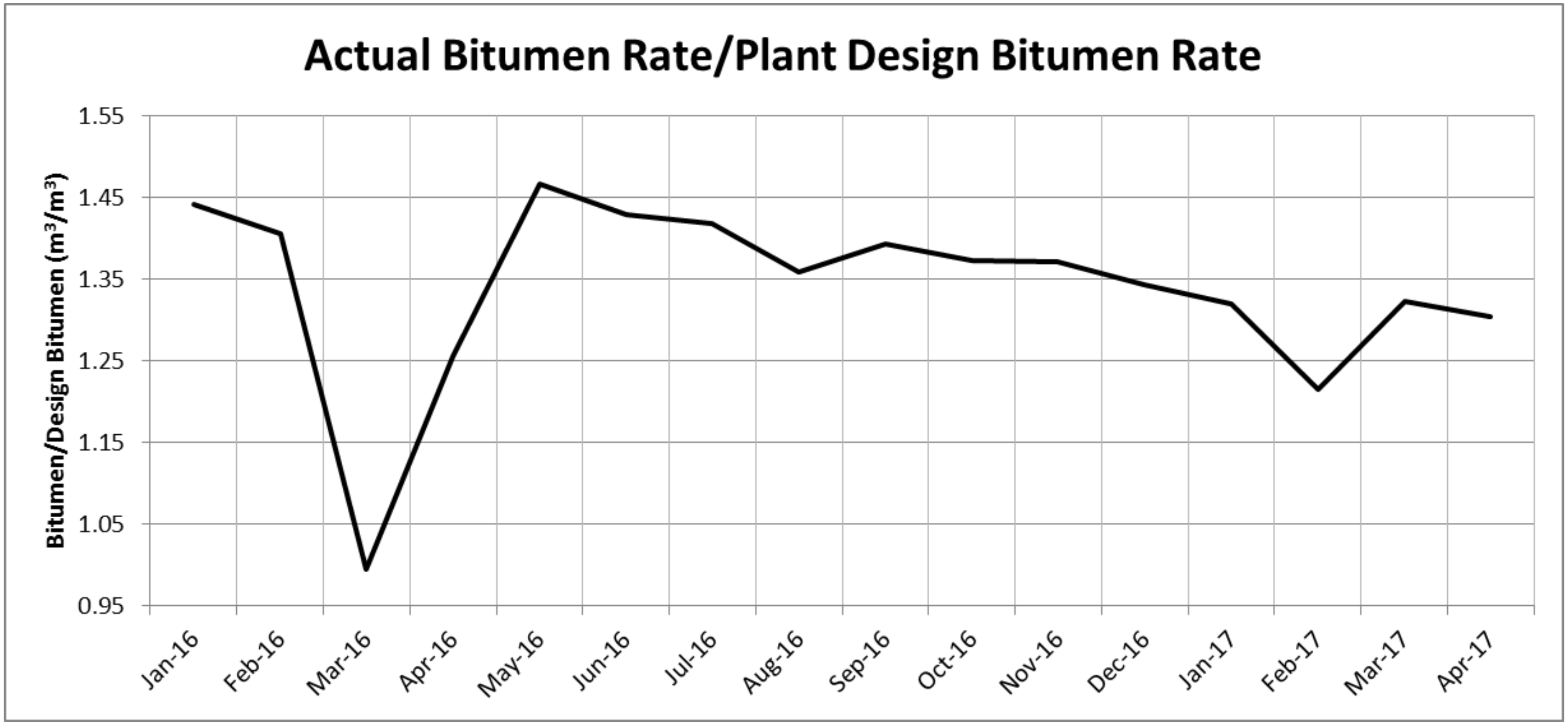
Operations

Additions/Modifications

- Second contactor train has been added to Sulphur Removal Unit to increase the gas handling hydraulic capacity
- Not expecting significant changes in sulphur rate into the plant

Facility Performance: Bitumen Treatment



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

Facility Performance: Bitumen Treatment

Successes

- Produced water exchanger fouling – implemented alternate chemical treating formulation which has significantly reduced fouling in the produced water exchangers in all phases.
- Continue skimming and fluid management strategy to reduce trucking.

Issues Being Addressed

- Solids removal from Phase 2 oil treating vessels.
- Skim fluid management in Phase 2B.

Facility Performance: Bitumen Treatment

Future Actions

- Continue optimization of chemical treatment program.
- Continue plant testing to establish ultimate capacity.
- Continued optimization of slop oil treating and reduction initiatives.

Facility Performance: Water Treatment

Successes

- Continue recycling high blowdown volumes.
- Saline water use ramped up in 2016/2017.
- Use of Intermediate Casing Point (ICP) apparatus to track boiler ion transport and optimize boiler internal treatment chemical usage.

Issues Being Addressed

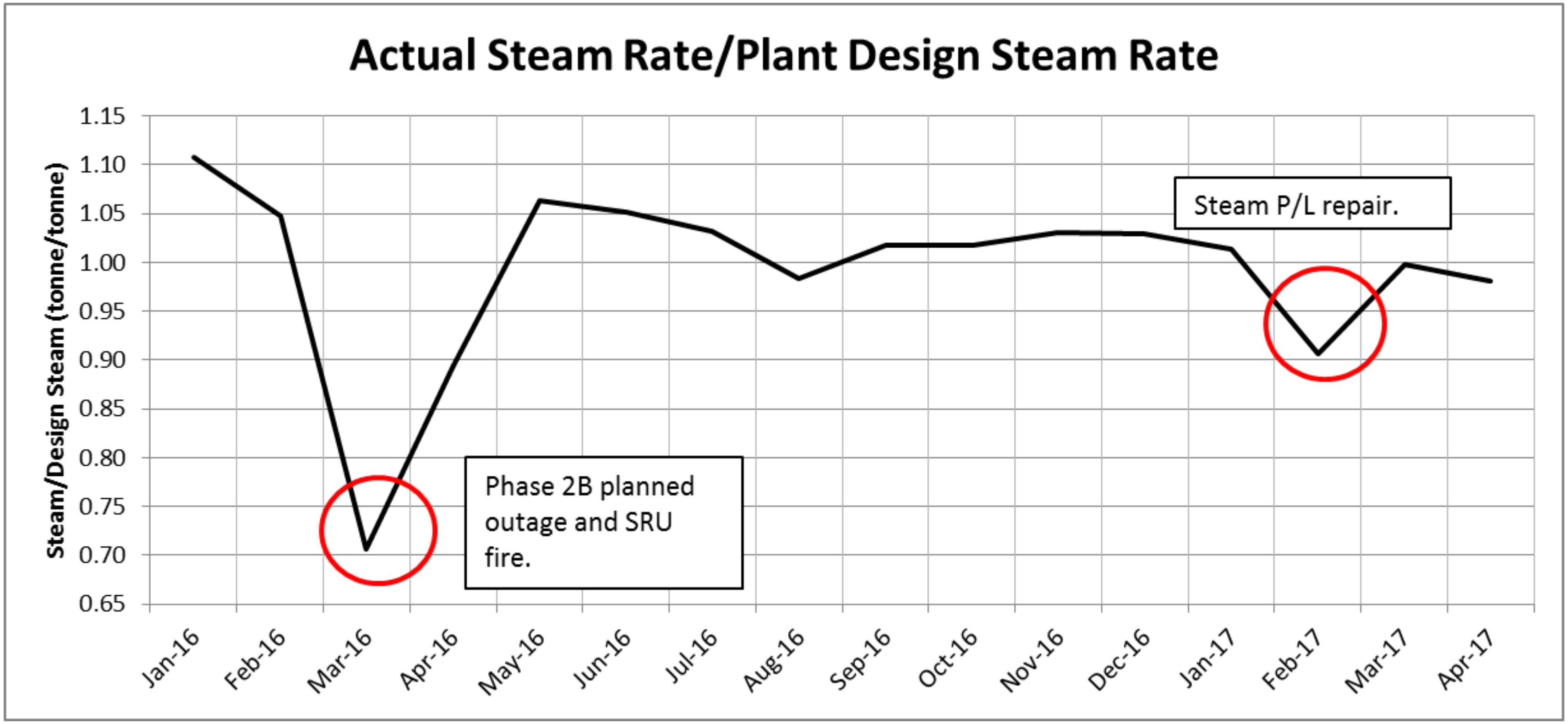
- Continue to monitor reliability of saline water system.
- Cleaning of blowdown pond and pond liner monitoring.

Facility Performance: Water Treatment

Future Actions

- Optimization of water treating chemical usage.

Facility Performance: Steam Generation



Facility Performance: Steam Generation

Successes

- Stable operation throughout the year
- Successfully completed tube repairs on Phase 2B HRSG

Issues Being Addressed

- Enhancing steam pipeline condensate removal facilities
- Steam pipeline repair

Facility Operations: Steam Generation

Future Actions

- Continue to implement overall HP steam distribution control philosophy.
- Continue monitoring of steam generator tube corrosion.
- Increasing focus on steam generator tracking to enhance reliability and efficiency.

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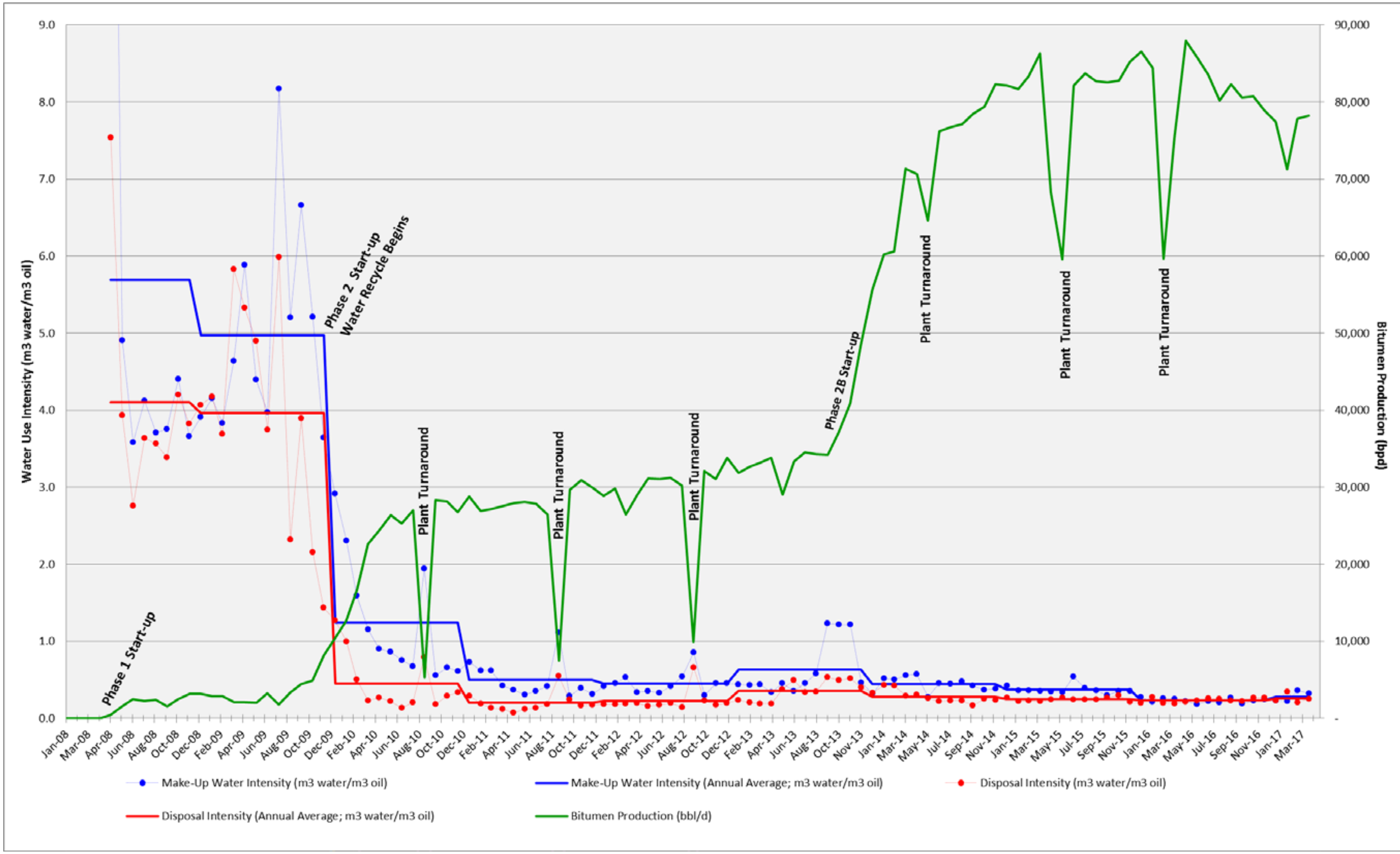
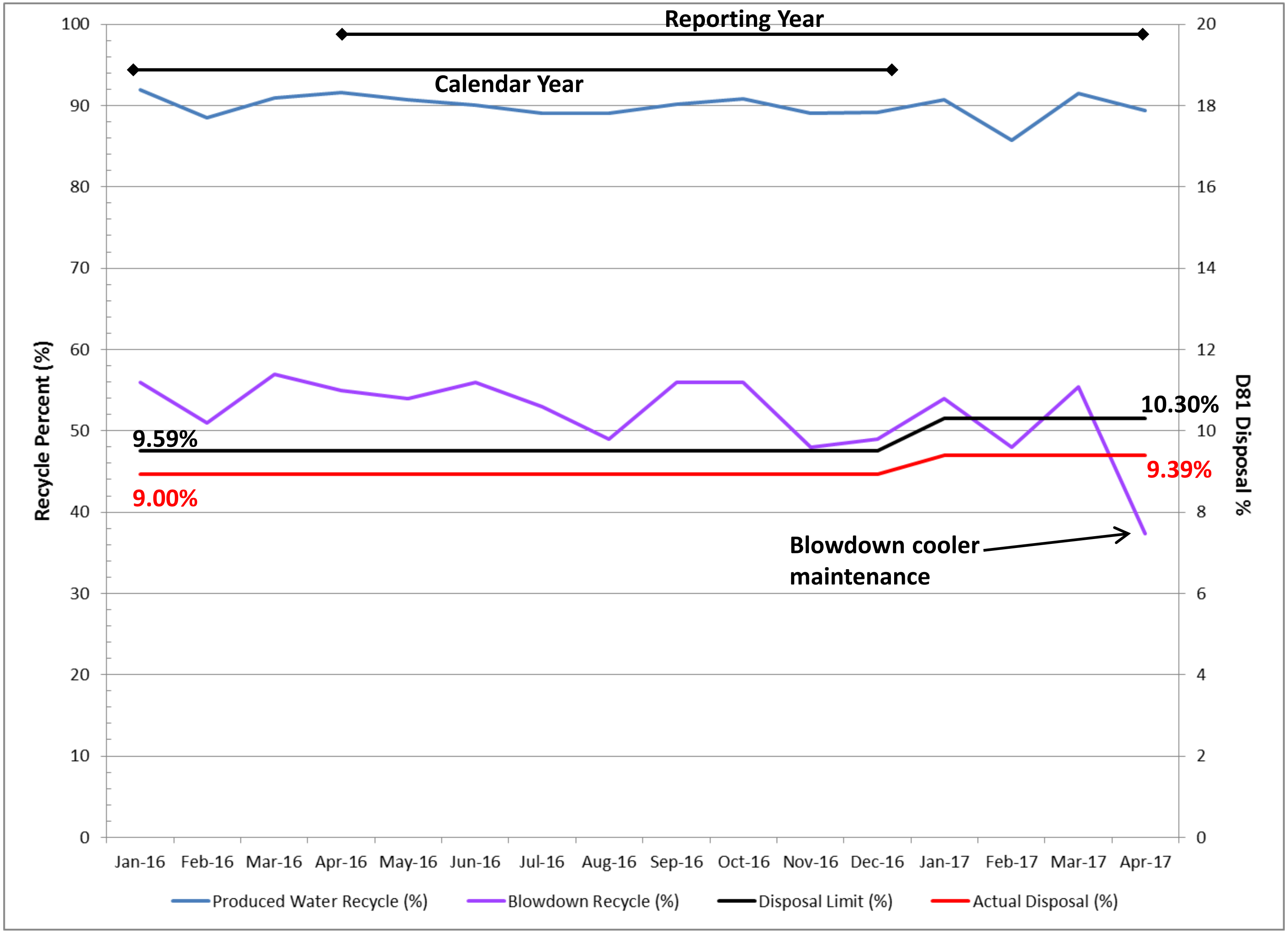
Water

CLRP Water Use Intensity



*2016 had lowest water use intensity in CLRP operations history (0.23 for both source and disposal)

Water Recycle and D81 Limits



D81 Compliant in 2016

*2016 disposal limit/actual percentages are for the calendar year
**2017 disposal limit/actual percentages are YTD to April 30

Water Management - Summary

- 2016 had lowest water use intensity in CLRP operations history
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for 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
- MEG continues to optimize blowdown recycle, adjusting to operational limitations
- Technology advancement to reduce SOR and increase overall water use efficiency
- Blowdown evaporator planned to further improve water recycle capabilities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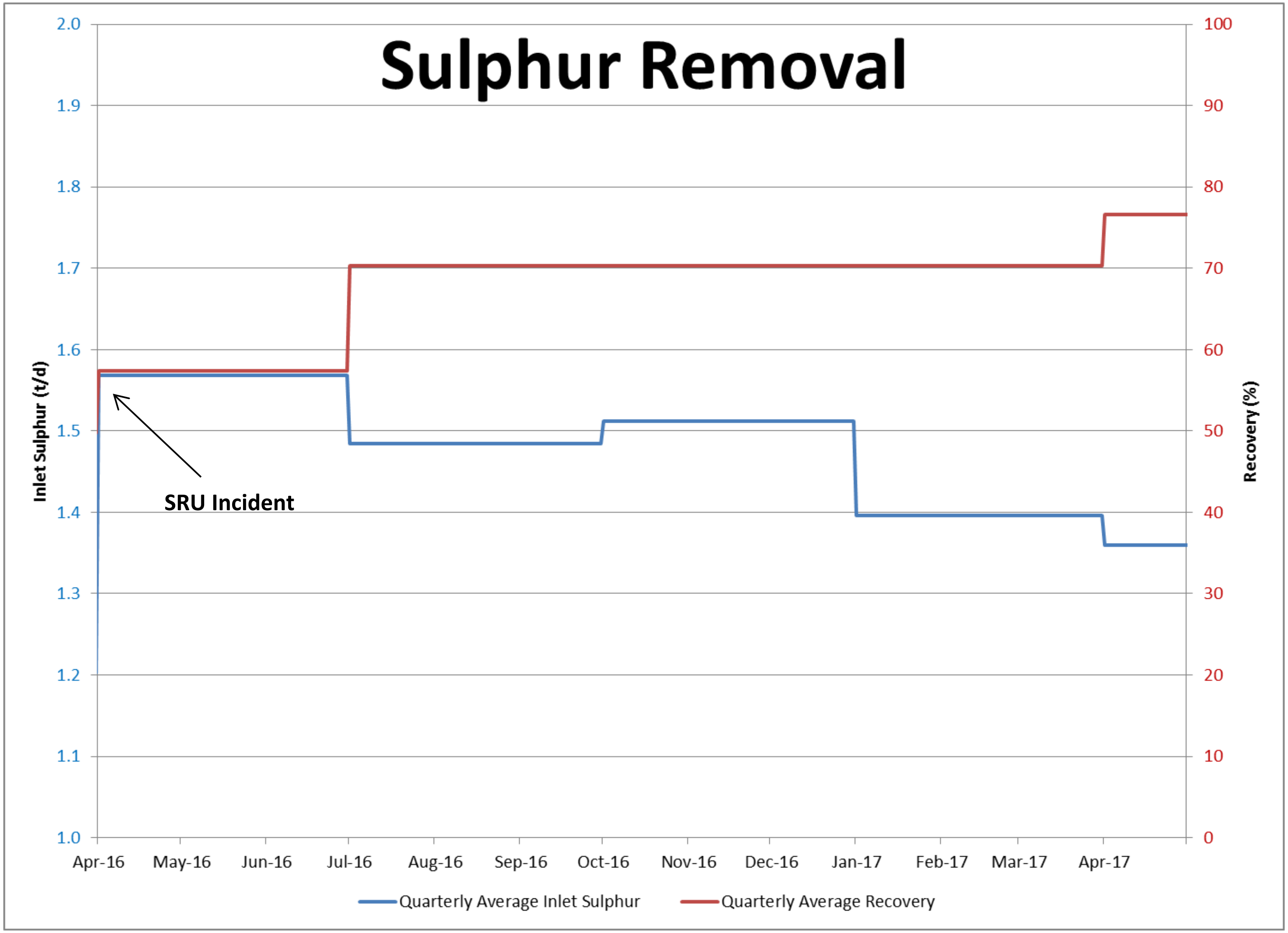
Compliance & Environment

Compliance & Environment

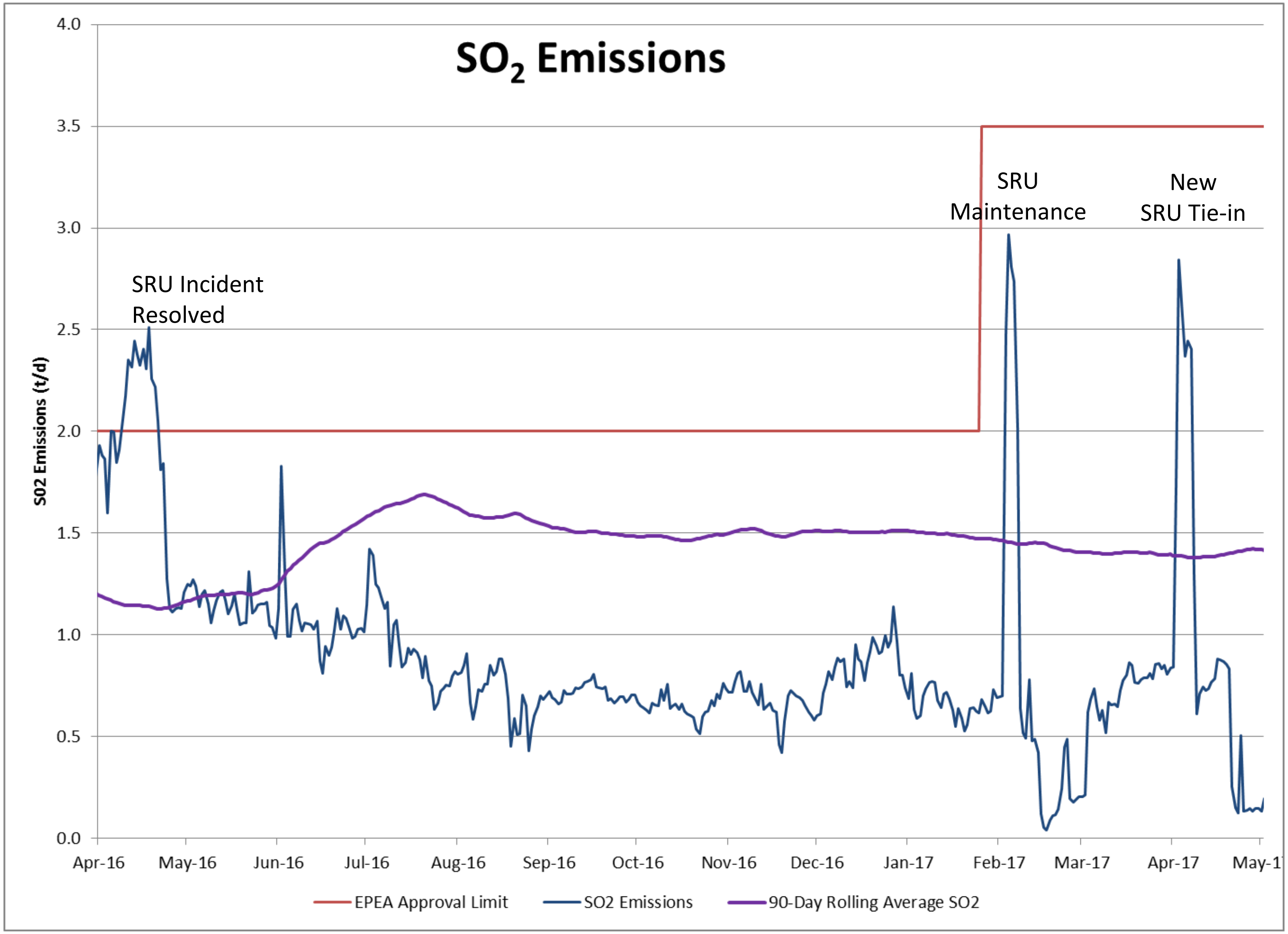
Reporting Year Highlights

- In January 2017, MEG received a 10 year renewal of its EPEA approval
- Our Monitoring Approach
- Sulphur Production and Removal
- Greenhouse Gas Management
- Compliance Summary
- Reclamation

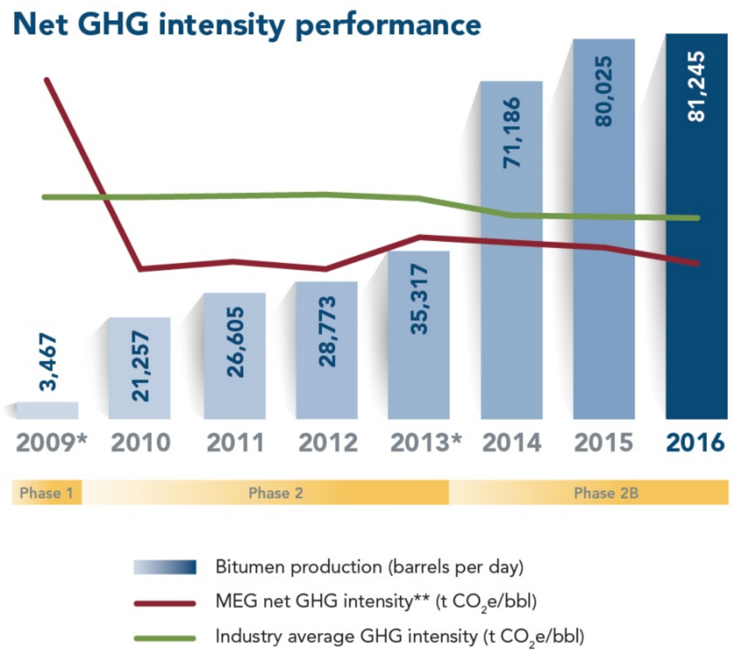
Sulphur Removal



SO_2 Emissions



Greenhouse Gas (GHG) Management



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

Sources: MEG"s net GHG data from 2010-2015 has been third-party verified. 2016 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.

- MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.
- GHG performance is attributed to reservoir performance (low SOR's), use of co-generation technology for steam generation, and ongoing reservoir efficiency technologies (ie. eMSAGP).

Compliance Summary

Self-Disclosures & Non-Compliances

- February 18, 2016: Voluntary Self Disclosure - Phase 2 utility water tank containment
    - Utility water composition changed from original design. AER approved alternate storage approach without secondary containment.
- January 10, 2017: Cement Pit Low Risk Non-Compliance (FIS# 459985)
    - MEG was assessed a low risk noncompliance for “Failure to provide information to the AER when requested or required - Low Risk“.
    - The cement pit was closed, and brought into compliance. AER was notified of the pit closure on May 30th, 2017.

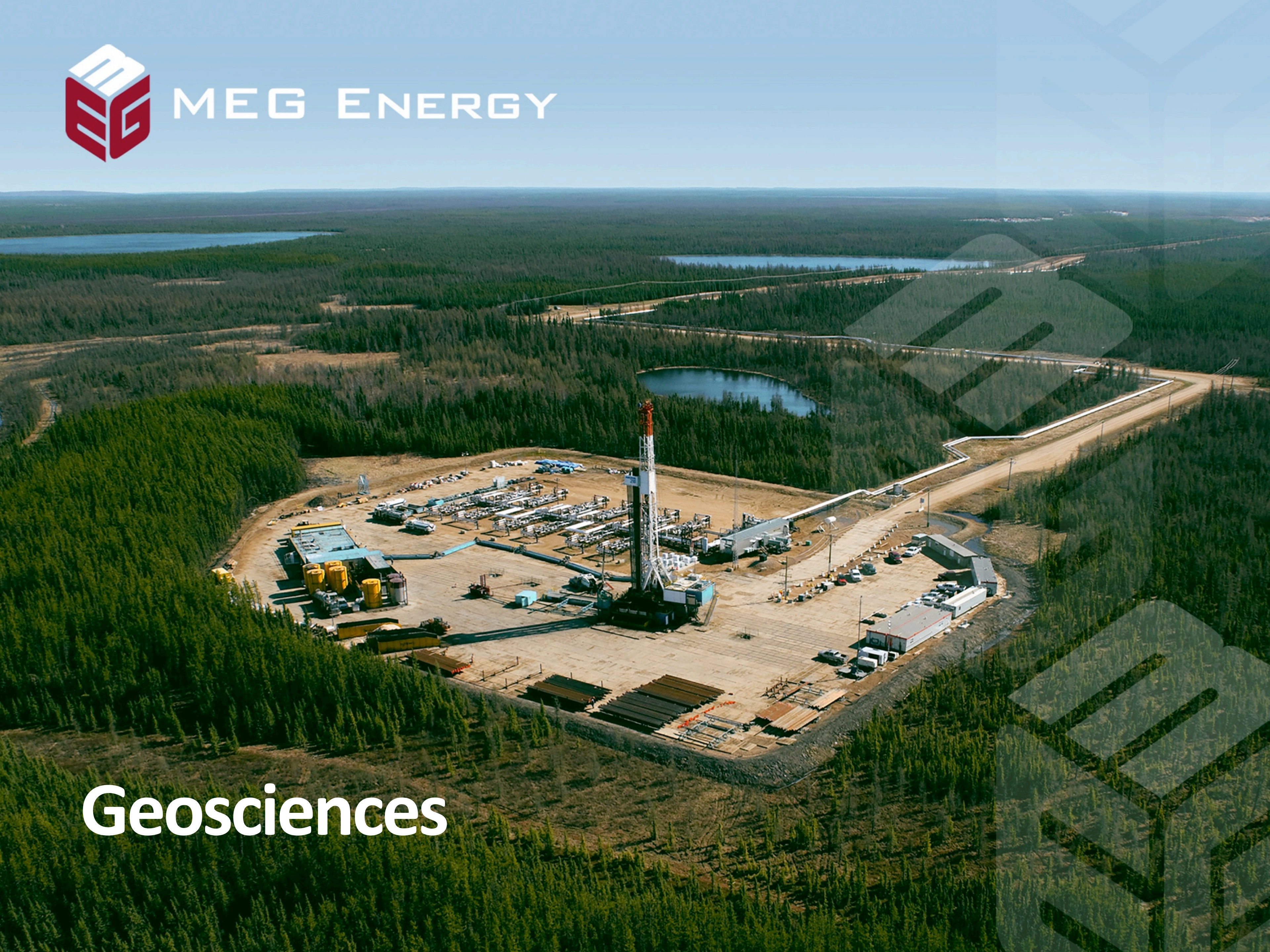
Compliance Summary

MEG reported 5 EPEA approval contraventions to the AER during the reporting period:

- April 30, 2016: Passive Sample Station Damage Contravention
  - Passive sampler was replaced May 8th, 2017.
- June 15, 2016: Phase 2B OTSG NOx Hourly Limit Exceedance
  - Firing mode were returned to ensure NOx mass emissions rate were below approval limits.
- October 9, 2016: – Phase 2B OTSG-A CEMS Unit Availability Contravention
  - Unit was repaired and met availability requirements (90% uptime).
- November 29, 2016: P2B OTSG CEMS Downtime.
  - Unit was repaired and met availability requirements (90% uptime).
- January 2017: Passive Sample Station – Missing Passive H2S Sampler
  - Missing sampler was replaced.
- January 18, 2017: S8 Clearwater Well - Brackish Water Backflow
  - Checkvalve was repaired and well was flushed.

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.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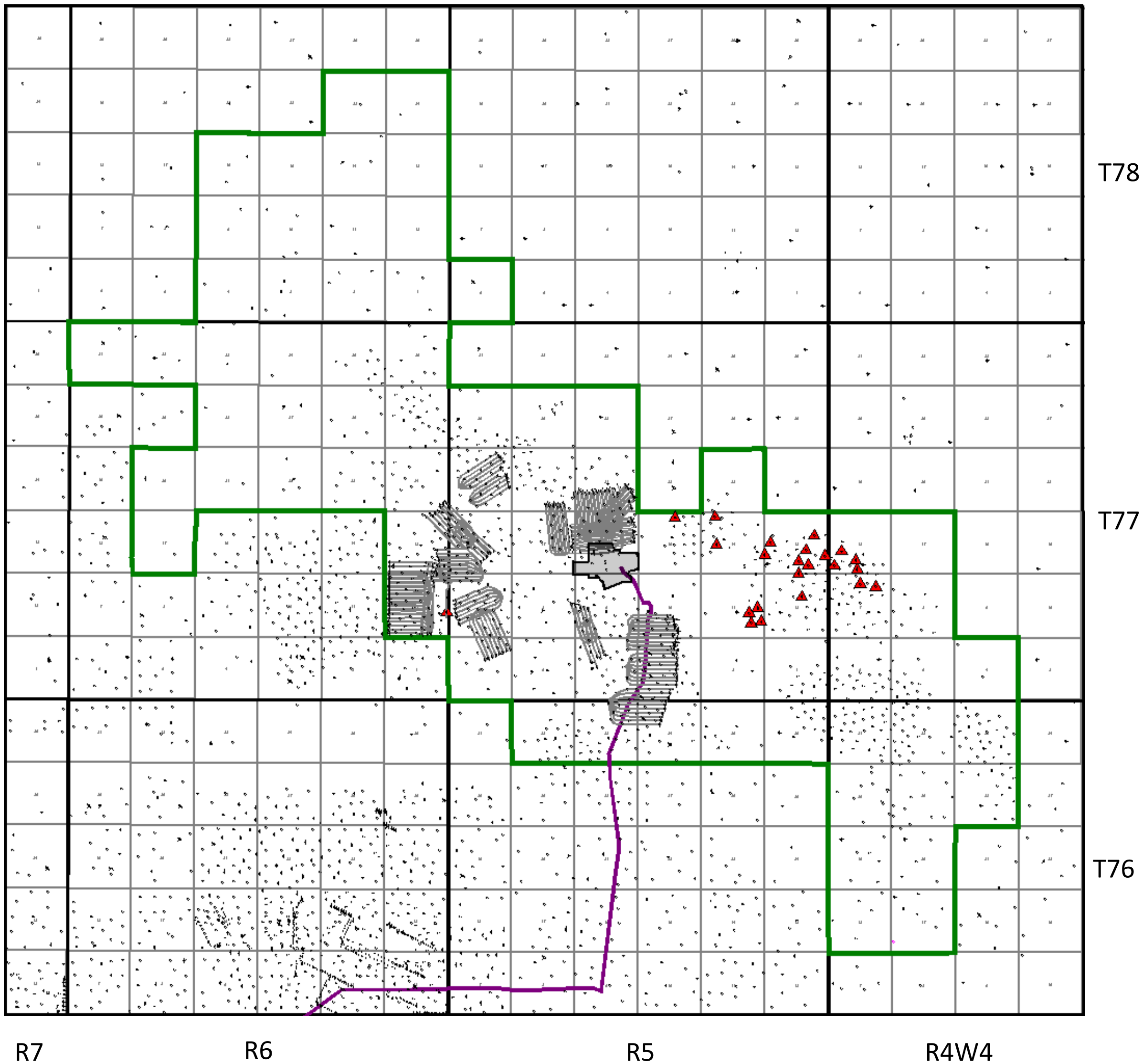
CLRP 2016 Stratigraphic Test Wells



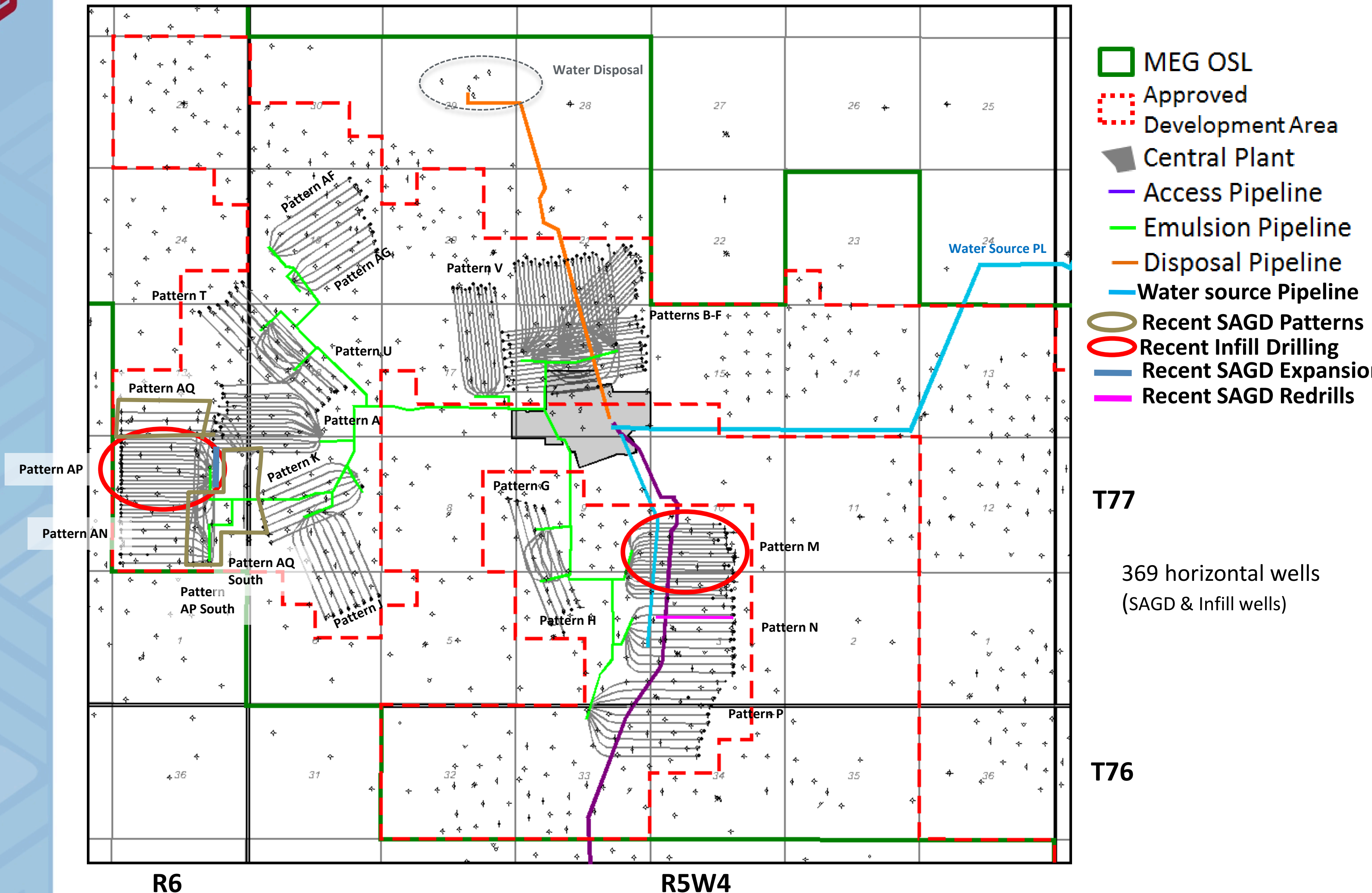
CLRP Project Area

2017 Wells

Over the 2017 reporting period

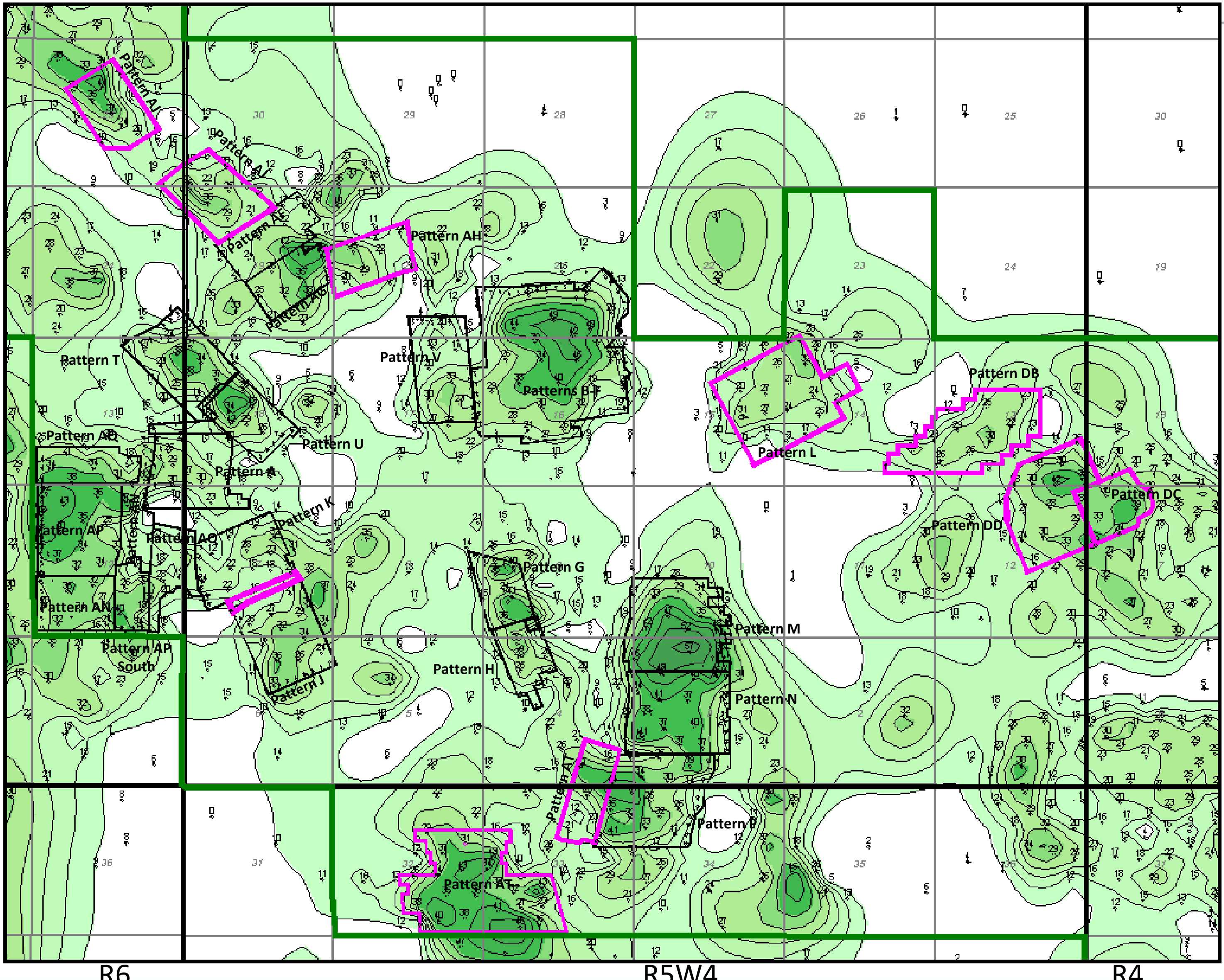
- 23 coreholes were drilled.
- No special core analysis was done.
- No GeoMechanical analysis was done.
- No reservoir Fracture pressure or Caprock Integrity tests were done.

CLRP Active Development Area (ADA)



369 horizontal wells
(SAGD & Infill wells)

CLRP: OBIP Approved Development Areas



CLRP Project Area

SAGD Patterns

Approved Patterns

T77

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

T76

min contour =10m
contour interval = 5 m

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Note: Figure represents MEG Energy volumetric estimates, not independent estimates from GLJ Petroleum Consultants.

Well Spacing

Pattern	Operating Wellpairs	Average Spacing Between SAGD Pairs (m)	Average Spacing Between SAGD Pair to Infill (m)
A	8	100	50
B	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
H	3	100	NA
J	8	100	NA
K	7	100	NA
M	10	100	50
N	9	100	NA
T	8	100	NA
U	6	100	NA
AP West	10	100	50
AP South	3	112	65
AF	5	100	NA
AG	5	100	NA
AN	8	100	50
P	10	100	NA
Total	143		

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Reservoir

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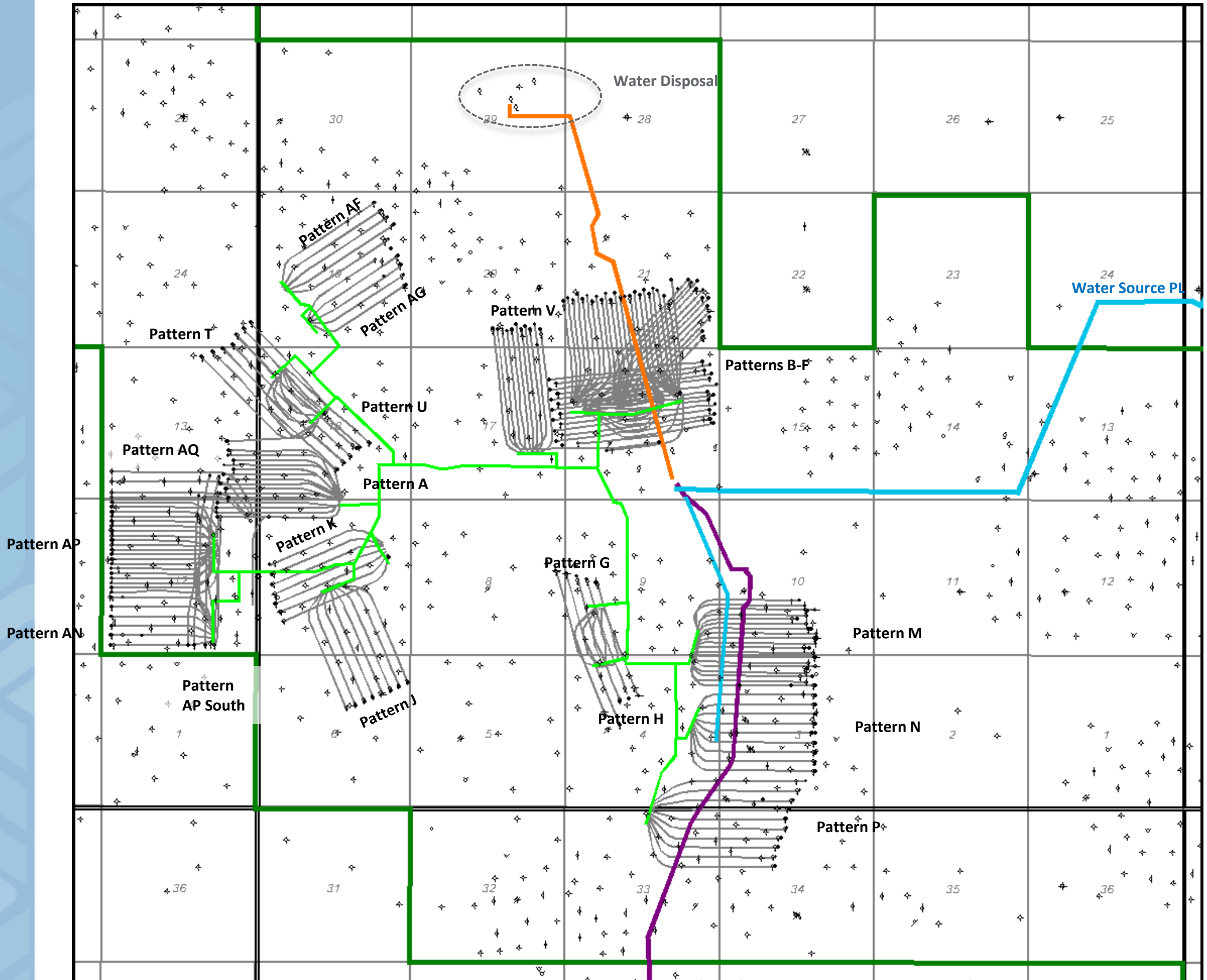
Scheme Performance

CLRP Pattern Layout



R6

R5W4

MEG OSL

Approved Development Area

Central Plant

Access Pipeline

Emulsion Pipeline

Disposal Pipeline

Water source Pipeline

Operating Wells (04/17)

T77

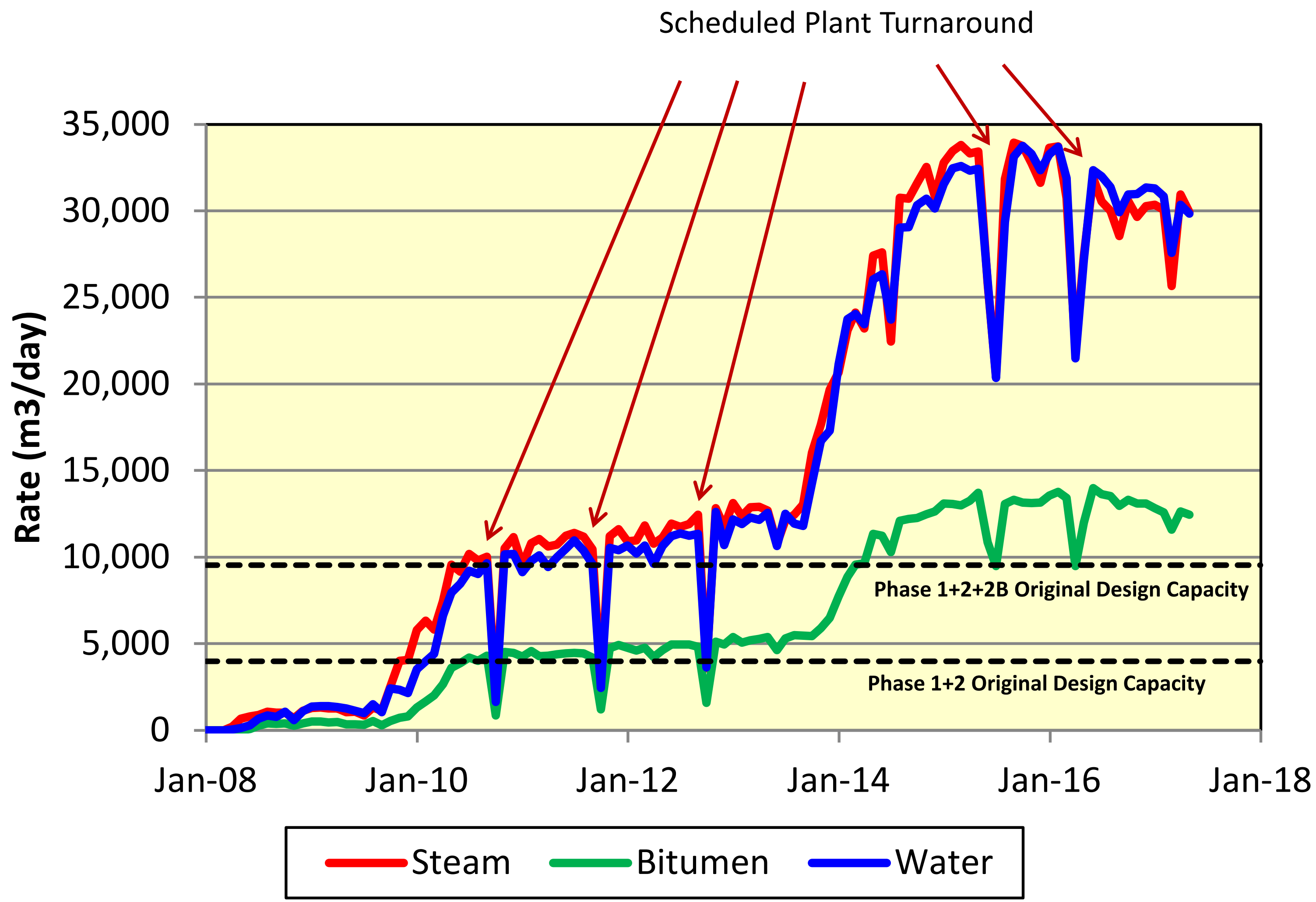
T76

Pattern	SAGD WPs	Infill Wells
A	8	7
B	2	3
BB	7	6
C	7	7
D	5	5
E	7	7
F	5	4
G	4	
H	3	
J	8	
K	7	
M	10	
N	9	
P	10	
T	8	
U	6	
V	6	6
AF	5	
AG	5	
AN	8	1
AP	13	11
Total	143	57

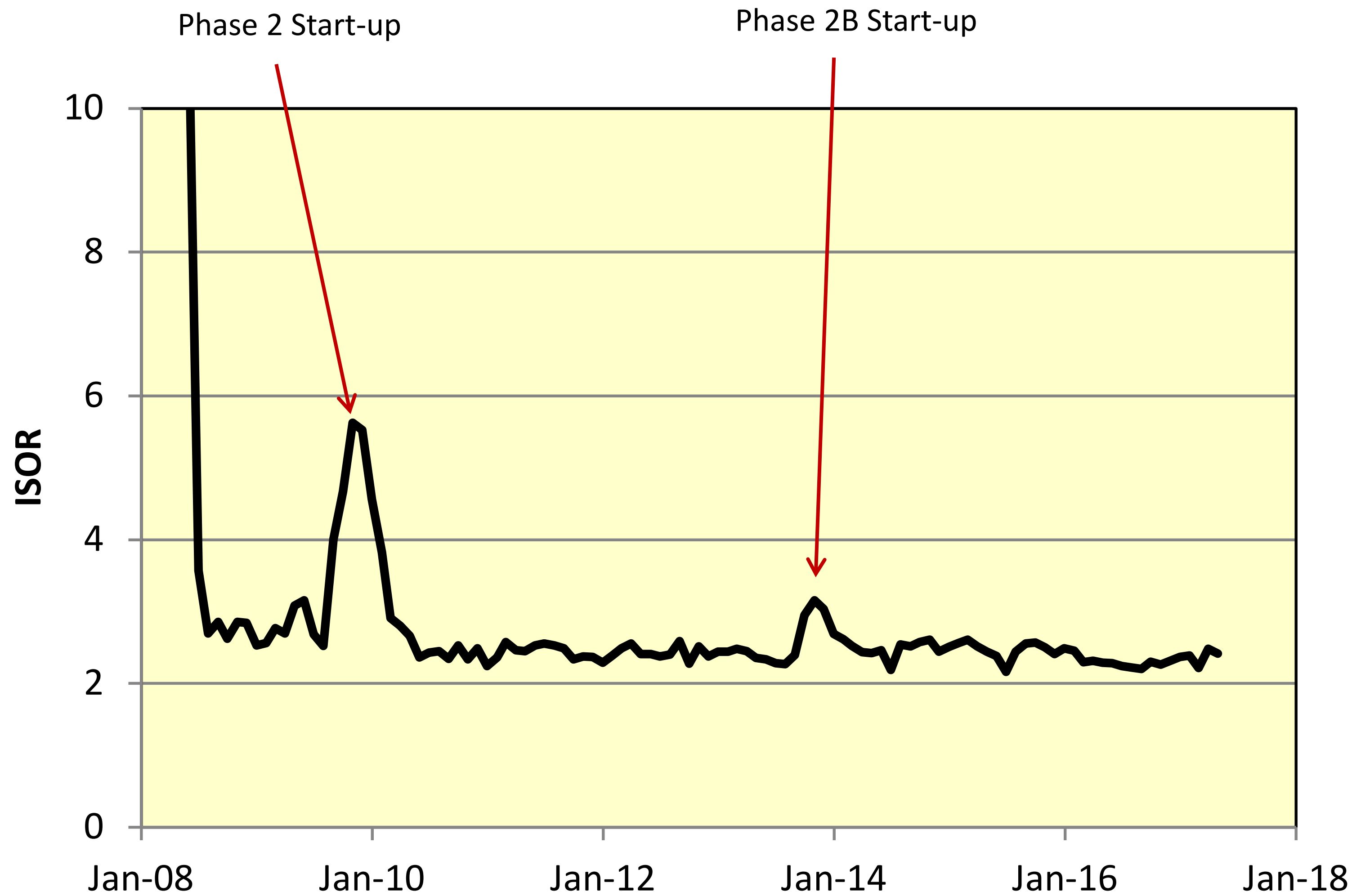
CLRP Reservoir Performance

- 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 m^3/d (25,000 bopd) by late April 2010.
- Phase 2B production ramp-up bettered Phase 2. Total production reached 11,340 m^3/d (71,300 bopd) in Q2 2014, far exceeded the combined original design capacity of 9,539 m^3/d (60,000 bpd).
- Production averaged 81,245 bopd in 2016. In Q1 2017, MEG achieved quarterly production of 77,309 bopd, a period which included some unplanned down time. April production averaged 78,245 bpd.
- The SOR of CLRP has ranged from 2.2 to 2.5 over the last 12 months and averaged 2.3 with new well start-ups.
- Current steam chamber pressure is between 2,160 and 2,350 kPag for Phases 1 and 2, between 2,300 and 3,450 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present.

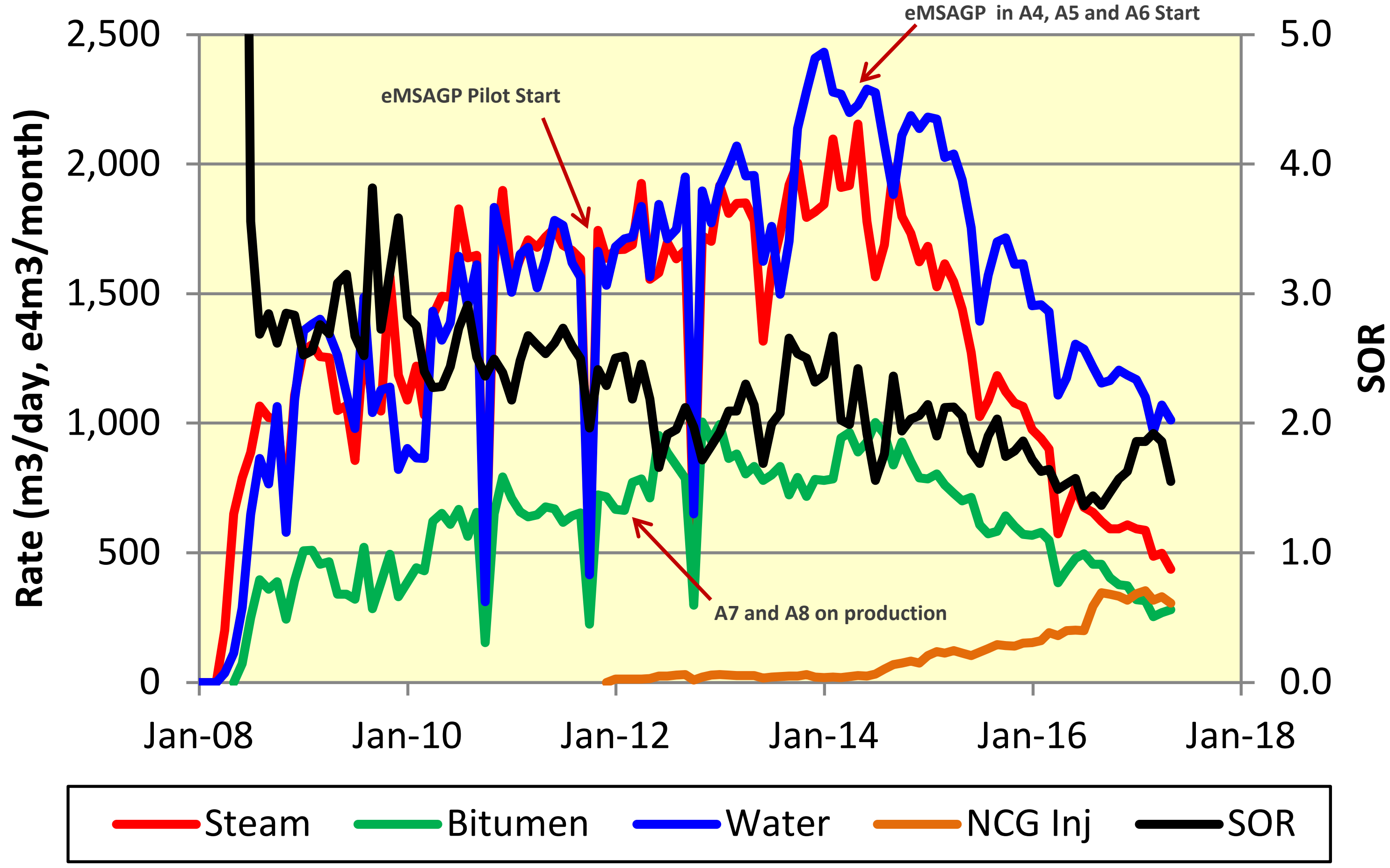
CLRP Production Performance



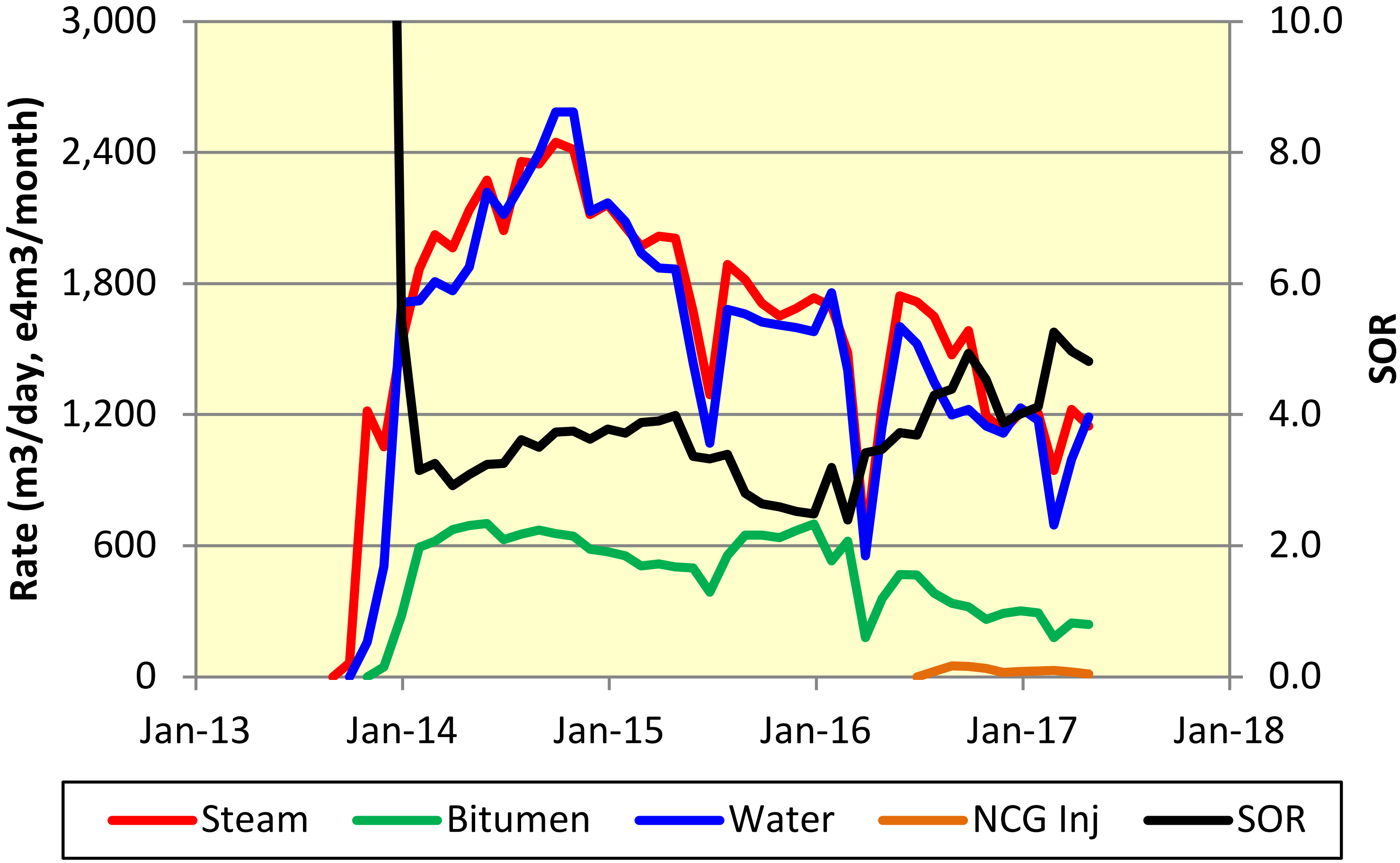
CLRP Performance – SOR of All Patterns



CLRP Performance – Pattern A

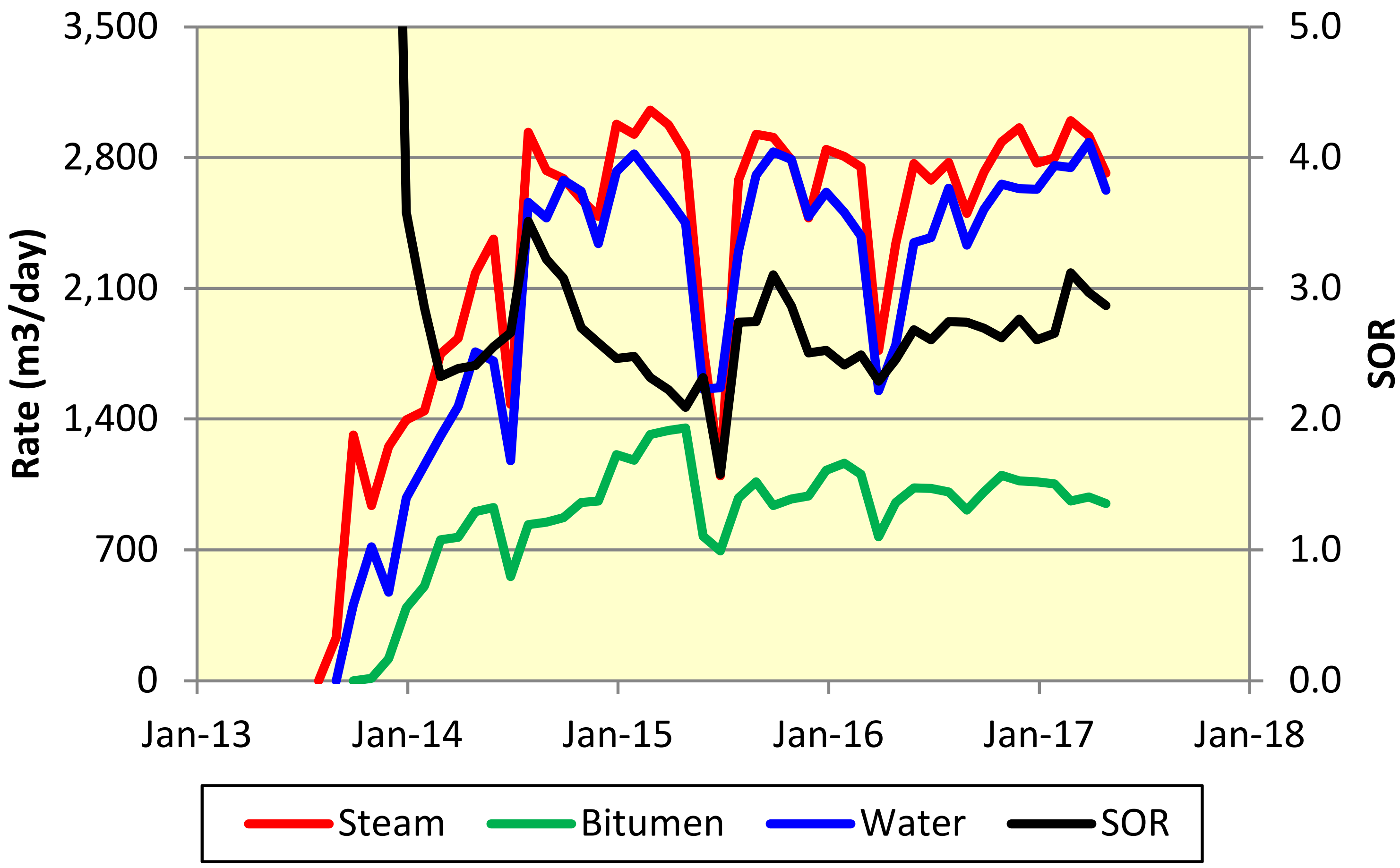


CLRP Performance – Pattern K



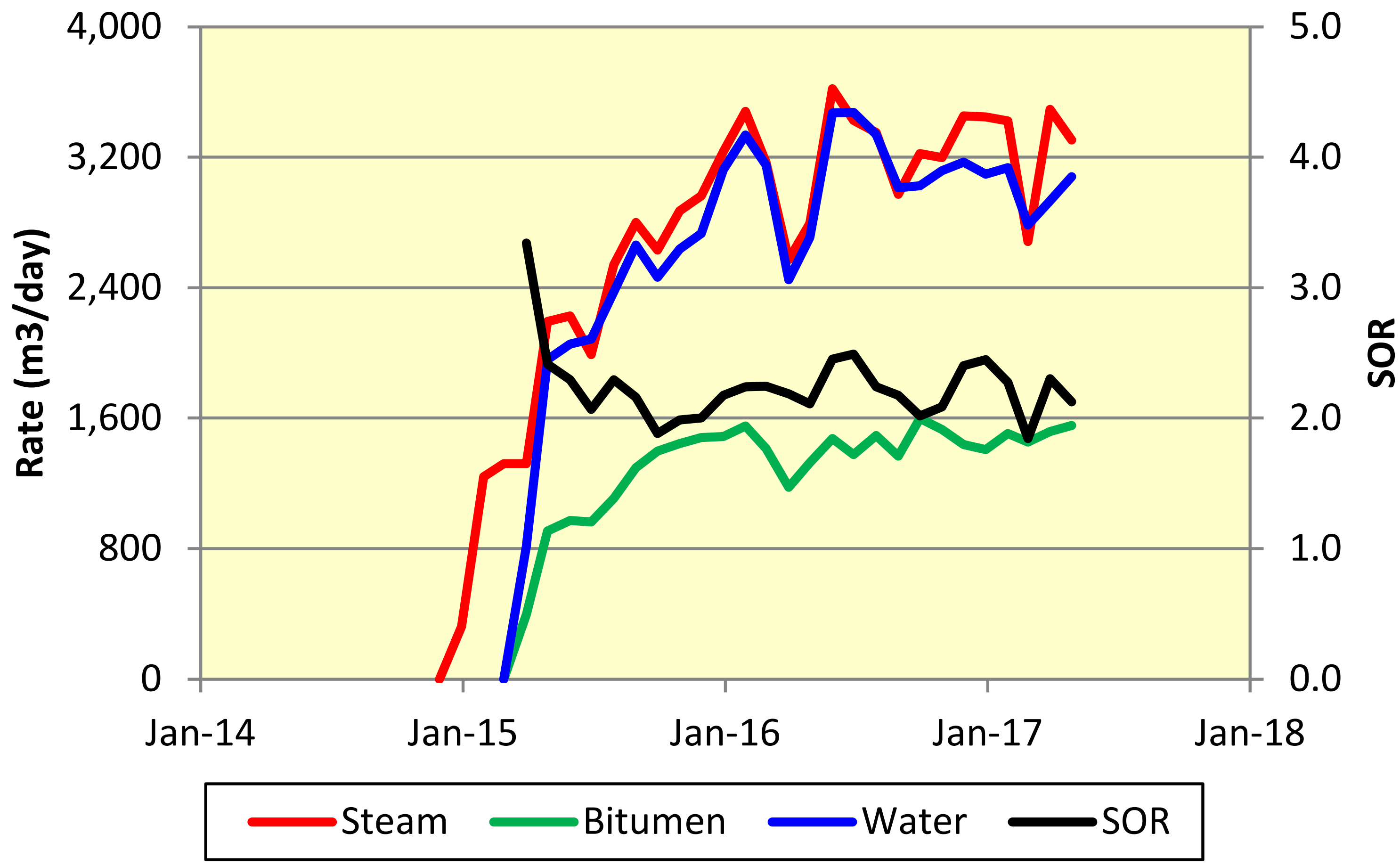
Low Performance Pad: Due primarily to injectors being drilled lower than planned making it difficult to control vapor production near heel. Well work-over to isolate the heel section of one injector resulted in better performance is expected following similar upcoming work-overs.

CLRP Performance – Pattern N



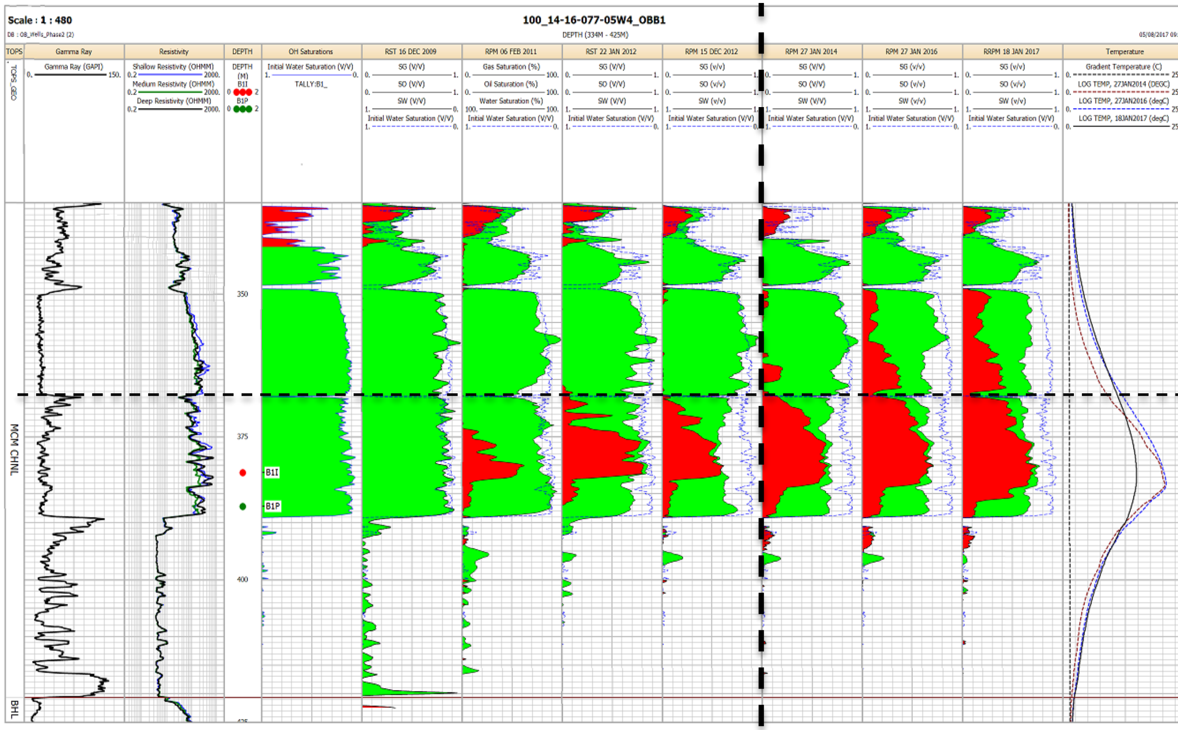
Medium Performance Pad: SAGD pay is under an associated gas cap and above bottom water. There has been no particular challenge in operating this pad to date.

CLRP Performance – Pattern AN



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.

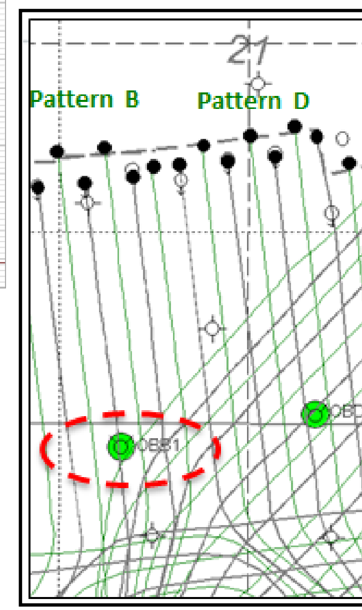
OBB1 Logging Results



Sandy IHS

Before NCG Co-injection
~3.5 years SAGD

After NCG Co-injection
~4.1 years eMSAGP



Vertical chamber growth through IHS is observed after co-injection of NCG

Bitumen Recovery

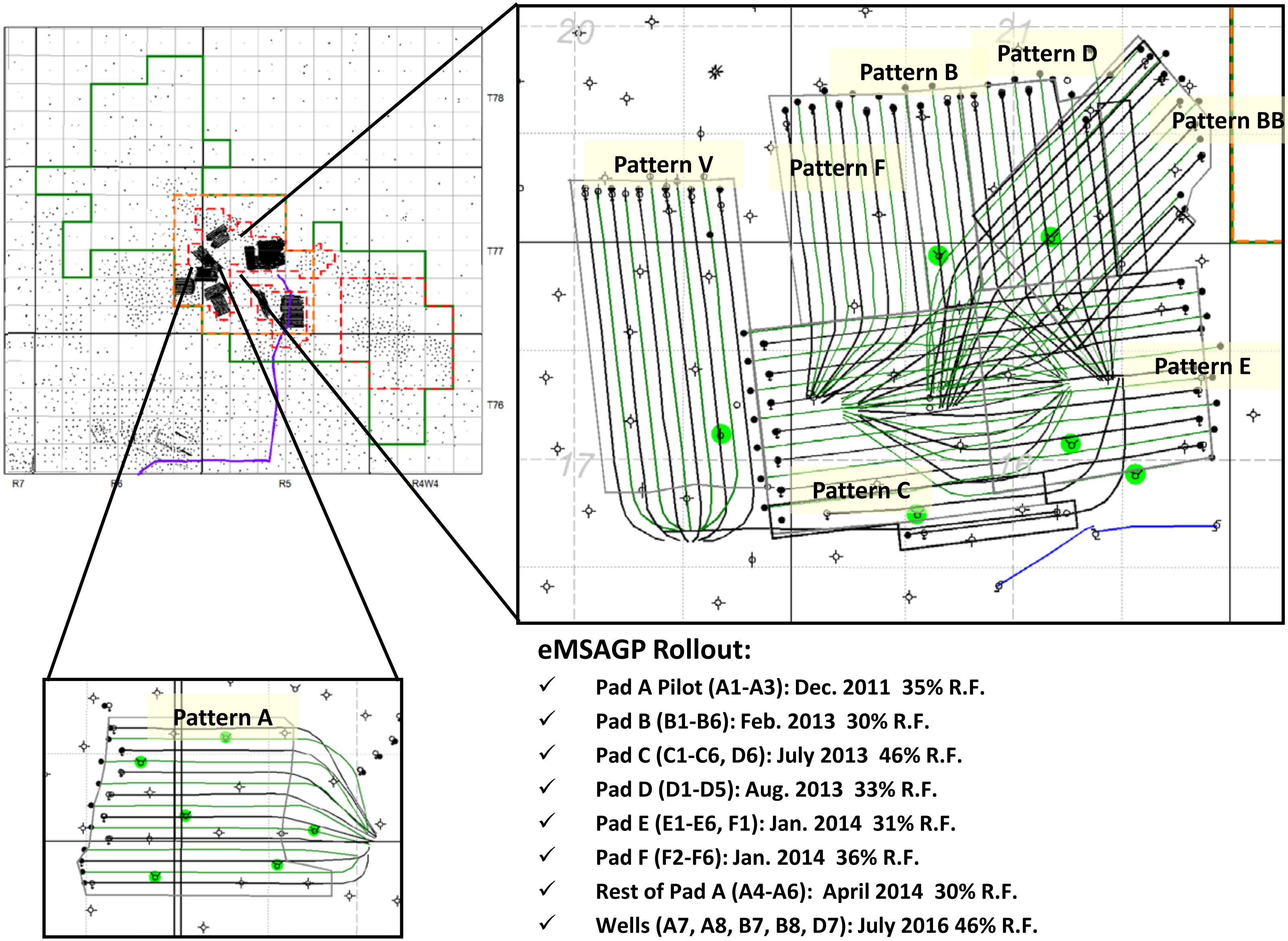
Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	SAGDable BIP (m^3)	Ultimate Recovery (m^3)	Cumulative Production (m^3)	Recovery to Date (%SAGDable)
A*	8	20	874	0.32	0.76	3,501,000	1,925,550	2,011,170	57.4%
B*	2	26	744	0.33	0.84	1,078,000	592,900	747,081	69.3%
BB+D7*	7	18	808	0.32	0.82	2,680,000	1,474,000	1,509,621	56.3%
C+D6*	7	26	841	0.33	0.76	4,090,000	2,249,500	3,126,650	76.4%
D-D6-D7*	5	18	678	0.34	0.81	1,686,000	927,300	1,027,547	60.9%
E+F1*	7	19	861	0.33	0.77	2,927,000	1,609,850	1,941,875	66.3%
F-F1	5	19	776	0.33	0.78	1,867,000	1,026,850	1,107,503	59.3%
V*	6	24	1084	0.31	0.73	3,479,000	1,913,450	853,541	24.5%
G	4	14	759	0.33	0.71	1,025,000	563,750	215,974	21.1%
H*	3	12	692	0.32	0.74	598,000	328,900	92,362	15.4%
J	8	18	986	0.33	0.76	3,592,000	1,975,600	571,574	15.9%
K	7	18	955	0.33	0.75	2,996,000	1,647,800	617,918	20.6%
M	10	27	998	0.32	0.75	6,469,000	3,557,950	1,674,717	25.9%
N	9	23	1054	0.33	0.81	5,887,000	3,237,850	1,200,709	20.4%
T*	8	13	980	0.31	0.81	2,570,000	1,413,500	462,595	18.0%
U	6	16	882	0.3	0.8	2,033,000	1,118,150	437,826	21.5%
AP West*	10	27	918	0.33	0.83	6,813,000	3,747,150	1,962,269	28.8%
AP South**	3	21	727	0.33	0.79	1,356,000	745,800	0	0.0%
AF	5	18	972	0.32	0.82	2,278,000	1,252,900	467,782	20.5%
AG*	5	20	836	0.33	0.77	2,095,000	1,152,250	249,785	11.9%
AN	8	23	870	0.32	0.83	4,187,000	2,302,850	1,054,568	25.2%
P**	10	20	957	0.32	0.76	4,655,000	2,560,250	430,395	9.2%
Total	**143**					**67,862,000**	**37,324,100**	**21,763,464**	**32.1%**

Note: Cumulative production to April, 2017
h is net pay: SAGD base to SAGD Top
L is liner length (including blanks) with 50m added to each end (100m total)
* Updated in May 2017
** New 2017

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.

Enhanced Modified Steam and Gas Push

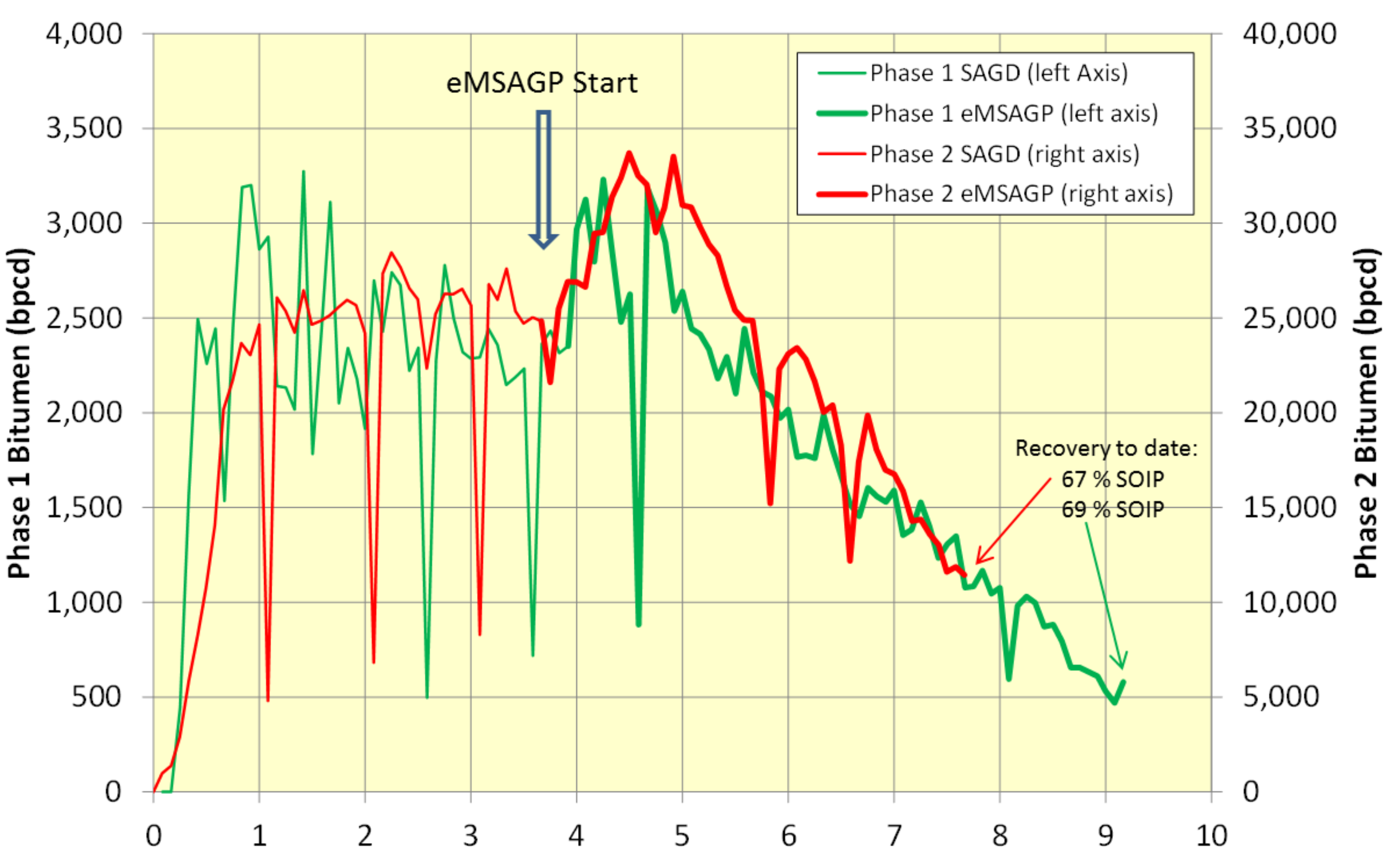
Phase 1 and Phase 2 Pad Layout



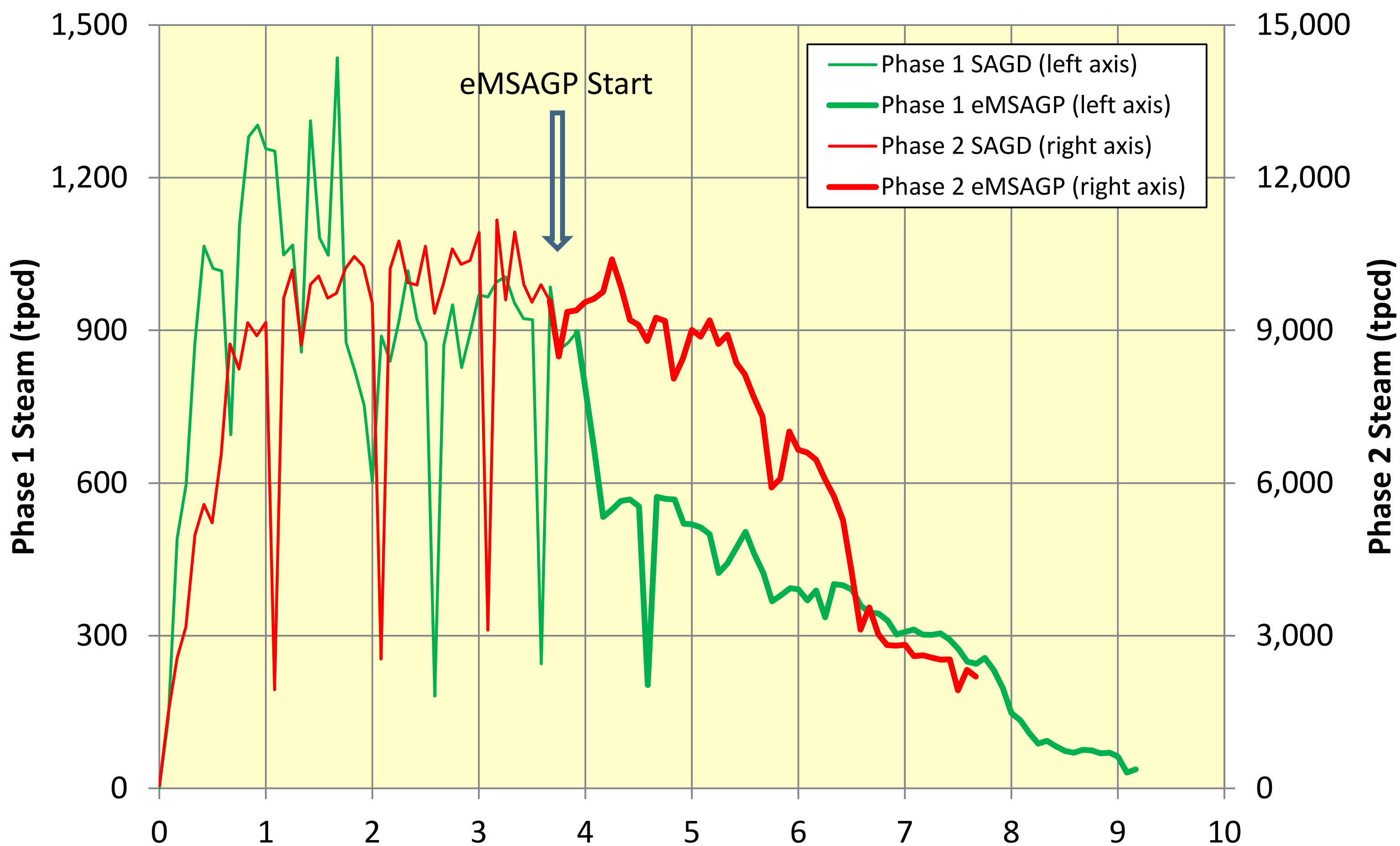
eMSAGP Rollout:

- ✓ Pad A Pilot (A1-A3): Dec. 2011 35% R.F.
- ✓ 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.

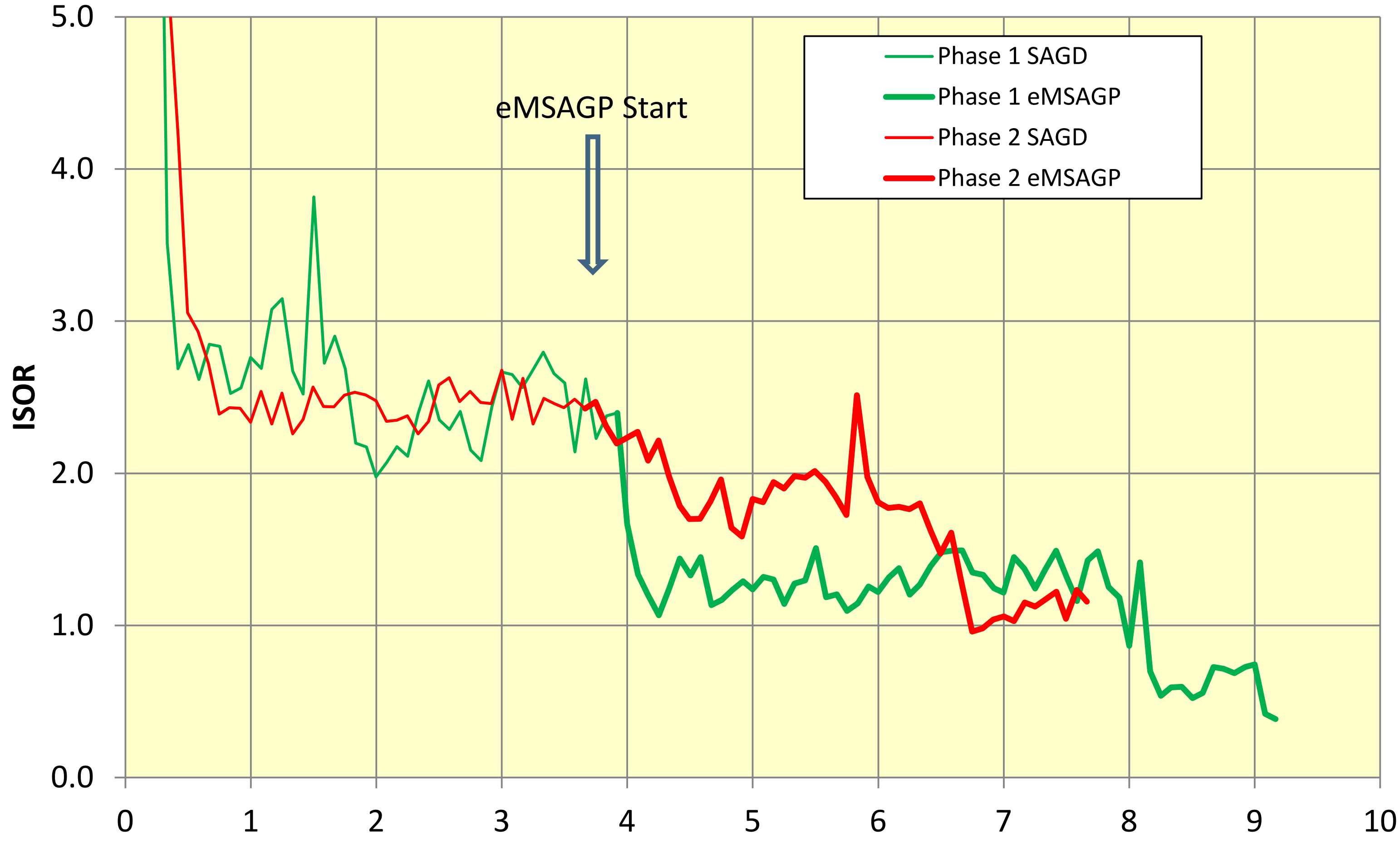
Bitumen Rates for Phases 1 and 2



Steam Rates for Phases 1 and 2



SOR for Phases 1 and 2



Summary of eMSAGP Development

- In 5.5 years of eMSAGP (9+ years total), the pilot demonstrated consistent and very satisfactory performance. Higher bitumen production and recovery were achieved at a much lower SOR, averaging 0.60 over the period. Recovery to April 2017 was 69% of the revised SAGDable OOIP.
- From the initiation of B Pattern eMSAGP in Feb 2013, Phase 2 eMSAGP showed repeatable performance. ISOR over the reporting period was 1.09. Bitumen recovery reached 67% of the revised SAGDable OOIP.
- After several years of operation, eMSAGP has demonstrated better performance than SAGD: better recoveries with significant SOR reductions.
- Steam freed up from eMSAGP process has been redeployed to new SAGD wells to increase overall production beyond original nameplate capacity without installing additional steam capacity.
- Opportunities exist to optimize the timing of eMSAGP implementation and the rate of steam reduction.

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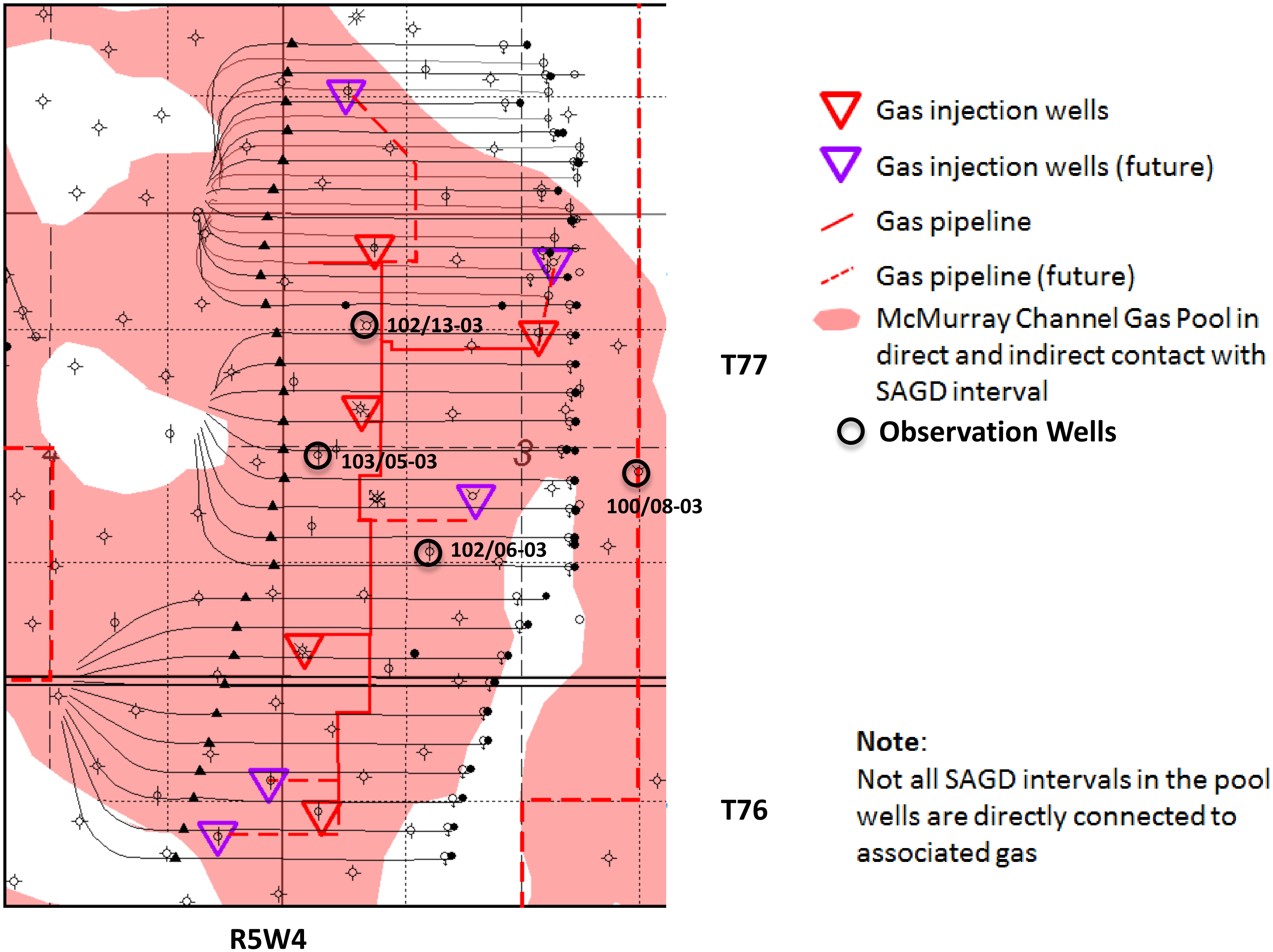
Gas Cap Re-pressuring

Gas Cap Re-pressuring Project Update

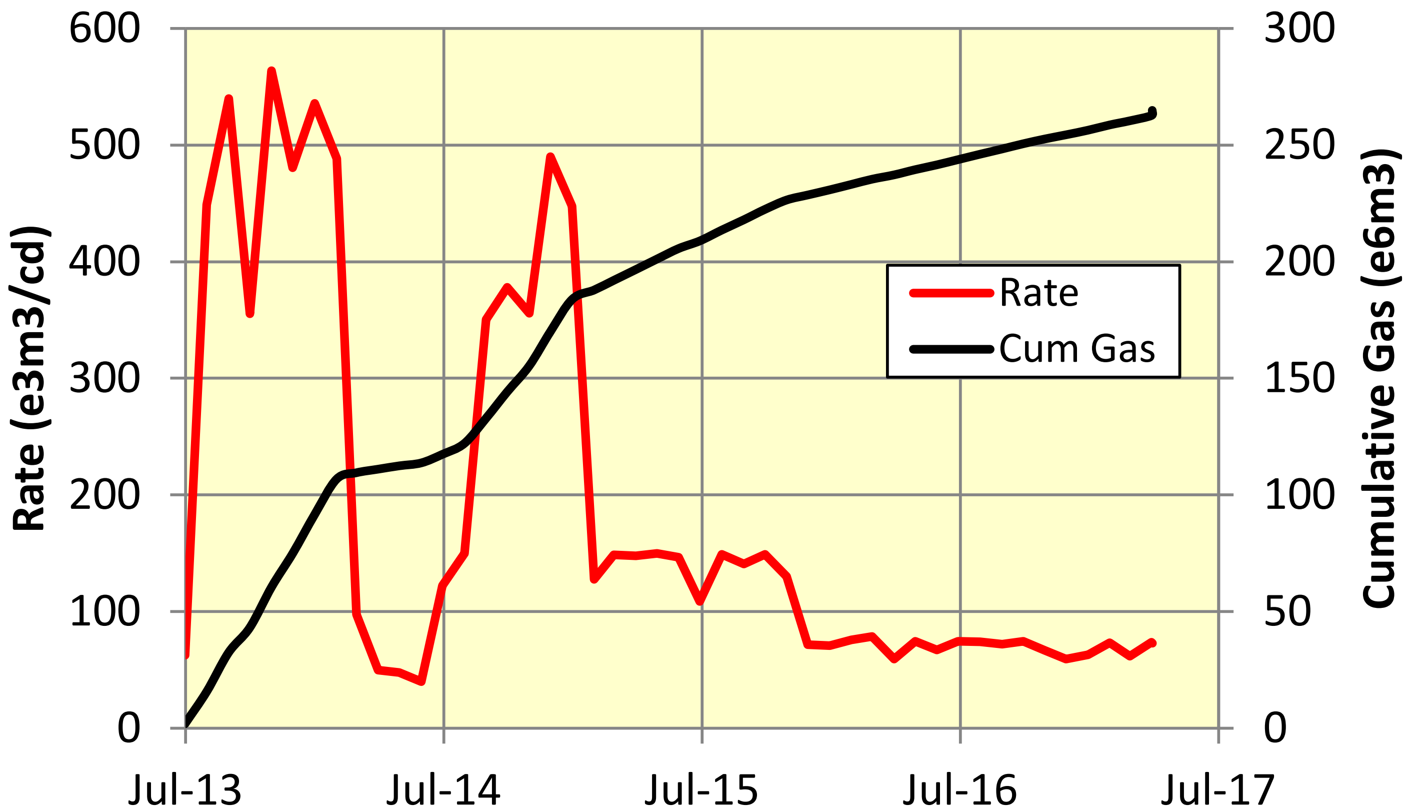
- The AER approval was granted in November 2012
- Natural gas injection into 5 wells commenced in June 2013
- Total injection to date was 265 e6m3 (~9.4 BCF), with an average injection rate of 70 e3m3/day (~2.5 mmscf/day) over the period
- Pressure responses have been observed in all 5 monitoring wells
- 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
- Thief zone effect of the gas cap has not been observed to date

CLRP Gas Cap Re-pressure (Patterns M, N & P)

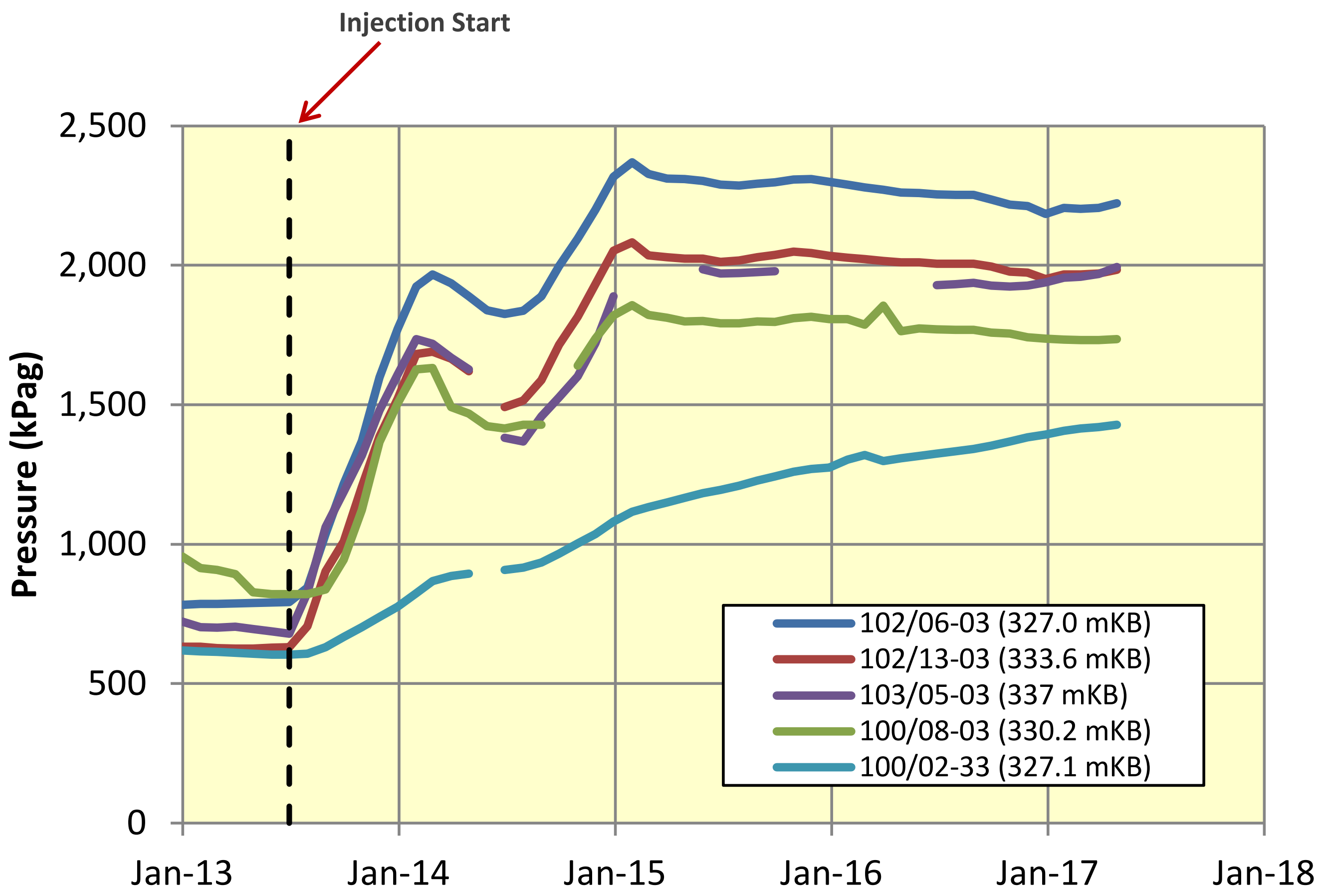


Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

Total Gas Injection



Observation Well Pressure Readings



The 100/02-33 well is roughly 1,600 meters away from the active injection/SAGD area

Unresolved Emulsion Injection

Unresolved Emulsion Overview

- Pilot project to proceed with the injection of unresolved emulsion into an active steam chamber limited to well pair V6
  - Plan would result in significant annual cost savings
  - Reduced truck traffic and emissions
  - Utilizing an existing wellpad (no additional surface disturbances)
- 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
  - In 2015, 774 round trips were made to ship the unresolved emulsion to approved third party processing facilities (>850 km round trip per load)
  - The fluid is loaded into a vacuum truck at the CPF from storage tanks and a surface loading station located at the wellhead is used to pump fluid downhole
- V6I selected because of low oil production rate and poor reservoir quality, which limits the risk of any potential production impacts
  - Downhole temperatures into V6I are hot, which will aid in separating the unresolved emulsion
  - Located at the edge of the Pattern, limiting the potential impact to other producers
- Scheme Amendment Approved on September 26, 2016

Unresolved Emulsion Overview

- Date of first injection: December 15, 2016
- Average monthly volumes injected:
  - December 2016 = 52 m^3 (includes 10 m^3 hot water for flushing)
  - January 2017 = 187 m^3 (includes 22 m^3 hot water for flushing)
  - February 2017 = 0 m^3
  - March 2017 = 0 m^3
  - April 2017 = 44 m^3 (includes 14 m^3 hot water for flushing)
- Total volume injected to date = 283 m^3 (includes 46 m^3 hot water for flushing; 237 m^3 unresolved emulsion)
  - Successfully pumped 237 m^3 unresolved emulsion into V6I
  - April injection commingled with steam down short tubing string
  - Demonstrated improved bottom hole pressure response due to better viscosity (higher bottom hole temperatures)
- Routine Intermediate Casing Point (ICP) water analysis
  - Pre-job vs. 3 separate post job samples 3 hr, 6 hr, 48 hr
  - Showed no changes indicating no cross flow of fluids from V6I to V6P
- MEG plans to continue injecting unresolved emulsion into V6I as required
  - V6P and V6N continue to trend on previous decline curve projections

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Future Plans

Regulatory Activity

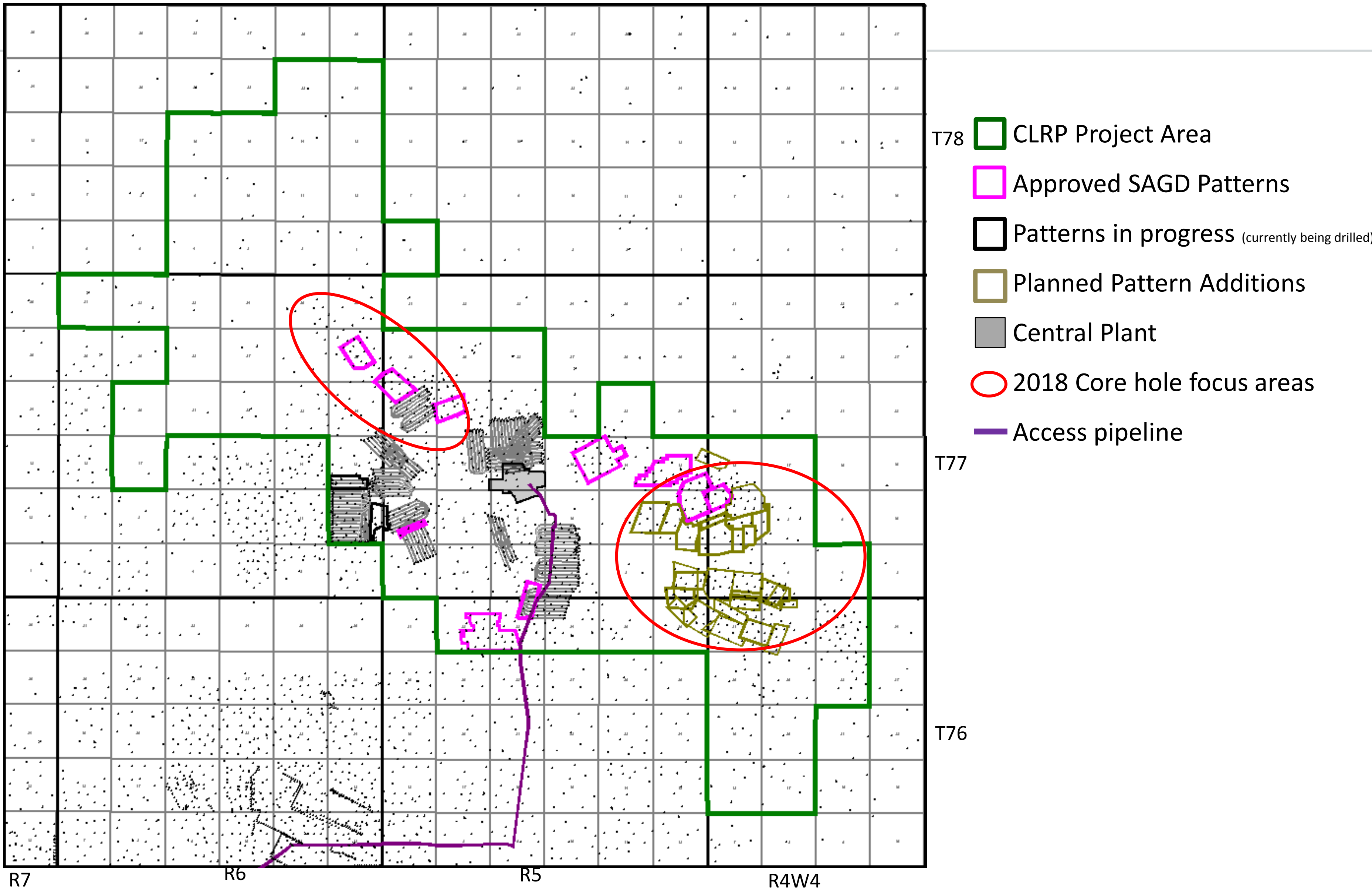
April 2016 - April 2017

- Various Directive 56 licenses and amendments for well pads and field facilities
- Sub-surface reconfiguration scheme amendments for patterns AQ, AT, L, and DB
- Expansion of NCG Co-Injection (eMSAGP) for patterns G, H, J, K, T, U, AF, AG, M, N, AP, AN, and P
- Unresolved emulsion injection project on well pair V6

April 2017 - April 2018

- Scheme amendment applications for sustaining patterns including AH, DC, and DD.
- New Pattern application for DG
- Scheme amendment application for gas cap repressurization

CLRP Future Development



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