ConocoPhillips

Annual Surmont SAGD Performance Review Approval 9426

April 4, 2018

Calgary, Alberta, Canada

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Subsurface

Surface

ConocoPhillips

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. (ConocoPhillips) and TOTAL E&P Canada Ltd; operated by ConocoPhillips.

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 9426MM – June 14, 2017

- Application No. 1880767 - Temporary MOP Increase at DA 262-3 to address problem wells

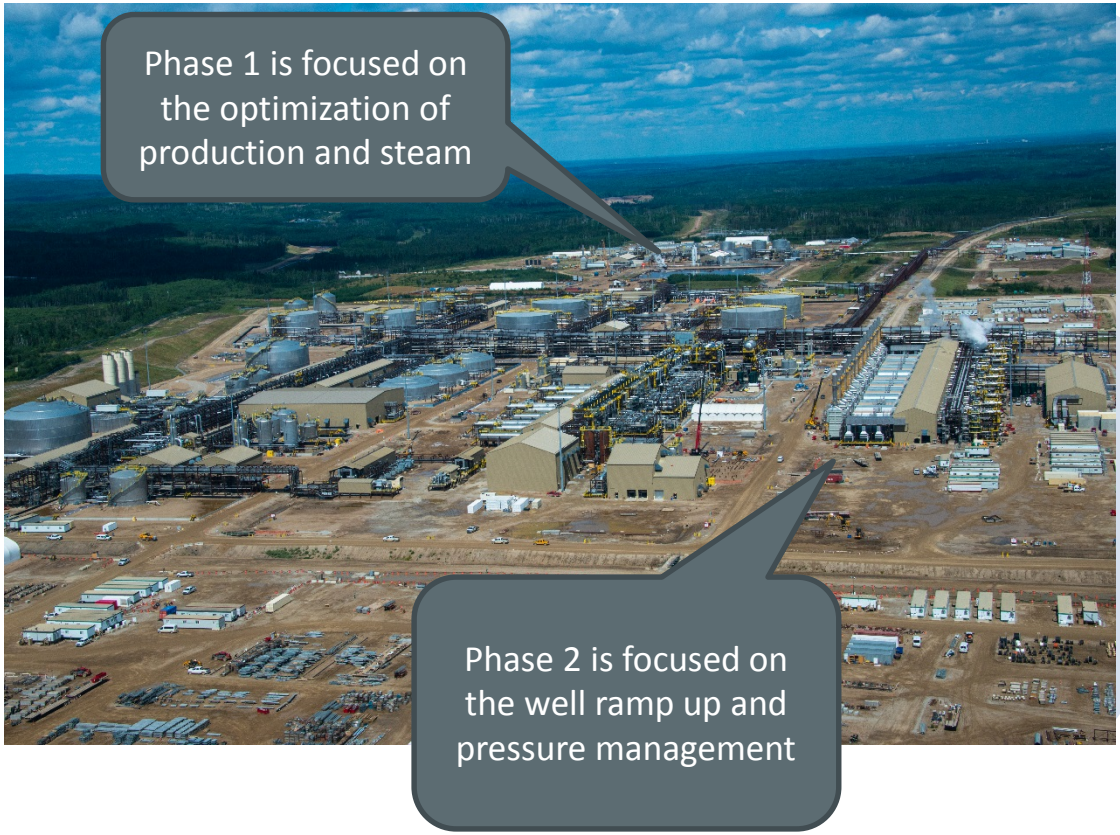
Approval 9426NN – February 1, 2018

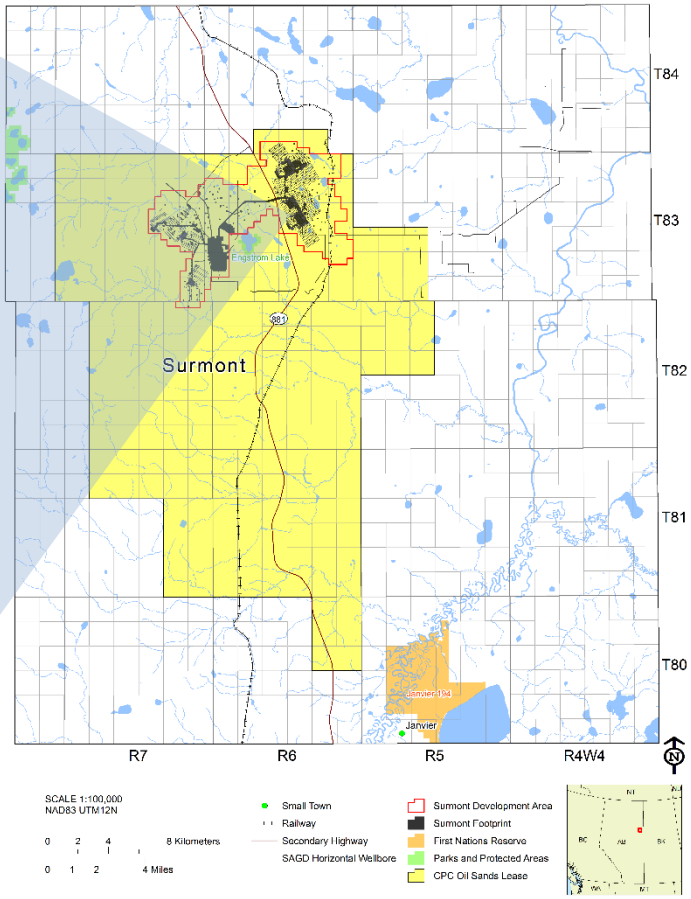
- Application No. 1902010 – NCG Co-injection at four Phase 1 DAs and eleven Phase 2 DAs
- Application No. 1903163 – MOP increase at six Phase 2 DAs: 266-2, 263-2, 264-2, 263-1, 264-1, and 103

Approval 9426OO – March 23, 2018

- Application No. 1906715 – Alternate diluent project to enable the use of condensate

Surmont Overview



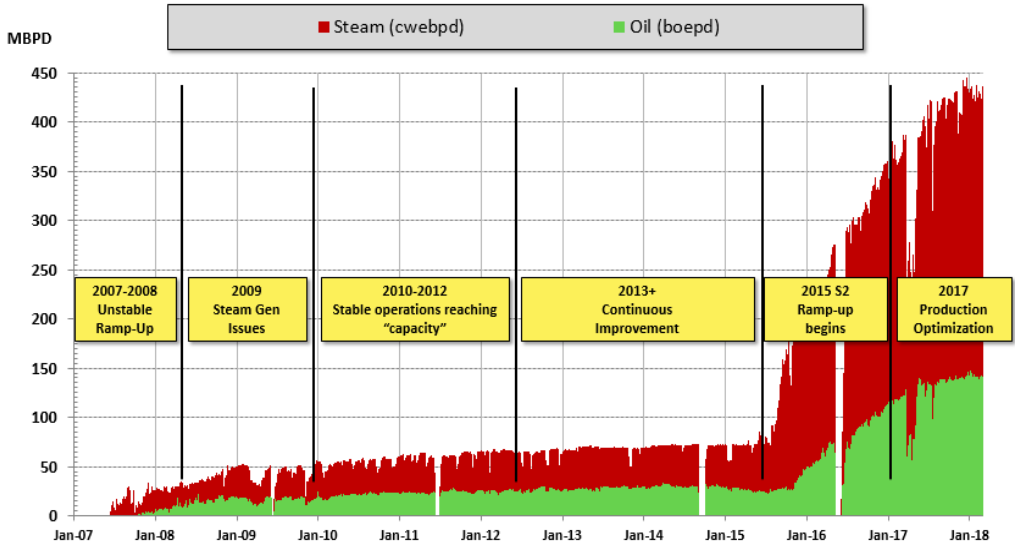


Currently in a "One Surmont" philosophy

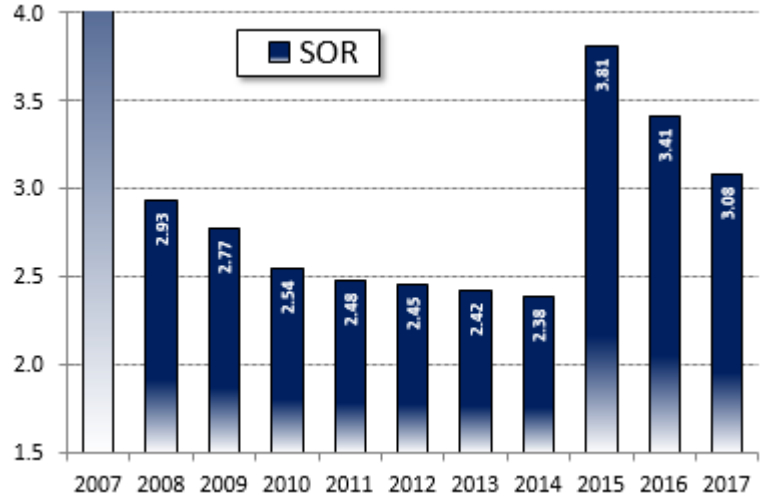
Surmont combined approved capacity is 29,964 m³/cd (188,700 bbl/cd)*
***(where cd is calendar day on an annual average basis)**

Surmont Performance

Historical Steam Injection and Bitumen Production



SOR



2017 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 wells.
- iSOR at February 28, 2018 is at an average 2.84.

Phase 2 continued ramp-up

- Tubing deployed flow control devices continued to strengthen Surmont oil output.
- Liner deployed flow control devices are confirming 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 original expectations. Evaluation of optimization opportunities continues.
- 266-2 pad start-up completed
- Forty-five ESP conversions were performed to enable pressure management strategy.
- iSOR at February 28, 2018 is at an average of 3.20.

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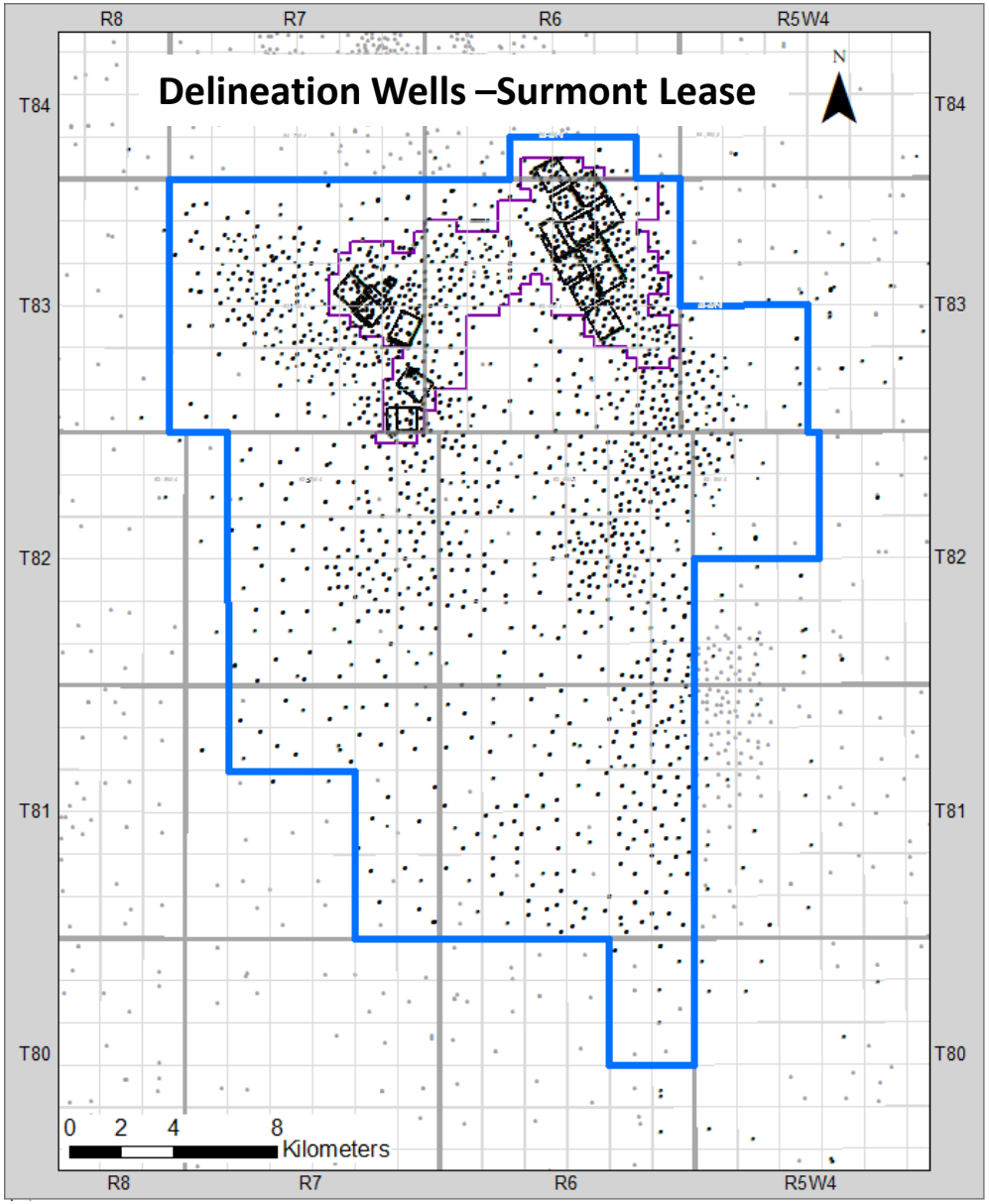
Subsurface Resource Evaluation and Recovery

Geology and Geoscience

Subsection 3.1.1 (2)

2017-2018 Delineation Campaign and Well Density



Surmont Lease as of March 1, 2018

1531 existing wells

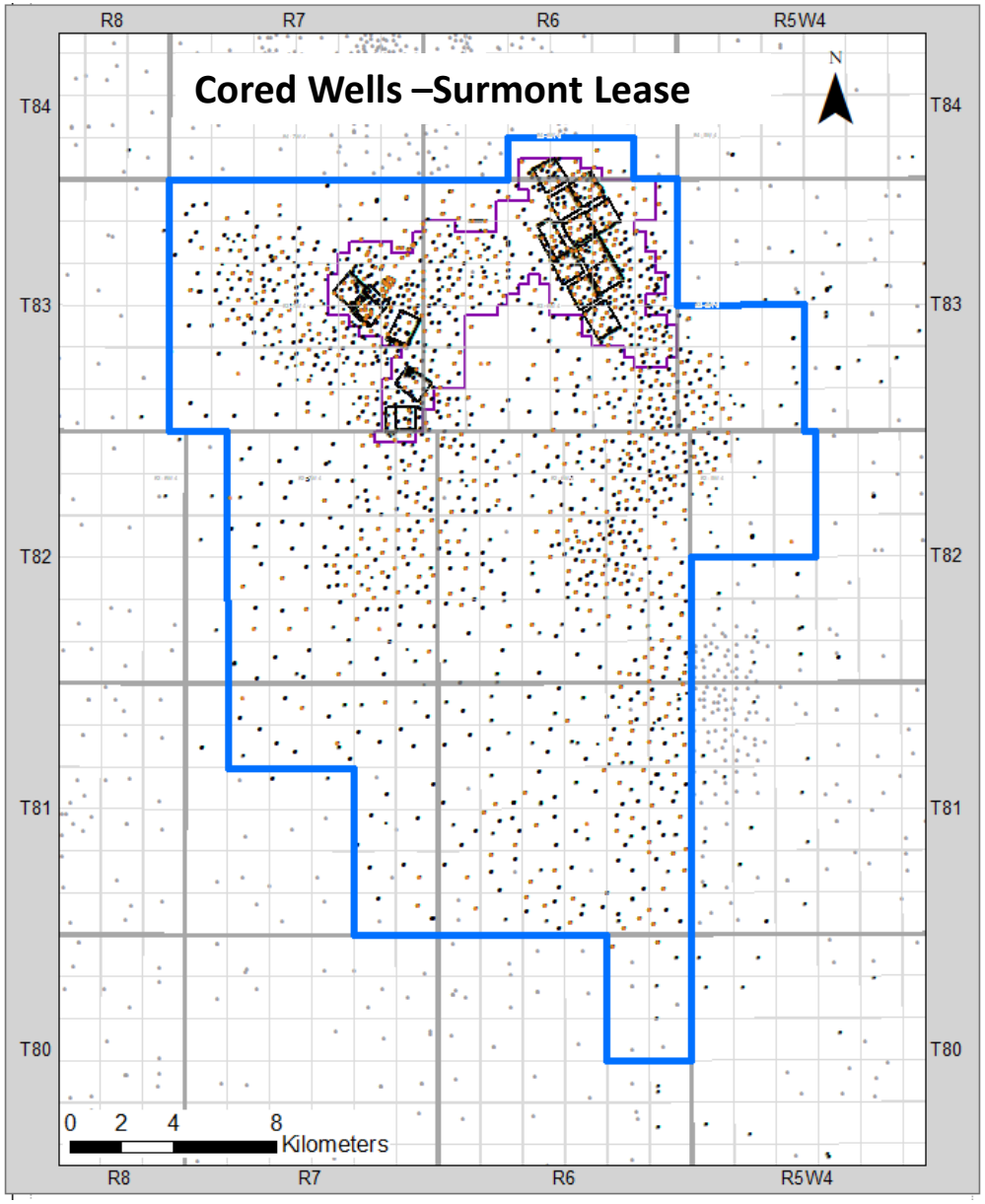
Phase 1 and Phase 2 Development Area

Drainage Areas

Surmont leases

No new wells were drilled between Mar 1, 2017 to Mar 1, 2018

2017-2018 Delineation Campaign and Core Density



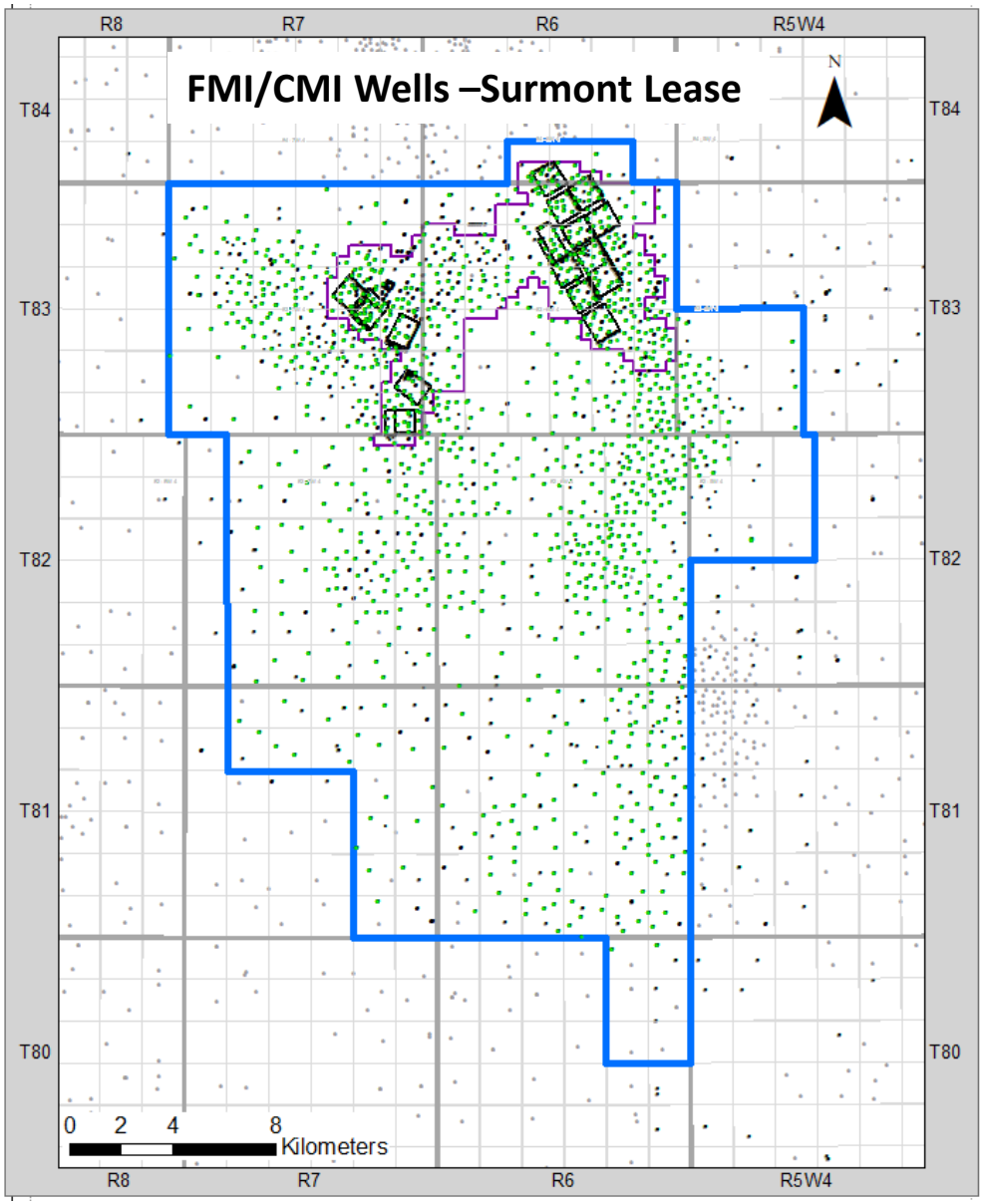
Surmont Lease as of March 1, 2018

- **1531 wells total**
- **549 existing core wells**
- **Phase 1 and Phase 2 Development Area**
- **Drainage Areas**
- **Surmont leases**

No new cores were cut between Mar 1, 2017 to Mar 1, 2018

Last years presentation stated there were 6 new core from the 2016-2017 program, however, 1 core had been cancelled leaving only 5

2017-2018 Delineation Campaign and FMI/CMI Logs



Surmont Lease as of March 1, 2018

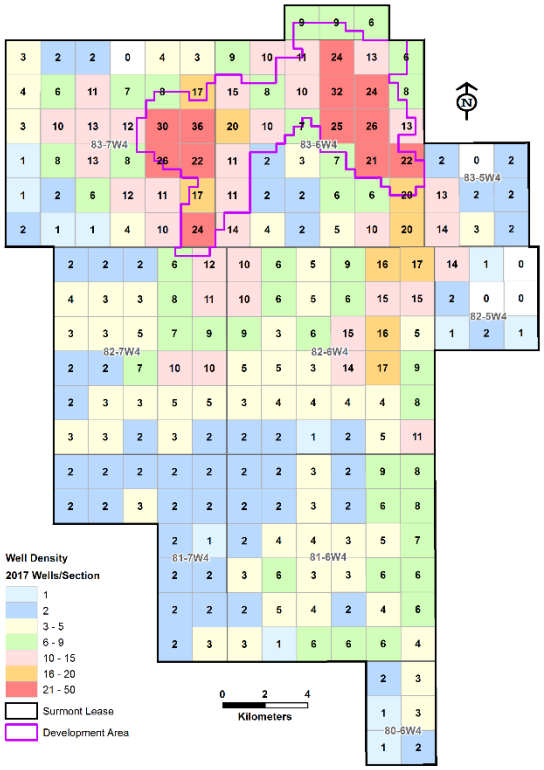
- **1531 wells total**
- **1154 existing FMI/CMI wells**
- **Phase 1 and Phase 2 Development Area**
- **Drainage Areas**
- **Surmont leases**

No new wells were drilled between March 1, 2017 and March 1, 2018; hence no FMI/CMI logs were taken

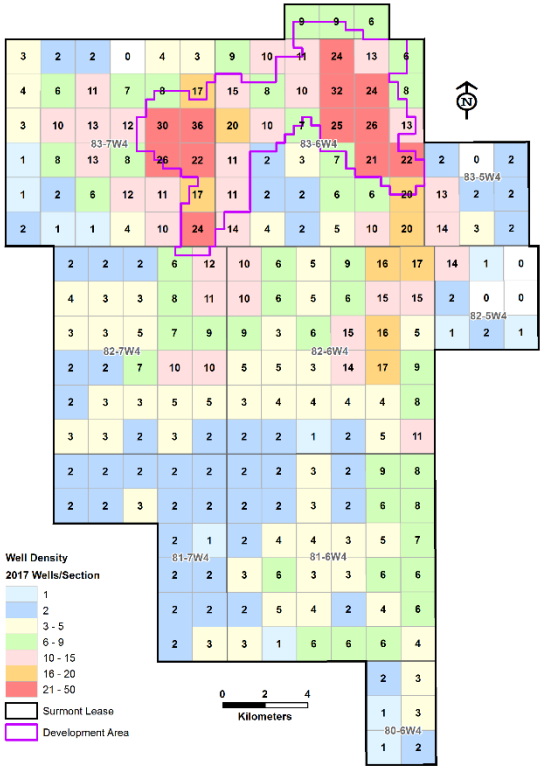
2017-2018 Delineation Campaign and Well Density

Delineation across Phases 1, 2, and 3

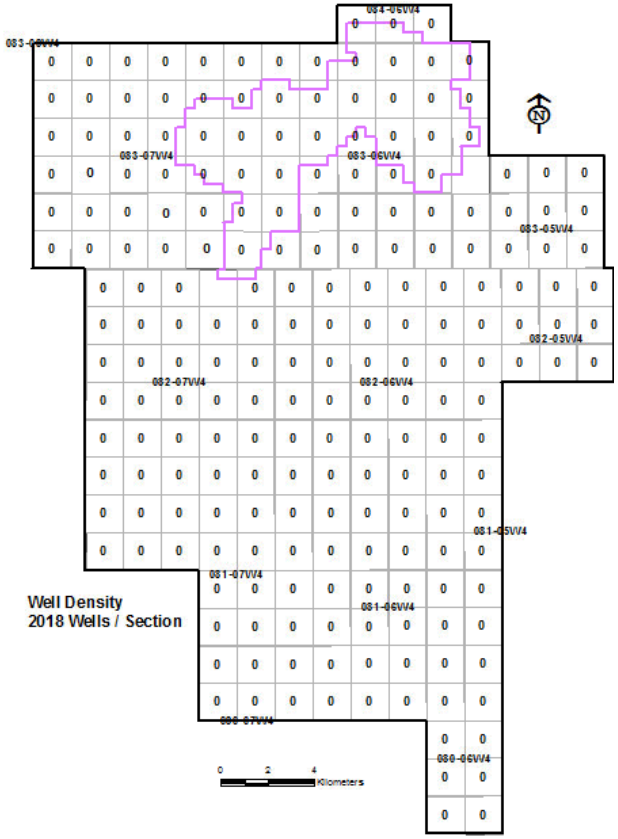
Delineation Well Density Map Mar 2017



Delineation Well Density Map Mar 2018



Density Map Difference

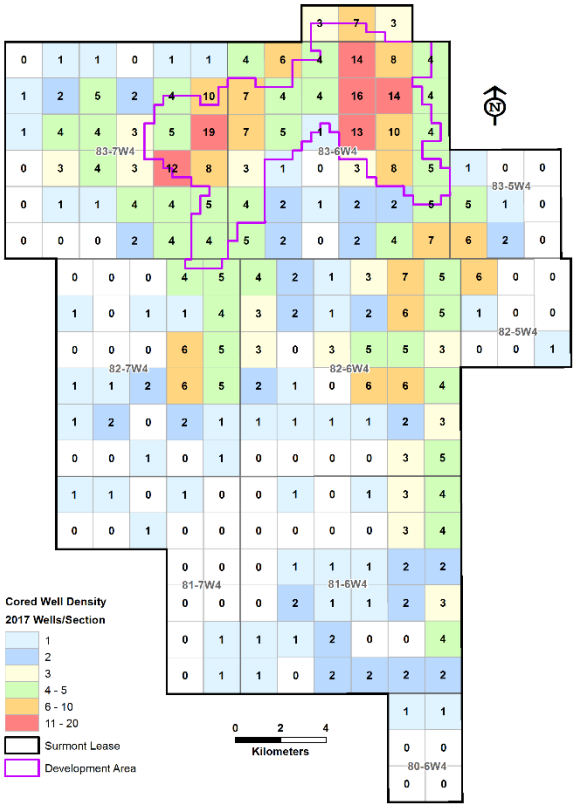


McMurray penetrated wells only

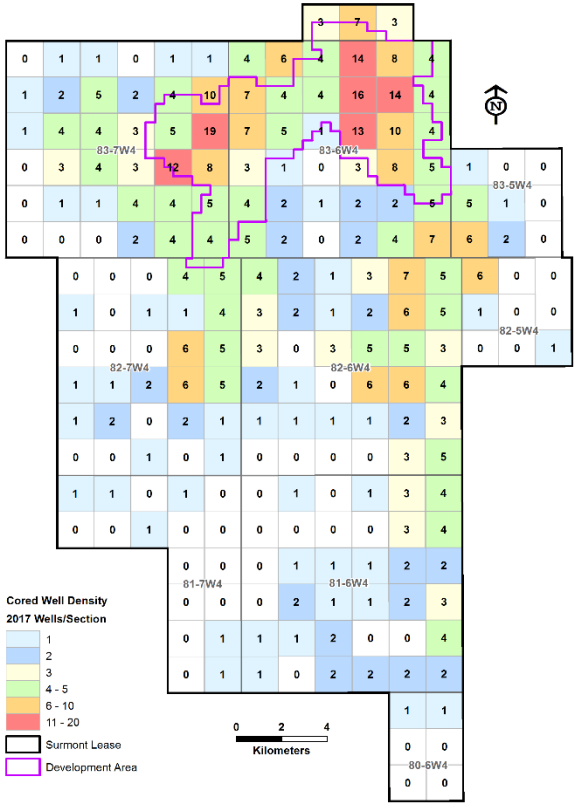
2017-2018 Delineation Campaign and Well Density

Increased core density with latest drilling

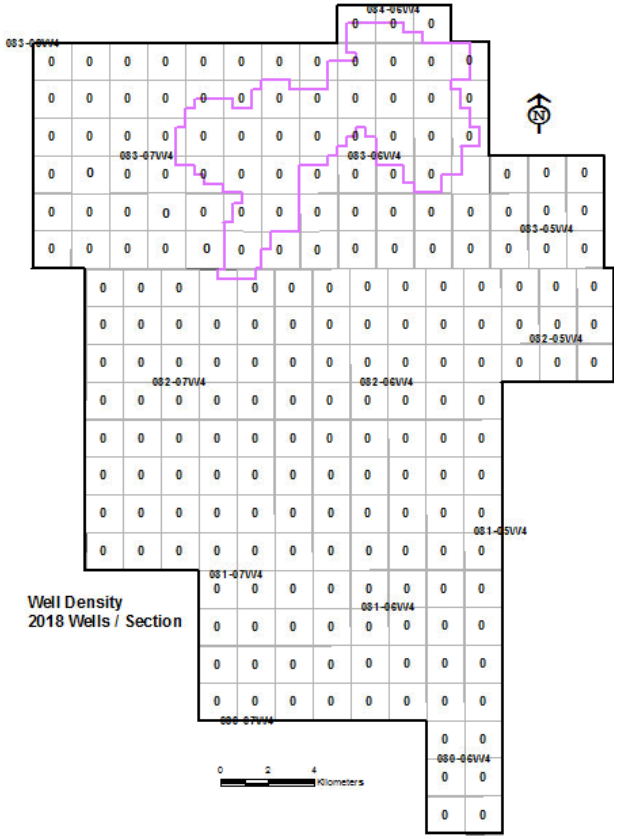
Cored Wells Density Map Mar 2017



Cored Wells Density Map Mar 2018



Cored Density Map Difference

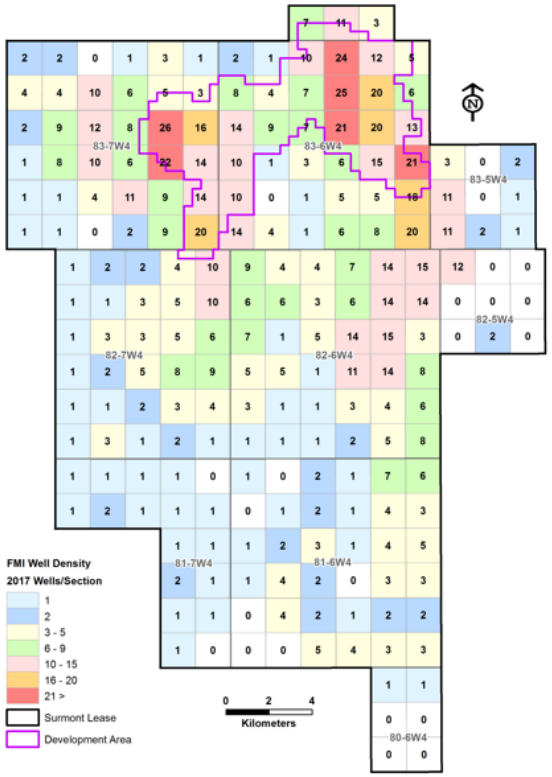


McMurray penetrated wells only

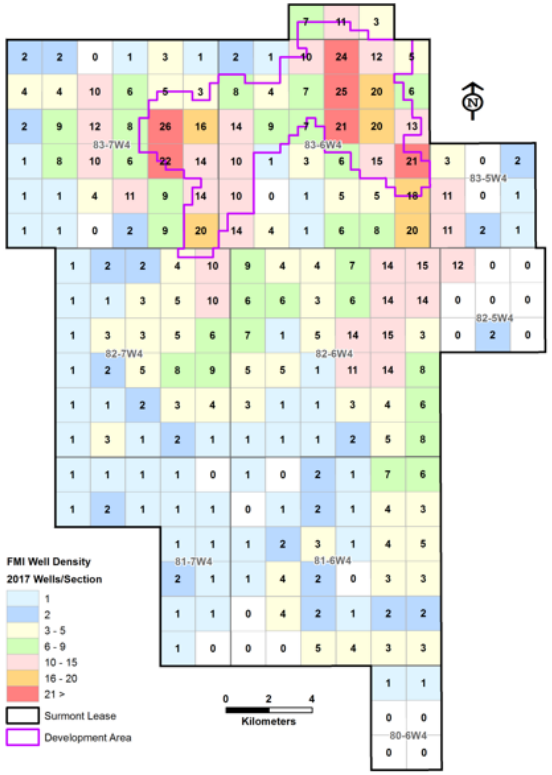
2017-2018 Delineation Campaign and Well Density

Increased Formation Micro Imaging density with latest drilling

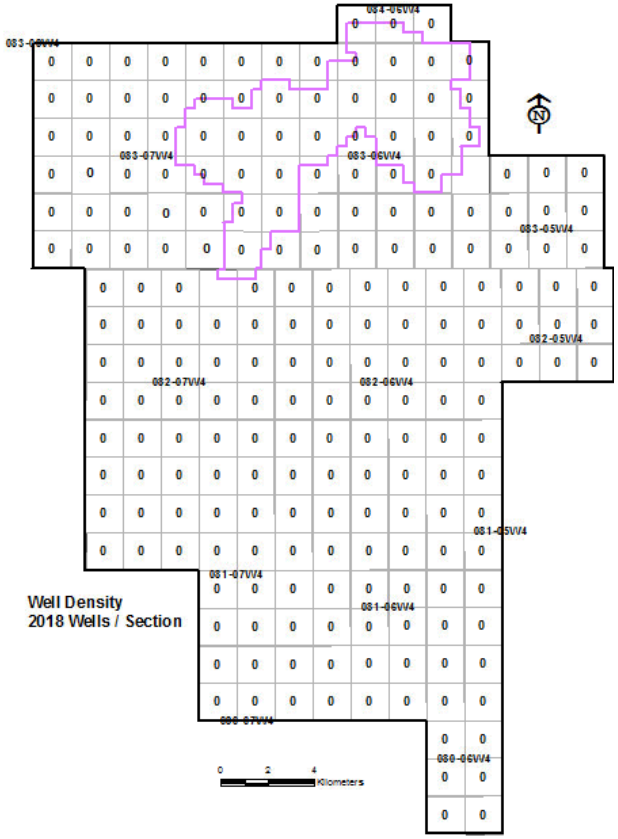
FMI Well Log Density Map
Mar – 2017



FMI Well Log Density Map
Mar - 2018

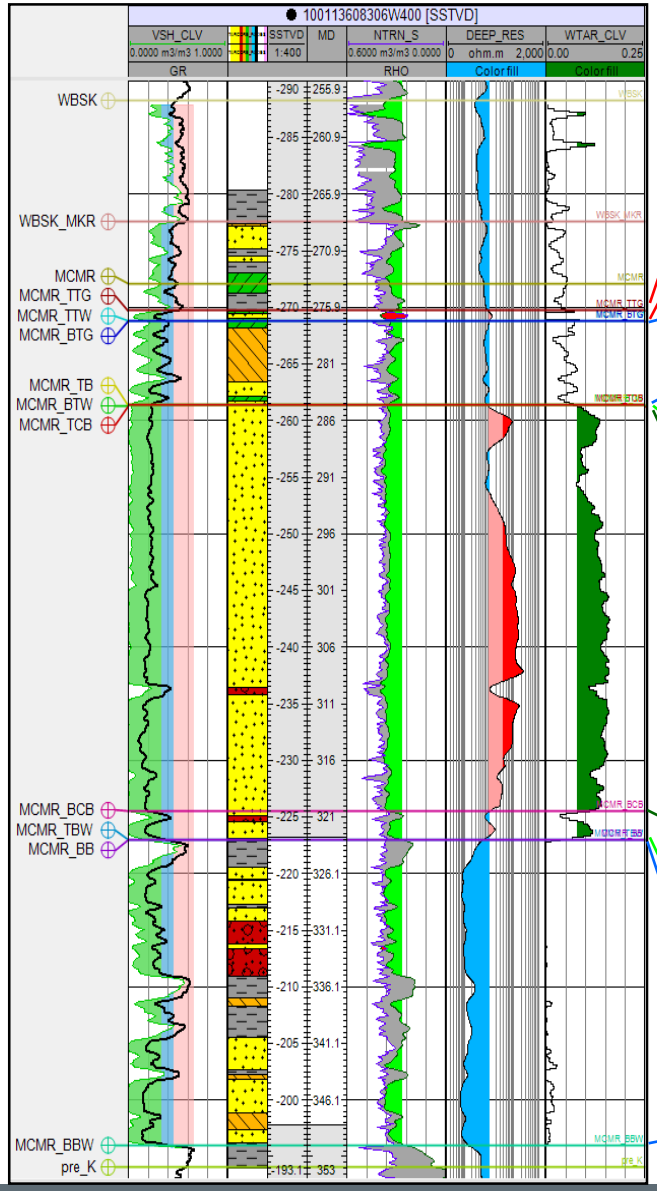


FMI Density Map Difference



McMurray penetrated wells only

INTERPRETTING SAGD INTERVAL



Fluid Surfaces

Top Gas Surface: The uppermost limit of gas-bearing sands

Bottom Gas Surface: The lowest occurrence of gas-bearing sands

Top Water Surface: The uppermost limit of water-bearing sands

Bottom Top Water Surface: The lowest occurrence of water-bearing sands above the bitumen

Top Bitumen Surface: The uppermost limit of bitumen-bearing sands with deep resistivity of 10 ohm or greater and a Vsh cutoff of less than 33%

Top Continuous Bitumen Surface (TCB): The uppermost limit of good reservoir, bitumen-bearing sands.

Base Continuous Bitumen Surface (BCB): The first occurrence of good reservoir, bitumen-bearing sands with deep resistivity of 40 ohmm or greater, or 8wt% bitumen.

Base Bitumen Surface: The lowest occurrence of bitumen-bearing sands with deep resistivity of 10 ohm or greater and a Vsh cutoff of less than 33%

Top Bottom Water Surface: The uppermost limit of water-bearing sands below bitumen

Bottom Water Surface: The lowest occurrence of water-bearing sands below the bitumen

Gross Fluids

Top Gas: Gross thickness of gas-bearing sands defined by the top and bottom gas surfaces

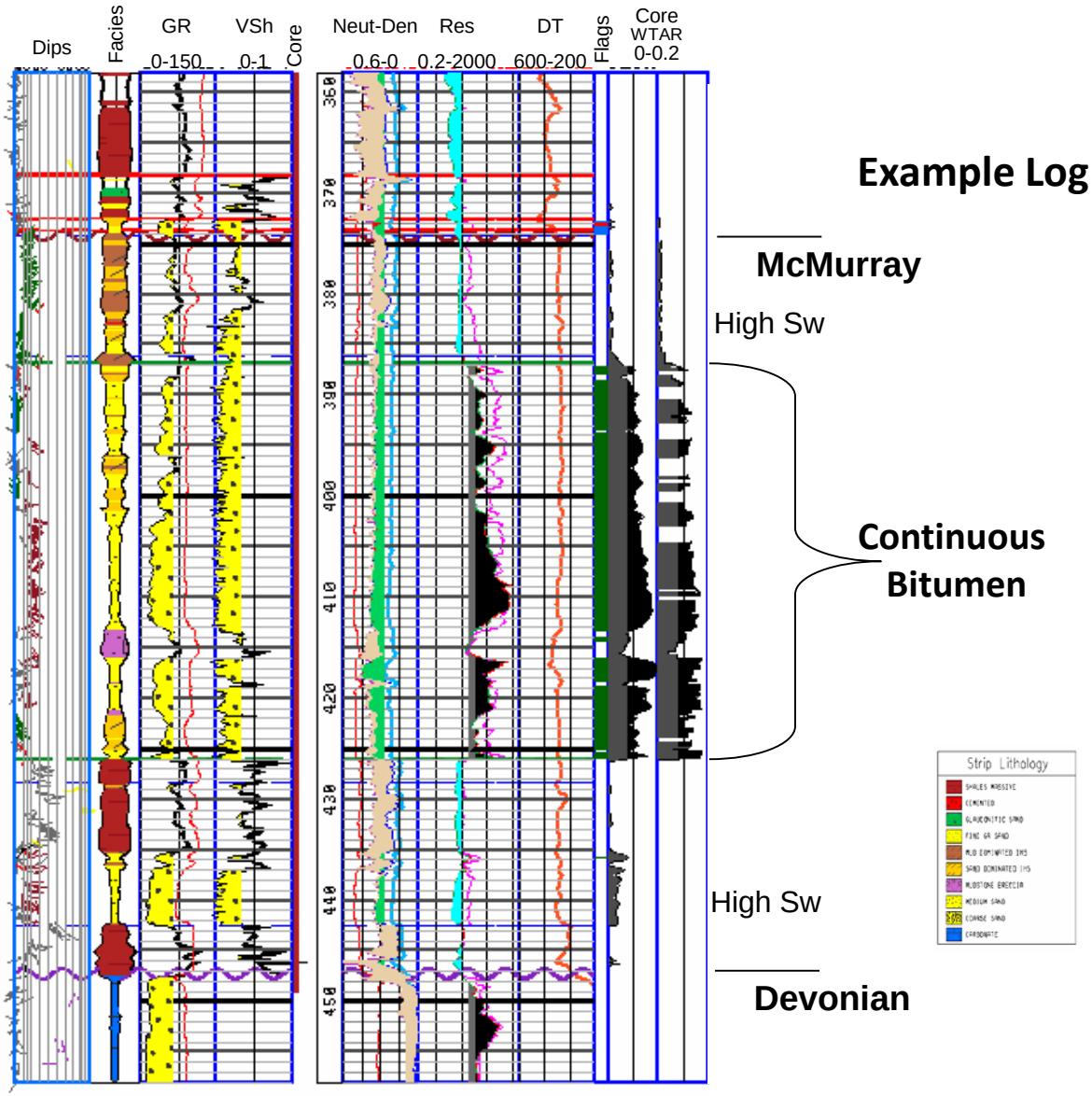
Top Water: Gross thickness of water-bearing sands defined by the top and bottom water surfaces

Continuous Bitumen / SAGD Interval
Gross thickness of continuous bitumen reservoir with deep resistivity of 40 ohmm or greater, and does not include continuous muds greater than 3m thick. SAGD interval would be from the producer level (approx. 5m above BCB) to the top of this zone.

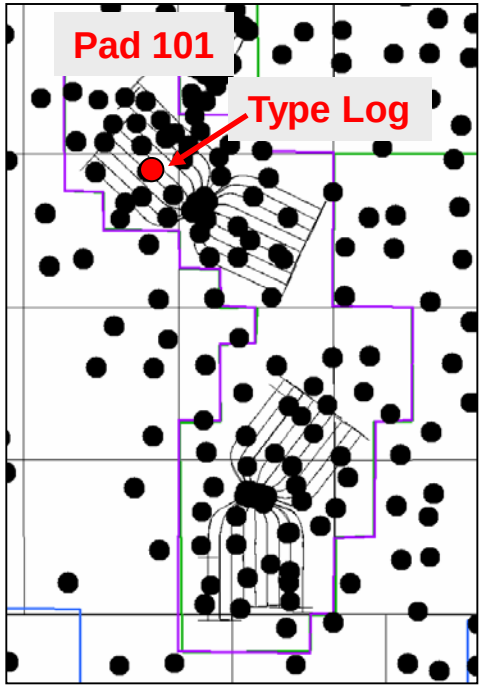
Bitumen: Gross thickness of bitumen-bearing sands defined by the top and base bitumen surfaces

Bottom Water: Gross thickness of water-bearing sands defined by the top and bottom water surfaces

Phase 1 Type Log Well Pad 101

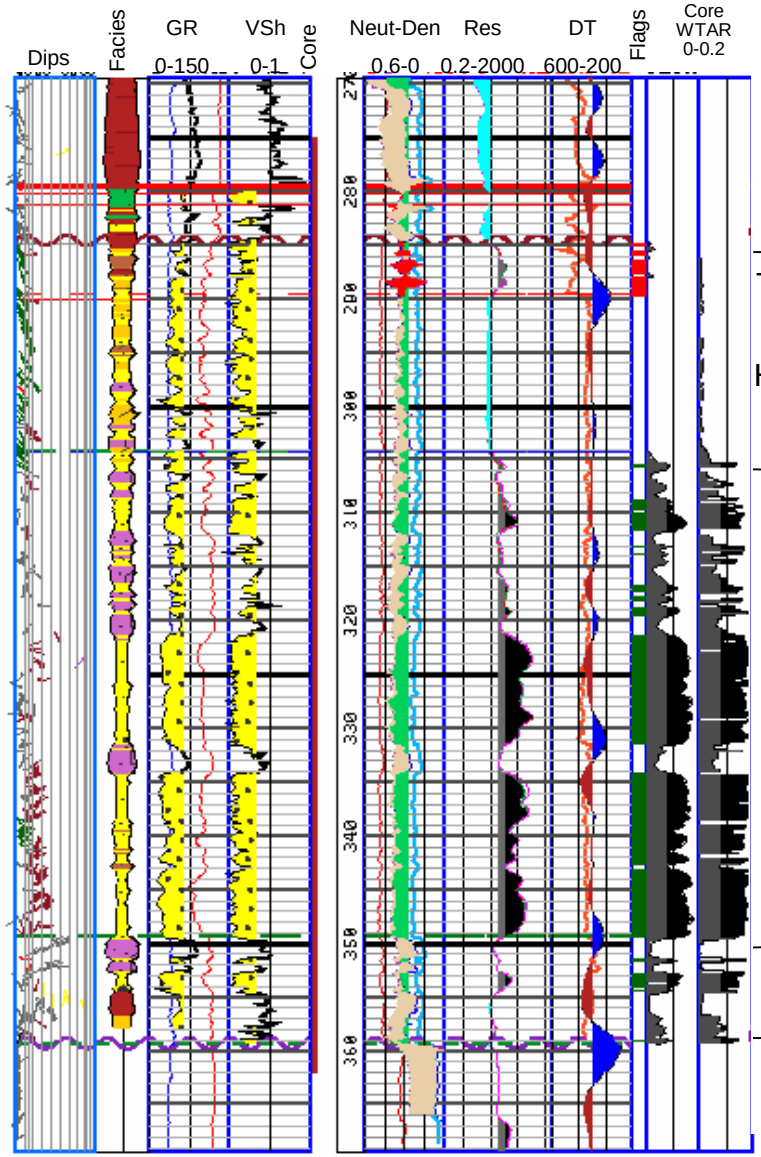


Example Log 100161408307w400



Phase 1 Area

Phase 2 Type Log – Well Pad 264-2



Example Log 100162208306w400

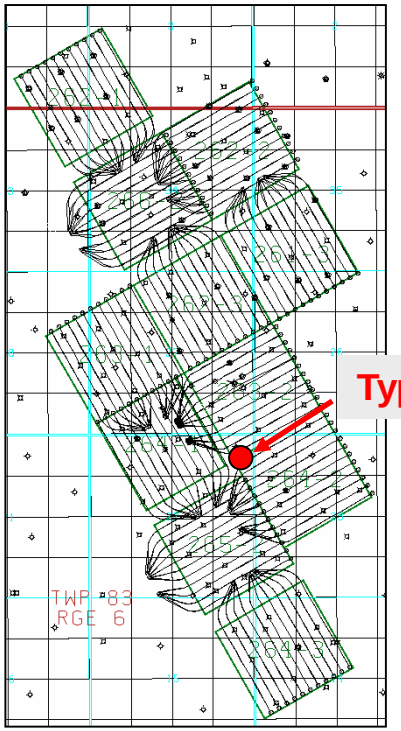
McMurray

Top Gas

High Sw

Continuous Bitumen

Devonian

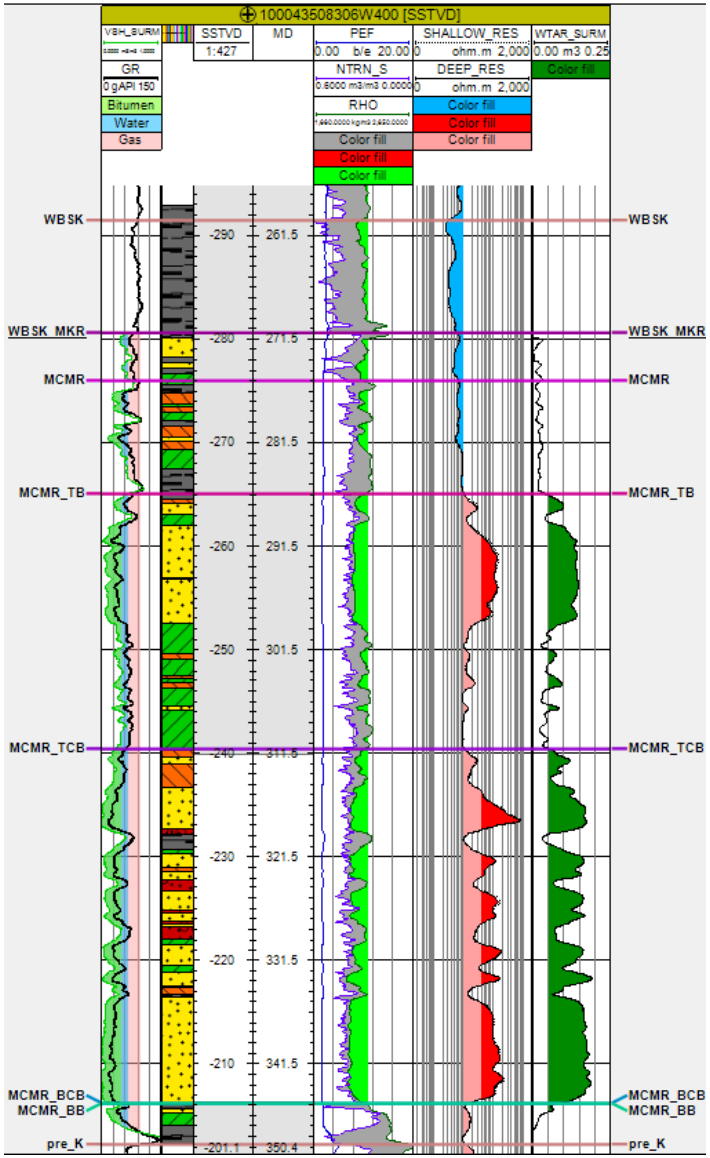


Type Log

Phase 2 Area

Phase 2 Type Log – Well Pad 261-3

Example Log 100043508306W400



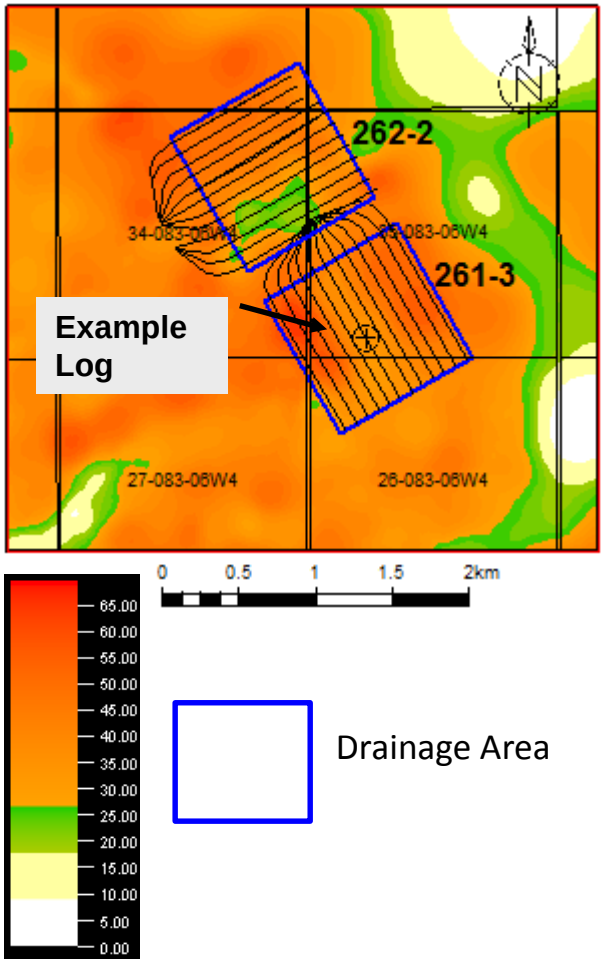
Tops Description
WBSK Wabiskaw Member
WBSK_MKR Wabiskaw Marker
MCMR McMurray Formation
MCMR_TB McMurray Top Bitumen
MCMR_TCB McMurray Top Continuous Bitumen
MCMR_BCB McMurray Base Continuous Bitumen
MCMR_BB McMurray Base Bitumen
pre_K Pre-Cretaceous Unconformity

Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Continuous Bitumen

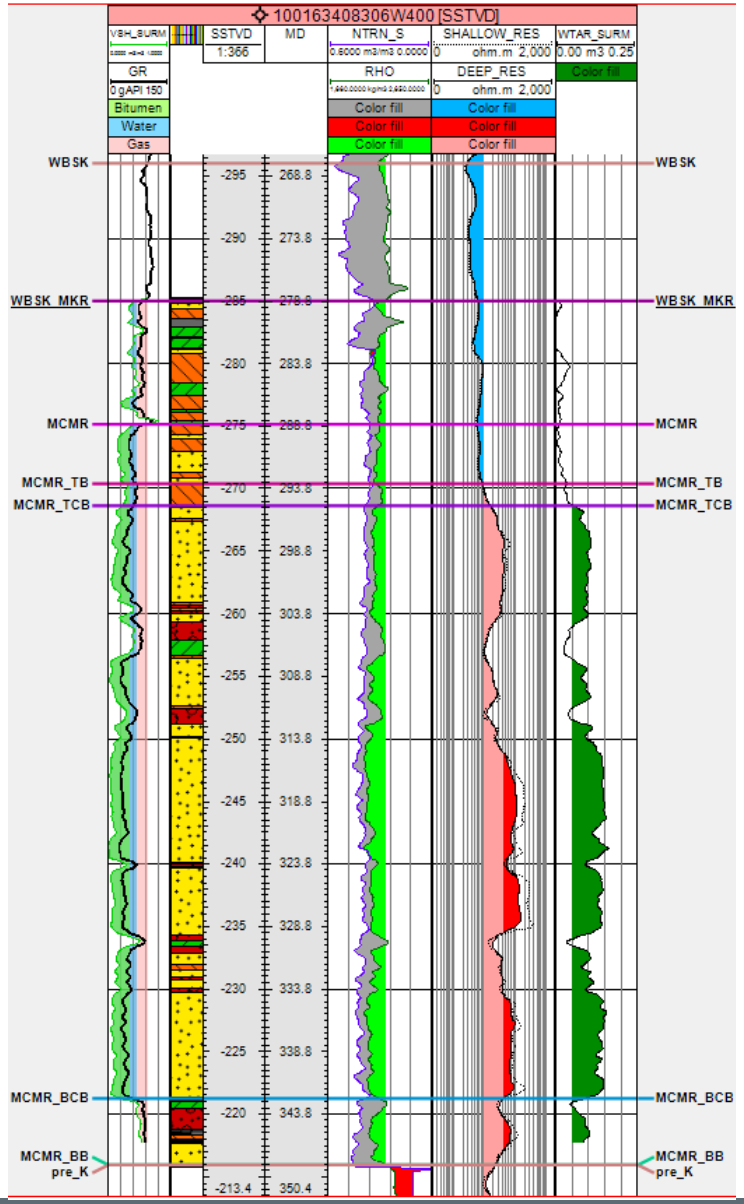
Phase 2 Area

McMurray Net Continuous Bitumen (NCB)



Phase 2 Type Log – Well Pad 262-2

Example Log 100163408306W400



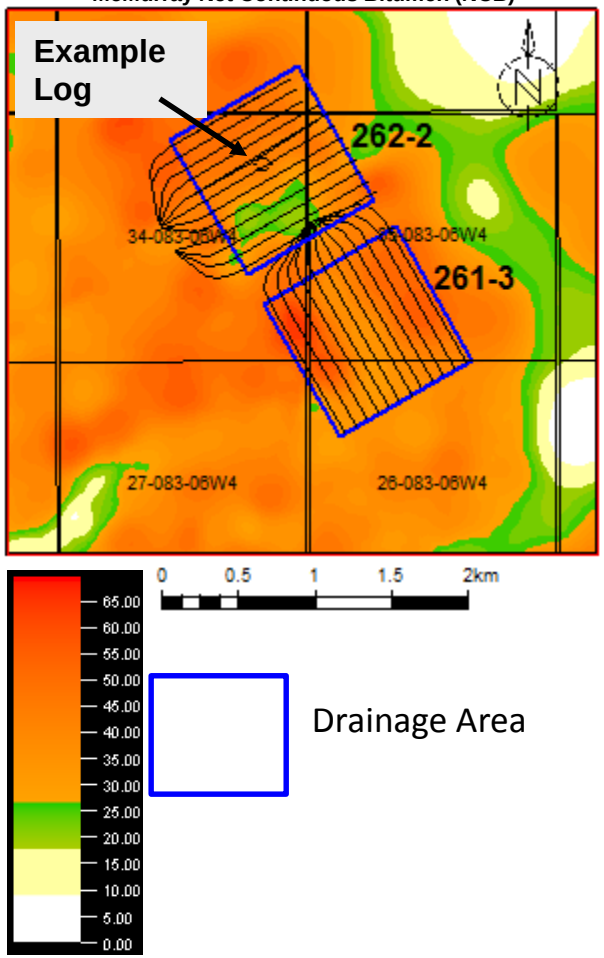
Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Continuous Bitumen

Tops Description
WBSK Wabiskaw Member
WBSK_MKR Wabiskaw Marker
MCMR McMurray Formation
MCMR_TB McMurray Top Bitumen
MCMR_TCB McMurray Top Continuous Bitumen
MCMR_BCB McMurray Base Continuous Bitumen
MCMR_BB McMurray Base Bitumen
pre_K Pre-Cretaceous Unconformity

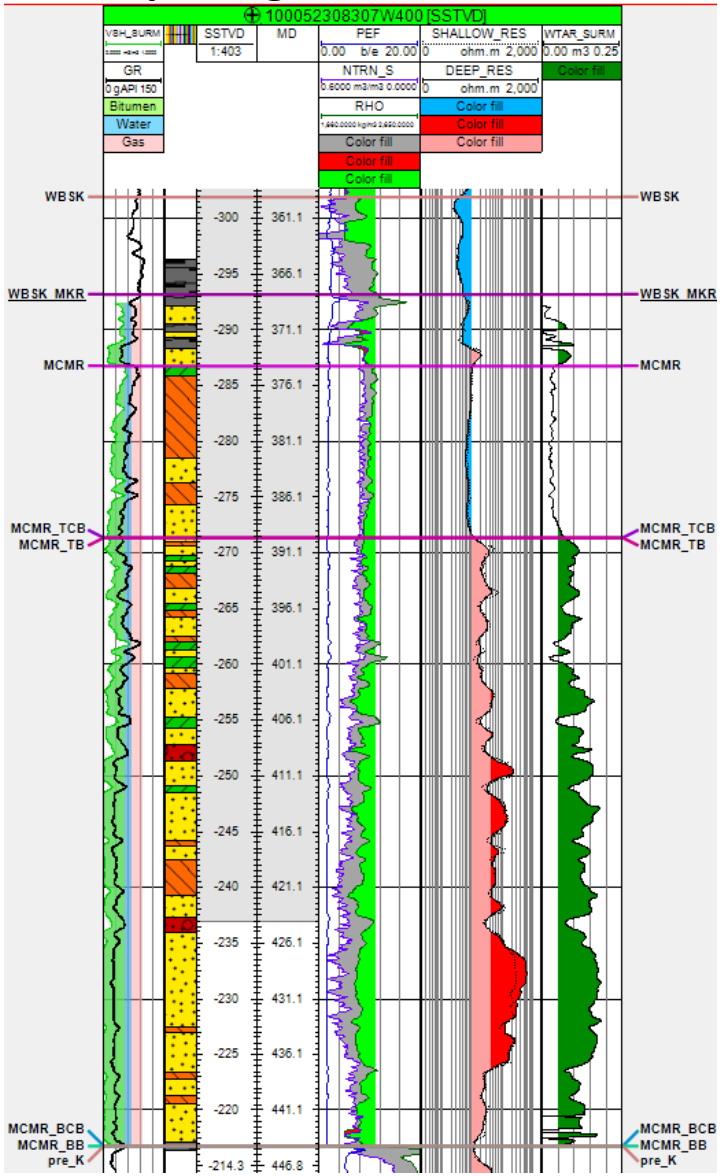
Phase 2 Area

McMurray Net Continuous Bitumen (NCB)



Phase 1 Type Log – Well Pad 103

Example Log 100052308307W400



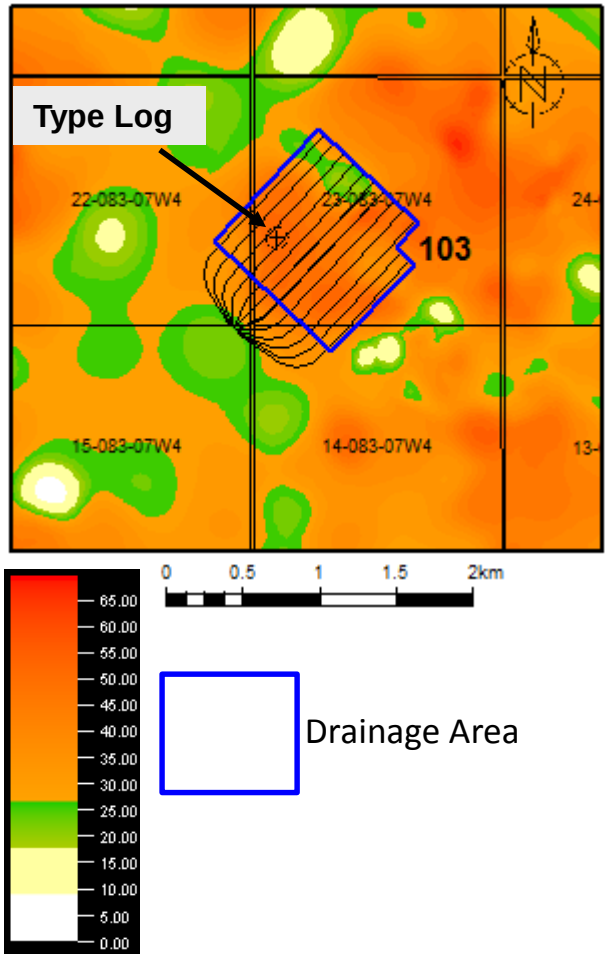
Tops Description	
WBSK	Wabiskaw Member
WBSK_MKR	Wabiskaw Marker
MCMR	McMurray Formation
MCMR_TB	McMurray Top Bitumen
MCMR_TCB	McMurray Top Continuous Bitumen
MCMR_BCB	McMurray Base Continuous Bitumen
MCMR_BB	McMurray Base Bitumen
pre_K	Pre-Cretaceous Unconformity

Name	Pattern
Coarse_sand	
Medium sand	
Fine sand	
Sandy IHS	
Muddy IHS	
Mudstone	
Carbonate	
Breccia	
Coal	
Cemented	
Till	
Rafted_Till	
Interbedded_Sand_Mud	
Bioturbated Sand & Mudstone	

Continuous Bitumen

Phase 1 Area

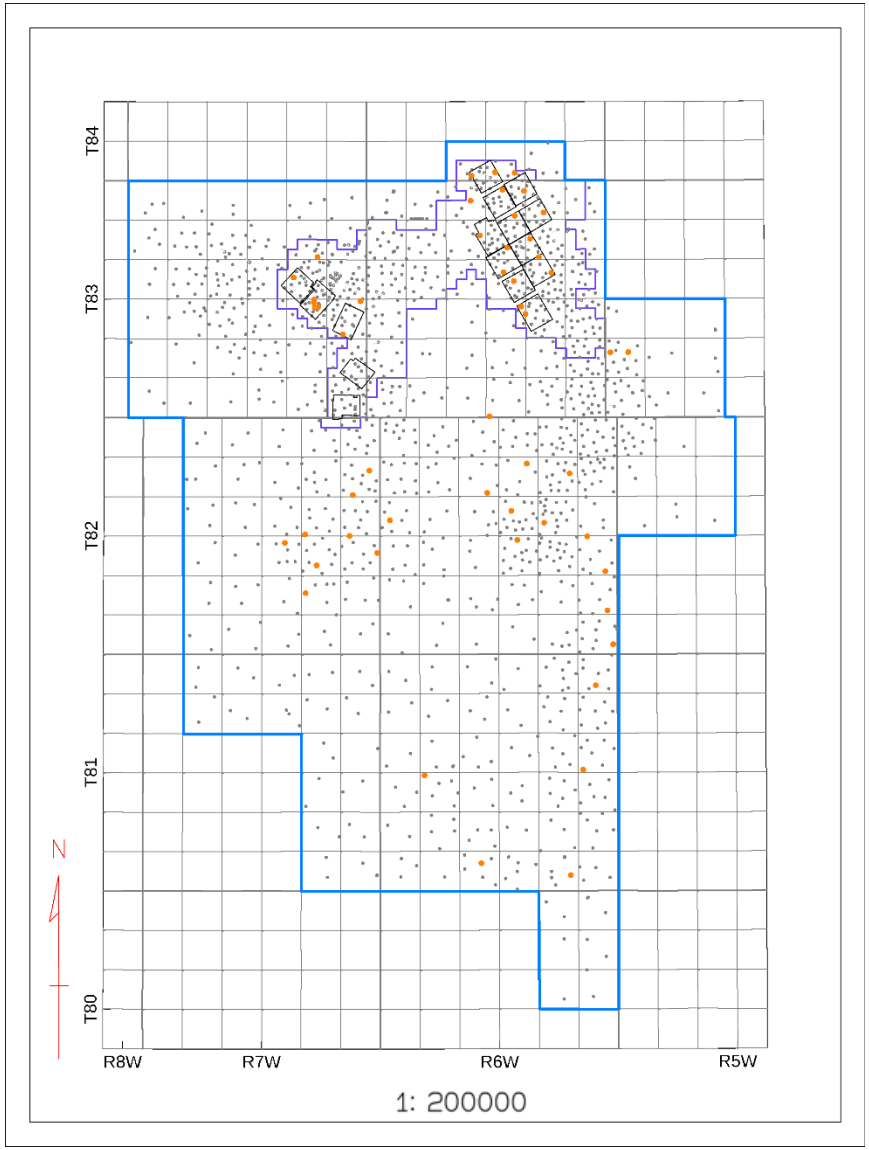
McMurray Net Continuous Bitumen (NCB)



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.

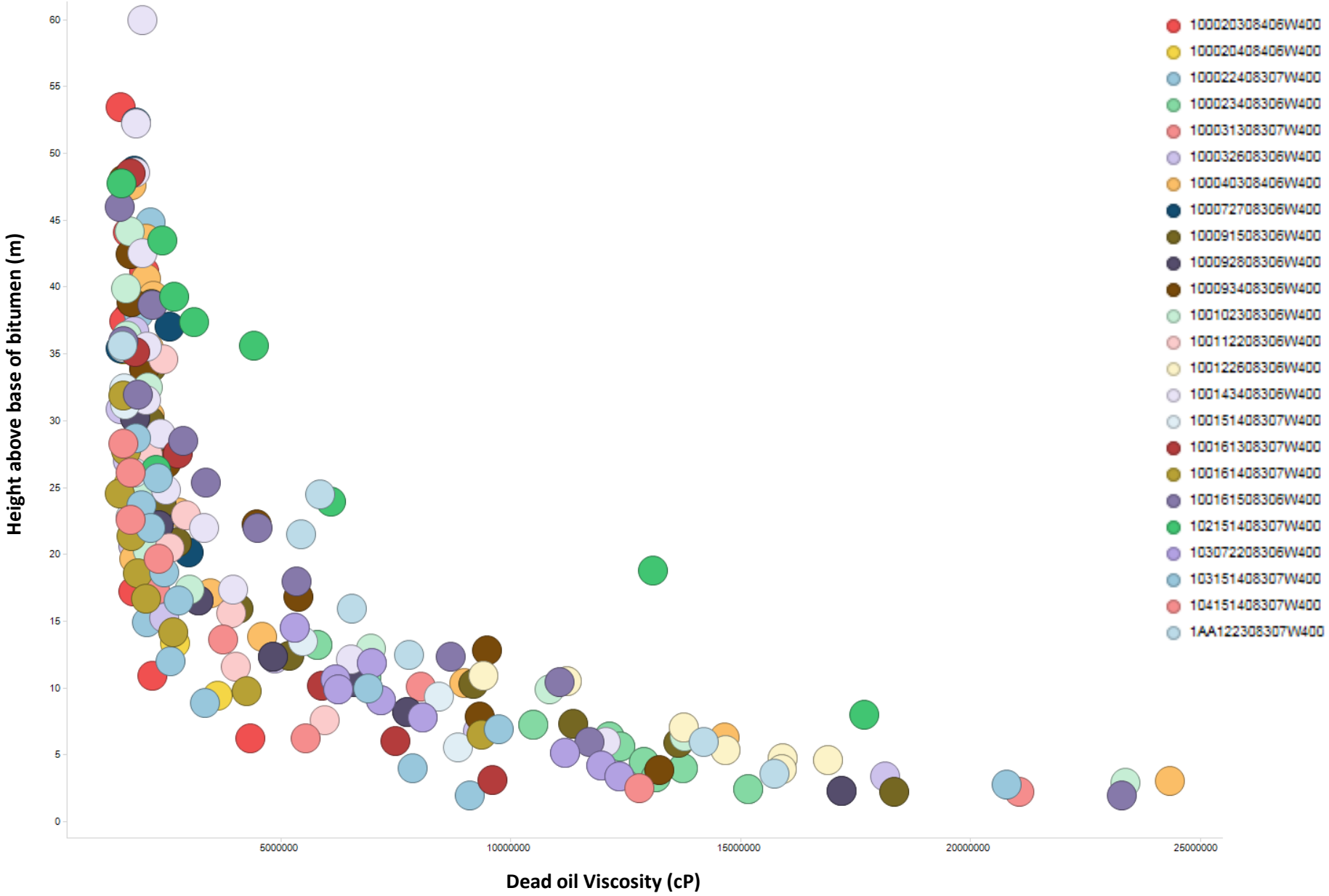
Viscosity increases with depth in the McMurray Formation.



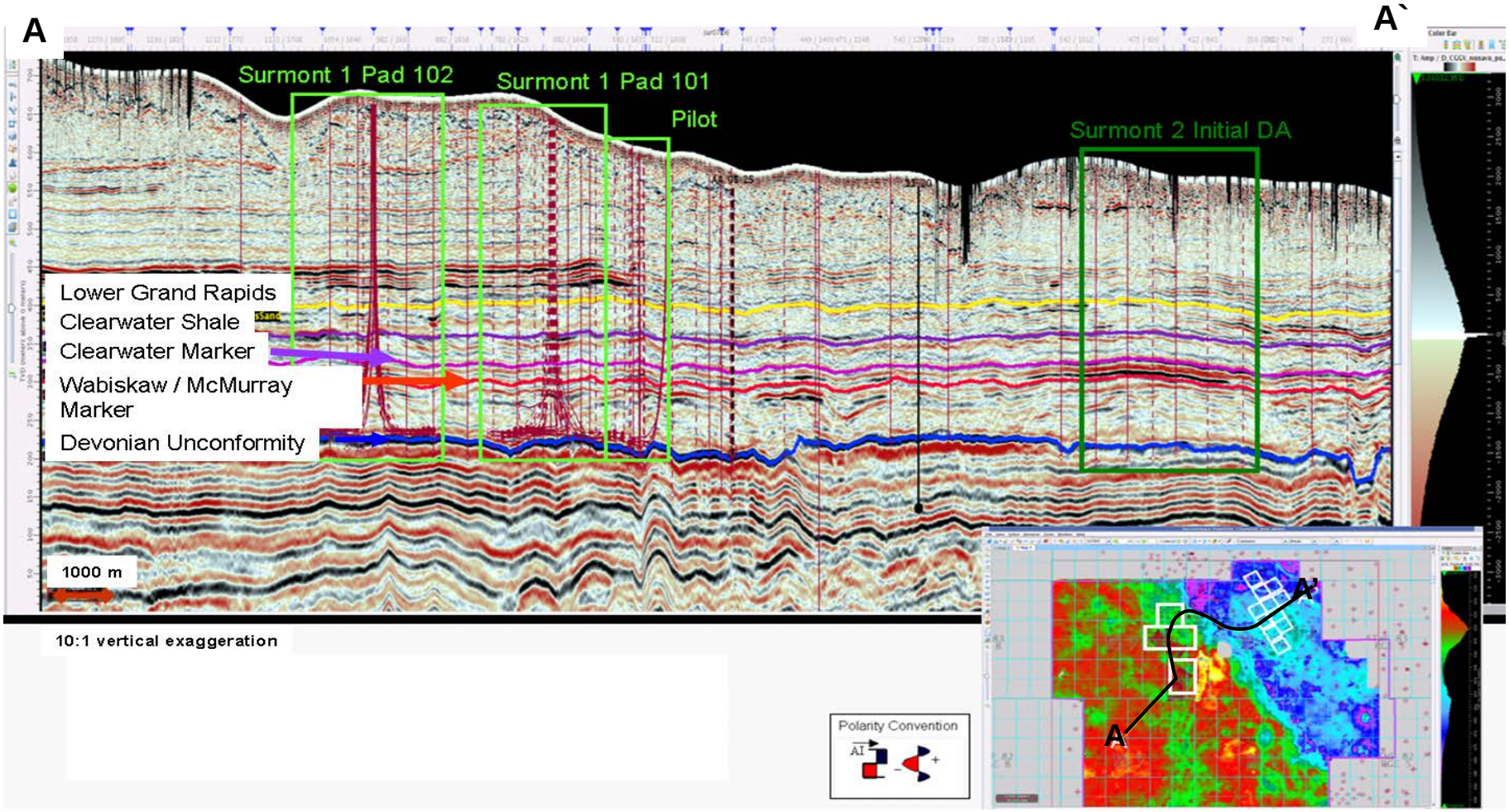
52 existing viscosity sample wells

Delineated Wells - Surmont

Viscosity Gradient



Representative Structural Cross Section

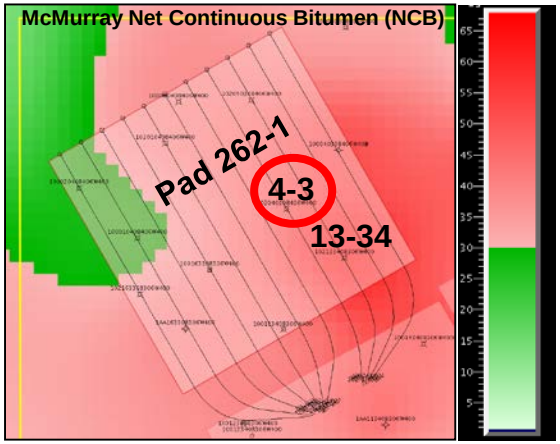


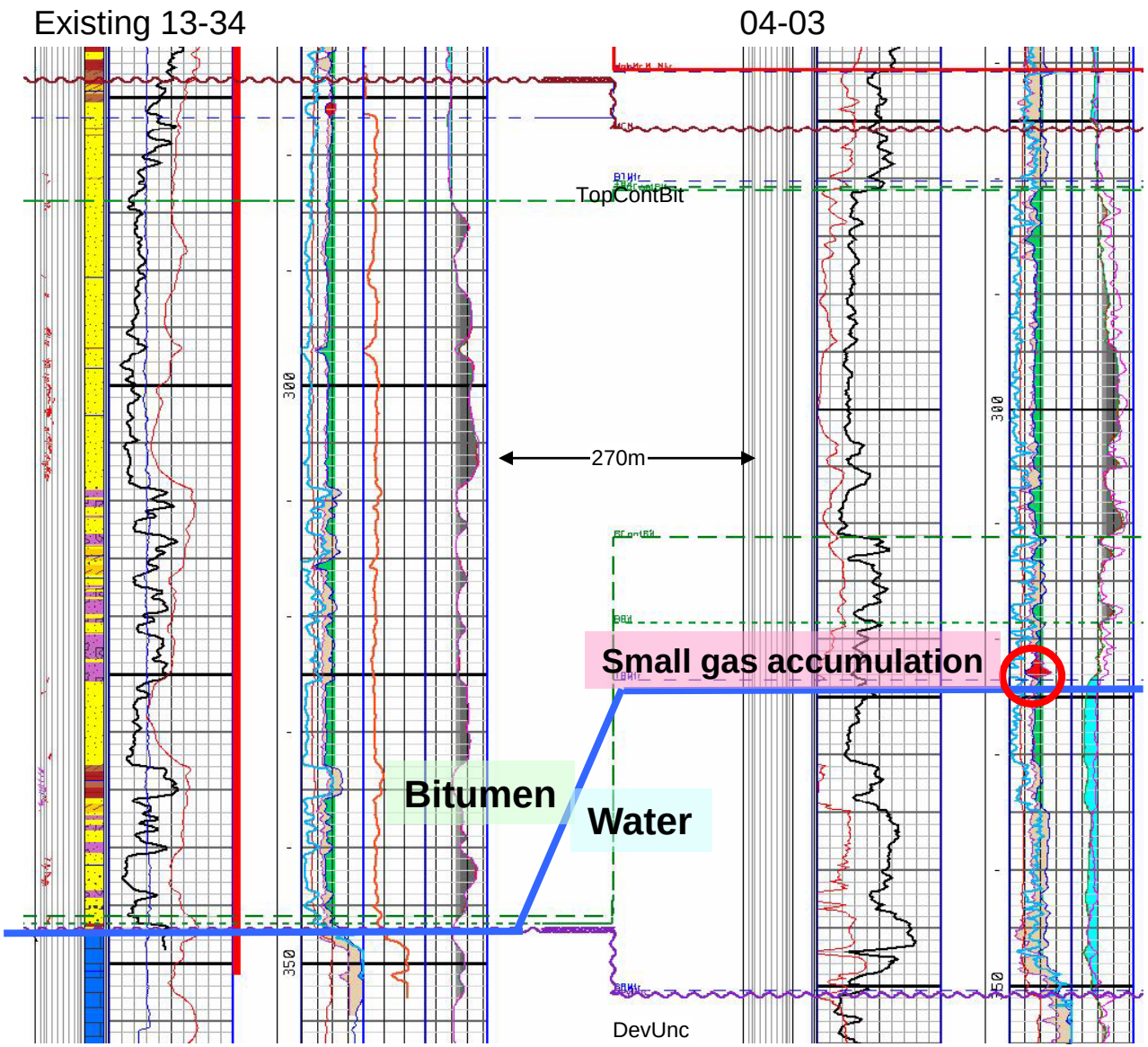
Well Pad 262-1 Variable Bitumen-Water Contact

- 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**

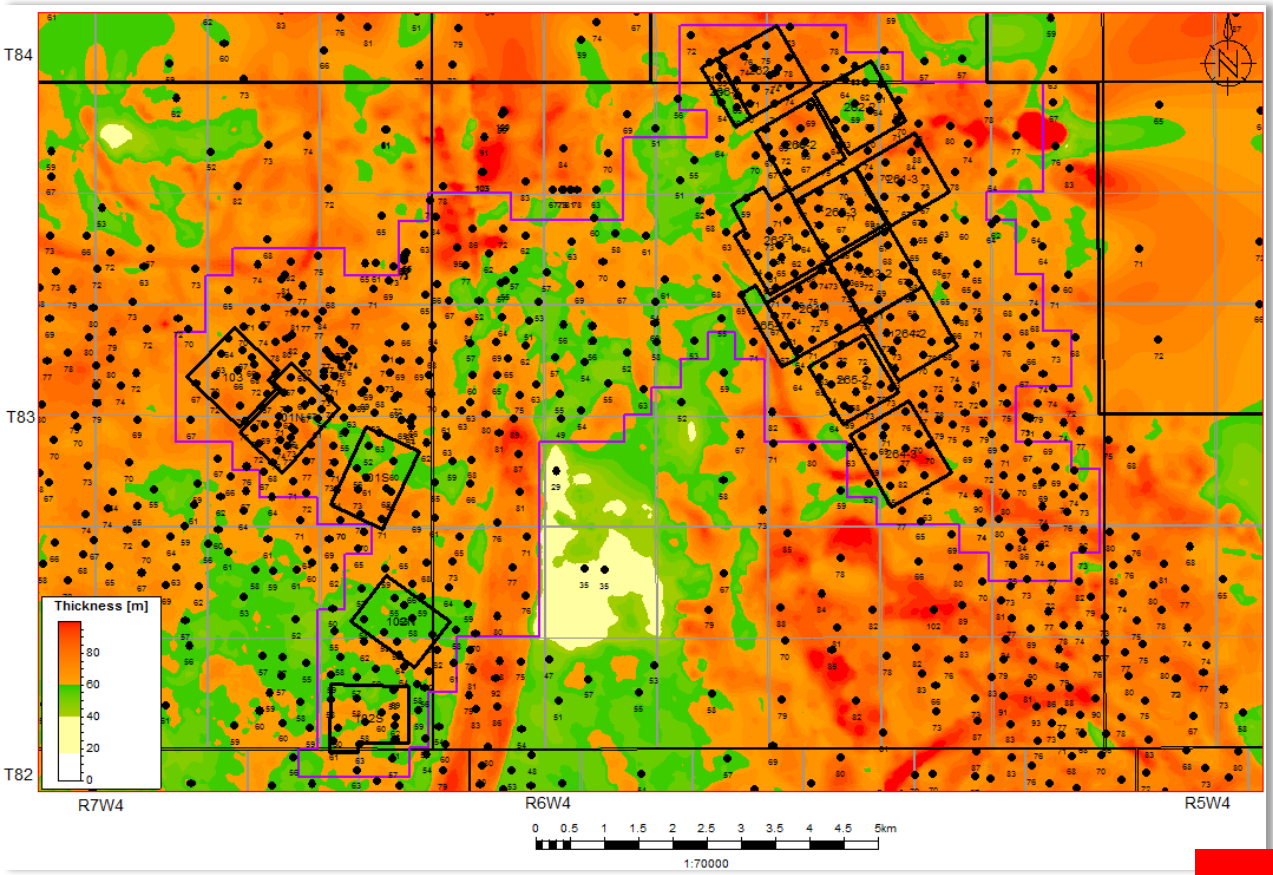


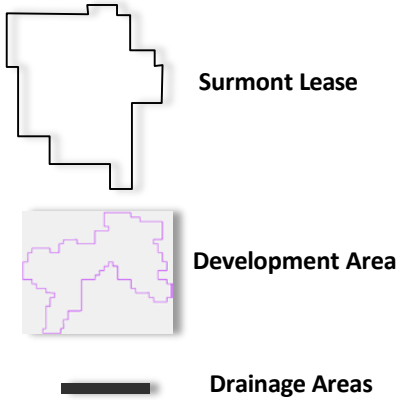


Reservoir Characteristics

Properties	Depth (masl)	Area (m2)	Thickness NCB (m)	Phie in NCB %	So in NCB %	KH in NCB (mD)	KV in NCB (mD)	Initial Pressure (KPa)
Lease	~250	578578000	23.07	31.82%	76.79%	4113	3423	1700
101N	277.52 - 212.11	1090775	35.53	32.58%	82.40%	4350	3614	1690
101S	272.96 - 218.47	1064692	37.43	33.19%	80.41%	5482	4604	1684
102N	276.39 - 223.91	975251	31.14	32.71%	80.29%	4636	3877	1735
102S	285.02 - 223.61	1019252	34.17	31.32%	74.33%	4001	3290	1800
103	272.82 - 211.40	1022239	42.80	32.21%	78.62%	4441	3691	1691
261-3	271.02 - 201.80	1000542	44.77	32.00%	78.07%	4342	3562	1328
262-1	273.64 - 206.15	996252	39.59	31.74%	80.05%	4195	3471	1307
262-2	271.89 - 212.60	974291	38.63	33.13%	78.56%	5239	4420	1296
262-3	271.57 - 208.64	943213	44.28	32.76%	78.21%	4968	4140	1368
263-1	272.12 - 211	1271315	36.14	32.98%	79.36%	4966	4170	1404
263-2	275.41 - 212.90	998219	40.90	32.44%	78.06%	4769	3979	1397
264-1	271.18 - 213.54	1033834	39.45	32.89%	79.71%	5148	4338	1444
264-2	269.27 - 213.75	1011337	42.08	32.65%	78.22%	4763	3965	1437
264-3	281.29 - 207.61	1209485	37.51	31.97%	75.58%	4446	3683	1564
265-2	271.50 - 215.59	917433	38.75	32.54%	76.83%	4917	4101	1496
266-2	276.26 - 210.21	949974	42.99	32.83%	80.08%	4925	4121	1337

McMurray Gross Isopach



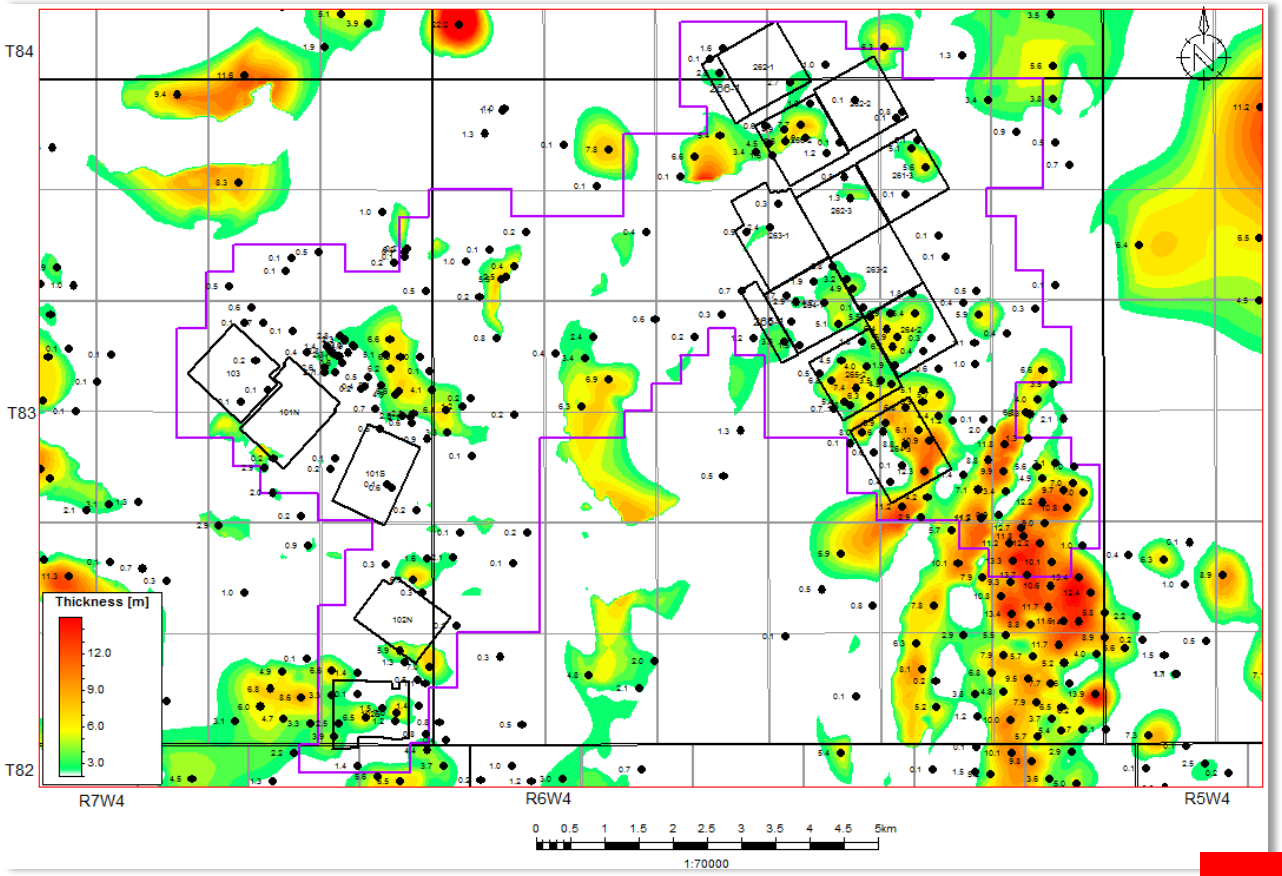


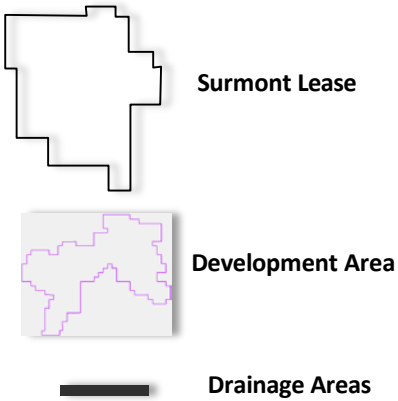
McMurray Gross Isopach

2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Gas Isopach





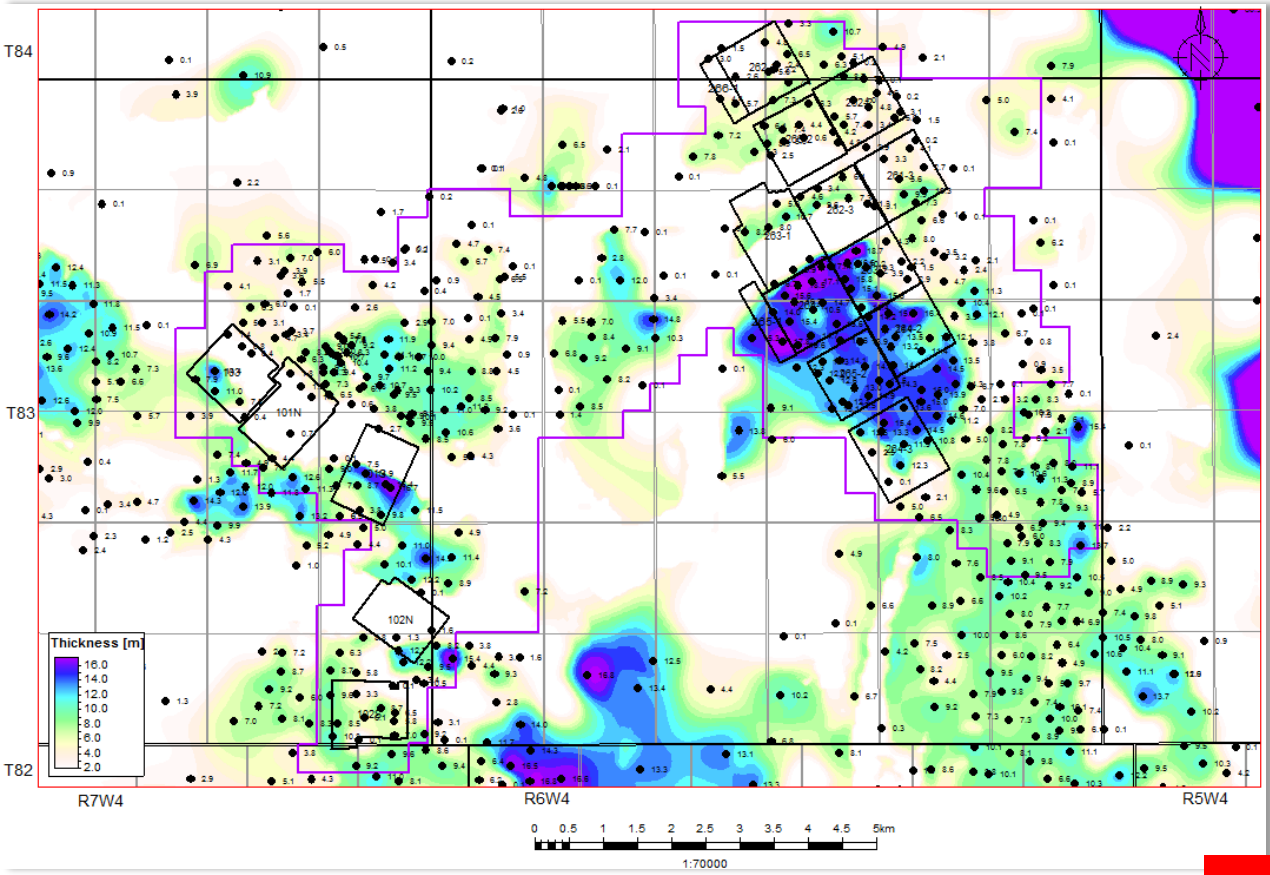
Net Top Gas thickness = sands have deep resistivity ≥10 Ω-m and Vsh <65%

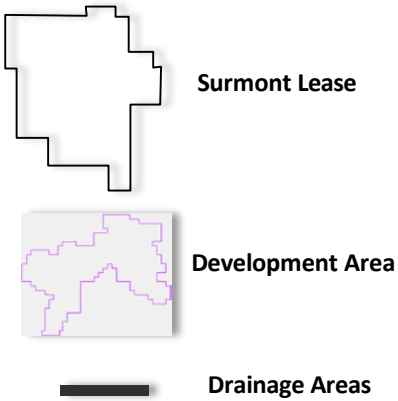
McMurray Net Gas Isopach

2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Top Water Isopach





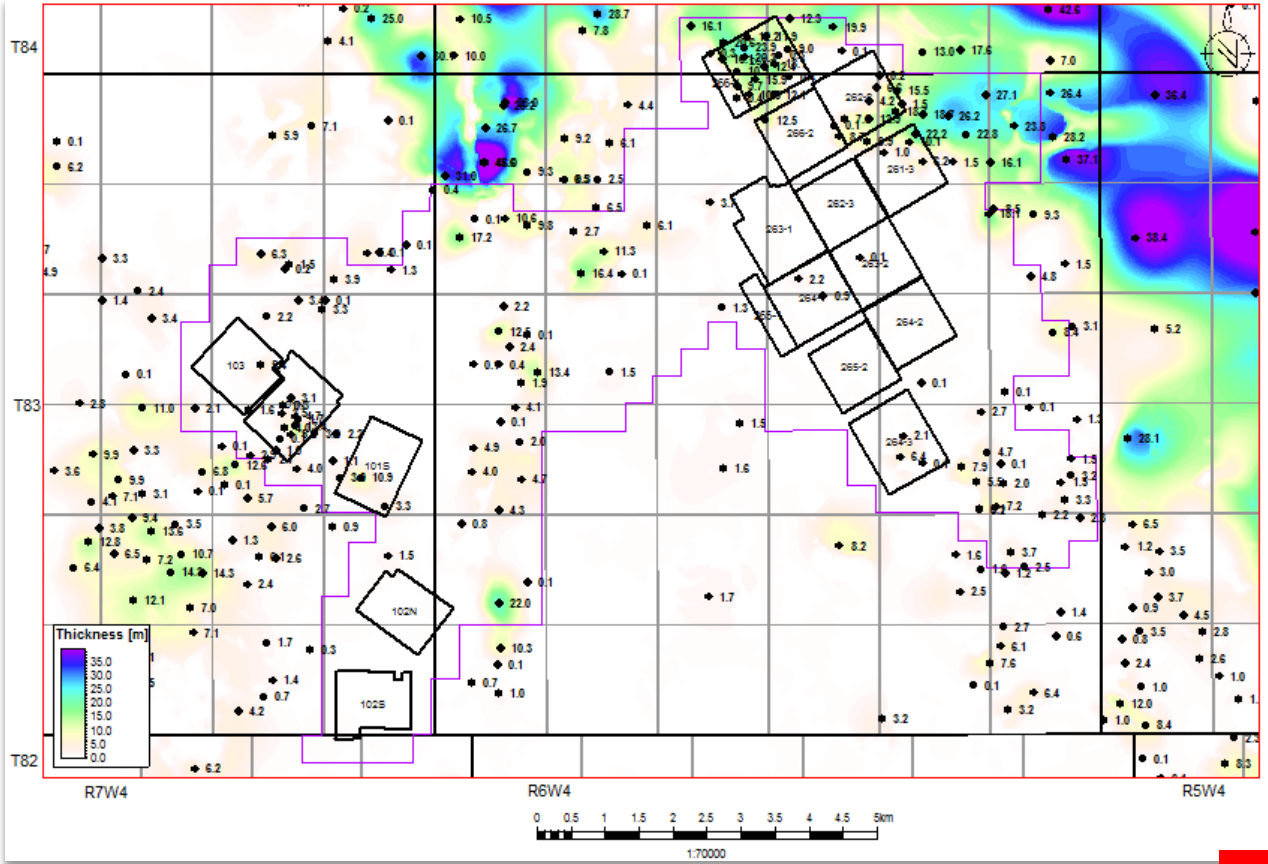
Net Top Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

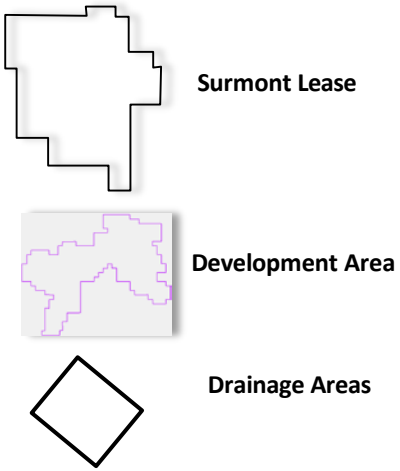
McMurray Net Top Water Isopach

2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Bottom Water Isopach





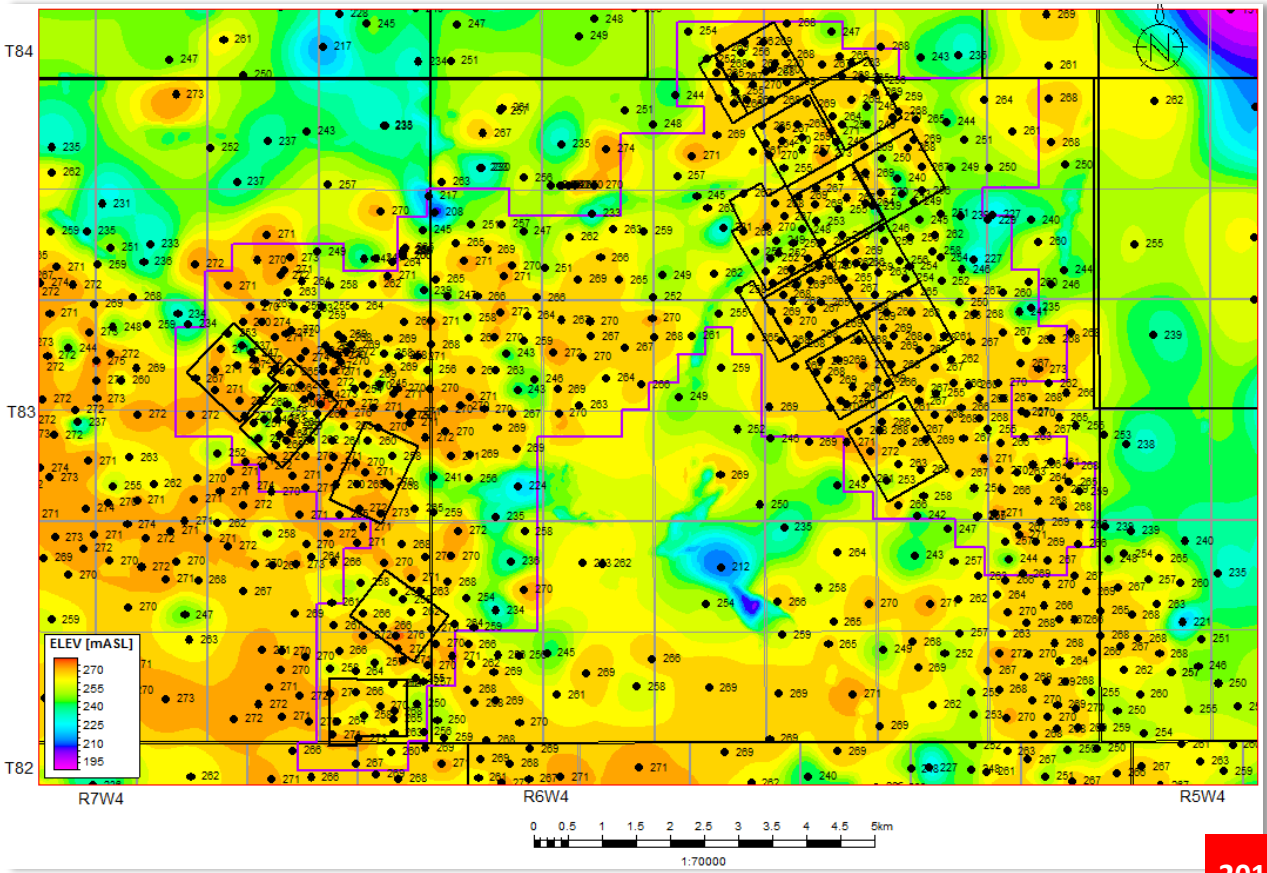
Net Bottom Water thickness = sands have deep resistivity <10 Ω-m and Vsh <45%

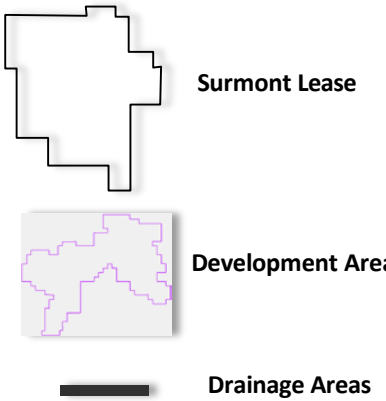
2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Bottom Water Isopach

McMurray Top Continuous Bitumen Structure





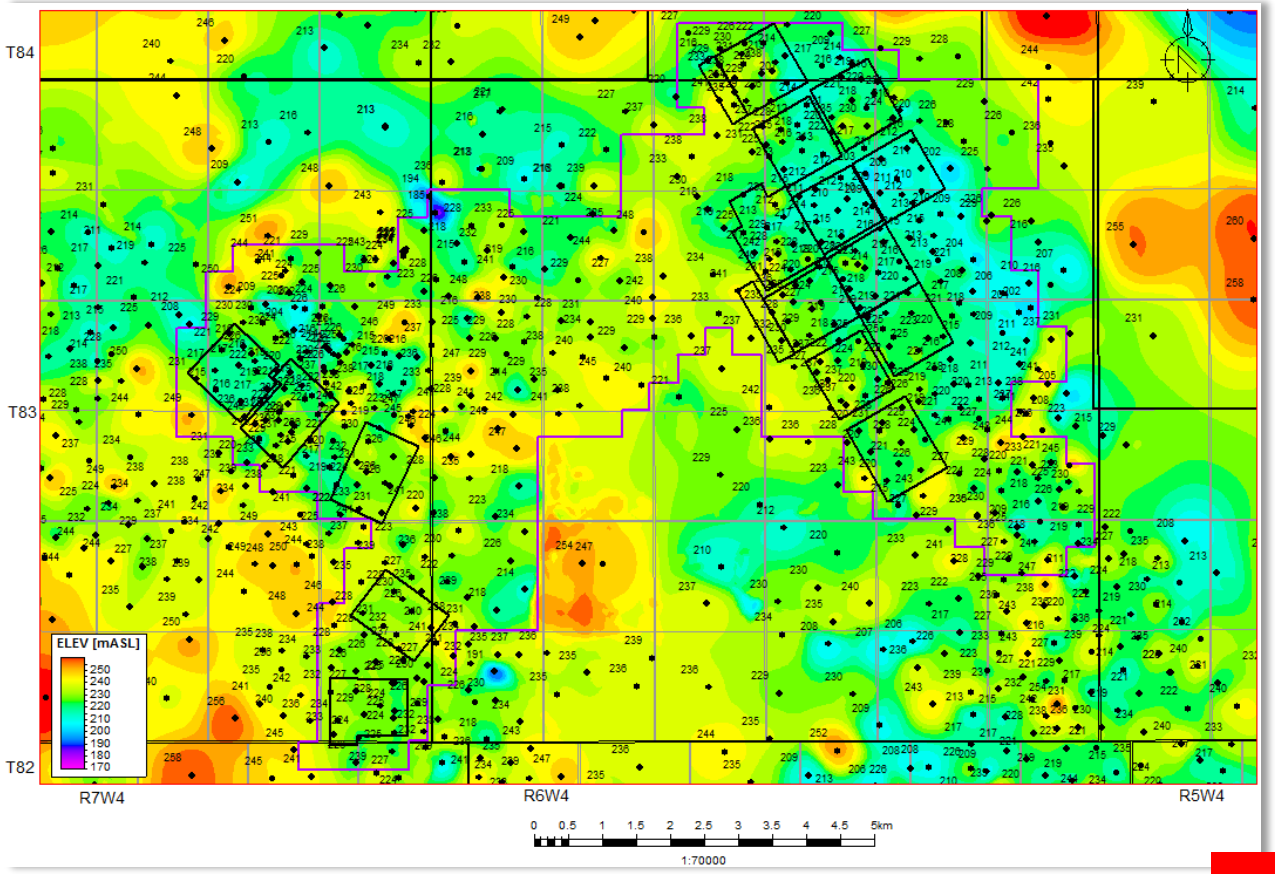
TCB = The uppermost limit of good reservoir, bitumen- bearing sands.

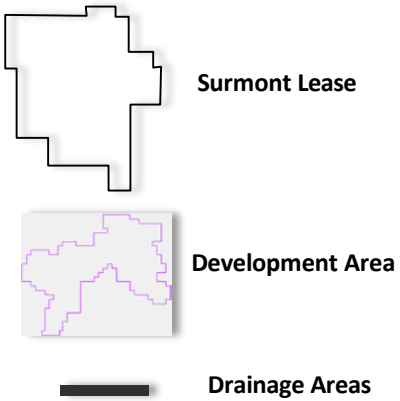
Top Continuous Bitumen Structure

2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Base Continuous Bitumen Structure





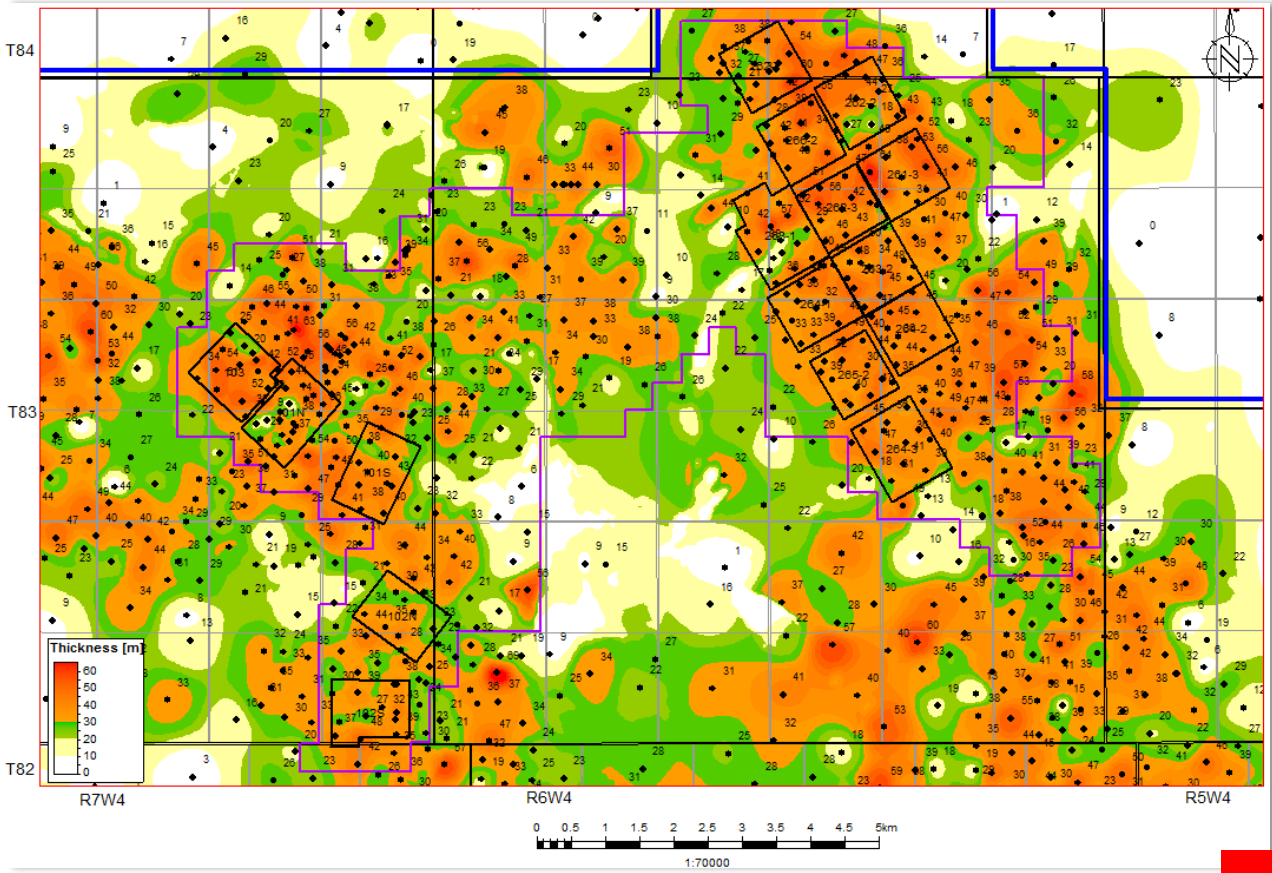
BCB = First occurrence of good reservoir, bitumen- bearing sands.

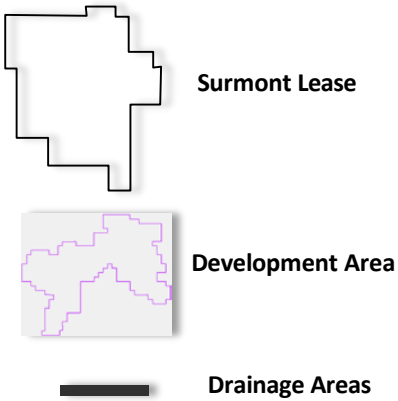
Base Continuous Bitumen Structure

2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Continuous Bitumen Thickness





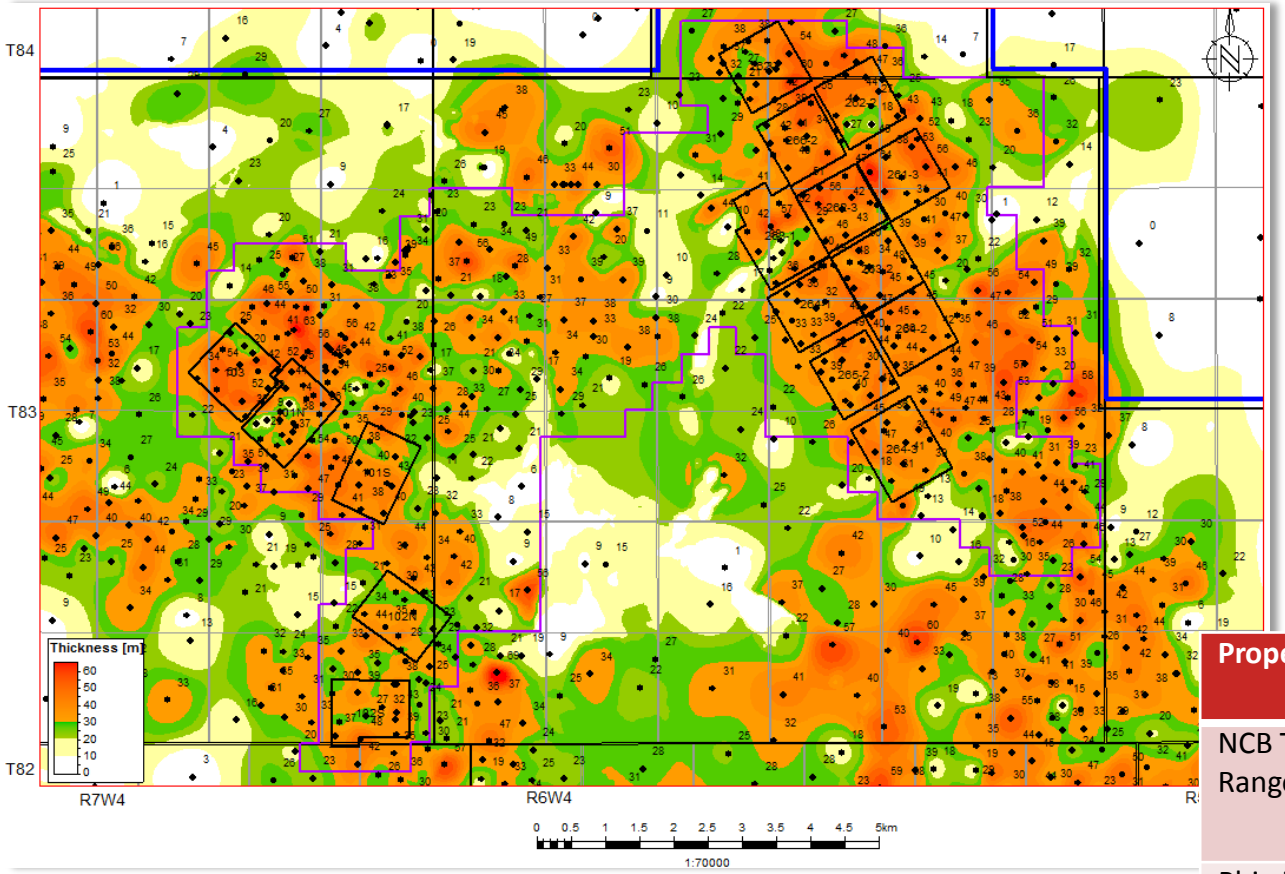
Net continuous bitumen = sands have deep resistivity > 40 Ω-m and Vsh <33%, and no shale greater than 3 m thick

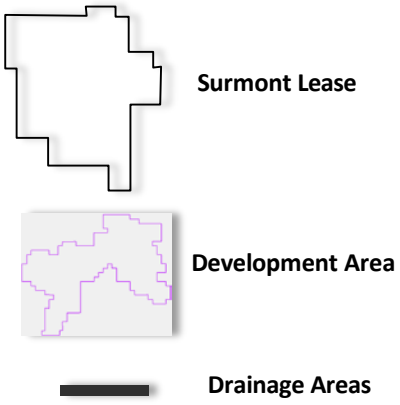
2017/2018 Mapping Update

- **Minor changes due to:**
  - **Revised Mapping Surfaces**
  - **Geological picks from 2016/2017 delineation wells**
  - **Re-evaluated/unified geologic picks**

McMurray Net Continuous Bitumen Pay

Surmont Leases OBIP



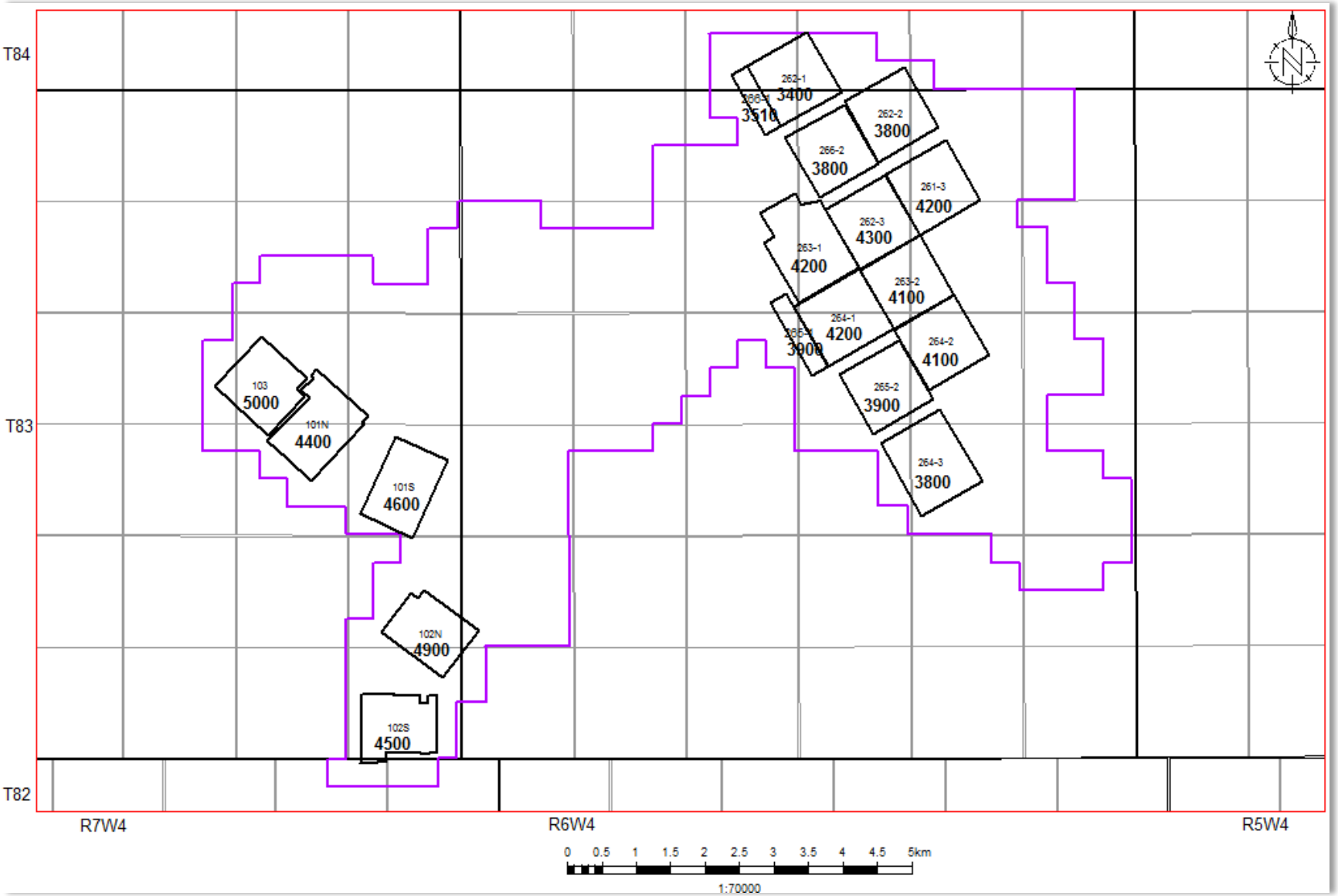


Properties	Development Area
NCB Thickness Range	0 to Greater than 30 m
Phie in NCB	31.72%
So in NCB	75.78%
OOIP in NCB > 18m	3423.25 MMbbls Deterministic

Surmont Development Area OBIP

OBIP = Thickness x Phie x So x Area

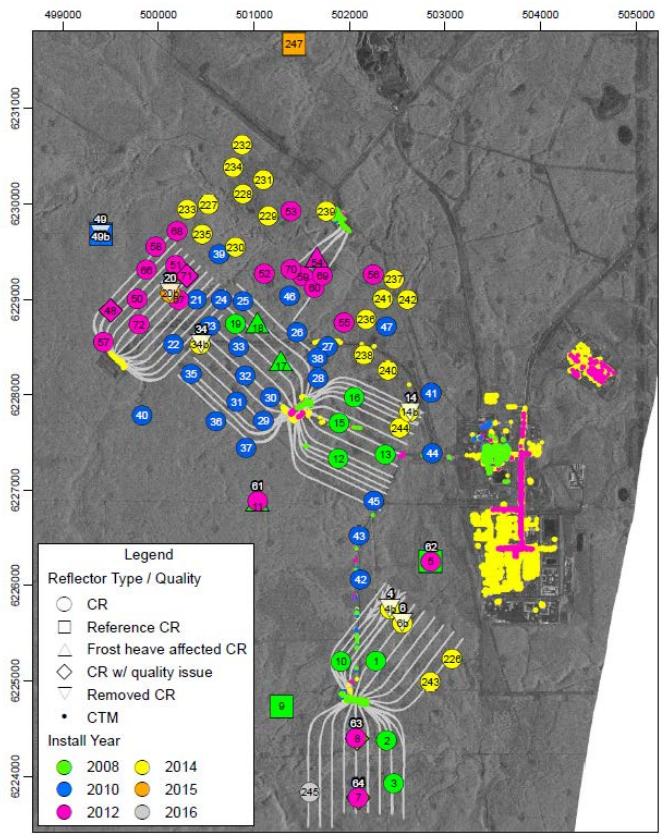
Maximum Bottomhole Injection Pressure (kPag) – ALL PADs



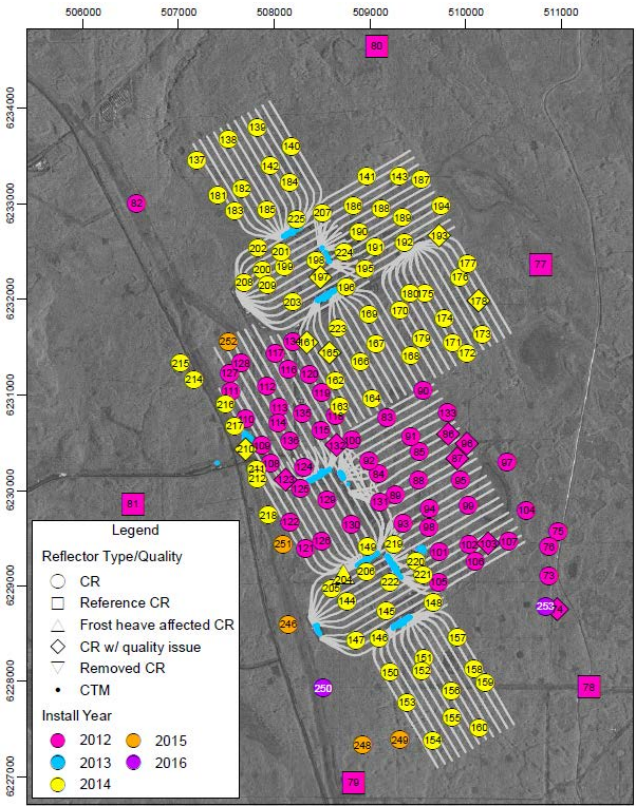
Surface Deformation Monitoring

- 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.
  - An additional 20 Corner reflectors were installed in 2017 at Phase 2 but are not tied into our current routine data collection yet, so they are not shown on the map.

Phase 1 Monitoring Locations

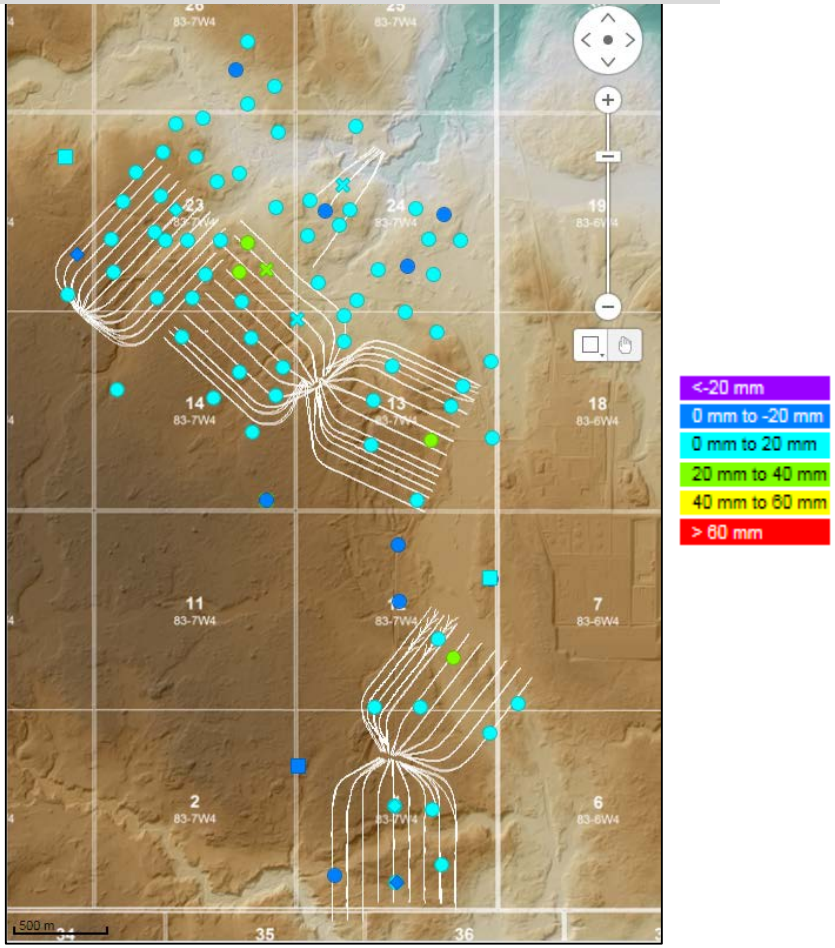


Phase 2 Monitoring Locations

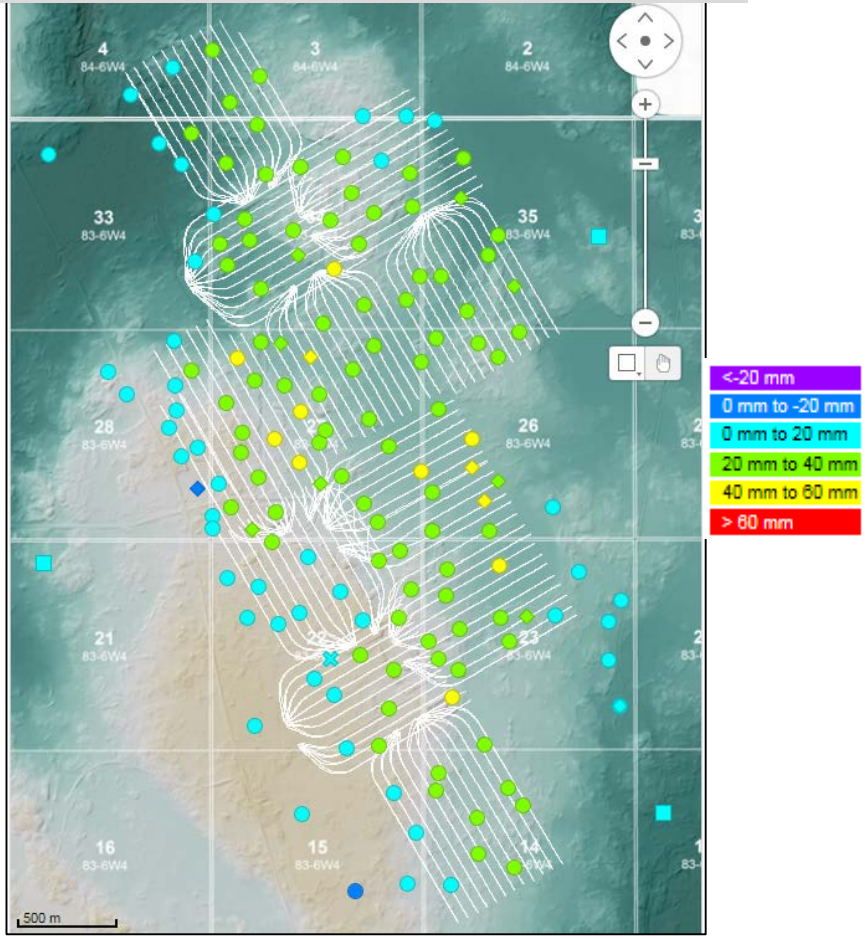


InSAR Surface Deformation Monitoring

Vertical Deformation *Mar 1 2017 to Jan 31 2018* (Surmont 1)



Vertical Deformation *Mar 1 2017 to Jan 31 2018* (Surmont 2)



- Deformation currently in line with expectations.

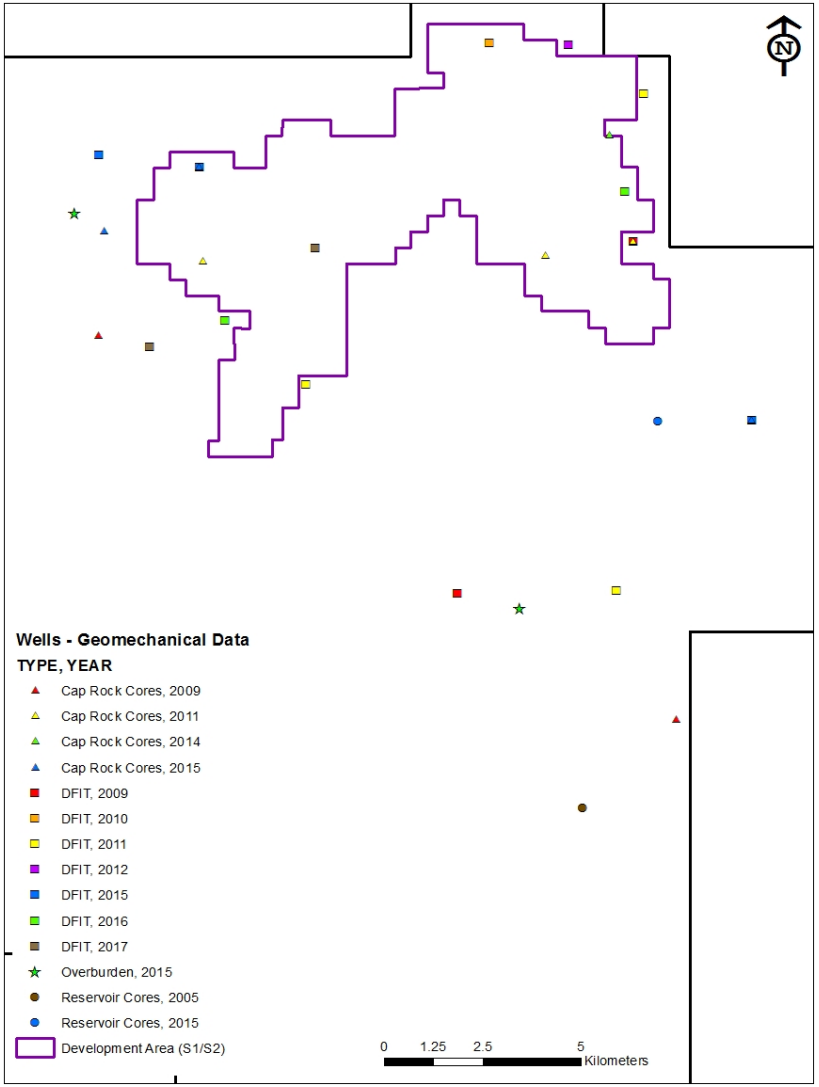
○ Corner Reflector
□ Reference Corner Reflector
◇ Corner Reflector w/quality issue
✕ Corner Reflector w/Frost Jacking

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 geological and geomechanical properties of the caprock allow for providing a continuous seal over the steam chamber.**



Caprock Integrity Analysis and Maximum Operating Pressure

- ConocoPhillips applies a highly conservative approach towards Subsurface Containment Assurance and follows a stringent approach based on internal SCA standards and regulations.

- Caprock integrity studies in ConocoPhillips include extensive geological, geophysical, petrophysical and geomechanical investigations. ConocoPhillips continues to acquire and interpret the data to mitigate SCA related risks.

- Results of caprock integrity studies allow ConocoPhillips to characterize and mitigate local risks related to geological and geomechanical variations. Analysis of caprock in the development area suggests while the previously used value of 18.4 kPa/m is valid, the minimum horizontal stress is higher in several drainage areas.

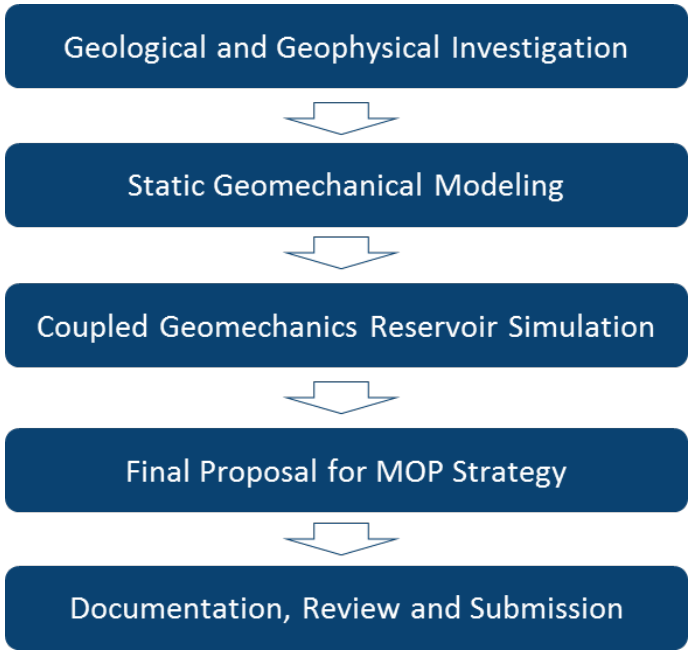
- ConocoPhillips continues to propose a flexible tapered strategy envelope bound by the cap rock integrity study and the associated Maximum Operating Pressure (MOP) on one side and economic achievable pressures on the other side. In 2017/18 temporary and permanent changes were made to the MOPs in a number of DAs in Surmont.

- ConocoPhillips has received approval to increase MOP from 15 kPa/m to 16.5 kPa/m in eight DAs in Surmont.

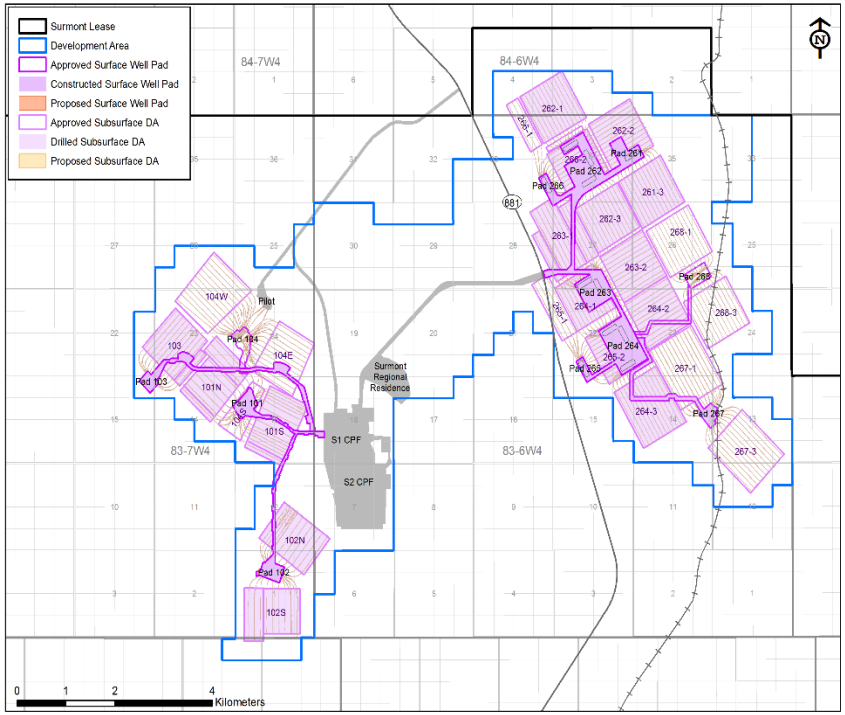
- Another approval was received to temporarily increase the MOP in one DA (262-3) to overcome near-wellbore barriers. A pilot test using one well pair was completed with the temporary MOP and results are being studied before proceeding with the rest of the DA well pairs.

Caprock Integrity Analysis and Maximum Operating Pressure

- The static geomechanical model used for caprock integrity analyses is regularly updated based on acquired and interpreted data.
- Static modeling of reservoir and caprock is used in combination with dynamic simulation of their geomechanical and pressure responses is used to estimate the SCA safety factors.
- For all applications and MOP changes, ConocoPhillips has demonstrated that the SCA safety factors have been maintained above 1.2 for the base cases.



Caprock Integrity Analysis Workflow



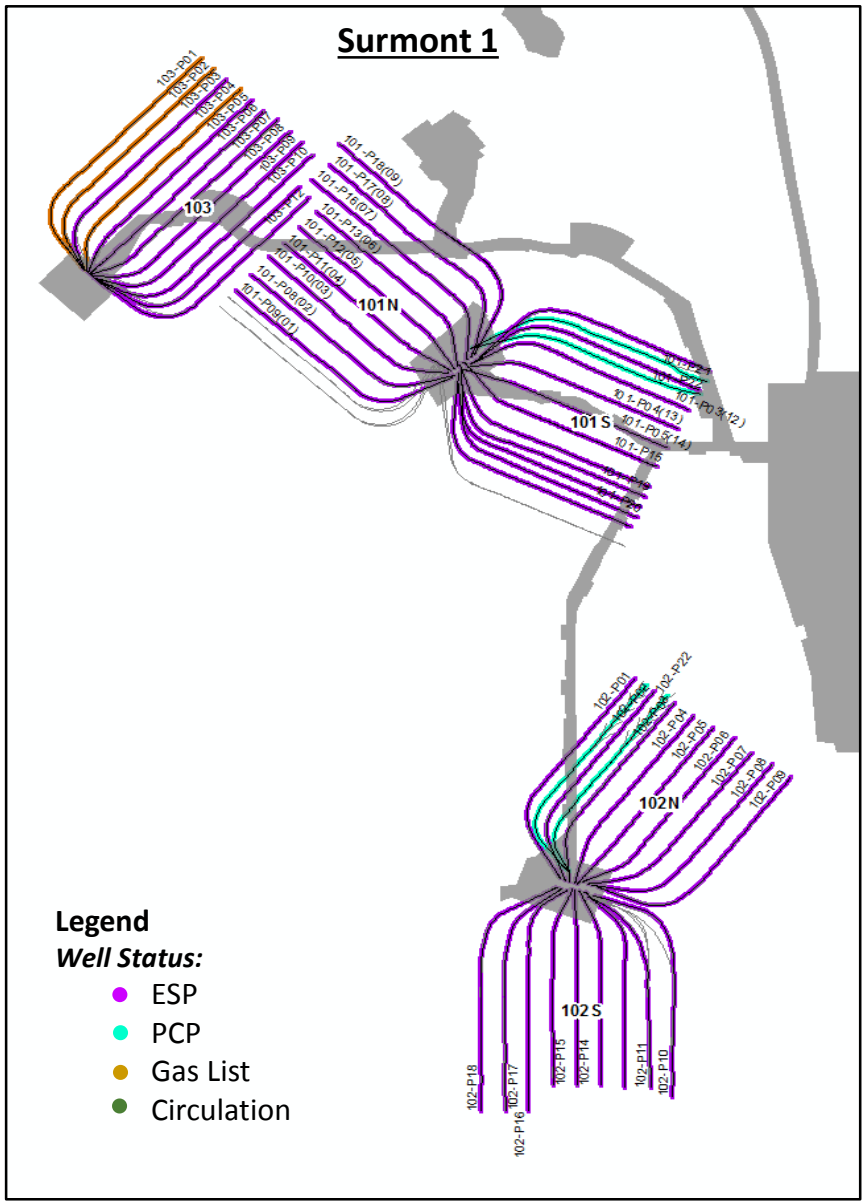
Surmont Development Area and Selected DAs for MOP Increase (red outline)

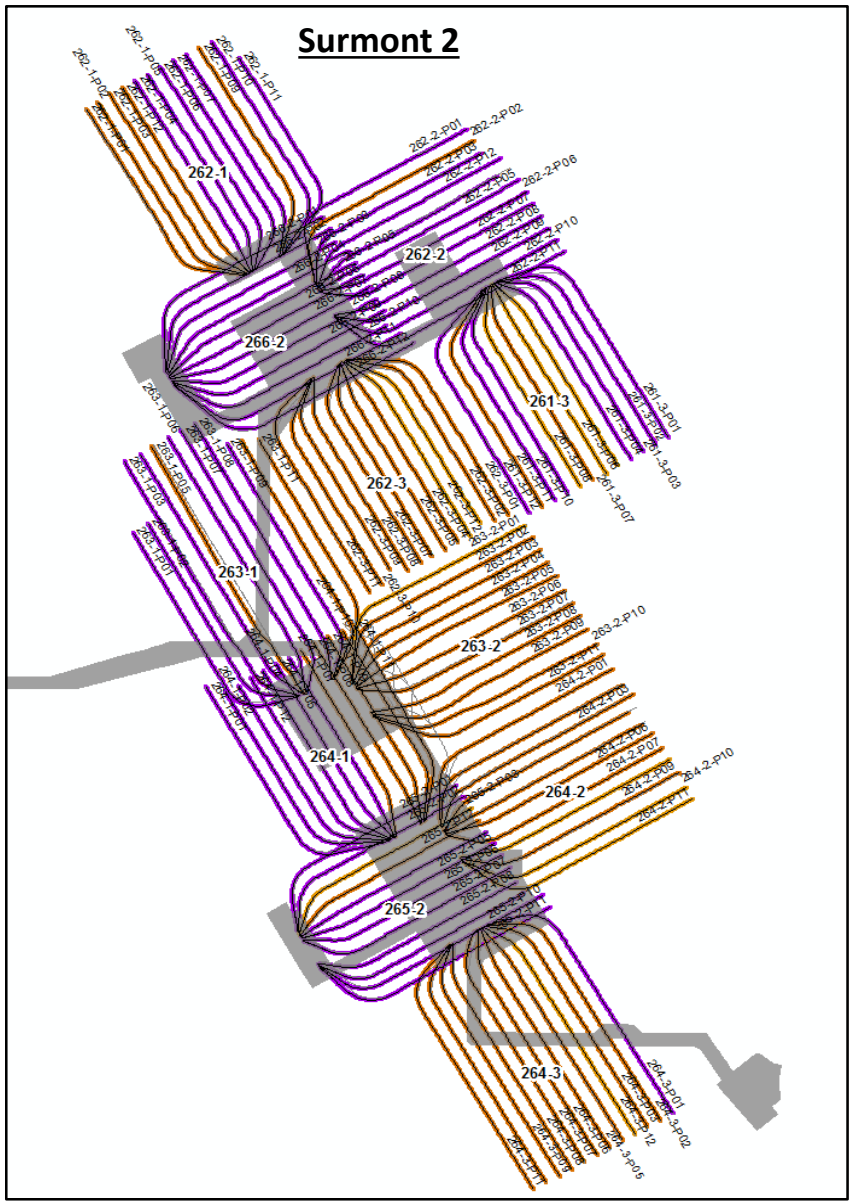
ConocoPhillips

Drilling and Completions

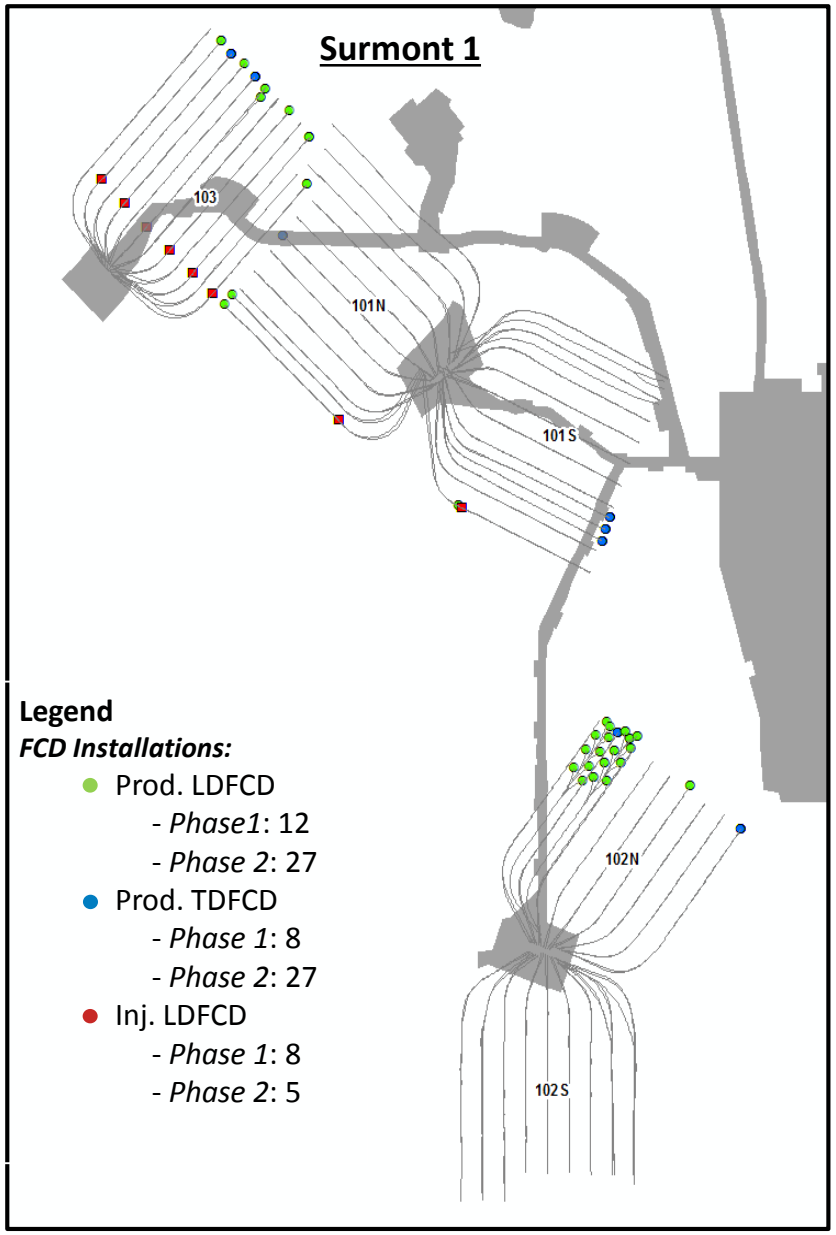
Subsection 3.1.1 (3)

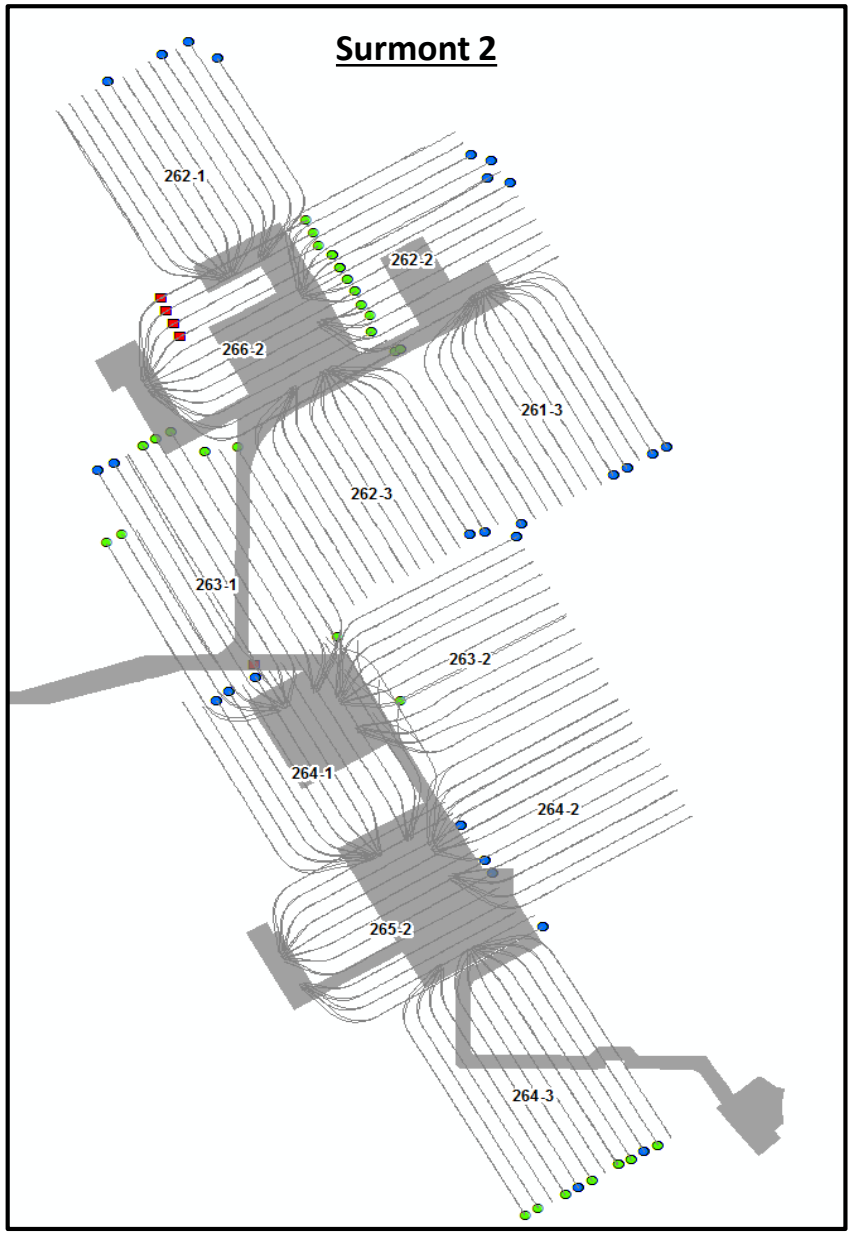
Surmont Well Summary





Surmont FCD Installations





Lateral Interwell Spacing

Well Identifier - Surface (Downhole)	Lateral Interwell Spacing	Average Infill Spacing
101	125 m	62.5 m
102	125 m	62.5 m
103	90 m	n/a
103 – WP 11 & 12	80 m	n/a
261-3	83 m	n/a
262-1	83 m	n/a
262-2	83 m	n/a
262-3	83 m	n/a
263-1	90 m	n/a
263-2	90 m	n/a
264-1	83 m	n/a
264-2	90 m	n/a
264-3	83 m	n/a
265-2	83 m	n/a
266-2	83 m	n/a

2017 Re-Drills

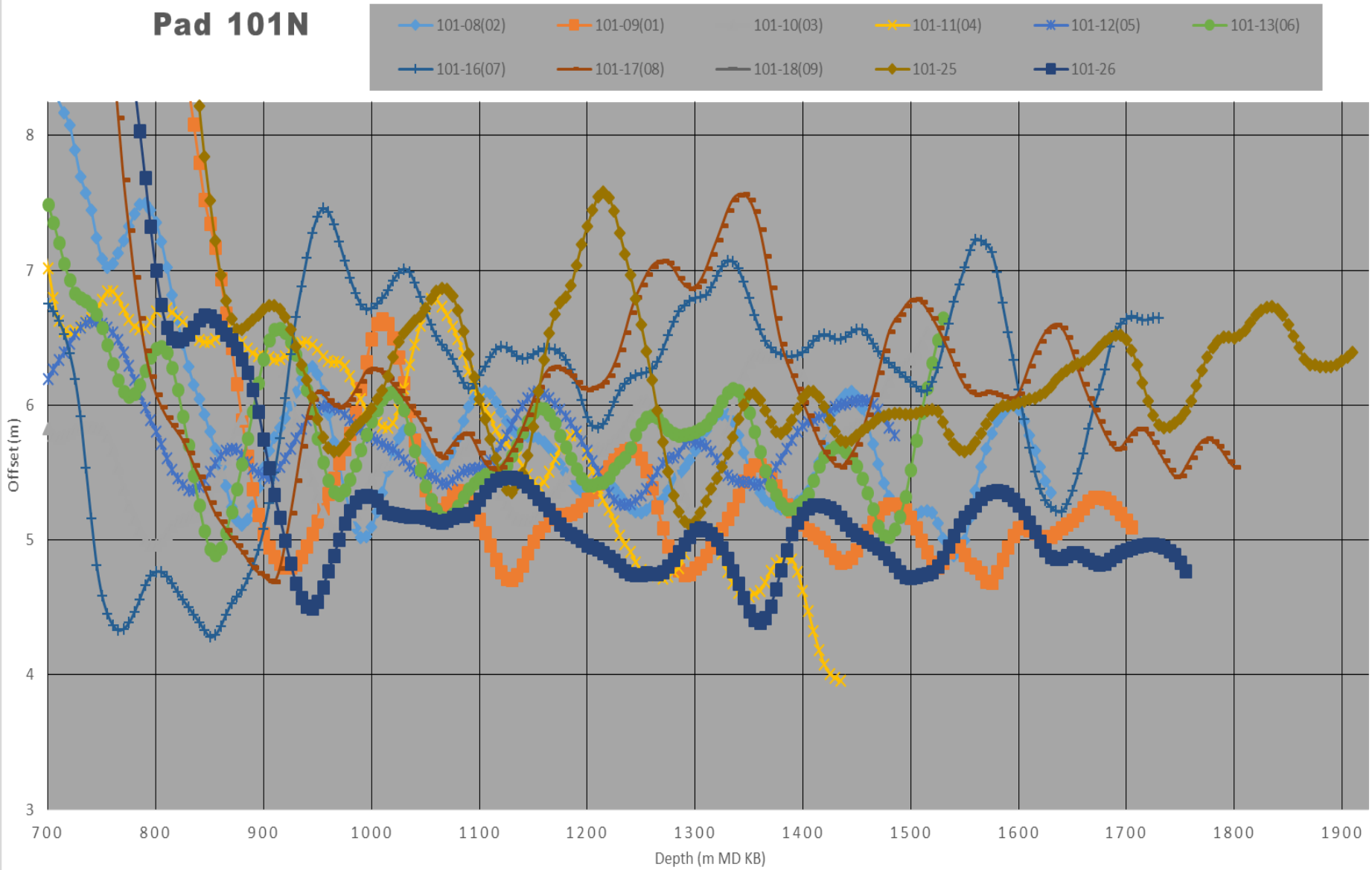
- Total of 6 re-drills in 2017.

	264-2 P04	264-2 P09	264-3 P04
Redrill Type	Whipstock	Whipstock	Whipstock
Reason for Redrill	Optimization/Unable to recover long tubing due to significant liner deformation	Half of Producer well not open to production due to sand control failure in 2016	The decision was driven by expected production uplift. The well was performing poorly and the liner was too deformed to allow us to run other completions in the existing wellbore.
Whipstock Depth (mKB)	430 mKB	432.5 mKB	447 mKB
Whipstock Depth (mTVD)	339 mTVD	333 mTVD	345 mTVD
Liner Length (m)	1096 m	1228 m	1342 m
FCD interval Length (m)	937 m	991 m	1195 m
Completion	Gas Lift	Gas Lift	Gas Lift
Comments	n/a	n/a	n/a

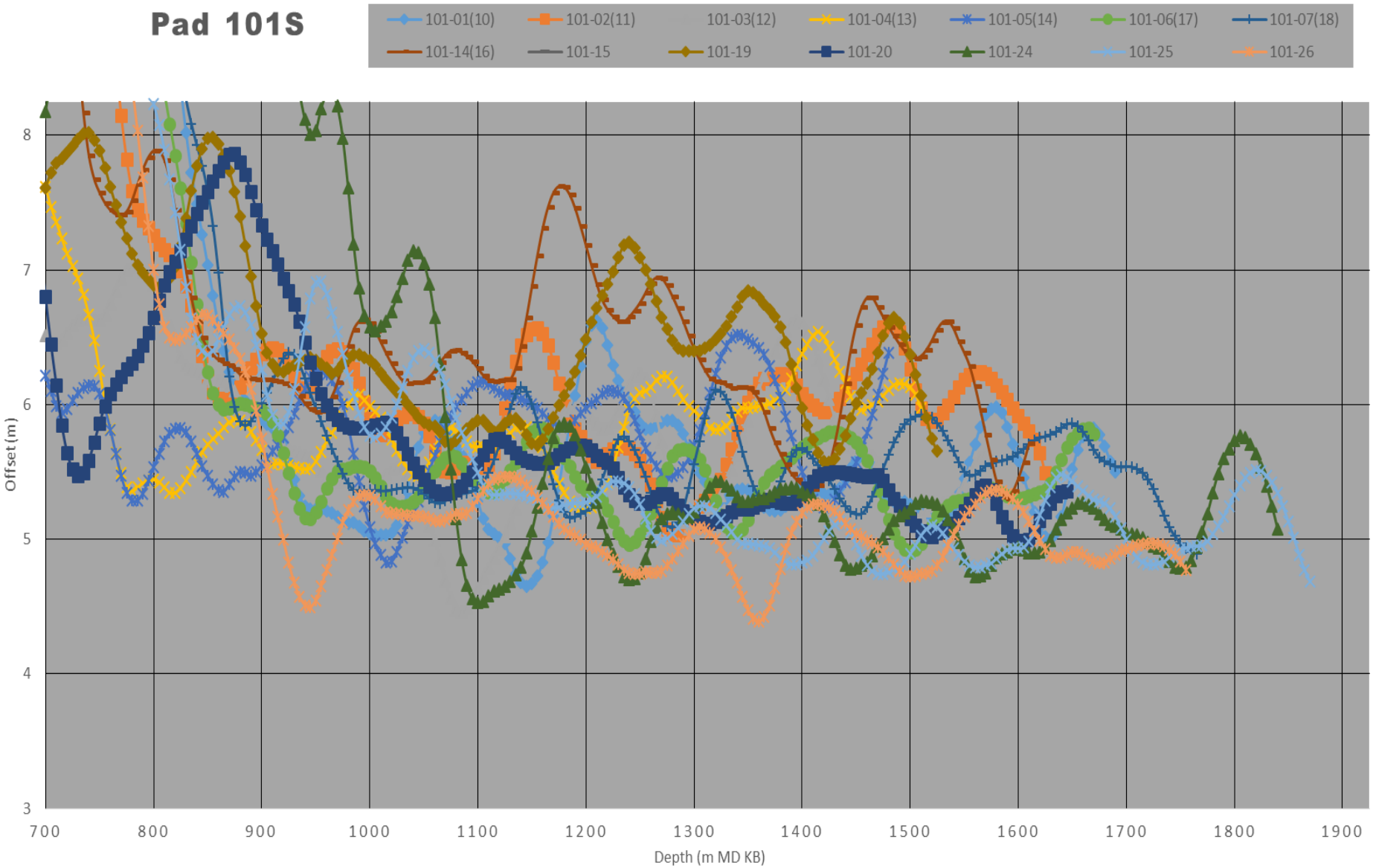
2017 Re-Drills Continued

	264-2 P05	266-2 I01	103 P07
Redrill Type	Whipstock	Whipstock	Whipstock
Reason for Redrill	Optimization/Unable to recover long tubing due to significant liner deformation	Steam injection significantly dropped off on both heel and toe, impacting chamber development and producer performance. Troubleshooting indicated potential liner plugging. Re-drilling the injector was the top option to fix the issue, and meet forecasted injection/ production rates.	4'' Toe Tubing Fish in well from 1356.79 to 1399.99 mkb. 392m of 15.9mm Lx Data coil in the lateral. 36 missing clamps in the lateral Liner Failure at 1259mkb. Packed sand in BHA and 15m of tubing. 4 gallons of metal shavings recovered. Hard Tag @ 1259mkb – did not get past. Opted for sidetrack
Whipstock Depth (mKB)	435 mKB	552.6	513.29
Whipstock Depth (mTVD)	345 mTVD	307	440.61
Liner Length (m)	1134 m	1094.36	1188.82
FCD interval Length (m)	976 m	655.71	991.87
Completion	Gas Lift	Baker Hughes - 52 Helix 0.2 FRR	LDFCD 1.6 FRR HELIX 100% Coverage
Comments	N/A	N/A	Sidetrack is 7'' O.D. ESP landed above sidetrack point due to 7'' ID restriction. Slimhole completion design is in development.

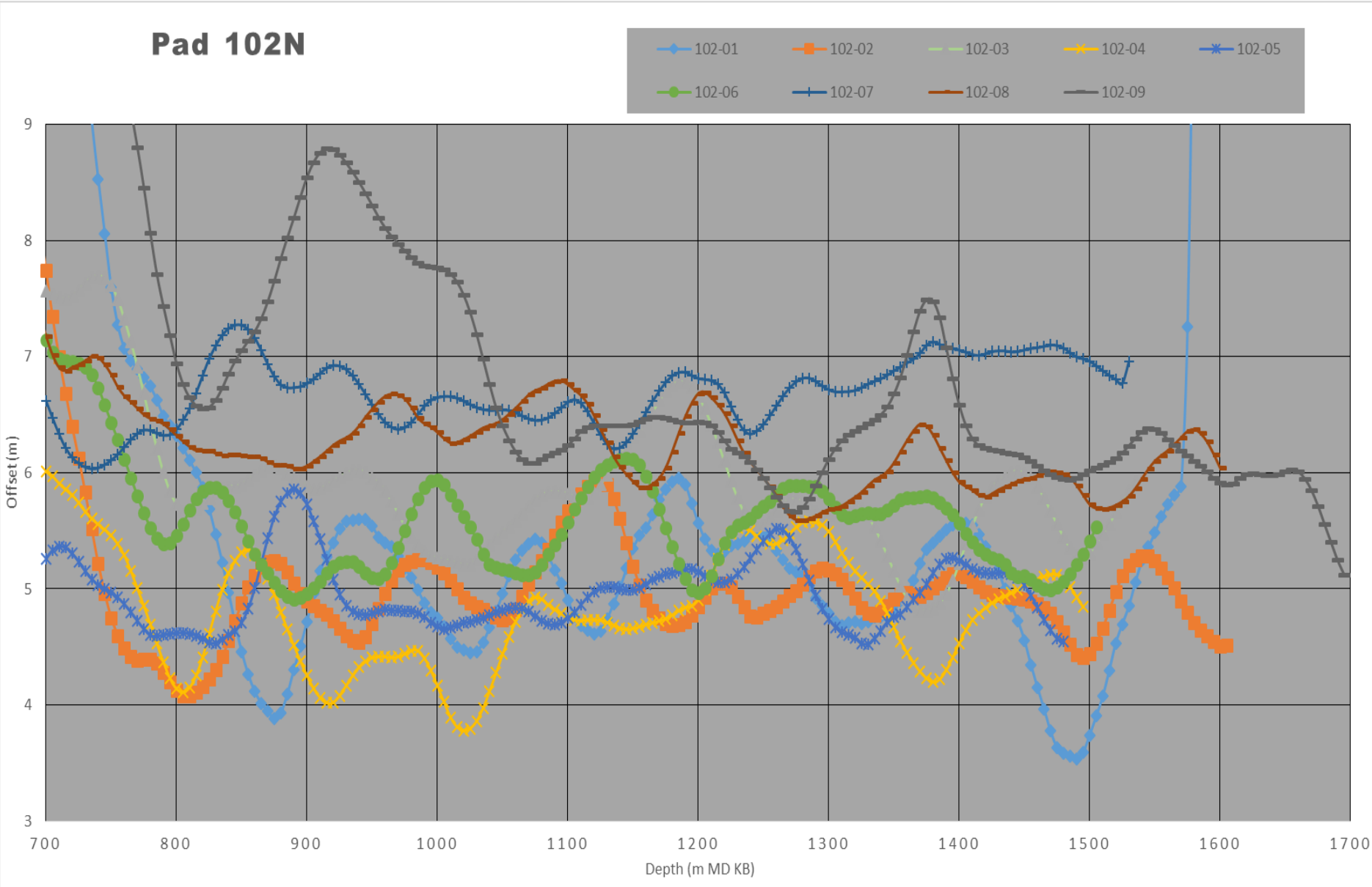
Well Pad 101 North
Producer and Injector Vertical Offset



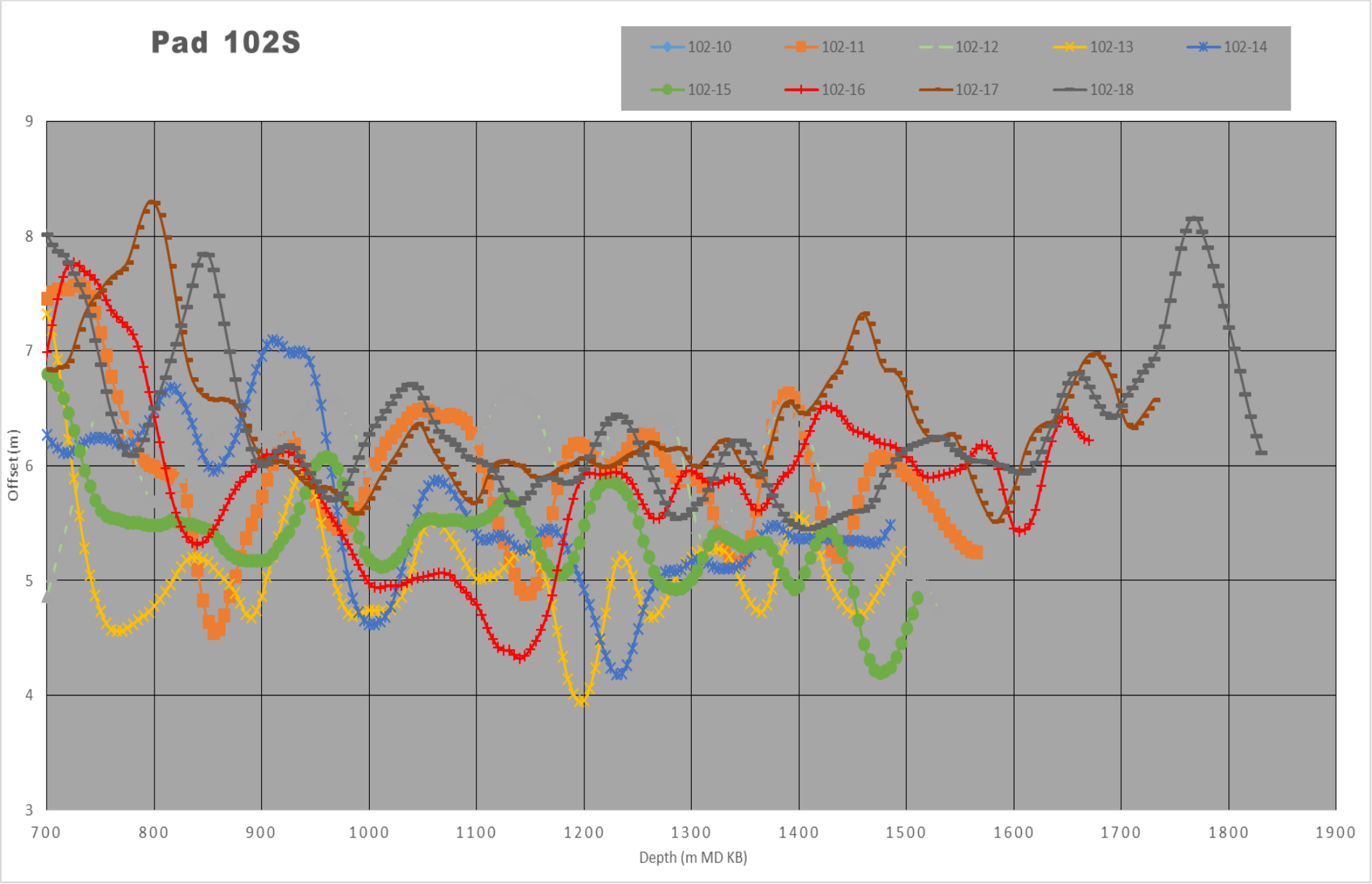
Well Pad 101 South
Producer and Injector Vertical Offset



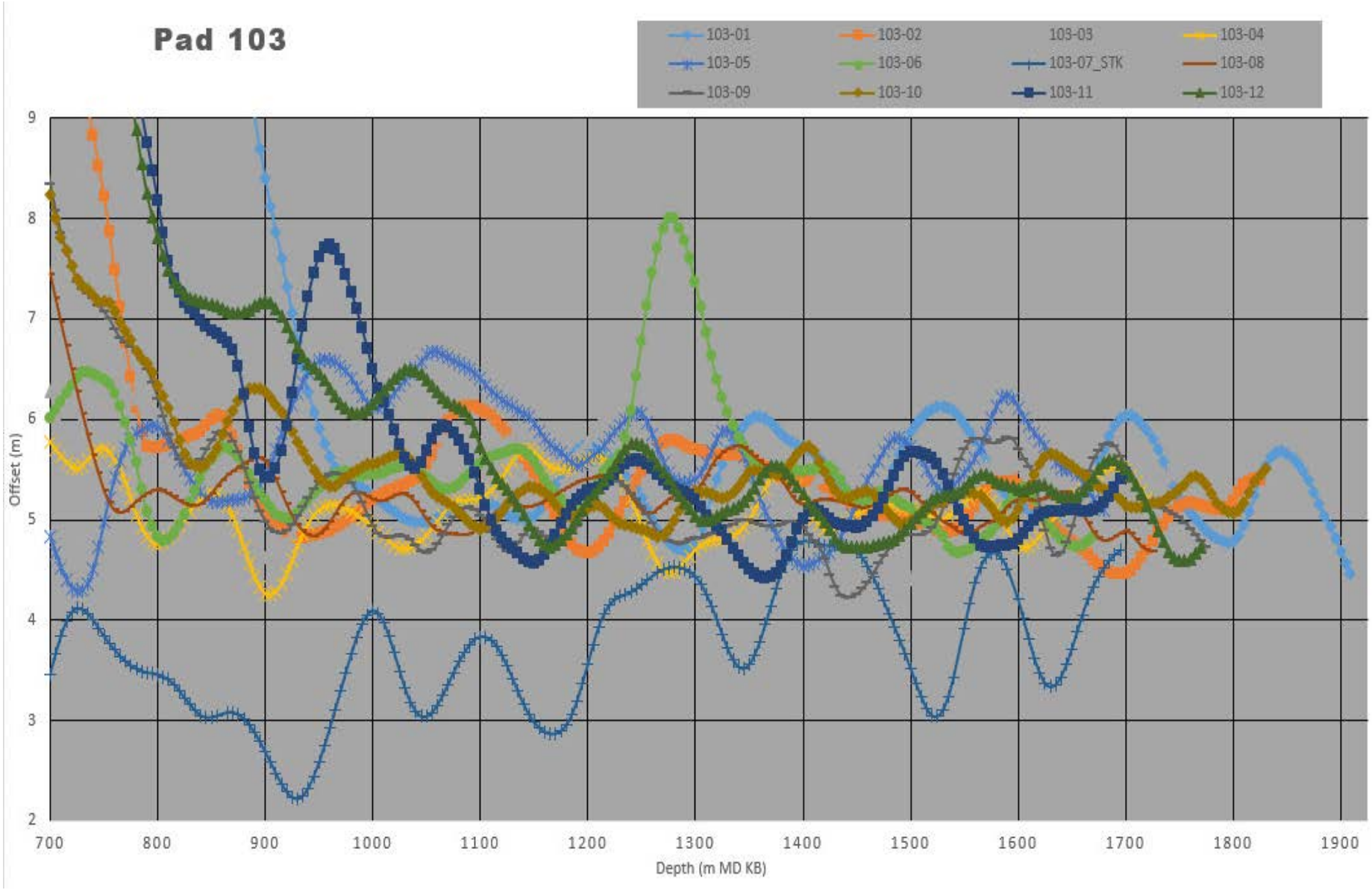
Well Pad 102 North
Producer and Injector Vertical Offset



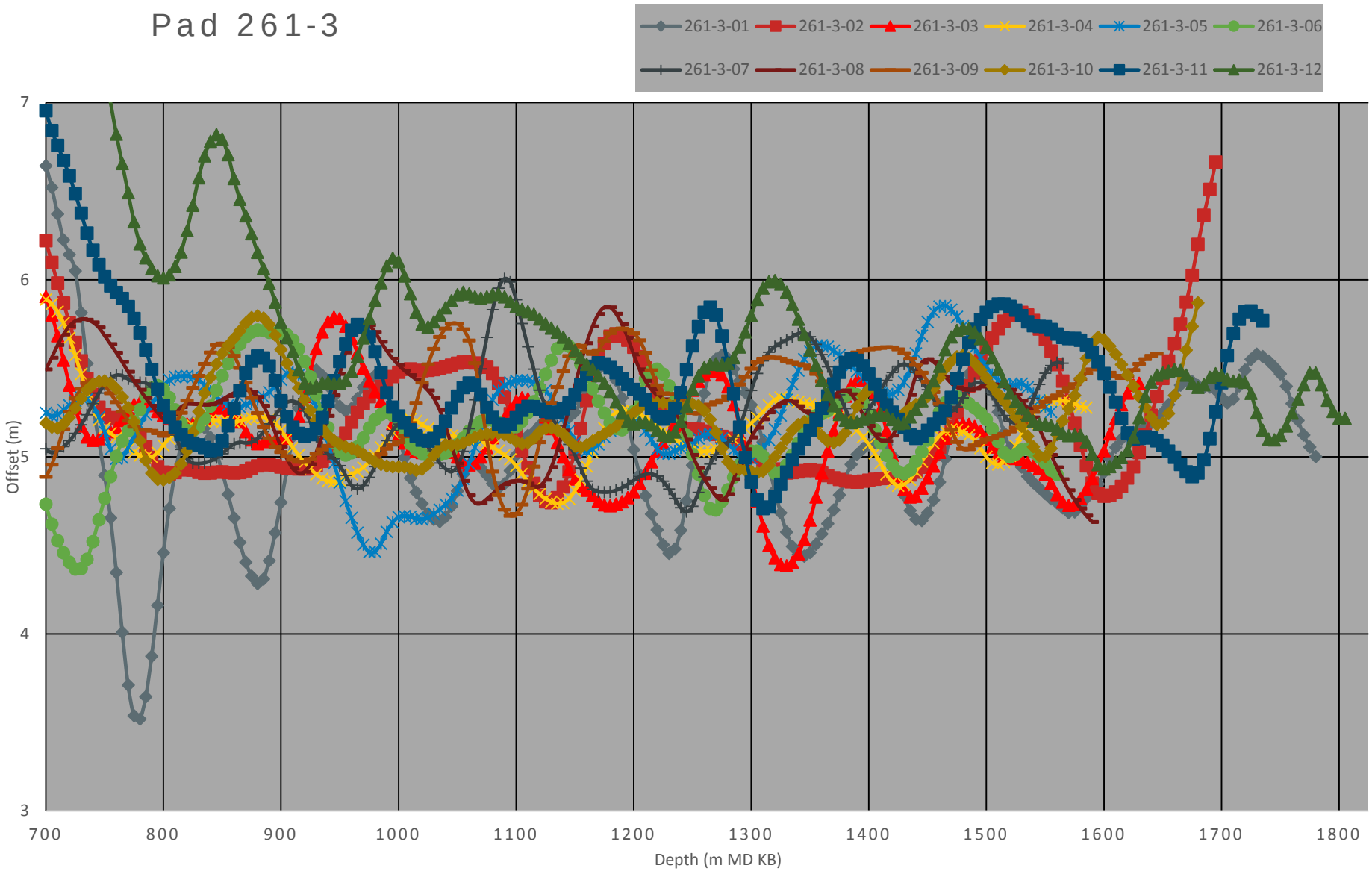
Well Pad 102 South
Producer and Injector Vertical Offset



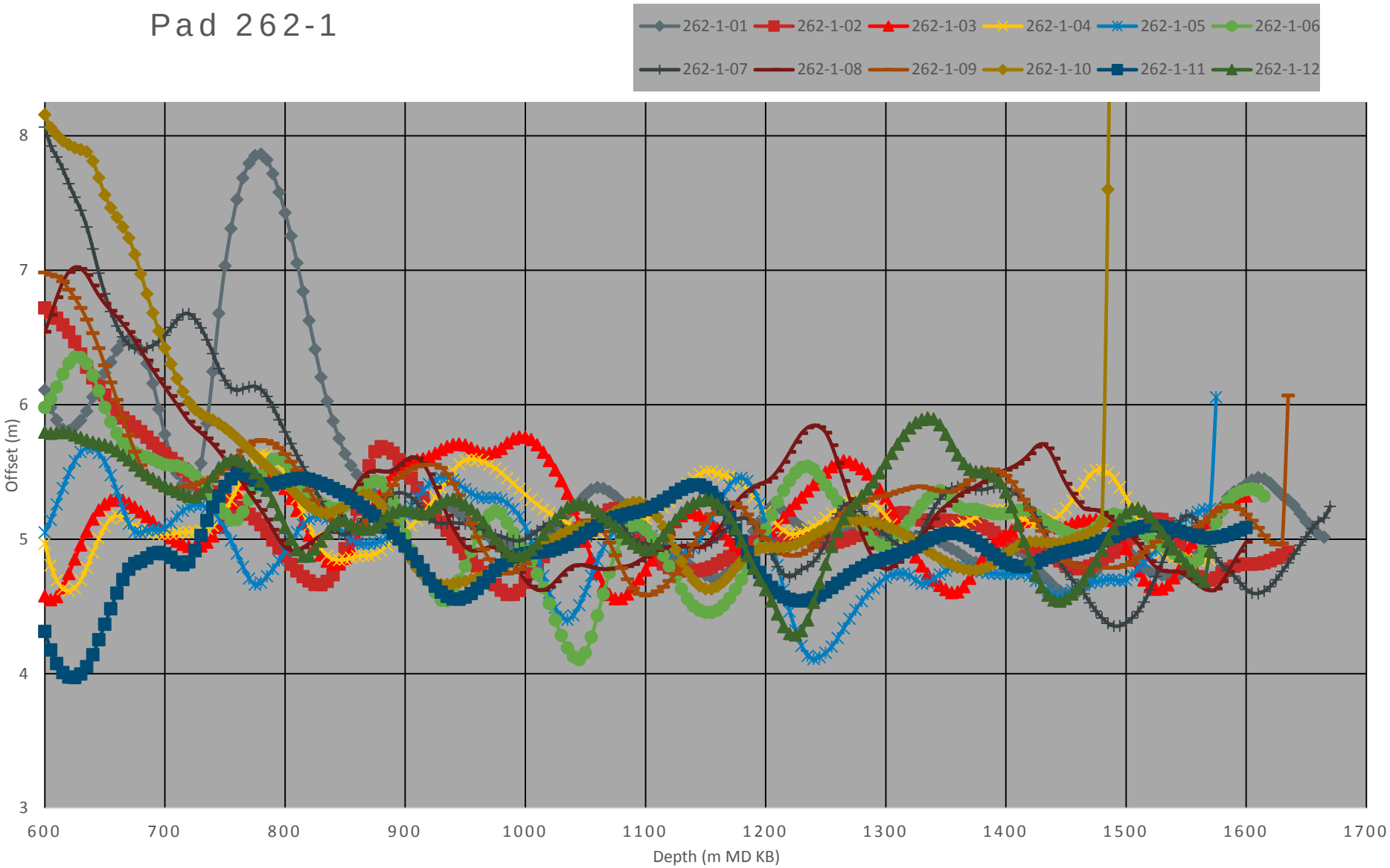
Well Pad 103
Producer and Injector Vertical Offset



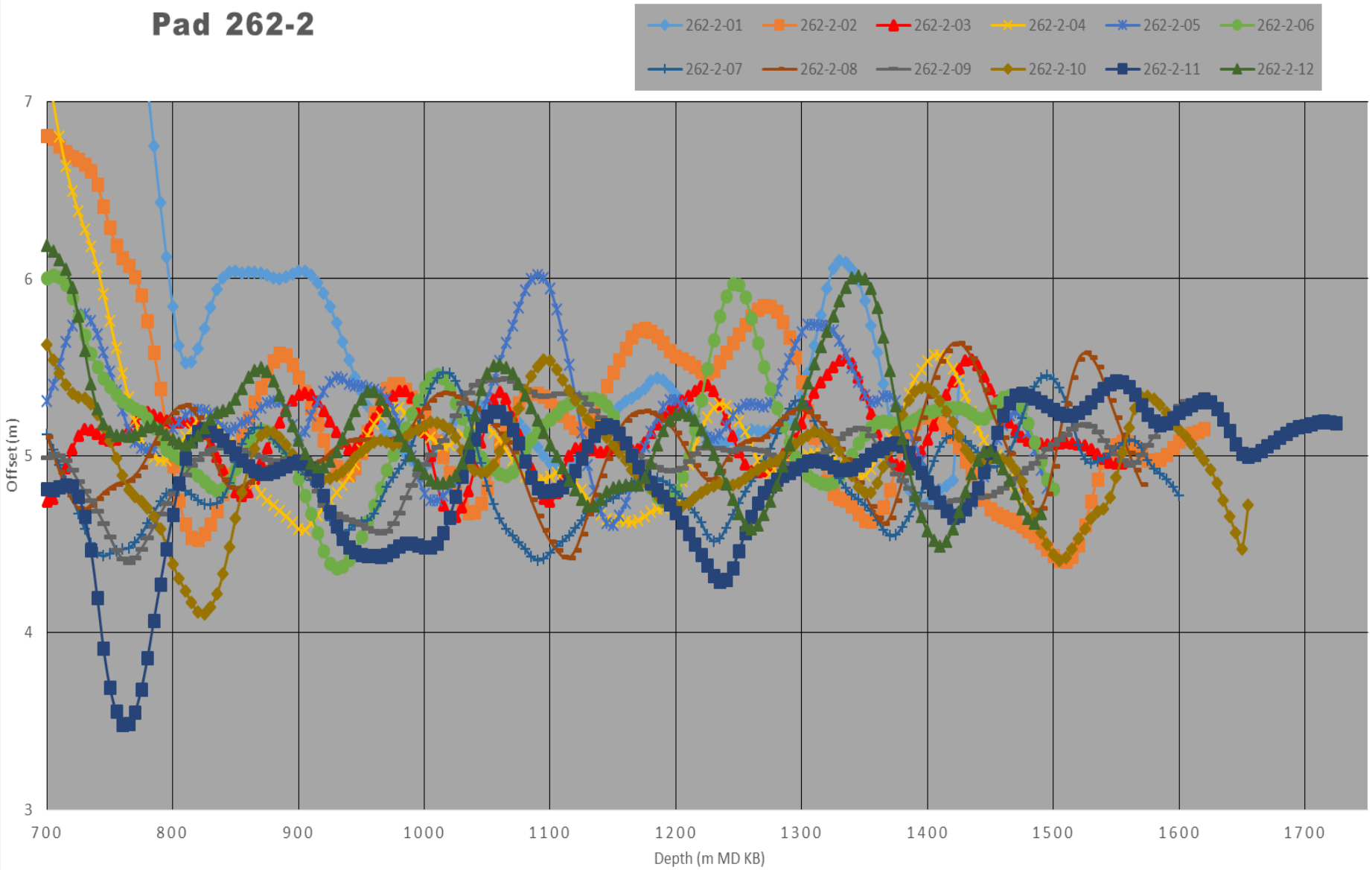
Well Pad 261-3
Producer and Injector Vertical Offset



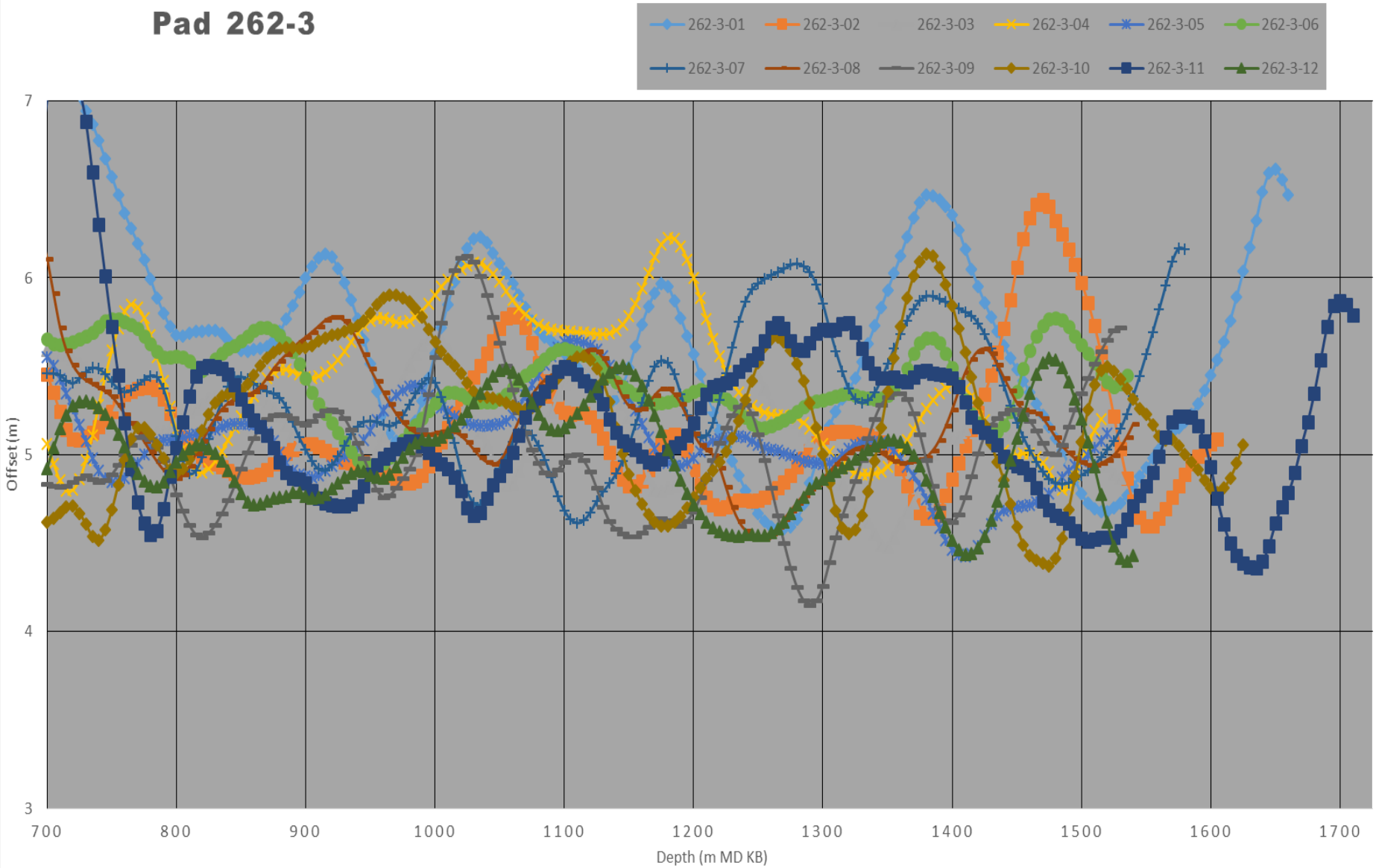
Well Pad 262-1
Producer and Injector Vertical Offset



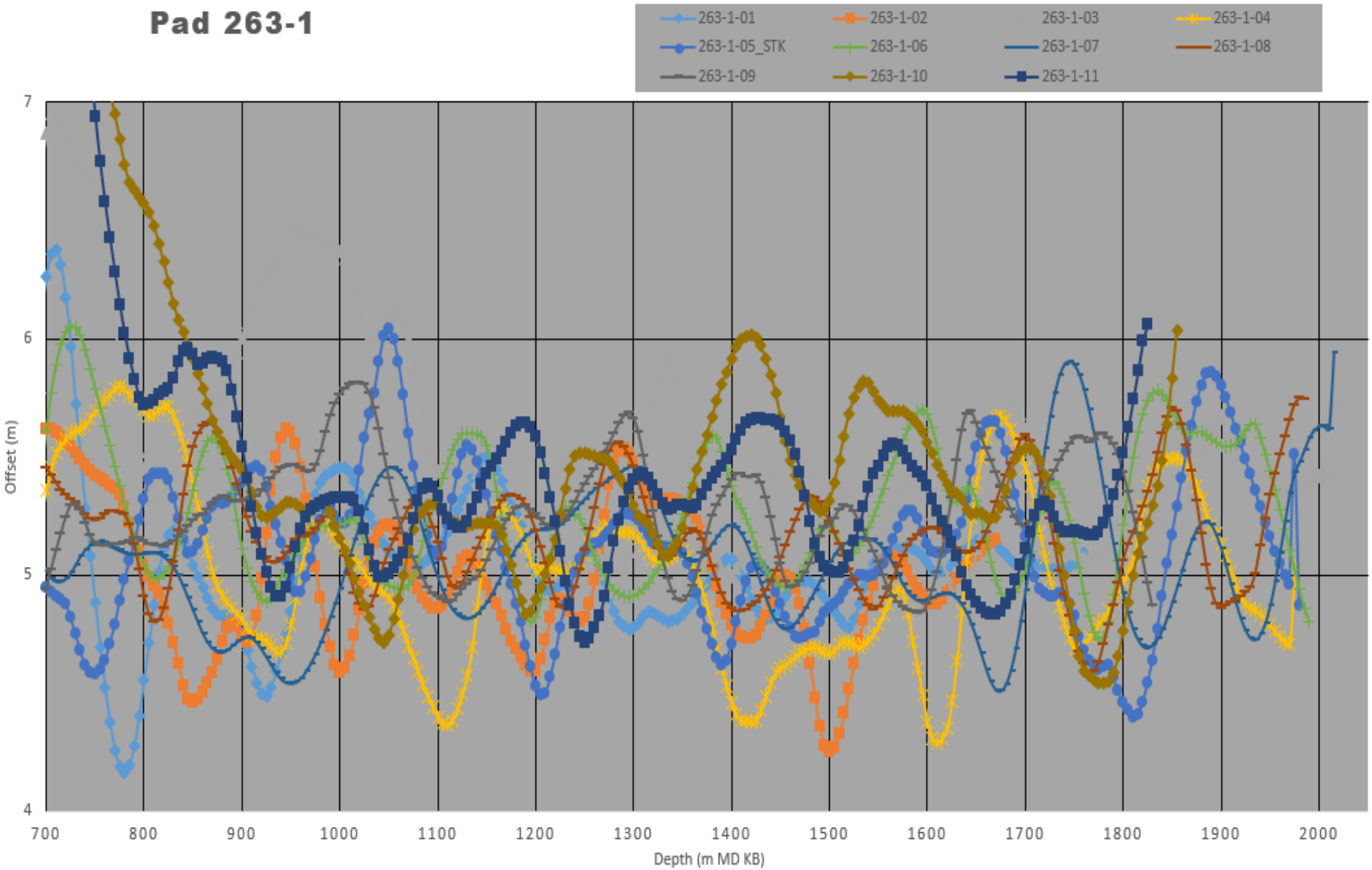
Well Pad 262-2
Producer and Injector Vertical Offset



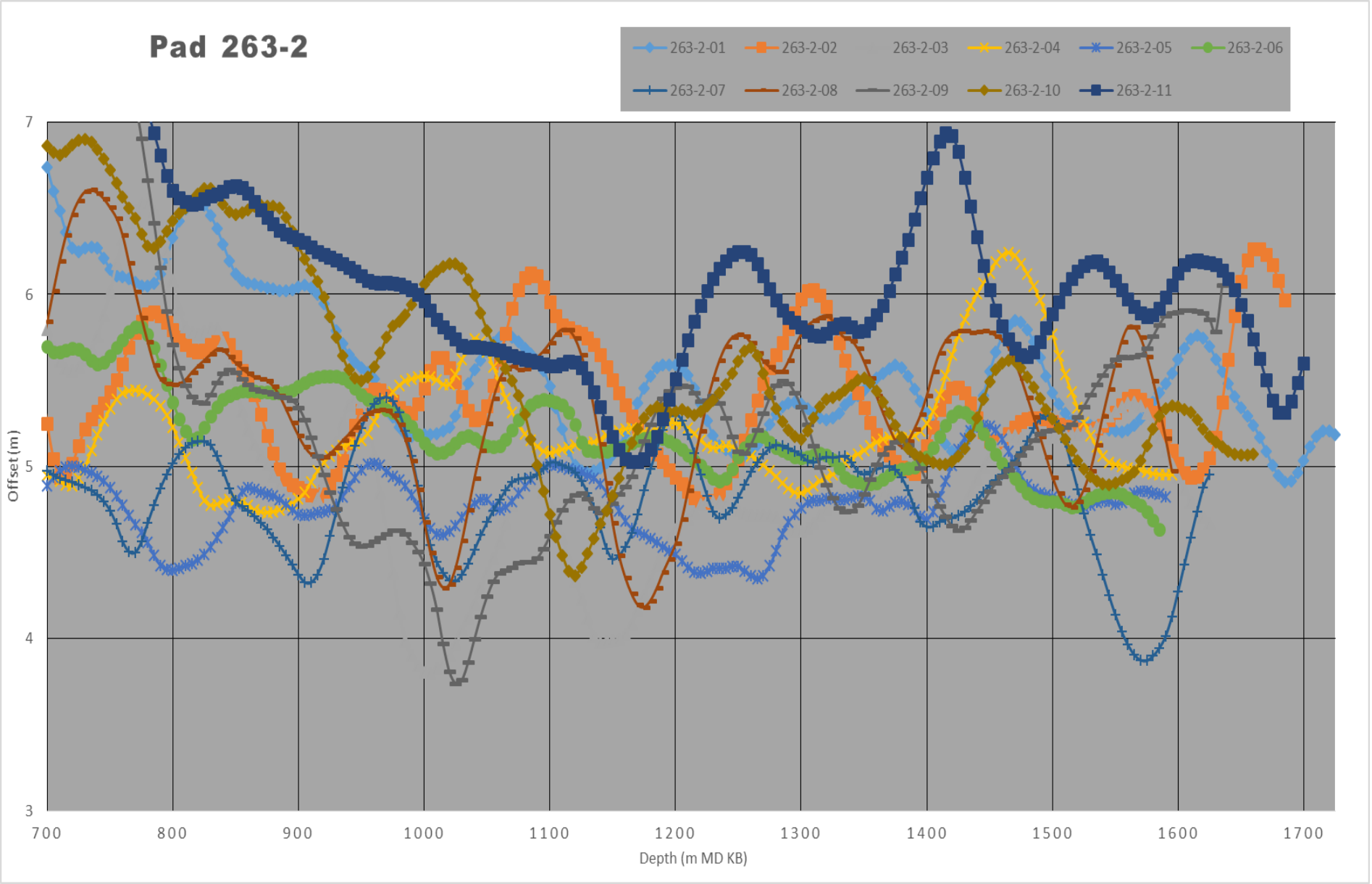
Well Pad 262-3
Producer and Injector Vertical Offset



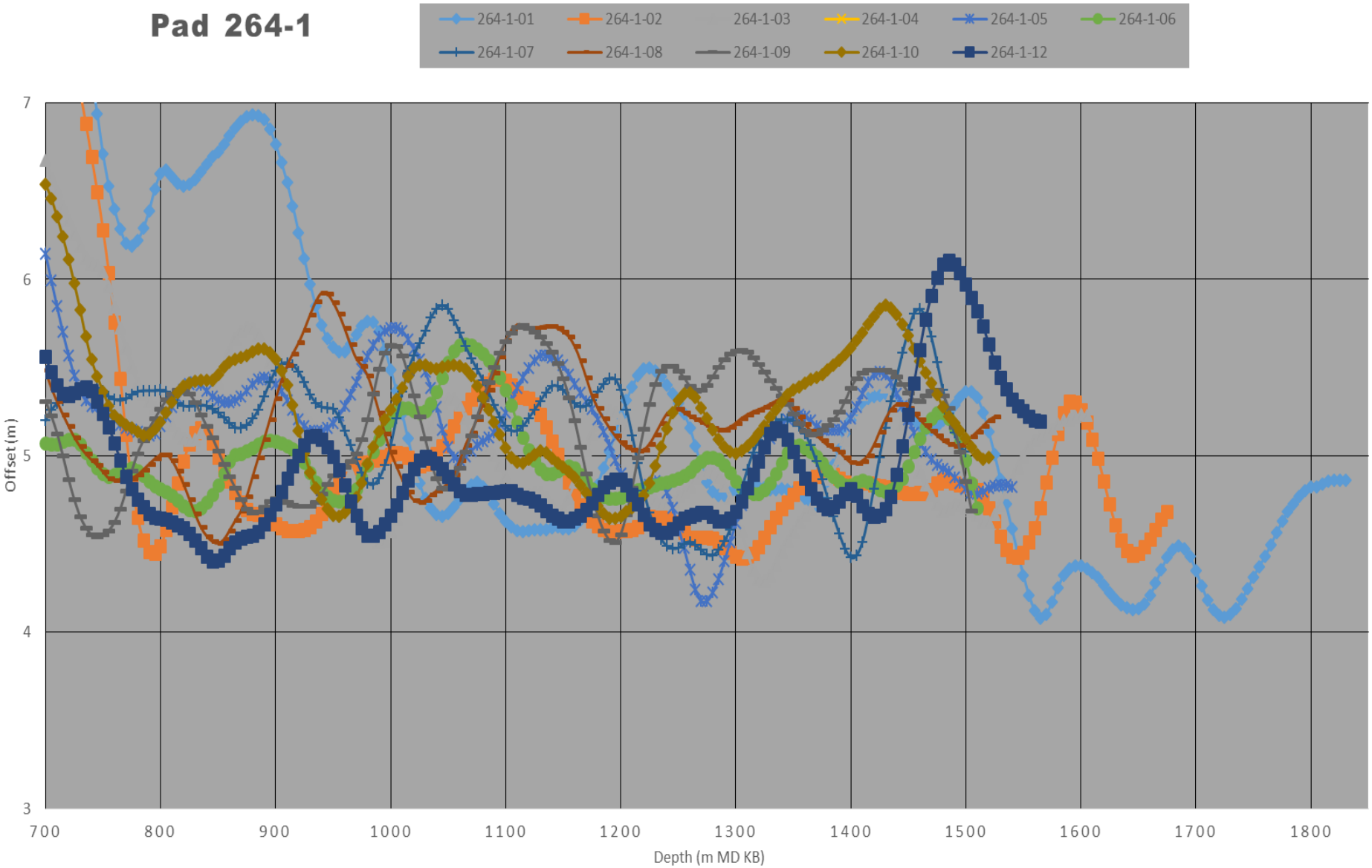
Well Pad 263-1
Producer and Injector Vertical Offset



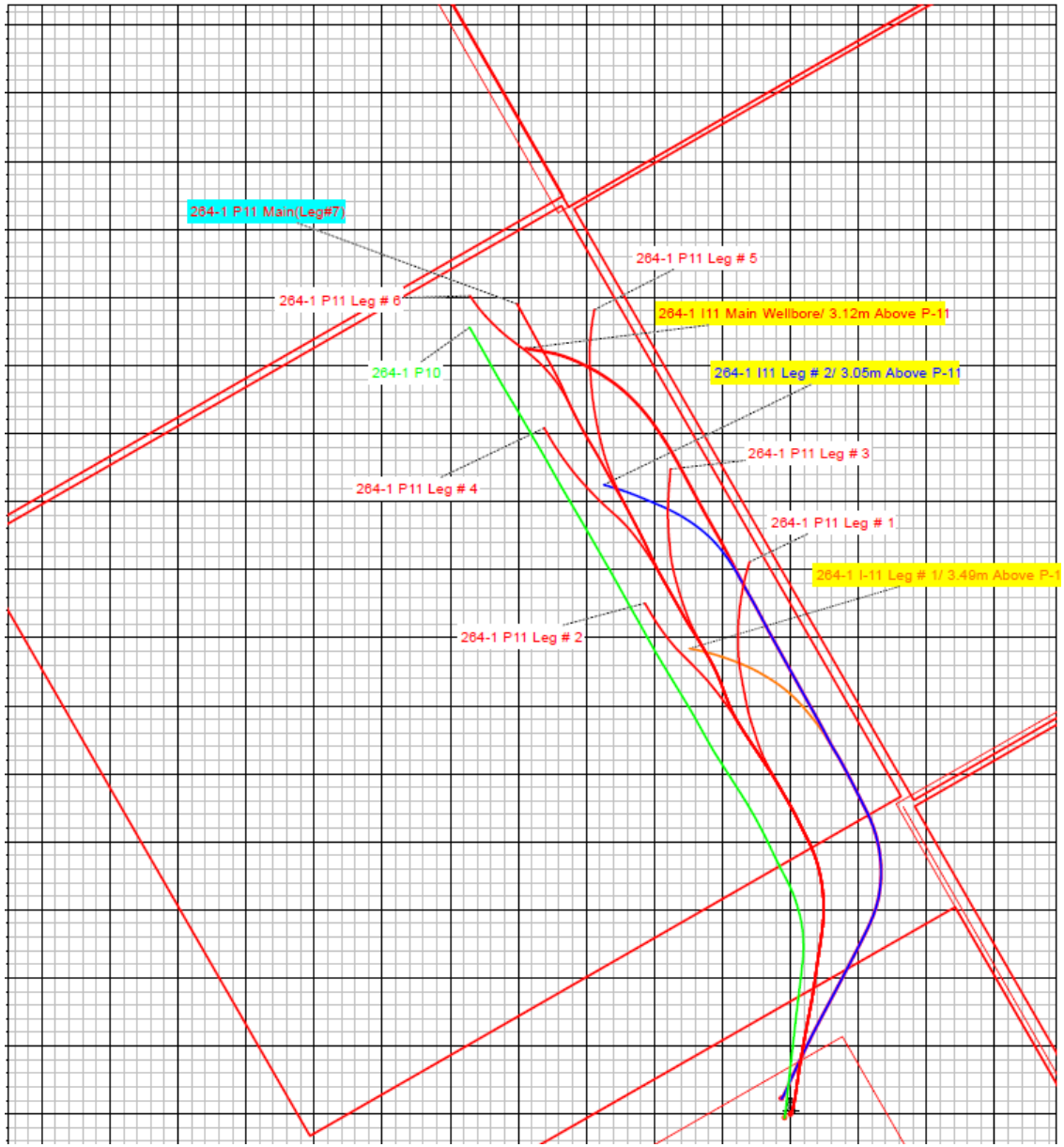
Well Pad 263-2
Producer and Injector Vertical Offset



Well Pad 264-1
Producer and Injector Vertical Offset

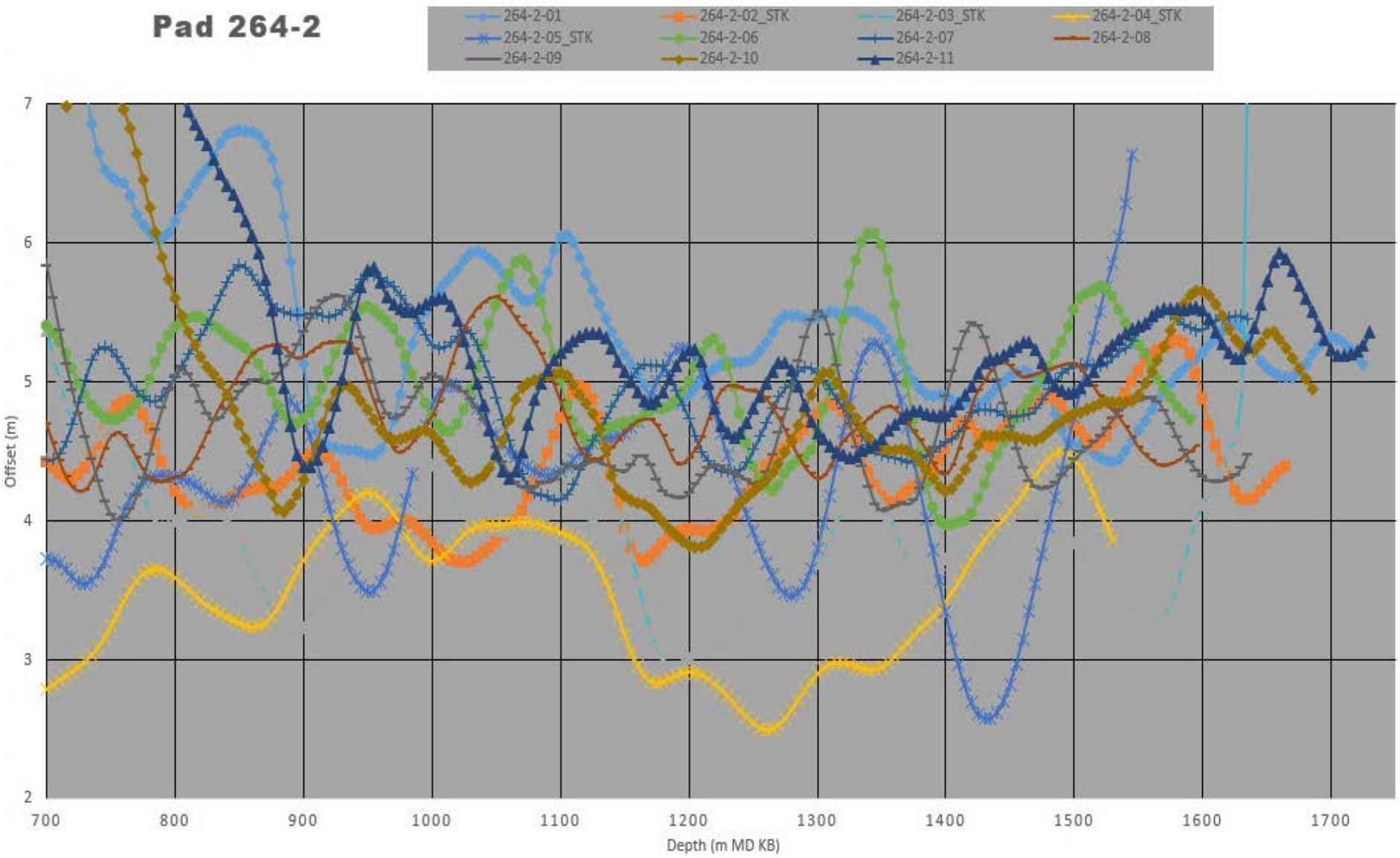


Well Pad 264-1-11 Fishbone
Producer and Injector Vertical Offset

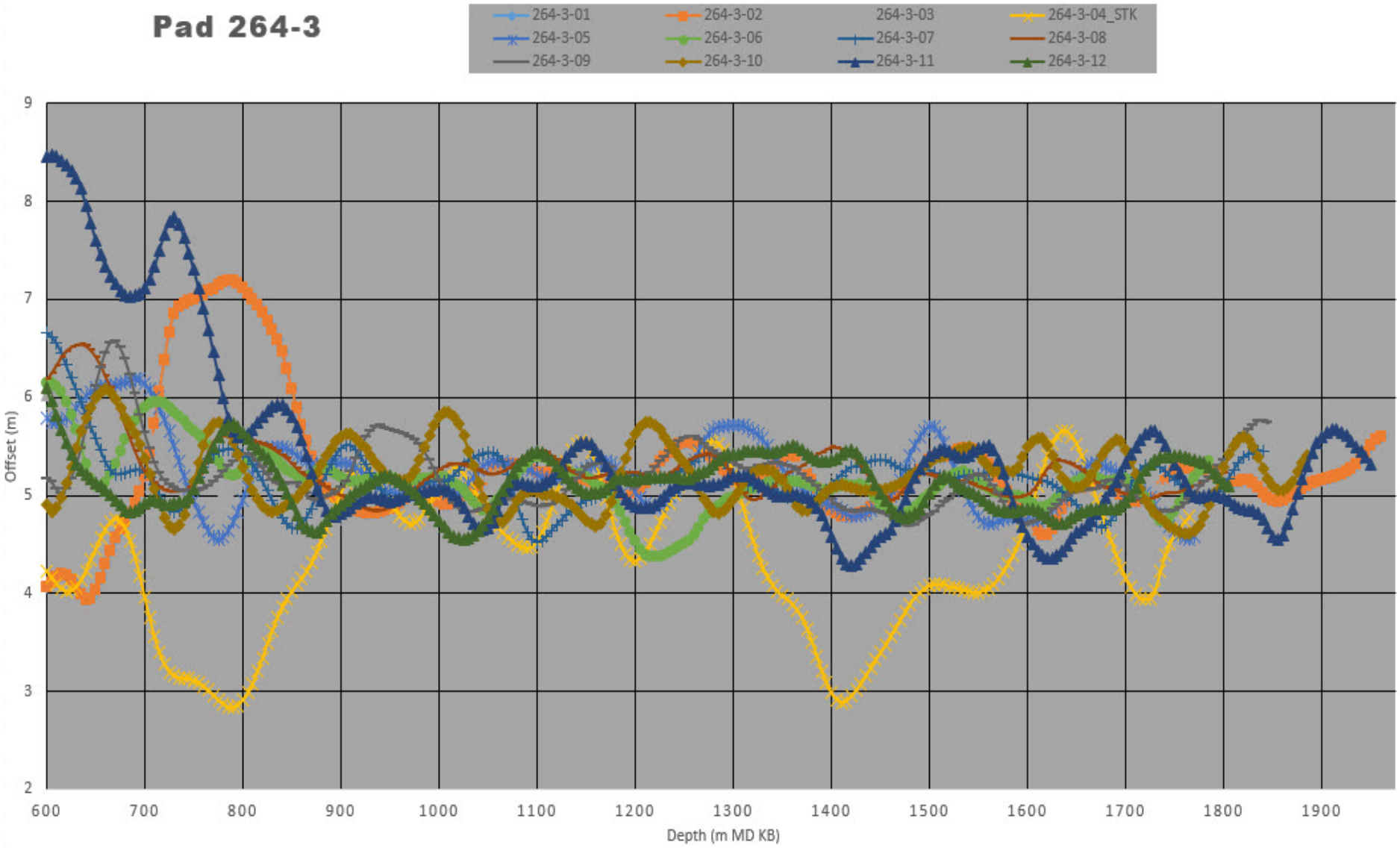


Injector has 3 legs while producer has 7 legs. 3 vertical offsets.

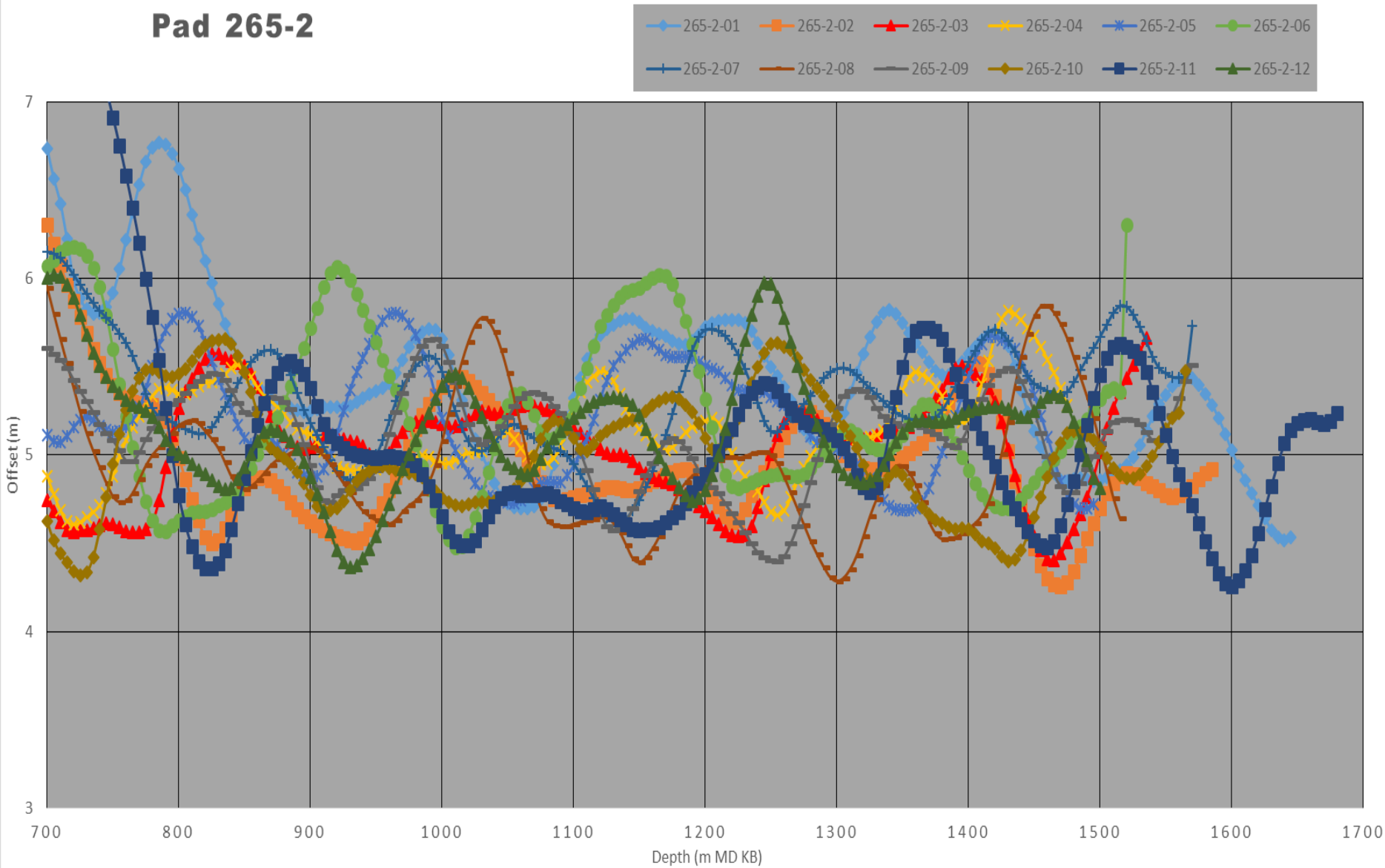
Well Pad 264-2
Producer and Injector Vertical Offset



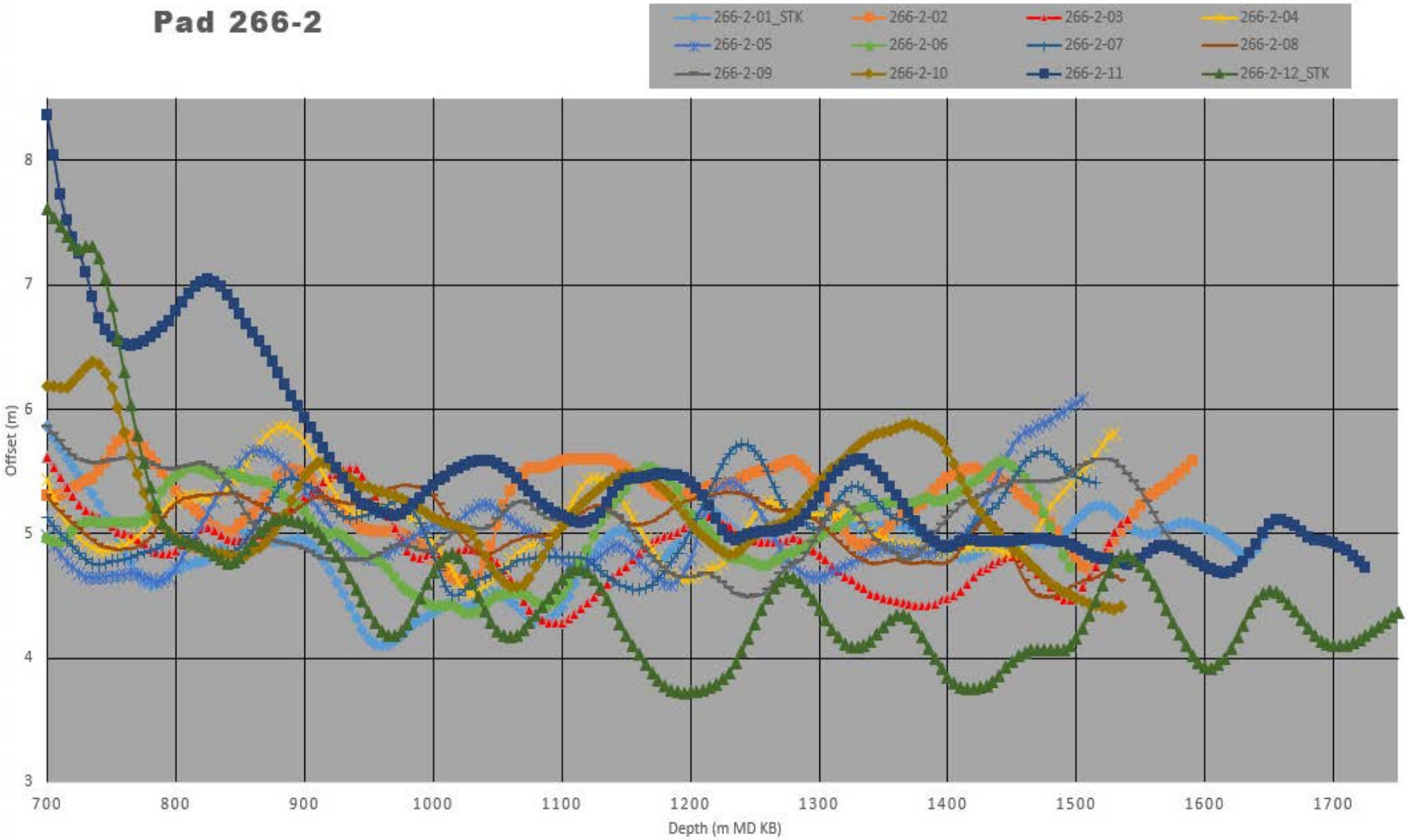
Well Pad 264-3
Producer and Injector Vertical Offset



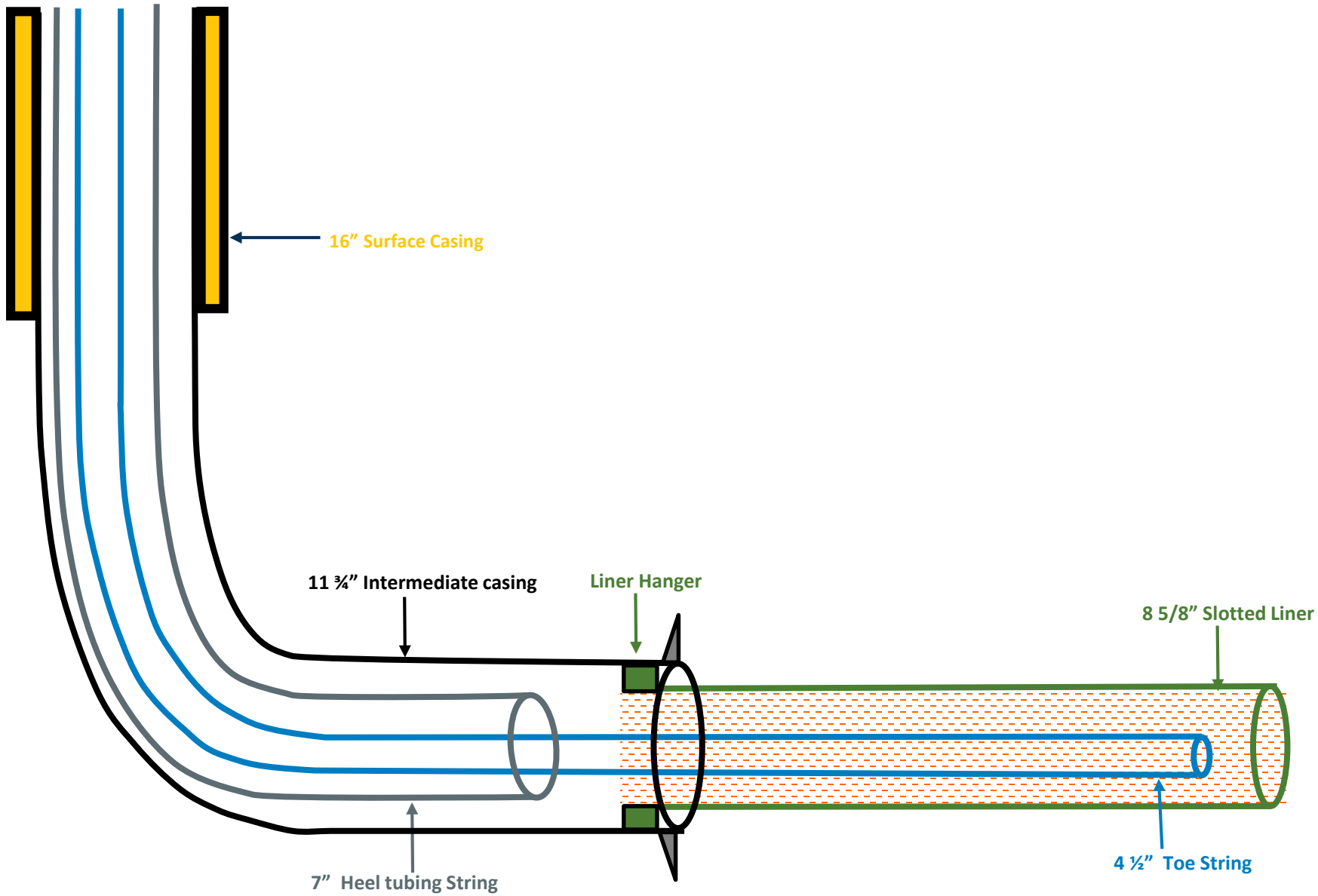
Well Pad 265-2
Producer and Injector Vertical Offset



Well Pad 266-2
Producer and Injector Vertical Offset



Typical Concentric Injector



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	Steam Splitter
101-04 (13DH)	ESP	Steam Splitter
101-05 (14DH)	ESP	Parallel
101-06 (17DH)	ESP(TDFCD)	Concentric
101-07 (18DH)	ESP	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	Steam Splitter
101-16 (07DH)	ESP	Steam Splitter
101-17 (08DH)	ESP	Steam Splitter
101-18 (09DH)	ESP	Steam Splitter
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	ESP	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	SAGD	Concentric
103-2	SAGD (FCD)	FCD
103-3	ESP (TDFCD)	Concentric
103-4	SAGD (FCD)	FCD
103-5	ESP (TDFCD)	Concentric
103-6	ESP (FCD)	FCD
103-7	ESP	Concentric
103-8	ESP (FCD)	FCD
103-9	ESP Day 1	Concentric
103-10	ESP Day 1 (FCD)	FCD
103-11	ESP Day 1	Concentric
103-12	ESP Day 1 (FCD)	FCD

Pad 261-3 & 262-1 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
261-3-01	ESP	Concentric
261-3-02	SAGD	Concentric
261-3-03	ESP	Concentric
261-3-04	ESP	Concentric
261-3-05	SAGD	Concentric
261-3-06	SAGD	Concentric
261-3-07	SAGD	Concentric
261-3-08	SAGD	Concentric
261-3-09	ESP	Concentric
261-3-10	ESP	Concentric
261-3-11	SAGD	Concentric
261-3-12	ESP (TDFCD)	Concentric

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
262-1-01	SAGD	Concentric
262-1-02	SAGD	Concentric
262-1-03	SAGD	Concentric
262-1-04	ESP (TDFCD)	Concentric
262-1-05	ESP	Concentric
262-1-06	ESP	Concentric
262-1-07	ESP	Concentric
262-1-08	ESP (TDFCD)	Concentric
262-1-09	SAGD	Concentric
262-1-10	ESP (TDFCD)	Steam Splitter
262-1-11	ESP (TDFCD)	Concentric
262-1-12	SAGD	Concentric

Pad 262-2 & 262-3 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
262-2-01	ESP	Concentric
262-2-02	SAGD	Concentric
262-2-03	ESP (TDFCD)	Concentric
262-2-04	ESP (TDFCD)	Concentric
262-2-05	ESP (TDFCD)	Concentric
262-2-06	ESP	Concentric
262-2-07	ESP	Concentric
262-2-08	ESP	Steam Splitter
262-2-09	ESP	Steam Splitter
262-2-10	ESP	Concentric
262-2-11	ESP	Concentric
262-2-12	ESP (TDFCD)	Concentric

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

Pad 263-1 & 263-2 Well Completions

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
263-1-01	ESP (FCD)	Steam Splitter
263-1-02	ESP (FCD)	Concentric
263-1-03	ESP (TDFCD)	Concentric
263-1-04	ESP (TDFCD)	Concentric
263-1-05	SAGD	FCD
263-1-06	ESP (FCD)	Concentric
263-1-07	ESP	Concentric
263-1-08	ESP (FCD)	Concentric
263-1-09	ESP (FCD)	Concentric
263-1-10	SAGD	Concentric
263-1-11	SAGD (FCD)	Concentric

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
263-2-01	SAGD (TDFCD)	Concentric
263-2-02	SAGD	Concentric
263-2-03	SAGD	Concentric
263-2-04	SAGD	Steam Splitter
263-2-05	SAGD	Steam Splitter
263-2-06	SAGD	Concentric
263-2-07	SAGD (FCD)	Concentric
263-2-08	SAGD	Concentric
263-2-09	SAGD	Concentric
263-2-10	SAGD	Concentric
263-2-11	SAGD	Concentric
263-2-01	SAGD	Concentric

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

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

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

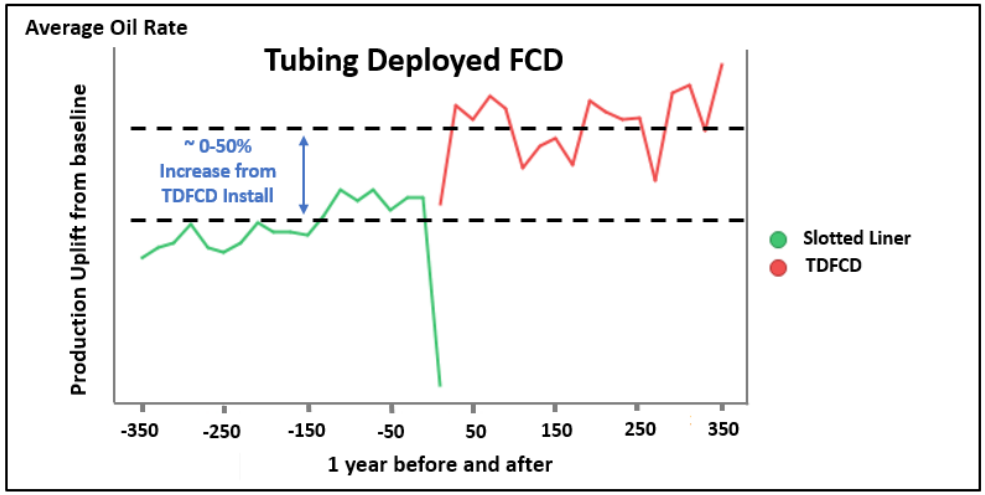
Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
264-3-01	ESP	Concentric
264-3-02	SAGD (FCD)	Concentric
264-3-03	SAGD (TDFCD)	Concentric
264-3-04	SAGD (FCD)	Concentric
264-3-05	SAGD	Concentric
264-3-06	SAGD (FCD)	Concentric
264-3-07	SAGD (TDFCD)	Concentric
264-3-08	SAGD (FCD)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

Pad 265-2 & 266-2 Well Completions

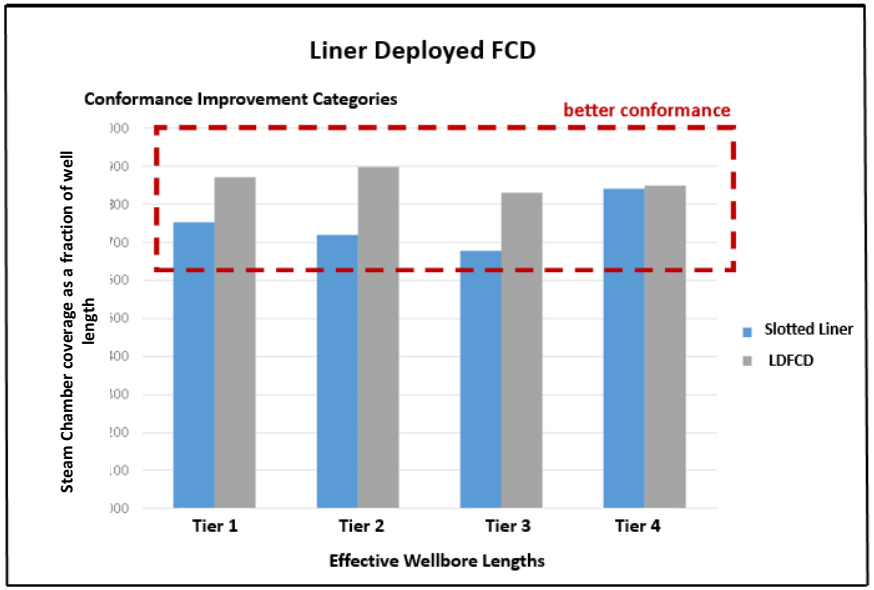
Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
265-2-01	ESP	Concentric
265-2-02	ESP	Concentric
265-2-03	ESP (TDFCD)	Concentric
265-2-04	ESP	Concentric
265-2-05	ESP (TDFCD)	Concentric
265-2-06	ESP (TDFCD)	Concentric
265-2-07	ESP	Steam Splitter
265-2-08	ESP	Steam Splitter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

Well Identifier - Surface (Downhole)	Producer Completion	Injector Completion
266-2-01	ESP Day 1 (FCD)	Concentric
266-2-02	ESP Day 1 (FCD)	FCD
266-2-03	ESP Day 1 (FCD)	FCD
266-2-04	ESP Day 1 (FCD)	FCD
266-2-05	ESP Day 1 (FCD)	Concentric
266-2-06	ESP Day 1 (FCD)	Concentric
266-2-07	ESP Day 1 (FCD)	Concentric
266-2-08	Circulation (FCD)	Concentric
266-2-09	Circulation (FCD)	Concentric
266-2-10	ESP Day 1 (FCD)	Concentric
266-2-11	ESP	Concentric
266-212	ESP (FCD)	Concentric

2017 FCD Performance



- TDFCD average uplift ~0-50% from 43 installations on data normalized before/after 1 year.
- Uplift dependent on the improvement that TDFCD provides to the level of operability on a per well basis.



- Higher tier indicates higher effective wellbore length.
- 4D volume indicates ~15% improvement in conformance in LDFCD compared to Slotted Liner wells.

Intermediate Casing Integrity

- Majority of failures were at the casing connection
- License# 447680 was a result of an under-reamer being activated in the casing.

License #	Well Name	UWI	Company	Fluid	Mode	Lahee	Type	Date Reported	Well Type	Status	Repair	Date of Repair
314289	COP 102-P05-HZ RESDELN 8-12-83-7	03/08-12-083-07W4/0	A5G3	Heavy Oil	SAGD	Development	Horizontal	3/27/2018	S1 - SAGD Producer	Open		
328323	COPRC 101-I15-HZ RESDELN 7-13-83-7	06/07-13-083-07W4/0	A5G3	Steam	SAGD	Development	Horizontal	6/30/2016	S1 - SAGD Injector	Closed	Casing Patch	11/12/2016
399986	COP 101-P18-HZ RESDELN 2-13-83-7	05/02-13-083-07W4/0	A5G3	Heavy Oil	SAGD	Development	Horizontal	7/18/2017	S1 - SAGD Producer	Closed	Casing Patch	7/27/2017
409082	COP 102-I11RD-HZ RESDELN 7-1-83-7	02/07-01-083-07W4/0	A5G3	N/A	Drain	Development Service	Horizontal	6/11/2010	S1 - SAGD Injector	Closed	Cement Squeeze/ Plug	3/3/2011
447680	COPRC HZ 2642I04 NEWBY 15-23-83-6	02/15-23-083-06W4/0	A5G3	Steam	SAGD	Development Service	Horizontal	9/21/2015	S2 - SAGD Injector	Closed	Casing Patch	9/23/2015

Table 1

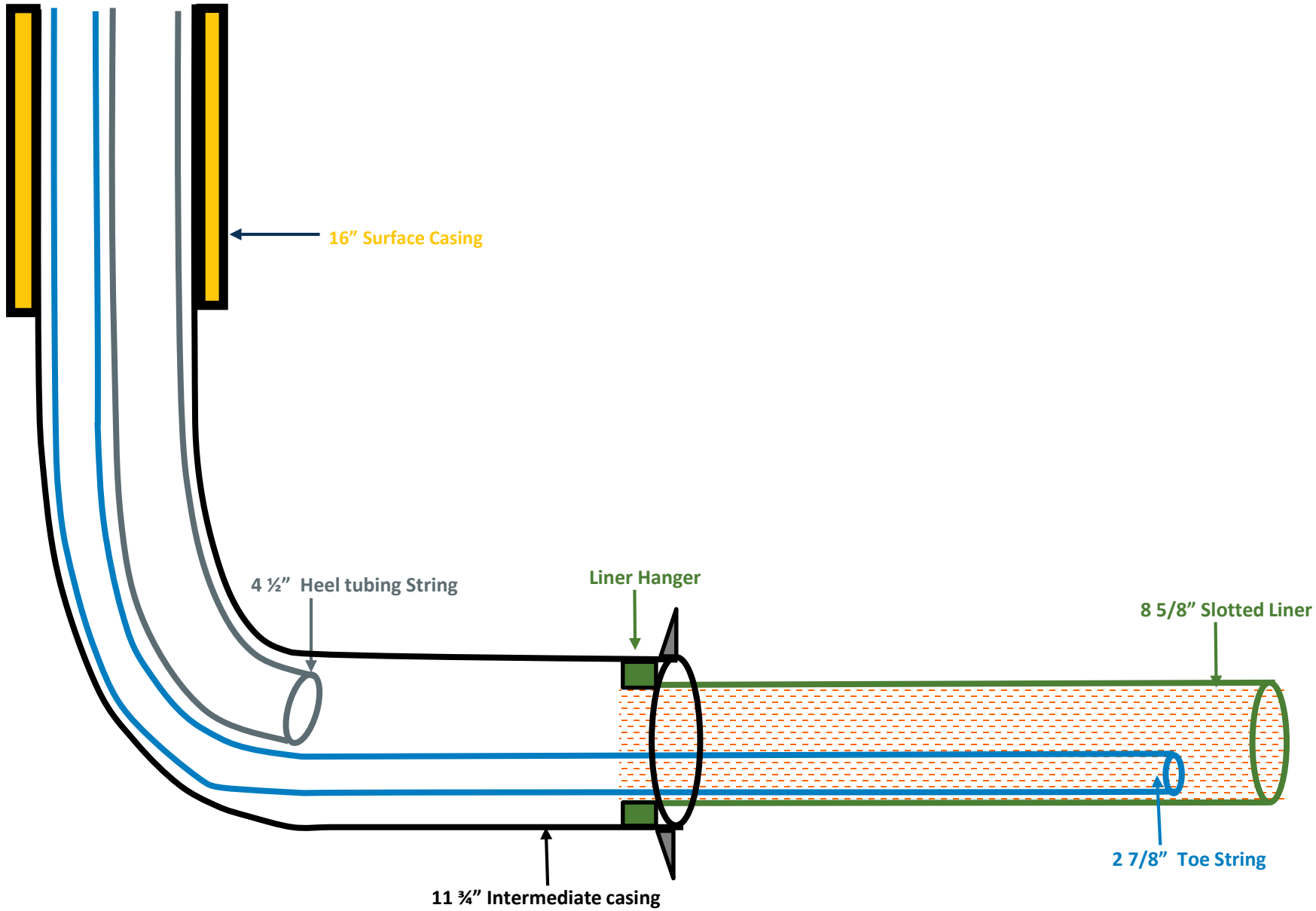
SCVF Summary

- **2016 SCVF Cold Testing – Summary**
  - Fort McMurray wildfire resulted in field-wide shut-in
  - Used the shutdown to test all SCVFs while the wells were cold (+20 days)
  - 359 SAGD wells bubble tested (10-minute bubble test when well is cold)
  - 4 wells failed
    - Diagnostics concluded:
      - Gas resembles production casing gas (i.e. blanket gas, lift gas, produced gas)
      - Cold flows are the result of minor seepage of blanket/lift gas across production casing connections*
    - High temperatures in operating SAGD wells:
      - May cause seeping surface and production casing connections
      - Quaternary / shallow water is boiled
      - Shallow organic material is heated liberating H2S and hydrocarbons
    - Low Risk
  - Testing wells while cold:
    - Diagnostically faster
    - Easier to identify legitimate SCVF issues
  - Continue to test SCVF on well pairs during well interventions and workovers, when well has cooled.

- Future Development Focus
  - Working with ConocoPhillips Global expert in cementing, we are testing the slurry designs to ensure that they meet the objectives, including minimizing SCVF /GM.
  - The drilling program is continuously improved, including suggestions from Global Cementing expert to ensure that best practices are included in the cement placement.
  - We participate in industry benchmark and knowledge sharing sessions on SAGD drilling topic.

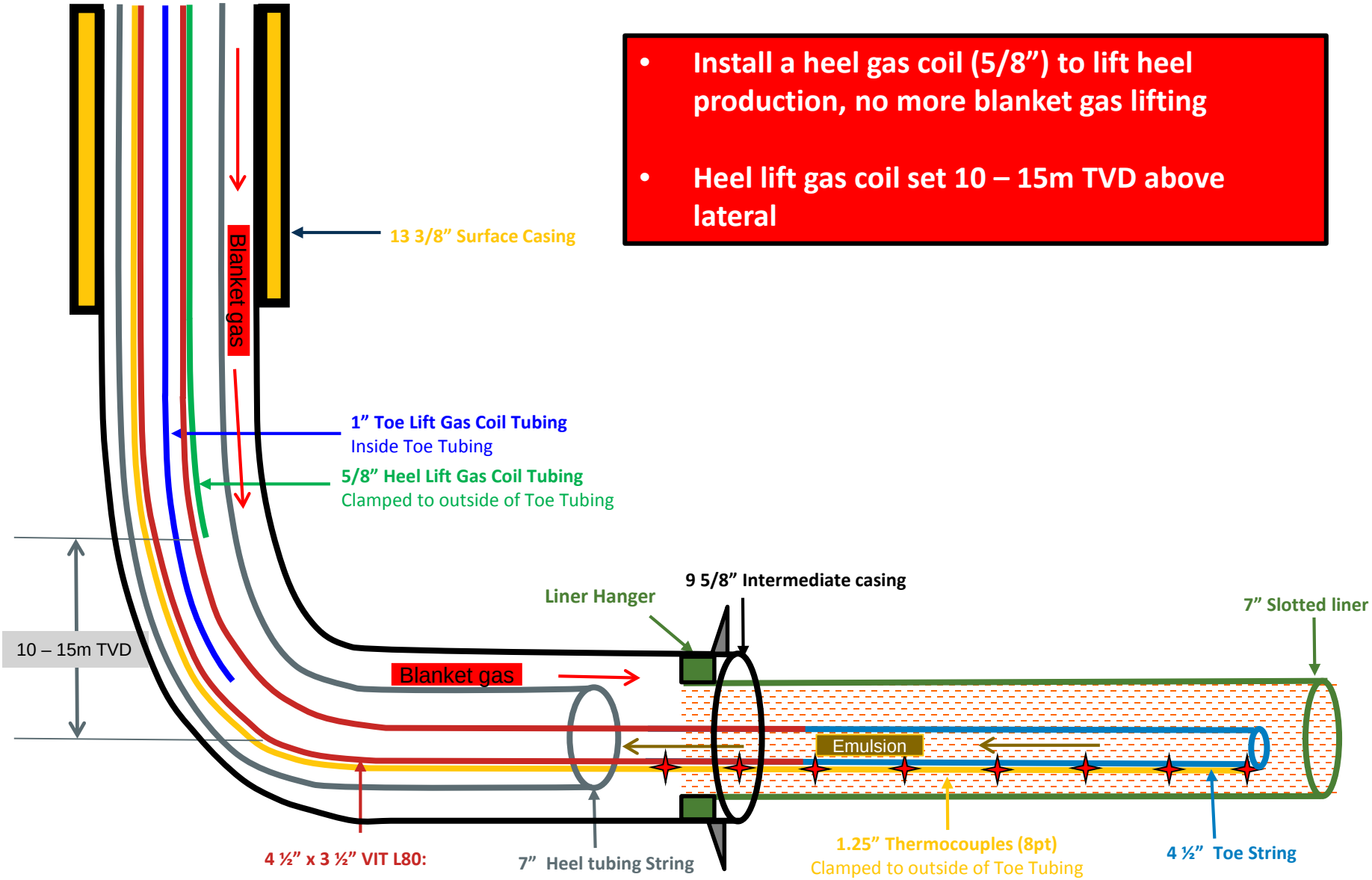
*The Thermal Well Casing Connection Evaluation Protocol (TWCCEP) considers a seepage rate of 0.06mL/min a threshold rate for reporting. This equates to a total of 86.4mL/day of seepage per connection.

Typical Parallel Injector



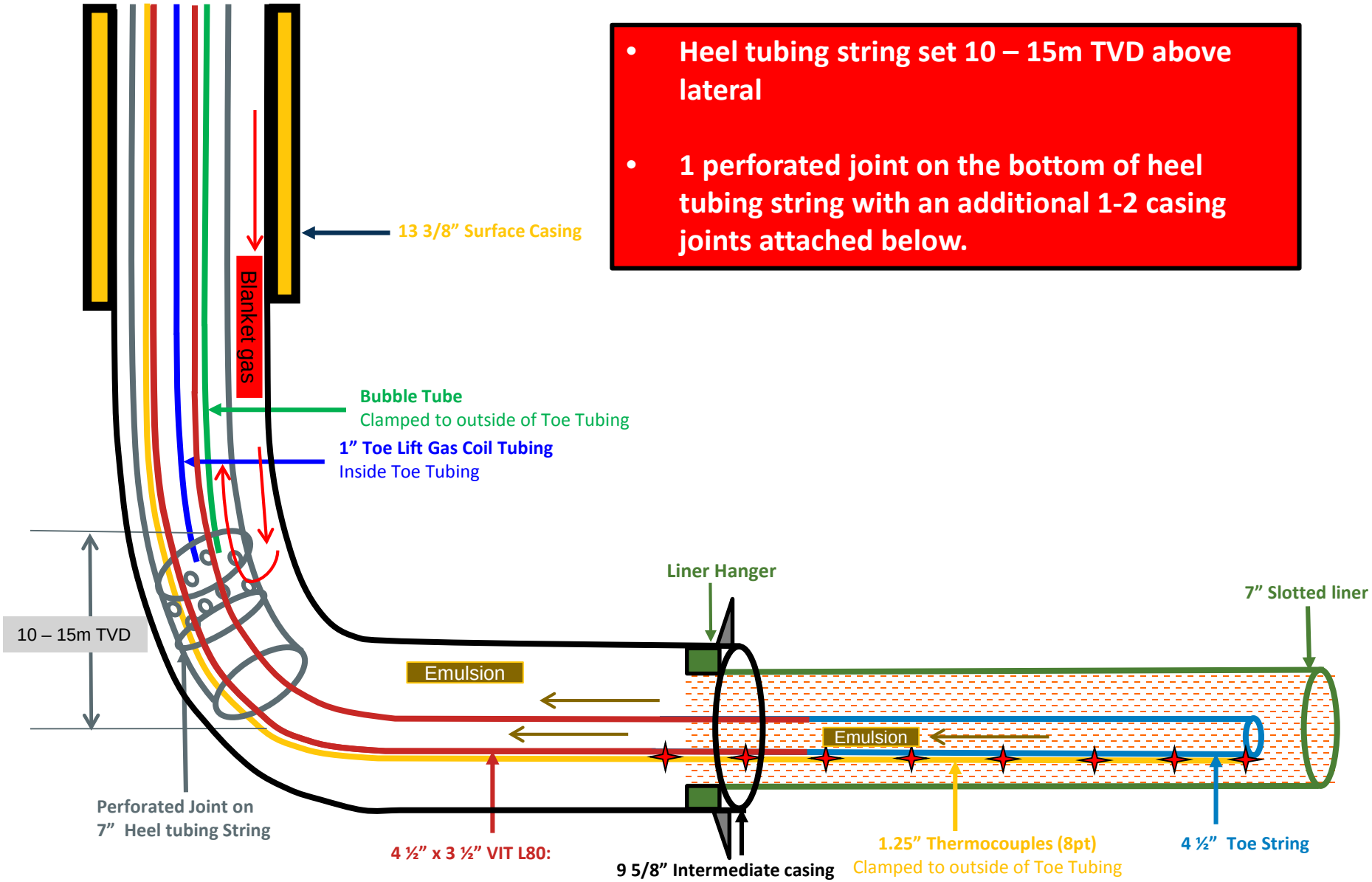
Improved Gas Lift Producer Design, 264-1

- **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**

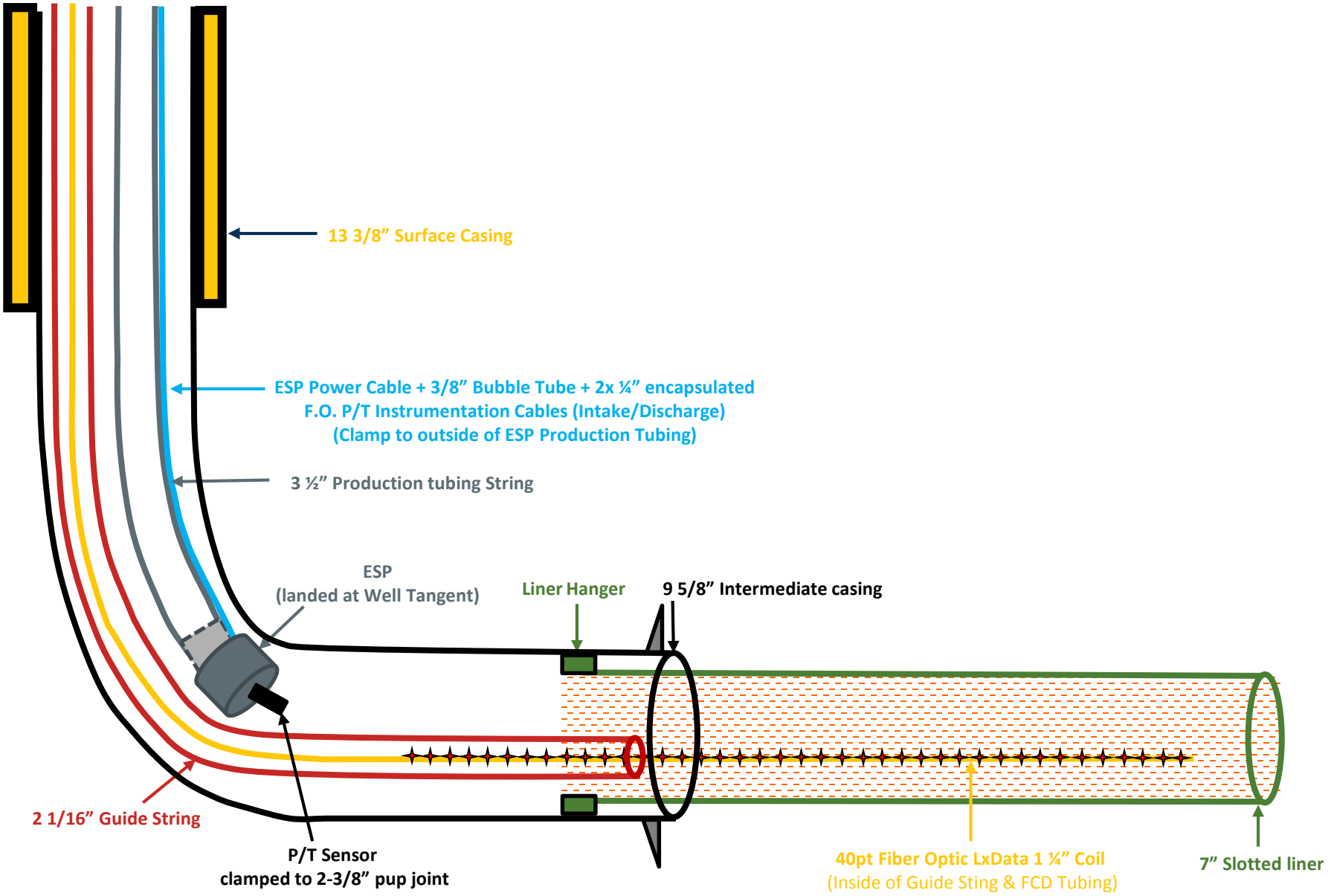


Improved Gas Lift Producer Design, 264-2, 263-2 & 263-1

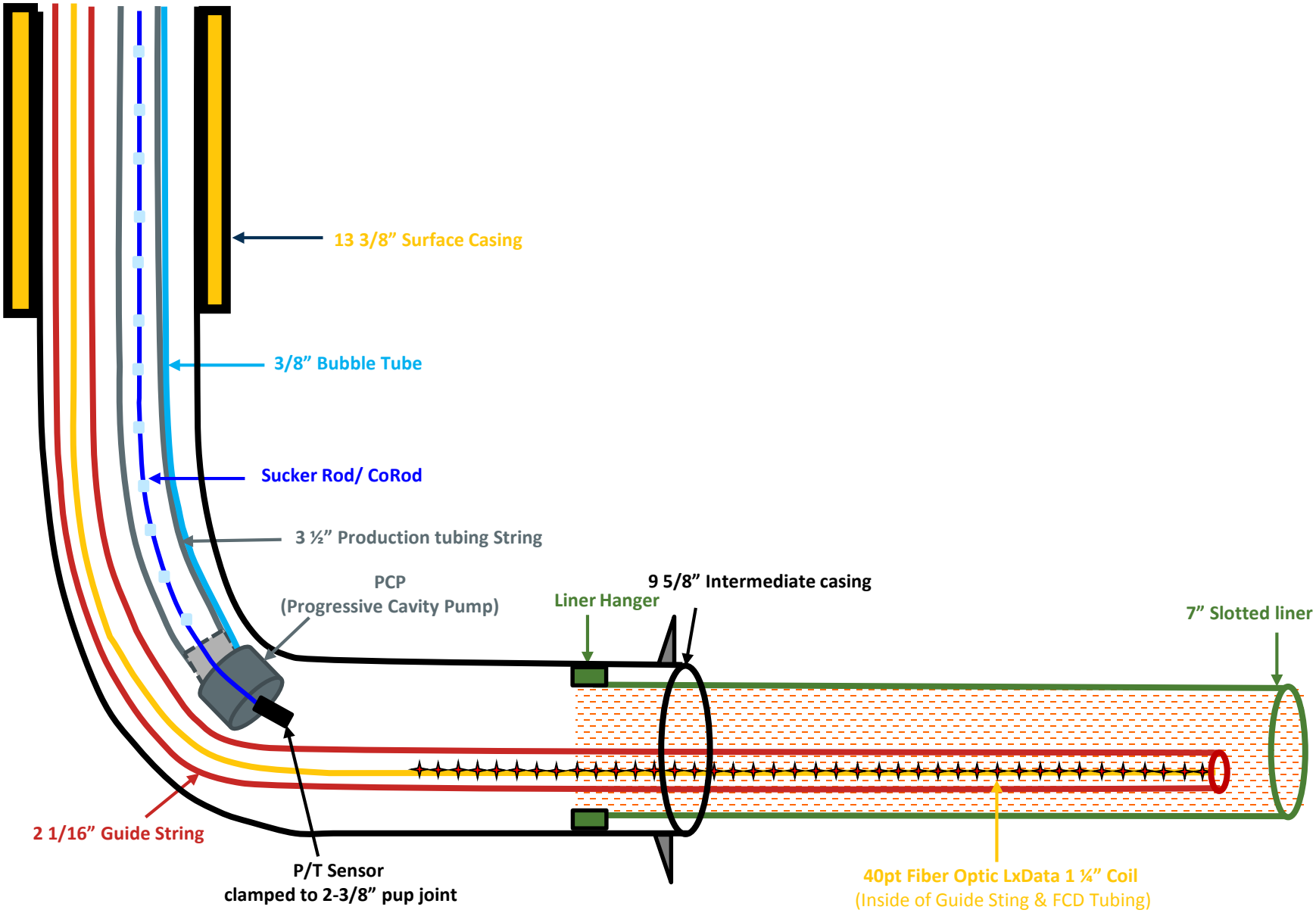
- **Heel tubing string set 10 – 15m TVD above lateral**
- **1 perforated joint on the bottom of heel tubing string with an additional 1-2 casing joints attached below.**



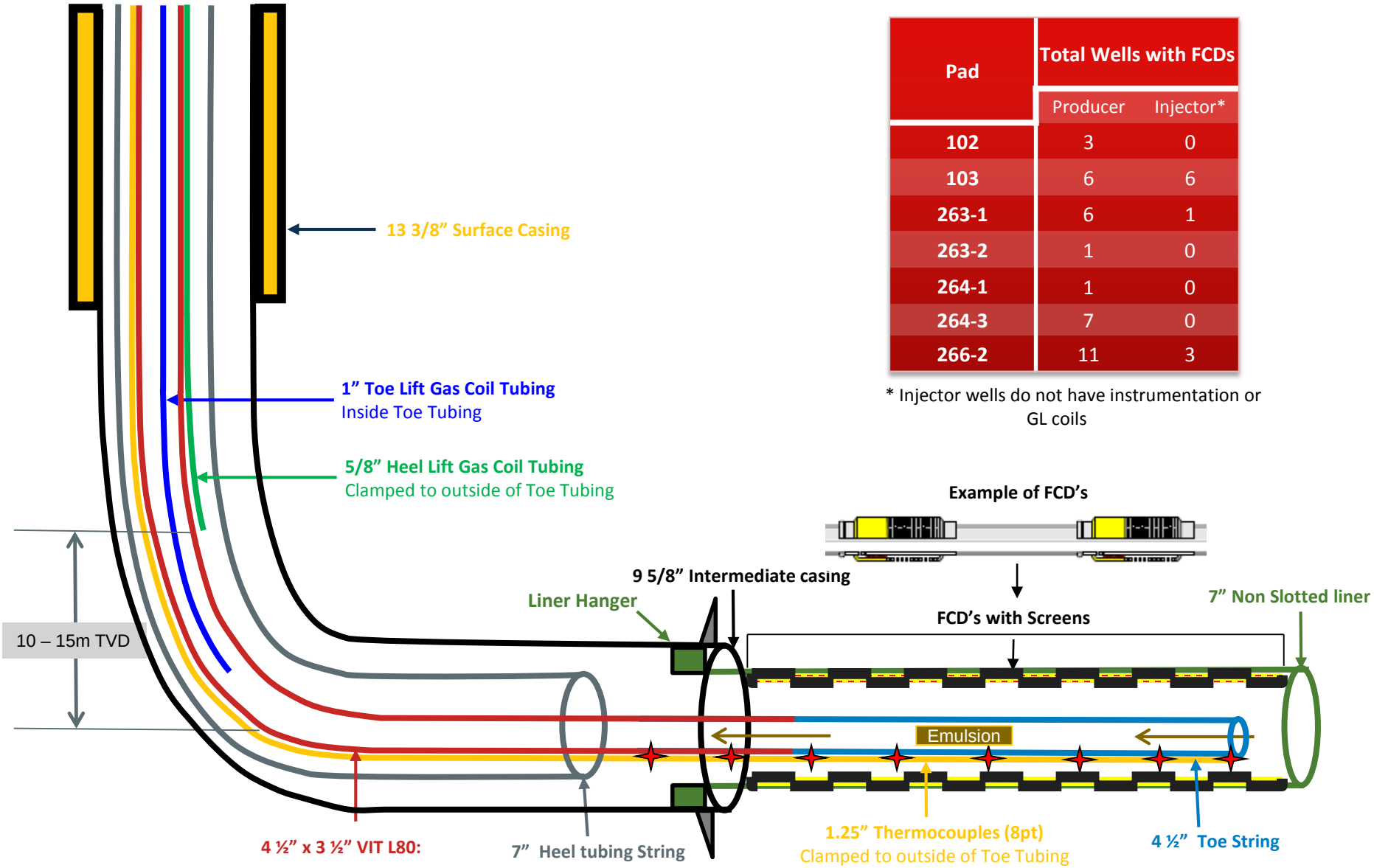
Typical ESP Producer



Typical PCP Producer



Typical Flow Control Device (FCD) Completion

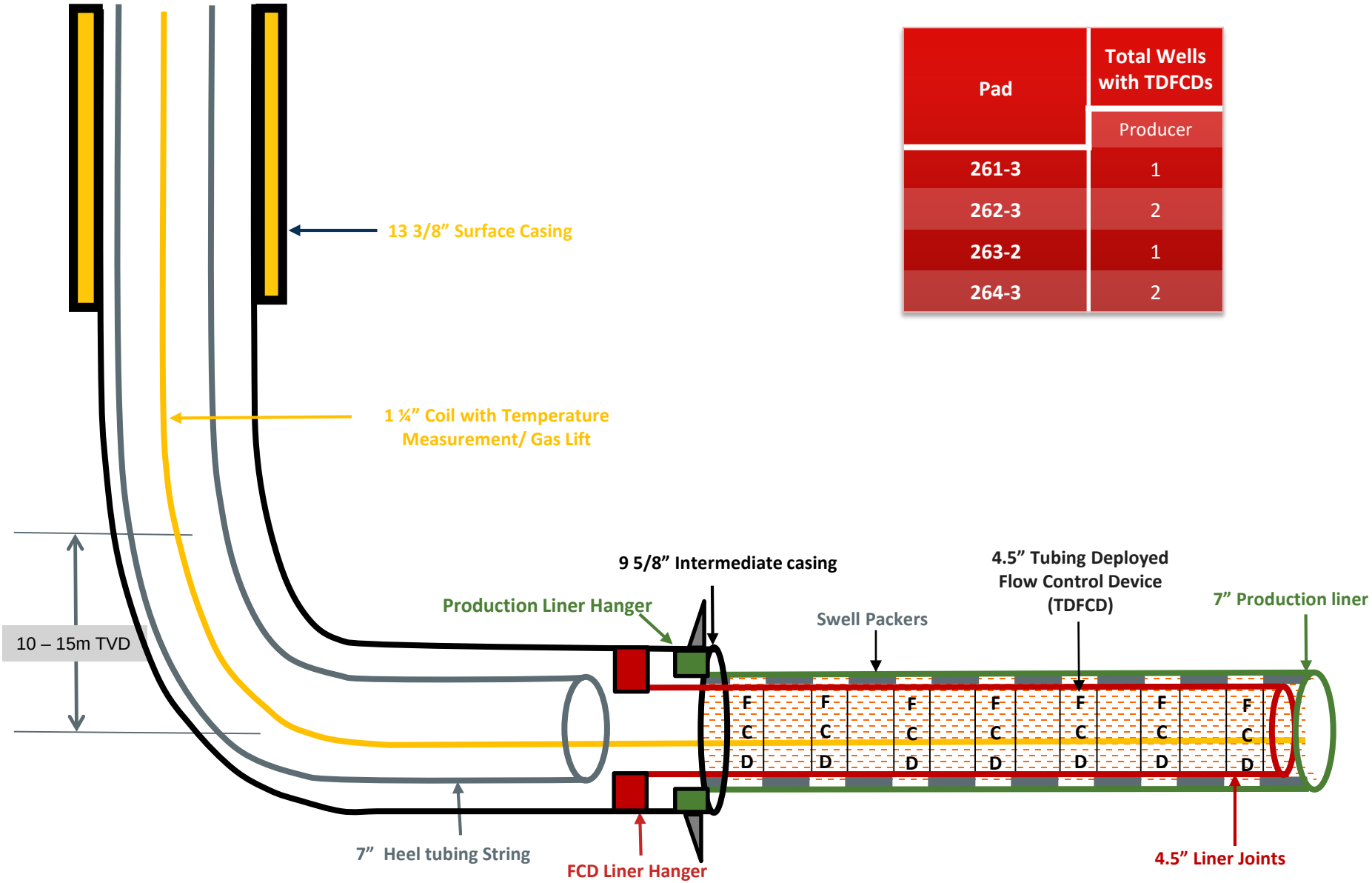


Pad	Total Wells with FCDs	
	Producer	Injector*
102	3	0
103	6	6
263-1	6	1
263-2	1	0
264-1	1	0
264-3	7	0
266-2	11	3

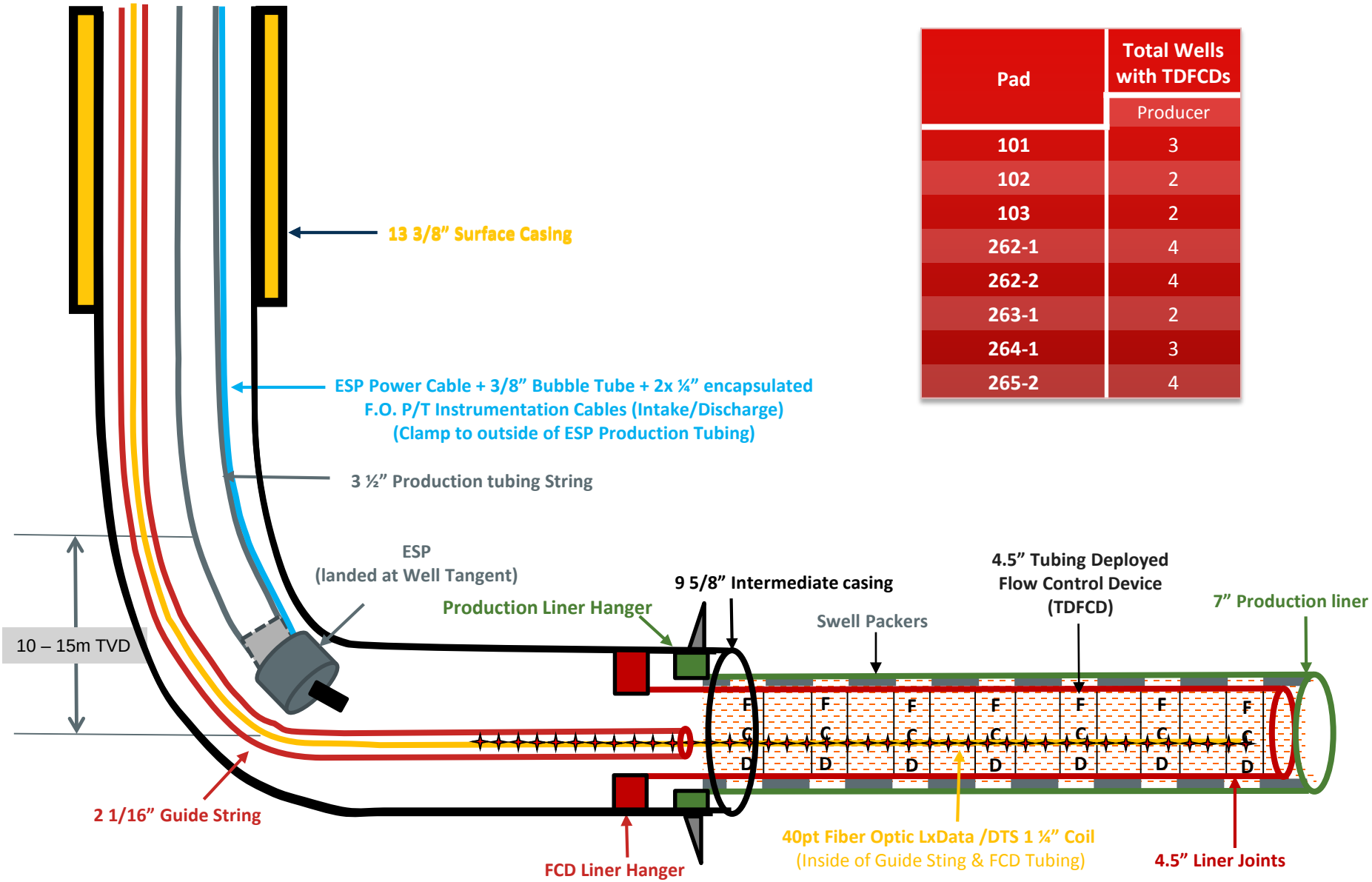
* Injector wells do not have instrumentation or GL coils

Typical Tubing Deployed FCD (TDFCD) Completion – Gas Lift

Pad	Total Wells with TDFCDs
	Producer
261-3	1
262-3	2
263-2	1
264-3	2



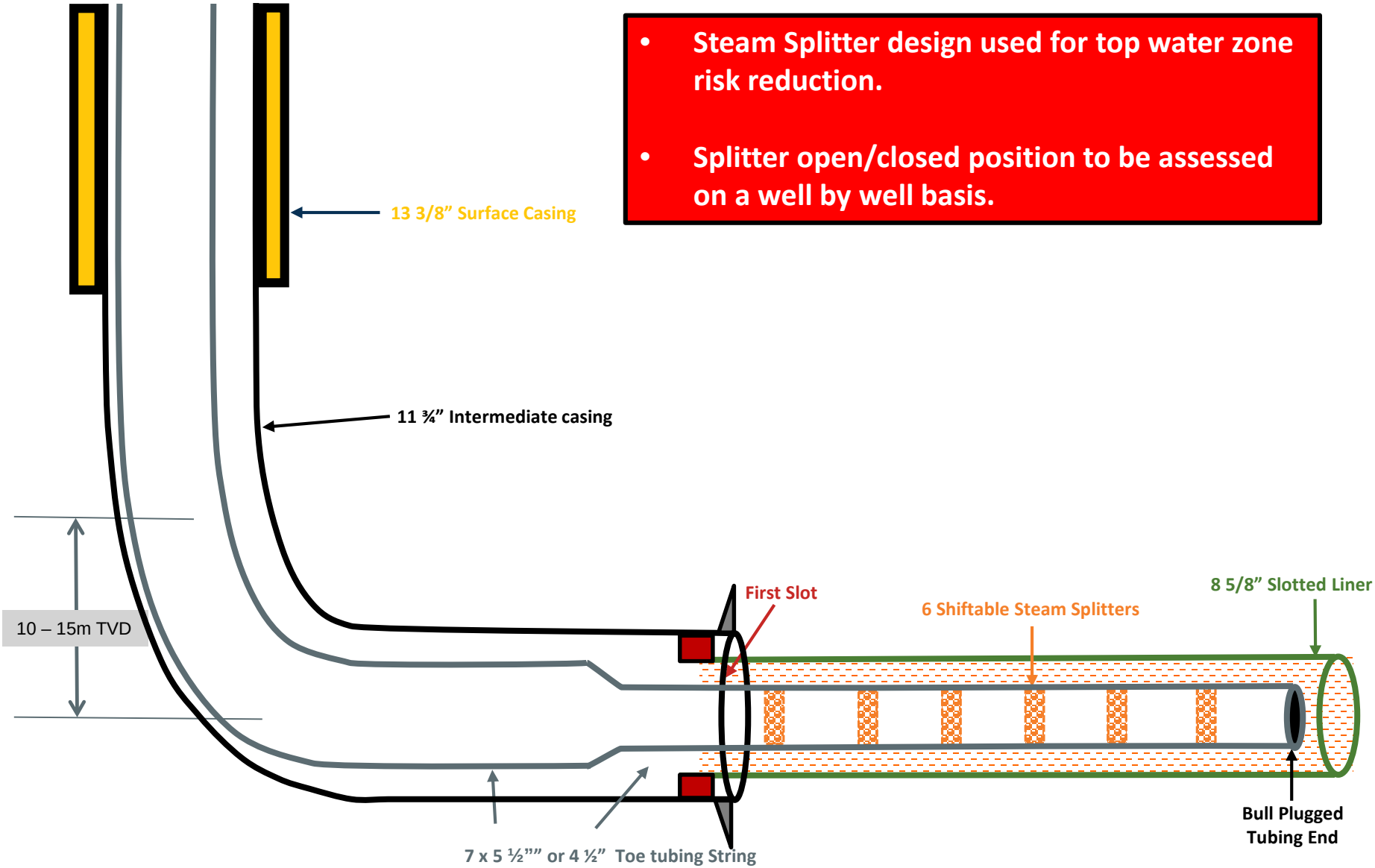
Typical Tubing Deployed FCD (TDFCD) Completion – ESP



Pad	Total Wells with TDFCDs
	Producer
101	3
102	2
103	2
262-1	4
262-2	4
263-1	2
264-1	3
265-2	4

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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Artificial Lift

Subsection 3.1.1 (4)

Artificial Lift Current Pad Overview

	Phase 1			Phase 2											TOTAL
	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	
ESP	19	17	9	7	7	11	0	8	0	7	0	1	10	12	108
PCP	2	2	0	0	0	0	0	0	0	0	0	0	0	0	4
Gas Lift	0	0	3	2	5	1	10	3	10	5	8	10	1	0	58
SSAGD	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Re-Circ.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Circ.	0	0	0	0	0	0	0	0	0	0	0	0	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 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

KPI's

Population: 99 ESP's

Cumulative MTTF: 32.5 months

Windowed* MTTF: 38.3 months

Average Runtime: 14.7 months

Windowed Runtime: 14.1 months

Average run life running ESP: 12.5 months

Windowed* Running ESP: 15.2 months

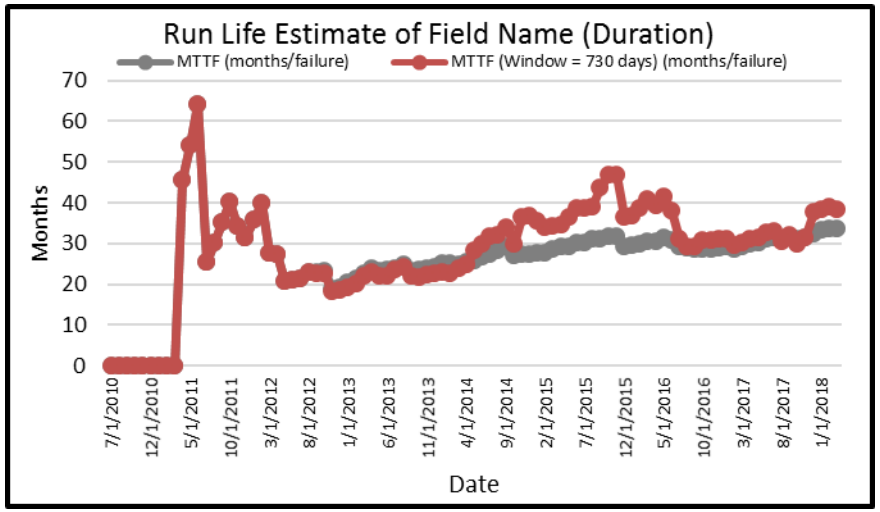
2016: 16 ESP failures

2017: 19 ESP failures

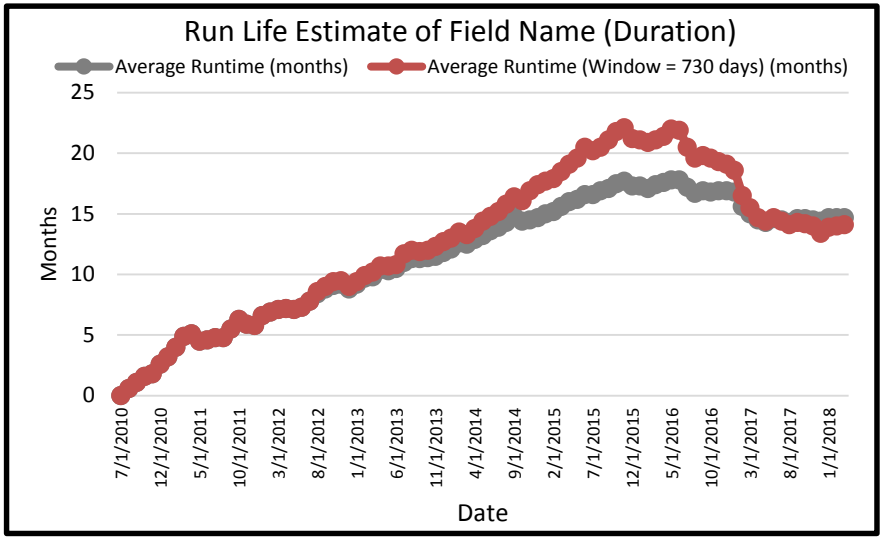
2018: 3 ESP Failure

*(730 day window)

MTTF



Average Runtime



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Instrumentation in Wells

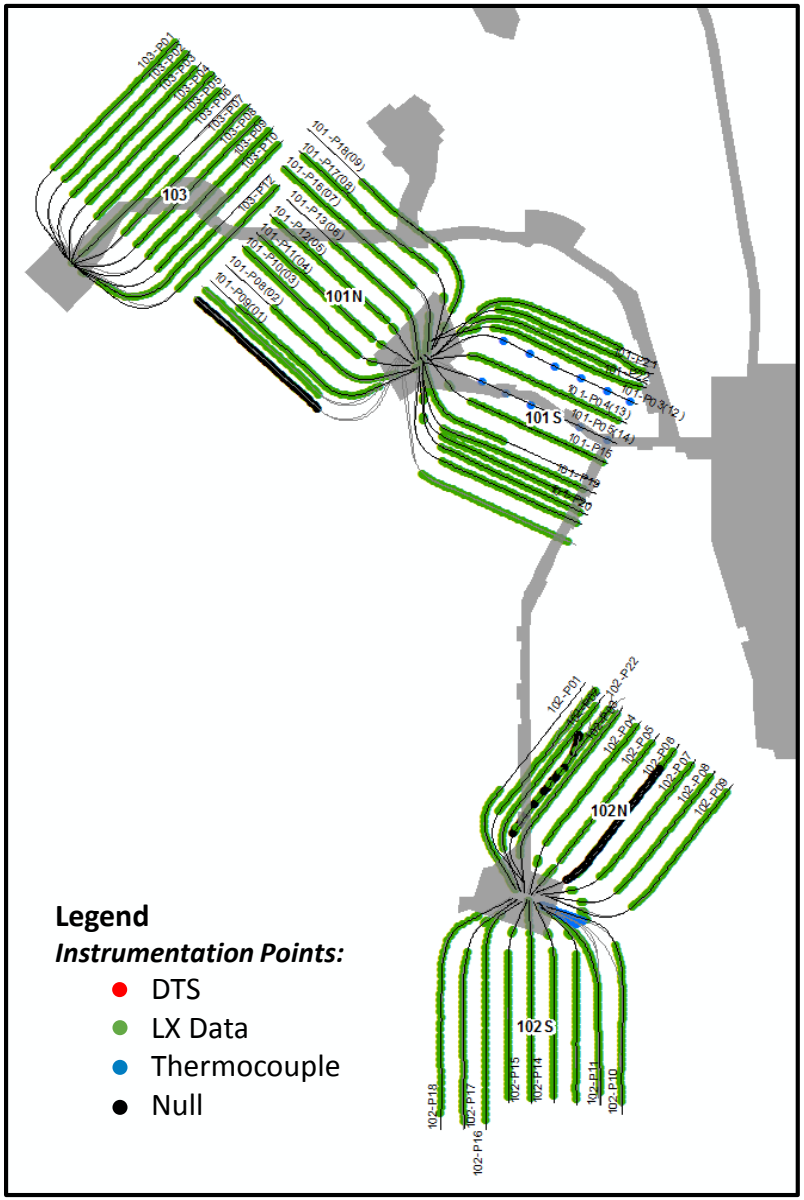
Subsection 3.1.1 (5)

Temperature & Pressure Measurement

- Temperature Measurement
  - Producer lateral temperature
    - Measured with 8 thermocouples, 40 LxData, or DTS fiber optic strings. See slides 91 & 92 for details
  - Injector lateral temperature
    - No temperature are measured

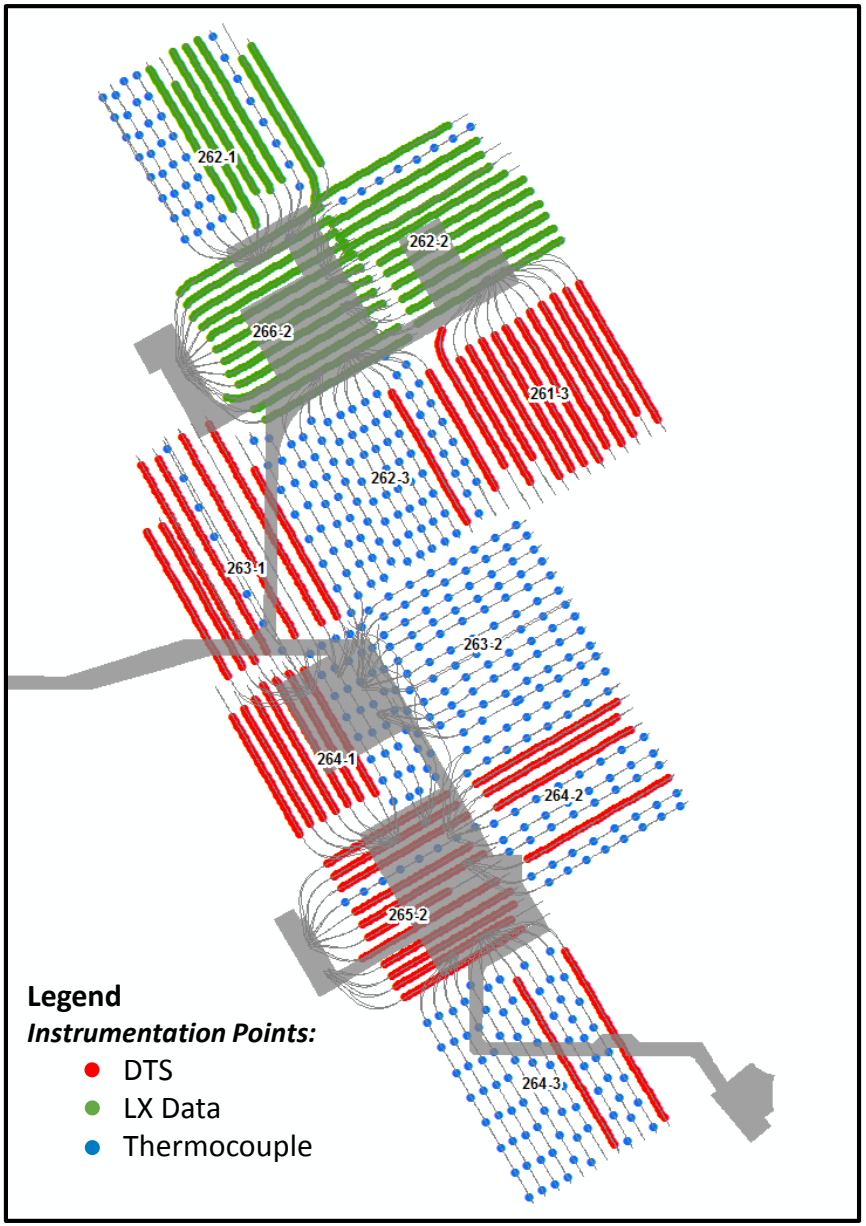
- Pressure Measurement
  - Producer
    - Primary bottom hole pressure measurement is done with a bubble tube corrected for TVD
    - Some LxData wells were equipped with toe pressure sensors, but have questions around accuracy
    - Secondary BHP measurement through 2 1/16 guidestring
  - Injector
    - Primary bottom hole pressure measurement is done with casing blanket gas

SAGD Well Instrumentation



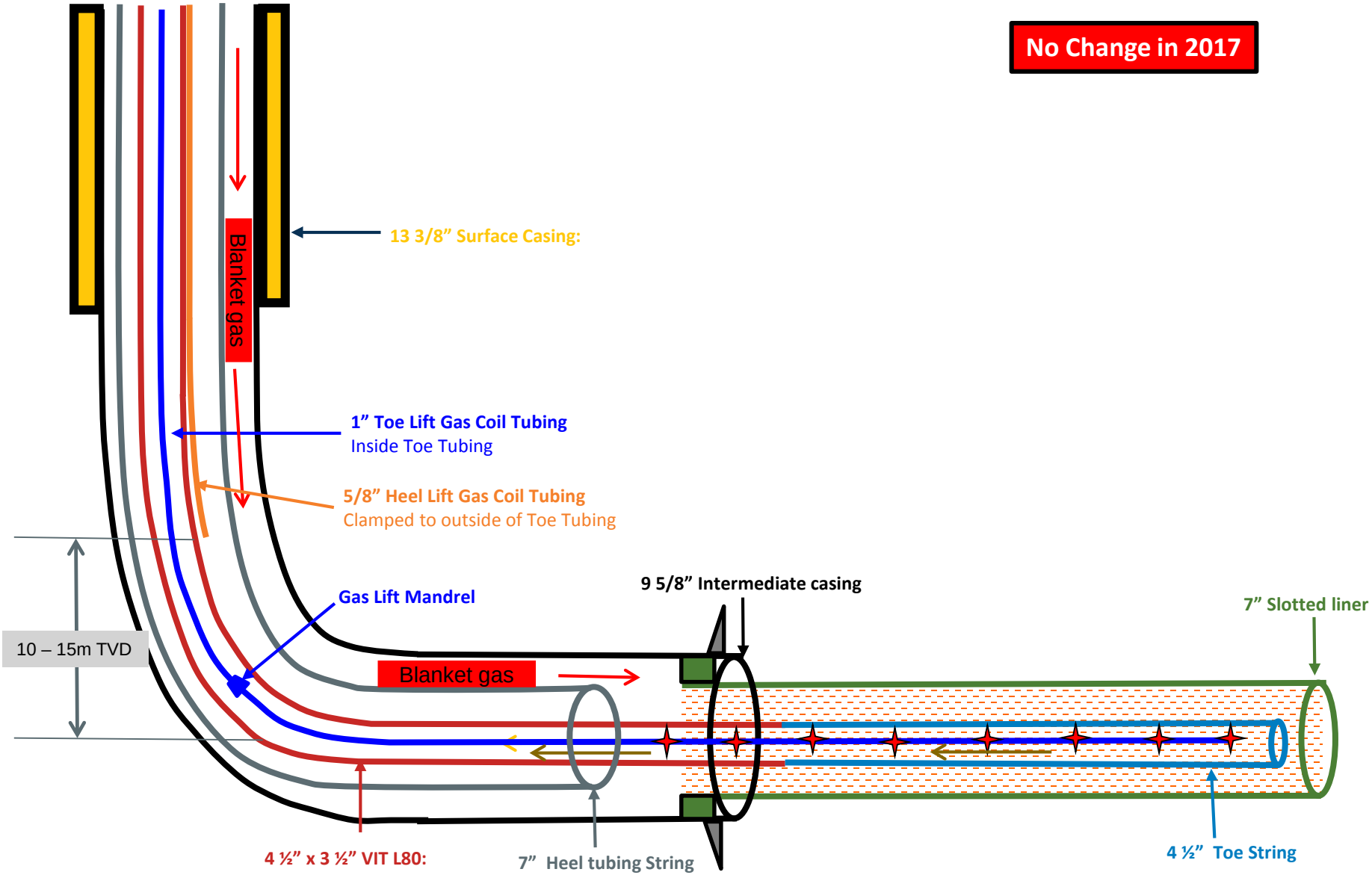
No Change in 2017

Phase 2 SAGD Well Instrumentation



1. **Phasing out all Thermocouples at ESP conversion**
2. **All wells will contain fiber temperature instrumentation. 3 LxData and 8 DTS pads.**

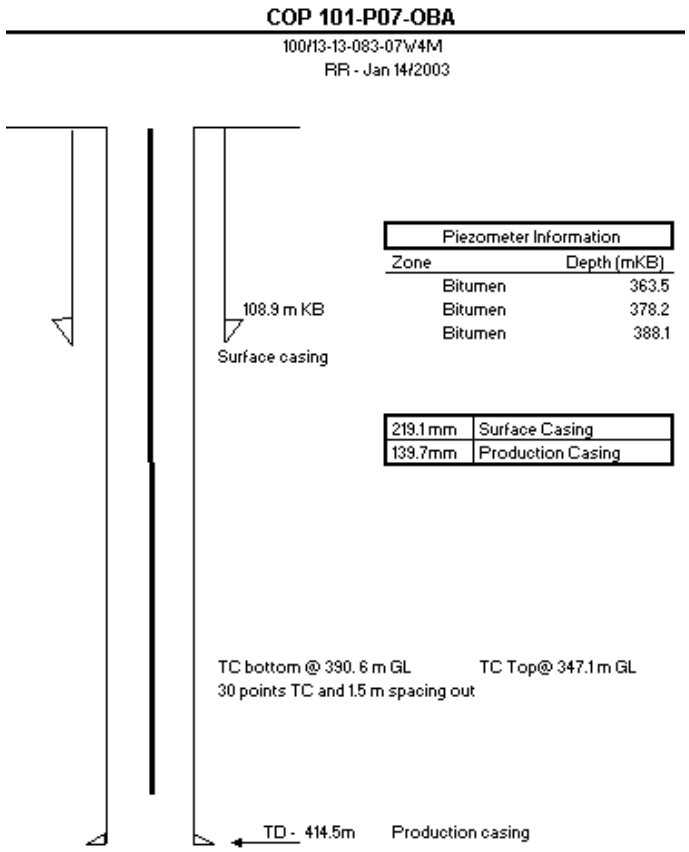
Distributed Temperature Sensing (DTS)



Typical Observation Well Measurement

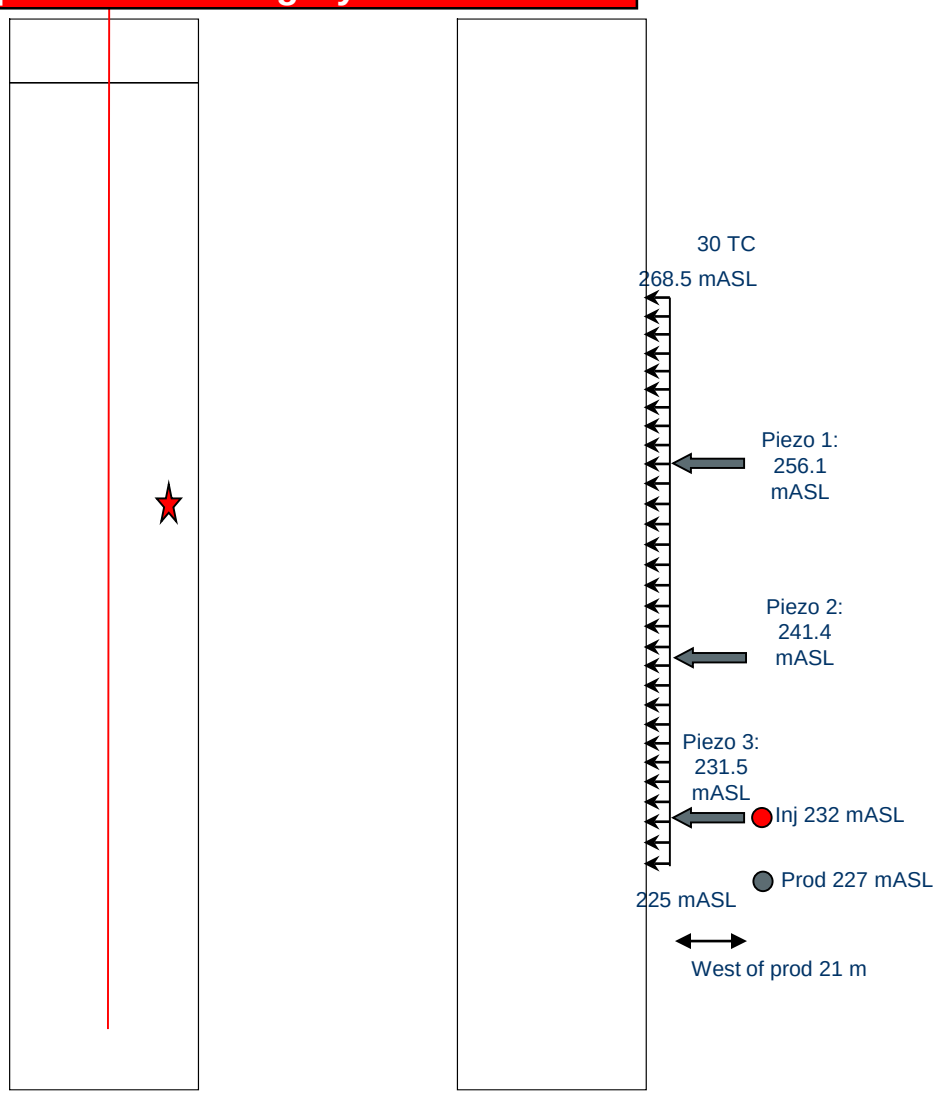
Soft cable Thermocouple (TC) strings were replaced by hard cable TC strings for improved well integrity

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



Piezometer Information	
Zone	Depth (mKB)
Bitumen	363.5
Bitumen	378.2
Bitumen	388.1

219.1 mm	Surface Casing
139.7mm	Production Casing

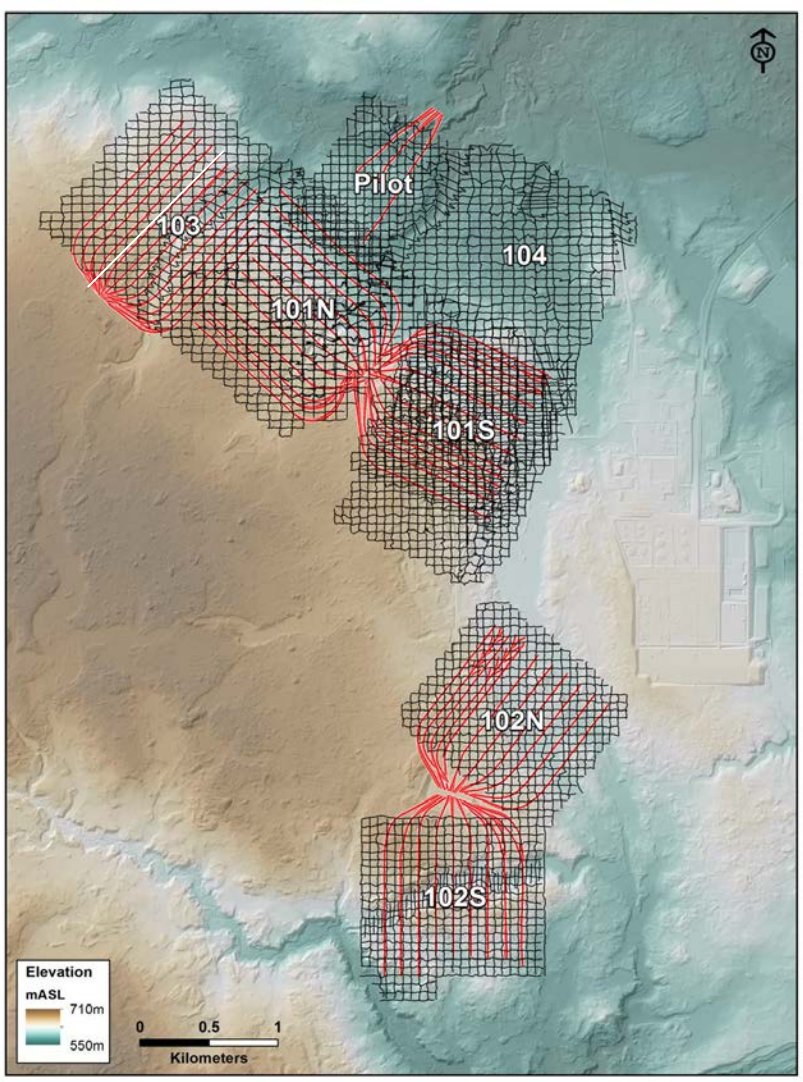


4D Seismic

Subsection 3.1.1 (6)

4D Seismic Location Map – Phase 1

Phase 1 Area



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
- 9th monitor acquired in March 2018

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

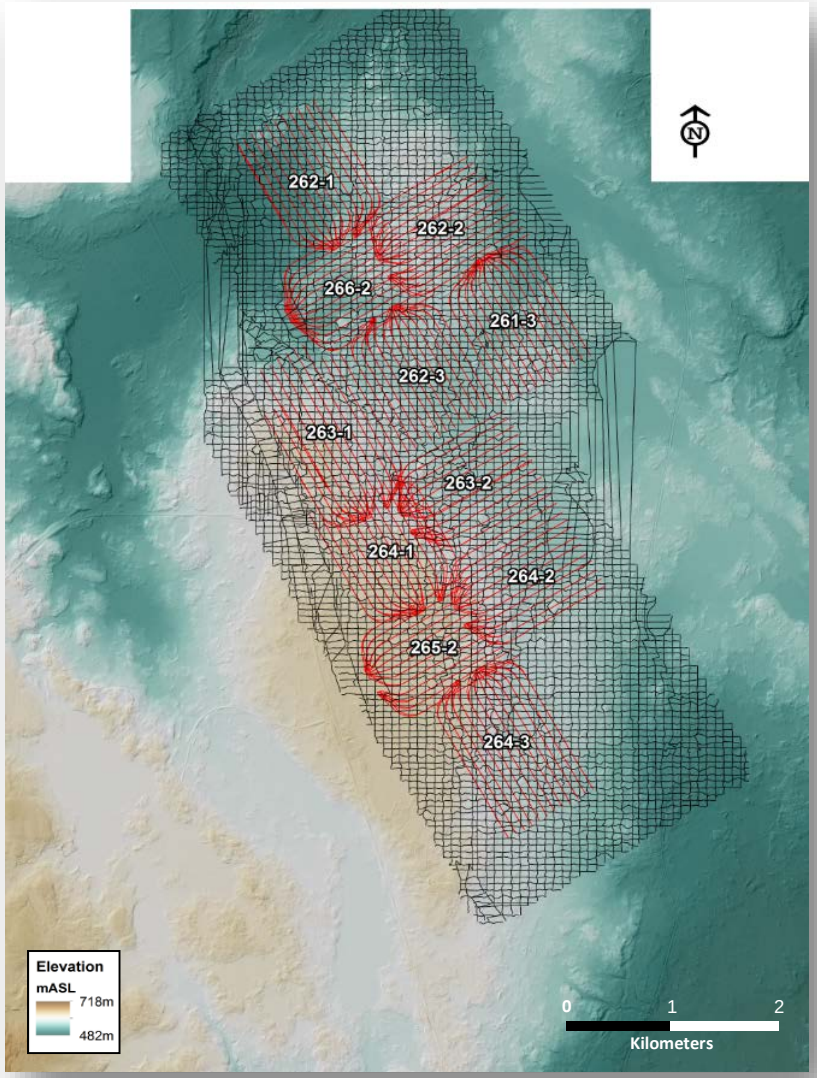
- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 6th monitor acquired in October 2016

Pads 103 and 104

- Buried analog single component geophones
- Cased dynamite shots (1/8 Kg) @ 6 m
- 3rd monitor acquired in October 2017 (103)

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 Monitors
  - Spring 2016: 263-2
  - Fall 2016: 263-1 / 264-1 / 265-2 / 264-3
  - Spring 2017: 262-2/261-3/262-3/263-2 (*) /264-2
  - Fall 2017: 262-1
- Second Monitors:
  - Fall 2017: 263-1/264-1/265-2/264-3

Phase 1 4D Seismic Program

PAD	2014		2015		2016		2017	
	Spring	Fall	Spring	Fall	Spring	Fall	Spring	Fall
101N	M	M	M					
101S	M		M					
102N	M		M					
102S	M					M		
Pilot		M		M				
103					M	M		M
104								

B Baseline

M Monitor

Phase 2 4D Seismic Program

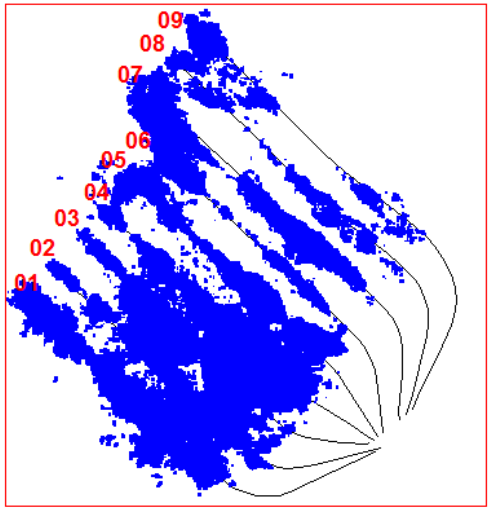
PAD	2017	
	Spring	Fall
263-1		M
264-1		M
265-2		M
264-3		M
262-1		M
266-2		
262-3	M	
263-2	M	
264-2	M	
262-2	M	
261-3	M	

B Baseline M Monitor

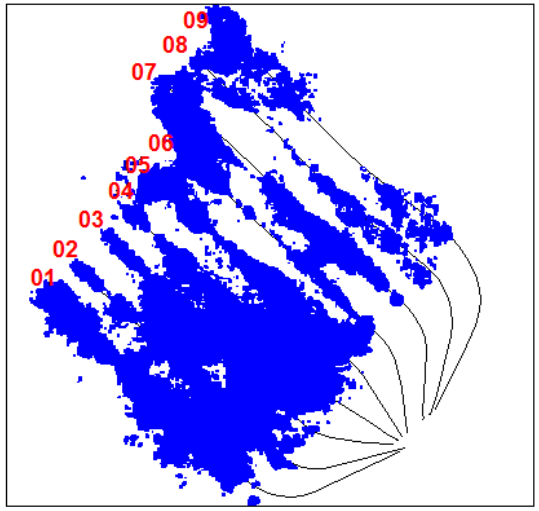
2015 4D Seismic Results Pad 101

- **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

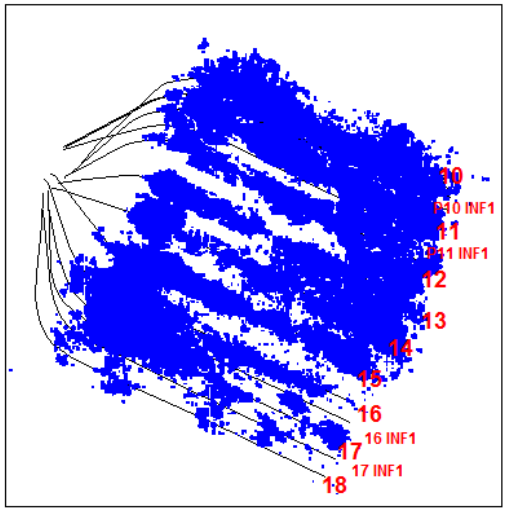


101 North 8th monitor - March 2015

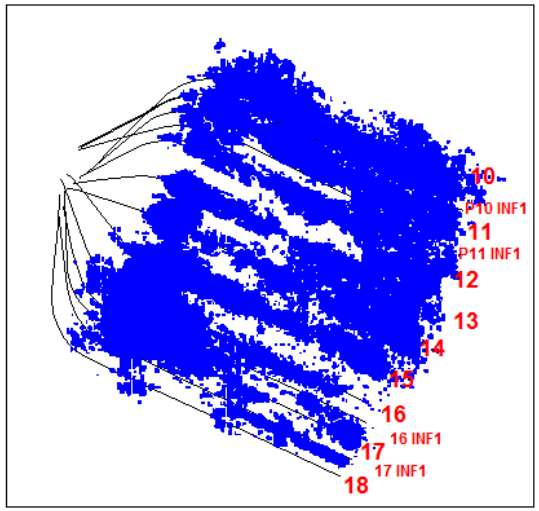


- **4D anomaly volumes have increased.**
- **Continued conformance improvement along Well Pad 10, 11, 16, 17.**
- **Infill wells drilled between Well Pads 10, 11, 12, 16, 17 and 18 to optimize production in a geological more complex zone.**

101 South 8th monitor - March 2014



101 South 9th monitor - March 2015



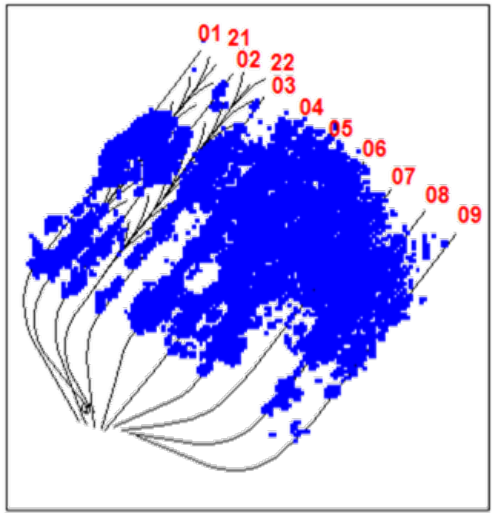
= 4D anomaly
~60 deg C Isotherm

0 200 400m

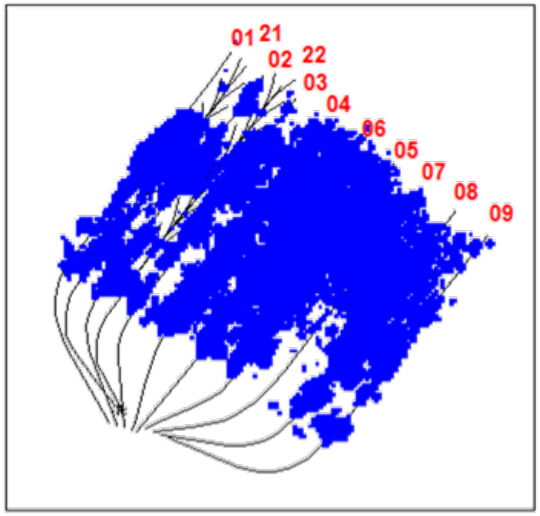
2016 4D Seismic Results Pad 102 (102S)

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

102 North 8th monitor - April 2014

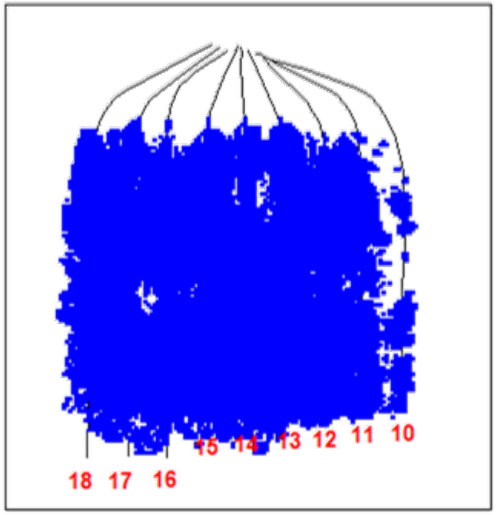


102 North 9th monitor - April 2015

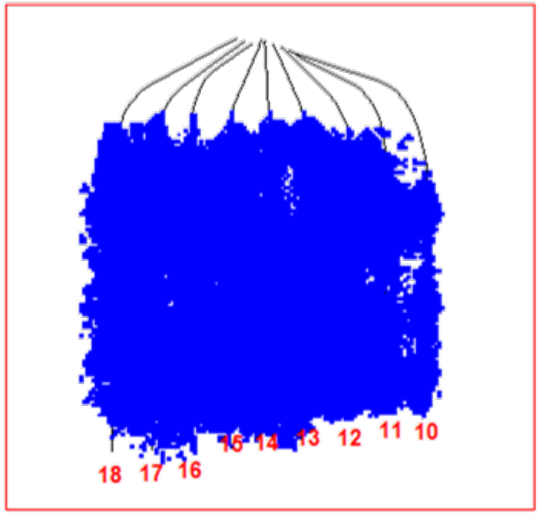


- **4D anomaly volume have increased. Improved conformance along well pairs 10 to 18.**

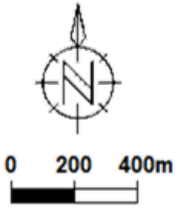
102 South 5th monitor -April 2014



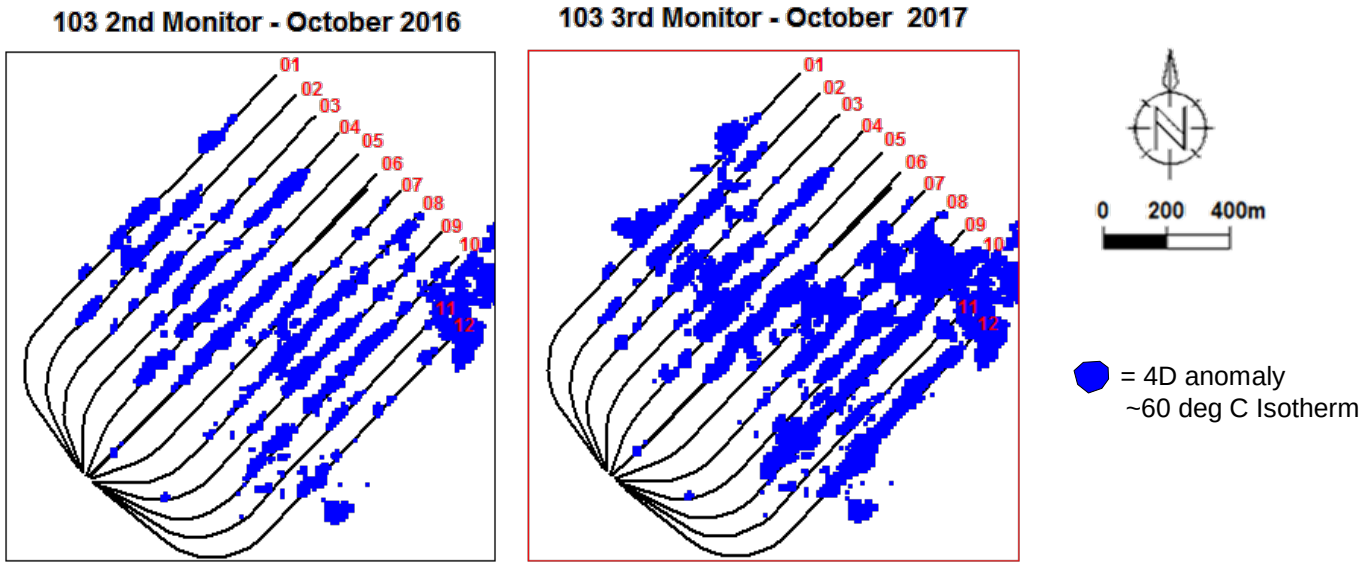
102 South 6th monitor - October 2016



= 4D anomaly
~60 deg C Isotherm



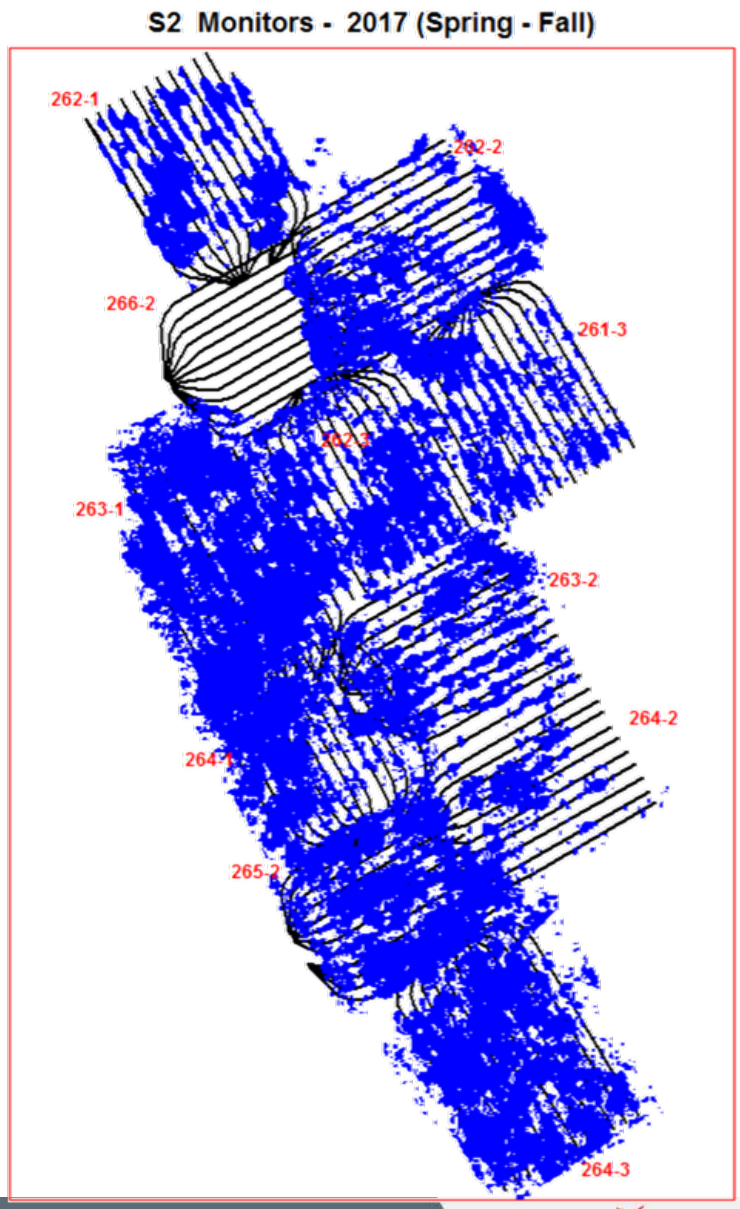
2017 4D Seismic Results Pad 103



- **Relative good conformance in most of well pair.**
- **4D indications of coalescence with thermal chamber of Pad 101N (103-08/12)**

2017 4D Seismic Results Phase 2

- **Spring Monitor:**
  - 262-2
  - 261-3
  - 264-2
  - 263-2
  - 262-3
- **Fall Monitors:**
  - 263-1
  - 264-1
  - 265-2
  - 264-3
  - 262-1
- **Relative good conformance in most well pairs (except 264-2)**
- **4D indications of coalescence between 263-1 and 264-1**



= 4D anomaly
~60 deg C Isotherm

0 500 1000m

Seismic Examples: 101-P16 Conformance (Toe)

Problem:

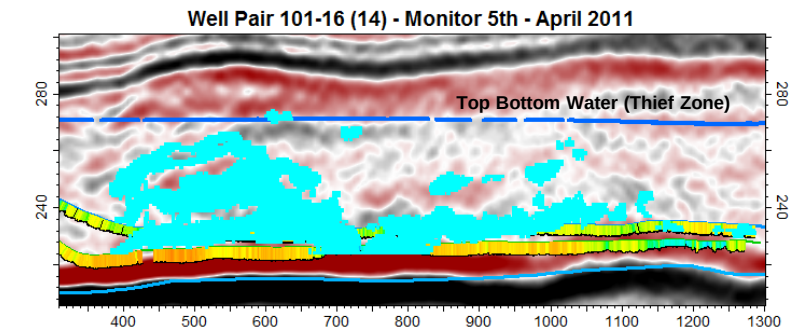
- **Well pair 101-P16 lacking good conformance along well pair.**

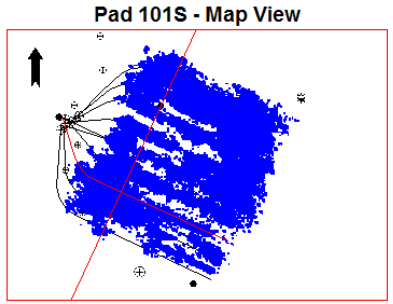
Action:

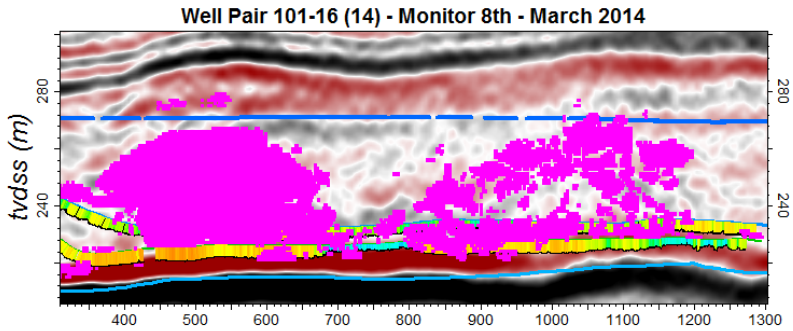
- **Increase pressure of steam injection at toe.**

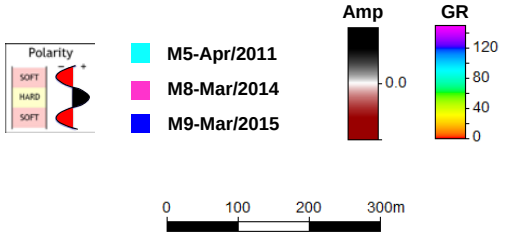
Results:

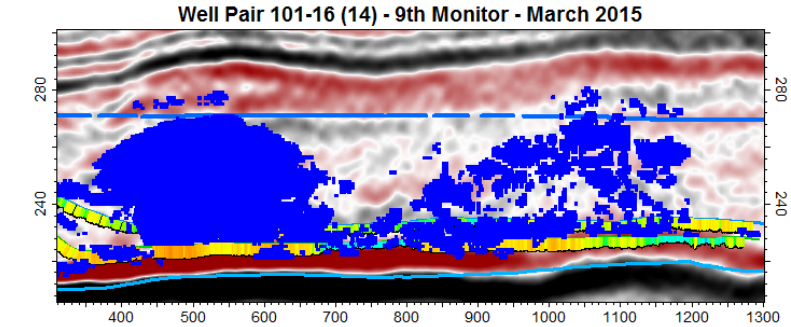
- **Conformance improved at toe.**

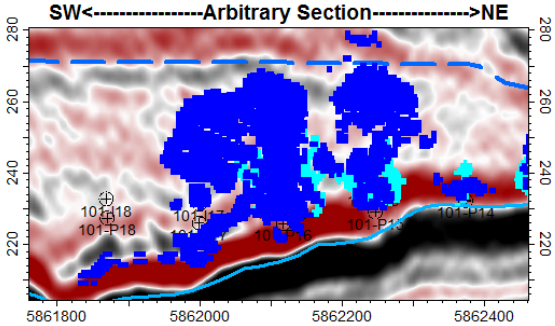




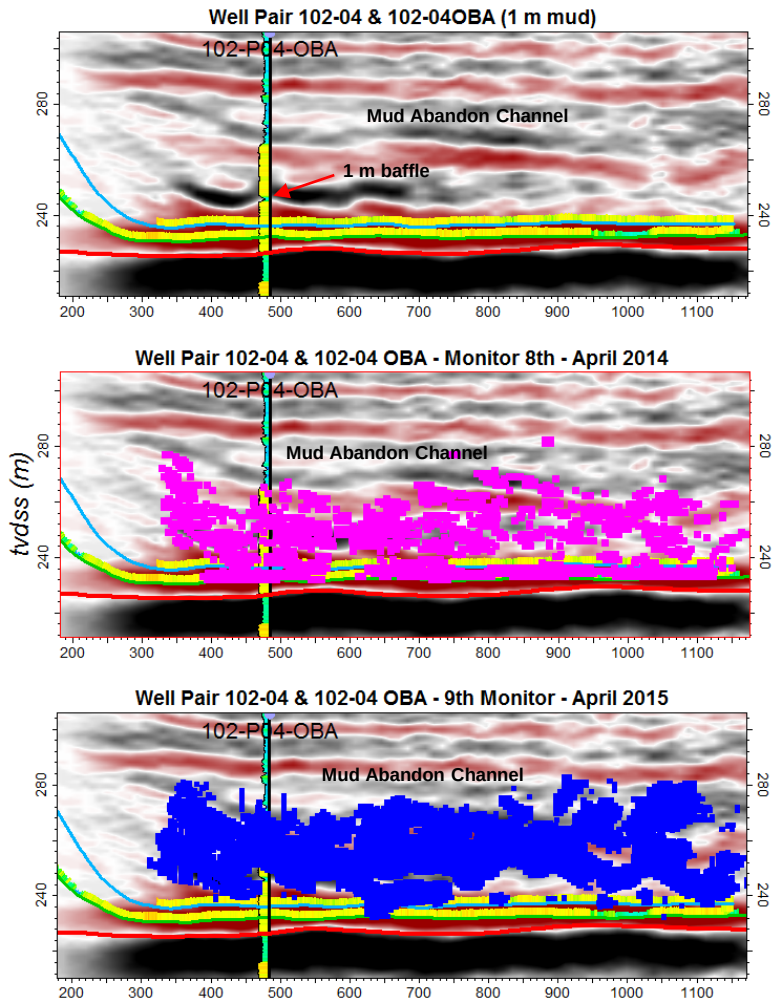


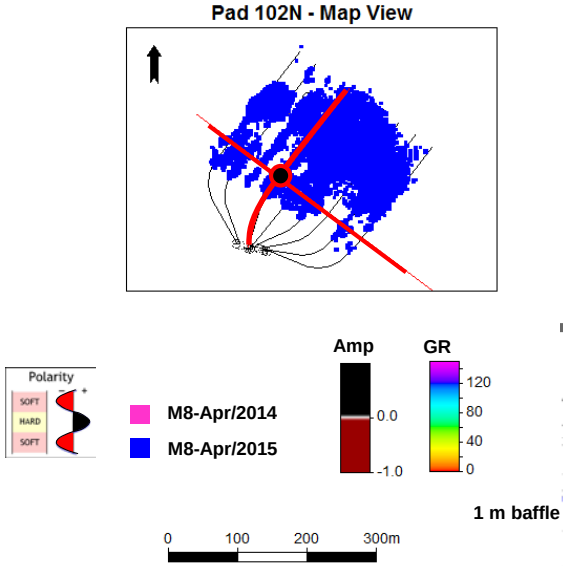


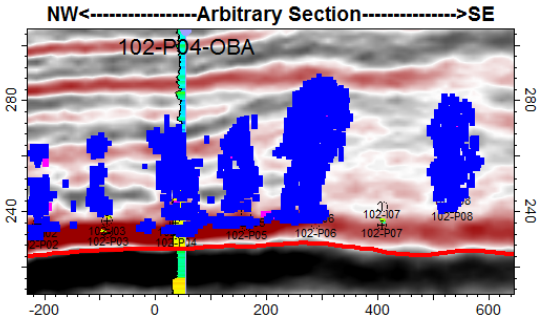


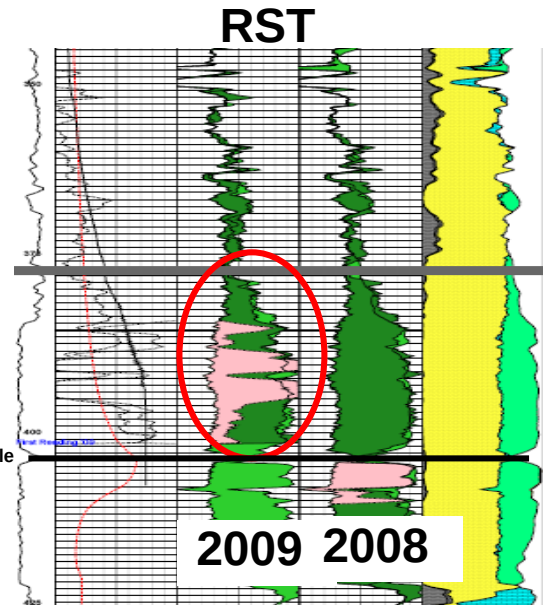


Seismic Examples: 102-04 OBA Baffle Breakthrough (Heel)









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

4D Seismic Program 2017

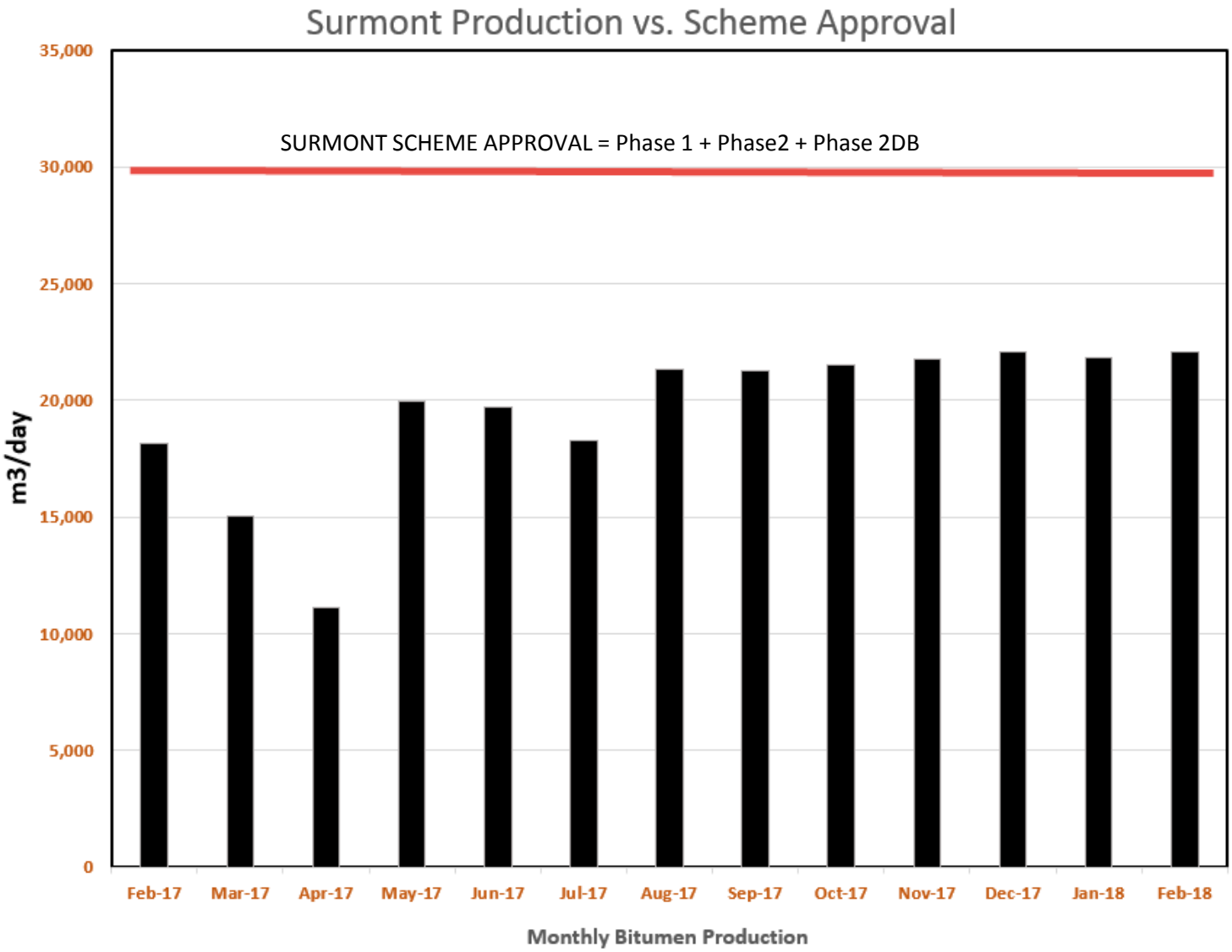
- 4D seismic has proven very useful in monitoring and optimizing conformance and pressure strategy.
- 4D correlates with observation well data.
- Continuing to optimize heel/toe production/injection splits using 4D results.
- Ongoing efforts to history match reservoir models using 4D seismic.

ConocoPhillips

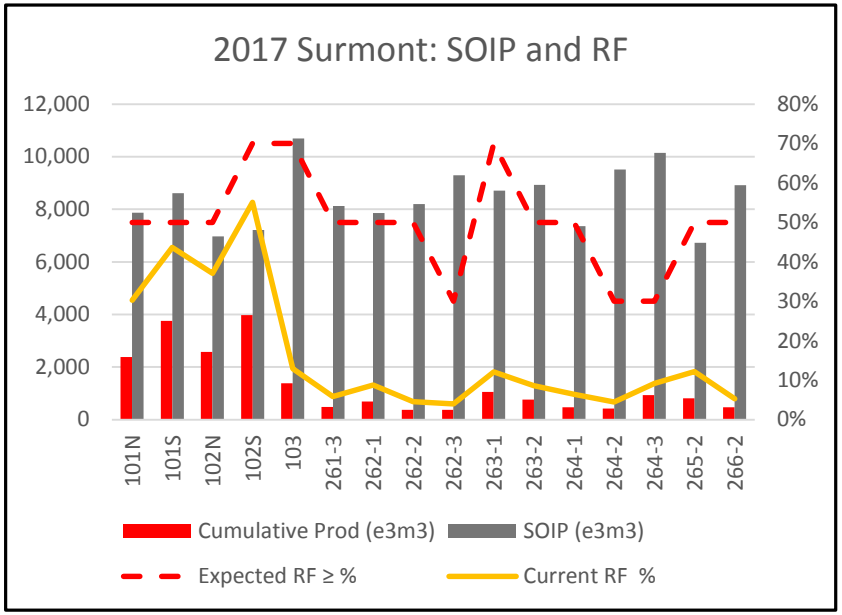
Scheme Performance

Subsection 3.1.1 (7)

Surmont: Production vs. Scheme Approval



Surmont: Phase 1 and 2 - SOIP and RF

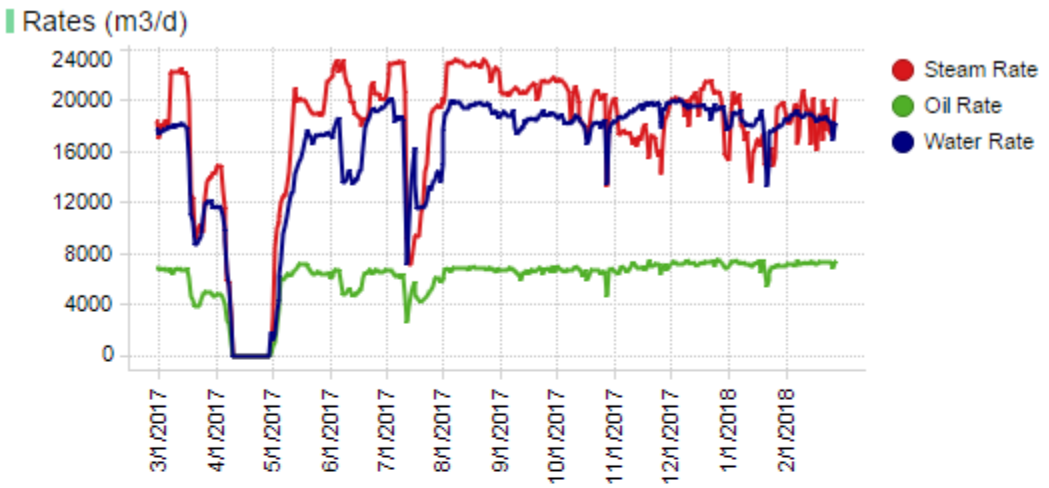


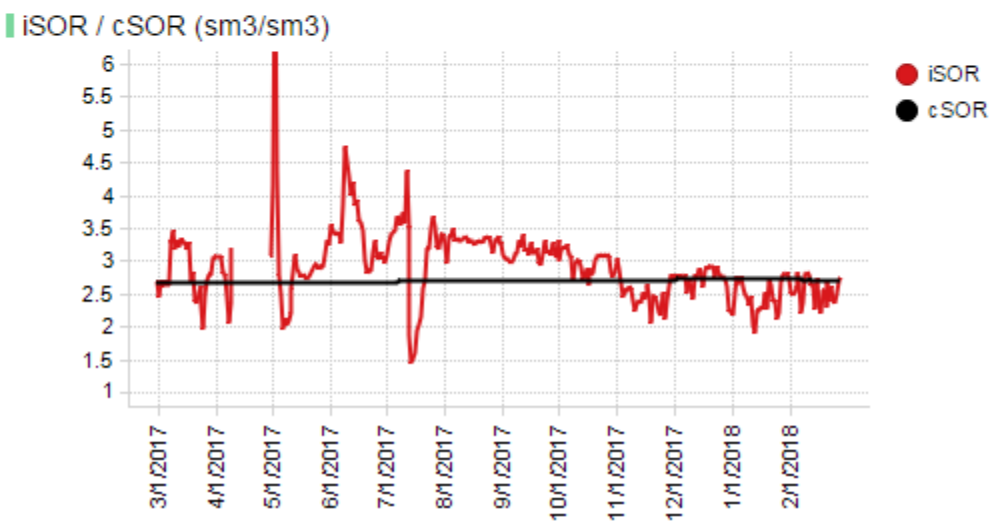
DA	Area (m2)	Thickness NCB (m)	Phie in NCB %	So in NCB %	Cumulative Prod (e3m3)	SOIP (e3m3)	Current RF
101N	1,090,775	35.53	32.58%	82.40%	2,383	7,868	30.30%
101S	1,064,692	37.43	33.19%	80.41%	3,758	8,609	43.70%
102N	975,251	31.14	32.71%	80.29%	2,582	6,965	37.10%
102S	1,019,252	34.17	31.32%	74.33%	3,979	7,216	55.10%
103	1,022,239	42.80	32.21%	78.62%	1,382	10,694	12.90%
261-3	1,000,542	44.77	32.00%	78.07%	483	8,126	5.90%
262-1	996,252	39.59	31.74%	80.05%	689	7,853	8.80%
262-2	974,291	38.63	33.13%	78.56%	375	8,202	4.60%
262-3	943,213	44.28	32.76%	78.21%	375	9,299	4.00%
263-1	1,271,315	36.14	32.98%	79.36%	1,056	8,708	12.10%
263-2	998,219	40.90	32.44%	78.06%	769	8,922	8.60%
264-1	1,033,834	39.45	32.89%	79.71%	474	7,355	6.40%
264-2	1,011,337	42.08	32.65%	78.22%	428	9,516	4.50%
264-3	1,209,485	37.51	31.97%	75.58%	930	10,139	9.20%
265-2	917,433	38.75	32.54%	76.83%	817	6,721	12.20%
266-2	949,974	42.99	32.83%	80.08%	472	8,916	5.30%

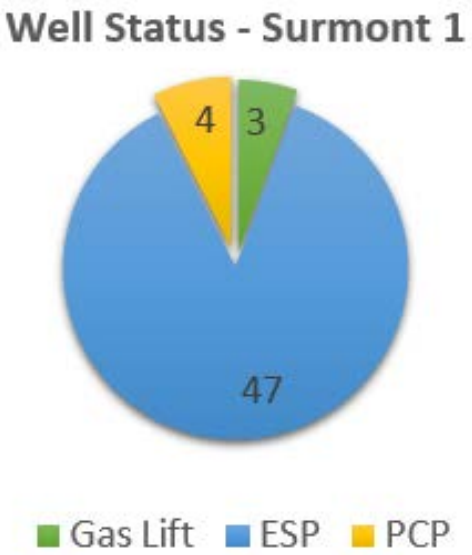
- **SOIP: 6,721 – 10,694 E3M3**
- **Current RF: 4.0% - 55.1%**
- **Porosity: 30.3% - 34.0%**
- **Oil saturation: 72.1% - 82.7%**
- **Blowdown timing will determine final EUR/RF.**
- **Recovery factors for drainage areas are based on performance. At this time, the expected ultimate recovery factor is difficult to predict, and these values are subject to change.**

	Expected Recovery Factor		
	Tier 1: RF ≥ 70%	Tier 2: RF ≥ 50%	Tier 3: RF ≥ 30%
101N		×	
101S		×	
102N		×	
102S	×		
103	×		
261-3		×	
262-1		×	
262-2		×	
262-3			×
263-1	×		
263-2		×	
264-1		×	
264-2			×
264-3			×
265-2		×	
266-2		×	

Surmont Phase 1 Aggregate Performance Plots

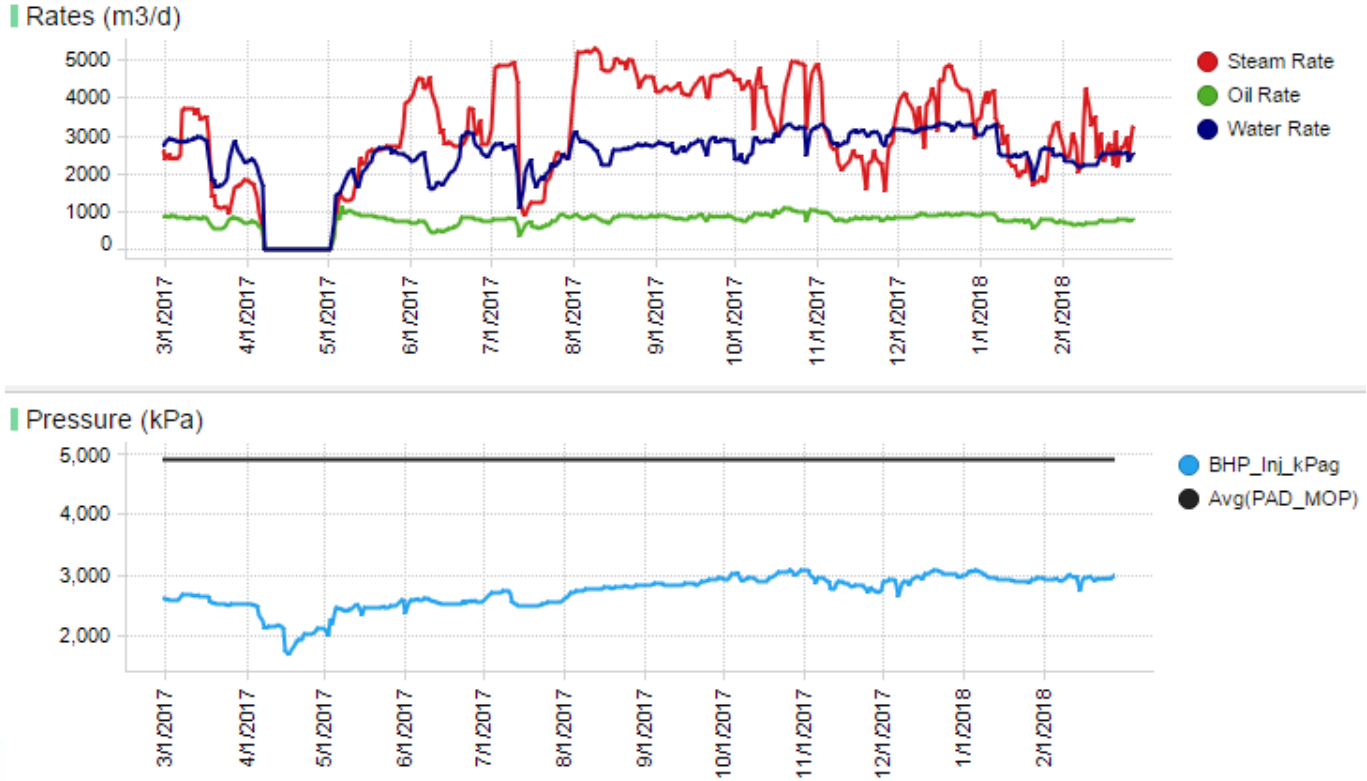


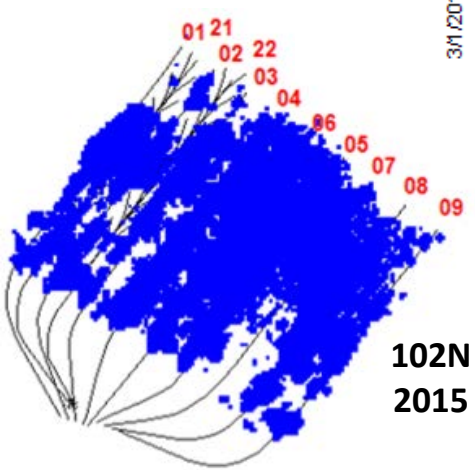




- Well Retrofits (TDFCD and Steam Splitters) were installed.
- 103-07 re-drilled due to downhole failure.
- 102 NCG Trial Ongoing.
- Strong performance on pad 103.

Performance / Chamber Development Challenges – Pad 102N

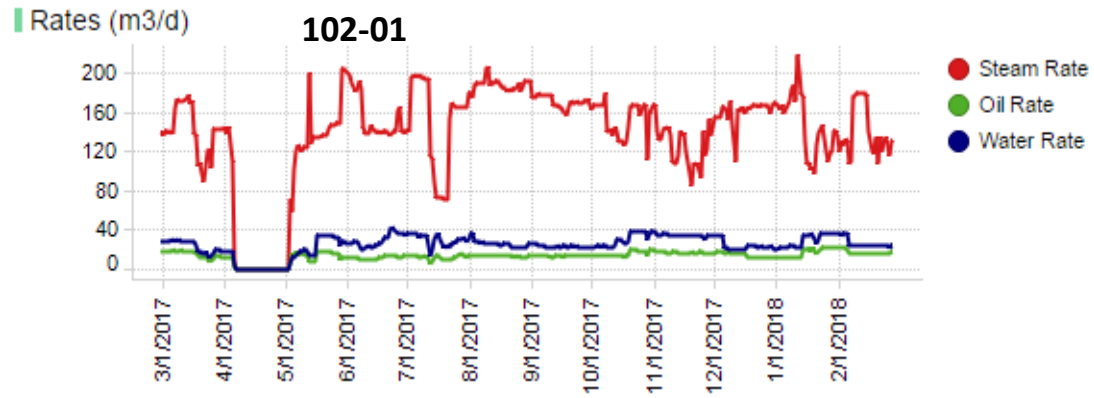


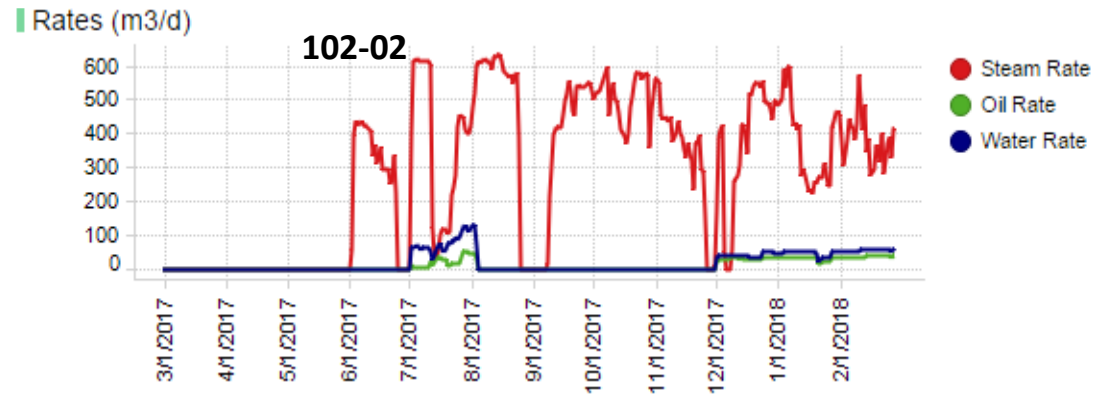


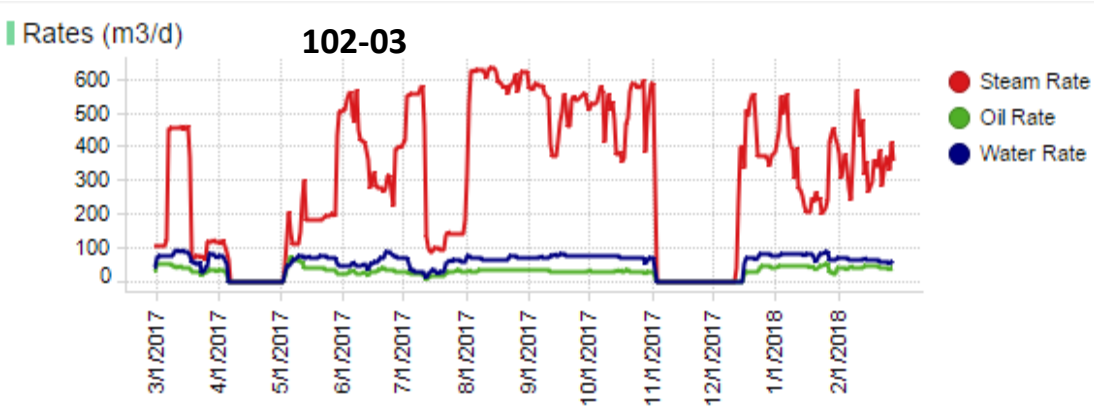
102N
2015

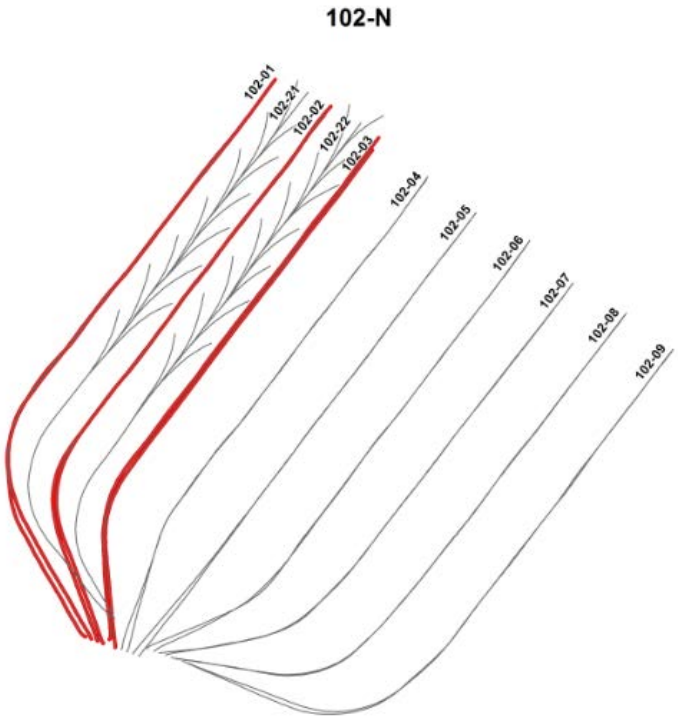
- **Performance and recovery on the west side of the pad has been challenged by multiple liner failures.**
- **Fishbone inline wells online and producing.**
- **Original LDFCD completion (102-06) continues to outperform slotted liner peers.**

Performance / Chamber Development Challenges – Pad 102N



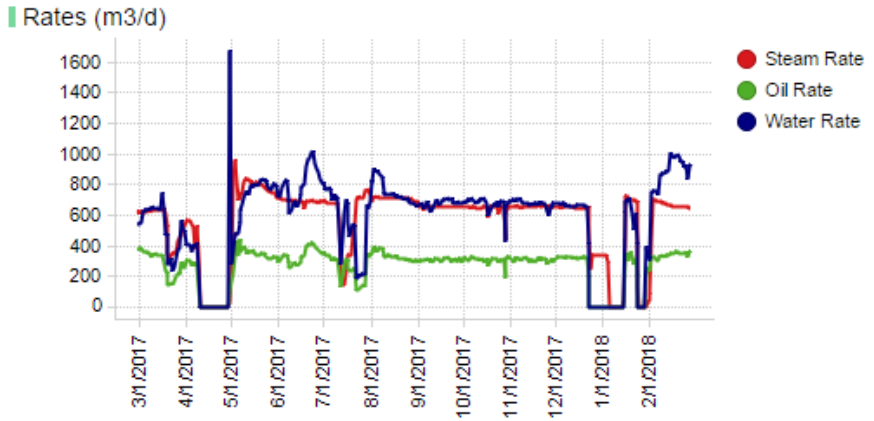




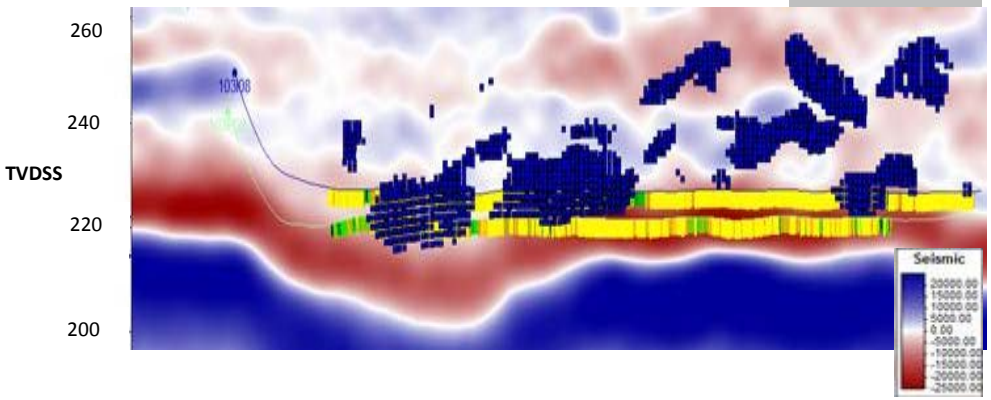


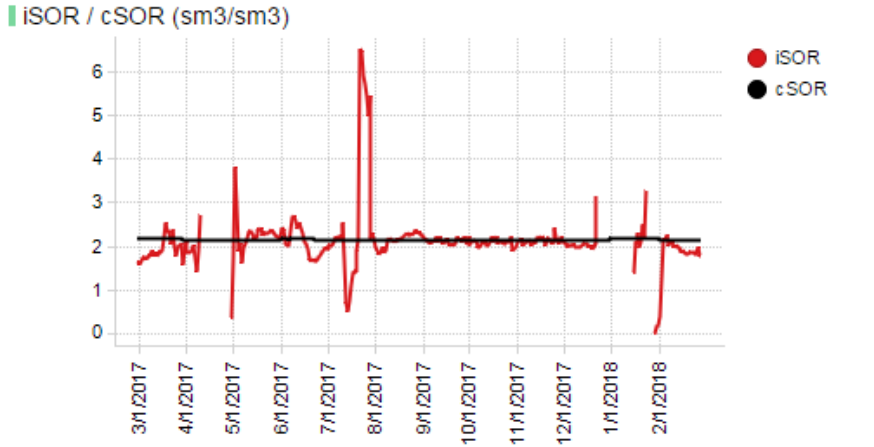
- **102-P01;02;03 have been the poorest producers on the pad.**
- **Recovery remains low and side-tracks are being considered.**

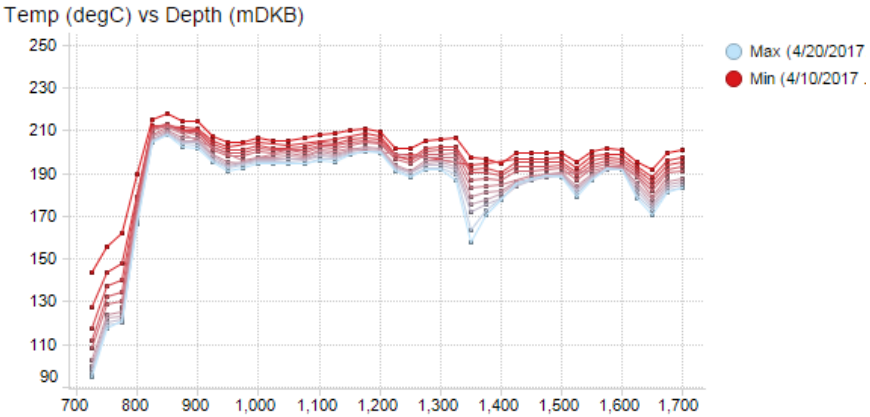
Good Performance – WP 103-08



October 2017

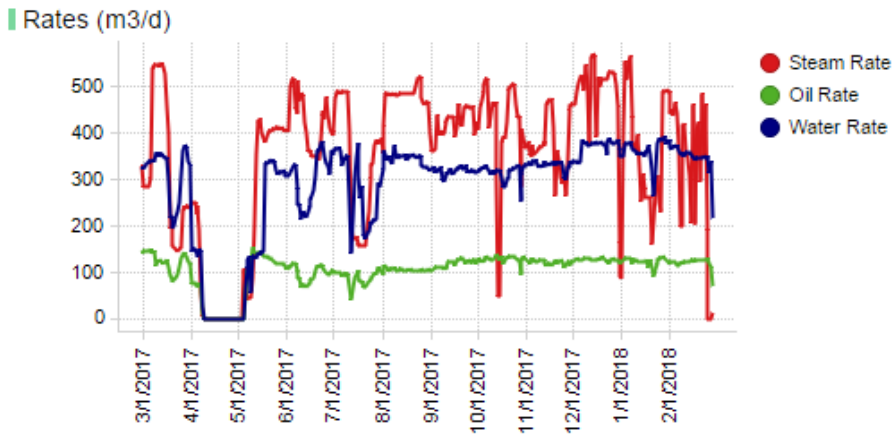


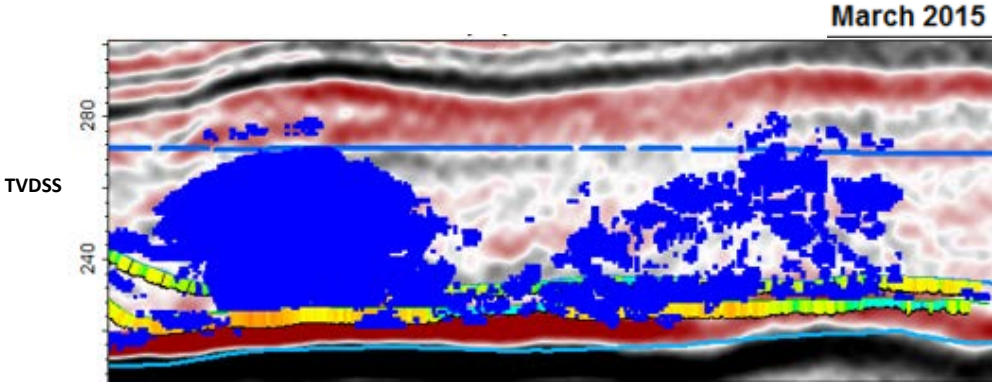


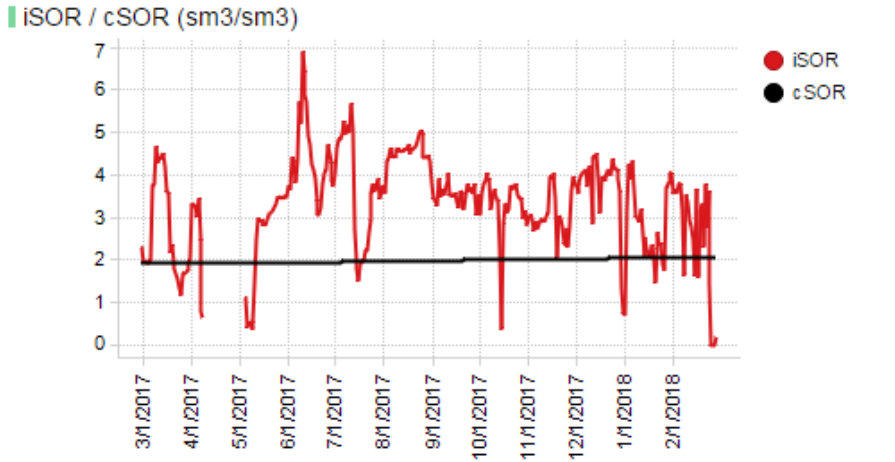


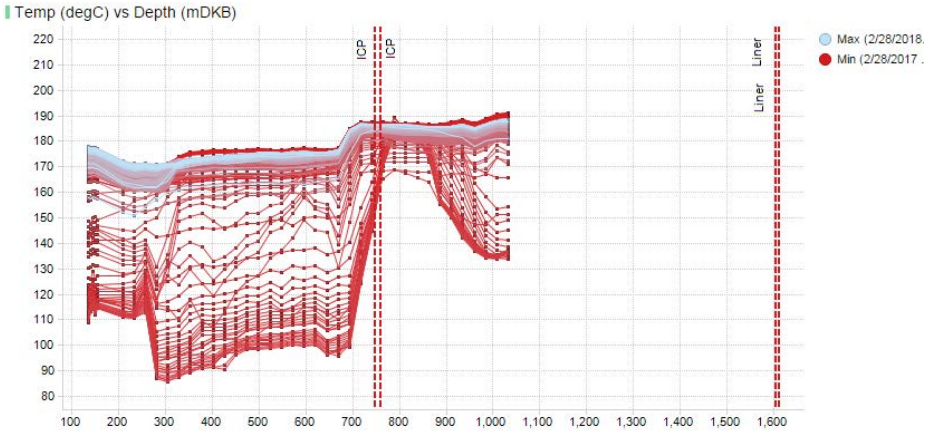
- **High quality reservoir.**
- **FCD installed in Injector and Producer.**
- **Falloff data and 4D seismic indicates well conformance.**

Average Performance – 101-14 (16)



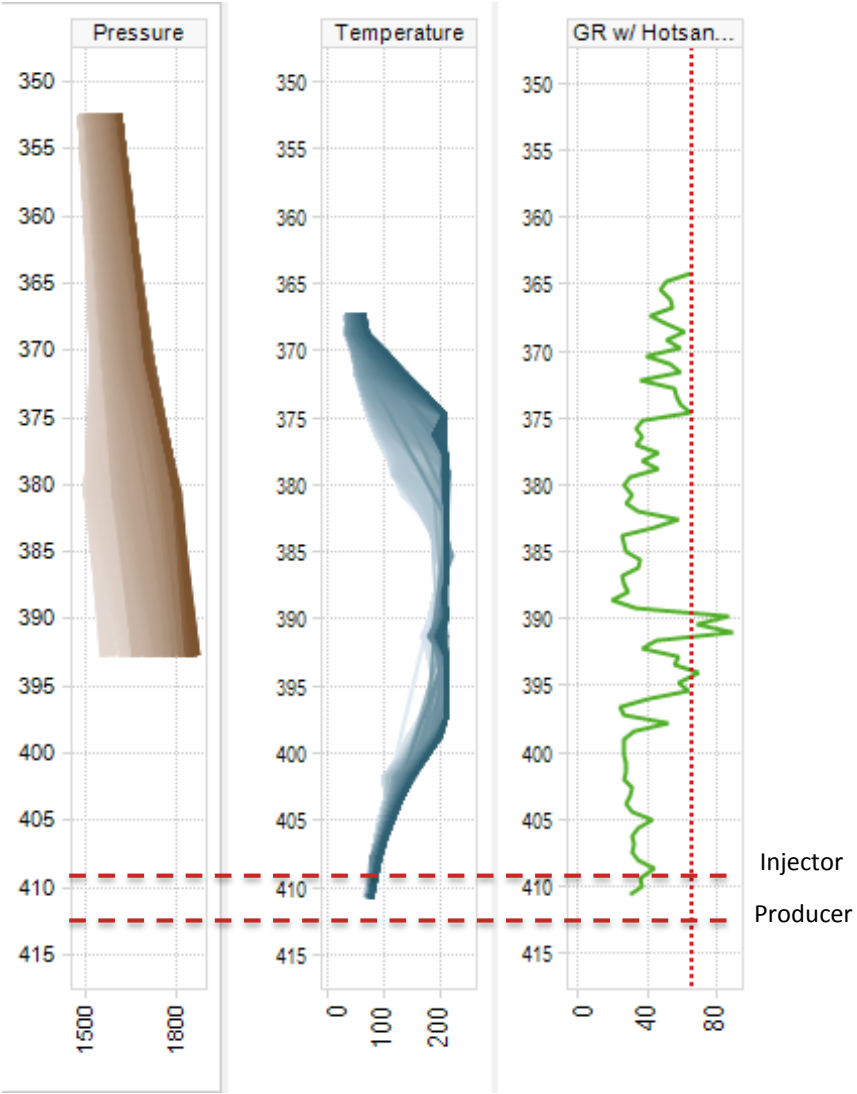


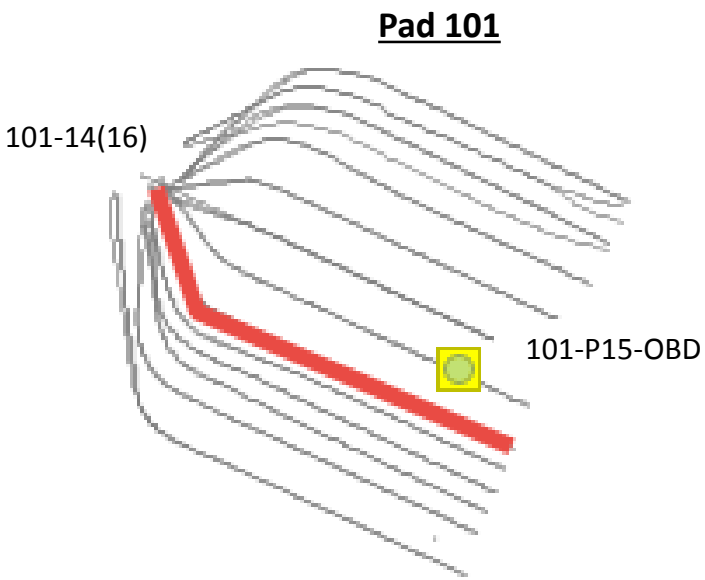




- **Well performance meets expectations.**
- **Steady rates in terms of injection and production.**
- **Conformance challenged in the toe, due to fish in hole.**

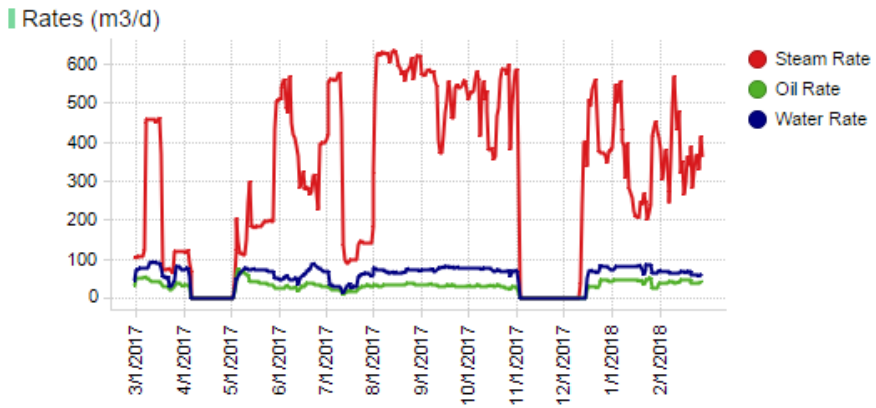
Obs Wells Temp & GR – 101-P15-OBD

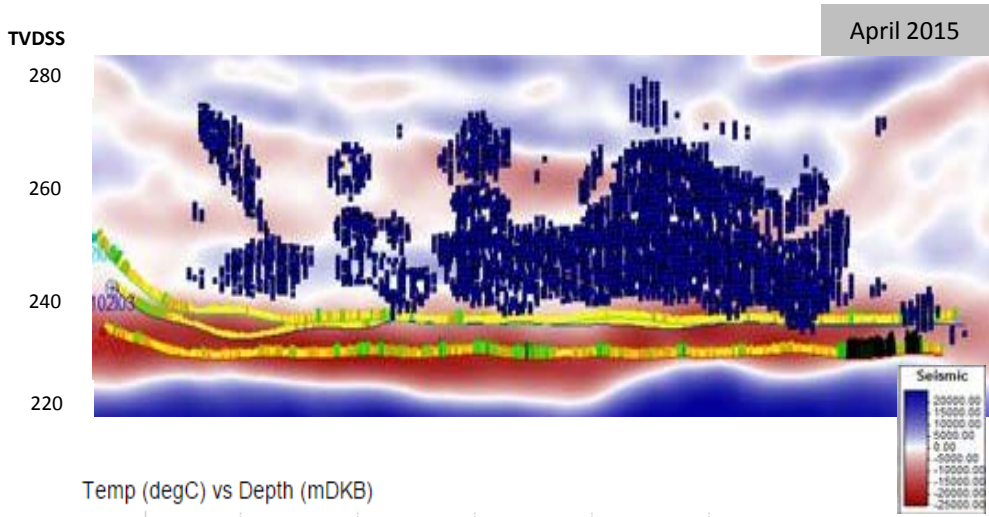


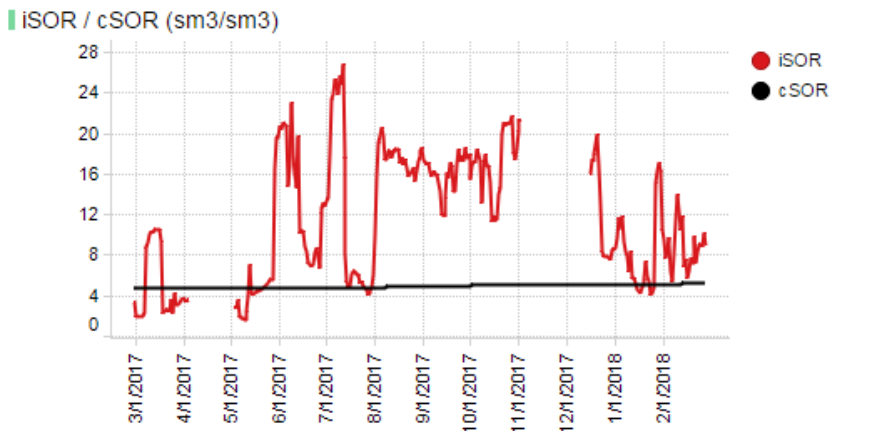


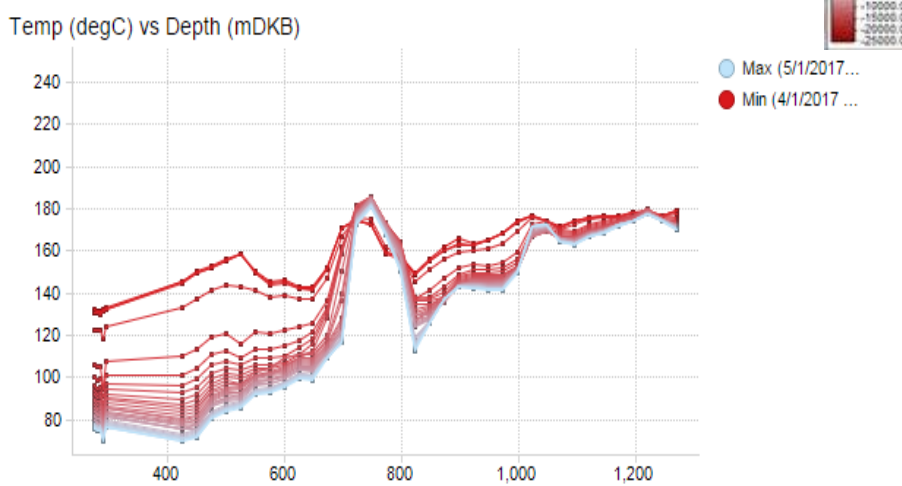
101-P15-OBD 105/07-13-083-07W4 / *8.4m offset*

Poor Performance – WP 102-03



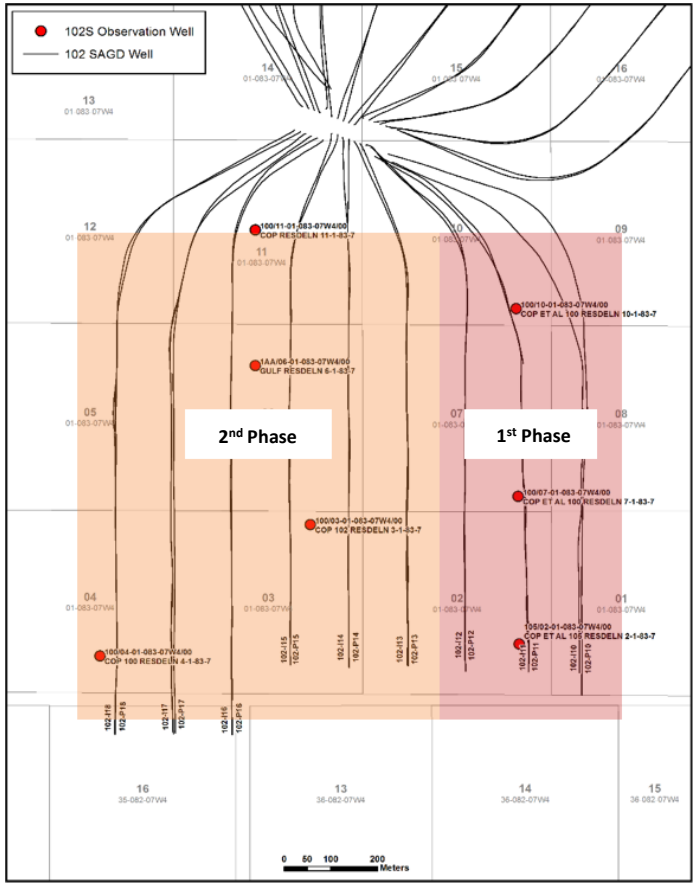






- **102-03 is one of the poorest producing well pairs on the pad; bridge Plug was milled out but did not impact production.**
- **Recovery remains low, and a side-track re-drill is being considered to recover the lateral wellbore length and increase production.**

Pad 102S Background / NCG Pilot



Pilot start dates

- NCG Co-injection started on 3 wells in Jan 2017
  - Pilot suspended in Apr-May 2017 due to diluent outage
  - Re-started and reset in Jun 2017
- Pilot expansion to all 9 wells in Sep 2017

Observations

- Reduction of emulsion rates
- Reduction of water cut

  } Oil rates flat
- iSOR reduction of ~30%
- Increase in BHP due to NCG injection
- All steam chambers currently in full coalescence

Phase 1 – Key Learnings

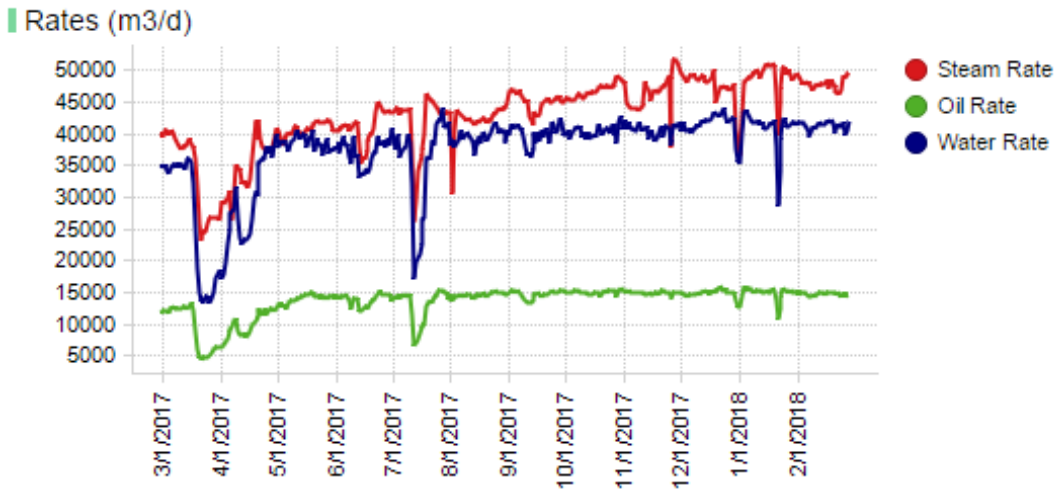
- At pad 101/102, incremental steam injected during 2016/2017 increased the reservoir chamber pressure which attributed to a flat bitumen production profile during the subject timeframe

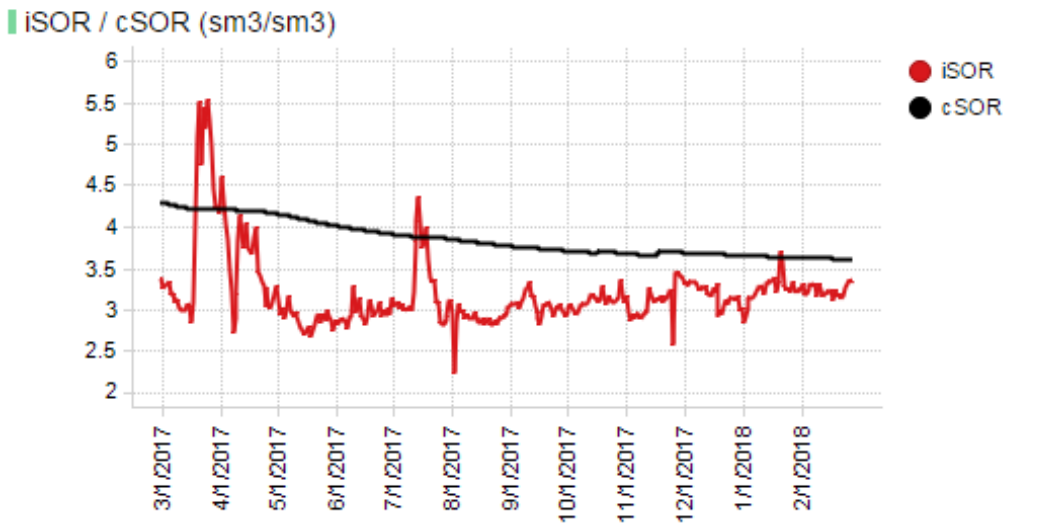
- Liner installed flow control devices at pad 103 continue to outperform slotted liner wells.

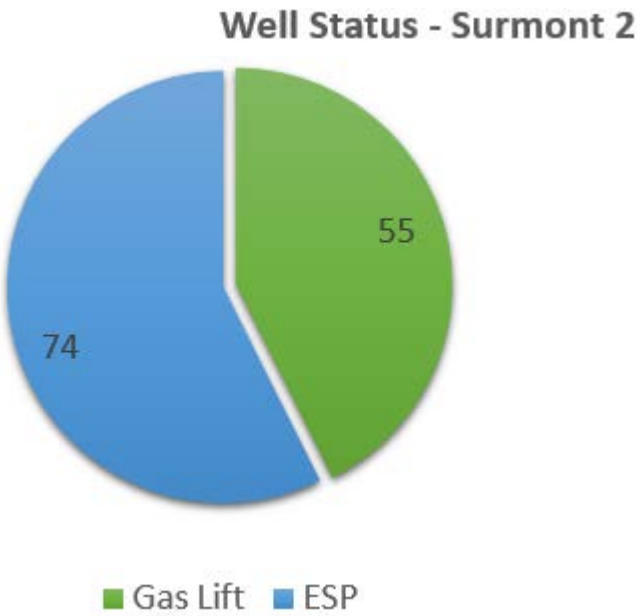
- Initial results from tubing deployed flow control devices at pad 101/102 continue to be assessed. However, early days are illustrating a net increase in total emulsion/bitumen rates.

- Optimization continues to improve performance of mature wells:
  - NCG pilot commenced January, 2017 on 102S.
  - Well stimulations (executed approximately ten stimulations)
    - 30% of the well stimulations have been successful in terms of reducing the scale/dP between the wells. This has contributed to higher production rates.
  - Completed two bridge plug drill-outs to recover lost sections of laterals (one on 101N and one on 102N).

Surmont Phase 2 Aggregate Performance Plots

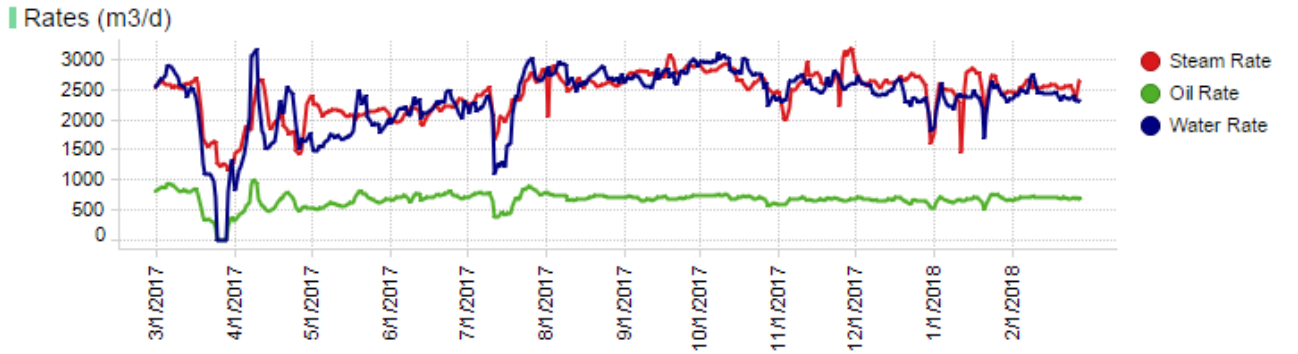


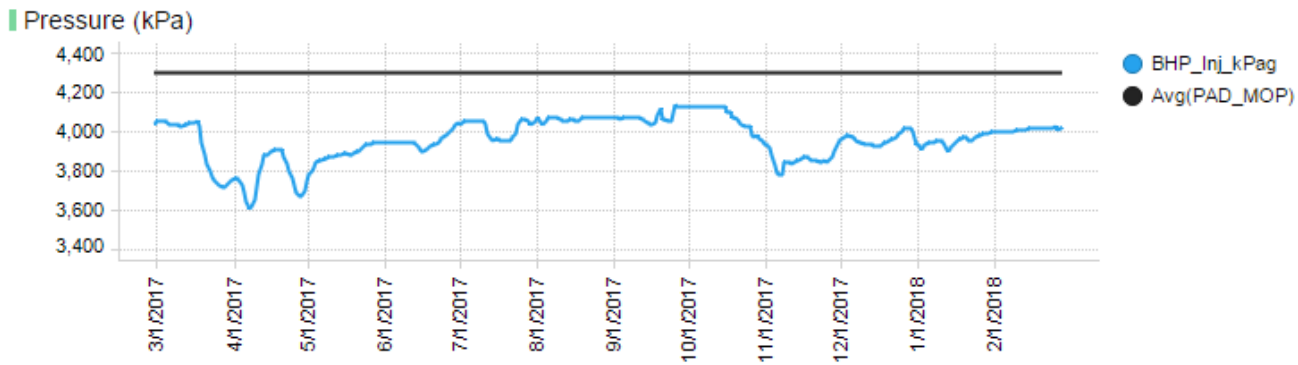


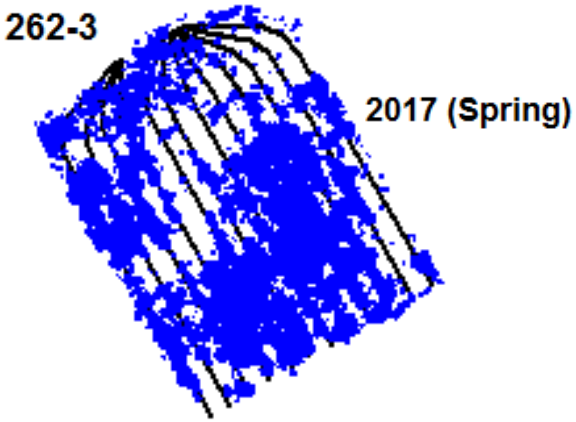


- **TW Thief zone interactions in Pads 264-3, 264-1, 263-1 and 265-2**
- **BW Thief zone interactions in 261-3, 262-1 and 262-2.**
- **One producer and one injector re-drilled due to downhole failures.**
- **Four producers re-drilled due to poor performance.**
- **ESP conversions ongoing.**

Performance / Chamber Development Challenges – Pad 262-3

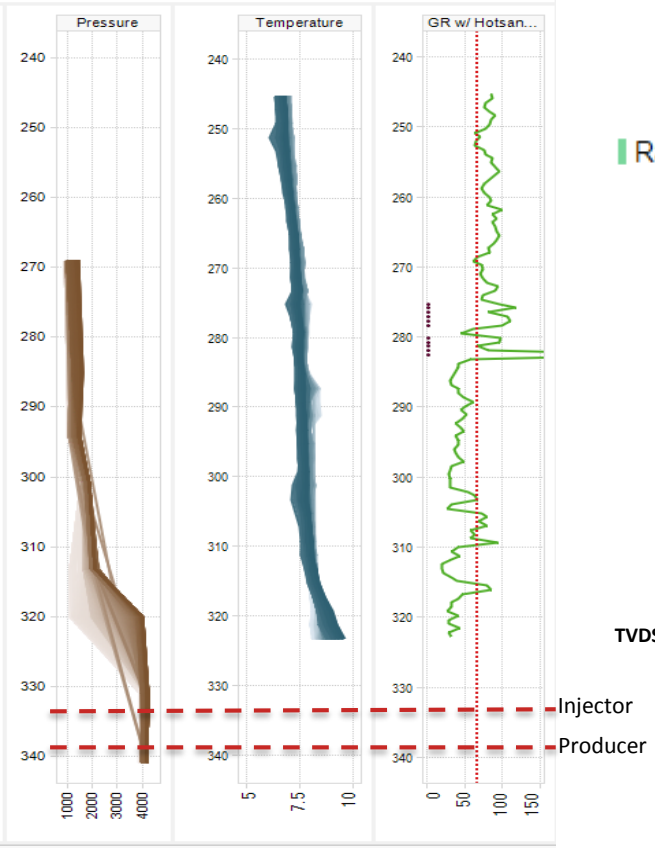




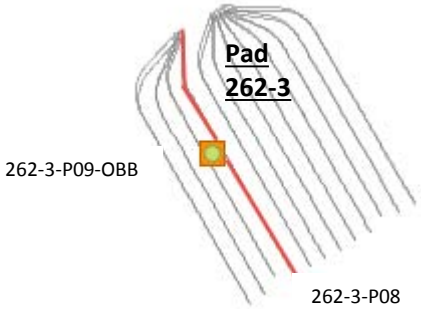


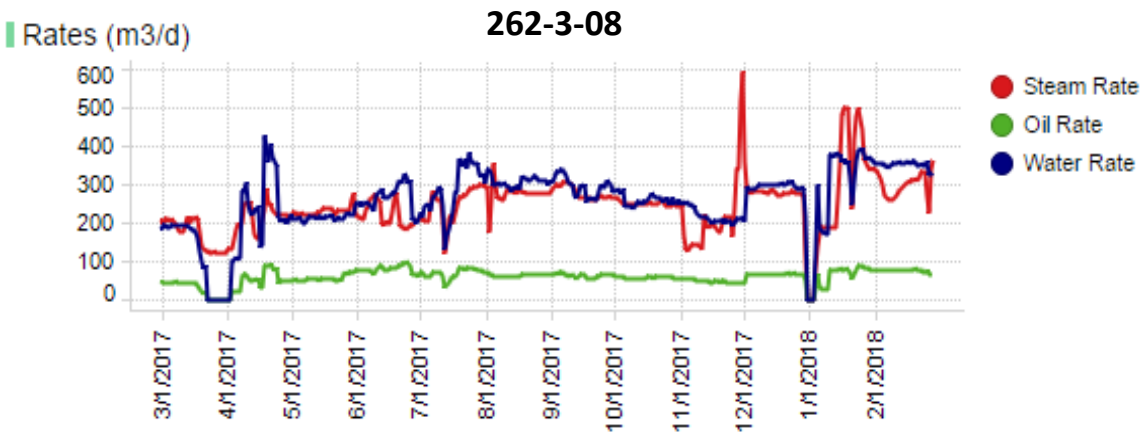
- **262-3 has been operating at a target pressure of 4,000 kPag**
- **12/12 wells converted to SAGD.**
- **Challenged performance from east to west.**
- **No thief zone issues.**

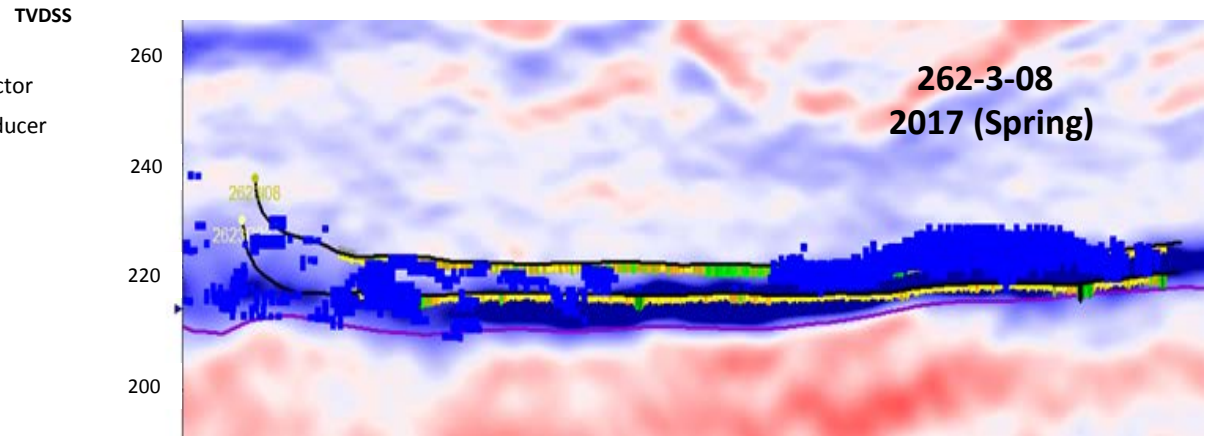
Performance / Chamber Development Challenges – Pad 262-3



262-3-P09-OBB 35.7 meters from well pair

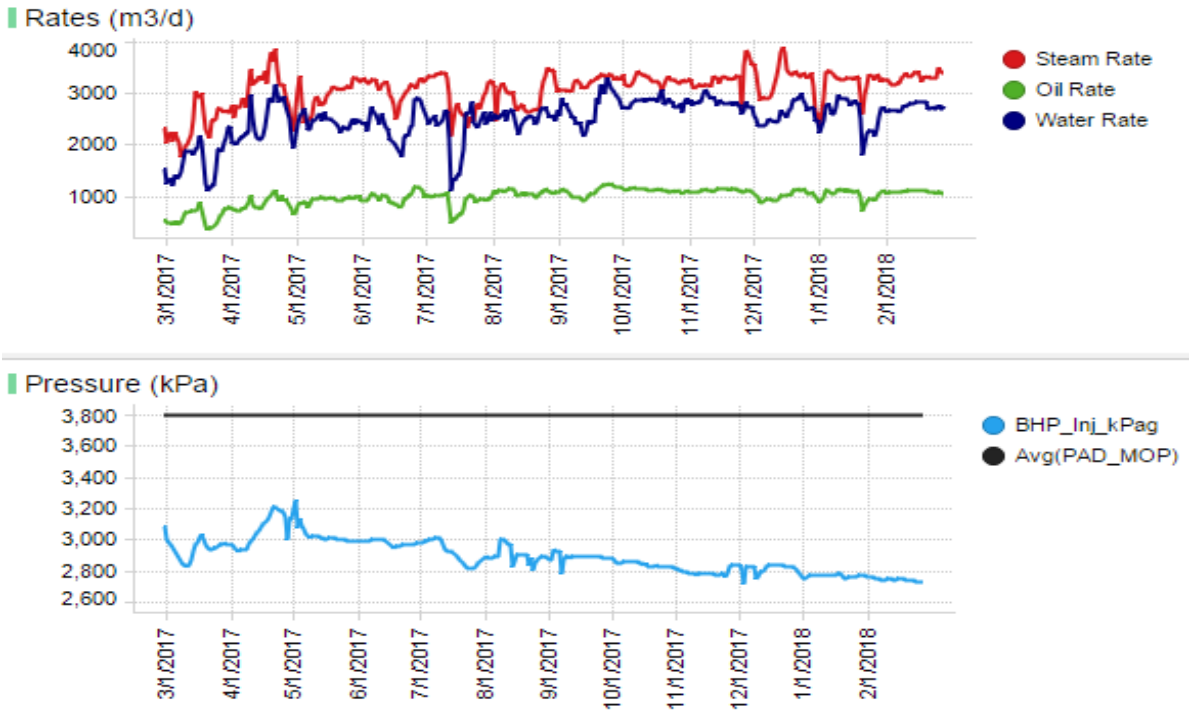


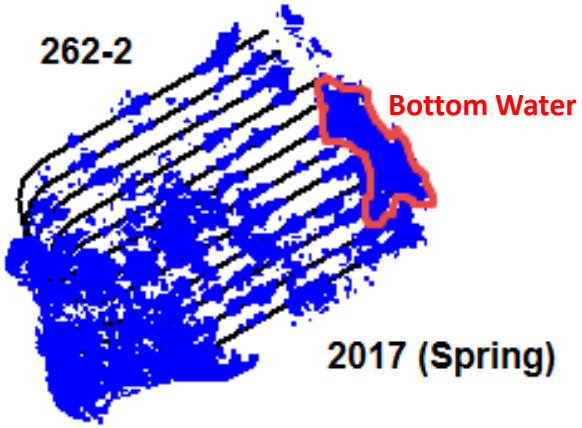




- **Limited chamber growth**

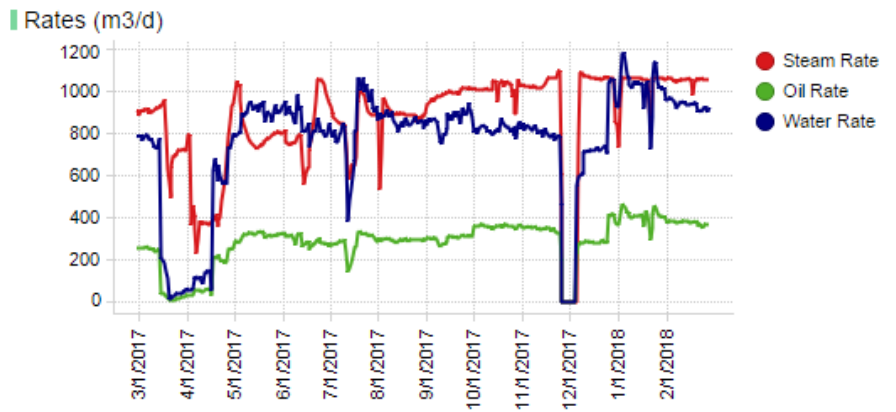
Performance / Chamber Development Challenges – Pad 262-2

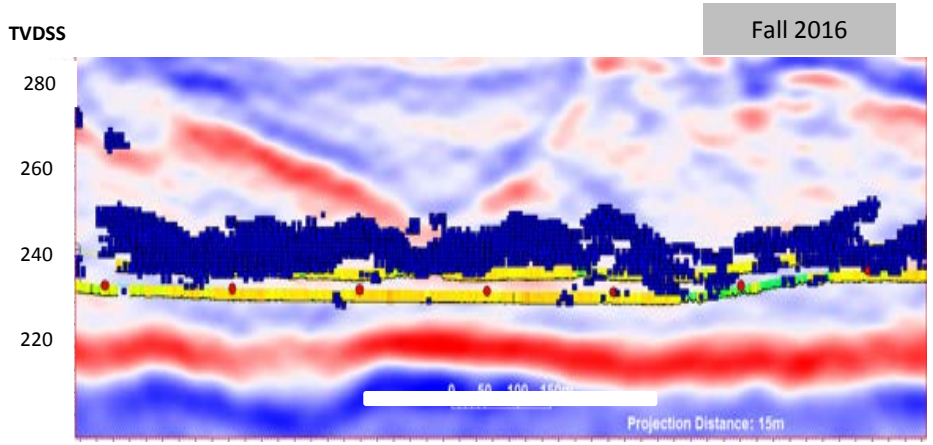


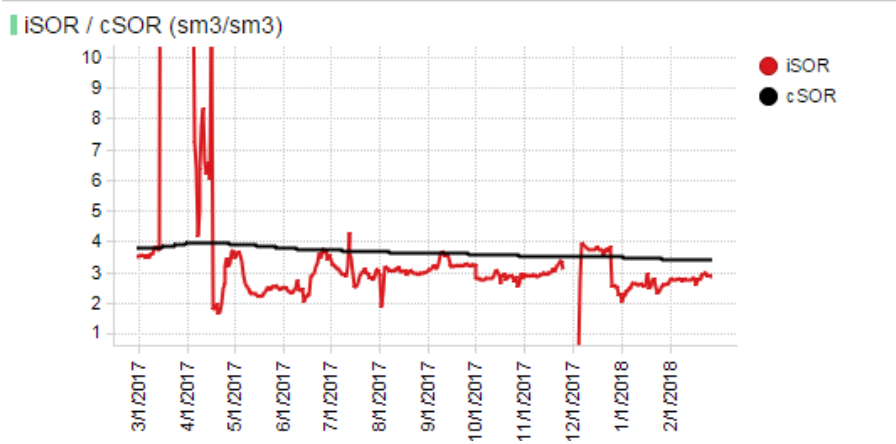


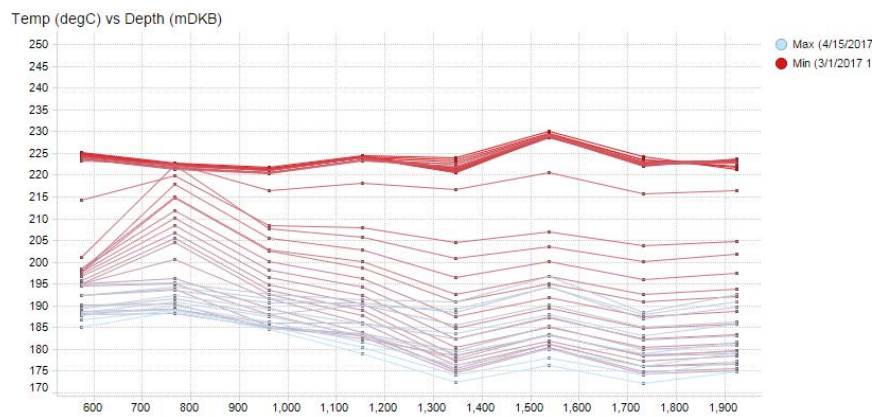
- **Severe bottom water interaction on many well pairs.**
- **Attempted to mitigate BW interaction with various injector retro-fits with limited success.**
- **Reduced pressure differential between chamber and low pressure BW on wells that are interacting with the BW.**

Good Performance – 263-1-07



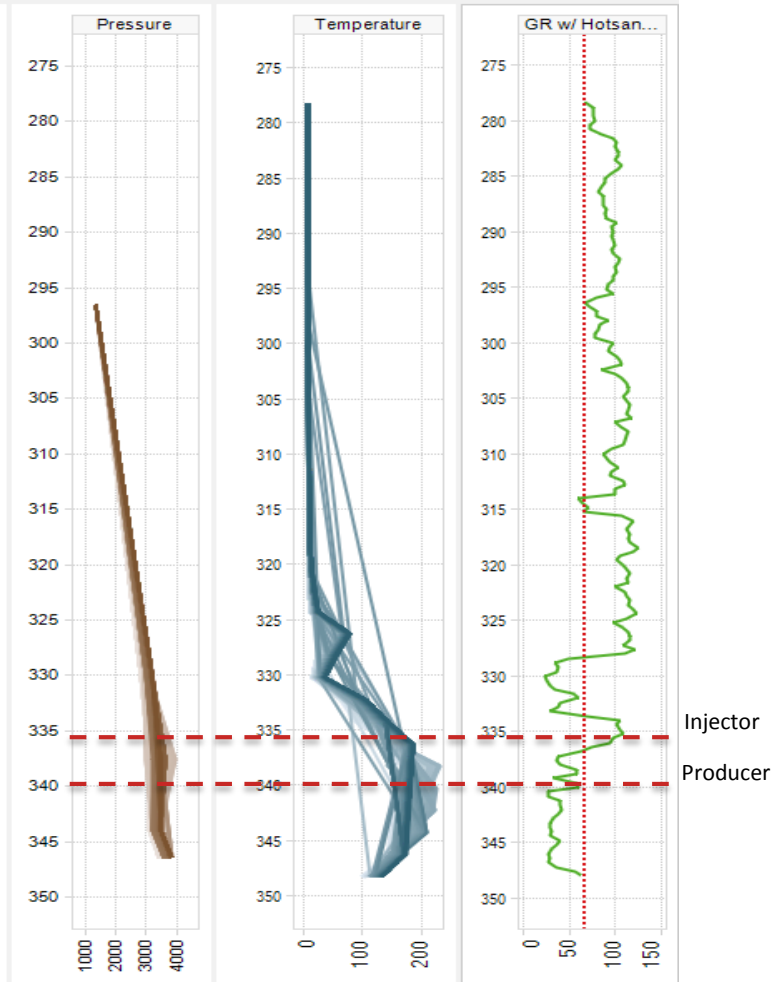




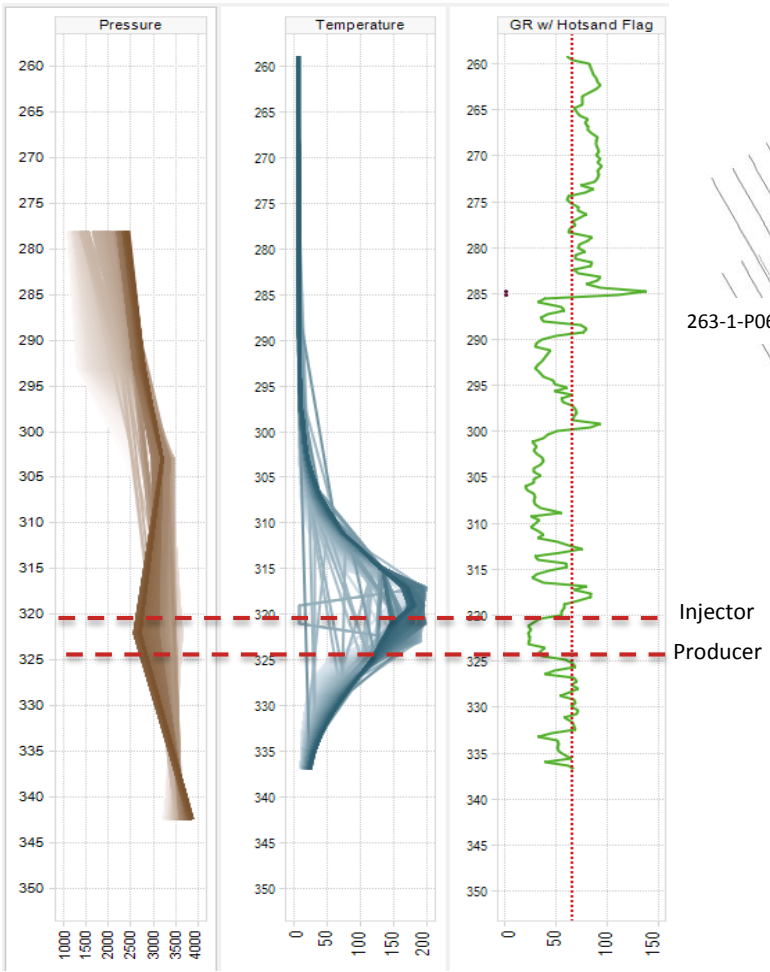


- **Well Performance exceeds expectations; due to FCD and ESP install.**
- **Steam management has led to high production volumes (increased pressure on pad 264-1 to decrease losses on 263-1).**
- **Mud channel continues to be a challenge.**

Surmont: Obs Wells Temp & GR – 263-1-P06-OBC, 263-1-P09-OBD

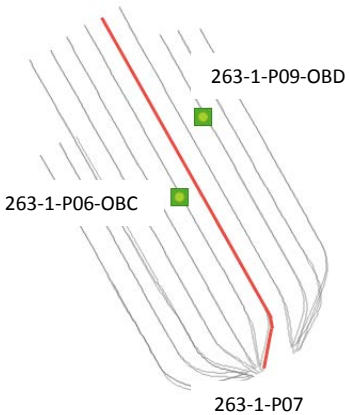


263-1-P06-OBC 103/12-27-083-06W4 / *8.9m offset*

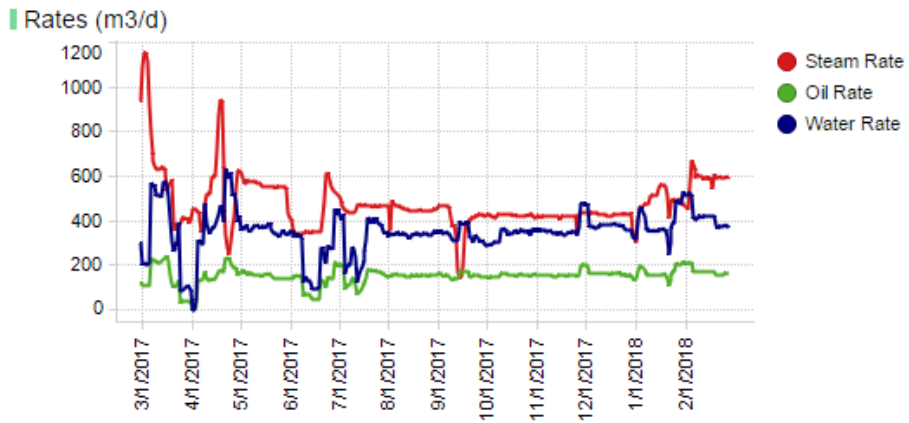


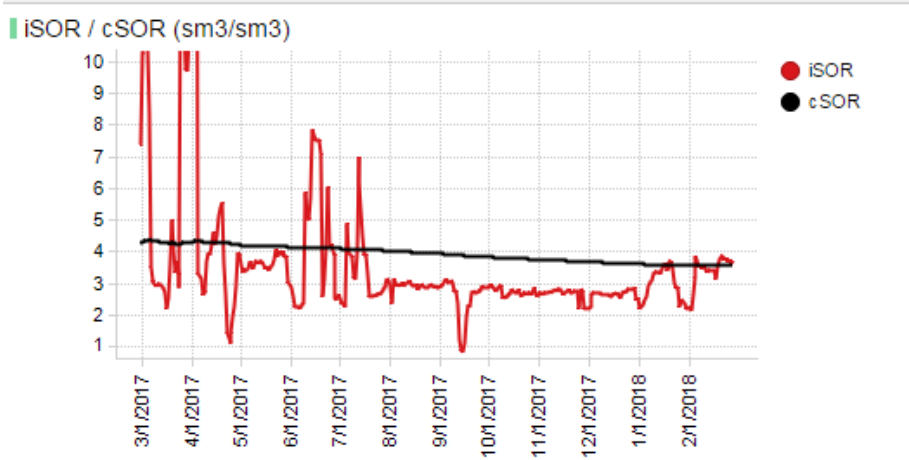
263-1-P09-OBD 102/12-27-083-06W4 *11.0m offset*

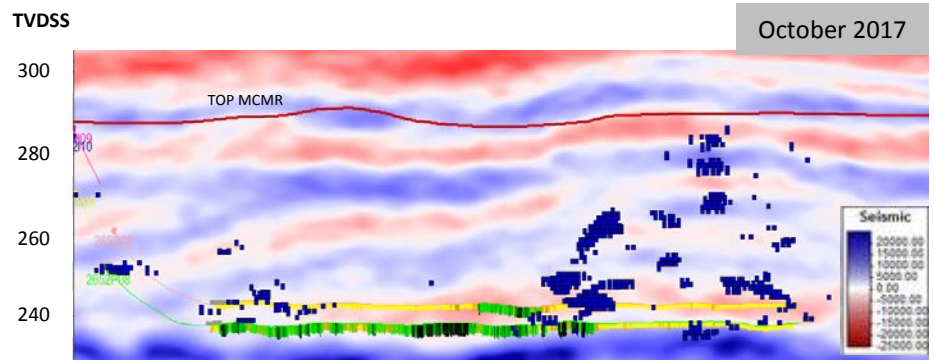
Pad 263-1

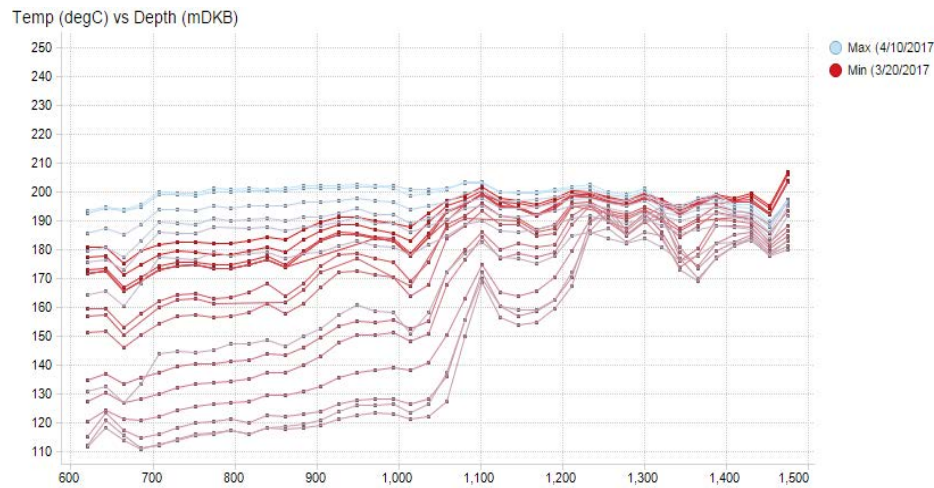


Average Performance – WP 265-2-08



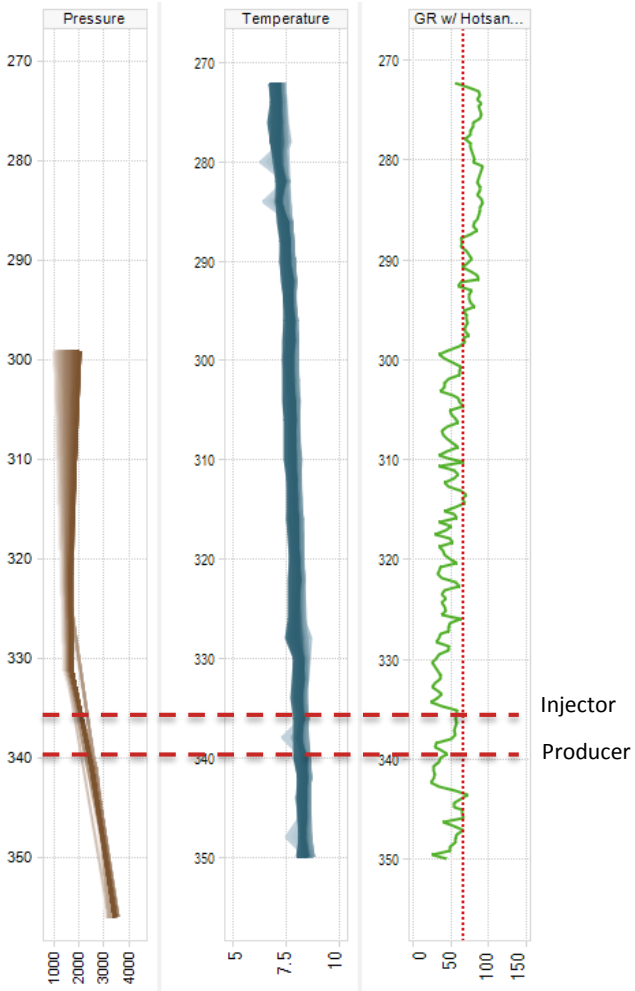




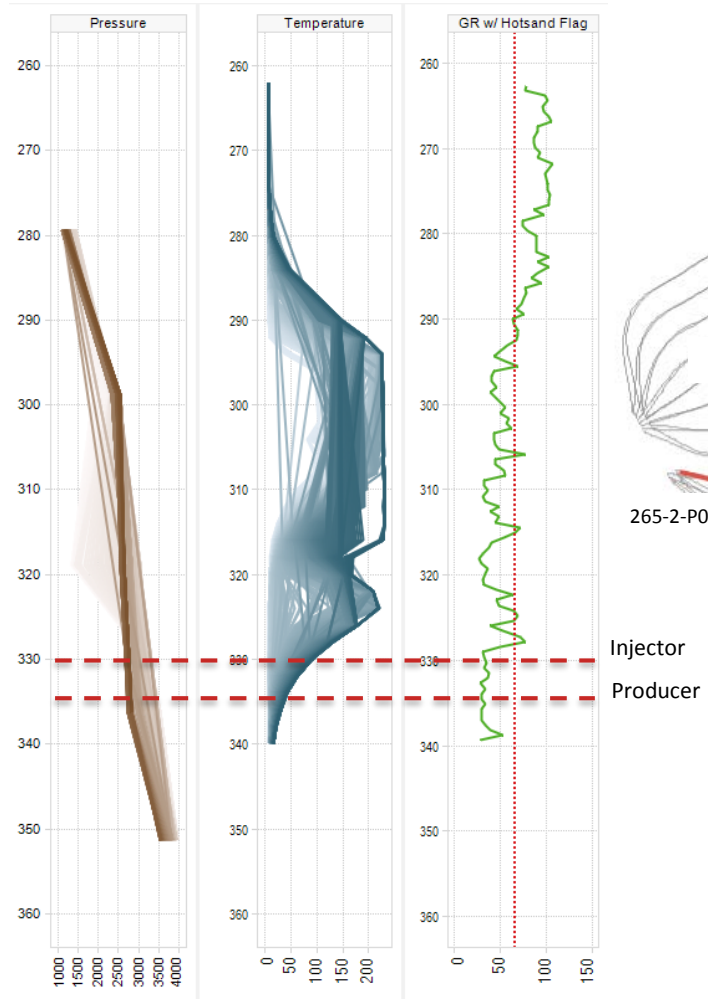


- **Stable 2017 production performance, meets expectations.**
- **Managed top thief zone interaction with dedicated pressure management.**

Surmont: Obs Wells Temp & GR – 265-2-P08-OBB, 265-2-P09-OBD

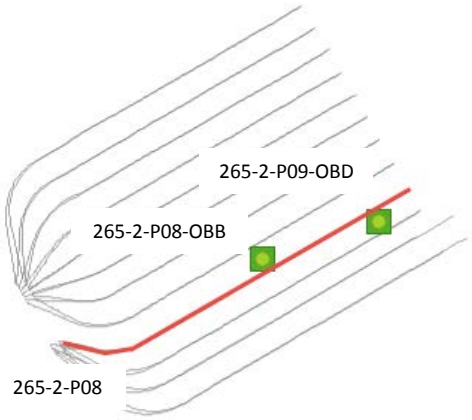


265-2-P08-OBB 103/01-22-083-06W4 / *43.9m offset*

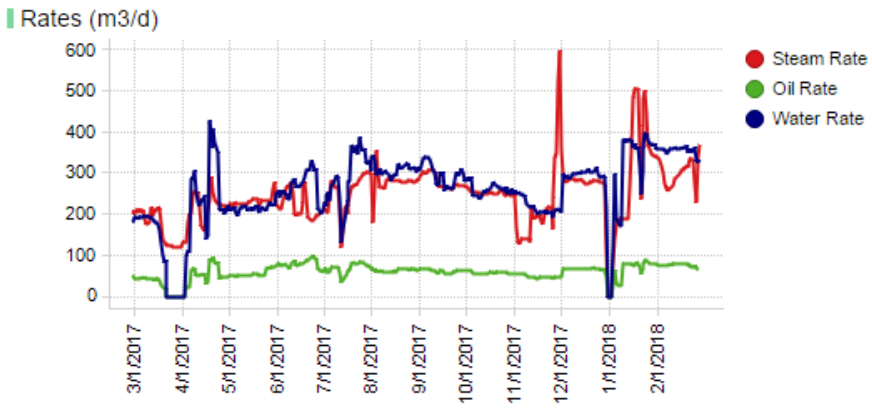


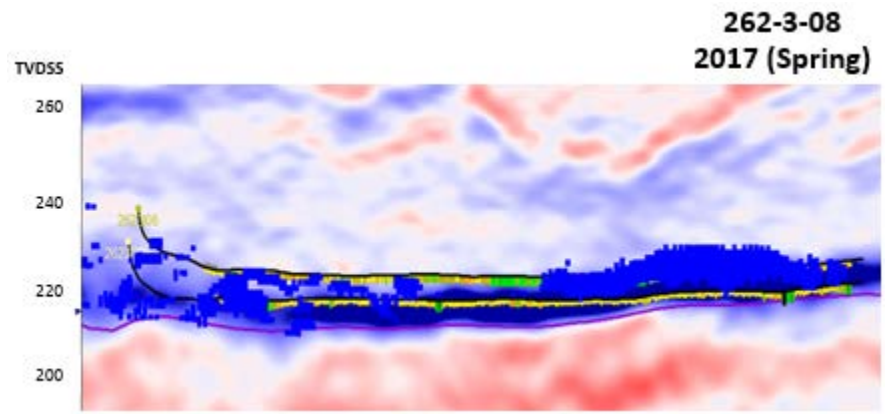
265-2-P09-OBD 102/05-23-083-06W4 *35.2m offset*

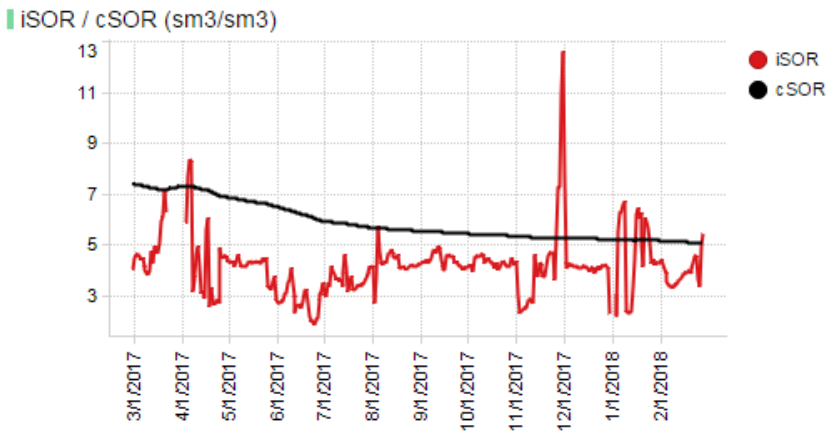
Pad 265-2

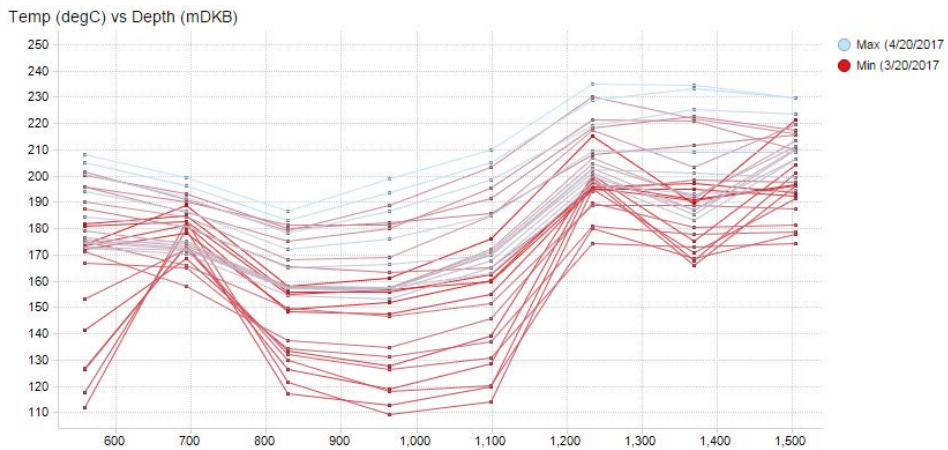


Poor Performance – WP 262-3-08



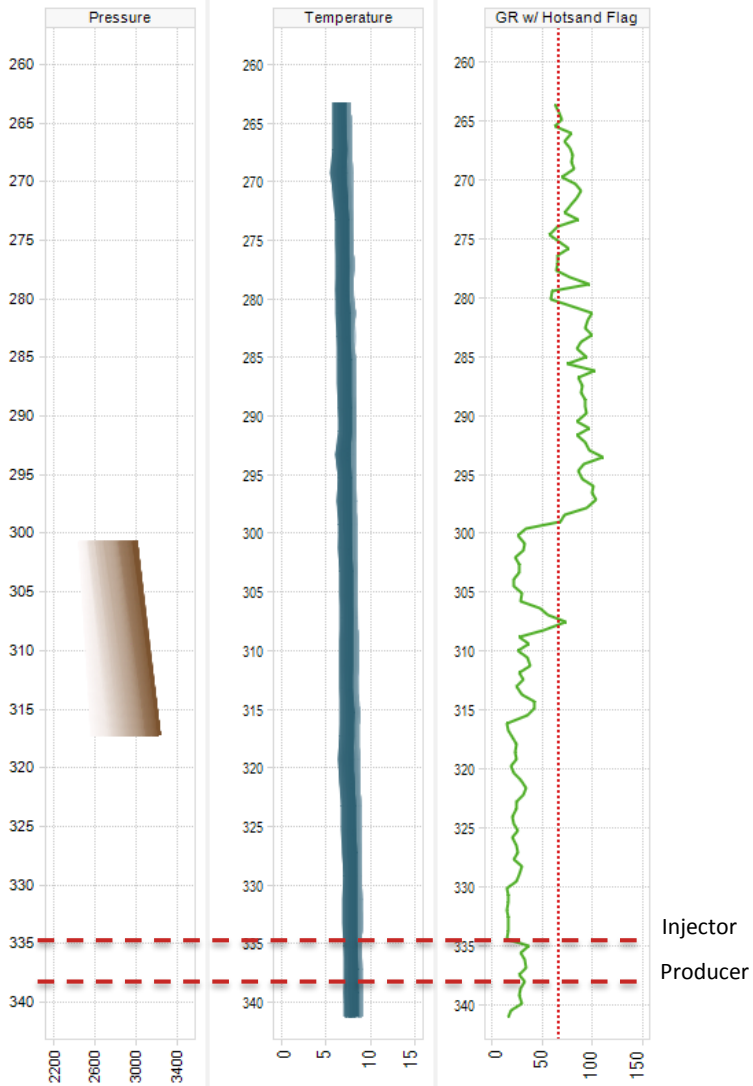


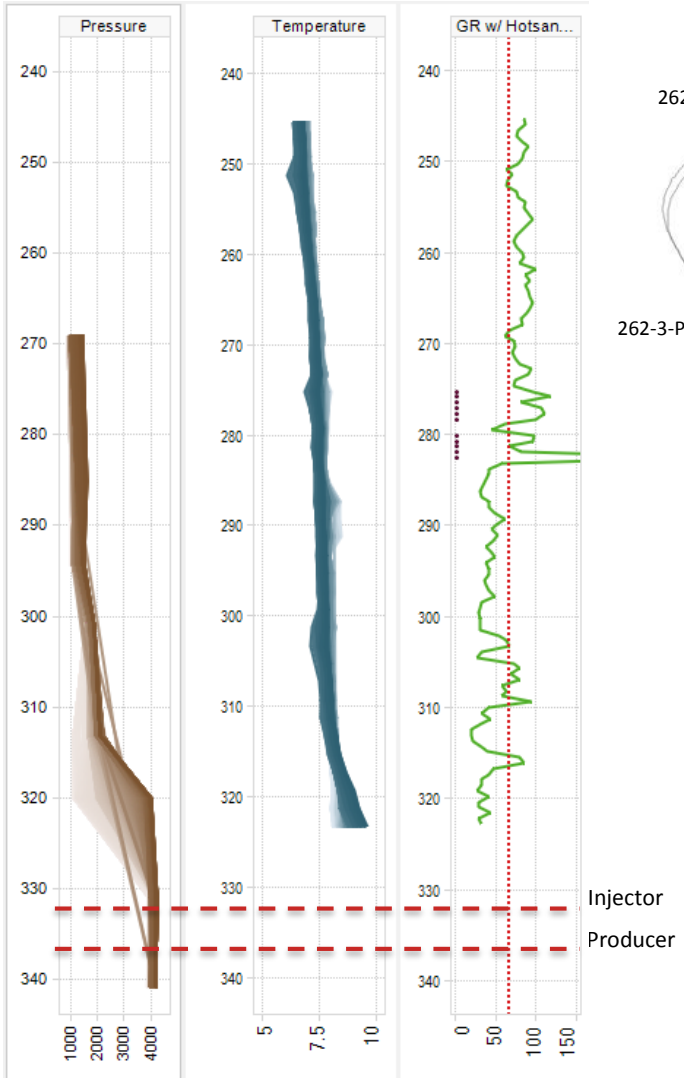


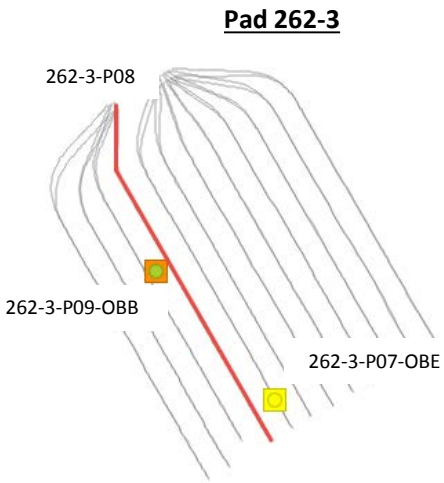


- **Challenged well; potential flow baffles above the pair.**

Surmont: Obs Wells Temp & GR – 262-3-P07-OBE, 262-3-P09-OBB







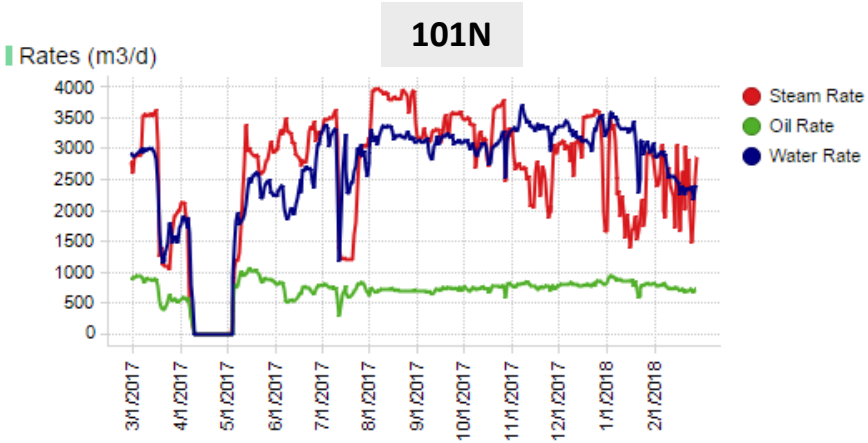
262-3-P07-OBE 100/10-27-083-06W4 / *5.3m offset*

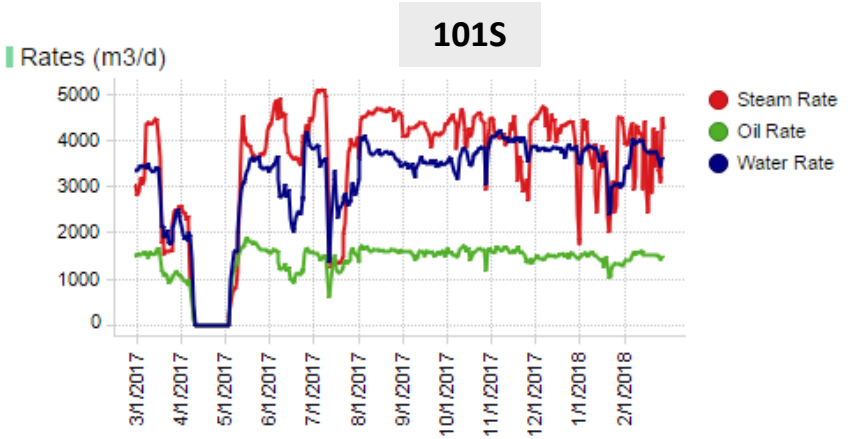
262-3-P09-OBB 103/14-27-083-06W4 *35.7m offset*

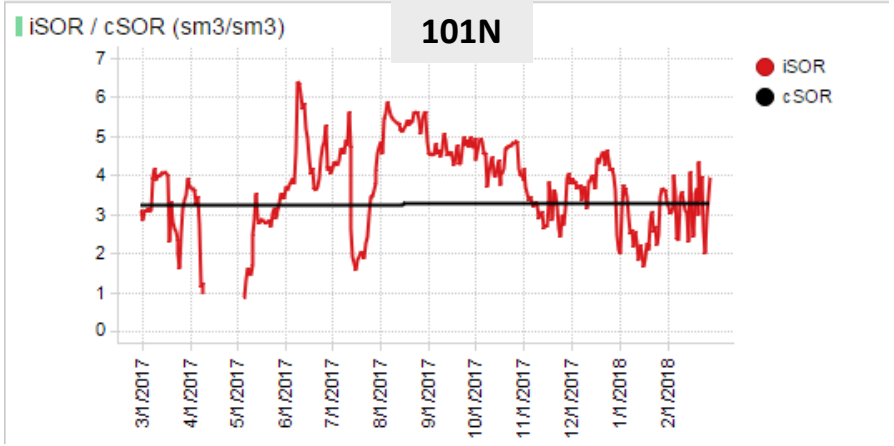
Phase 2 - Key Learnings

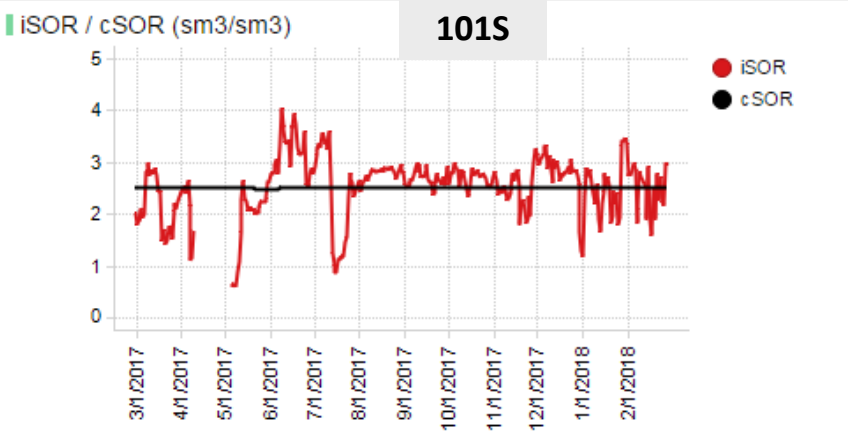
- At pad 262-3, higher reservoir chamber pressure has been trialed to overcome under performance with minimal success. A single-well dilation process has also been attempted with minimal success. The pad performance remains to be challenged.
- Tubing Deployed FCDs continue to bring uplift in a sustained manner on base production.
- Injector steam splitters are still being evaluated for SOR improvement. No conclusions to date.
- BW has been very challenging to mitigate due to the early interaction of some wells and the high differential pressure between chamber and the BW zone.
- TW interaction is being mitigated thanks to dedicated pressure management and ESP conversion strategy.

Surmont: Phase 1 Well Pad Rates and SOR / Pad 101

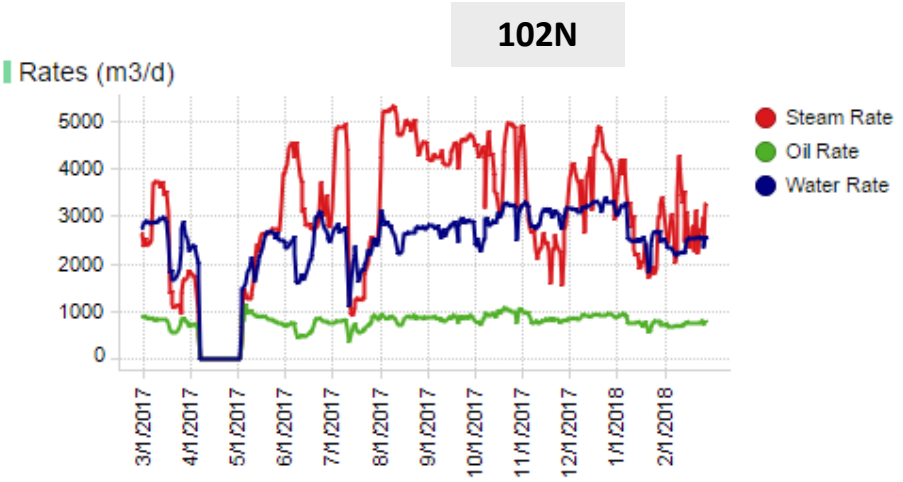


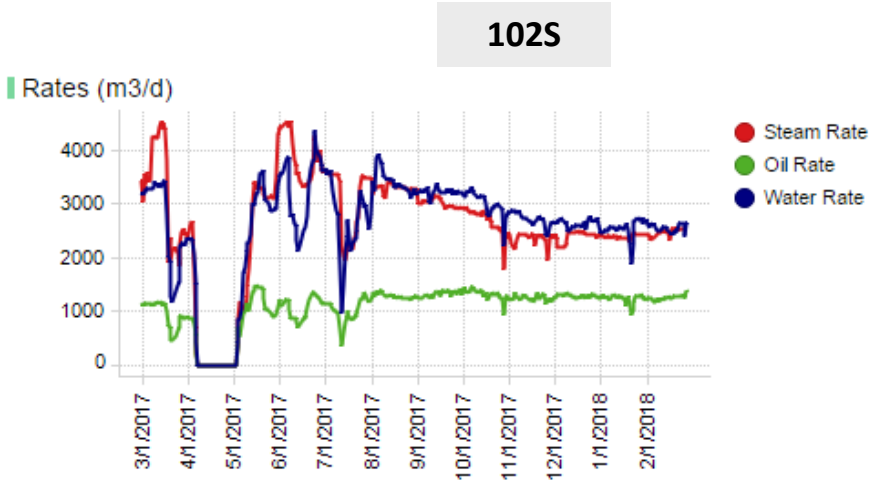


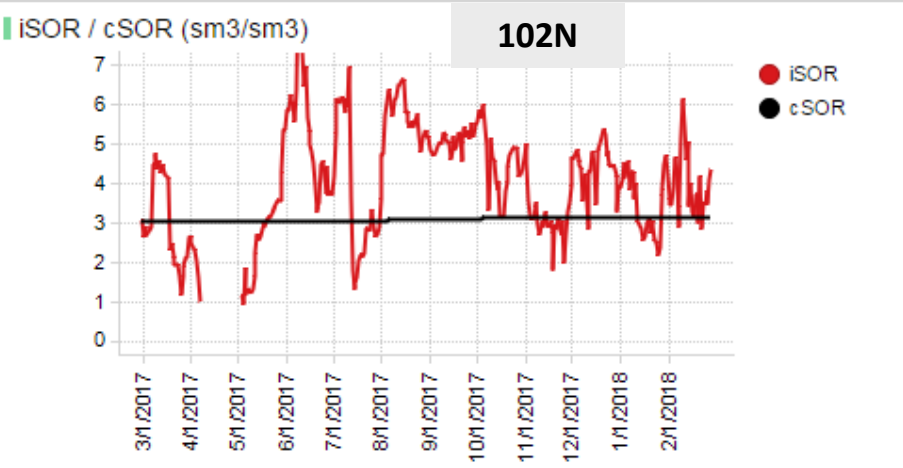


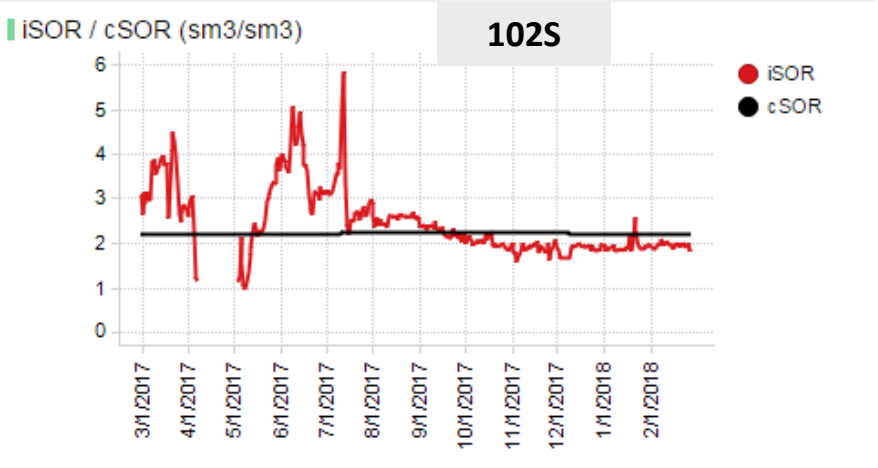


Surmont: Phase 1 Well Pad Rates and SOR / Pad 102

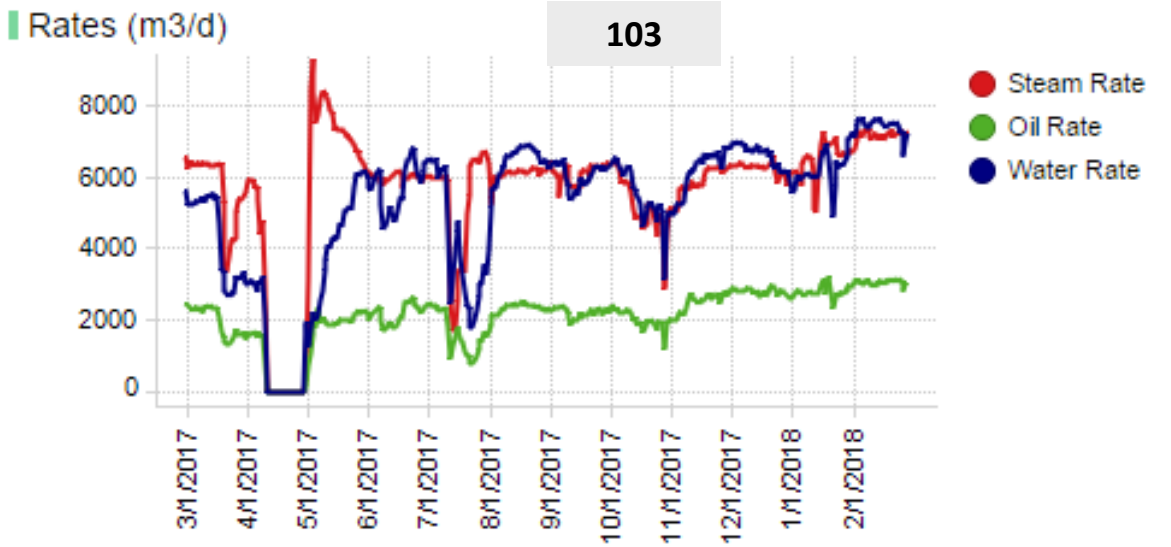


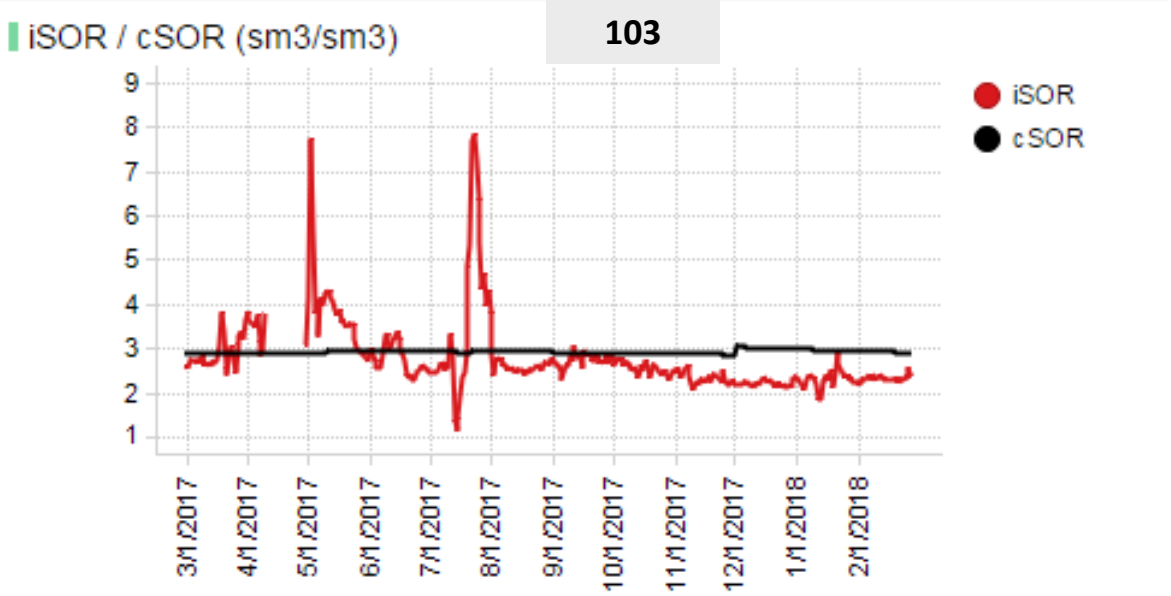




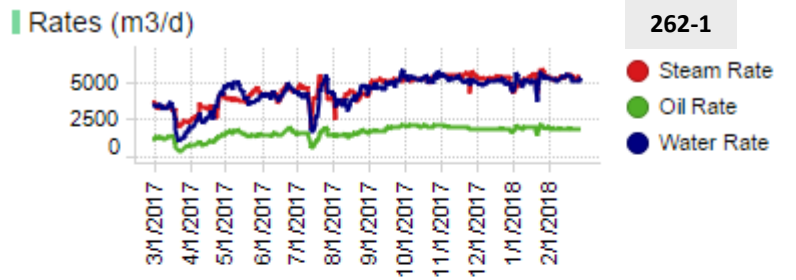


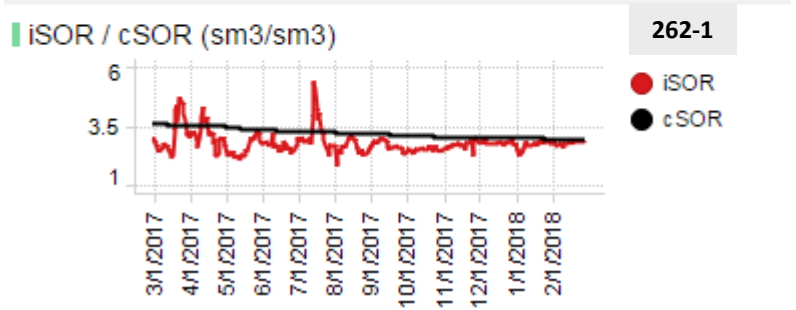
Surmont: Phase 1 Well Pad Rates and SOR / Pad 103

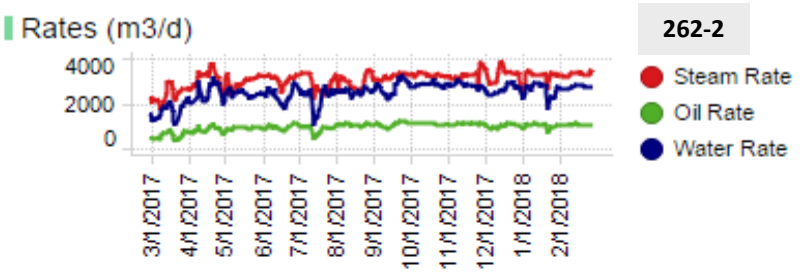


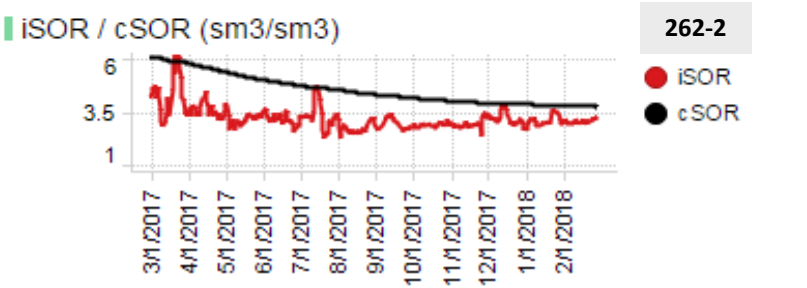


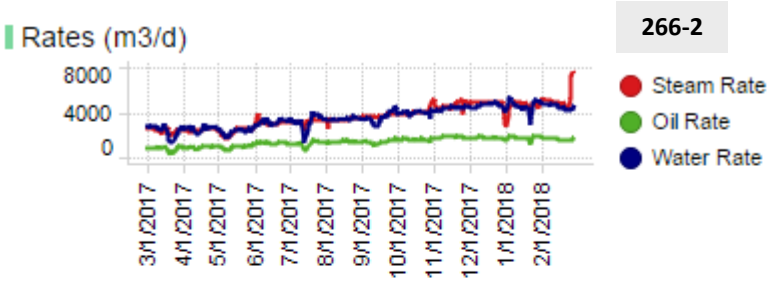
Surmont: Phase 2 Well Pad Rates and SOR

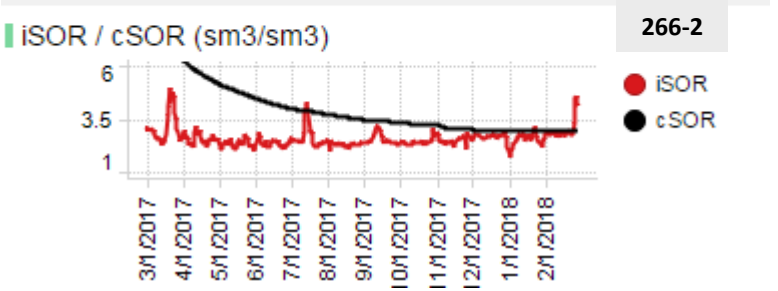


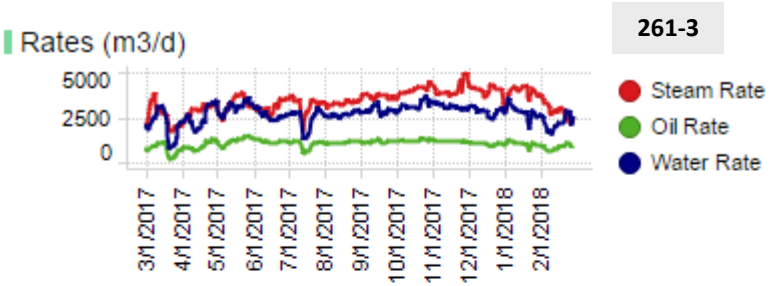


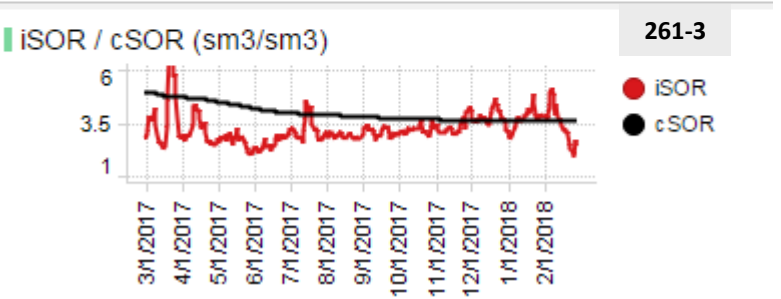




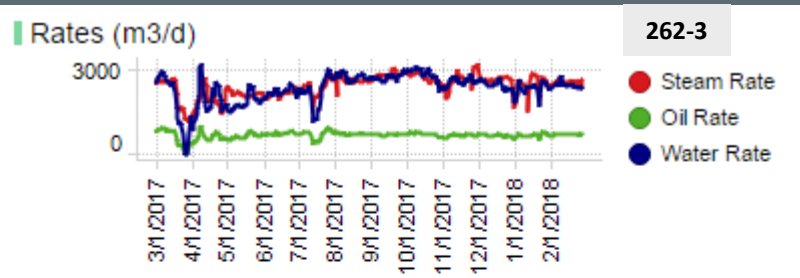


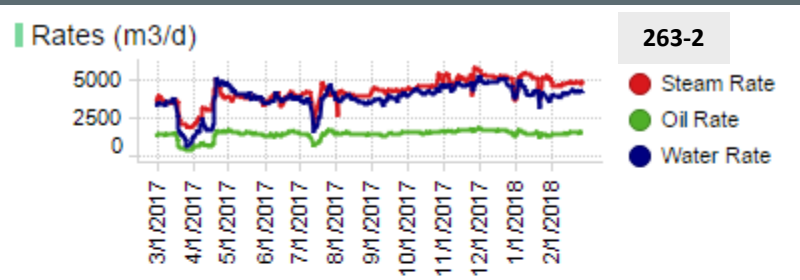


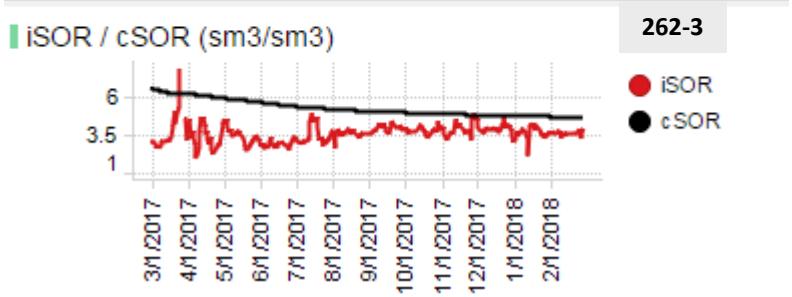


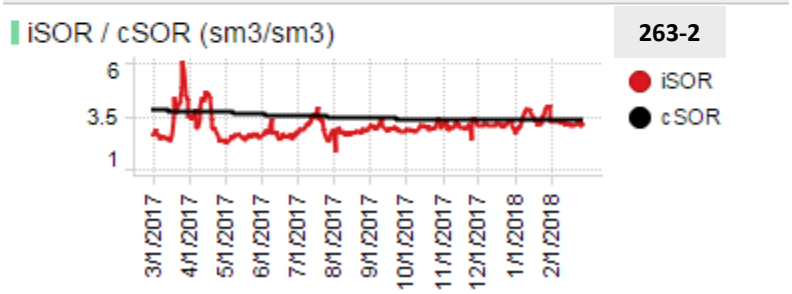


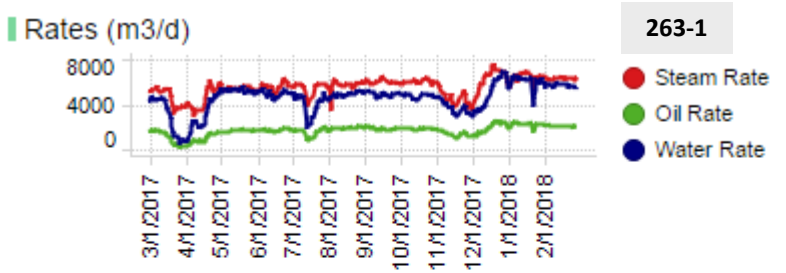
Surmont: Phase 2 Well Pad Rates and SOR

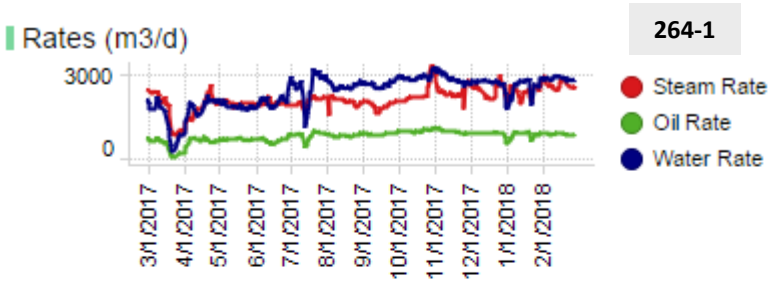


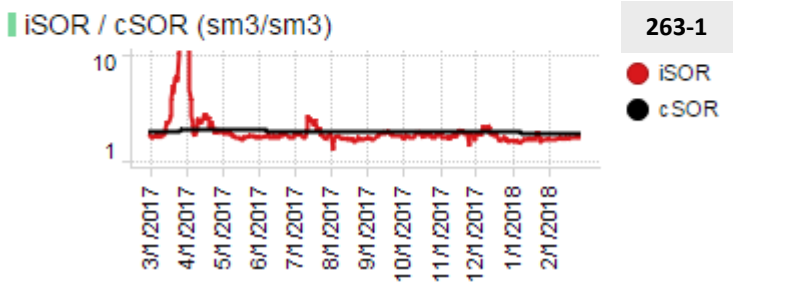


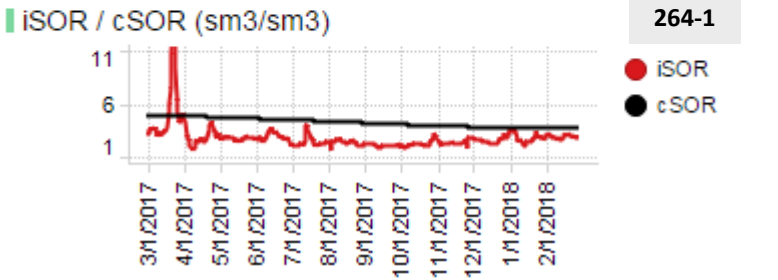




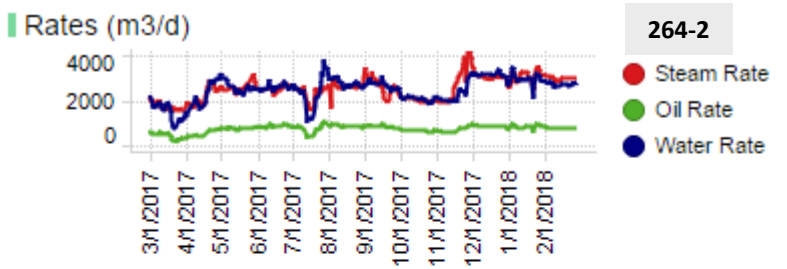


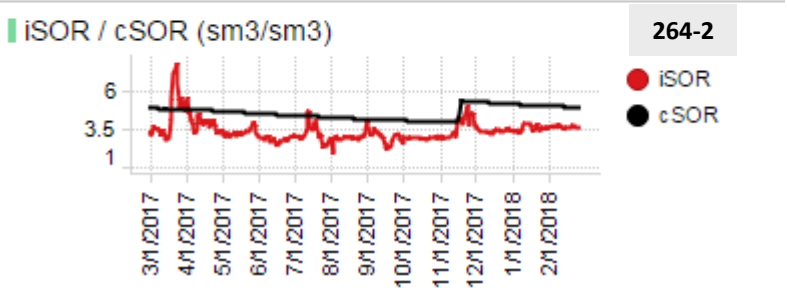


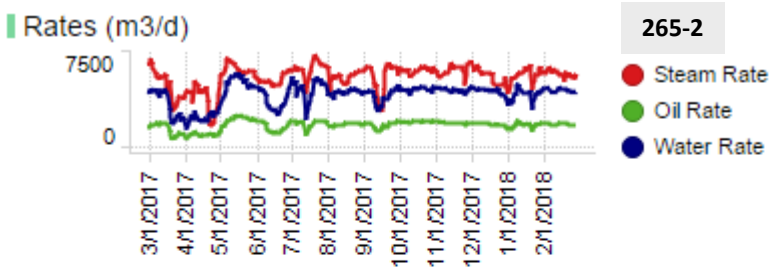


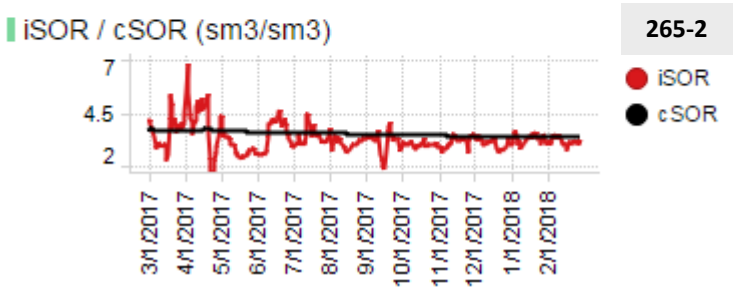


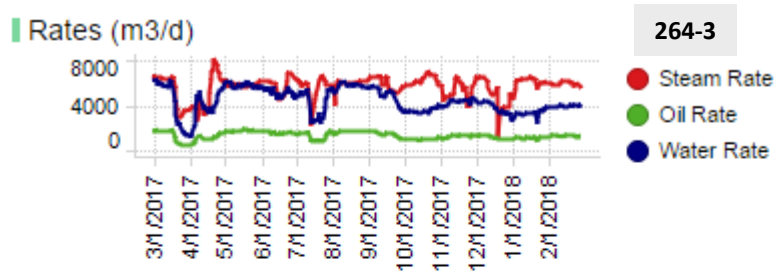
Surmont: Phase 2 Well Pad Rates and SOR

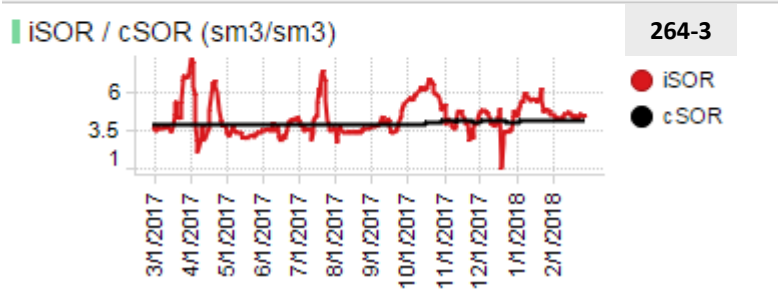




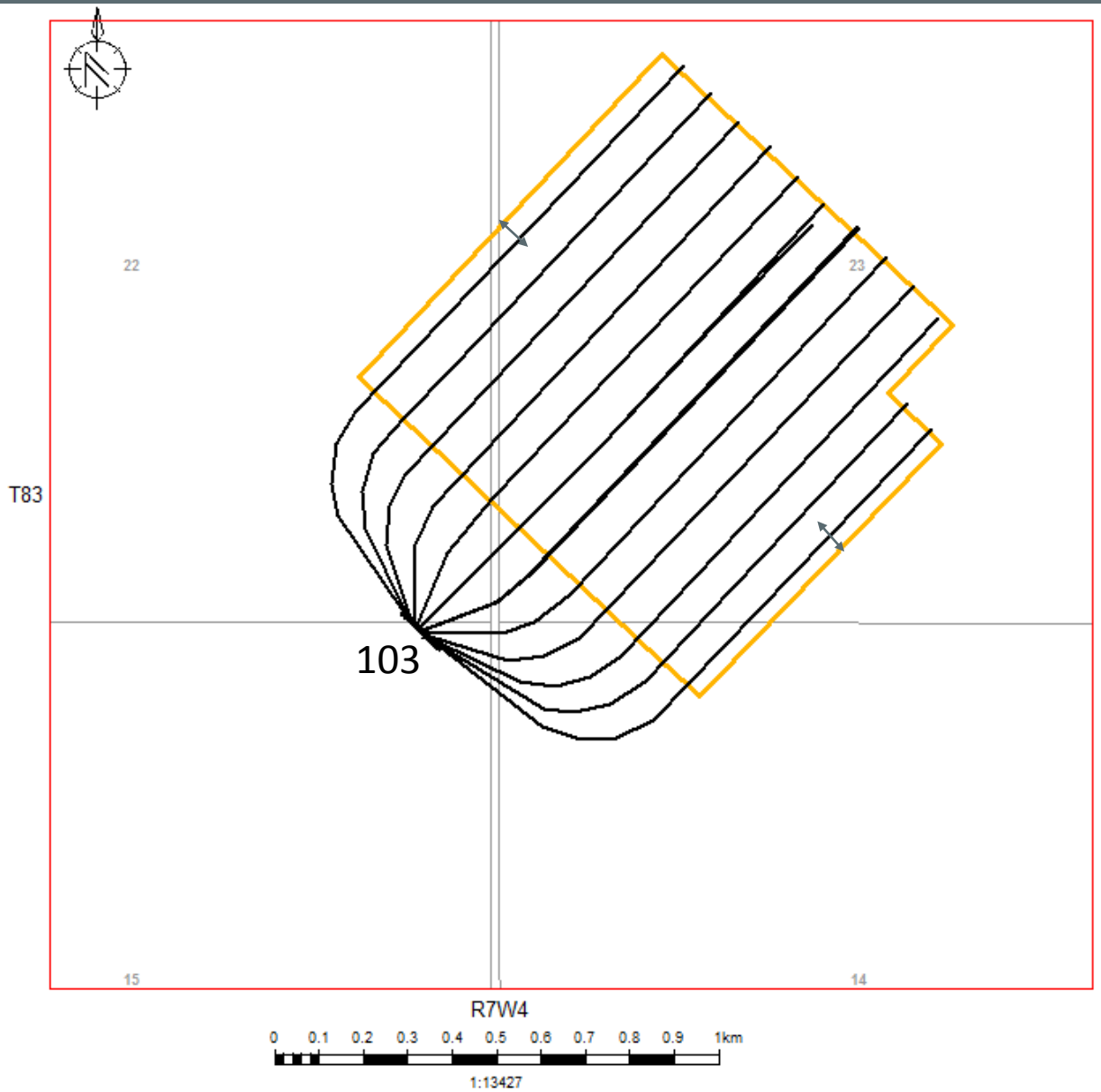




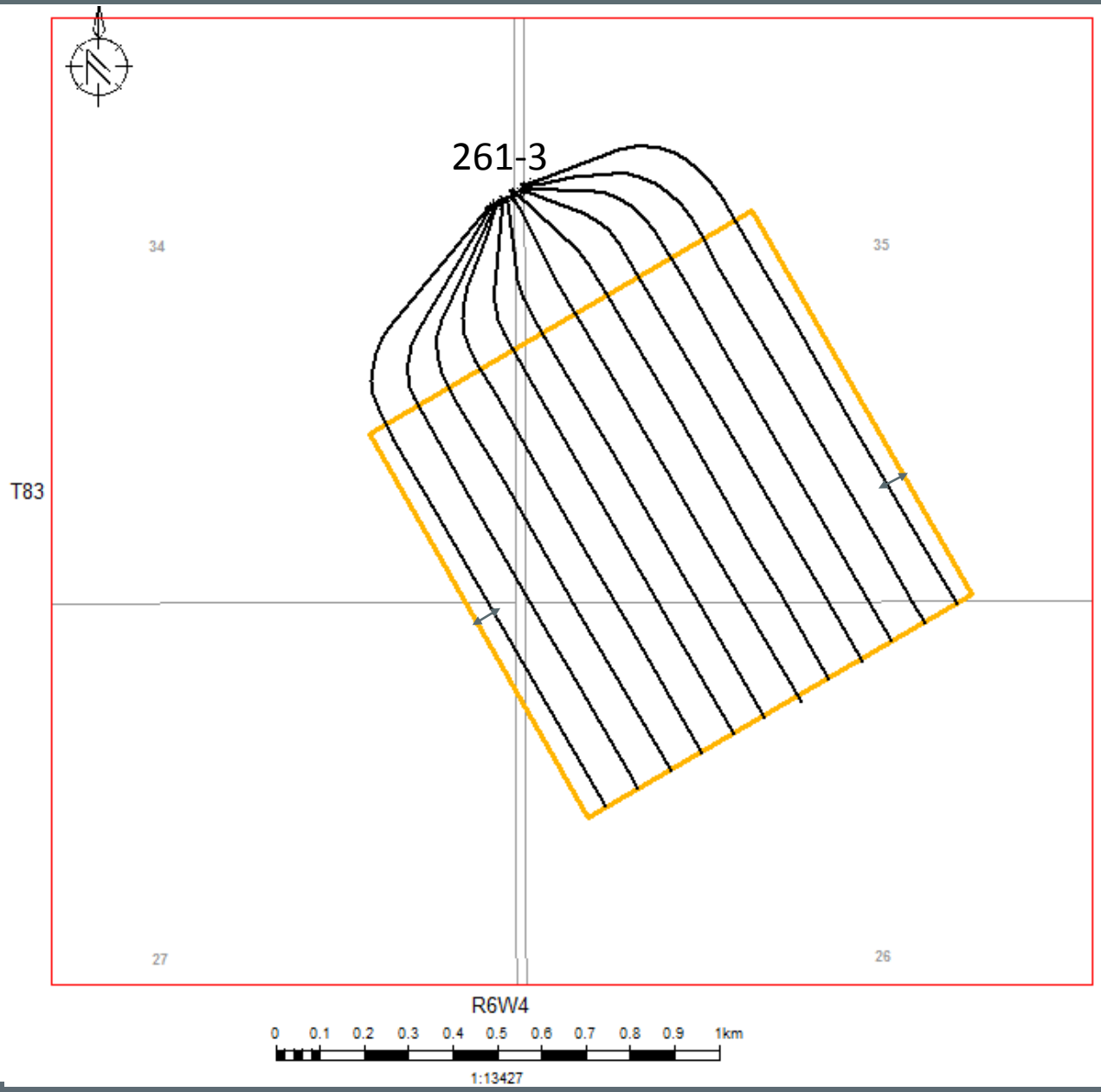




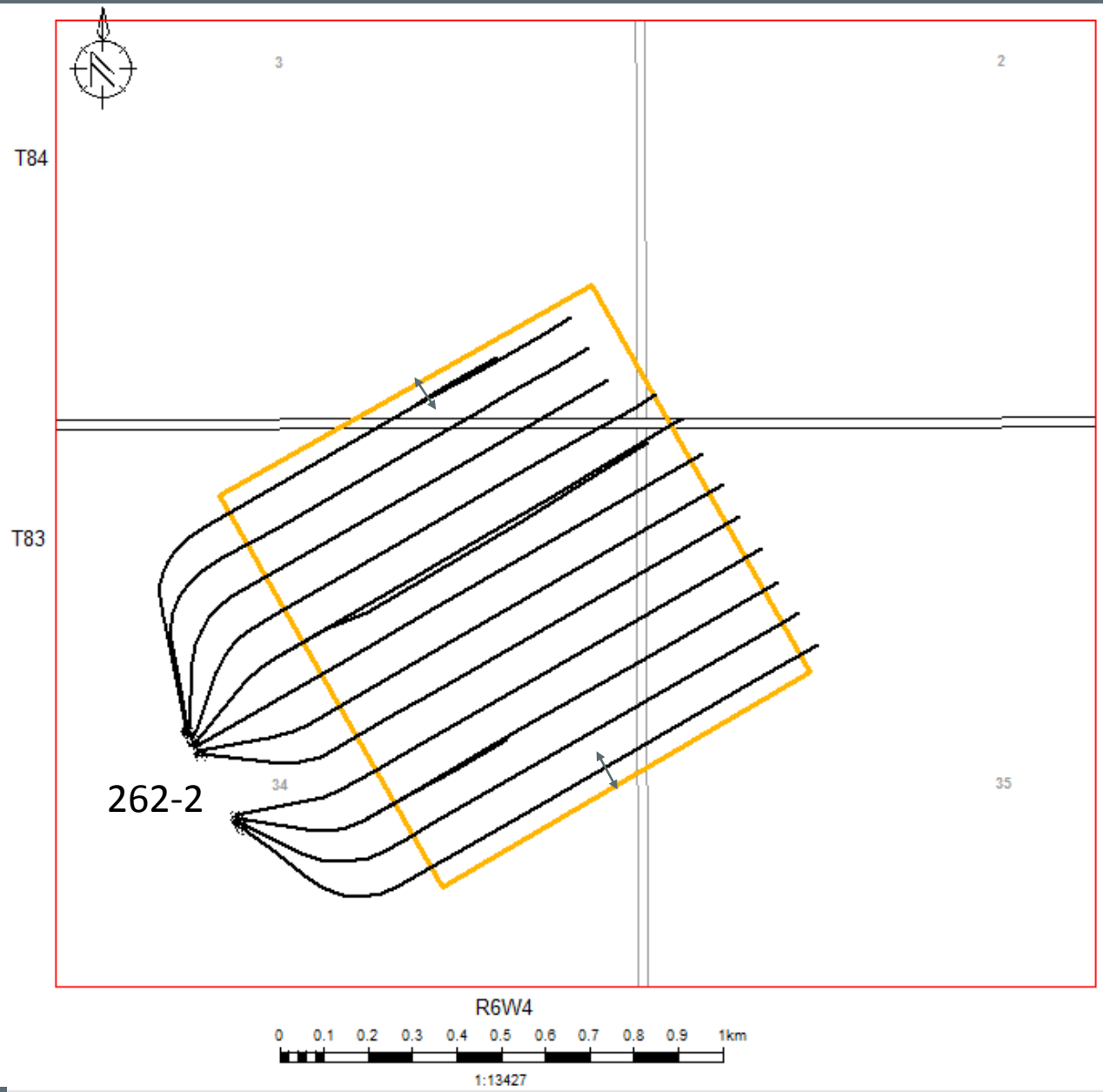
Expected Drainage Area Outline- PAD 103



Expected Drainage Area Outline-– PAD 261-3



Expected Drainage Area Outline-– PAD 262-2



Future Plans

Subsection 3.1.1 (8)

Future Plans – Surmont

Surmont 1

- NCG pilot is ongoing on Pad 102S and expanding to 101N and 101S.
- Well stimulations are ongoing to determine the optimal chemical product for SAGD well scale treatment in Surmont.
- Evaluating the tie-in of three outboard Wells in Pad 101.
- Additional tubing deployed flow control devices will be looked at for potential install.
- NCG pilot from 101N to help with pressure support with 103.
- Evaluating infill opportunities.

Surmont 2

- ESP conversions ongoing.
- Continue tubing deployed flow control device installations.
- Evaluation of steam optimization retrofits and their possible mitigation under thief zones interactions.
- Evaluate redevelopment opportunities for under performing pads.

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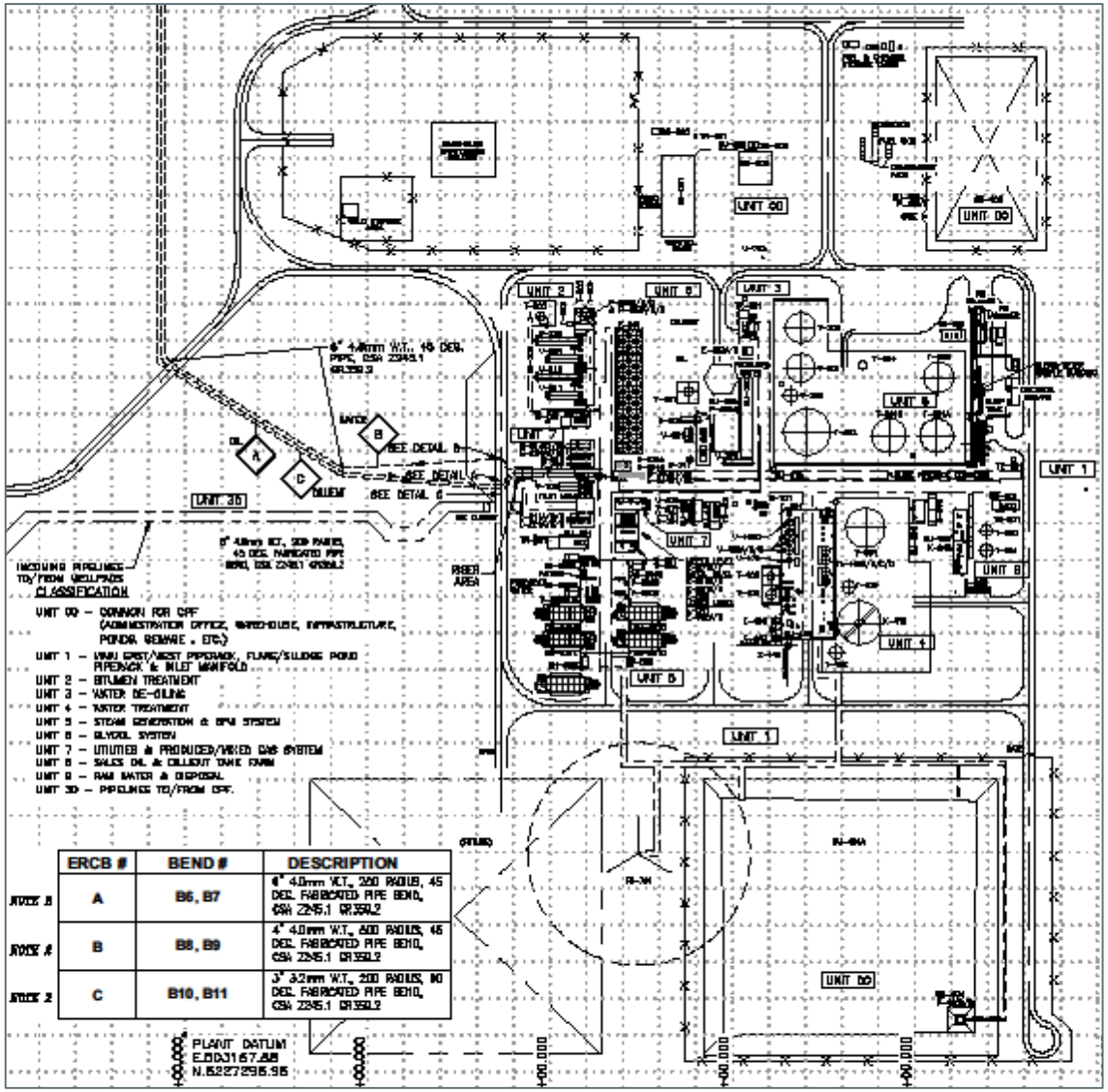
Surface Operations and Compliance Surmont Project Approval 9426

Facilities

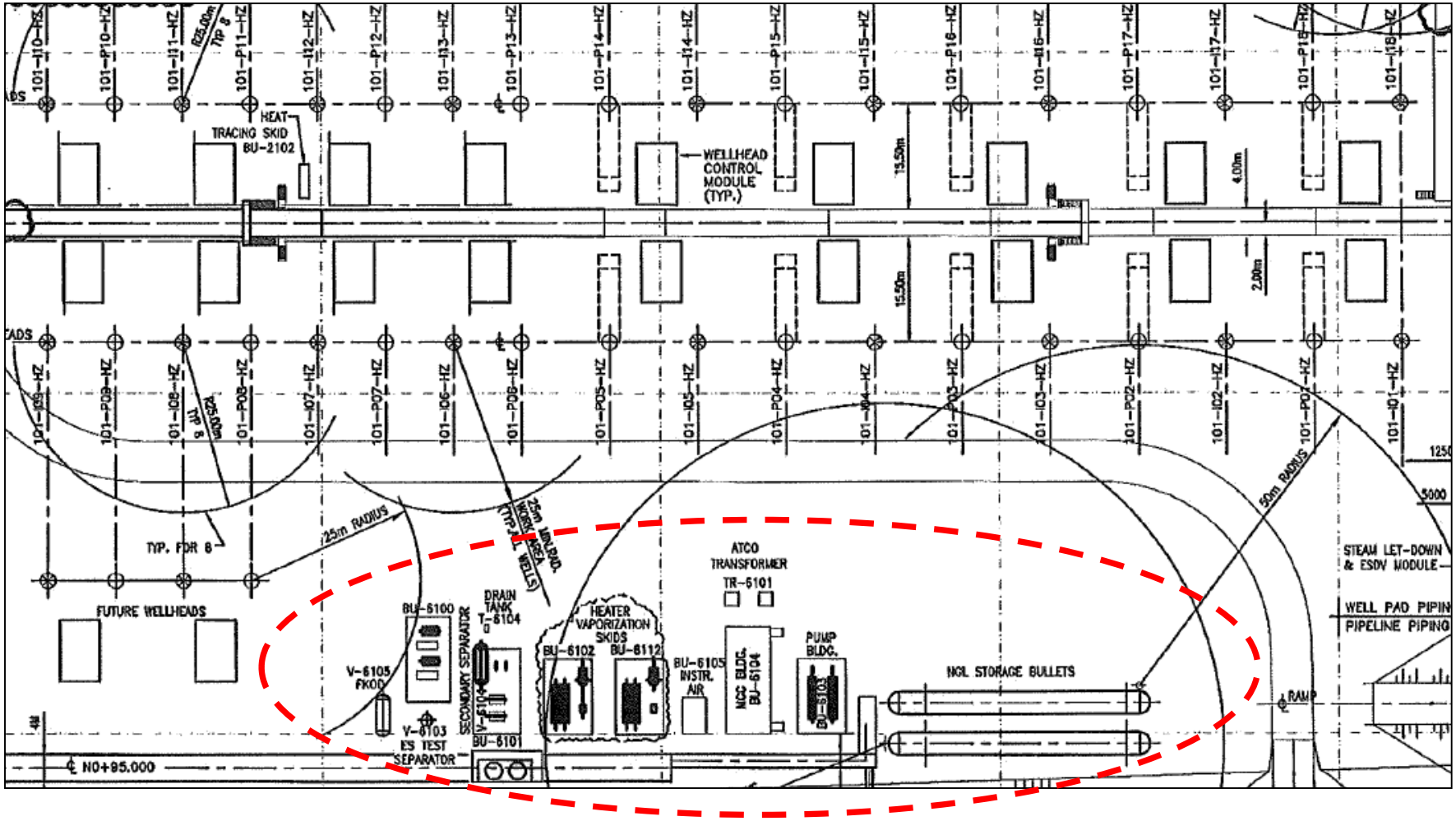
Subsection 3.1.2 (1)

Phase 1 Plot Plan: CPF



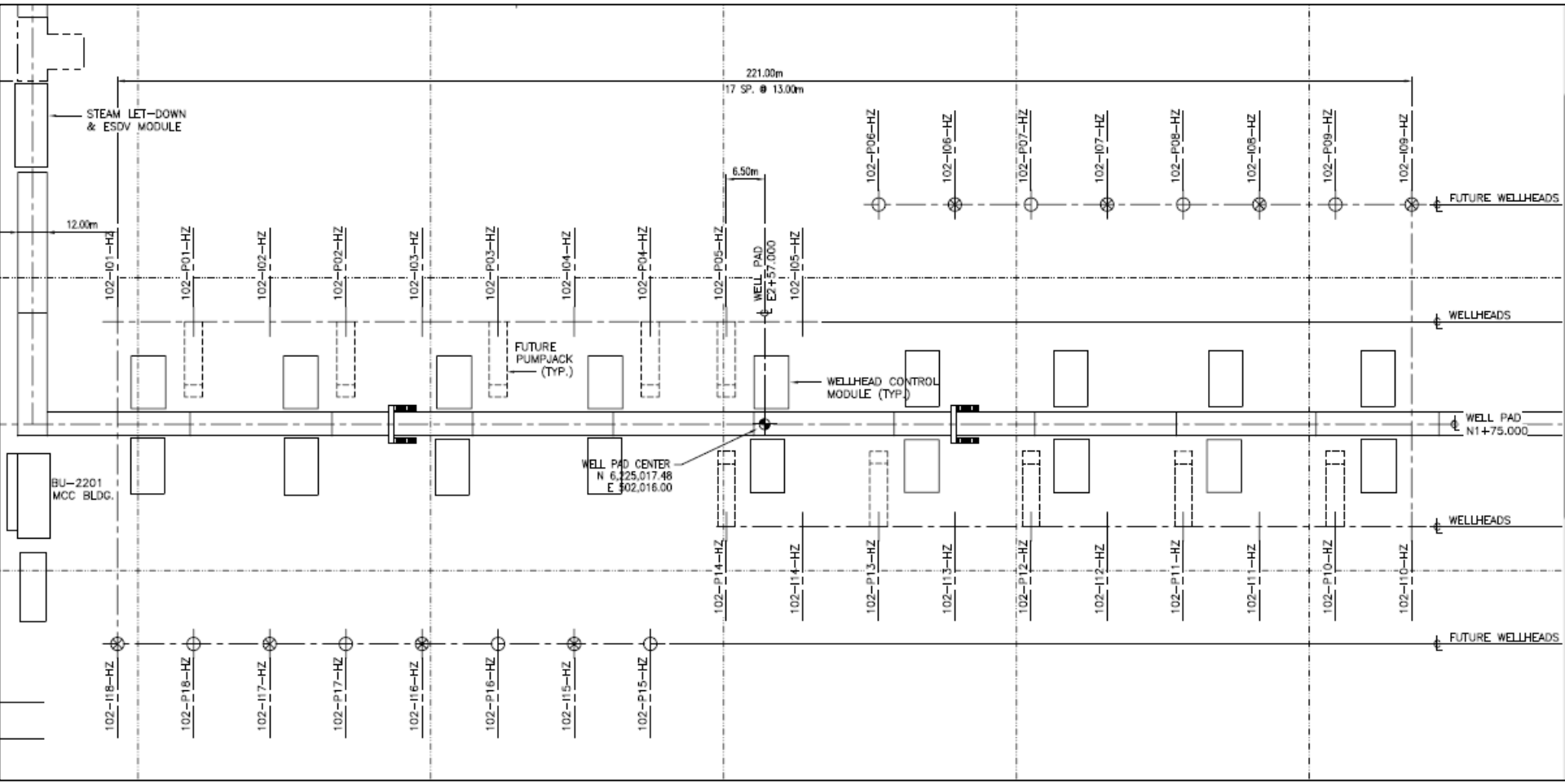
	ERCB #	BEND #	DESCRIPTION
NOTE 8	A	B6, B7	6" 4.0mm W.T., 300 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2
NOTE 4	B	B8, B9	4" 4.0mm W.T., 300 RADIUS, 45 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2
NOTE 2	C	B10, B11	3" 3.2mm W.T., 200 RADIUS, 90 DEG. FABRICATED PIPE BEND, CSA Z245.1 GR.359.2

Phase 1 Plot Plan: Pad 101



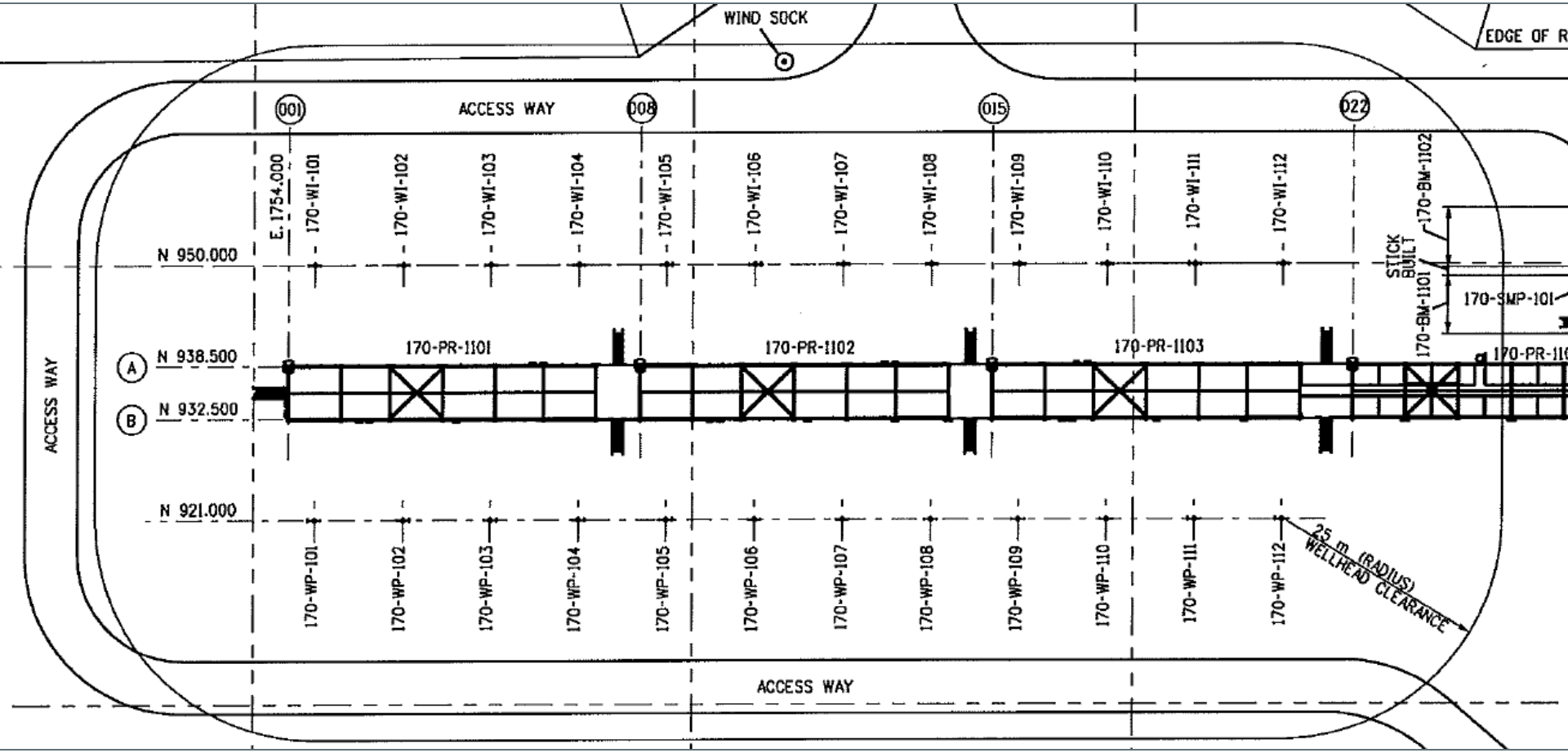
- **E-SAGD Equipment was de-commissioned in 2017**

Phase 1 Plot Plan: Pad 102



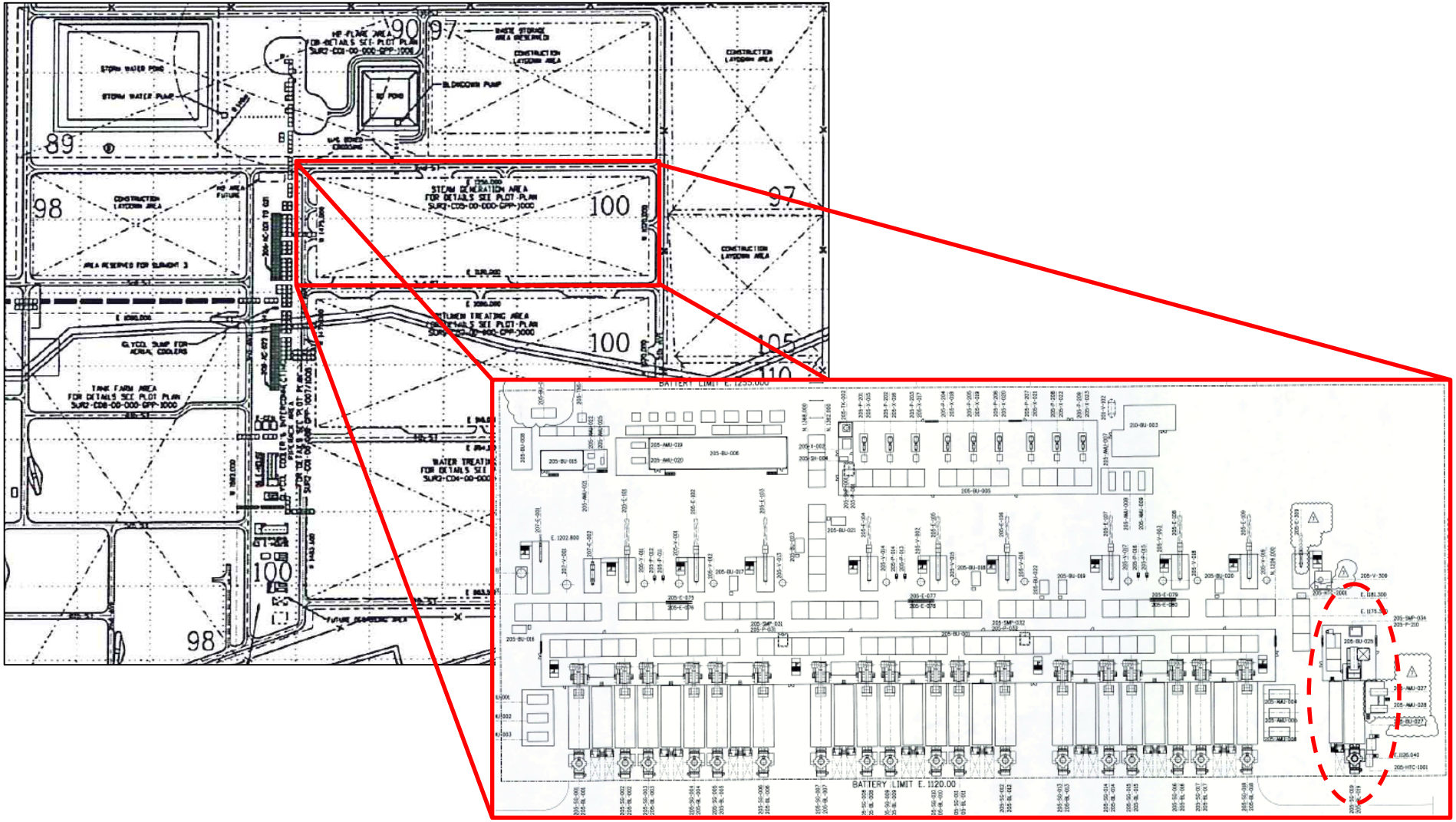
- **No Major Modifications in 2017**

Phase 1 Plot Plan: Pad 103



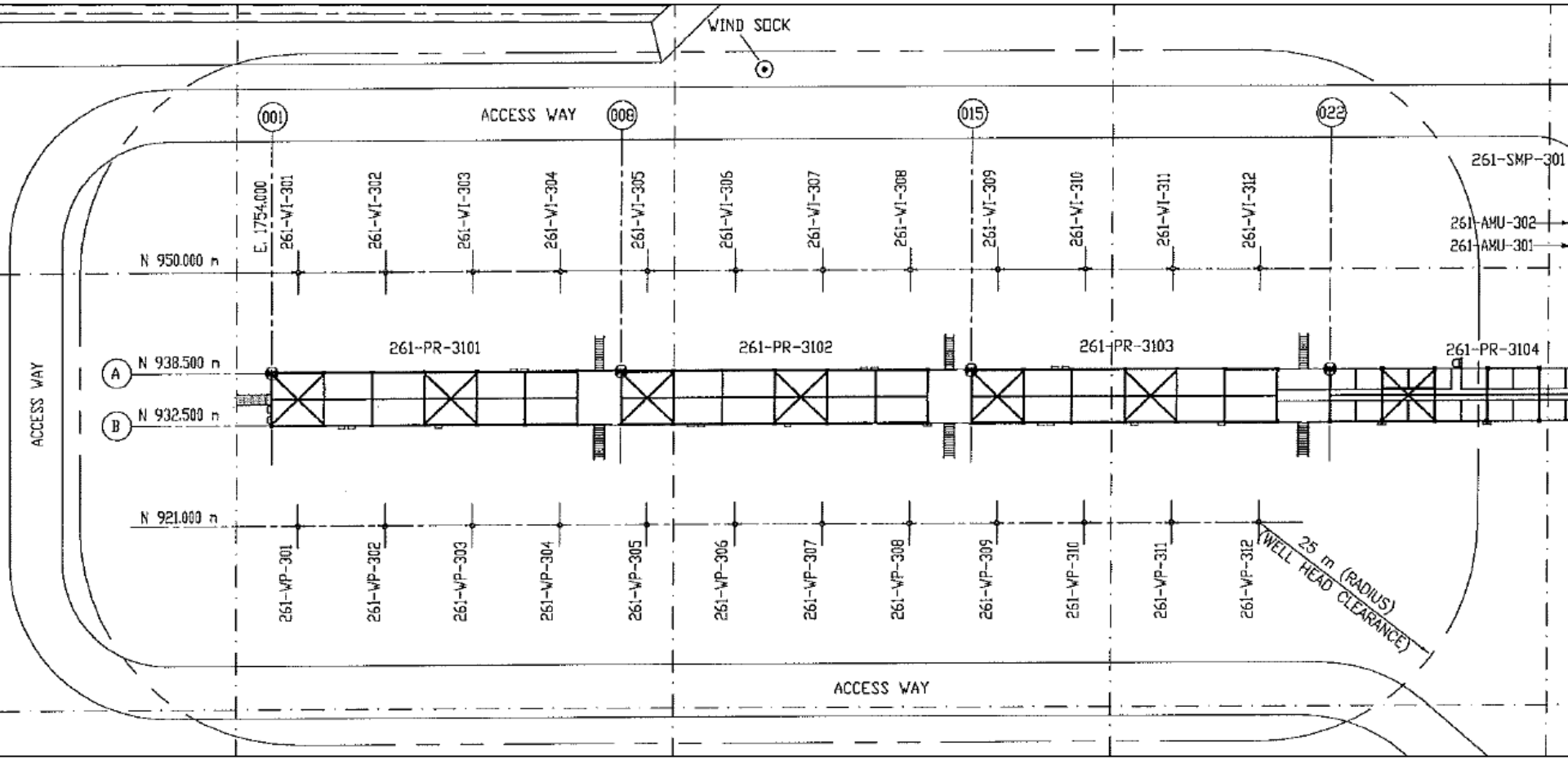
- **No Major Modifications in 2017**

Phase 2 Plot Plan: CPF



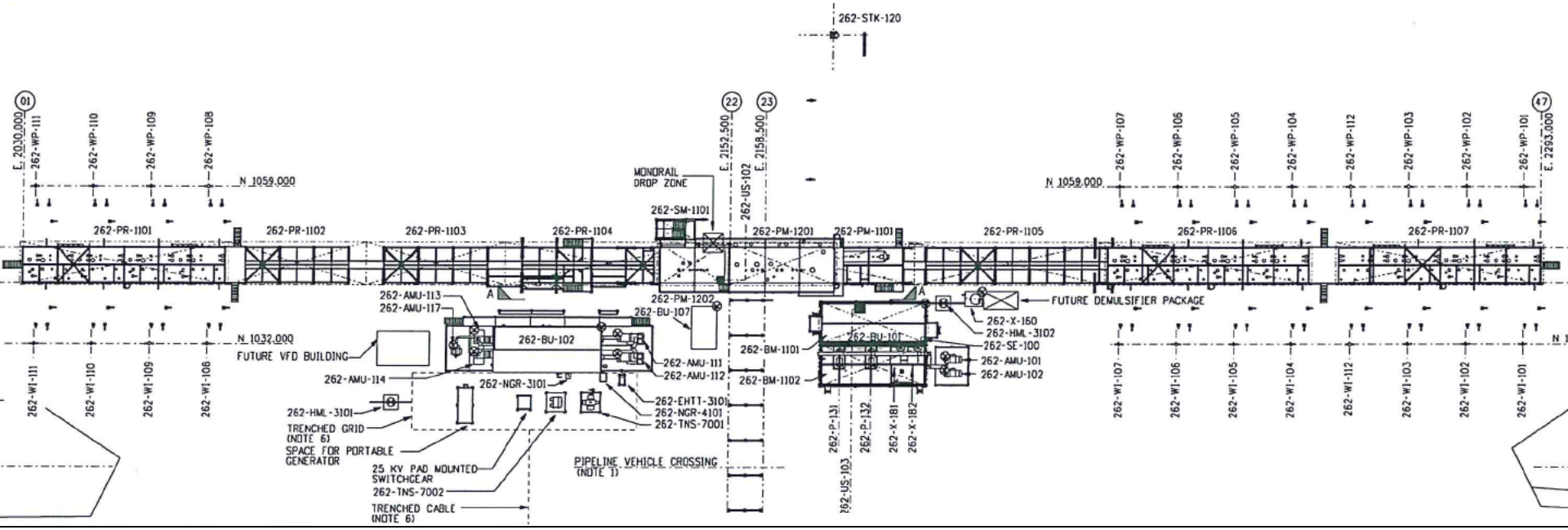
Installation of one additional OTSG and associated heat exchanger at Surmont 2, OTSG is now operational. No other major changes in other areas of the plant.

Phase 2 Plot Plan: Pad 261-3



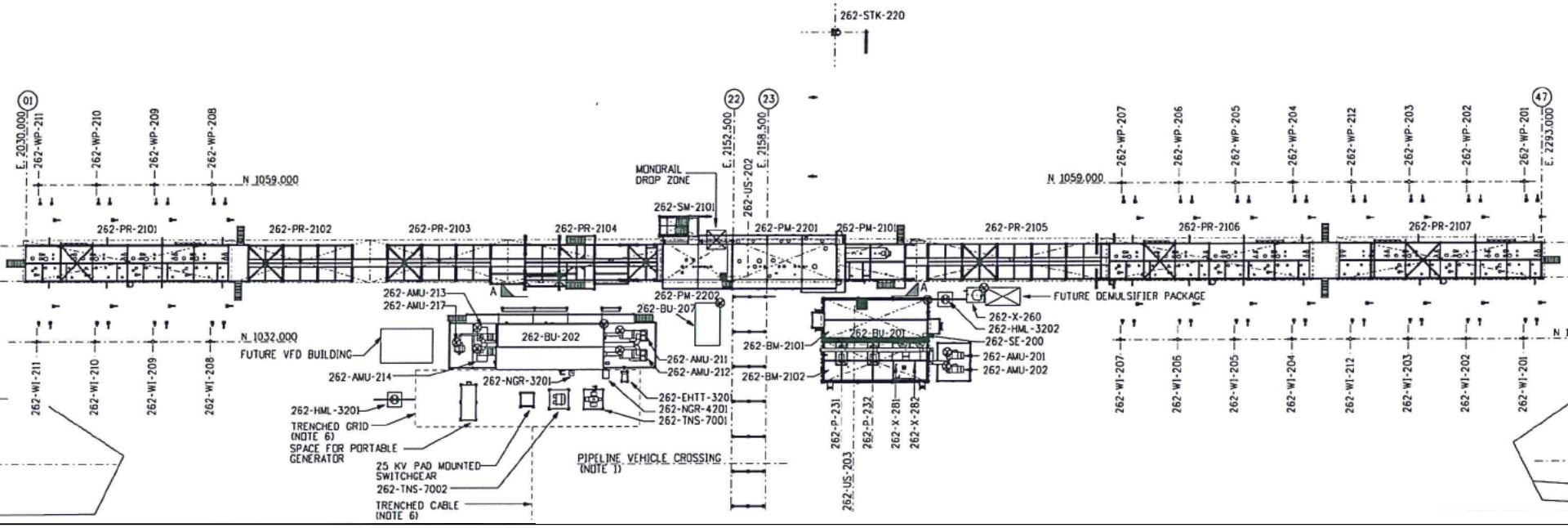
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 262-1



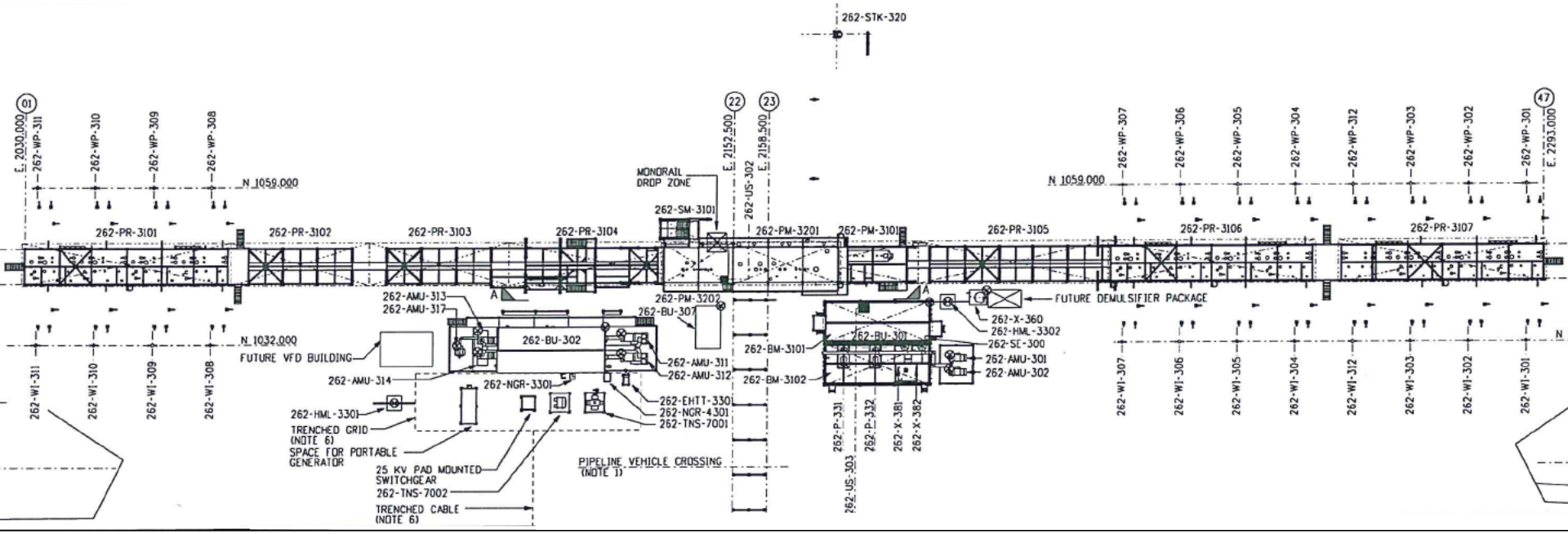
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 262-2



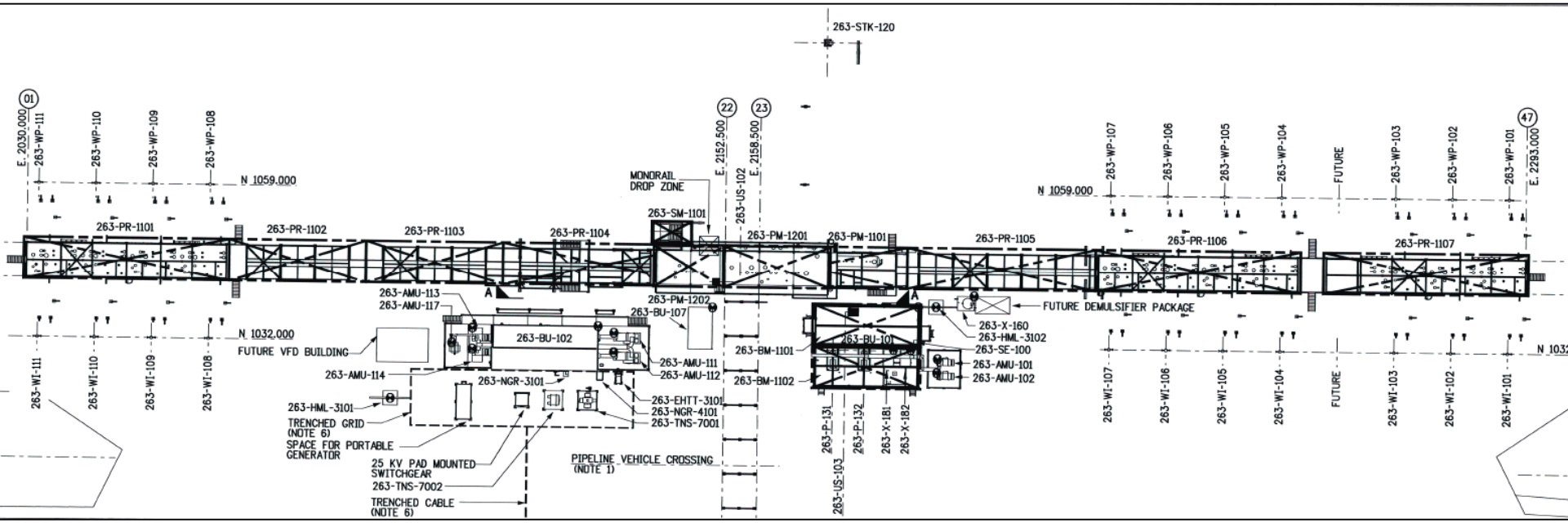
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 262-3



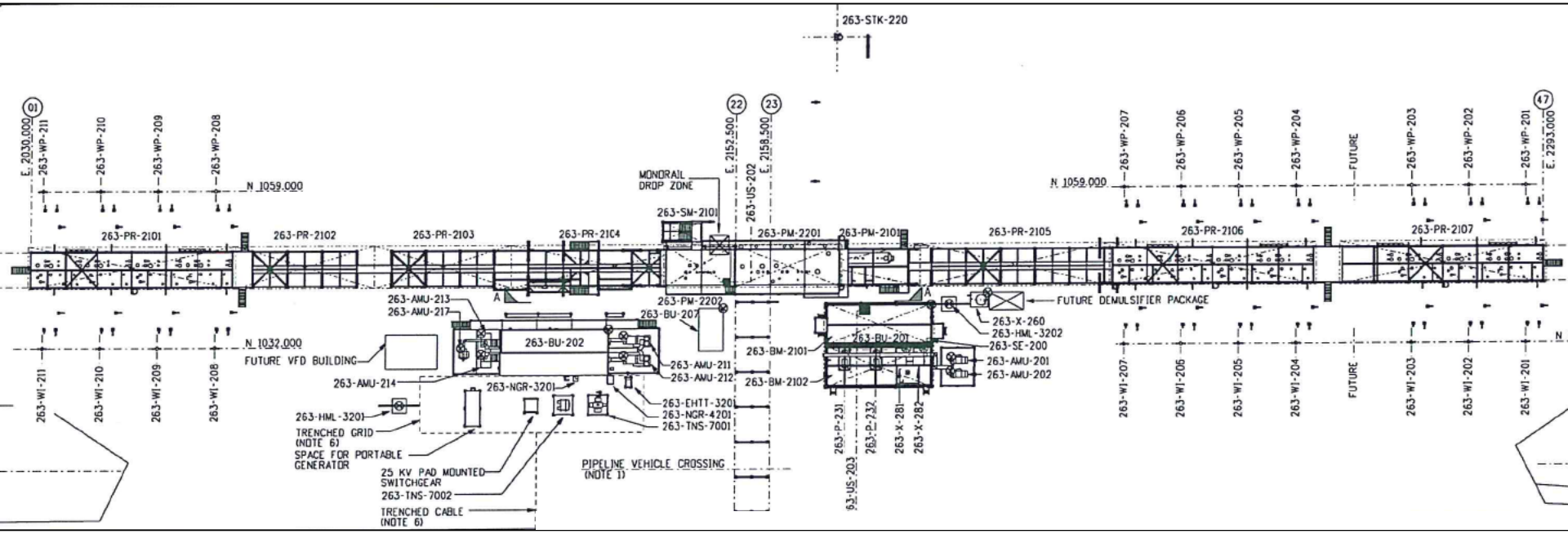
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 263-1



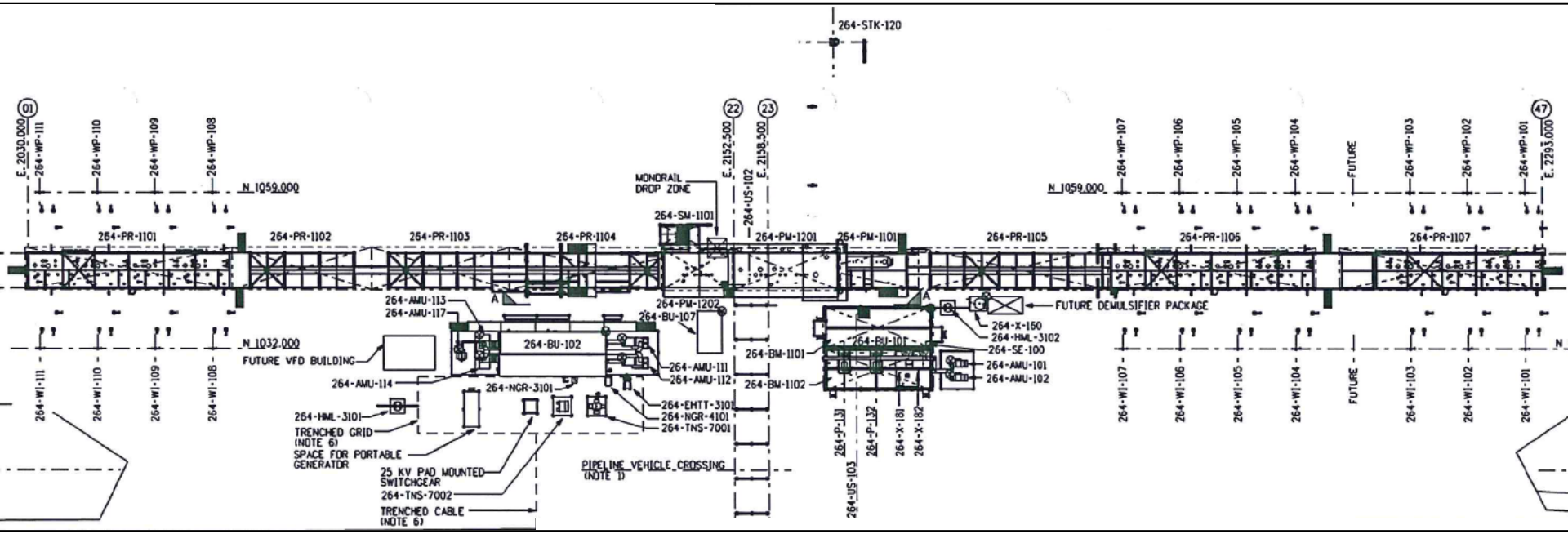
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 263-2



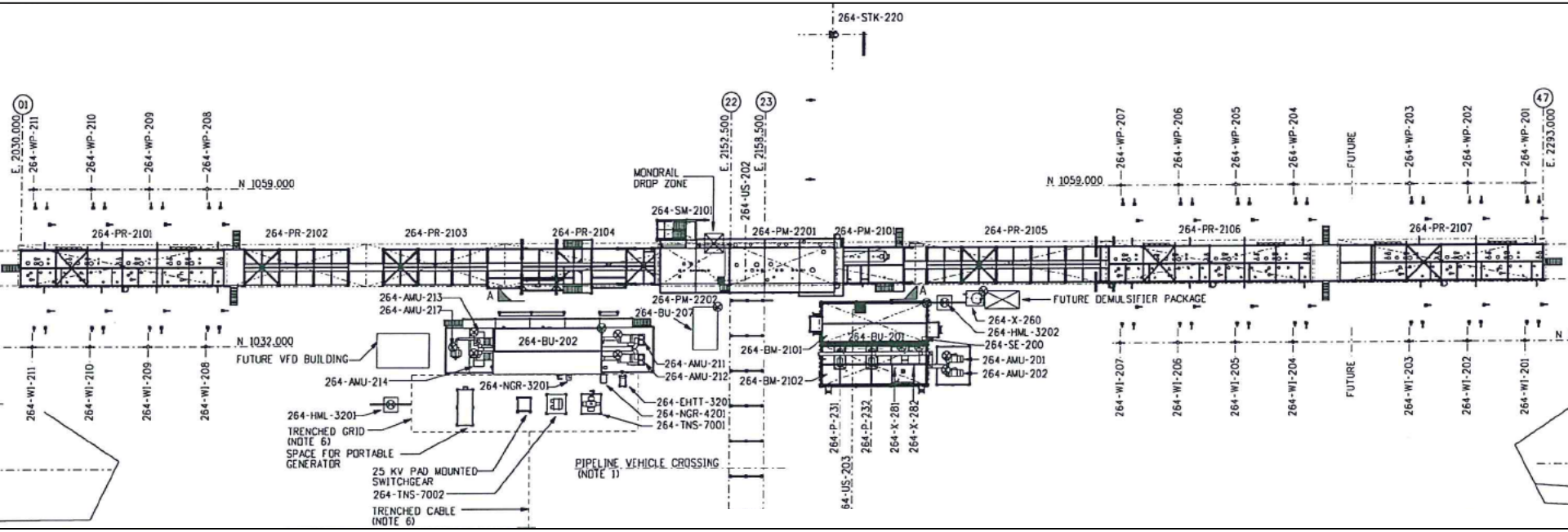
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 264-1



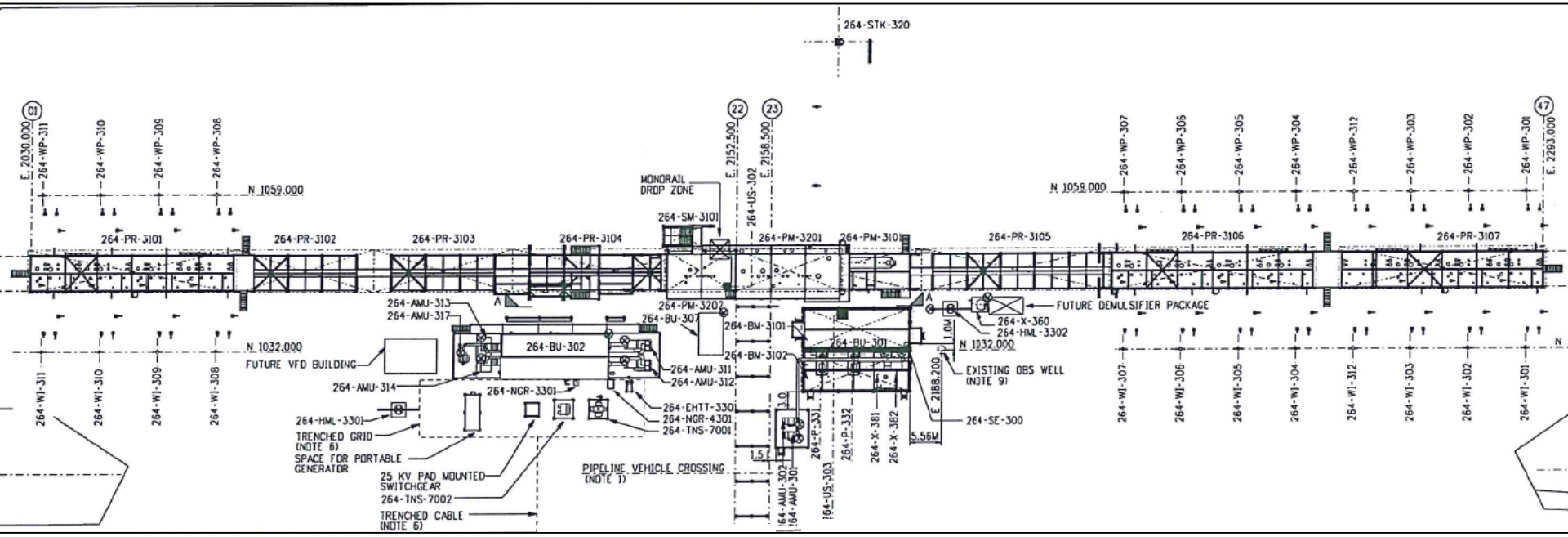
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 264-2



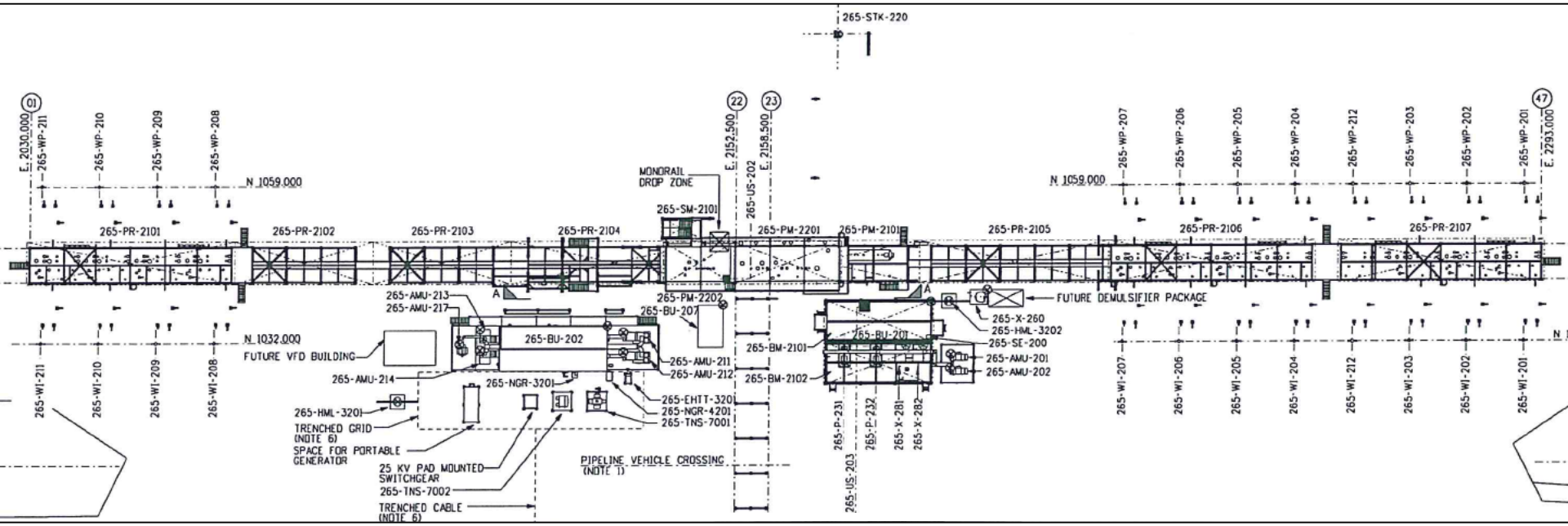
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 264-3



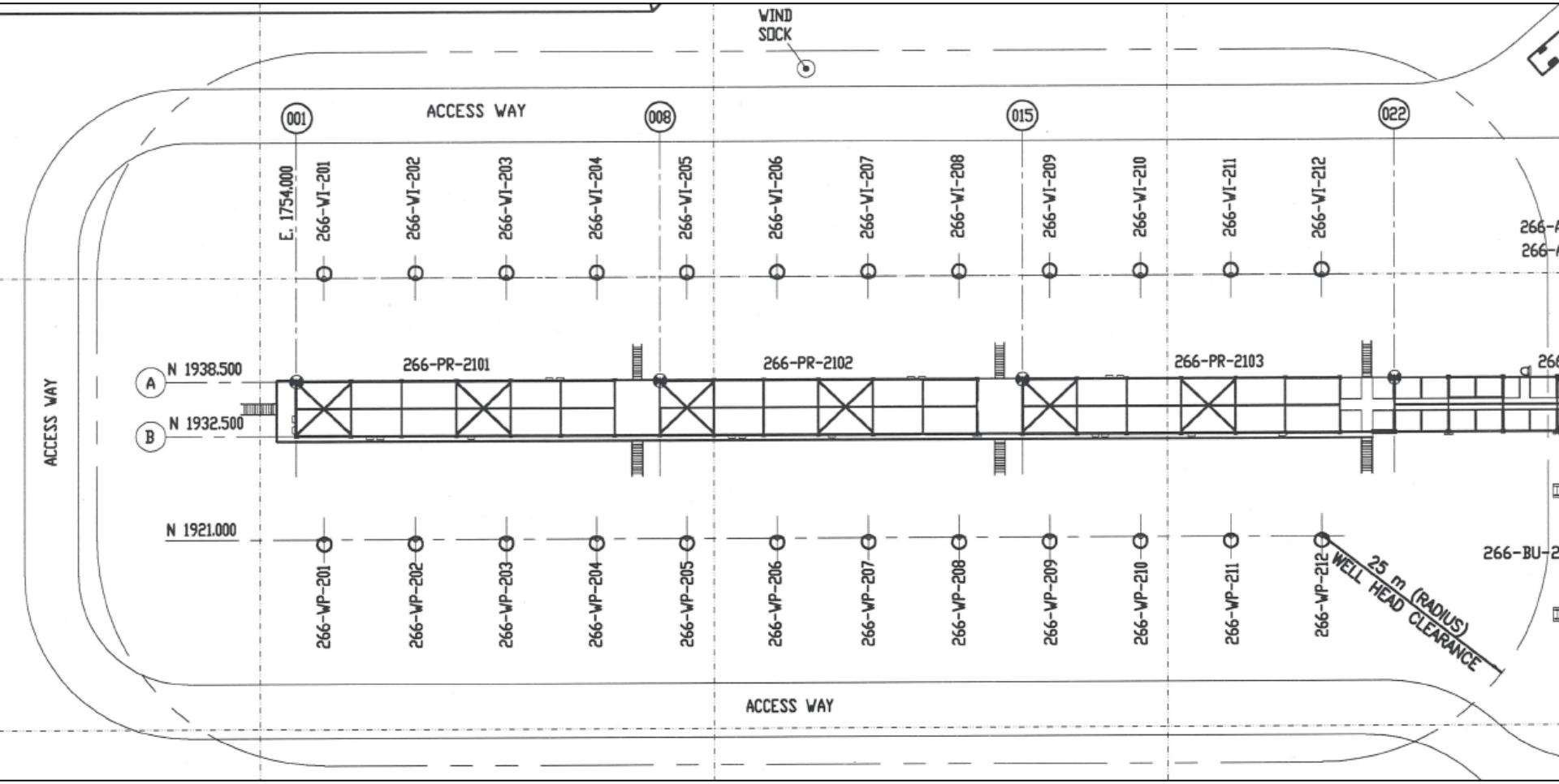
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 265-2



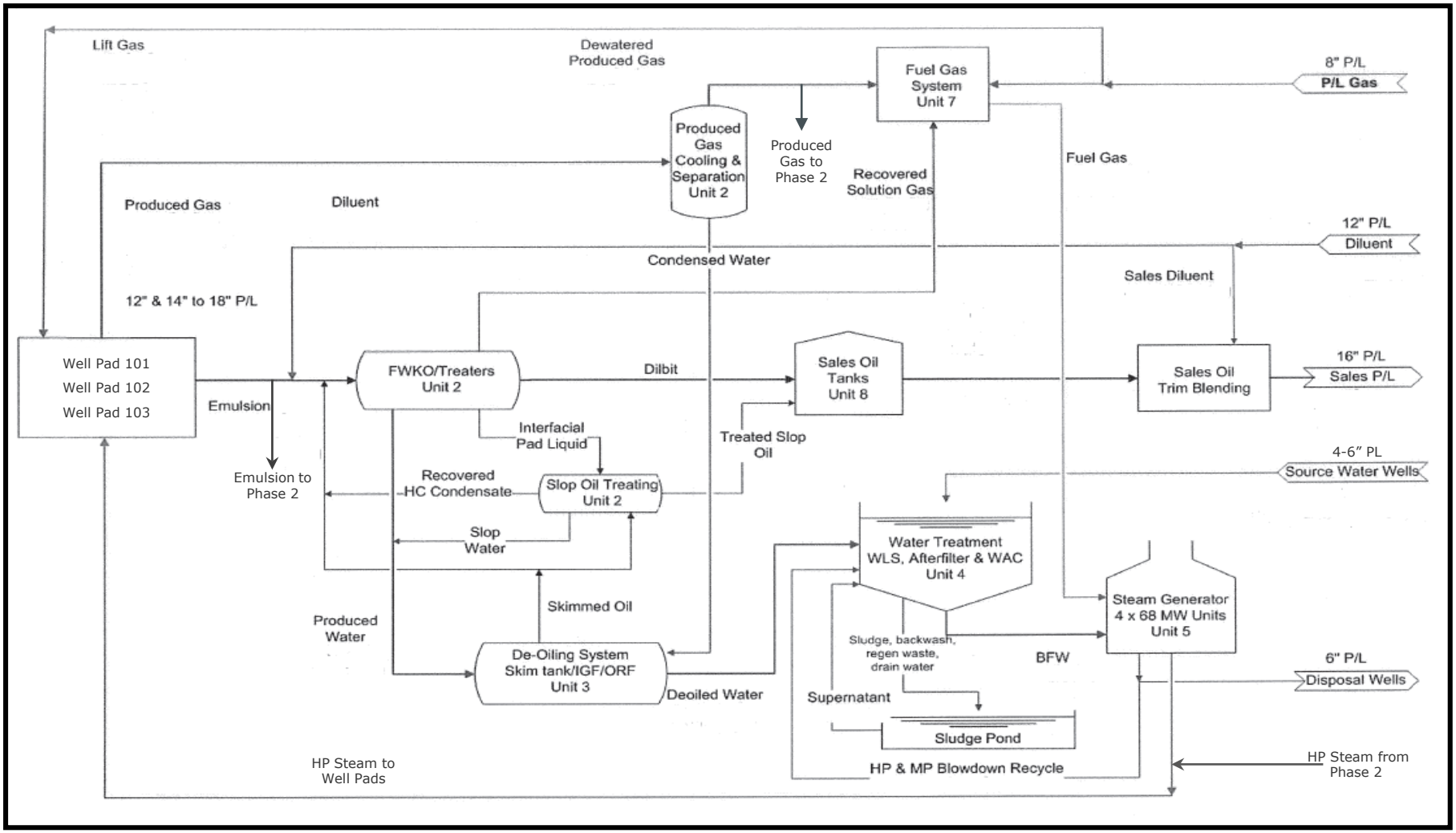
- **No Major Modifications in 2017**

Phase 2 Plot Plan: Pad 266-2

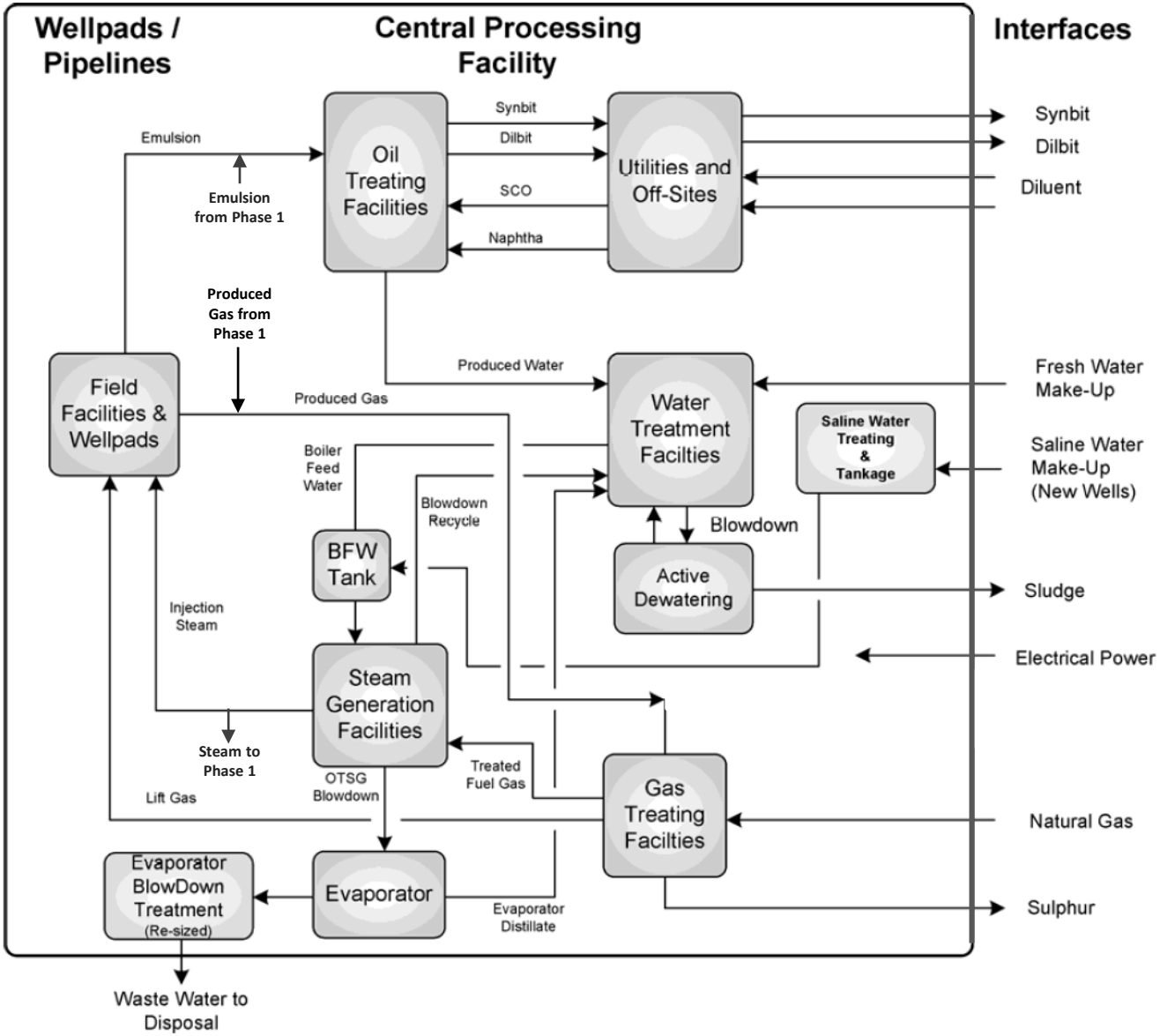


- **No Major Modifications in 2017**

Plant Schematic: Phase 1



Plant Schematic: Phase 2



2017 Surmont Operations

- **Phase 1:**
  - Installed new Economizer box on OTSG with upgraded materials and additional monitoring capabilities.
  - Completed turn around activities at Pad 101, Pad 102 and CPF.
  - Completed steam quality increase from 75% to 85%.
  - Decommissioned Pad 101 E-SAGD equipment.

- **Phase 2**
  - Reached name plate bitumen production.
  - Completed steam quality increase from 75% to 85%.
  - OTSG 19 construction and commissioning complete and operational.
  - Successfully completed a trial with partial condensate blending.

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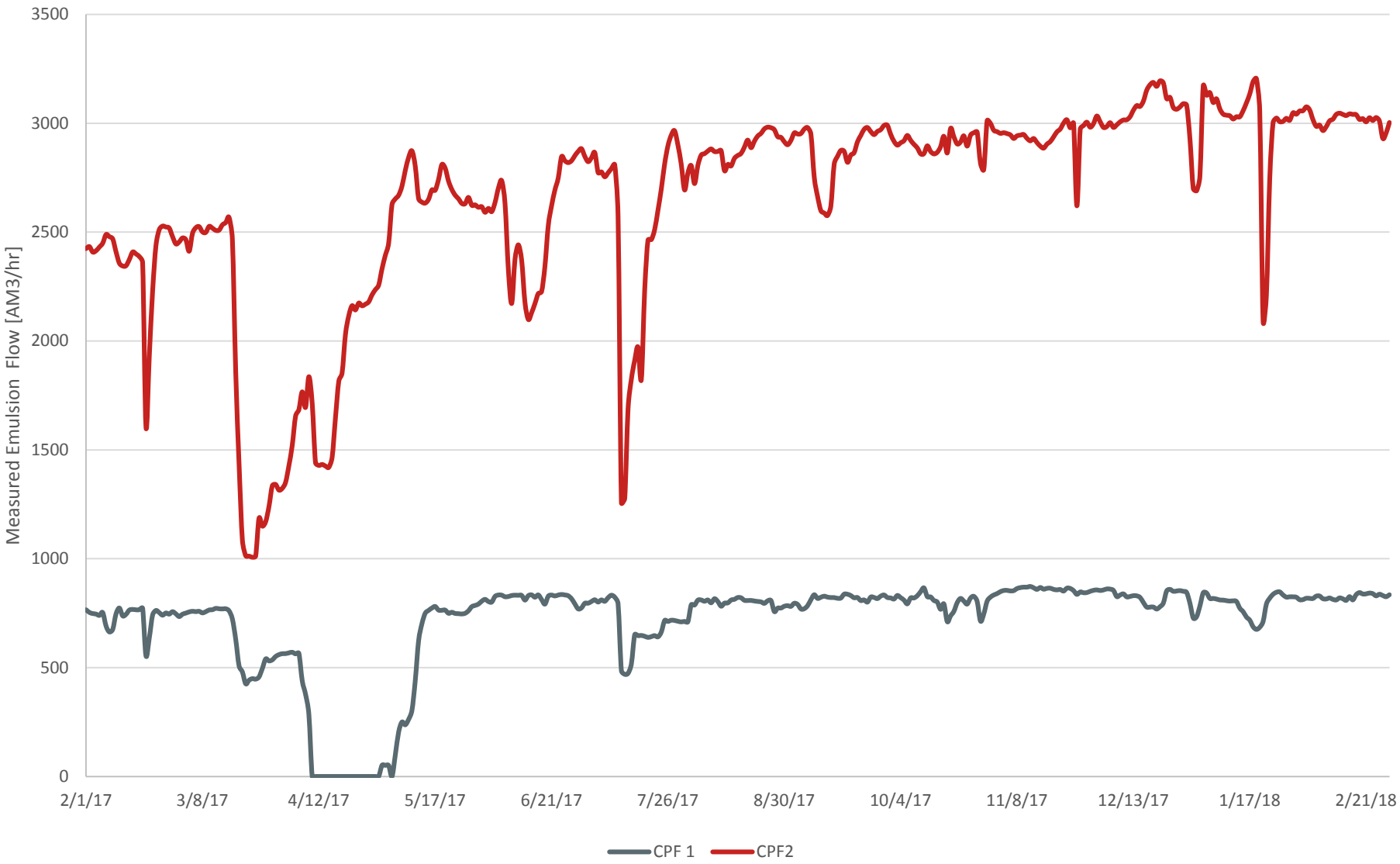
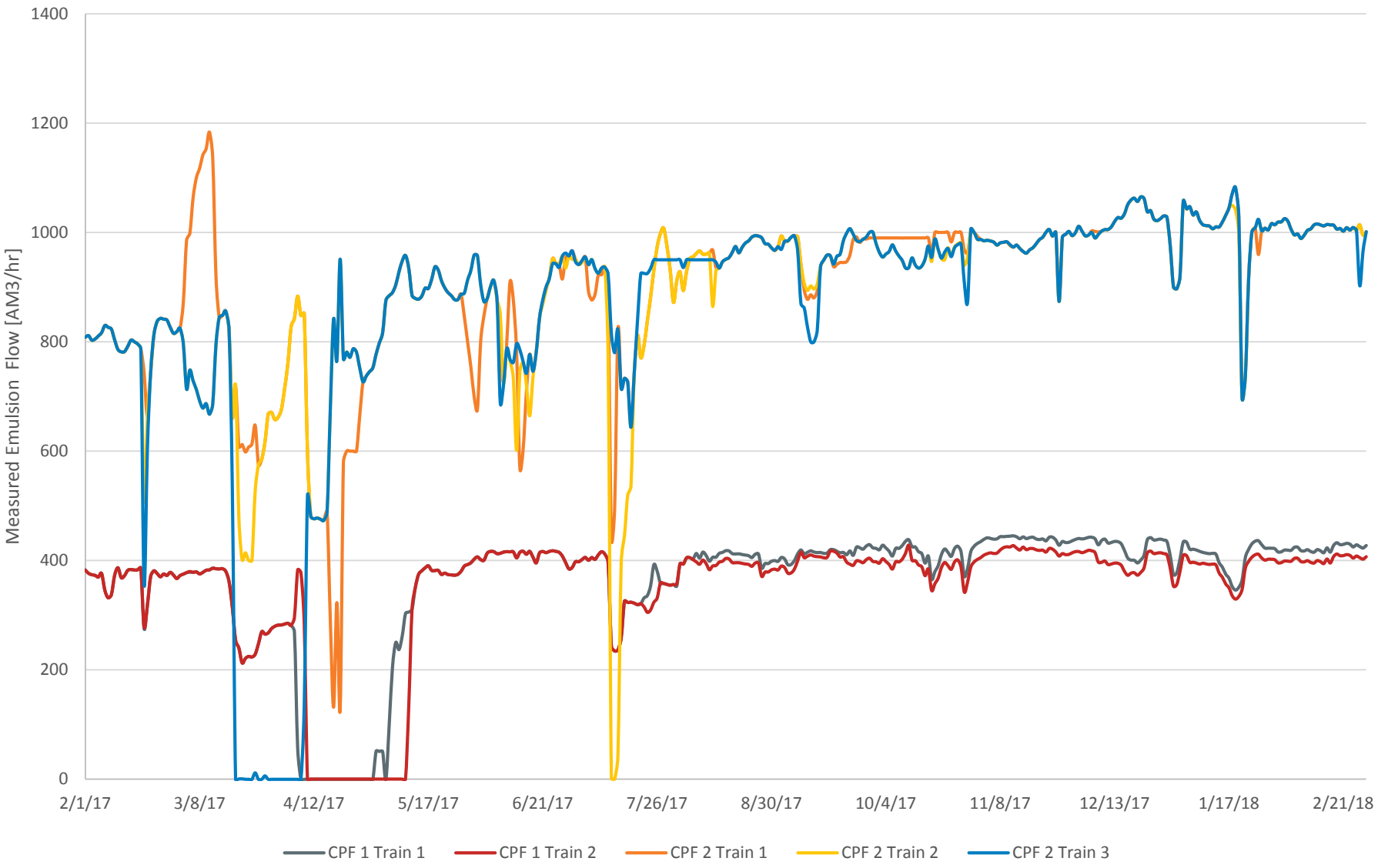
Facility Performance

Subsection 3.1.2 (2)

Facility Performance: Bitumen Treatment by CPF

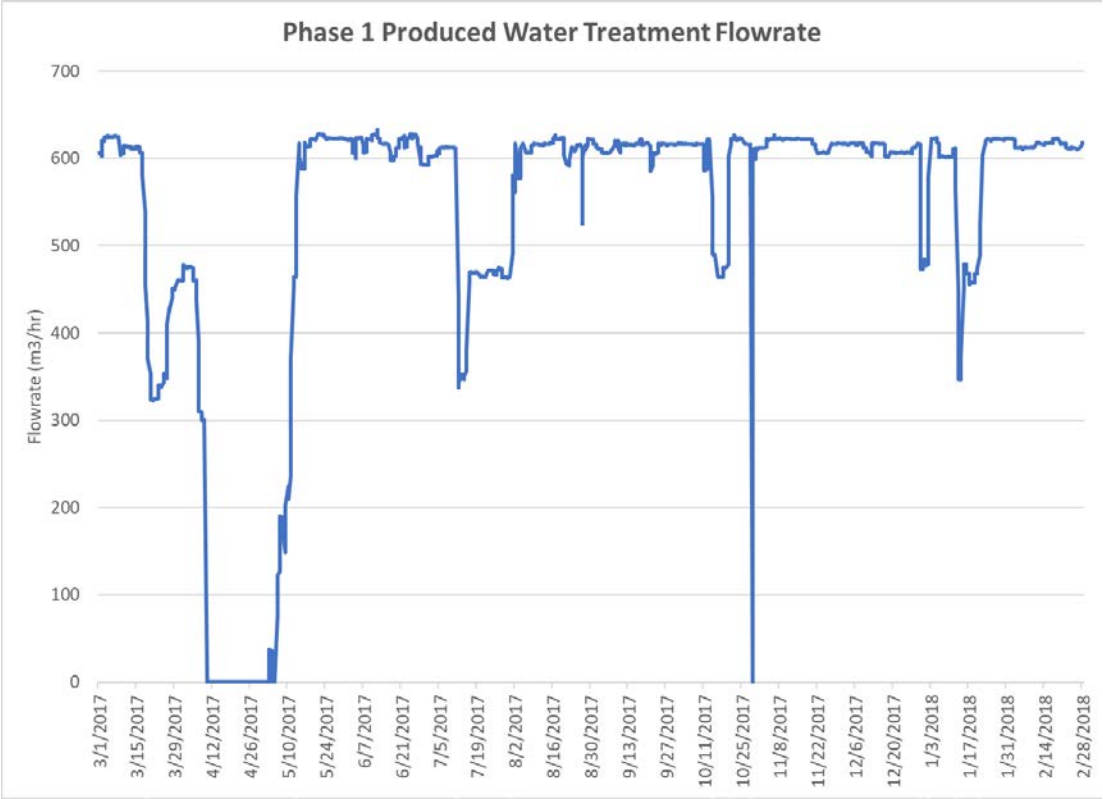


Facility Performance: Bitumen Treatment by Train



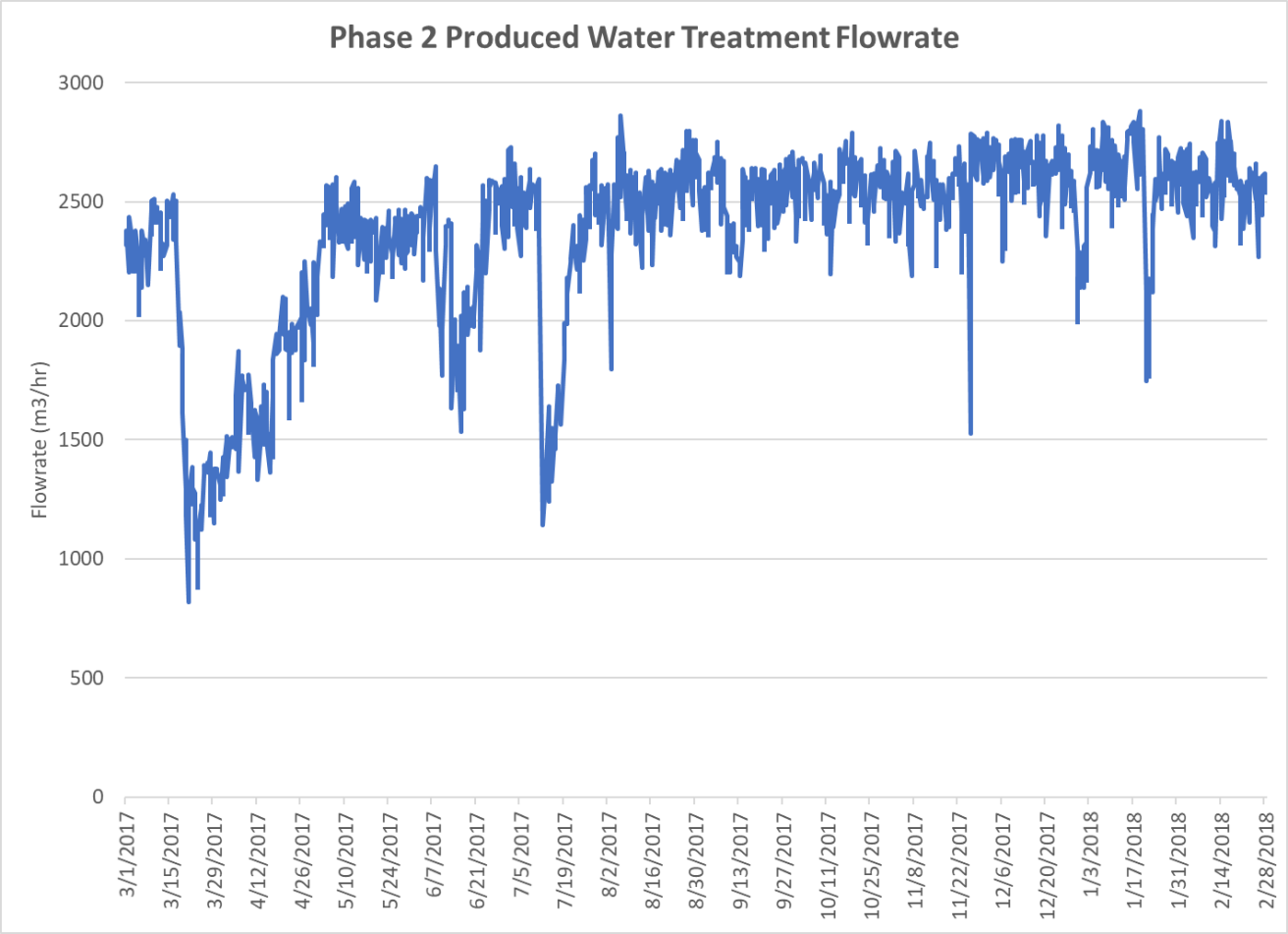
Facility Performance: Phase 1 Water Treatment

- Phase 1 water treatment plant continues to operate as per design.
- Phase 1 sludge pond was successfully dredged to remove lime sludge in 2017.
- A maintenance shutdown was successfully completed for Phase 1 in April.
- Monitoring of the sludge pond interstitial space is ongoing.



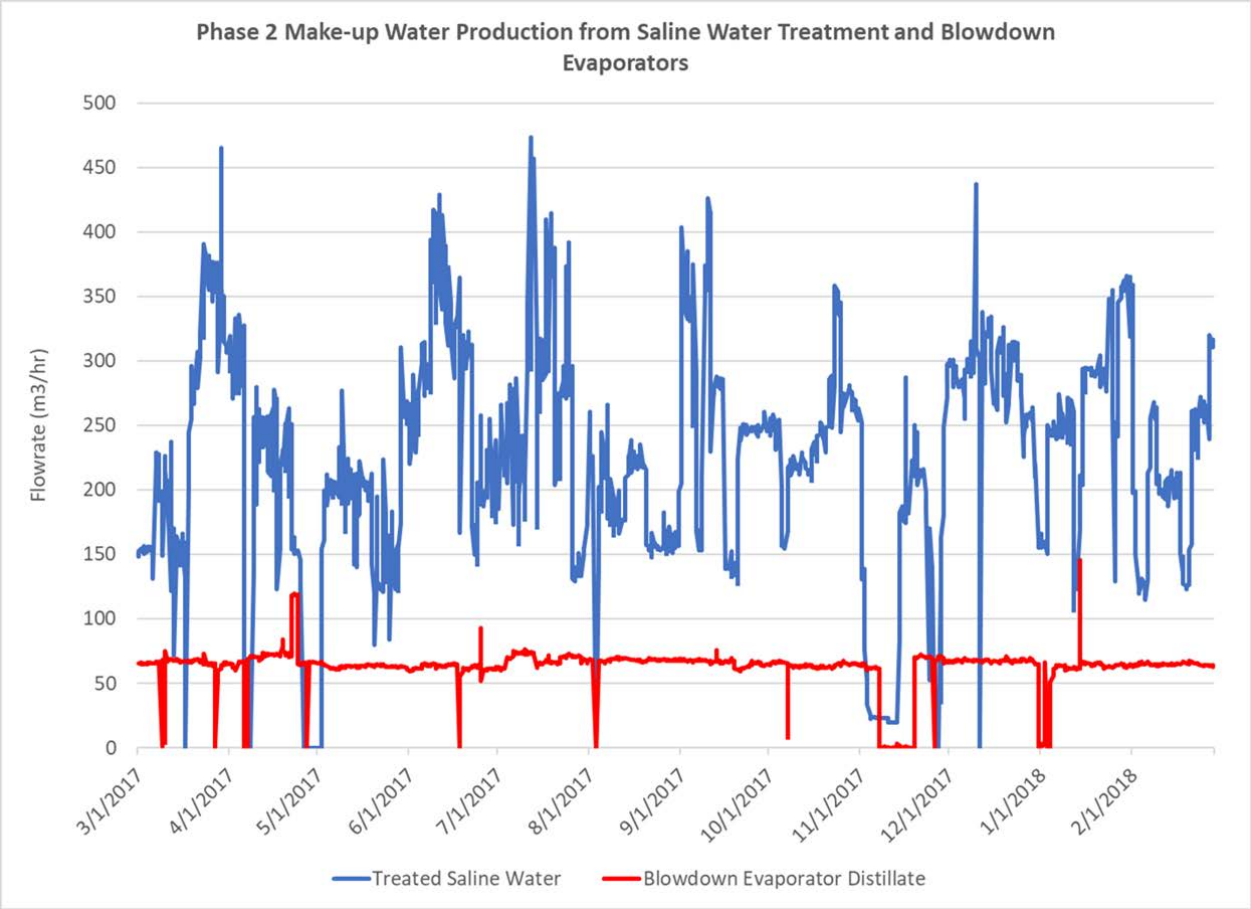
Facility Performance: Phase 2 Water Treatment

- Continued successful ramp up of Phase 2 water treatment plant to design rates.
- Focused improvement on the reliability of the dry chemical feed system.
- Chemical trials initiated to further improve water treatment performance.



Facility Performance: Phase 2 Saline Water Treatment and Blowdown Evaporators

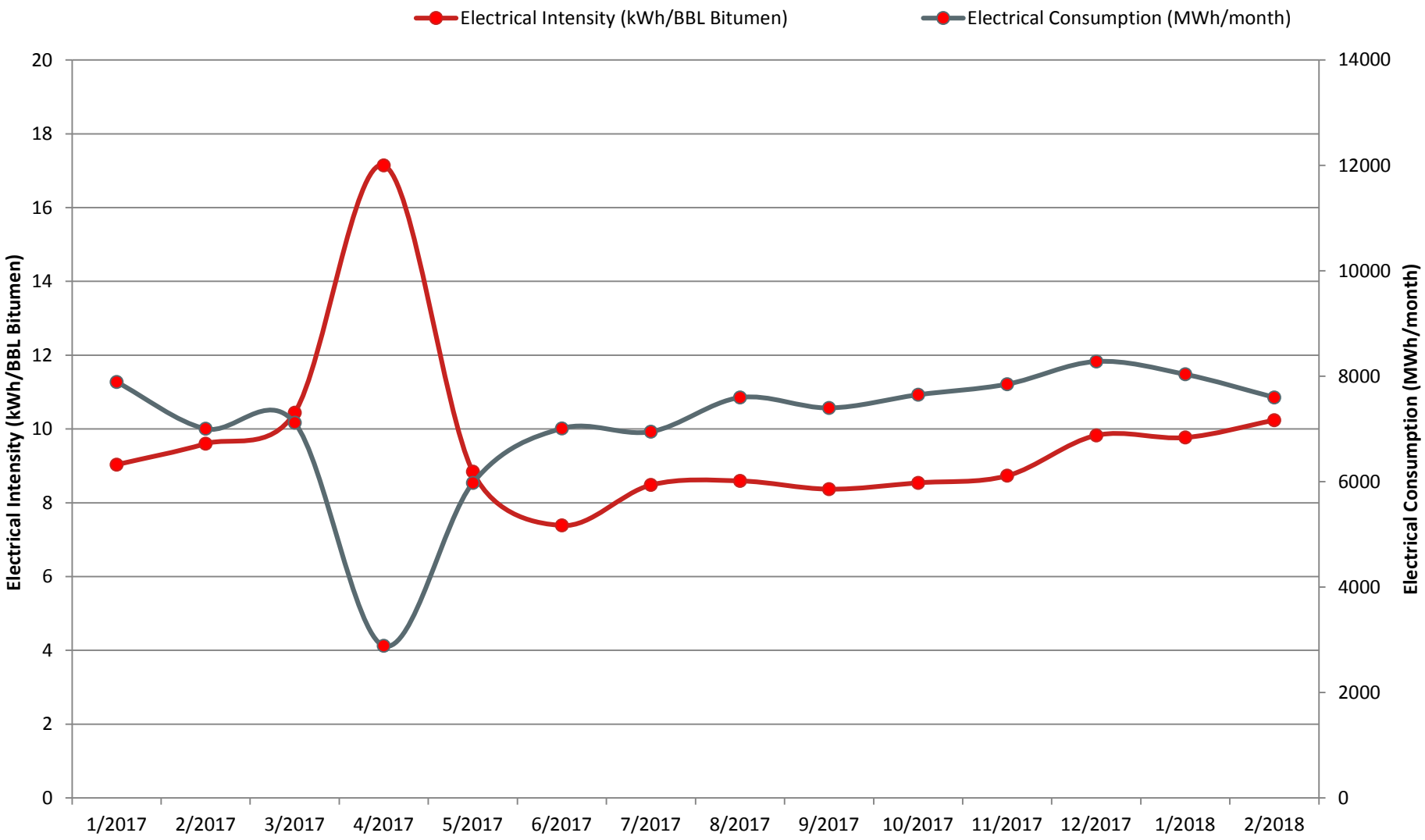
- Saline water treatment plant operating as per design. Treatment flowrates varied as per water balance make-up requirements.
- OTSG blowdown evaporators impacted by higher steam quality operation. Currently operating one of two available blowdown evaporators.



Surmont : Steam Generation Performance & Path Forward

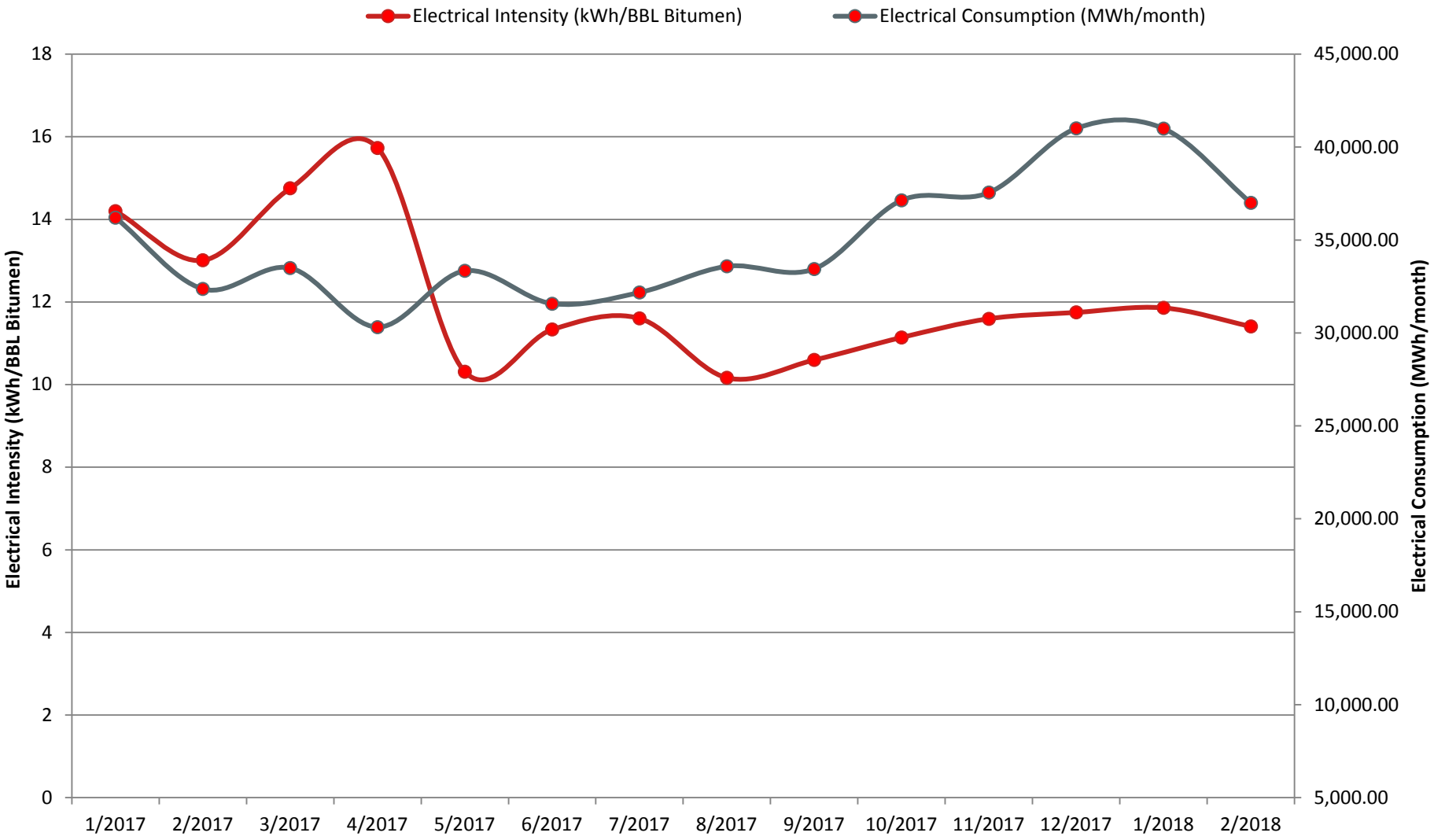
- The 19th OTSG was commissioned at Phase 2 in 2017:
  - 4 OTSGs in service at Surmont 1.
  - 19 OTSGs in service at Surmont 2.
- Economizer section of Surmont 1 OTSG SG-531 A replaced (upgraded).
  - Operation at higher steam qualities (83-85%).
- Implemented learnings from steam enhancement trial across all of Surmont Phase 1 and Phase 2.
  - All of the steam generators target up to 85% steam quality.
- Steam generator pigging frequency decreased.
  - Targeting 365+ days between OTSG outages for pigging (tube cleaning).
- 2018 focus is to maintain online reliability while maximizing steam output.

Facility Performance: Electricity Consumption Surmont 1



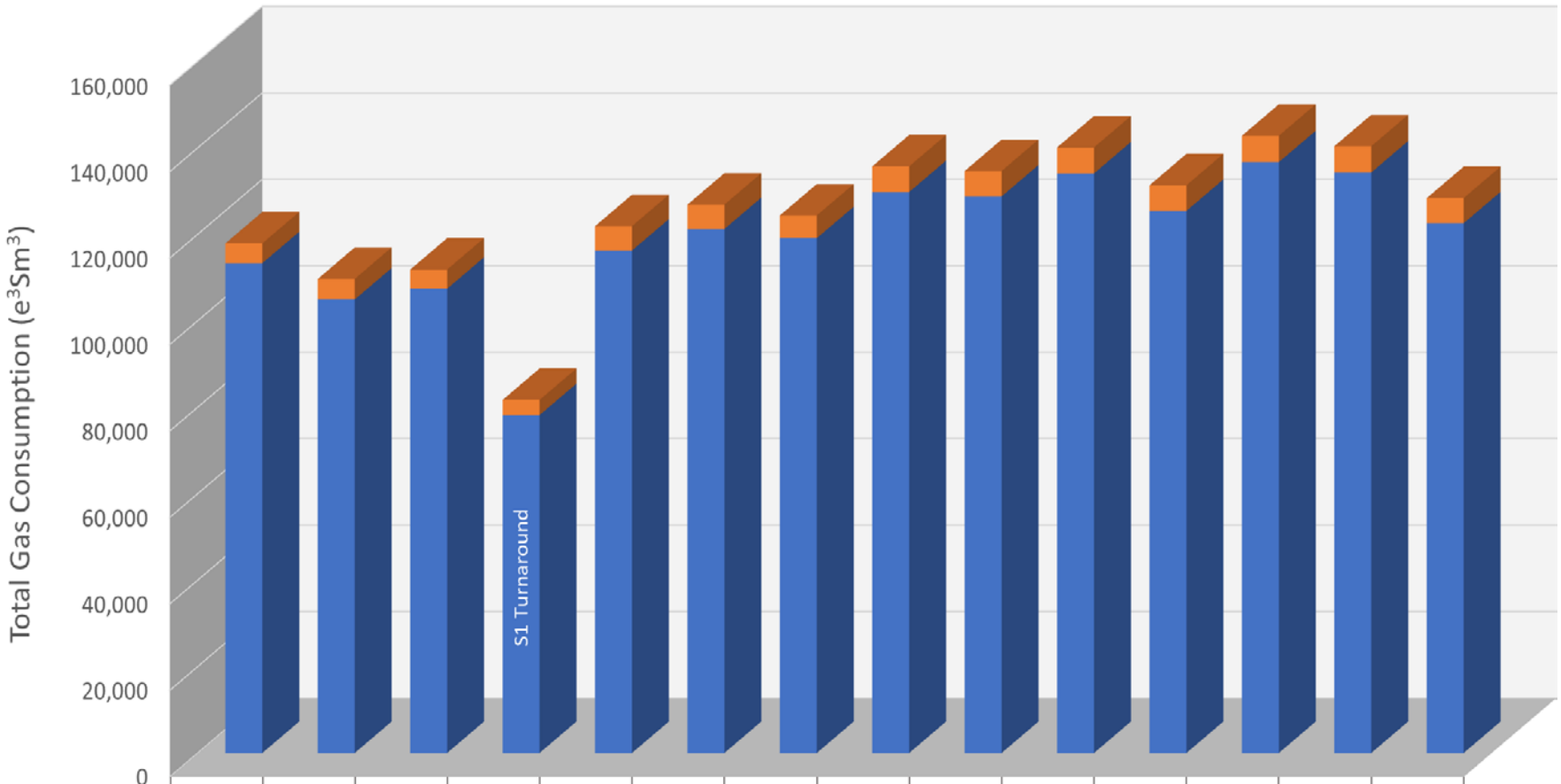
- **Phase 1 is at a steady state of production and electrical consumption, however the curtailment in April caused the anomaly in 2017.**

Facility Performance: Electricity Consumption Surmont 2



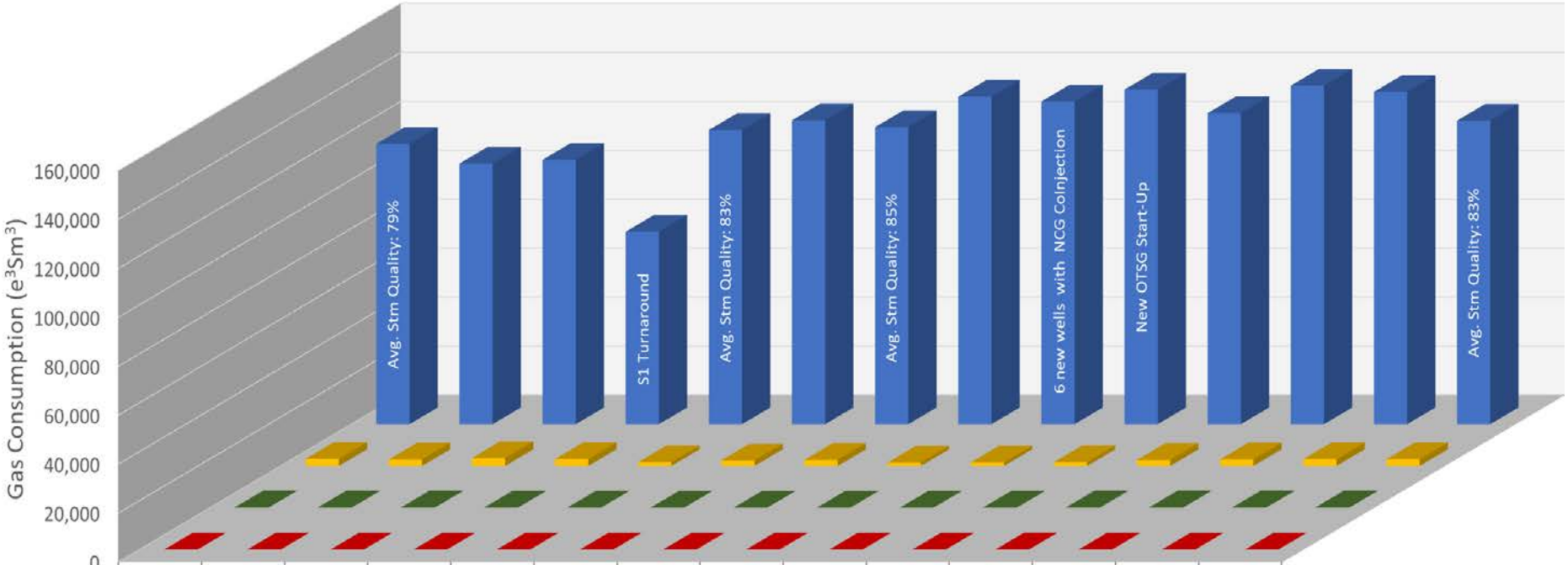
- **Effect of curtailment in April created variance – plant up near capacity this year.**

Facility Performance: Gas Consumption



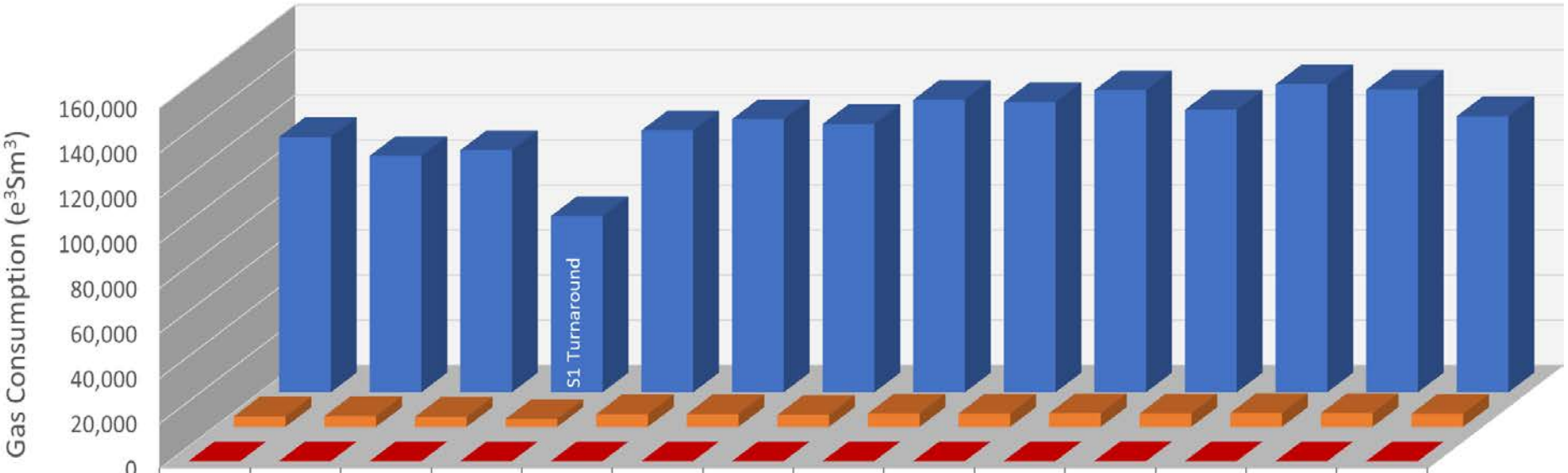
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18
Solution Gas	4,586	4,752	4,418	3,513	5,640	5,647	5,257	5,917	5,867	6,009	5,912	6,114	6,065	5,817
Imports (TCPL)	113,311	104,930	107,418	78,178.	116,243	121,223	119,106	129,797	128,776	134,091	125,430	136,690	134,310	122,568

Facility Performance: Gas Consumption by Location



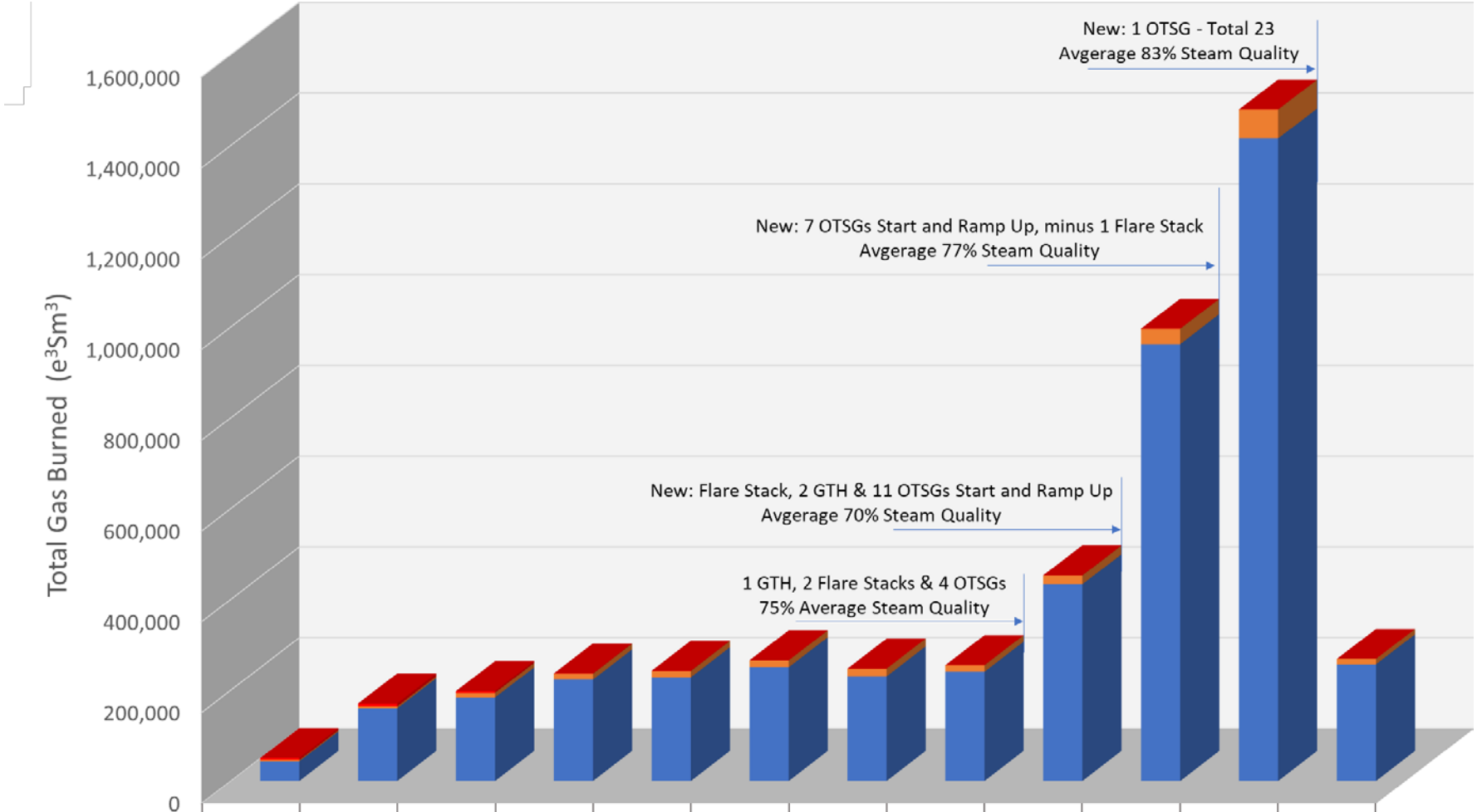
	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18
Flared Gas	8	43	12	9	12	6	0	37	0	19	64	30	1	0
Camp	213.8	189.5	195.6	137.1	91.3	70.4	64	63.2	79.4	133.4	201.6	207.9	217.1	210.9851
Battery	2,907	2,674	3,237	2,827	1,545	2,290	2,488	1,389	1,430	1,555	2,487	2,709	2,789	2,754
OTSGs	114,556	106,519	108,077	78,690	120,234	124,202	121,408	133,860	131,896	136,757	127,121	138,377	135,822	124,075

Surmont Facility Performance: 2017 Gas Usage



	Jan-17	Feb-17	Mar-17	Apr-17	May-17	Jun-17	Jul-17	Aug-17	Sep-17	Oct-17	Nov-17	Dec-17	Jan-18	Feb-18
Flared Gas	8	43	12	9	12	6	0	37	0	19	64	30	1	0
Solution Gas	4,586	4,752	4,418	3,513	5,640	5,647	5,257	5,917	5,867	6,009	5,912	6,114	6,065	5,817
Imports (TCPL)	113,31	104,93	107,41	78,178	116,24	121,22	119,10	129,79	128,77	134,09	125,43	136,69	134,31	122,56

Surmont Facility Performance: Year over Year Gas Usage

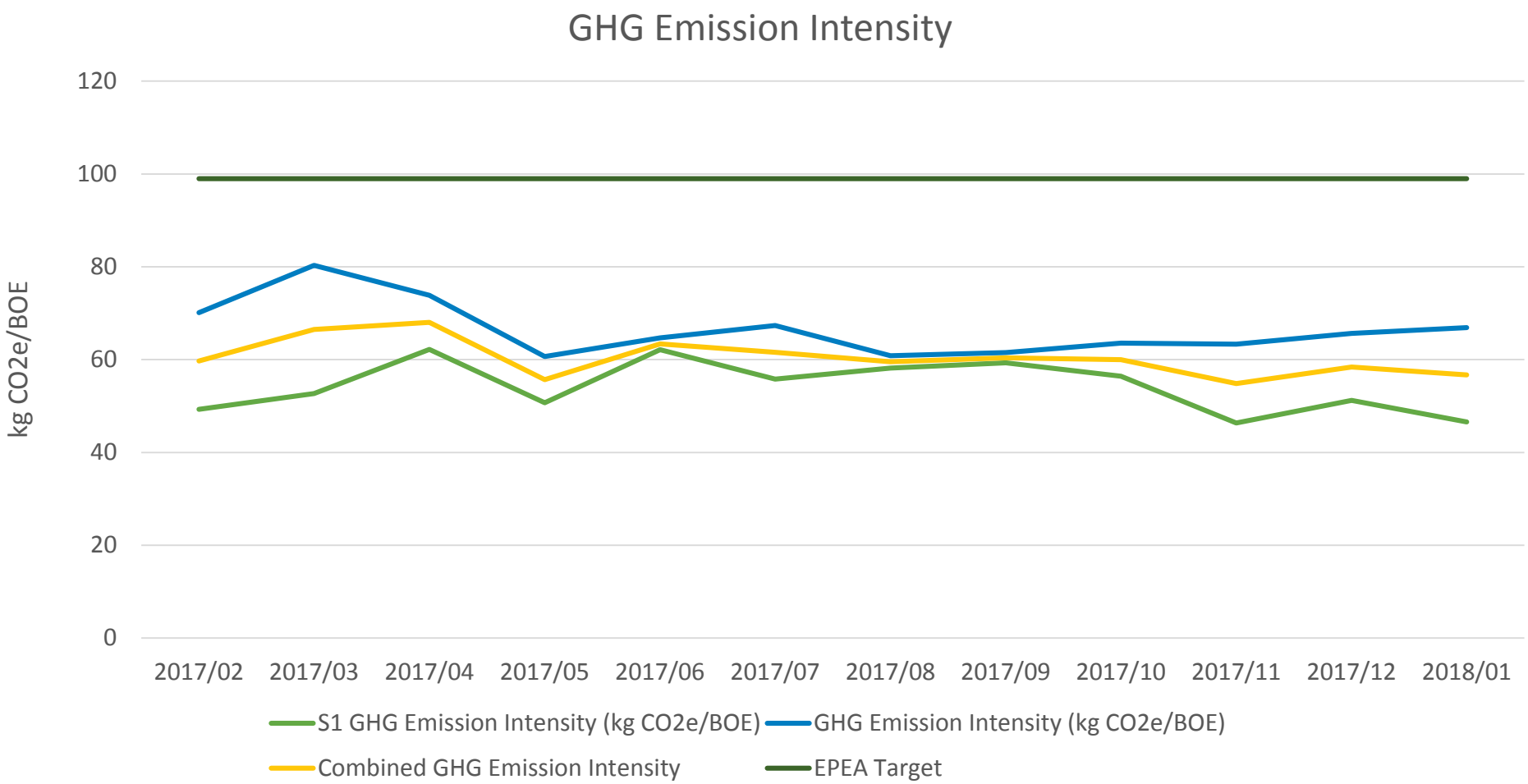


	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	Feb.2018
Flared Gas	4,641	6,439	3,962	705	625	218	117	271	475	371	239	1
Solution Gas	2,755	4,155	10,073	12,703	13,869	15,193	17,005	14,246	19,301	33,636	63,633	11,883
TCPL Imports	42,999	160,095	183,933	223,447	228,344	250,412	230,339	240,496	433,138	962,313	1,415,198	256,879
Average GOR		7.04	12.10	10.87	10.83	10.81	10.85	8.55	12.12	7.78	9.19	8.92
Average SOR		3.29	2.76	2.56	2.45	2.45	2.42	2.18	3.67	3.67	3.10	3.00
% Sol. Gas Recovery				94.45%	95.49%	98.57%	99.31%	98.10%	97.54%	98.90%	99.62%	100.0%

Surmont Facility Performance: Gas Usage - Highlights

- Phase 2 battery utility FG measurement has been relocated to each user for better measurement of battery FG and solution gas quantification.
- Phase 1 continuing flaring of TCPL gas, through the VRU, after plant trips has been significantly reduced (to almost zero) through DCS logic reconfiguration.
- 2017 flare volumes reduced by 35% from 2016:
  - Major flare events due to plant trips as a result of power outages.
  - Completed Surmont 1 turnaround, with flared volumes significantly reduced compared to 2014 TA.
- Overall increased FG usage, mainly due to increased steam production:
  - Total of 23 OTSGs running (1 new in 2017).
  - Average steam quality increased from 77% in 2016 to 83% in 2017.
- Six new wells added to the NCG co-injection trial (total of 9 wells). Gas co-injected with steam is assumed to remain in the reservoir (does NOT return with solution gas to plant).

Facility Performance: Greenhouse Gas



- **Agreement with AER to continue reporting Phase 2 CO2e emission, through its ramp-up, separately from Phase 1.**
- **2017 SGER intensity reduction target of 20% was not achieved.**
- **2017 GHG Emission intensity is currently being verified for payment submission.**

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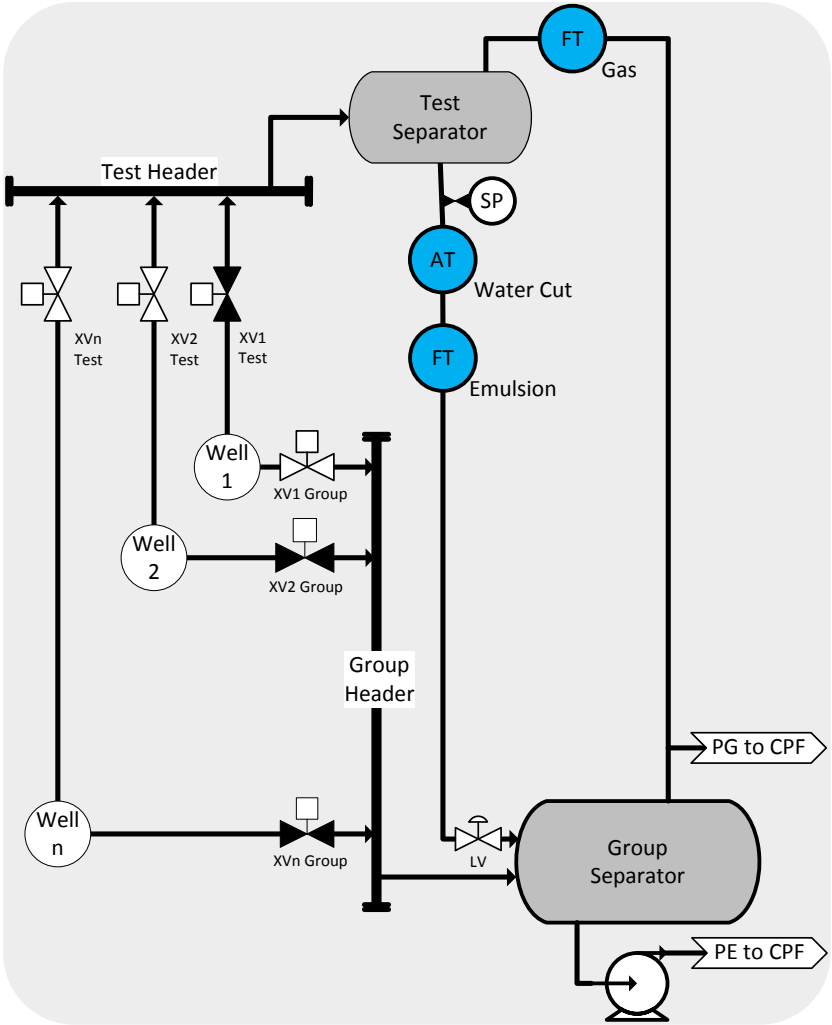
Measurement and Reporting

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 =

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

Well Monthly Estimated Water Production =

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

- Well Estimated Daily Water Production =

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

Well Allocated Oil Production

Well Estimated Monthly Oil Production × 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 =

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

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

Well Estimated Monthly Water Production × Water Proration Factor

- Water Proration Factor =

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

- Battery Produced Water =

Water Dispositions + Battery Tank Inventory – Receipts + Well Load Water

- Total Estimated Monthly Water Production =

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

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

- Water Dispositions =

Dispositions to Injection Facility + Truck−Out

- Water in Battery's Tank Inventory =

Skim Oil Tanks + Slop OilTanks + DeSand/BackWash/ORF Tanks + Sales/OffSpec/Diluent Tanks

- Receipt =

IF Condensate Returns + Water in Diluent + Truck−In

Well Allocated Gas Production

Well Allocated Oil Production × GOR

- Gas to Oil Ration (GOR) =

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

- Battery Produced Gas =

Gas Dispositions – Receipts

- Gas Dispositions =

Battery Utility FG[2]*+ Steam Generators FG + Flare Purge + NCG Co−Injection + Flared Gas*

- Receipt =

TCPL Fuel Gas CTM[1]

[1] CTM: Custody Transfer Meter

[2] Phase 2 Battery Utility FG relocated to measure each users FG consumption.

Well Allocated Steam

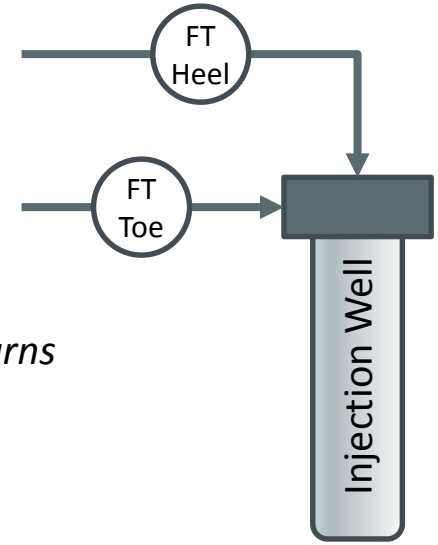
Well Measured Steam × Steam Proration Factor

- Well Measured Steam =

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

- Steam Proration Factor =

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



- Steam Produced =

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

- Total Measured Steam =

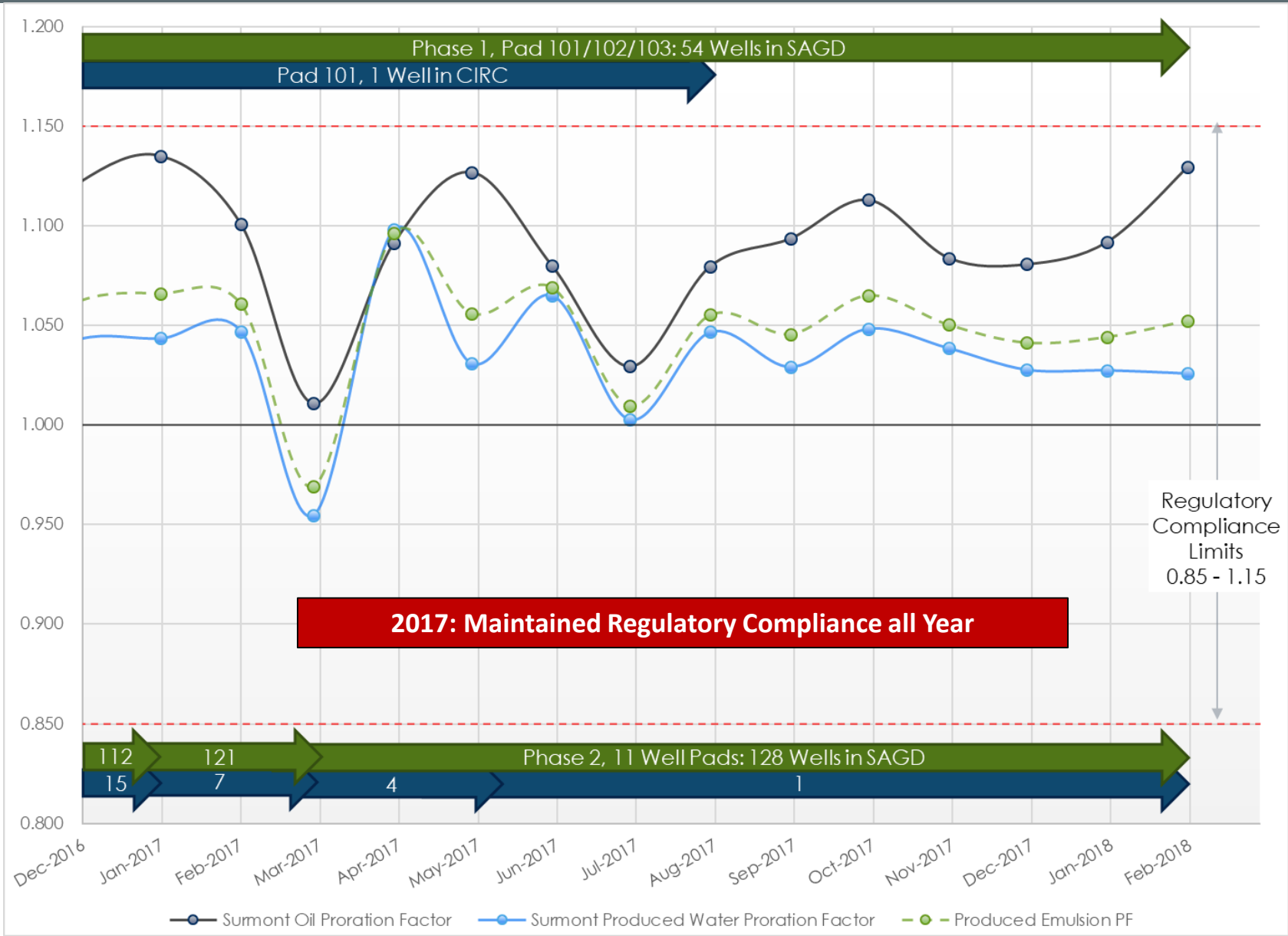
$$\sum_{n=1}^{x} \textit{Well}_n \textit{ Measured Steam}$$

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

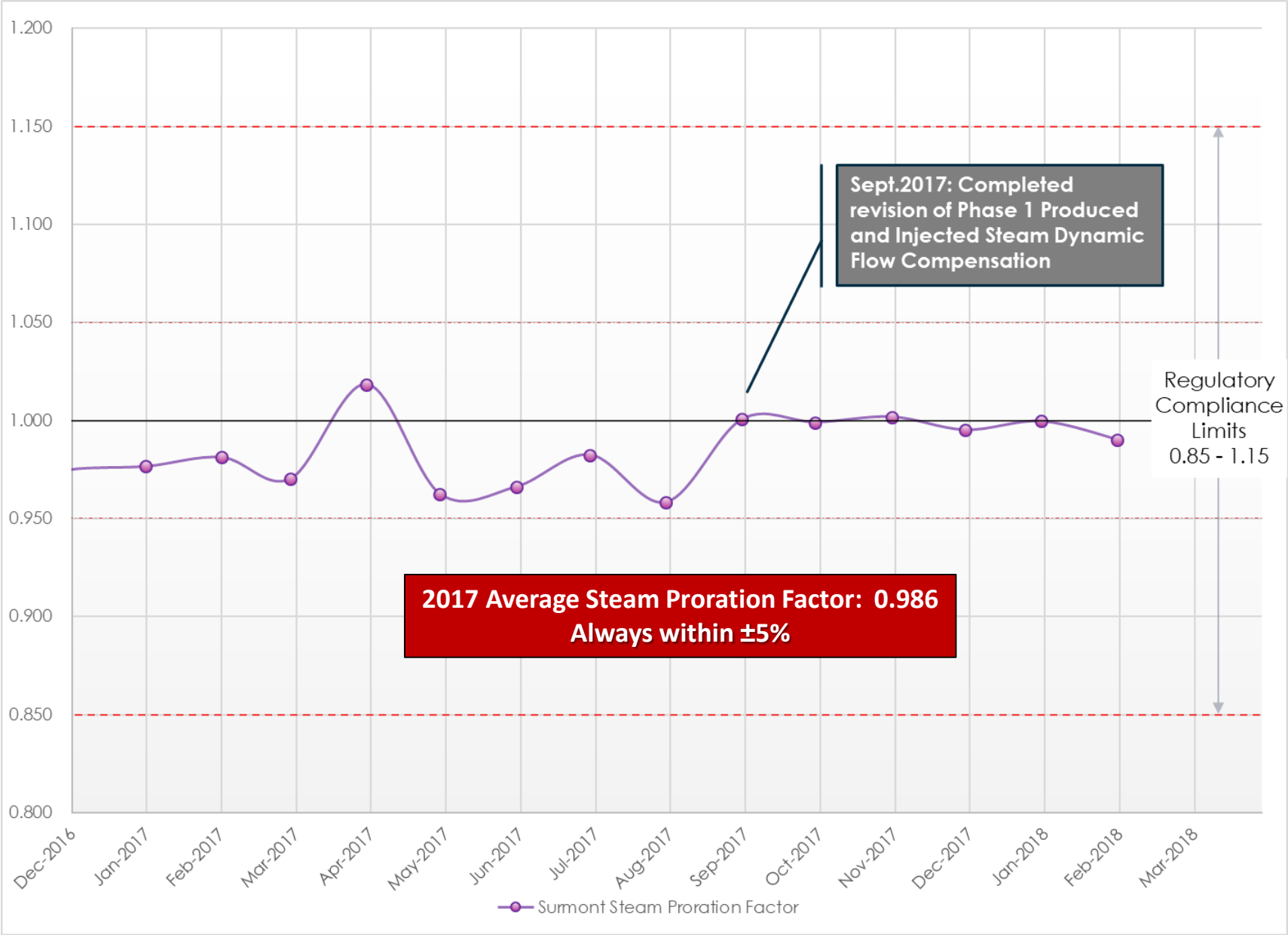
2017 Highlights and Changes

- Phase 2 battery utility FG measurement relocated to each user for better quantification solution gas.
- *Directive 017* Compliance: Updated Phase 1 dynamic flow compensations of steam flow rates after September 2017.
- Condensate blending trial completed:
  - Developing flashed diluent recovery unit.
- Non condensable gas (NCG) co-injection trial:
  - Initiated November 2016 in 3 wells.
  - Extended to 6 other wells starting September 2017.
  - Co-injected volumes added to battery's gas dispositions (assumes gas co-injected with steam does not return to the injection facility with solution gas).
- Maintained proration factor regulatory compliance through all 2017, with increased number of producing wellheads and operational changes:
  - 182 wells in SAGD operation (107 pump and 75 gas lift).
  - 1 well in steam circulation.

Oil and Water Production Proration Factors



Steam Injection Proration Factor



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Water Production, Injection, and Uses

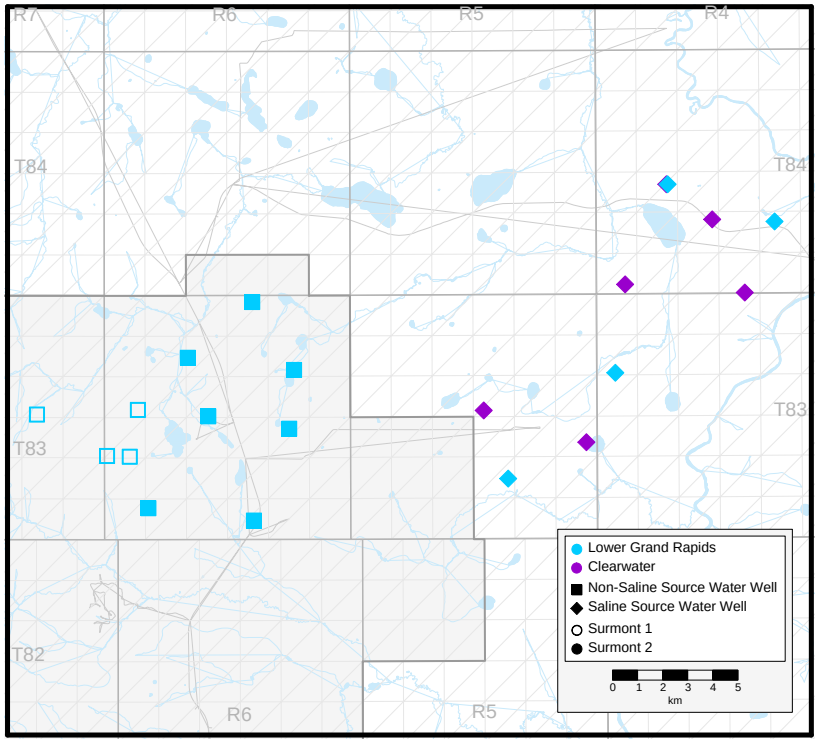
Subsection 3.1.2 (4)

Surmont Phase 1 and Phase 2 Water Source Wells

Surmont Phase 1 Non-Saline Water Source Wells			
Source Well	**Observation Well**	**Formation**	**Water Act Licence No.**
1F1021808306W400	1F2021808306W400	Lower Grand Rapids	00253532-02-00
1F1041808306W400	102041808306W400	Lower Grand Rapids	00253532-02-00
1F1011908306W400	100011908306W400	Lower Grand Rapids	00253532-02-00
1F1032308307W400	100032308307W400	Lower Grand Rapids	00253532-02-00

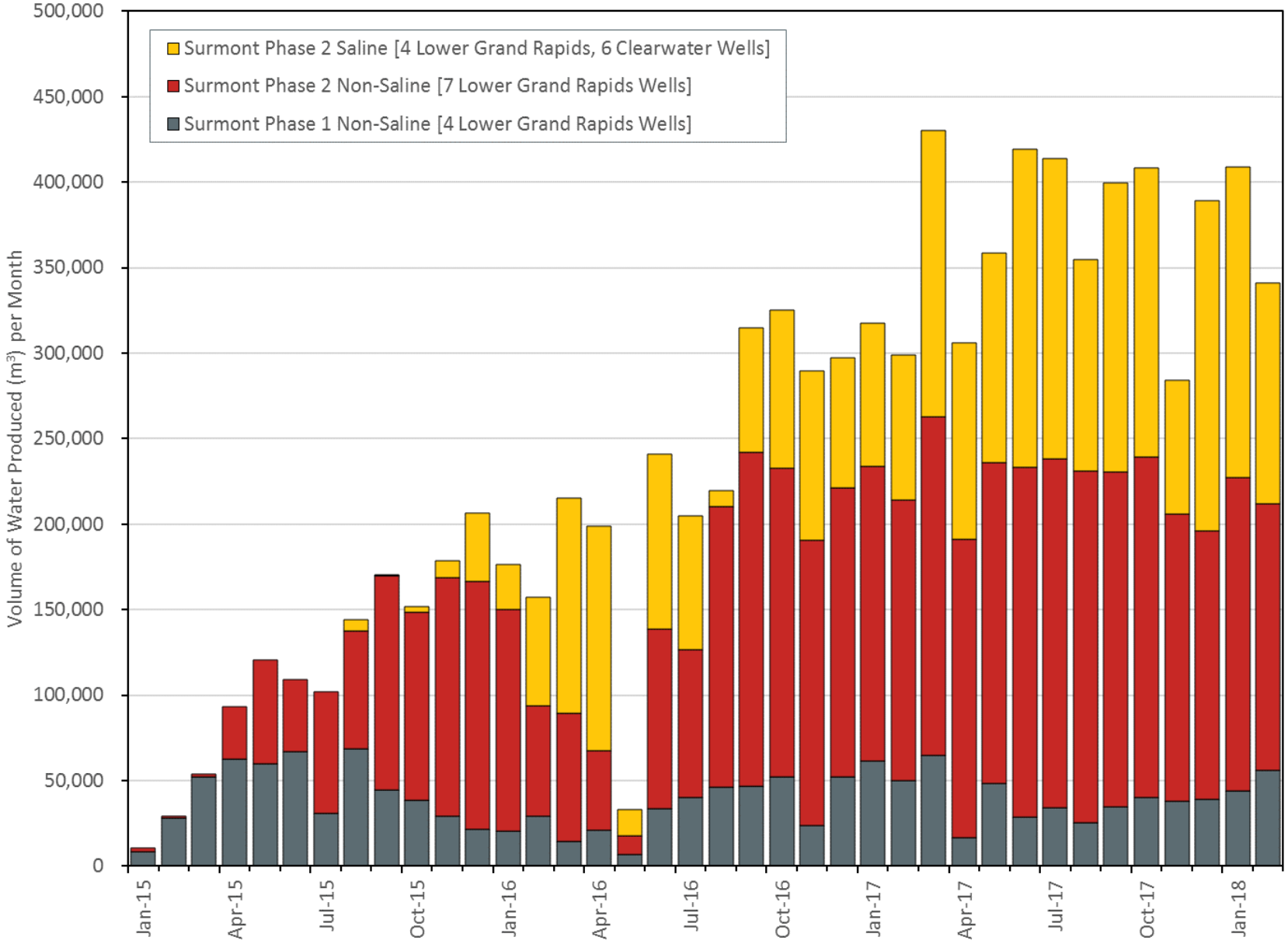
Surmont Phase 2 Non-Saline Water Source Wells			
Source Well	**Observation Well**	**Formation**	**Water Act Licence No.**
1F1022108306W400	100022108306W400	Lower Grand Rapids	00312463-01-00
1F1022608306W400	100022608306W400	Lower Grand Rapids	00312463-01-00
1F1052808306W400	100052808306W400	Lower Grand Rapids	00312463-01-00
1F1070308306W400	1F2070308306W400	Lower Grand Rapids	00312463-01-00
1F1101408306W400	1F1111408306W400	Lower Grand Rapids	00312463-01-00
1F1130508306W400	100130508306W400	Lower Grand Rapids	00312463-01-00
1F1153408307W400	1F2153408307W400	Lower Grand Rapids	00312463-01-00

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

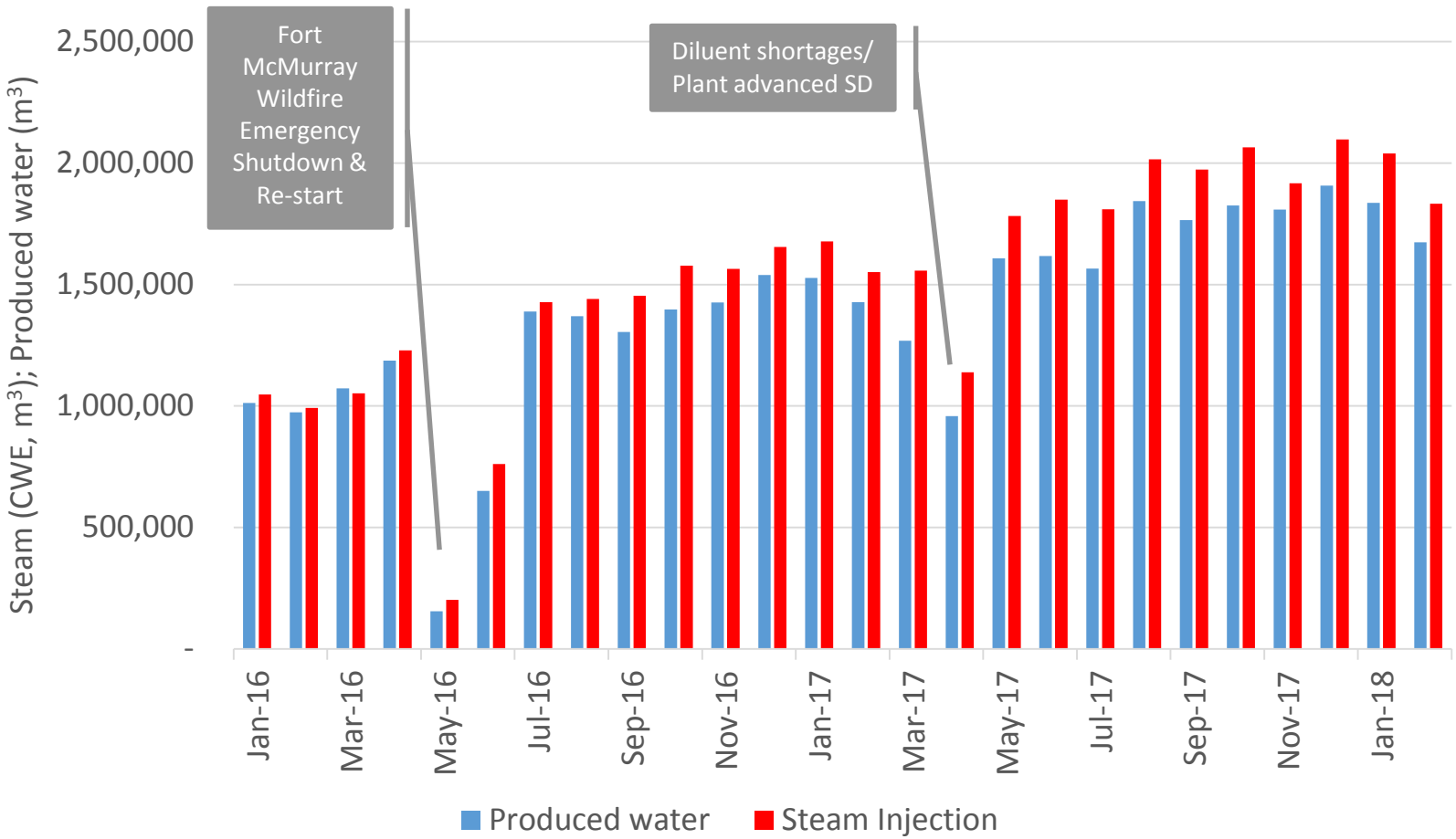


No Changes in 2017

Surmont Non-Saline and Saline Water Source Wells Production Volumes

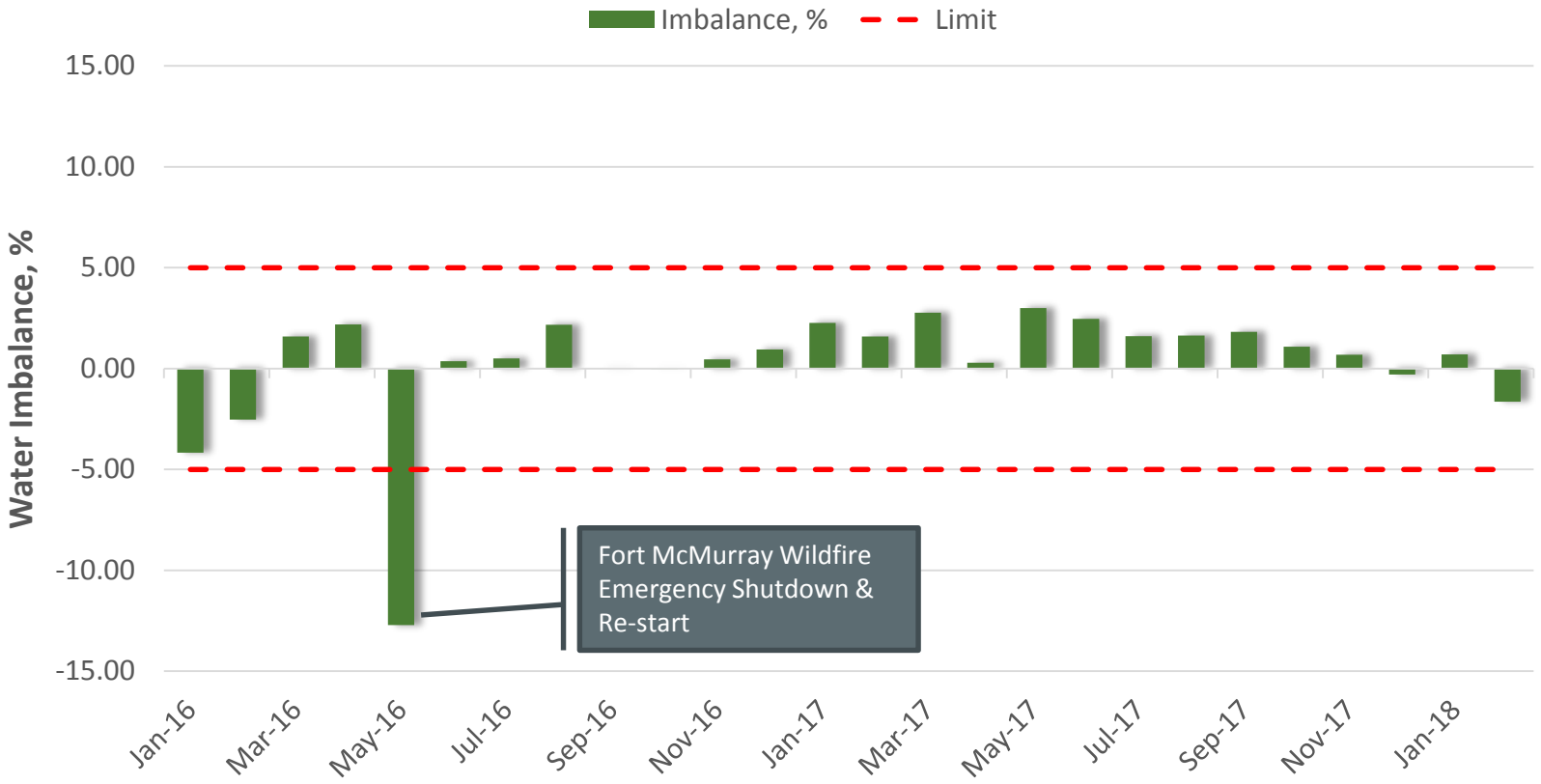


Water Production and Steam Injection Volumes

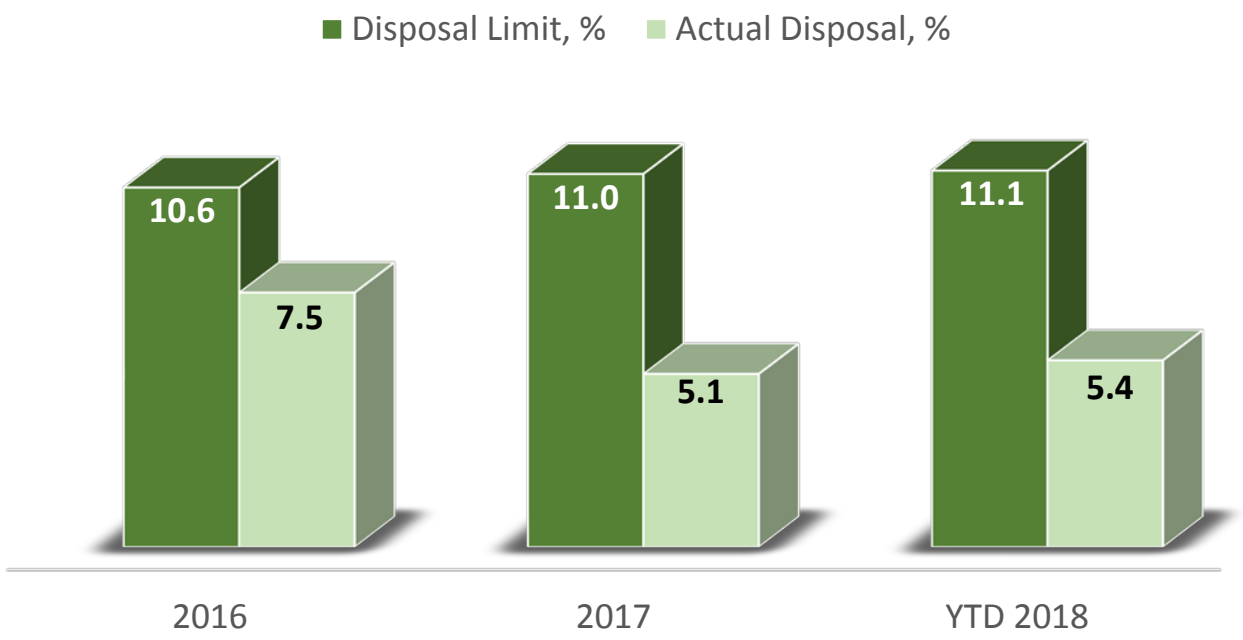


Directive 81: Injection Facility Water Imbalance

- Surmont in compliance with *Directive 81* Injection Facility Water Imbalance since June 2014
- No issues foreseen for 2018



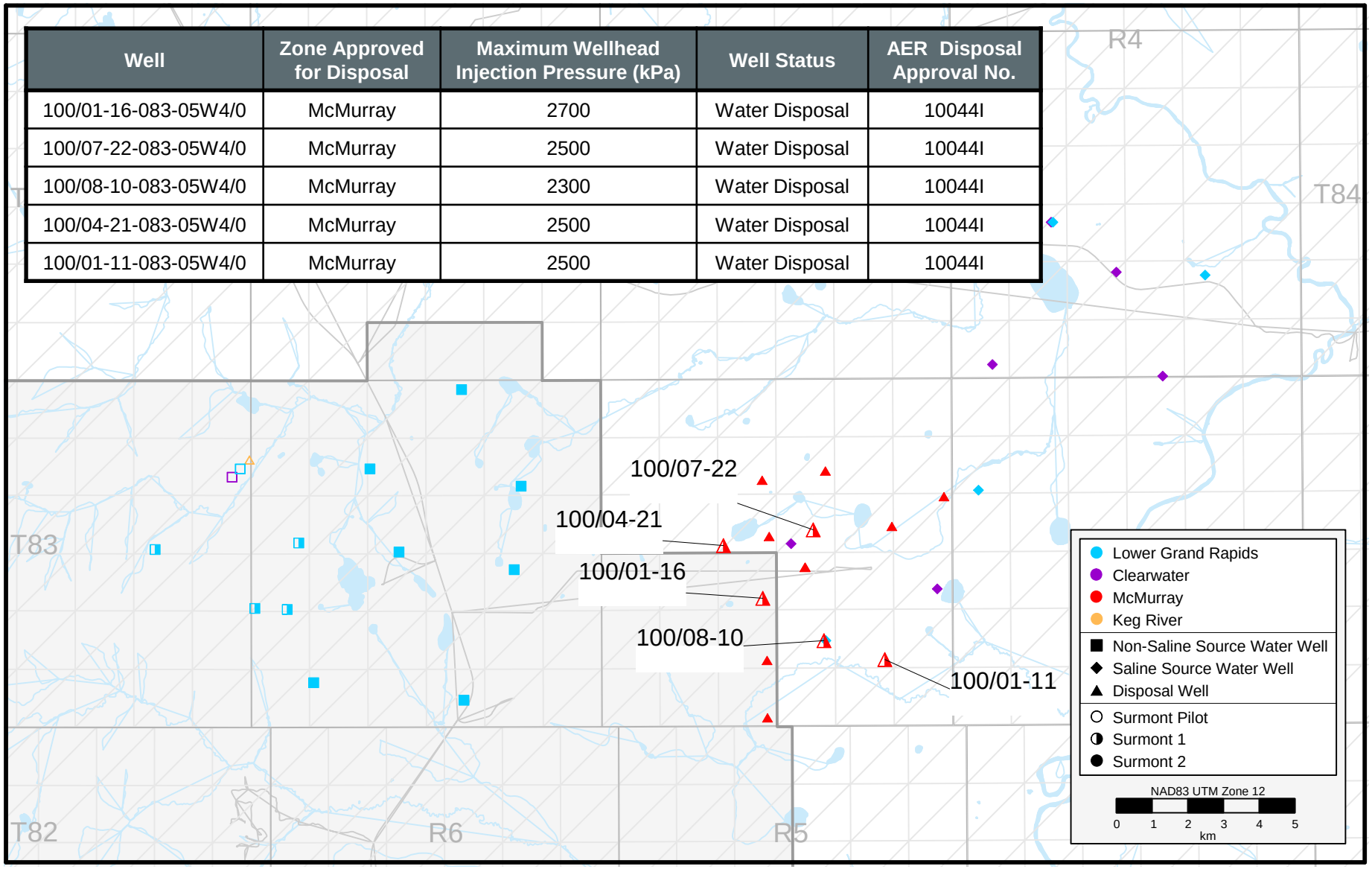
Directive 81: Annual Disposal performance



- Surmont anticipates *Directive 81* disposal limit compliance in 2018 as per current trend (5.4% actual vs. 11.1% disposal limit)
- Surmont accomplished *D-81* compliance in 2016 (7.5% actual vs. 10.6% disposal limit) after commissioning brackish water system and blowdown evaporators at Phase 2 CPF
- Increased steam quality contributing to reduced blowdown disposal rates

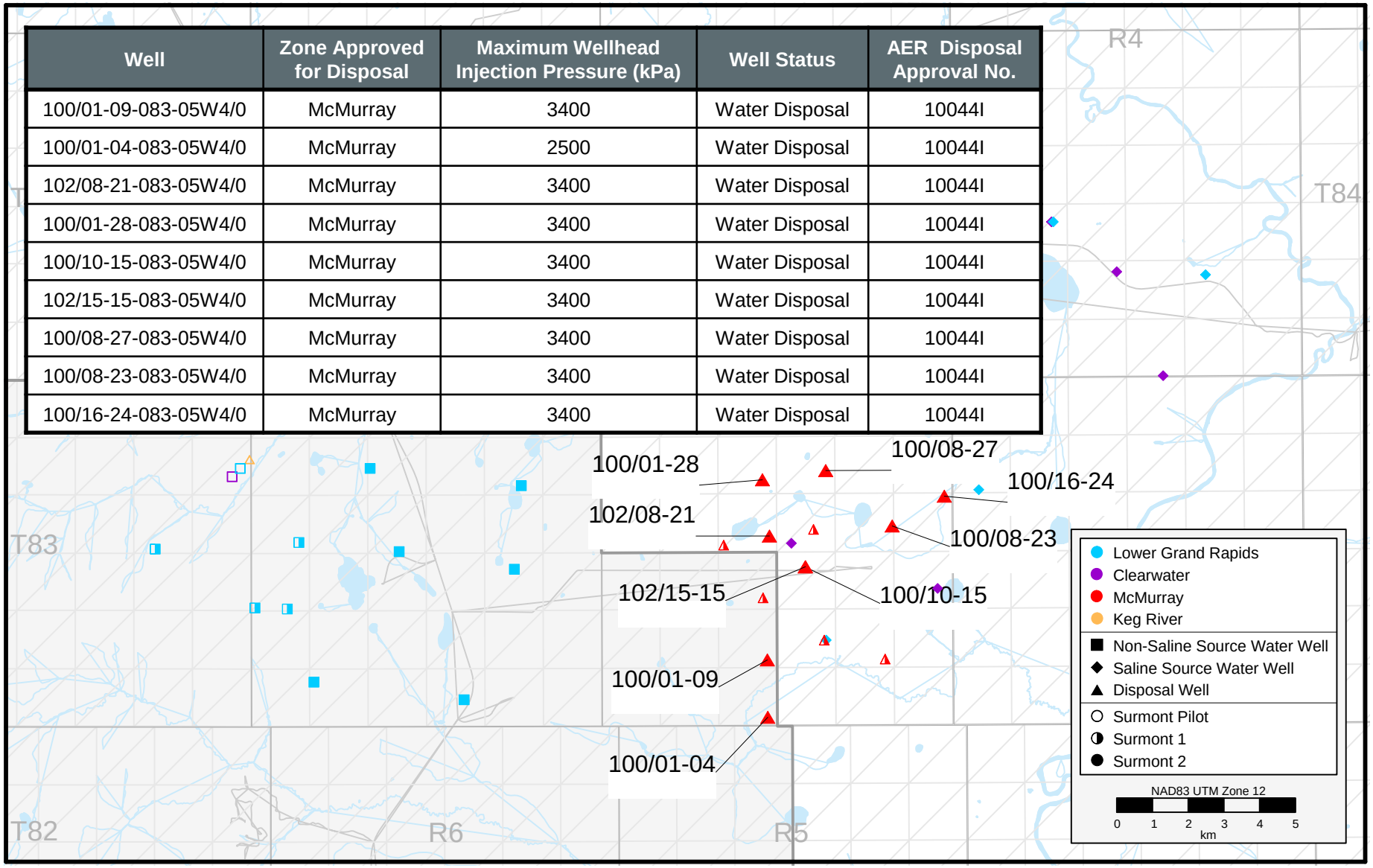
Surmont Phase 1 Water Disposal Wells

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	10044I
100/07-22-083-05W4/0	McMurray	2500	Water Disposal	10044I
100/08-10-083-05W4/0	McMurray	2300	Water Disposal	10044I
100/04-21-083-05W4/0	McMurray	2500	Water Disposal	10044I
100/01-11-083-05W4/0	McMurray	2500	Water Disposal	10044I

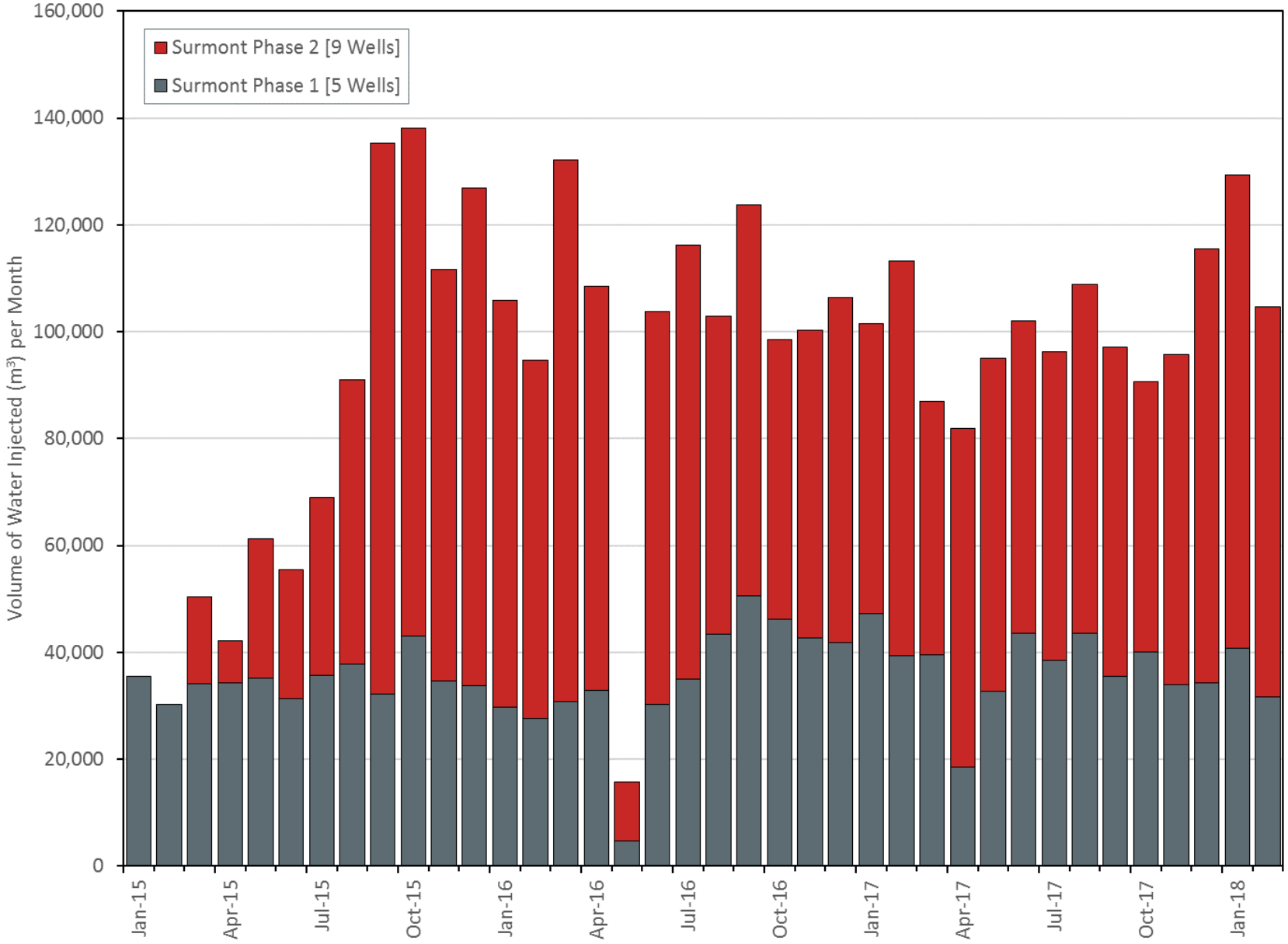


Surmont Phase 2 Water Disposal Wells

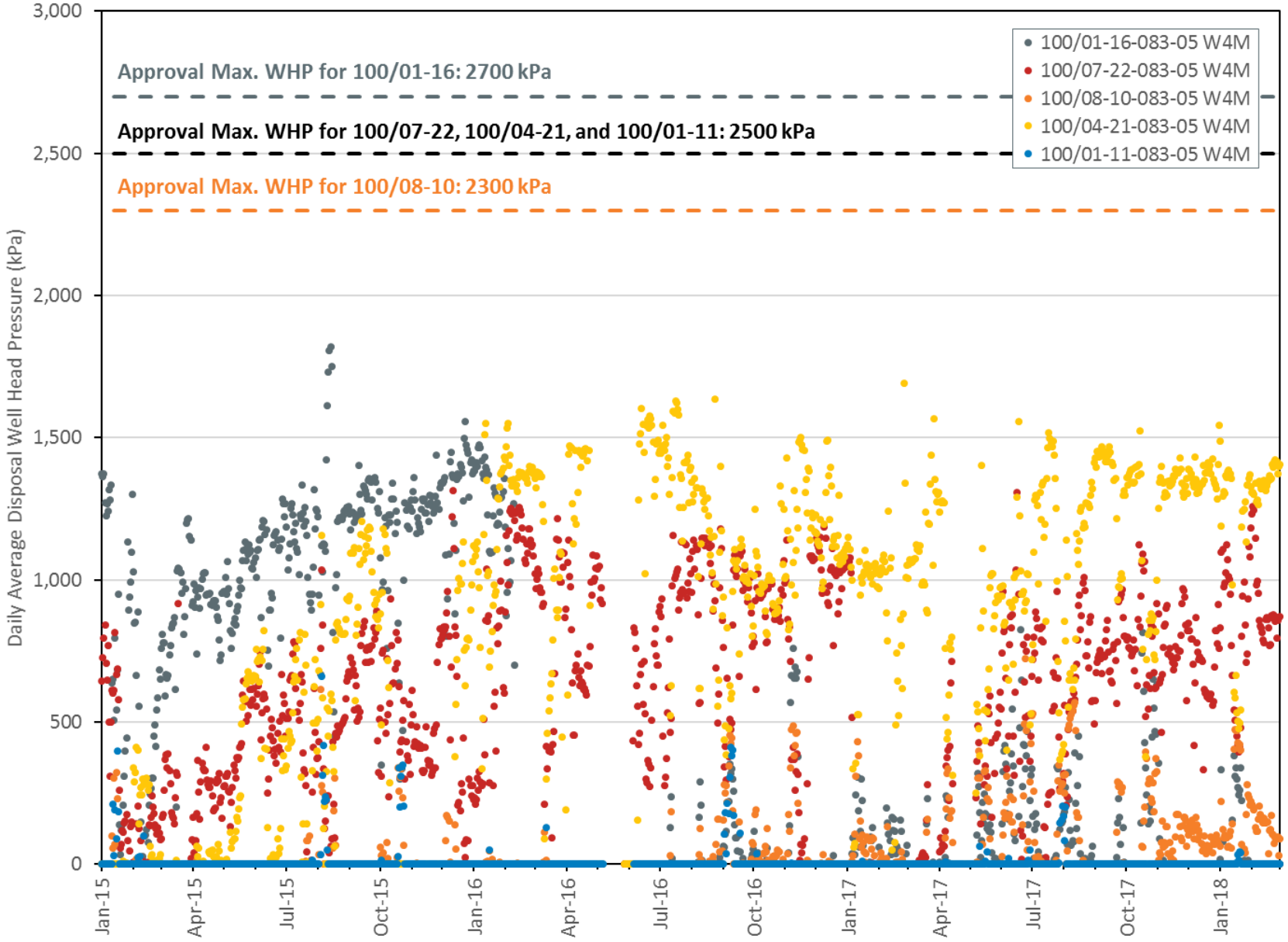
Well	Zone Approved for Disposal	Maximum Wellhead Injection Pressure (kPa)	Well Status	AER Disposal Approval No.
100/01-09-083-05W4/0	McMurray	3400	Water Disposal	10044I
100/01-04-083-05W4/0	McMurray	2500	Water Disposal	10044I
102/08-21-083-05W4/0	McMurray	3400	Water Disposal	10044I
100/01-28-083-05W4/0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



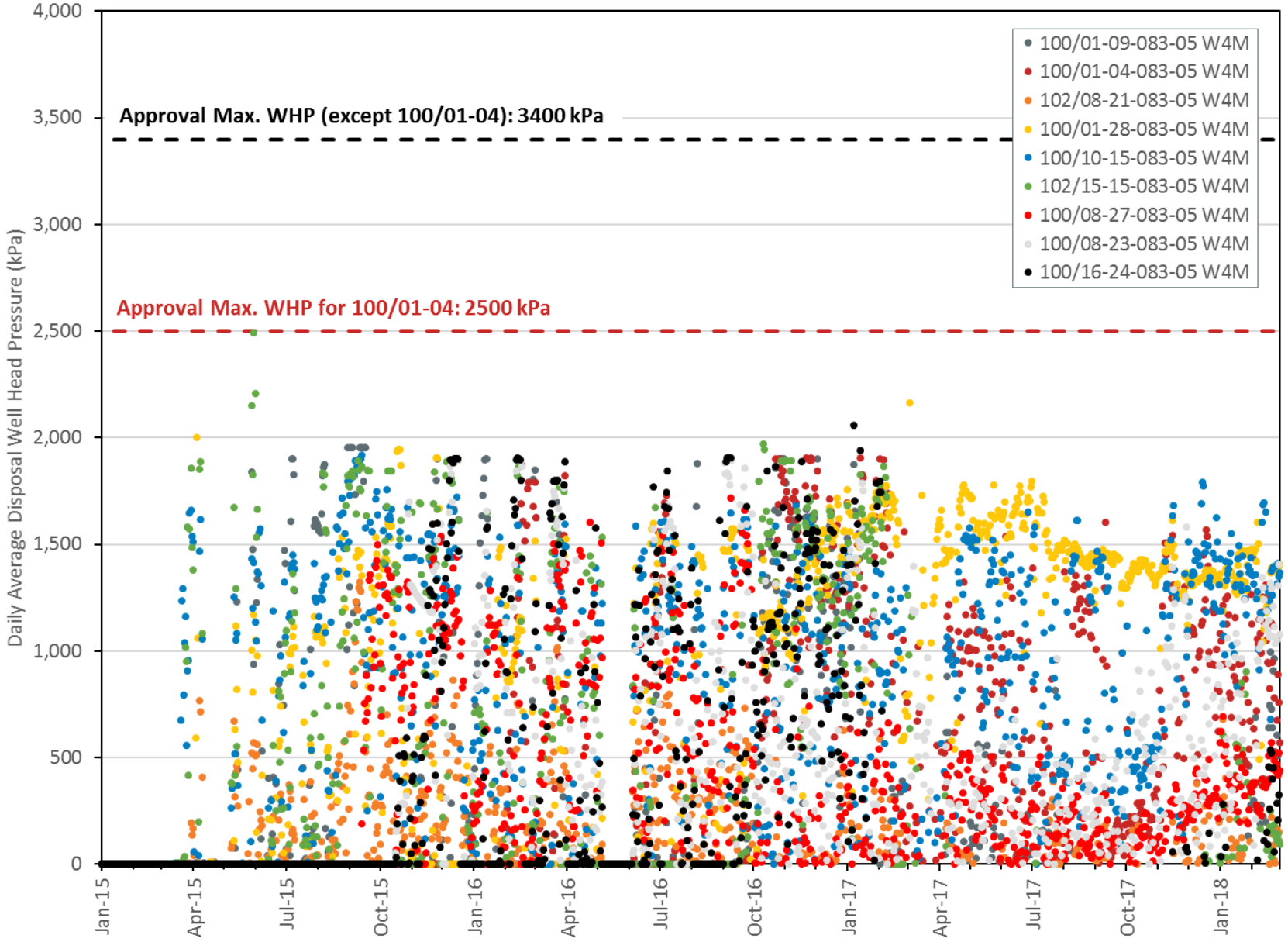
Surmont Water Disposal Wells Injection Rates (McMurray)



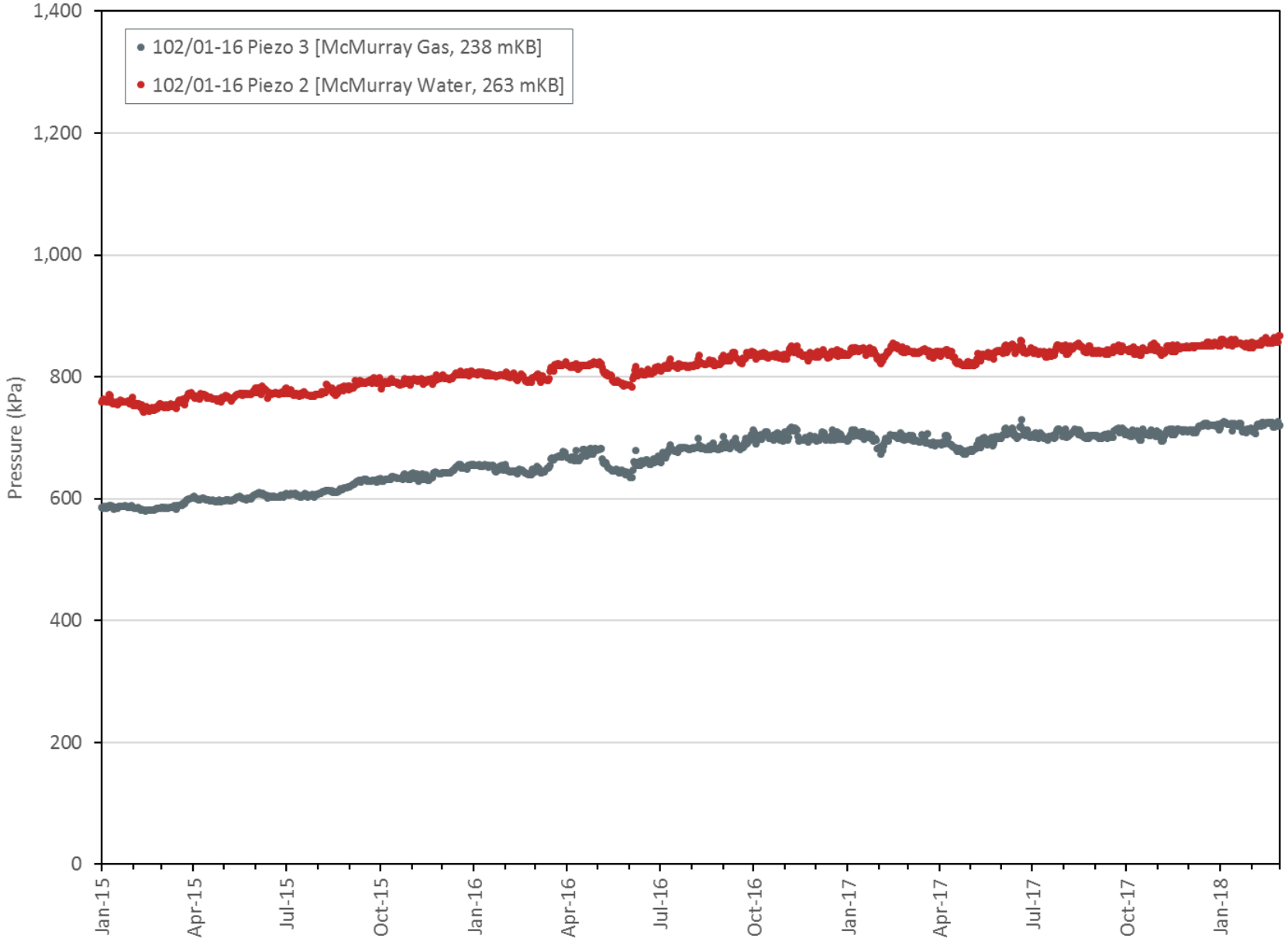
Surmont Phase 1 Water Disposal Wells Well Head Pressure (McMurray)



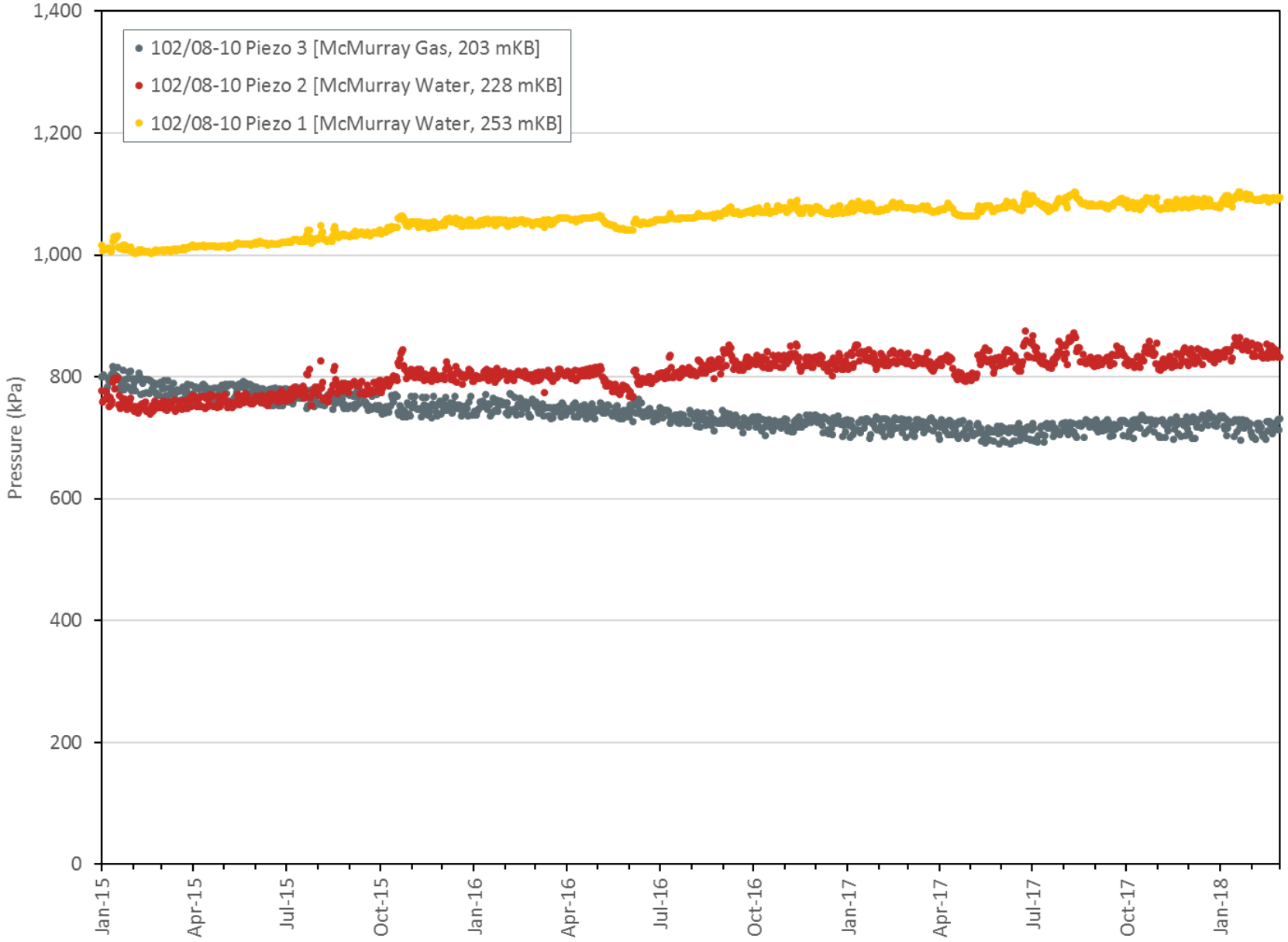
Surmont Phase 2 Water Disposal Wells Well Head Pressure (McMurray)



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	24,436	
Hydrocarbon/Emulsion Sludge	1,357	Oilfield Waste Processing Facility
Crude Oil/Condensate Emulsions	21,779	Oilfield Waste Processing Facility
Various	1,300	Landfill
Non-Dangerous Oilfield Waste	66,659	
Lime Sludge	56,938	Landfill
Various	9,486	Landfill
Well Fluids	235	Cavern

Waste Recycling

Waste Description	Disposal Weight (Tonnes)	Disposal Method
Oil	12	Used Oil Recycler
Empty Containers	21	Recycling Facility
Fluorescent Light Tubes	0.93	Recycling Facility
Batteries	8	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

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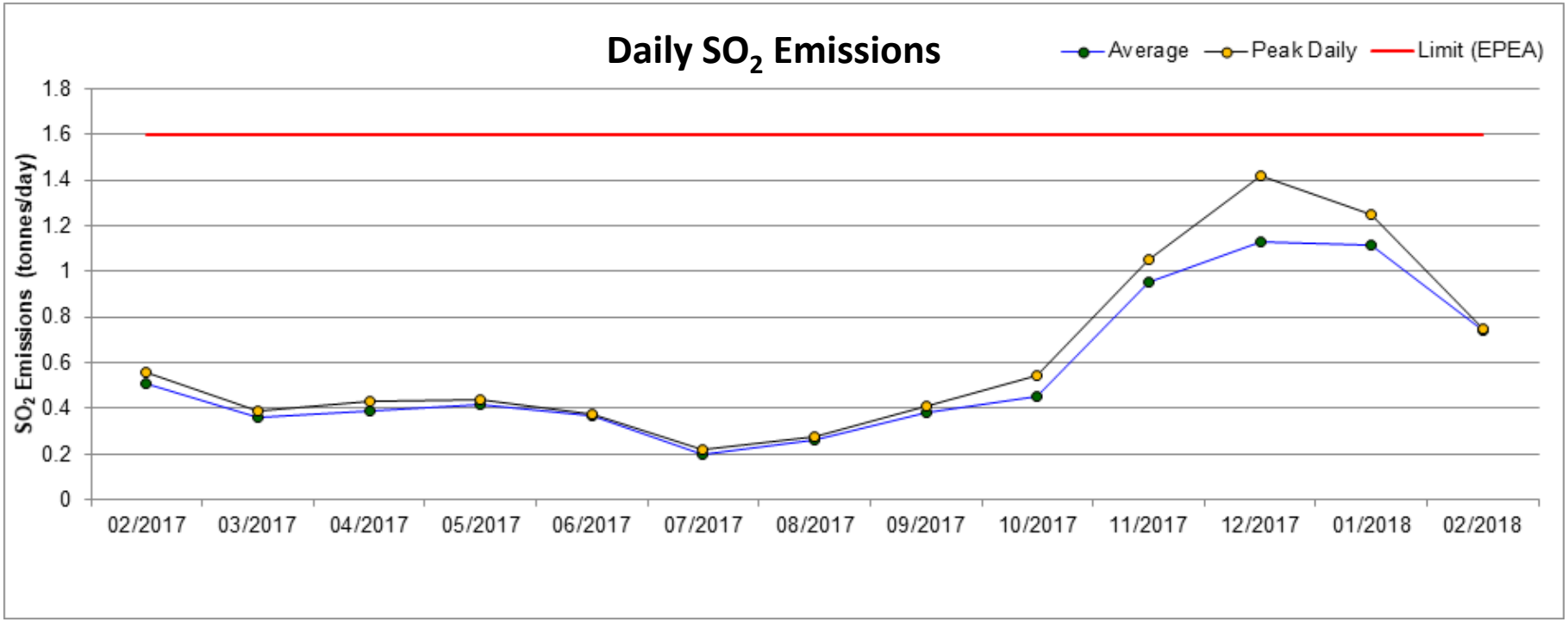
Sulphur Production

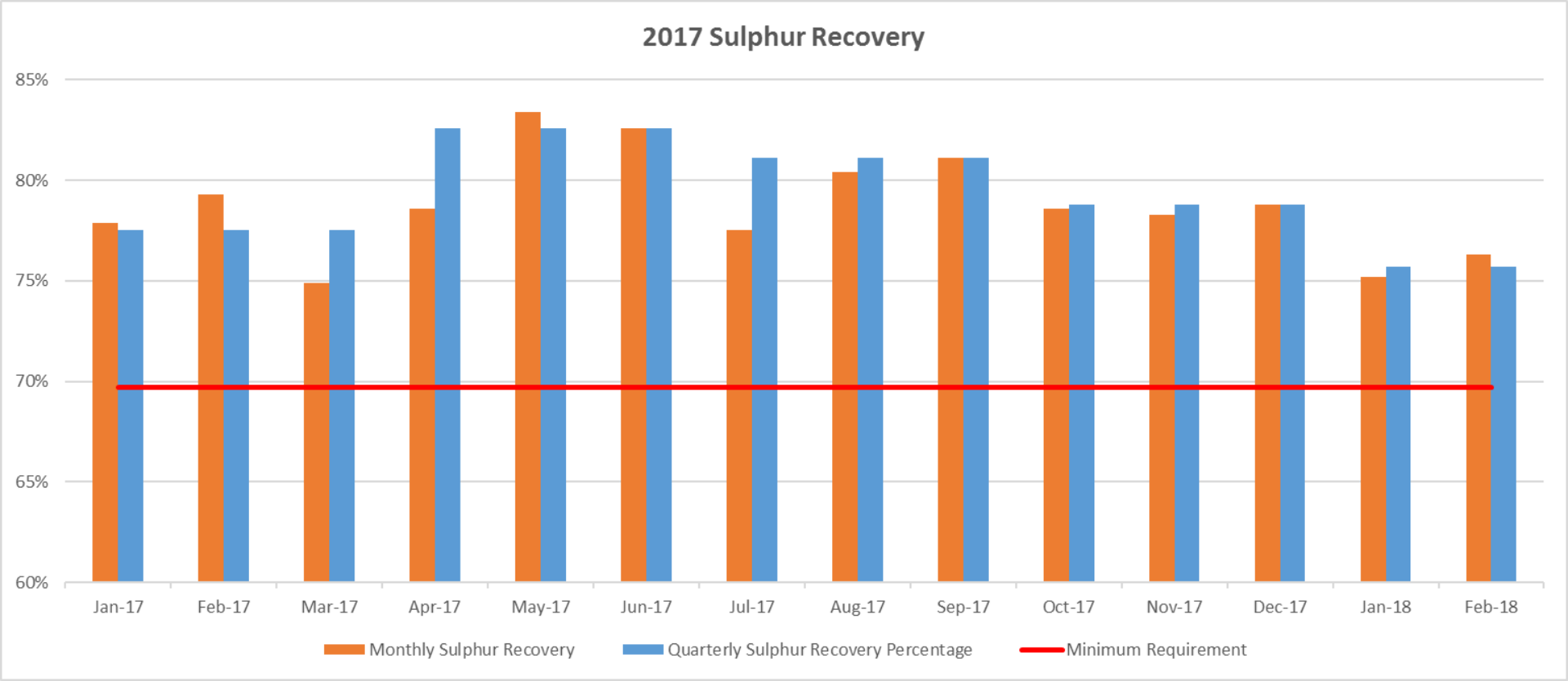
Subsection 3.1.2 (5)

Daily SO_2 Emissions



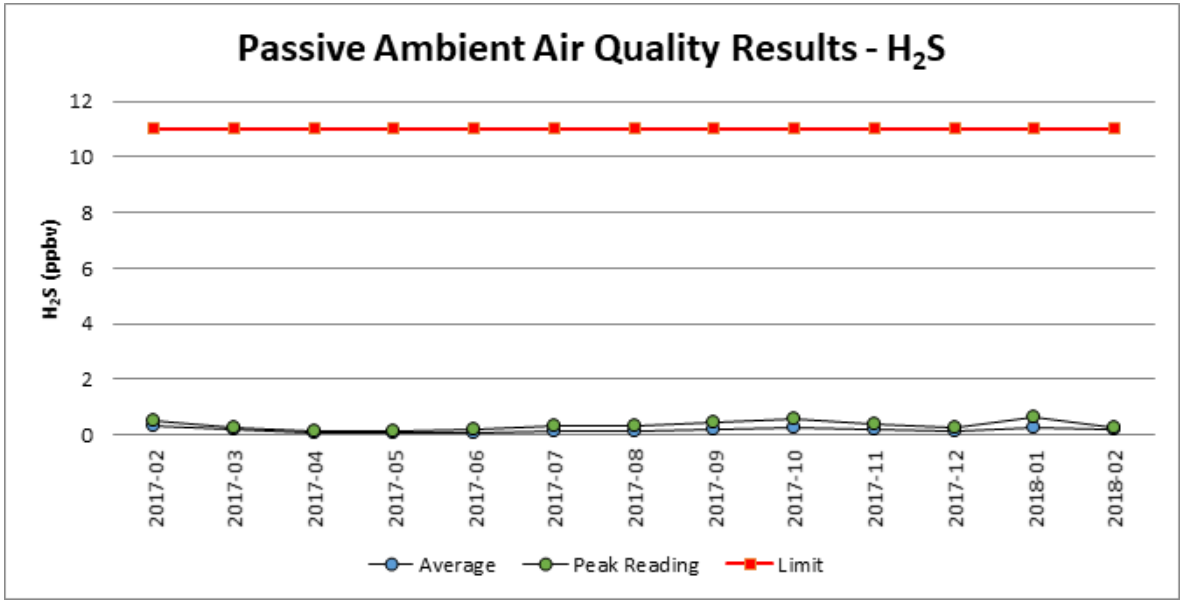
- **SO2 emissions were managed below the 1.6t/d in 2017.**
- **The decreased SO2 emissions in February 2018 were due to a conservative philosophy with regard to operating the Produced Gas header to remain below the 1.6 tpd SO2 limit.**
- **Operations is working on a strategy to safely manage the liquid buildup in the Produced Gas header without risking a plant trip.**

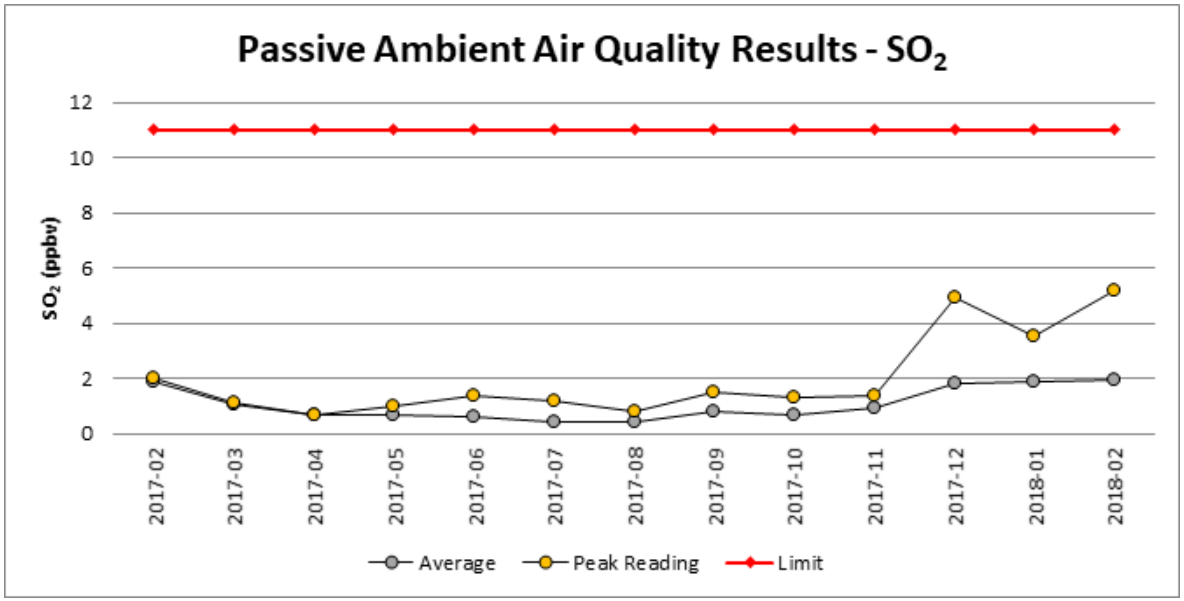
Surmont Project Sulphur Recovery



- Sulphur recovery unit maintained 100% uptime.
- Surmont achieved greater than the required 69.7% quarterly sulphur recovery in 2017.

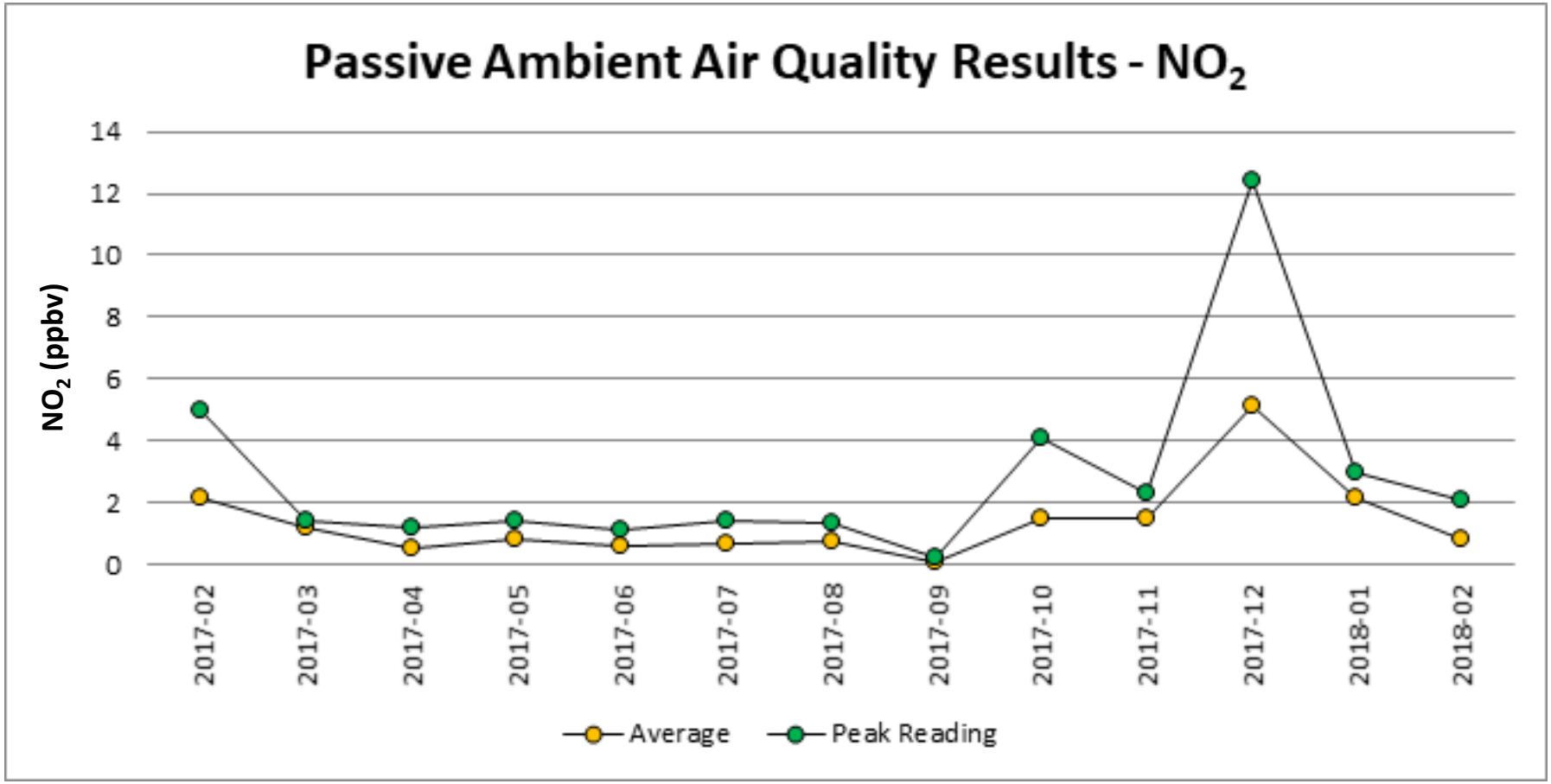
Ambient Air Quality Monitoring





- **Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2017**

Ambient Air Quality Monitoring



Falsely high readings in December due to heavy machinery exhaust next to air quality monitor

- **Continuous ambient air monitoring: all Alberta Ambient Air Quality Objectives were met in 2017**

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Environmental Compliance

Subsection 3.1.2 (6)

Environmental Monitoring

- Groundwater Monitoring Program:
  - Program revised to focus monitoring on early change detection.
  - 2017 monitoring results are being analyzed in 2018.
  - Installed new monitoring wells at the Central Processing Facility 1 and the Well Pads.
- Wetlands:
  - Program revised to focus monitoring on early change detection.
  - 2017 monitoring results are being analyzed in 2018.
  - Installed new monitoring wells around saline source wells.
- Wildlife Monitoring Program:
  - Wildlife handling permit obtained.
  - No vehicle/animal collisions.
  - No serious nuisance wildlife or human-bear interactions.
- Reclamation Work:
  - Re-vegetation, through the establishment of reclamation trials, was initiated on two borrow pits in 2017.
  - Temporary reclamation areas were identified and planted with a mix of native trees and shrubs.

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 submitted November 30, 2017.
- 2017 Soil monitoring at Surmont complete as per 5 year rotational requirement outlined in EPEA Approval 48263-01-00.
- Air monitoring trailer purchased from Wood Buffalo Environmental Association to comply with continual ambient monitoring during facility operations as per EPEA Approval number 48263-01-00.

ConocoPhillips

Compliance Confirmation and Non Compliances

Subsection 3.1.2 (7) + (8)

Compliance Confirmation and Non Compliances

ConocoPhillips is in regulatory compliance for 2017 with the exception of the following:

Surmont Well 264-1 I05 Valve Failure – FIS Incident 20170074:

- Incident occurred between Jan 7-10, 2017.
- Cause of the incident was determined to be a master valve bonnet failure due to freezing.
- Environmental clean up is complete and the Incident Investigation was closed on Jan 15, 2018.

Surmont Well 264-3 I12 Steam Injector Release – FIS Incident 20173863:

- Incident occurred on Dec 19, 2017 for approximately 5 hours.
- Cause of the incident was determined to be a result of the fluid column in the well boiling off allowing flow to surface.
- Secondary cause of the incident was determined to be an inoperable TIW safety valve, likely due to freezing.
- Environmental clean up is complete and the Incident Investigation is active.

Surmont Phase 1 Pond Primary Liner:

- A corrective action plan was submitted in 2015 and the action items were completed.
- ConocoPhillips provided an update to the AER on Mar 17, 2017 indicating that the pond Action Leakage Rate is not currently exceeded and will continue to monitor.

Future Plans

Subsection 3.1.2 (9)

Future Plans – Surmont

- Design work for the Surmont landfill will be on-going in 2018 with construction planned for 2019.

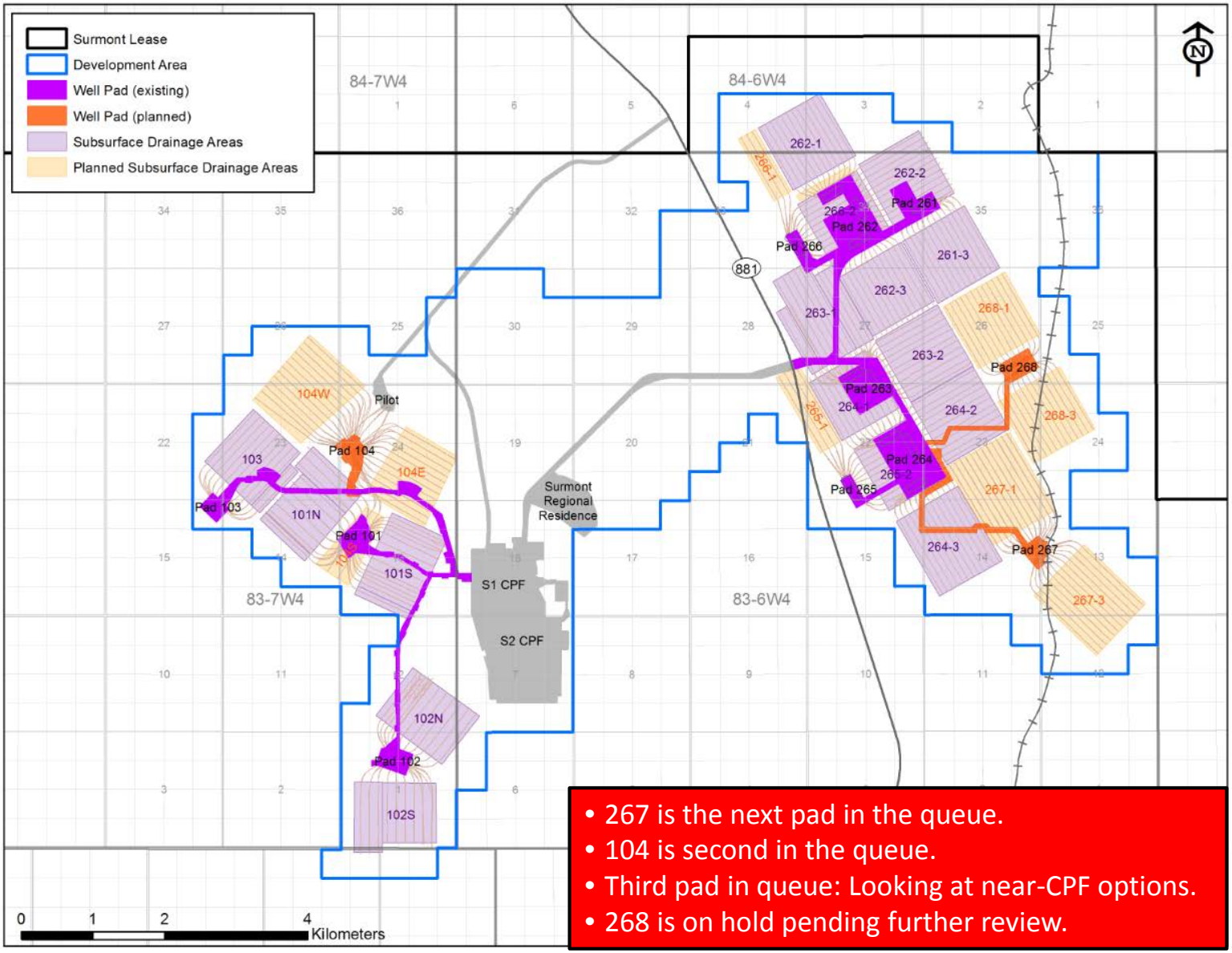
Phase 1:

- Pad 103 turn-around planned for 2018.
- Continued monitoring of sludge pond primary liner.
- Potential expansion of NCG co-injection pilot to Pad 101 in 2018.

Phase 2:

- Pad 264-1 turn-around planned for 2018.
- Continuous partial condensate blending operation planned to start in 2018.
- Design work on-going for modifications for 100% condensate blending through 2018, with planned construction in 2019.
- Full plant turn-around is in planning stage for 2019 execution.

Future Pad Developments



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