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Annual Surmont SAGD Performance Review Approvals 9426 and 9460

May 17, 2017

Calgary, Alberta, Canada

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Surface

Introduction, Overview and Highlights

Subsection 3.1.1 (1)

Ownership and Approvals

Ownership

- The Surmont In Situ Oil Sands Project is a 50/50 joint venture between ConocoPhillips Canada Resources Corp. and TOTAL E&P Canada Ltd; Operated by ConocoPhillips Canada.

Project History

- 1997 - First steam at pilot project
- 2007 - First steam at Phase 1
- 2010 - Construction start at Phase 2
- 2015 - Start-up of Phase 2, solvent soak on well pairs 7&8 on pad 103
- 2016 - Start-up of liquid scavenging system

Approval Update - AER Approval No. 9426

Approval 9426KK – September 15, 2016

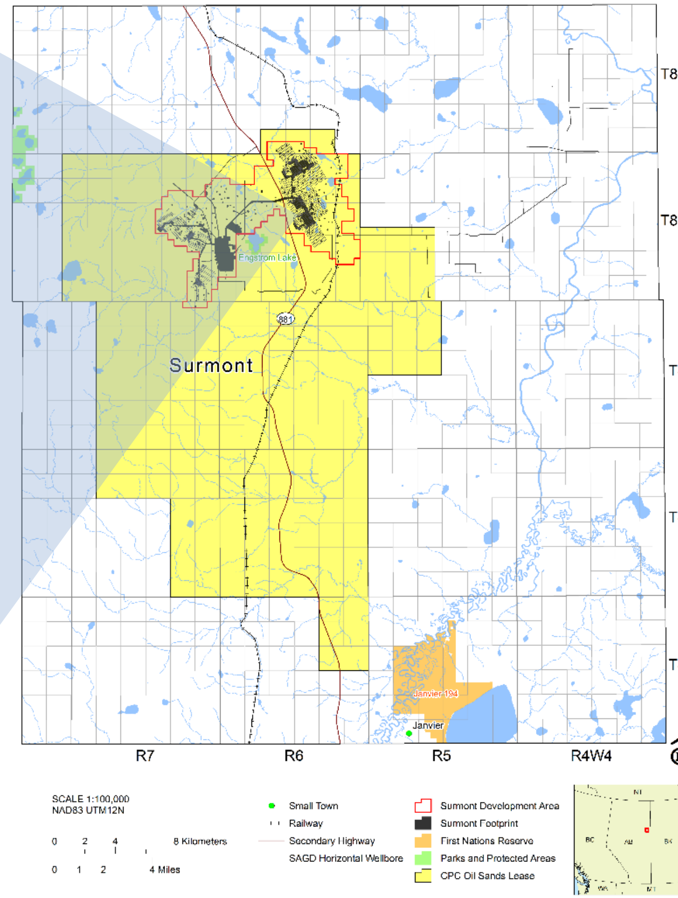
- Application No. 1857927 - Increase of MOP at DAs 261-3and 262-3
- Application No. 1862673 - Extension of well pair lengths at Pad 267 and cancellation of three outboard well pairs at DA 264-2

Approval 9426LL – October 19, 2016

- Application No. 1867584 – to correct MOP value for DA 267-1

Application No. 1880767 (submitted February 28)– Temporary increase of MOP at DA 262-3 to address problem wells

Surmont Overview



Currently in a "One Surmont" philosophy

Surmont combined approved capacity is 29,964 m^3/cd (188,700 bbl/cd)*
***(where cd is calendar day on an annual average basis)**

2016 Highlights

Phase 1 production recovery

- Initial results from tubing deployed flow control devices at Pad 101/102 illustrate an increase in total emulsion/bitumen rates
- Liner installed flow control devices at Pad 103 continue to outperform slotted liners (SL) wells
- Instantaneous Steam Oil Ratio (iSOR) continues to improve and trend lower
- Steam splitters were installed on 6 wells

Phase 2 continued ramp-up

- Tubing deployed flow control devices installed on 8 wells in 2016 and have shown an improvement in oil rates
- Liner deployed flow control devices have shown to promote faster development of the wells compared to typical slotted liner wells
- Some wells are still challenged with injectivity/productivity issues, which translates into a slower ramp-up or underperformance based on expectations. Evaluation of optimization opportunities continues.
- Start up of remaining pads from circulation to SAGD except for 266-2.

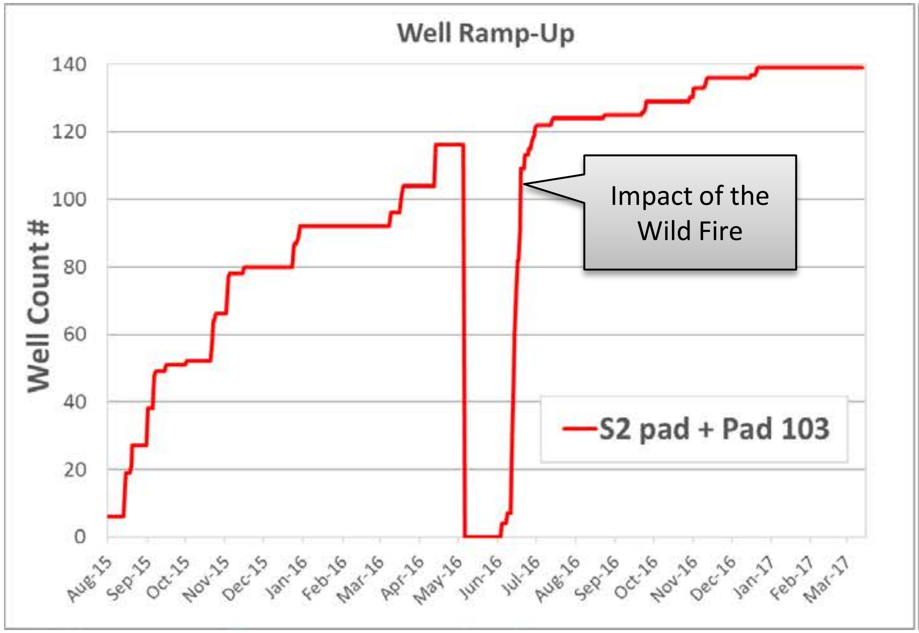
Sustaining pads

- Surmont 1 infill program deferred
- Pad 267 start-up in 2019

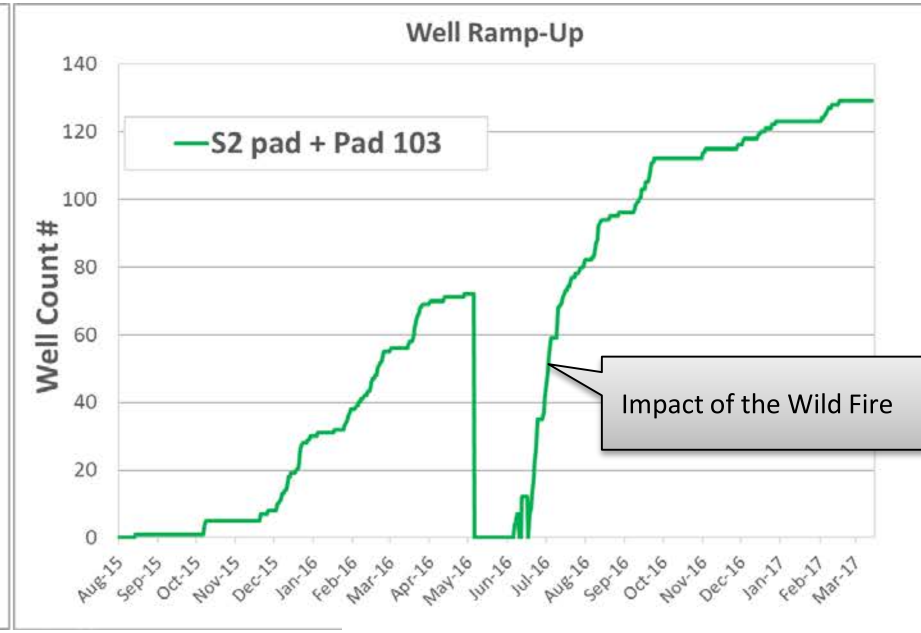
2016 Fort McMurray Wildfire Emergency Shutdown and Re-start

Surmont 2 Ramp-up

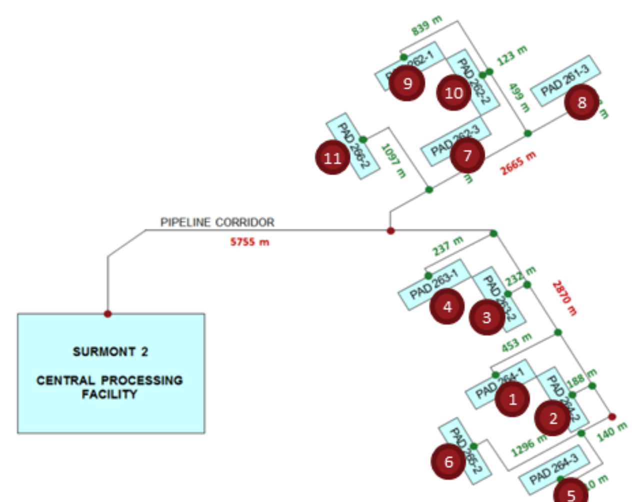
Surmont Well Circulation Start-up



Surmont SAGD Conversions



- Well pads 261-3, 262-2, 262-1 and 266-2 brought online before end of 2016.
- Convert last 11 wells in circulation to SAGD when ready.
- The well start up base plan was primarily based on a conventional circulation pre-heat period of 90 days. Actual performance has taken longer.
- Futures FCD start up plans are anticipated to recover these poorer performances



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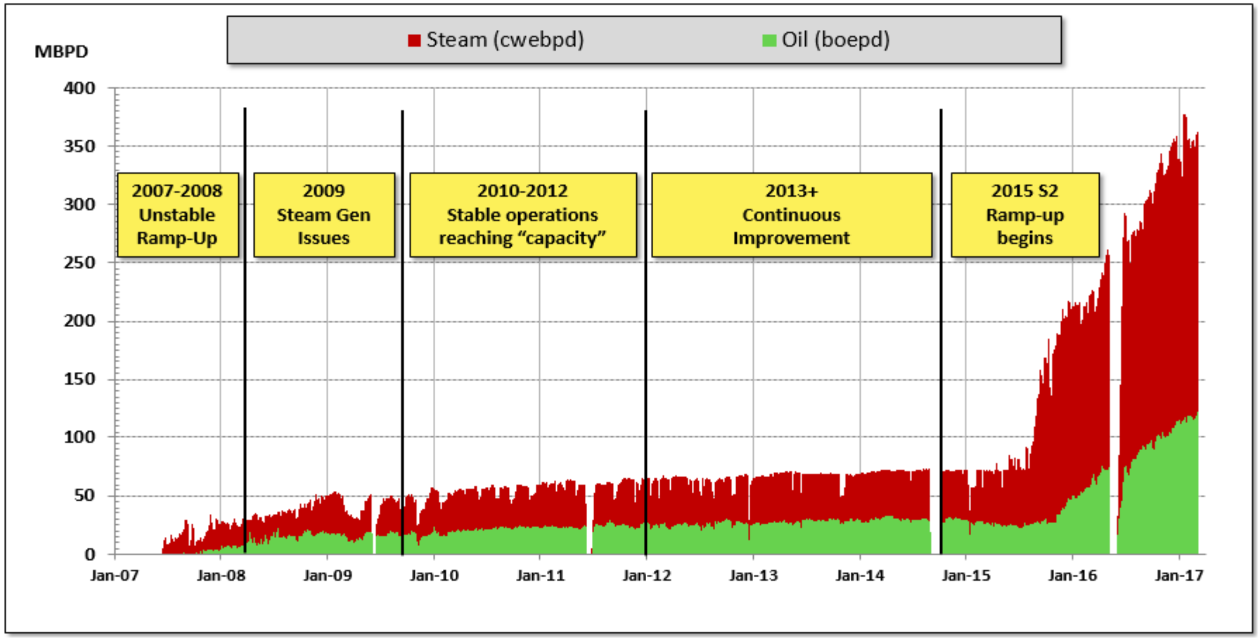
Surmont Performance

Historical Steam Injection and Bitumen Production



2015 Key Challenges

- OTSG fouling
- Front-end treatment
- Pressure drop from 2014 T/A
- Steam constraints (PAD 103 accelerated S/U)

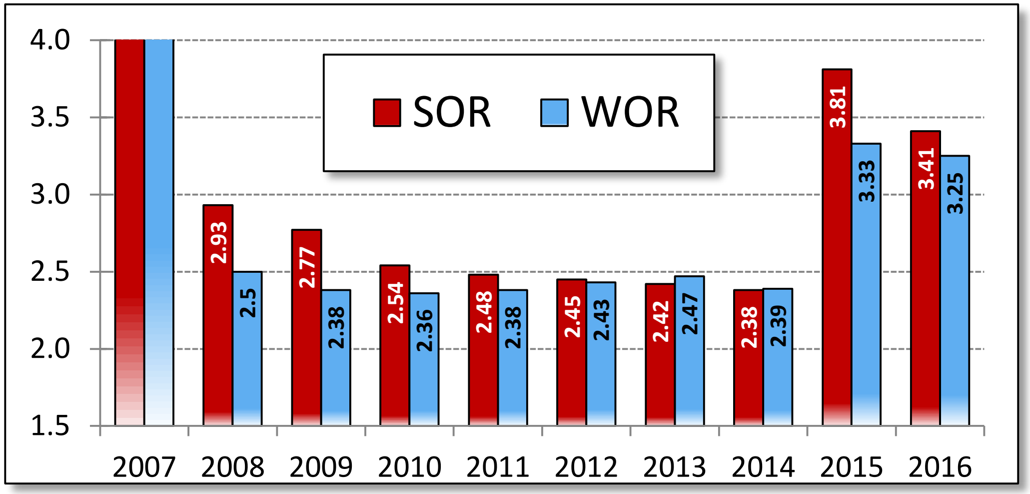
2016 Key Challenges

- Slotted liner Ramp-up performance
- Horizontal liner deformation
- Increased performance on S1 base due to re-pressurization
- Fort McMurray Wildfire Recovery

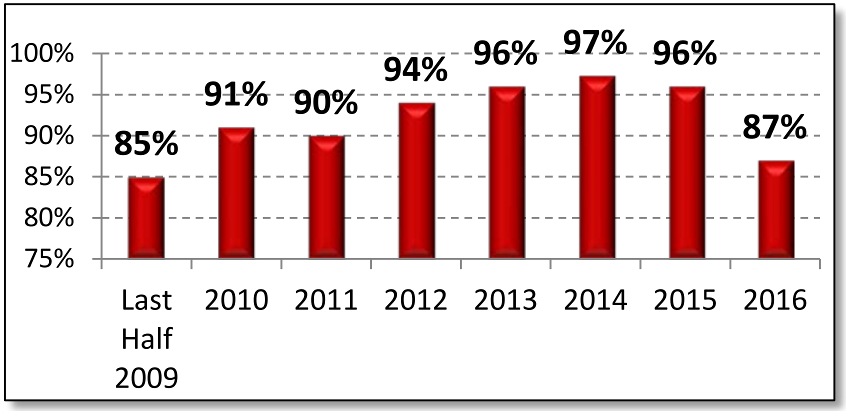
2017 Key Focus Items

- ESP conversions
- TDFCD installations
- Steam allocation

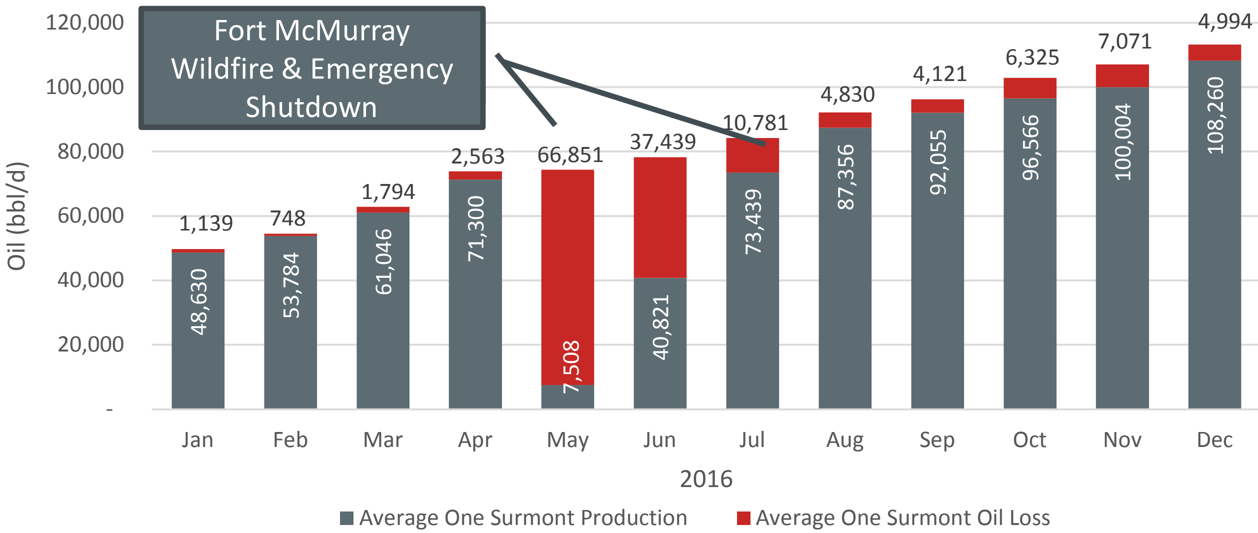
SOR and WOR



Average Steam Uptime

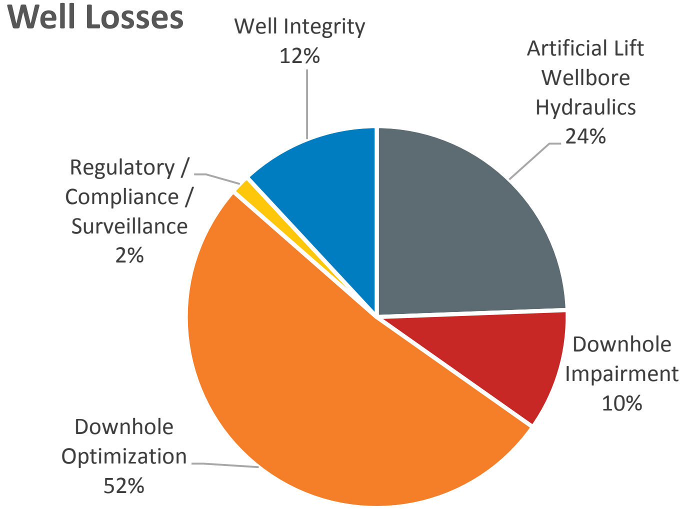


2016 Loss Production Summary

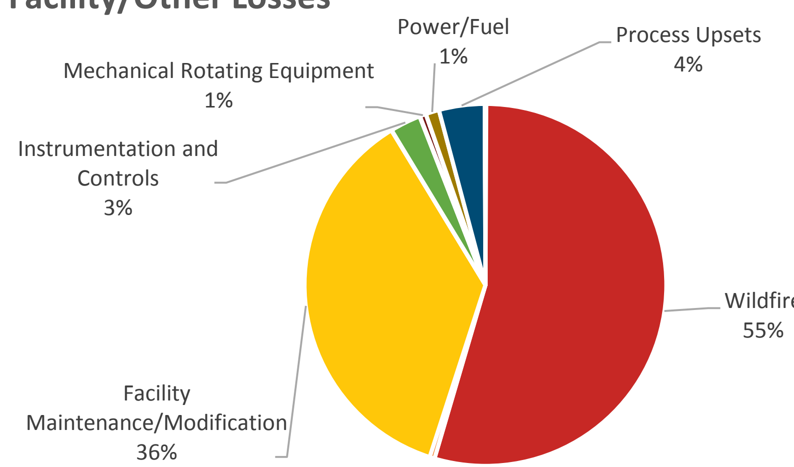


Average Performance	
Oil Average Production (bbl/d)	70,088
Average Oil Loss (bbl/d)	13,666
DOE (Excl. Wildfire)	94%
DOE (Incl. Wildfire)	84%
Steam Uptime (exclusive of wildfires in May 2016)	86.8%

Well Losses



Facility/Other Losses

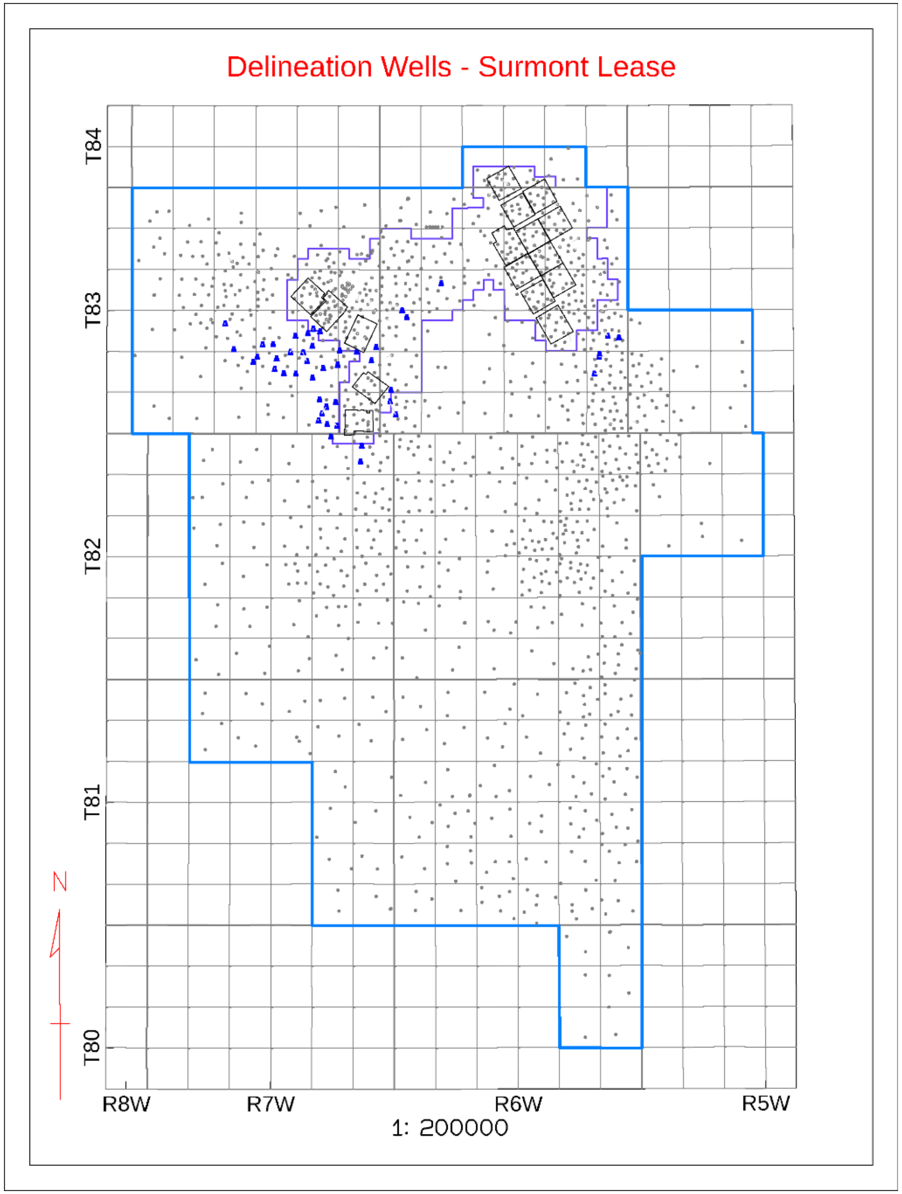


Subsurface Resource Evaluation and Recovery

Geology and Geophysics

Subsection 3.1.1 (2)

2016-2017 Delineation Campaign and Well Density



1485 existing wells – 46 new

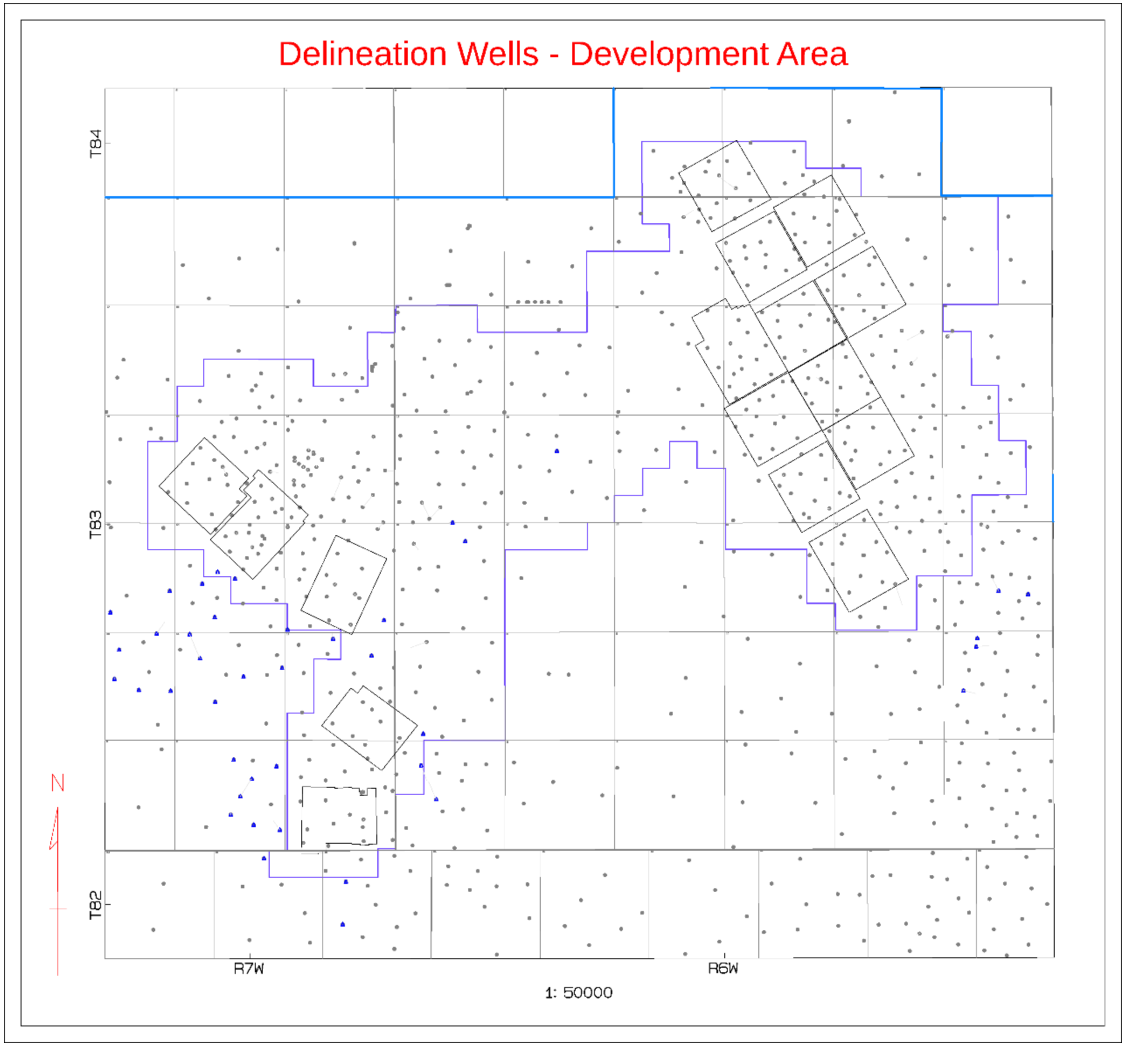
46 new vertical wells (as of Mar 1, 2017)

Phase 1 and Phase 2 Development Area

Drainage Areas

Surmont leases

2016-2017 Delineation Campaign and Well Density

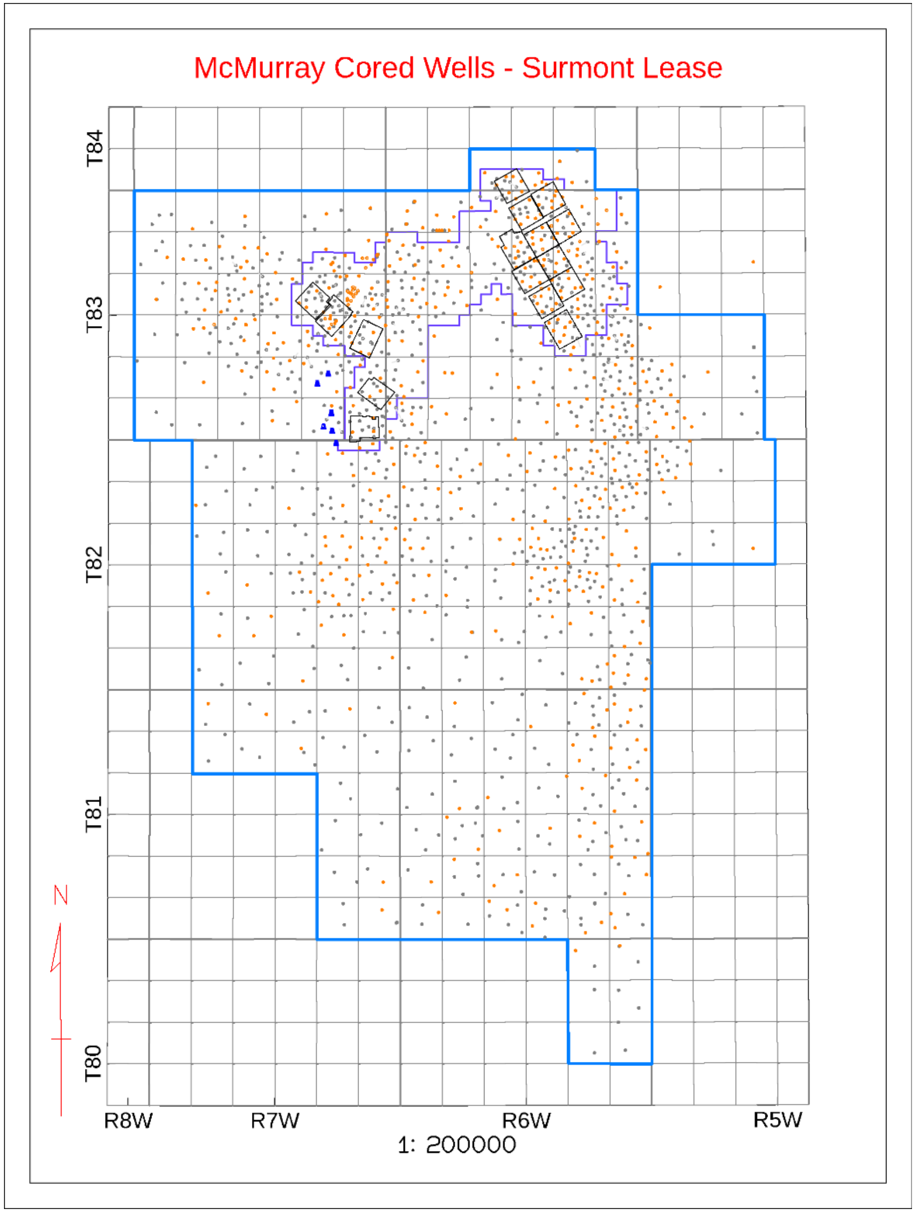


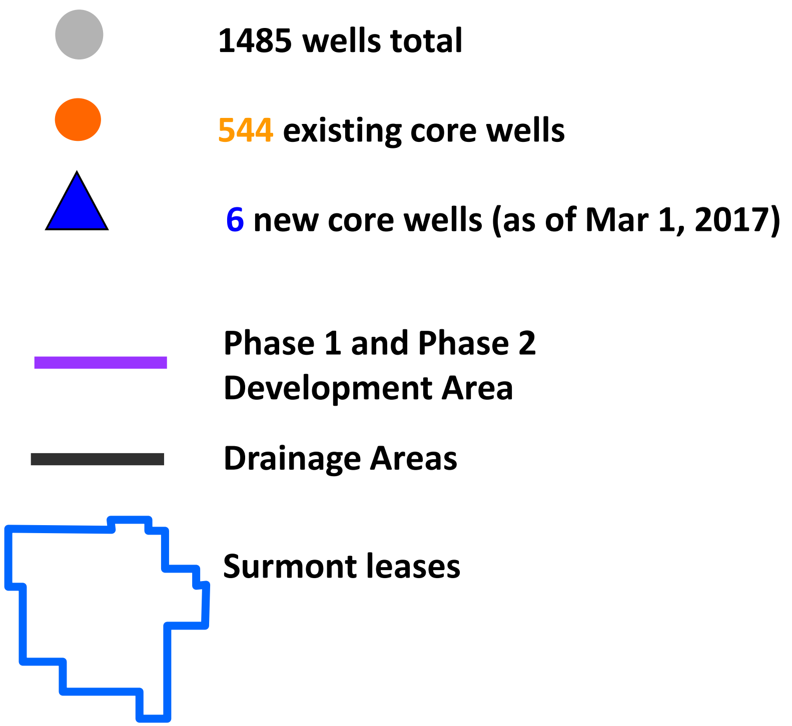
Focus on Surmont Phase 1 sustaining pad locations as well as delineation of Phase 3

(only wells that penetrate the McMurray)

- Existing wells
- New vertical wells (as of Mar 1, 2017)
- Phase 1 and Phase 2 Development Area
- Drainage Areas
- Surmont leases

2016-2017 Delineation Campaign and Core Density





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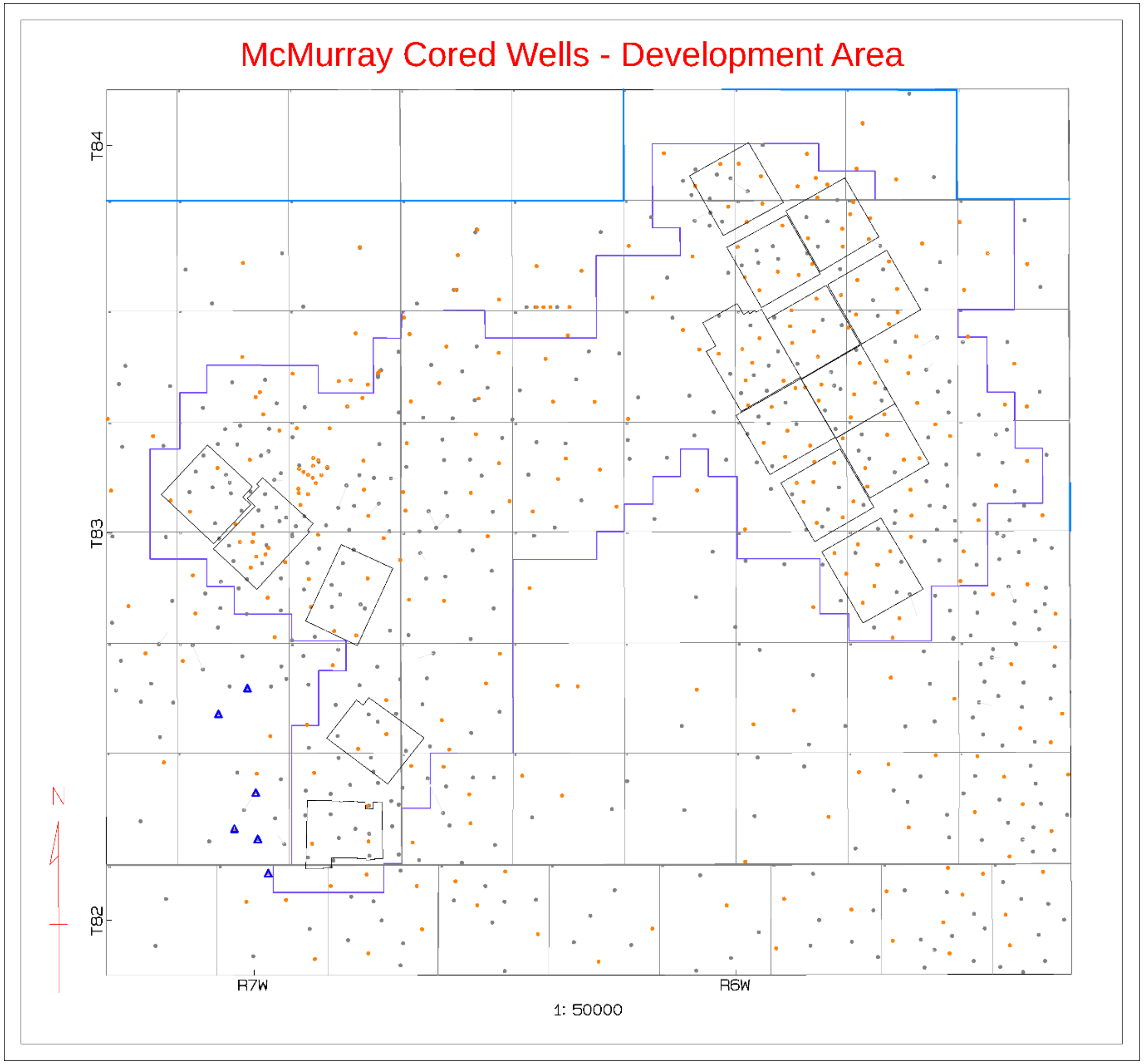
2016-2017 Delineation Campaign and Core Density



Existing wells

Existing cored wells

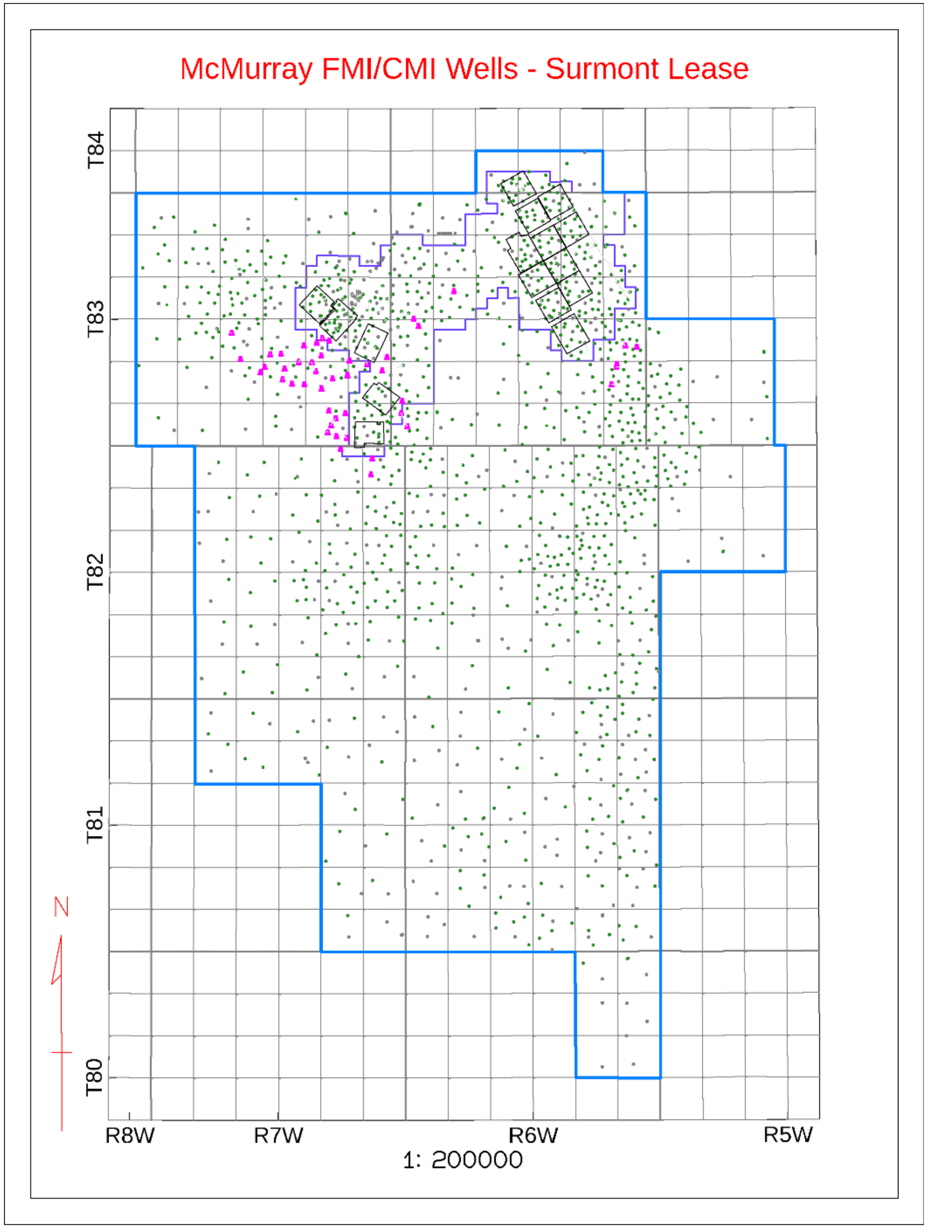
New core wells (as of Mar 1, 2017)

Phase 1 and Phase 2 Development Area

Drainage Areas

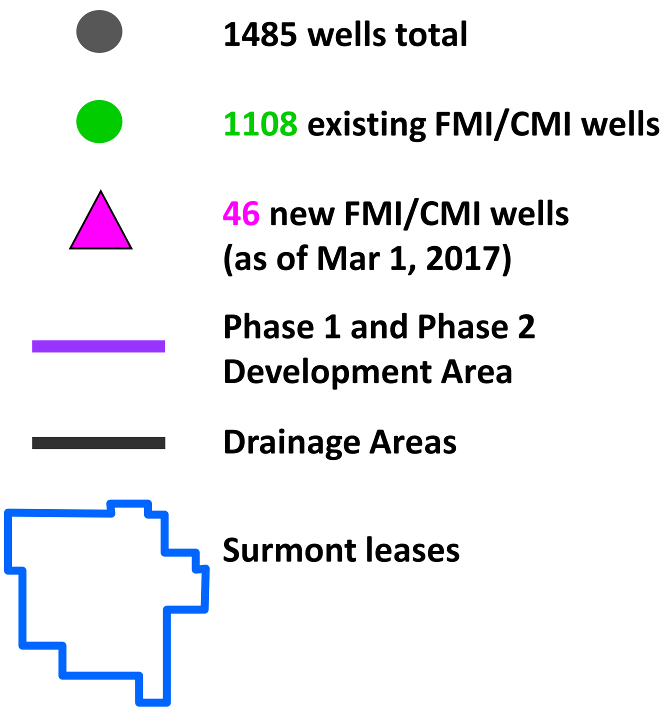
Surmont leases

2016-2017 Delineation Campaign and FMI/CMI Logs

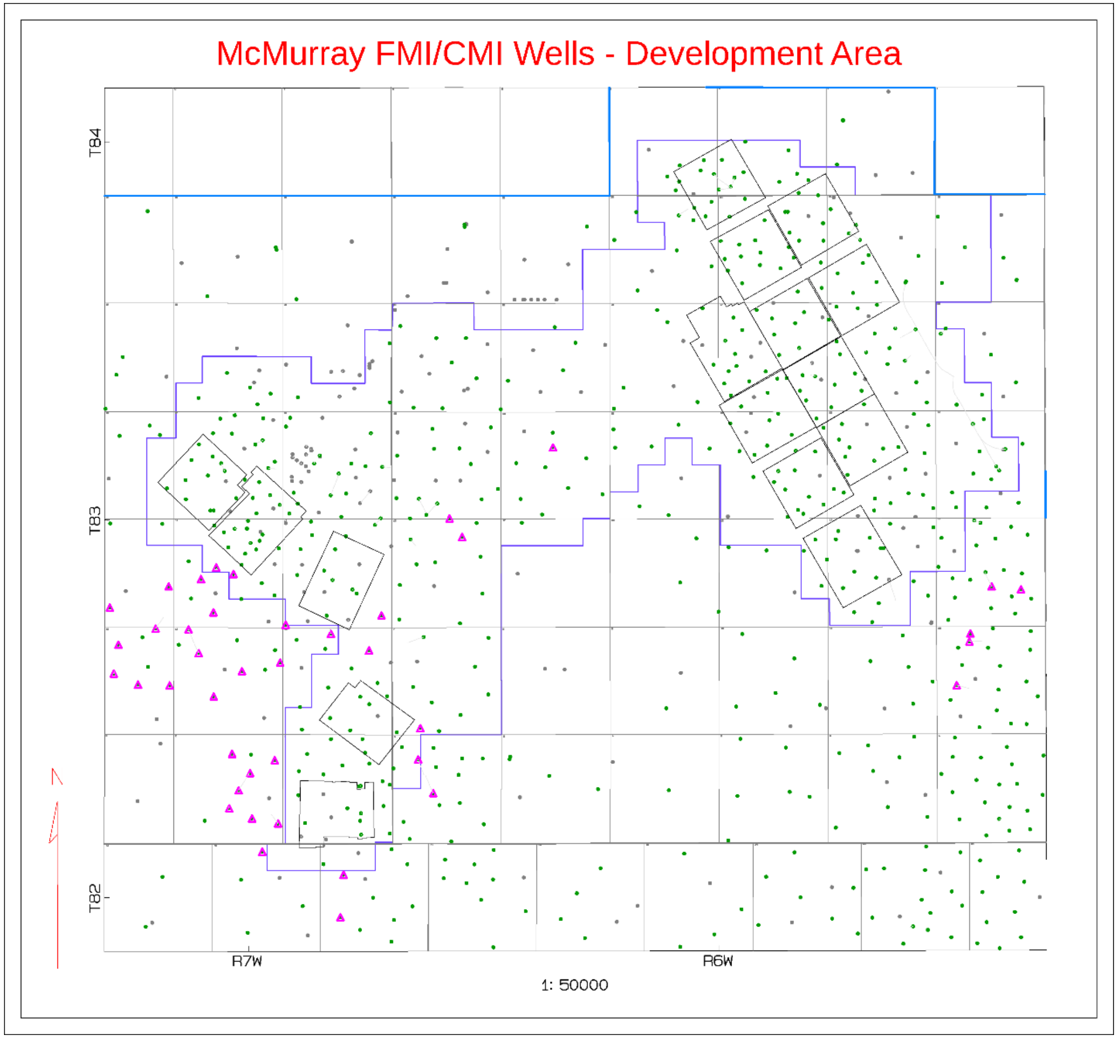


100% Coverage of FMI/CMI Data in 2016/2017 program

- **Important for breccia identification**



2016-2017 Delineation Campaign and FMI/CMI Logs



100% Coverage of FMI/CMI Data in 2016/2017 program

- **Important for breccia identification**
- **Geomechanical Modeling**

Existing wells

Existing FMI wells

New FMI wells (as of Mar 1, 2017)

Phase 1 and Phase 2 Development Area

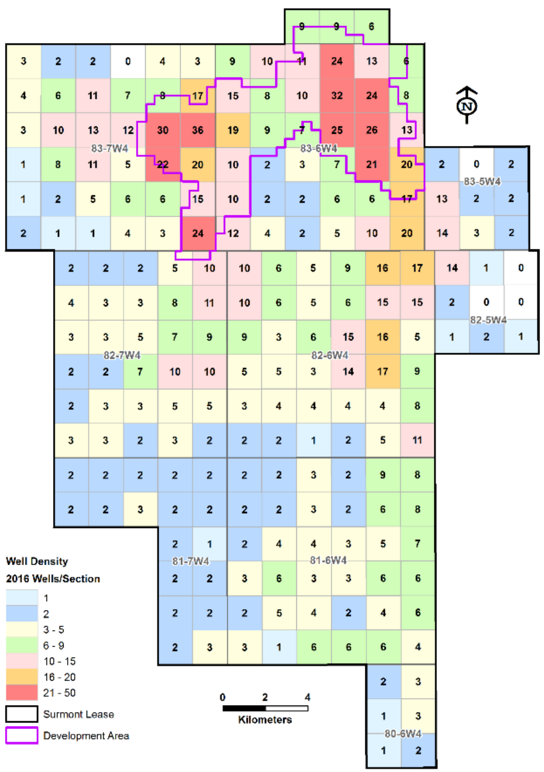
Drainage Areas

Surmont leases

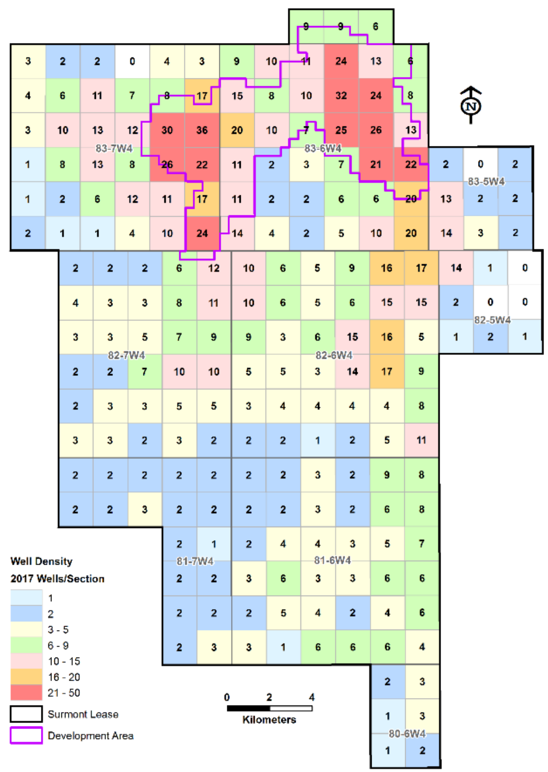
2016-2017 Delineation Campaign and Well Density

Delineation across Phases 1, 2, and 3

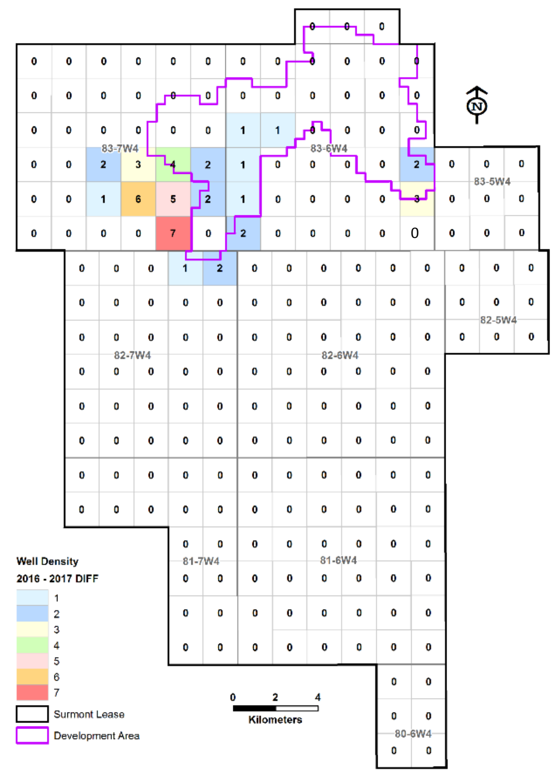
Delineation Well Density Map - 2016



Delineation Well Density Map - Mar 2017



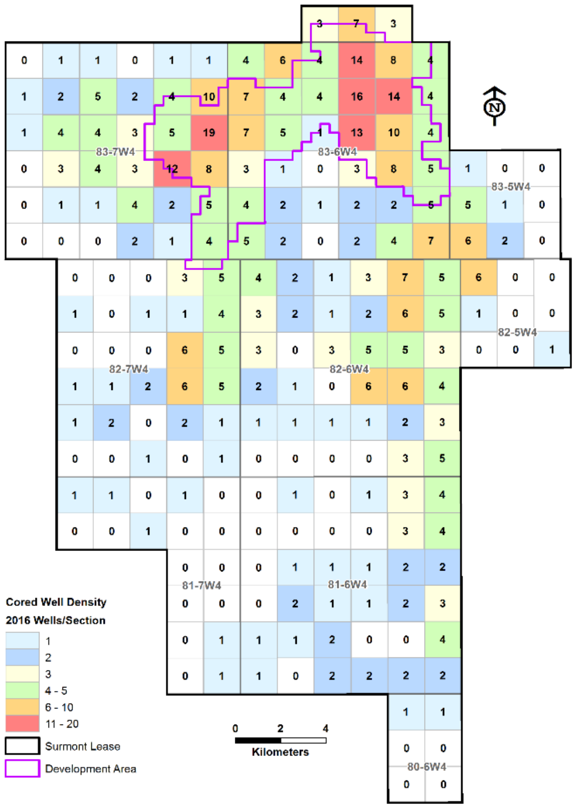
Density Map Difference



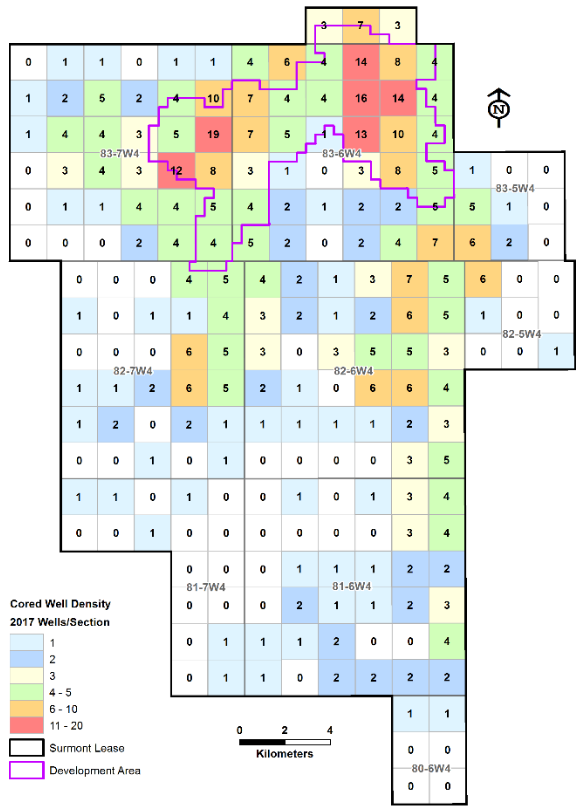
McMurray penetrated wells only

Increased core density with latest drilling

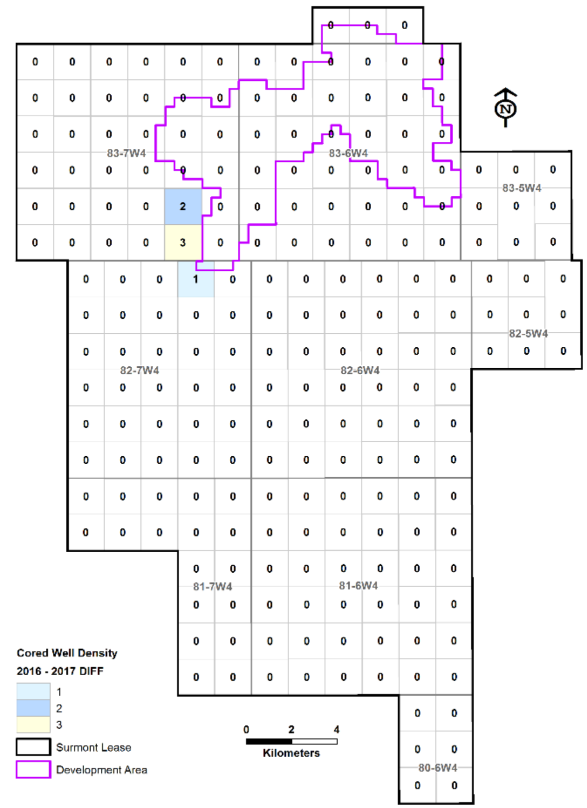
Cored Wells Density Map - 2016



Cored Wells Density Map - Mar 2017



Cored Density Map Difference

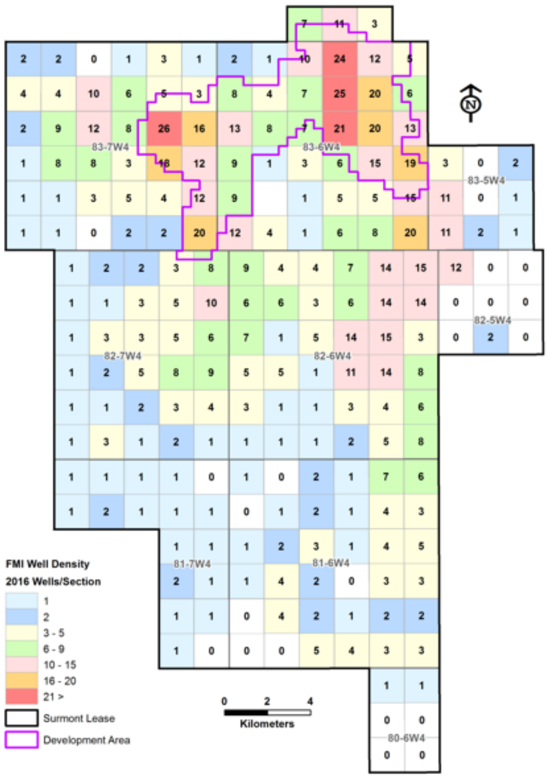


McMurray penetrated wells only

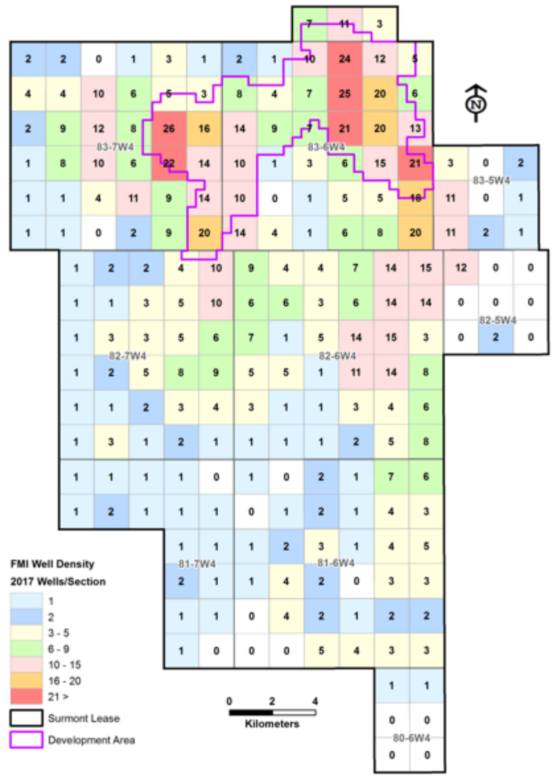
2016-2017 Delineation Campaign and Well Density

Increased Formation Micro Imaging density with latest drilling

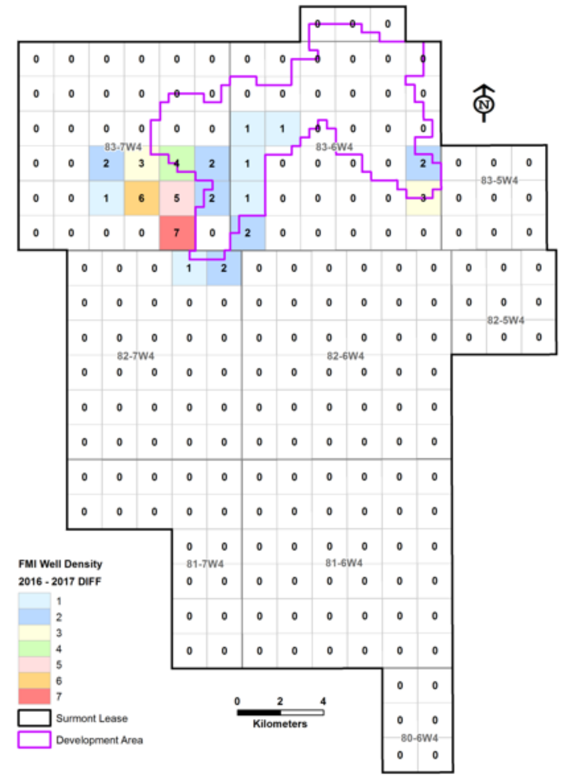
FMI Well Log Density Map – 2016



FMI Well Log Density Map – Mar 2017

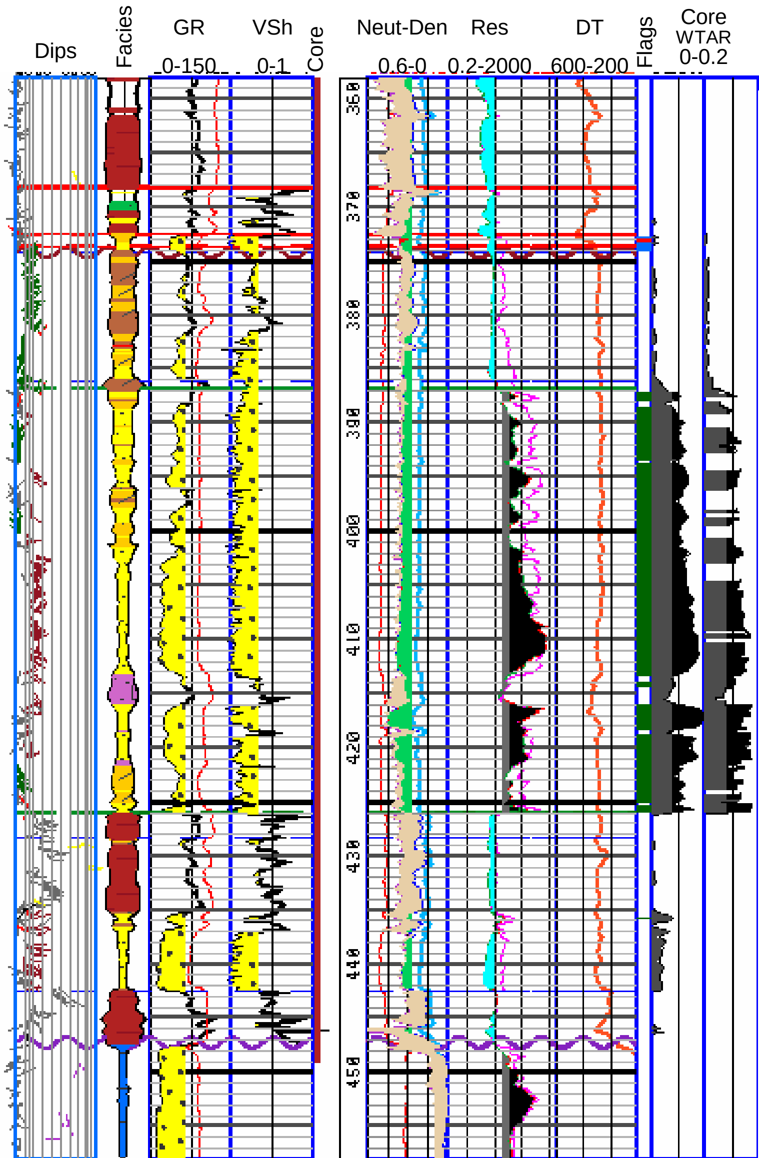


FMI Density Map Difference



McMurray penetrated wells only

Phase 1 Type Log Well Pad 101



Example Log 100161408307w400

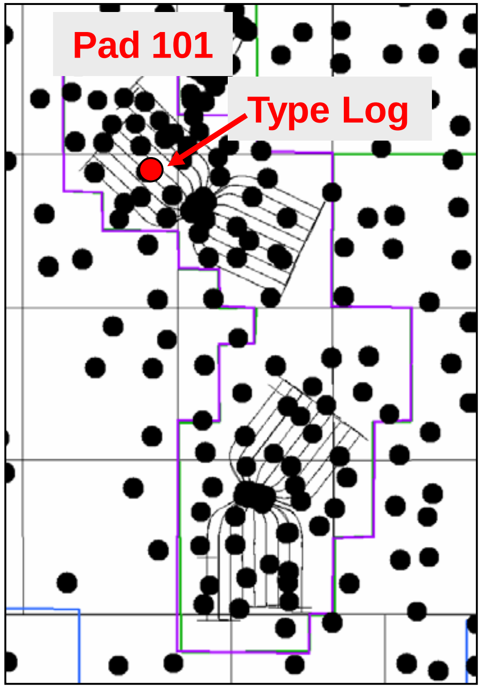
McMurray

High Sw

Continuous Bitumen

High Sw

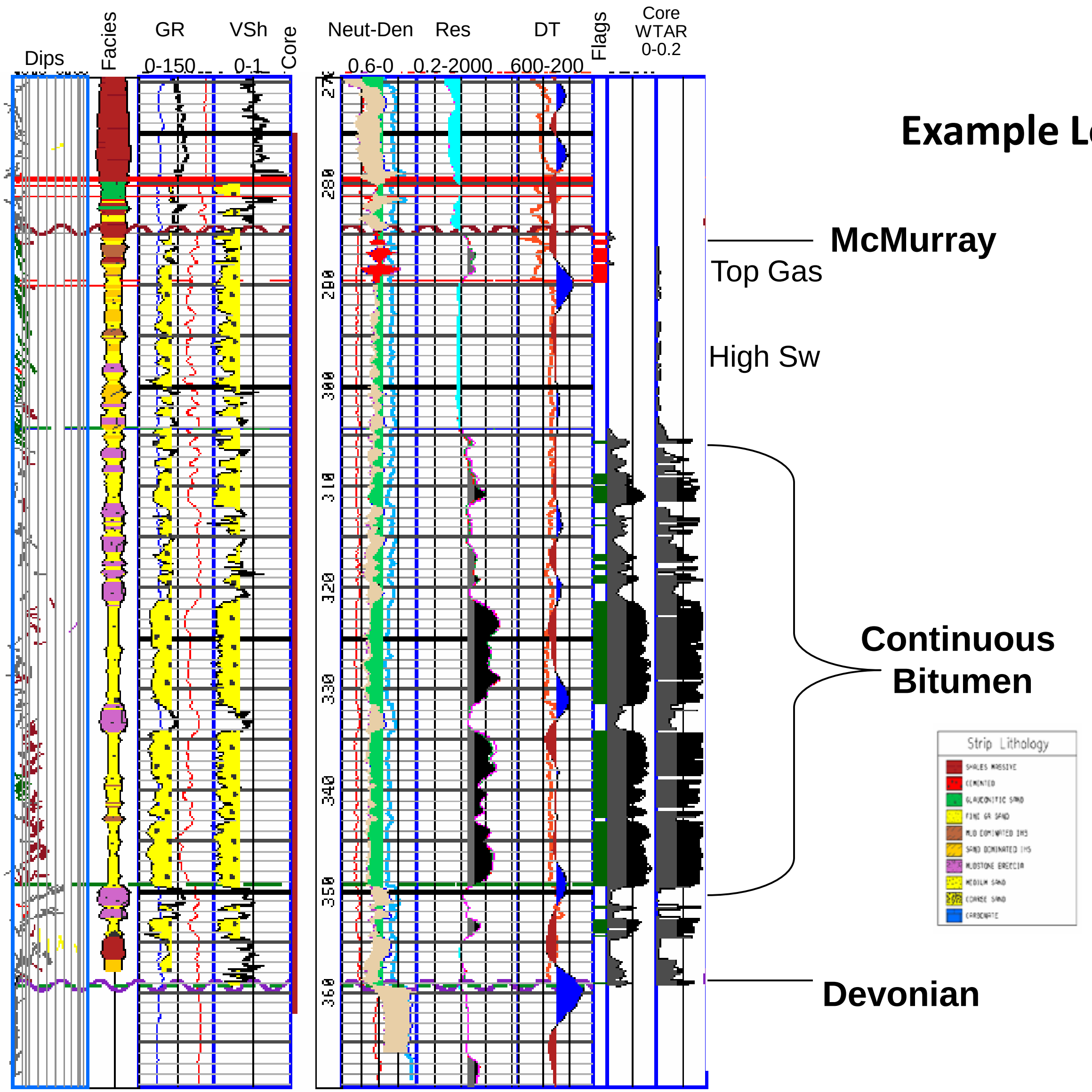
Devonian

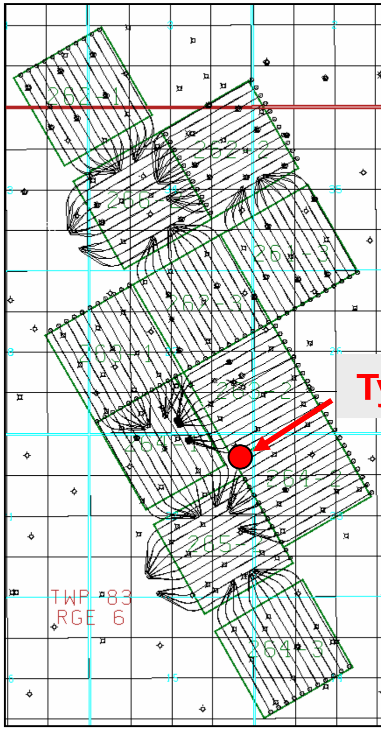


Phase 1 Area

Phase 2 Type Log – Well Pad 264-2

Example Log 100162208306w400





Phase 2 Area

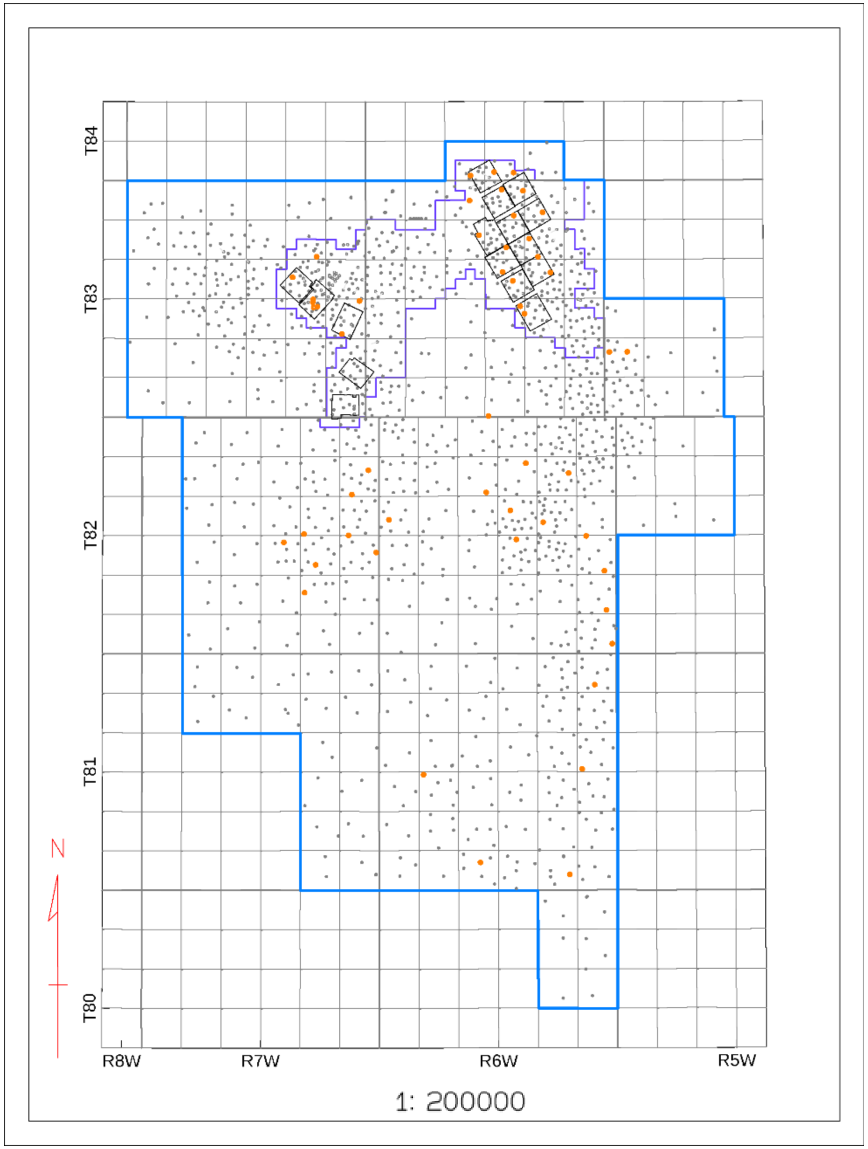
Special Core Analyses Bitumen Viscosity Sampling

- **Objectives:**
  - Characterize vertical and lateral variance in viscosity at different temperatures.
  - Model the variance in bitumen properties and its implications for bitumen production rates during SAGD.
  - Characterize relationship between viscosity, density and geochemical composition.

Viscosity increases with depth in the McMurray Formation.

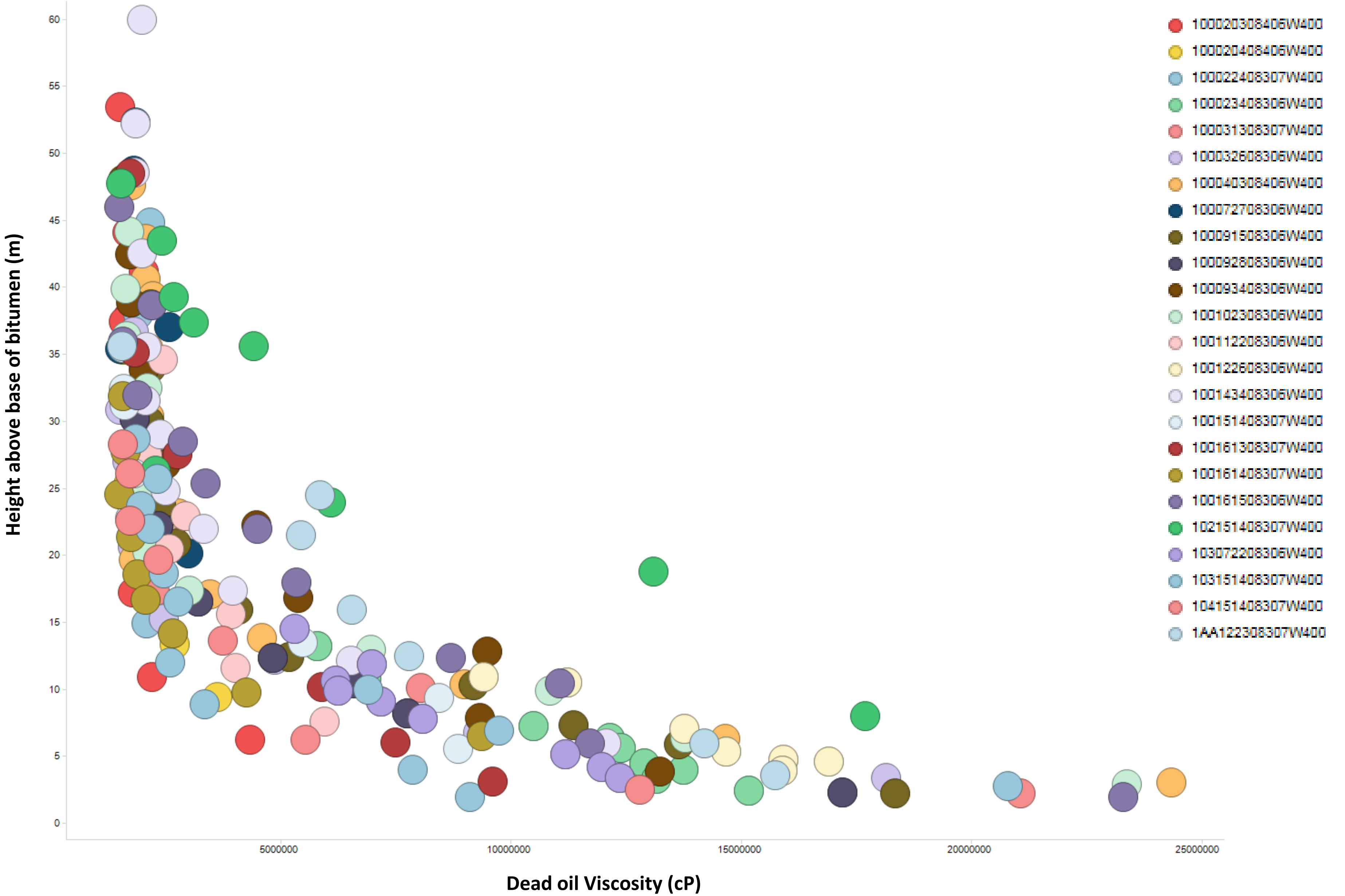
52 existing viscosity sample wells

Delineated Wells - Surmont

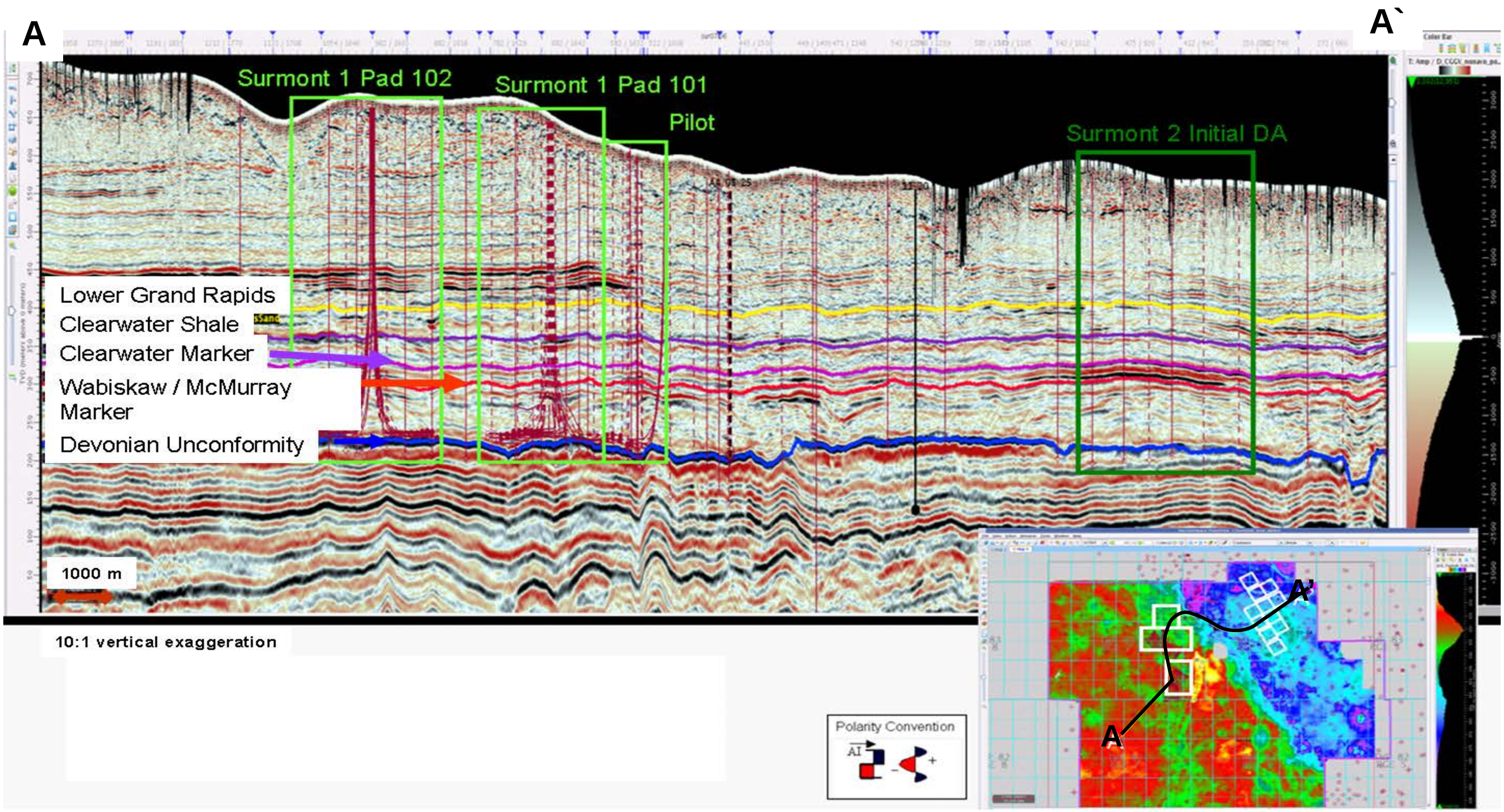


2016 – 2017 Delineation

Viscosity Gradient



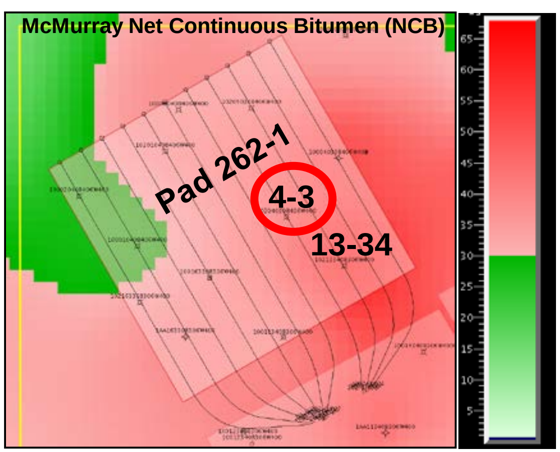
Representative Structural Cross Section

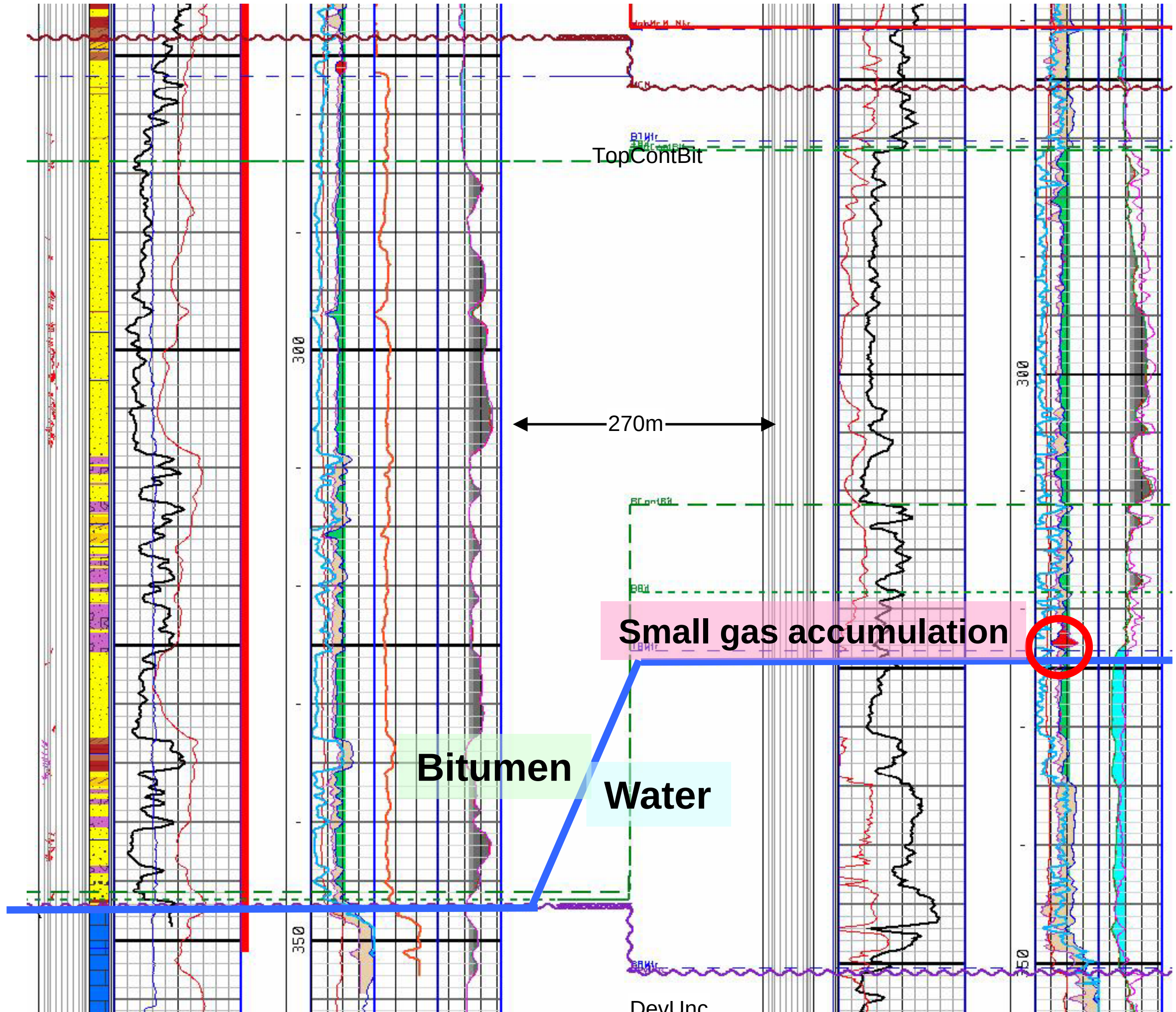


Well Pad 262-1 Variable Bitumen-Water Contact

- A well at 4-3-84-6 W4M intersected a raised bitumen/water contact, the contact is ~ 12 m higher than the nearest offset.
- The well also intersected a small gas pool under the bitumen.

- **The presence of basal water becomes a potential impact on production performance on Well Pad 262-1**





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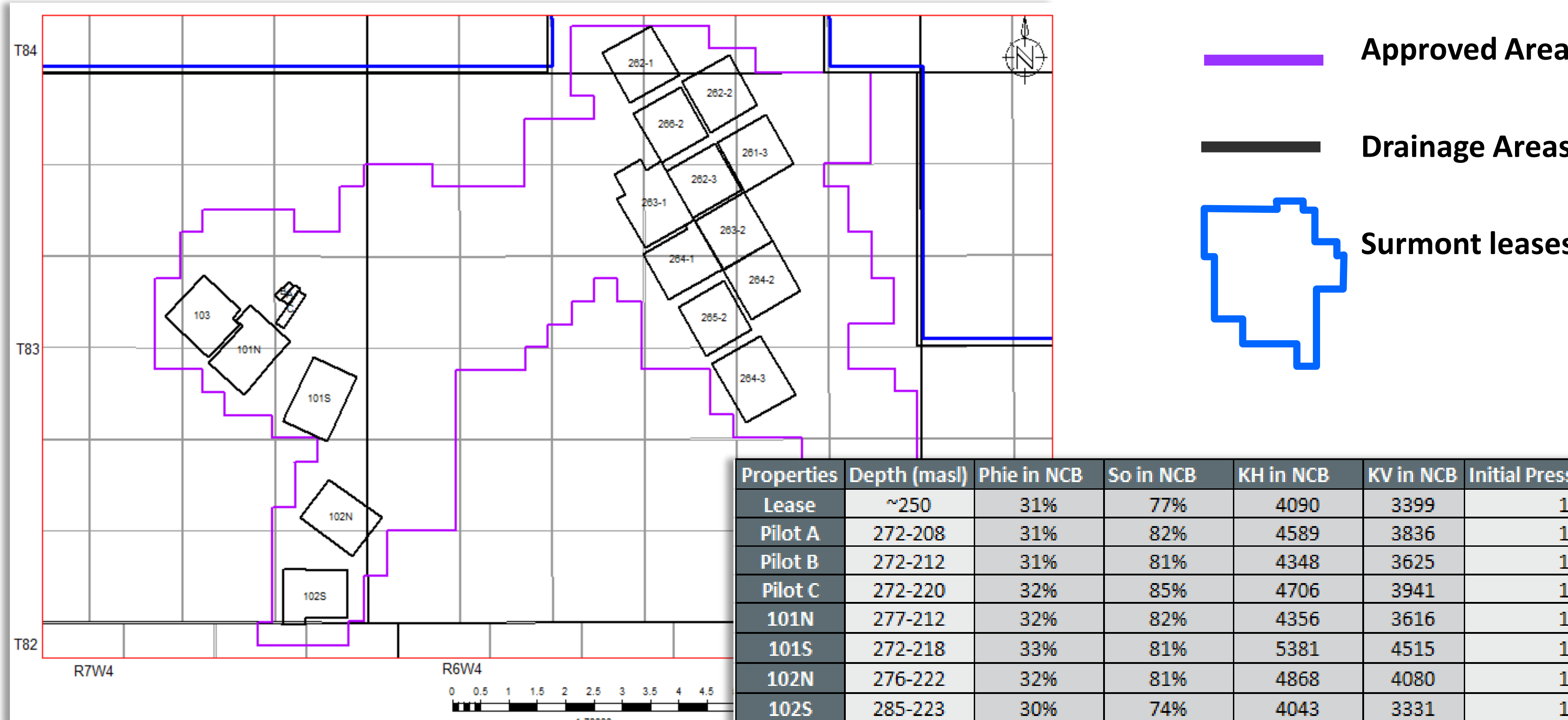
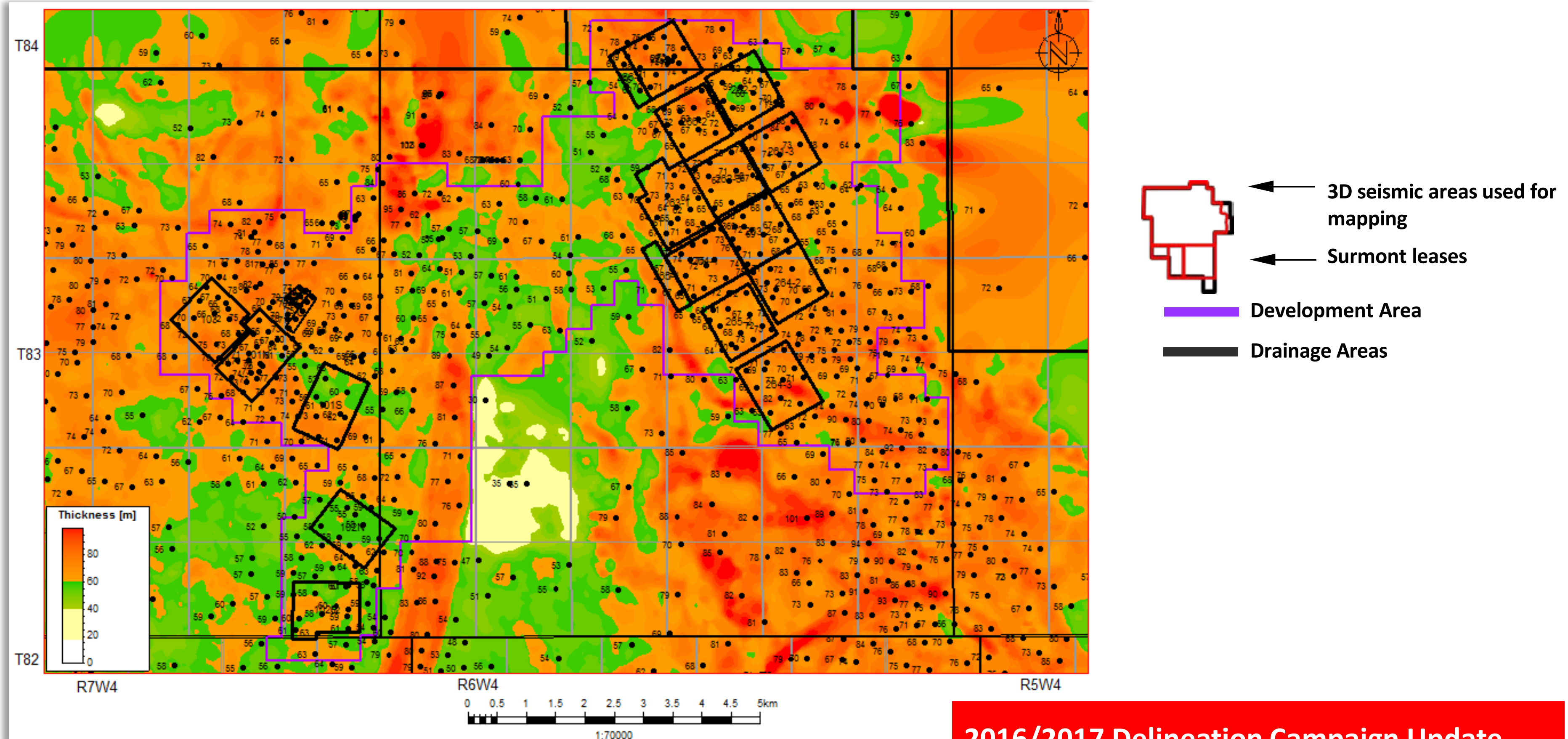
Reservoir Characteristics



Properties	Depth (masl)	Phie in NCB	So in NCB	KH in NCB	KV in NCB	Initial Pressure (KPa)
Lease	~250	31%	77%	4090	3399	1700
Pilot A	272-208	31%	82%	4589	3836	1734
Pilot B	272-212	31%	81%	4348	3625	1715
Pilot C	272-220	32%	85%	4706	3941	1675
101N	277-212	32%	82%	4356	3616	1690
101S	272-218	33%	81%	5381	4515	1684
102N	276-222	32%	81%	4868	4080	1735
102S	285-223	30%	74%	4043	3331	1800
103	272-212	31%	83%	4451	3706	1691
261-3	271-202	31%	78%	4319	3537	1328
262-1	273-206	31%	80%	4160	3440	1307
262-2	272-212	33%	79%	5257	4436	1296
262-3	271-208	32%	78%	4939	4119	1368
263-1	272-211	32%	79%	5028	4226	1404
263-2	275-213	32%	78%	4773	3978	1397
264-1	271-213	32%	80%	5106	4303	1444
264-2	269-214	32%	78%	4791	3995	1437
264-3	281-208	31%	76%	4470	3703	1564
265-2	271-215	32%	77%	5095	4252	1496
266-2	276-210	32%	80%	4805	4013	1337

McMurray Gross Isopach

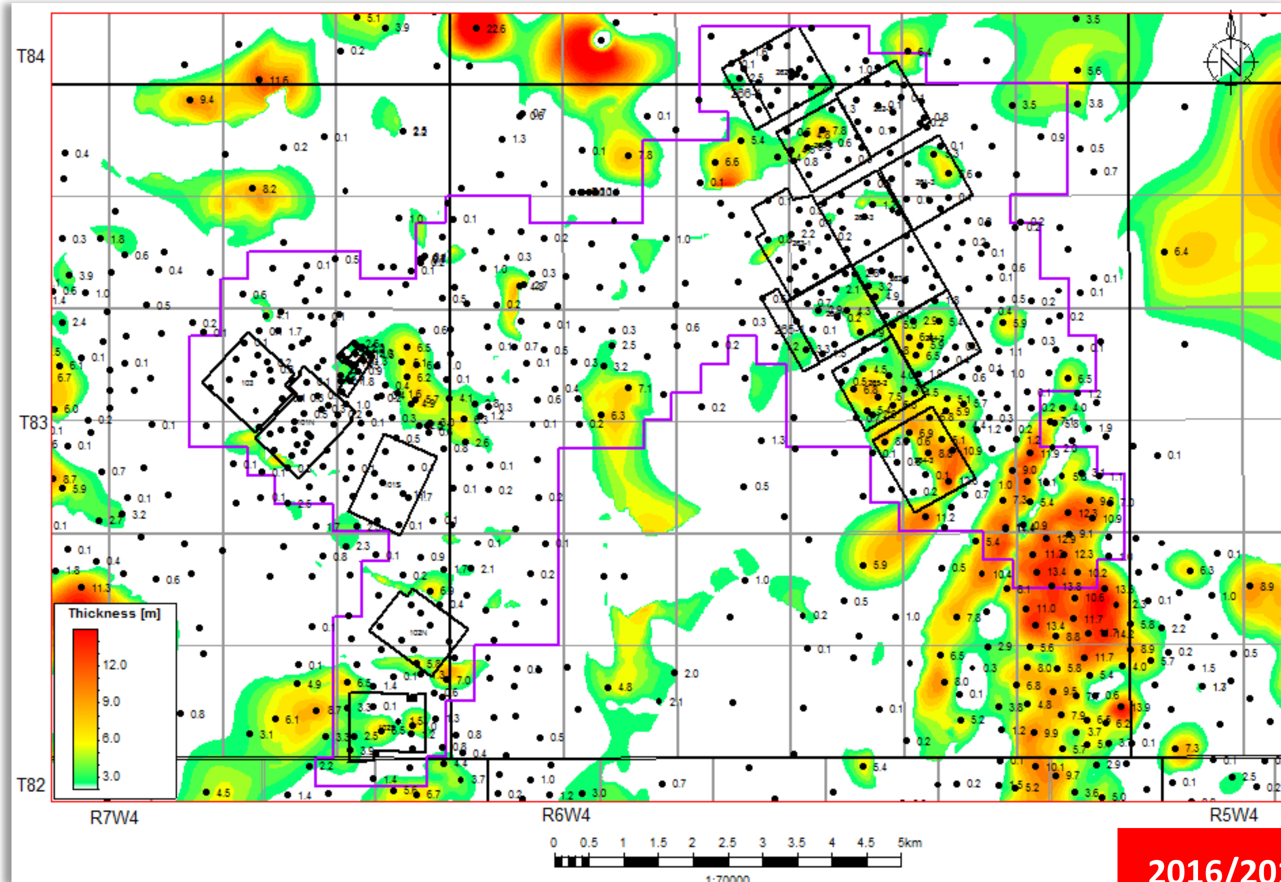


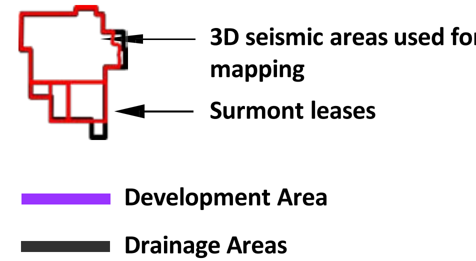
McMurray Gross Isopach

2016/2017 Delineation Campaign Update

- **Minor changes due to:**
  - **Geological picks from new Wells**
  - **Re-evaluated/unified geologic picks**
  - **Revised Seismic Interpretation**

McMurray Net Gas Isopach





Net Top Gas thickness = sands have deep resistivity ≥10 Ω-m and Vsh <65%

McMurray Net Gas Isopach

2016/2017 Delineation Campaign Update

- **Minor changes due to:**
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  - **Re-evaluated/unified geologic picks**
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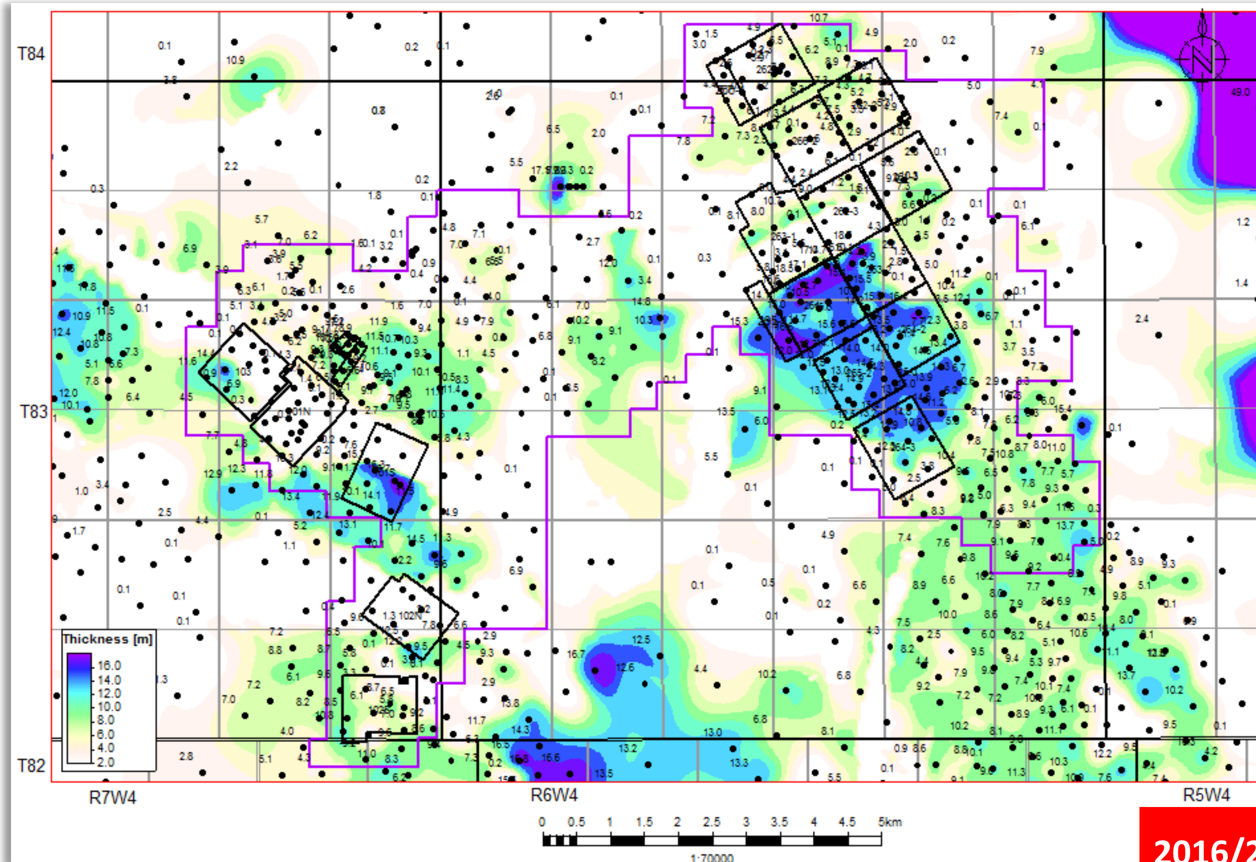
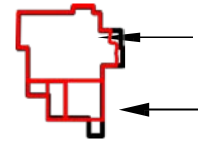
McMurray Net Top Water Isopach





3D seismic areas used for mapping

Surmont leases

Development Area

Drainage Areas

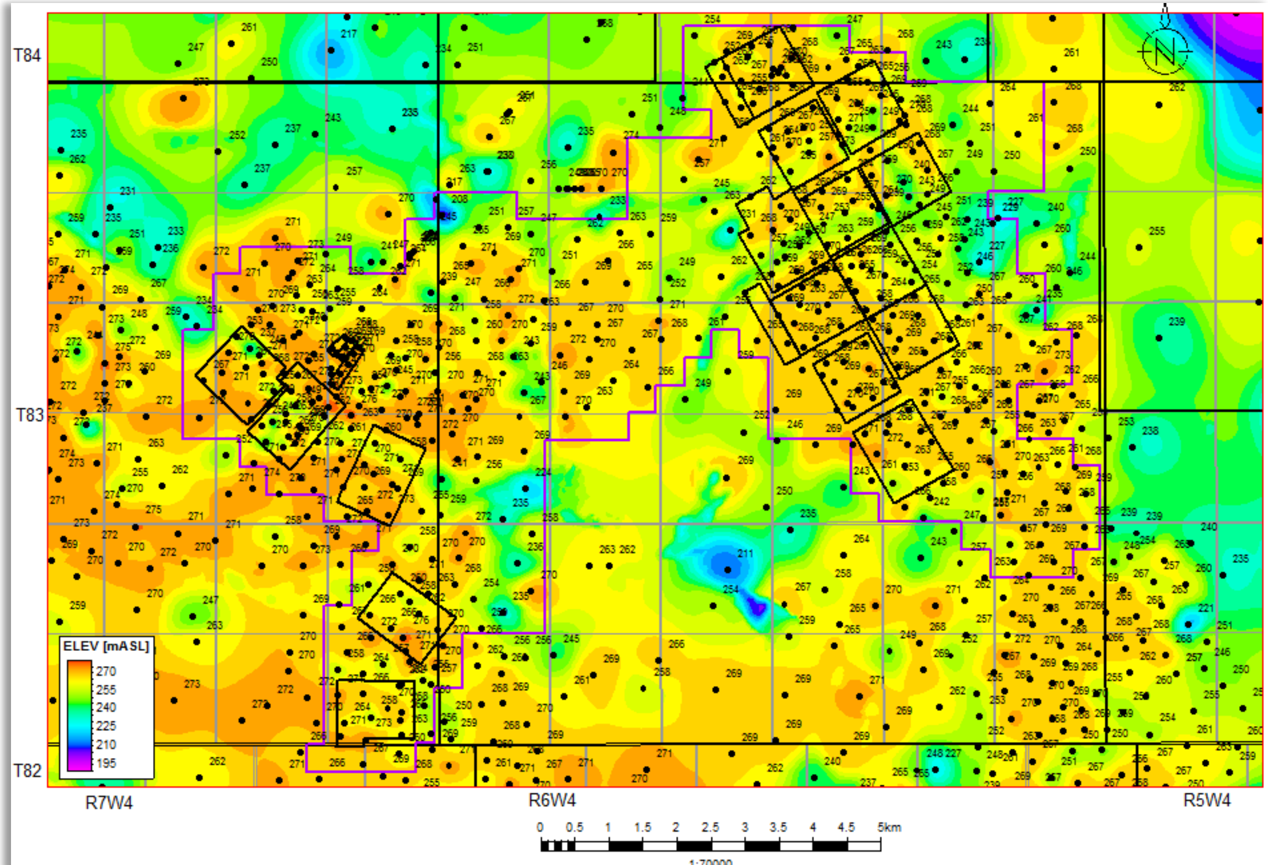
Net Top Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

McMurray Net Top Water Isopach

2016/2017 Delineation Campaign Update

- **Minor changes due to:**
  - **Geological picks from new Wells**
  - **Re-evaluated/unified geologic picks**
  - **Revised Seismic Interpretation**

McMurray Top Continuous Bitumen Structure



3D seismic areas used for mapping

Surmont leases

Development Area

Drainage Areas

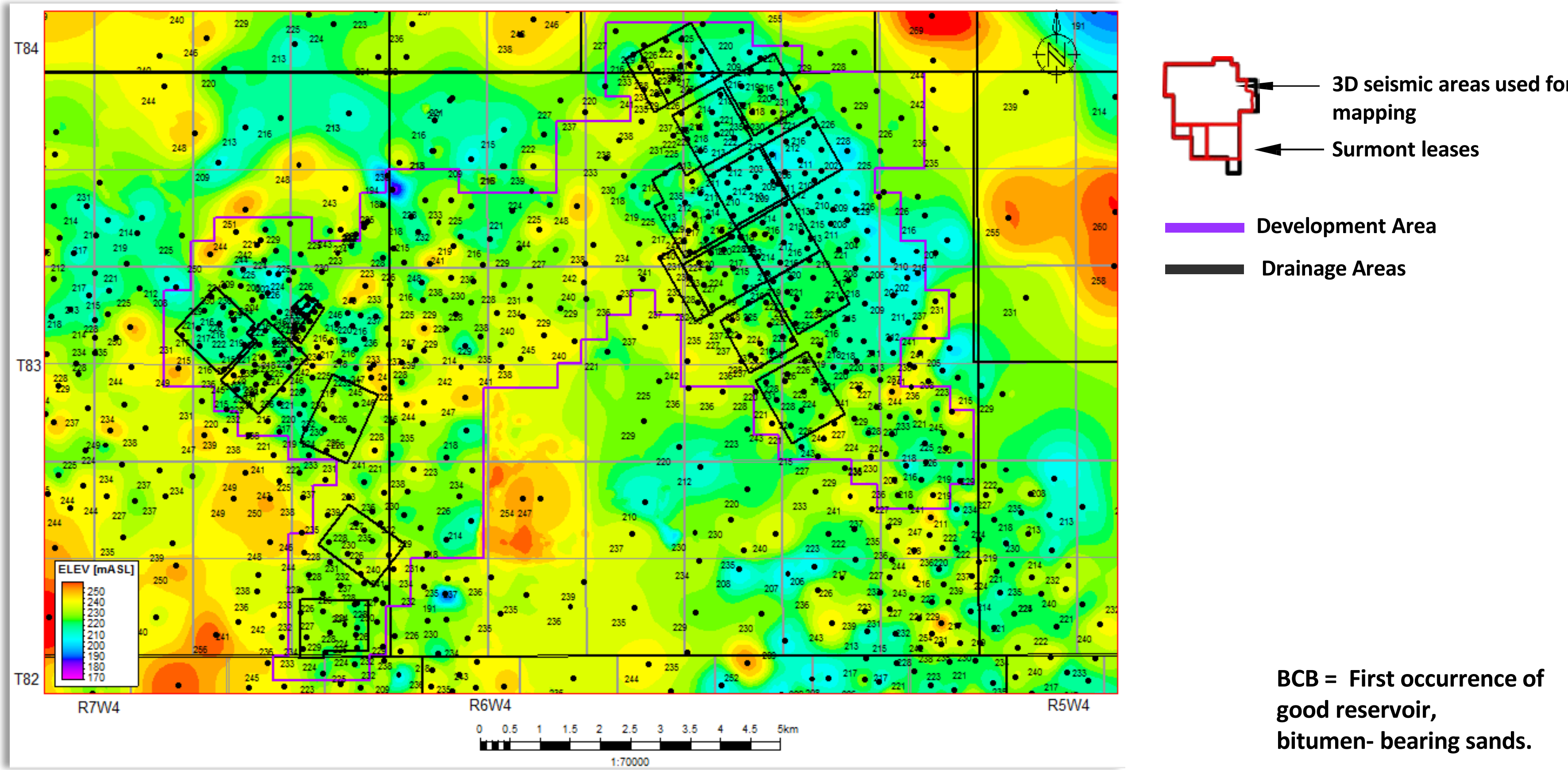
TCB = The uppermost limit of good reservoir, bitumen- bearing sands.

Top Continuous Bitumen Structure

2016/2017 Delineation Campaign Update

- Minor changes due to:
  - Geological picks from new Wells
  - Re-evaluated/unified geologic picks
  - Revised Seismic Interpretation

McMurray Base Continuous Bitumen Structure



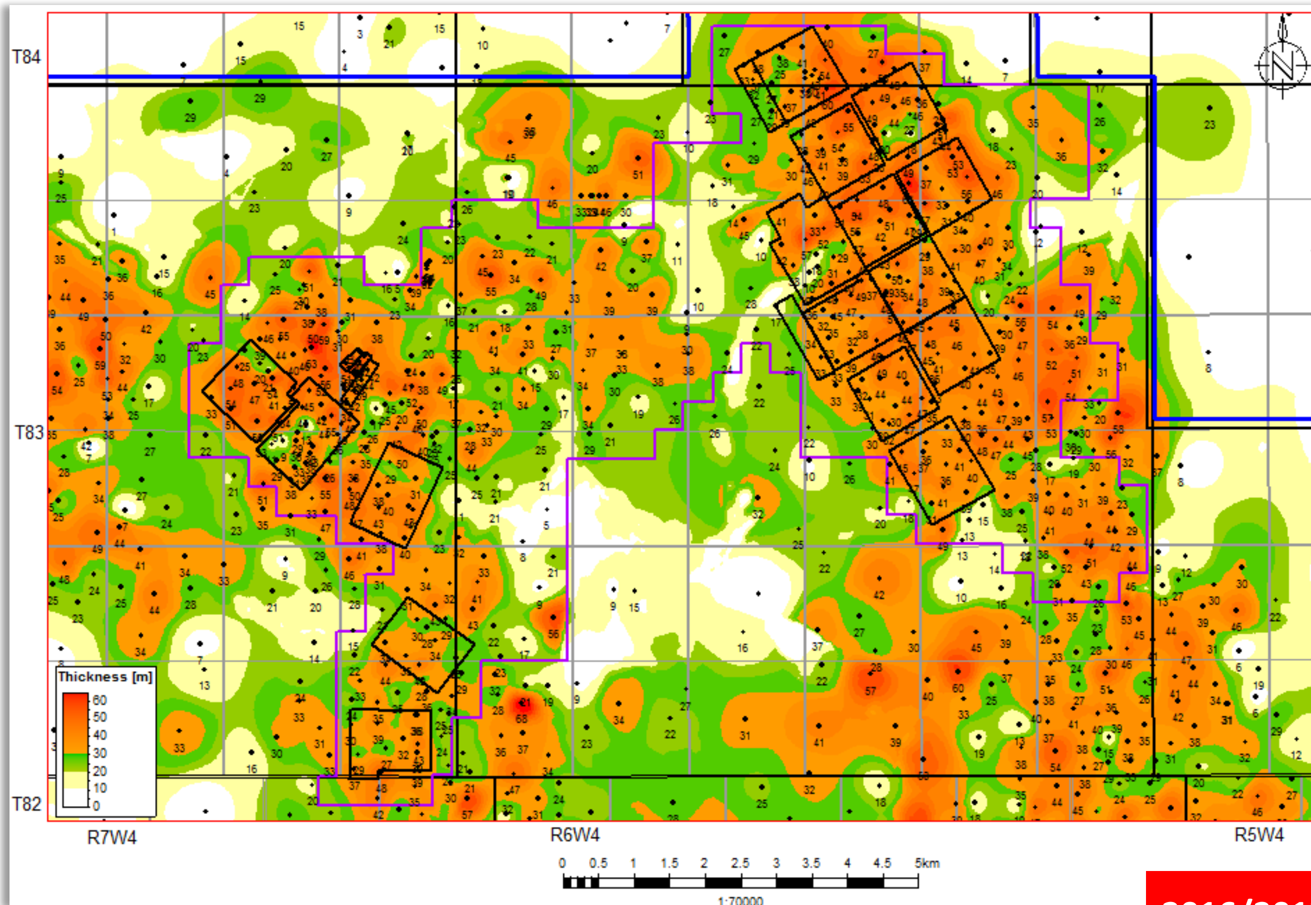
BCB = First occurrence of good reservoir, bitumen- bearing sands.

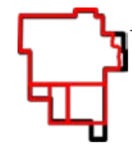
Base Continuous Bitumen Structure

2016/2017 Delineation Campaign Update

- Minor changes due to:
  - Geological picks from new Wells
  - Re-evaluated/unified geologic picks
  - Revised Seismic Interpretation

McMurray Net Continuous Bitumen Thickness





3D seismic areas used for mapping

Surmont leases

Development Area

Drainage Areas

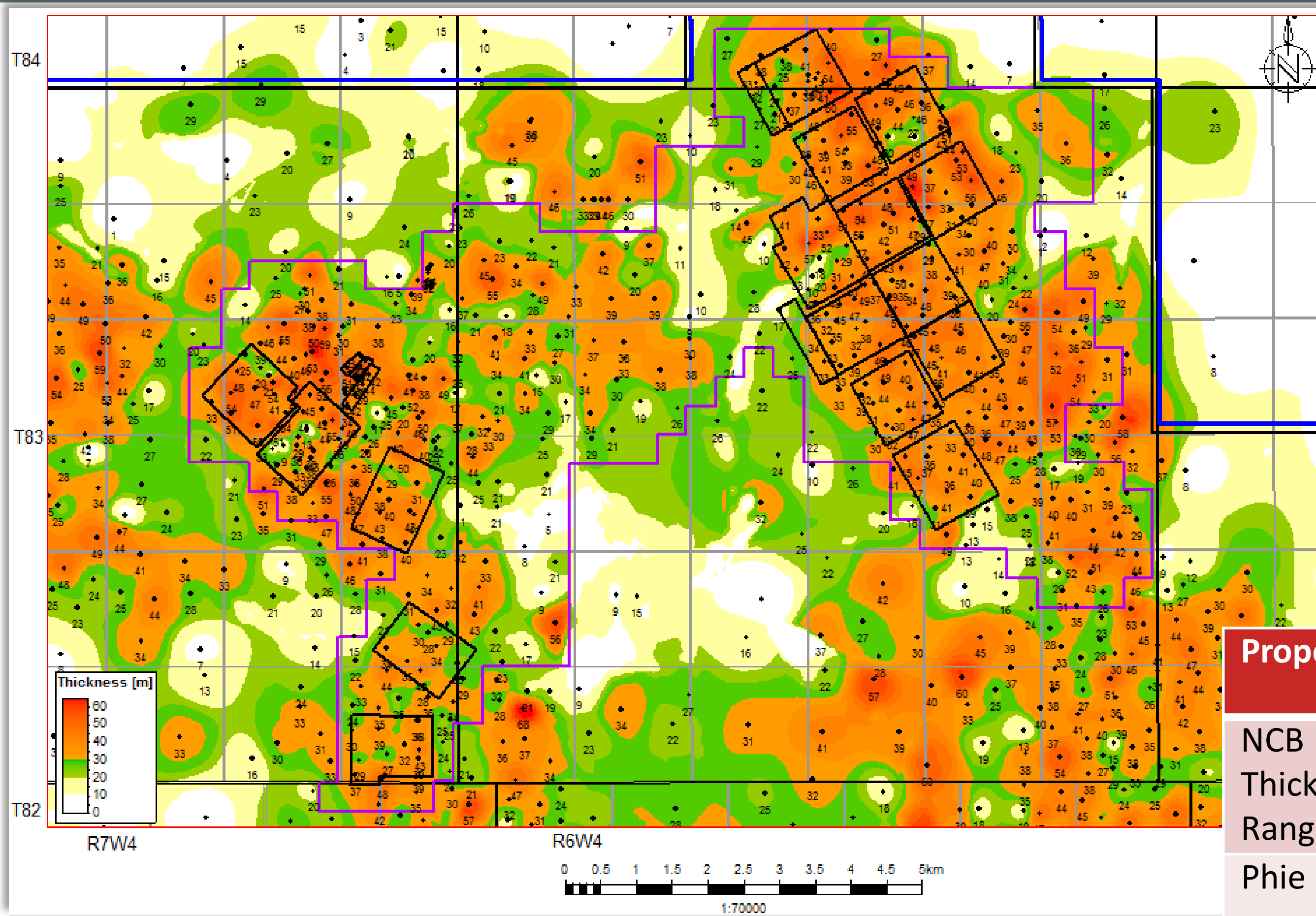
Net continuous bitumen = sands have deep resistivity > 40 Ω-m and Vsh <33%, and no shale greater than 3 m thick

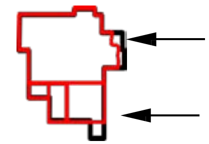
McMurray Net Continuous Bitumen Pay

2016/2017 Delineation Campaign Update

- Minor changes due to:
  - Geological picks from new Wells
  - Re-evaluated/unified geologic picks
  - Revised Seismic Interpretation

Surmont Leases OBIP





Development Area

Drainage Areas

Surmont Development Area OBIP

Properties	Development Area
NCB Thickness Range	0 to Greater than 30 m
Phie in NCB	31.86%
So in NCB	76.48%
OOIP in NCB > 18m	3509.43 MMbbls Deterministic

OBIP = Thickness x Phie x So x Area

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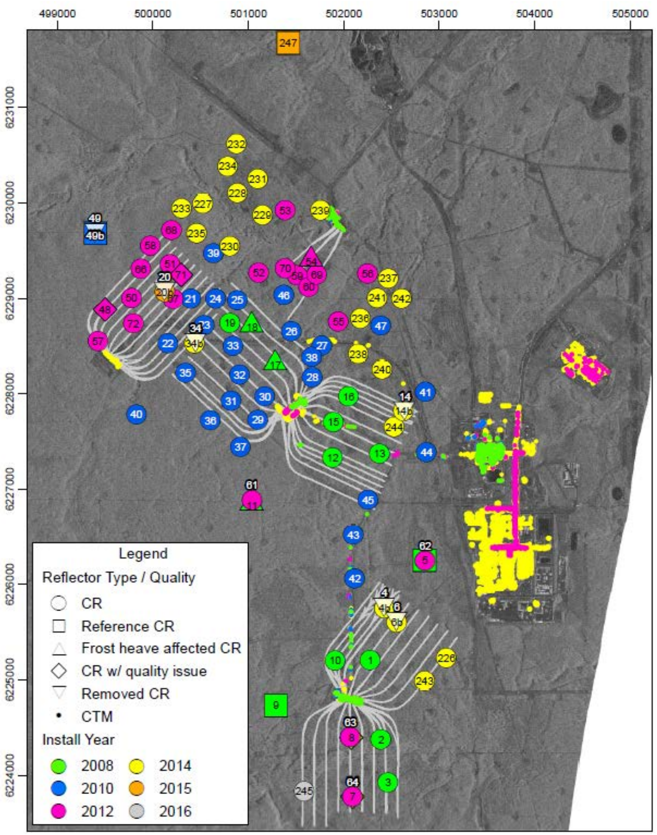
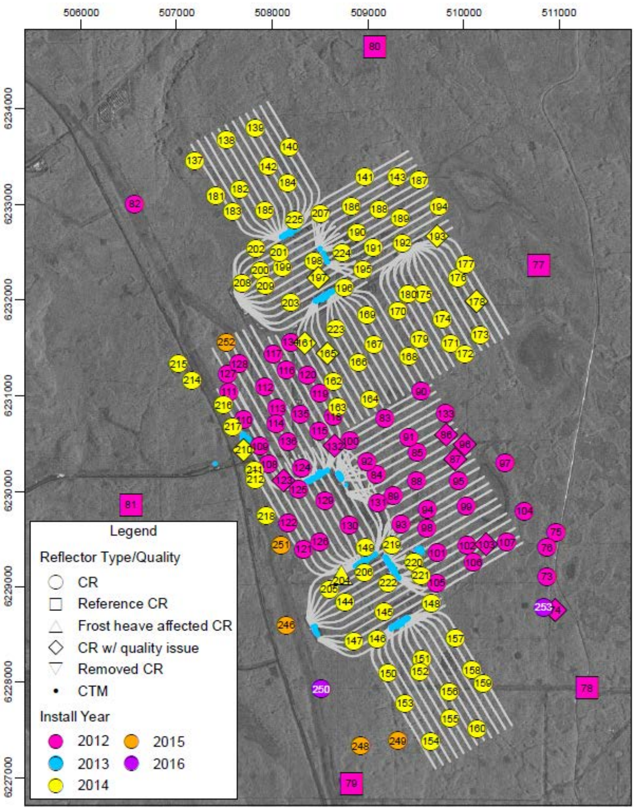
Surface Deformation Monitoring

- Satellite (RADARSAT-2) measurements every 24 days
- Interferometric Synthetic Aperture Radar (InSAR):
  - Corner Reflectors (CR) installed over pads and in areas to measure background deformations
  - 256 CR's installed since monitoring program began in 2008

Phase 1 Monitoring Locations

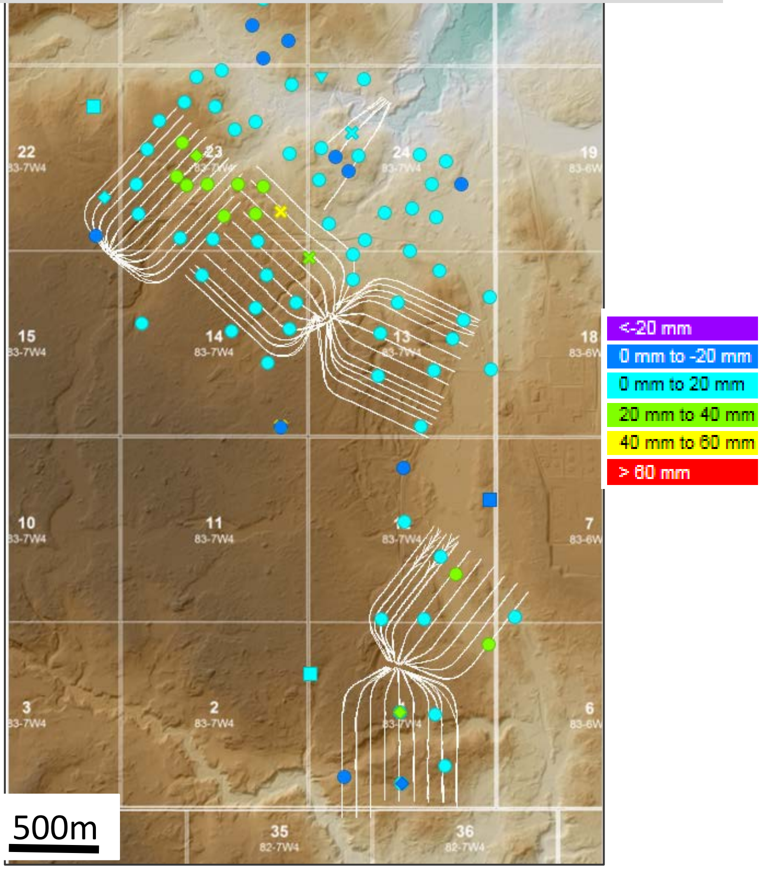


Phase 2 Monitoring Locations

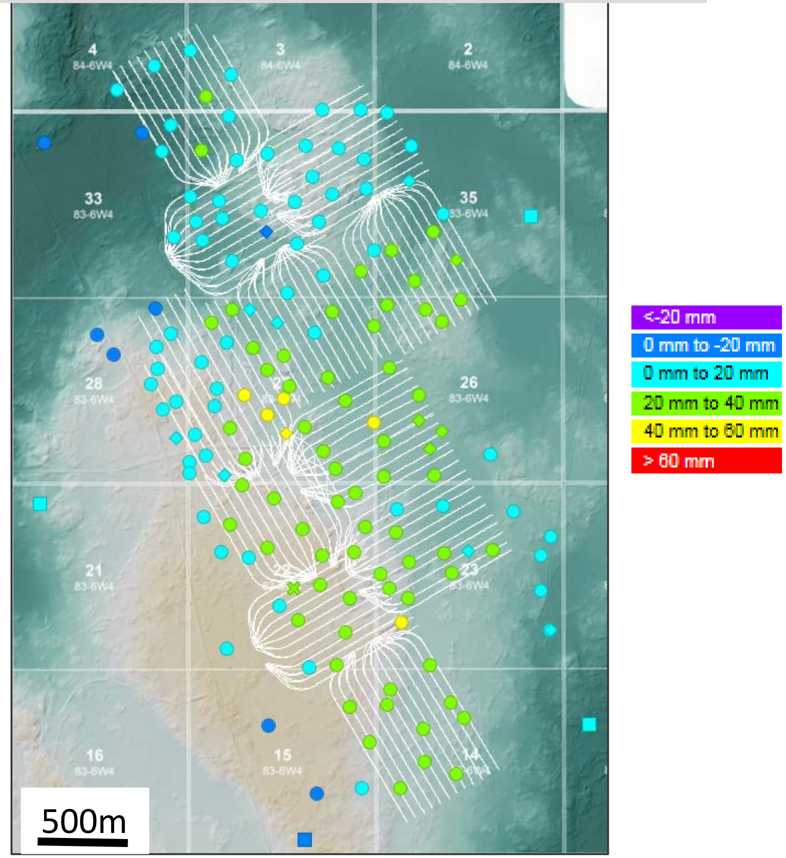


InSAR Surface Deformation Monitoring

Vertical Deformation *Dec 30 2015 to Mar 1 2017* (Surmont 1)



Vertical Deformation *Dec 30 2015 to Mar 1 2017* (Surmont 2)



- Deformation currently in line with expectations

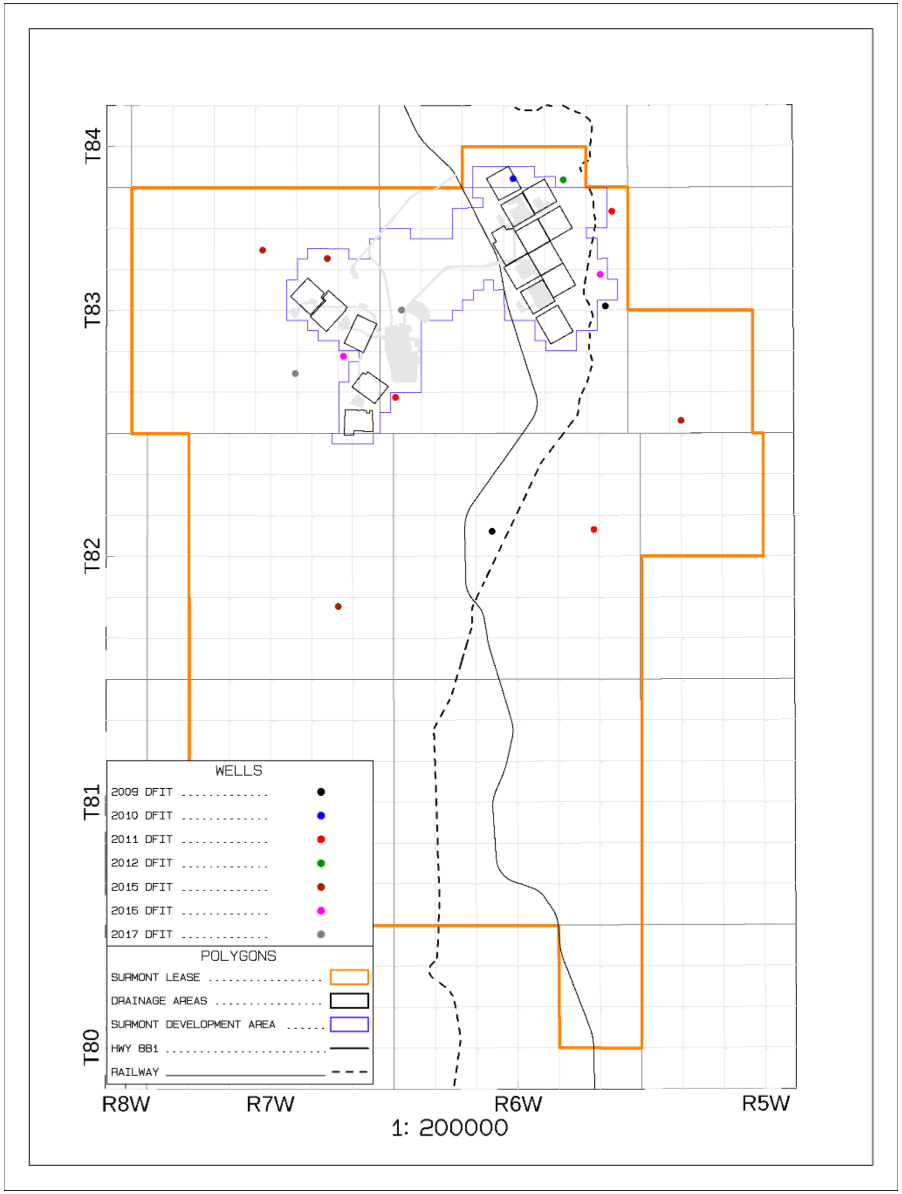
○ Corner Reflector
□ Reference Corner Reflector
◇ Corner Reflector w/quality issue
Corner Reflector w/Frost Jacking

Caprock Integrity

- Caprock Core Analysis:
  - 14 caprock cores were drilled and analyzed in 2015-2017.
  - Four rock mechanics testing programs were conducted in 2015-2017.
- Diagnostic Fracture Injectivity Tests (DFITs):
  - 8 DFITs were carried out in 2015-2017
  - DFIT locations were selected based on structural and geomechanical analysis of the caprock.
- The completed analysis verified that
  - The best seals within the cap rock interval are the deeper water deposits occurring on maximum flooding surfaces.
  - The seal over the development area is continuous, consistent and laterally extensive.

Conclusions from the study:

- **Best Seal: Deeper water deposits**
- **Muds are more than 80% clay and are correlated throughout and beyond the Surmont lease.**
- **The mechanical properties of the caprock allow for providing a continuous seal over the steam chamber.**



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Maximum Operating Pressure

- ConocoPhillips Canada continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated Maximum Operating Pressure (MOP) on one side and economic achievable pressures on the other side.
- The DFITs are strategically placed to characterize stress changes due to structural changes while measuring the baseline stresses in the caprock.
- Wellbore image log and other open-hole logs were analyzed in detail for stress analysis and natural fractures characterization.
- The results suggest while the previously used value of 18.4 kPa/m is valid, the minimum horizontal stress is higher in several drainage areas.
- In 2016, ConocoPhillips received approval from the AER to increase the MOP in one of the drainage areas.
- ConocoPhillips Canada has submitted an application to temporarily increase MOP in one of the drainage areas at Phase 2.
- In the future, select drainage areas may be investigated for potential application of higher MOP.

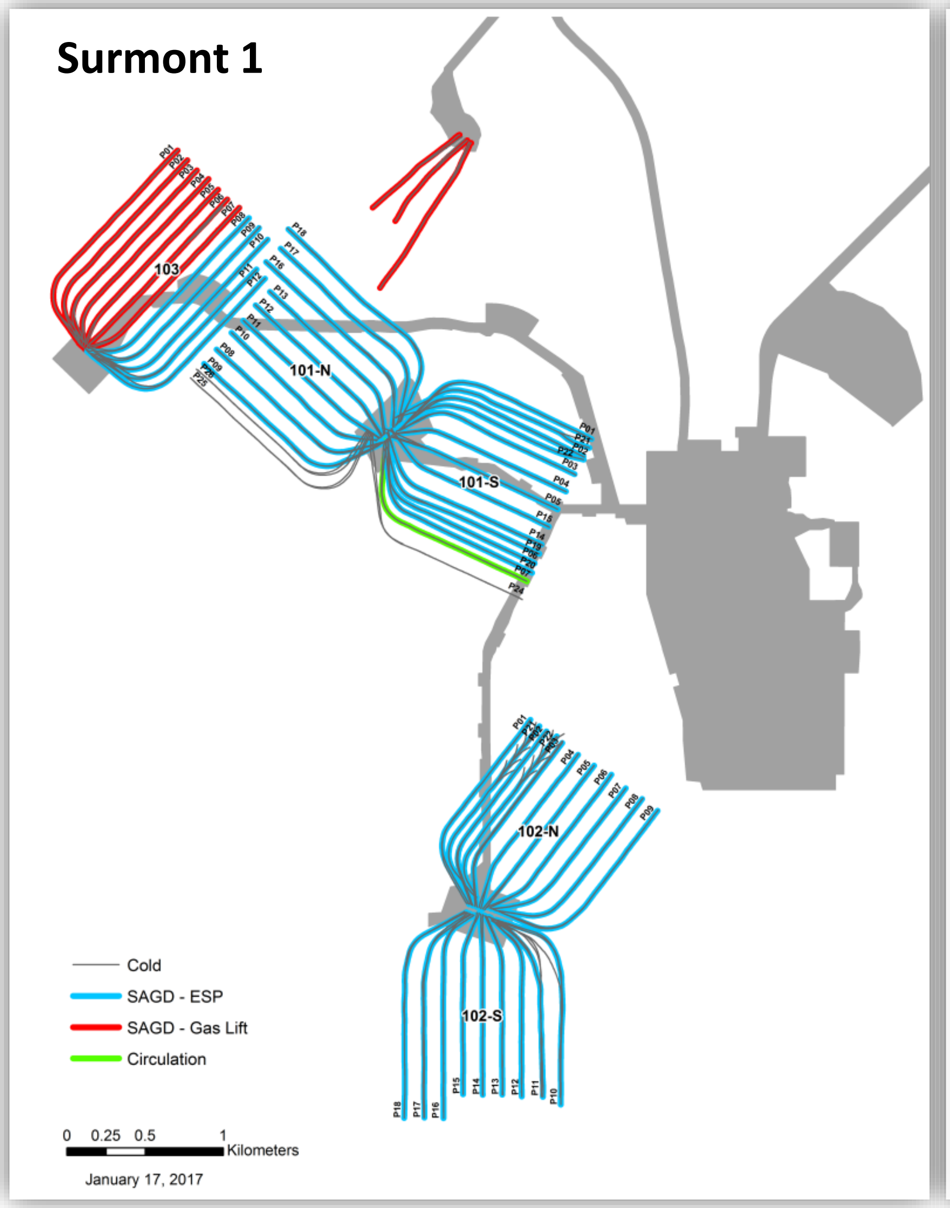
Conclusions from the study:

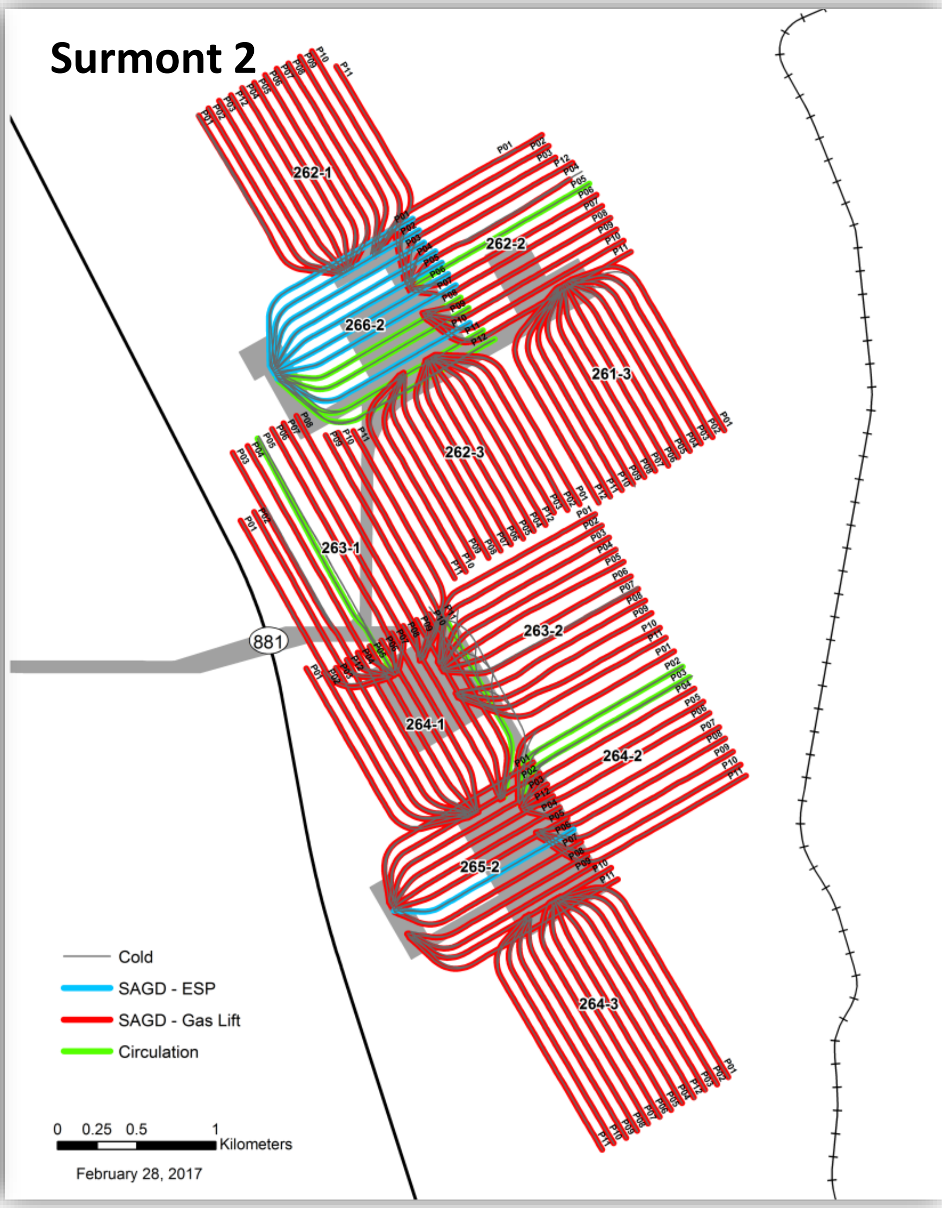
- **The results suggest that in many parts of Surmont the caprock minimum horizontal stress is above the used value of 18.4 kPa/m in the MOP calculation.**
- **While the recommended 15 kPa/m MOP gradient is verified and valid, higher MOP gradient will be requested for select drainage areas.**

Drilling and Completions

Subsection 3.1.1 (3)

One Surmont Well Summary





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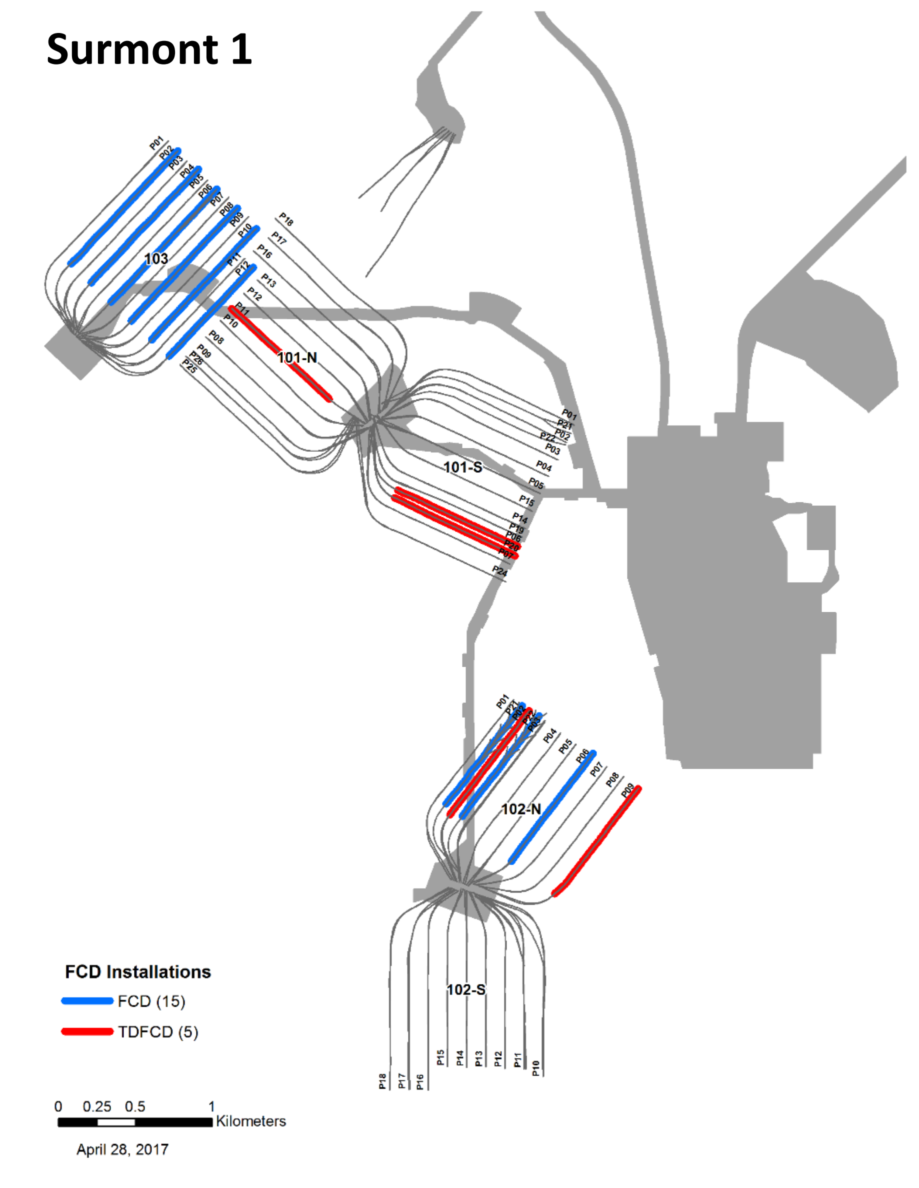
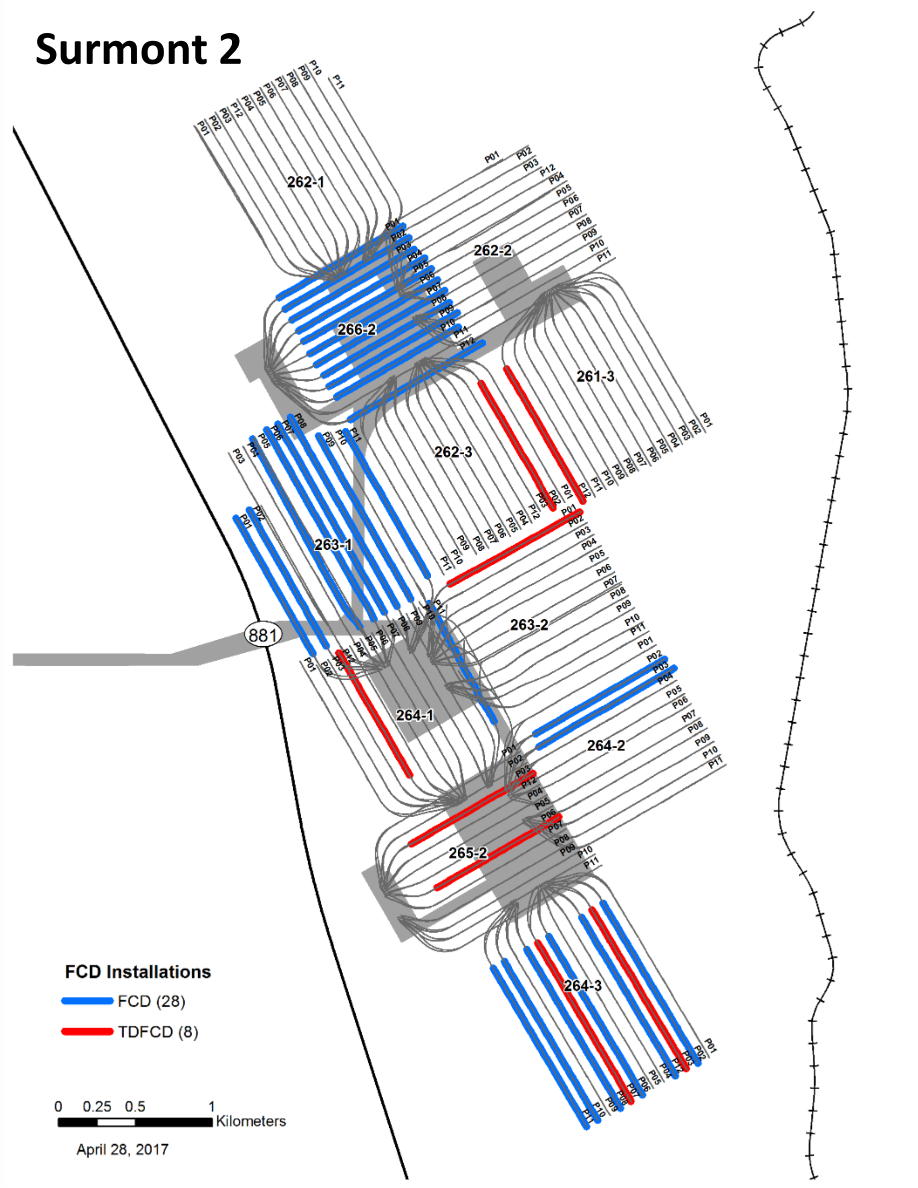
FCD Installations



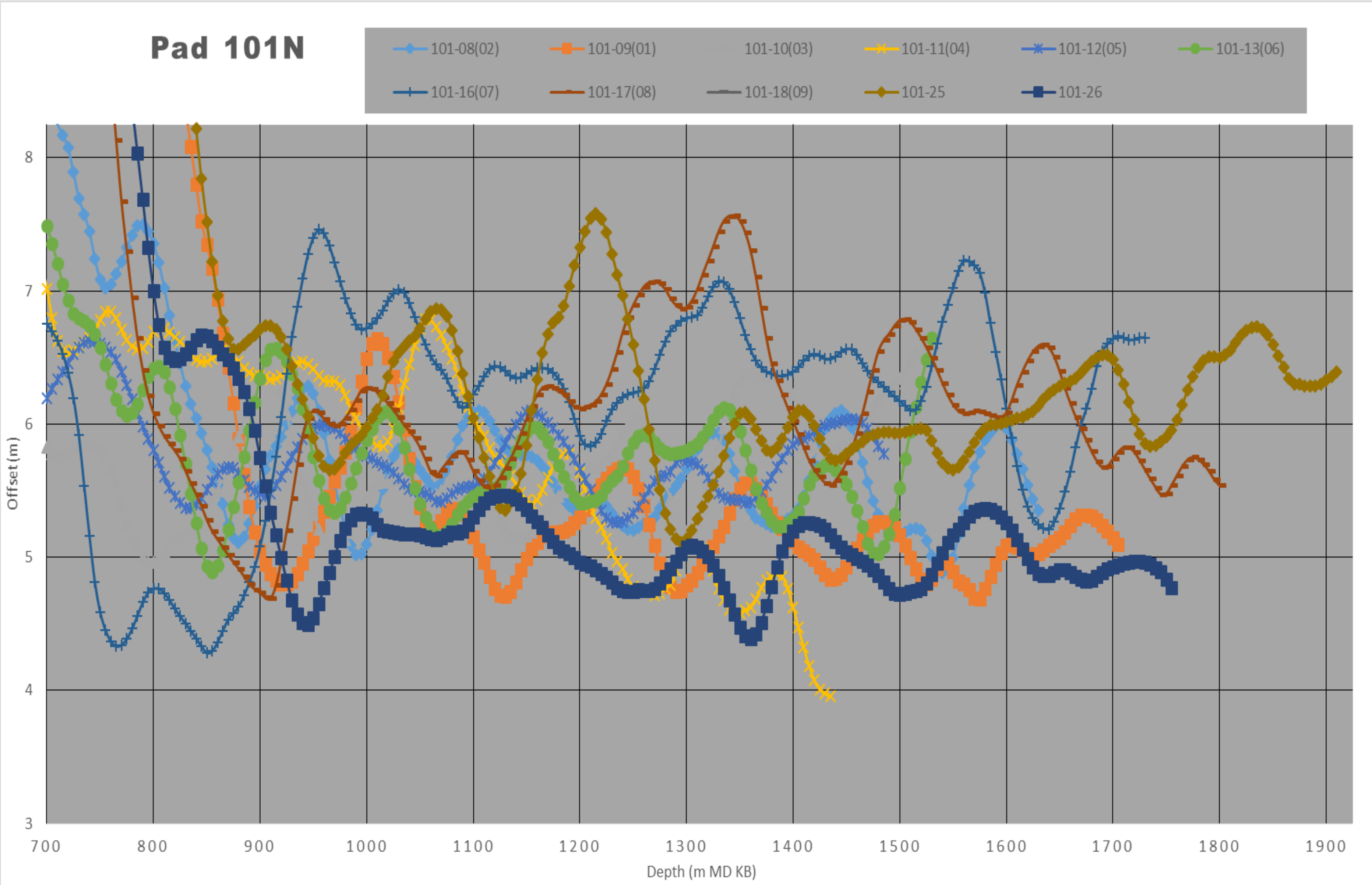


2016 Re-Drills

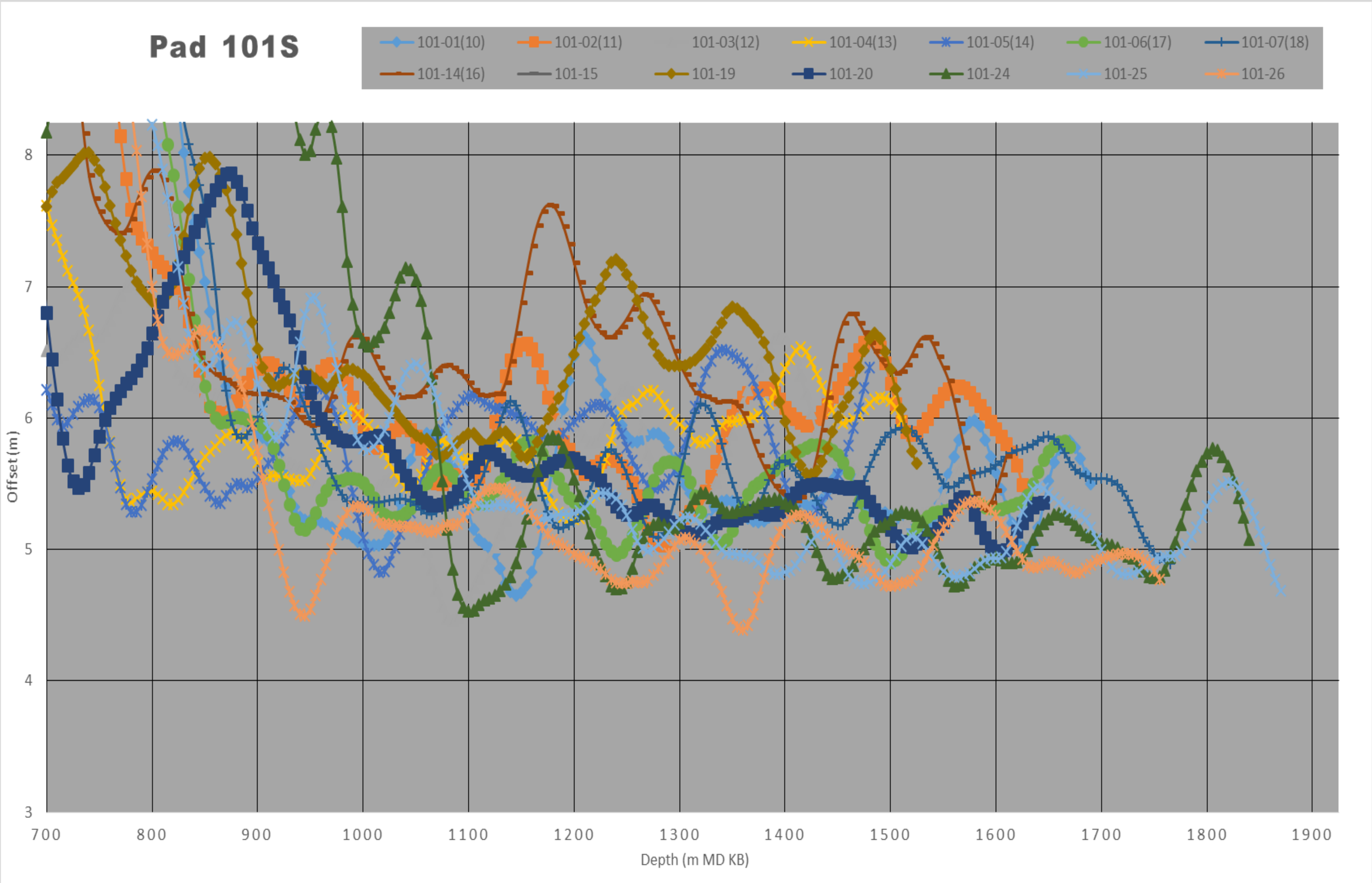
- In 2016 we had a total of 5 re-drills.

	264-2 P02	264-2 P03	266-2 P12	263-1 I05	263-1 P05
Redrill Type	Whipstock	Whipstock	Whipstock	Whipstock	Whipstock
Reason for Redrill	Producer liner failure during circulation phase. Production tubing was unable to be recovered due to sand.	Producer liner failure during circulation phase. Production tubing was unable to be recovered due to sand.	Intermediate casing was found to be damaged in McMurray formation after initial drilling operation. Attempts to remedy the sand control issue was not successful.	Liner failure during circulation phase discovered at time of P05 Redrill. Production tubing was unable to be recovered due to sand.	Liner failure during circulation phase. Production tubing was unable to be recovered due to sand as well as casing damage in McMurray
Whipstock Depth (mKB)	481	423	734	408	364
Whipstock Depth (mTVD)	339	334	322	328	317
Liner Length (m)	1156	1224	1096	1557	1629
FCD interval Length (m)	952	1035	1002	1369	1402
Completion	7" heel, 4" toe with 5/8" TC string on outside of toe string	Not yet completed.	7" heel, 4" toe with 1.25" Fiber string ran inside toe string	7" heel, 4" toe with no TC's installed	7" heel, 4" toe with 5/8" TC string on outside of toe string
Comments	Successfully drilled, completed and put on steam circulation Dec 2016	Successfully drilled. Completion encountered difficulty with sand incursion. Currently investigating.	Successfully drilled, completed and put on steam circulation Dec 2016	Successfully drilled and completed. Awaiting P05 completion before starting on circulation Q1 2017	Successfully drilled. Completion operation to be executed shortly.

Well Pad 101 North
Producer and Injector Vertical Offset



Well Pad 101 South
Producer and Injector Vertical Offset



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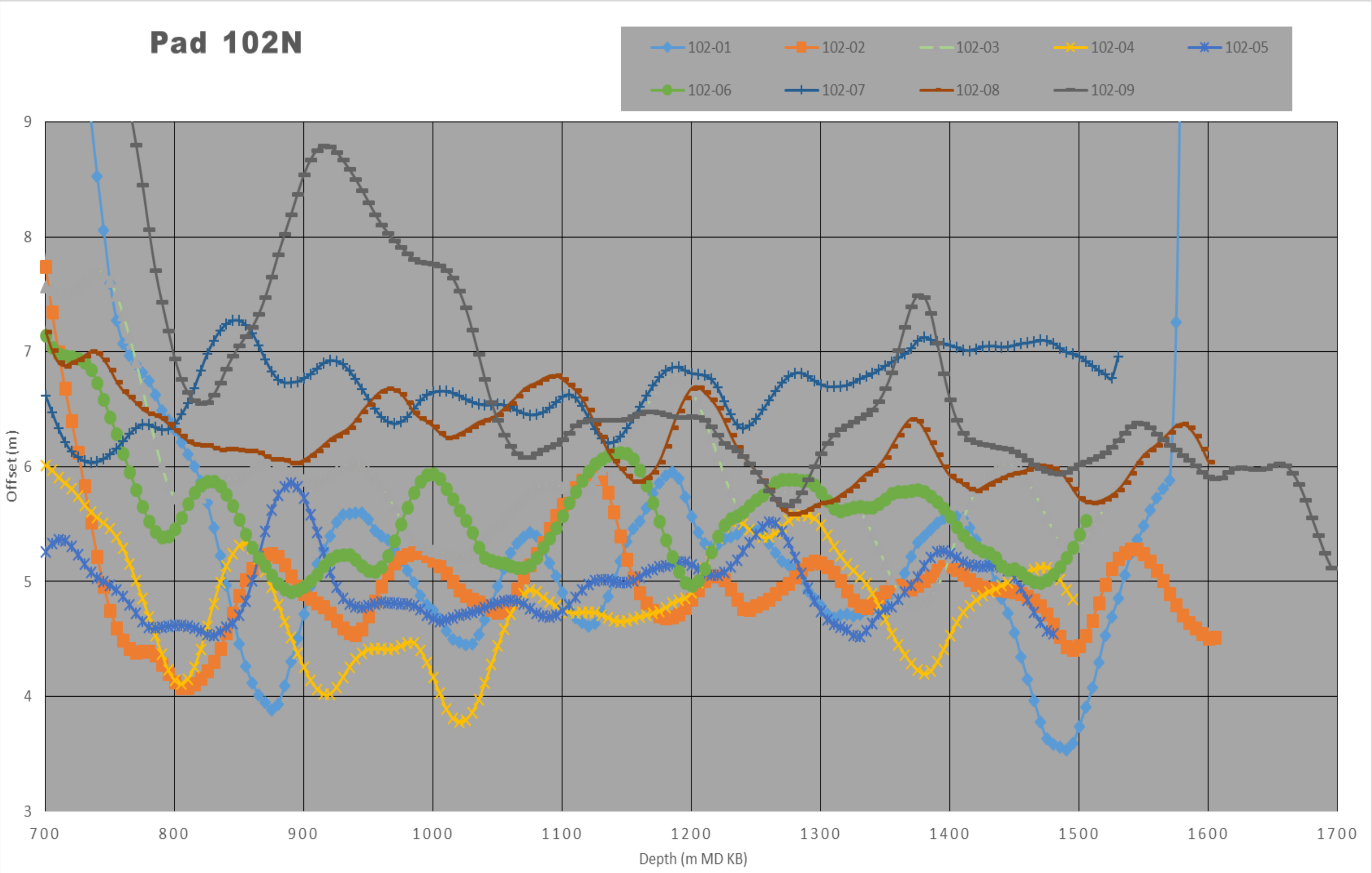
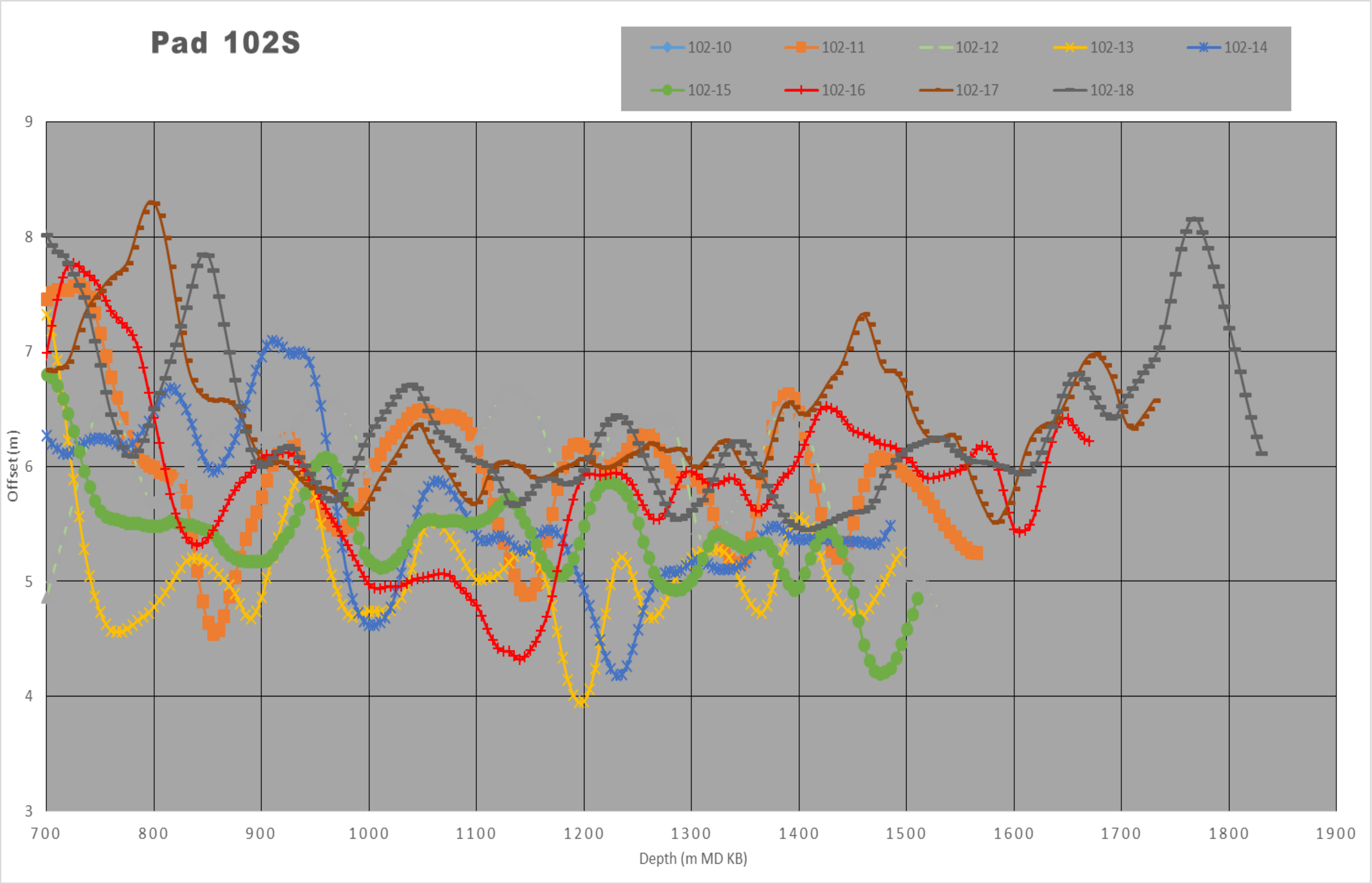
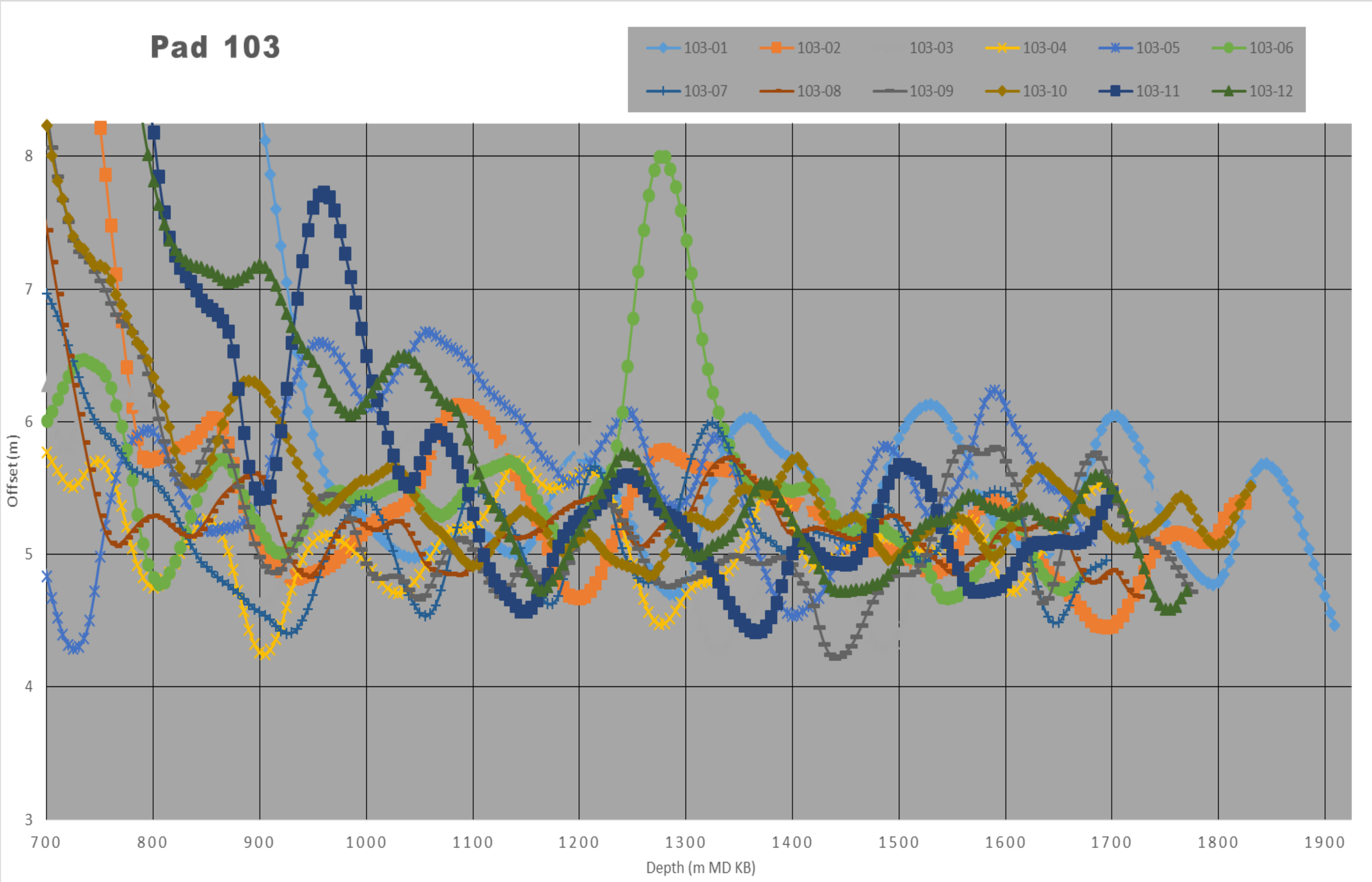
Well Pad 102 North
Producer and Injector Vertical Offset



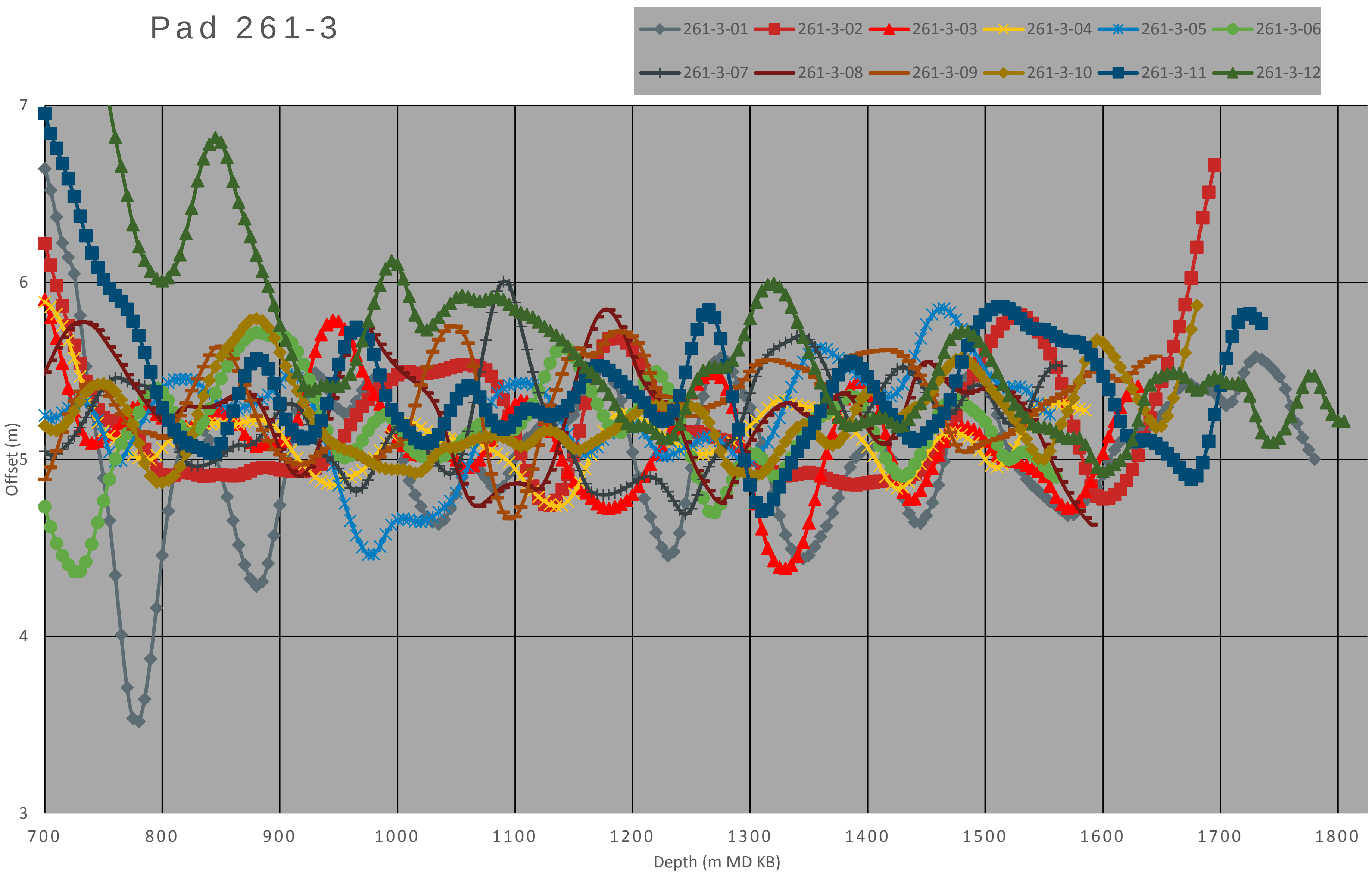
Well Pad 102 South
Producer and Injector Vertical Offset



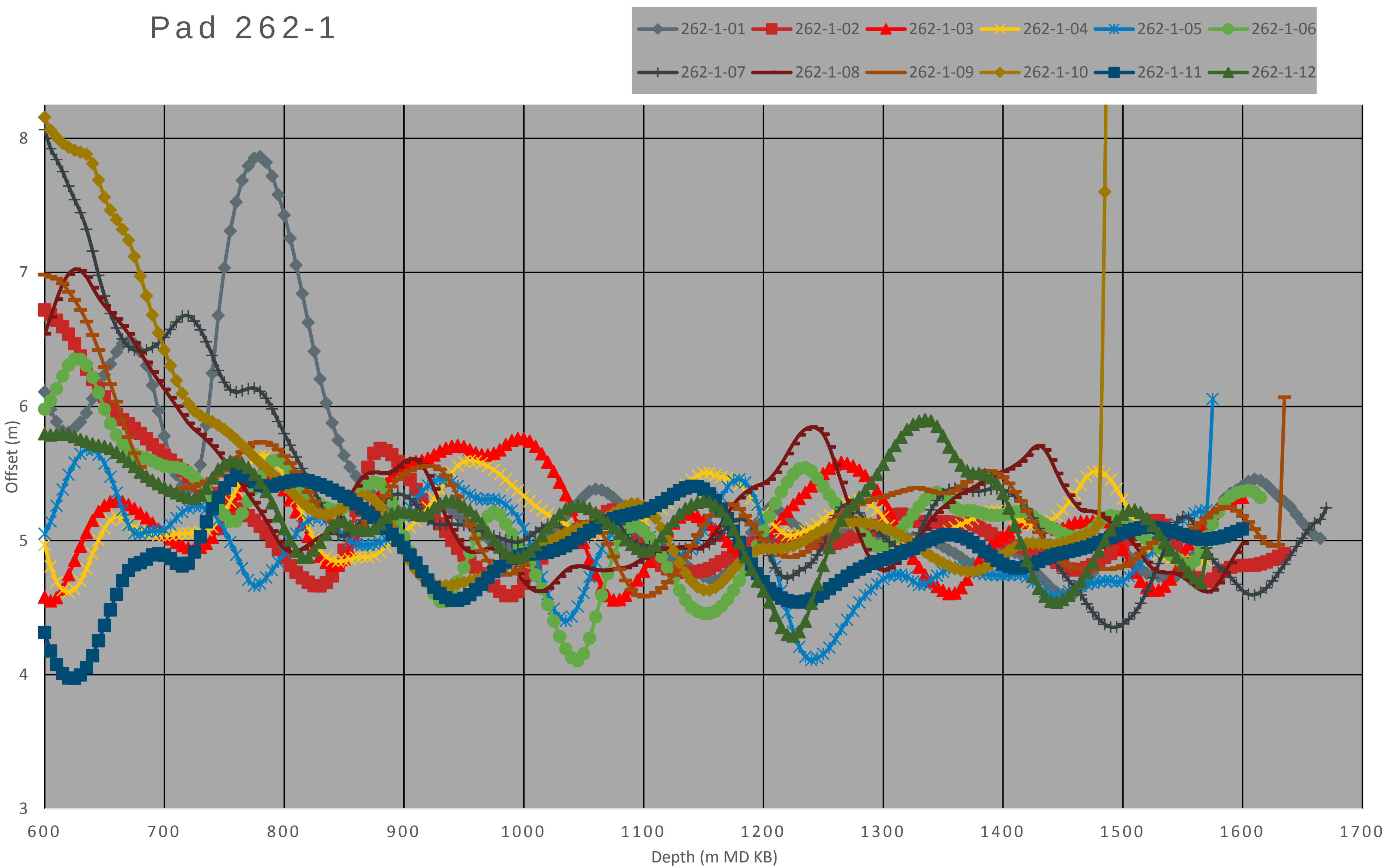
Well Pad 103
Producer and Injector Vertical Offset



Well Pad 261-3
Producer and Injector Vertical Offset

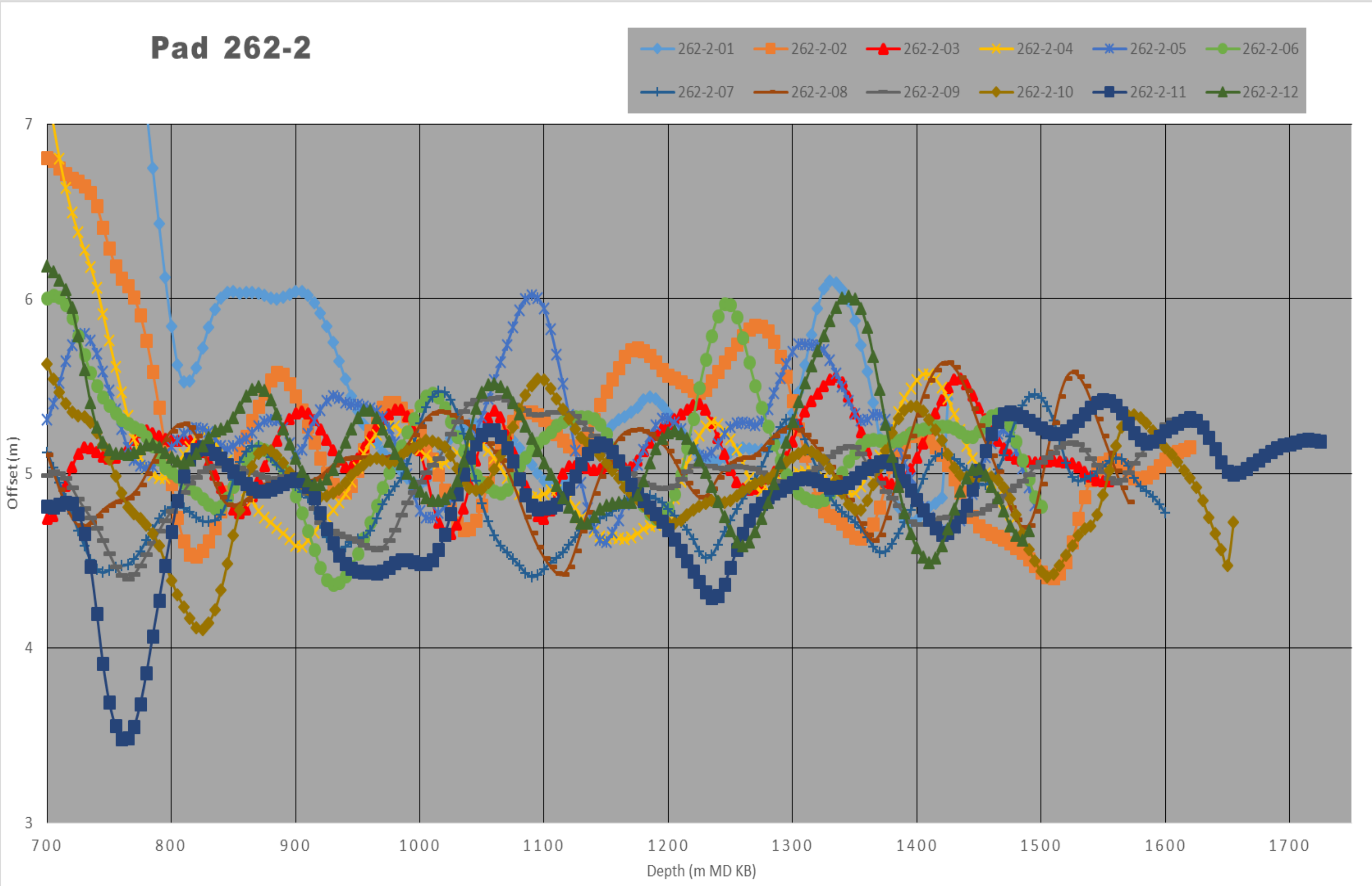


Well Pad 262-1
Producer and Injector Vertical Offset

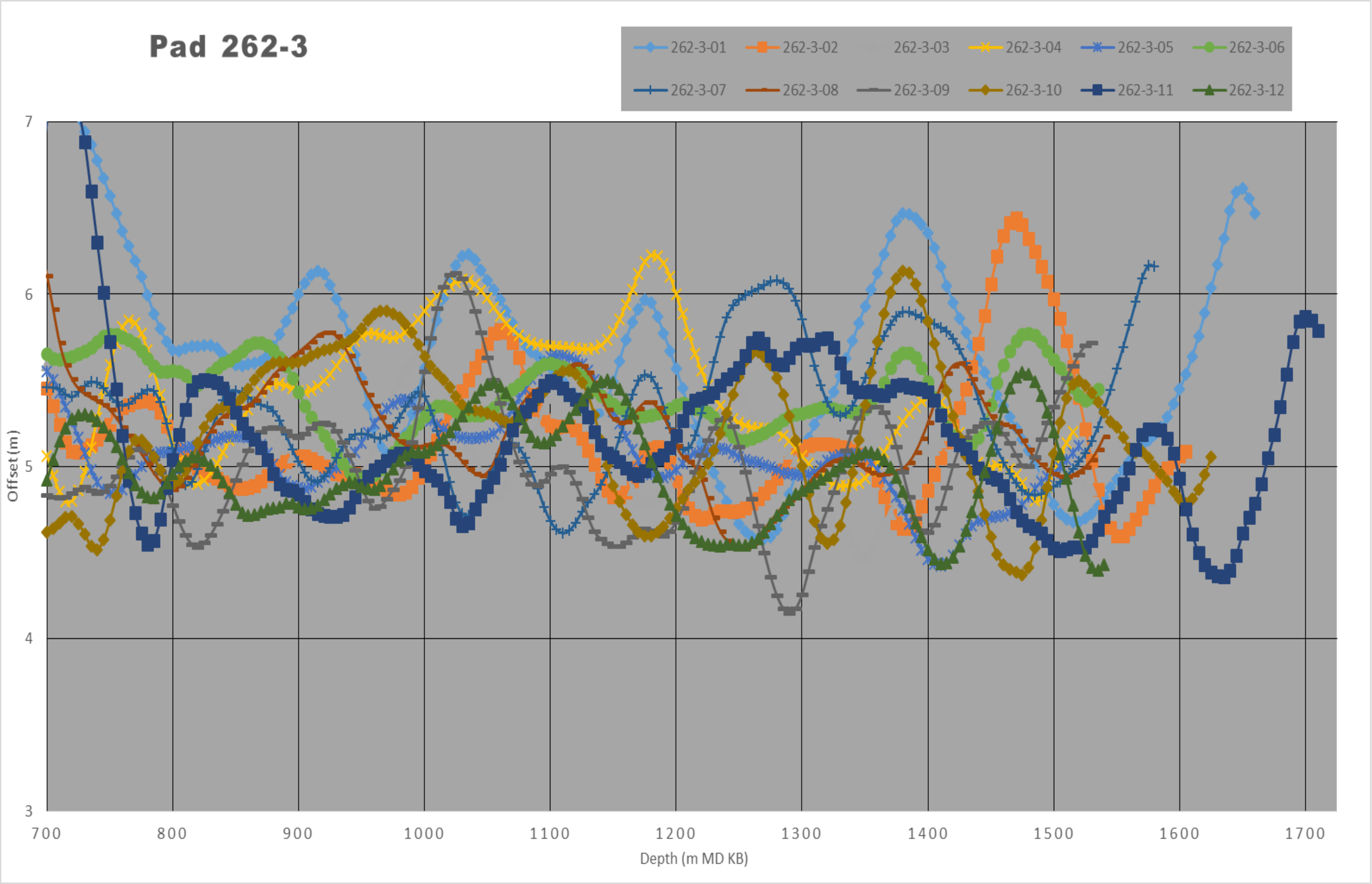


ConocoPhillips

Well Pad 262-2
Producer and Injector Vertical Offset



Well Pad 262-3
Producer and Injector Vertical Offset



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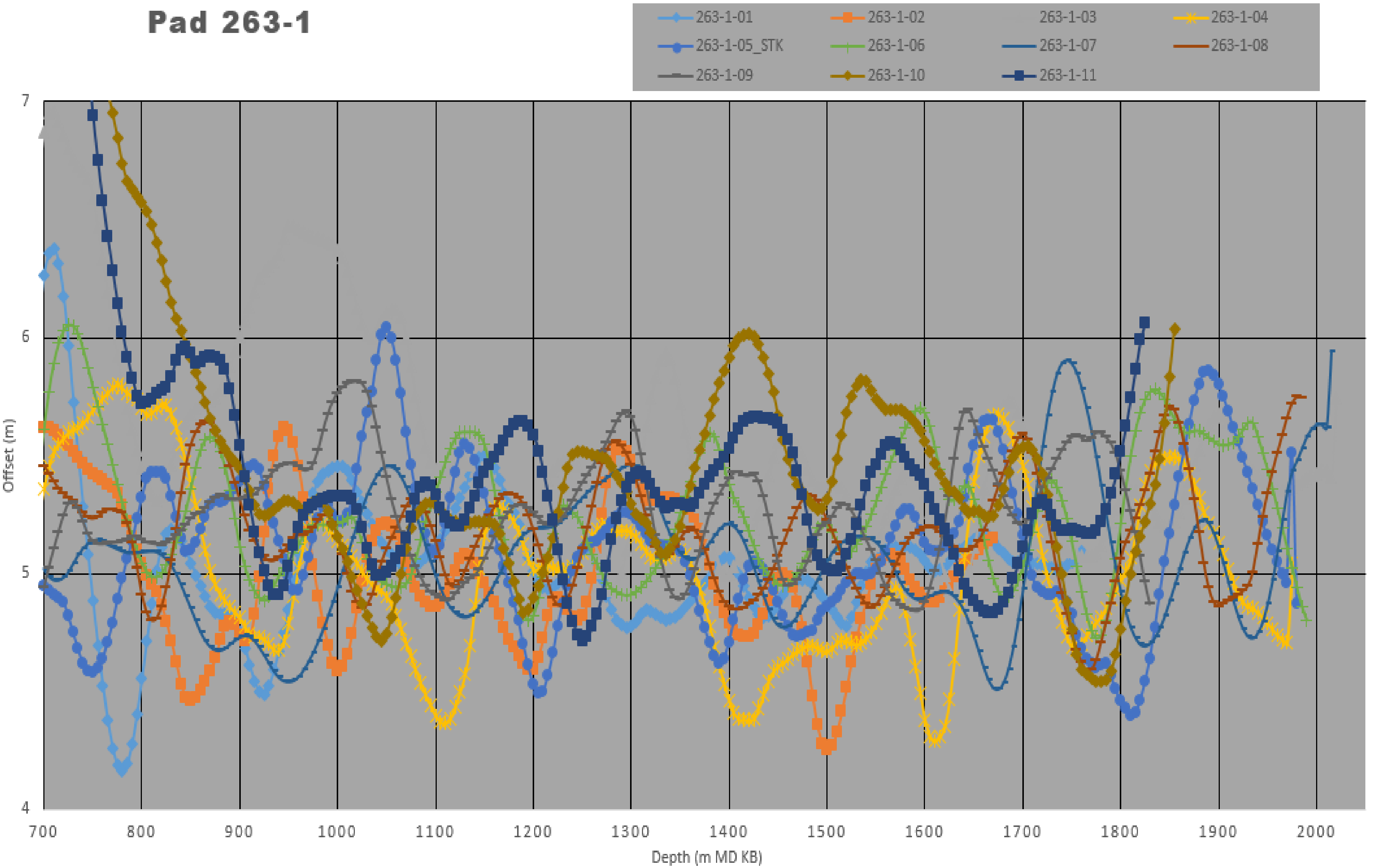
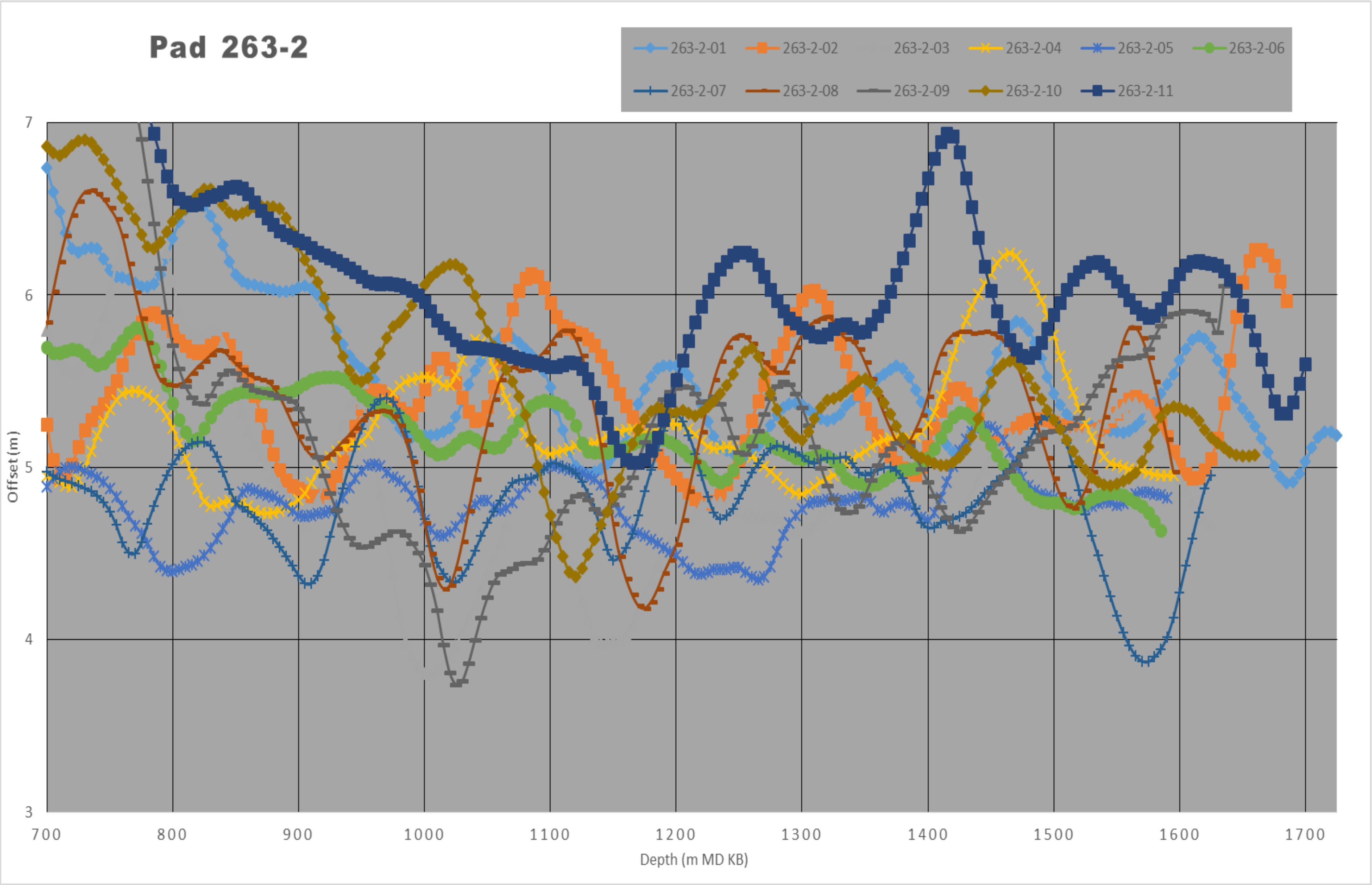
Well Pad 263-1
Producer and Injector Vertical Offset

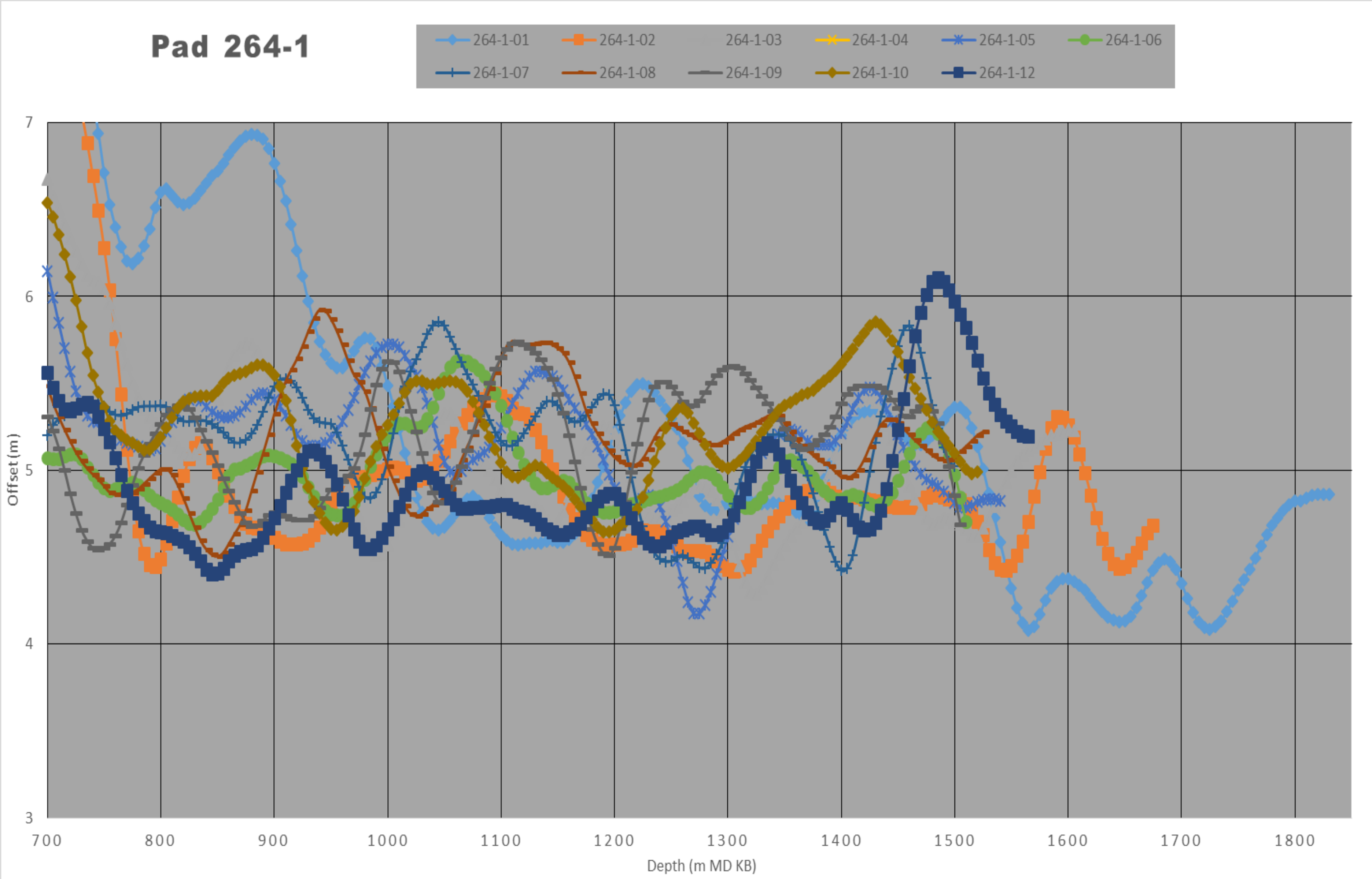


Well Pad 263-2
Producer and Injector Vertical Offset



ConocoPhillips

Well Pad 264-1
Producer and Injector Vertical Offset



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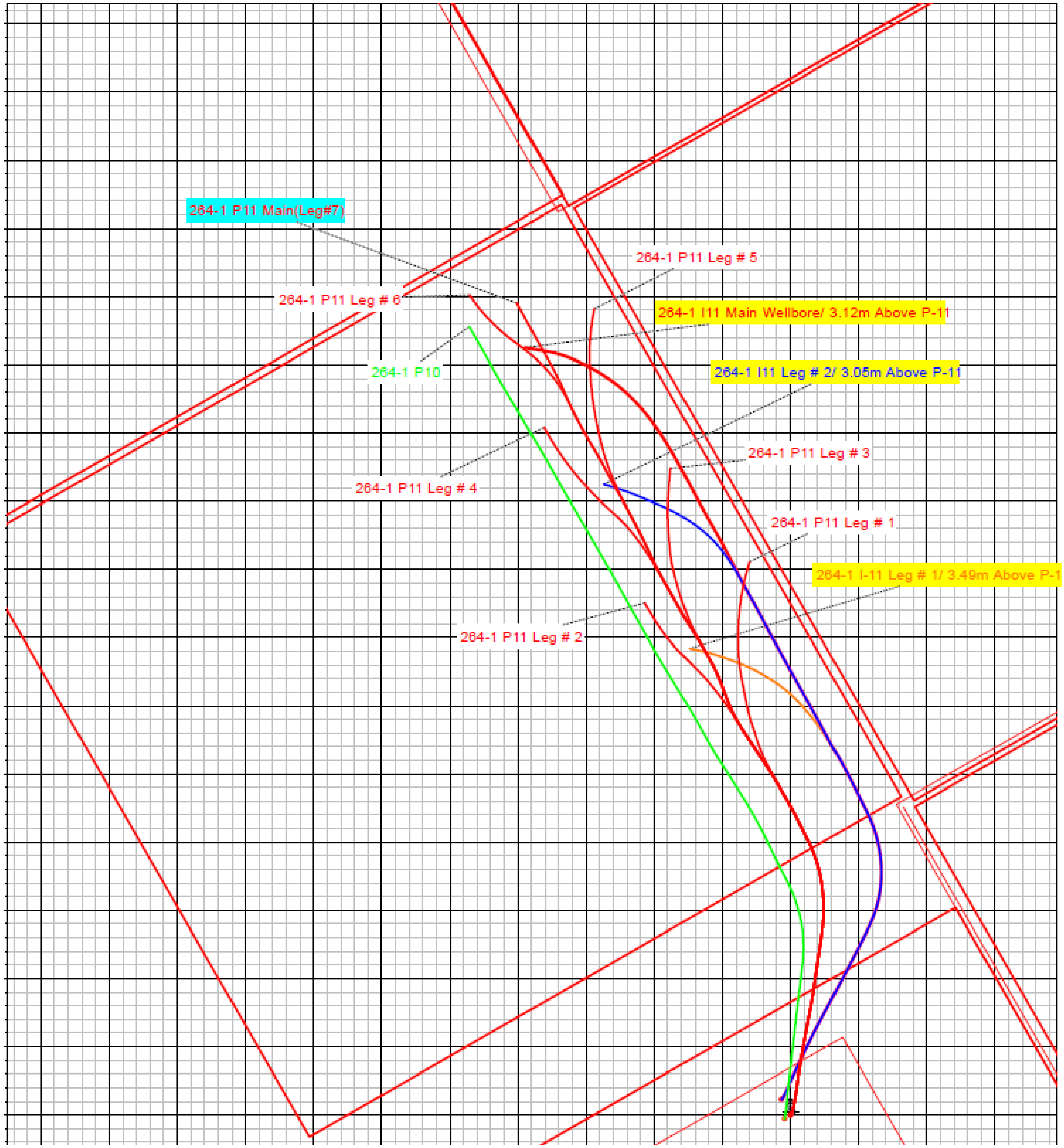
Well Pad 264-1-11 Fishbone
Producer and Injector Vertical Offset



Injector has 3 legs while producer has 7 legs. 3 vertical offsets.

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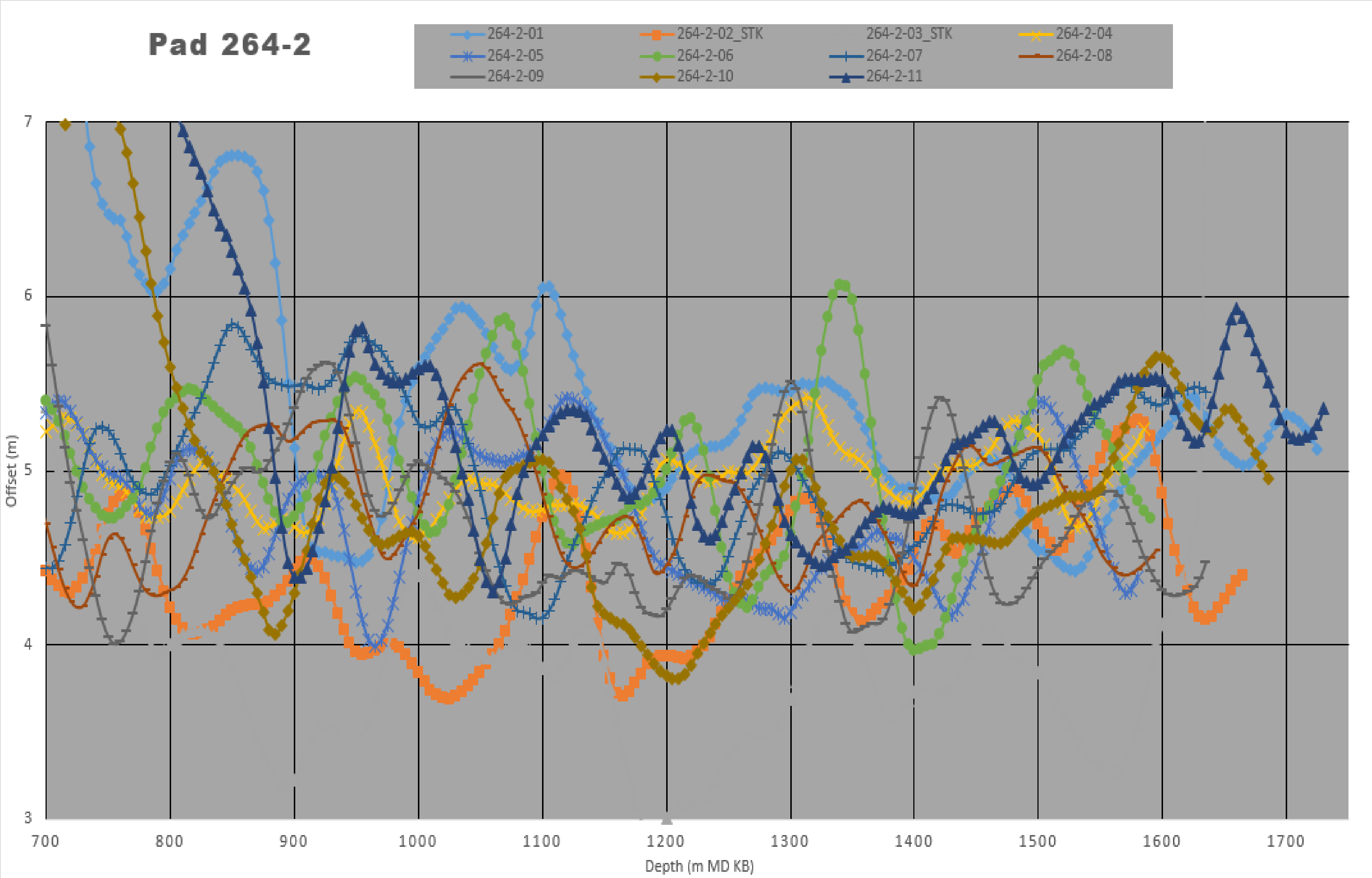
Well Pad 264-2
Producer and Injector Vertical Offset



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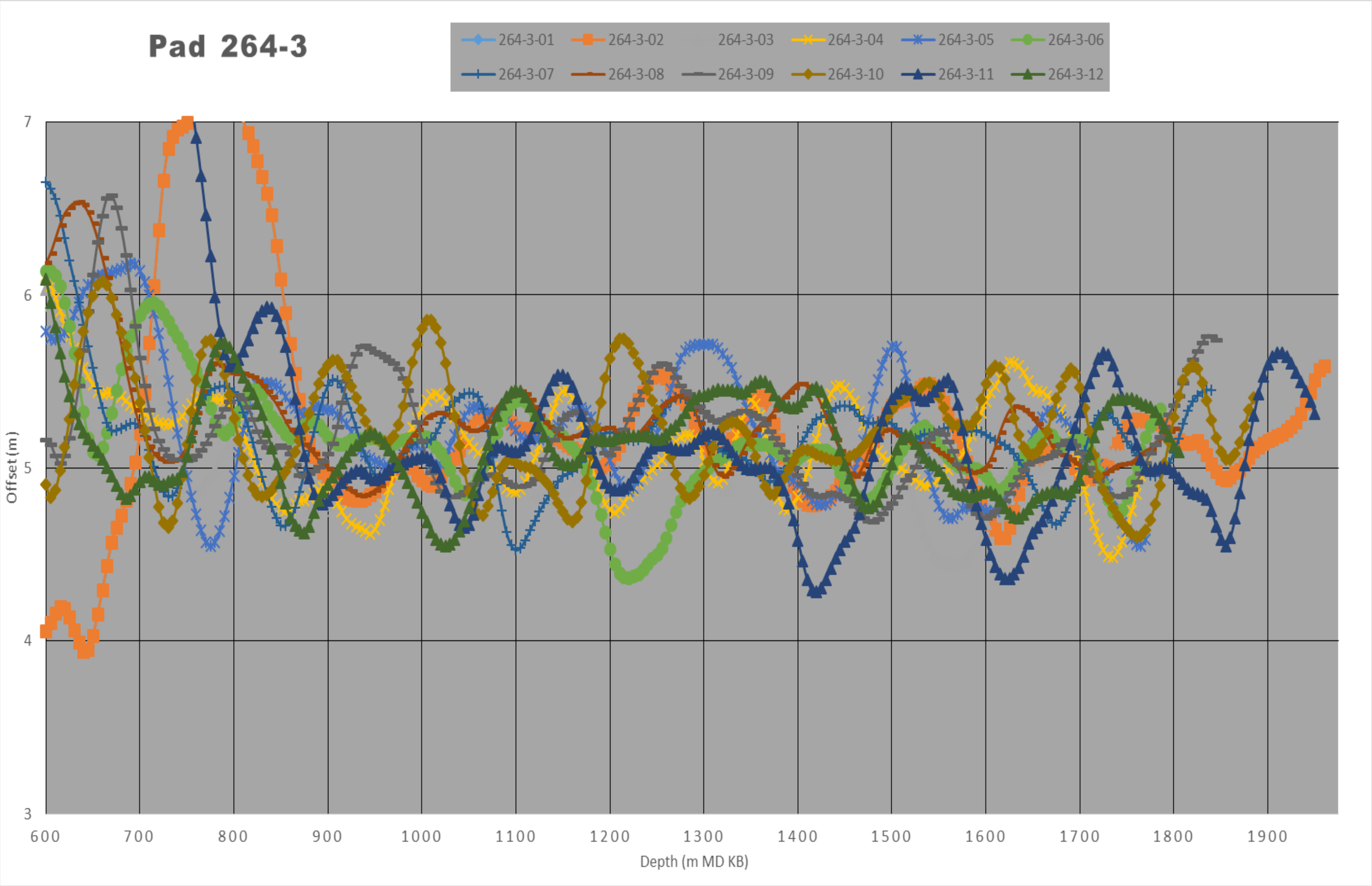
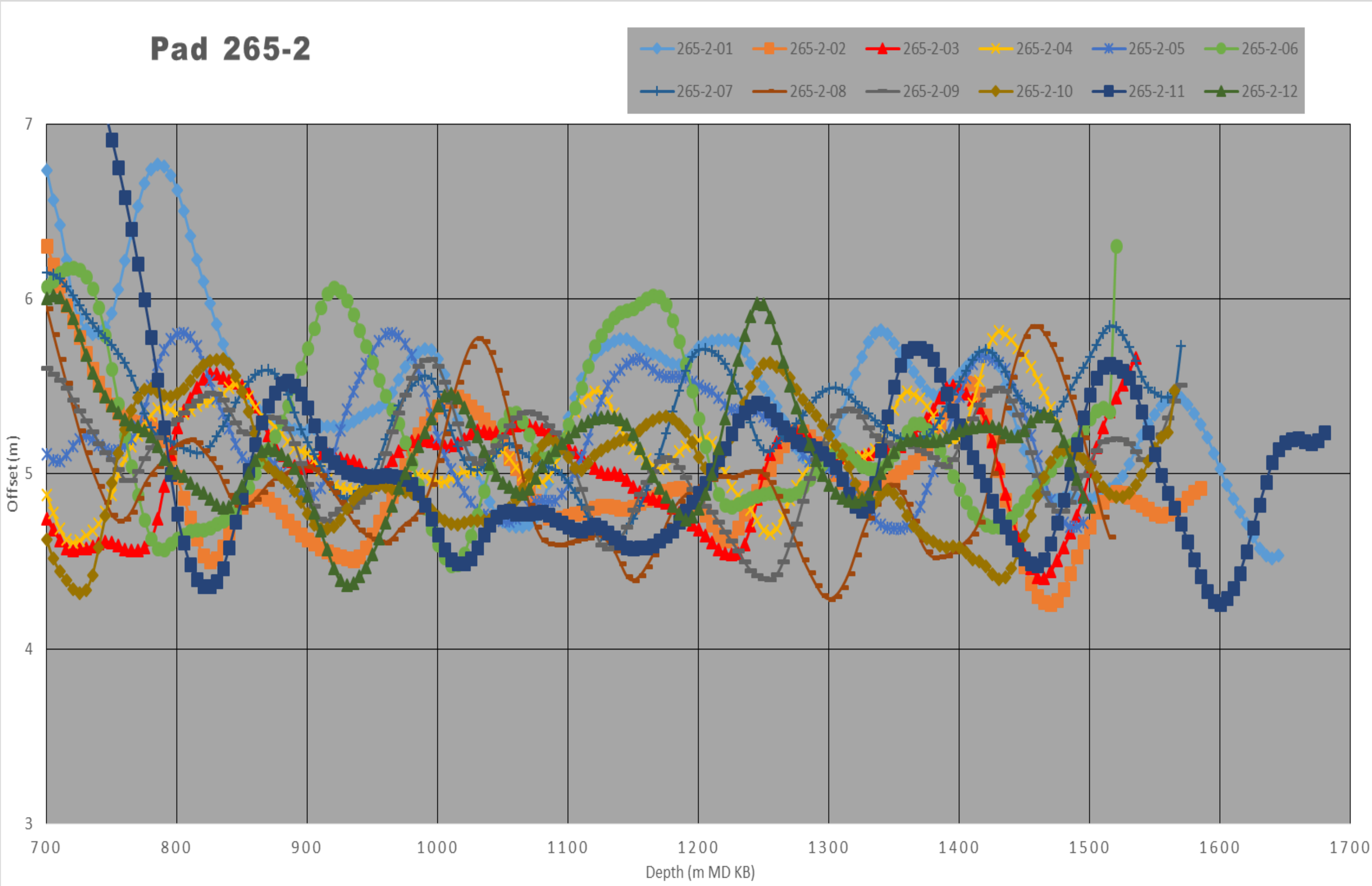
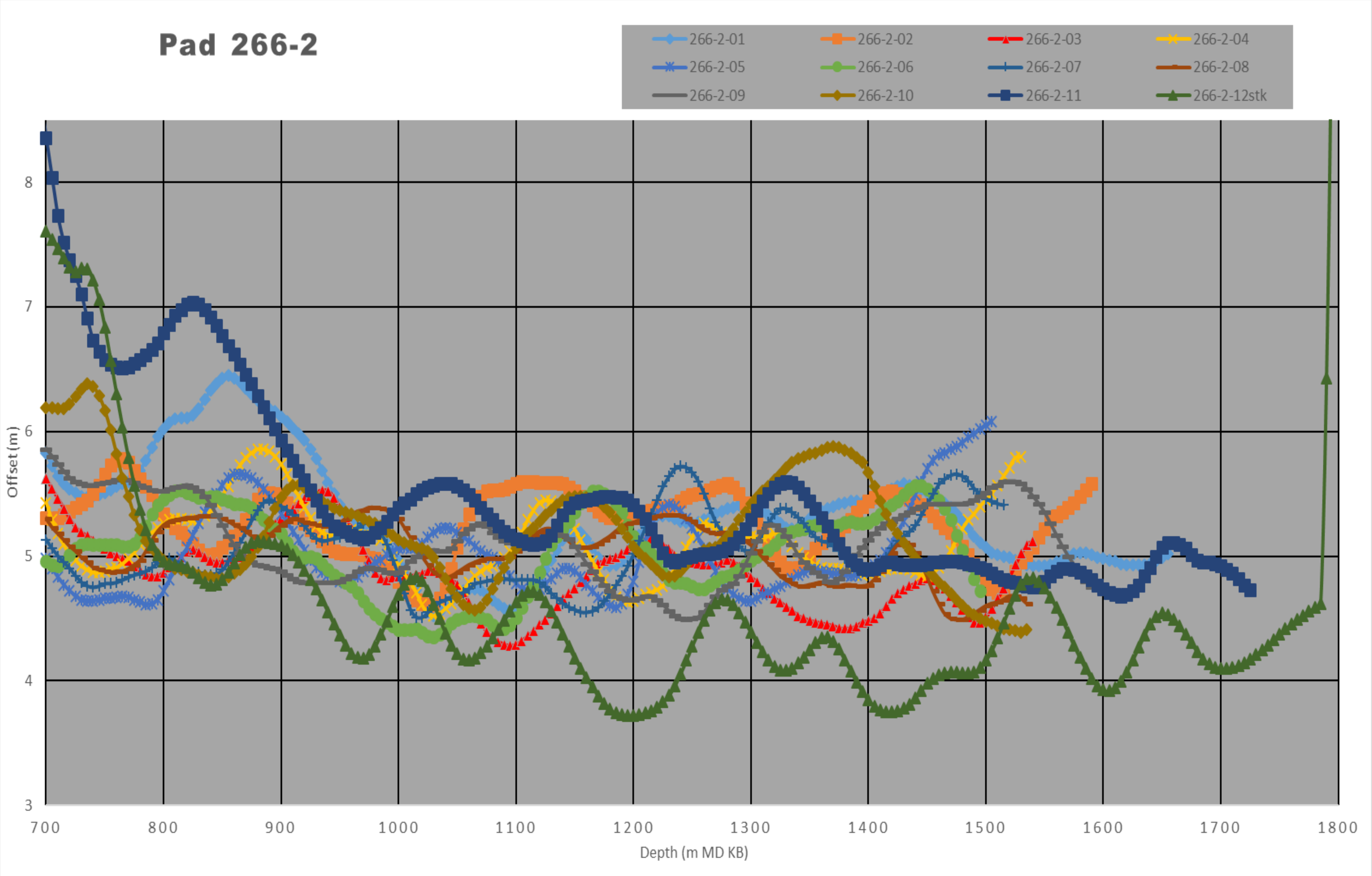
Producer and Injector Vertical Offset



Producer and Injector Vertical Offset

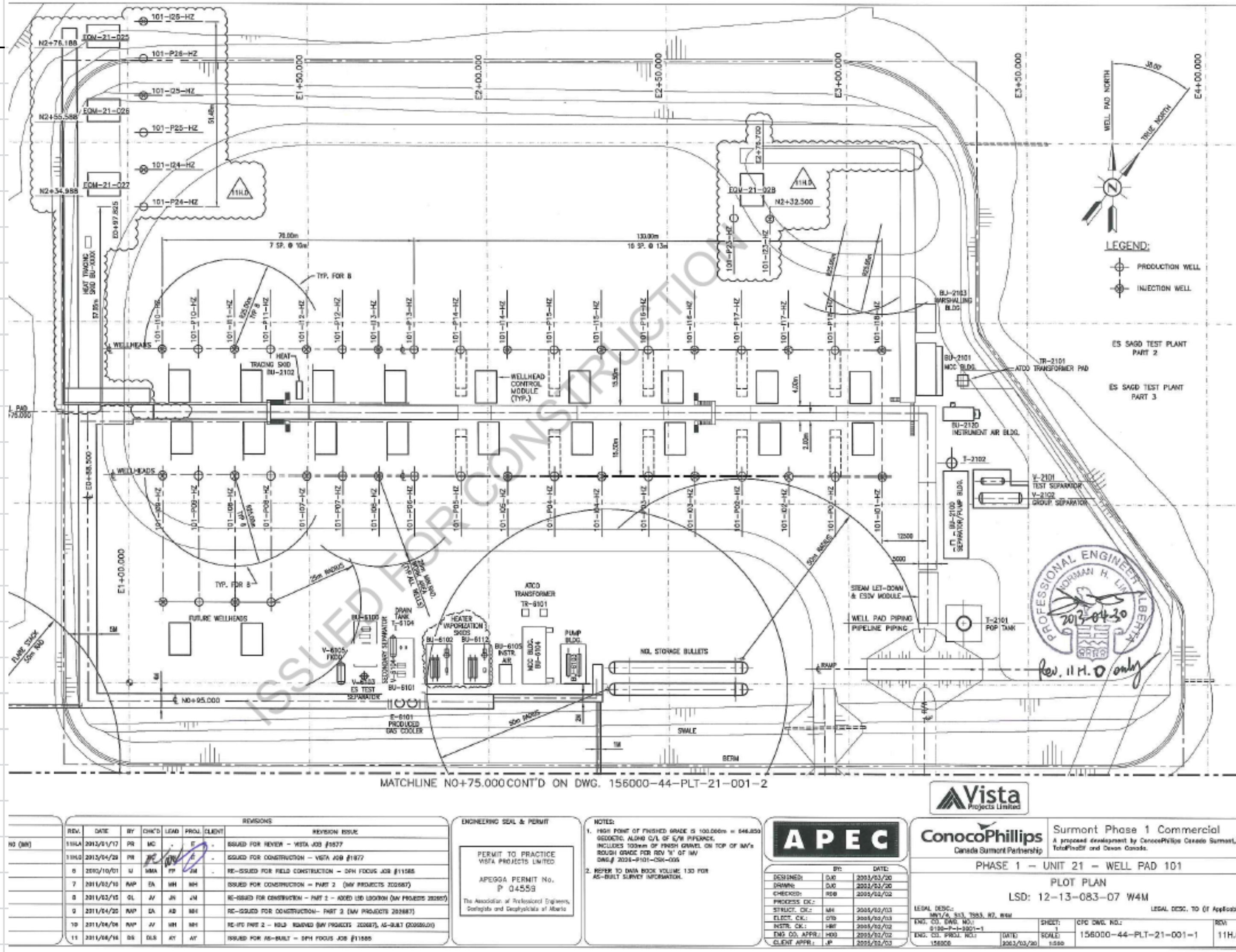


Well Pad 266-2
Producer and Injector Vertical Offset



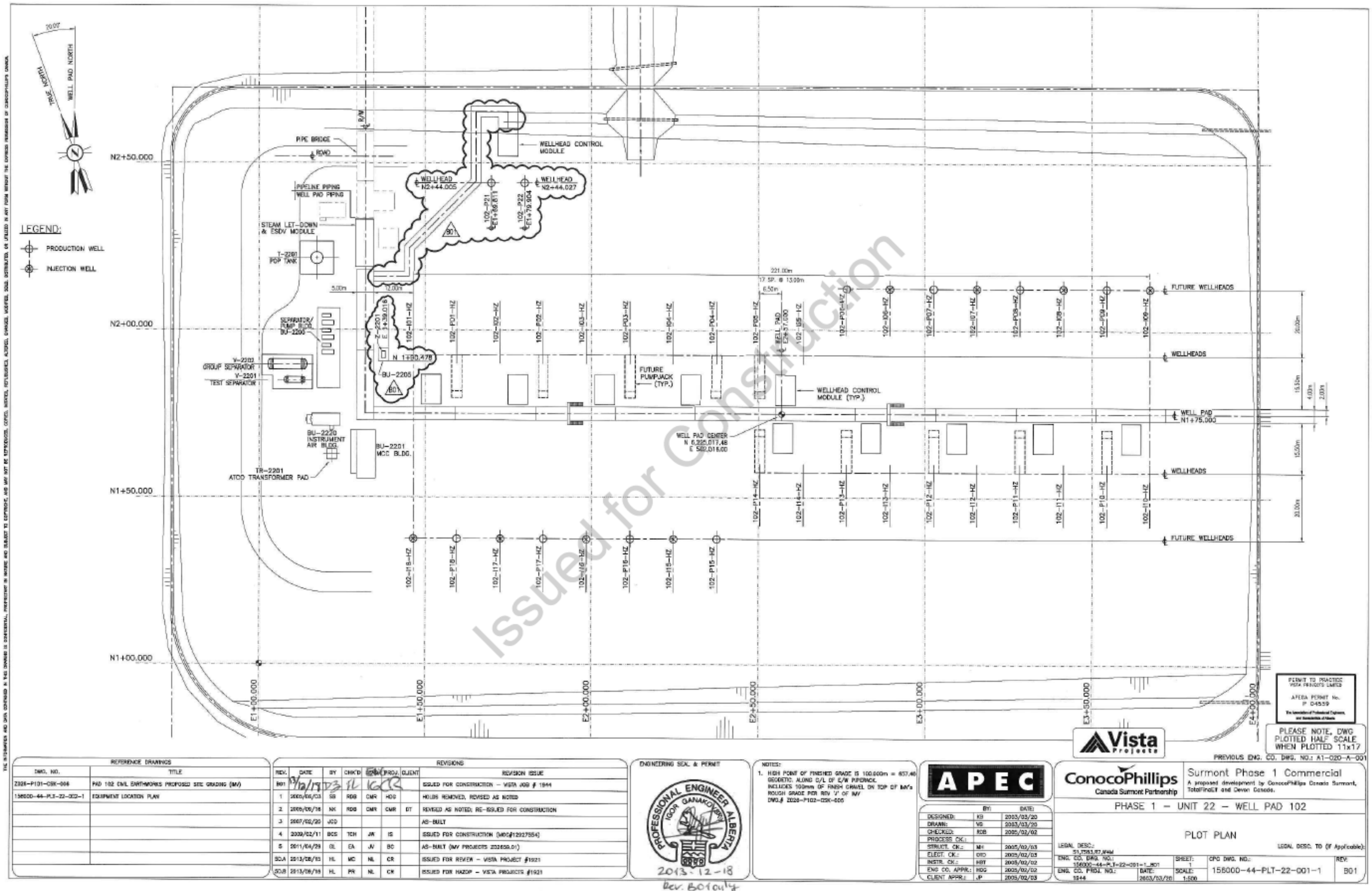
Pad 101 Plot Plan

Surface Well Name	Downhole Well Name
101-01	101-10
101-02	101-11
101-03	101-12
101-04	101-13
101-05	101-14
101-06	101-17
101-07	101-18
101-08	101-02
101-09	101-01
101-10	101-03
101-11	101-04
101-12	101-05
101-13	101-06
101-14	101-16
101-15	101-15
101-16	101-07
101-17	101-08
101-18	101-09
101-19	101S16INF1
101-20	101S17INF1
101-21	101S10INF1
101-22	101S11INF1
101-24	101-24
101-25	101-25
101-26	101-26

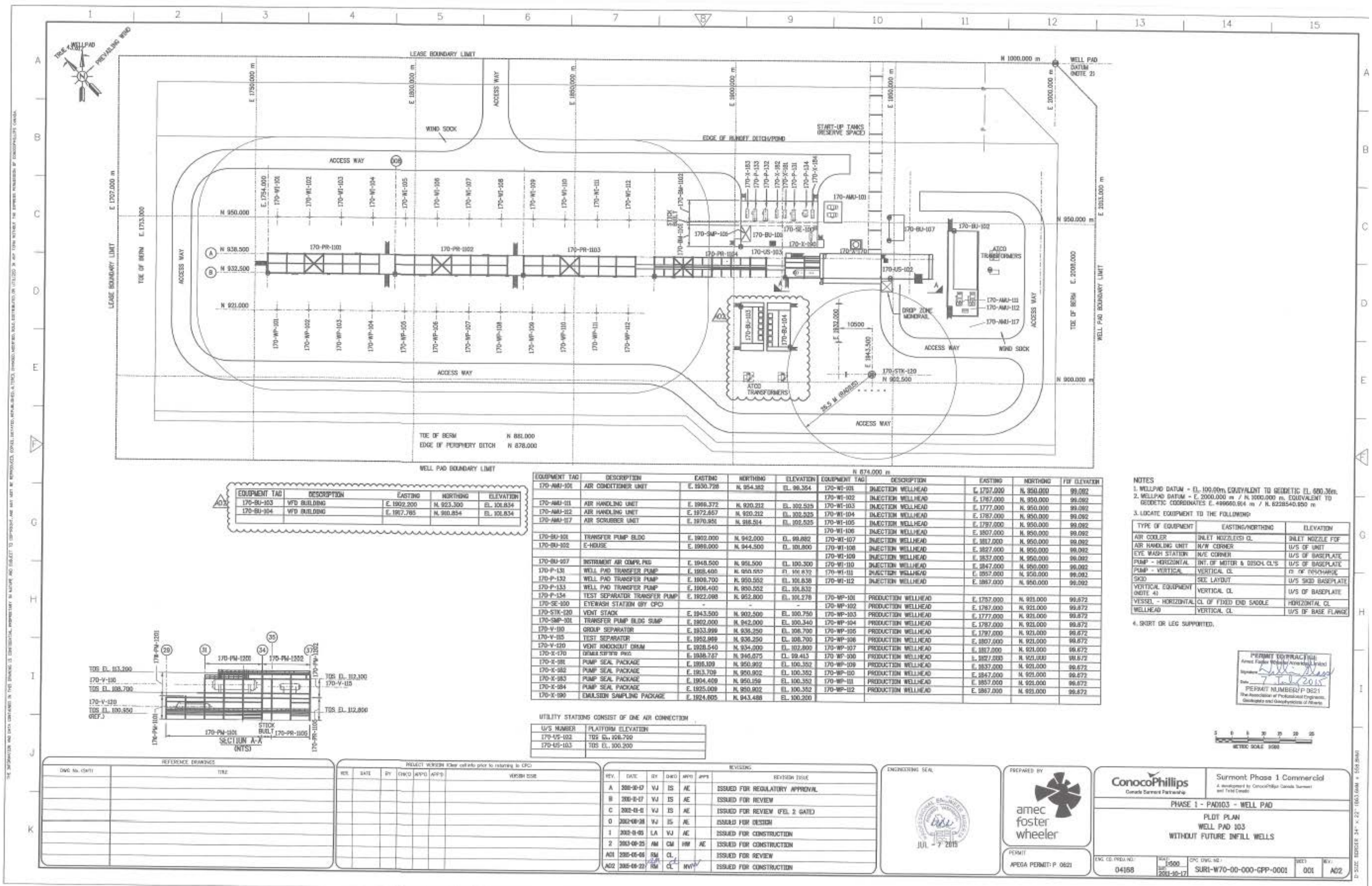


ConocoPhillips

Pad 102 Plot Plan



Pad 103 Plot Plan



EQUIPMENT TAG	DESCRIPTION	EASTING	NORTHING	ELEVATION
170-BU-103	VFD BUILDING	E. 1902.200	N. 923.300	EL. 101.834
170-BU-104	VFD BUILDING	E. 1907.785	N. 910.854	EL. 101.834

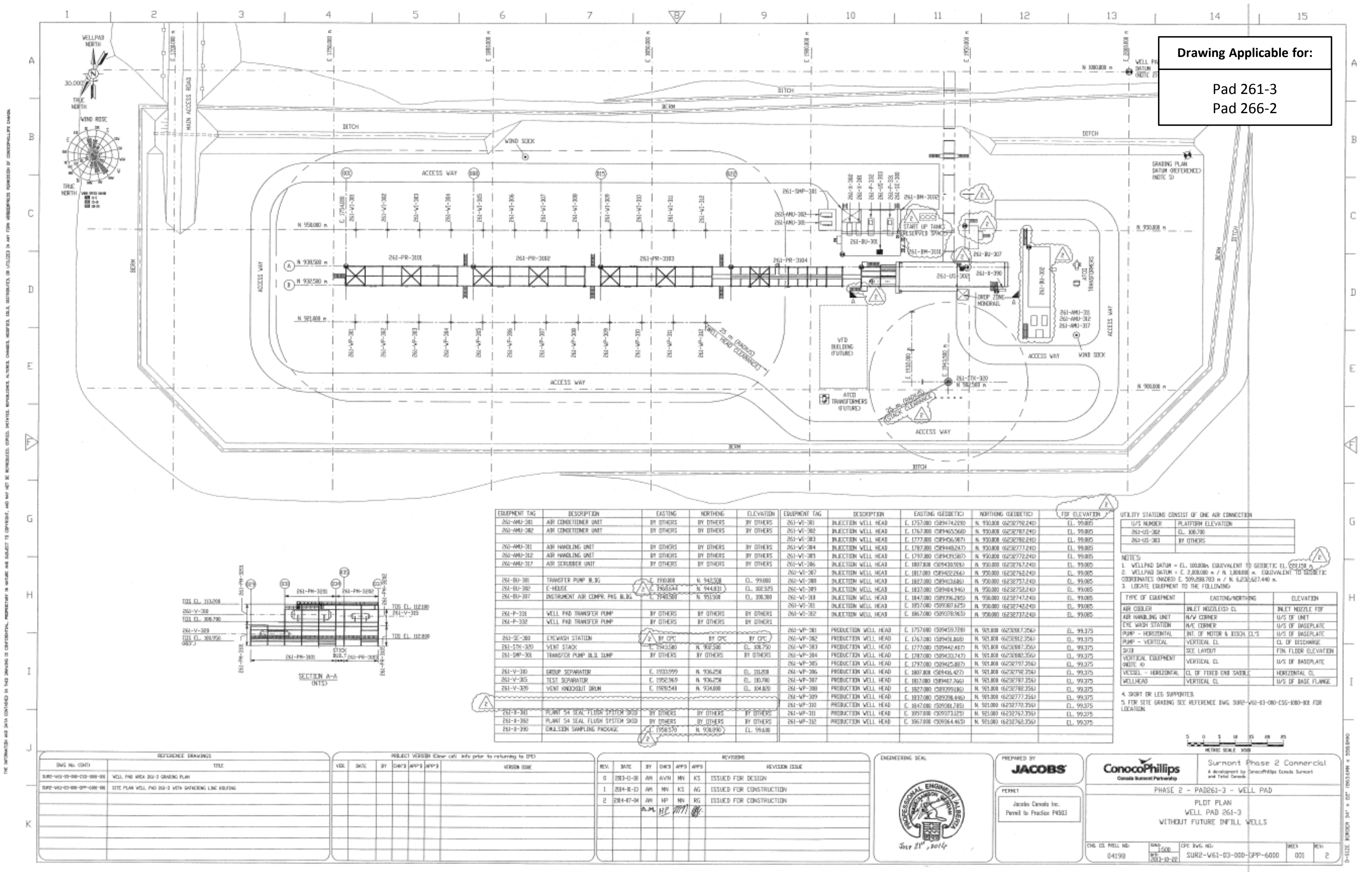
EQUIPMENT TAG	DESCRIPTION	EASTING	NORTHING	ELEVATION
170-AMU-101	AIR CONDITIONER UNIT	E. 1930.728	N. 954.382	EL. 98.354
170-AMU-111	AIR HANDLING UNIT	E. 1969.372	N. 920.212	EL. 102.525
170-AMU-112	AIR HANDLING UNIT	E. 1972.657	N. 920.212	EL. 102.525
170-AMU-117	AIR SCRUBBER UNIT	E. 1970.951	N. 918.514	EL. 102.525
170-BU-101	TRANSFER PUMP BLDG	E. 1902.000	N. 942.000	EL. 99.882
170-BU-102	E-HOUSE	E. 1988.000	N. 944.500	EL. 101.800
170-BU-107	INSTRUMENT AIR COMPR. PKG	E. 1948.500	N. 951.500	EL. 100.300
170-P-131	WELL PAD TRANSFER PUMP	E. 1908.400	N. 950.552	EL. 101.832
170-P-132	WELL PAD TRANSFER PUMP	E. 1909.700	N. 950.552	EL. 101.838
170-P-133	WELL PAD TRANSFER PUMP	E. 1906.400	N. 950.552	EL. 101.832
170-P-134	TEST SEPARATOR TRANSFER PUMP	E. 1922.098	N. 952.800	EL. 101.278
170-SE-100	EYEWASH STATION (BY CPC)	-	-	-
170-STK-120	VENT STACK	E. 1943.500	N. 902.500	EL. 100.750
170-SMP-101	TRANSFER PUMP BLDG SUMP	E. 1902.000	N. 942.000	EL. 100.340
170-V-110	GROUP SEPARATOR	E. 1933.999	N. 936.250	EL. 108.700
170-V-115	TEST SEPARATOR	E. 1952.989	N. 936.250	EL. 108.700
170-V-120	VENT KNOCKOUT DRUM	E. 1928.540	N. 934.000	EL. 102.800
170-X-170	DEMULSIFIER PKG	E. 1938.747	N. 946.675	EL. 99.413
170-X-181	PUMP SEAL PACKAGE	E. 1916.109	N. 950.902	EL. 100.352
170-X-182	PUMP SEAL PACKAGE	E. 1913.709	N. 950.902	EL. 100.352
170-X-183	PUMP SEAL PACKAGE	E. 1904.409	N. 950.159	EL. 100.352
170-X-184	PUMP SEAL PACKAGE	E. 1925.009	N. 950.902	EL. 100.352
170-X-190	EMULSION SAMPLING PACKAGE	E. 1924.805	N. 943.488	EL. 100.200

EQUIPMENT TAG	DESCRIPTION	EASTING	NORTHING	FDF ELEVATION
170-WI-101	INJECTION WELLHEAD	E. 1757.000	N. 950.000	99.092
170-WI-102	INJECTION WELLHEAD	E. 1767.000	N. 950.000	99.092
170-WI-103	INJECTION WELLHEAD	E. 1777.000	N. 950.000	99.092
170-WI-104	INJECTION WELLHEAD	E. 1787.000	N. 950.000	99.092
170-WI-105	INJECTION WELLHEAD	E. 1797.000	N. 950.000	99.092
170-WI-106	INJECTION WELLHEAD	E. 1807.000	N. 950.000	99.092
170-WI-107	INJECTION WELLHEAD	E. 1817.000	N. 950.000	99.092
170-WI-108	INJECTION WELLHEAD	E. 1827.000	N. 950.000	99.092
170-WI-109	INJECTION WELLHEAD	E. 1837.000	N. 950.000	99.092
170-WI-110	INJECTION WELLHEAD	E. 1847.000	N. 950.000	99.092
170-WI-111	INJECTION WELLHEAD	E. 1857.000	N. 950.000	99.092
170-WI-112	INJECTION WELLHEAD	E. 1867.000	N. 950.000	99.092
170-WP-101	PRODUCTION WELLHEAD	E. 1757.000	N. 921.000	99.672
170-WP-102	PRODUCTION WELLHEAD	E. 1767.000	N. 921.000	99.672
170-WP-103	PRODUCTION WELLHEAD	E. 1777.000	N. 921.000	99.672
170-WP-104	PRODUCTION WELLHEAD	E. 1787.000	N. 921.000	99.672
170-WP-105	PRODUCTION WELLHEAD	E. 1797.000	N. 921.000	99.672
170-WP-106	PRODUCTION WELLHEAD	E. 1807.000	N. 921.000	99.672
170-WP-107	PRODUCTION WELLHEAD	E. 1817.000	N. 921.000	99.672
170-WP-108	PRODUCTION WELLHEAD	E. 1827.000	N. 921.000	99.672
170-WP-109	PRODUCTION WELLHEAD	E. 1837.000	N. 921.000	99.672
170-WP-110	PRODUCTION WELLHEAD	E. 1847.000	N. 921.000	99.672
170-WP-111	PRODUCTION WELLHEAD	E. 1857.000	N. 921.000	99.672
170-WP-112	PRODUCTION WELLHEAD	E. 1867.000	N. 921.000	99.672

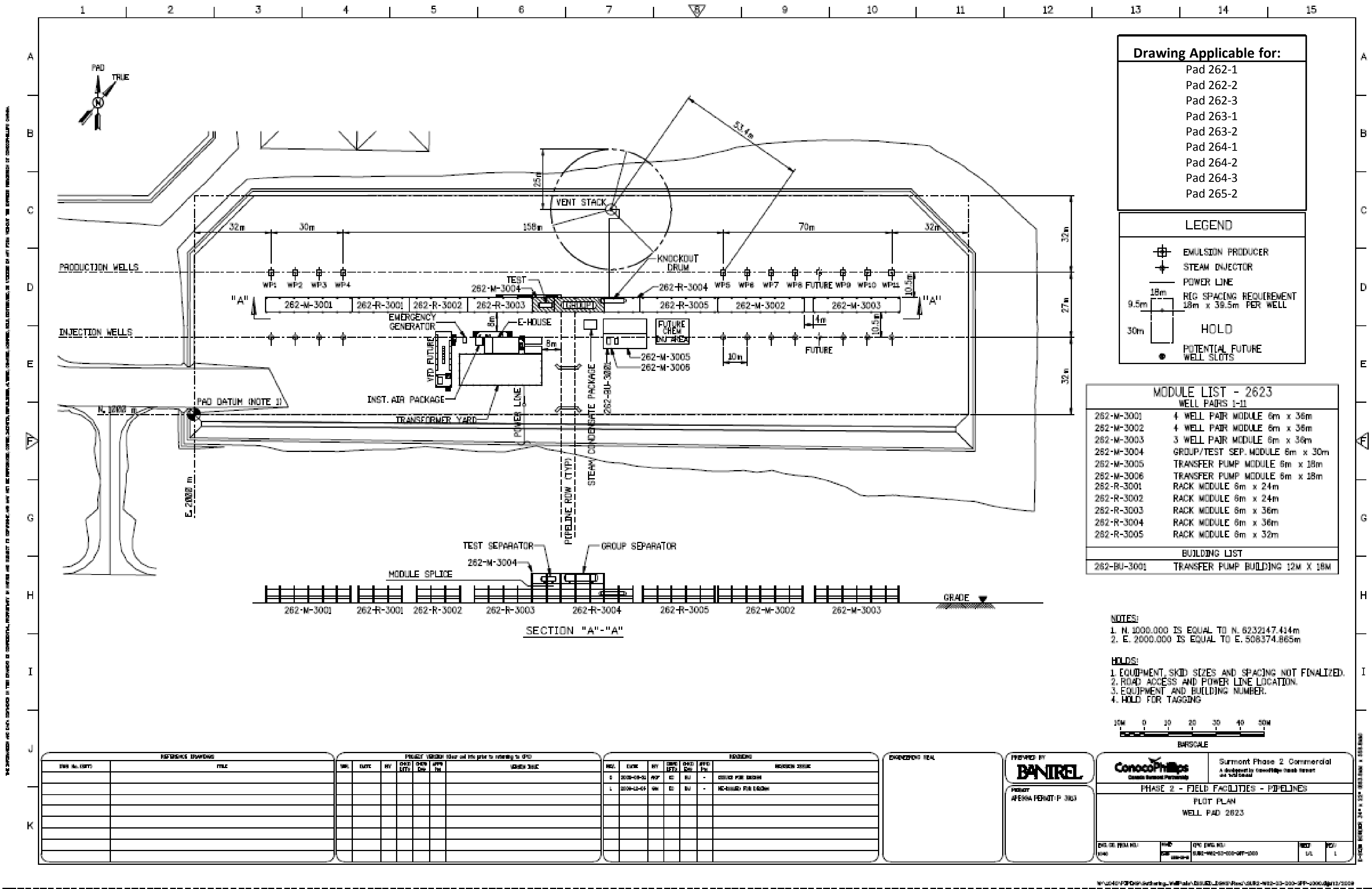
U/S NUMBER	PLATFORM ELEVATION
170-US-102	TOS EL. 108.790
170-US-103	TOS EL. 100.200

TYPE OF EQUIPMENT	EASTING/NORTHING	ELEVATION
AIR COOLER	INLET NOZZLE(S) CL	INLET NOZZLE FOF
AIR HANDLING UNIT	N/W CORNER	U/S OF UNIT
EYE WASH STATION	N/E CORNER	U/S OF BASEPLATE
PUMP - HORIZONTAL	INT. OF MOTOR & DISCH. CL'S	U/S OF BASEPLATE
PUMP - VERTICAL	VERTICAL CL	CL OF [illegible]
SKID	SEE LAYOUT	U/S SKID BASEPLATE
VERTICAL EQUIPMENT (NOTE 4)	VERTICAL CL	U/S OF BASEPLATE
VESSEL - HORIZONTAL	CL OF FIXED END SADDLE	HORIZONTAL CL
WELLHEAD	VERTICAL CL	U/S OF BASE FLANGE

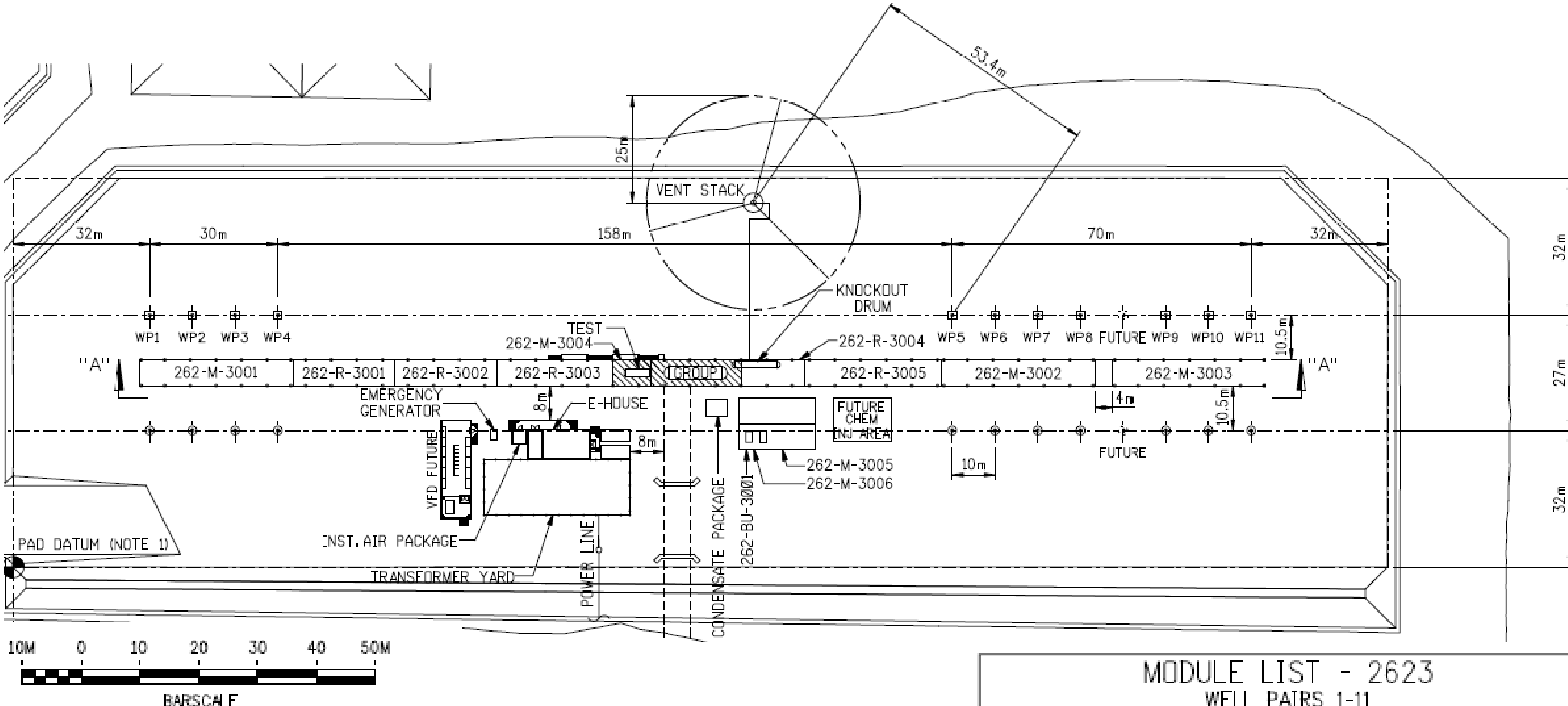
Jacobs S2 Pad Design



Drawing Applicable for:
Pad 261-3 Pad 266-2


Drawing Applicable for:
Pad 262-1
Pad 262-2
Pad 262-3
Pad 263-1
Pad 263-2
Pad 264-1
Pad 264-2
Pad 264-3
Pad 265-2
LEGEND
EMULSION PRODUCER
STEAM INJECTOR
POWER LINE
RIG SPACING REQUIREMENT 18m x 39.5m PER WELL
HOLD
POTENTIAL FUTURE WELL SLOTS
MODULE LIST - 2623
WELL PAIRS 1-11
262-M-3001 4 WELL PAIR MODULE 6m x 36m
262-M-3002 4 WELL PAIR MODULE 6m x 36m
262-M-3003 3 WELL PAIR MODULE 6m x 36m
262-M-3004 GROUP/TEST SEP. MODULE 6m x 30m
262-M-3005 TRANSFER PUMP MODULE 6m x 18m
262-M-3006 TRANSFER PUMP MODULE 6m x 18m
262-R-3001 RACK MODULE 6m x 24m
262-R-3002 RACK MODULE 6m x 24m
262-R-3003 RACK MODULE 6m x 36m
262-R-3004 RACK MODULE 6m x 36m
262-R-3005 RACK MODULE 6m x 32m
BUILDING LIST
262-BU-3001 TRANSFER PUMP BUILDING 12M X 18M
PRODUCTION WELLS
INJECTION WELLS
VENT STACK
KNOCKOUT DRUM
TEST SEPARATOR
GROUP SEPARATOR
MODULE SPLICE
SECTION "A"-"A"
GRADE
EMERGENCY GENERATOR
E-HOUSE
INST. AIR PACKAGE
TRANSFORMER YARD
POWER LINE
PIPELINE ROW (TYP)
STEAM CONDENSATE PACKAGE
PAD DATUM (NOTE 1)
NOTES:
1. N. 1000.000 IS EQUAL TO N. 6232147.414m
2. E. 2000.000 IS EQUAL TO E. 508374.865m
HOLDS:
1. EQUIPMENT, SKID SIZES AND SPACING NOT FINALIZED.
2. ROAD ACCESS AND POWER LINE LOCATION.
3. EQUIPMENT AND BUILDING NUMBER.
4. HOLD FOR TAGGING
BARSCALE
BANTREL
ConocoPhillips
Surmont Phase 2 Commercial
PHASE 2 - FIELD FACILITIES - PIPELINES
PLOT PLAN
WELL PAD 2623

Bantrel S2 Pad Design



Drawing Applicable for:

Pad 262-1
Pad 262-2
Pad 262-3
Pad 263-1
Pad 263-2
Pad 264-1
Pad 264-2
Pad 264-3
Pad 265-2

LEGEND

- EMULSION PRODUCER
- STEAM INJECTOR
- POWER LINE
- RIG SPACING REQUIREMENT 18m x 39.5m PER WELL (18m; 9.5m; 30m)
- HOLD
- POTENTIAL FUTURE WELL SLOTS

MODULE LIST - 2623
WELL PAIRS 1-11

262-M-3001	4 WELL PAIR MODULE 6m x 36m
262-M-3002	4 WELL PAIR MODULE 6m x 36m
262-M-3003	3 WELL PAIR MODULE 6m x 36m
262-M-3004	GROUP/TEST SEP. MODULE 6m x 30m
262-M-3005	TRANSFER PUMP MODULE 6m x 18m
262-M-3006	TRANSFER PUMP MODULE 6m x 18m
262-R-3001	RACK MODULE 6m x 24m
262-R-3002	RACK MODULE 6m x 24m
262-R-3003	RACK MODULE 6m x 36m
262-R-3004	RACK MODULE 6m x 36m
262-R-3005	RACK MODULE 6m x 32m

BUILDING LIST

262-BU-3001	TRANSFER PUMP BUILDING 12M X 18M

Pad 101, 102 & 103 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
101-01 (10DH)	ESP	Parallel
101-02 (11DH)	ESP	Parallel
101-03 (12DH)	ESP	Concentric
101-04 (13DH)	ESP	Parallel
101-05 (14DH)	ESP	Parallel
101-06 (17DH)	ESP(TDFCD)	Concentric
101-07 (18DH)	Gas Lift	Concentric
101-08 (02DH)	ESP	Concentric
101-09 (01DH)	ESP	Concentric
101-10 03DH)	ESP	Concentric
101-11 (04DH)	ESP(TDFCD)	Concentric
101-12 (05DH)	ESP	Concentric
101-13 (06DH)	ESP	Concentric
101-14 (16DH)	ESP	Parallel
101-15 (15DH)	ESP	Parallel
101-16 (07DH)	ESP	Parallel
101-17 (08DH)	ESP	Parallel
101-18 (09DH)	ESP	Parallel
101-19 (17INF)	ESP	Concentric
101-20 (16INF)	ESP(TDFCD)	Concentric
101-21 (10INF)	PCP	N/A
101-22 (11INF)	PCP	N/A

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
102-1	ESP	Parallel
102-2	ESP (TDFCD)	Parallel
102-3	PCP	Parallel
102-4	ESP	Parallel
102-5	ESP	Parallel
102-6	ESP (FCD)	Parallel
102-7	ESP	Concentric
102-8	ESP	Concentric
102-9	ESP (TDFCD)	Concentric
102-10	ESP	Concentric
102-11	ESP	Concentric
102-12	ESP	Parallel
102-13	ESP	Parallel
102-14	ESP	Parallel
102-15	ESP	Concentric
102-16	ESP	Concentric
102-17	ESP	Concentric
102-18	ESP	Concentric
102-21 (INF)	PCP (FCD)	N/A
102-22 (INF)	PCP (FCD)	N/A

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
103-1	Improved Gas Lift Producer A	Concentric
103-2	Improved Gas Lift Producer A (FCD)	Concentric (FCD)
103-3	Improved Gas Lift Producer A	Concentric
103-4	Improved Gas Lift Producer A (FCD)	Concentric (FCD)
103-5	Improved Gas Lift Producer A	Concentric
103-6	Improved Gas Lift Producer A (FCD)	Concentric (FCD)
103-7	Improved Gas Lift Producer A	Concentric
103-8	ESP (FCD)	Concentric (FCD)
103-9	ESP	Concentric
103-10	ESP (FCD)	Concentric (FCD)
103-11	ESP	Concentric
103-12	ESP (FCD)	Concentric (FCD)

Pad 261-3 & 262-1 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
261-3-01	Improved Gas Lift Producer A	Concentric
261-3-02	Improved Gas Lift Producer A	Concentric
261-3-03	Improved Gas Lift Producer A	Concentric
261-3-04	Improved Gas Lift Producer A	Concentric
261-3-05	Improved Gas Lift Producer A	Concentric
261-3-06	Improved Gas Lift Producer A	Concentric
261-3-07	Improved Gas Lift Producer A	Concentric
261-3-08	Improved Gas Lift Producer A	Concentric
261-3-09	Improved Gas Lift Producer A	Concentric
261-3-10	Improved Gas Lift Producer A	Concentric
261-3-11	Improved Gas Lift Producer A	Concentric
261-3-12	Improved Gas Lift Producer A	Concentric

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
262-1-01	Improved Gas Lift Producer A	Concentric
262-1-02	Improved Gas Lift Producer A	Concentric
262-1-03	Improved Gas Lift Producer A	Concentric
262-1-04	Improved Gas Lift Producer A	Concentric
262-1-05	Improved Gas Lift Producer A	Concentric
262-1-06	Improved Gas Lift Producer A	Concentric
262-1-07	Improved Gas Lift Producer A	Concentric
262-1-08	Improved Gas Lift Producer A	Concentric
262-1-09	Improved Gas Lift Producer A	Concentric
262-1-10	Improved Gas Lift Producer A	Concentric
262-1-11	Improved Gas Lift Producer A	Concentric
262-1-12	Improved Gas Lift Producer A	Concentric

Pad 262-2 & 262-3 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
262-2-01	Improved Gas Lift Producer A	Concentric
262-2-02	Improved Gas Lift Producer A	Concentric
262-2-03	Improved Gas Lift Producer A	Concentric
262-2-04	Improved Gas Lift Producer A	Concentric
262-2-05	Improved Gas Lift Producer A	Concentric
262-2-06	Improved Gas Lift Producer A	Concentric
262-2-07	Improved Gas Lift Producer A	Concentric
262-2-08	Improved Gas Lift Producer A	Concentric
262-2-09	Improved Gas Lift Producer A	Concentric
262-2-10	Improved Gas Lift Producer A	Concentric
262-2-11	Improved Gas Lift Producer A	Concentric
262-2-12	Improved Gas Lift Producer A	Concentric

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
262-3-01	Improved Gas Lift Producer A	Concentric
262-3-02	Improved Gas Lift Producer A(TDFCD)	Concentric
262-3-03	Improved Gas Lift Producer A	Concentric
262-3-04	Improved Gas Lift Producer A	Concentric
262-3-05	Improved Gas Lift Producer A	Concentric
262-3-06	Improved Gas Lift Producer A	Concentric
262-3-07	Improved Gas Lift Producer A	Concentric
262-3-08	Improved Gas Lift Producer A	Concentric
262-3-09	Improved Gas Lift Producer A	Concentric
262-3-10	Improved Gas Lift Producer A	Concentric
262-3-11	Improved Gas Lift Producer A	Concentric
262-3-12	Improved Gas Lift Producer A	Concentric

Pad 263-1 & 263-2 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion	Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
263-1-01	Improved Gas Lift Producer B(FCD)	Concentric	263-2-01	Improved Gas Lift Producer B(TDFCD)	Concentric
263-1-02	Improved Gas Lift Producer B(FCD)	Concentric	263-2-02	Improved Gas Lift Producer B	Concentric
263-1-03	Improved Gas Lift Producer B	Concentric	263-2-03	Improved Gas Lift Producer B	Concentric
263-1-04	Improved Gas Lift Producer B	Concentric	263-2-04	Improved Gas Lift Producer B	Concentric
263-1-05	Improved Gas Lift Producer B	Concentric (FCD)	263-2-05	Improved Gas Lift Producer B	Concentric
263-1-06	Improved Gas Lift Producer B(FCD)	Concentric	263-2-06	Improved Gas Lift Producer B	Concentric
263-1-07	Improved Gas Lift Producer B(FCD)	Concentric	263-2-07	Improved Gas Lift Producer B	Concentric
263-1-08	Improved Gas Lift Producer B(FCD)	Concentric	263-2-08	Improved Gas Lift Producer B	Concentric
263-1-09	Improved Gas Lift Producer B(FCD)	Concentric	263-2-09	Improved Gas Lift Producer B	Concentric
263-1-10	Improved Gas Lift Producer B	Concentric	263-2-10	Improved Gas Lift Producer B	Concentric
263-1-11	Improved Gas Lift Producer B(FCD)	Concentric	263-2-11	Improved Gas Lift Producer B	Concentric
263-1-01	Improved Gas Lift Producer B	Concentric	263-2-01	Improved Gas Lift Producer B	Concentric

Pad 264-1, 264-2 & 264-3 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
264-1-01	Improved Gas Lift Producer A	Concentric
264-1-02	Improved Gas Lift Producer A	Concentric
264-1-03	Improved Gas Lift Producer A	Concentric
264-1-04	Improved Gas Lift Producer A	Concentric
264-1-05	Improved Gas Lift Producer A	Concentric
264-1-06	Improved Gas Lift Producer A	Concentric
264-1-07	Improved Gas Lift Producer A	Concentric
264-1-08	Improved Gas Lift Producer A	Concentric
264-1-09	Improved Gas Lift Producer A	Concentric
264-1-10	Improved Gas Lift Producer A	Concentric
264-1-11	Improved Gas Lift Producer A (FCD)	Concentric
264-1-12	Improved Gas Lift Producer A (TDFCD)	Steam Splitter

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
264-2-01	Improved Gas Lift Producer B	Concentric
264-2-02	Improved Gas Lift Producer B(FCD)	Concentric
264-2-03	Cold	Concentric
264-2-04	Improved Gas Lift Producer B	Concentric
264-2-05	Improved Gas Lift Producer B	Concentric
264-2-06	Improved Gas Lift Producer B	Concentric
264-2-07	Improved Gas Lift Producer B	Concentric
264-2-08	Improved Gas Lift Producer B	Concentric
264-2-09	Improved Gas Lift Producer B	Concentric
264-2-10	Improved Gas Lift Producer B	Concentric
264-2-11	Improved Gas Lift Producer B	Concentric

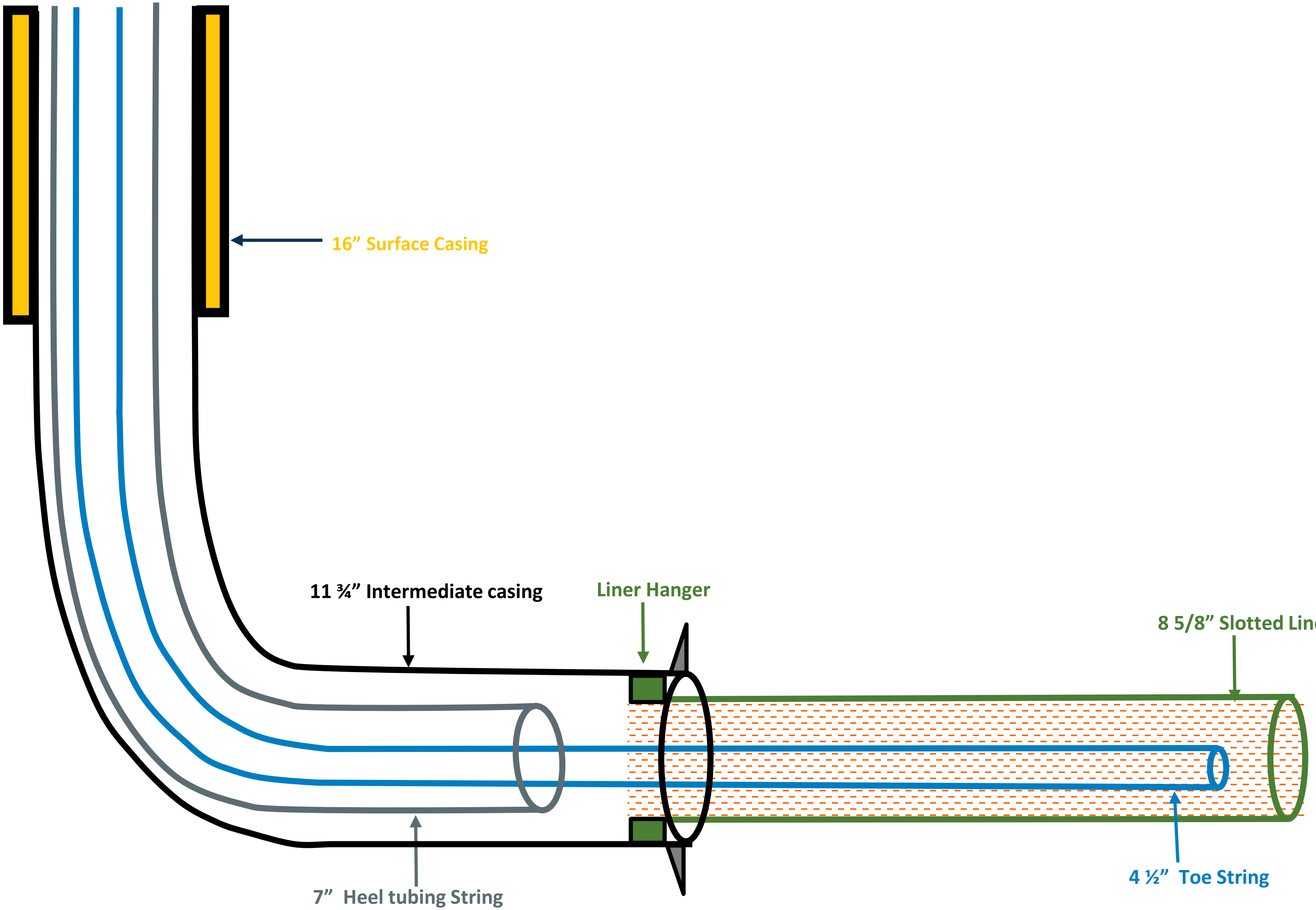
Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
264-3-01	Improved Gas Lift Producer A	Concentric
264-3-02	Improved Gas Lift Producer A	Concentric
264-3-03	Improved Gas Lift Producer A (TDFCD)	Concentric
264-3-04	Improved Gas Lift Producer A	Concentric
264-3-05	Improved Gas Lift Producer A	Concentric
264-3-06	Improved Gas Lift Producer A (FCD)	Concentric
264-3-07	Improved Gas Lift Producer A (TDFCD)	Concentric
264-3-08	Improved Gas Lift Producer A (FCD)	Concentric
264-3-09	Improved Gas Lift Producer A	Concentric
264-3-10	Improved Gas Lift Producer A (FCD)	Concentric
264-3-11	Improved Gas Lift Producer A (FCD)	Concentric
264-3-12	Improved Gas Lift Producer A (FCD)	Concentric

Pad 265-2 & 266-2 Well Completions

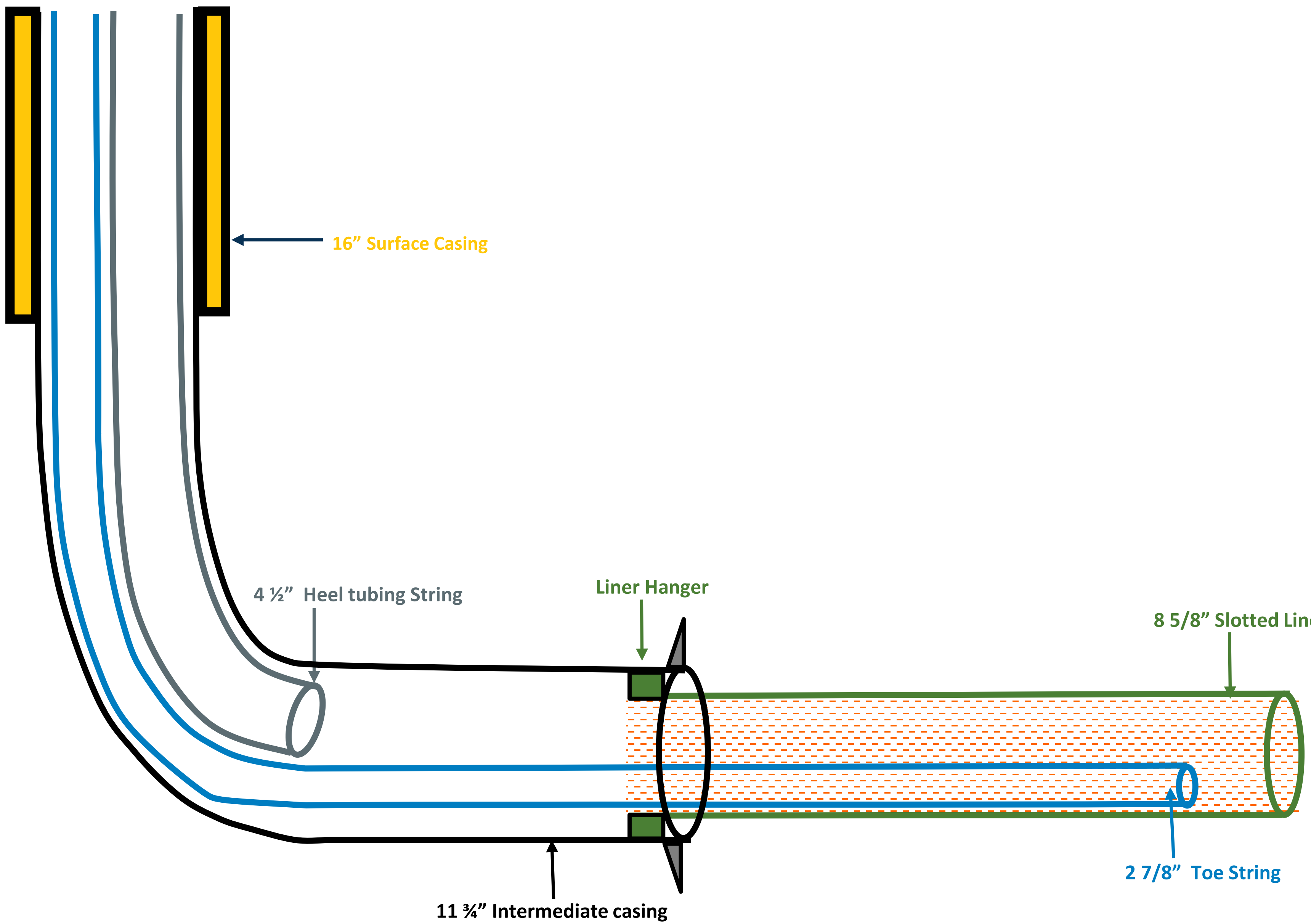
Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
265-2-01	Improved Gas Lift Producer A	Concentric
265-2-02	Improved Gas Lift Producer A	Concentric
265-2-03	Improved Gas Lift Producer A	Concentric
265-2-04	Improved Gas Lift Producer A	Concentric
265-2-05	Improved Gas Lift Producer A	Steam Splitter
265-2-06	ESP (TDFCD)	Concentric
265-2-07	ESP	Steam Splitter
265-2-08	ESP	Steam Splitter
265-2-09	Improved Gas Lift Producer A	Steam Splitter
265-2-10	Improved Gas Lift Producer A	Concentric
265-2-11	Improved Gas Lift Producer A	Steam Splitter
265-2-12	Improved Gas Lift Producer A	Concentric

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
266-2-01	ESP (FCD)	Concentric
266-2-02	ESP (FCD)	Concentric
266-2-03	ESP (FCD)	Concentric
266-2-04	ESP (FCD)	Concentric
266-2-05	ESP (FCD)	Concentric
266-2-06	ESP (FCD)	Concentric
266-2-07	ESP (FCD)	Concentric
266-2-08	Improved Gas Lift Producer A (FCD)	Concentric
266-2-09	Improved Gas Lift Producer A (FCD)	Concentric
266-2-10	ESP (FCD)	Concentric
266-2-11	Improved Gas Lift Producer A	Concentric
266-212	Improved Gas Lift Producer A (FCD)	Concentric

Typical Concentric Injector

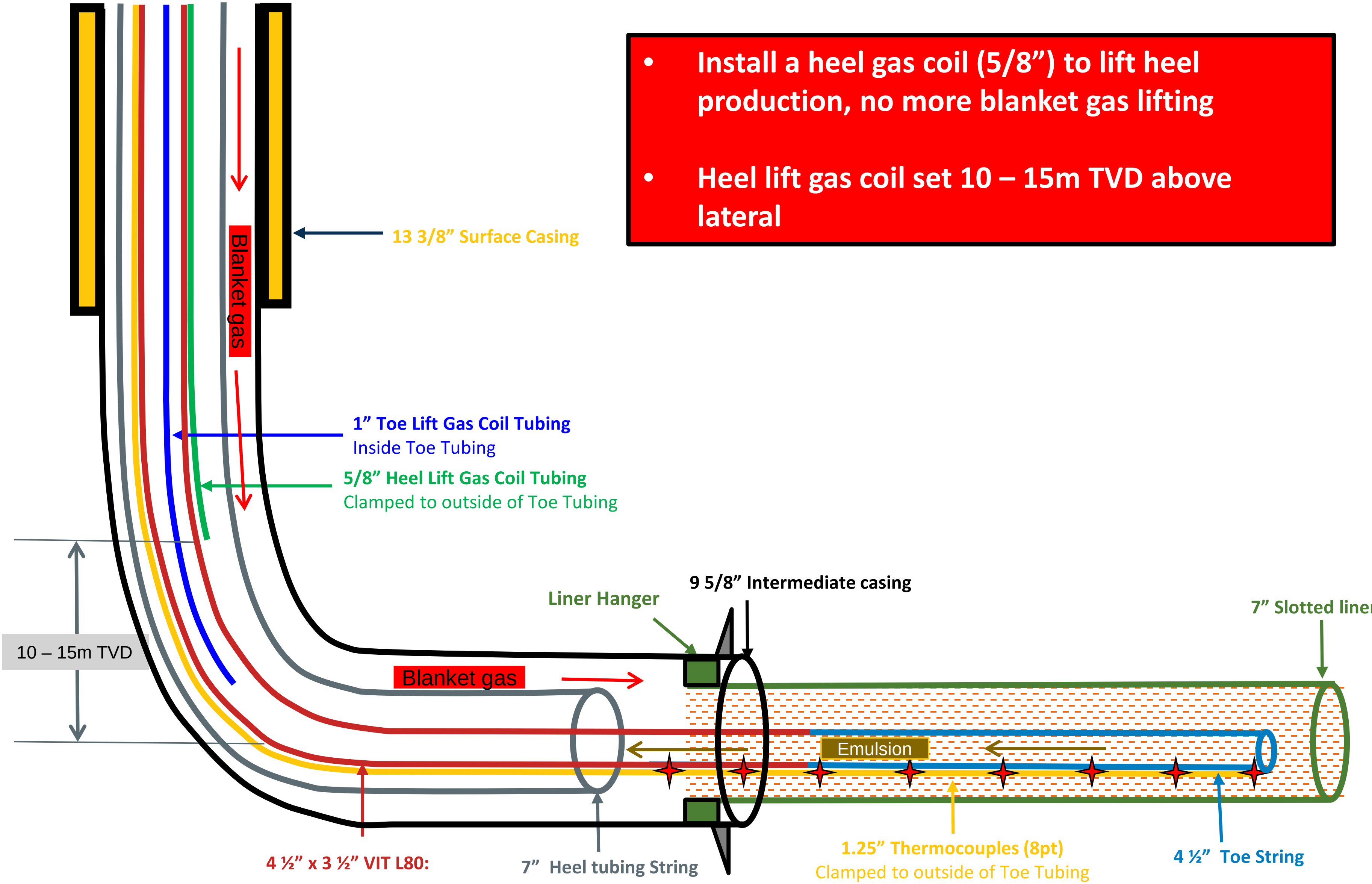


Typical Parallel Injector



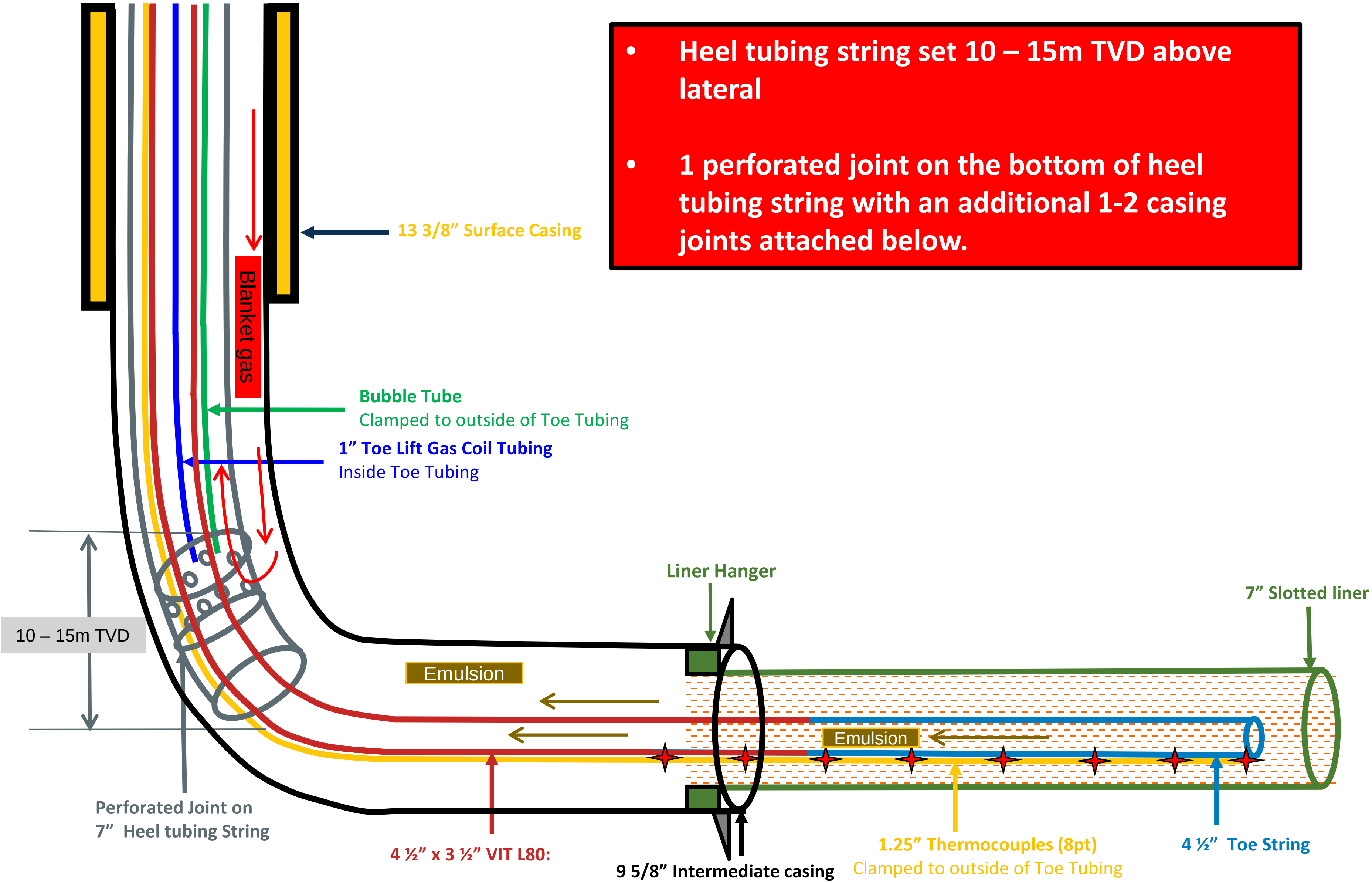
Improved Gas Lift Producer Design, 264-1

- Install a heel gas coil (5/8”) to lift heel production, no more blanket gas lifting
- Heel lift gas coil set 10 – 15m TVD above lateral

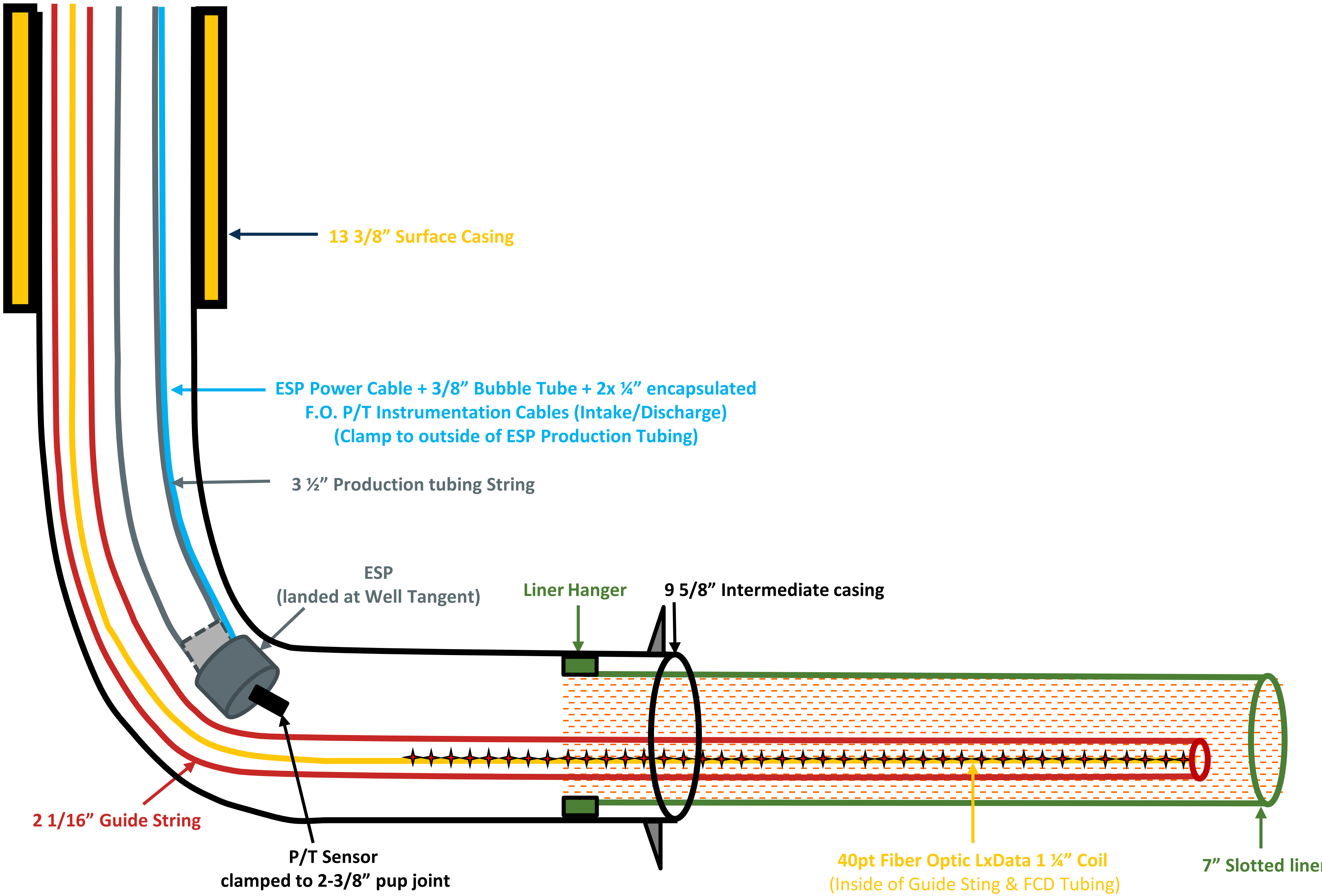


Improved Gas Lift Producer Design, 264-2, 263-2 & 263-1

- **Heel tubing string set 10 – 15m TVD above lateral**
- **1 perforated joint on the bottom of heel tubing string with an additional 1-2 casing joints attached below.**



Typical ESP Producer



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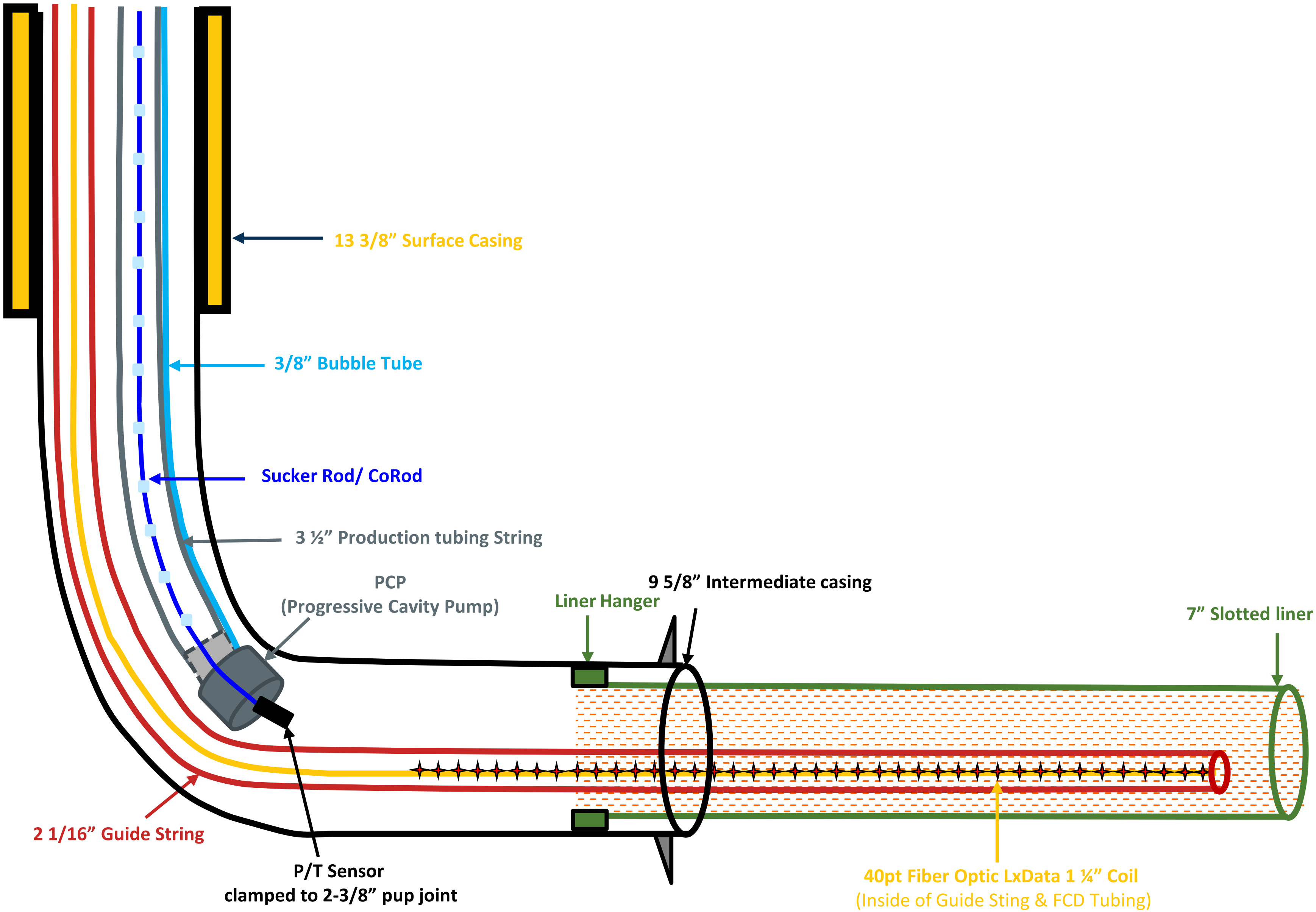
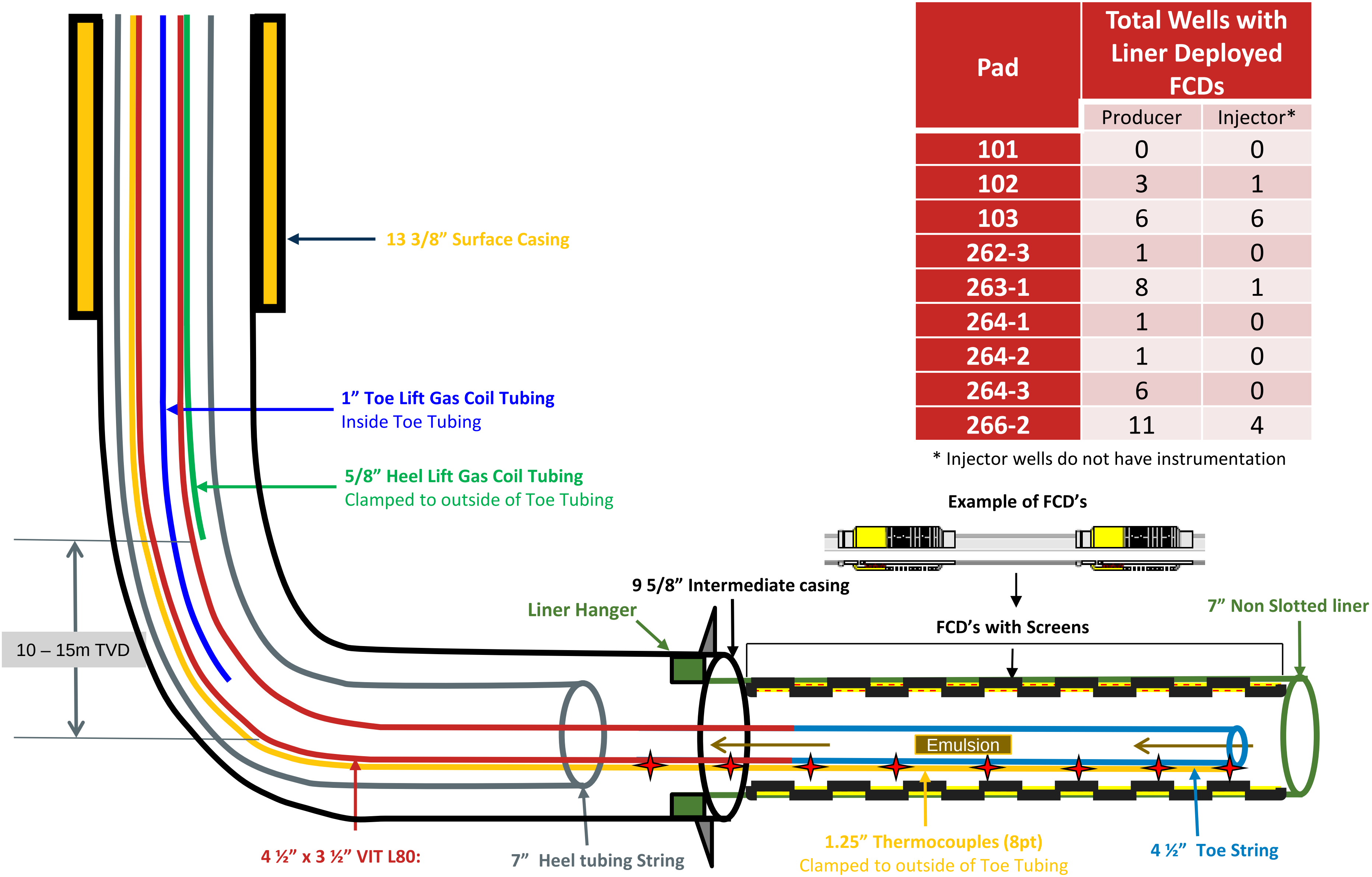
Typical PCP Producer



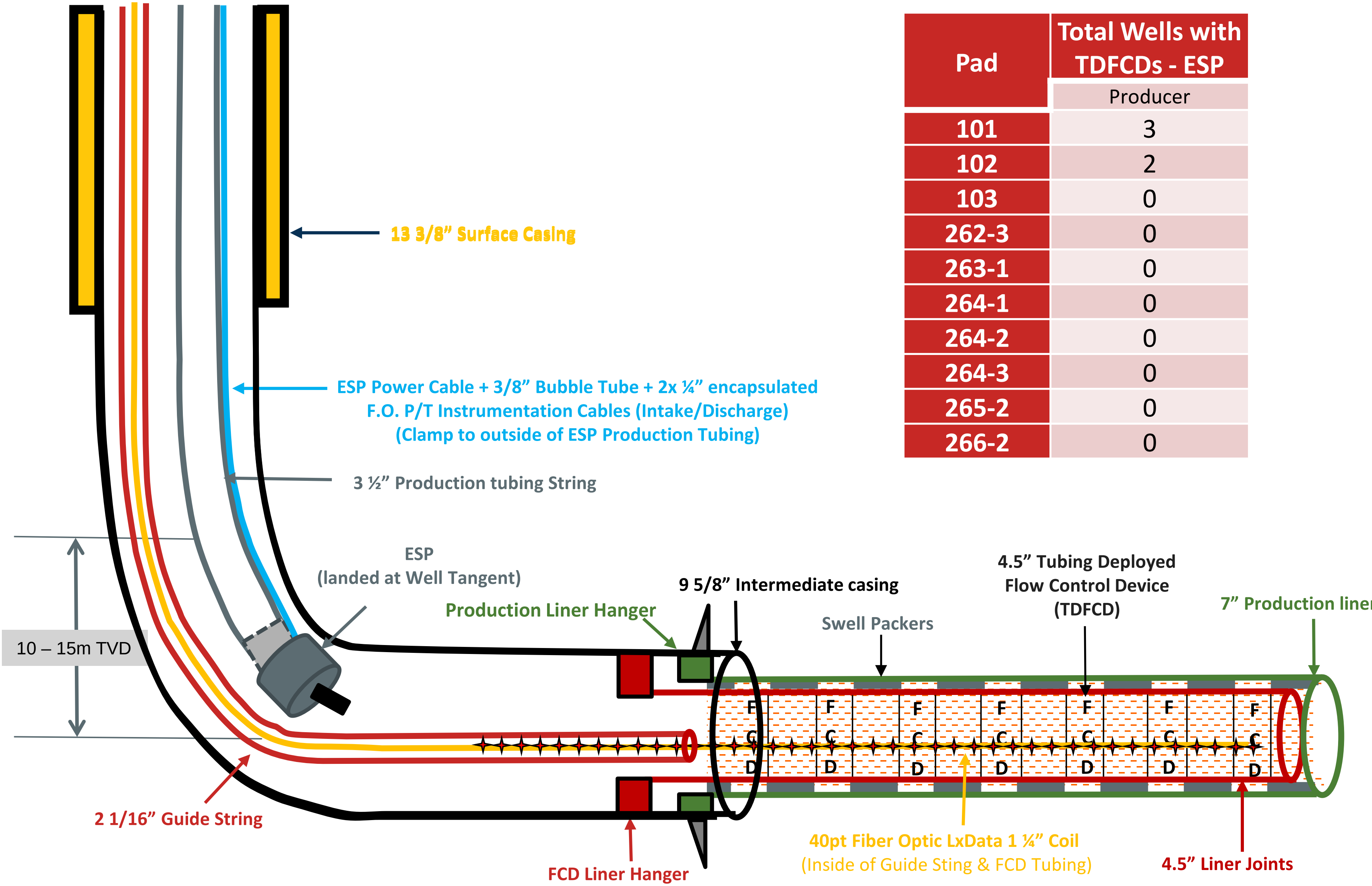
Typical Flow Control Device (FCD) Completion



Pad	Total Wells with Liner Deployed FCDs	
	Producer	Injector*
101	0	0
102	3	1
103	6	6
262-3	1	0
263-1	8	1
264-1	1	0
264-2	1	0
264-3	6	0
266-2	11	4

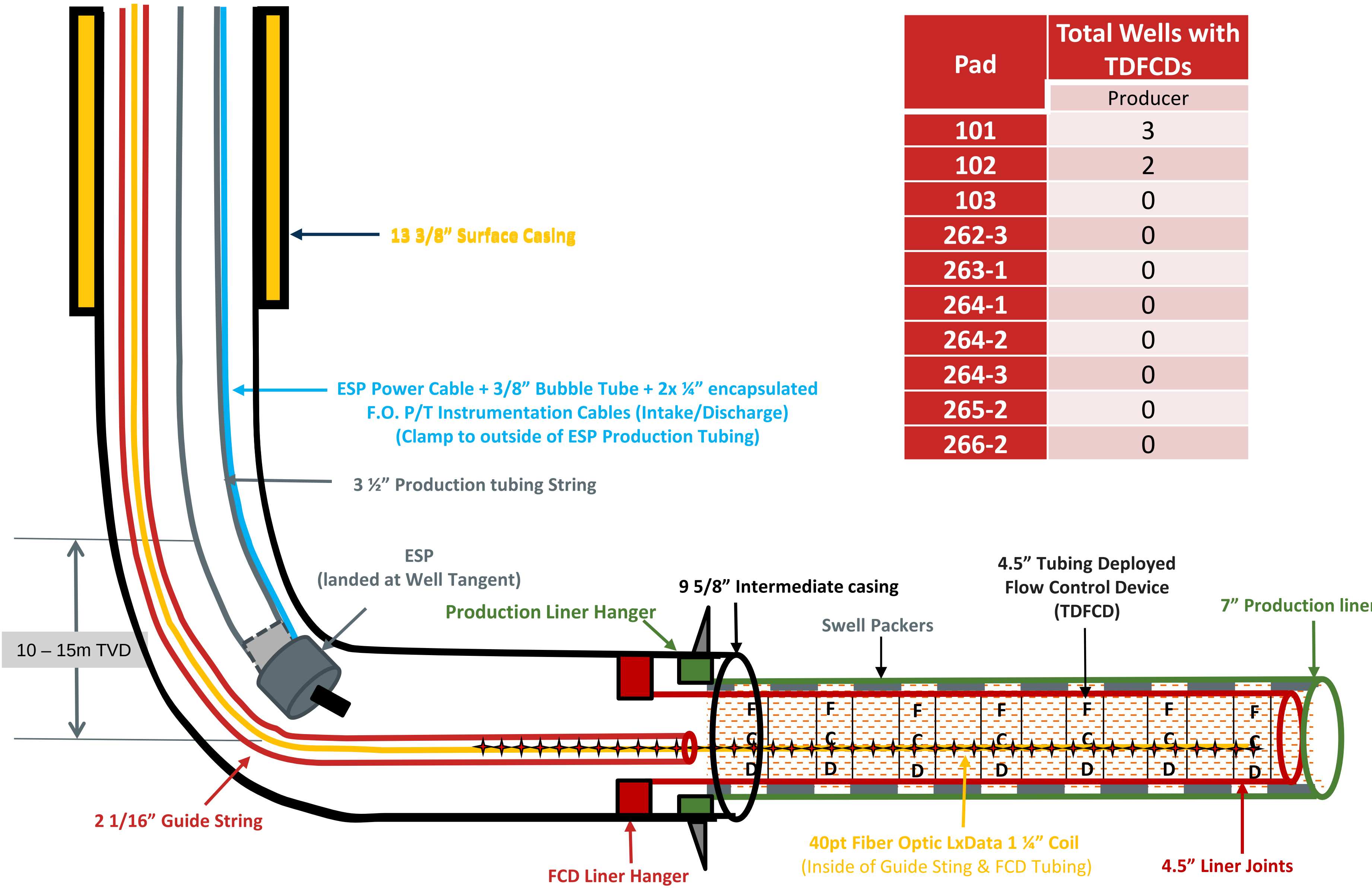
* Injector wells do not have instrumentation

Typical Tubing Deployed FCD (TDFCD) Completion – ESP



Pad	Total Wells with TDFCDs - ESP
	Producer
101	3
102	2
103	0
262-3	0
263-1	0
264-1	0
264-2	0
264-3	0
265-2	0
266-2	0

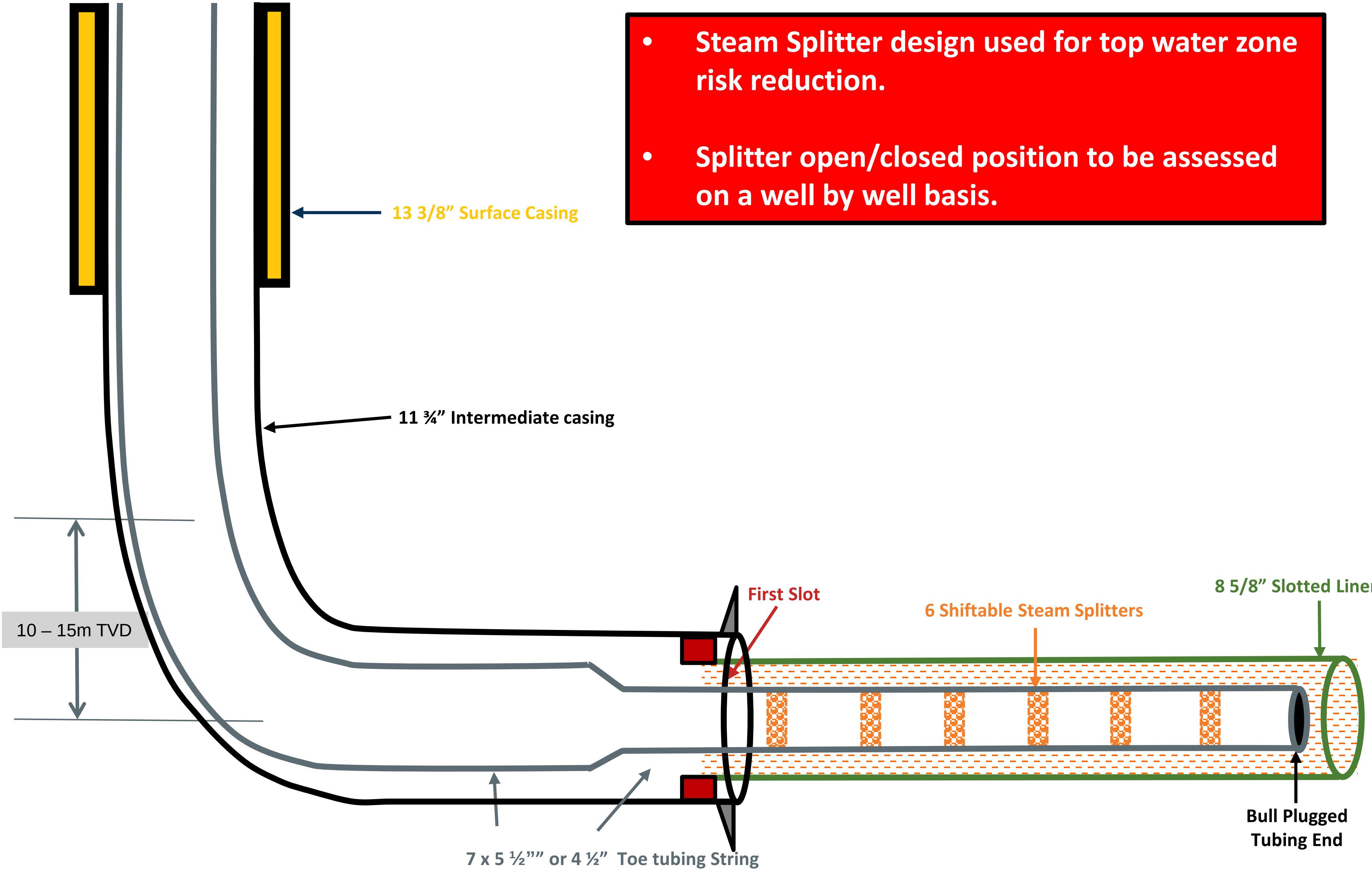
Typical Tubing Deployed FCD (TDFCD) Completion – ESP



Pad	Total Wells with TDFCDs
	Producer
101	3
102	2
103	0
262-3	0
263-1	0
264-1	0
264-2	0
264-3	0
265-2	0
266-2	0

Current Surmont 2 Steam Splitter Design

- Steam Splitter design used for top water zone risk reduction.
- Splitter open/closed position to be assessed on a well by well basis.



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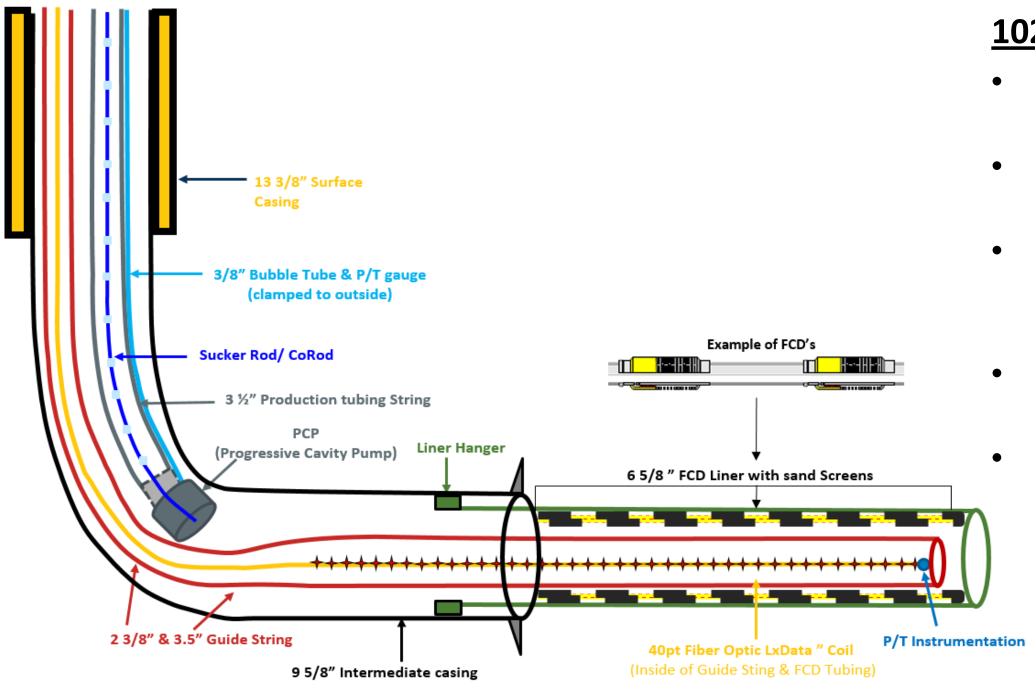
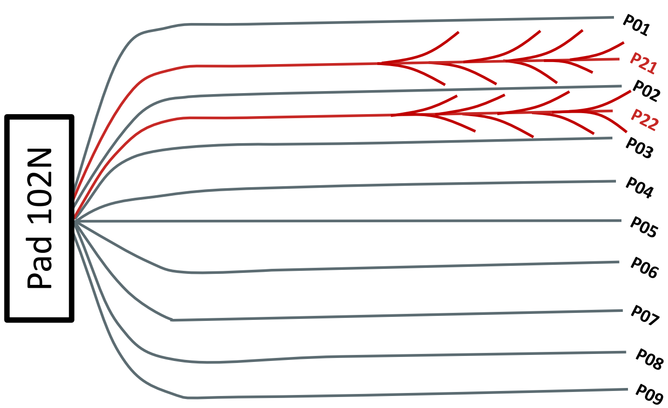
Fishbone Completion Pad 102-P21 & P22 Infills





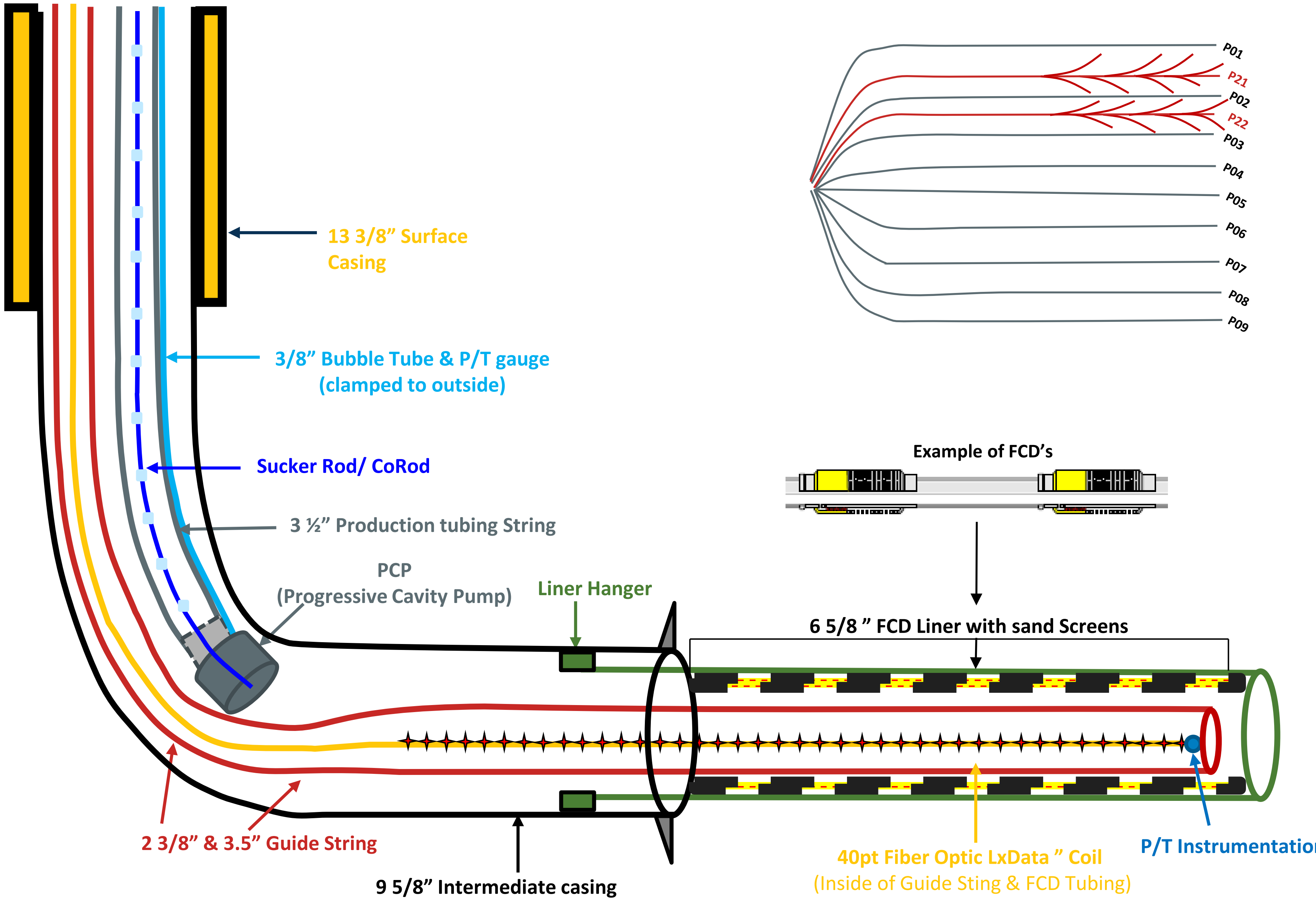
102-P21 (INF)

- Restarted warmup operations with steam bullheading in Q1 and Q3 2016
- Workover September 2016 to identify previous source of challenges with pump operation
- New PCP pump installed October 2016 and well restarted with steam assist to keep rod torque at manageable levels
- Consistent production from October to present, including improvement in lateral temperatures
- Expecting to remove steam assist as temperatures continue to improve

102-P22 (INF)

- Short warmup cycle ran for 2 weeks in Q3 2016. Well has been on standby to use learnings from 102-21
- Downhole temps were showing some improvement along with good injectivity
- Back on warmup Q1 2017 with intention of startup of production with steam assist before Q2 2017

102 P21 Fishbone Completion



Artificial Lift

Subsection 3.1.1 (4)

Artificial Lift Current Pad Overview

TOTAL
52
5
107
2
0
9
7
1

	Phase 1					Phase 2										
	101		102		103	261-3	262-1	262-2	262-3	263-1	263-2	264-1	264-2	264-3	265-2	266-2
	1	13	1	13	1	1	1	1	1	1	1	1	1	1	1	1
	2	14	2	14	2	2	2	2	2	2	2	2	2	2	2	2
	3	15	3	15	3	3	3	3	3	3	3	3	3	3	3	3
	4	16	4	16	4	4	4	4	4	4	4	4	4	4	4	4
	5	17	5	17	5	5	5	5	5	5	5	5	5	5	5	5
	6	18	6	18	6	6	6	6	6	6	6	6	6	6	6	6
	7	19	7		7	7	7	7	7	7	7	7	7	7	7	7
	8	20	8		8	8	8	8	8	8	8	8	8	8	8	8
	9	21	9	21	9	9	9	9	9	9	9	9	9	9	9	9
	10	22	10	22	10	10	10	10	10	10	10	10	10	10	10	10
	11		11		11	11	11	11	11	11	11	11	11	11	11	11
	12		12		12	12	12	12	12			12		12	12	12
ESP	19		17		5	0	0	0	0	0	0	0	0	0	3	8
PCP	2		3		0	0	0	0	0	0	0	0	0	0	0	0
GAS LIFT	0		0		7	10	12	7	12	10	10	10	8	12	9	0
SSAGD	0		0		0	0	0	2	0	0	0	0	0	0	0	0
RE-CIRC	0		0		0	0	0	0	0	0	0	0	0	0	0	0
CIRC	1		0		0	0	0	0	0	1	0	2	1	0	0	4
OFFLINE	0		0		0	2	0	3	0	0	1	0	1	0	0	0
COLD	0		0		0	0	0	0	0	0	0	0	1	0	0	0

Artificial Lift Types

- **Gas Lift**
  - Gas lift is effective with bottom hole flowing pressures >2,700 kPa with pressure of well head (Pwh) approx. 1,000 kPa
  - Lifting from heel and toe with gas assist at start of vertical section
  - Current production rates range from 100 m3/d to 700 m3/d of emulsion targeting 3,500 kPa

- **Electric Submersible Pump (ESP)**
  - ESP for thermal SAGD applications can be sized to meet the specific deliverability of the well.
  - Operating temperatures typically below 215°C
  - Typically Series 500 installed, and Series 400 pumps installed due to casing restrictions

- **Progressive Cavity Pumps (PCP)**
  - Generally PCPs have been used for low deliverability wells and where potential solids may be produced.*
  - Installation of metal to metal pumps

- * ConocoPhillips Canada initial strategy for PCPs was to use them on low deliverability wells where the current ESP designs were deemed less appropriate. However, installation of larger PCP are being considered for wells that may produce relatively “cold” viscous fluid for some time.

ESP Run Life Definitions

- **MTTF:** This run-life measure is calculated as the total exposure time of all systems (running, pulled and failed) divided by the number of failed systems.

- **Average Runtime:** This run-life measure is calculated as the total exposure time of all systems (running, pulled and failed) divided by the number of systems (running, pulled and failed)

- **Average run life running ESP:** This run-life measure is calculated as the total exposure time of running systems divided by the number of running systems.

- **Window:** window time allows for changes in average run-life to be more apparent, as they are less obscured by previous data.

ESP Performance

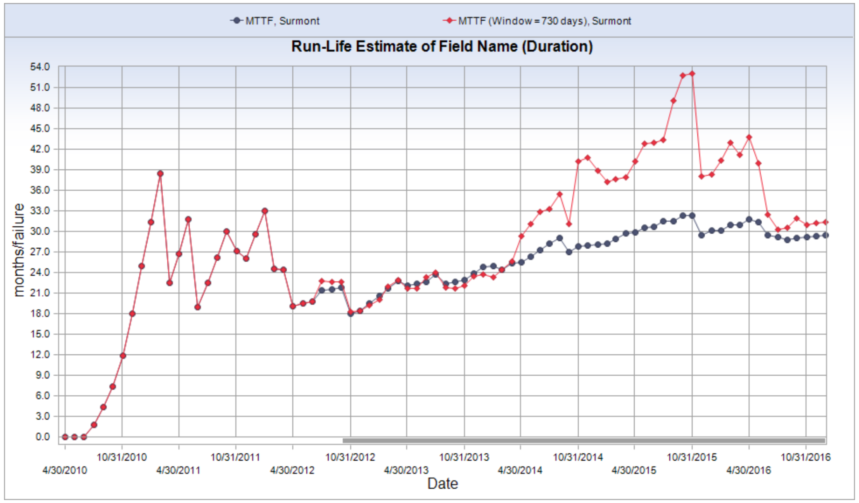
KPIs

Population:	52 ESP’s
Cumulative MTTF:	29.1 months
Windowed* MTTF:	31.4 months
Average Runtime:	15.4 months
Windowed Runtime:	18.8 months
Average run life running ESP:	10.6 months

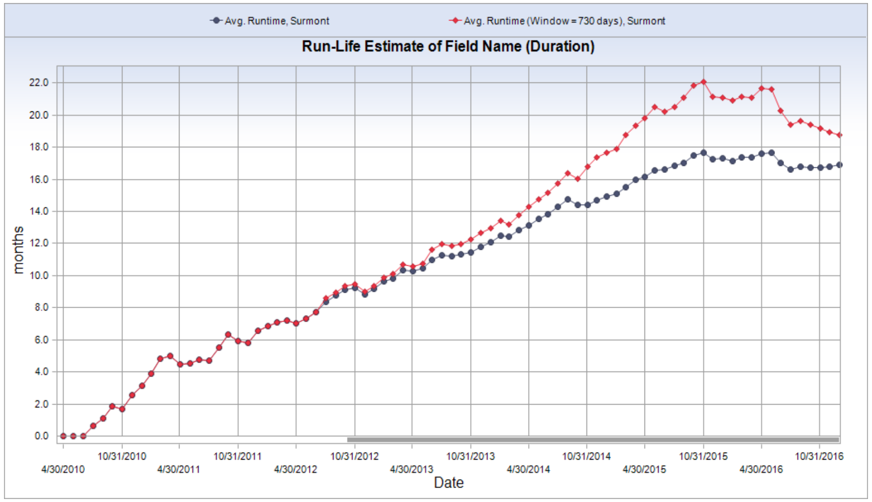
2016:	16 ESP failures
2017:	5 ESP failures

*(730 day window)

MTTF



Average Runtime



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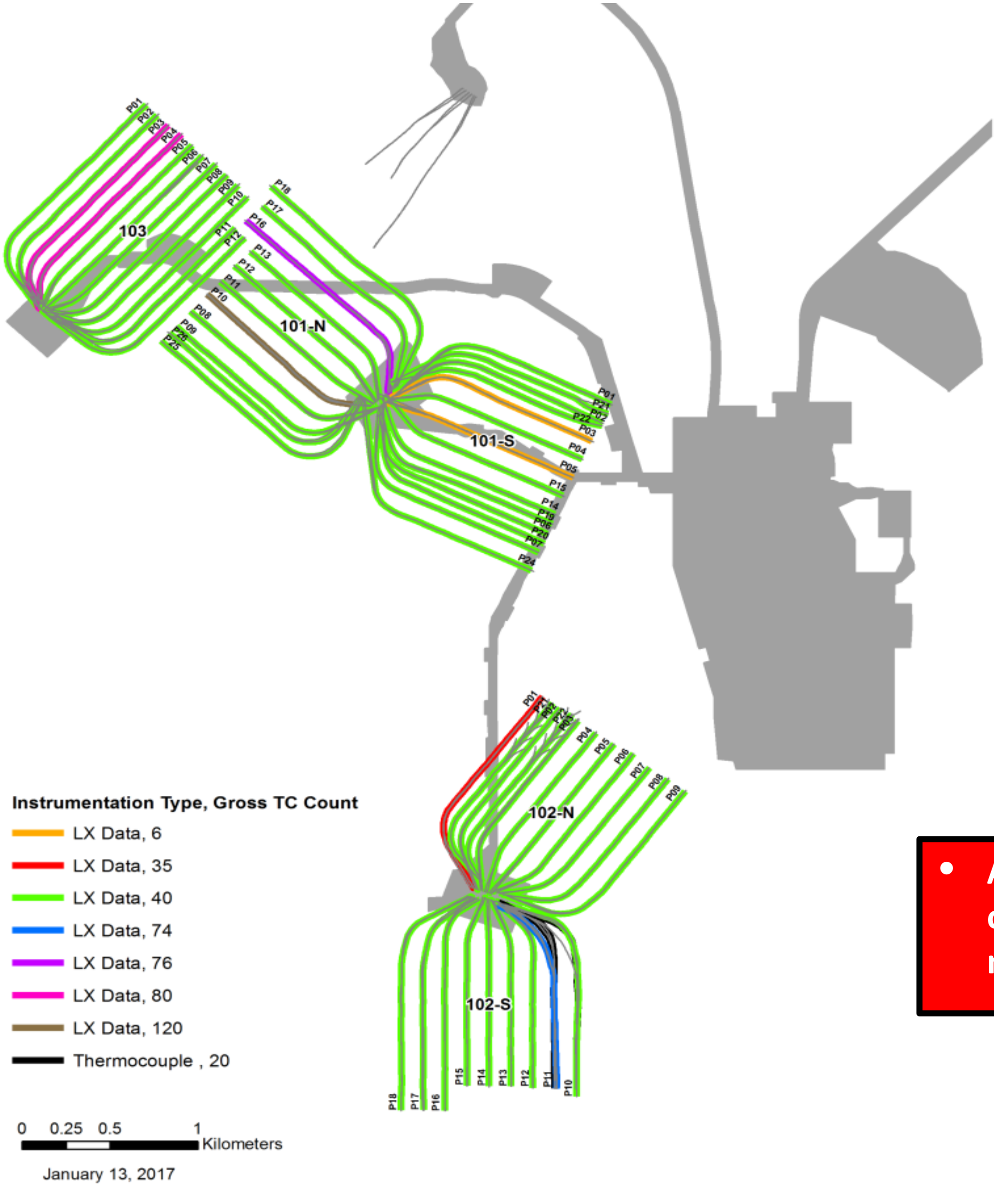
Artificial Lift Strategy & Performance

- The artificial lift mode selection is reliant on the pressure strategy for any given well, or drainage area (DA).
  - Phase 2 wells currently utilize Gas Lift (GL) and then will be converted to ESP when the flowing bottom hole pressure is below the effective GL operating point.
  - Four wells in Pad 103 will be ESP day 1. Which means following the circulation time the well will be converted directly to ESP. 266-2 is an ESP Day 1 pad as well.

Instrumentation in Wells

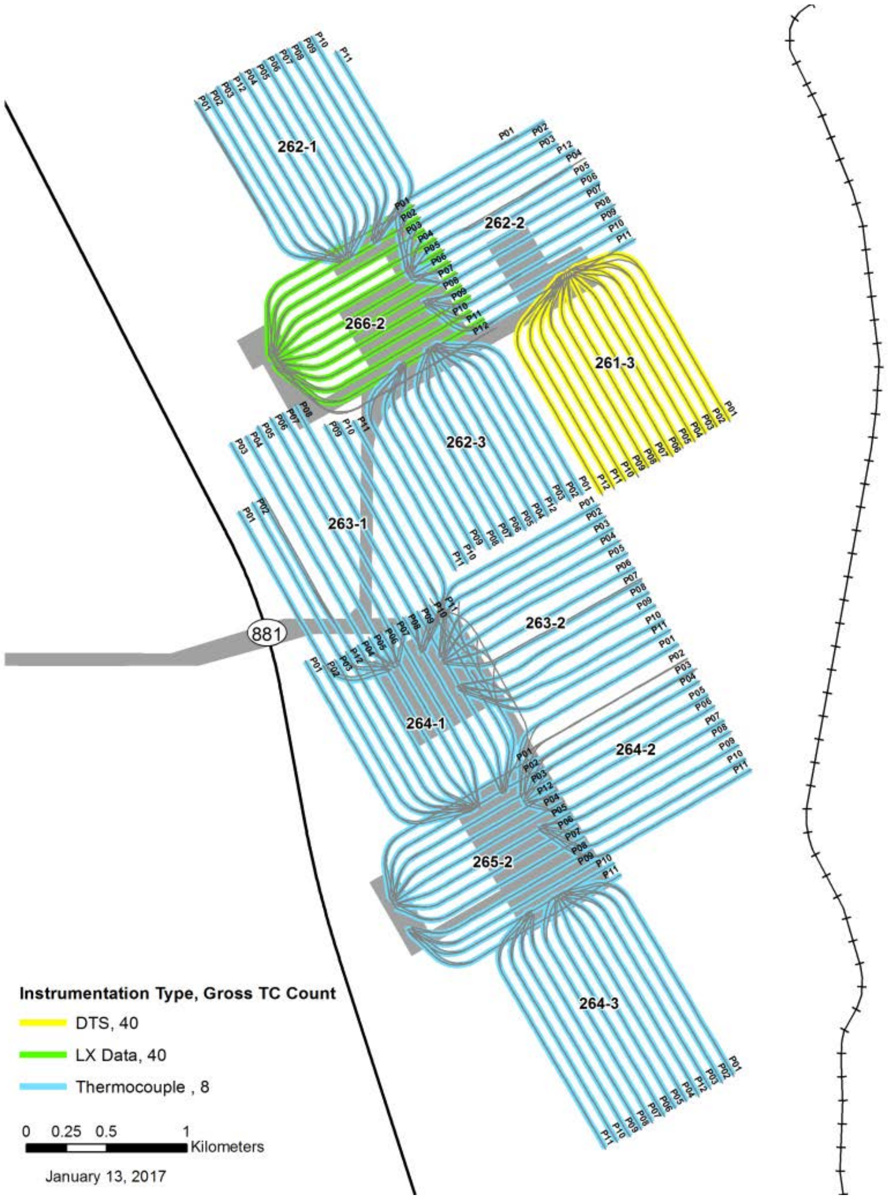
Subsection 3.1.1 (5)

SAGD Well Instrumentation



- **All wells on Phase 1 pads contain 40 point fiber optic strings in the producers unless otherwise noted**

Phase 2 SAGD Well Instrumentation



- **9 of the 11 pads currently online contain 8 thermocouples in the producers.**
- **The other remaining pads contain 40 instrumentation points as per the image.**
- **Pads not online as of Feb 2017:**
  - **Pad 267**

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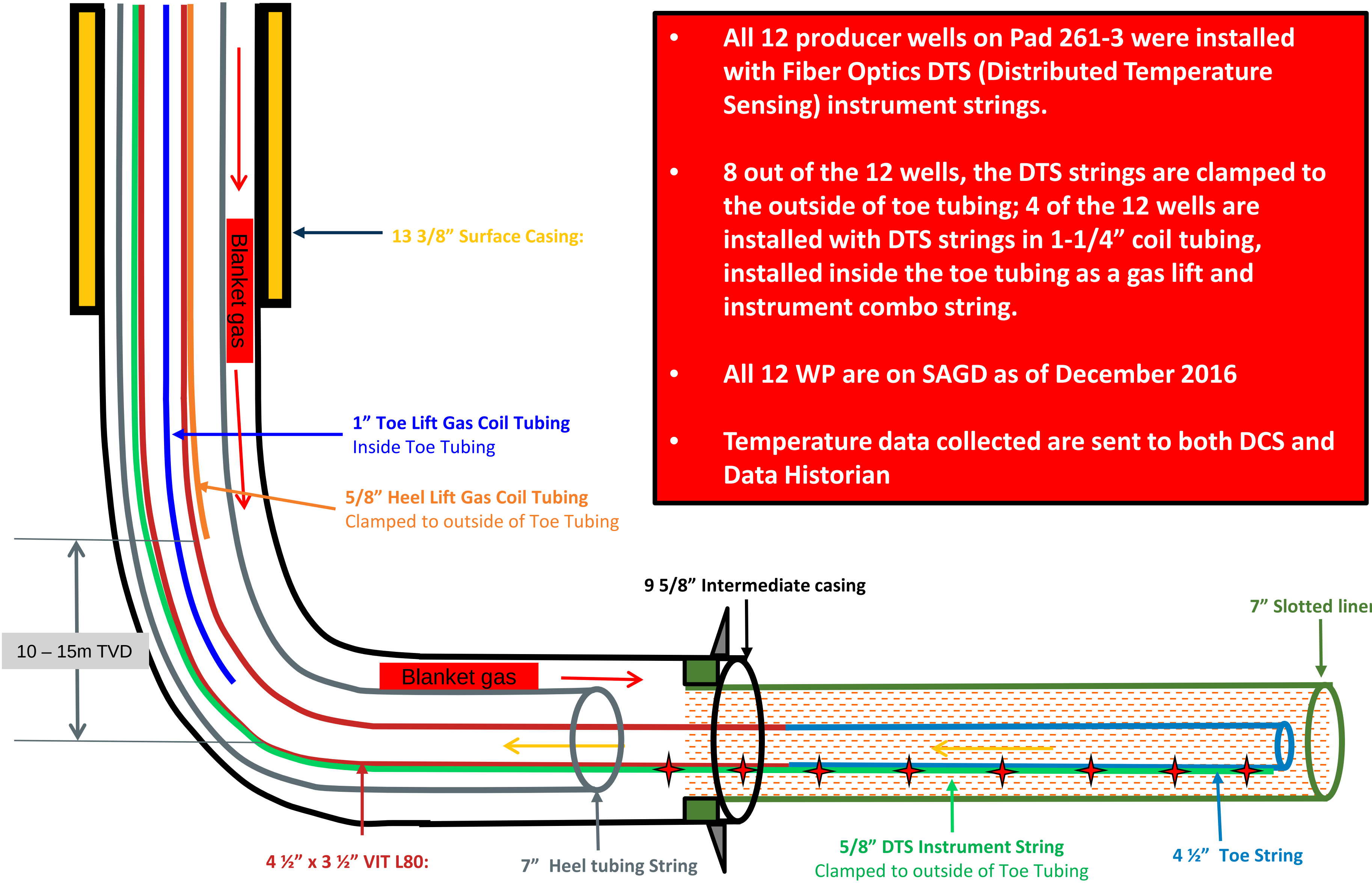
Distributed Temperature Sensing (DTS) - Pad 261-3



- **All 12 producer wells on Pad 261-3 were installed with Fiber Optics DTS (Distributed Temperature Sensing) instrument strings.**
- **8 out of the 12 wells, the DTS strings are clamped to the outside of toe tubing; 4 of the 12 wells are installed with DTS strings in 1-1/4” coil tubing, installed inside the toe tubing as a gas lift and instrument combo string.**
- **All 12 WP are on SAGD as of December 2016**
- **Temperature data collected are sent to both DCS and Data Historian**

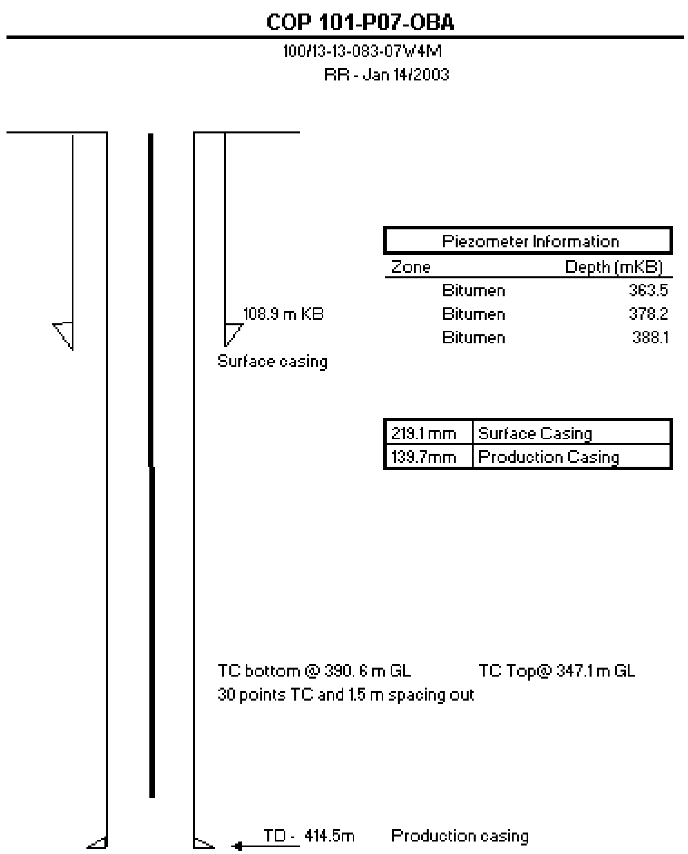
Distributed Acoustic Sensing (DAS) – Pad 103

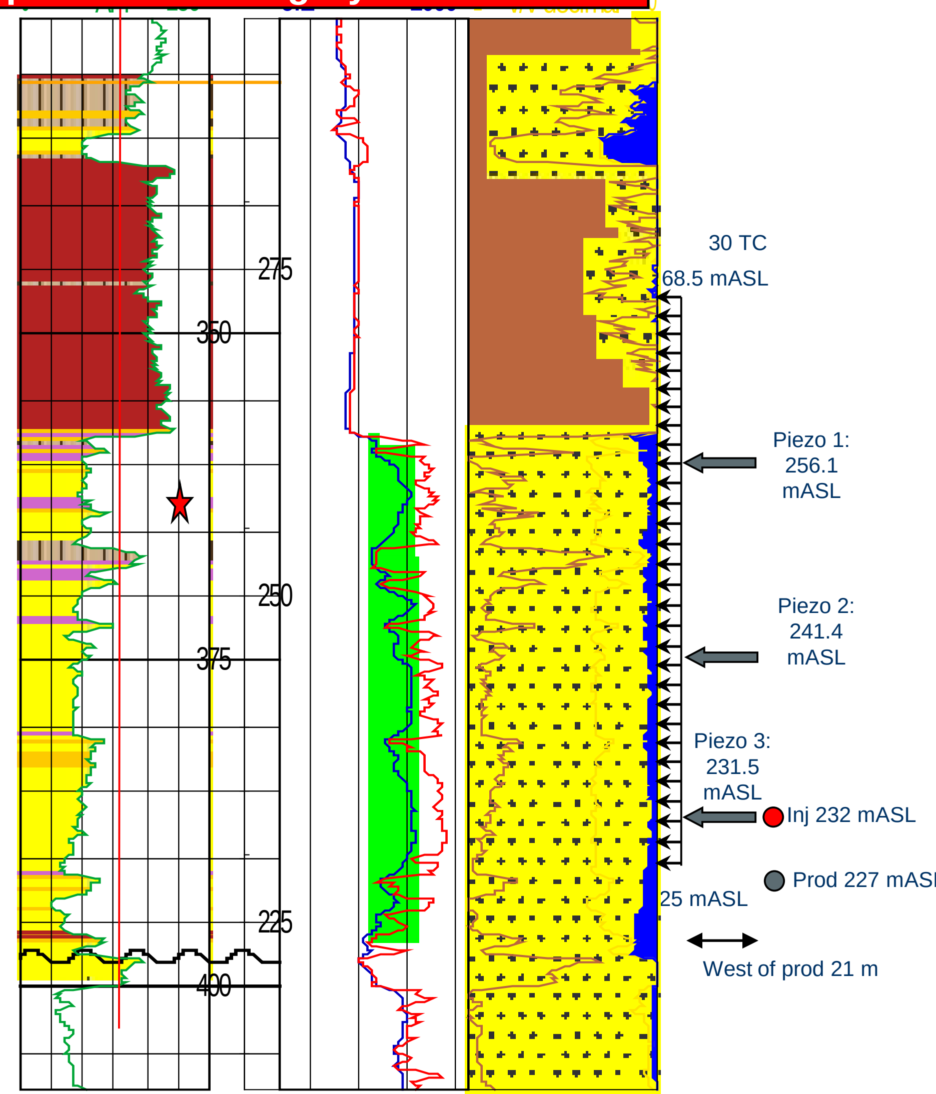
- DAS was piloted at Surmont to understand if it can be used to reduce the frequency of 4D seismic monitors
    - Similar to a VSP it uses a receiver within the well along with a source at surface
    - Additionally it can passively record within the well to complement seismic
- The DAS trial aimed to utilize the DAS technology on producer wells completed with FCD's
- Initial flow rate from DAS data analysis shows DAS data has potential for production profiling at Surmont
- The same capillary tube as LxData or DTS can be used to perform the DAS survey

Typical Observation Well Measurement

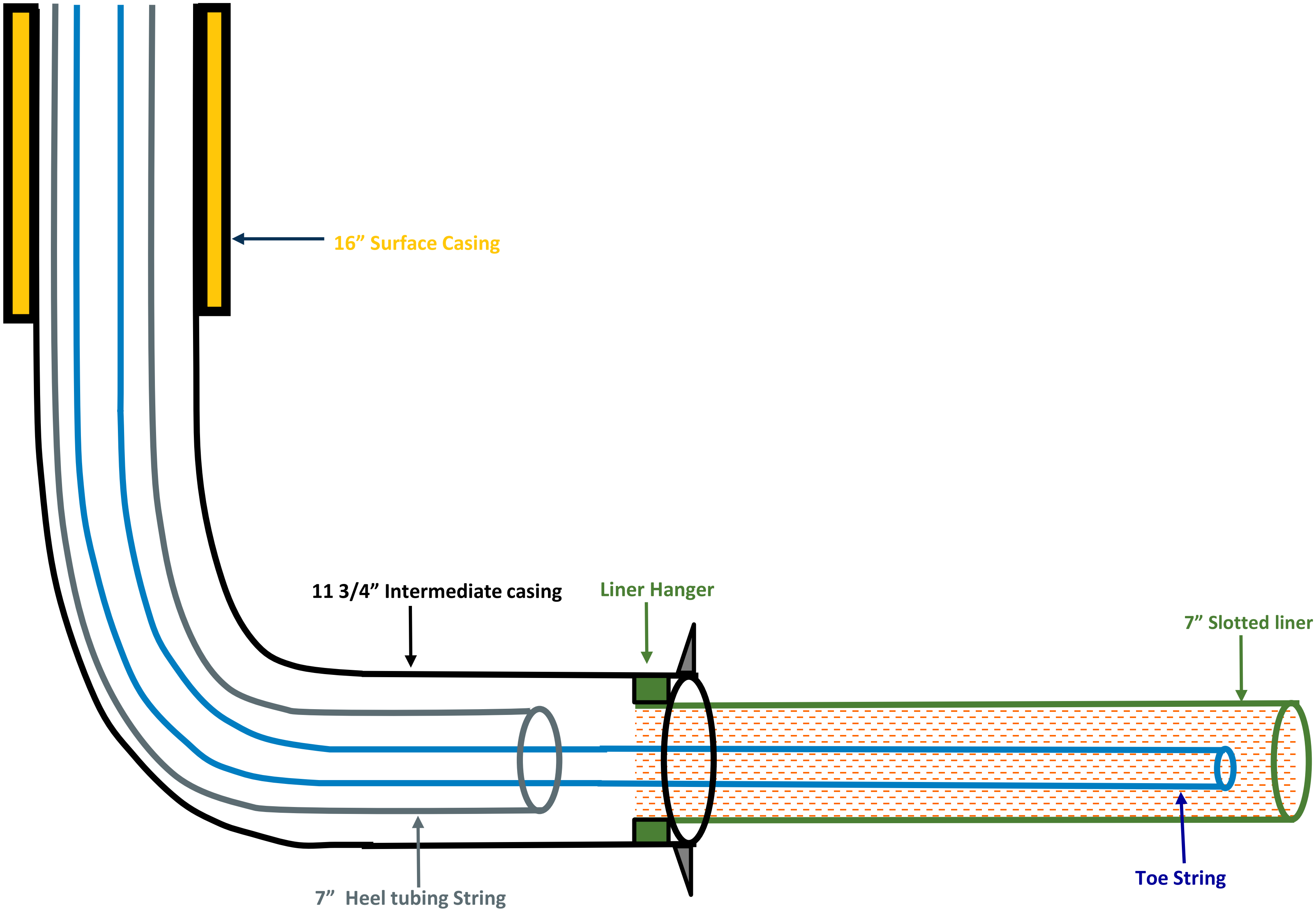
Soft cable Thermocouple (TC) strings were replaced by hard cable TC strings for improved well integrity

- Example thermocouple and piezometer (101-07-OBA)
- Typically 40 TC (2m spacing)
- 0-10 piezometers placed at varying intervals





Typical Injector Well Configuration



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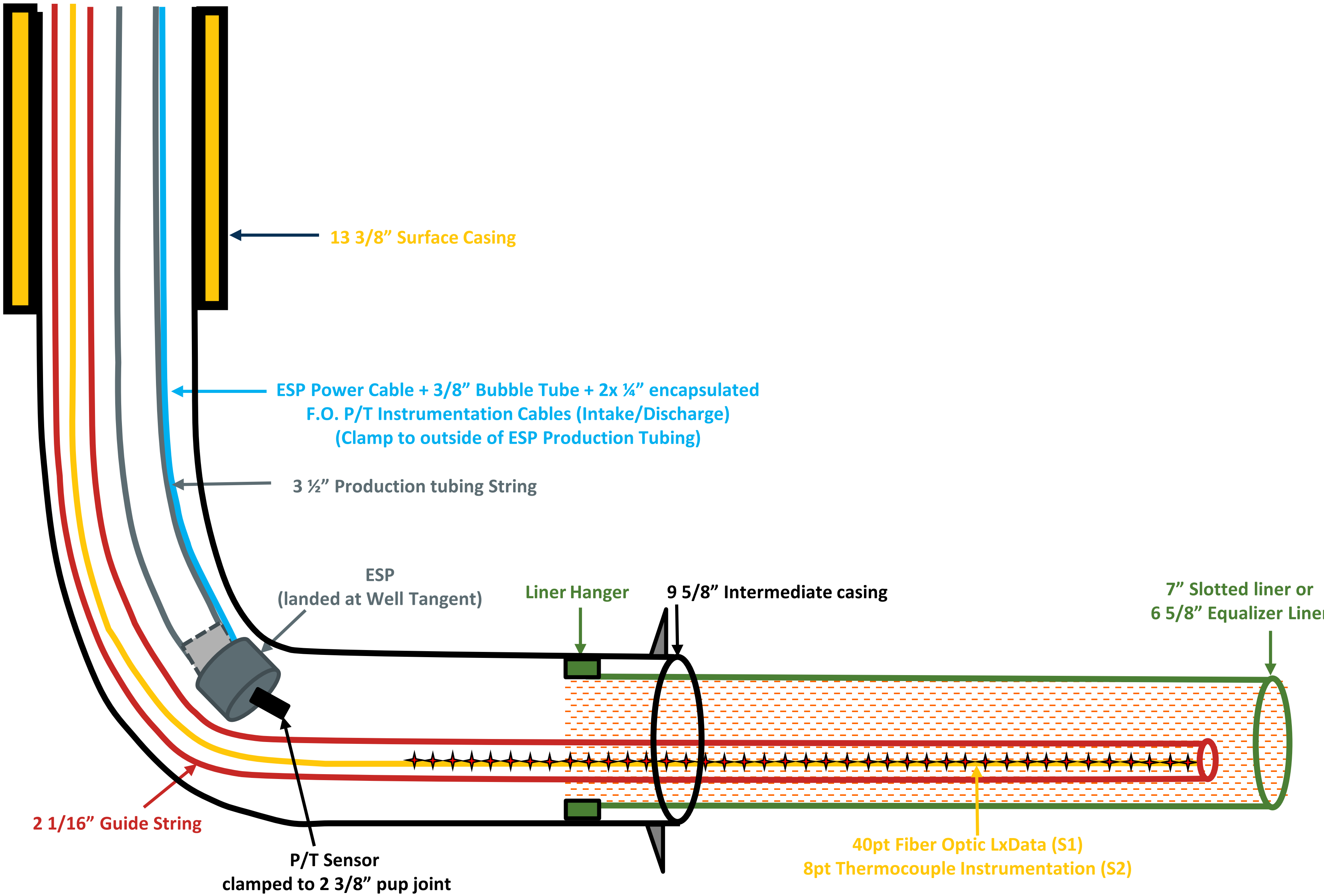
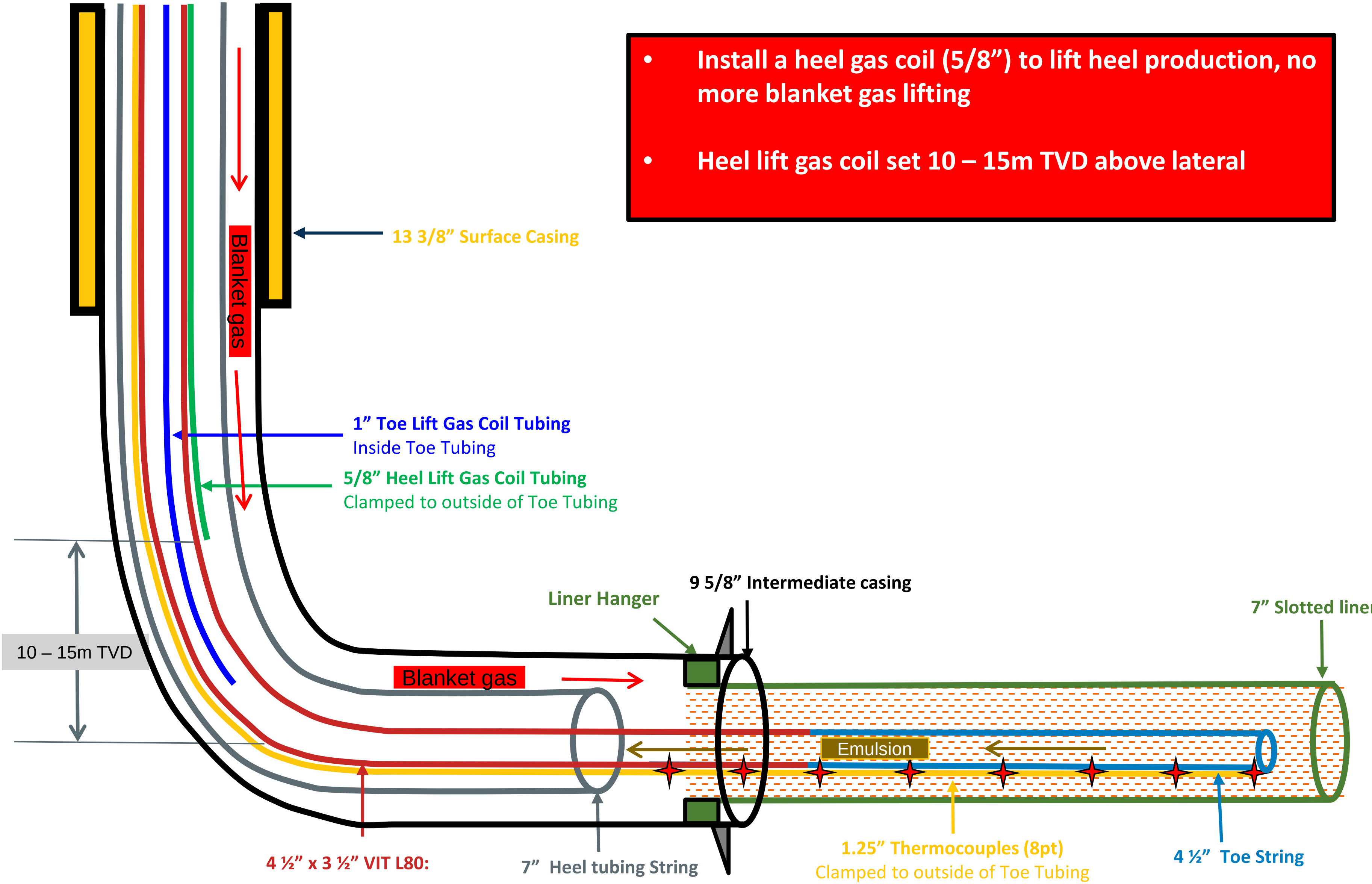
Typical ESP Well Configuration



Improved Gas Lift Producer A: All Pads Excluding 263-1, 263-2 & 264-2

- **Install a heel gas coil (5/8") to lift heel production, no more blanket gas lifting**
- **Heel lift gas coil set 10 – 15m TVD above lateral**



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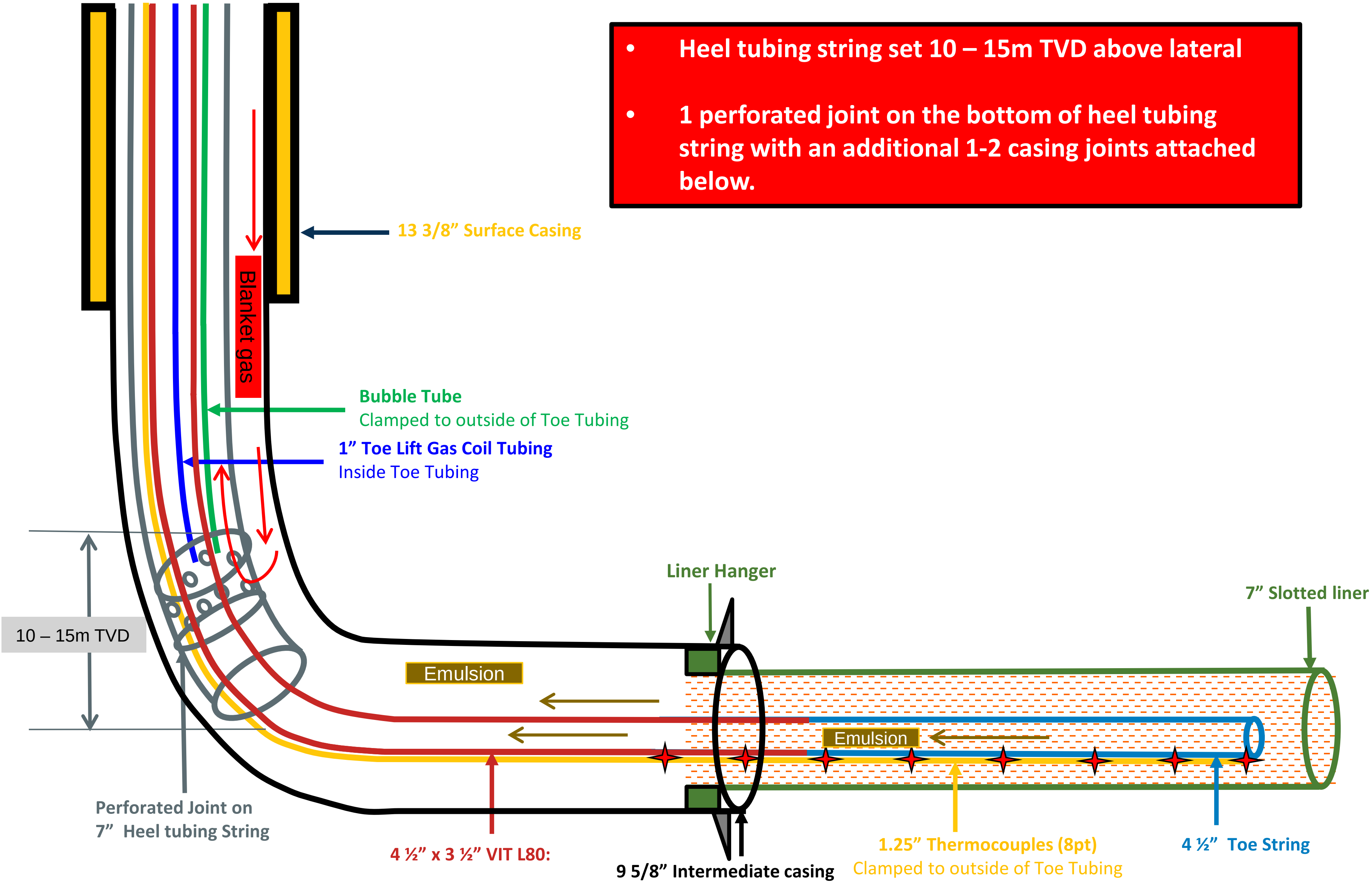
Improved Gas Lift Producer B: 263-1, 263-2 & 264-2

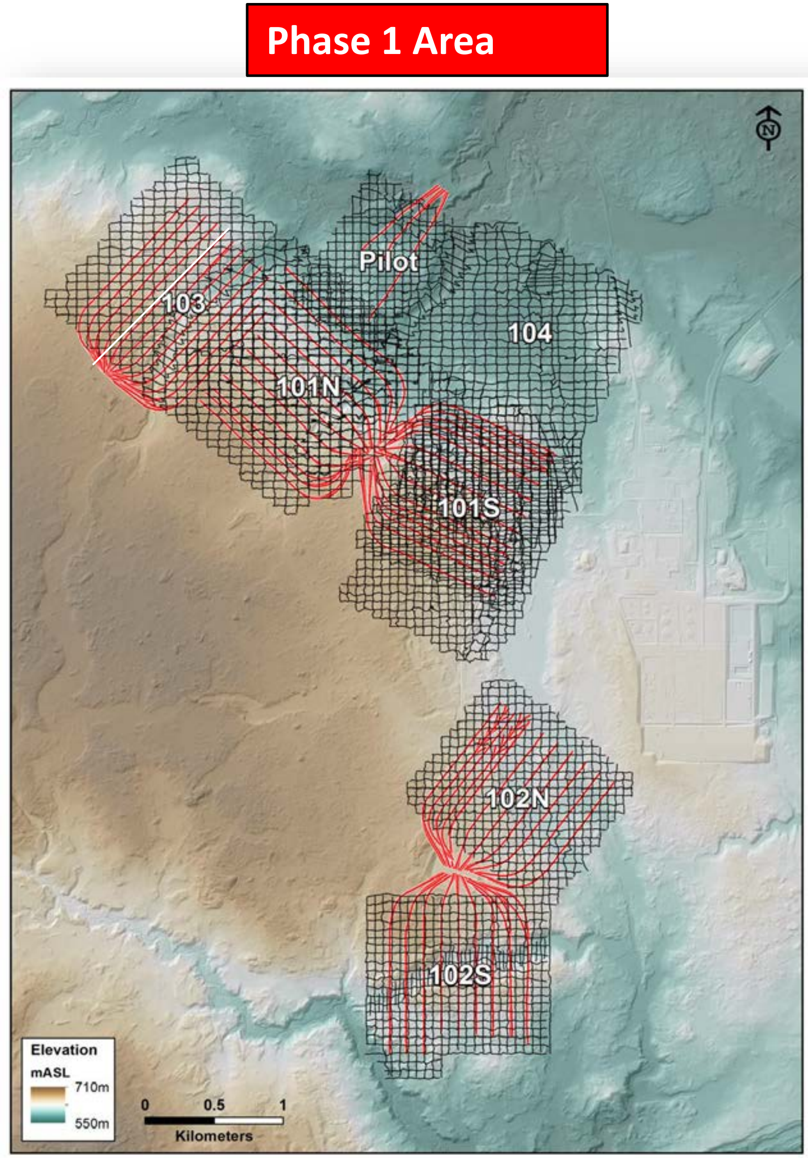
- Heel tubing string set 10 – 15m TVD above lateral
- 1 perforated joint on the bottom of heel tubing string with an additional 1-2 casing joints attached below.



4D Seismic

Subsection 3.1.1 (6)

4D Seismic Location Map – Phase 1



Pilot

- Buried analog single component geophones
- Cased dynamite shots (1/4 Kg) @ 9 m
- 14th monitor acquired in September 2015

Pad 101N

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 8th monitor acquired in March 2015

Pad 101S

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 9th monitor acquired in March 2015

Pad 102N

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 9th monitor acquired in April 2015

Pad 102S

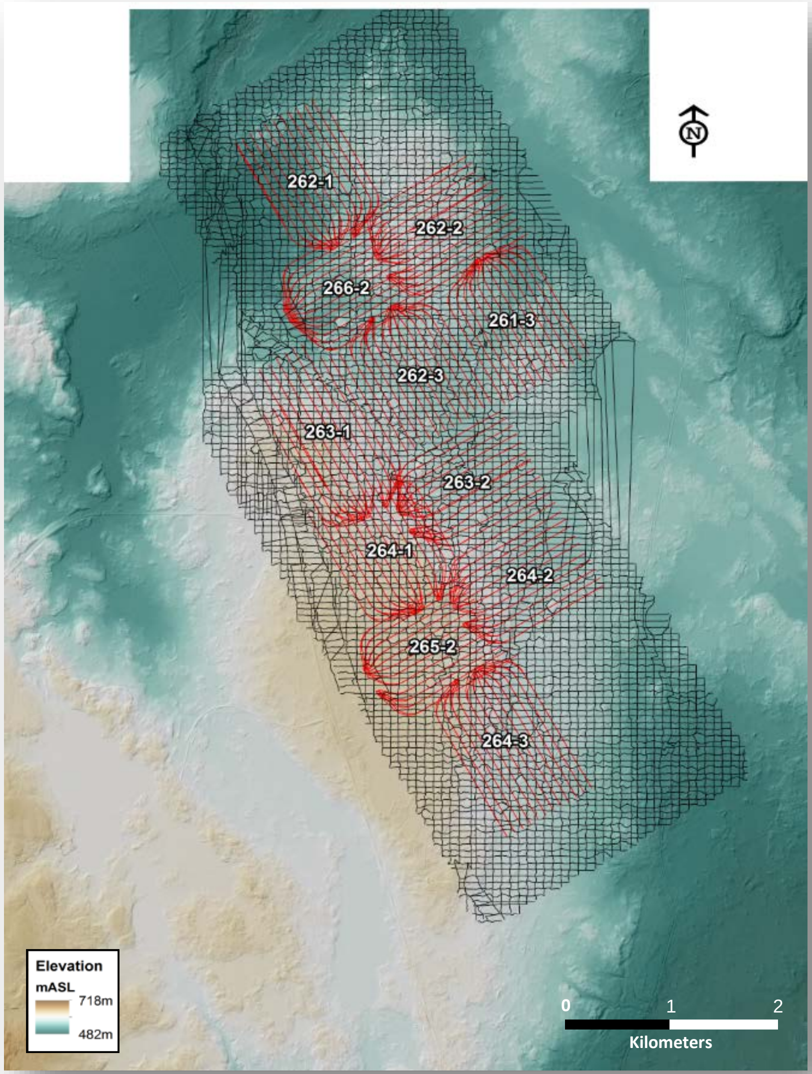
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 6th monitor acquired in October 2016

Pads 103 and 104

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 2nd monitor acquired in October 2016

4D Seismic Location – Phase 2

Phase 2 Area



Phase 2

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- Acquired in three stages:
  - Initial 11 DA's: 2010-11
  - South extension: 2013-14
  - North extension: 2014-2015
- First Monitor acquired in Spring 2016: 263-2

Phase 1 4D Seismic Program

PAD	2013		2014		2015		2016	
	Spring	Fall	Spring	Fall	Spring	Fall	Spring	Fall
101N	M	M	M	M	M			
101S	M		M		M			
102N	M		M		M			
102S			M					M
Pilot		M		M		M		
103							M	M
104								

B **Baseline** M **Monitor**

Phase 2 4D Seismic Program

PAD	2016	
	Spring	Fall
263-1		M
264-1		M
265-2		M
264-3		M
262-1		
266-2		
262-3		
263-2	M	
264-2		
262-2		
261-3		

B Baseline M Monitor

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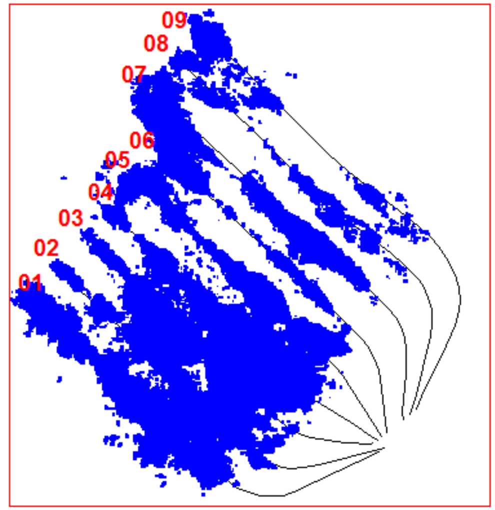
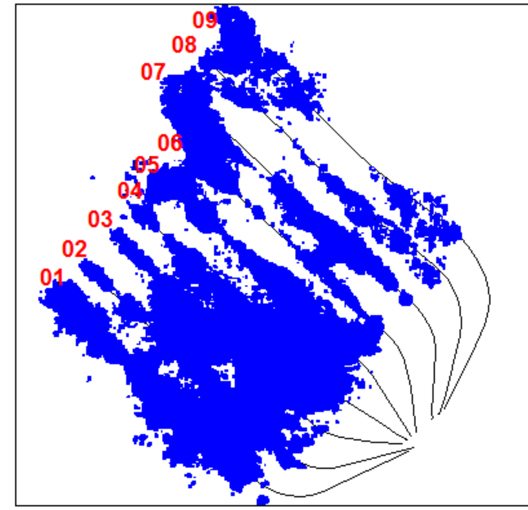
2015 4D Seismic Results Pad 101

- Well Pair 07/08/09, without a true baseline.
- 4D anomaly volume have increased for the remaining well pairs.
- Good conformance, especially at the heel.

101 North 7th monitor - September 2014

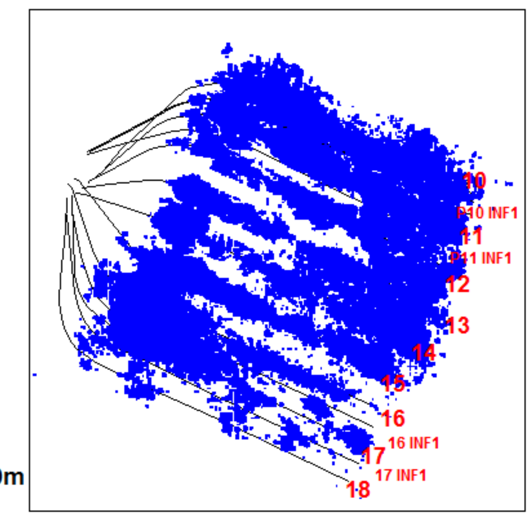


101 North 8th monitor - March 2015

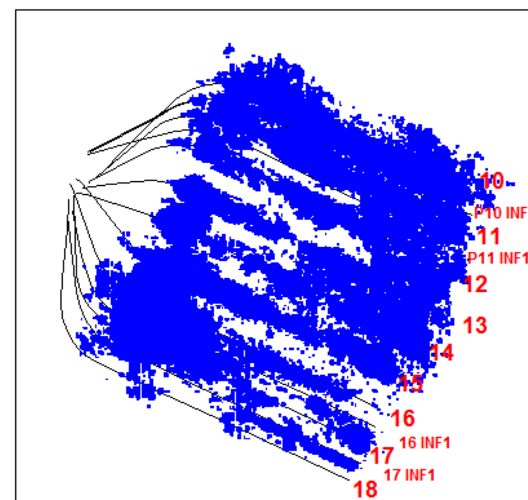


- 4D anomaly volumes have increased.
- Continued conformance improvement along Well Pad 10, 11, 16, 17.
- Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.

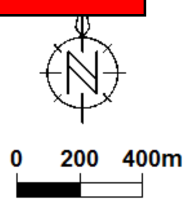
101 South 8th monitor - March 2014



101 South 9th monitor - March 2015



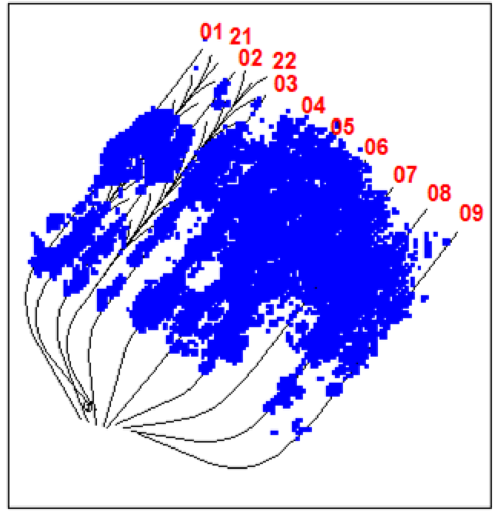
= 4D anomaly
~60 deg C Isotherm



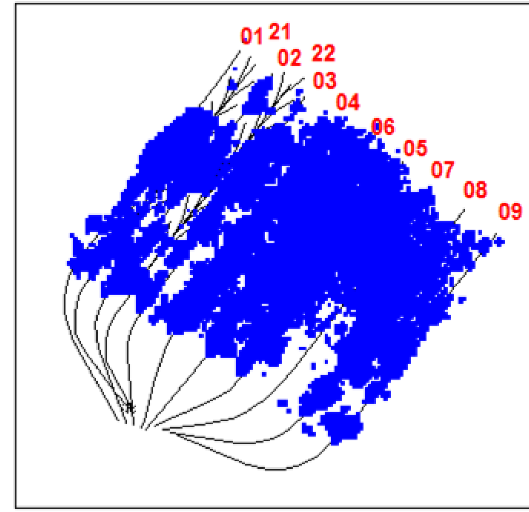
2016 4D Seismic Results Pad 102 (102S)

- **4D anomaly volumes have increased. Improved conformance along well pairs 1 to 9.**

102 North 8th monitor - April 2014

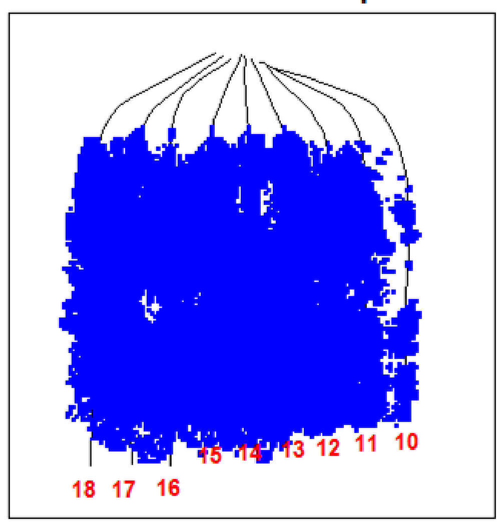


102 North 9th monitor - April 2015

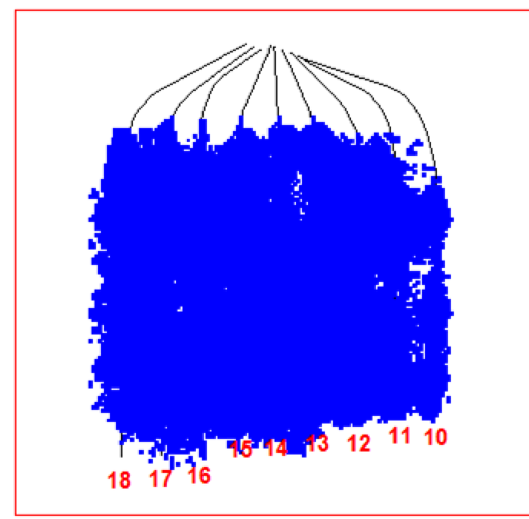


- **4D anomaly volume have increased. Improved conformance along well pairs 10 to 18.**

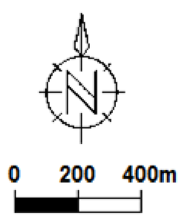
102 South 5th monitor -April 2014



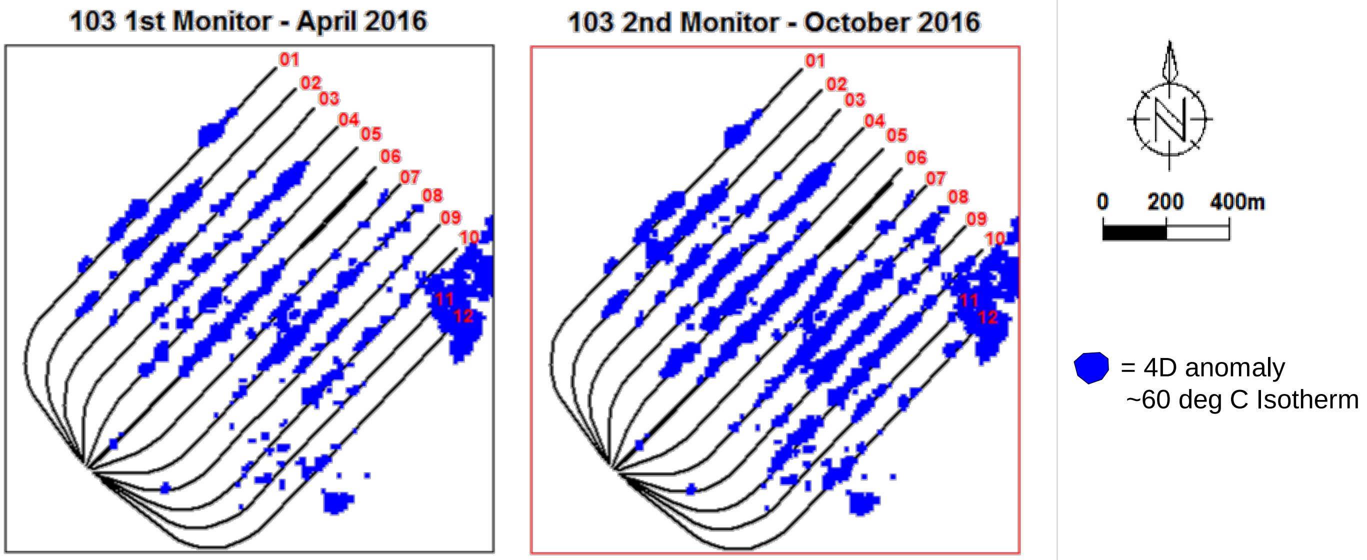
102 South 6th monitor - October 2016



= 4D anomaly
~60 deg C Isotherm



2016 4D Seismic Results Pad 103

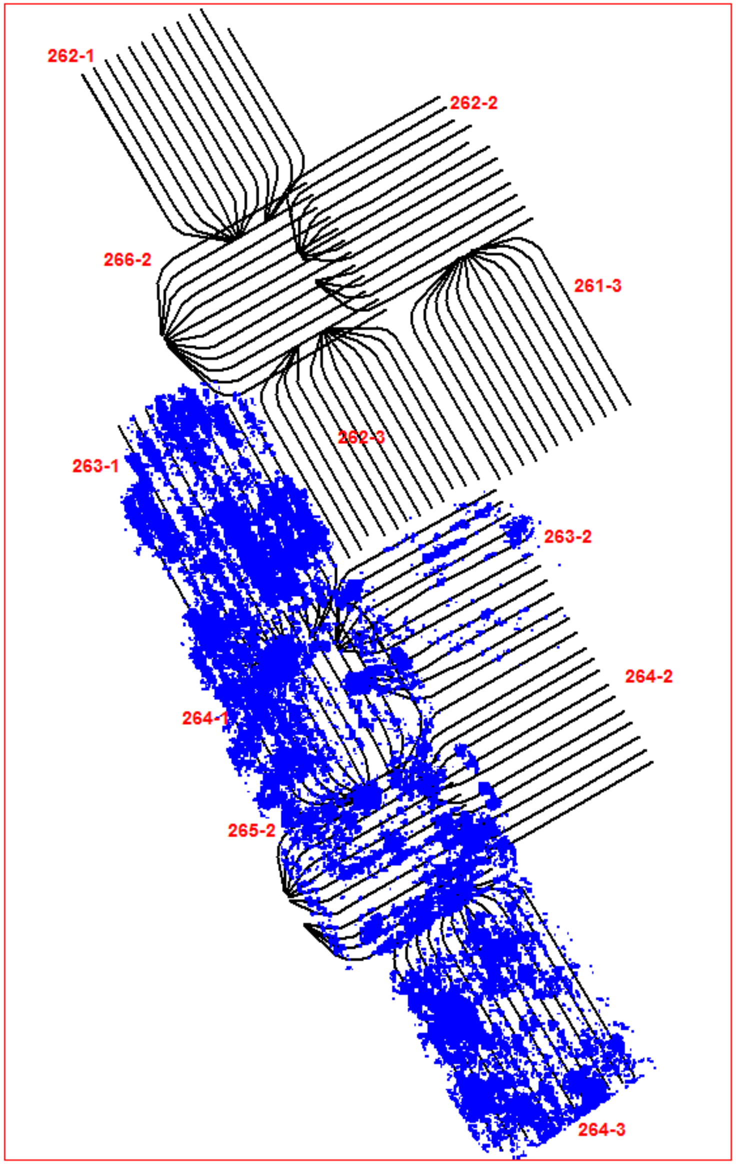


- **Relative good conformance in most of well pair.**
- **4D indications of coalescence with thermal chamber of Pad 101N (103-11 and 103-12)**

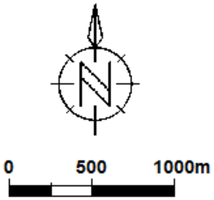
2016 4D Seismic Results Phase 2

- **Spring Monitor:**
  - **263-2**
- **Fall Monitors:**
  - **263-1**
  - **264-1**
  - **265-2**
  - **264-3**
- **Relative good conformance in most well pairs (except 263-2 – First Monitor few months after SAGD conversion)**
- **4D indications of coalescence between 263-1 and 264-1**

S2 1st Monitor - 2016 (Spring - Fall)



= 4D anomaly
~60 deg C Isotherm



Problem:

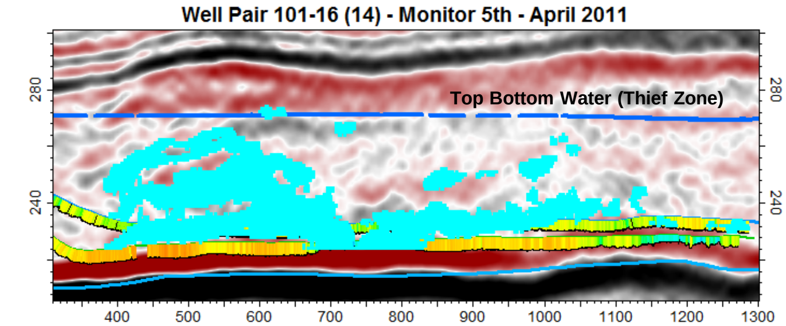
- Well pair 101-P16 lacking good conformance along well pair.

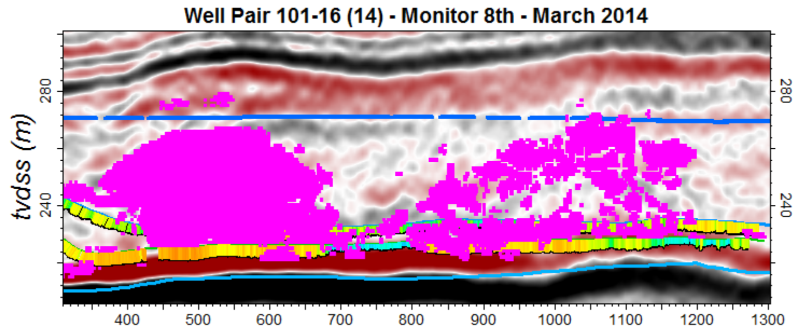
Action:

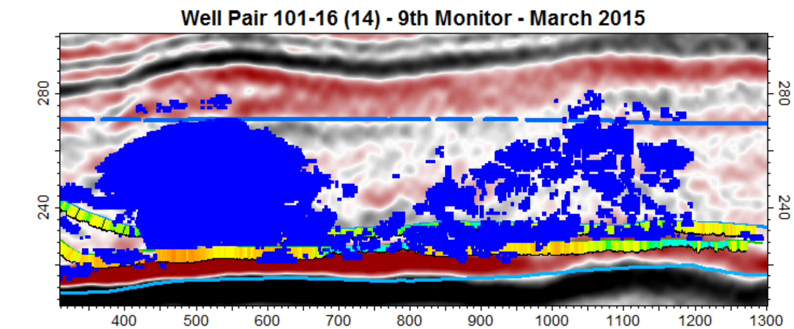
- Increase pressure of steam injection at toe.

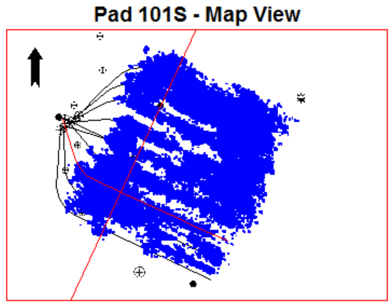
Results:

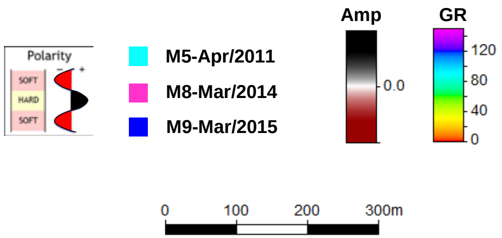
- Conformance improved at toe.

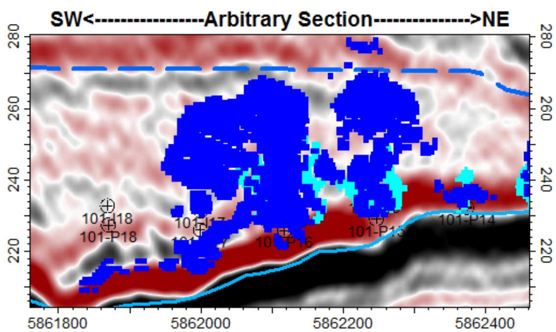




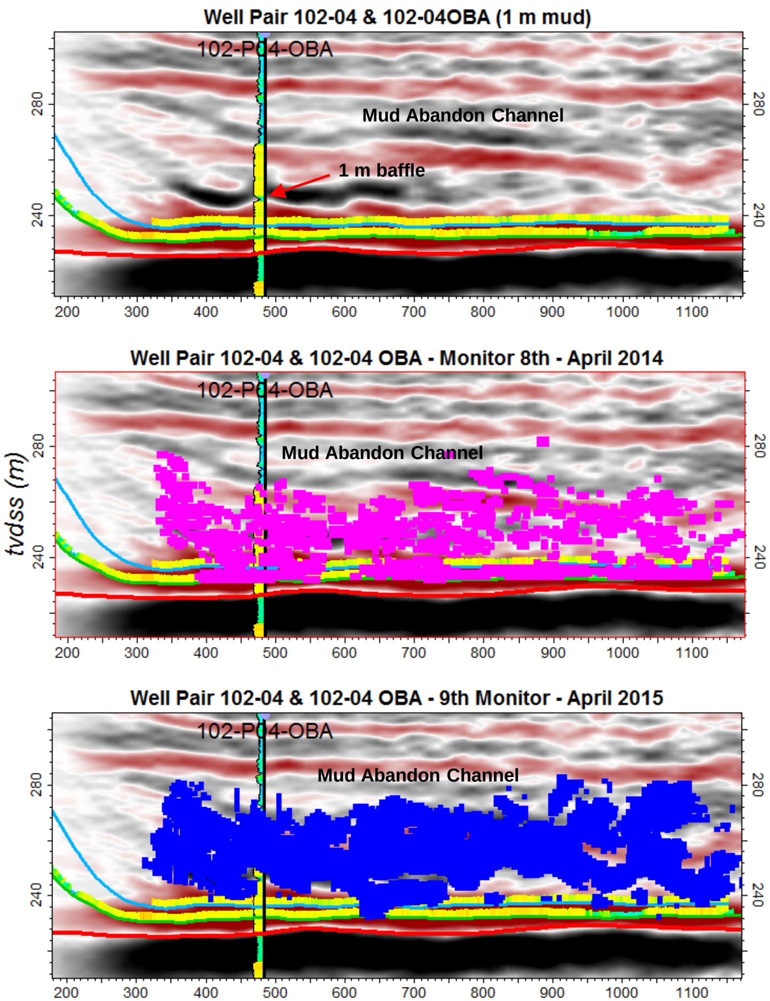


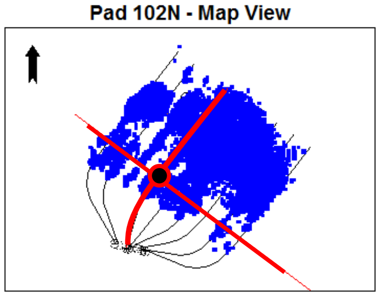


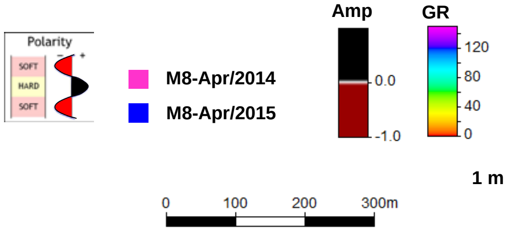


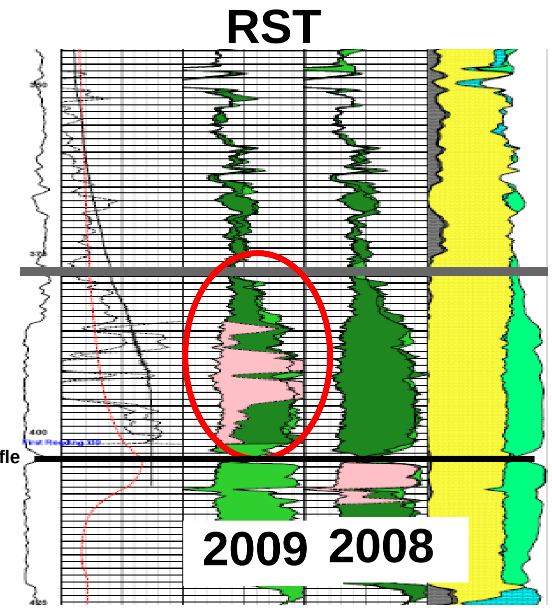


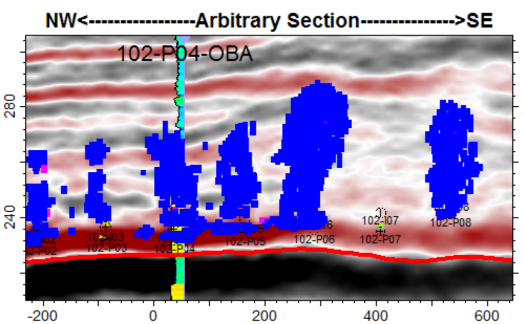
Seismic Examples: 102-04 OBA Baffle Breakthrough (Heel)











- 2009 RST and 4D surveys confirmed recovery above mudstone.
- Operating pressure reduced to manage thief zone interactions.

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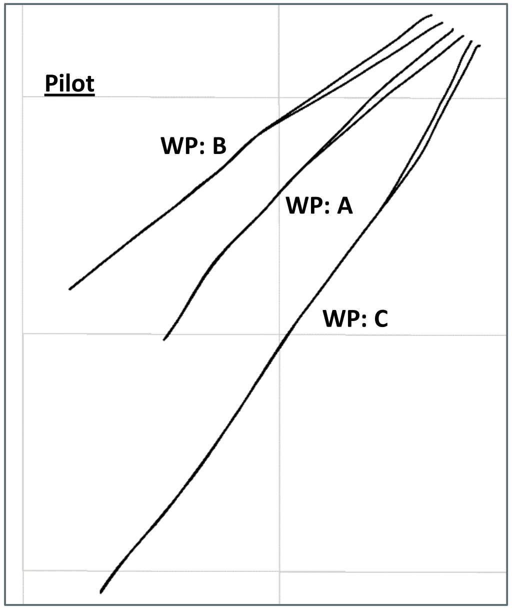
4D Seismic Program 2016

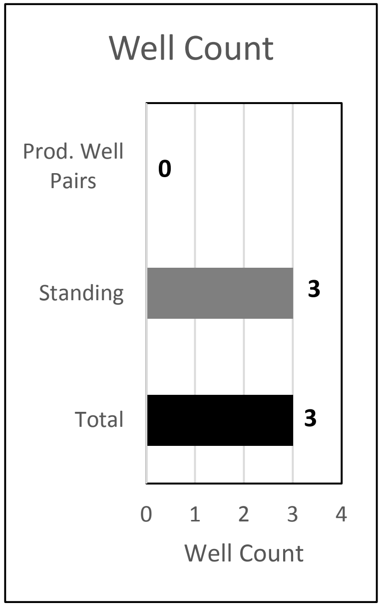
- 4D seismic has proven very useful in monitoring and optimizing conformance and pressure strategy.
- 4D correlates with observation well data.
- Continuing to optimize heel/toe production/injection splits using 4D results.
- Ongoing efforts to history match reservoir models using 4D seismic.

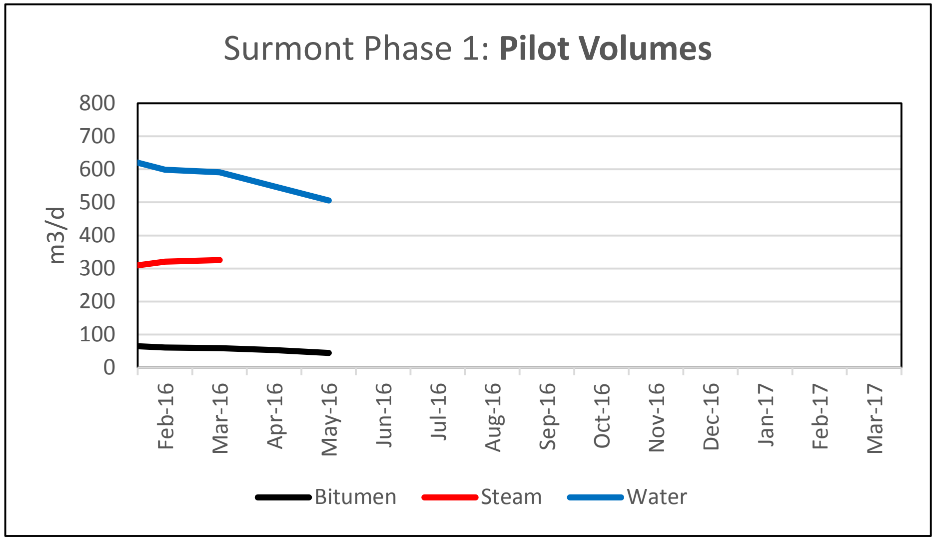
Scheme Performance

Subsection 3.1.1 (7)

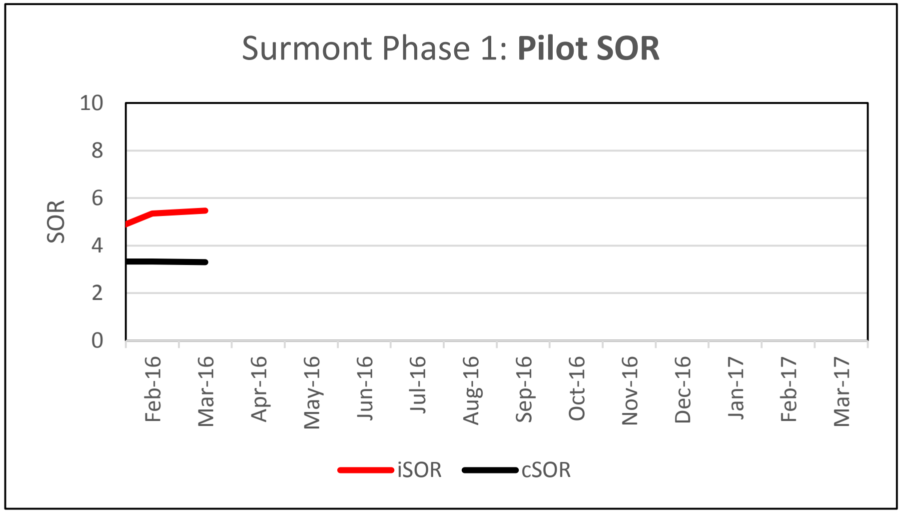
Surmont: Pilot Performance Plot







Volumes (E3M3) – Oil: 7; Steam: 20; Water: 68



Ratios– SOR: 5.4; WOR: 9.9

- **Pilot ceased operations after the Fort McMurray Wildfire Emergency Shutdown on May 5, 2016.**

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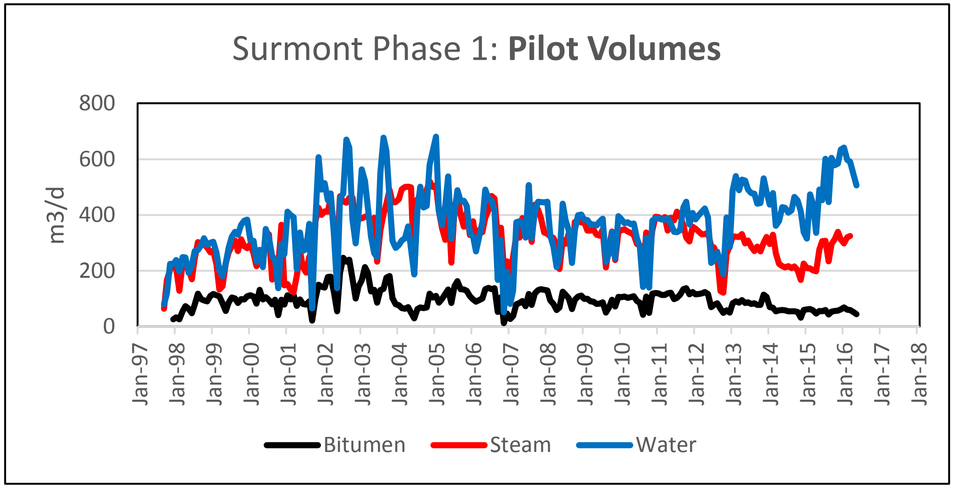
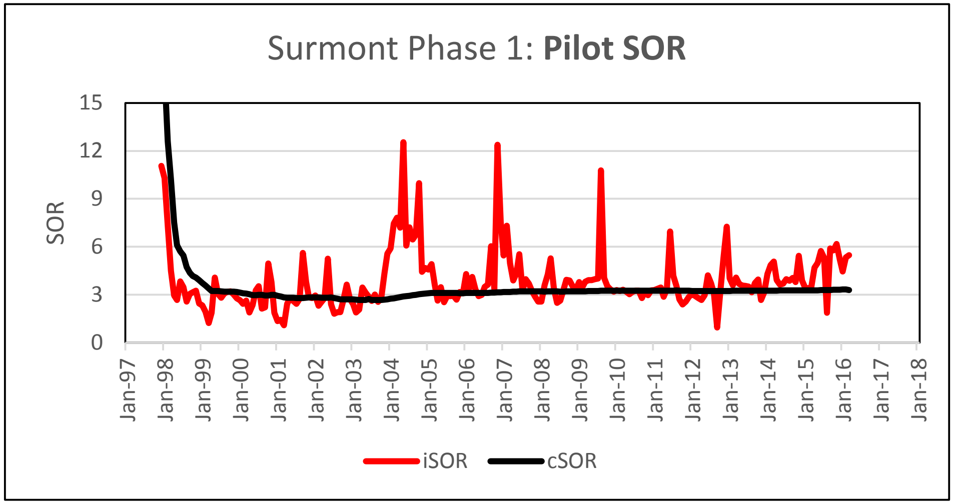
Surmont: Historical Pilot Performance Plot

SURMONT PILOT– WELL PAIRS A, B, C



VOLUMES (E3M3) - OIL: 642; STEAM: 2135; WATER: 2528

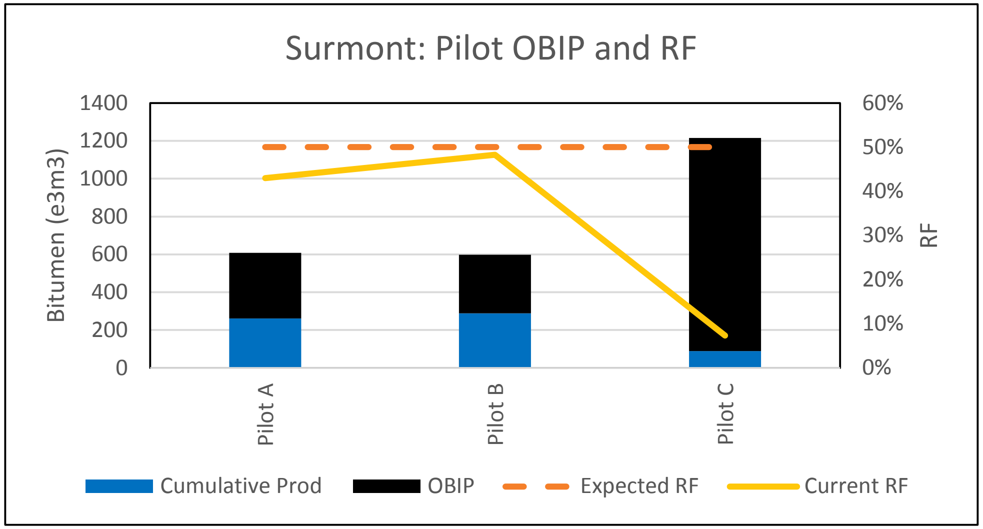


AGGREGATE RATIOS- cSOR: 3.3; cWOR: 3.9

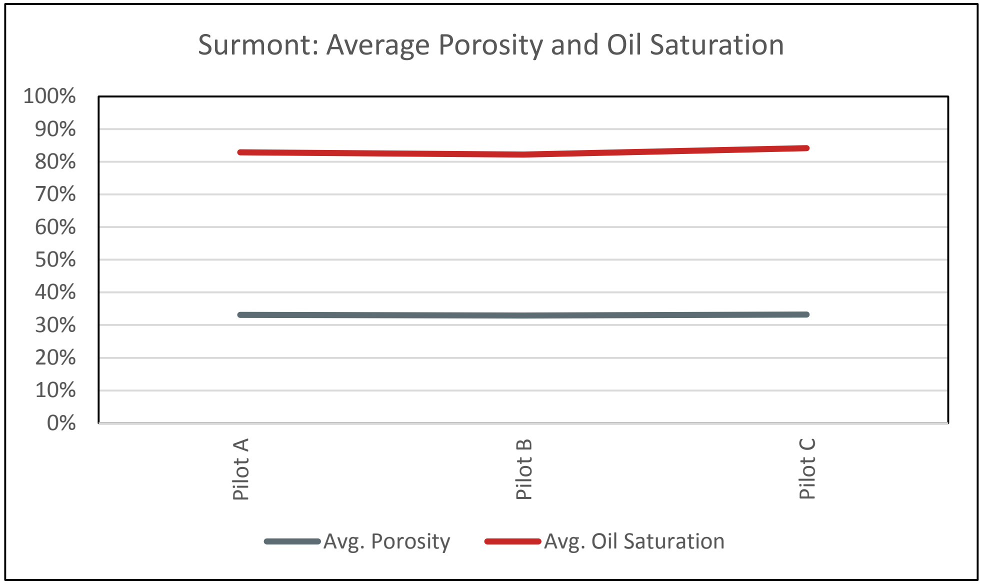
- **Late life Pilot performance was impacted by thief zone (top water) interaction.**

Surmont: Pilot – OBIP and RF

OBIP = (BV)(Φ)(So)

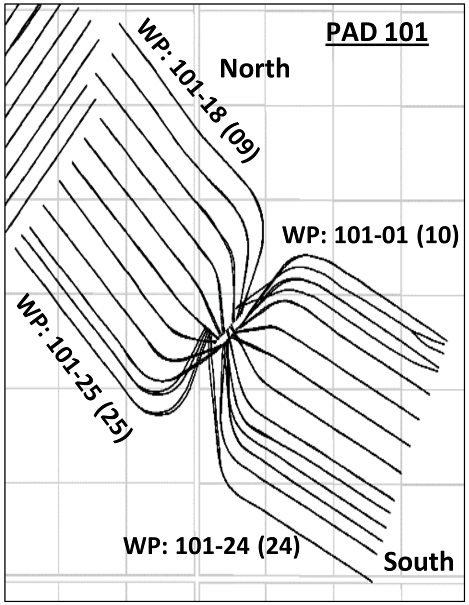


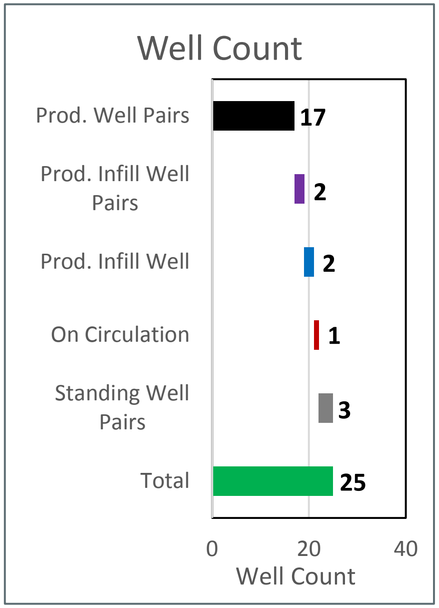
- **OBIP: 597 – 1215 E3M3**
- **Current RF: 7% - 48%**

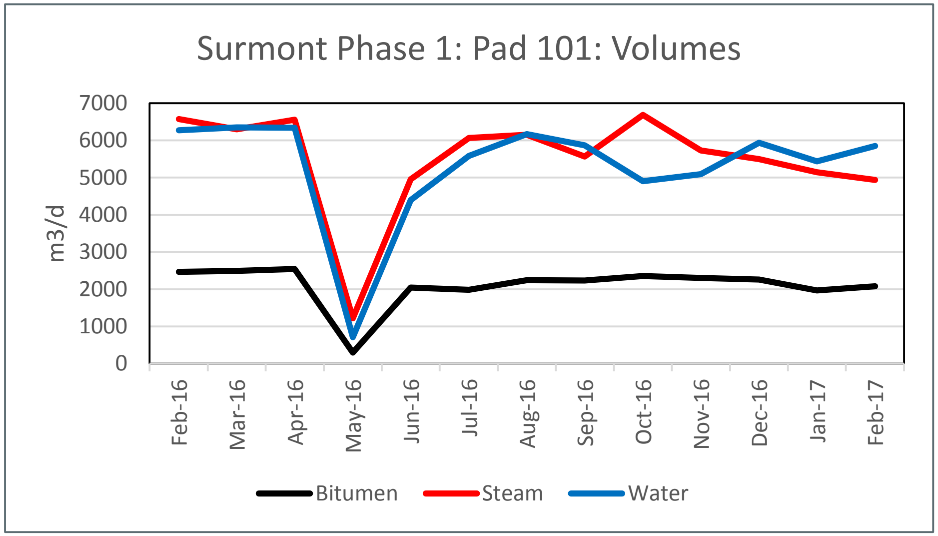


- **Porosity: 33%**
- **Oil saturation: 82% - 84%**

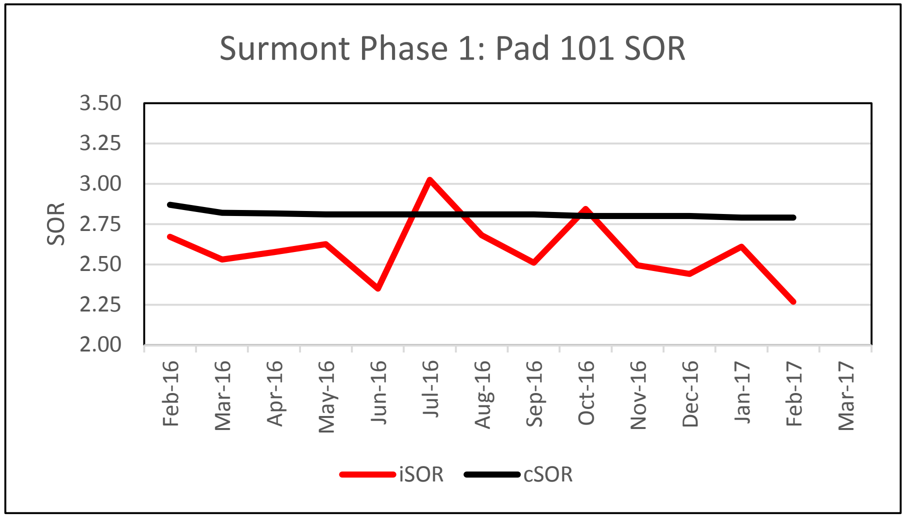
Surmont: Pad 101 Performance Plots







Volumes (E3M3) – Bitumen: 826; Steam: 2162; Water: 2085



Ratio – SOR: 2.62; WOR: 2.52

- **101-07(18) is on circulation**
  - **~ 18 months of circulation**
  - **Slim hole completion**
- **Installed tubing deployed flow control devices on 3 producers**
  - **101-06 (17) – increased total emulsion rate**
  - **101-11(04) – installed Feb 14, 2017**
  - **101-20 - increased total emulsion rate**

- **Increased steam injection has resulted in incremental bitumen production as the iSOR has remained flat or decreased**

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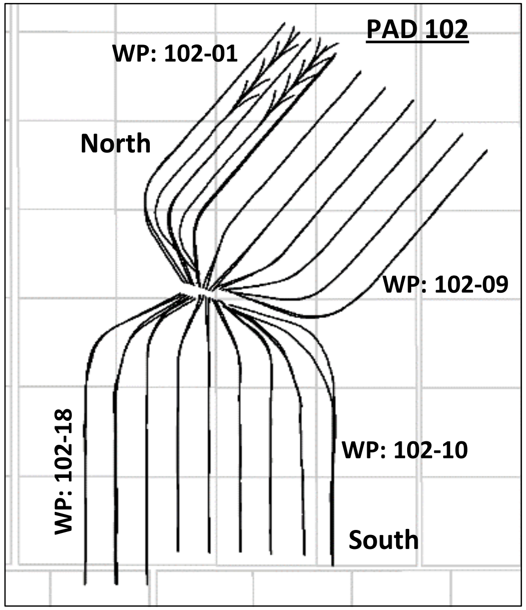
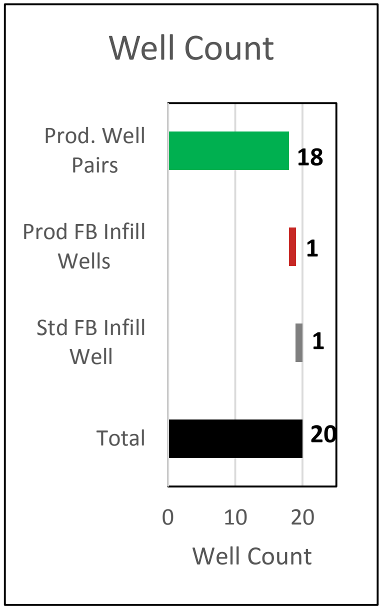
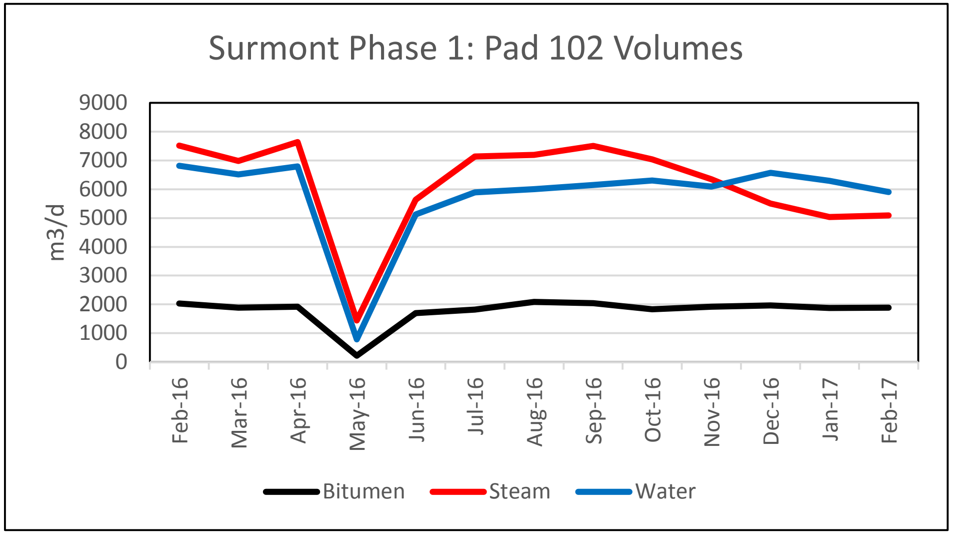
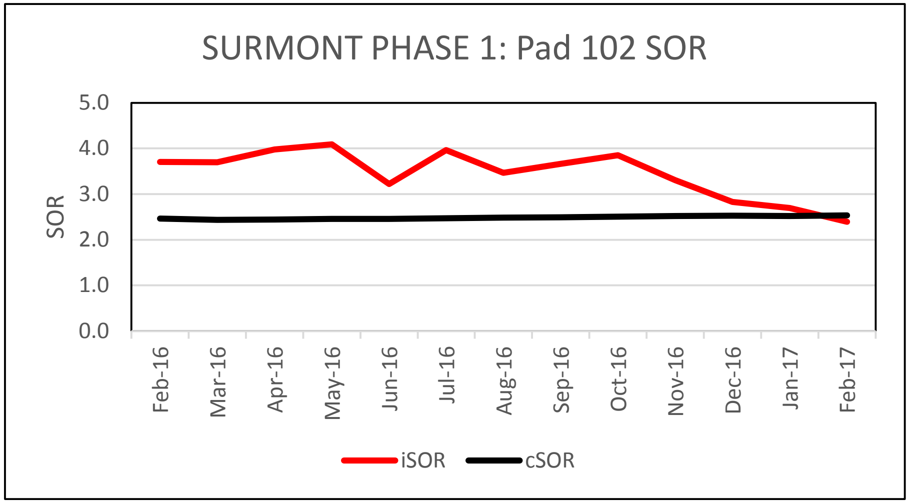
Surmont: Pad 102 Performance Plots







Volumes (E3M3) – Bitumen: 702; Steam: 2424; Water: 2277

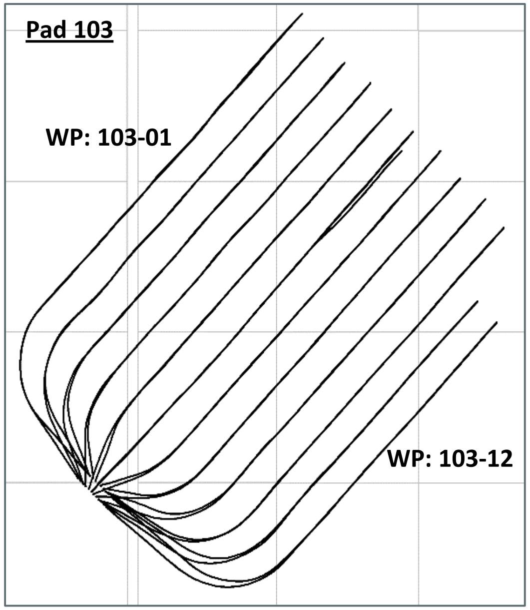


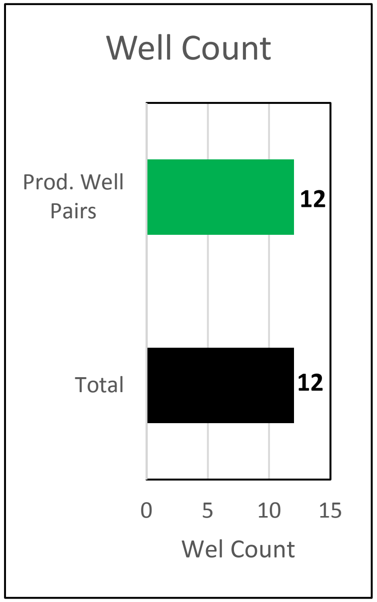
Ratio – SOR: 3.5; WOR: 3.2

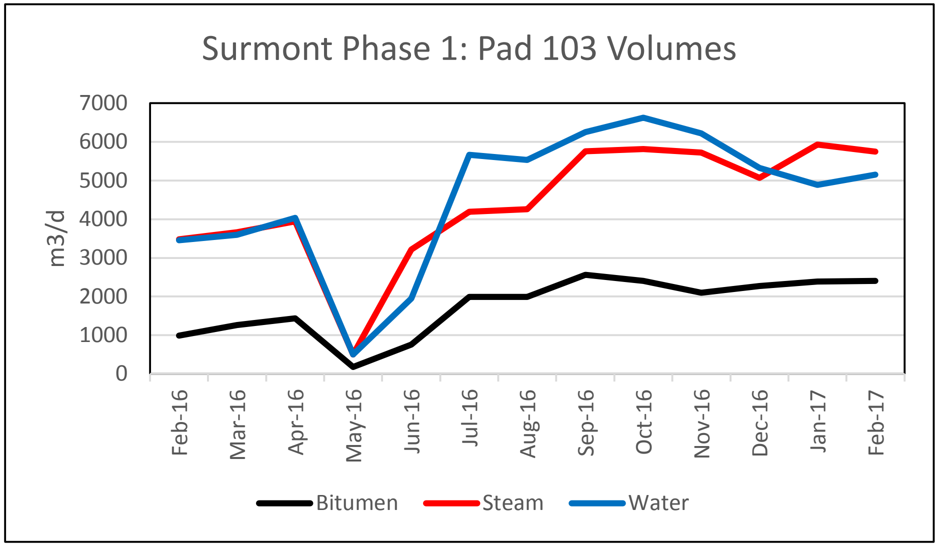
- **Sustained production from P21 FB infill well**
  - **Learnings are being applied to P22 FB infill well**
- **NCG pilot commenced Jan, 2017 on WP 102-10/11/12**
- **Installed tubing deployed flow control devices on 2 producers**
  - **102-02: ESP failure; performance is TBD**
  - **102-09: Increased total emulsion rate**

- **Lower steam injection has resulted in a lower iSOR but higher reservoir pressures have contributed to sustaining a flat bitumen production rate.**

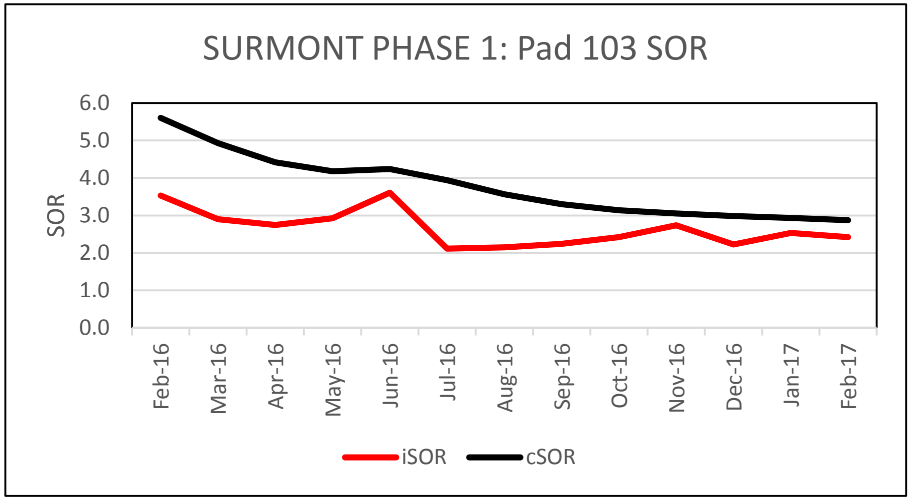
Surmont: Pad 103 Performance Plots







Volumes (E3M3) – Bitumen: 688; Steam: 1734; Water: 1794

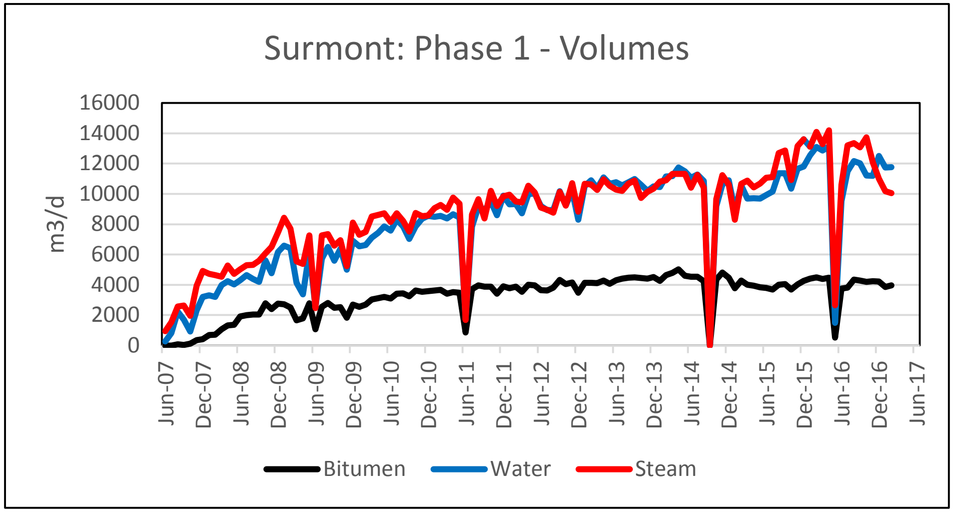


Ratio – SOR: 2.5; WOR: 2.6

- **Initial production performance in line with forecasted expectations.**
- **ISOR continues to decline as expected with a new pad startup.**

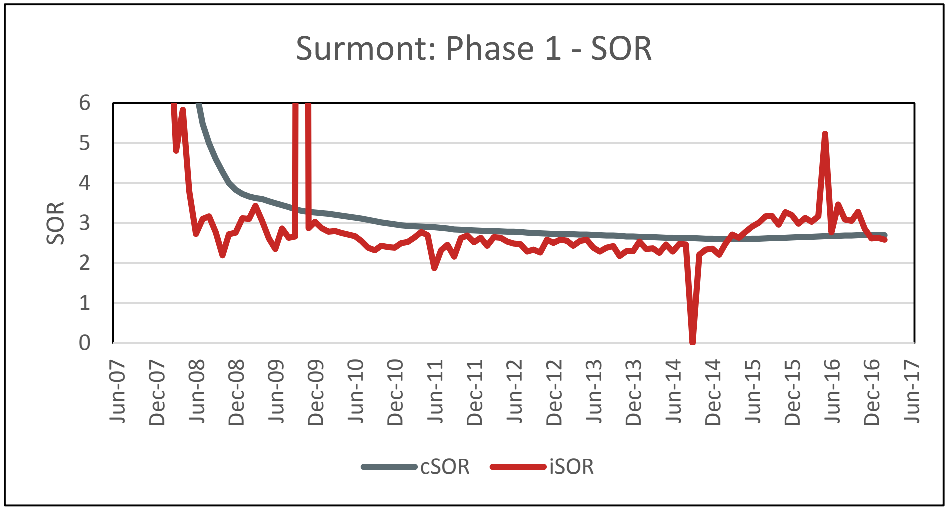
Surmont: Phase 1 Historical Performance Plots

PADS 101 / 102 / 103



VOLUMES (E6M3) - BITUMEN: 11.6; STEAM: 29.2; WATER: 31.2

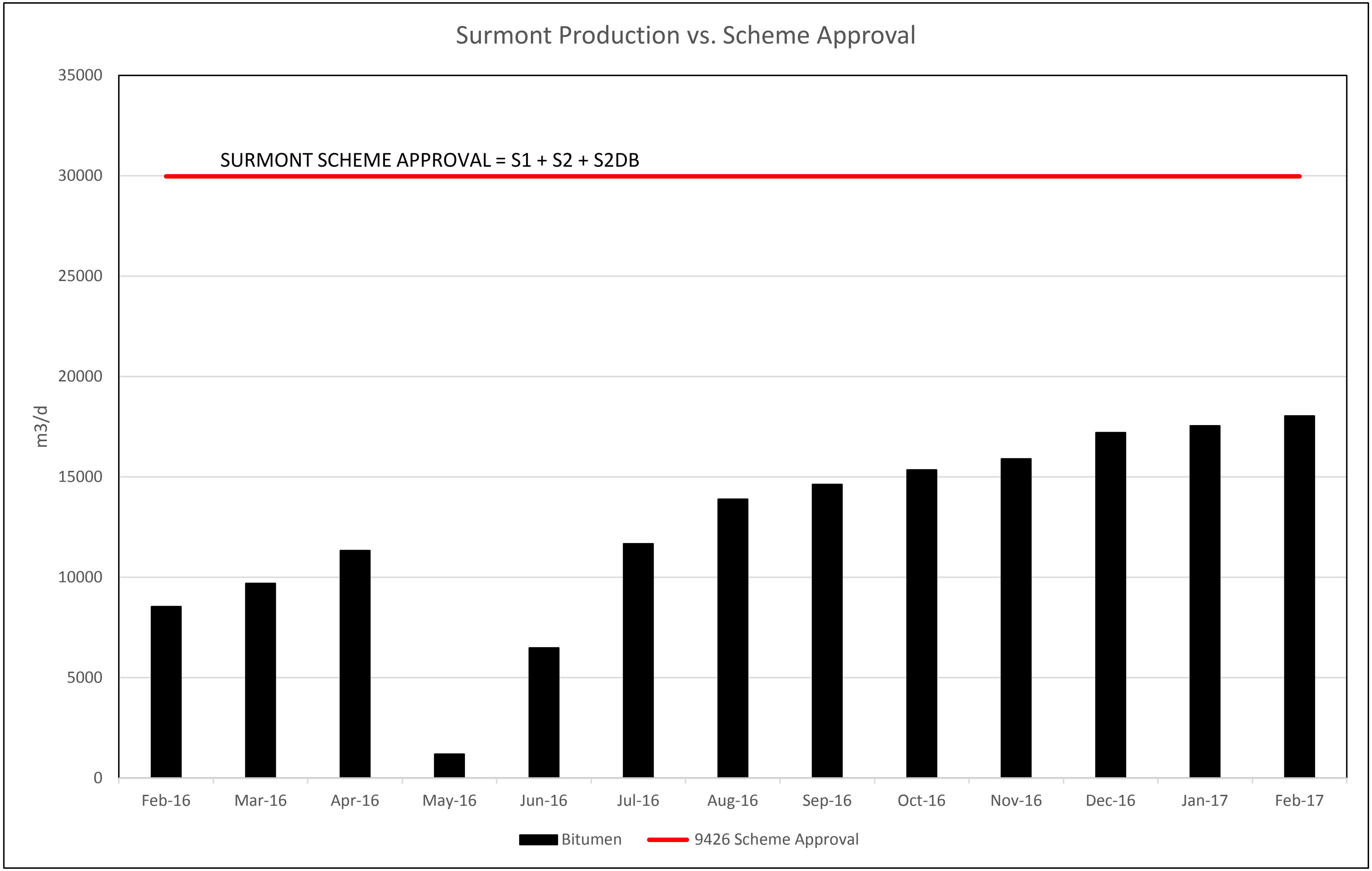
- **Focus remains on sustaining our maturing base production at Pad 101 and 102 and optimizing Pad 103 performance**



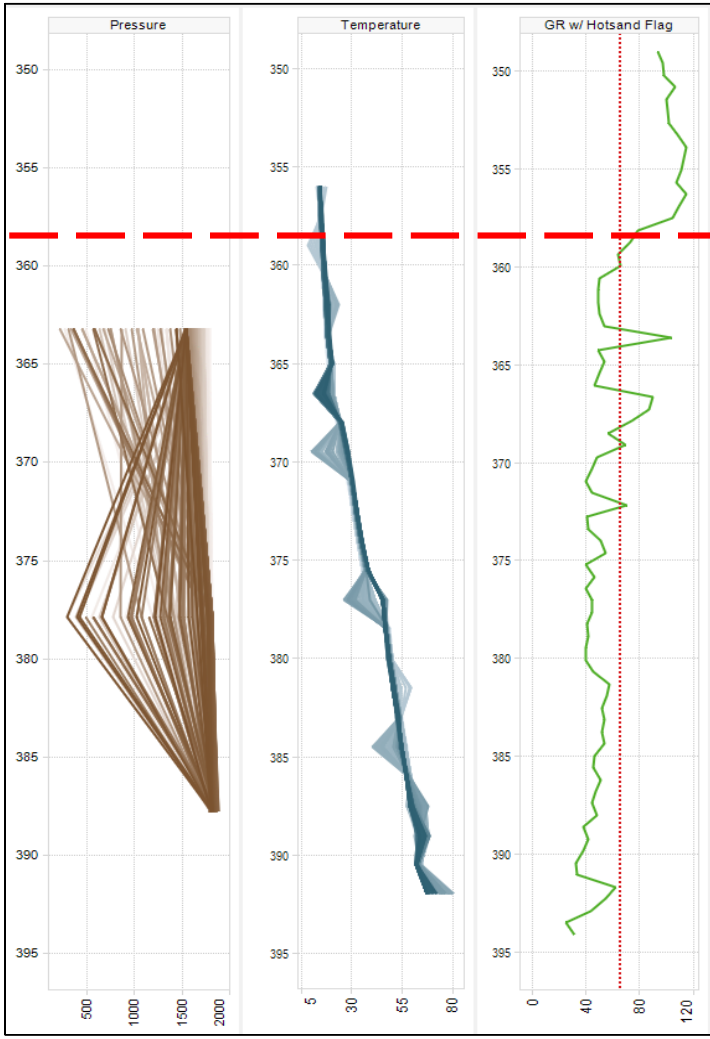
RATIOS – cSOR: 2.7; cWOR: 2.5

- **Phase 1 iSOR remains within expectations.**

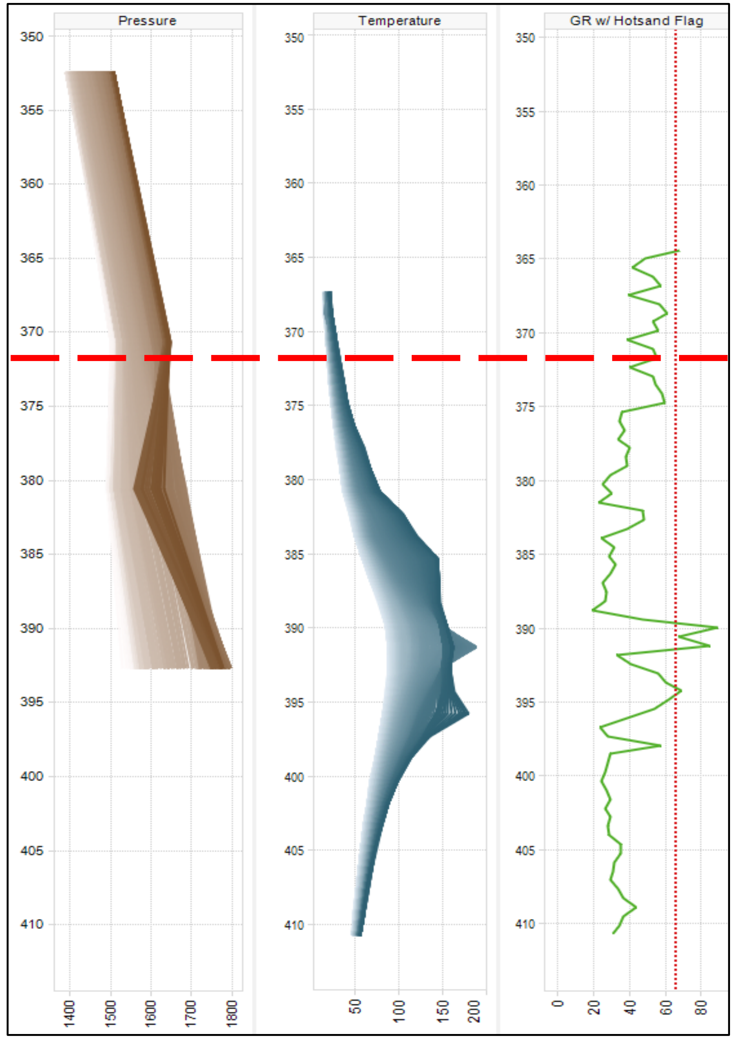
Surmont: Production vs. Scheme Approval



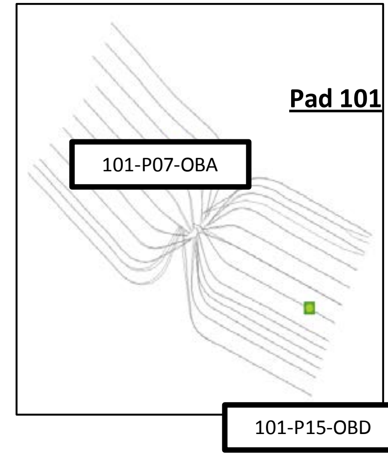
Obs Wells Temp & GR – 101-P07-OBA, 101-P15-OBD



101-P07-OBA 100-13-13-083-07W4 / *21.9m offset*

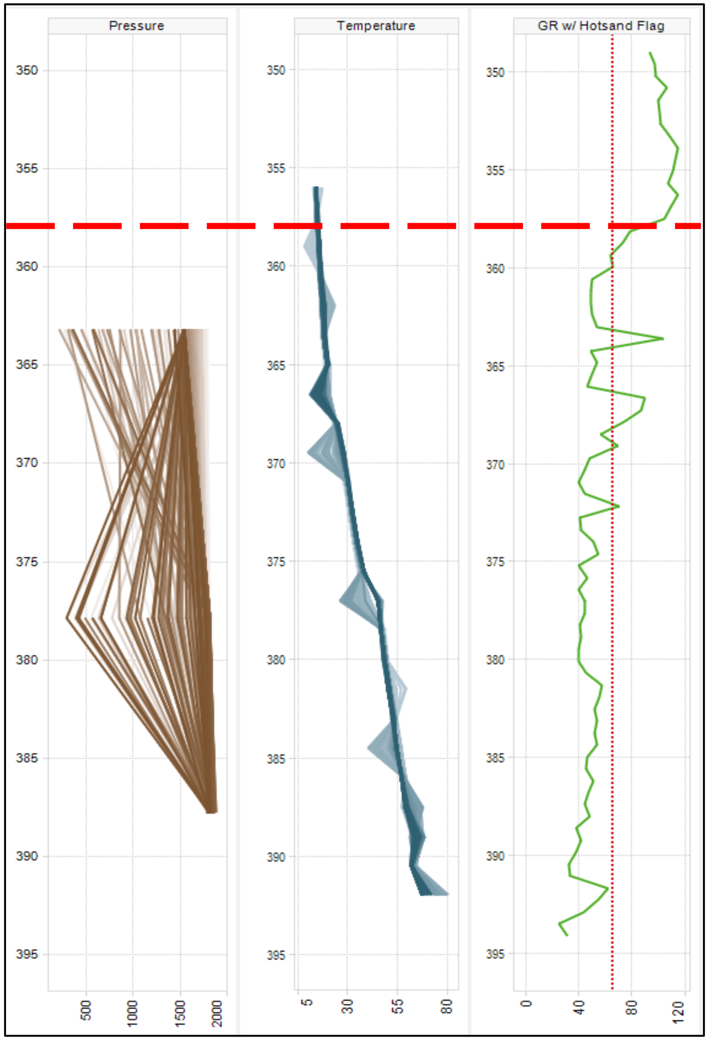


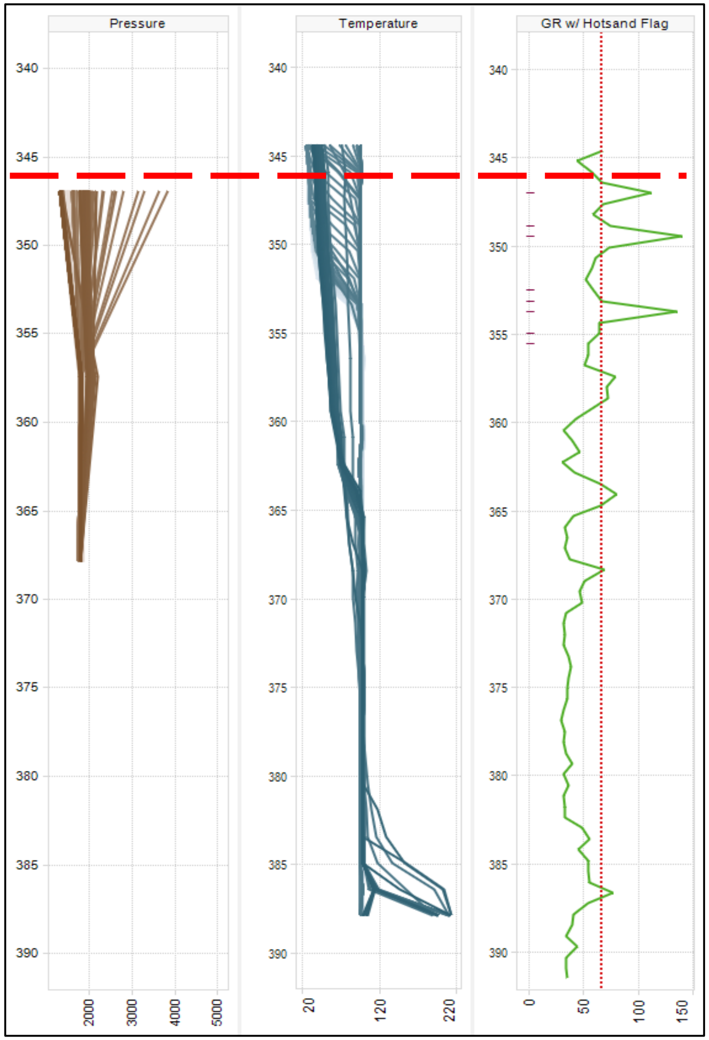
101-P15-OBD 105/07-13-083-07W4 / *5.0m offset*

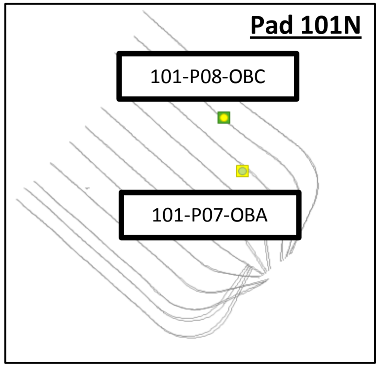


- Temperature and pressure development; No significant changes.

Surmont: Obs Wells Temp & GR – 101-P07-OBA, 101-P08-OBC





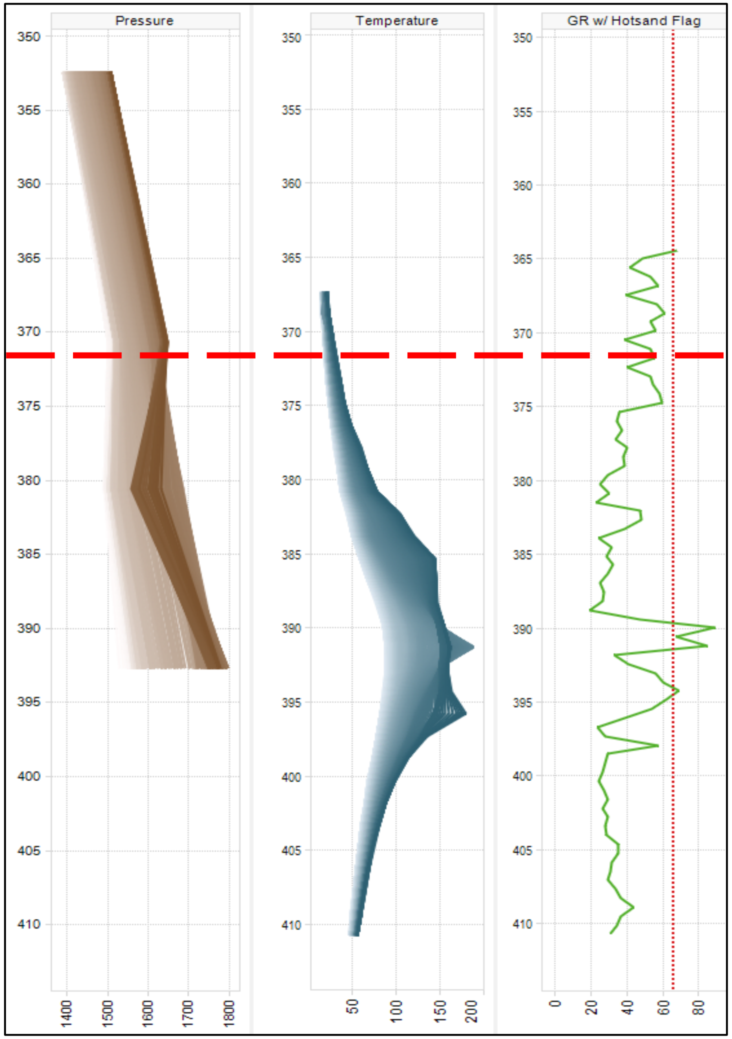


101-P07-OBA 100/13-13-083-07W4 *21.9m offset*

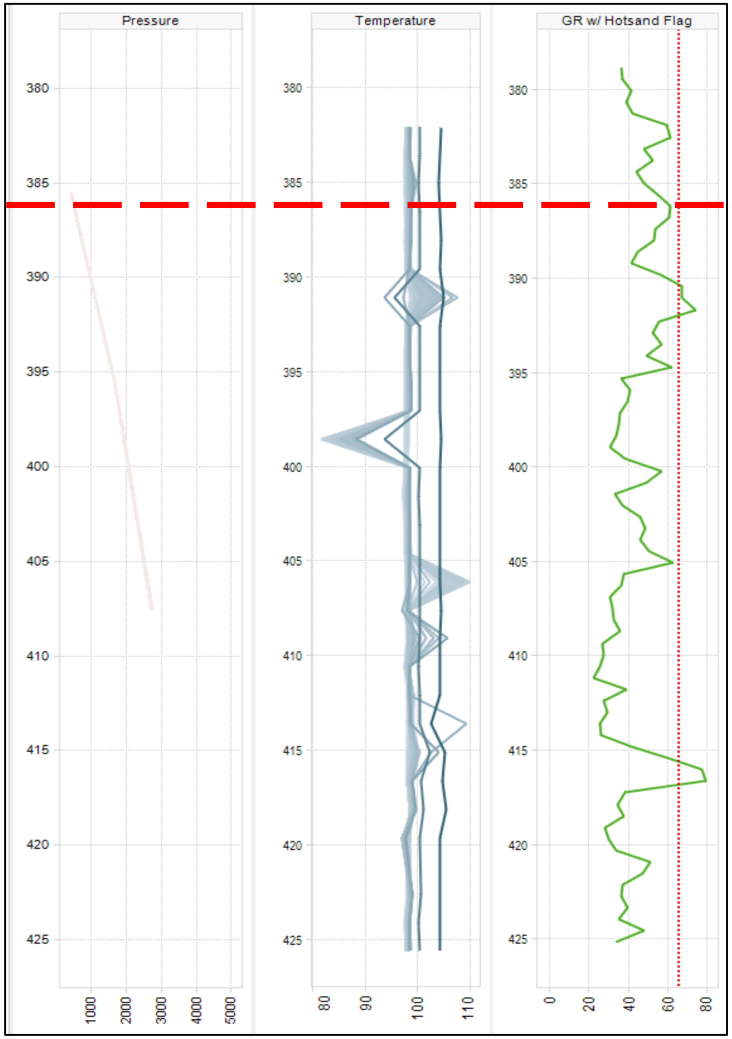
101-P08-OBC 103/01-23-083-07W4 *8.41m offset*

- Temperature and pressure development; No significant changes.

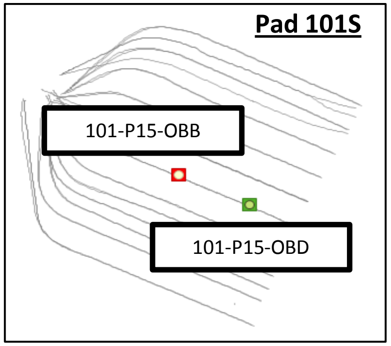
Surmont: Obs Wells Temp & GR – 101-P15-OBD, 101-P15-OBB



101-P15-OBD 105/07-13-083-07W4 *5.0m offset*



101-P15-OBB 100/06-13-083-07W4 *8.38m offset*



- Temperature and pressure development; No significant changes.

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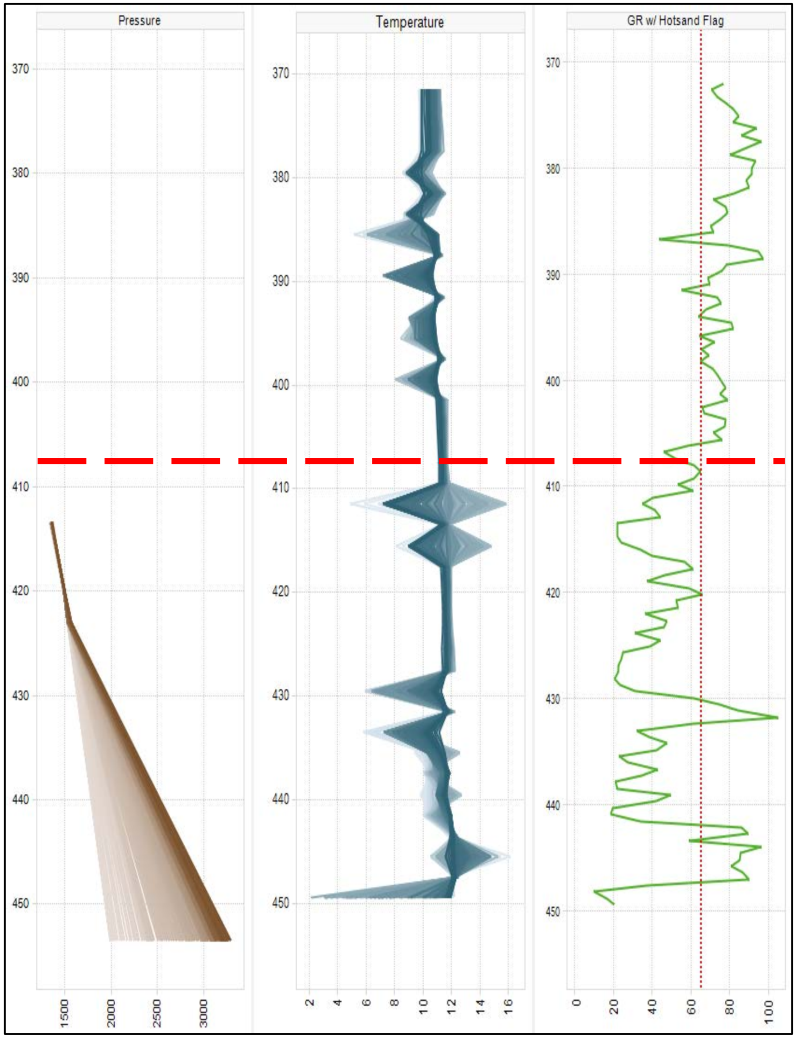
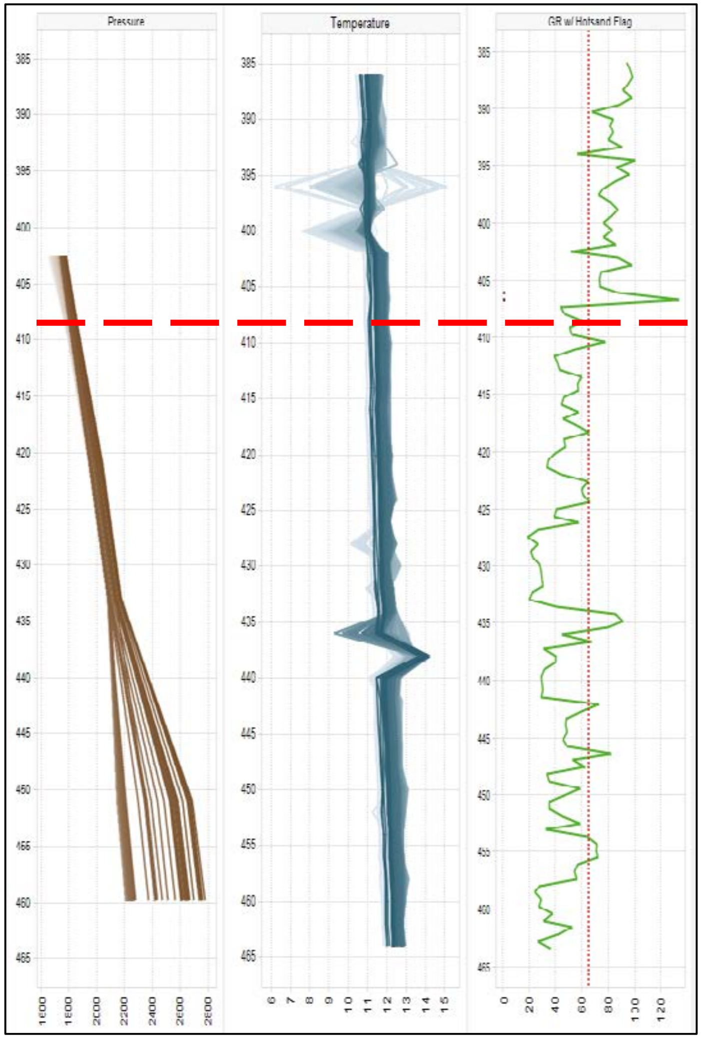
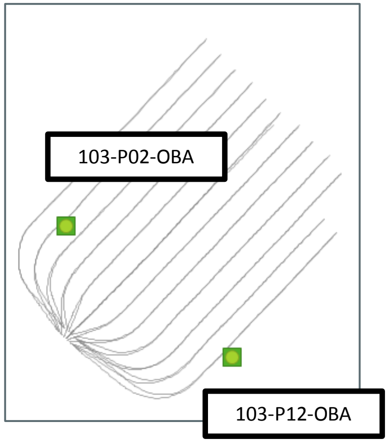
Obs Wells Temp & GR – 103-P02-OBA, 103-P12-OBA



103-P02-OBA 100/08-22-083-07W4 / *20.7m offset*

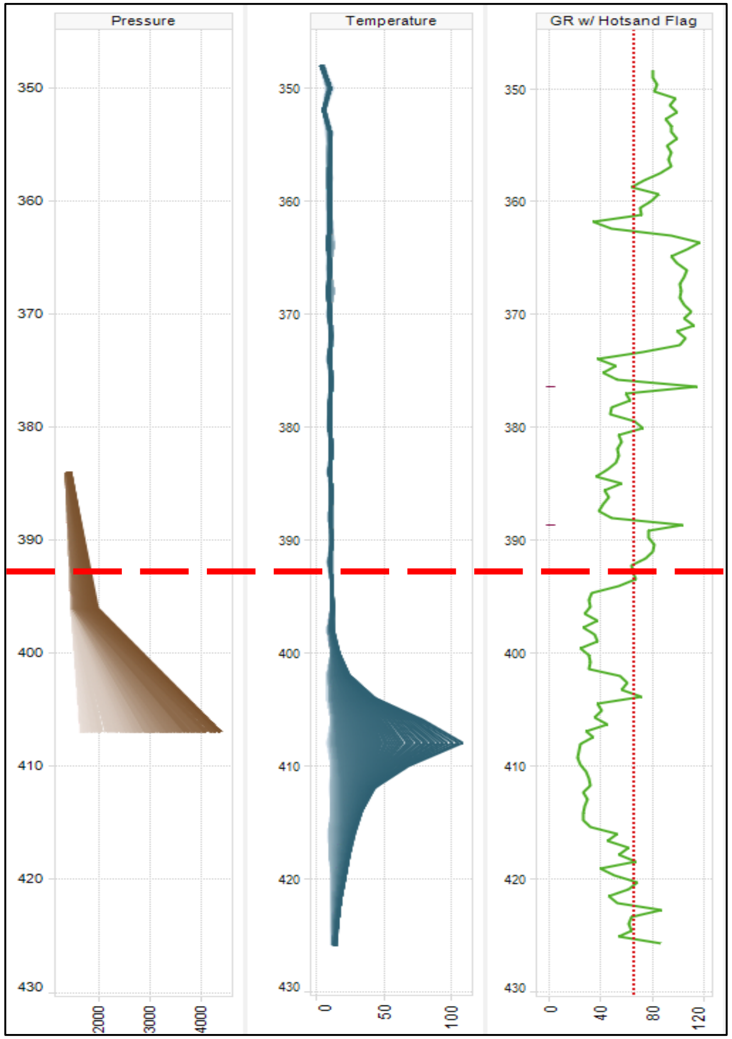


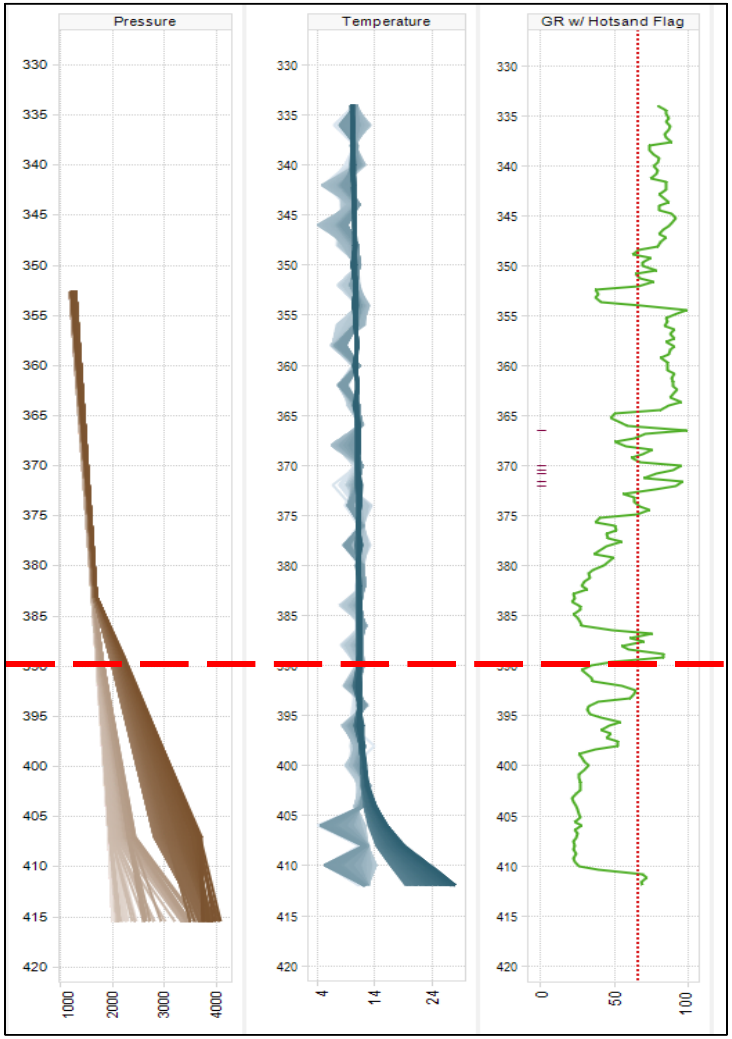
103-P12-OBA 105/14-14-083-07W4 / *41.3m offset*

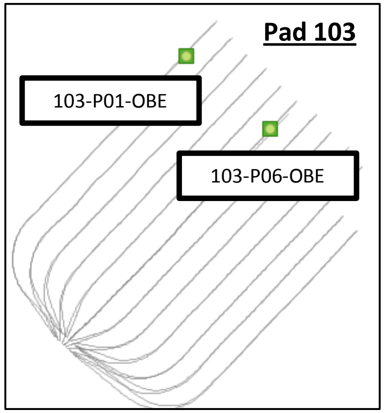


- Temperature and pressure development; No significant changes.

Surmont: Obs Wells Temp & GR – 103-P01-OBE, 103-P06-OBE







103-P01-OBE 100/12-23-083-07W4 *10.2m offset*

103-P06-OBE 100/11-23-083-07W4 *2.5m offset*

- Temperature and pressure development; No significant changes.

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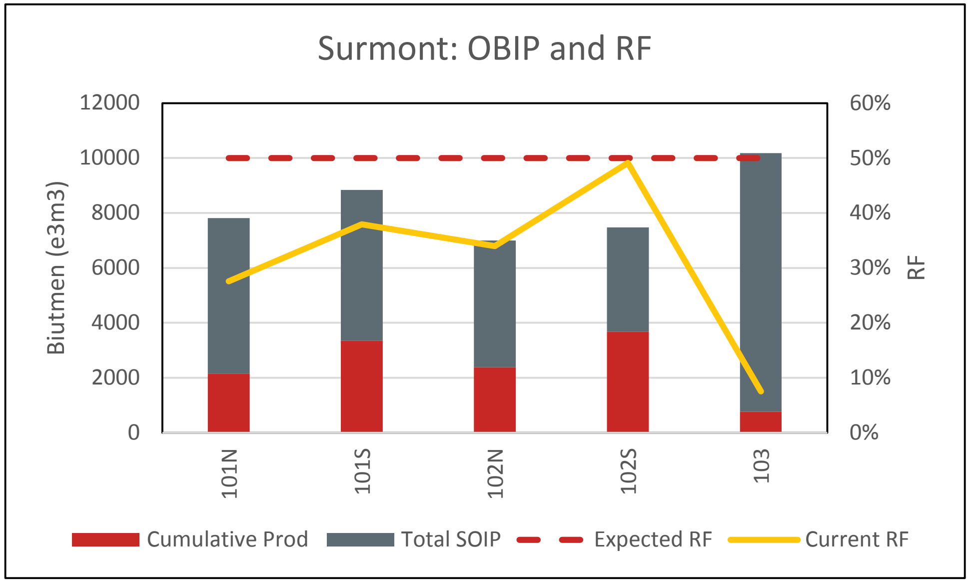
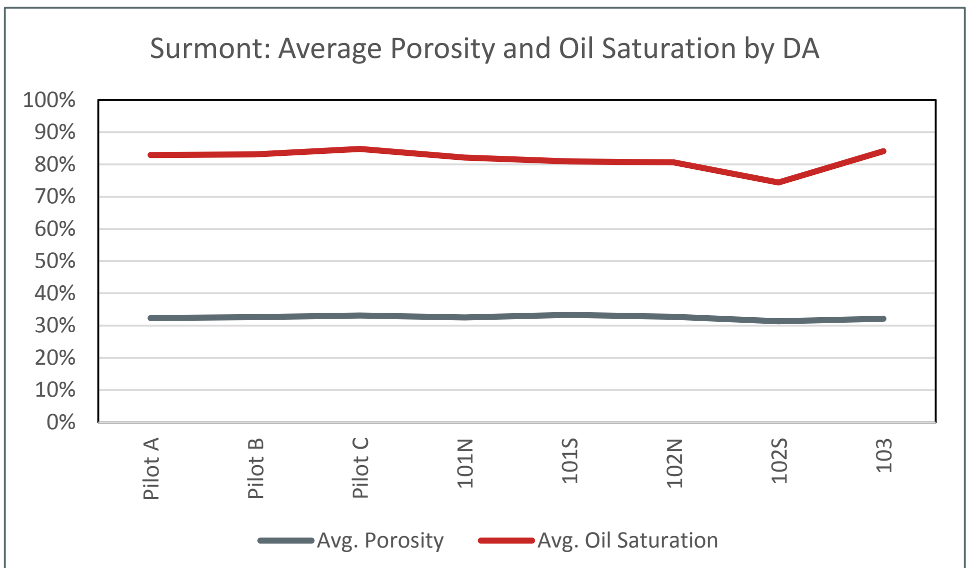
Surmont: Phase 1 - OBIP and RF



DA	Cumulative Prod E3m3	SOIP E3m3	Expected RF	Current RF	Avg Phi	Avg So
101N	2155	7817	50%	28%	33%	82%
101S	3352	8842	50%	38%	33%	81%
102N	2379	6998	50%	34%	33%	81%
102S	3676	7481	50%	49%	31%	74%
103	768	10176	50%	8%	32%	84%

- **OBIP: 6,998 – 10,176 E3M3**
- **Current RF: 7.5% - 49%**



- **Porosity: 31% - 33%**
- **Oil saturation: 74% - 84%**

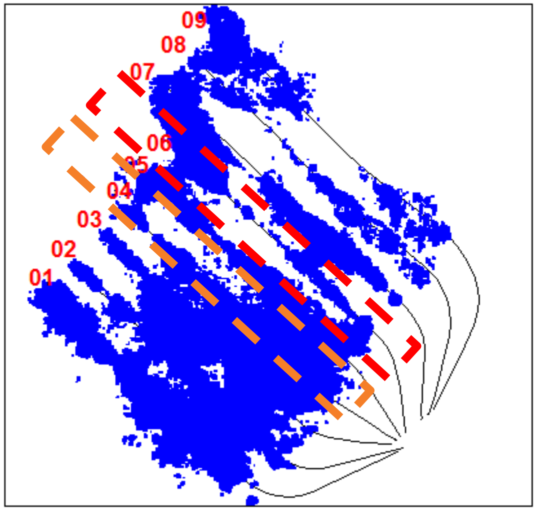
- **Cumulative volumes and recoveries align with internal forecasts. Blowdown timing will determine final EUR/RF.**

ConocoPhillips

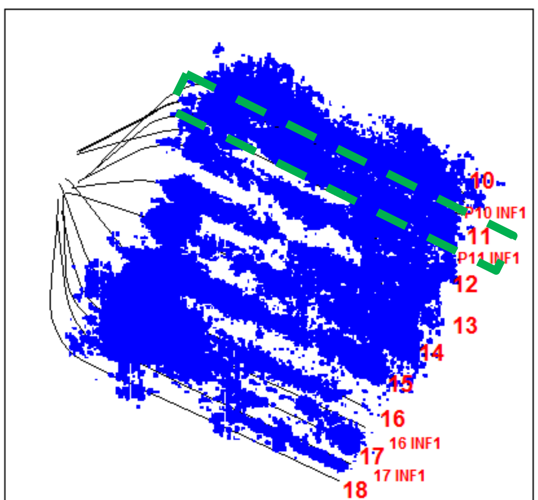
Surmont: Pad 101 Low, Medium, High Recovery Examples

- Low Recovery: 101-13(06)   - Medium Recovery: 101-11(04)   - High Recovery 101-02(11)

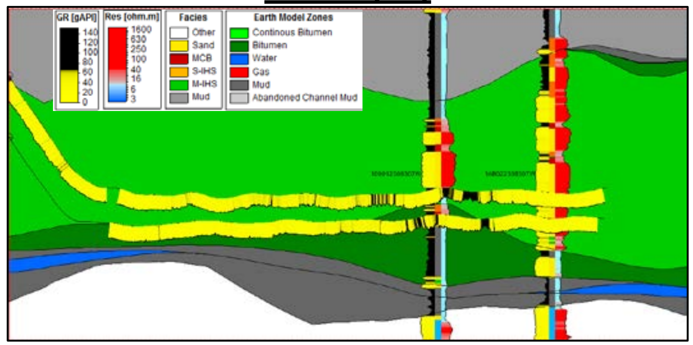
101 North 8th monitor - March 2015



101 South 9th monitor - March 2015

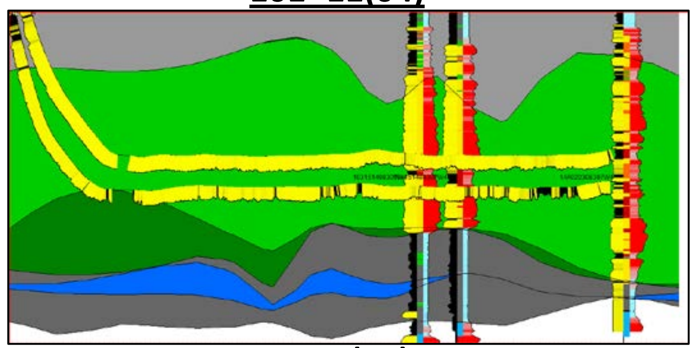


101-13(06)



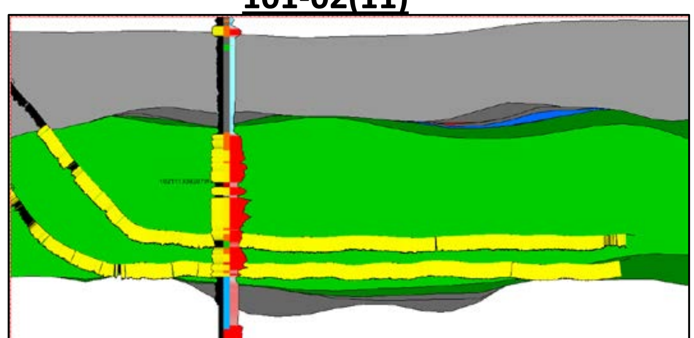
- Low ceiling in the middle.
- Low quality geology a driver behind overall well performance.
- Injector toe tubing landed in the middle.

101- 11(04)



- Low quality at the producer toe.
- Good steam chamber development along wellbore.

101-02(11)

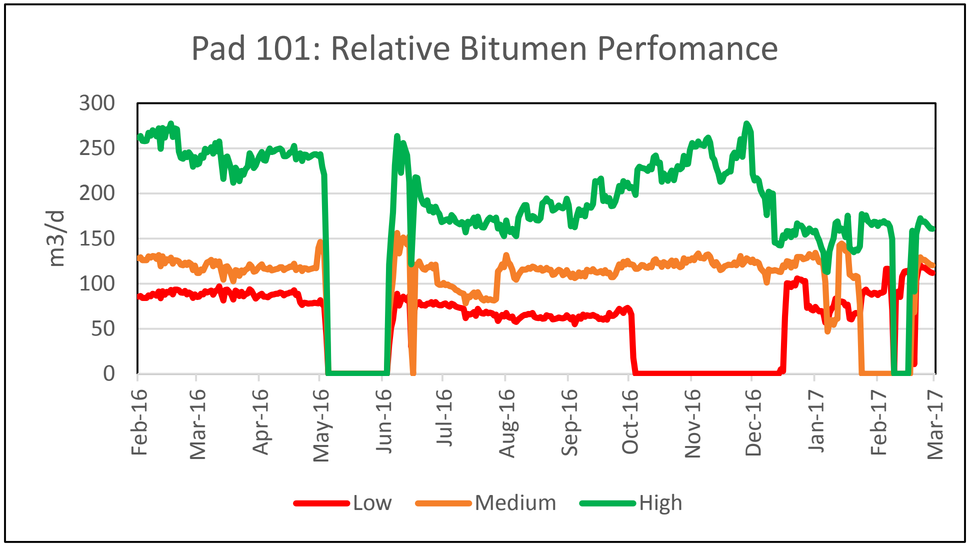


V.E.= 1:8, Scale = 1:4000

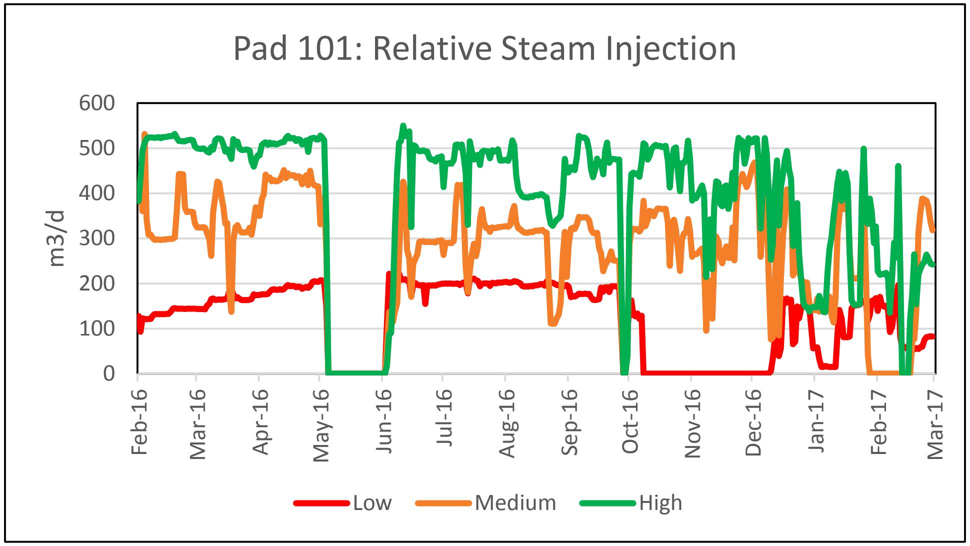
- Very good steam chamber development along wellbore.
- Clean I/P.

Surmont: Pad 101 Low, Medium, High Recovery Examples

- Low Recovery: 101-13(06) - Medium Recovery: 101-11(04) - High Recovery: 101-02(11)



- **Sustained / increased bitumen production from subject wells.**

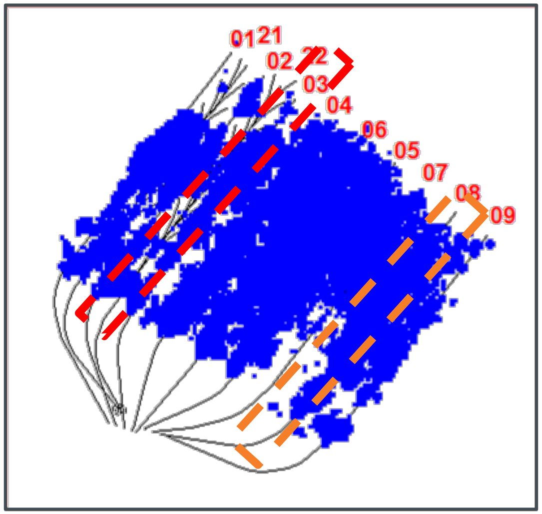


- **Effective steam management improved performance of 101-06.**

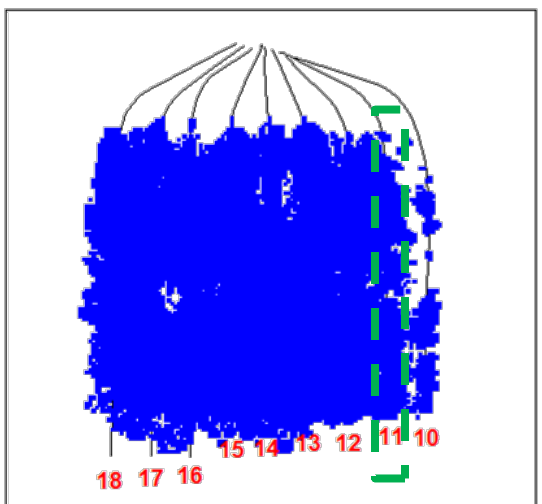
Surmont: Pad 102 Low, Medium, High Recovery Examples

- Low Recovery: 102-03   - Medium Recovery: 102-08   - High Recovery: 102-11

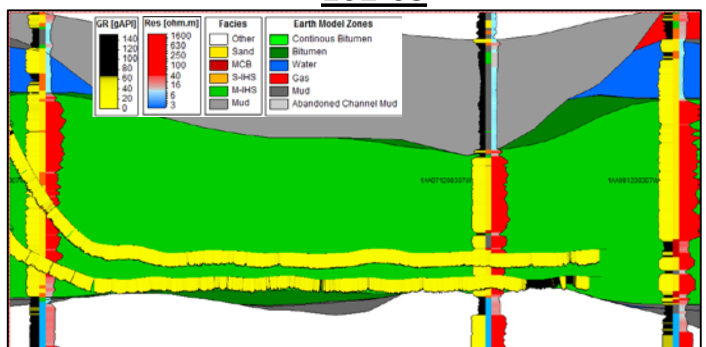
102 North 9th monitor - April 2015



102 South 5th monitor - April 2014

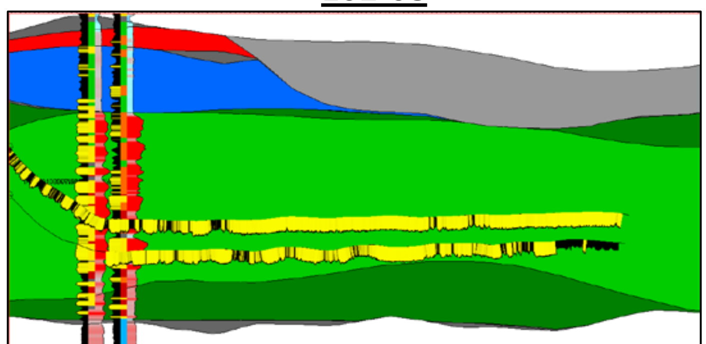


102-03



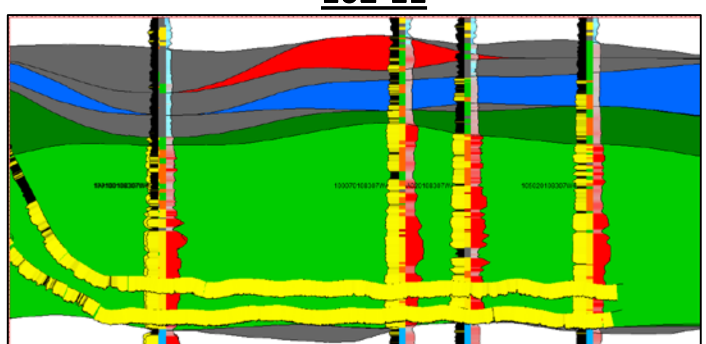
- Limited steam chamber development
- Poor geology a significant driver behind overall well performance
- I/P landed in muddy sands

102-08



- Significant steam chamber development
- I/P landed in marginal geology

102-11

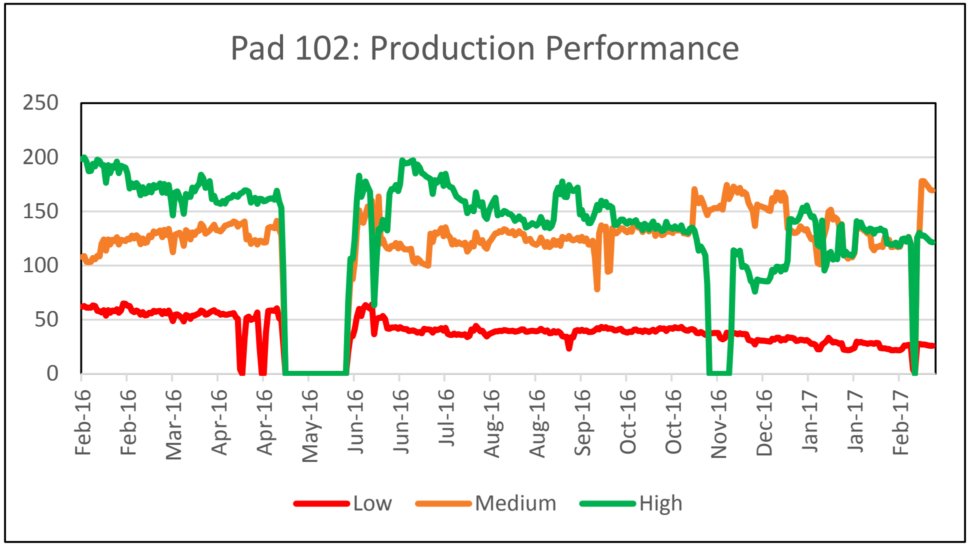


V.E.= 1:8, Scale = 1:4000

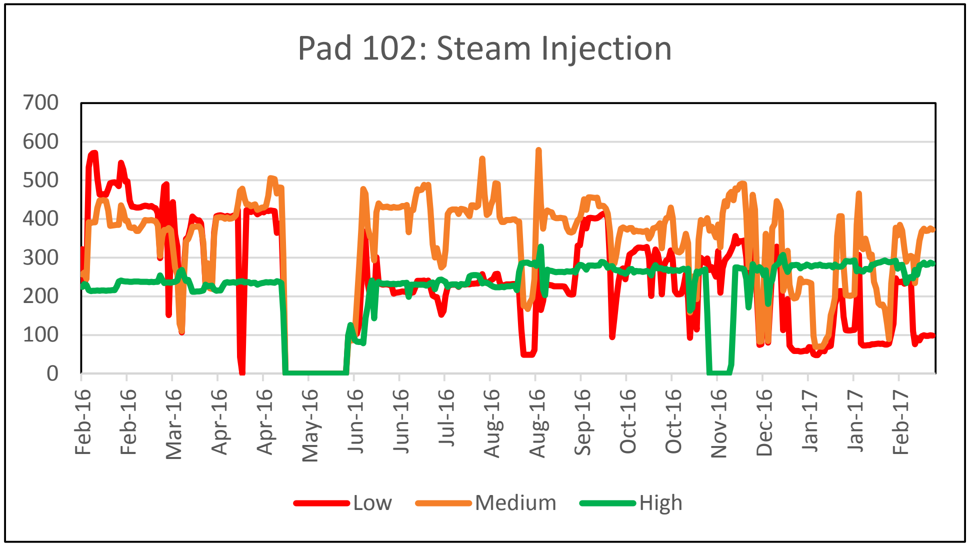
- Significant steam chamber development
- I/P landed in good geology
- Toe impacted by low muddy ceiling

Surmont: Pad 102 Low, Medium, High Recovery Examples

- Low Recovery (102-03) - Medium Recovery (102-08) - High Recovery (102-11)



- **Sustained / increased bitumen production from subject wells.**

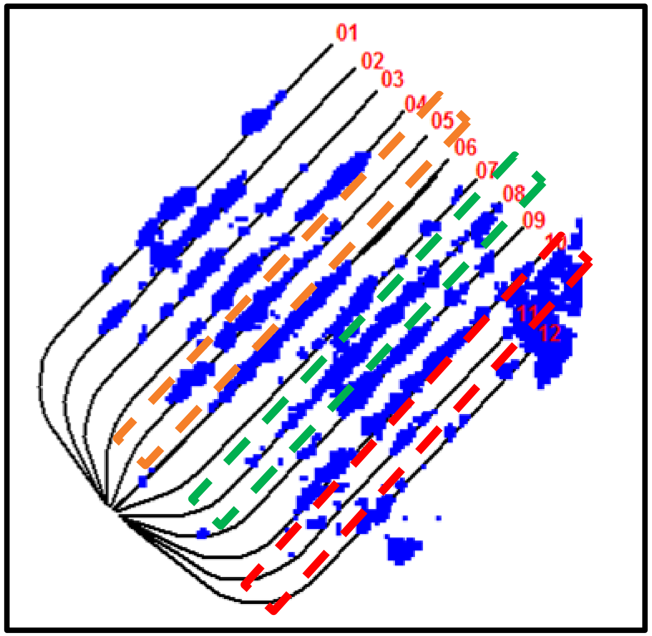


- **Optimized steam injection to maximize bitumen production from 102-11.**

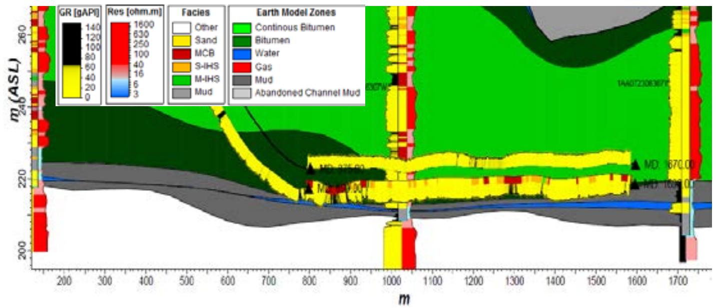
Surmont: Pad 103 Low, Medium, High Recovery Examples

- Low Recovery (103-11) - Medium Recovery (103-05) - High Recovery (103-08)

Pad 103 2nd Monitor – October, 2016

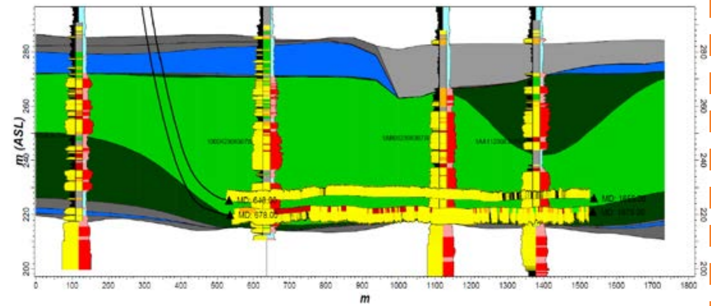


103-11



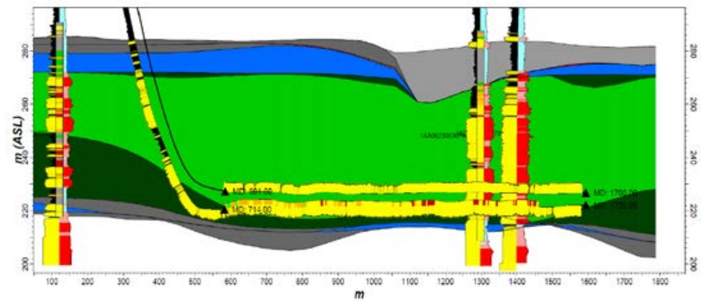
- Interaction will low pressure chamber of 101N
- Short well (790m)
- Fish in hole

103-05



- SL completion
- Good geology

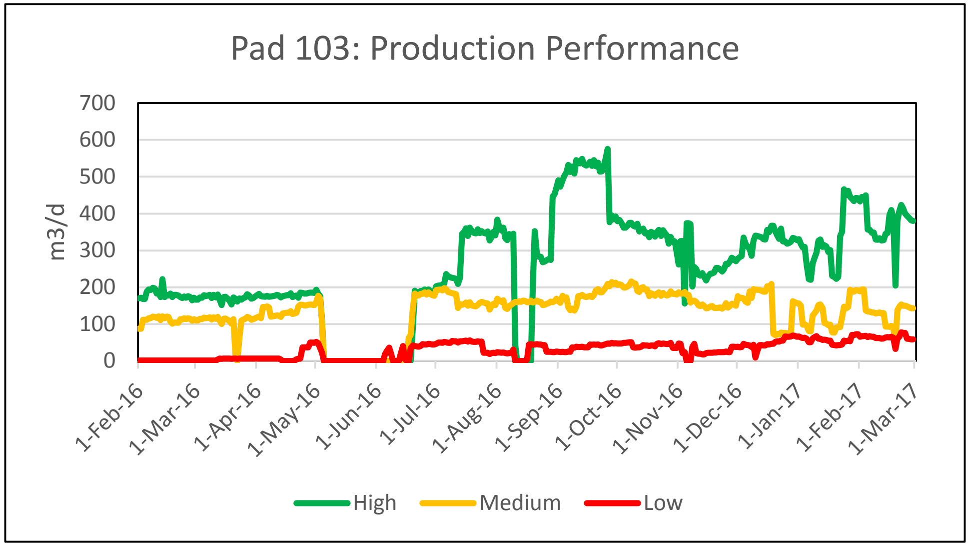
103-08



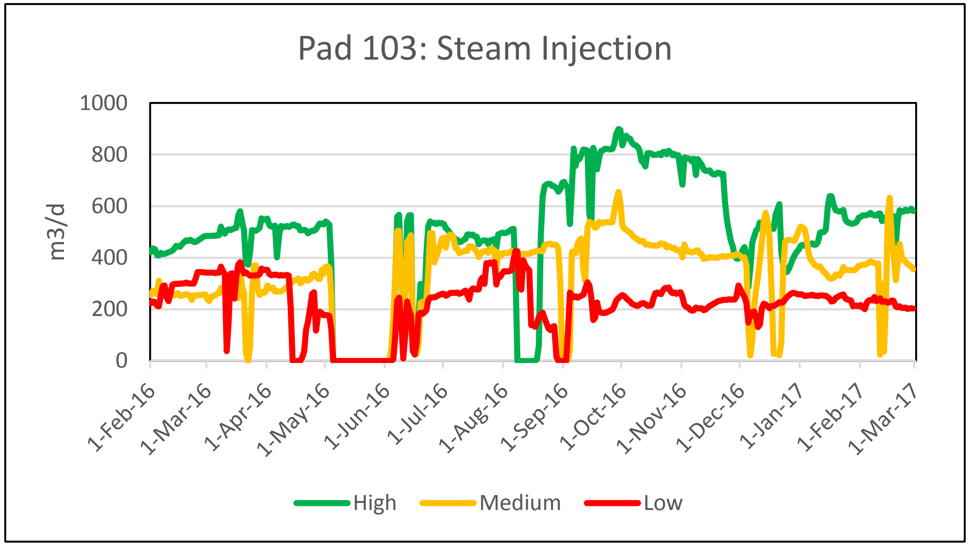
- FCD completion
- Good geology
- Early ESP conversion

Surmont: Pad 103 Low, Medium, High Recovery Examples

- Low Recovery (103-11) - Medium Recovery (103-05) - High Recovery (103-08)



- **FCD completion continues to outperform SL**

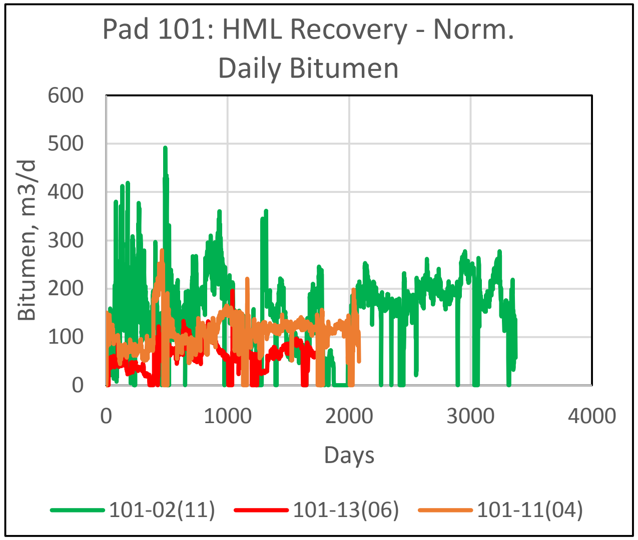


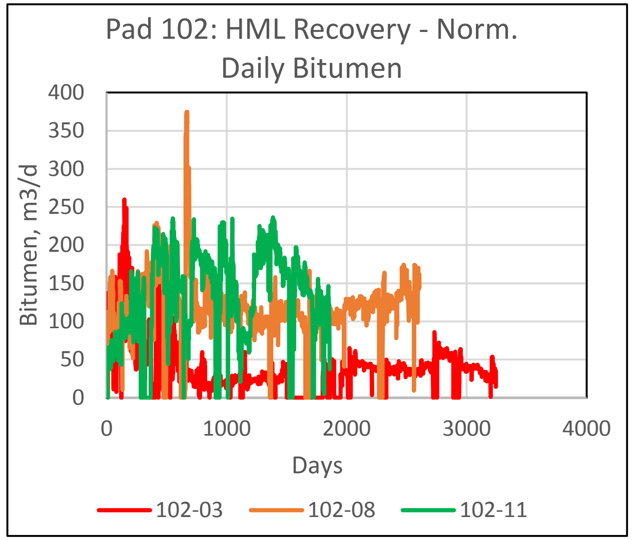
Surmont 1 – Recovery Examples – Normalized Well Life Production Data

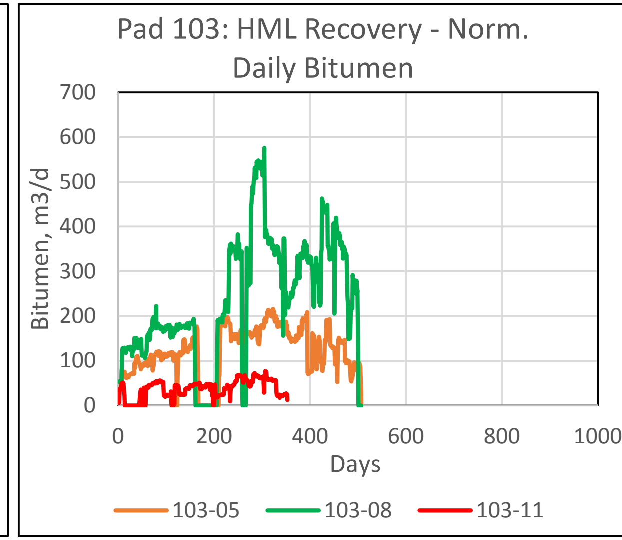
- Low Recovery

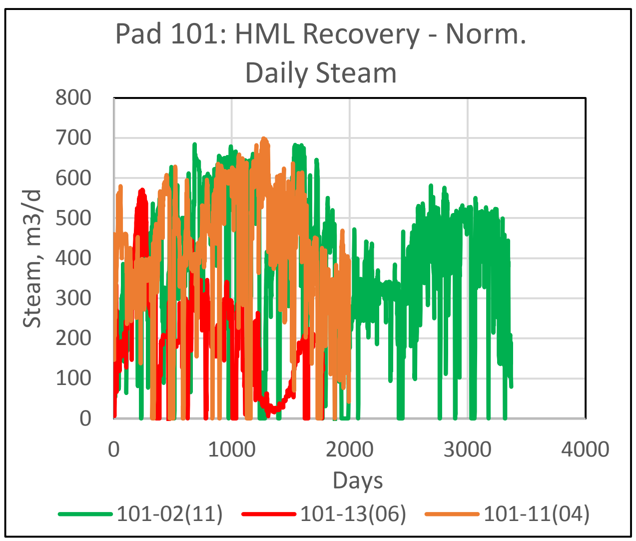
- Medium Recovery

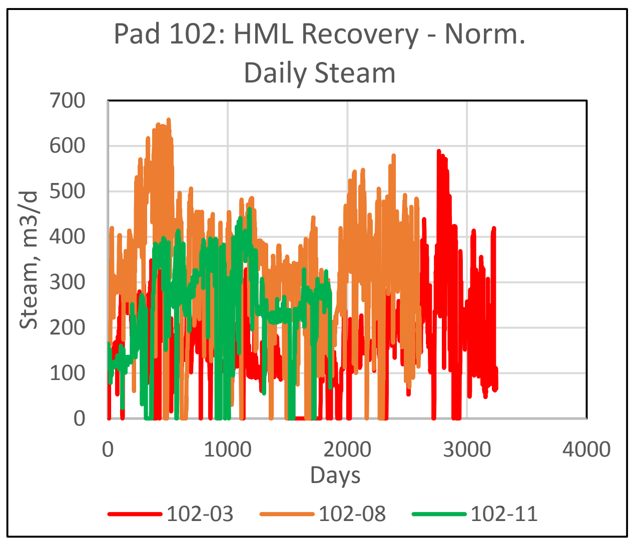
- High Recovery

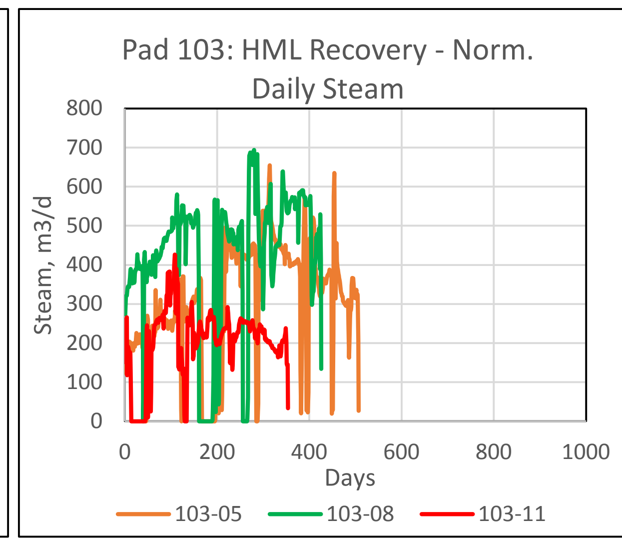




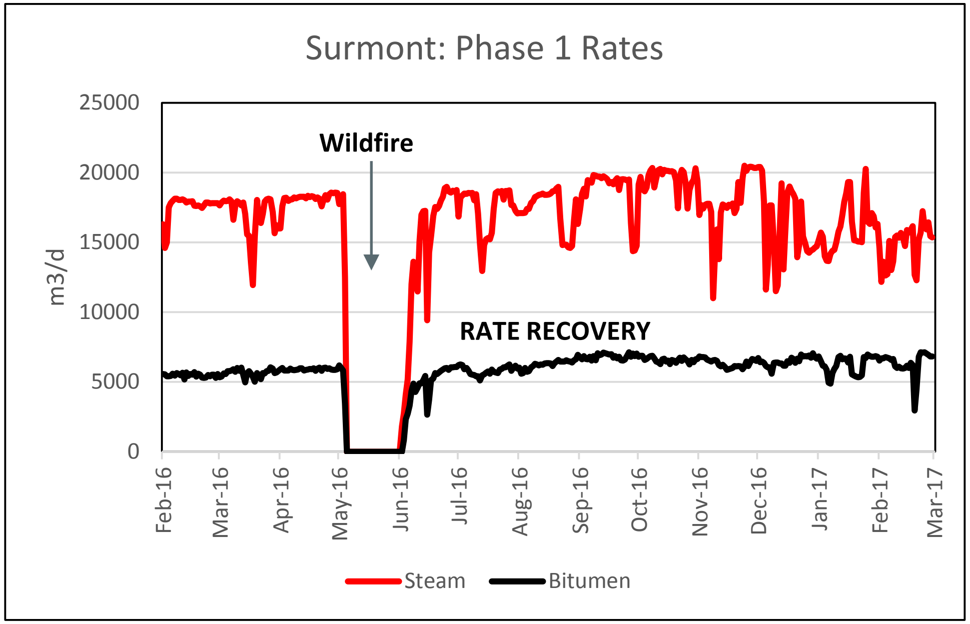


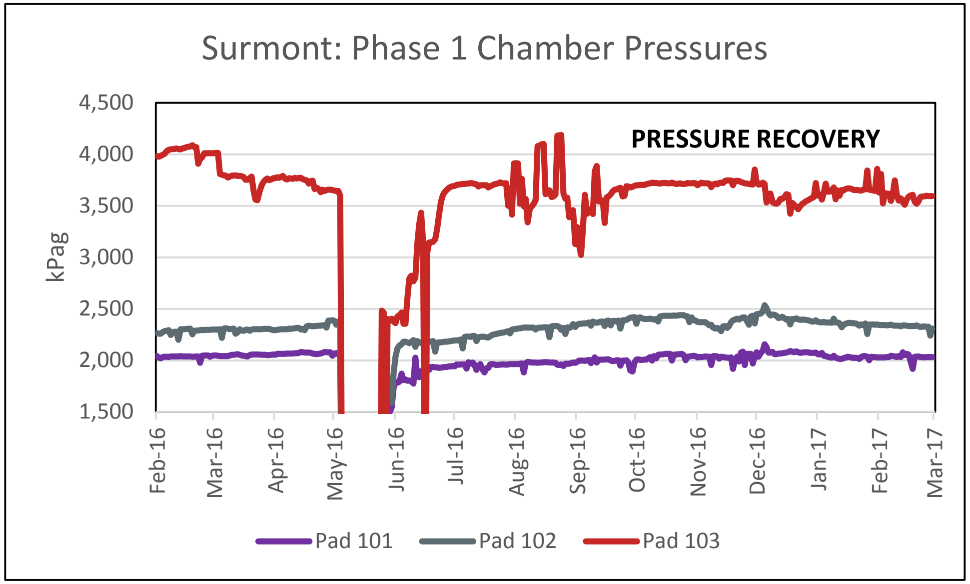






Surmont: Post Fort McMurray Wildfire Performance Plots





- **Reservoir performance on trend with pre-Fort McMurray Wildfire baseline.**

Phase 1 – Key Learnings

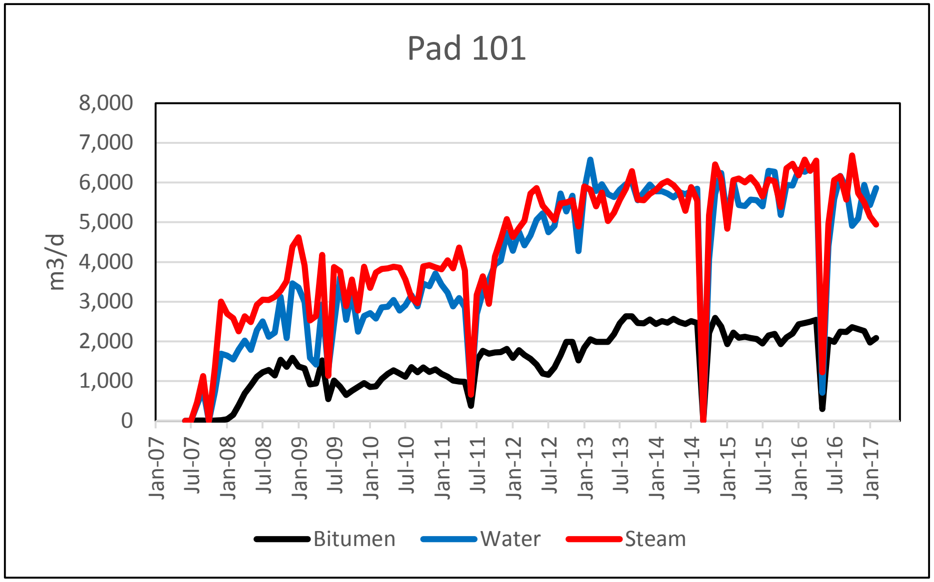
- At pad 101/102, incremental steam injected during 2015/2016 increased the reservoir chamber pressure which attributed to a flat bitumen production profile during the subject timeframe
  - Even during Q4, 2016 when steam injection rates were considerably curtailed, bitumen production rates have held constant.
  - iSOR continues to improve and trend lower

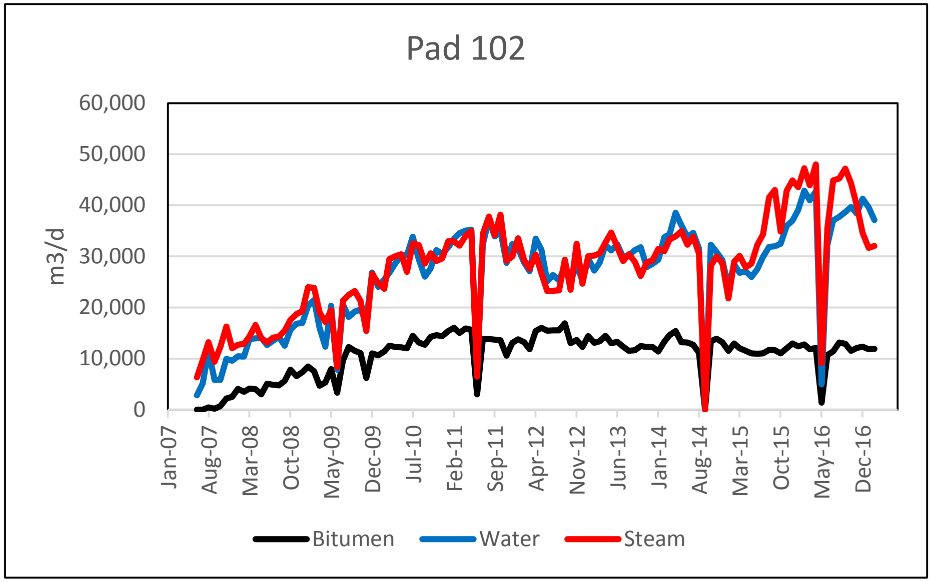
- Liner installed flow control devices at Pad 103 continue to outperform SL wells.

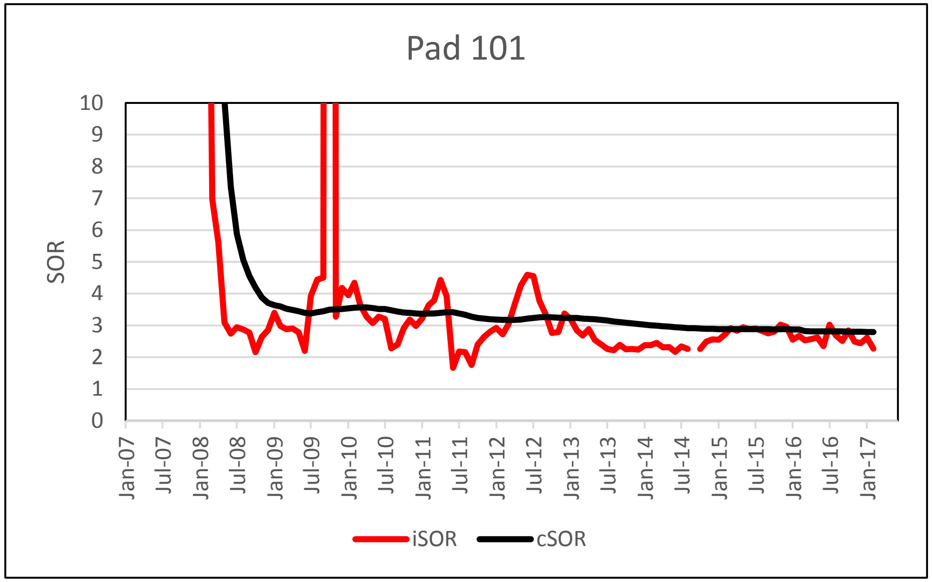
- Initial results from tubing deployed flow control devices at Pad 101/102 continue to be assessed however, early days are illustrating a net increase in total emulsion/bitumen rates.

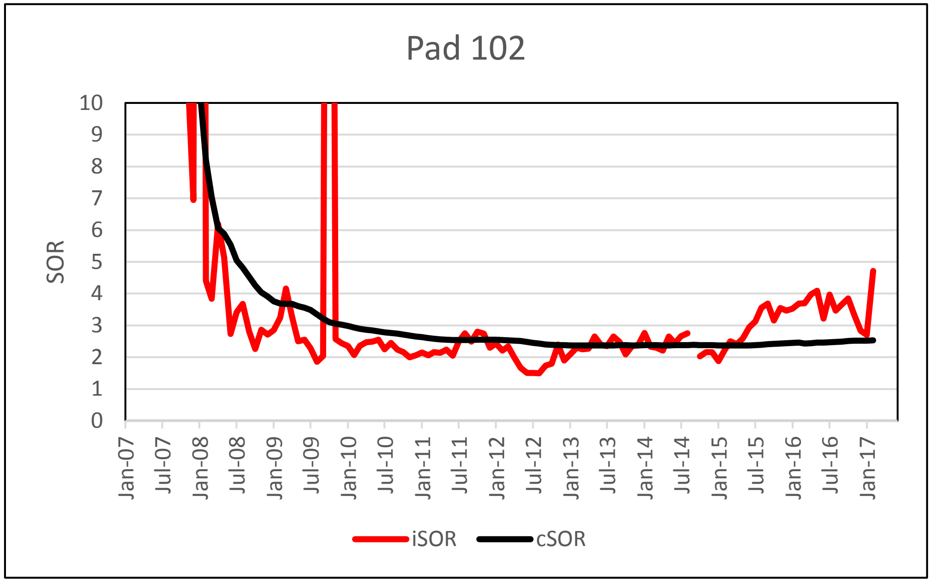
- Optimization continues to improve performance of mature wells:
  - NCG pilot commenced January, 2017 on 3 wells at Pad 102
  - Fishbone infill well 102-22 expected to be onstream in Q2, 2017
  - Steam injection optimization
  - Subcool management
  - Well stimulations
  - Changes in injector tubing landing depths
  - Additional tubing deployed flow control devices
  - Investigating possible BP drill outs to recover lost sections of laterals

Surmont: Phase 1 Well Pad Rates and SOR

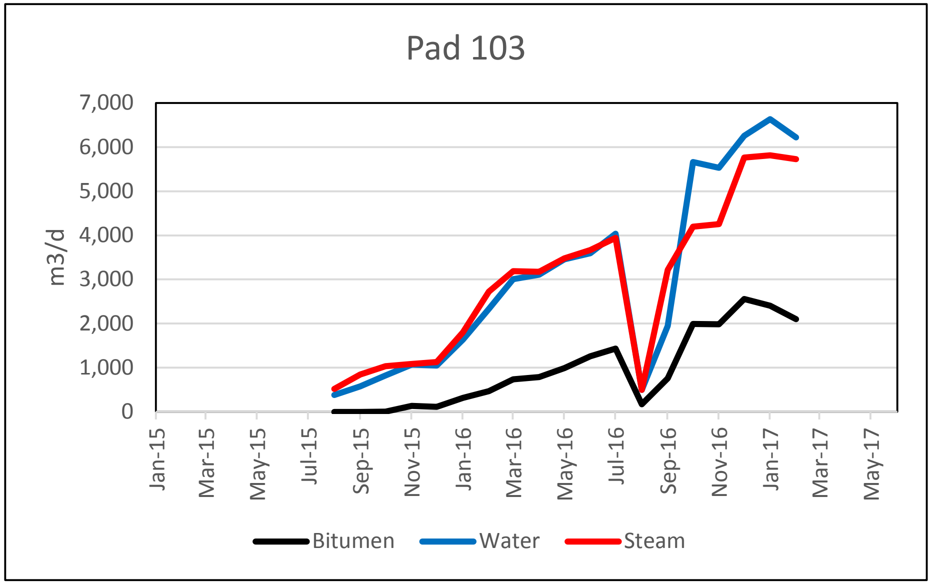


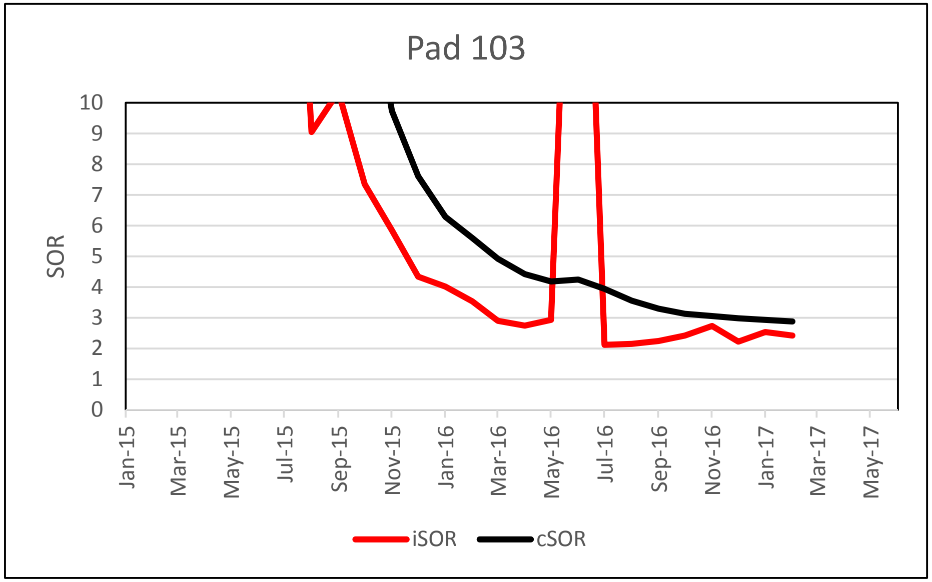






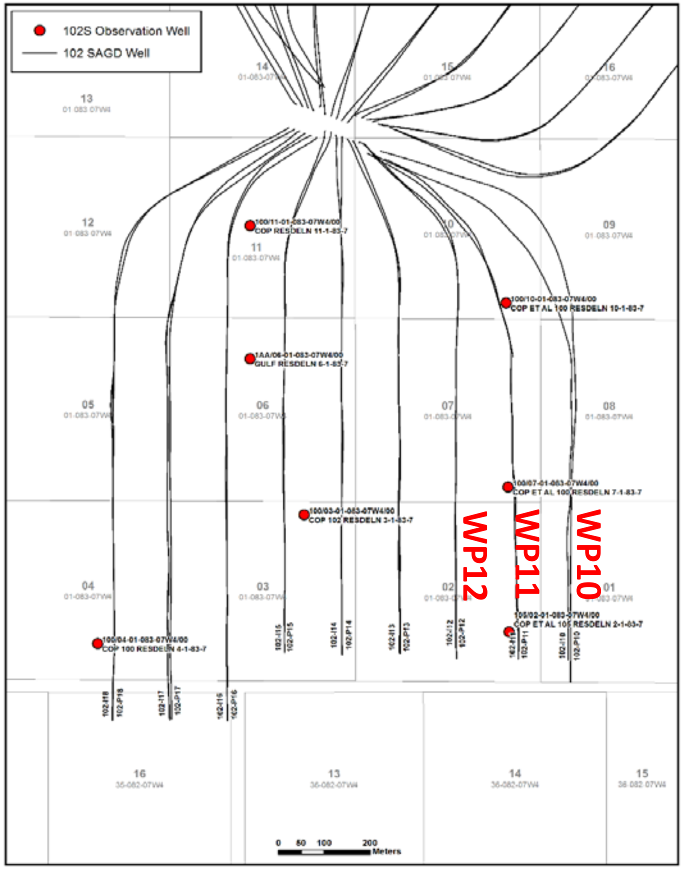
Surmont: Phase 1 Well Pad Rates and SOR





102 NCG Co-Injection Trial

Pad 102S

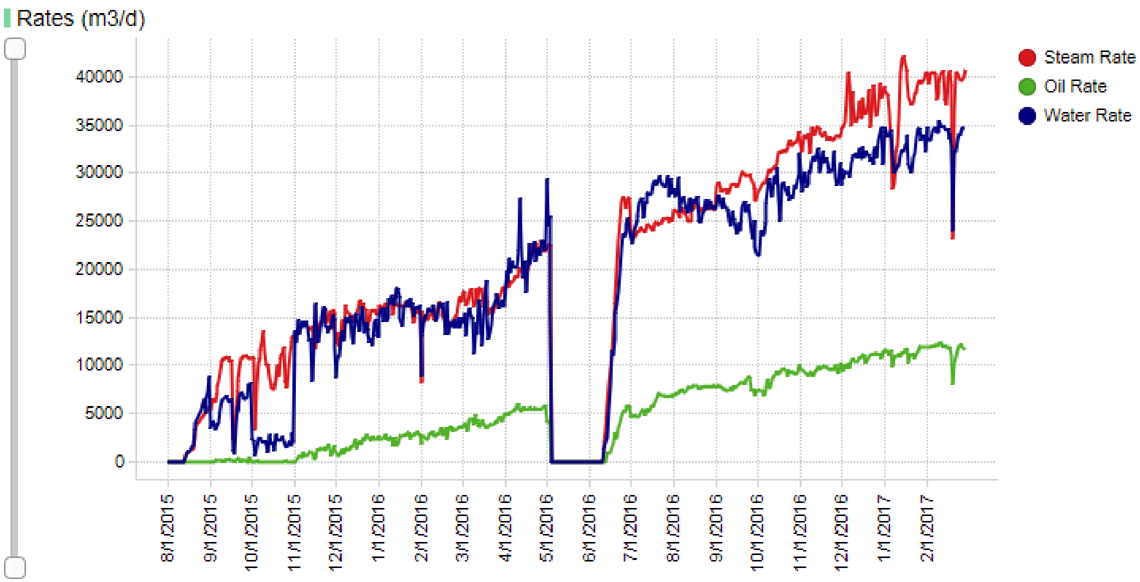


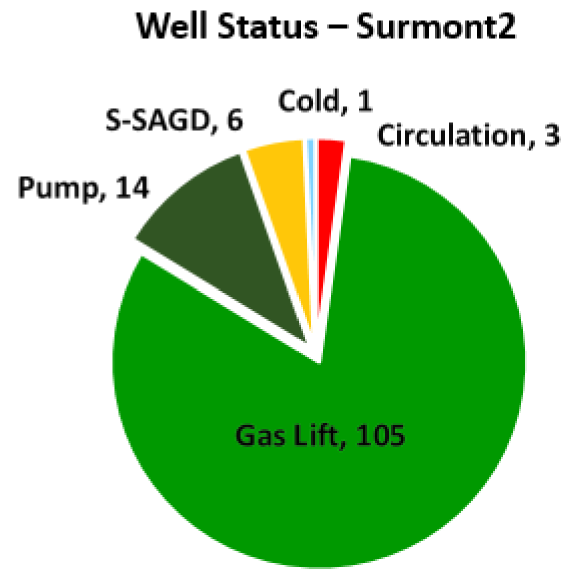
- Pilot focused on co-injection of fuel gas with steam in order to reduce steam requirements – ultimately reducing water usage, fuel consumption and lower greenhouse gas emissions.

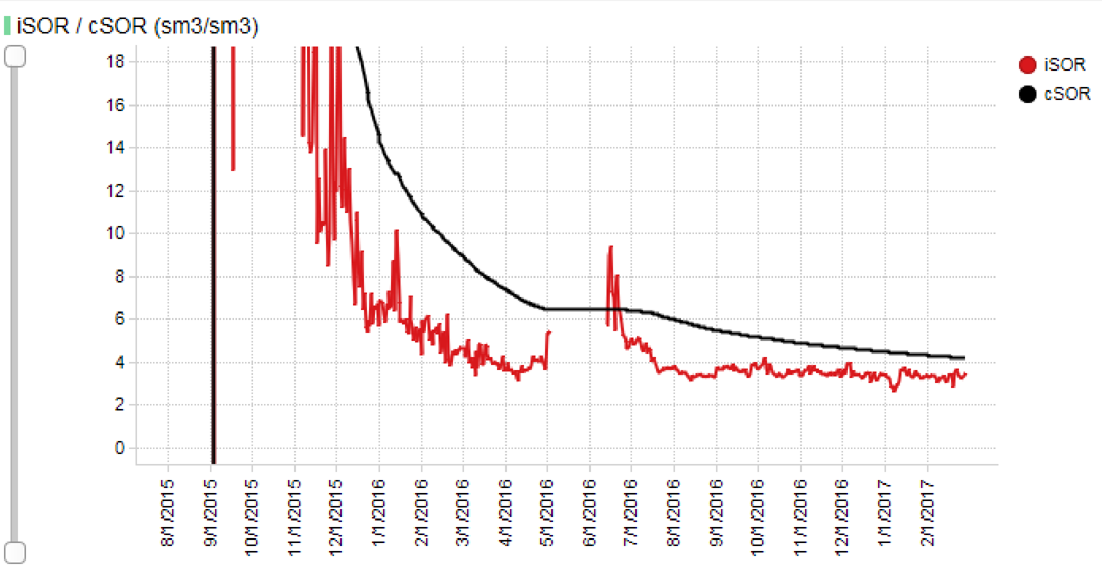
- Pilot on 102 South is located on the western side of the well pad. Subject pilot wells are:
    - 102-WP10
    - 102-WP11
    - 102-WP12

- Injection concentrations are up to a maximum of 2 mol% methane or 10 E3m^3/d per well pair.

Surmont Phase 2 Aggregate Performance Plots



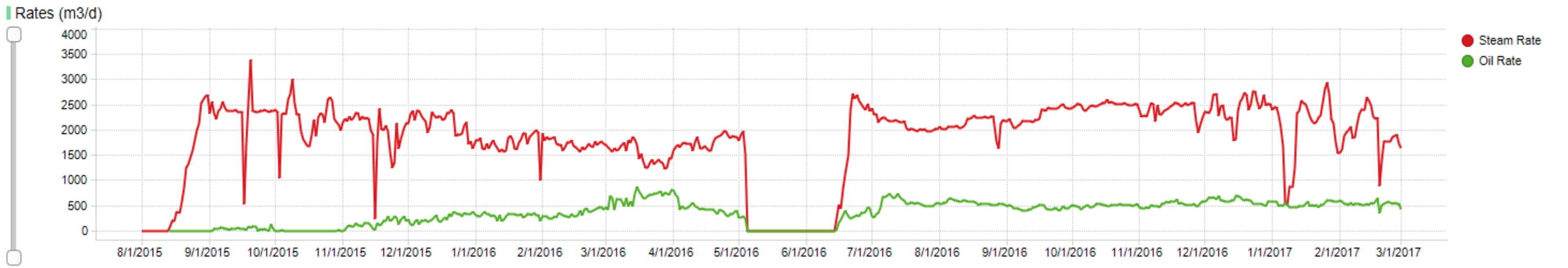


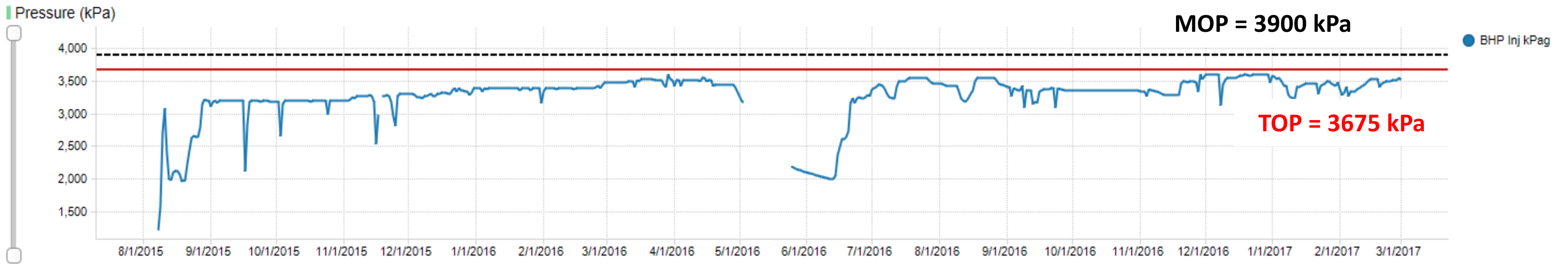


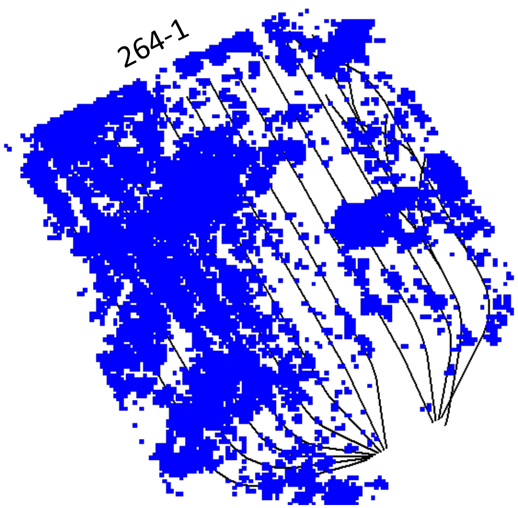
- All eleven pads started as of February 28, 2017.
- Steam/Water trends diverting result of thief zone interactions in Pads 264-1, 263-1, 265-2, 262-2
- Three well pairs re-drilled due to downhole failures

- Surmont 2 ramp-up ongoing.

Performance / Chamber Development Challenges – Pad 264-1

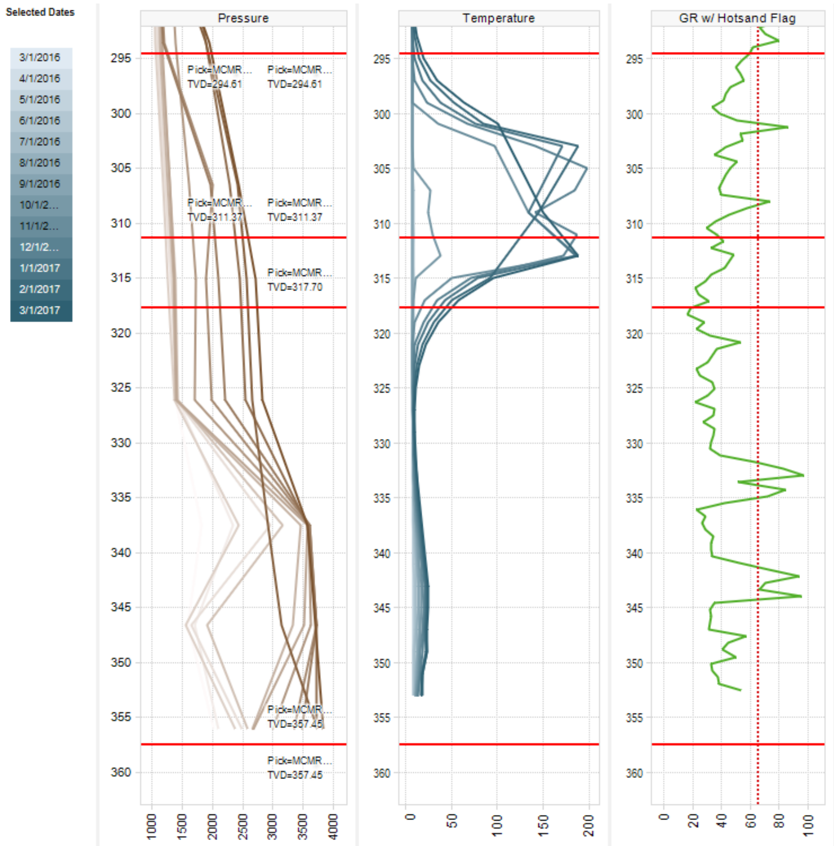




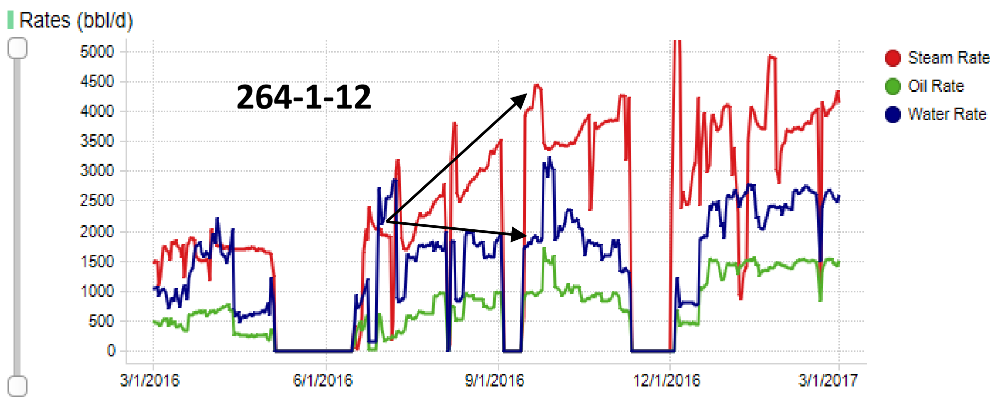


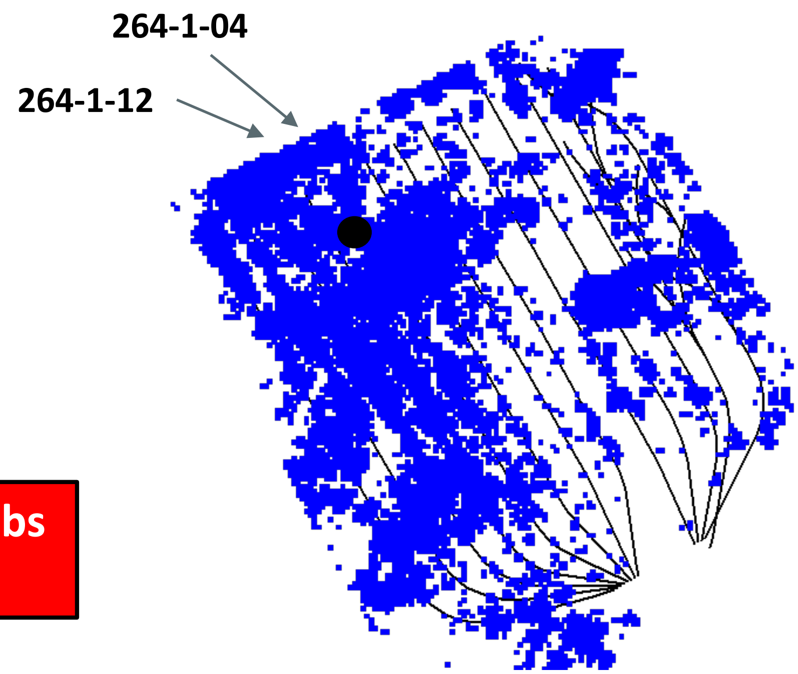
- **264-1 has been operating at a target pressure of 3,675 kPa**
- **11/12 wells converted to SAGD. 1 well circulating**
- **Good development on West side of DA, however challenging performance on Eastern area**
- **Top water interaction has been identified in three wells**
- **Coalescence with Pad to the North on West side**

Performance / Chamber Development Challenges – Pad 264-1

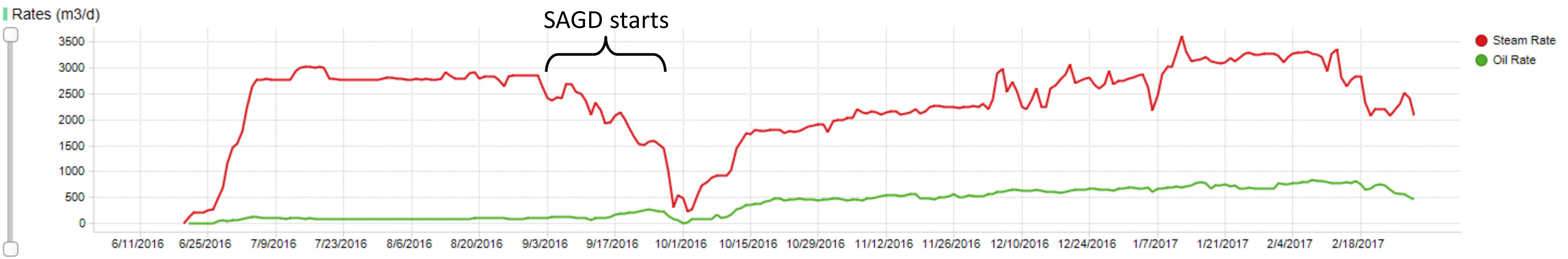


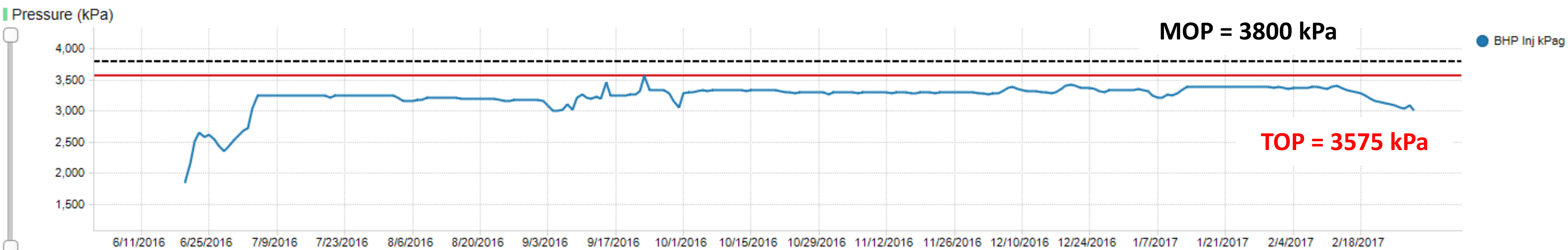
264-1-P04-OBD. 17 meters from well pair

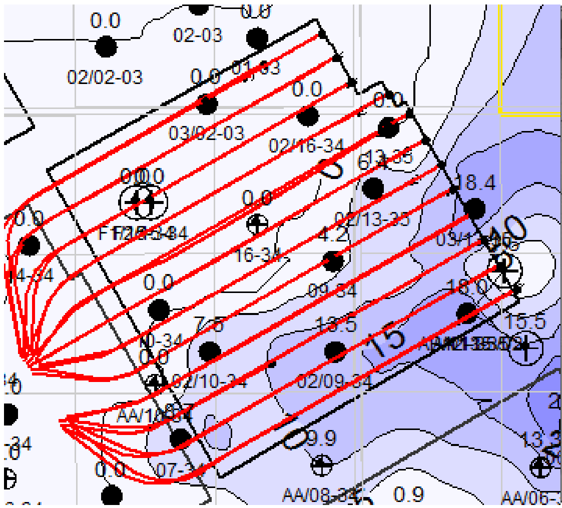




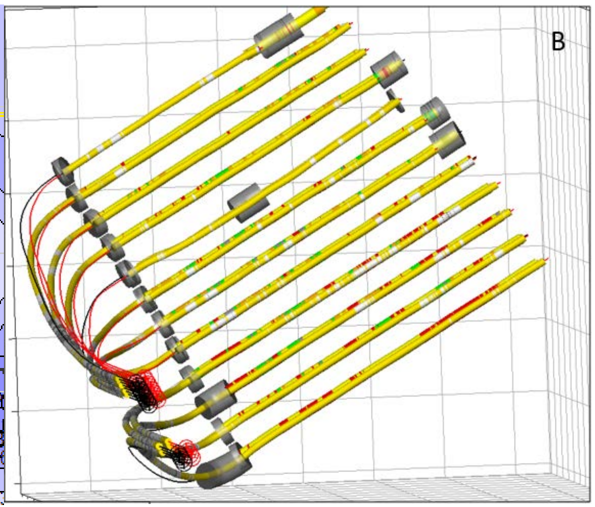
- **Top Water interaction observed from Obs Well data and WSR**







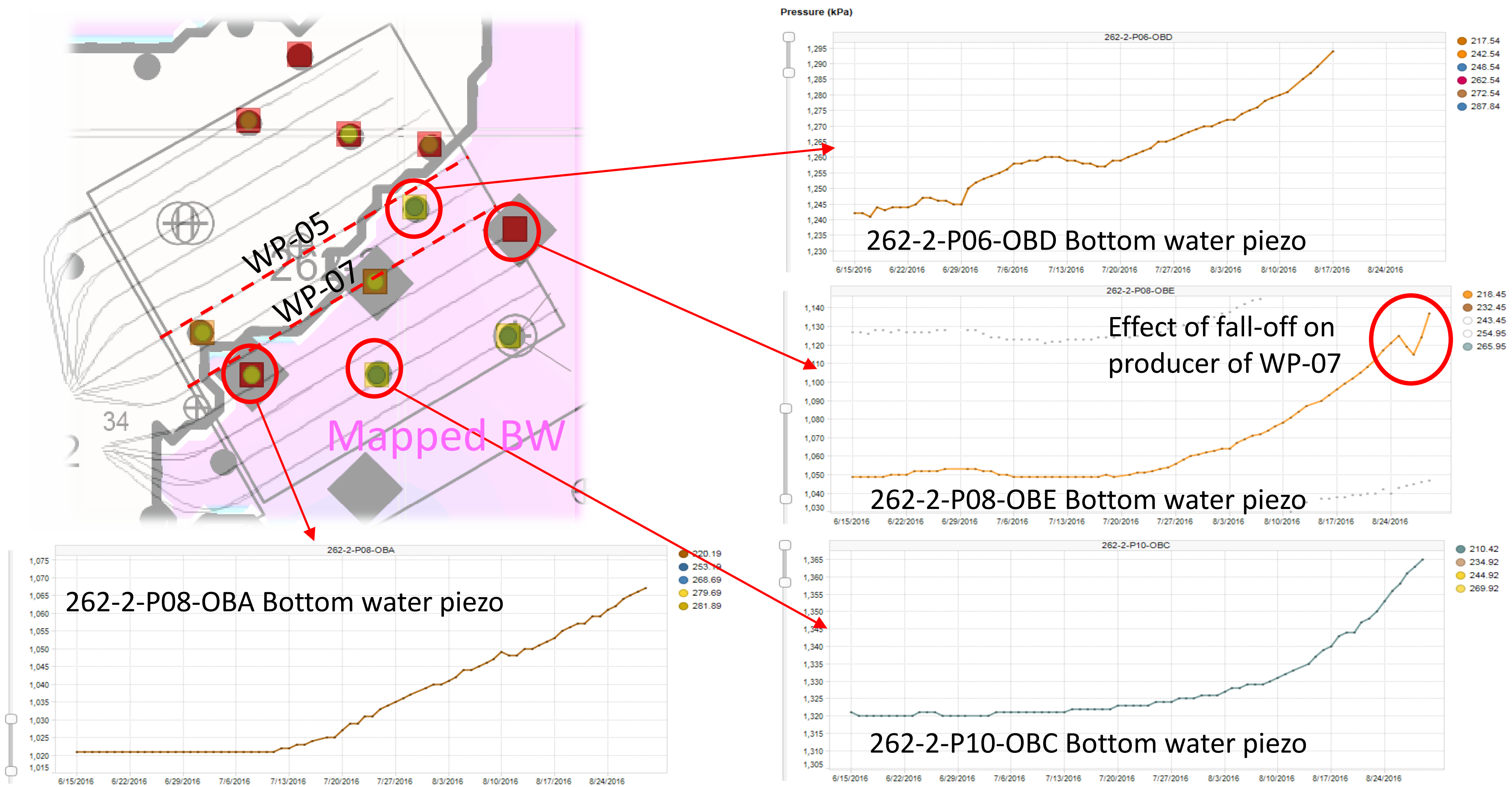
262-2 Bottom Water Isopach



262-2 Blanked Lean Zones

- **Started circulation after Fort McMurray Wildfire Emergency Shutdown & Re-start**
- **Close proximity to Bottom Water NE of Surmont**
- **Some wells encountered low resistivity zones while drilling, blanked liners in these zones**

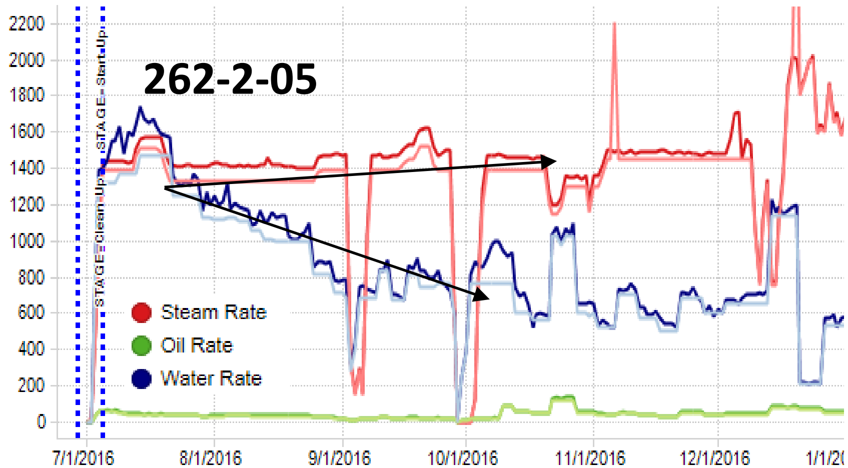
Performance / Chamber Development Challenges – Pad 262-2

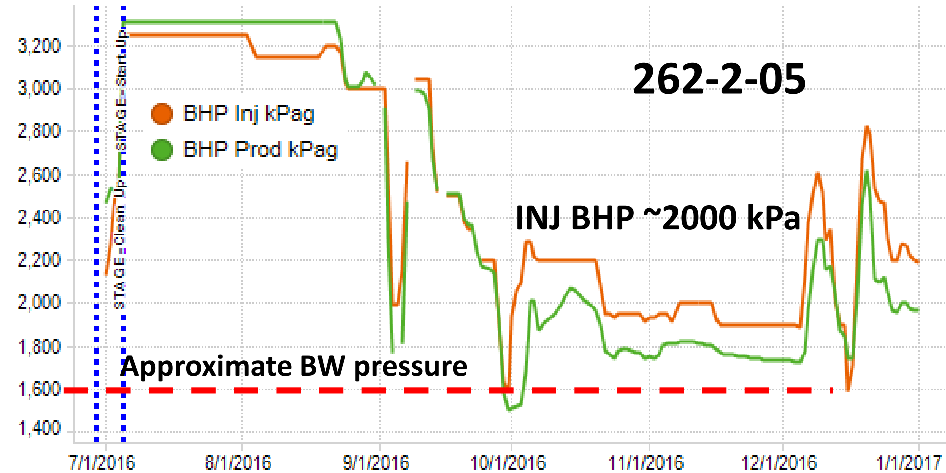


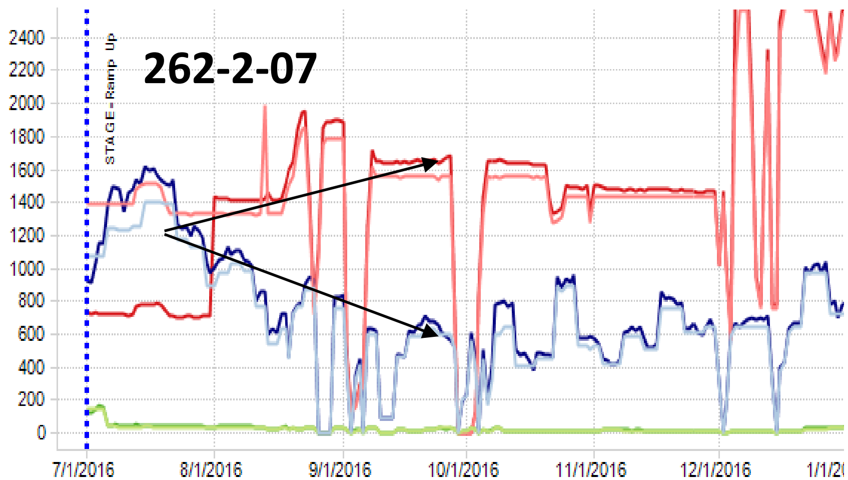
- **Bottom Water pressurization noticed early after circulation start**
- **Wells 05/07 direct contact with BW reducing circulation effectiveness**

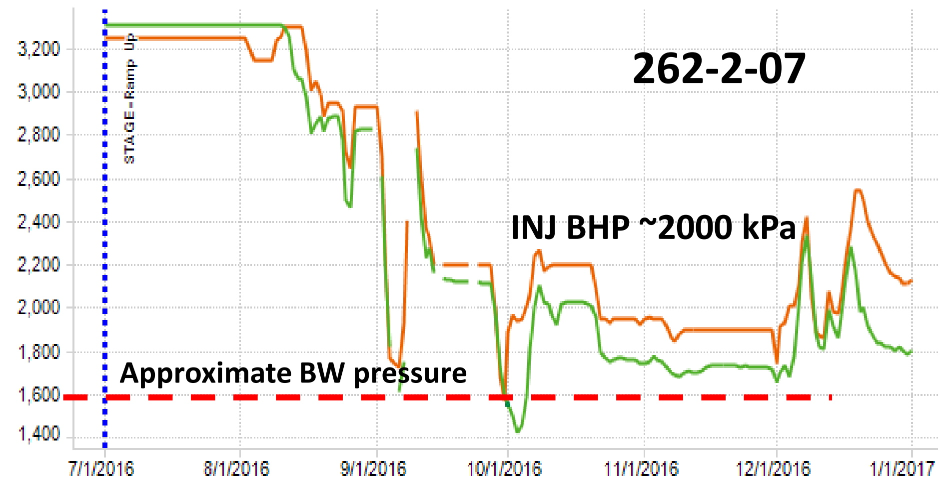
Performance / Chamber Development Challenges – Pad 262-2

- **Steam leak noticed early after circulation start by reduction of WSR (steam/water trends diverting)**
- **Pressure reduction mitigation to ~2000 kPa however this is too low for Gas Lift hence needing ESPs**









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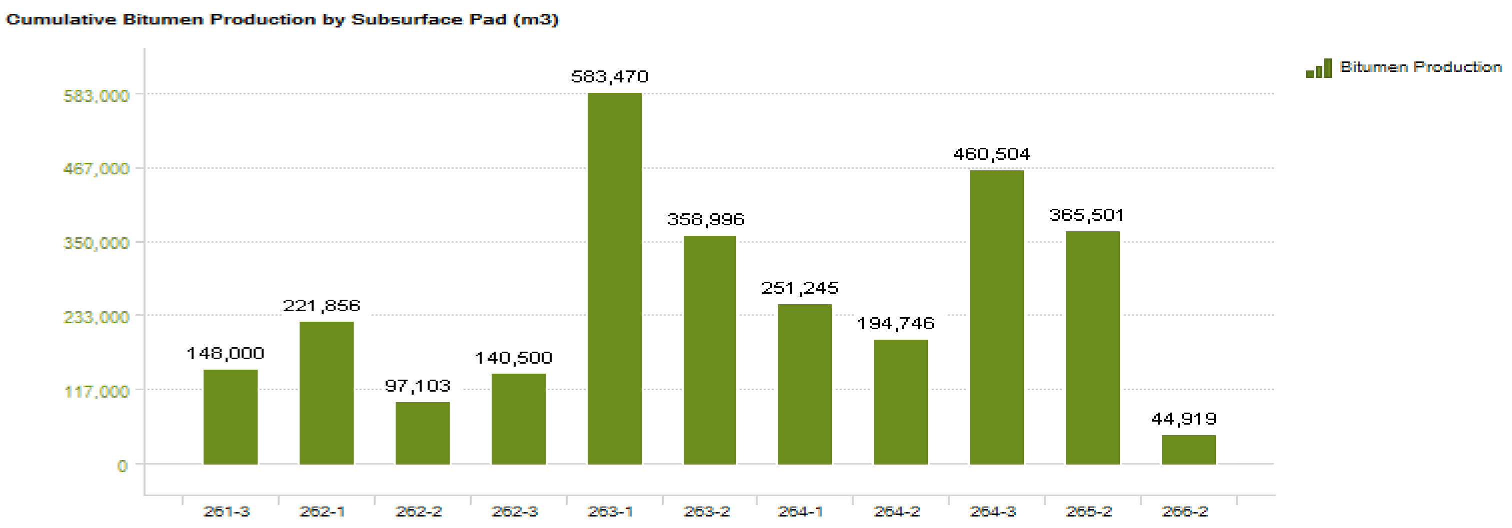
SOIP & Recovery Per Pad

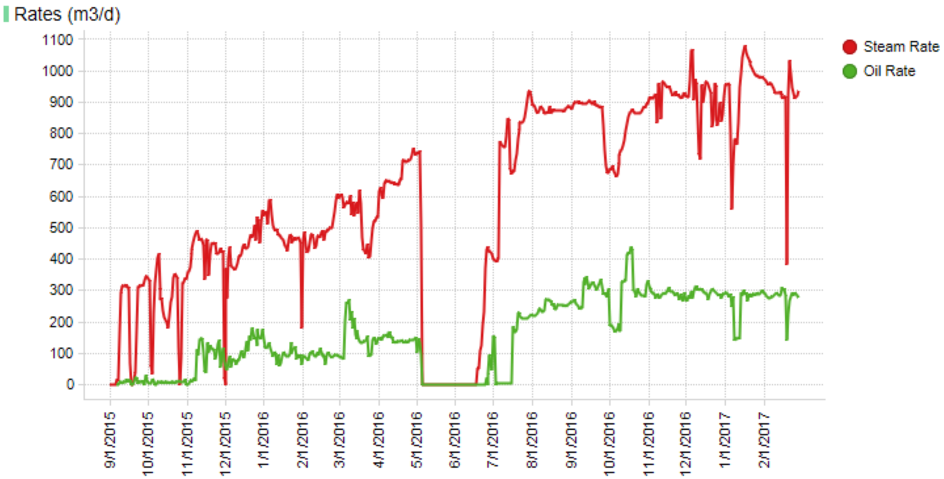
DA	SOIP* (E3M3)	CUM OIL (E3M3)	Recovery Factor
261-3	9,755	148.0	1.5%
262-1	8,755	221.9	2.5%
262-2	8,461	97.1	1.1%
262-3	9,552	140.5	1.5%
263-1	9,146	583.5	6.4%
263-2	8,954	359.0	4.0%
264-1	7,573	251.2	3.3%
264-2	9,845	194.7	2.0%
264-3	10,122	460.5	4.5%
265-2	6,839	365.5	5.3%
266-2	9,383	44.9	0.5%

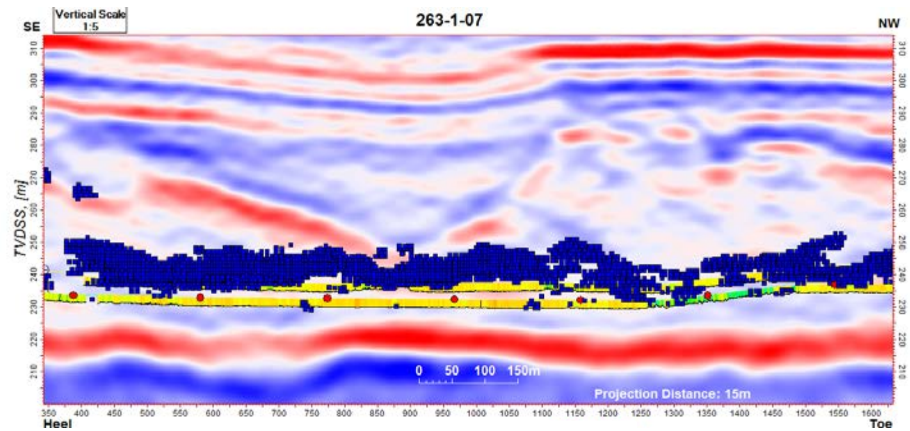
*SOIP: SAGDable Oil in Place

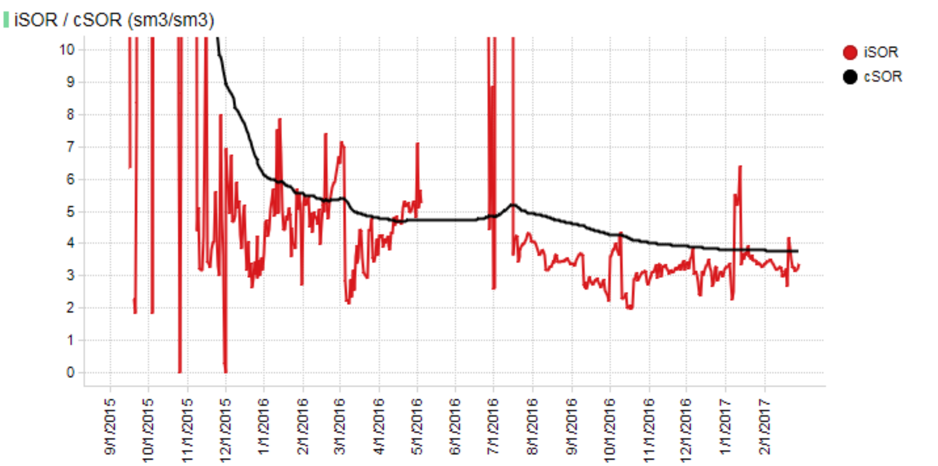


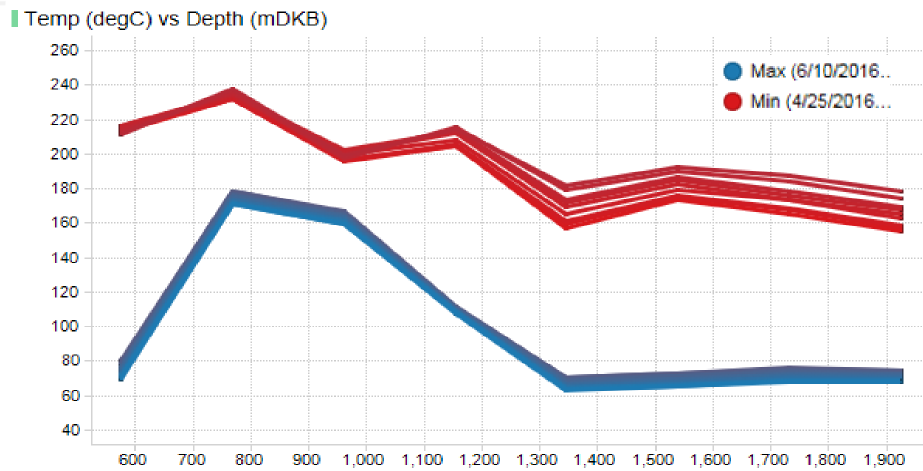
Pads ramping-up. Oil allocated during circulation accounted for RF.

Good Performance – WP 263-1-07





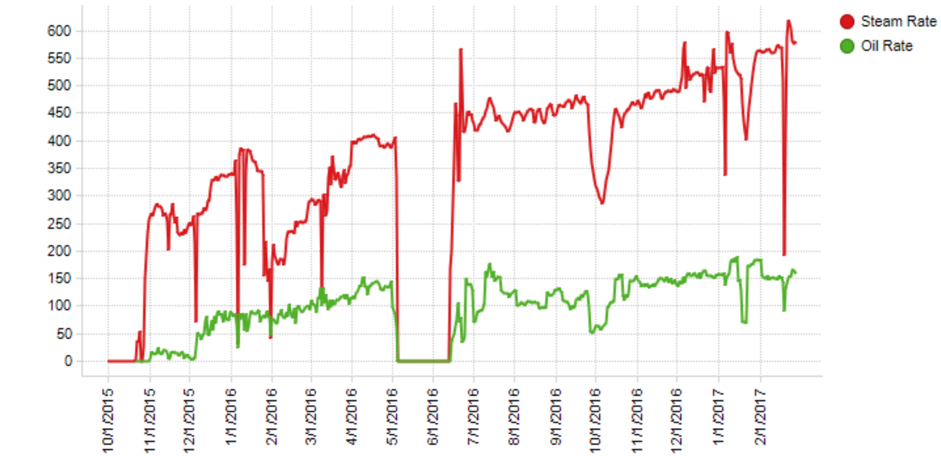


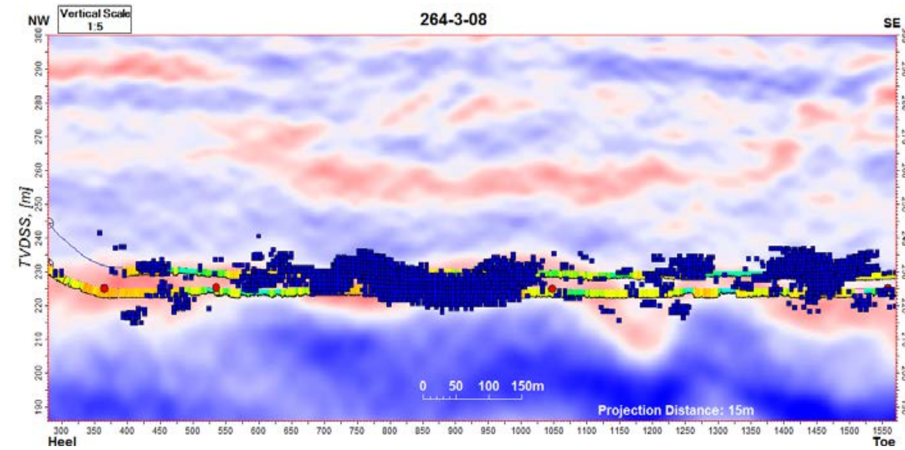


- **Well Performance exceeds expectations.**
- **Very good injectivity translating into fast ramp-up and good production rate.**
- **Falloff data (confirmed with 4D) shows mainly first half of well contributing to production**

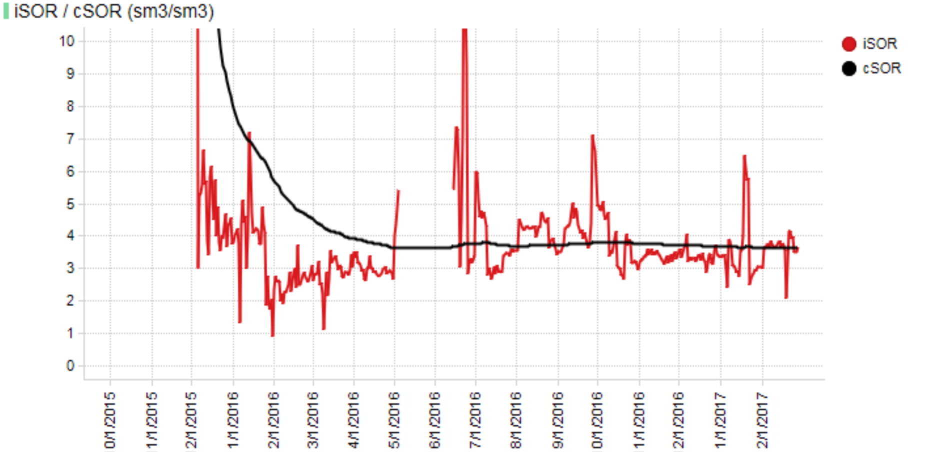
Average Performance – WP 264-3-08

Rates (m3/d)

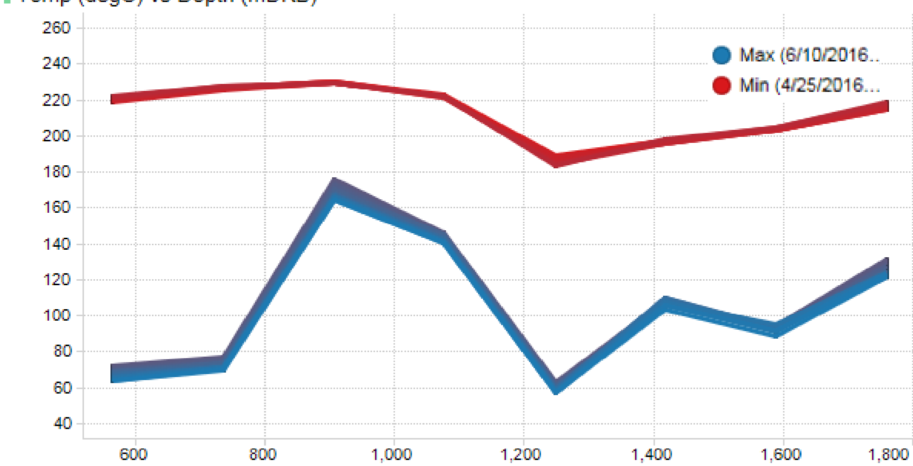




iSOR / cSOR (sm3/sm3)

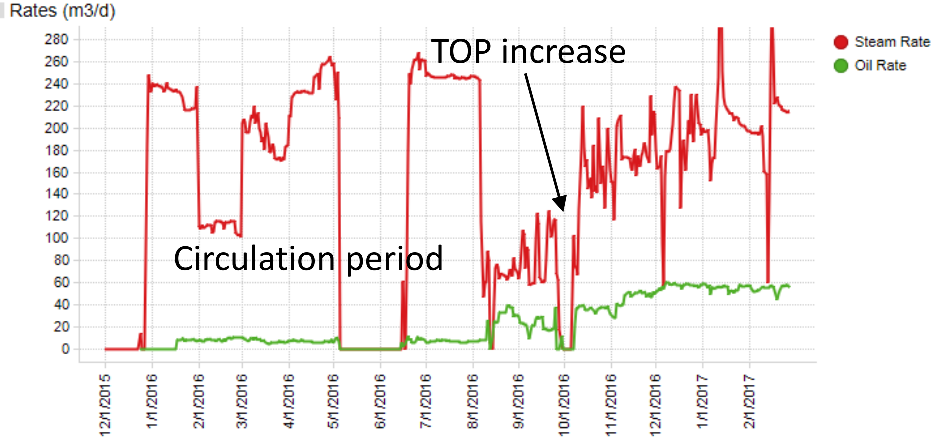


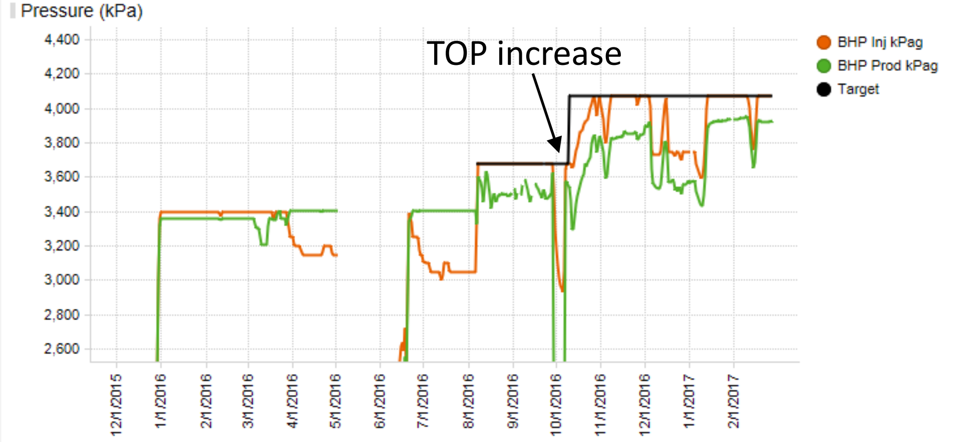
Temp (degC) vs Depth (mDKB)

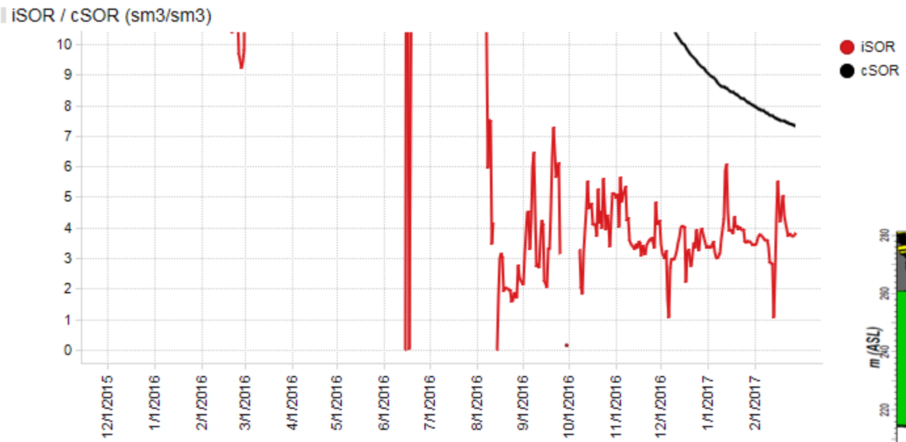


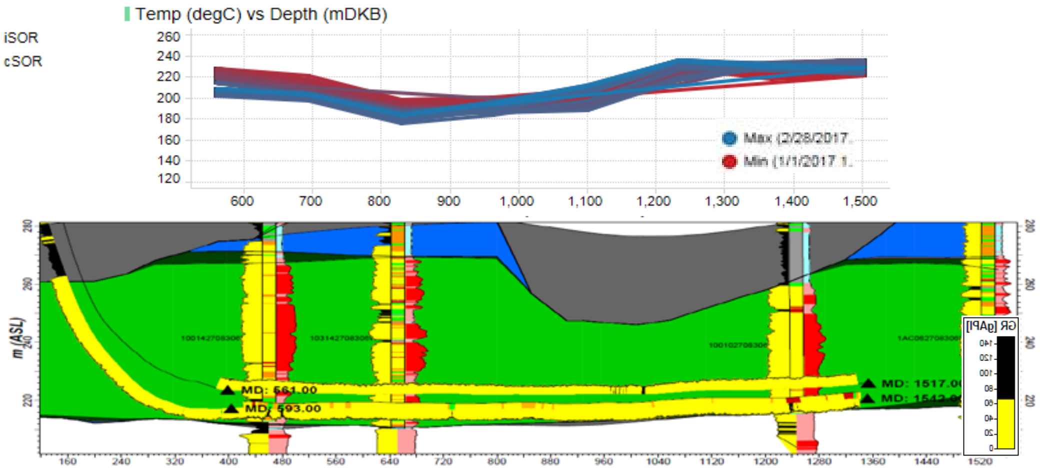
- **Well Performance meets expectations.**
- **Very good injectivity translating into fast ramp-up and good production rate.**
- **Falloff data (confirmed with 4D) shows two main sections contributing to production**

Poor Performance – WP 262-3-08







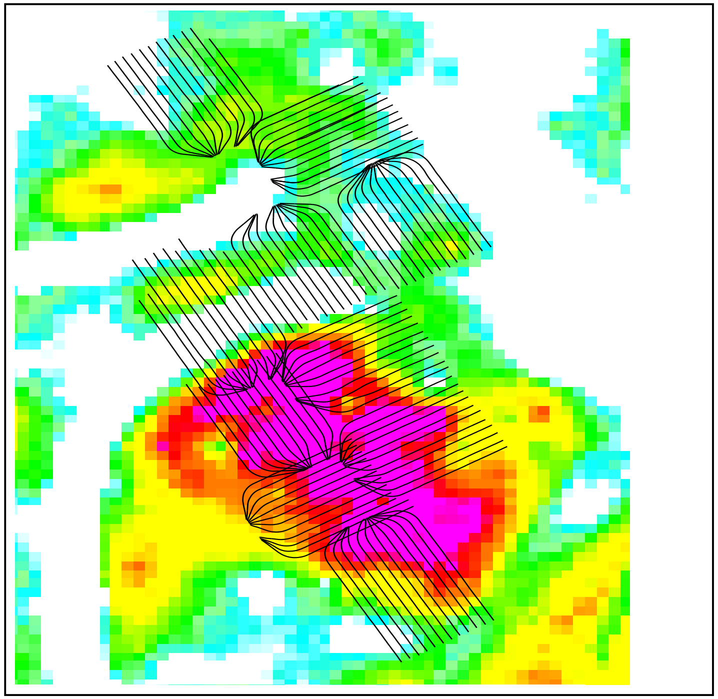


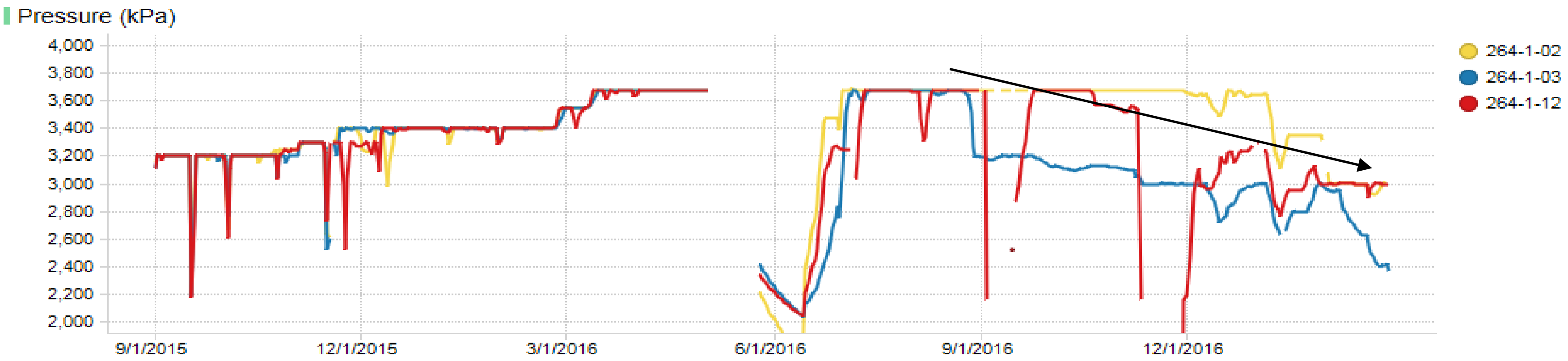
- **Well Performance below expectations despite good geology. Large circulation period (~5 months) indicated poor communication between injector/producer wells**
- **Pad MOP increased to 4300kPa in SAGD which helped increase injectivity in the formation**
- **Flowing temperature data indicates poor development in middle section of the well**

Surmont 2 – Operating Pressure Strategy

- Surmont 2 base case Operating Strategy follows a declining pressure profile, which is influenced by the efficiency of artificial lift, SOR, thief zone (TZ) interaction, etc.
- Certain DAs have been identified at risk for top and bottom water TZ interaction, which has already been observed in some wells.
- Strategy for these DA's account for a more aggressive pressure drop to minimize steam loss into the TZ, but still keeping an overbalanced condition to avoid water influx into the chambers.
- Timing of pressure drop is dependent on each DA's condition. This has already been implemented in some individual wells where interaction has occurred.
- ESP conversions will help implement a lower pressure strategy where required.

Effective Top Water Thickness (meters)





Example of wells in Pad 264-1 where pressure has been decreased to mitigate TZ interaction

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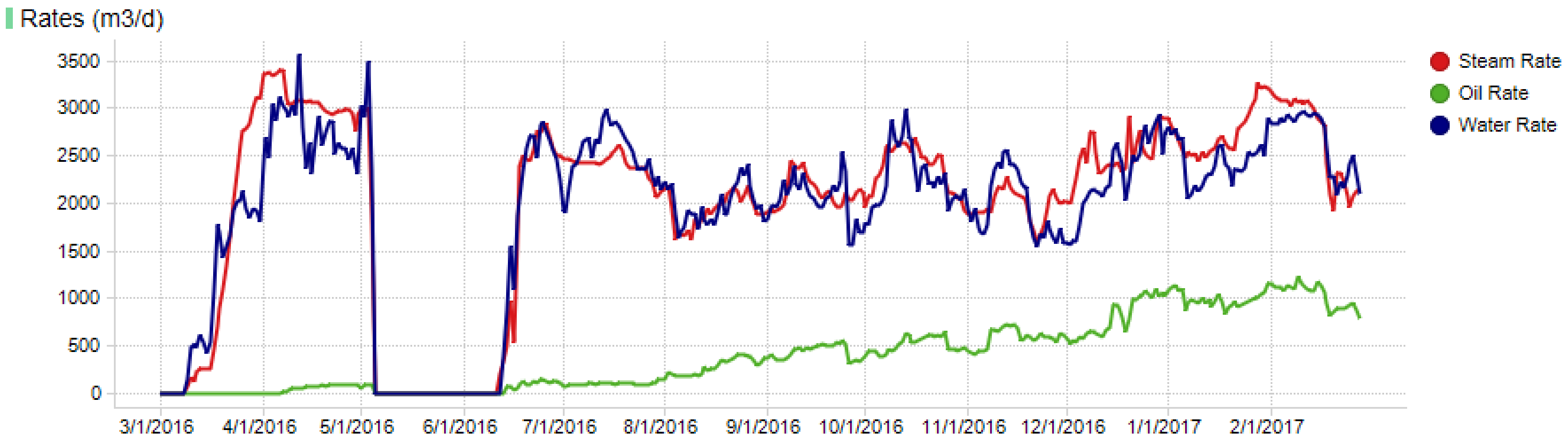
Phase 2 - Key Learnings

- Some wells are still challenged with injectivity/productivity issues, which translates into a slower ramp-up or underperformance based on expectations. Evaluation of optimization opportunities is work in progress.
- Liner deployed Flow Control Devices have showed to promote faster development of the wells compared to typical slotted liner wells, mainly due to the operational benefit they provide.
- Proper risk ranking and identification of thief zone areas, combined with close monitoring of chamber development is of great importance for timely execution of operating strategy.
- Optimization projects still under evaluation include:
    - Tubing Deployed FCDs
    - Injector steam splitters
    - Well stimulations

Surmont 2 – 261-3 Pad



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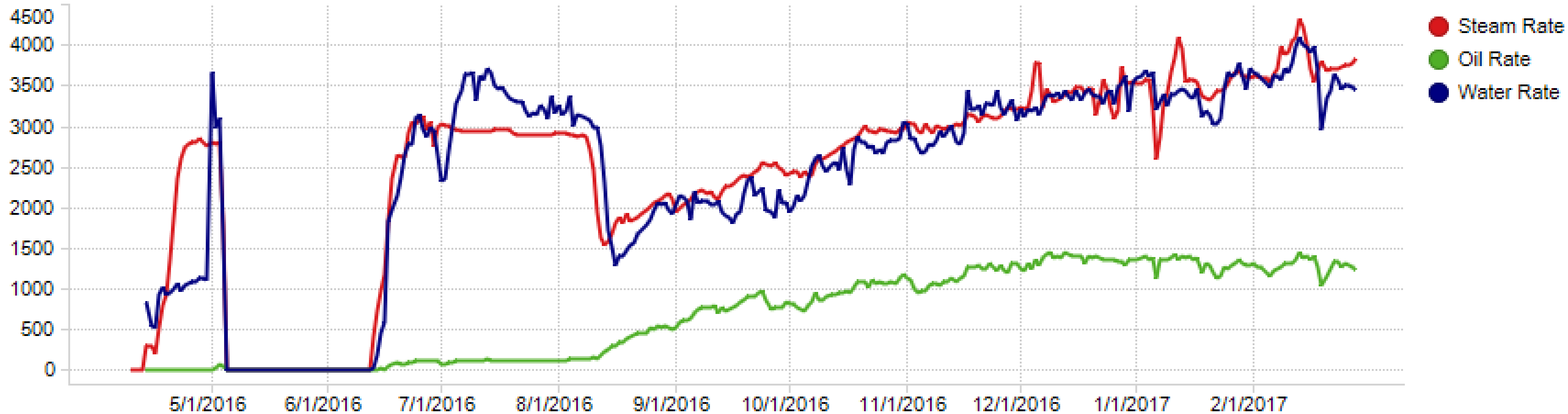
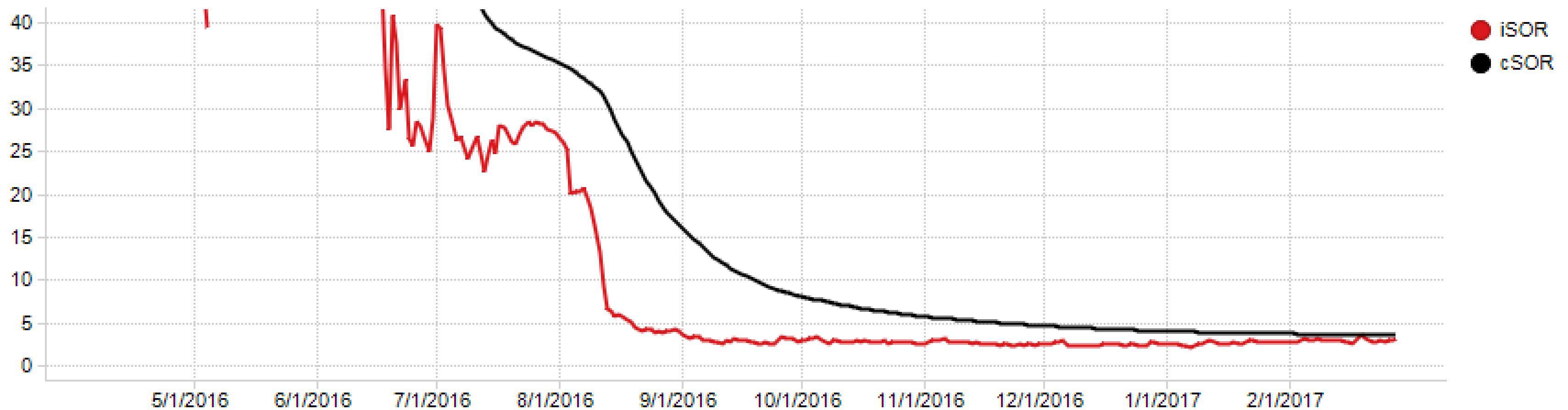
Surmont 2 – 262-1 Pad

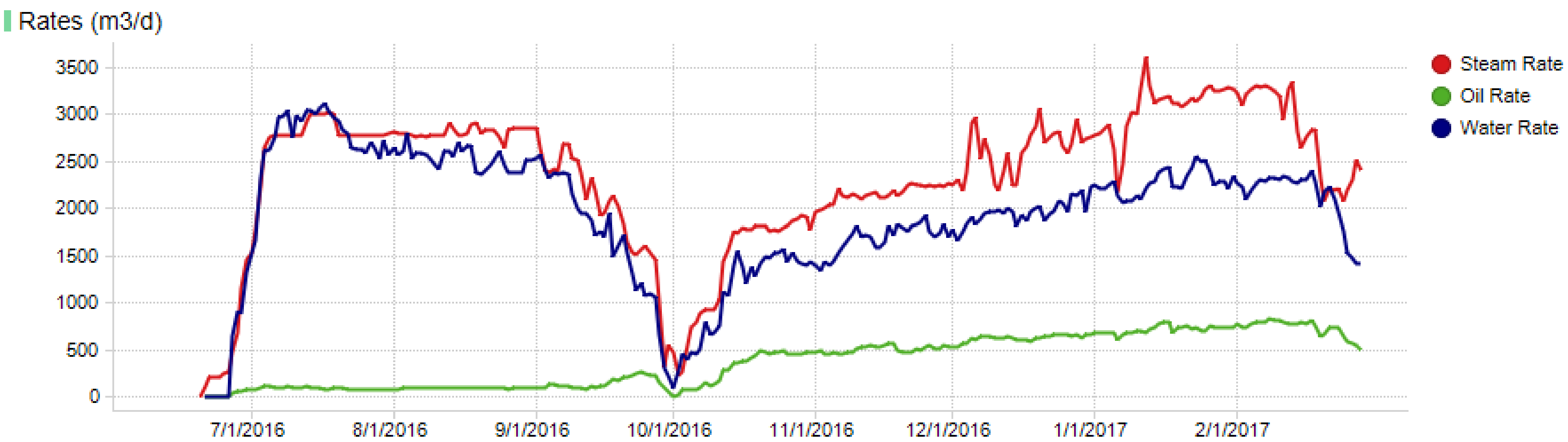
Rates (m3/d)

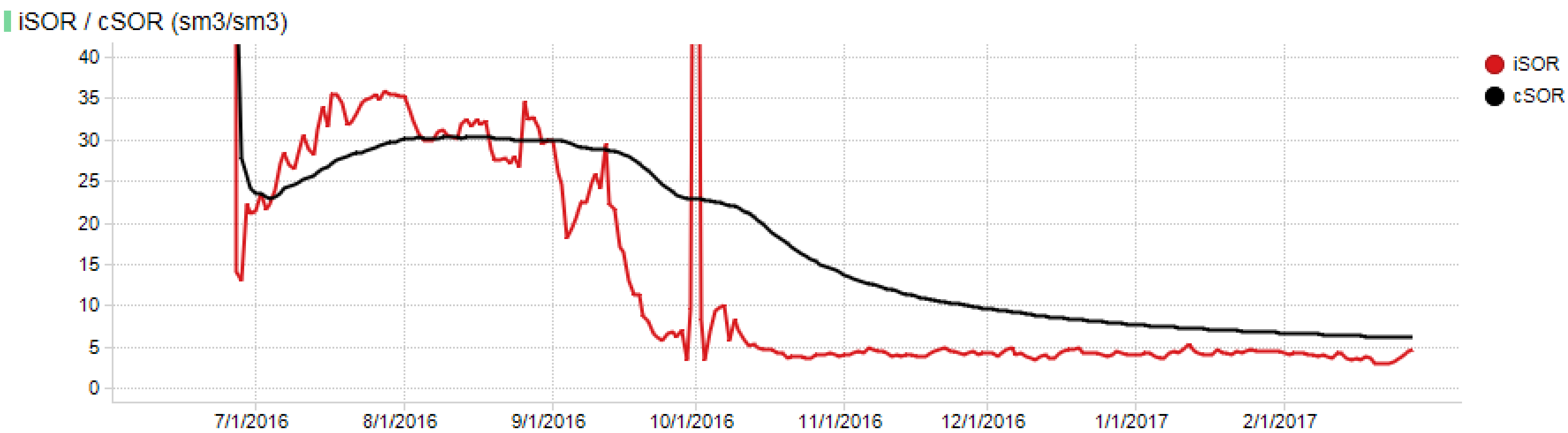


iSOR / cSOR (sm3/sm3)

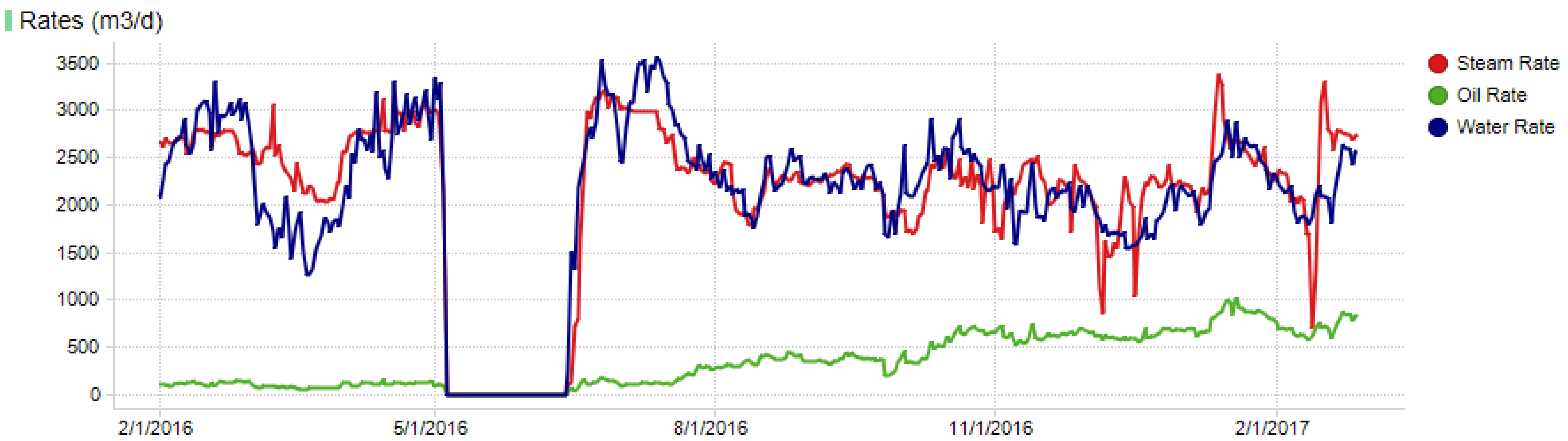


Surmont 2 – 262-2 Pad

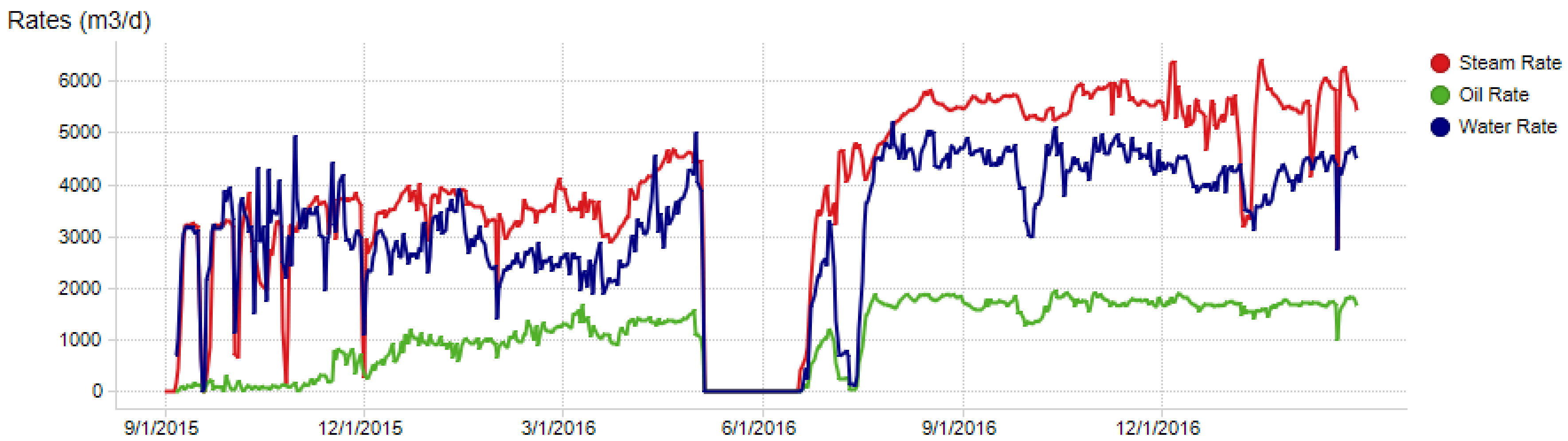


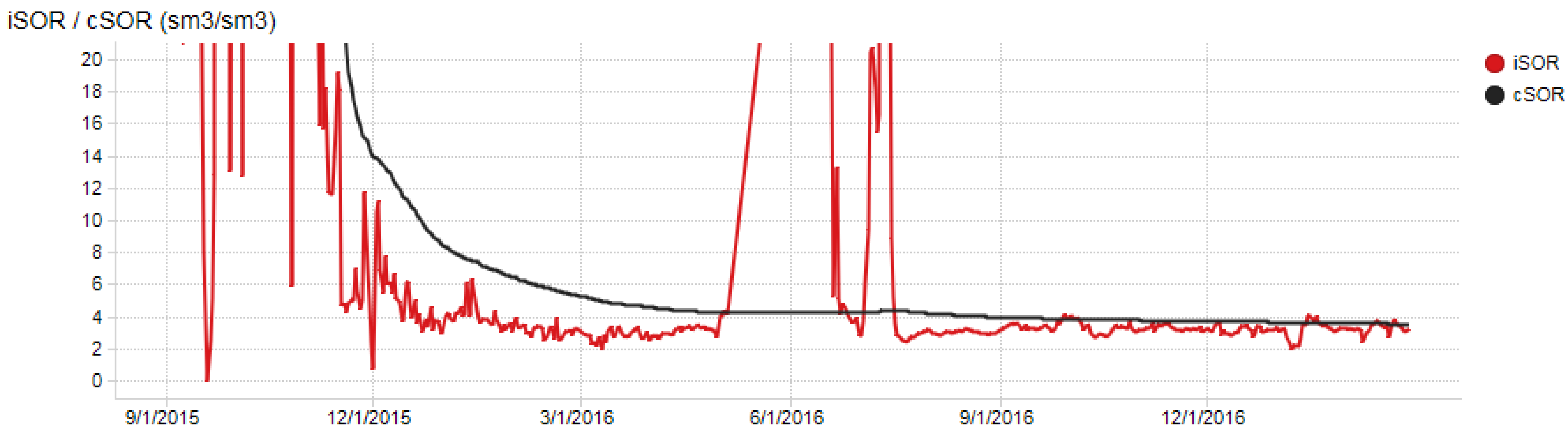


Surmont 2 – 262-3 Pad

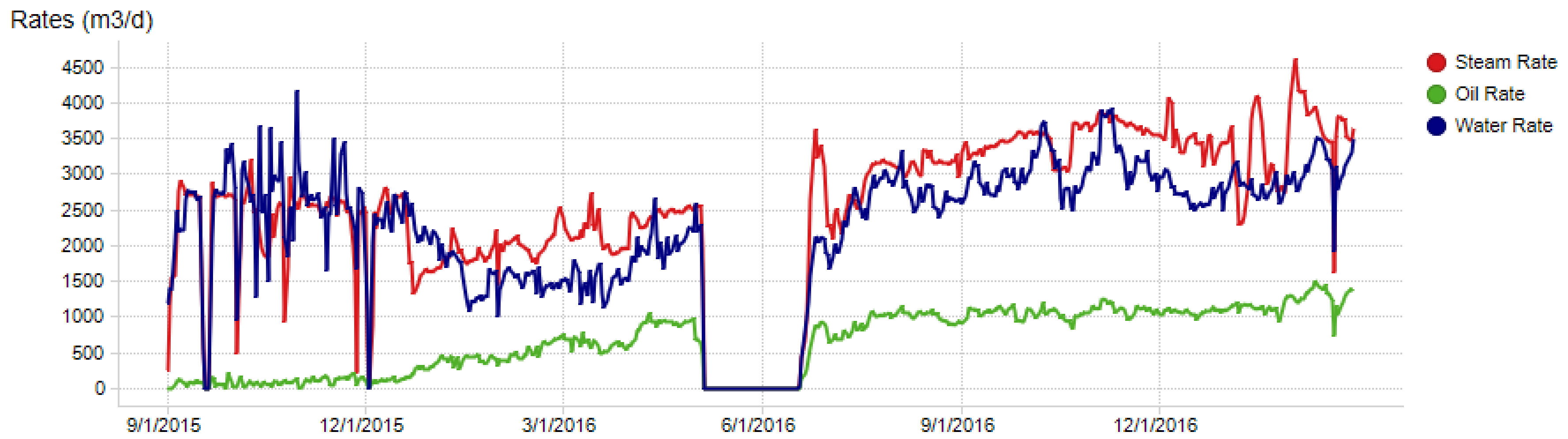


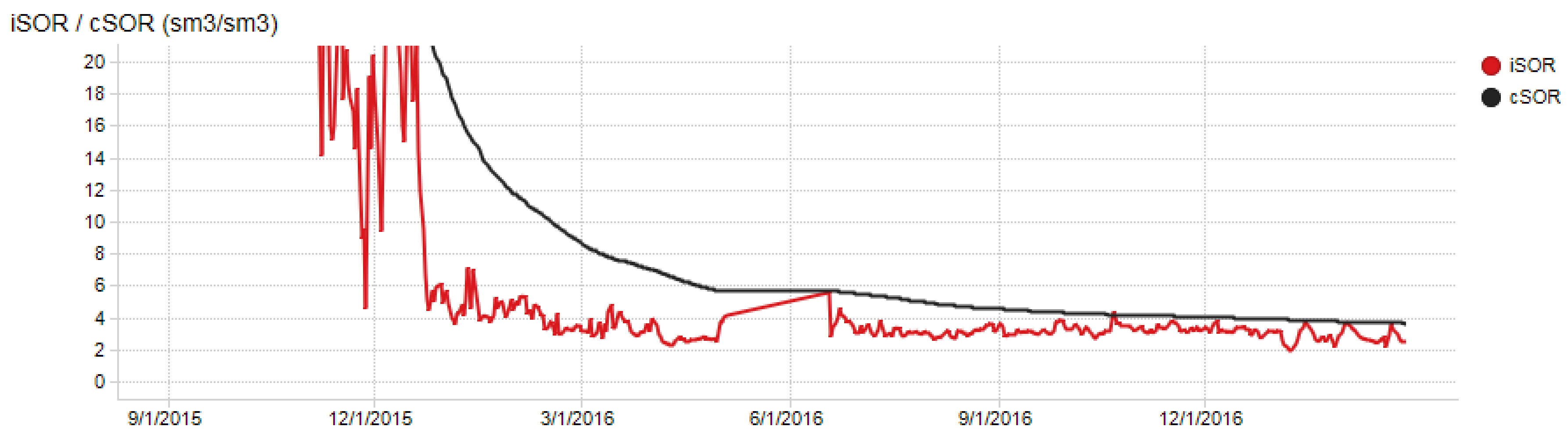
Surmont 2 – 263-1 Pad



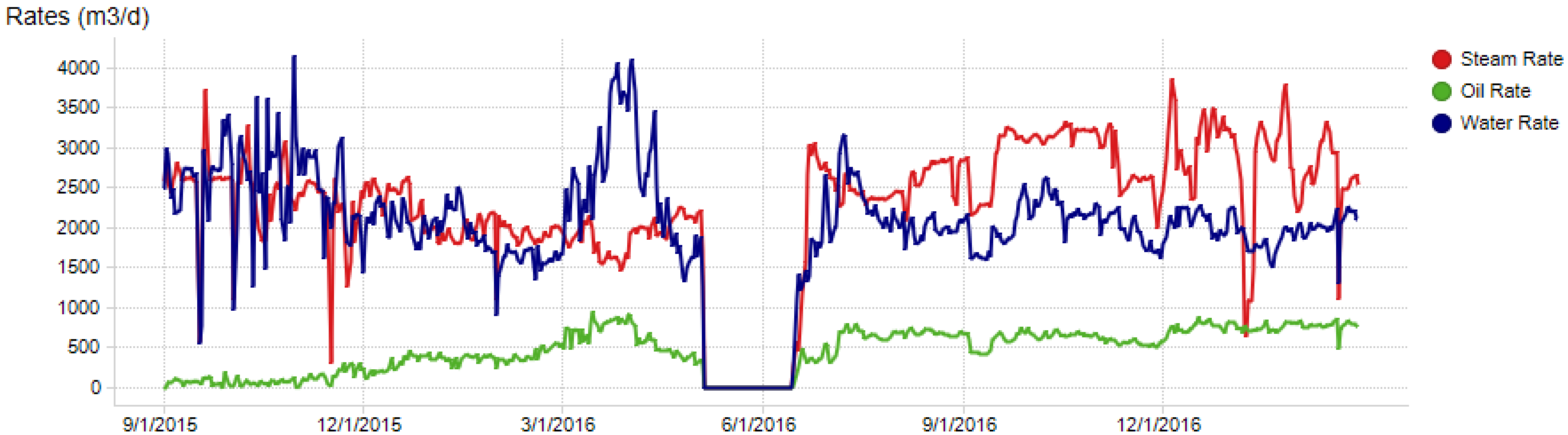


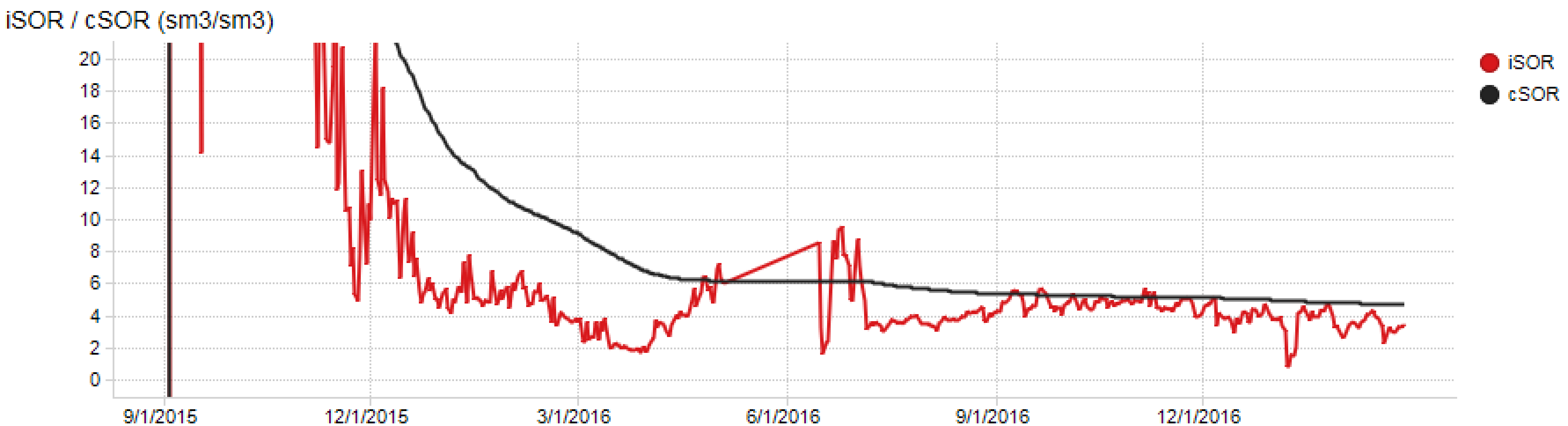
Surmont 2 – 263-2 Pad



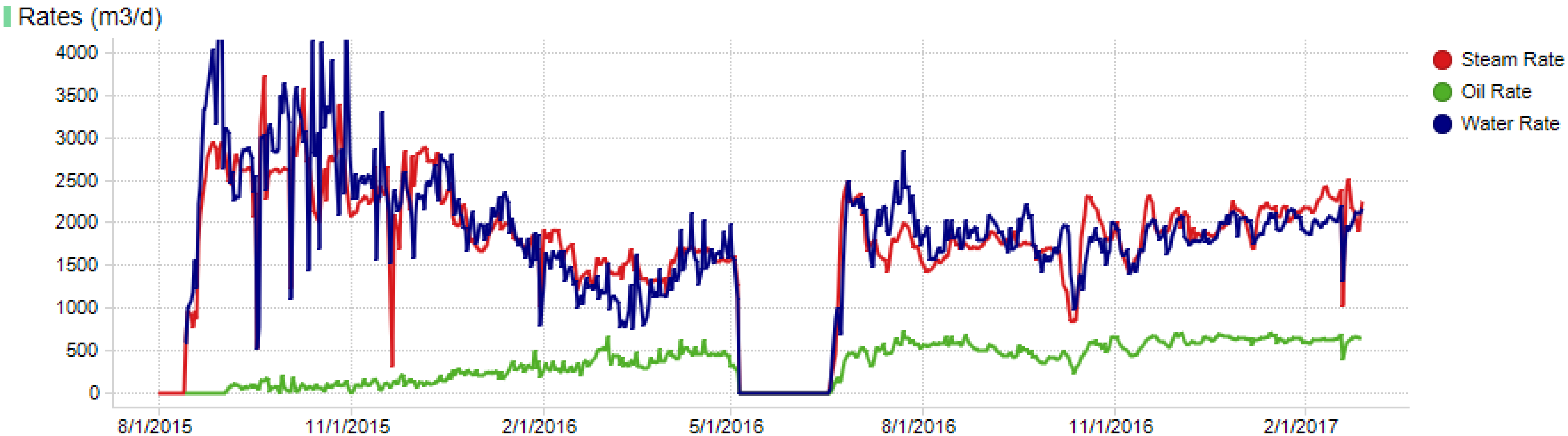


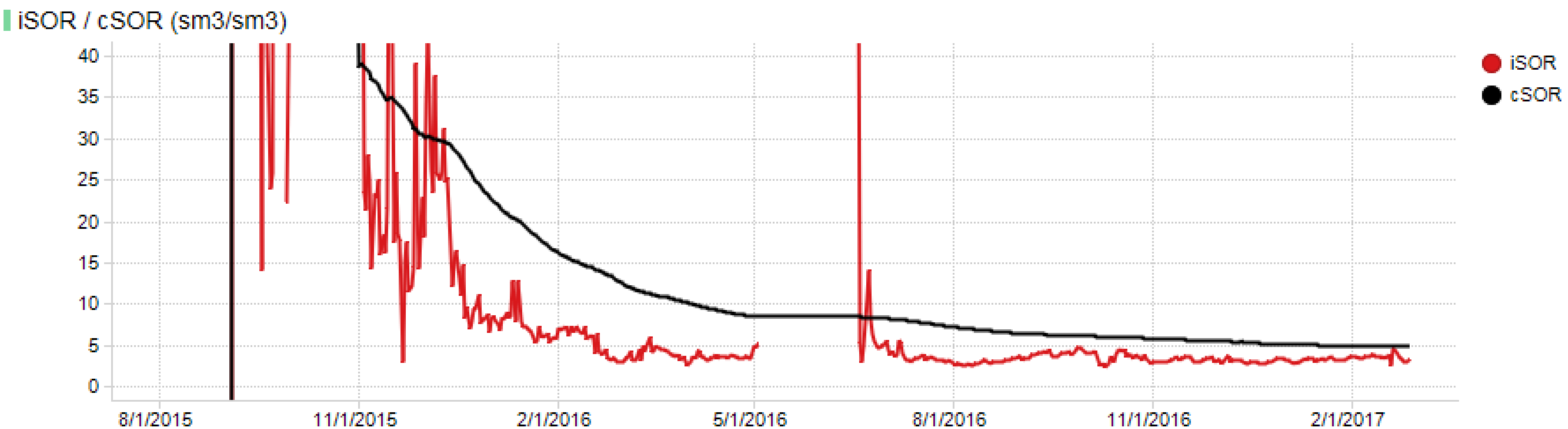
Surmont 2 – 264-1 Pad





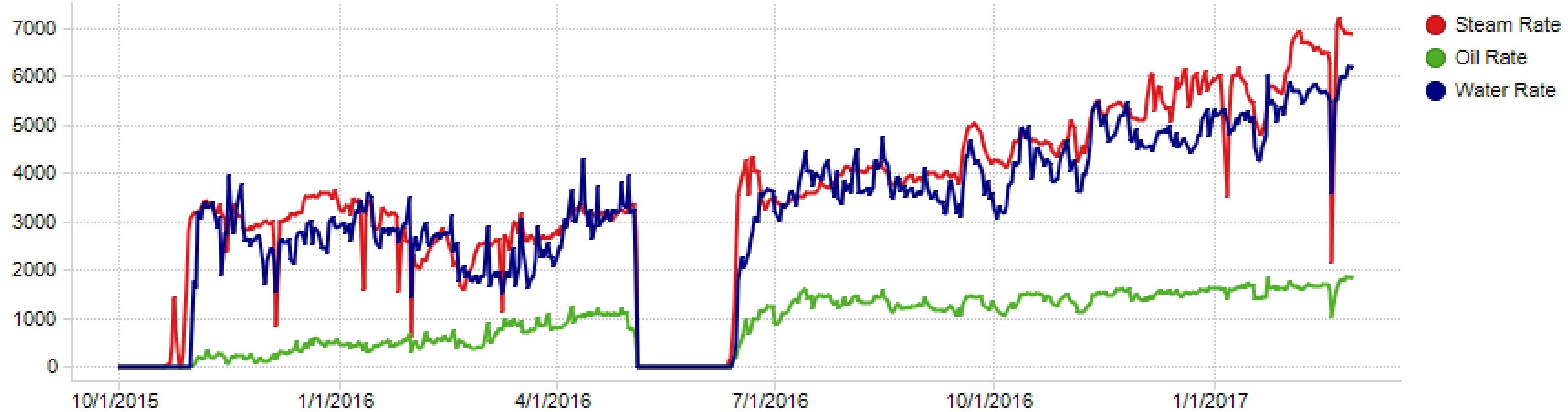
Surmont 2 – 264-2 Pad



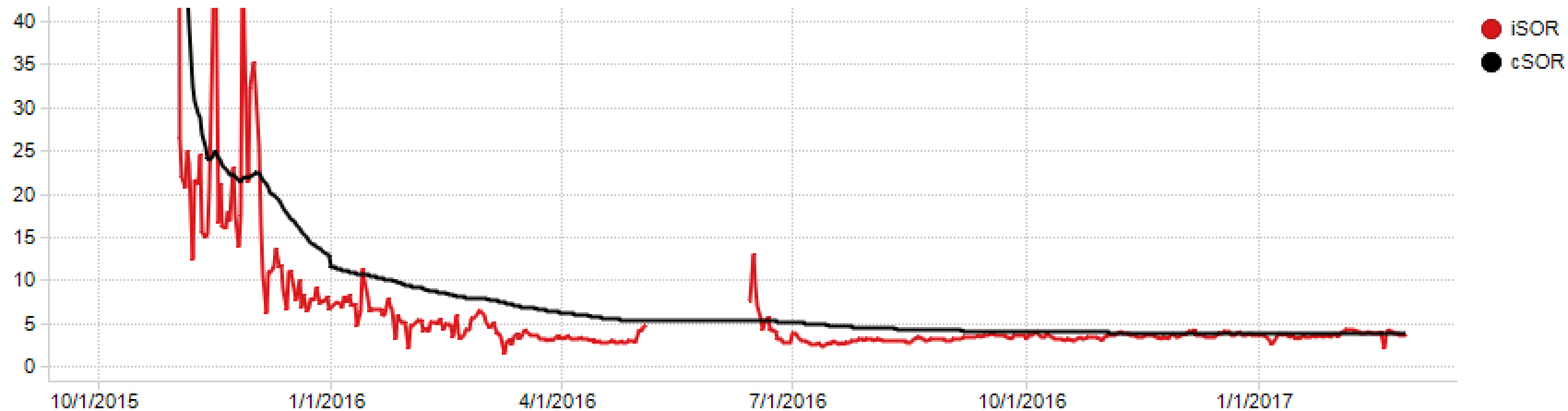


Surmont 2 – 264-3 Pad

Rates (m3/d)



iSOR / cSOR (sm3/sm3)



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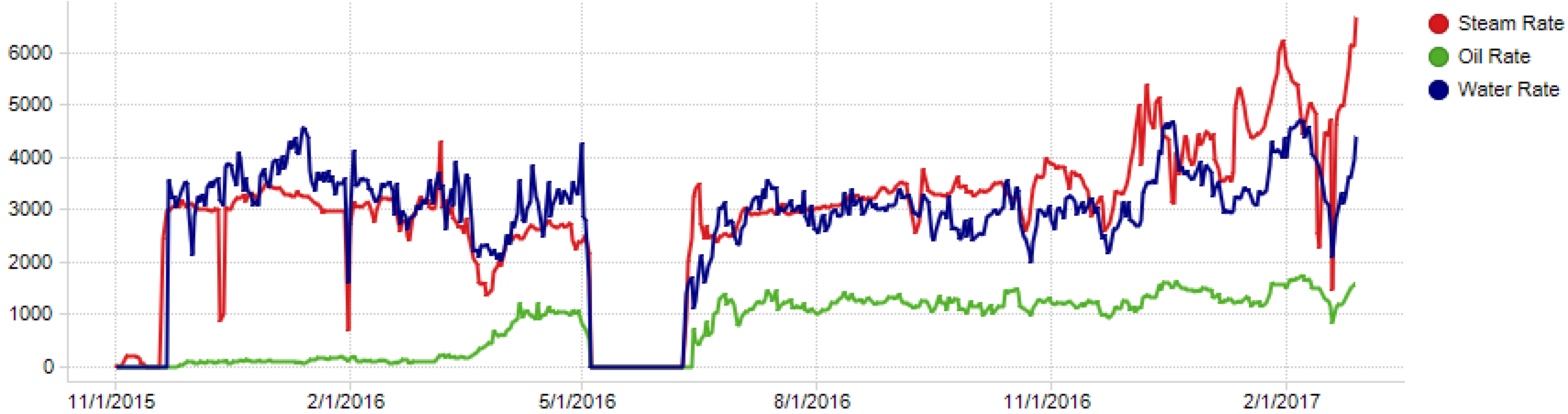
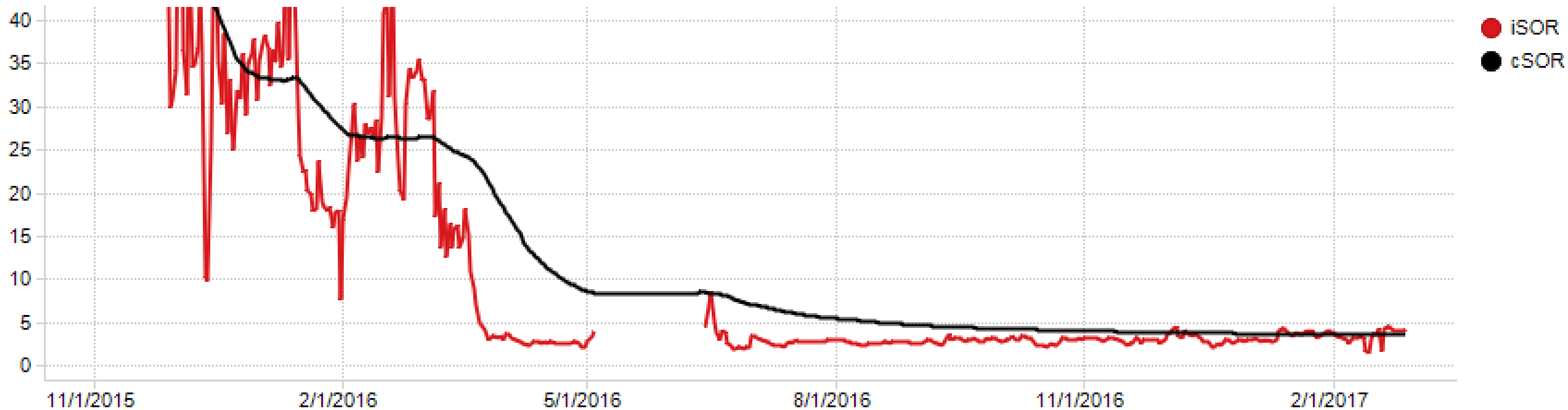
Surmont 2 – 265-2 Pad

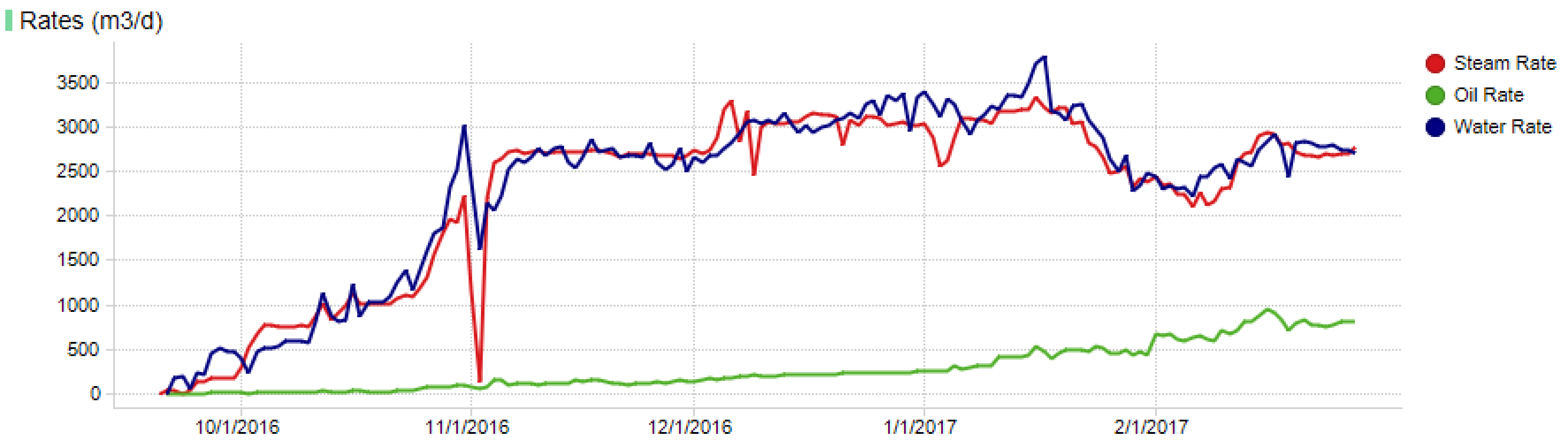
Rates (m3/d)



iSOR / cSOR (sm3/sm3)



Surmont 2 – 266-2 Pad



Future Plans

Subsection 3.1.1 (8)

Future Plans – Surmont

Surmont 1

- Fishbone infill well 102-22 expected to be onstream in Q2, 2017
- NCG pilot commenced January, 2017 on 3 wells at Pad 102
- Well stimulations are being investigated
- Additional tubing deployed flow control devices will be looked at for install
- Investigating possible BP drill outs to recover lost sections of laterals

Surmont 2

- Start-up remaining 11 wells in Q1 2017
- Start ESP conversions for 5 different pads
- Continue tubing deployed flow control device installations
- Continue more steam splitter installations
- Evaluate well stimulations and redrill opportunities for under performing pads

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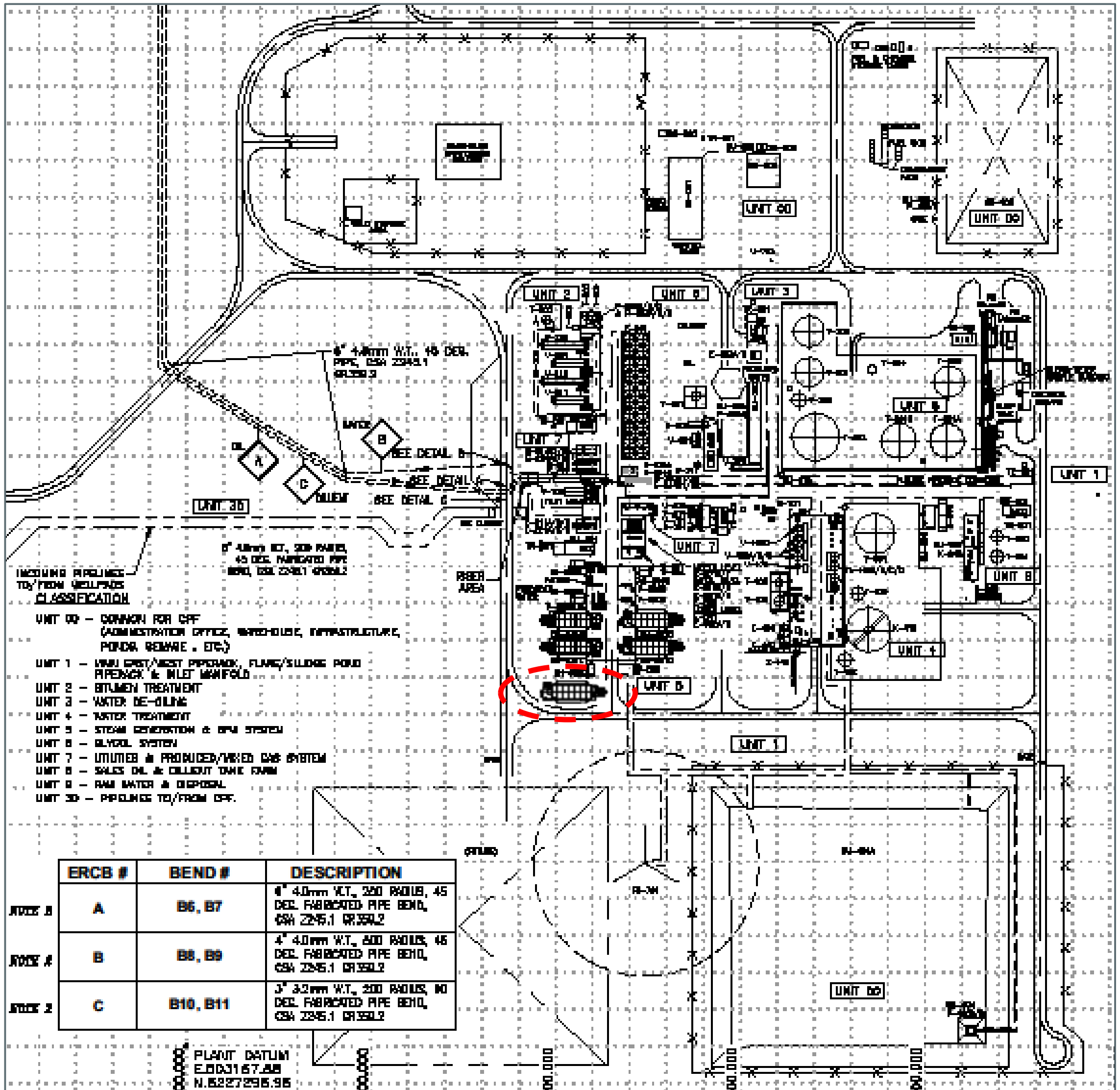
Surface Operations and Compliance
Surmont Project
Approval 9426

Facilities

Subsection 3.1.2 (1)

Phase 1 Plot Plan: CPF



ERCB #	BEND #	DESCRIPTION
A	B6, B7	4" 4.0mm W.T., 250 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2
B	B8, B9	4" 4.0mm W.T., 600 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2
C	B10, B11	3" 3.2mm W.T., 200 RADIUS, 90 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2

- **Steam Generator (installed but never tied in) was removed from Phase 1**

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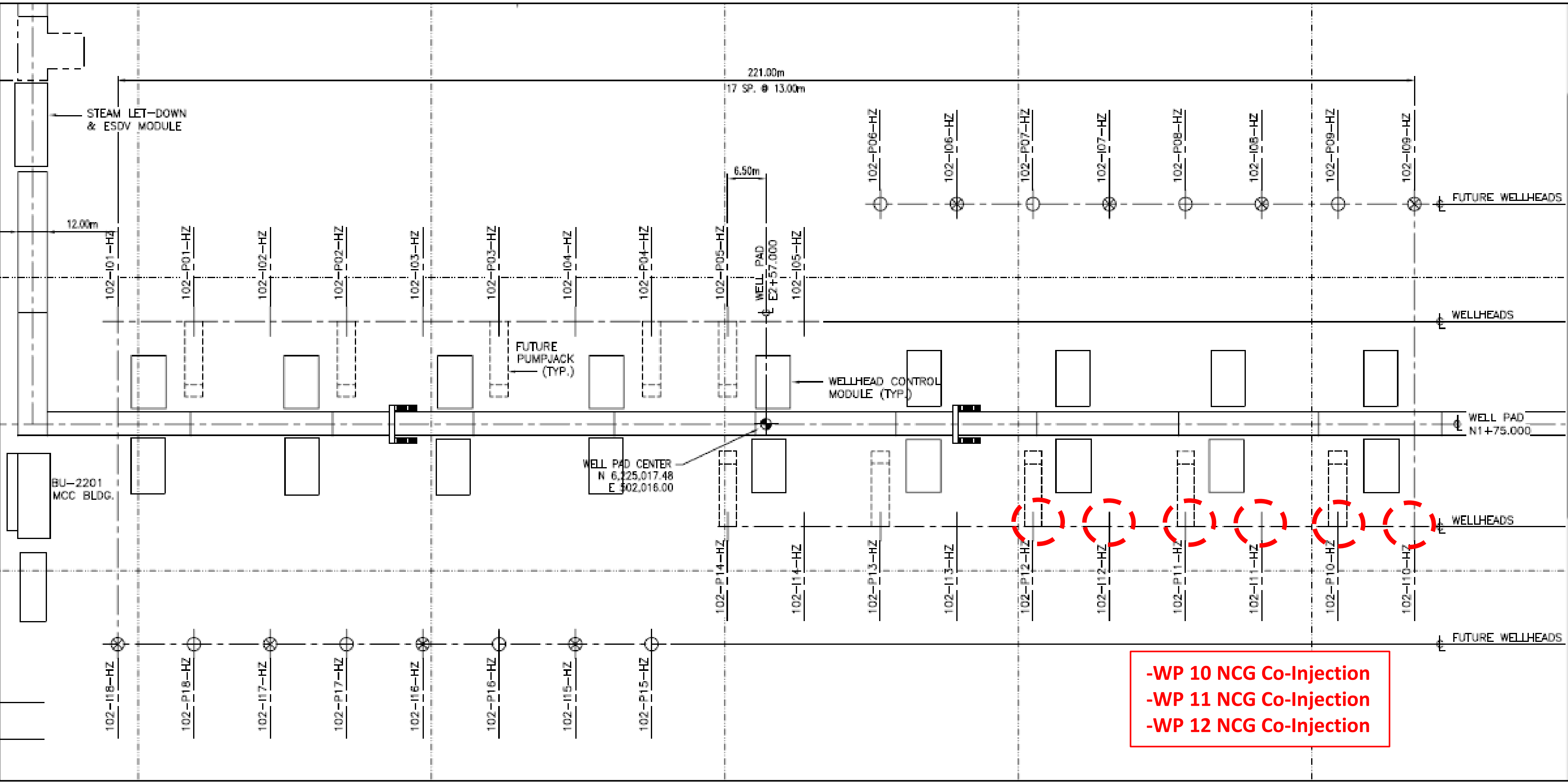
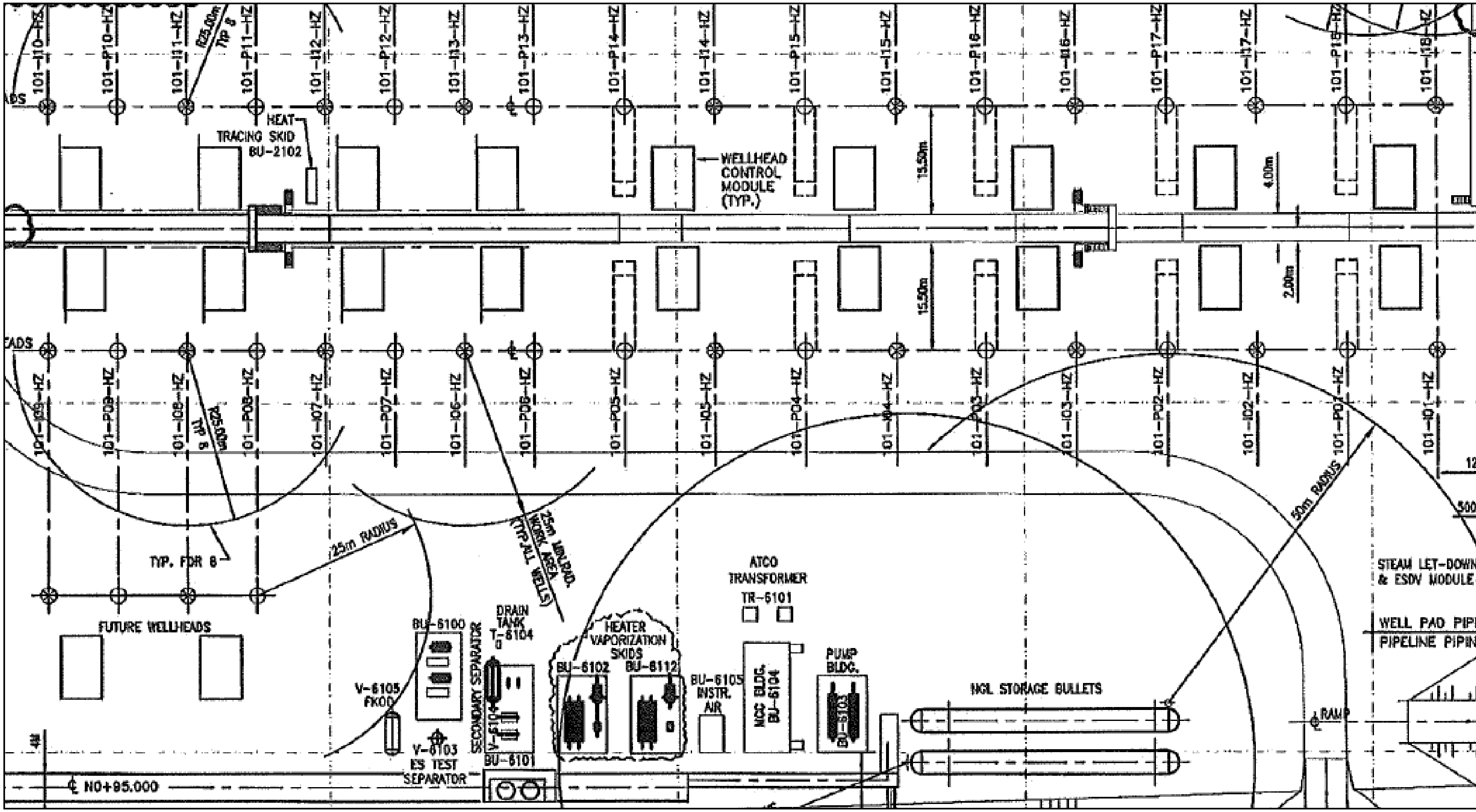
Phase 1 Plot Plan: Pad 102



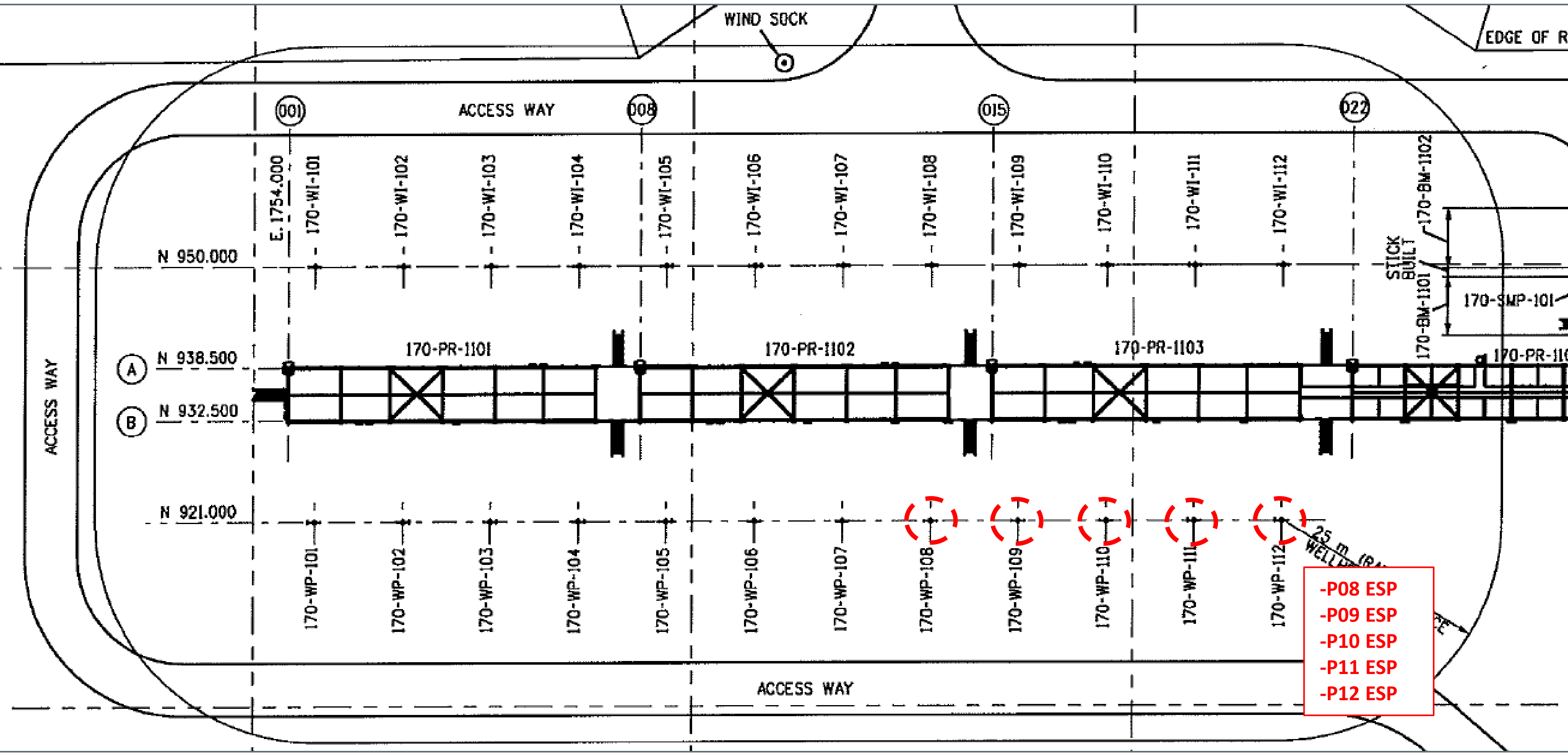
- **Non-Condensable Gas (NCG) Co-Injection trial required piping modifications on wellpairs 10, 11, and 12 to tie lift gas lines into heel steam injection lines.**

Phase 1 Plot Plan: Pad 101



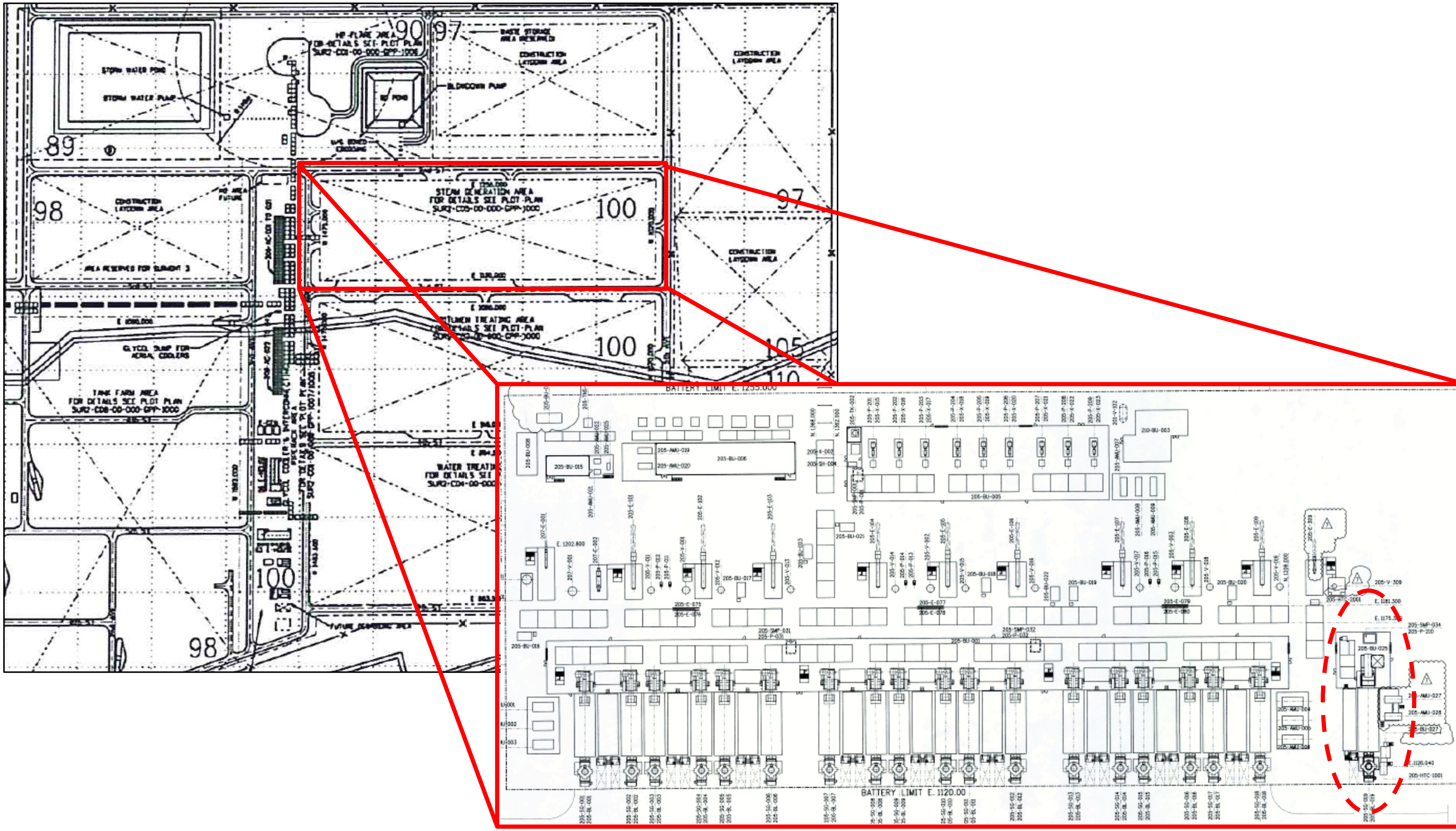
- **No ESP Conversions or Major Modifications at Pad 101.**

Phase 1 Plot Plan: Pad 103



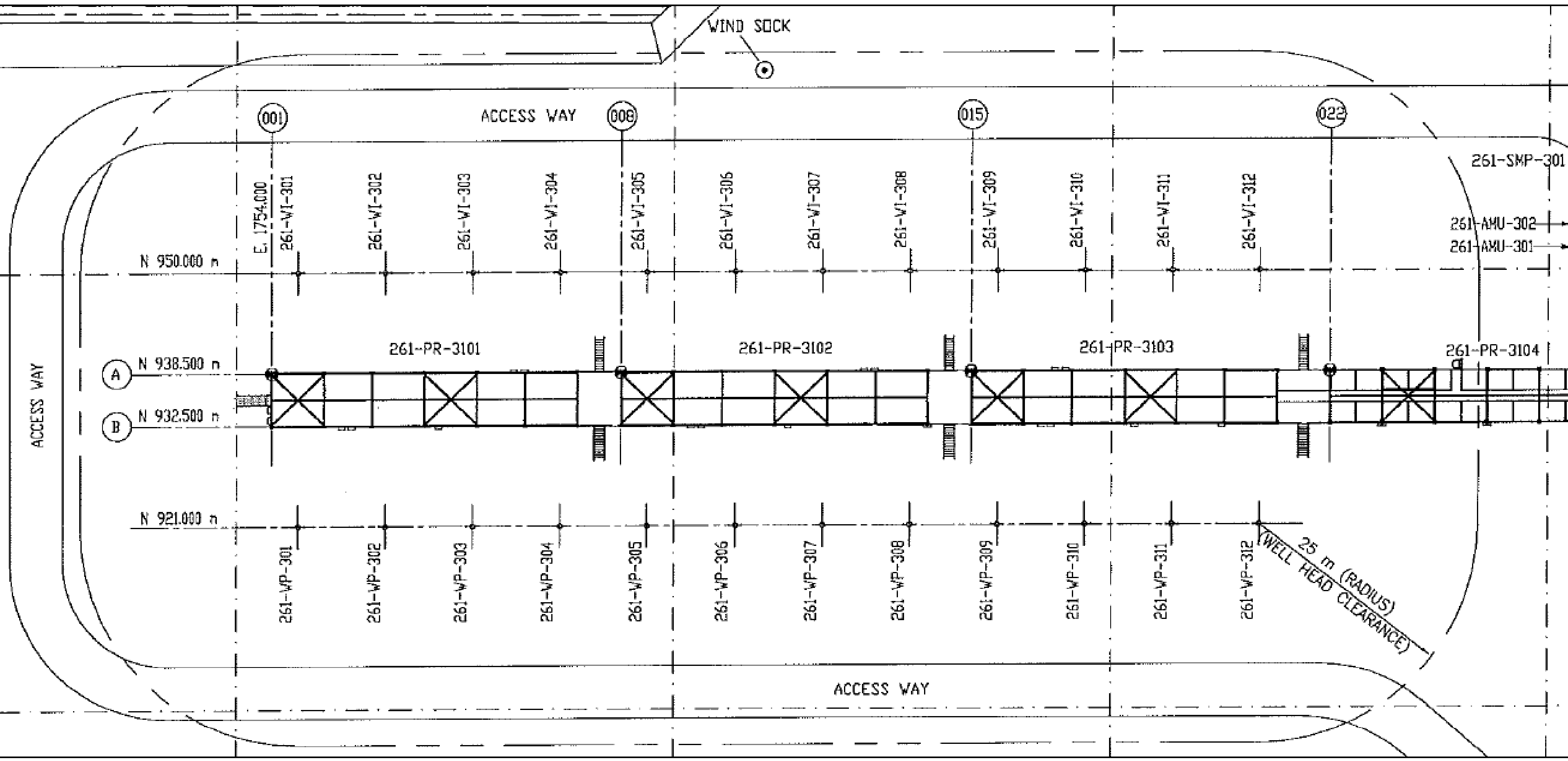
- **Pad 103 ESP Conversions: Added 3 ESPs in Feb 2016, 1 in Apr 2016, and 1 in Aug 2016**

Phase 2 Plot Plan: CPF



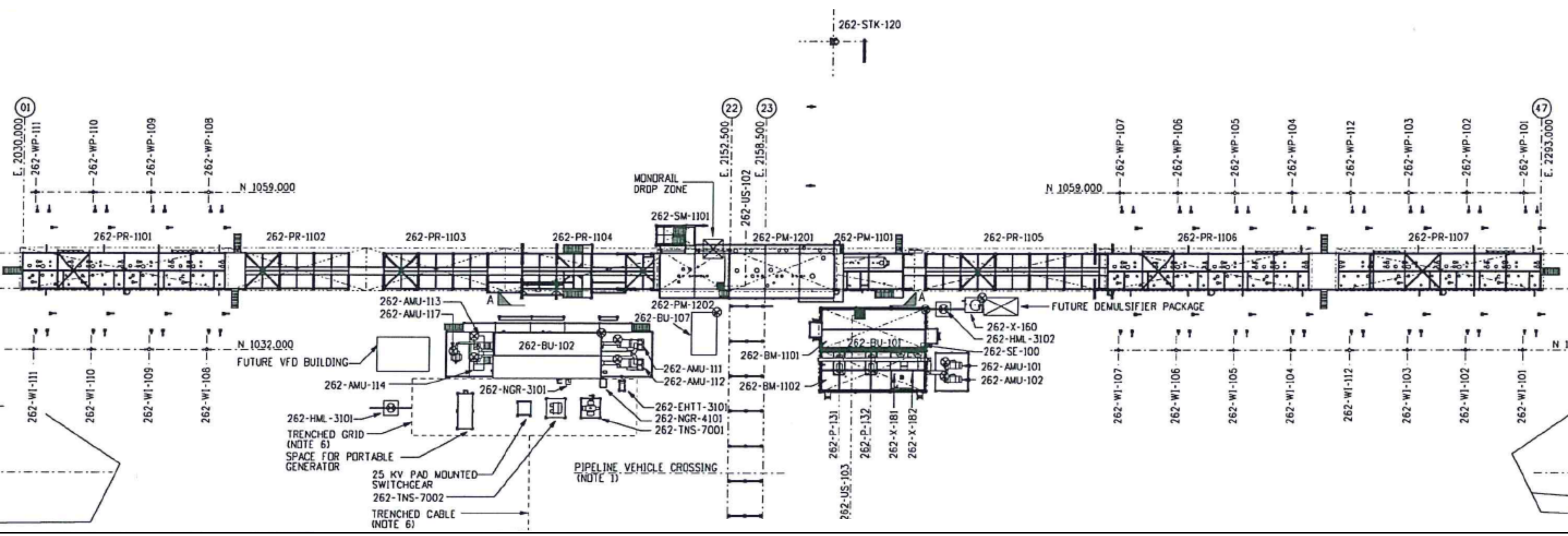
Installation of one additional OTSG at Surmont 2, construction work is on-going.
No changes in other areas of the plant

Phase 2 Plot Plan: Pad 261-3



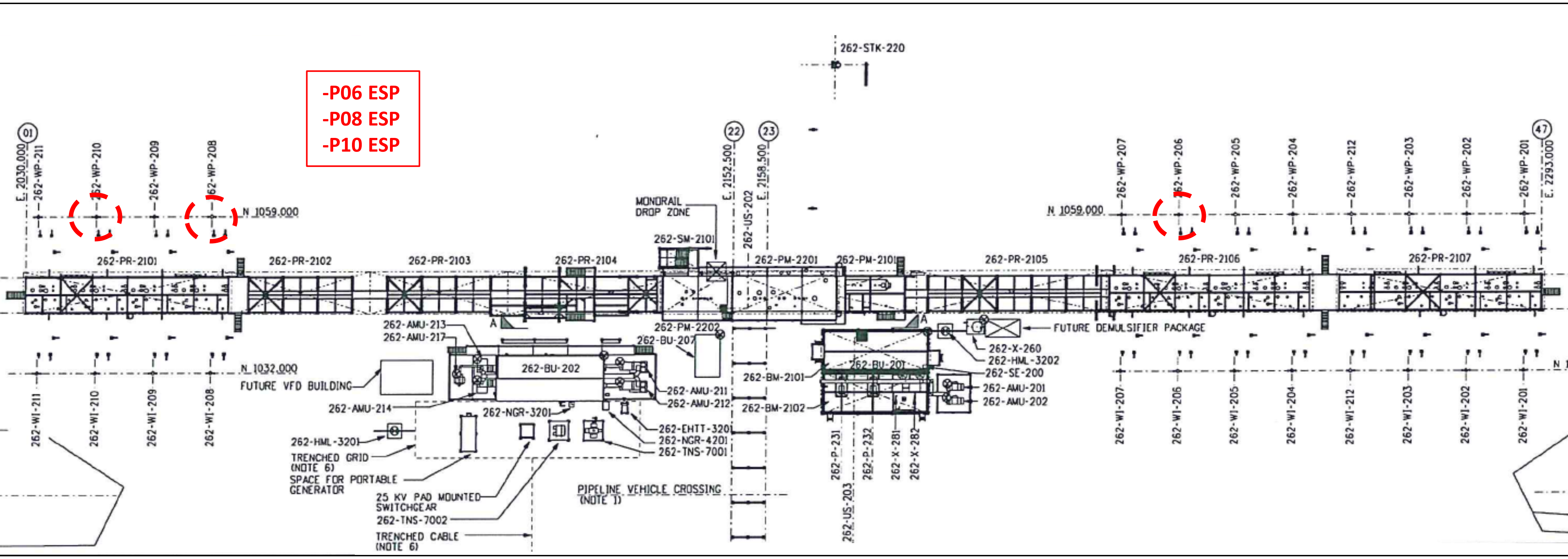
- **No ESP Conversions or Major Modifications at Pad 261-3**

Phase 2 Plot Plan: Pad 262-1



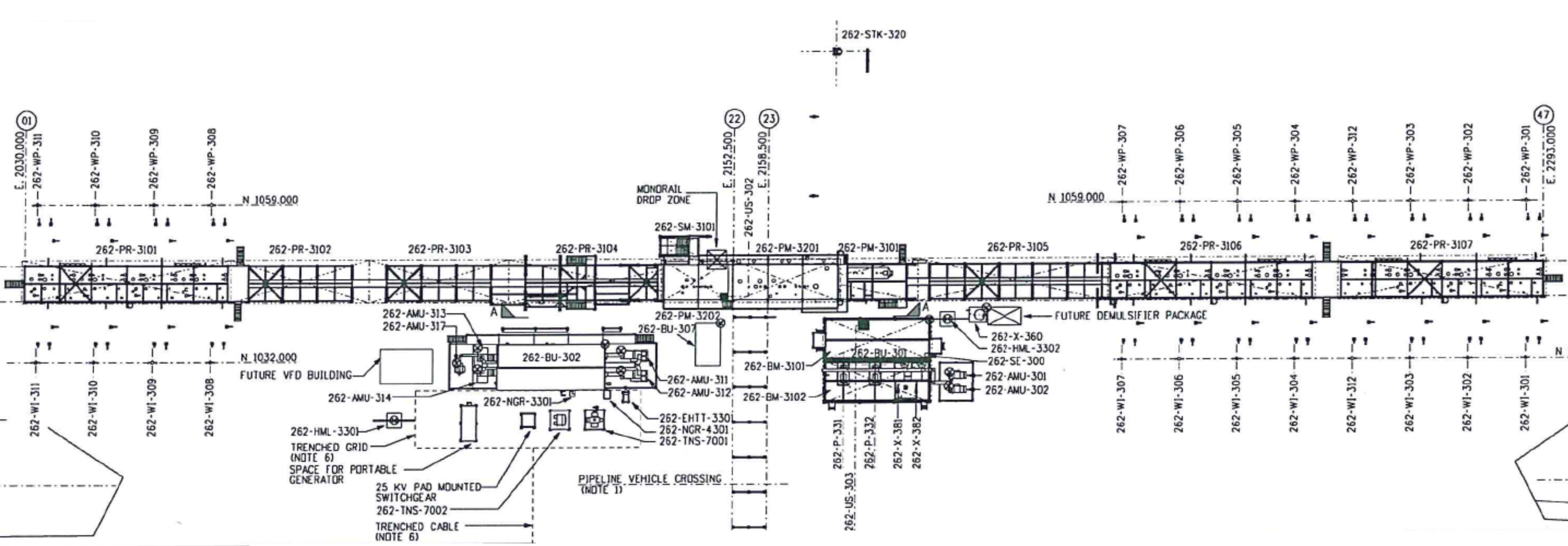
- **No ESP Conversions or Major Modifications at Pad 262-1**

Phase 2 Plot Plan: Pad 262-2



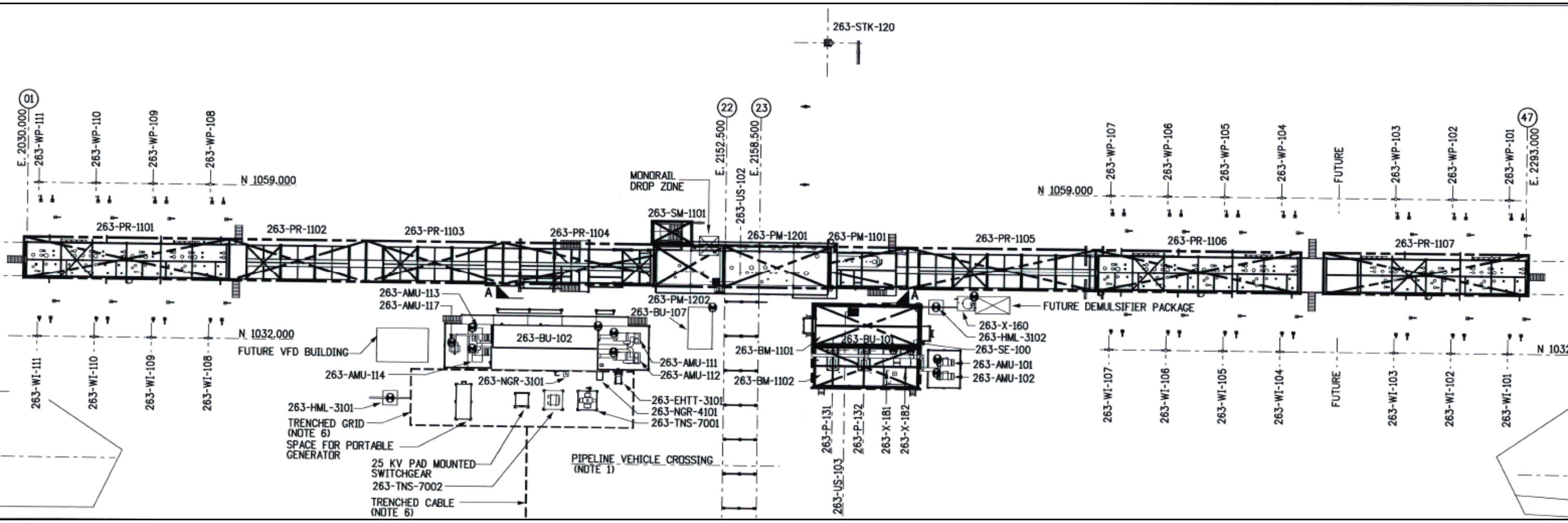
- **Pad 262-2 ESP Conversions: Added 3 ESPs in Feb 2017**

Phase 2 Plot Plan: Pad 262-3



- **No ESP Conversions or Major Modifications at Pad 262-3**

Phase 2 Plot Plan: Pad 263-1



- **No ESP Conversions or Major Modifications at Pad 263-1**

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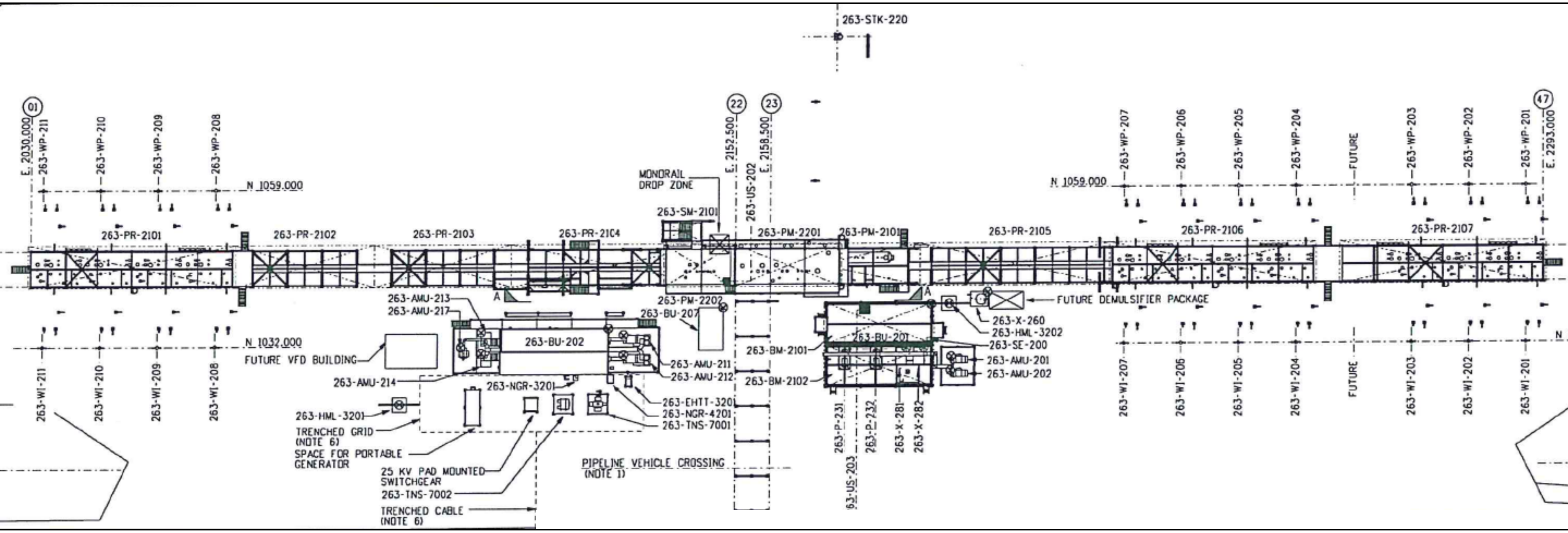
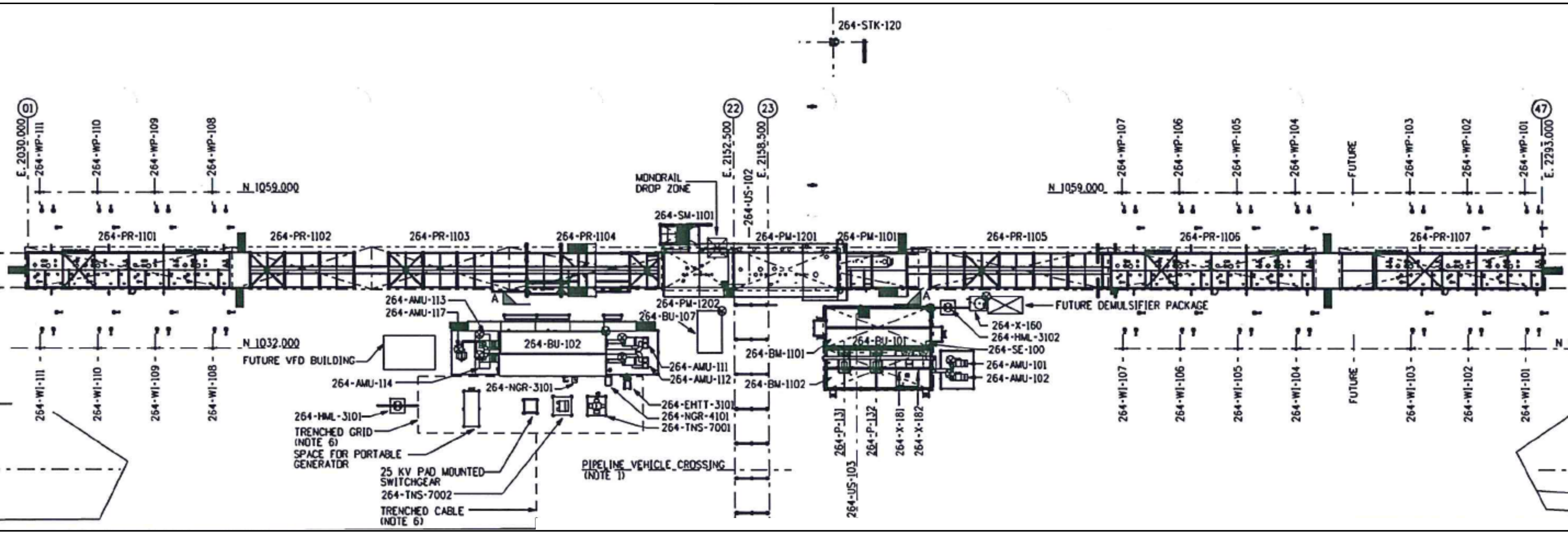
Phase 2 Plot Plan: Pad 263-2



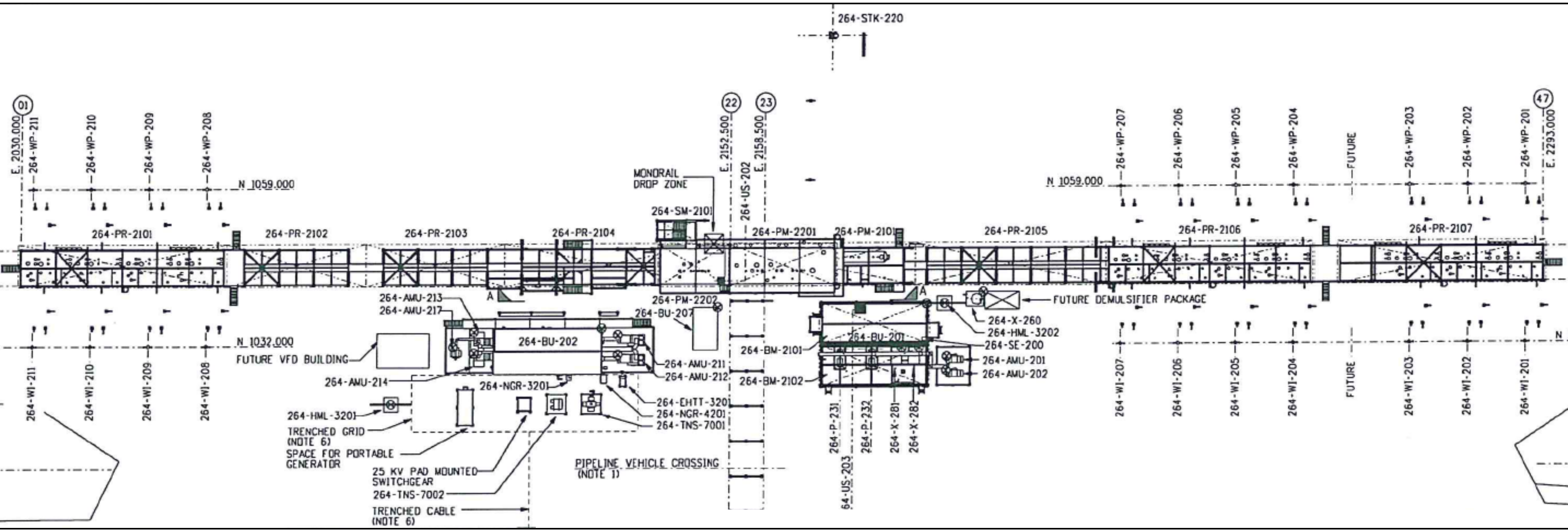
- **No ESP Conversions or Major Modifications at Pad 263-2**

Phase 2 Plot Plan: Pad 264-1



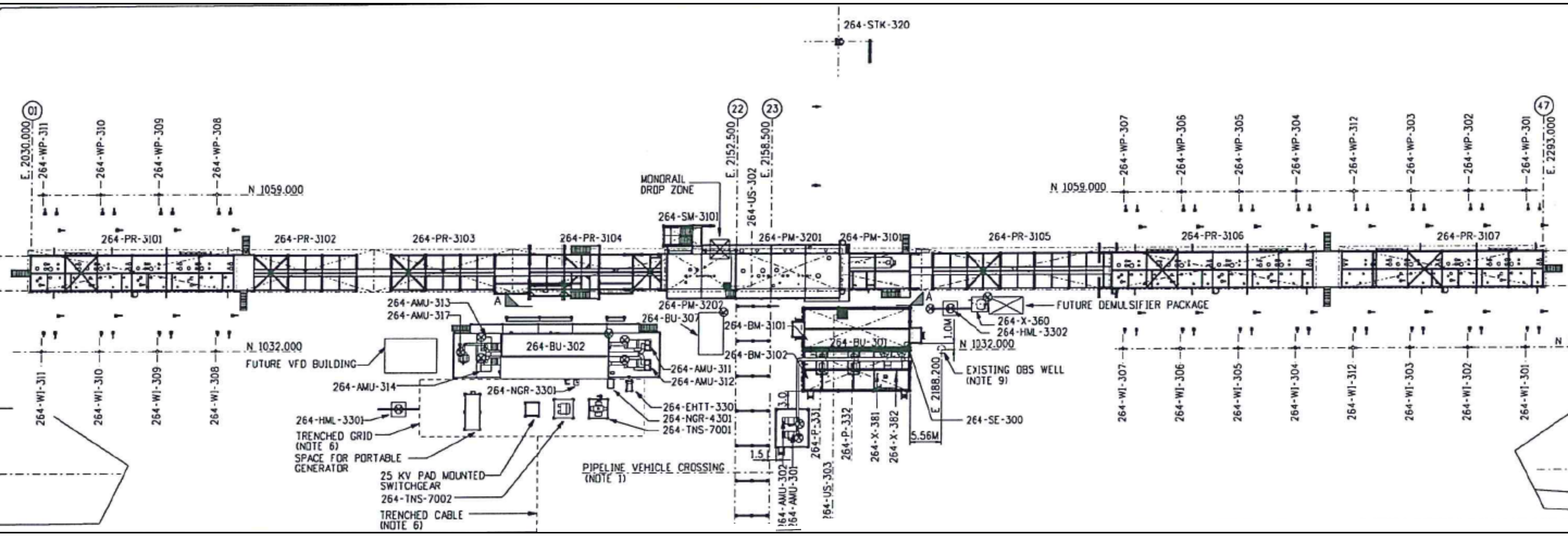
- **No ESP Conversions or Major Modifications at Pad 264-1**

Phase 2 Plot Plan: Pad 264-2



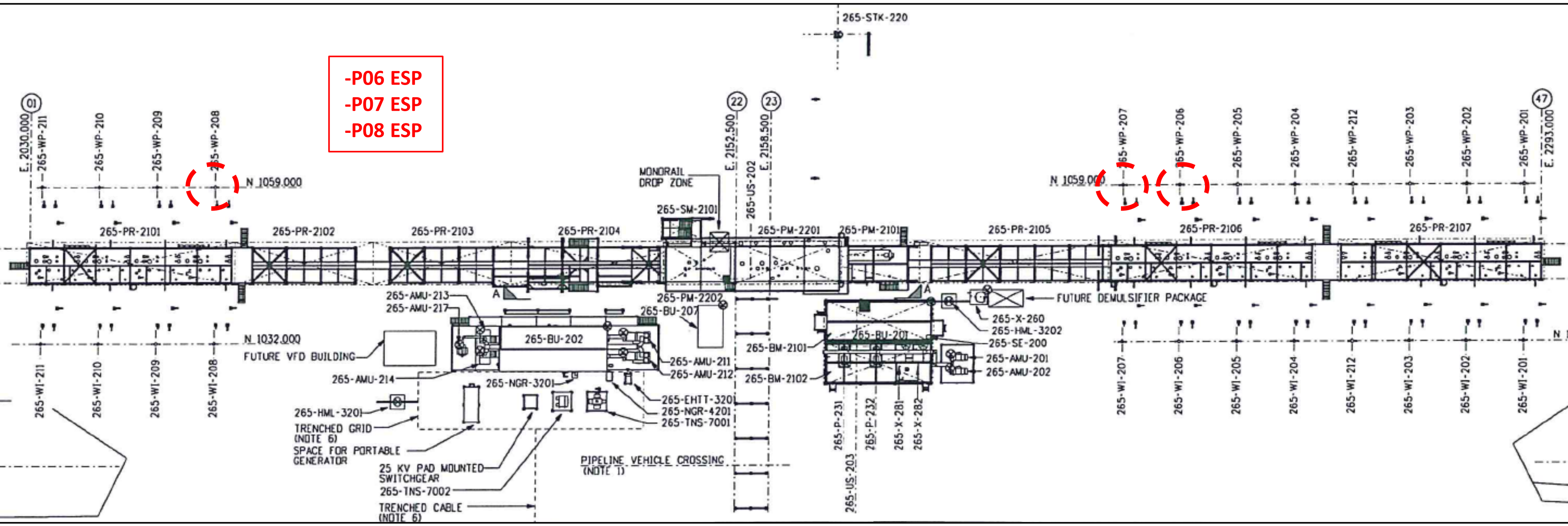
- **No ESP Conversions or Major Modifications at Pad 264-2**

Phase 2 Plot Plan: Pad 264-3



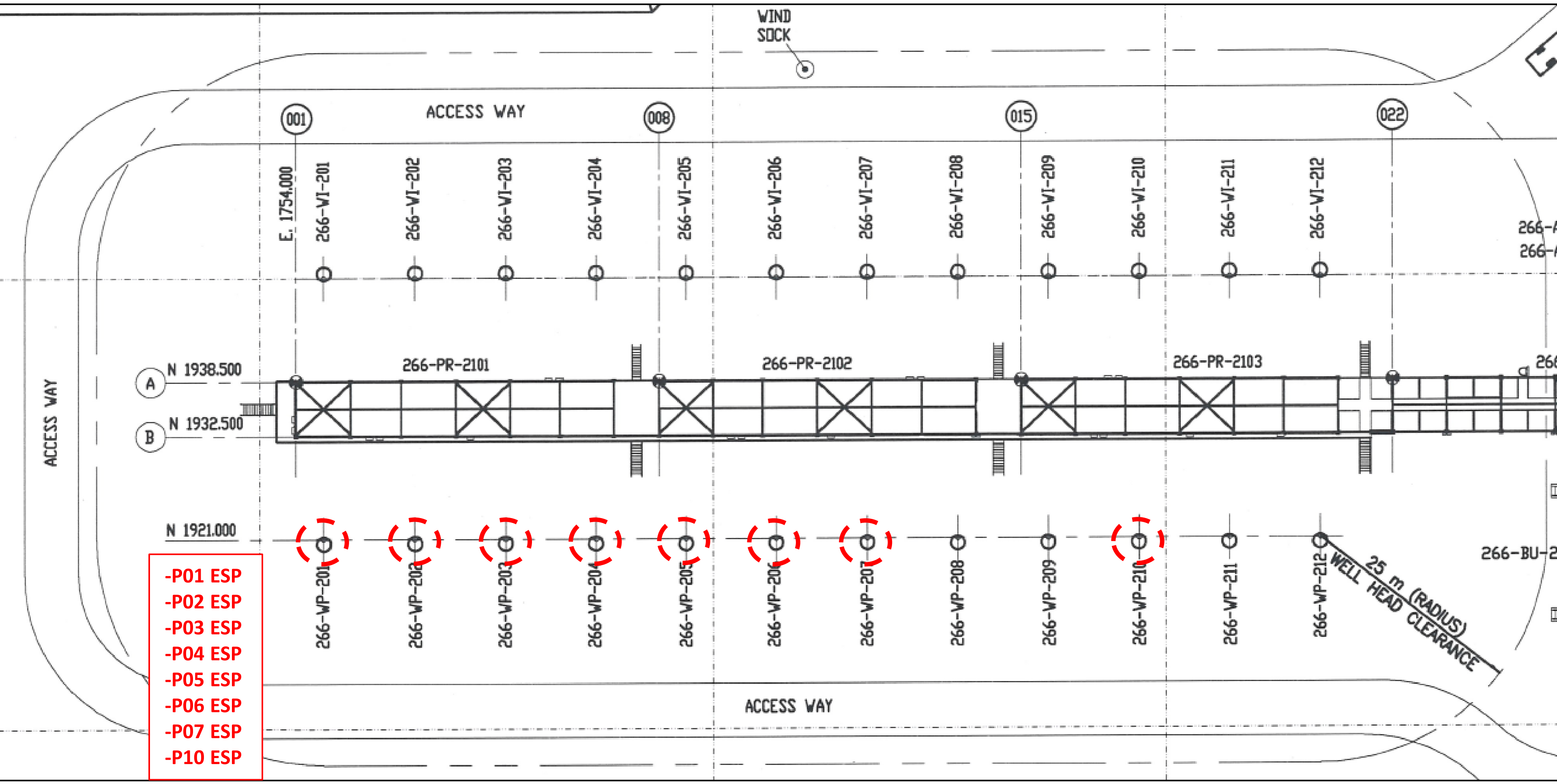
- **No ESP Conversions or Major Modifications at Pad 264-3**

Phase 2 Plot Plan: Pad 265-2



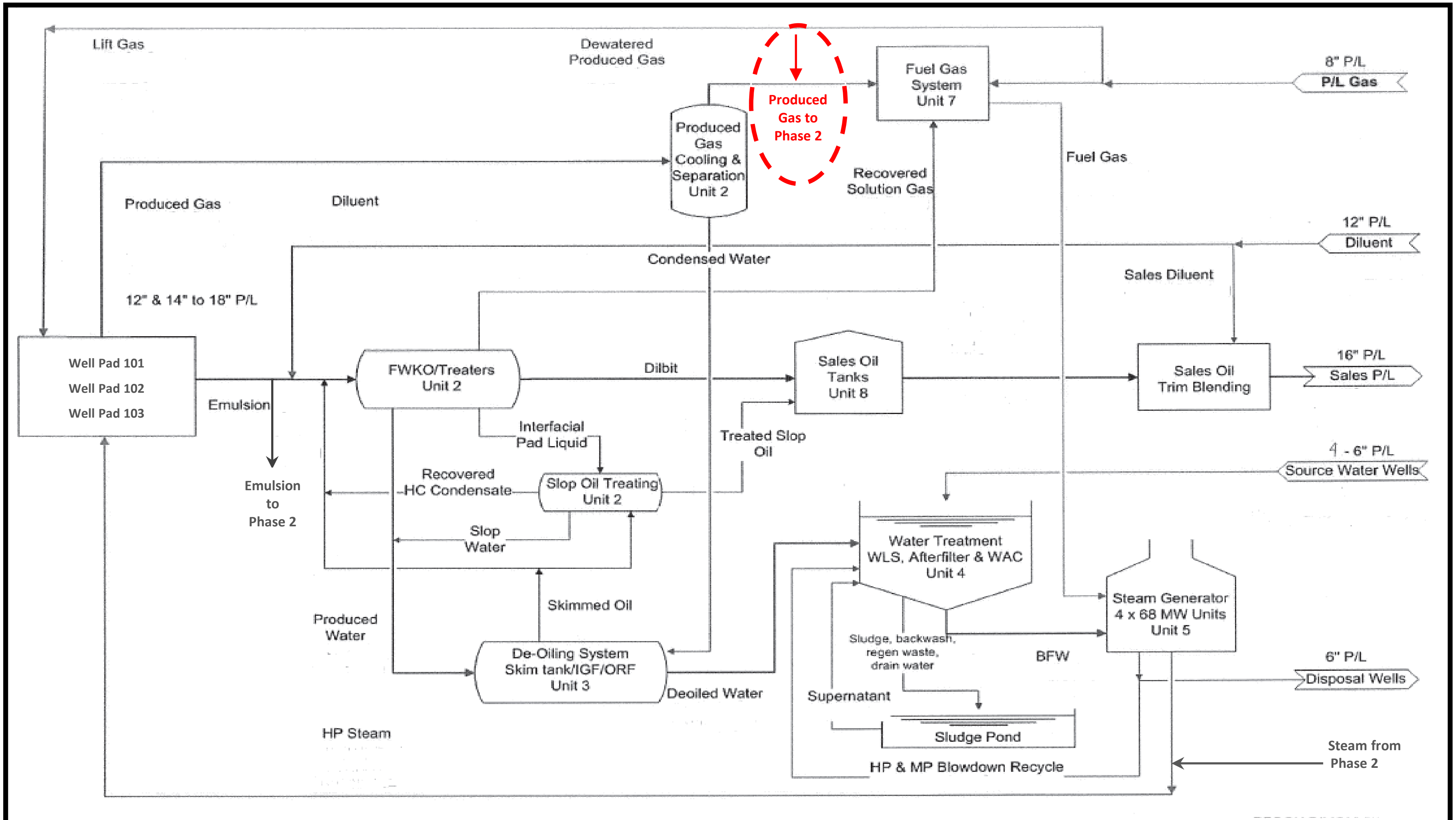
- **Pad 265-2 ESP Conversions: Added 3 ESPs in Feb 2017**

Phase 2 Plot Plan: Pad 266-2



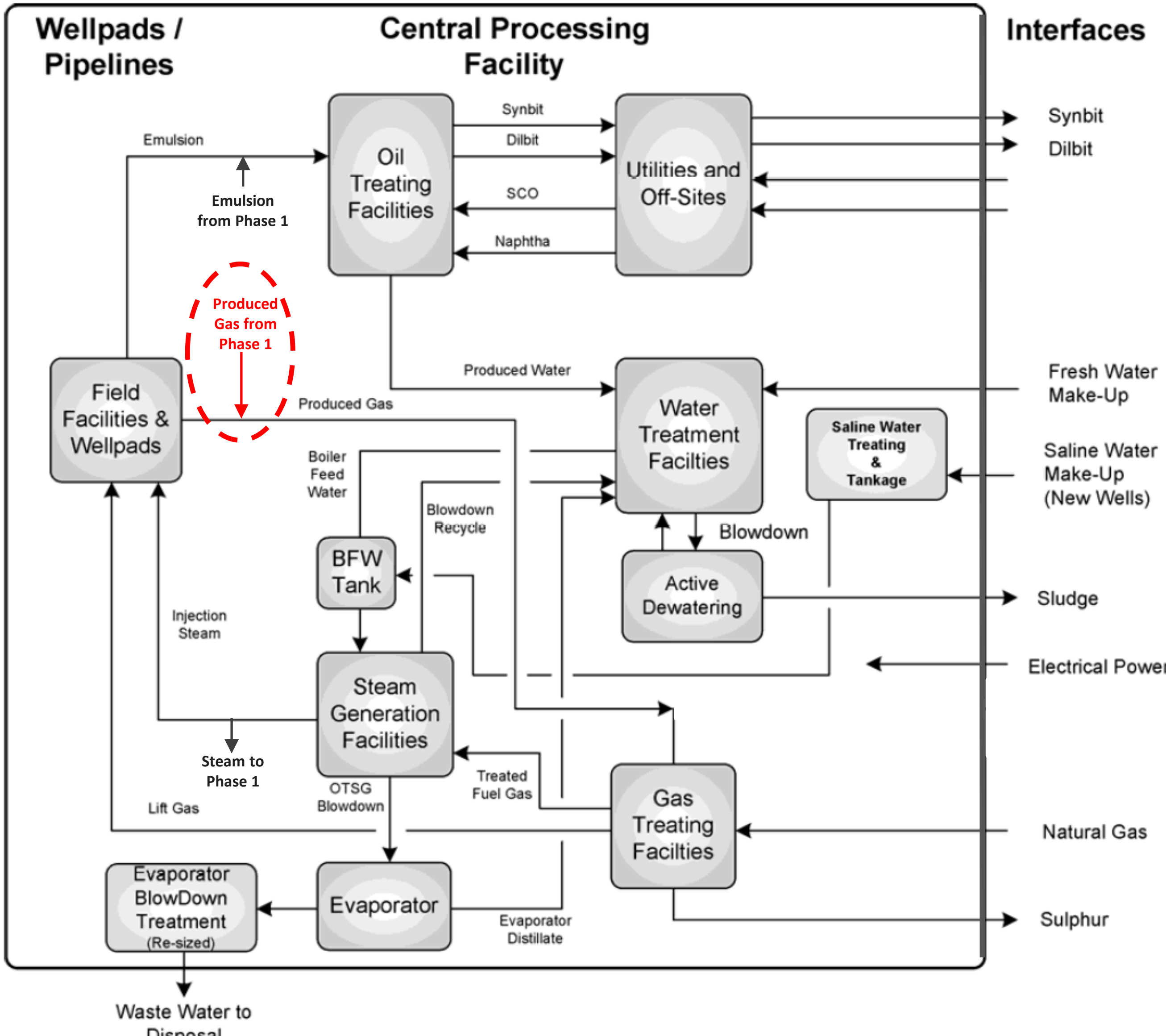
- **Pad 266-2 ESP Conversions: Added 8 ESPs in Feb 2017**

Plant Schematic: Phase 1



- **Produced Gas interconnect from Phase 1 to Phase 2 operational in 2016**

Plant Schematic: Phase 2



- **Produced Gas interconnect from Phase 1 to Phase 2 operational in 2016**

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2016 Surmont Operations

- **Phase 1:**
  - Installed new Economizer box on one steam gen with upgraded materials and additional monitoring capabilities.
  - Steam control valves upgraded to increase steam production to Pads.
  - Installation of forced draft fans on steam generators to maximize air flow, improve combustion and maximize steam production.

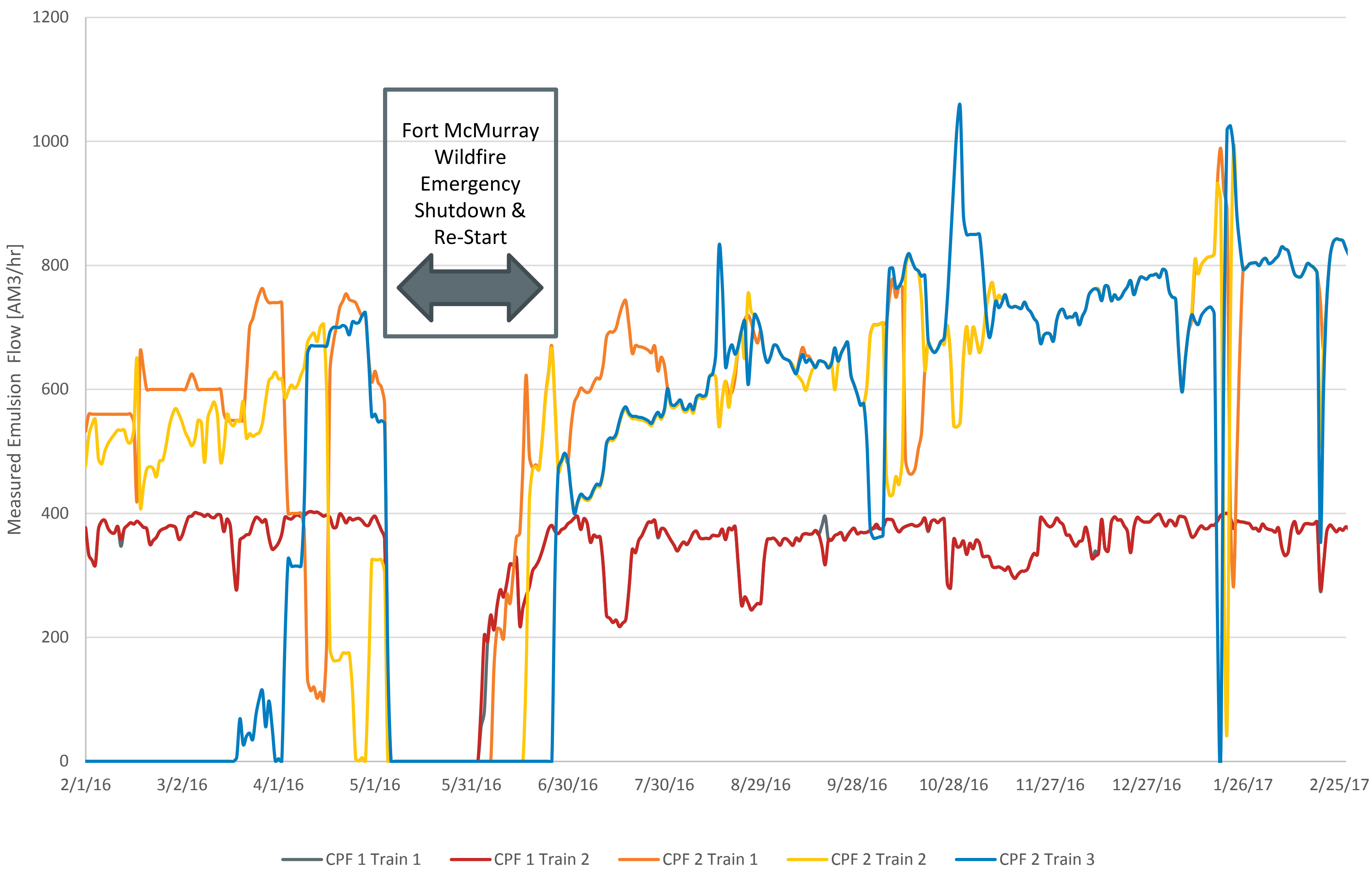
- **Phase 2**
  - Train 2 and train 3 commissioned and started up.
  - Commissioned and started up remaining well pads and prepared for 2017 ESP conversions.
  - Low fin thermocouples installation, for monitoring fouling and pigging initiated.

Facility Performance

Subsection 3.1.2 (2)

Facility Performance: Bitumen Treatment by CPF

Facility Performance: Bitumen Treatment by Train



Facility Performance: Phase 1 Water Treatment

- Phase 1 water treatment plant continues to operate as per design.
- Chemical trials conducted in 2016 have improved water treatment performance.
- Successful ramp-up from the Fort McMurray Wildfire Emergency Shutdown & Re-start.

Boiler Feed Water Quality (Feb 1, 2016 to Feb 28, 2017)

Parameter	BFW Specification	Avg. Value	% of time on Spec
Hardness (Total), mg/L	<0.5	0.31	92.9
Silica, as SiO2, mg/L	<50	19.6	99.6
Bitumen in Water, ppm	<0.5	0.24	99.7
Turbidity, NTU	<3.5	1.05	99.5

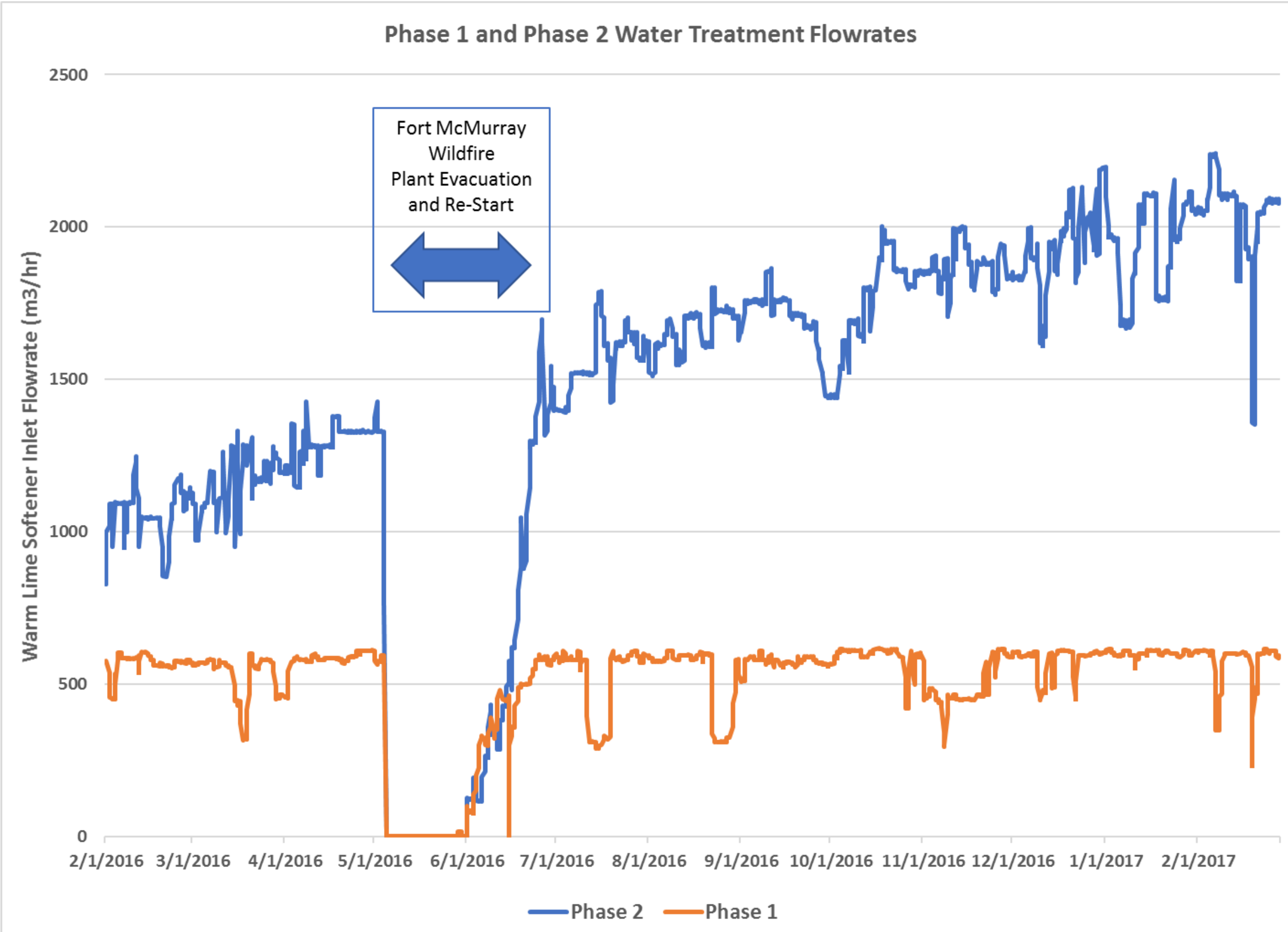
Facility Performance: Phase 2 Water Treatment

- Continued successful ramp up of Phase 2 water treatment plant. Water plant is operating at approximately 80% of nameplate design.
- New well start-ups created deoiling challenges, however the well count has stabilized.
- Successful ramp-up from the Fort McMurray Wildfire Emergency Shutdown & Re-start.

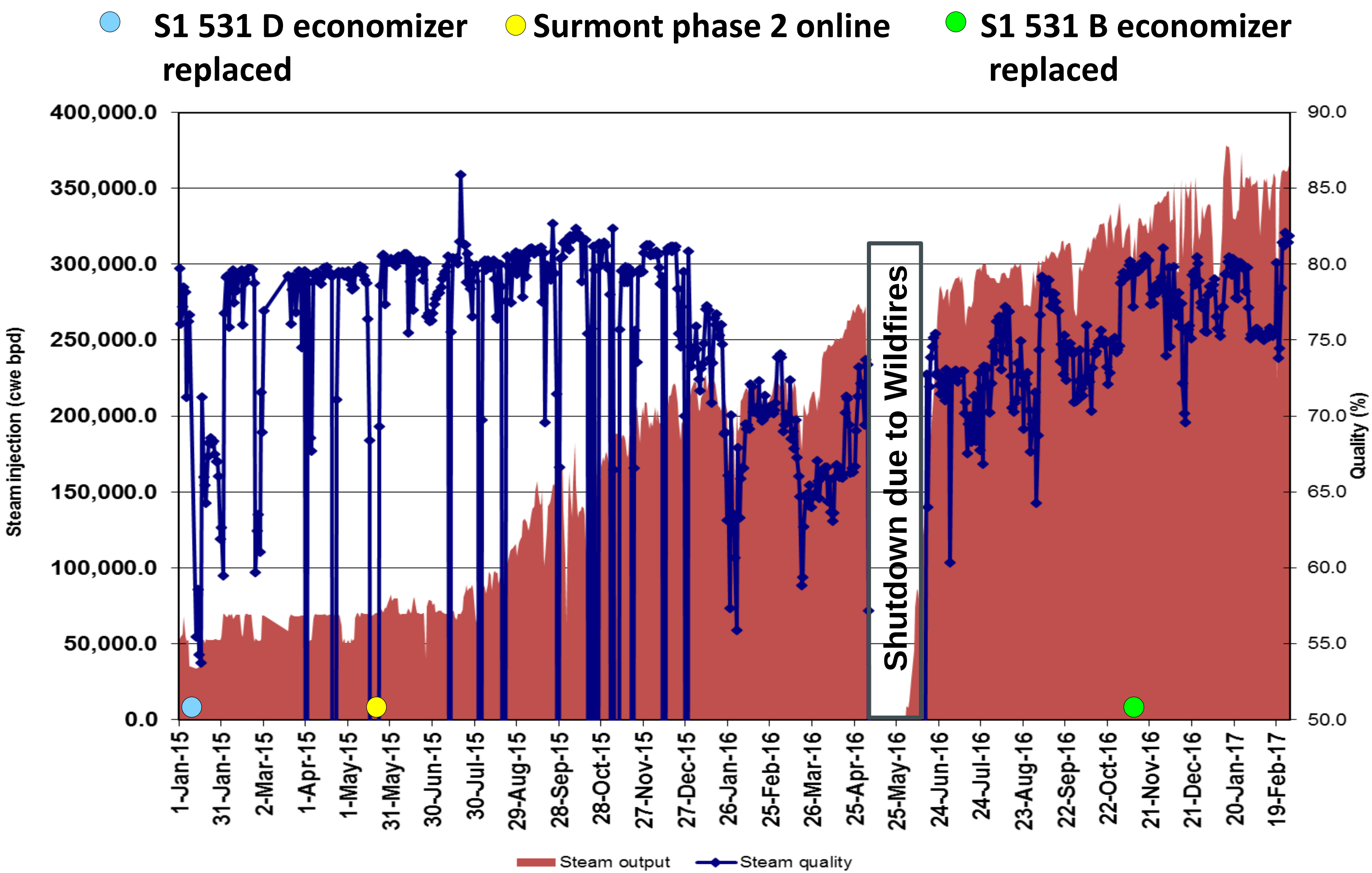
Boiler Feed Water Quality (Feb 1, 2016 to Feb 28, 2017)

Parameter	BFW Specification	Avg. Value	% of time on Spec
Hardness (Total), mg/L	<0.5	0.38	83.7
Silica, as SiO2, mg/L	<50	21.4	100
Bitumen in Water, ppm	<0.5	0.41	82.4
Turbidity, NTU	<3.5	1.63	89.9

Facility Performance: Water Treatment



Surmont Project: Steam Generation Performance

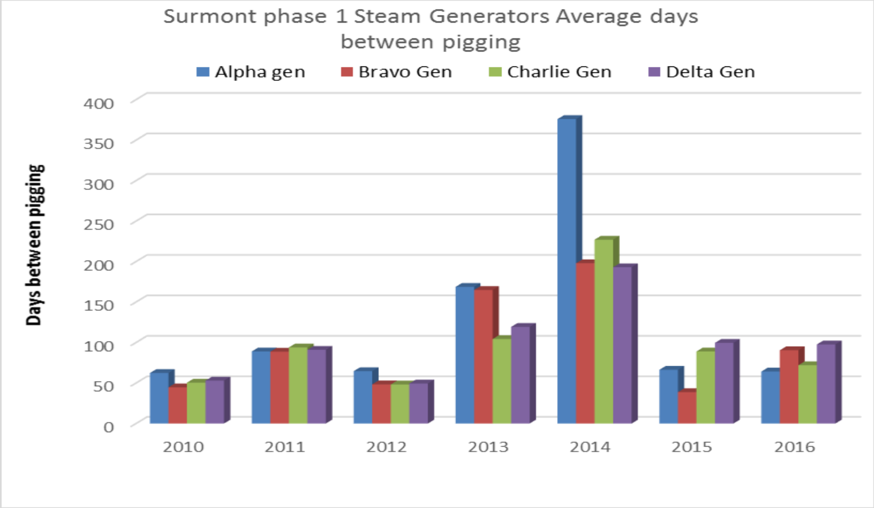


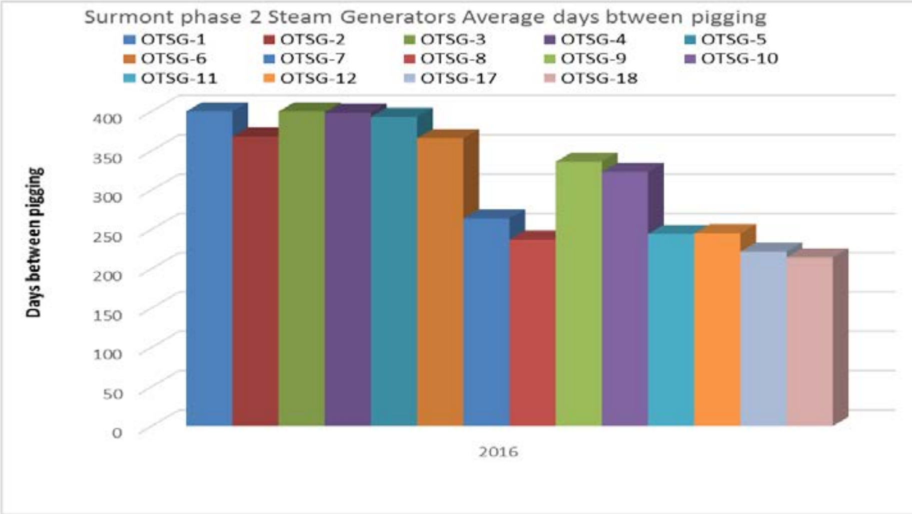
Surmont Phase 2: Steam Generation Performance

- Phase 2 steam generators were commissioned in 2015 and 2016.
- SG-531 B and SG-531 D economizers were replaced (upgraded) on November 2016, allowing for higher steam qualities (83-85%).
- Steam interconnect between Phase 2 and Phase 1 was commissioned in 2015. Excess of steam from Phase 2 is directed to Phase 1 wellpads.
- Average steam rates through interconnect:
  - 2015: ~11,786 bpd.
  - 2016: ~40,021 bpd.
  - 2017: ~29,423 bpd. (January 1 to February 28, 2017)
- Phase 2 continued ramp up in 2016.
- Implementing optimization opportunities like steam enhancement trial

Phase 1 and 2 OTSG Pigging Frequency

Number of pigging events on steam generators and days between pigging.





- The number of pigging events at Phase 1 decreased in 2016 compared with 2015 (15 vs 28 pigging events).
- Well stimulation during October 2015 impacted water quality and pigging frequency during the first quarter of 2016.
- Overall, Phase 2 steam generators have better run time than Phase 1.

Phase 2 Steam Quality Enhancement Trial

			Complete	Complete		In progress	
Q fire, GJ/h	273		287	294		300	
Target Steam	115 m3/h		Avg. Target 122 m3/h	Avg. Target 125 m3/h		Avg. Target 127 m3/h	
	Step 0 - 100% Firing		Step 1 - 105% Firing	Step 2 - 107% Firing		Step 3 - 110% Firing	
Steam Quality	80%	Pigging & SP	80-83%	83-85%	Pigging & SP	85%	Pigging & SP
BFW rate	144 m3/h		153 m3/h	153 m3/h		153 m3/h	
Steam Output	115 m3/h		121-127 m3/h	127-130 m3/h		130 m3/h	
Time Line	June-2016 July-2016		Aug-2016 Oct-2016	Oct -2016 Dec -2016		Jan-2017 June-2017	

Step 3 started on Jan 12

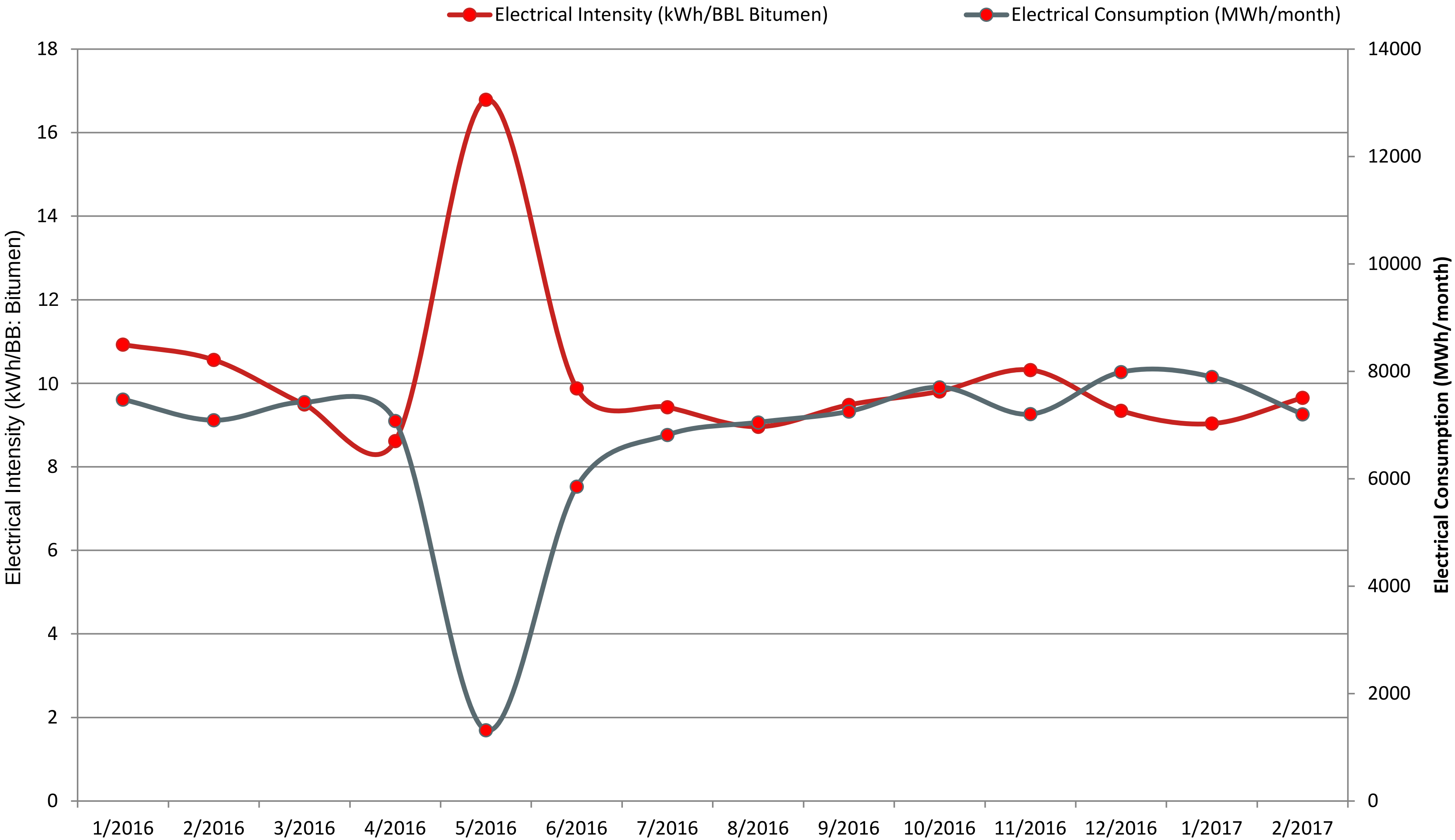
2017 Goal: Step 3 started on January 12, 2017 and data is currently being collected and analyzed.

Phase 2 Steam Quality Enhancement Trial

2017 Path forward:

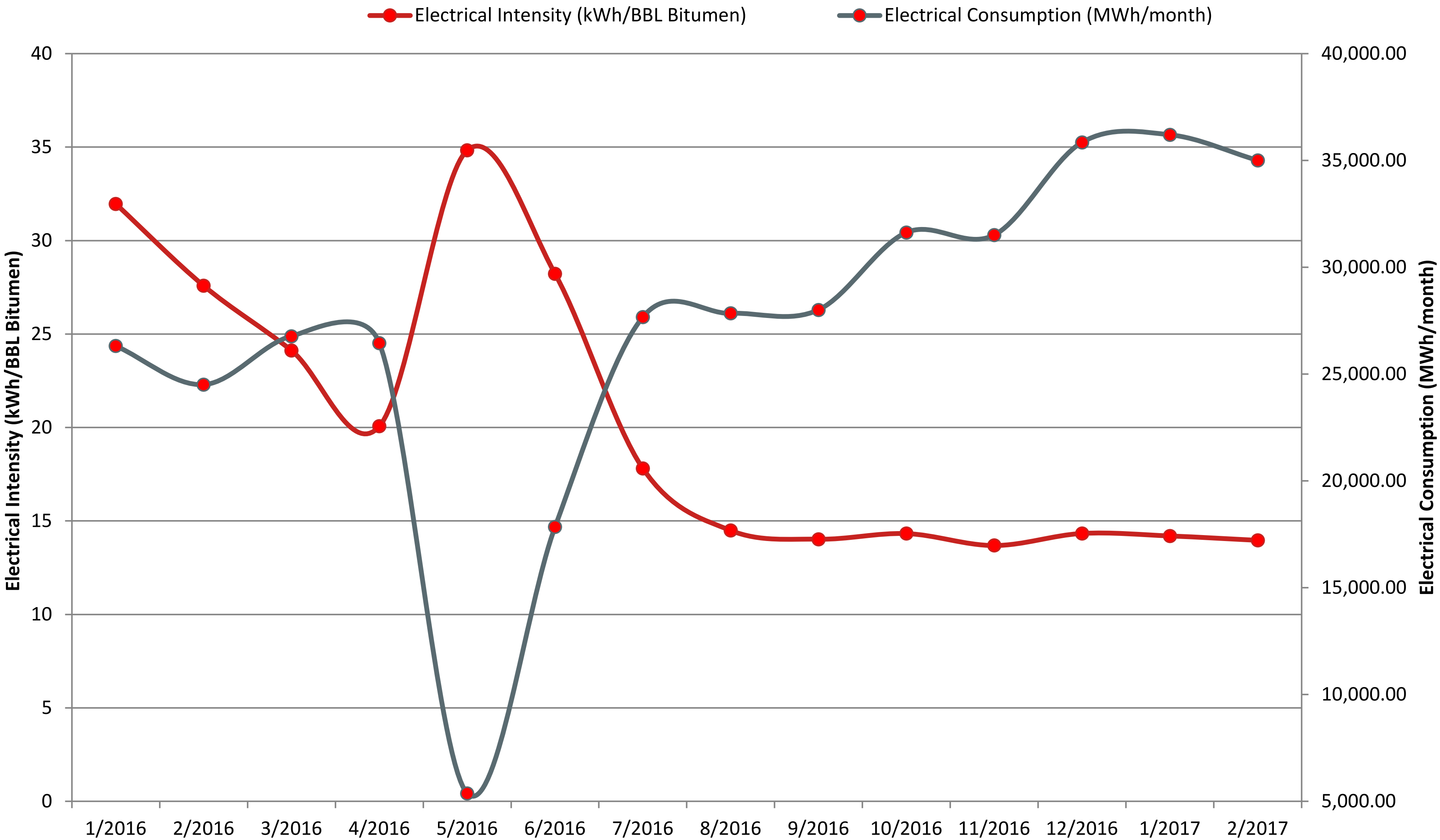
- Steam trials expected to be complete by end of June, 2017.
- Steam gens equipped with additional thermocouples will be fired at 80 – 83% steam quality.
- Install additional thermocouples on remaining Phase 2 gens in 2017.
- Maximize Phase 2 steam production based on learnings from Trial.

Facility Performance: Electricity Consumption Phase 1



- **Phase 1 is at a steady state of production and electrical consumption, however the Fort McMurray Wildfire Emergency Shutdown and Re-start resulted in a variance.**

Facility Performance: Electricity Consumption Phase 2

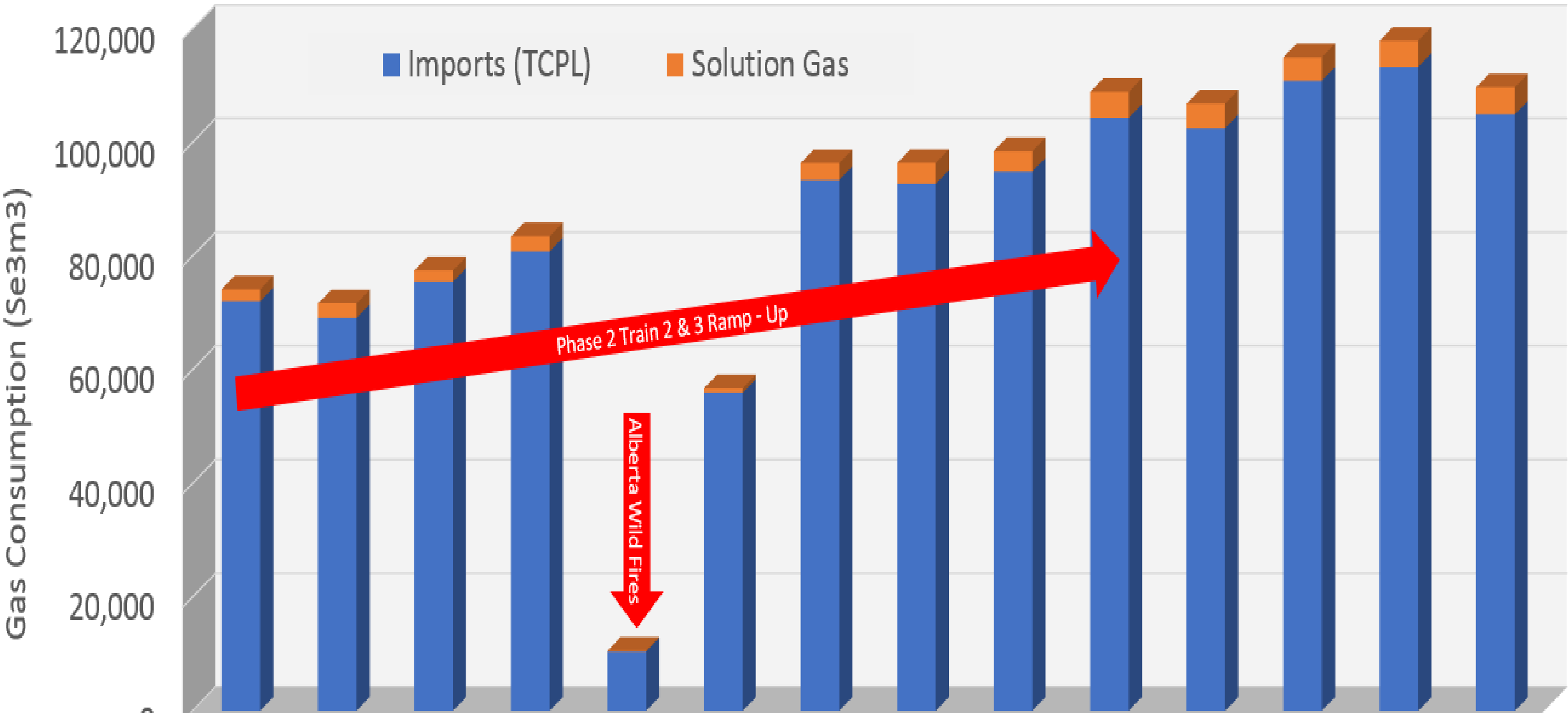


- **Effect of Fort McMurray Wildfire Emergency Shutdown and Re-start created variance – plant moving towards steady state**

Surmont Facility Performance: Gas Usage

YEAR	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
TCPL Gas Imports (10^3m^3)	42,999	160,095	183,933	223,447	228,344	250,412	230,339	240,496	433,138	962,313	218,242
Solution Gas (10^3m^3)	2,755	4,155	10,073	12,703	13,869	15,193	17,005	14,246	19,301	33,636	9,337
Flared Gas (10^3m^3)	4,641	6,439	3,962	705	625	218	117	271	475	371	50
% of Solution Gas Recovery			60.67%	94.45%	95.49%	98.57%	99.31%	98.10%	97.54%	98.90%	99.46%

Facility Performance: Gas Consumption



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17
Solution Gas	2,111	2,566	1,952	2,655	150	804	3,017	3,695	3,592	4,579	4,358	4,156	4,586	4,752
Imports (TCPL)	72,035	69,095	75,501	80,831	10,404	55,955	93,342	92,694	94,861	104,295	102,482	110,819	113,312	104,931

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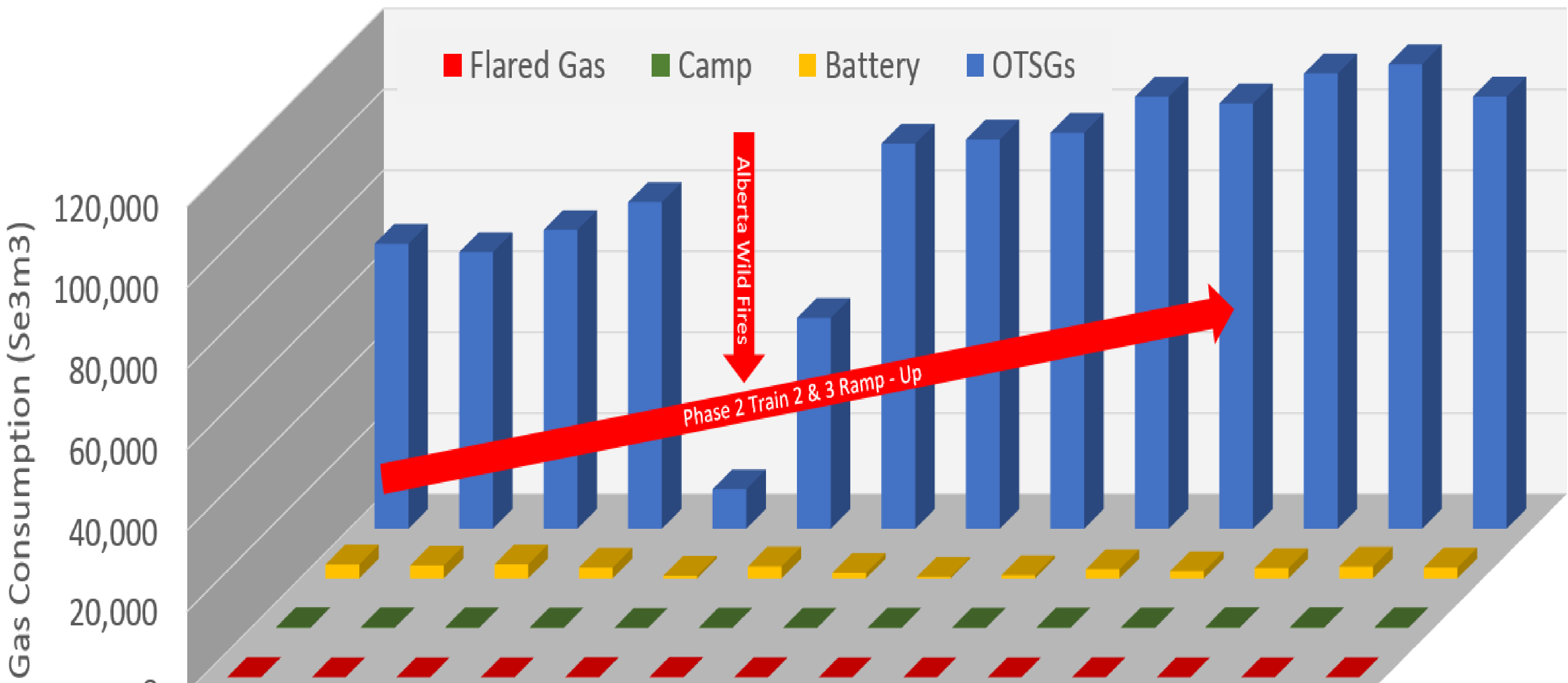
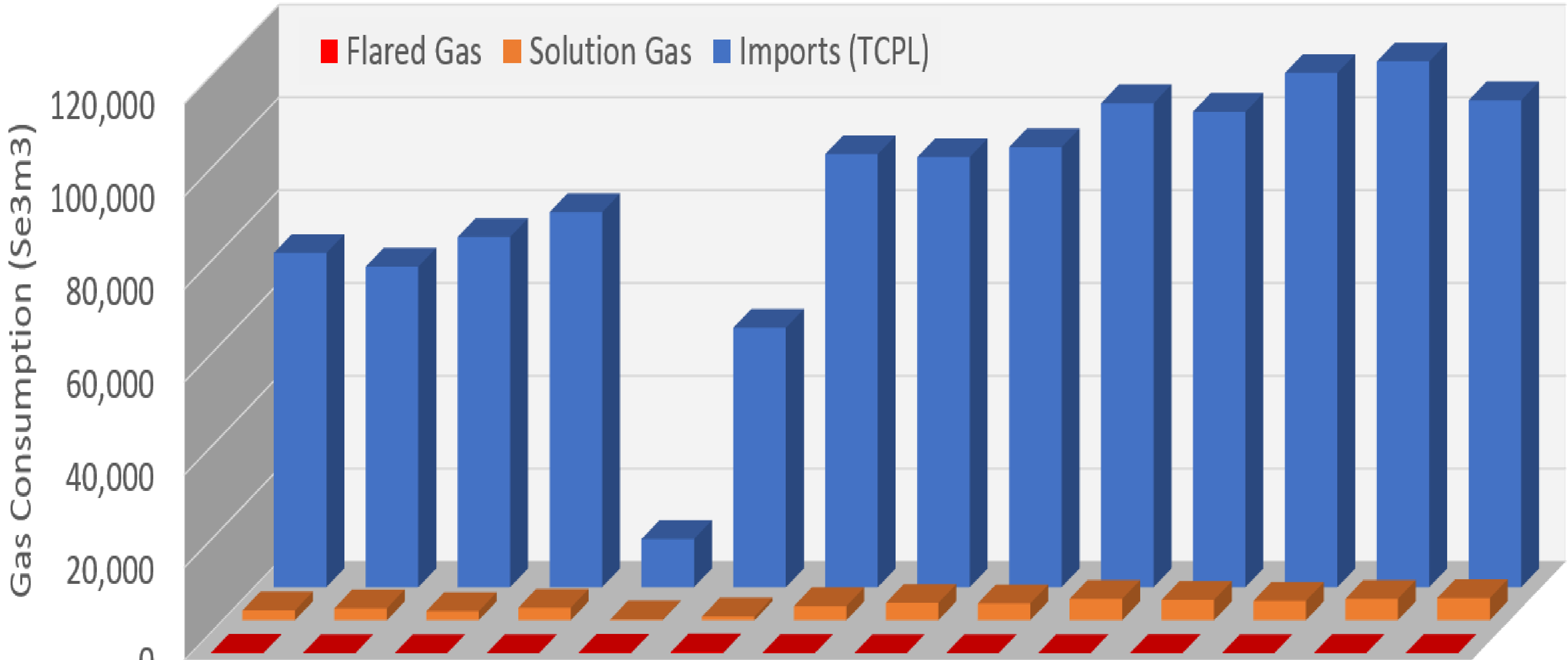
Facility Performance: Gas Consumption by Location



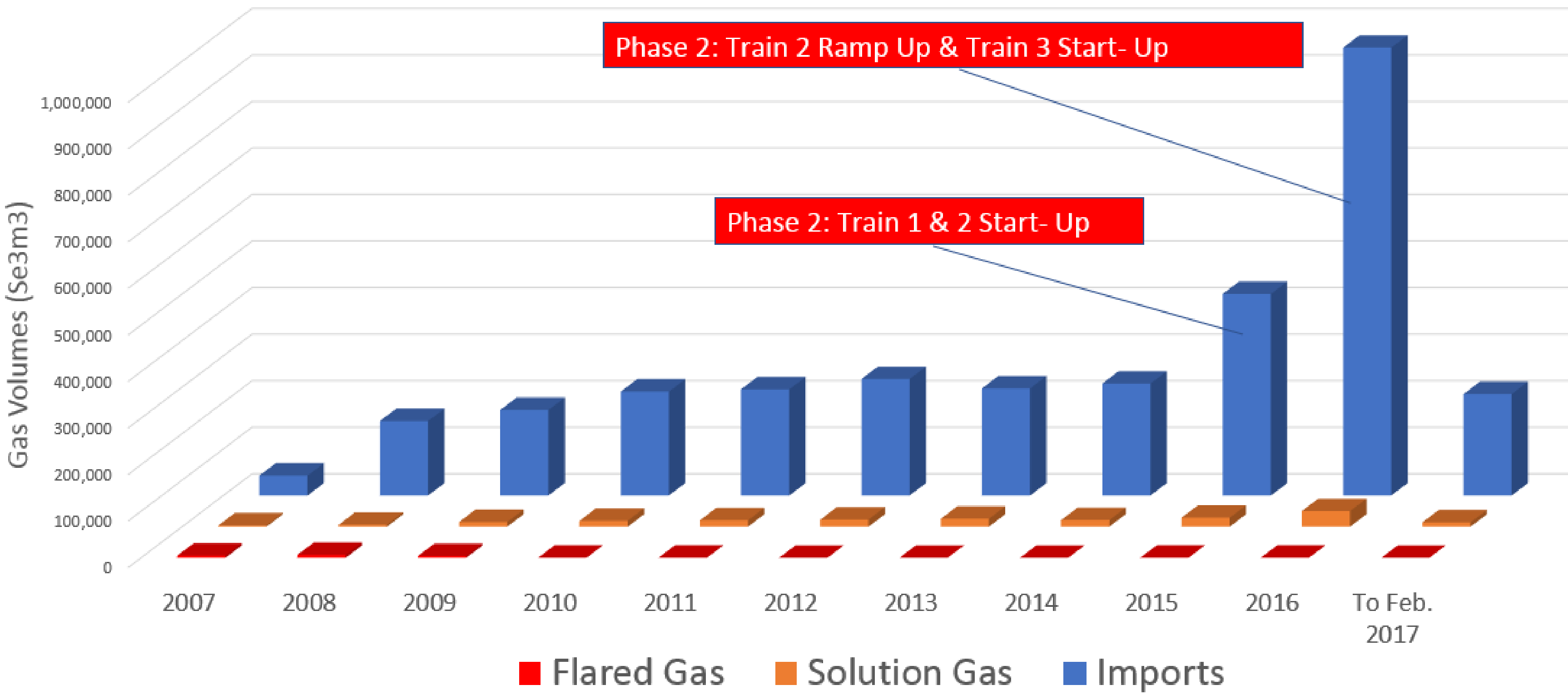
	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17
Flared Gas	84	-	-	-	84	133	46	-	-	-	18	6	8	43
Camp	214	182	161	120	25	70	70	73	88	156	156	238	214	190
Battery	3,422	3,146	3,451	2,668	660	2,941	1,332	379	774	2,230	1,788	2,527	2,907	2,674
OTSGs	70,427	68,334	73,842	80,698	9,786	52,118	95,162	96,188	97,834	106,739	105,121	112,461	114,769	106,777

Surmont Facility Performance: 2016 Gas Usage



	Jan-16	Feb-16	Mar-16	Apr-16	May-16	Jun-16	Jul-16	Aug-16	Sep-16	Oct-16	Nov-16	Dec-16	Jan-17	Feb-17
Flared Gas	84	-	-	-	84	133	46	-	-	-	18	6	8	43
Solution Gas	2,111	2,566	1,952	2,655	150	804	3,017	3,695	3,592	4,579	4,358	4,156	4,586	4,752
Imports (TCPL)	72,035	69,095	75,501	80,831	10,404	55,955	93,342	92,694	94,861	104,295	102,482	110,819	113,312	104,931

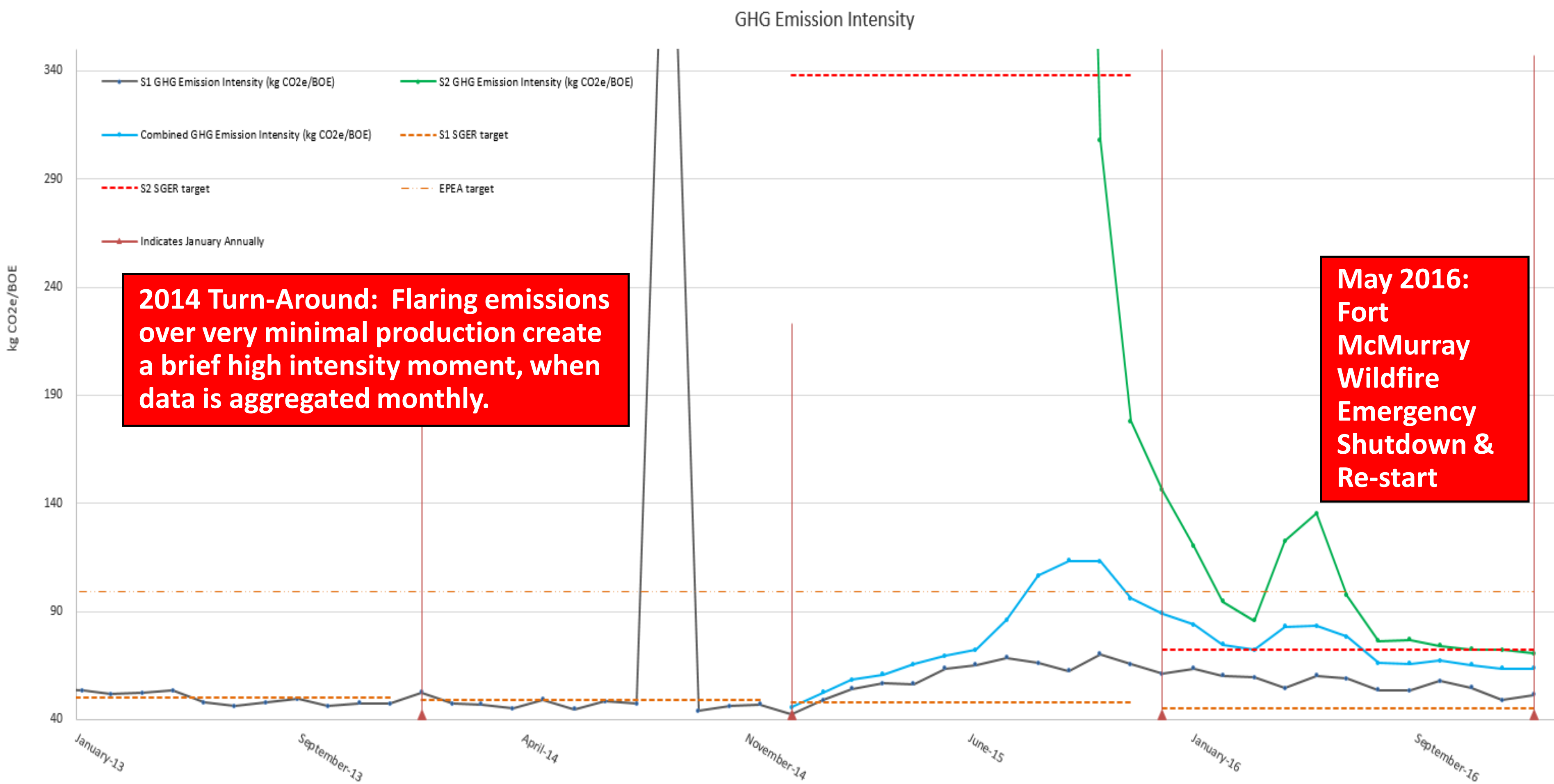
Surmont Facility Performance: Gas Usage



Surmont Facility Performance: Gas Usage - Highlights

- Amount of flared gas was influenced by the following events in 2016:
  - Start-up of Surmont 2 Trains 2 and 3
  - Start-up of six Surmont 2 Well Pads
  - Well Operation shifting from Circulation to Gas Lift and/or ESP
  - May Fort McMurray Wildfire Emergency Shutdown and June re-start

Facility Performance: Greenhouse Gas



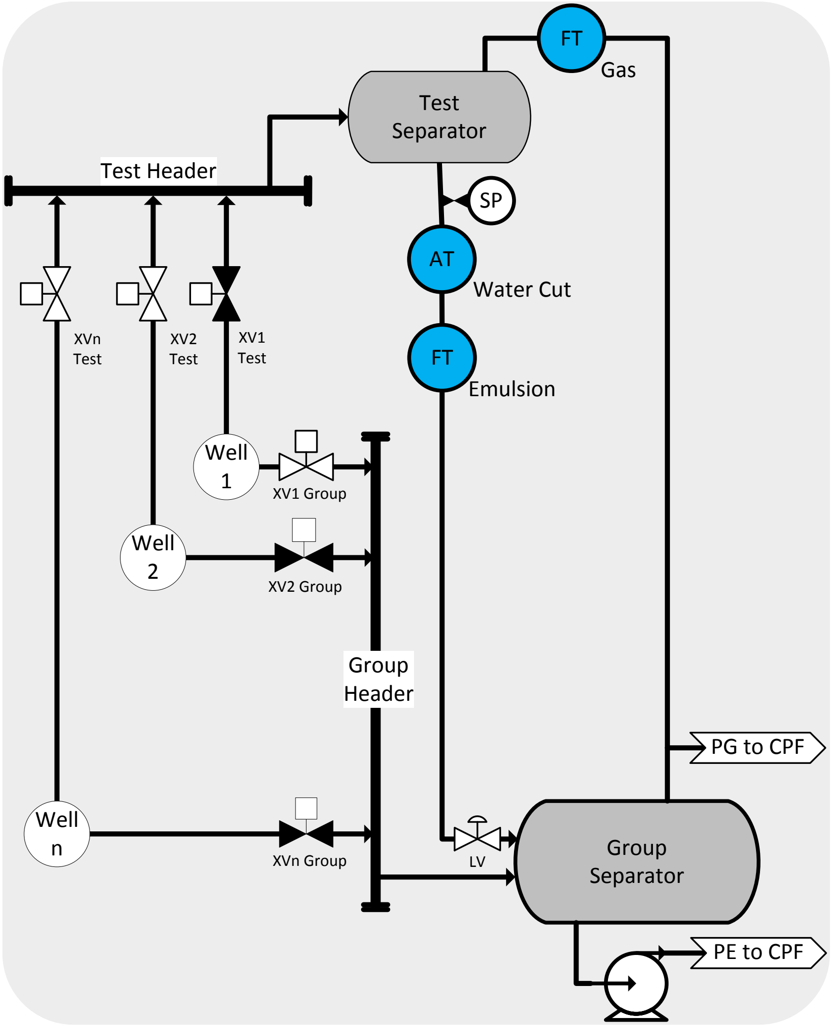
- Agreement with AER to continue reporting Phase 2 CO2e emission, through its rampup, separately from Phase 1.
- 2016 Phase 1 SGER intensity reduction target of 15% was not achieved.
- 2016 GHG Emission intensity has ben completed, verified and payment submitted.

Measurement and Reporting

Subsection 3.1.2 (3)

Well Testing

- Surmont Well Pads are configured to, automatically and sequentially, align each production well into the Test Separator.
- Well Test Duration, Total Produced Emulsion, Average Water Cut and Total Produced Water Vapors are recorded for each Well Test.
- Well Test Results are reviewed to “Approve”, if representative of the wells production, or “Reject.”
- Well Test Durations range from 5 to 10 hours, with up to 4 hours purge, based on the wells previous liquid production rates.



Well Estimated Monthly Production

Each well's estimated monthly production is calculated using only "*approved*" Well Test Results. Daily estimated volumes are used to calculate the wells monthly estimated volume from the time of an approved well test, until its next approved well test.

Well Monthly Estimated Oil Production =

$$\textit{Well Estimated Daily Oil Production} \times \textit{Hours per Days in Operation}$$

- Well Estimated Daily Oil Production =

$$\frac{\textit{Test Produced Emulsion Volume} \times (1 - \textit{WC\%})}{\textit{Test Duration (hours)}} \times \textit{24 hours}$$

Well Monthly Estimated Water Production =

$$\textit{Well Estimated Daily Water Production} \times \textit{Hours per Days in Operation}$$

- Well Estimated Daily Water Production =

$$\frac{\textit{Test Produced Emulsion Volume} \times \textit{WC\%} + \textit{Water Vapor}}{\textit{Test Duration (hours)}} \times \textit{24 hours}$$

Well Allocated Oil Production

$$\textbf{\textit{Well Estimated Monthly Oil Production}} \times \textbf{\textit{Oil Proration Factor}}$$

- Oil Proration Factor =

$$\frac{\textit{Battery Produced Oil}}{\textit{Total Estimated Monthly Oil Production}}$$

- Battery Produced Oil =

Oil Dispositions + Battery Tank Inventory + Shrinkage – Receipts + Well Load Oil

- Total Estimated Monthly Oil Production =

$$\sum_{n=1}^{x} Well_n \textit{ Estimated Montly Oil Production}$$

where x is the total number of production wells for the reporting period.

- Oil Dispositions =

Sales CTM[1] *+ Enbridge Tank Inventory + TruckOut*

- Oil in Battery's Tank Inventory =

Sales Oil Tanks + OffSpec Tanks + Slop Oil Tanks + Skim Oil Tanks

- Receipt =

Diluent CTM[1]*+ Diluent Tank Inventory + Diluent TruckIn*

Well Allocated Water Production

$$\textbf{\textit{Well Estimated Monthly Water Production}} \times \textbf{\textit{Water Proration Factor}}$$

- Water Proration Factor =

$$\frac{\textit{Battery Produced Water}}{\textit{Total Estimated Monthly Water Production}}$$

- Battery Produced Water =

$$\textit{Water Dispositions} + \textit{Battery Tank Inventory} - \textit{Receipts} + \textit{Well Load Water}$$

- Total Estimated Monthly Water Production =

$$\sum_{n=1}^{x} Well_n \textit{ Estimated Montly Water Production}$$

where x is the total number of production wells for the reporting period.

- Water Dispositions =

$$\textit{Dispositions to Injection Facility} + \textit{Truck-Out}$$

- Water in Battery's Tank Inventory =

$$\textit{Skim Oil Tanks} + \textit{Slop OilTanks} + \textit{DeSand/BackWash/ORF Tanks} + \textit{Sales/OffSpec/Diluent Tanks}$$

- Receipt =

$$\textit{IF Condensate Returns} + \textit{Water in Diluent} + \textit{Truck-In}$$

2016 Well Oil and Water Production Highlights and Changes

- After May 2016 Pilot Plant ceased operations, Diluent, Produced Oil and Water receipt/dispositions between Surmont and the Pilot Plant no longer exist.
- At the Test Separator, include the accounting of Water Produced as Vapour, to better estimate water returns during Steam Circulation.
- Large number of wells shifting operating mode, from start-up Circulation to SAGD Production, Gas Lift and/or ESP.
- Considerable effort implemented to achieve water cut meter's performance under shifting well operating conditions.

Well Allocated Gas Production

$$\textbf{\textit{Well Allocated Oil Production}} \times \textbf{\textit{GOR}}$$

- Gas to Oil Ration (GOR) =

$$\frac{\textit{Battery Produced Gas}}{\textit{Battery Produced Oil}}$$

- Battery Produced Gas =

$$\textit{Gas Dispositions} - \textit{Receipts}$$

- Gas Dispositions =

$$\textit{Battery Utility FG} + \textit{Steam Generators FG} + \textit{Flare Purge} + \textit{NCG CoInjection} + \textit{Flared Gas}$$

- Receipt =

$$\textit{TCPL Fuel Gas CTM}^{1}$$

[1] CTM: Custody Transfer Meter

2016 Well Gas Production Highlights and Changes

- Non Condensable Gas (NCG) Co-Injection Trial initiated November 2016. Co-Injected volumes are measured and added to the Battery's gas dispositions.
- Plant Control System (DCS) shutdown during Fort McMurray Wildfire Emergency Shutdown & Re-start. Flare volumes were accounted for until DCS shutdown.
- After wildfires, fuel gas was injected into the injection wall (semi-SAGD operation) to restart some S2 wells. The fuel gas injected did not immediately return to the Battery; therefore, the calculated Battery's Produced Gas resulted into "negative volumes" for June 2016 reporting period.

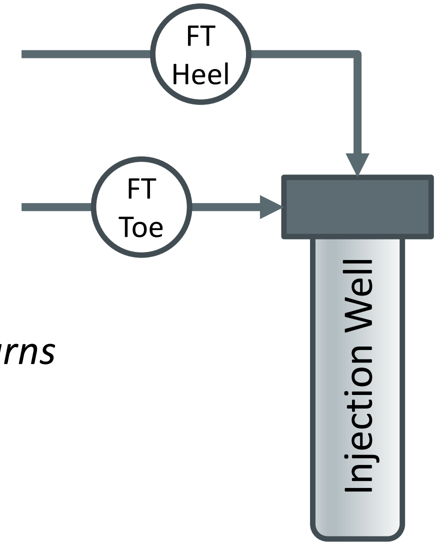
$$\textit{Well Measured Steam} \times \textit{Steam Proration Factor}$$

- Well Measured Steam =

$$\textit{Steam Injected @Heel} + \textit{Steam Injected @Toe}$$

- Steam Proration Factor =

$$\frac{\textit{Steam Produced}}{\textit{Total Measured Steam}}$$



- Steam Produced =

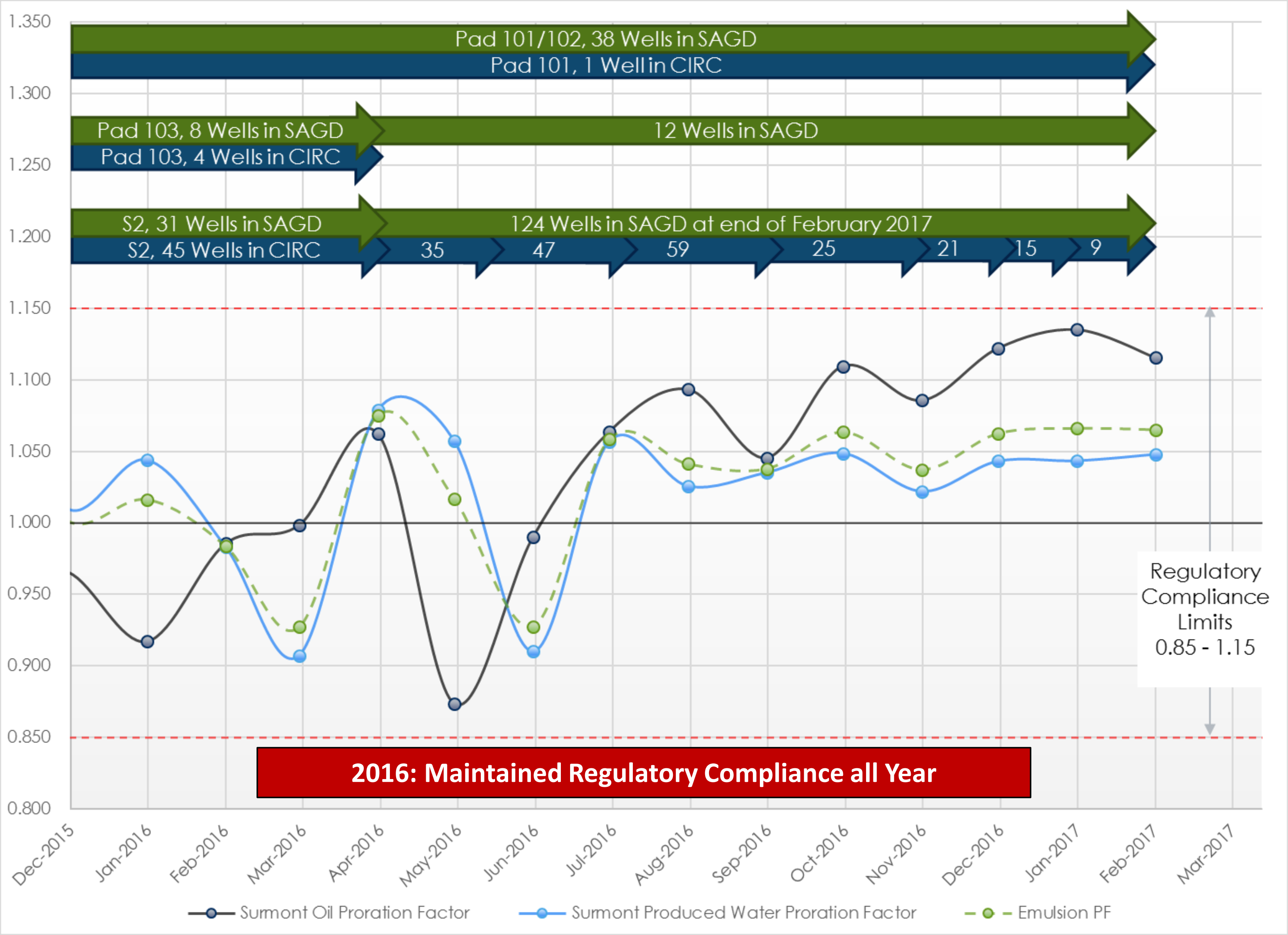
$$\textit{Steam Generated (CPF) – Steam Condensate Returns}$$

- Total Measured Steam =

$$\sum_{n=1}^{x} \textit{Well}_n \textit{ Measured Steam}$$

where x is the total number of injection wells during the reporting period.

Oil and Water Production Proration Factors



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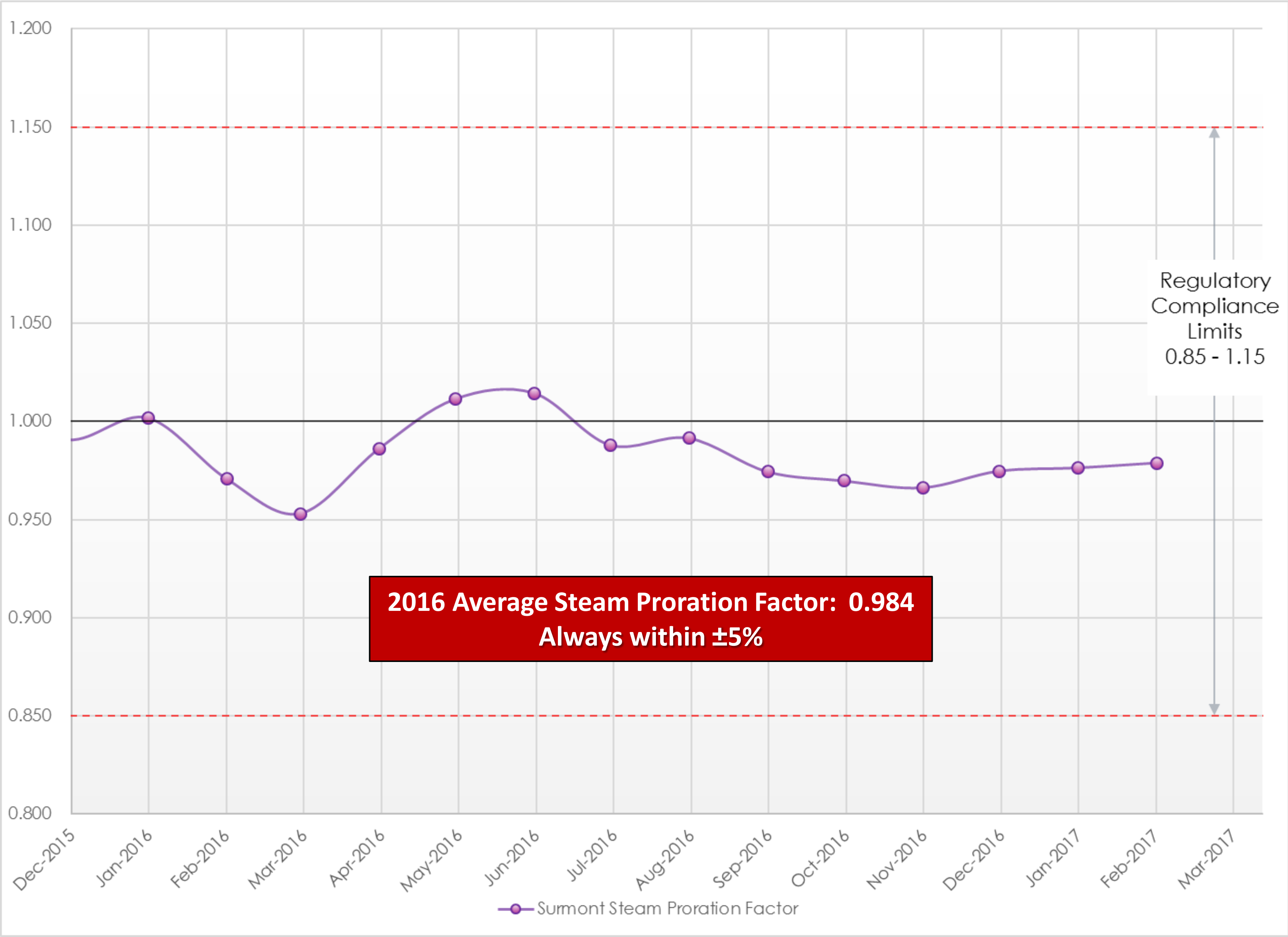
Steam Injection Proration Factor



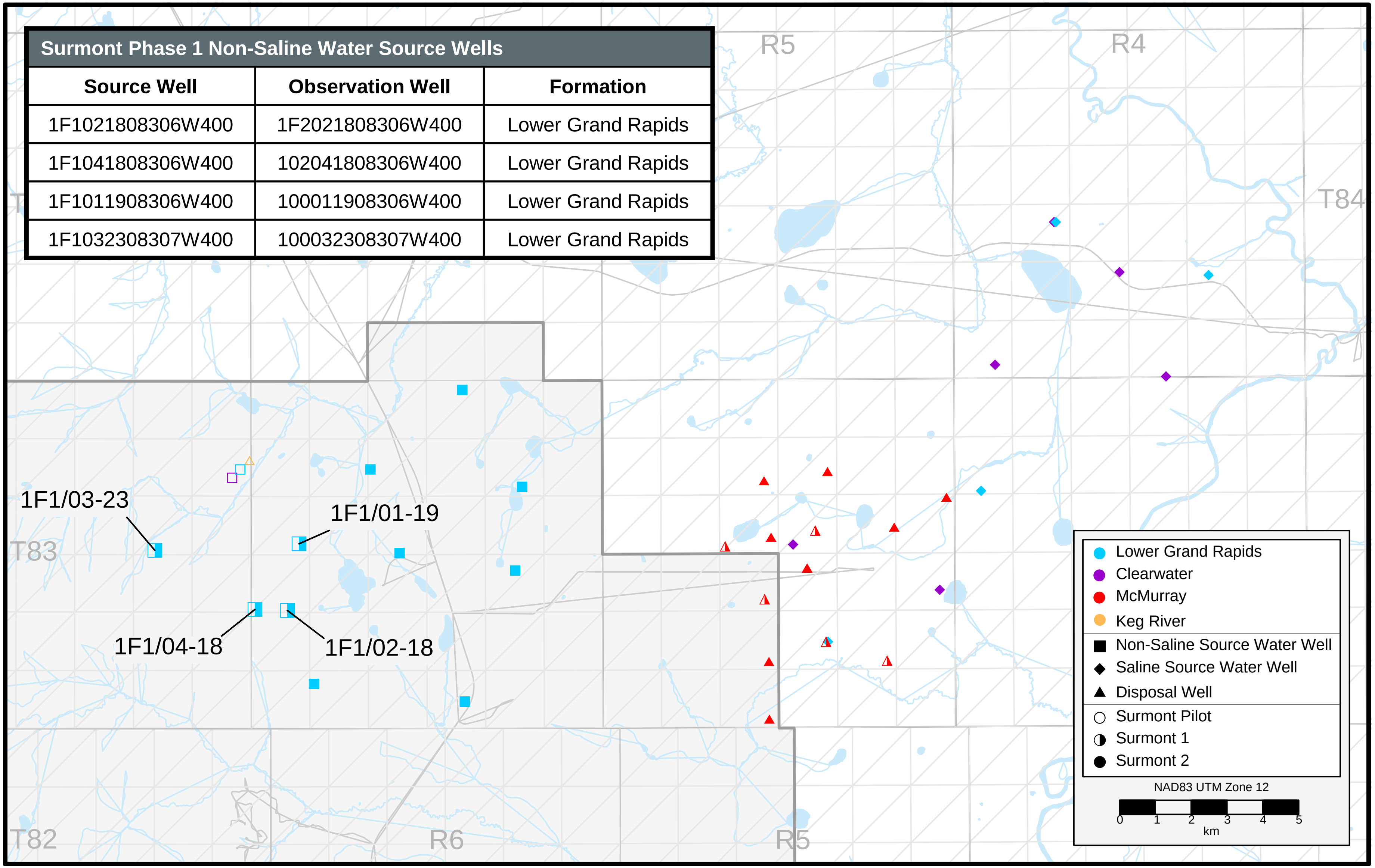
Water Production, Injection, and Uses

Subsection 3.1.2 (4)

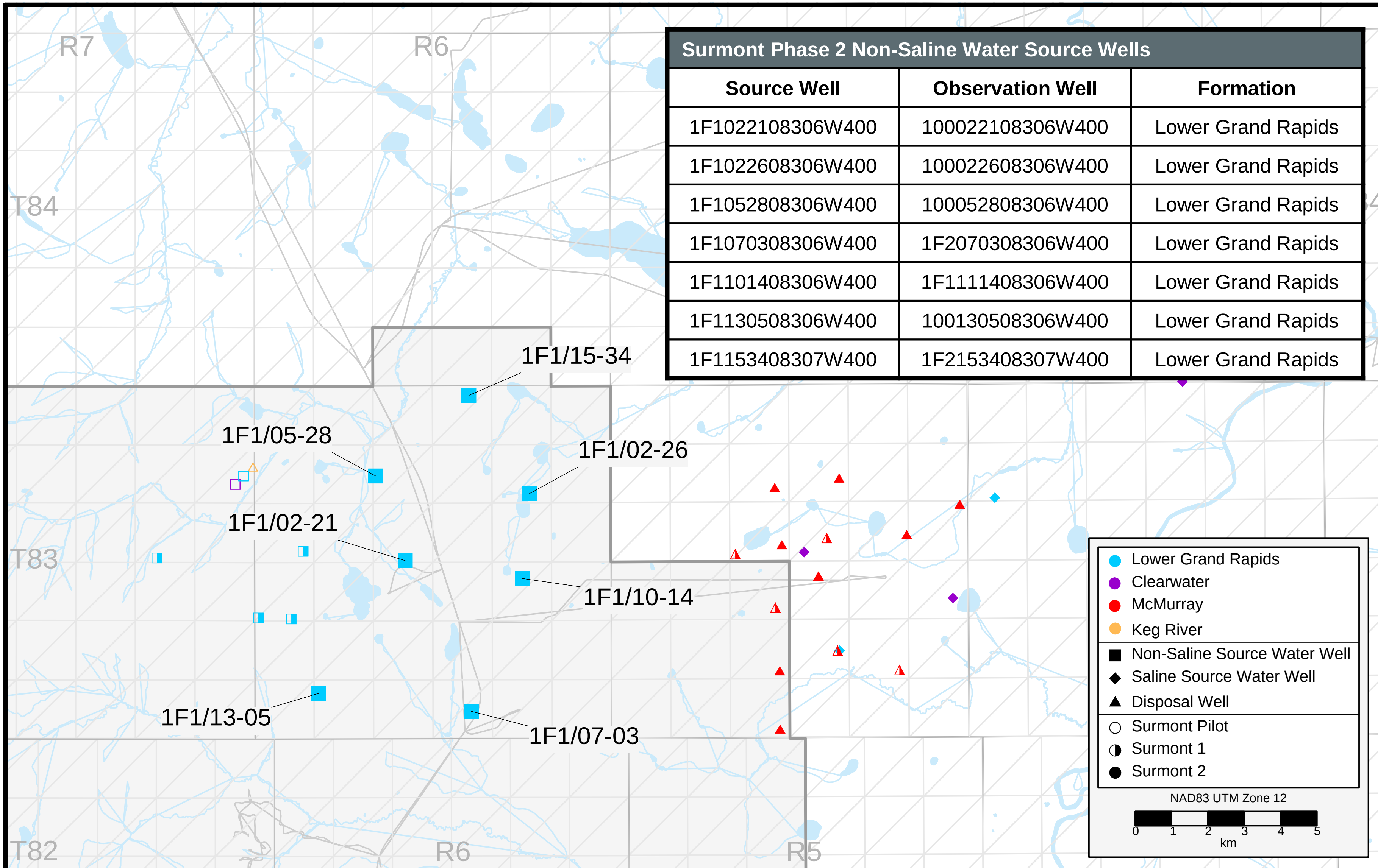
Surmont Phase 1 Non-Saline Water Source Wells

Surmont Phase 1 Non-Saline Water Source Wells

Source Well	Observation Well	Formation
1F1021808306W400	1F2021808306W400	Lower Grand Rapids
1F1041808306W400	102041808306W400	Lower Grand Rapids
1F1011908306W400	100011908306W400	Lower Grand Rapids
1F1032308307W400	100032308307W400	Lower Grand Rapids



Surmont Phase 2 Non-Saline Water Source Wells



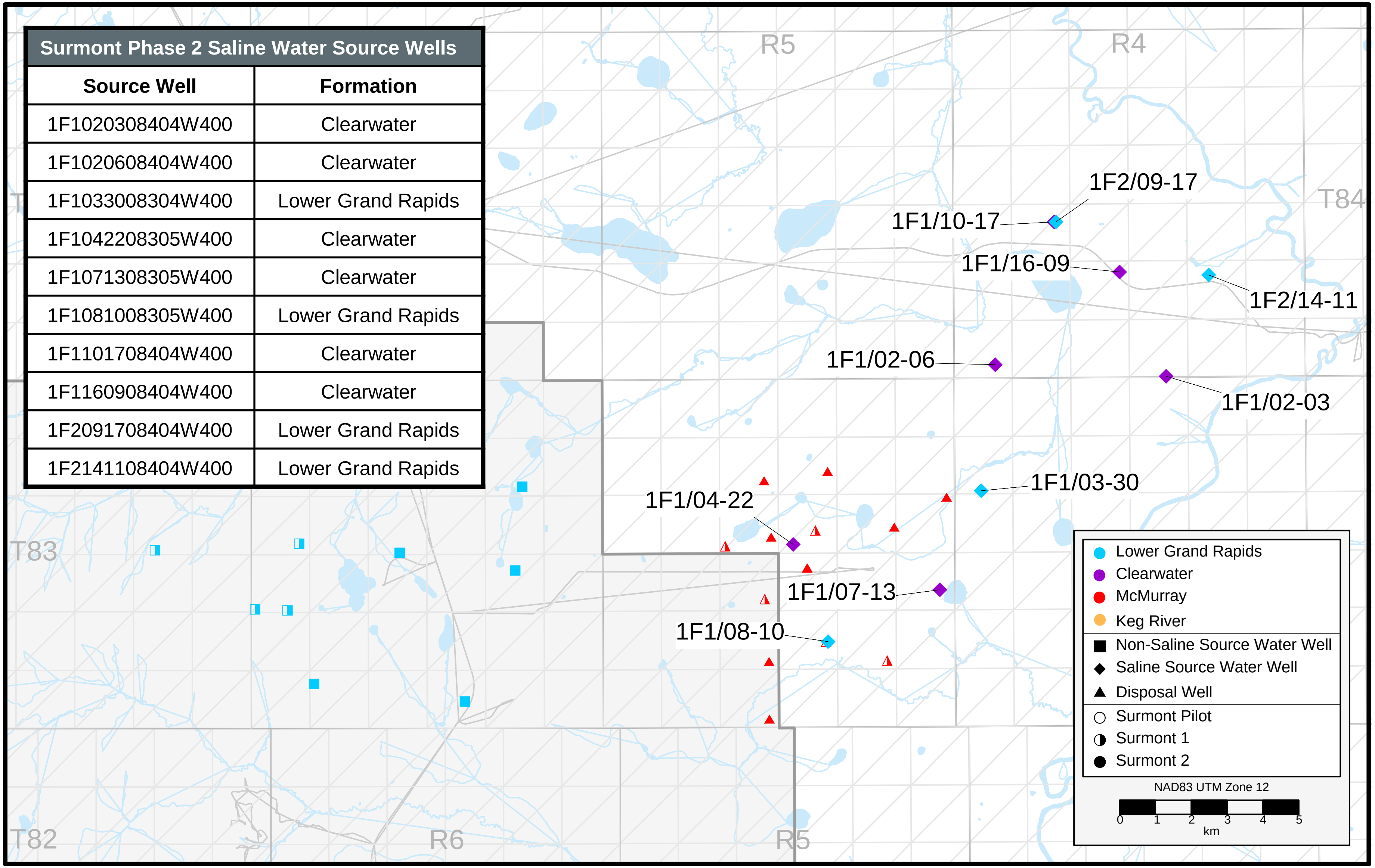
Surmont Phase 2 Non-Saline Water Source Wells

Source Well	Observation Well	Formation
1F1022108306W400	100022108306W400	Lower Grand Rapids
1F1022608306W400	100022608306W400	Lower Grand Rapids
1F1052808306W400	100052808306W400	Lower Grand Rapids
1F1070308306W400	1F2070308306W400	Lower Grand Rapids
1F1101408306W400	1F1111408306W400	Lower Grand Rapids
1F1130508306W400	100130508306W400	Lower Grand Rapids
1F1153408307W400	1F2153408307W400	Lower Grand Rapids

Surmont Phase 2 Saline Water Source Wells

Surmont Phase 2 Saline Water Source Wells

Source Well	Formation
1F1020308404W400	Clearwater
1F1020608404W400	Clearwater
1F1033008304W400	Lower Grand Rapids
1F1042208305W400	Clearwater
1F1071308305W400	Clearwater
1F1081008305W400	Lower Grand Rapids
1F1101708404W400	Clearwater
1F1160908404W400	Clearwater
1F2091708404W400	Lower Grand Rapids
1F2141108404W400	Lower Grand Rapids



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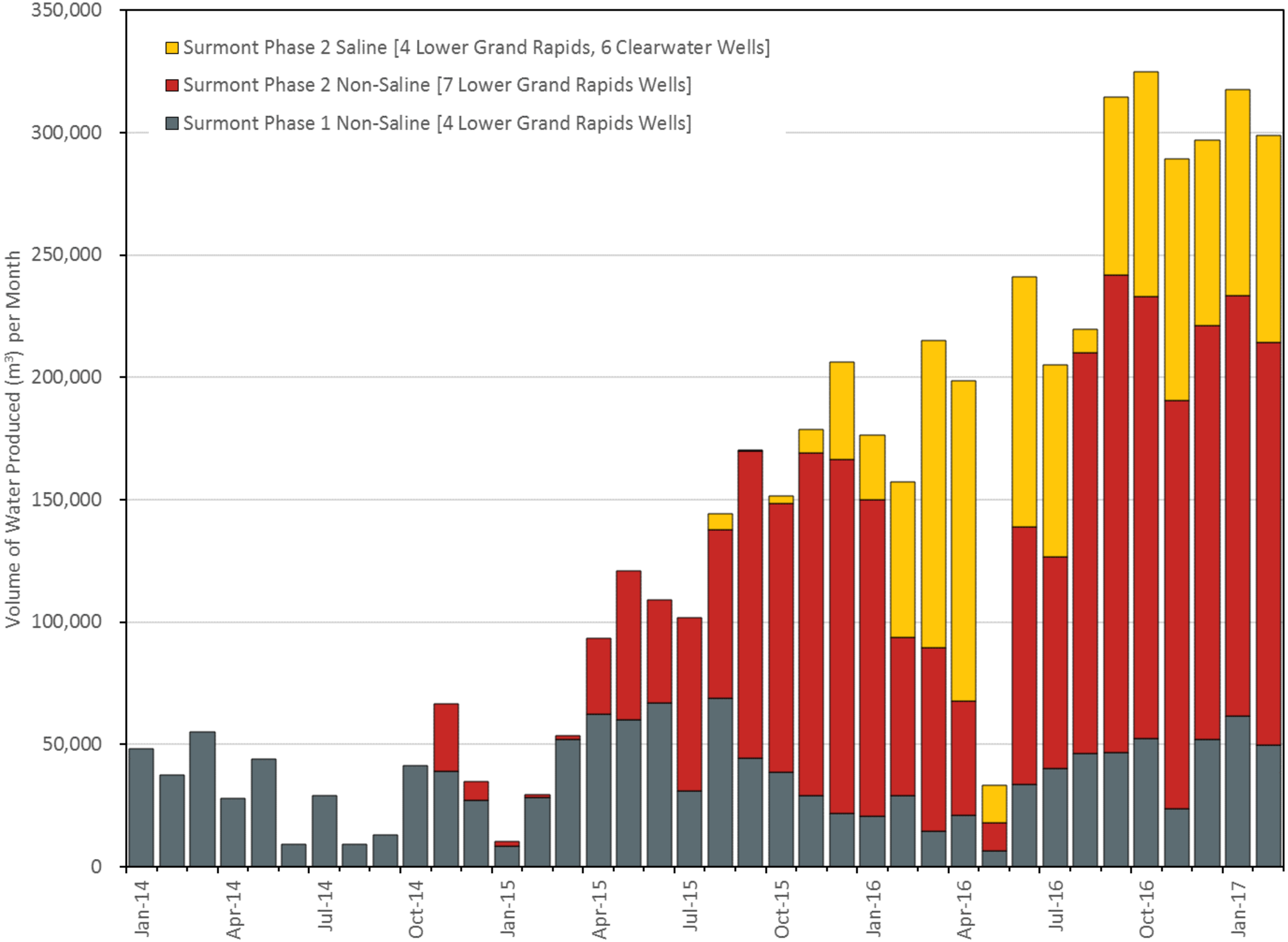
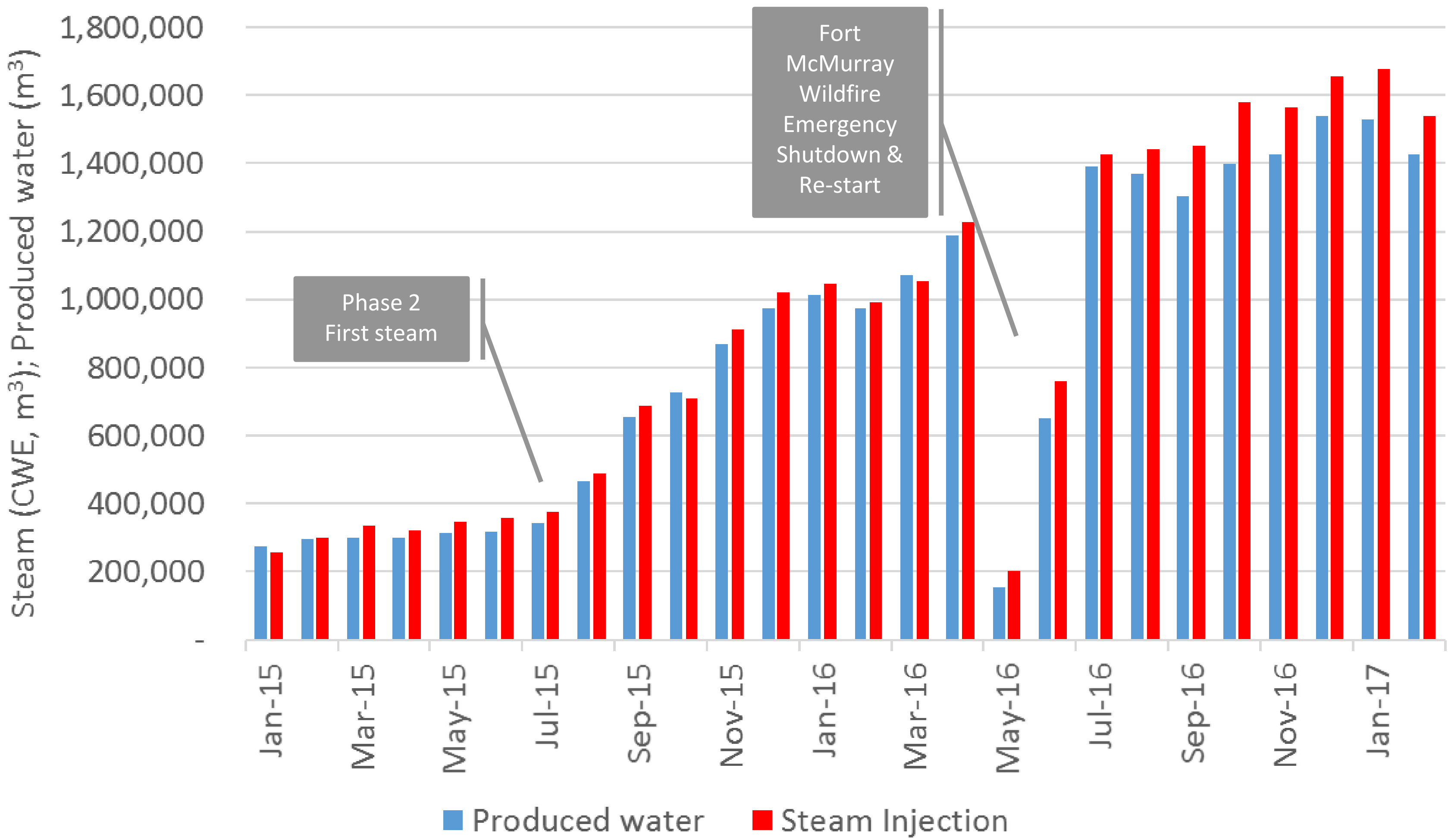
Surmont Non-Saline and Saline Water Source Wells Production Volumes

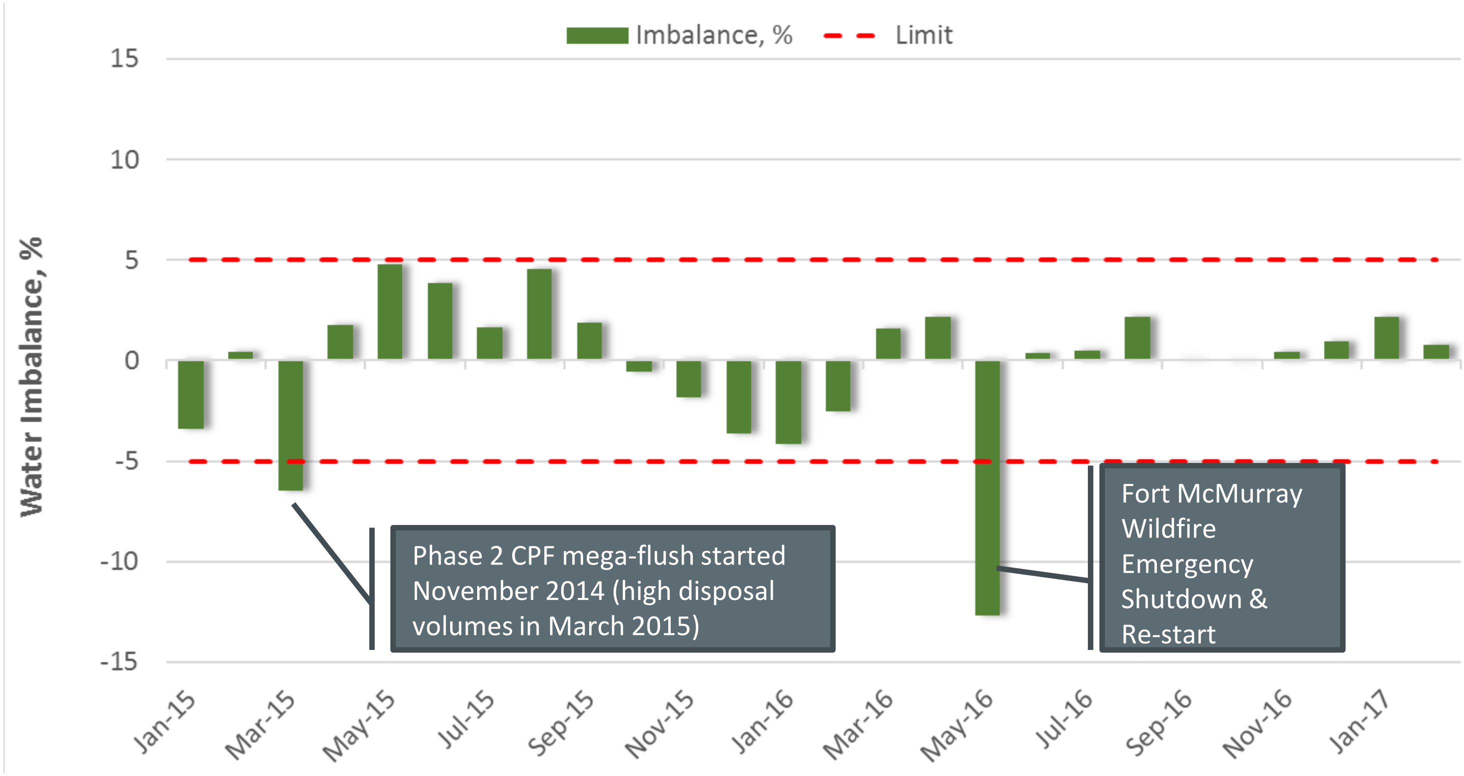


Water Production and Steam Injection Volumes

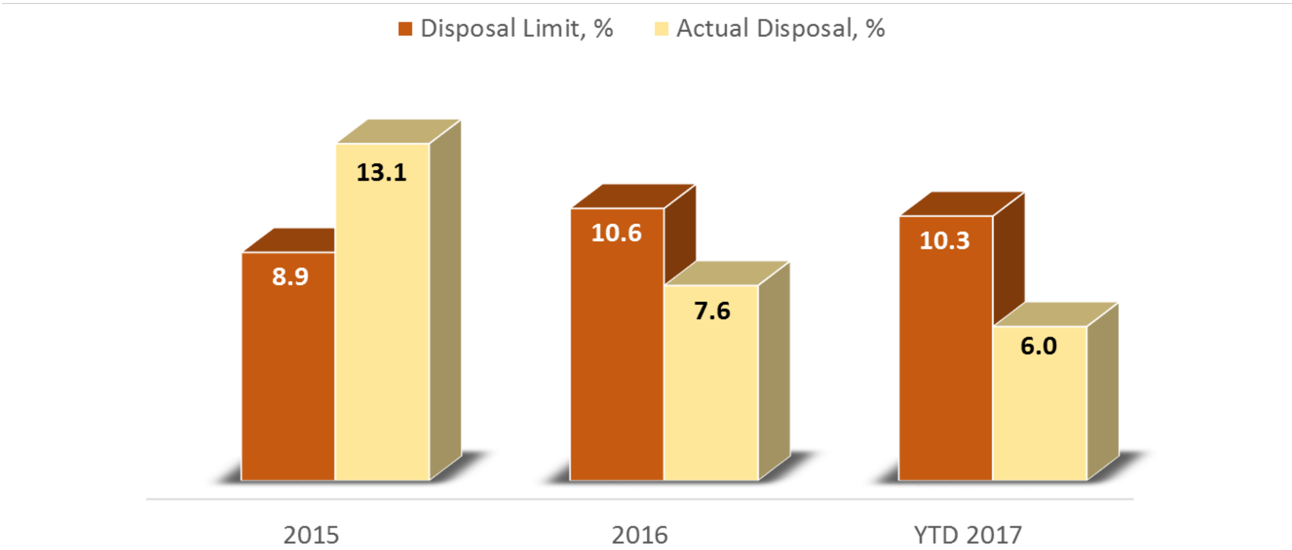


Directive 81: Injection Facility Water Imbalance

- Surmont in compliance with *Directive 81* Injection Facility Water Imbalance since June 2014
- Challenging to keep metering imbalance within 5% when performing large projects (Phase 2 CPF mega-flush Nov 2014 - Mar 2015) or unplanned events (Fort McMurray Wildfire Emergency Shutdown and Re-start May 2016)
- Maintained compliance during Phase 2 ramp up



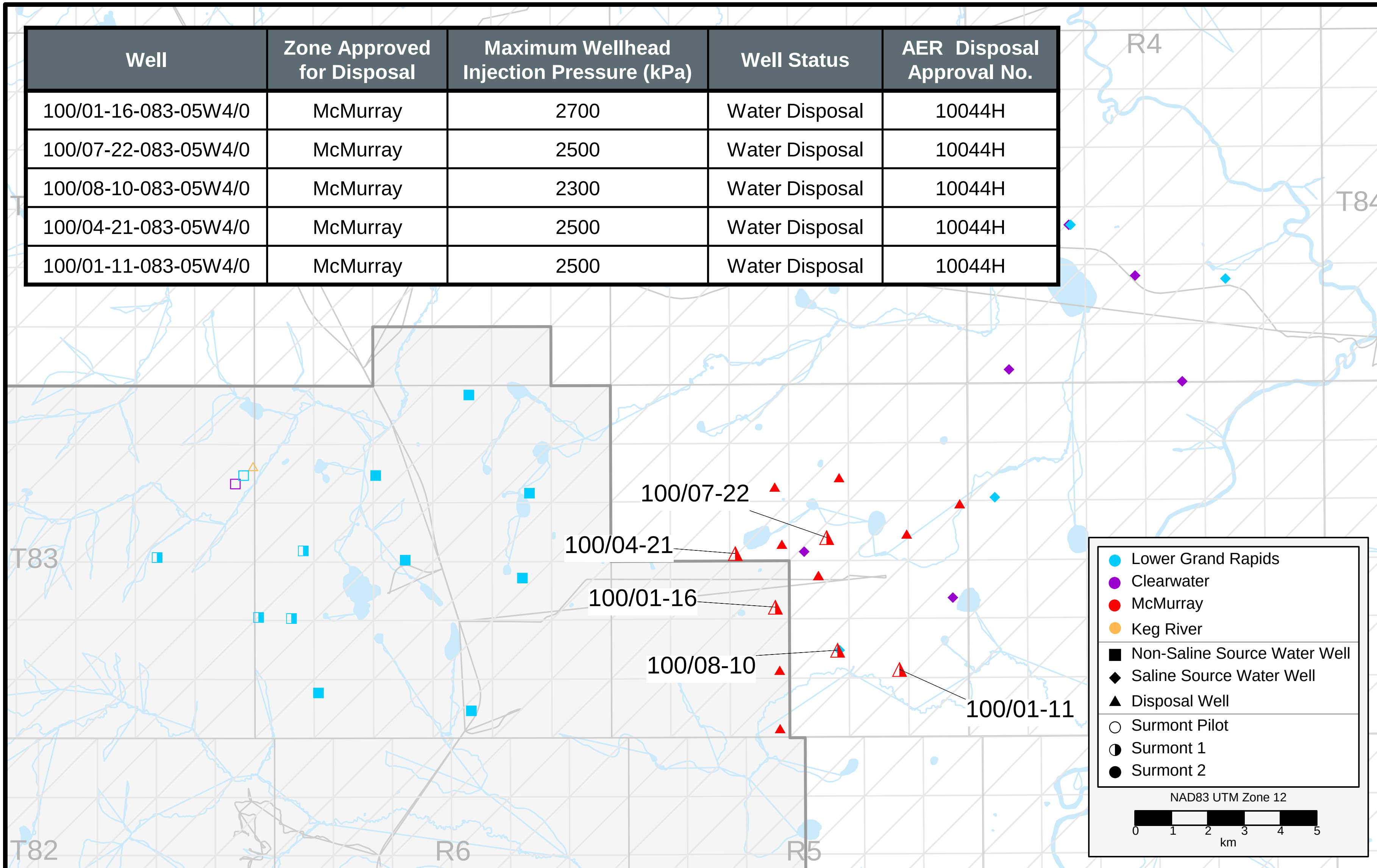
Directive 81: Annual Disposal performance



- Surmont anticipates *Directive 81* disposal limit compliance in 2017 as per current trend (6.0% actual vs. 10.3% disposal limit)
- Surmont accomplished *D-81* compliance in 2016 (7.6% actual vs. 10.6% disposal limit) after commissioning brackish water system and blowdown evaporators at Phase 2 CPF
- Excess disposal in 2015 due to:
  - Phase 2 ramp-up (Testing 12 out of 18 OTSGs)
  - Performed Phase 2 CPF mega-flush (started in Nov 2014 and disposed in Mar 2015)
  - Significant repair work on Phase 1 OTSG-D
  - Well caustic work causing significant water plant upset

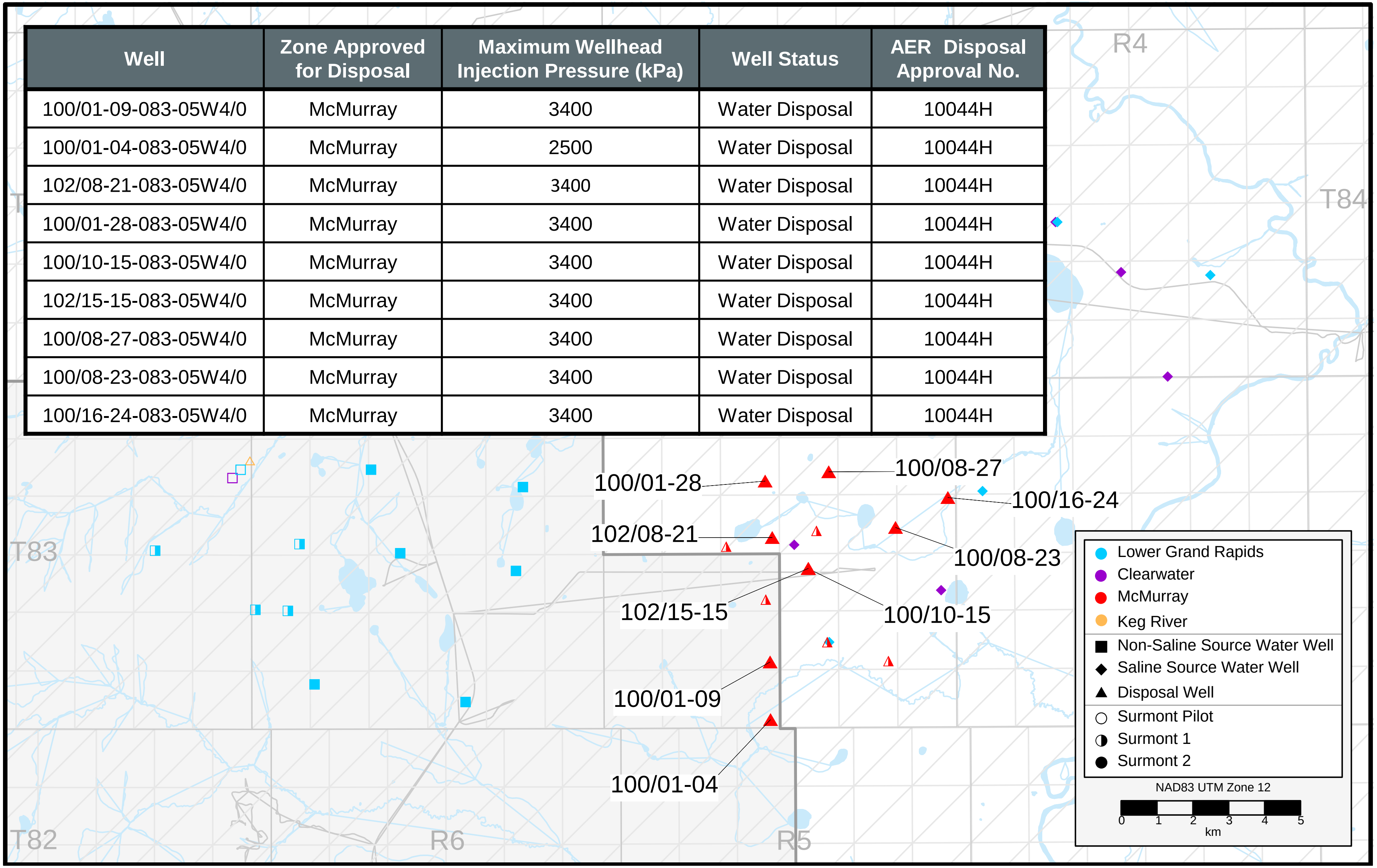
Surmont Phase 1 Water Disposal Wells

Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/01-16-083-05W4/0	McMurray	2700	Water Disposal	10044H
100/07-22-083-05W4/0	McMurray	2500	Water Disposal	10044H
100/08-10-083-05W4/0	McMurray	2300	Water Disposal	10044H
100/04-21-083-05W4/0	McMurray	2500	Water Disposal	10044H
100/01-11-083-05W4/0	McMurray	2500	Water Disposal	10044H

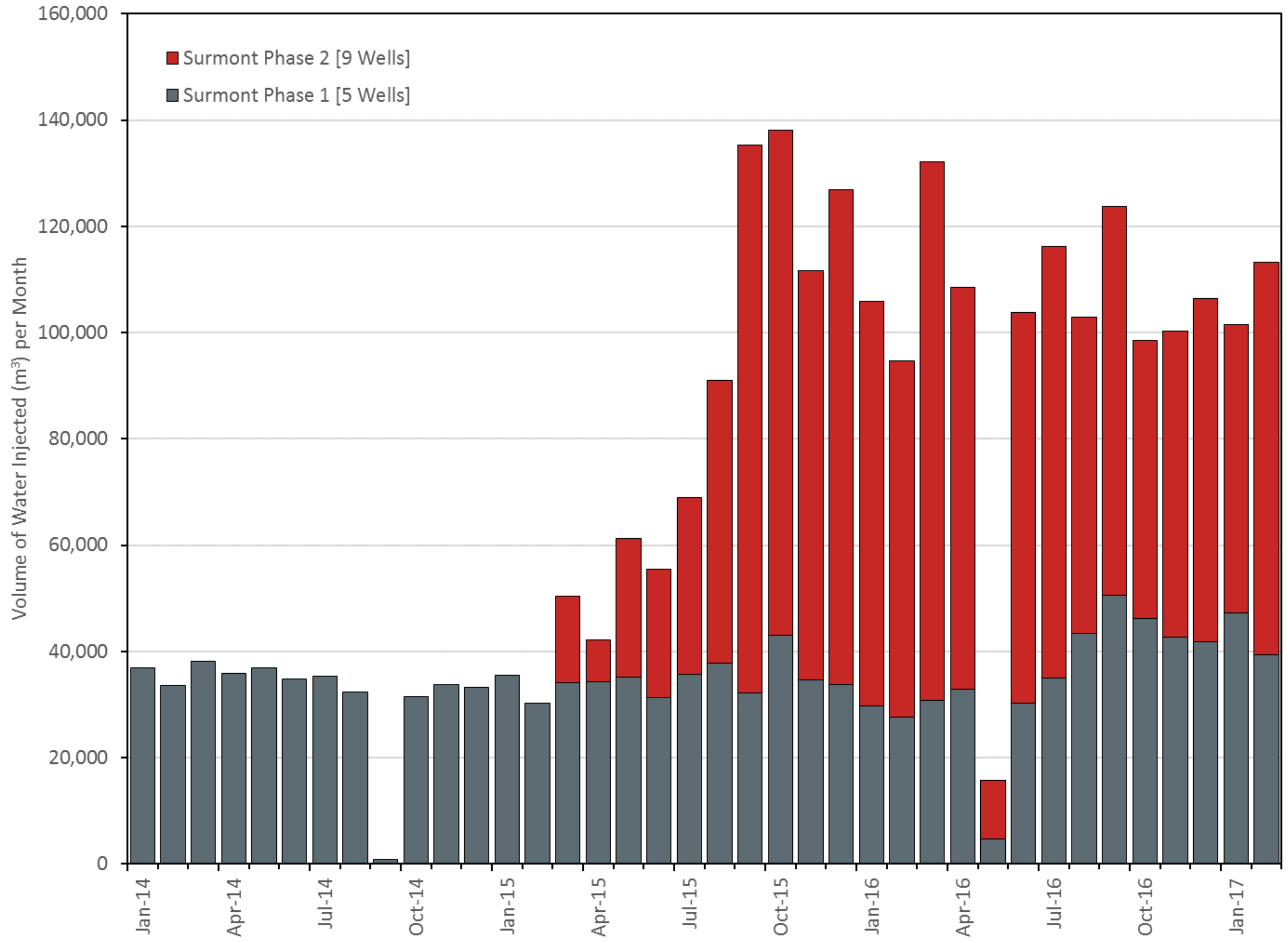


Surmont Phase 2 Water Disposal Wells

Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/01-09-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/01-04-083-05W4/0	McMurray	2500	Water Disposal	10044H
102/08-21-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/01-28-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/10-15-083-05W4/0	McMurray	3400	Water Disposal	10044H
102/15-15-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/08-27-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/08-23-083-05W4/0	McMurray	3400	Water Disposal	10044H
100/16-24-083-05W4/0	McMurray	3400	Water Disposal	10044H



Surmont Water Disposal Wells Injection Rates (McMurray)



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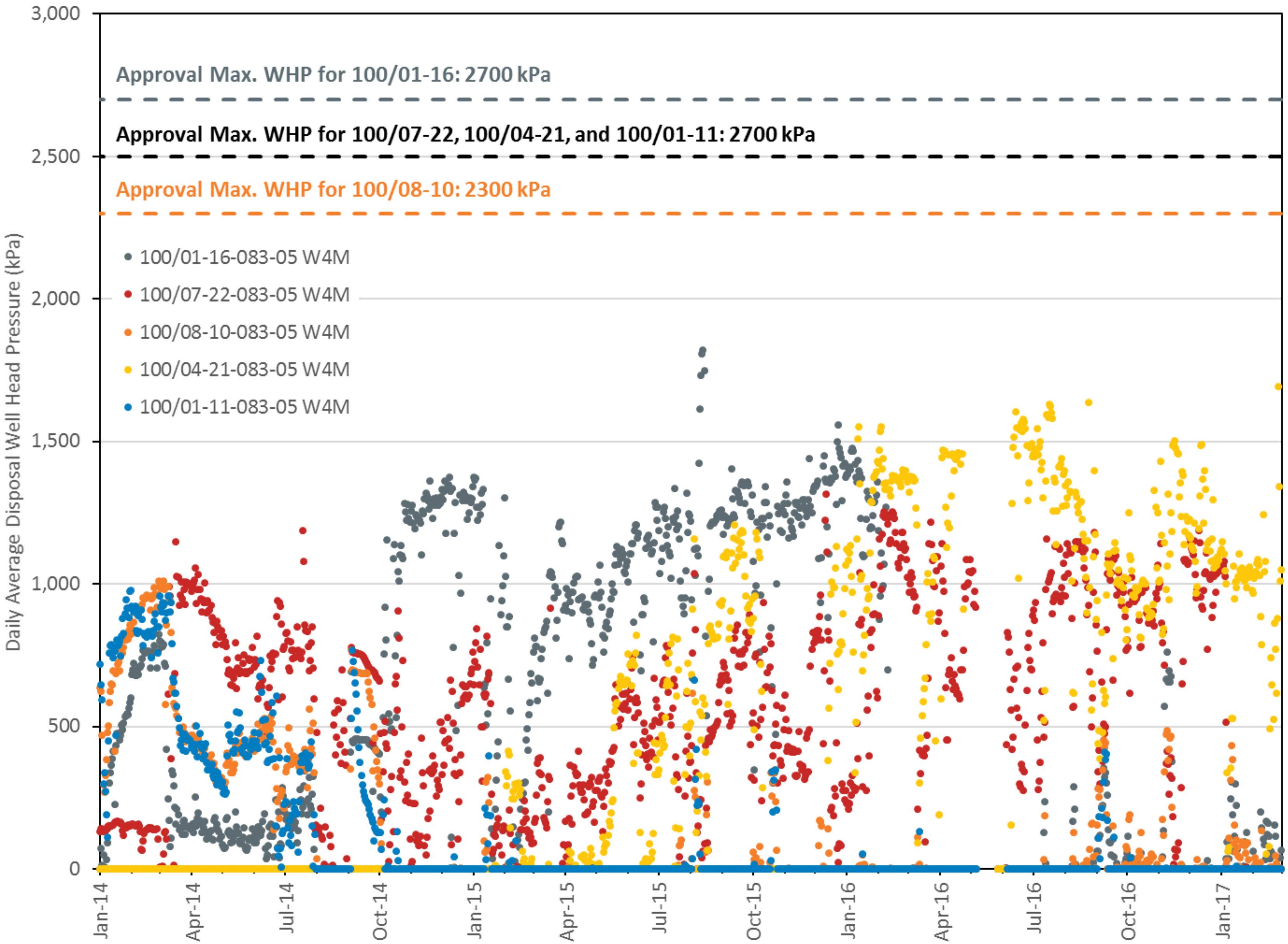
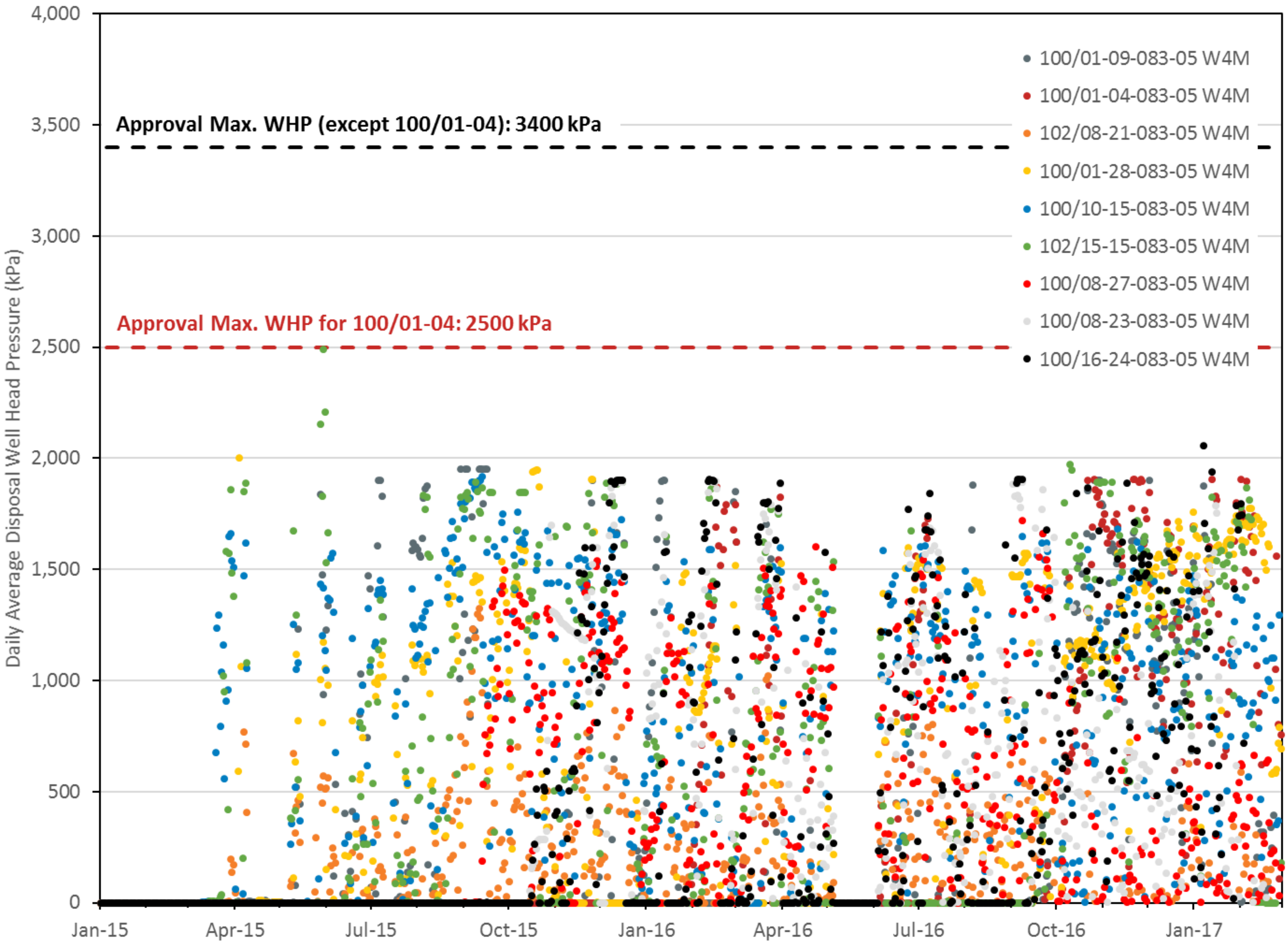
Surmont Phase 1 Water Disposal Wells Well Head Pressure (McMurray)



Surmont Phase 2 Water Disposal Wells Well Head Pressure (McMurray)



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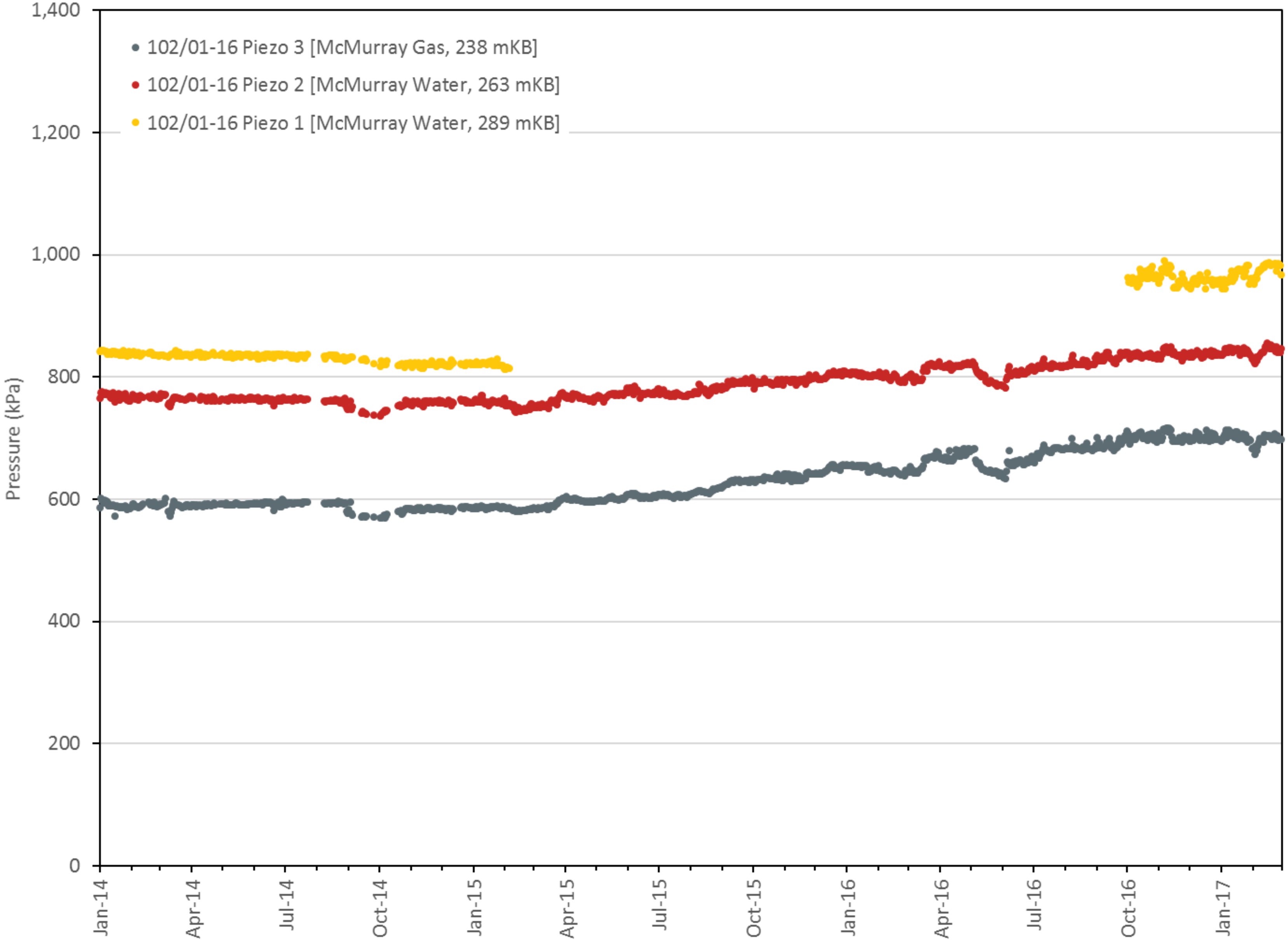
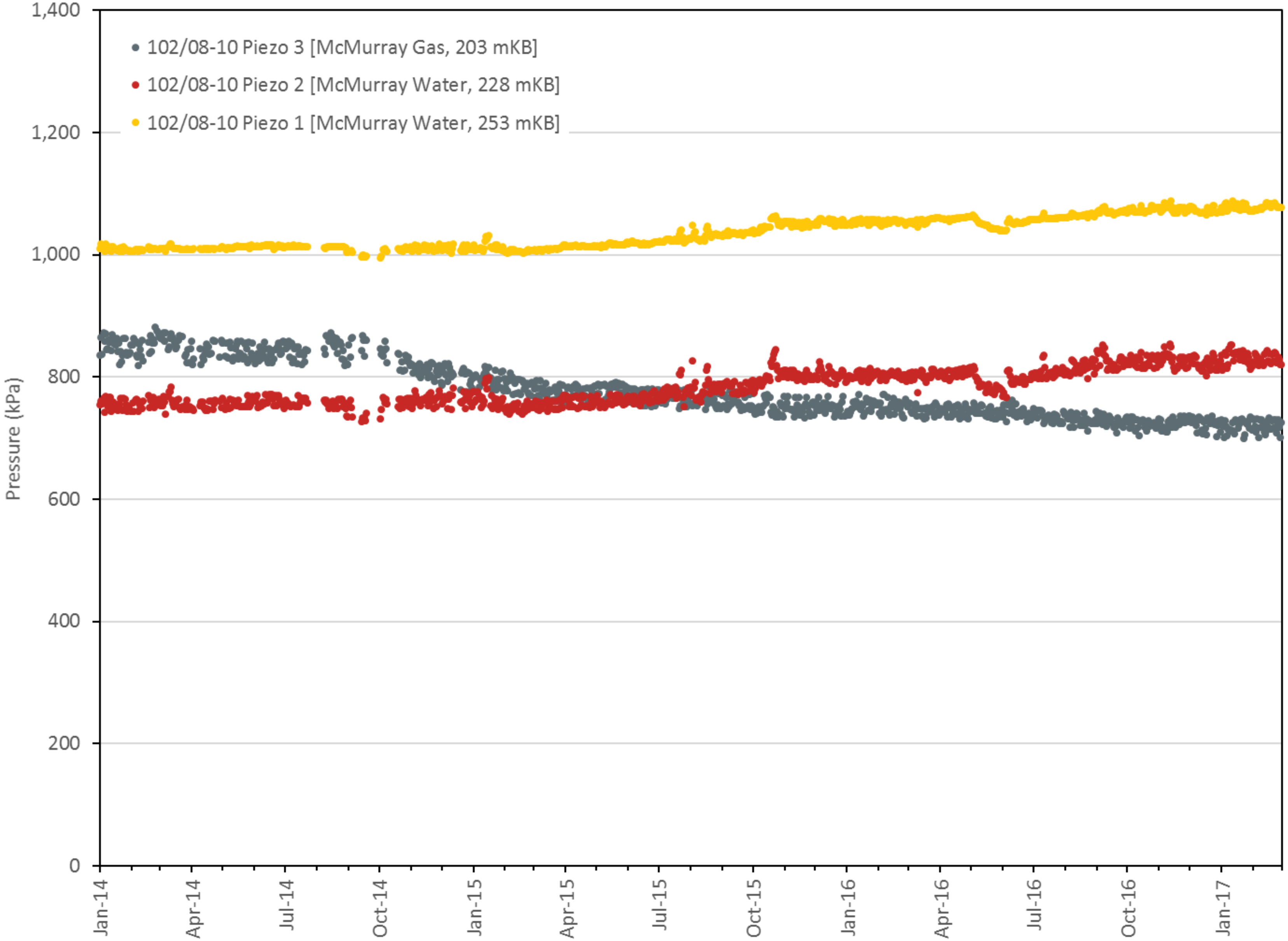
Water Disposal Well 100/01-16-083-05 W4M Observation Well Pressure (McMurray)



Water Disposal Well 100/08-10-083-05 W4M Observation Well Pressure (McMurray)



Waste Disposal

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Dangerous Oilfield Waste	63,855	
Hydrocarbon/Emulsion Sludge	4,167	Oilfield Waste Processing Facility
Crude Oil/Condensate Emulsions	58,463	Oilfield Waste Processing Facility
Various	1,224	Landfill
Non-Dangerous Oilfield Waste	27,918	
Lime Sludge	17,633	Landfill
Various	9,486	Landfill
Well Fluids	799	Cavern

Waste Recycling

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Oil	17	Used Oil Recycler
Empty Containers	4	Recycling Facility
Fluorescent Light Tubes	1	Recycling Facility
Batteries	3	Recycling Facility

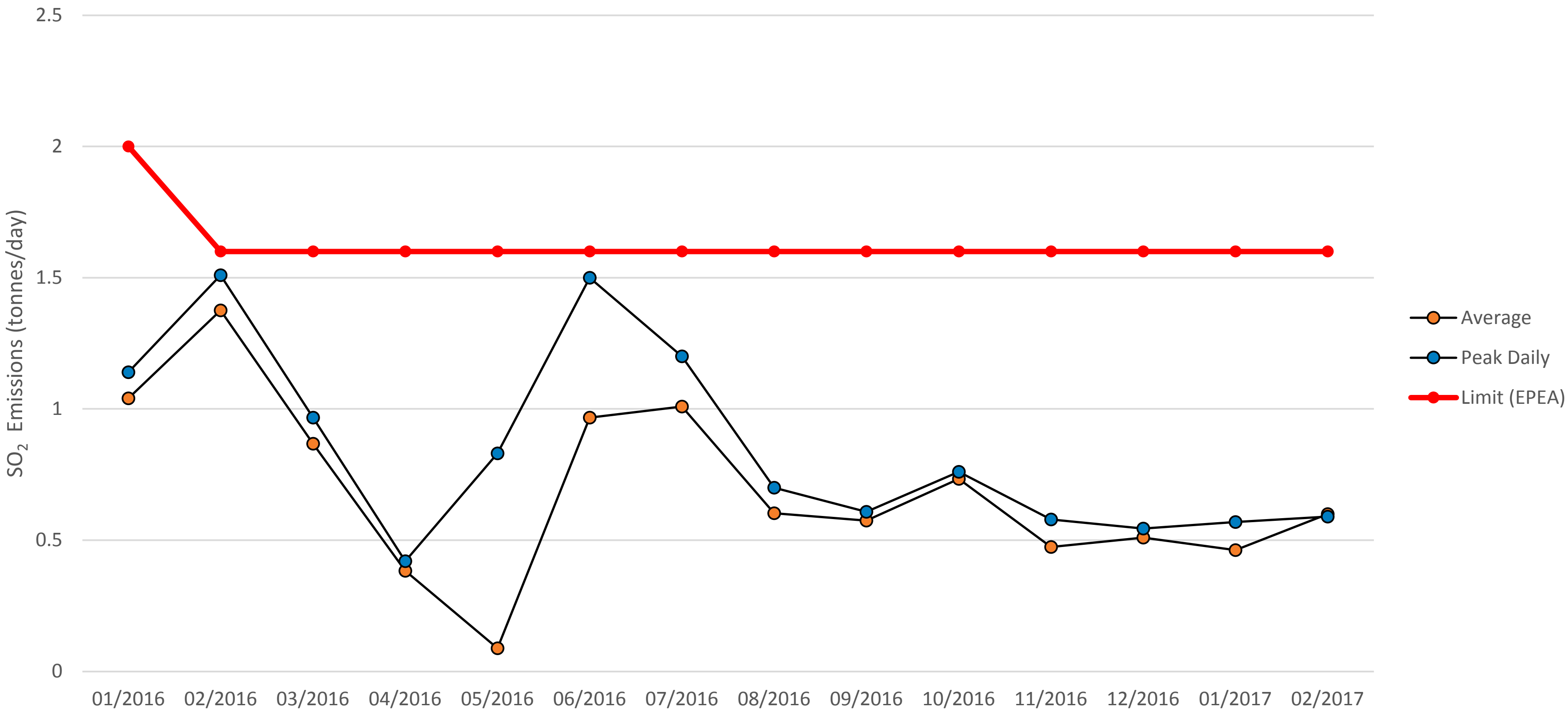
Typical Water Analysis

Parameter	Non-Saline Makeup Water (mg/L)	Saline Makeup Water (mg/L)	Produced Water (mg/L)	Disposal Water (mg/L)
pH	8.5	8.2	7.5	11.8
Total Dissolved Solids (TDS)	1,400	8,000	1,800	23,000
Chloride	200	2,800	650	9,500
Hardness as $CaCO_3$	<0.5	225	10	5
Alkalinity as $CaCO_3$	900	350	250	2,700
Silica	8	7	190	225
Total Boron	6	3.3	40	260
Total Organic Carbon	15	4	500	2,150
Oil Content	<1	<1	65	30

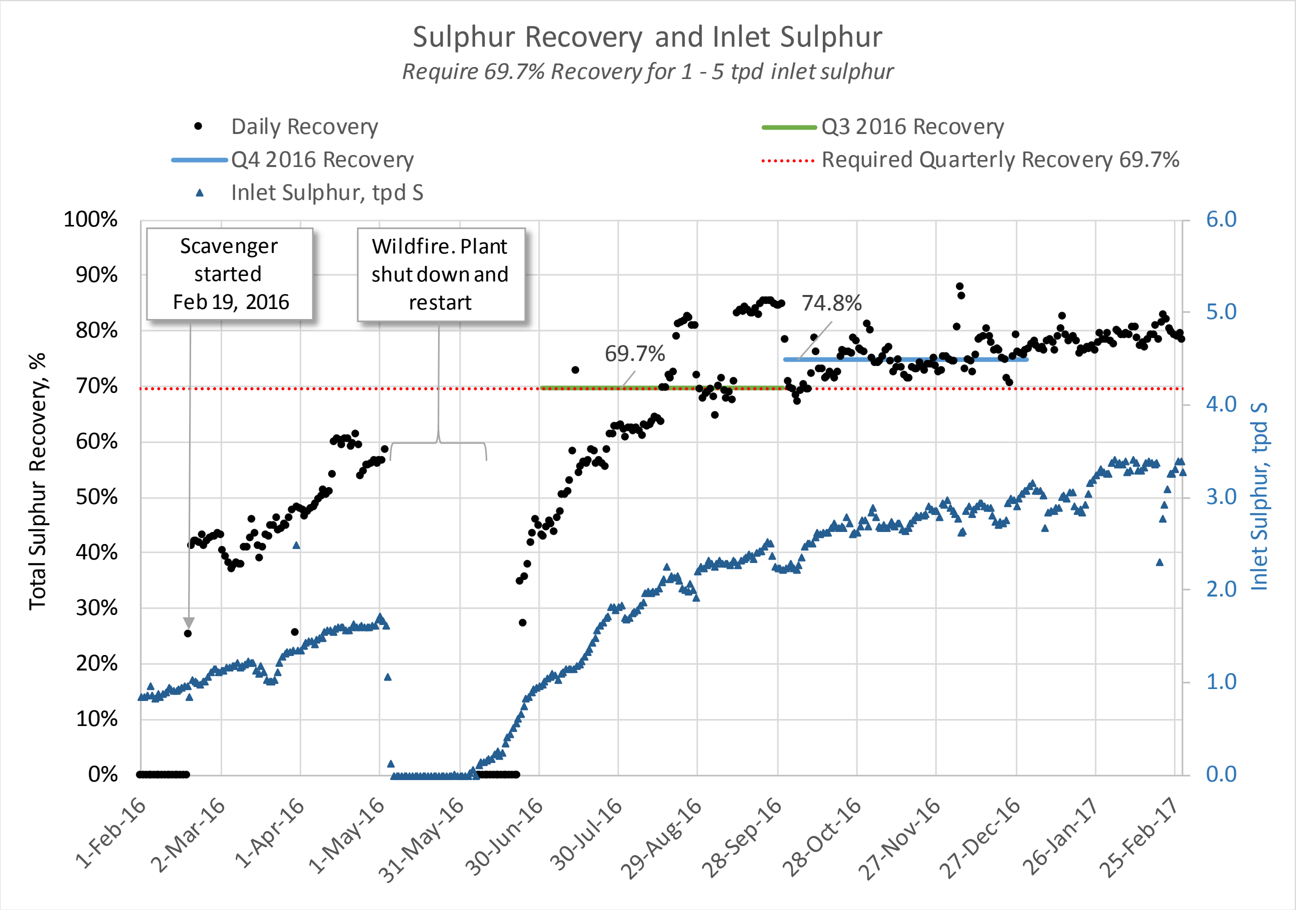
Sulphur Production

Subsection 3.1.2 (5)

Daily SO_2 Emissions



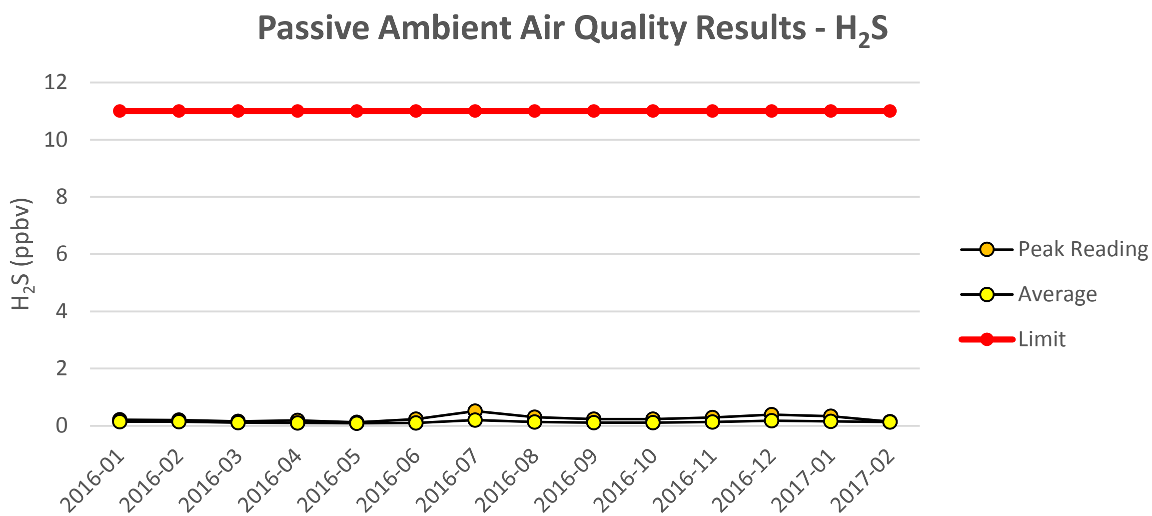
Surmont Project Sulphur Recovery

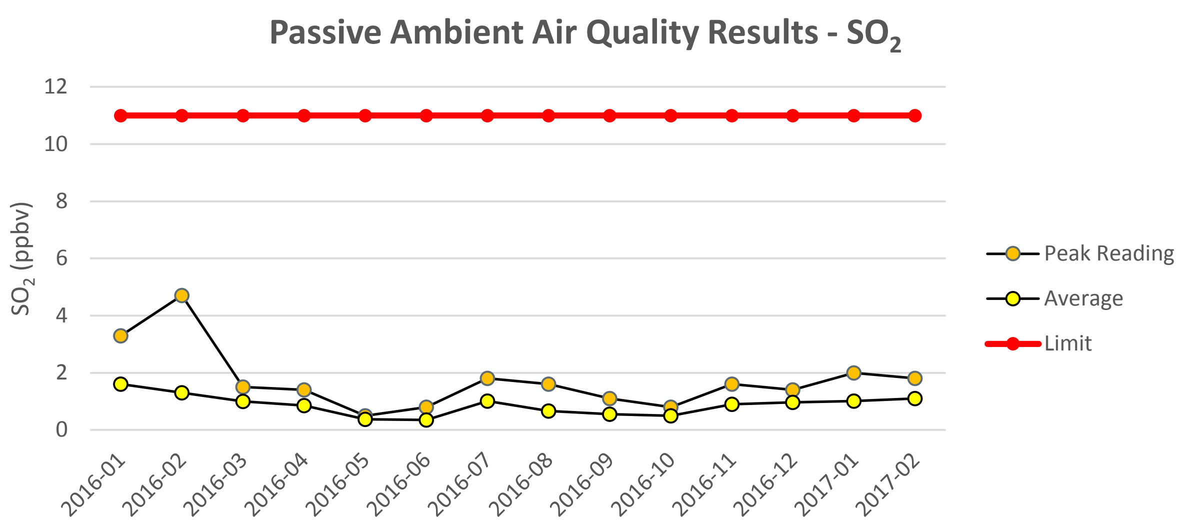


Quarter	Sulphur Recovery	Comment
Q1 2016	--	Sulphur recovery system started part way through the quarter, on Feb 19, 2016
Q2 2016	--	Wildfire forced plant shut down and partial restart operations in this quarter
Q3 2016	69.7%	Plant restart and ramp-up after wildfire
Q4 2016	74.8%	Steady operations

- Sulphur recovery unit commissioned in Q1 and restarted in Q2
- Sulphur recovery unit met or exceeded 69.7% recovery limit during Q3 and Q4.

Ambient Air Quality Monitoring





- **Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2016**

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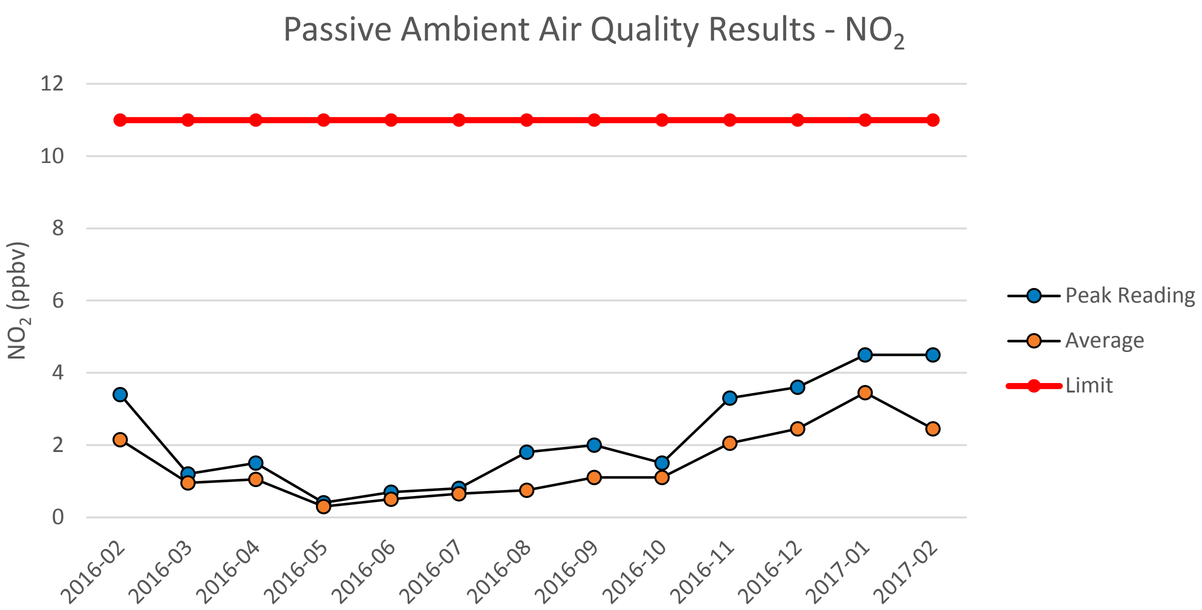
Ambient Air Quality Monitoring



- **Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2016**

Environmental Compliance

Subsection 3.1.2 (6)

Environmental Monitoring

- Groundwater Monitoring Program
  - Management triggers introduced as per EPEA approval 48263-01-00.
  - 2016 monitoring results are being analyzed in 2017
  - New monitoring well northeast of the Surmont Phase 1 Storm Pond.
- Wetlands
  - Management triggers introduced as per EPEA approval 48263-01-00.
  - Program revised to focus monitoring on early change detection.
  - 2016 results are within background concentrations.
- Wildlife Monitoring Program
  - Management triggers introduced as per EPEA approval 48263-01-00.
  - Program revised to focus monitoring on early change detection.
  - One vehicle – animal collision.
  - No serious nuisance wildlife or human-bear interactions.
- Reclamation Work
  - No final reclamation completed in 2016.
  - A density trial was conducted by planting 44,710 vegetation seedlings at soil stockpile near the Surmont Regional Residence

Environmental Compliance

- Update to the Reclamation Monitoring Program Proposal
  - Per Schedule IX of EPEA Approval number 48263-01-00, as amended, a update to the Reclamation Monitoring Program proposal was due to AEP on or before December 31, 2016.
  - An extension to February 28, 2017 was granted and the updated proposal was submitted.

Compliance Confirmation and Non Compliances

Subsection 3.1.2 (7) + (8)

Compliance Confirmation and Non Compliances

ConocoPhillips Canada is in regulatory compliance for 2016 with the exception of the following:

264-2 I09 Overpressure Event

- Bottomhole pressure exceeded by 100 kPa for 7.5 hours.

Surmont Phase 1 Pond Primary Liner Leak

- A corrective action plan was submitted in 2015 and the action items were completed.
- CPC will be submitting an update to the AER during Q2 2017.

Surmont Phase 2 Storm Pond Certificate of Completion Submitted March 22, 2016

- Certificate of Completion was not submitted within 60 days of completion.

Remote Sump Non-Compliance (33-081-06W4)

- The site entrance was missing a sign, and it has been corrected.

Compliance Confirmation and Non Compliances

AER Investigation into Master Well Valve Failure (264-1 I05, January 7, 2017)

- AER investigation is still on-going.
- No non-compliances were identified during clean-up inspections to date.

Air Monitoring Frequency

- Continuous Emissions Monitoring System (CEMS) and air monitoring trailer downtime exceedance.

Future Plans

Subsection 3.1.2 (9)

Future Plans – Surmont

Phase 1

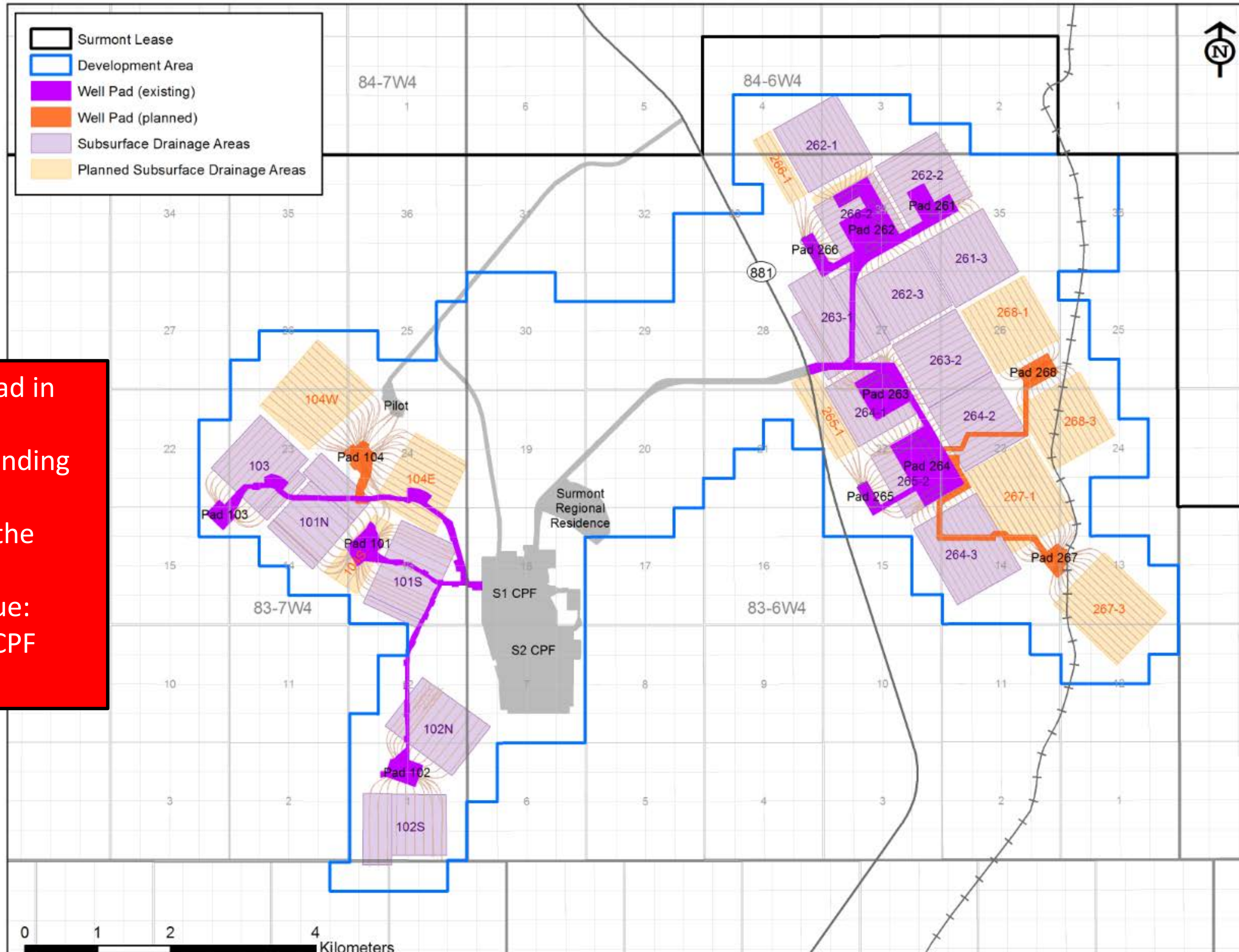
- Turn around planned for September 2017
- Upgrade of economizer box on remaining Phase 1 steam generator (OTSG A) to improve steam quality
- Continued monitoring of leaking Pond Primary Liner

Phase 2

- Completion of construction of relocated steam generator and high pressure steam separator, commissioning is targeting Q4 2017
- Design work is ongoing for the installation of an additional steam generator
- Mechanical cleaning of select Boiler Feed Water Pre-heat exchangers for improved heat integration
- Continued work on steam quality enhancement
- Continued ramp-up of Phase 2 production towards plant capacity
- Trial for alternative diluent supply scheduled for Q2 2017

Future Pad Developments

- 267 is the next pad in the queue.
- 268 is on hold pending further review.
- 104 is second in the queue.
- Third pad in queue: Looking at near-CPF options.



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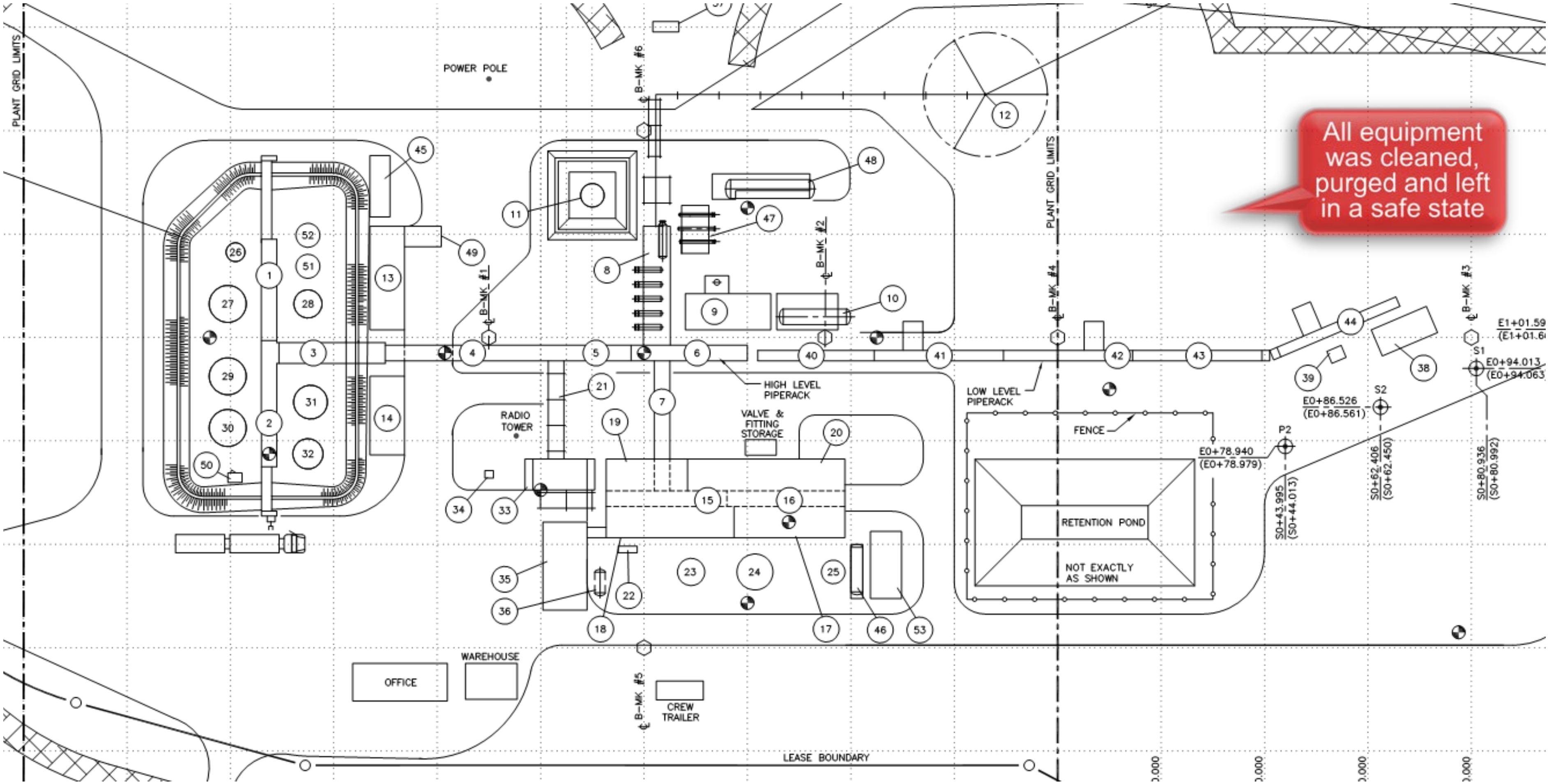
Surface Operations and Compliance
Pilot Project Approval 9460

Facilities

Subsection 3.1.2 (1)

Site Survey Plan & Facility Modifications



All equipment was cleaned, purged and left in a safe state

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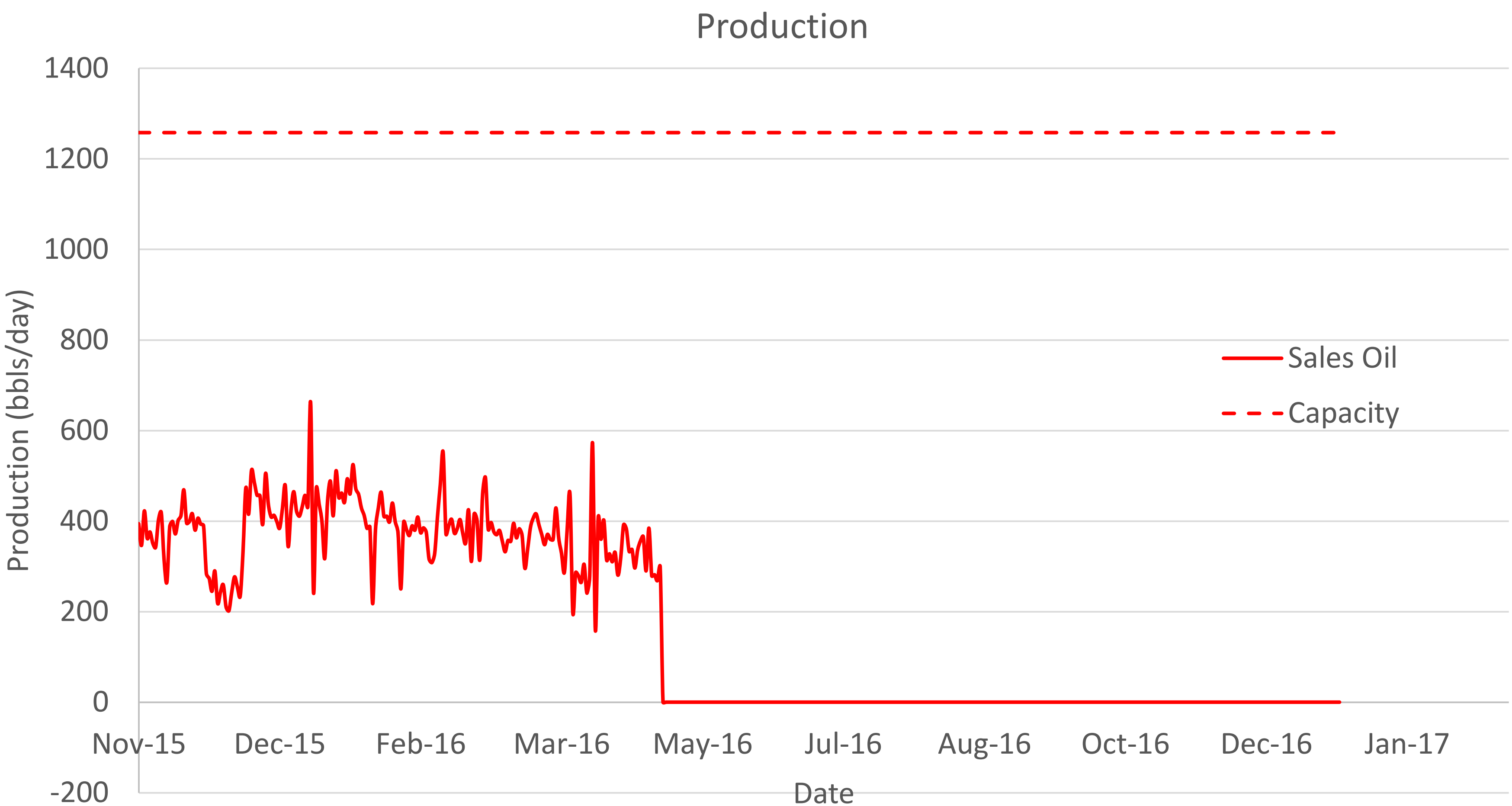
Facility Performance

Subsection 3.1.2 (2)

Pilot Plant Performance Bitumen Production



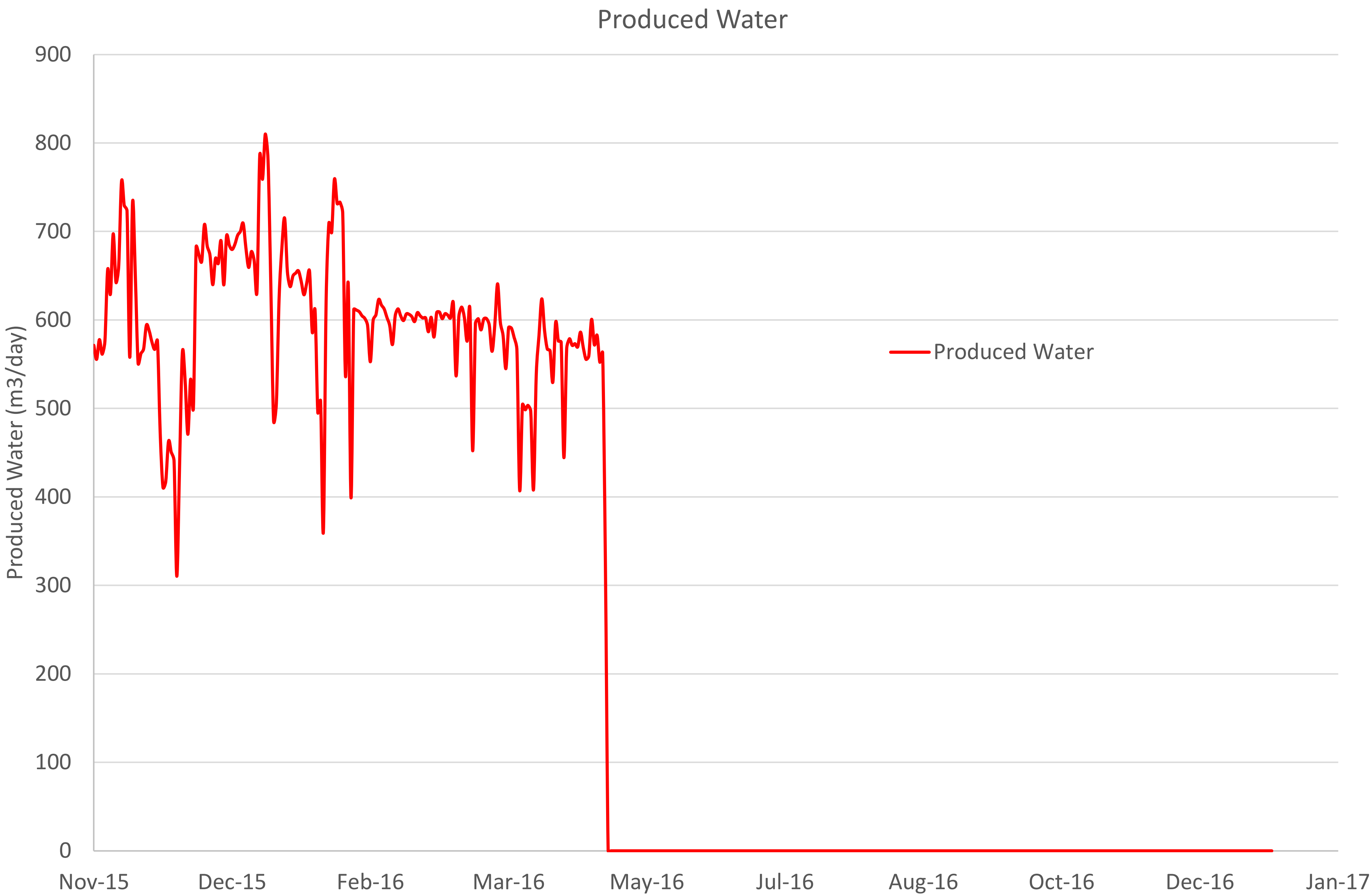
- Thief zone interaction limiting production
- Cease of production on May 5th

2015 Production = ~352 bbls/day

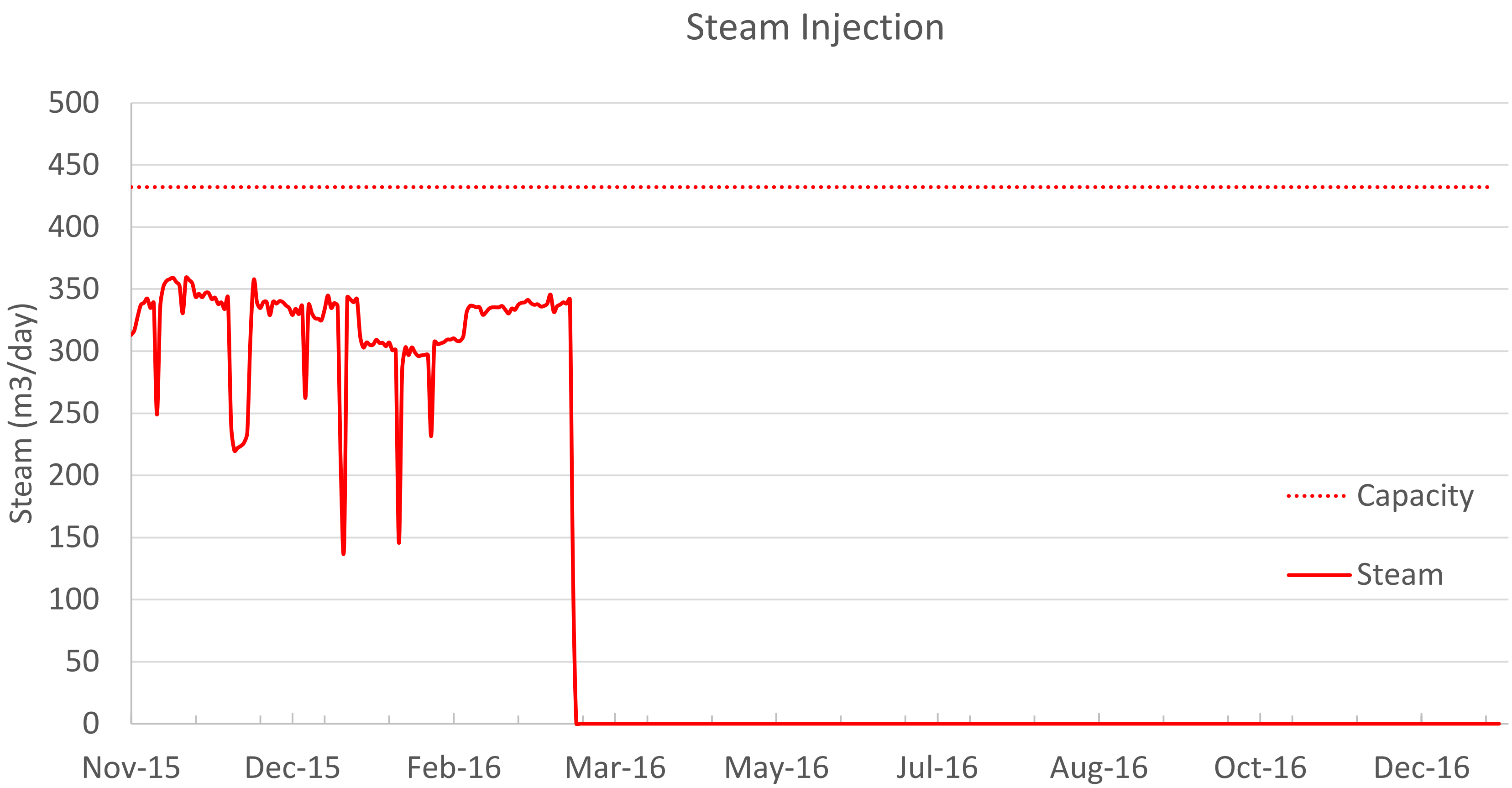
2016 Production = ~163.5 bbls/day

Production Jan – May 2016 = 375.4 bbls/d

Pilot Plant Performance Produced Water

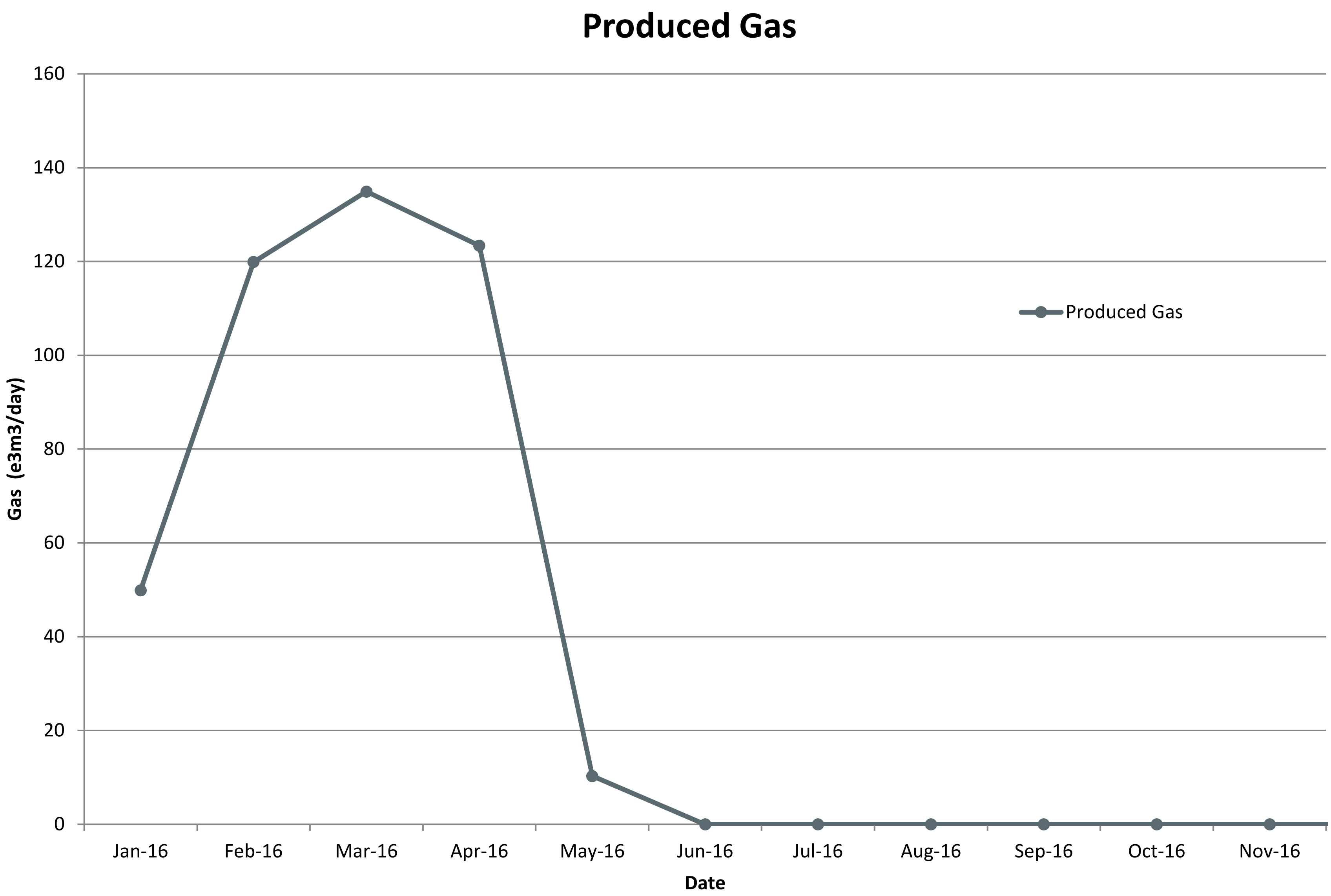


Pilot Plant Performance Steam Generation

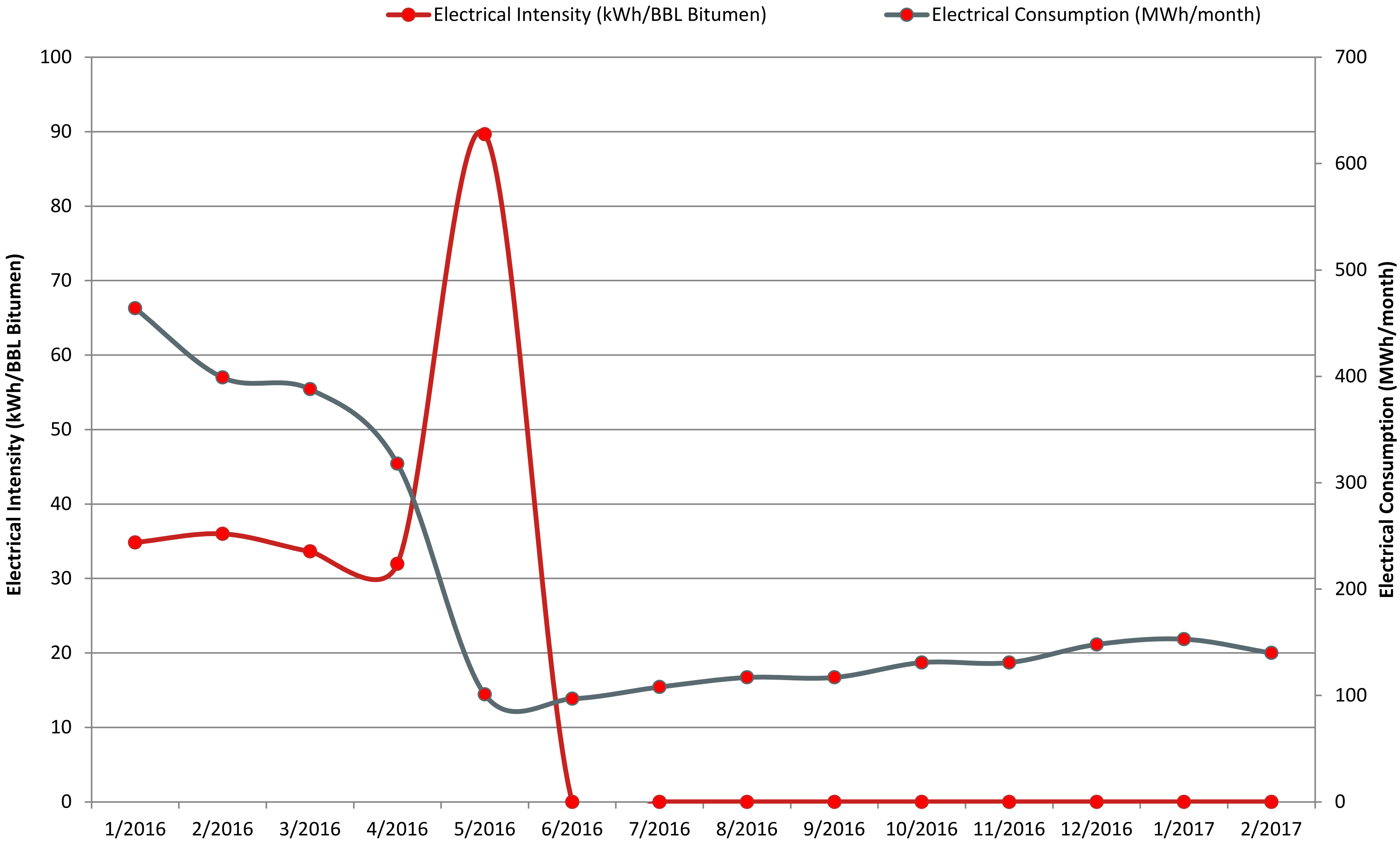


- Steam injection ceased on March 17th, 2016
- Blowdown monitoring began

Pilot Plant Performance Produced Gas



Facility Performance: Electricity Consumption Surmont Pilot



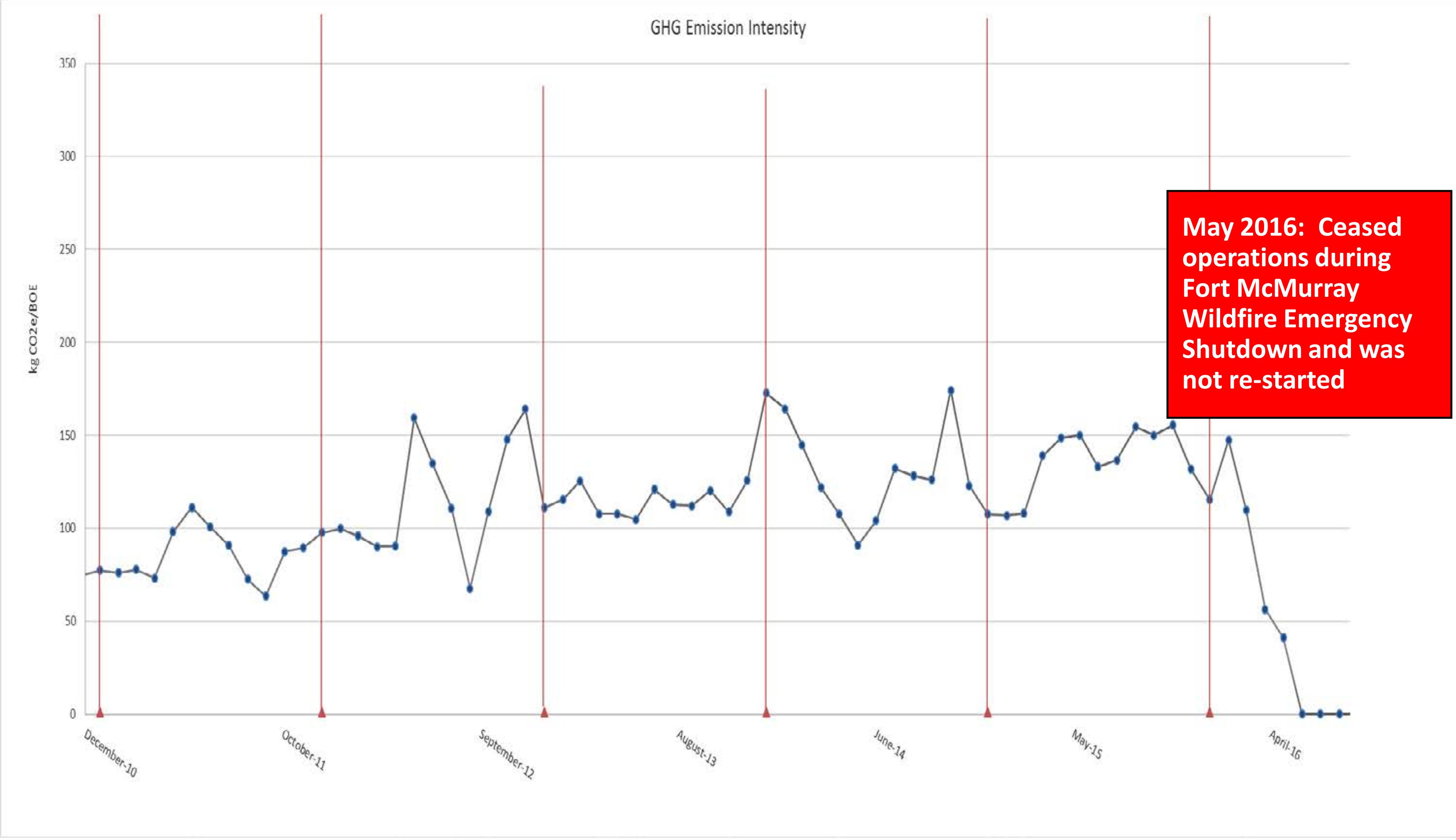
Pilot ceased operations in May due to Fort McMurray Wildfire.

Pilot Plant Performance: Gas Usage

	TCPL Gas Imports (10^3m^3)	Produced Gas (10^3m^3)	Flared Gas (10^3m^3)	% of Produced Gas Recovery
2011	8,068.6	1,339.2	2.4	99.8%
2012	9,727.7	2,947.5	2.5	99.9%
2013	11,828.3	3,229.2	85.4	97.4%
2014	10,511.0	1,152.0	31.7	97.2%
2015	9,228.8	697.4	7.3	99.0%
2016	2,421.6	438.4	204.3	53.4%
2017	-	-	-	

Pilot Plant ceased operations in May 2016.
Volume displacement due to decommissioning of the Plant extended to December 2016.

Pilot Plant Performance: Greenhouse Gas



May 2016: Ceased operations during Fort McMurray Wildfire Emergency Shutdown and was not re-started

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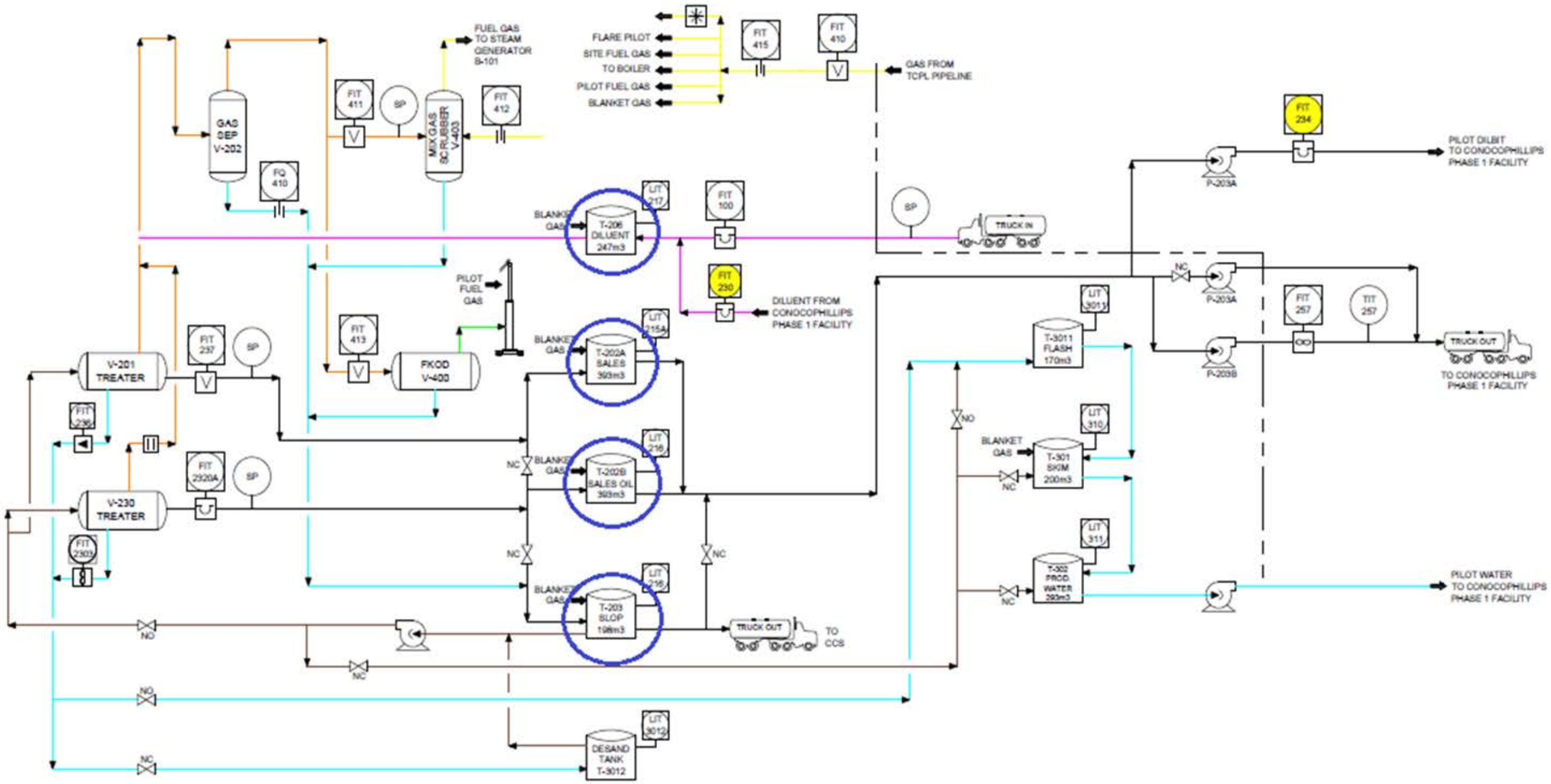
Measurement and Reporting

Subsection 3.1.2 (3)

Bitumen Measurement and Reporting



Battery Actual Bitumen Production:

[Closing Inventories – Opening Inventories (Oil portion of Sales and Slop)]/Shrinkage Factor – Diluent Received + [Closing Inventories – Opening Inventories (Diluent)] + [Closing – Opening (Injected Fluids into Producers)] + Sales Shipped to S1 and Trucked

Battery Estimated Bitumen Production:

Well bitumen production is calculated from well tests (pro-rated battery)

No changes to accounting formula

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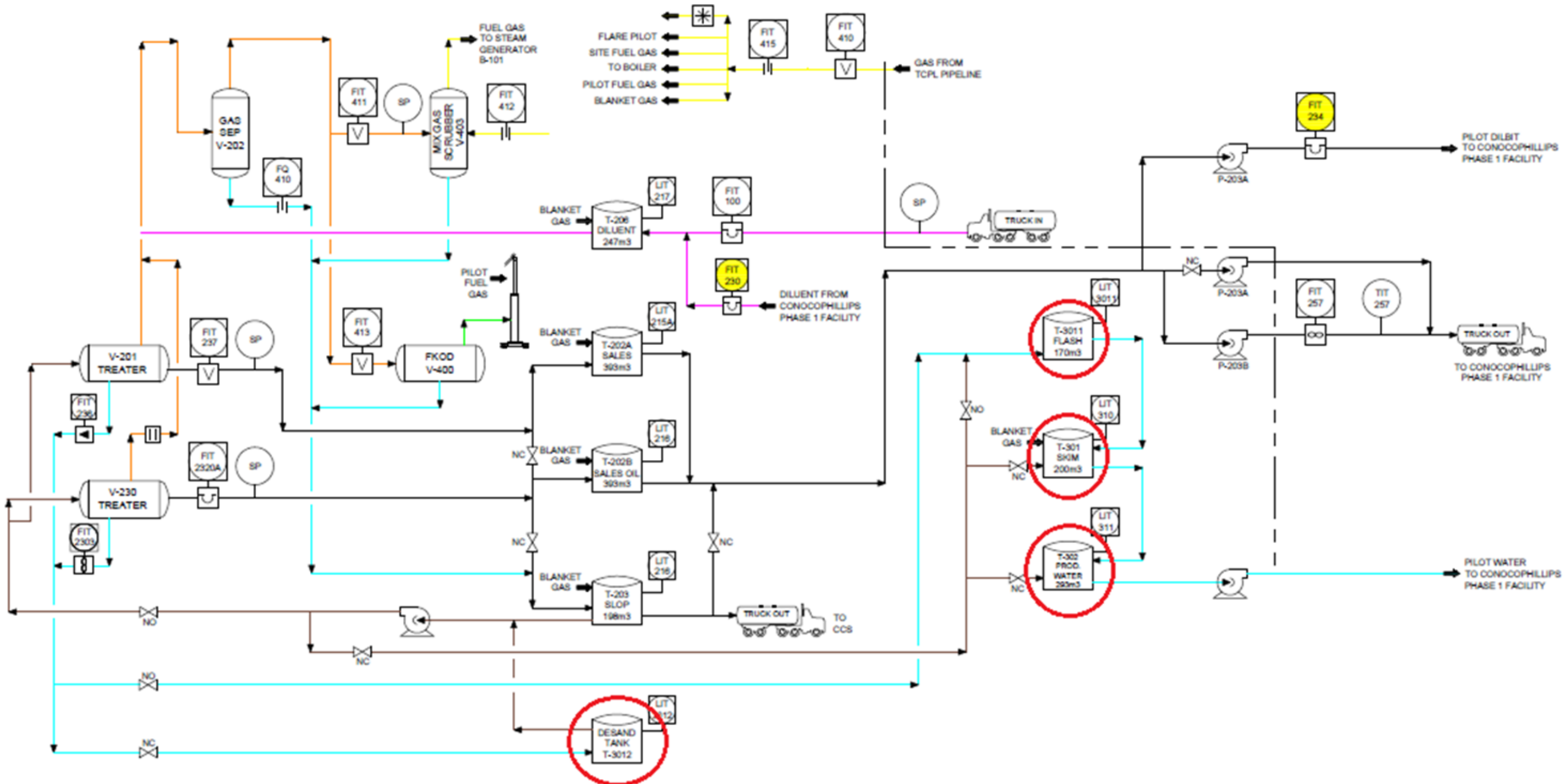


Water Production:

[Closing inventories – Opening Inventories (Water portion of Sales, Slop, Flash, Skim and Produced Water)] – Water Content of Received Diluent or Oil + [Closing – Opening (Injected Fluids into Producers)] + Produced Water + Produced Water Truck Tickets + Water Content of Sales Oil

Battery Estimated Water Production:

Well water production is calculated from well tests (pro-rated battery)

No changes to accounting formula

Measurement and Reporting Methods

Production Gas

- Total battery gas production estimated from inlet of FKOD, Scrubber and P3 usage.
- Well gas production calculated from well oil production and GOR.
- GOR = battery gas production / battery bitumen production.
- Gas proration factor = total battery gas production / well test gas production.

Steam

- Steam injection metered individually at each well and allocated using the group steam injection meter.

Well Testing

- One well on test at a time.
- Target a minimum of two tests per well per month (24 hours in length).
- All well pairs tests regularly tested to meet minimum monthly target.

No changes to accounting formula

2016 Surmont Pilot Plant Highlights and Changes

- Surmont Pilot Plant was operating until the Fort McMurray Wildfire Emergency Shutdown in May 2016.
- In June 2016, a decision was made not to restart the Plant.
- Pilot production volumes displaced continued to be reported until December 2016.

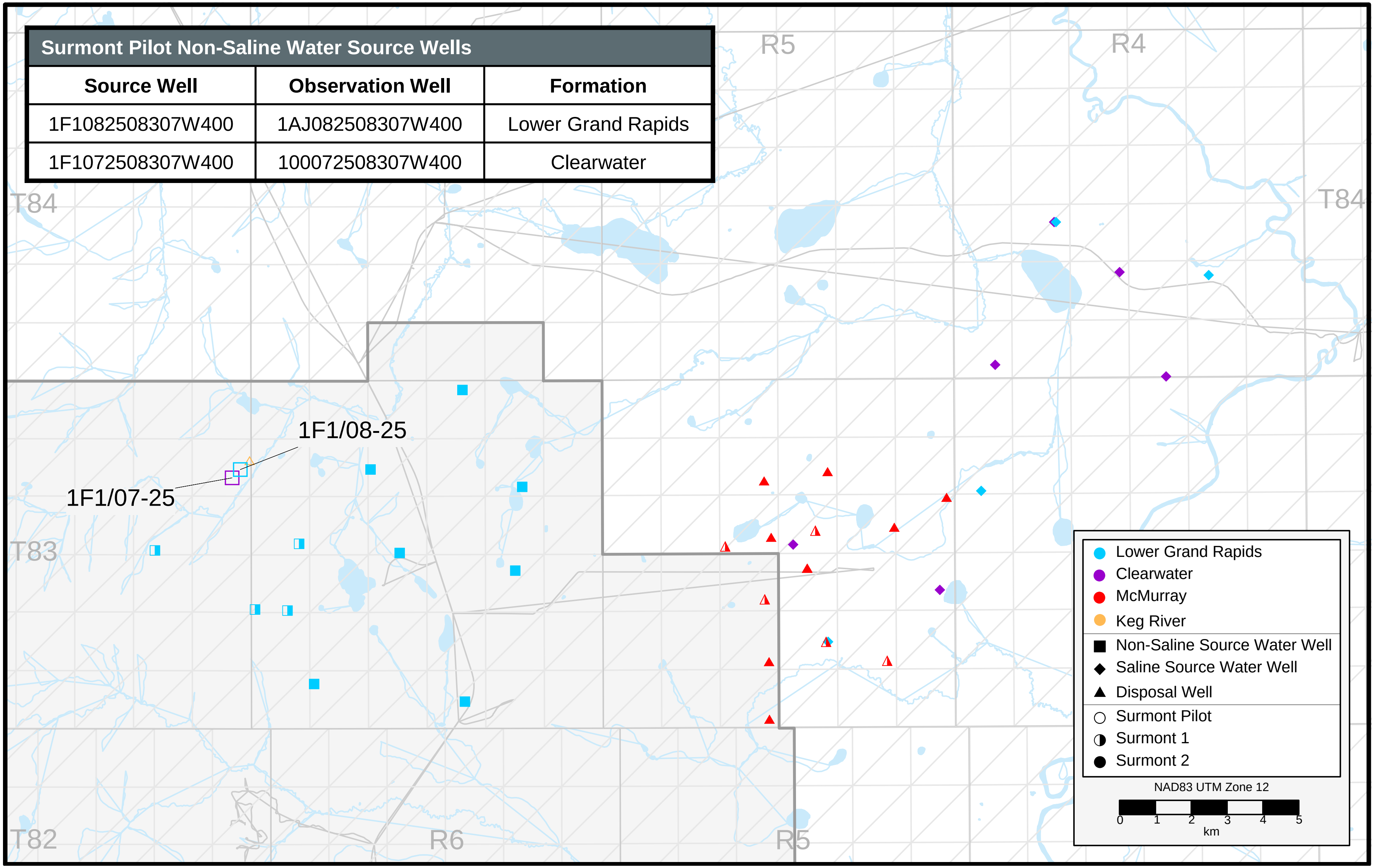
Water Production, Injection, and Uses

Subsection 3.1.2 (4)

Surmont Pilot Non-Saline Water Source Wells

Surmont Pilot Non-Saline Water Source Wells

Source Well	Observation Well	Formation
1F1082508307W400	1AJ082508307W400	Lower Grand Rapids
1F1072508307W400	100072508307W400	Clearwater



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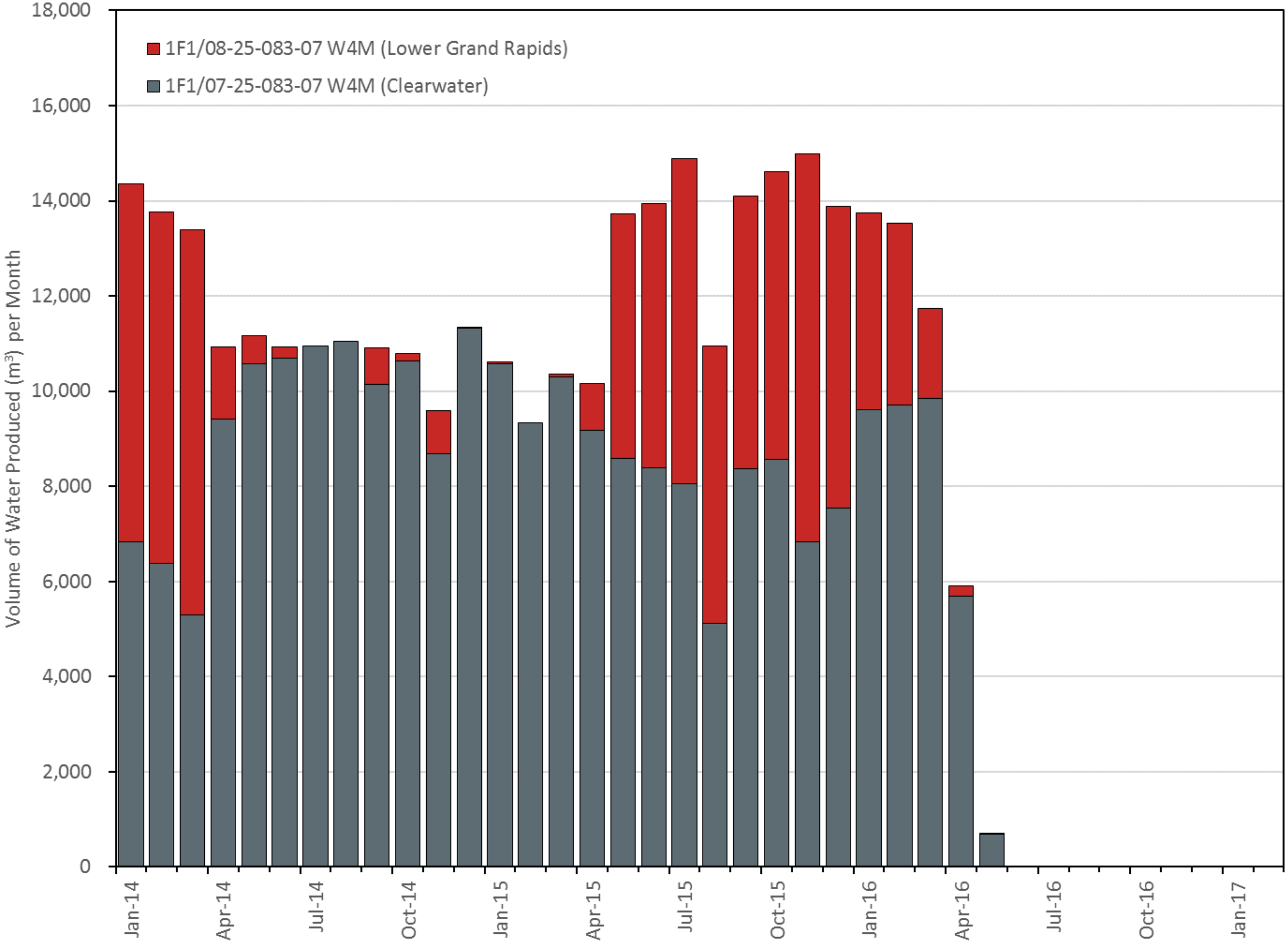
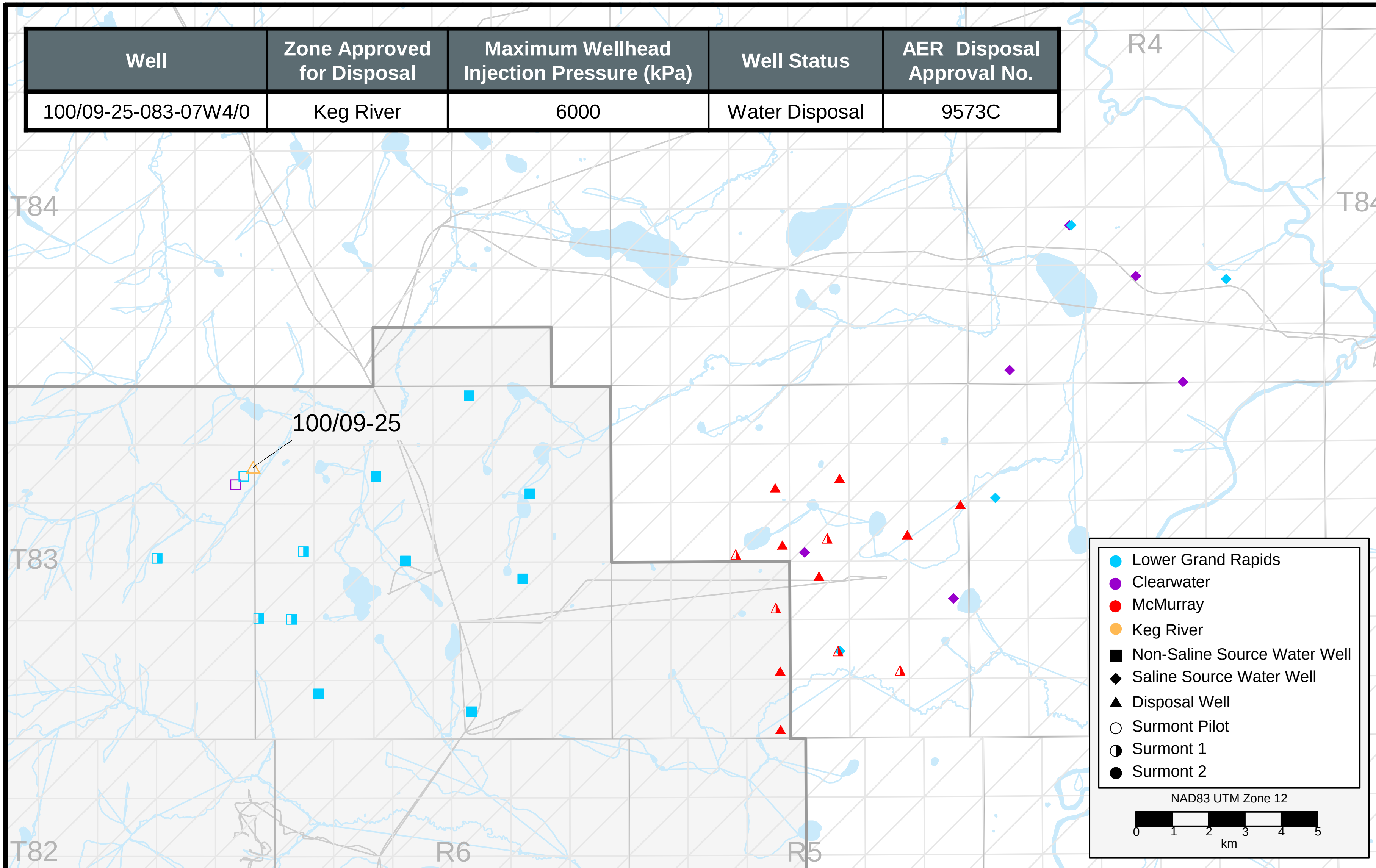
Pilot Water Source Wells Production Volumes

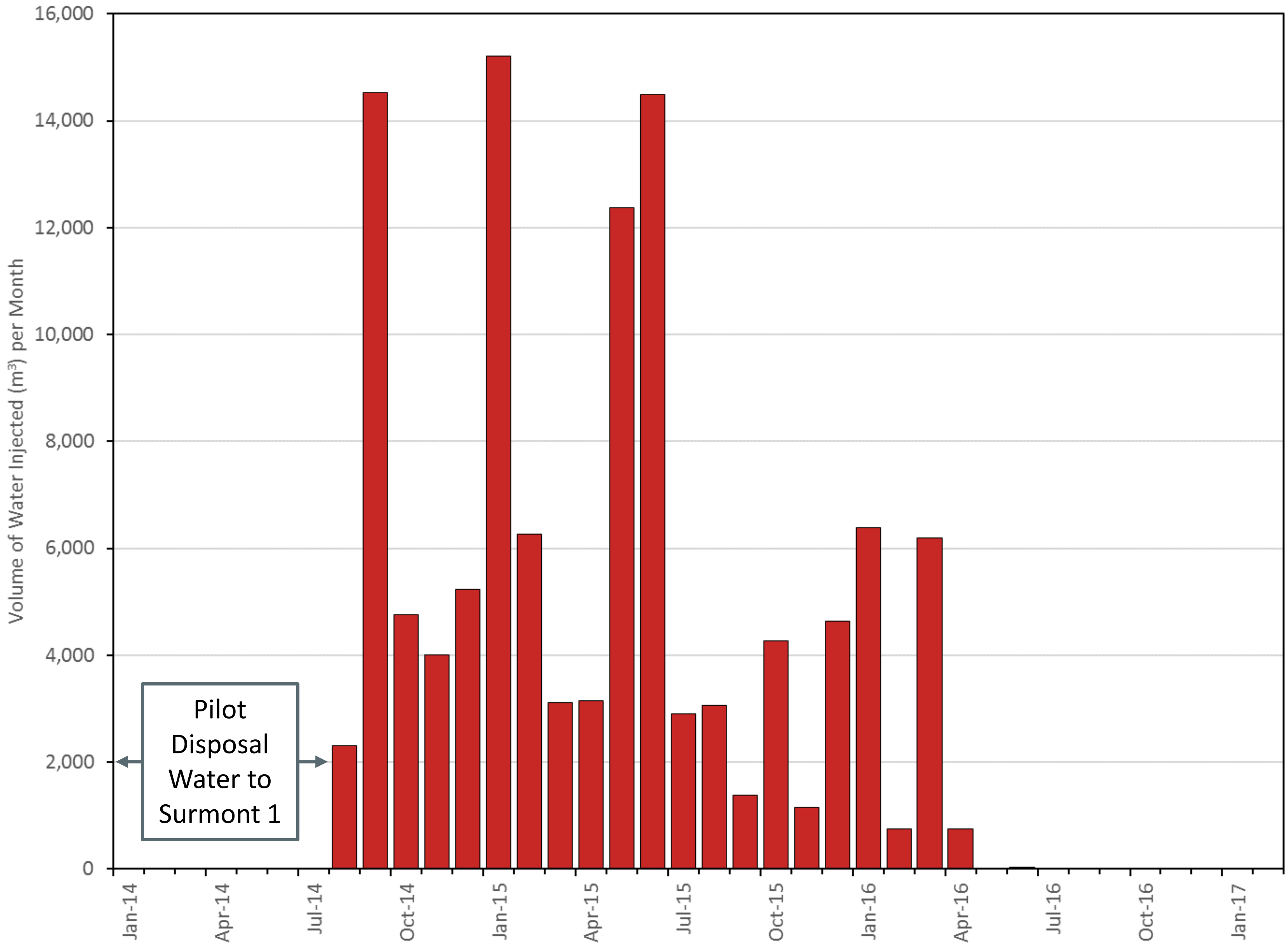


Surmont Pilot Water Disposal Well

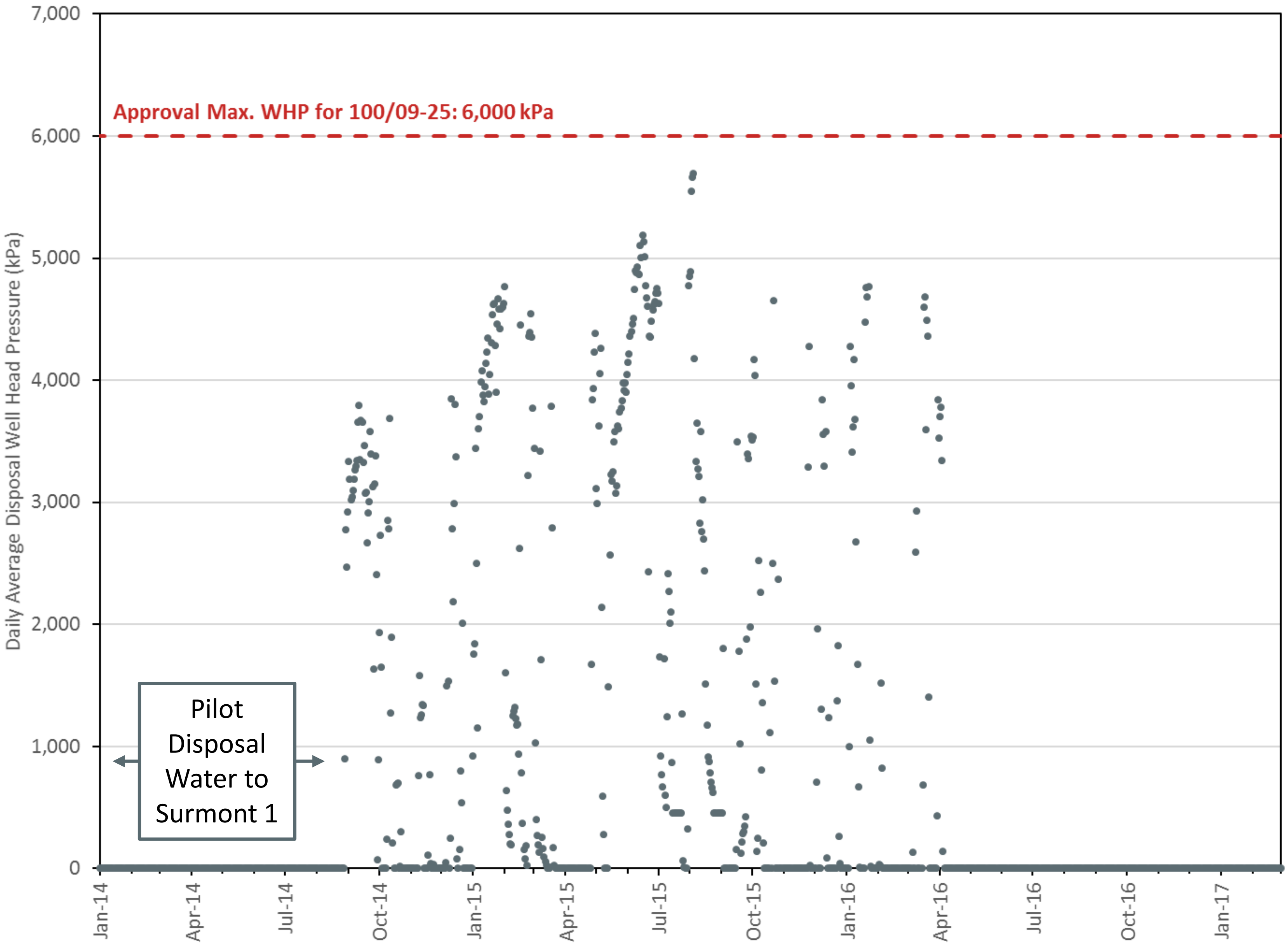
Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/09-25-083-07W4/0	Keg River	6000	Water Disposal	9573C



Pilot Water Disposal Well 100/09-25-083-07 W4M Injection Rate (Keg River)



Pilot Water Disposal Well 100/09-25-083-07 W4M Well Head Pressure (Keg River)



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Waste Disposal & Recycling

Solid Waste

Waste Description	Disposal Weight (kg)	Disposal Method
Recycled Materials	25	Recycled
Dangerous Oilfield Waste	4	Landfill
Non-Dangerous Oilfield Waste	25	Landfill

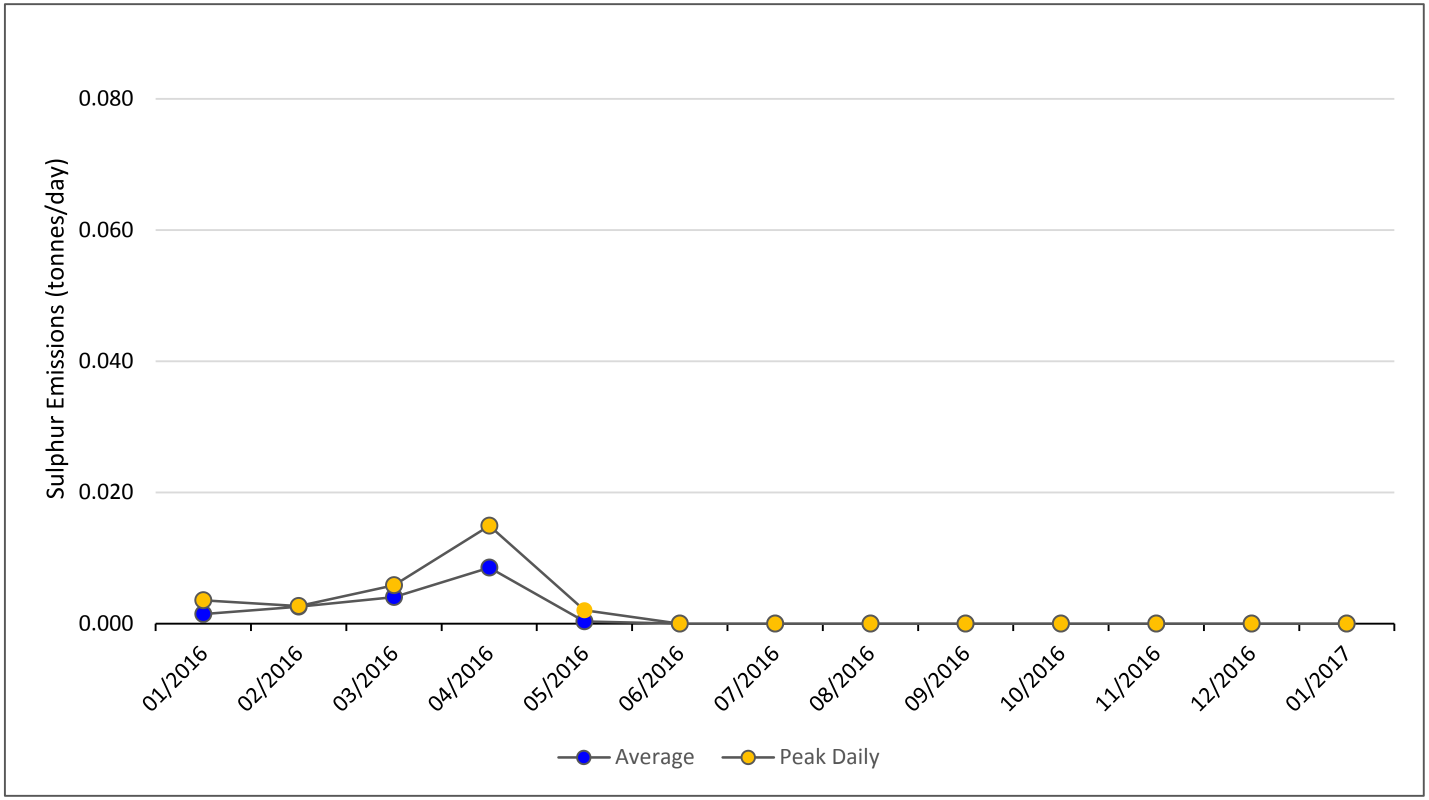
Fluid Waste

Waste Description	Disposal Volumes (m^3)	Disposal Method
Dangerous Oilfield Waste	208	Cavern
Non-Dangerous Oilfield Waste	1,039	Cavern

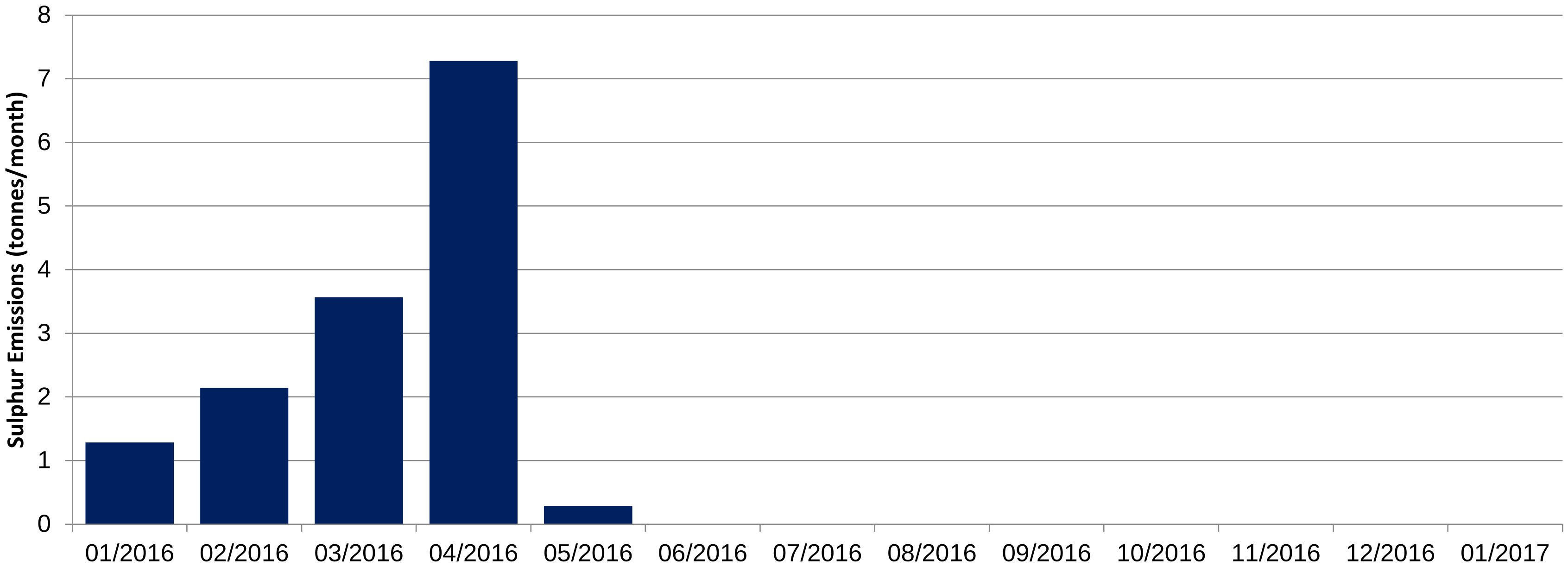
Sulphur Production

Subsection 3.1.2 (5)

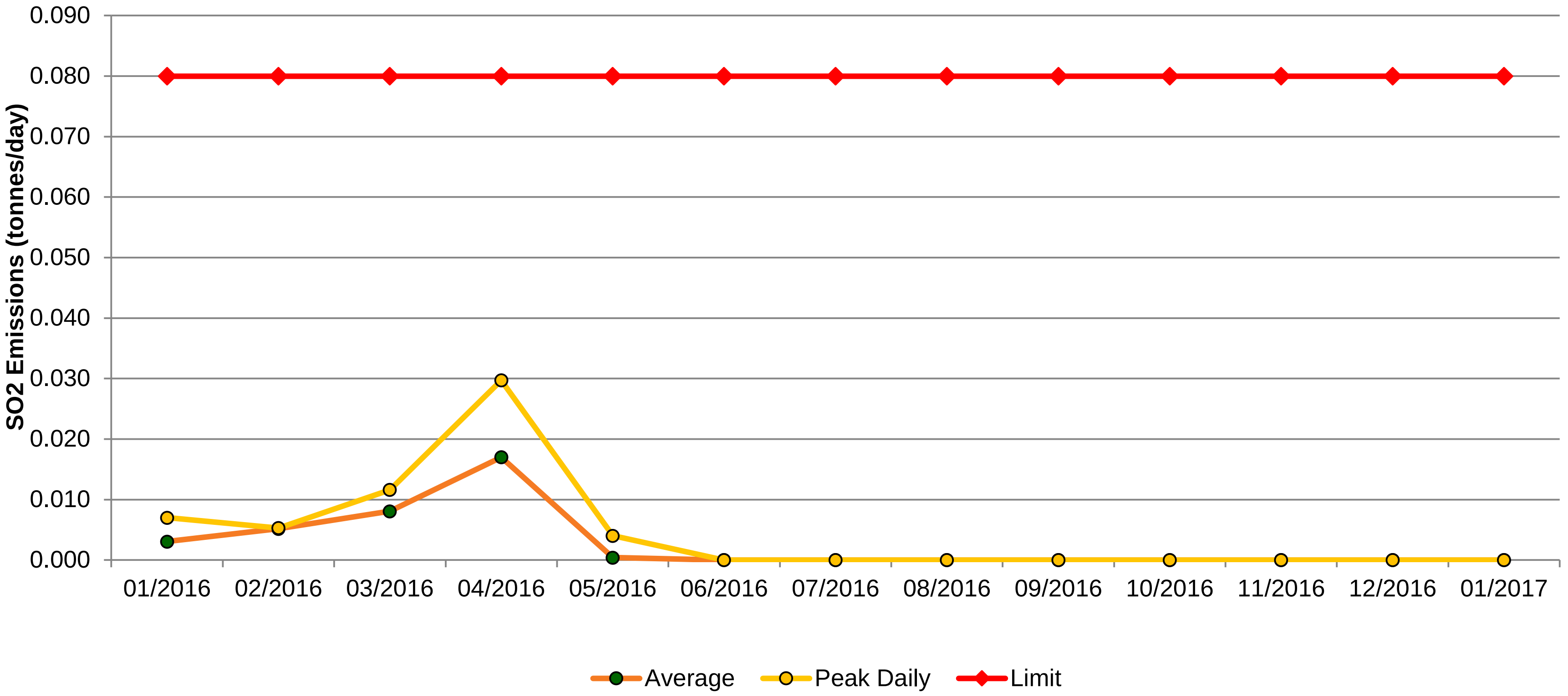
Daily Sulphur Emissions



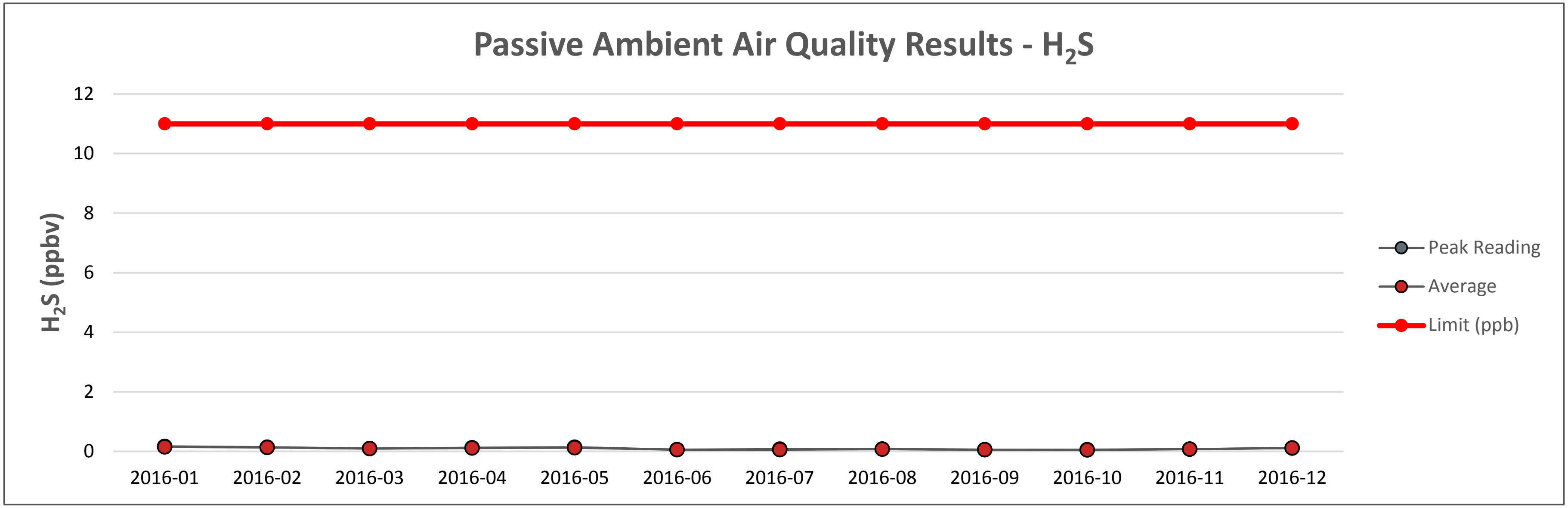
Monthly Sulphur Emissions

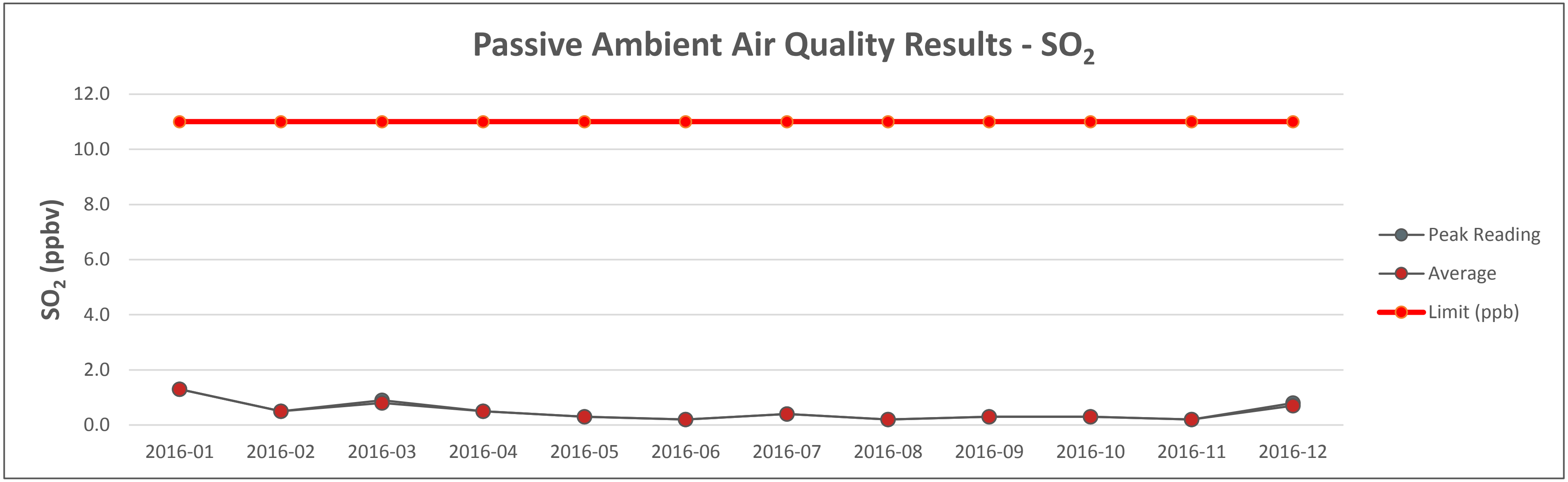


Daily SO_2 Emissions



Ambient Air Quality Monitoring





Environmental Compliance

Subsection 3.1.2 (6)

Environmental Compliance

Groundwater Monitoring

- 2016 results have changed from background in some wells. No changes have been observed in downstream surface water chemistry.

Soil Monitoring

- 2016 results within historical/background concentrations.

Reclamation Programs

- No reclamation in 2016

Compliance Confirmation and Non Compliances

Subsection 3.1.2 (7) + (8)

Compliance Confirmation and Non Compliances

ConocoPhillips Canada is in compliance in all areas of the regulations for 2016.

Flaring during Blowdown Phase

- D60 flaring variance application was submitted in March 2016.
- AER responded that an approval letter was not required to flare during blowdown phase.

Notification of Shut-in

- Originally we submitted a notification letter stating a June 15th shut-in.
- Following the wildfires in May, we submitted an update informing that the pilot would not start up post fire.

Future Plans

Subsection 3.1.2 (9)

Future Plans

- Suspension of the Pilot Plant was completed in November 2016 leaving the facility in a safe and secure state.
  - All pipelines were discontinued and have been purged, cleaned and blinded.
  - All 6 wells were downhole suspended.
- A Decommissioning and Land Reclamation Plan was submitted to the AER in December 2016 and approval is pending.
- Logging data will continue to be collected up to 2020.
- Decommissioning and Land Reclamation activities at the Pilot Plant are scheduled to begin in 2020.