Suncor Firebag
2017 AER Performance Presentation
Commercial Scheme Approval No. 8870

May 9, 2017
Reporting Period: March 1, 2016 to February 28, 2017

Section 3.1.1 – Subsurface Issues Related to Resource Evaluation and Recovery

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- **Safety Moment**
- Introduction
- Geoscience
- Surface Heave and Caprock Integrity
- Drilling and Completions
- Artificial Lift
- Instrumentation in Wells
- 4D Seismic
- Scheme Performance
- Future Plans
- Compliance Commitments

Journey to Zero Fundamental Beliefs

Safety is a critical part of Suncor's culture – it's how we do business

Safety is everyone's responsibility and a leadership performance accountability

The safety and health of team members, the environment, communities and operations are our top priorities

No job is so urgent or routine that it can't be done safely – if we can't do it safely, we don't do it

Expectations for All Employees

- Be a leader in safety no matter what you job title is. Your family expects this
- Protect yourself and your coworkers from harm and speak up for safety
- Always follow procedures and if you aren't sure about a job, ask
- Be safety minded even if you have done a job hundreds of times and you think you are in a safe environment
- If you see a hazard, you are expected to report it if you can't immediately fix it yourself

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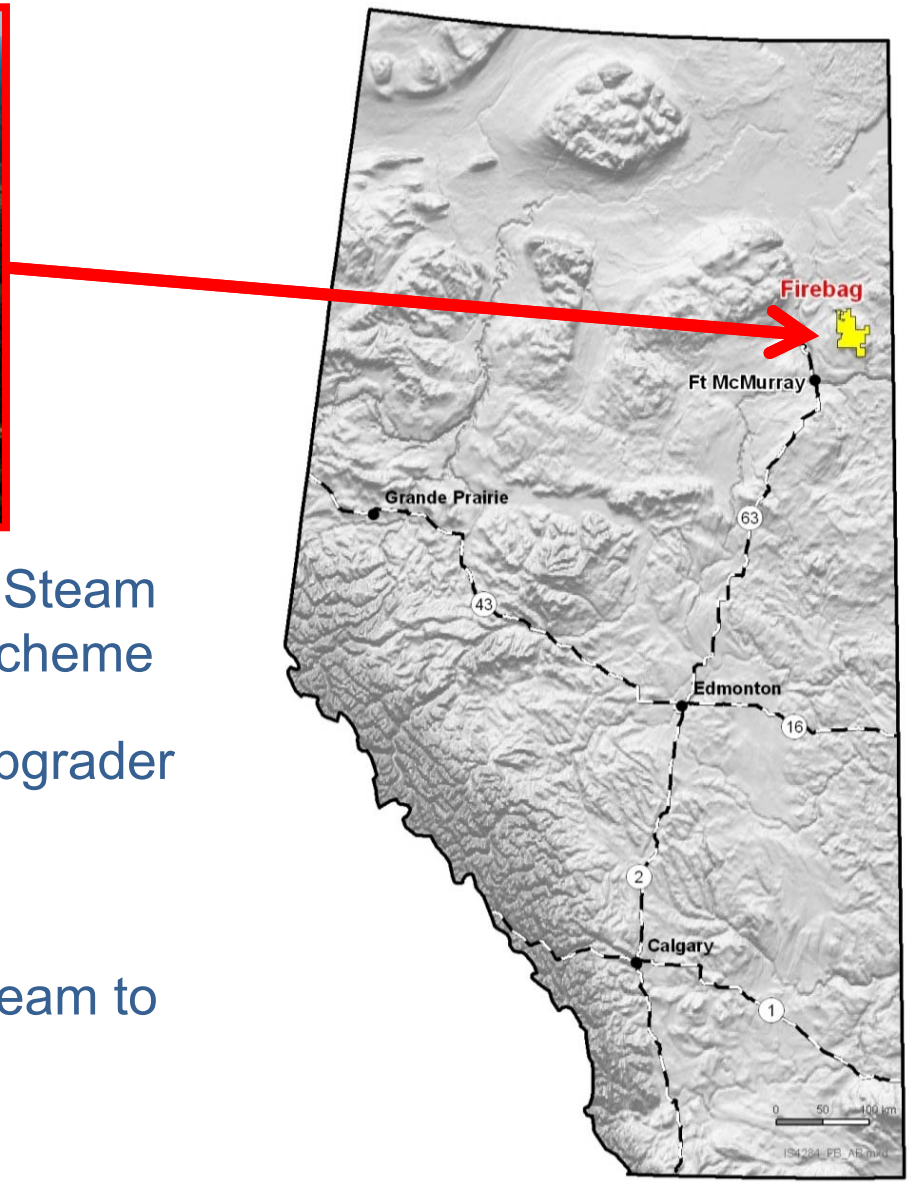
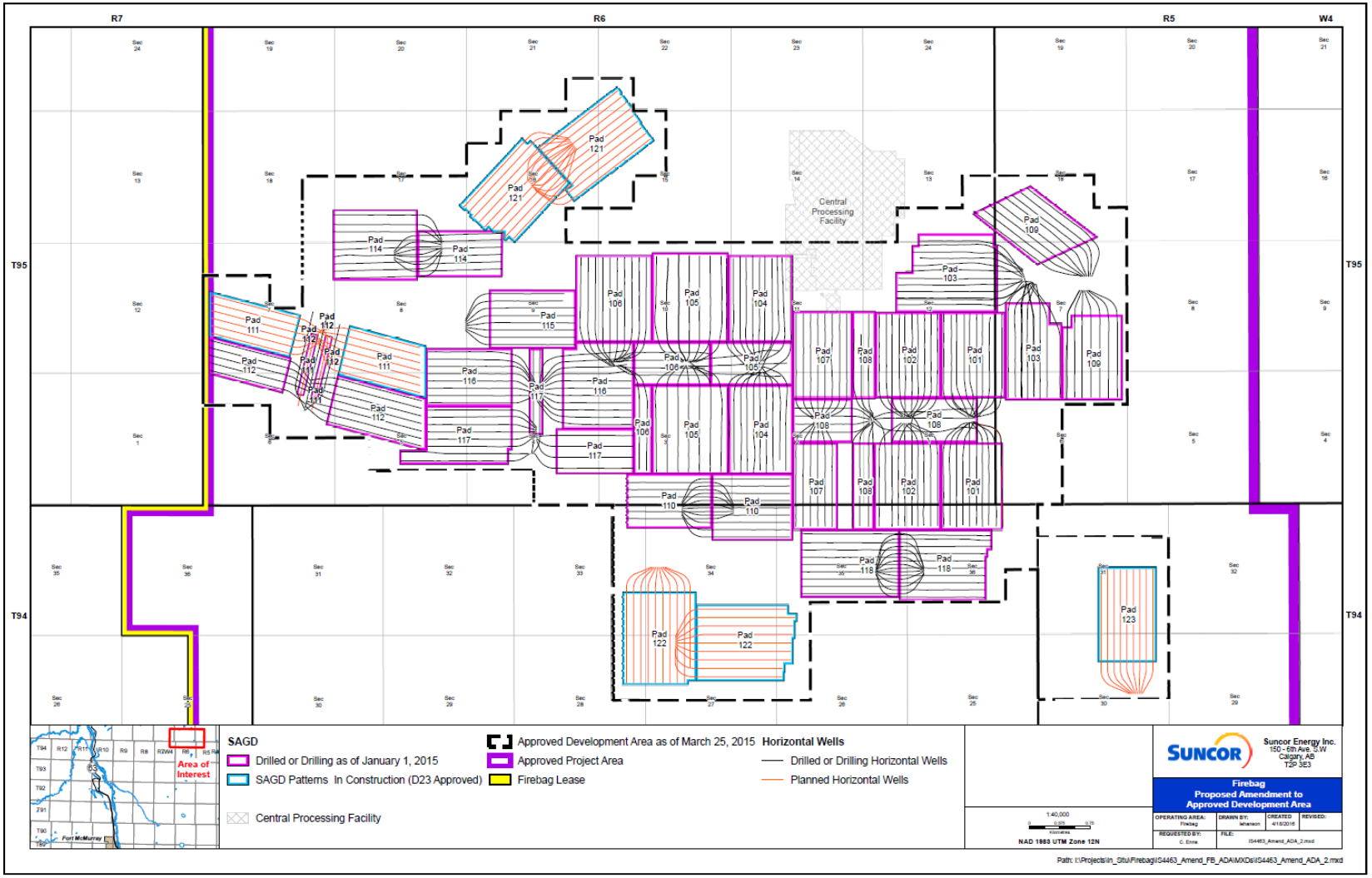
Firebag Project Overview



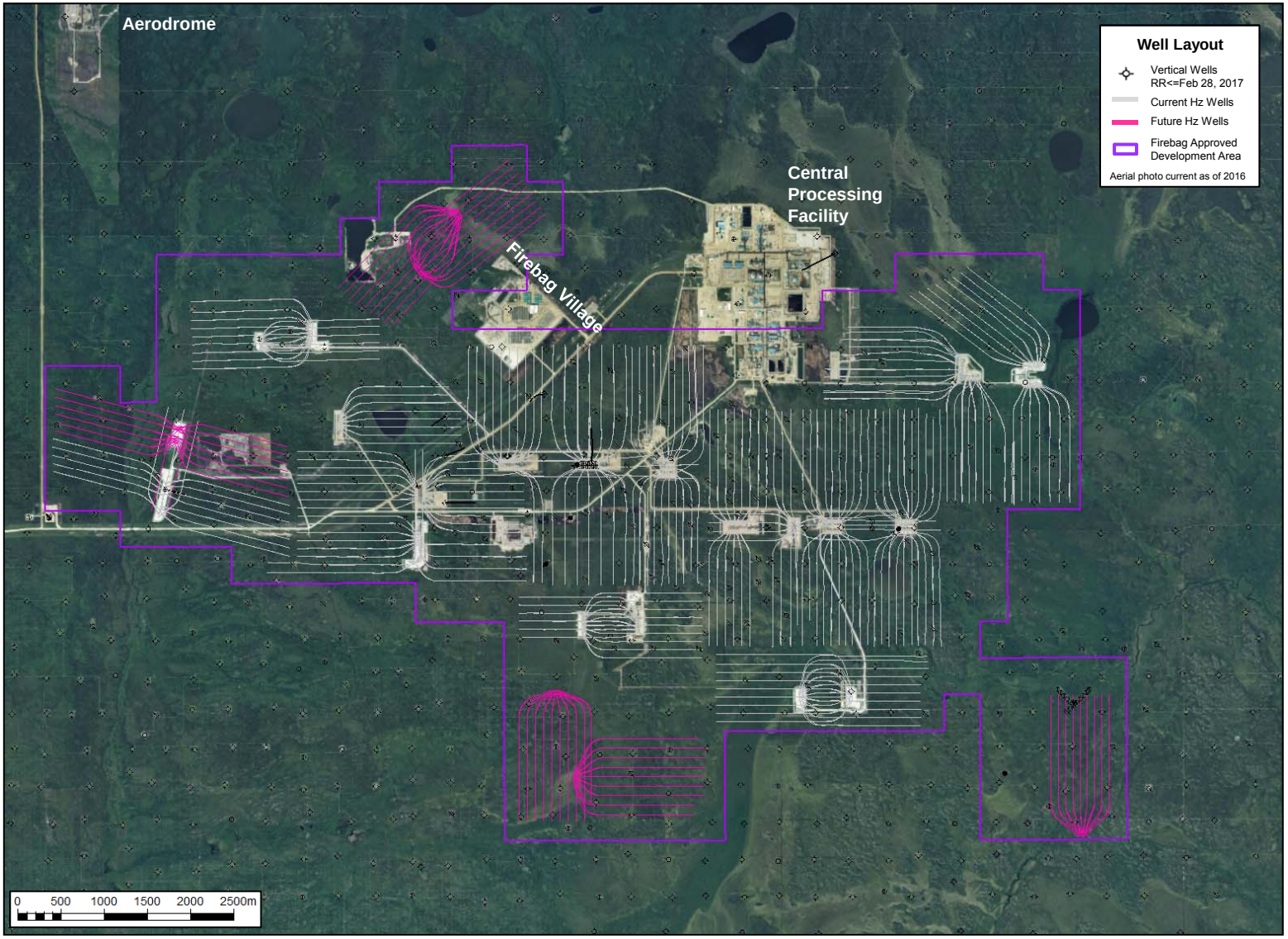
- The Firebag Project is a commercial Steam Assisted Gravity Drainage (SAGD) scheme
- Supplies bitumen to the Oil Sands Upgrader and sales to market
- Average production is 181,020 bbl/d (28,780 m^3/day) of bitumen with a Steam to Oil Ratio (SOR) of 2.64

AER Project & Approved Development Areas



Firebag Approval 8870 as of March 2017

Composite Aerial Photo of Firebag



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Firebag Stratigraphic Chart

GENERALIZED STRATIGRAPHY OF THE FIREBAG PROJECT
NORTHEAST ALBERTA, CANADA

ERATHEM	GROUP	FORMATION	MEMBER	SUB-MEMBER	DESCRIPTION	
CENOZOIC	Quaternary glacial, fluvial, and modern deposits				till, clay, sand, gravel, peat, and muskeg	
MESOZOIC	MANNVILLE	GRAND RAPIDS			mudstone >>> siltstone (lithic sand?)	CAPROCK
		CLEARWATER	upper Clearwater		shale, mudstone >>> siltstone	CAPROCK
			Wabiskaw	upper Wabiskaw	shale, mudstone, sand	CAPROCK
				lower Wabiskaw		RMZ*
		MCMURRAY	upper McMurray		sand, mudstone, IHS, intraclast breccia, lignite, and karst breccia	RESERVOIR
			middle McMurray			RESERVOIR
			lower McMurray	lower McMurray 3		RESERVOIR
				lower McMurray 2		RESERVOIR
				lower McMurray 1		RESERVOIR
	BEAVERHILL LAKE	WATERWAYS	Firebag		fossiliferous calcareous mudstone	

RMZ * : Reservoir Monitoring Zone

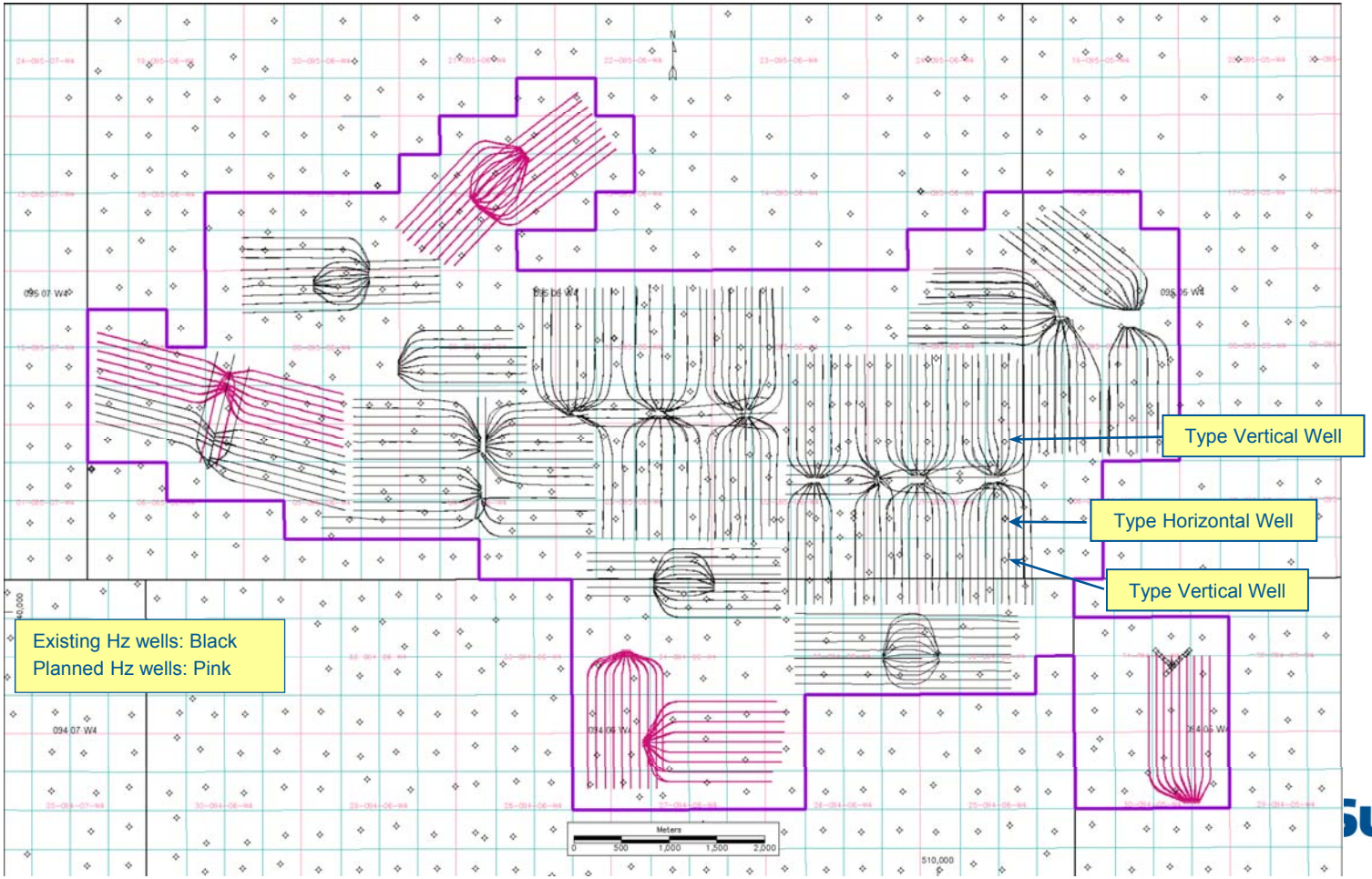
Type Well Location Map

Type Wells

- 1AA/01-01-095-06W4
- 1AA/16-01-095-06W4

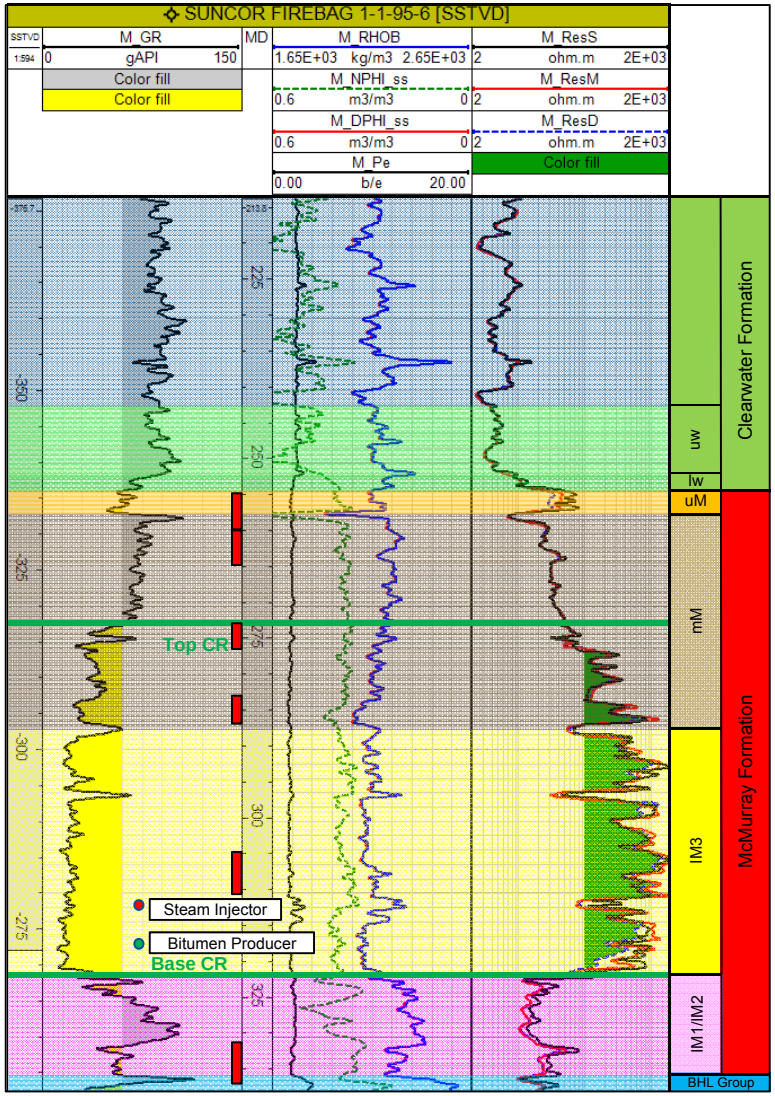
Type Horizontal Well

- Pad 101 Pair 7

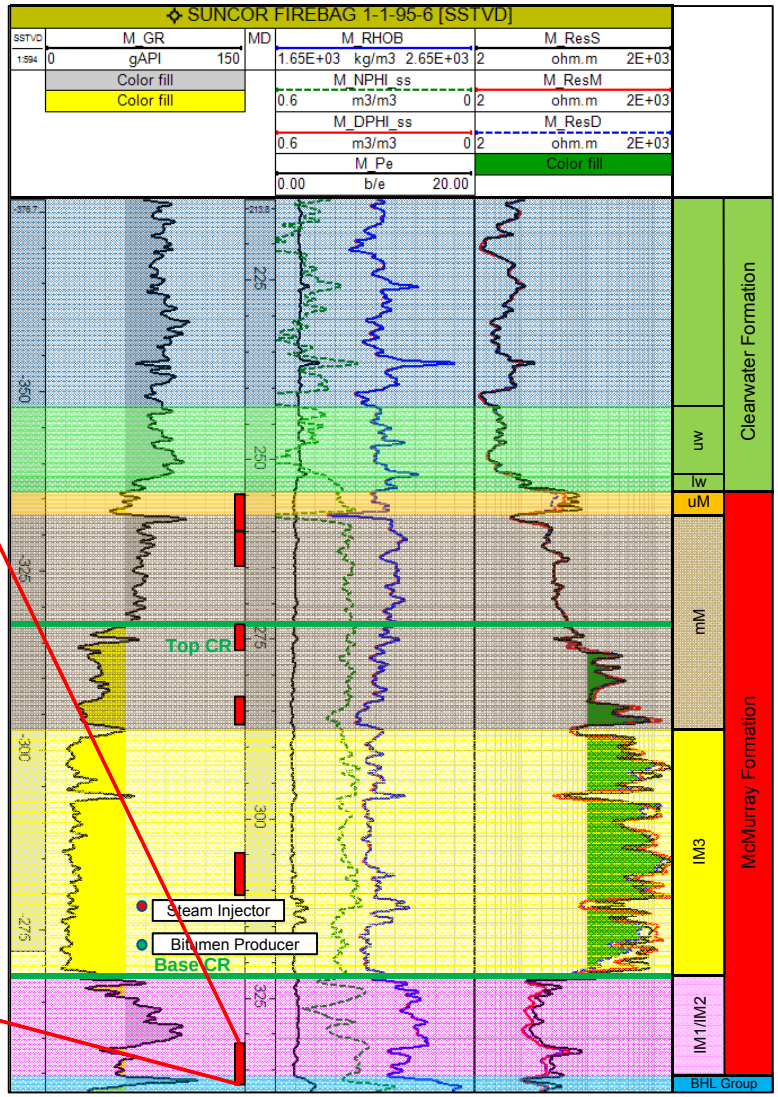


Firebag Type Well 1AA/01-01-095-06W4/00

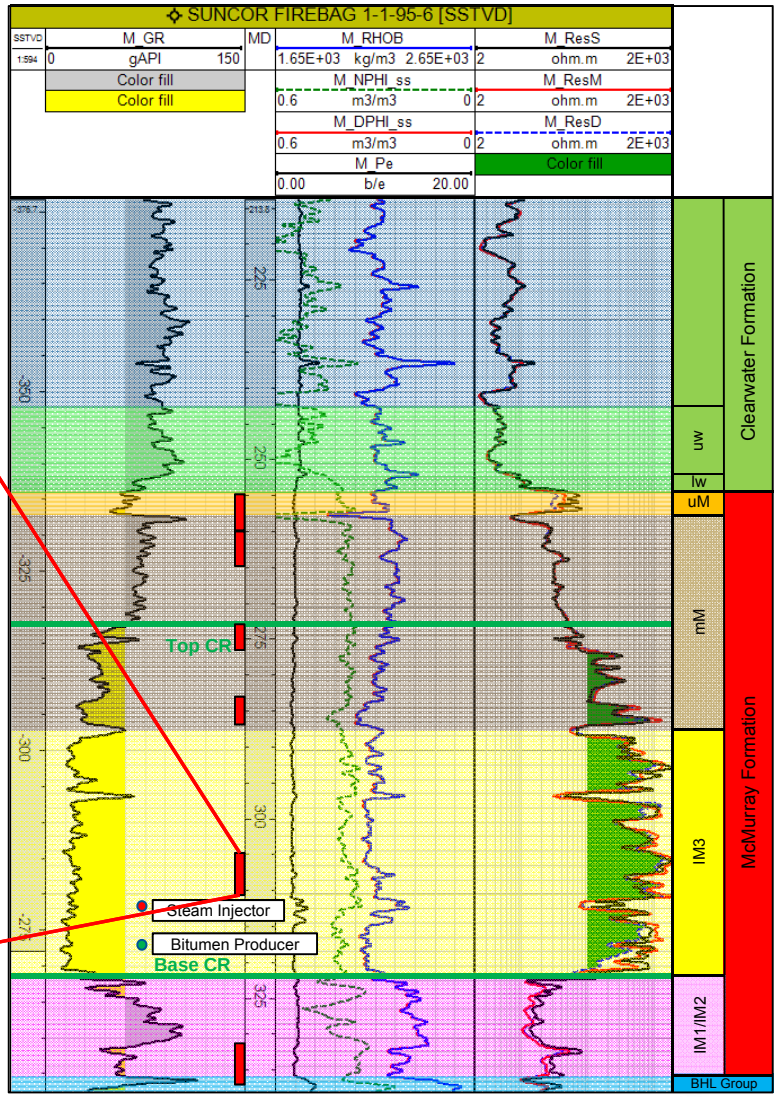
- McMurray Fm: 82.2 m
- upper McMurray: 3.2 m
- middle McMurray: 30.6 m
- lower McMurray 3: 34.4 m
- lower McMurray 2: 13.6 m
- lower McMurray 1: 0.4 m
- Continuous Reservoir (CR) zone:
  - CR thickness: 49.2 m
  - Core Porosity: 35.7%
  - Core Sw: 21.9%
  - Kh: 8-10 D
  - Kv: 4-5 D
- 45 m west of Pad 101 Pair 7



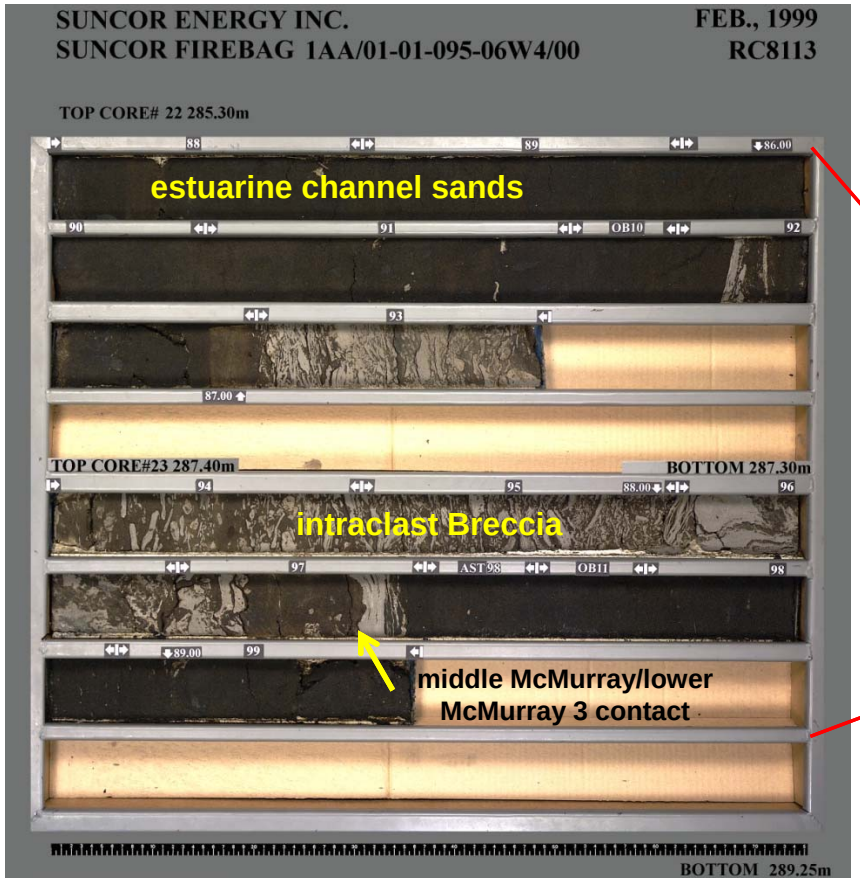
Lower McMurray 1 & 2 Units (Non Reservoir)

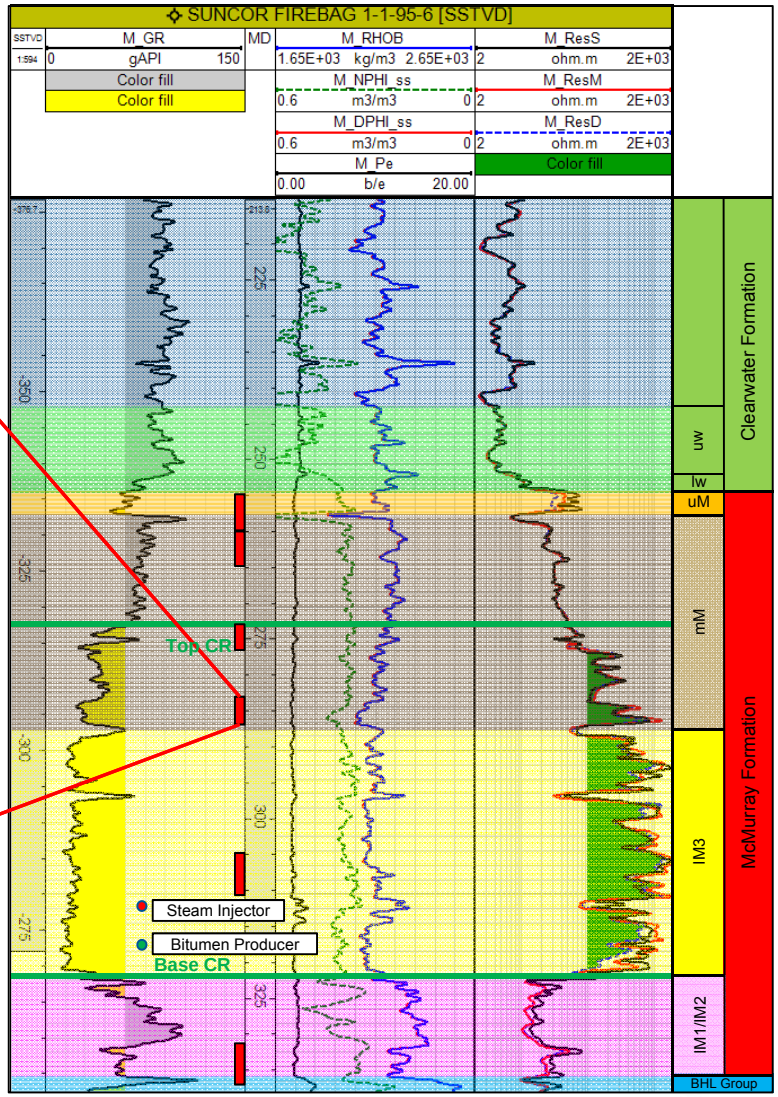


Lower McMurray 3 Oil Sands Reservoir

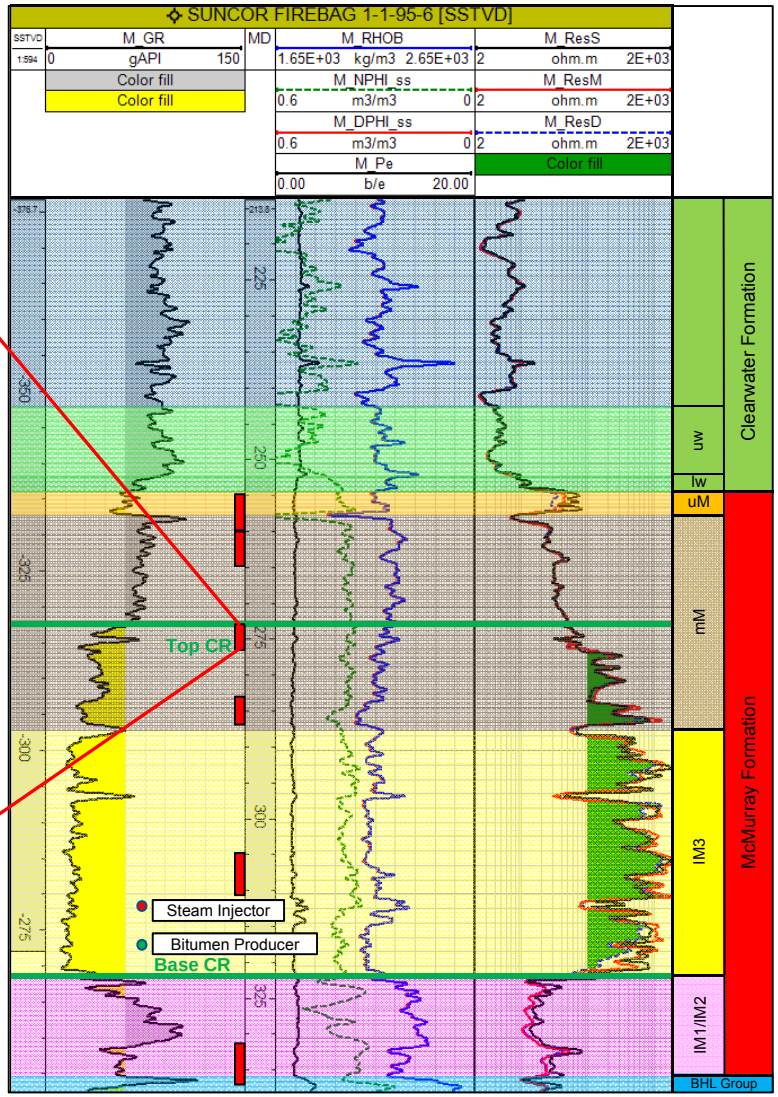


Middle McMurray - Intraclast Breccia





Middle McMurray Estuarine Channels and Associated Point Bars



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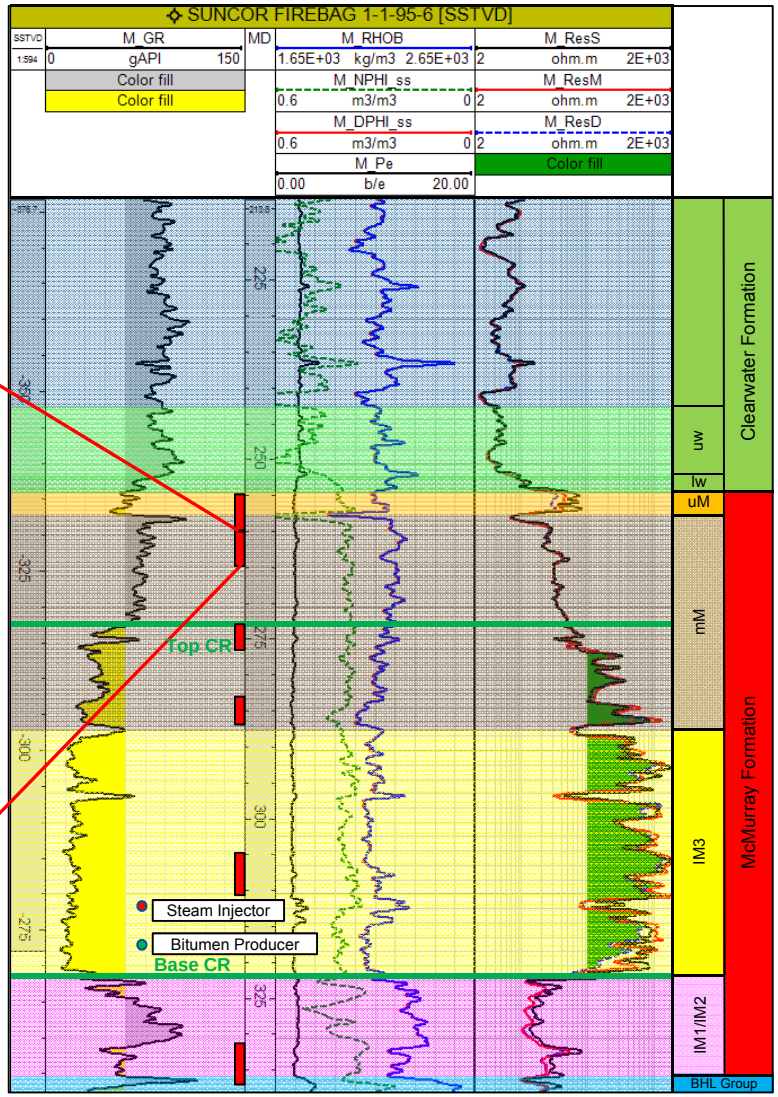
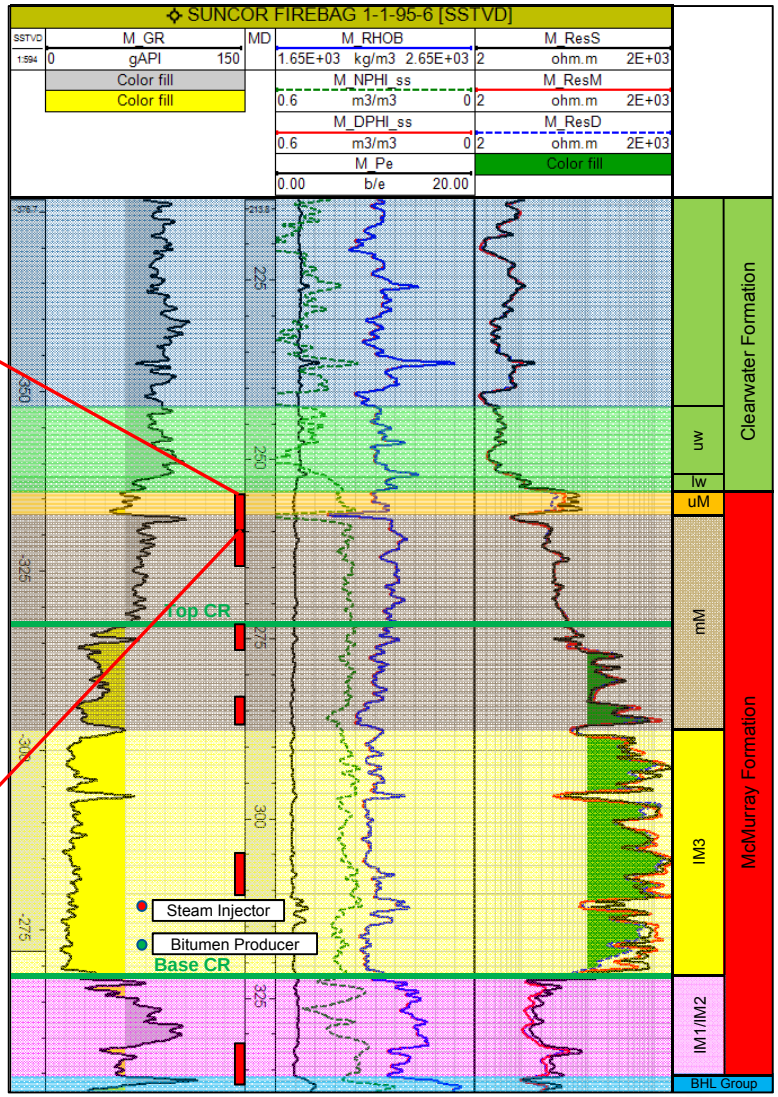
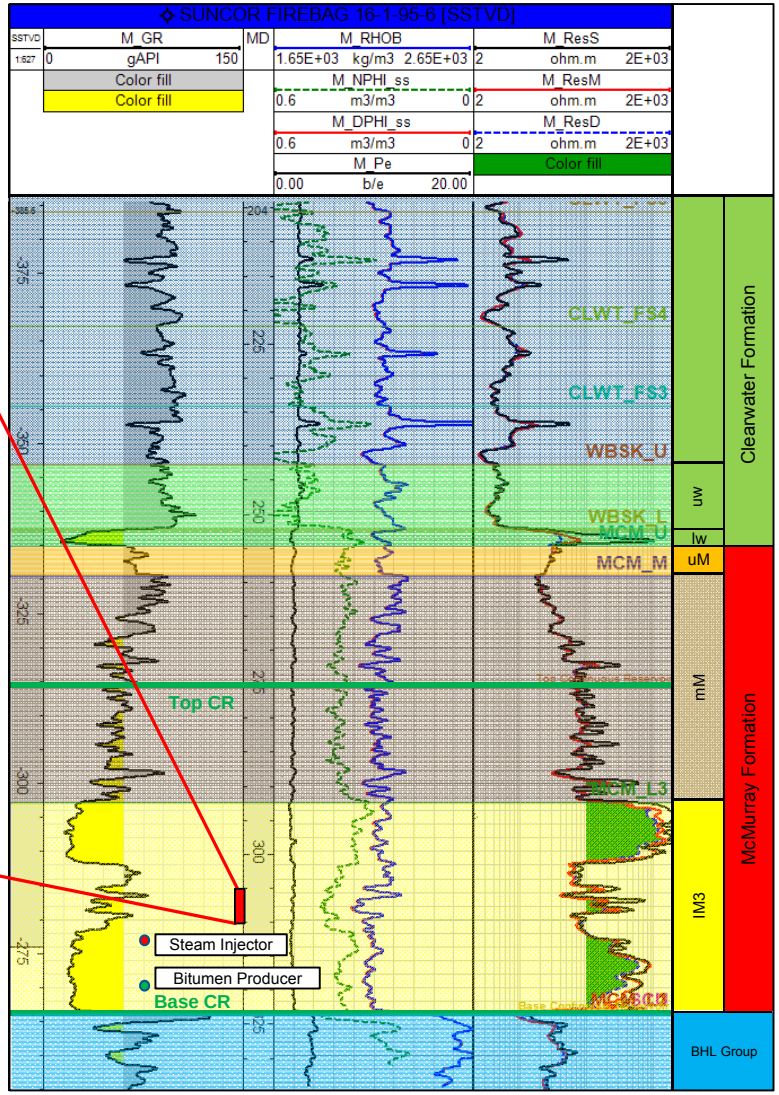


Middle McMurray and Upper McMurray Units

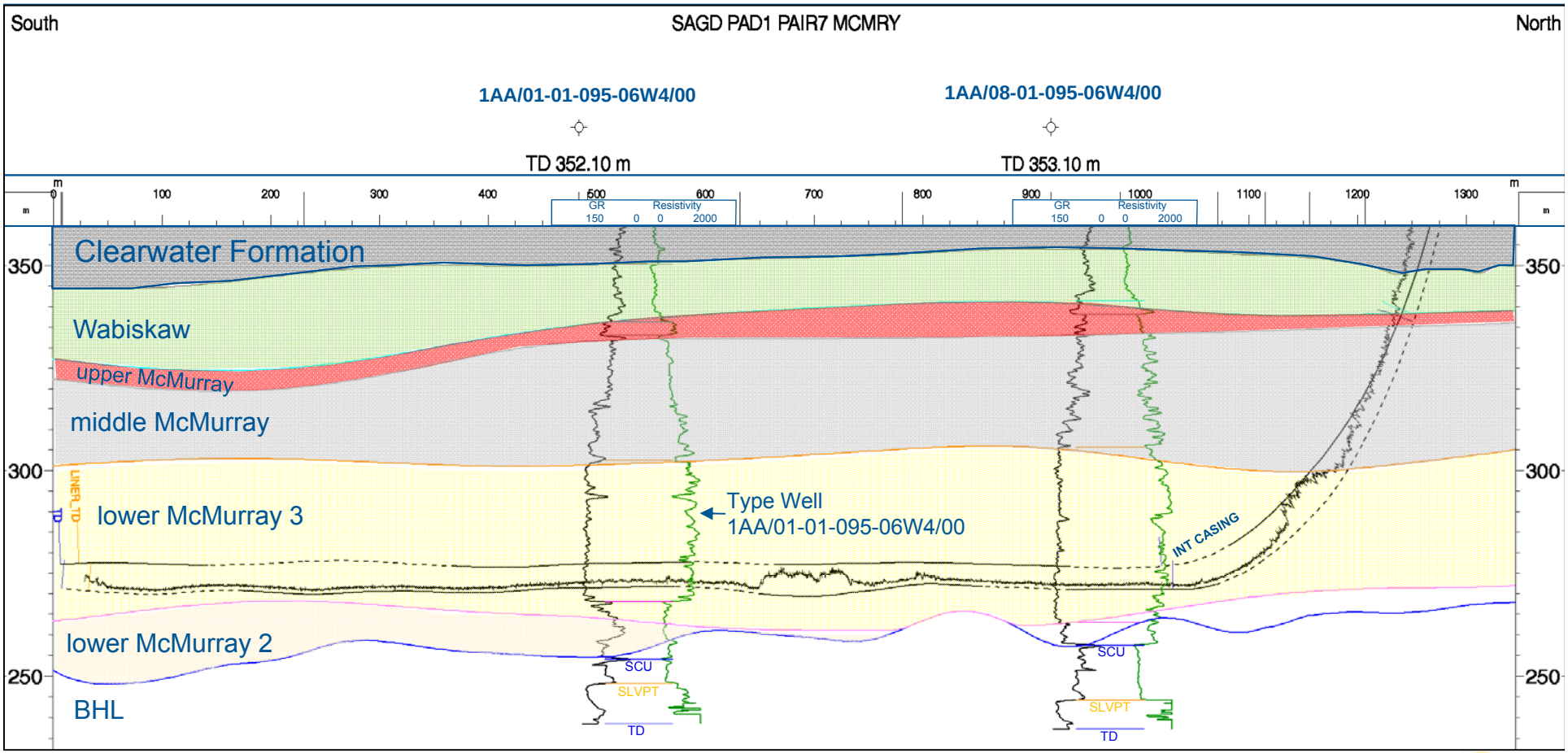


Firebag Type Well 1AA/16-01-095-06W4/00



- Lower McMurray 3 floodplain mud
- Reservoir quality within McMurray varies and can present challenges

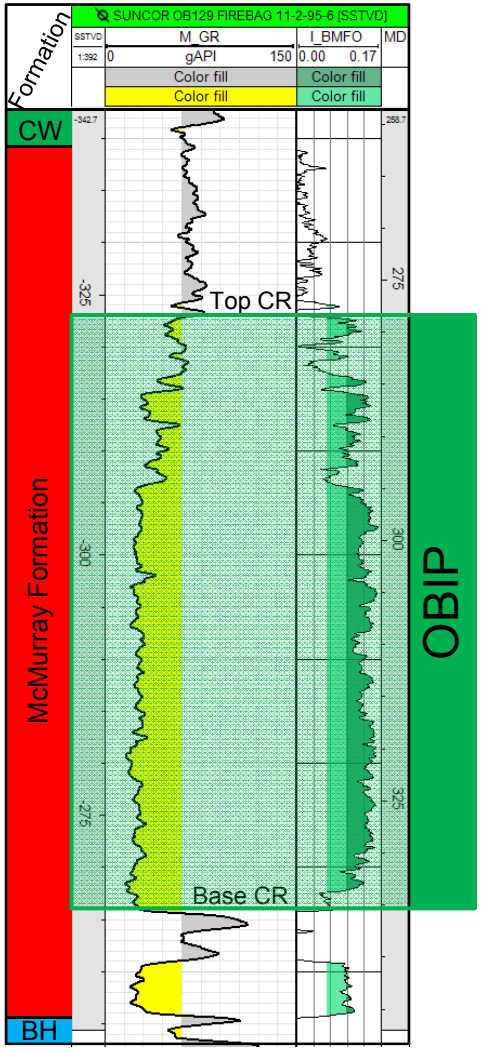
Pad 101 Pair 7 Structural Cross Section



*Coreholes are projected onto cross section

OBIP Methodology

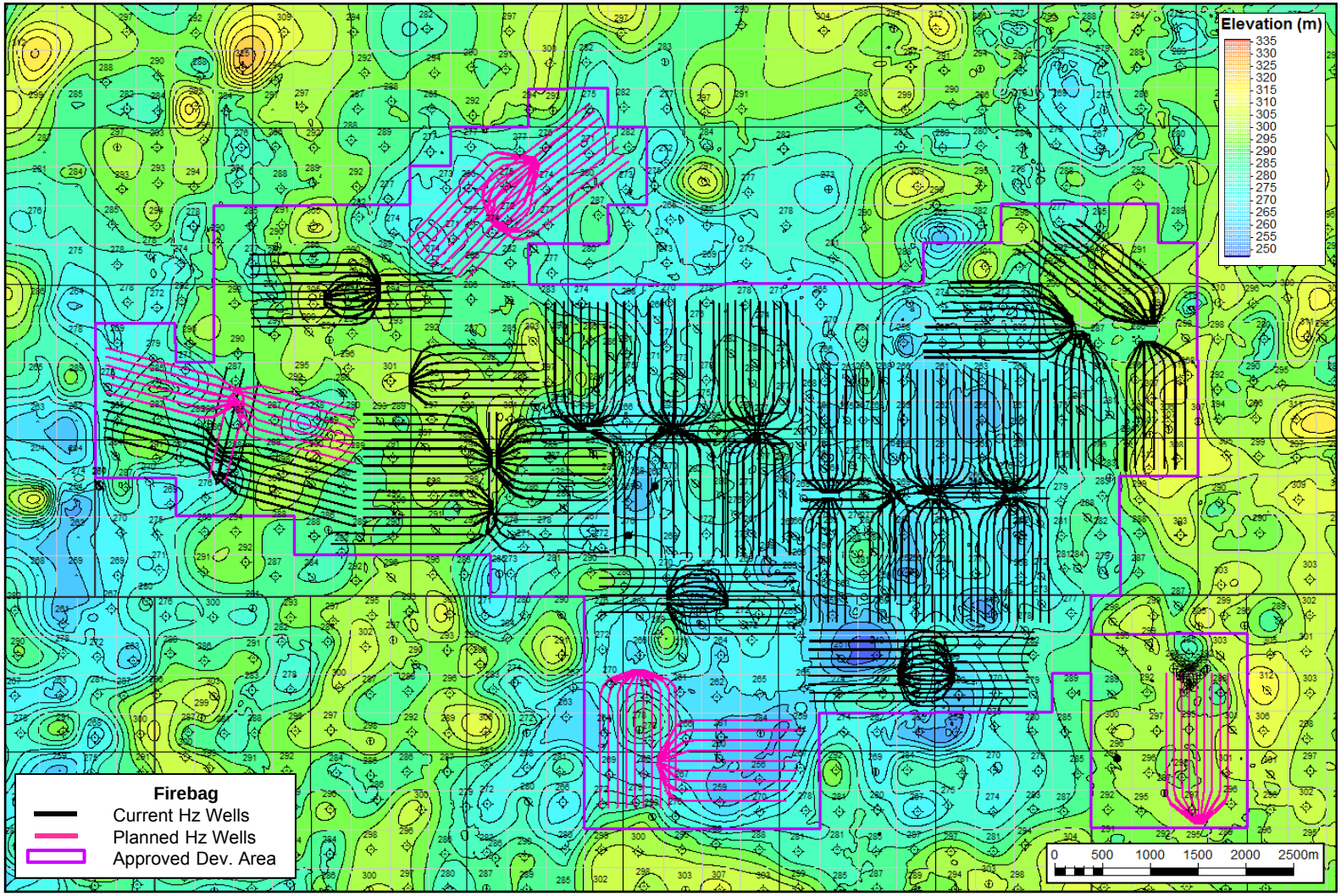
- OBIP is defined in each well by the top and base of Continuous Reservoir. It is selected at the base of a continuous sand unit either developed or most likely to be developed.
  - Continuous Reservoir base: lowest portion of the continuous reservoir sandstone with BMFO cut off of 6%, <3 m of >50% mud/breccia in the lower portion.
  - Continuous Reservoir top: 2 m of mudstone, no BMFO or porosity cut offs.
- Upper Lean, Middle Lean, Gas Zones that are in pressure communication with the continuous reservoir are included, with no thickness cutoffs.
- Observation wells and 4D seismic will take precedence over the geology pick.



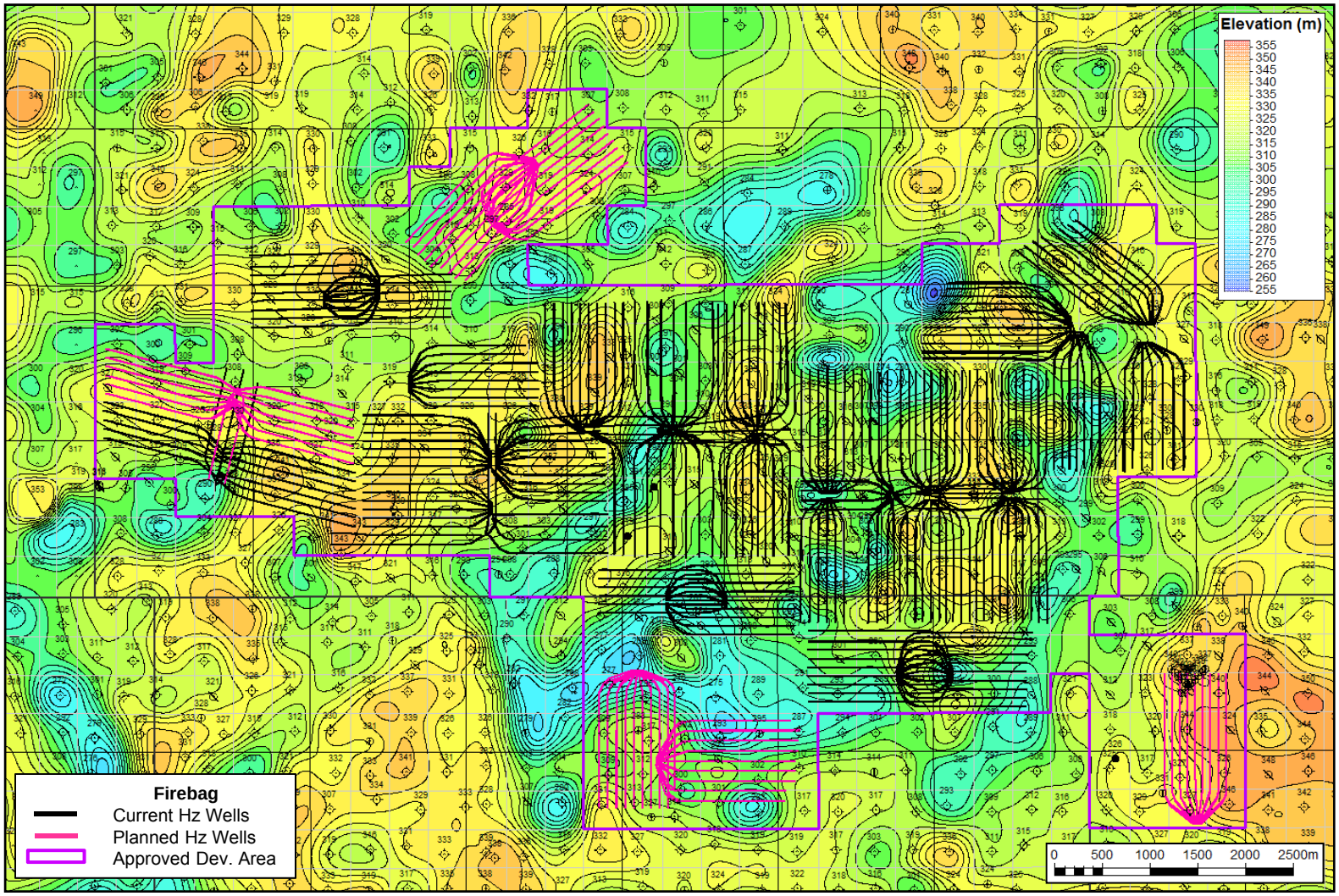
CW: Clearwater Formation
BH: Beaverhill Lake Group

OBIP: Original Bitumen in Place

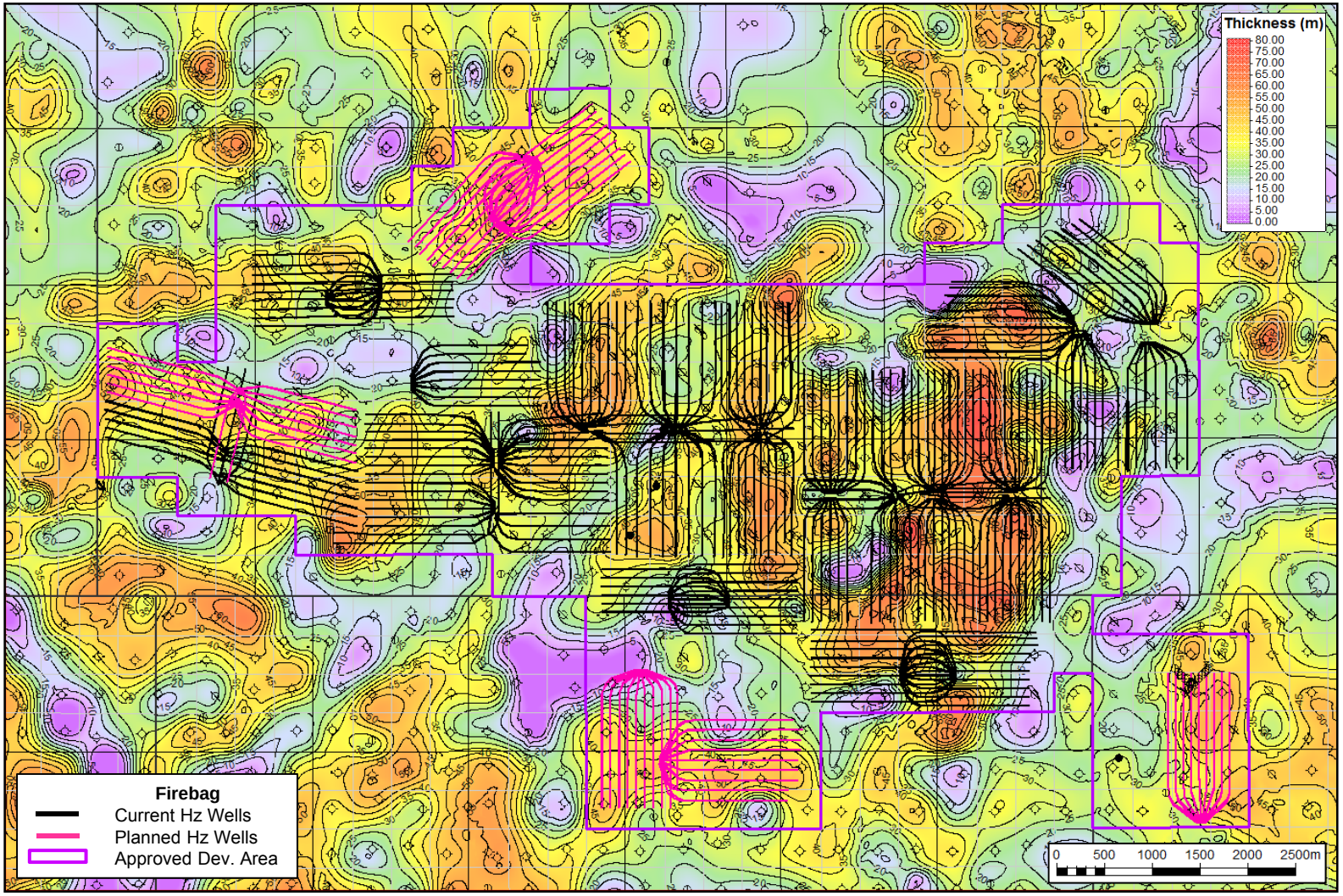
Structure Map of Base Continuous Reservoir



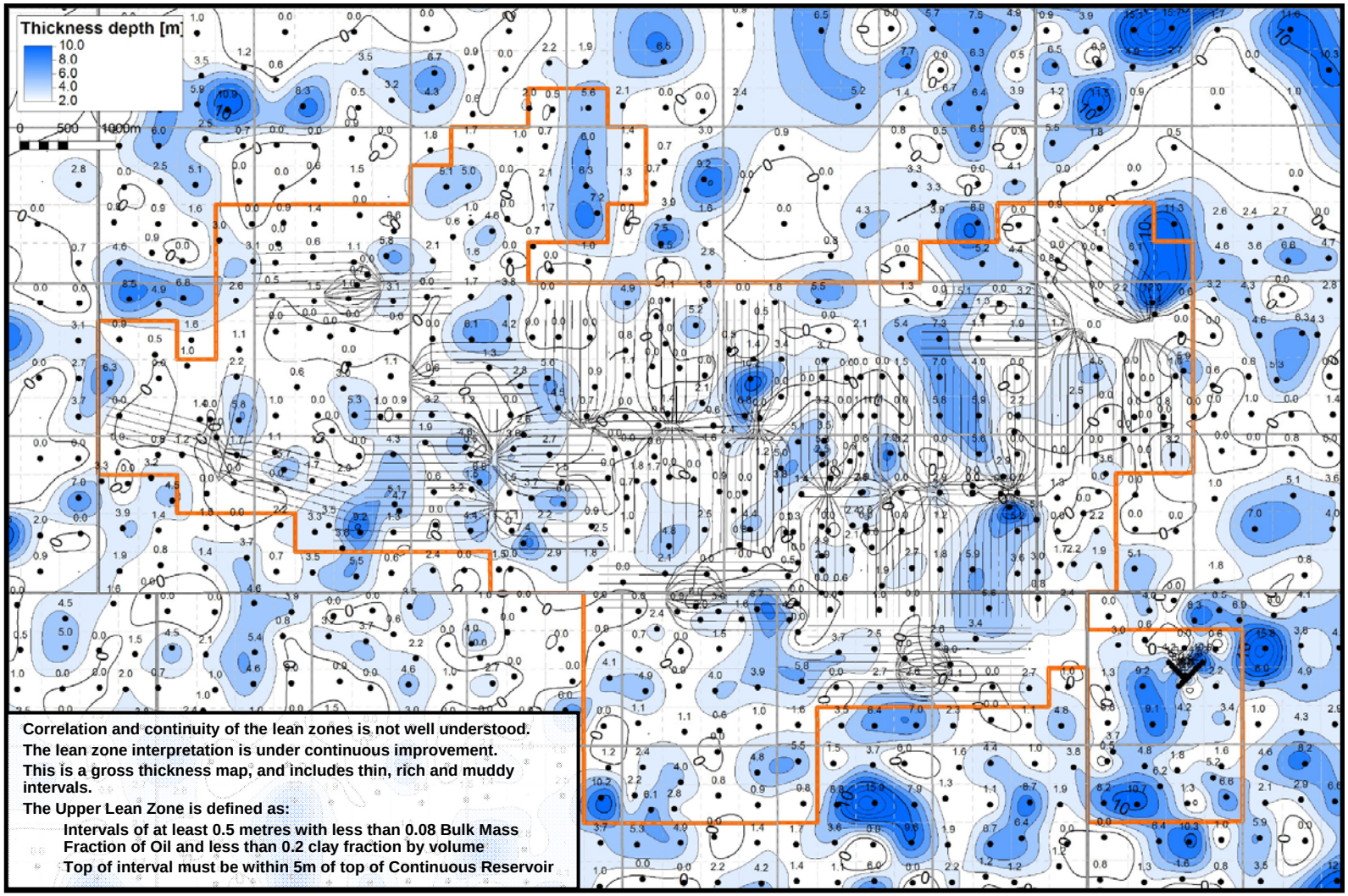
Structure Map of Top Continuous Reservoir



Isopach Map of Continuous Reservoir



Upper Lean Zone – Gross Thickness



Correlation and continuity of the lean zones is not well understood.

The lean zone interpretation is under continuous improvement.

This is a gross thickness map, and includes thin, rich and muddy intervals.

The Upper Lean Zone is defined as:

- Intervals of at least 0.5 metres with less than 0.08 Bulk Mass Fraction of Oil and less than 0.2 clay fraction by volume
- Top of interval must be within 5m of top of Continuous Reservoir

Original Bitumen in Place (OBIP) & Average Reservoir Properties

	Area (m^2)	Continous Reservoir Thickness (m)	Continous Reservoir Volume (e^6m^3)	Porosity	Oil Saturation	Formation Volume Factor	OBIP[1] (e^6m^3)	OBIP[1] (MMbbl)
SAGD Pad 101	1,808,410	50.9	92.1	0.32	0.78	1	23.0	144.9
SAGD Pad 102	1,607,250	50.4	81.1	0.32	0.75	1	19.4	122.2
SAGD Pad 103	1,960,780	36.2	71.0	0.32	0.78	1	17.6	110.6
SAGD Pad 104	1,834,350	44.1	80.8	0.32	0.77	1	20.1	126.3
SAGD Pad 105	2,625,740	35.3	92.6	0.33	0.79	1	24.0	150.8
SAGD Pad 106	1,684,110	36.4	61.3	0.33	0.81	1	16.1	101.2
SAGD Pad 107	1,381,100	38.3	52.9	0.32	0.74	1	12.5	78.8
SAGD Pad 108	1,631,420	42.5	69.4	0.32	0.75	1	17.0	106.6
SAGD Pad 109	1,485,780	22.8	33.9	0.33	0.76	1	8.5	53.6
SAGD Pad 110	1,449,000	29.1	42.2	0.33	0.72	1	9.8	61.5
SAGD Pad 111	1,407,442	35.3	49.7	0.33	0.79	1	12.8	80.4
SAGD Pad 112	1,453,330	38.6	56.1	0.33	0.78	1	14.6	91.6
SAGD Pad 114	1,468,800	33.9	49.8	0.32	0.77	1	12.4	77.8
SAGD Pad 115	779,670	28.5	22.2	0.33	0.74	1	5.3	33.6
SAGD Pad 116	1,660,640	39.2	65.2	0.33	0.79	1	16.7	105.3
SAGD Pad 117	1,573,170	33.3	52.4	0.32	0.74	1	12.5	78.6
SAGD Pad 118	2,027,660	37.3	75.5	0.31	0.76	1	18.0	113.3
SAGD Pad 121	1,894,950	41.2	78.0	0.32	0.71	1	18.0	113.5
SAGD Pad 122	2,160,572	25.9	78.0	0.23	0.70	1	17.0	107.2
SAGD Pad 123	848,821	43.2	36.7	0.32	0.75	1	8.8	55.3
SAGD TOTAL	**32,742,995**	**37.89**	**1240.7**	**0.32**	**0.76**	**1**	**304.2**	**1913.2**
Firebag Approved Project Area	**194,039,420**	**28.8**	**5,595**	**0.32**	**0.72**	**1.0**	**1,277.8**	**8,036.3**

[1]OBIP: Original Bitumen in Place

Average Reservoir Properties

- Average reservoir properties for the operating portion of the scheme (Pads ***101-108***, ***108N***, Pads ***109-110*** and Pads ***115 - 117***)
  - Initial reservoir pressure: 800kPa
  - Initial reservoir temperature: 8°C
  - Average continuous reservoir= 38.4 m
  - Average porosity = 0.32
  - Average oil saturation = 0.77
  - Effective horizontal permeability: 3 to 4 D
  - Effective vertical permeability: 2 to 3 D
  - Viscosity: ~ 11cp @ 215°C

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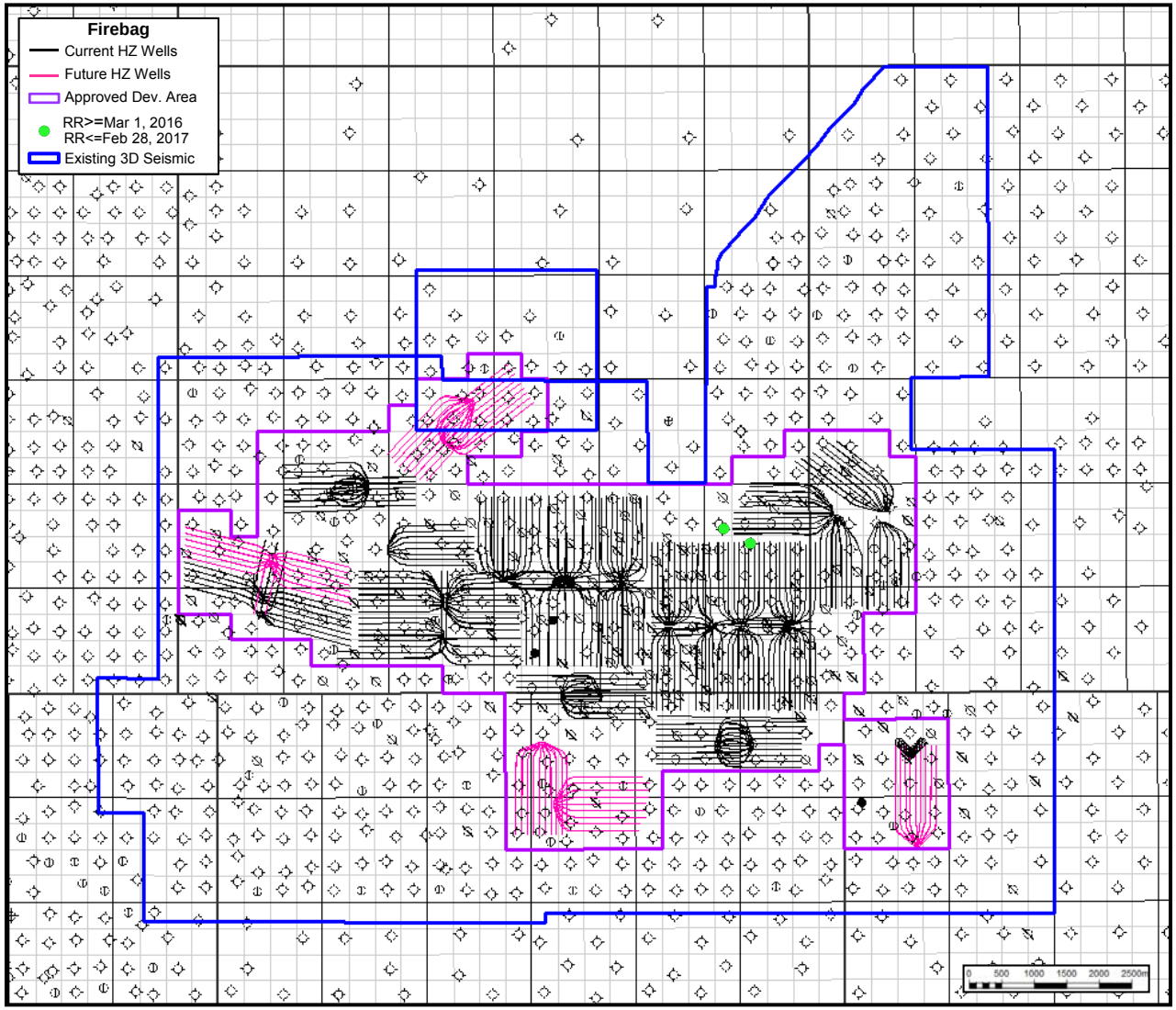
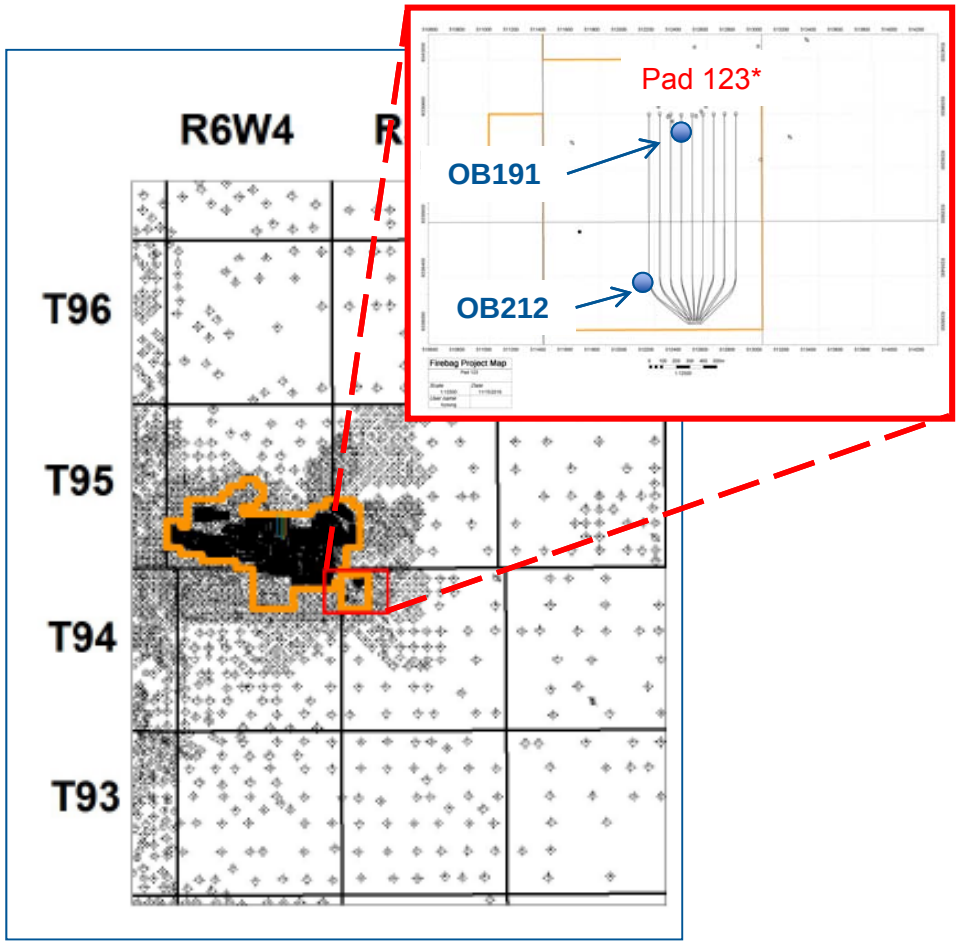
2016/2017 Winter Delineation Program



- Existing wells in black
- No 2015-2016 Drilling Program (RR Mar. 01, 2015 to Feb. 29, 2016)
- New wells 2016-2107 Program (RR Mar. 01, 2015 to Feb. 28, 2016) in green

2015/2016 Winter Program Testing in OB212 and OB191



Results and Learnings:

- OB212
  - PLT test was completed and show higher injectivity of intervals with low mud content and high water saturation
  - New design of PCP pump was successfully tested
  - Flow and build-up test was completed and demonstrated water production capability at OB212 location
- OB191
  - Successfully pressure tested open hole packers
  - Tested disposal capability in two zones
  - Very low injectivity in upper zone (Collapsed Matrix Supported Breccia Zone)
  - Upper Keg River Formation has shown high potential to be used for disposal
  - Permeability mainly controlled with fracture system in Upper Keg River Formation

* Pad 123 trajectories as per approved D23 (planned; not drilled yet)

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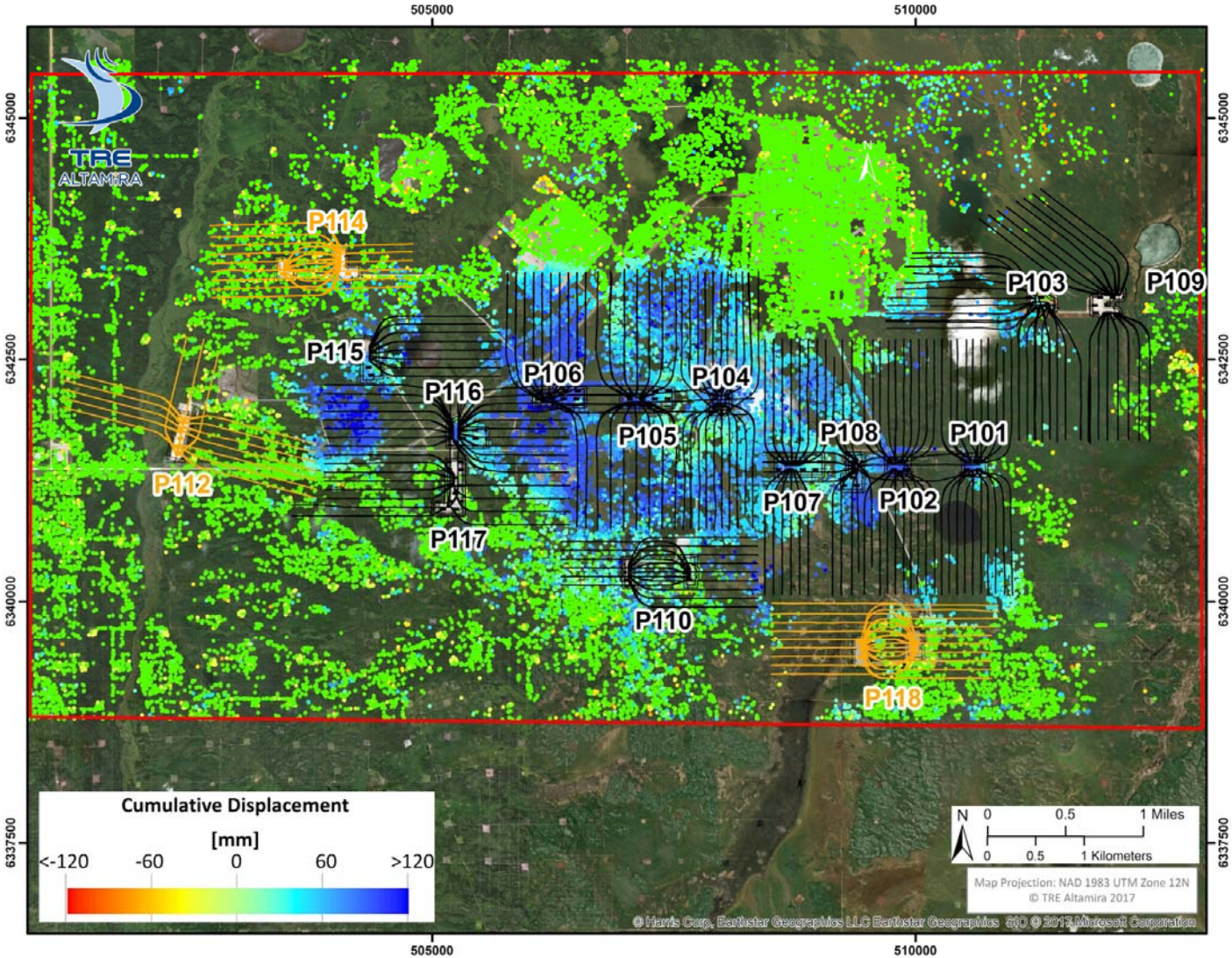
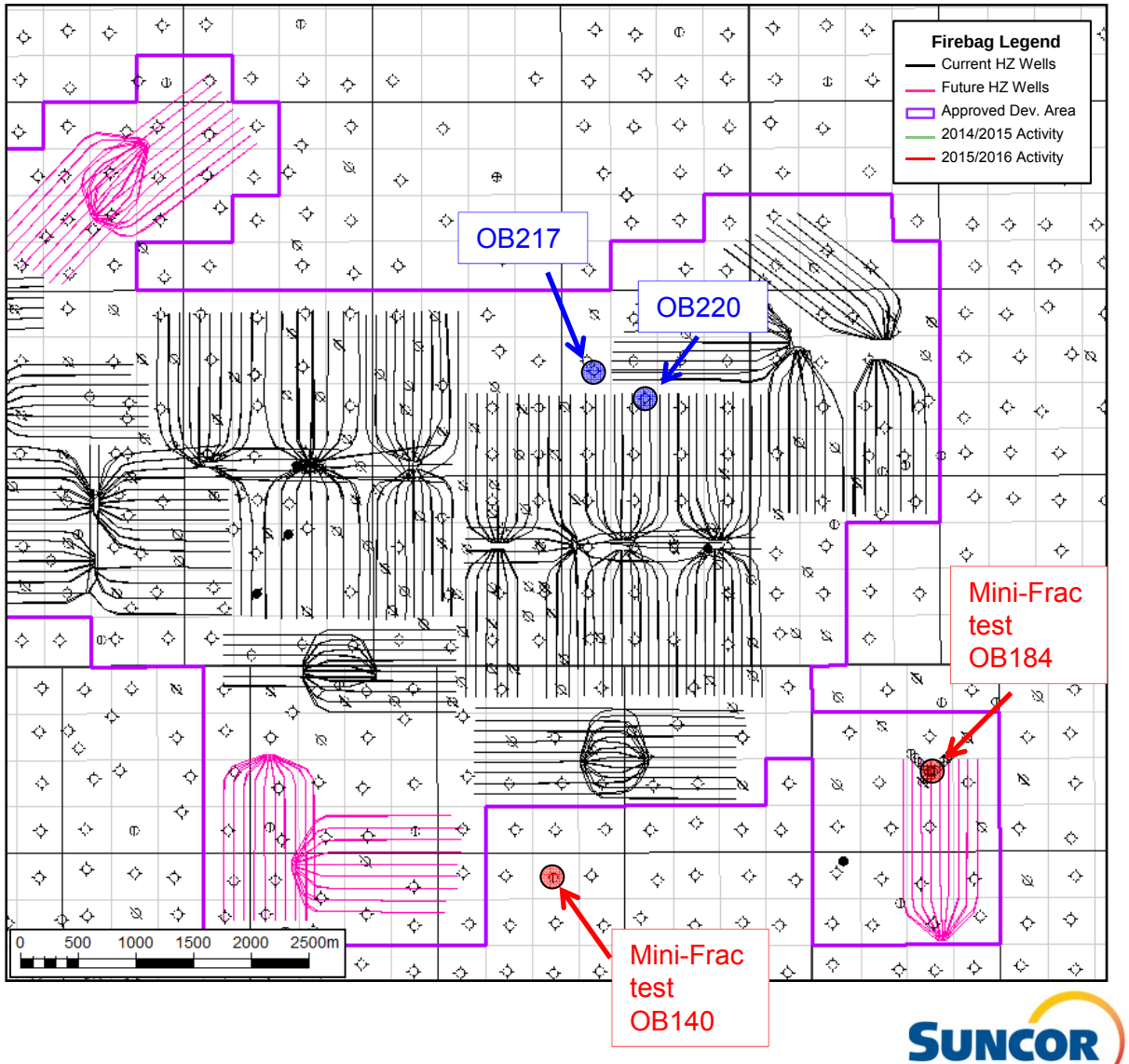
InSAR Cumulative Heave May 2013 to October 2016



- Maximum heave of 188 mm observed at Pad 106 / Pad 116
- Heave data is used to:
  - Calibrate geomechanical models
  - Monitor subsurface safety (flag area which look anomalous)

Caprock – Geological Activity

- **2015/16 Summary**
  - No new observation wells
  - Mini-Frac test at OB 140
  - No new high core collection
- **2016/2017 Summary**
  - OB 217 and OB 220
  - Mini-Frac test on OB 184



Caprock Integrity Assurance

- Mini-Frac in 2017 to provide coverage for Pad 123
  - OB184 (100/07-31-094-05W4/0) tested the Wabiskaw/Clearwater
  - Data were analyzed based on SPE Paper 157843, and consistent with SPE Gulf Coast Section Completions & Production Study Group Luncheon: Re-examining DFIT Interpretation Methods
- Suncor Geomechanical Modeling
  - Geomechanical simulations are run to assess all new pad startups
- All of these activities confirm that operating at the approved MOP does not impact Firebag Caprock Integrity

Reservoir Fracture Closure Gradients 2017

Date	Well	Well Alias	TVD Perforated Interval (mKB)	Target	Minimum Stress (kPaa)	Fracture Closure Gradient (kPag/mGL)
15-Mar-12	01-16-095-06W4	OB134	297-298	lower McMurray 3 sand	5238.9	17.6
17-Mar-12	09-09-095-06W4	OB135	263-264	middle McMurray sand	5106.1	19.3
13-Mar-12	11-10-095-06W4	OB136	268-269	middle McMurray sand	4835.6	18.0
23-Feb-14	16-07-095-05W4	OB205	273-274	lower McMurray 3 sand	4319.7	15.7
11-Feb-15	05-07-095-06W4	OB147	255-258	middle McMurray sand	3868.3	15.1
10-Feb-16	15-26-094-06W4	OB140	296-299	middle McMurray sand	6171.9	20.6
16-Mar-12	01-16-095-06W4	OB134	277-278	middle McMurray mudstone	5398.7	19.4
18-Mar-12	09-09-095-06W4	OB135	247.5-248.5	middle McMurray mudstone	4020.2	16.1
13-Mar-12	11-10-095-06W4	OB136	257-258	middle McMurray mudstone	4910.0	19.0
24-Feb-14	16-07-095-05W4	OB205	247-248	middle McMurray IHS	4407.6	17.7
12-Feb-15	05-07-095-06W4	OB147	227-228	middle McMurray mudstone	4111.5	18.0
10-Feb-16	15-26-094-06W4	OB140	276-277	middle McMurray mudstone	4731.0	16.9
16-Mar-12	01-16-095-06W4	OB134	253.5-254.5	Wabiskaw/lower Clearwater	5482.5	21.6
18-Mar-12	09-09-095-06W4	OB135	231-232	Wabiskaw/lower Clearwater	5060.2	21.9
14-Mar-12	11-10-095-06W4	OB136	238-239	Wabiskaw/lower Clearwater	4532.7	19.0
5-Mar-13	01-09-095-06W4	OB182	232.5-233.5	Wabiskaw/lower Clearwater	5237.2	22.5
25-Feb-14	16-07-095-05W4	OB205	225.5-226.5	Wabiskaw/lower Clearwater	4952.2	22.0
12-Feb-15	05-07-095-06W4	OB147	209.5-210.5	Wabiskaw/lower Clearwater	4679.0	22.3
11-Feb-16	15-26-094-06W4	OB140	250.5-251.5	Wabiskaw/lower Clearwater	5434.6	22.3
16-Feb-17	07-31-094-05W4	OB184	225.5-226.5	Wabiskaw/lower Clearwater	4915.9	22.2

- No change recommended to currently approved injection pressures:
  - 4,040 kPag Startup MOP based on an 80% S.F. overburden based closure pressure
  - 3,570 kPag MOP during production phase

Pressure Monitoring

- Surface injection pressure is limited to approved overburden based MOP during startup and production phase
- All existing injection wells are set up to monitor downhole pressure
  - Some wells have thermocouple monitoring temperatures along the horizontal for startup
- Production wells capable of periodically monitoring pressure via blanket gas during startup period

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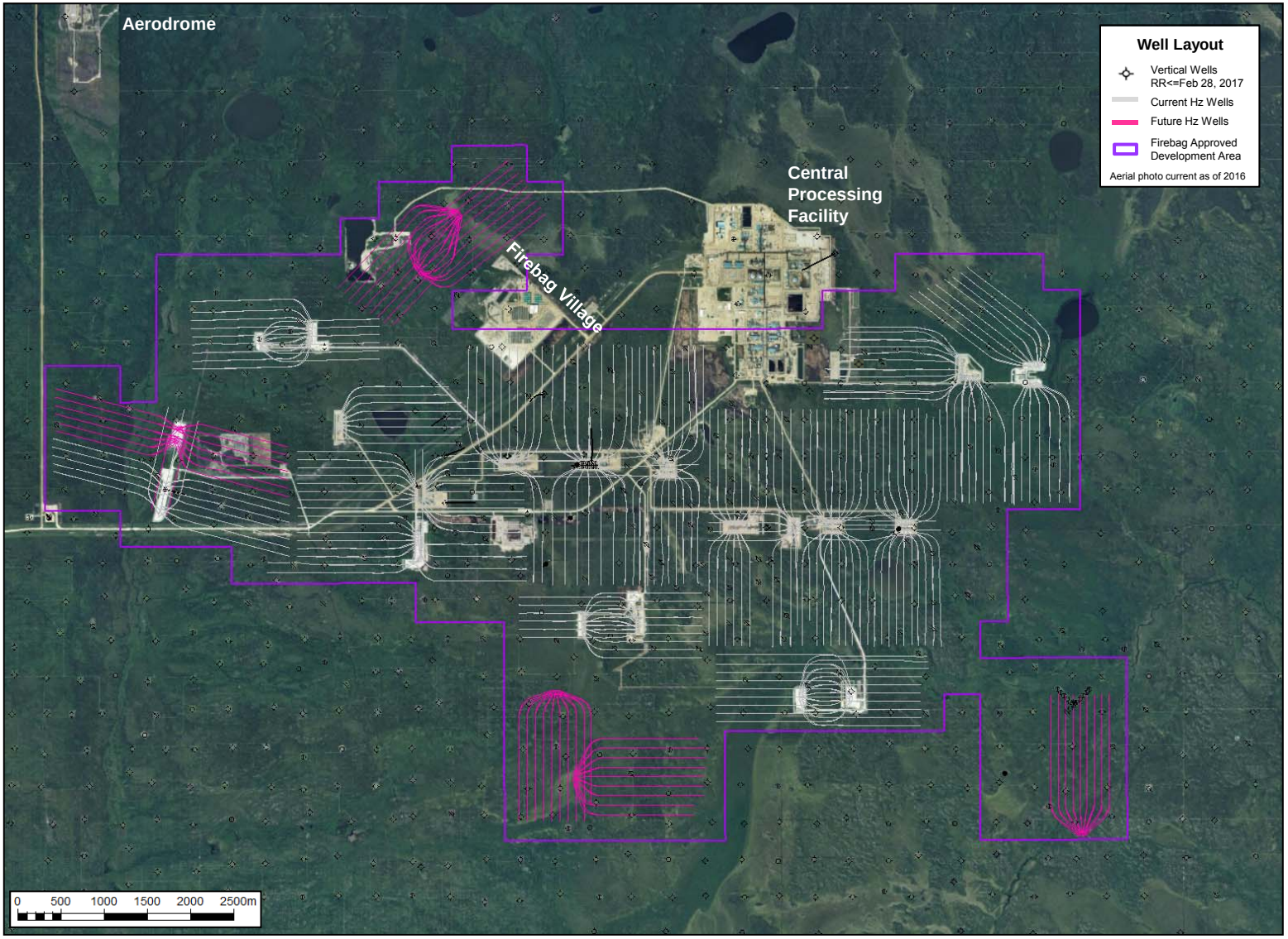
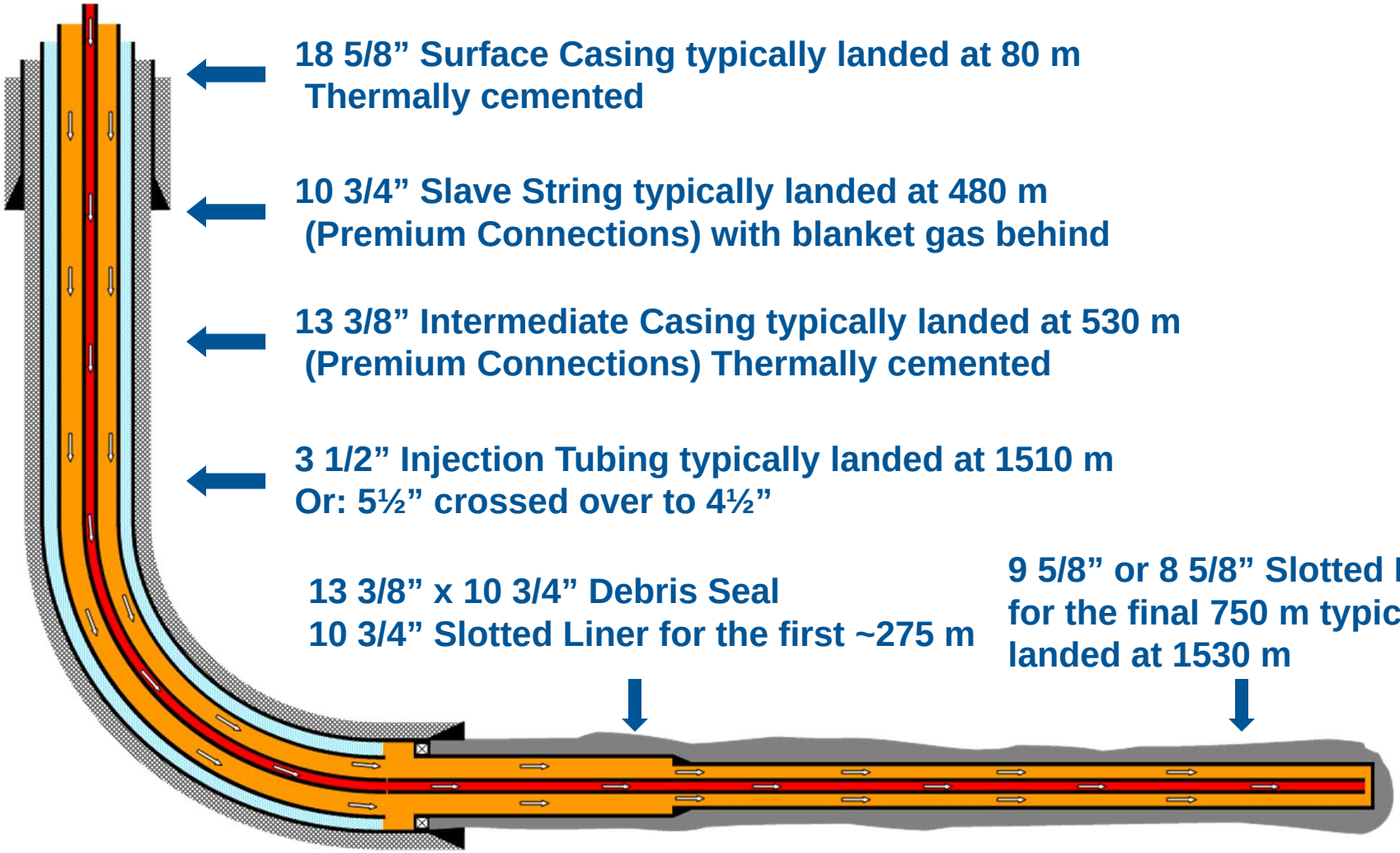
SAGD Well Layout



Drilled SAGD Pads Interwell Spacing

Pad	Average Interwell Spacing (m)
SAGD Pad 101	160
SAGD Pad 101 Post-infills	80
SAGD Pad 102	160
SAGD Pad 102 Post-infills	80
SAGD Pad 103	160
SAGD Pad 103 Post-infills	80
SAGD Pad 104	160
SAGD Pad 104 Post-infills	80
SAGD Pad 105 North & South	130
SAGD Pad 105 East	120
SAGD Pad 106	90
SAGD Pad 107	90
SAGD Pad 108 North & South	90
SAGD Pad 108 East	115
SAGD Pad 108 West	100
SAGD Pad 109 North	90
SAGD Pad 109 South	100
SAGD Pad 110	90
SAGD Pad 112	90
SAGD Pad 114	90
SAGD Pad 115	90
SAGD Pad 116	90
SAGD Pad 117 North	80
SAGD Pad 117 East	135
SAGD Pad 117 West	90
SAGD Pad 118	90

Typical SAGD Injector



18 5/8” Surface Casing typically landed at 80 m
Thermally cemented

10 3/4” Slave String typically landed at 480 m
(Premium Connections) with blanket gas behind

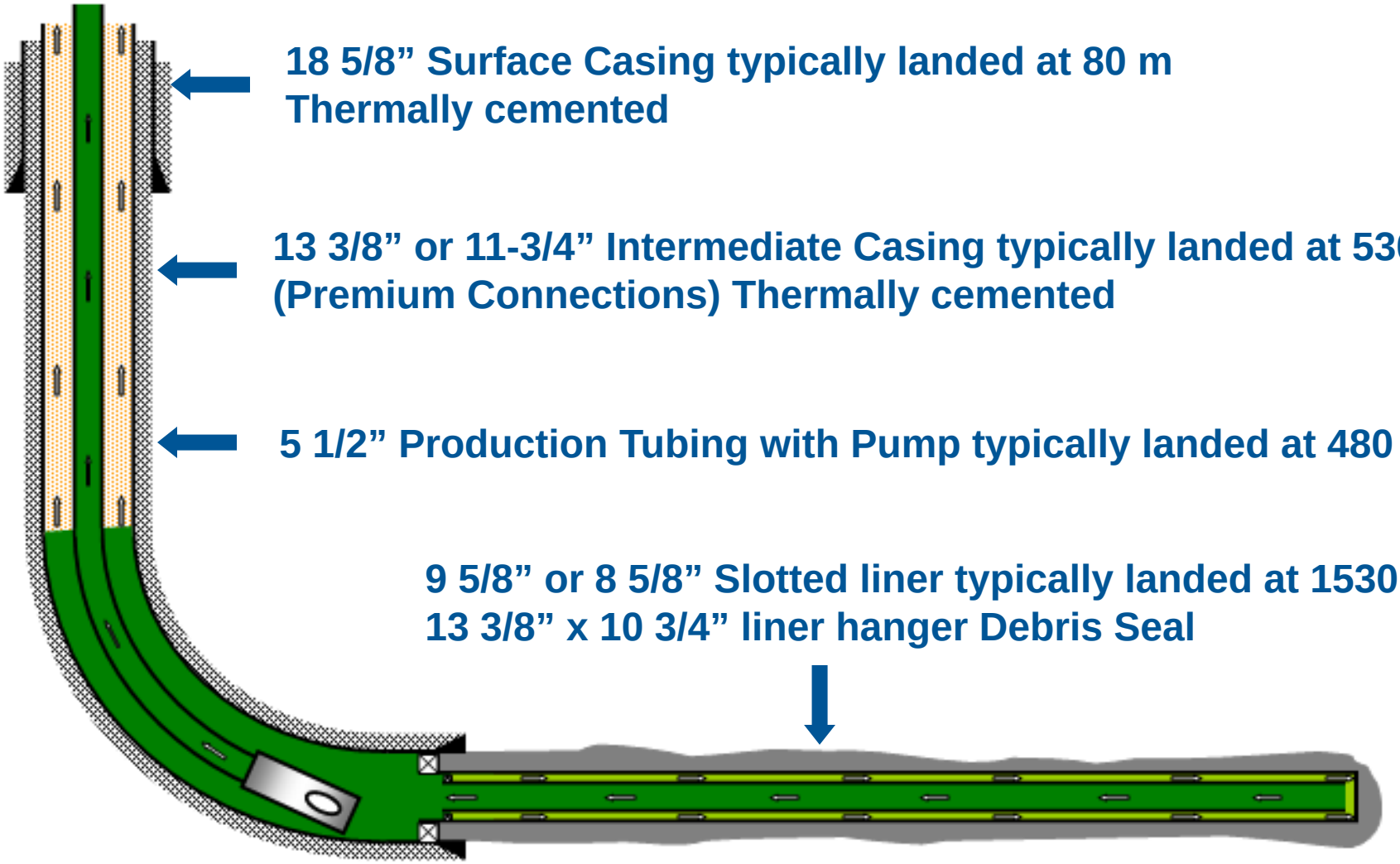
13 3/8” Intermediate Casing typically landed at 530 m
(Premium Connections) Thermally cemented

3 1/2” Injection Tubing typically landed at 1510 m
Or: 5½” crossed over to 4½”

13 3/8” x 10 3/4” Debris Seal
10 3/4” Slotted Liner for the first ~275 m

9 5/8” or 8 5/8” Slotted Liner
for the final 750 m typically
landed at 1530 m

Typical Concentric Producer ML-SAGD (includes infills)



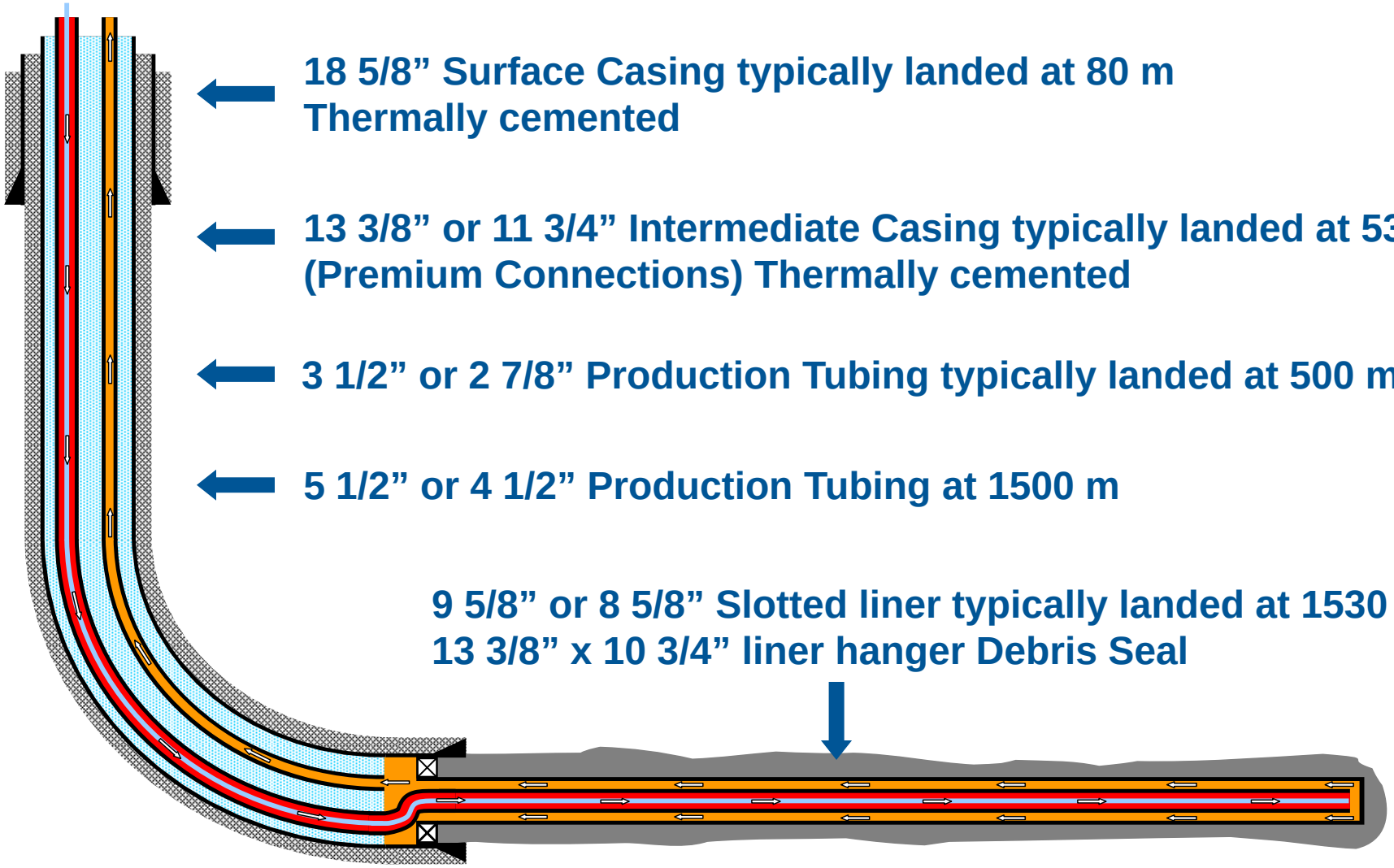
18 5/8” Surface Casing typically landed at 80 m
Thermally cemented

13 3/8” or 11-3/4” Intermediate Casing typically landed at 530 m
(Premium Connections) Thermally cemented

5 1/2” Production Tubing with Pump typically landed at 480 m

9 5/8” or 8 5/8” Slotted liner typically landed at 1530 m
13 3/8” x 10 3/4” liner hanger Debris Seal

Typical Producer Startup Setup



18 5/8” Surface Casing typically landed at 80 m
Thermally cemented

13 3/8” or 11 3/4” Intermediate Casing typically landed at 530 m
(Premium Connections) Thermally cemented

3 1/2” or 2 7/8” Production Tubing typically landed at 500 m

5 1/2” or 4 1/2” Production Tubing at 1500 m

9 5/8” or 8 5/8” Slotted liner typically landed at 1530 m
13 3/8” x 10 3/4” liner hanger Debris Seal

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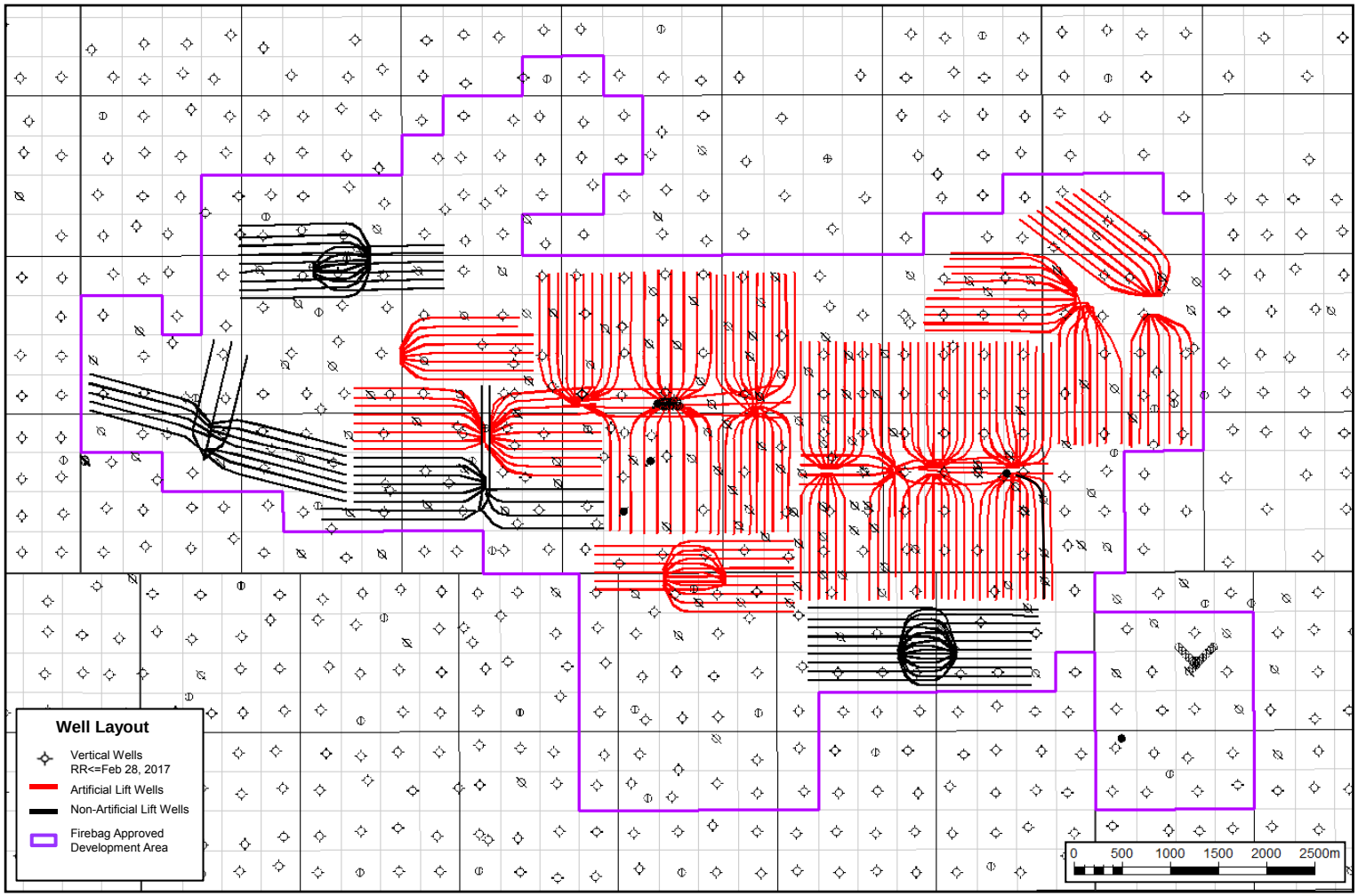
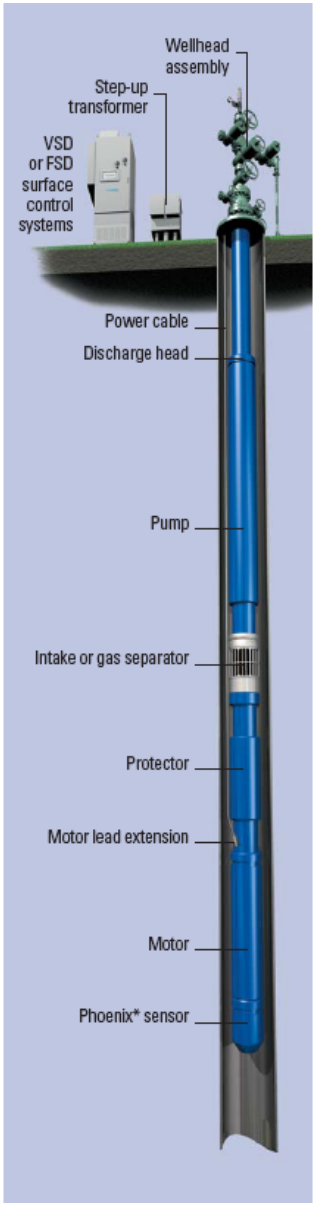
Artificial Lift Wells

- Wells highlighted in red have been converted to artificial lift



Artificial Lift Performance



- Mechanical Lift
  - Electric submersible pumps (ESP)
  - 12 – 36 Stages depending on application
  - Total fluid lift capacity ranges from 100 to 3,000 m^3/d depending on pump size
  - Averaged 800 m3/d total fluid production per well over reporting time frame
  - Maximum operating temperatures ~ 250ºC, as measured at the pump
    - Pumps generally run between 135ºC and 220ºC (UHT and SA-3)
  - Pump mean time to failure since day 1 is 672 days
  - Run-life is increasing as operational practices and pump technology improve

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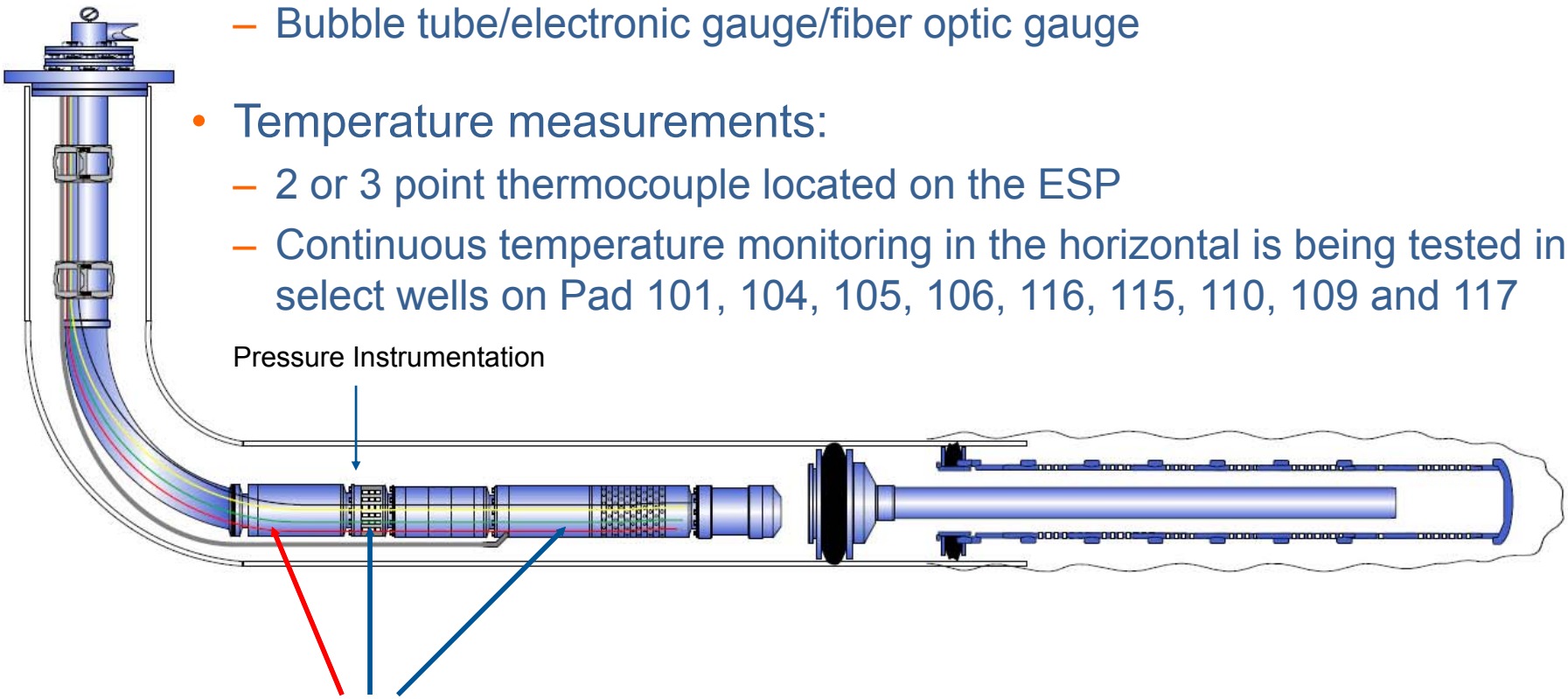
Typical SAGD Producer Well – Instrumentation Locations

- Pressure measurements:
  - Located on the ESP
  - Bubble tube/electronic gauge/fiber optic gauge
- Temperature measurements:
  - 2 or 3 point thermocouple located on the ESP
  - Continuous temperature monitoring in the horizontal is being tested in select wells on Pad 101, 104, 105, 106, 116, 115, 110, 109 and 117



Instrumentation - SAGD Wells

Pad #	Temperature	Pressure
Pad 101 (including infills)	- 2-3 pt. ESP Thermocouple - Fiber in 1P6B - Motor winding/intake (infills)	- Bubble Tube - 1P6B – Piezometer - Intake gauge (infills)
Pad 102 (including infills)	- 2-3 pt. ESP Thermocouple - Motor winding/intake (infills)	- 2P1/2/4/5/7/8 – gas gauge - 2P3/10 – Piezometer - Bubble Tube (infills)
Pad 103/104 (including infills)	- 2-3 pt. ESP Thermocouple - 3P9 internal motor TC - 104 N infills, 4N9, 4N10 and 3N8 Fiber	- Bubble Tube - P/T Intake gauges (infills) - 3N9/N10 - Piezometer
Pad 107/108	- 2-3 pt. ESP Thermocouple - 7P5 Motor winding/intake	- Bubble Tube
Pad 105	- 2-3 pt. ESP Thermocouple	- Bubble Tube
Pad 106	- 2 pt. ESP Thermocouple - Fiber in 6P2/4/6/8 - 6 pt. Thermocouple - 6P5 2 pt. Combo Line TC only	- Bubble Tube
Pad 115	- 2 pt. ESP Thermocouple - 6 pt. Thermocouple (15P4/6/8)	- Bubble Tube
Pad 116	- 2 pt. ESP Thermocouple - 6 pt. Thermocouple 16P1/2/3/4/7/8/10/11/12/14/17/19 - Fiber in 16P5/9/13/15/16/18	- Bubble Tube
Pad 110	- 2 pt. ESP Thermocouple - Fiber in 10P2/3/4/5/6/7/8	- Bubble Tube - 10P3 - Piezometer
Pad 109	- 2 pt. ESP Thermocouple - 6 pt. Thermocouple in 9P2/4/6/8/10	- Bubble Tube
Pad 117	- 2 pt. ESP Thermocouple - 6 pt. Thermocouple in 17P2/4/6/7/8/10/12/14	- Bubble Tube
All Injectors	- 15S4 (6pt TC), 15S5 (fiber)	- Blanket Gas

Downhole Instrumentation Learnings

- The following has been learned through continuous downhole temperature measurement in the horizontal of SAGD production wells:
  - Confirm ‘steam-to-toe’ during start-up phase to ensure even heating of reservoir
    - Suncor has adjusted startup strategy by changing injection rates and monitoring instrumentation to determine when steam has reached the toe of the horizontal well
  - Ability to assess temperature differences along the well and relate to
    - Wellbore deviation
    - Completion
    - Reservoir quality
  - Identification of steam breakthrough zones using downhole temperature
    - Steam breakthrough zones may hurt production, as steam will be preferentially produced over emulsion. Steam will also gas lock the ESP and cause a trip or unstable operation

FCDs (Flow Control Devices)

- Defined as downhole tools that limit the inflow or outflow of fluid <u>at different points</u> along the horizontal
  - Note: tail pipe (scab liners), and steam diverters do not satisfy this definition

- Firebag has flow control devices installed in:
  - (7) Production wells
  - (0) Injection wells

Location of Production Well FCD Installations at Firebag

Pad	Wells	Type
Pad 101	1P6B	Series of orifices
Pad 104	4N8	Impinging orifices
Pad 106	6P6	Series of orifices
Pad 110	10P2/4/6/8	Series of orifices

- Main Learnings:
  - Hot spots can develop in a wellbore due to well operating practices or reservoir heterogeneity
    - We believe FCDs choke steam production, aiding in steam trap control. This allows us to increase drawdown and improve production conformance

SUNCOR

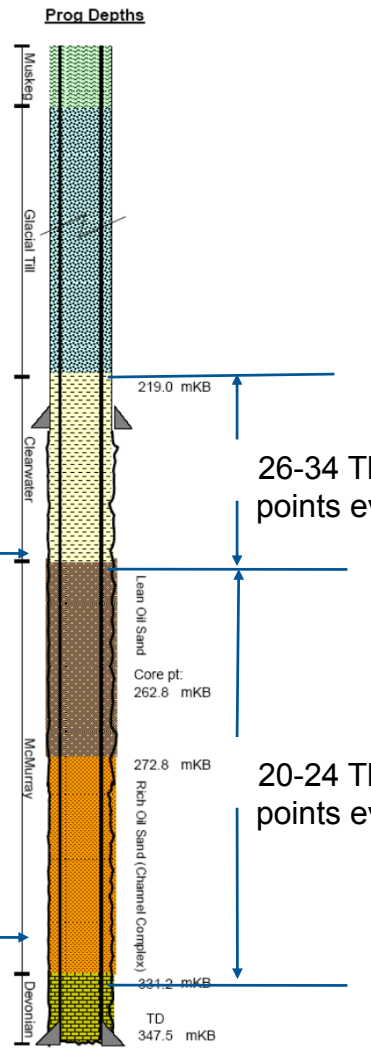
Typical SAGD Observation Wells

Pressure Instrumentation

Two Piezometers

Location:

1. Lower Wabiskaw
2. 15 m above base of McMurray



Piezometer #1

Piezometer #2

26-34 Thermocouple points evenly spaced

20-24 Thermocouple points evenly spaced

Temperature Instrumentation

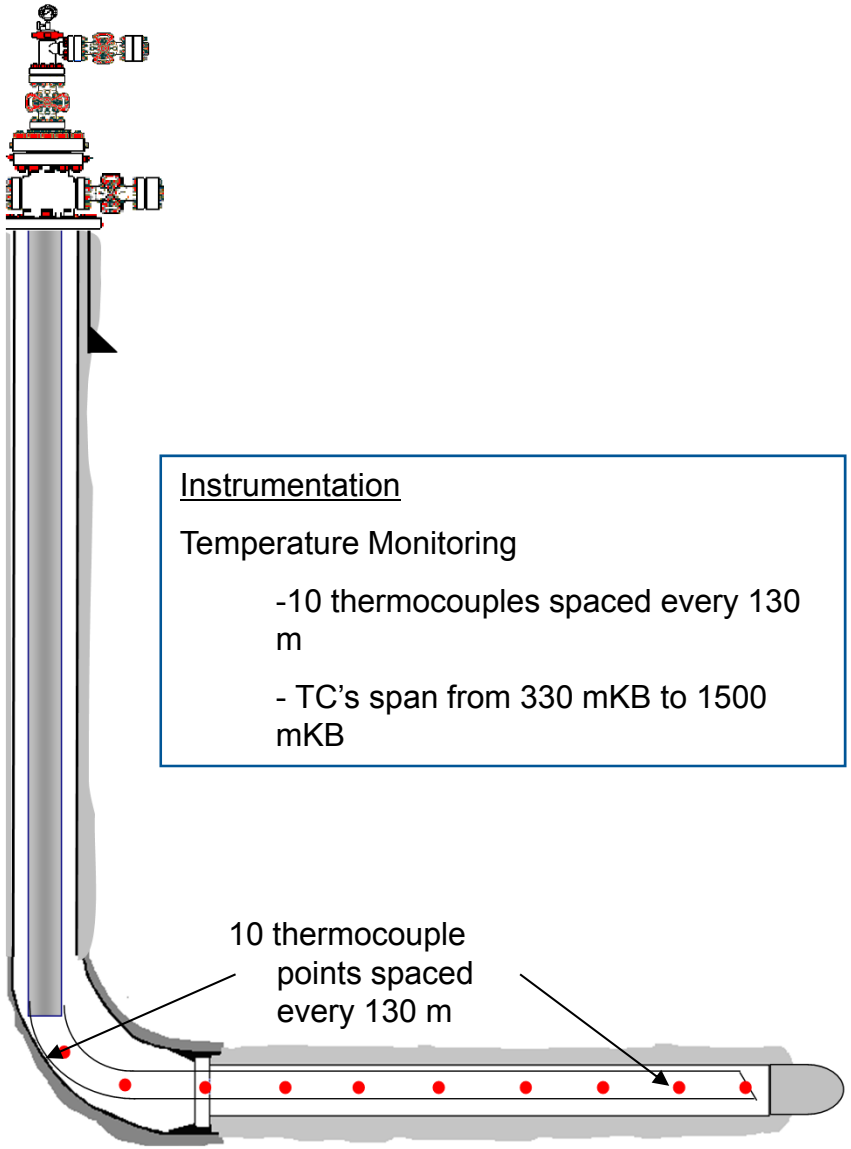
Standard Obs well:
- Base to top of McMurray
- 20-24 TC spaced every 3 to 4 m

Clearwater Obs well (2010):
- Base of RMZ to top of Clearwater
- 26-34 TC spaced every 2 m

Instrumentation strapped to outside of casing string

- 95% reliability of observation wells instrumentations
- Process and Field Improvements
  - Annual preventative maintenance program
  - Equipment upgrades
    - Power Systems
    - SCADA communications

Horizontal Observation Well Configuration



Instrumentation

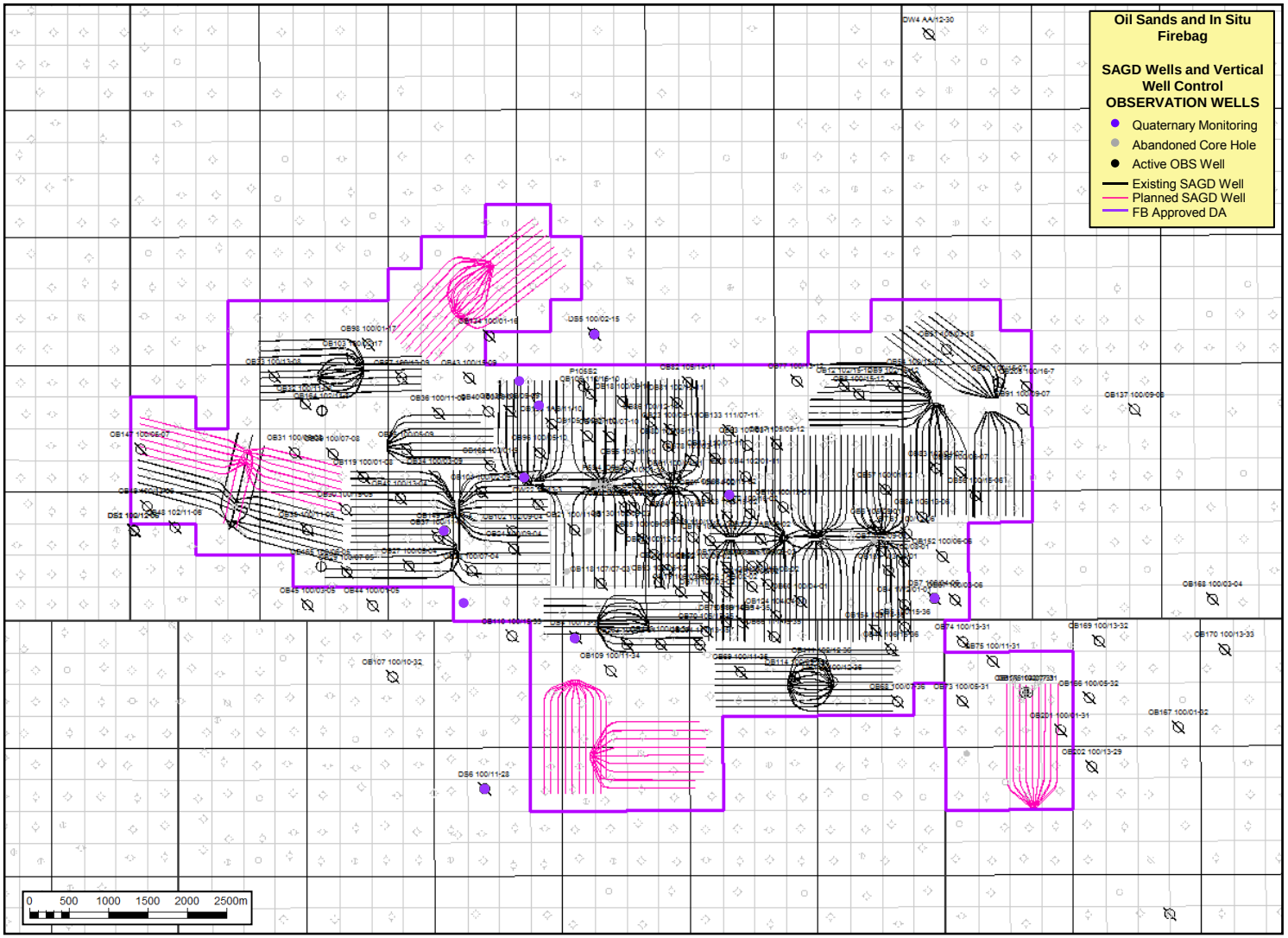
Temperature Monitoring

-10 thermocouples spaced every 130 m

- TC's span from 330 mKB to 1500 mKB

- Observation wells ETS1, 5S2, 5S3 and 5S4 have 10 point thermocouples placed in horizontal sections

Observation Well Location Map



Instrumentation – SAGD Observation Wells

Well	Temperature (# of measurements)	Pressure (# of measurements)
OB11, OB111, OB114, OB119, OB137, OB138, OB149, OB24, OB205, QW1-2, QW4, DS2	1	1
DW OB1, OB DW4	1	2
OB107, OB110, OB167-168, OB170, OB67-69, OB74-75, OB8	2	2
OB19	2	1
OB10, DS1, DS5, OB166, OB169, OB201	3	3
DS8	4	4
OB164, DS6, DS7	5	5
OB165	6	6
ETS1, P5S2-4 OB	10	N/A
ETS OB4, OB12-14, OB17-18, OB20-23, OB27-36, OB42-45, OB6-7, OB9	24	N/A
OB182	24	2
OB49, OB51, OB54, OB56, OB62	25	1
OB37-40, OB48	26	2
OB63	27	3
OB152	29	5
OB202	33	3
OB122-127, OB129-130, OB132-133, OB143	40	N/A
OB128, OB135-136	41	1
OB118, OB131, OB134	42	2

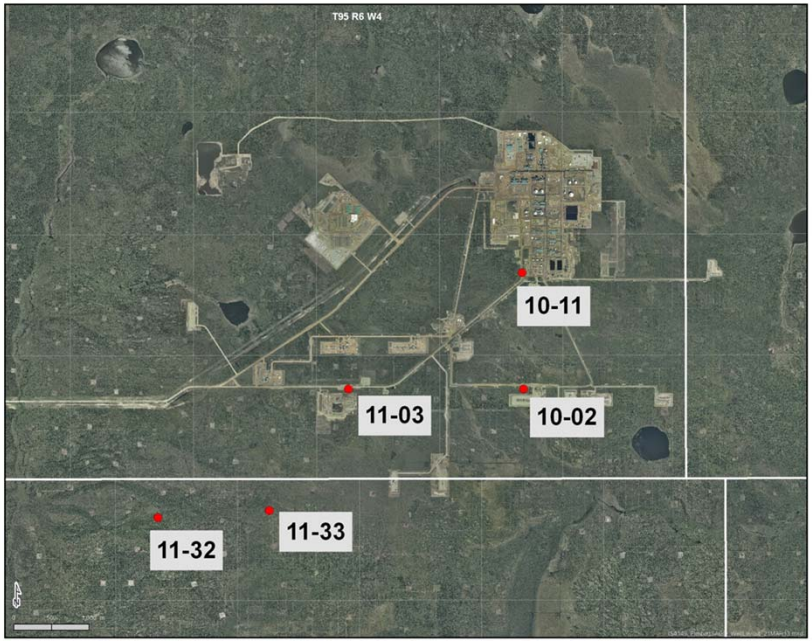
Instrumentation – SAGD Observation Wells

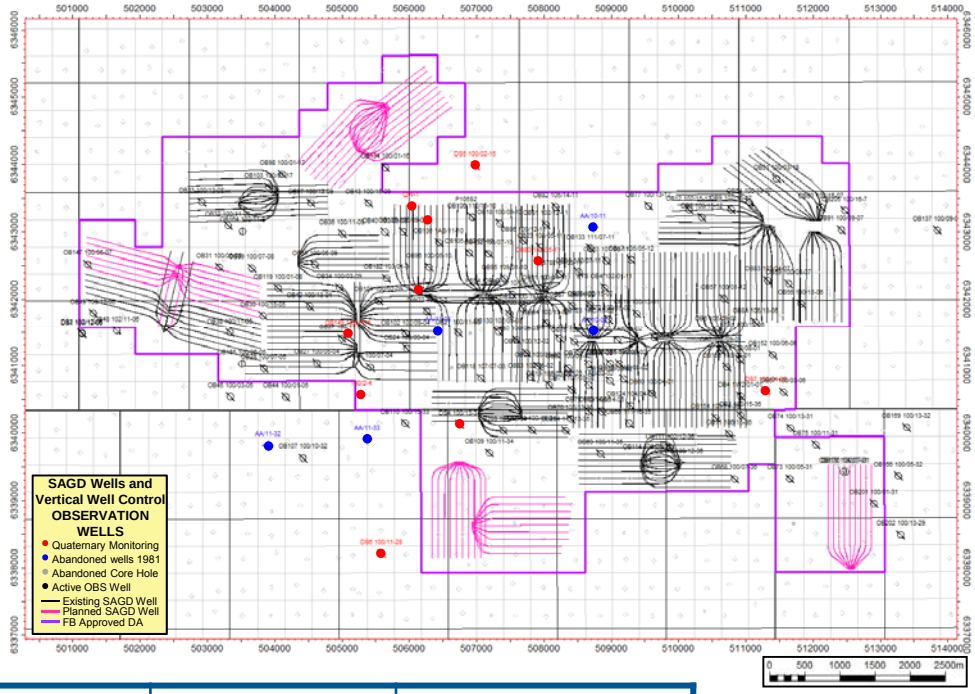
Well	Temperature (# of measurements)	Pressure (# of measurements)
OB203-204	44	4
OB153-4	45	5
OB57	46	2
OB DS4	49	6
OB3, OB5	54	N/A
OB59, OB80, OB87	55	1
OB4	55	2
OB66, OB70-73, OB76-79, OB81-86, OB88-95, OB97-98, OB101-103, OB105-106	56	2
OB96	57	3
OB61	59	1
OB60	60	2
OB DW12, OB147	N/A	1

1981 Abandoned Wells

- Five wells were drilled as per regulatory standards in 1981
  - The wells were abandoned with Oilwell G cement, not Thermal 40
  - Following a detailed risk assessment and discussion with the AER, the decision was made to monitor the wells for any noticeable changes along with yearly inspections
  - Field visits have been conducted at these locations and there have been no noticeable changes
  - Nearby observation wells monitor Quaternary pressure and temperature which is consistently stable

1981 Abandoned Wells Locations





UWI	License #	Spud Date	Distance to Planned Steam Operations (m)	Closest Well	Closest Quaternary Observation Well
10-02-095-06W4	A0088049C	2/4/1981	Approx. 3	Pad 108, 8S10	102051109506W400 – 1333 m (OB80)
11-03-095-06W4	A0088049D	1/27/1981	Approx. 34	Pad 116, 16P9	109041009506W400 – 670 m (QW4)
10-11-095-06W4	A0088049E	2/14/1981	Approx. 355	Pad 104, 4N6	102051109506W400 – 966 m (OB80)
11-32-094-06W4	A0088049B	1/18/1981	Approx. 1060	Pad 117, 17S7	100020409506W400 – 1583 m (DS8)
11-33-094-06W4	A0088048E	1/28/1981	Approx. 876	Pad 117, 17P6	100020409506W400 – 667 m (DS8)

1981 Abandoned Wells Locations Continued

- All 1981 Abandoned Wells were inspected Sept. 13 - 14, 2016

10-11-95-06-W4M

10-02-95-06-W4M

11-32-94-06-W4M

11-33-94-06-W4M

11-03-95-06-W4M

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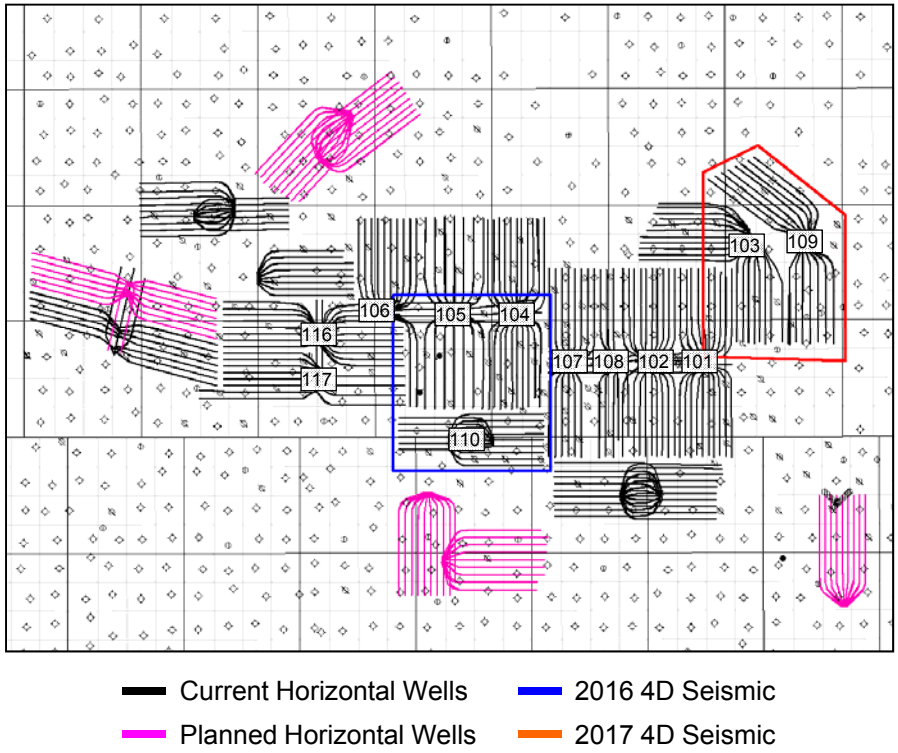
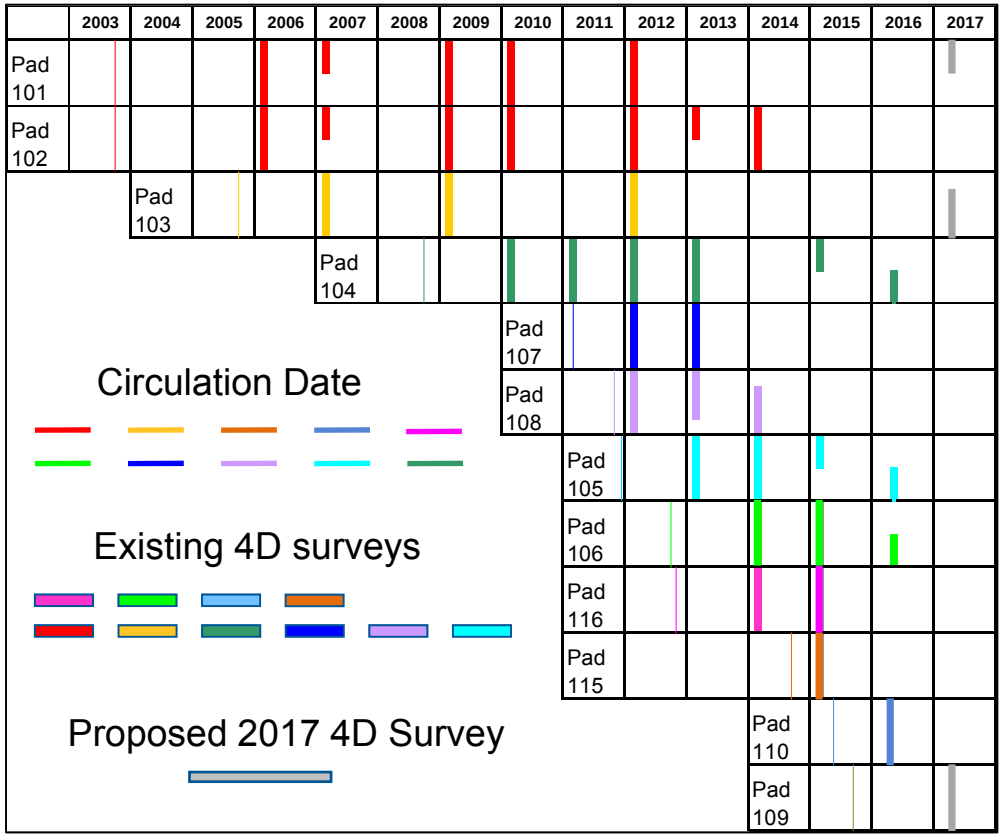
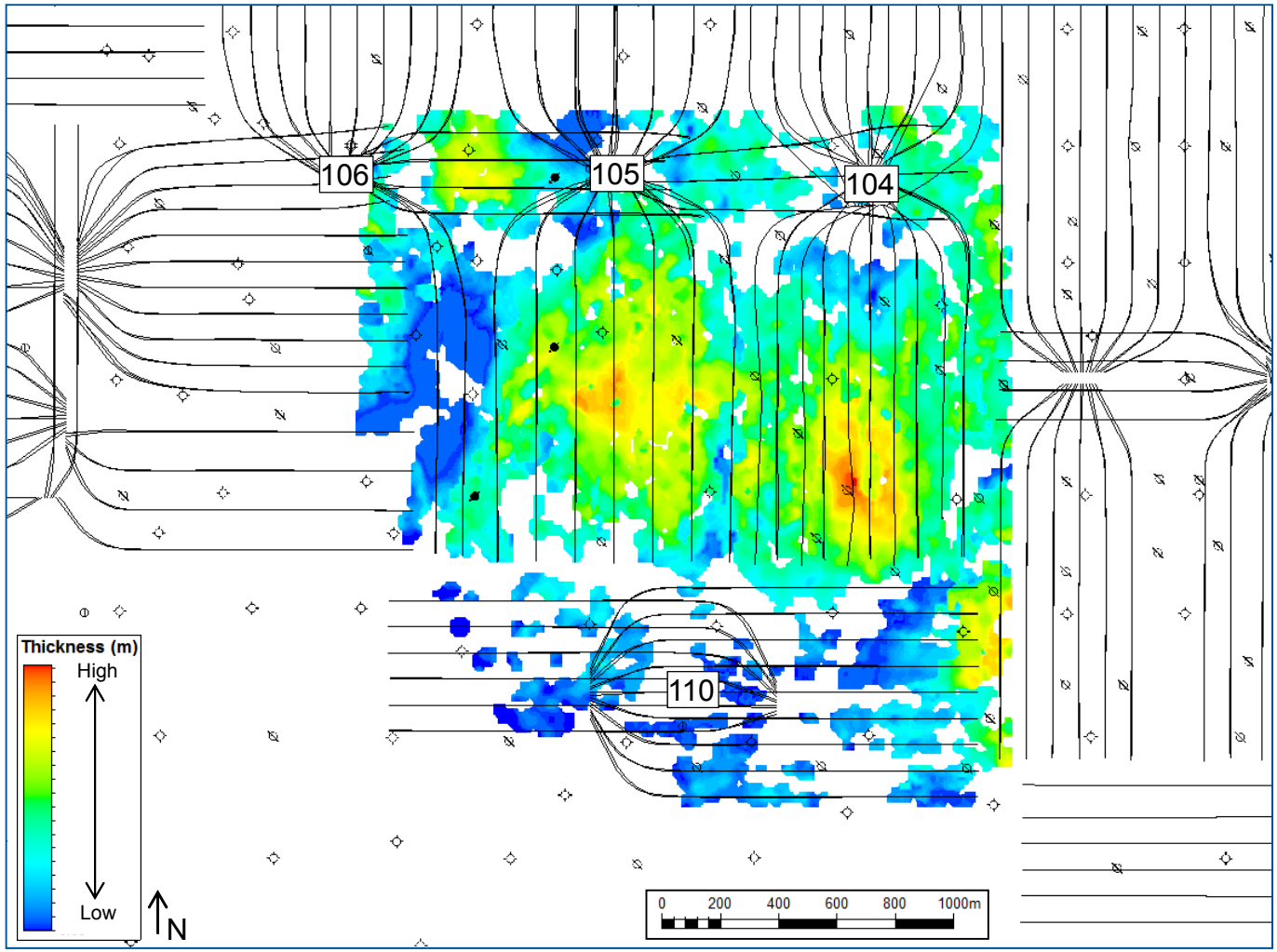
4D Seismic Survey Outlines

- Data were collected in the year indicated and interpretation reported the following year due to required process and interpretation time





2016 4D Seismic - Steam Chamber Thickness Map



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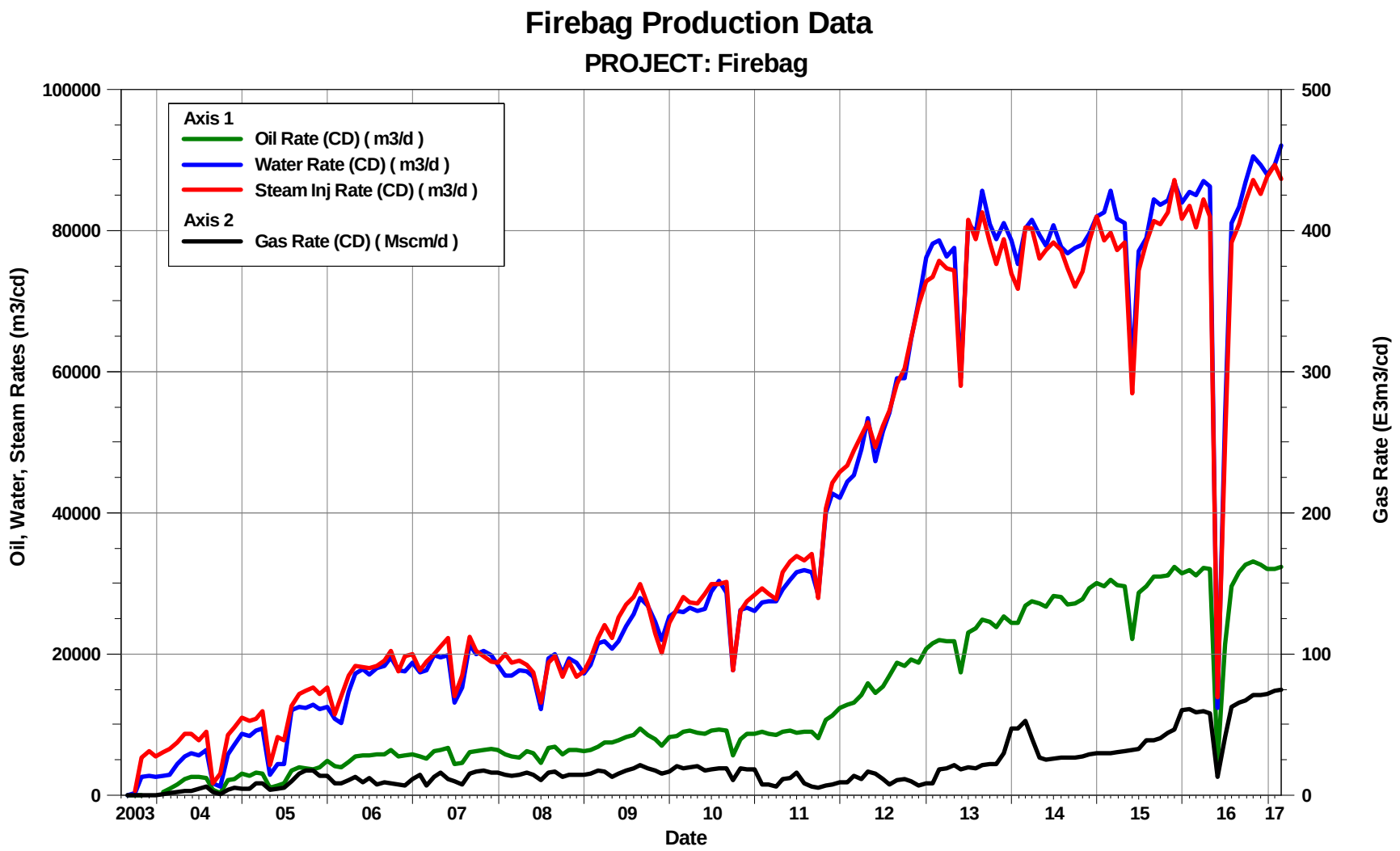
Methodology for Predicting Performance

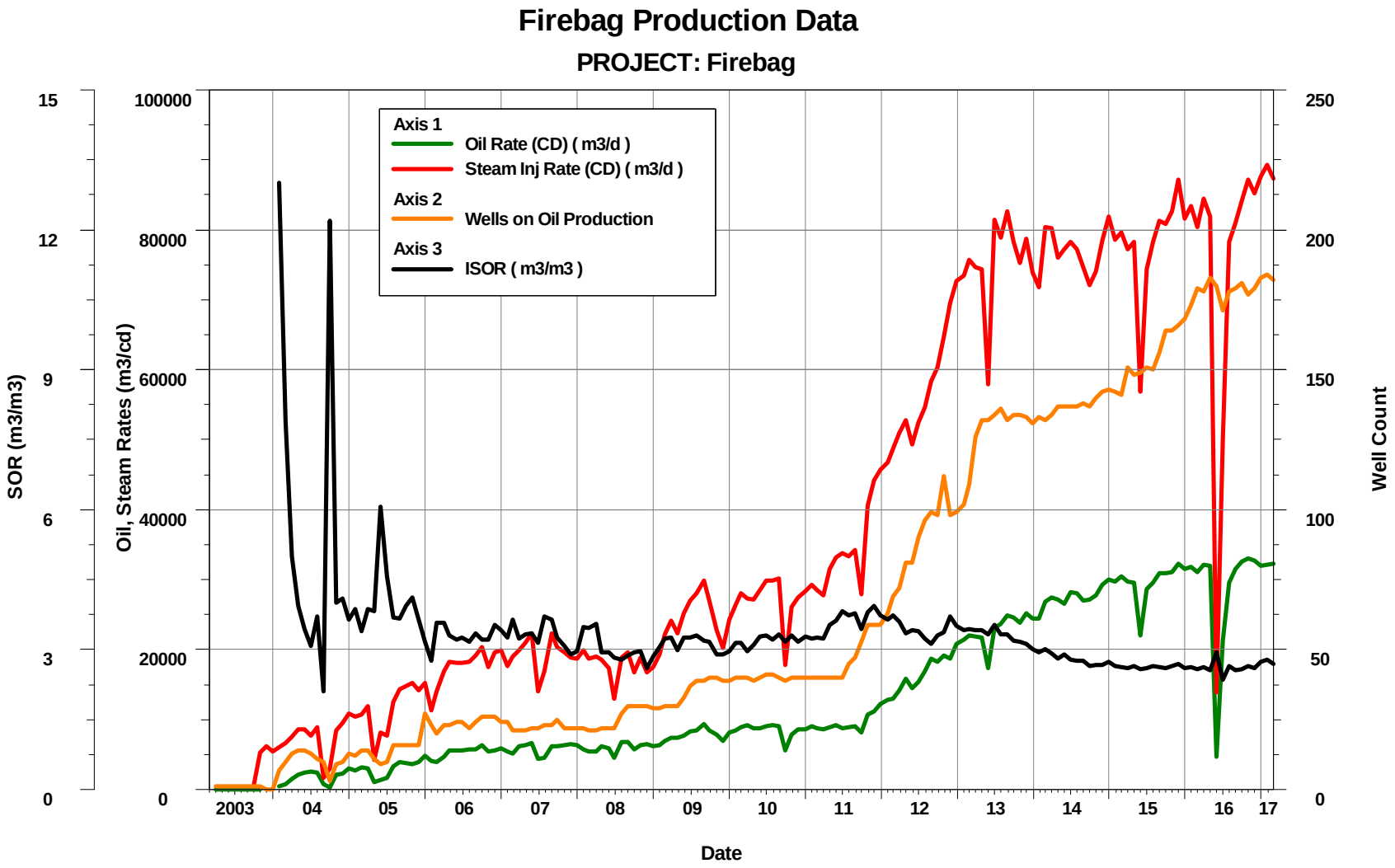
- At Firebag, future performance is predicted by leveraging multiple tools
  - Analytical Models:
    - Modified Butler's Tandrain equations
    - Water balance to monitor well communication
  - Analytical models and flow simulations are history matched on a well pair, pattern and field level

- Constraints are applied to the forecast
  - Plant turnarounds
  - Well downtime
  - New plant expansion and development pad schedule / availability

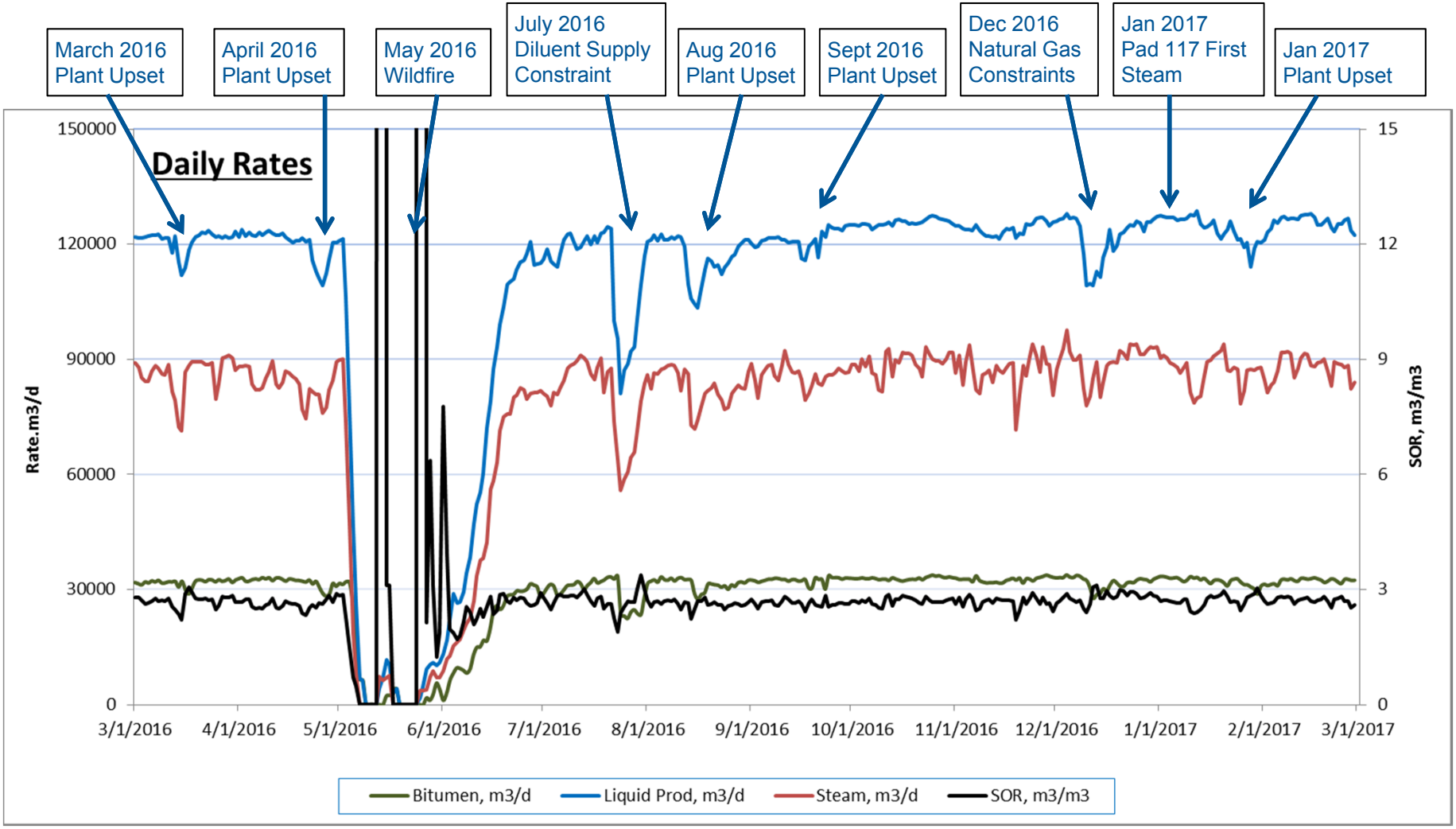
Scheme Performance – Well Production History



Scheme Performance – Well Production History



Issues and Milestones



Firebag Production

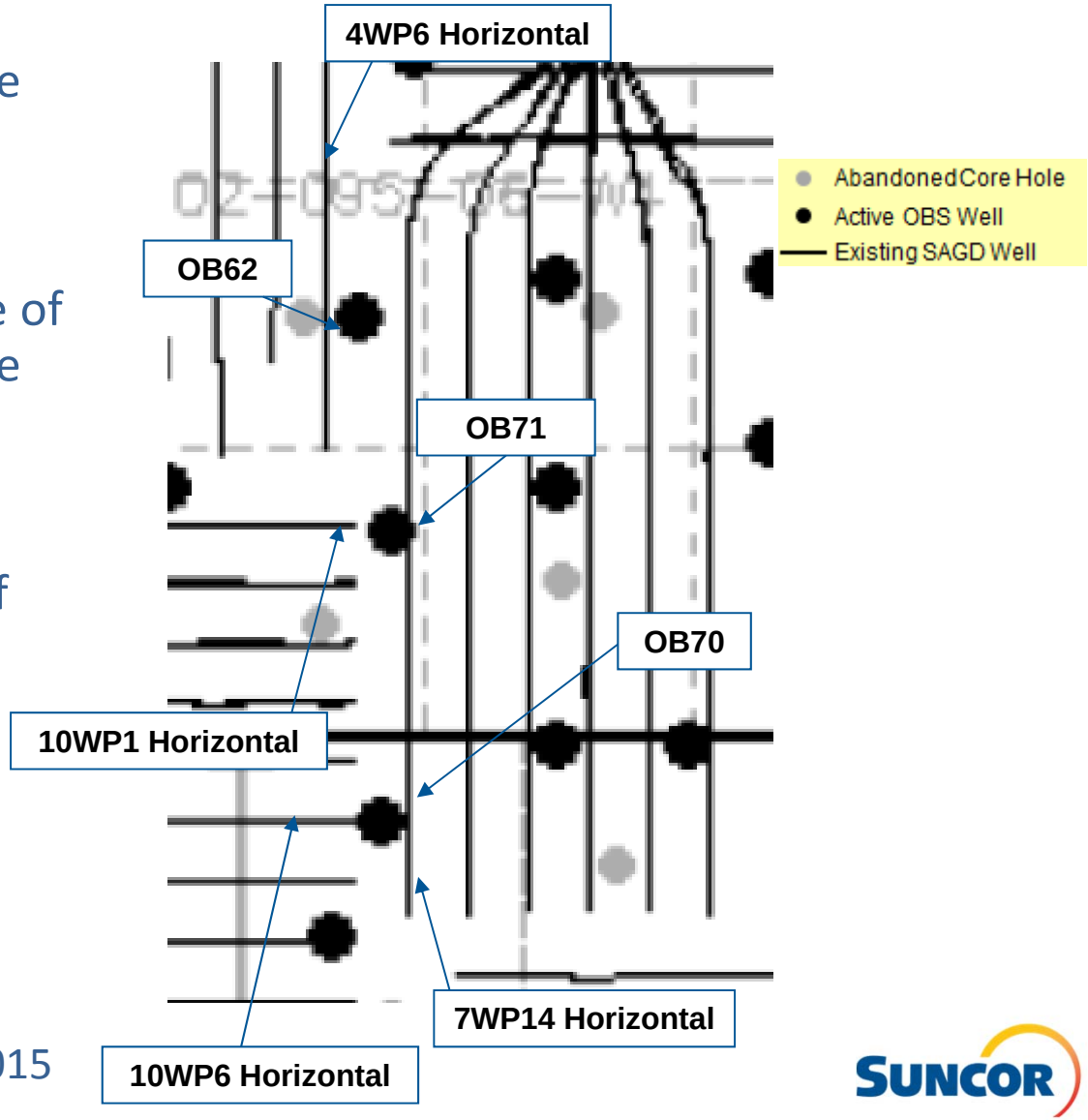
- Highest monthly average bitumen production over reporting period was 207,880 bopd (33,050 m^3/cd) and occurred in October 2016
  - Stages 1, 2, 3, and 4 currently on production
  - Ramp up pads: Pad 110 (15 Well pairs) and Pad 109 (15 Well pairs)
  - New Pads: Pad 117 (14 Well pairs, first steam in Jan 2017)

- SOR Discussion
  - As of Feb. 28, 2017 cumulative SOR at Firebag is 3.01 m^3/m^3
  - ISOR over the reporting period was 2.64 m^3/m^3
    - ISOR has been relatively the same as last year

- Infill Wells
  - Pads 101, 102, 103, and 104
  - Positive impact on rate and recovery as well as SOR

Steam Chamber Discussion – 7WP14 / Pad 110 / 4WP6

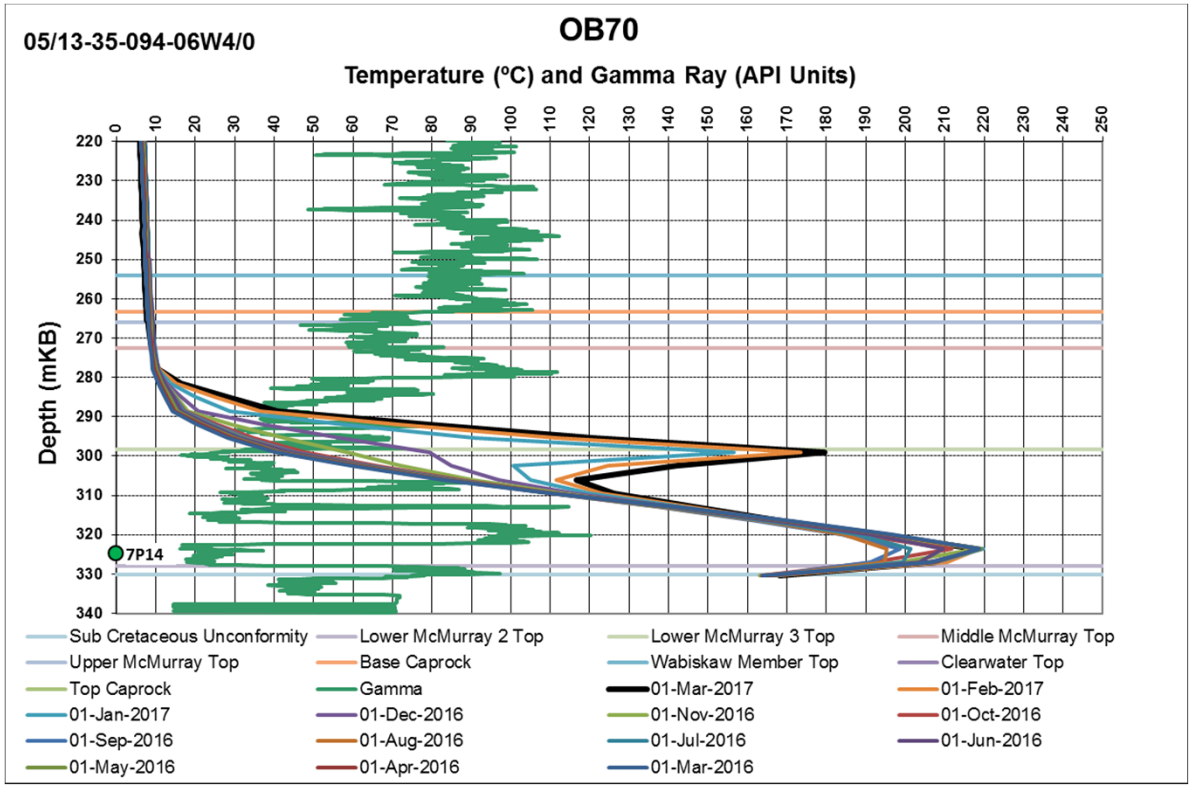
- OB70 located near the toe of 7WP14 and east of 10WP6 toe
  - 38.7m W of 7WP14
  - 38.8m E of 10WP6
- OB71 located near the middle of 7WP14 and east of 10WP1 toe
  - 25.7m W of 7WP14
  - 52.5m E of 10WP1
- OB62 located near the heel of 7WP14 and toe of 4WP6
  - 51m E of 4WP6
  - 73m W of 7WP14
- First steam dates:
  - 7WP14 in May 2011
  - 4WP6 in October 2008
  - 10WP1 and 10WP6 in April 2015



Steam Chamber Discussion – 7WP14 / 10WP6

OB70 – Toe of 7WP14 and 10WP6

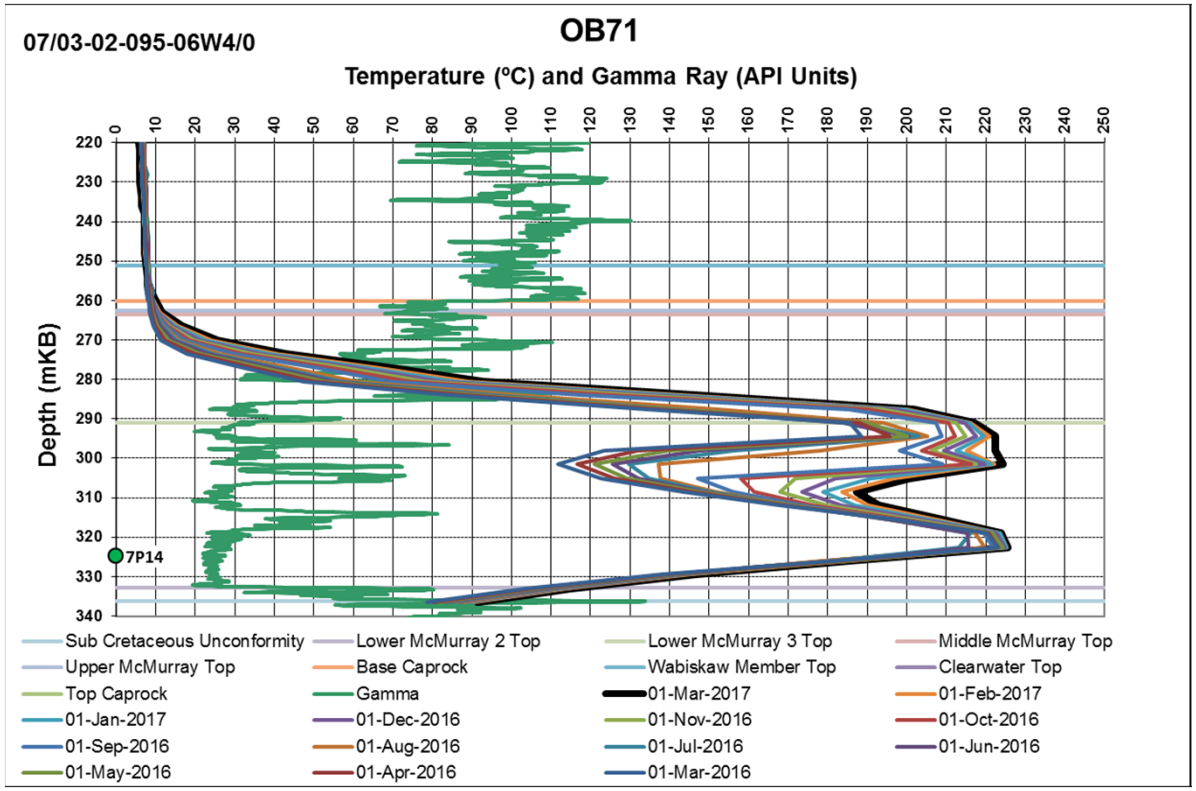
- 38.7m W of 7WP14 and 38.8m E of 10WP6
- Instrumented with 56-point thermocouples covering the lower McMurray 3 and into the Clearwater
- Temperature began increasing in August 2012, 7WP14 first steam in May 2011
- Steam chamber top capped underneath mud at 323mKB from 2012 to Dec 2016
- Steam chamber expanded above the mud since Jan 2017



Steam Chamber Discussion – 7WP14 / 10WP1

OB71 – Middle of 7WP14 and Toe of 10WP1

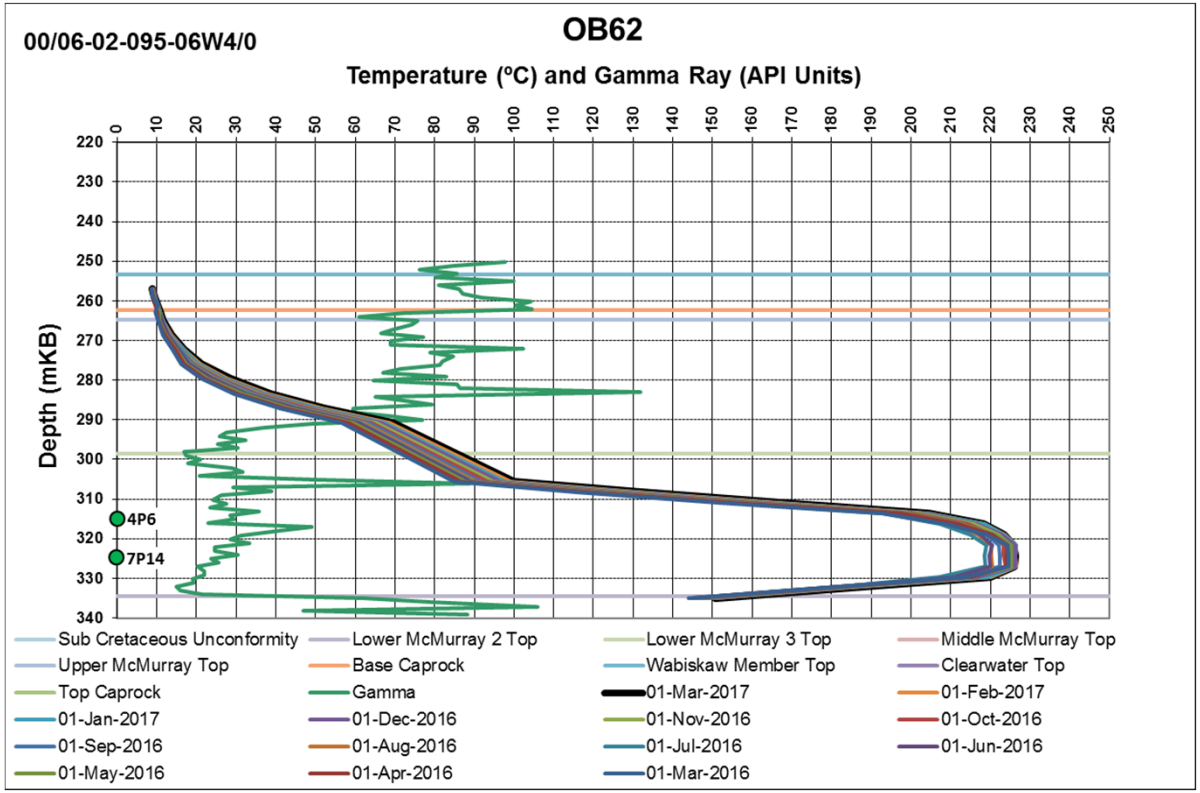
- 25.7m W of 7WP14 and 52.5m E of 10WP1
- Instrumented with 56-point thermocouples covering the lower McMurray 2 and into the Clearwater
- Temperature began increasing in August 2012, 7WP14 first steam in May 2011
- Steam chamber top capped underneath a mud at 318mKB from 2012 to May 2015
- Steam temperature was seen above the mud since June 2015, indicating steam chamber is growing above



Steam Chamber Discussion – 7WP14 / 4WP6

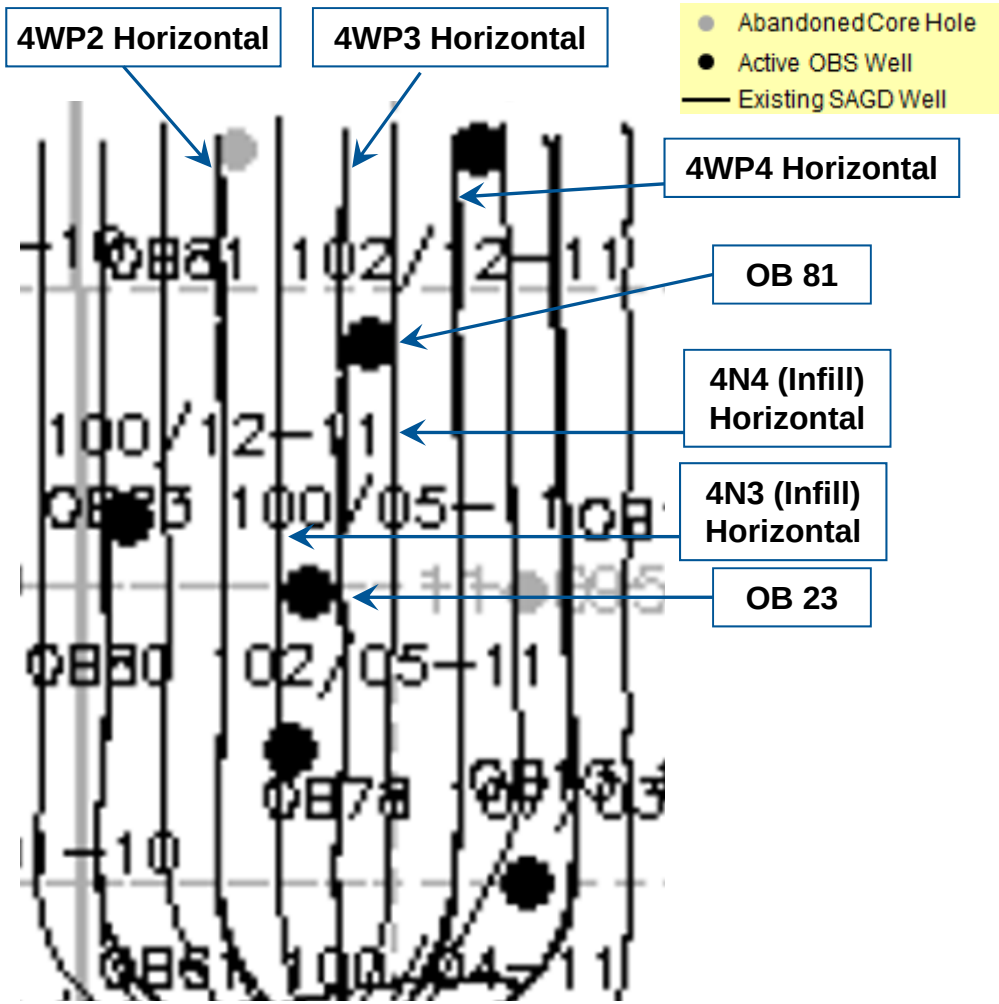
OB62 – Near the heel of 7WP14 and toe of 4WP6

- 51m E of 4WP6 and 73m W of 7WP14
- Instrumented with 20-point thermocouples covering the lower McMurray 3 and into the Wabiskaw
- Temperature began recording in March 2011 and seeing temperature increase
- 7WP14 first steam in May 2011 and 4WP6 first steam in October 2008
- Steam chamber top is at 320mKB



Steam Chamber Discussion – 4WP3

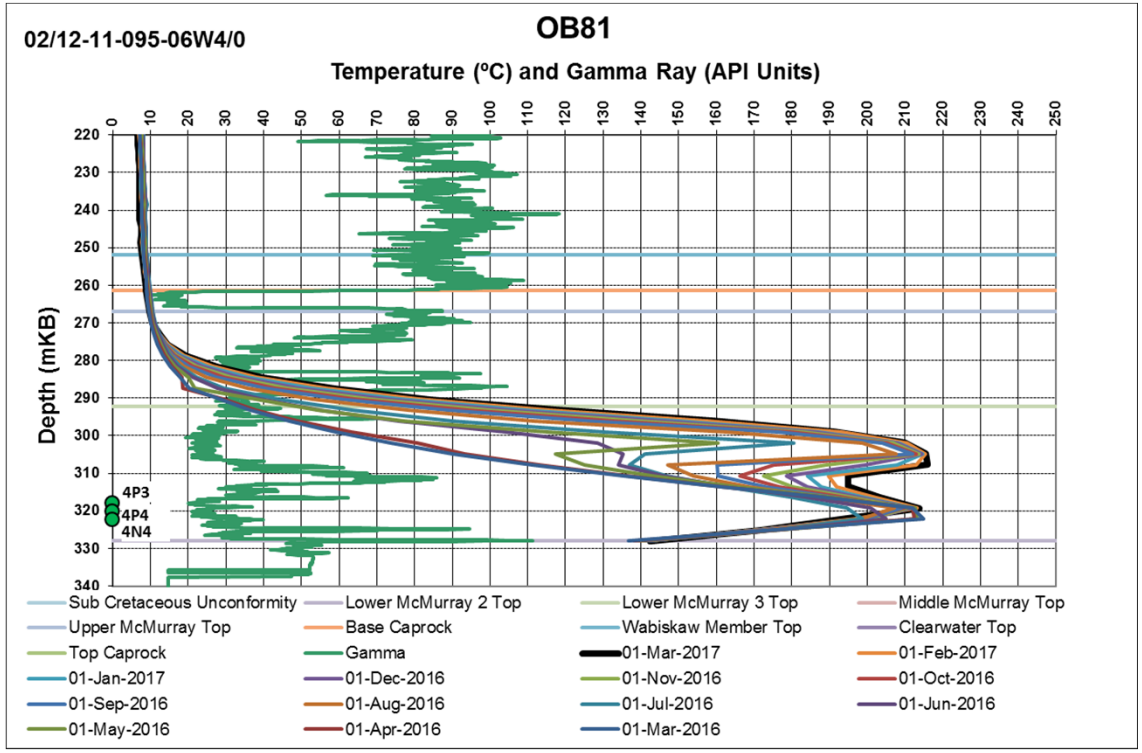
- OB81 located near the toe of 4WP3 and west of 4WP4 and 4N4 toe
  - 40.8m E of 4WP3
  - 113.7m W of 4WP4
- OB23 located near the middle of 4WP3 and east of 4WP2 and 4N3
  - 41.7m W of 4WP3
  - 117m E of 4WP2
- First steam dates:
  - 4WP2 in Nov 2008
  - 4WP3 in Nov 2008
  - 4WP4 in Dec 2008



Steam Chamber Discussion – 4WP3

OB81 – toe of 4WP3 and west of 4WP4 and 4N4

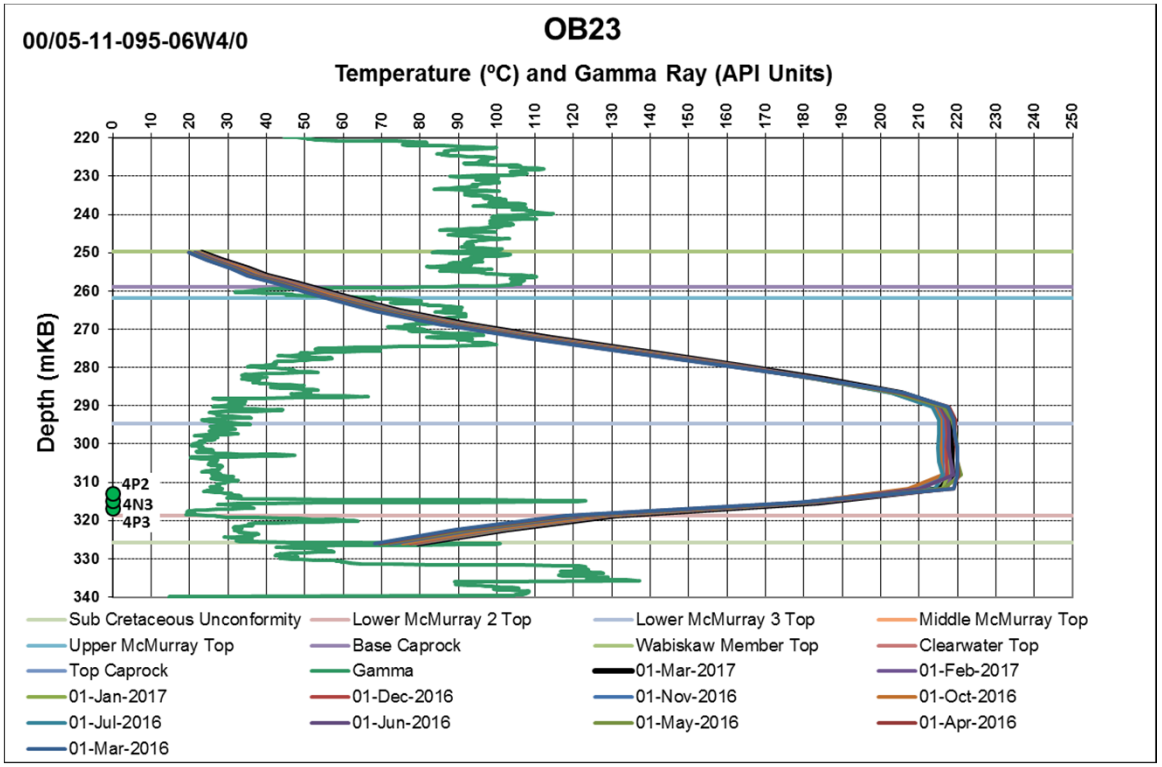
- 40.8m E of 4WP3 and 113.7m W of 4WP4
- Instrumented with 56-point thermocouples covering the lower McMurray 3 and into the Clearwater
- Temperature began increasing July 2011, 4WP3 first steam in Nov 2008
- Steam chamber top capped underneath a mud at 311mKB from 2013 to April 2016
- Steam was seen above the mud since May 2016, indicating steam chamber is growing above



Steam Chamber Discussion – 4WP3

OB23 – middle of 4WP3 and east of 4WP2 and 4N3

- 41.7m W of 4WP3 and 117m E of 4WP2
- Instrumented with 24-point thermocouples covering the lower McMurray 2 and into the Clearwater
- Temperature began increasing Feb 2009, 4WP3 first steam in Nov 2008
- Steam chamber top capped underneath mud at 287.6mKB from 2009 to March 2017



Pad Recoveries

Pad	101	102	103	104	Stage 1 & 2 Totals
Recovery to Date, e3m3	13,040	10,632	9,213	8,248	41,132
Recovery Factor to Date, %	57%	55%	52%	41%	51%
Expected Ultimate Recovery, e3m3	14,816	13,788	12,515	12,333	53,452
Expected Ultimate Recovery Factor, %	64%	71%	71%	61%	67%
OBIP, e3m3	23,034	19,432	17,587	20,088	80,141

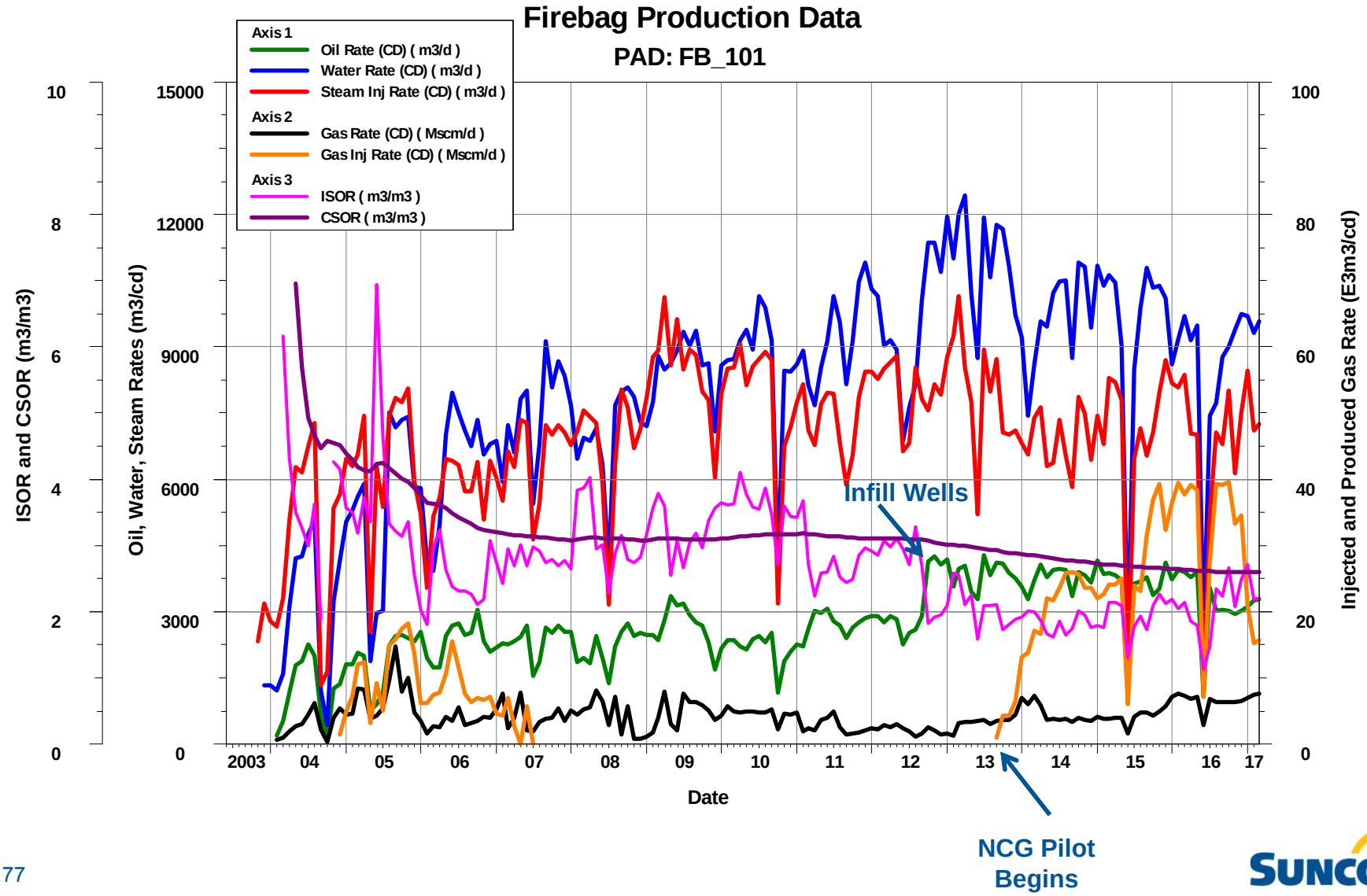
Pad	105	106	107	108	109	110	115	116	117	Stage 3 & 4 Totals
Recovery to Date, e3m3	5,511	4,156	4,564	3,042	467	887	722	4,617	0	23,966
Recovery Factor to Date, %	23%	26%	36%	18%	5%	9%	14%	28%	0%	20%
Expected Ultimate Recovery, e3m3	13,031	9,015	7,763	7,790	6,260	6,371	2,852	10,865	9,147	63,948
Expected Ultimate Recovery Factor, %	54%	56%	62%	46%	73%	65%	53%	65%	73%	52%
OBIP e3m3	23,979	16,098	12,523	16,955	8,525	9,781	5,348	16,749	12,494	122,452

- Pads 117 is included

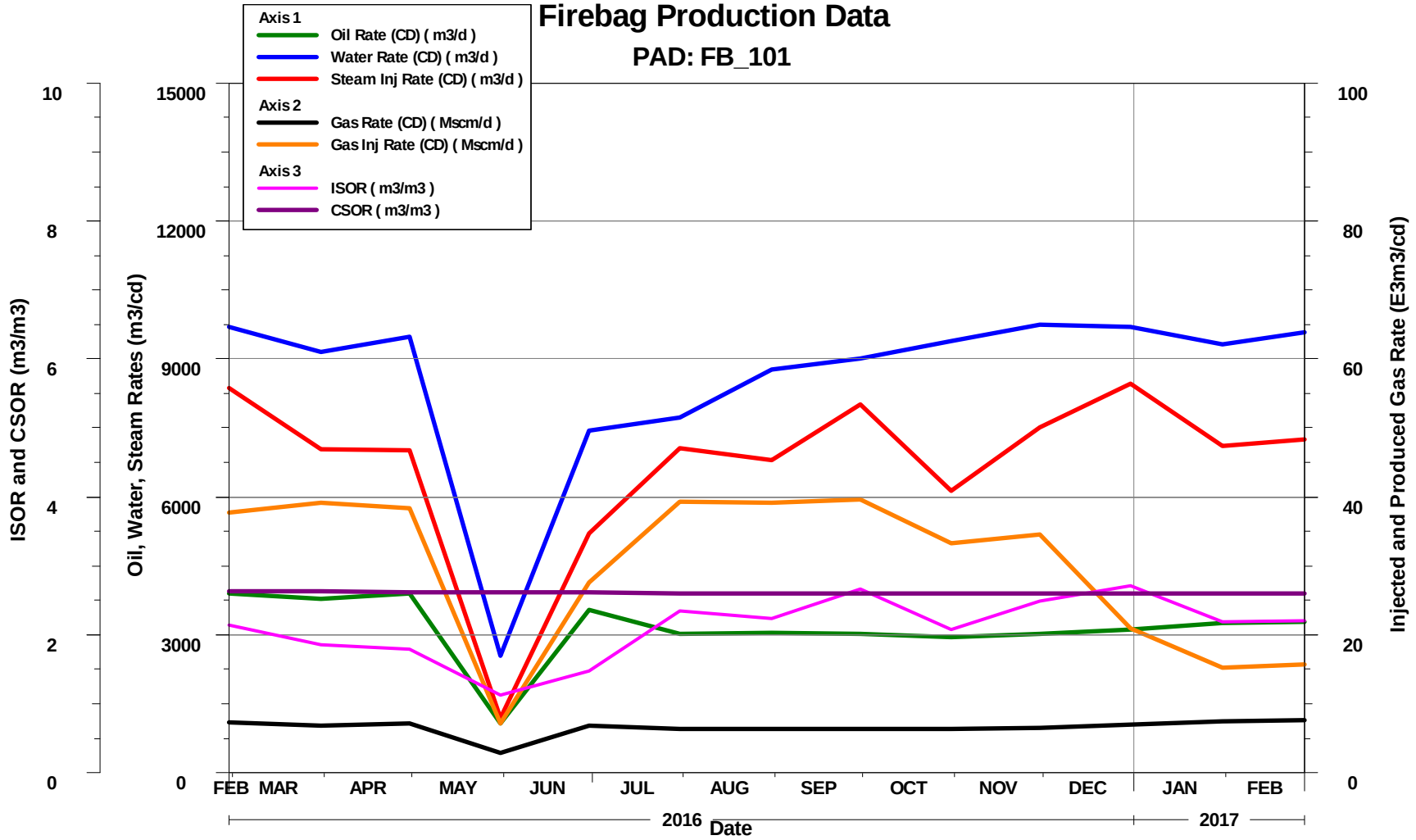
Pad 101 Performance – High Recovery Pad

- Pad 101
  - Most mature pad
  - 18 wells on production
    - 8 well pair producers and 10 infills
  - Monthly steam chamber pressures:
    - Average: 2,172 kPag
    - Range: 2,137 kPag – 2,221 kPag
  - Performance as of Feb. 28, 2017:
    - Cumulative steam injected is 33,825,739 m^3
    - Cumulative oil produced is 13,039,595 m^3
    - Cumulative SOR = 2.59 m^3/m^3
    - Recovery Factor of 57%
  - Non-Condensable Gas Trial started Aug. 2013
    - NCG is injected in 1WP6,7,8 injectors
  - Pad Learnings
    - Base wells are declining while infills maintain their strong performance and improving the SOR of the pad
    - Mature pad with more resilience to shut-in during outages

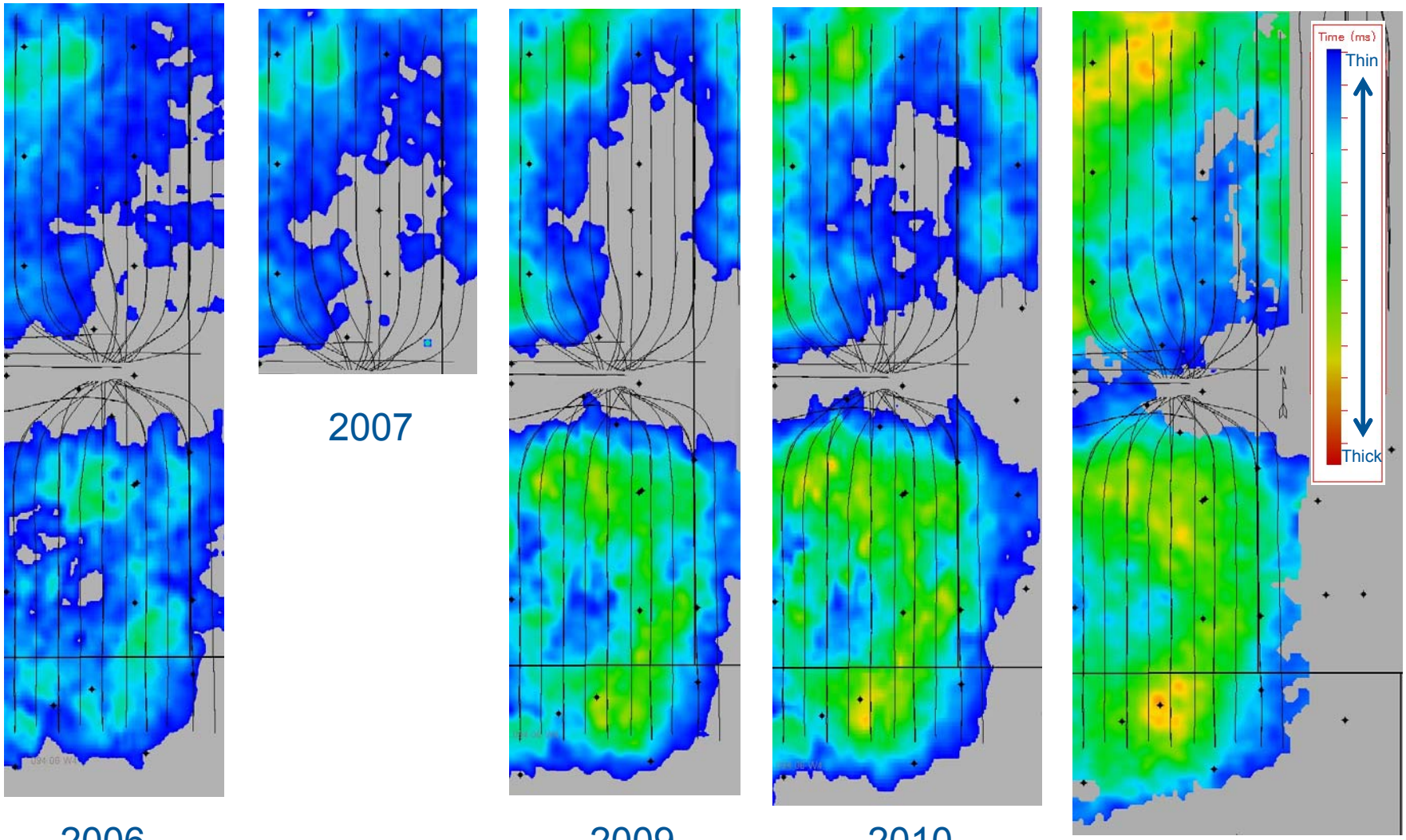
Pad 101 Performance



Pad 101 Performance



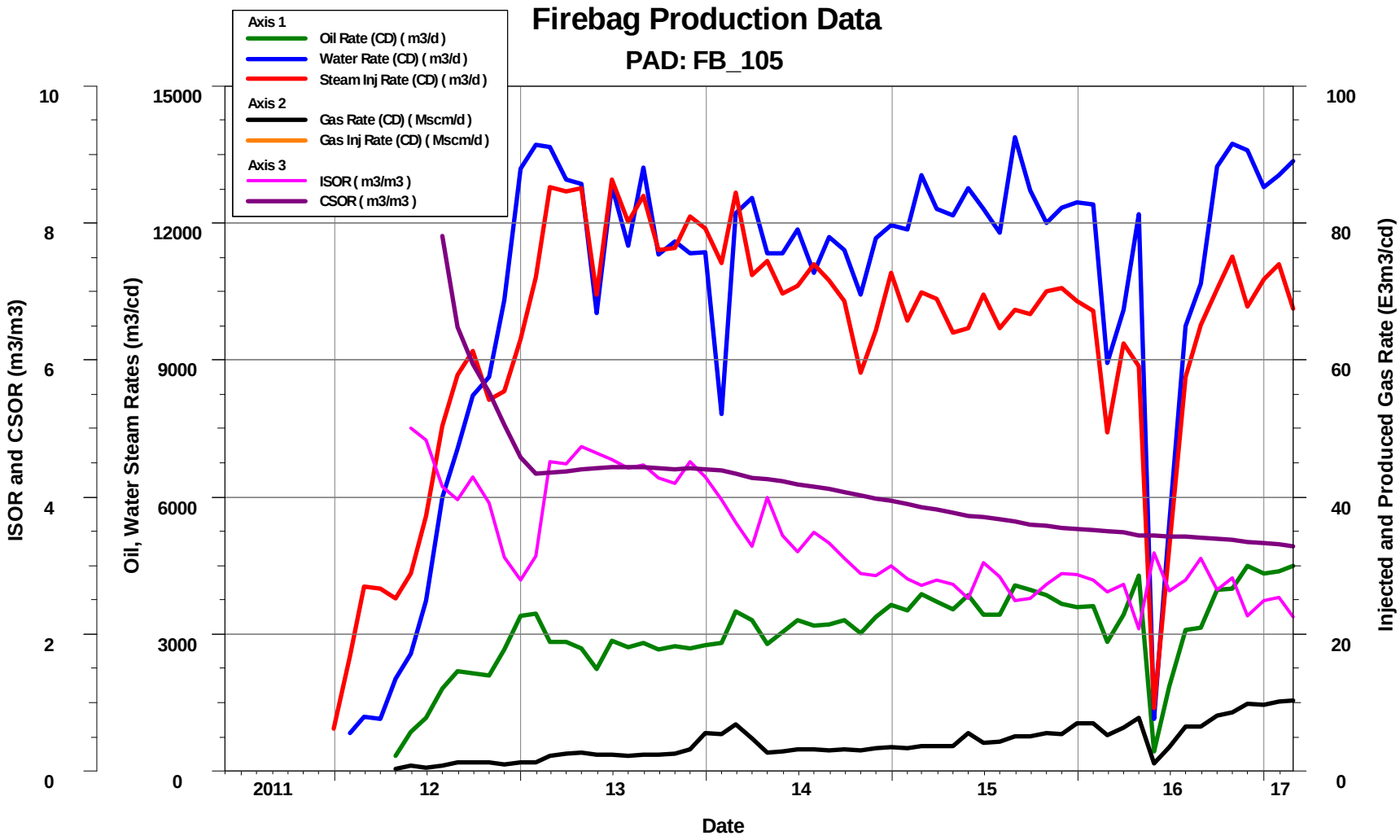
Pad 101 Performance – 4D Seismic Time Delay



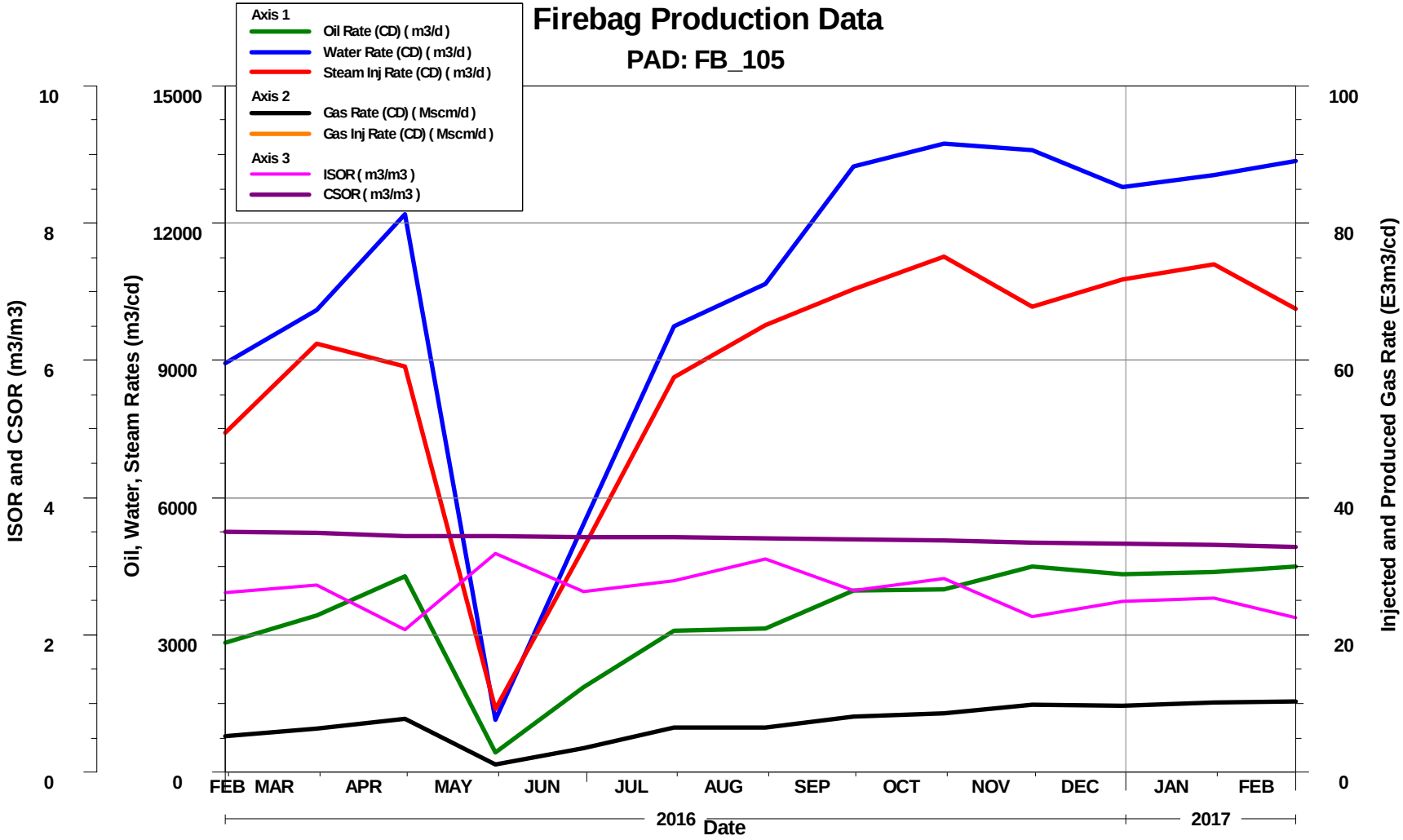
Pad 105 Performance - Medium Recovery Pad

- Pad 105
  - 17 wells currently on production
  - First oil in April 2012
  - Monthly steam chamber pressures:
    - Average: 2,097 kPag
    - Range: 1,960 kPag – 2,178 kPag
  - Performance as of Feb. 28, 2017:
    - Cumulative steam injected is 18,088,132 m^3
    - Cumulative oil produced is 5,510,911 m^3
    - Cumulative SOR = 3.28 m^3/m^3
    - Recovery Factor of 23%
  - Pad Learnings
    - Differential chamber pressure with nearby pads and across the pad can cause fluid migration
    - Balancing the chamber pressure across the pad helps improving the chamber growth and well conformance

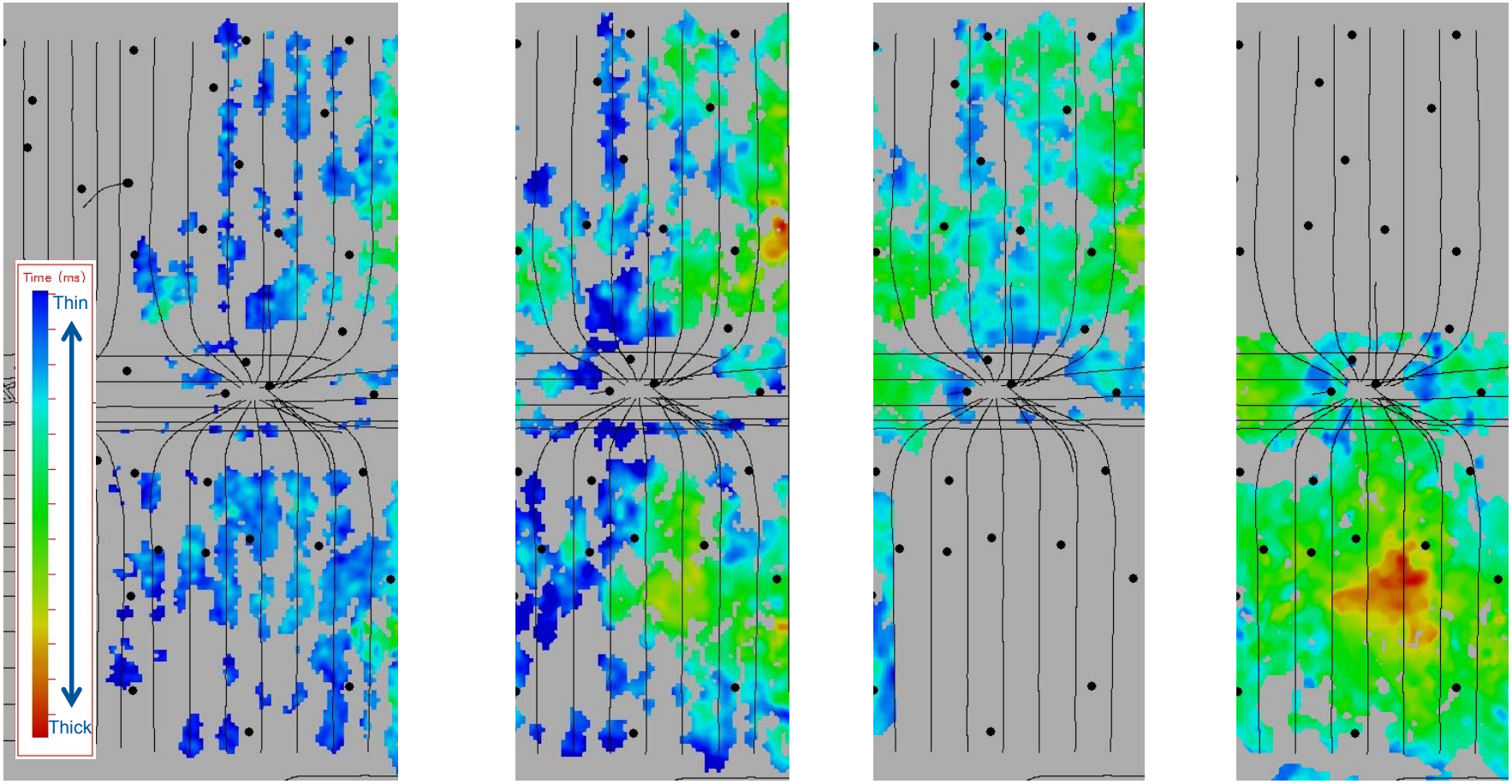
Pad 105 Performance



Pad 105 Performance



Pad 105 Performance - 4D Seismic Time Delay

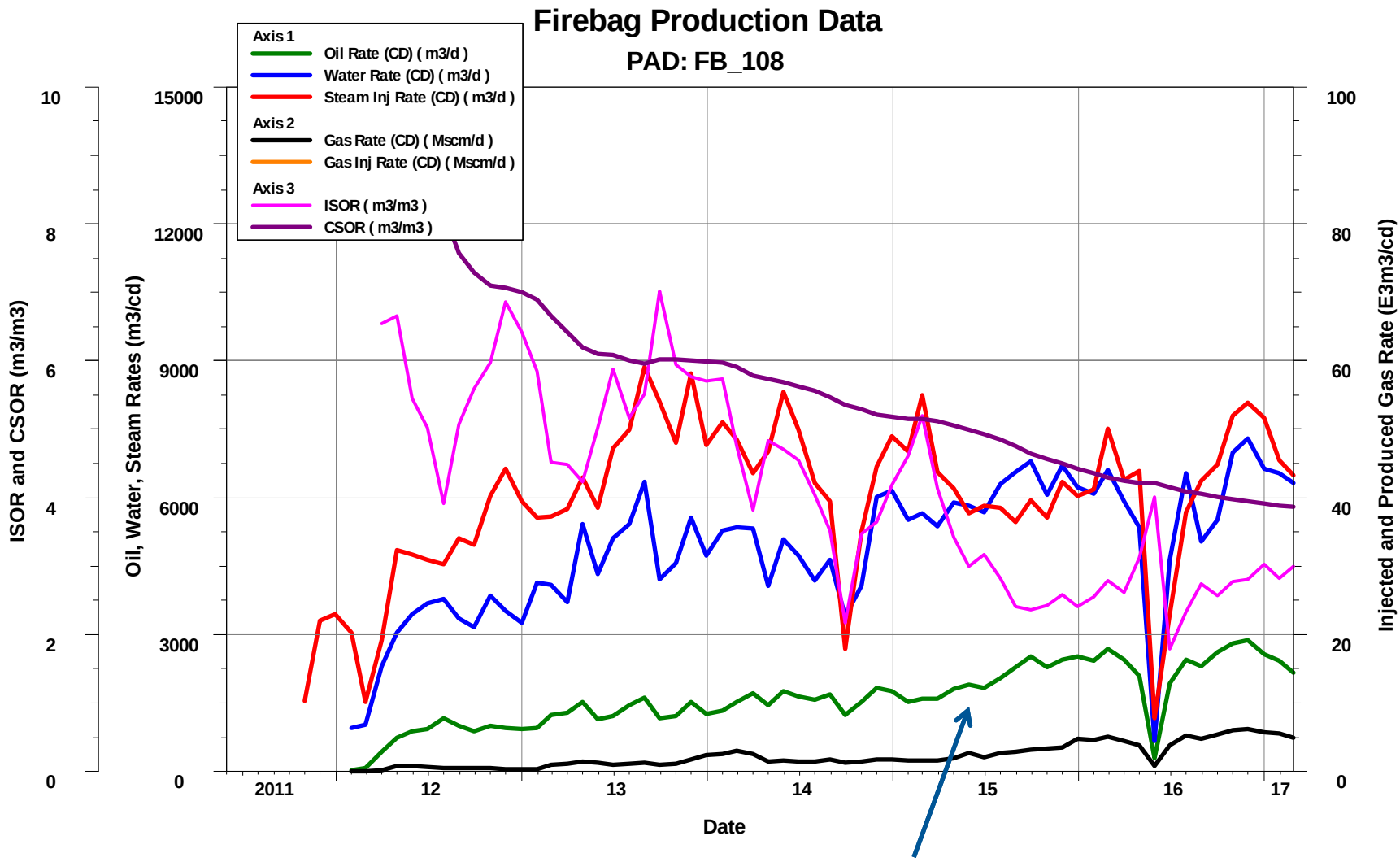


2013 2014 2015 2016

Pad 108 Performance - Low Recovery Pad

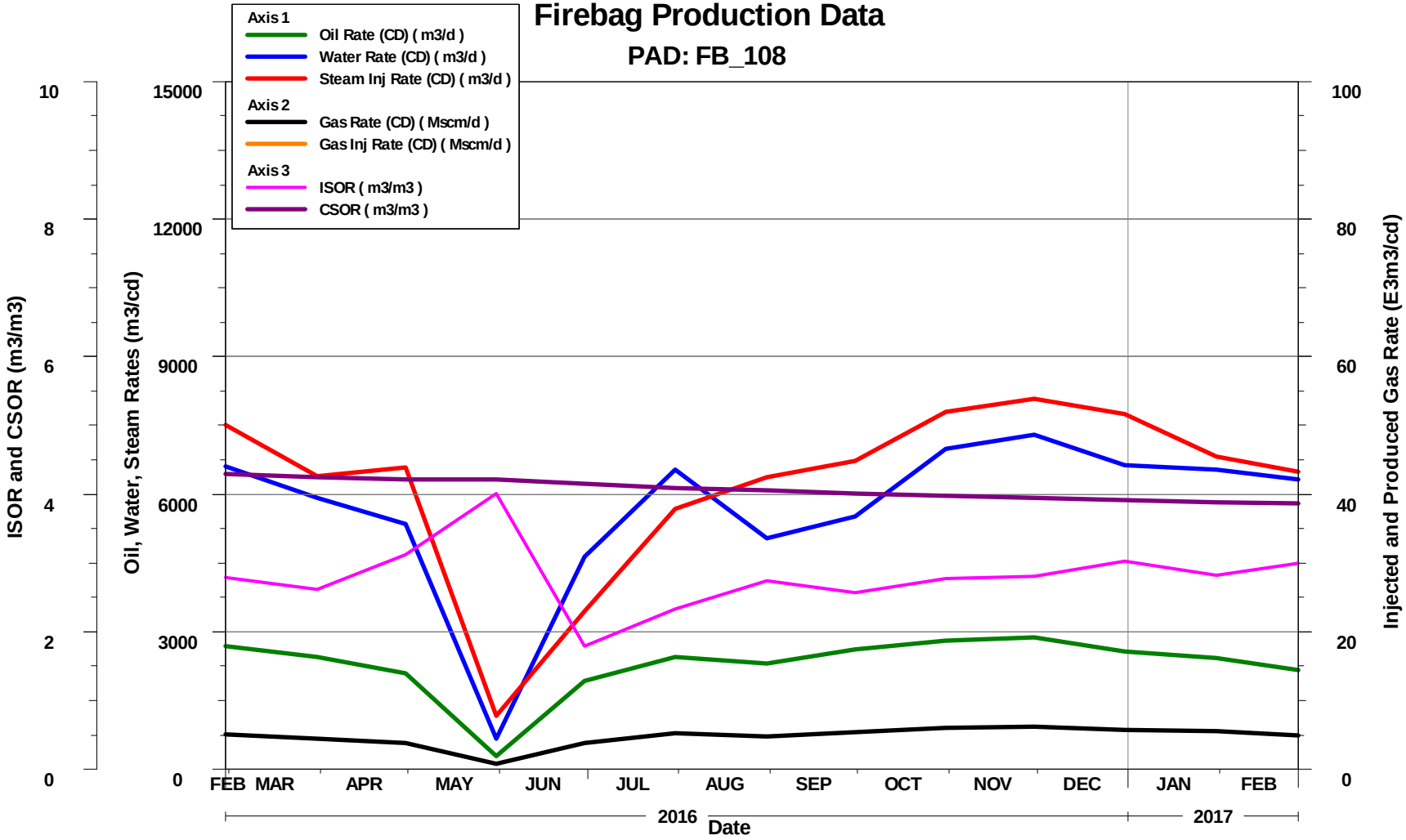
- Pad 108
  - 14 wells currently on production
  - First oil in Jan 2012
  - Monthly steam chamber pressures:
    - Average: 2,251 kPag
    - Range: 2,113 kPag – 2,344 kPag
  - Performance as of Feb. 28, 2017:
    - Cumulative steam injected is 11,772,209 m^3
    - Cumulative oil produced is 3,042,234 m^3
    - Cumulative SOR = 3.87 m^3/m^3
    - Recovery Factor of 18%
  - Pad Learnings
    - Steam chamber coalescence with mature pads providing optimization opportunities
    - Geological complexities can cause performance challenges

Pad 108 Performance

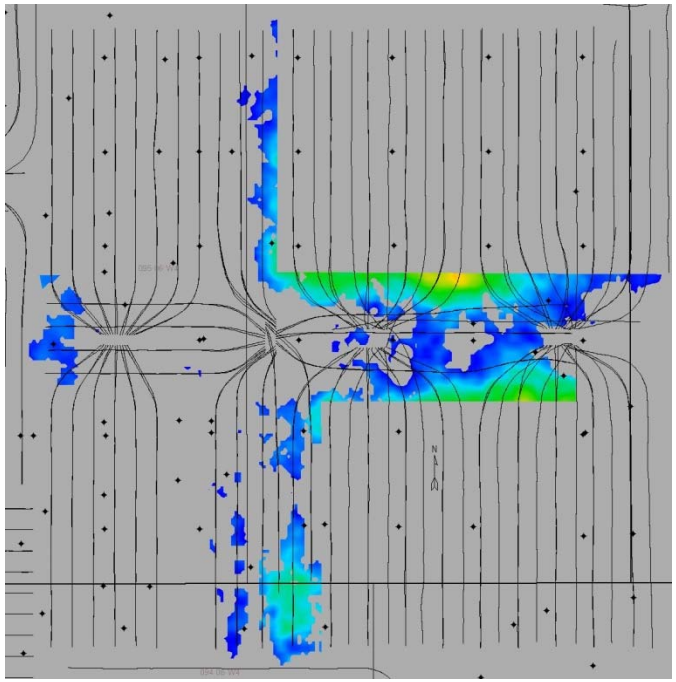


2 new wells
and 1 infill

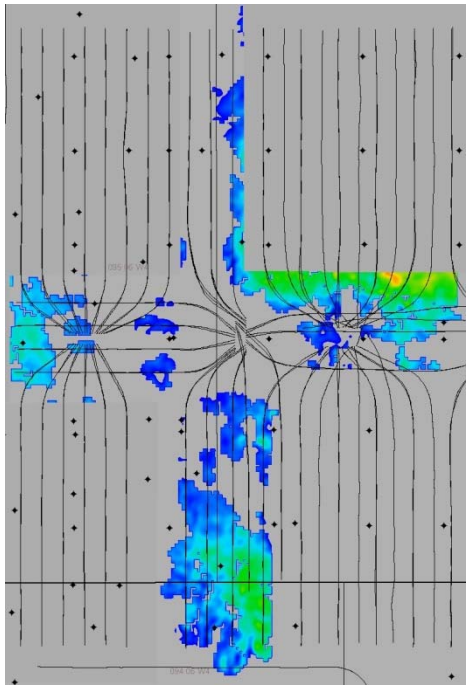
Pad 108 Performance



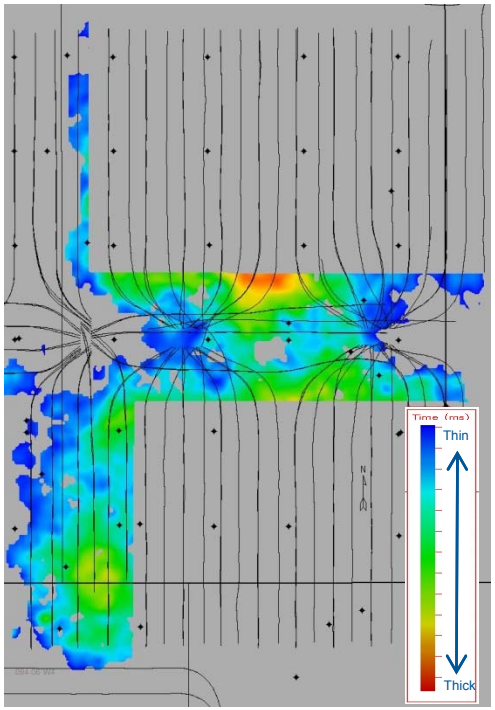
Pad 108 Performance – 4D Seismic Time Delay



2012



2013



2014

Future Plans – Pad Abandonments

- Do not anticipate abandonment of any SAGD pads within the next 5 years

Summary of Closure and Land Reclamation Activities (Ha)

Facility	Permanent Reclamation Activities						Reclaimed	
	[ha]							
	Pad Materials Removed	Recontoured	Soils Placed	Revegetated	Wetland Reclamation Trial Area	Total Area Undergoing Reclamation	Permanently Reclaimed	Area Certified
Borrow Pit 2	0	0	0	0	0	0	1	0
Borrow Pit 3	0	0	0	0	0	0	0	0
Borrow Pit 4	0	0	1	0	0	1	0	0
Borrow Pit 5	0	0	0	0	0	0	1	0
Borrow Pit 6	0	0	0	0	0	0	5	0
Borrow Pit 8	0	0	0	0	0	0	1.4	0
Borrow Pit 9	0	0	0	0	0	0	0	0
Borrow Pit 13	0	0	0	0	0	0	0	0
Borrow Pit 14	0	0	6	0	0	6	0	0
Borrow Pit 38	0	0	0	0	0	0	0	0
Camp (MLL0036)	0	0	0	0	0	0	0	0
Construction Yard	0	0	0	0	0	0	0	0
CPF Stages 1 to 6	0	0	0	0	0	0	0	0
East Athabasca Highway (EAH)	0	0	0	0	0	0	0	0
Electrical Substations	0	0	0	0	0	0	0	0
ETS plant	0	0	0	0	0	0	0	0
Firebag Village	0	0	0	0	0	0	0	0
Firebreaks	0	0	0	0	0	0	0	0
Observation, Monitoring and Disposal Wells	0	0	0	0	0	0	0	0
Old Canterra Road	0	0	0	0	0.8	0.8	0	0
Reclamation Material Stockpile Area	0	0	0	0	0	0	0	0
Storage Site	0	0	0	0	0	0	1	0
Waste Management Facility	0	0	1	0	0	1	0	0
Wellpad 101	0	0	0	0	0	0	0	0
Wellpad 102	0	0	0	0	0	0	0	0
Wellpad 103	0	0	0	0	0	0	0	0
Wellpad 104	0	0	0	0	0	0	0	0

Summary of Closure and Land Reclamation Activities (Ha)

Facility	Permanent Reclamation Activities						Reclaimed	
	[ha]							
	Pad Materials Removed	Recontoured	Soils Placed	Revegetated	Wetland Reclamation Trial Area	Total Area Undergoing Reclamation	Permanently Reclaimed	Area Certified
Wellpad 105	0	0	0	0	0	0	0	0
Wellpad 106	0	0	0	0	0	0	0	0
Wellpad 106 Road	0	0	0	0	0	0	3	0
Wellpad 107	0	0	0	0	0	0	0	0
Wellpad 108	0	0	0	0	0	0	0	0
Wellpad 109	0	0	0	0	0	0	0	0
Wellpad 110	0	0	0.9	0	0	0.9	0	0
Wellpad 111	0	0	0	0	0	0	0	0
Wellpad 112	0	0	0	0	0	0	0	0
Wellpad 114	0	0	0	0	0	0	0	0
Wellpad 115	0	0	0.7	0	0	0.7	0	0
Wellpad 116	0	0	0	0	0	0	0	0
Wellpad 117	0	0	0	0	0	0	0	0
Wellpad 118	0	0	0	0	0	0	0	0
Wellpad 123	0	0	0	0	0	0	0	0
Remote Sumps	0	0	0	0	0	0	0	0
Security Gate	0	0	0	0	0	0	0	0
Engineered Wetlands	0	0	0	0	0	0	0	0
Total	0	0	9.6	0	0.8	10.4	15	0

Notes: Access roads are included in associated facility areas.
CPF = Central Processing Facility; ETS = Enhanced Thermal Solvent; ha = hectare.

Steam Injection Properties

- Approved MOP of currently producing pads:
  - 4,040 kPag (251°C) during startup
  - 3,570 kPag (243°C) during SAGD
- Average monthly casing injection pressure during Feb. 2017 (as measured by blanket gas) was 2,380 kPag (224°C)
- Steam quality decreases between the central plant and the pads
  - Steam quality leaving the plant is approximately 100% at 11 MPag
  - Steam quality at the wellhead is not measured, but has been modelled and estimated to be 95%
- These conditions are in line with those in the original design

Steam Injection Properties

- The transportation distance from the central plant to the pads in which steam can be delivered at reasonable qualities will vary depending upon:
  - Line size
  - Insulation thickness
  - Initial pressure
  - Desired steam rate

- Steam transport distance remains economic at approximately 10 km from Firebag facility
  - Current longest steam transport distance to an operating pad is approximately 6 km

Steam Strategy

- Operating Pressure
  - Operating pressures ranged from 1,900-2,400 kPag chamber pressure in SAGD, depending on the pad
  - Plan to drop chamber pressures on mature wells over next few years
- Under normal operating conditions, steam is allocated to balance chamber pressures across patterns
- In periods of lower steam supply, priority generally given to younger wells

Summary of Key Learnings

- Infill Performance and Operation
- Bullheading
- Pad 101 NCG Pilot
- Pad 104 North Surfactant Test
- Advanced reservoir management for improved energy efficiency
- 2016 Wildfire Learnings

Summary of Key Learnings

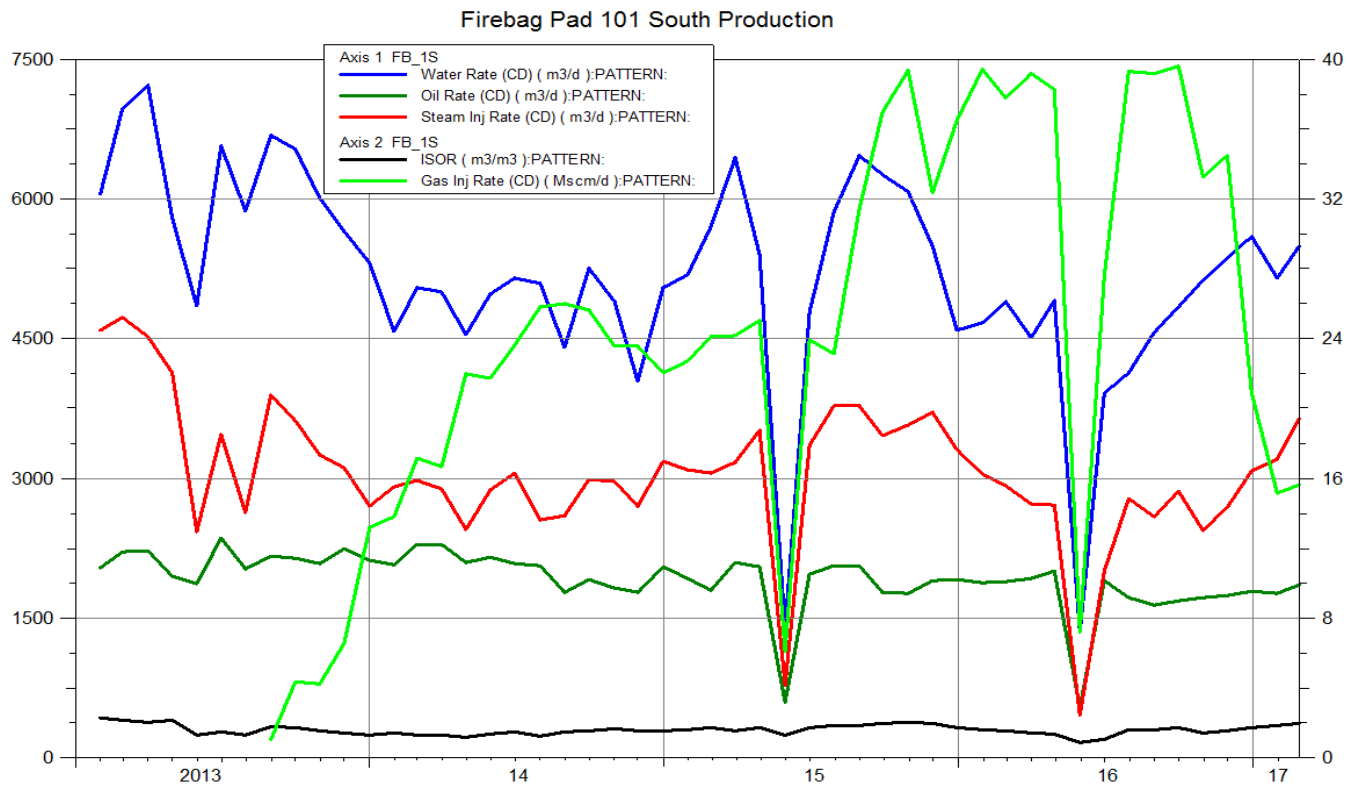
- Infill Performance
  - Total 38 infills to date, average oil production of 1,250 bopd (200 m^3/d)
  - Bottom hole temperatures vary greatly well to well
    - Depends on nearby wells' steam chamber development and when the infills are brought on production
    - Some infills require multiple steaming cycles while others encounter steam chamber and require suspension (e.g. 3N7)
  - Optimal timing on infill well drilling is highly variable and needs to be assessed based on geology/steam chamber development in infill location (use of 4D seismic data)
  - During production, infill/base well interaction needs to be managed to optimize performance at a chamber level
  - Positive impacts on SOR and WOR, which improve overall field performance

Summary of Key Learnings

- Bullheading Startup
  - Operates within AER approved MOP
  - Injecting steam into the reservoir without circulating a portion of the steam back to surface
  - By not taking returns, bullheading:
    - Requires less cumulative steam to achieve the same reservoir heating as circulation
    - Reduces CSOR and thus emissions/bbl produced
  - Bullheading startup to date: 105, 107, 108, 109, 110, 116, 104/103 Infills, 115 and 117
  - Circulation considered when bullheading is unable to achieve target injection rate under MOP

Summary of Key Learnings

- Pad 101 NCG Pilot Co-injection
  - Impact to resource recovery is not anticipated
  - Significant NCG partial pressure effects have not been observed
  - NCG return production is not significant enough with current injection rates to be empirically substantiated
  - No detrimental impact on oil rate has been observed
  - NCG injection cut back in late 2016 due to gas supply issues



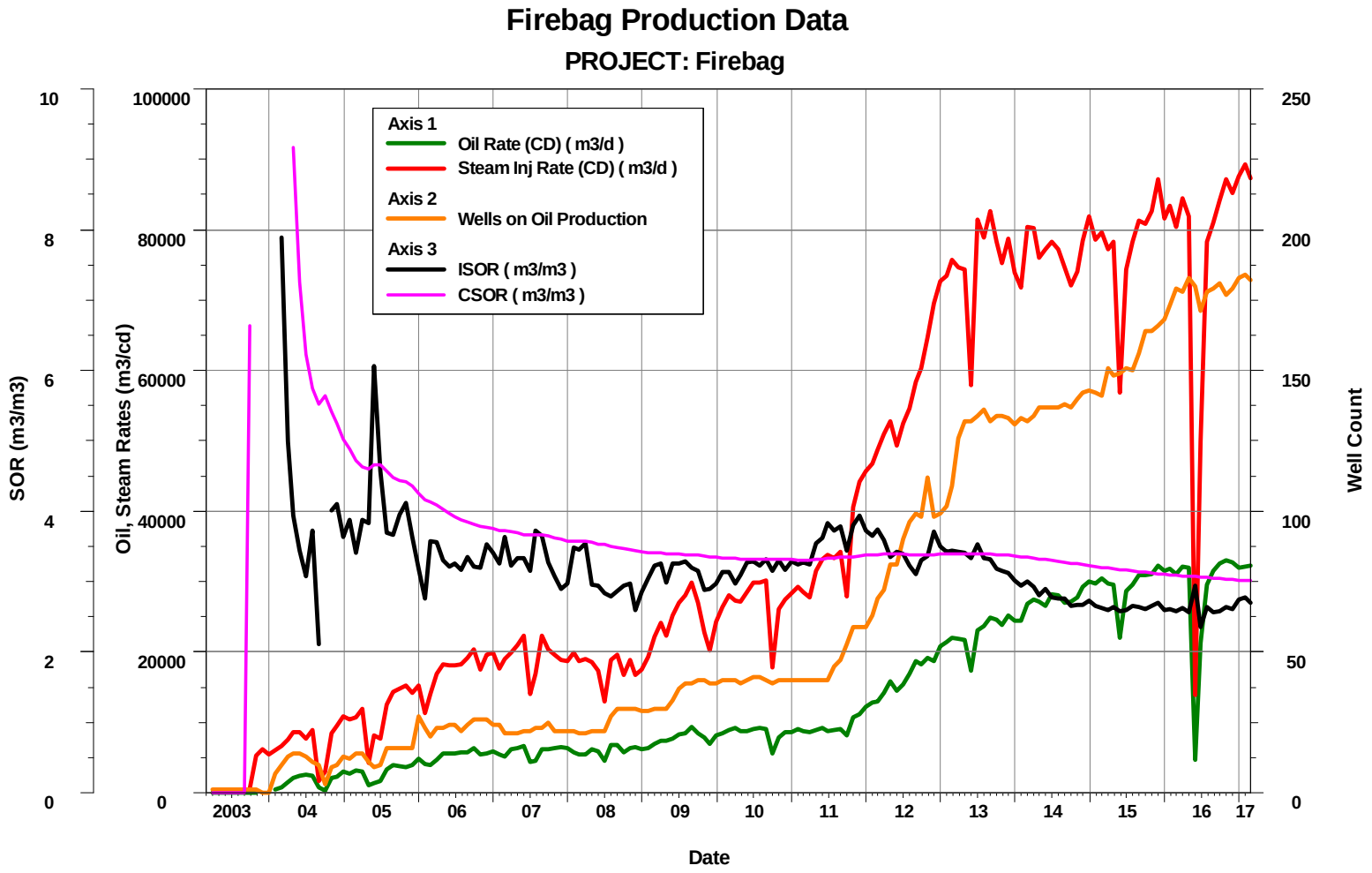
NCG Composition	
C1	91.90%
C2	5.02%
C3	1.38%
NC4	0.26%
IC4	0.20%
NC5	0.05%
IC5	0.06%
NC6	0.02%
NC7	0.01%
NC8	0.01%
HE	0.04%
H2	0.00%
N2	0.47%
CO2	0.59%
	100.00%

Summary of Key Learnings

- Pad 104 North Surfactant Test
  - A surfactant aiming to improve interfacial tension in a high temperature environment was co-injected with steam in 3 wells of pad 104 north. Injection started in Q3 2015 and ended in Q1 2016
  - Effectiveness of this surfactant test was potentially impacted as a result of:
    - Delays delivering skids (~2 years) compromised the technology opportunity. The pilot was originally scoped for smaller steam chambers and in the absence of infill wells
    - Low dosage (volume) injected in the treated wells
  - No safety incidents, corrosion, or spills reported during the duration of this pilot
  - Suncor continues to identify promising surfactants for future pilot consideration

Summary of Key Learnings

- Advanced reservoir management for improved energy efficiency



Summary of Key Learnings

- Advanced reservoir management for improved energy efficiency
  - Steam prioritized to be directed towards younger pads to ensure stable steam chamber development
  - Optimize leak-off from edge well pairs to avoid losing energy to virgin reservoir
  - Balance steam chamber pressures between pads for optimization and also heat efficiency
    - Avoid energy lost through fluid migration into cold regions between steam chambers due to differential chamber pressures
  - Allocate steam from mature pads to new pads that are coming online
    - Total field steam injection is not increased while increasing production by steaming more pads
    - Chamber pressure in the mature pads is gradually reduced as a result
  - Conduct extended steam flush on wells with conformance issues and poor communication between injector and producer

Summary of Key Learnings

- 2016 Wildfire Learnings:
  - Affected production from May 3 to 27 due to Fort McMurray wildfire
  - Safely started 180+ wells without downhole overpressure incidents
  - Production restored to pre-wildfire level within a month of restart
  - Steam chambers are more resilient than expected. Less pressure/temperature loss with increasing pad age
  - Extended shut-in provided optimization opportunities and challenges:
    - Hot wells showed conformance improvement (healing hot spots)
    - Experienced the challenge of ramping up young pads

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- Safety Moment
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- Geoscience
- Surface Heave and Caprock Integrity
- Drilling and Completions
- Artificial Lift
- Instrumentation in Wells
- 4D Seismic
- Scheme Performance
- **Future Plans**
- Compliance Commitments

Future Plans – Regulatory Applications

- Approved Applications

Directive 78 Amendments	Description	Date Submitted	Date Approved	Approval
Non-Condensable Gas (NCG) Co-injection Expansion		24-Feb-16	2-Jun-16	8870JJJ
Chemical Co-injection	Pad 116	29-Jul-16	2-Sep-16	8870KKK
Daily Average Maximum Operating Pressure		26-Aug-16	7-Nov-16	8870LLL
Pad 122 Well Pair Surface Location and S10 Amendment	Pad 122	31-Oct-16	12-Dec-16	8870MMM
Pad 123 Gas Injection	Pad 123	12-Dec-16	26-Jan-17	8870NNN
NCG Co-injection on All Pad 107 Injectors	Pad 107	18-Dec-16	2-Feb-17	8870OOO
Pad 105 Infills	Pad 105	9-Jan-17	1-Mar-17	8870PPP
McMurray Gas Injection Test (Rich Zone)	OB183/ OB189	16-Feb-17	20-Mar-17	8870QQQ

- Future Applications
  - Geoscience and Reservoir Development teams are continuing work to determine optimal depletion plans for current and future pads
  - Continuing work on NCG co-injection next phase development and ES-SAGD testing

Future Plans – Drilling Activities

- There were no completed horizontal drilling activities during the reporting period
- There were no re-entries or re-drills during the reporting period
- No drilling is currently in progress
- Future Drilling
  - Pad 105 infills expected to commence drilling in Q3 2017
  - Pad 118 additional 2 injectors expected to commence drilling in Q1/Q2 2018
  - Coreholes/observation wells will be drilled as necessary to:
    - Adequately delineate the resource
    - Monitor SAGD operations
    - Further caprock integrity analysis
    - Hydrogeology analysis
    - Water disposal analysis
    - Land retention

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Future Plans – Testing

- McMurray Gas Injection Test in OB 183
  - Test planned for Q2 2017
- Pad 116 Surfactant Test
  - Test planned for Q4 2017
- Pad 123 Gas Injection Test
  - Test planned for Q2 2017

Future Plans – Pad Development

- Pad 114
  - First steam planned for Q3/Q4 2017
- Pad 118
  - First steam planned for Q3/Q4 2018
- Pads 112 and 121
  - First steam planned for 2019
- Pads 123, 122, 111
  - First steam planned between 2020-2022

- Development plans are evaluated annually and therefore subject to change

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- **Compliance Commitments**

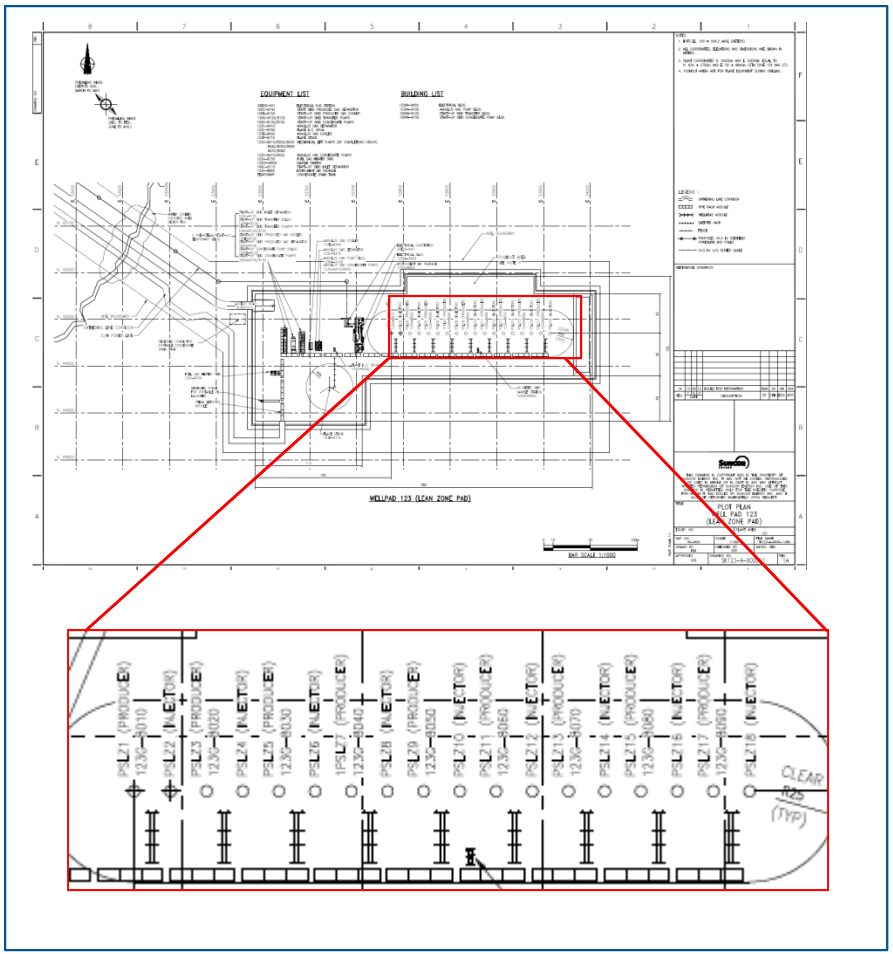
Compliance with Daily Average Maximum Operating Pressure

- Following occurrences are reported as per the daily average MWHIP approval (No. 8870LLL):

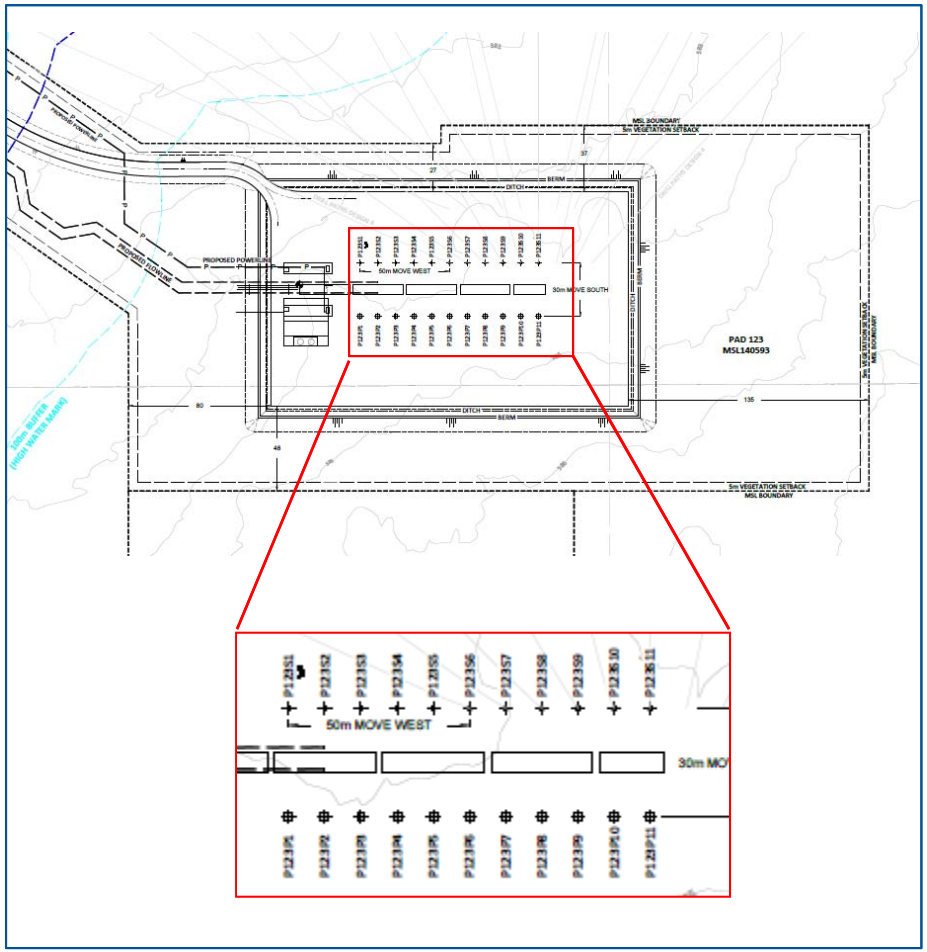
	Number of Occurrences	Date of Occurrence	Severity	Details of Occurrence
Maximum Wellhead Injection Pressure	1	6-Feb-17	Peak pressure: 3,622 kPa Daily Average Injection Pressure: 3,293 kPa Duration: < 1 min	1S9 tubing injection pressure briefly exceeded MWIP pressure of 3570 kPa due to control valve fluctuations. The pressure control valve responded to the exceedance immediately, bringing pressure below MWIP within 1 minute.
Maximum Wellhead Injection Pressure	1	23-Jan-17	Peak pressure: 3,751 kPa Daily Average Injection Pressure: 2,955 kPa Duration: 75 min	Following an increase of steam flow rate to the wellpair, 1S3 tubing injection pressure exceeded MWIP pressure of 3570 kPa. The control valve shut-in steam to the well within 1 minute, after which the wellhead pressure dropped below MWIP.
Maximum Wellhead Injection Pressure	1	22-Jan-17	Peak pressure: 3,961 kPa Daily Average Injection Pressure: 3,076 kPa Duration: < 1 min	1S4 tubing injection pressure briefly exceeded MWIP pressure of 3570 kPa. The control valve shut-in steam to the well within 1 minute, after which the wellhead pressure dropped below MWIP.
Maximum Wellhead Injection Pressure	1	9-Jan-17	Peak pressure: 4,142 kPa Daily Average Injection Pressure: 2,422 kPa Duration: < 1 min	2S4 casing injection pressure briefly exceeded MWIP pressure of 3570 kPa due to control valve fluctuations. The pressure control valve responded to the exceedance immediately, bringing pressure below MWIP within 1 minute.

- Corrective actions have been implemented to improve controller valve tuning to optimize valve response and decrease the likelihood of reoccurrence
- When necessary, maintenance work has been done to repair the affected equipment

Pad 123 Surface layout update*



Pad 123 Original Design Layout



Pad 123 New Design Layout

* As per correspondence during Pad 123 D78 application, Suncor is presenting the change in the surface layout of Pad 123 from a single row to the new two row design , as it was used to license wells on Pad 123

The new Pad 123 surface layout is 25% smaller than the old layout. Futures pads will see similar pad layouts as the new design.

Section 3.1.2 – Surface Operations, Compliance and Issues Not Related to Resource Evaluation and Recovery

Table of Contents

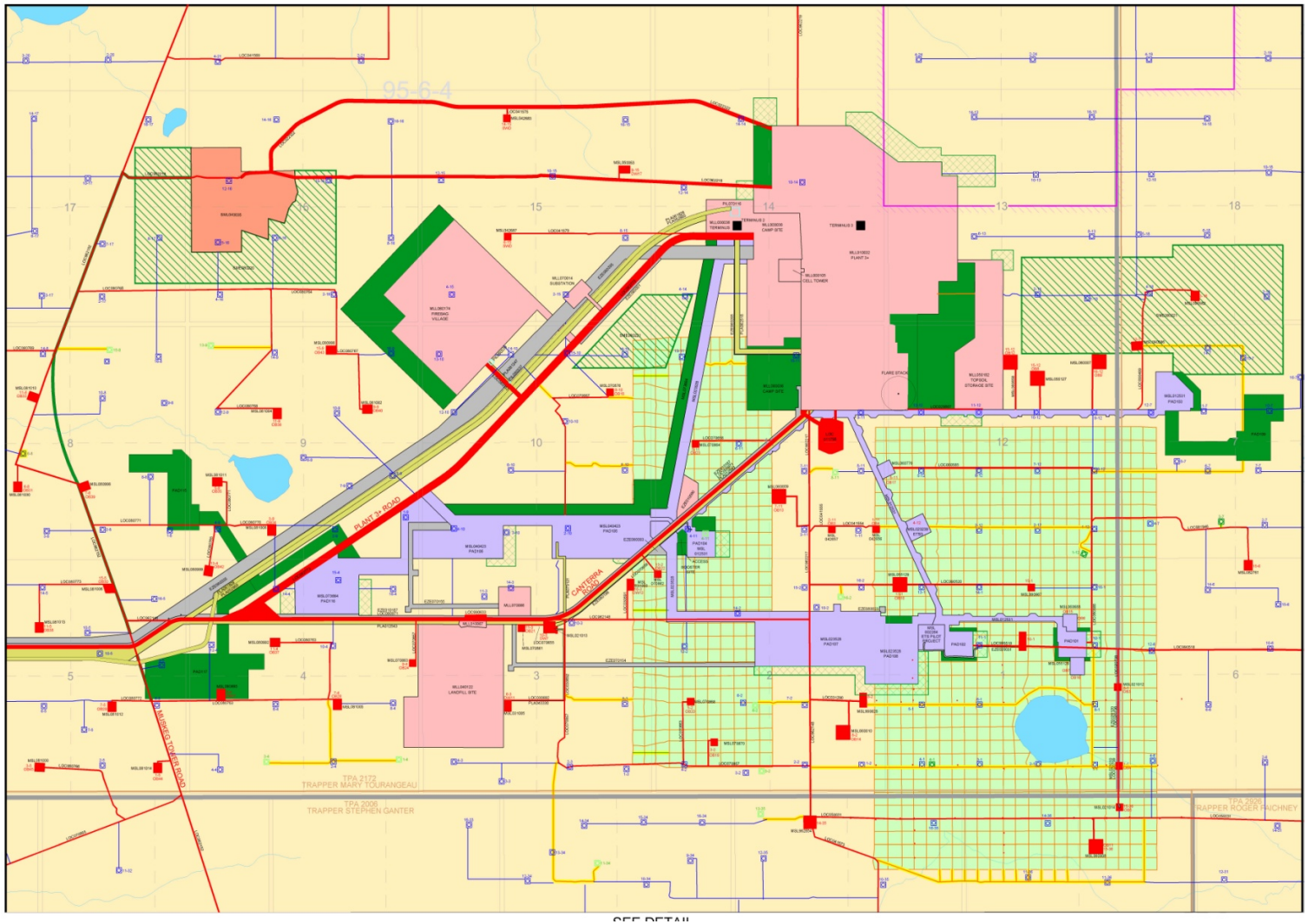
- **Operations and Facility Performance**
- Measurement and Reporting
- Water Production, Injection and Usage
- Sulphur Production
- Environmental Performance
- Future Plans

Firebag Performance Presentation

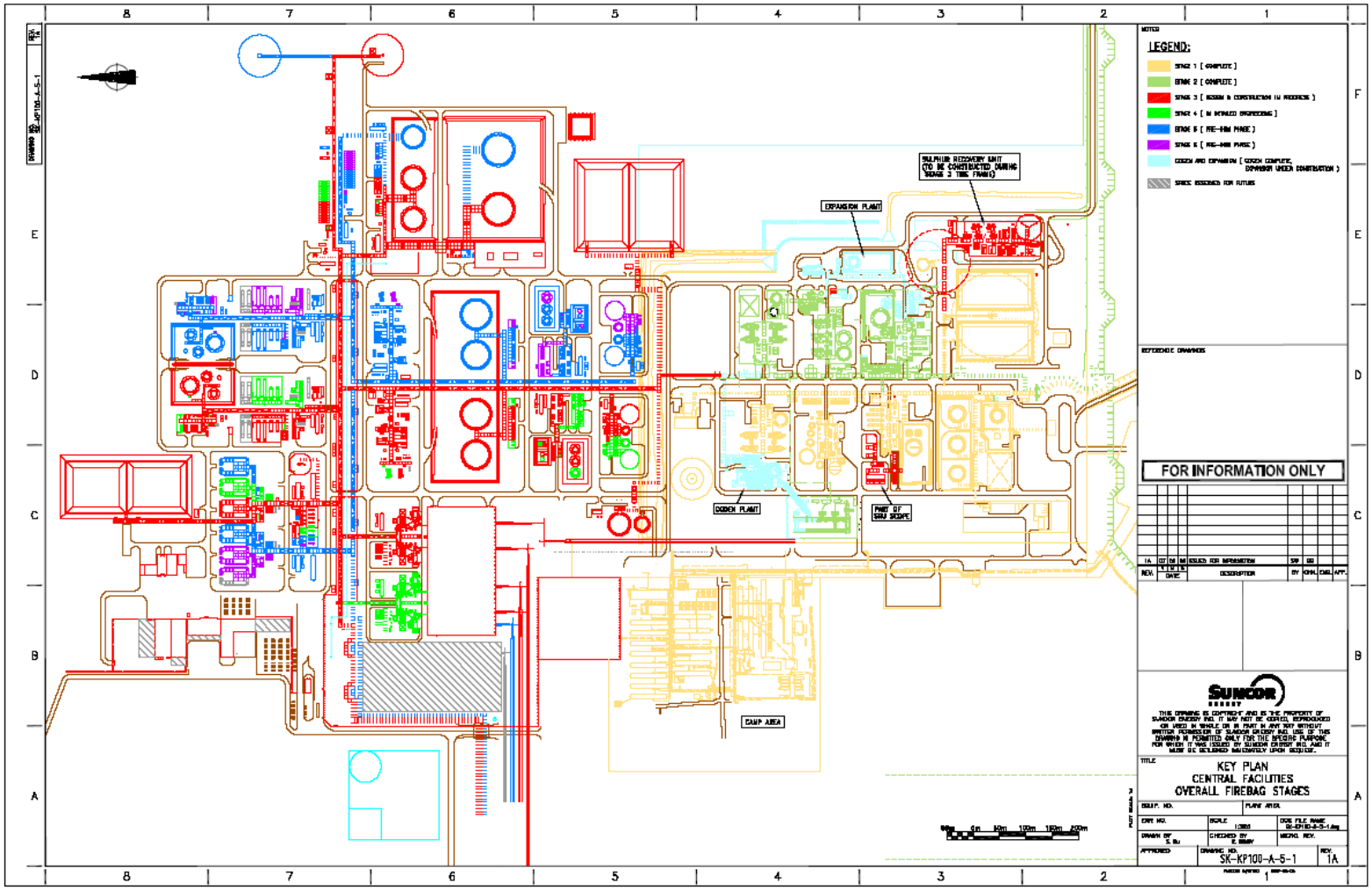
Operations and Facility Performance

May 9th, 2017

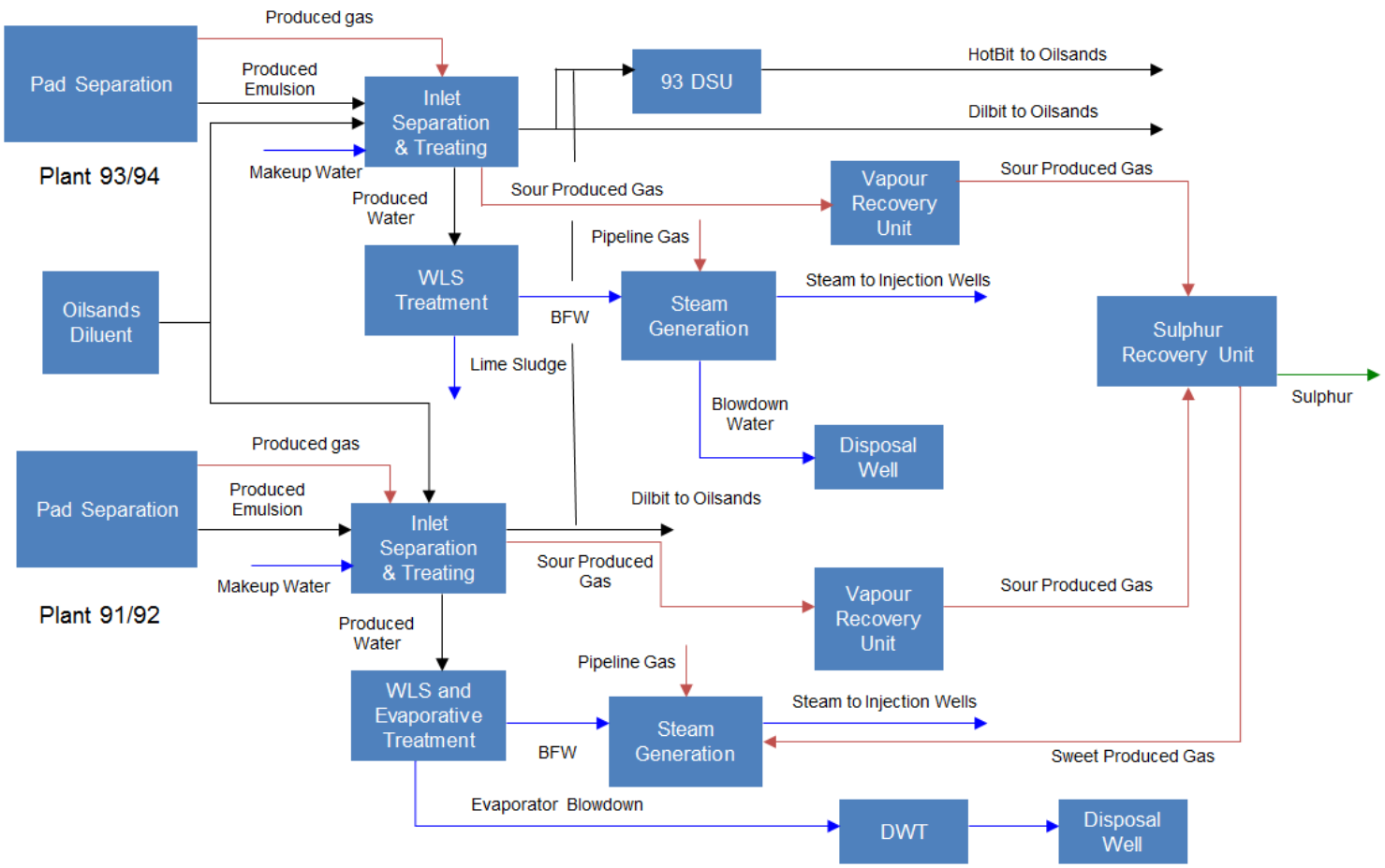
Site Survey Plan



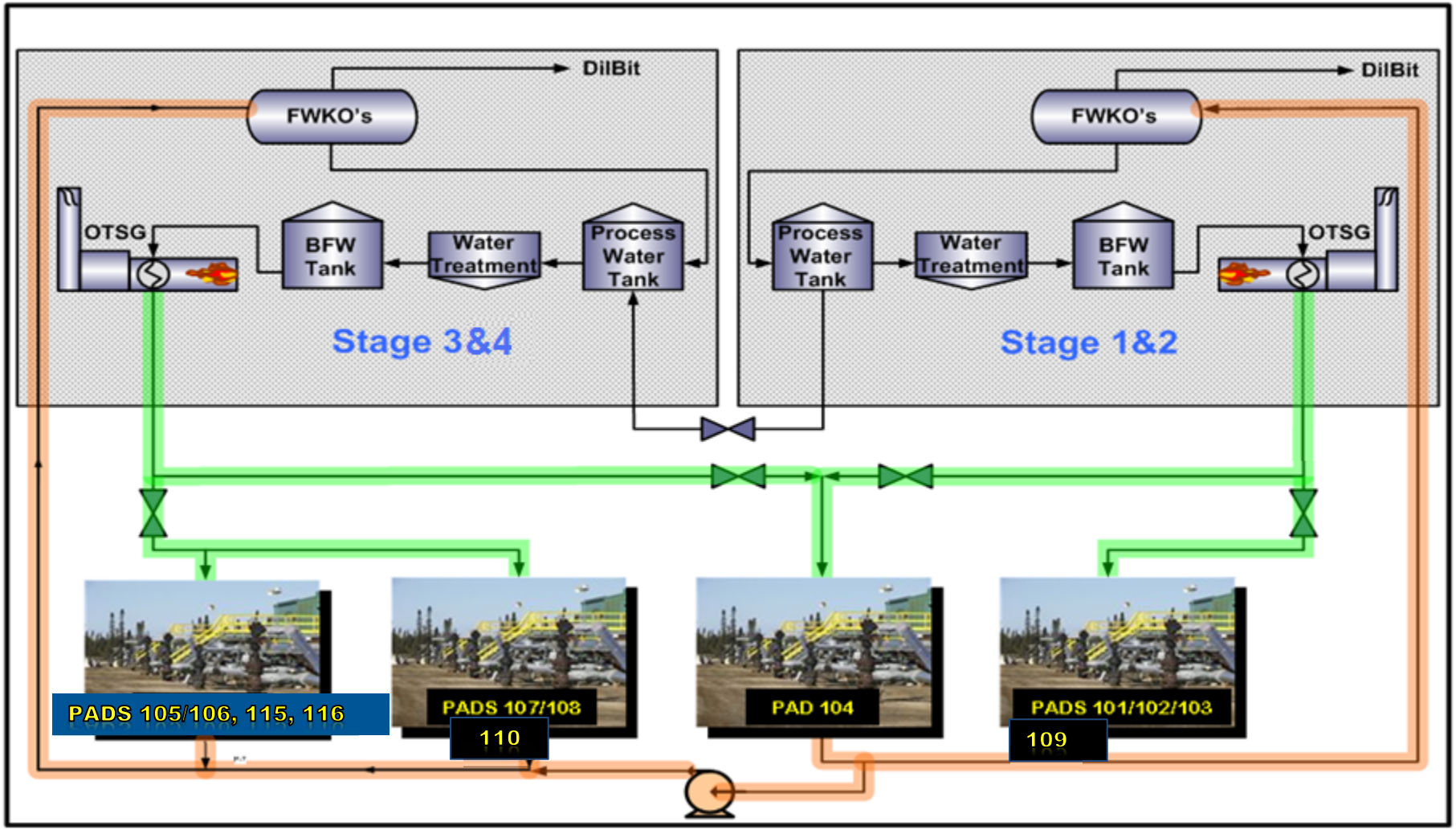
Firebag Site Layout



Firebag Simplified Process Block Diagram



Stages 1, 2, 3 & 4


DilBit
FWKO's
OTSG
BFW Tank
Water Treatment
Process Water Tank
Stage 3&4
DilBit
FWKO's
Process Water Tank
Water Treatment
BFW Tank
OTSG
Stage 1&2
PADS 105/106, 115, 116
PADS 107/108
110
PAD 104
PADS 101/102/103
109

Oil Treatment Technologies

- All Plants
  - Free Water Knockout Drums and Treaters for bitumen separation
  - Inject diluent upstream of the free water knockout drum

- Plant 93/94 primary differences from Plant 91/92:
  - Produced gas cooling and liquid removal at the pads
  - Electrostatic grids in the Treaters
  - Spiral Produced Water Coolers versus conventional shell and tube
  - Oil Removal Filters (ORF's)

- Skim Tanks in Plant 91/92

- Micro-Bubble Flotation (MBF) in 92 Expansion and Plant 93/94

- Diluent Stripping Unit (DSU) that produces Hotbit and recovers diluent from Dilbit

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Oil Treatment Risks and Opportunities

- All Plants
  - Ongoing operation improvement to reduce venting incidents
    - Venting task force created to categorize venting causes in order effectively address them.
  - Ongoing flushing of utility water system to prevent corrosion
    - Biological corrosion is no longer a significant issue. However other sources of corrosion may still exist.
  - Debottlenecking opportunities via handling of the Produced Water.
    - Re-route Expansion Treater Dumps to Plant 91/92 Skim Tank to improve Expansion MBF performance and potentially increase Expansion throughput.
    - Evaluate different units' relief capacities where they are bottlenecks to find ways to address limitations.
  - Continuous improvement in the operation of the Oil Removal Filters.
  - Re-commission Plant 92 Inlet Separator to improve Plant overall performance.
  - Improve DSU operation by being able to go on full recycle with two furnaces operating to improve stability while operating on modified Hotbit mode.

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Water Treatment Technologies

- Water treatment technology used at Firebag:
  - Plant 91 - Warm Lime Softening (WLS), Filtration (Anthracite), Weak Acid Cation Exchange (WAC)
  - Plant 92 - Evaporators and Disposal Water Treatment (DWT) Technology
  - Plant 93 – WLS, Filtration (Walnut Shell), WAC
  - Plant 94 – WLS, Filtration (Walnut Shell), WAC

Water Treatment Risks and Opportunities

- 91 – WLS Performance
  - Chemical Optimization

- 92 – Evaporator Improvement Trials
  - Targeting extended run times between chemical cleanings and vessel entries for mechanical cleaning

- 93/94 – WLS Performance
  - Improve chemical system reliability
  - Chemical reduction and optimization
  - Reduction of off-spec incidents

Steam Generation Risks and Opportunities

- Optimization of steam generation capacity during steam long situations
- Trialing new tube temperature monitoring equipment to help understand impact of water quality excursions
- Improved pigging frequency and use to maximize steam generator usage
- Improved reliability of 93/94 One Through Steam Generators (OTSGs) due to erosion/corrosion issues

Sulphur Recovery Technologies

- The Firebag Sulphur Recovery Complex (SRC) came online successfully in February 2011
- It consists of both an Amine Stripping Unit (ASU) and a Sulphur Recovery Unit (SRU)
- The SRC is an integral part in the development and operation of Firebag
- Two ASU Trains using MDEA for sour gas sweetening
- Two SRU trains utilizing a three stage Claus process. The capacity of each train is 13.5 T/day sulphur
- The Amine unit sweetens the produced gas which is used as fuel gas
- Since start-up, several constraints and challenges have been overcome to achieve a high sulphur recovery level

Sulphur Recovery Plant Risk and Opportunities

- Increased compressor throughput, in order to help excess PG handling result in increase in Production
- Improve plant reliability by reducing foaming upset condition through continues skimming
- Reduction of gas to the SRU by optimization of the blanket gas and additional cooling in plants 93/94/DSU

	Average Inlet Sulphur (tonnes/day)	Sulphur recovery (%)	Sulphur Balance (%)	Sour Gas Flared (e3m3)	Sulphur Flared (tonnes)
Q2 2016	6.6	91.9%	2.5%	585.9	24.2
Q3 2016	9.9	97.8%	3.7%	88.7	2.0
Q4 2016	11.1	98.3%	3.9%	35.4	0.9
Q1 2017	11.2	98.4%	3.1%	17.6	0.8

Pads/Gathering Technologies

- Currently: 12 Pads and 190 Producing Wells
- New Pads: Pad-109, Pad-110, Pad-117, Pad 104 infill
- Future Pads: 114, 112, 118 and 111 (Firebag development program)
- Produced emulsion from Pads 101 to 104 and 109 is transferred to Plant-91/92
- Booster pumps to transfer some of the emulsion from Pads-101-104 and Pad 109 to Plant-93/94
- Produced emulsion from Pads 105, 106, 107, 108, 116, 110, 115 ,117 is transferred to Plant-93/94

Boiler Feed Water (BFW) Quality

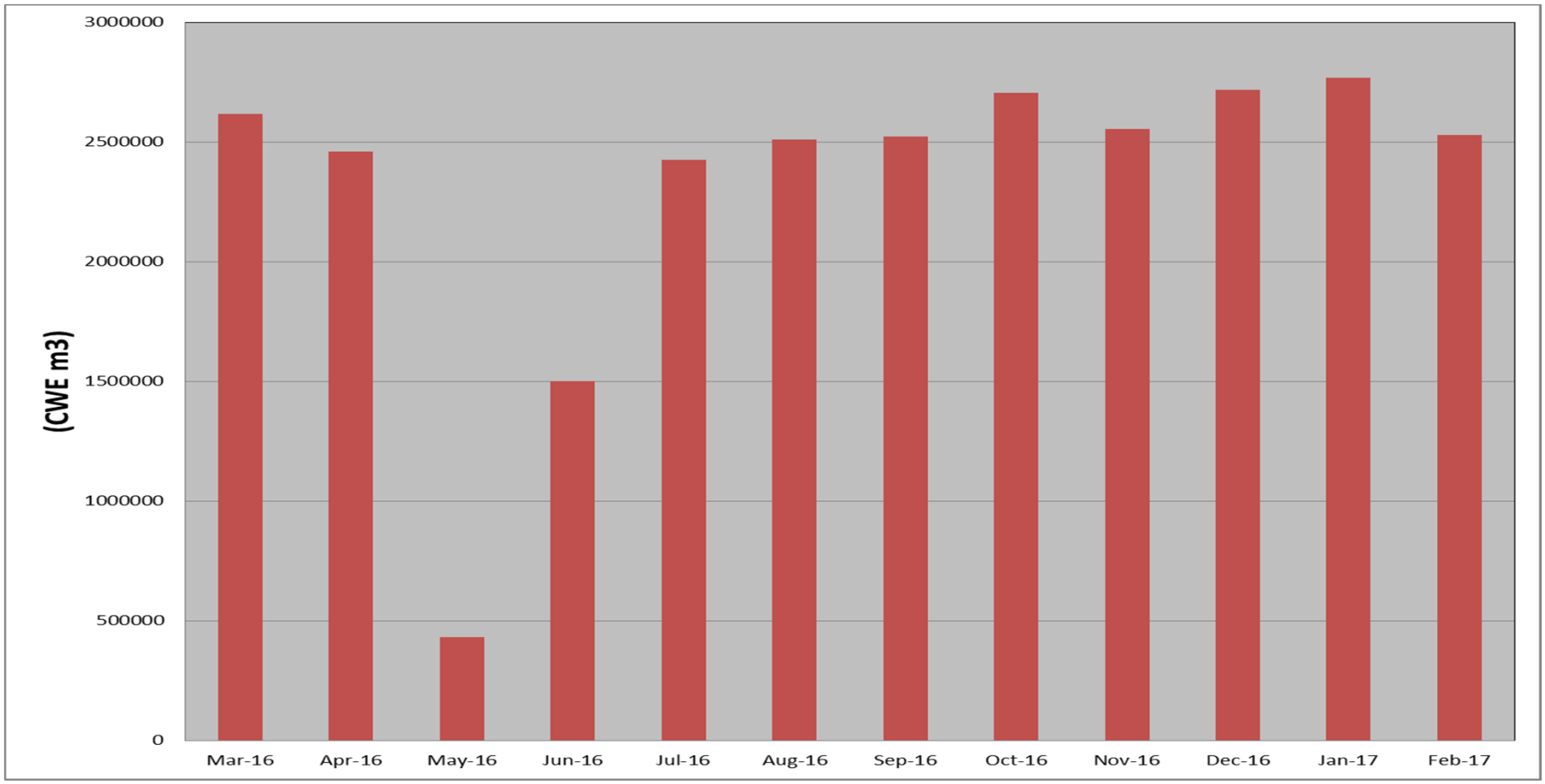
	Plant 91	Plant 92	Cogen (HRSG)	Plant 93/94
Total Dissolved Solids (mg/L)	1600	580	800	2100
Reactive Silica (mg/L)	38	12	17	20
Hardness (mg/L as $CaCO_3$)	<0.3	<0.3	<0.3	<0.3

Plant Improvements

- Continuous optimization of the Free Water Knockout (FWKO) and Deoiling to ensure onspec Basic Sediment & Water (BS&W) in Dilbit and Oil in Water
- Evaluate the relief capacities of various units Firebag to allow for increased capacity
- Optimized steam generation capacity during steam long situations to maximize energy efficiency by operating in their most efficient combustion zones
- Chemical cleaning and demister reliability program on 92 Evaporators to extend time between manned vessel entries
- Improved Water Treatment Plant Chemical Injection Reliability
- Improved the foaming issue in Amine unit significantly by automated skimming of water from stripper column reflux drum.
- Reduction in SOR assisted with higher DilBit production

Steam Injected

From March 2016 to February 2017, Firebag injected on average 75,986 m3/day of steam into the wells

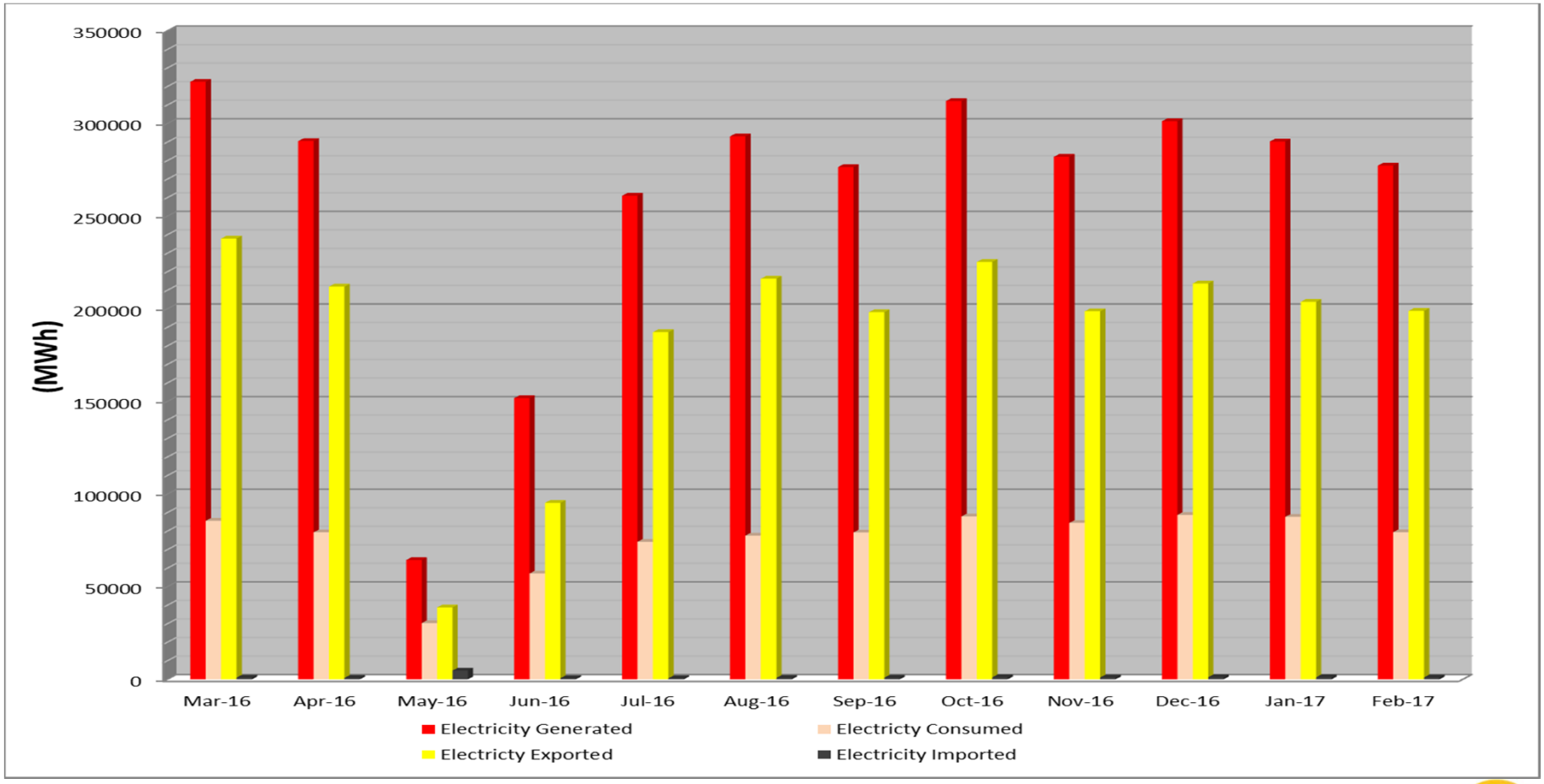


Steam Qualities

	Pland 91 OTSGs	Plant 92 OTSGs	Plant 91 Cogen	Plant 93 OTSGs	Plant 93 Cogens	Plant 94 OTSGs	Plant 94 Cogens
Mar-16	75.0	77.2	76.6	72.0	73.0	74.9	72.4
Apr-16	75.4	78.3	77.8	74.5	73.6	73.0	72.9
May-16	70.5	77.1	74.7	71.5	72.4	74.6	73.6
Jun-16	72.1	77.1	73.9	70.8	76.4	73.5	72.7
Jul-16	73.4	79.9	79.1	74.9	75.8	74.3	73.9
Aug-16	74.6	79.7	77.4	73.9	74.1	75.0	72.7
Sep-16	73.8	78.6	77.6	72.7	73.7	73.6	72.4
Oct-16	74.1	78.2	77.0	73.9	74.7	74.5	74.0
Nov-16	73.6	77.3	77.7	73.1	74.6	73.5	74.3
Dec-16	71.7	77.4	78.3	73.3	74.9	73.6	74.5
Jan-17	74.9	77.7	78.8	72.6	74.6	71.5	73.2
Feb-17	72.7	78.7	77.0	72.9	77.9	72.4	73.5
Average:	**73.5**	**78.1**	**77.2**	**73.0**	**74.7**	**73.7**	**73.3**

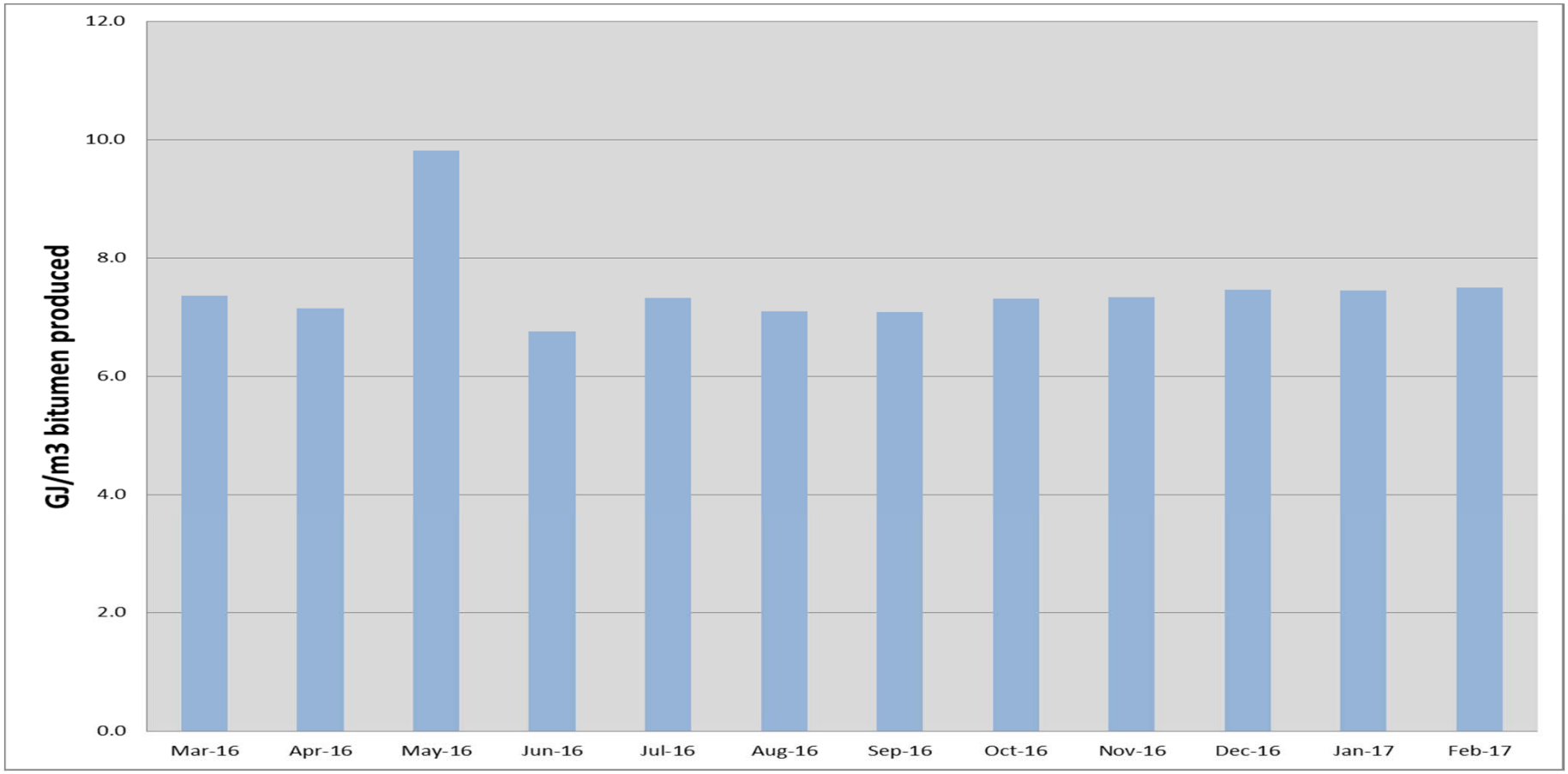
Electricity Generation/Consumption

From March 2016 to February 2017, Firebag generated 3,123 GW-hours of electricity, with 2,226 GW-hours being exported for sale



Energy Intensity

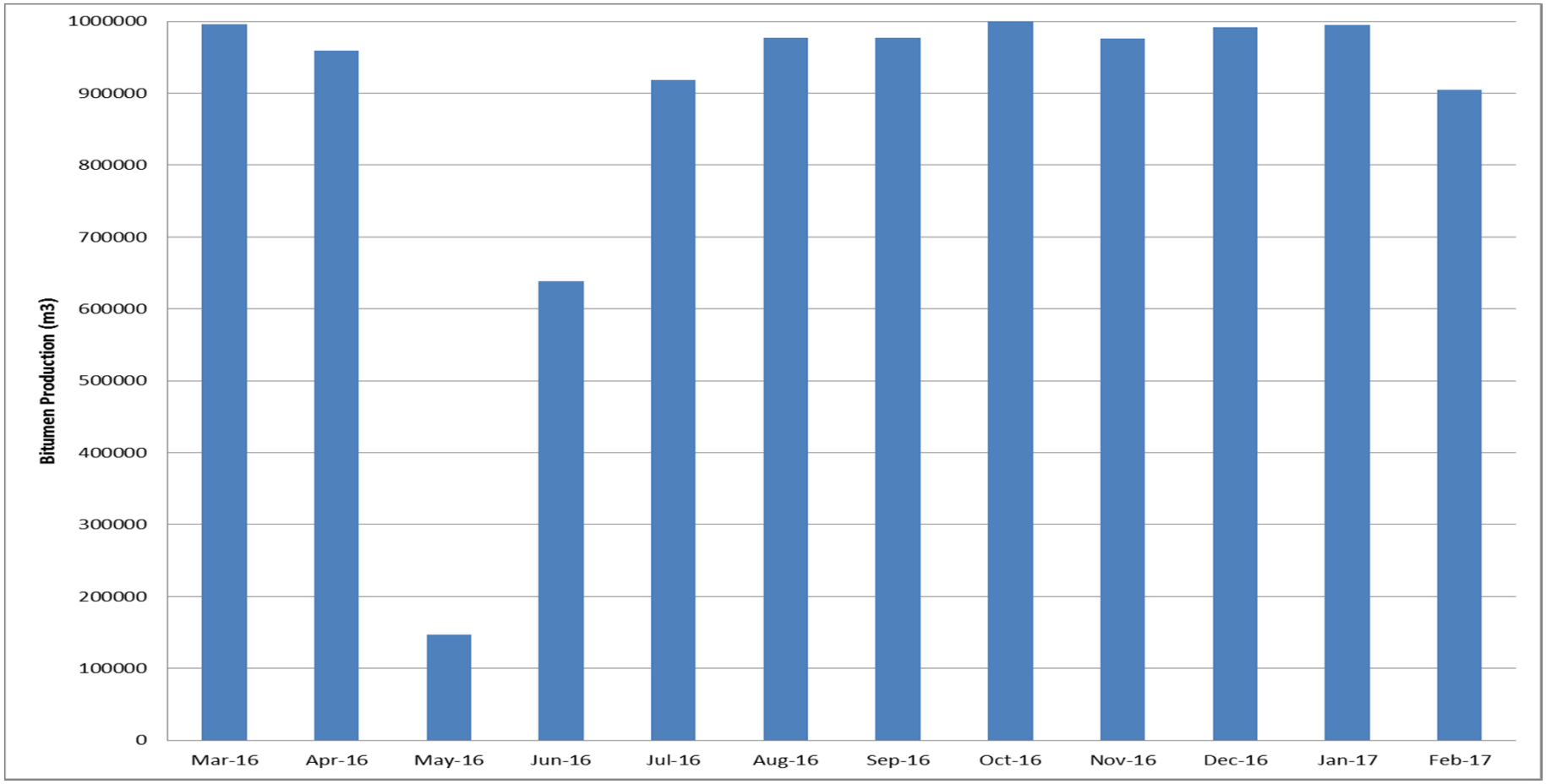
Firebag's average energy intensity was 7.5 GJ per m3 of production, from March 2016 to February 2017



Note: Energy Intensity includes all facility gas consumption and both electricity imported and exported

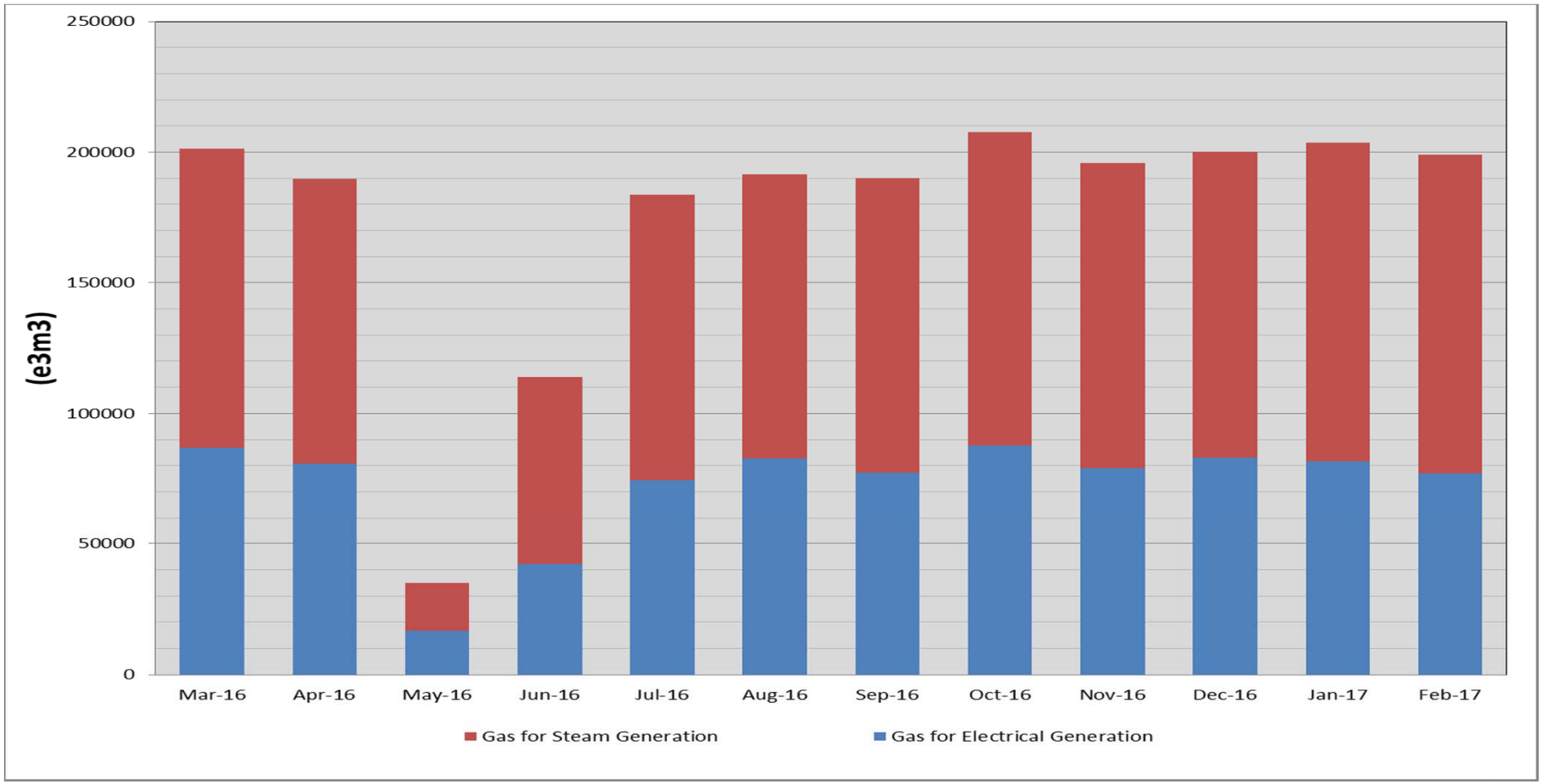
Monthly Bitumen Production

Firebag averaged 28,780 m3/day (181,020 BPD) of production from March 2016 to February 2017



Purchased Gas Usage

Firebag used on average 6,336 e3m3 of natural gas per day, from March 2016 to February 2017



Facility Environmental Performance

Emissions Parameter	Mar 2016 - Feb 2017
Solution Gas Produced (e^3m^3)	22,052.5
Solution Gas Flared (e^3m^3)	226.0
Solution Gas Vented[1] (e^3m^3)	115.3
Solution Gas Recovery	98.5%
Total Gas Flared (e^3m^3)	1171.4
Total Gas Vented[3] (e^3m^3)	115.3
H_2S Emissions[2] (kg)	14741.5

[1] Solution gas vented = gas vented from tanks upstream of produced gas separators (i.e. production tanks)

[2] H_2S emissions = H_2S gas vented at Firebag as communicated through the Digital Data Submission System (DDS)

[3] Total Gas Vented = gas vented at Firebag as communicated through the Digital Data Submission System (DDS)

GHG Emission Parameter	Jan 2016 – Dec 2016
2016 GHG Emissions (tonnes CO_2e) Calendar Year	4,809,852.4
2016 GHG Emission Intensity (tonnes CO_2e/m^3) Calendar Year	0.33

❖CO_2e is based on AENV SGER Reporting for the 2016 calendar year

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Measurement and Reporting

May 9th, 2017

Measurement, Accounting and Reporting Plan (MARP)

- 2016 MARP Audits
  - Internal EPAP audit
  - Facility Infrastructure Group audit
  - Detailed Operations Inspection – Tim Crest

- 2017 MARP Updates
  - Include Sulphur recovery calculations
  - General updates
  - Submit to AER in Q4

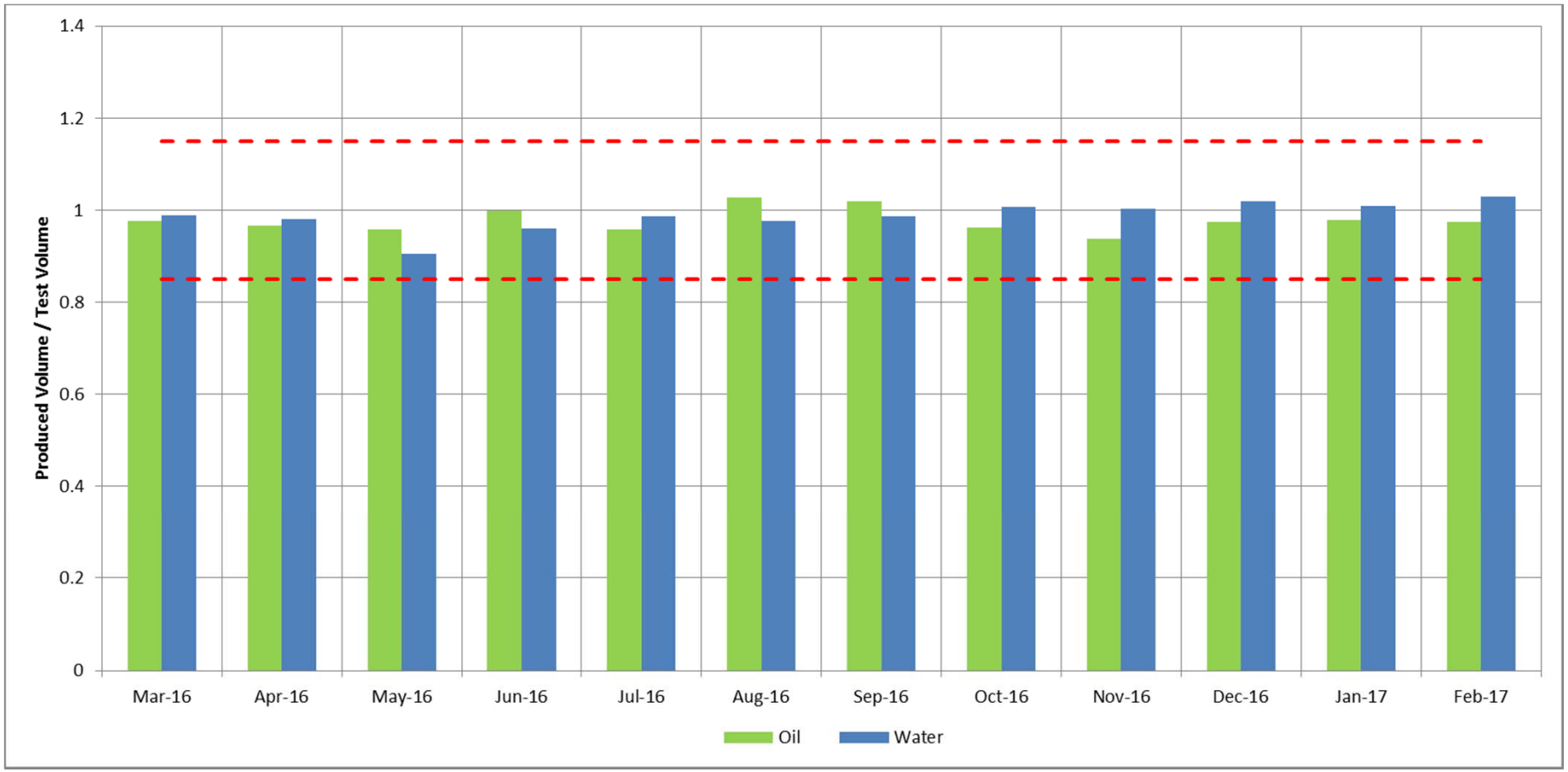
Estimating Well Production & Steam Injection Volumes

- Fluid production tests are performed as per Directive 17 requirements
- BS&W metering and manual cuts are applied to emulsion to determine water and oil production
- Well test bitumen is prorated based on facility bitumen production
- Well test water production is prorated on facility produced water
- Steam volumes are metered at the wellheads and prorated against the plant steam

Testing Improvements

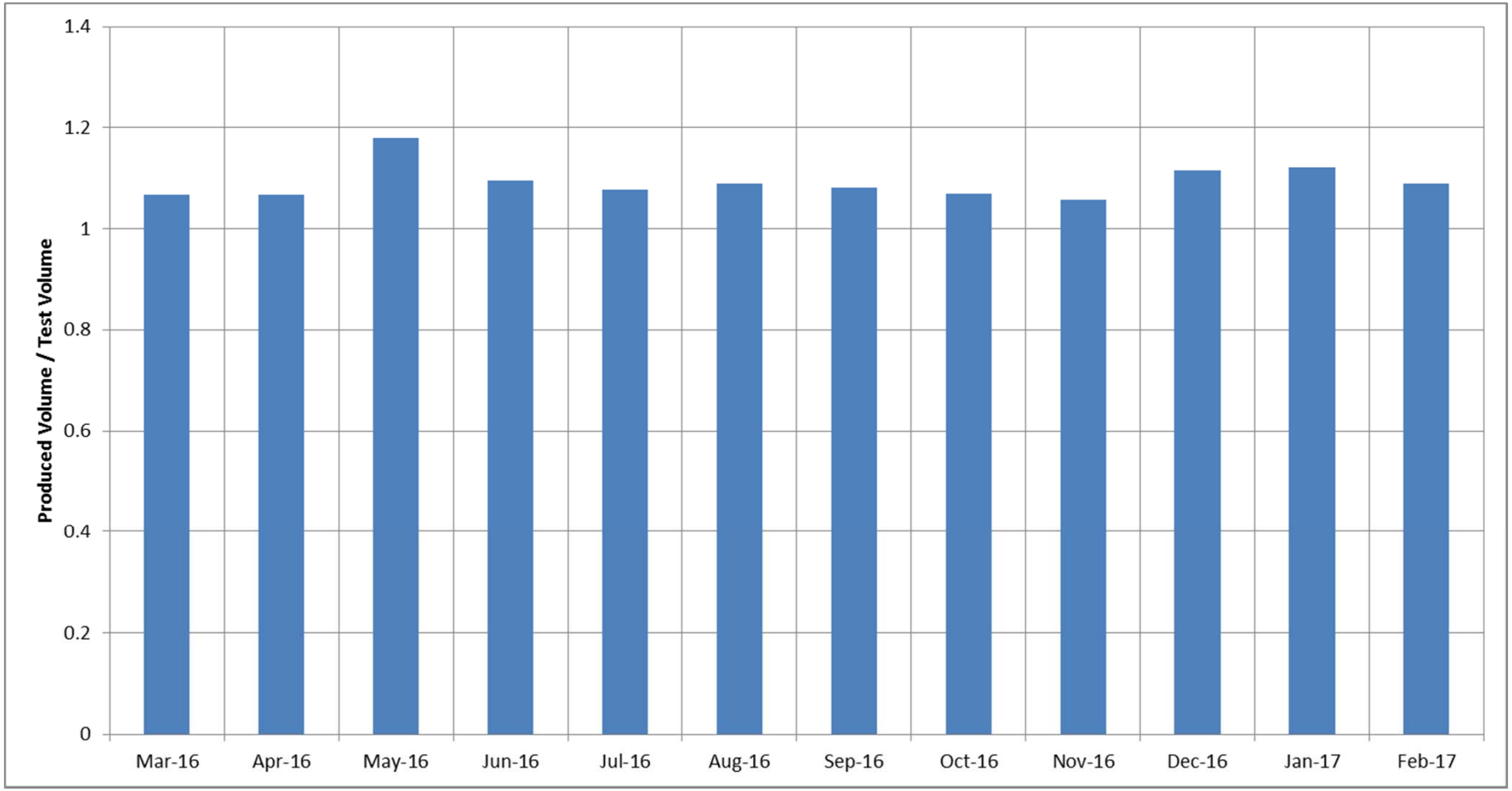
- Dec. 16, 2011 received approval for Multiphase Flow Meter (MPFM) on Pad 105 and future developments
- Fit for purpose Well Production Test software (WPT)
- MPFM now present on Pads 101 infills, 102 infills, 103 infills, 104 infills, 105, 106, 108 North, 115, 116, 110, 109, 117

Oil and Water Proration Values



Oil and water proration factors consistently well within Directive 17 limits through the reporting period

Steam Proration Values



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Water Production, Injection and Usage

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Water Sources

- Primary makeup water source for process operations is one waste water stream from Oil Sands Base Plant:
  - Pond Effluent Water (PEW): The total volume of PEW used from March 2016 to February 2017 was 84,889.3 m3 (2016 calendar year usage was 17,110.0 m^3)

Water Usage

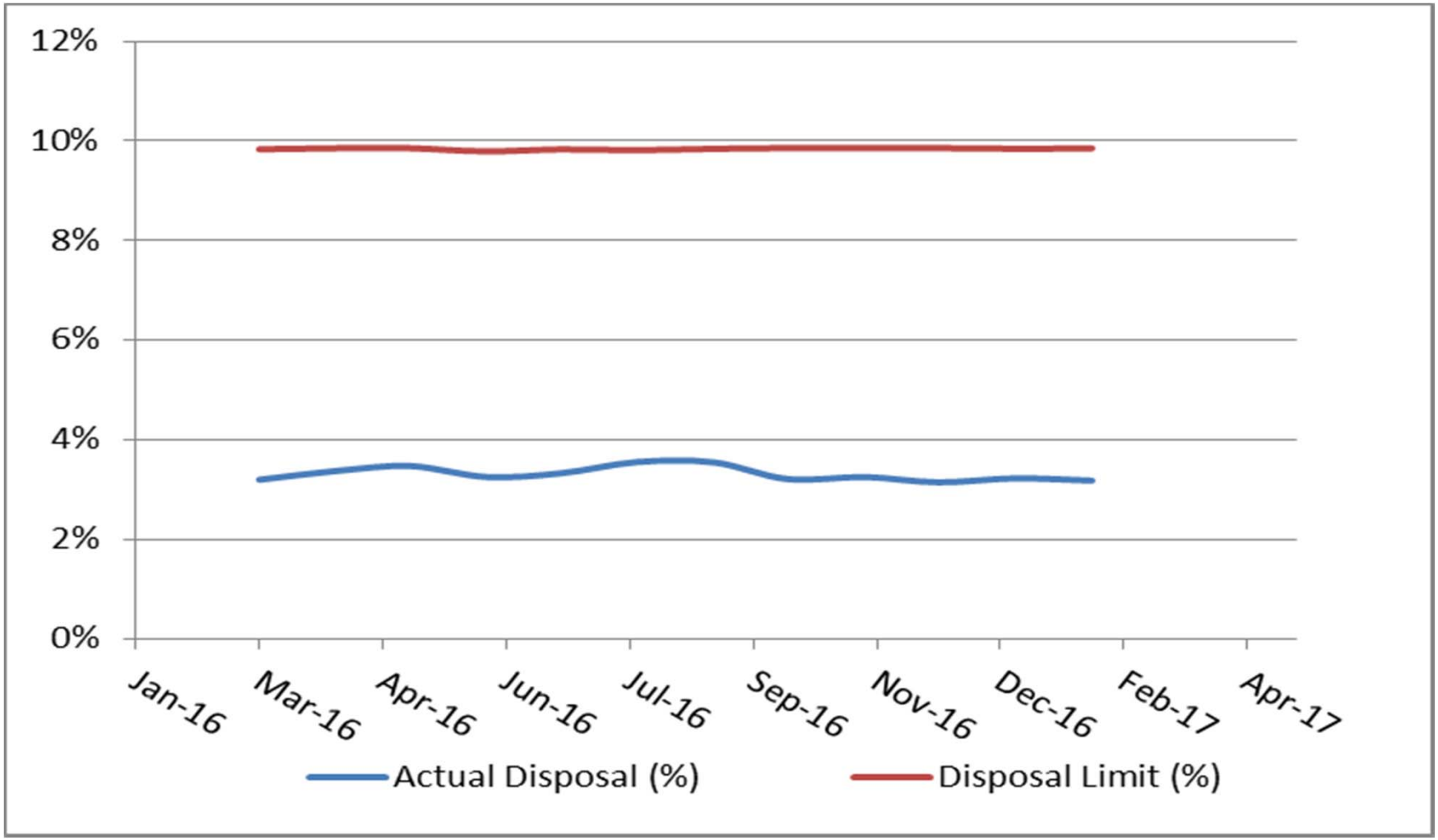
- Site runoff water (rainfall and snow melt) is routed to the site process ponds and reused in the process

- A total of 58,675 m^3 of storm water runoff water was diverted for process use from March 2016 to February 2017 (for the 2016 calendar year, usage was 58,410 m^3; 9,237 m^3 for the Stages 1/2 area and 49,173 m^3 for the Stages 3/4 area)

  - Water Act Approval 00310571-00-00 for ponds in NE 11-095-06-04-W4 (Stages 1/2 Area) for diversion of up to 95,000 m^3 annually
  - Water Act Approval 00310571-00-00 for ponds in SW 13-095-06-W4, NW 12-092-06-W4 and NE 14-095-06-W4 (Stages 3/4 Area) for diversion of up to 250,000 m^3 annually

- Water Act License 00233808 for Production Well 03-05 and 11-14-095-04-W4 as back-up supply for up to 620,500 m^3 annually. A total of 582,602 m^3 of well water was diverted for process use (utility water and firewater make-up) from March 2016 to February 2017.

Disposal Limits and Actual Disposal



* Calculated as per formulas stated in Directive 81: *Water Disposal Limits and Reporting Requirements for Thermal In Situ Oil Sands Schemes*

Waste Management – Disposal

Disposal Well Locations

- Current disposal wells:
  - 100/10-03-095-06W4/00
  - 100/06-03-095-06W4/00
  - 100/02-10-095-06W4/00
- All disposal wells approved for use as per Approval Class 1b Approval No. 9487G (February 12, 2016)

Overall Facility Water Balance

WATER BALANCE FOR OVERALL FIREBAG FACILITY										
	Fresh Water			Steam	Produced Water				Disposal	Imbalance
	FW1	FW4	FW5	INT	PW1	PW8	PW4	PW5	DIT	Scheme
	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	
Mar-16	66,428	24,056	23,727	2,615,824	2,753,101	54,069	185,232	171,506	93,260	2.3%
Apr-16	87,655	23,727	24,018	2,458,543	2,634,921	48,838	171,506	210,625	93,770	2.8%
May-16	40,122	24,018	23,201	430,841	391,620	9,298	210,625	193,017	15,860	-0.9%
Jun-16	49,919	23,201	23,993	1,499,119	1,643,060	39,203	193,017	207,390	77,268	3.3%
Jul-16	62,675	23,993	24,006	2,425,883	2,561,320	47,269	207,390	174,667	93,410	3.2%
Aug-16	70,504	24,006	23,948	2,508,401	2,634,280	54,147	174,667	164,093	102,441	1.7%
Sep-16	59,622	23,948	23,954	2,523,808	2,656,376	50,567	164,093	191,355	100,587	0.5%
Oct-16	59,514	23,954	24,003	2,704,020	2,862,715	54,855	191,355	187,244	99,683	2.2%
Nov-16	57,414	24,003	23,808	2,554,191	2,730,574	52,469	187,244	176,324	95,399	3.2%
Dec-16	58,163	23,808	23,973	2,717,588	2,782,575	42,214	176,324	139,543	94,657	0.8%
Jan-17	62,616	23,973	23,958	2,768,072	2,828,684	58,678	139,543	162,733	97,557	-1.8%
Feb-17	54,476	23,958	23,926	2,528,607	2,608,173	52,766	162,733	205,752	87,650	-1.7%

Waste Management – Disposal

Disposal Information – 100/10-03-095-06W4

(data shown is averaged across the month)

Month	Injection Rate (Sm3/day)	Wellhead Pressure (kPa-g)	Downhole Pressure (kPa-g)	Injection Temperature (^oC)
March-2016	599	1318	4904	50
April-2016	605	1366	4955	51
May-2016	222	176	3050	32
June-2016	852	521	3731	50
July-2016	672	1049	4759	54
August-2016	699	1170	4896	59
September-2016	773	1537	5077	55
October-2016	721	1381	4990	50
November-2016	668	1475	5103	50
December-2016	665	1475	5104	46
January-2017	688	1473	5094	47
February-2017	686	1533	5147	47

Waste Management – Disposal

Disposal Information – 100/06-03-095-06W4

(data shown is averaged across the month)

Month	Injection Rate (Sm3/day)	Wellhead Pressure (kPa-g)	Downhole Pressure (kPa-g)	Injection Temperature (^oC)
March-2016	347	1194	5131	49
April-2016	381	1234	5155	50
May-2016	72	192	3090	30
June-2016	169	597	3835	48
July-2016	512	1133	5065	53
August-2016	551	1264	5149	57
September-2016	550	1465	5302	53
October-2016	505	1324	5202	49
November-2016	501	1390	5298	49
December-2016	481	1399	5316	44
January-2017	475	1372	5286	45
February-2017	452	1414	5344	45

Waste Management – Disposal

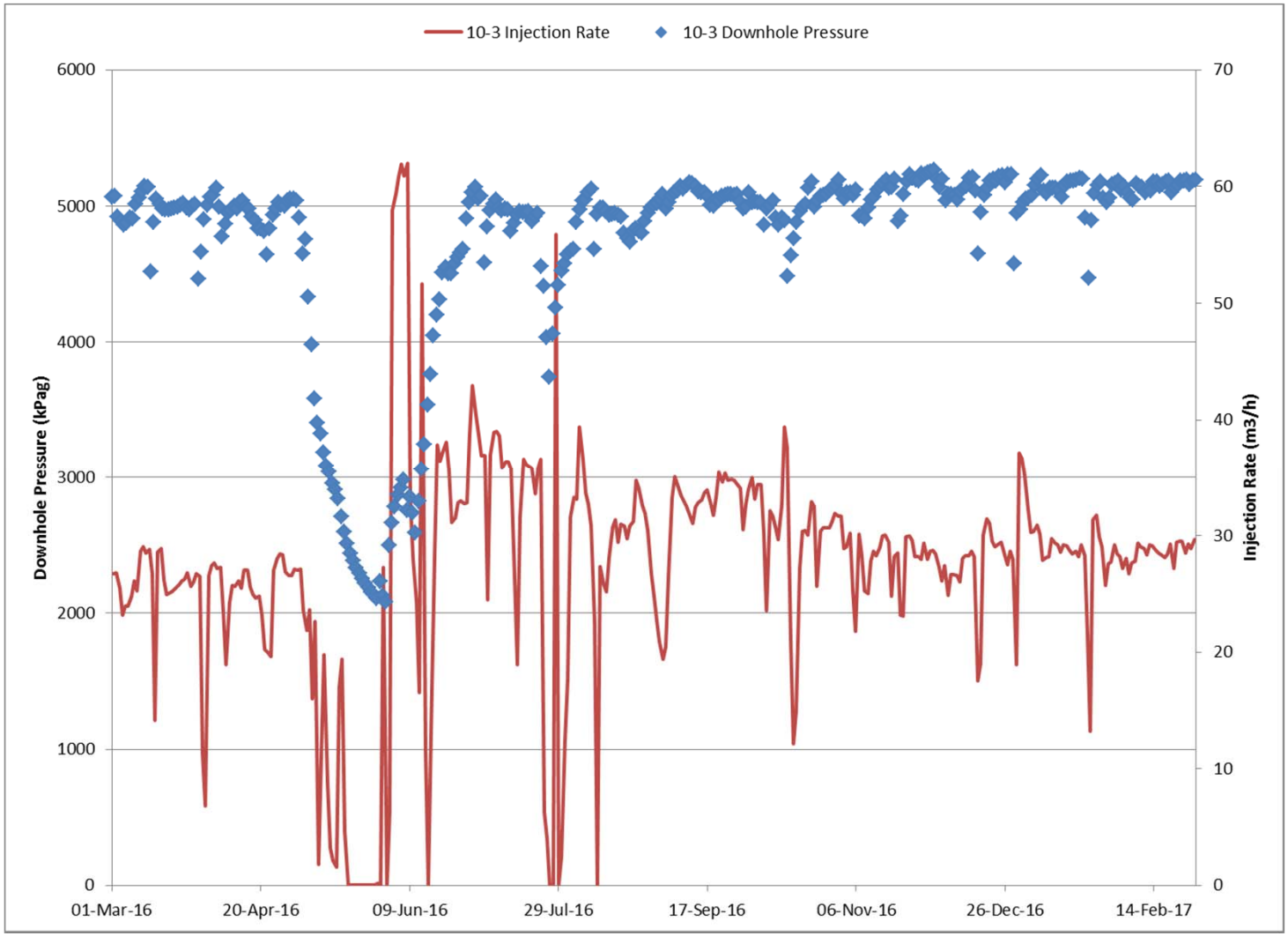
Disposal Information – 100/02-10-095-06W4

(data shown is averaged across the month)

Month	Injection Rate (Sm3/day)	Wellhead Pressure (kPa-g)	Downhole Pressure (kPa-g)	Injection Temperature (^oC)
March-2016	1911	1339	5381	50
April-2016	1970	1356	5383	51
May-2016	325	211	3400	32
June-2016	1271	583	4100	50
July-2016	1637	1032	5148	54
August-2016	1782	1239	5295	59
September-2016	1783	1473	5472	55
October-2016	1751	1334	5397	50
November-2016	1799	1479	5475	50
December-2016	1718	1480	5335	46
January-2017	1730	1466	5240	47
February-2017	1772	1502	5219	47

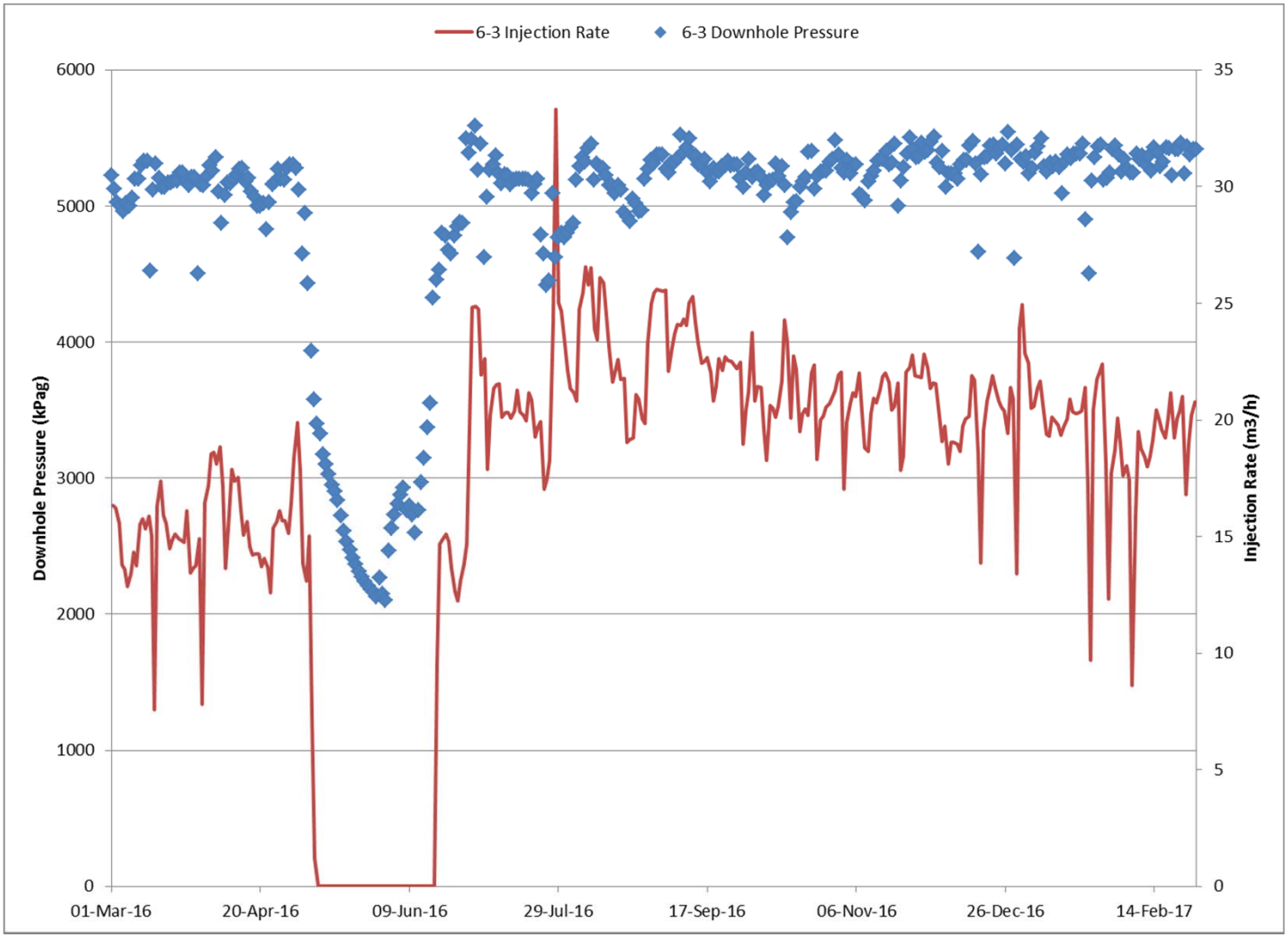
Waste Management – Disposal

Disposal Information – 100/10-03-095-06W4 (daily data)



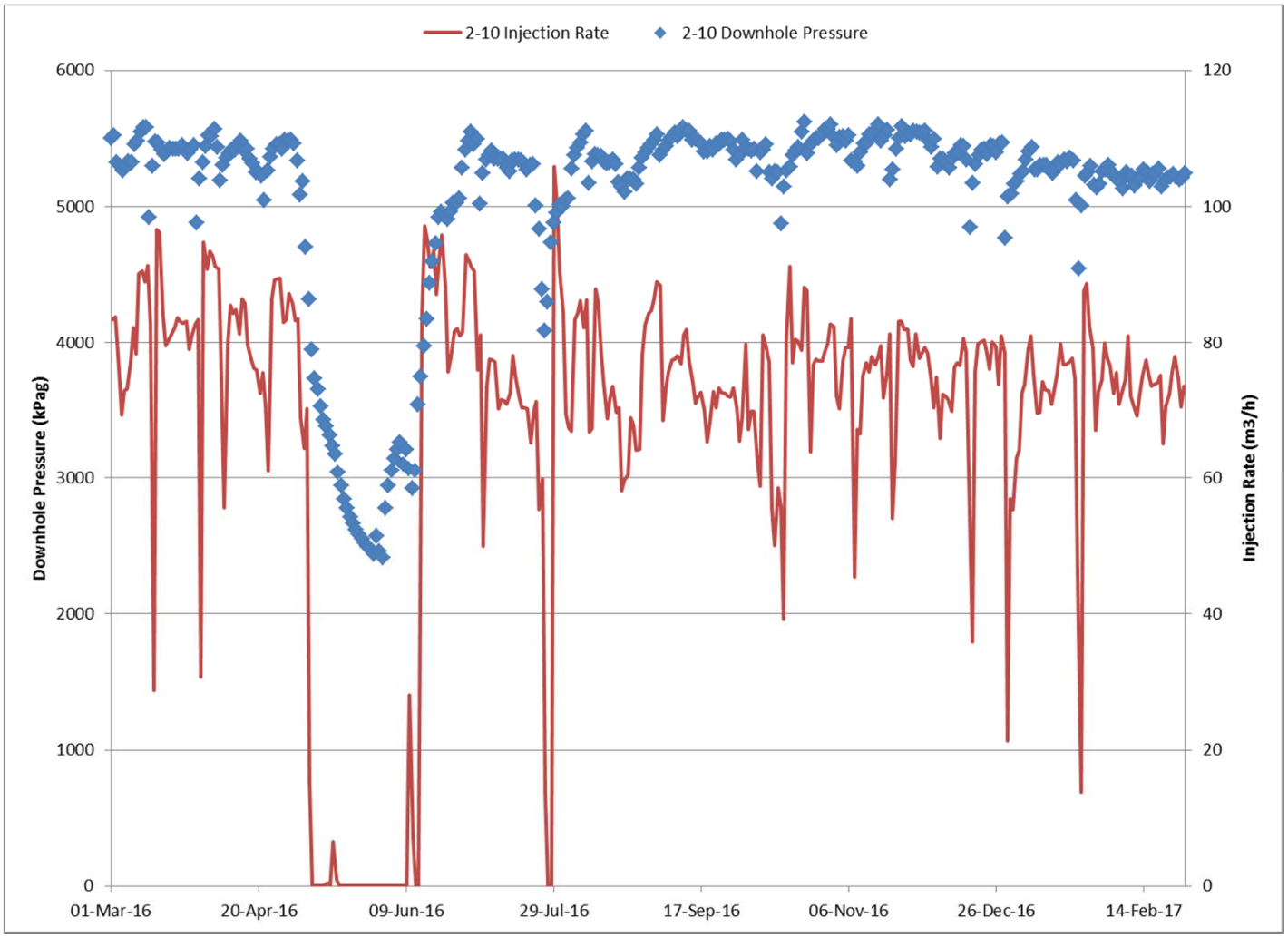
Waste Management – Disposal

Disposal Information – 100/06-03-095-06W4 (daily data)



Waste Management – Disposal

Disposal Information – 100/02-10-095-06W4 (daily data)



Waste Management – Disposal

Disposal Observation Well Locations

- Current Observation Wells:
  - *100/12-06-095-06W4/00 (DS1)*
  - *102/12-06-095-06W4/00 (DS2)*
  - *103/12-06-095-06W4/00 (DS3)*
  - *100/13-34-094-06W4/00 (DS4)*
  - *100/02-15-095-06W4/00 (DS5)*
  - *100/11-28-094-06W4/00 (DS6)*
  - *100/04-06-095-05W4/00 (DS7)*
  - *100/02-04-095-06W4/00 (DS8)*
  - *109/13-03-095-06W4/00 (PP7/DW22)*
  - *100/08-02-095-06W4/00 (DW OB1)*
  - *100/16-03-095-06W4/00 (DW12)*
  - *1AA/12-30-095-05W4/00 (DW4)*

Waste Management – Disposal

- During the reporting period, the following was completed:
  - Re-sampled chemistry at DS1, DS2, DS3, DS4, DS5, DS6, DS7, DS8 and PP7
  - Clean out and installation of sand screen in DS2 to mitigate issue with influx of sand/bitumen encountered while sampling McMurray last winter
  - Monitoring of downhole pressures and temperatures continued at all disposal observation well locations
  - All results (chemistry, pressure and temperature) will be reported as part of the annual disposal well monitoring report, to be submitted October 31 of each year
- Numerical modeling, based on all data acquired to date, is ongoing

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Sulphur Production

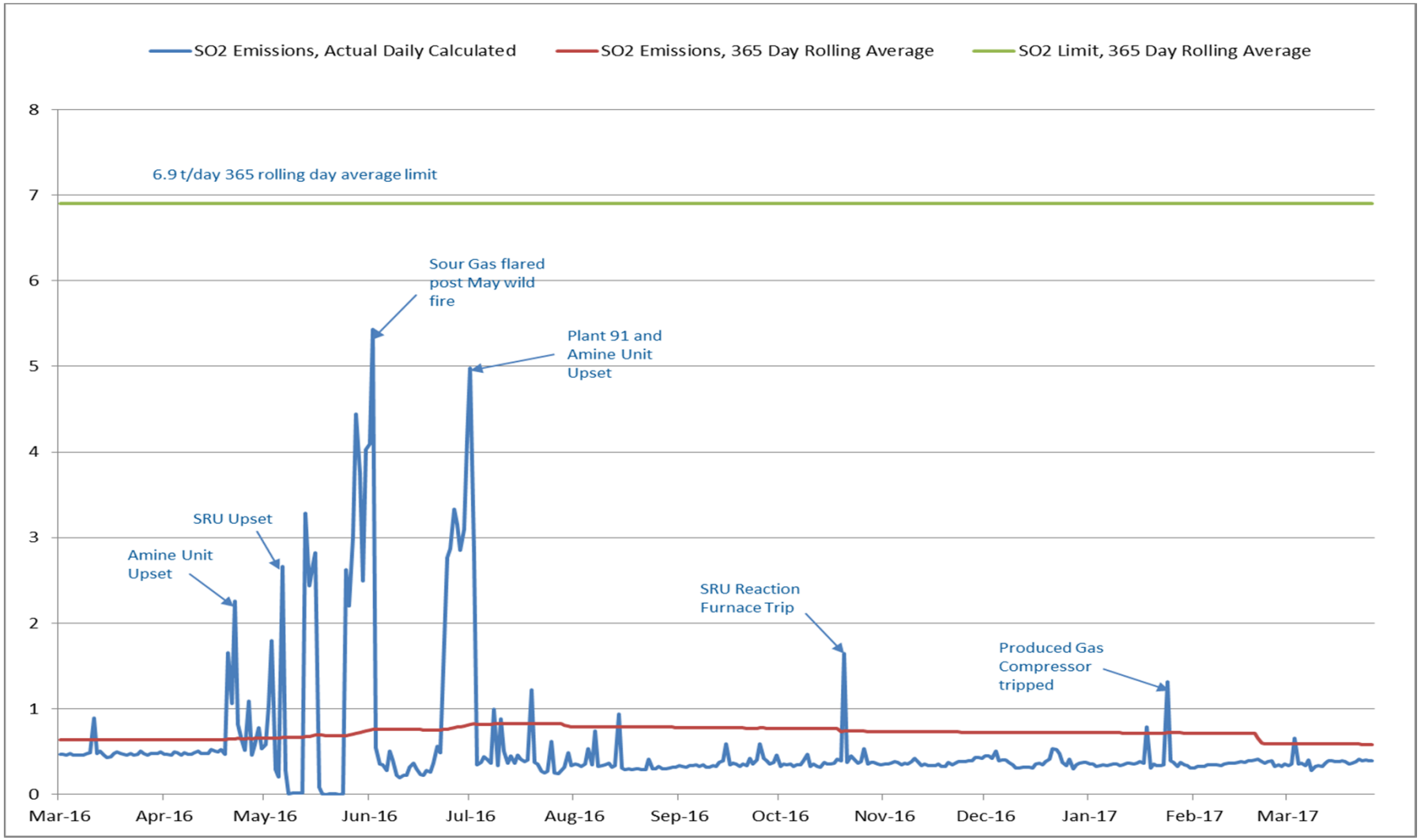
May 9th, 2017

Sulphur Recovery

	Average Inlet Sulphur (tonnes/day)	Sulphur recovery (%)	Sulphur Balance (%)	Sour Gas Flared (e3m3)	Sulphur Flared (tonnes)
Q2 2016	6.6	91.9%	2.5%	585.9	24.2
Q3 2016	9.9	97.8%	3.7%	88.7	2.0
Q4 2016	11.1	98.3%	3.9%	35.4	0.9
Q1 2017	11.2	98.4%	3.1%	17.6	0.8

- Regulatory requirement of > 95.9% sulphur recovery per calendar quarter for inlet rates > 10-50 tonnes/day
- Sulphur recovery rates in 2016 and 2017 year-to-date have consistently been above these requirements
- Sulfur Recovery for Q2 2016 was lower due to the May 2016 wild fires. Firebag received a sulfur recovery exemption from AER for this quarter.

SO_2 Emissions



SO_2 Emissions

- EPEA SO_2 Limit for Firebag Stages 1 to 4 =< 6.9 tonnes/day rolling 365-day average
- SO_2 Daily Average = 0.64 tonnes/day
- SO_2 Total = 234.2 tonnes
- Average Inlet H_2S Concentration = 5.2%

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Environmental Performance

May 9th, 2017

Other Environmental Initiatives

- Suncor is an active member of:
  - Canada's Oil Sands Innovation Alliance (COSIA)
  - Cumulative Environmental Management Association (CEMA)
  - Wood Buffalo Environmental Association (WBEA)
  - Alberta Biodiversity Monitoring Institute (ABMI)
  - Alberta Water Council (Watershed Planning Advisory Council)
  - Boreal Leadership Council (BLC)

Regulatory – AER Compliance Items

	Number of Occurrences	Reference Number(s)	Date(s) of Occurrence	Details of Occurrence	Suncor Actions
Industrial Runoff Uncontrolled Release	1	310205	April 12, 2016	Suncor had one event where surface runoff water flowed over the berm at the Village and resulted in an uncontrolled release to the environment. A sample was taken and tested which met pump-off parameter requirements for pH, chlorides and no oil sheen.	Suncor retained a third party survey company to conduct surveys of the berm areas within the CPF, operational well pads and the Village developed area. These surveys have been used to perform runoff system enhancements at each of the problematic areas on-site. In this case the berm has been reinforced and any snow and ice build-up removed prior to spring runoff. This practice will ensure that any blockages in the runoff control system will not result in a uncontrolled release.
SO2 Exceedance	4	310524 310621 310940 317459	April 20, 2016 April 22, 2016 May 3, 2016 October 20, 2016	There were four instances where SO2 exceeded the Firebag EPEA approval limits (133 kg/h) for a one hour average.	Suncor continues to address each of the SO2 exceedance events on a case by case basis and implement corrective actions accordingly. 310524/310621 - The incident learnings and improvements to the start up and / or ASU train switch process have been implemented and reviewed with all the operational crews. 310940 - A communication Directive and procedural updates have been implemented, which were distributed and reviewed with all operation crews to operate the flash tank at 300 kPag with the make-up fuel gas adjusted to a minimum 10% open. Actions were completed to review major control loops in the ASU to prevent cycling and improve controllability and ensure logic to freeze the SO2 value during daily calibration (i.e. at the correct time). 317459 - The belts come off of the combustion air blower on the reaction furnace causing the furnace to trip. A review of the equipment strategy data sheet for the preventative maintenance schedule now includes the inspection of the belts on a six month basis as well as a requirement to change out the belts on the combustion air blower drive system on an annual schedule.
NOx CEMS Exceedance	3	312677 317052 321219	June 14, 2016 October 7, 2016 February 20, 2017	There were three events where NOx limits were exceeded on the cogeneration units (191F-5000,).	Suncor has implemented corrective actions reflective of the root causes for each of these incidents. 312677 - the incident was reviewed with the operations crew to clarify expectations during a high NOx event; the unit is to be shutdown before the NOx limit is exceeded. Actions were also assigned for E&I to change the oil filter and clean the oil on this unit. Procedure updates were completed to include the operational expectations when the unit goes into an extended lean-lean mode. 317052 - The root cause was a high ambient temperature within the Cogeneration unit building which caused the digital valve controller (DVC) on the inlet bleed heat valve to malfunction. The DVC was replaced and also shielded to prevent the electronics from exposure to these high temperatures. 321219 - At this time there is no clear reason why the flame scanner detected a flame within the primary zone of the turbine. Suncor continues to monitor this situation for a potential repeat occurrence. If the issue persists and all points to the same chamber area then the Cogeneration Unit will be shut down, a borescope will be performed on the combustion chamber and spark plug installation shall be verified. If no hardware or installation issue can be found then a Dry Low NOx re-tuning is suggested by the vendor.
Venting	60	DDS, CIC		There were 60 venting incidents reported to the AER during this reporting period via the CIC and the DDS system.	Suncor continues to address the number and duration of venting incidents by identifying root causes and implementing corrective actions for each venting event to prevent future occurrences.

Regulatory – AER Compliance Items

	Number of Occurrences	Reference Number(s)	Date(s) of Occurrence	Details of Occurrence	Suncor Actions
Ambient Air Station Downtime/Passive Missing Sample Medium	2	317372 321013	September 2016 January 2017	Less than 90% Operational Uptime for the THC Analyzer at Ambient Station and incomplete O3 passive analysis due to missing sample medium.	Following the AEP inspection of the ambient station it was determined that the operation uptime of the THC analyzer at the Firebag ambient air station was <90% due to an unstable air pressure outlet to the FID. The control cable to the air pressure was re-seated and air pressure stabilized. A multipoint calibration was performed - the air pressure remained stable and the analyzer response was as expected with no adjustments required. In February 2017 when the passive samples were received at the lab for January 2017 the station #9 O3 sample medium was missing. Corrective actions include verification of sample medium prior to departing the lab to the field and upon receipt from and return to the lab for analysis.
Missed Water Act (WA) Approval Analysis	1	320099	December 2016 (annual requirement)	The annual sample analysis was not completed as per WA	The annual Regulatory Compliance Tool task was modified to include additional clarity on the requirement of this approval in respect to the annual required sample analysis.
CEMS Monthly Operational Uptime <90%	2	319661 320693	December 2016 & January 2017 February 2017	The CEMS for Cogeneration Unit 193F-5000 did not meet the 90% minimum data availability requirement for the months of December 2016, January and February 2017 due to a failure of the external power supply for 193PT-50051..	Suncor has added a high/low pressure alarm on all CEMS systems to address the failed pressure transmitter issue. This alarm will flag the CEMS data to notify E&I of the issue when it occurs. Suncor procedures outline the daily inspection requirements which have been reiterated and reviewed with the E&I teams. The external power supply for 193PT-50051 has since been replaced and the issue addressed.
Missed TDL Stream Flow Measurement (DCL)	1	319744	December 17, 2016	TDL 385610 Condition 18: The Licensee shall measure the rate of flow in each source of water that is a watercourse listed on this temporary diversion licence, as follows: (a) within one week prior to commencing the water diversion operation; and (b) a minimum of once every 2 weeks, during the water diversion operation.	Suncor has added TDL's with flow rate conditions to the Suncor Regulatory Compliance (RC)Tool which is an environmental management system to ensure project managers are following up with Field Supervisors on all conditions prior to project start-up. The Suncor RC tool sends email reminders to the owners that a regulatory requirement is due on a specified date. In addition, Suncor has followed up with all Field Supervisors to review TDL conditions in detail for all projects.

Regulatory – AER Compliance Items

	Number of Occurrences	Reference Number(s)	Date(s) of Occurrence	Details of Occurrence	Suncor Actions
Data Outage at 102/12-06-095-06W4/0 DS2	1	VSD	February 12, 2016 to April 2, 2016	The bottomhole pressure and temperature data from the sensors monitoring the McMurray in DS2. This data outage was due to the piezometer/thermocouple being pulled out of the well in order to take the annual routine water samples for water chemistry analysis as required by Approval No. 9487G, clause 3.	The DS2 McMurray pressure and temperature gauge have been re-run inside the tubing and have since worked correctly. All pressure and temperature data collected was included as part of the annual monitoring report requirements.
WMF 095 - Missed Leachate Measurements	1	VSD	May 16 - 29, 2016 (disclosed June 4, 2016)	Two weekly level measurements of leachate levels in the oilfield waste cells were missed during the 2016 Horse River wildfire when the site was	As soon as the workers at the WMF were mobilized back to site following the evacuation the measurements were taken. Suncor continues to take the weekly measurements as per the approval requirements which have not been missed since.
WMF 095 - Surface Runoff Discharge Outside WMF pH Approval Limits	1	VSD	2013 - 2015 (disclosed April 8, 2016)	Storm water from the WMF was outside the pH limit on four occasions between July 26, 2013 and August 24, 2015.	Suncor has implemented corrective actions to address this issue including a review of water sample results by Suncor's Roads and Grounds Coordinators and Supervisors prior to discharge from all locations on-site. All pump-off at the WMF is reviewed by the WMF with the contractors performing surface water discharge. Once the two review the results and confirm that the results meet the required criteria as per the WMF approval the WMF operator approves the contractor to proceed with
Waste Storage Component Non-Approved Waste Stream	1	VSD	2013-2016 (disclosed November 14, 2017)	Aerodrome waste was deposited in the CPF waste storage component (Eco Pit) from February 2013 to October 2016.	Suncor implemented actions to stop the deposition of Aerodrome waste into the waste storage component (EcoPit) upon discovery. The EcoPit technician was notified to ensure that no fluid from outside of the approval parameters was to enter the EcoPit. The facility and waste storage component approval were reviewed by the Waste Coordinators and the EcoPit technician and supervisor to ensure a consistent understanding of the approval requirements to operate the EcoPit

Regulatory – AER Compliance Items

	Number of Occurrences	Reference Number(s)	Date(s) of Occurrence	Details of Occurrence	Suncor Actions
Maximum Operating Wellhead Pressure Exceeded Approval Limit	1	VSD	December 30, 2016	The 6-3 disposal well maximum wellhead injection pressure exceeded the approval limit (2045 kPag) by 6 kPag for a total duration of 11 seconds.	Corrective actions have been implemented as a result of this incident including: - testing the hydraulic ESD for functionality; - correcting the unreliable operation of the automatic valves on the 2-10 and 6-03 disposal wells; - providing additional training on the proper operation of the ESD valves and the limitations and configuration of the 2-10 and 6-03 automatic valves; and - the wellhead injection pressure set points have been adjusted to 1575 kPag to provide additional margin between normal operation and the maximum approved injection pressure..
Exceedence of Maximum Operating Pressure ate Disposal Well 06-03-095-06 W4M	1	NA	January 5, 2017	A Maximum Wellhead Injection Pressure exceedance in the 00/06-03-095-06W4 (6-03) disposal well (Approval No. 9487G.	Suncor has implemented corrective actions reflective of each of the root causes. Procedures have been reviewed and updated to include instructions for the Control Room Operator (CRO), prior to lining up sweep air or tail gas vents and to enable the stack top violation alarming in the DCS. An operations procedure has been developed for preparing and isolating the sweep air flame arrestors for servicing. Other actions completed include additional training for SRU regulatory requirements and CEMS functions for the CRO on each shift.
Data outage at Disposal monitoring well 100/13-34-094-06W4/0 DS4	1	NA	Februray 9,2017	The bottomhole pressure and temperature data from the gauges monitoring the Slave Point and Elk Point in DS4 was unavailable from January 20, 2017 .	The wellhead injection pressure set points for Pressure Control valves were decreased to lower the likelihood of reoccurrence

Regulatory Compliance Summary

- Suncor Energy is in compliance with all regulatory approvals, decisions, regulations and conditions; except for compliance items identified in this presentation or otherwise disclosed

Firebag Performance Presentation

Future Plans

May 9th, 2017

Future Plans

- Suncor is continually investigating opportunities to improve process efficiency

Appendix - Surface

Overall Facility Water Balance

Below are a set of definitions of the terms used in the water balance table provided in this presentation

Freshwater

- REC (FW1): The sum of all freshwater streams received. Firebag receives water from the Suncor Oilsands site (AB OS 0077189) and from surface runoff (AB RO). Firebag also has source water wells (AB WI 100151109506W400) and (AB WI 100151409506W400). Water Received from Diluent into Firebag
- INVOP (FW4): Fresh water tank opening inventory. This volume is carried forward from last month's closing inventory.
- INVCL (FW5): Fresh water tank closing inventory. This volume takes into consideration levels in Fresh water tanks.

Steam

- INJ (INT): The total steam injected at the wells. Steam is metered at each of the steam generators in Plants 91-94 OTSGs and Cogeneration units.

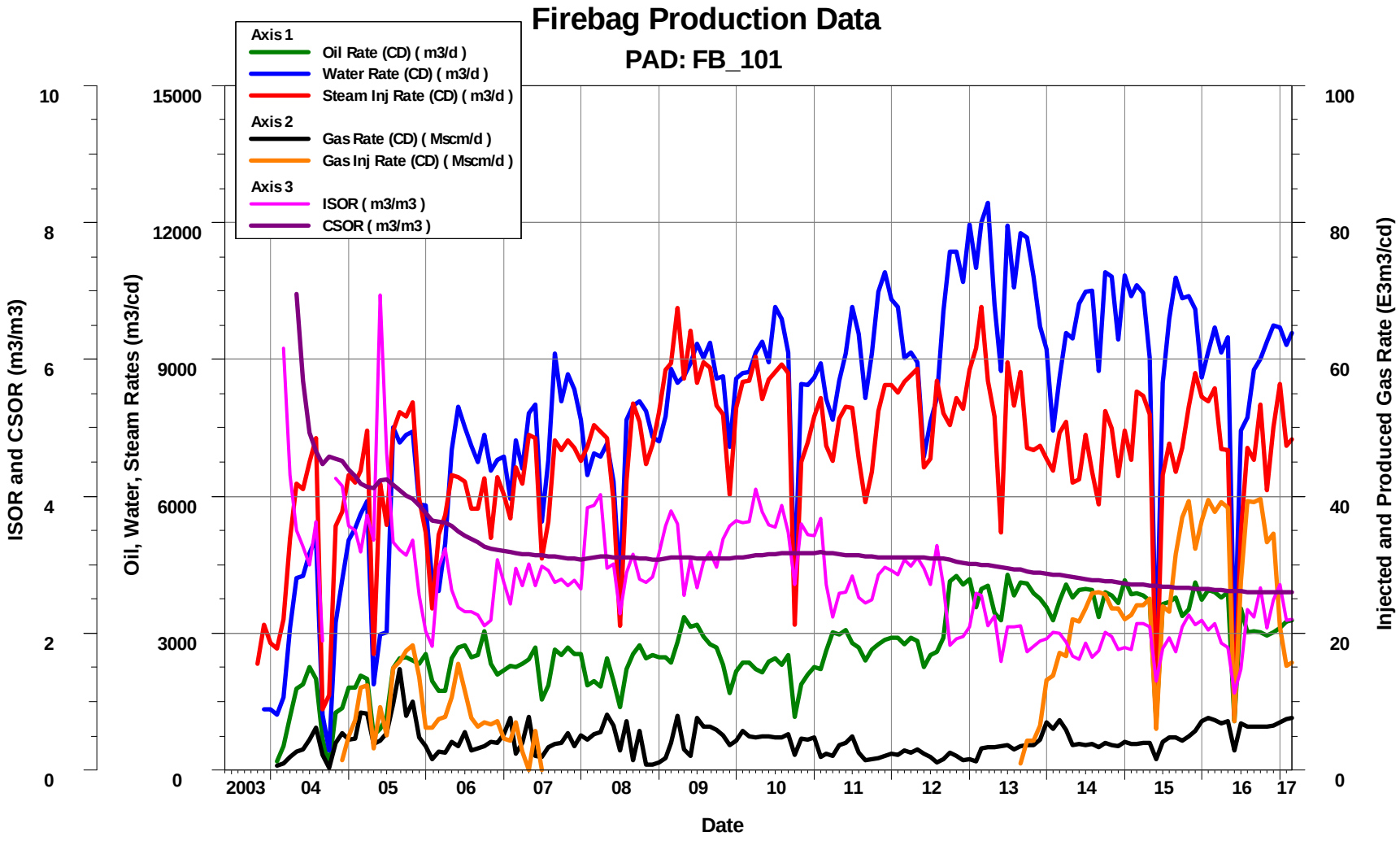
Water

- REC (PW1): The water received from the wells. This includes produced water from the wells, plus (PW8) the steam condensate sent to the Pads and a portion of the volume is collected at the steam traps and sent to the CPF, the remaining condensate is injected into the wells.
- DISP (PW8): Steam and condensate sent to the oil battery (AB BT 0078417). This water is received back into the injection facility along with the produced water from the wells.
- INVCL (PW5): Water tank closing inventory. This volume takes into consideration levels in water tanks.
- INVOP (PW4): Water tank opening inventory. This volume is carried forward from last months closing inventory.
- INJ (DIT): Water injected to the two disposal wells (AB WI 100060309506W400, AB WI 100100309506W400 and AB WI 100021009506W400).

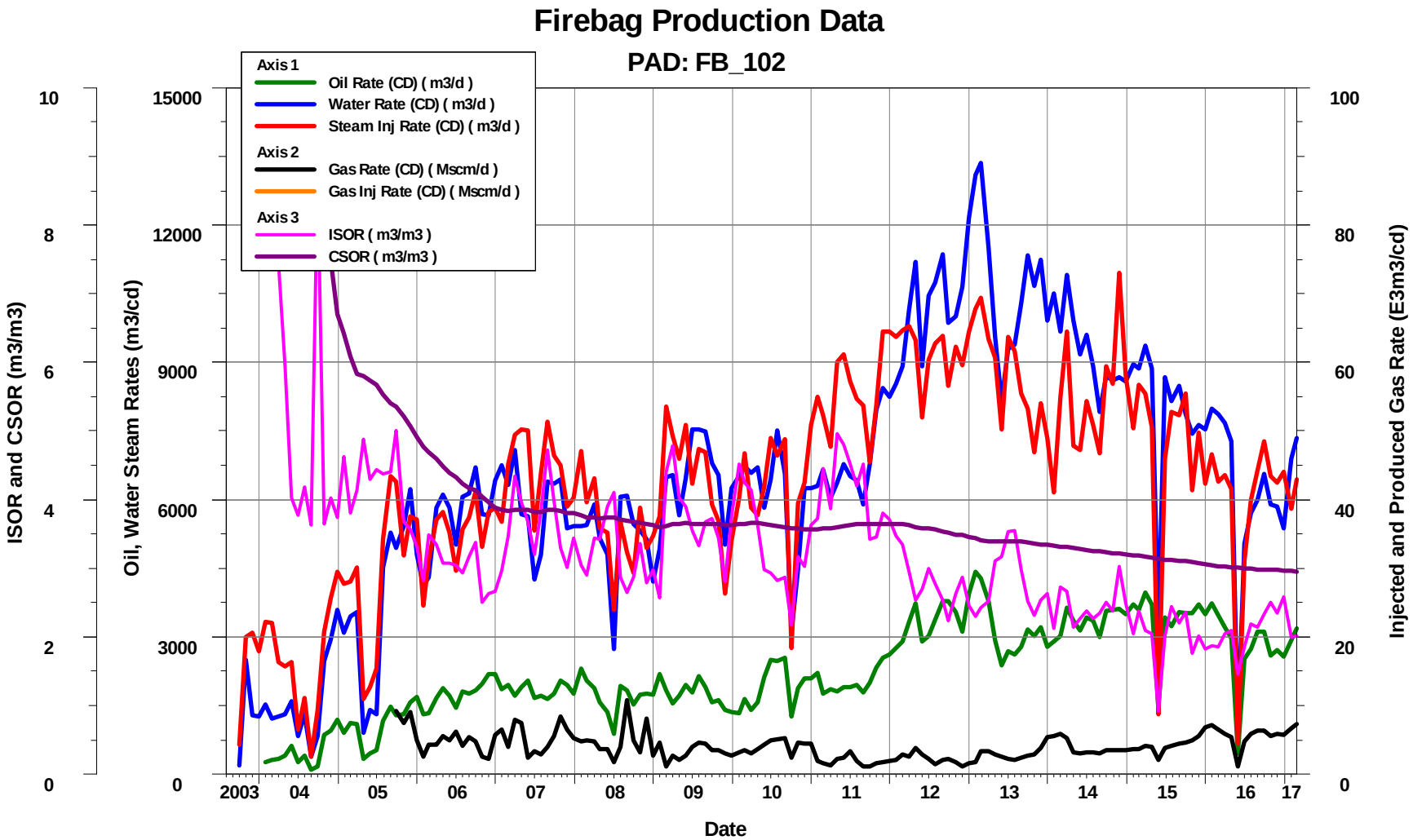
Appendix
2017 Appendix to AER Subsurface Presentation

May 9, 2017
Reporting Period: March 1, 2016 to February 28, 2017

Pad Produced & Injected Fluids Plots



Pad Produced & Injected Fluids Plots



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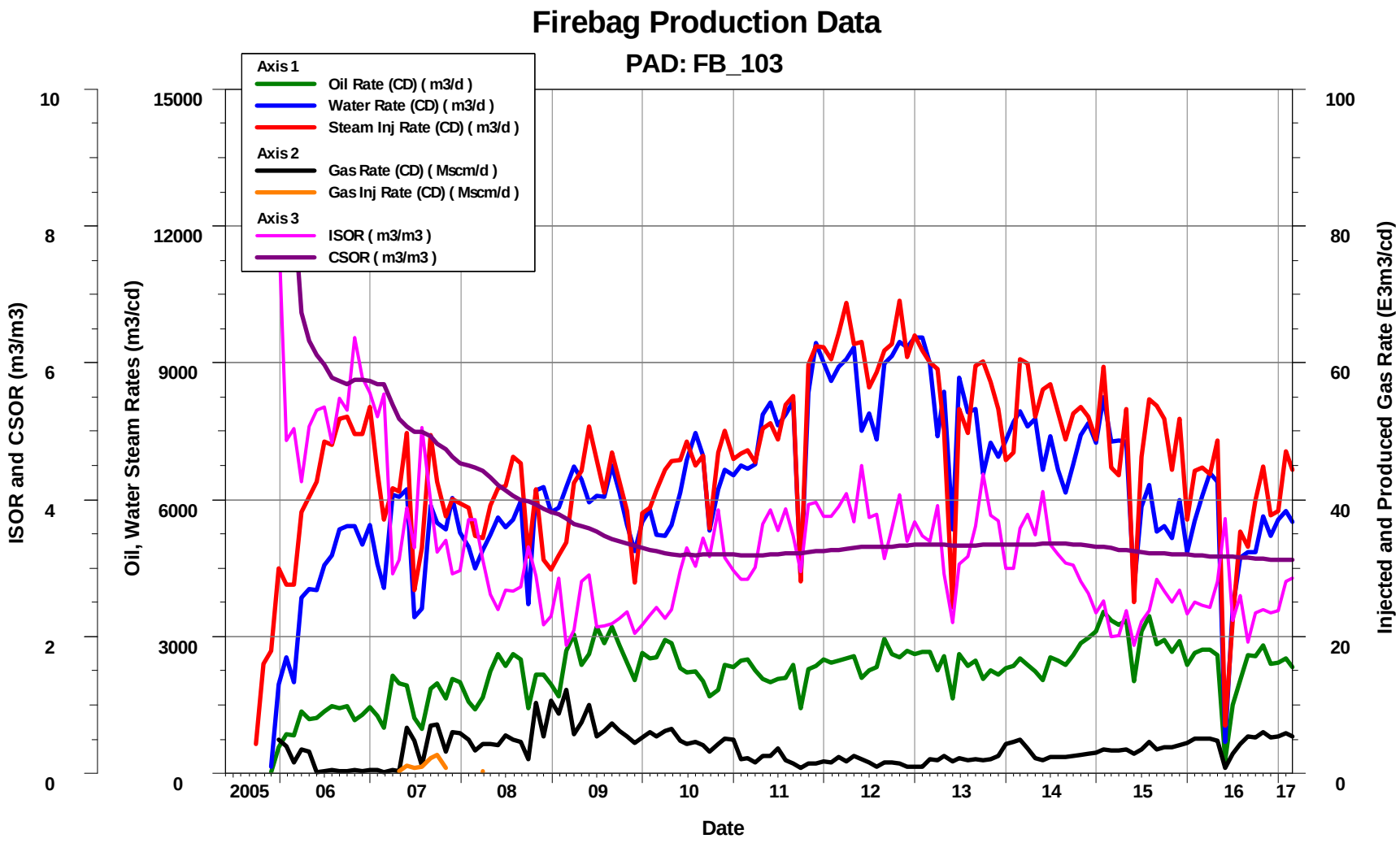

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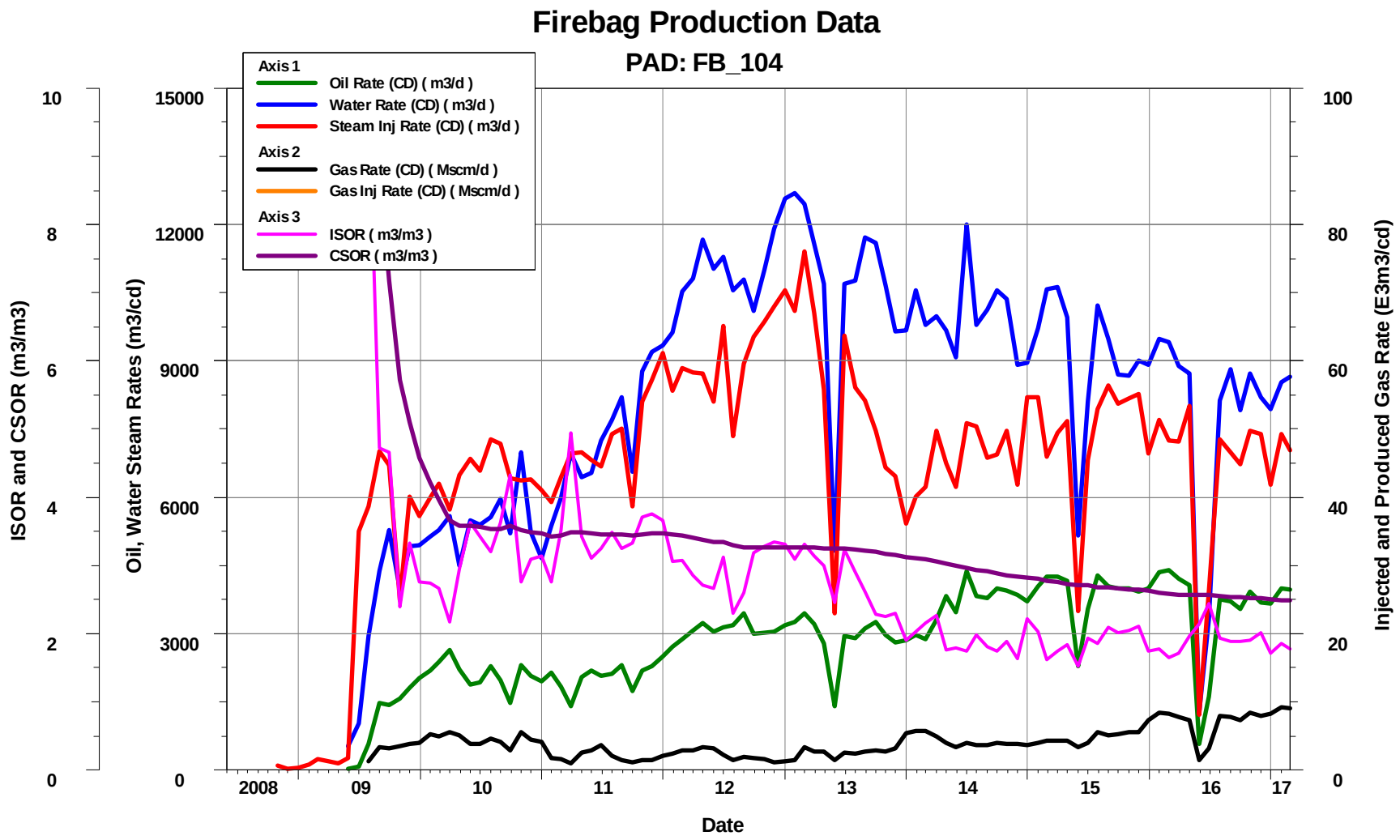

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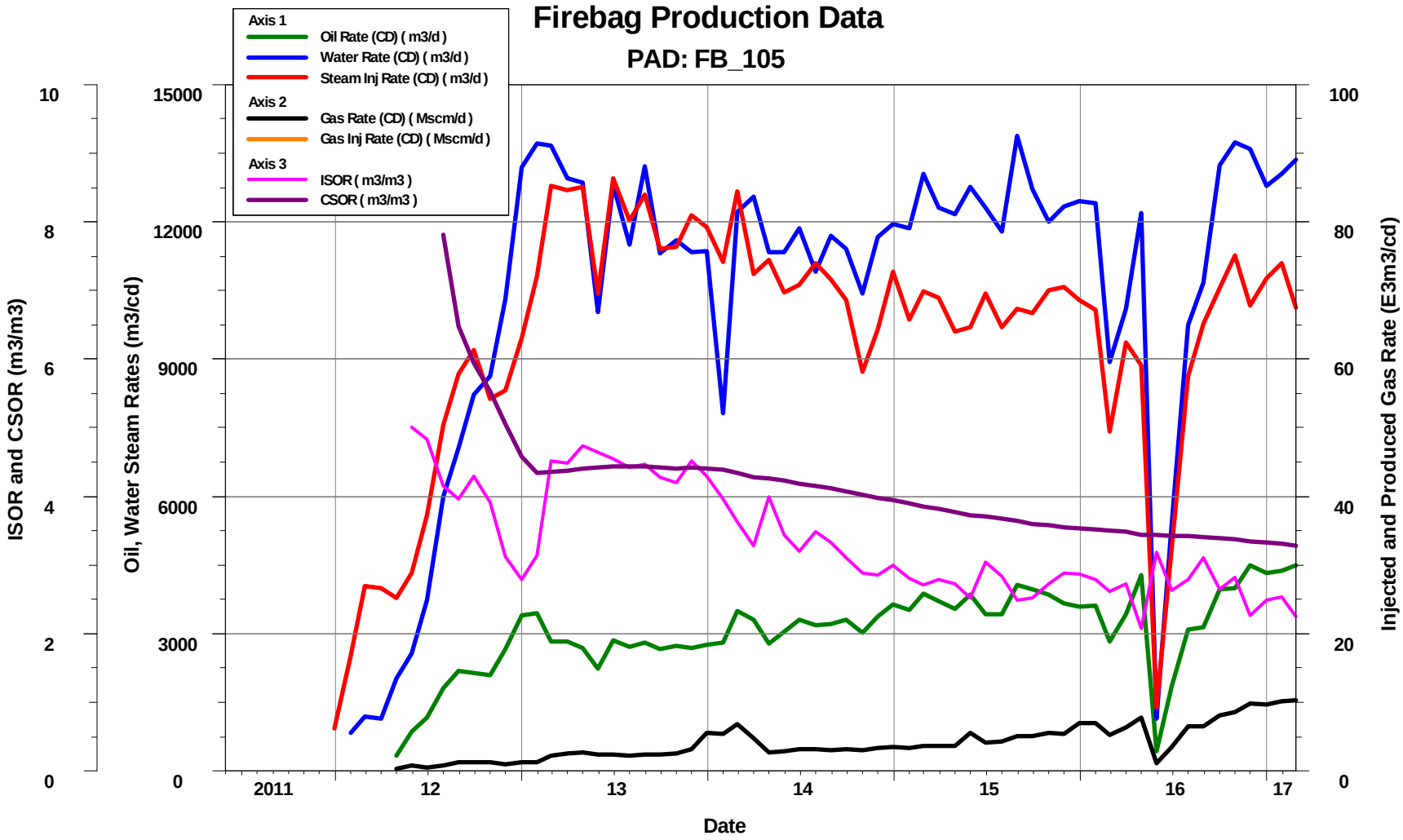

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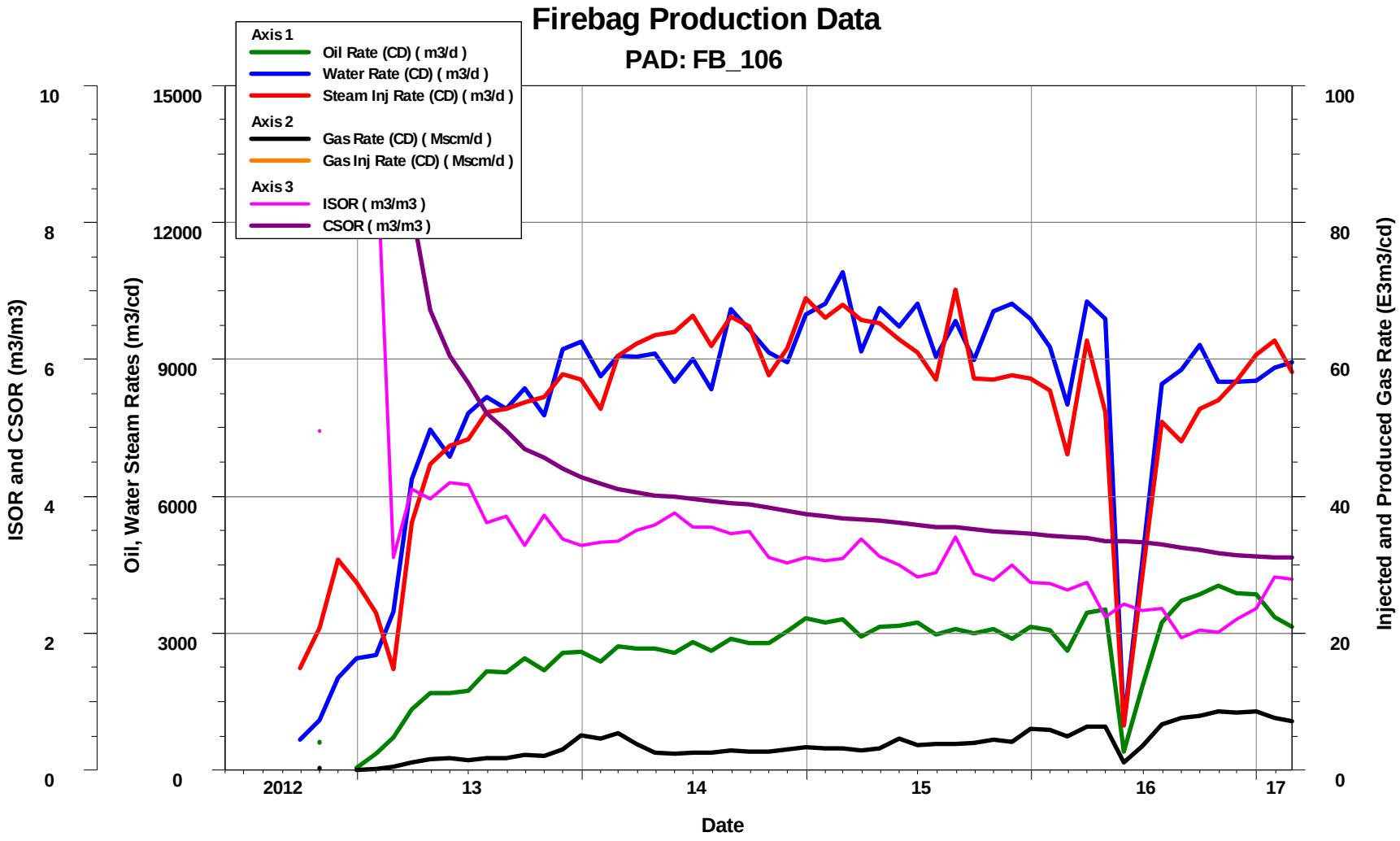

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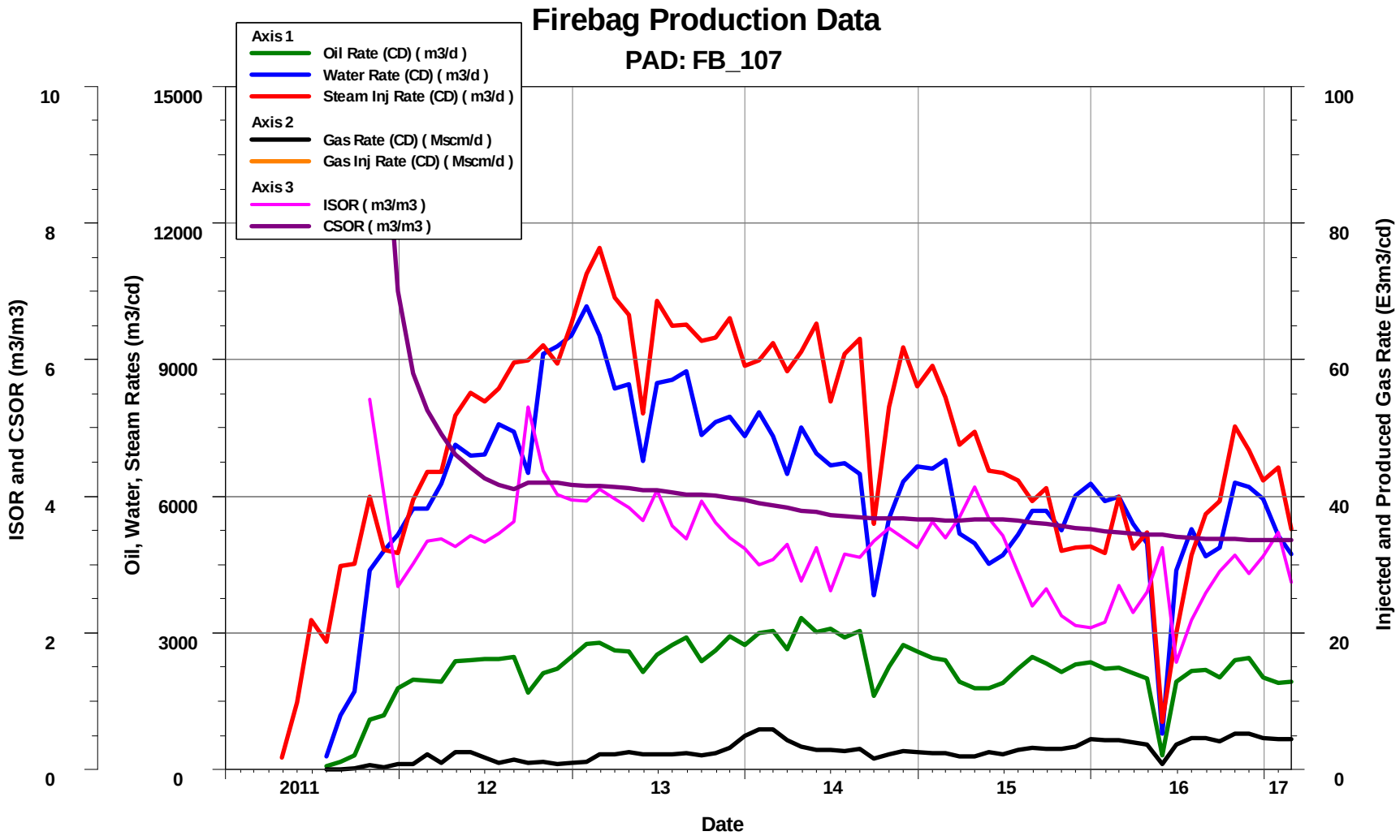

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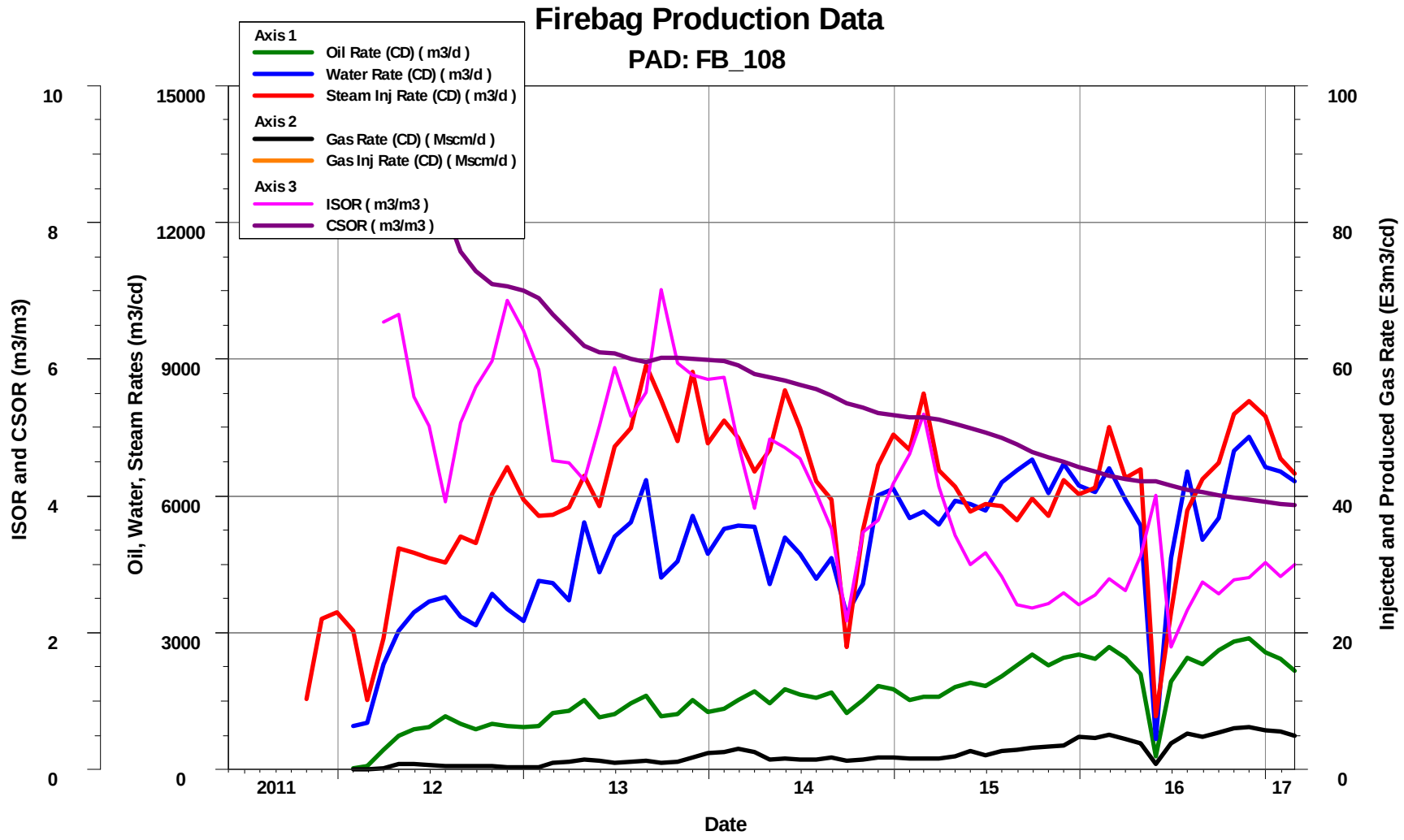

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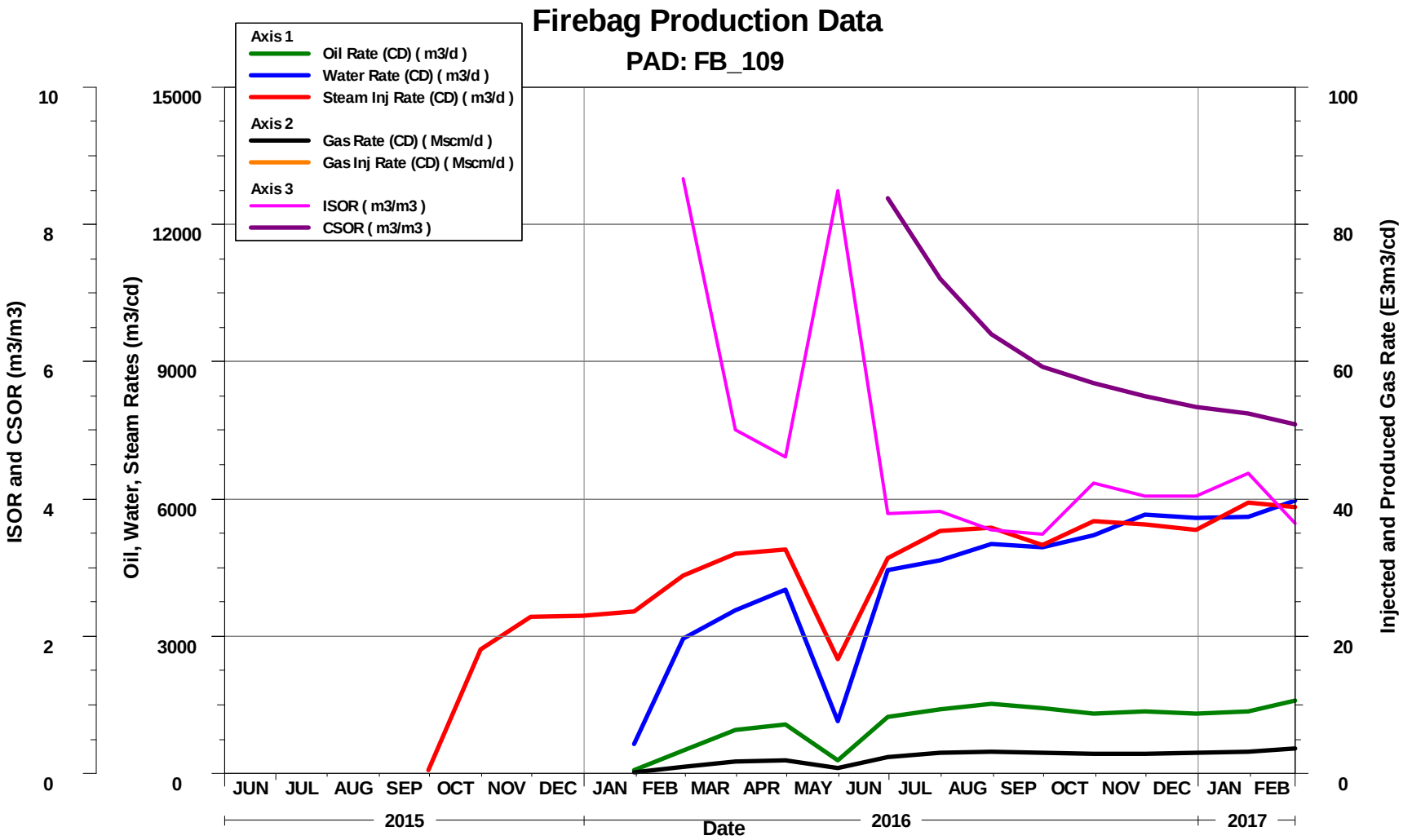

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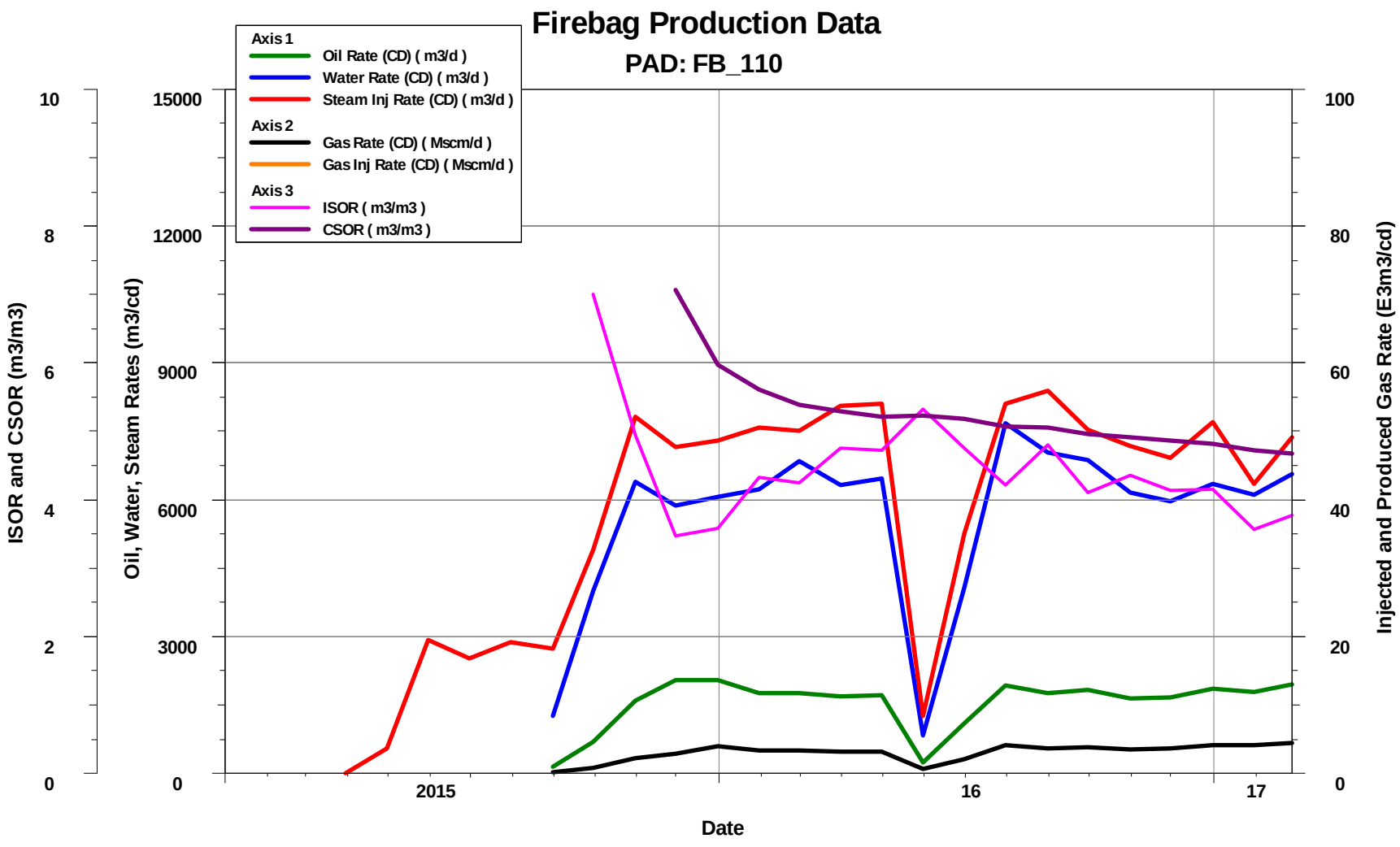

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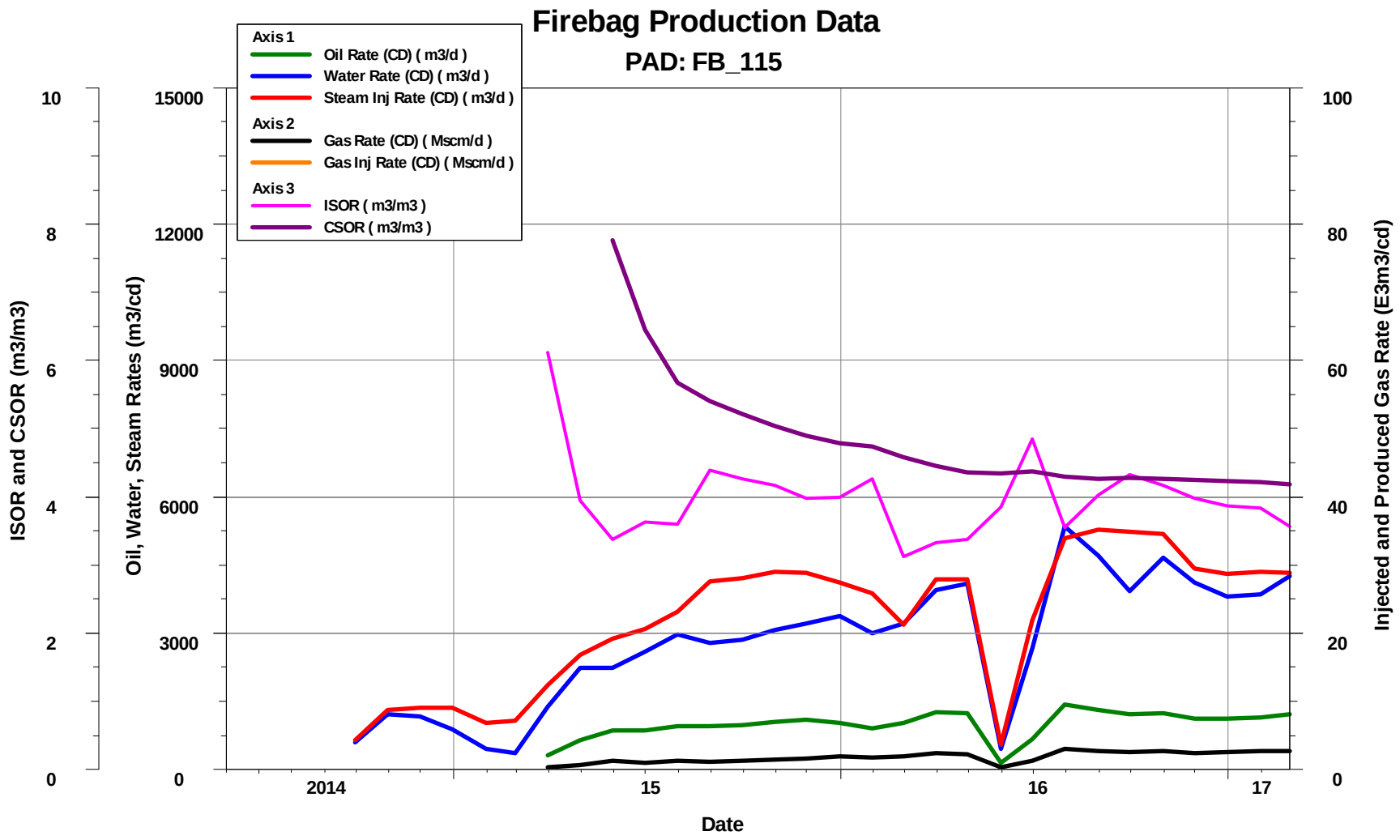

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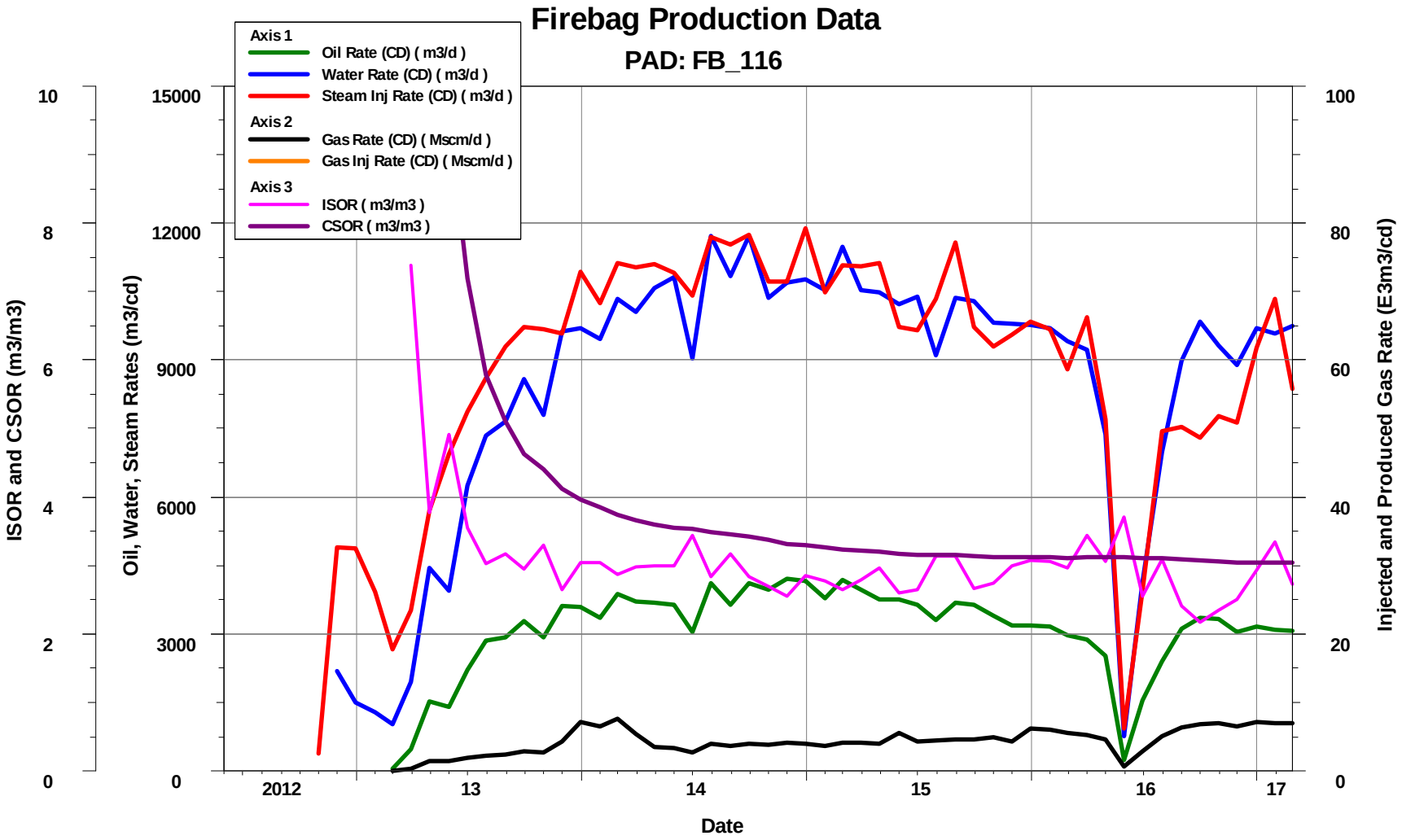

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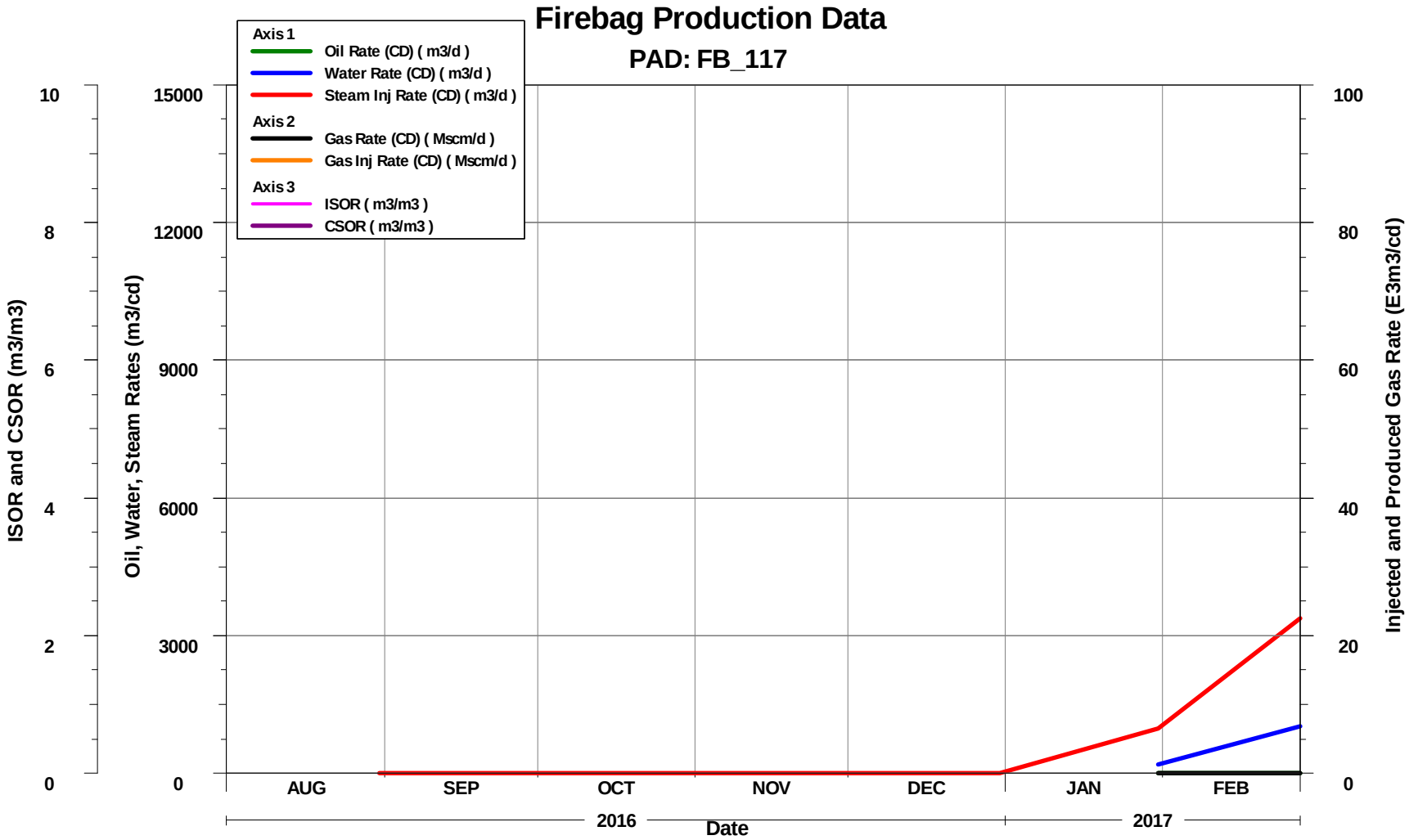


SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
DS1	00/12-06-095-06W4/0	P12P12_planned	512 m SW	262.6
DS2	02/12-06-095-06W4/0	P12P12_planned	504 m SW	262.6
DS4	00/13-34-094-06W4/0	P10P10	31 m S	329.7
DS5	00/02-15-095-06W4/0	P5P3	568 m N	314.5
DS6	00/11-28-094-06W4/0	P10P10	2117 m SW	313.52
DW OB1	00/08-02-095-06W4/0	P8P6	20 m W	313.6
ETS 1	00/12-06-095-05W4/0	P8P1 (ETS 1 heel) P8P1 (ETS 1 heel) P1N5 (ETS 1 toe) P8P1 (ETS 1 toe) P8P2 (ETS 1 toe)	27 m S 52 m N 235 m SW 303 m SE 297.5 m NE	313.8 m TVD 318.3 m TVD 318.1 m TVD 312.68 m TVD 323.5 m TVD
ETS OB4	02/01-11-095-06W4/0	P8P13B P814B	57.6m E 35.9m W	315.0m MD 316.0m MD
OB10	00/13-01-095-06W4/0	P8P15 P2S1 P2P1	38 m E 91.5 m W 91.5 m W	328 m MD 319.55 m MD 326.59 m MD
OB101	00/02-09-095-06W4/0	P16S3 P16P4	41 m S of horizontal 21.6 m N of horizontal	287.9m MD 293.9m MD
OB102	02/09-04-095-06W4/0	P16P9 P16P10	24.3 m S of horizontal 65.2 m N of horizontal	304m MD 309.7m MD
OB103	00/02-17-095-06W4/0	P15P1 P6P1 P16P19	965 m NW of horizontal 1890 m NW 1439 m N	290.2m MD 288.5m MD 285.4m MD
OB105	02/07-10-095-06W4/0	P5S2 P5P3	53.5 m E of horizontal 86.5 m W of horizontal	310.8m MD 320.25m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB106	12/15-10-095-06W4/0	P5P2B P5P3	81.3 m E of horizontal 44.3 m W of horizontal	319.7m MD 318.7m MD
OB107	00/10-32-094-06W4/0	P16P11	2025 m SW of build	307.5m MD
OB11	06/15-36-094-06W4/0	P1S7 P1P7	76 m S of toe 76 m S of toe	312.83 m MD 318.61 m MD
OB110	00/15-33-094-06W4/0	P6P16	835.5 m SW of toe	308.5m MD
OB111	02/12-36-094-06W4/0	P2N8 P2P8	298.5m S of toe 299.1 m SE of toe	320.7 m MD 319.7m MD
OB114	00/09-35-094-06W4/0	P2P10 ST1 P2P9	447.6 m SE of toe 450.4 m SW of toe	311.8 m MD 311.7 m MD
OB118	07/07-03-095-06W4/0	P5P16 P5P15 P10P15	88.0 m E 44.9 m W 199.2 m N	328.4 m MD 327.3 m MD 328.1 m MD
OB119	00/01-08-095-06W4/0	P16P19 P16P18	59.1 m S 31.3 m N	285.0 m MD 285.9 m MD
OB12	02/15-12-095-06W4/0	P3S9 P3P9	21.6 m N 26 m N	302.05 m MD 314.91 m MD
OB122	00/09-02-095-06W4/0	P7NP10_planned P8P9 P8P8	1.0 m S 50.1 m S 49.4 m N	315.4 m MD 315.4 m MD 315.4 m MD
OB123	02/15-02-095-06W4/0	P7P3 P7P4 P8P10	47.0 m E 42.9 m W 135.8 m N	323.7 m MD 326.0 m MD 319.1 m MD
OB124	04/04-01-095-06W4/0	P8P5 P8P4	56.6 m E 50.1 m W	313.9 m MD 313.3 m MD
OB125	00/02-02-095-06W4/0	P7P12 P7P11	43.8 m E 47.4 m W	325.6 m MD 324.3 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB126	00/07-02-095-06W4/0	P7P12 P7P11	42.2 m E 45.1 m W	325.8 m MD 325.1 m MD
OB127	04/08-02-095-06W4/0	P8P6 P8P5	45.5 m E 46.0 m W	312.9 m MD 315.3 m MD
OB128	05/08-02-095-06W4/0	P7P9 P8P6 P8P7	96.3 m E 155.6 m W 200.6 m S	327.2 m MD 314.0 m MD 315.9 m MD
OB129	10/11-02-095-06W4/0	P4P7 P4P6	77.4 m E 82.9 m W	319.1 m MD 326.1 m MD
OB13	10/07-11-095-06W4/0	P7S2 P7P2 P7P1	16.8 m W 14.9 m W 74.2 m E	322.66m MD 322.7m MD 318.5m MD
OB130	02/09-03-095-06W4/0	P5P14 P5P13	78.7m E 58.8 m W	324.7 m MD 324.8 m MD
OB131	10/01-10-095-06W4/0	P5P8 P5P10	95.2 m S 5.0 m N	311.3 m MD 311.3 m MD
OB132	03/07-10-095-06W4/0	P5P4 P5P5	64.7 m E 66.8 m W	312.3 m MD 312.4 m MD
OB133	11/07-11-095-06W4/0	P7P3 P7P4	88.7 m NE 61.6 m NW	325.6 m MD 330.1 m MD
OB134	00/01-16-095-06W4/0	P6P1	582.6 m NW	292.1 m MD
OB135	06/09-09-095-06W4/0	P6P2 P6P3	42.7 m E 45.7 m W	296.7 m MD 296.2 m MD
OB136	00/11-10-095-06W4/0	P6P8 P6P9	31.2 m E 59.0 m W	299.0 m MD 301.8 m MD
OB137	00/09-08-095-05W4/0	P9P1	1475.8 m NE	276.9 m MD
OB138	00/07-09-095-05W4/0	P9P1	2765.3 m E	274.5 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB14	03/08-02-095-06W4/0	P8P6 P7P9	160.2 m W 91.2 m E	312.4m MD 325.0m MD
OB143	00/16-34-094-06W4/0	P10P7 P10P8	66.8 m S 24.8 m N	320.5 m MD 323.5 m MD
OB147	00/05-07-095-06W4/0	P11P11_planned P11P10_planned	58.7 m E 51.3 m W	270.9 m MD 270.9 m MD
OB149	02/11-04-095-06W4/0	P17P1 P16P12 P17P14	101 m W 155 m SE 193 m SE	287.7 294.7 292.2
OB152	00/06-06-095-05W4/0	P3P3B P3PB P1P6	523 m S 512 m S 508 m E	299.18 300.17 315
OB153	03/08-01-095-06W4/0	P1P7 P1N7	32 m W 37 m E	320.6 322.1
OB154	09/14-36-094-06W4/0	P1P8 P1N8	39 m W 41 m E	319.6 321
OB164	02/11-08-095-06W4/0	P14P7_planned	164 m S	281.3
OB165	00/06-05-095-06W4/0	P12P10_planned P17P8	104 m SW 82 m NW	289.9 289.4
OB166	00/05-32-094-05W4/0	P1P6	2448 m SE	308.71
OB167	00/01-32-094-05W4/0	P1P6	3635 m SE	313.96
OB168	00/03-04-095-05W4/0	P1P6	3923 m E	309.1
OB169	00/13-32-094-05W4/0	P1P6	2467 m E	309.2
OB17	05/05-12-095-06W4/0	P2P1 P7P8	199.7 m W 202.3 m E	326.5m MD 313.5m MD
OB170	00/13-33-094-05W4/0	P1P6	4058 m SE	307.06
OB18	00/09-10-095-06W4/0	P5P6 P5P5	33.8 m W of horizontal 100 m E of horizontal	319m MD 320 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB182	03/01-09-095-06W4/0	P15P8 P16P1	5 m S 127 m N	285.5 (-303.5 m SS) 305.0 (-284 m SS)
OB19	06/03-02-095-06W4/0	P4S7 P4P7	83.5 m E of toe 49.9 m S of toe	319.31 m MD 326.4 m MD
OB20	00/05-02-095-06W4/0	P4S9 P4P9	78.4 m E of horizontal 74.9 m E of horizontal	317.28 m MD 323.23 m MD
OB201	00/01-31-094-05W4/0	P23P9_planned	42 m E	278
OB202	00/13-29-094-05W4/0	P23P9_planned	438 m E	289
OB203	00/15-34-094-06W4/0	P10P8 P10P7	15 m N 76 m S	331 327
OB204	17/13-35-094-06W4/0	P10P8 P10P7	14 m N 81 m S	321 318
OB205	00/16-07-095-05W4/0	P9P15	480 m SE of ICP	293
OB21	00/11-03-095-06W4/0	P5P18 P5P17	21.3 m E of horizontal 116.8 m W of horizontal	325 m MD 326.6 m MD
OB22	00/13-02-095-06W4/0	P5P11 P4P10 P5P12	80 m S 90 m N 200 m NE	313.33 m MD 318.4 m MD 319.1 m MD
OB23	00/05-11-095-06W4/0	P4S3 P4P3	41.7 m W of horizontal 42.7 m W of horizontal	311.87 m MD 318.49 m MD
OB24	00/09-04-095-06W4/0	P16P11	75 m S of horizontal	316.2 m MD
OB27	00/05-04-095-06W4/0	P16P12	559 m S of horizontal	296.2m MD
OB28	00/07-04-095-06W4/0	P16P11	400m SW of ICP	315.75m MD
OB29	00/07-05-095-06W4/0	P16P12	643.7 m SW of toe	293m MD
OB3	02/08-01-095-06W4/0	P1S6 P1P6	2.7 m E 1 m E	310.06 m MD 316.58 m MD
OB30	00/15-05-095-06W4/0	P16P14 P16P13	63.4 m SW of toe 87.6 m NW of toe	285.5m MD 288m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB31	00/06-08-095-06W4/0	P16P19 P15P1	750 m NW of toe 795 m SW of ICP_PLAN	275.75m MD 275.5m MD
OB32	00/11-08-095-06W4/0	P15P1	476 m W of horizontal	277m MD
OB33	00/13-08-095-06W4/0	P15P1	868 m W of horizontal	270.5m MD
OB34	00/03-09-095-06W4/0	P16P19 P16P18	90.4 m SE of ICP 97.6 m NE of ICP	285.75m MD 286.2m MD
OB35	00/05-09-095-06W4/0	P15P6 P15P5	92.6 m NW of ICP_PLAN 119 m SW of ICP_PLAN	285m MD 285m MD
OB36	00/11-09-095-06W4/0	P15P1	206.5 m N of horizontal	286.4m MD
OB37	00/11-04-095-06W4/0	P16P12 P16P10	218 m SE of ICP 585 m SW of ICP	294.3m MD 306.2m MD
OB38	00/11-05-095-06W4/0	P16P12	557 m SW of toe	288m MD
OB39	00/07-08-095-06W4/0	P16P19 P15P1	320 m NW of toe 539 m SW of ICP_PLAN	281.2m MD 280.6m MD
OB4	W2/01-01-095-06 W4/0	P1S6 P1P6	3.1 m E 4 m E	310.33 m MD 316.61 m MD
OB40	00/09-09-095-06W4/0	P6P1 P15P1	132.7 m W of horizontal 229 m N of horizontal	291m MD 288.4m MD
OB42	00/13-04-095-06W4/0	P16P15 P16P16	27.5 m N of horizontal 60.5 m S of horizontal	288.7m MD 288.3m MD
OB43	00/15-09-095-06W4/0	P6P1 P15P9	383 m NW of toe 658 m N of horizontal	292.2m MD 289.2m MD
OB44	00/01-05-095-06W4/0	P16P12	1065 m S of horizontal	296.4m MD
OB45	00/03-05-095-06W4/0	P16P12	1191 m SW of toe	285.6m MD
OB48	02/11-06-095-06W4/0	P16P12	2229 m SW of toe	274.8m MD
OB49	00/13-06-095-06W4/0	P16P14	2582 m W of toe	262.8m MD
OB5	00/15-36-094-06W4/0	P1S6 P1P6	1.3 m E 0.9 m W	310.21 m MD 316.71 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB51	00/03-18-095-05W4/0	P3P10	725 m NE of ICP	307.7m MD
OB54	00/13-07-095-05W4/0	P3S10	53m NE of heel	299.67 m MD 302.91 m MD
OB56	00/15-06-095-05W4/0	P3S1 P3P1	108.64 m E of horizontal 110.92 m E of horizontal	306.67 m MD 314.85 m MD
OB57	00/01-12-095-06W4/0	P1S4 P1P4	77.9 m W of horizontal 78.6 m W of horizontal	316.76 m MD 324.6 m MD
OB59	00/03-07-095-05W4/0	P3S2 P3P2 3WP1	85.46 m E of horizontal 85.0 m E of horizontal 76m W of hz	304.39 m MD 311.11 m MD 303.5m MD (prod)
OB6	05/09-01-095-06W4/0	P1S2 P1P2 P8P1	165 m SE of heel 165 m SE of heel 16.5 m N	318.65 m MD 324.2 m MD 309.2m MD
OB60	00/04-01-095-06W4/0	P2S9 P2P9 P8P12 P2N9	25.1 m W of horizontal 22.5 m W of horizontal 56.6 m E of horizontal 101.9 m W of horizontal	305.27 m MD 312.29 m MD 333.5 m MD 326.0 m MD
OB61	00/04-11-095-06W4/0	P4S4 P4P4	27.13 m E of heel 3.32 m E of heel	211.76 m MD 157.52 m MD
OB62	00/06-02-095-06W4/0	P4P6_ST1N P7P14	51 m E of horizontal 73 m W of horizontal	325m MD 331.1m MD
OB63	07/08-11-095-06W4/0	P7P6 P7P7	34 m E of horizontal 55 m W of horizontal	323.6m MD 316.6m MD
OB66	11/15-35-094-06W4/0	P8S5 P8S4	31.2 m E of horizontal 75.3 m W of horizontal	307.2m MD 307.3m MD
OB67	00/03-06-095-05W4/0	P1S6	645.3 m E of Horizontal	308m MD
OB68	00/07-36-094-06W4/0	P1S7	747.3 m SE of toe	316.5m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB69	00/11-35-094-06W4/0	P7S9	365.5 m SW of toe	320.1m MD
OB7	02/09-01-095-06W4/0	P1S8 P1P8 P8P3	138.5 m NE of heel 138.5 m NE of heel 60.6 m N	313.49 m MD 320.94 m MD 320.0m MD
OB70	05/13-35-094-06W4/0	P7P14	38.7 m W of horizontal	326.4m MD
OB71	07/03-02-095-06W4/0	P7P14	25.7 m W of horizontal	326.2m MD
OB72	00/16-02-095-06W4/0	P7S6 P7S7	68.5 m E of horizontal 19.6 m W of horizontal	316.5m MD 310.5m MD
OB73	00/05-31-094-05W4/0	P1S6	1041.5 m SE of toe	307.5m MD
OB74	00/13-31-094-05W4/0	P1S6	738.1 m E of horizontal	307.5m MD
OB75	00/11-31-094-05W4/0	P1S6	1141 m SE of toe	below TD of OB well
OB76	09/11-02-095-06W4/0	P8S8 P8S9	25 m N of horizontal 73.5 m S of horizontal	309.6m MD 311.9m MD
OB77	00/13-12-095-06W4/0	P3P9 P3P10	353.4 m NW of toe 350.8 m SW of toe	317m MD 313m MD
OB78	07/03-11-095-06W4/0	P4P4 P4P5	94.7 m E 61.2 m W	319.1m MD 326.2m MD
OB79	10/14-35-094-06W4/0	P7S12 P7S11	40.8 m E of horizontal 48.2 m W of horizontal	320m MD 321.2m MD
OB8	00/15-12-095-06W4/0	P3P9 P3P8	98.3 m S 89 m N	N/A - between P3P8 and P3P9
OB80	02/05-11-095-06W4/0	P4P3 P4S2	71.4 m W of horizontal 92.7 m E of horizontal	319.8m MD 307.2m MD
OB81	02/12-11-095-06W4/0	P4S3 P4S4	40.8m E of horizontal 113.7m E of horizontal	309.6m MD 314.6m MD
OB82	05/14-11-095-06W4/0	P4S4 P4P5	29.9 m E of horizontal 94.8 m W of horizontal	313.5m MD 326.5m MD

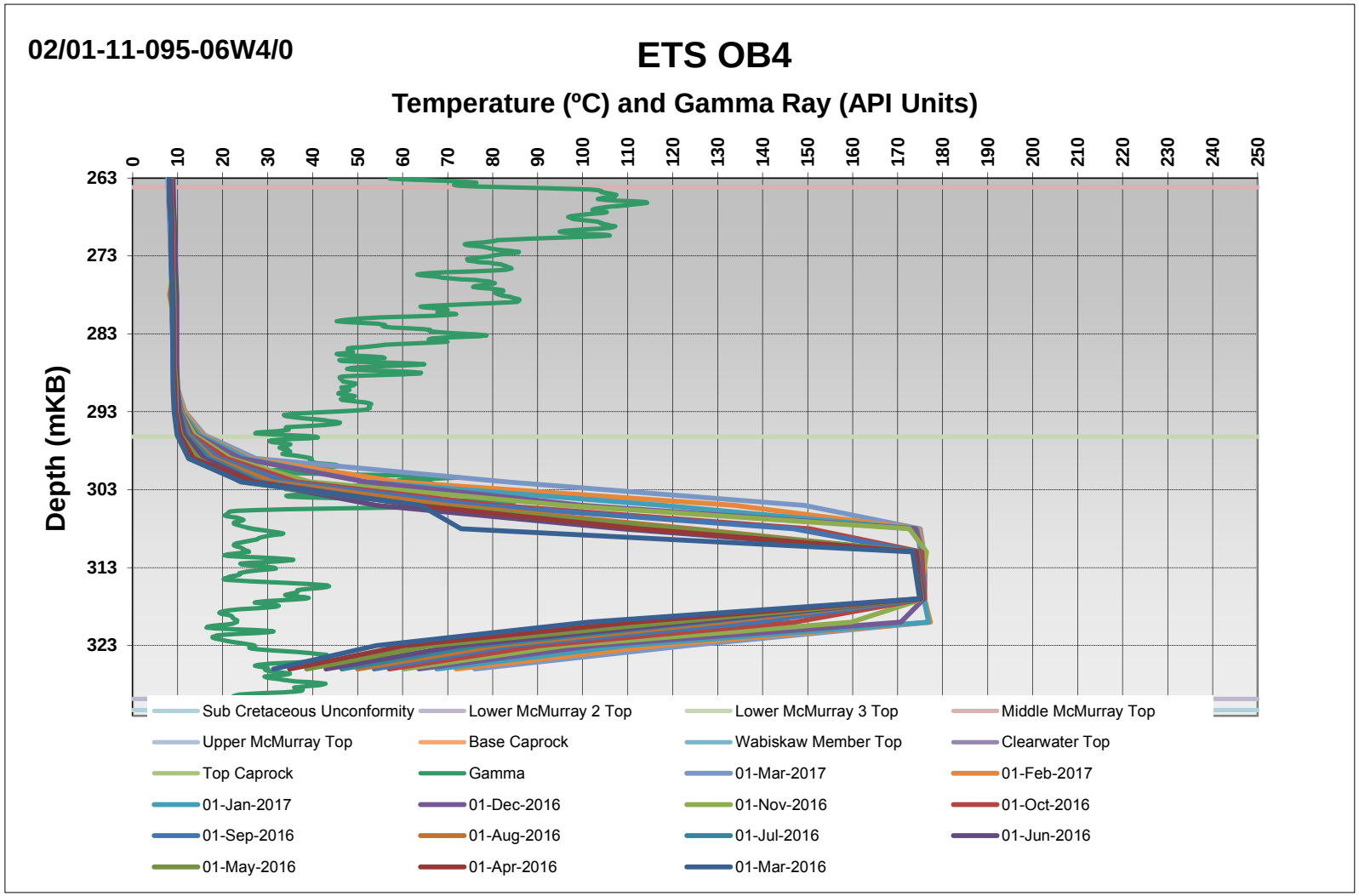
SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB83	03/04-07-095-05W4/0	P3P4B P3P3B	81.6 m E of horizontal 59.4 m W of horizontal	302m MD 301m MD
OB84	06/13-06-095-05W4/0	P3S5 P3S4	70.45 m SE of horizontal 87.6 m W of horizontal	297m MD 294m MD
OB85	00/09-03-095-06W4/0	P5P12 P4P10	73.8 m E of horizontal 78.8 m W of horizontal	322.1m MD 321.9m MD
OB86	00/12-11-095-06W4/0	P4S1 P4S2	24.4 m E of horizontal 131.9 m W of horizontal	305.4m MD 311.4m MD
OB87	04/14-02-095-06W4/0	P4S6 P7S1	105 m NE of horizontal 25.5 m W of horizontal	311.3m MD 316.4m MD
OB88	00/15-02-095-06W4/0	P7P3 P7S4	63.6 m E of horizontal 25.1 m W of horizontal	325.4m MD 322.8m MD
OB89	09/14-35-094-06W4/0	P7S10 P7S9	59.9 m E of horizontal 29.3 m W of horizontal	319.6m MD 319.2m MD
OB9	02/16-12-095-06W4/0	P3S9 P3P9	18.7 m N 20 m N	303.67 m MD 311.52 m MD
OB90	00/15-07-095-05W4/0	P3S1	790 m NE of horizontal	279m MD
OB91	00/09-07-095-05W4/0	P3S1	862.2 m NE of horizontal	296m MD
OB92	00/12-02-095-06W4/0	P4P10 P4P9	70.1 m E of horizontal 91.5 m W of hoizontal	323.5m MD 321.8m MD
OB93	02/05-02-095-06W4/0	P4P10 P4S9	129.8 m E of horizontal 29.3 m W of horizontal	321.5m MD 312.9m MD
OB94	02/13-02-095-06W4/0	P4S8 P4S7	44.4 m E of horizontal 114.9 m W of horizontal	313m MD 313.6m MD
OB95	09/01-10-095-06W4/0	P5P6 P5P7	59.2 m E of horizontal 61.25 m W of horizontal	319.3m MD 317.6m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB96	00/05-10-095-06W4/0	P6S6 P6P7	65.1 m E of horizontal 24.3 m W of horizontal	285.8m MD 294.7m MD
OB97	00/13-09-095-06W4/0	P15P1 P6P1 P16P19	487.5 m N of horizontal 1241 m W 1203 m N	295.5m MD 290.5m MD 287.4m MD
OB98	00/01-17-095-06W4/0	P15P1 P6P1 P16P19	1023.8 m NW of horizontal 1729 m NW 1633 m N	294.2m MD 290.7m MD 287.6m MD
P5S2 OB	06/15-10-095-06W4/2	P5P2	0m	10.47 m MD
P5S3 OB	05/15-10-095-06W4/0	P5P3	0m	17.16m MD
P5S4 OB	04/02-10-095-06W4/0	P5P4	0m	13.45m MD
QW1	11/13-10-095-06W4/0	P6P4 P6P3	19 m W 71 m E	296.1 297.6
QW2	00/12-10-095-06W4/0	P6P7 P6P6	58 m W 33 m E	295.5 293.2
QW4	09/04-10-095-06W4/0	P16P2 P16P3	7.5 m S 81 m N	303.6 304.3

Piezometer Plots & Temperature vs Depth Plots



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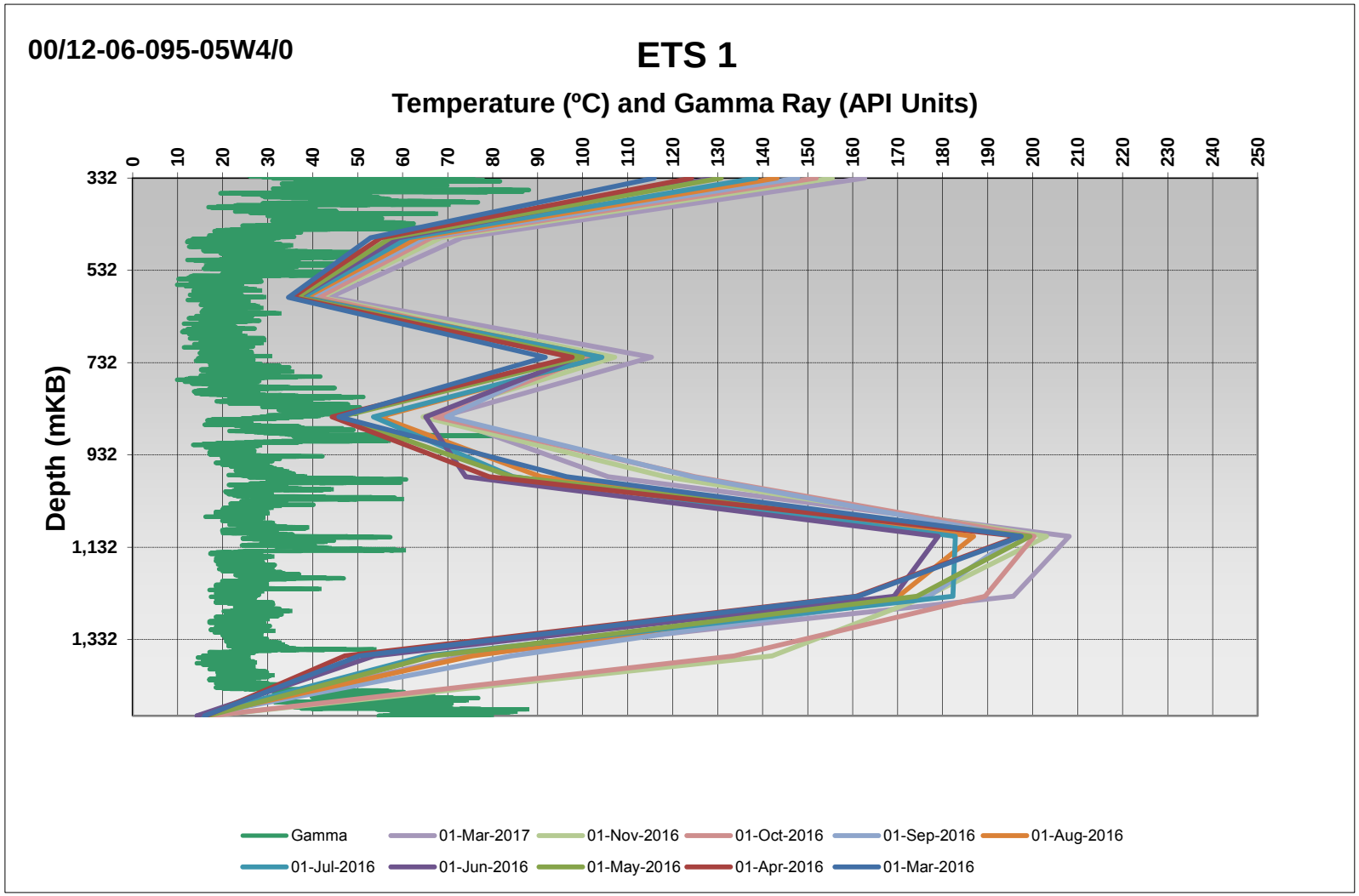

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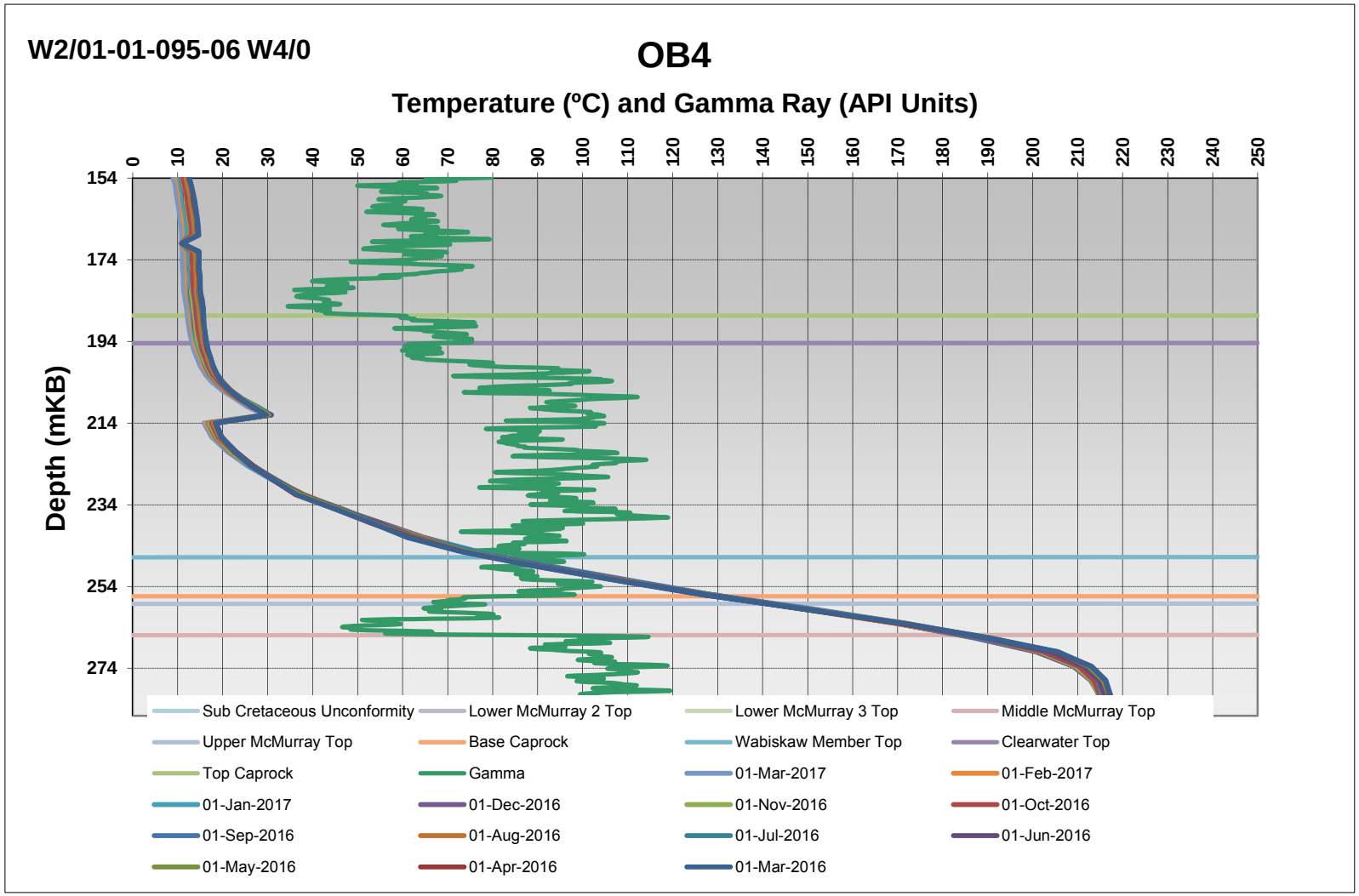

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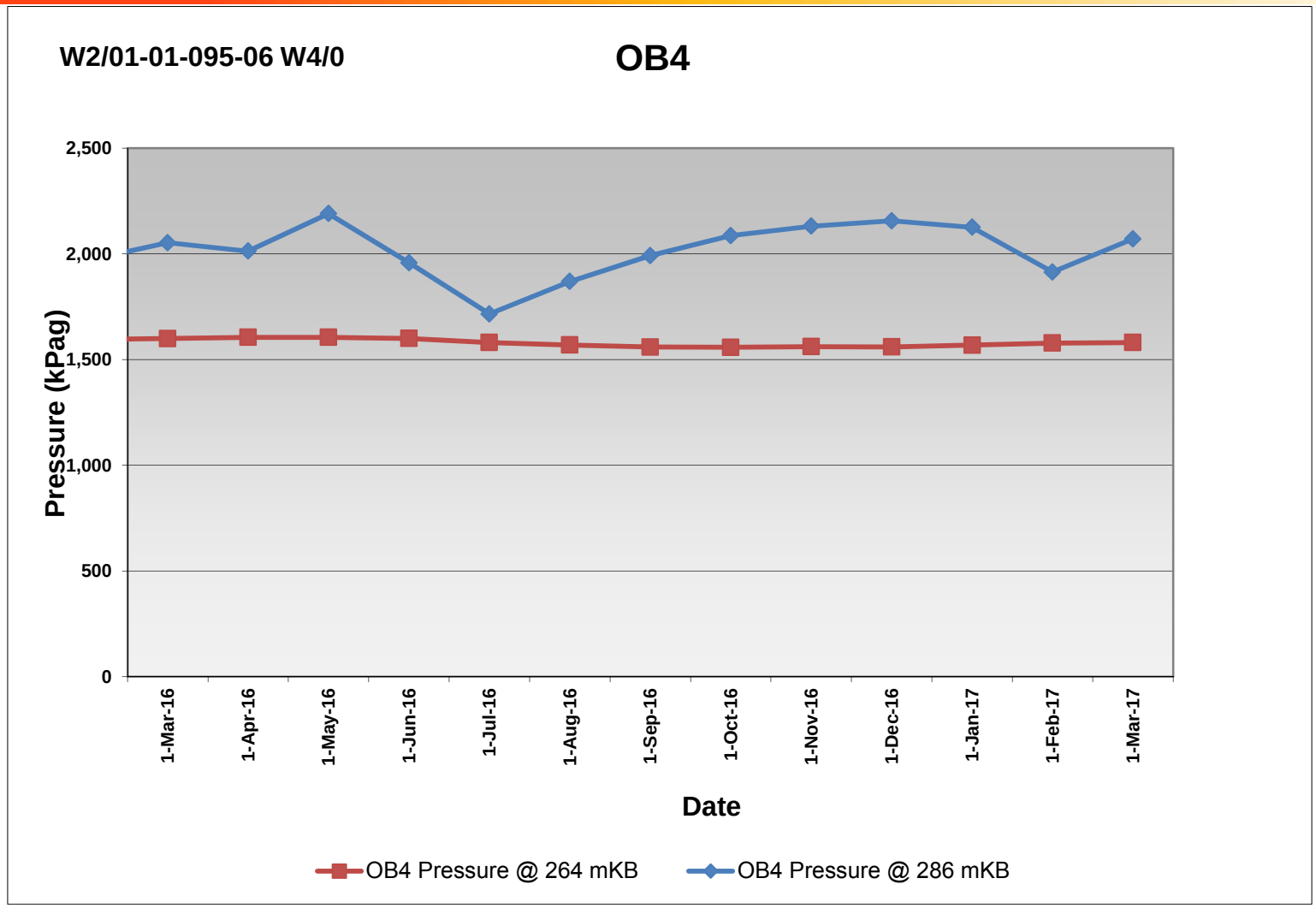

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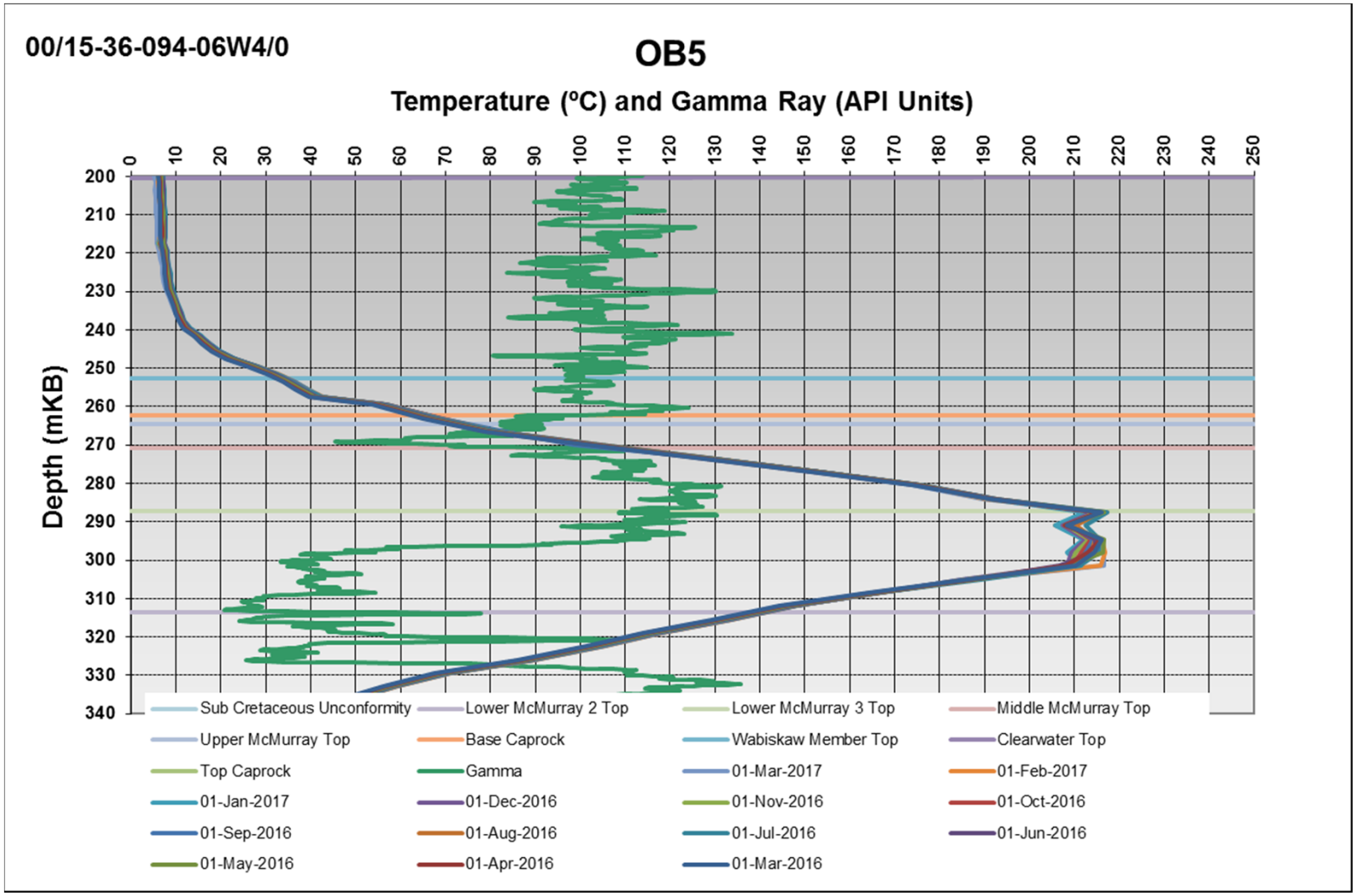

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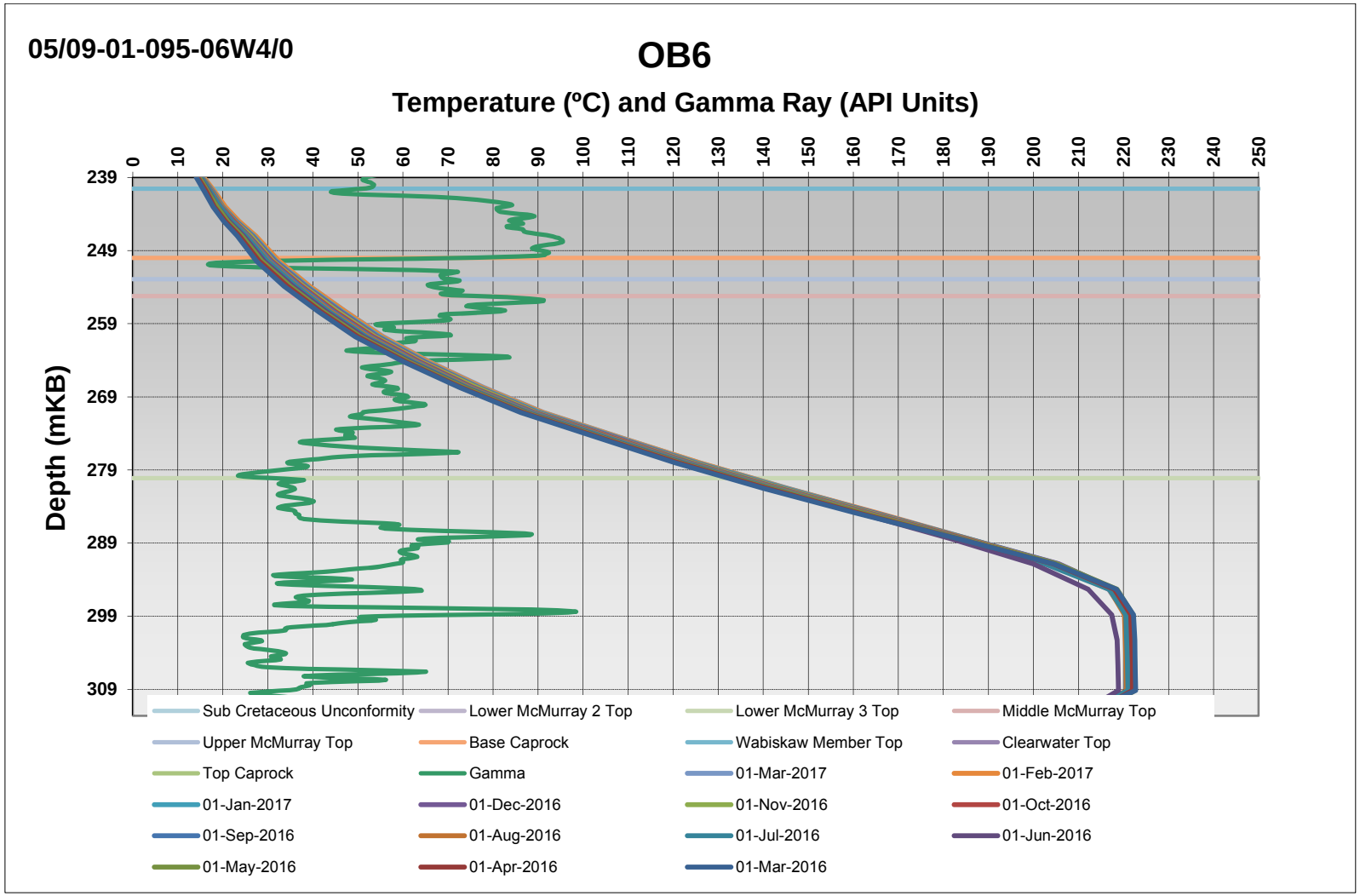

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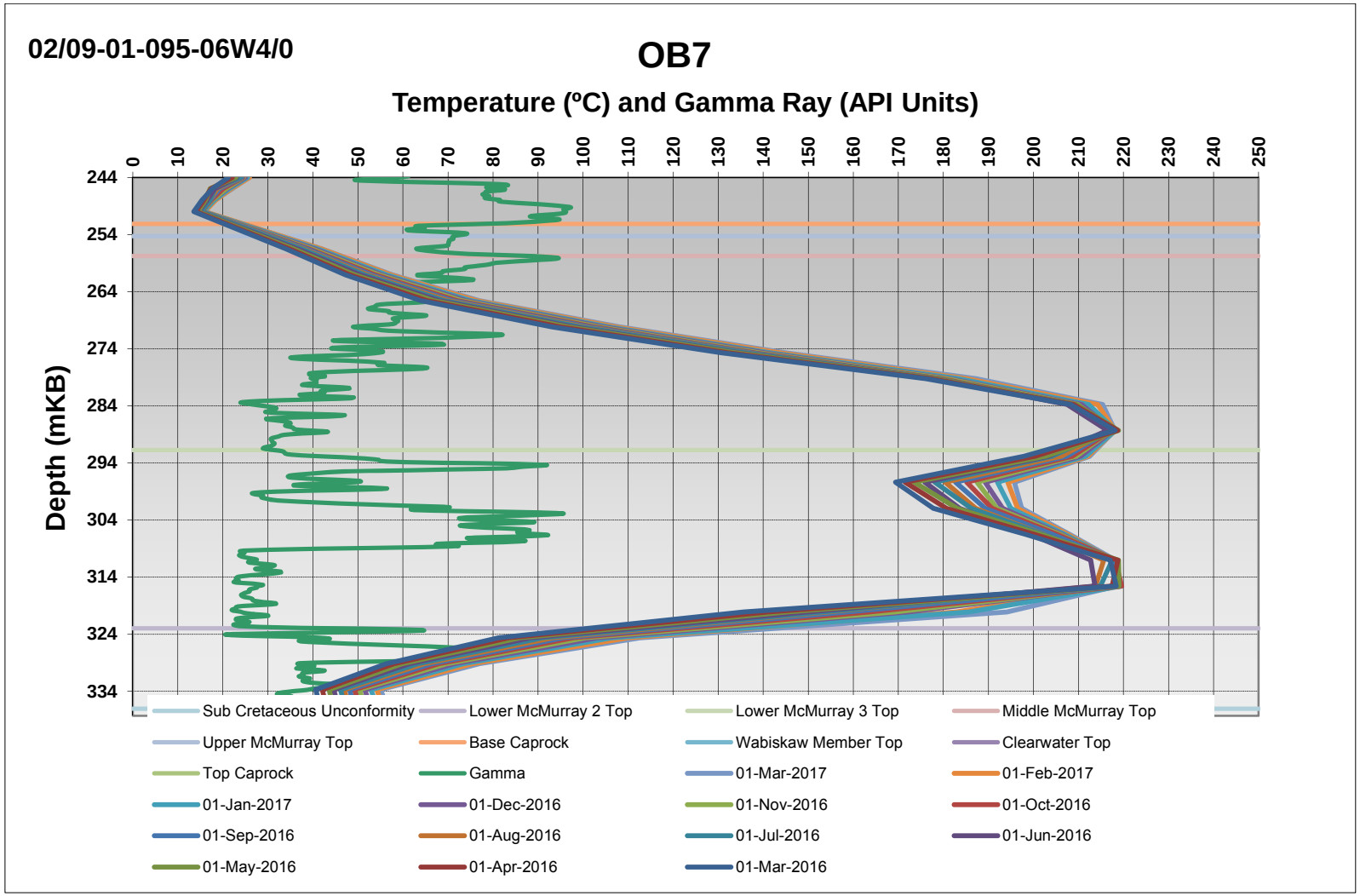

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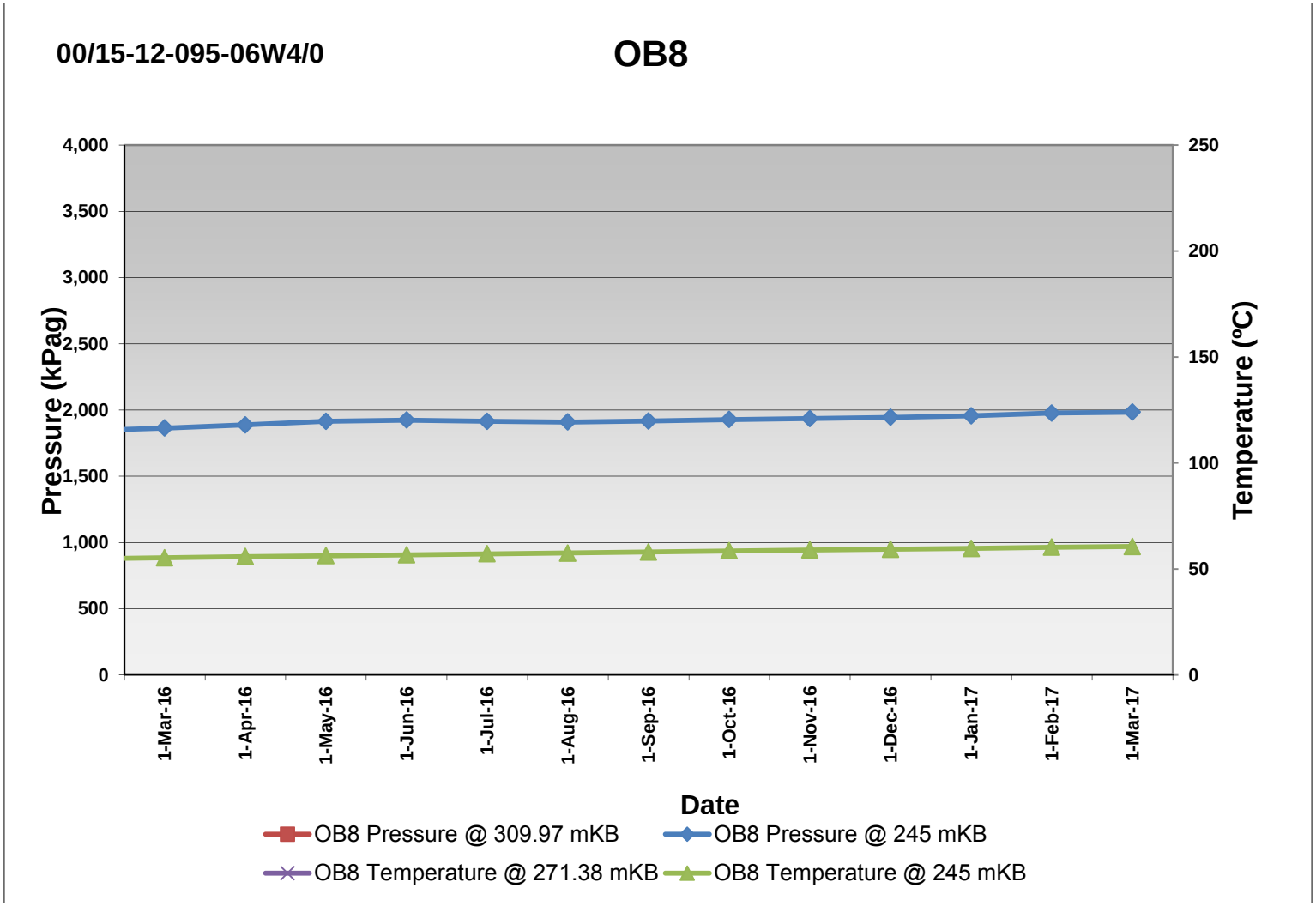

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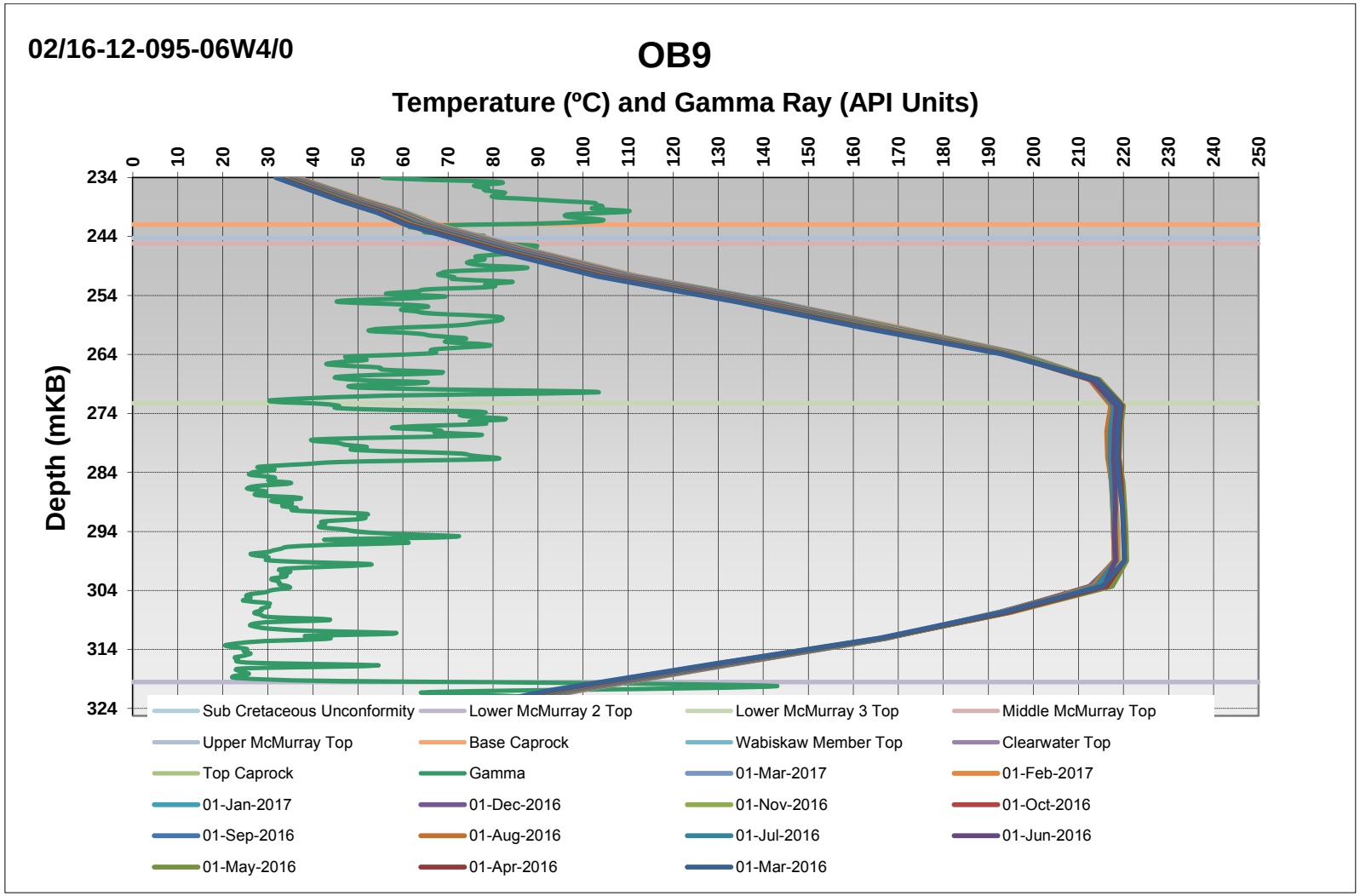

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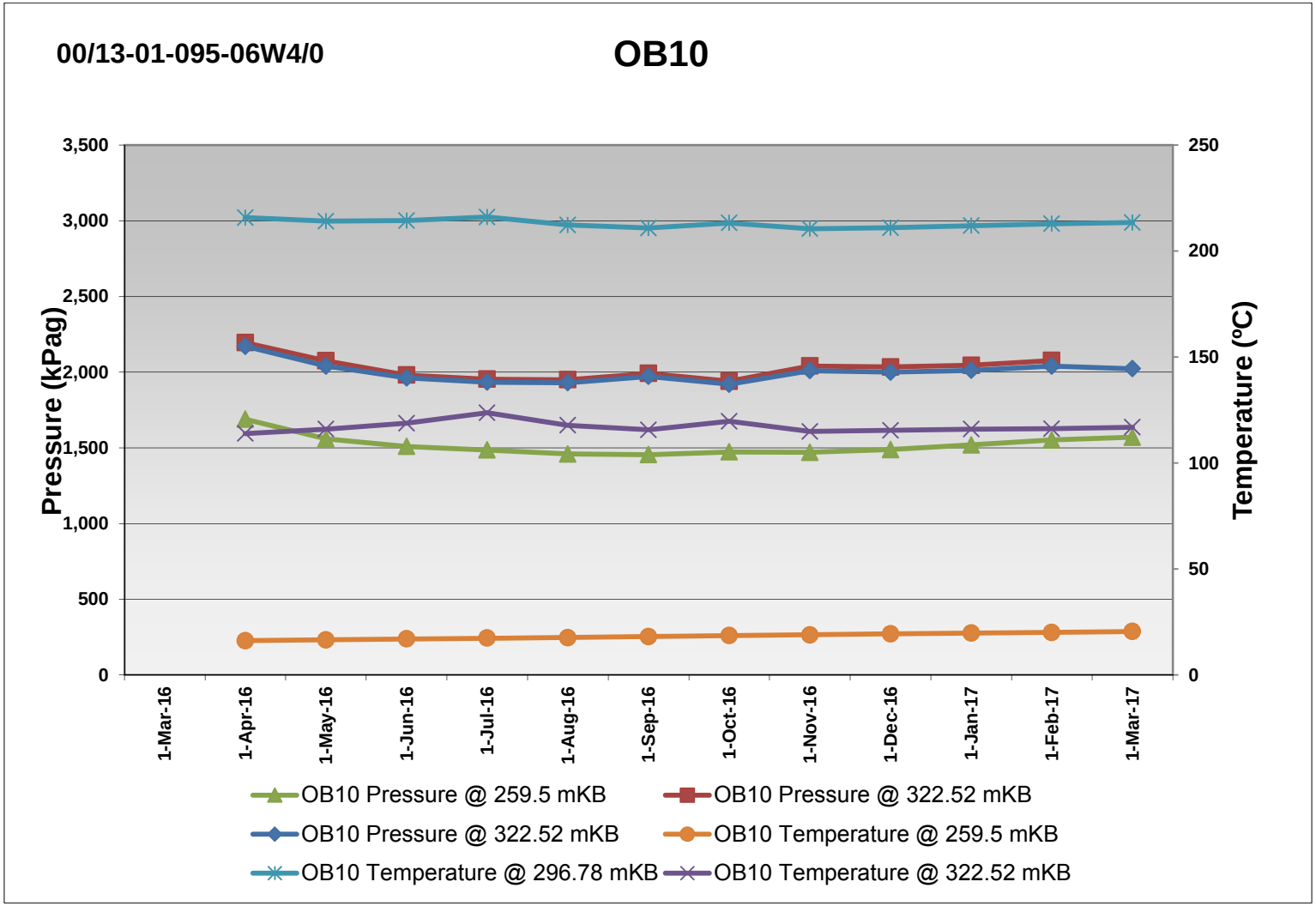

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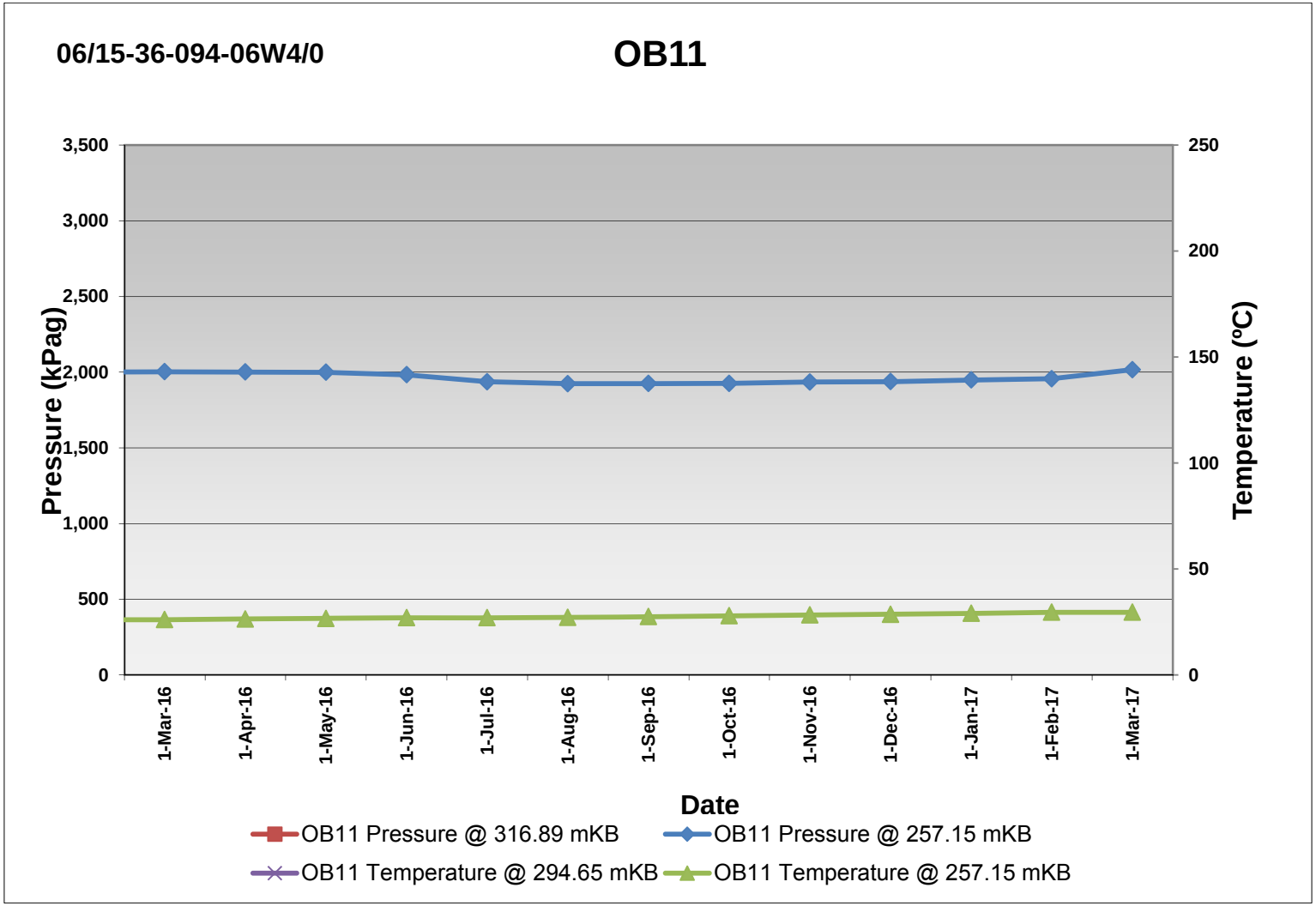

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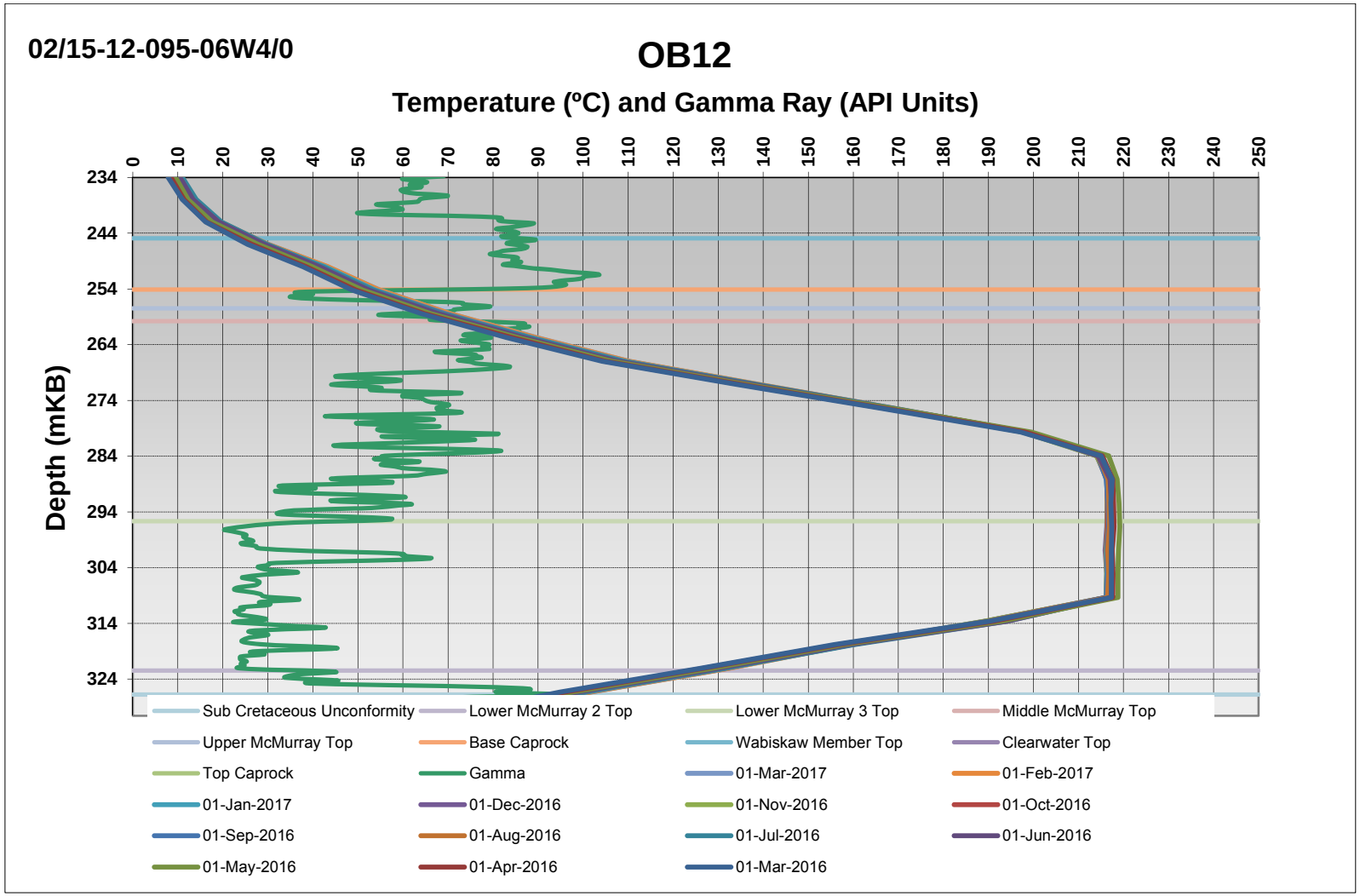

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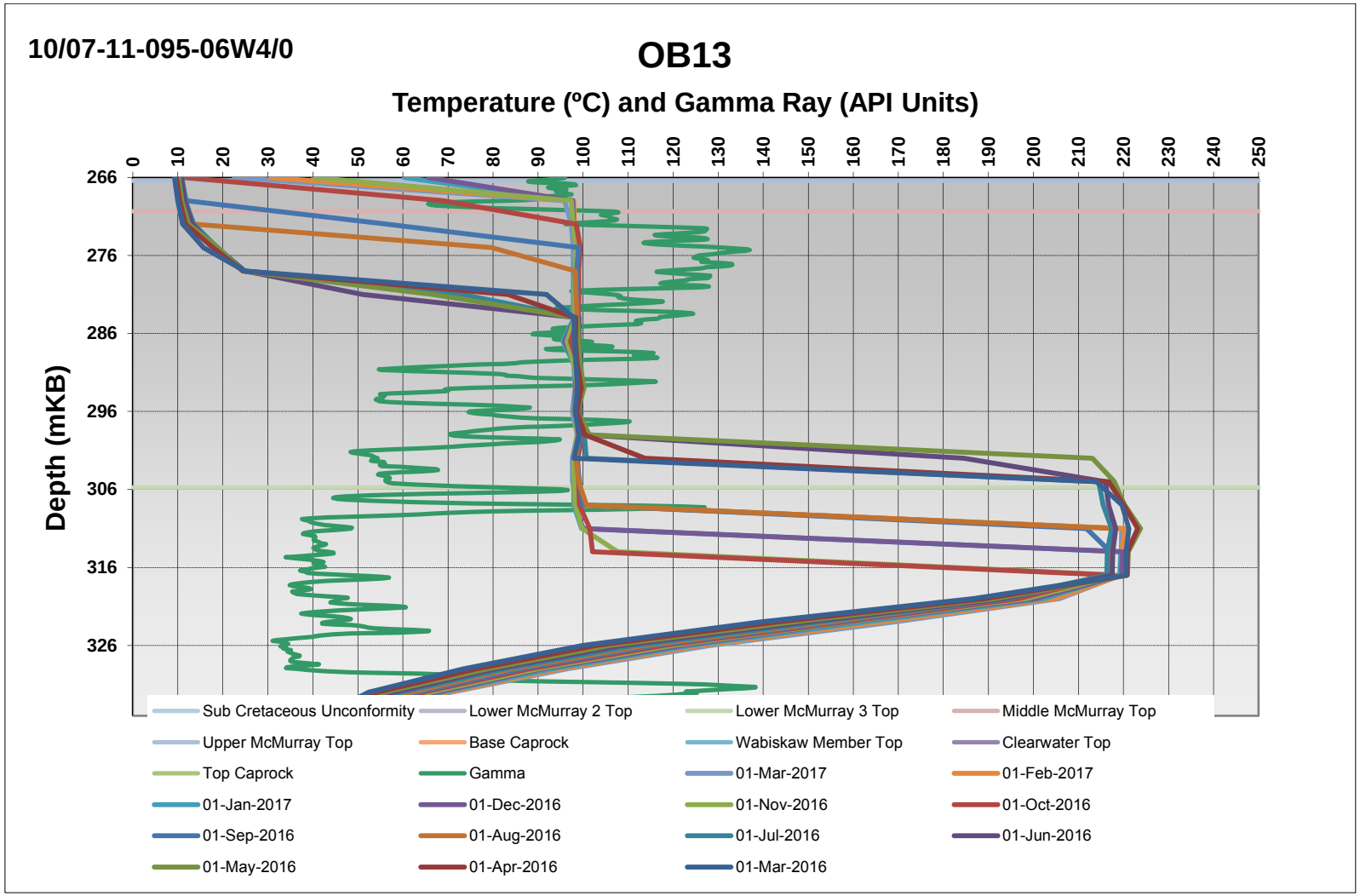

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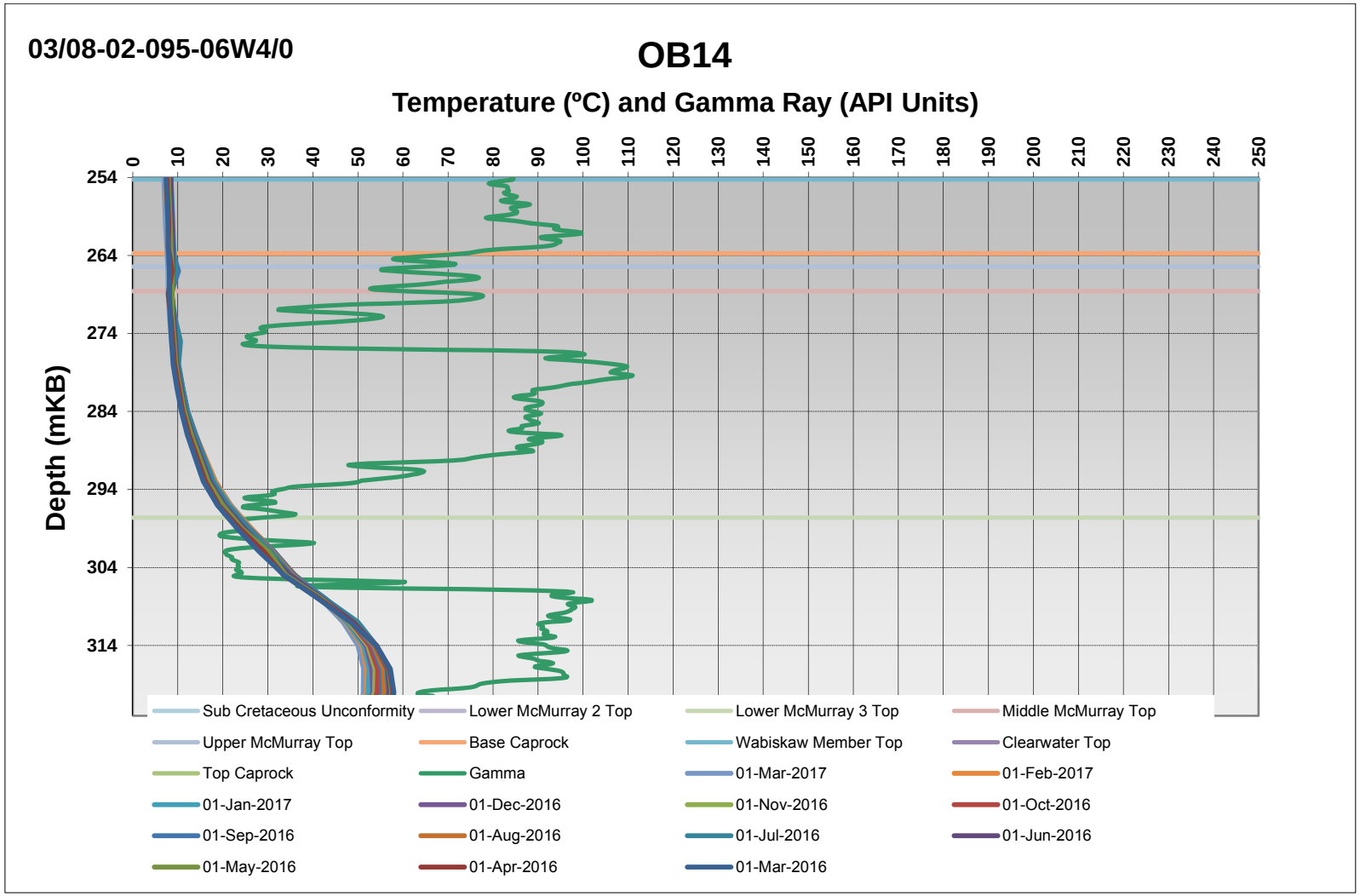

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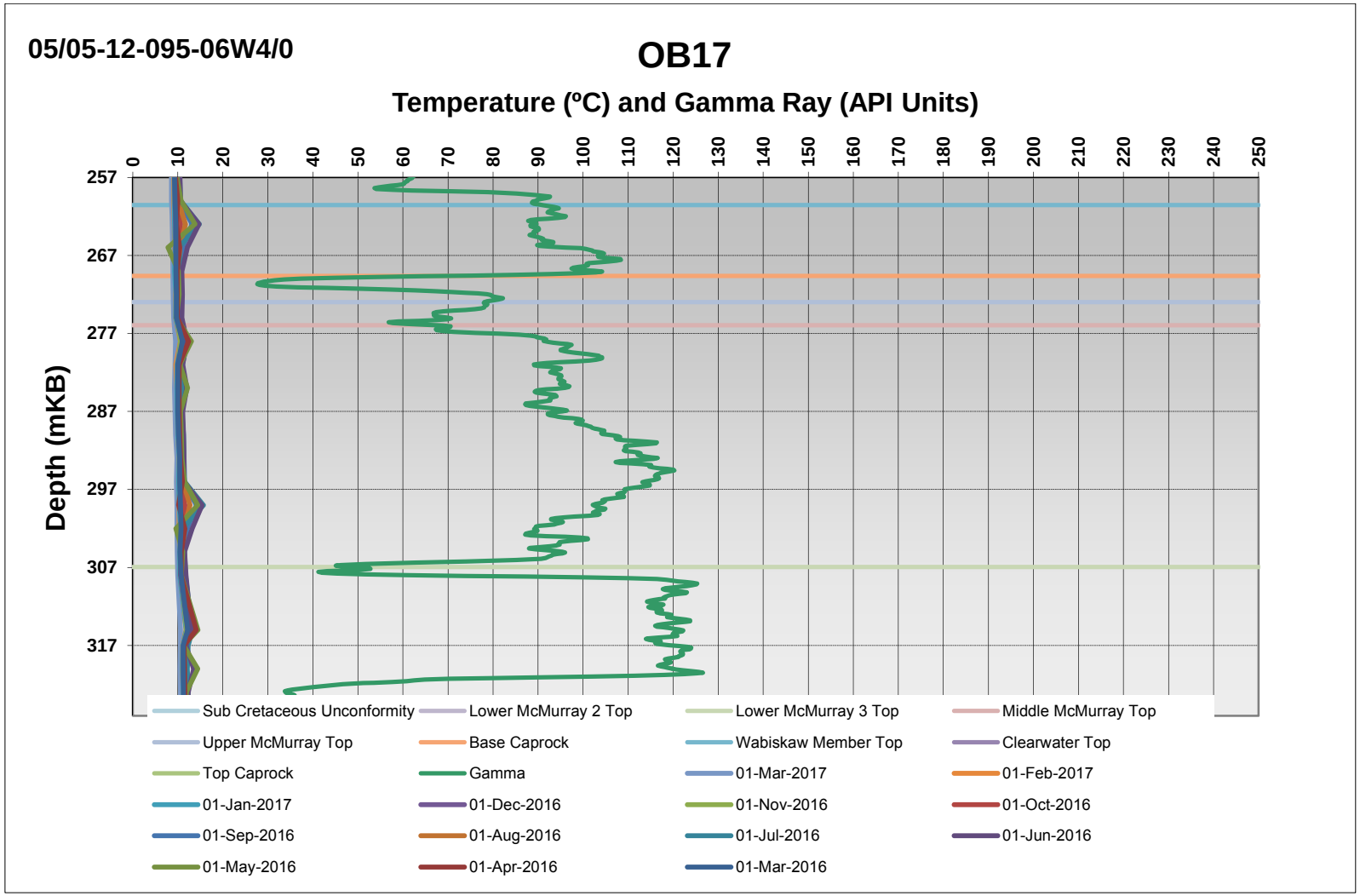

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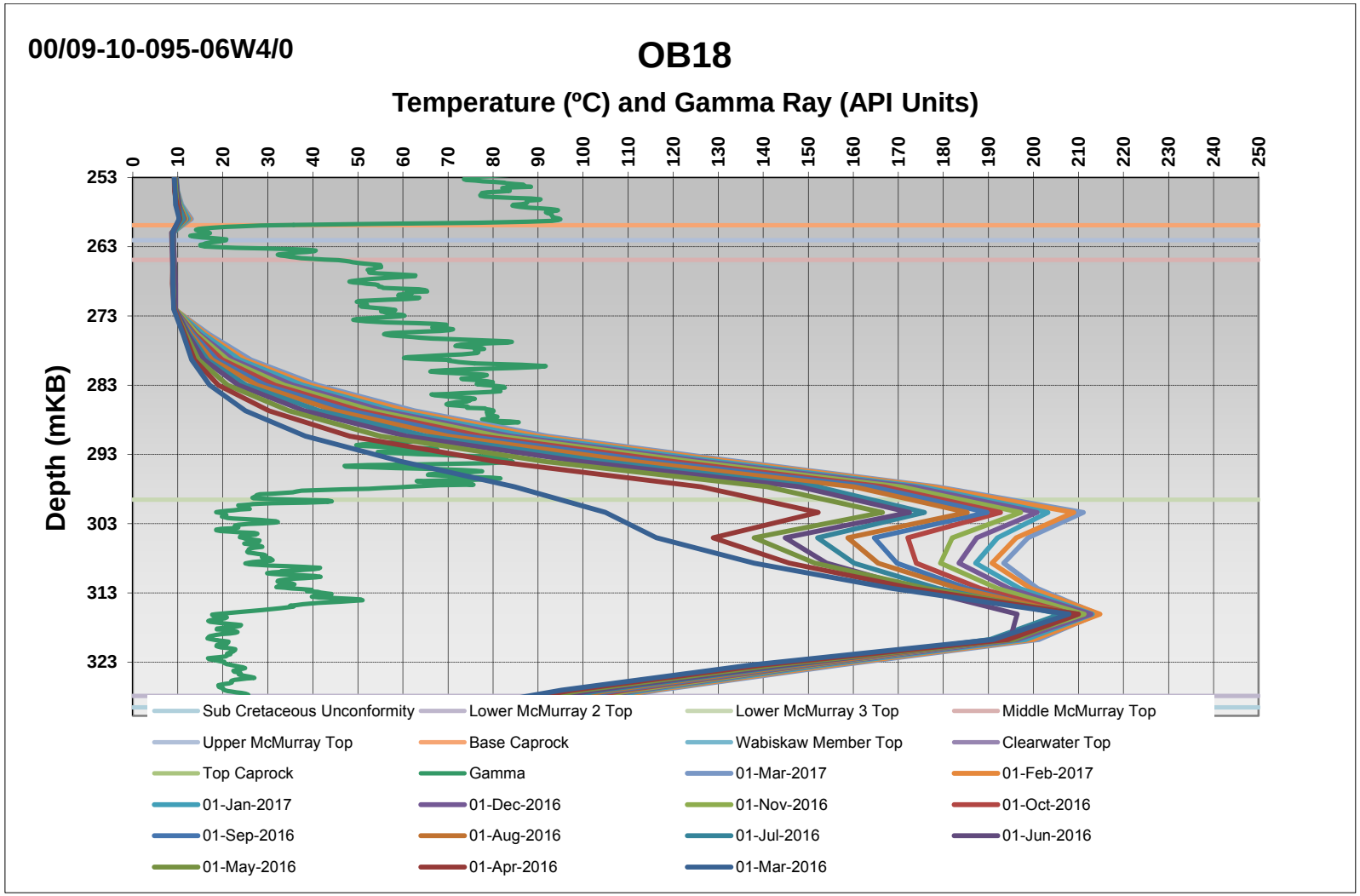

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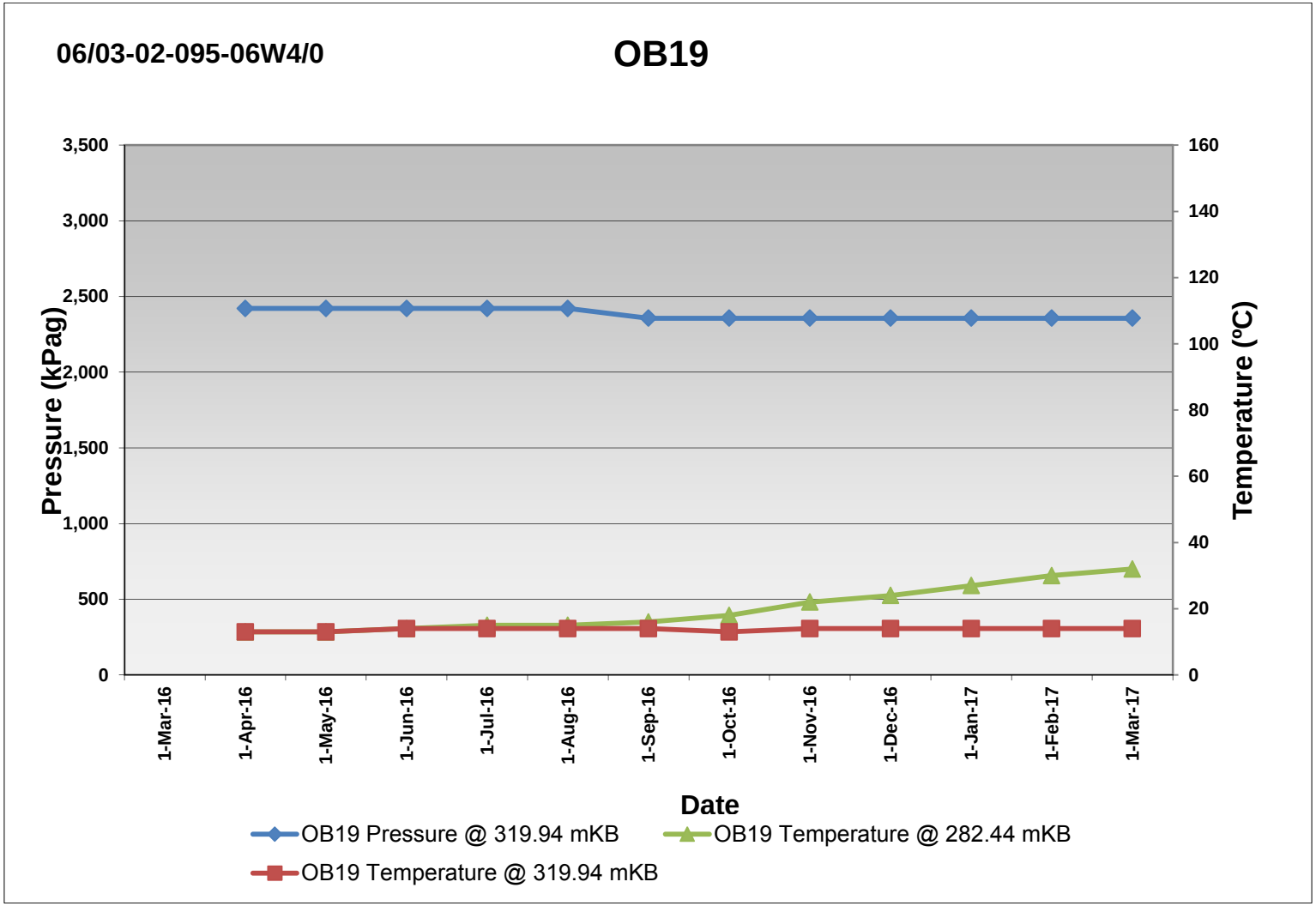

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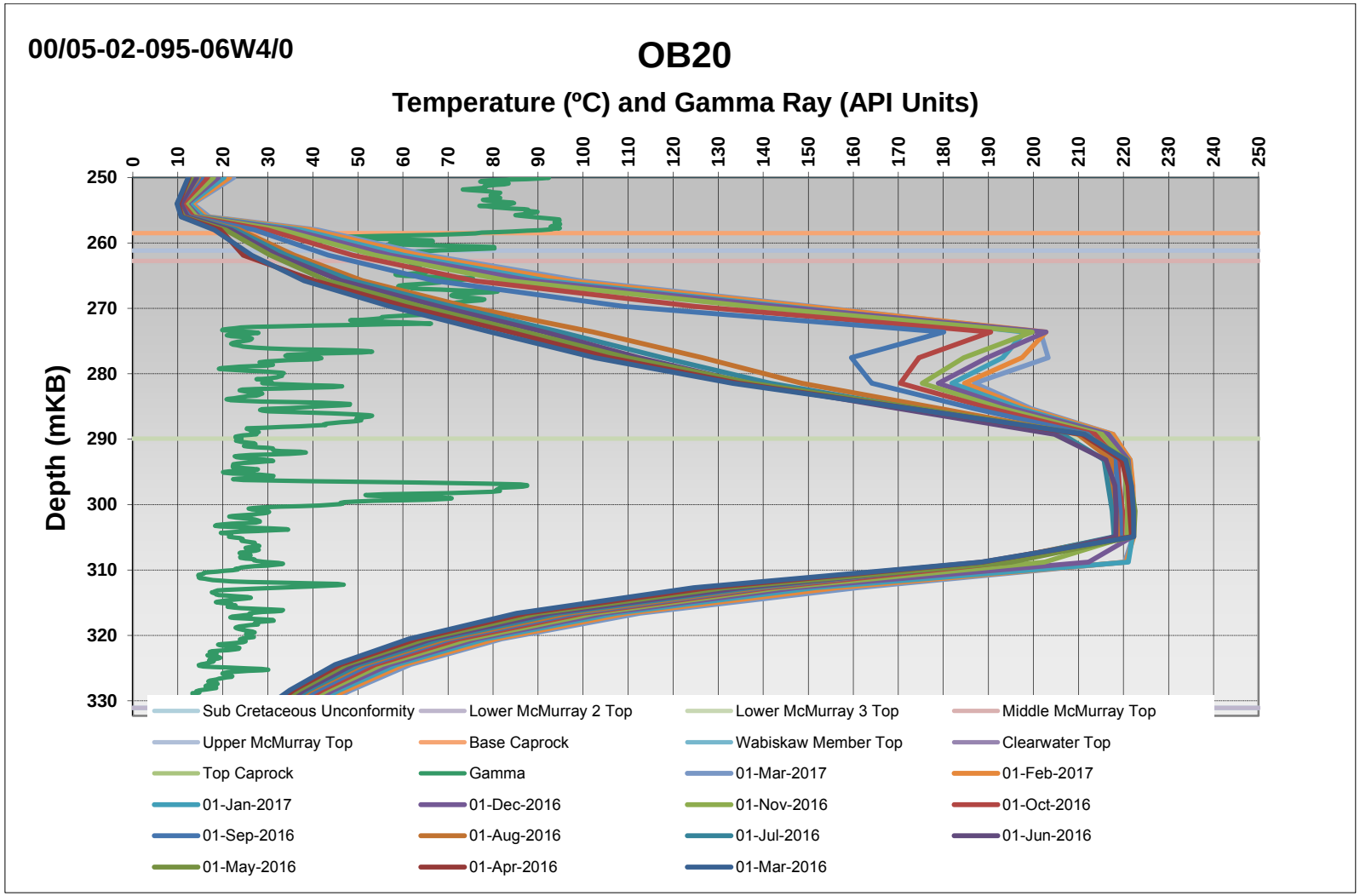

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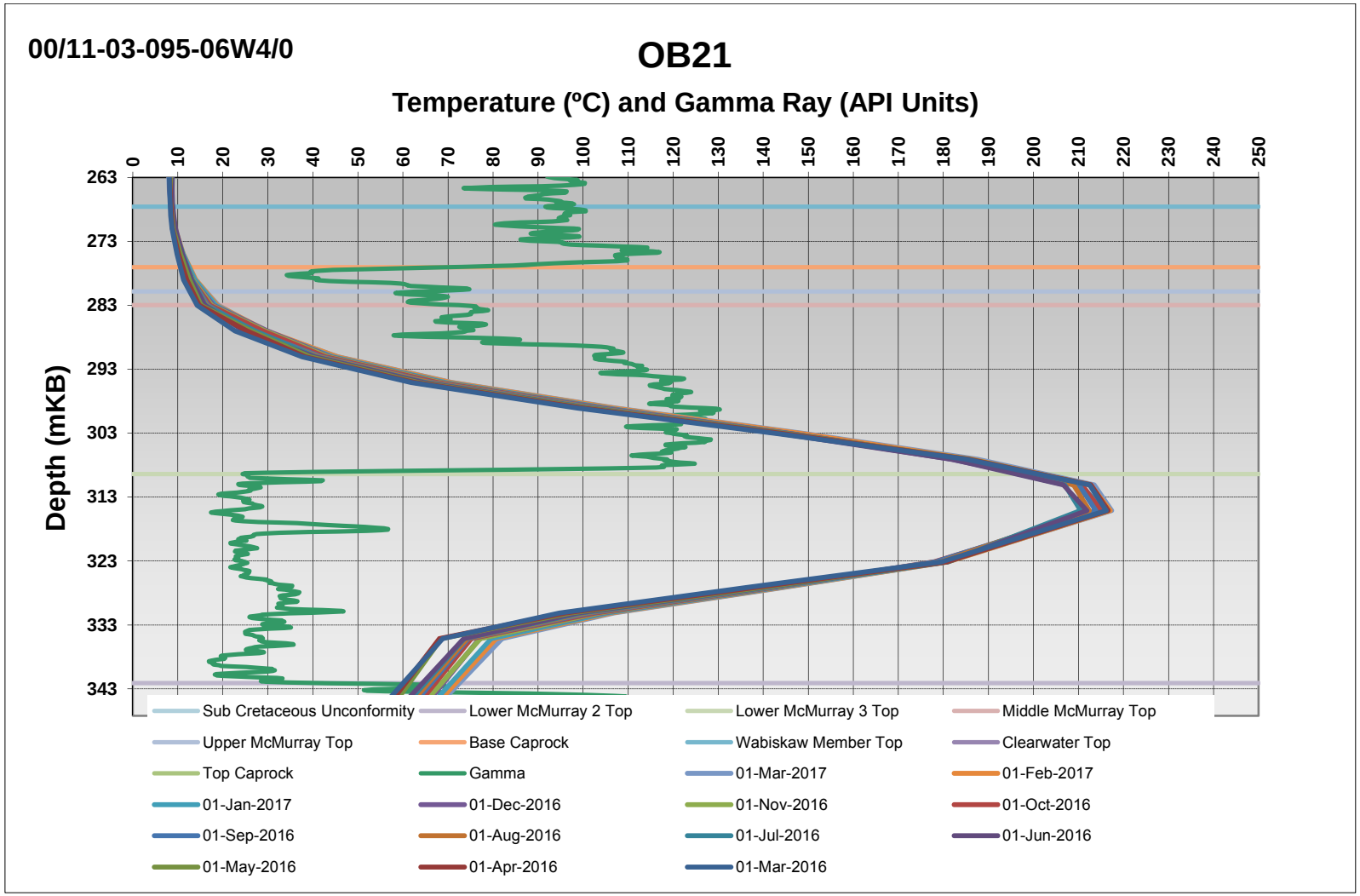

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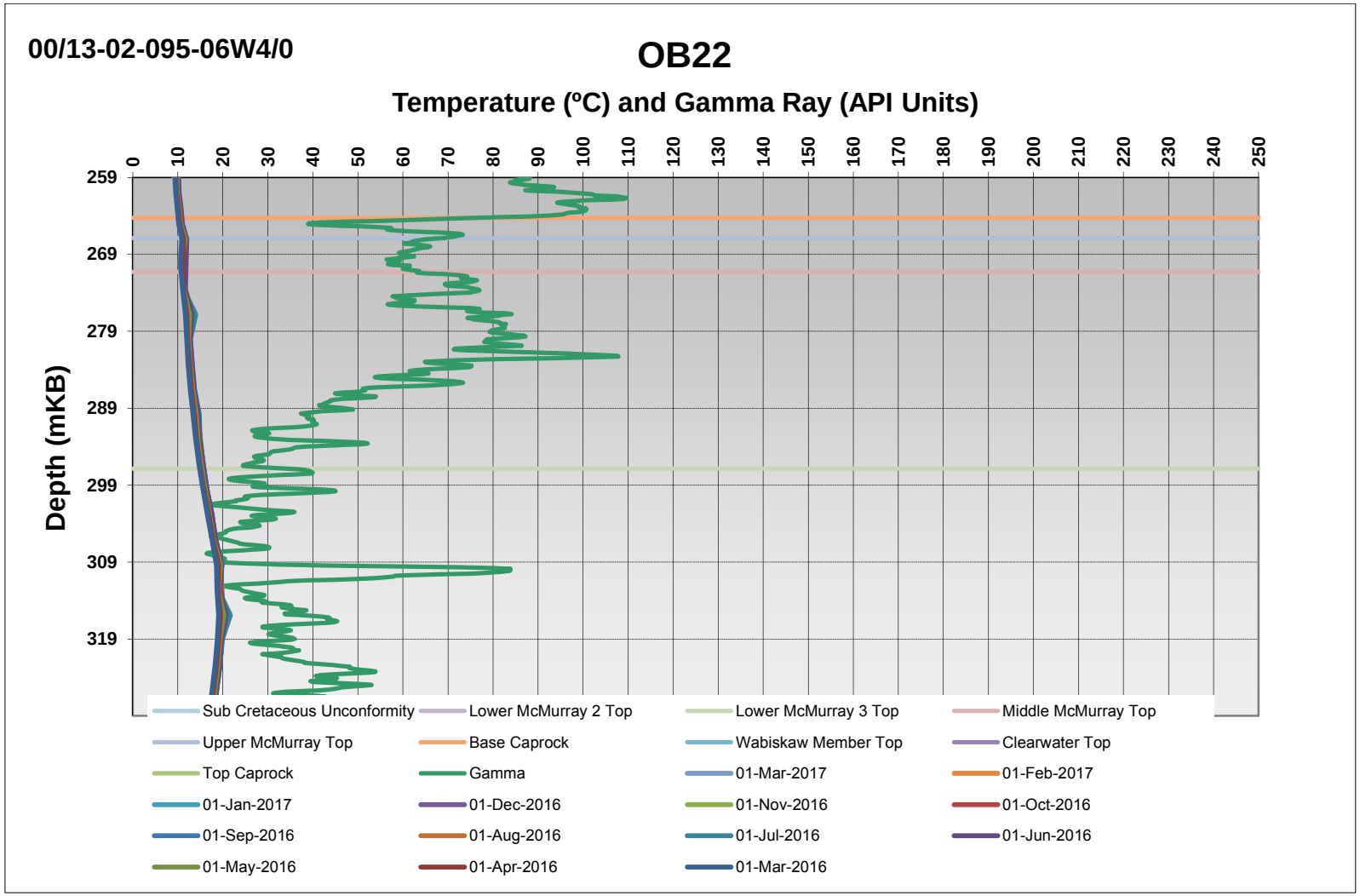

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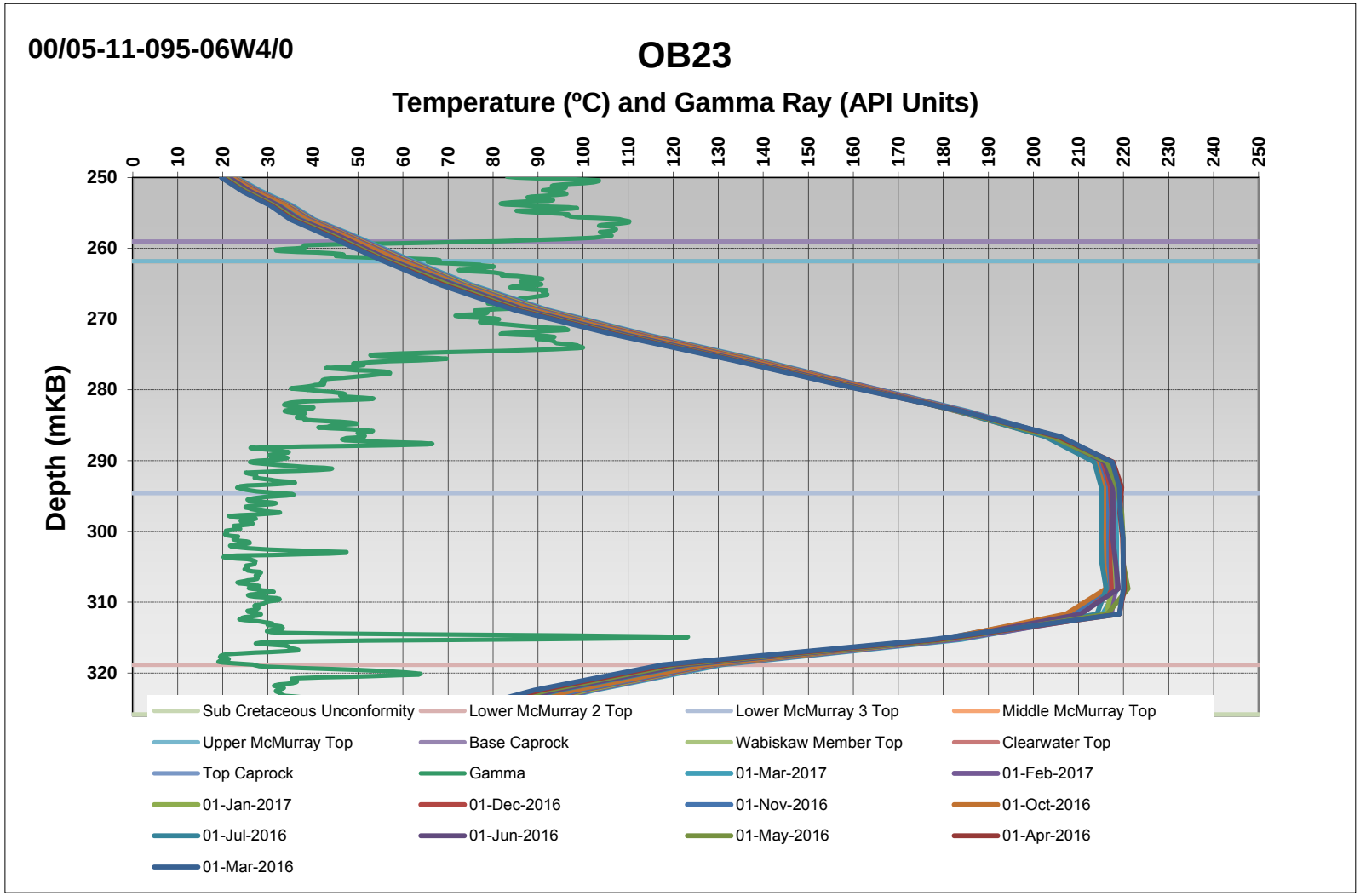

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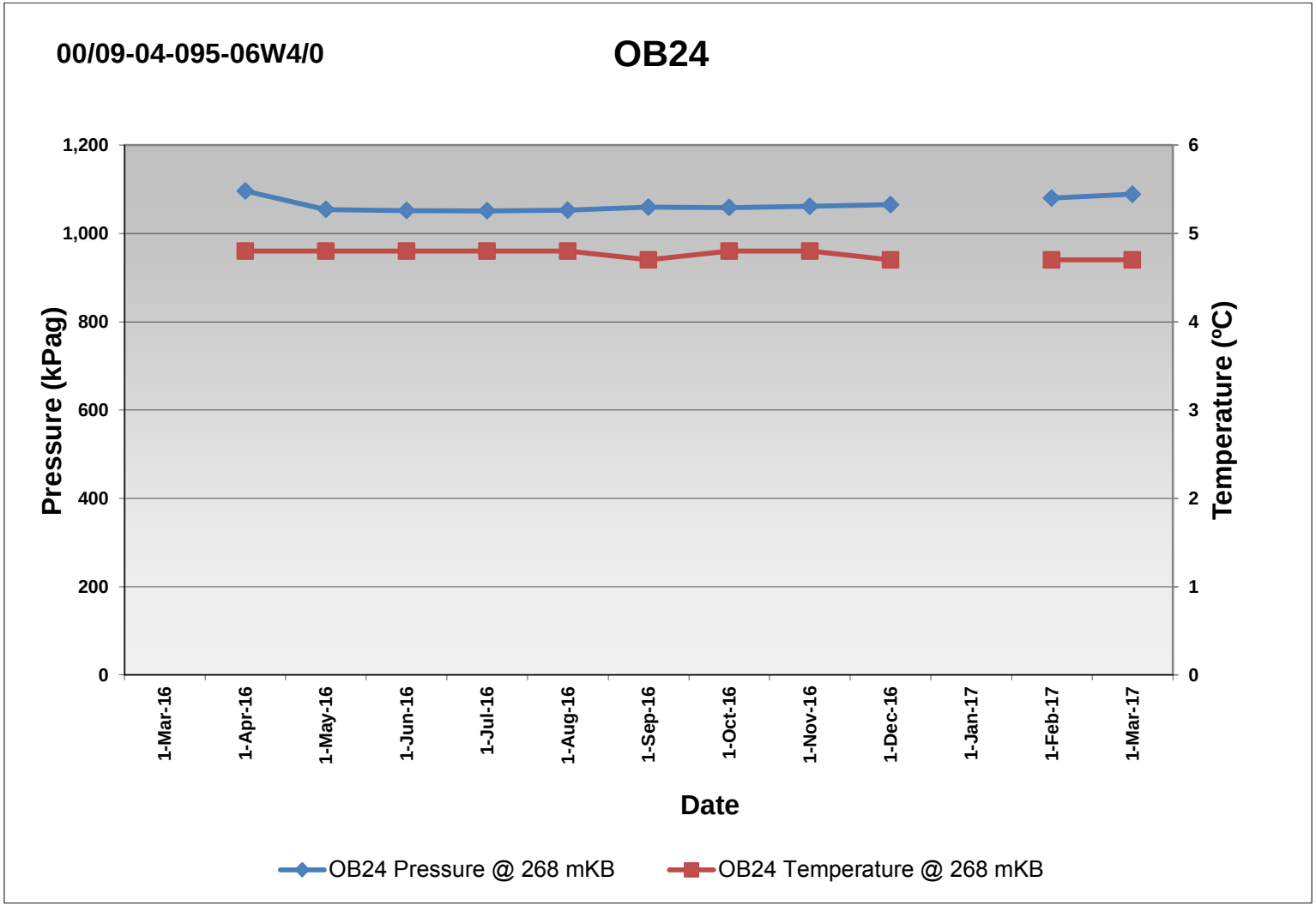

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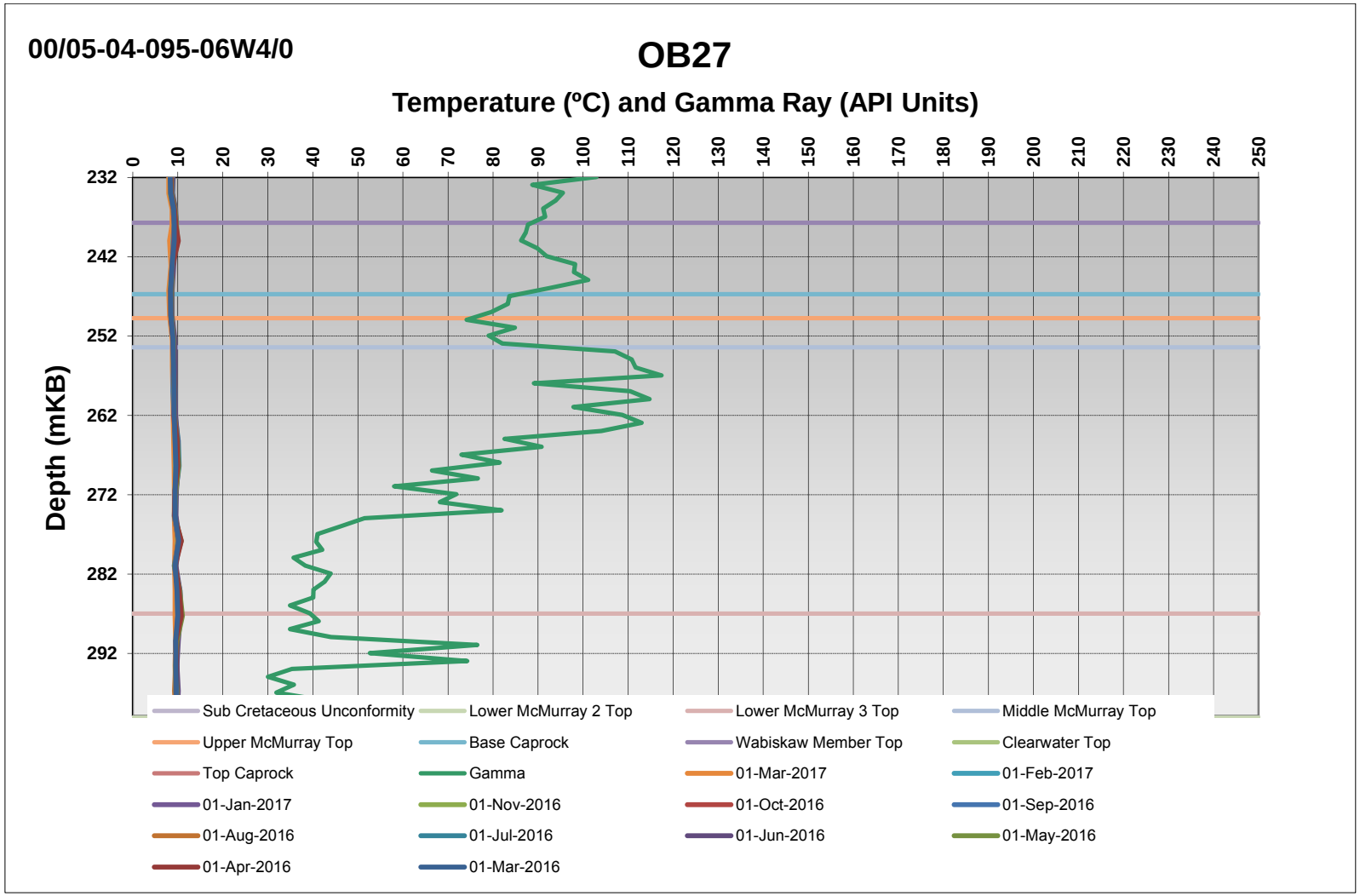

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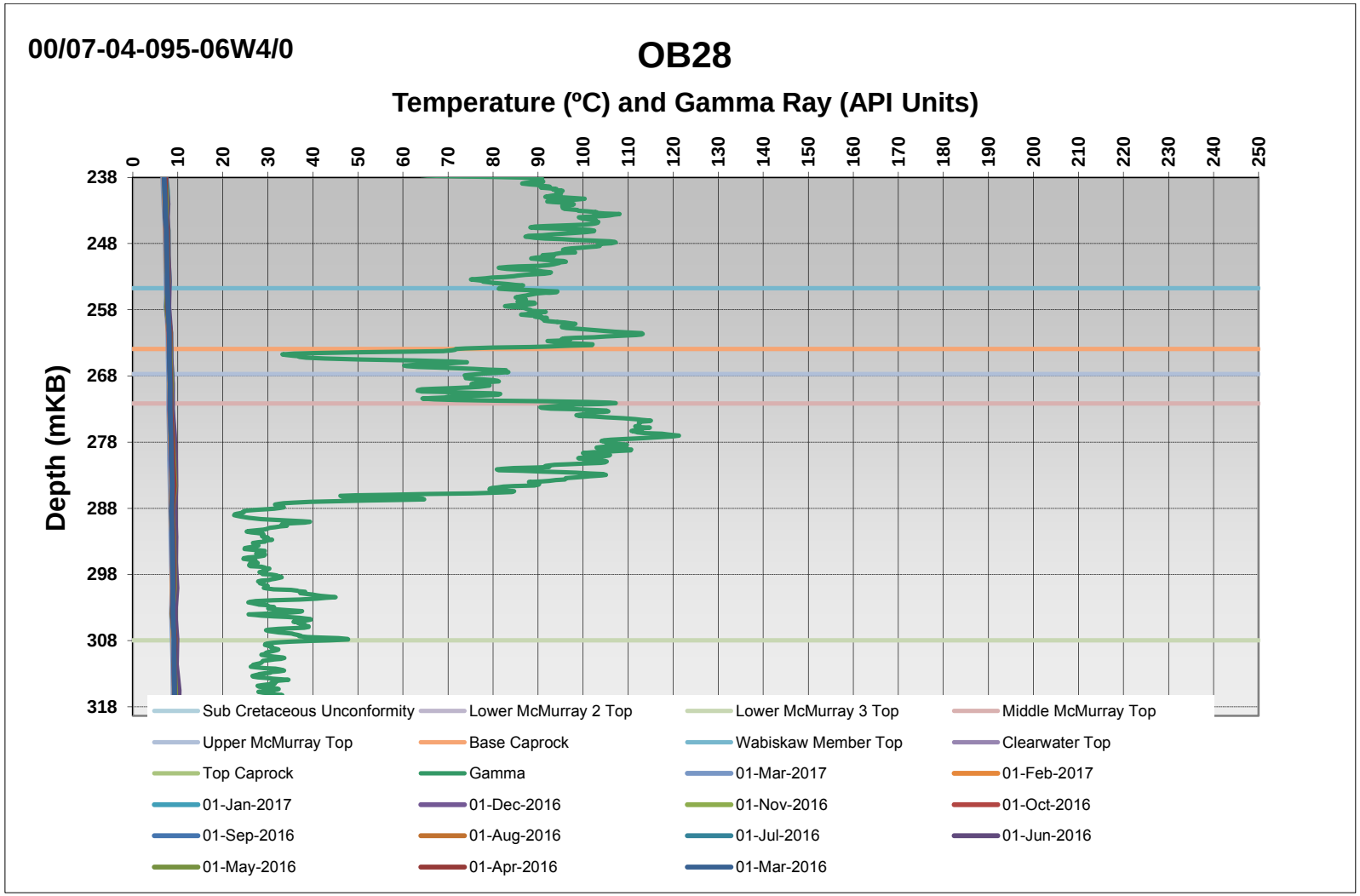

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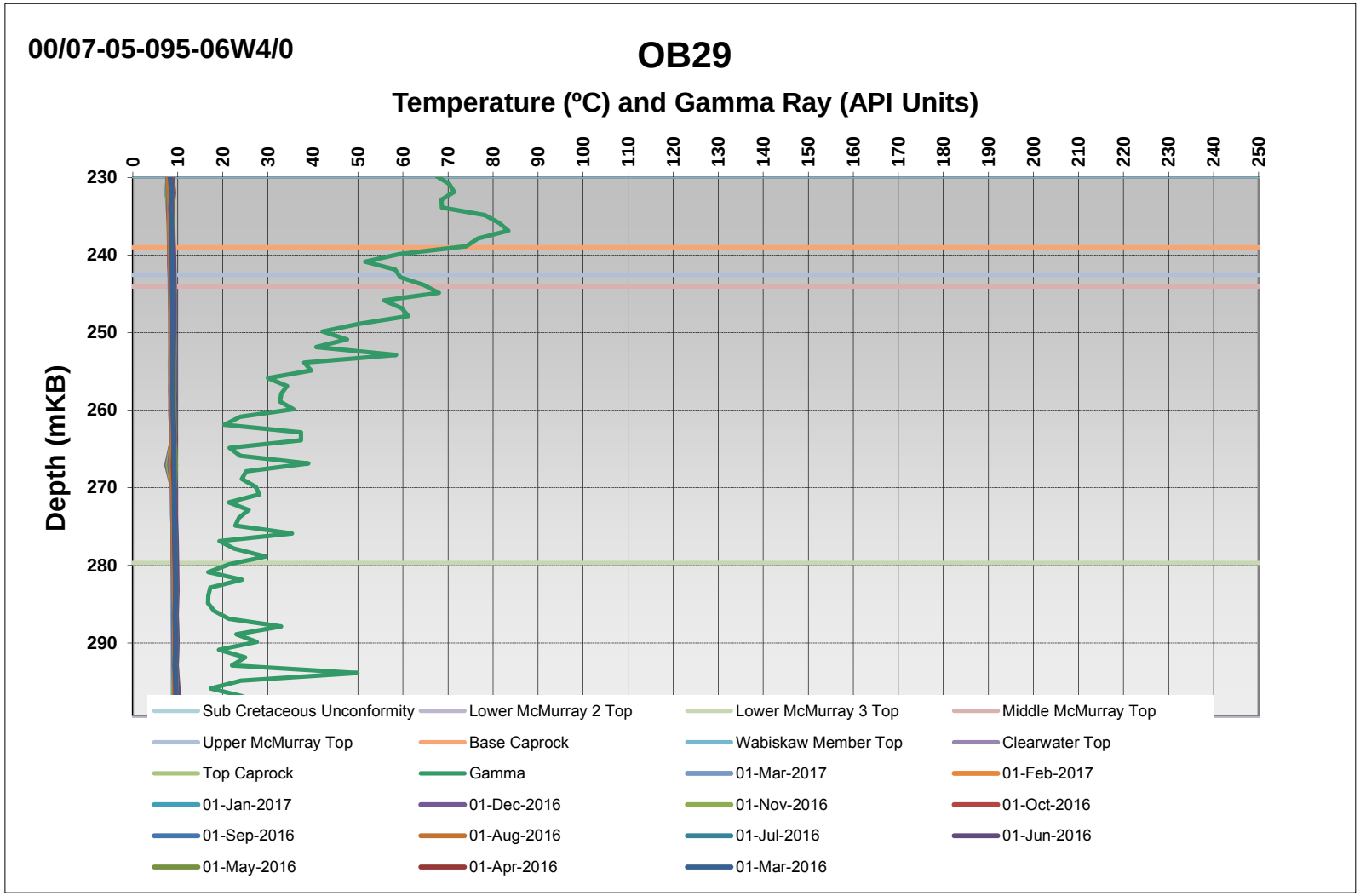

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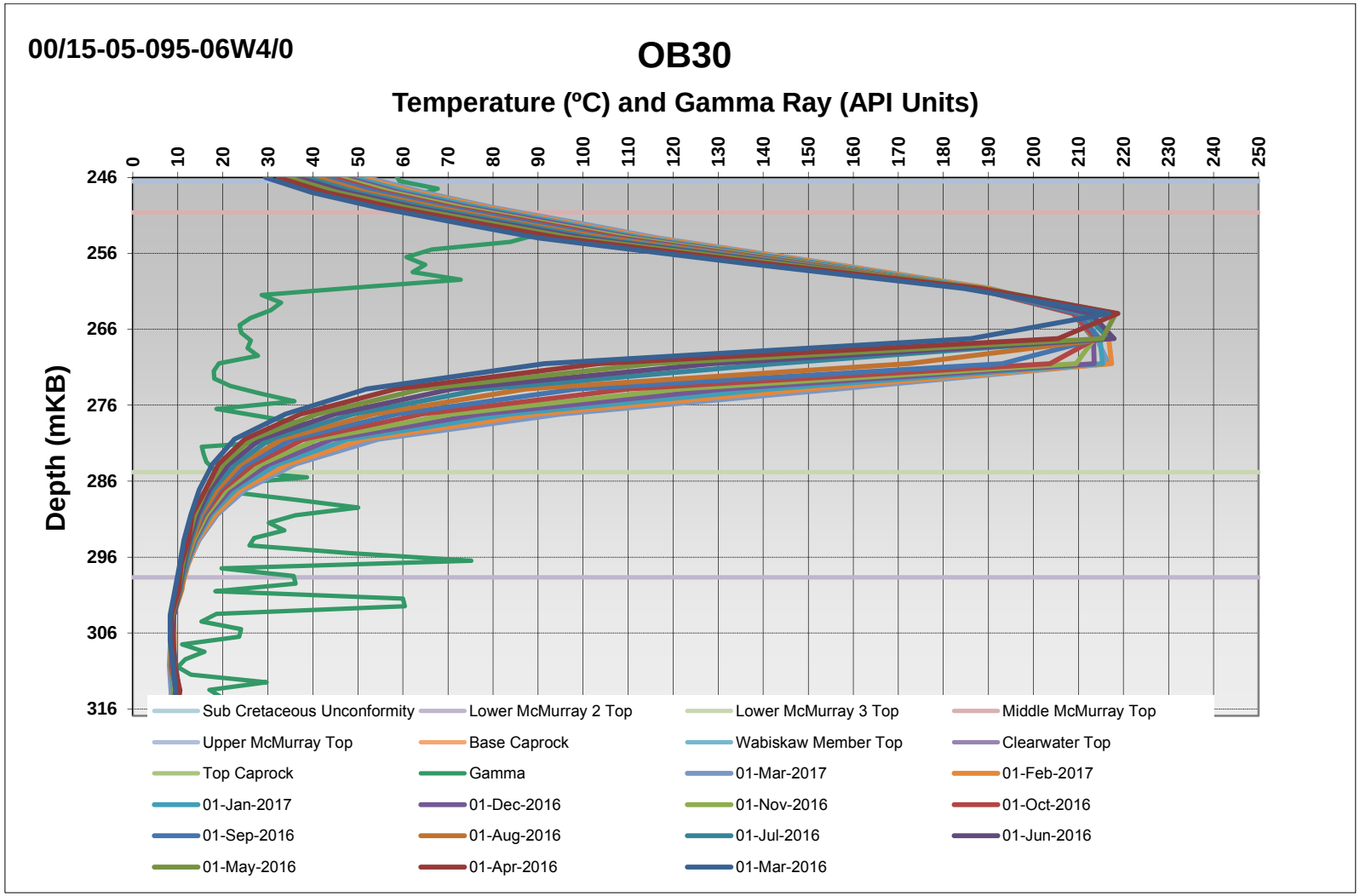
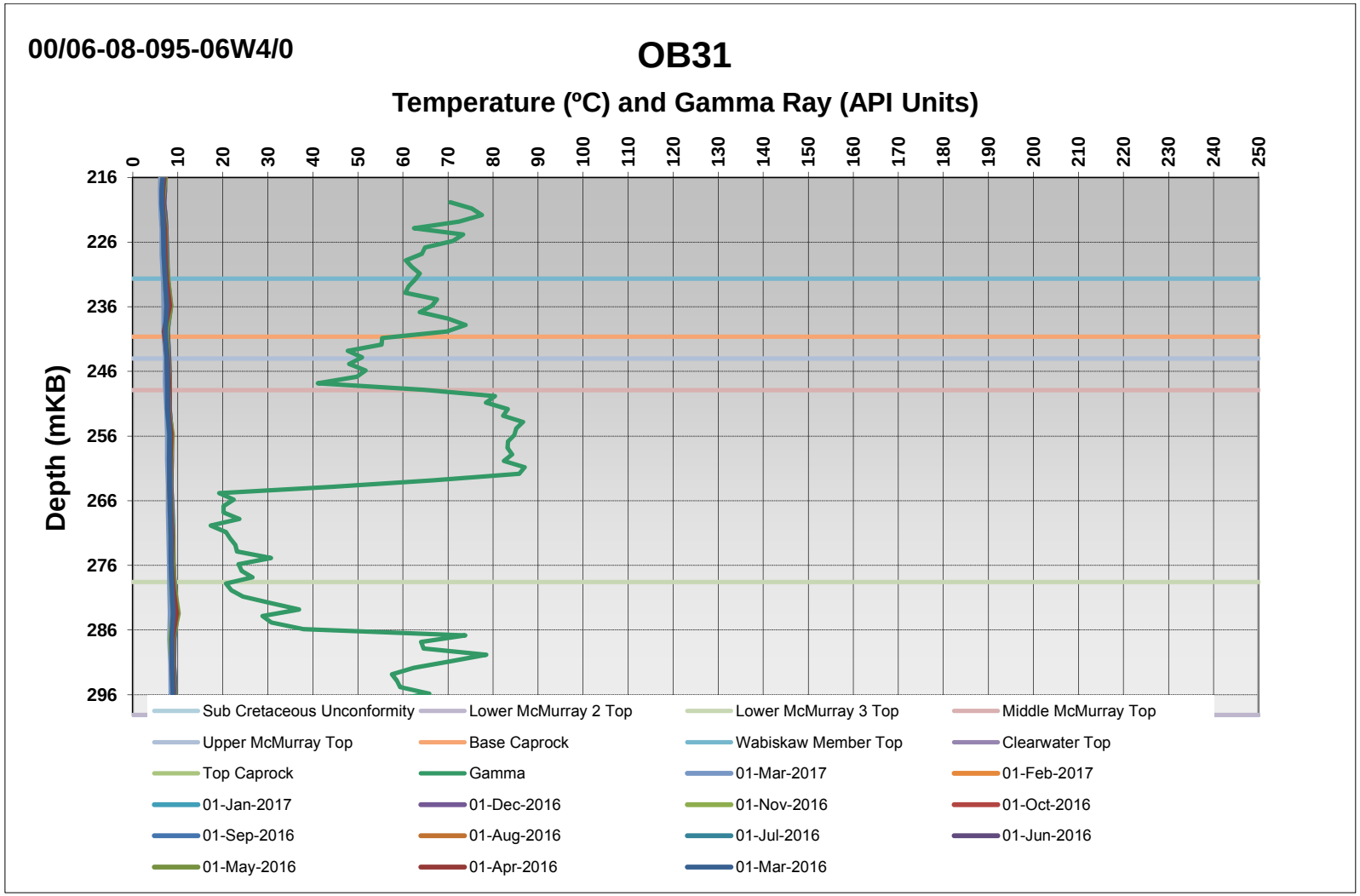


Piezometer Plots & Temperature vs Depth Plots



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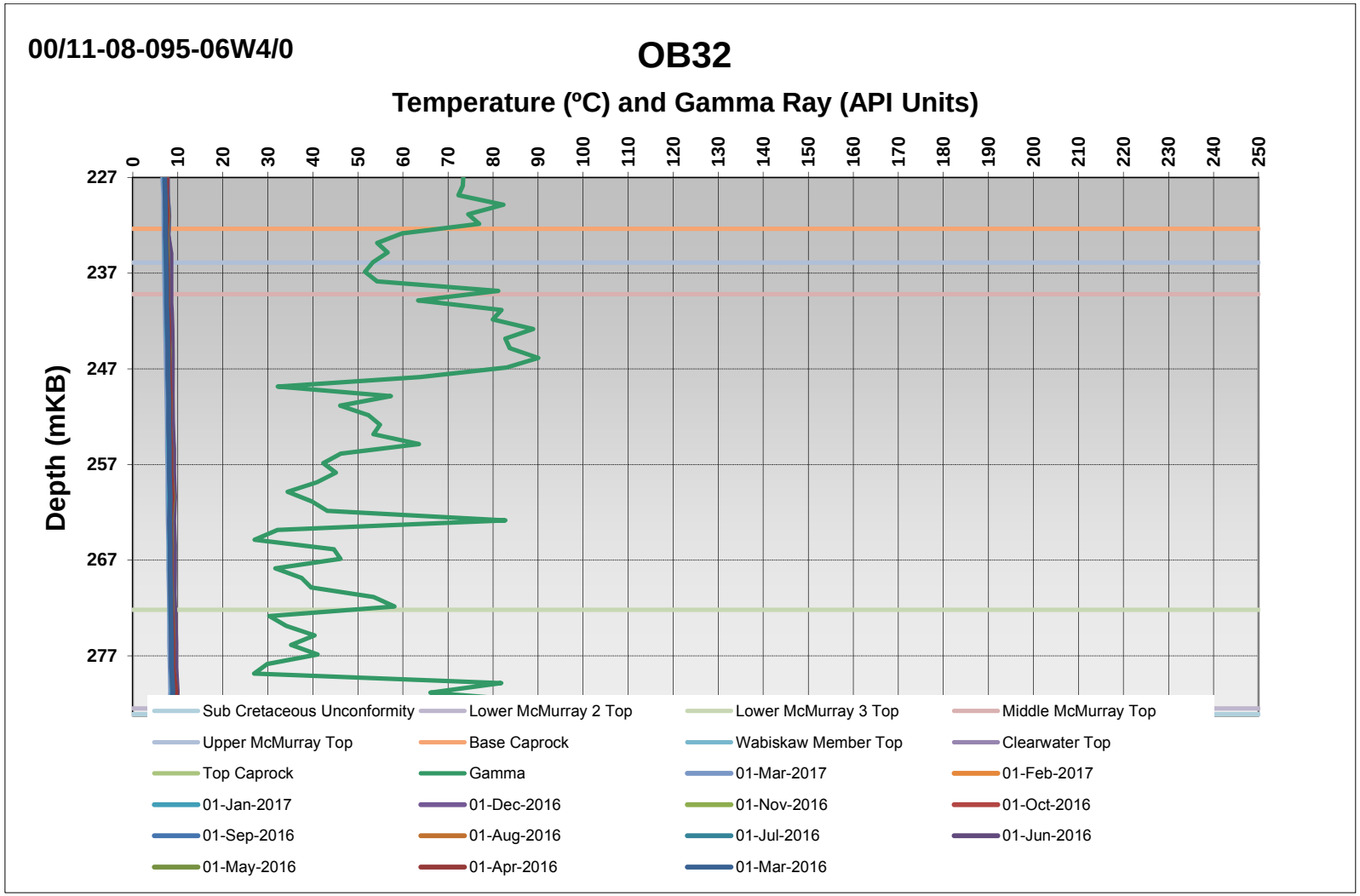

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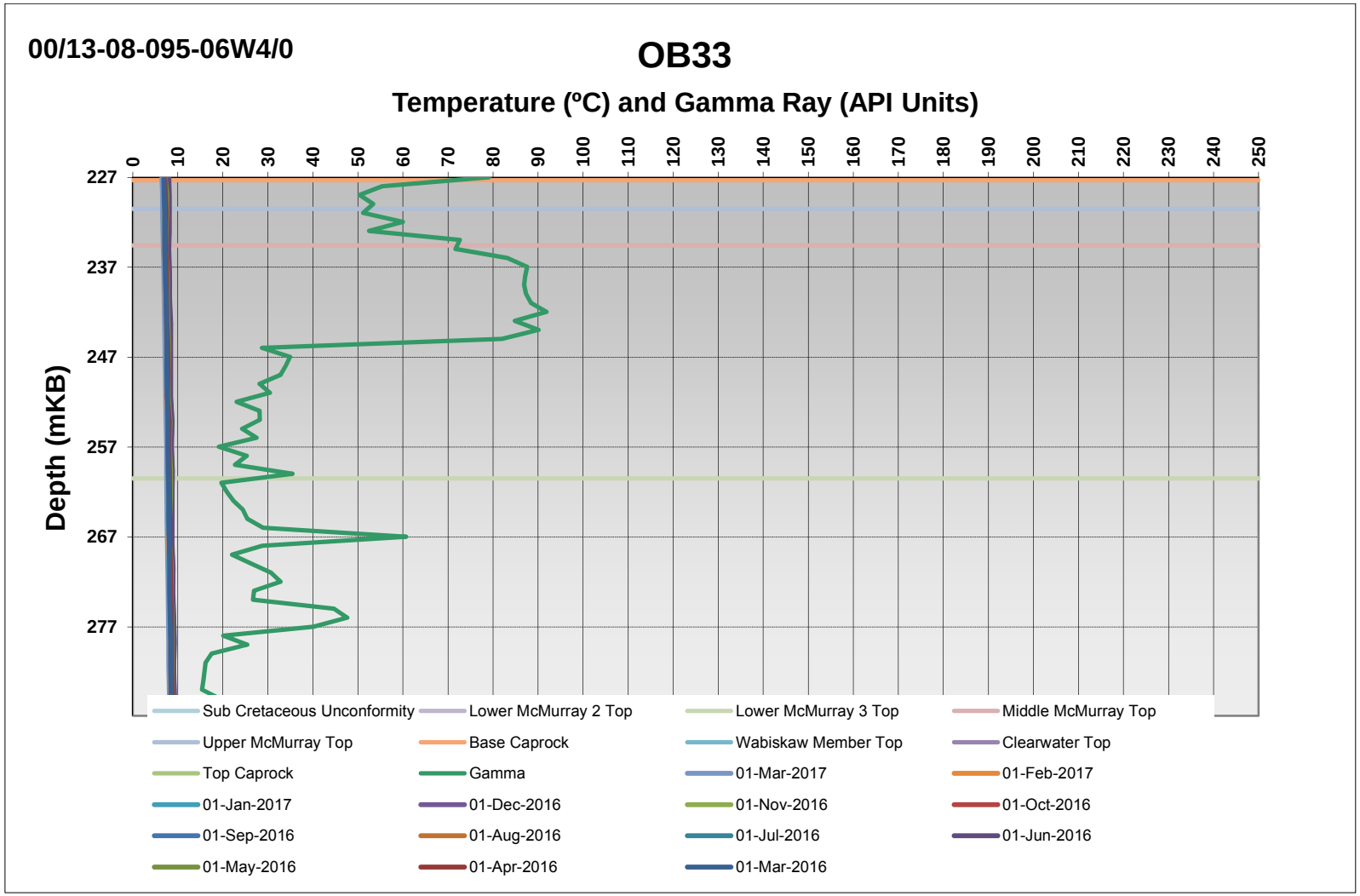

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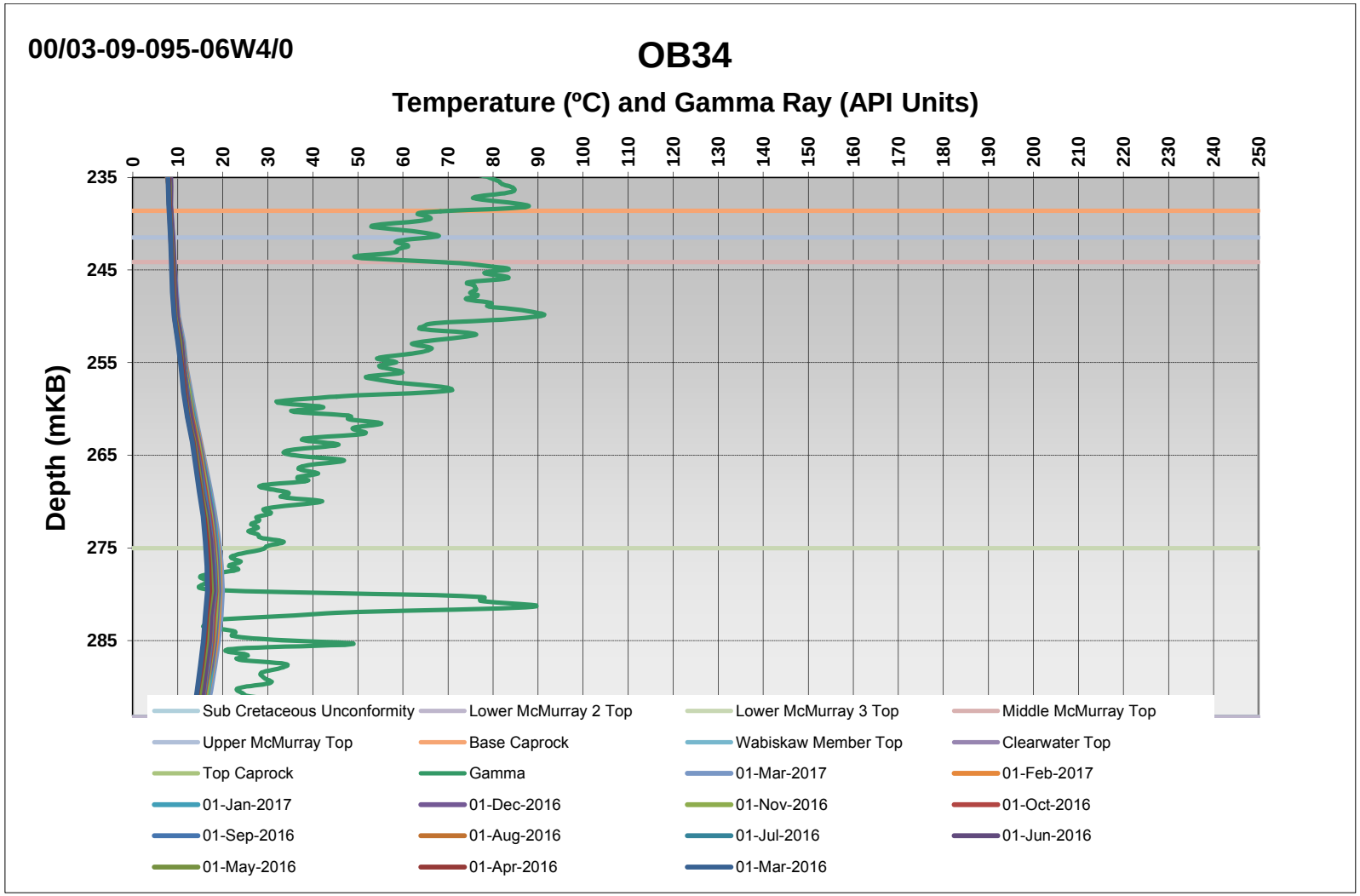

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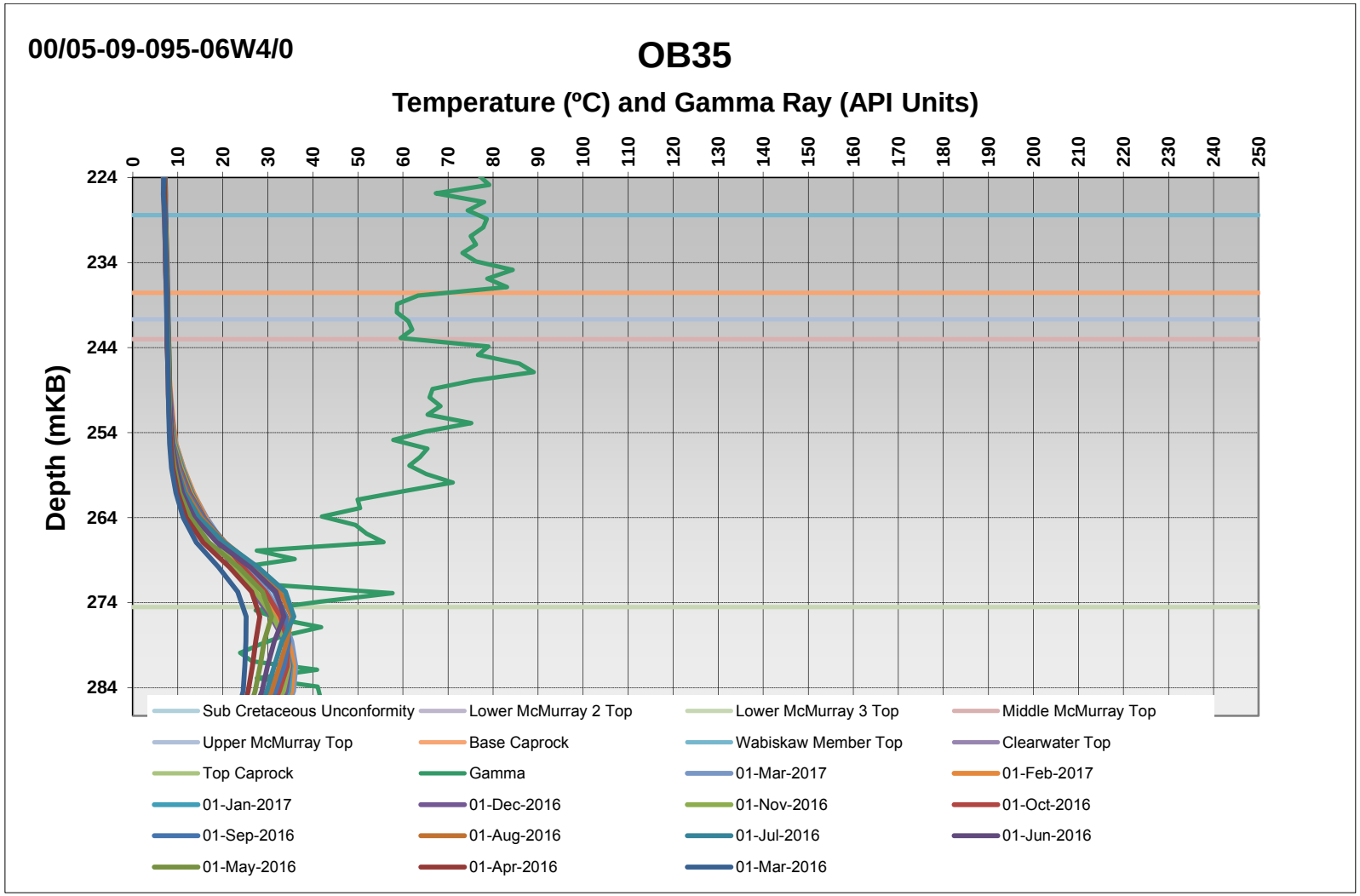

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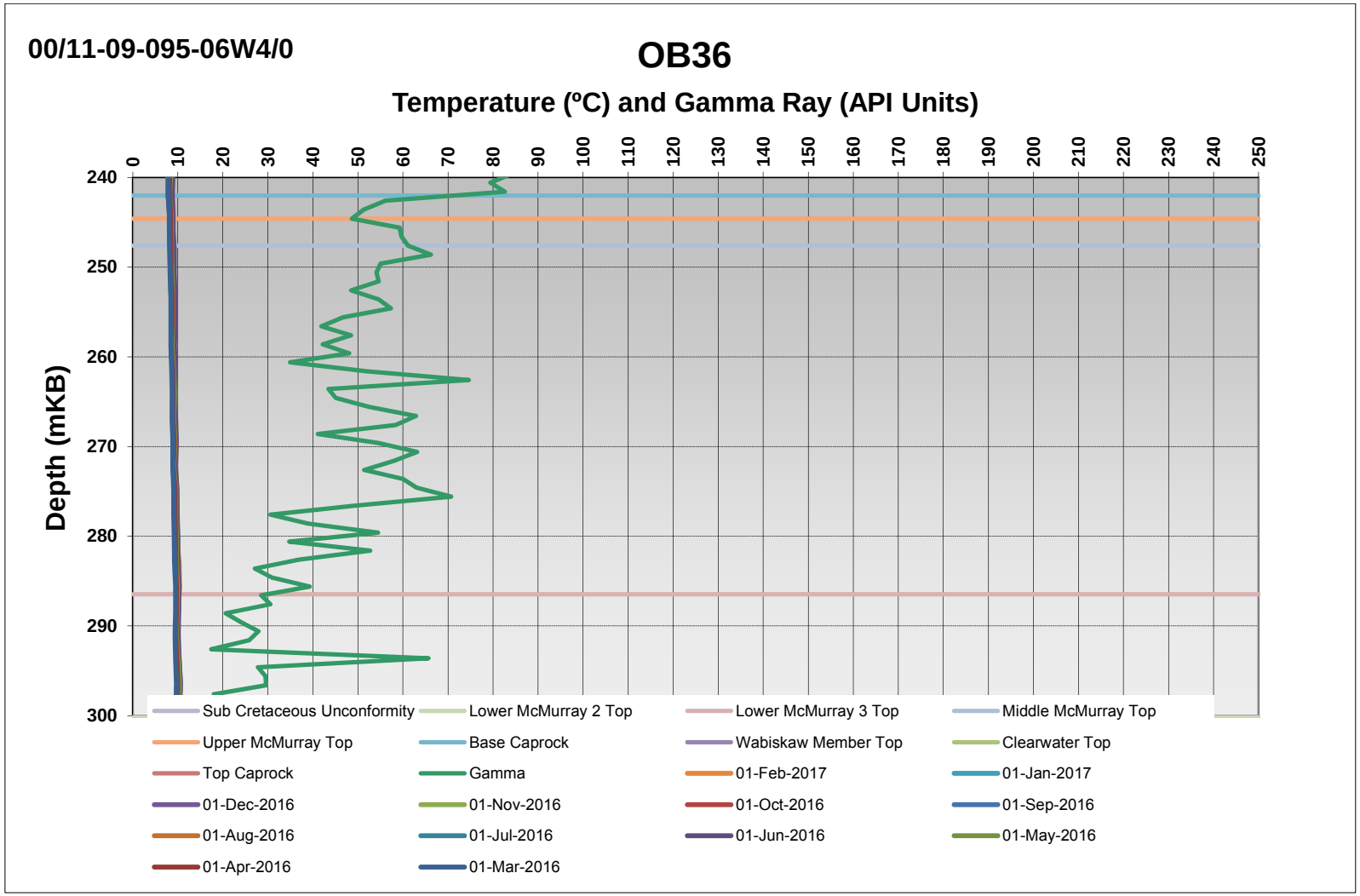

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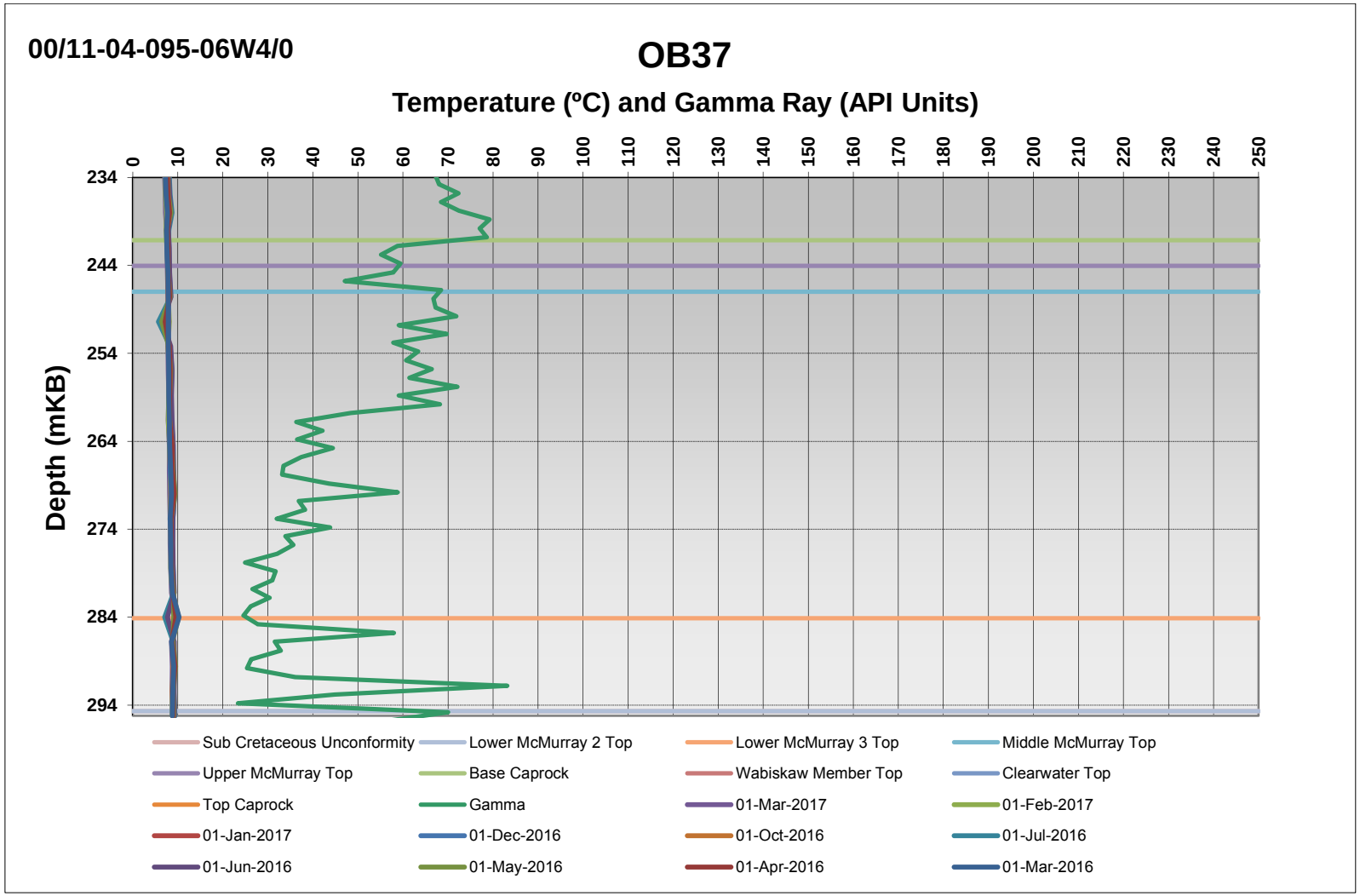

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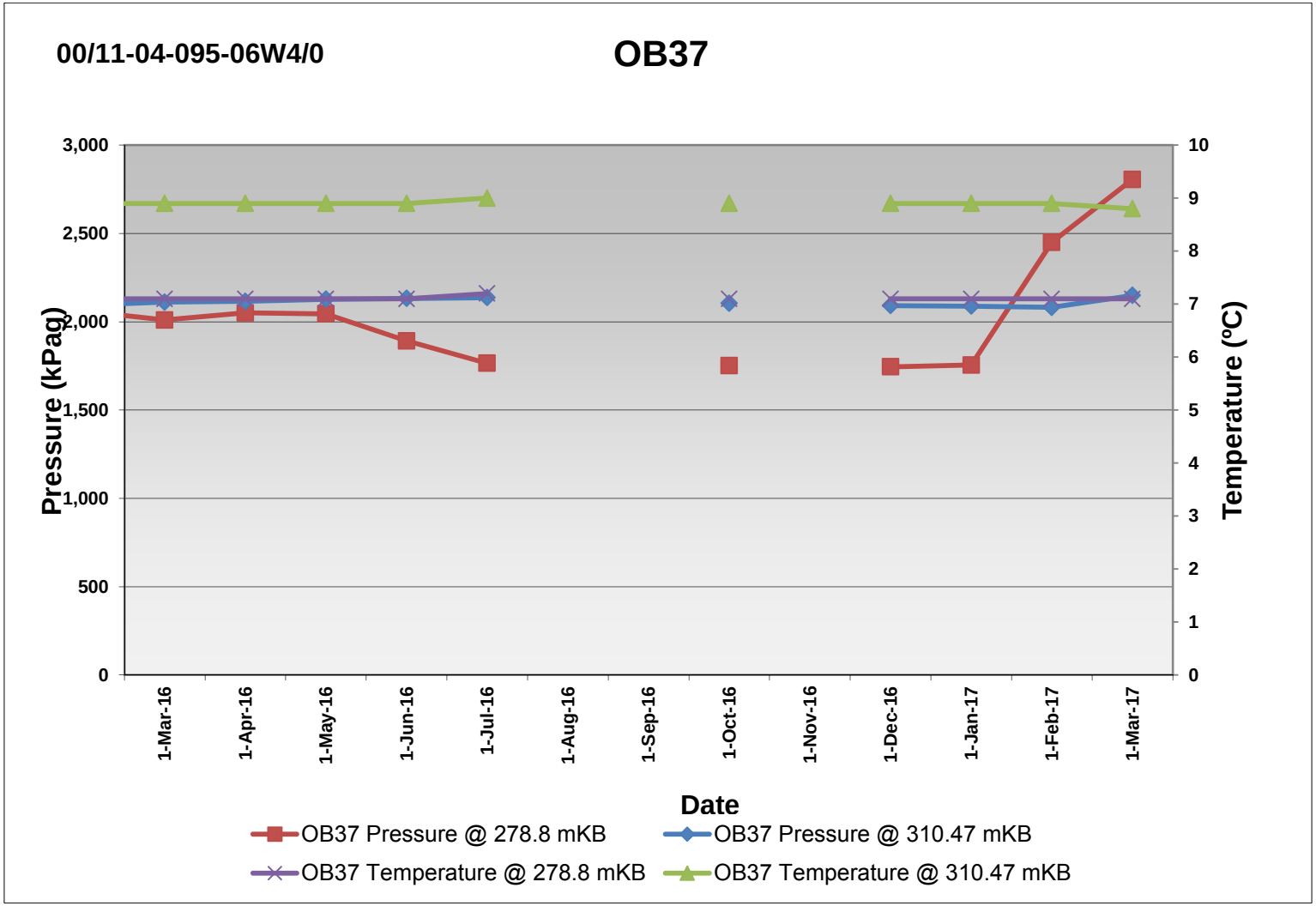

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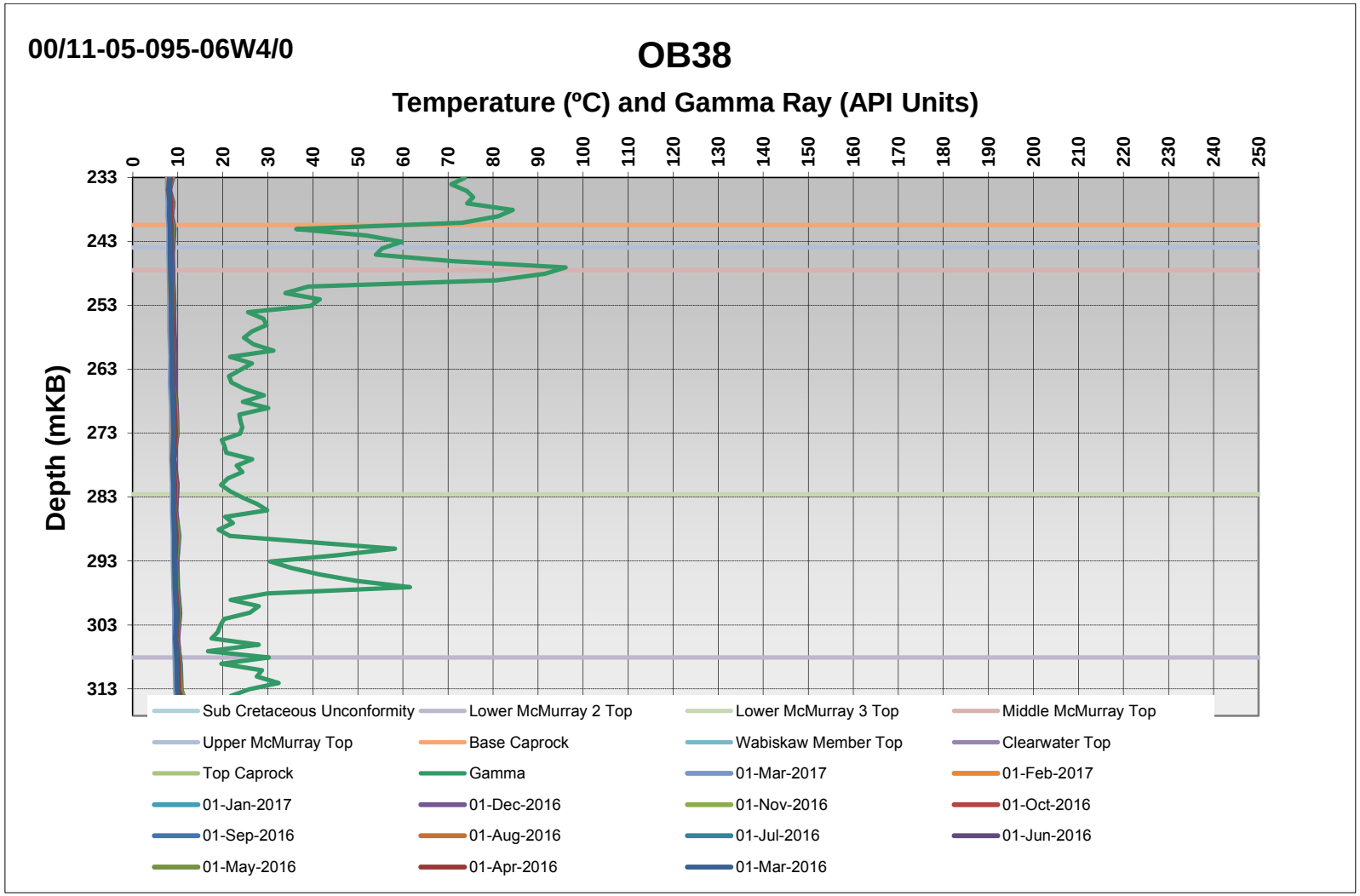

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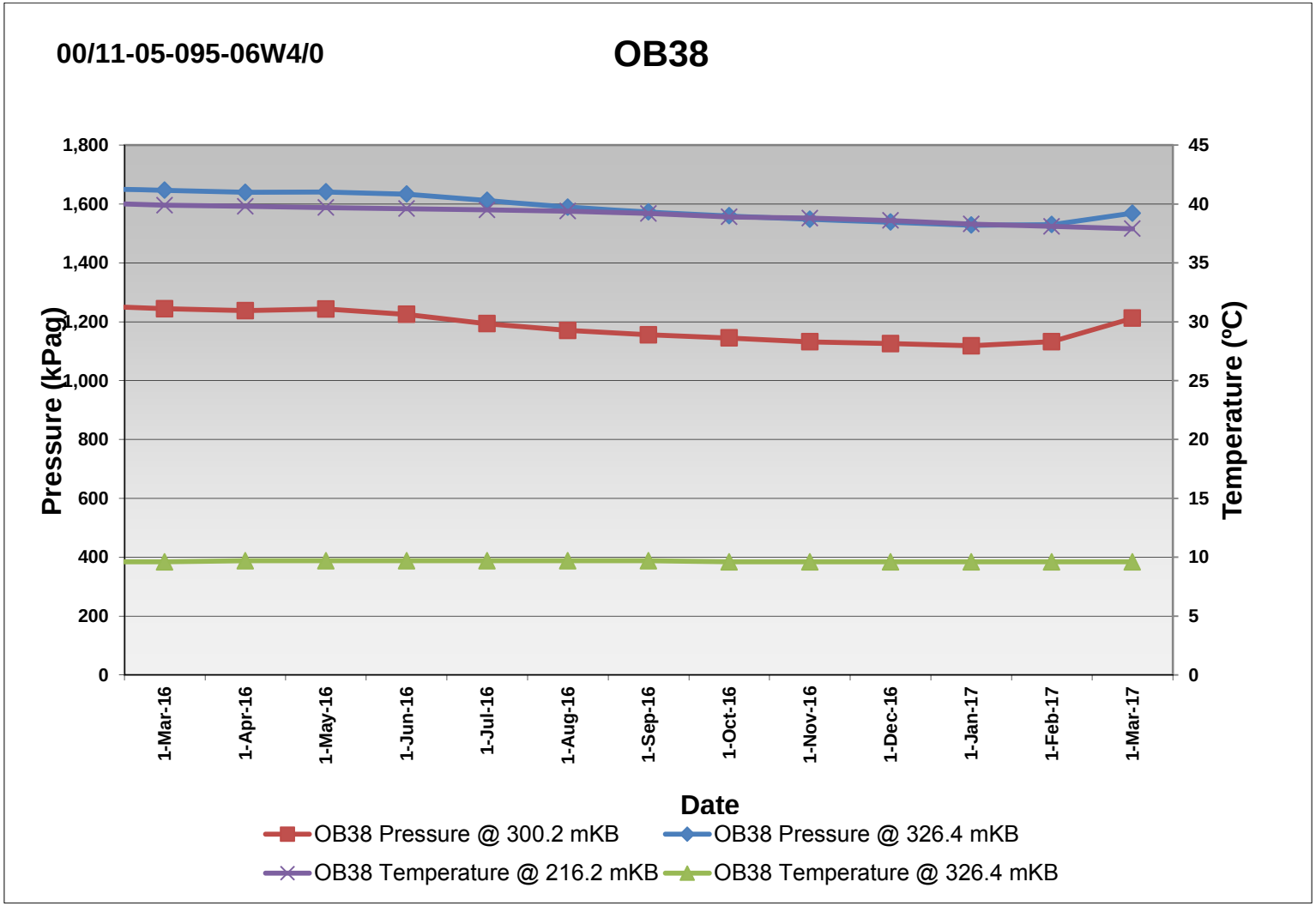

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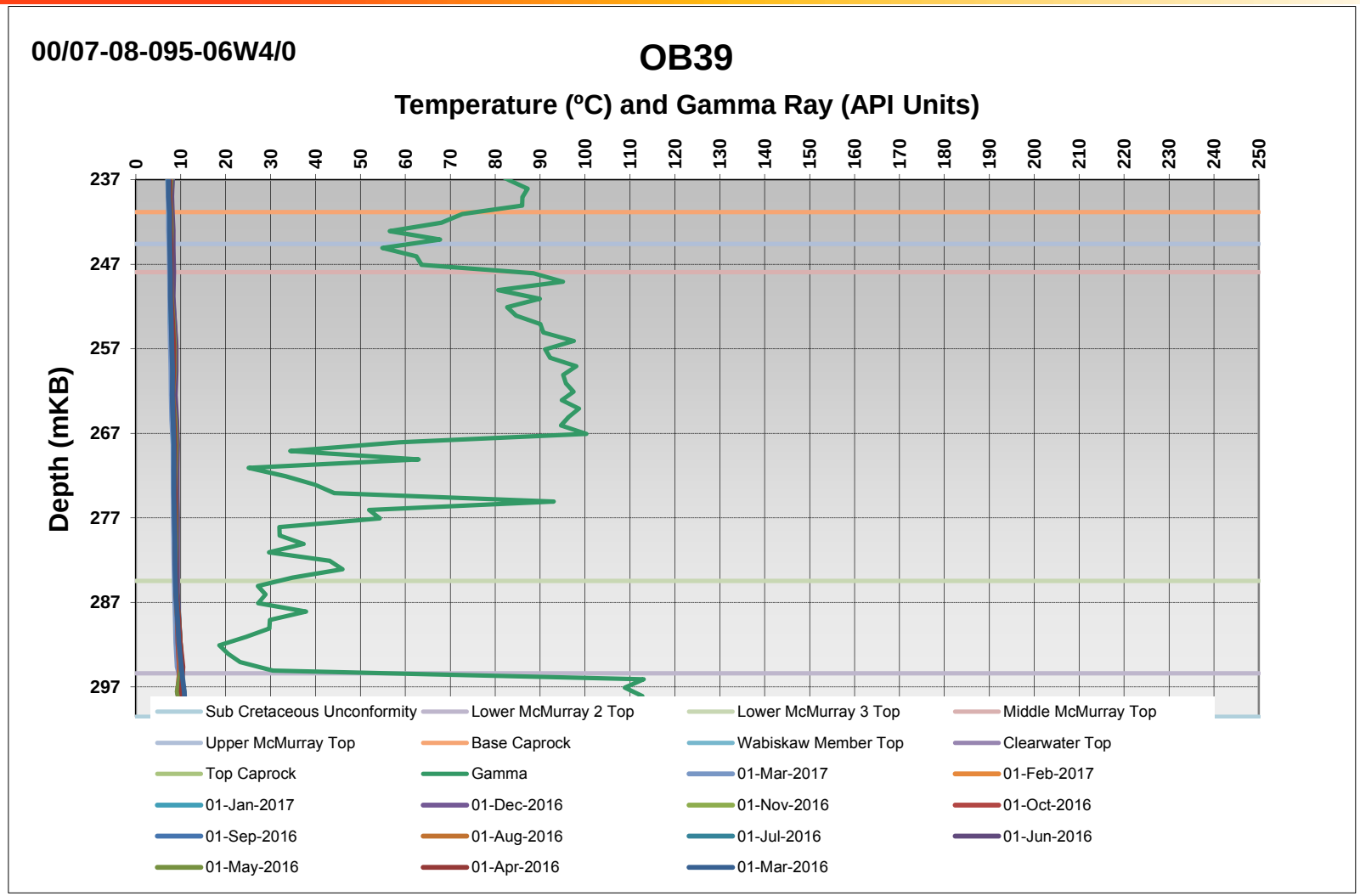

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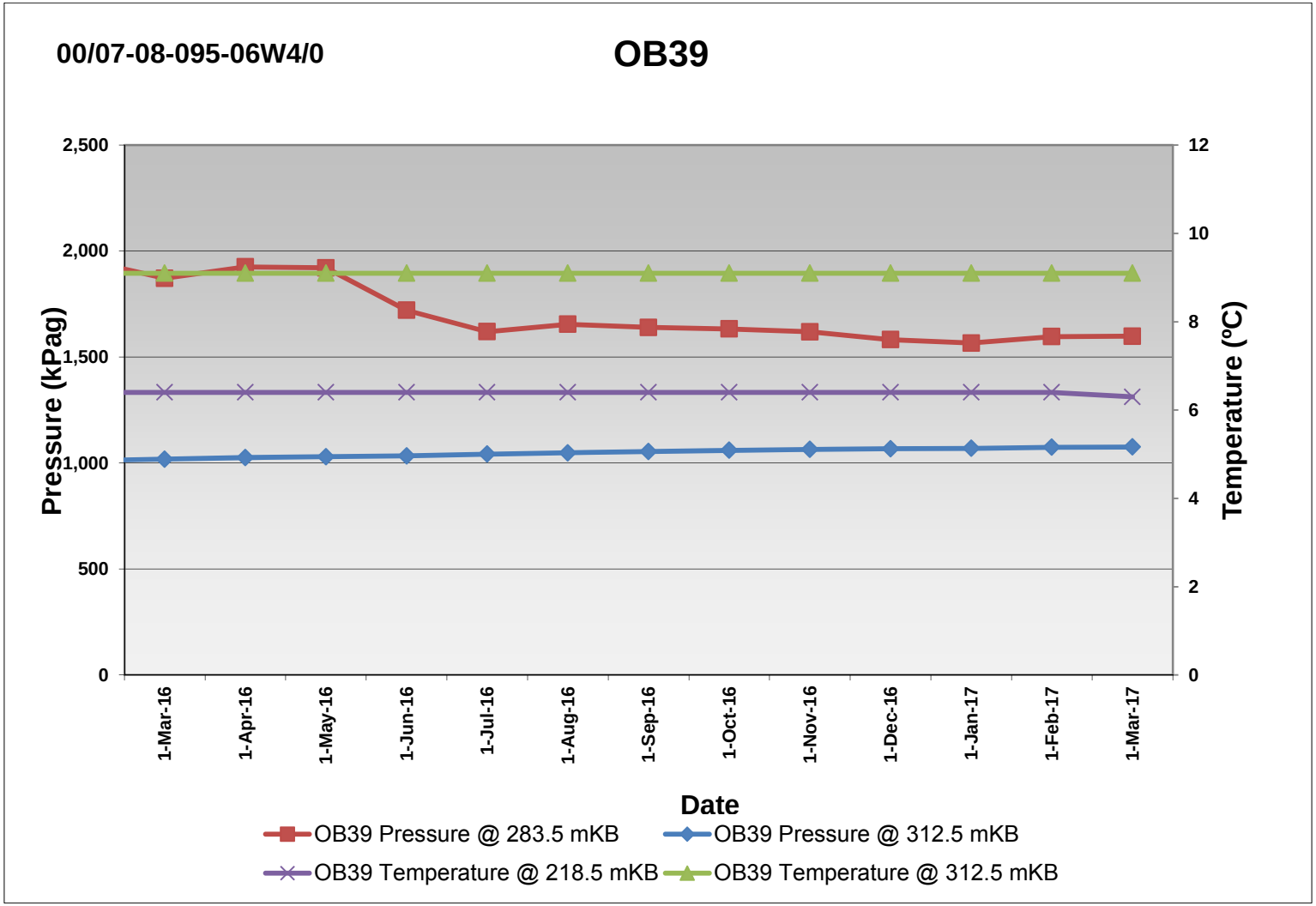

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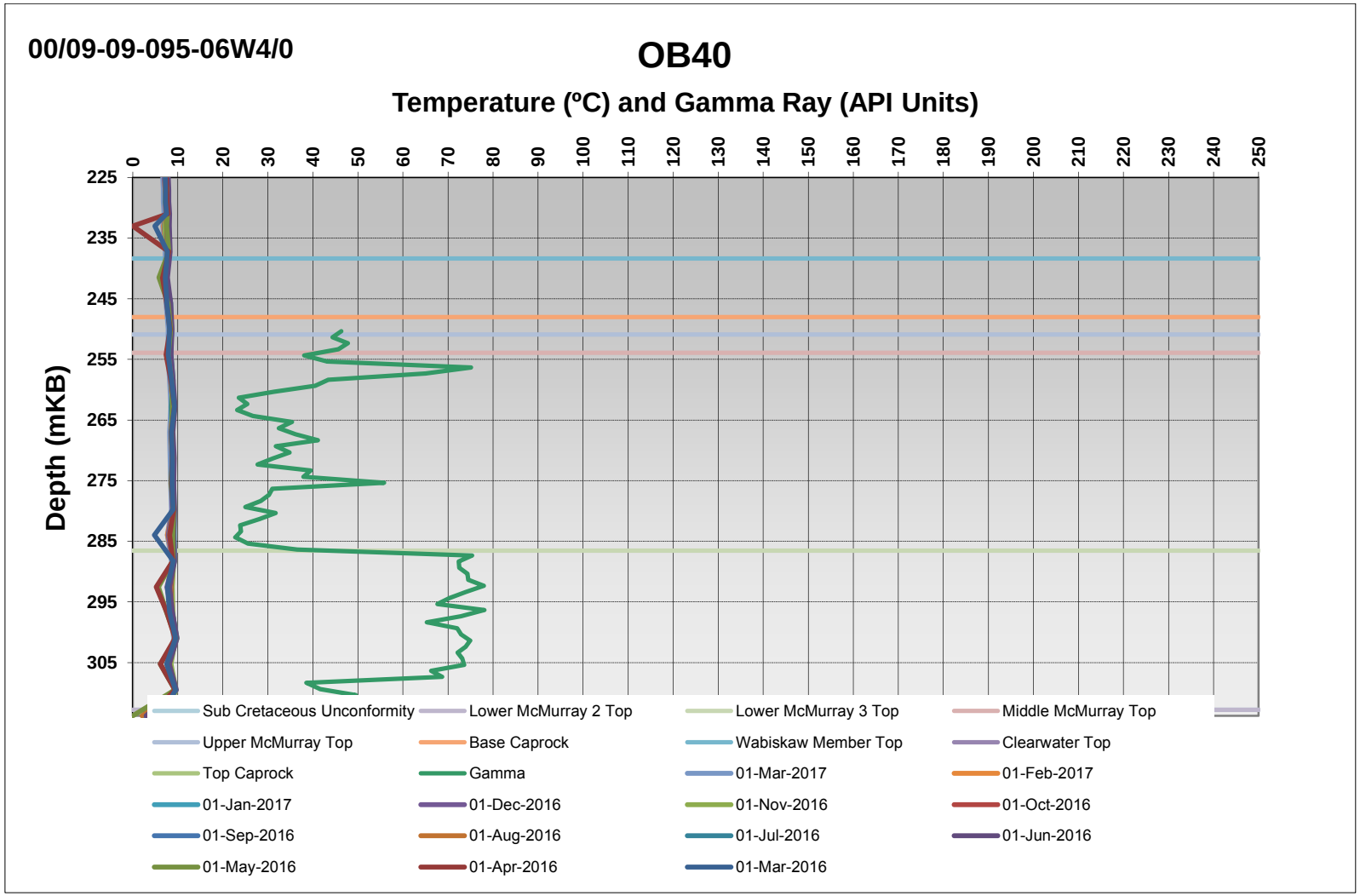

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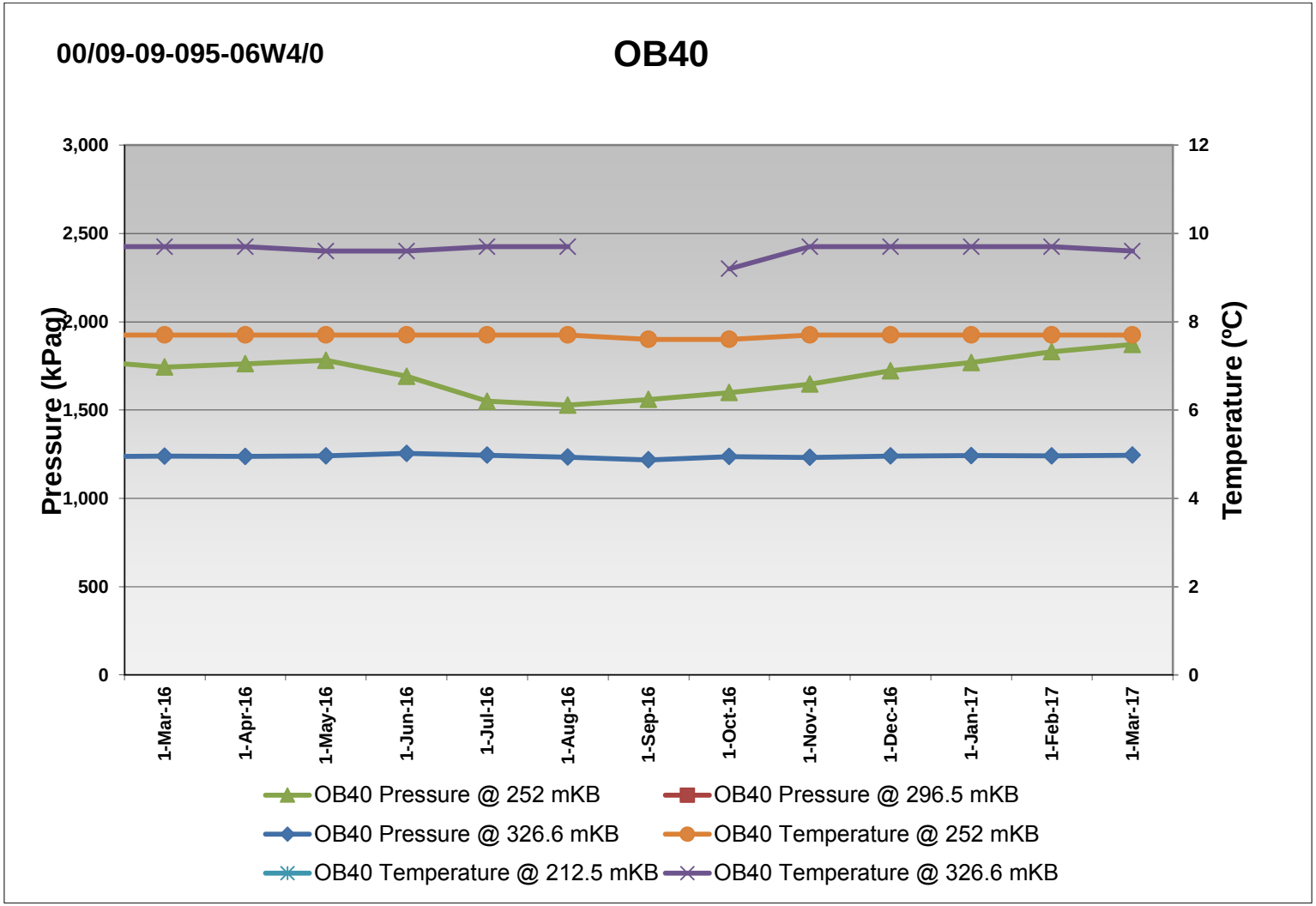

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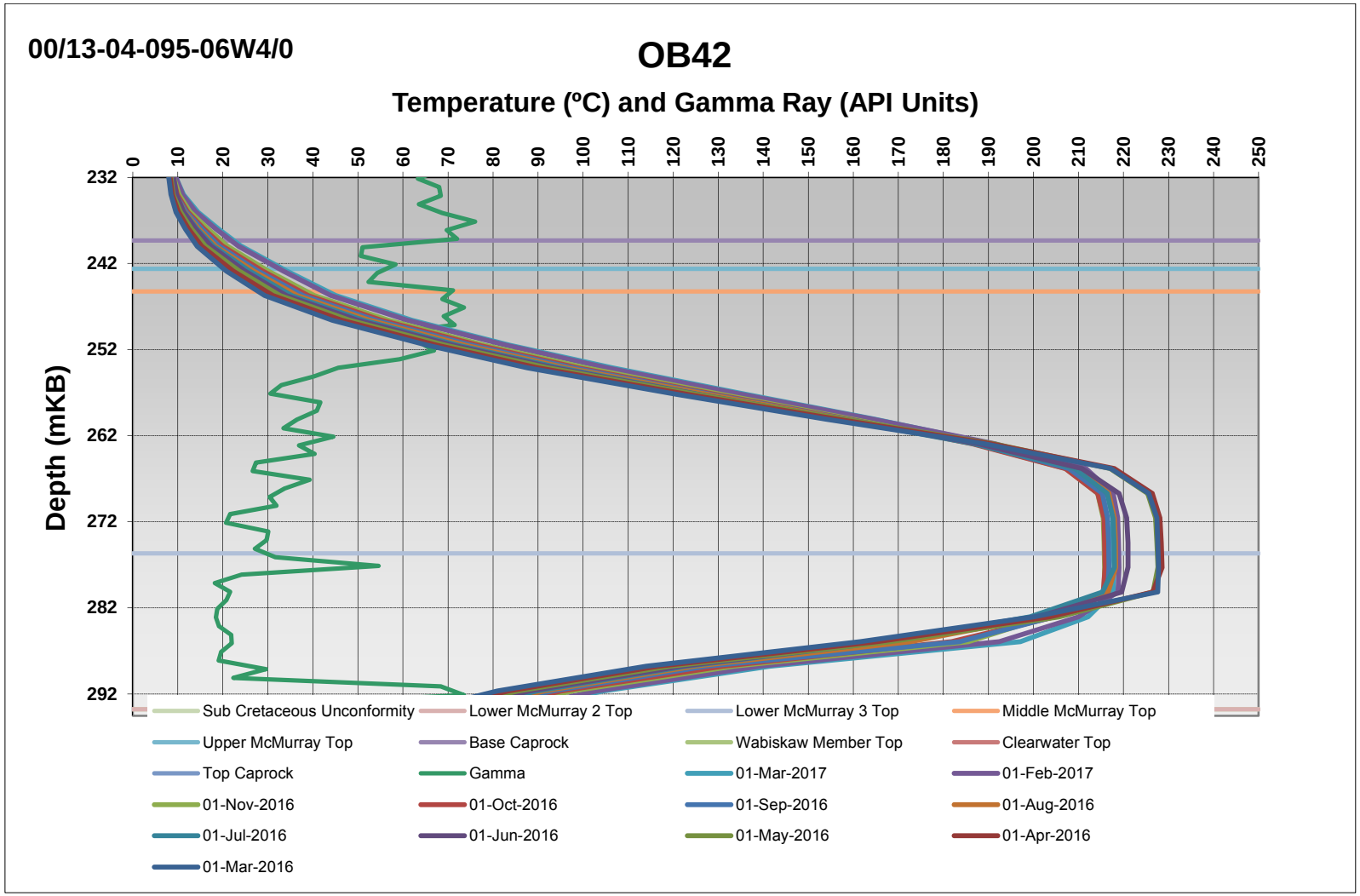

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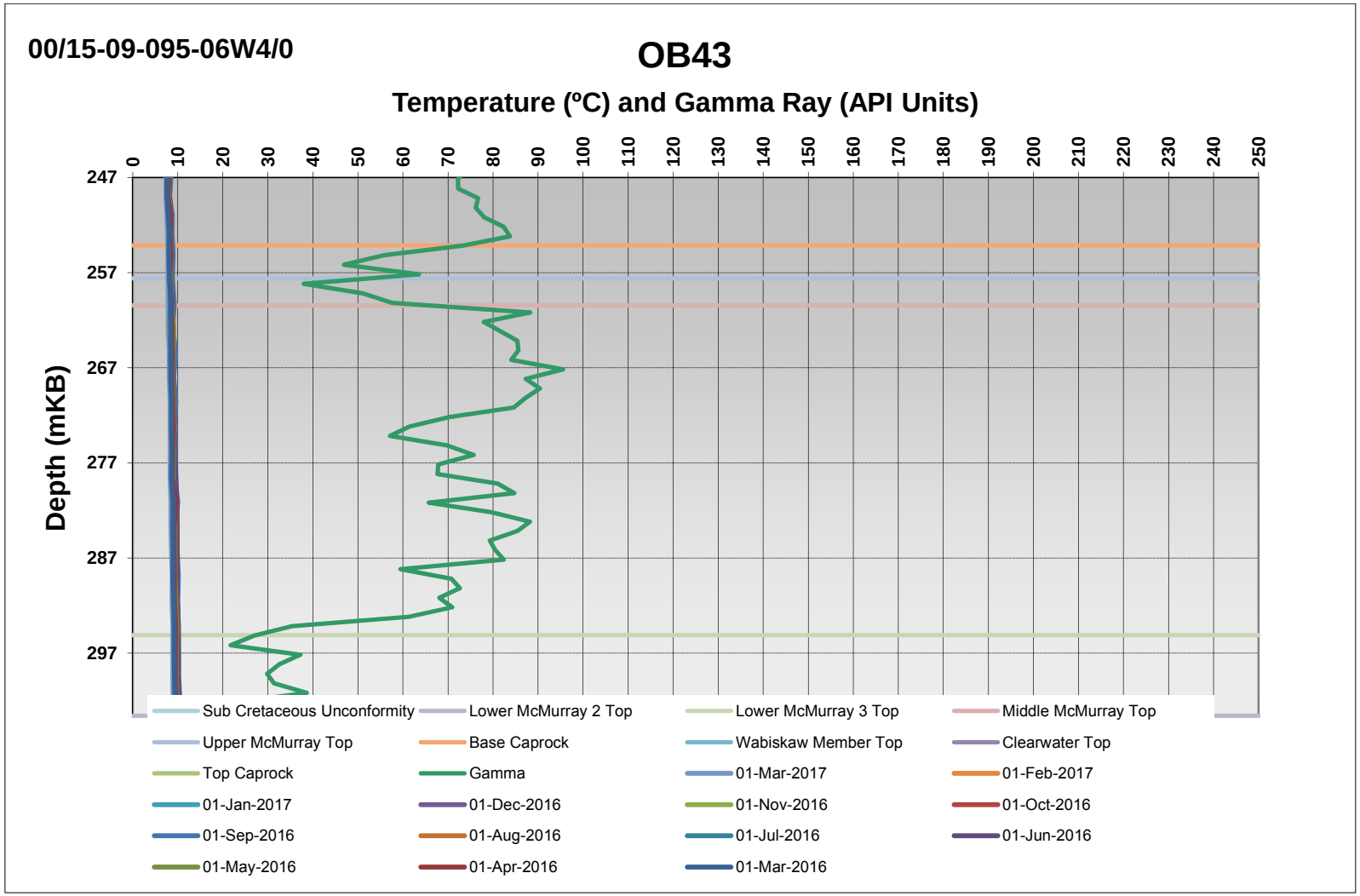

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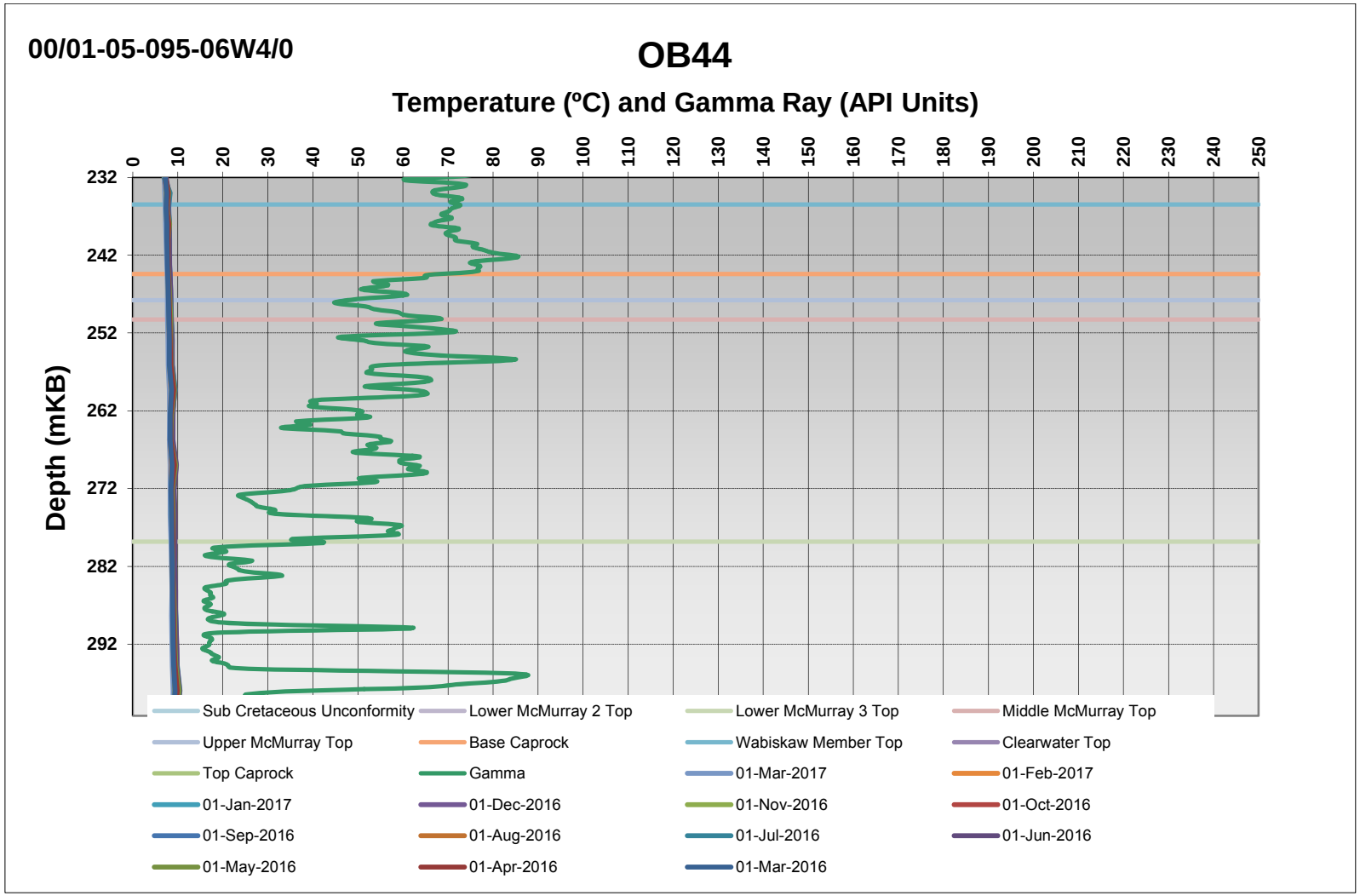

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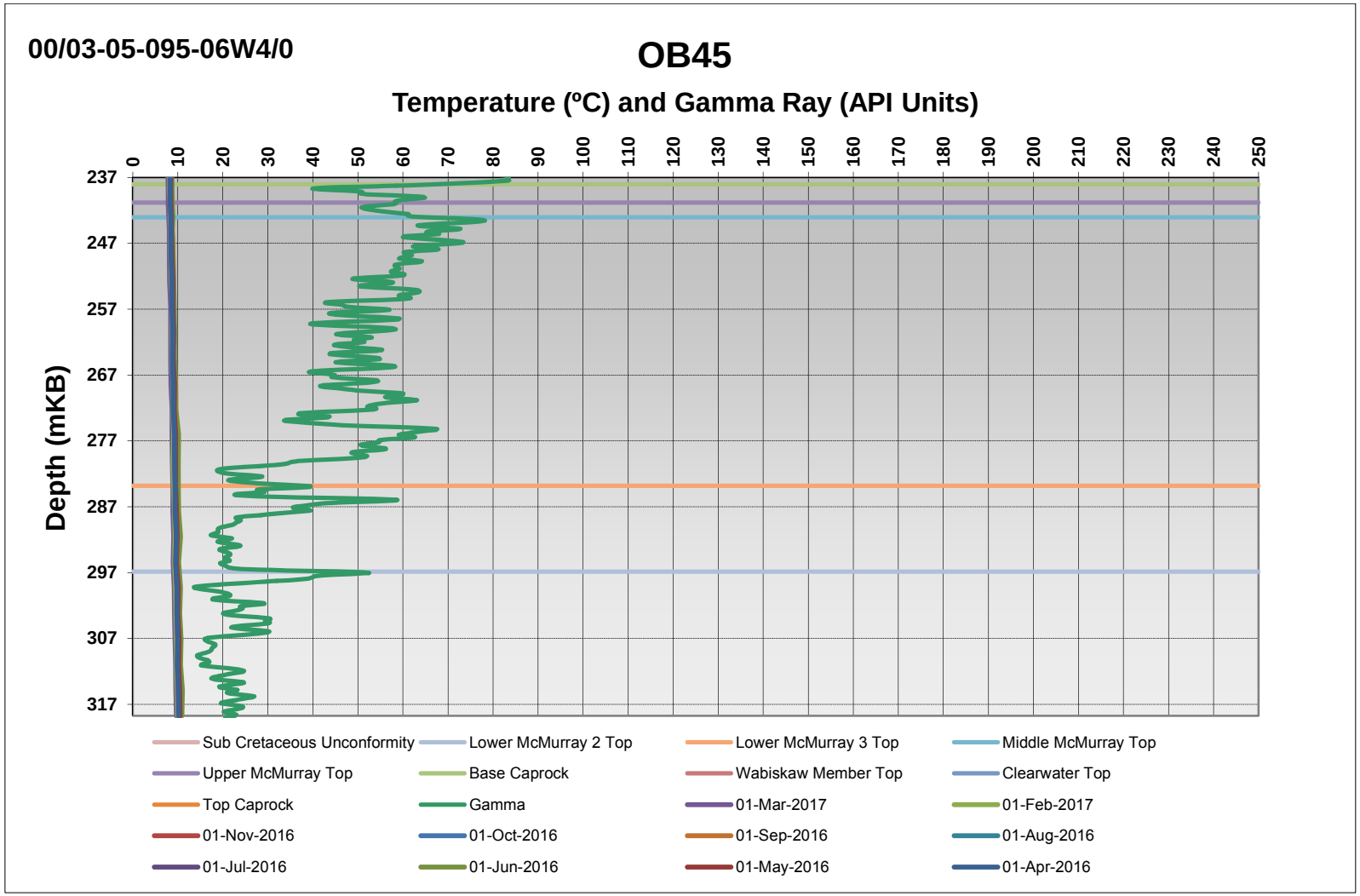

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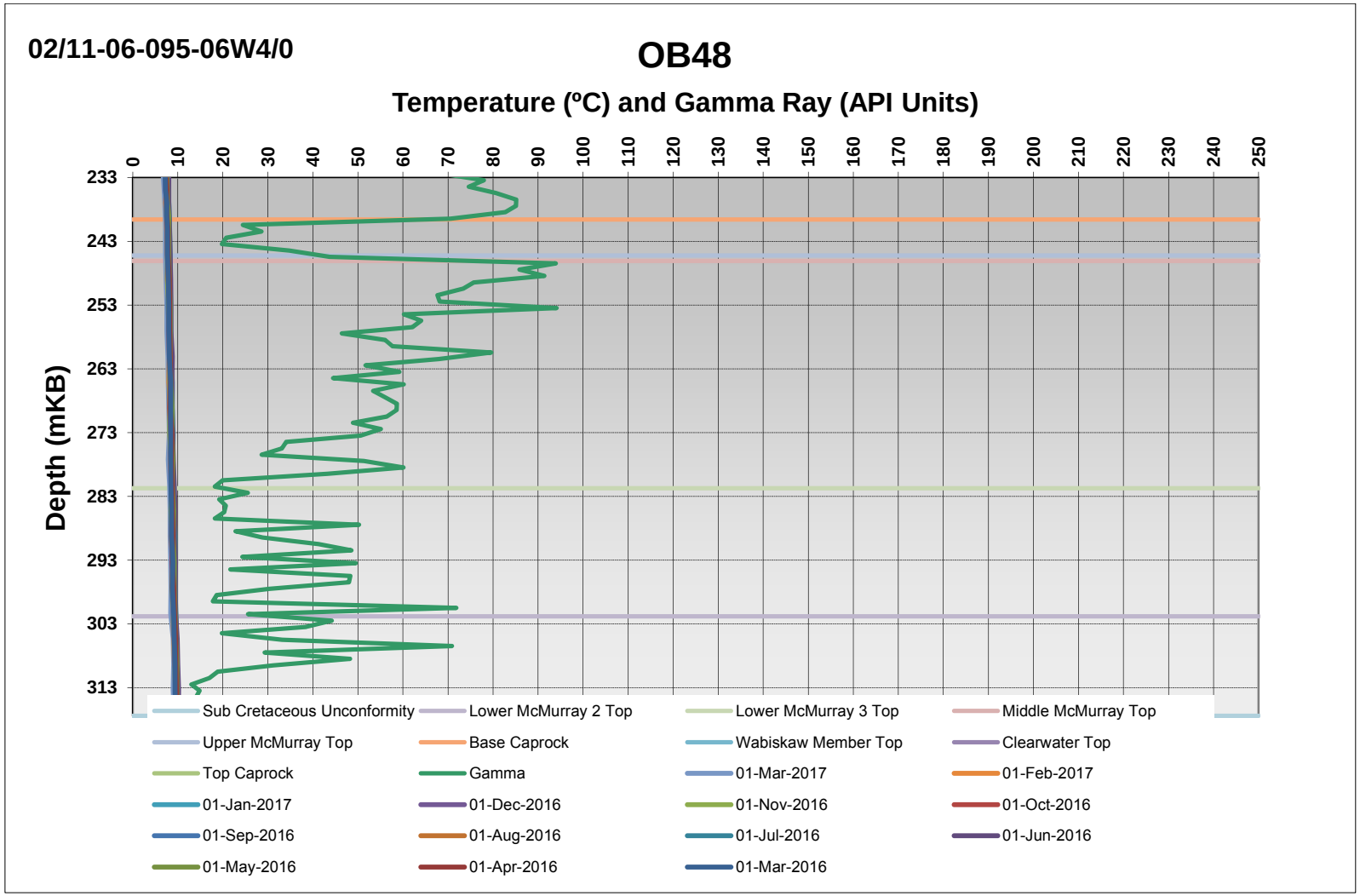

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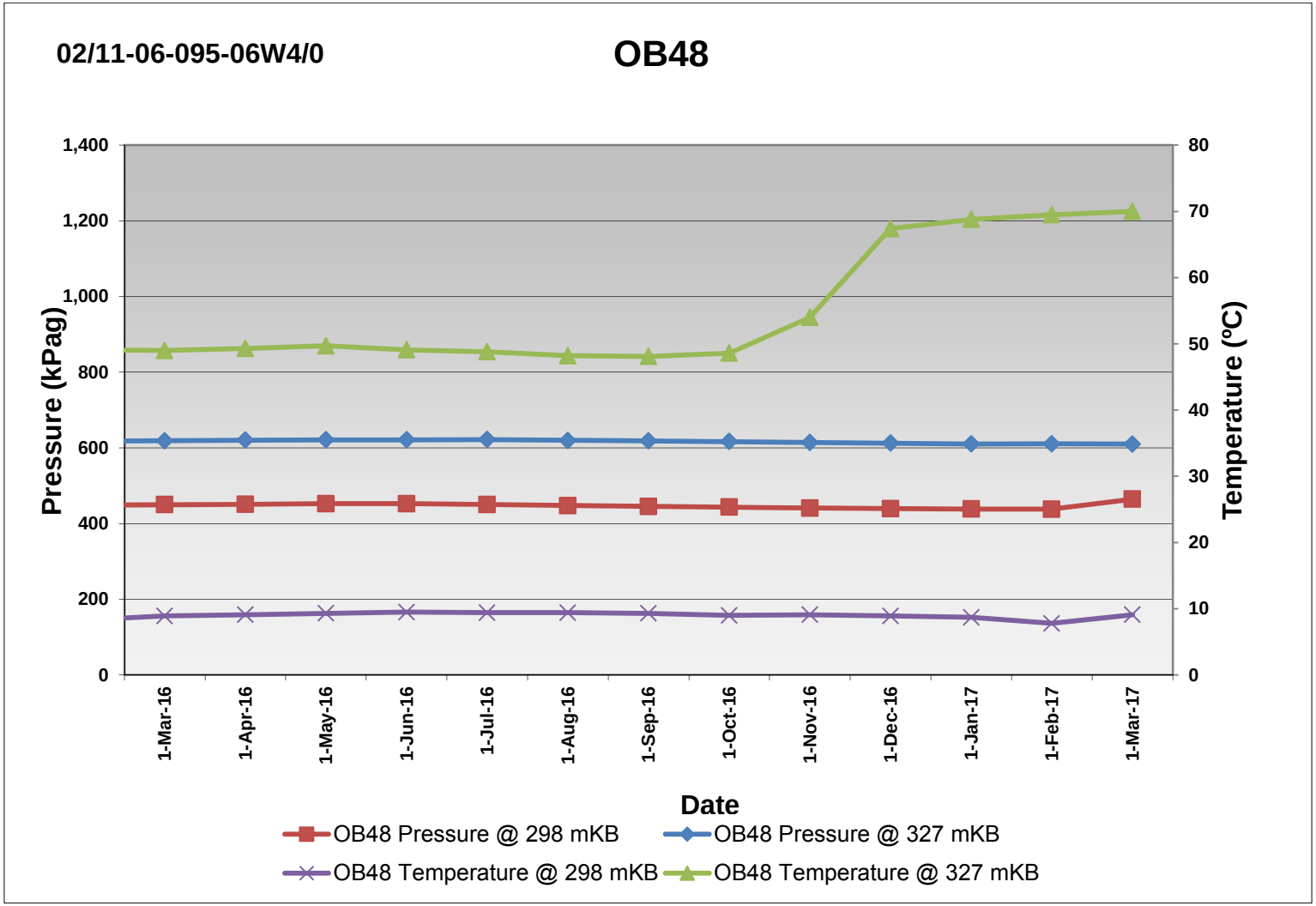

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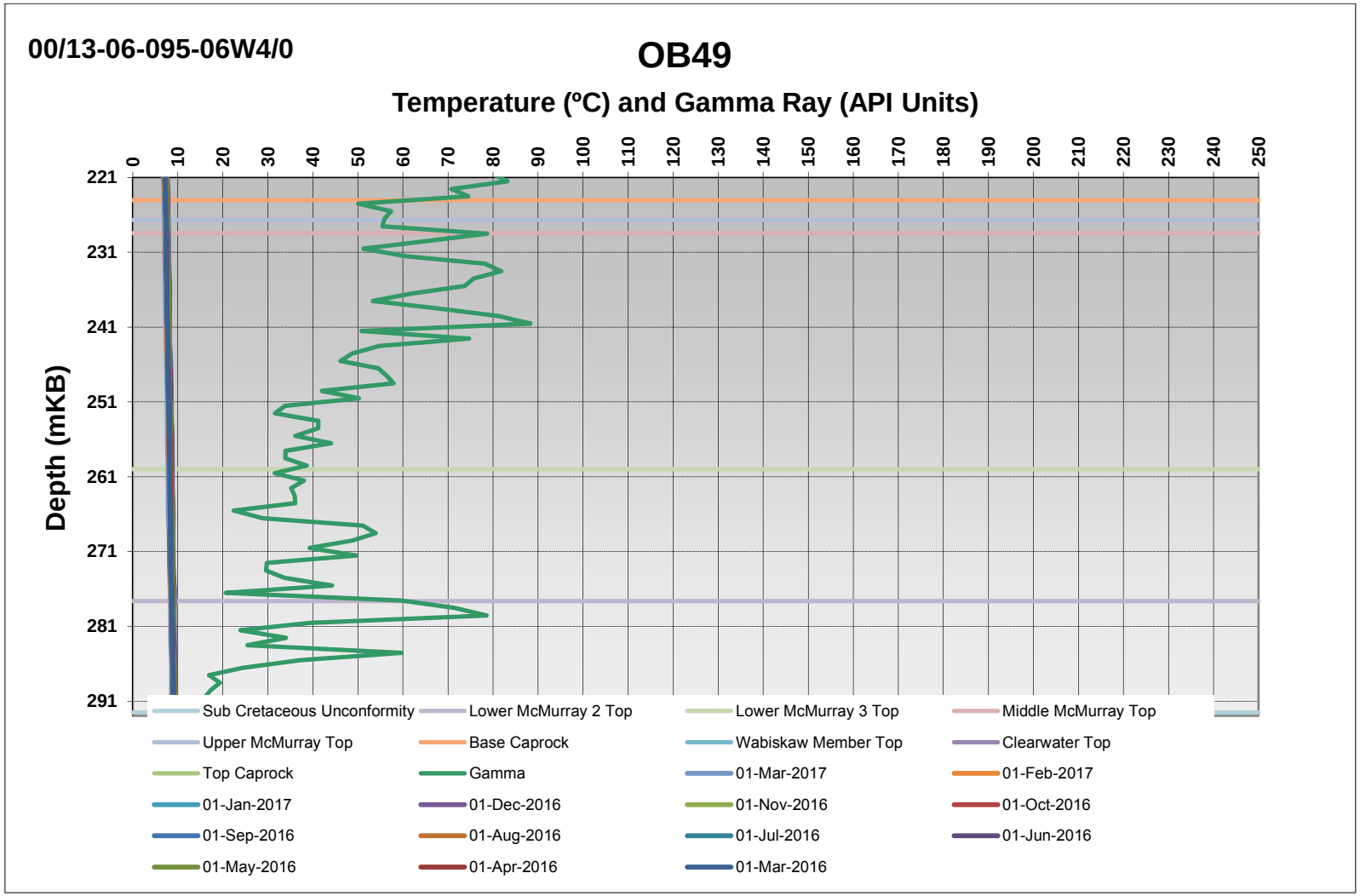

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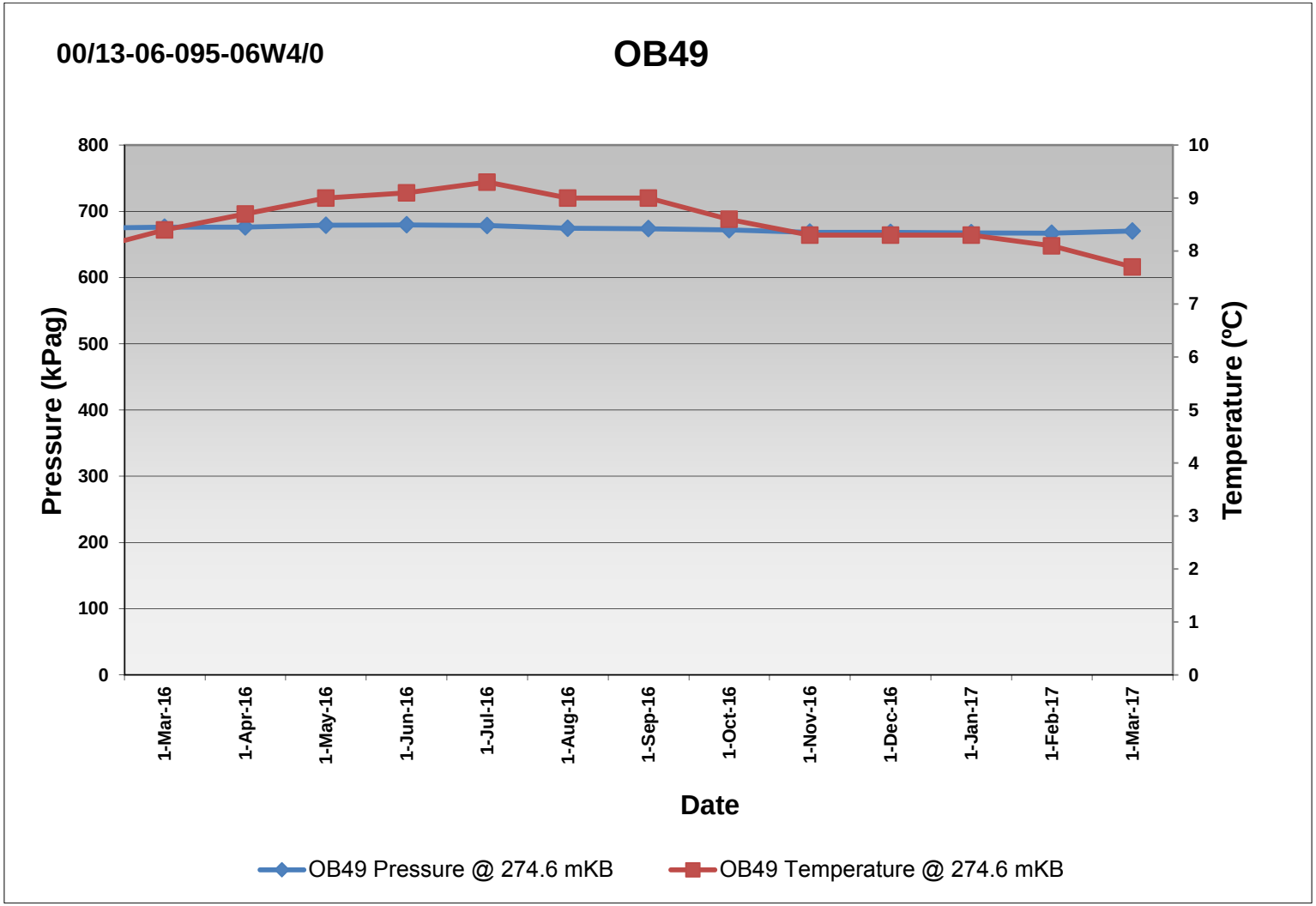

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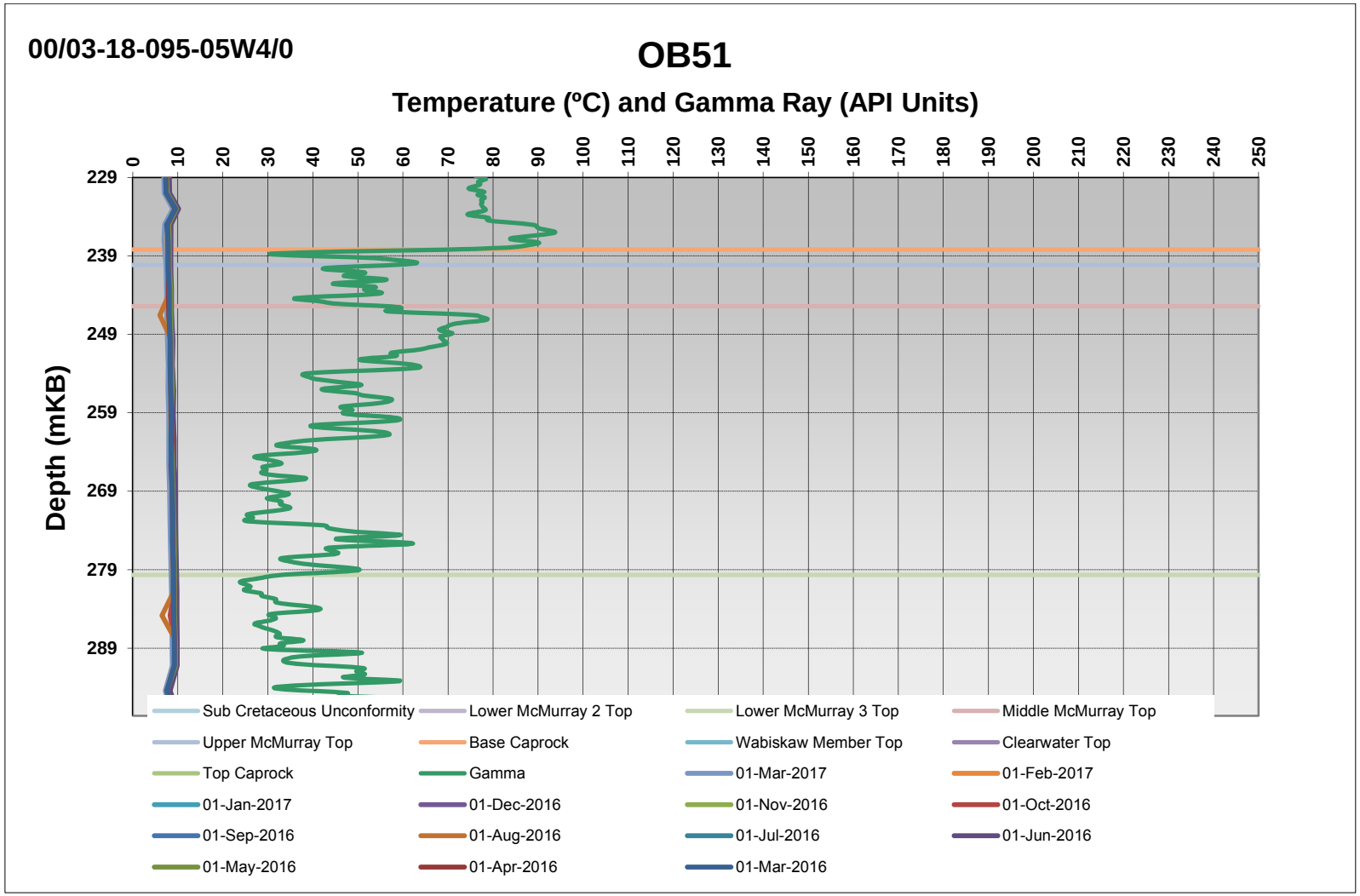

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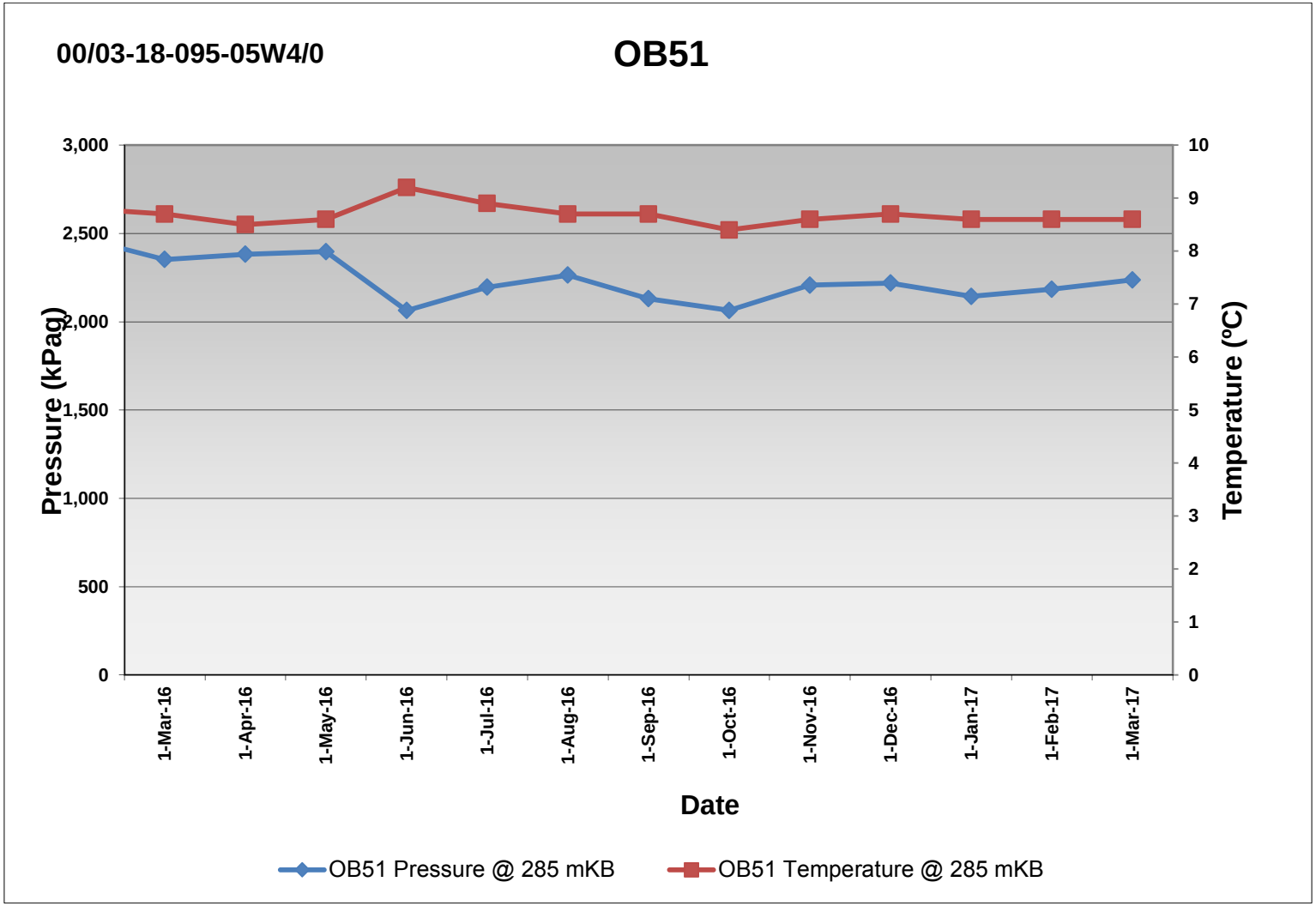

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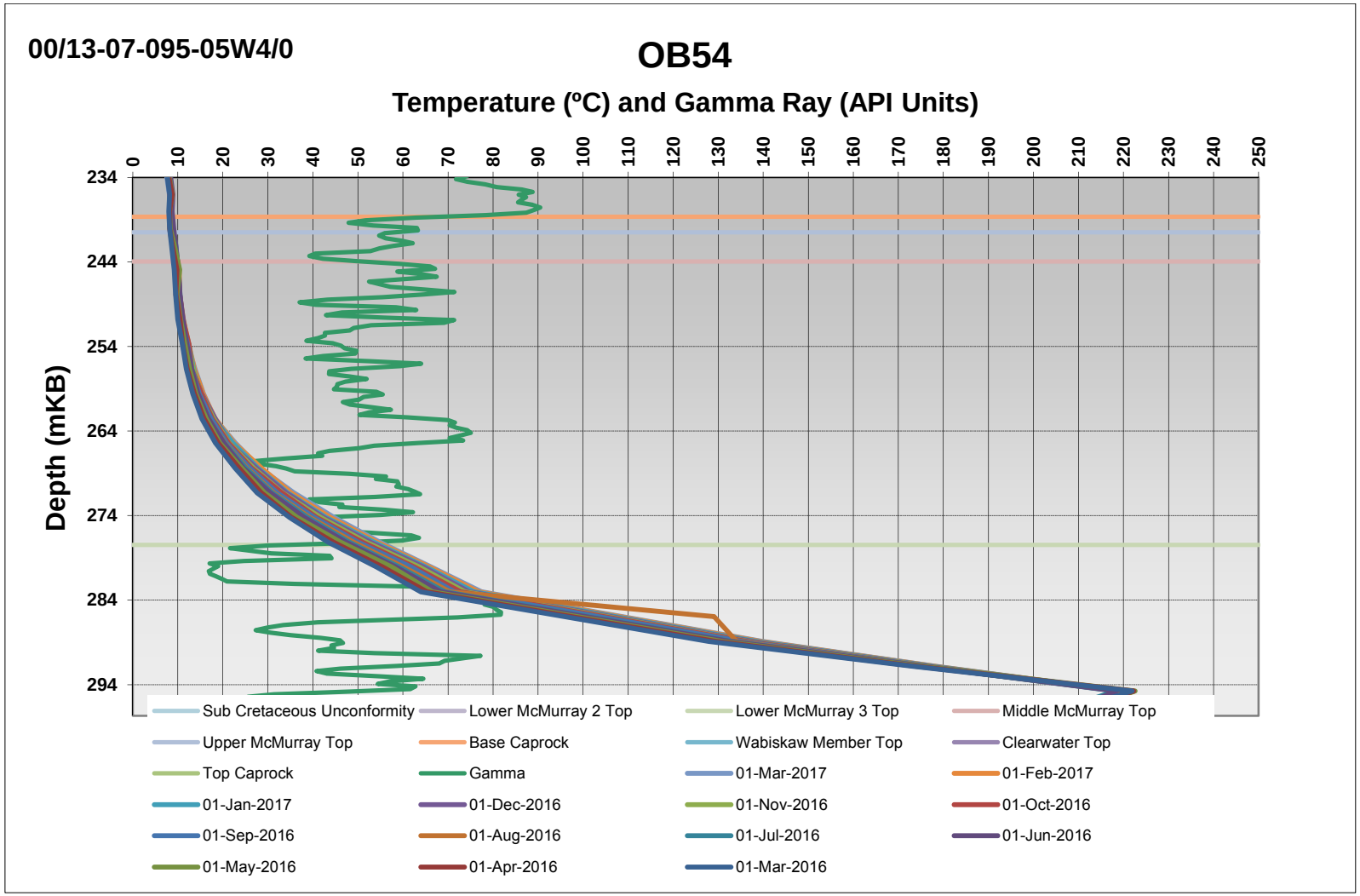

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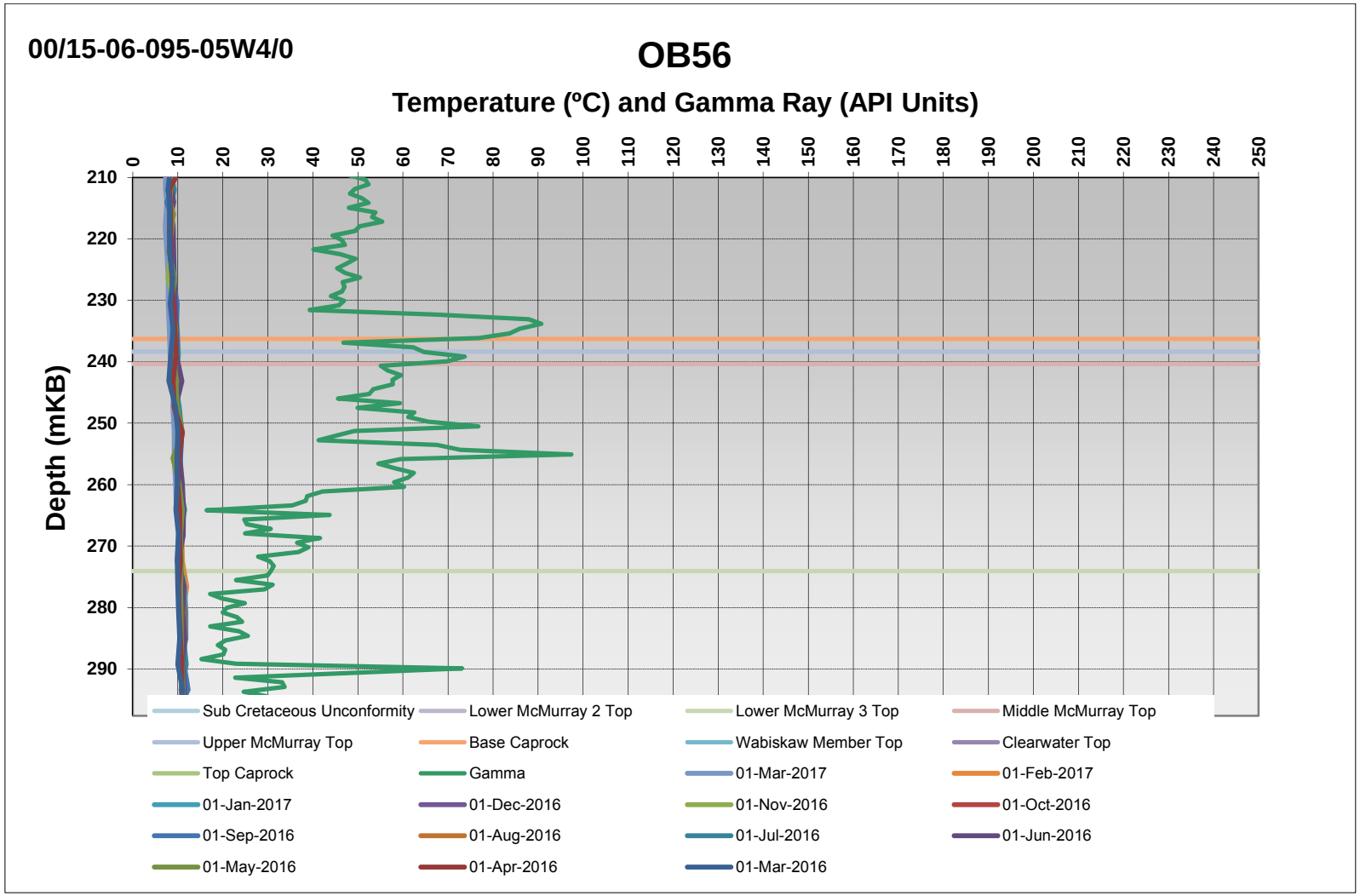

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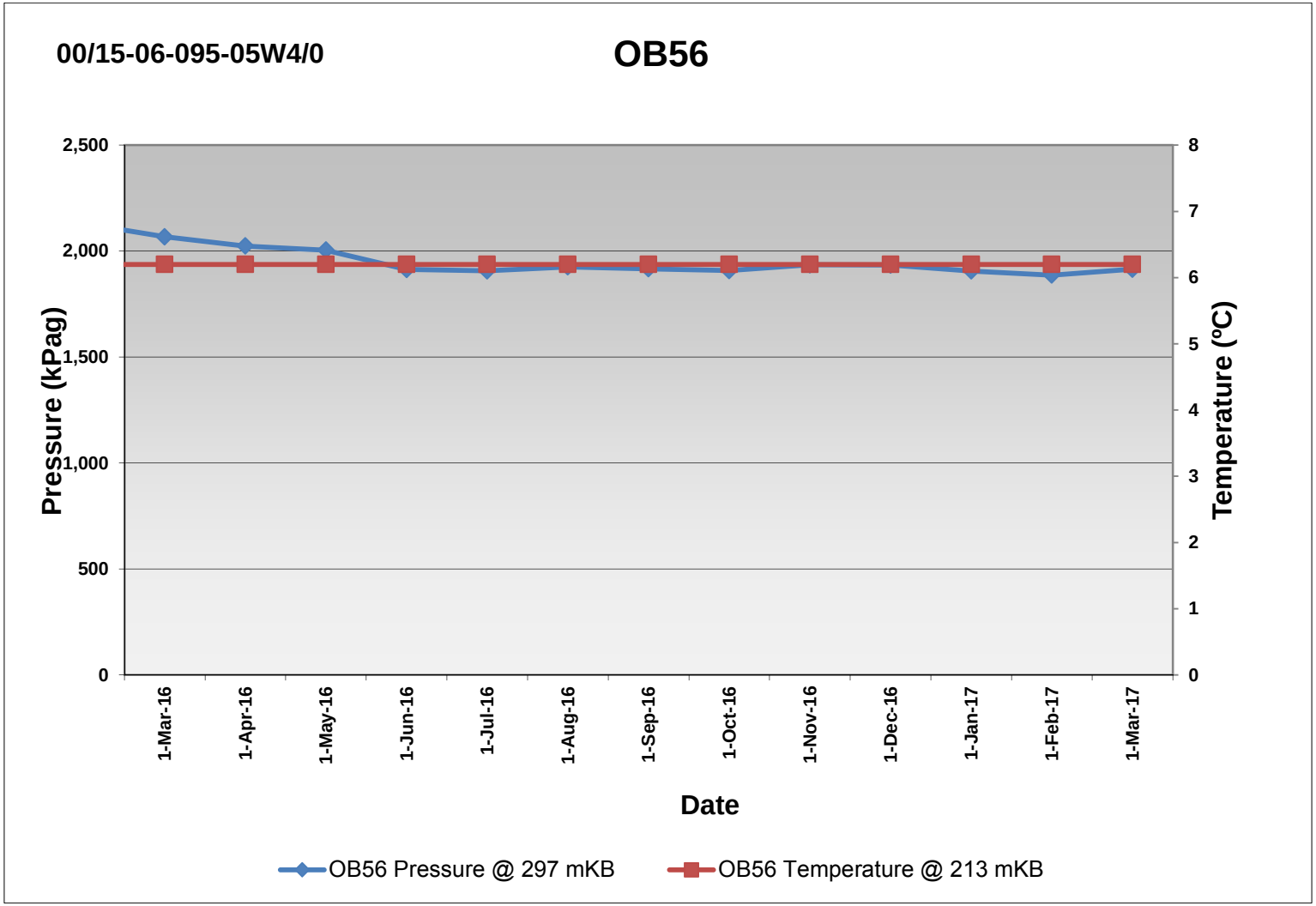

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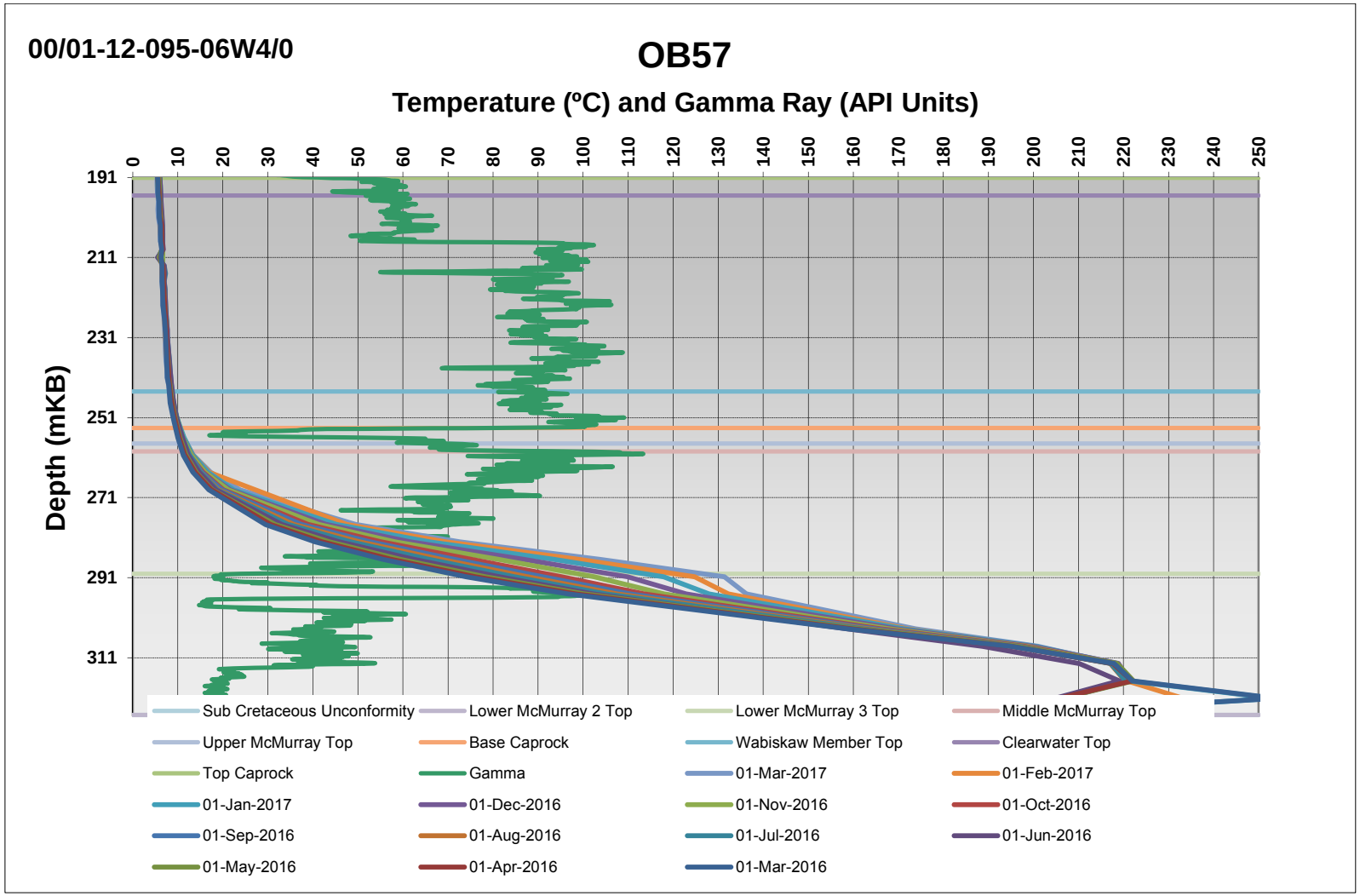

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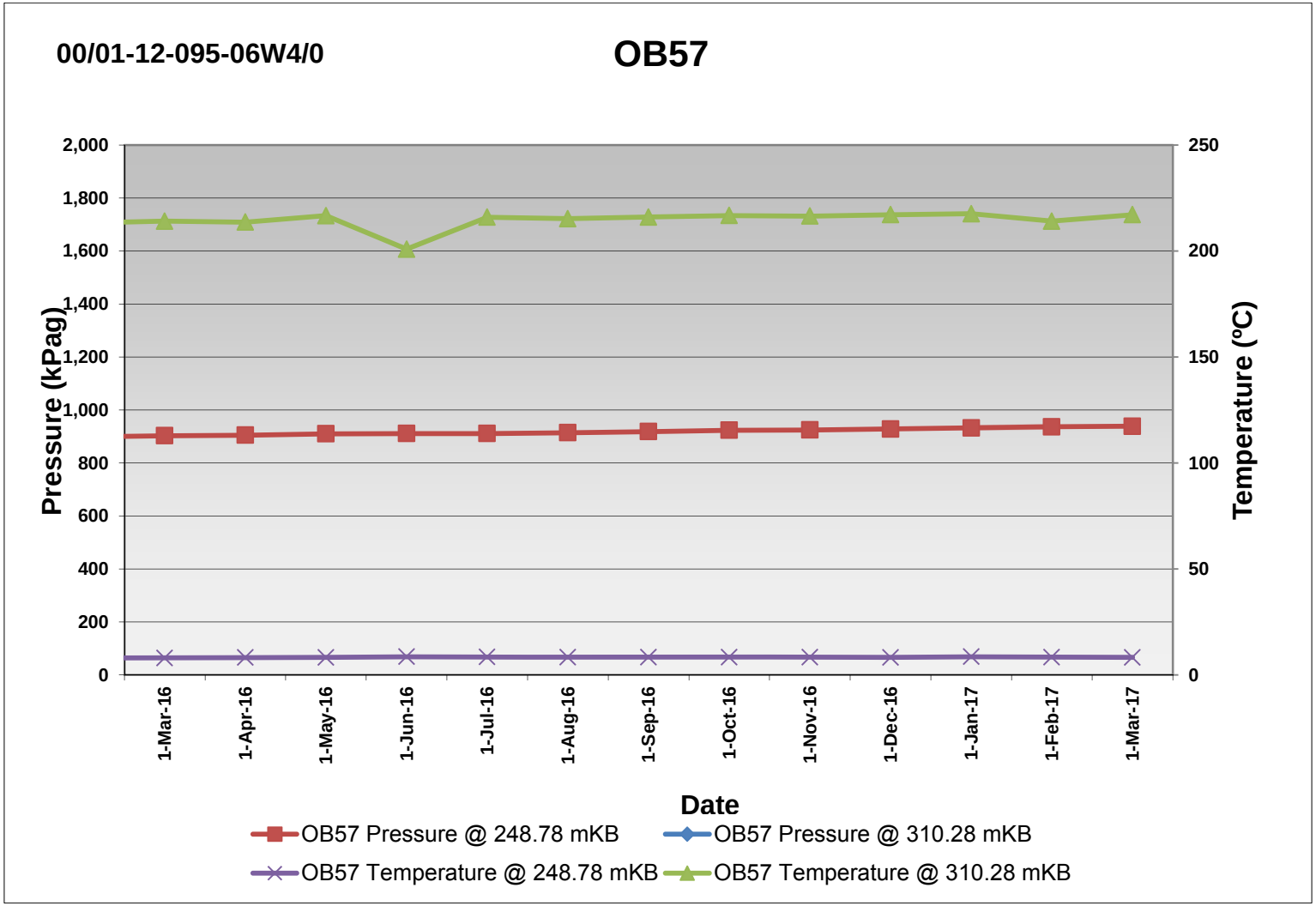

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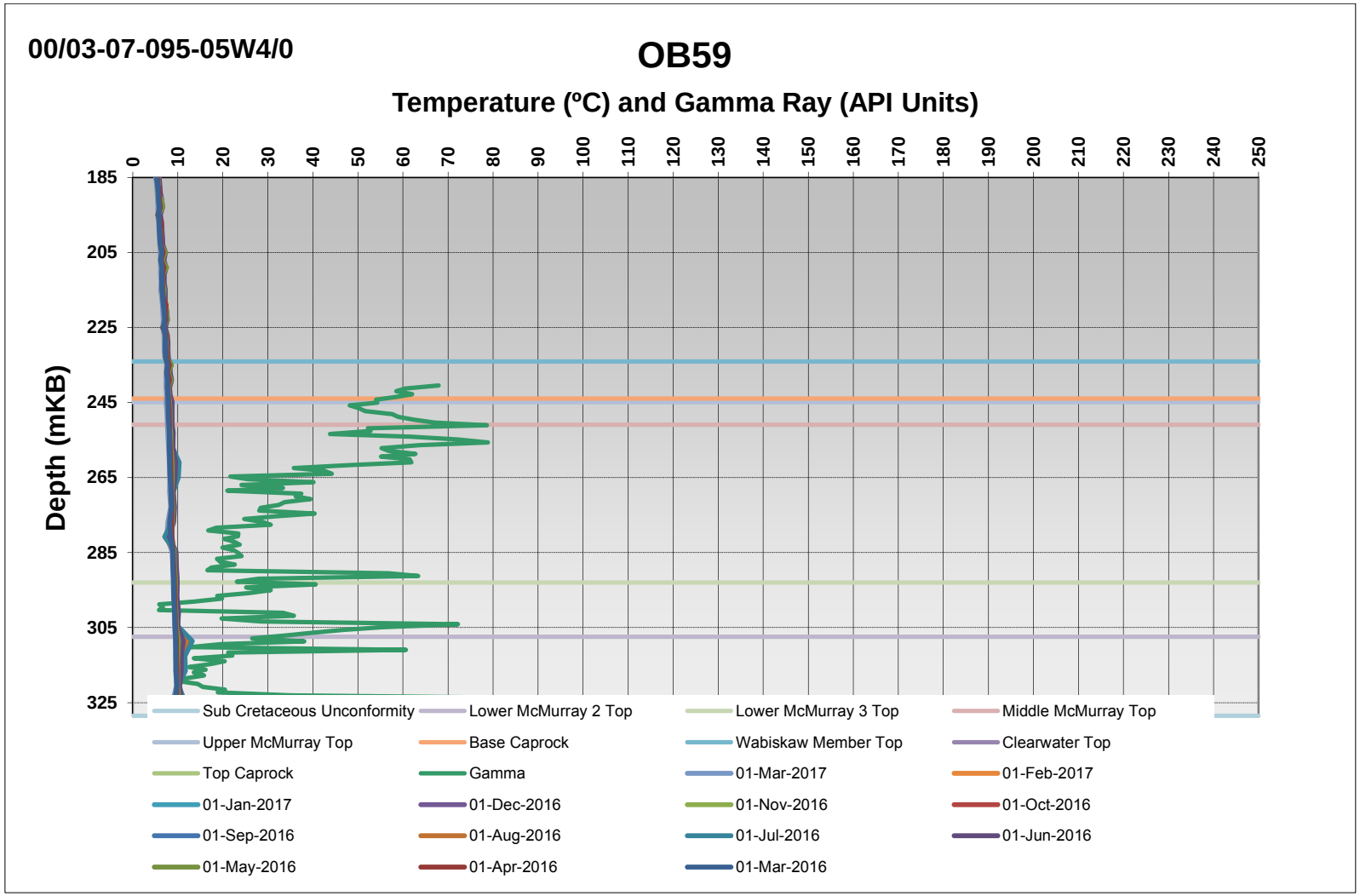

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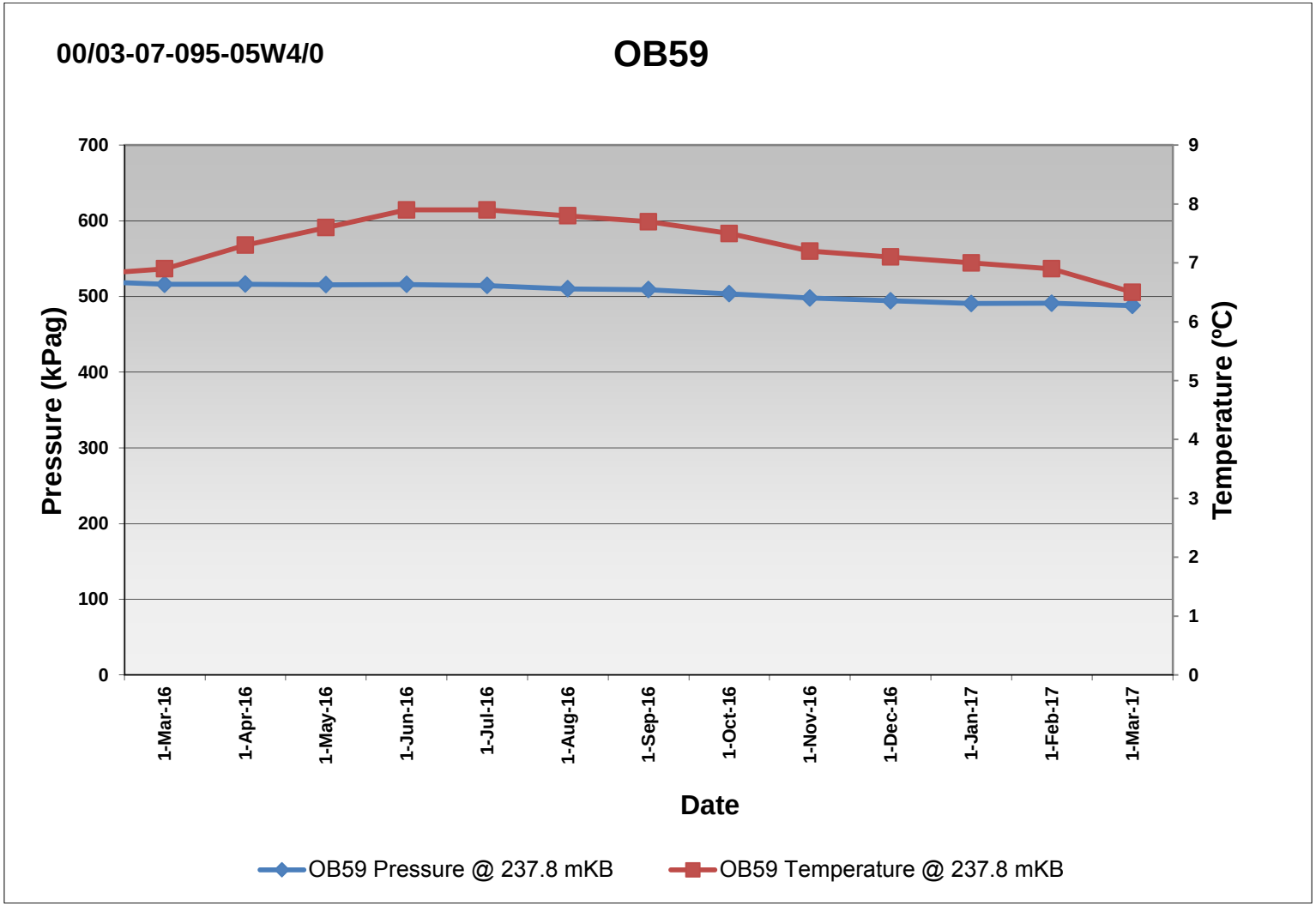

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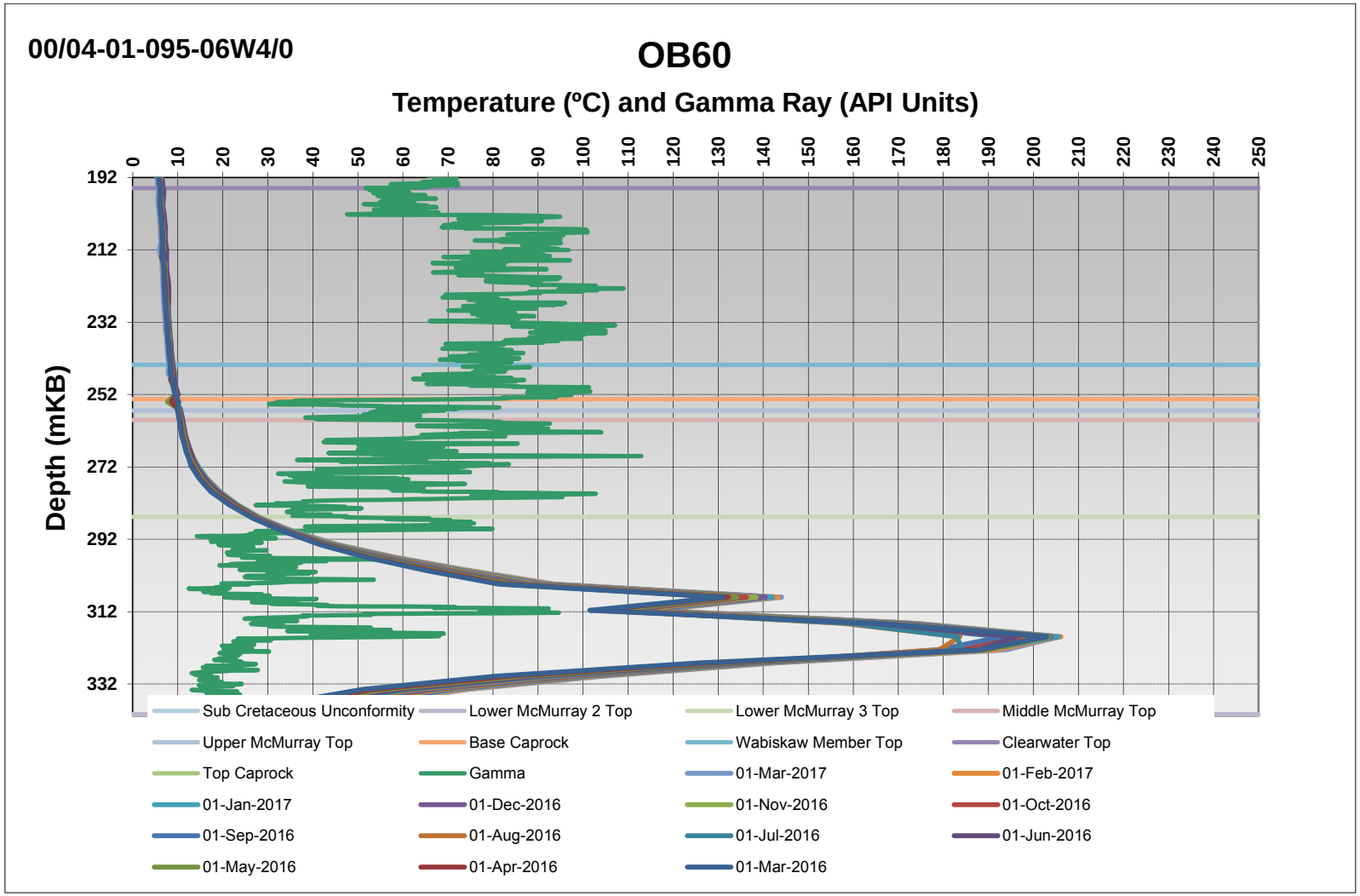

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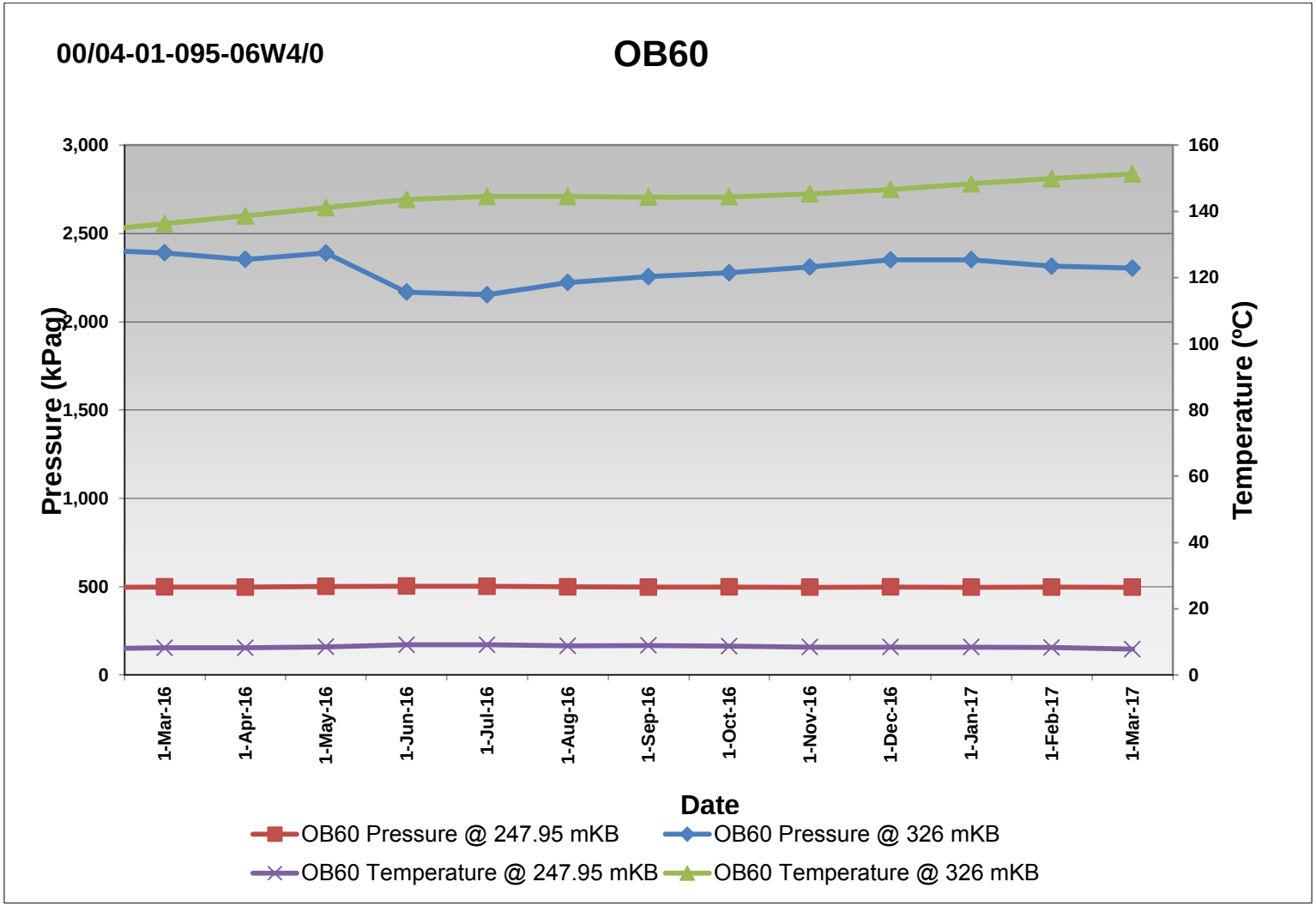

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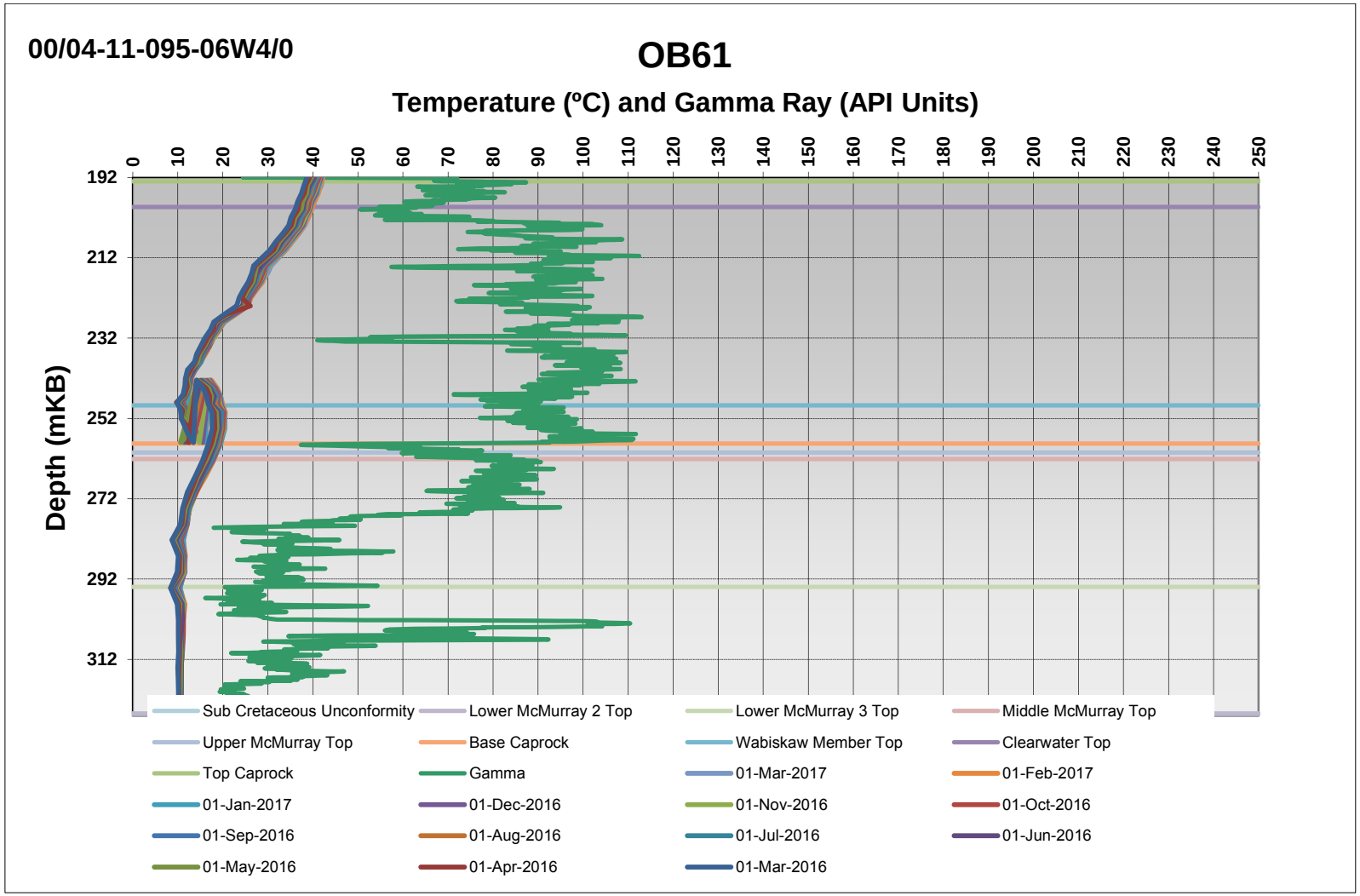

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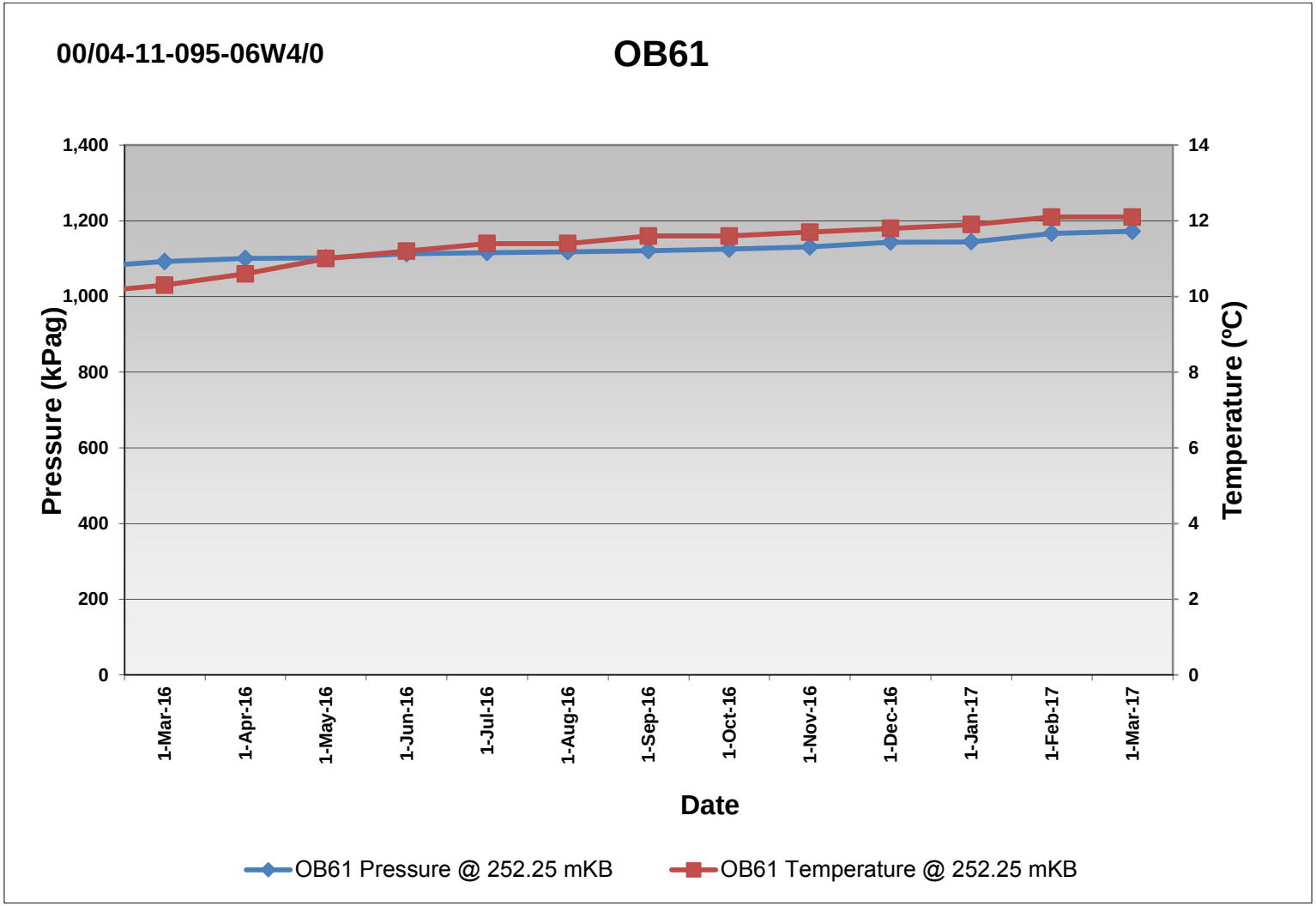

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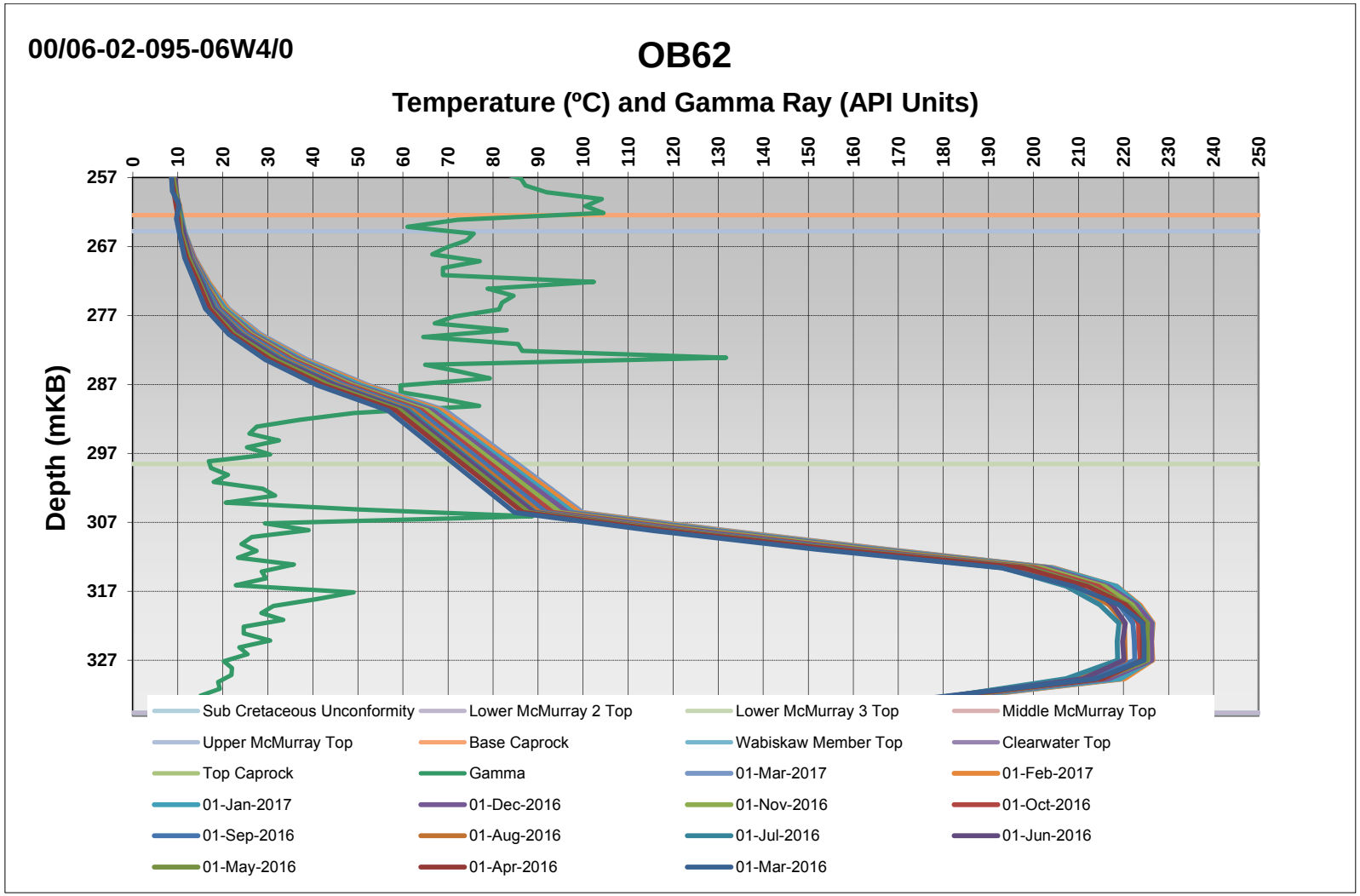

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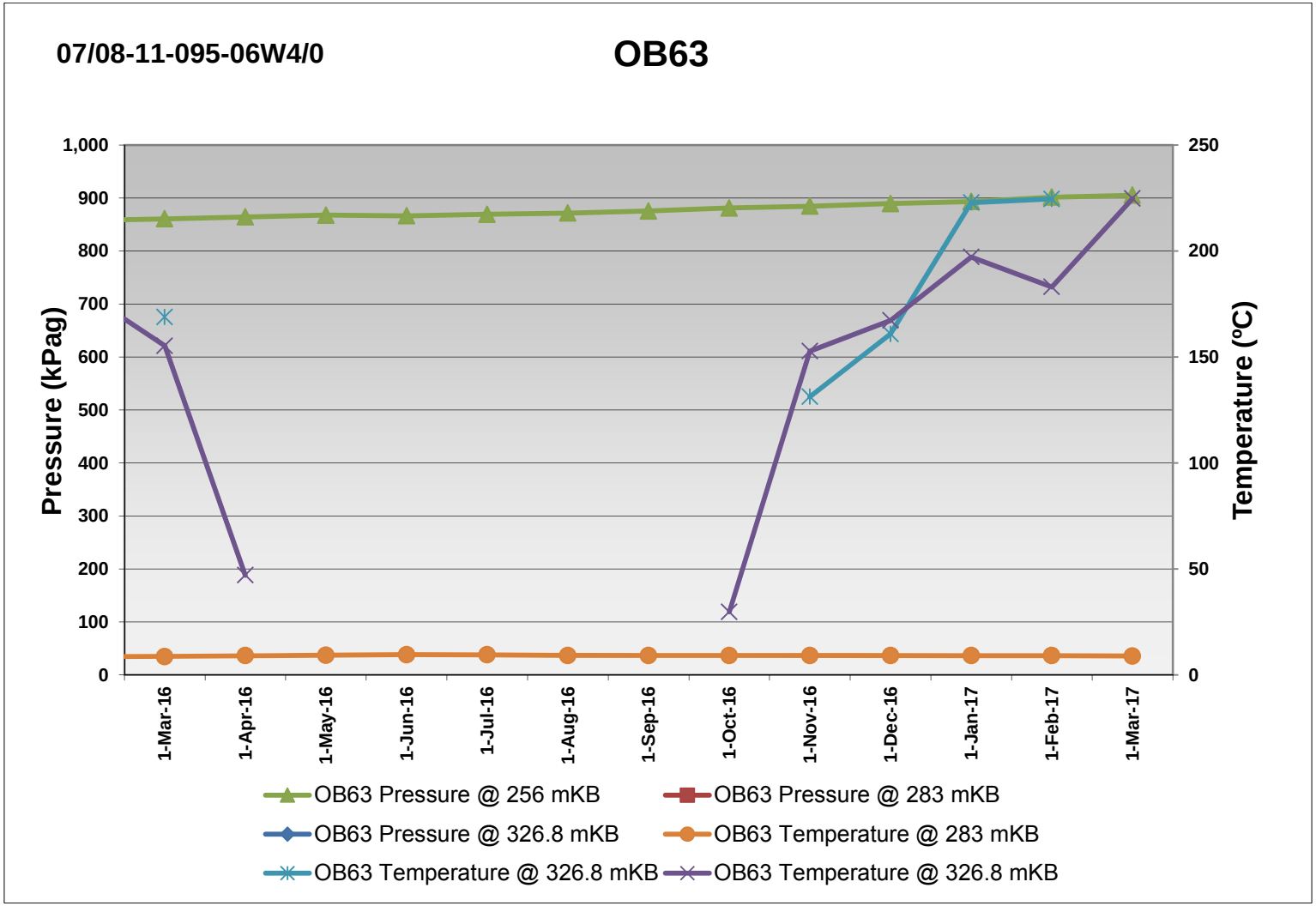

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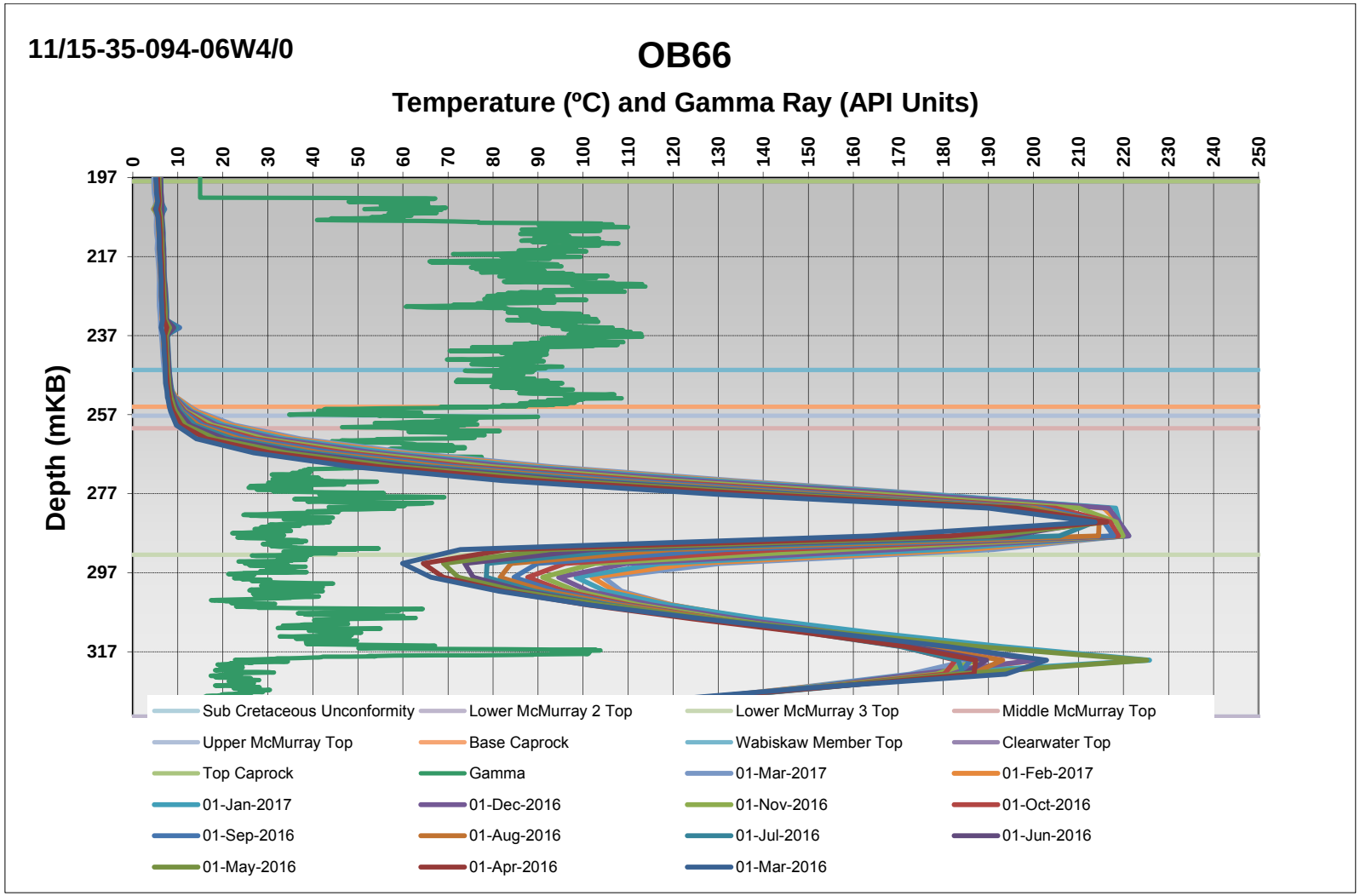

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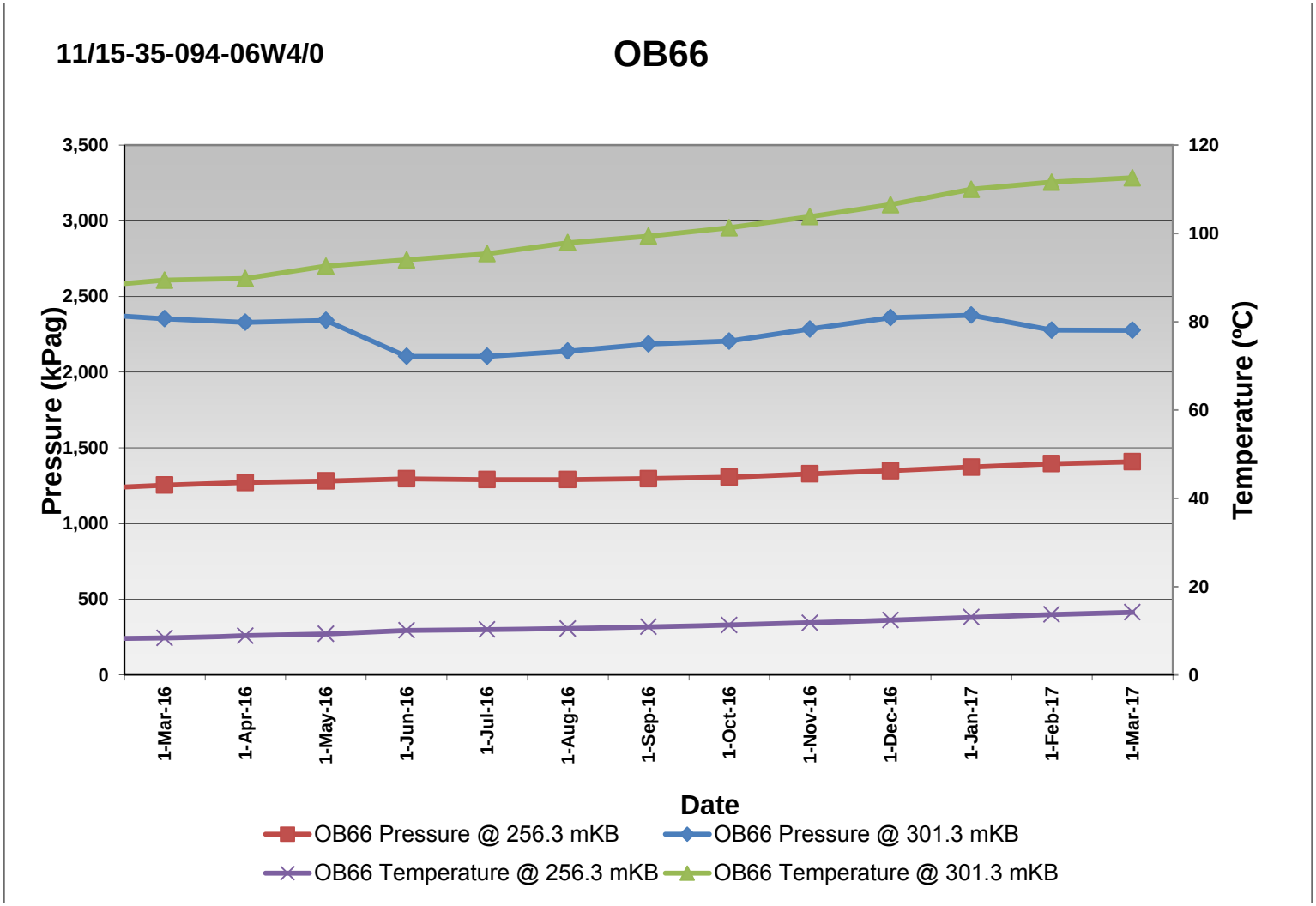

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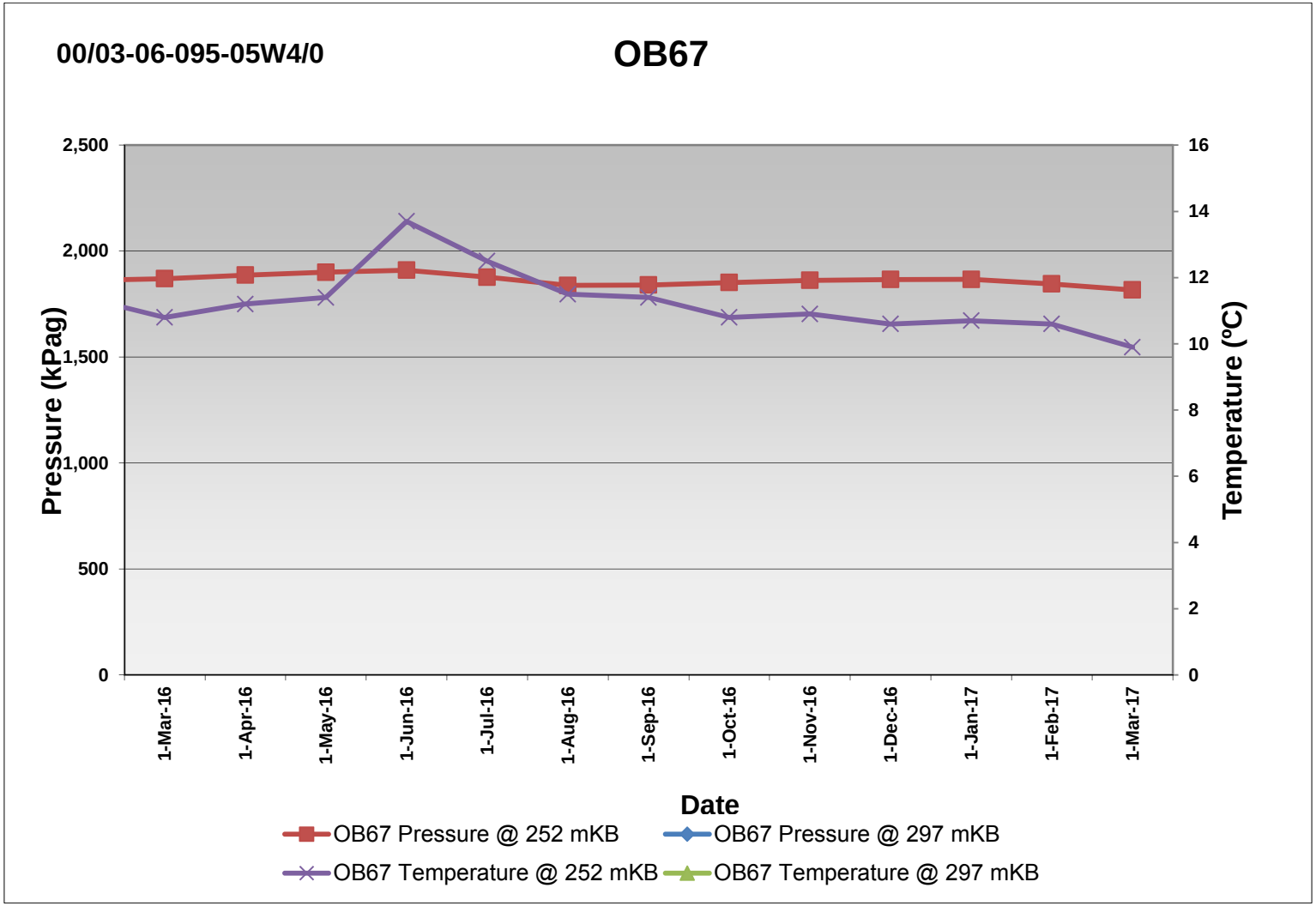

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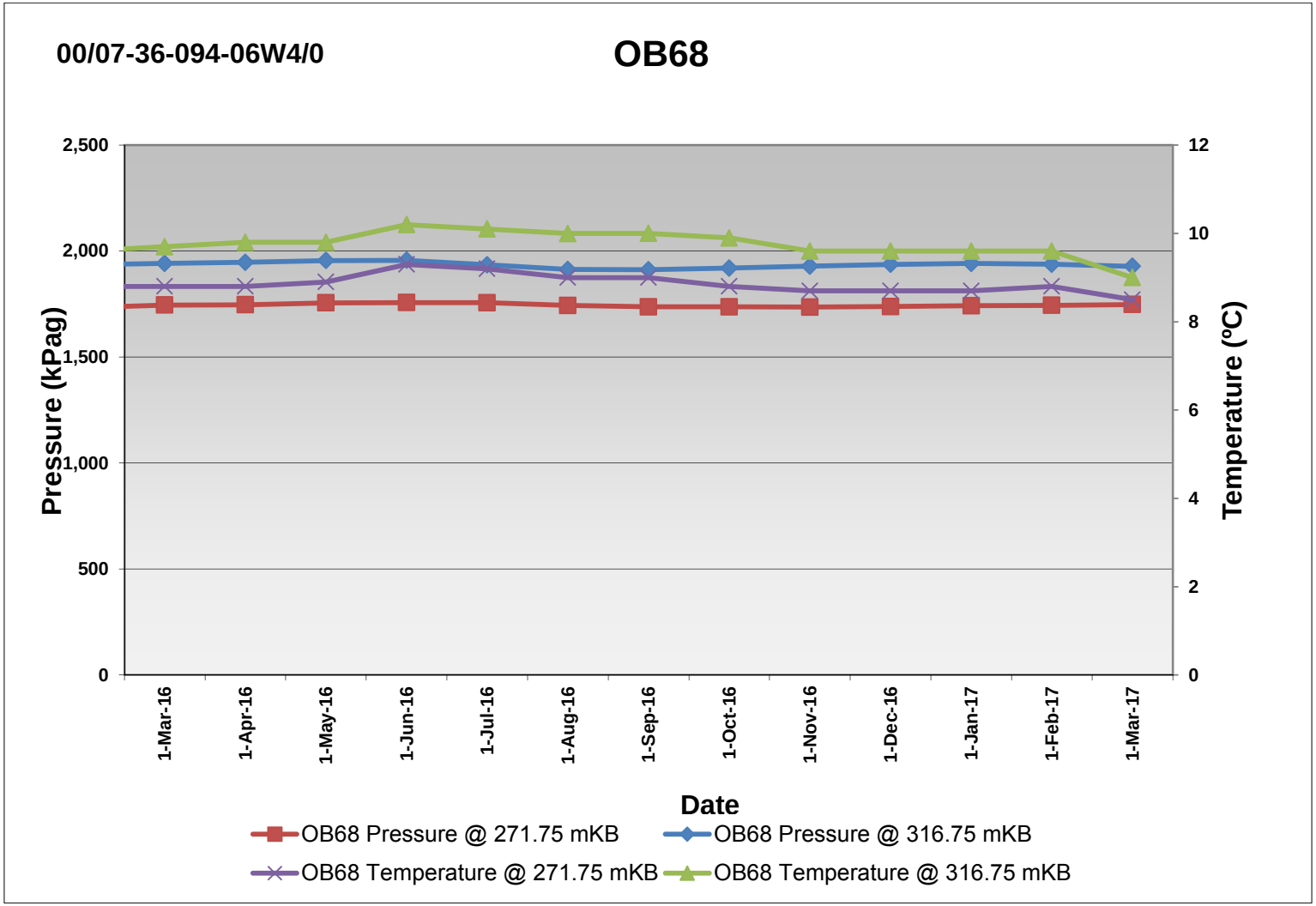

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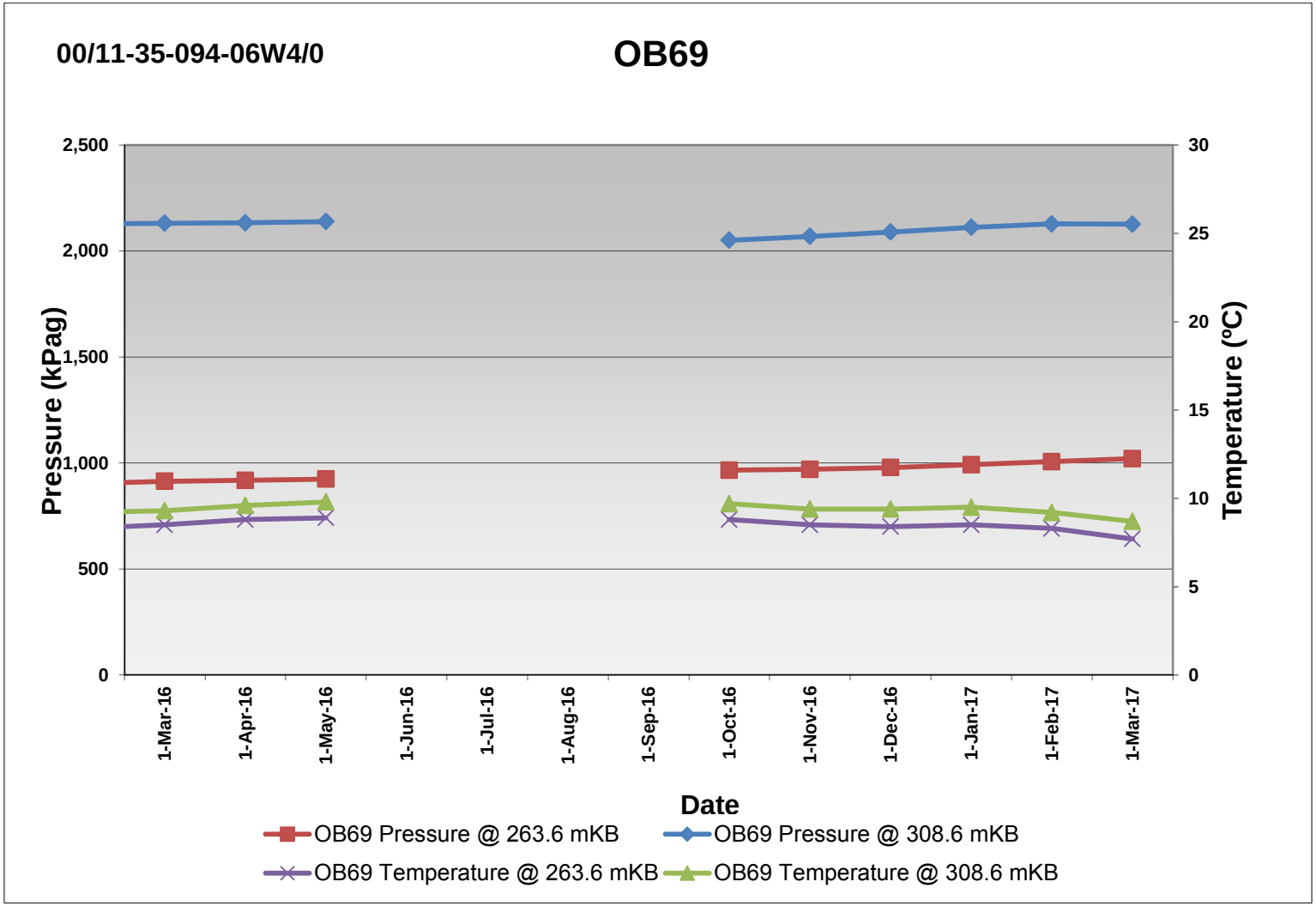

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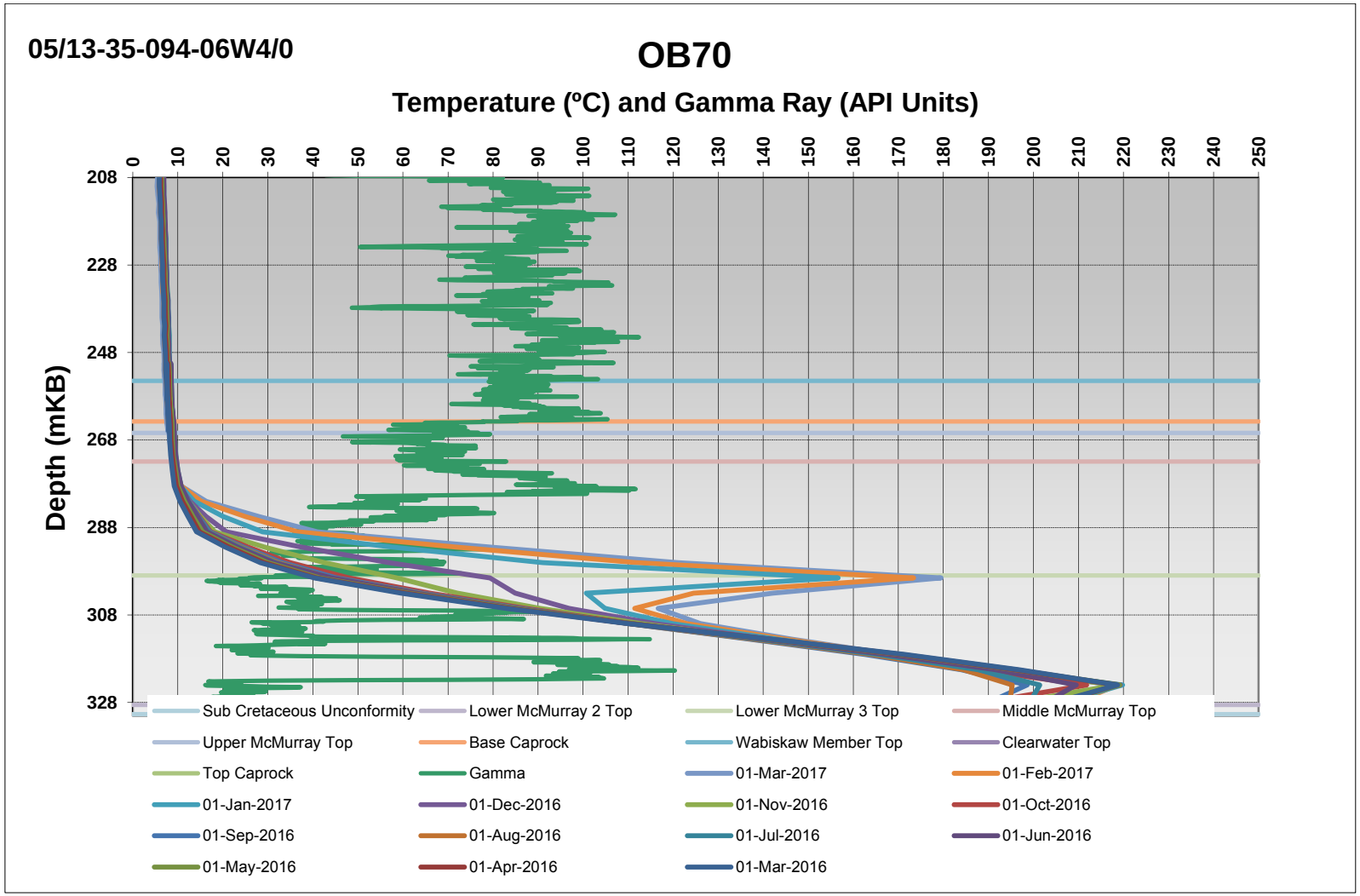

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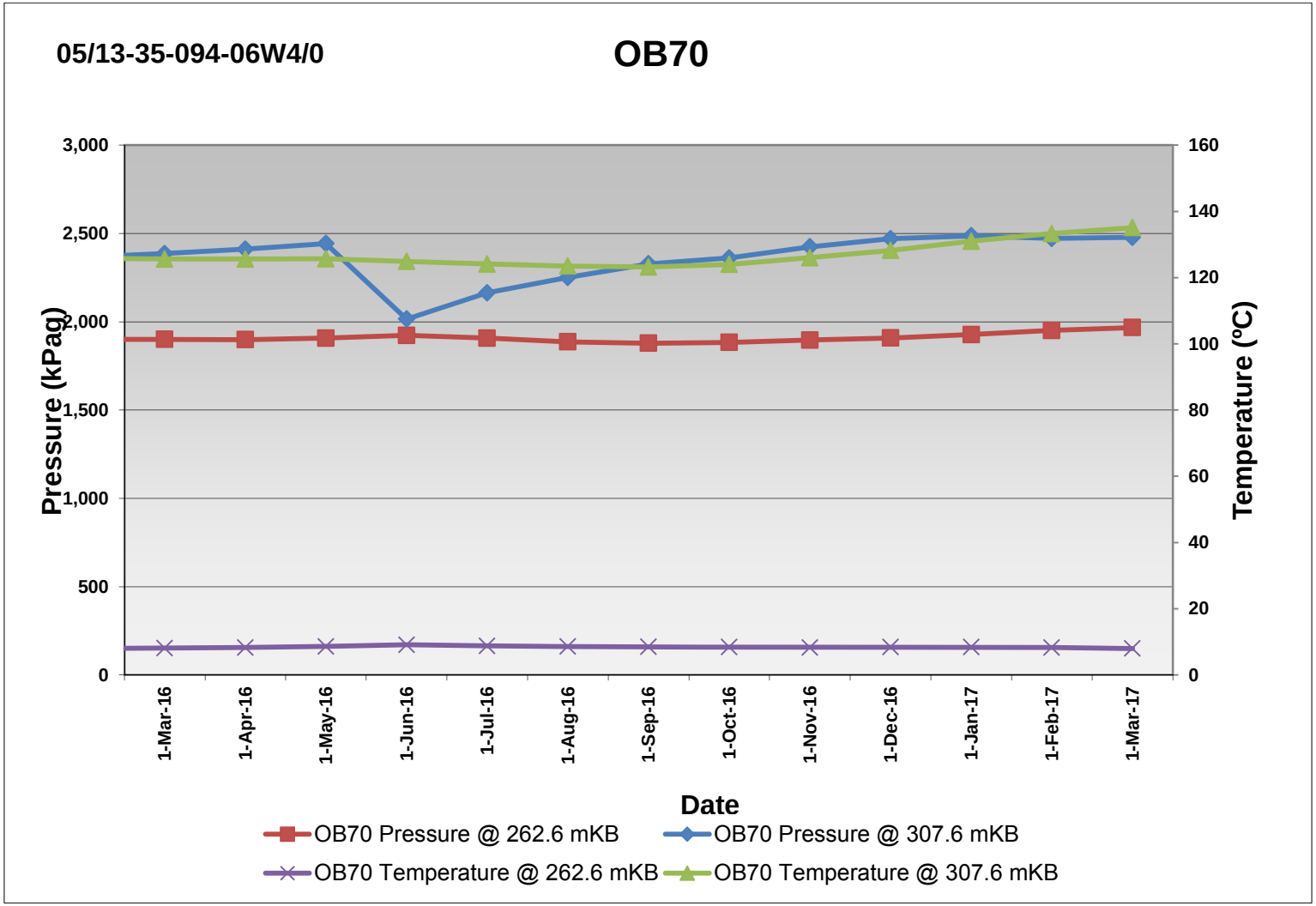

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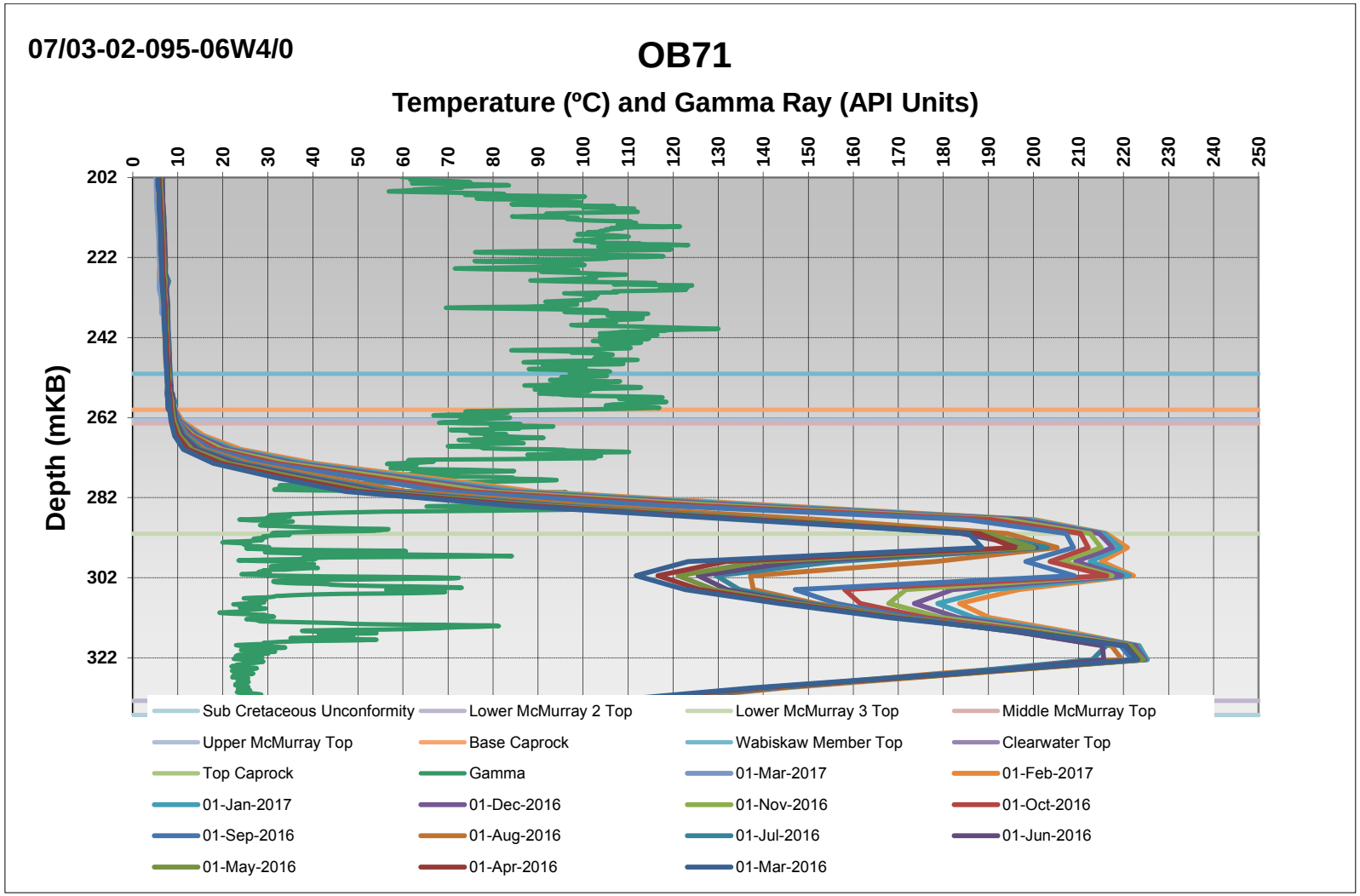

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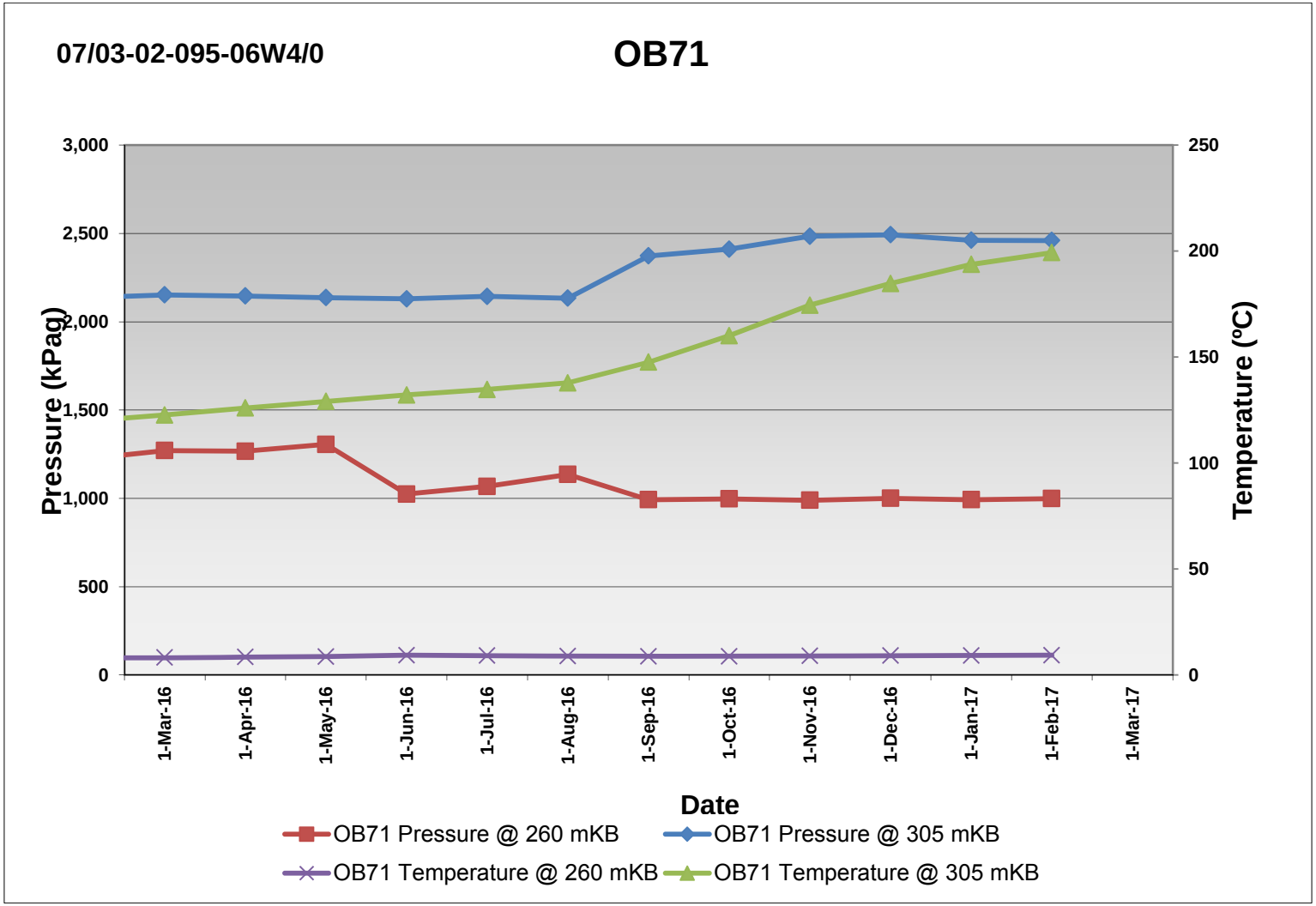

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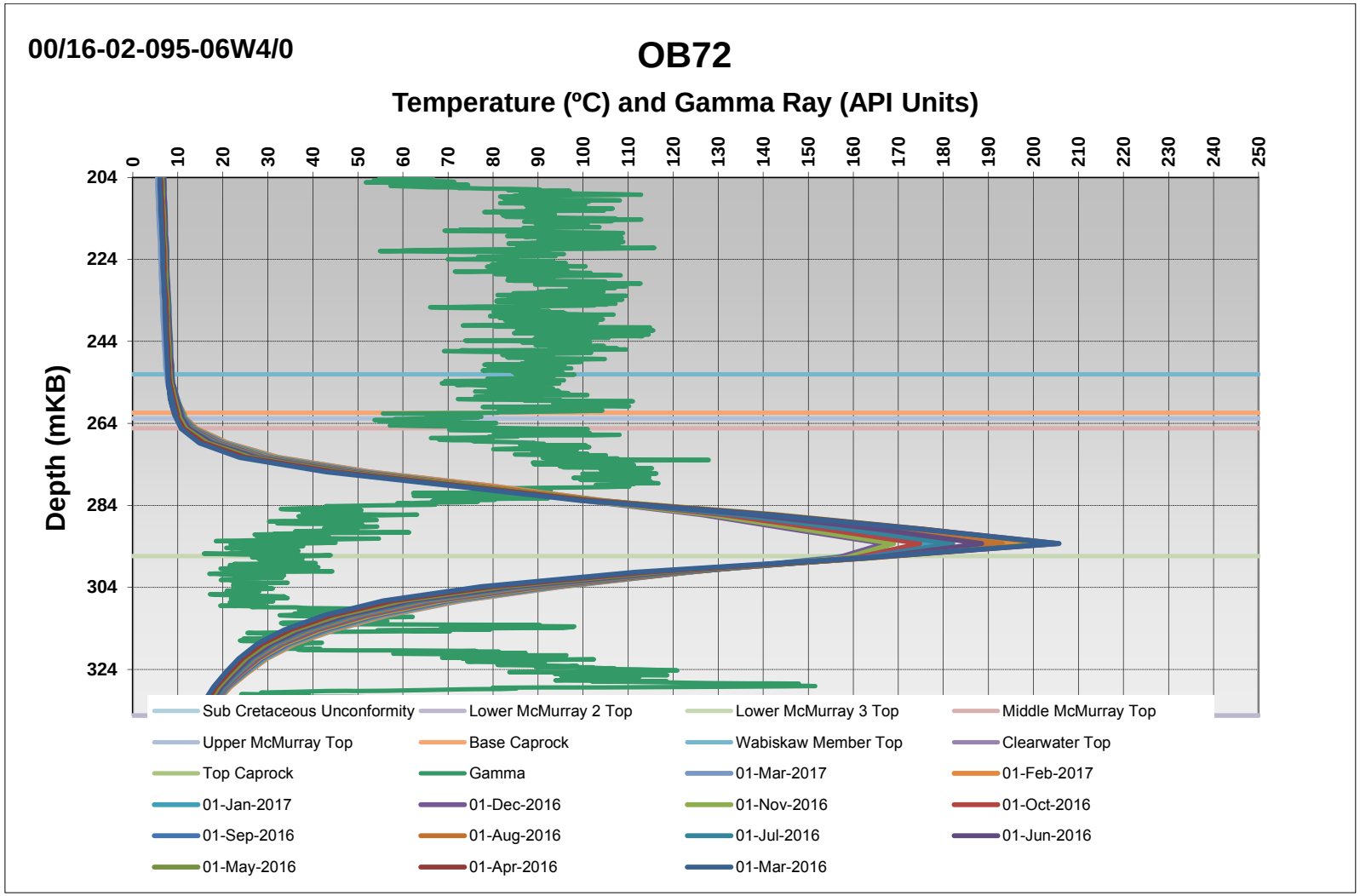

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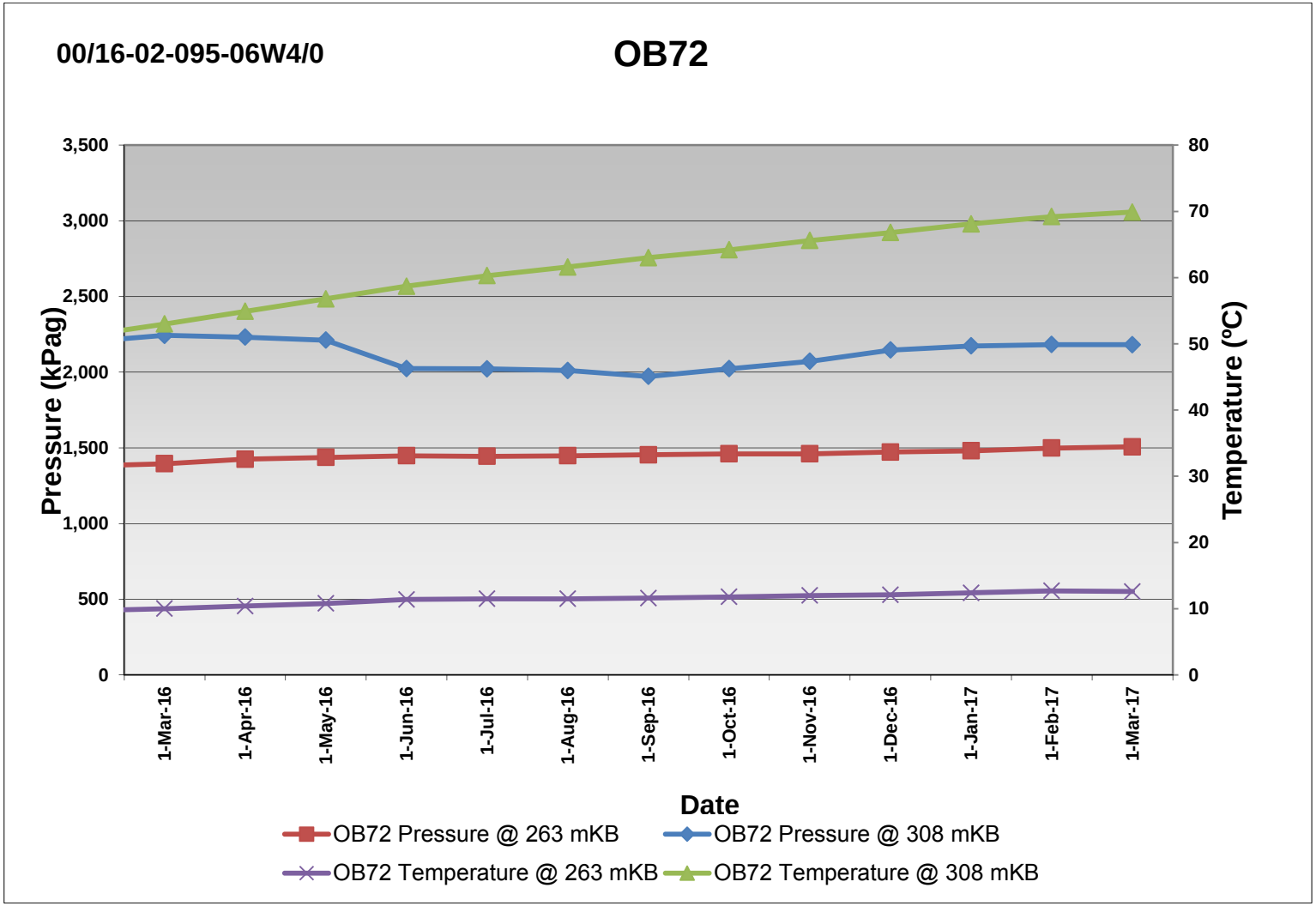

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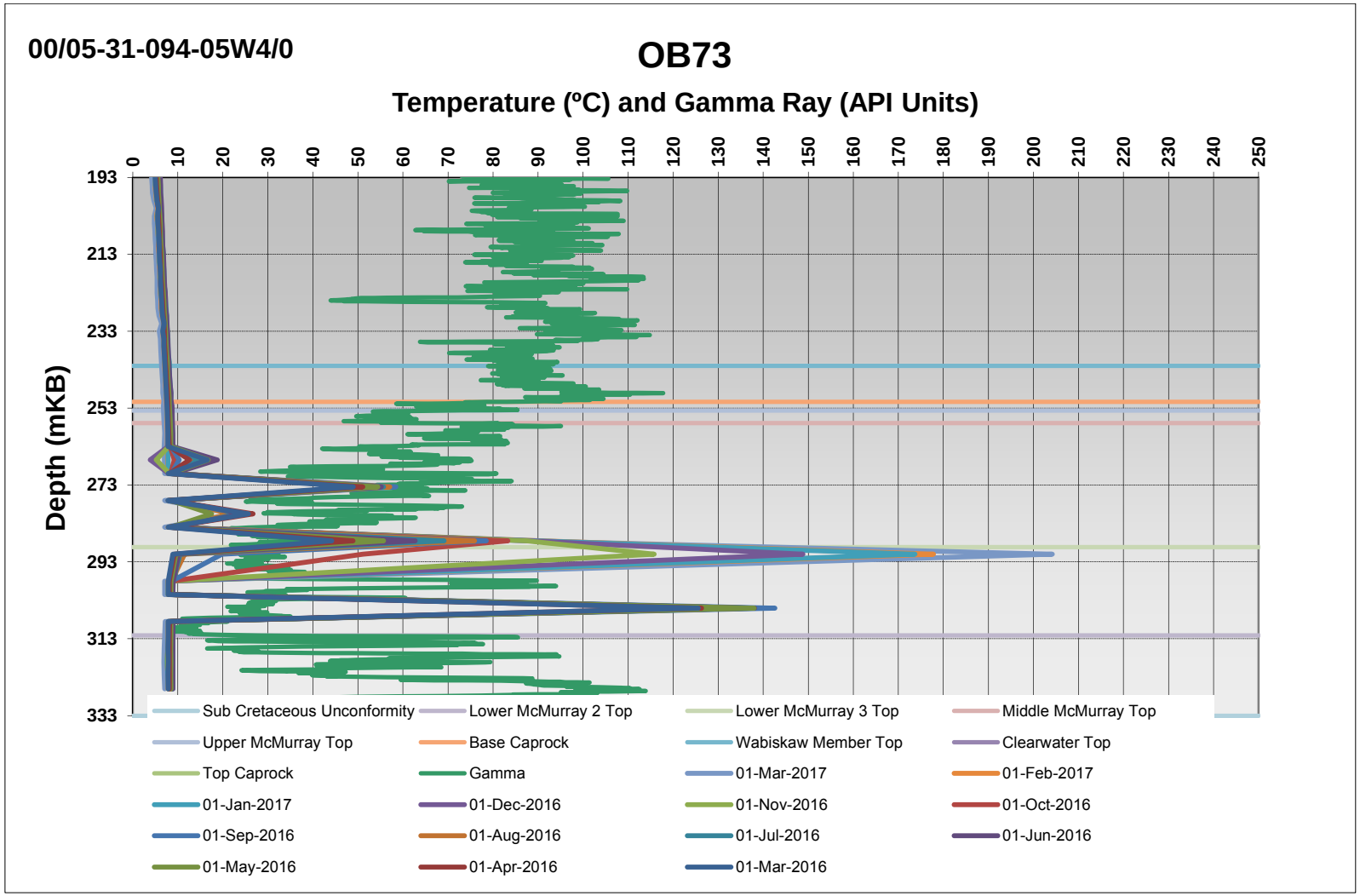

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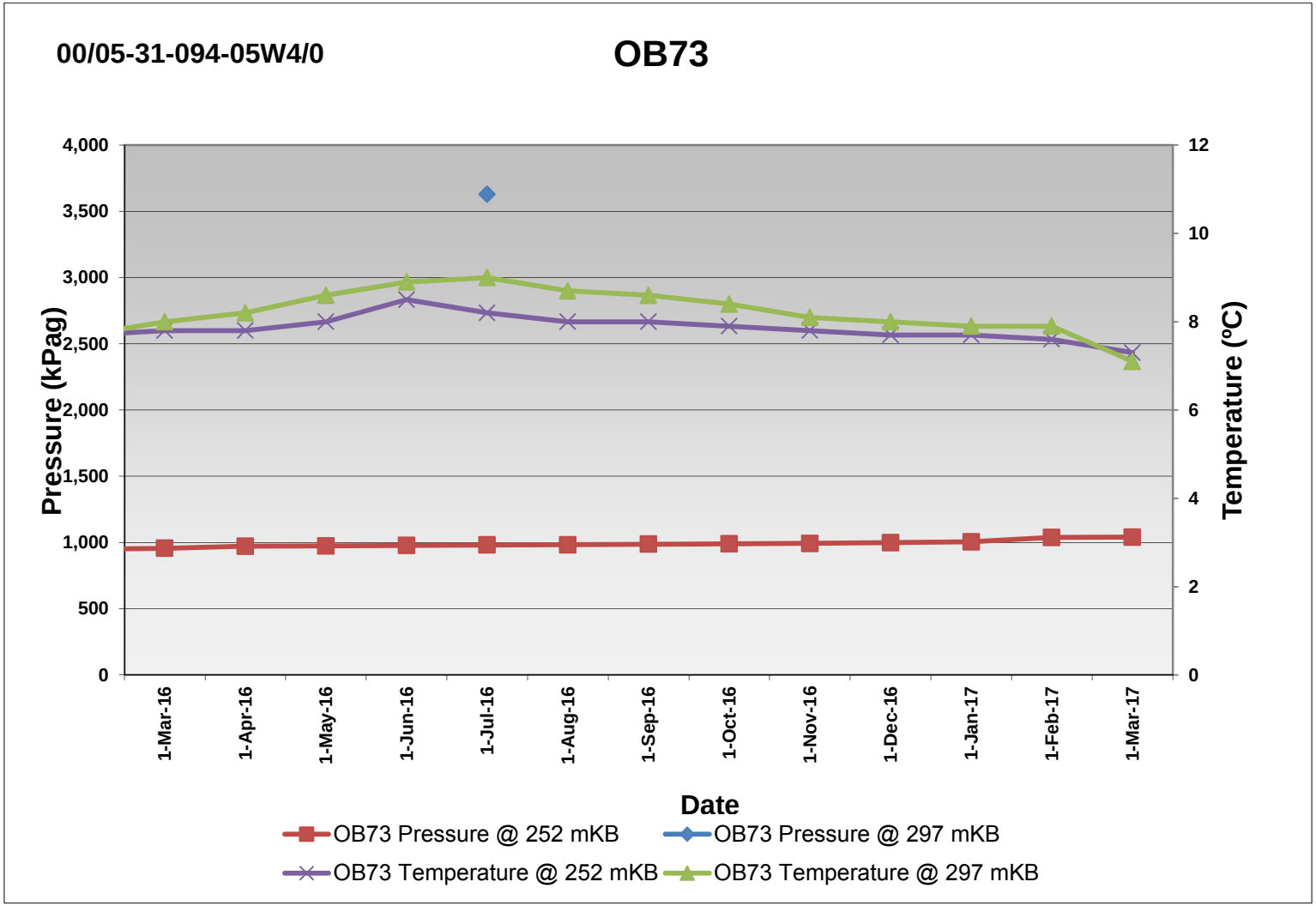

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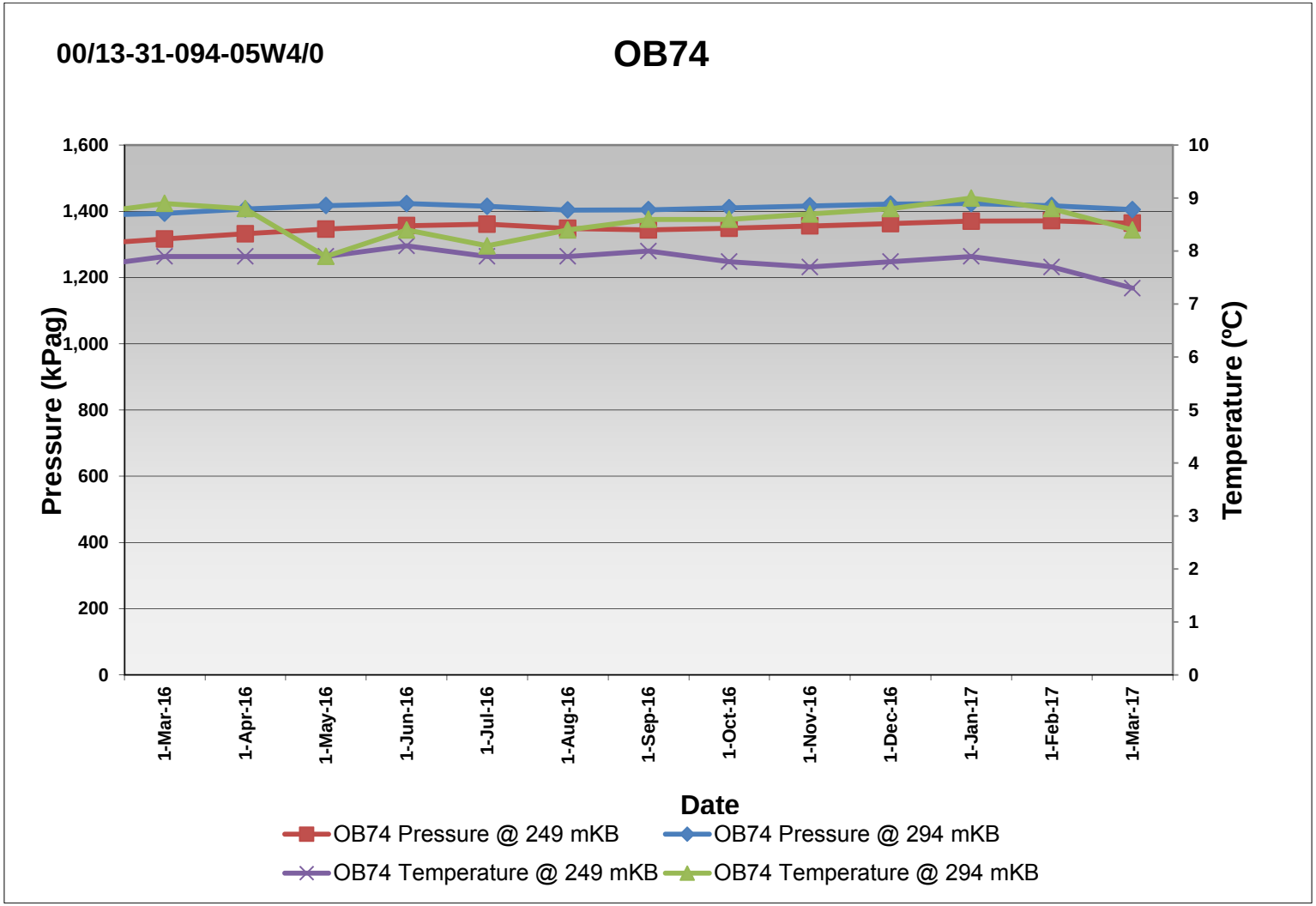
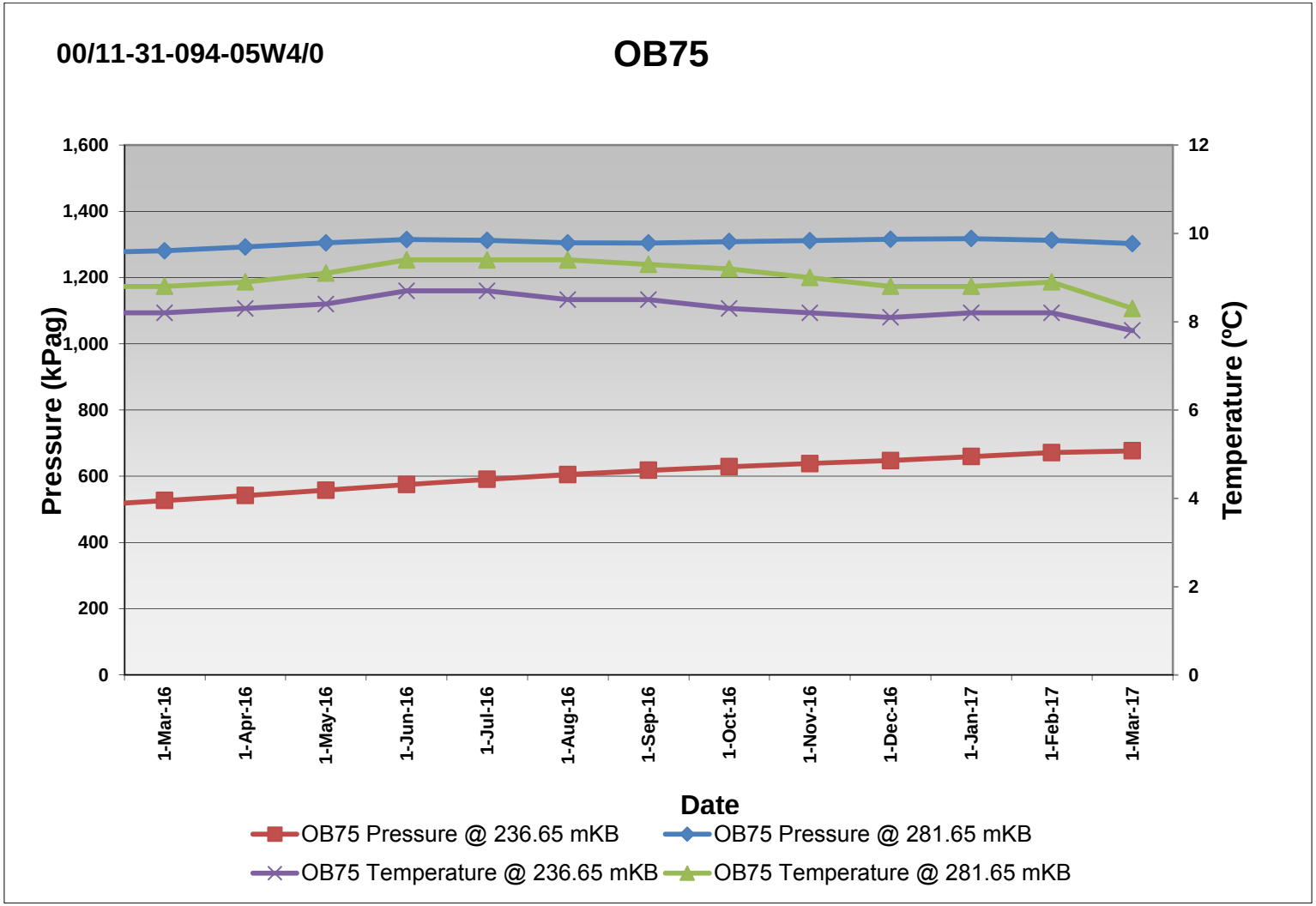


Piezometer Plots & Temperature vs Depth Plots



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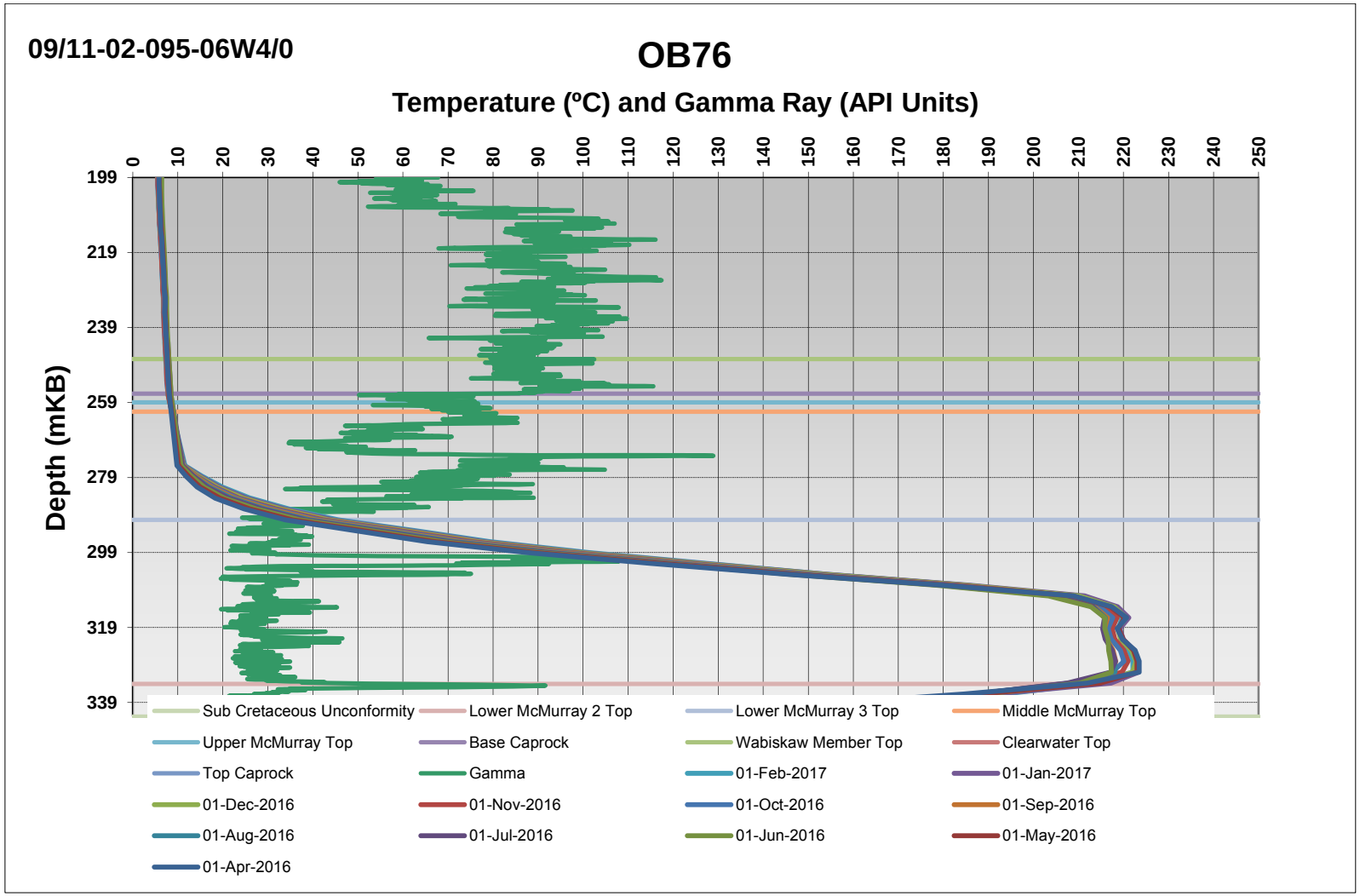

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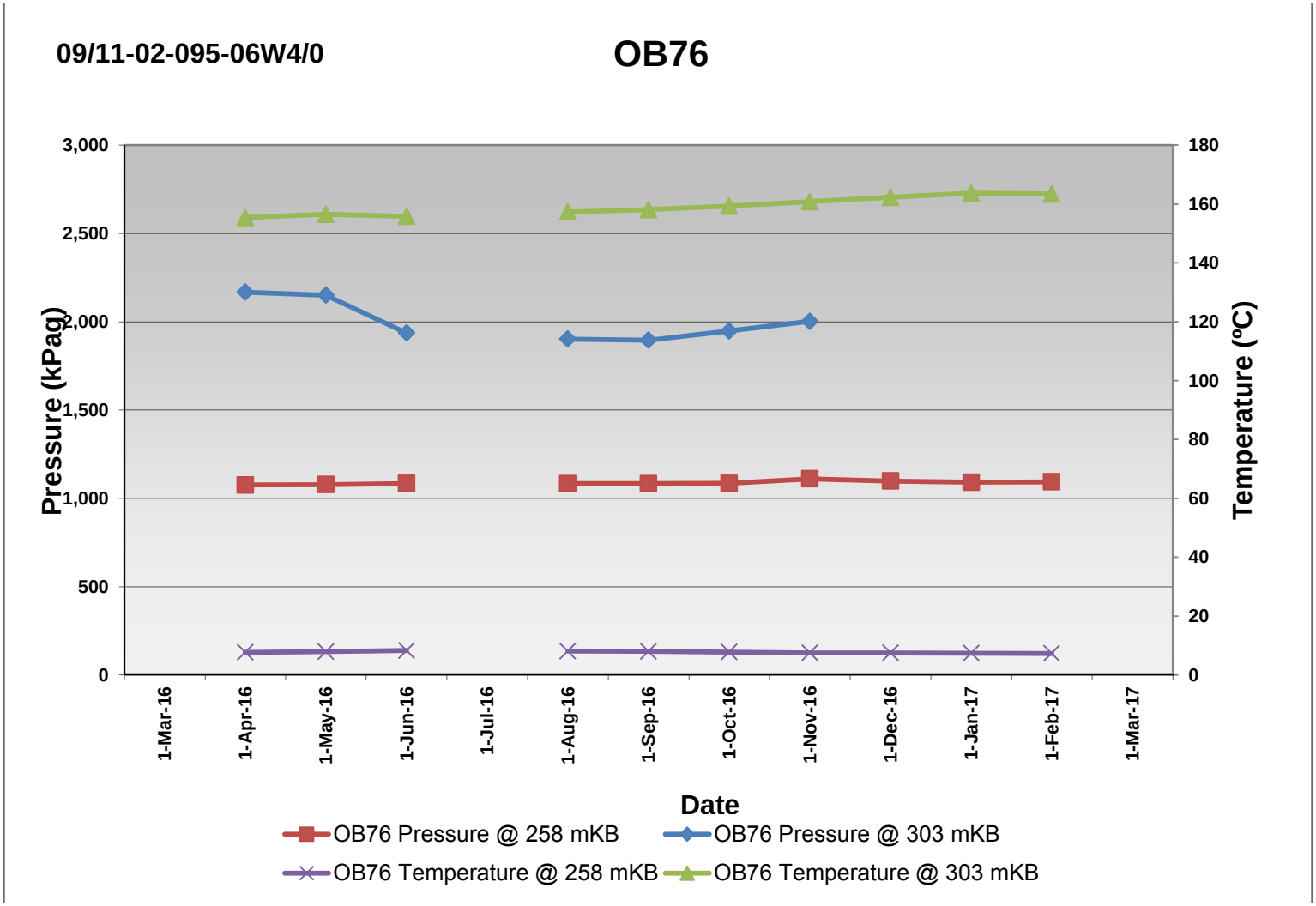

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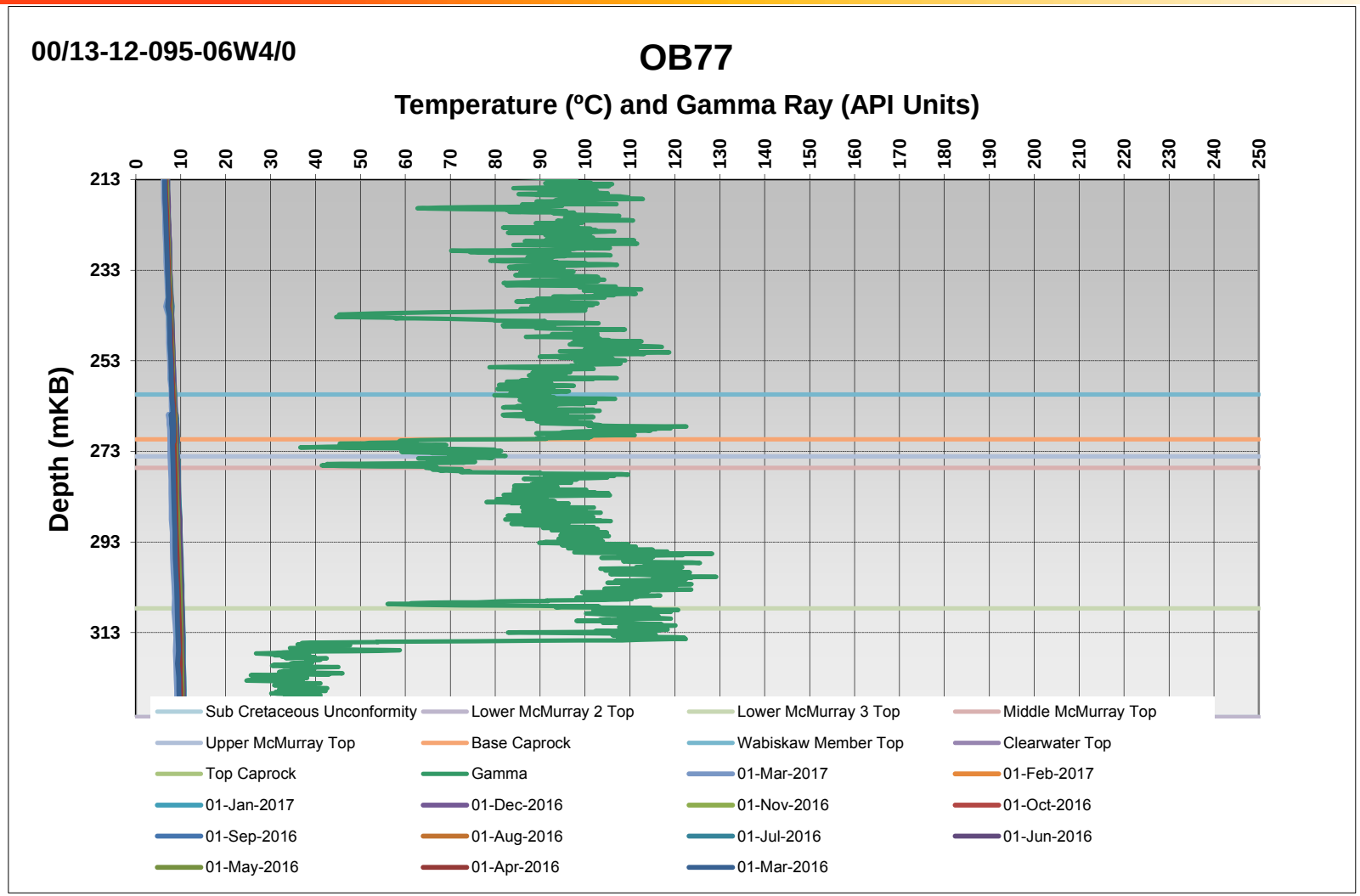

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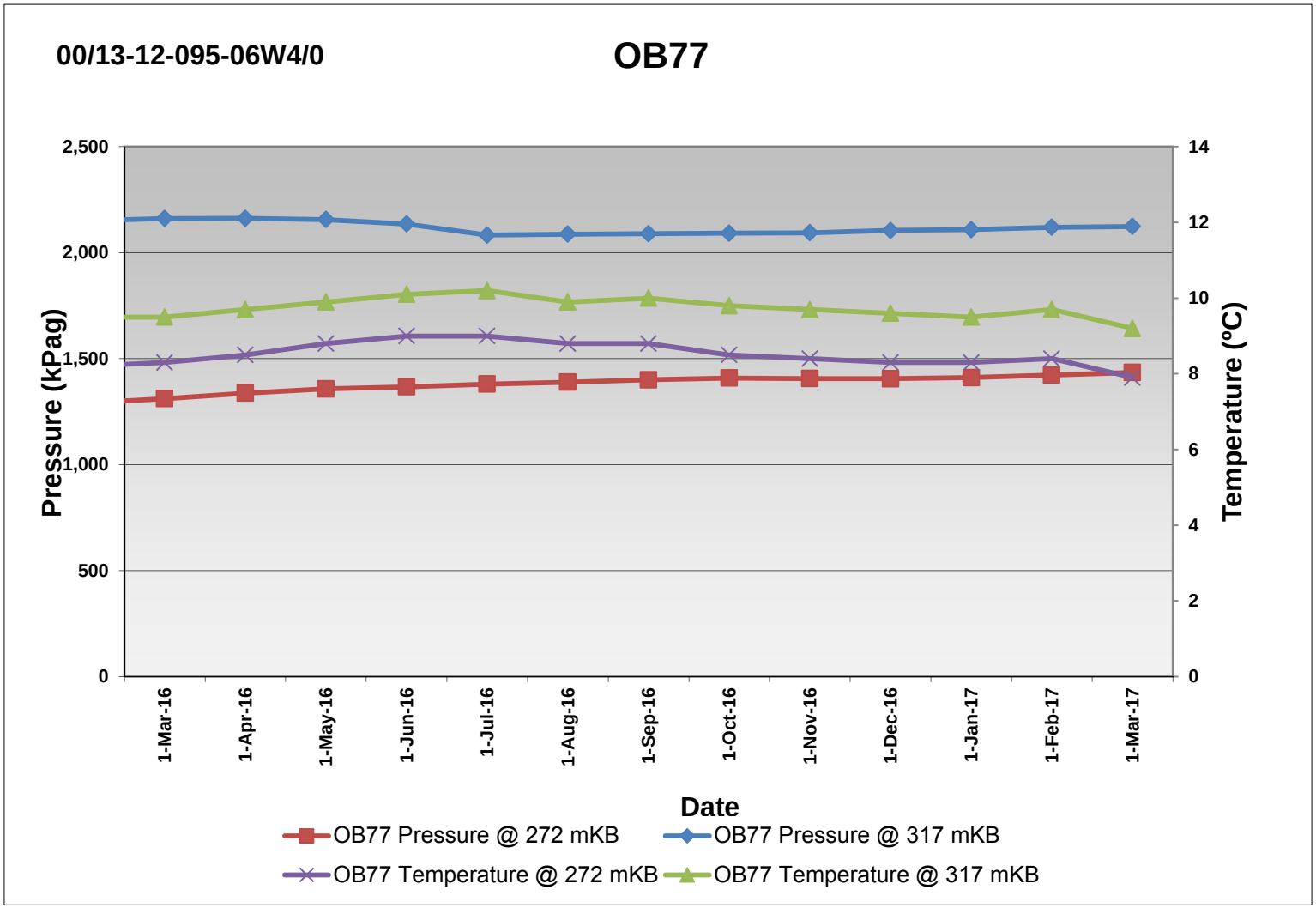

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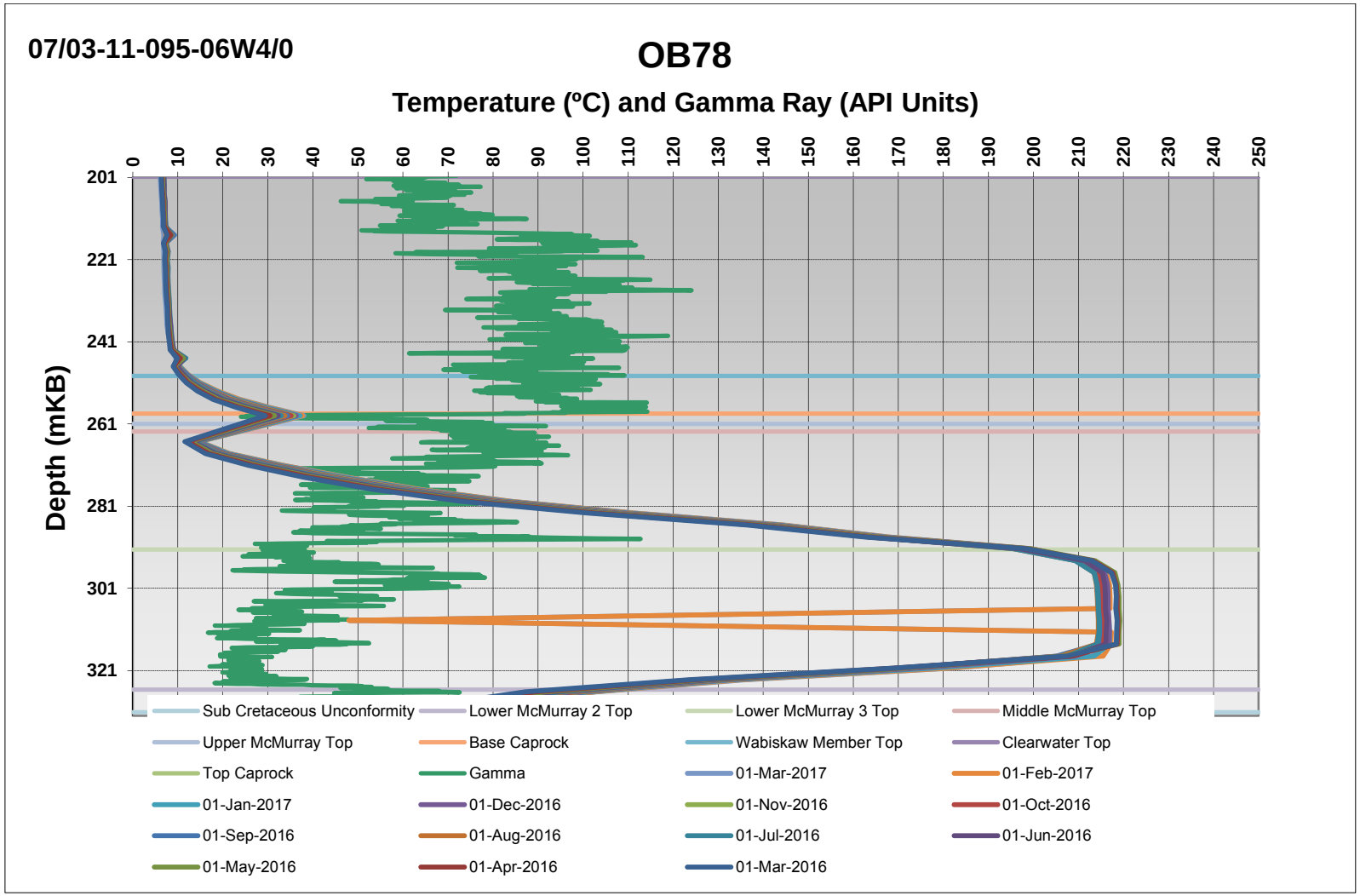

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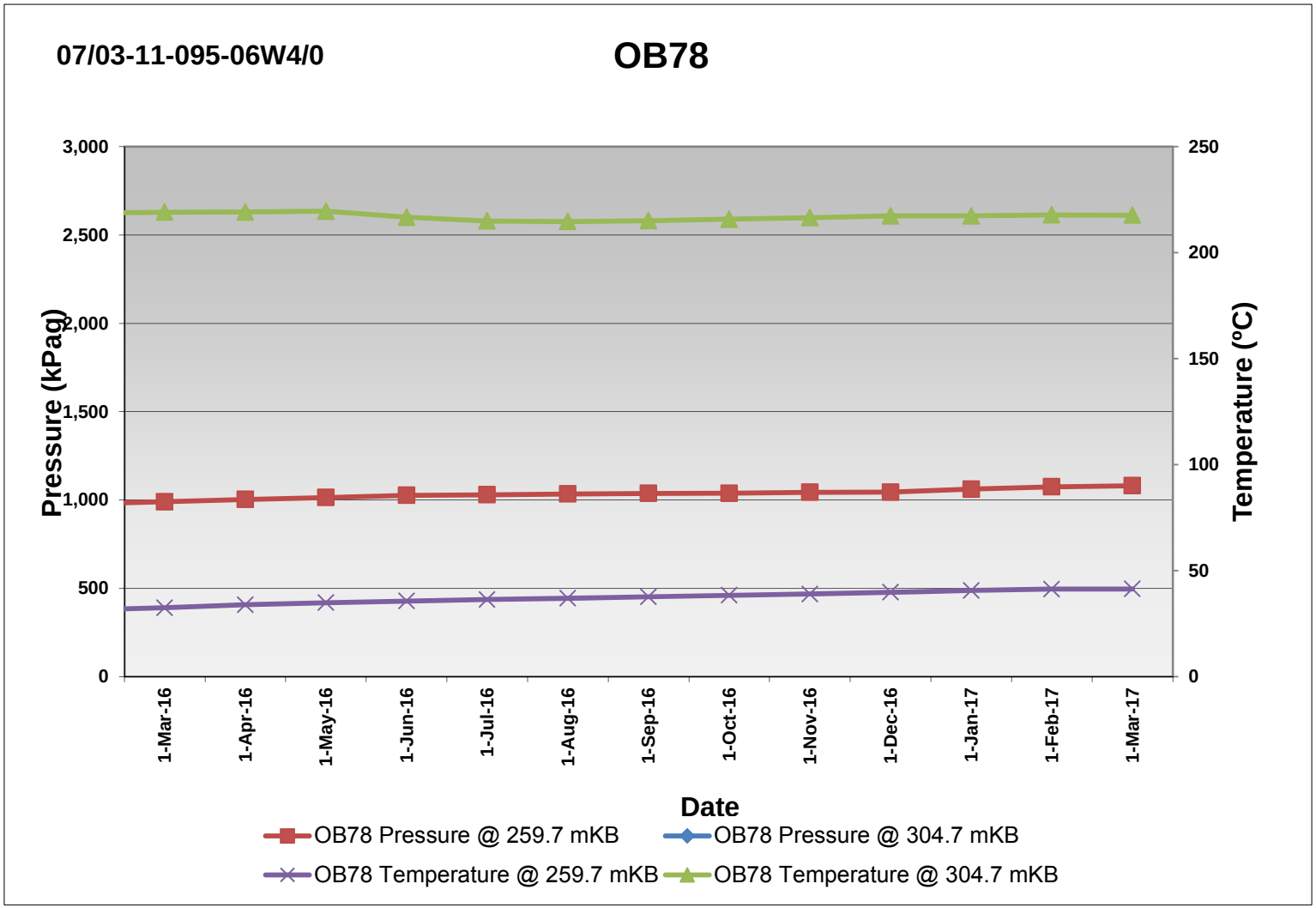

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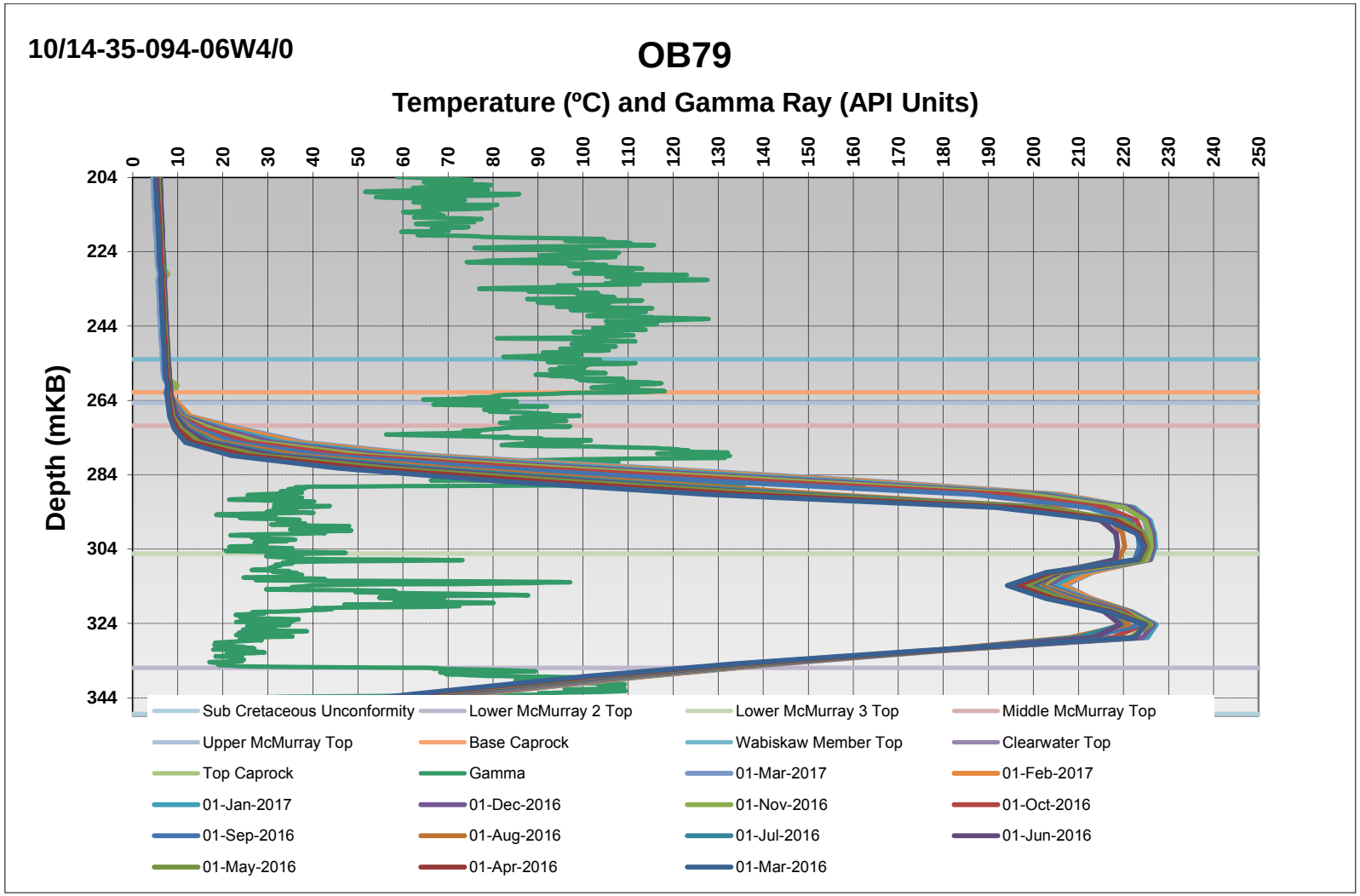

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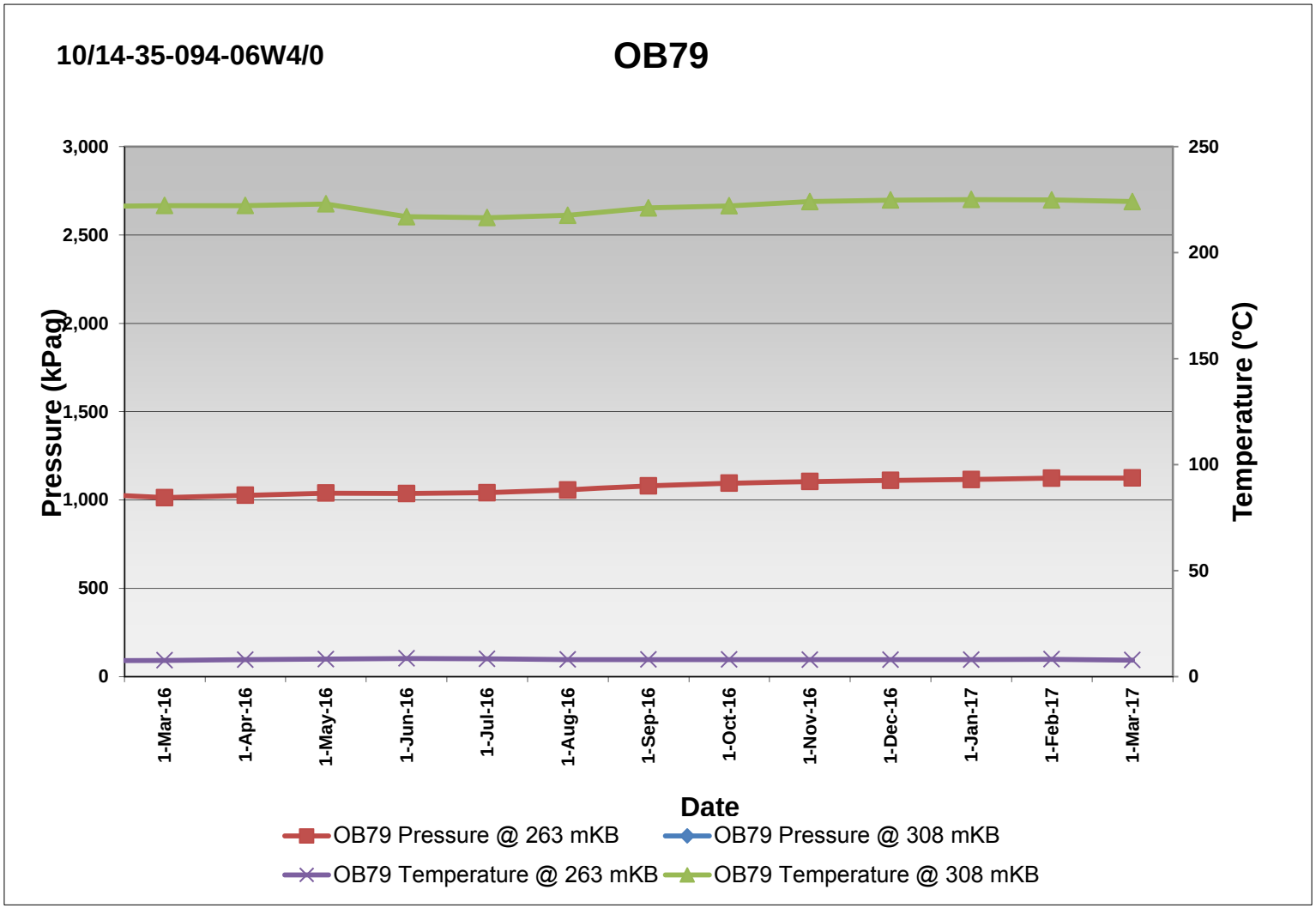

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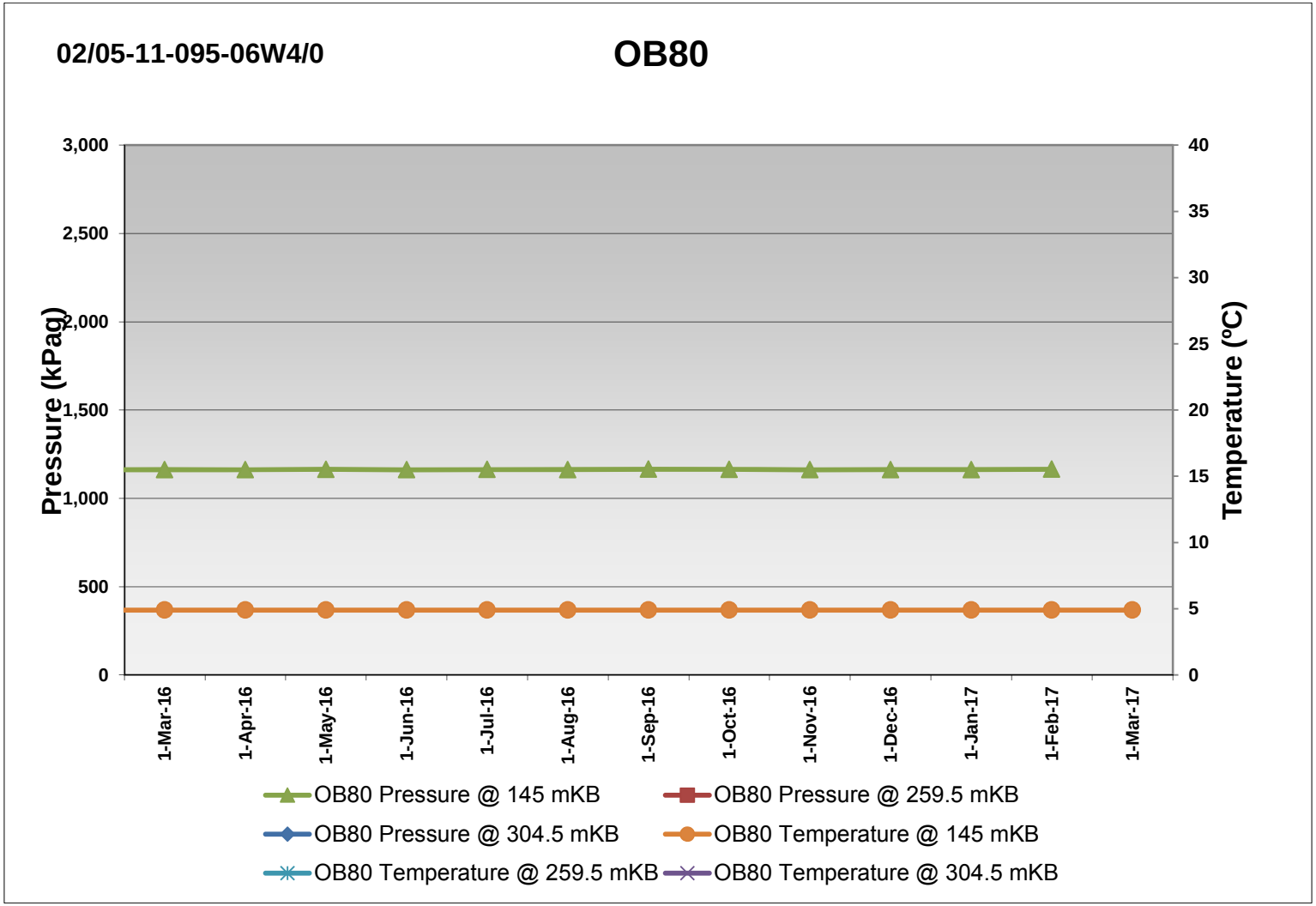

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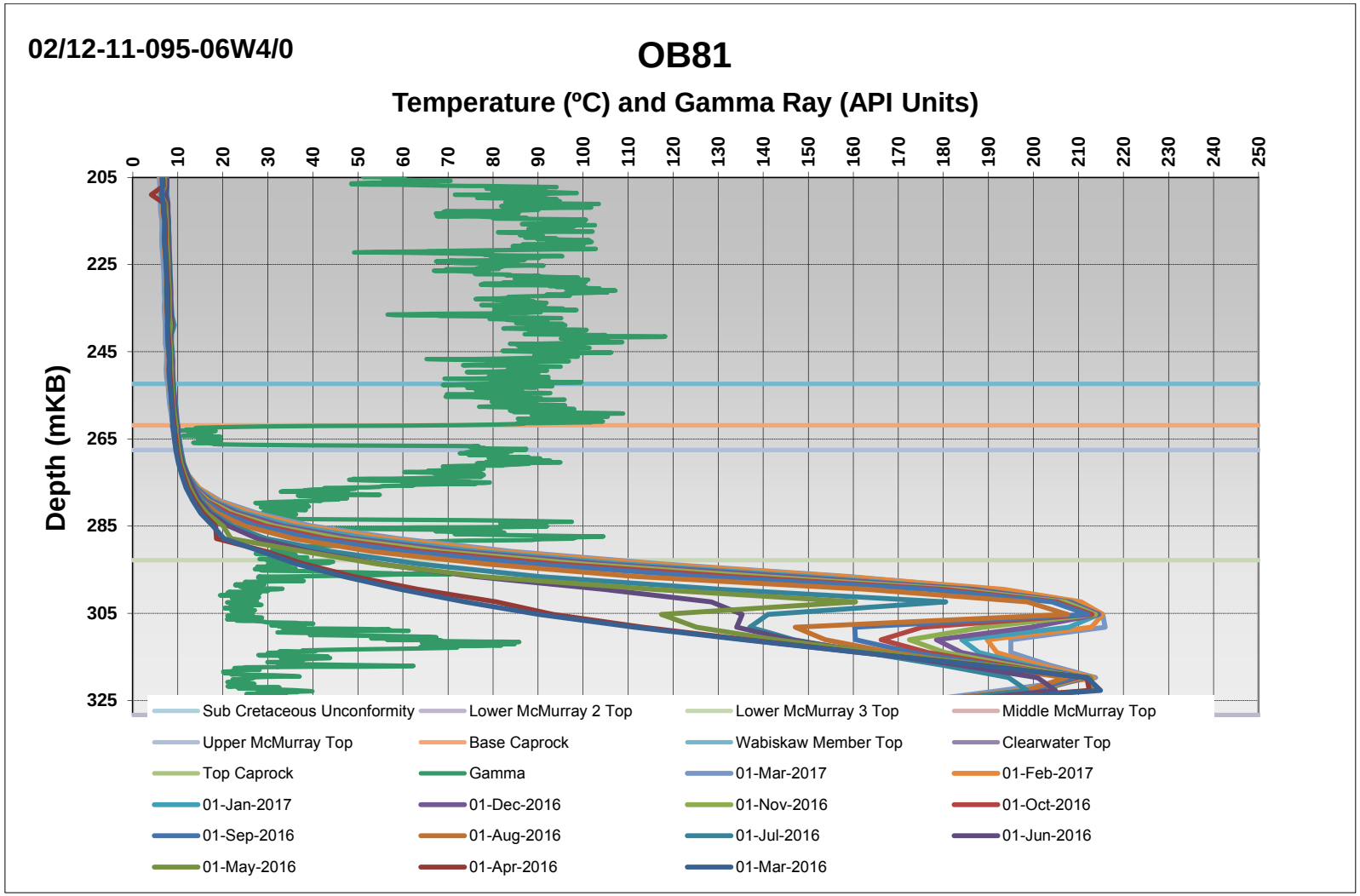

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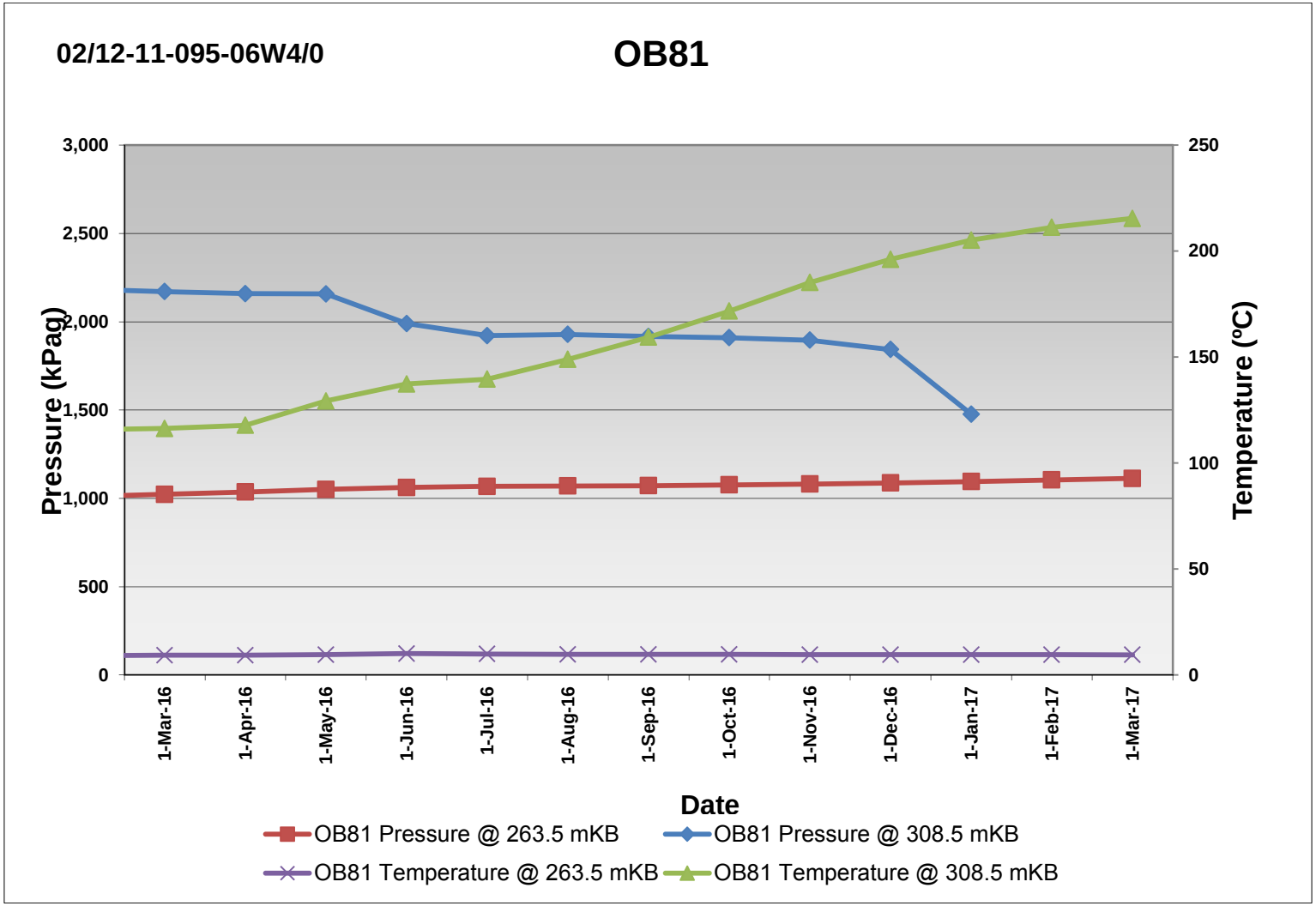

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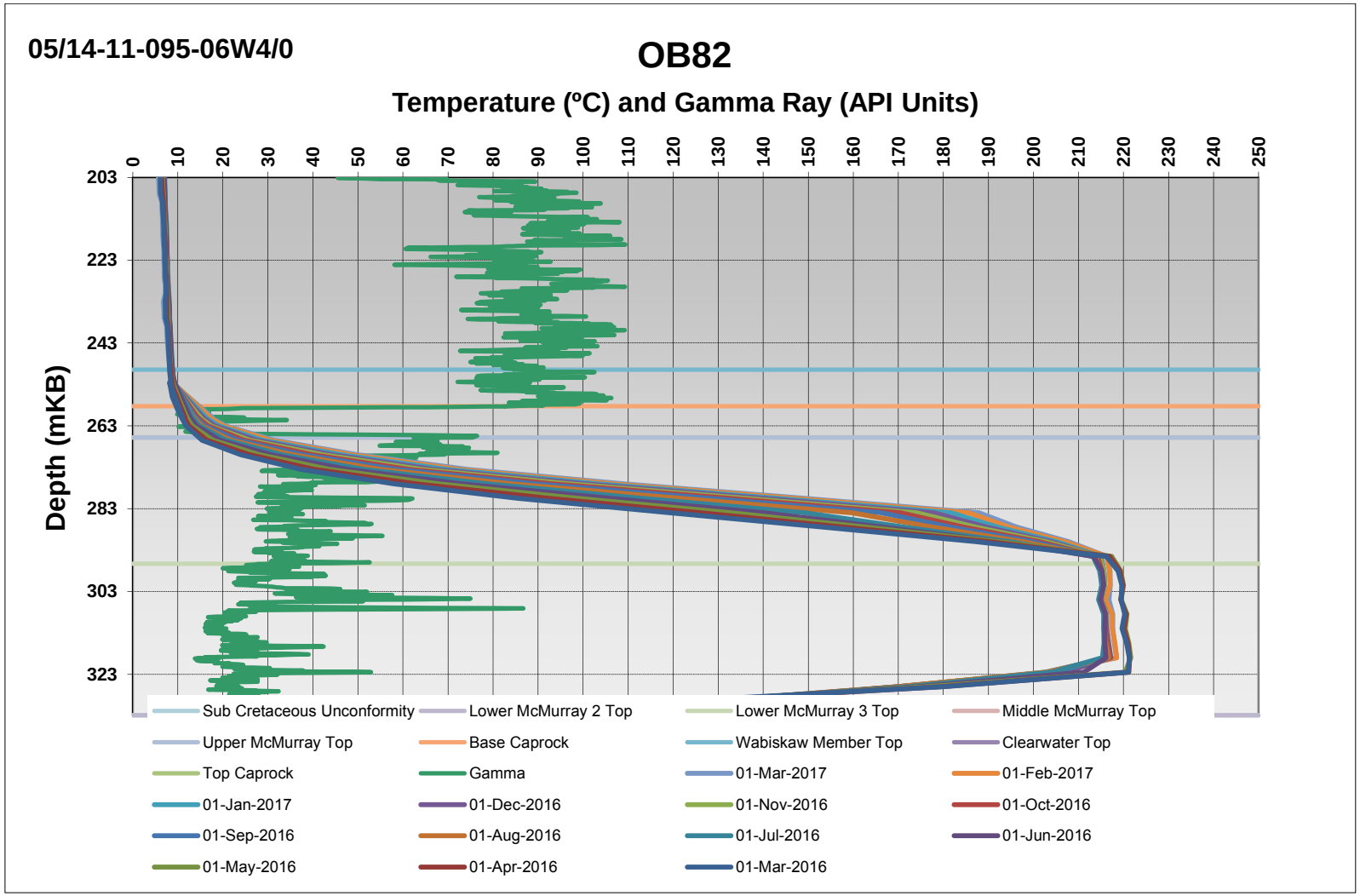

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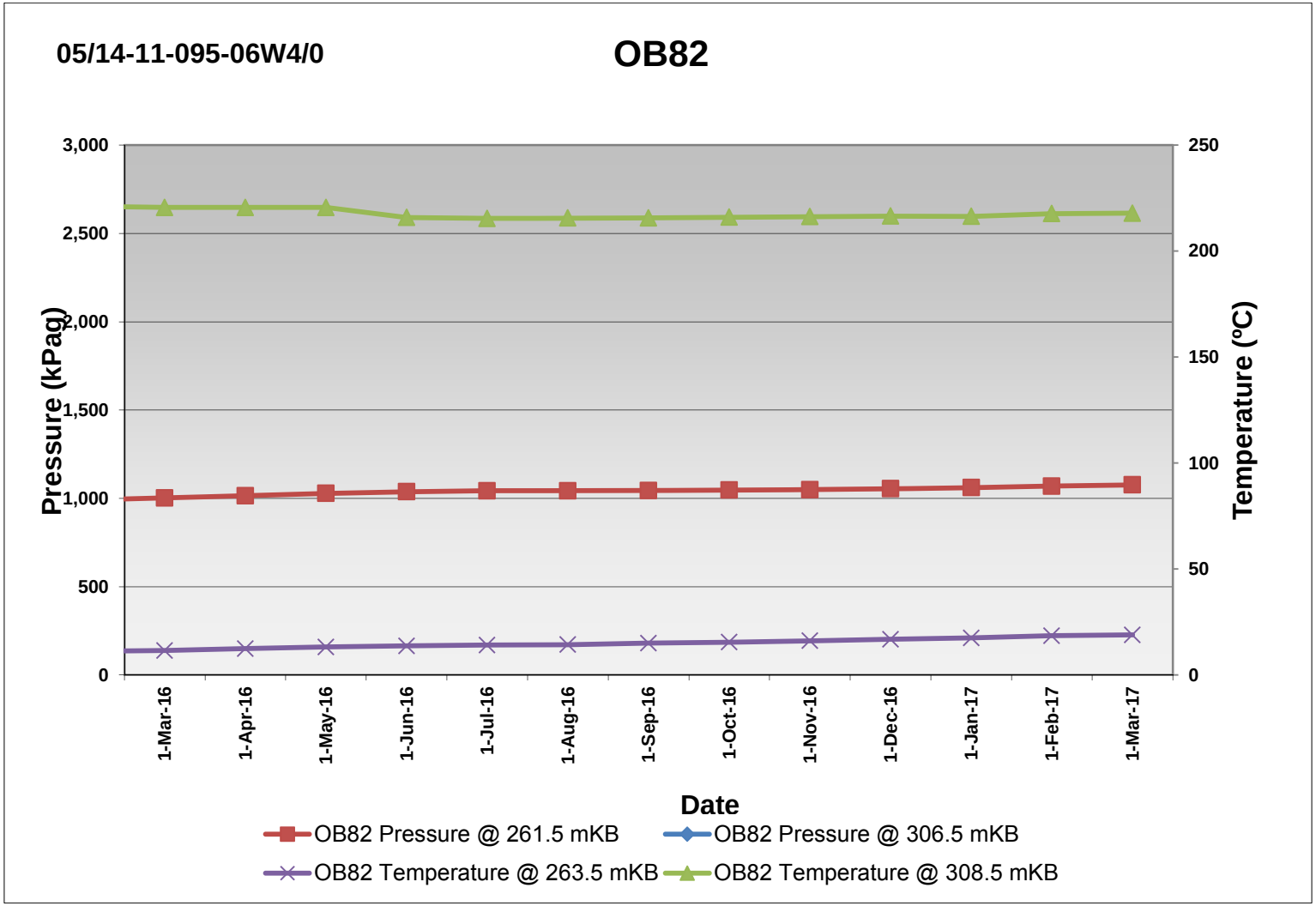

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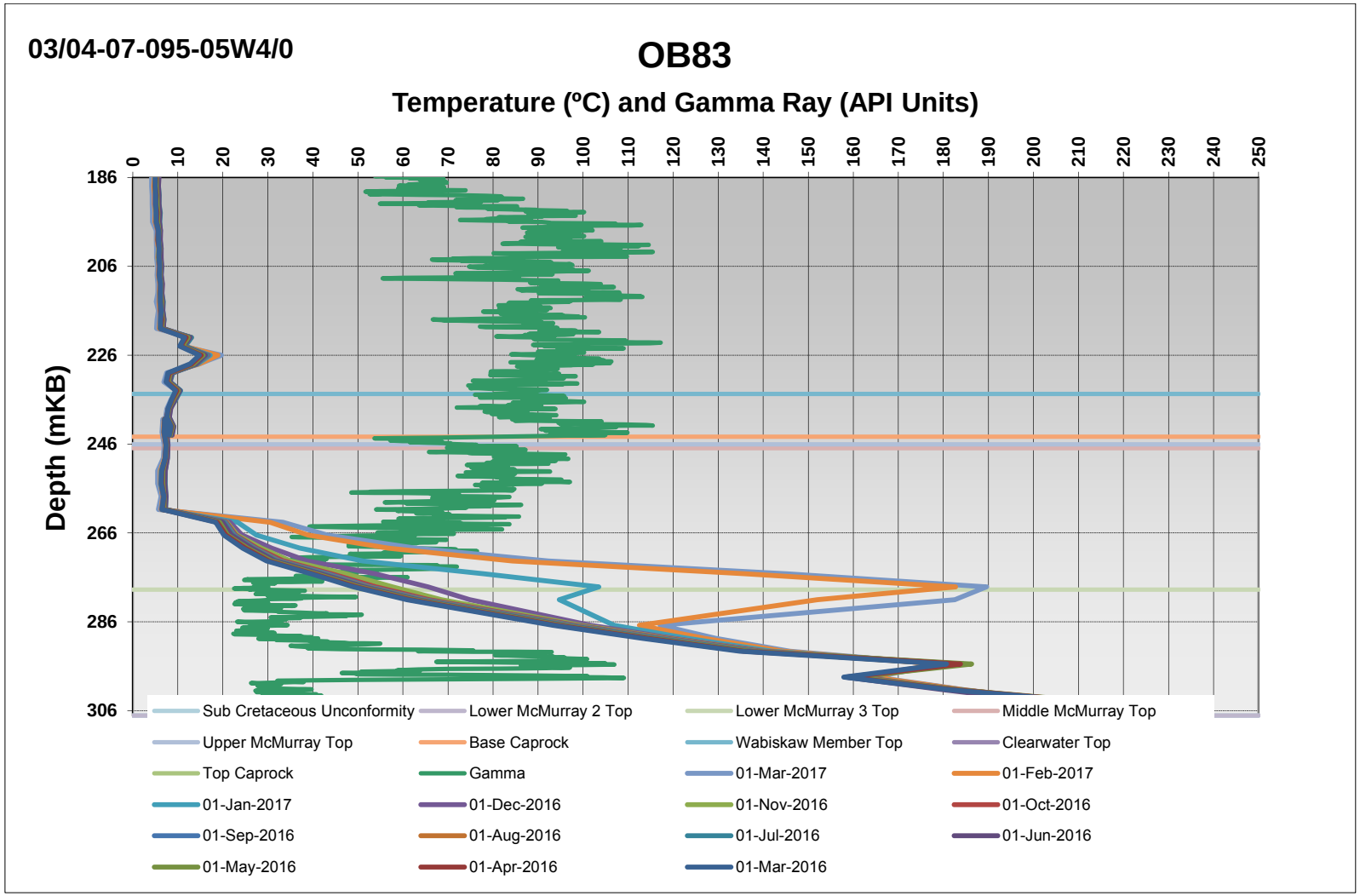

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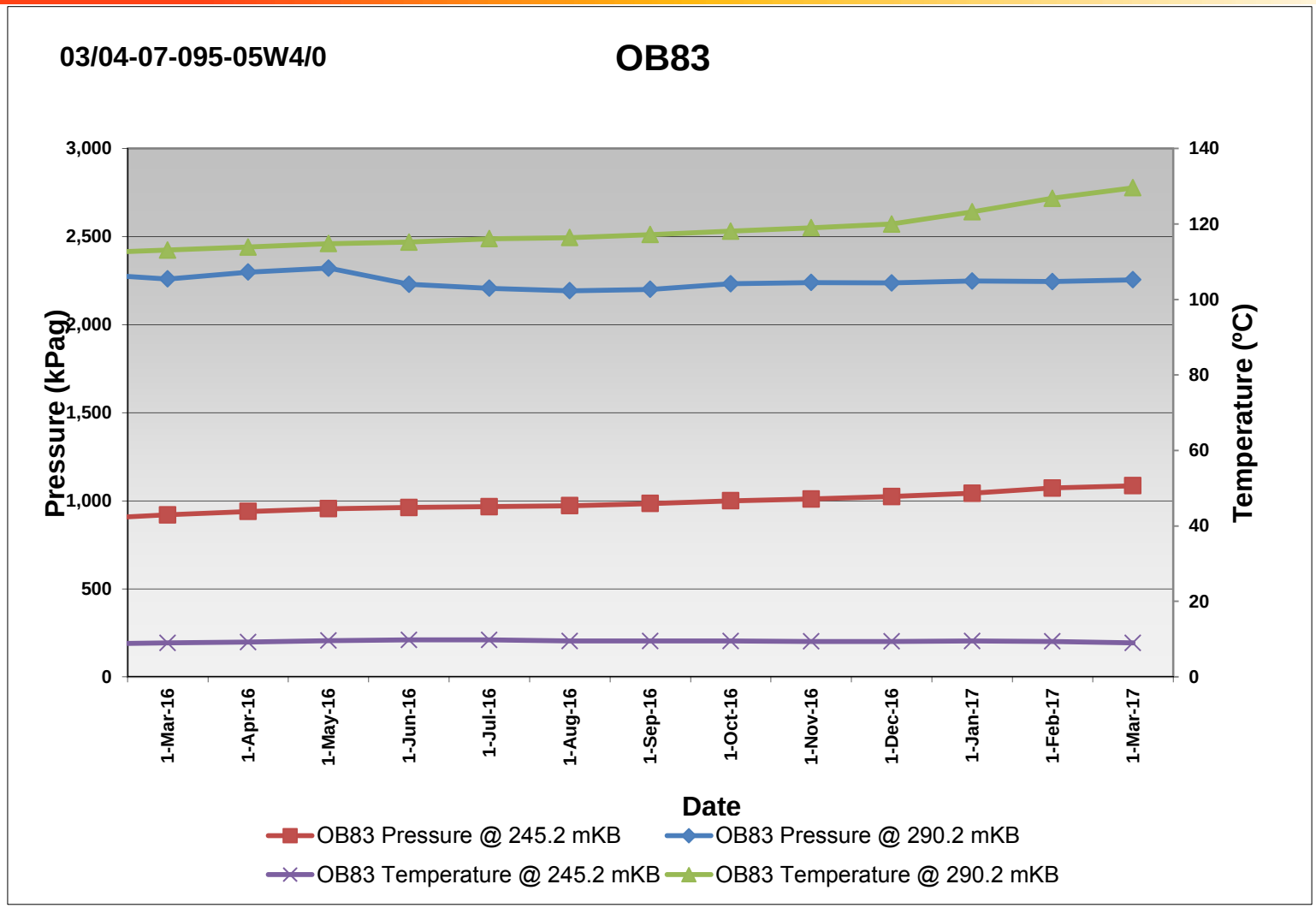

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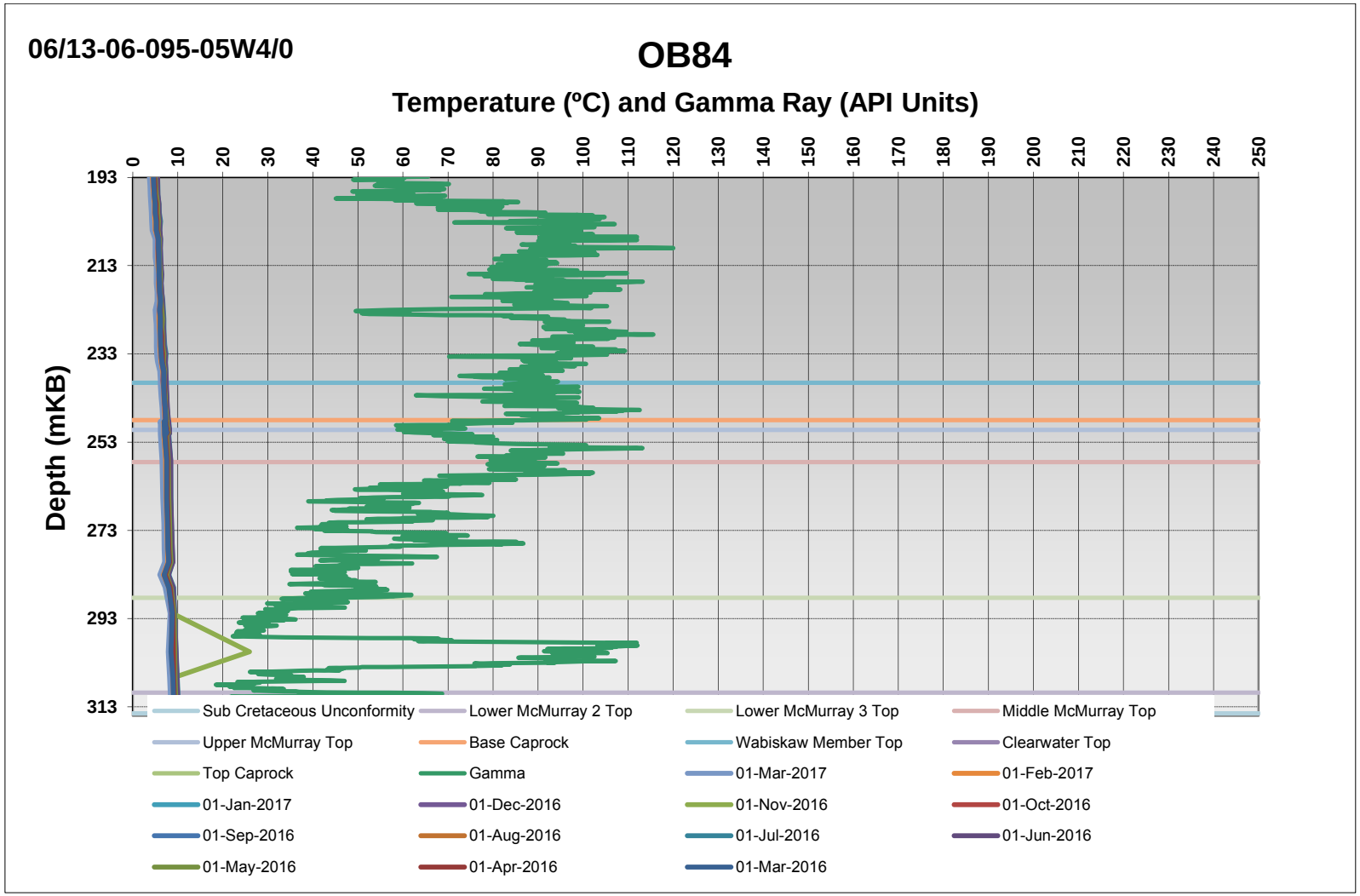

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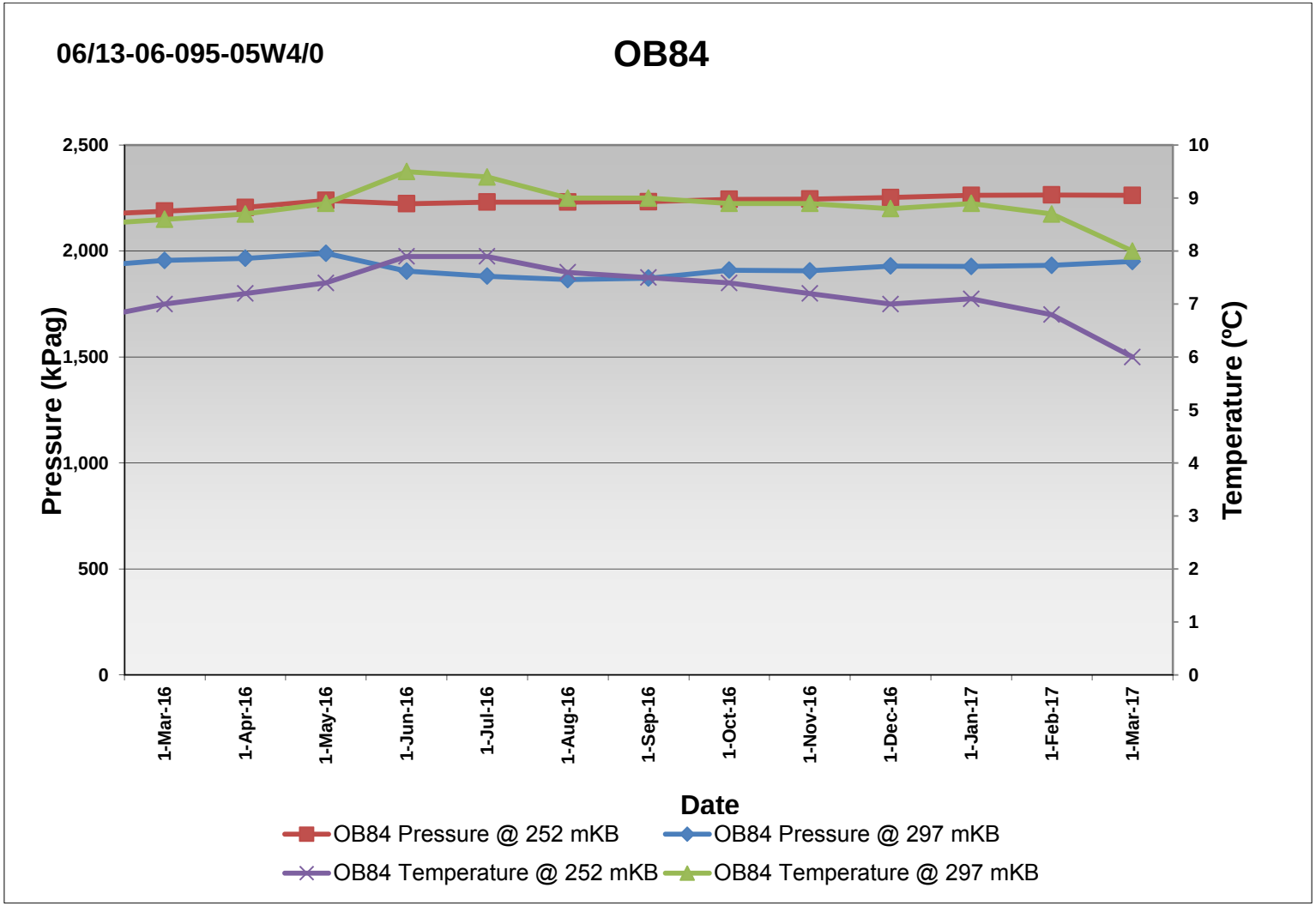

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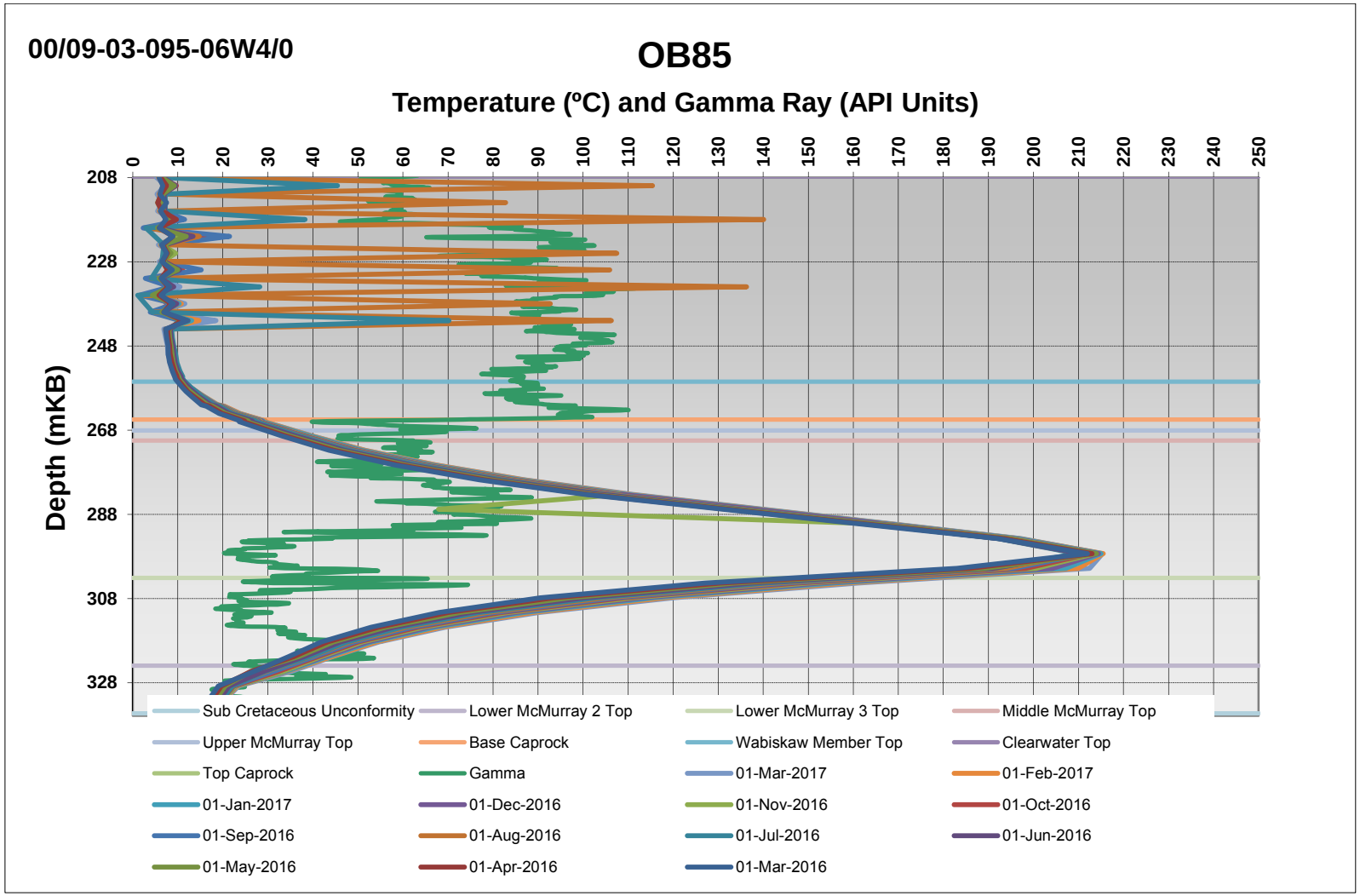

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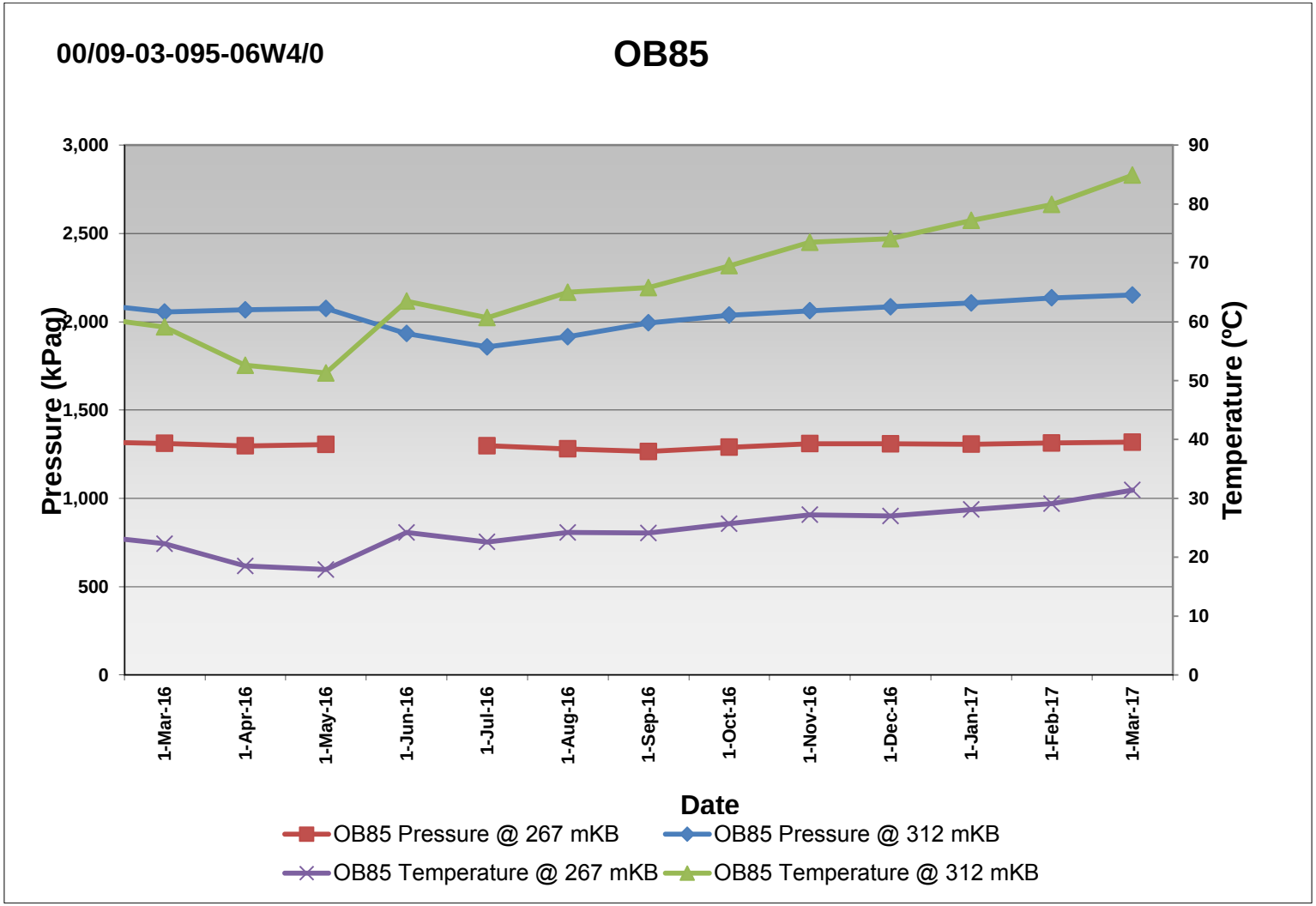

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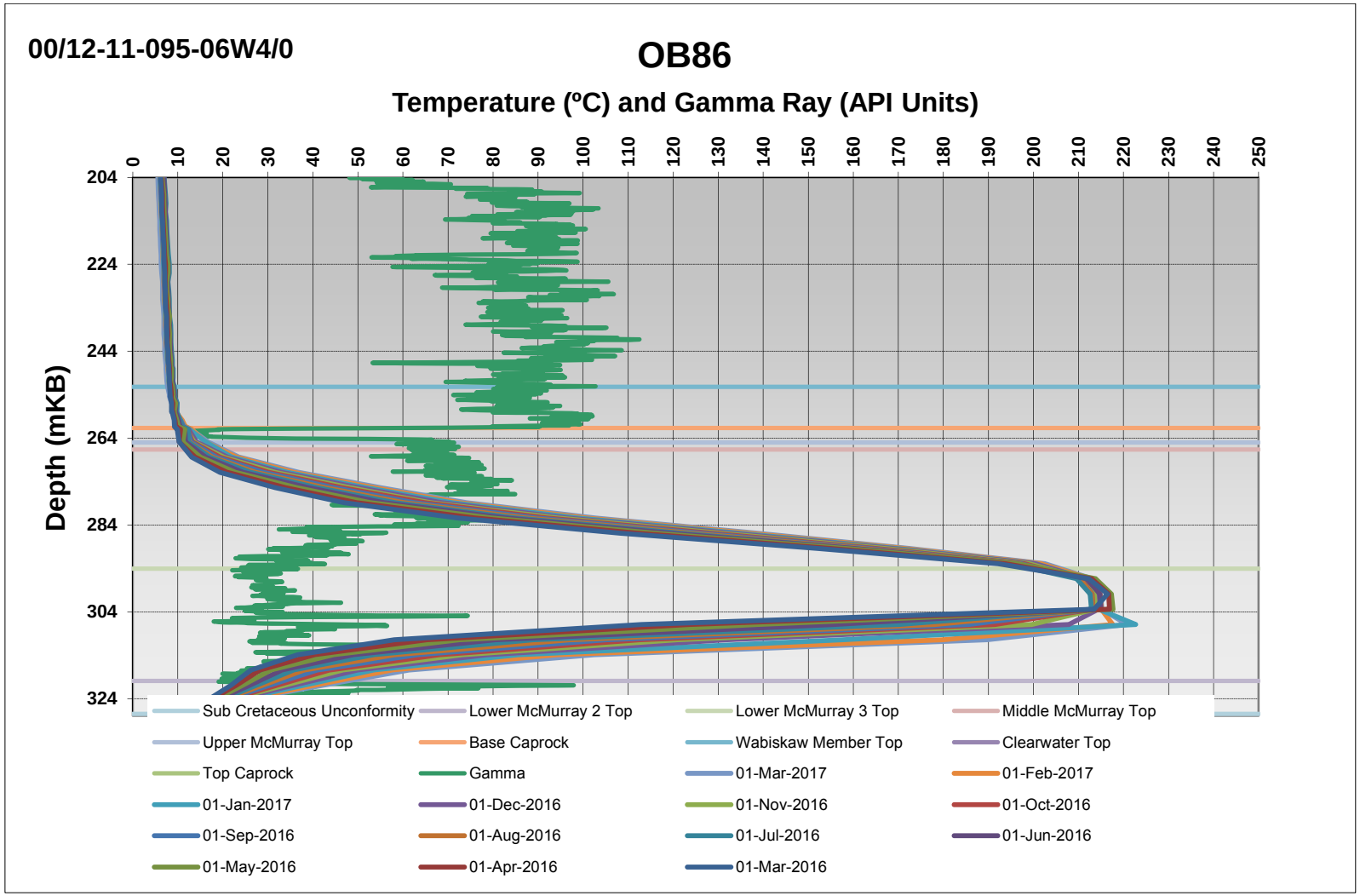

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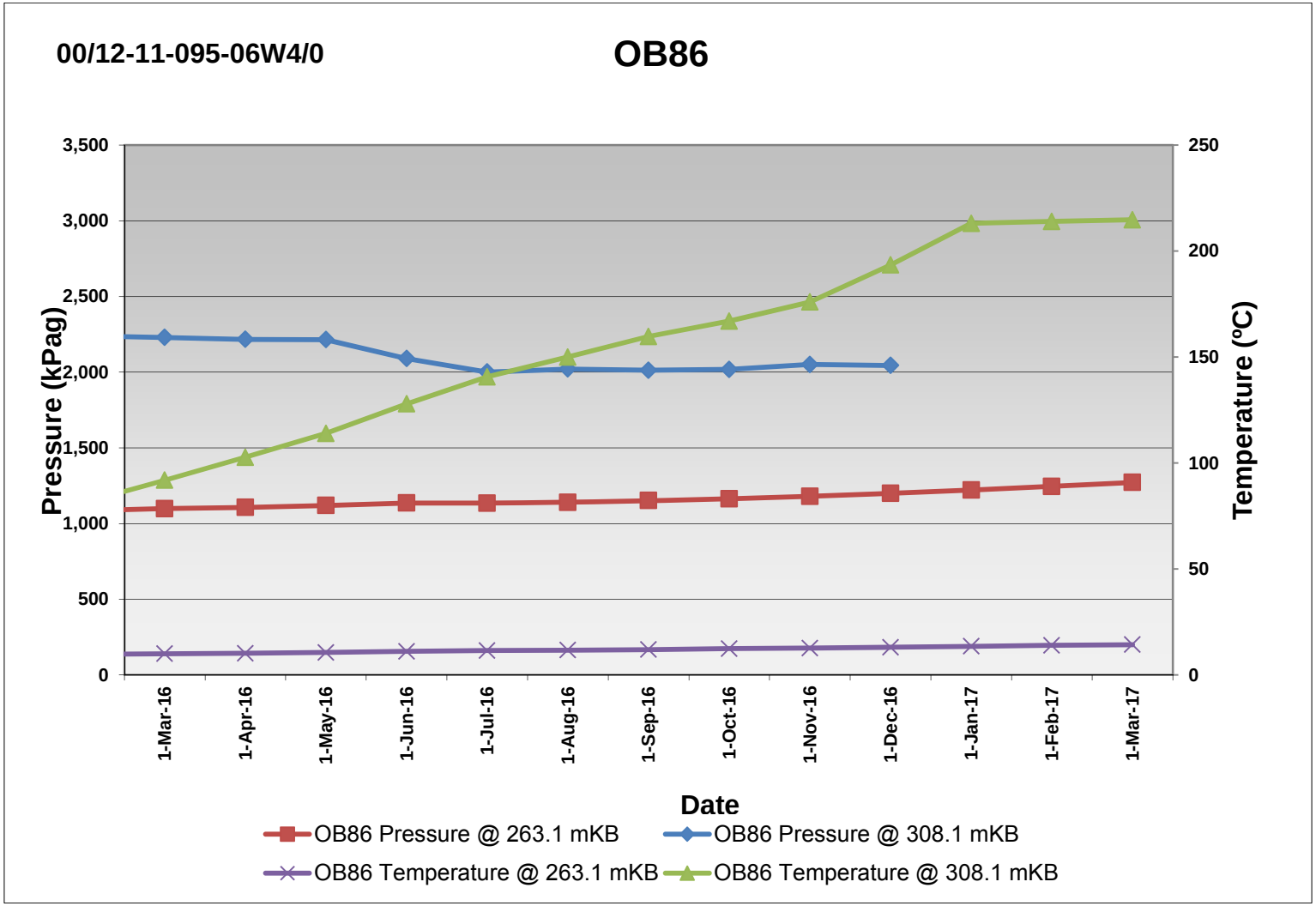

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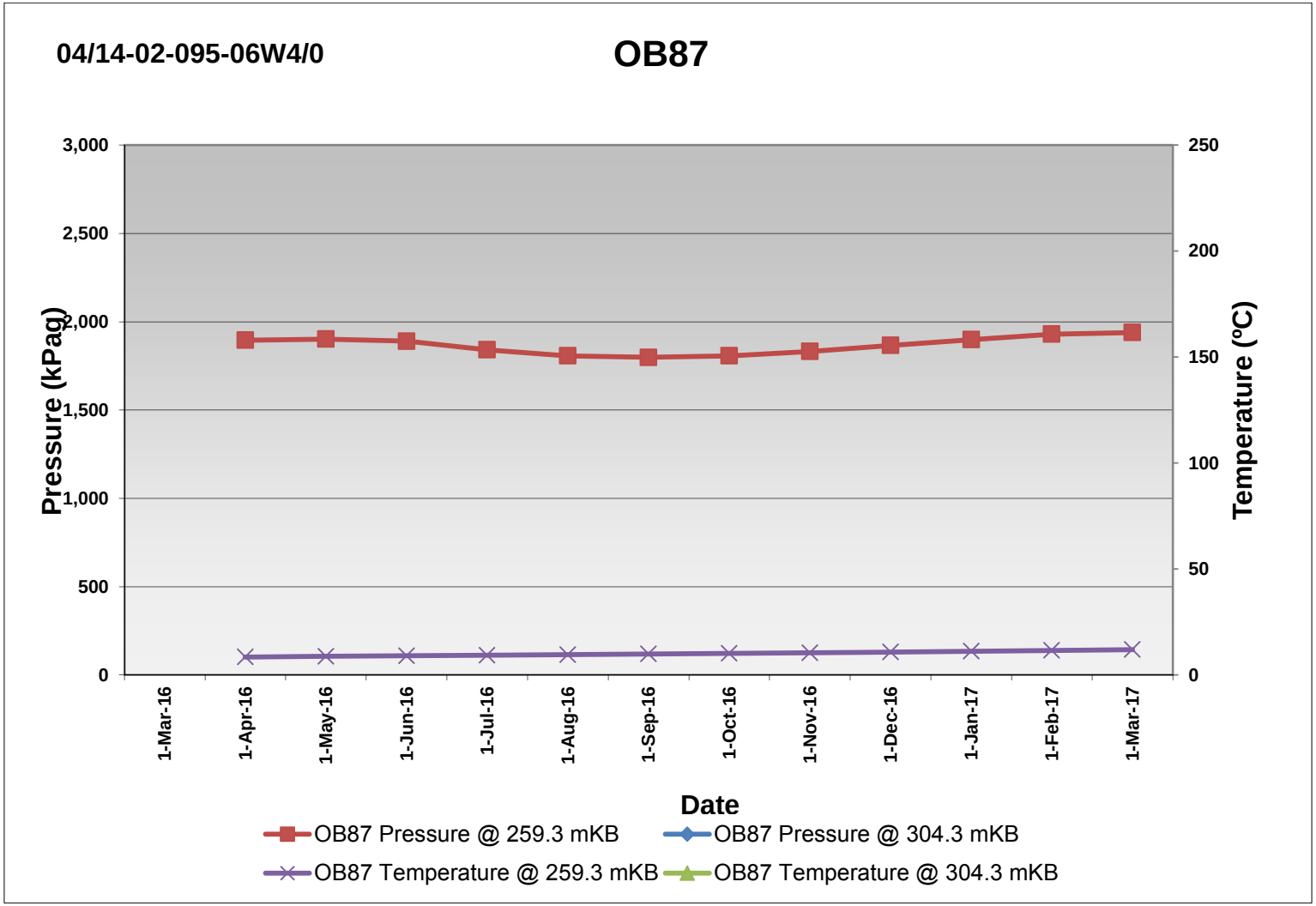

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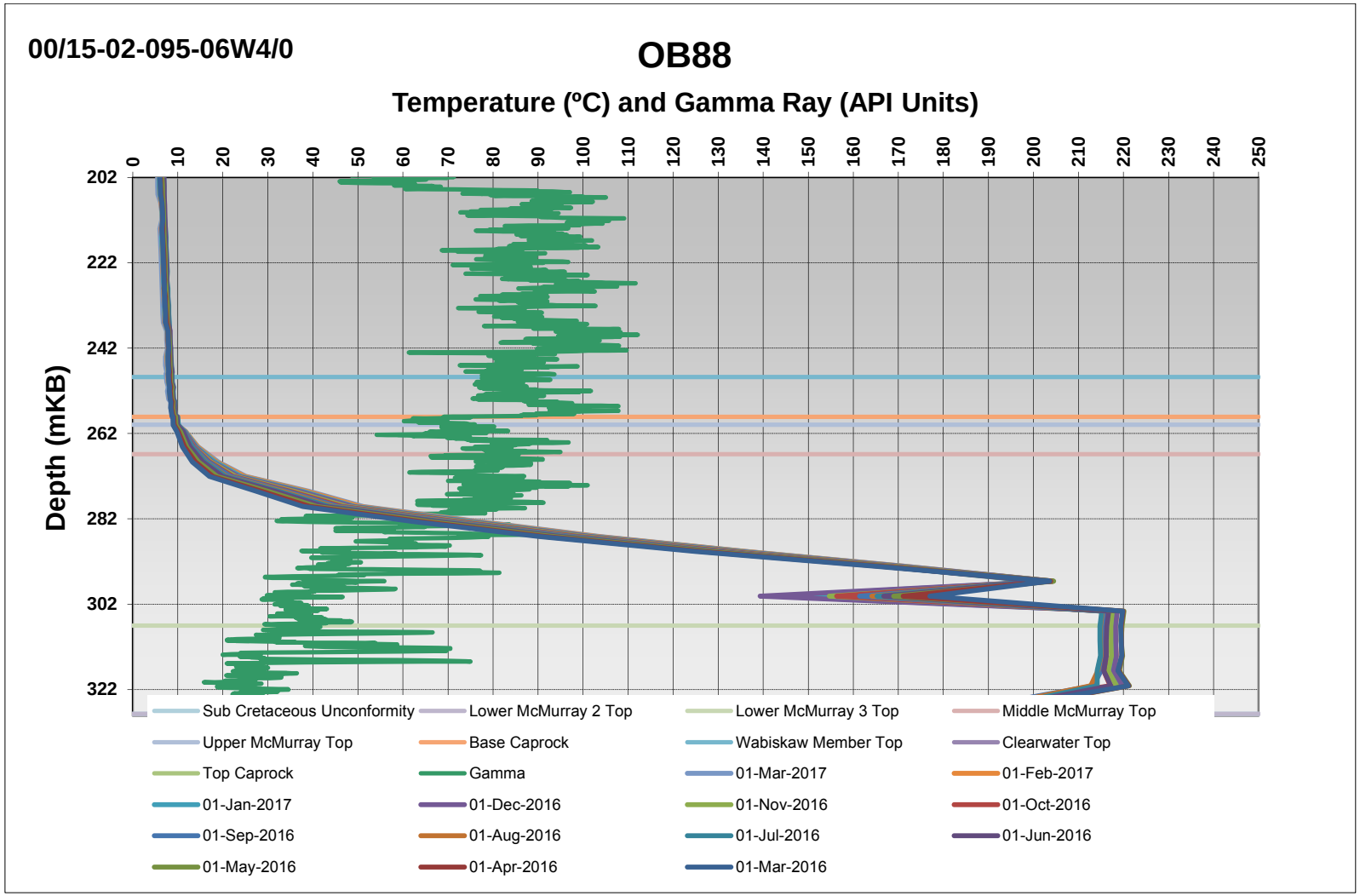

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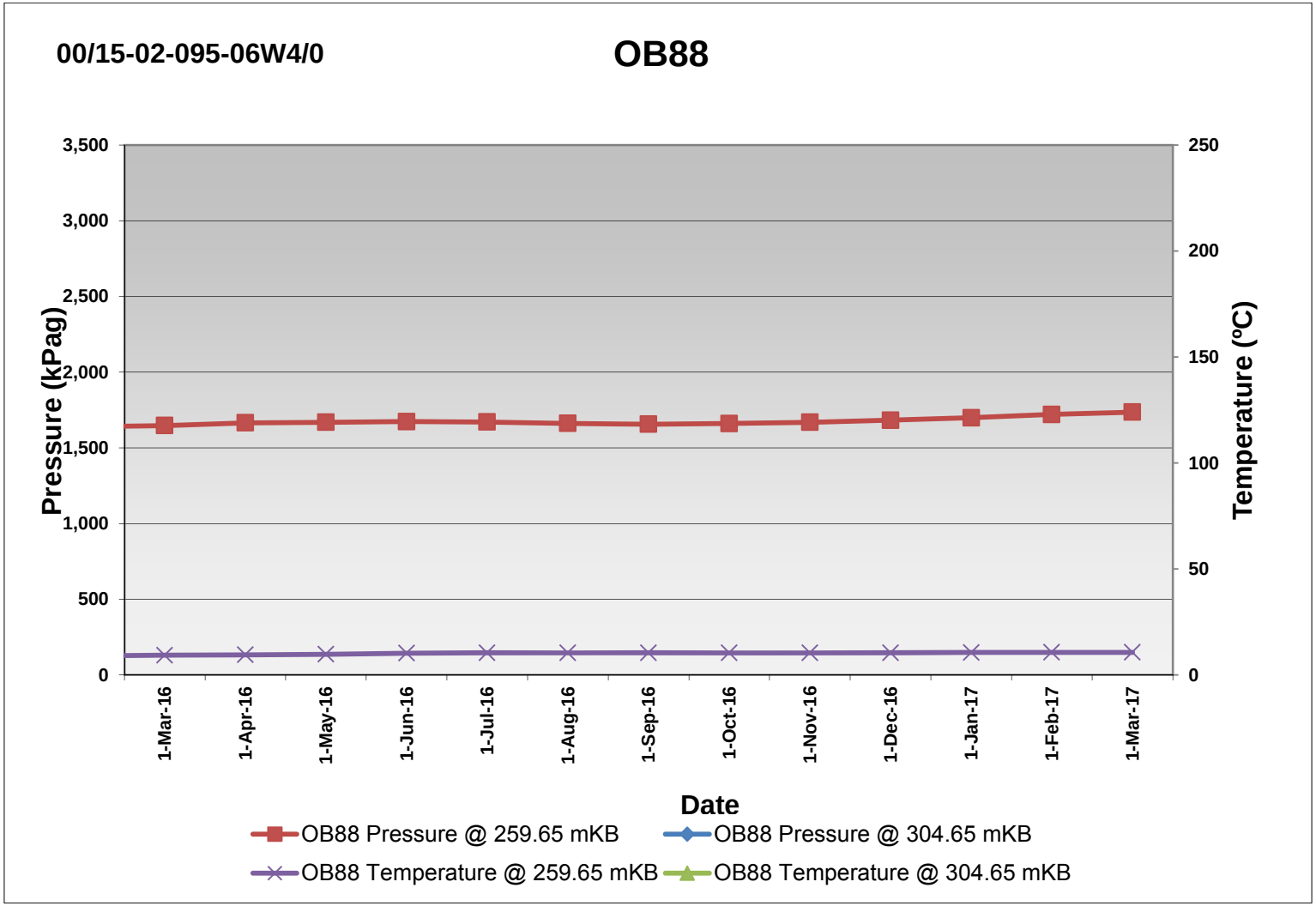

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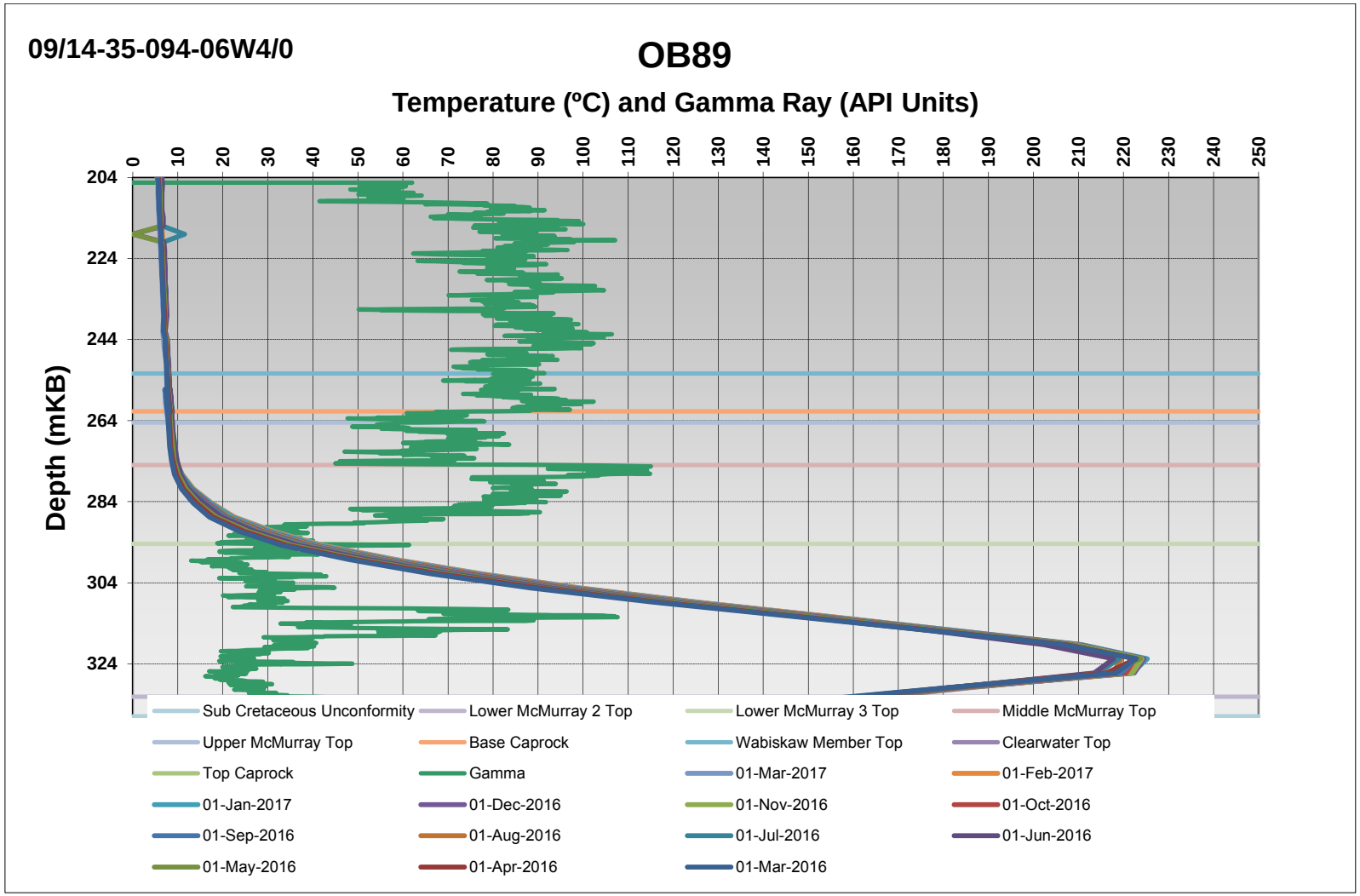

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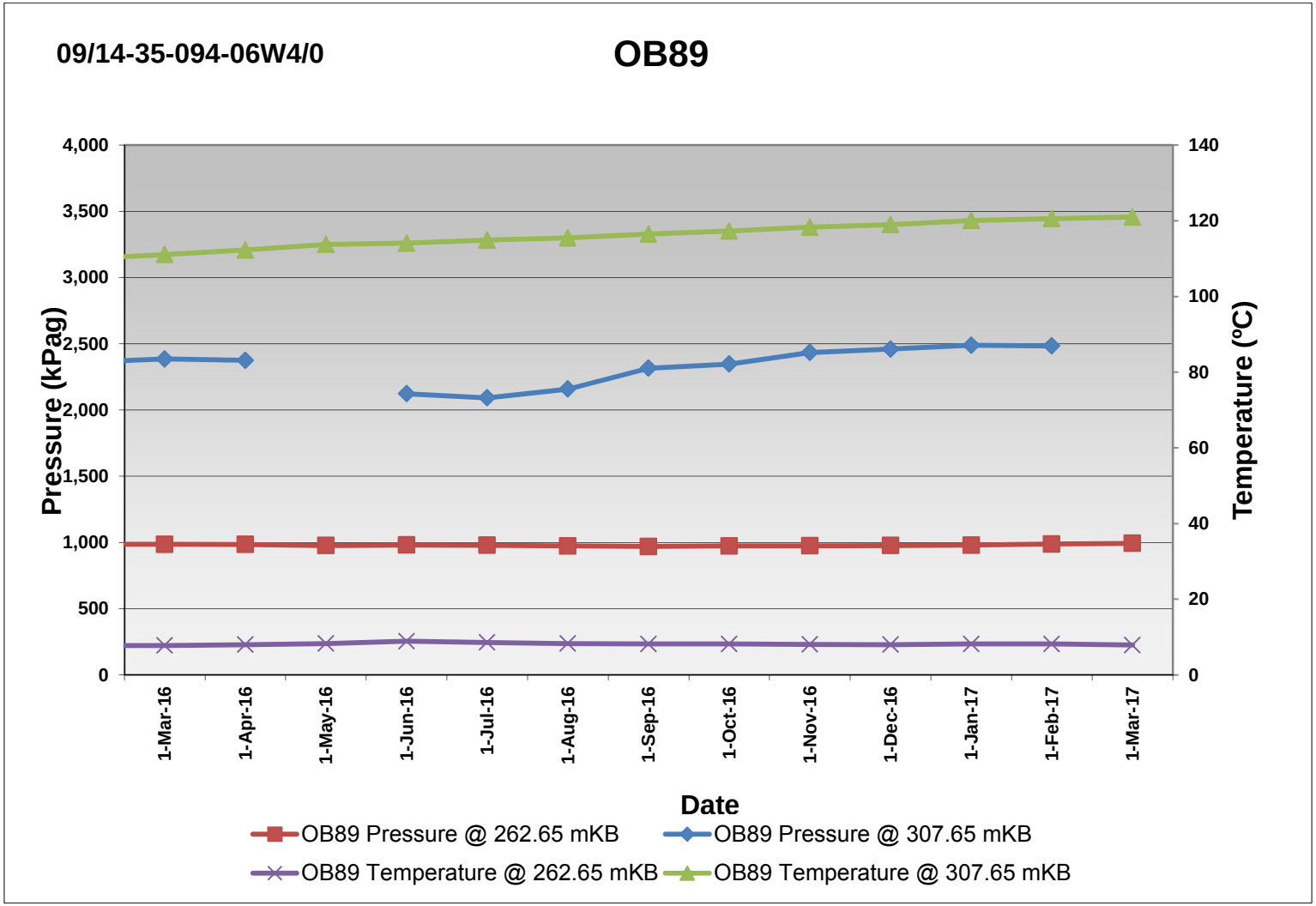

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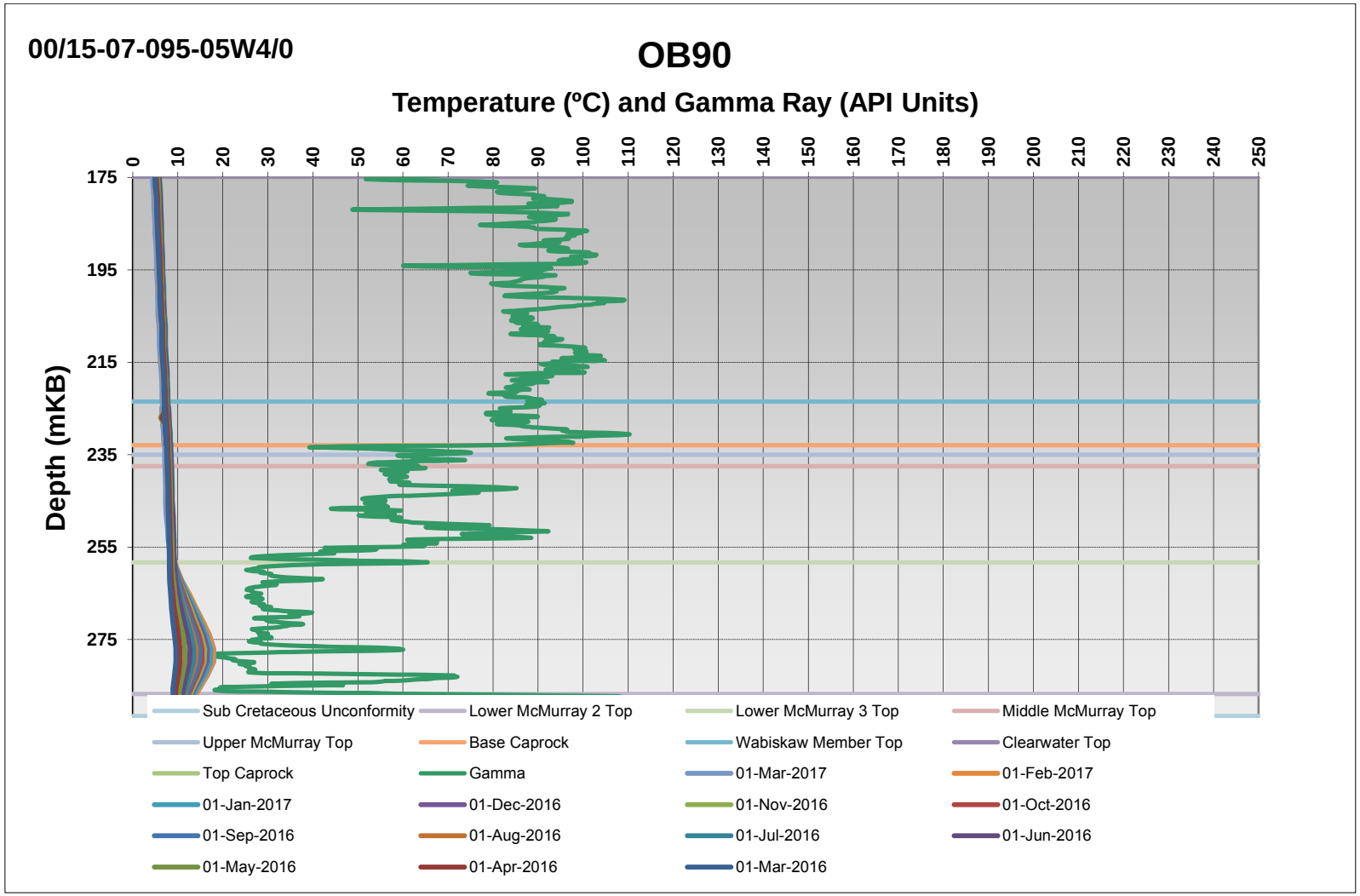

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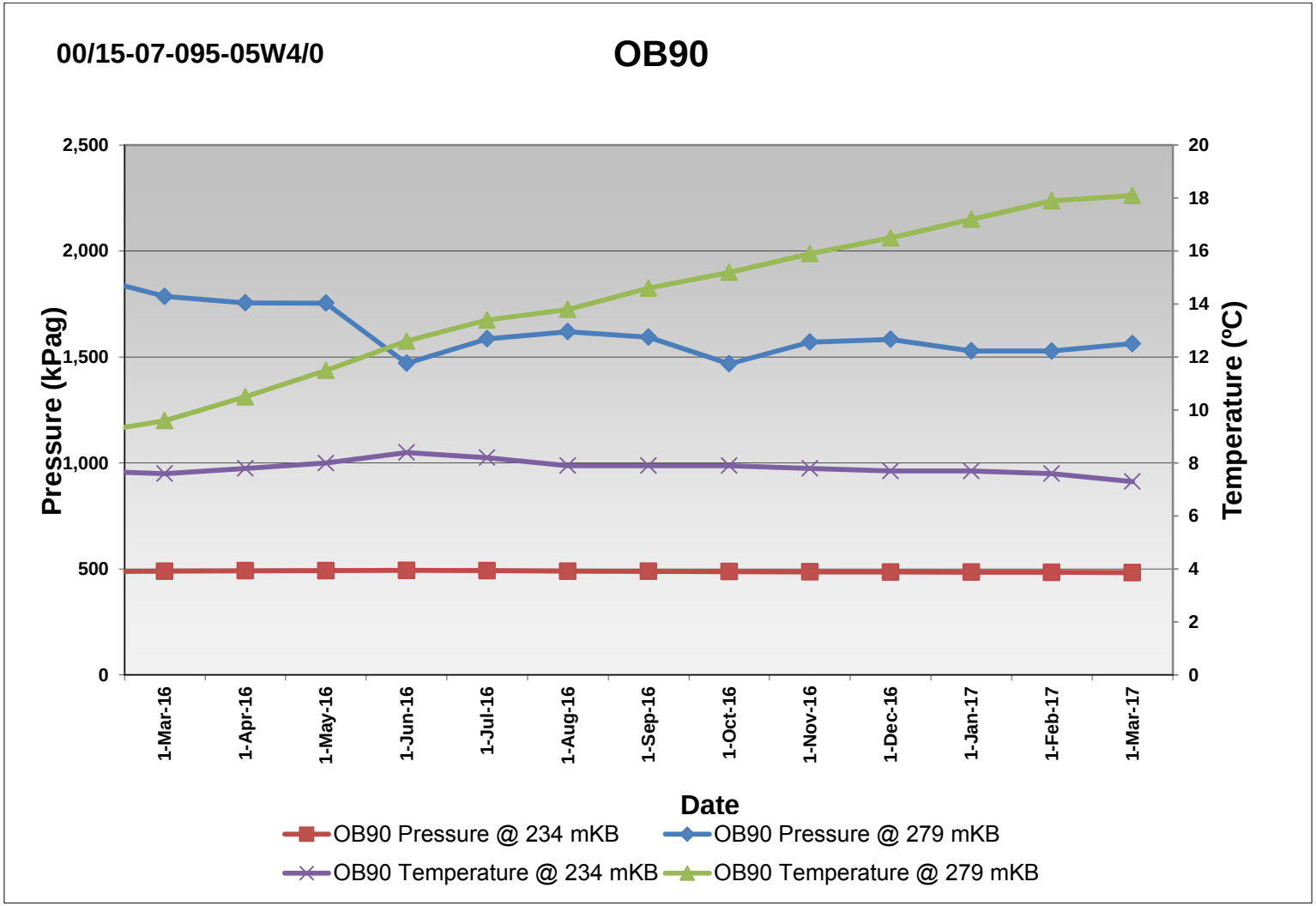

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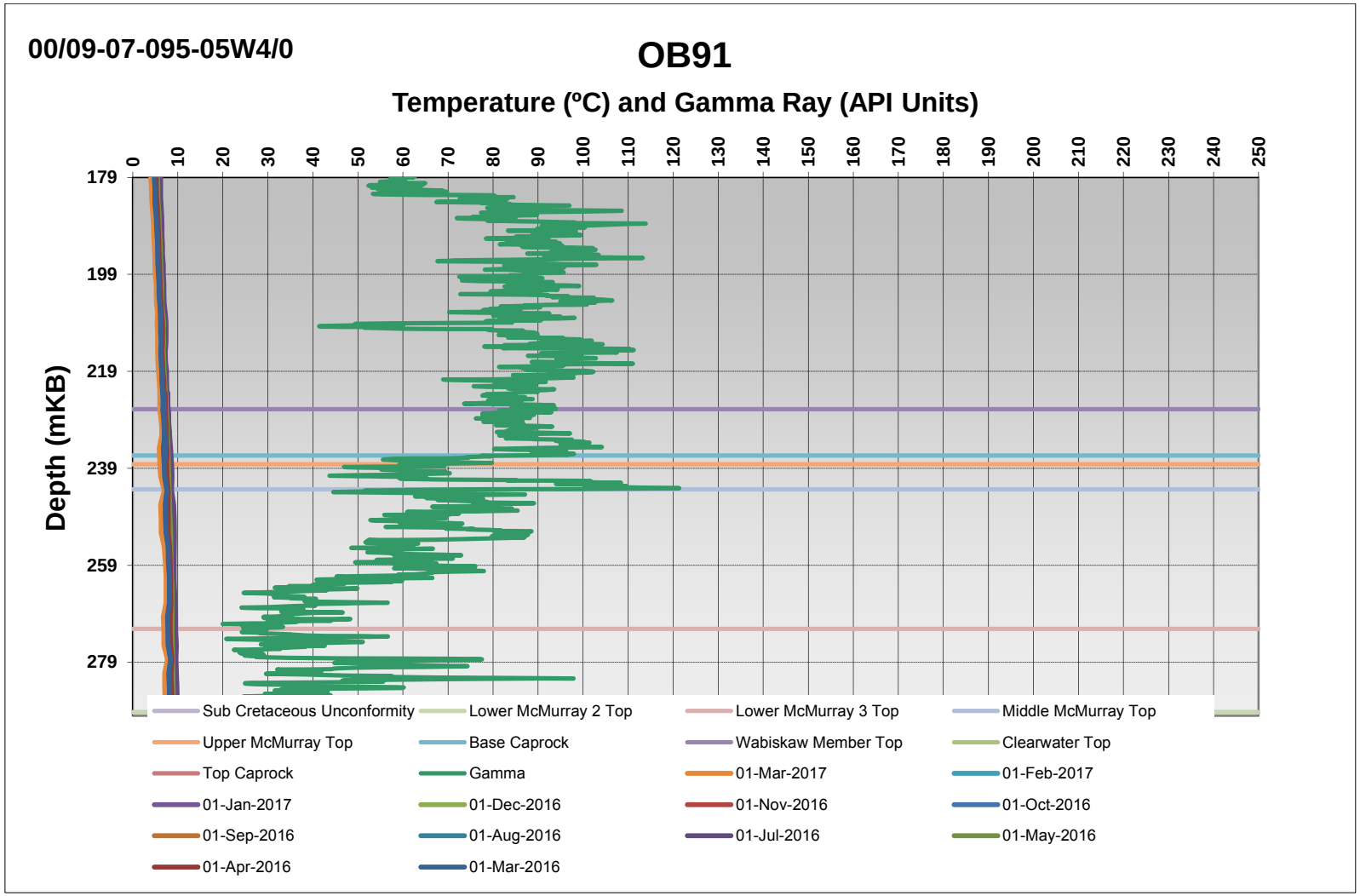

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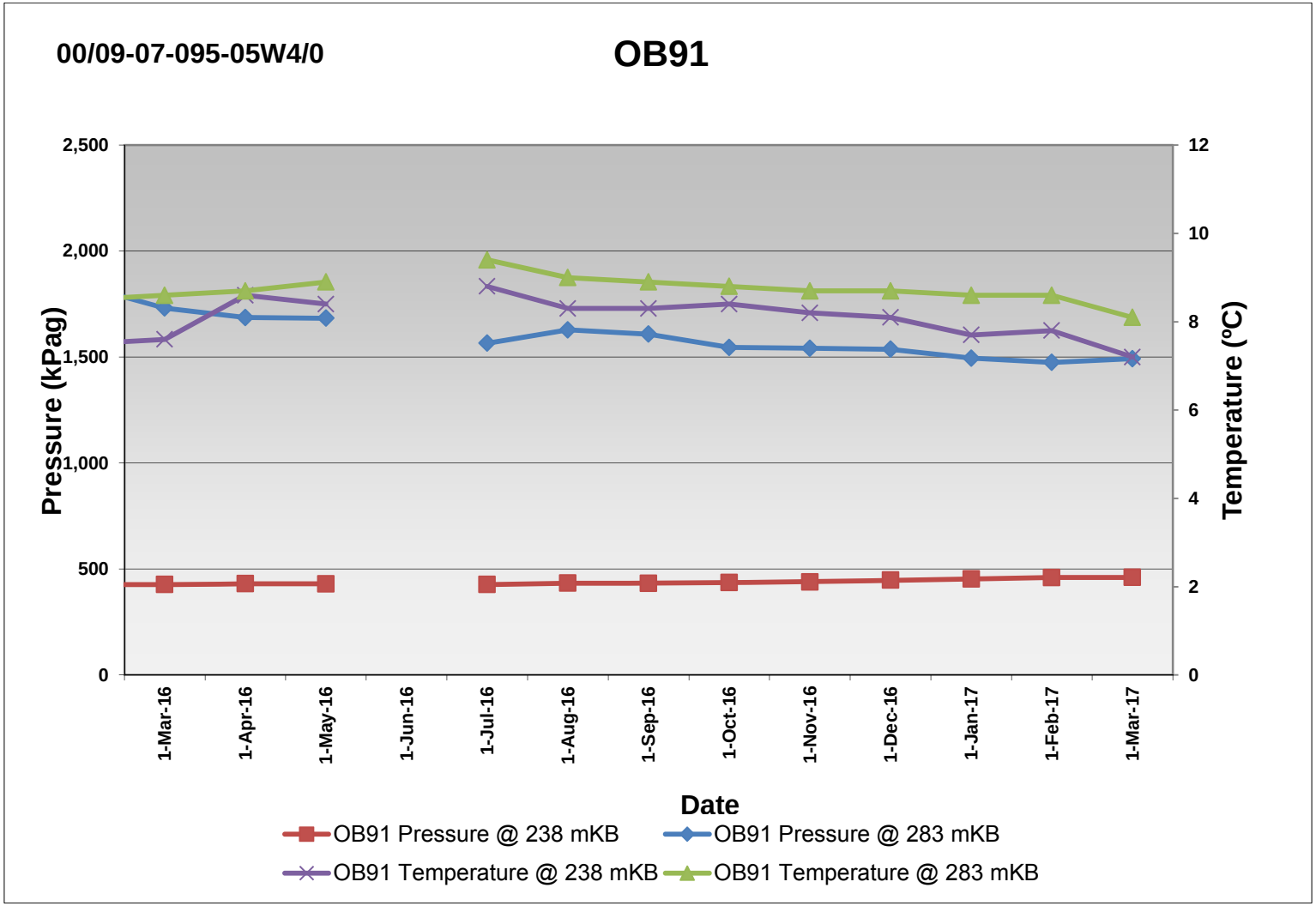

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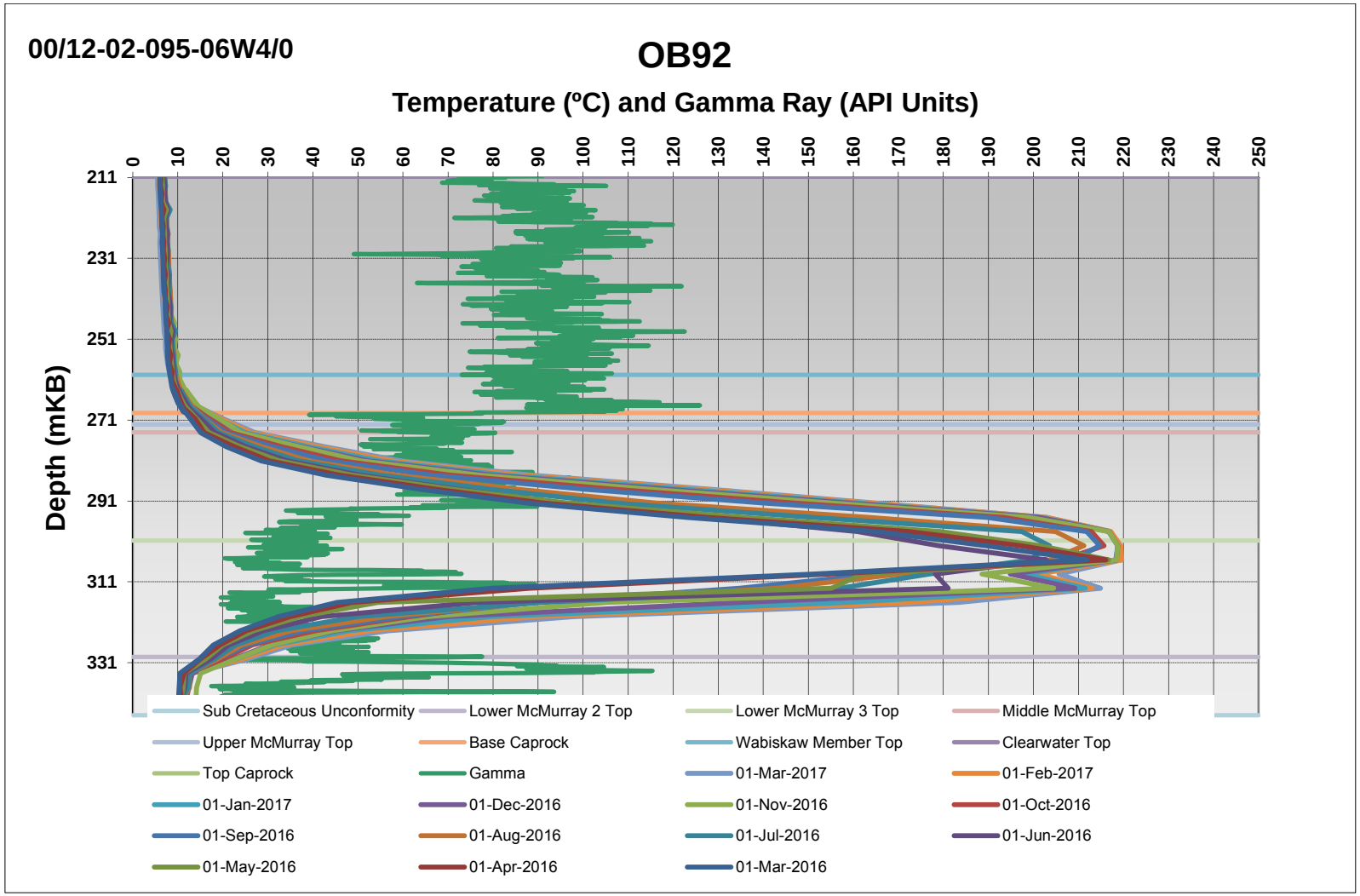

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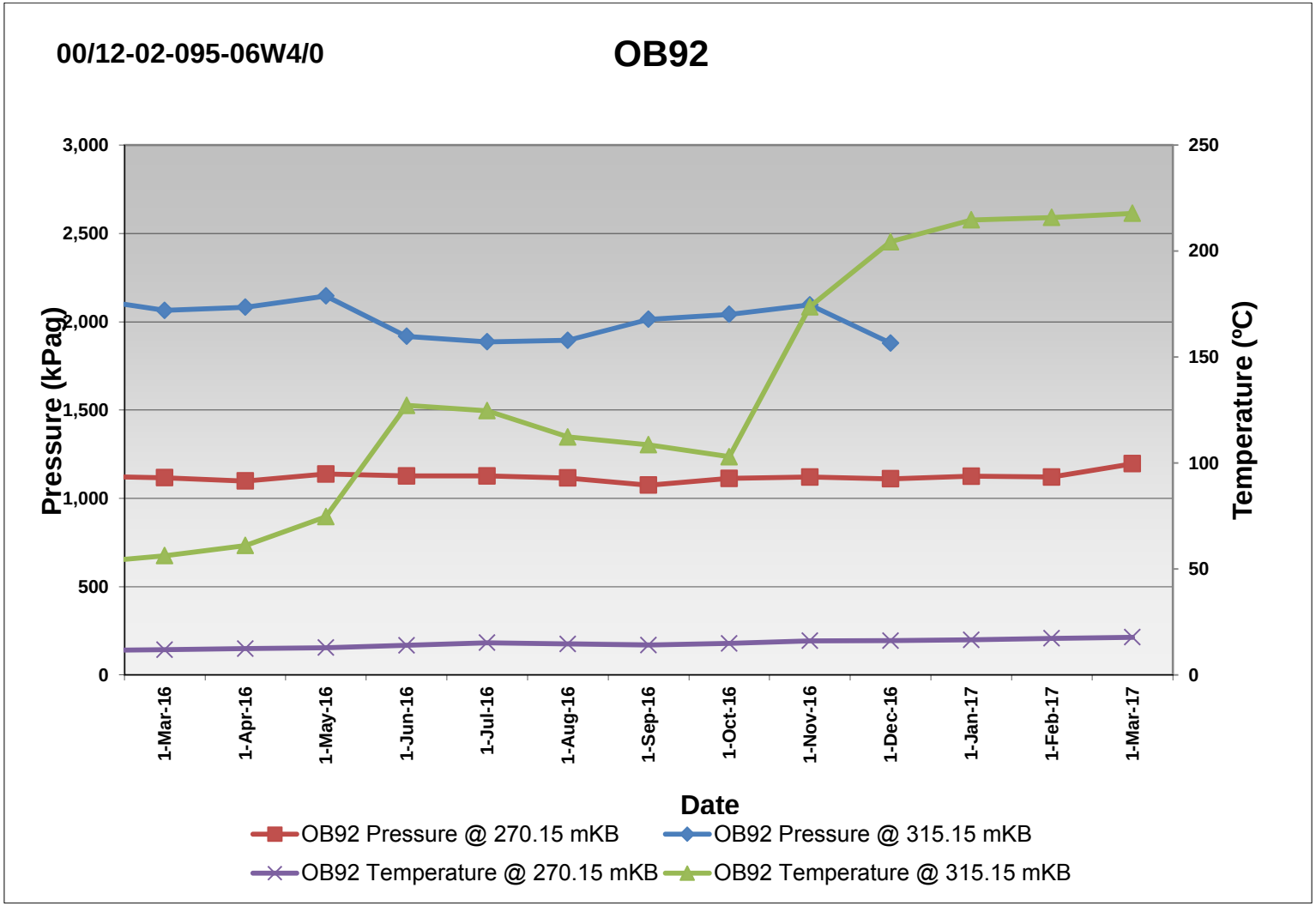

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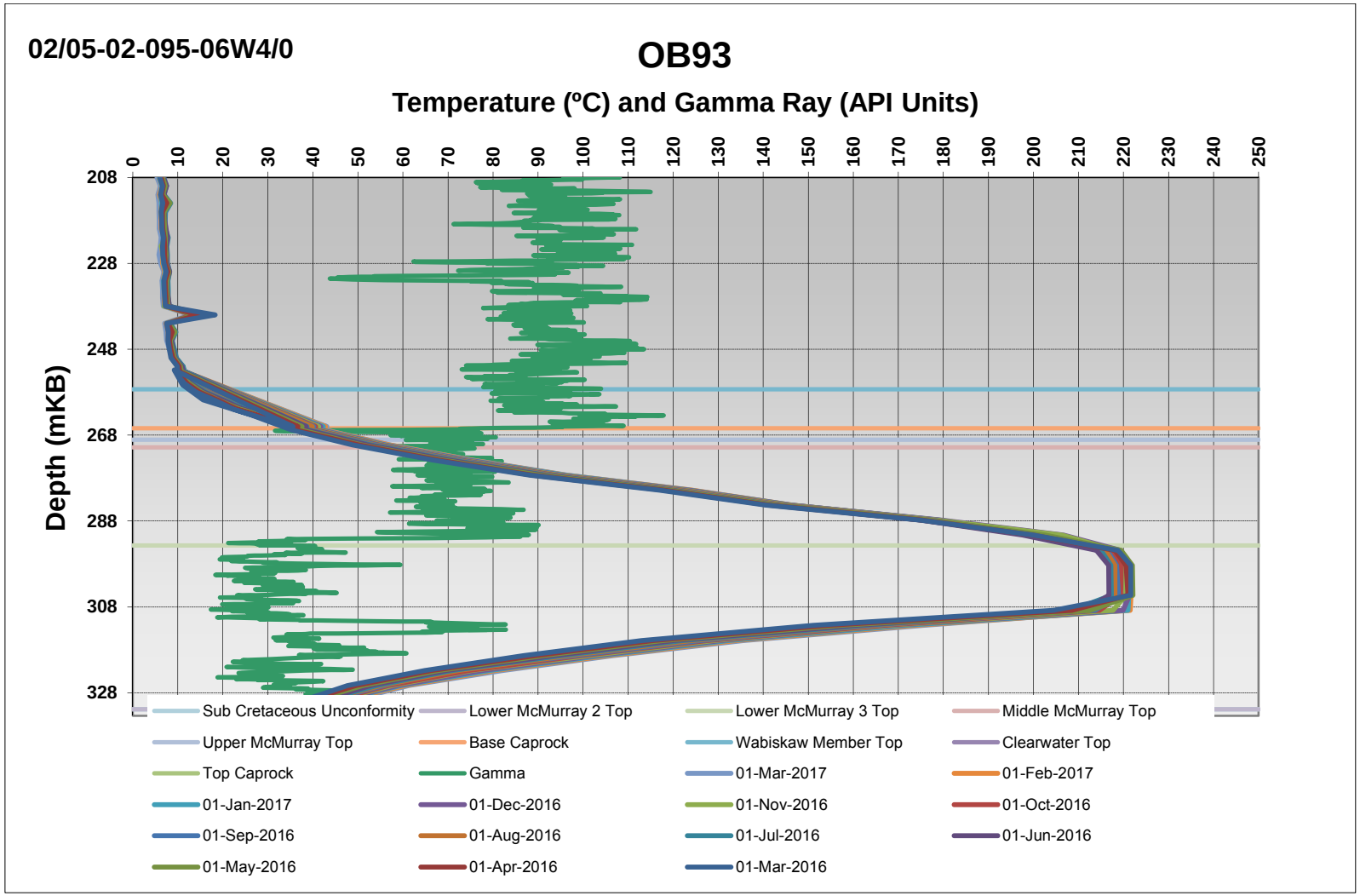

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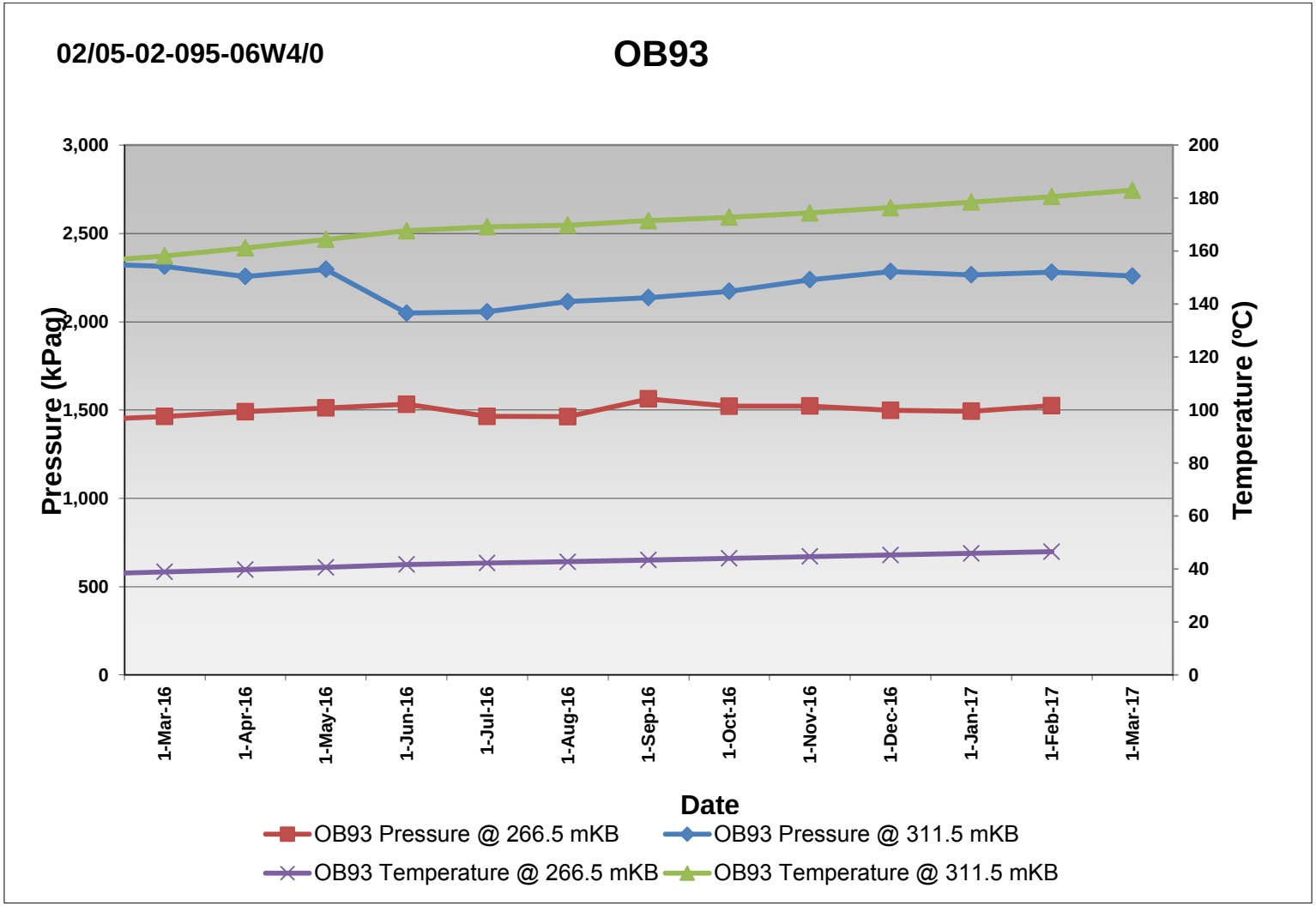

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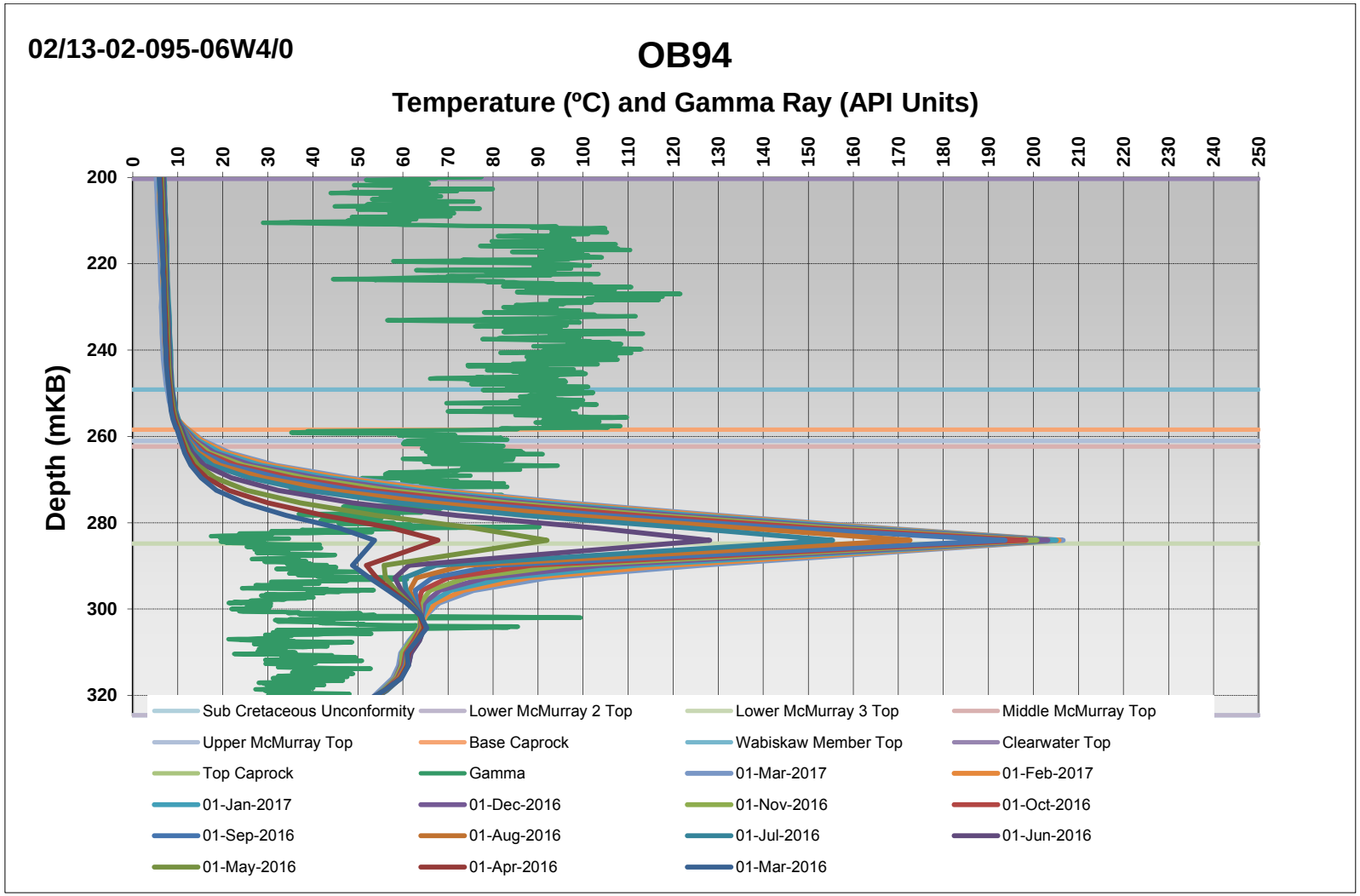

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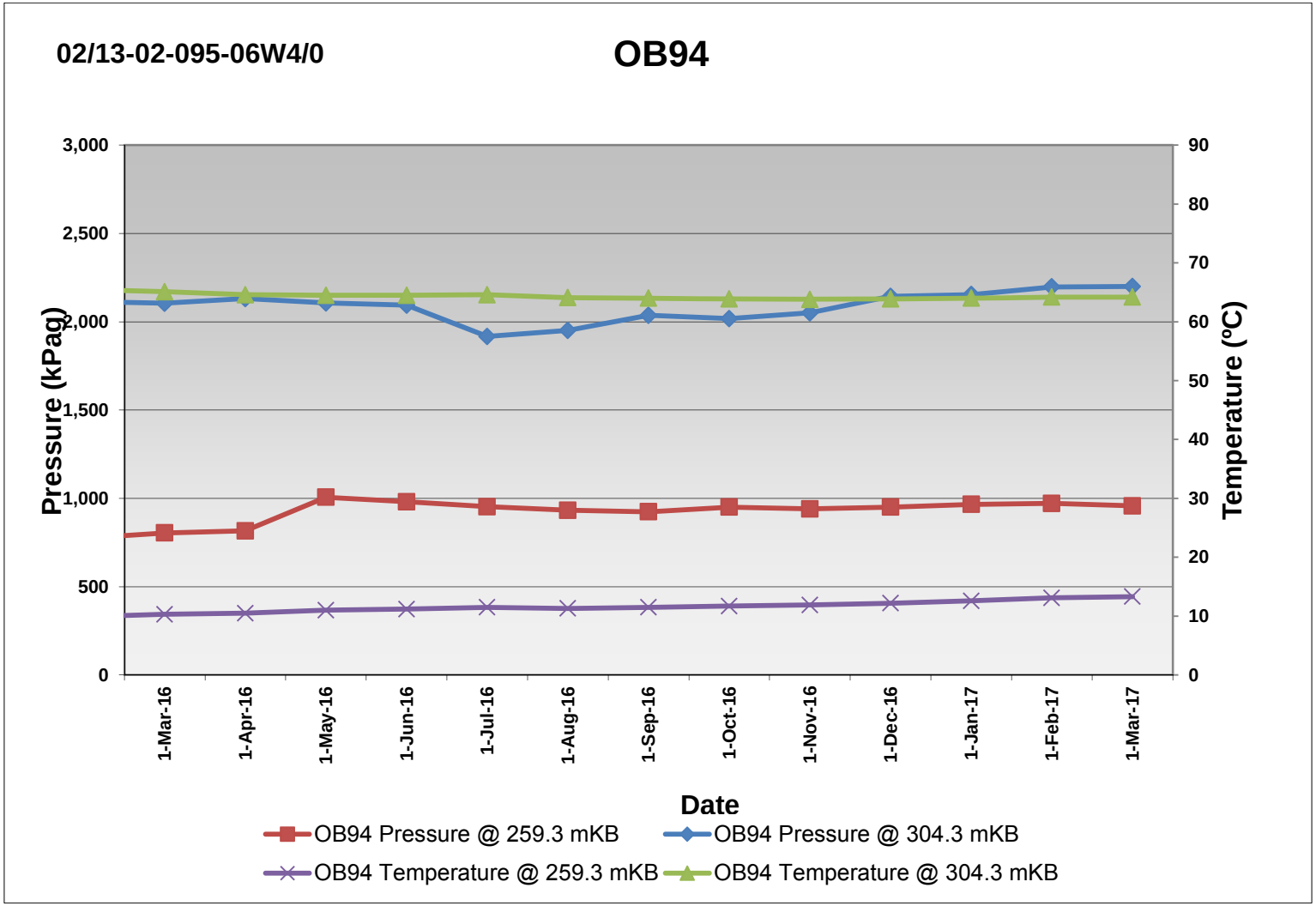

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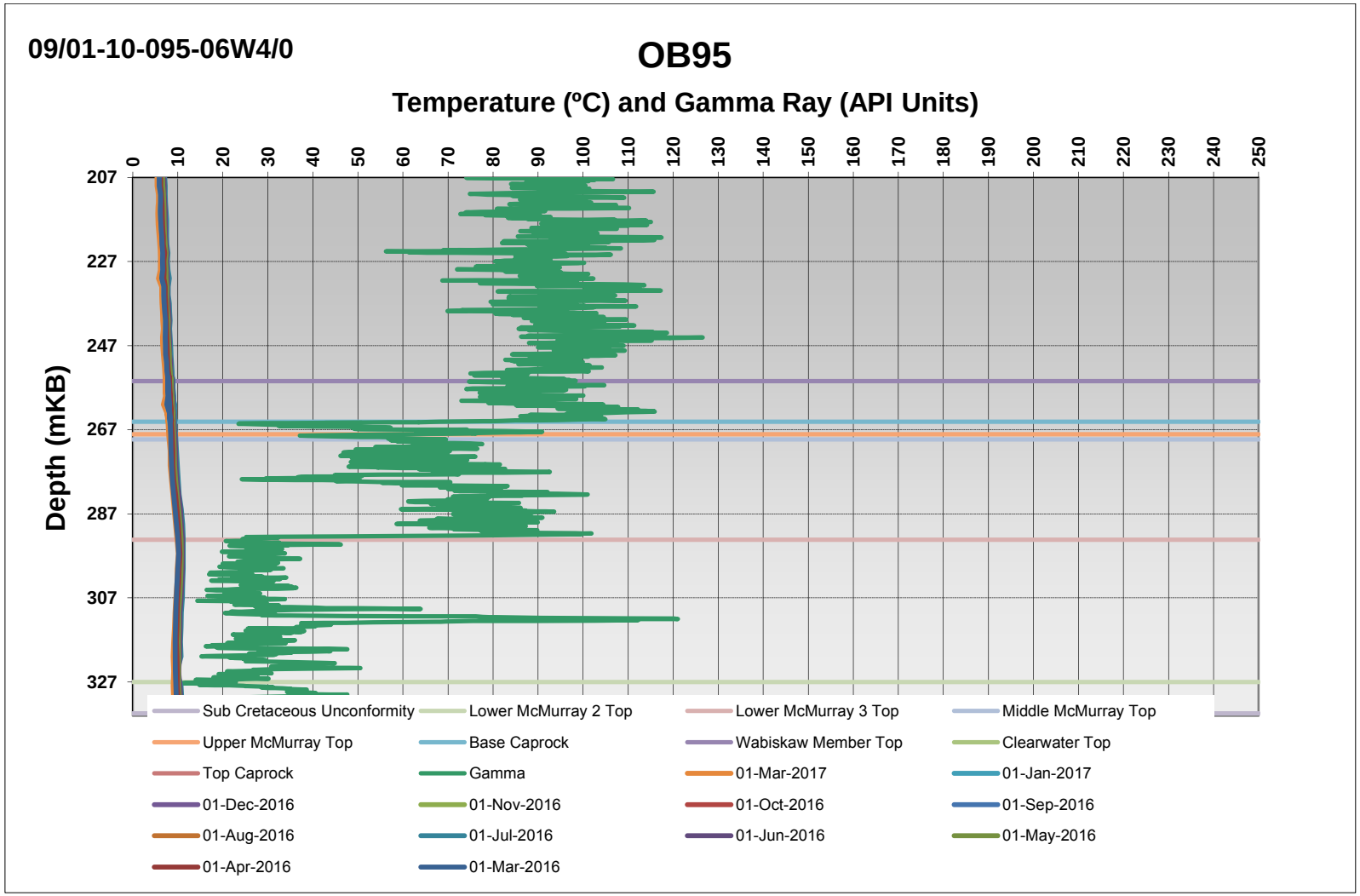

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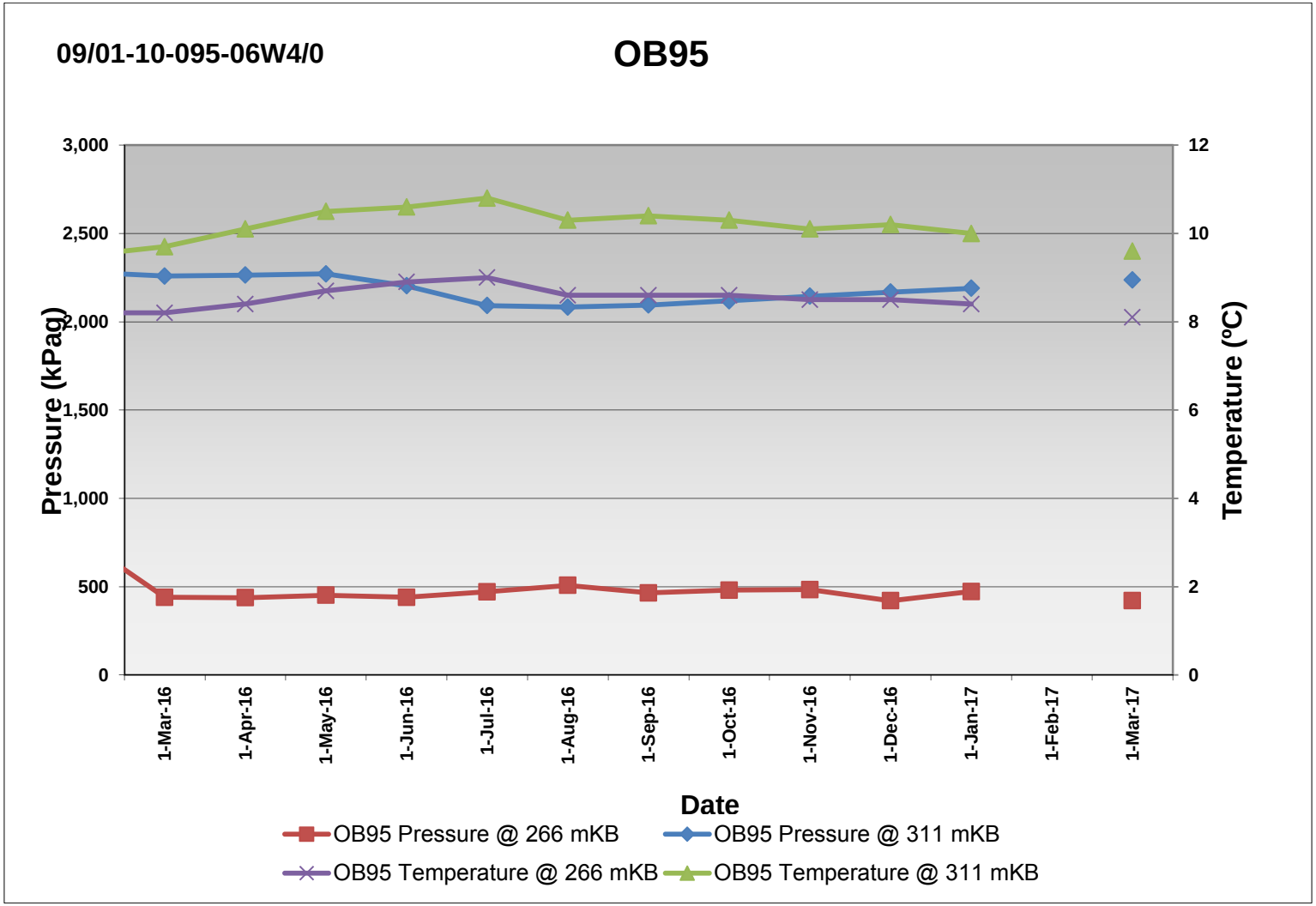

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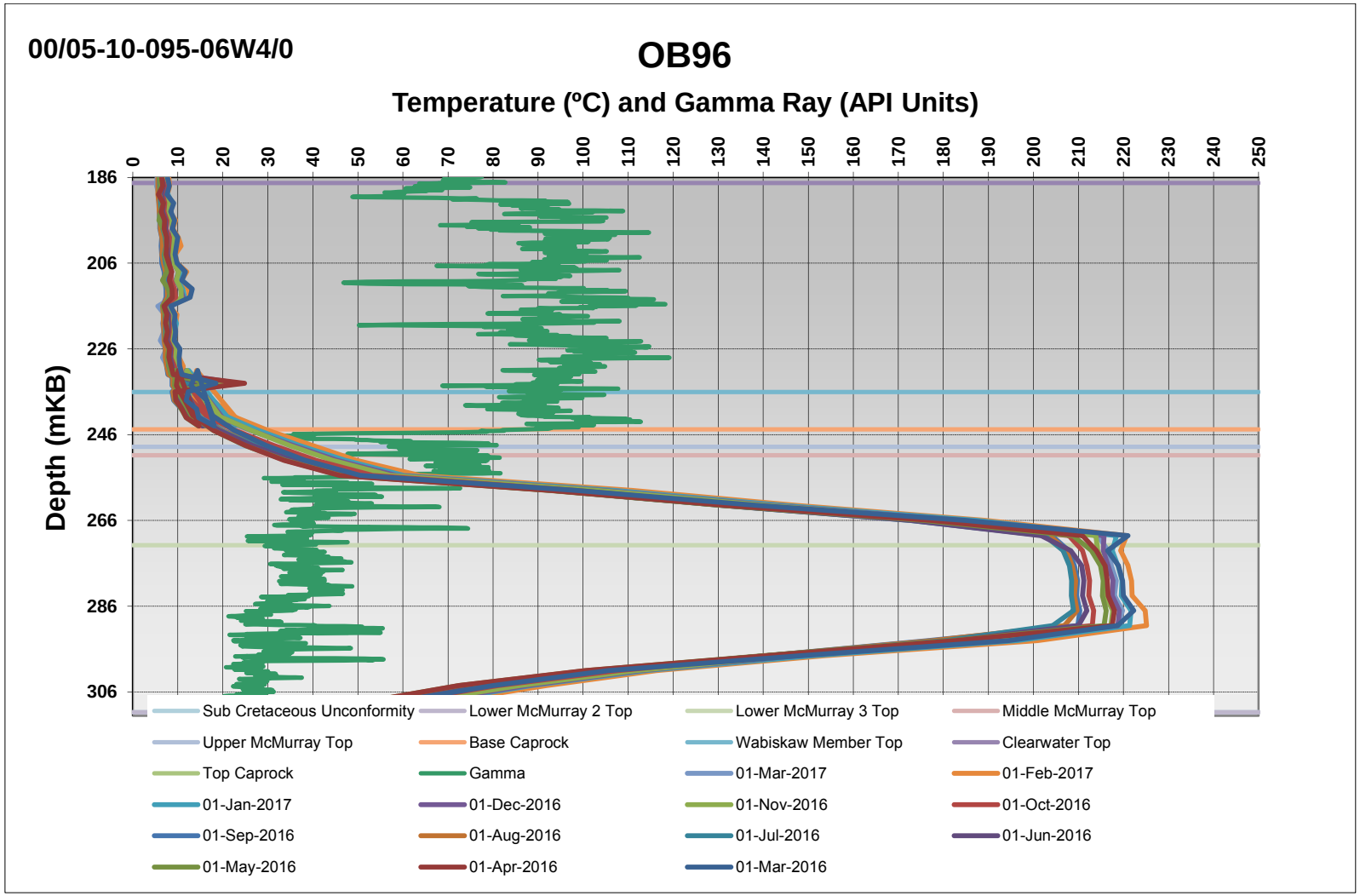

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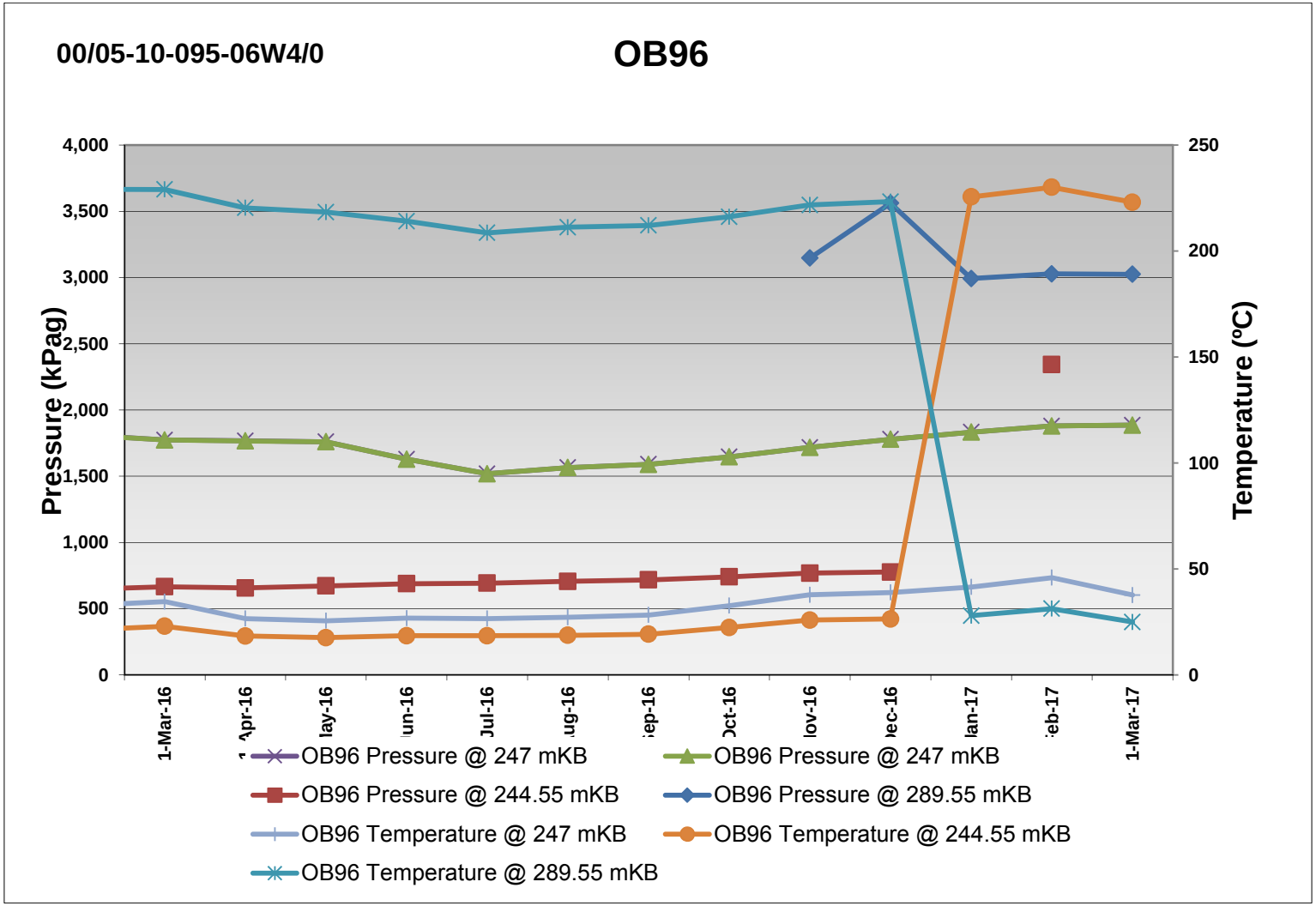

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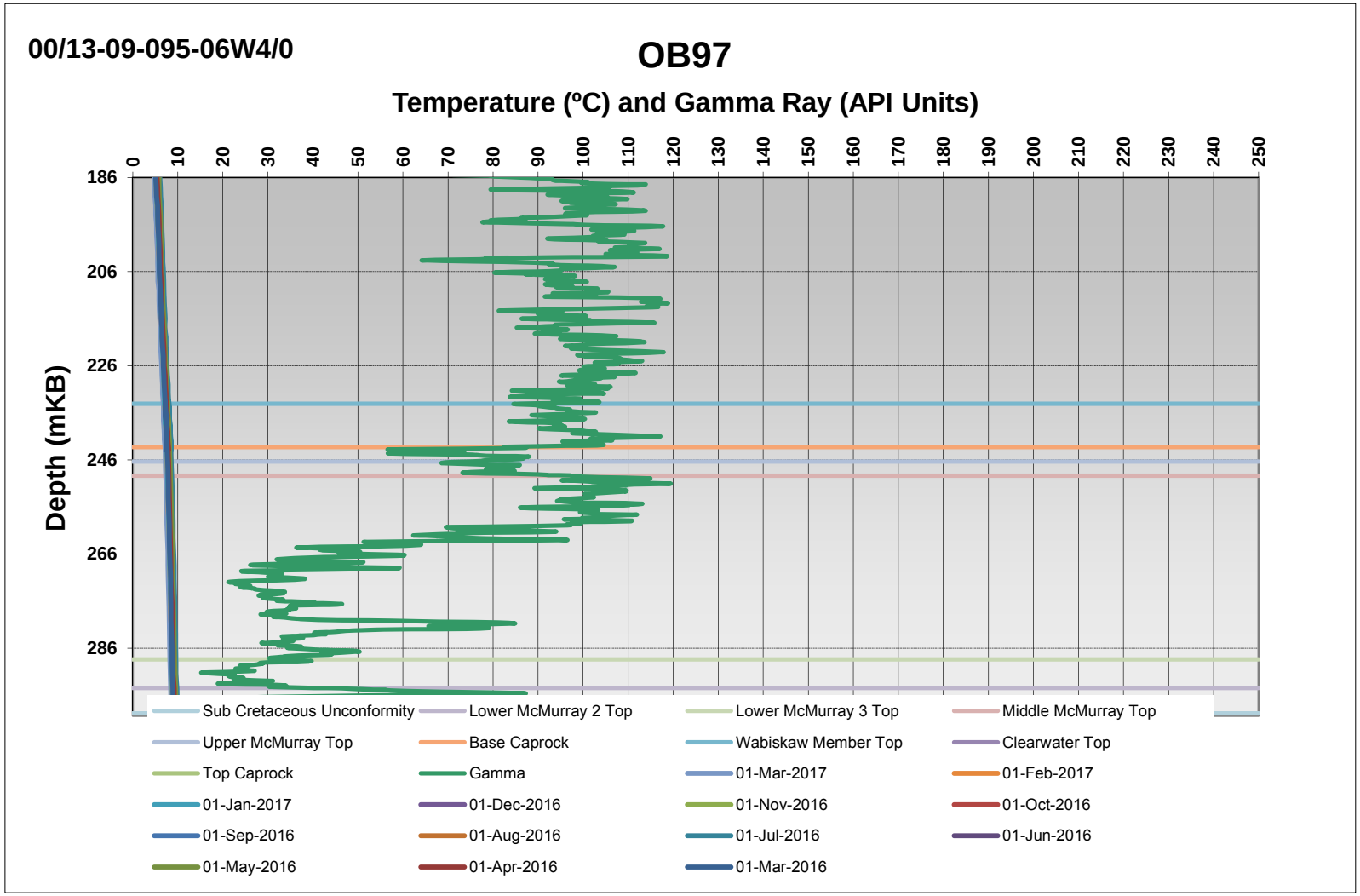

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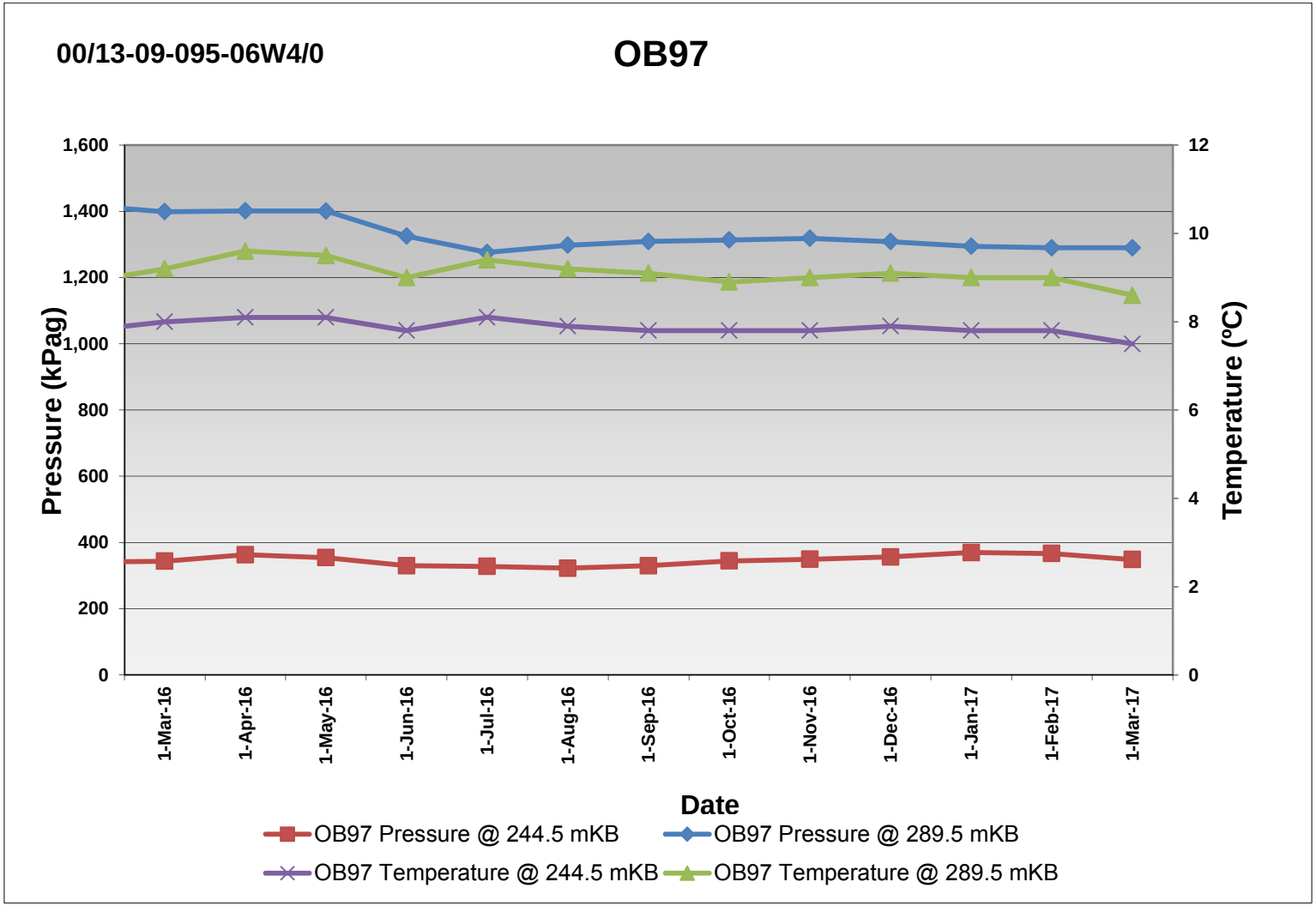

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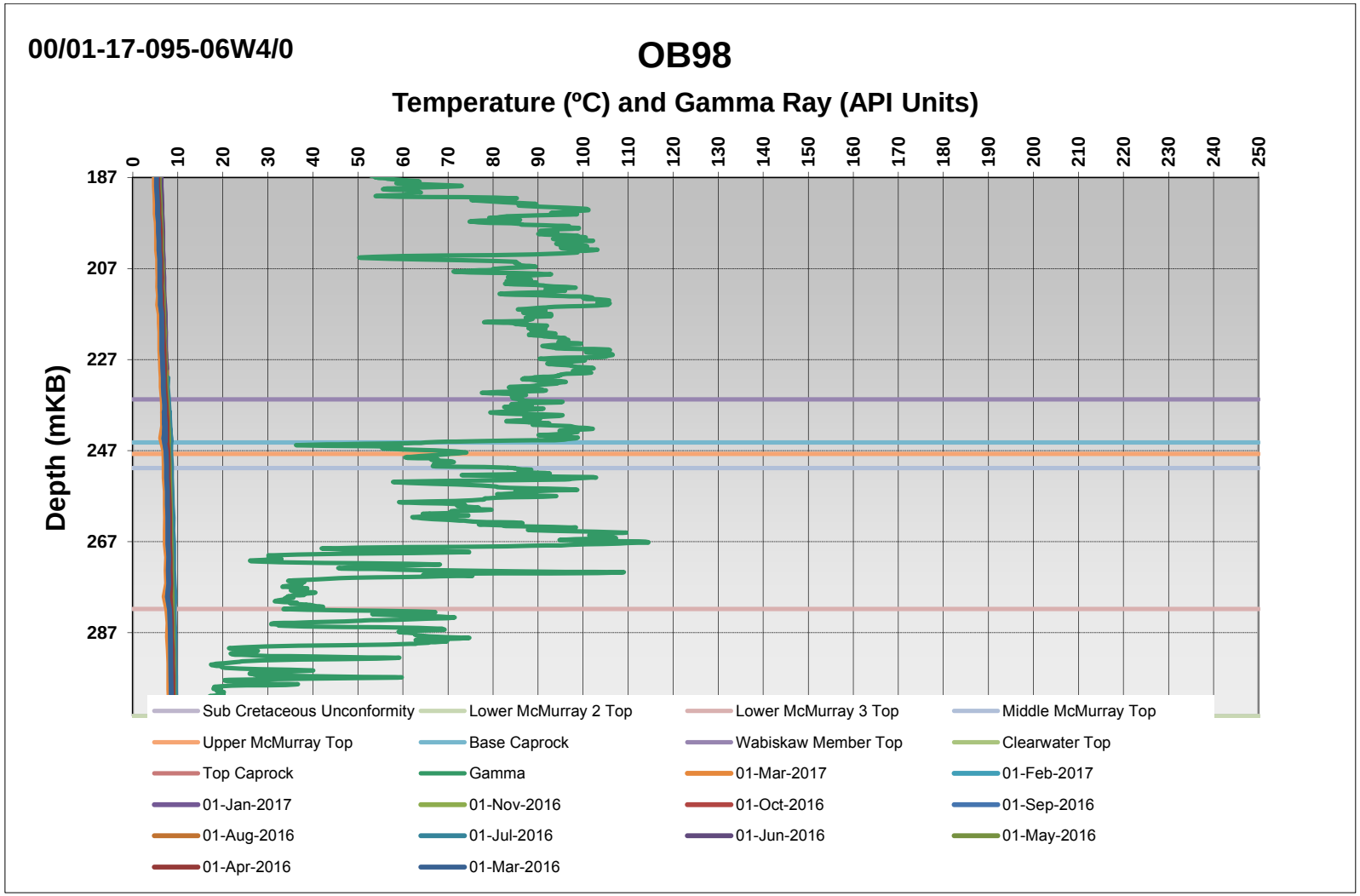

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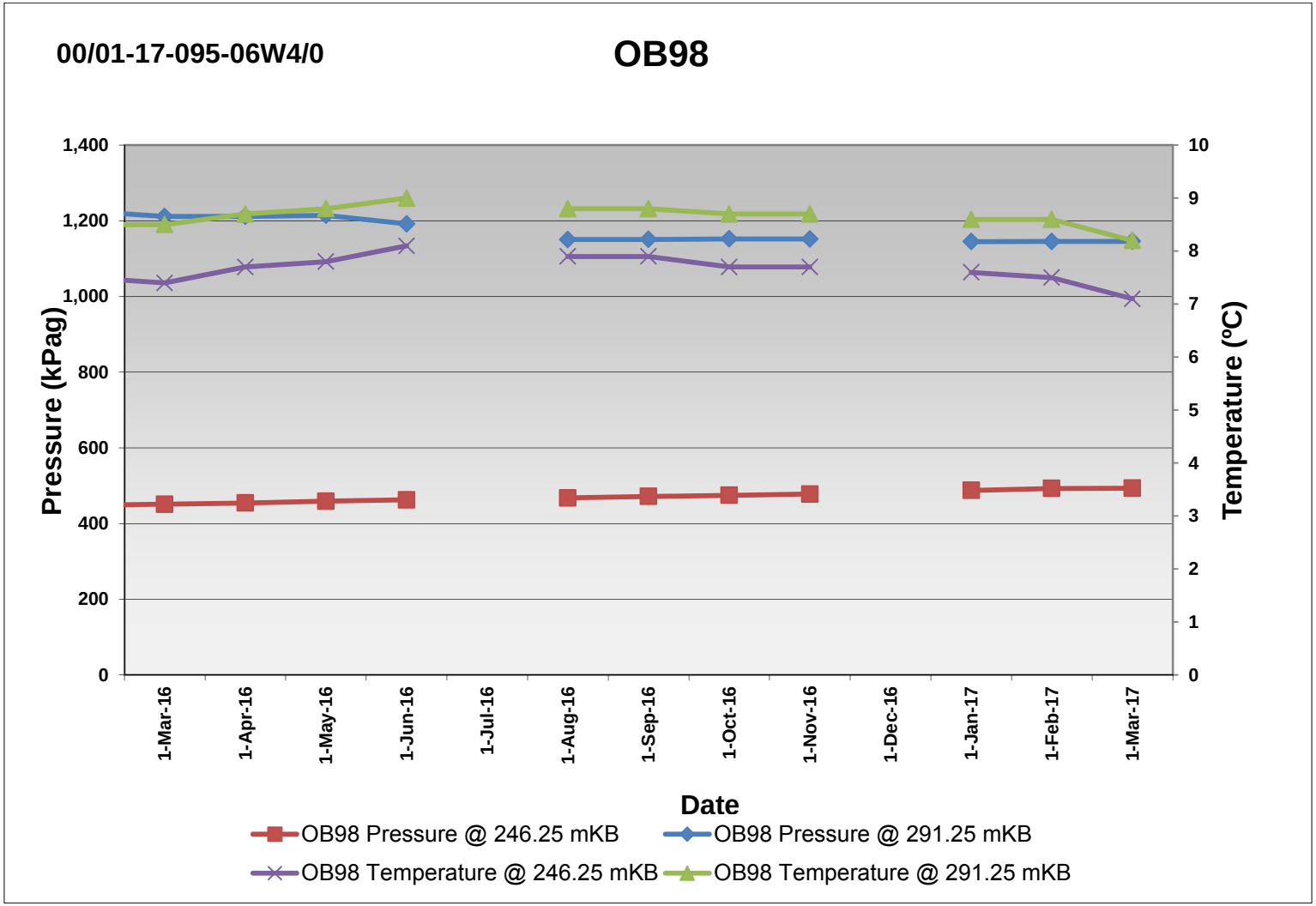

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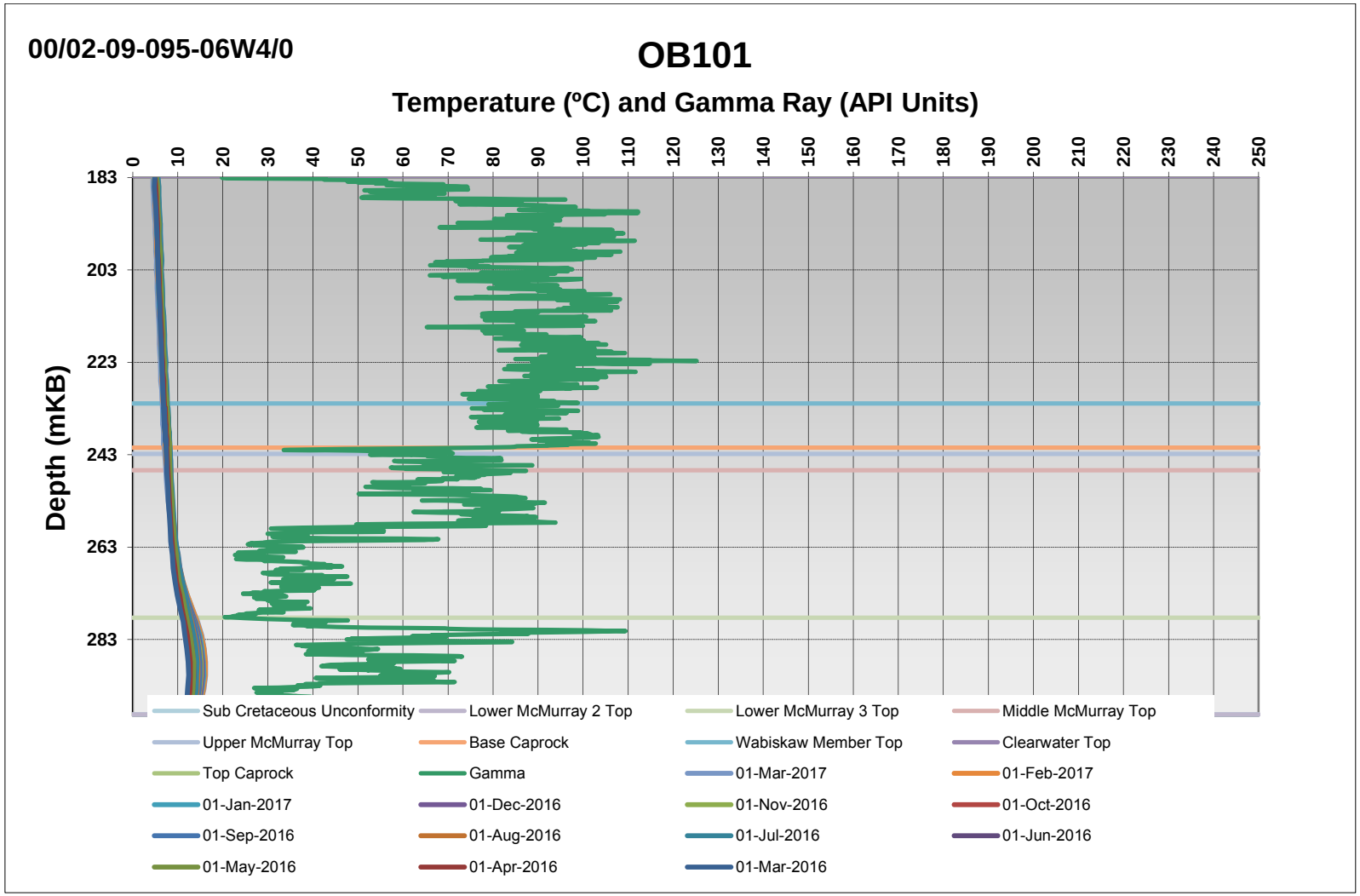

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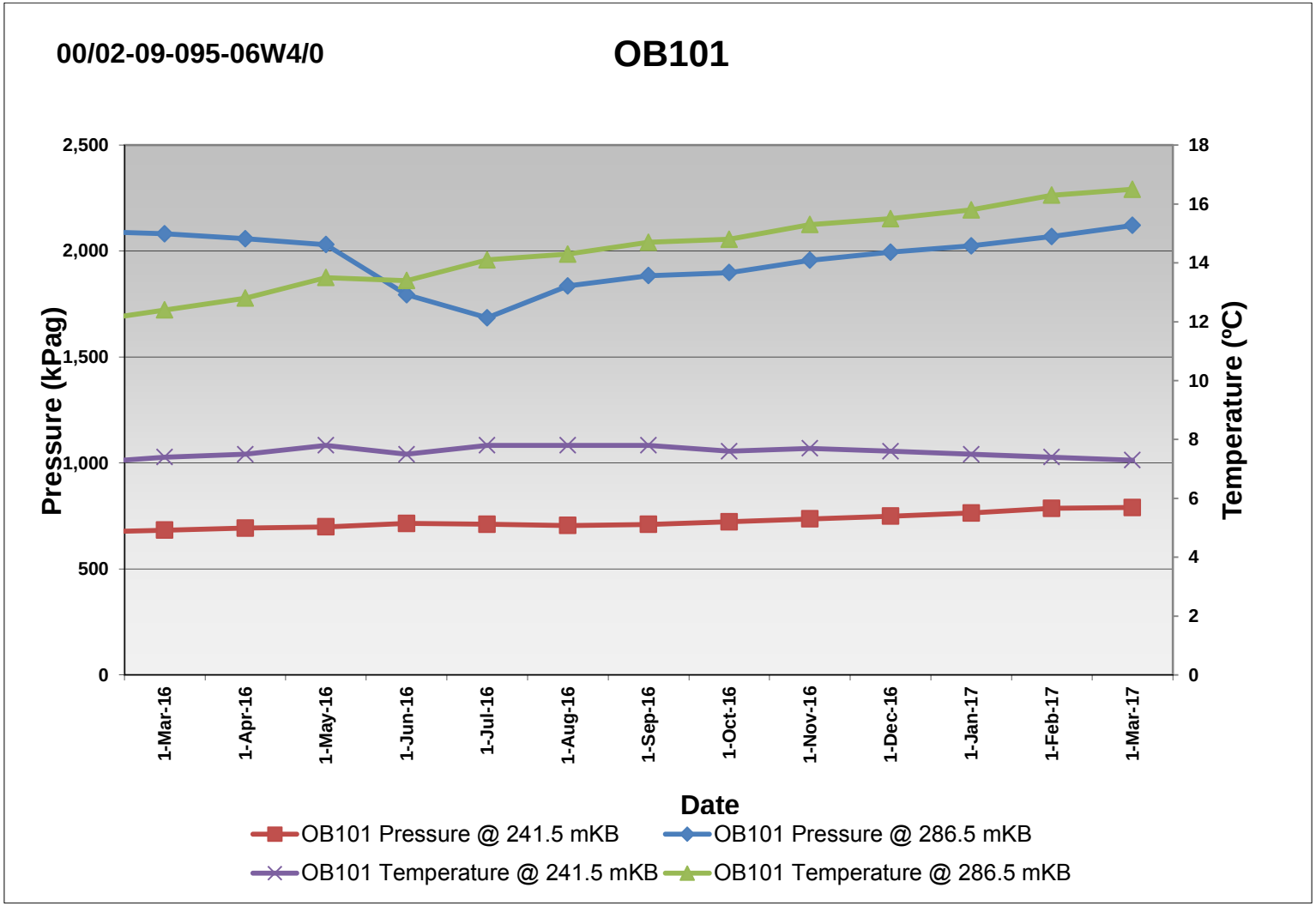

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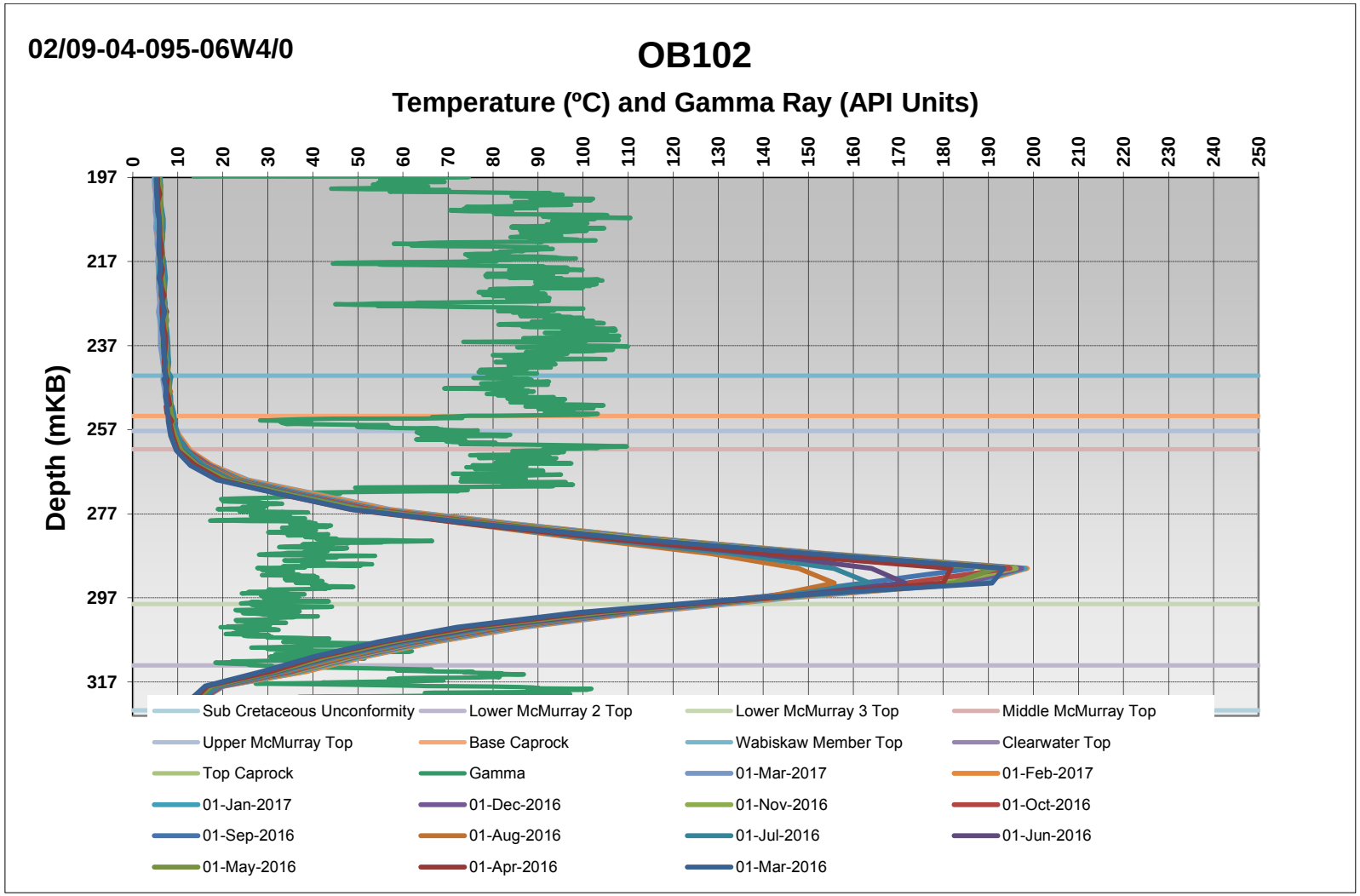

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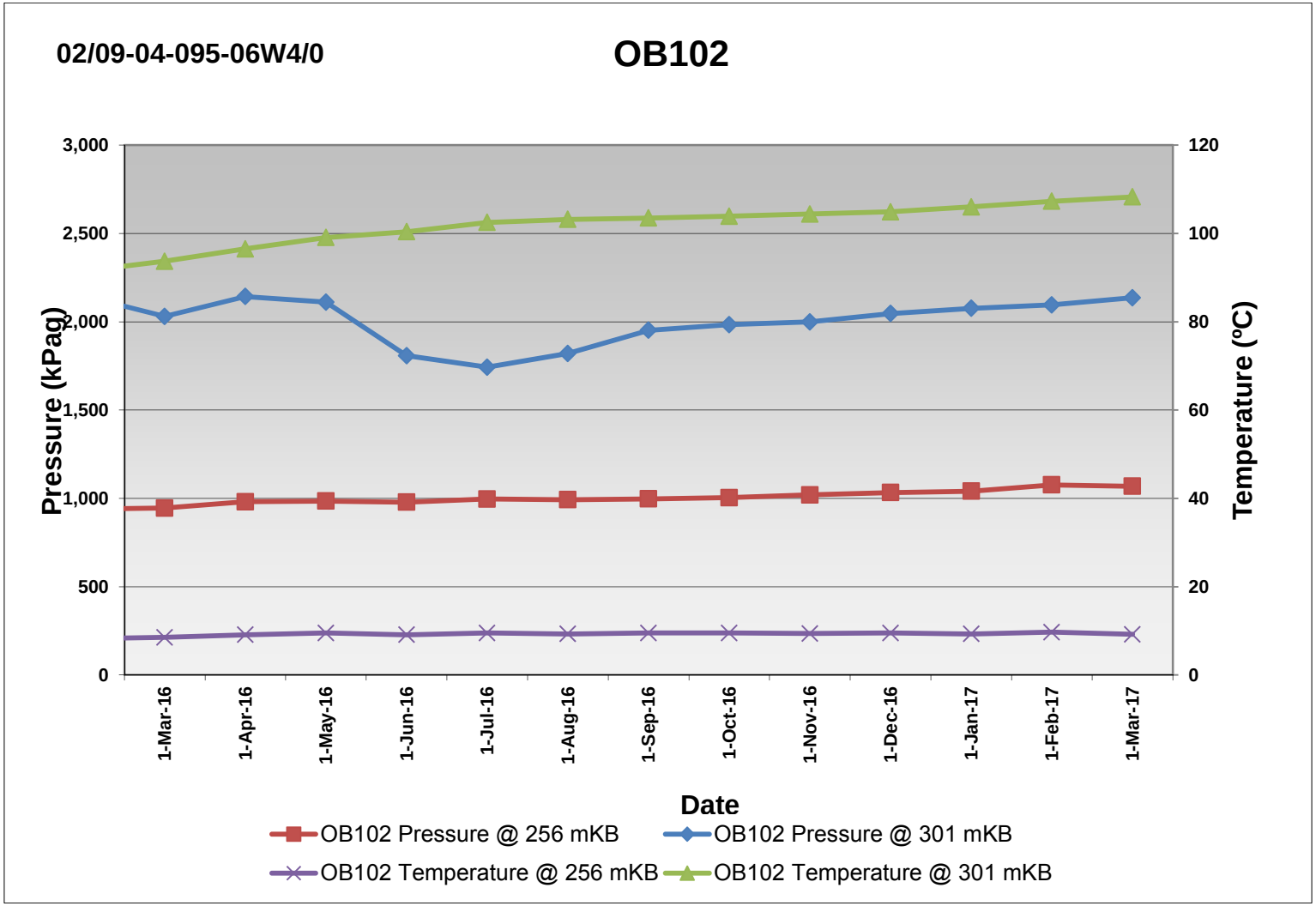

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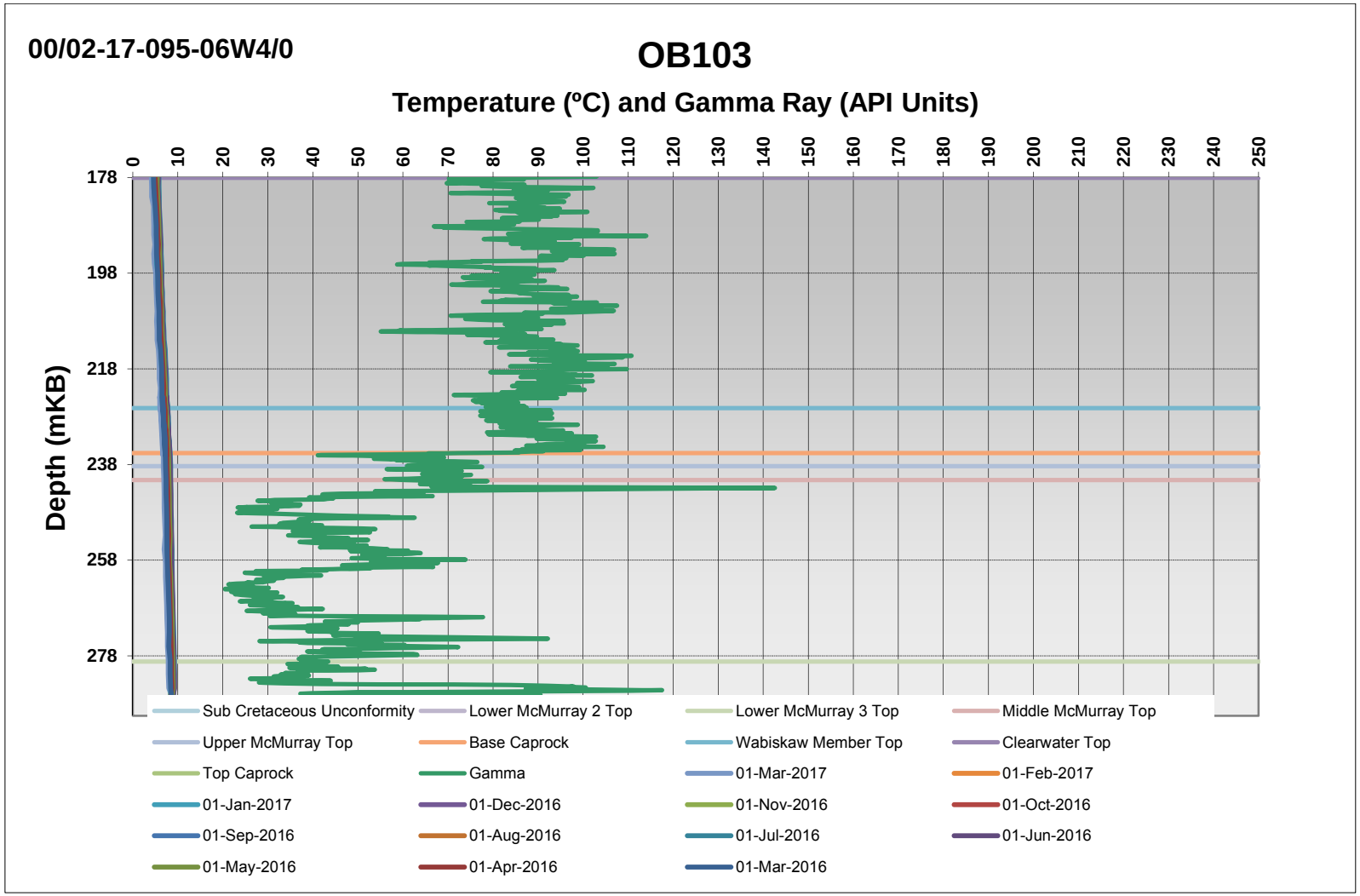

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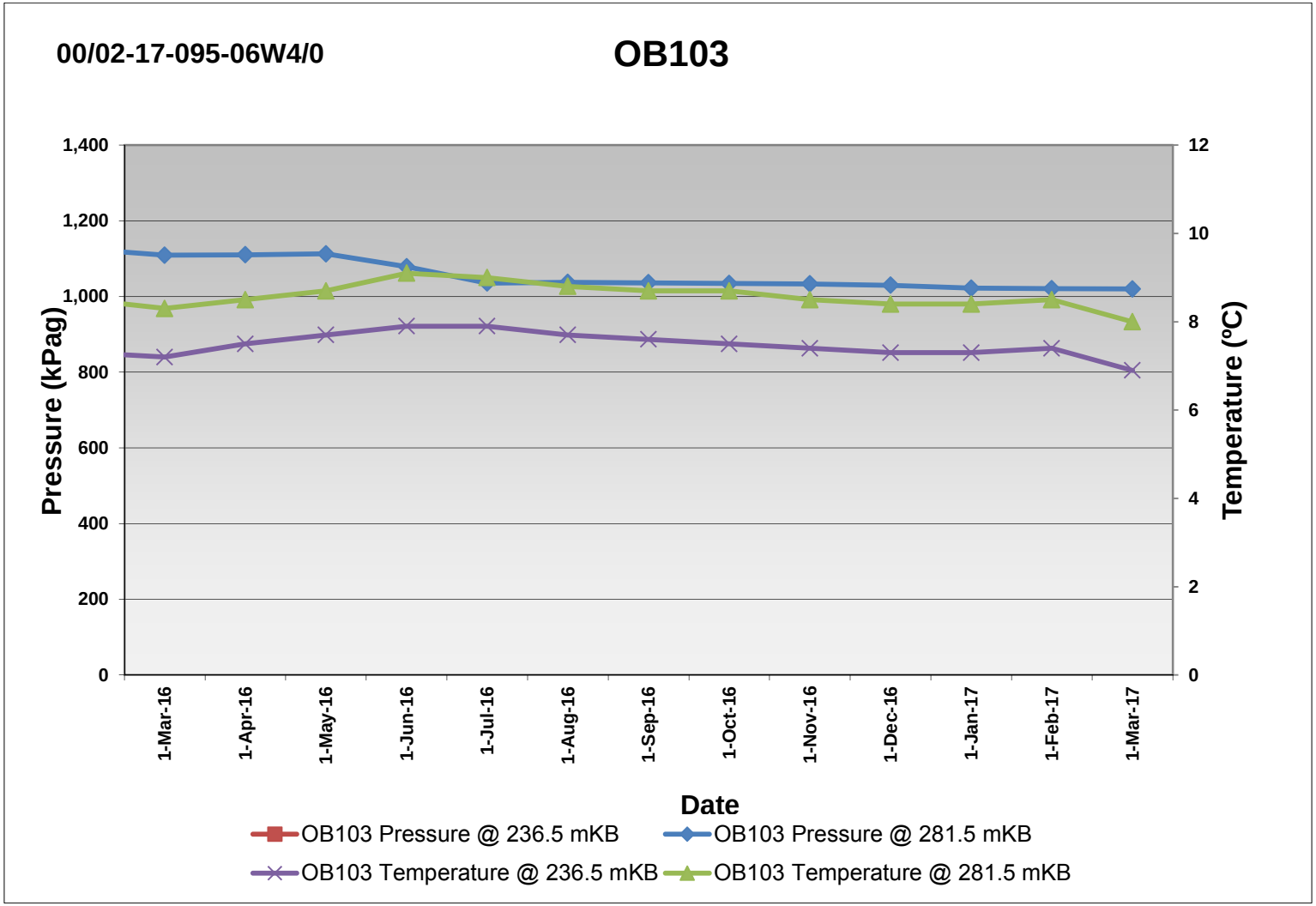
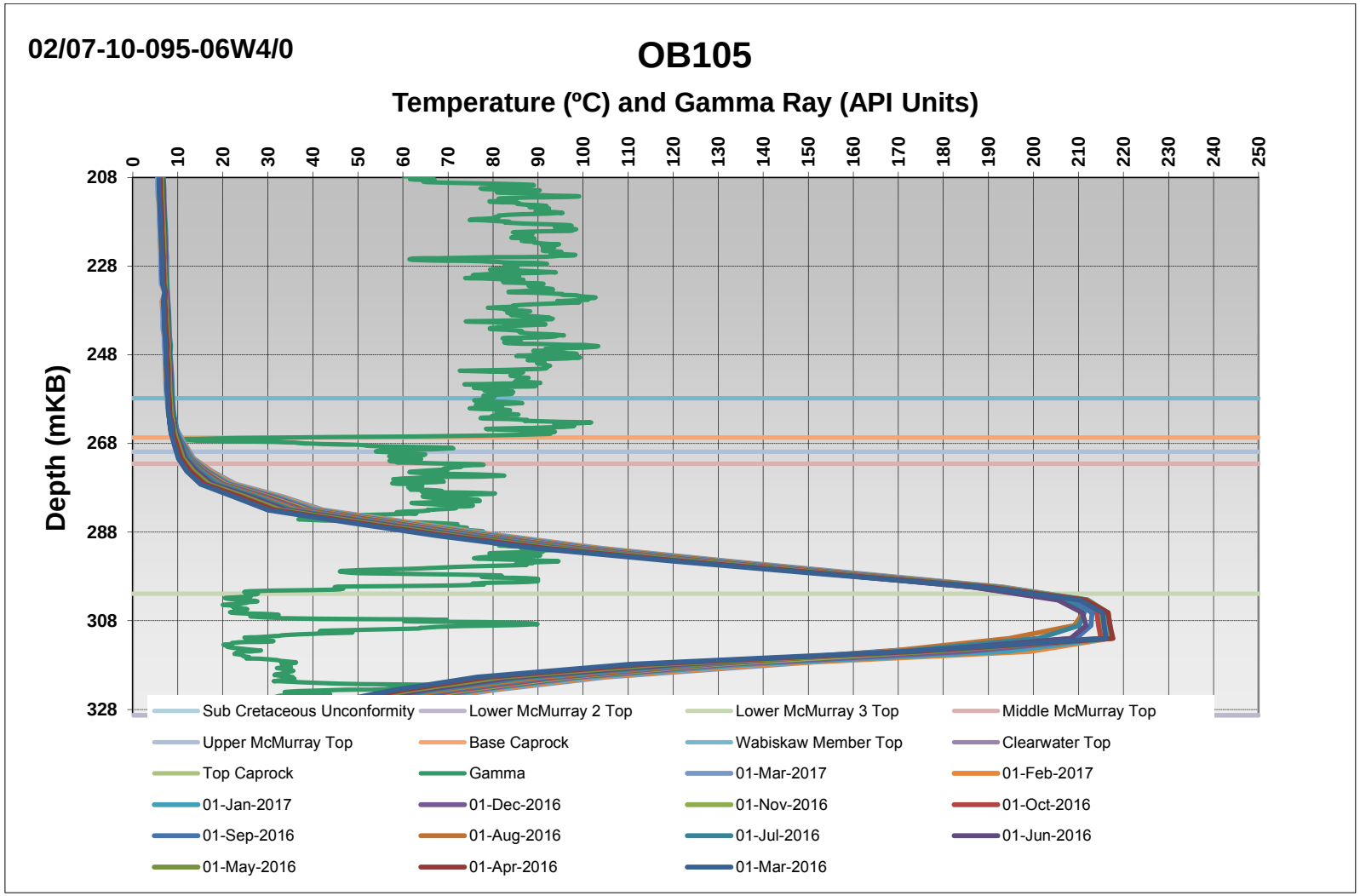


Piezometer Plots & Temperature vs Depth Plots



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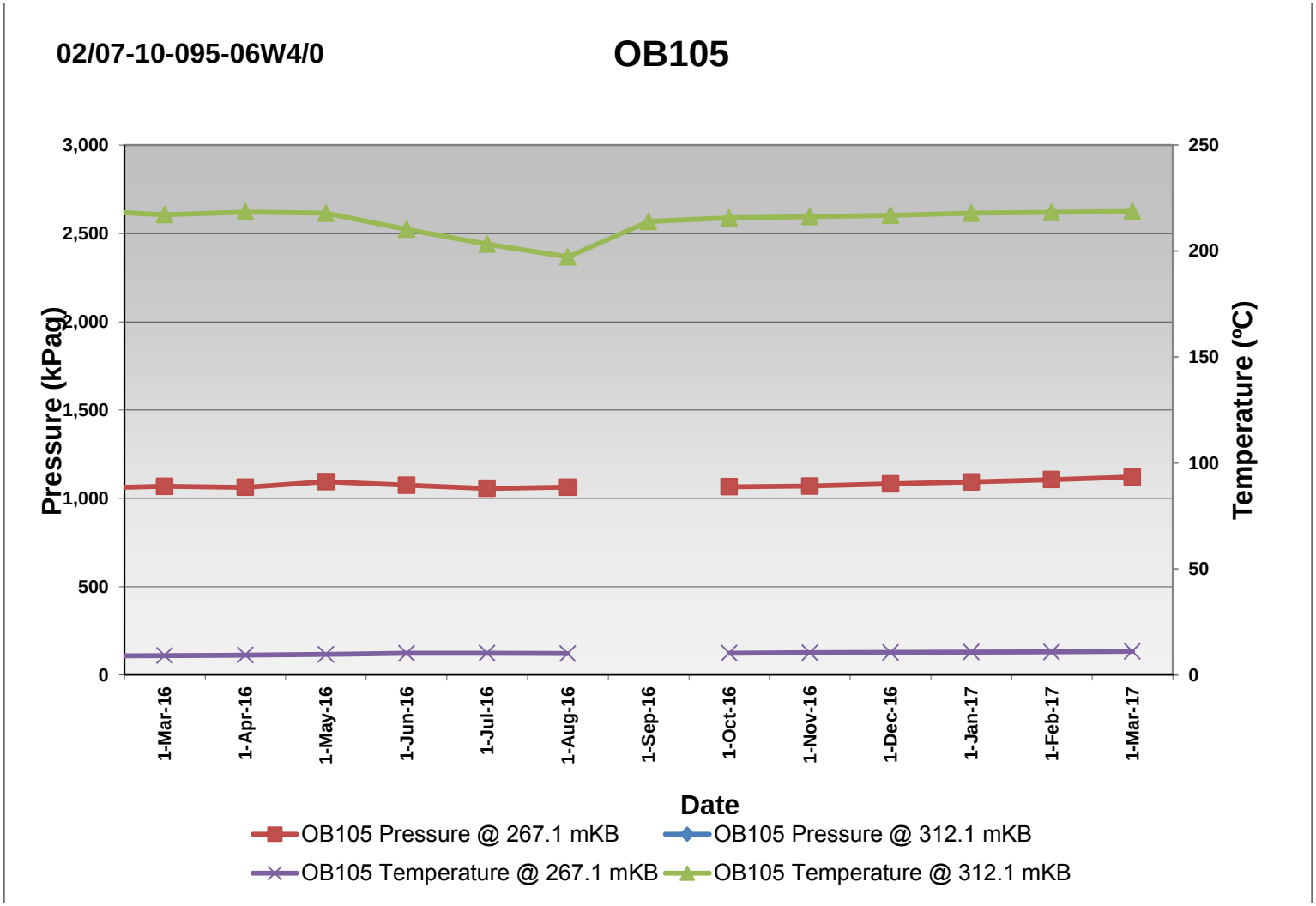

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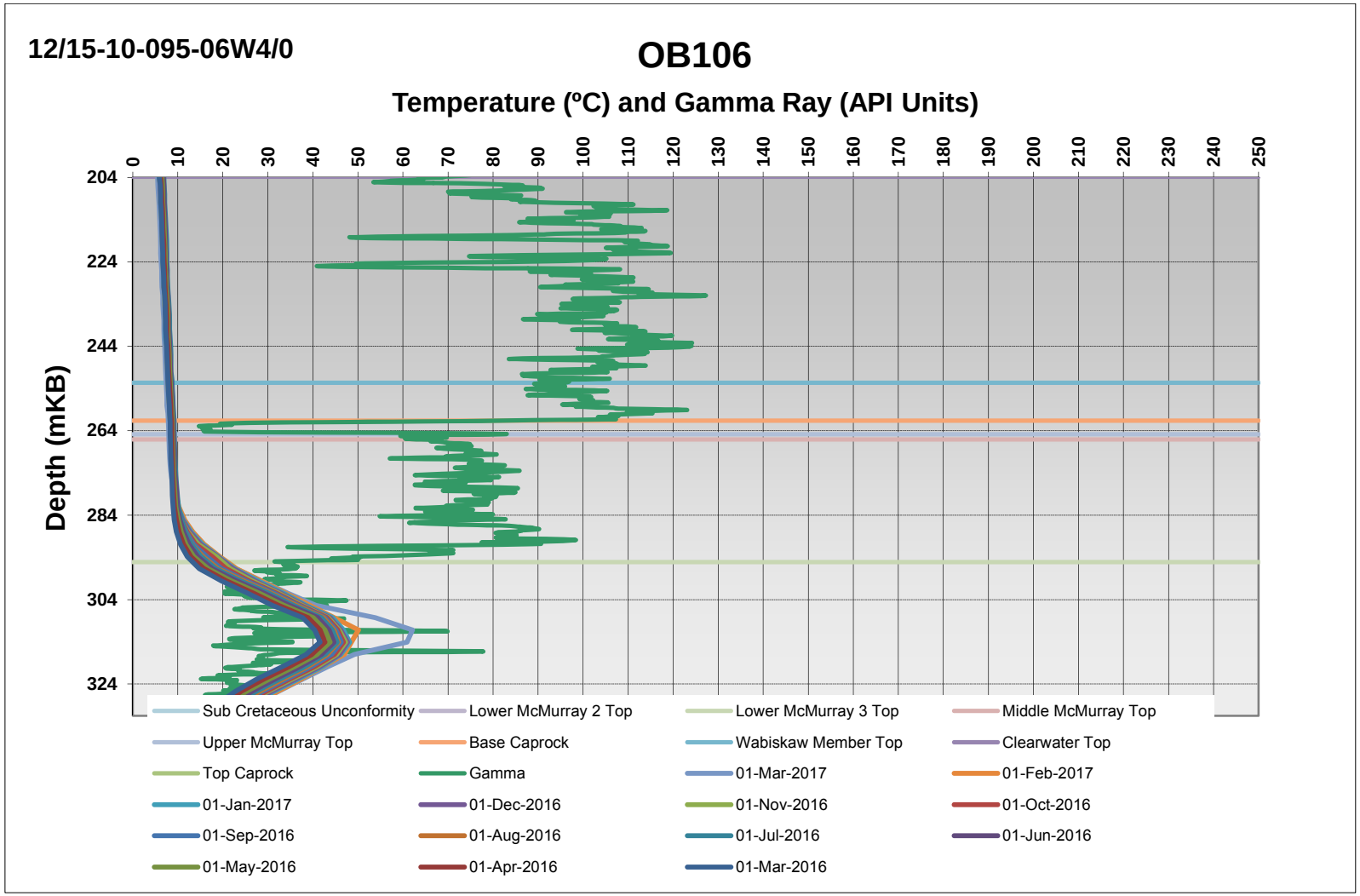

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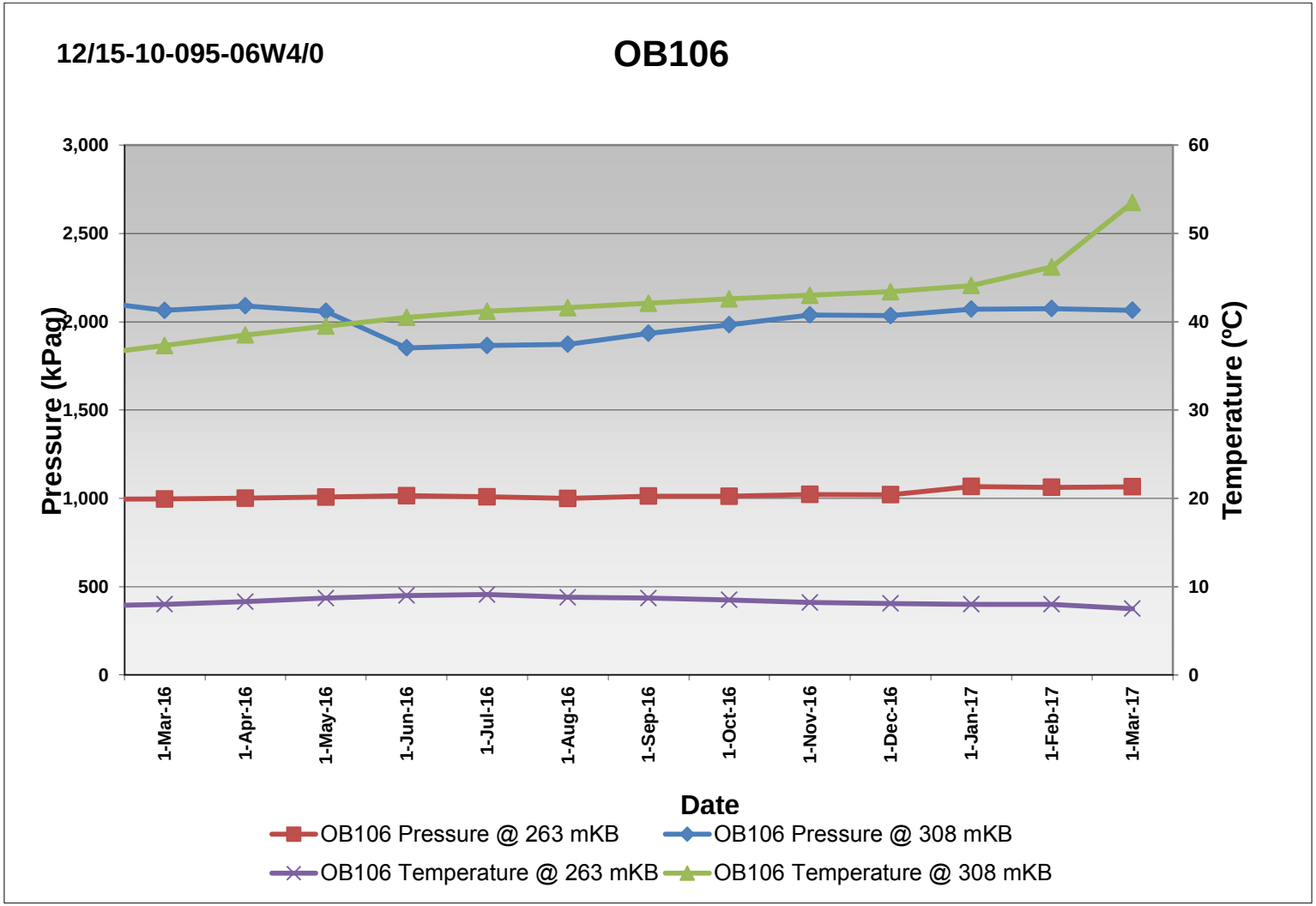

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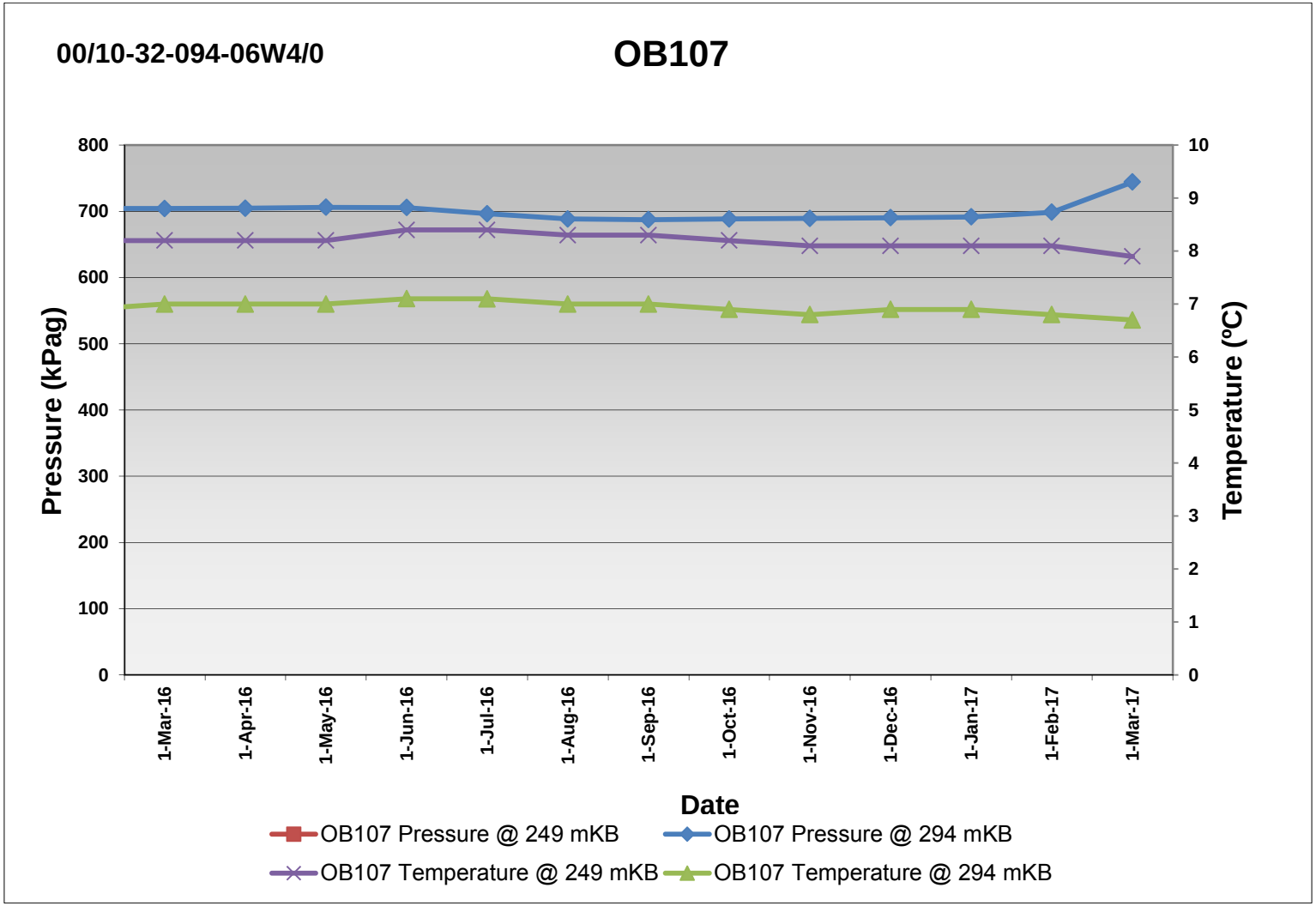

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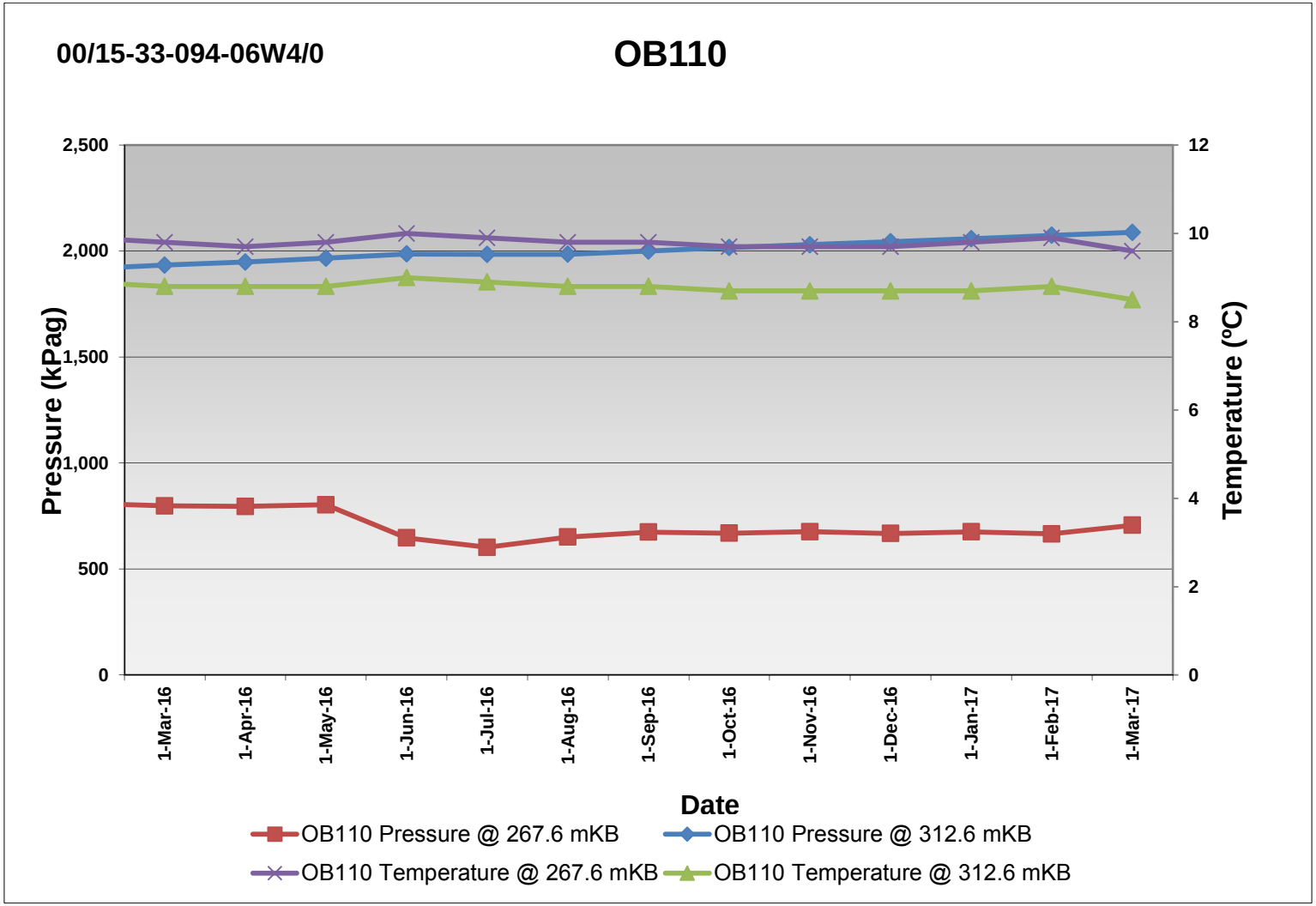

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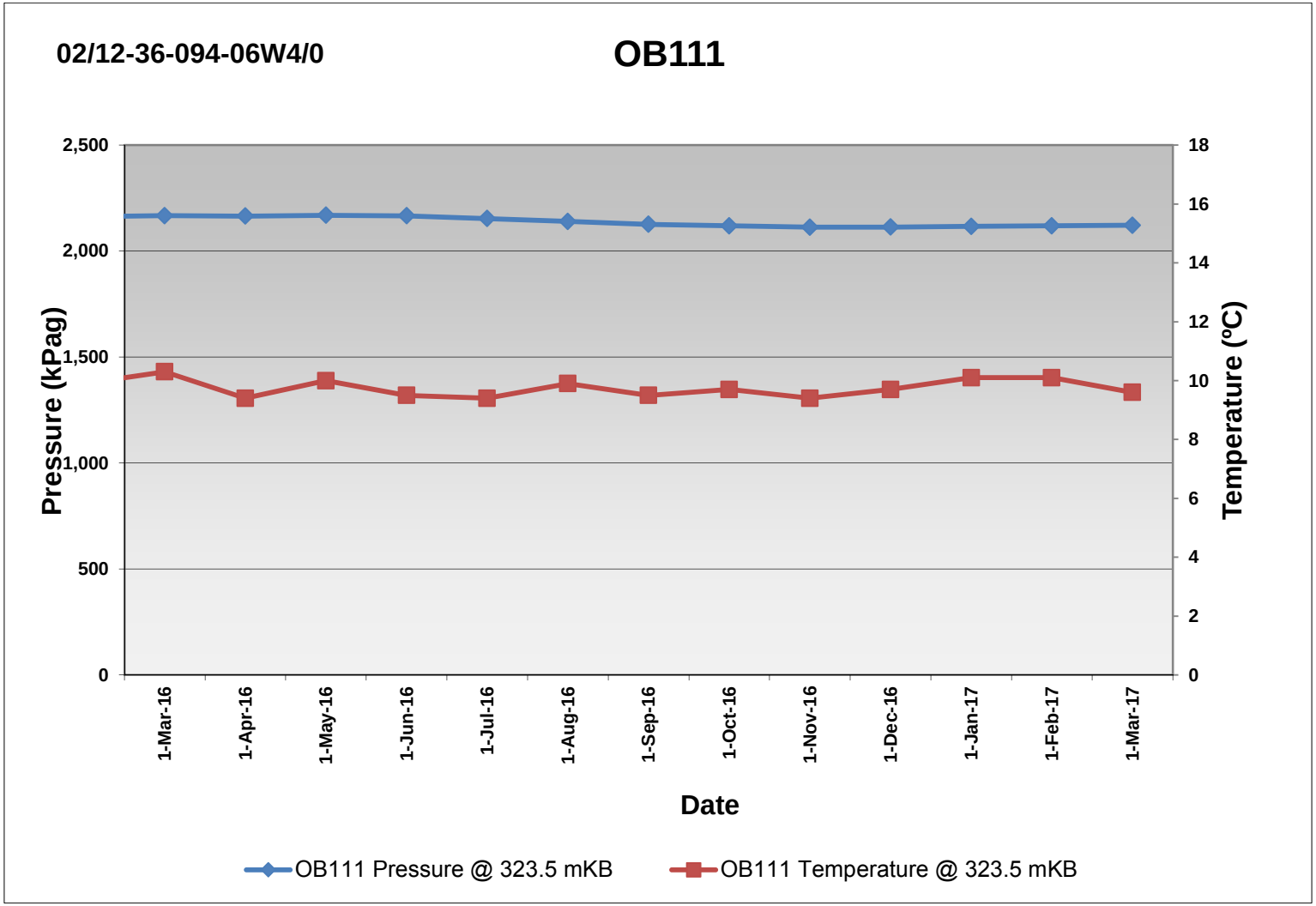

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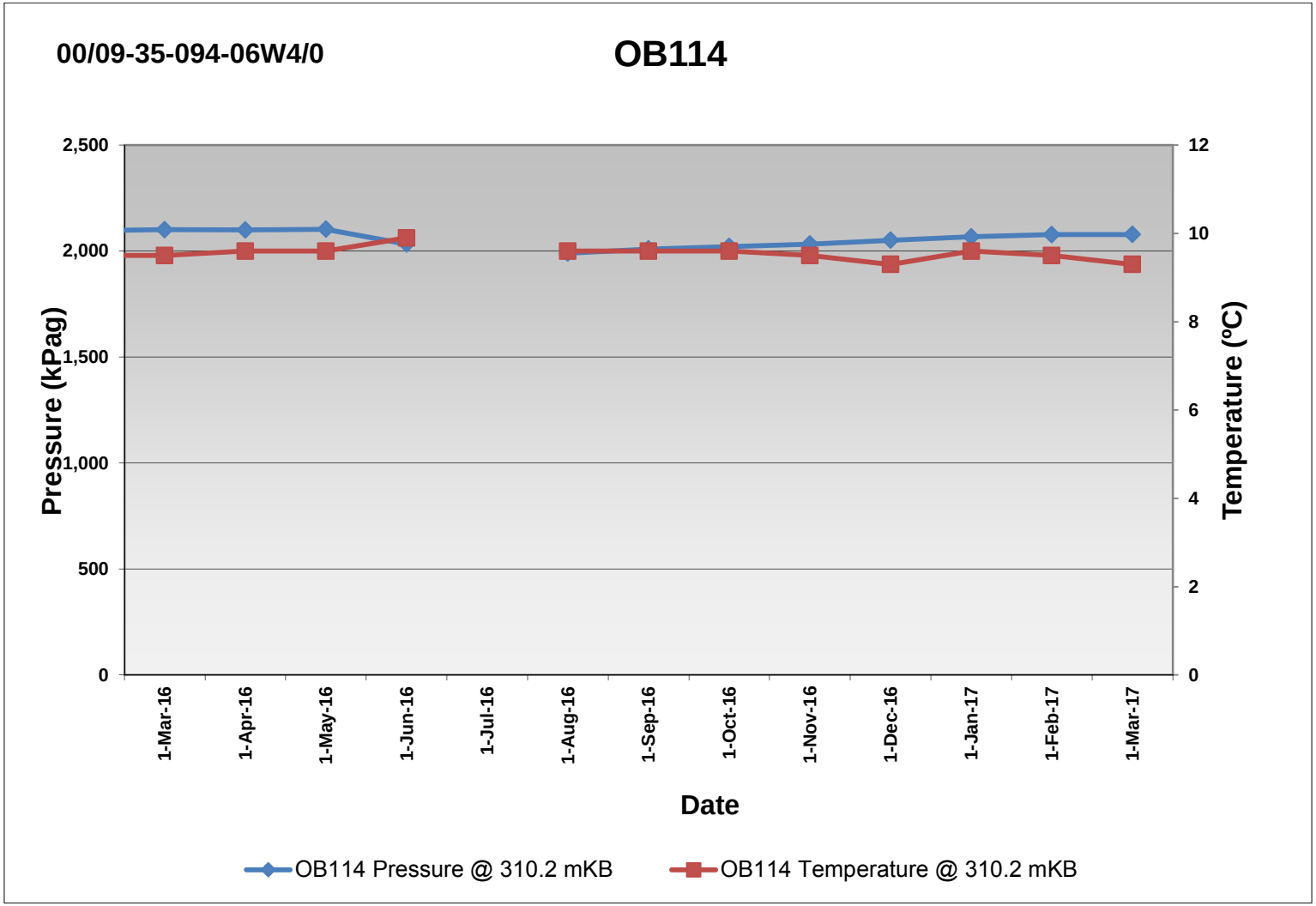

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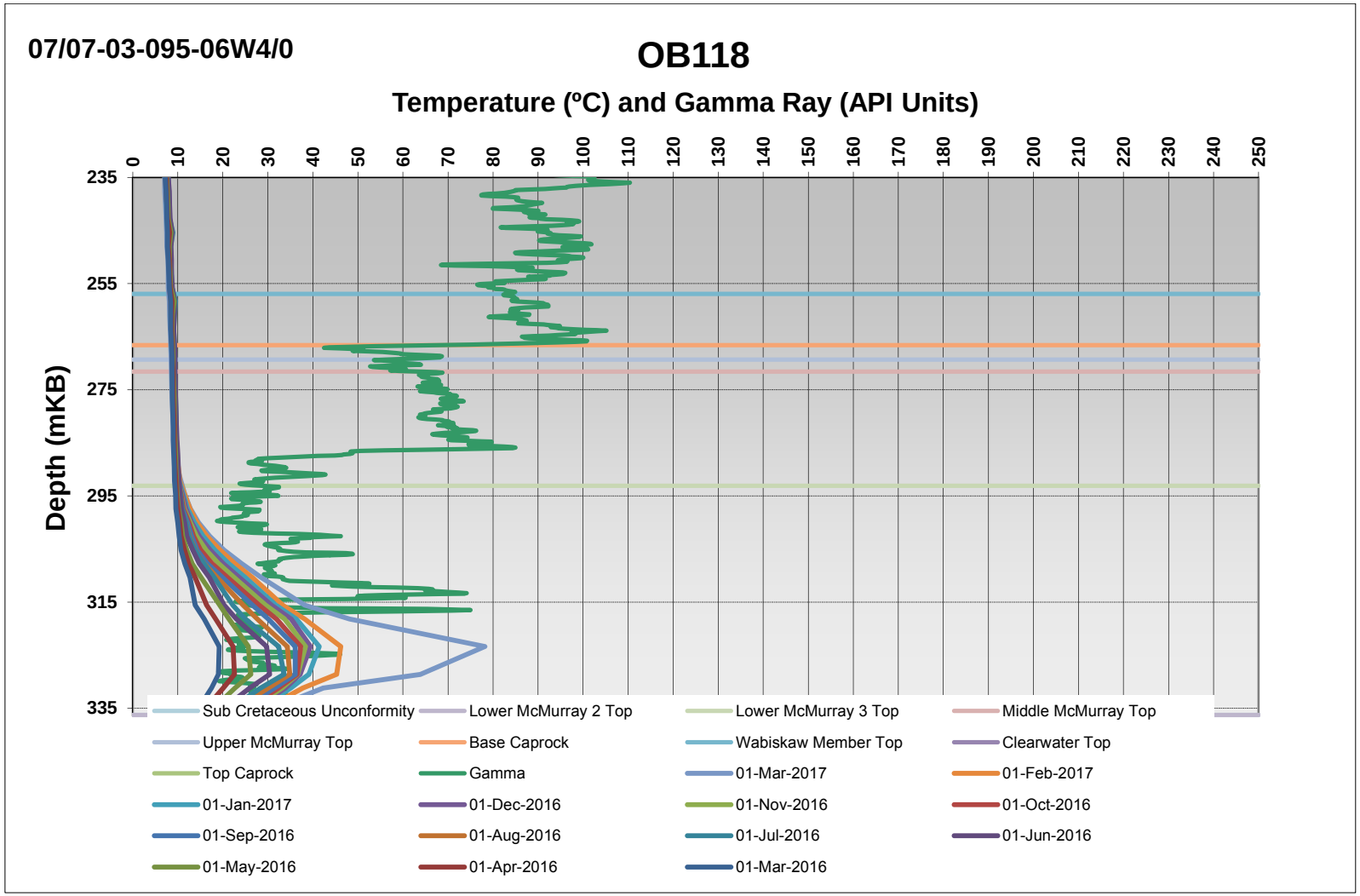

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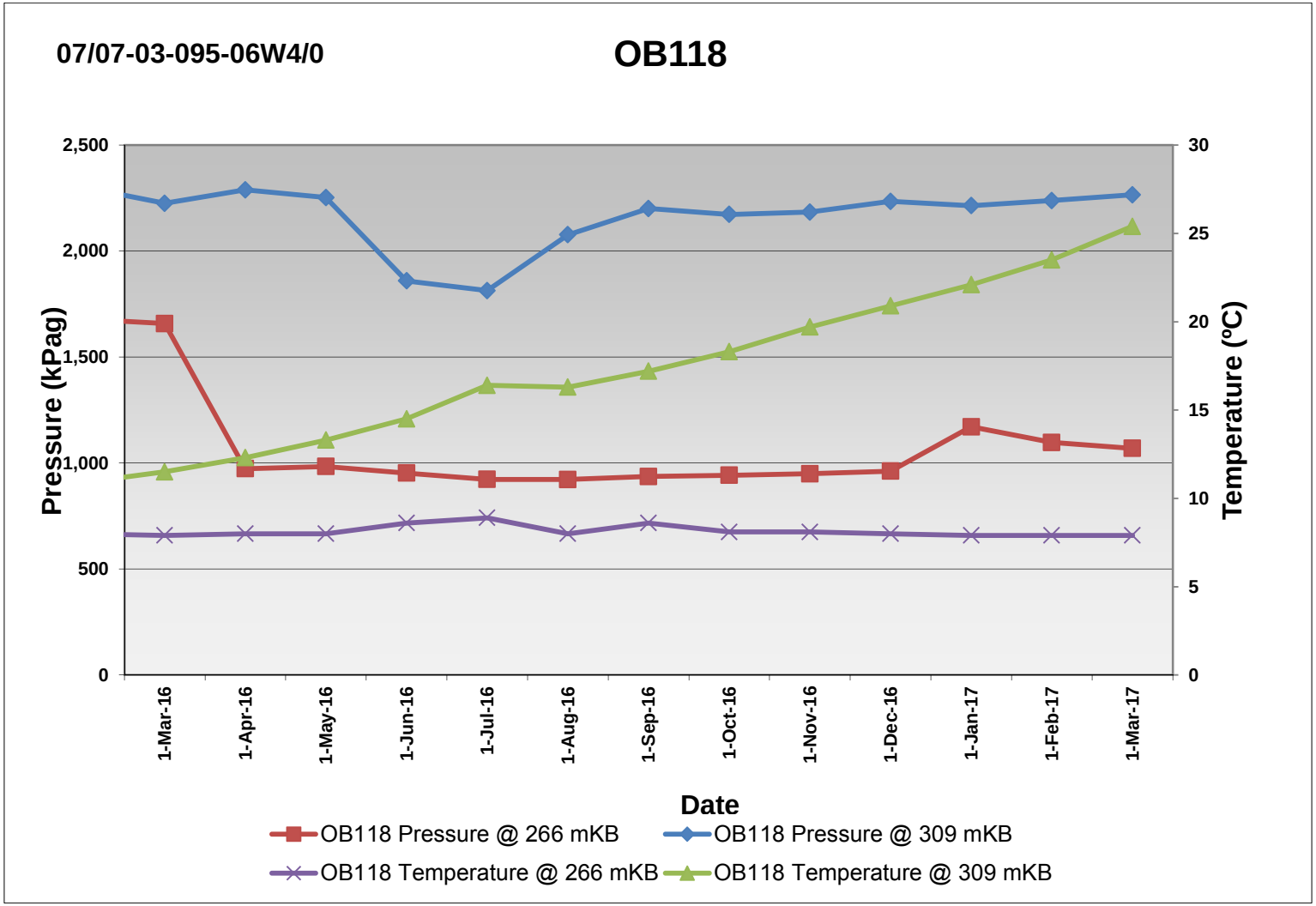

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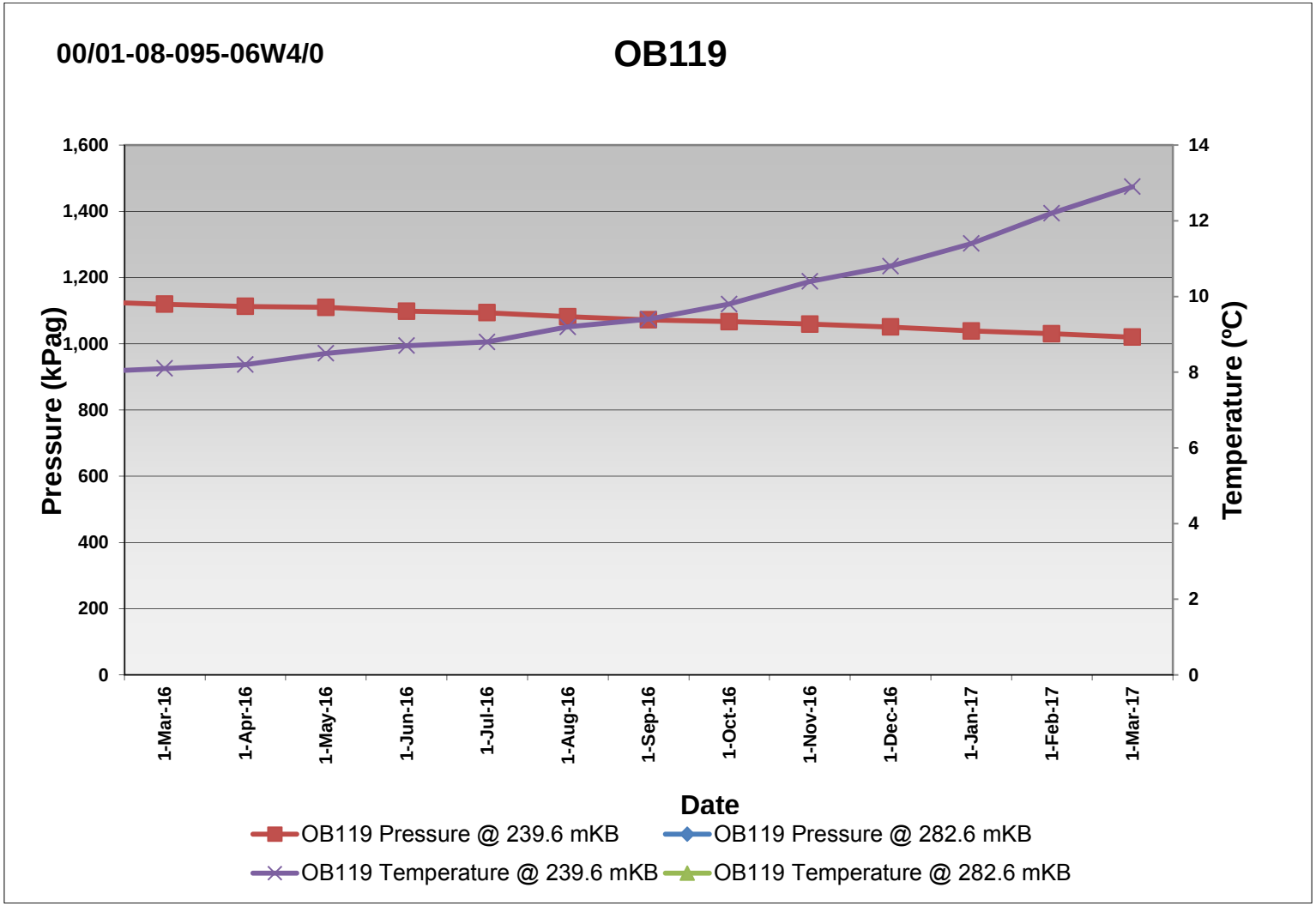

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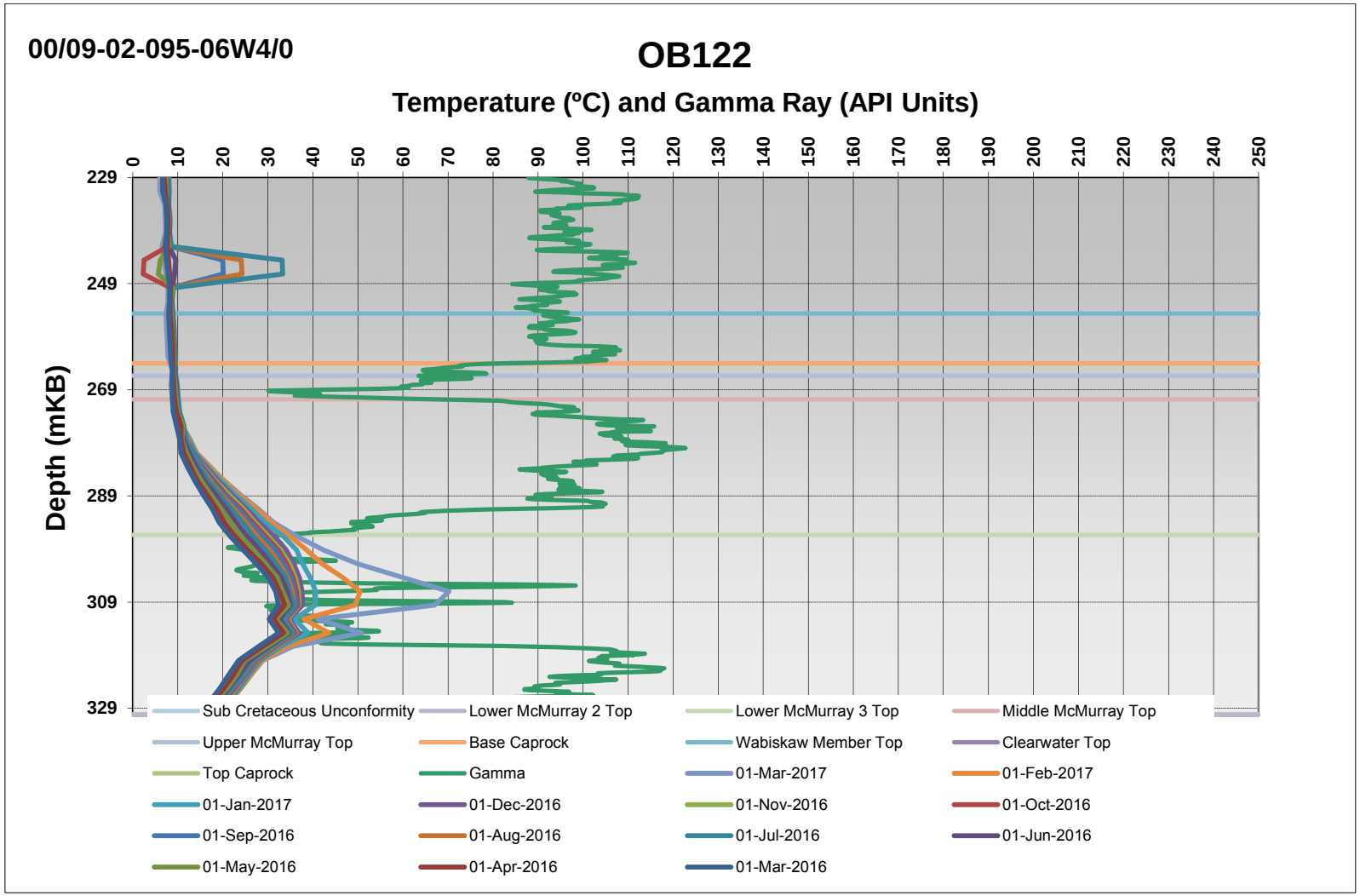

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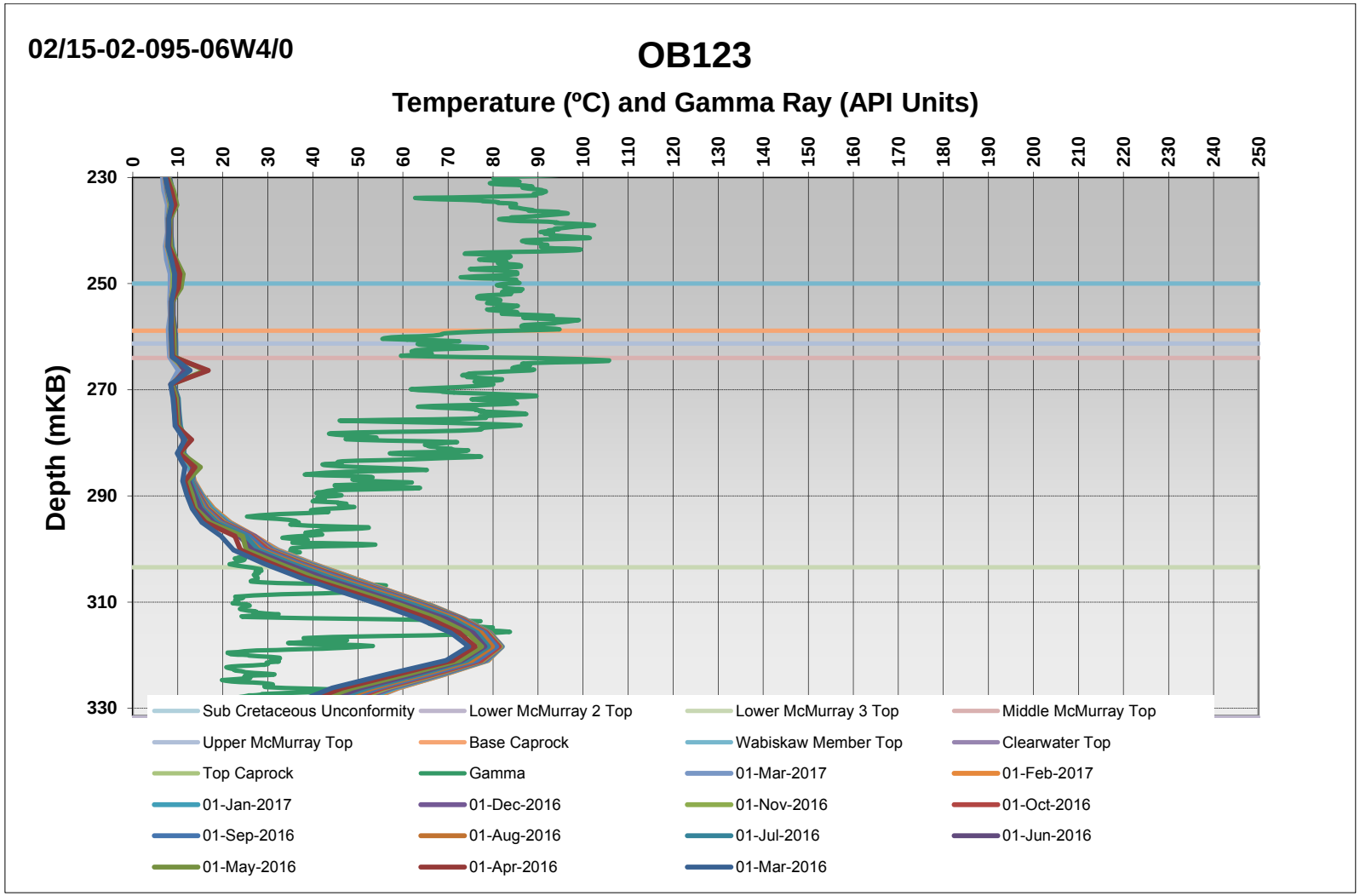

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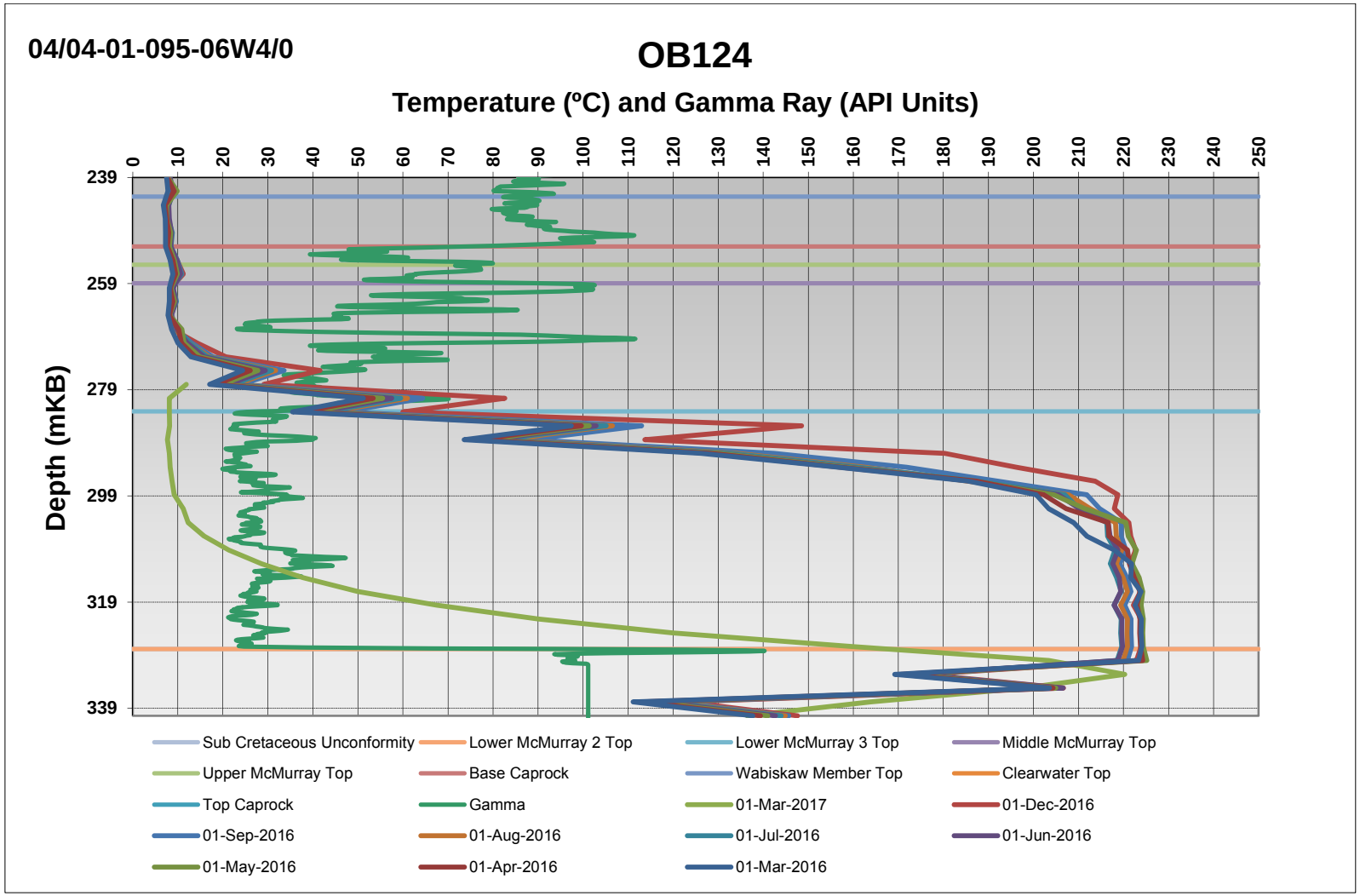

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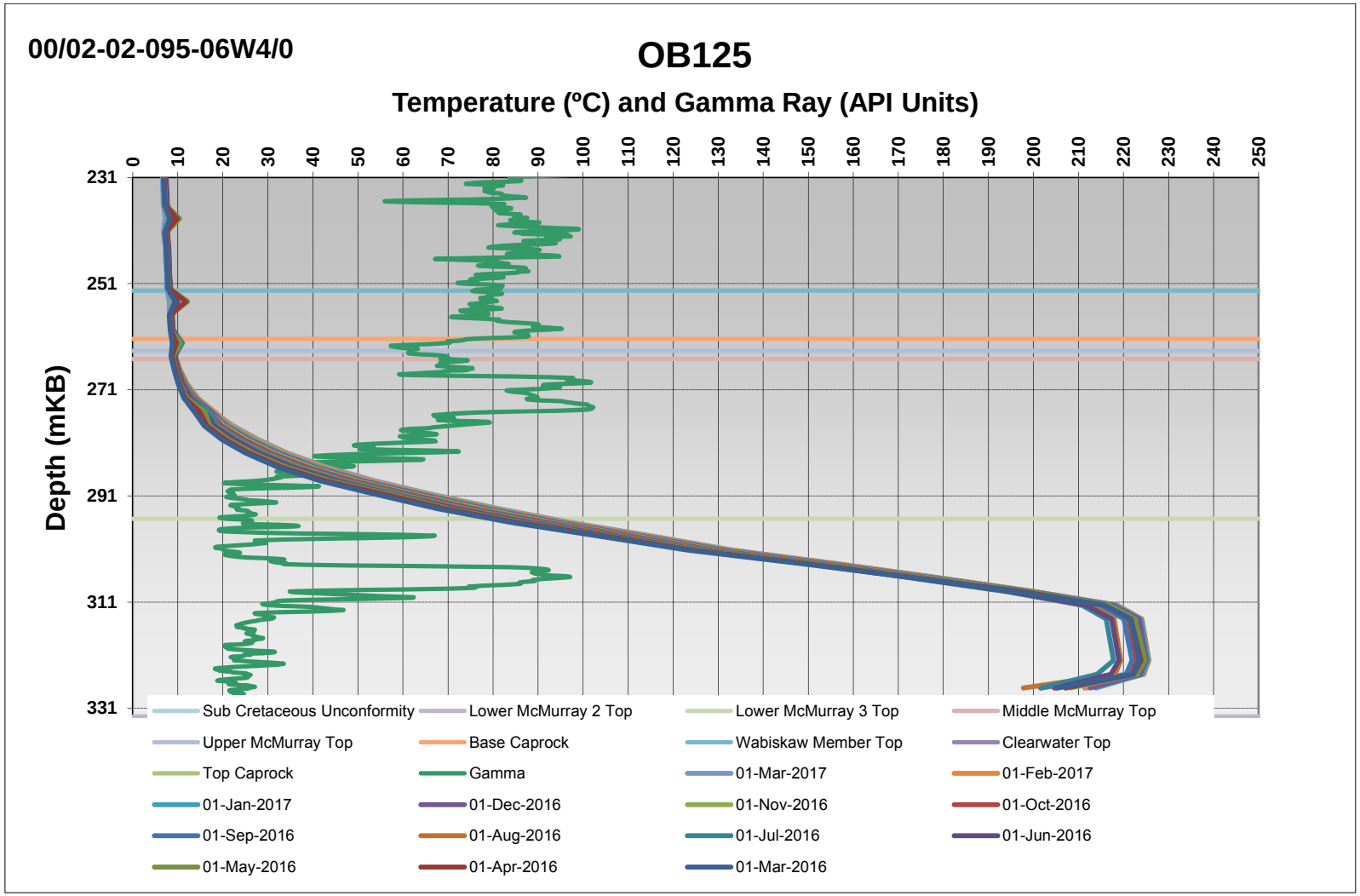

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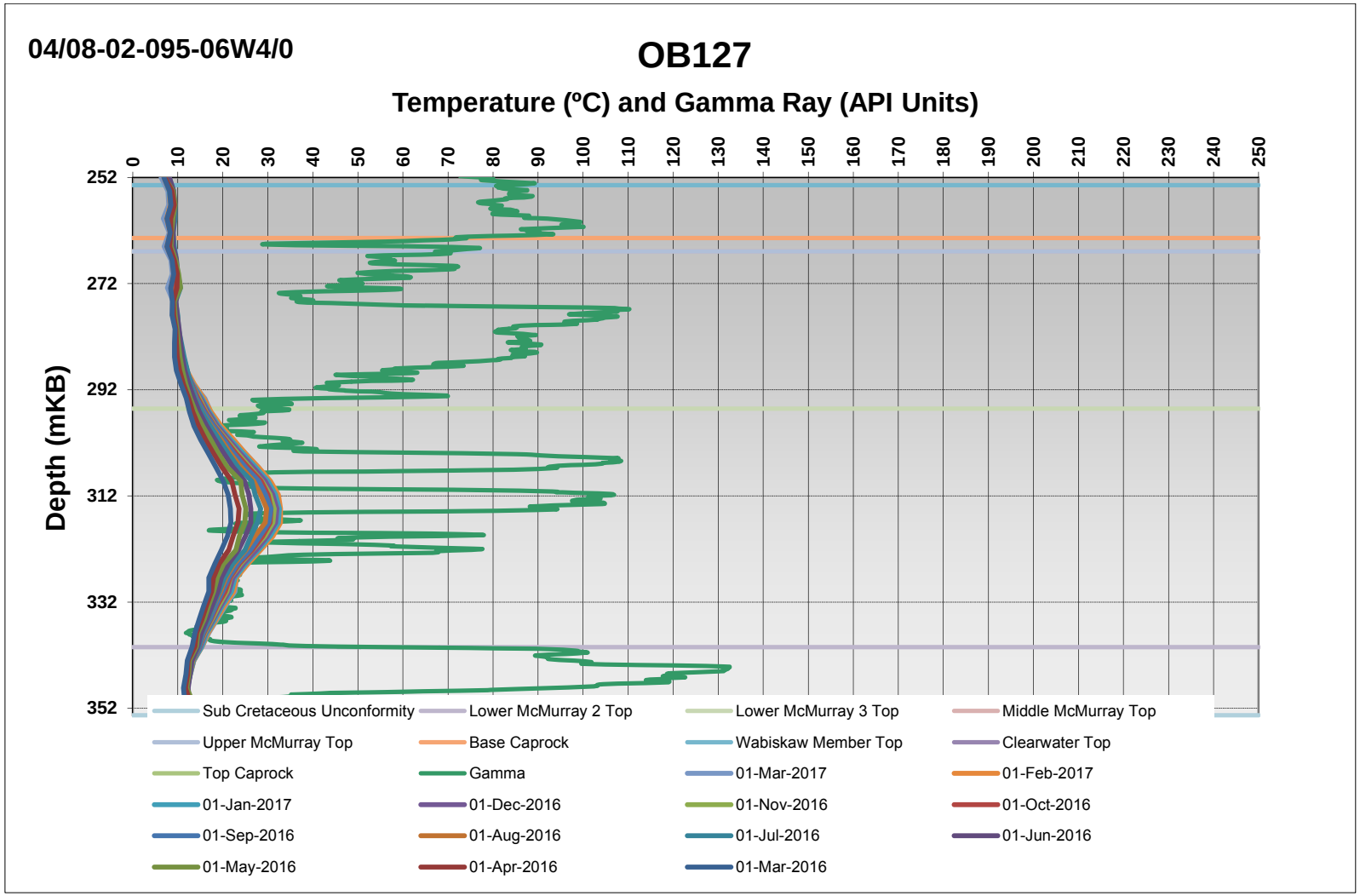

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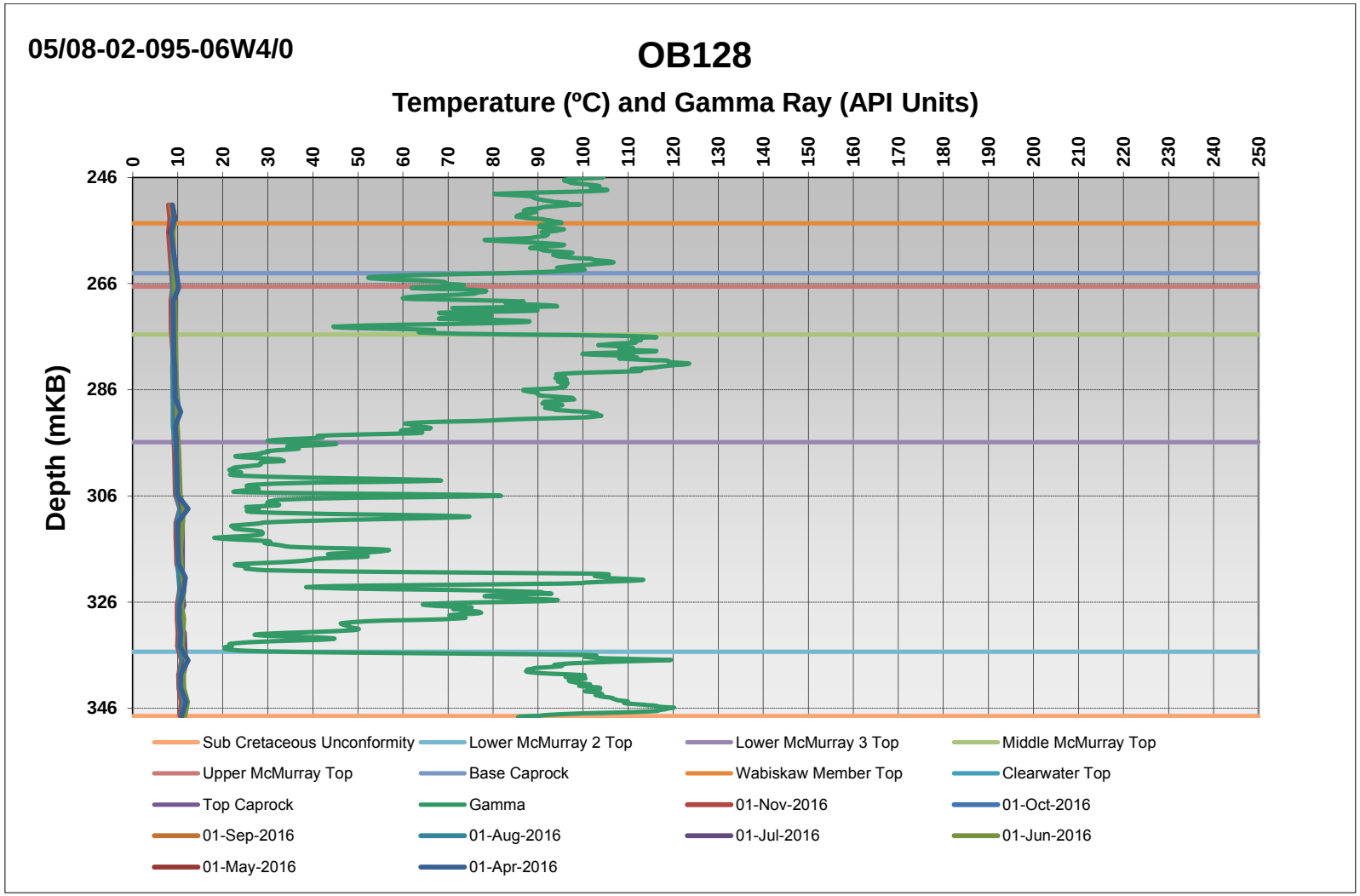

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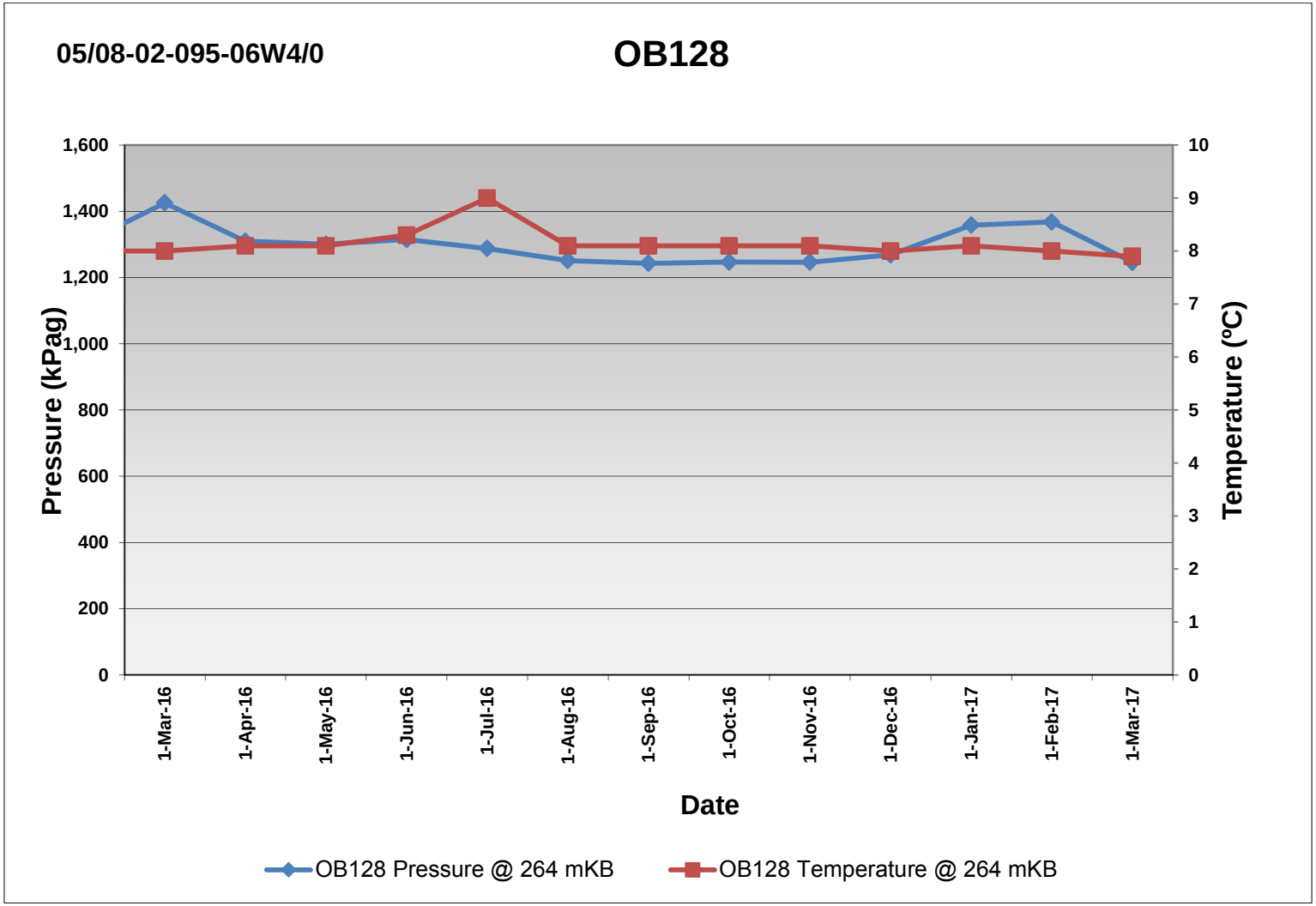

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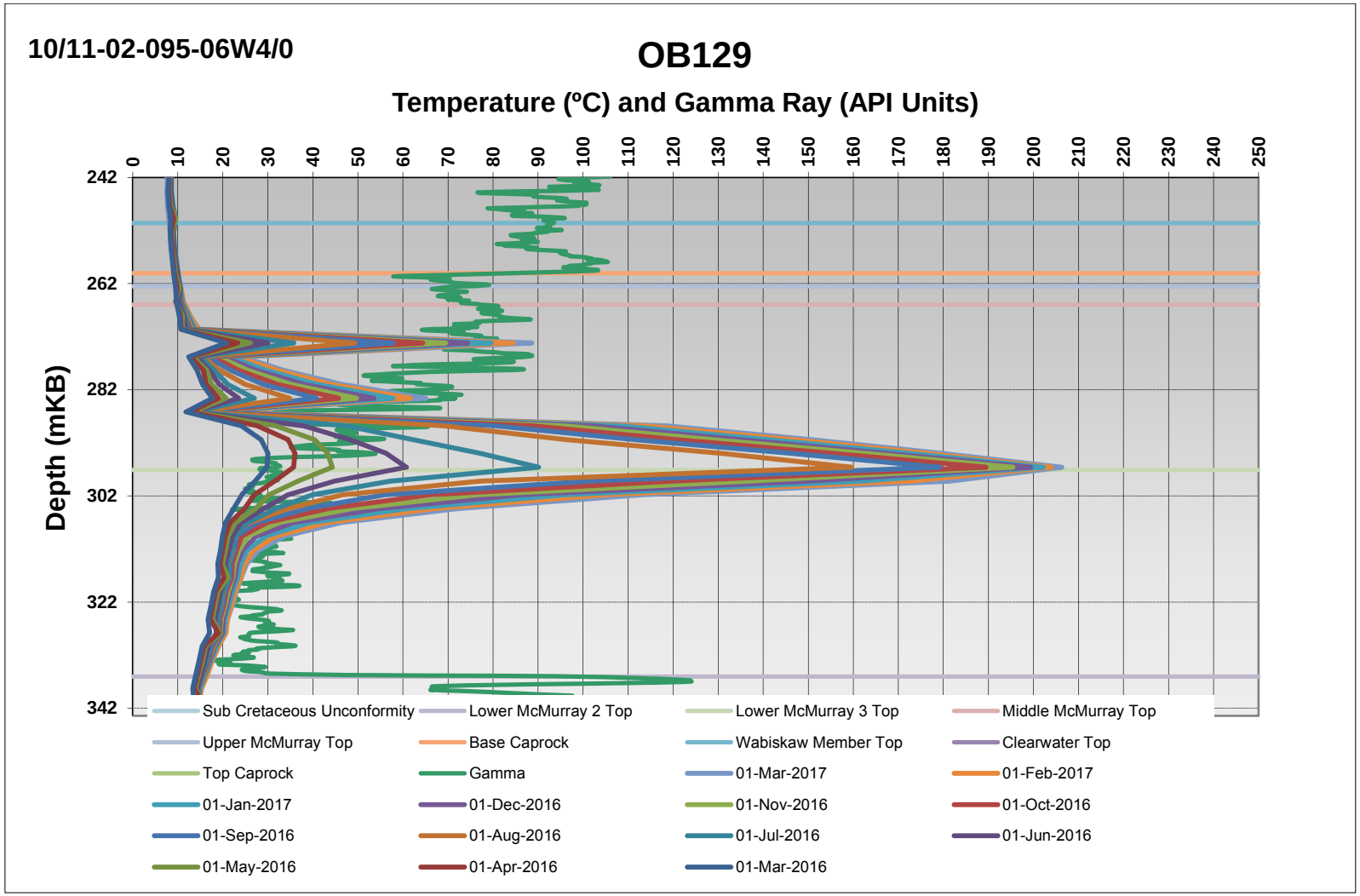

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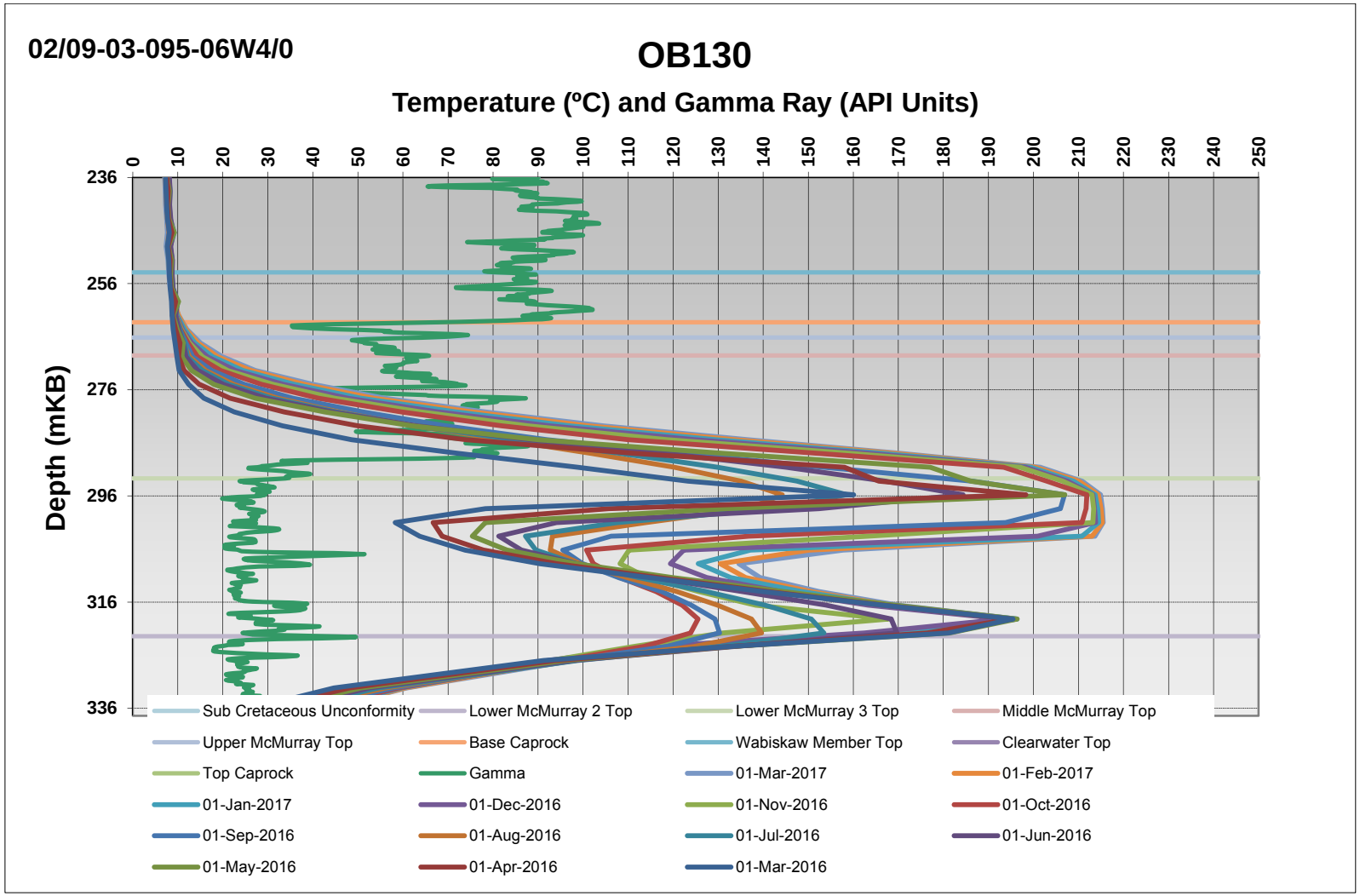

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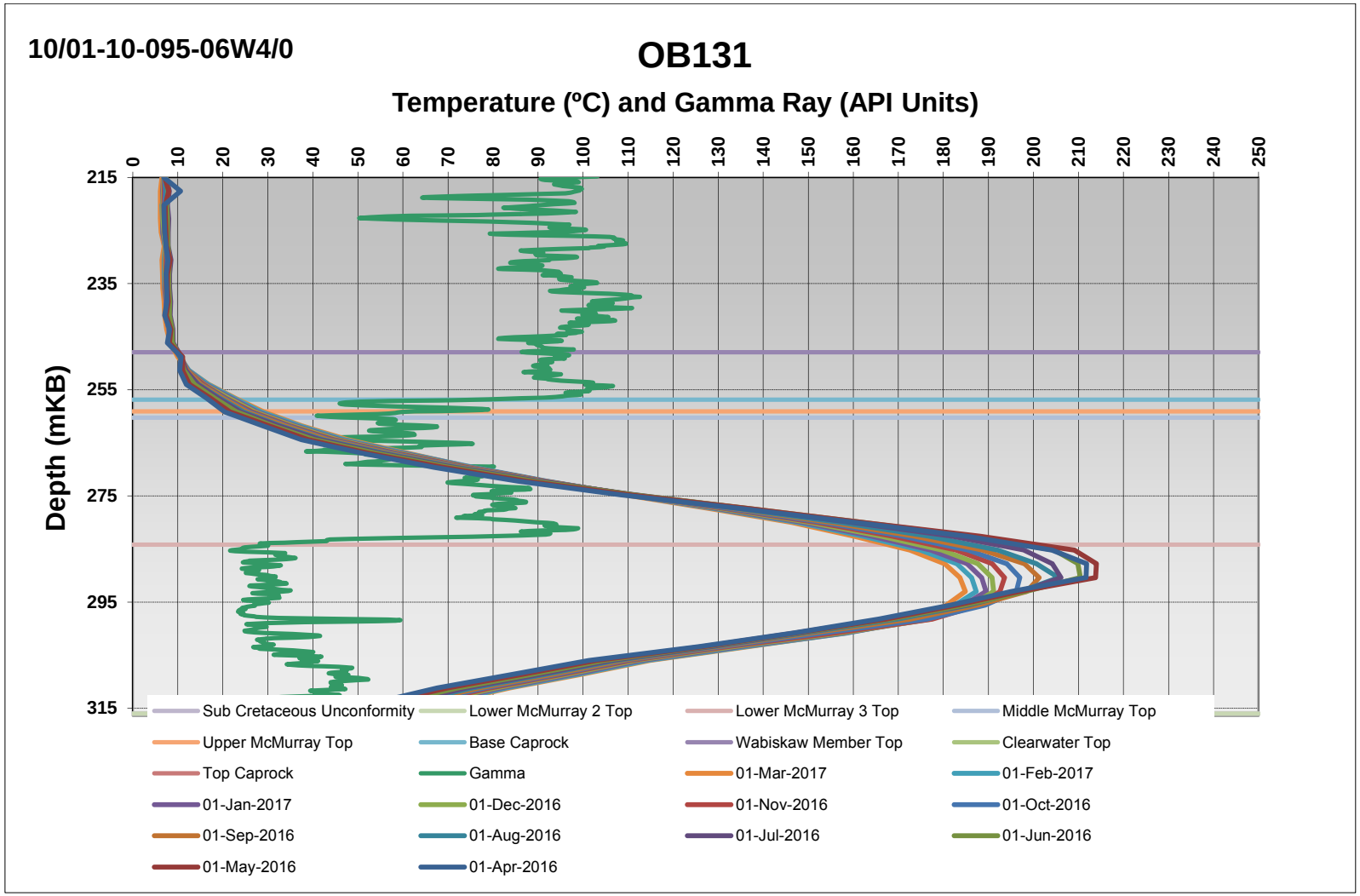

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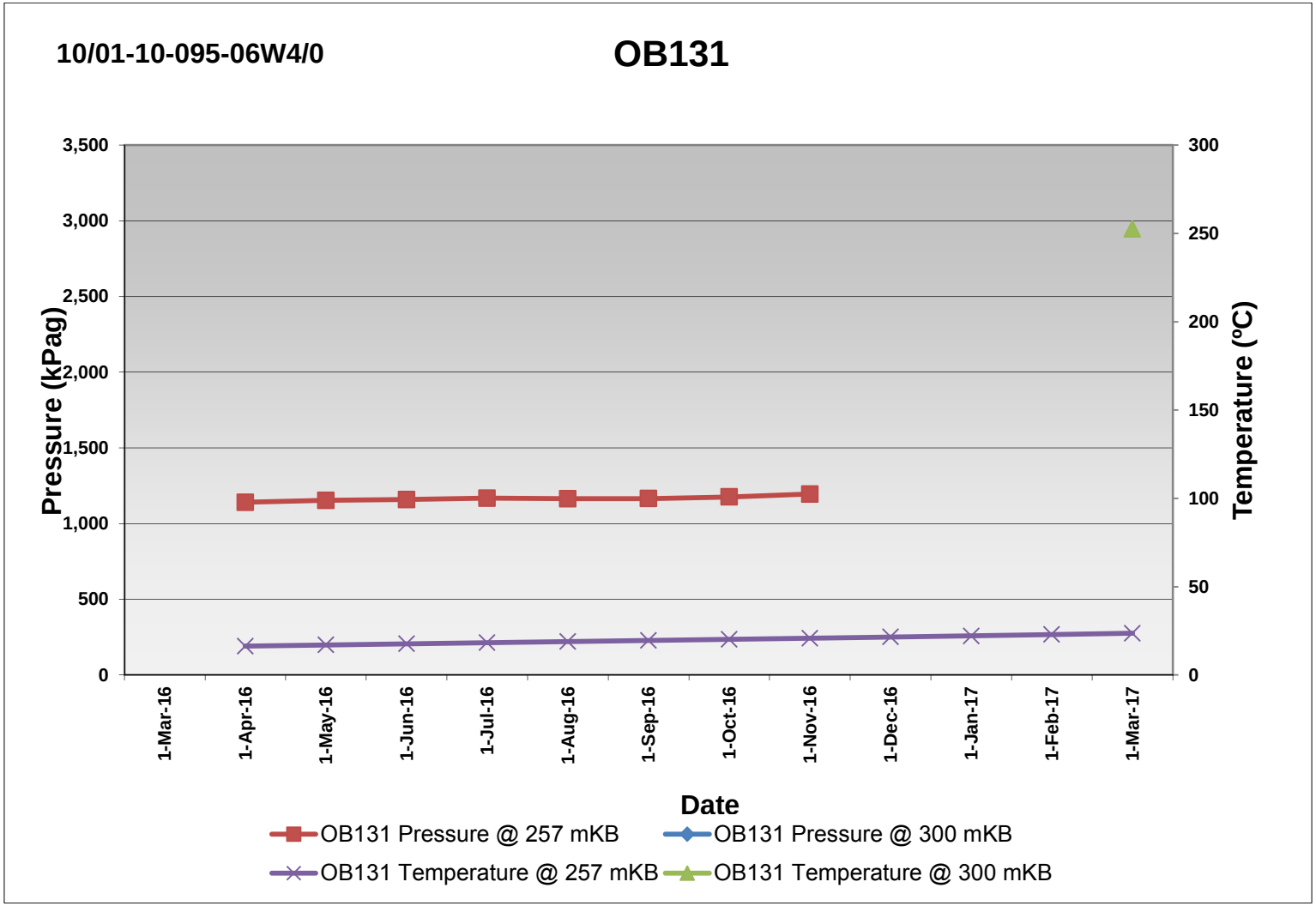

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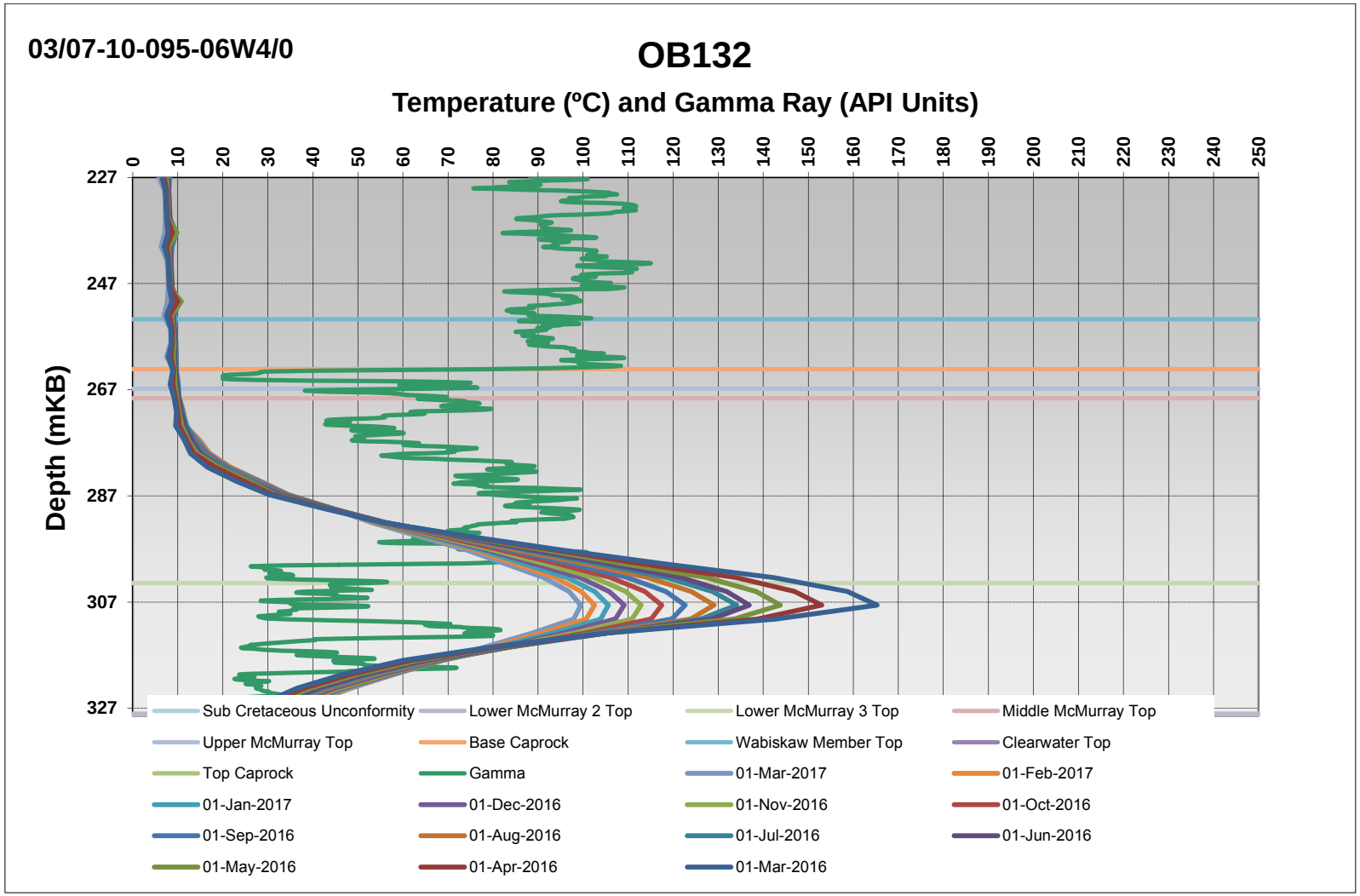

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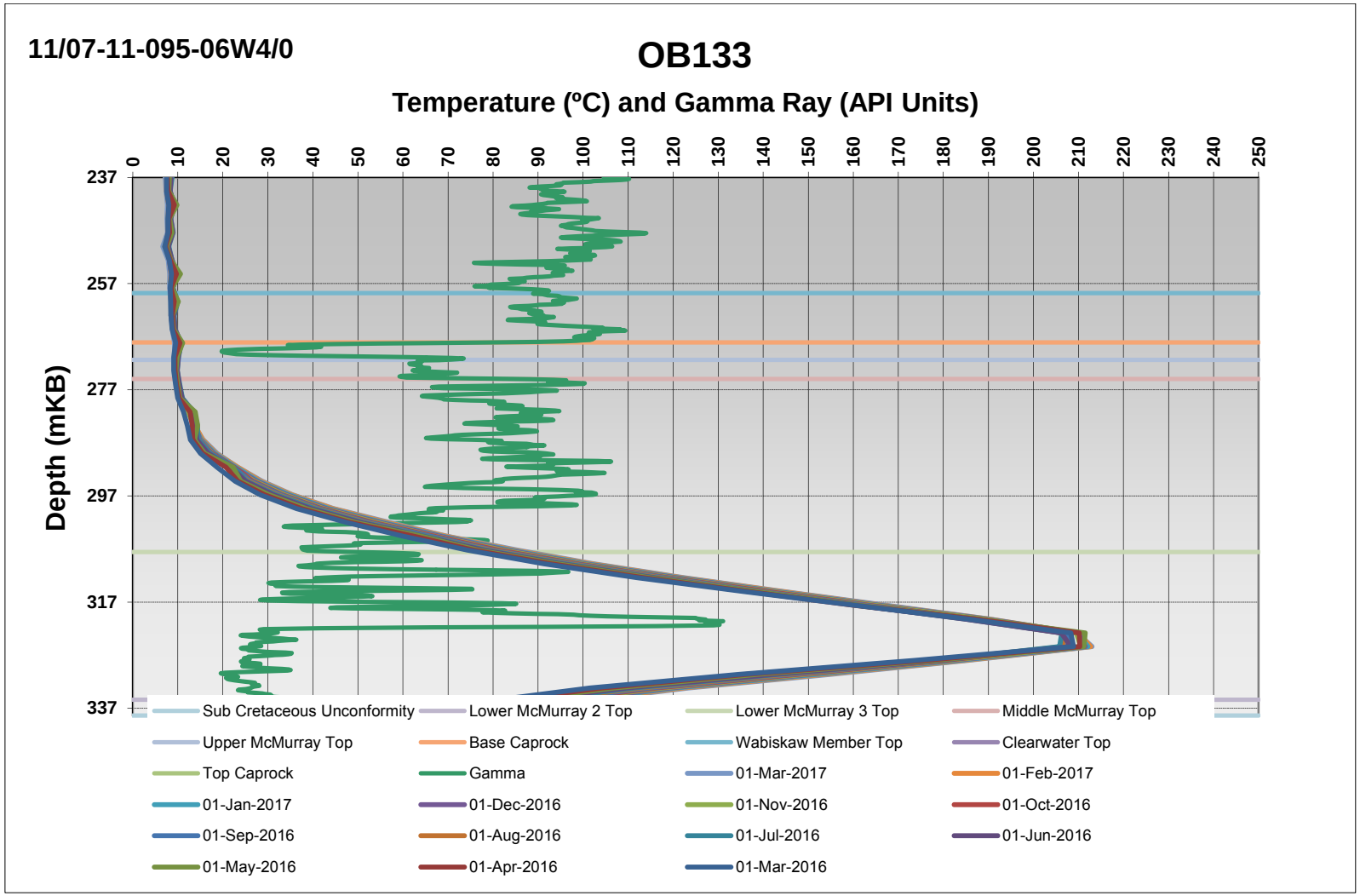

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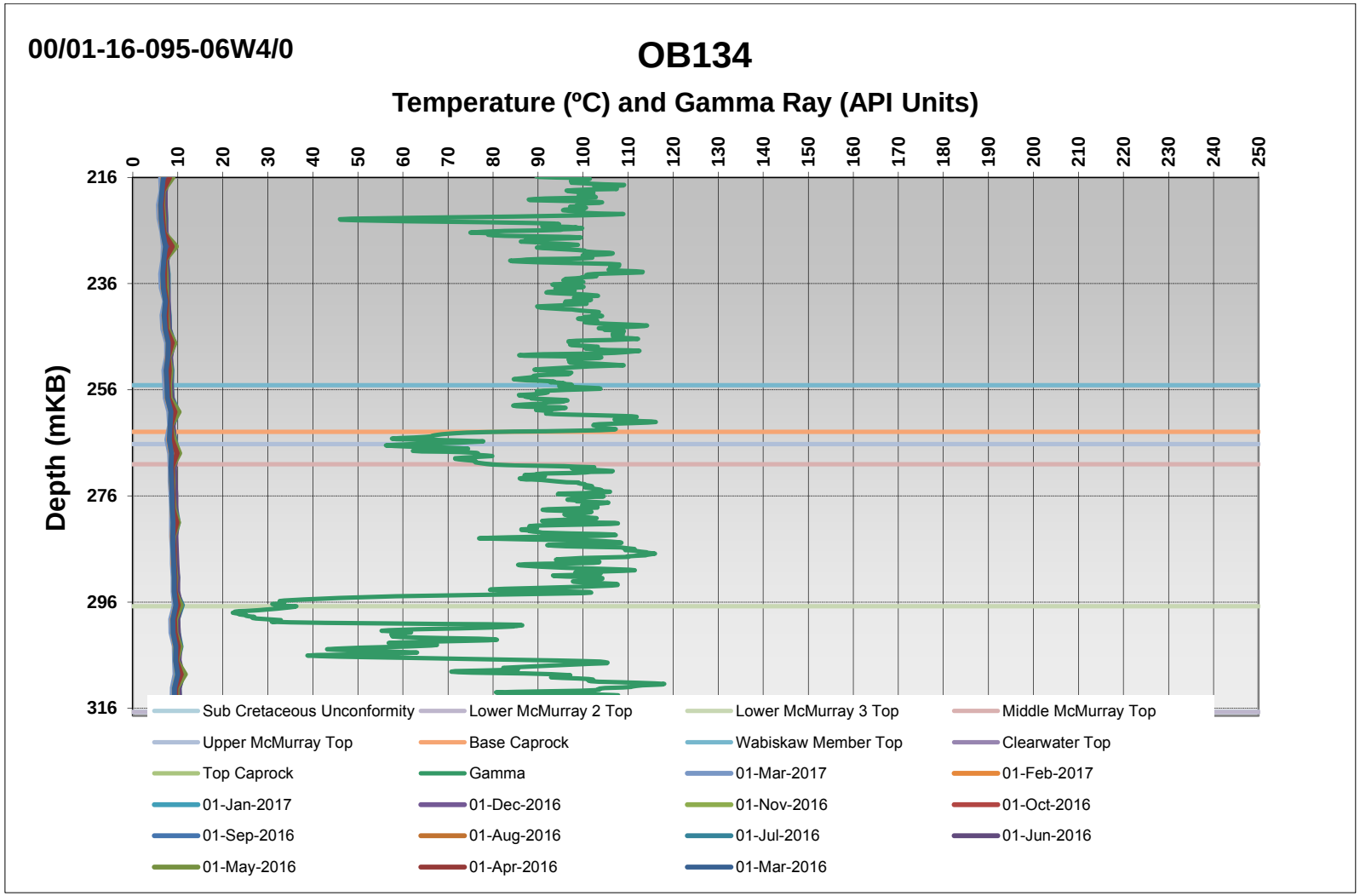

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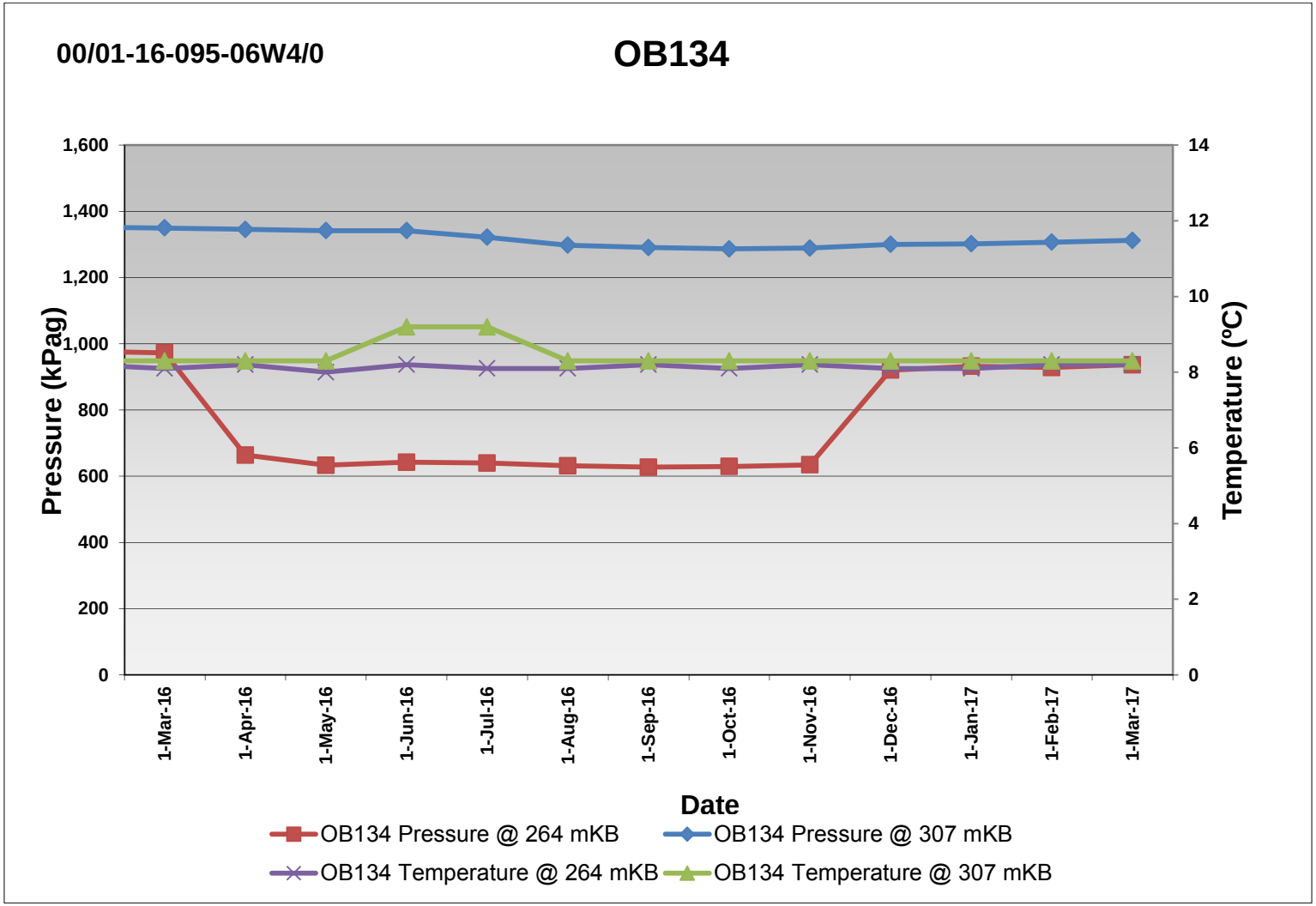

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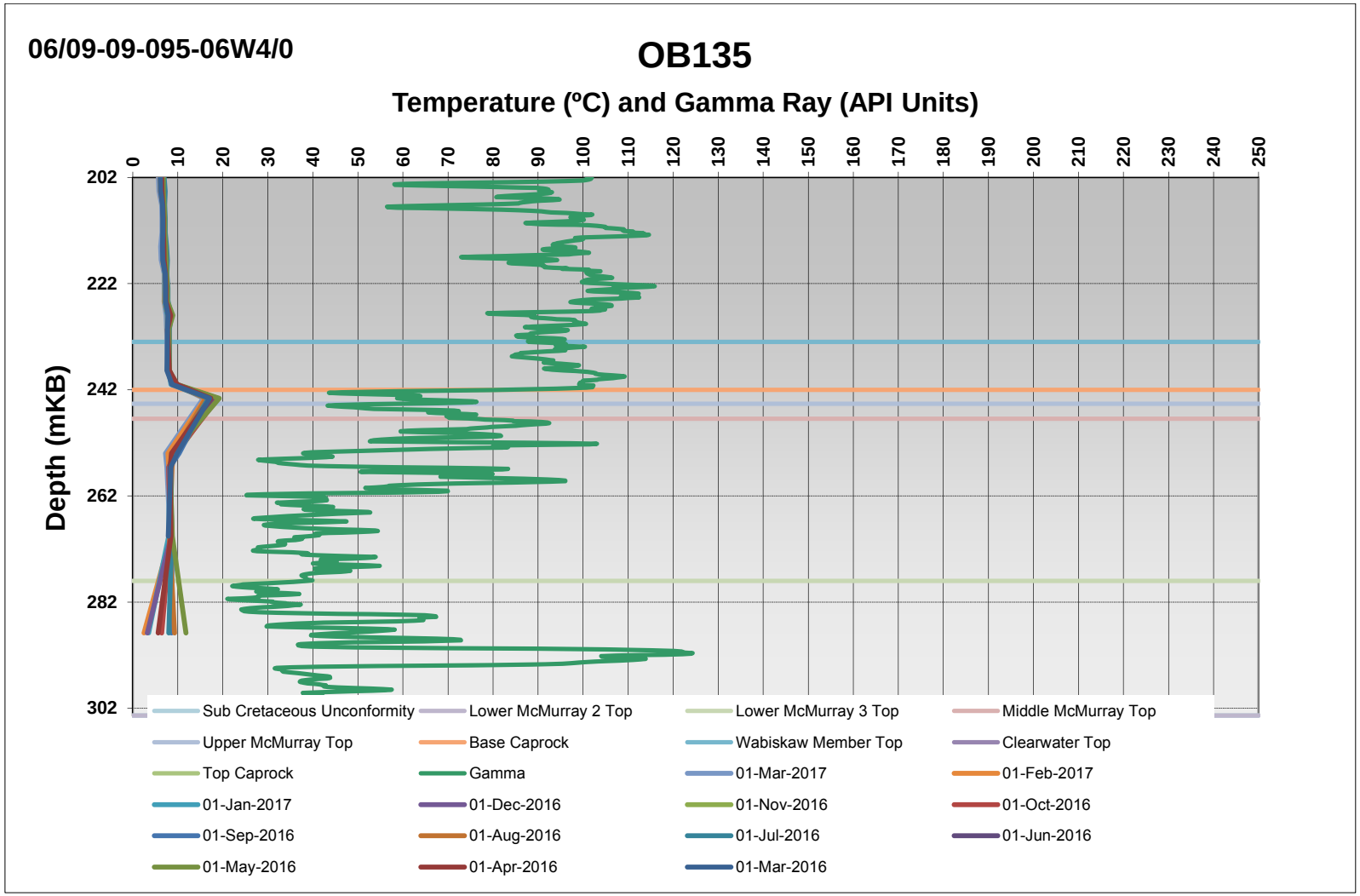

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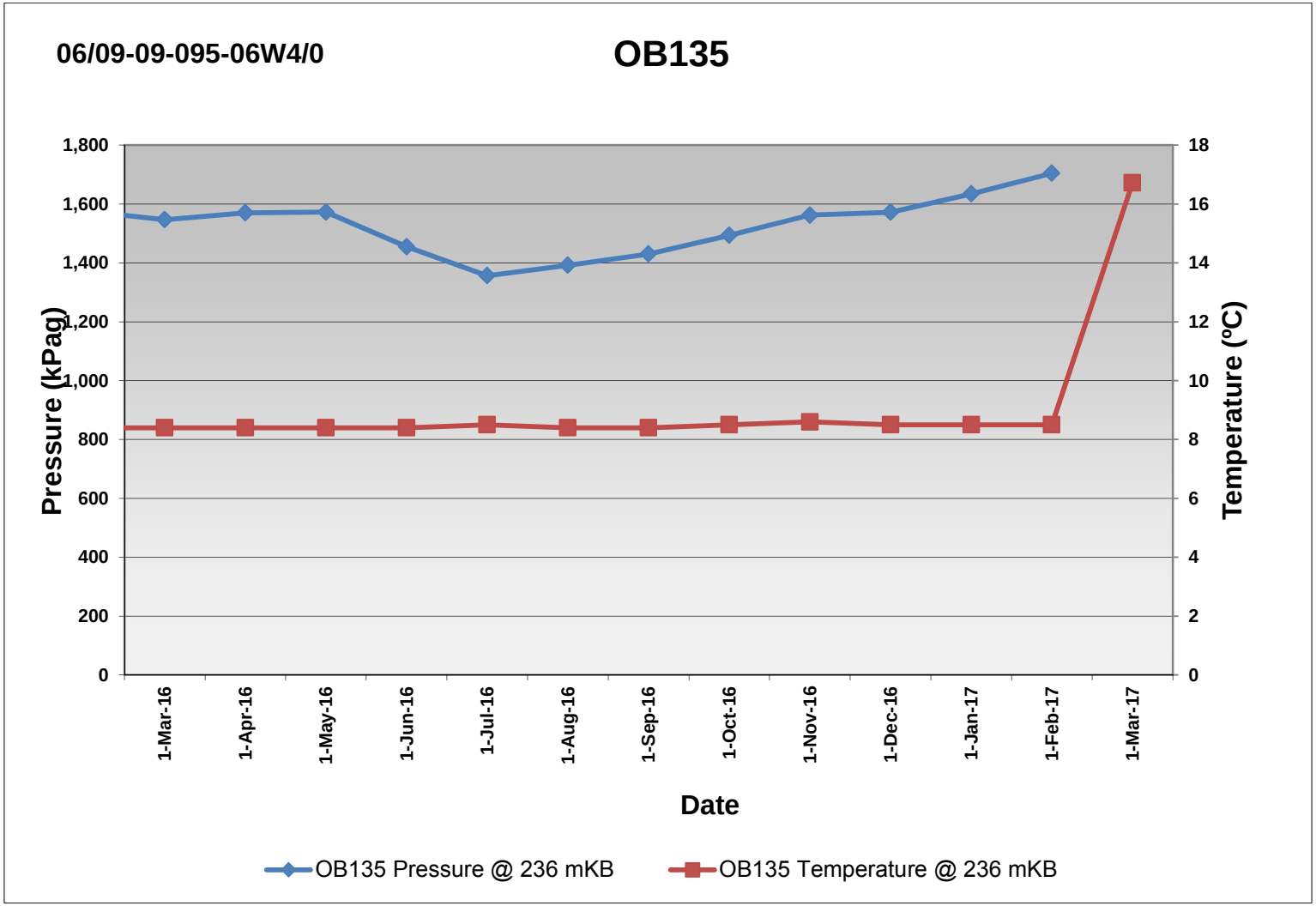

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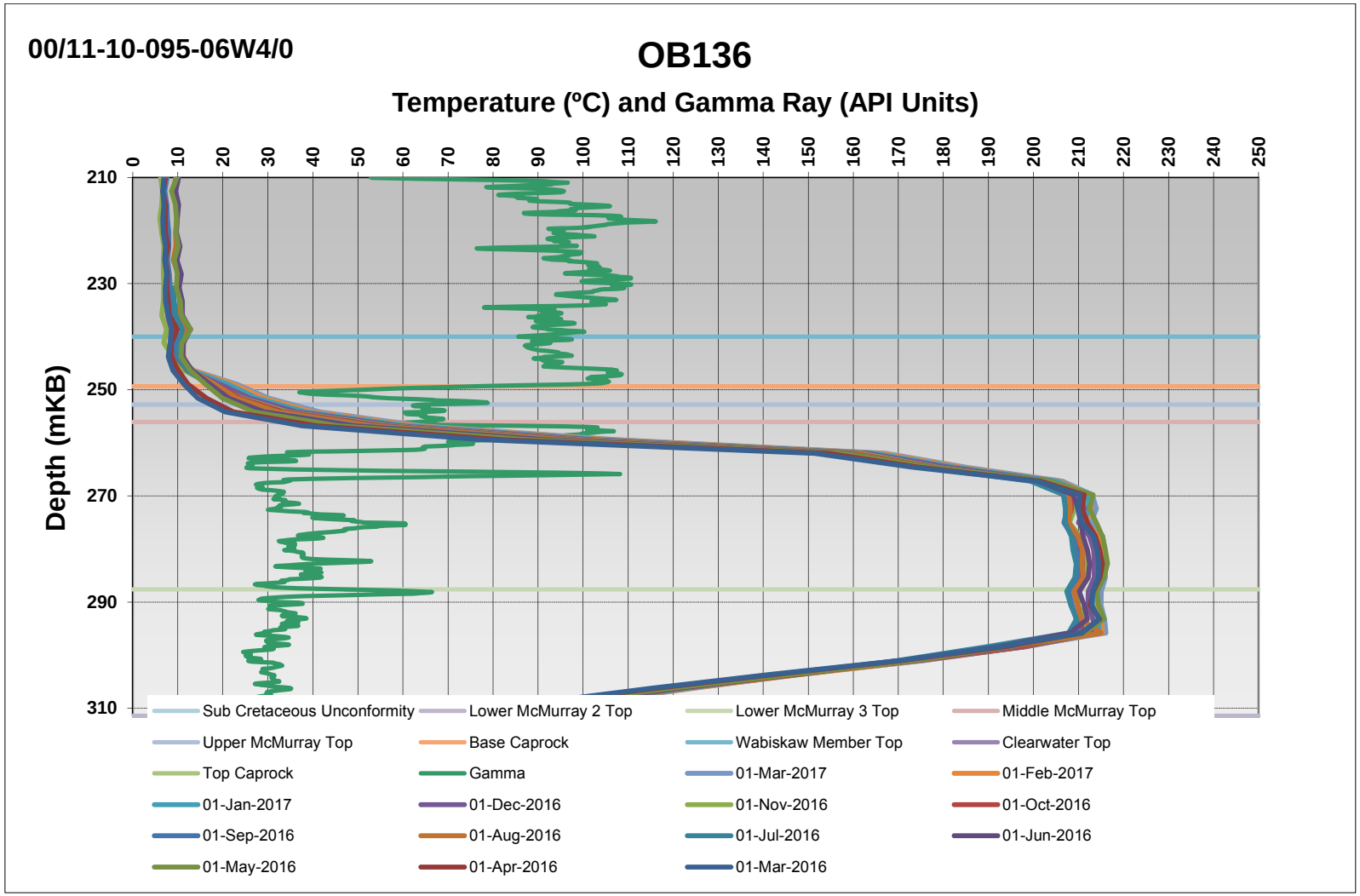

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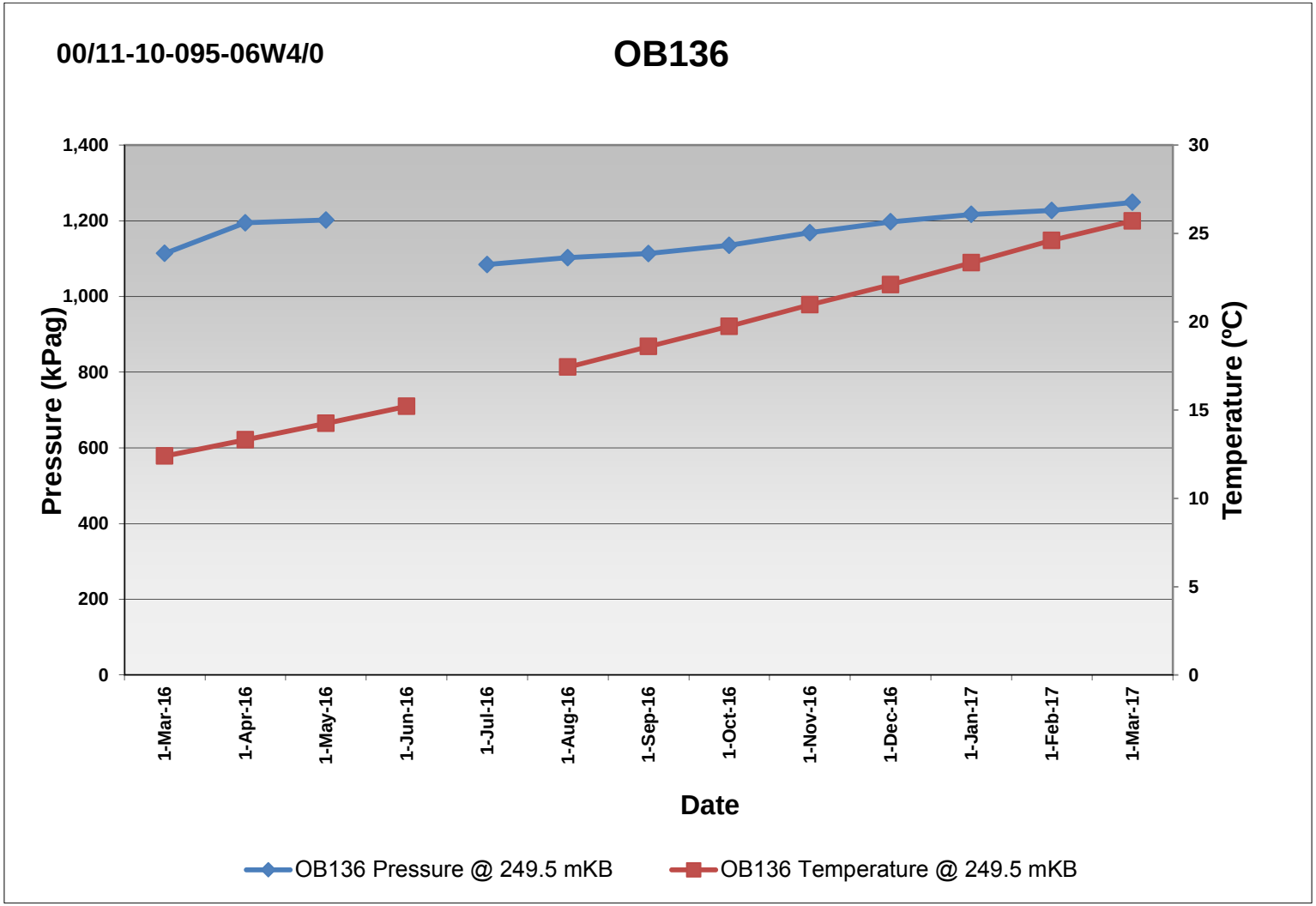

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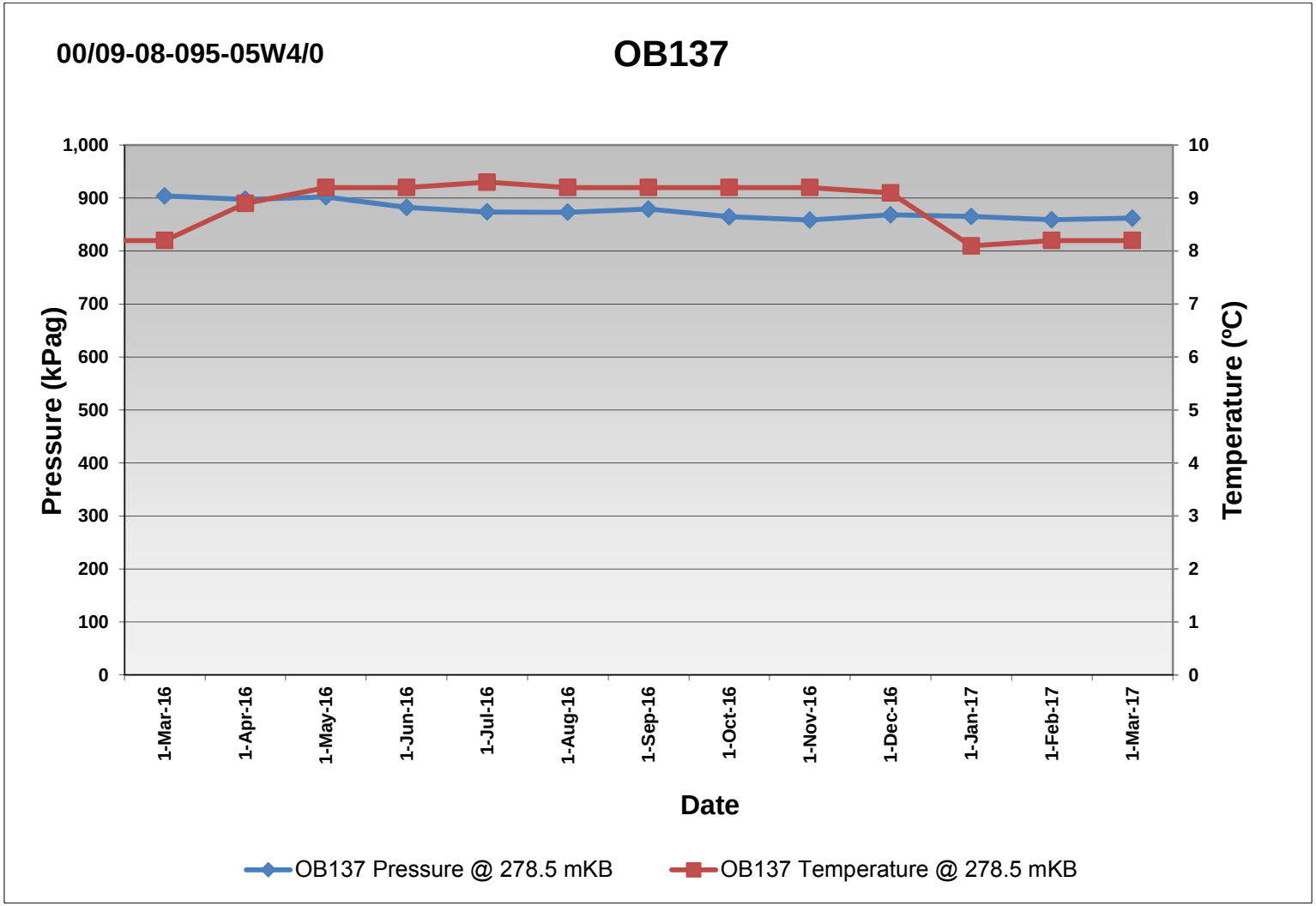

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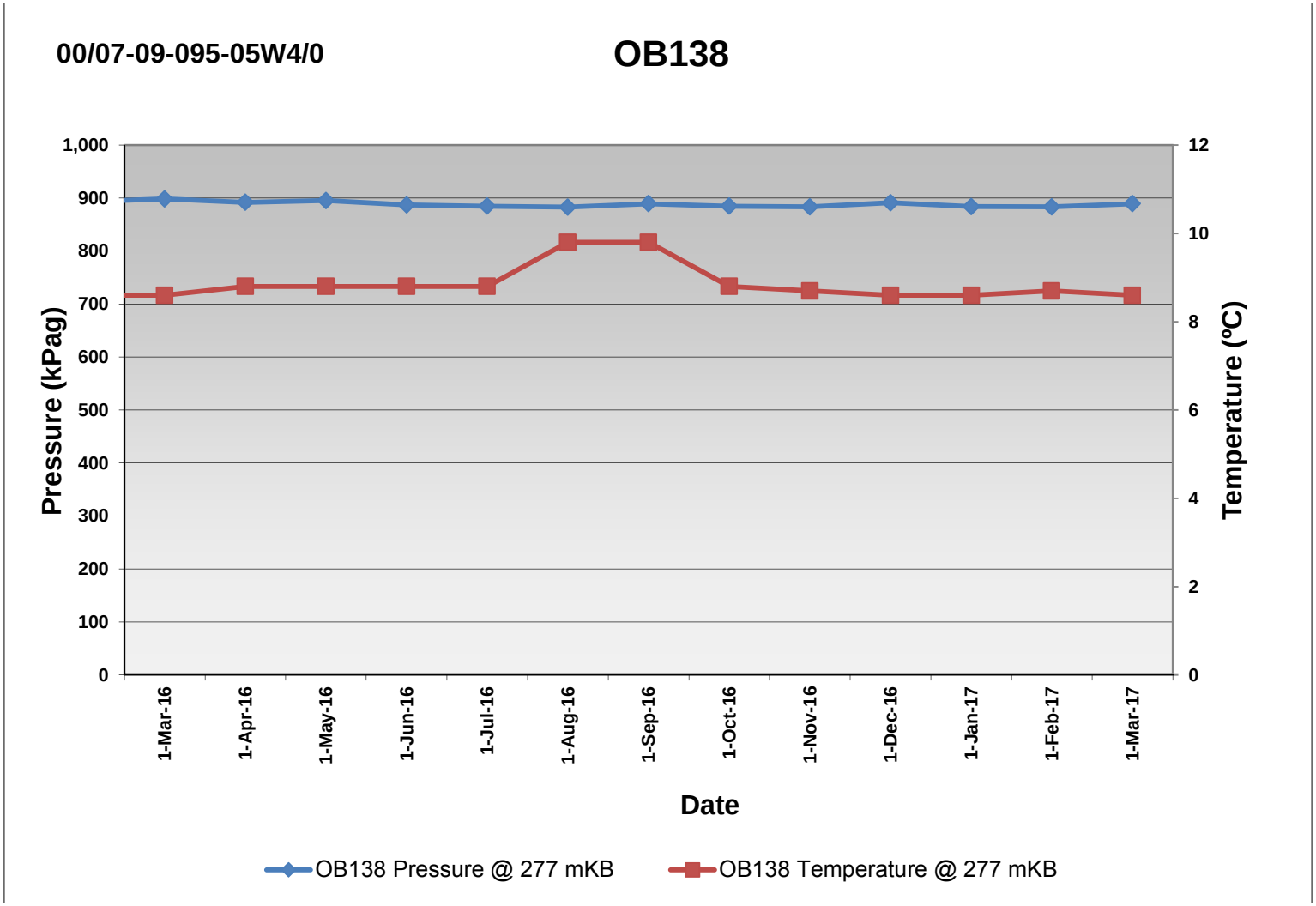

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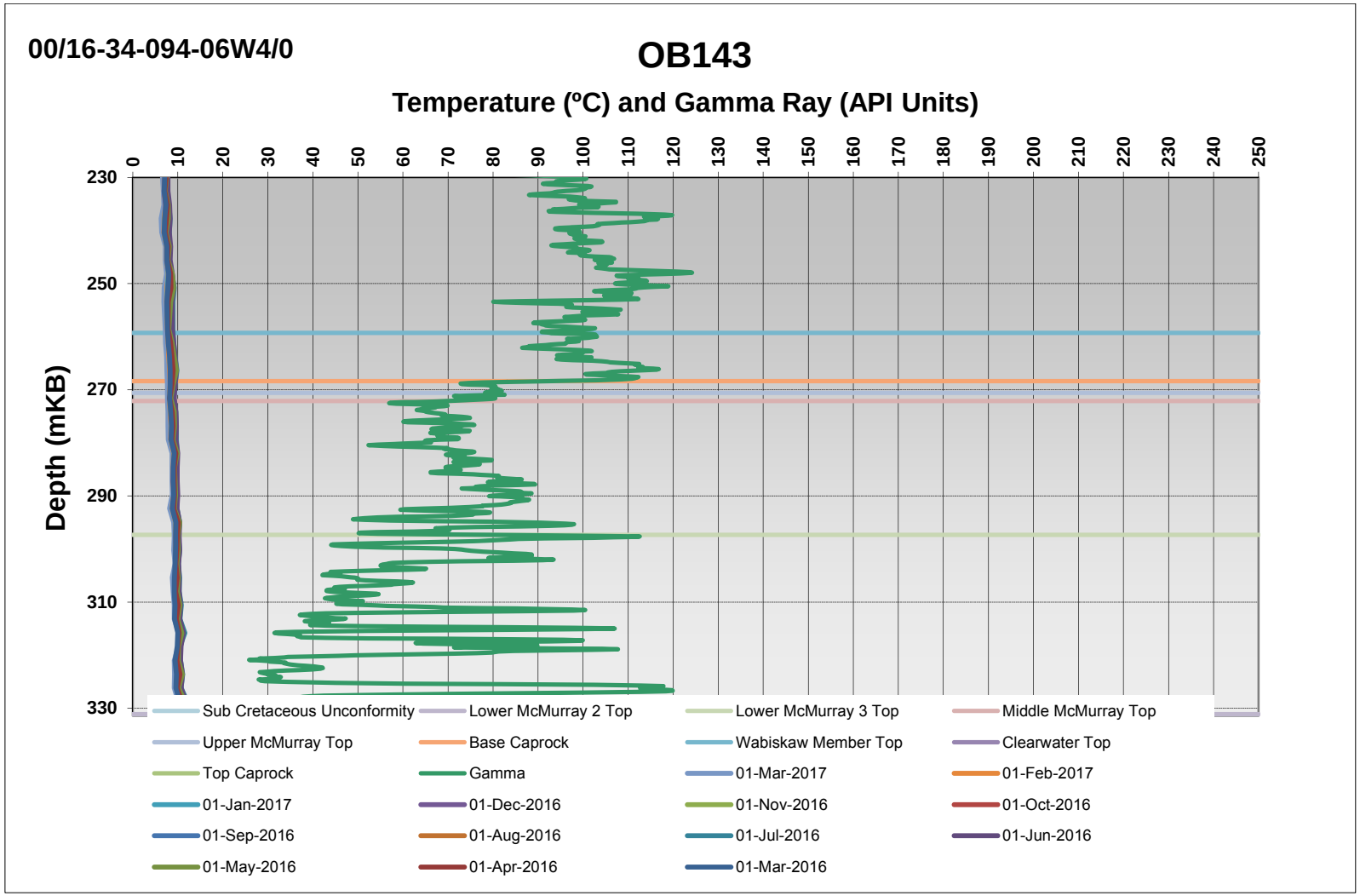

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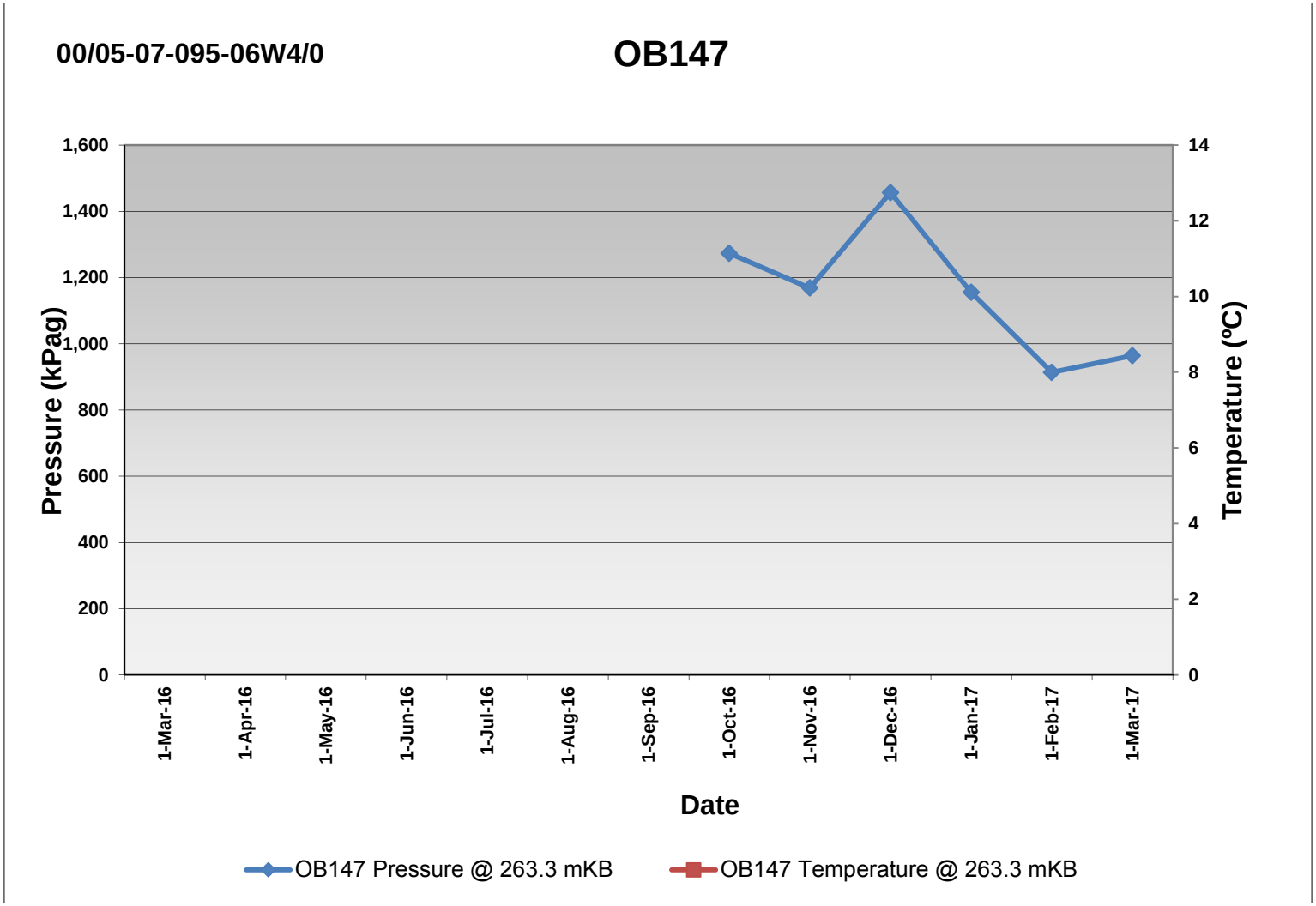

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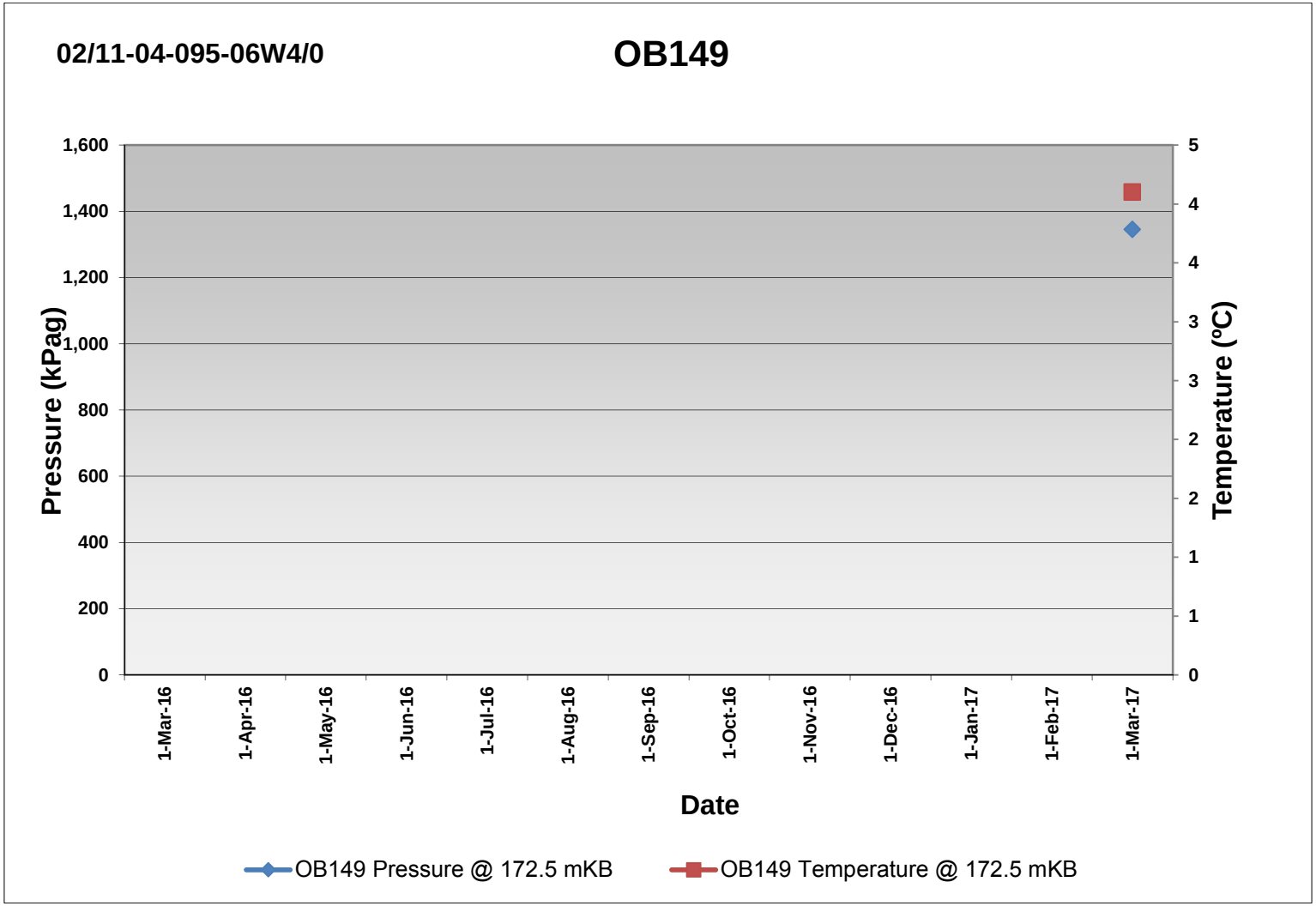

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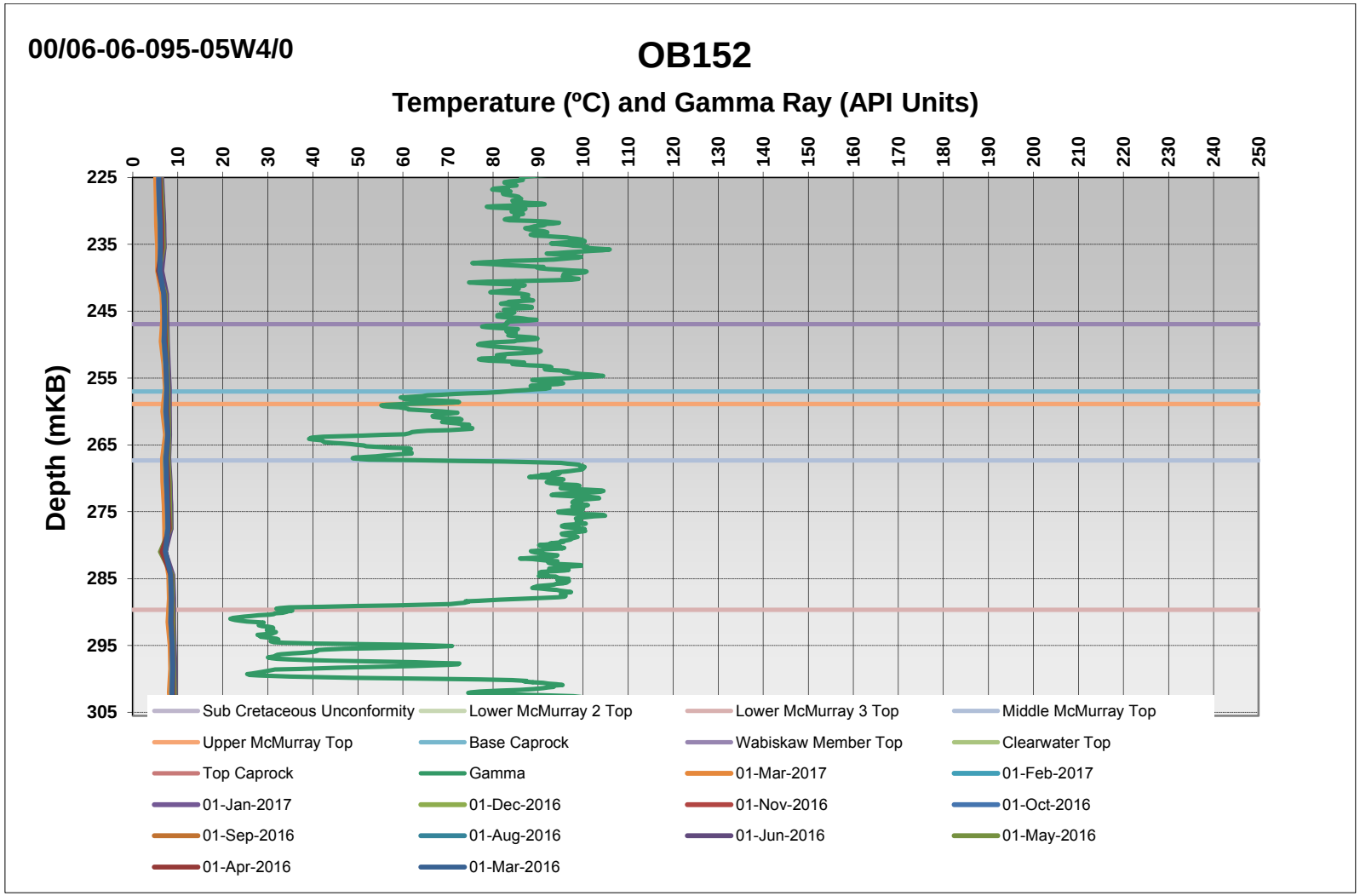

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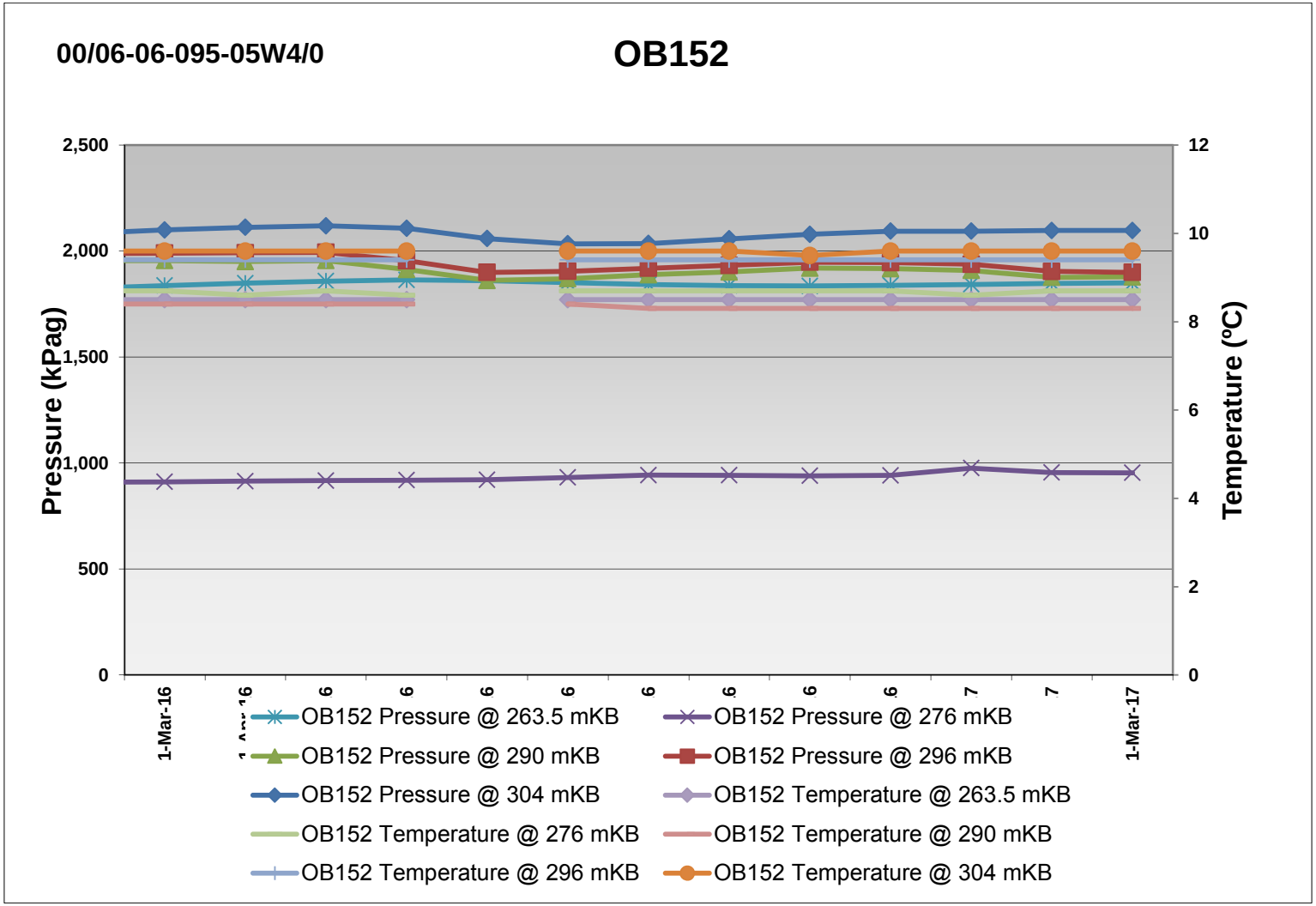

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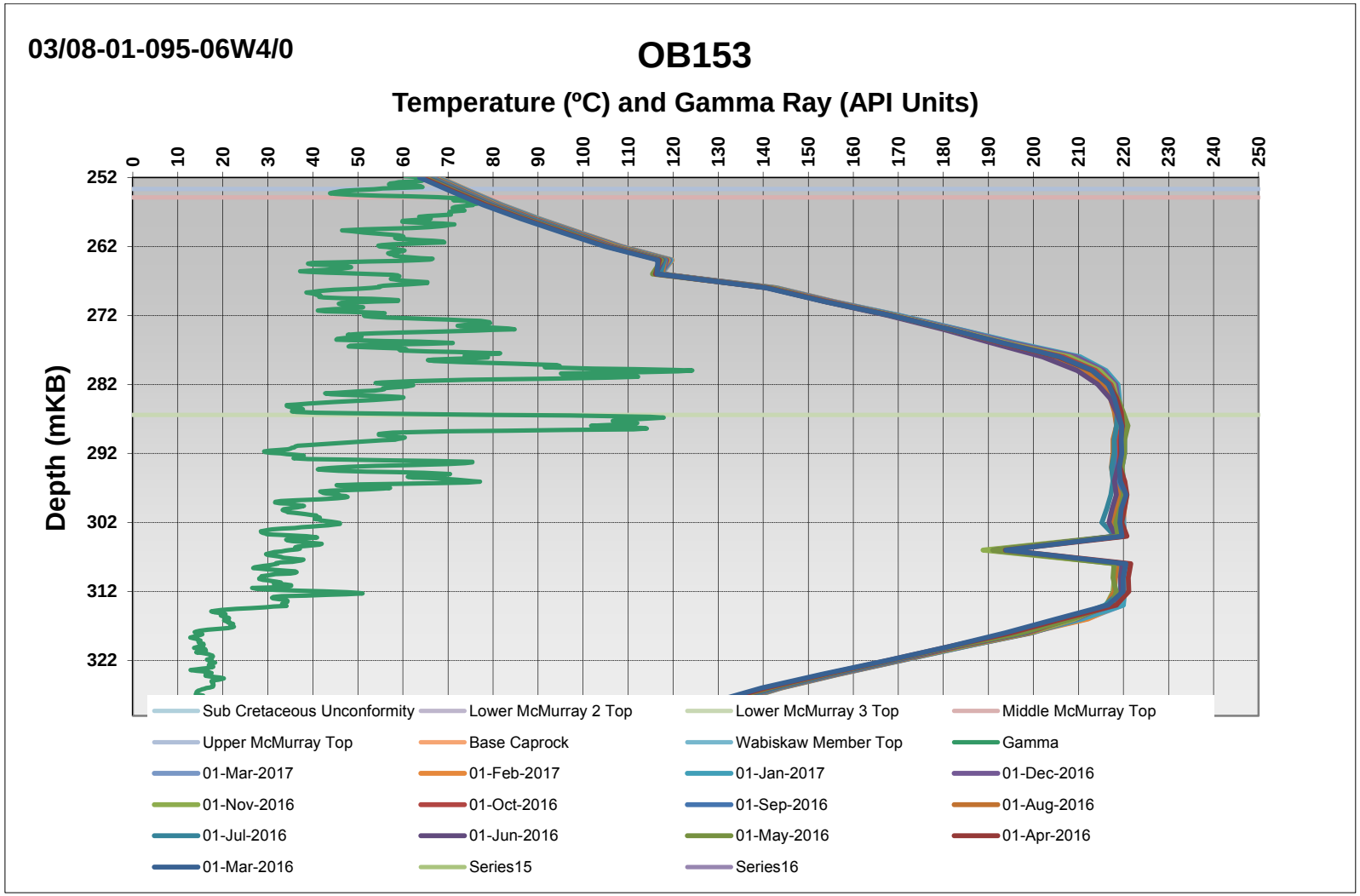

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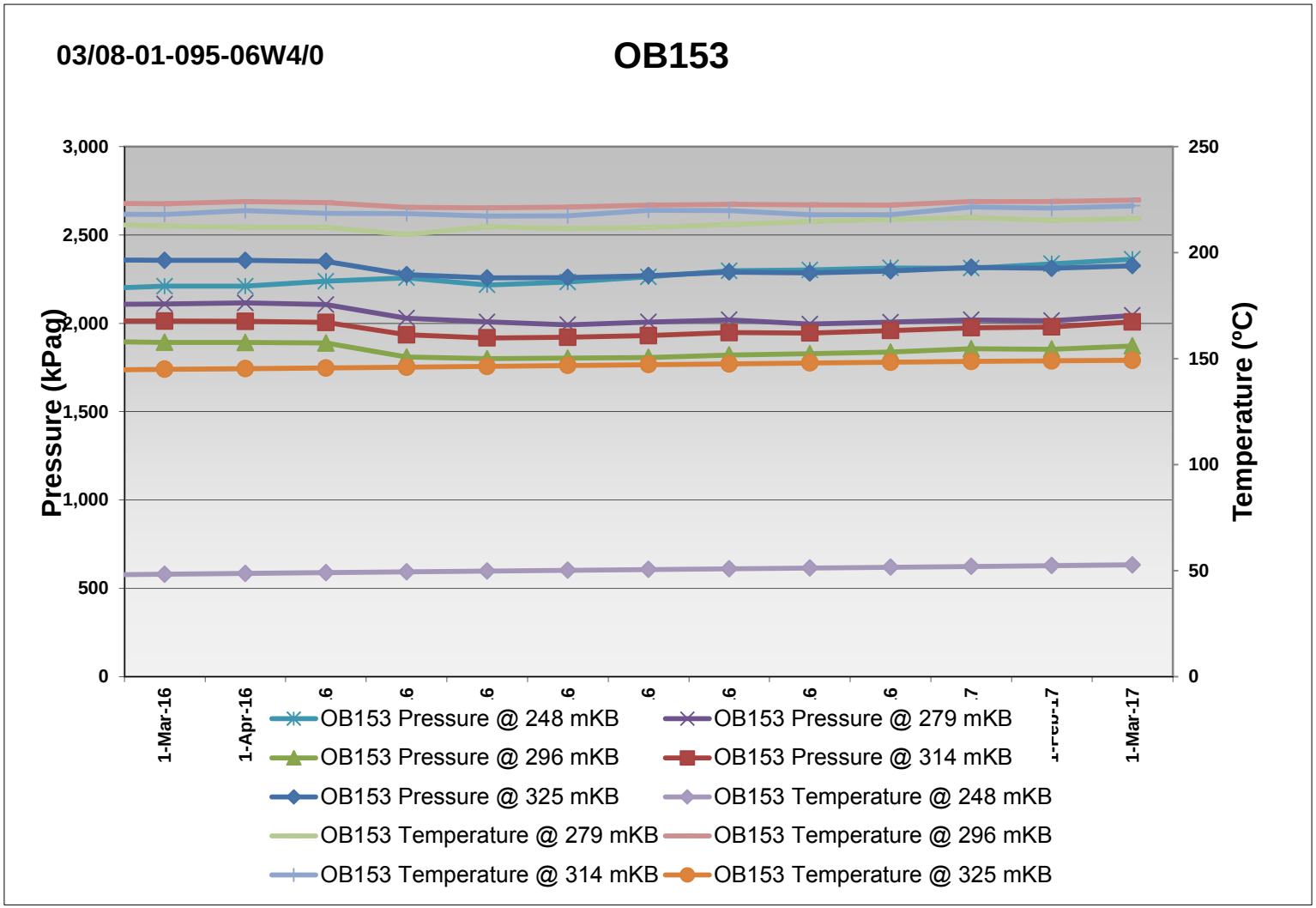

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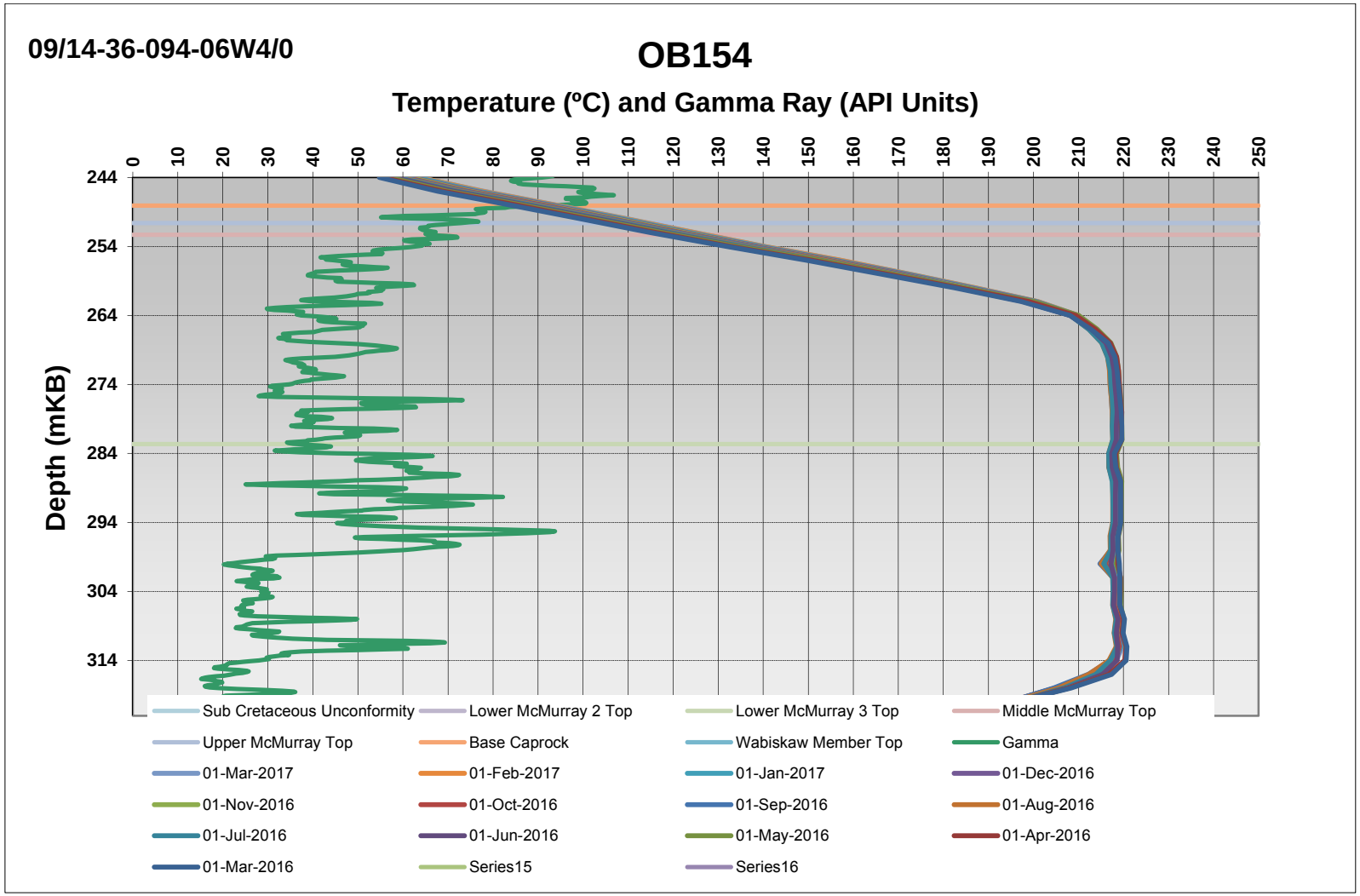

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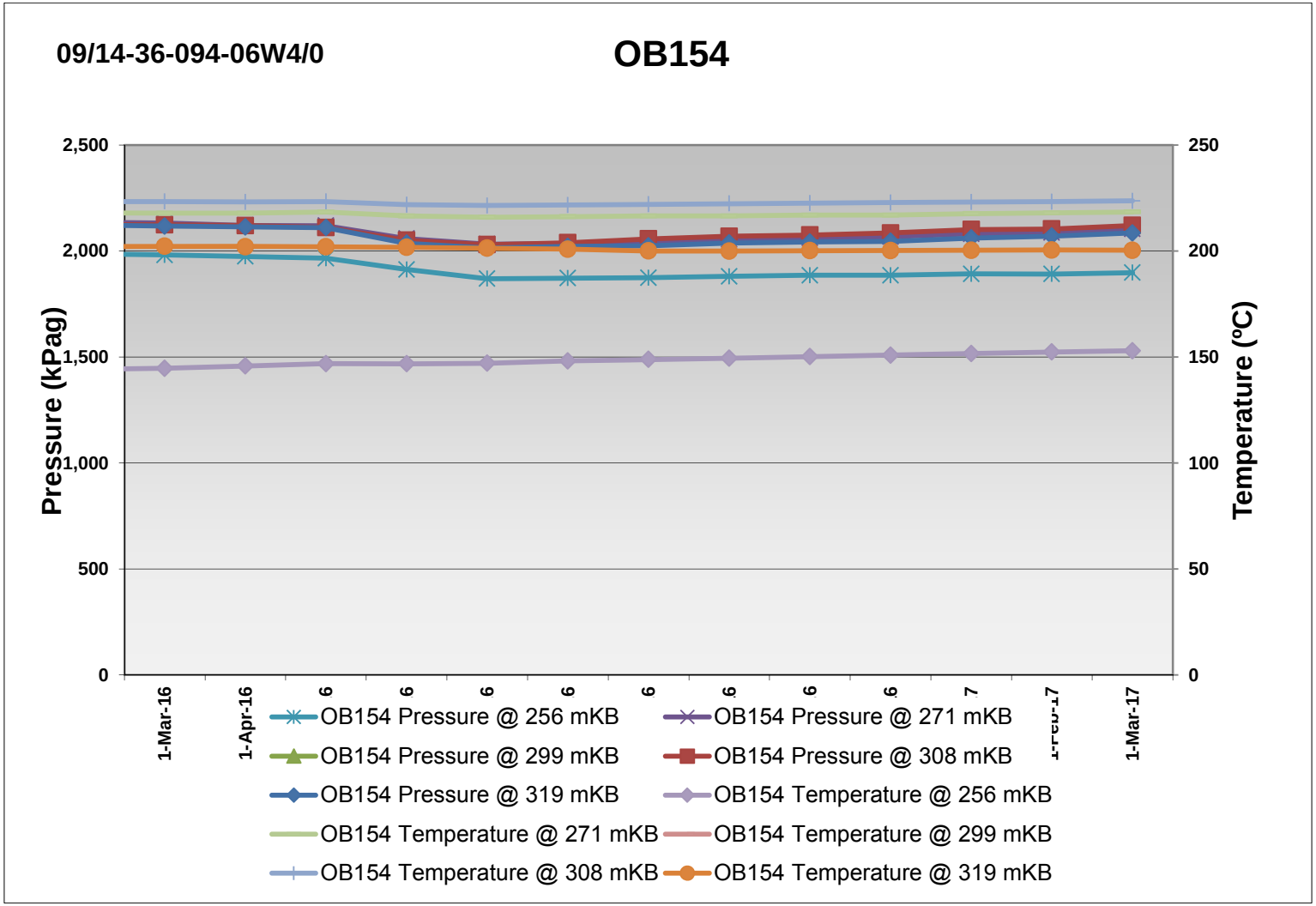

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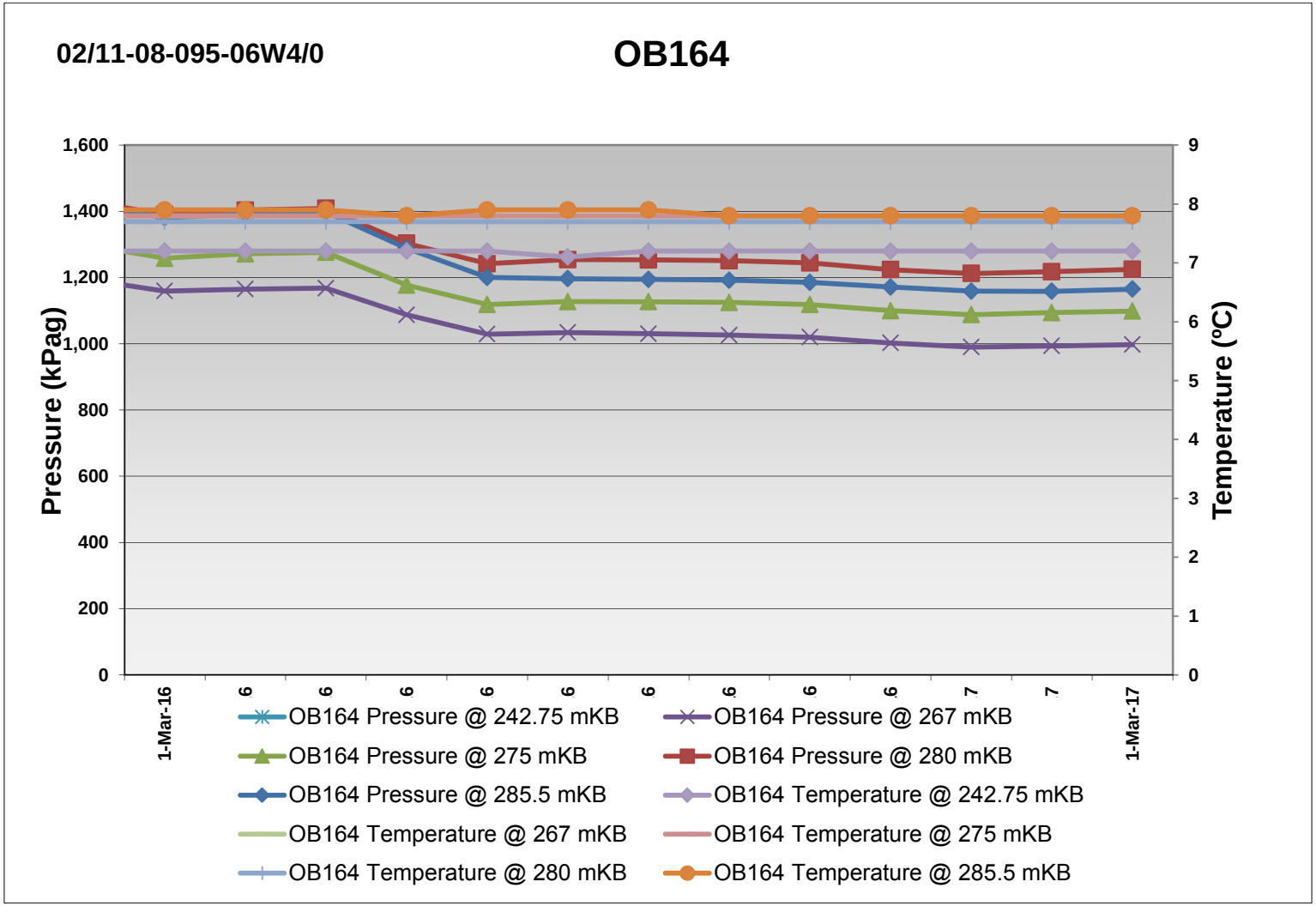

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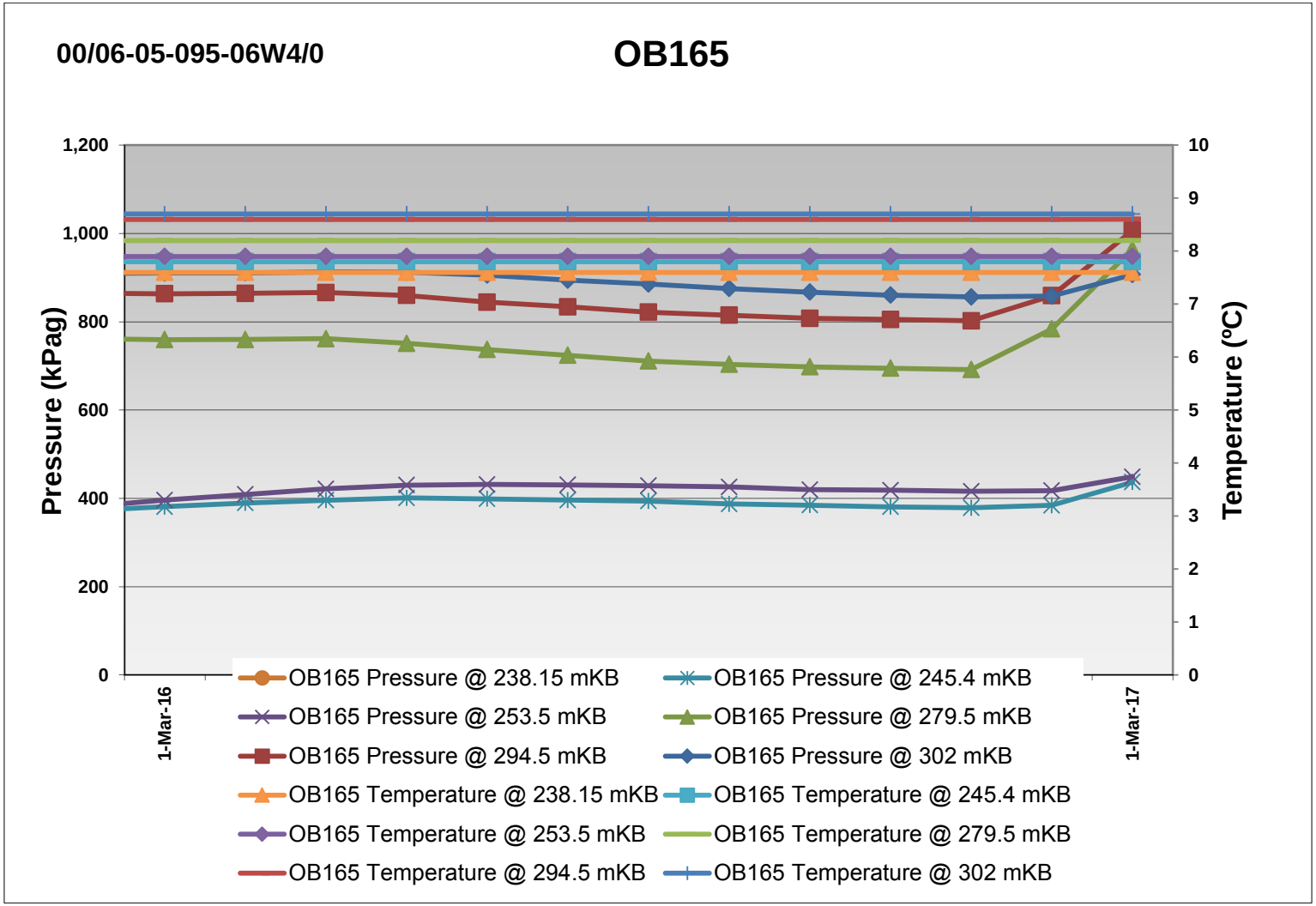

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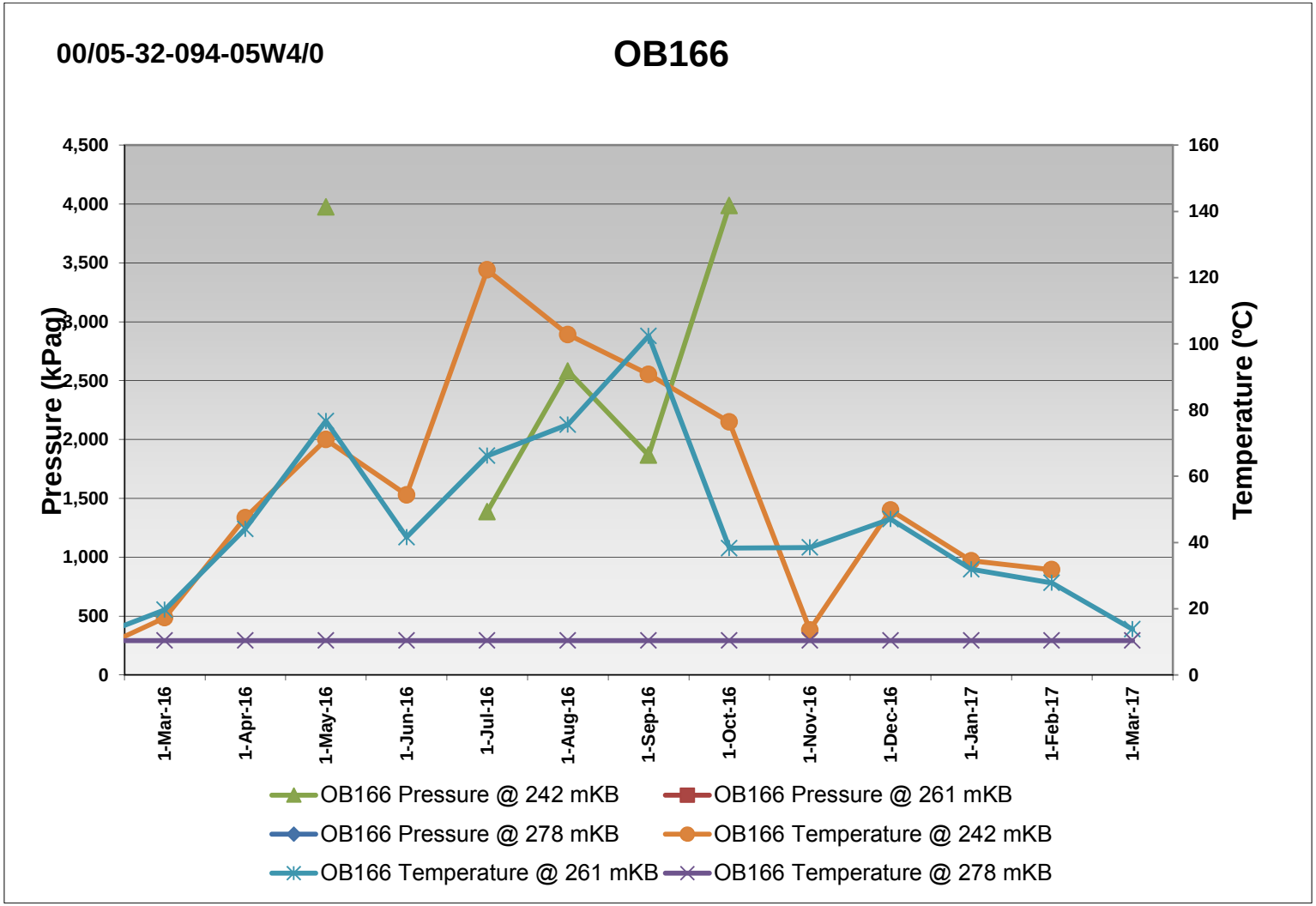

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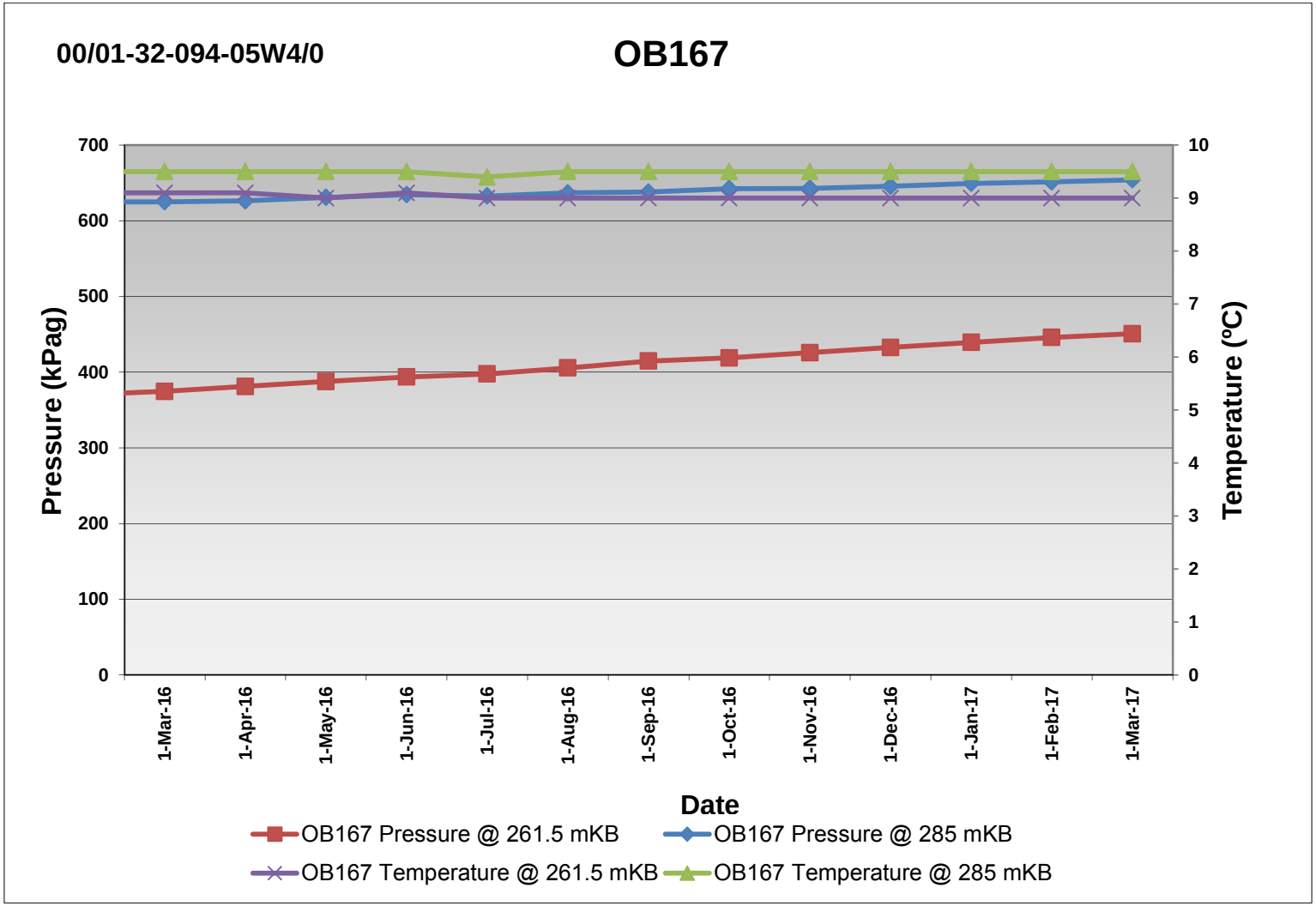

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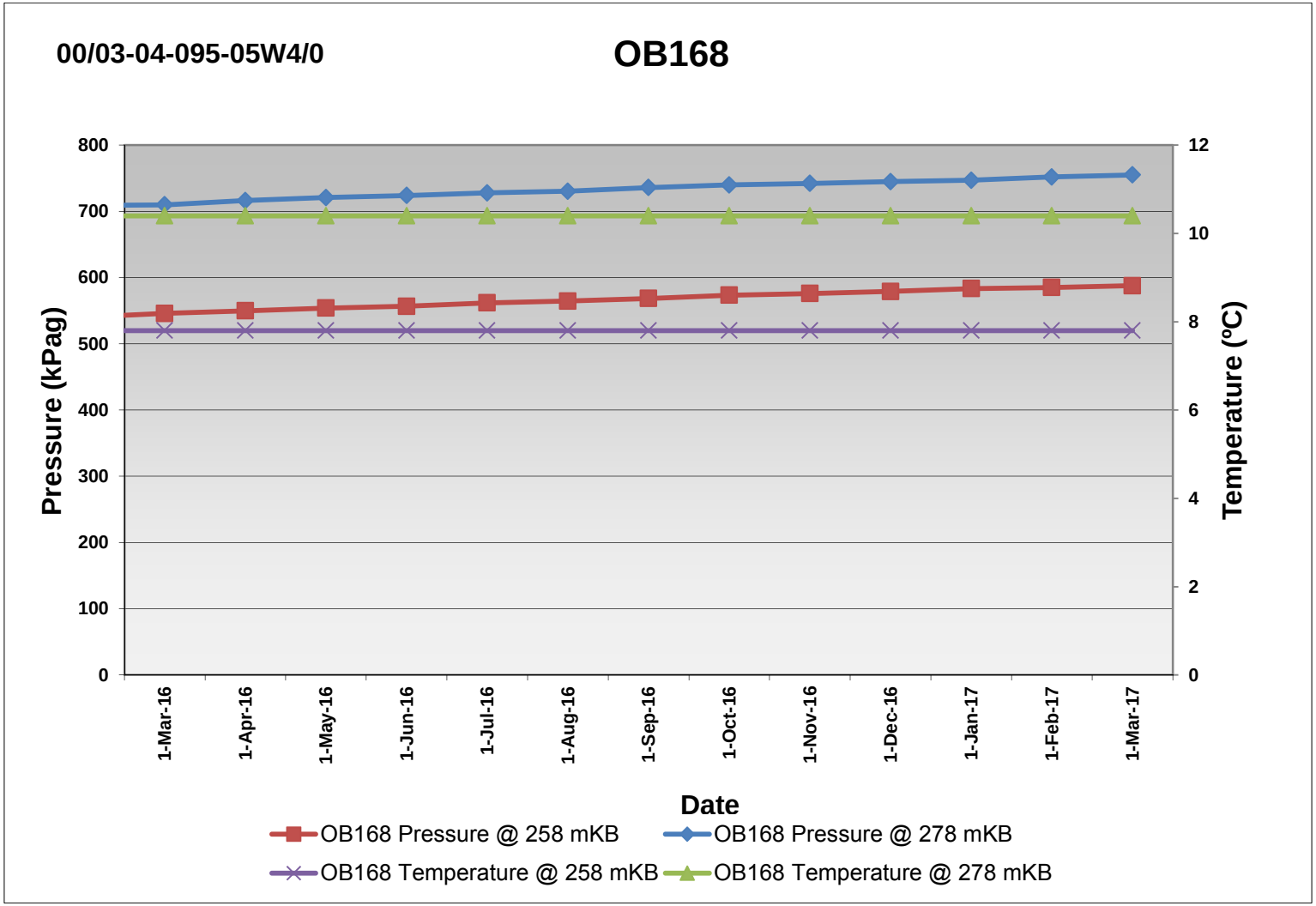

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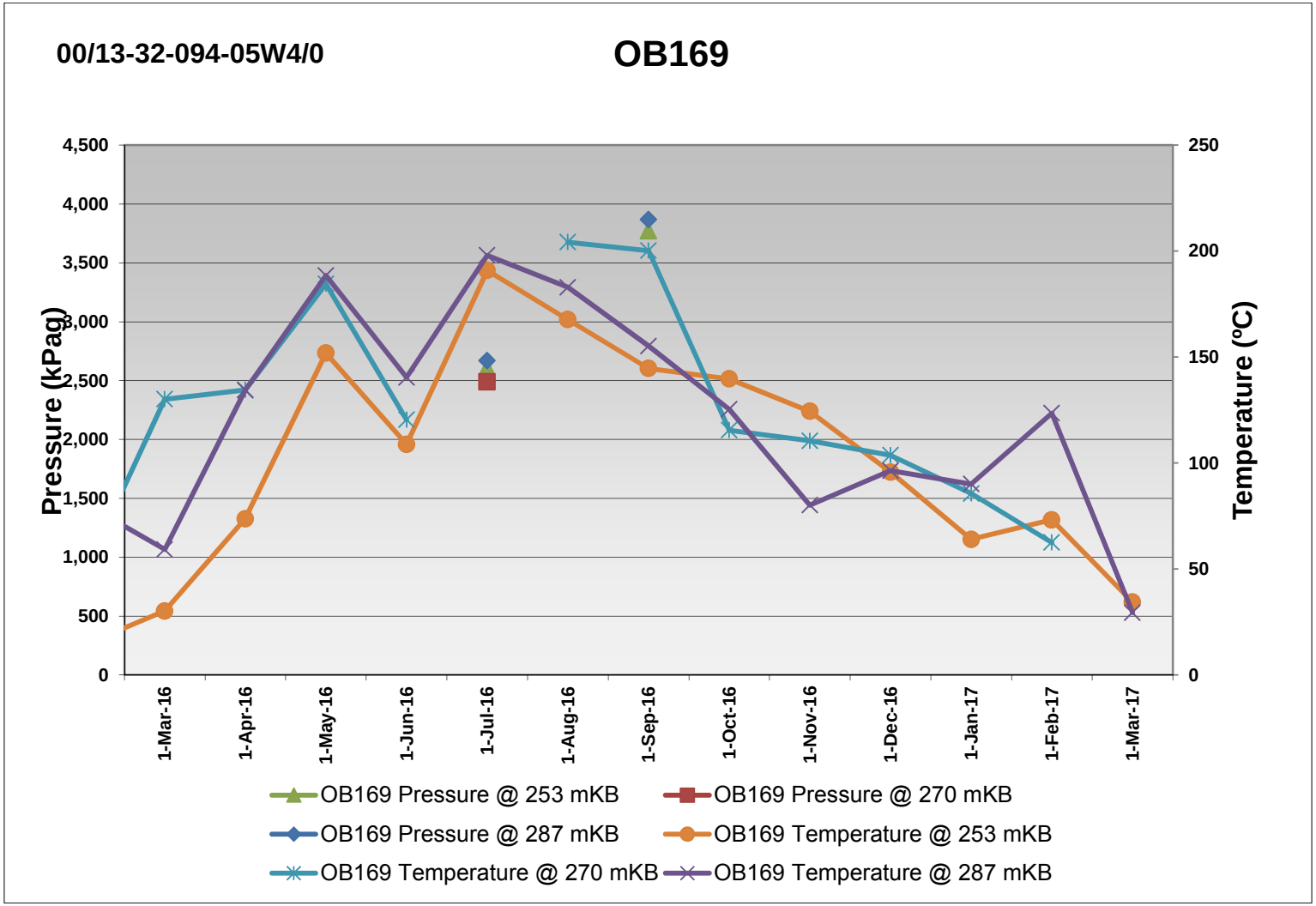

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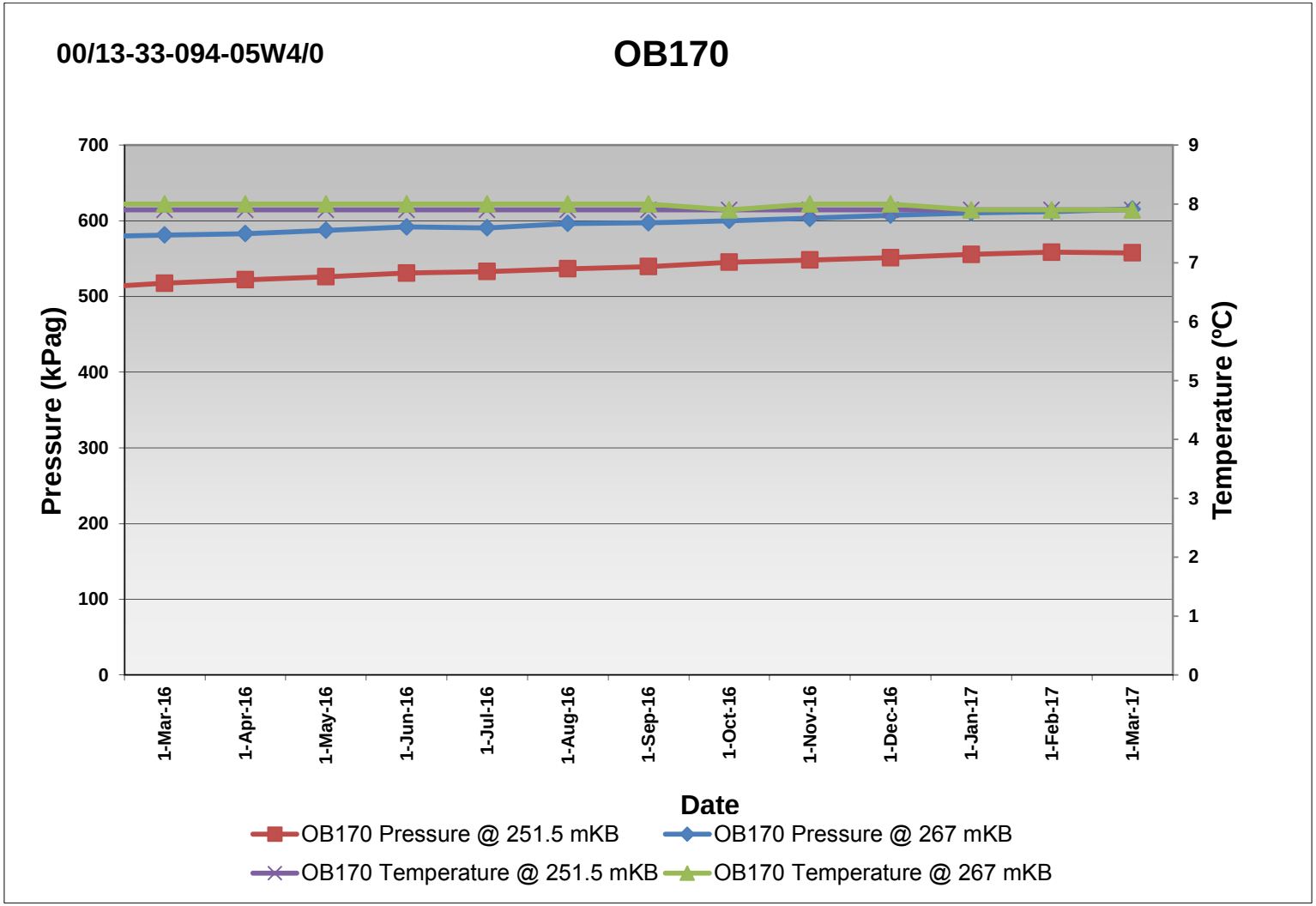

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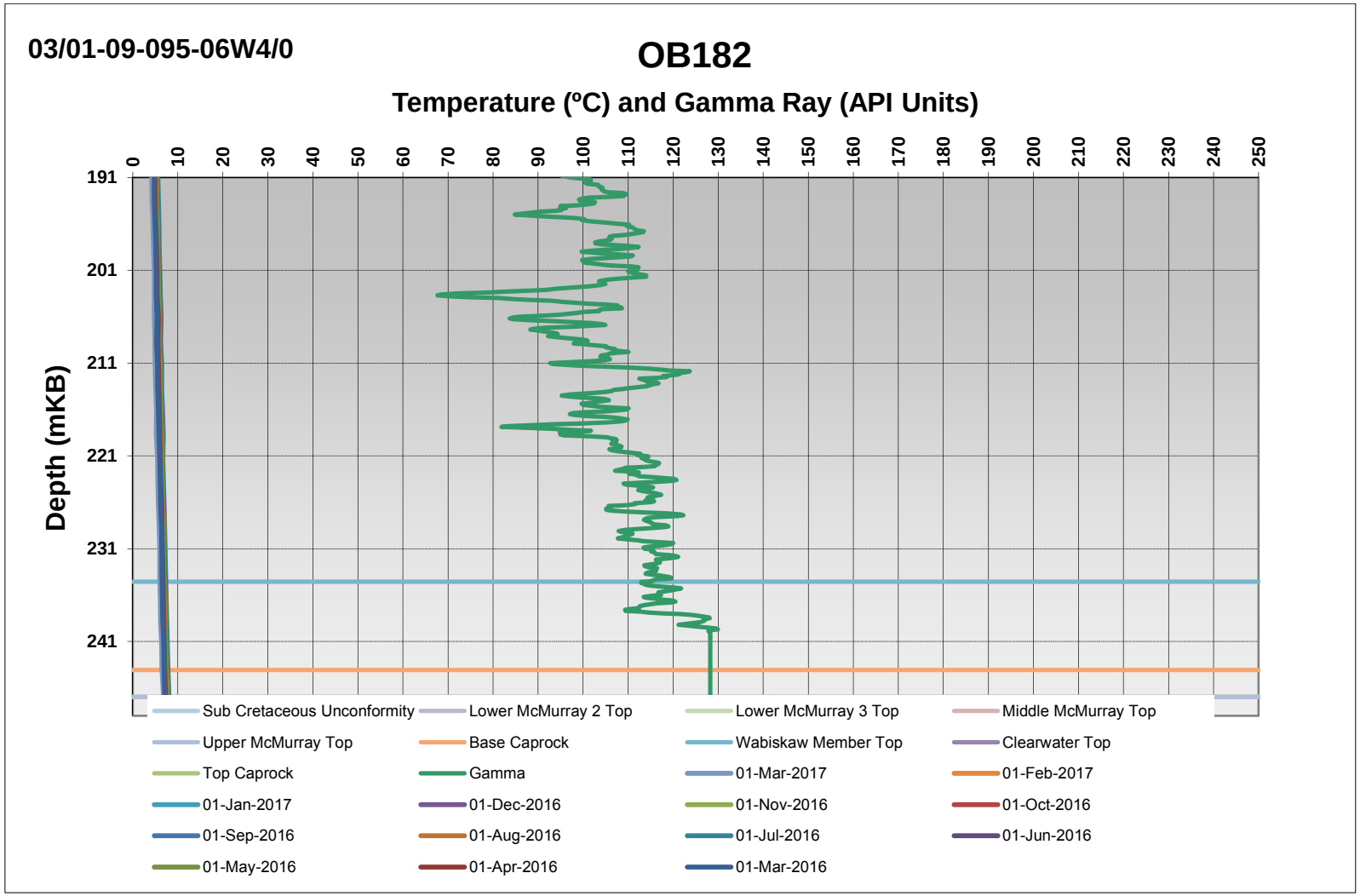

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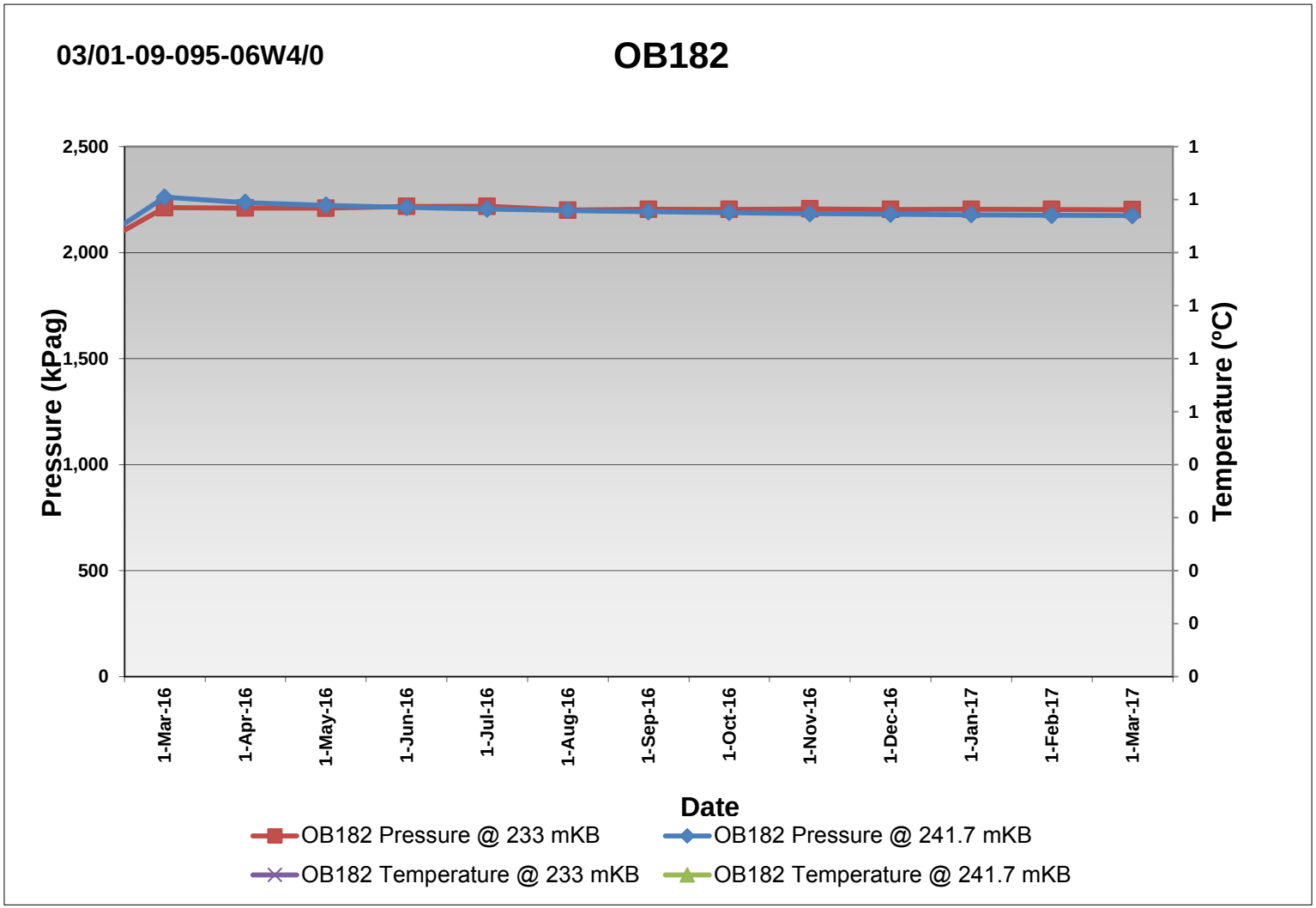

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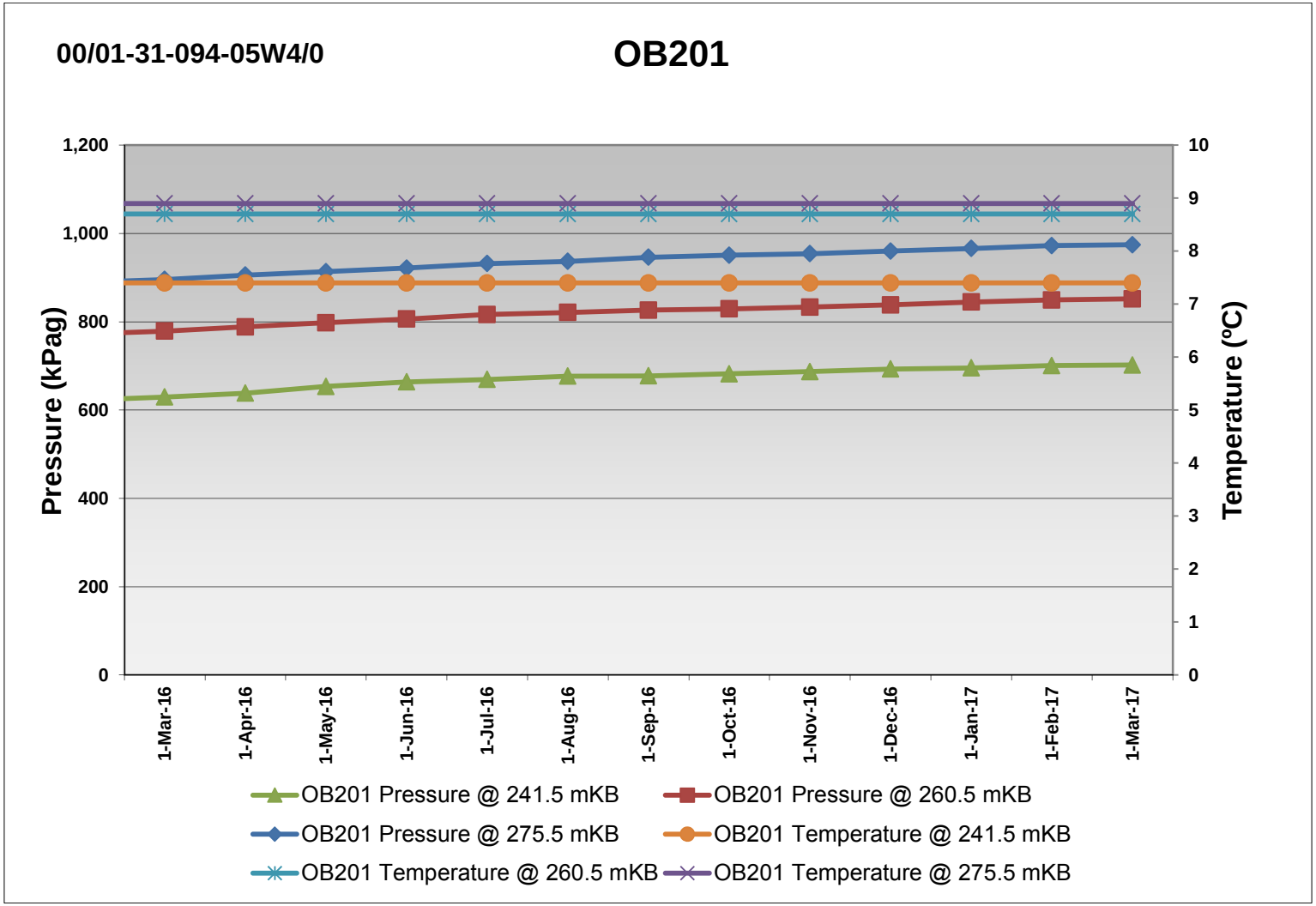
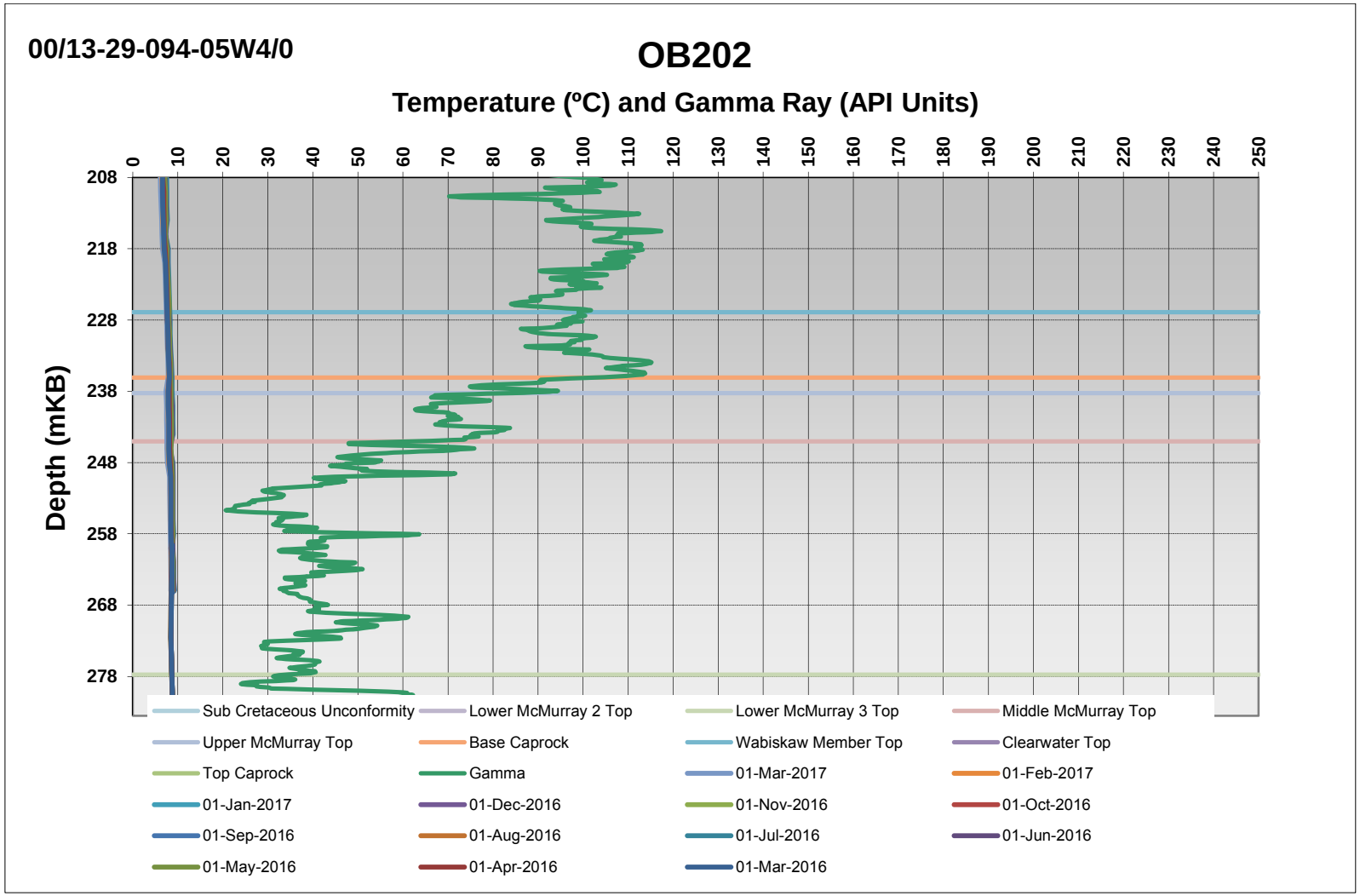
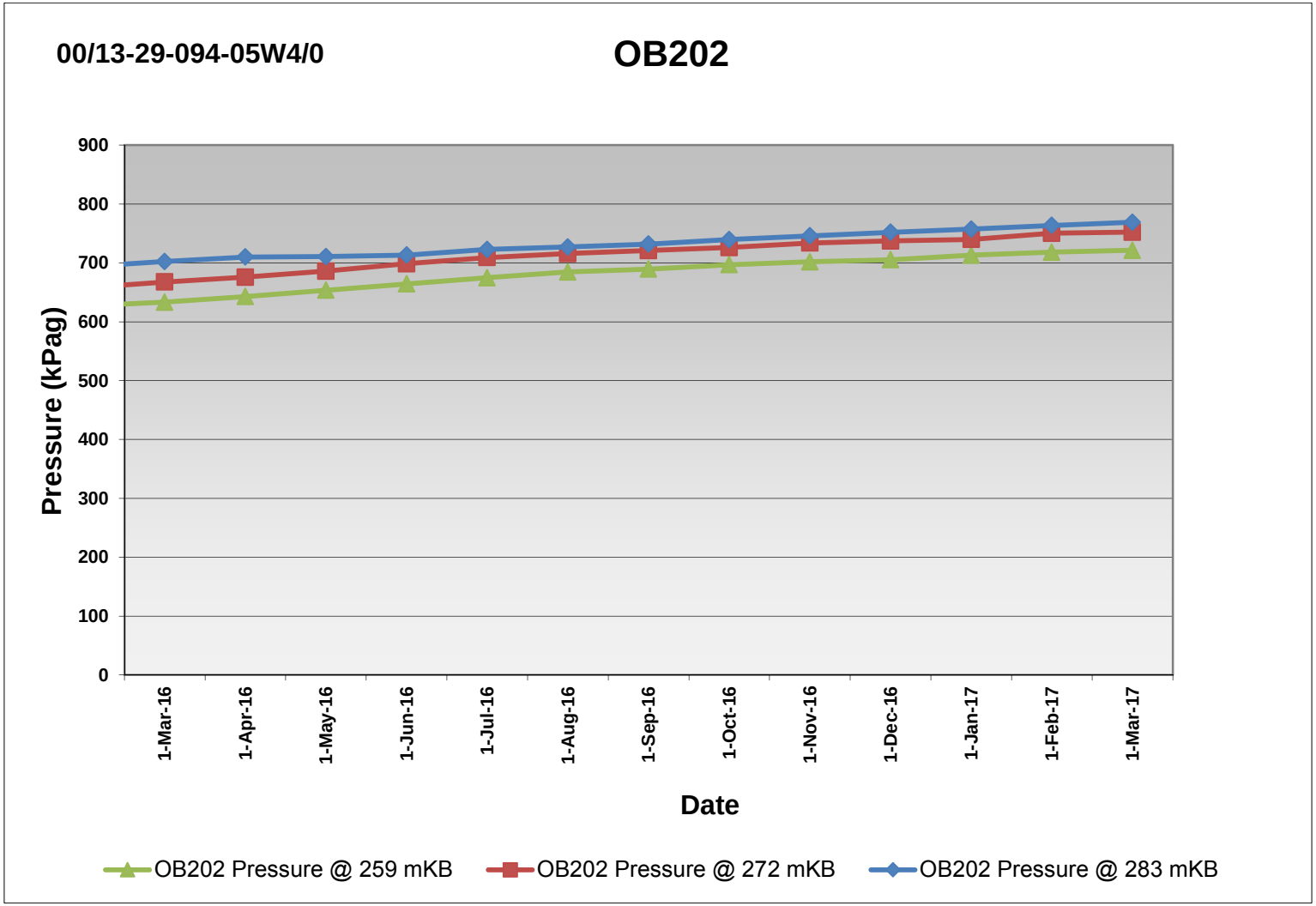


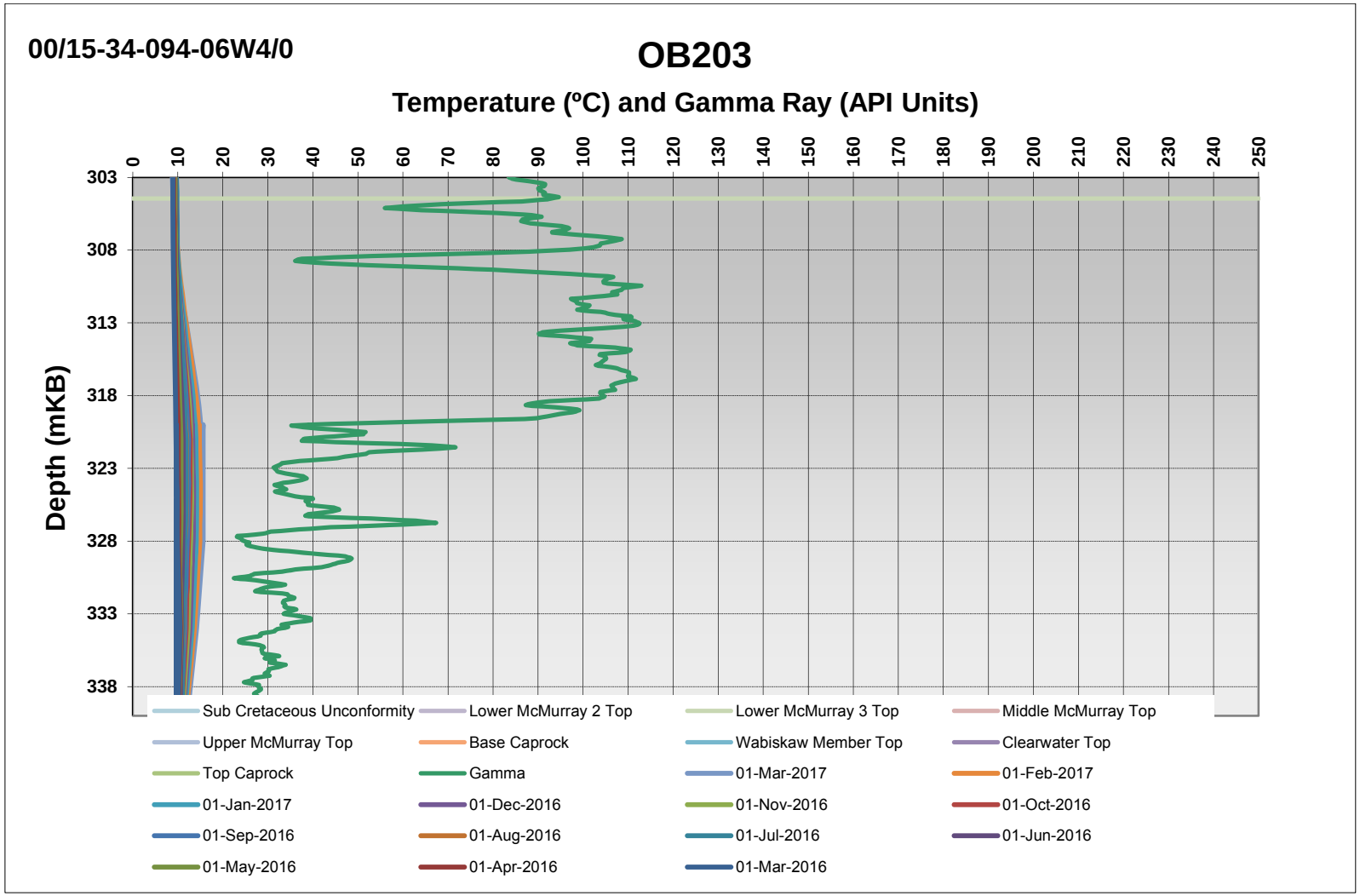
Piezometer Plots & Temperature vs Depth Plots



Piezometer Plots & Temperature vs Depth Plots



Piezometer Plots & Temperature vs Depth Plots



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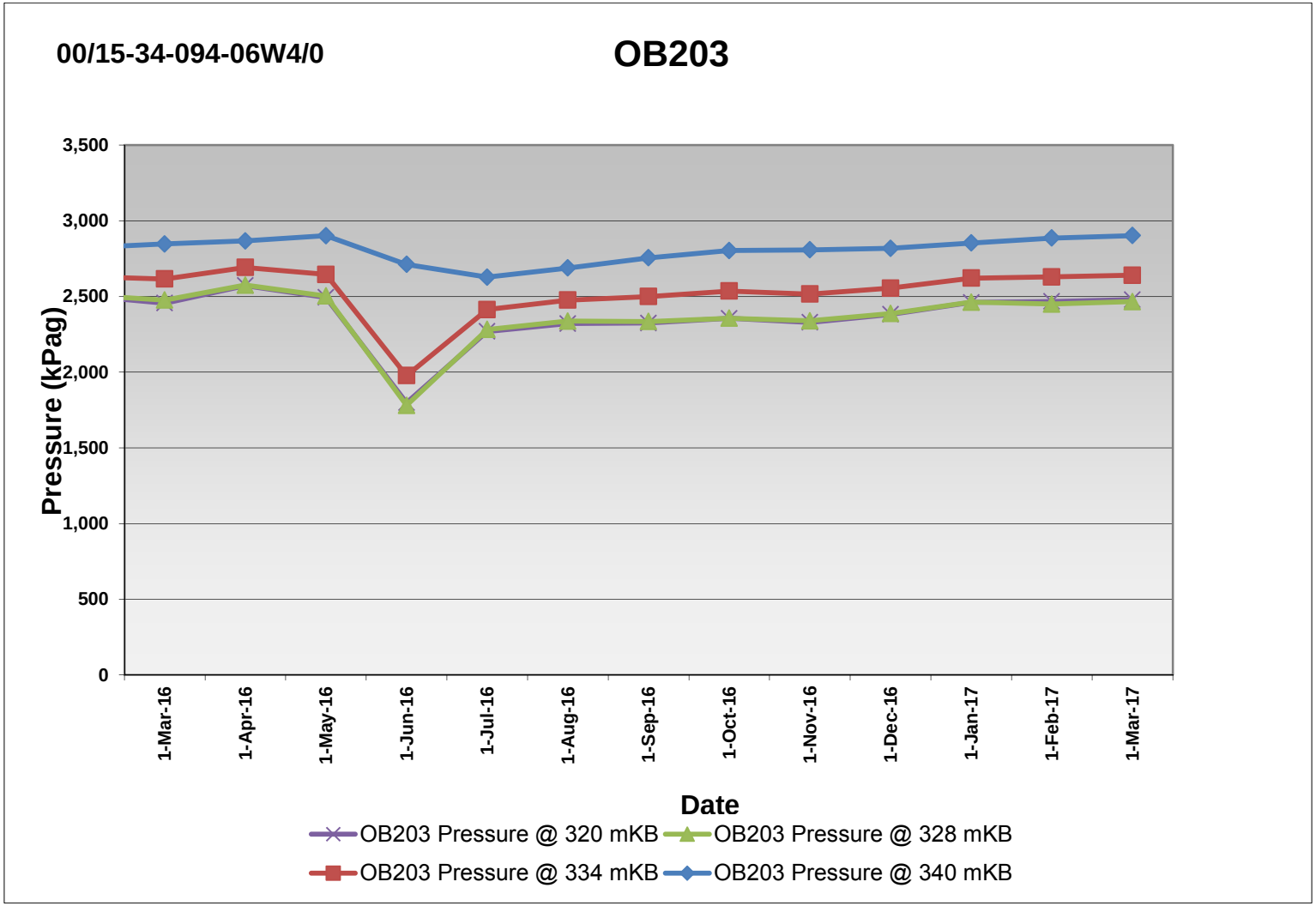

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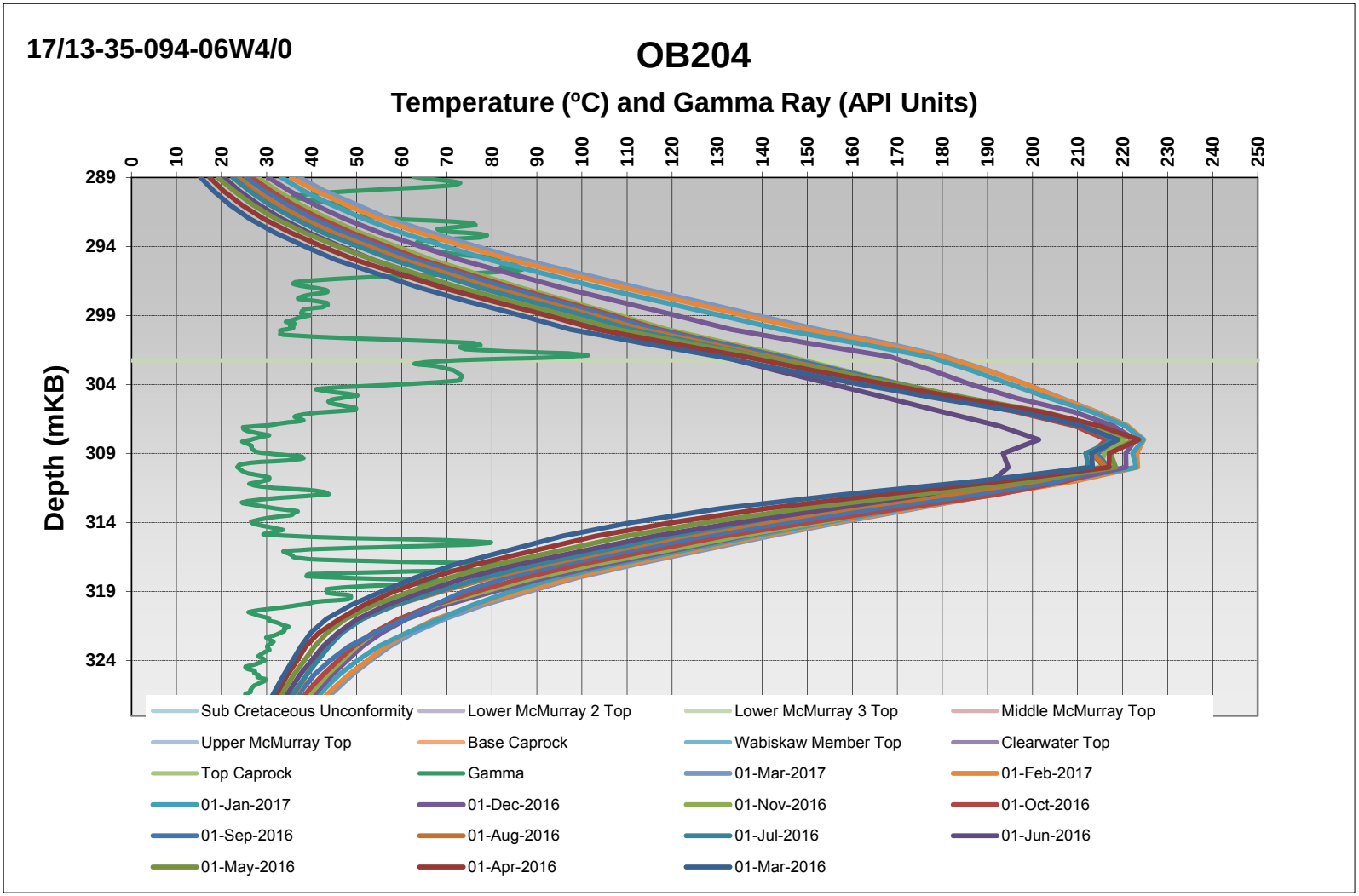

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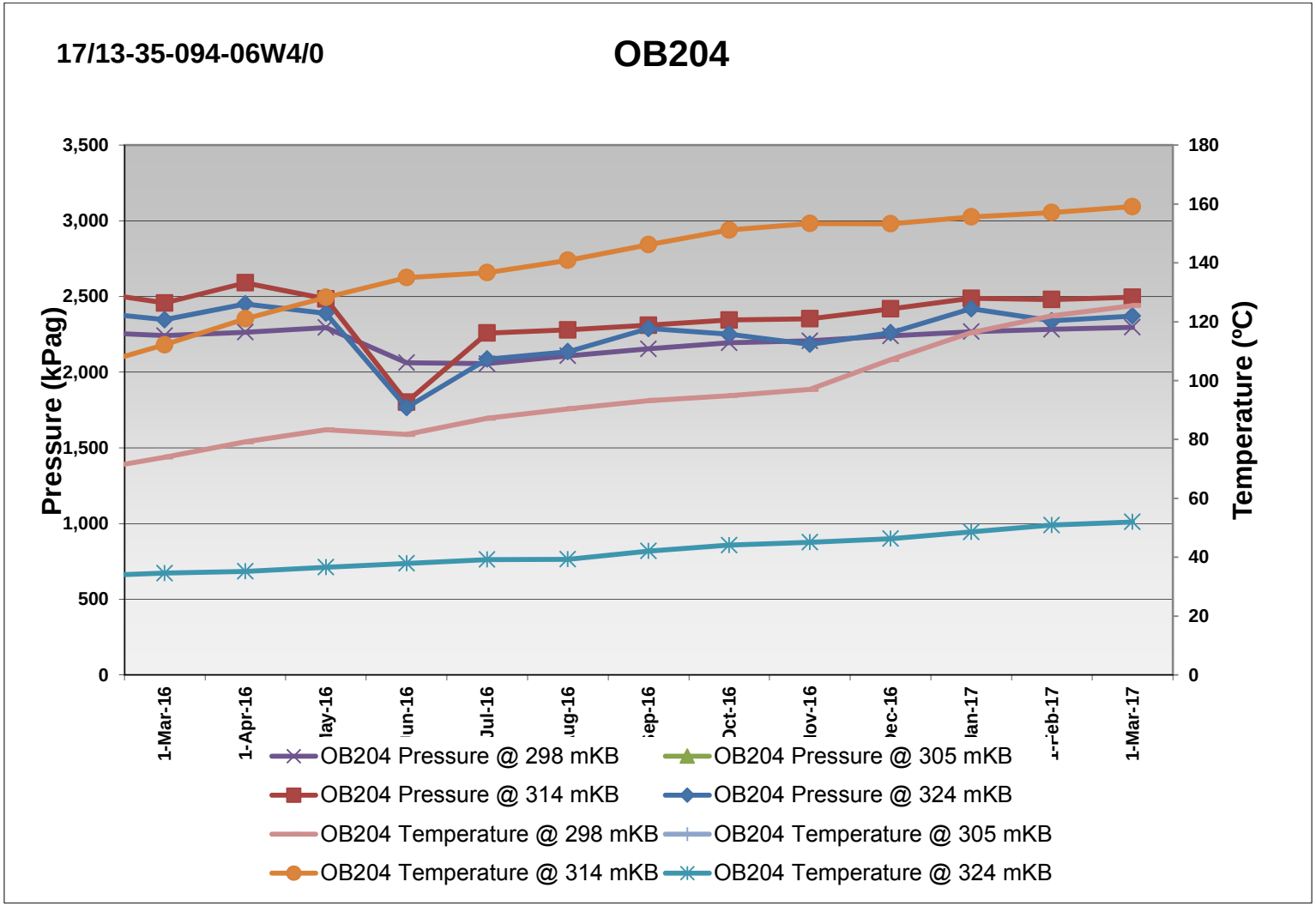

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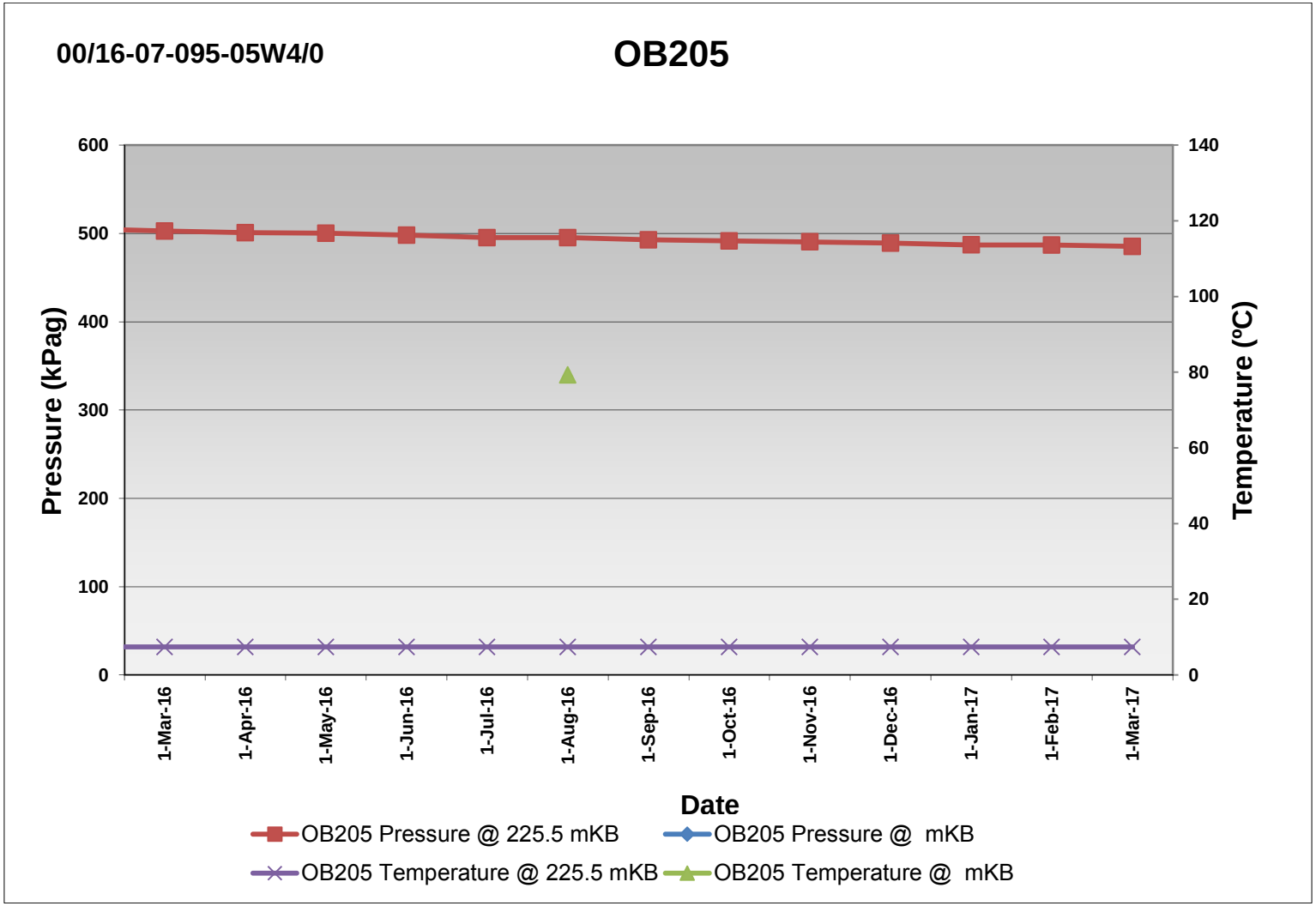

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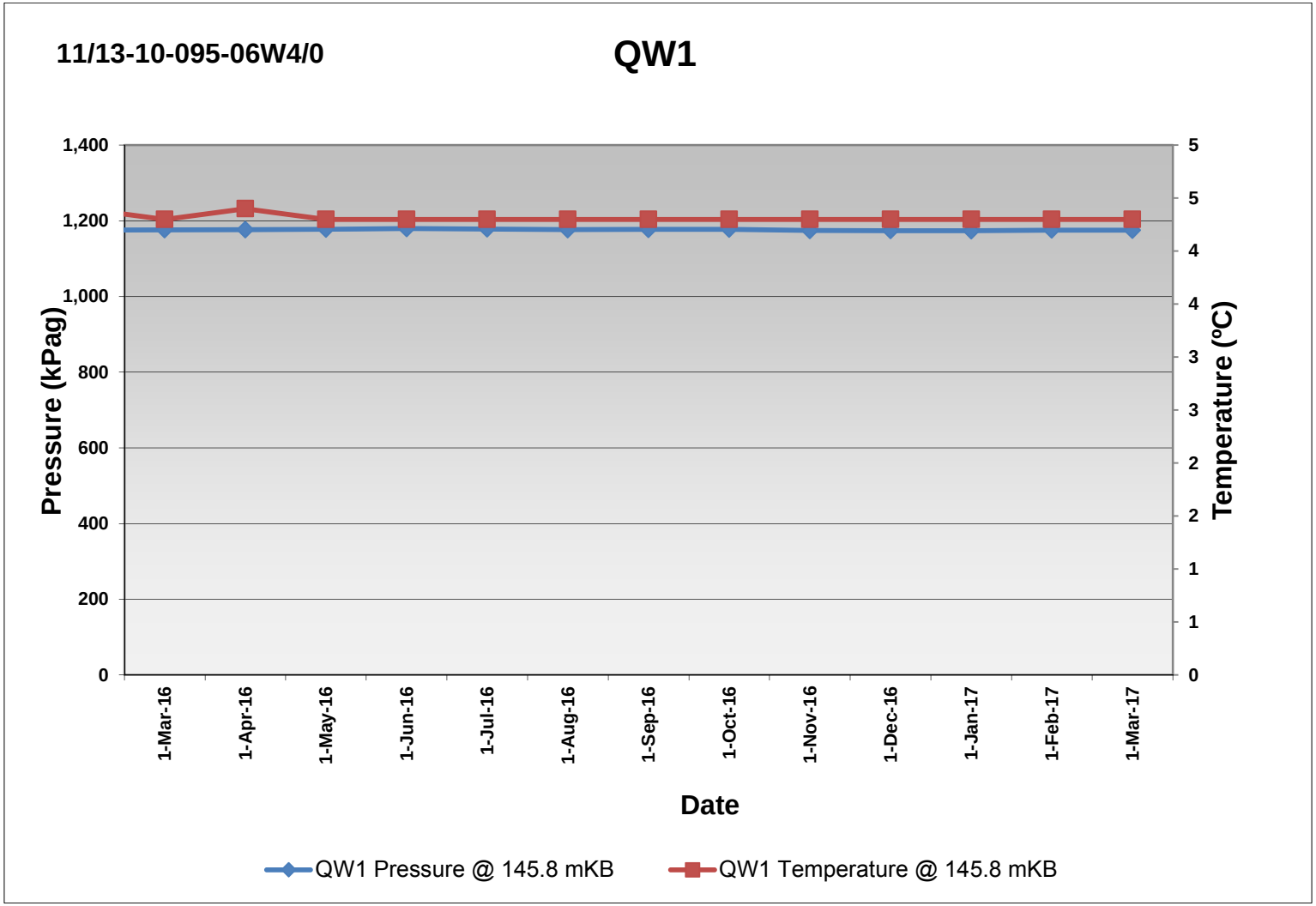

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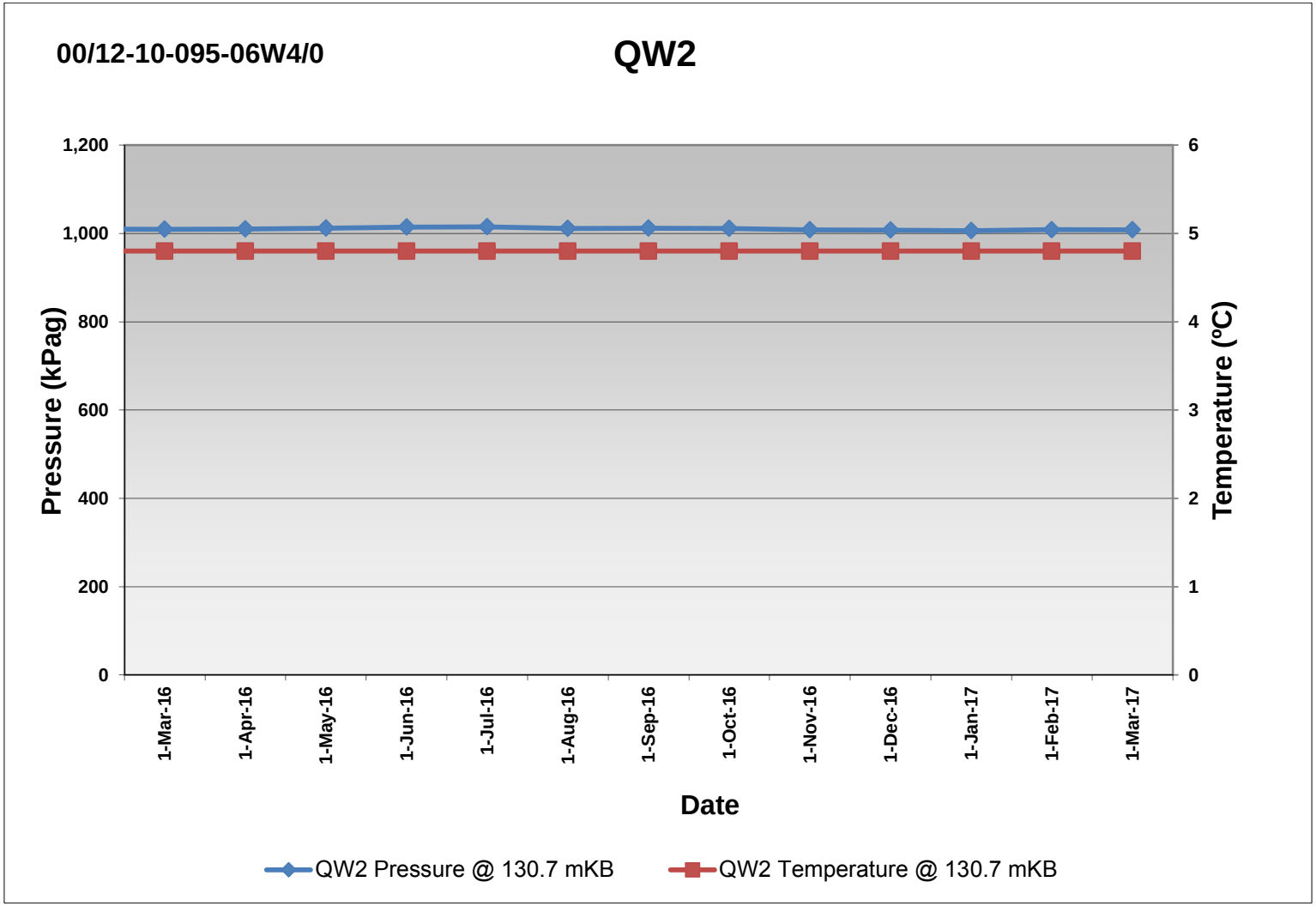

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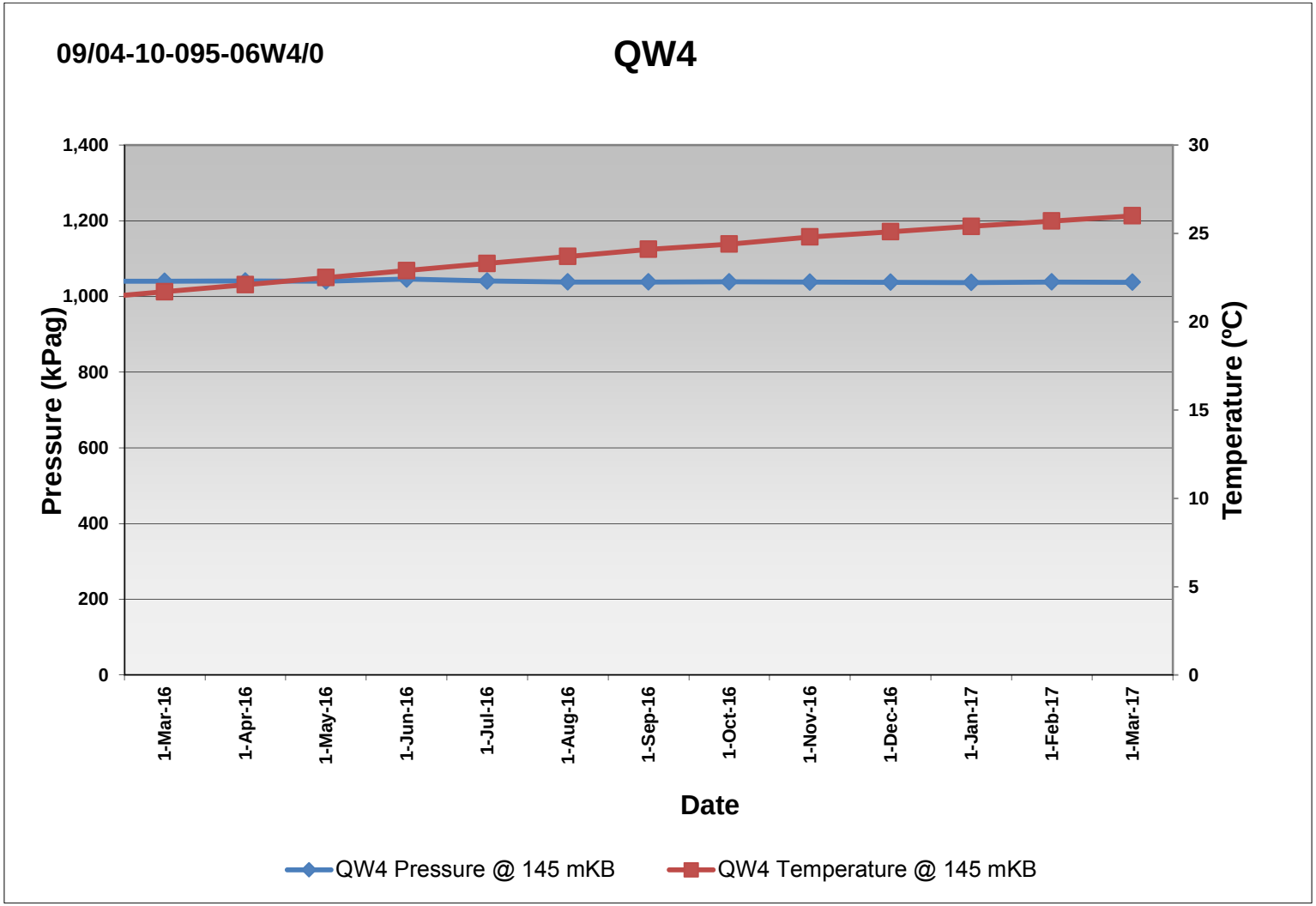

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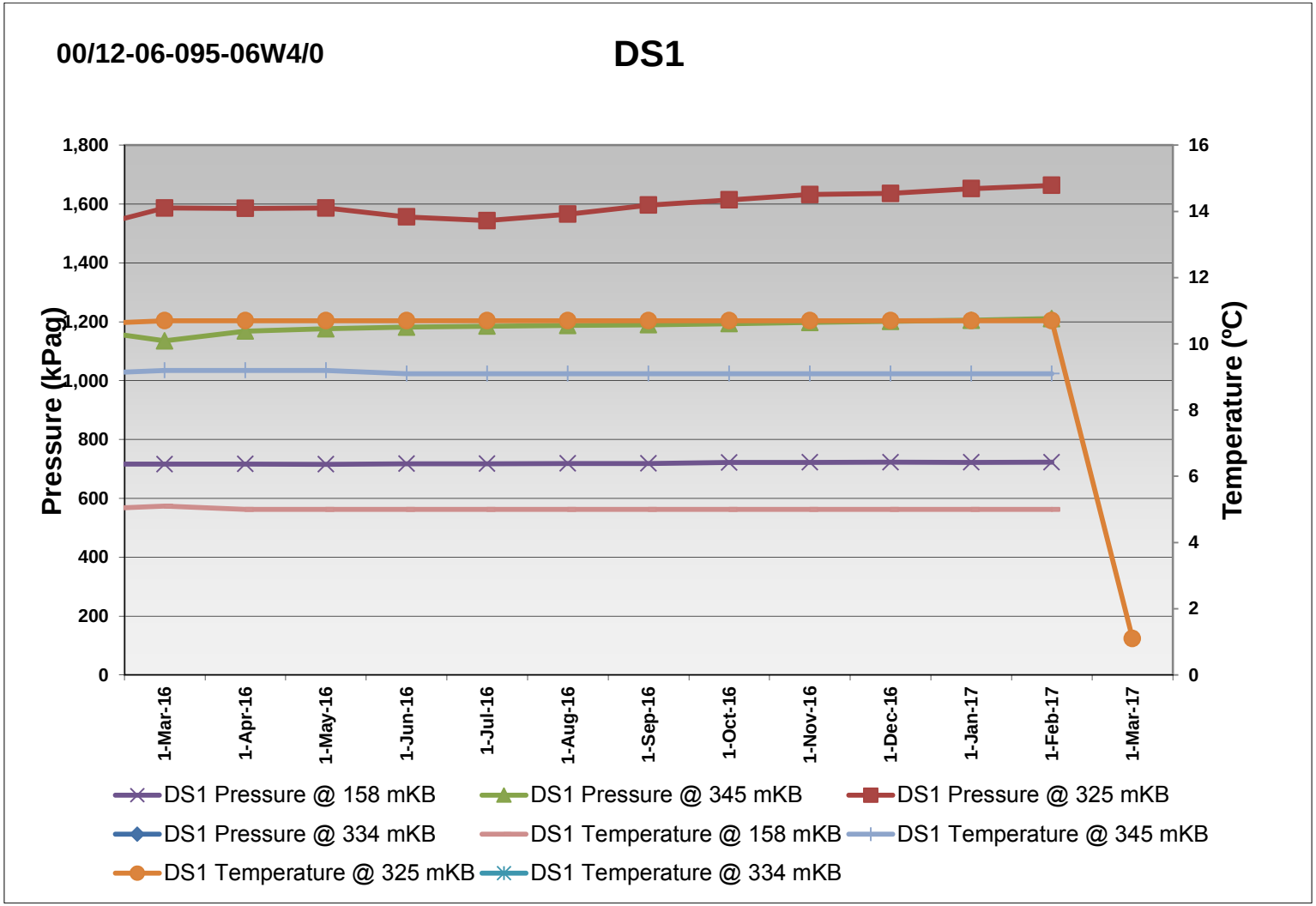

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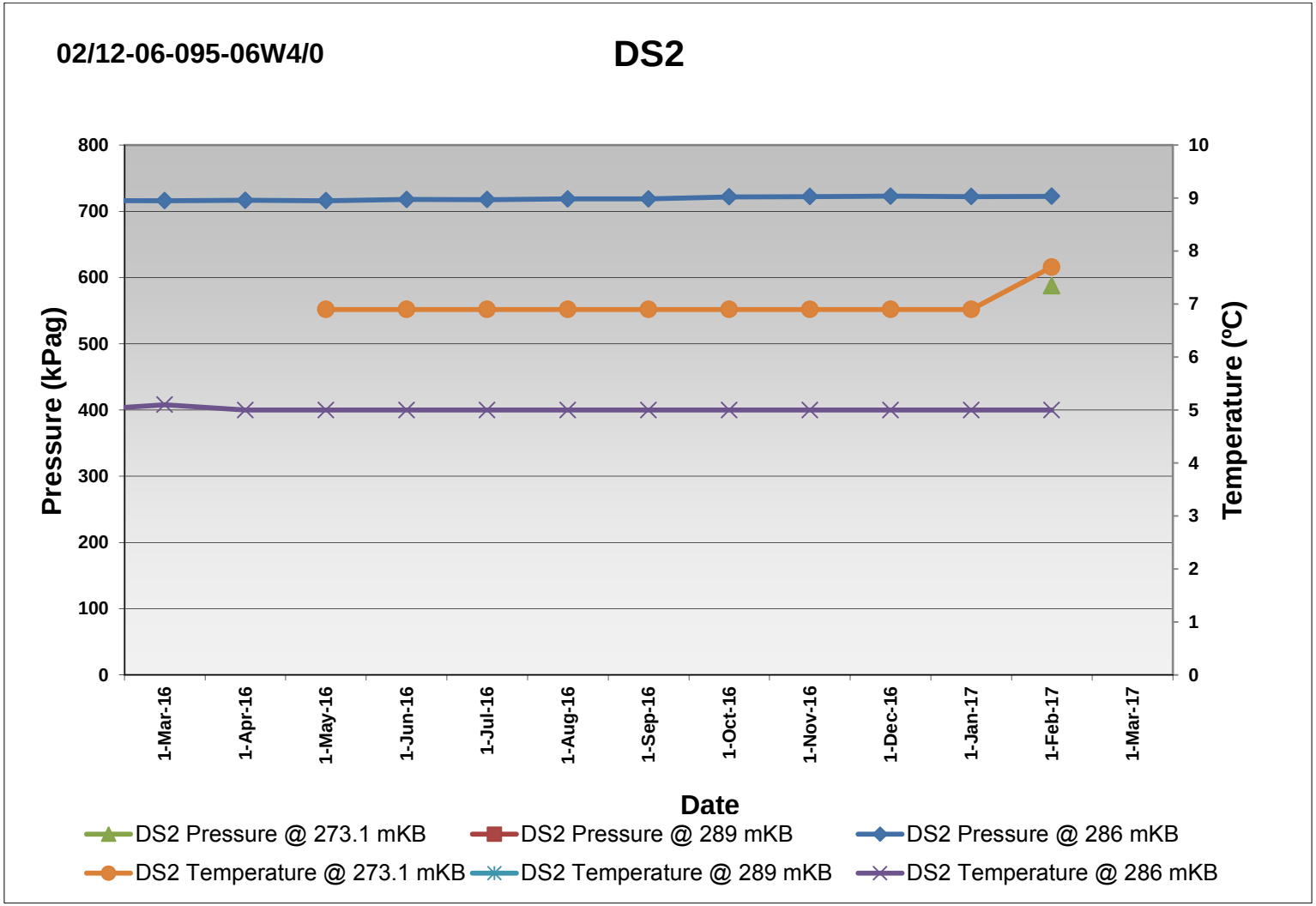

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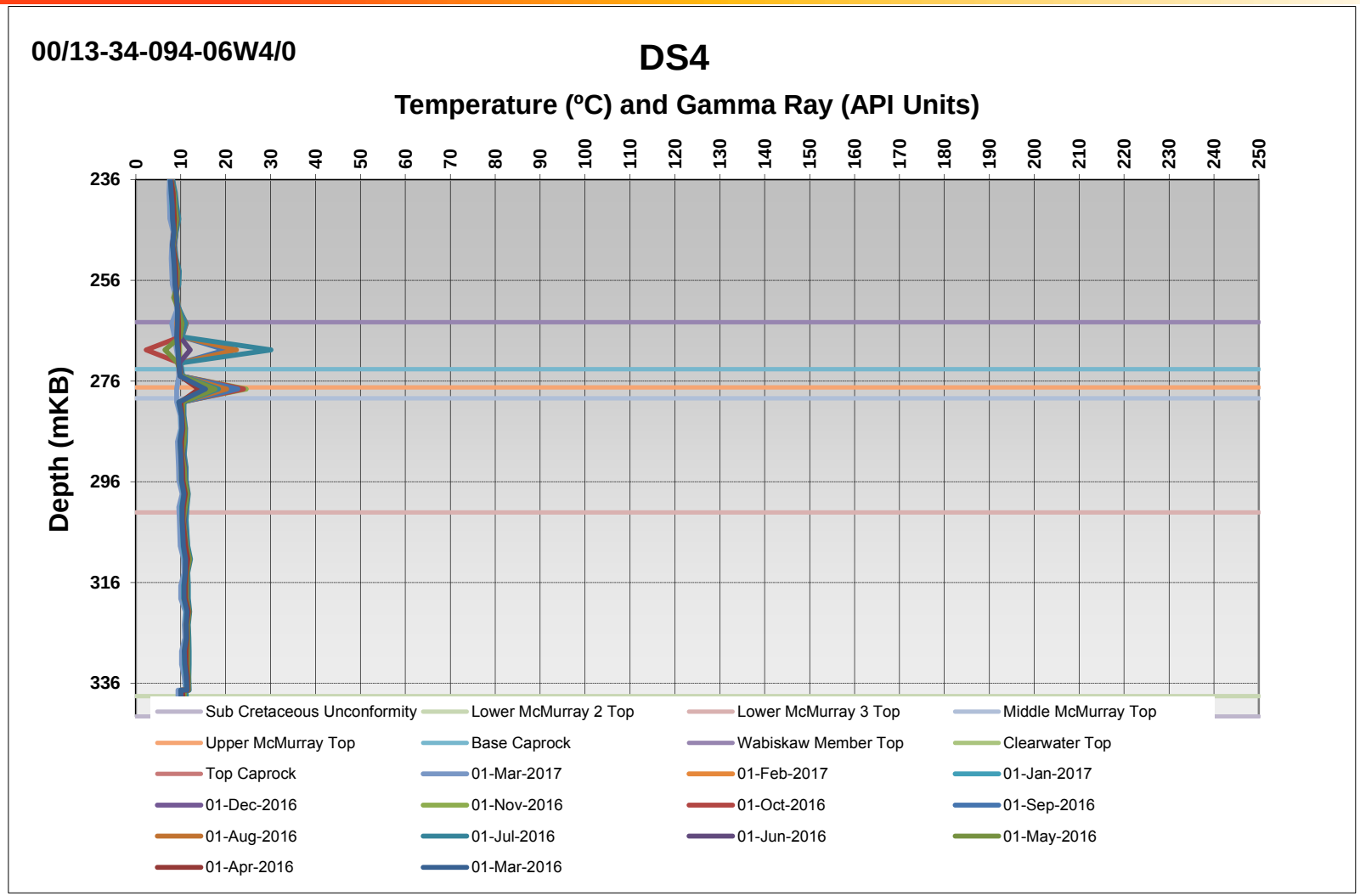

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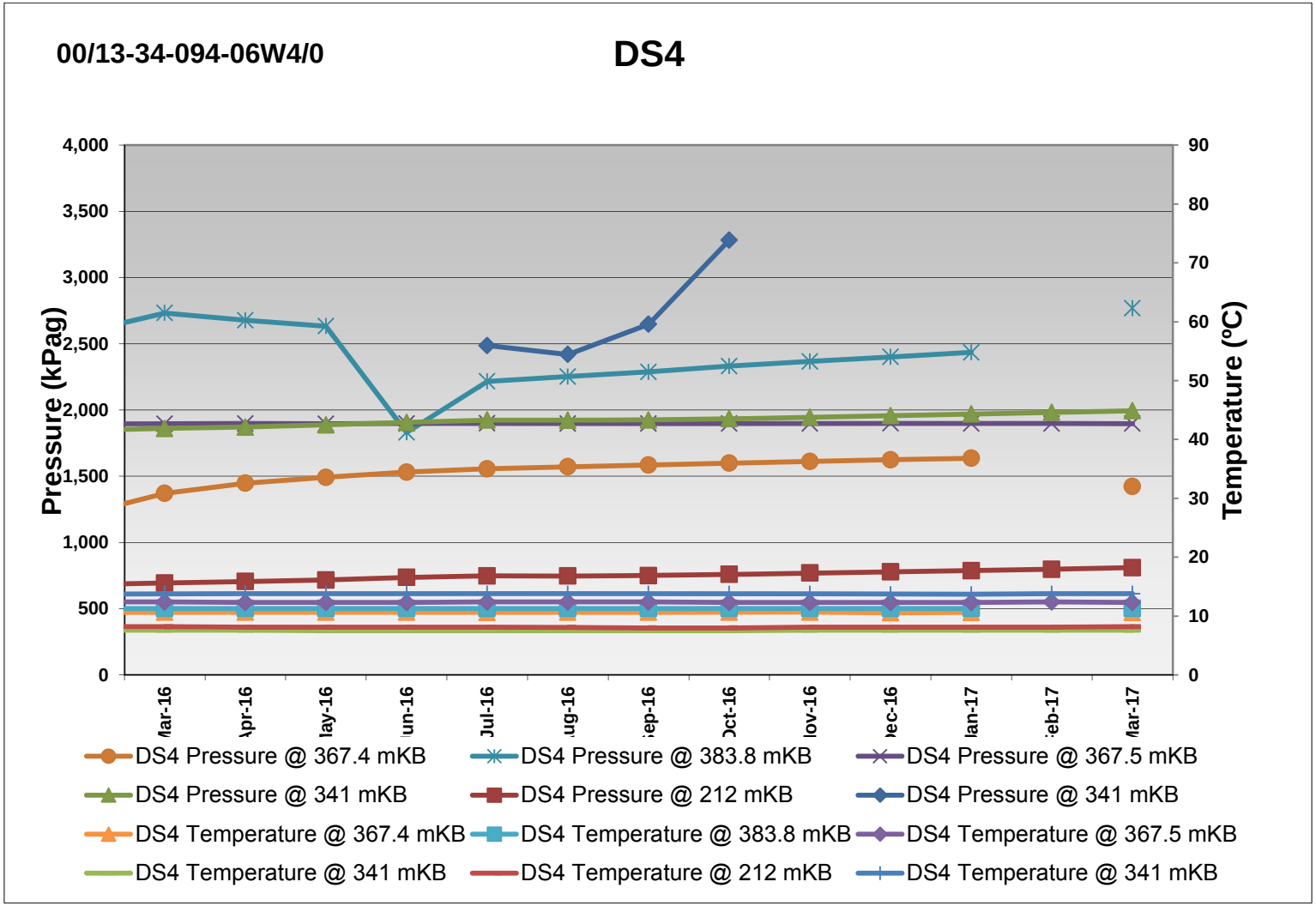

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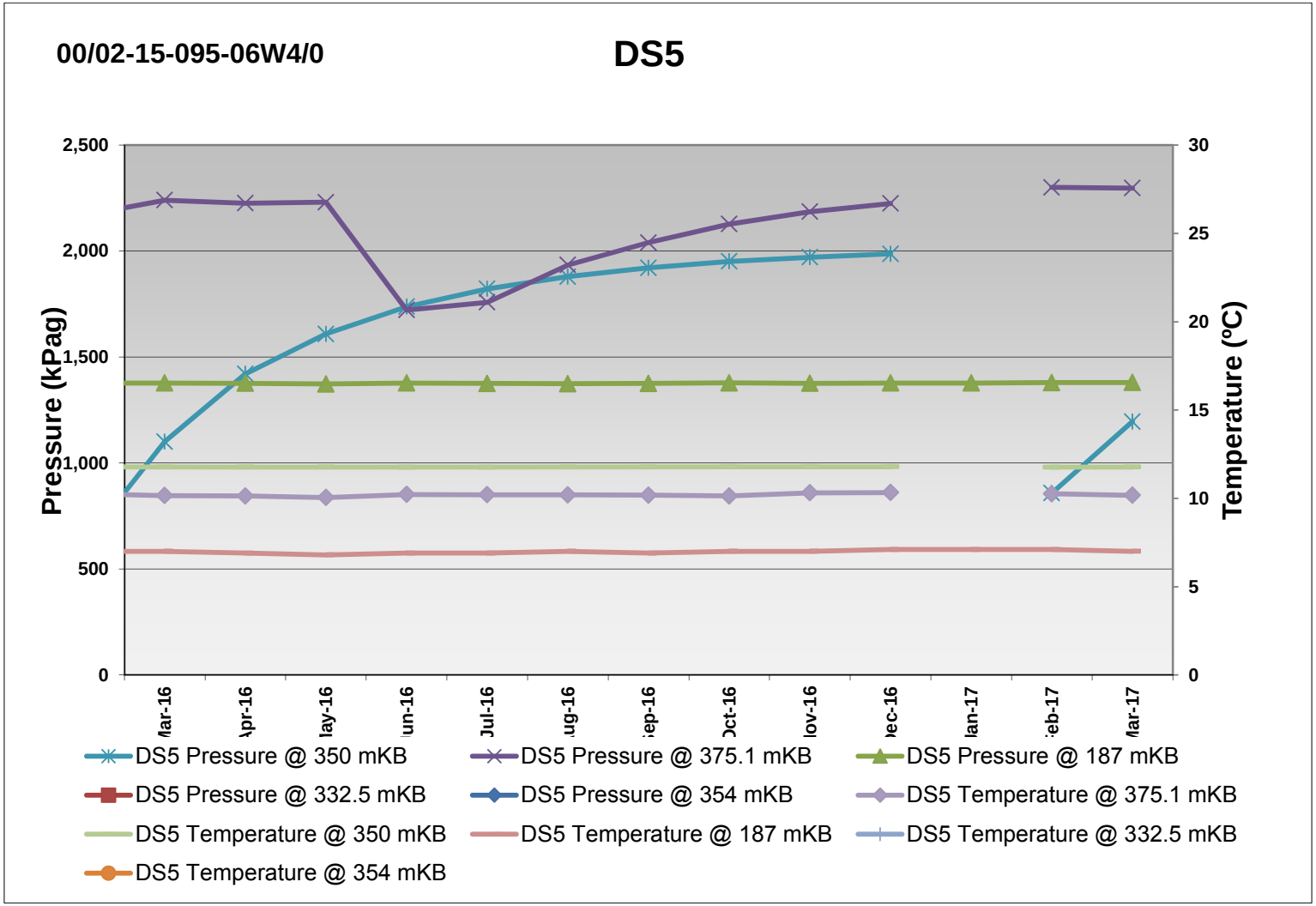

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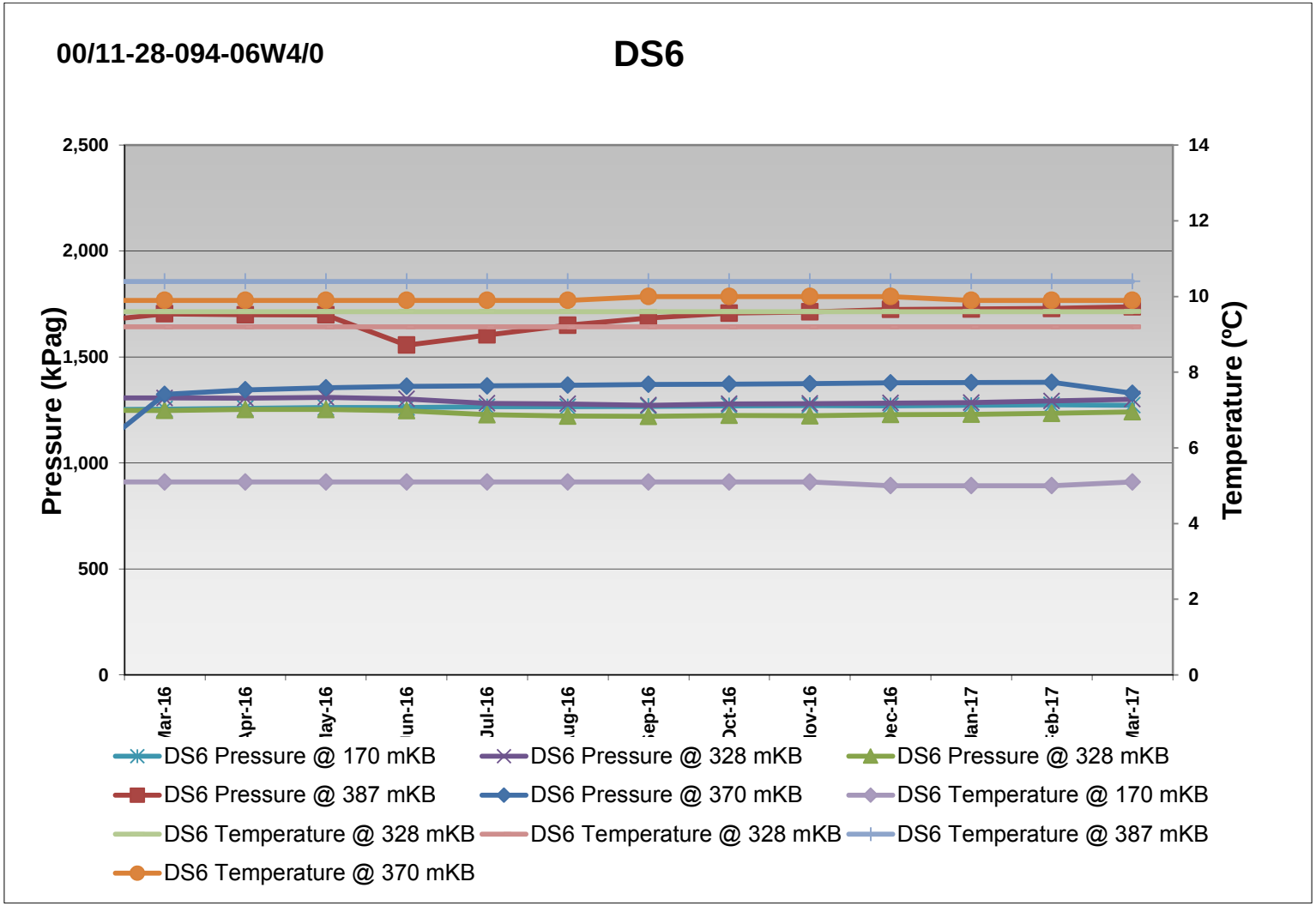

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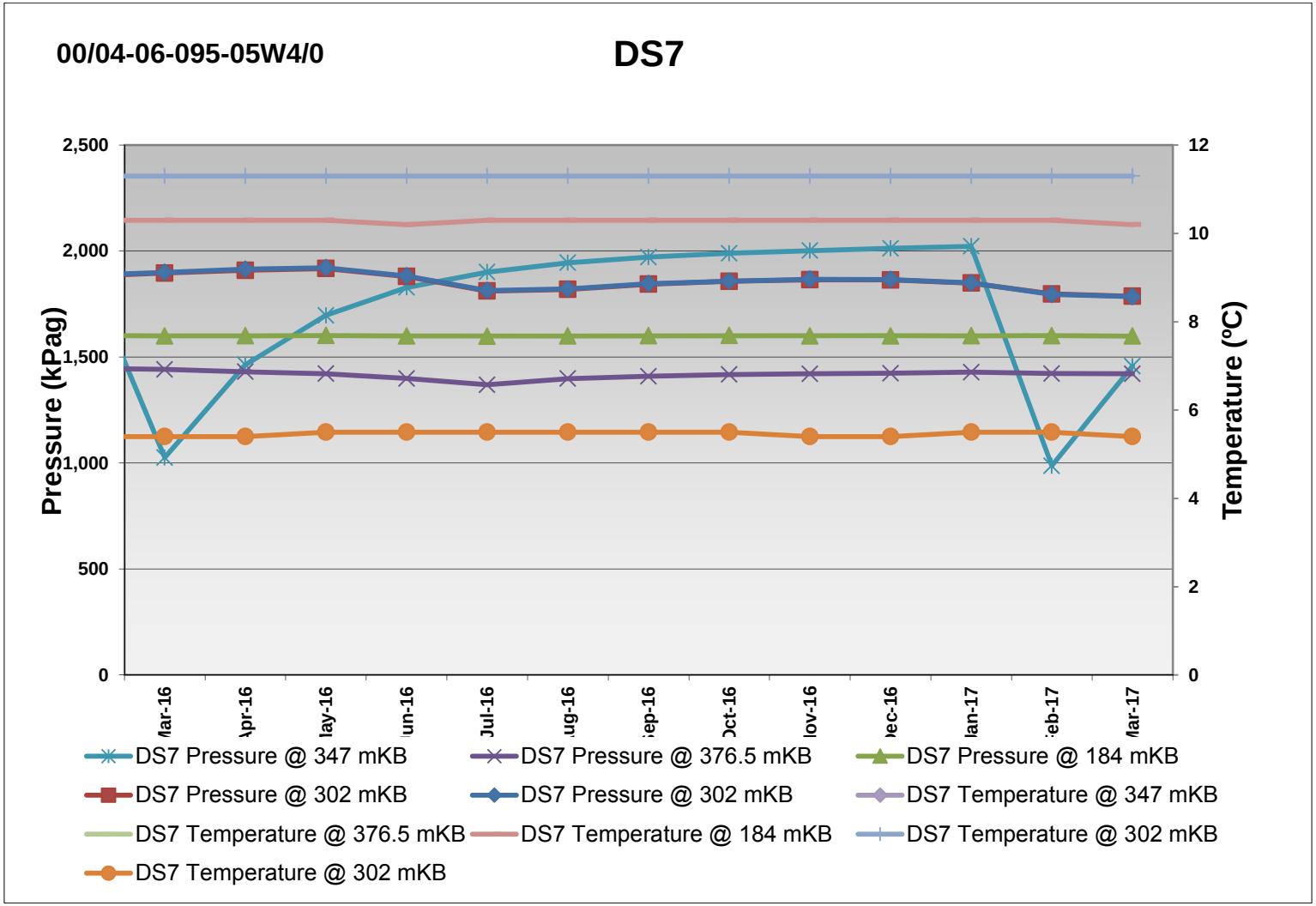

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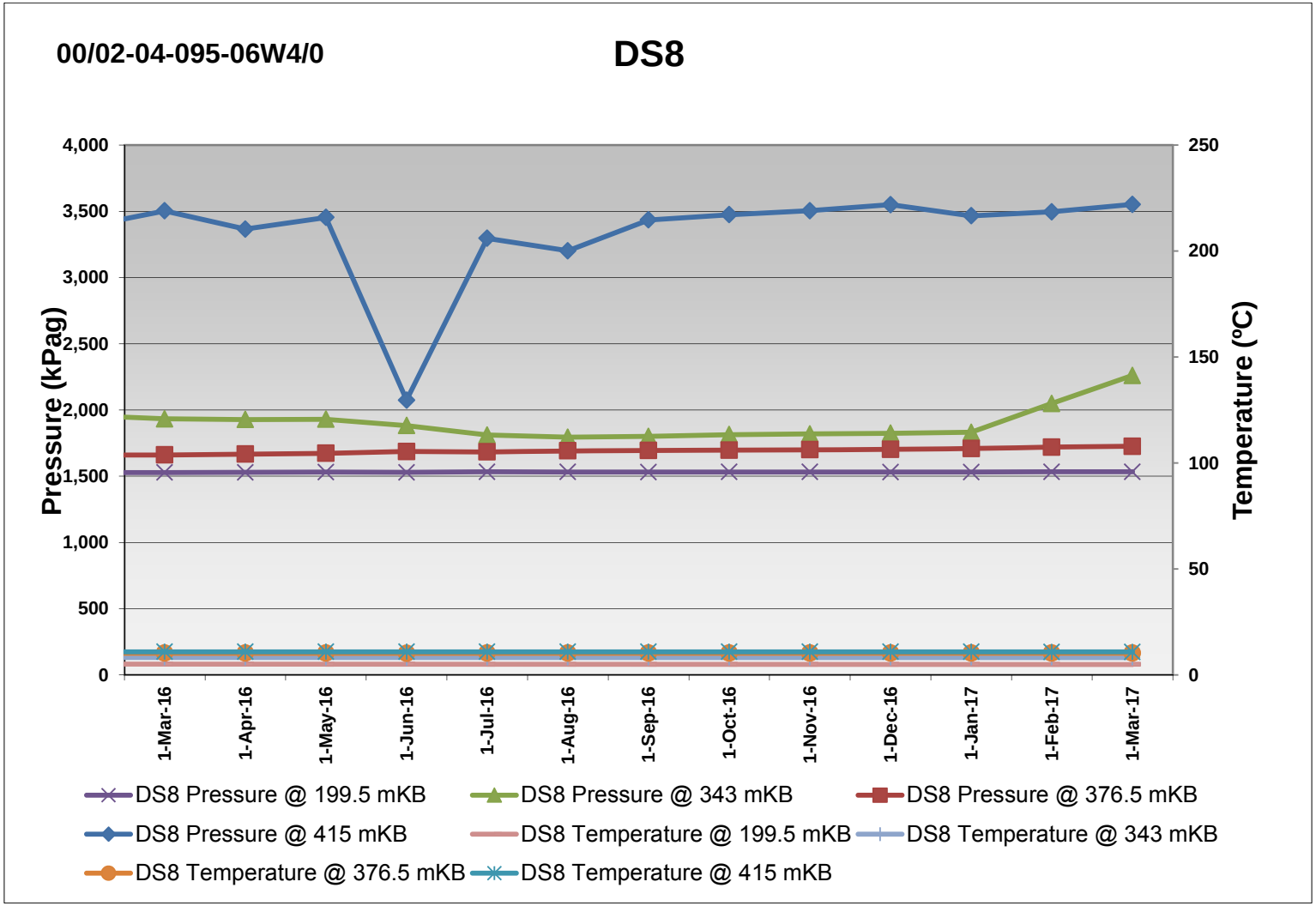

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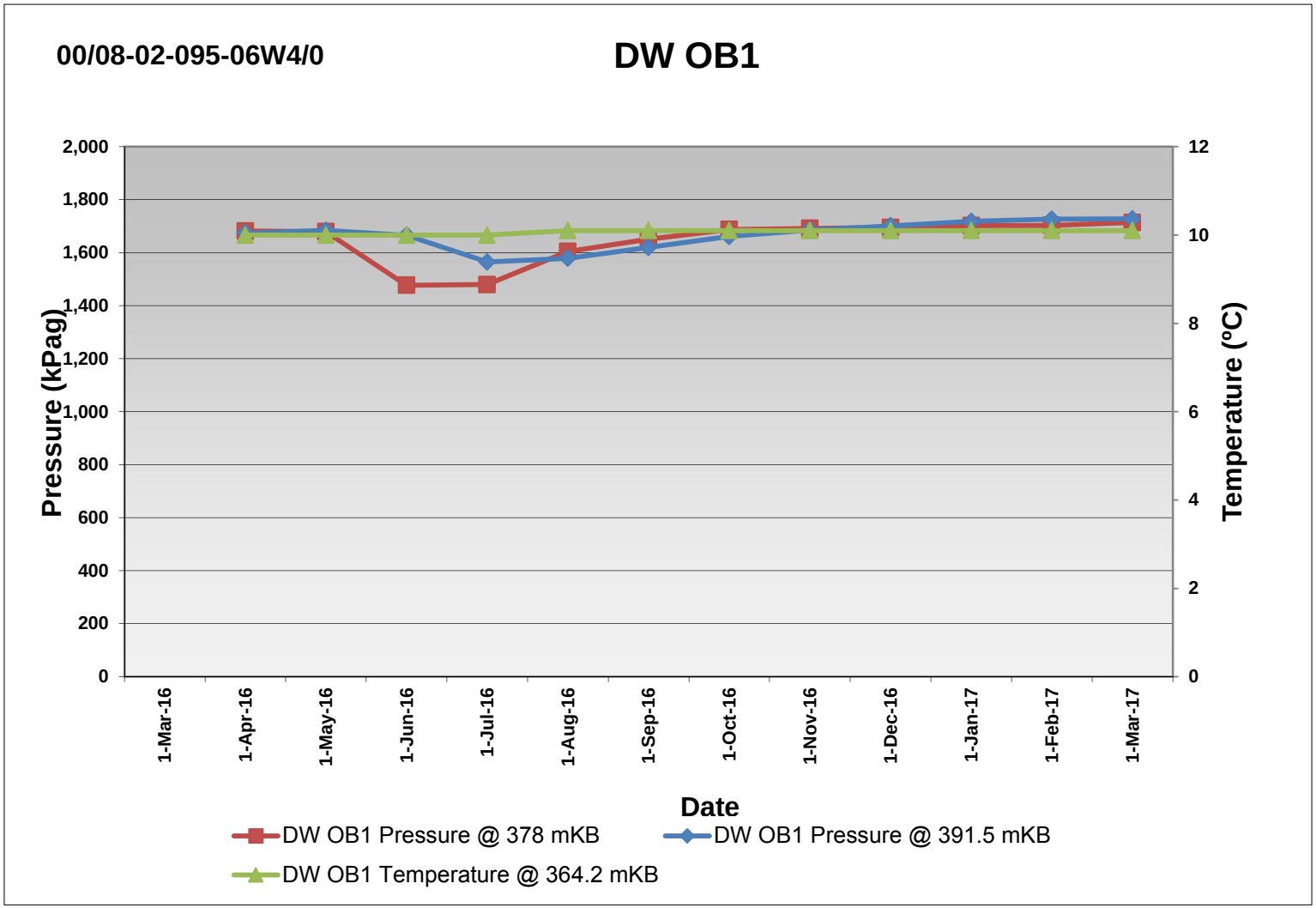

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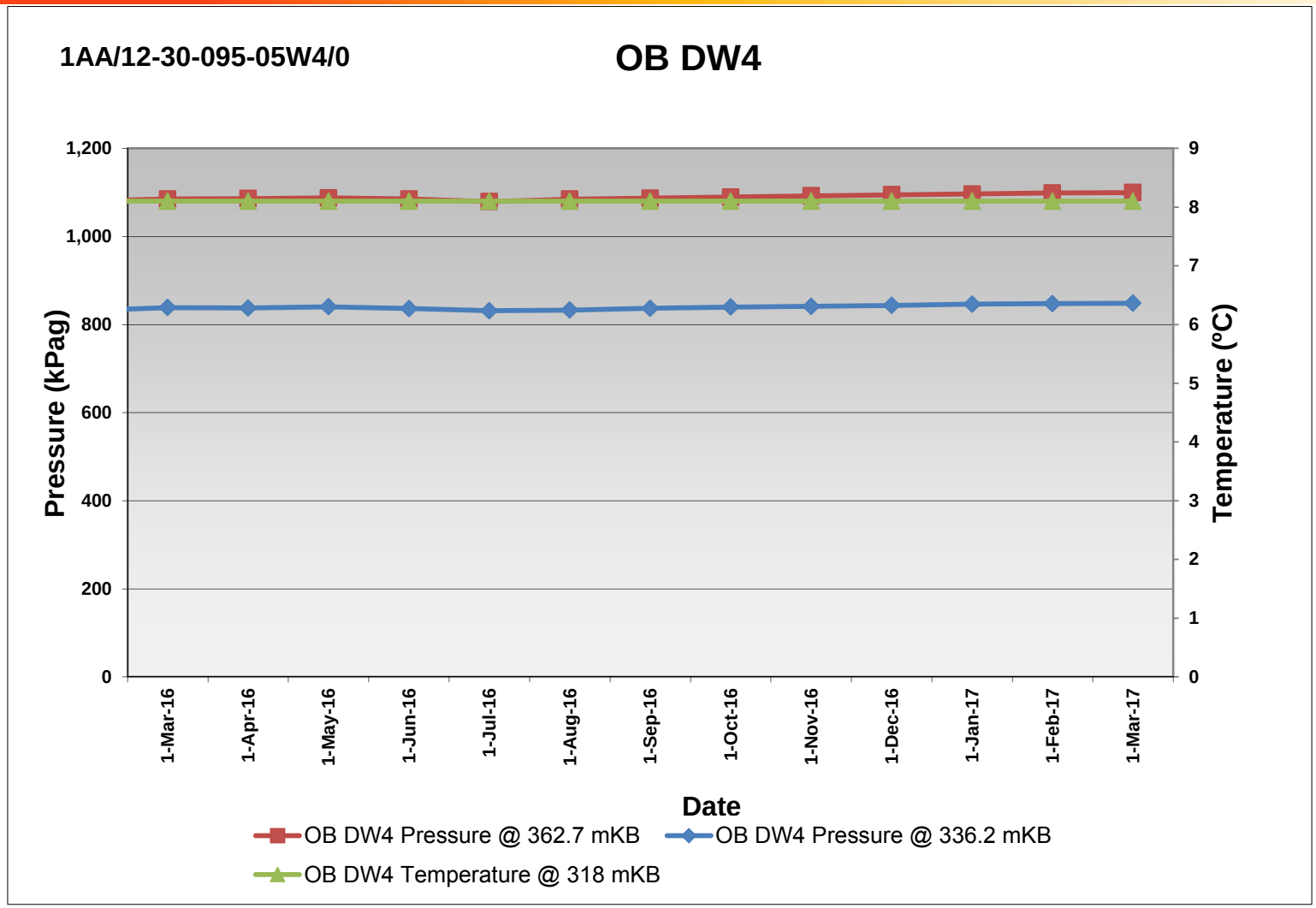

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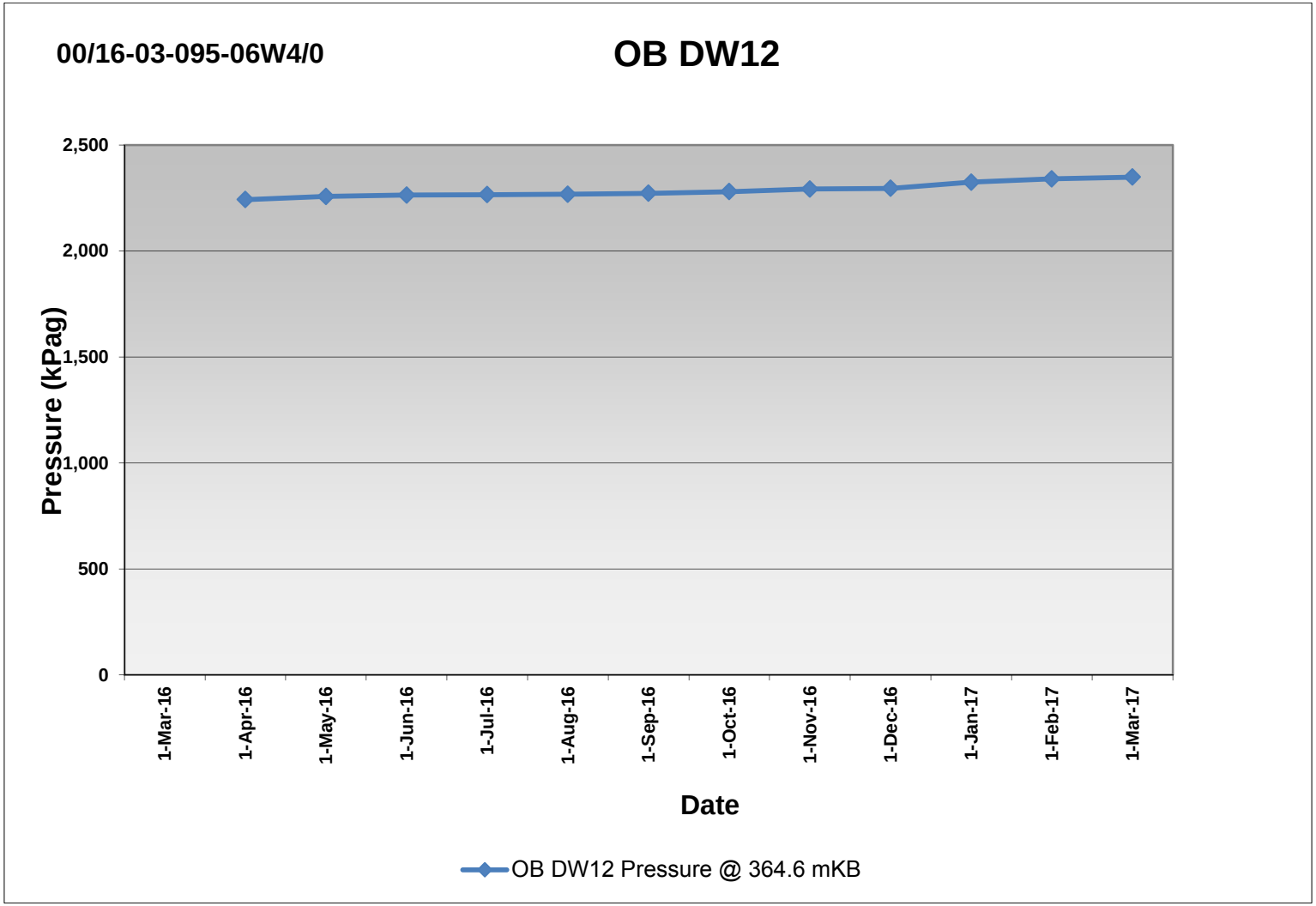

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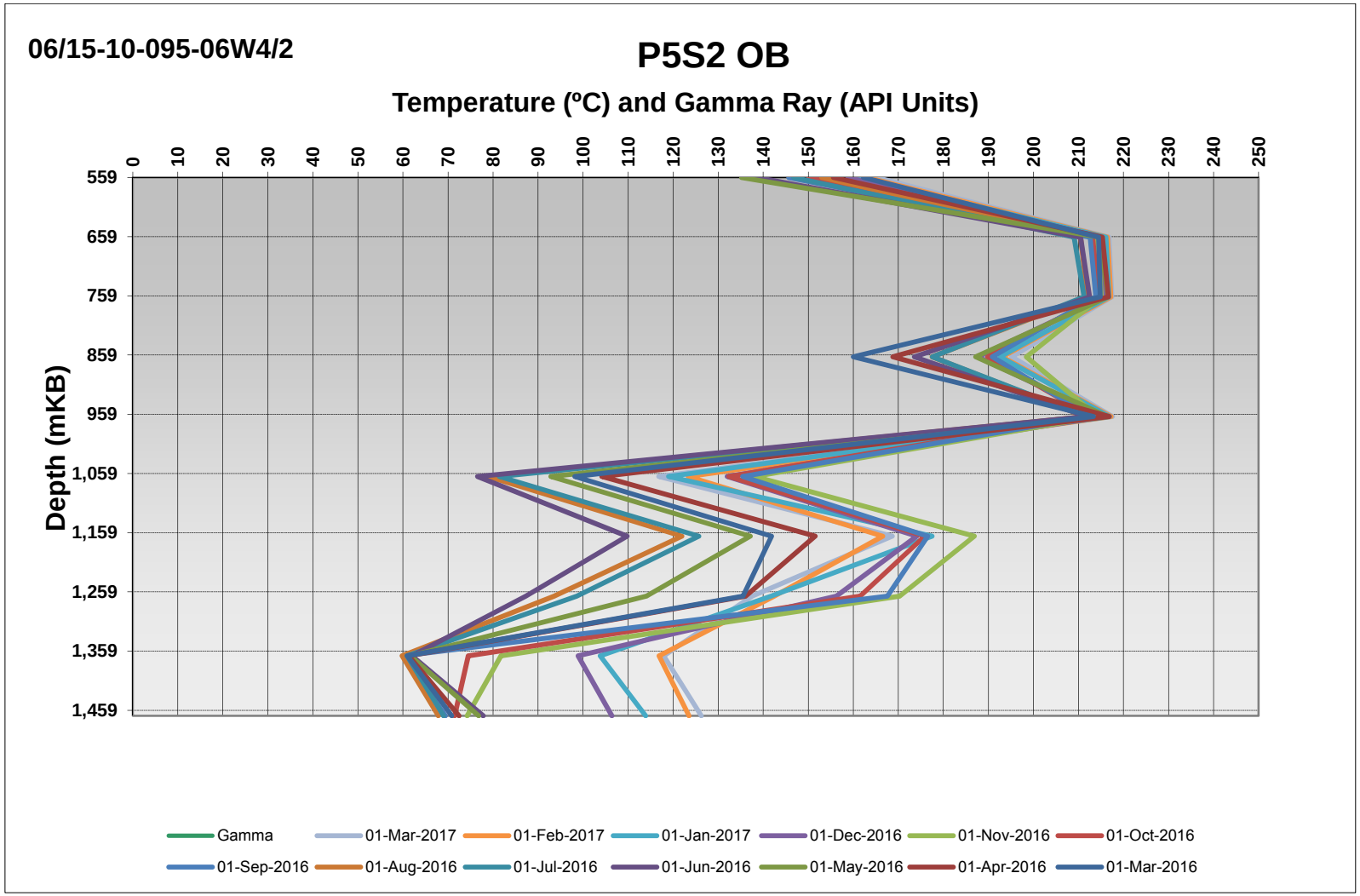

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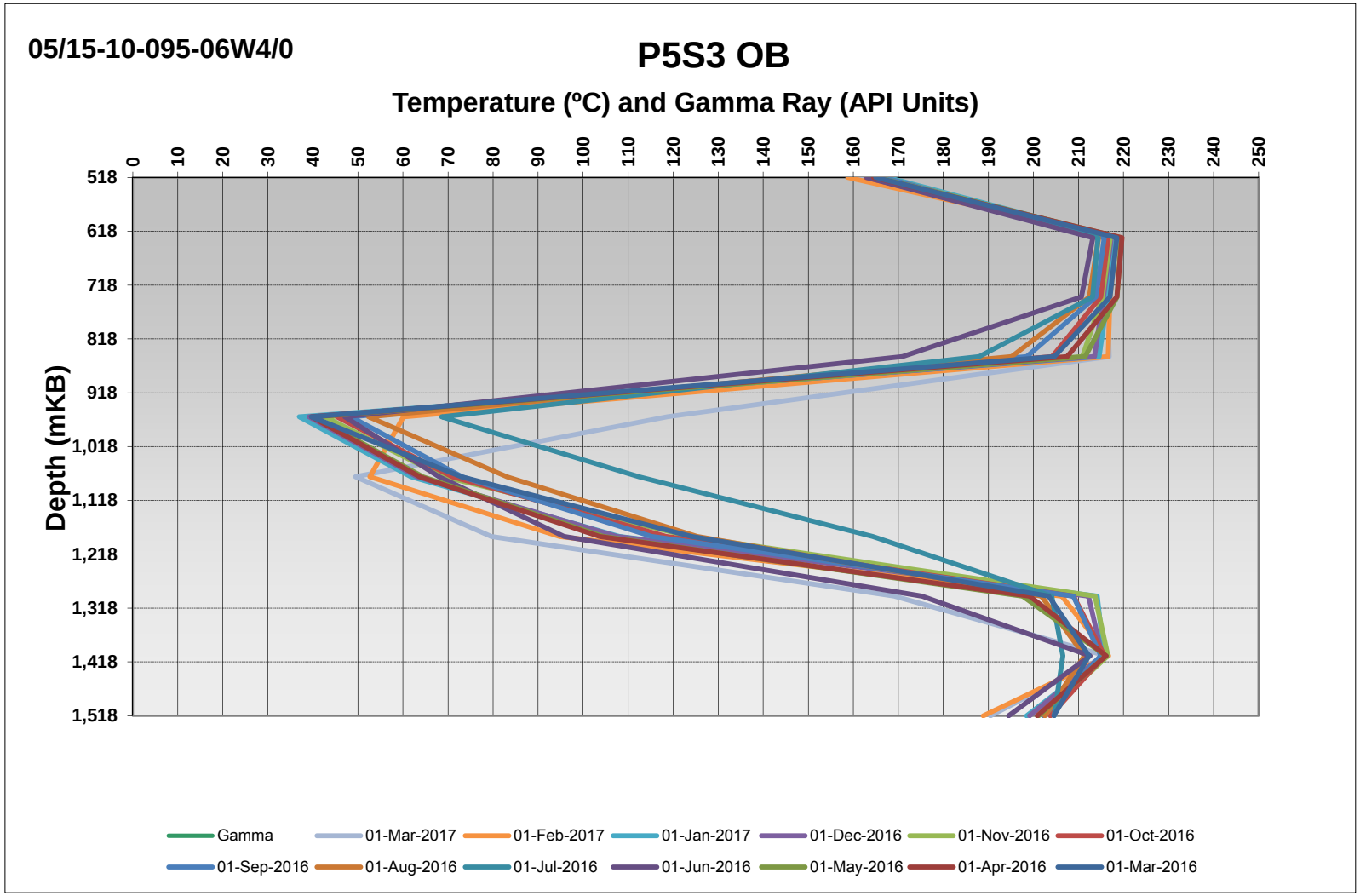

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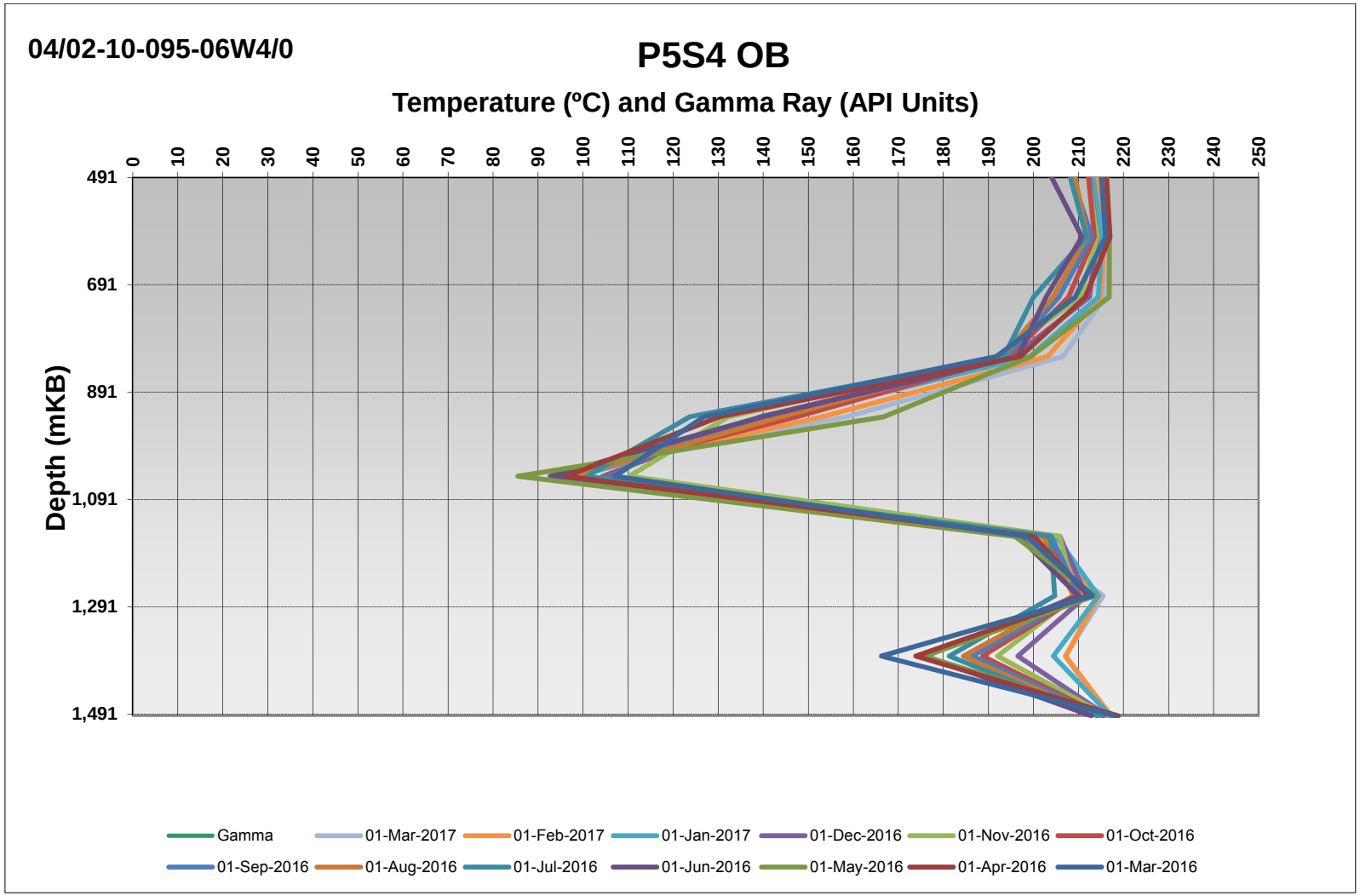

RST Logs

- Suncor has completed RST log in the following observations wells
- The Analysis is underway and will be presented in next D54 presentation to AER in 2018

well	Date RST completed
OB73	2/12/2017
OB186	2/13/2017
OB190	2/15/2017
OB213	2/16/2017
OB215	2/7/2017
OB216	2/6/2017
OB166	2/10/2017
OB169	2/9/2017
OB 07-31	2/14/2017
OB 09-31	2/18/2017