MEG ENERGY

Christina Lake Regional Project

2014/2015 Performance Presentation
Commercial Scheme Approval No. 10773

June 16
2015

Disclaimer

This presentation is not, and under no circumstances is to be construed to be a prospectus, offering memorandum, advertisement or public offering of any securities of MEG Energy Corp. (“MEG”). Neither the United States Securities and Exchange Commission (the “SEC”) nor any other state securities regulator nor any securities regulatory authority in Canada or elsewhere has assessed the merits of MEG’s securities or has reviewed or made any determination as to the truthfulness or completeness of the disclosure in this document. Any representation to the contrary is an offence.

Recipients of this presentation are not to construe the contents of this presentation as legal, tax or investment advice and recipients should consult their own advisors in this regard.

MEG has not registered (and has no current intention to register) its securities under the United States Securities Act of 1933, as amended (the “U.S. Securities Act”), or any state securities or “blue sky” laws and MEG is not registered under the United States Investment Act of 1940, as amended. The securities of MEG may not be offered or sold in the United States or to U.S. persons unless registered under the U.S. Securities Act and applicable state securities laws or an exemption from such registration is available. Without limiting the foregoing, please be advised that certain financial information relating to MEG contained in this presentation was prepared in accordance with Canadian generally accepted accounting principles, which differ from generally accepted accounting principles in the United States and elsewhere. Accordingly, financial information included in this document may not be comparable to financial information of United States issuers.

The information concerning petroleum reserves and resources appearing in this document was derived from a report of GLJ Petroleum Consultants Ltd. dated effective as of December 31, 2013, which has been prepared in accordance with the Canadian Securities Administrators National Instrument 51-101 entitled Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) at that time. The standards of NI 51-101 differ from the standards of the SEC. The SEC generally permits U.S. reporting oil and gas companies in their filings with the SEC, to disclose only proved, probable and possible reserves, net of royalties and interests of others. NI 51-101, meanwhile, permits disclosure of estimates of contingent resources and reserves on a gross basis. As a consequence, information included in this presentation concerning our reserves and resources may not be comparable to information made by public issuers subject to the reporting and disclosure requirements of the SEC.

There are significant differences in the criteria associated with the classification of reserves and contingent resources. Contingent resource estimates involve additional risk, specifically the risk of not achieving commerciality, not applicable to reserves estimates. There is no certainty that it will be commercially viable to produce any portion of the resources. The estimates of reserves, resources and future net revenue from individual properties may not reflect the same confidence level as estimates of reserves, resources and future net revenue for all properties, due to the effects of aggregation. Further information regarding the estimates and classification of MEG’s reserves and resources is available by contacting MEG’s investor relations department.

Anticipated netbacks are calculated by adding anticipated revenues and other income and subtracting anticipated royalties, operating costs and transportation costs from such amount.

Disclosure Advisories

Forward-Looking Information

Certain statements contained in this presentation constitute forward-looking statements. These statements relate to future events or MEG's future performance. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential" and "capable" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this presentation should not be unduly relied upon. These statements speak only as of the date of this presentation. In addition, this presentation may contain forward-looking statements and forward-looking information attributed to third party industry sources.

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

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

In addition, information and statements in this presentation relating to "reserves" and "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future.

The forward-looking statements included in this presentation are expressly qualified by this cautionary statement and are made as of the date of this presentation. MEG does not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities laws. For more information regarding forward-looking statements, please see "Risk Factors" and "Regulatory Matters" within the AIF.

MEG Energy Corp.

Meeting agenda

• **Overview**	Simon Geoghegan
• **Geosciences**	Greg Helman
• **Reservoir**	John Kelly
• **Operations**	Bill Mazurek
• **Water**	Scott Rayner
• **Compliance & Environment**	Mike Robbins
• **Future Plans**	Simon Geoghegan

MEG Energy Corp.

Who We Are

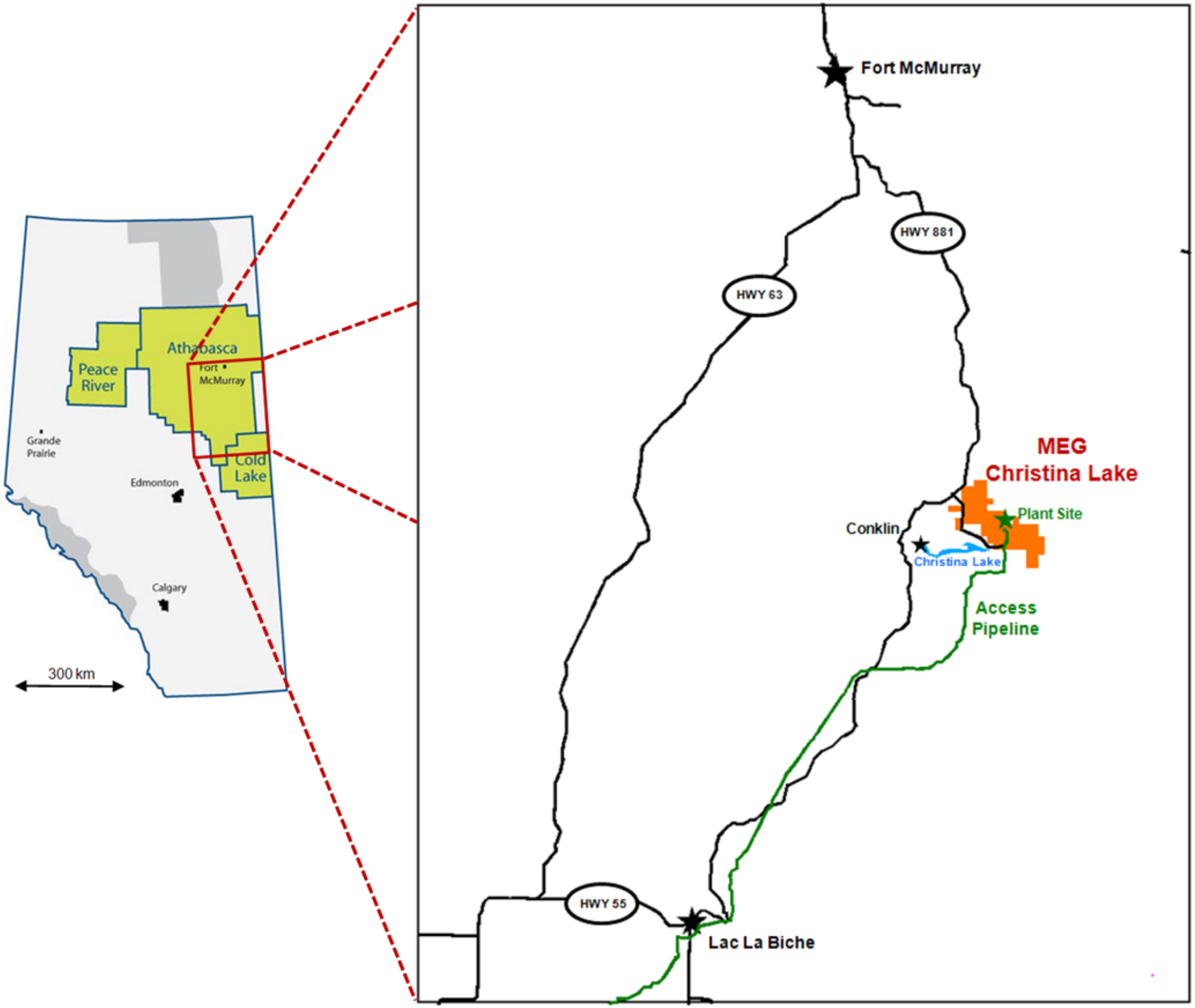
MEG Energy Corp. (MEG) is a public Calgary-based energy company focused on the development and recovery of bitumen and the generation of power in northeast Alberta.

MEG Energy Corp.

Who We Are

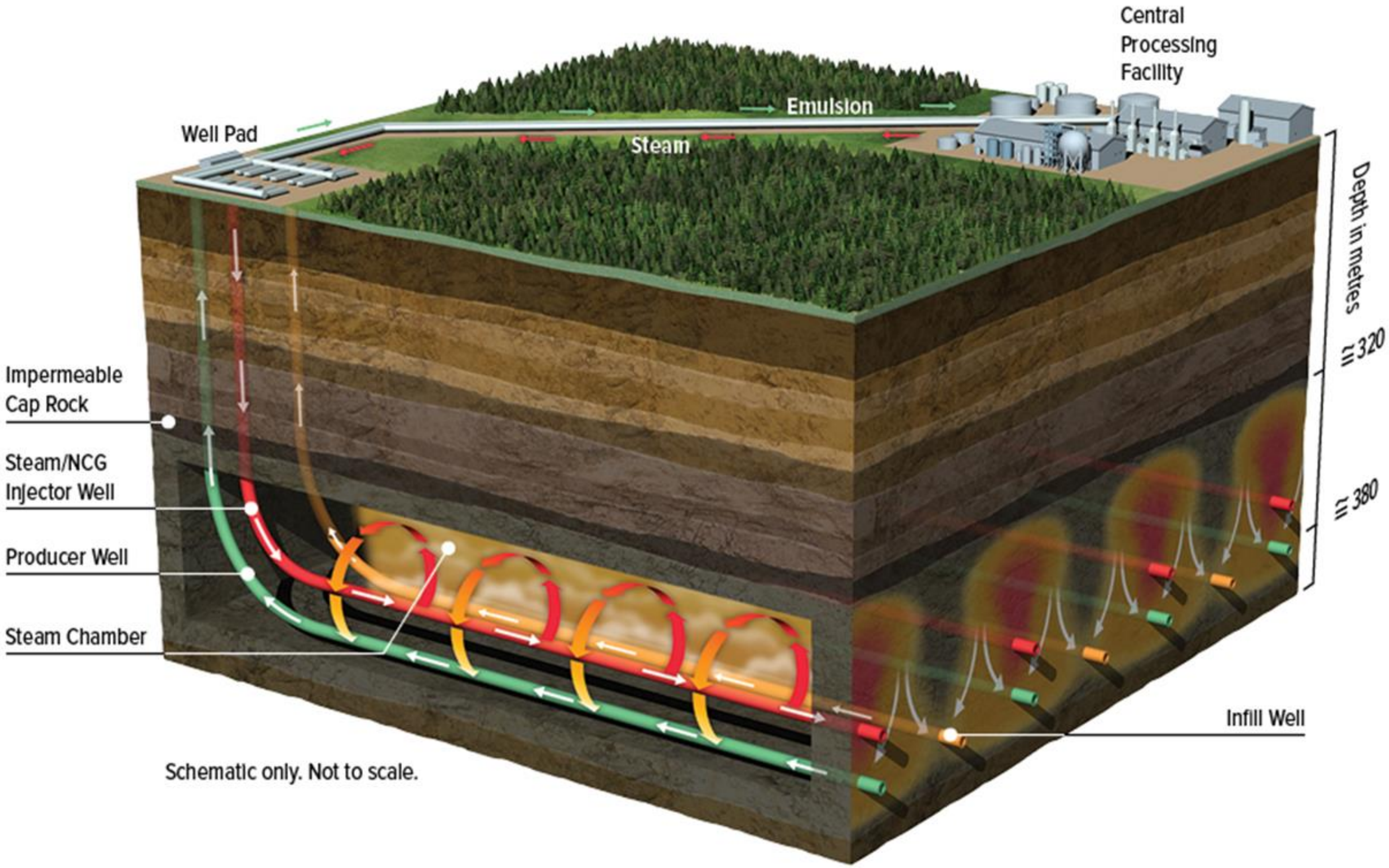
- Established in 1999
- Utilize steam-assisted gravity drainage (SAGD) technology to extract bitumen from the oil sands
- Operating Area– Christina Lake Project Phases 2 (includes Phase 1) and 2B
- 50%-ownership of the Access Pipeline

Christina Lake Regional Project (CLRP)



Steam-Assisted Gravity Drainage (SAGD)

An Efficient Technology



Christina Lake Regional Project

Project history

Phase 1

- Approved in February 2005 for bitumen production of 477 m^3/d (3,000 bpd)
- Sustained steaming commenced March 2008

Phase 2

- Approved in March 2007 for total production of 3,975 m^3/d or 25,000 bpd (incremental 3,523 m^3/d or 22,000 bpd)
- First steam Q3 2009
- Phase 1/2 pads: A, B, C, D, E, F, V

Phase 2B

- Approved plant expansion to 9,540 m^3/d or 60,000 bpd (incremental 5,540 m^3/d or 35,000 bpd)
- First steam Q3 2013
- Phase 2B pads: M, N, J, K, G, H, T, U, AP, AF, AG, AN

Phase 3

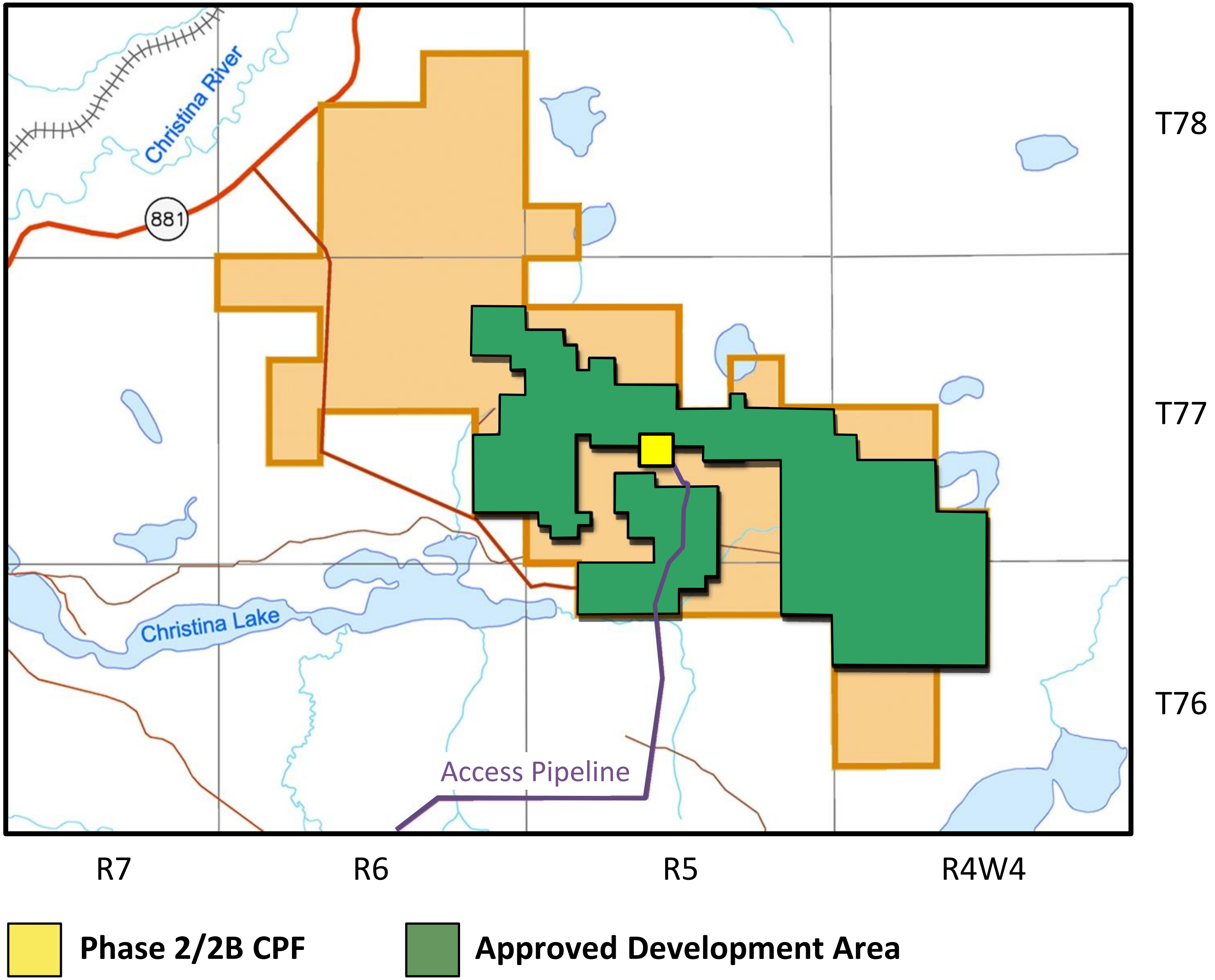
- Approval granted January 2012, expansion to 33,390 m^3/d or 210,000 bpd

Christina Lake Regional Project

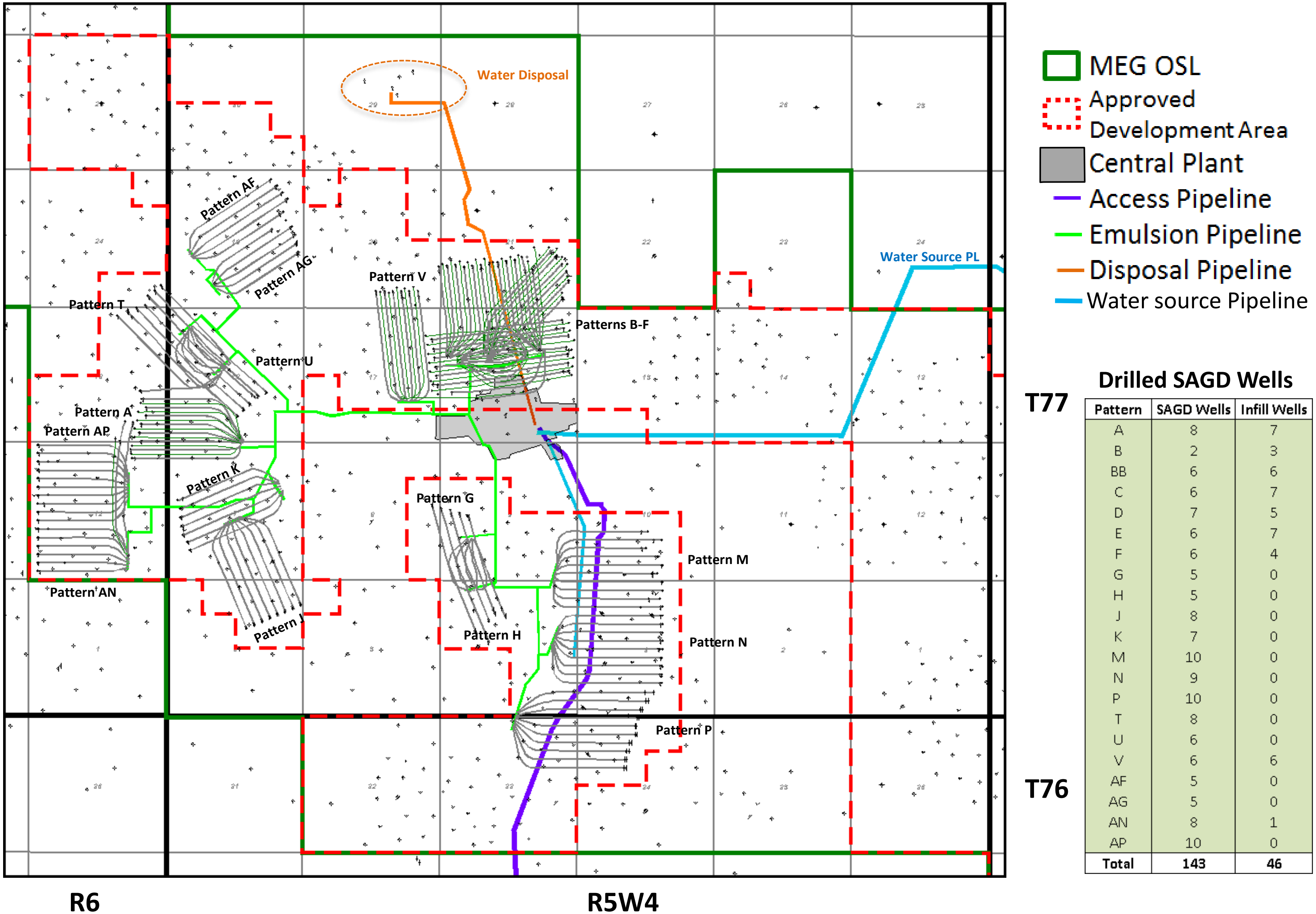
2014-2015 Operating Highlights

- 2014 bitumen production from both Phase 2 and 2B facilities averaged 71,186 bpd
- Q1 2015 bitumen production of 82,398 bpd and field wide SOR of 2.6
- Expanded implementation of eMSAGP

Christina Lake Regional Project (CLRP)



CLRP Active Development Area (ADA)



Drilled SAGD Wells

Pattern	SAGD Wells	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	0
N	9	0
P	10	0
T	8	0
U	6	0
V	6	6
AF	5	0
AG	5	0
AN	8	1
AP	10	0
Total	**143**	**46**

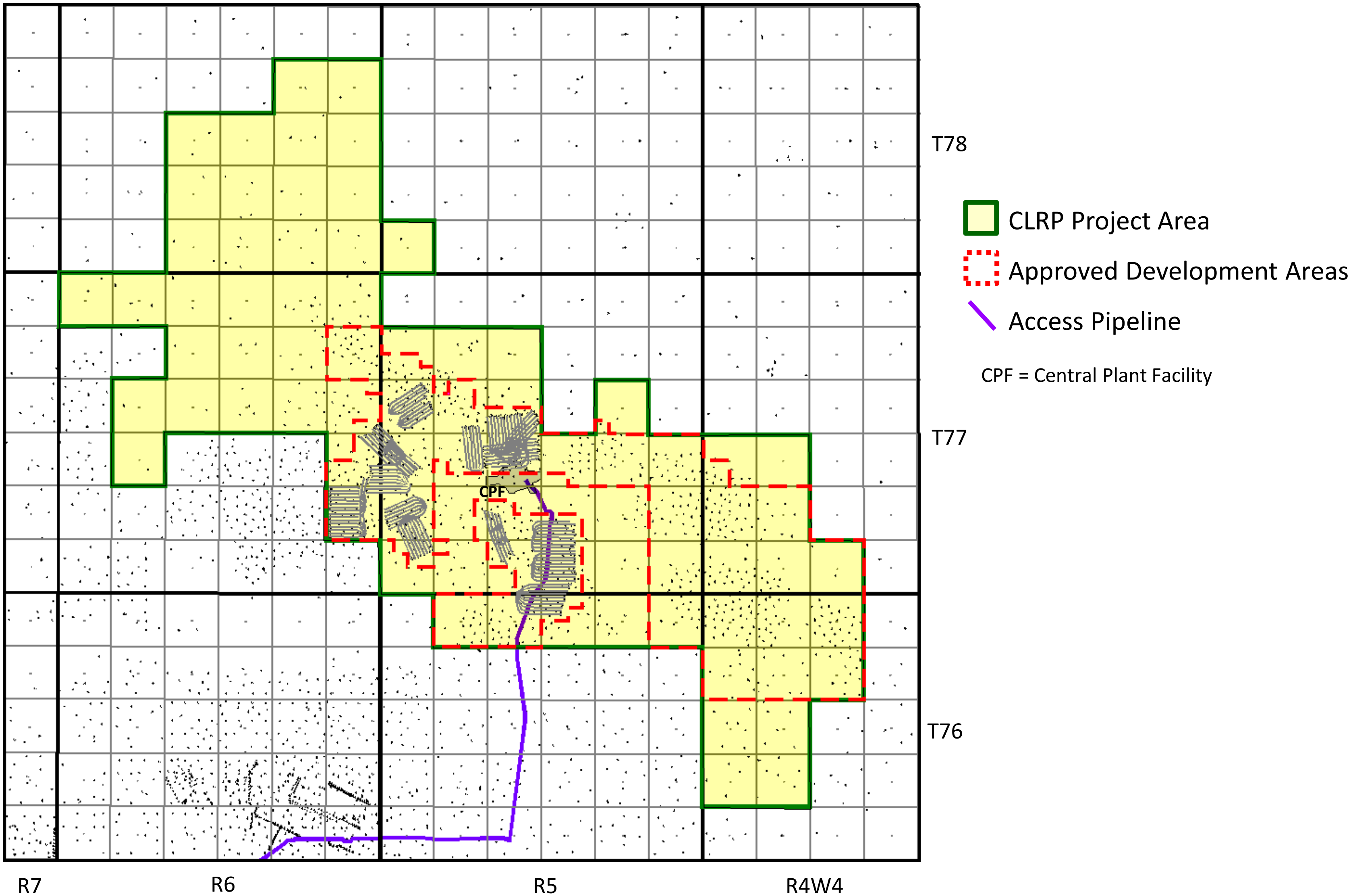
MEG ENERGY

Geosciences

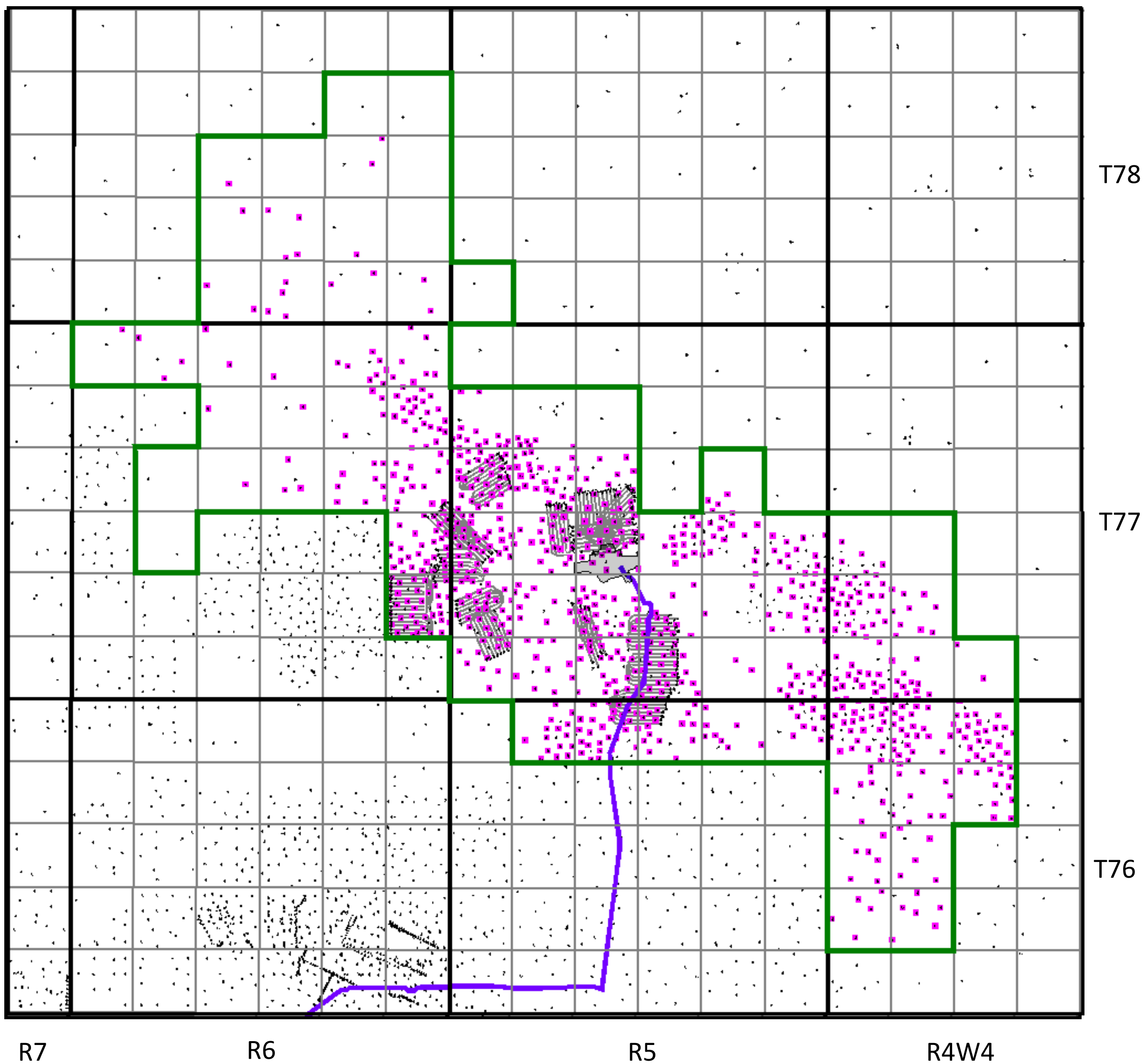
CLRP Geoscience Review

- Well and Seismic Data
- Stratigraphic Framework
- Reservoir and Pay Parameters
- Active Development Area Bitumen Pay
- SAGD Patterns
    - New SAGD Patterns for 2014
- McMurray Water Resources
- Cap Rock Geology
- Active Development Area Associated Gas Resources
- Legacy Wells

Christina Lake Regional Project (CLRP)

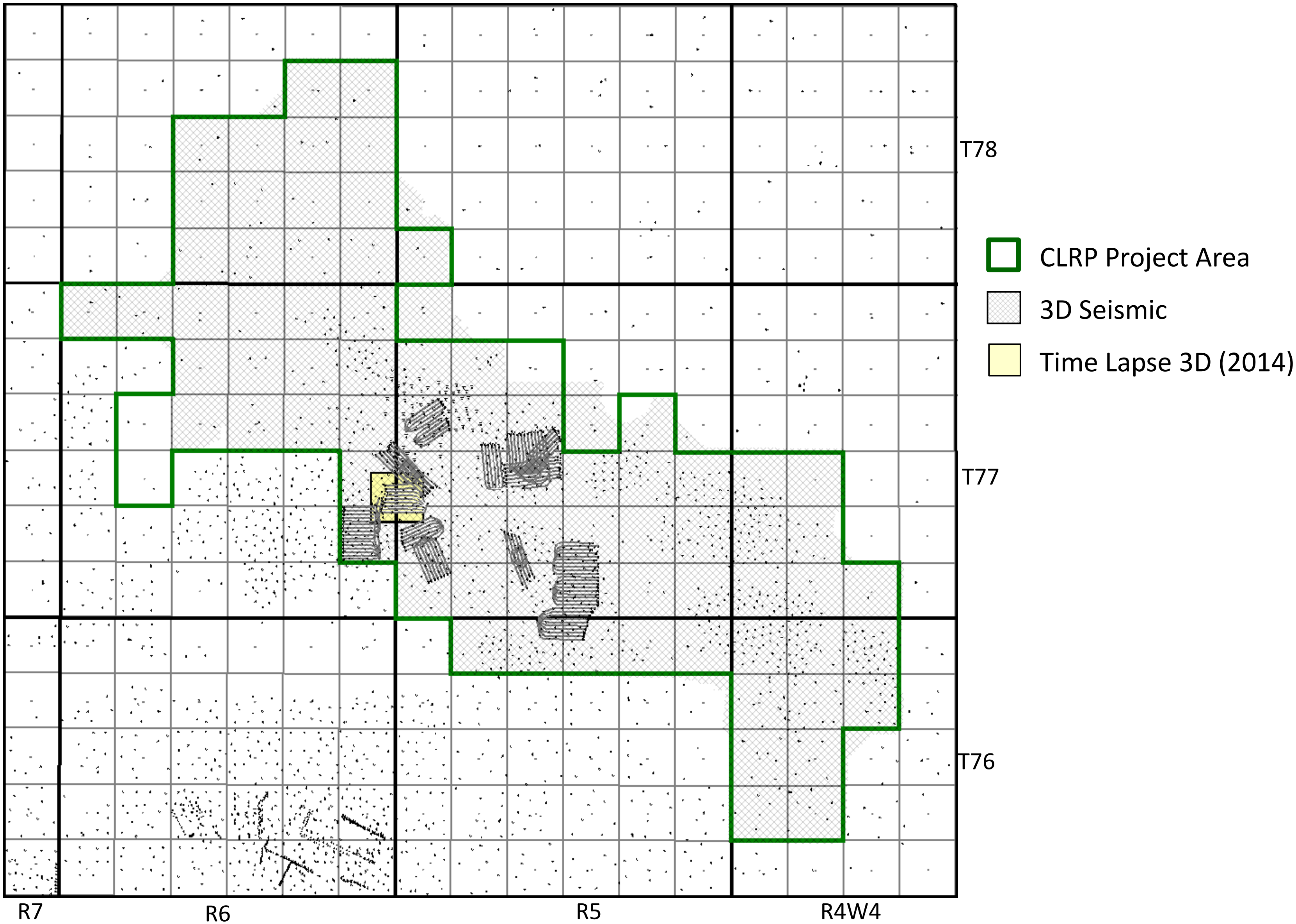


CLRP Wabiskaw / McMurray Cores

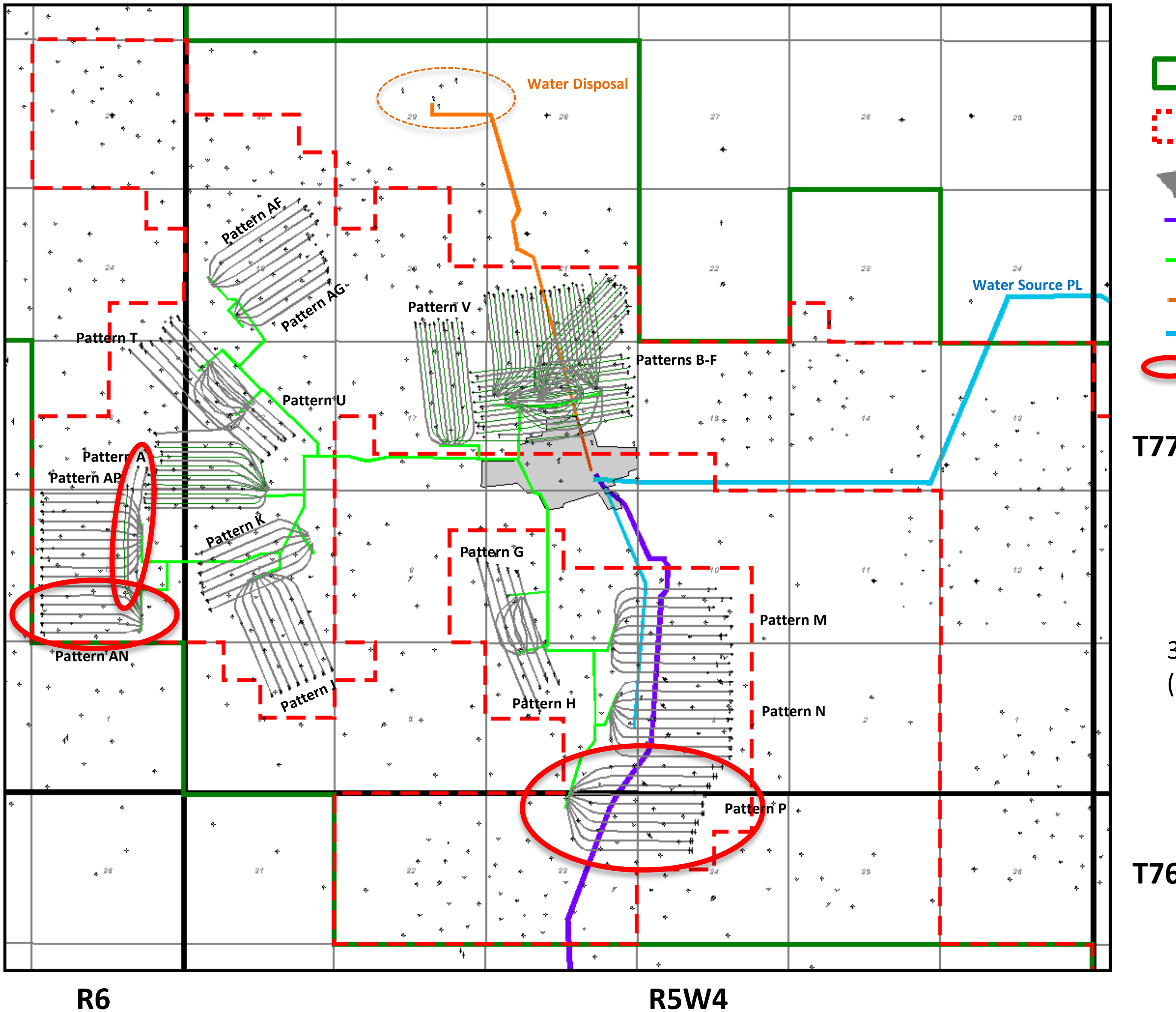


- 827 cored wells
- 85% of all wells are cored

CLRP 3D Seismic



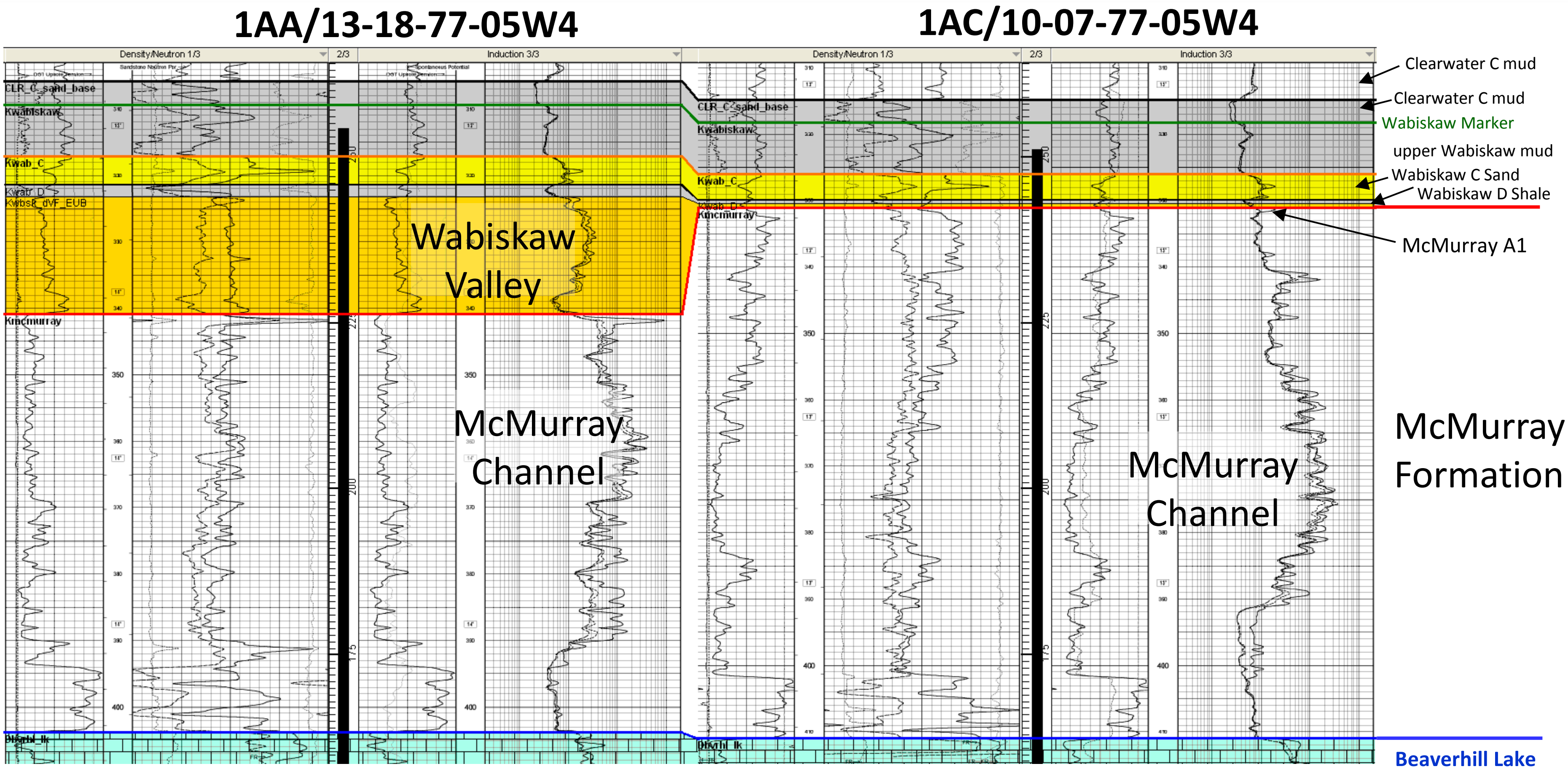
CLRP Active Development Area (ADA)



MEG OSL
Approved Development Area
Central Plant
Access Pipeline
Emulsion Pipeline
Disposal Pipeline
Water source Pipeline
Recent SAGD Pattern

332 horizontal wells
(SAGD & Infill wells)

CLRP: Wabiskaw/McMurray Stratigraphy



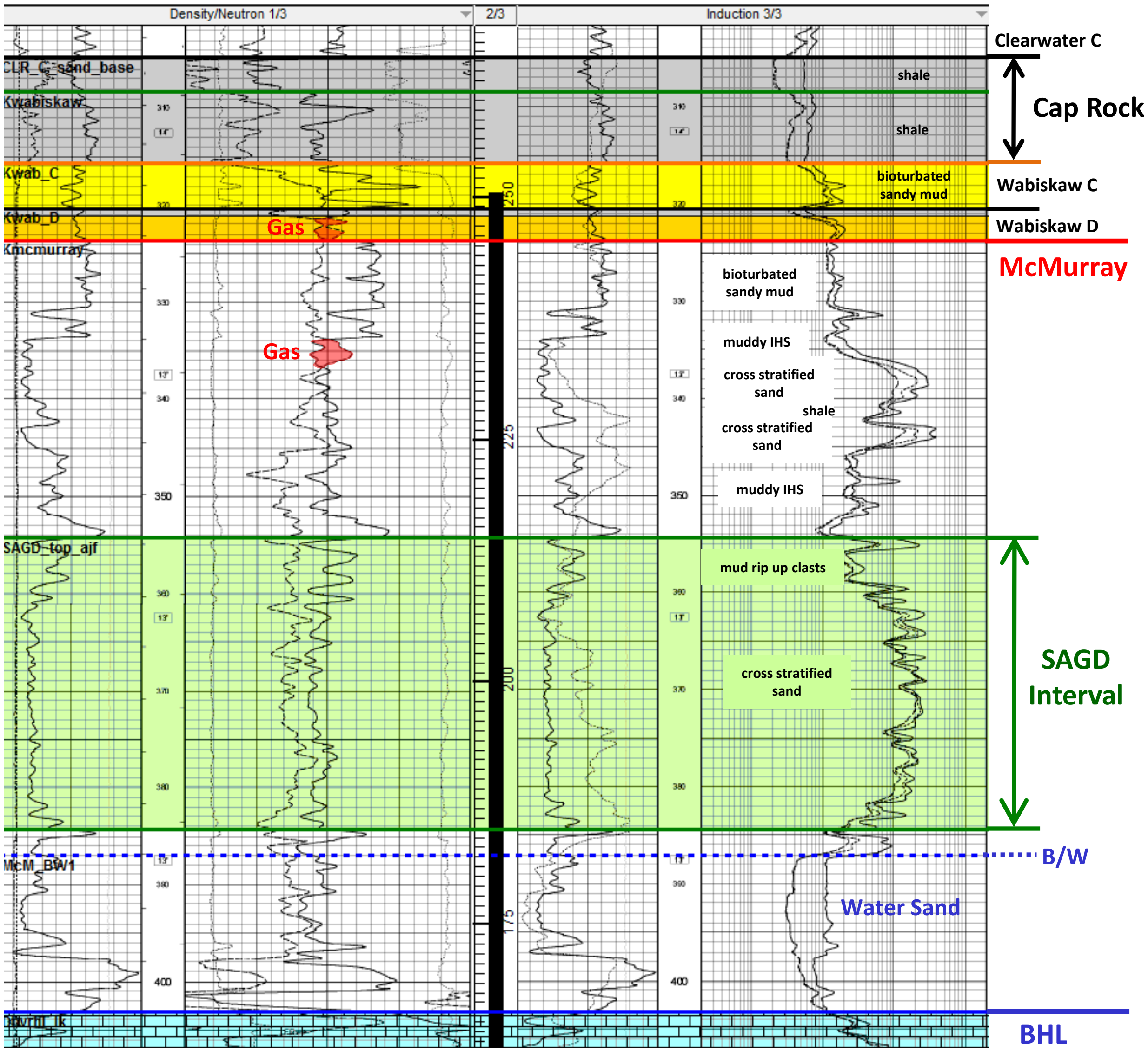
Stratigraphic Unit	Facies Association
lower Clearwater C	offshore mud
upper Wabiskaw	offshore / lower shoreface mud
Wabiskaw C	shoreface sand
Wabiskaw D Shale	bay mud
Wabiskaw D Valley	bay sand and mud
McMurray A1	shoreface sand / coal
upper McMurray Channel	tidal flat / creek sand and mud
lower McMurray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

McMurray stratigraphy after ERCB RGS 2003

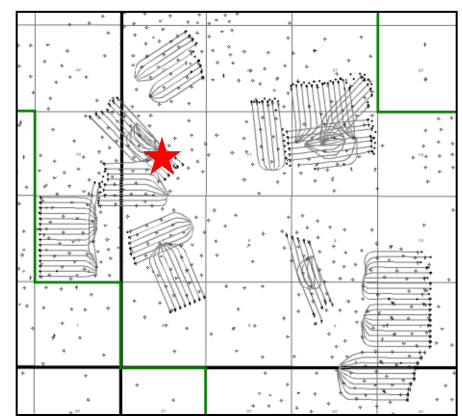
MEG ENERGY

CLRP: Wabiskaw / McMurray Reference Well

1AE/06-18-77-05W400



	McMurray	SAGD
h (m)	47.6	30.3
avg Ø	0.311	0.314
Avg S_o	0.770	0.794
BMO (calc)	0.114	0.120
McMurray Pay ≥ 6 wt% BMO		



CLRP: McMurray SAGD Pay Parameters

SAGD Pay

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

R_t = Deep Induction

parameters for S_o calculation

$Ø_{density}$ ≥ 25%

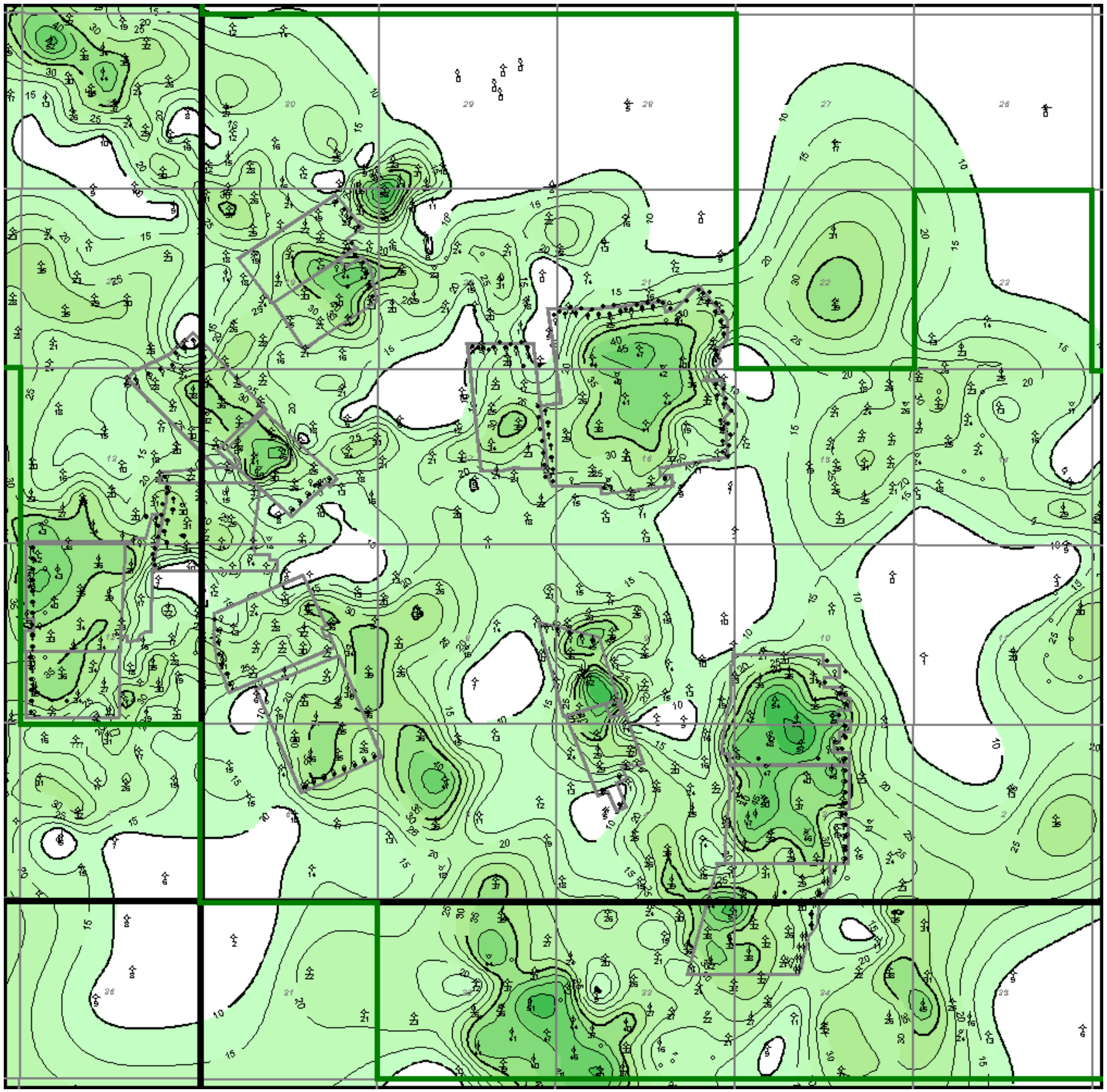
S_o (bitumen saturation) ≥ 50%

gas and coal excluded

CLRP: Average McMurray Reservoir Properties

average pay (m)	18.7
average depth to reservoir top (mTVD)	359
average porosity (frac)	0.32
average S_w (frac)	0.25
average K_h (Darcies)	5,000
average K_v (Darcies)	2,500
initial reservoir pressure (kPag)	2,100
reesrvoir temperature (^{o}C)	13

CLRP ADA Total McMurray SAGD Pay ≥ 10 m



CLRP Project Area

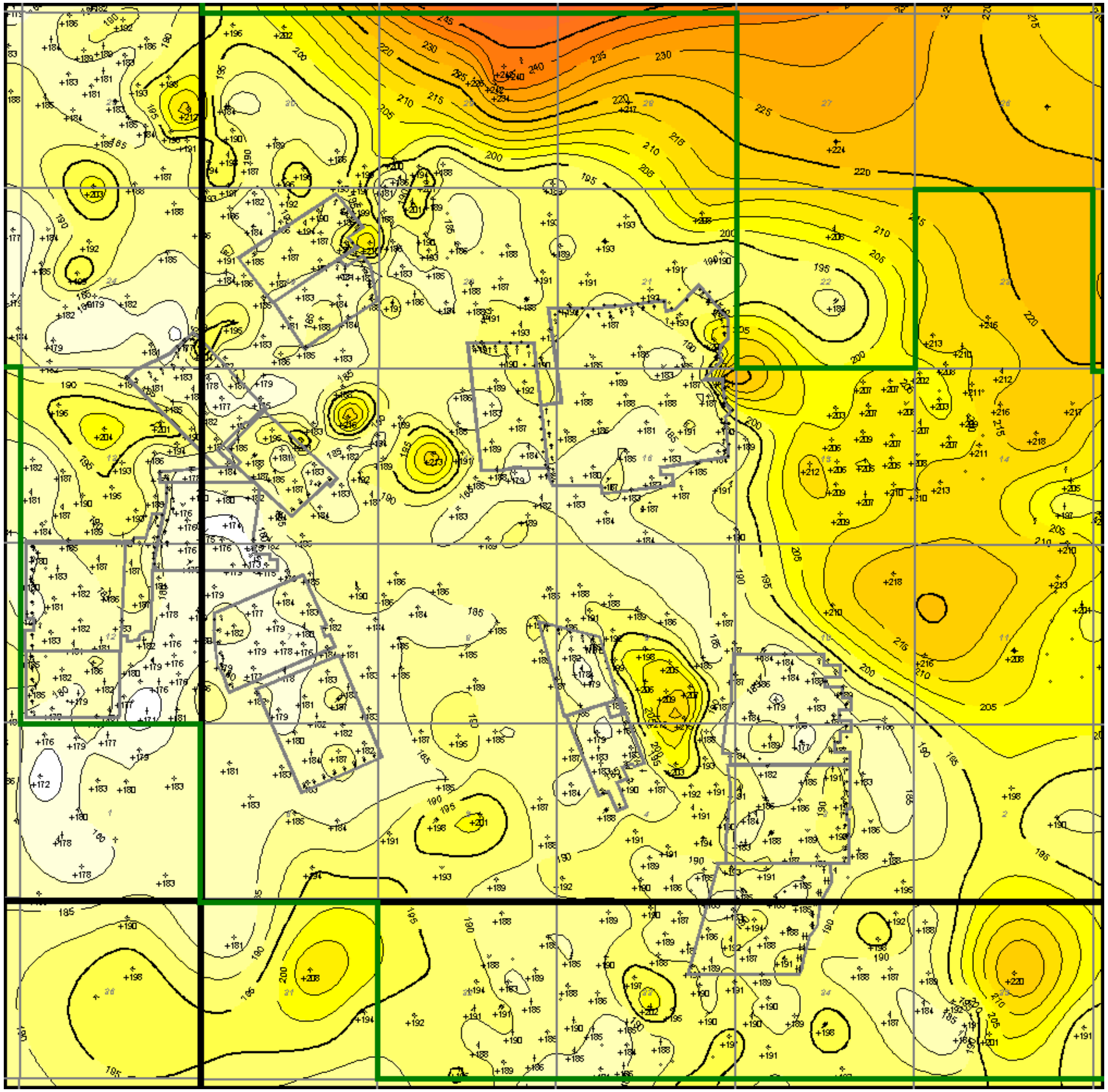
SAGD Patterns

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

T77

contour interval = 5 m

CLRP ADA Base SAGD Pay Structure



CLRP Project Area

SAGD Patterns

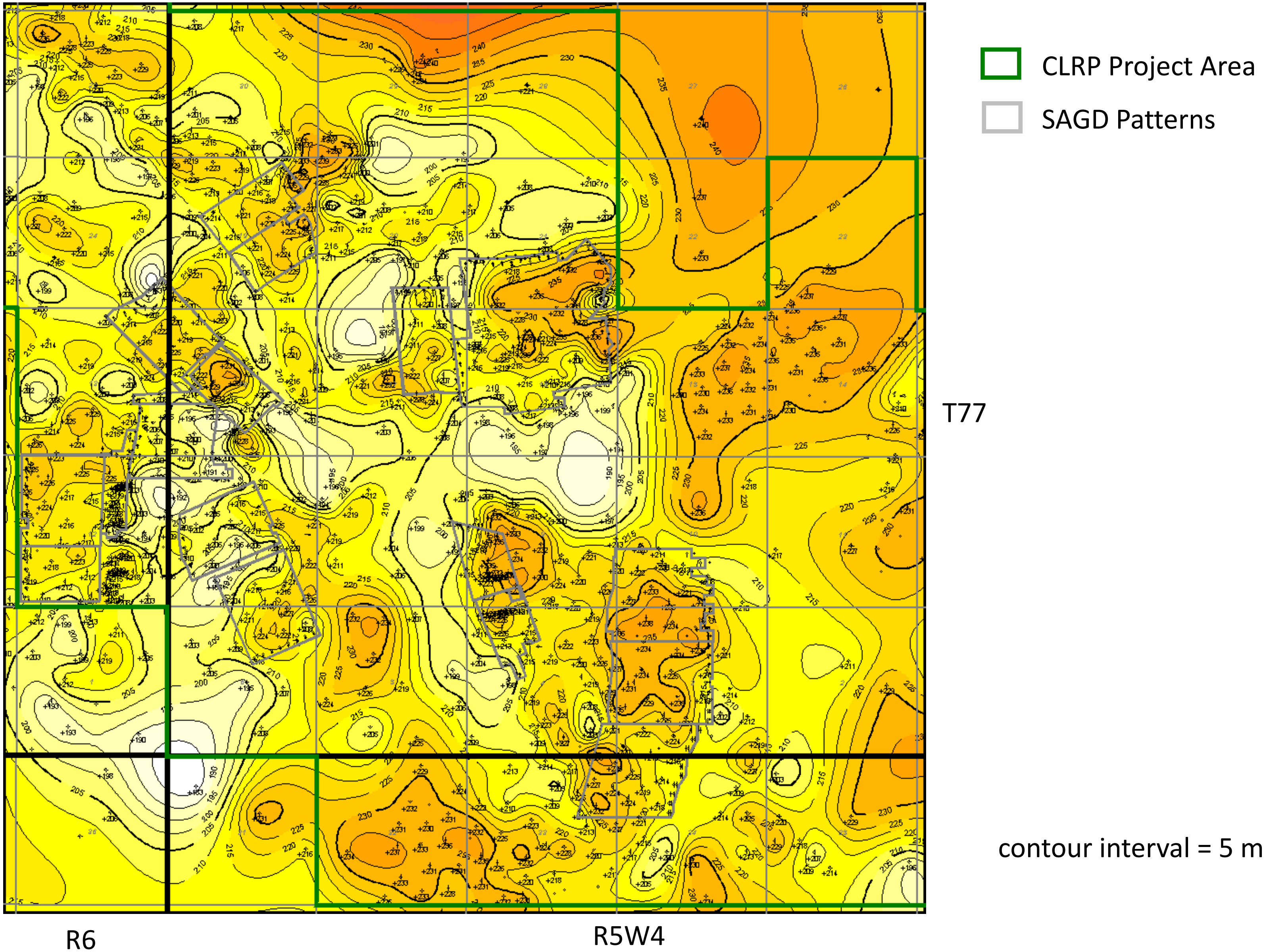
T77

contour interval = 5 m

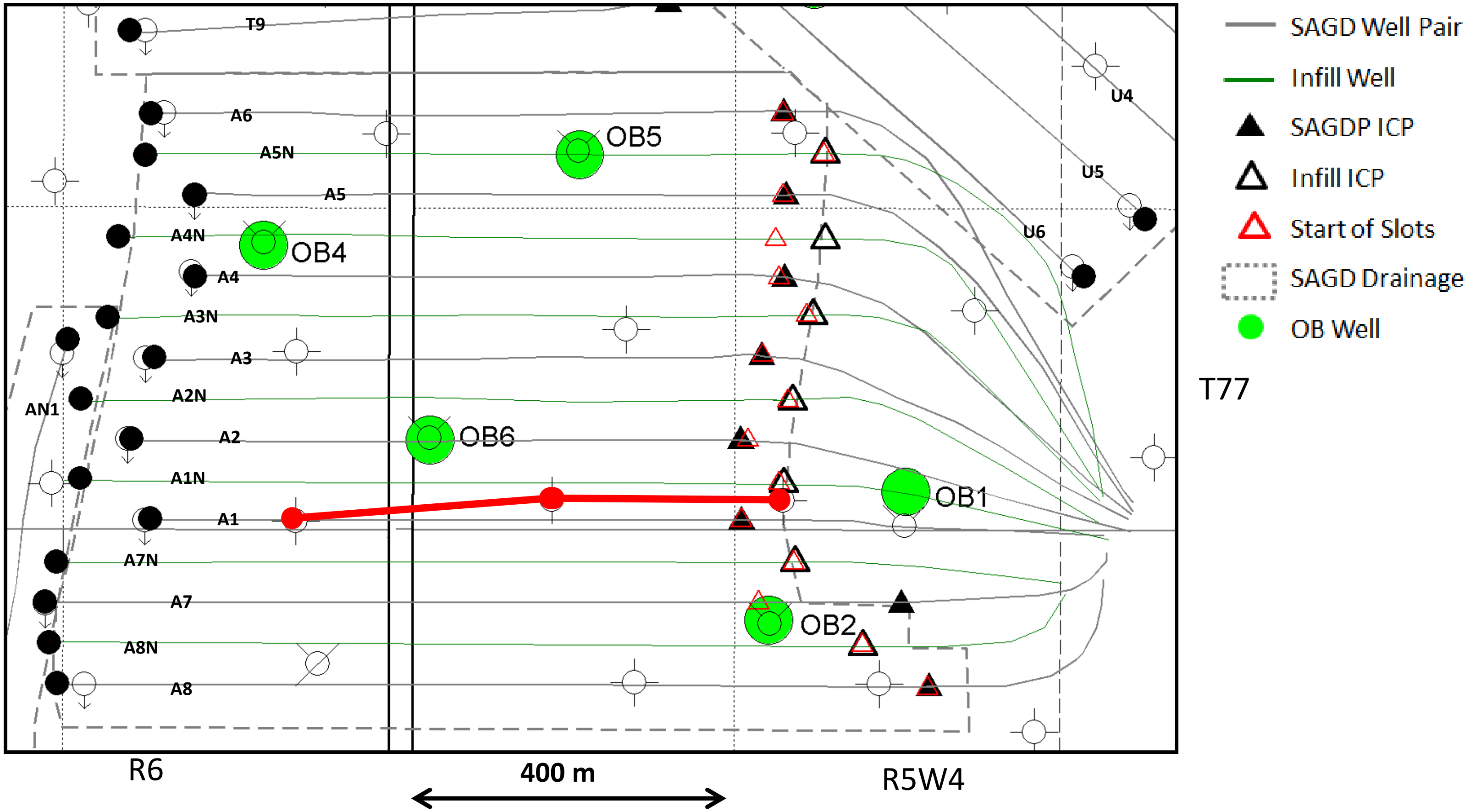
R6

R5W4

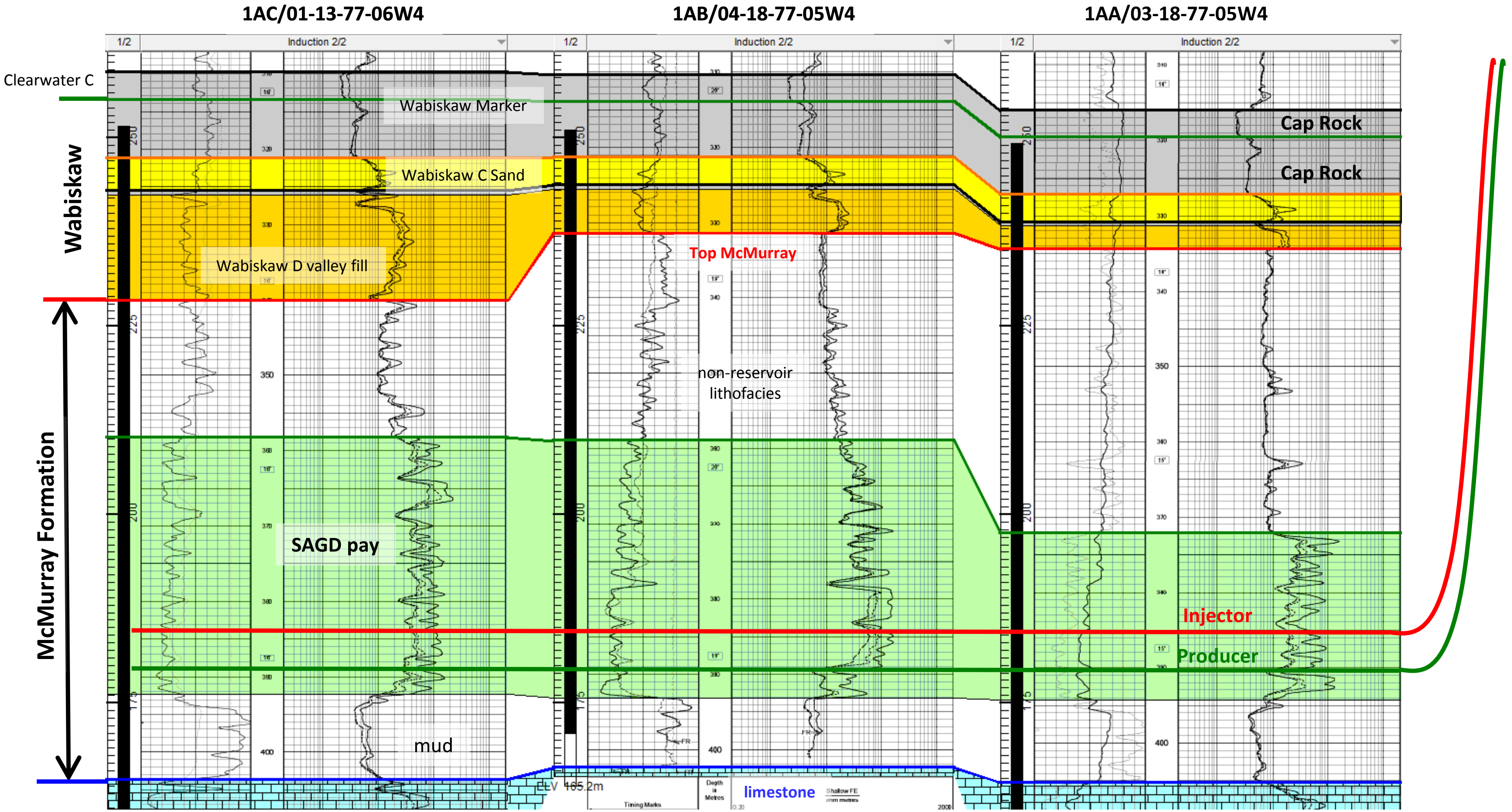
CLRP ADA Top SAGD Pay Structure



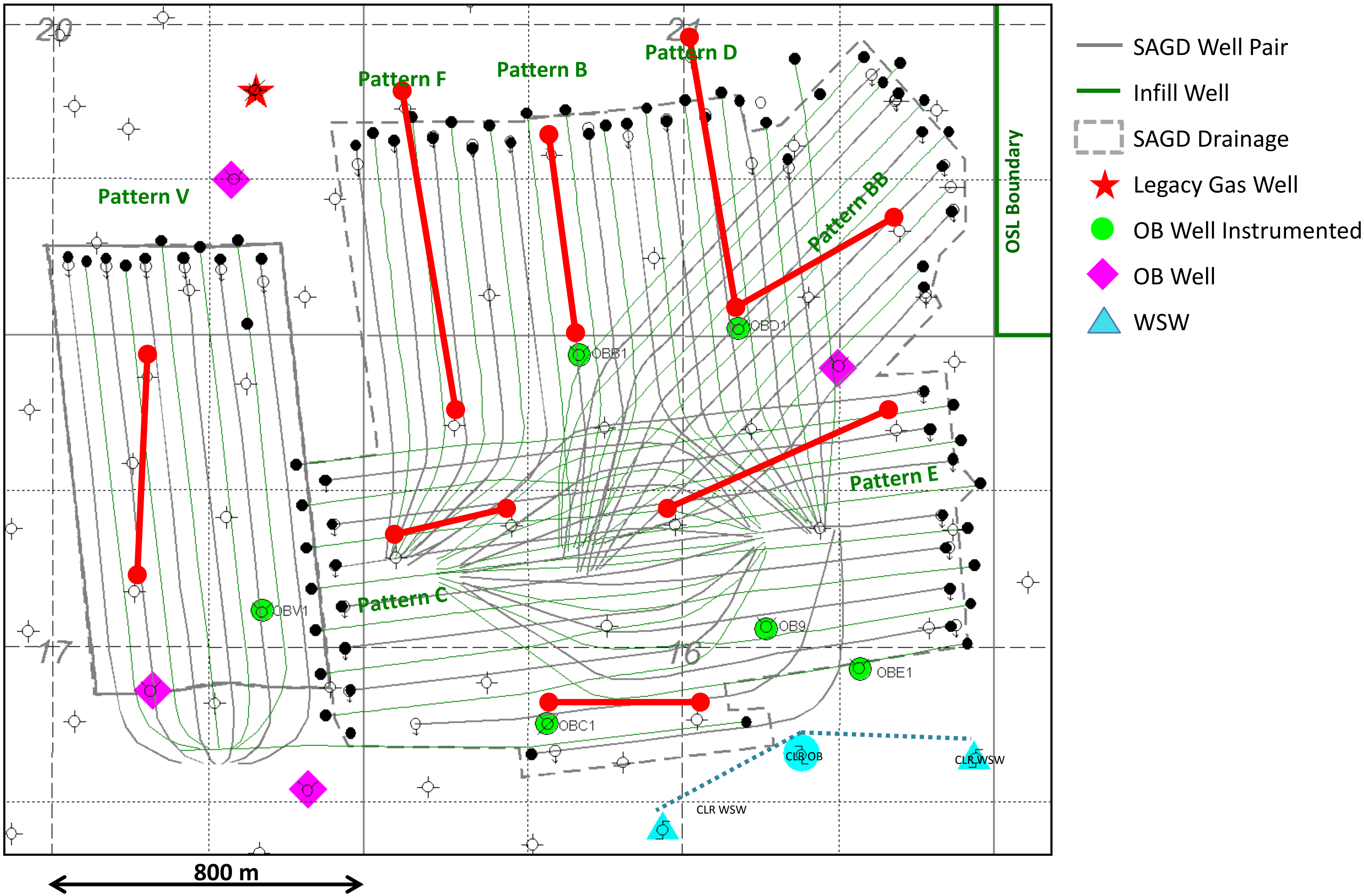
SAGD Pattern A Map View



CLRP Pattern A SAGD Development

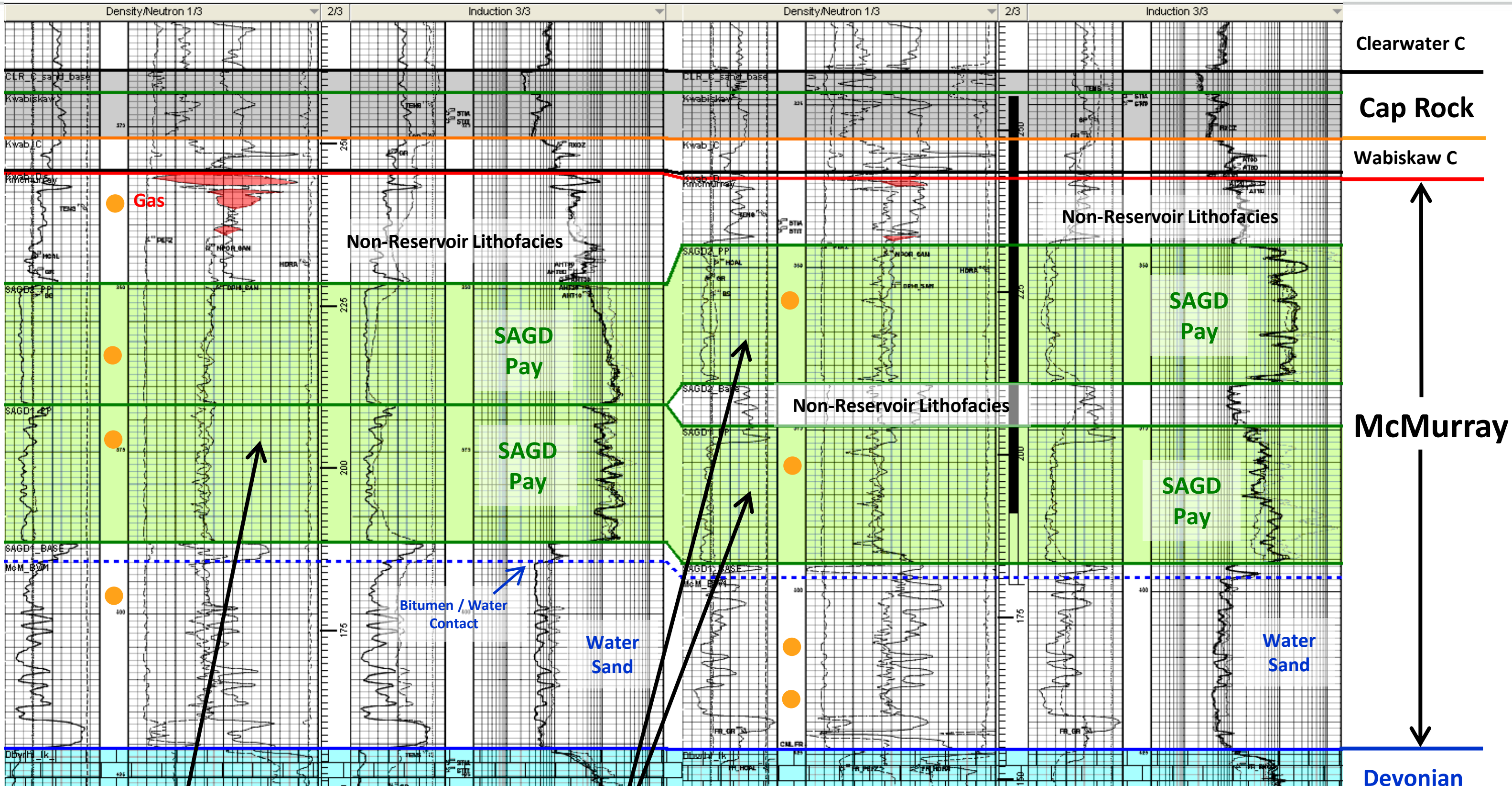


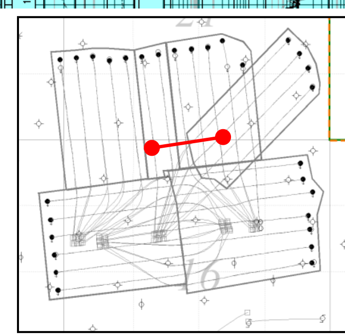
CLRP Phase 2 SAGD and Infill Wells Map View



CLRP Stacked SAGD Pay

100/14-16-77-05W4 OBB1 100/02-21-77-05W4 OBD1



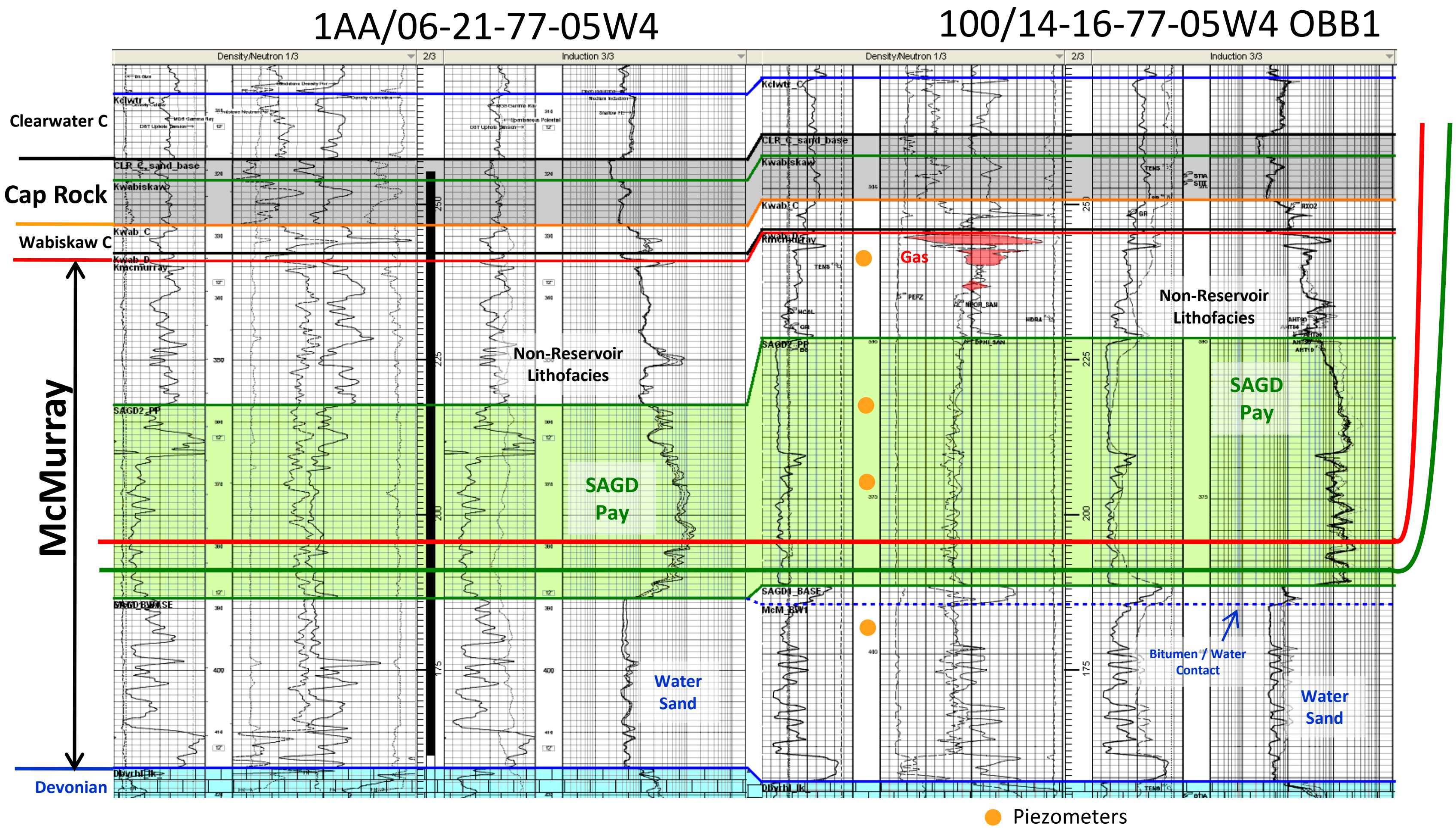


Single Pattern Development
(Single Pay Interval)

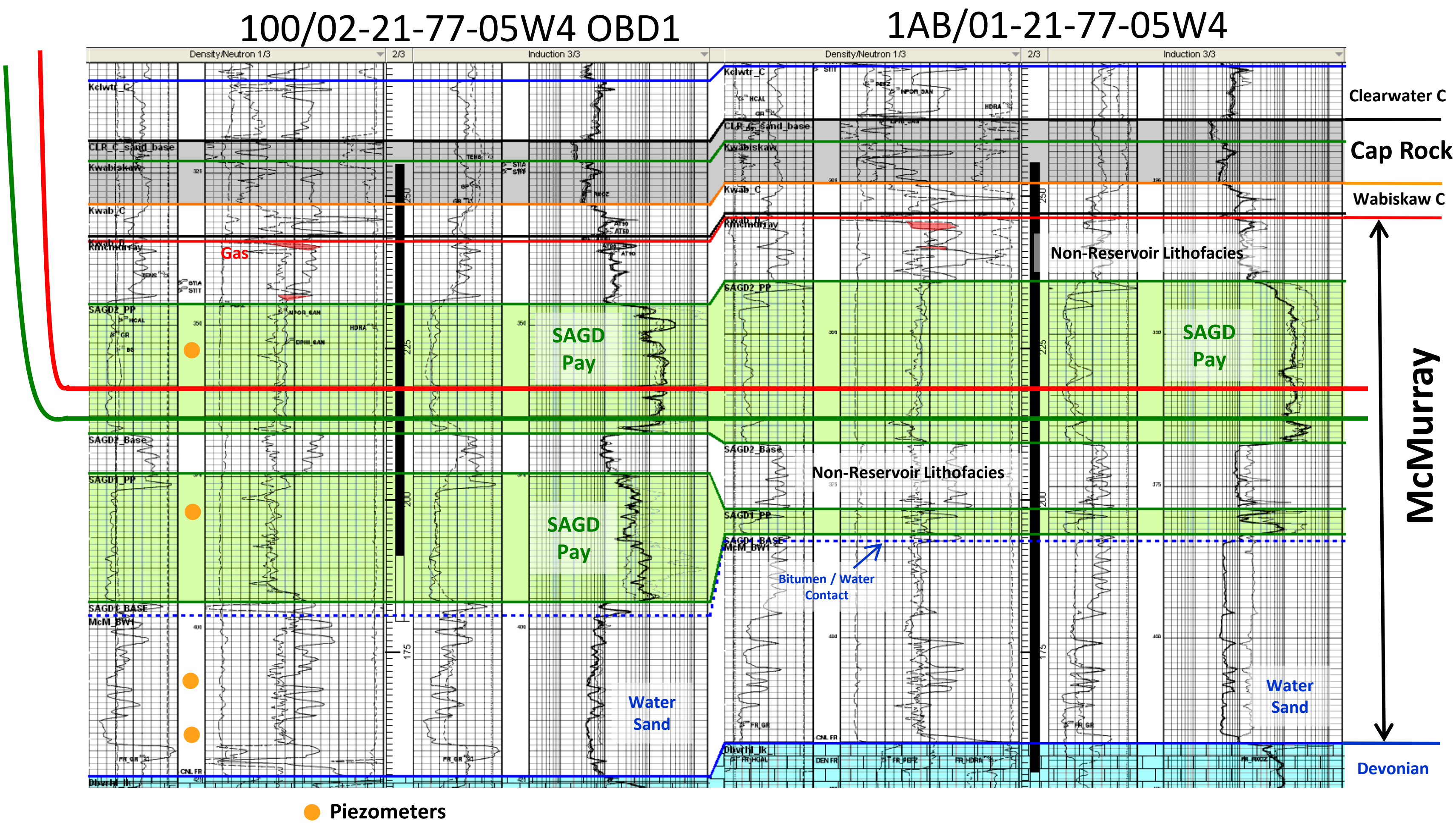
Stacked Pattern Development
(Multiple Pay Intervals)

Piezometers

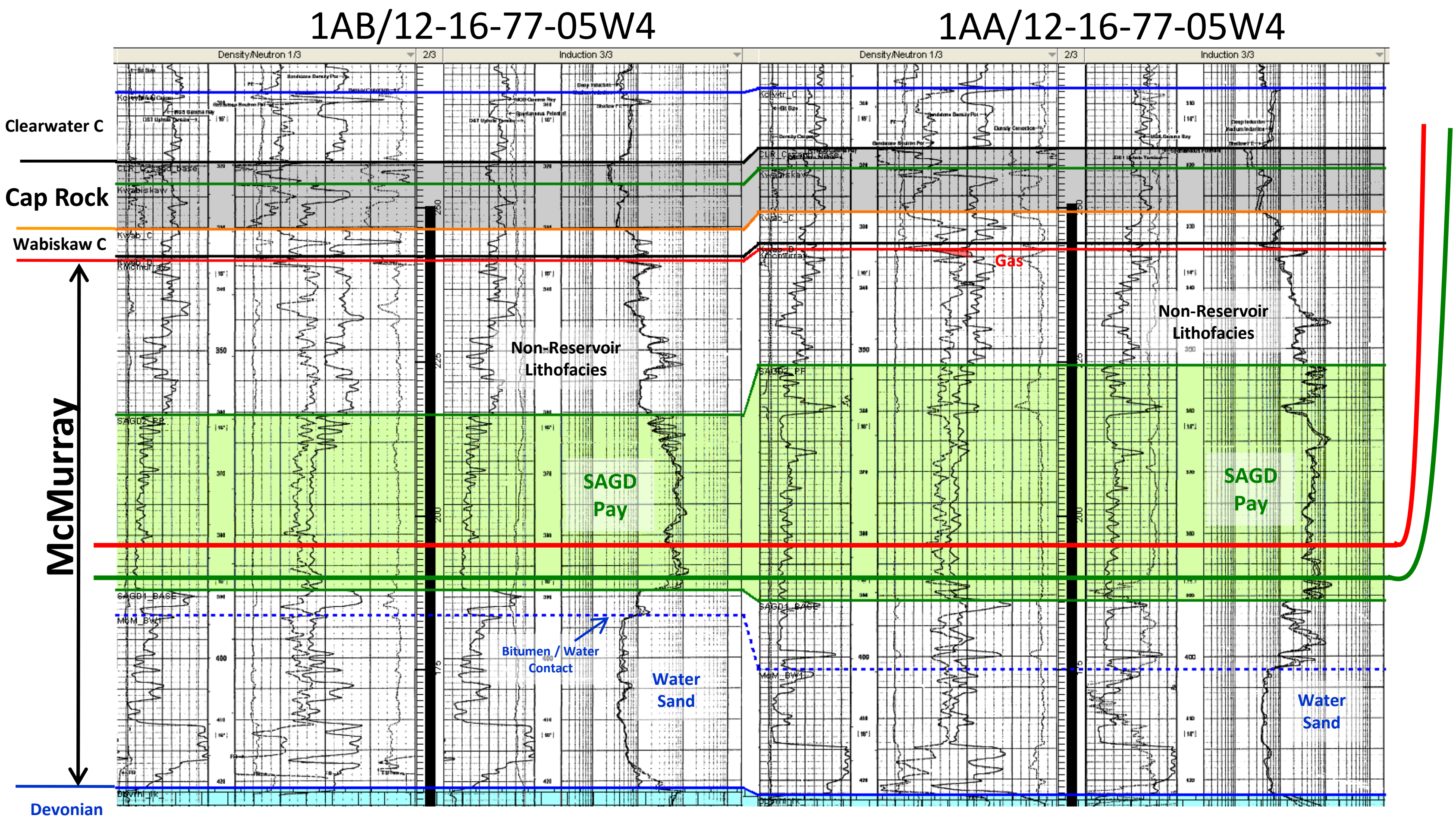
CLRP Pattern B SAGD Development



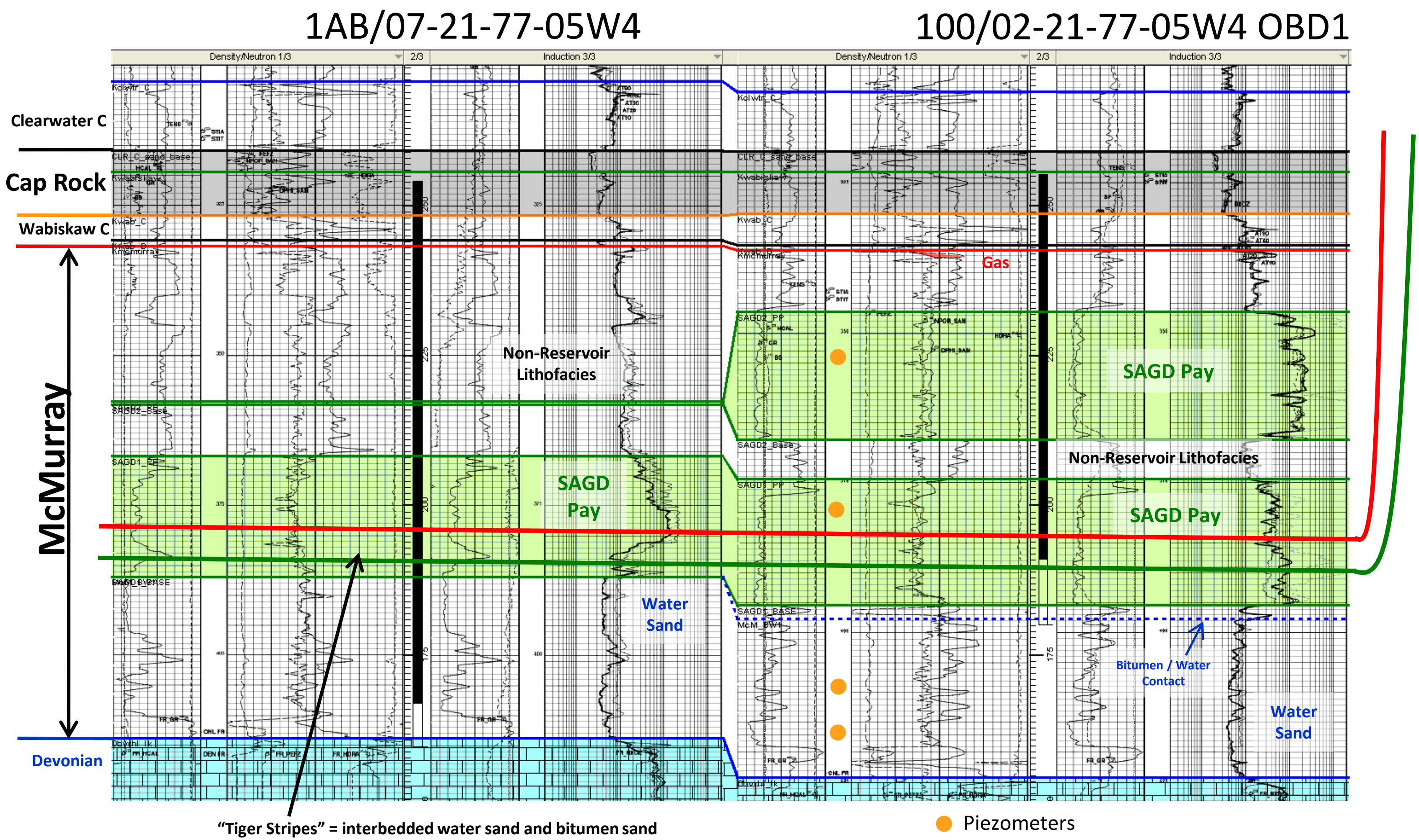
CLRP Pattern BB SAGD Development



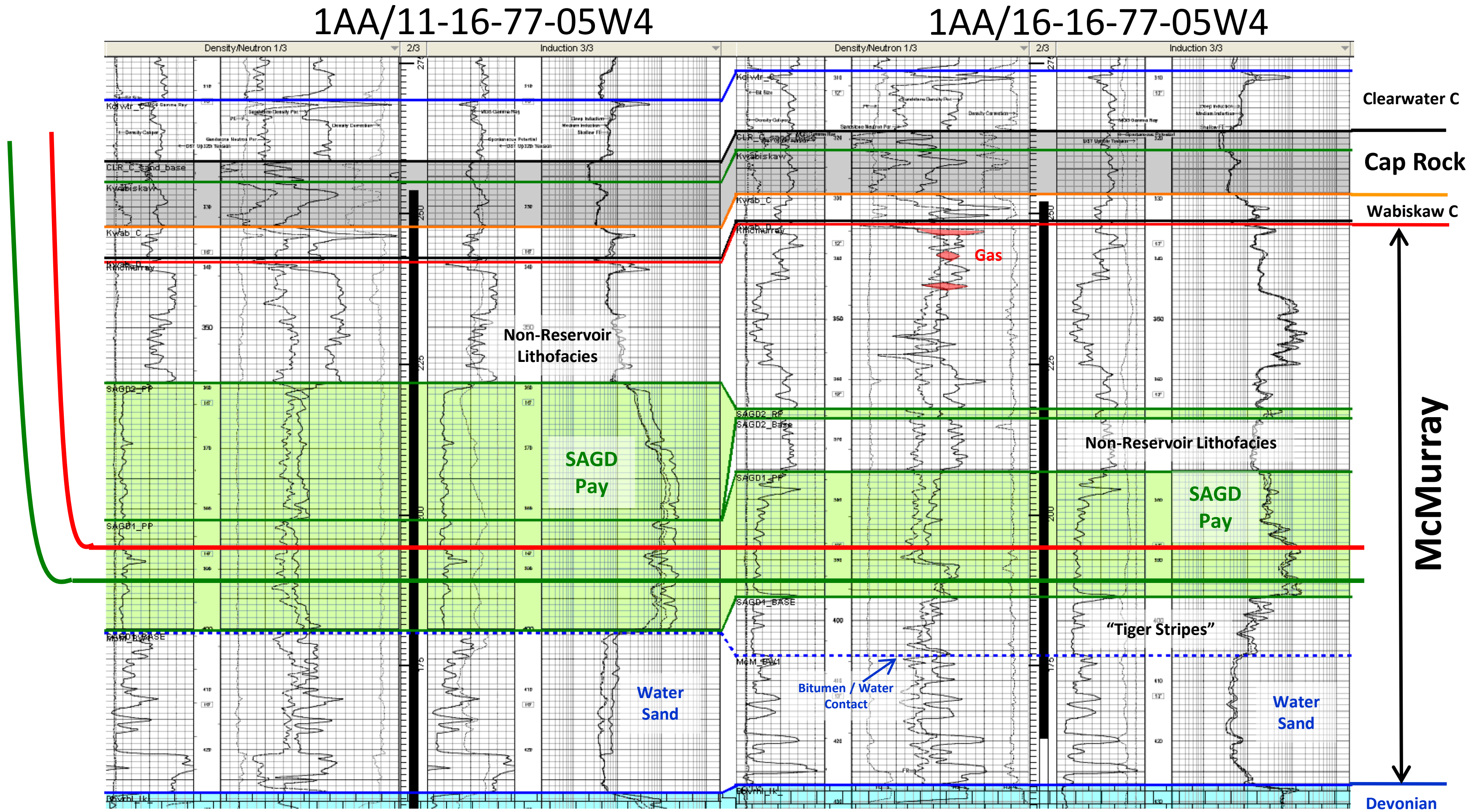
CLRP Pattern C SAGD Development



CLRP Pattern D SAGD Development

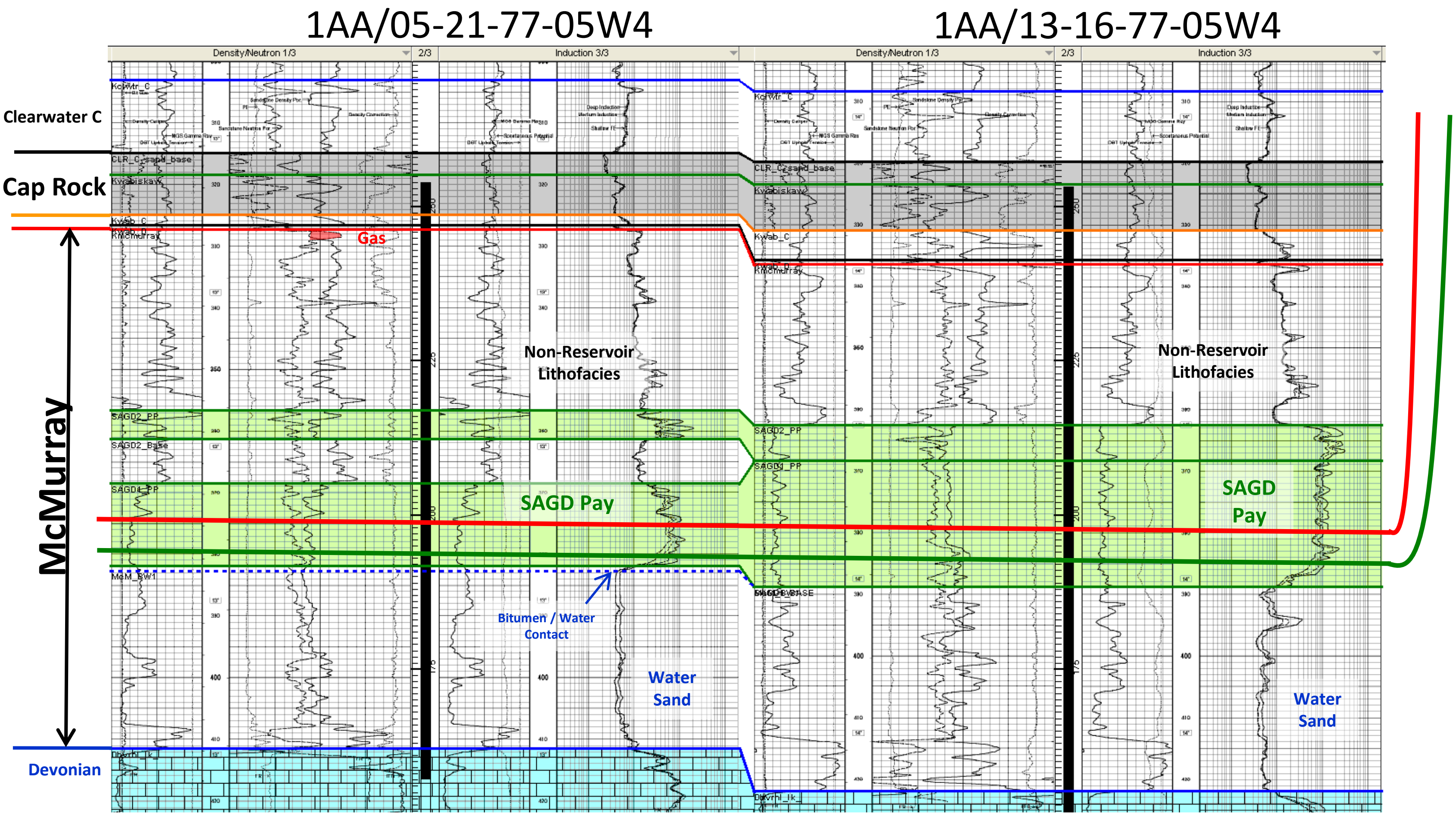


CLRP Pattern E SAGD Development

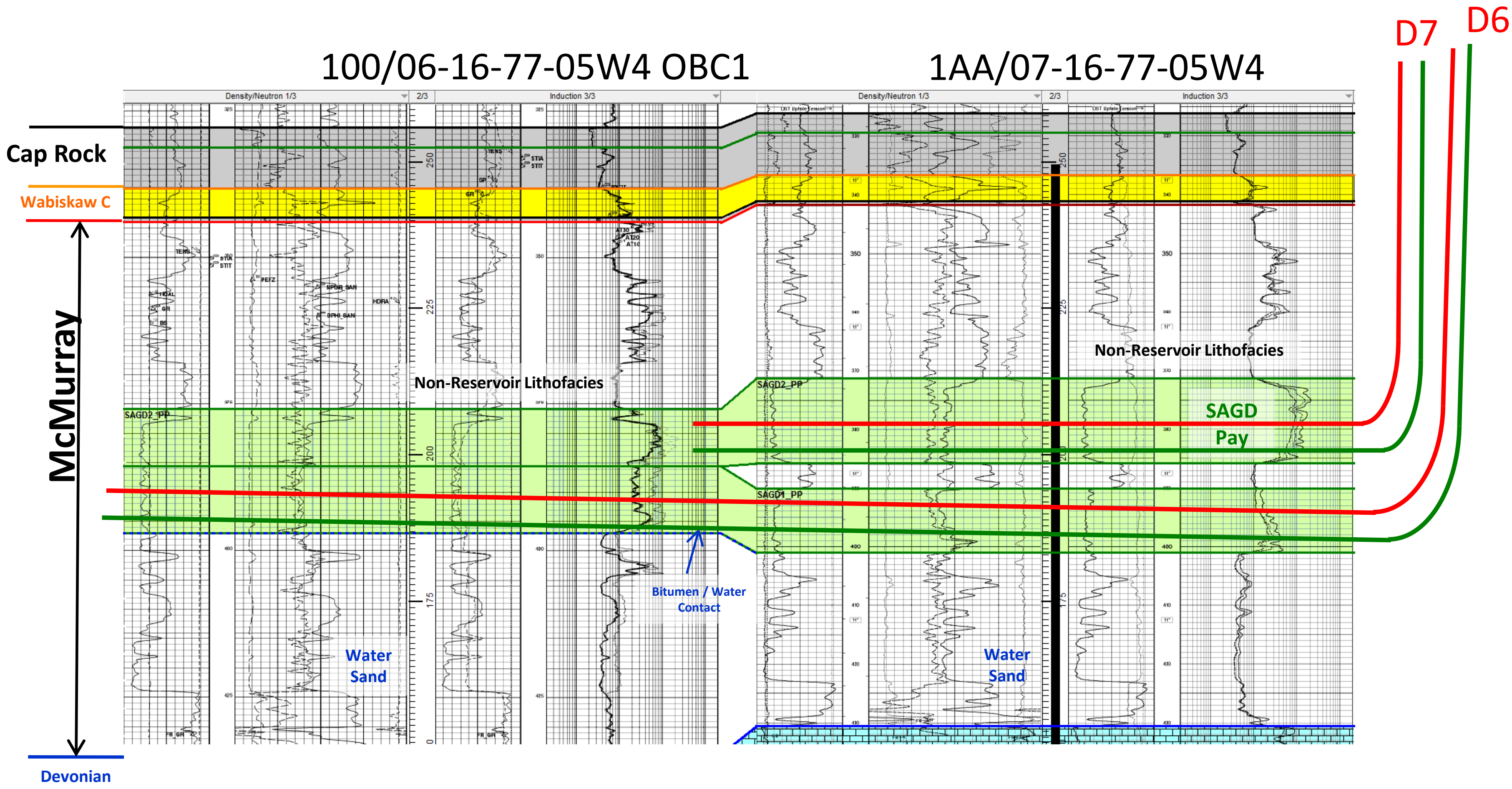


"Tiger Stripes" = interbedded water sand and bitumen sand

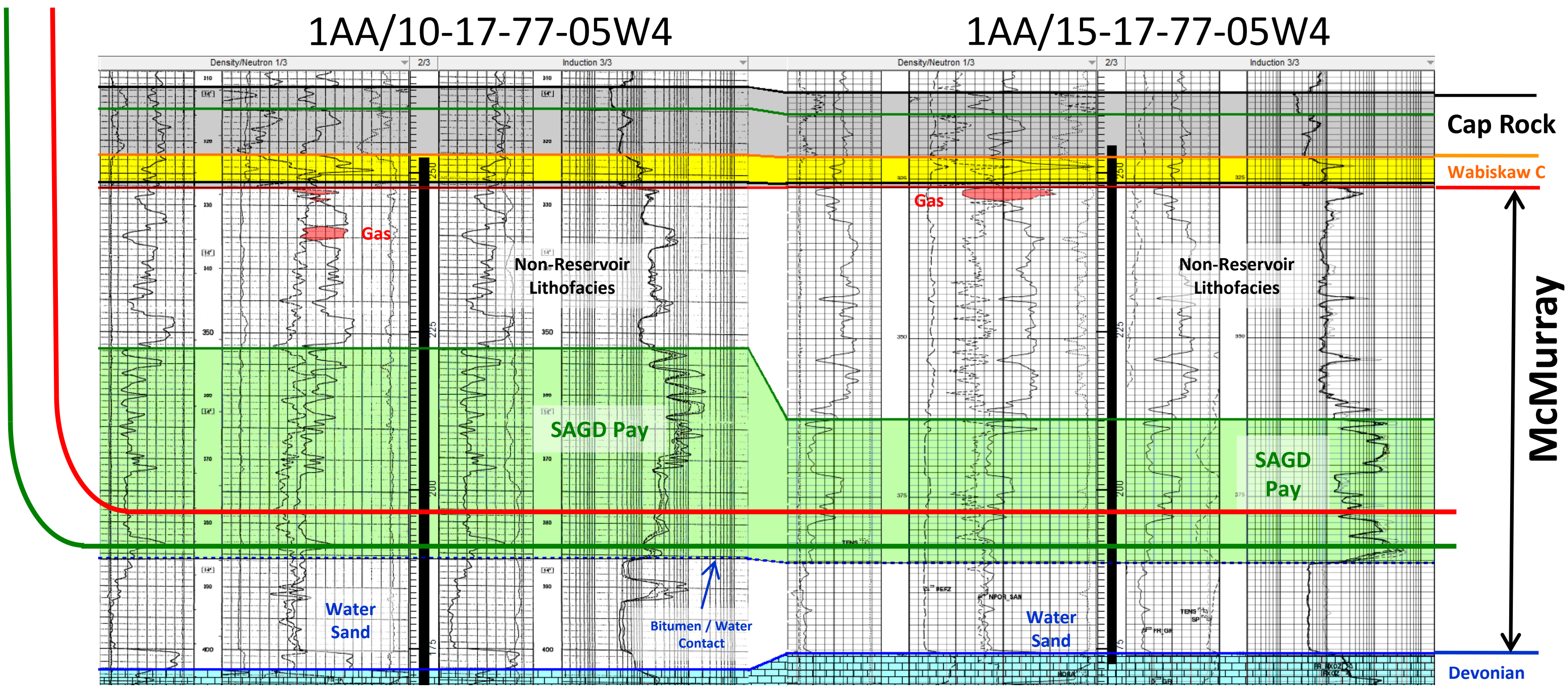
CLRP Pattern F SAGD Development



CLRP Pattern D6/D7 SAGD Development

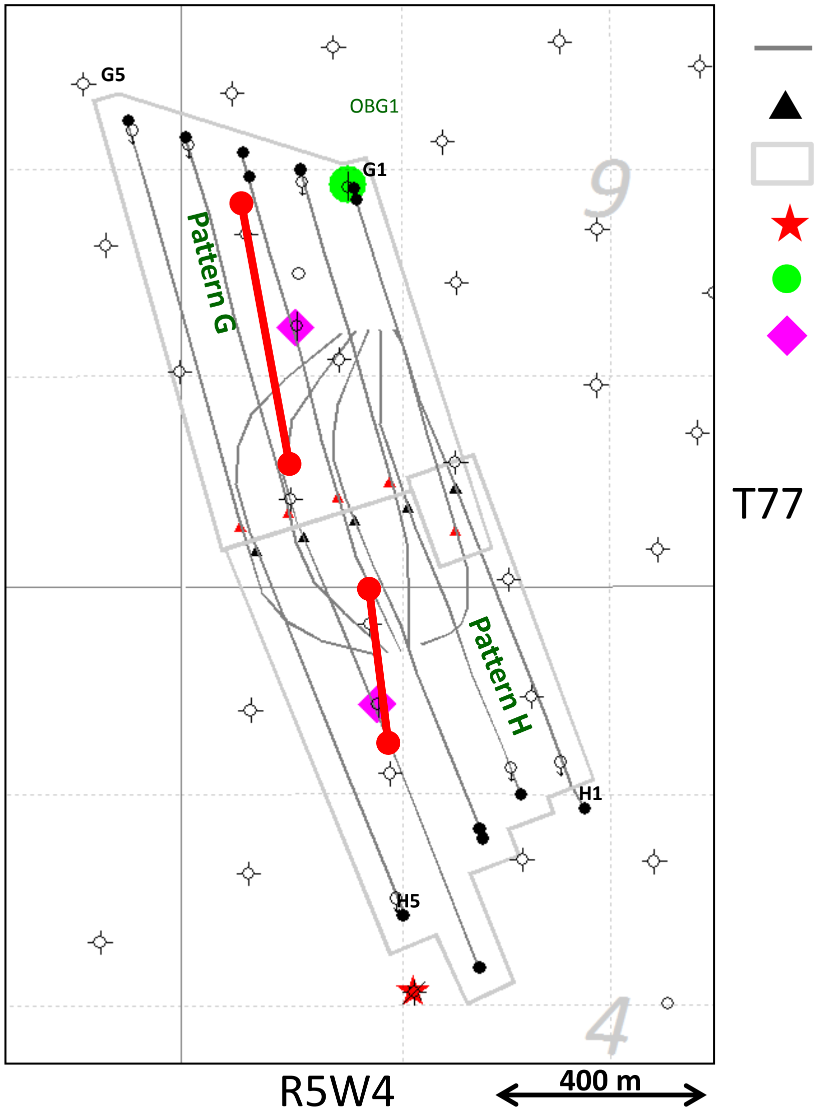


CLRP Pattern V SAGD Development



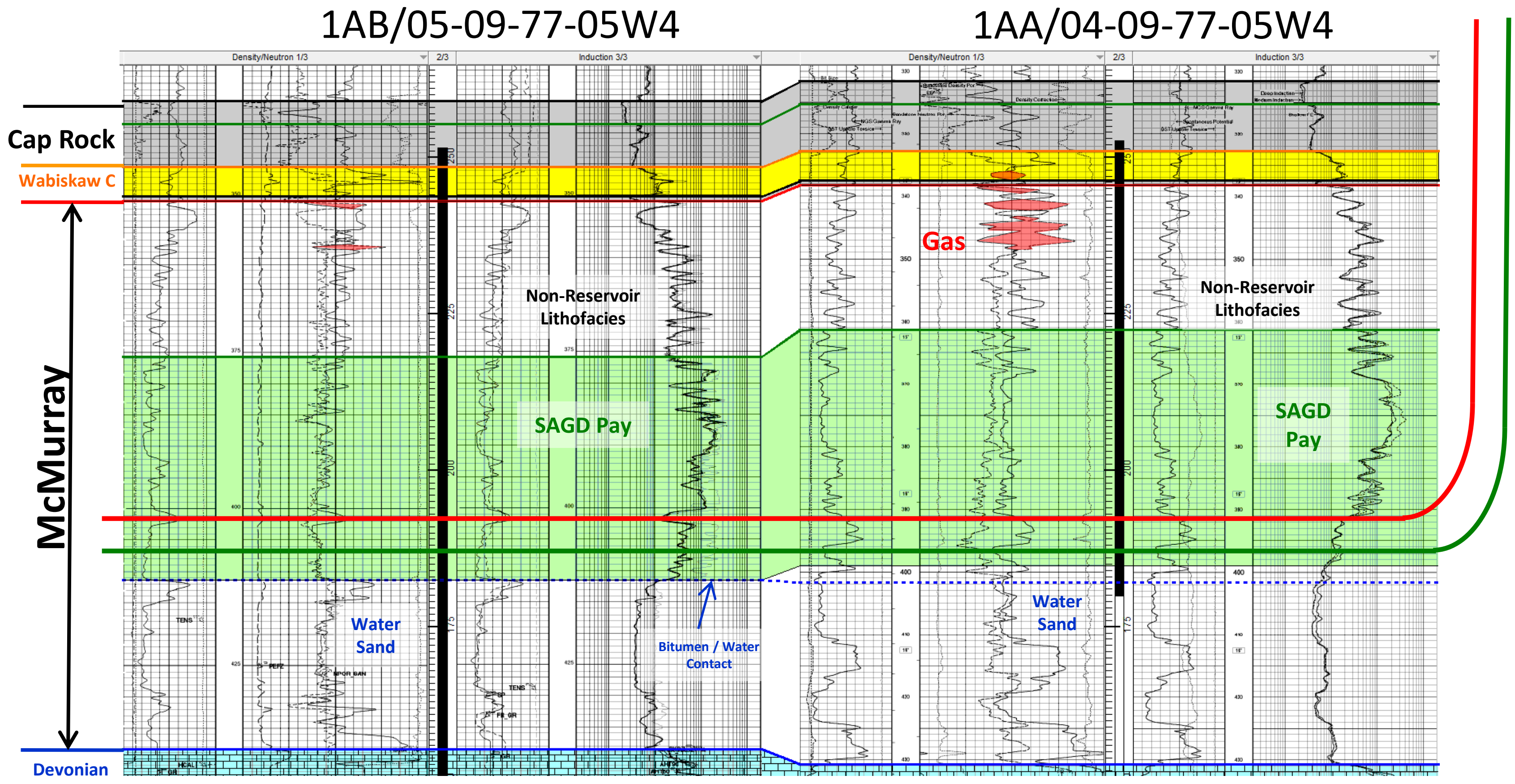
MEG ENERGY

CLRP G & H SAGD Development

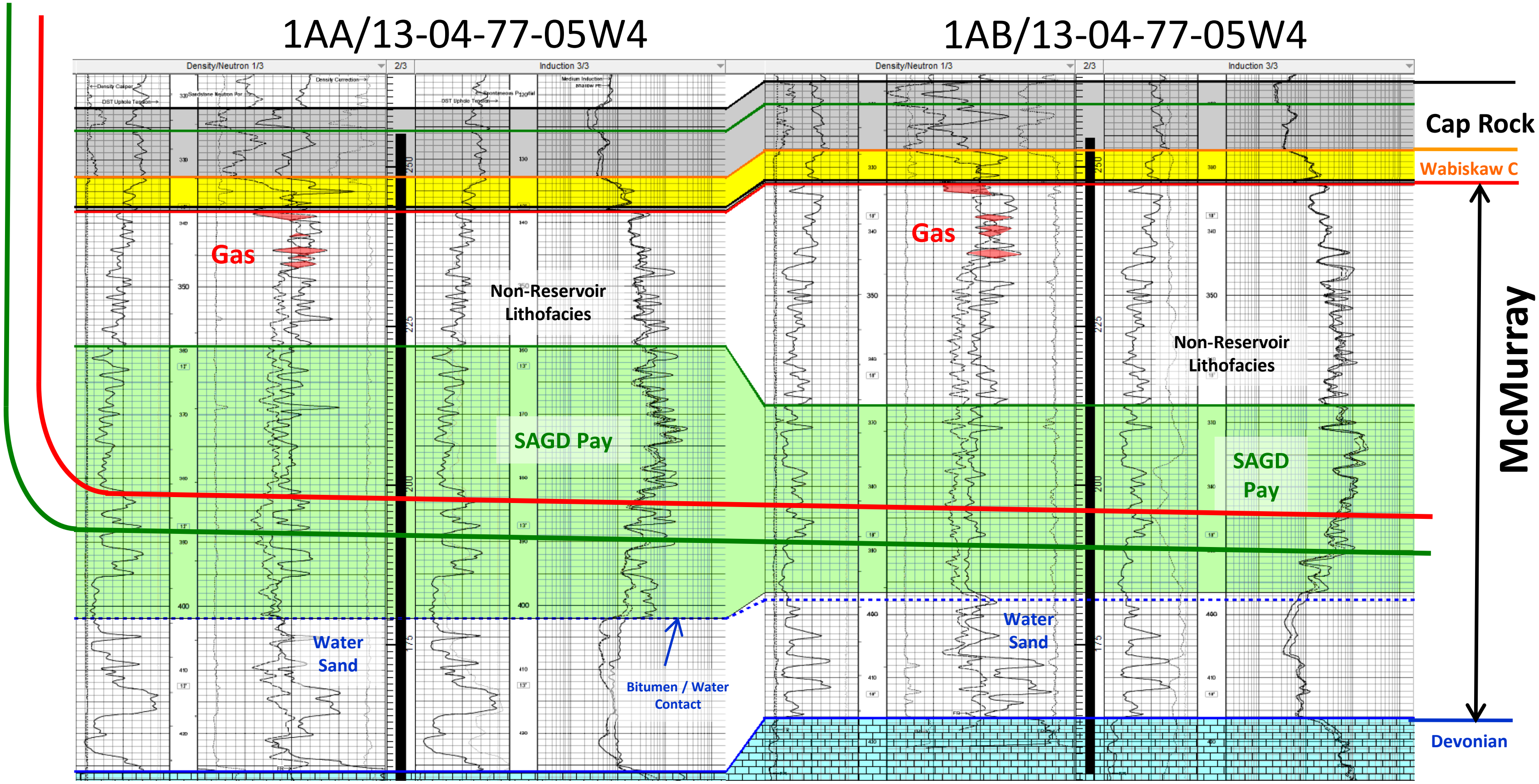


SAGD Well Pair
SAGD Prod ICP
SAGD Drainage
Legacy Gas Well
OB Well Instrumented
OB Well

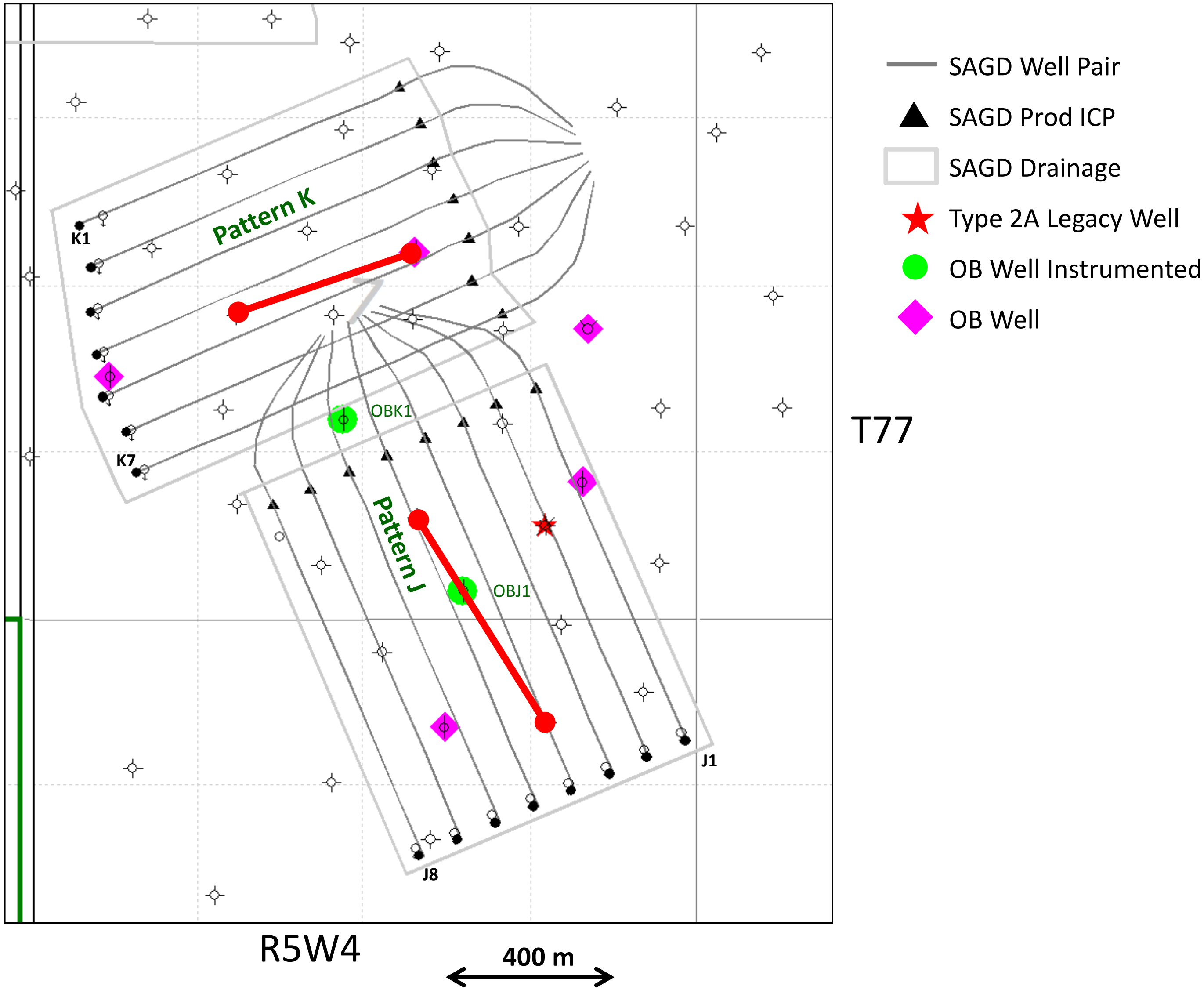
CLRP Pattern G SAGD Development



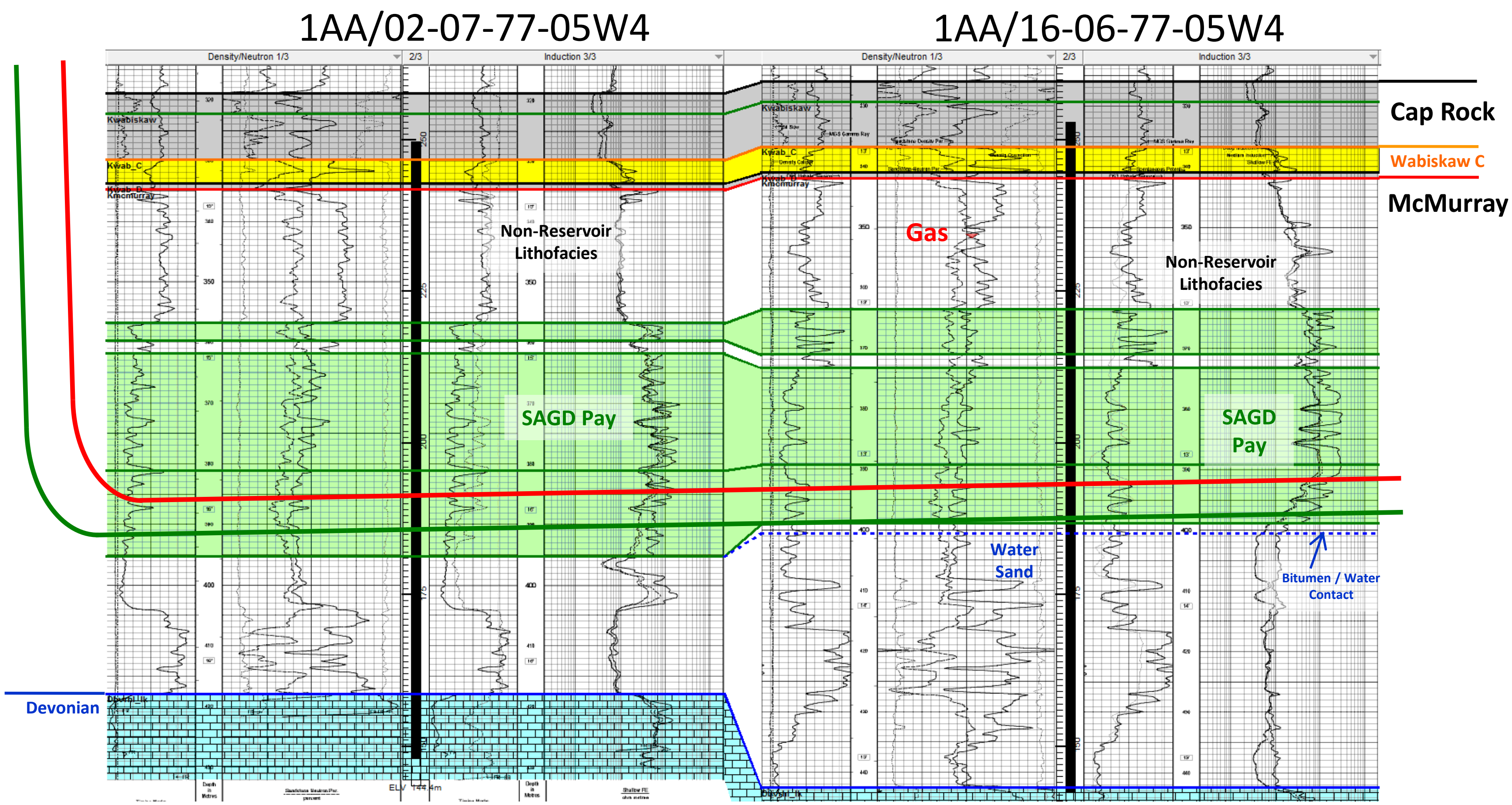
CLRP Pattern H SAGD Development



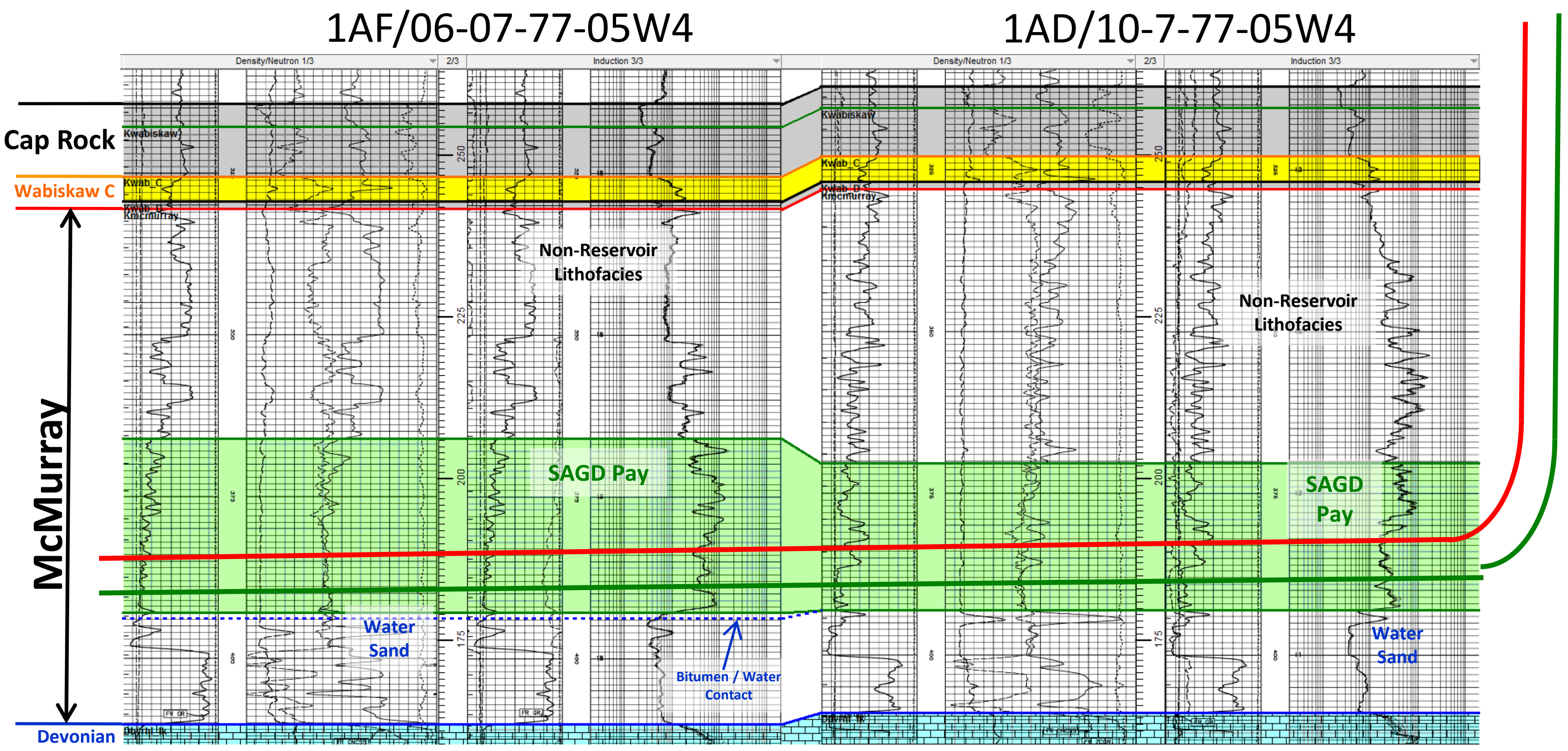
CLRP J & K SAGD Development



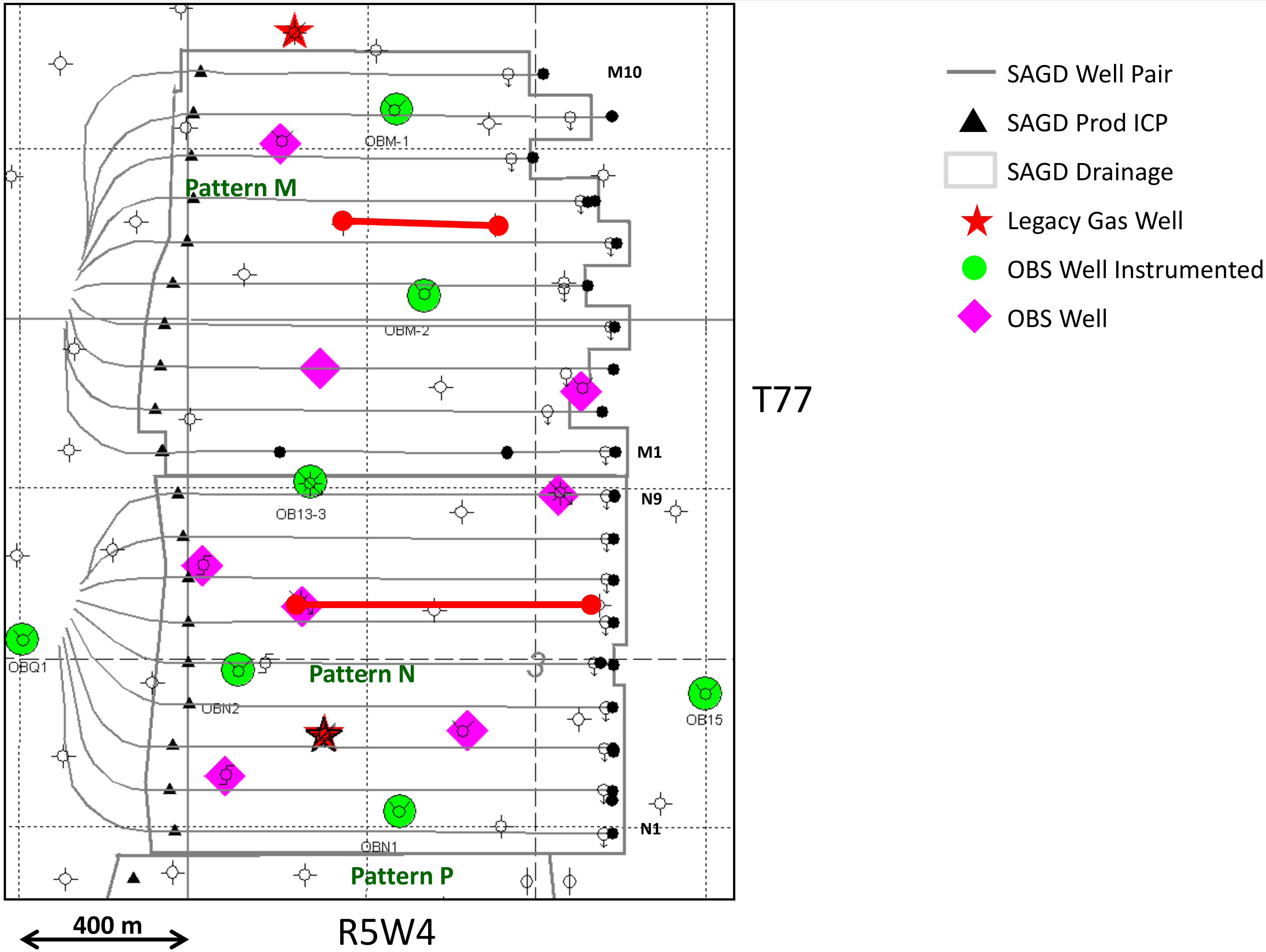
CLRP Pattern J SAGD Development



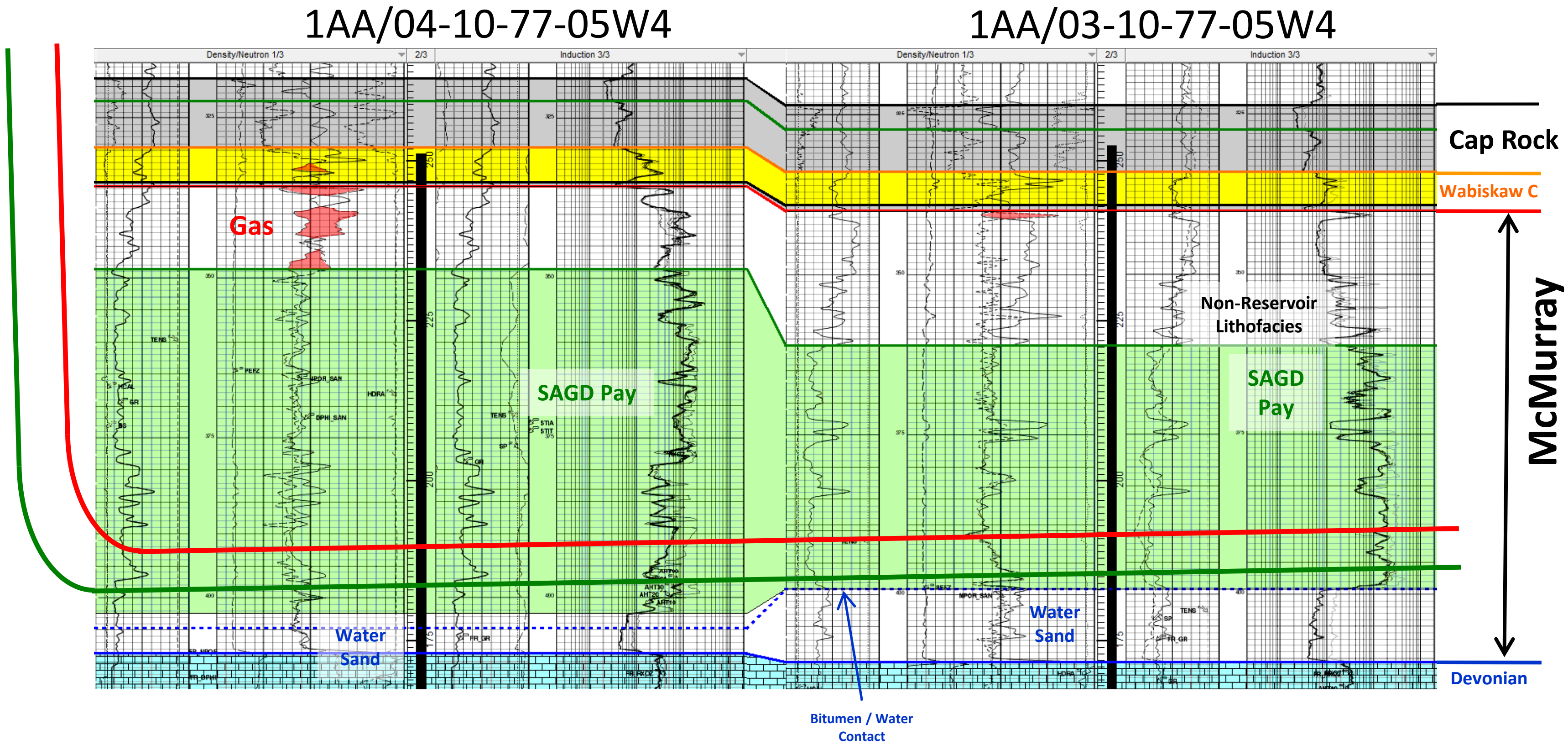
CLRP Pattern K SAGD Development



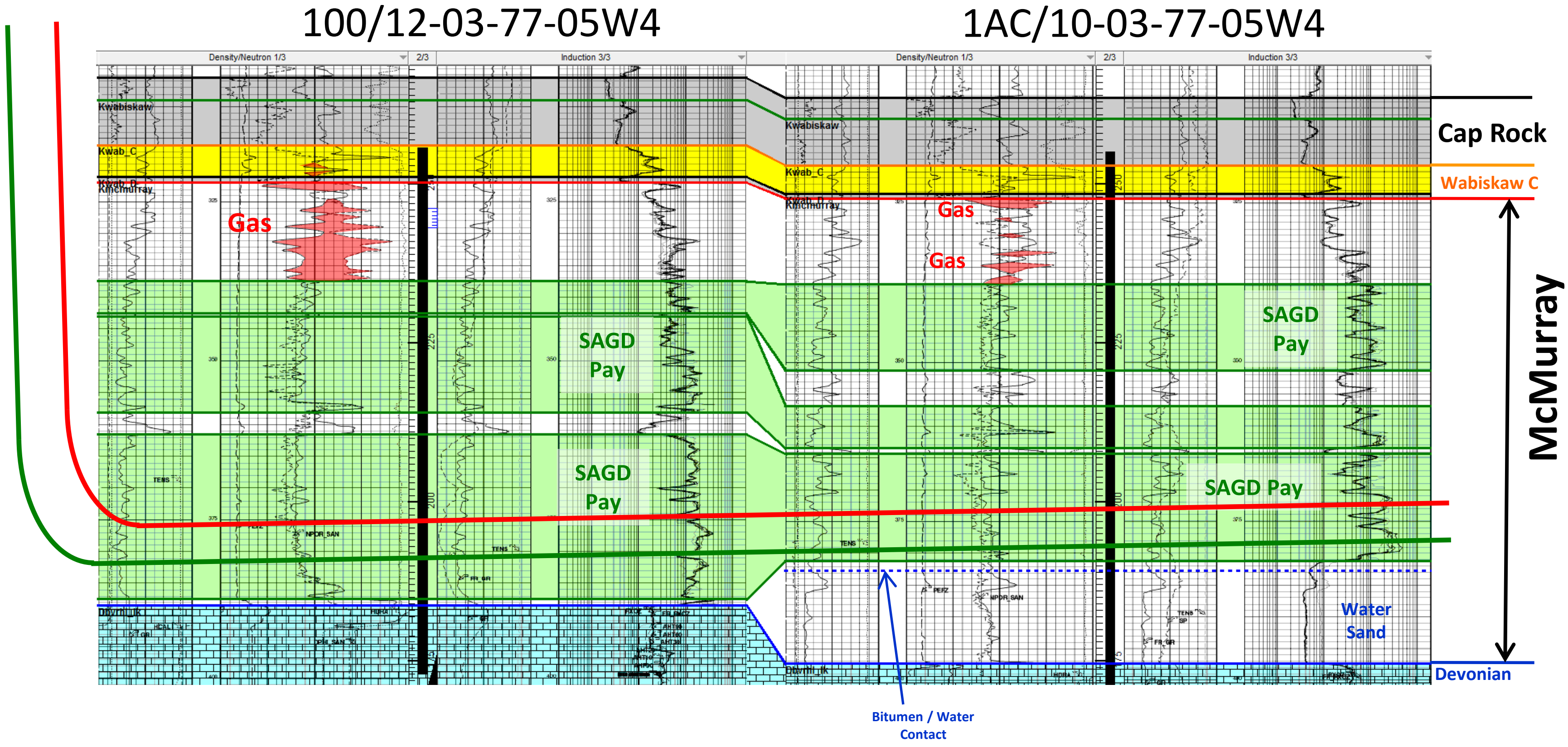
CLRP M & N SAGD Development



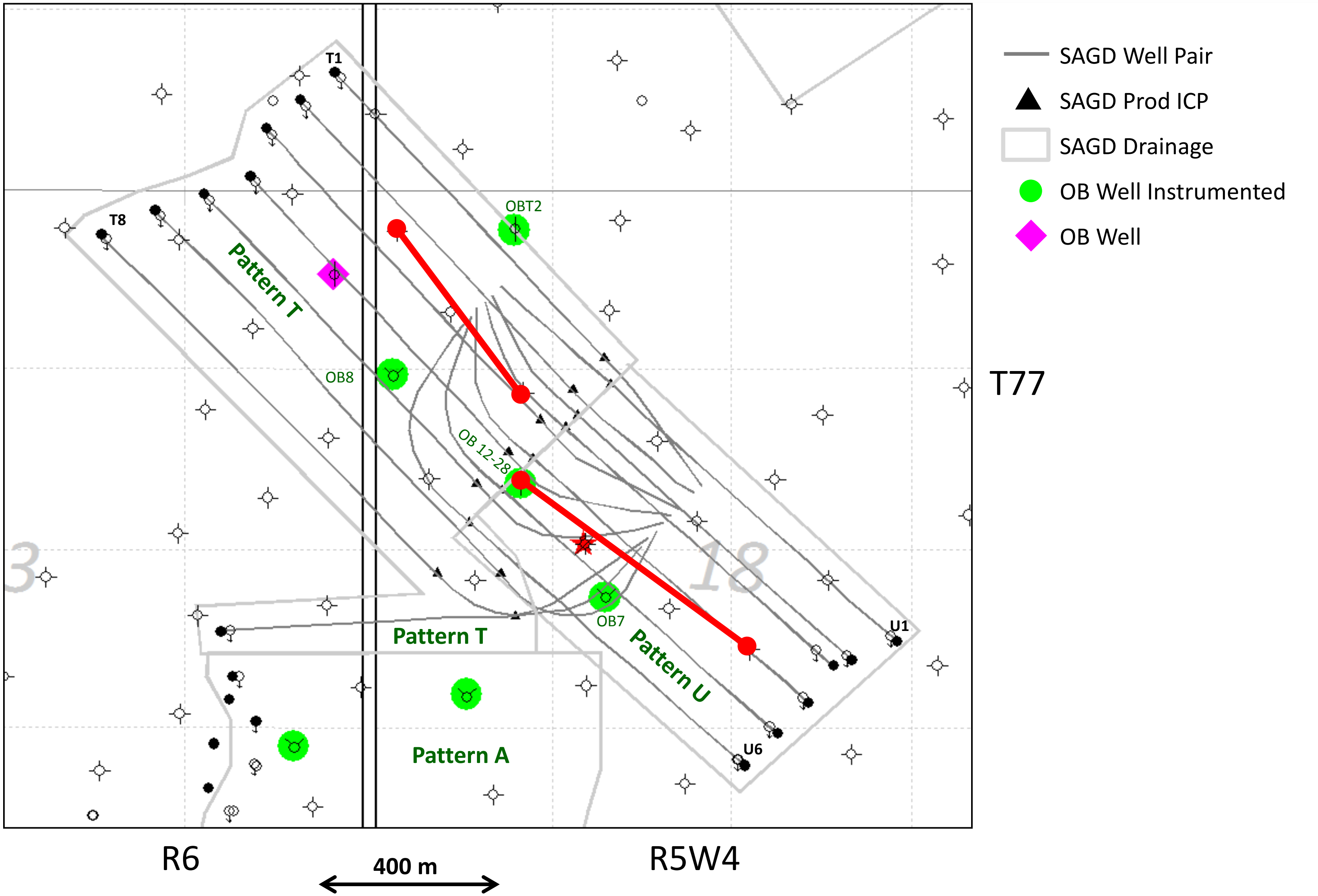
CLRP Pattern M SAGD Development



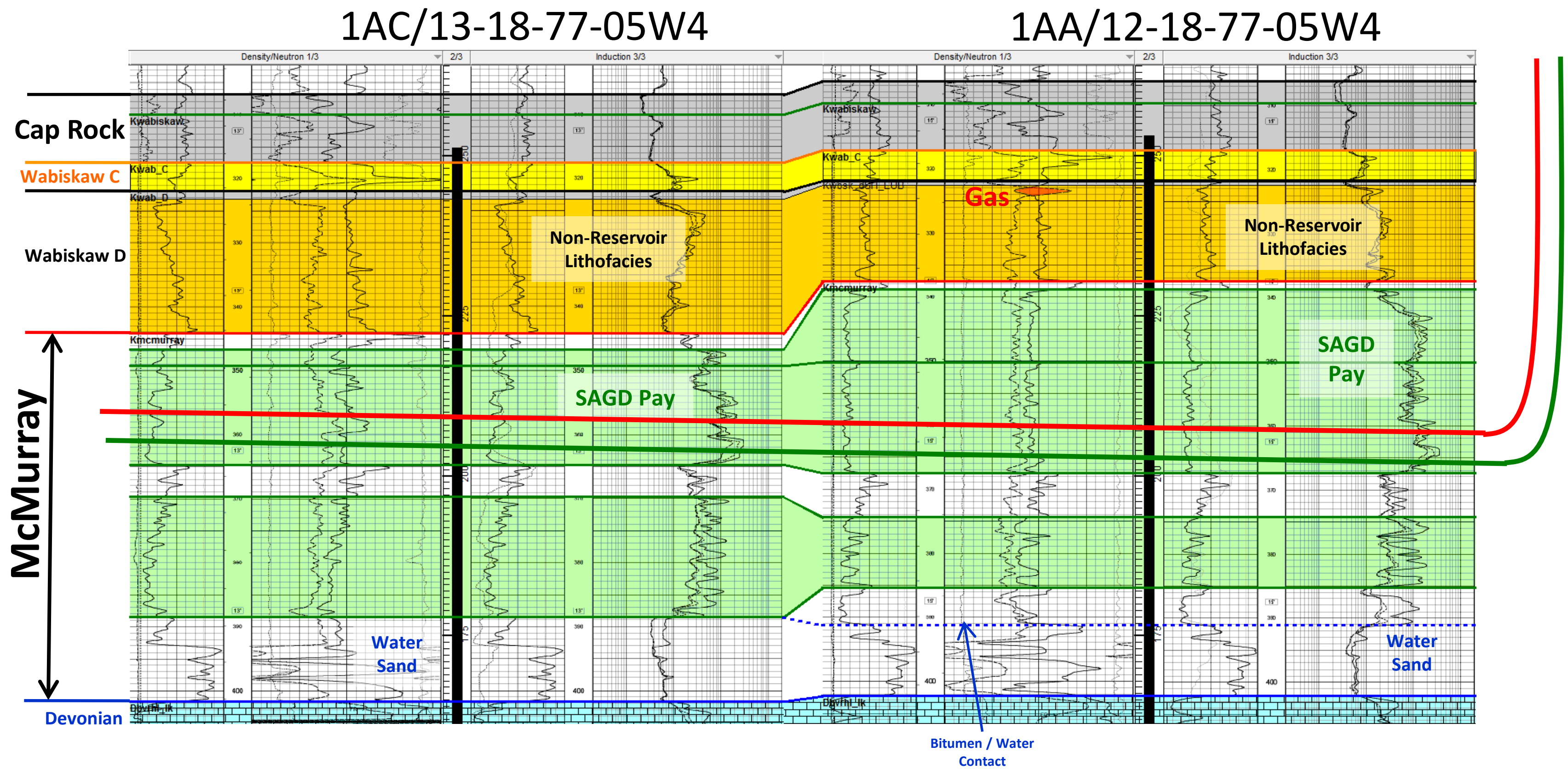
CLRP Pattern N SAGD Development



CLRP T & U SAGD Development

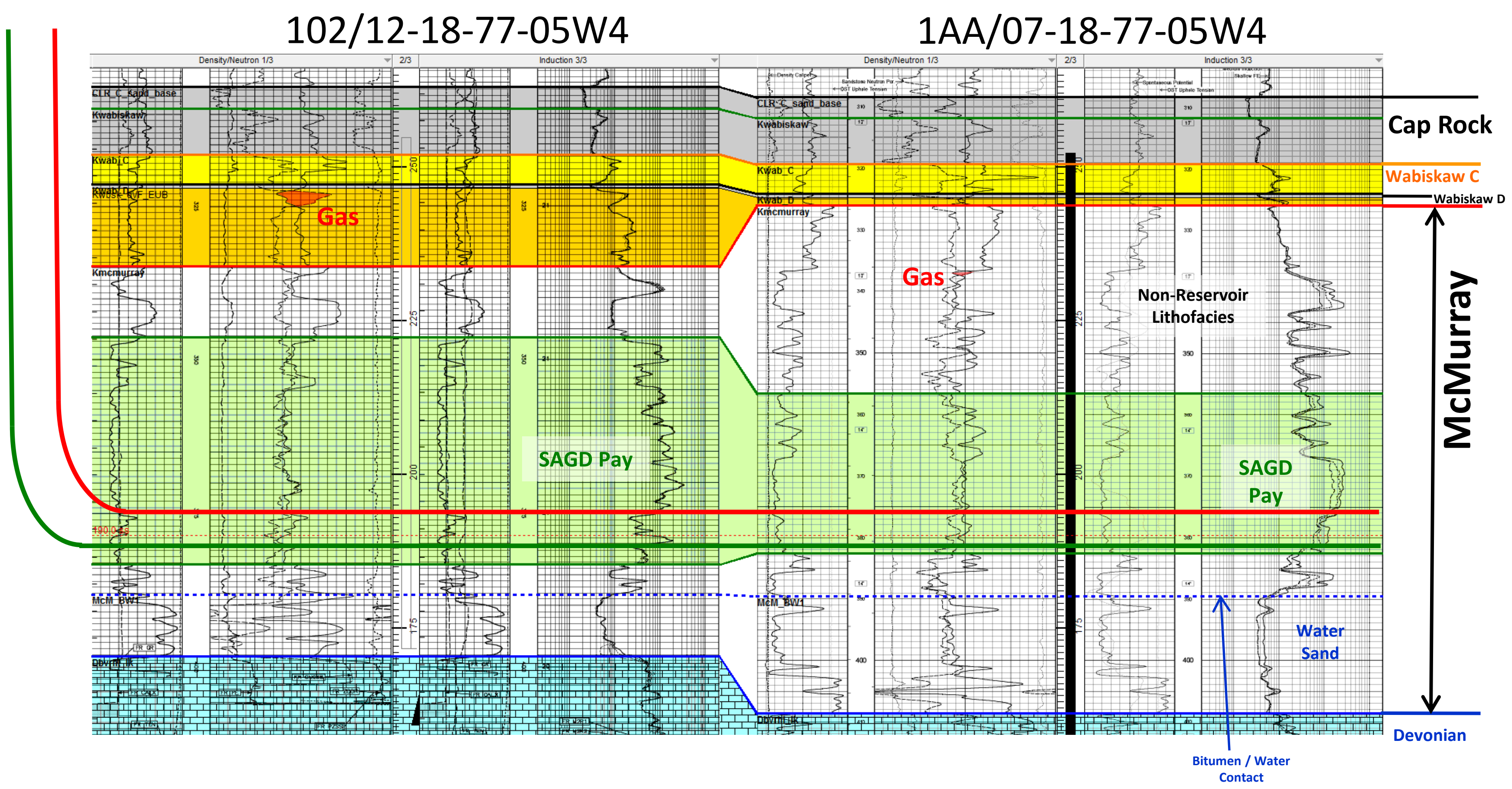


CLRP Pattern T SAGD Development

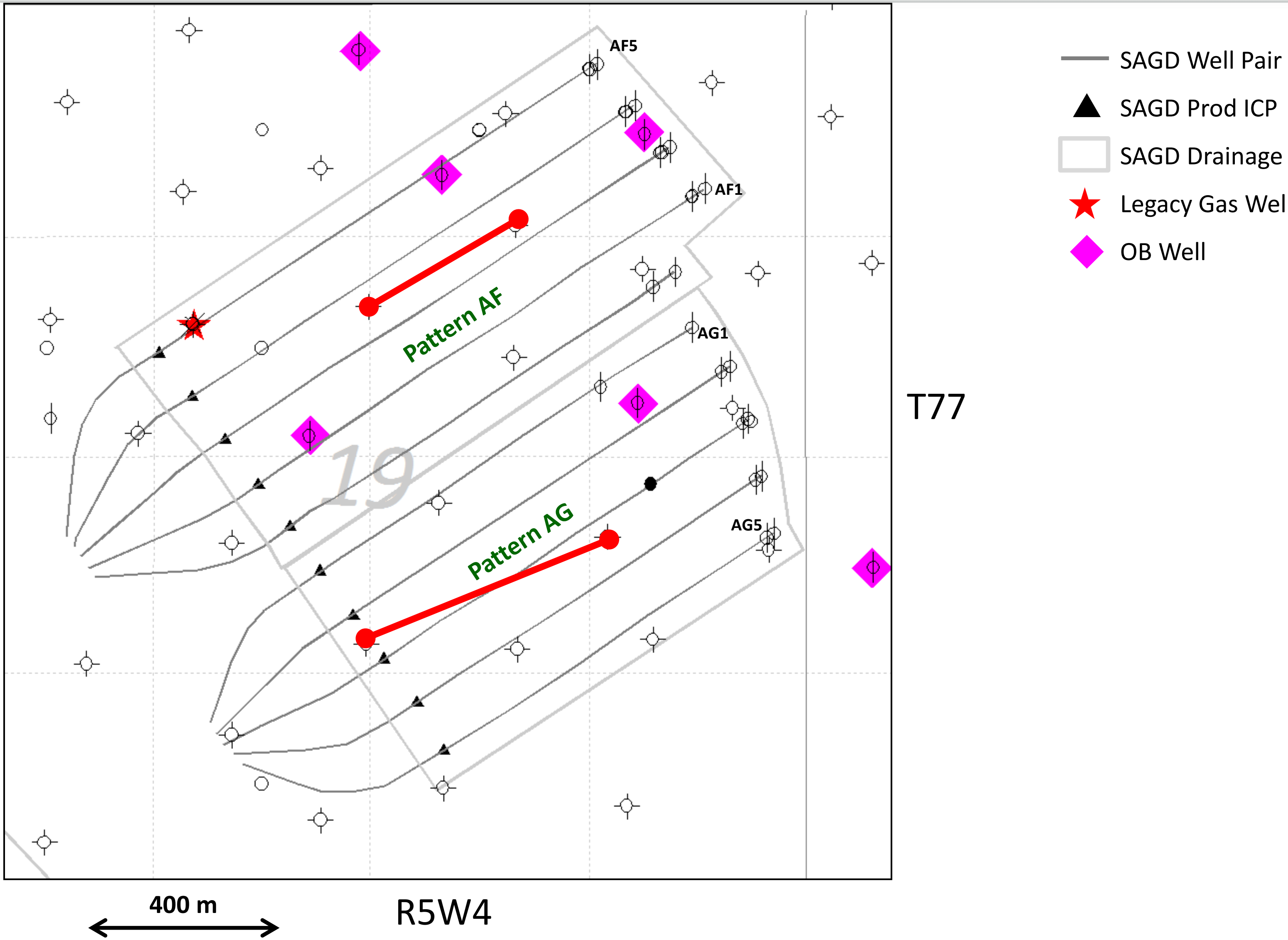


Lower sands to be developed at a later date

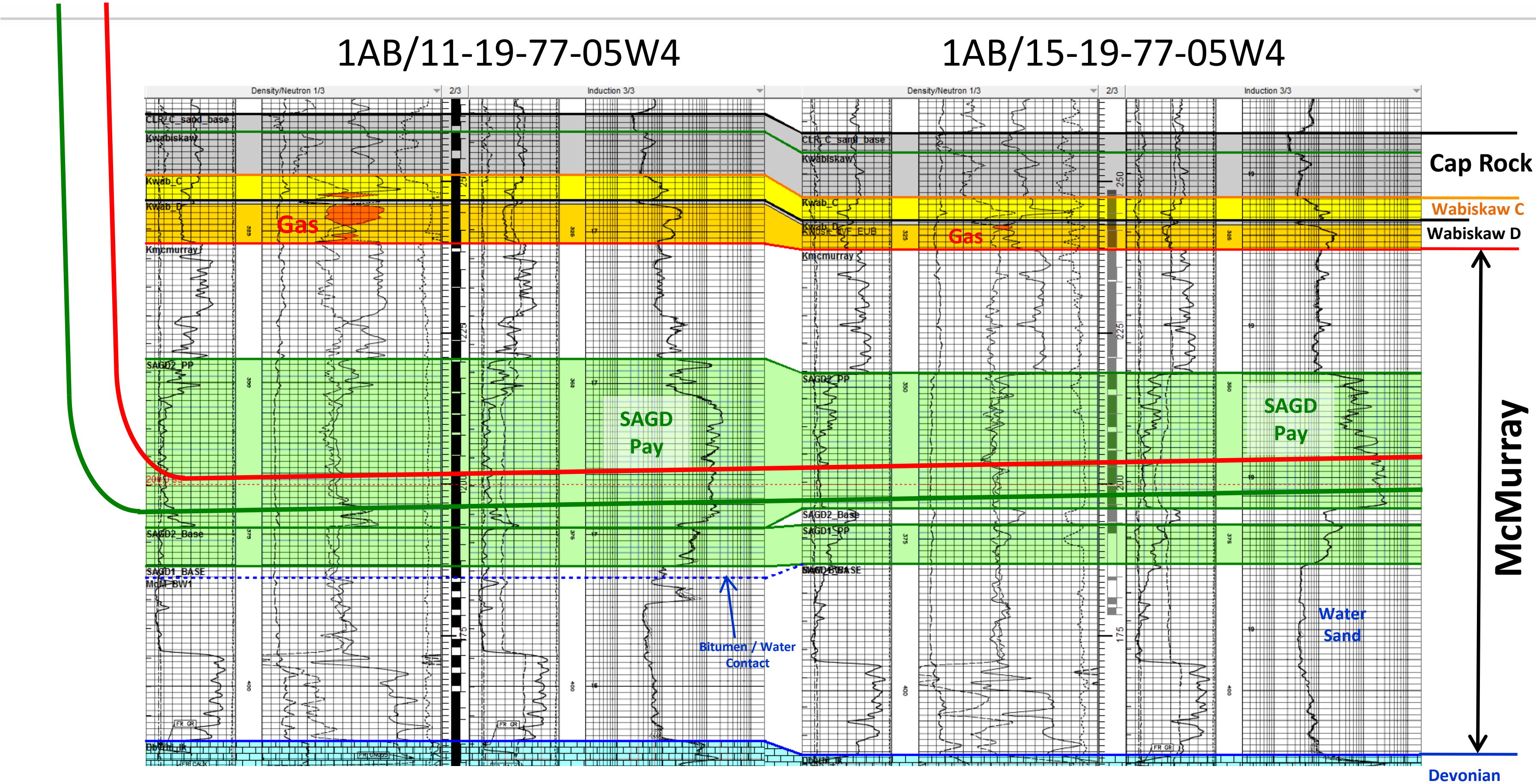
CLRP Pattern U SAGD Development



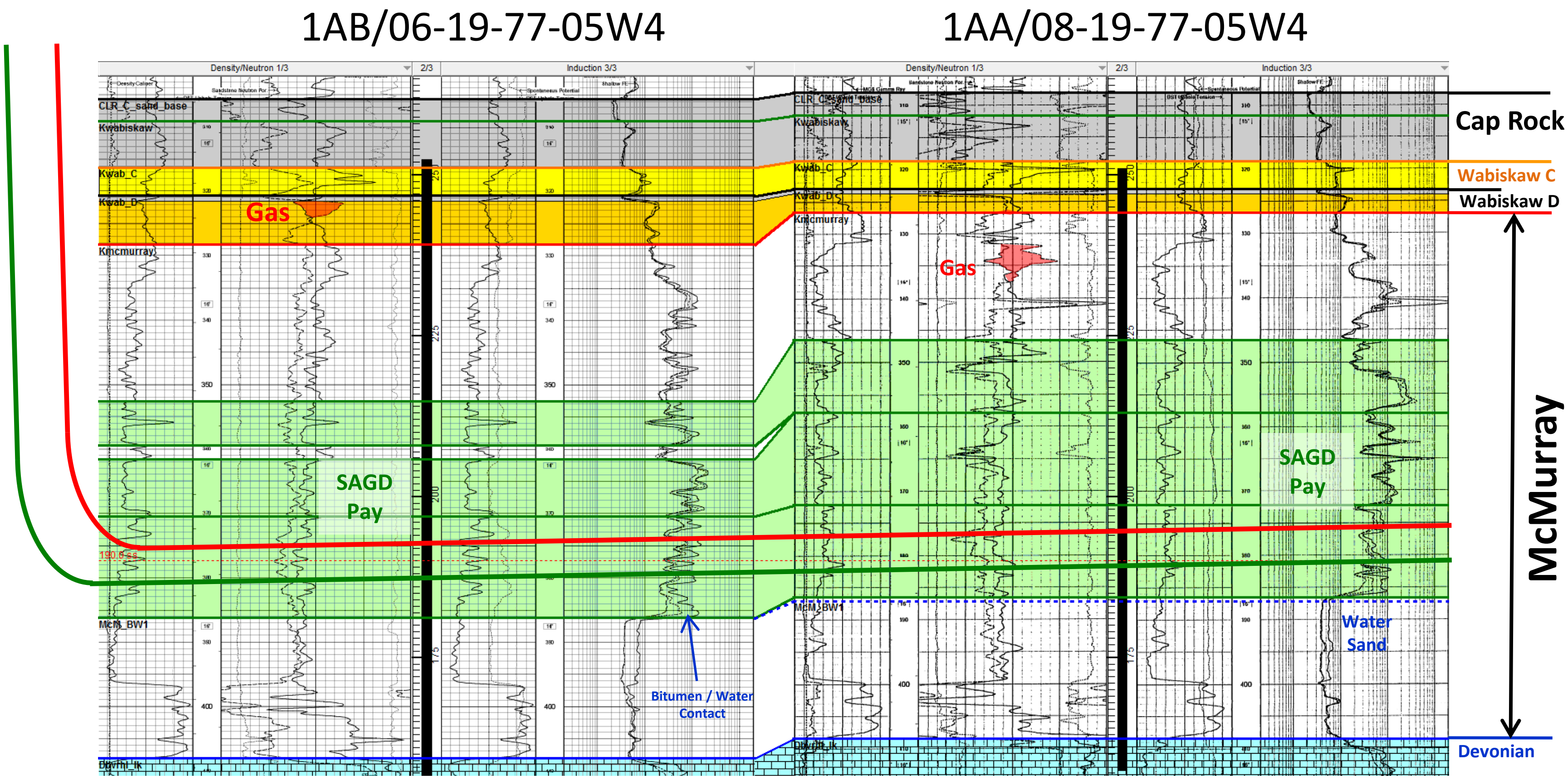
CLRP AF & AG SAGD Development



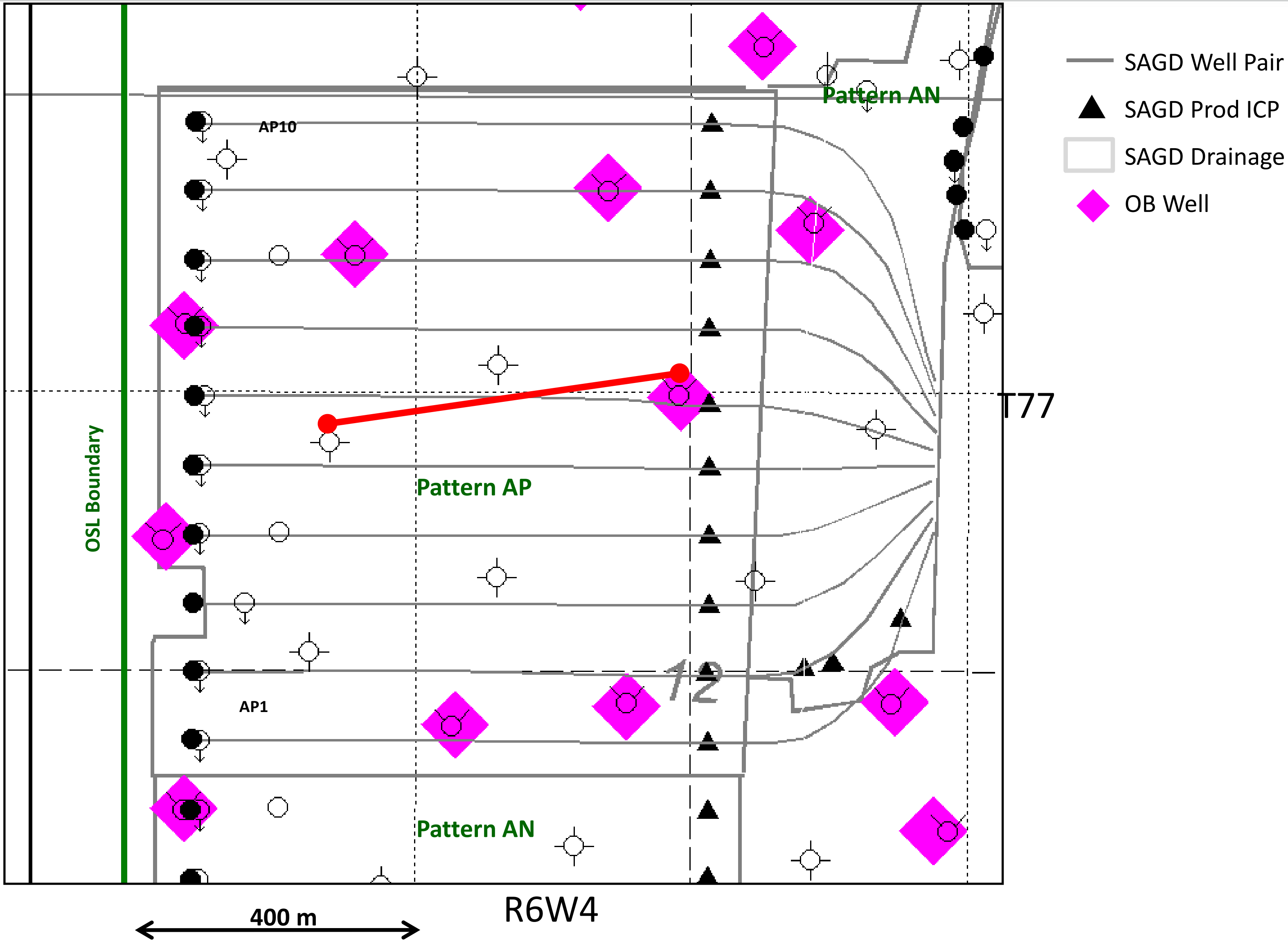
CLRP Pattern AF SAGD Development



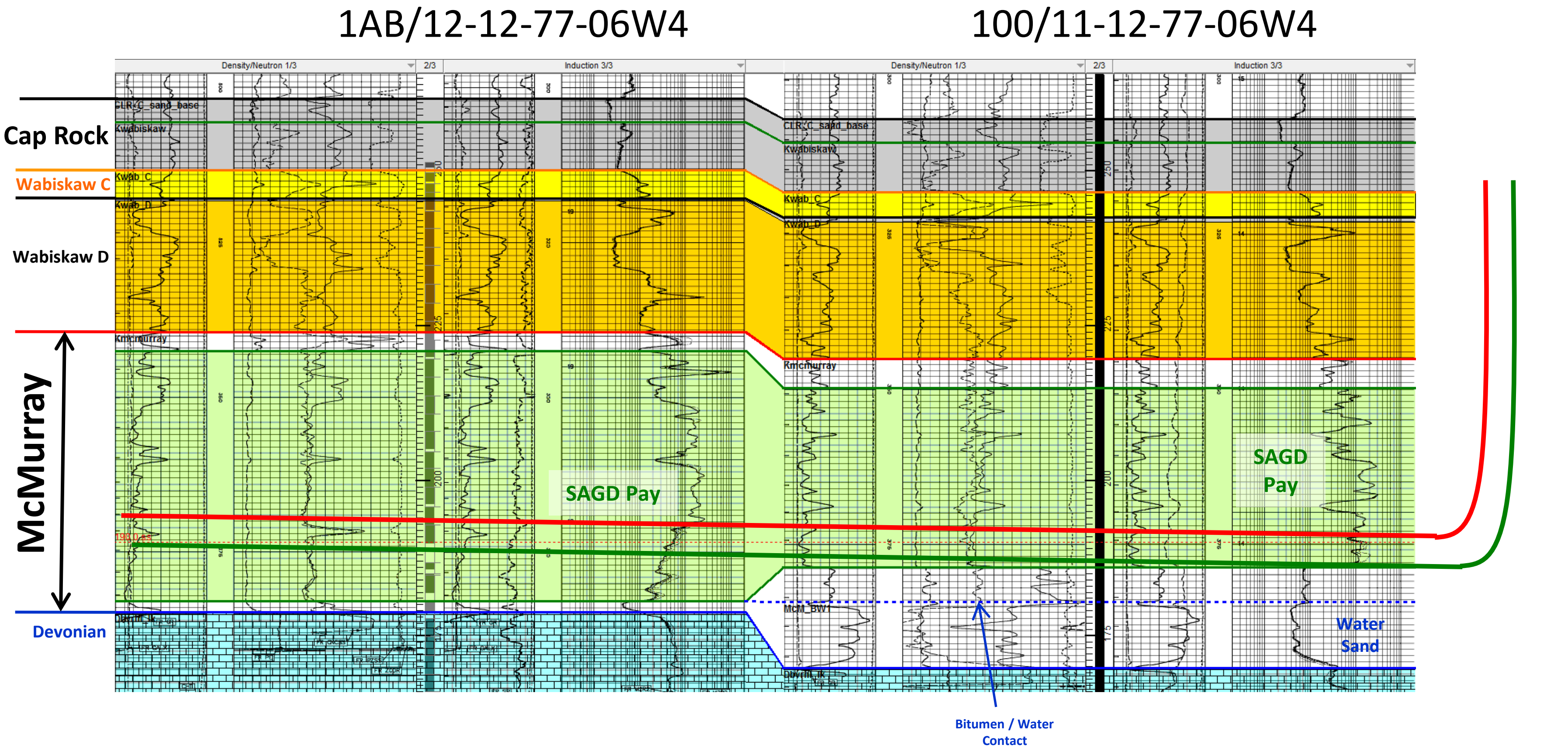
CLRP Pattern AG SAGD Development



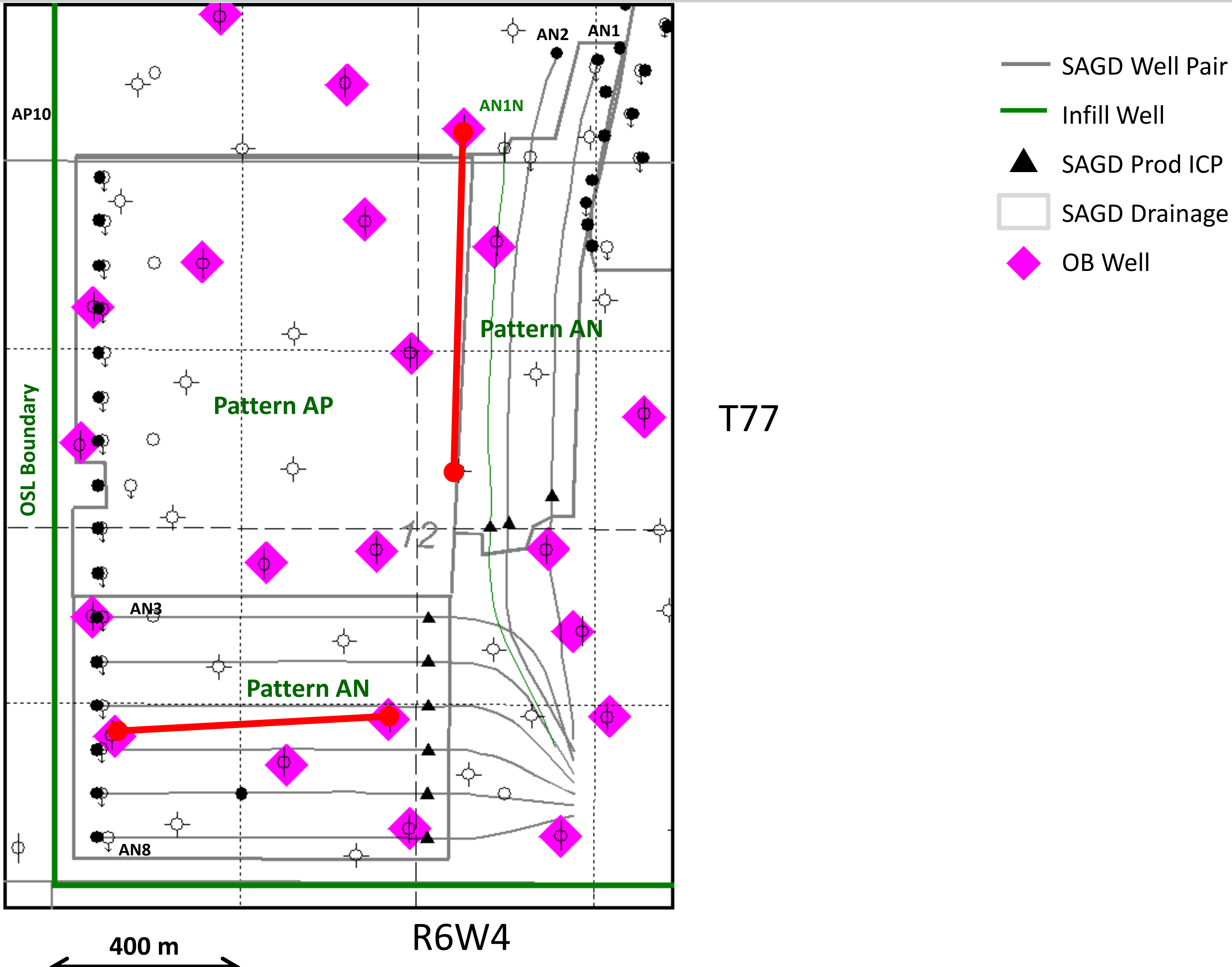
CLRP AP SAGD Development



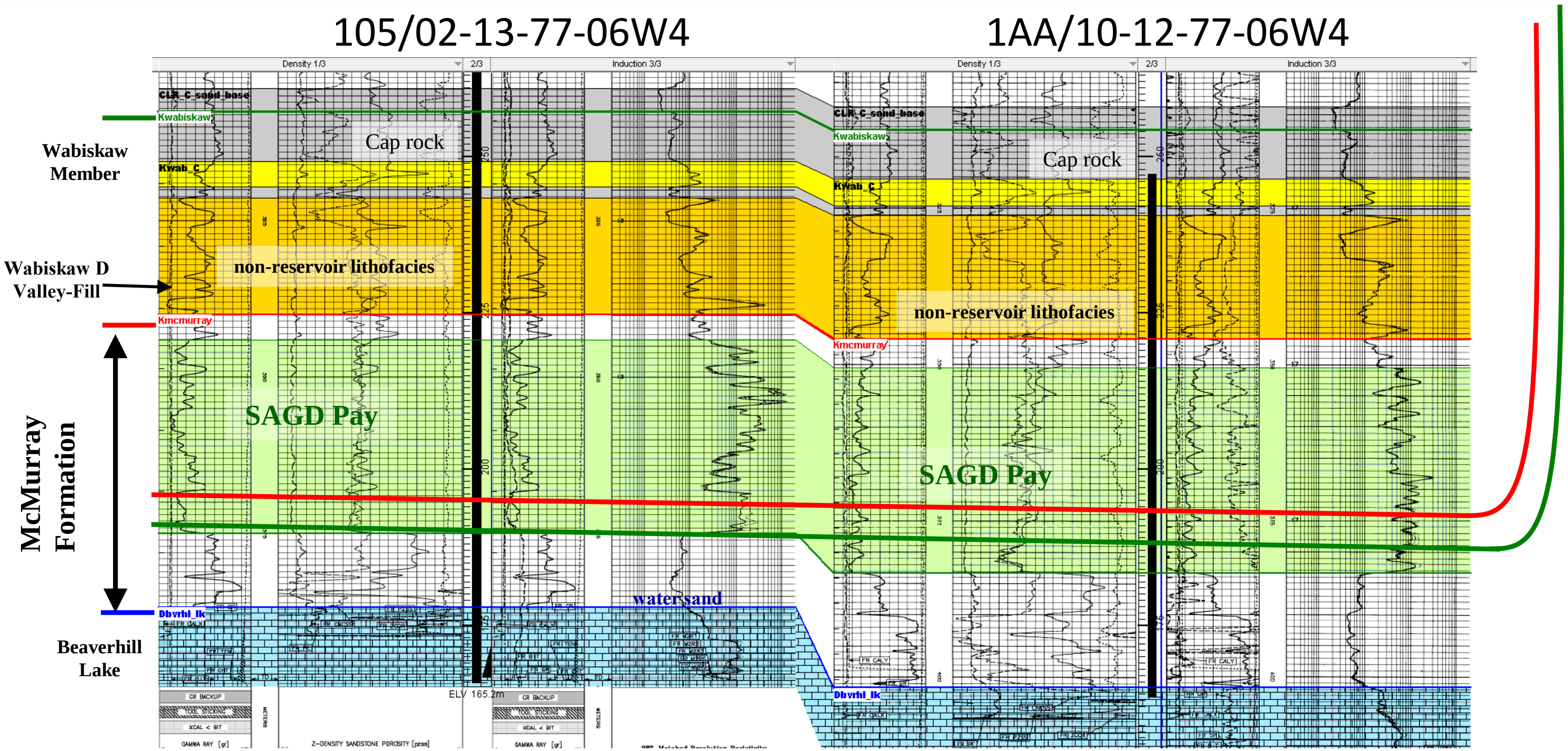
CLRP Pattern AP SAGD Development



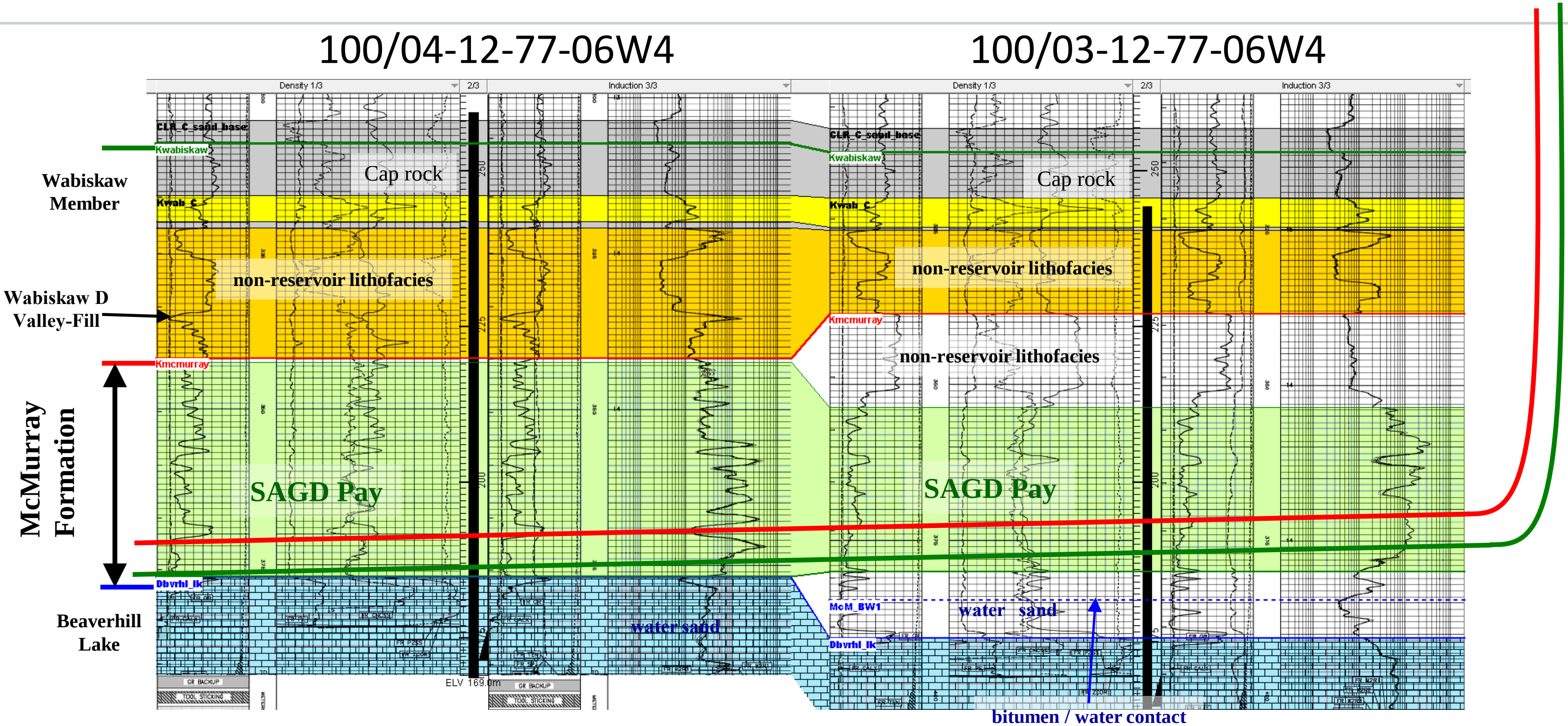
CLRP AN SAGD Development



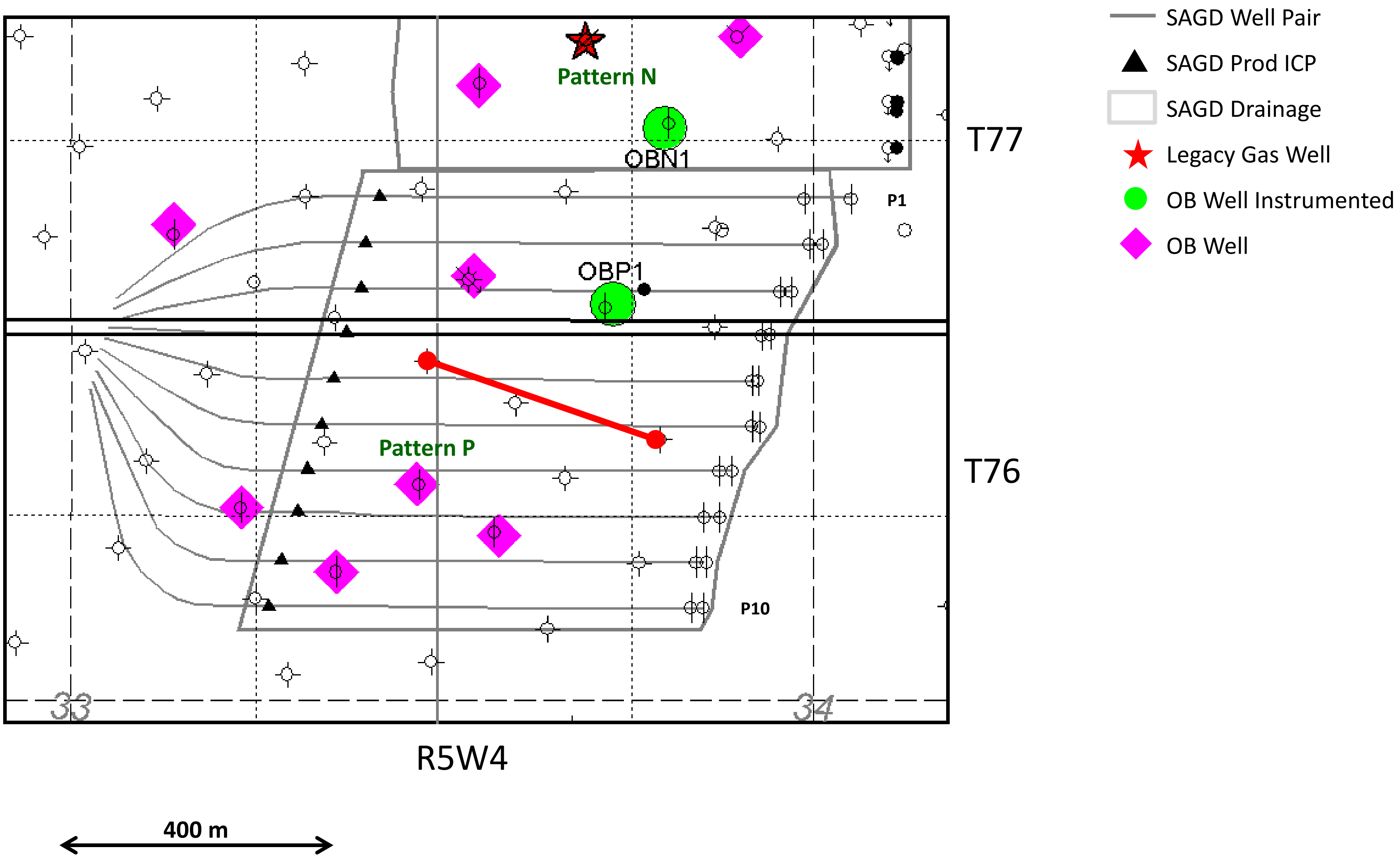
CLRP Pattern AN SAGD Development



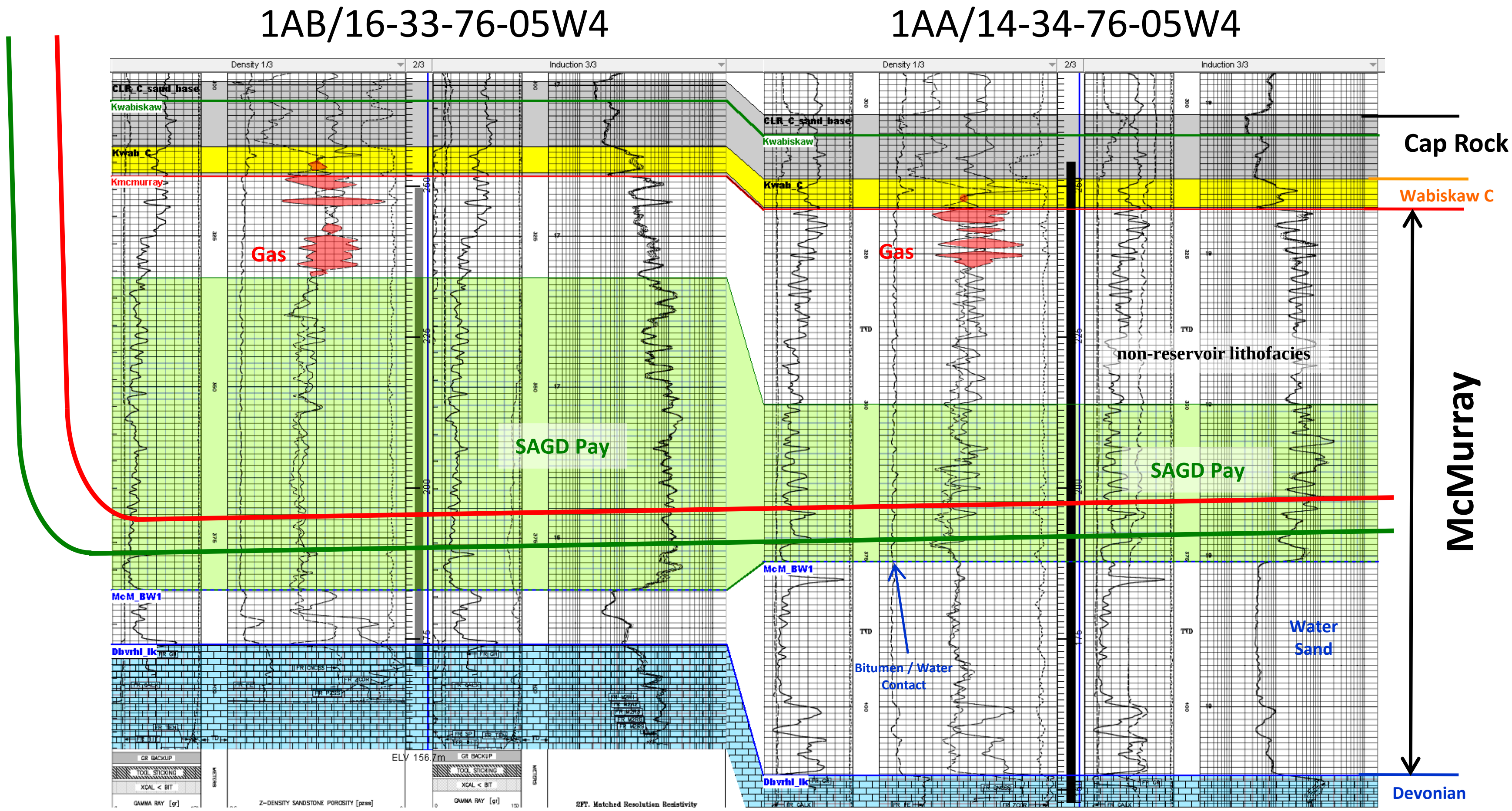
CLRP Pattern AN SAGD Development



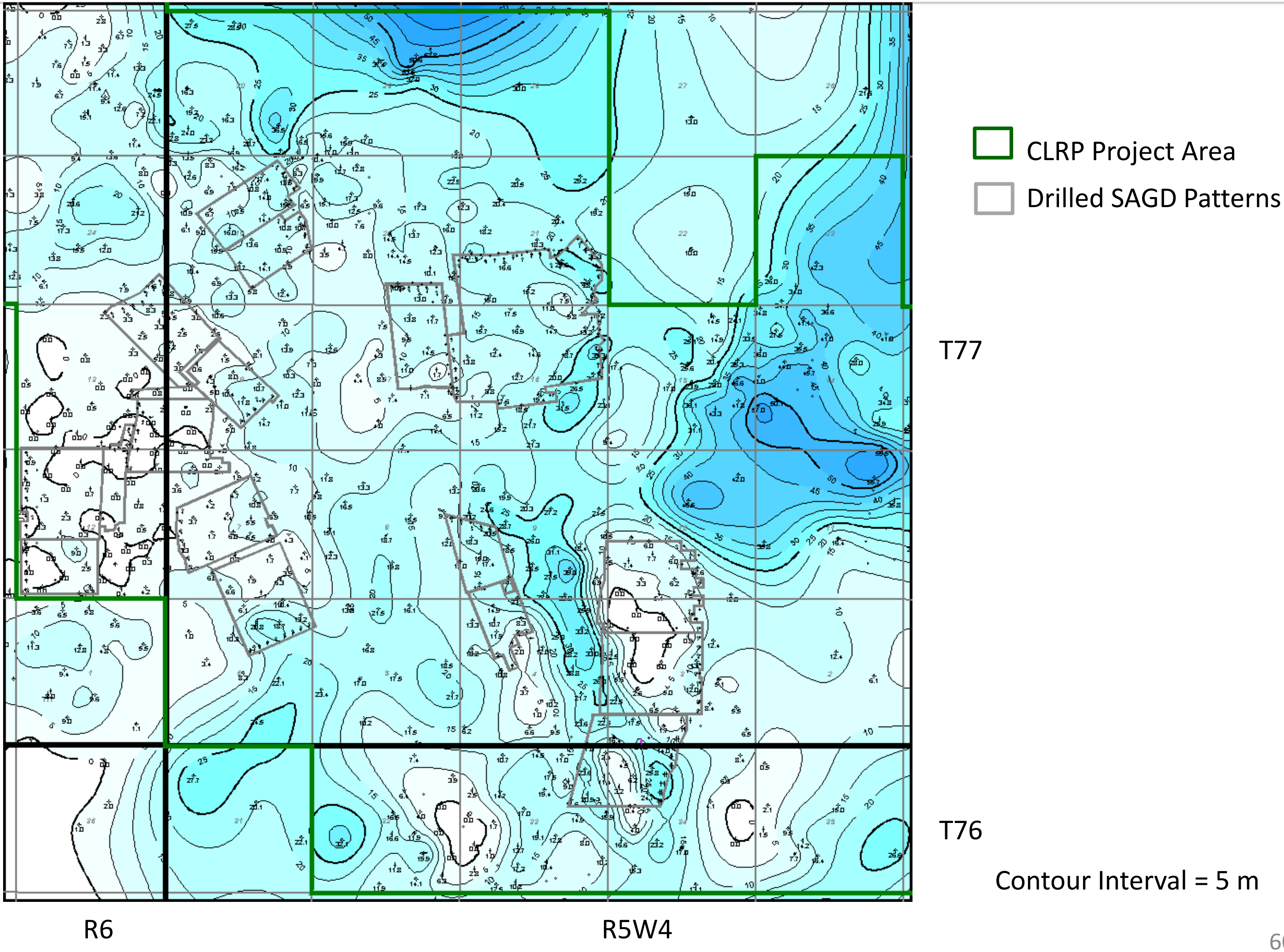
CLRP P SAGD Development



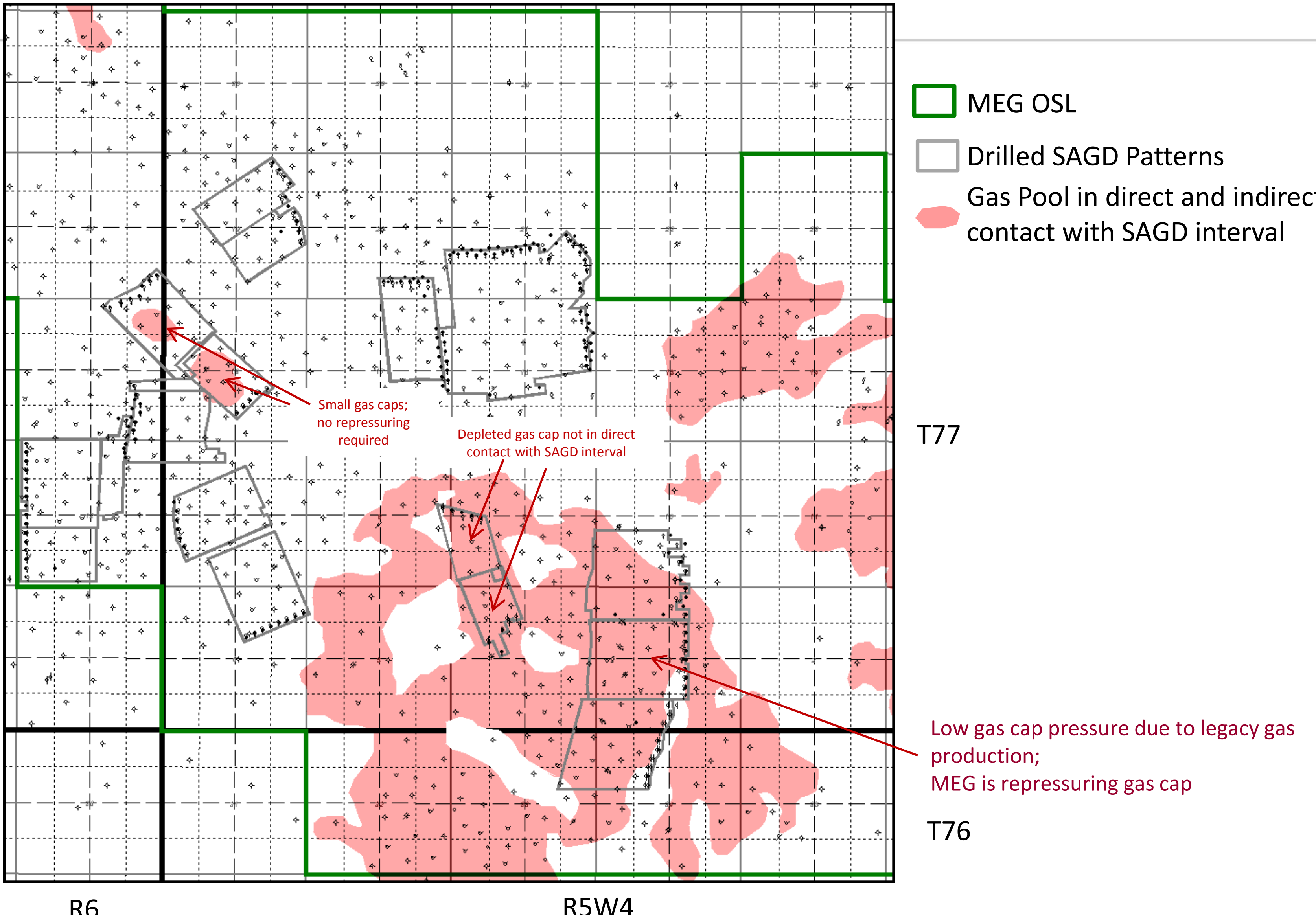
CLRP Pattern P SAGD Development



CLRP ADA Basal McMurray Net Water Isopach



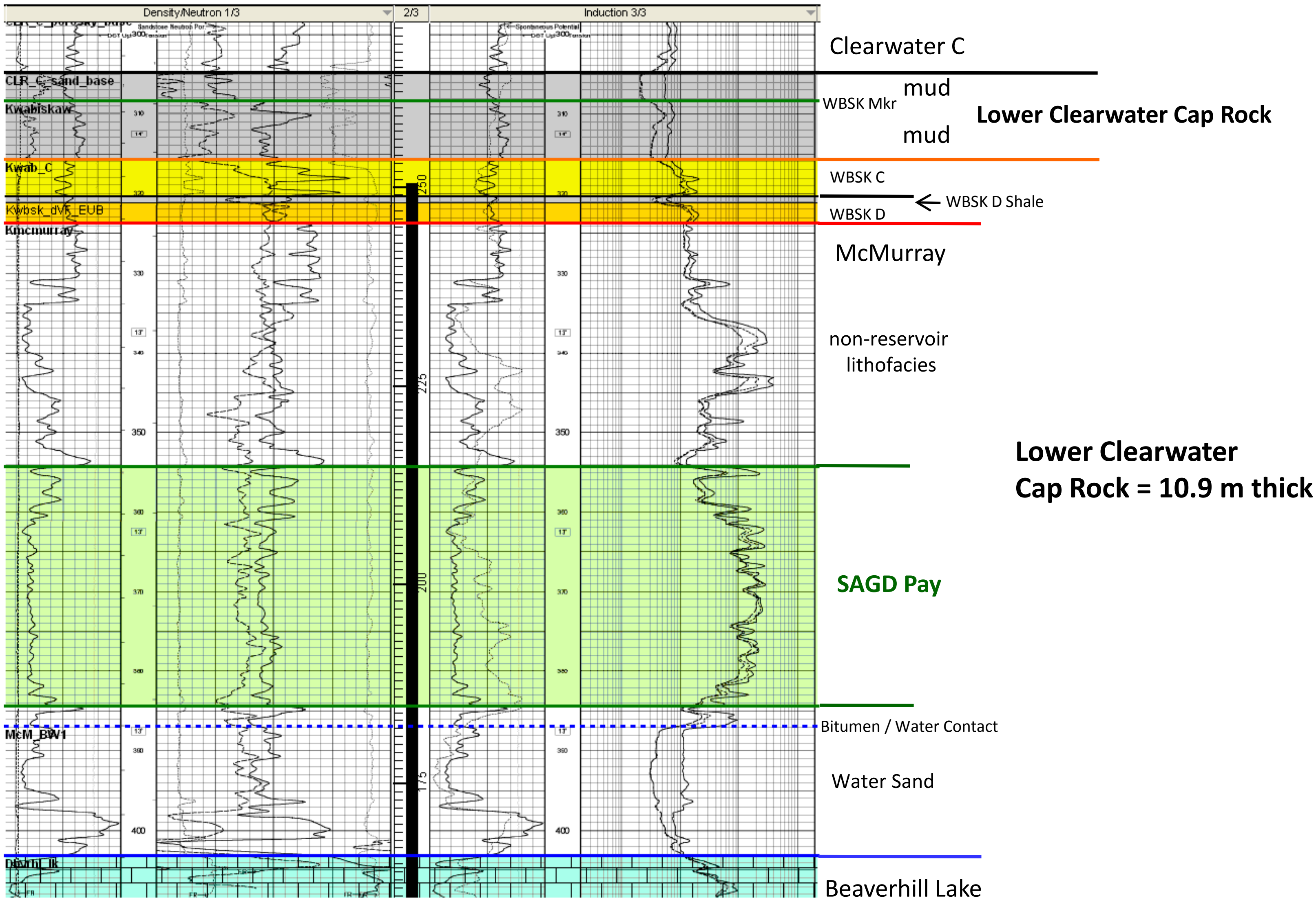
CLRP ADA Associated McMurray Gas Pools



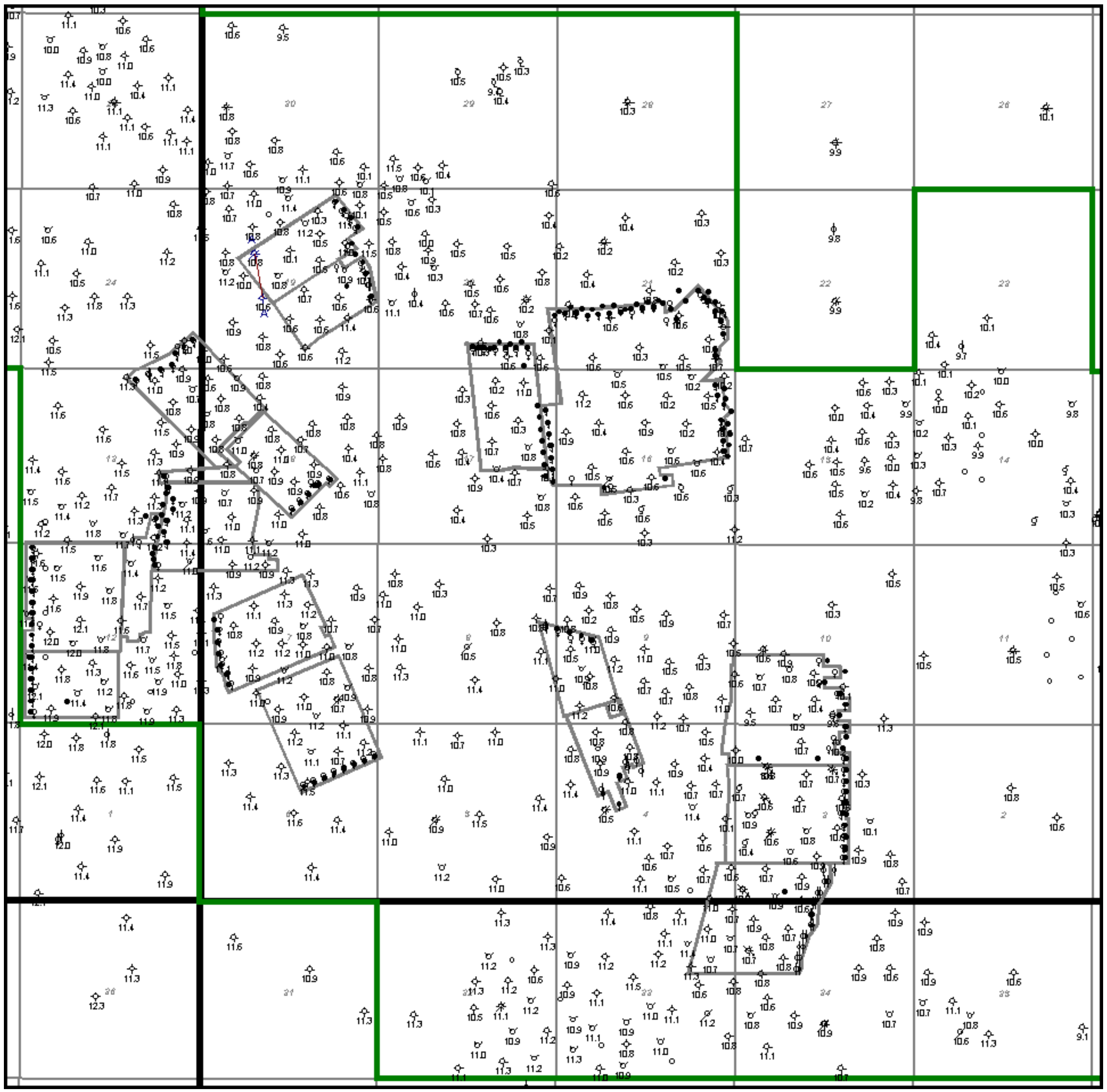
Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

CLRP Lower Clearwater Cap Rock

1AE/06-18-77-05W4



CLRP ADA Lower Clearwater Cap Rock



CLRP Project Area

Drilled SAGD Patterns

T77

Active Development Area

Average Cap rock Thickness = 10.8 m

Minimum Thickness = 8.6 m

Maximum Thickness = 13.1 m

T76

Thickness in Metres

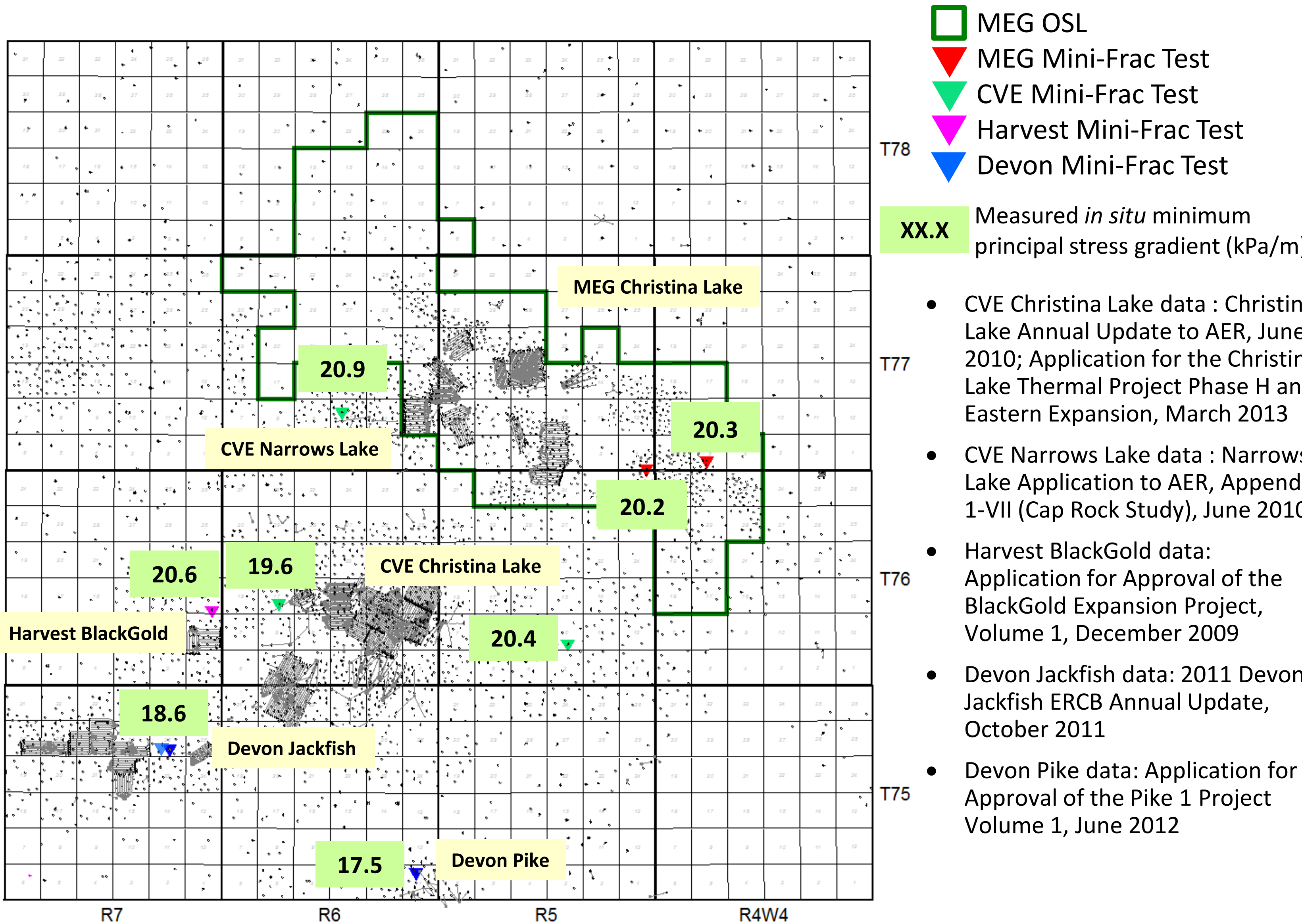
R6

R5W4

CLRP Lower Clearwater Cap Rock Testing

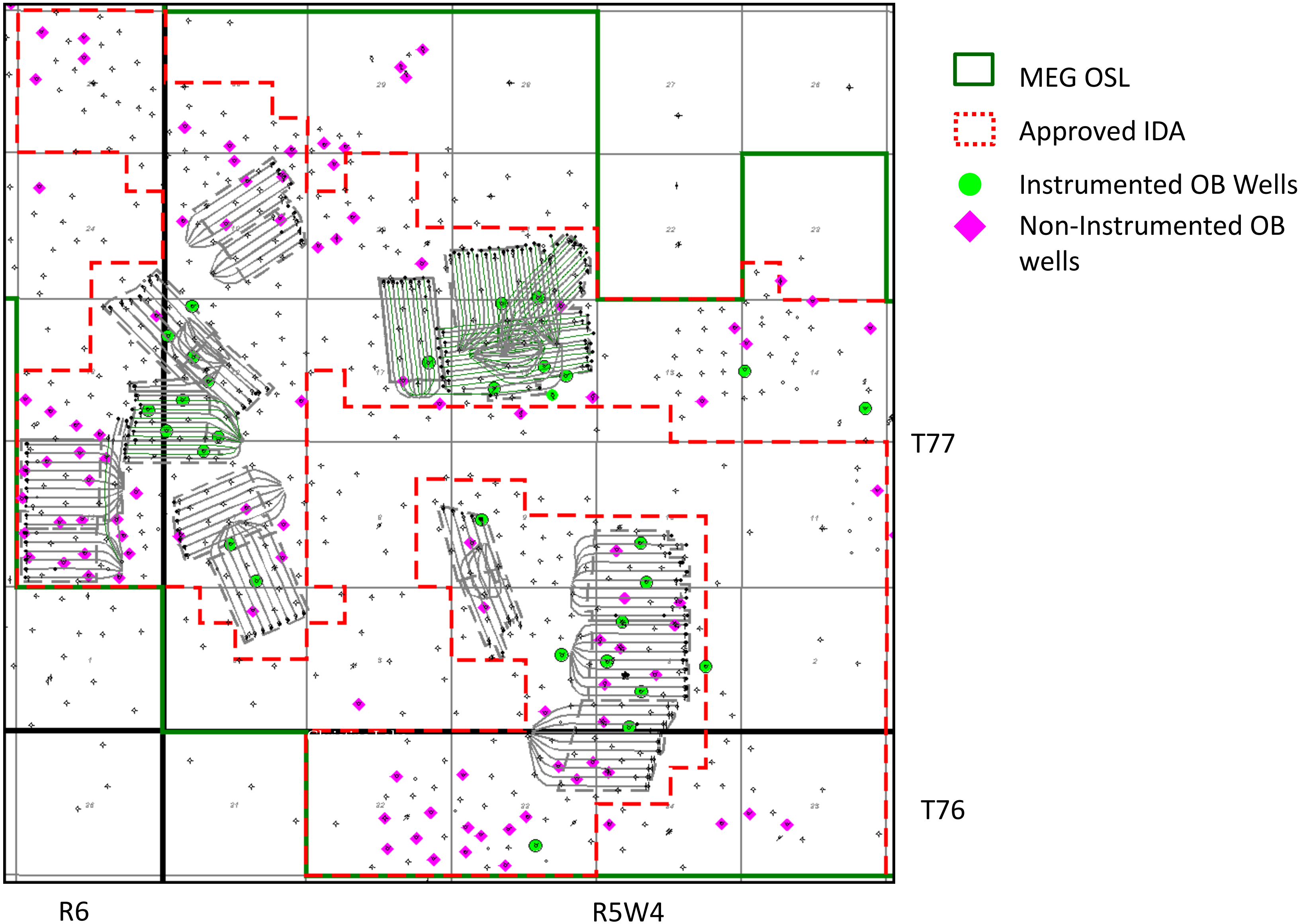
- The measured minimum *in situ* principal stress gradient in the Clearwater cap rock is approximately 20 kPa/m. This gradient coincides with the weight of the overburden as derived from density logs indicating the minimum principal stress is in the vertical direction, i.e., if fracturing were to occur, it is likely in the horizontal direction.
- For a typical cap rock depth of 320 m in the CLRP area, the minimum principal stress is 6,400 kPa. This is more than twice the anticipated steady state SAGD operating pressure.
- The measured minimum *in situ* principal stress gradient in the McMurray oil sands is slightly lower at approximately 18 kPa/m. This indicates the minimum principal stress is likely in the horizontal direction, i.e., if fracturing were to occur, it is likely in the vertical direction.
- Quote from BitCan Geosciences & Engineering Inc.:
  - *"…if a vertical fracture inadvertently propagated out of the payzone into the cap rock, it would eventually turn horizontal. This is due to the in-situ stress regime in the caprock favoring horizontal fractures. Therefore, the vertical fracture extending upwards from the payzone is arrested in the caprock and does not propagate further upwards, i.e., it cannot form the hydraulic conduit connecting the payzone and aquifers."*
- MEG's measurements are consistent with other operators' mini-frac results in the Christina Lake area.

Regional Cap Rock Mini-Frac Test Results



- CVE Christina Lake data : Christina Lake Annual Update to AER, June 2010; Application for the Christina Lake Thermal Project Phase H and Eastern Expansion, March 2013
- CVE Narrows Lake data : Narrows Lake Application to AER, Appendix 1-VII (Cap Rock Study), June 2010
- Harvest BlackGold data: Application for Approval of the BlackGold Expansion Project, Volume 1, December 2009
- Devon Jackfish data: 2011 Devon Jackfish ERCB Annual Update, October 2011
- Devon Pike data: Application for Approval of the Pike 1 Project Volume 1, June 2012

CLRP ADA OB and Cased Wells



MEG ENERGY

Reservoir

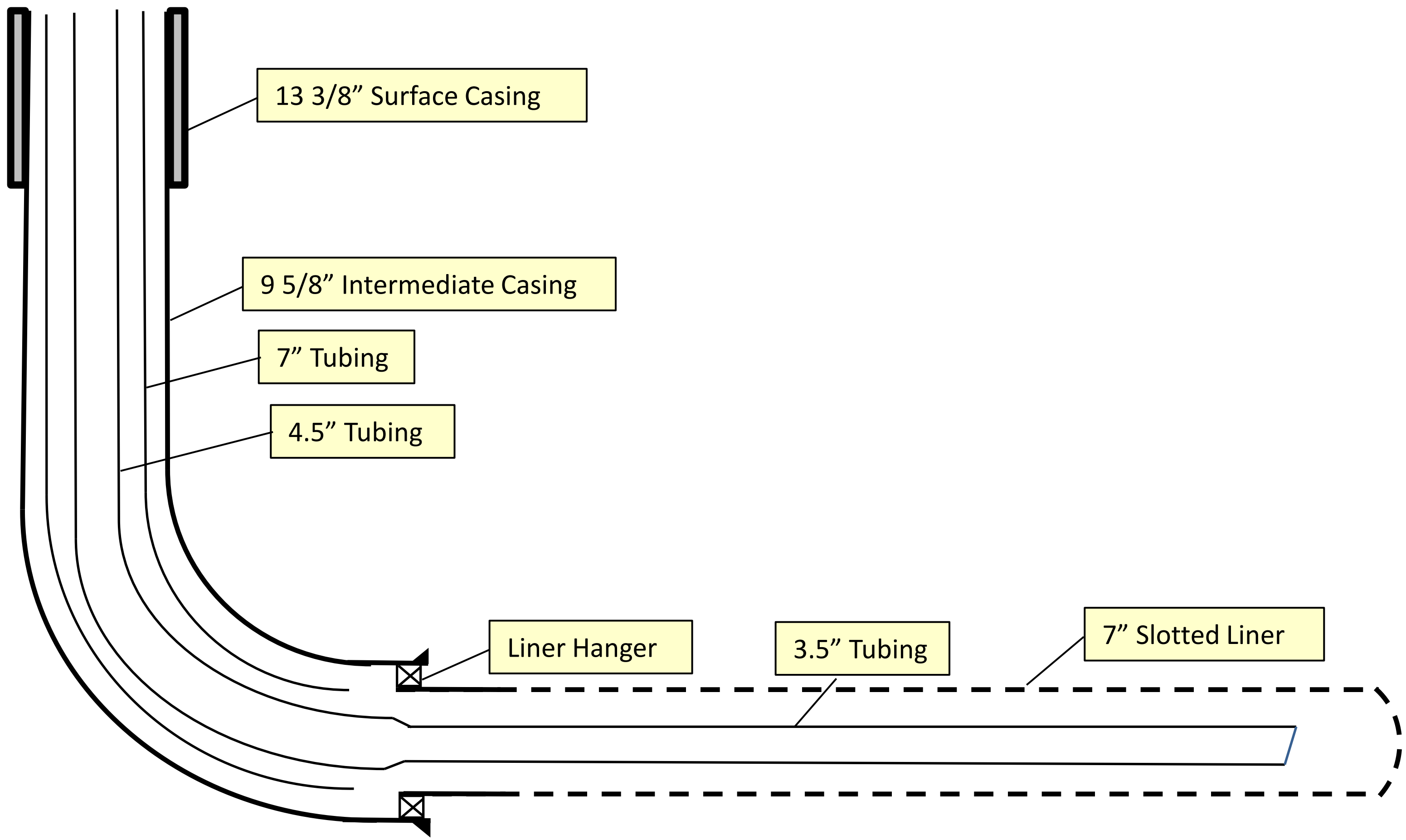
CLRP Reservoir Review

- Wells
  - Schematics
  - Well Integrity Management
  - Work overs
  - Artificial Lift
- Current Performance
  - Field performance
  - Pattern performance
  - eMSAGP update
- Associated gas cap re-pressuring

MEG Energy

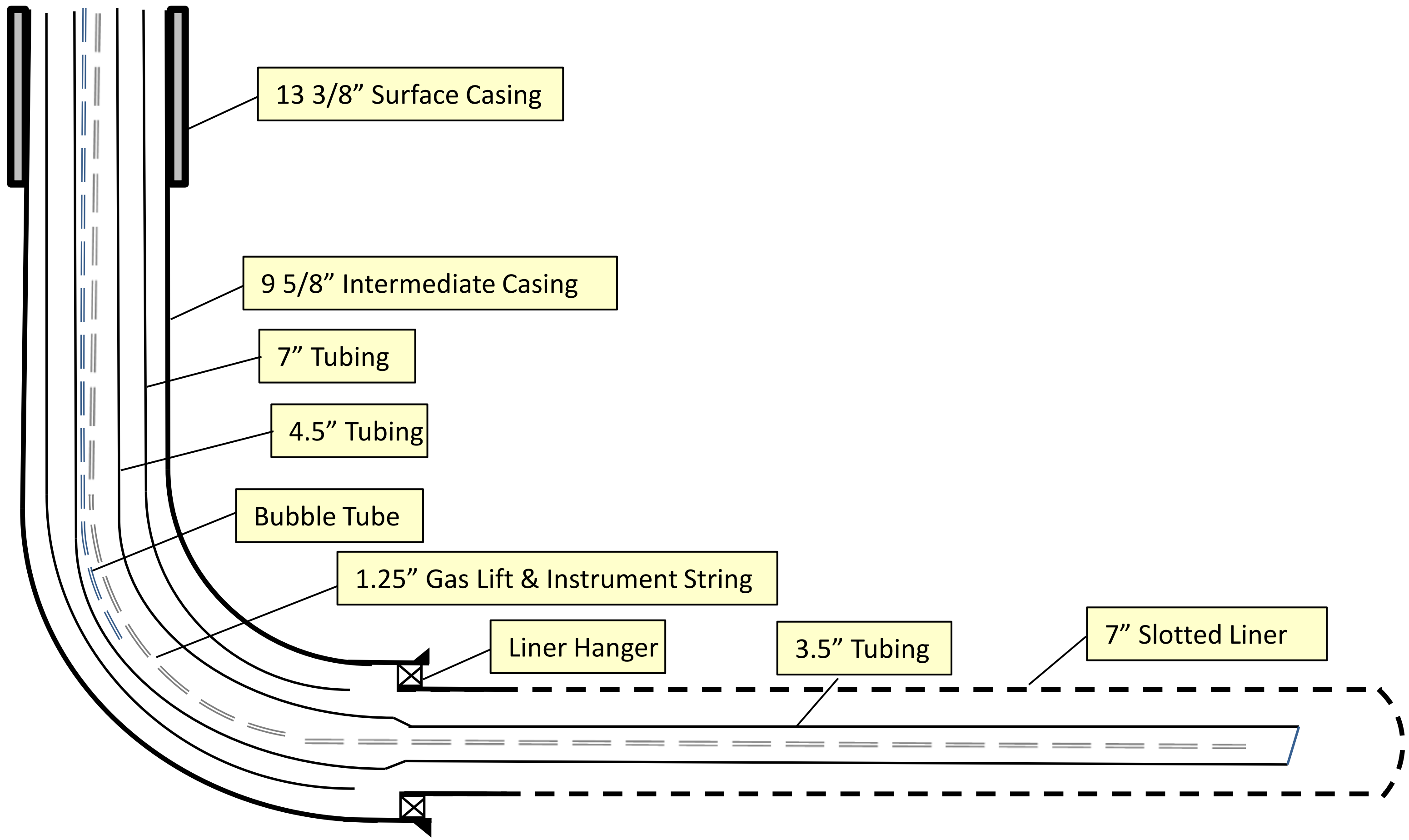
Wells

Well Completions – SAGD Injector



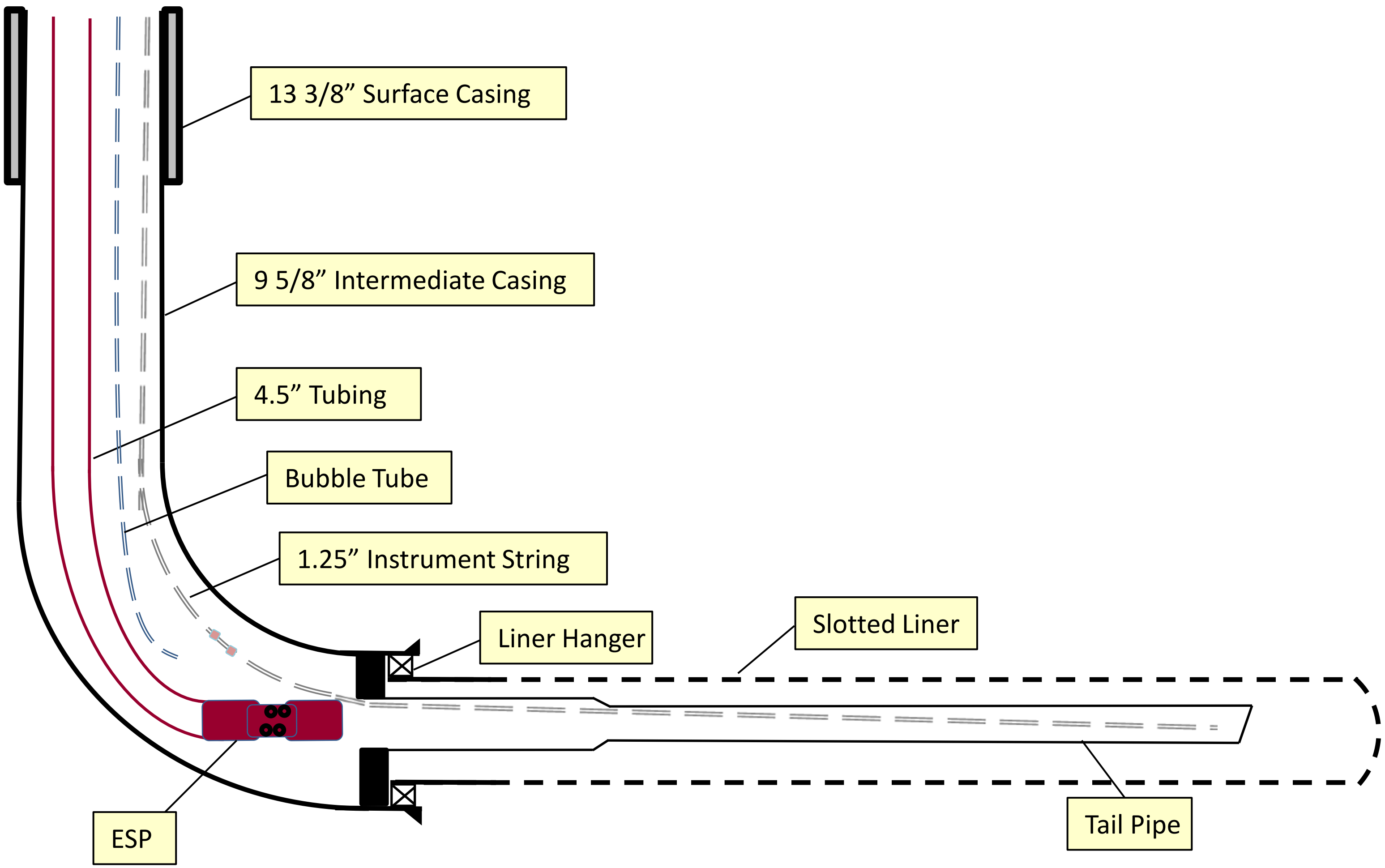
- Steam injected into both long tubing and short tubing
- Blanket gas on annulus

Well Completions – SAGD Producer (Gas Lift)



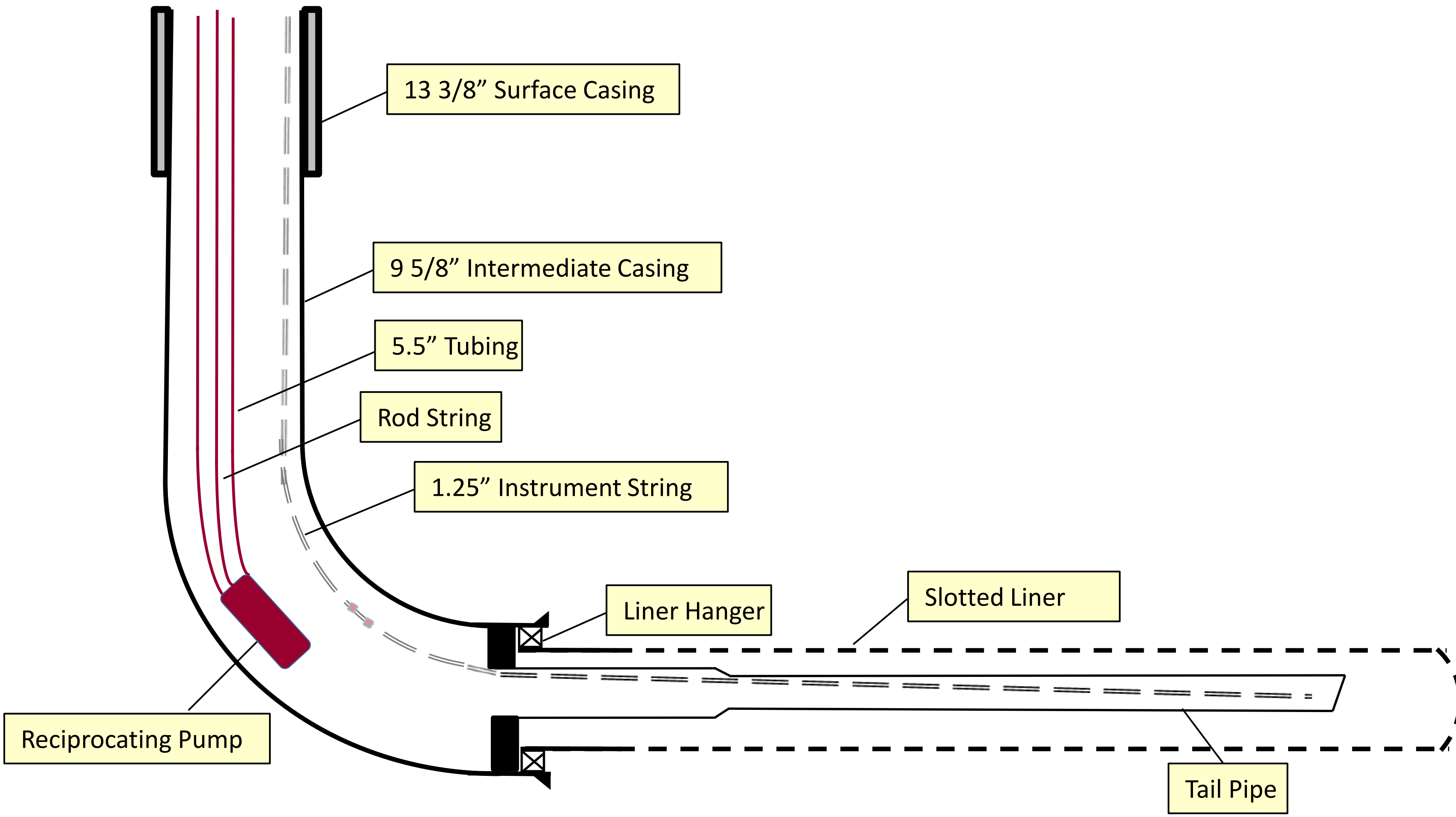
- Thermocouples are inside the instrument string to provide temperature measurements at selected locations
- Bubble tube landed near bottom of well to provide pressure measurement

Well Completions – SAGD Producers (ESP)



- Thermocouples 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 – Infill Producers

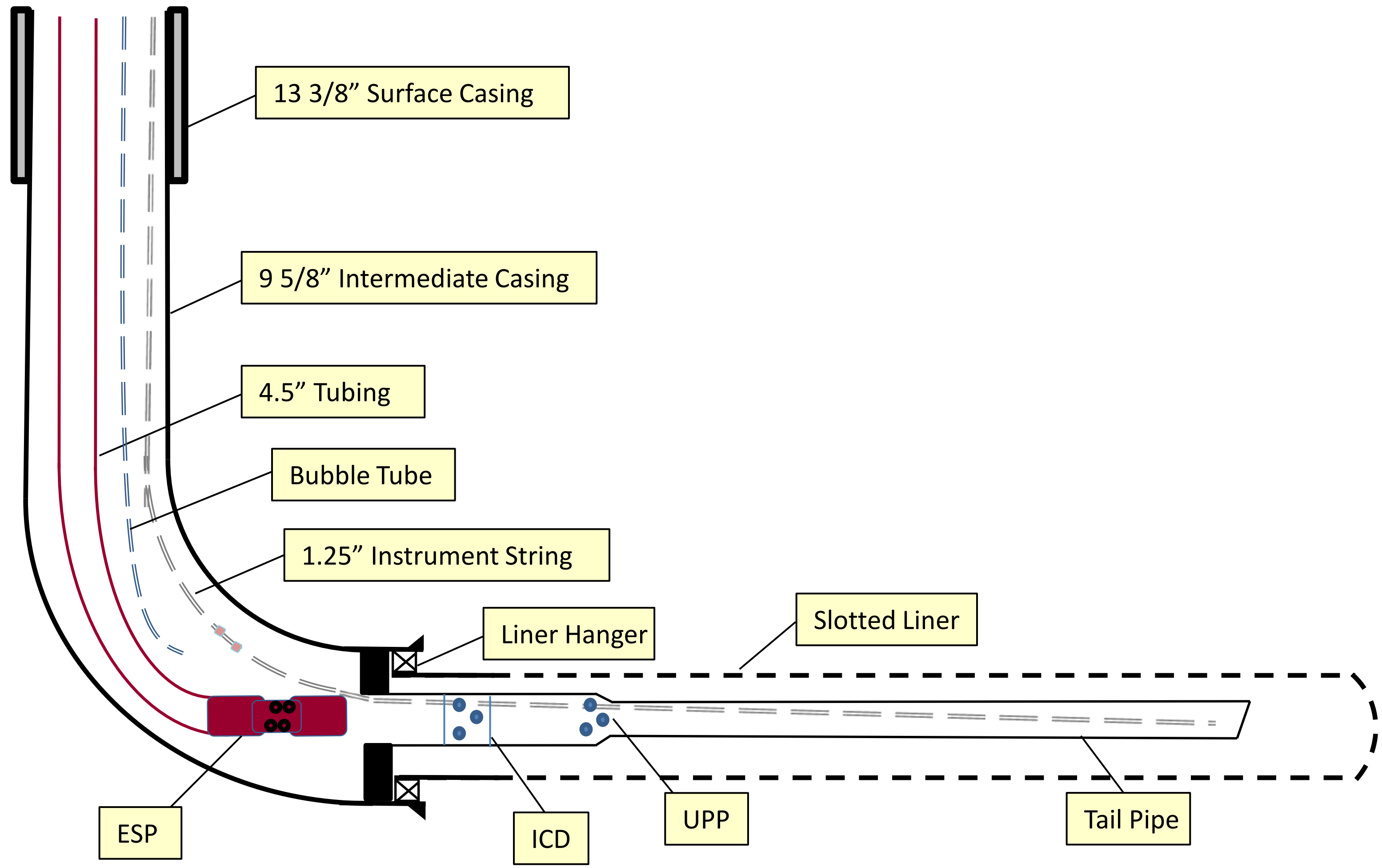


- Thermocouples are inside the instrument string to provide temperature measurements at selected locations
- Bottom hole pressure is estimated from fluid level measurement

Temperature Measurement

- Have historically relied on four-point thermocouple strings in all SAGD and infill wells due to proven accuracy
- Currently have installed thermal fibre on V Pad infill wells (V2N – V7N) and AF SAGD producers (AF1P – AF5P)
- Thermocouples, while accurate, provide far fewer points of measurement and require a well intervention to replace. In the event of thermocouple failure the replacement could be delayed to coincide with an ESP replacement.
- Early experience with thermal fibre implementation required efforts to ensure accurate calibration, reliability, and data system integration. Increased coverage of temperature profile and ease of replacement can provide better well optimization and protection of slotted liner.
- P Pad, newest SAGD pad scheduled for steam-in Q3 2015, has fibre installed as part of an ongoing evaluation of performance and costs which will determine the choice of technology for future pads

Well Completions – Inflow Control Devices



- Upset production port (UPP) typically consists of 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

ICD Lessons Learned

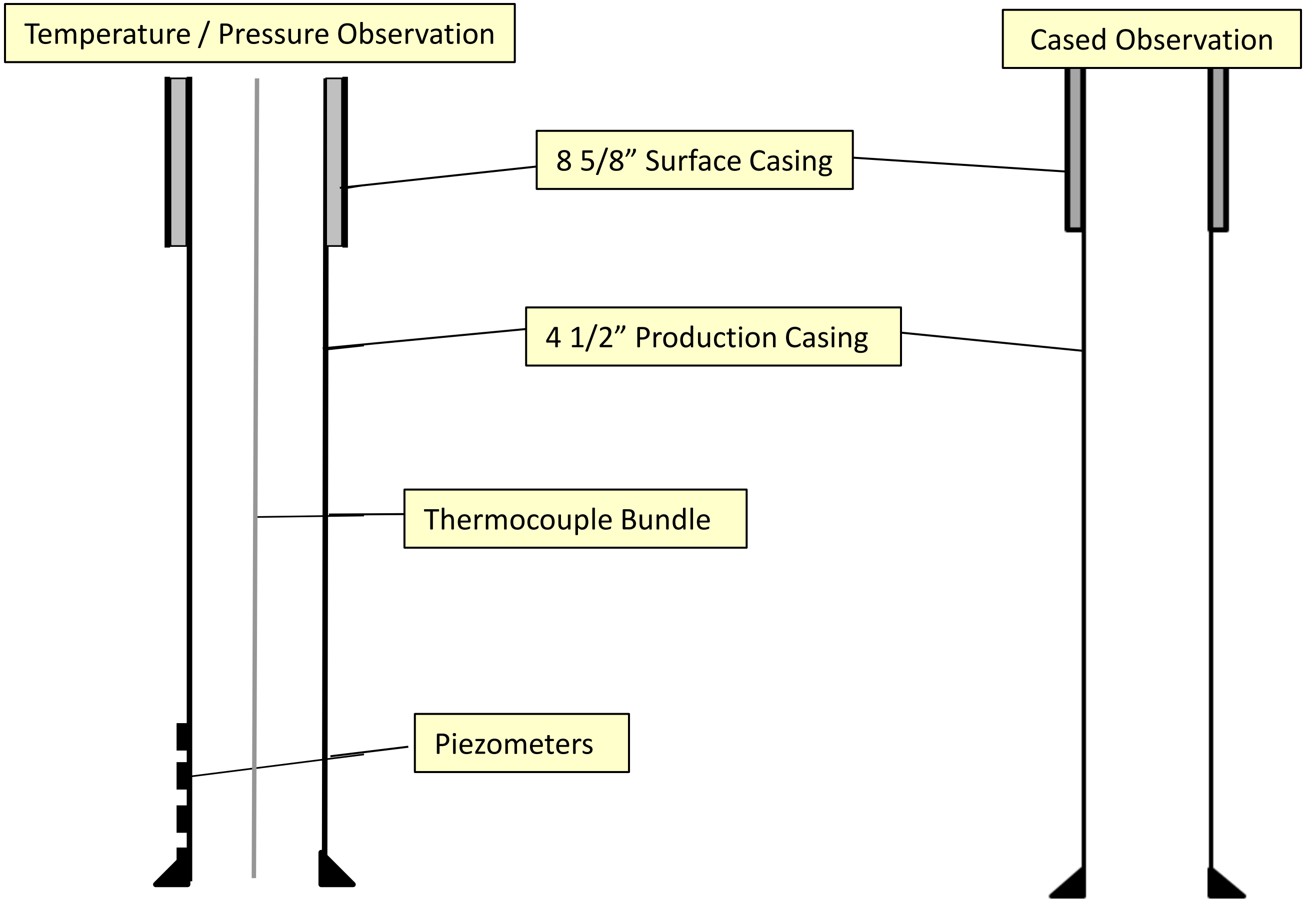
Early Lessons

- 10 wells have had ICDs opened as wells reach maturity
- Most have shown an improved rate and good conformance, enabling higher peak production rates without requiring more expensive workovers
- Low cost of initial installation, and flexibility in choosing if or when to open, has led to many new installations while earlier results are being evaluated

Wells with ICDs Installed

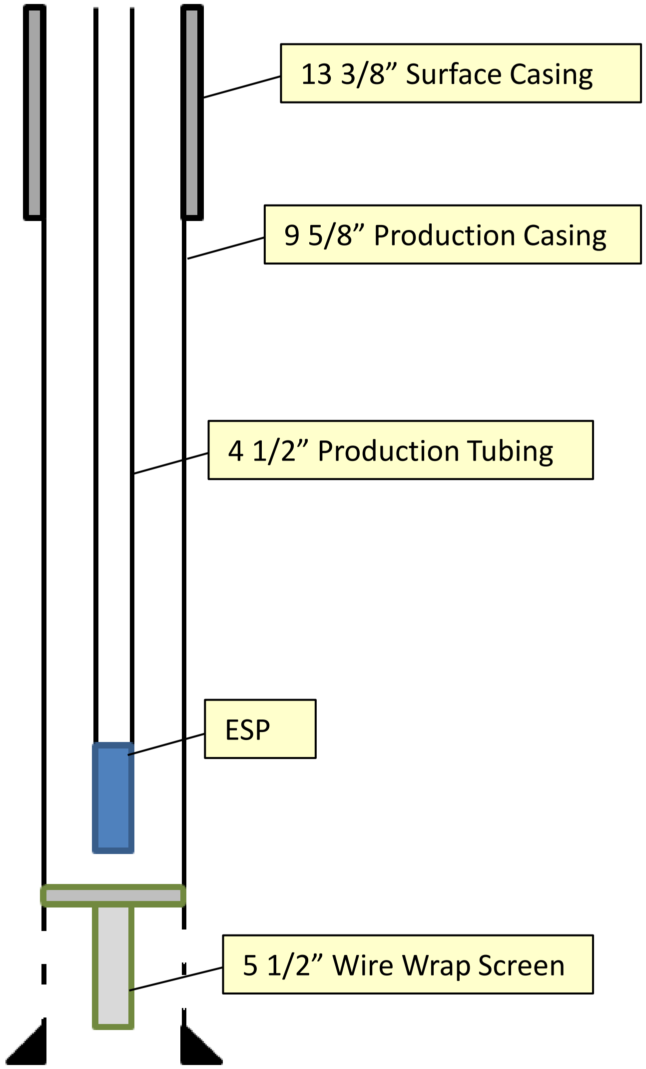
- 38 wells have ICDs installed
- M1P, M2P, M3P, M4P, M5P, M6P, M7P, M9P
- N2P, N3P, N4P, N5P, N6P, N8P, N9P
- T8P
- U2P, U3P
- AP1P, AP2P, AP4P, AP5P, AP6P, AP7P, AP8P, AP9P, AP10P
- AG1P, AG2P, AG3P
- AN1P, AN2P, AN3P, AN4P, AN5P, AN6P, AN7P, AN8P

Observation Wells

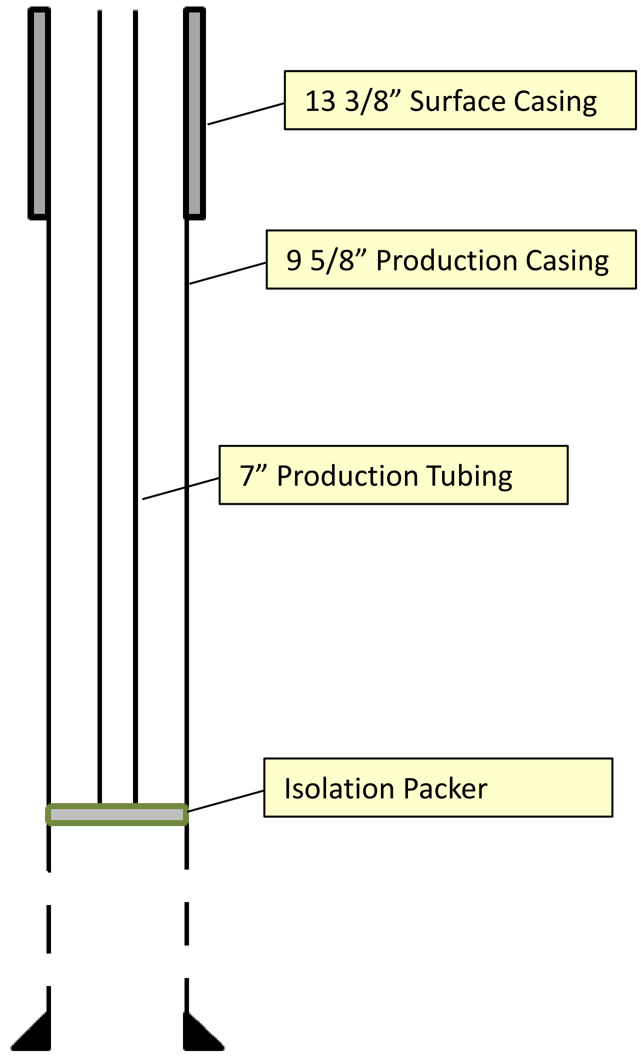


- Thermocouples are landed over expected steam zone
- Piezometers are placed in areas of geological interest (gas, bitumen, water zones and potential pay breaks)

Water Source Wells



Water Disposal Wells



CLRP Well Integrity Management

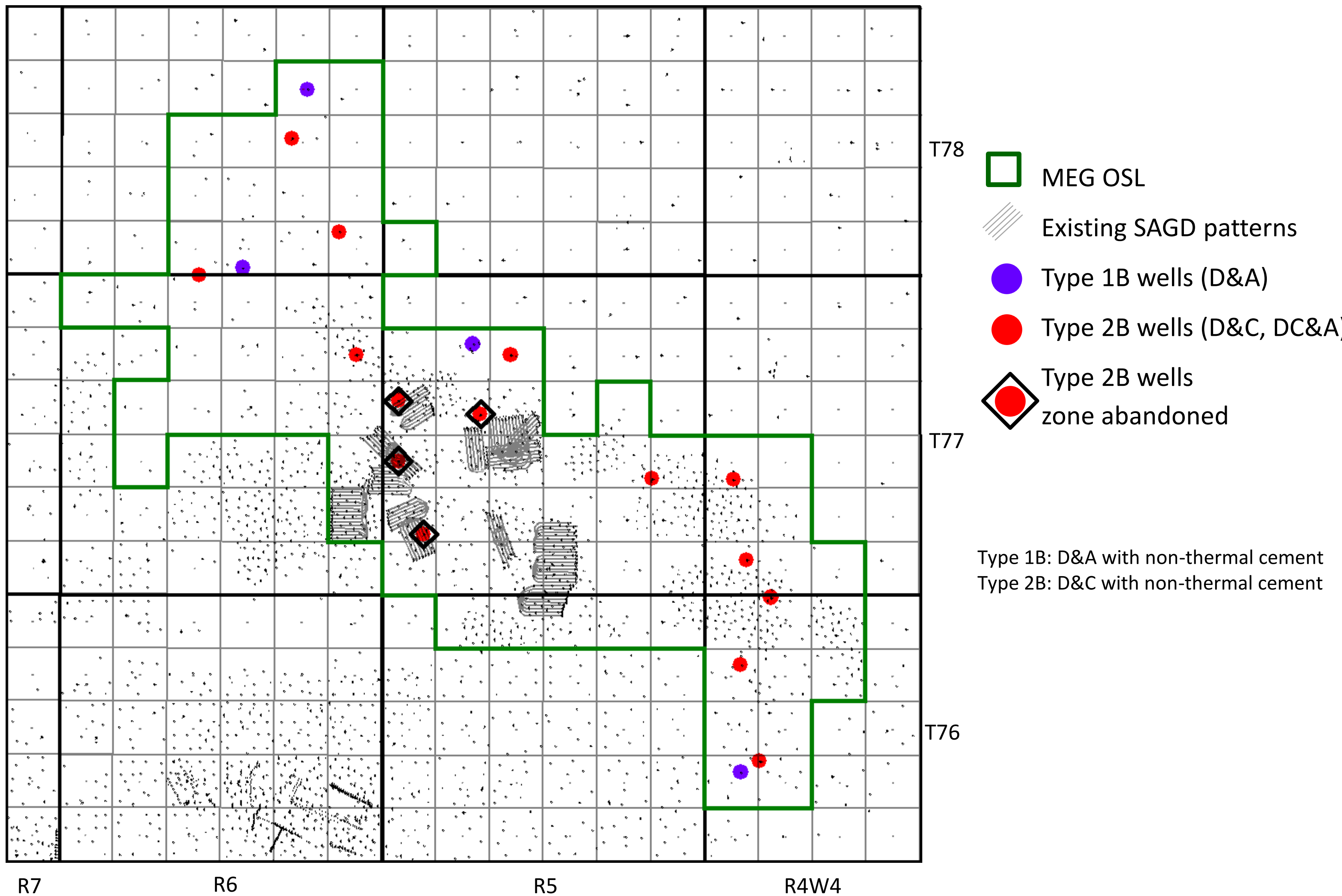
Developing Well Integrity Best Practices for CLRP

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

The Well Integrity Program includes:

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

CLRP Legacy Wells



Type 1B: D&A with non-thermal cement
Type 2B: D&C with non-thermal cement

Legacy Well Thermal Compatibility

- Thermal compatibility addressed on a pad by pad basis in conjunction with IDA amendment applications
- Specific D-20 abandonment applications have been filed and approved for requisite wells within the ADA
- MEG has developed a thermal compatibility program which has been reviewed by AER staff. The program includes:
  - A detailed assessment of compatibility of existing all wellbores within the CLRP project area
  - General abandonment strategies to ensure well integrity thermal development areas
  - Monitoring and surveillance plans

CLRP Well Workovers – BB6I

Issue

- Surface Casing Vent Flow (SCVF) on SAGD injector
- Cement micro-annulus has formed behind the 7” slimhole casing, source is inside the well below the slimhole casing shoe

Implications

- Identified a casing gas vent flow through the slimhole cement while the well was operating
- Confirmed that original intermediate casing breach which caused the well to be slimholed is not the SCVF source
- Proved the slimhole casing integrity through pressure testing

Actions

- Set a wireline retrievable bridge plug in the well for suspension which has isolated the SCVF source
- Successfully continuing to operate BB6 producer without support from BB6 injector

CLRP Well Workover Learnings

Issue

- In-zone isolated liner impairments on 4 SAGD producer wells identified in 2013: V3P, N2P, N3P, and M7P

Highlights

- All 4 wells were successfully re-drilled utilizing the existing intermediate section and have since resumed SAGD operation with no issues
- The impairments developed during circulation and were not production induced
- These wells had an average lateral length of about 1000 metres

Optimization

- Analysis has suggested the impairments may be a result of thermal induced deformation in longer lateral wells
- Slotted liner design has been adjusted on re-drills and subsequent wells and there have been no further liner issues

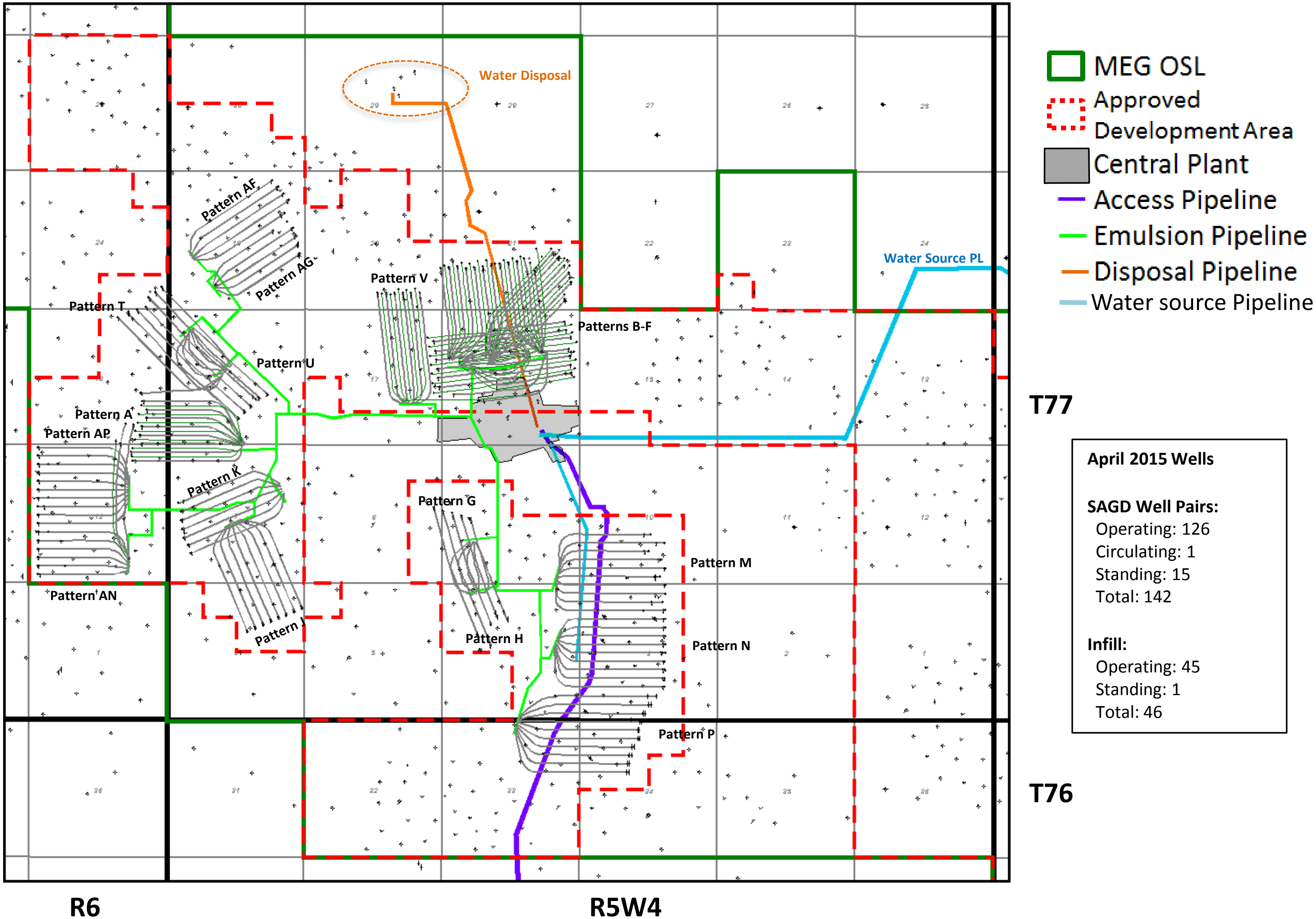
CLRP Artificial Lift

- **All MEG SAGD well pairs are initially completed with gas lift capabilities**
- **125 Electric submersible pumps (ESP) in operation**
  - Approximately 55% ESPs rated to 220°C and 45% rated to 250°C
  - Operating pressures range from 2,100-3,200kPag
  - Design fluid rates 200-1200m^3/d
  - Run-time between pulls is 625-675 days
  - Run-time improvements have been realized by utilizing higher quality equipment where required
- **45 rod pumps installed in the infill wells**
  - Operating pressures range from 2,000-2,500kPag
  - Design fluid rates 100-500m^3/d

MEG Energy

Scheme Performance

CLRP Pattern Layout



April 2015 Wells

SAGD Well Pairs:
- Operating: 126
- Circulating: 1
- Standing: 15
- Total: 142

Infill:
- Operating: 45
- Standing: 1
- Total: 46

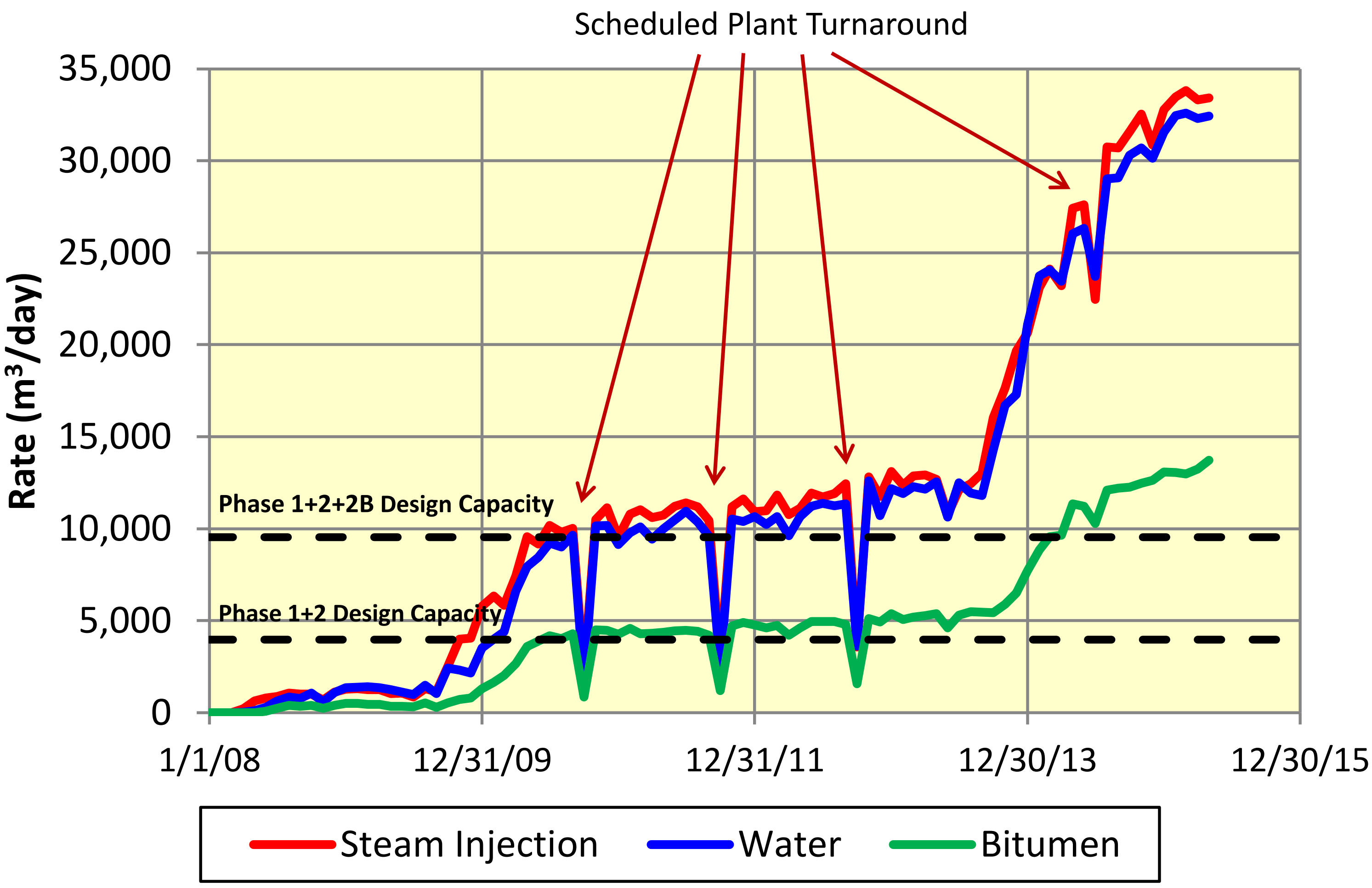
CLRP Reservoir Performance

- 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
- Current steam chamber pressure is between 2,000 and 2,900 kPag for Phases 1 and 2, between 2,300 and 3,400 kPag for Phase 2B. The steam chamber pressure is close to the initial pressure in the basal water zone where bottom water is present.
- The combined bitumen production from Phases 1 and 2 reached the design capacity of 3,975 m^3/d (25,000 bopd) by late April 2010.
- Phase 2B production ramp-up bettered that of Phase 2. Total production from all phases reached 11,340 m^3/d (71,300 bopd) in Q2 2014, exceeded the combined initial design capacity of 9,539 m^3/d (60,000 bopd).

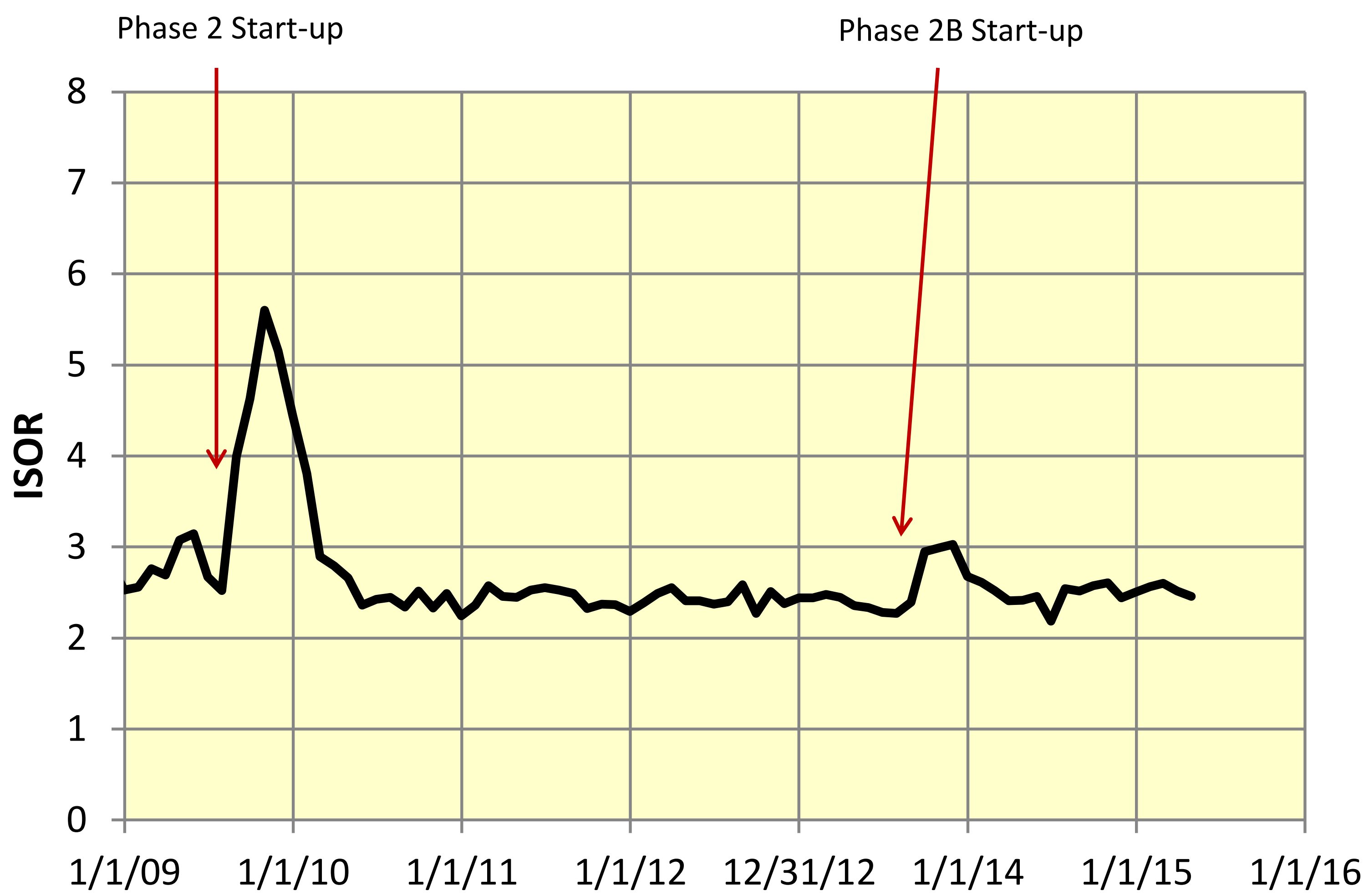
CLRP Reservoir Performance (continued)

- The SOR of CLRP has ranged from 2.2 to 2.6 over the last 12 months and averaged 2.5 with new well start-ups.
- The Phase 1 eMSAGP pilot was initiated in December 2011, which showed very successful results. Commercial eMSAGP was expanded to wells A4, A5, A6 and patterns B, C, D, E and F in 2013.
- The SOR of the eMSAGP wells (36 SAGD WP’s and 37 infill wells) averaged 1.9 relative to the SAGD design level of 2.8 in the period, which allowed MEG to utilize the freed up steam to bring more SAGD wells on production.
- In Q1 2015, MEG achieved record quarterly production of 82,398 bopd, an increase of 41% over the same period of 2014. April production averaged over 86,280 bopd.

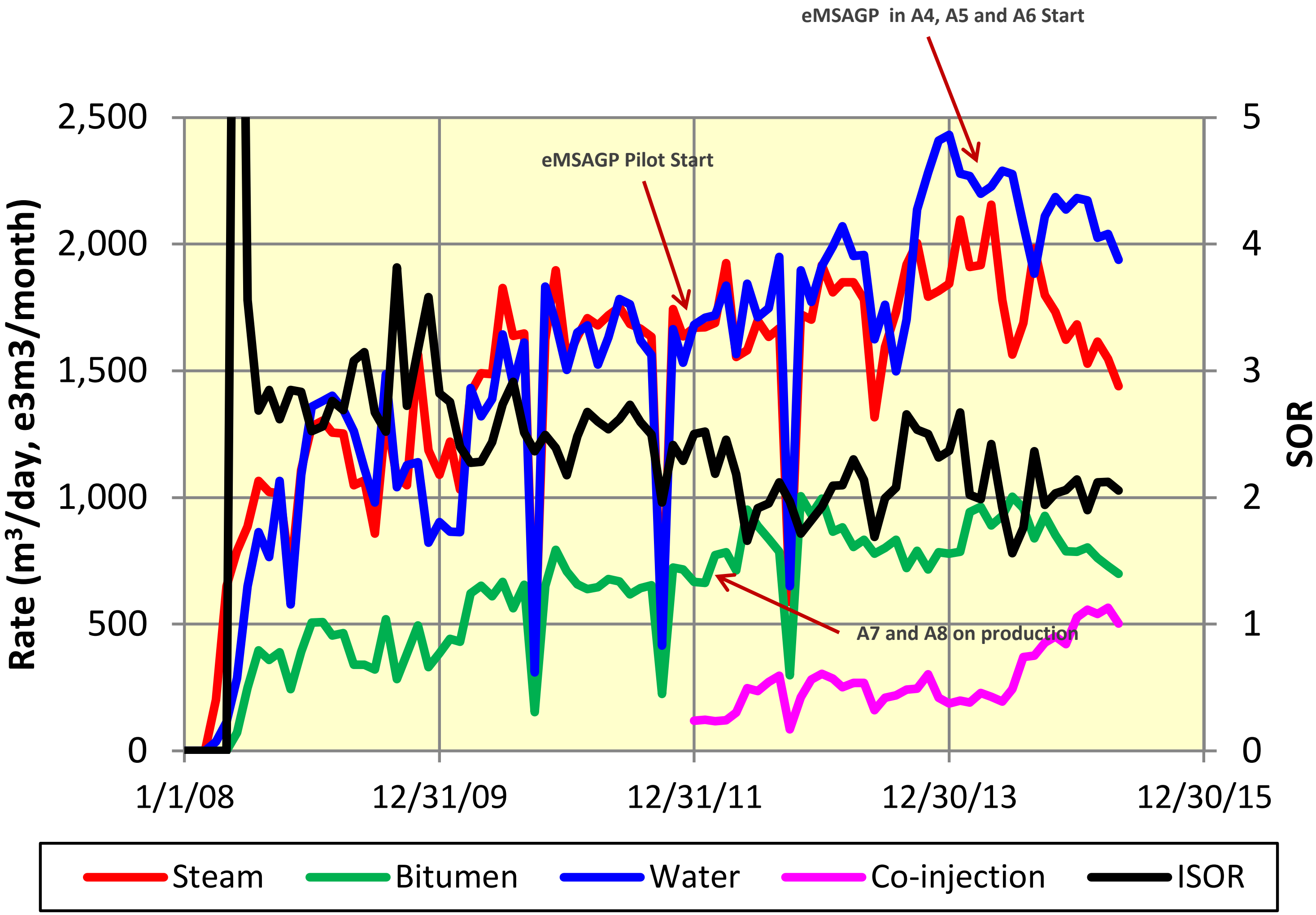
CLRP Production Performance



CLRP Performance – SOR of All Patterns

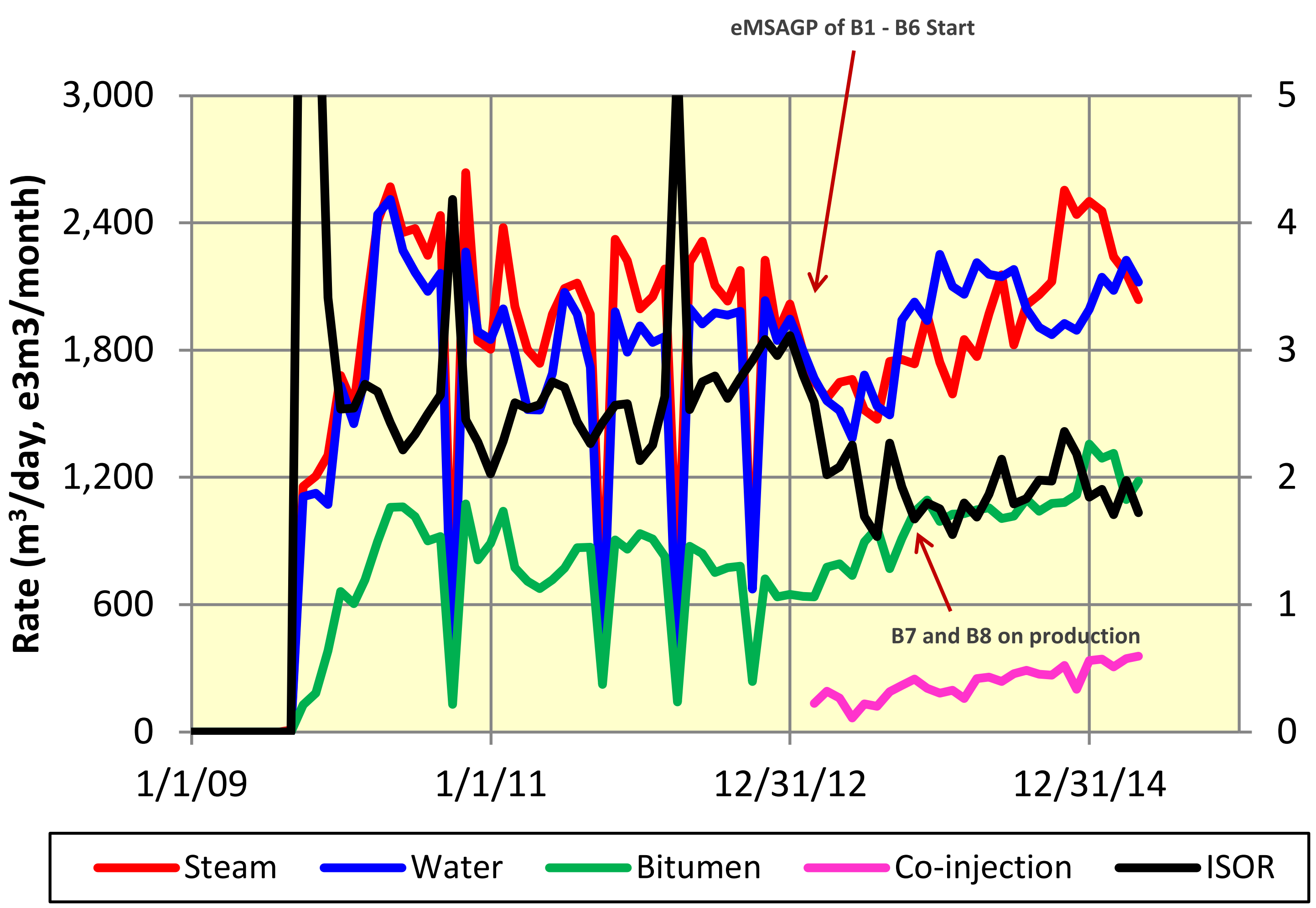


CLRP Performance – Pattern A



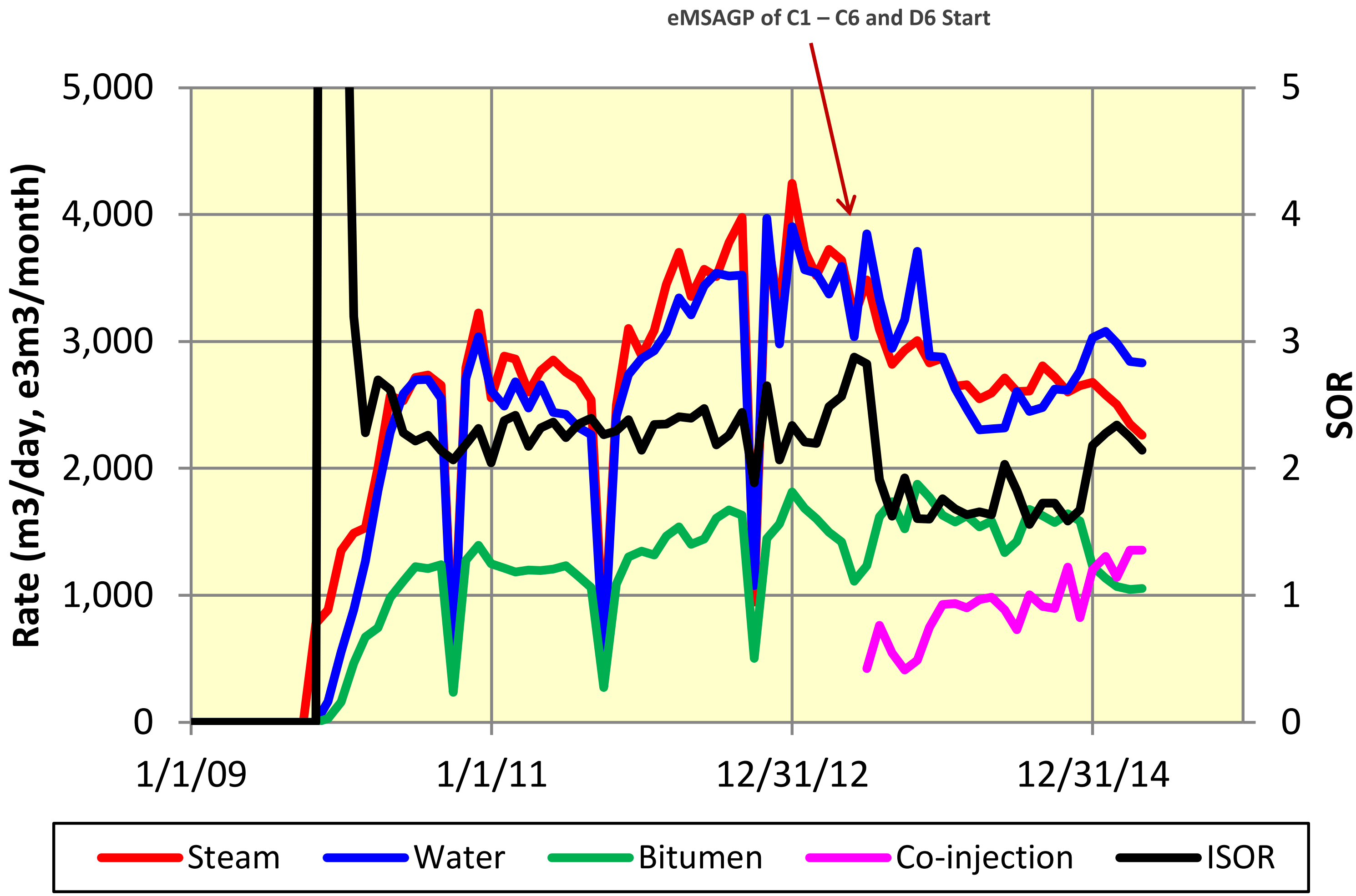
Increased water to steam ratio noted recently was mostly from two edge SAGD well pairs (A6 and A8), a result of edge or bottom water incursion

CLRP Performance – Pattern B



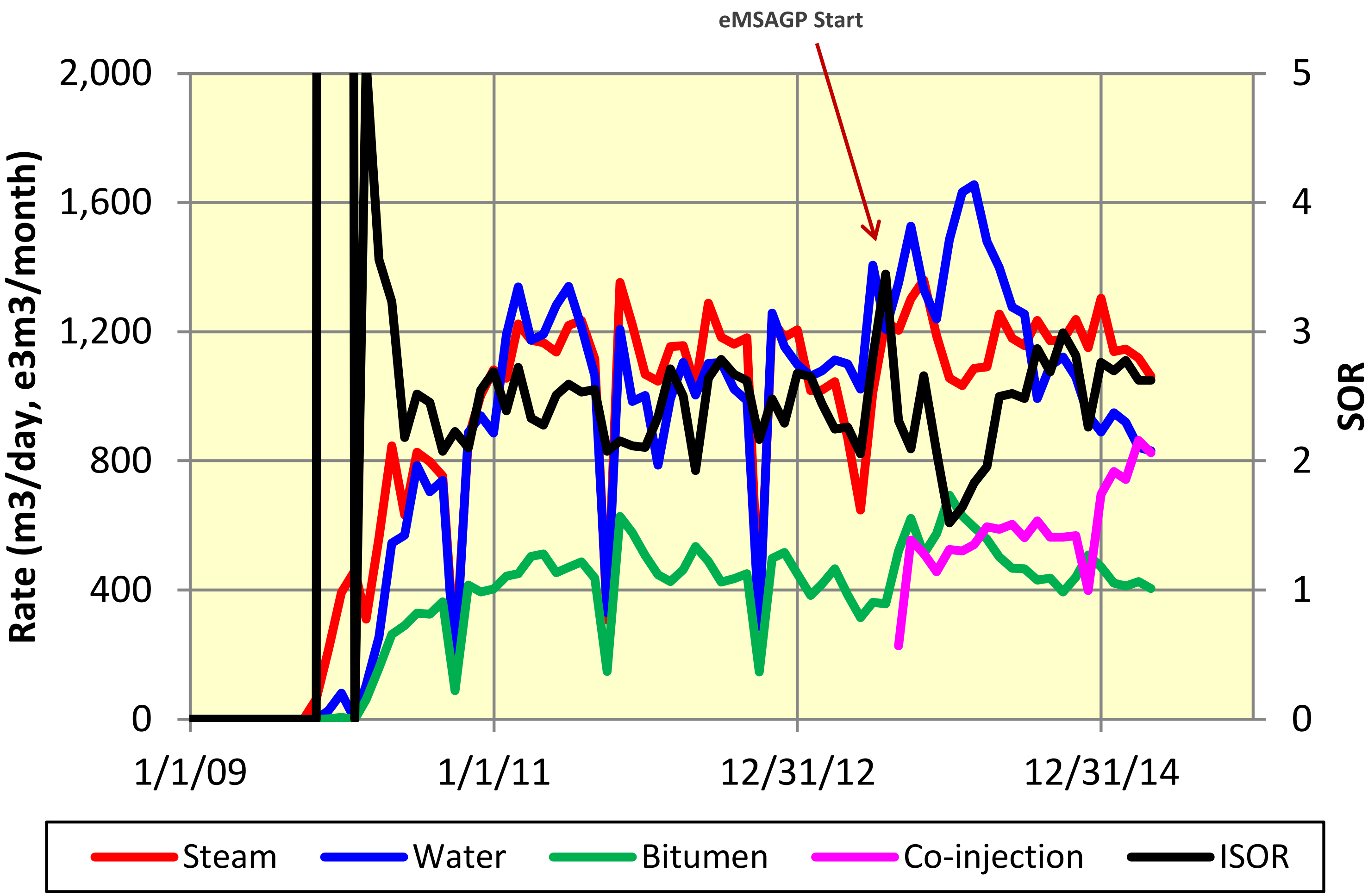
Increased steam injection rate was to increase the steam chamber pressure in two SAGD well pairs (B1 and B2) that have bottom water

CLRP Performance – Pattern C

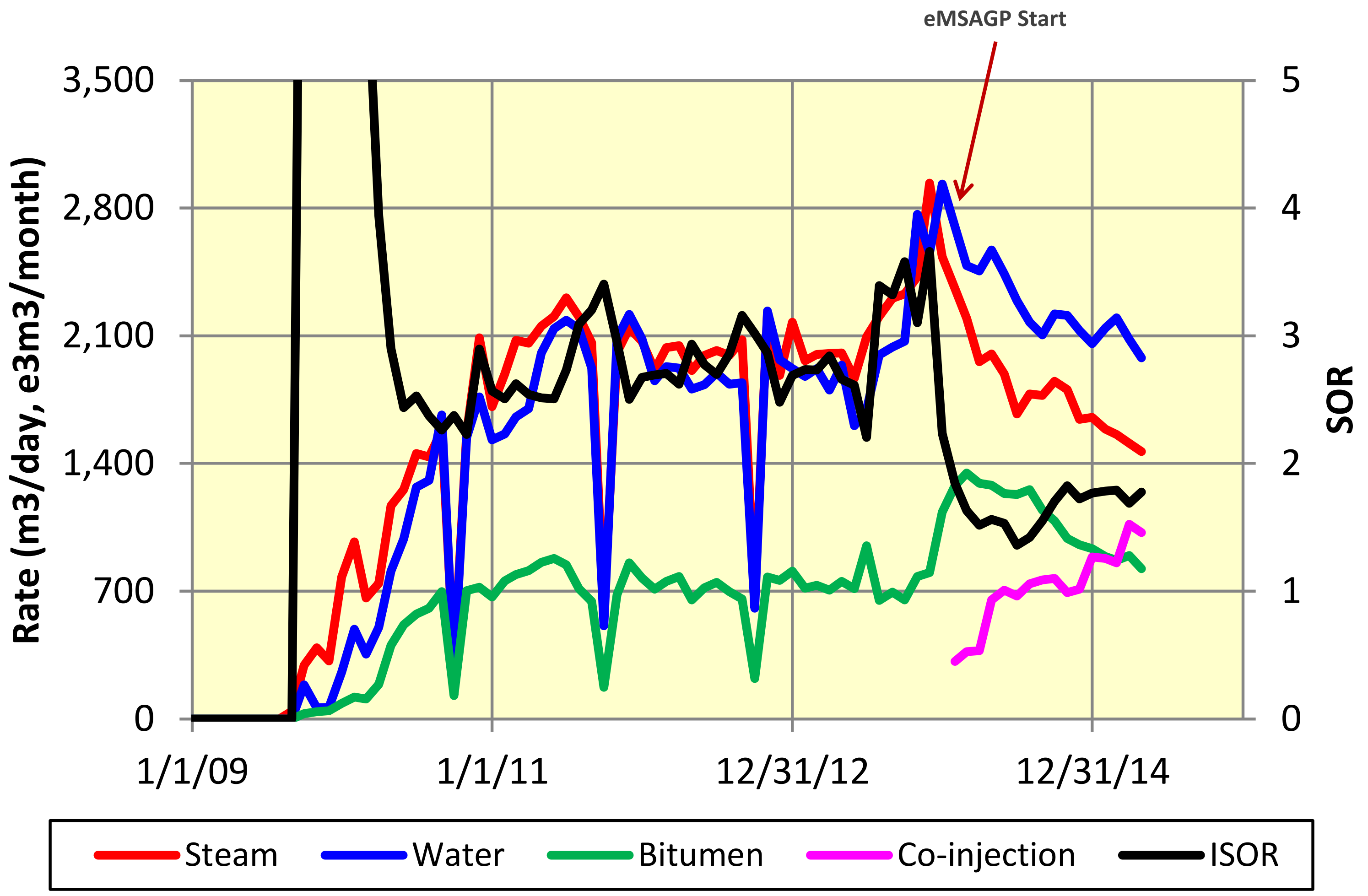


Bitumen production drop in December 2014 was partially due to measurement calibration

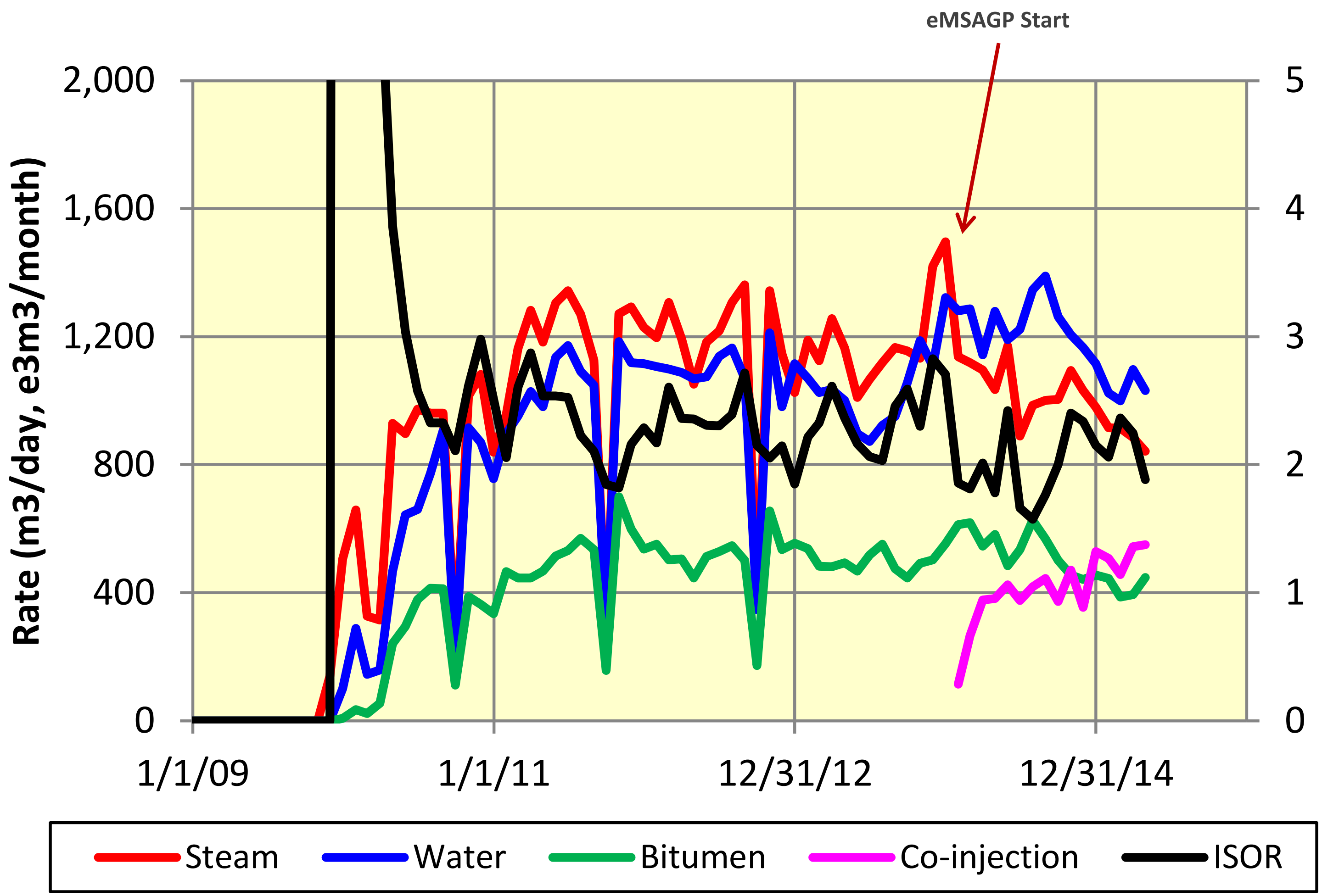
CLRP Performance – Pattern D



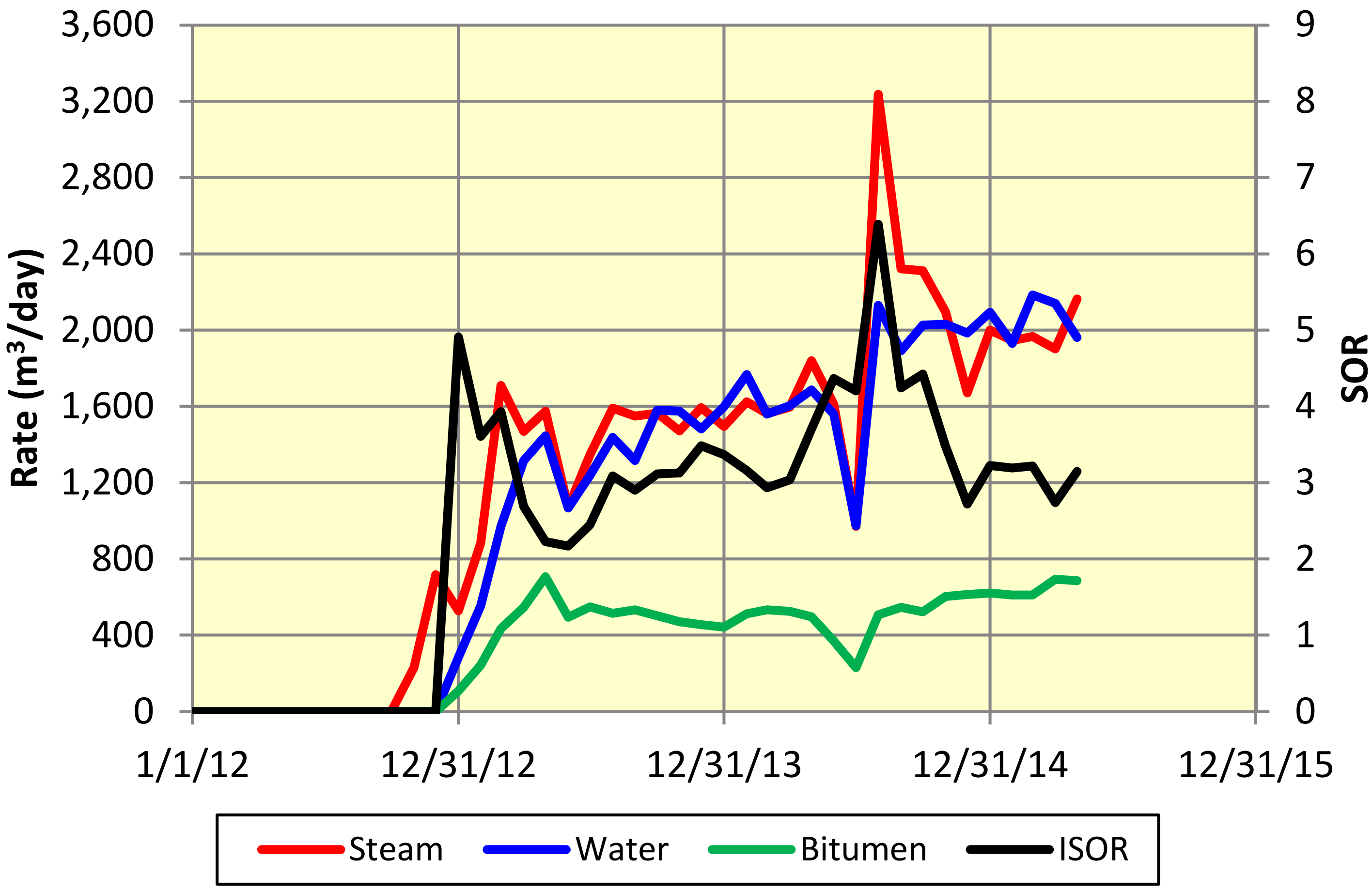
CLRP Performance – Pattern E



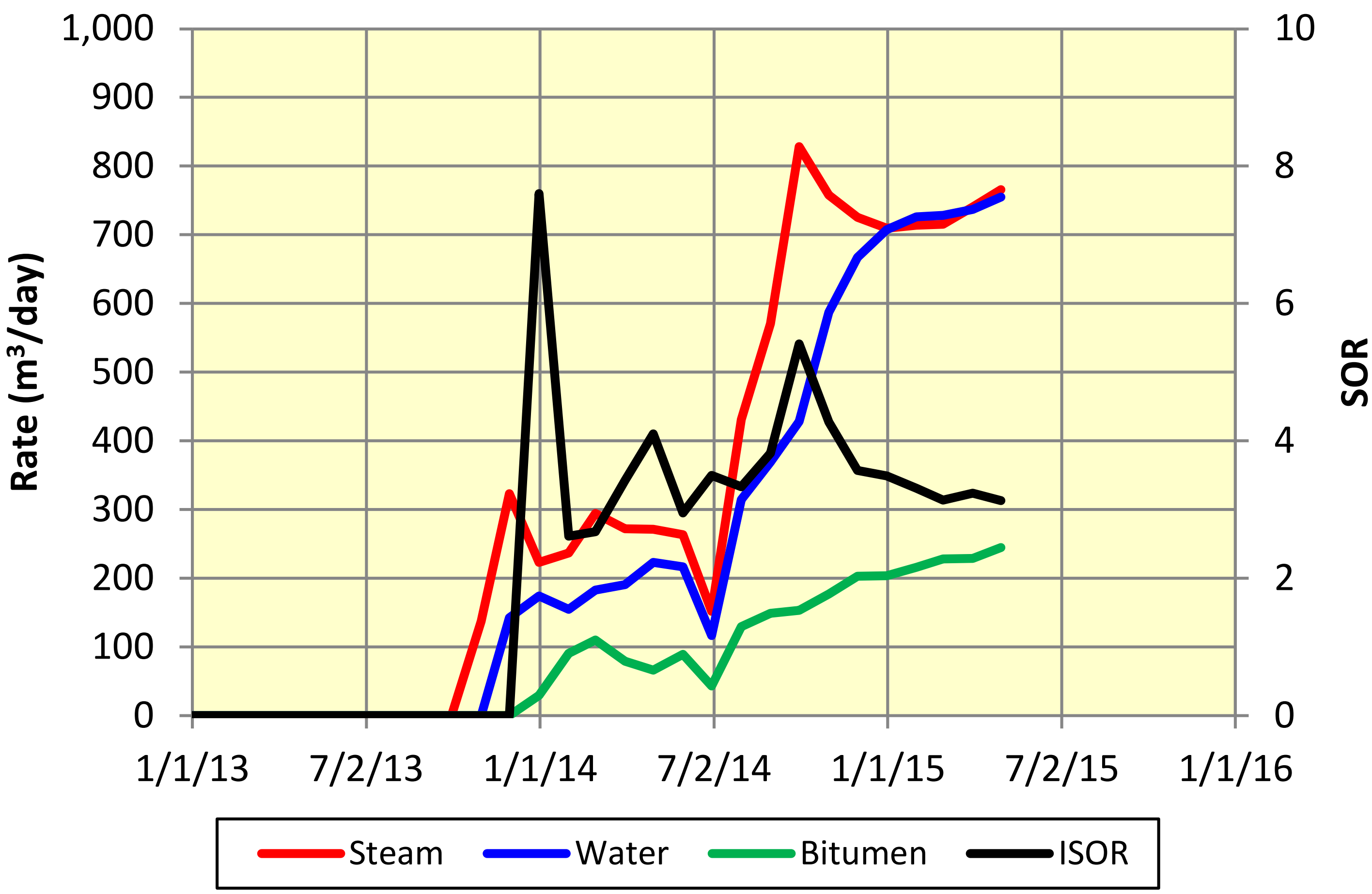
CLRP Performance – Pattern F



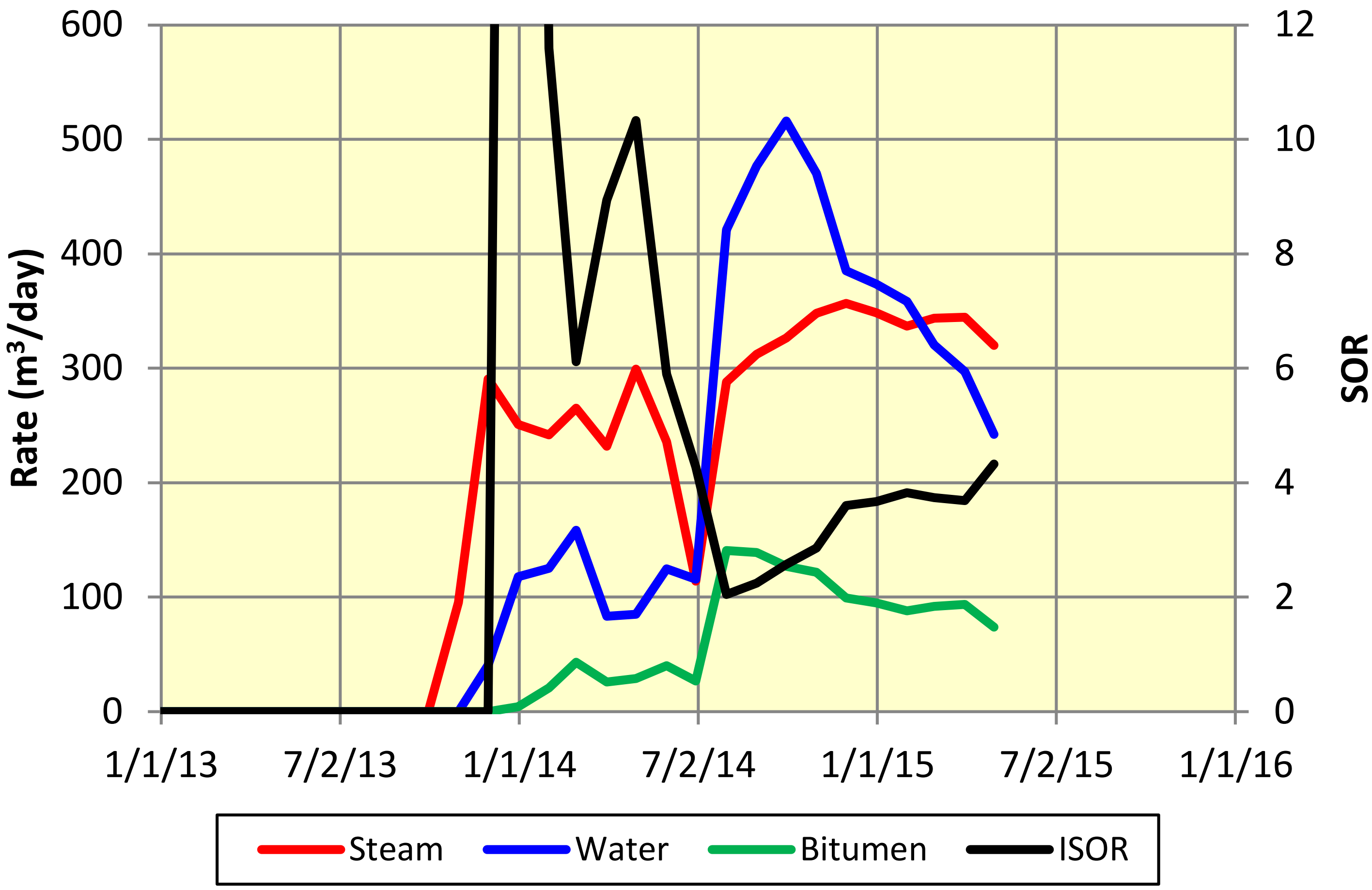
CLRP Performance – Pattern V



CLRP Performance – Pattern G

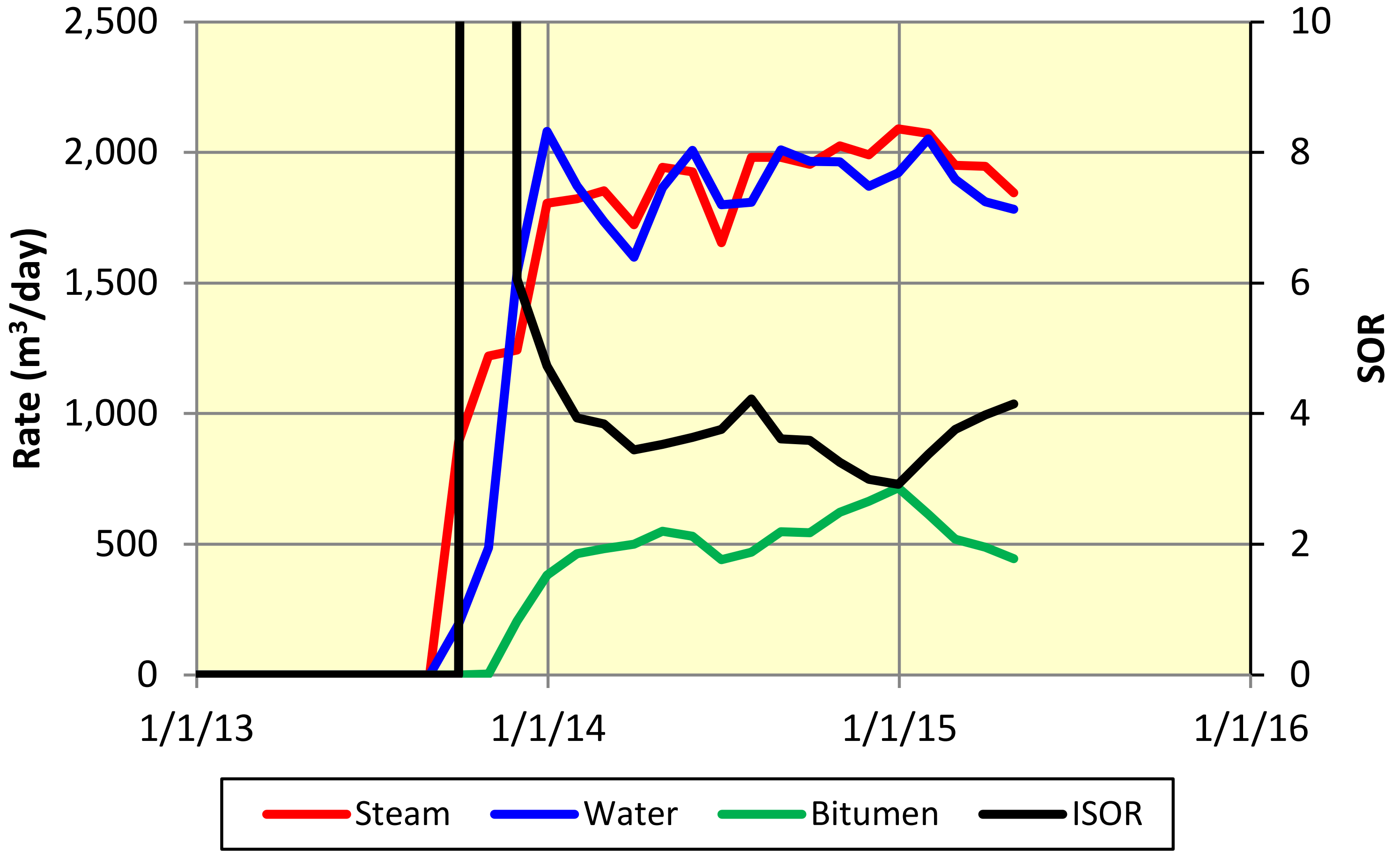


CLRP Performance – Pattern H

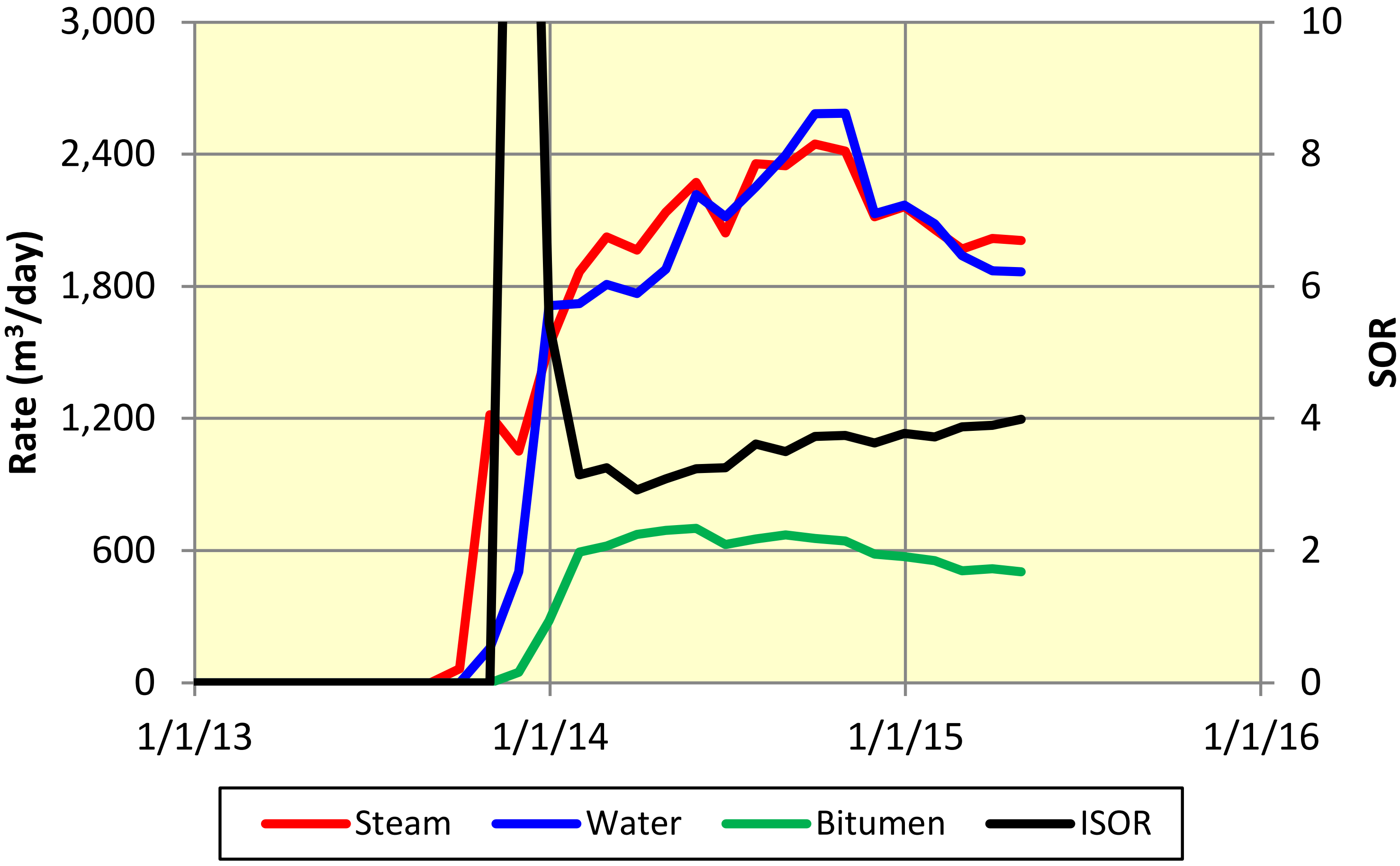


In mid-2014 workovers were performed on H4I, H4P, and H3P which led to a large surge in production but do not reflect sustainable rates

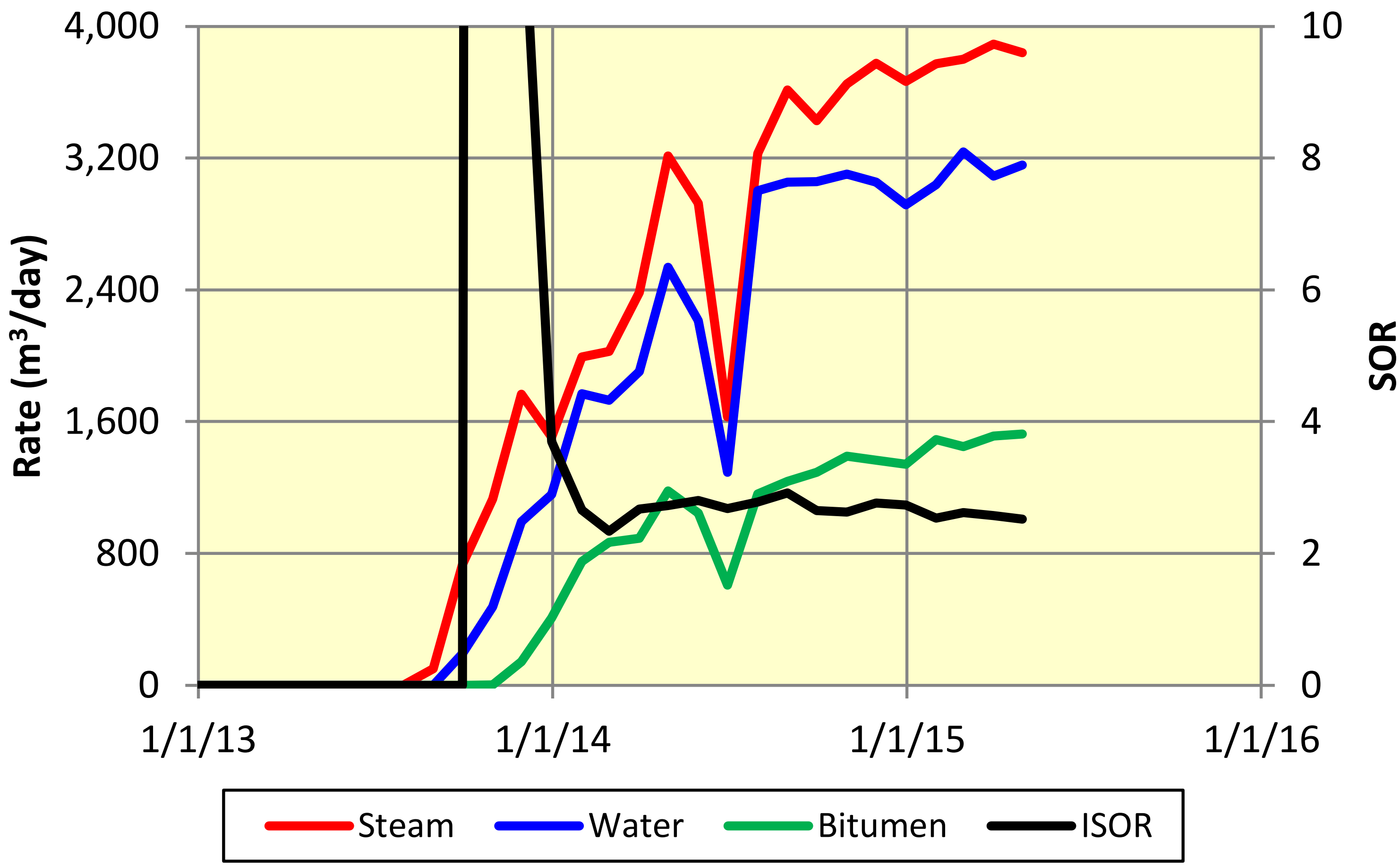
CLRP Performance – Pattern J



CLRP Performance – Pattern K



CLRP Performance – Pattern M

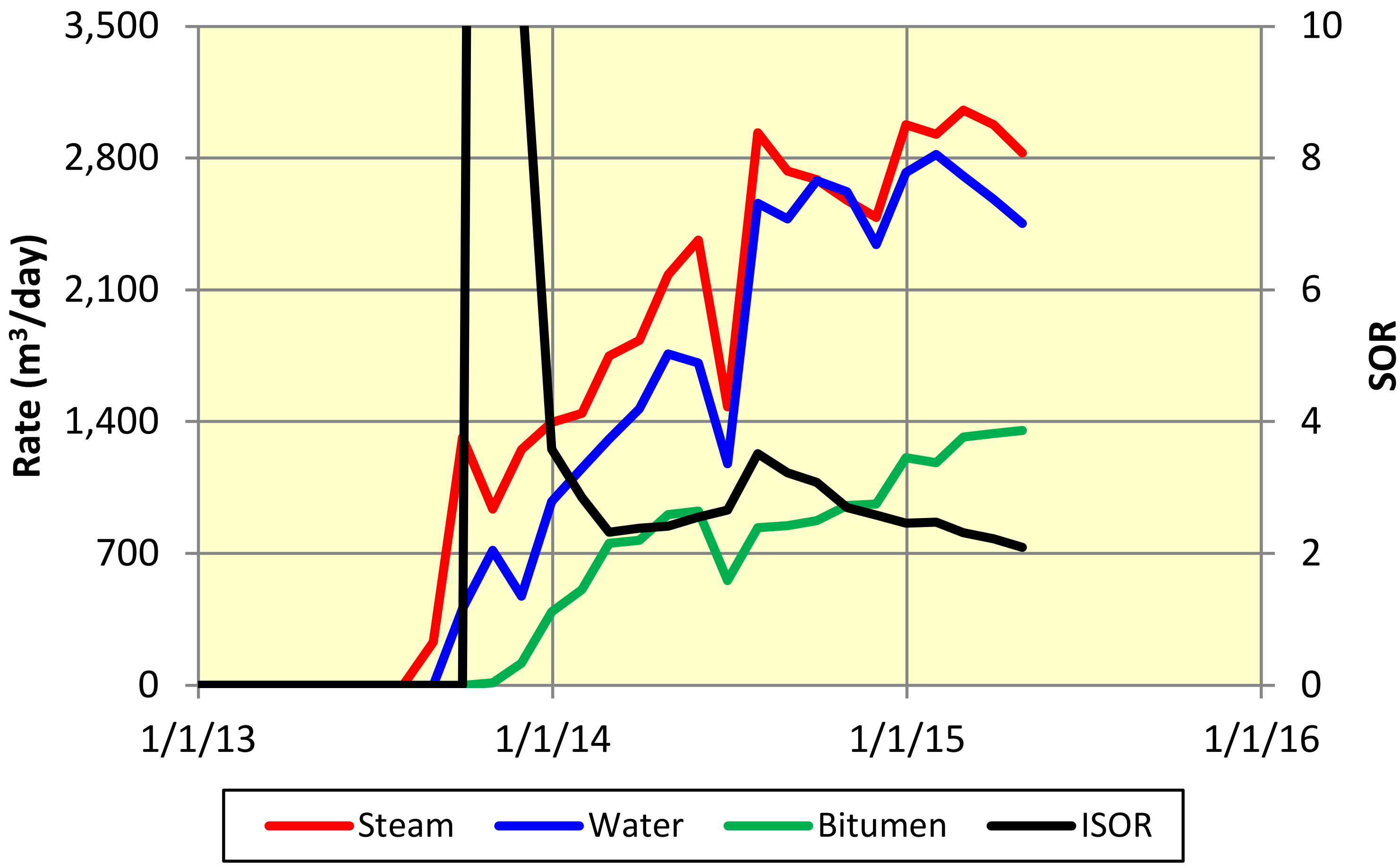


M9P and M10P have low TFSR due to poor producer inflow, lowering the overall WSR. Both wellpairs operate at low pressure so steam is not considered lost to thief zones. Temporary steam reduction due to pipeline construction activity in mid-2014 .

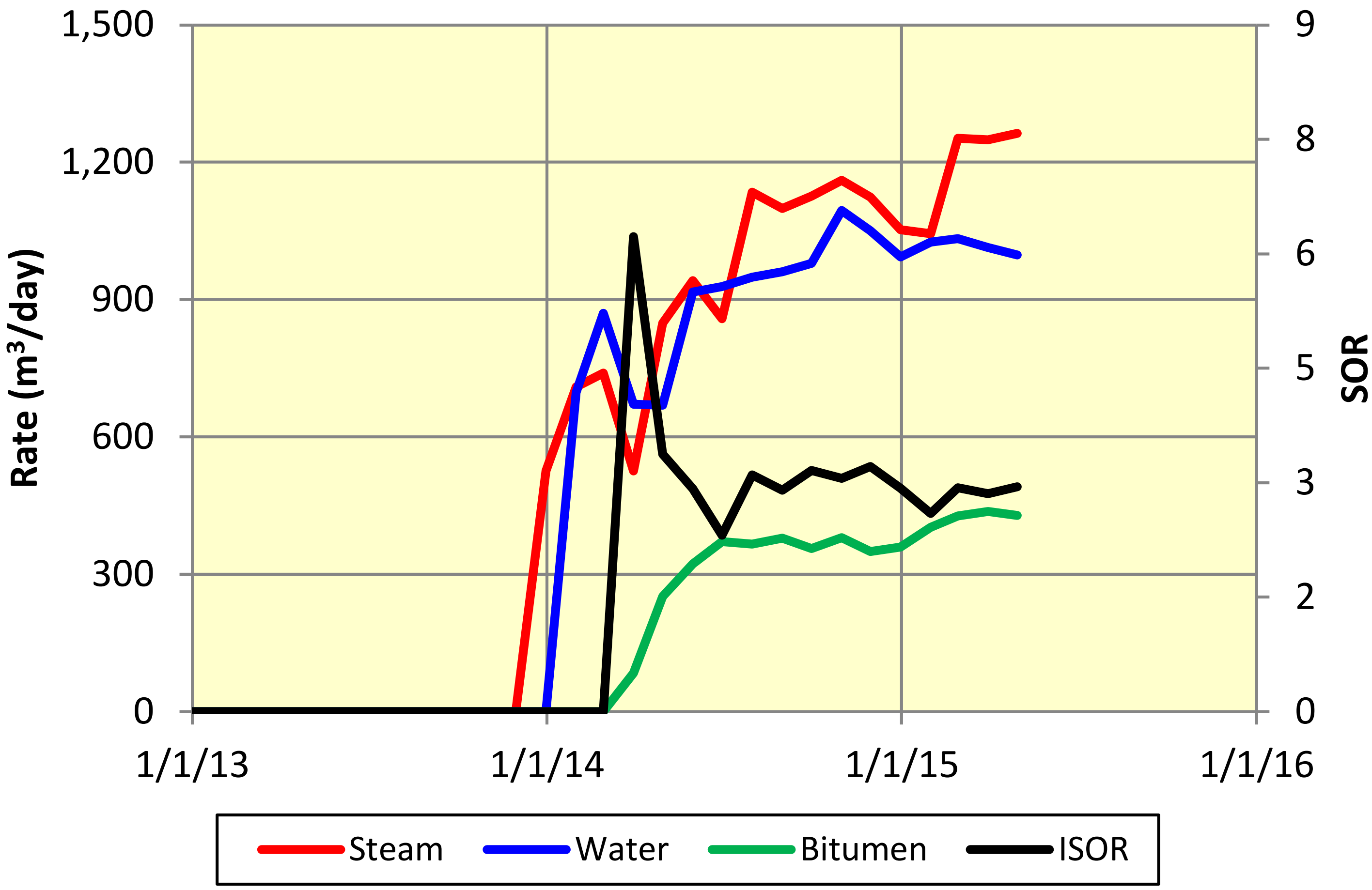
Implementation and Recovery Rate

- For the Phase 2 wells, eMSAGP was implemented near 30% recovery of pay above the producer, with individual pattern recoveries ranging from about 30% to 46%
- The patterns which experienced the greatest increase in rate of recovery had eMSAGP initiated earlier, suggesting that implementation at advanced stages of recovery is sub-optimal

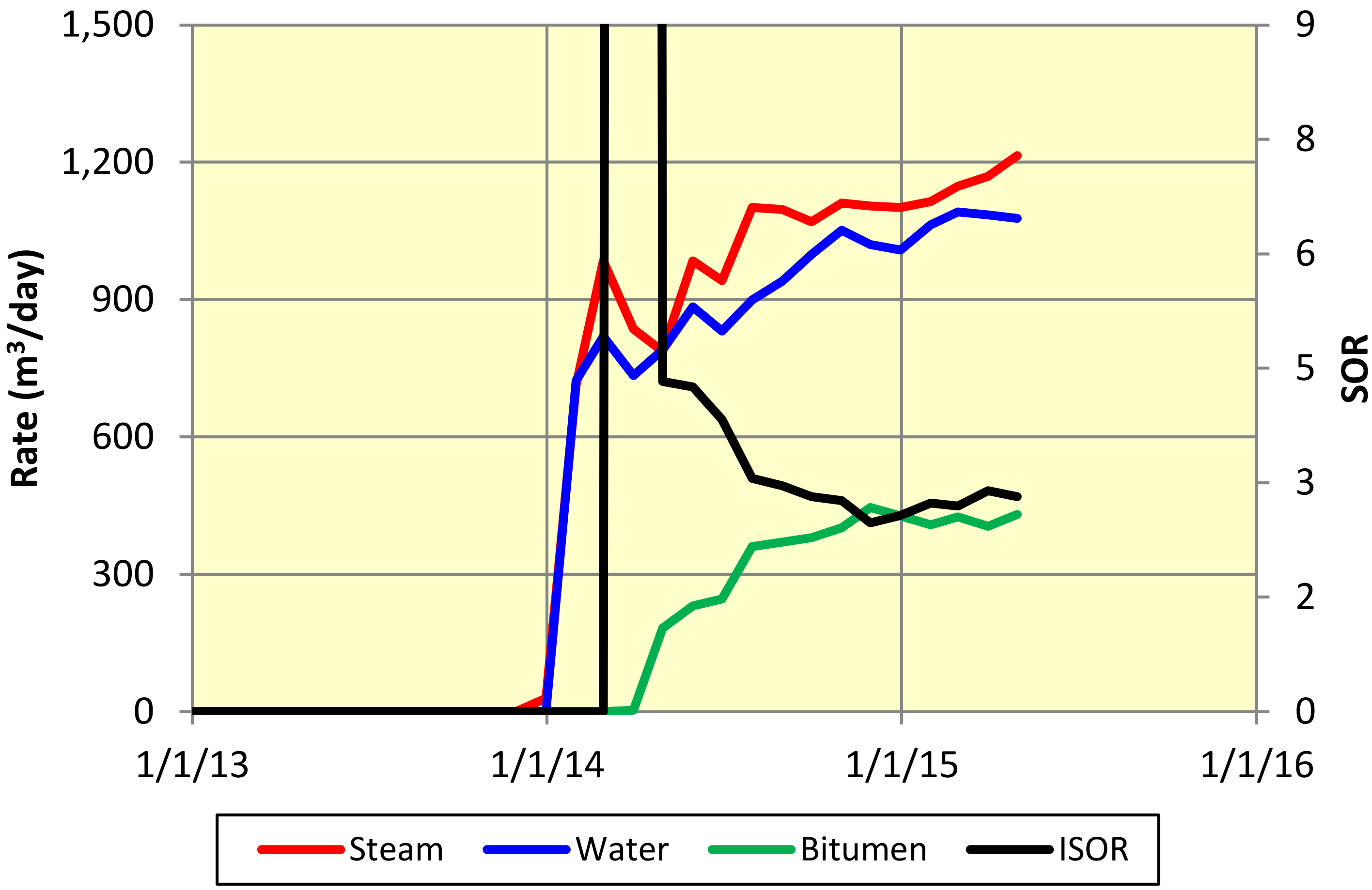
CLRP Performance – Pattern N



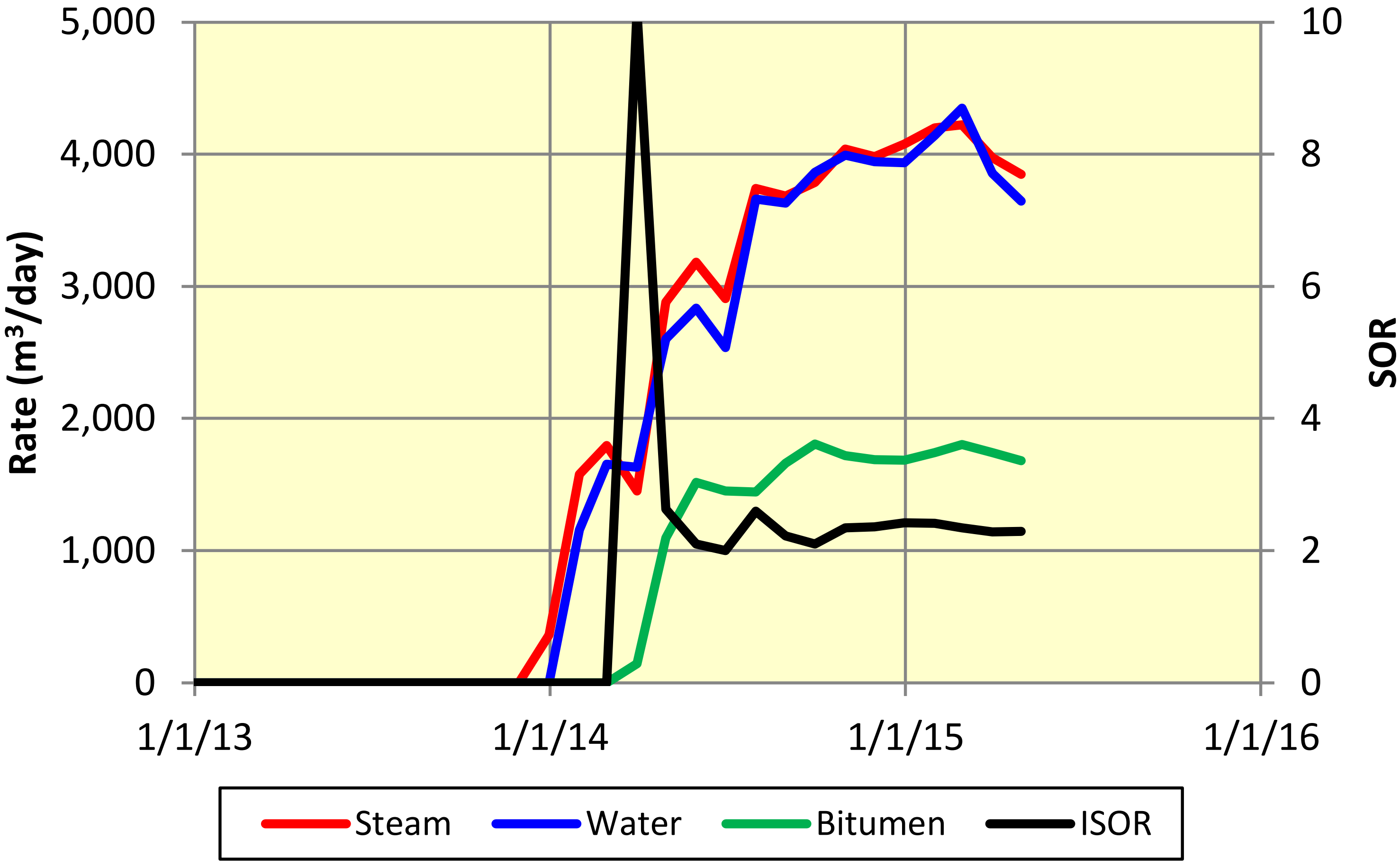
CLRP Performance – Pattern T



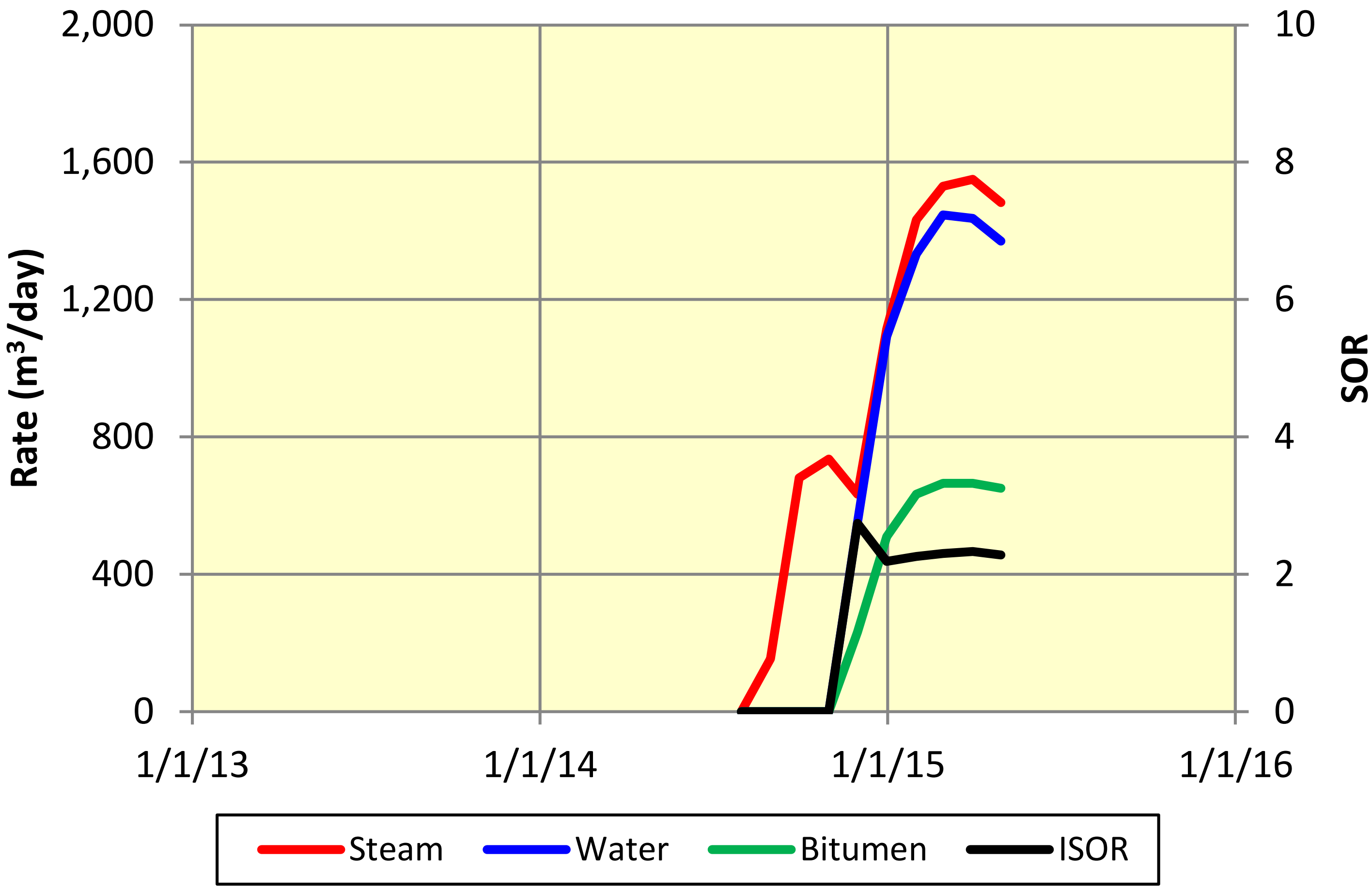
CLRP Performance – Pattern U



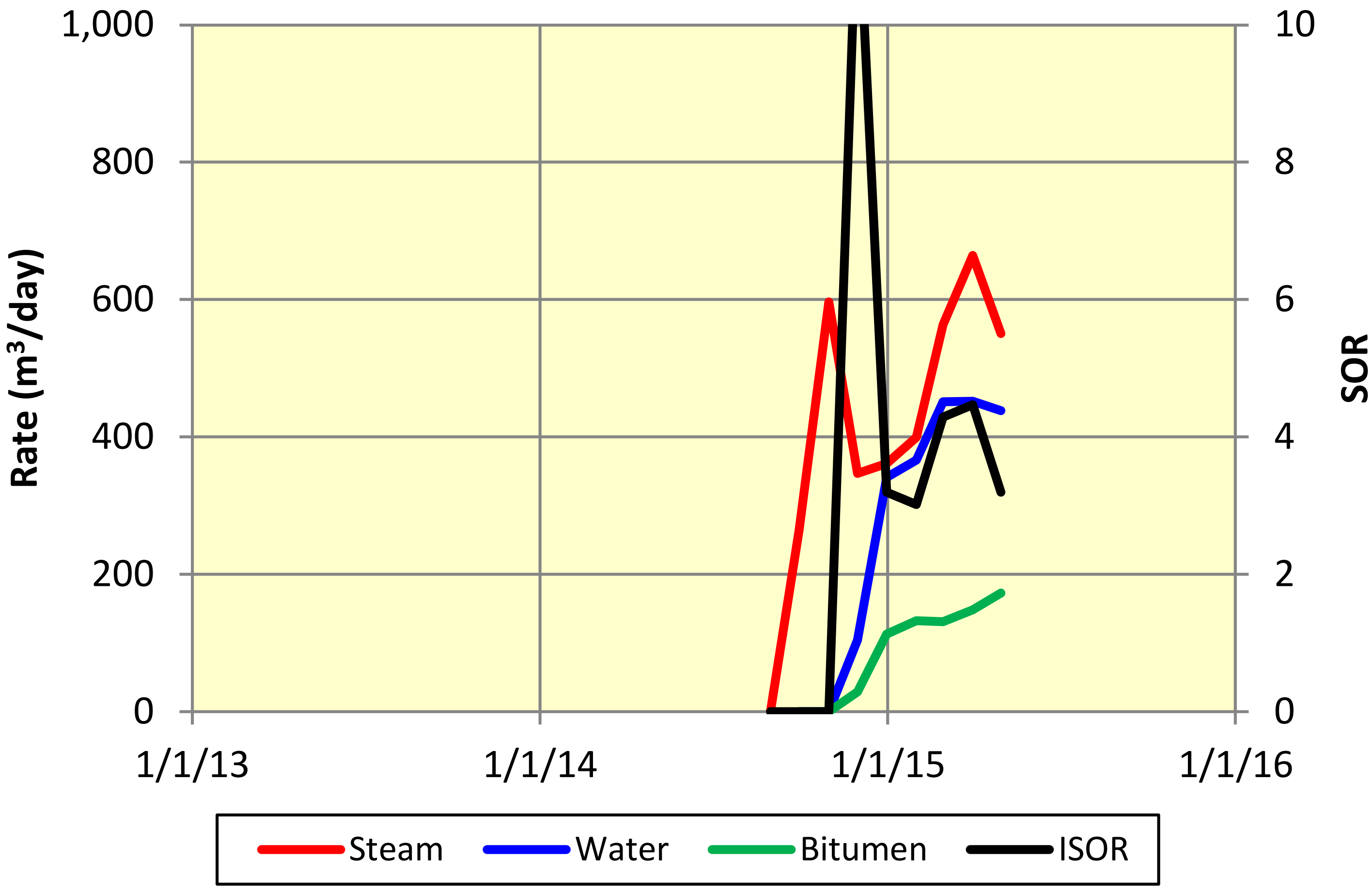
CLRP Performance – Pattern AP



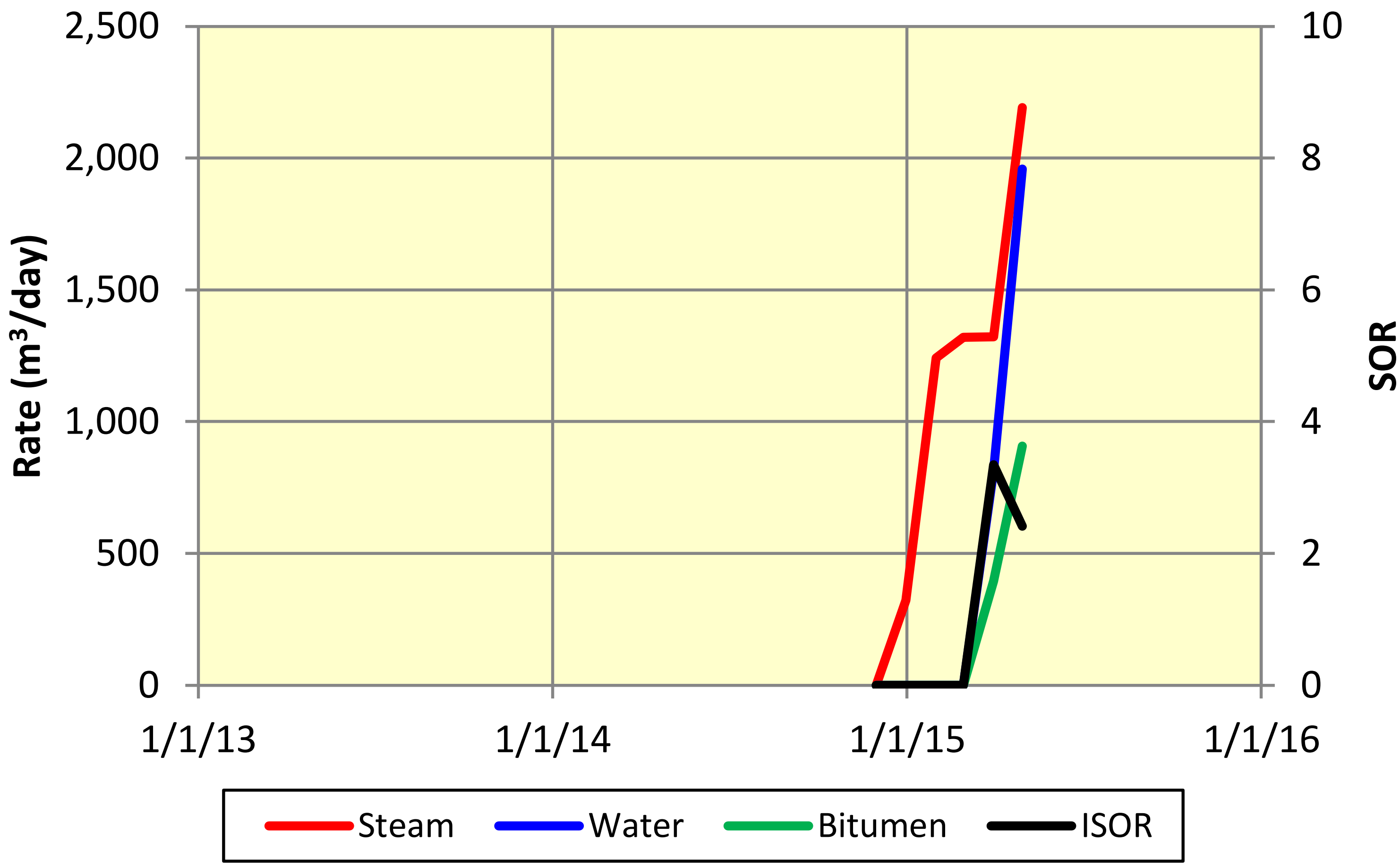
CLRP Performance – Pattern AF



CLRP Performance – Pattern AG



CLRP Performance – Pattern AN



Original Oil in Place

Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	OOIP (m^3)
A	8	22	889	34%	72%	3,815,000
B	2	33	745	34%	82%	1,371,000
BB + D7	7	20	846	33%	83%	3,199,000
C + D6	7	27	803	34%	75%	3,889,000
D-D6-D7	5	21	680	34%	78%	1,847,000
E + F1	7	23	819	33%	77%	3,278,000
F - F1	5	22	776	33%	78%	2,148,000
V	6	21	1139	33%	72%	3,464,000
G	4	17	759	33%	71%	1,237,000
H	2	16	832	33%	72%	1,237,000
J	8	21	986	33%	76%	4,191,000
K	7	21	955	33%	75%	3,496,000
M	10	30	998	32%	75%	7,185,000
N*	9	26	1054	33%	80%	6,634,000
T	7	19	952	32%	81%	3,325,000
U	6	19	882	30%	80%	2,414,000
AP*	10	33	832	33%	83%	7,393,000
AF	5	23	972	32%	82%	2,862,000
AG	4	22	835	33%	77%	1,872,000
AN	8	27	870	32%	83%	4,940,000
TOTAL	**127**					**69,797,000**

Note: 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 2015

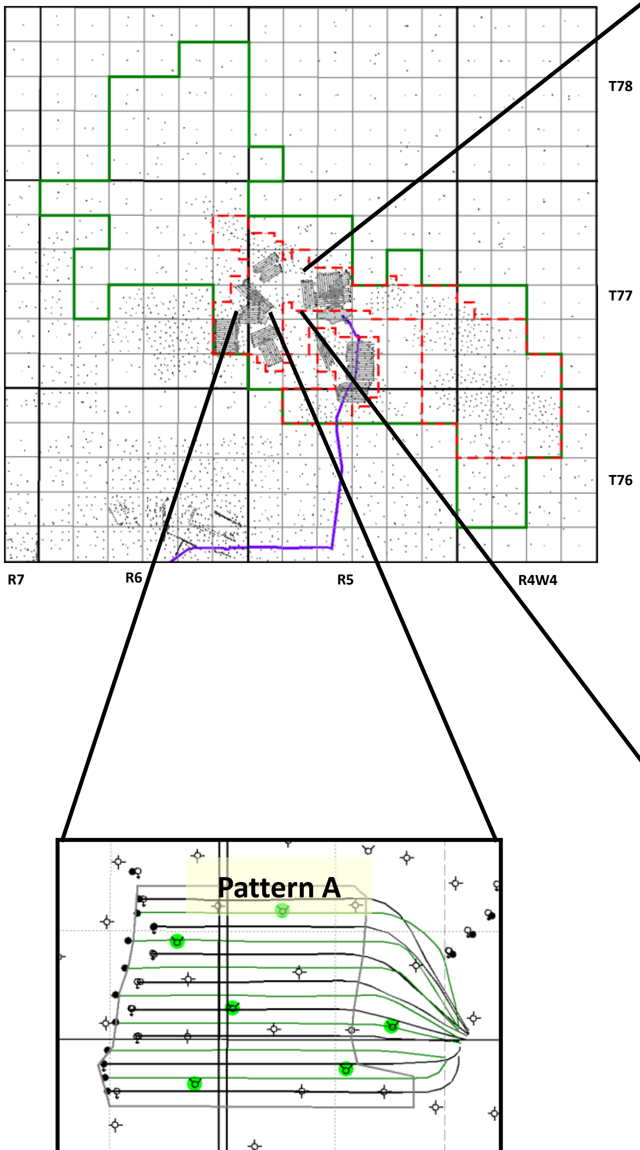
Oil Recovery

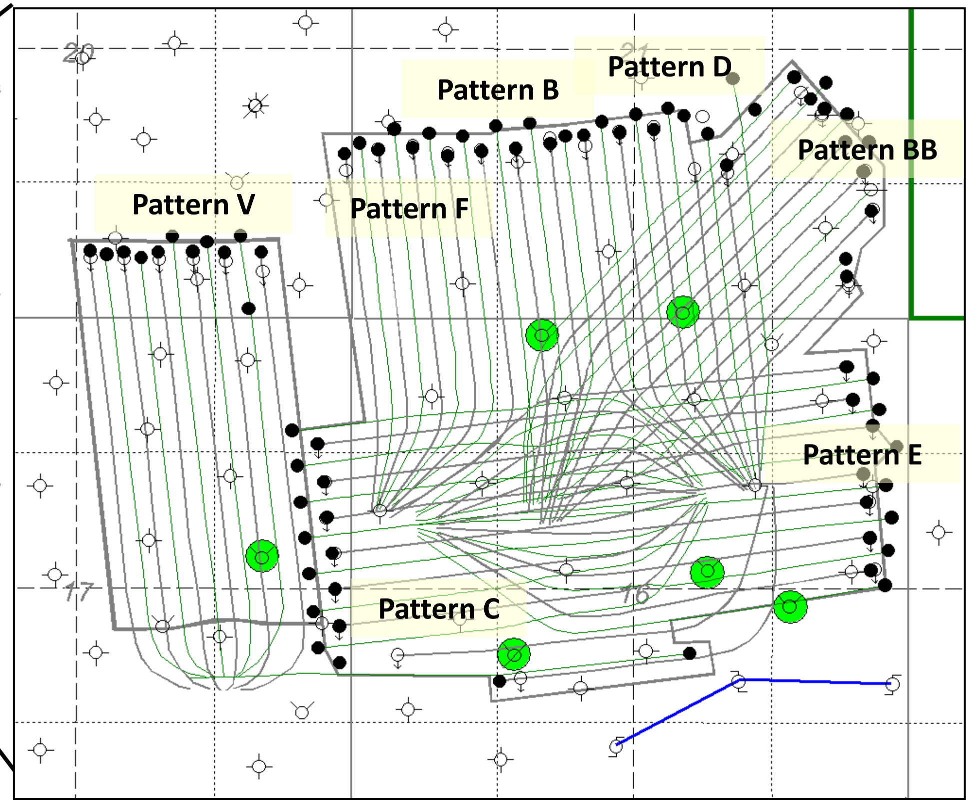
Pattern	Operating Wellpairs	Average h (m)	Average L (m)	Average Porosity	Average Oil Saturation	OOIP (m^3)	Ultimate Recovery (m^3)	Cumulative Production (m^3)	Recovery (% SAGDable)
A	8	19	889	34%	72%	3,296,000	1,812,800	1,667,238	50.6%
B	2	30	745	34%	82%	1,246,000	685,300	554,837	44.5%
BB + D7	7	17	846	33%	83%	2,714,000	1,492,700	1,179,803	43.5%
C + D6	7	24	803	34%	75%	3,453,000	1,899,150	2,564,841	74.3%
D-D6-D7	5	18	680	34%	78%	1,622,000	892,100	826,600	51.0%
E + F1	7	20	819	33%	77%	2,915,000	1,603,250	1,505,002	51.6%
F - F1	5	19	776	33%	78%	1,867,000	1,026,850	886,934	47.5%
V	6	18	1139	33%	72%	2,970,000	1,633,500	445,906	15.0%
G	4	14	759	33%	71%	1,025,000	563,750	73,925	7.2%
H	2	13	832	33%	72%	509,000	279,950	38,305	7.5%
J	8	18	986	33%	76%	3,592,000	1,975,600	278,977	7.8%
K	7	18	955	33%	75%	2,996,000	1,647,800	306,542	10.2%
M	10	27	998	32%	75%	6,469,000	3,557,950	596,407	9.2%
N*	9	23	1054	33%	81%	5,887,000	3,237,850	479,017	8.1%
T	7	16	952	32%	81%	2,803,000	1,541,650	149,334	5.3%
U	6	16	882	30%	80%	2,033,000	1,118,150	143,271	7.0%
AP*	10	28	832	33%	83%	6,439,000	3,541,450	643,207	10.0%
AF	5	18	972	32%	82%	2,278,000	1,252,900	101,099	4.4%
AG	4	20	835	33%	77%	1,701,000	935,550	21,928	1.3%
AN	8	23	870	32%	83%	4,187,000	2,302,850	39,496	0.9%
TOTAL	**127**					**60,002,000**	**33,001,100**	**12,502,668**	20.8%

Note: Production volume and number of operating wellpairs are as of April 2015
h is net pay above the producer
L is Liner length (including blanks) with 50m added to each end (100m total)
Cumulative production includes associated infill wells
* Updated in May 2015

Update on enhanced Modified Steam and Gas Push (eMSAGP)

Phase 1 and Phase 2 Pad Layout





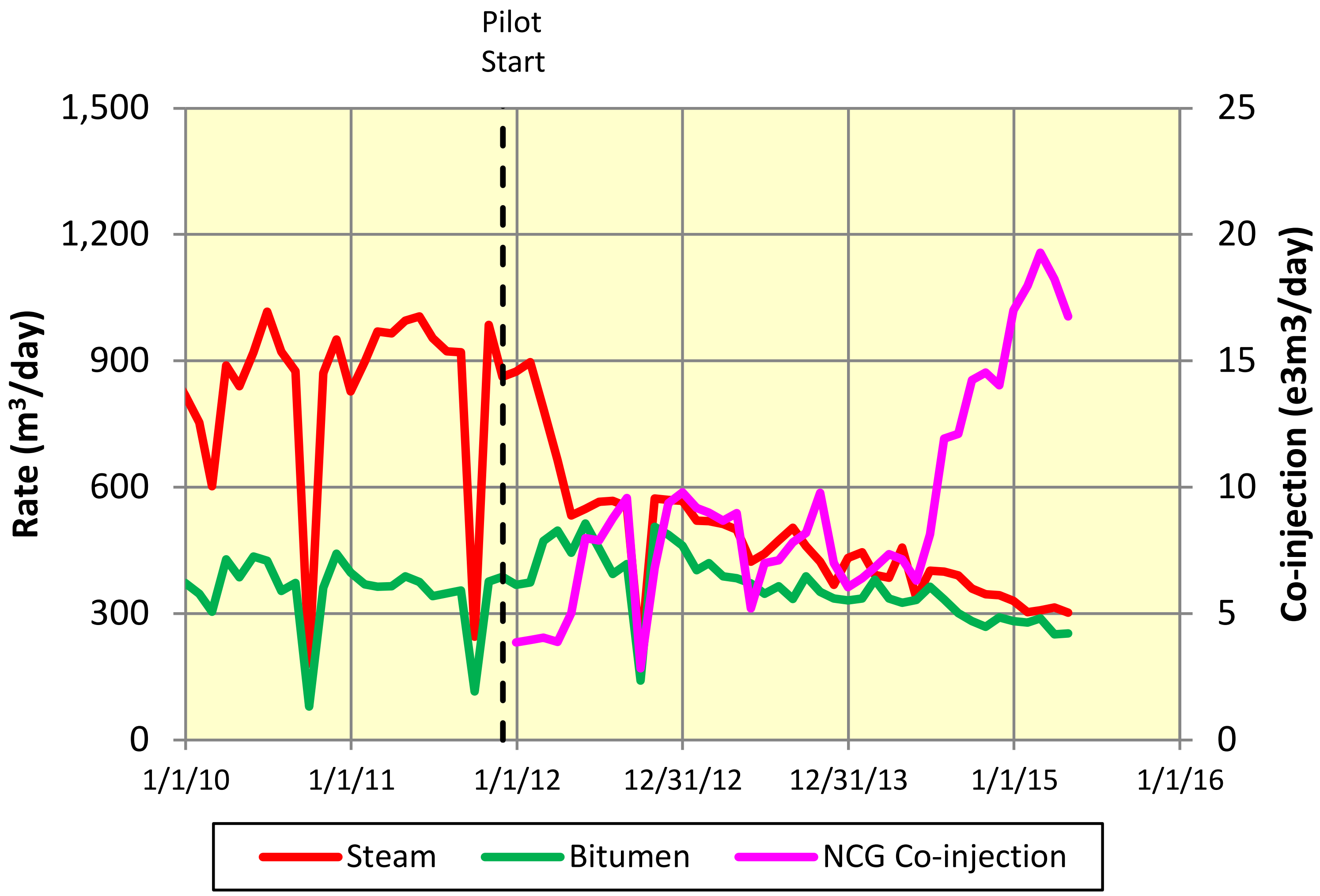
eMSAGP Rollout:

- ✓ Pad A Pilot (A1-A3): Dec. 2011
- ✓ Pad B (B1-B6): Feb. 2013
- ✓ Pad C (C1-C6, D6): July 2013
- ✓ Pad D (D1-D5): Aug. 2013
- ✓ Pad E (E1-E6, F1): Jan. 2014
- ✓ Pad F (F2-F6): Jan. 2014
- ✓ Rest of Pad A (A4-A6): April 2014

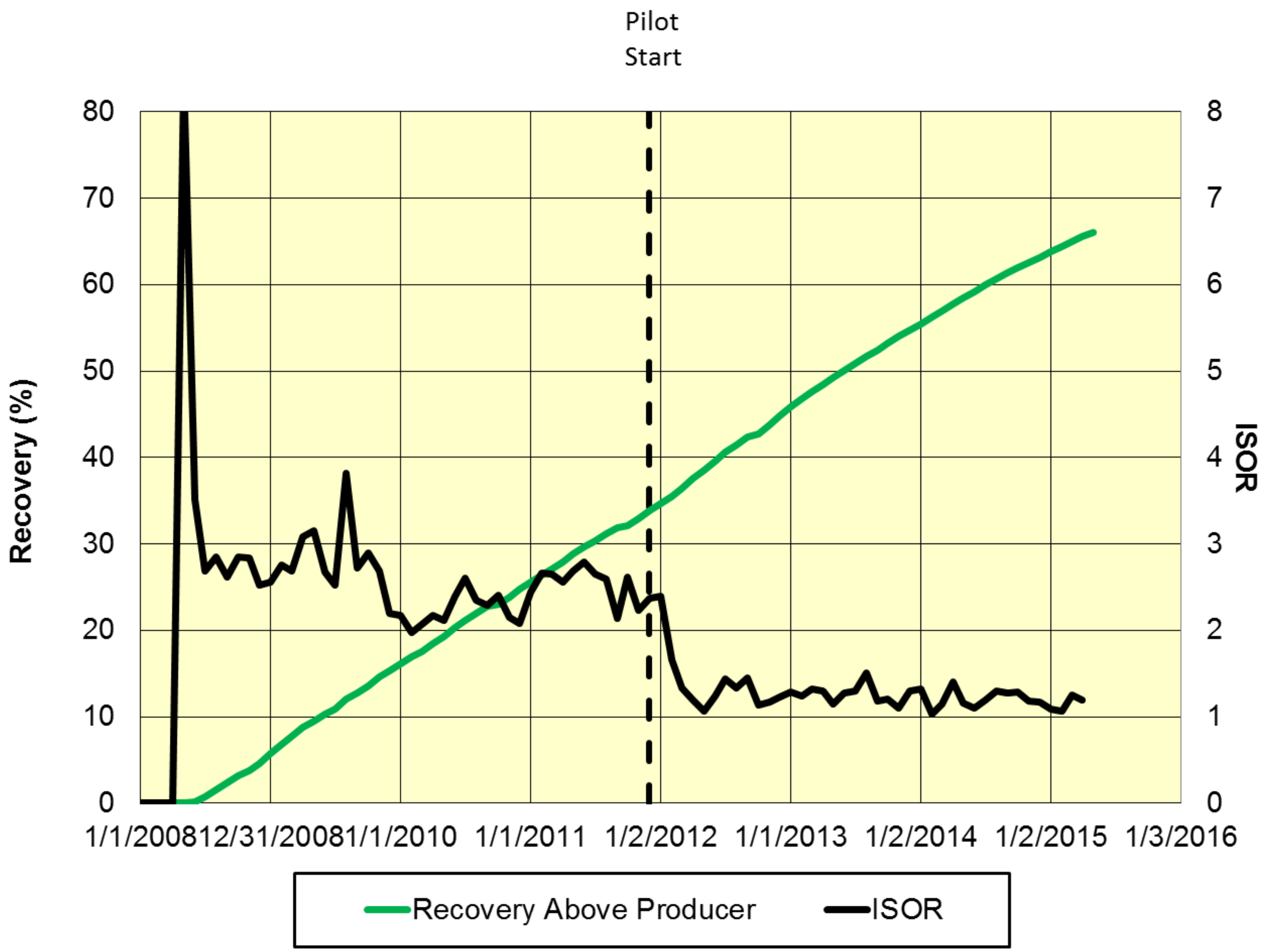
eMSAGP Pilot in Pattern A

- The eMSAGP pilot involves 3 SAGD well pairs (A1, A2 and A3) and 3 infill wells (initially A1N and A2N, later also 0.5*A3N and 0.5*A7N). Non-condensable gas (NCG) and steam are injected into SAGD injectors; production is through SAGD producers and infill wells.
- Co-injection commenced in December 2011. The first two infill wells were brought on production in January 2012 after steam stimulation. A3N and A7N were put on production in January 2014.
- Over ~3.5 years, steam injection has been reduced by about 63%.
  - NCG injection reduces steam requirement while maintaining steam chamber pressure.
  - Combined bitumen production is consistently better than that expected from SAGD alone.
  - SOR has dropped from ~2.5 to ~1.2, resulting in more wells being brought on and proportionally lower emissions and water usage.
- To-date, pilot performance has been very satisfactory.

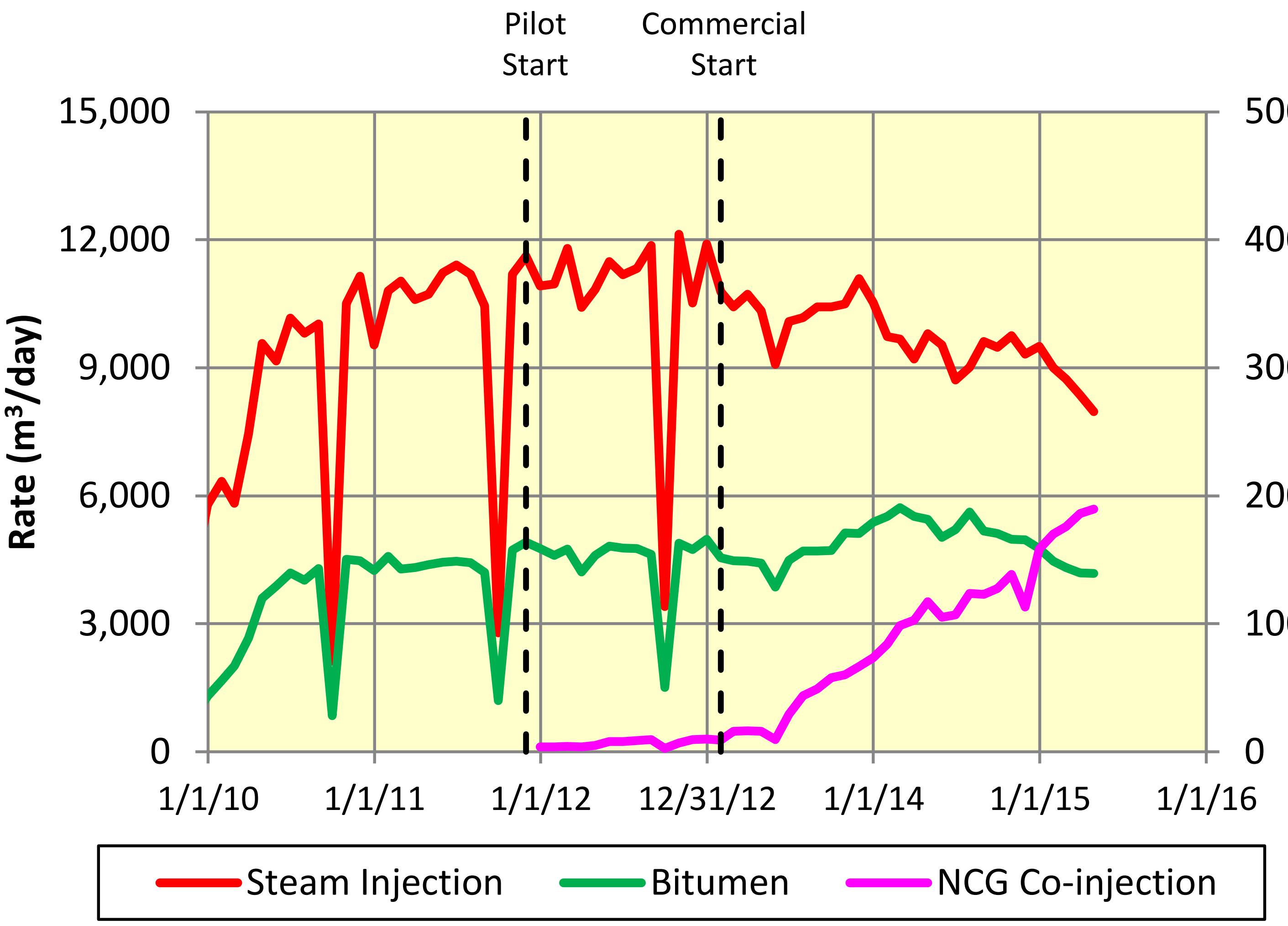
Performance of eMSAGP Pilot



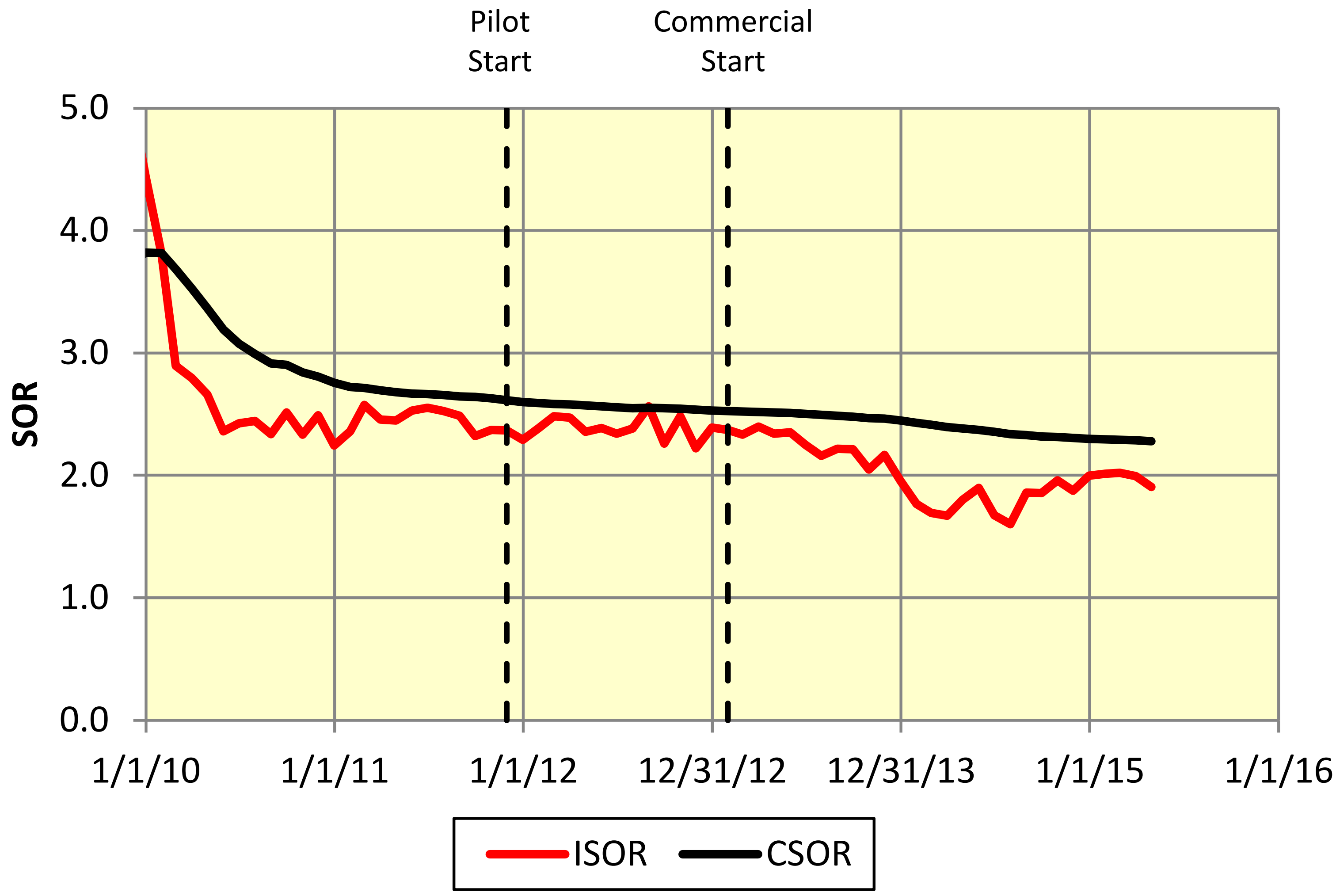
Performance of eMSAGP Pilot



Performance of eMSAGP Wells



SOR of eMSAGP Wells



Summary of eMSAGP Development

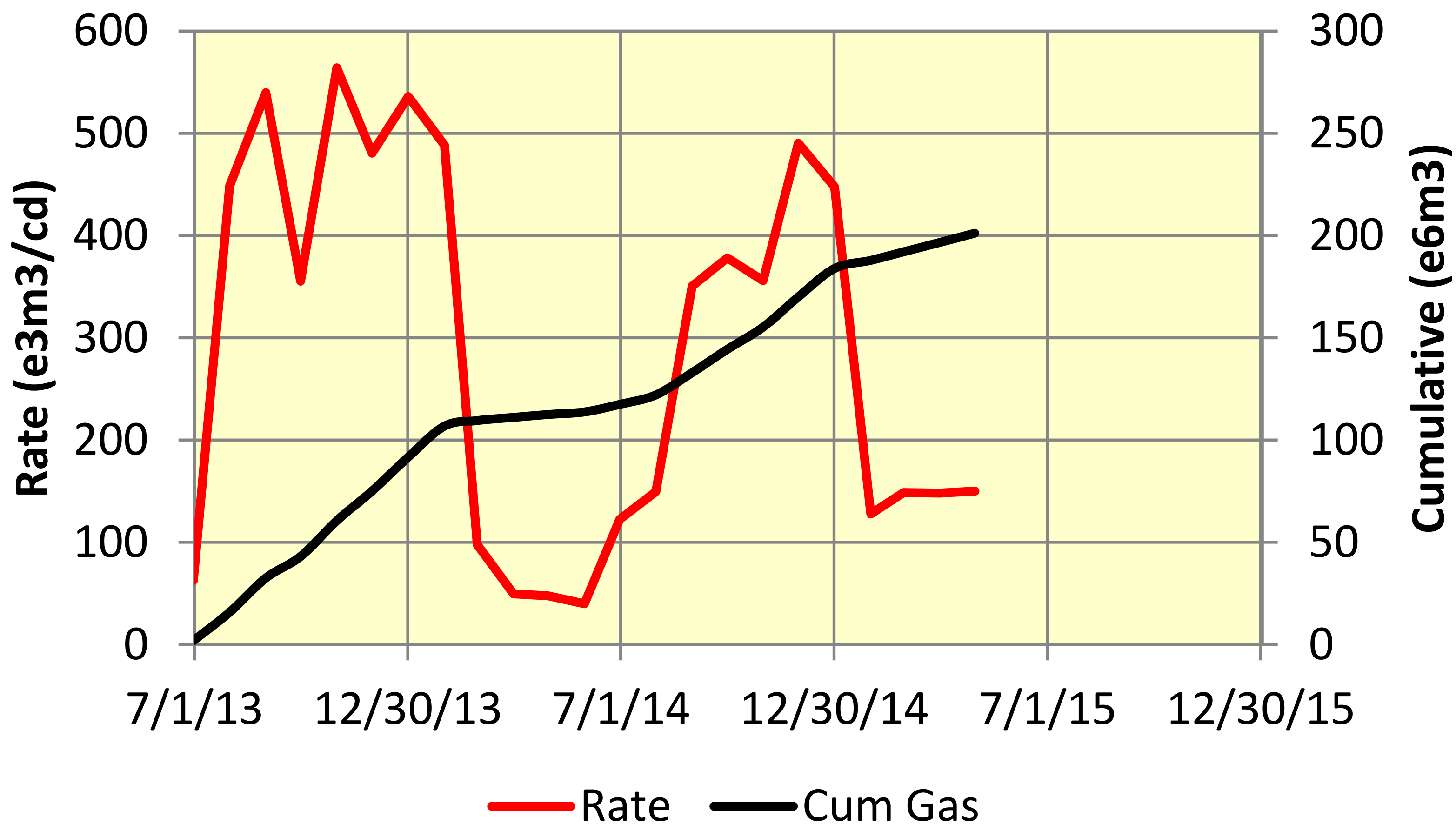
- After 3.5 years, the eMSAGP pilot has demonstrated consistent and very satisfactory performance. Higher bitumen production rate was achieved at a much lower SOR, averaging 1.2 over the period.
- Following the success of the pilot, commercial application of eMSAGP has been implemented in patterns B, C, D, E, F and 3 more wells in Pattern A (A4 to A6).
- Performance to date strongly suggests repeatable performances from pattern to pattern.
- Freed up steam has been redeployed to start new SAGD and infill wells.
- Since the initiation of B Pattern eMSAGP in Feb 2013, the bitumen production rate for Phases 1 and 2 has increased and ISOR has come down from 2.4 to 1.9. Total reduction is steam injection was about 27% to April 2015.

CLRP Gas Cap Re-pressuring

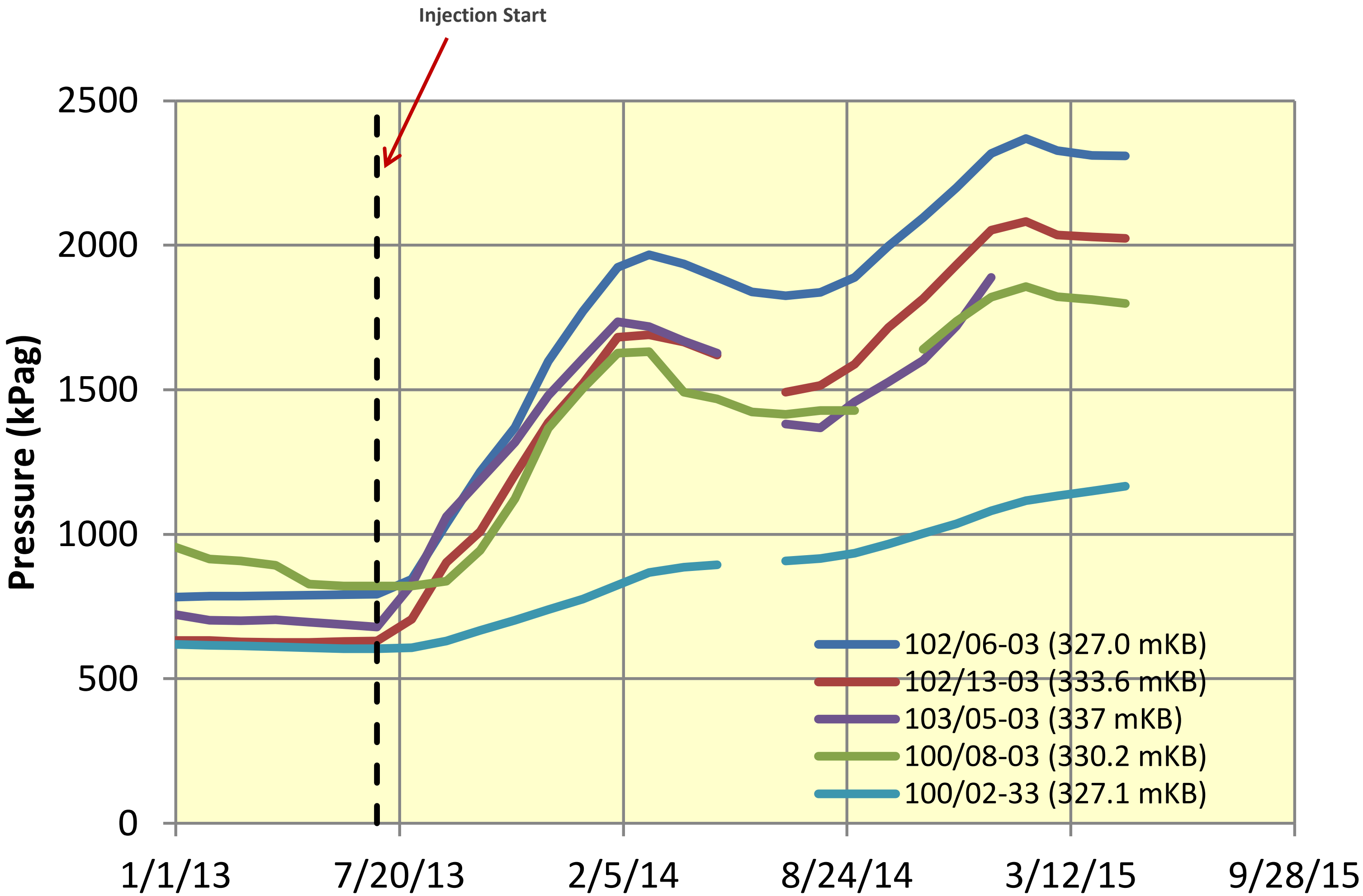
Gas Cap Re-pressuring Project Update

- The AER approval was granted in November 2012
- Natural gas injection into 5 wells commenced in June 2013
- Total injection to date was 201 e6m3 (~7.1 BCF), with an average injection rate of 242 e3m3/day (8.7 mmscf/day) over the period
- Pressure responses have been observed in all 5 monitoring wells
- Estimated gas zone pressure above the active SAGD patterns (M & N) was about 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
- Plan is to maintain the current pressure on top of the active SAGD area and monitor pressures in gas and SAGD zones closely

Gas Injection

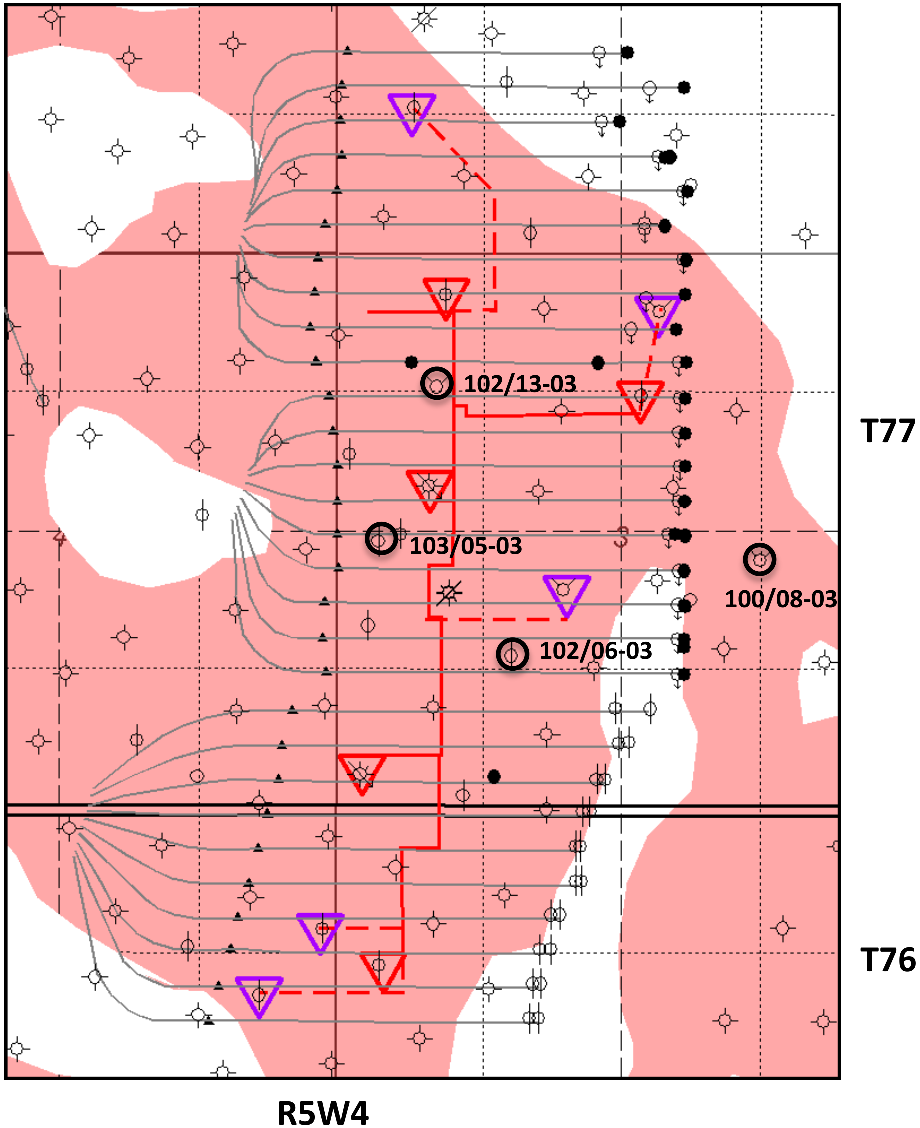


Observation Well Pressure Readings



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

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



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

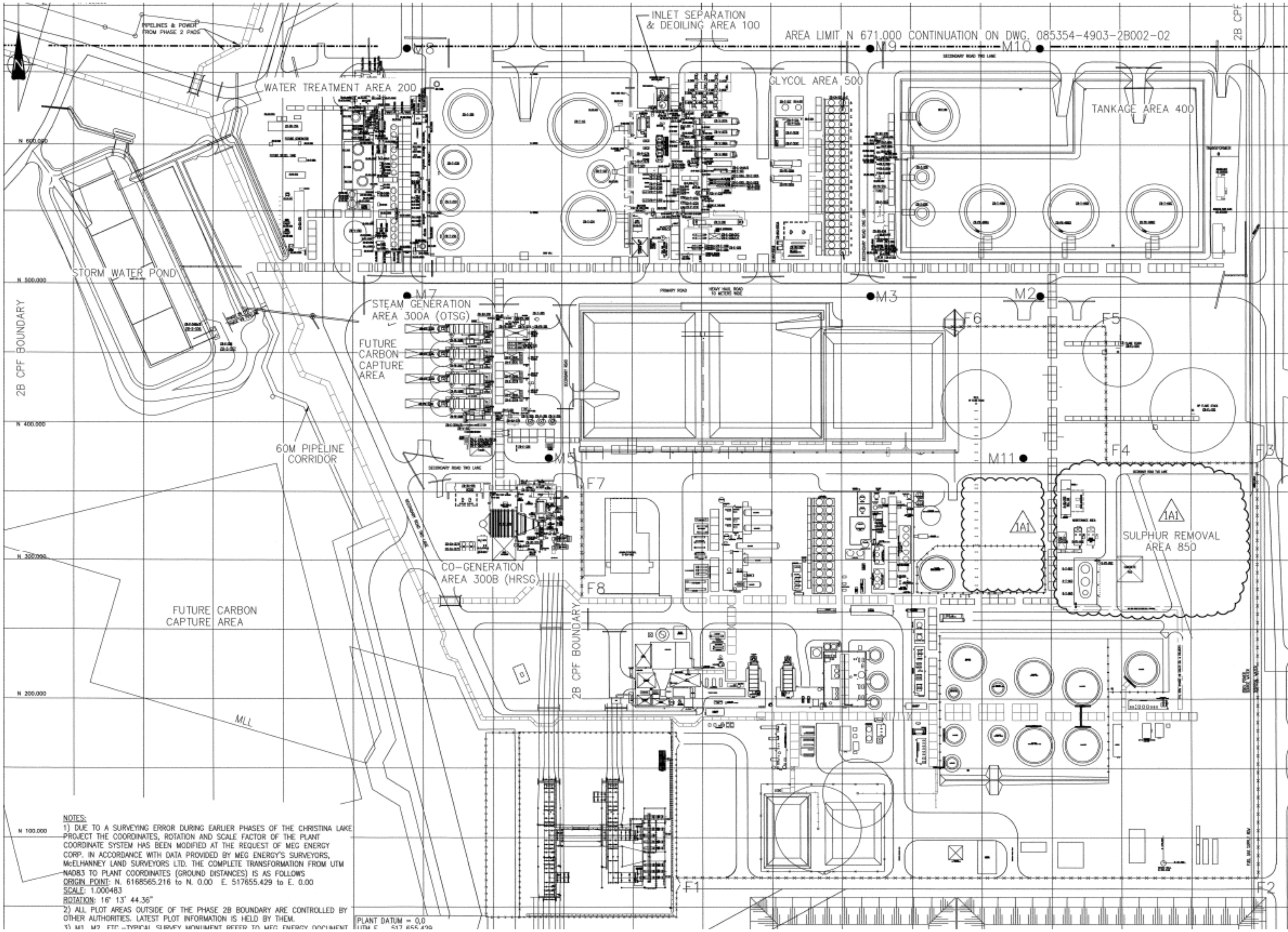
Note:
Not all SAGD intervals in the pool wells are directly connected to associated gas

Operations

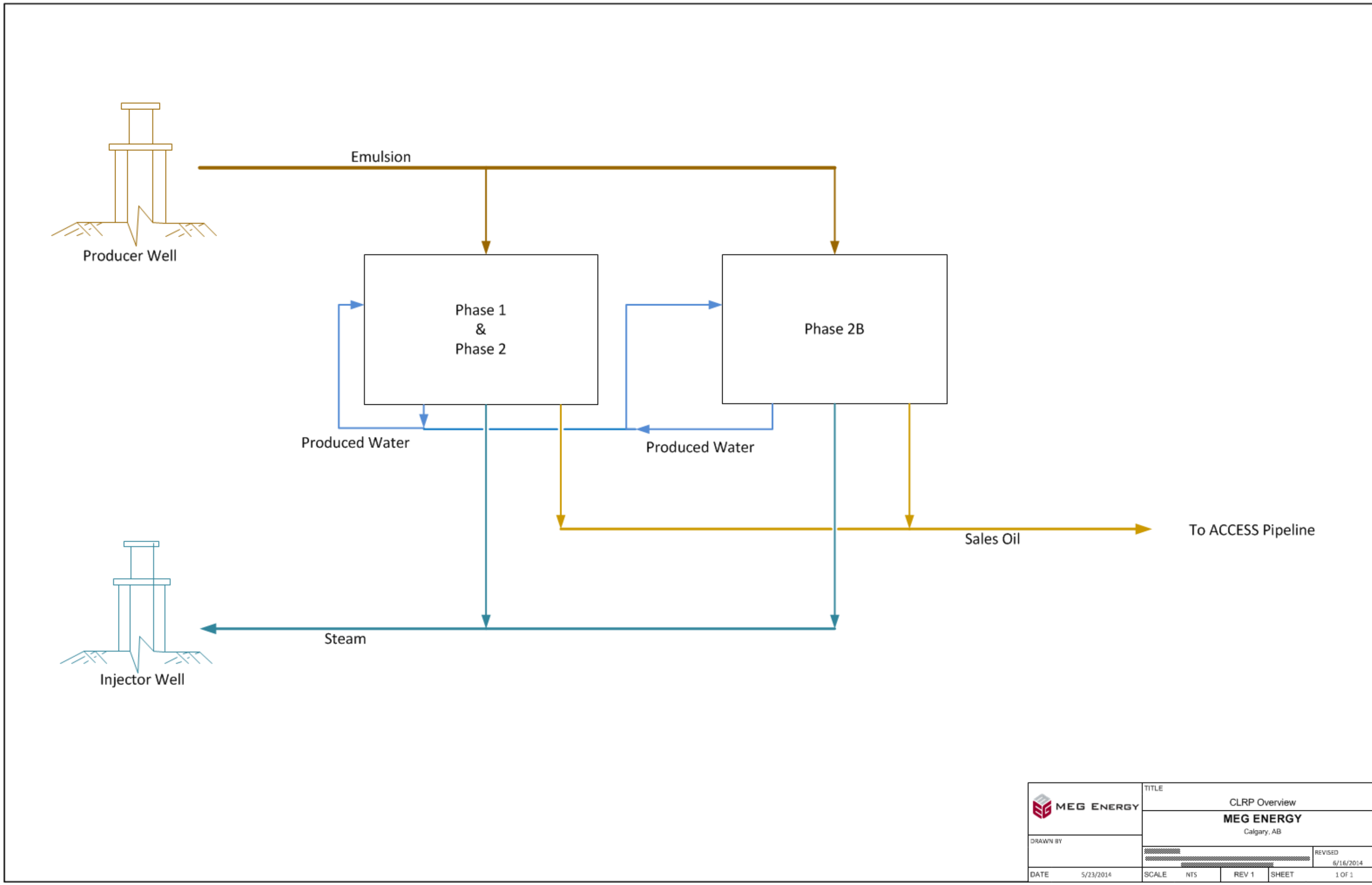
Operations Overview

- Operation Overview
- Bitumen Treatment
- Water Treatment
- Steam Generation
- Power Generation
- Gas Usage
- Measurement and Reporting

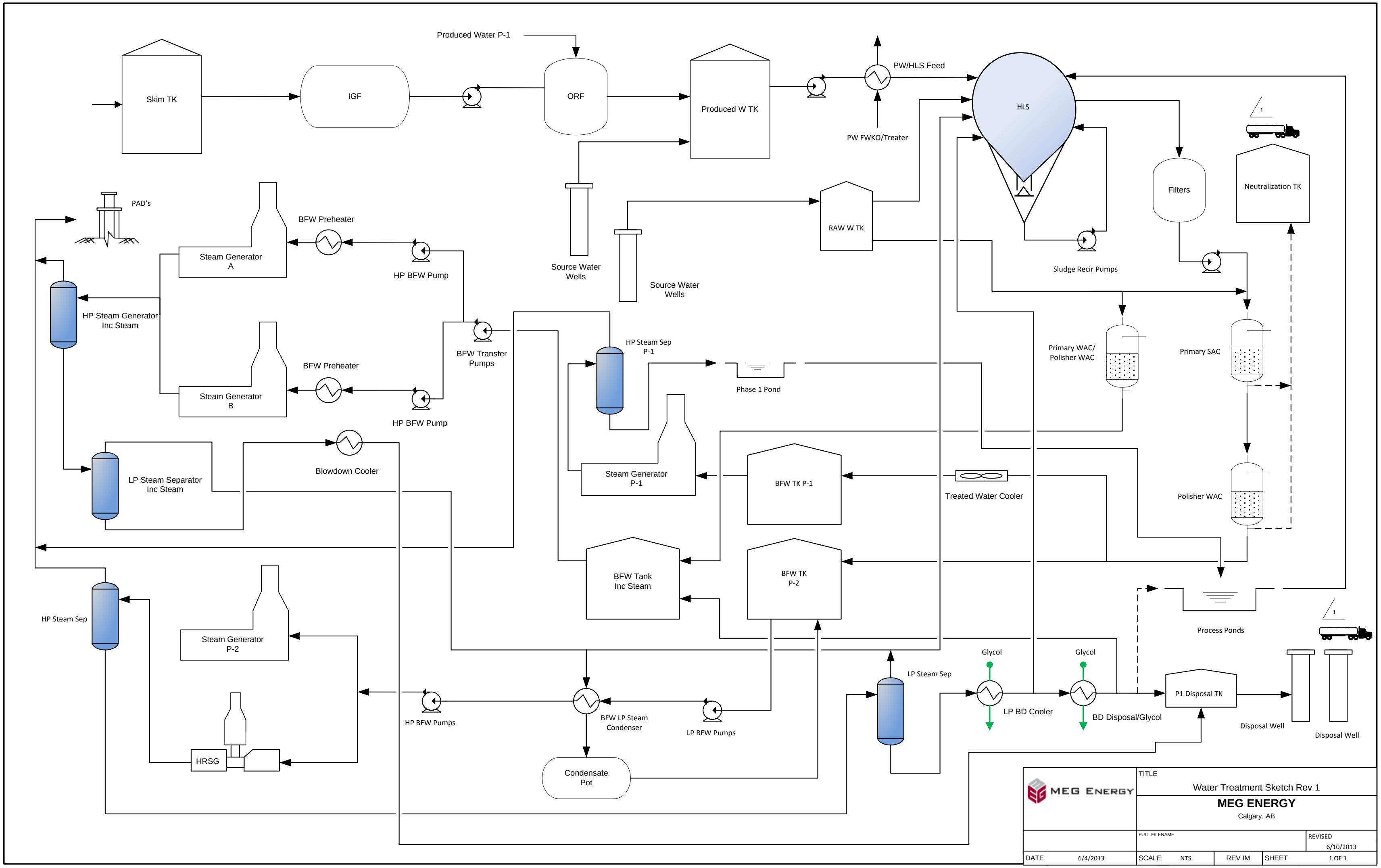
CPF Site Plan



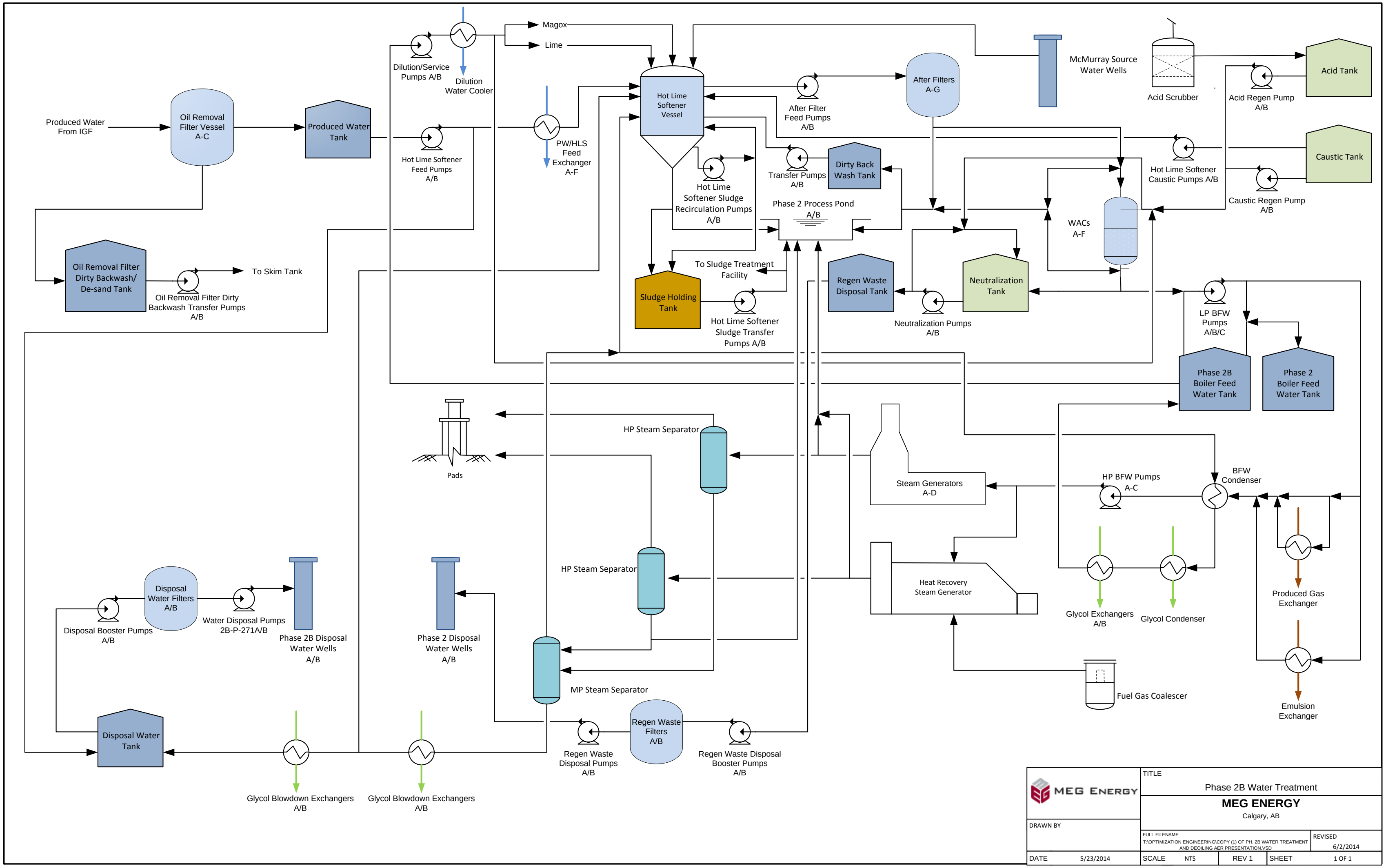
Integrated Distribution/Gathering System



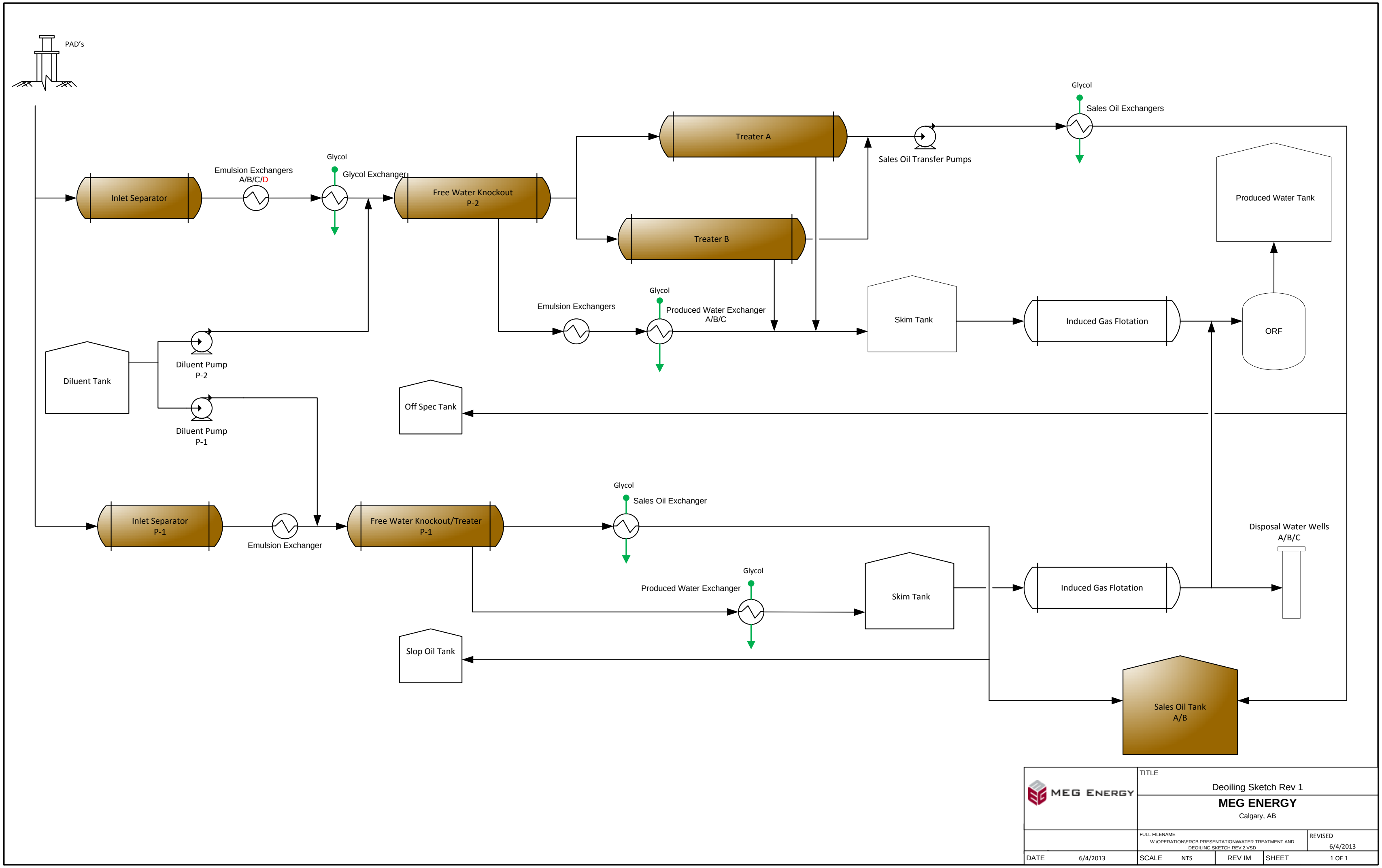
Water and Steam Process Overview Phase 1 and 2



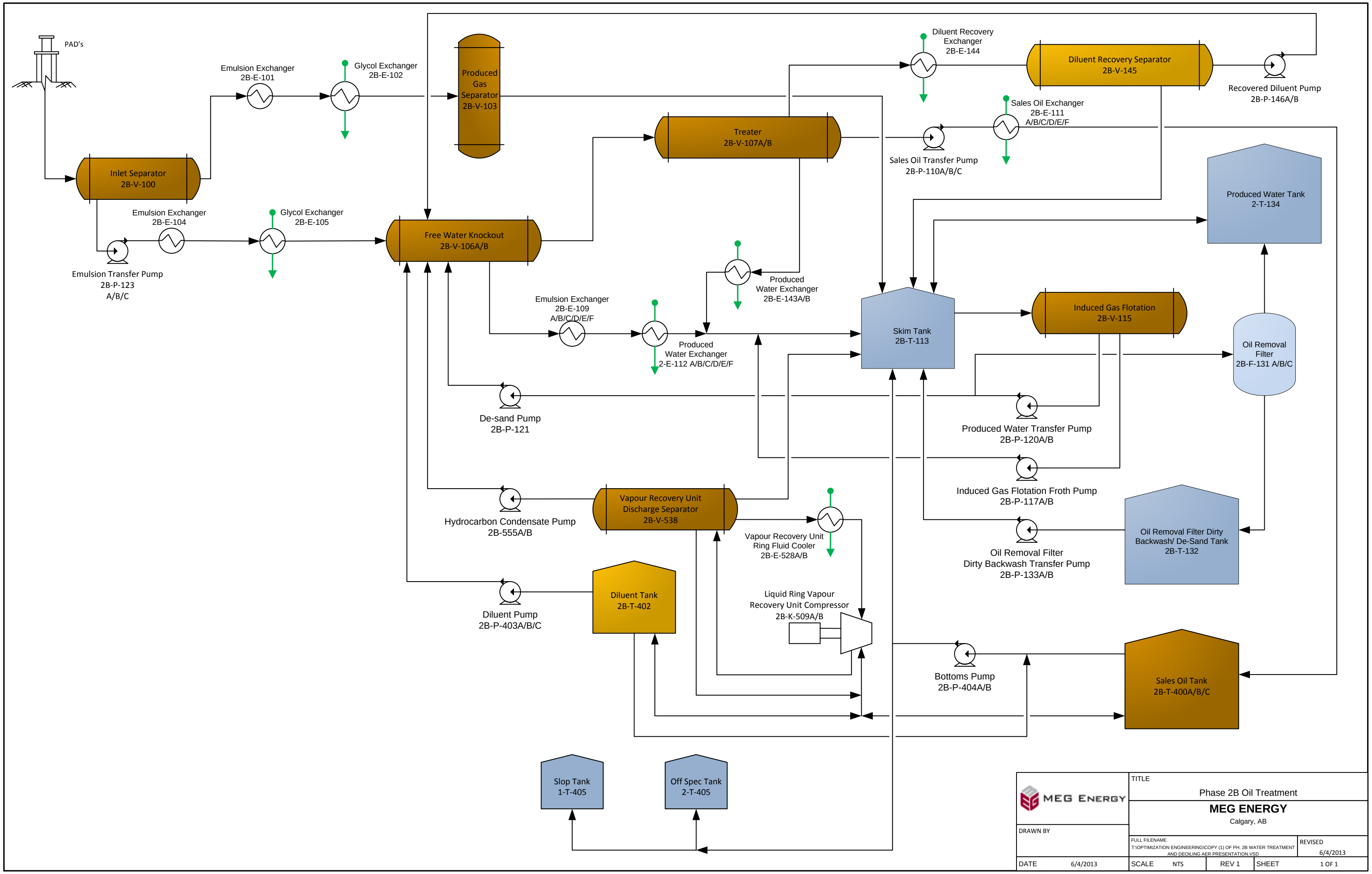
Water and Steam Process Overview Phase 2B



Oil Treatment Overview Phase 1 and 2



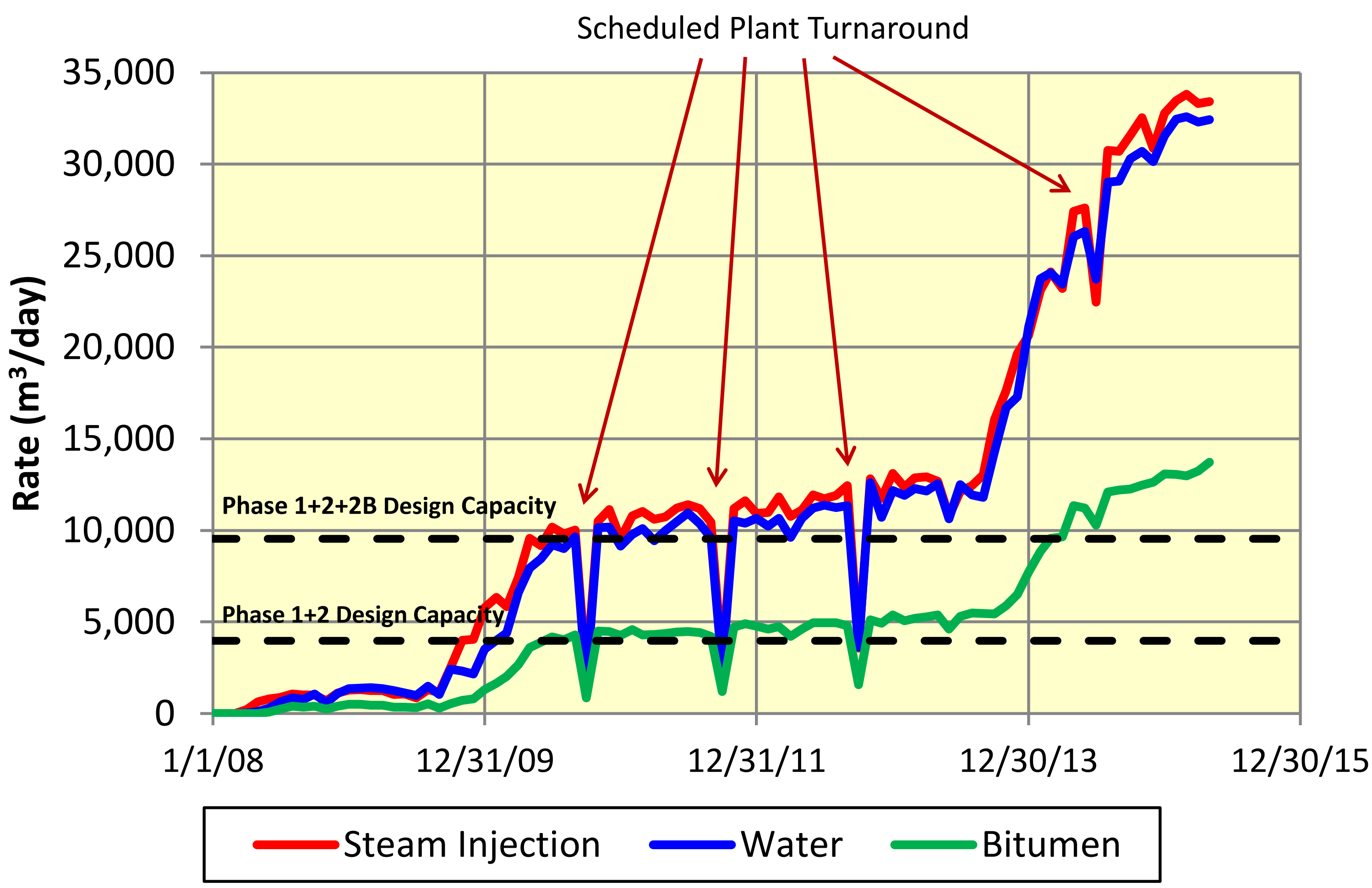
Oil Treatment Overview Phase 2B



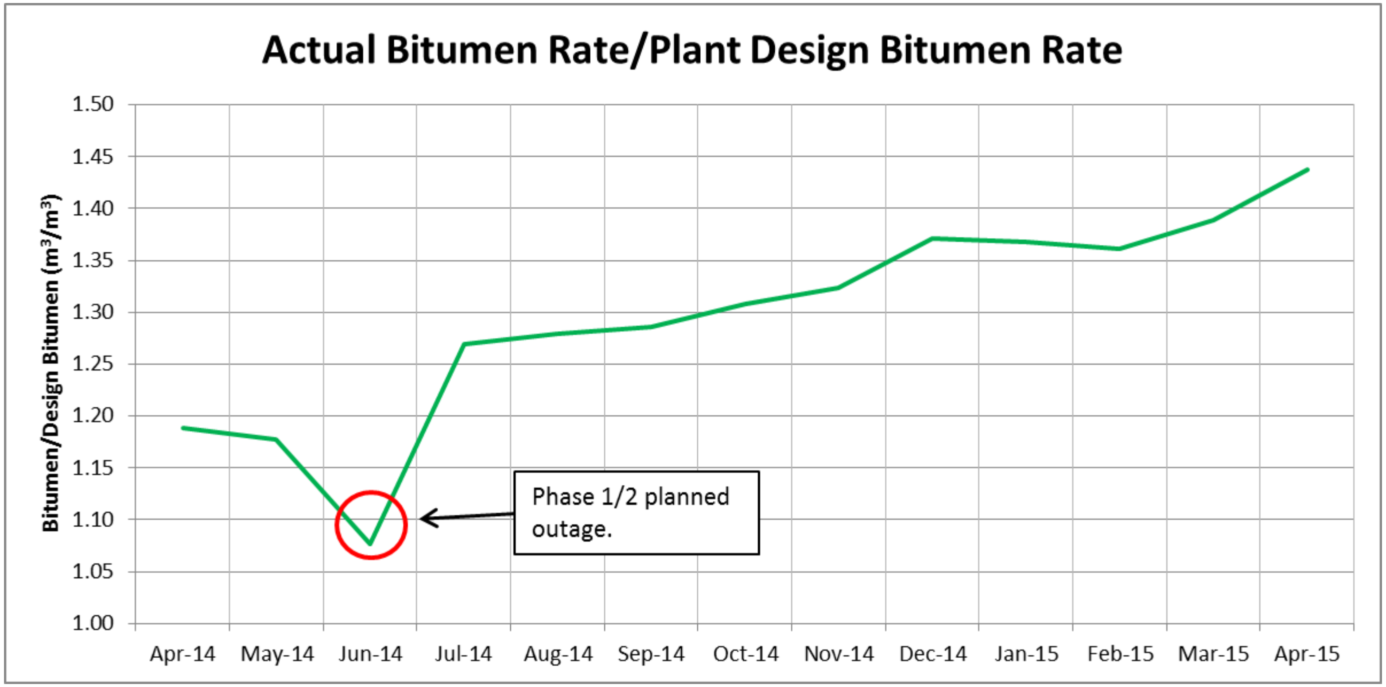
Additions/Modifications

- Sulfur Removal Unit completed and started up in August 2014.
  - Allowed MEG to continue to meet EPEA and Interim Directive 2001-3 commitments.

CLRP Production Performance



Facility Performance: Bitumen Treatment



MEG's Phase 2 and Phase 2B FWKOs and Treaters were designed using a range of diluents with densities ranging from synthetic crude to naphtha.

Since plant commissioning, MEG has been using a naphtha based diluent. Since less naphtha diluent than synthetic crude diluent is required to meet the target dilbit density, the dilbit contains a higher percentage of bitumen. This increases the overall oil capacity of an oil processing plant.

In addition to the above, MEG's equipment design has a designated residence time. In actual operation, a lower residence time than the original design has been required to achieve satisfactory oil-water separation. This has allowed the overall capacity of the plant to be increased.

Facility Performance: Bitumen Treatment

Successes

- Implemented various small projects to increase capacity of Phase 2B plant.
- Implemented skimming and fluid management strategy to reduce trucking.
- Produced gas routed to Sulfur Removal Unit for treatment.
- Implemented load shedding scheme to mitigate impact of plant or well pad trips on emulsion gathering system.
- Cleaned glycol coolers for improved cooling capacity.

Issues Being Addressed

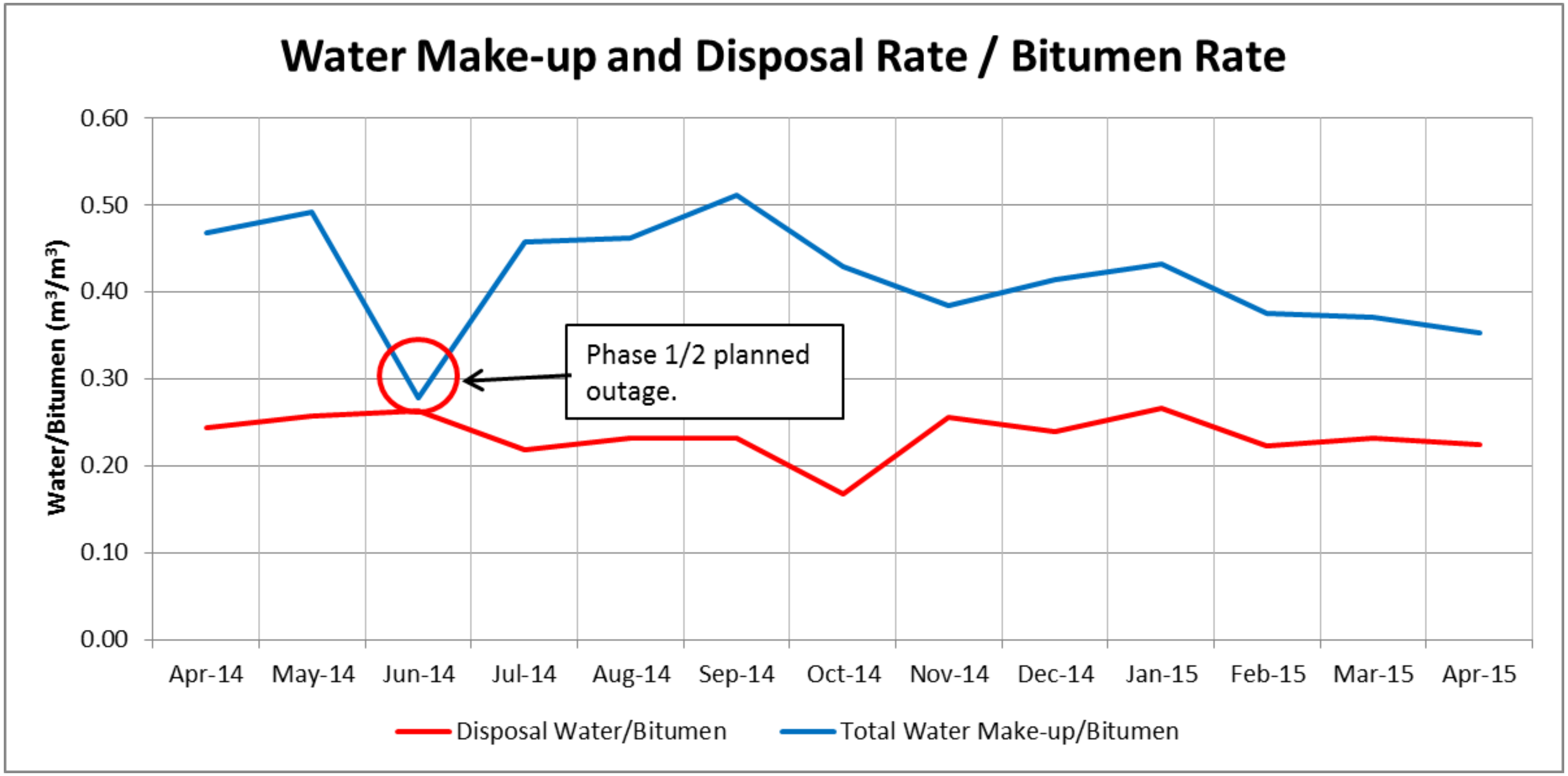
- Produced water exchanger fouling
- Phase 2 glycol cooling system is limited during summer months.

Facility Performance: Bitumen Treatment

Future Actions

- As production is ramped up, optimizing recovery of heat from emulsion to BFW pre-heat.
- Managing operation of PW exchangers to maximize recovery of heat into the HLS feed.
- Continued optimization of slop oil treating and reduction initiatives.

Facility Performance: Water Treatment



Facility Performance: Water Treatment

Successes

- Continue recycling high blowdown volumes.
- Continuous use of saline water.
- New liner installed in west pond

Issues Being Addressed

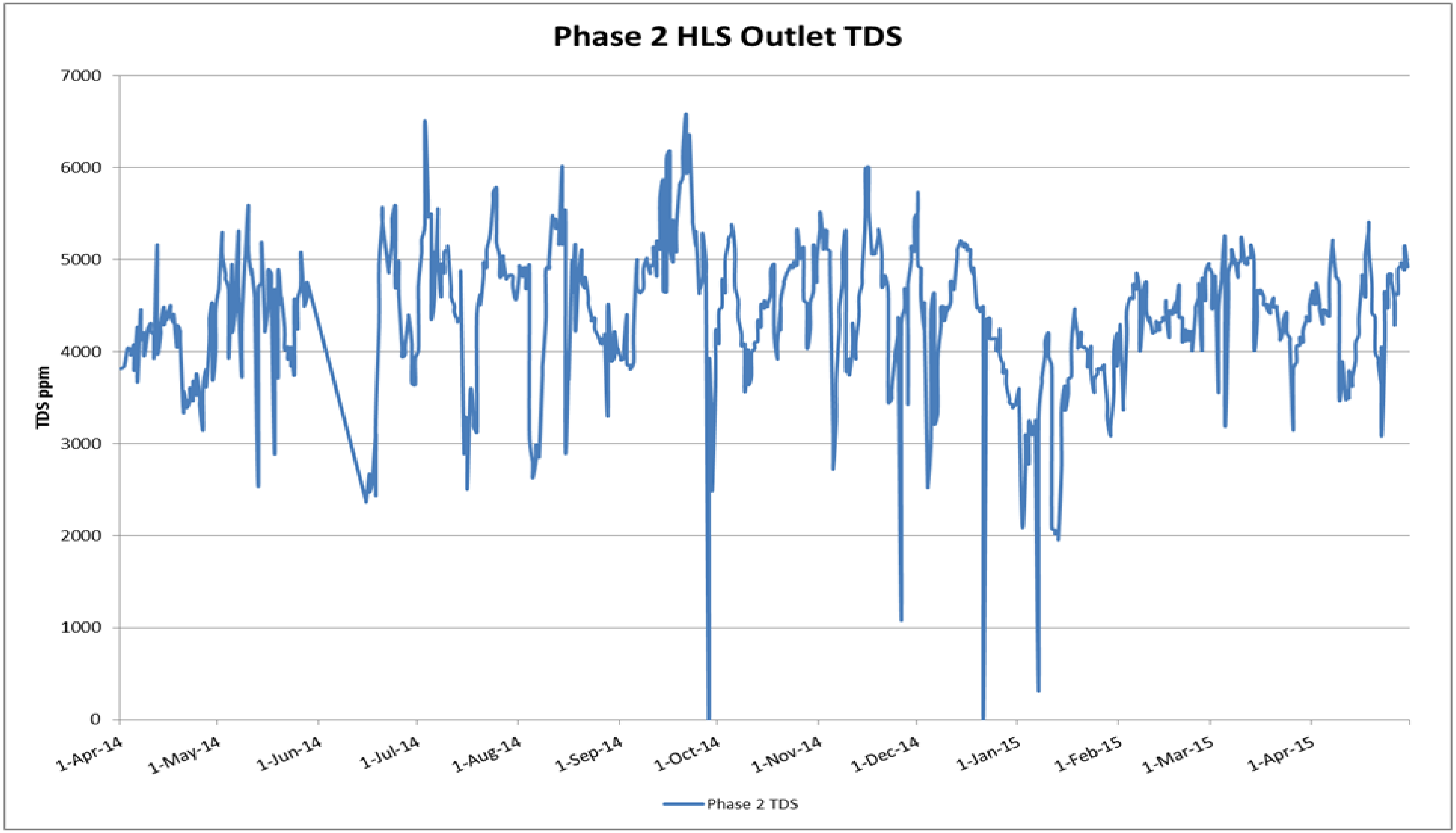
- After-filter media carryover.
- Phase 2B magnesium oxide feeding issues.
- Leaking around penetration point in west pond.

Facility Performance: Water Treatment

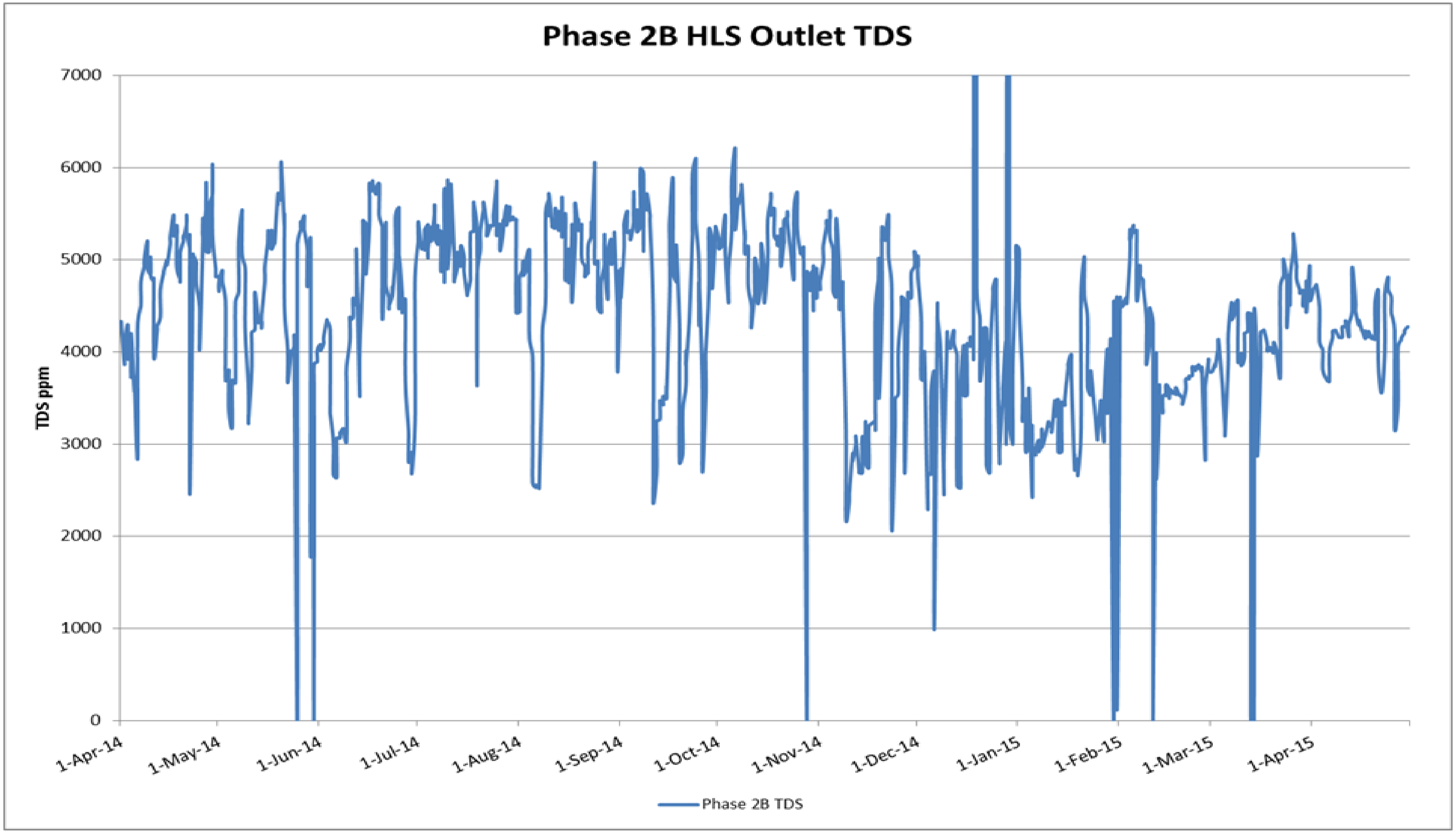
Future Actions

- West pond liner penetration being removed.
- Testing mono-media in after-filters.
- Continuing testing of magnesium oxide feeding options.

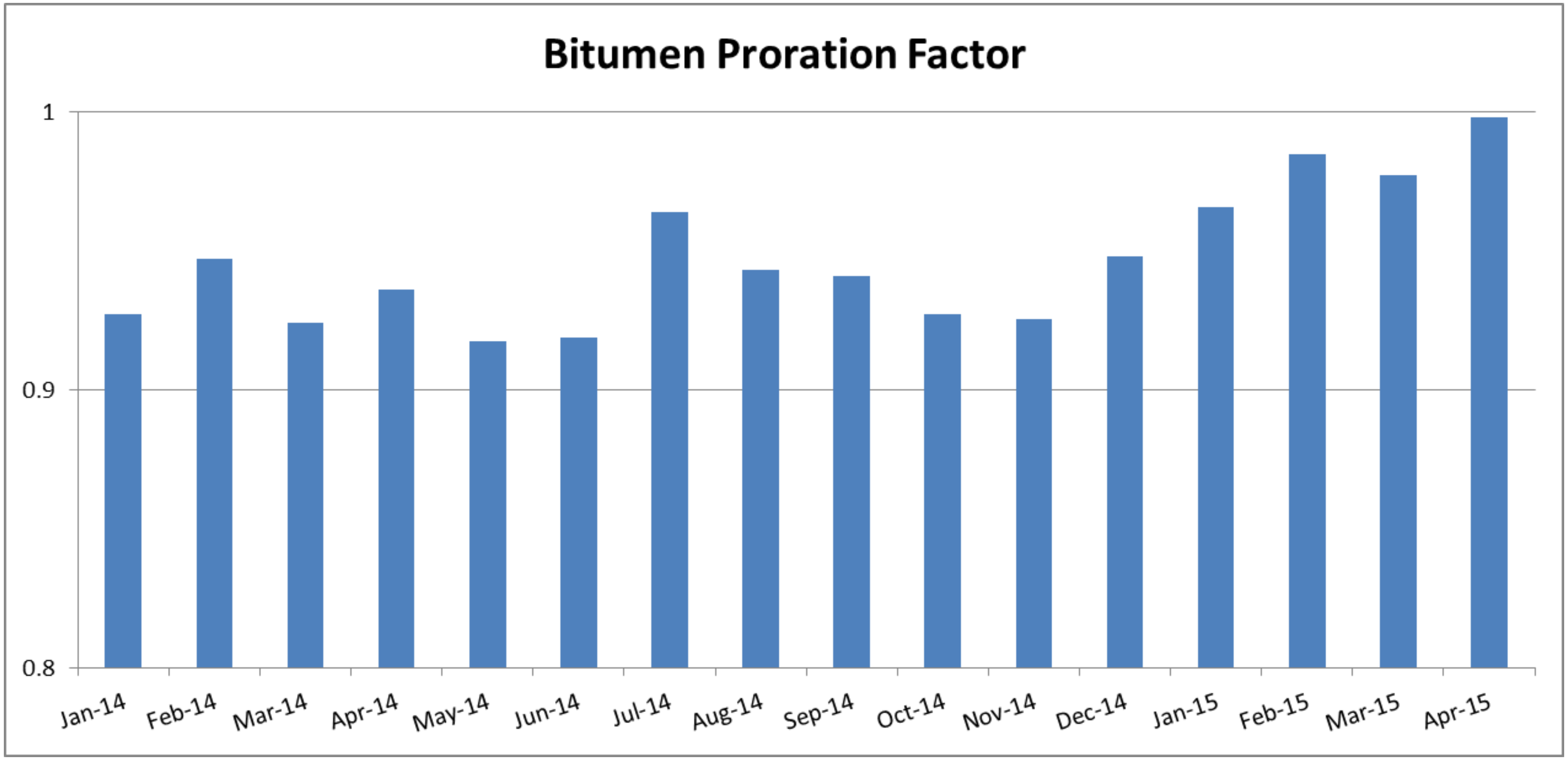
Phase 2 TDS Boiler Feed Water



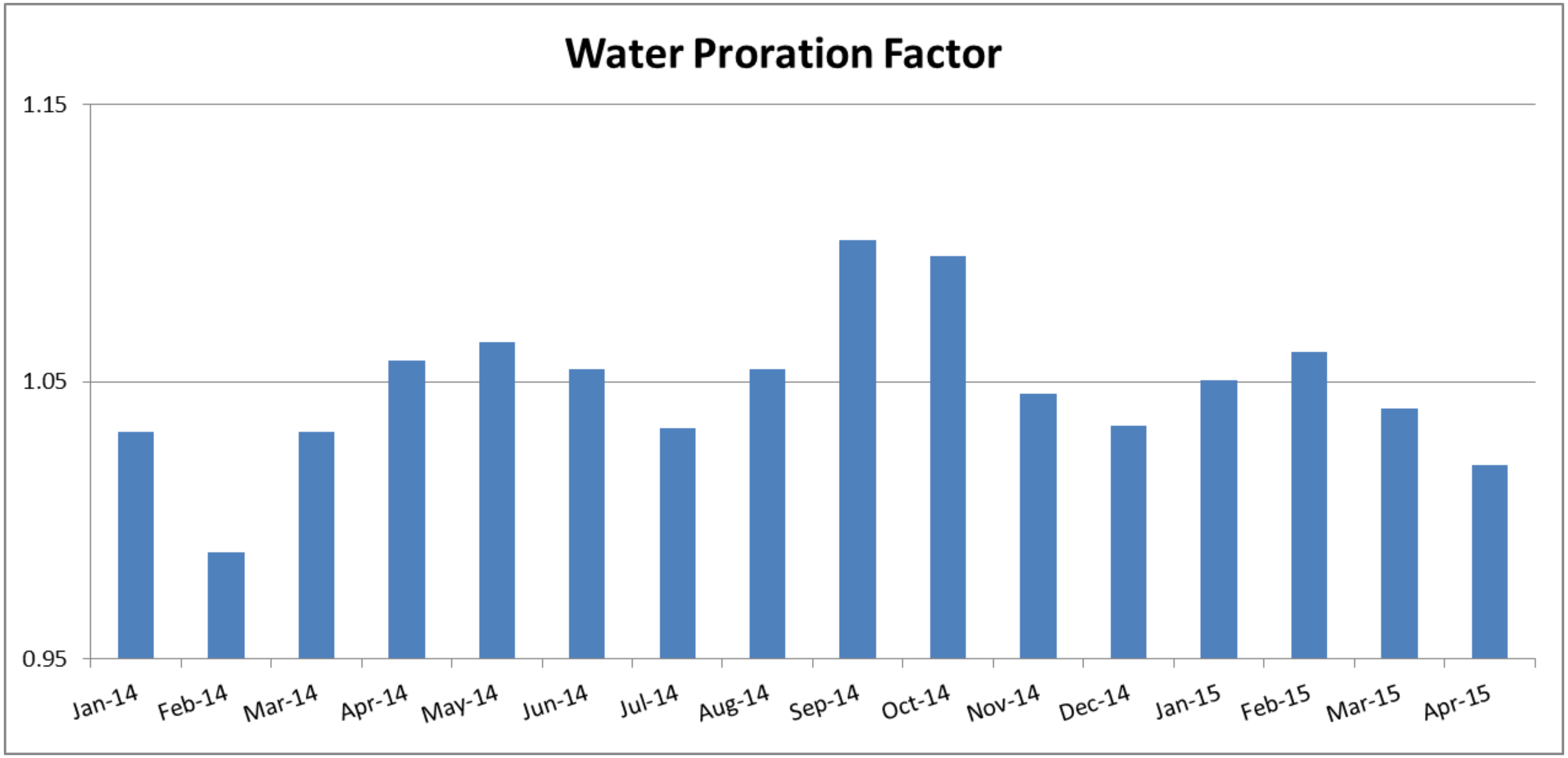
Phase 2B TDS Boiler Feed Water



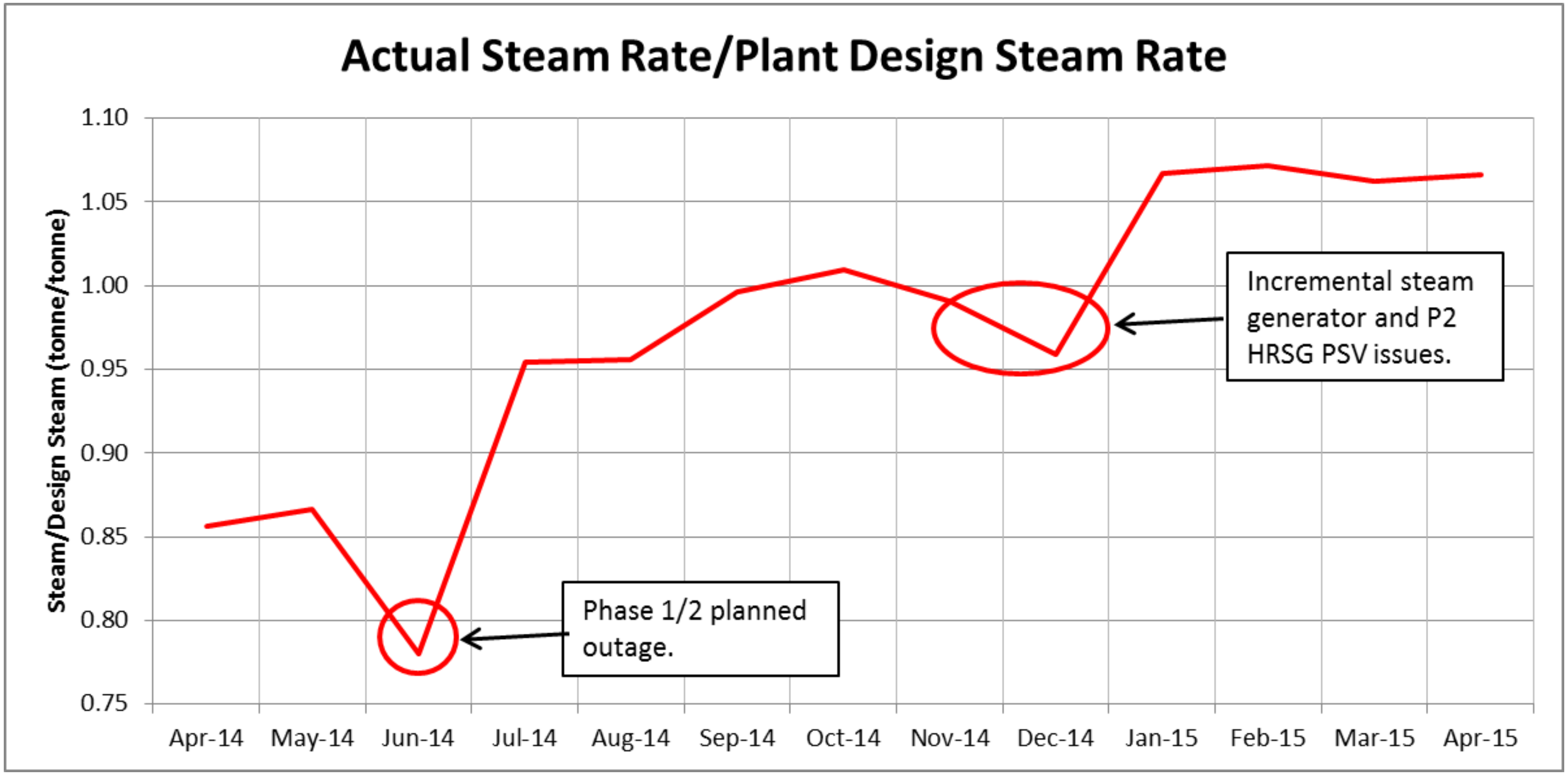
Proration Factors



Proration Factors



Facility Performance: Steam Generation



Facility Performance: Steam Generation

Successes

- Stable operation throughout the year
- Took advantage of lower operating pressures in the Phase 2B HRSG and OTSGs to increase steaming capacity.
- Increased steam quality in the Phase 1/2/2B OTSGs from 78% to 80% (design quality).
- Planned Phase 1/2 plant outage – completed combustion inspection on Phase 2 GTG and pigged Phase 2 HRSG and Phase 1/2 OTSGs.
- Wind fence trial at pond to reduce blowdown plume appears successful – looking at expanding.
- Successfully implemented steam balance as secondary measurement.

Issues Being Addressed

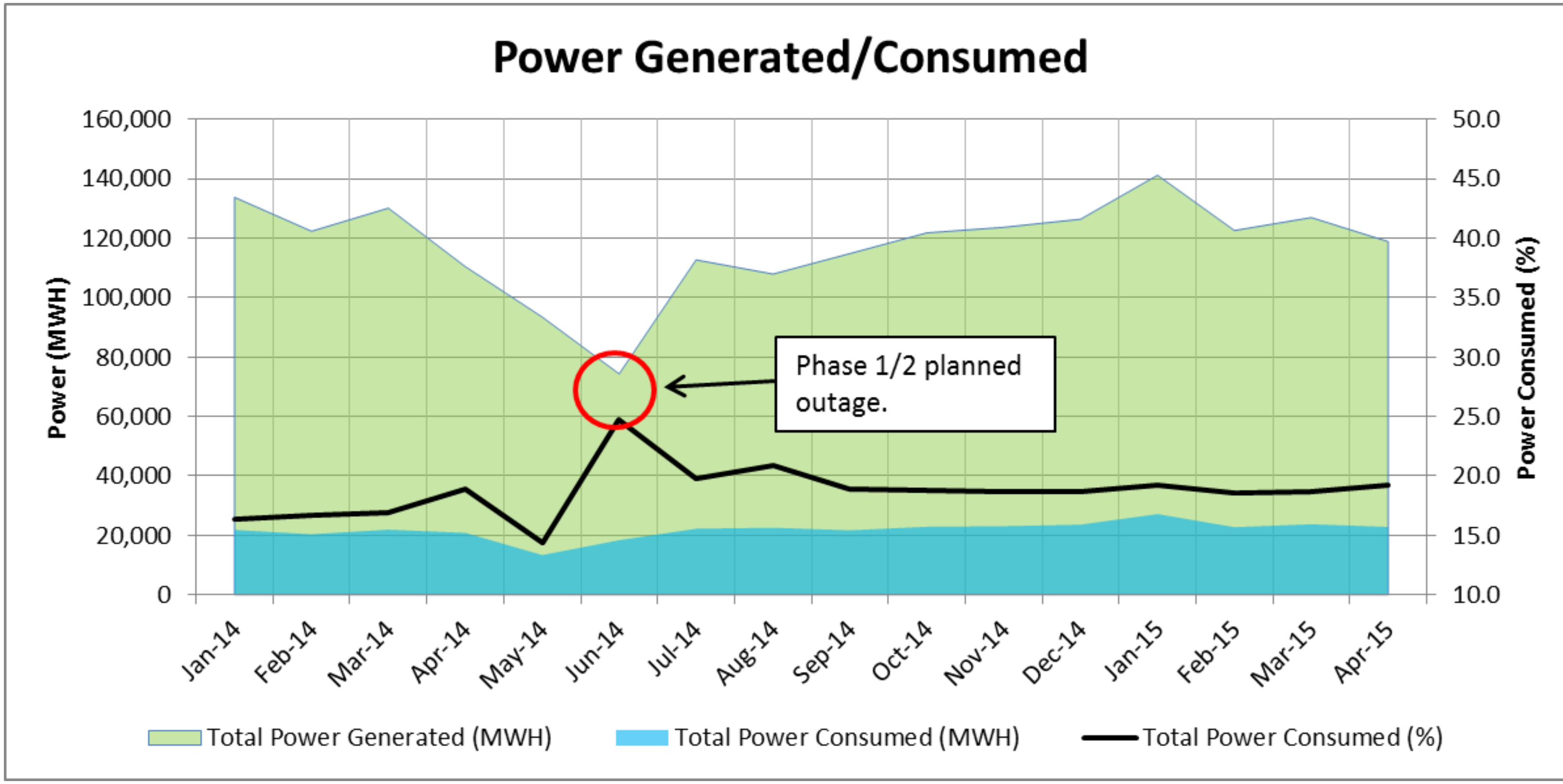
- Tube corrosion issues in two 50 MMBtu/hr boilers.
- Relief valve leaking on Phase 2 HRSG

Facility Operations: Steam Generation

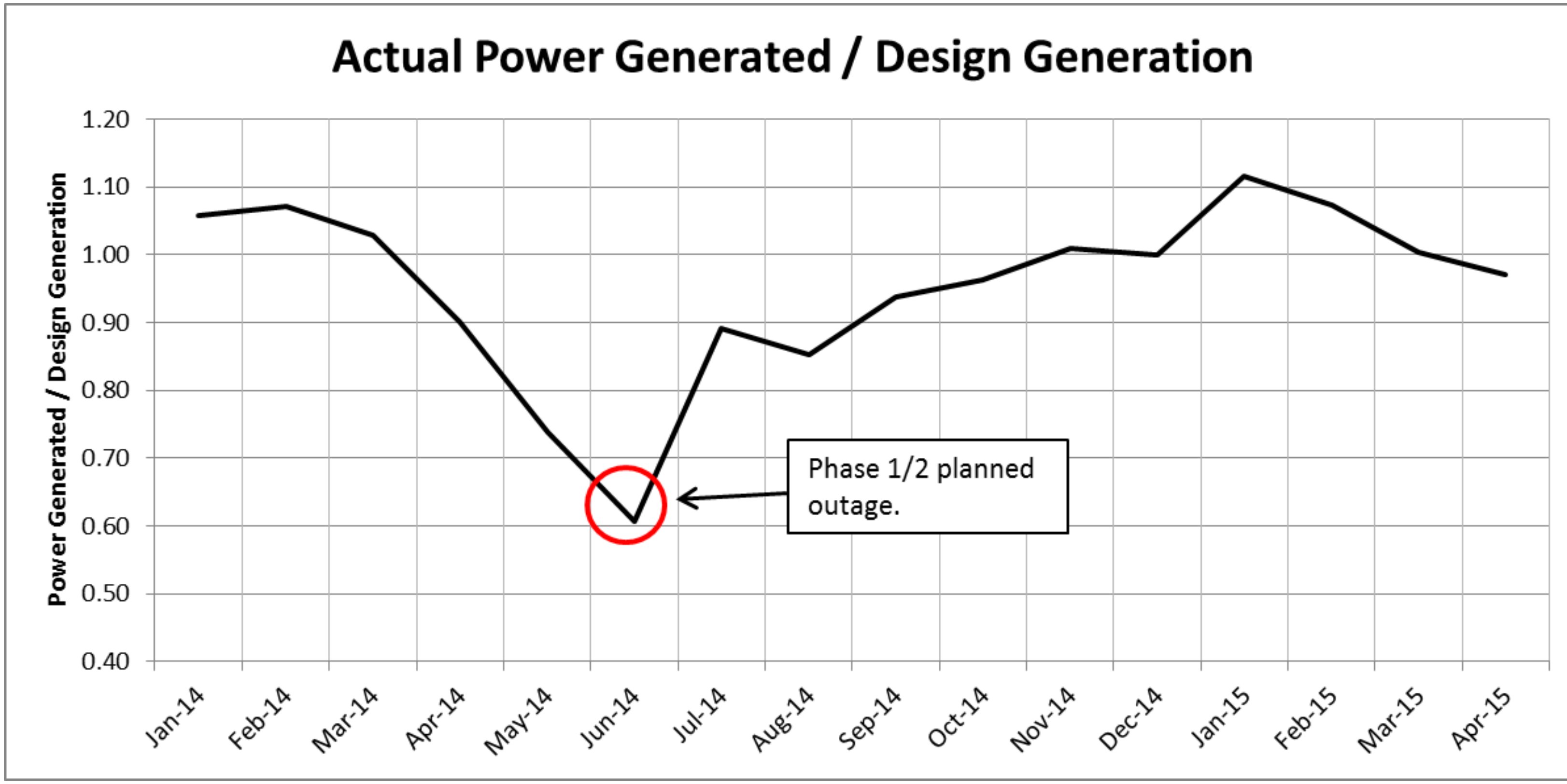
Future Actions

- Continue optimizing steam generator discharge quality while implementing enhanced monitoring program.
- Implement overall HP steam distribution control philosophy.
- Implement more detailed steam generator availability and utilization tracking.

Facility Performance: Power Generation



Facility Performance: Power Generation



Facility Performance: Power Generation

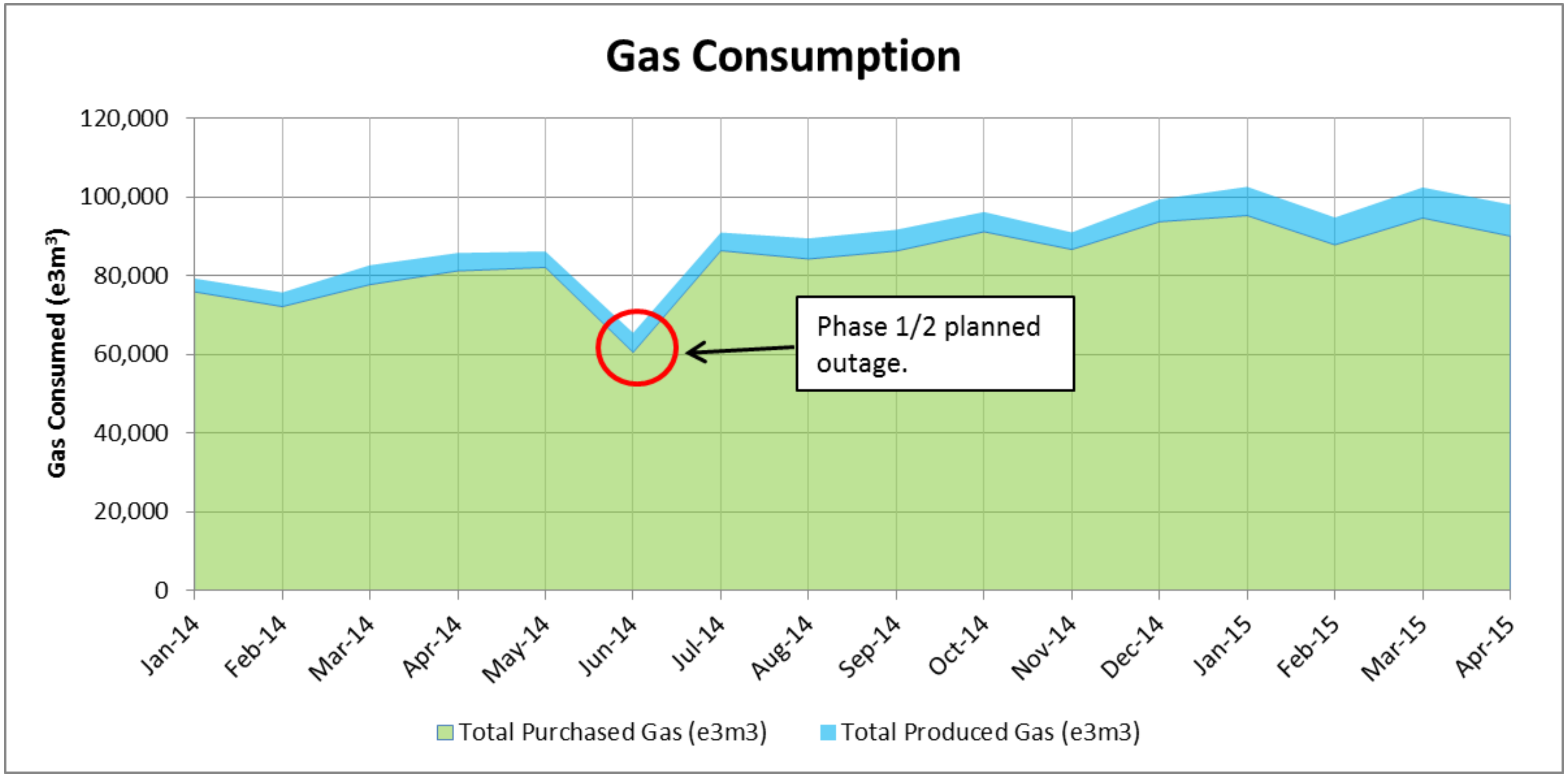
Successes

- Stable operation throughout the year

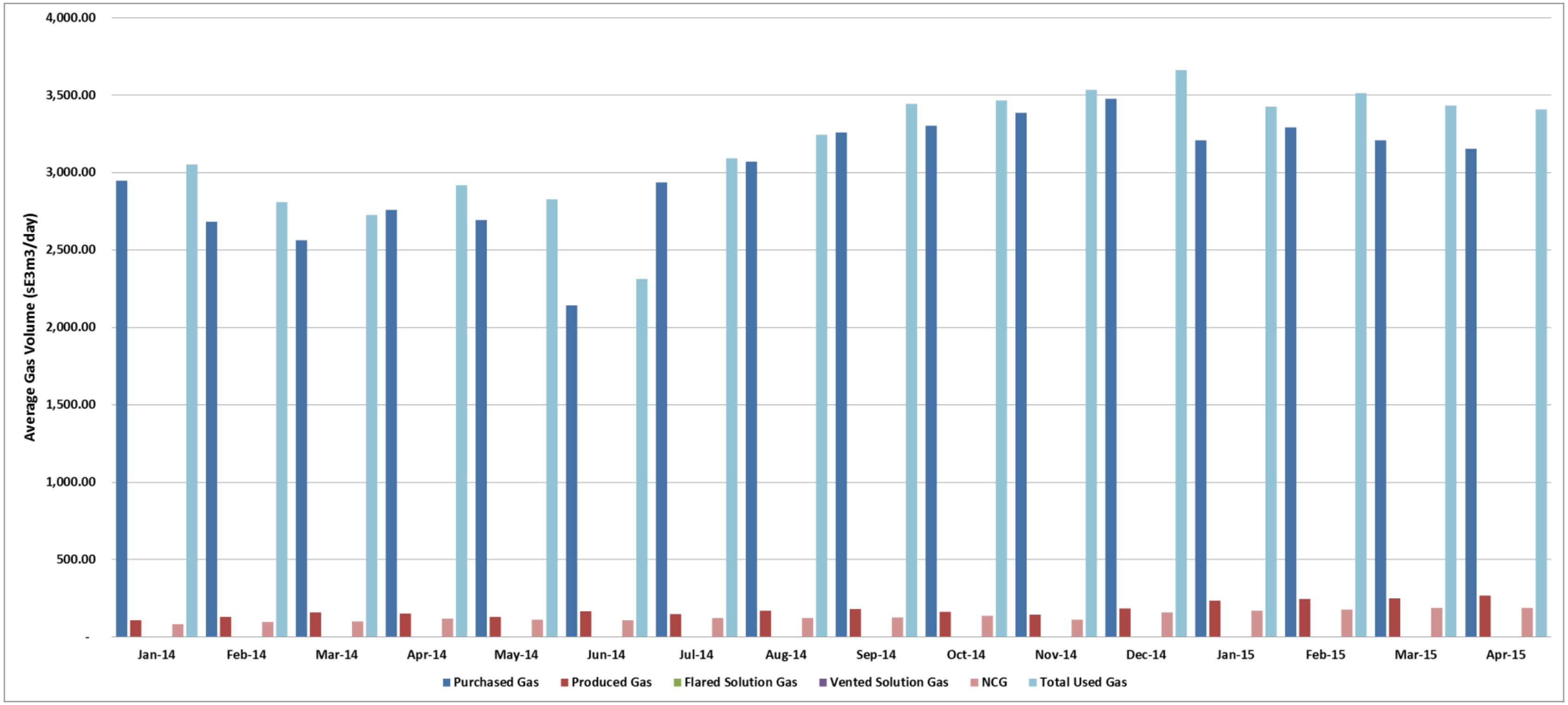
Issues Being Addressed

- No significant issues.

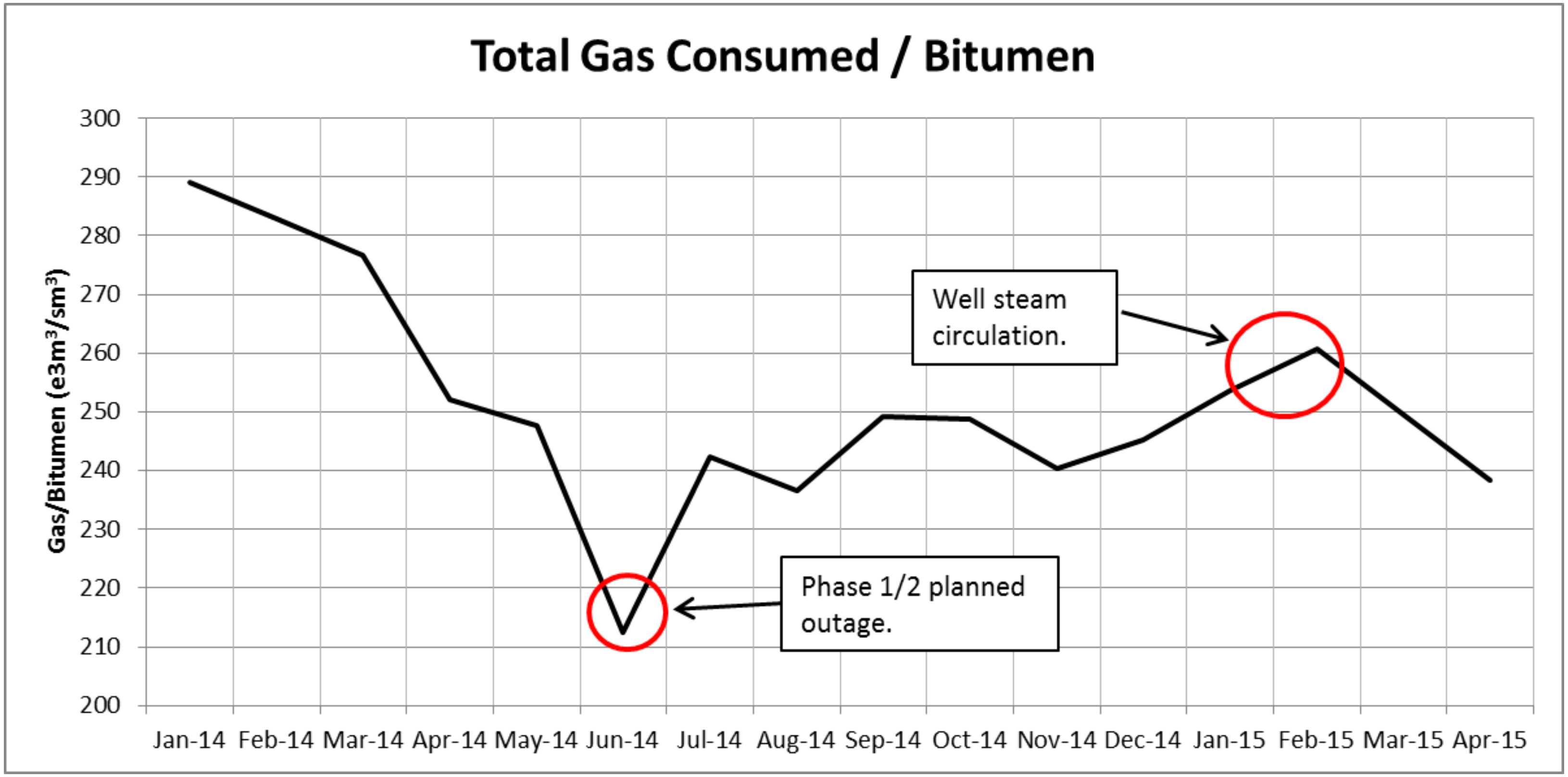
Facility Performance: Gas Usage



CLRP Gas Balance



Facility Performance: Gas Usage

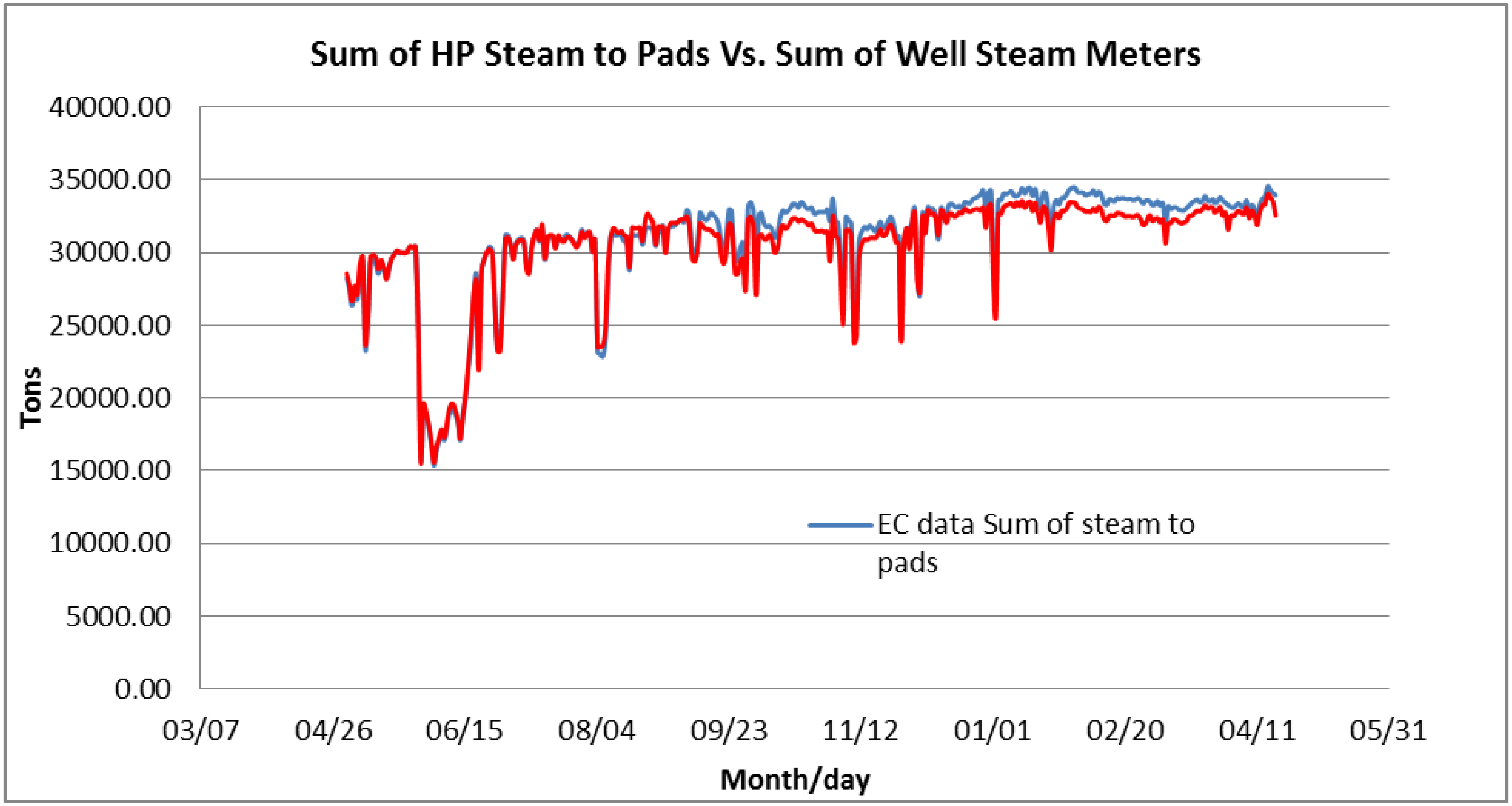


Facility Performance: Measurement

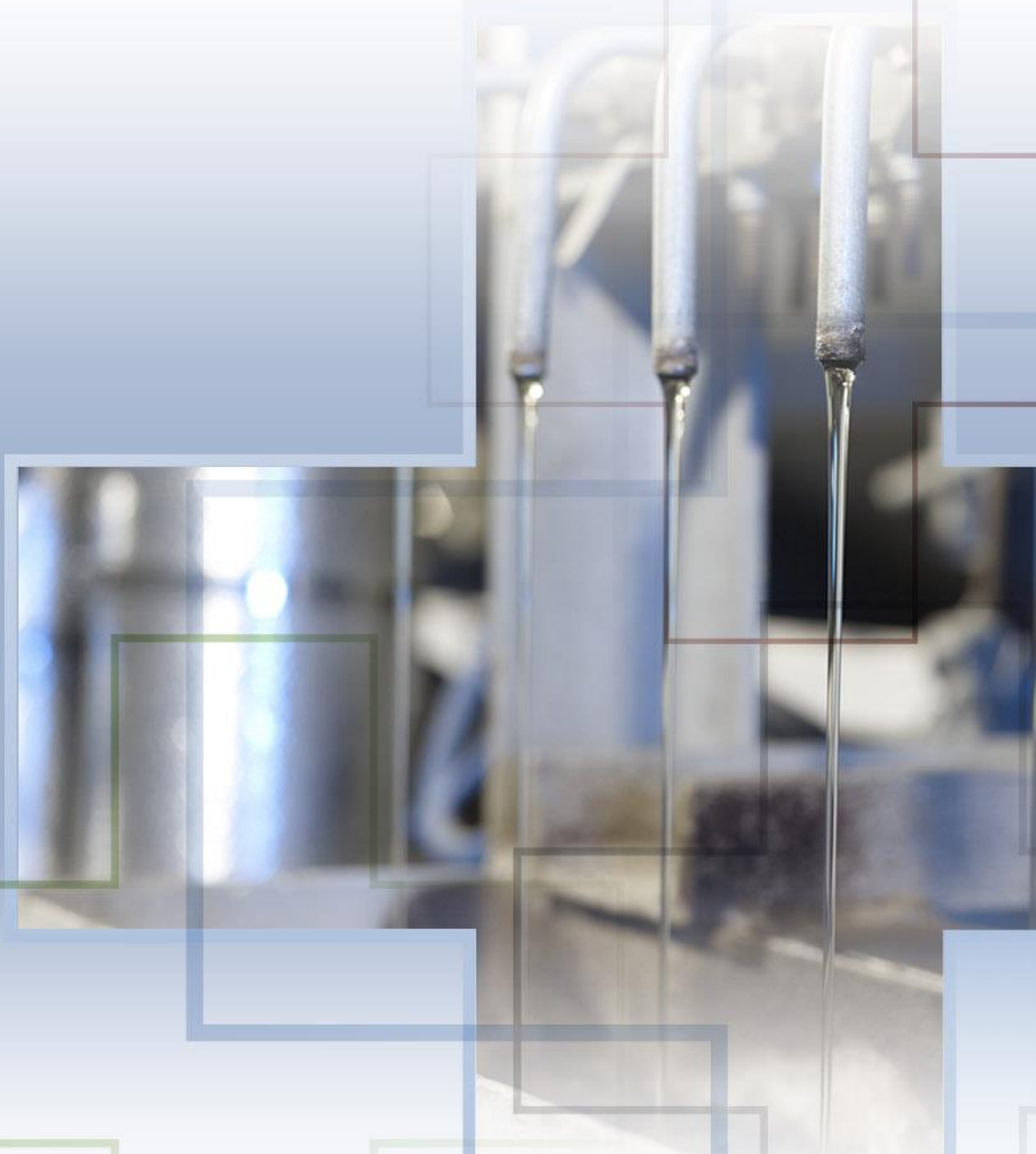
- AGAR BS&W meters commissioned and calibrated for all operational pads in 2014.
  - Full PM cycle and annual calibration approximately 75% complete for 2015.
- Successfully completed three years of testing of P1/2 water wells and one year of well tests on the new P2B water wells.
  - No significant gas detected via third party well testing.
- Implemented engineering calculation for secondary steam measurement for Phase 2B HP steam to well pads.

Facility Performance: Measurement

- Yearly comparison of “Sum of HP steam to well pads” and “Sum of well pad steam meters” returned a yearly average of 1.6%.



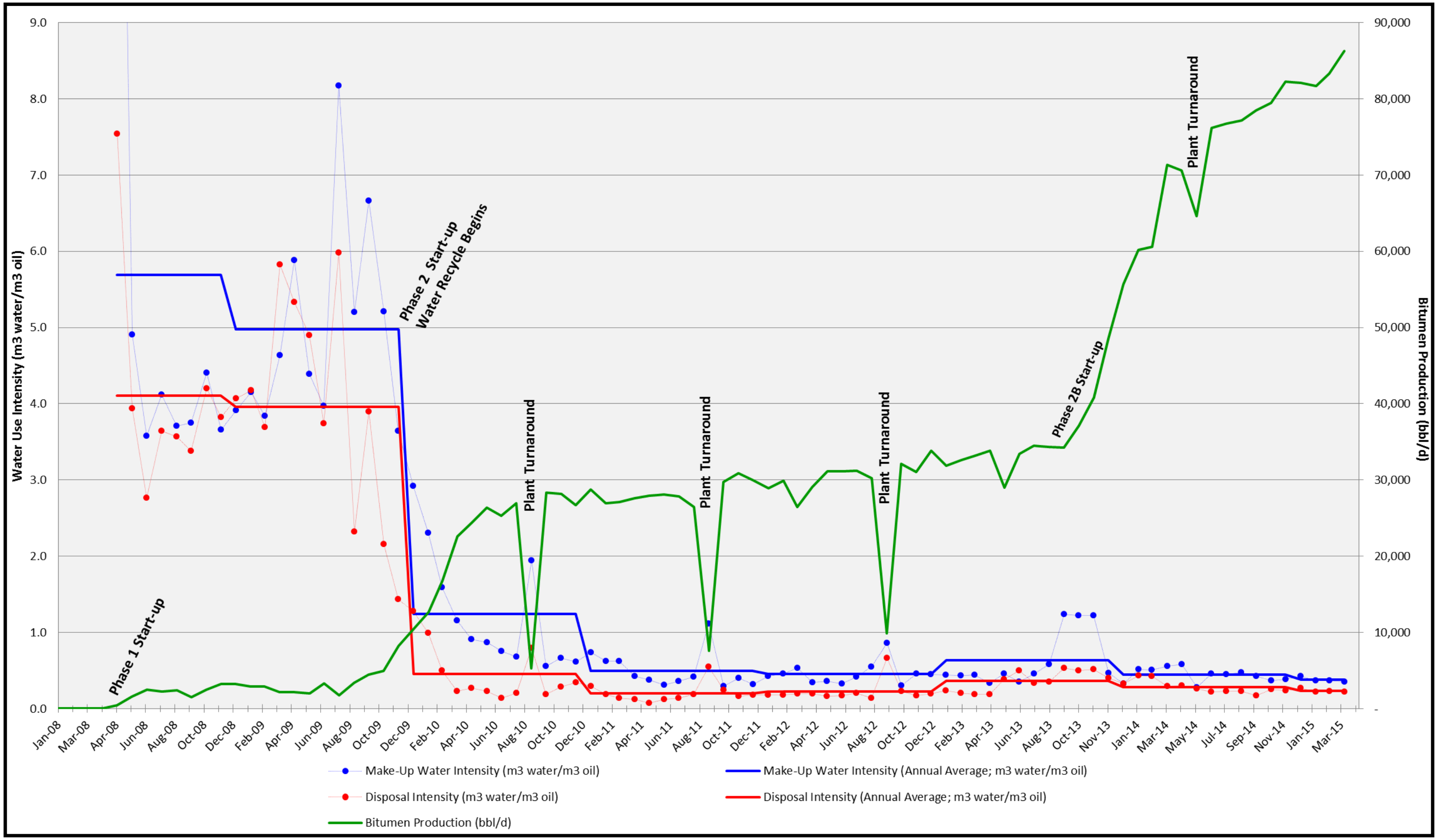
Water



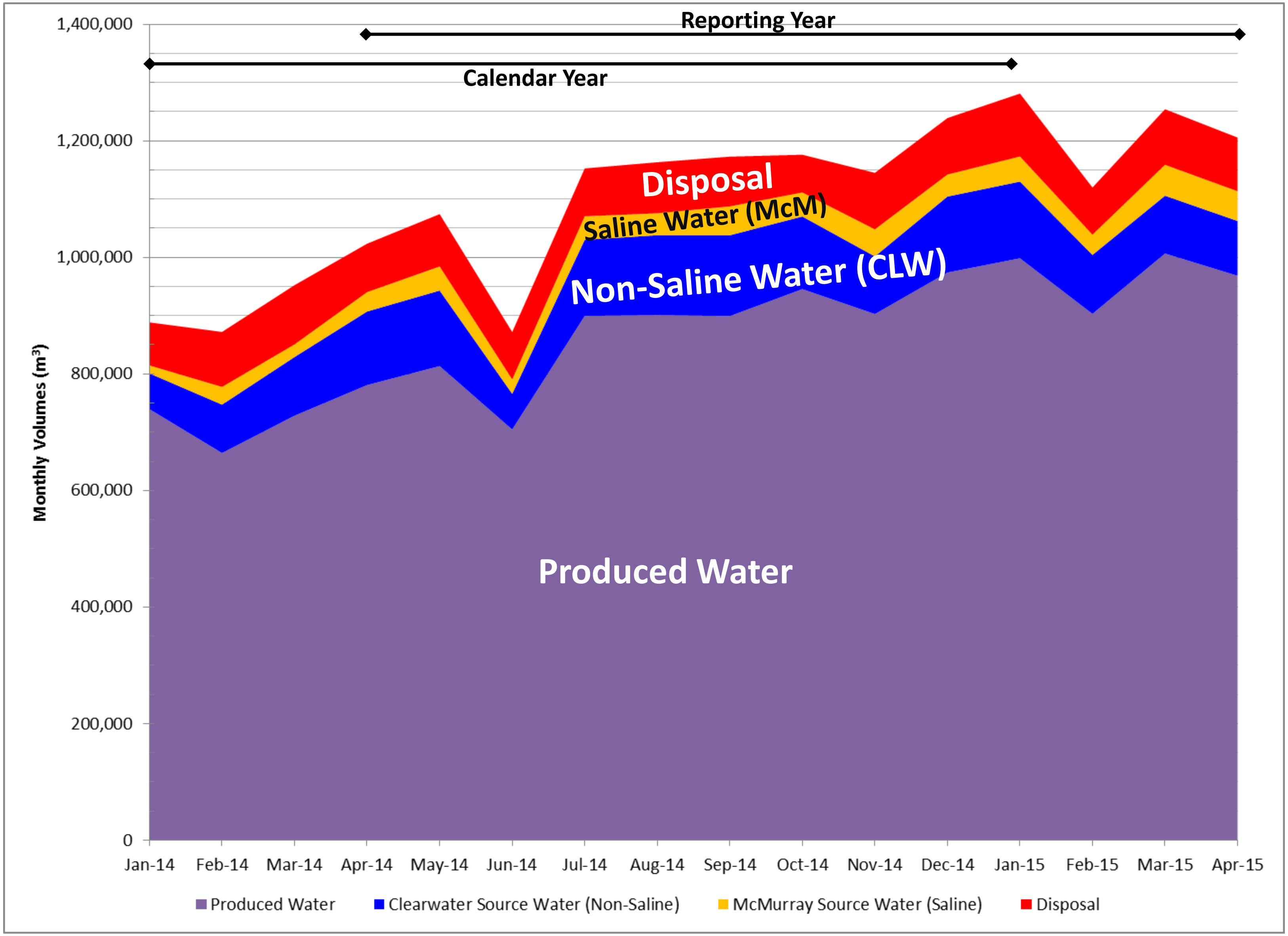
Water Management

- Water Use Intensity, Volumes and Recycle
- Water Source
- Water Disposal
- Water Use Optimization

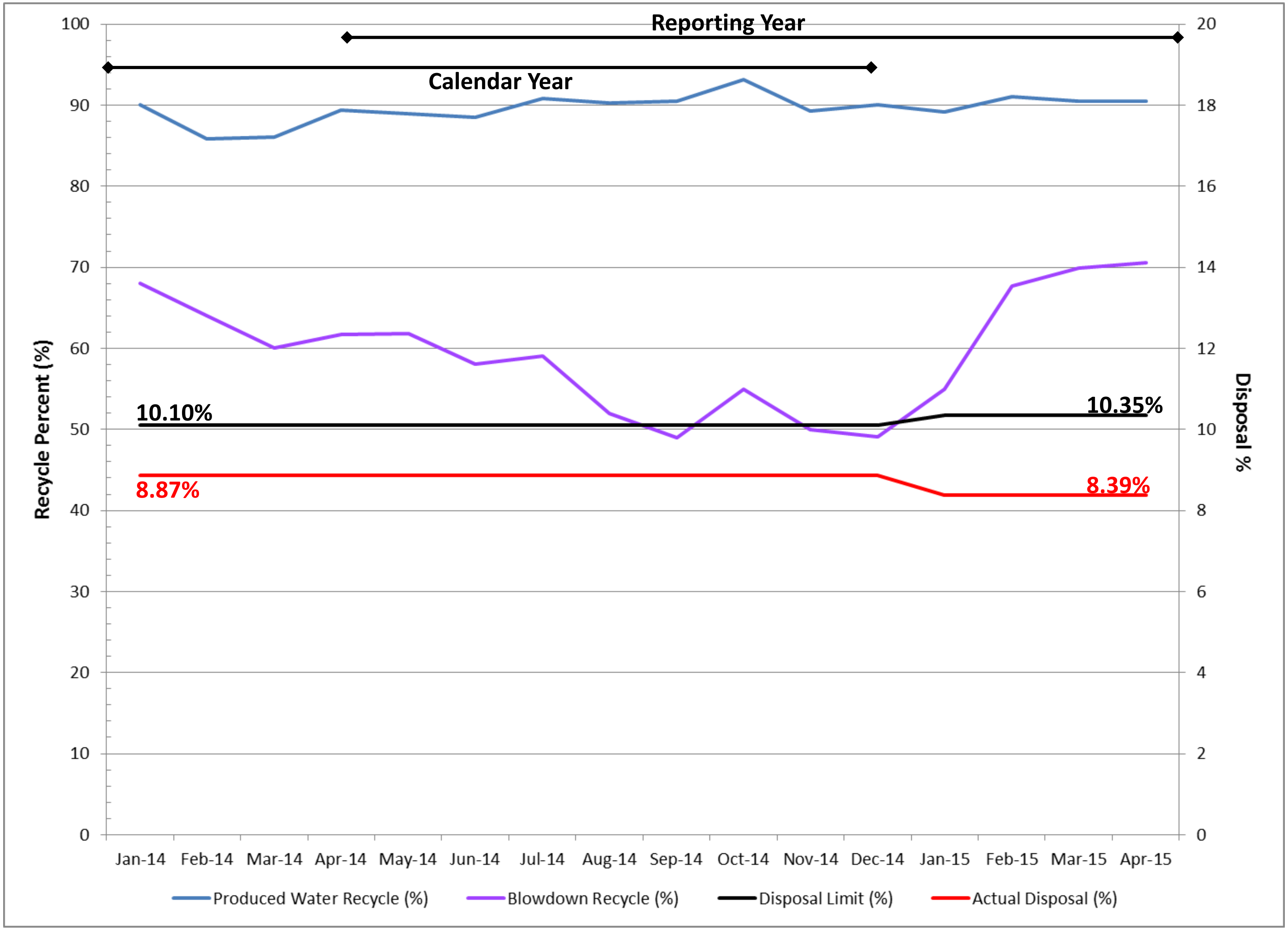
CLRP Water Use Intensity



Monthly Water Volumes

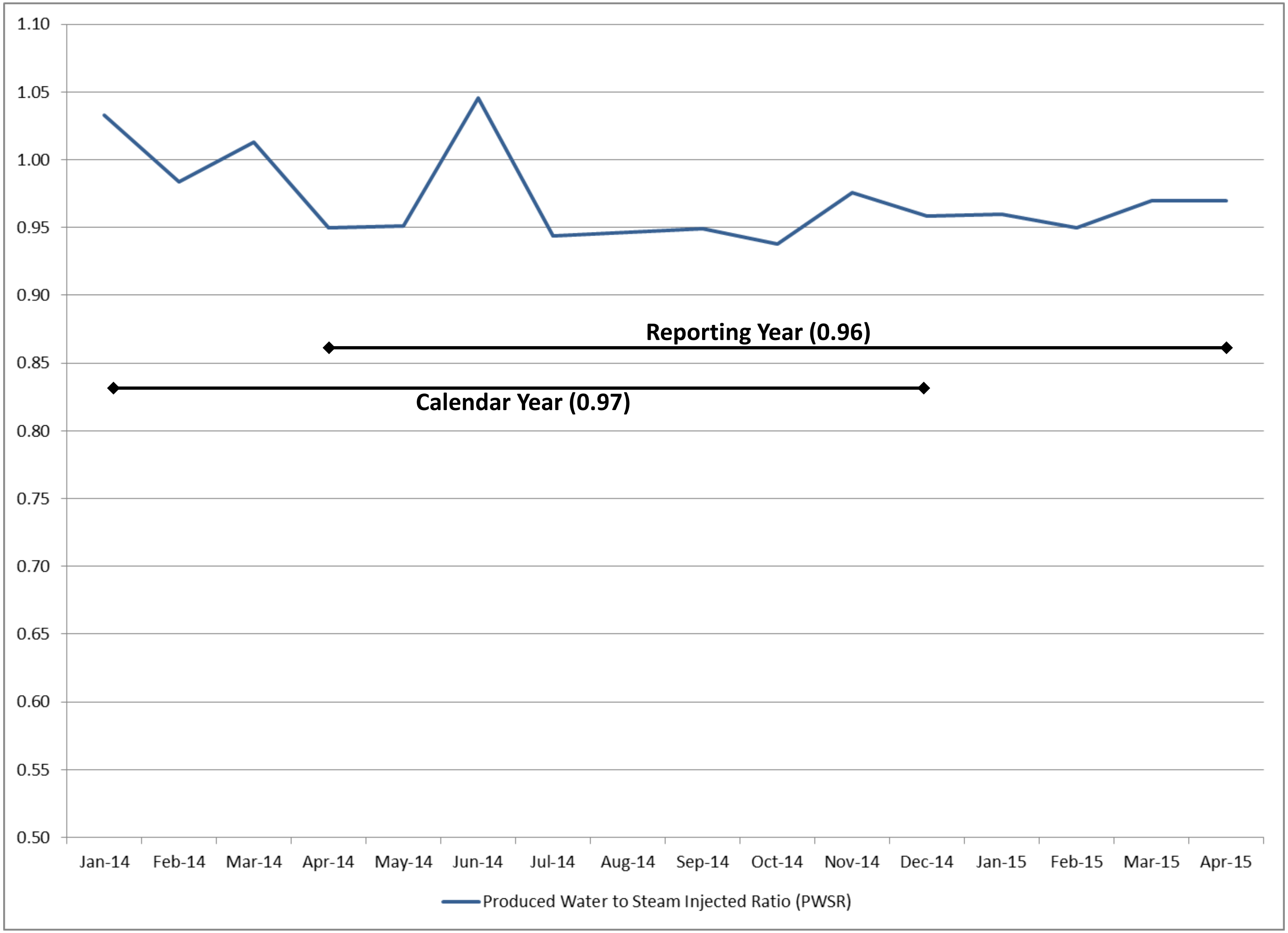


Water Recycle and D81 Limits

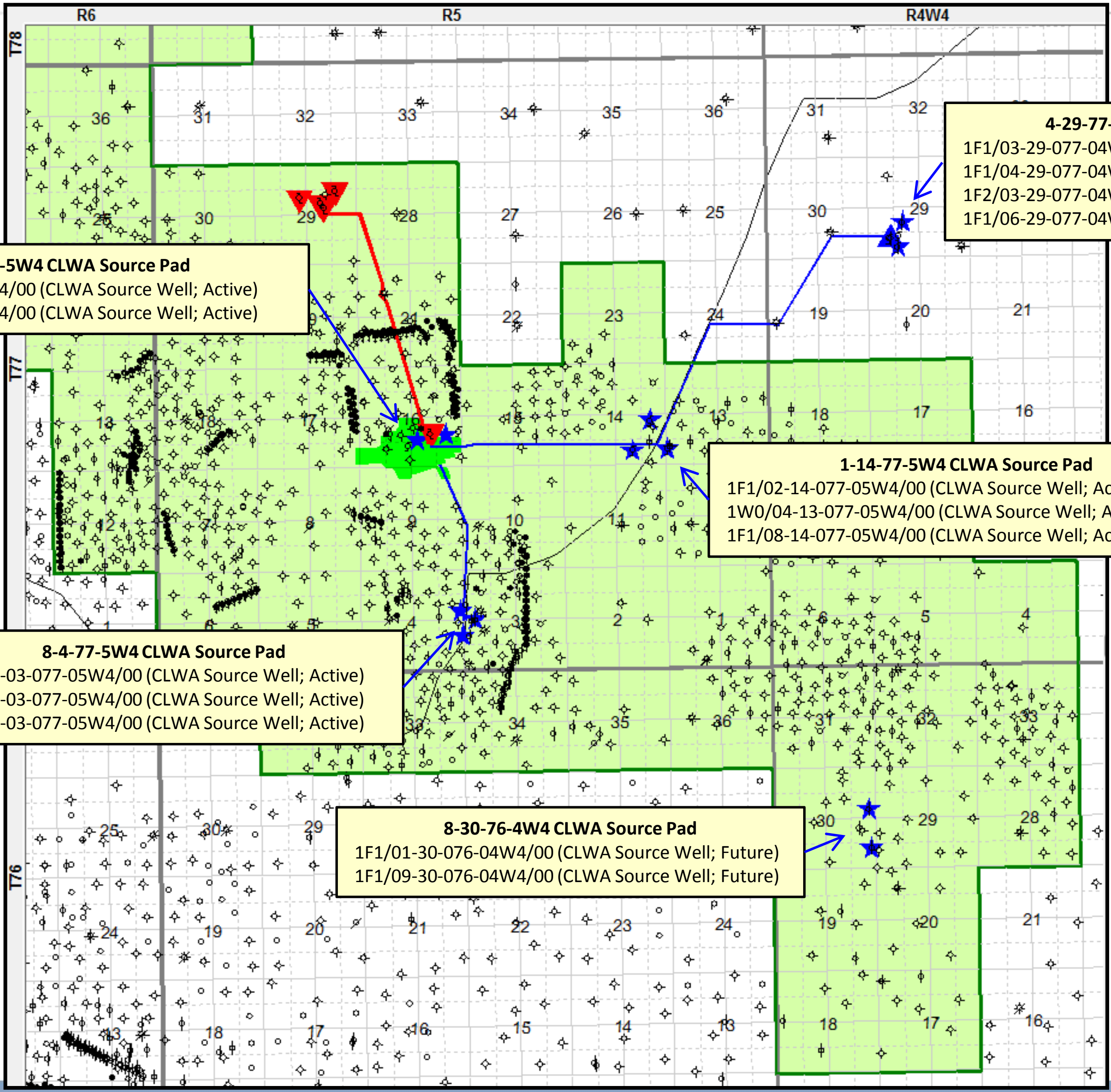


D81 Compliant in 2014

Produced Water to Steam Injected Ratio



CLRP Source Water Well Locations

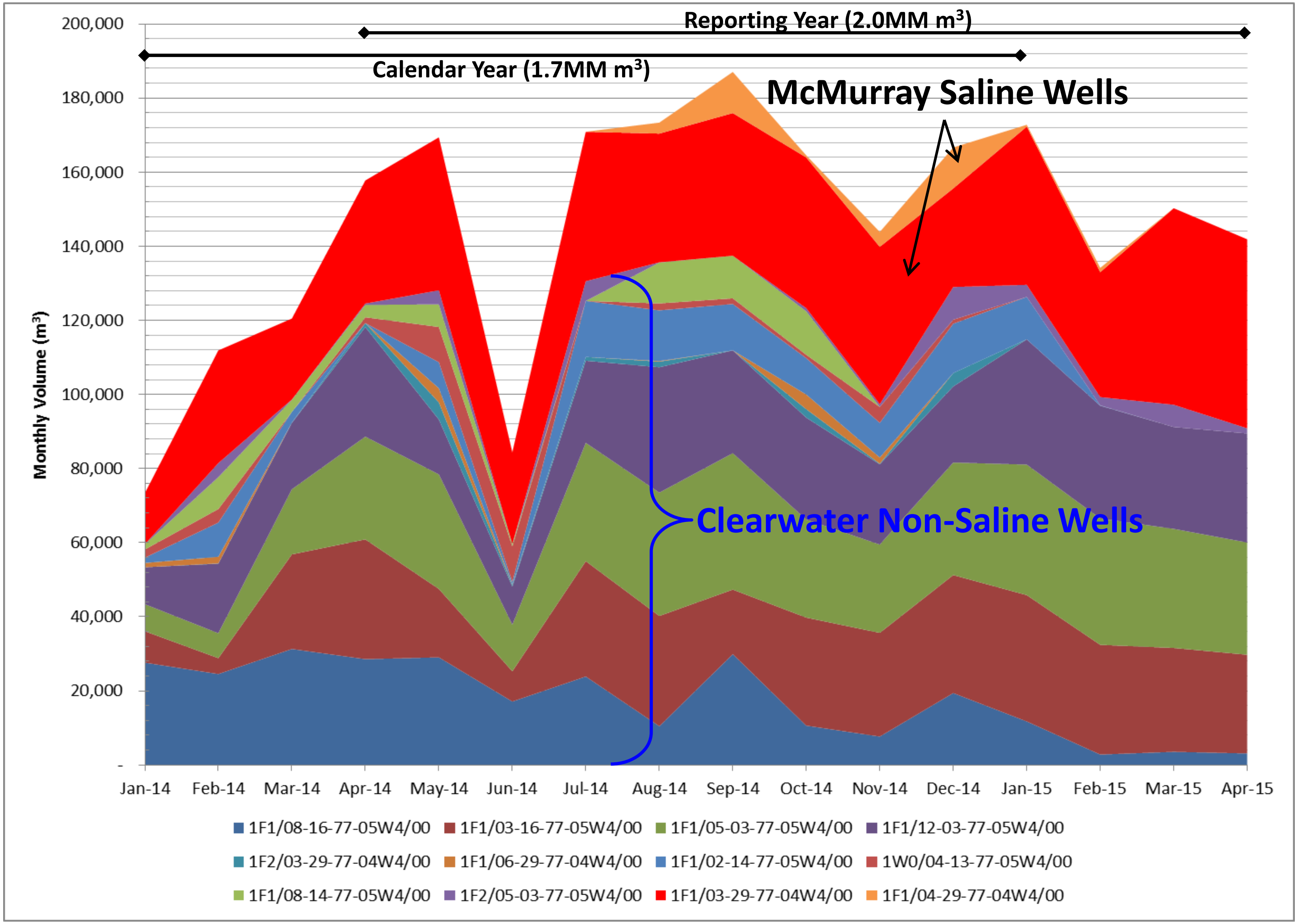


- 10 active Clearwater non-saline source wells

- 2 active McMurray saline source well

MEG Energy

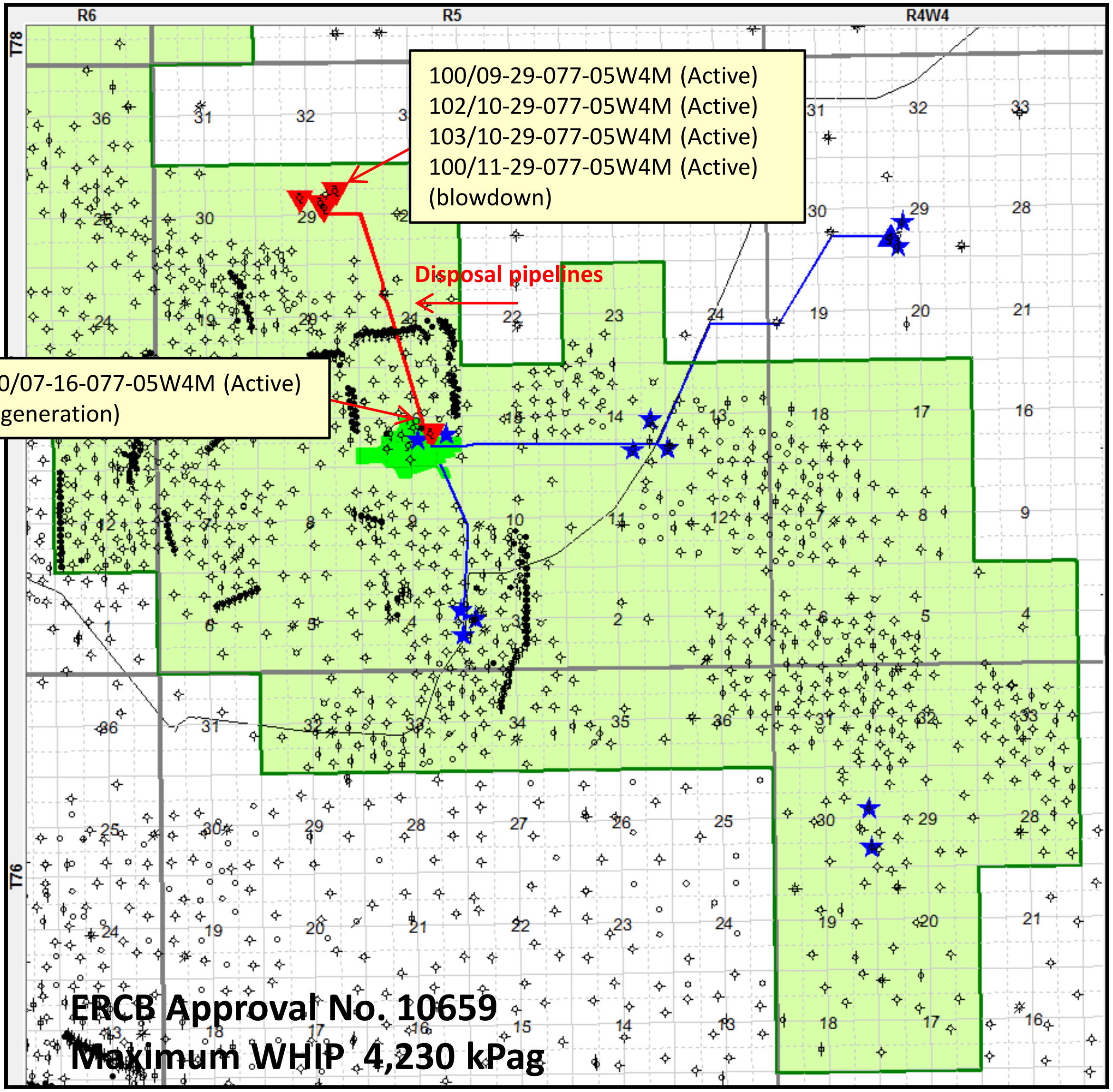
Source Well Production



Source Water Management

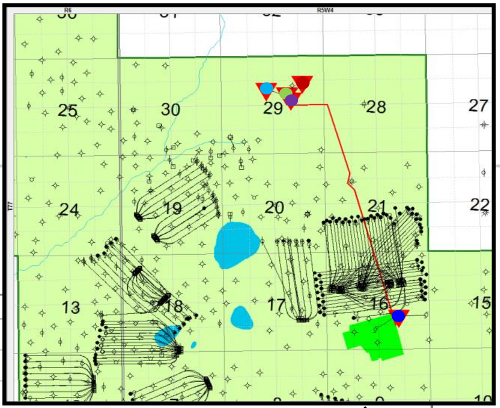
- Saline McMurray groundwater production ongoing since November 2013
- Non-saline Clearwater A and Ethel Lake groundwater production and pressure monitored in accordance with *Water Act* licenses
- Ethel Lake, Clearwater and McMurray aquifers are responding to pumping as expected

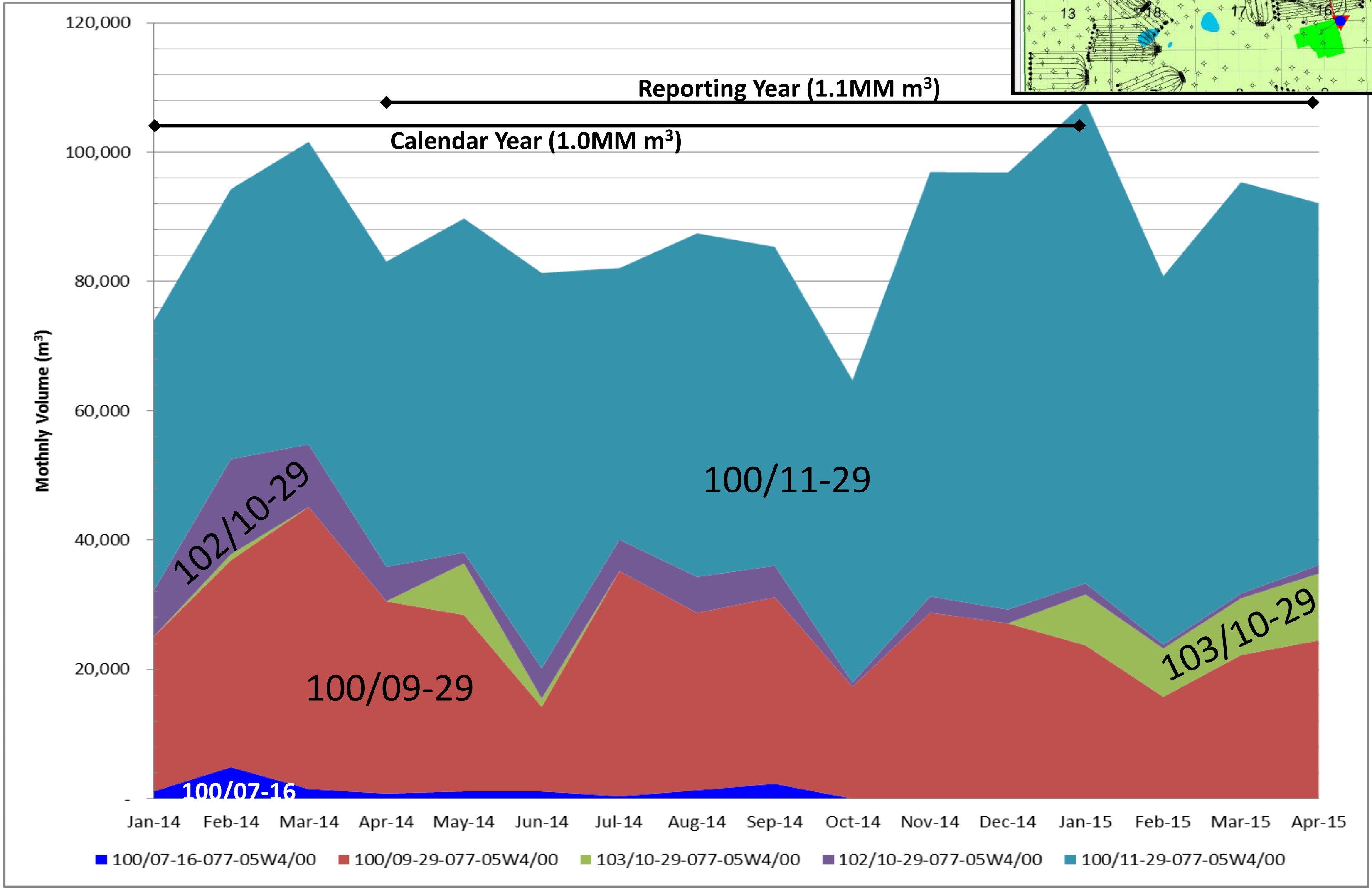
CLRP McMurray Disposal Wells



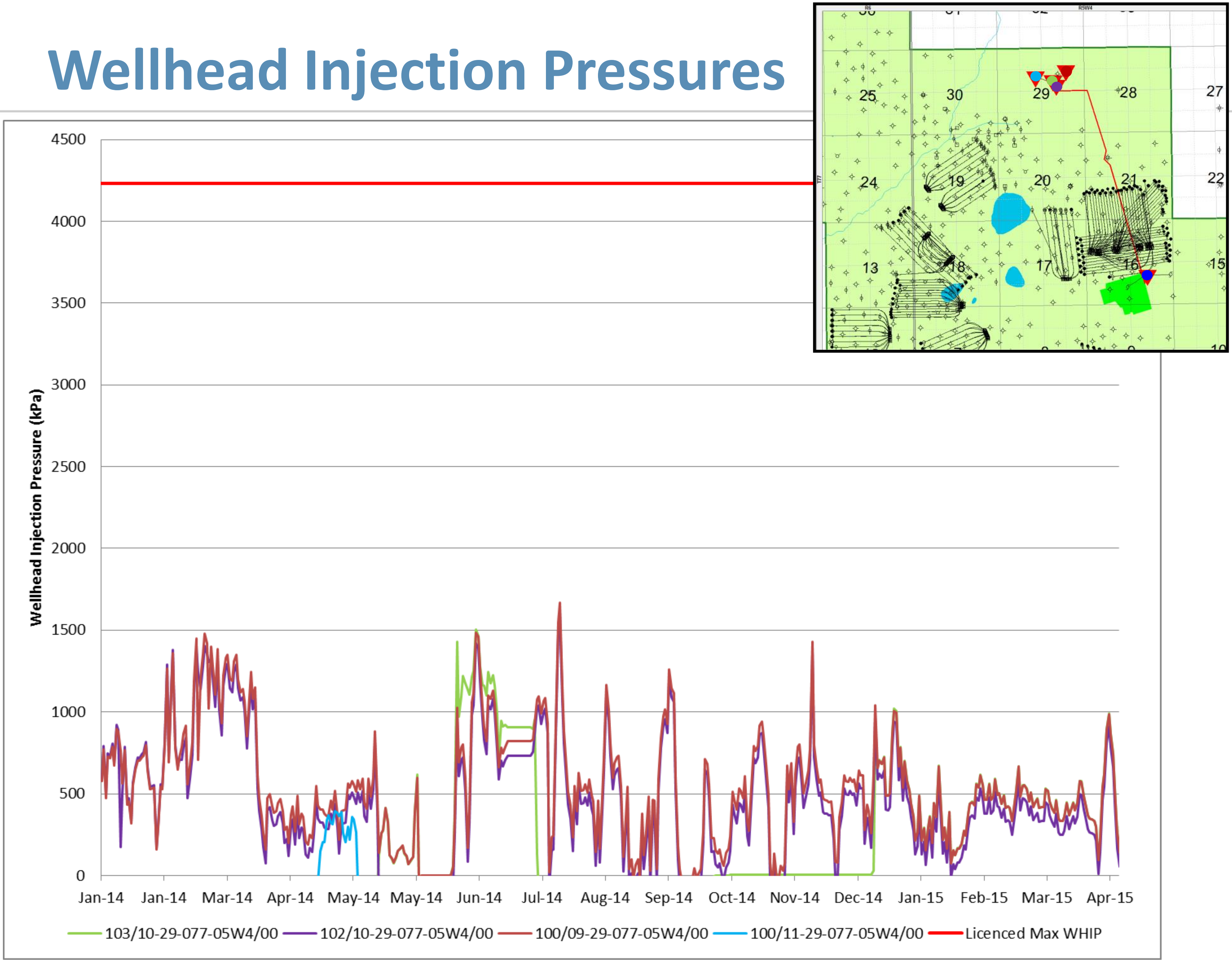
- 5 active McMurray disposal wells

Disposal Summary



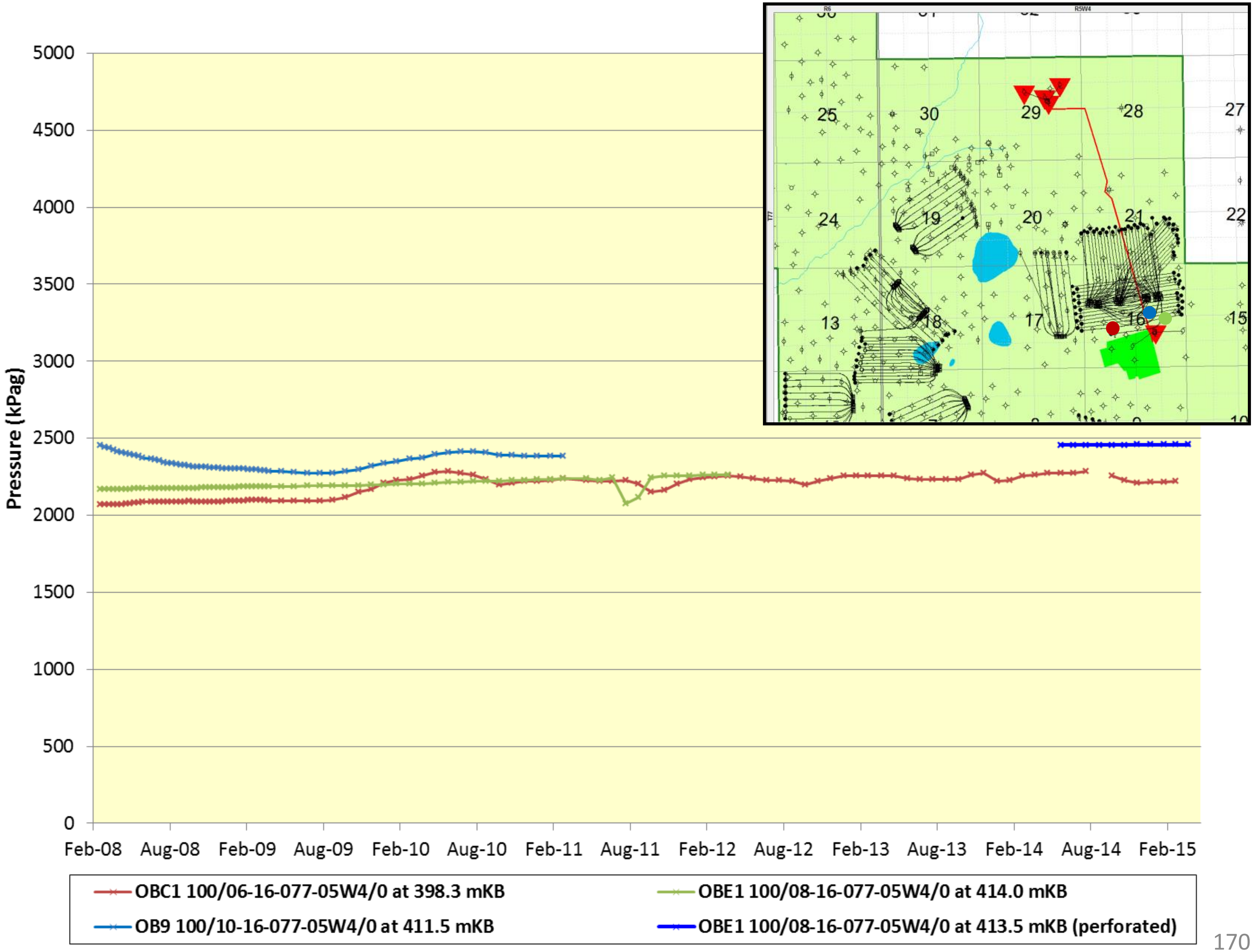


Wellhead Injection Pressures



*100/07-16-077-05W4/00 well on vacuum during operation

Basal McMurray Water Sand Pressure Monitoring



Water Use Optimization

- MEG continues to optimize blowdown recycle (exceeding design and adjusting to operational limitations)
- Saline water use (McMurray) ongoing since November 2013. MEG plans to continue to utilize saline water for make-up.
- Technology advancement to reduce SOR (eMSAGP)
- Blowdown evaporator planned to further improve water recycle capabilities

MEG Energy

Compliance & Environment

Compliance & Environment

Reporting Year Highlights

- Our Monitoring Approach
- 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 new 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

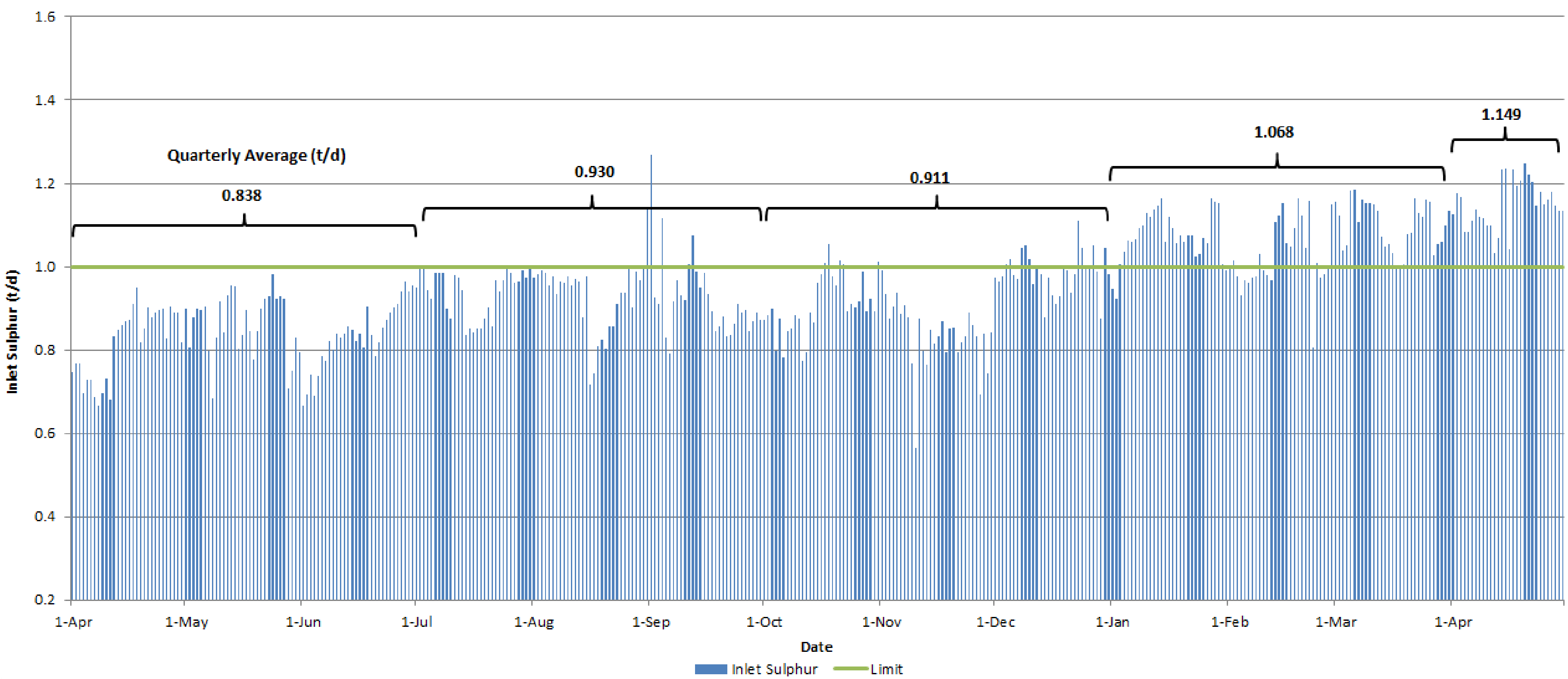
Vegetation
Monitor species composition and abundance

Sulphur Production and Removal

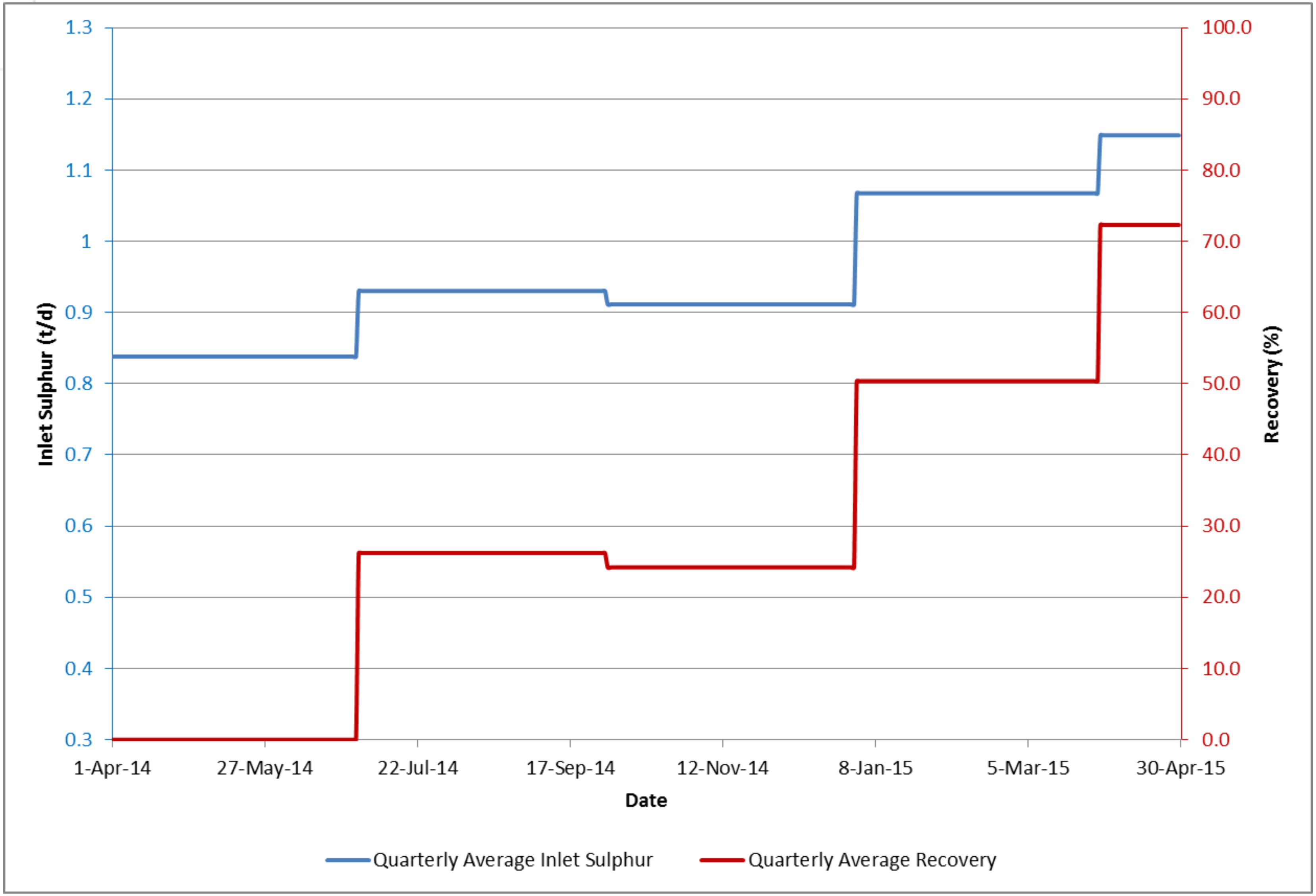
- Sulphur Removal Unit completed and started up in August 2014.
  - Allows MEG to meet EPEA and Interim Directive 2001-3 limits
  - Continuous monitoring of produced gas H_2S concentrations for system control

- Average 1 tonne/day inlet sulphur reached in Q1-2015
  - Operating challenges resulted in <70% recovery for calendar quarter
  - SRU maintenance and modifications undertaken in Q1 to improve operability
  - Compliant with approval requirements in Q2-2015

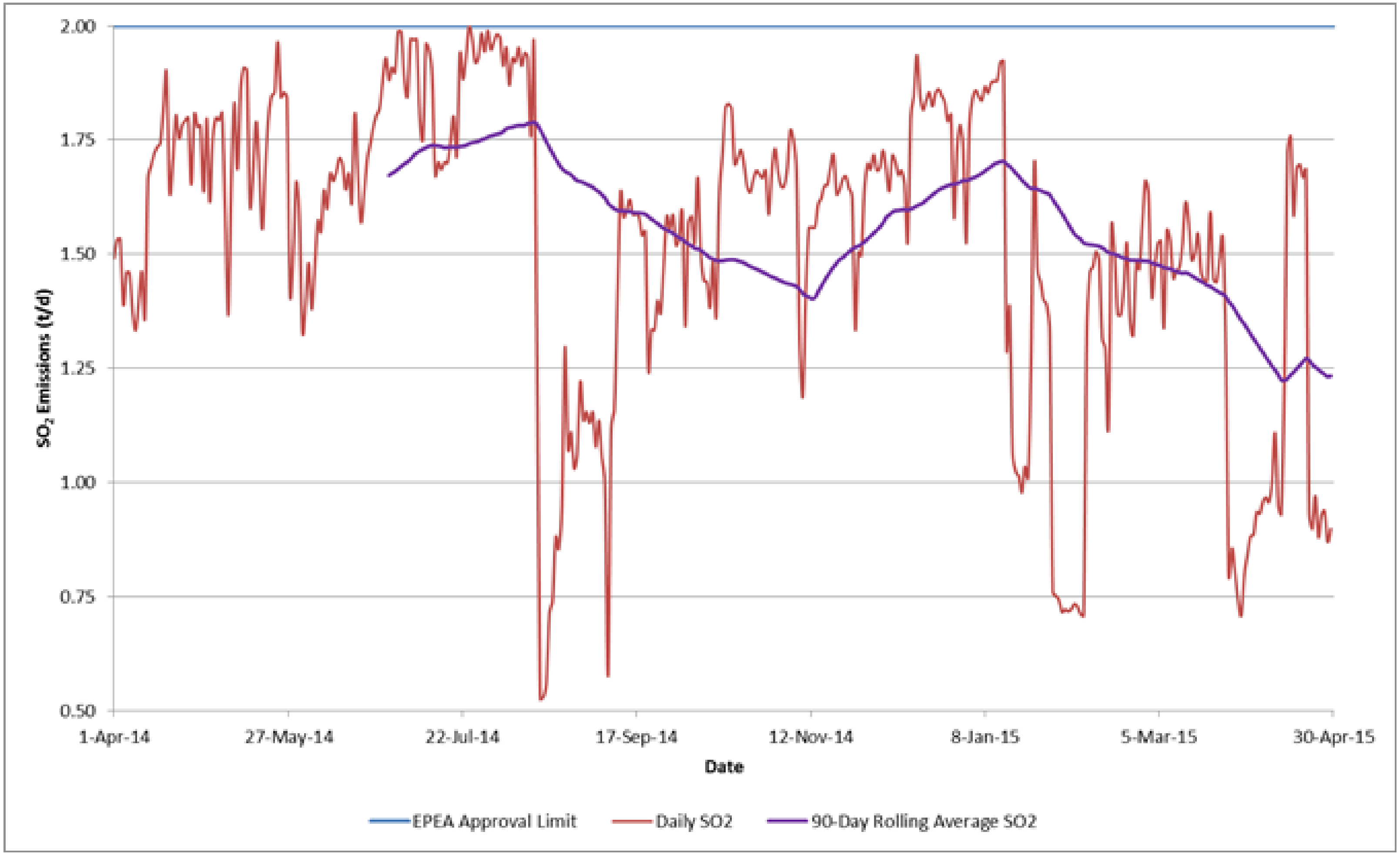
Daily Inlet Sulphur



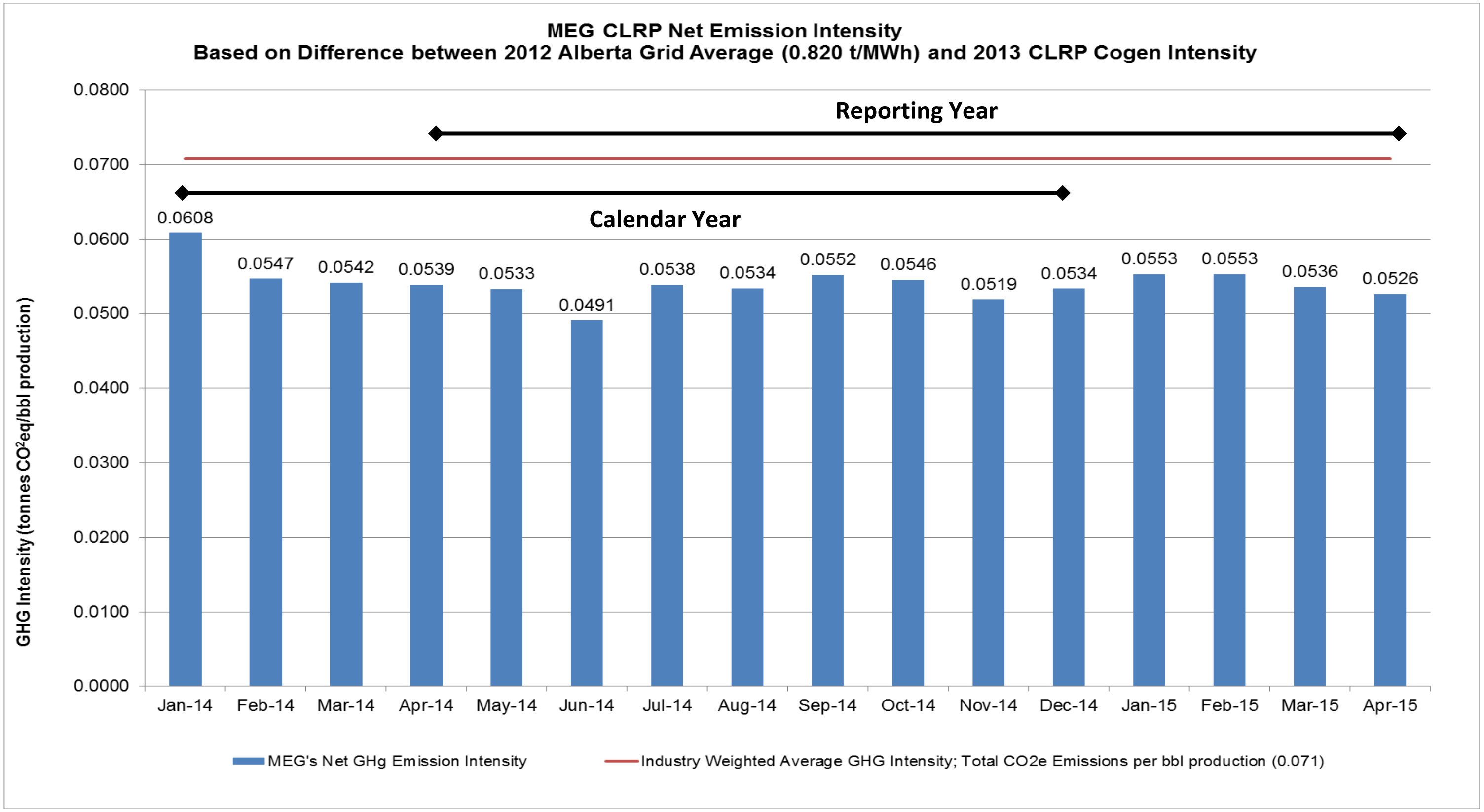
Sulphur Removal



SO_2 Emissions



Greenhouse Gas (GHG) Management



- MEG CLRP continues to produce one of the lowest net GHG intensity barrels in the industry.
- Q1 2015 performance of ~0.0526 T/bbl CO_2e vs an industry average of 0.071T/bbl CO_2e.
- 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

Inspections

- An inspection was conducted March 2015, which was deemed satisfactory

Site Visit

- Senior staff from the AER Bonnyville Field Office visited the CLRP for a site tour September 30, 2014

Compliance Summary

Self-Disclosures

MEG reported 5 self-disclosures to the AER during the reporting period:

- April 28, 2014: License Amendments from Oil Sands Evaluation to Observation wells
- August 11, 2014: Pad P Construction Soil Salvage Non-Compliance
- January 29, 2015: Well Test Frequency Non-Compliance
- March 18, 2105: Long Term Water Diversion Licence Annual Reports Late Submission
- March 7, 2015: Failure to Meet Calendar Quarter-Year Sulphur Removal Efficiency

Compliance Summary

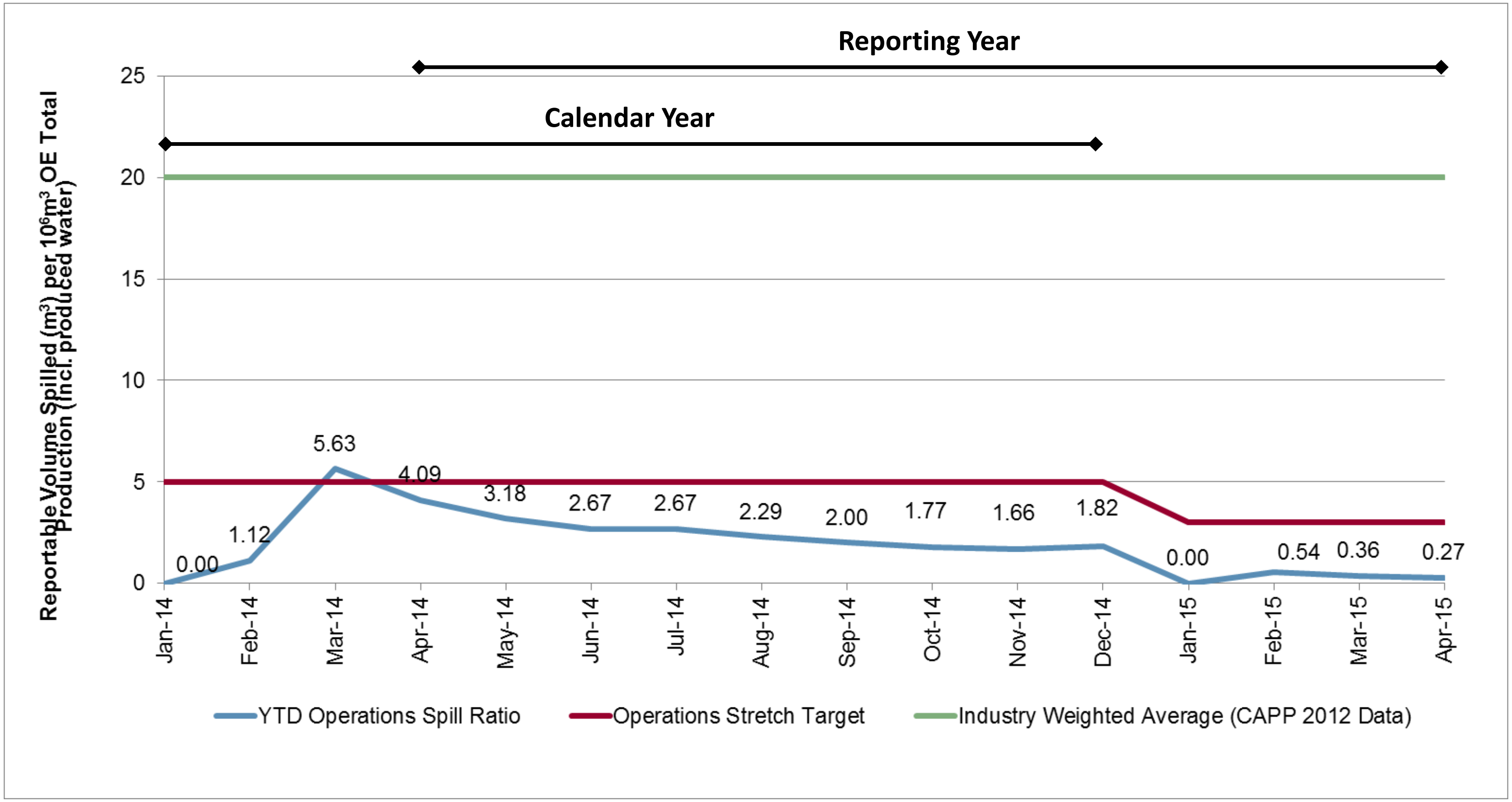
MEG reported 5 incidents to the AER during the reporting period:

- April 13, 2014: Ambient Air Monitoring Trailer H_2S Hourly Exceedance
  - 31 minutes exceedance, data validity suspect
- June 28, 2014: Passive Air Sampler Failure
  - Sample cartridge found on ground, data compromised
- September 8, 2014: Continuous Emissions Monitoring System (CEMS) Non-Compliance
  - Missed 90% uptime requirement, due to equipment malfunction
- February 10, 2015: Wastewater Treatment Plant
  - Missing sampling parameters specified in new EPEA approval for pending equipment
- March 16, 2015: Oilfield Drilling Waste Reporting Delay
  - Missed reporting timeline

Regulatory Compliance

Spills

- 12 reportable spills occurred at MEG from April 2014 to April 2015. All reports were filed with the AER and remediation has been completed. MEG's 2014/15 spill intensity ranks well below industry average (CAPP, 2012).



Compliance Summary

2012 Temporary Diversion Licence Exceedance

- **February 6th, 2015**: MEG received an Administrative Penalty of $30,500 related to 2012 exceedances of withdrawal limits related to four Temporary Water Diversion Licences. MEG originally self-reported this matter in accordance with its *Water Act* approvals. As part of our commitment to continuous improvement, MEG has implemented improved training, monitoring and internal reporting processes. The AER has reviewed MEG's corrective actions and commended MEG regarding the success of these initiatives.

Ambient Air Quality Monitoring

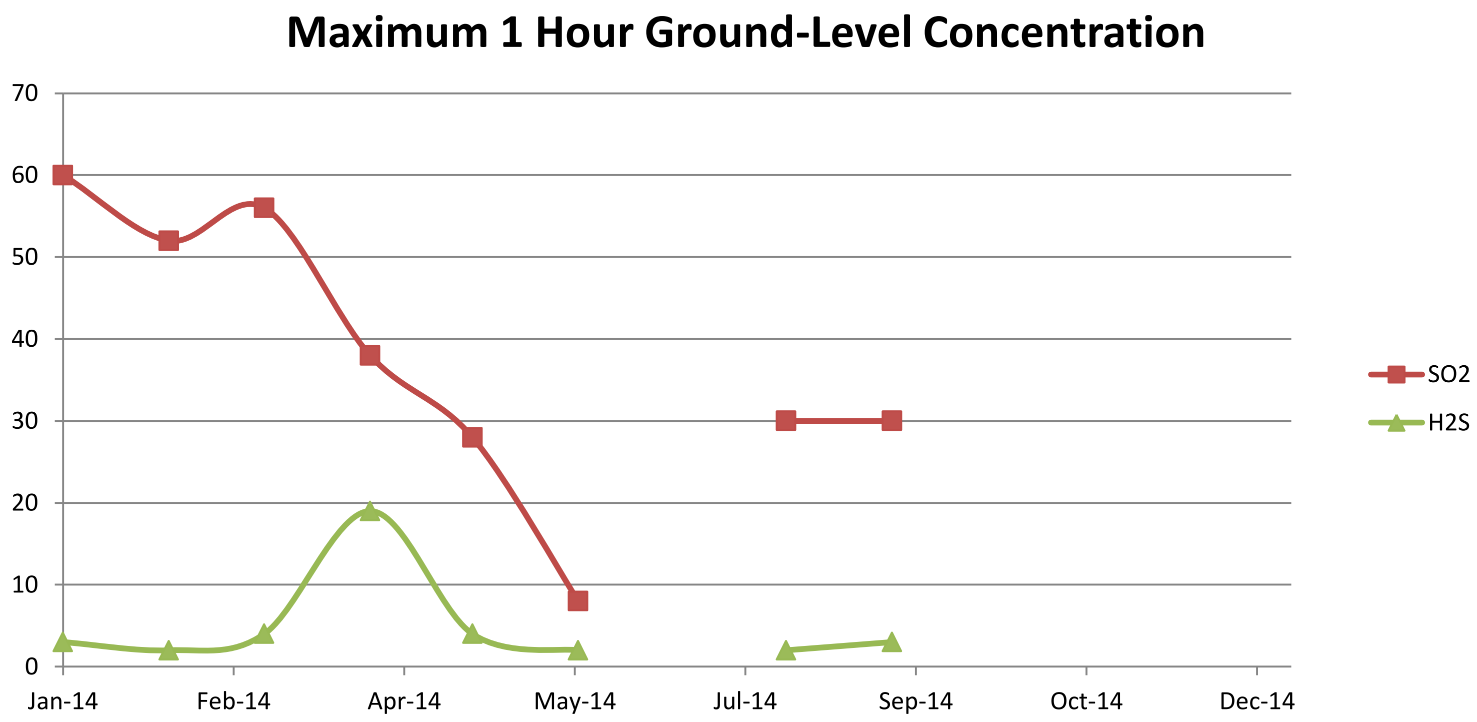
Continuous Ambient Air Monitoring Trailer and Passive Sampling

- MEG employed the use of a continuous ambient air monitoring trailer from January to June 2014 for phases 1, 2 and 2B as required by our approval.
- Additional monitoring was completed through August and September, prior to and during the start-up of the SRU.
- Four passive monitors are installed around the CLRP site for the measurement of H_2S and SO_2 with readings taken on a monthly basis.
- Two ambient air contraventions were reported in 2014

Ambient Air Quality Monitoring

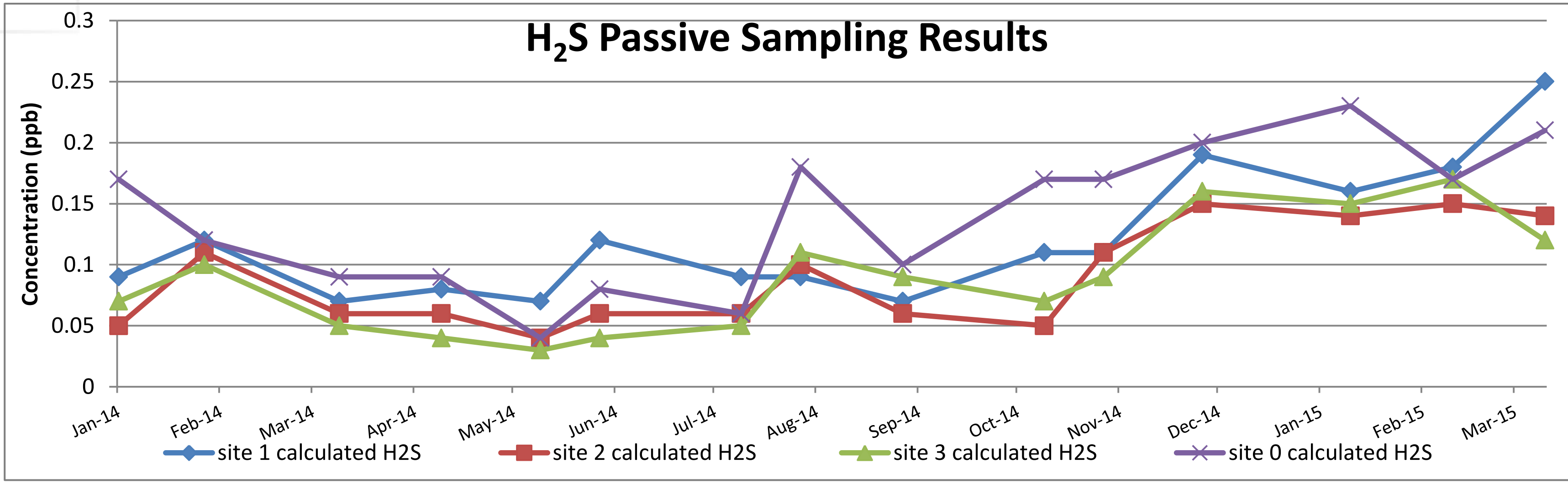
Continuous Monitoring Results

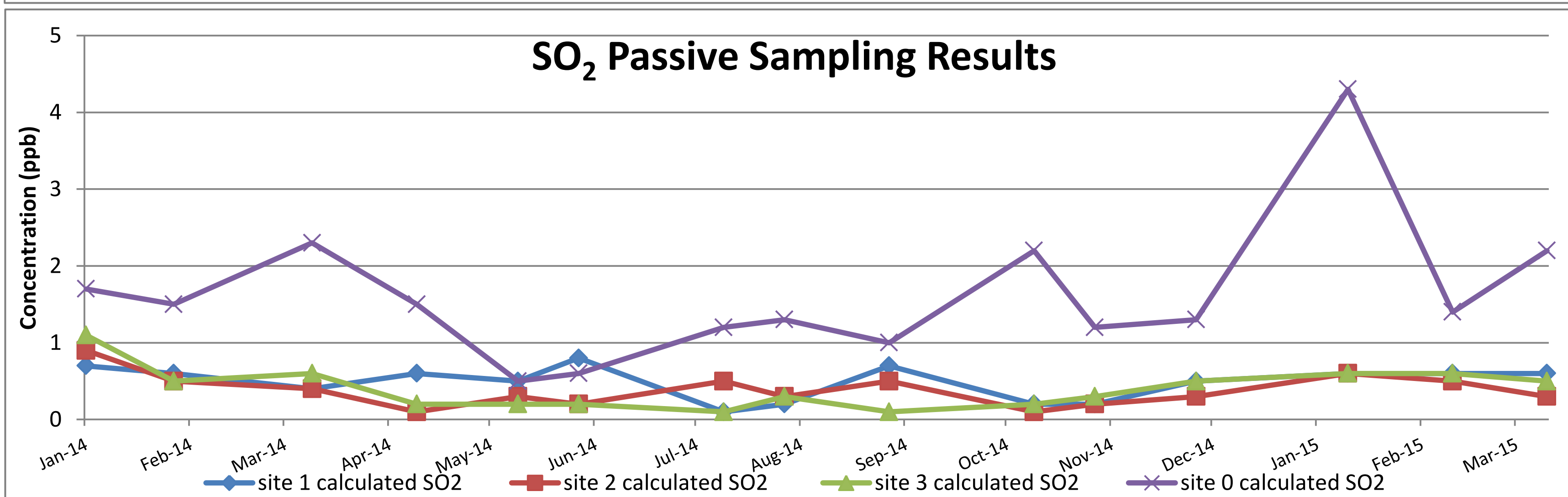
	Maximum Reading for 2014 (ppbv)	Month of Maximum Reading in 2014	Limit (ppbv)
SO2	60	January	172
H2S	19	April	10



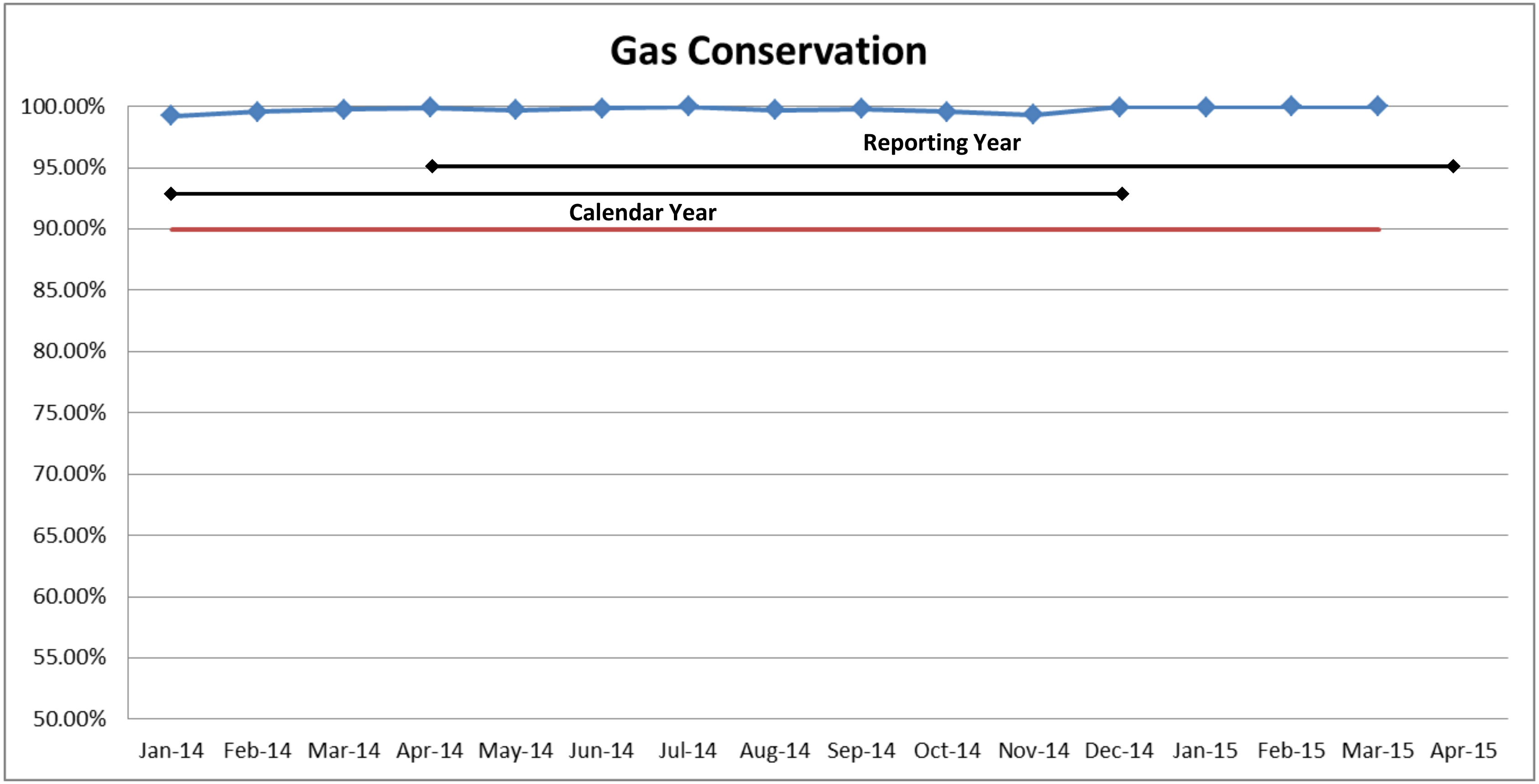
Ambient Air Quality Monitoring

Passives Sampling Results





Gas Usage



- Overall gas conservation >99%
- MEG reported 16 flaring and 2 venting notifications to the AER including exceedances and outages.

Conservation & Reclamation

Reporting Year Highlights

- Wetland Reclamation Trial Program
  - Ongoing reclamation of two borrow pits for the purpose of permanent reclamation.
- Caribou Habitat Reclamation Trial
- Oil Sands Exploration (OSE) reclamation and assessment program
- Ongoing research and monitoring programs
  - Woodland Caribou Mitigation and Monitoring Program
  - Canadian Oil Sands Innovation Alliance Faster Forest Program
  - Rare Plant Mitigation and Monitoring

OSE Reclamation

Summary

- Reclamation Certificates are being submitted immediately for:
  - CLRP 050040
  - CLRP 060068
  - CLRP 070107
  - May River 060066
  - May River 070069
- Reclamation Certificates to be submitted spring 2015:
  - Jackfish 060065
  - Jackfish 070079
  - Thornbury 070077
- Reclamation Certificates to be submitted fall 2015:
  - CLRP 090055
  - Duncan 100059
  - May River 090043

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.

MEG ENERGY

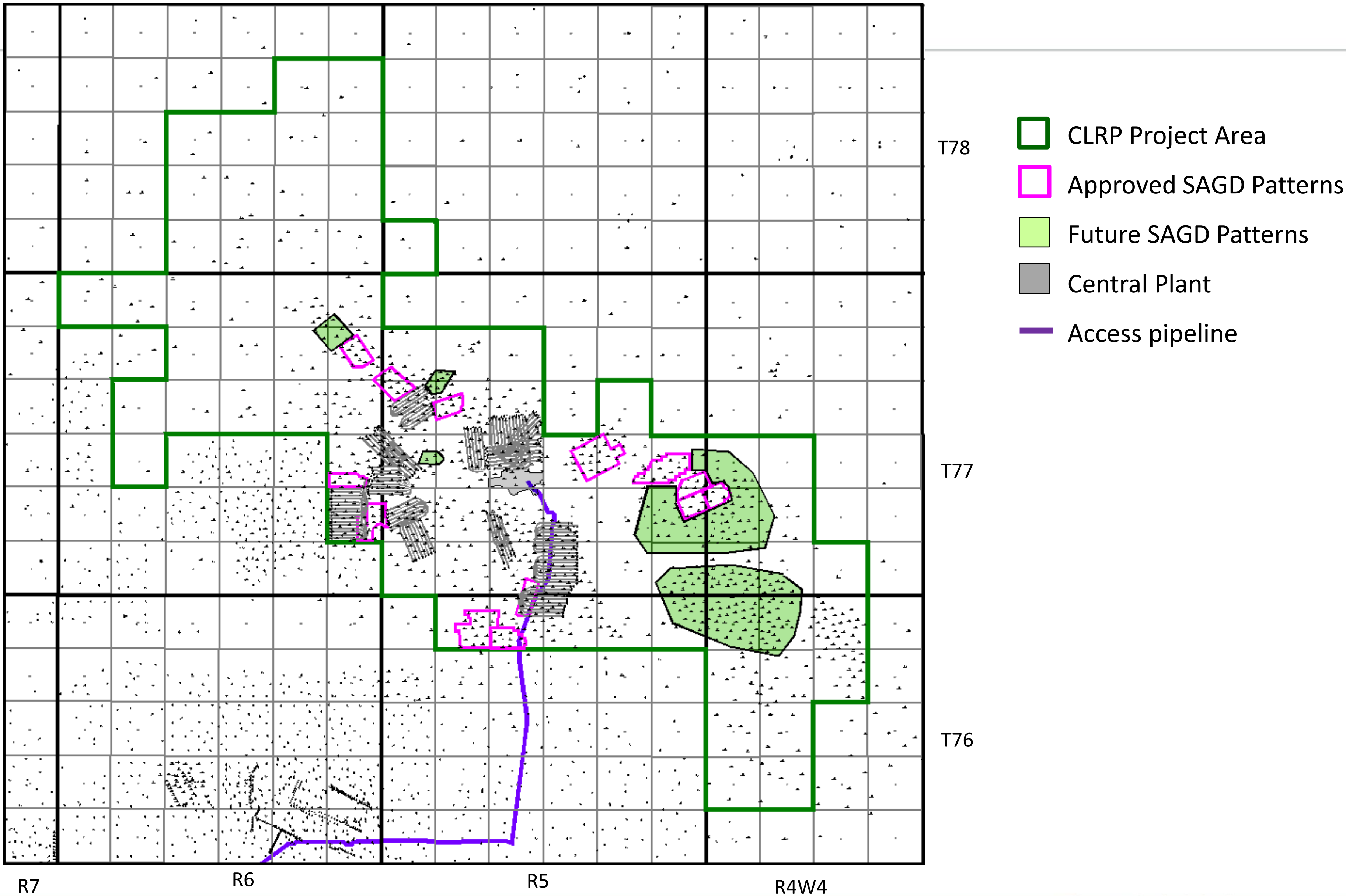
CLRP
Future Plans

Regulatory Amendments

Amendments approved April 2014 - April 2015

- Phase 2B4X facilities relocation amendment approval received
- Expand IDA to include 6 new subsurface patterns
- Various amendments to pad orientation
- Expansion of NCG Co-Injection on Pads A through F

CLRP Future Development



CLRP Future Plans

- Ongoing de-bottlenecking of Phase 2B facilities
- Ongoing pattern addition within CLRP development area
- Continued development of eMSAGP within Active Development Area
- Ongoing resource assessment

MEG ENERGY

Questions and Comments