Suncor Firebag
2015 AER Performance Presentation
Commercial Scheme Approval No. 8870

May 7, 2015

Reporting Period: March 1, 2014 to February 28, 2015

Section 3.1.1 – Subsurface Issues Related to Resource Evaluation and Recovery

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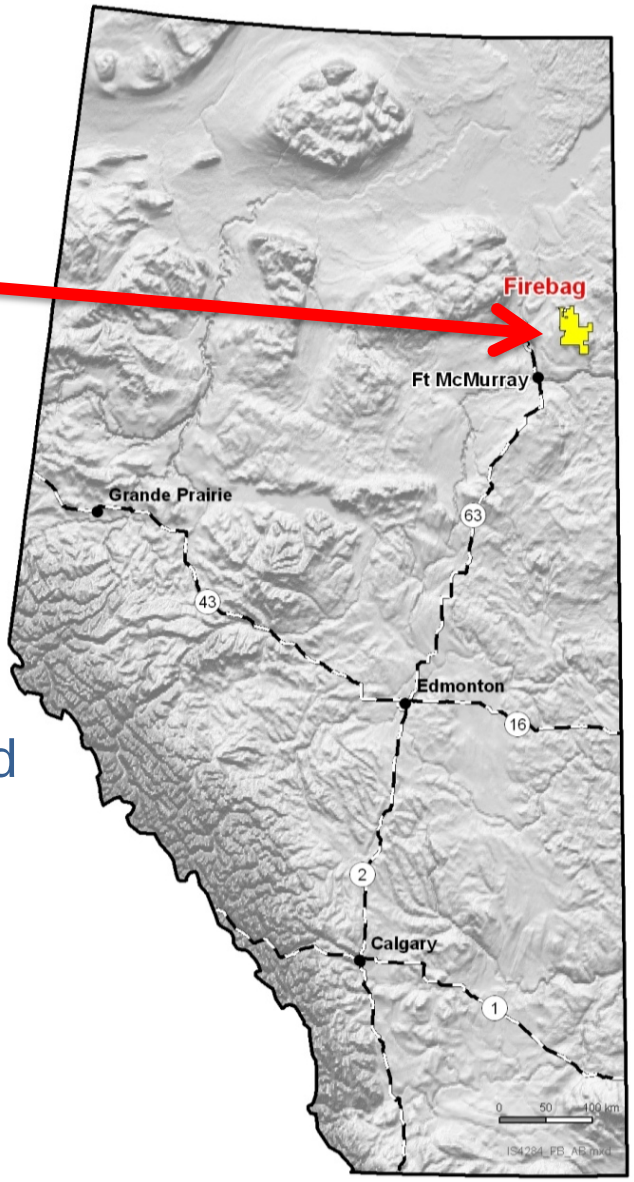
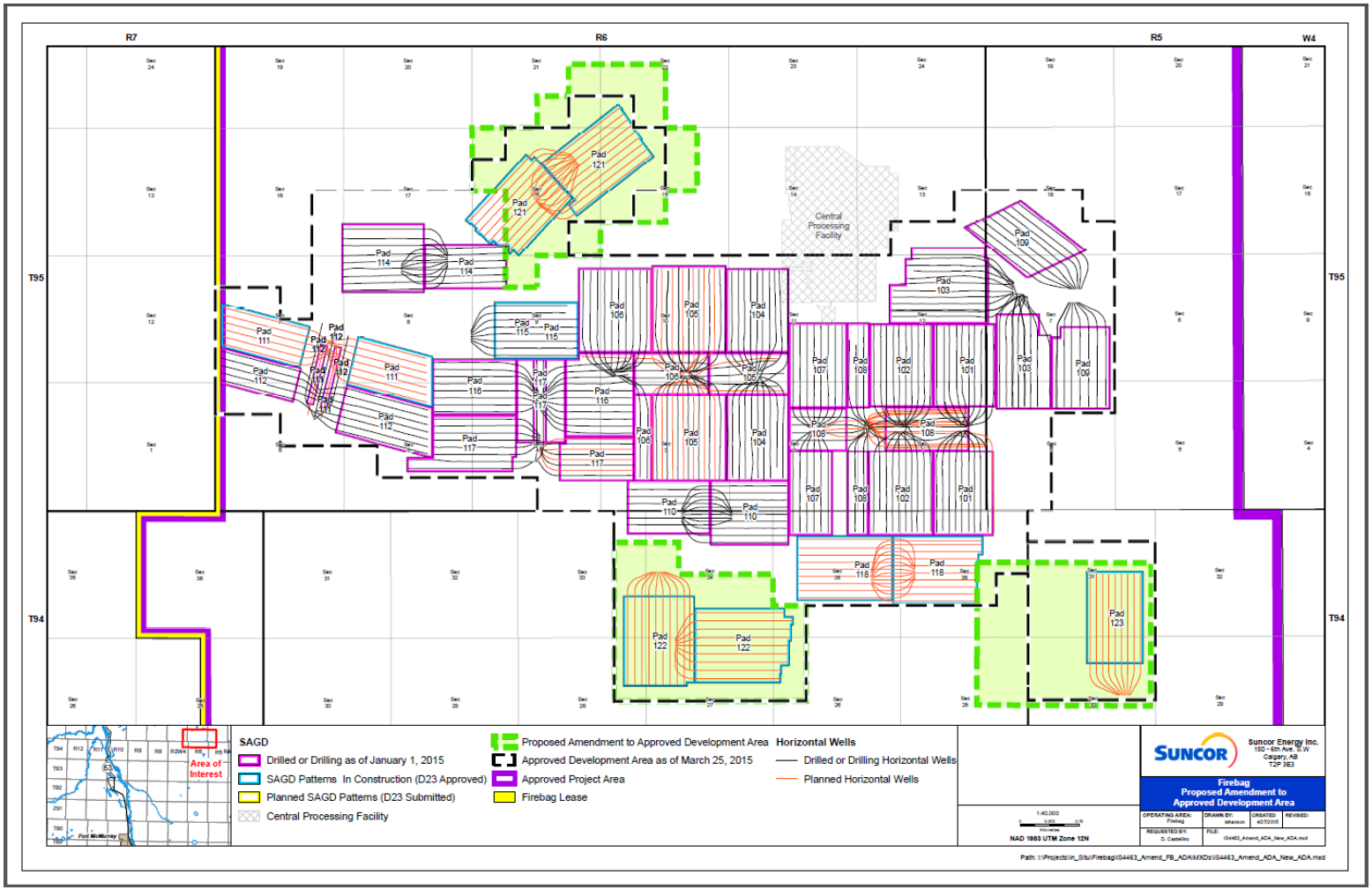
- **Introduction**
- Geoscience
- Surface Heave and Cap Rock Integrity
- Drilling and Completions
- Artificial Lift
- Instrumentation in Wells
- 4-D Seismic
- Scheme Performance
- Future Plans

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 28,201 m3/day (177,398 bbl/d) of bitumen with a Steam to Oil Ratio (SOR) of 2.71

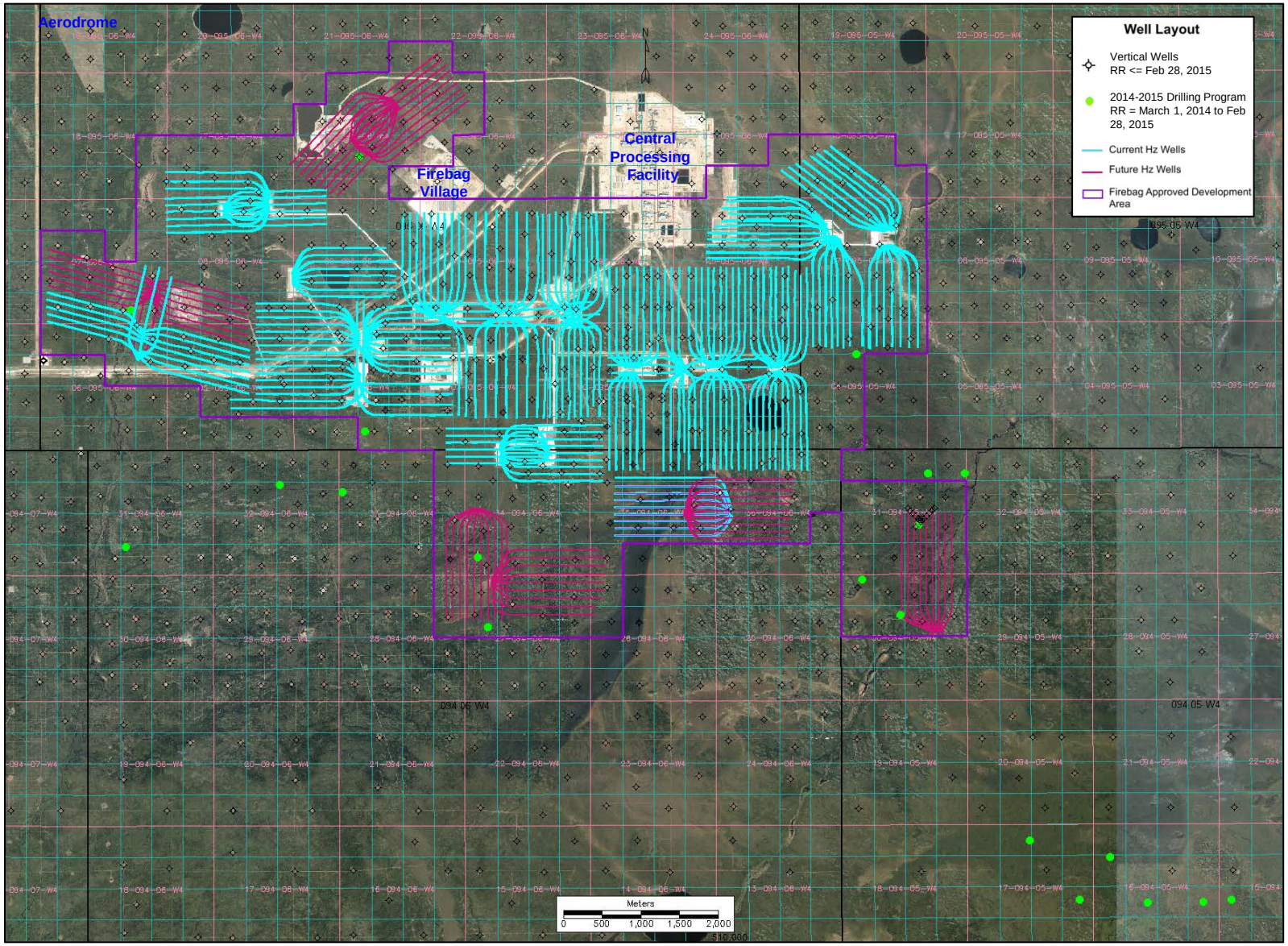
AER Project & Approved Development Areas



Firebag Approval 8870 as of March 2015

- Change during report period due to AER approval of Pads
  - 123 (8870BBB)
  - 121 & 122 (8870CCC)

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			TBD	till, clay, sand, gravel, peat, and muskeg	
MESOZOIC	MANNVILLE	GRAND RAPIDS		TBD	mudstone >>> siltstone (lithic sand?)	CAPROCK
		CLEARWATER	upper Clearwater	TBD	shale, mudstone >>> siltstone	
			Wabiskaw	upper Wabiskaw	shale, mudstone, sand	
				lower Wabiskaw		RMZ
		MCMURRAY	upper McMurray		sand, mudstone, IHS, intraclast breccia, lignite, and karst breccia	
			middle McMurray	TBD		RESERVOIR
			lower McMurray	***lower McMurray 3***		
				lower McMurray 2		
				lower McMurray 1		
PALEOZOIC	BEAVERHILL LAKE	WATERWAYS	Firebag		fossiliferous calcareous mudstone	

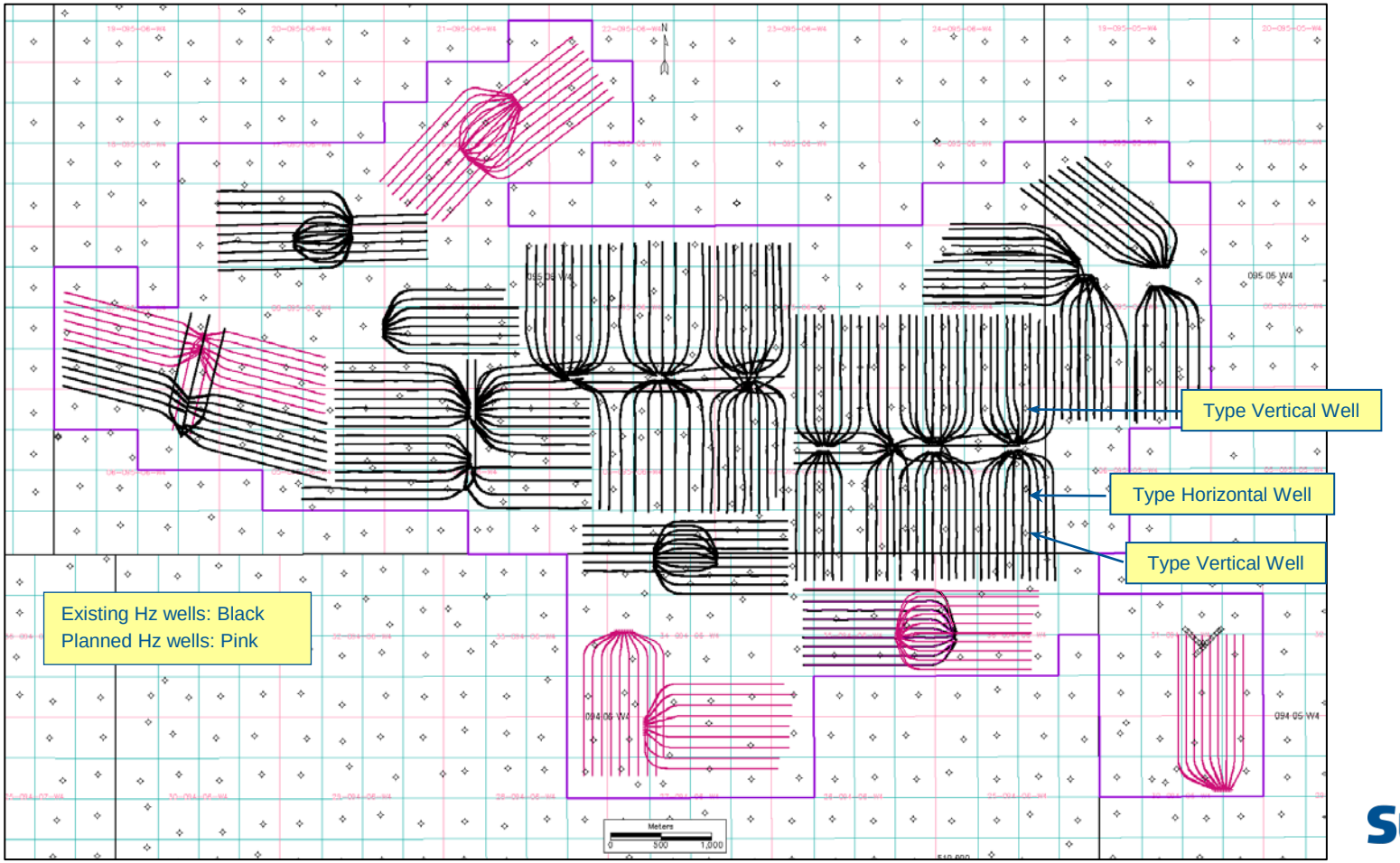
Type Well Location Map

Type Wells

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

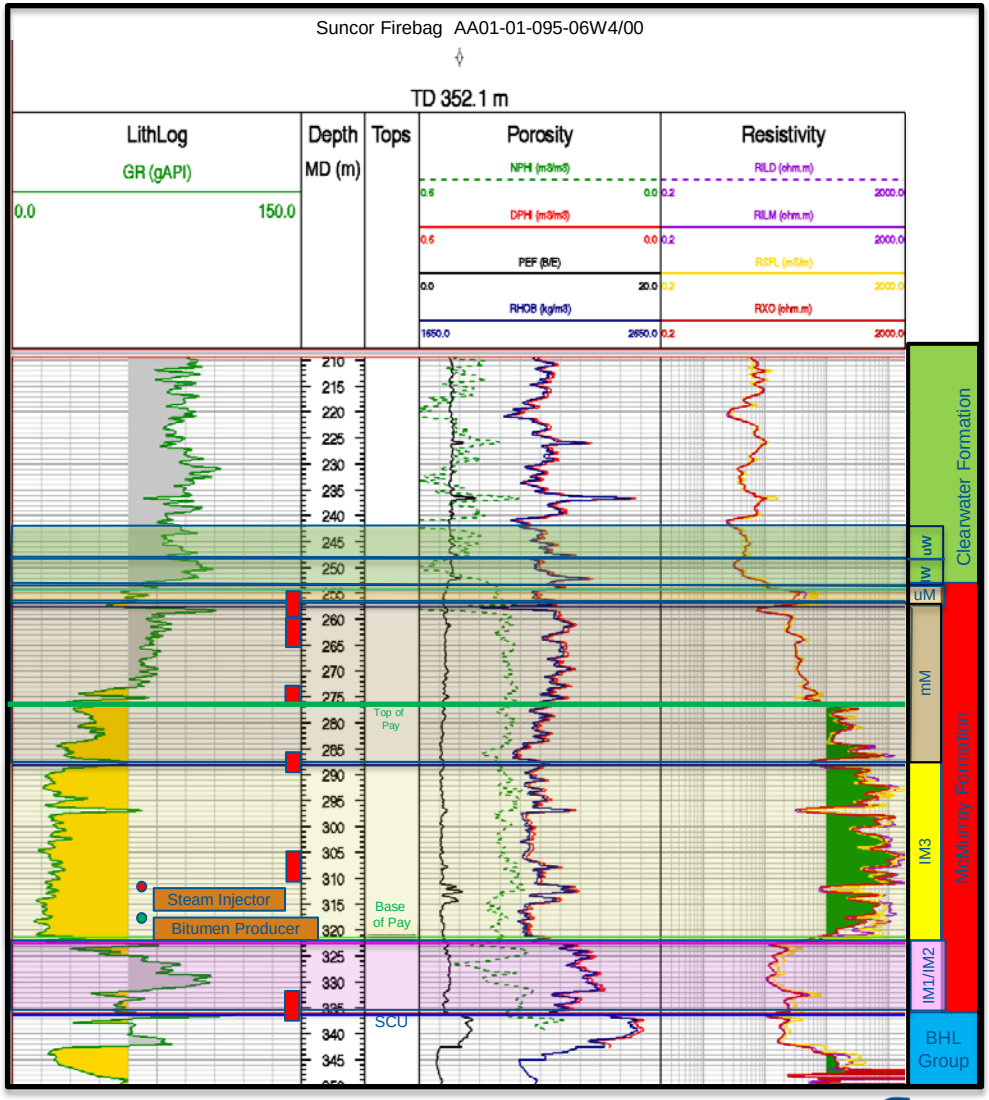
Type Horizontal Well

- Pad 101 Pair 7

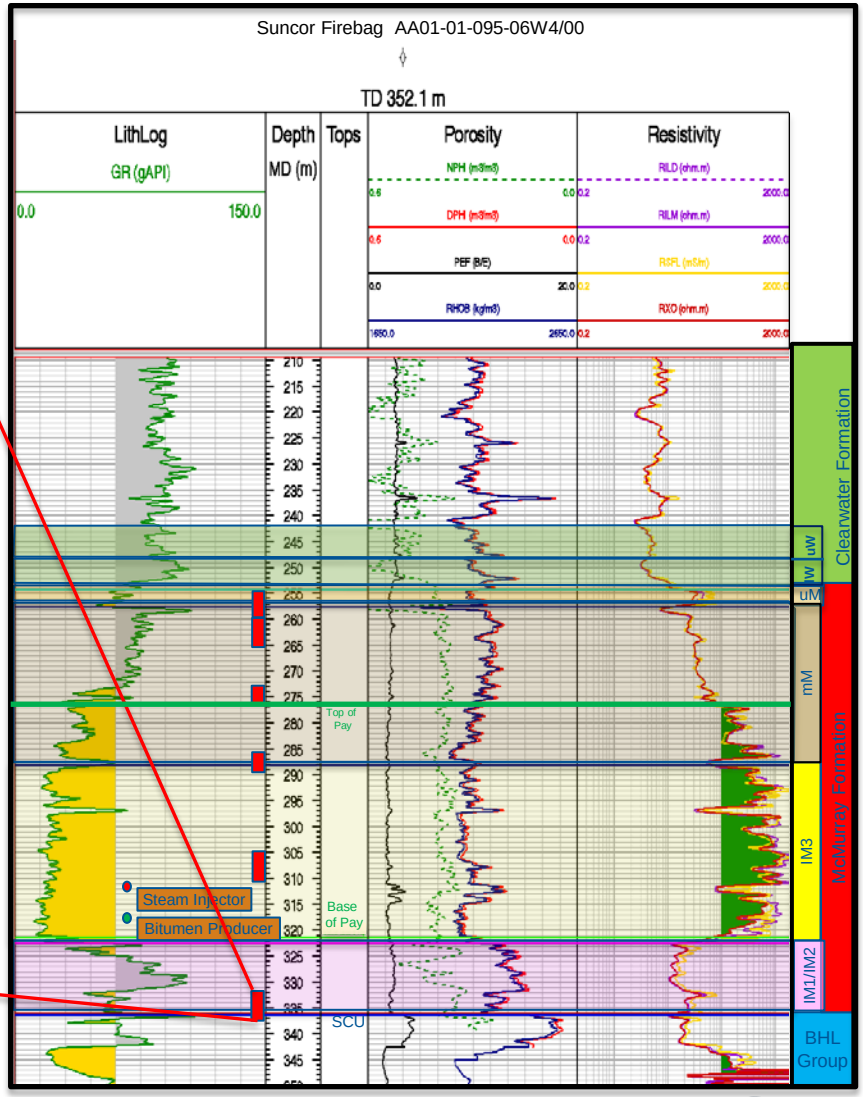


Firebag Type Well 1AA/01-01-095-06W4/00

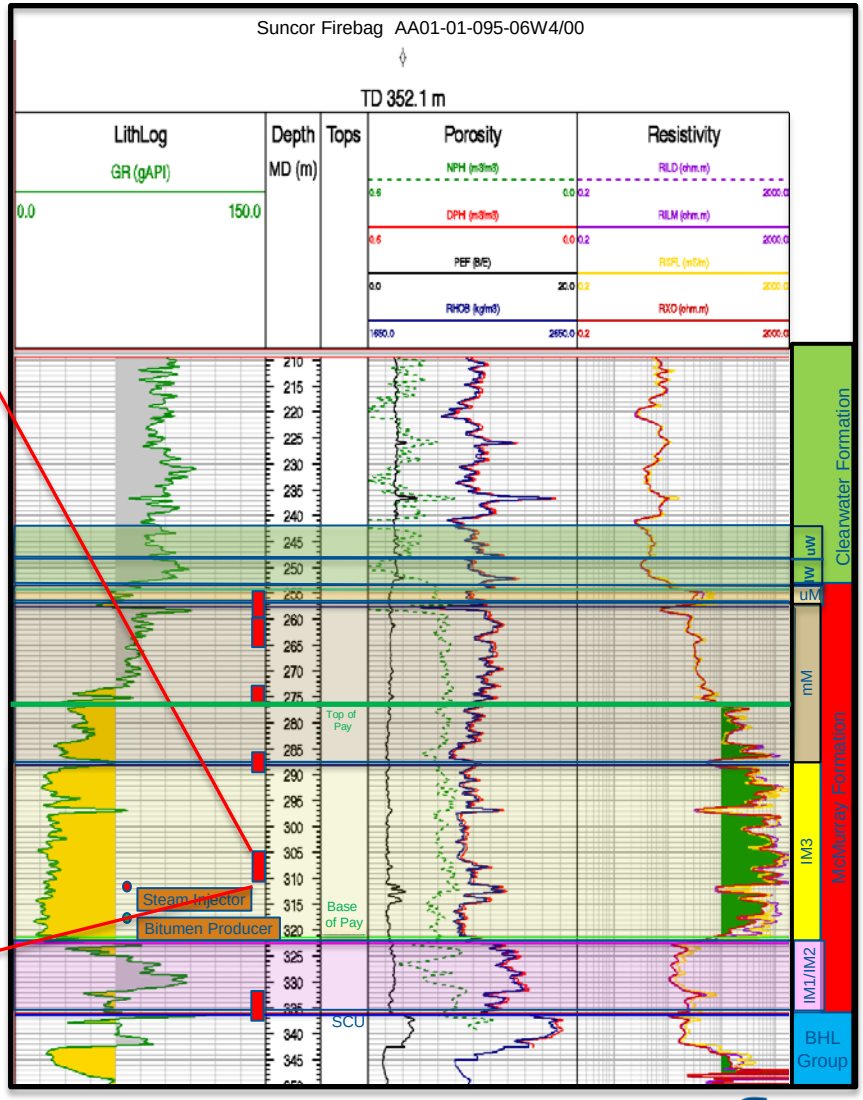
- McMurray Fm: 82.2 m
- upper McMurray: 3.2 m
- middle McMurray: 30.6 m
- lower McMurray 3: 34.4 m
- continuous pay zone:
  - Net Pay: 41.6 m
  - NTG: 0.98
  - Core Porosity: 35.7%
  - Core Sw: 21.9%
  - Kh: 8-10 D
  - Kv: 4-5 D
- lower McMurray 2: 13.6 m
- lower McMurray 1: 0.4 m
- 45 m west of Pad 101 Pair 7



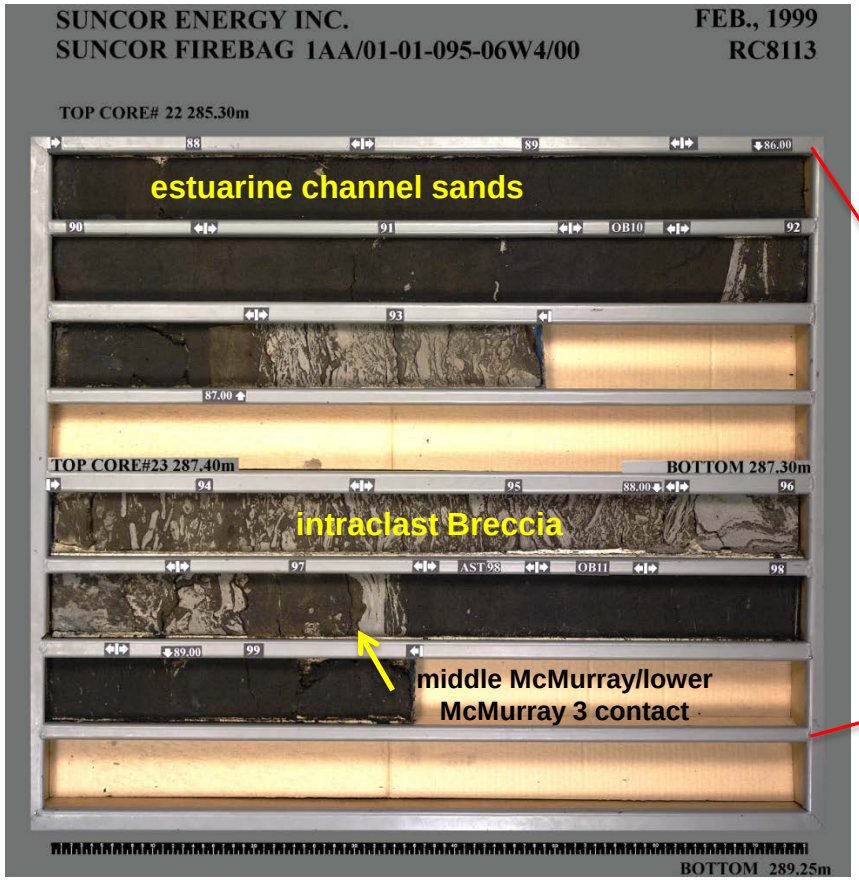
Lower McMurray 1 & 2 Units (Non Reservoir)

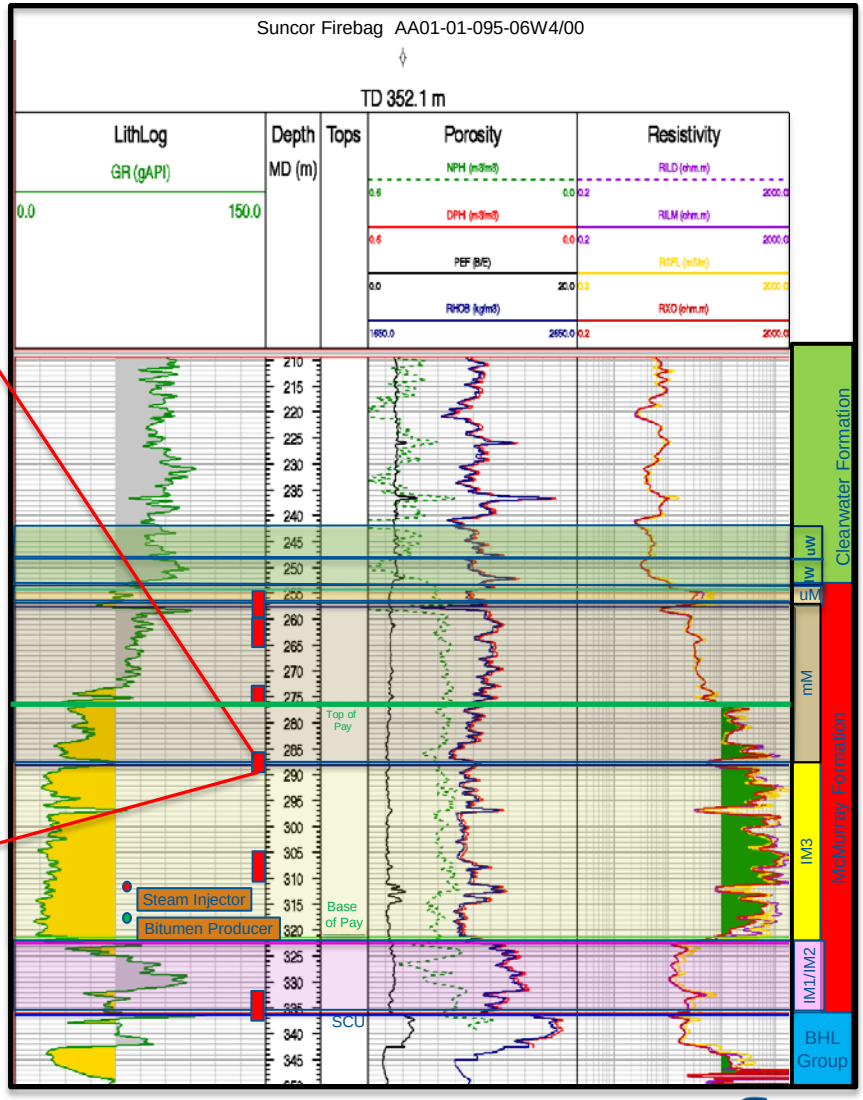


Lower McMurray 3 Oil Sands Reservoir

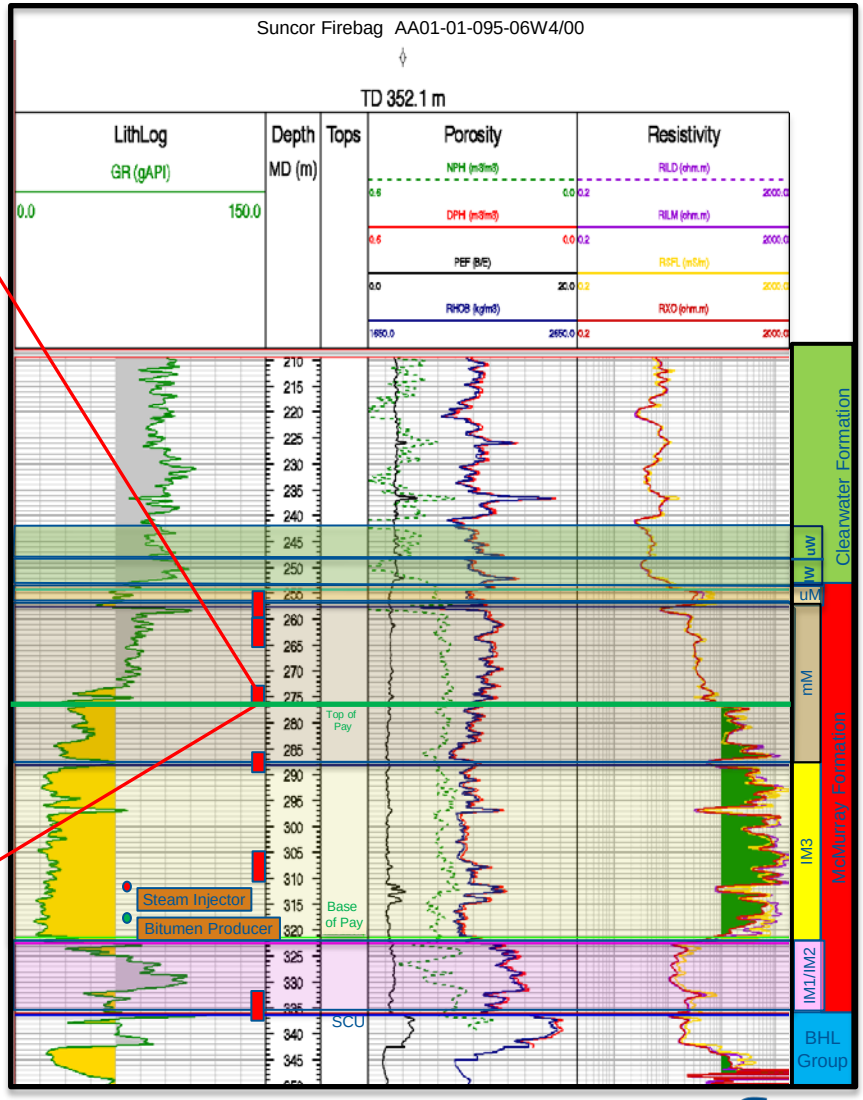


Middle McMurray - Intraclast Breccia





Middle McMurray Estuarine Channels and Associated Point Bars



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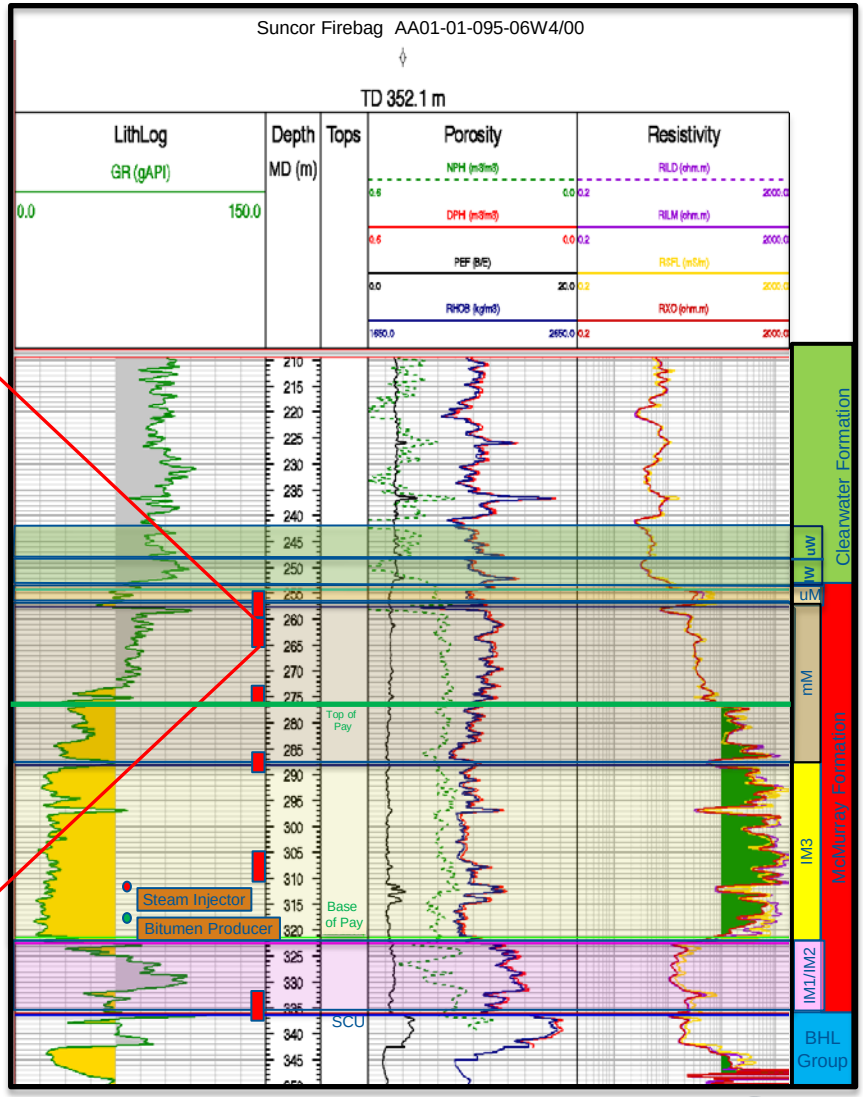
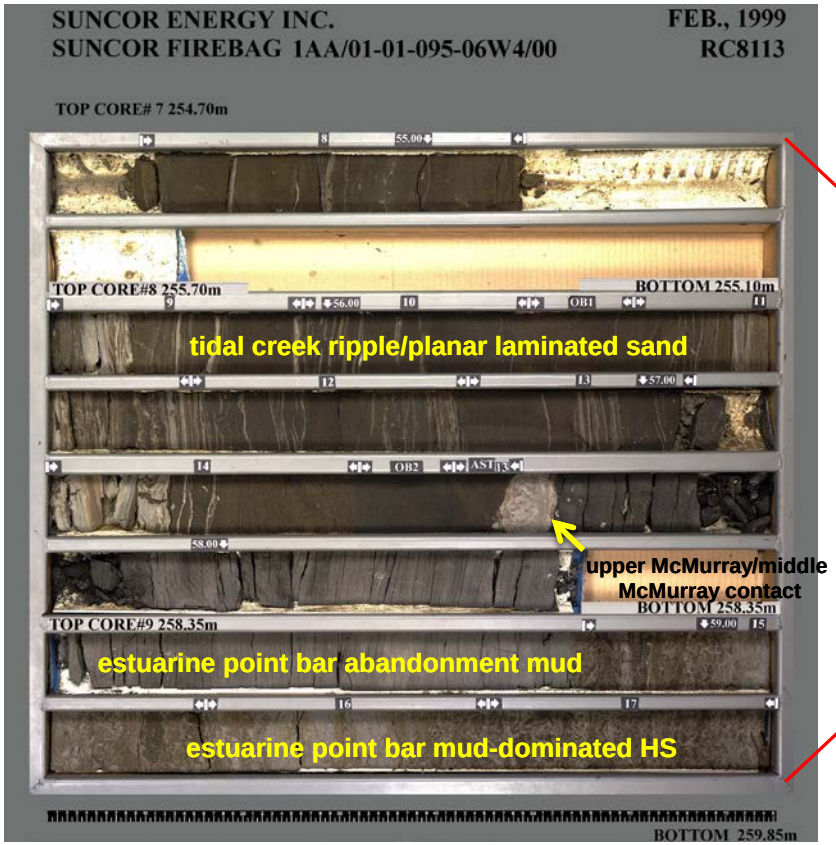
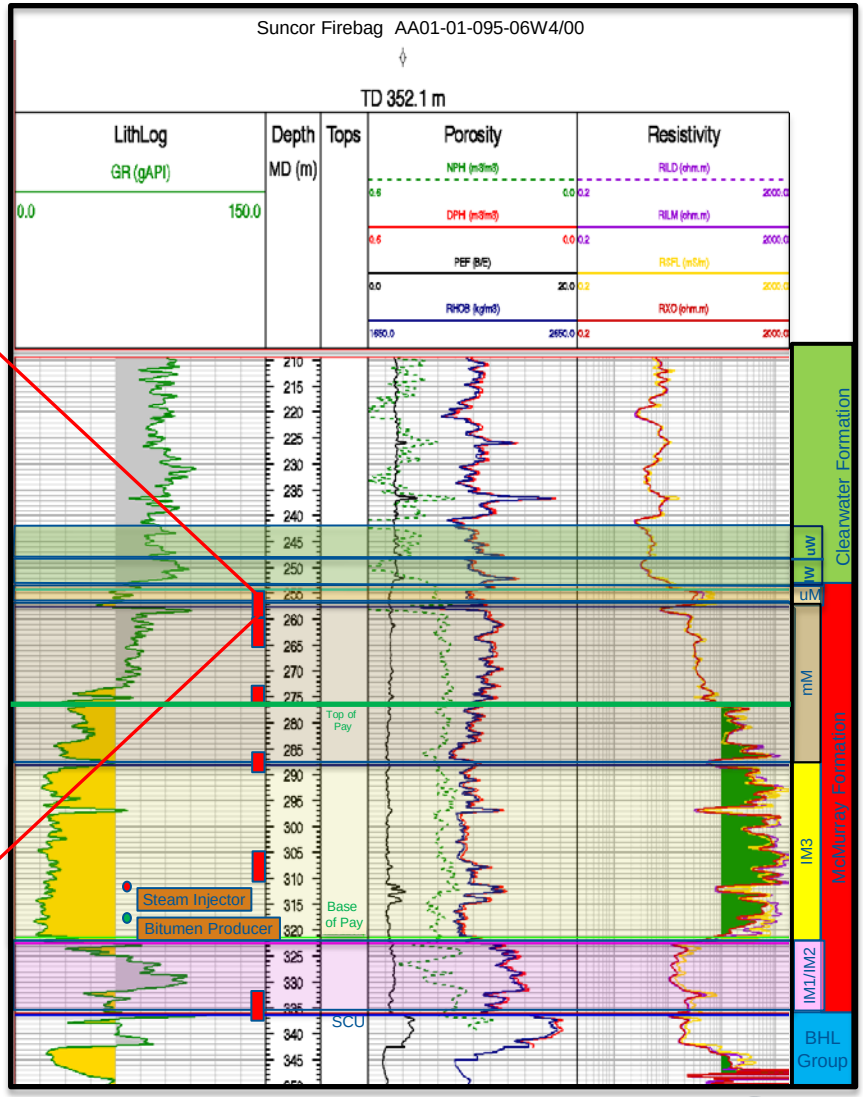
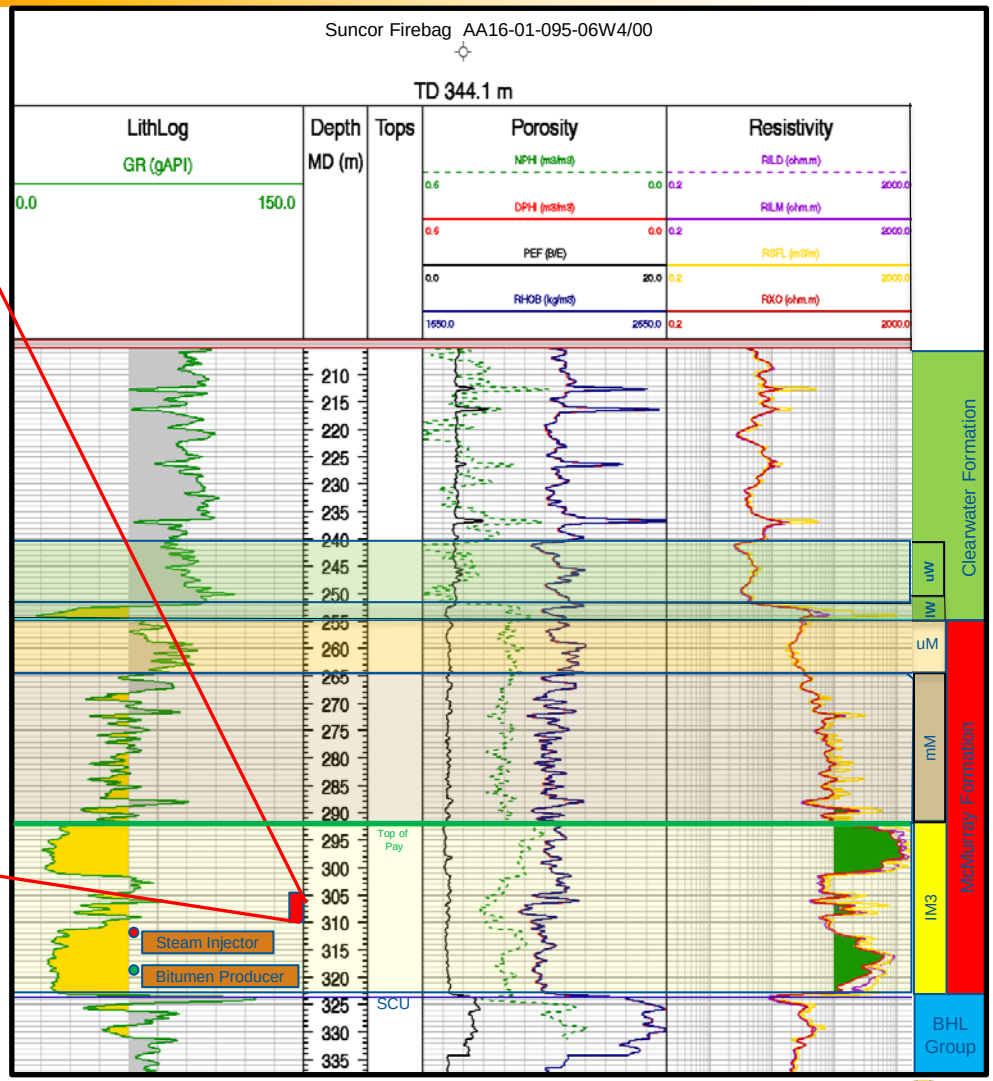


Middle McMurray and Upper McMurray Units



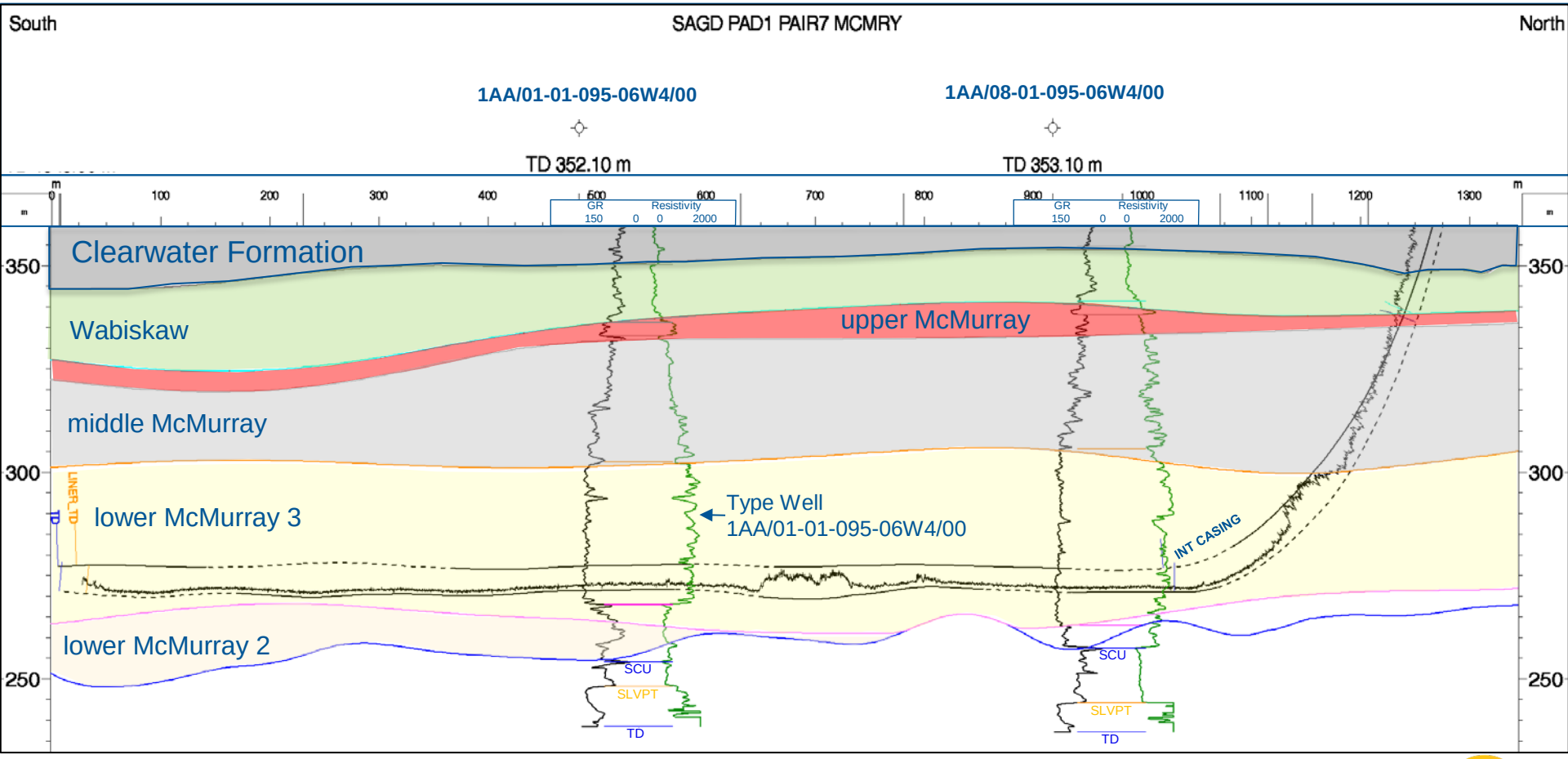


Firebag Type Well 1AA/16-01-095-06W4/00



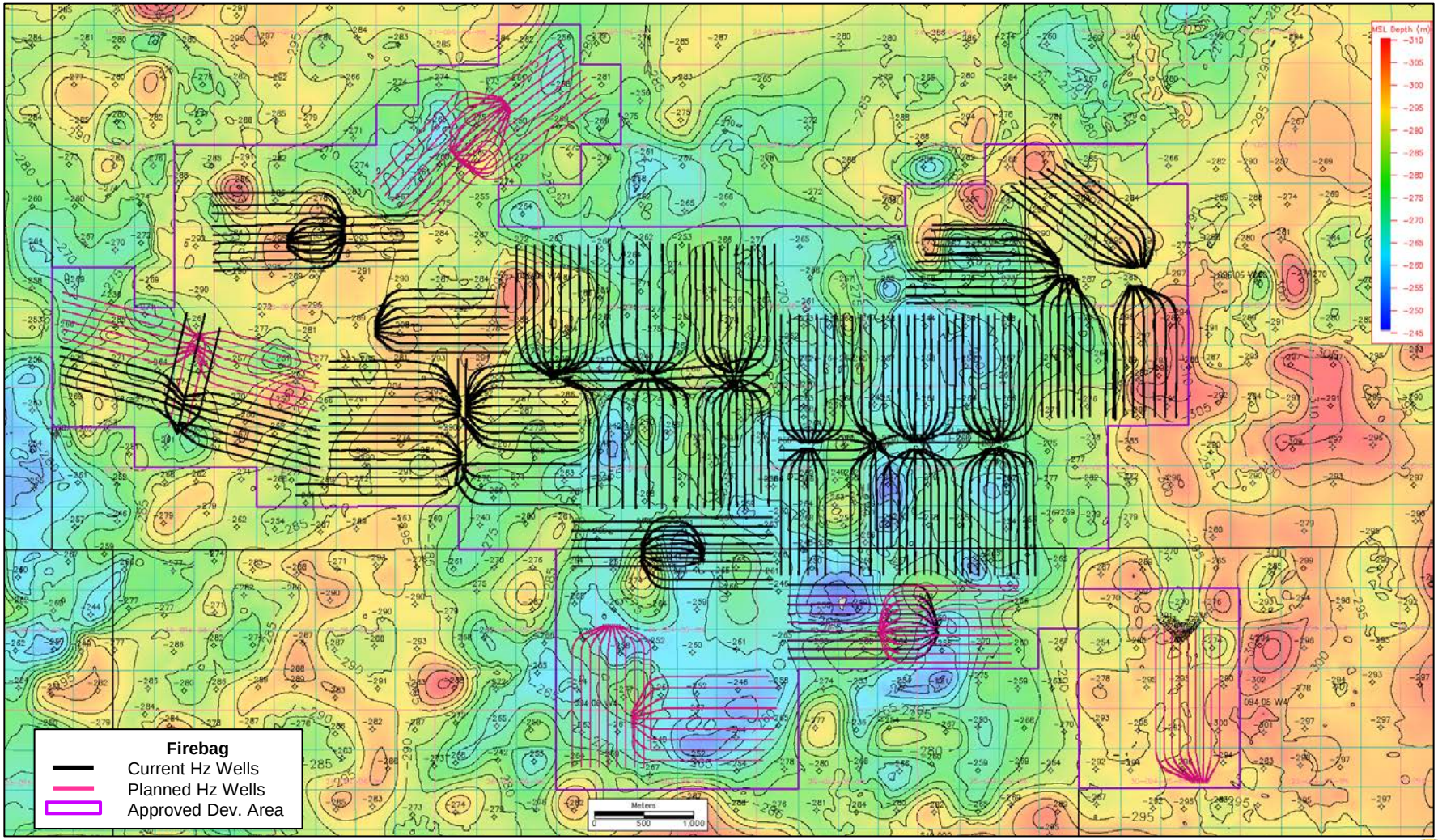
- Lower McMurray 3 floodplain mud
- Reservoir quality within McMurray varies and can present challenges

Pad 101 Pair 7 Structural Cross Section



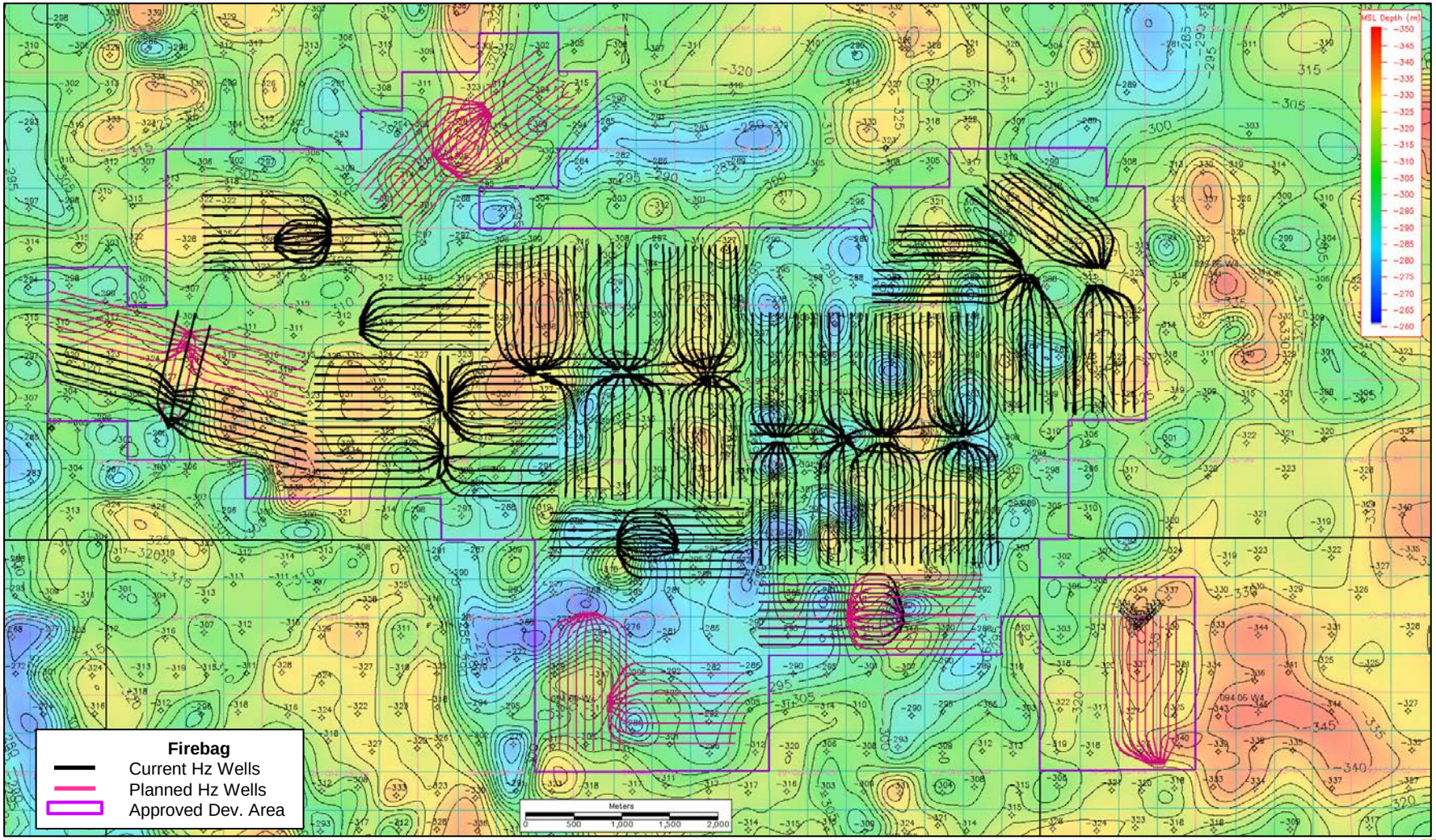
*Coreholes are projected onto cross section

Structure Map of Base of Gross Bitumen Pay Interval



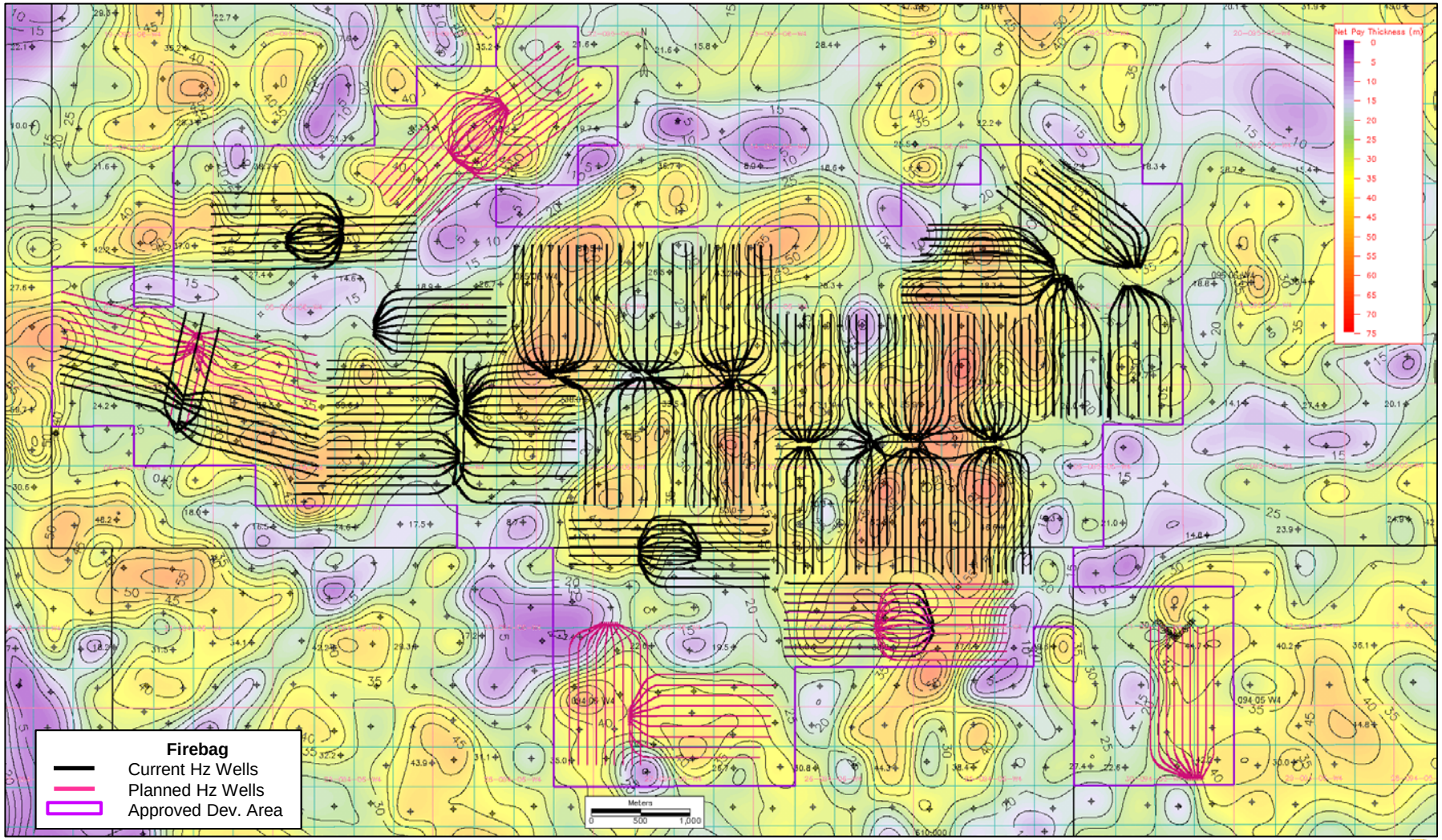
- Base of the lower McMurray 3 pay interval

Structure Map of Top of Gross Bitumen Pay Interval



- Top of middle McMurray pay interval

Isopach Map of Cumulative Net Bitumen Pay



- Continuous Pay Cut-Offs being developed
- Updated interpretation in progress to incorporate 2015 wells
- No bottom or top water has been identified within the project area
- Lean bitumen has been identified below, within, and on top of the pay within the project area

Original Bitumen in Place (OBIP) & Average Reservoir Properties

	Area (m^2)	Gross Thickness (m)	Gross Rock Volume (e^6 m^3)	Net-to-Gross Ratio[1]	Net Pay Thickness (m)	Porosity	Oil Saturation	Formation Volume Factor	OBIP[2] (e^6 m^3)	OBIP[2] (MMbbl)
SAGD Pad 101	1,676,270	52.4	87.7	0.89	47.0	0.34	0.87	1	23.1	145.3
SAGD Pad 102	1,748,969	55.7	97.5	0.86	47.7	0.34	0.84	1	23.4	147.2
SAGD Pad 103	1,930,447	47.0	90.7	0.81	37.9	0.32	0.85	1	20.0	125.8
SAGD Pad 104	1,720,517	46.8	80.5	0.86	40.5	0.31	0.86	1	18.5	116.4
SAGD Pad 105	2,617,022	36.8	96.4	0.88	32.6	0.32	0.86	1	23.3	146.6
SAGD Pad 106	1,755,033	44.9	78.8	0.87	39.3	0.31	0.86	1	18.5	116.4
SAGD Pad 107	1,394,006	42.1	58.6	0.78	32.8	0.32	0.85	1	12.6	79.3
SAGD Pad 108	1,243,933	54.5	67.8	0.81	44.3	0.32	0.85	1	15.2	95.6
SAGD Pad 108 North	307,575	38.1	11.7	0.77	29.4	0.32	0.88	1	2.5	15.9
SAGD Pad 109	1,500,886	36.8	55.3	0.83	30.7	0.33	0.82	1	12.6	79.3
SAGD Pad 110	1,463,974	43.2	63.2	0.74	31.8	0.32	0.82	1	12.0	75.5
SAGD Pad 111	1,406,408	40.6	57.0	0.83	33.7	0.31	0.82	1	12.2	76.5
SAGD Pad 112	1,447,415	46.2	66.9	0.83	38.2	0.32	0.81	1	14.2	89.0
SAGD Pad 114	1,512,000	36.7	55.4	0.84	30.7	0.31	0.83	1	11.9	74.9
SAGD Pad 115	749,429	34.2	25.6	0.75	25.6	0.32	0.80	1	4.9	30.8
SAGD Pad 116	1,684,175	43.5	73.3	0.89	39.1	0.31	0.85	1	17.3	108.8
SAGD Pad 117	1,525,139	36.3	55.3	0.81	29.7	0.32	0.82	1	11.7	73.8
SAGD Pad 118	2,010,652	47.5	95.4	0.84	39.7	0.32	0.84	1	21.3	134.0
SAGD Pad 123	848,565	44.6	38.8	0.81	36.2	0.30	0.84	1	7.7	48.3
SAGD Pad 121	1,935,515	43.4	83.9	0.79	34.2	0.31	0.81	1	16.8	105.4
SAGD Pad 122	2,135,632	44.7	95.4	0.80	35.7	0.29	0.80	1	17.9	112.4
SAGD TOTAL	32,613,561	44.0	1435.3	0.83	36.6	0.32	0.84	1	317.5	1997.1
Firebag Approved Project Area	193,970,483	35.9	6,970.1	0.74	26.7	0.31	0.84	1	1,299.3	8172.6

[1] Net-to-Gross Ratio: Net pay cutoffs applied are GR>60 API, Porosity < 0.22, and Sw > 0.50.

[2] OBIP: Original Bitumen in Place

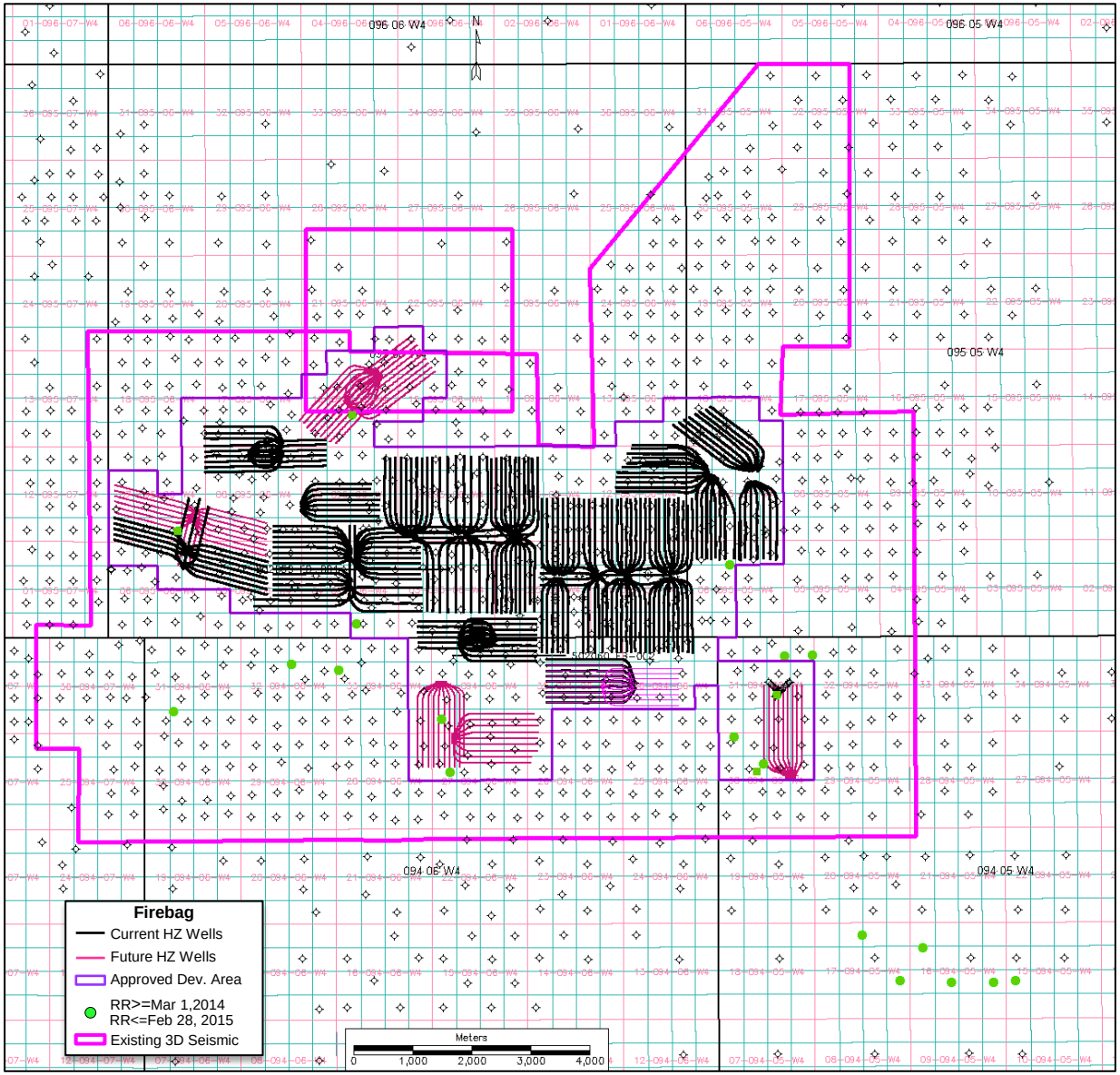
From Pad 122 D23 Application

Average Reservoir Properties

- Average reservoir properties for the operating portion of the scheme (Pads 101-108, 108N and Pad 115 - 116)
  - Initial reservoir pressure: 800kPa
  - Initial reservoir temperature: 8°C
  - Average gross pay = 45.7 m
  - Average net pay = 38.9 m
  - Average porosity = 0.321
  - Average oil saturation = 0.85
  - Effective horizontal permeability: 3 to 4 D
  - Effective vertical permeability: 2 to 3 D
  - Viscosity: ~ 11cp @ 215°C

SUNCOR

2014/2015 Winter Delineation Program and 3D Seismic



- Existing wells in black
- New wells 2014-2015 Drilling Program (RR Mar 01, 2014 to Feb 28, 2015) in green

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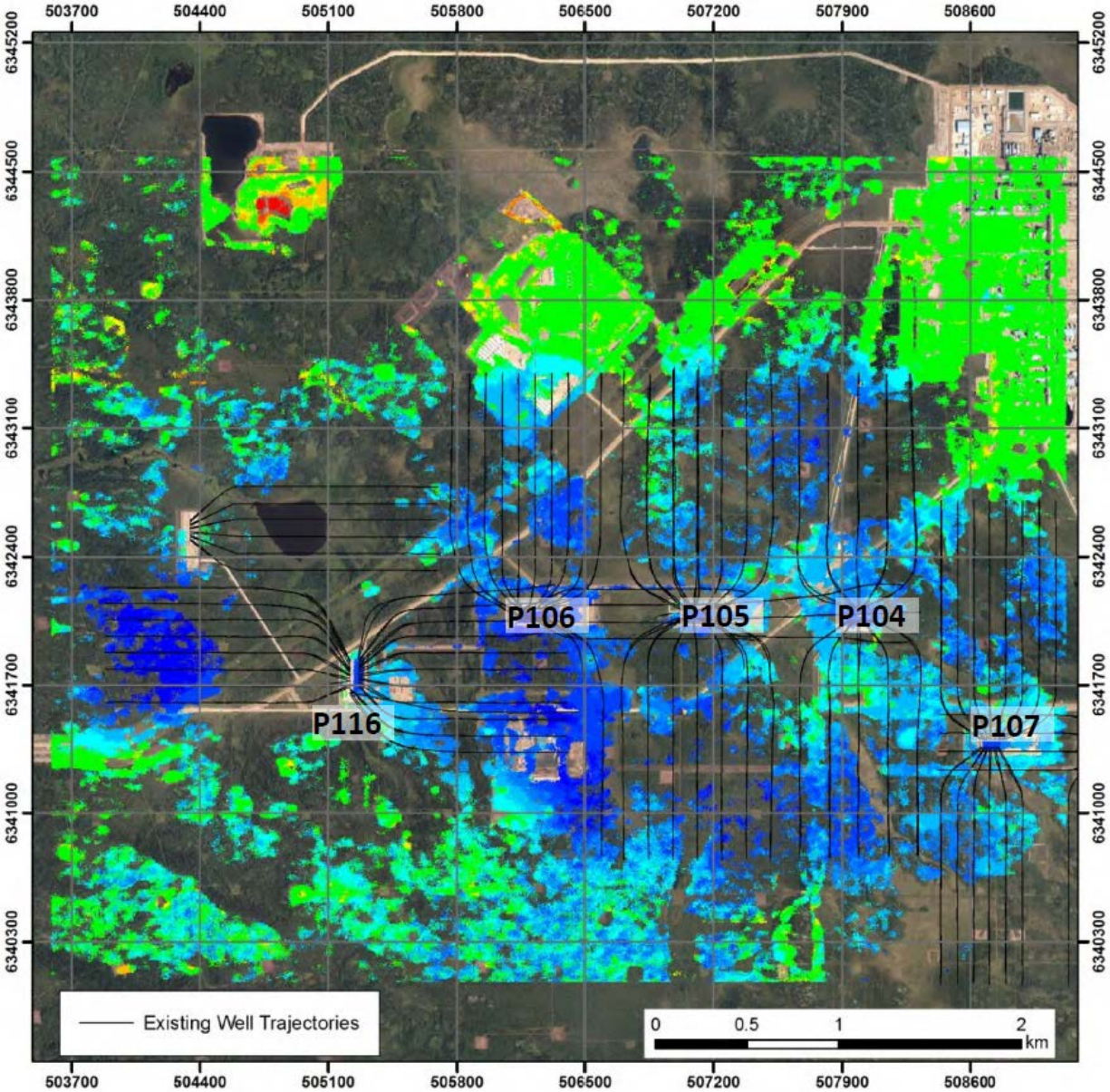
Pads 106 & 116 InSar Heave Map - May 2013 to Oct 2014



- Maximum heave observed of 6 cm on Pad 106 and 116
- Pad 101/102 surface heave discontinued due to maturity of pad area and reference markers being influenced by Pad 116

Accumulated Displacement from May 2013 to October 2014 [mm]

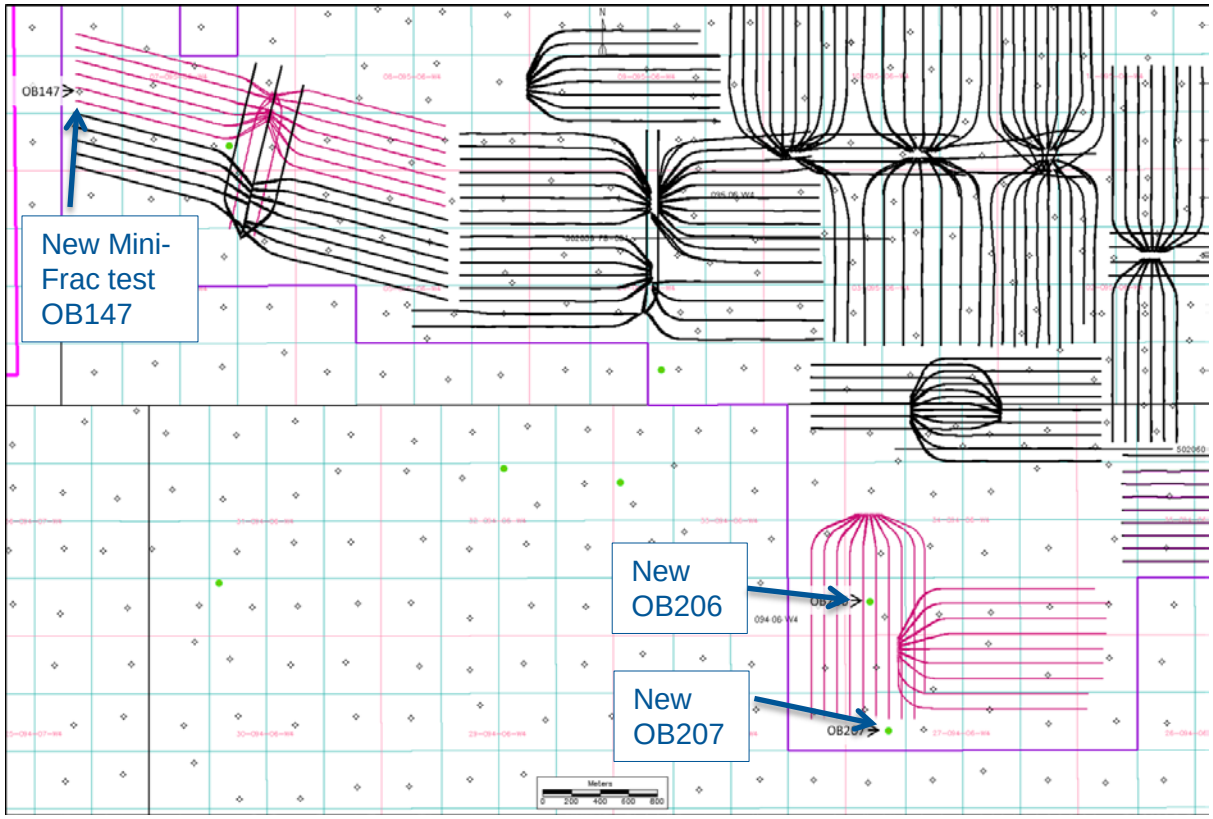
Heave
- More than 60
- From 40 to 60
- From 30 to 40
- From 20 to 30
- From 10 to 20

Stability

Subsidence
- From 10 to 20
- From 20 to 30
- From 30 to 40
- From 40 to 60
- More than 60

Caprock – Geological Activity

- 2014/15 Winter Drilling Program
- New Observation Wells – OB 206 and OB 207
  - Both obs. wells have 3 pt. Piezometer pressure measurement
  - Both obs. wells have 2 Thermocouple Bundles (24 and 30 pt)
  - Both obs. wells were cored in the lower McMurray 2 & 3, middle McMurray, upper McMurray, and Wabiskaw

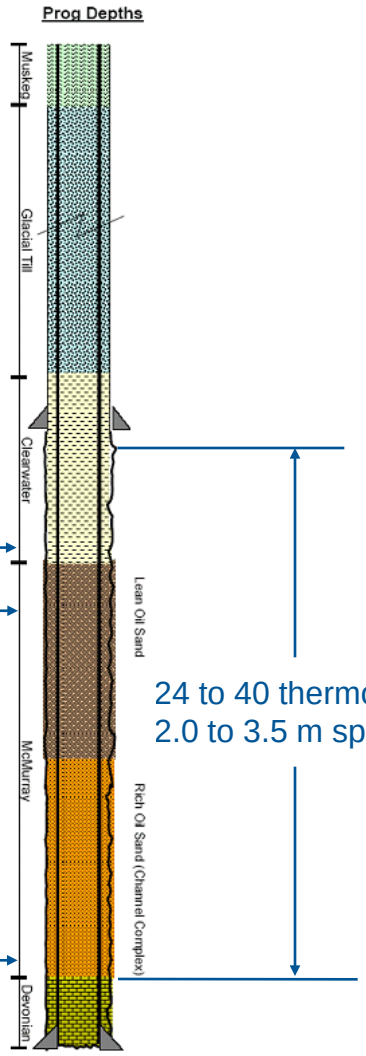


2 New Caprock Monitoring Wells

Piezometer

Locations vary

by well



24 to 40 thermocouples
2.0 to 3.5 m spacing

Temperature Instrumentation

Reservoir Thermocouple (TC) String:

- OB 206 and OB 207 have two bundles of thermocouples (a lower 24 pt string at 3.5 m spacing and an upper 30 pt string at 2 m spacing) which covers from the base of the lower McMurray 3 up into the Surface Casing

Pressure Instrumentation

Piezometers

1. OB 206 and OB 207 have 3 piezometers outside casing at the lower McMurray 3, middle McMurray, and lower Wabiskaw (RMZ)
2. OB 147 Mini-frac well was suspended but future piezometers planned

Note: There are 4 wells that monitor above the Caprock in the Quaternary Zone:

QW1, QW2, QW4, OB80

Caprock Integrity Assurance

- Mini-Fracs in 2015
  - OB147 tested the lower McMurray 3, middle McMurray, Reservoir Monitoring Zone, and Clearwater via mini-frac in 2015
  - Data were analyzed in-house and is consistent with SPE Paper 157843
- Suncor Geomechanical Modeling
  - Models are being updated as data comes in
  - Heave monitoring program and 4-D seismic has been useful for calibrating geomechanical models
  - New geomechanical models have been consistent with the 2013 Pad 101 South heave history match and prediction model
- All of these activities confirm that operating at the approved MOP does not impact Firebag Caprock Integrity

Reservoir Fracture Closure Gradients 2015

Date	Well	Well Alias	TVD Perforated Interval (mKB)	Target	Minimum Stress (kPaa)	Fracture Closure Gradient (kPaa/mKB)	Fracture Closure Gradient (kPag/mGL)
15-Mar-12	01-16-095-06W4	OB134	297-298	lower McMurray 3 sand	5238.9	17.6	17.6
17-Mar-12	09-09-095-06W4	OB135	263-264	middle McMurray sand	5106.1	19.4	19.3
13-Mar-12	11-10-095-06W4	OB136	268-269	middle McMurray sand	4835.6	18.0	18.0
23-Feb-14	16-07-095-05W4	OB205	273-274	lower McMurray 3 sand	4319.7	15.8	15.7
11-Feb-15	05-07-095-06W4	OB147	255-258	middle McMurray sand	3868.3	15.2	15.1
16-Mar-12	01-16-095-06W4	OB134	277-278	middle McMurray mudstone	5398.7	19.5	19.4
18-Mar-12	09-09-095-06W4	OB135	247.5-248.5	middle McMurray mudstone	4020.2	16.2	16.1
13-Mar-12	11-10-095-06W4	OB136	257-258	middle McMurray mudstone	4910.0	19.1	19.0
24-Feb-14	16-07-095-05W4	OB205	247-248	middle McMurray IHS	4407.6	17.8	17.7
12-Feb-15	05-07-095-06W4	OB147	227-228	middle McMurray mudstone	4111.5	18.1	18.0
16-Mar-12	01-16-095-06W4	OB134	253.5-254.5	Wabiskaw/lower Clearwater	5482.5	21.6	21.6
18-Mar-12	09-09-095-06W4	OB135	231-232	Wabiskaw/lower Clearwater	5060.2	21.9	21.9
14-Mar-12	11-10-095-06W4	OB136	238-239	Wabiskaw/lower Clearwater	4532.7	19.0	19.0
5-Mar-13	01-09-095-06W4	OB182	232.5-233.5	Wabiskaw/lower Clearwater	5237.2	22.5	22.5
25-Feb-14	16-07-095-05W4	OB205	225.5-226.5	Wabiskaw/lower Clearwater	4952.2	22.0	22.0
12-Feb-15	05-07-095-06W4	OB147	209.5-210.5	Wabiskaw/lower Clearwater	4679.0	22.3	22.3

- No change recommended to currently approved injection pressures:
  - Startup MOP based on an 80% S.F. overburden based closure pressure (4040 kPag except for Pads 111 and 112 where thinner overburden thickness has reduced Startup MOP to 3980 kPag)
  - 3570 kPag during production phase

Pressure Monitoring

- Surface injection pressure will be limited to approved overburden based MOP during start-up and 3570 kPag during the production phase
  - Friction losses will provide an extra margin of safety for protecting the reservoir
- All existing injection wells are set up to monitor downhole pressure
  - Some wells have thermocouple monitoring temperatures along the horizontal for start-up
- Production wells capable of periodically monitoring pressure via blanket gas during start-up period
  - Some wells have thermocouple or fibre monitoring temperature along the horizontal for start-up
  - During mechanical lift conversion, pressure and temperature monitoring at the ESP is installed on all wells (bubble tubes/pressure gauges, thermocouples)

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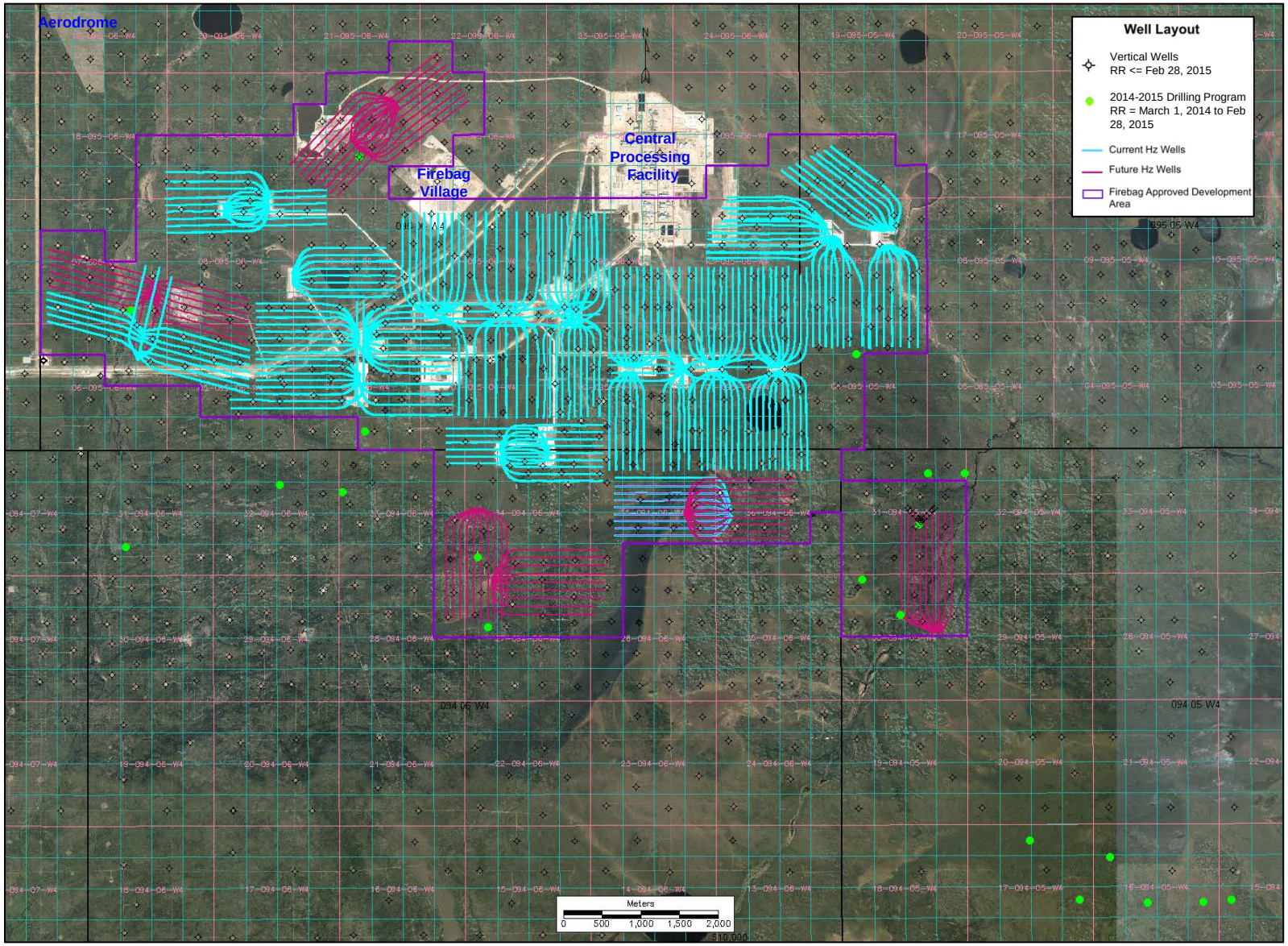
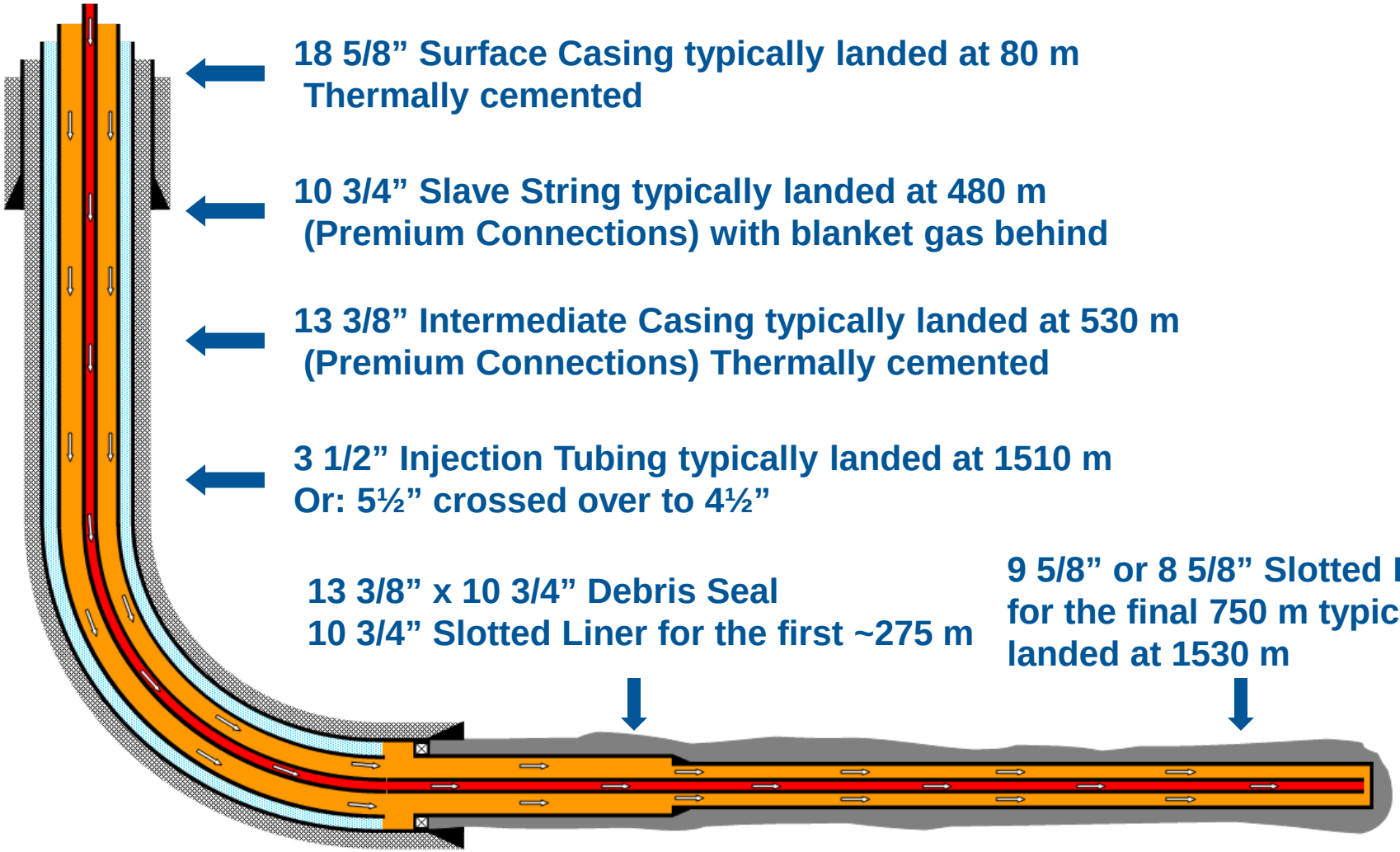
SAGD Well Layout



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

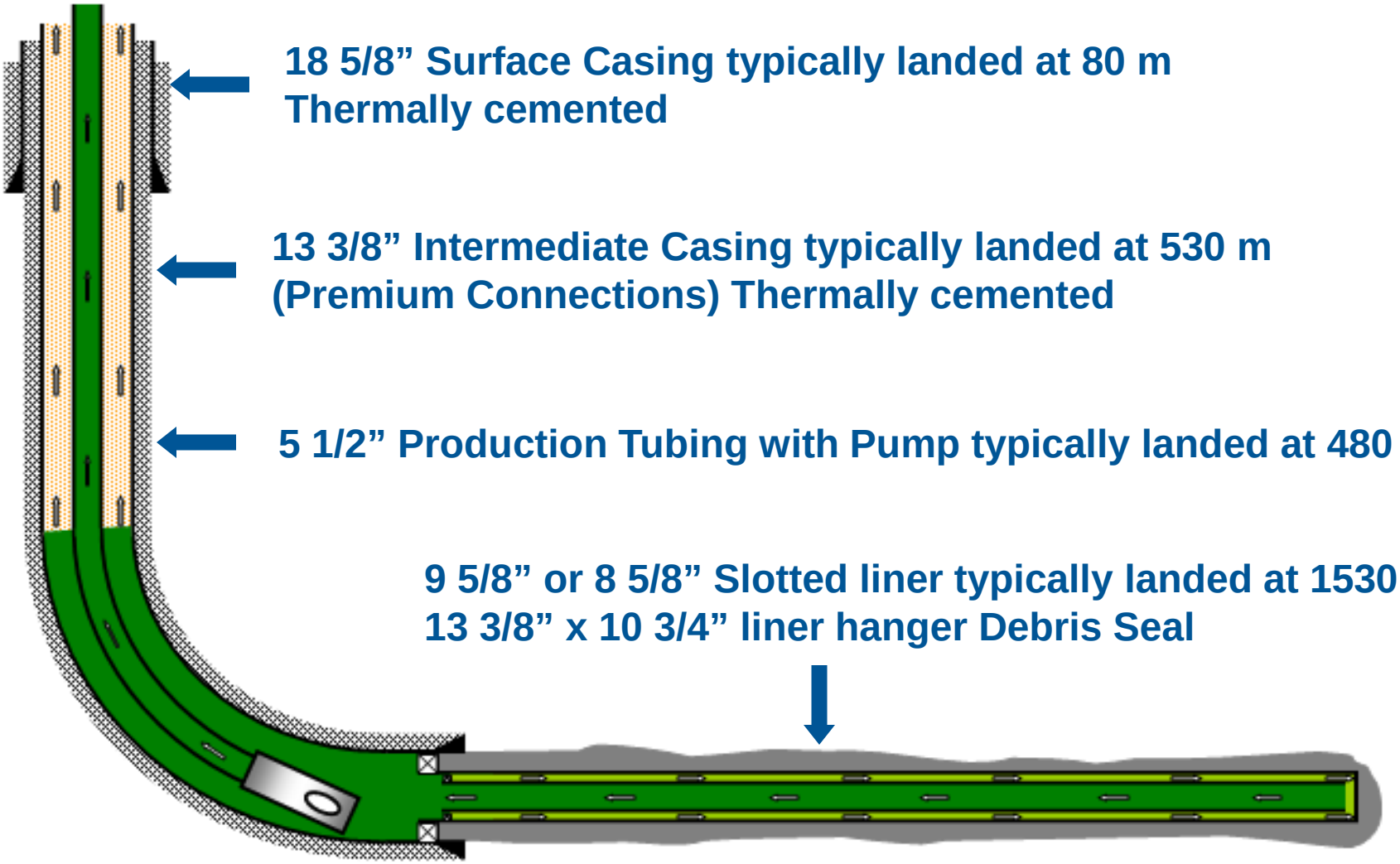
13 3/8” Intermediate Casing typically landed at 530 m
(Premium Connections) Thermally cemented

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

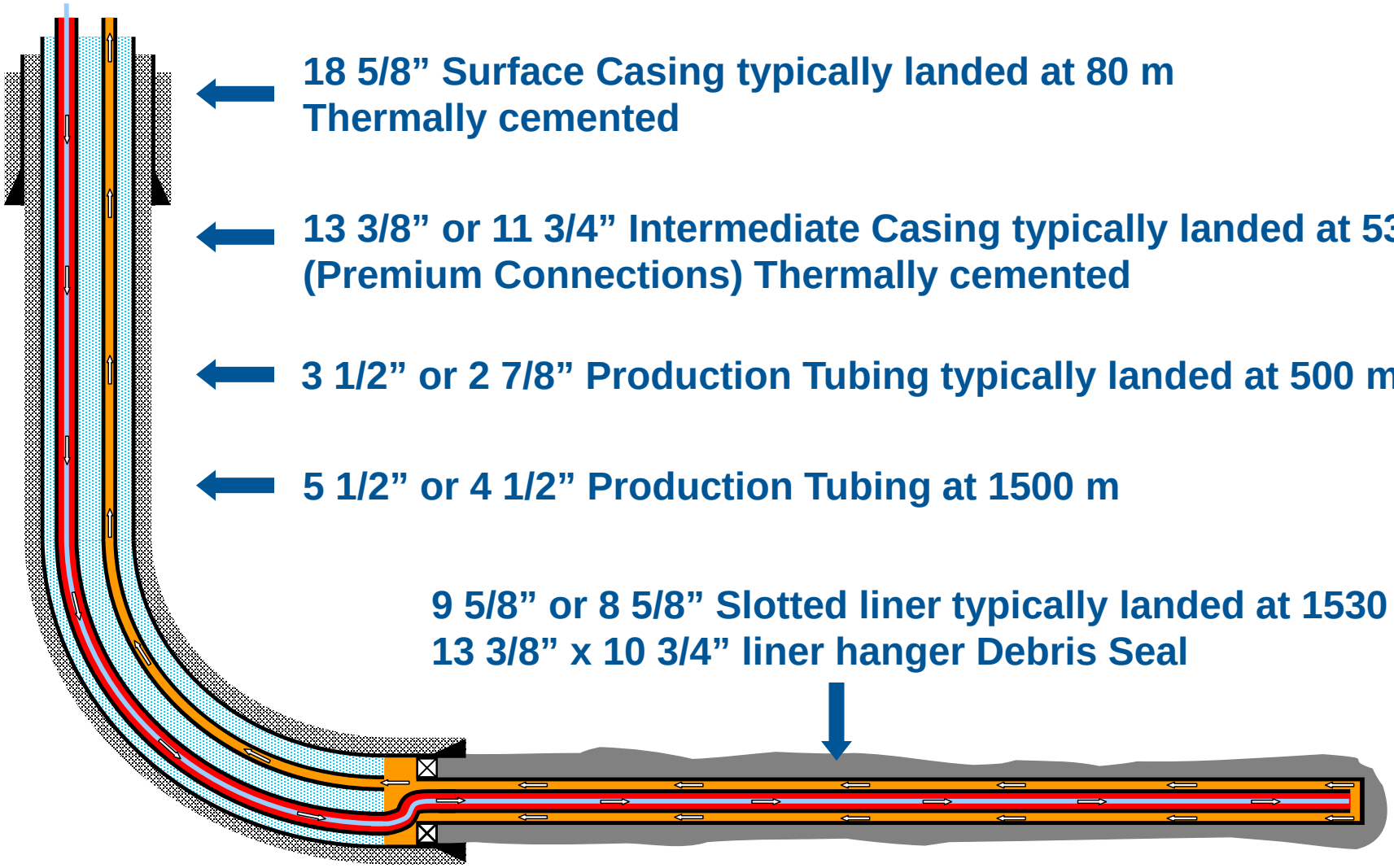
13 3/8” x 10 3/4” Debris Seal
10 3/4” Slotted Liner for the first ~275 m

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)



Typical Producer Circulation 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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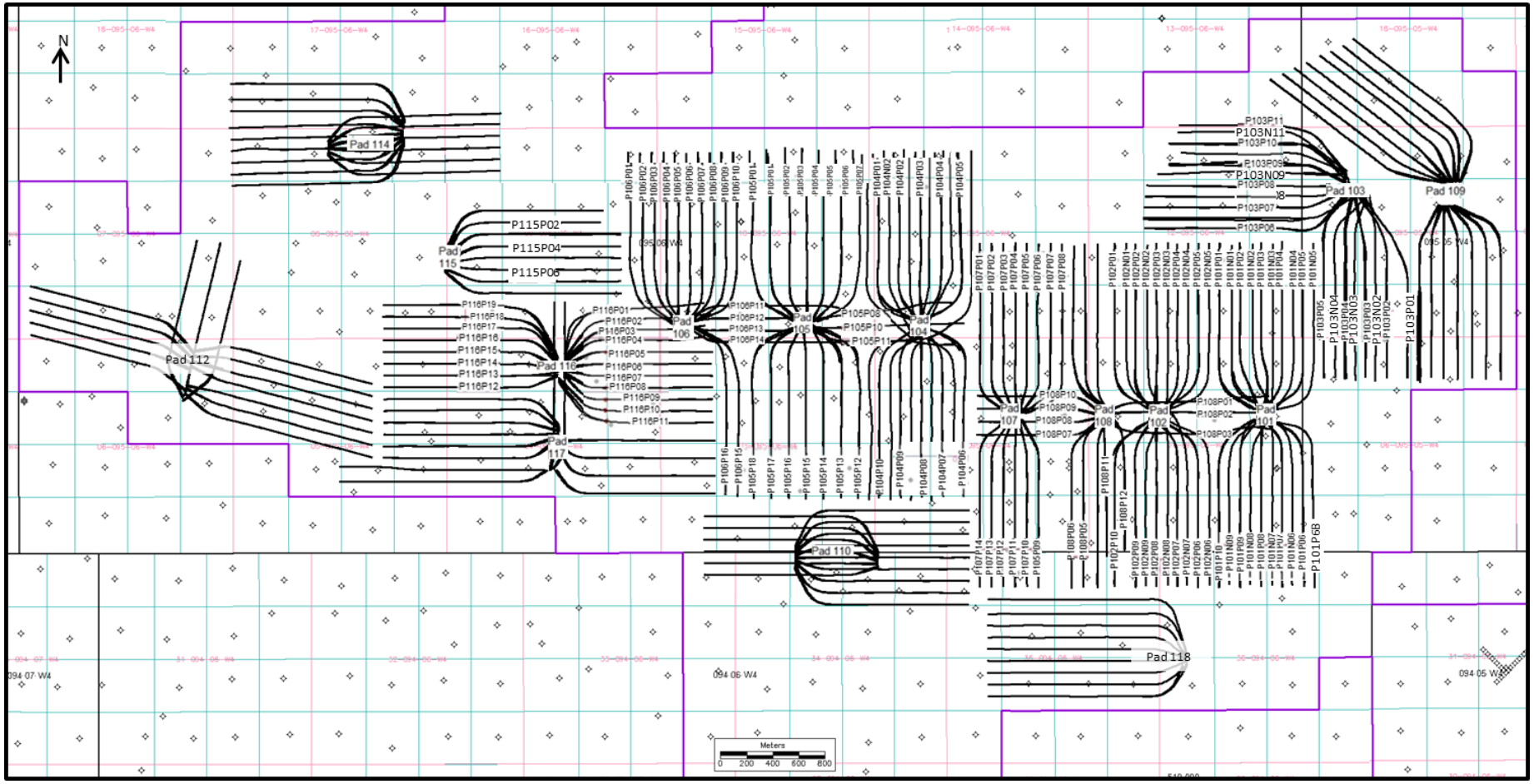
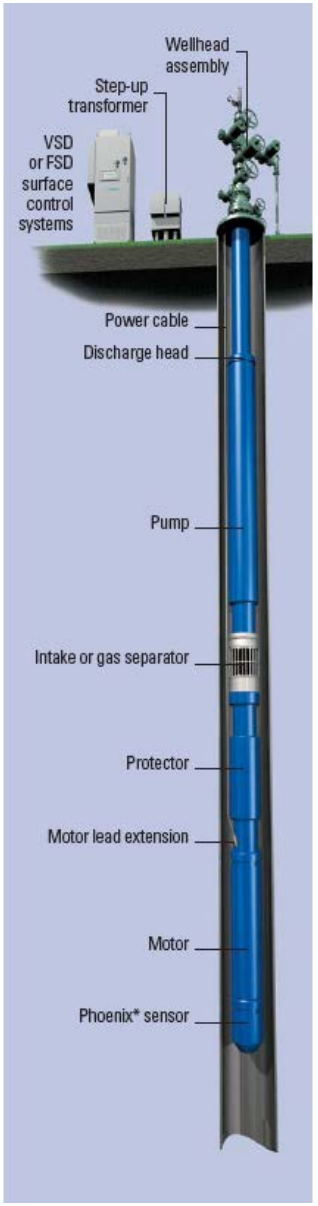
Artificial Lift Wells

- Labeled wells are operating on mechanical lift (151 wells) as of Feb 28, 2015
  - Well 1P6 abandoned and replaced with 1P6B
  - Pad 115 conversion underway, 15P2,4,6 producing as of Feb 28, 2015
  - First production from infills P103N02,03,04,08,09,11 and P104N01,02,03,04,05 in reporting period



Artificial Lift Performance



- Mechanical Lift
  - Electric submersible pumps (ESP)
  - 12 – 36 Stages depending on application
  - Total fluid lift capacity ranges from 100 to 3000 m3/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 640 days
  - Run-life is increasing as operational practices and pump technology improve

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Casing and Liner Failures

This has not been a major issue at Firebag. Incidents which have occurred to date are listed below:

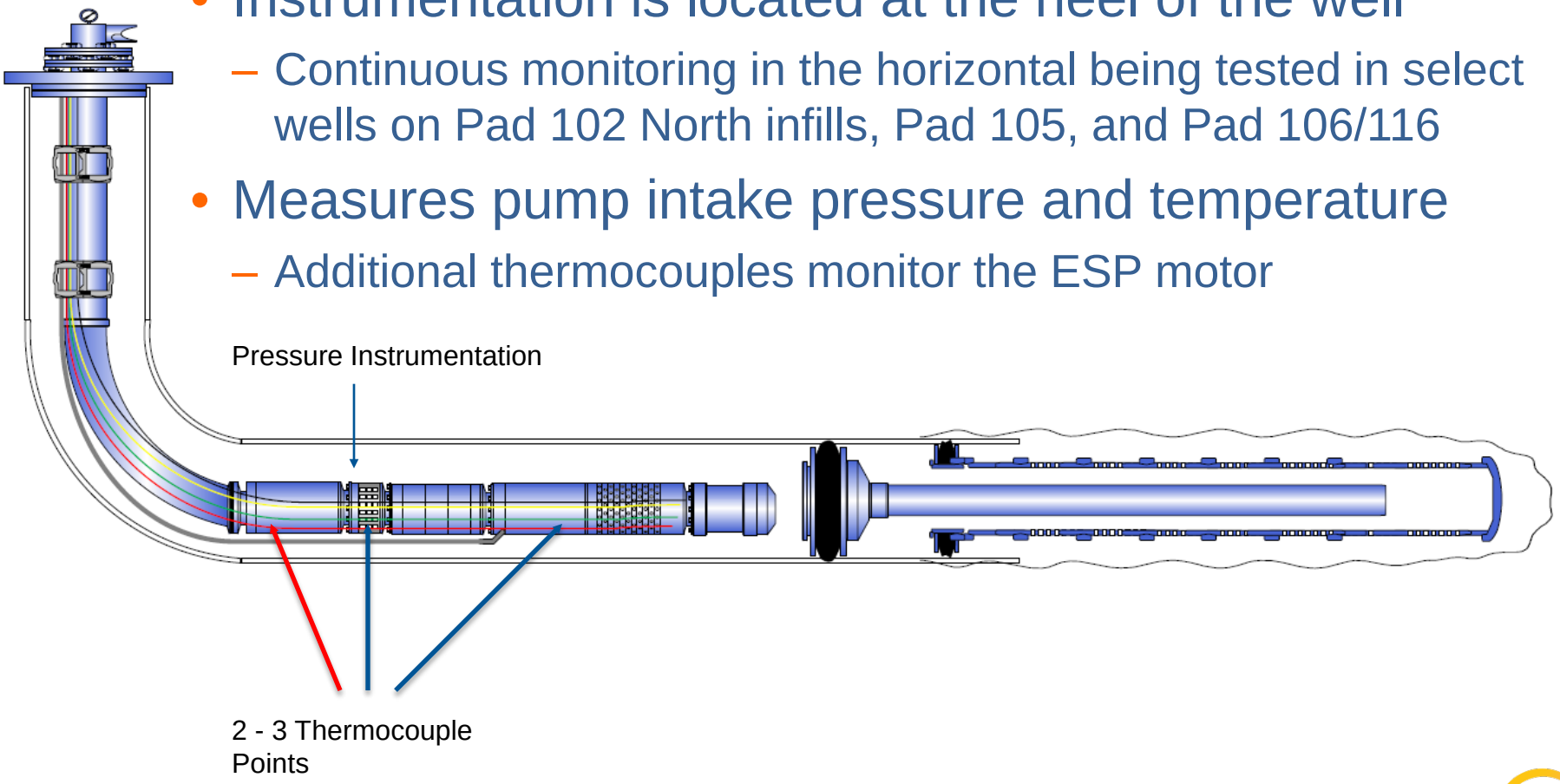
- 2P3 (producer)
  - Liner hanger failure in McMurray. Second DSP set in 2008. No fluid losses.
- 3P3 (producer)
  - Slotted liner parted midway in horizontal in McMurray. Re-drilled in 2009. No fluid losses.
- 3P4 (producer)
  - Intermediate casing failure in McMurray. Re-drilled in 2009. No fluid losses.
- 3P4B (producer)
  - Intermediate casing collapse in Quaternary near surface. Formation protected by cemented surface casing. Slimhole workover conducted in 2010. No fluid losses.
- 1P6 (producer)
  - Suspected liner failure in McMurray. Redrilled in 2014. No fluid losses.

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 - Fiber in 2N2/3 - Motor winding/intake (infills)	- Bubble Tube - P2P6 – Piezometer - 2P9 intake & discharge
Pad 103/104 (including infills)	- 2-3 pt. ESP Thermocouple - 3P9 internal motor TC - 104 infills and 3N8 Fiber	- Bubble Tube - P/T Intake gauges (infills)
Pad 107/108	- 3 pt. ESP Thermocouple - 7P5 Pain & RTD sensor	- Bubble Tube
Pad 105	- 3 pt. ESP Thermocouple - 5P14/15 Fiber	- 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 (2/4/6)	- Bubble Tube
Pad 116	- 2 pt. ESP Thermocouple - 6 pt. Thermocouple - Fiber in 16P5/6/9/13/15/16/18	- Bubble Tube
All Injectors	- Fiber in 5S14/15	- Blanket Gas

Typical SAGD Producer Well – Instrumentation Locations

- Instrumentation is located at the heel of the well
  - Continuous monitoring in the horizontal being tested in select wells on Pad 102 North infills, Pad 105, and Pad 106/116
- Measures pump intake pressure and temperature
  - Additional thermocouples monitor the ESP motor



Instrumentation & Downhole Technology

- New Technology Testing Program in 2014
  - Horizontal downhole temperature monitoring on Pad 101/102/103/104 infills, 105, 106, 115, and 116
  - Vacuum insulated tubing on 15S4
  - NCG injection on Pad 101S
  - Chemical injection trial on Pad 115
  - FCD's in a production well
  - 250C BIW connectors
  - New generation high temperature pumps rated to 250C – Ultra High Temperature Pump (UHT) and Hotline 3 Pump (HL3)

Future SAGD Well Instrumentation Plans

- Suncor Firebag is currently reviewing the following down hole pressure and temperature measurement schemes against their technical and economic merit. These technologies will be given consideration against the current pressure and temperature monitoring requirements for both producers and injector wells.
- Integrated pressure and temperature sensors with ESP
- ESP Discharge pressure gauge
- Temperature measurement in horizontal

Instrumentation – SAGD Observation Wells

Well	Temperature	Pressure
OB111, OB114	1 Point Thermocouple	1 Piezometer
DW OB1, OB DW4	1 Point Thermocouple	2 Piezometers
OB10, OB107, OB110, OB19, OB37-40, OB67-69, OB74-75, OB8	2 Point Thermocouple	2 Piezometers
ETS1, P5S2-4 OB	10 Point Thermocouple	N/A
ETS OB1, ETS OB3, ETS OB4, OB12-14, OB17-18, OB20-23, OB27-36, OB42-45, OB47, OB6-7, OB9	24 Point Thermocouple	N/A
OB49, OB51, OB54, OB56, OB62	24 Point Thermocouple	1 Piezometer
OB48, OB182	24 Point Thermocouple	2 Piezometers
OB63	24 Point Thermocouple	3 Piezometers
OB152	24 Point Thermocouple	5 Piezometers
OB202	30 Point Thermocouple	3 Piezometers
OB122-127, OB129-130, OB132-133, OB143	40 Point Thermocouple	N/A
OB128, OB135-137	40 Point Thermocouple	1 Piezometer
OB118-119, OB131, OB134	40 Point Thermocouple	2 Piezometers
OB203-204	40 Point Thermocouple	4 Piezometers
OB153-4	40 Point Thermocouple	5 Piezometers
OB DS4	43 Point Thermocouple	6 Piezometers
OB57	46 Point Thermocouple	2 Piezometers
OB3, OB5	54 Point Thermocouple	N/A
OB59, OB4	54 Point Thermocouple	2 Piezometers

Instrumentation – SAGD Observation Wells

Well	Temperature	Pressure
OB66, OB70-73, OB76-98, OB101-103, OB105-106	56 Point Thermocouple	2 Piezometers
OB61	58 Point Thermocouple	1 Piezometer
OB60	58 Point Thermocouple	2 Piezometers
OB DW12, OB138, QW1-2, QW4, OB147	N/A	1 Piezometer
PP7, OB167-168, OB170, OB205	N/A	2 Piezometers
OB DS2, DS5, OB166, OB169, OB201	N/A	3 Piezometers
OB DS1	N/A	4 Piezometers
DS6	N/A	5 Piezometers

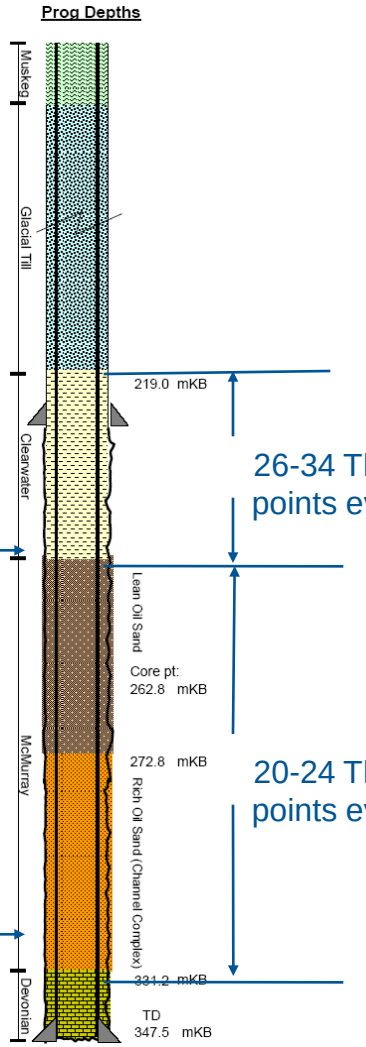
Typical SAGD Observation Wells

Pressure Instrumentation

Two Piezometers

Location:

1. Middle of upper RMZ
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:

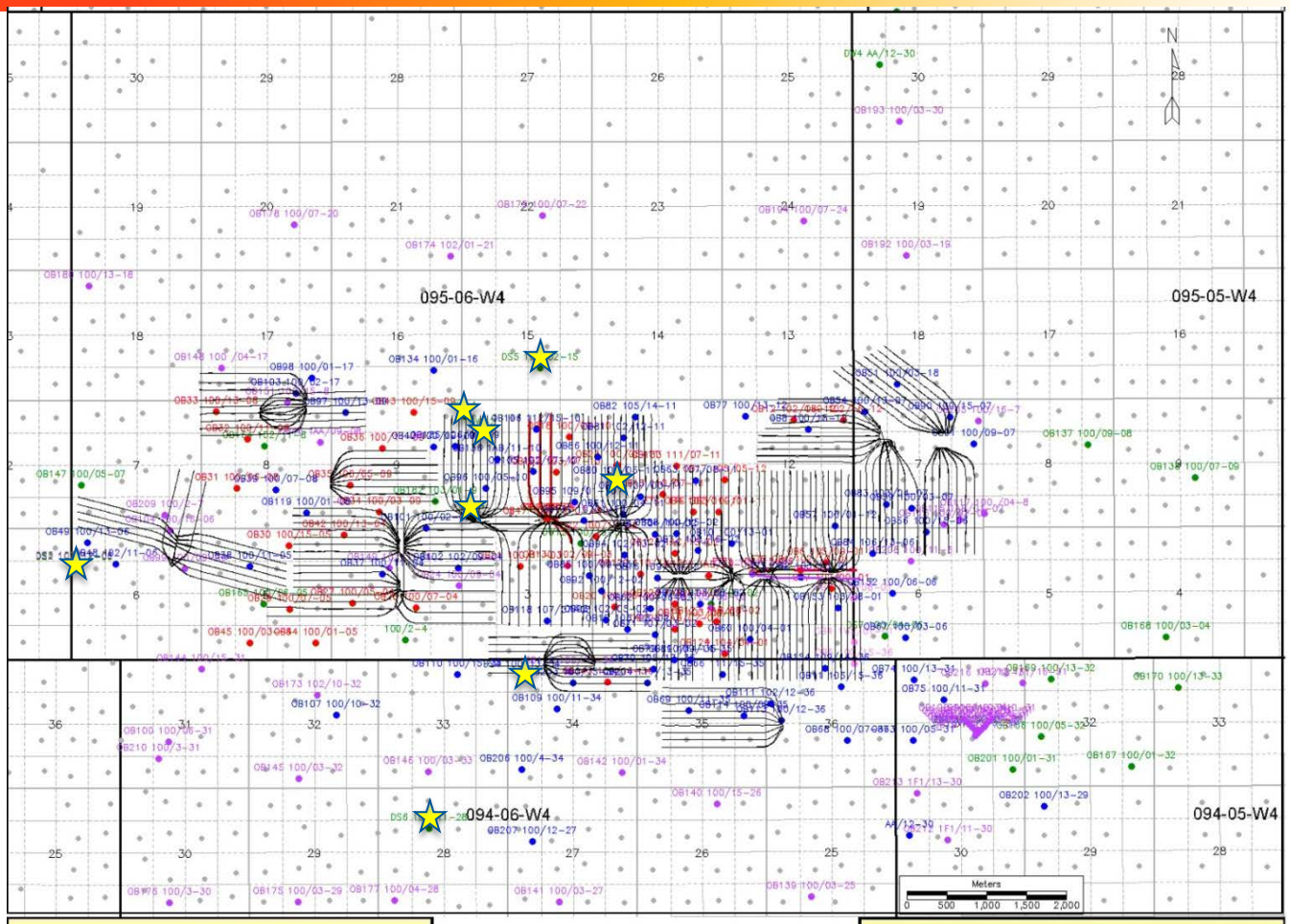
- Base to top of McMurray
- 20-24 TC spaced every 3 to 4 m

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

Observation Well Location Map



Legend:
- Abandoned or No Instrumentation
- Only Thermocouple(s)
- Fibre (Temperature Only)
- Piezometers and Thermocouples
- Only Piezometers
- Abandoned Core Hole
- Existing SAGD Well

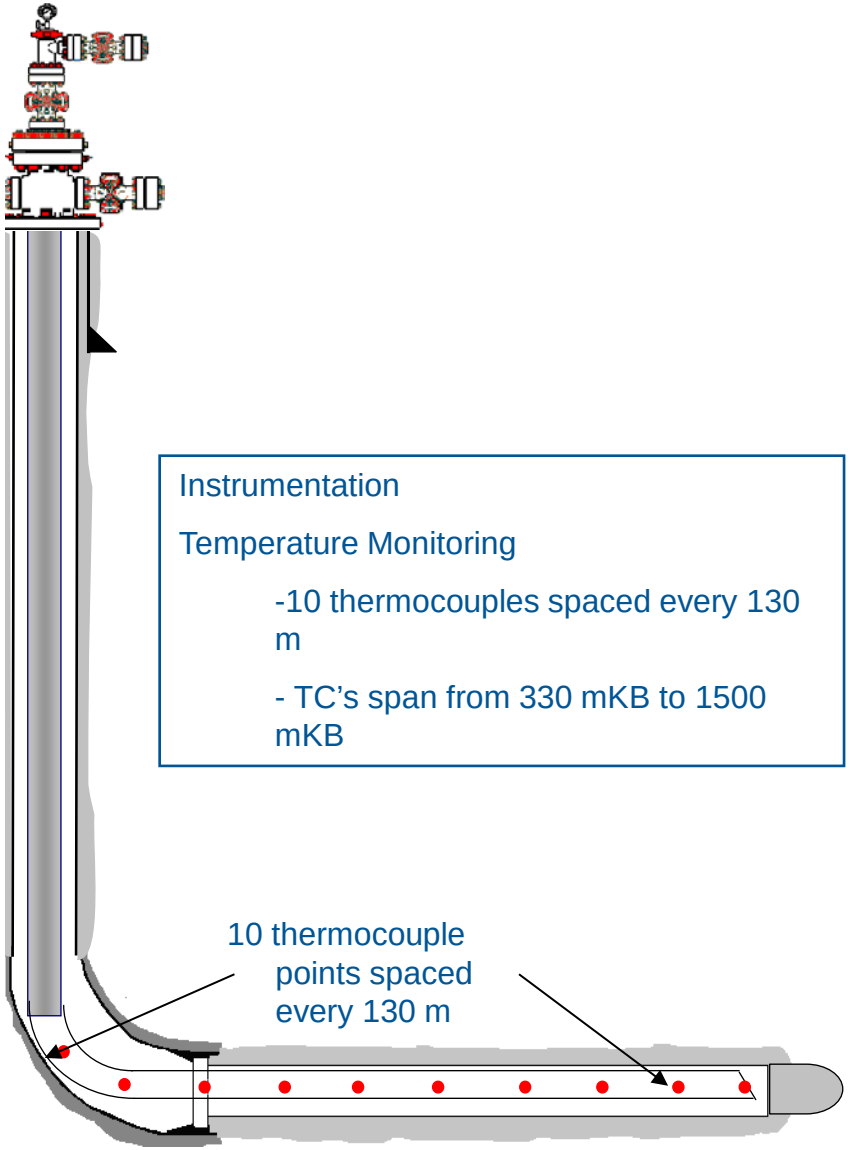
Quaternary Monitoring

Note: No bottom or top water has been identified within the project area

Oil Sands and In Situ
Firebag

SAGD Wells and Vertical Well Control
OBSERVATION WELLS

ETS 1 (100/12-06-095-05 W4M)
Horizontal Observation Well Configuration



Instrumentation

Temperature Monitoring

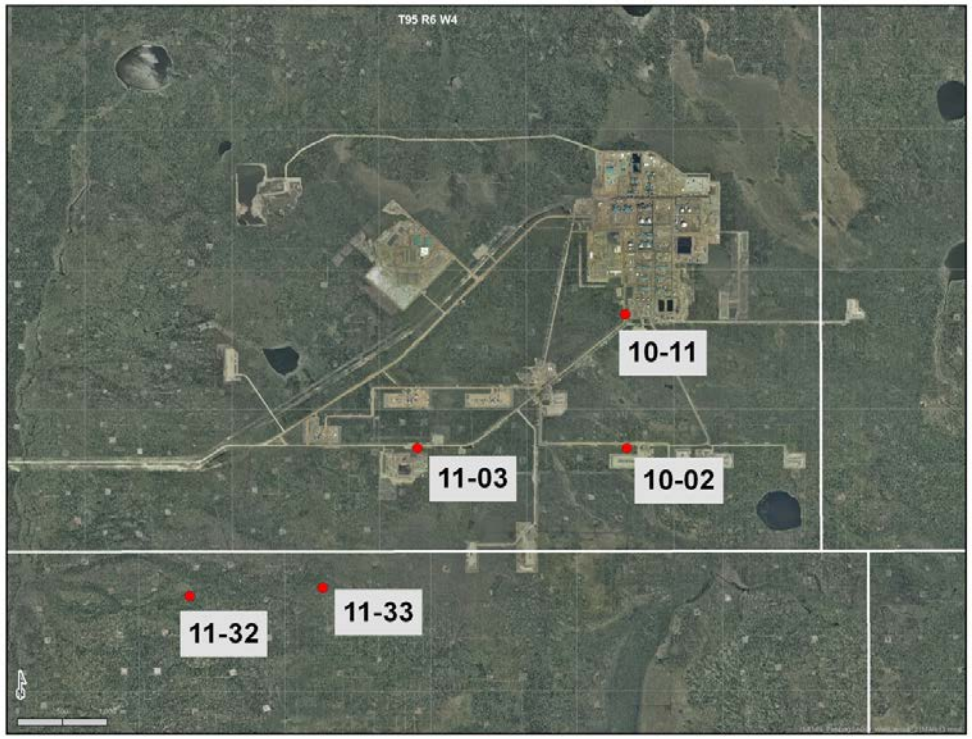
- -10 thermocouples spaced every 130 m
- - TC's span from 330 mKB to 1500 mKB

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

1981 Inactive Wells

- Five wells were drilled as per regulatory standards in 1981
  - The wells were cemented 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

1981 Inactive Wells Locations



UWI	License #	Spud Date	Distance to Planned Steam Operations (meters)
10-02-095-06W4	A0088049C	2/4/1981	Approx. 4.3
11-03-095-06W4	A0088049D	1/27/1981	Approx. 22
10-11-095-06W4	A0088049E	2/14/1981	Approx. 365
11-32-094-06W4	A0088049B	1/18/1981	Approx. 965
11-33-094-06W4	A0088049E	1/28/1981	Approx. 1000

1981 Inactive Wells Locations Continued

- All 1981 Inactive Wells were inspected March 13-19th, 2015

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

1964 Vintage Wells

- Six of seven 1964 vintage well sites in the Firebag thermal recovery area have been located and properly abandoned with thermal cement

UWID	Licence #	Spud Date	Distance from steam operations	Re-Abandonment Approved by AER	Comments
1AA/11-22-095-06W4/00	0025561D	3/24/1964	Approximately 3000m	Yes	Located & Abandoned 2009
1AA/05-28-094-06W4/00	0026040A	3/9/1964	Approximately 3000m	Yes	Located & Abandoned 2009
1AA/06-08-095-06W4/00	0026038A	3/15/1964	Approximately 4000m	Yes	Located & Abandoned 2010
1AA/15-32-095-06W4/00	0025561E	3/28/1964	Approximately 6000m	Yes	Located & Abandoned 2010
1AA/14-32-093-06W4/00	Y0002251	2/18/1964	Approximately 10000m	Yes	Located in 2011, Abandoned in 2012
1AA/08-22-093-06W4/00	0026039A	2/22/1964	Approximately 10000m	Yes	Located in 2011, Abandoned in 2012
1AA/16-15-096-06W4/00	0025561F	3/30/1964	Approximately 10000m	Yes	1 of 2 wells located in 2011, other to be located and both to be abandoned with indication of development in area

- 11-22, 6-8, 5-28, 15-32, 14-32, and 08-22 were abandoned with thermal cement and cut and capped according to current Directive 20 standards
- 2 joints of casing were cemented in place to ensure future identification
- 16-15 had two wellbores drilled originally
  - Have located the shallower of the two, will be abandoned at a later date
  - To be located and abandoned when development plans move north of current pads
  - Access to location has been built

SUNCOR

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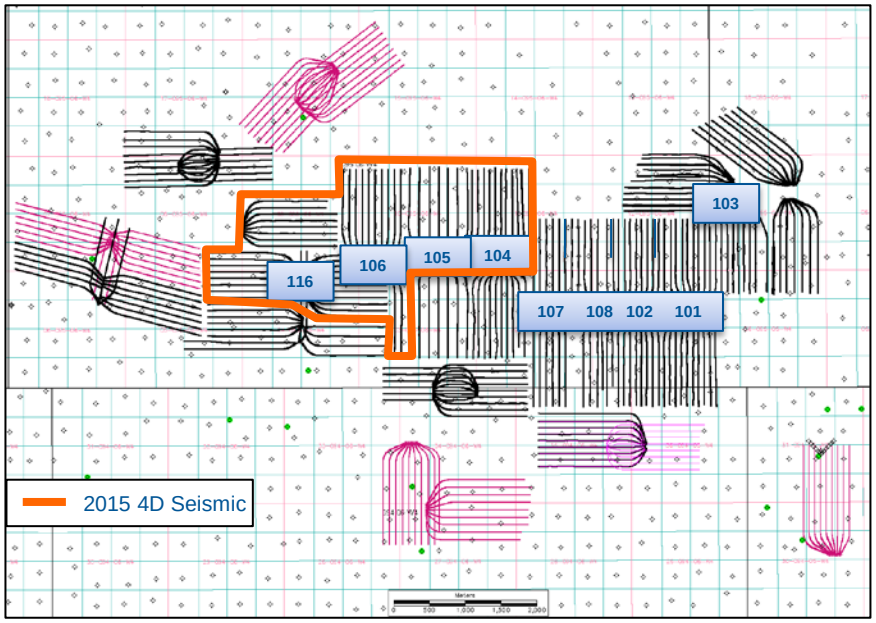
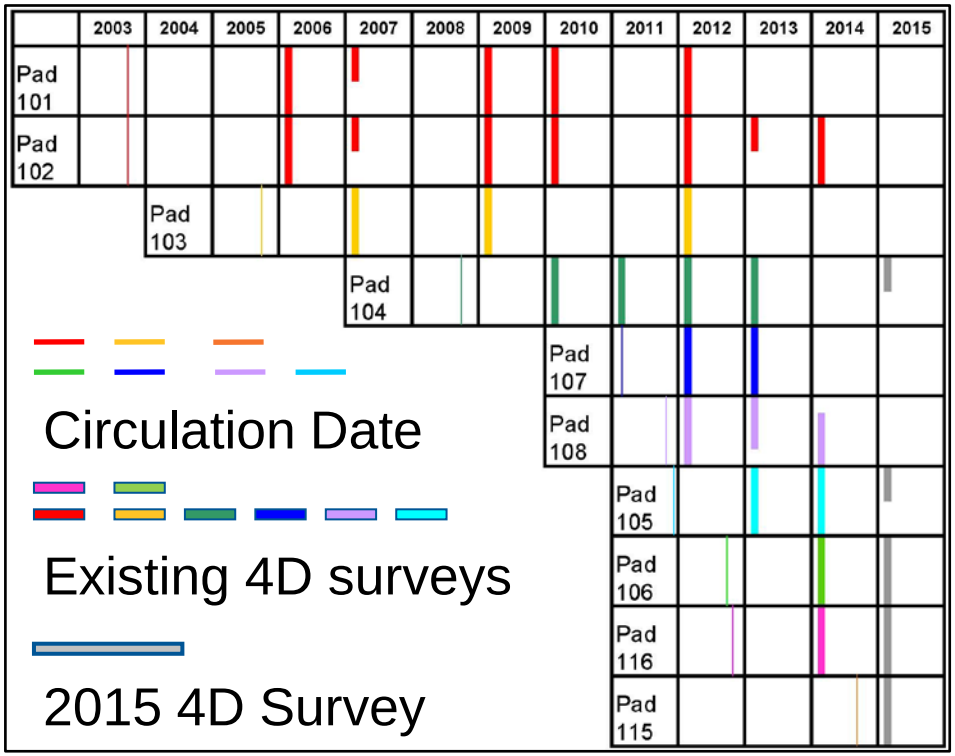
4D Seismic - Survey Outlines

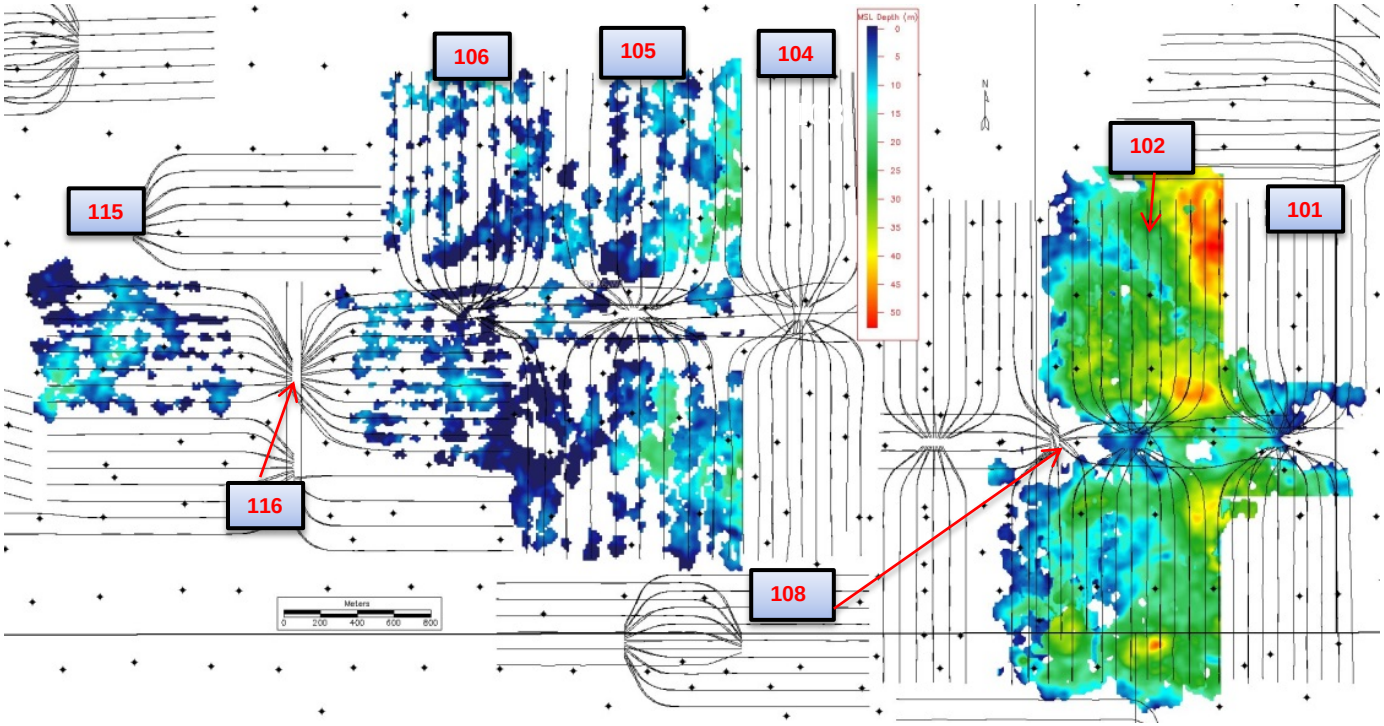
- Suncor places a high value on 4D seismic
- Data were collected in the year indicated and interpretation reported the following year due to required process and interpretation time





2014 4D Seismic - Steam Chamber Thickness Map

- Steam chamber thickness ranges from 0 to 54 m (Pad102 N).
- Pad 106 and Pad116 early days in the life of the pad, up to 19 m of steam chamber growth
- Variations due to mud baffles or barriers



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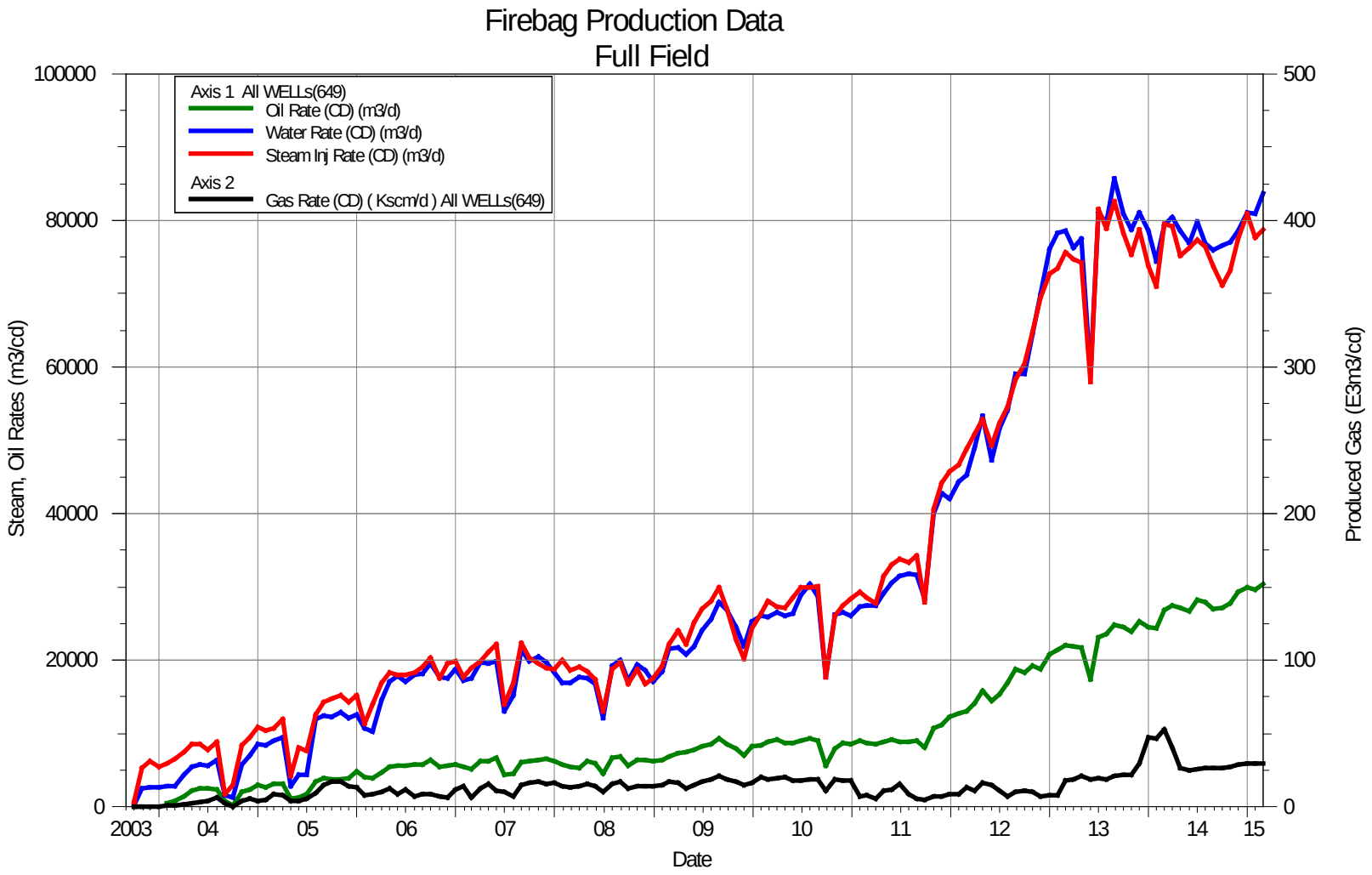
Methodology for Predicting Performance

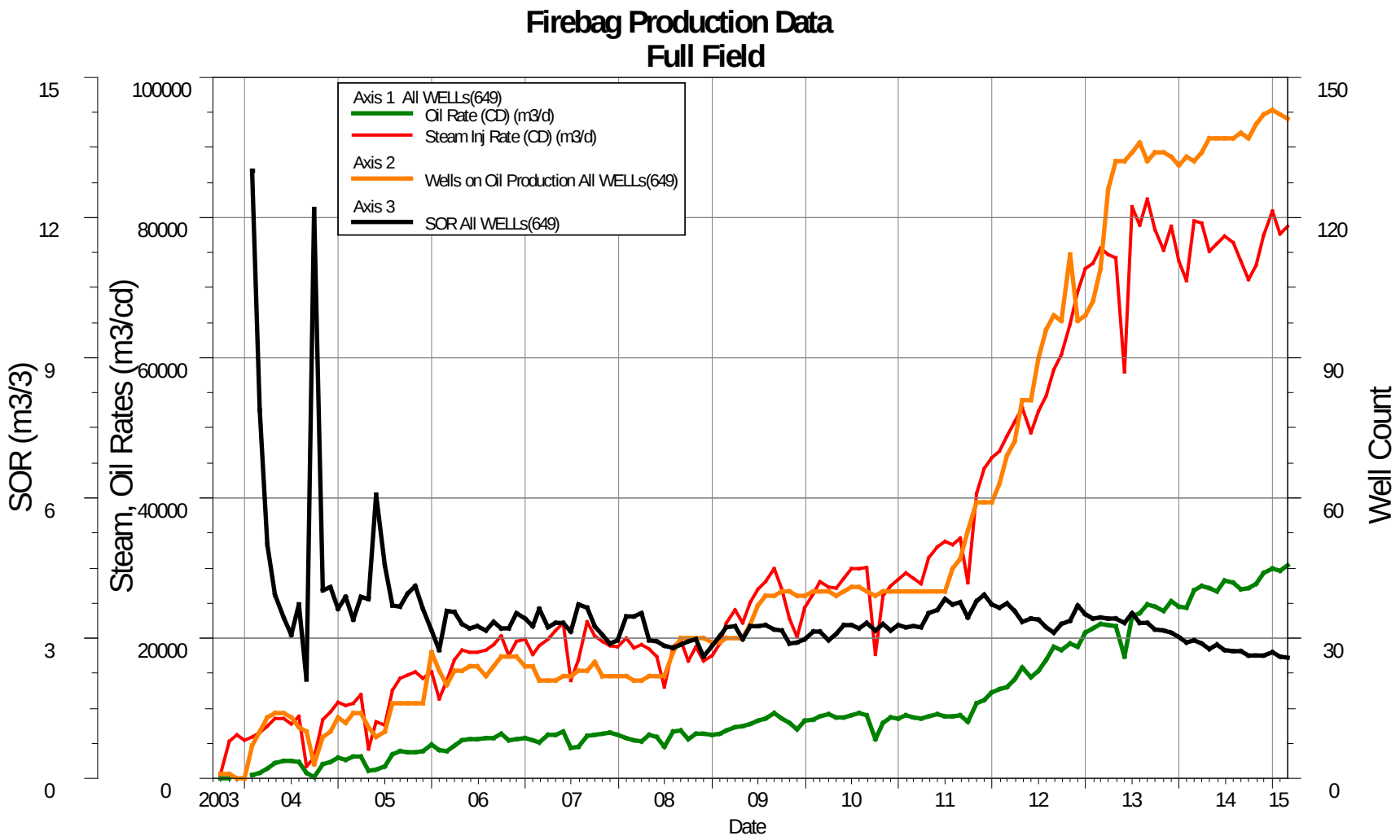
- At Firebag, future performance is predicted by leveraging multiple tools
  - Analytical Models:
    - Modified Butler's Tandrain equations
    - Water balance to monitor well communication
  - Analytical models and flow simulations are history matched on a well pair, pattern and field level

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

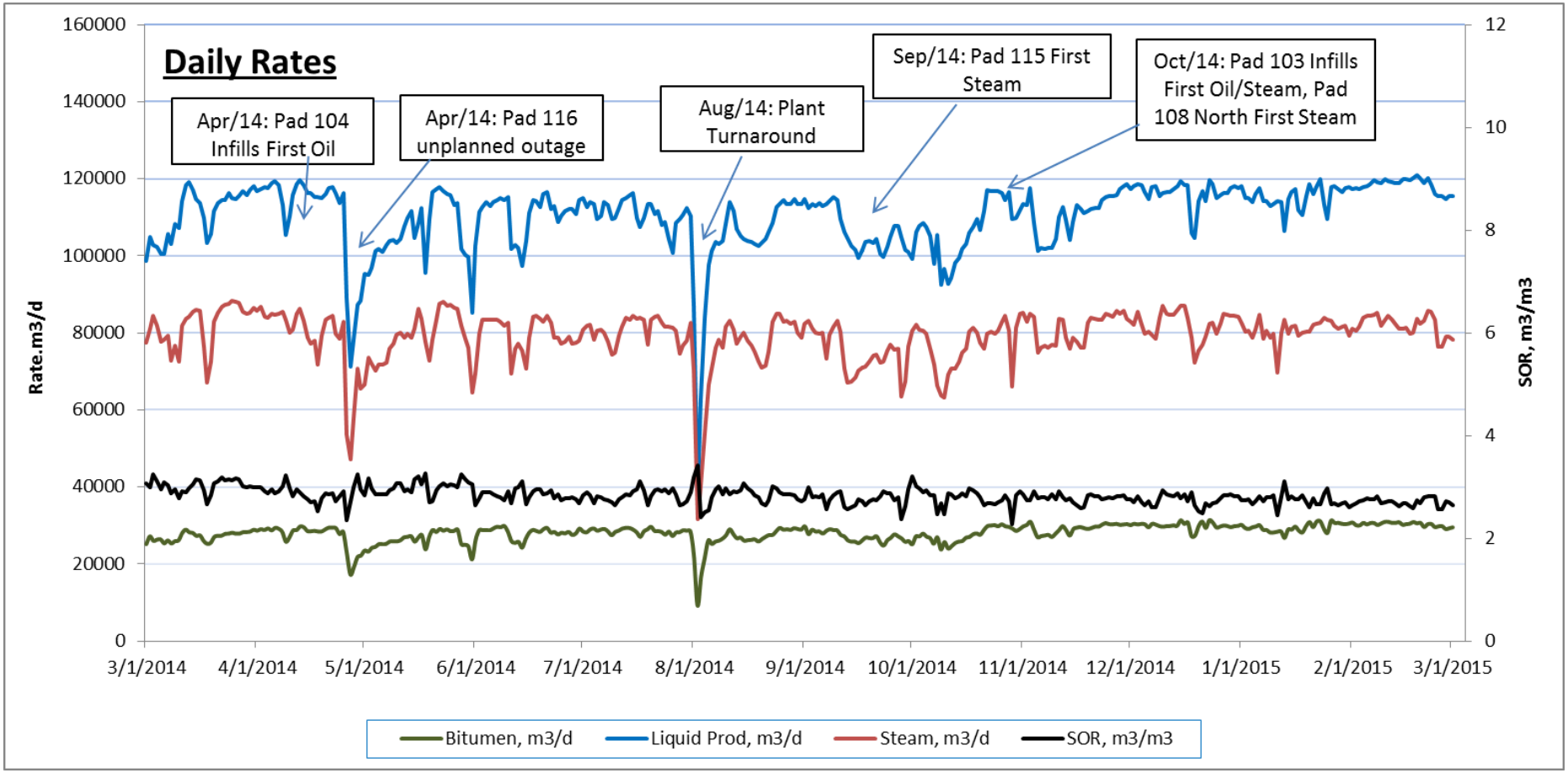
Scheme Performance – Well Production History



Scheme Performance – Well Production History



Issues and Milestones



Firebag Production

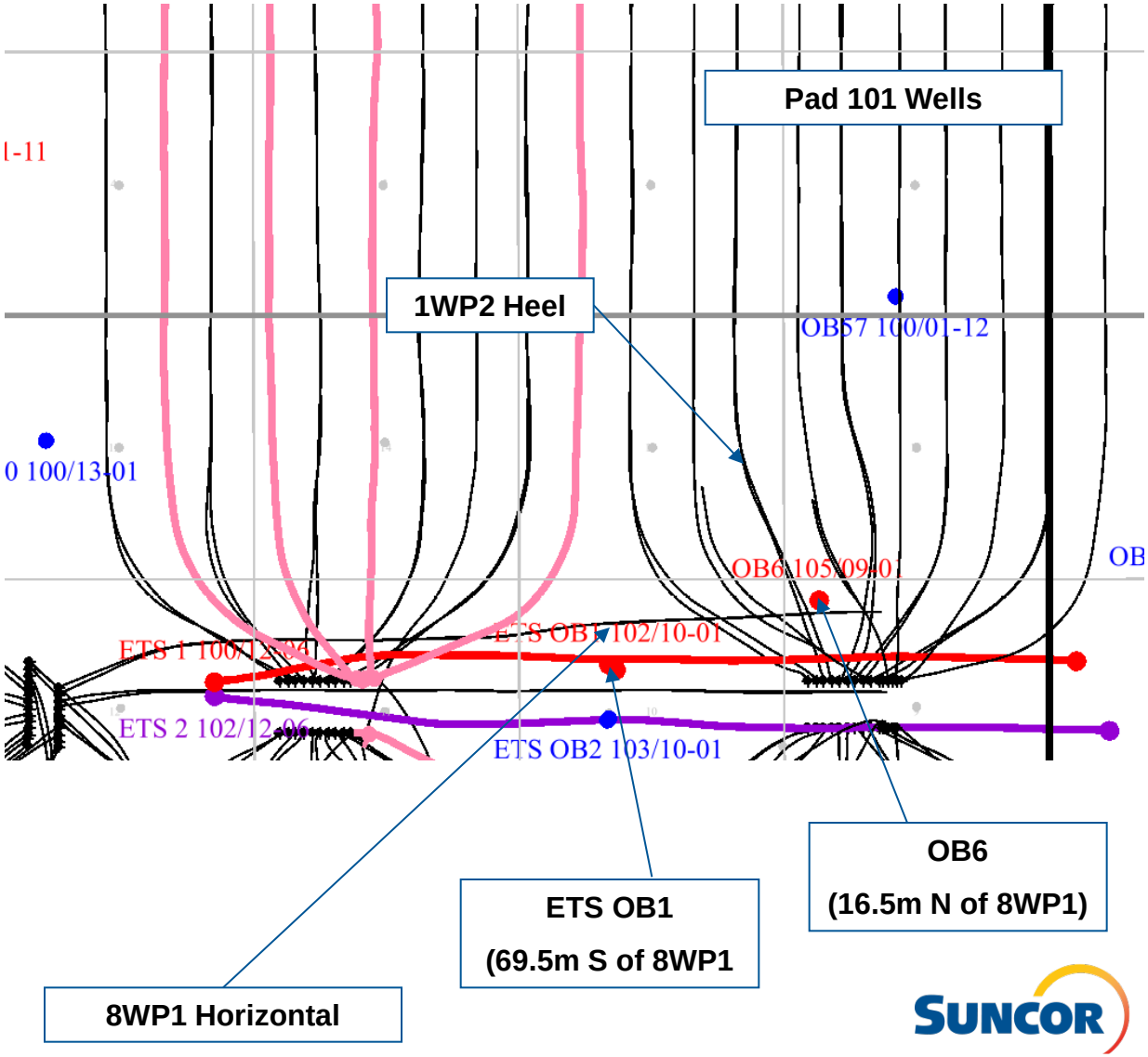
- Highest monthly average bitumen production over reporting period was 191,409 bopd (30,434 m^3/cd) and occurred in February 2015
  - Stages 1, 2, 3, and 4 currently on production
  - Producing well count up by 5% over reporting period

- SOR Discussion
  - As of Feb 28, 2015 cumulative SOR at Firebag is 3.20 m^3/m^3
  - SOR over the reporting period was 2.71 m^3/m^3
    - SOR has been improving over the reporting period
    - Infill wells positively impacted SOR

- Infill Wells
  - Pads 101, 102, 103, and 104
  - Current interwell spacing of 80 meters
  - Positive impact on rate and recovery as well as SOR

Steam Chamber Discussion – 8WP1 / 1WP2

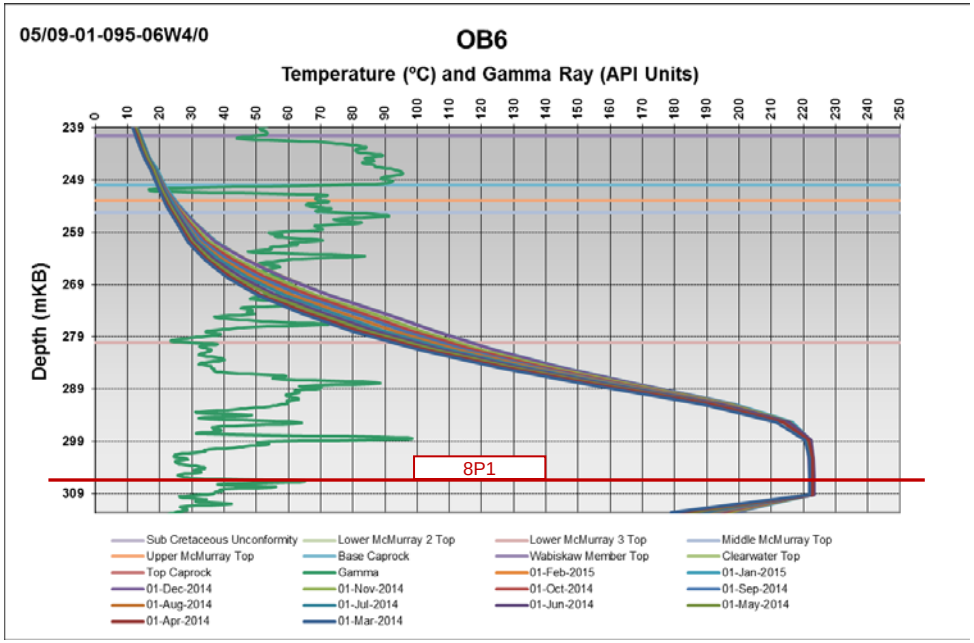
- OB6 located near the toe of 8WP1
  - 16.5 m N of 8WP1
  - 165 m SE of 1WP2
- OB ETS1 is located at the midpoint, between 8WP1 and 8WP2
  - 69.5 m S of 8WP1
  - 32.6 m N of 8WP2
- 8WP1 first steam in October 2011
- 1WP2 first steam in October 2003

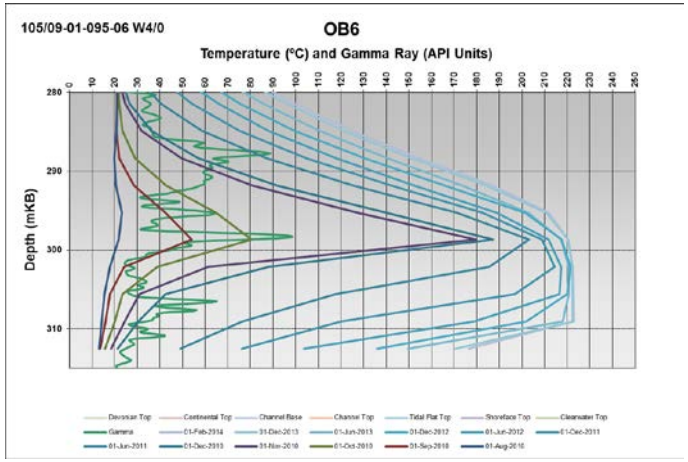


Steam Chamber Discussion – 8WP1 / 1WP2

OB6 – Toe of 8WP1, and riser section of 1WP2

- 16.5 m north of 8WP1
- Mid way along 1WP2 build section,165m SE of 1WP2
- Instrumented with 24 thermocouples covering the lower McMurray 3 and into the Clearwater
- Temp began increasing Sept 2010, 8WP1 first steam Oct 2011
- Steam chamber expanding past the heel of 1WP2
- Steam chamber top interpreted at 295 mKB

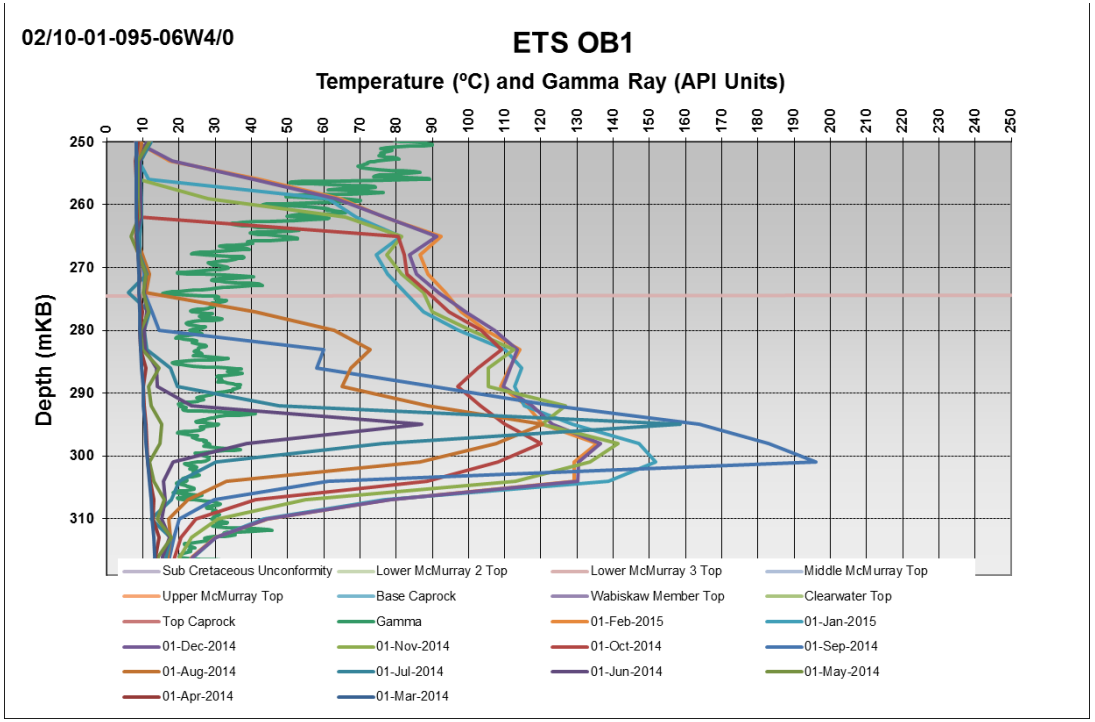




Steam Chamber Discussion – 8WP1 / 1WP2

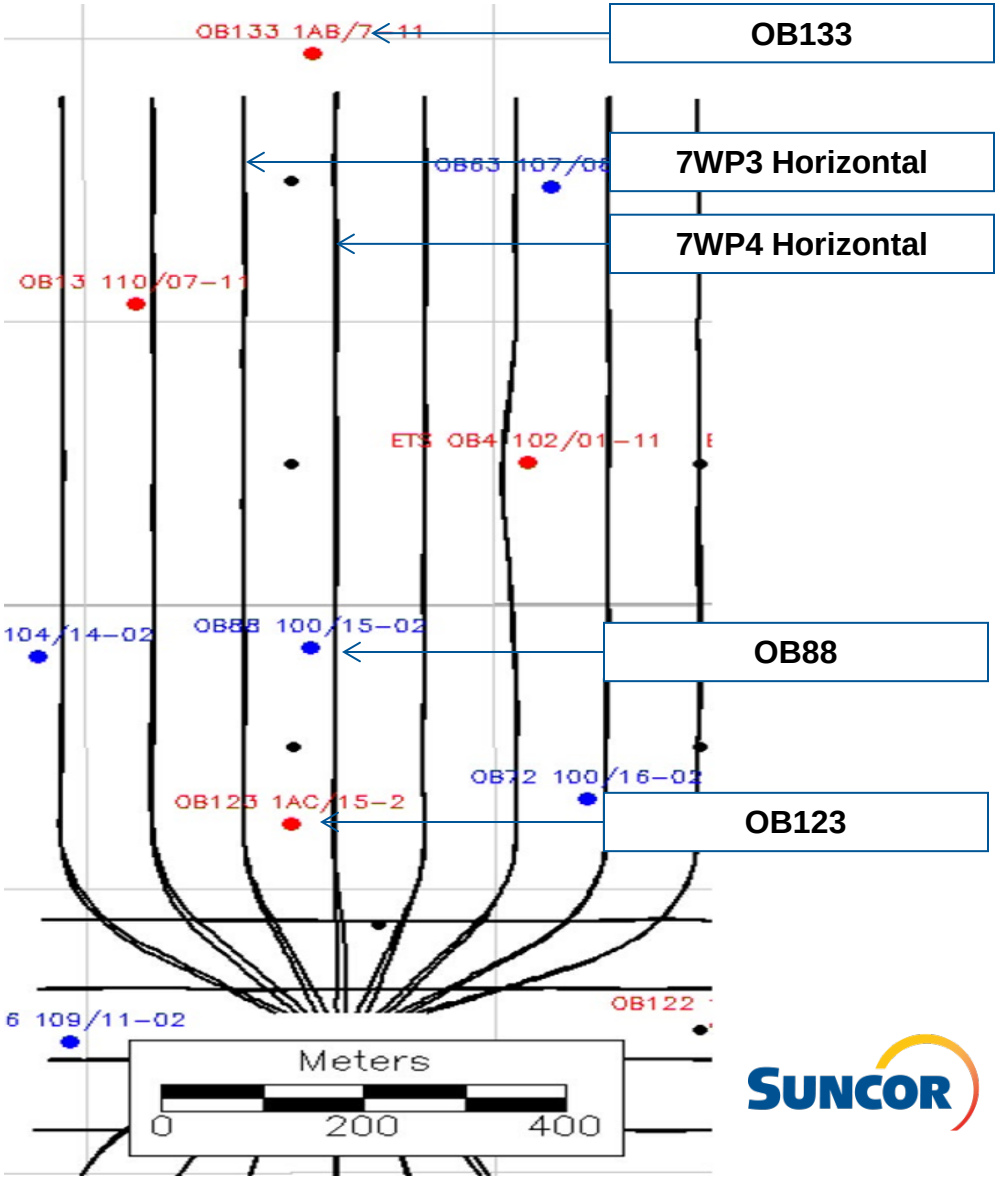
ETS OB1 – Midpoint between 8WP1 and 8WP2

- 69.5 m S of 8WP1
- 32.6 m N of 8WP2
- Mid way along 8WP1 and 8WP2
- Instrumented with 24 thermocouples covering the lower McMurray 3 and into the middle McMurray
- Temp began increasing June 2014, 8WP1 and 8WP2 first steam Oct 2011
- Area at this OB well is heating up due to offsetting steam chamber growth



Steam Chamber Discussion – 7WP4

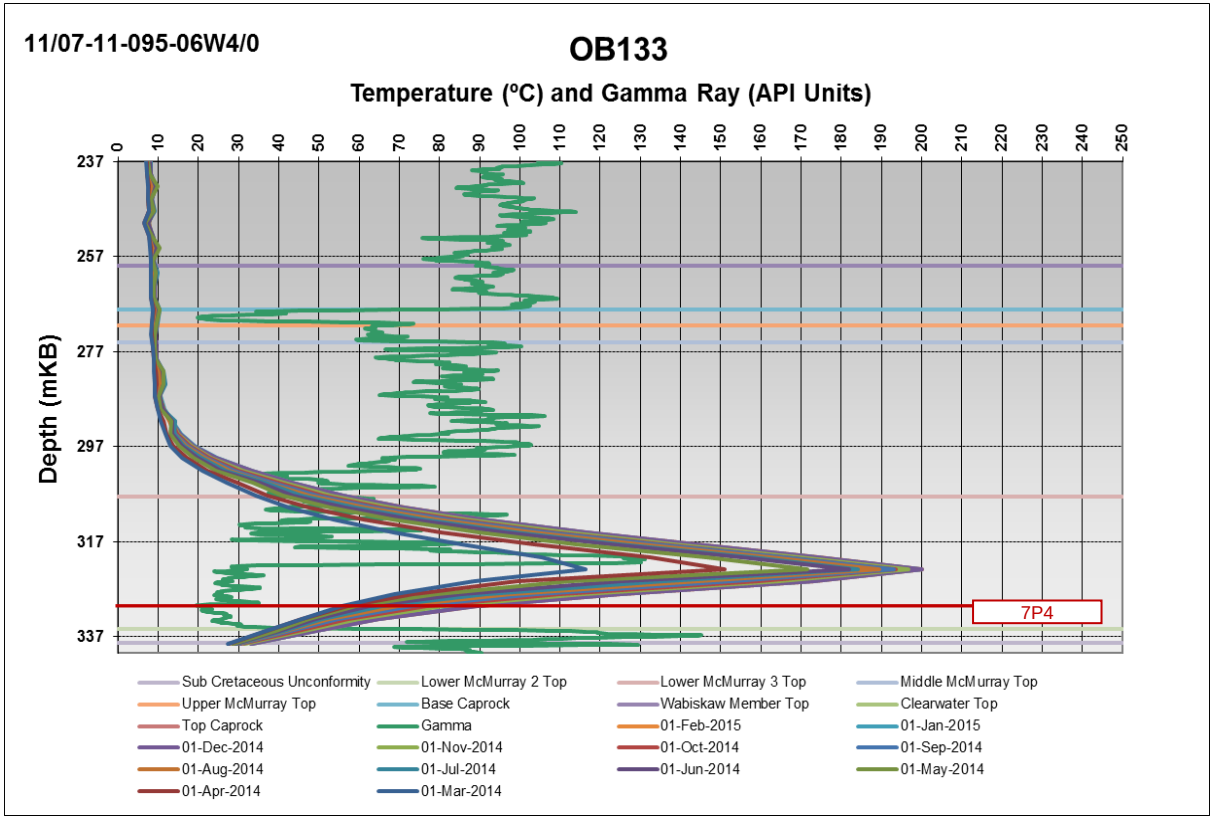
- 7WP4 has three observation wells nearby
- OB133 is located off the toe of 7WP4
  - 88.7 m NE of 7WP3
  - 61.6 m NW of 7WP4
- OB88 is located close to the mid-point of 7WP4
  - 63.6 m E of 7WP3
  - 25.1 m W of 7WP4
- OB123 is located at the heel between 7WP3&4
  - 47.0 m E of 7WP3
  - 42.9 m W of 7WP4



Steam Chamber Discussion – 7WP4

OB133 – Toe of P7WP4, 61.6 m Northwest

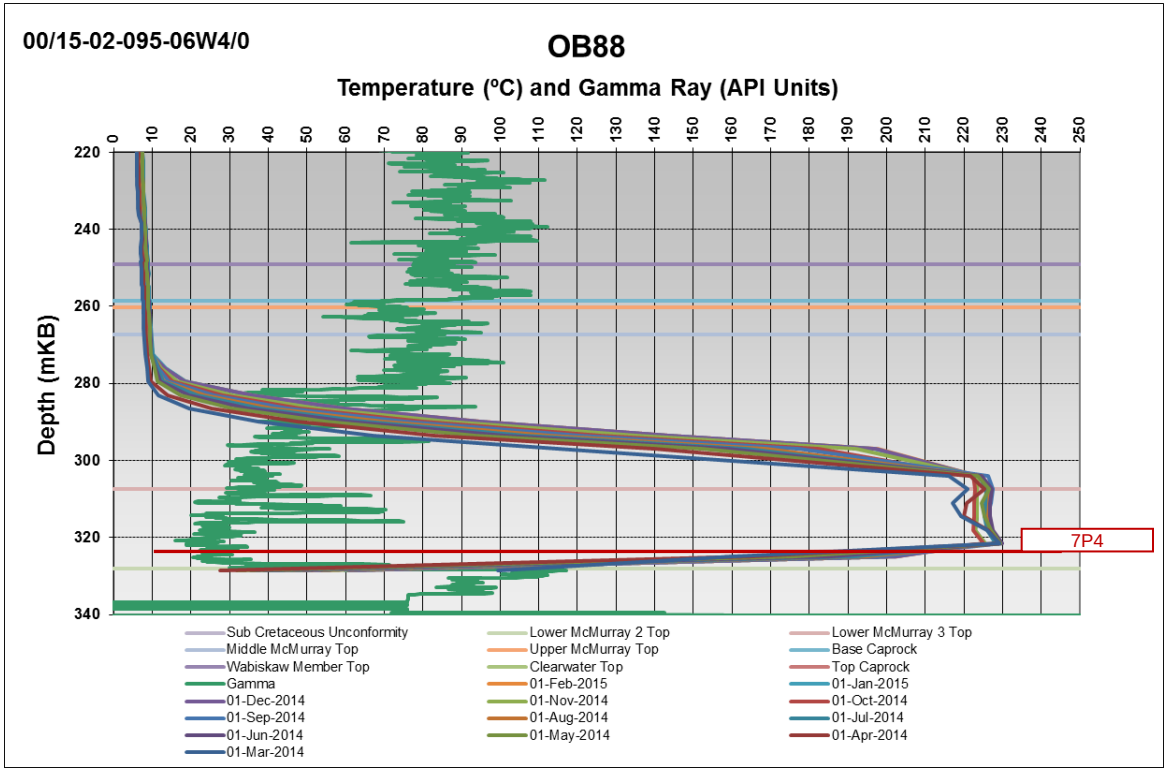
- Instrumented with 40 thermocouples covering the lower McMurray 2 and into the Clearwater
- First reading Aug 2012 showed warmer temperatures up to about 98 deg C (1st steam April 2011)
- Continued heating over the last year
- Indicates chamber expansion extends from toe of well
- Chamber growth vertically appears to be slowed by a shale barrier at about 320 m



Steam Chamber Discussion – 7WP4

OB88 – Mid-Point of P7WP4, 25.1 m West

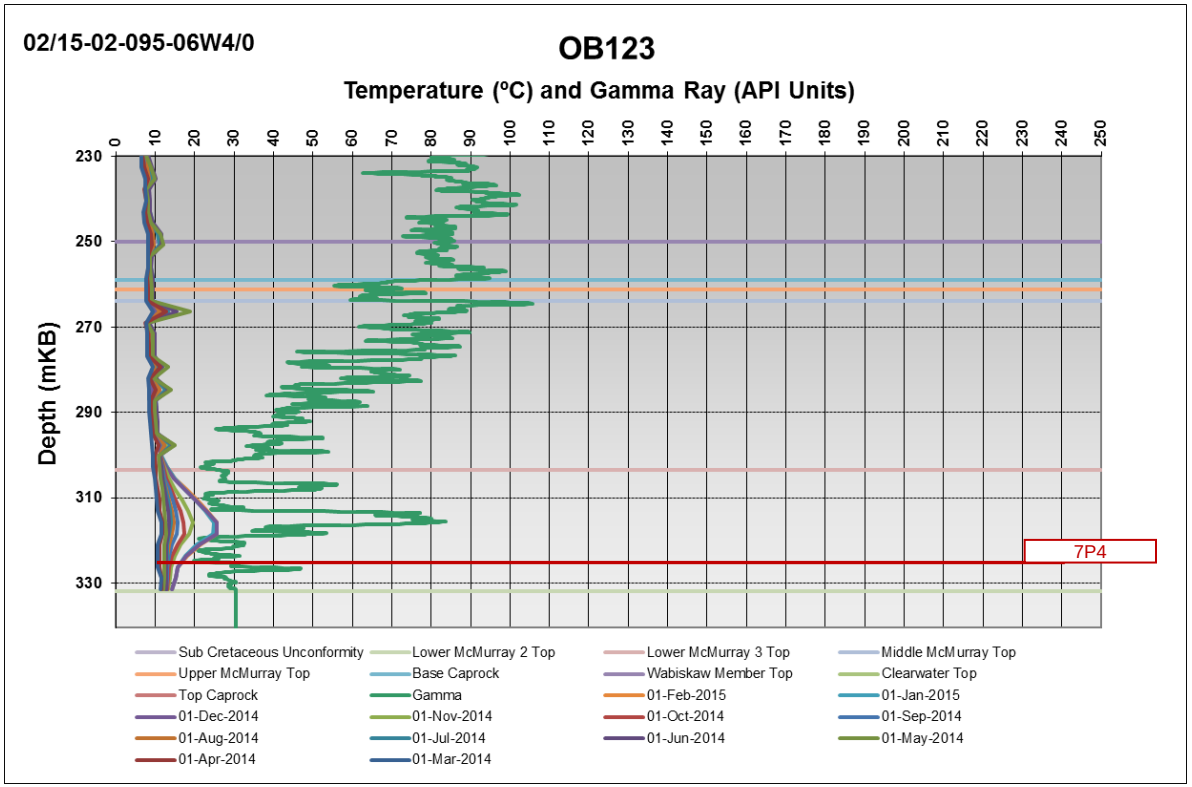
- Instrumented with 56 thermocouples covering the lower McMurray 3 and into the Clearwater
- Temperature started increasing Apr 2012, 7S4 first steam Apr 2011
- Chamber continues to grow over past year vertically with steam chamber top at 304 mKB



Steam Chamber Discussion – 7WP4

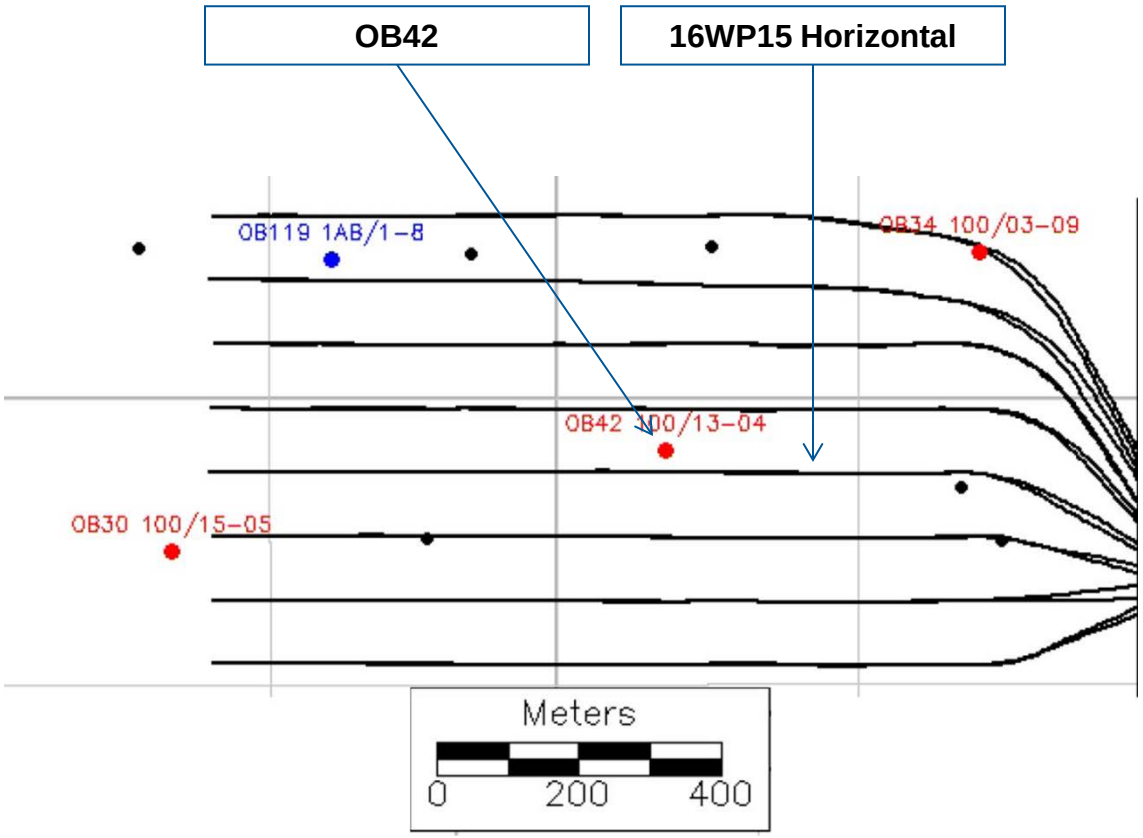
OB123 – Heel between P7WP4 and 7WP3

- Instrumented with 40 thermocouples covering the lower McMurray 3 and into the Clearwater
- Temperature started increasing Aug 2014, 7S4 first steam Apr 2011
- Chamber has been slow in growing towards this area but is starting to slowly warm up.



Steam Chamber Discussion – 16WP15

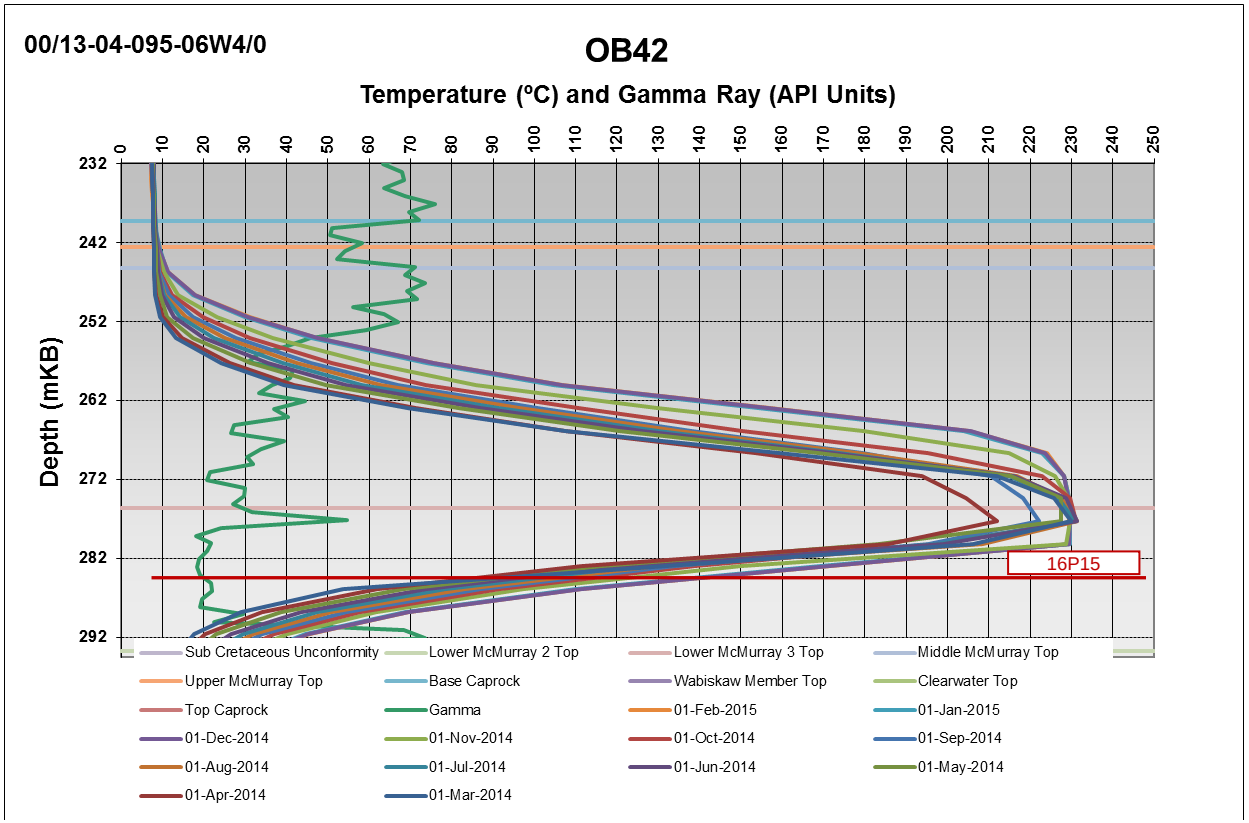
- 16WP15 has one observation well
- OB42 is located at the mid-point of 16WP15
  - 27.5 m N of 16WP15
  - 60.5 m S of 16WP16



Steam Chamber Discussion – 16WP15

OB42 – Mid-point of 16WP15, 27.5 m North

- Instrumented with 24 thermocouples covering the lower McMurray 3 and into the Clearwater
- First steam Oct 2012
- Good steam chamber development, chamber top at 272mKB and continuing to grow upwards



Pad Recoveries

Pad	101	102	103	104	Stage 1 & 2 Totals
Recovery to Date, e^3m^3	10,626	8,415	7,355	5,570	31,967
Recovery Factor to Date, %	46%	36%	37%	30%	38%
Expected Ultimate Recovery, e^3m^3	13,952	13,183	12,102	11,575	50,812
Expected Ultimate Recovery Factor, %	60%	56%	61%	63%	60%
OBIP, e^3m^3	23,100	23,400	20,000	18,500	85,000

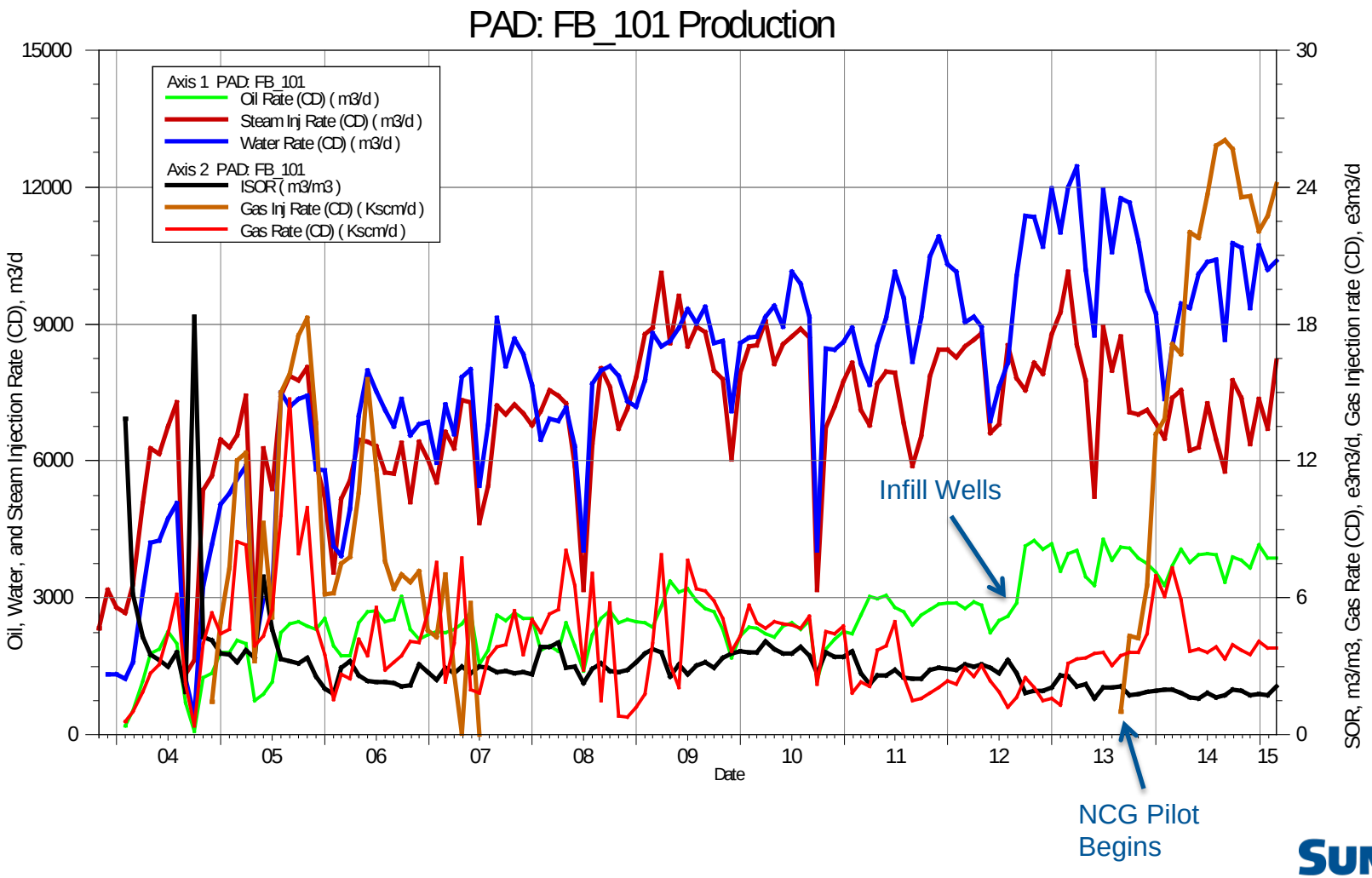
Pad	105	106	107	108	115	116	Stage 3 & 4 Totals
Recovery to Date, e^3m^3	2,910	1,885	3,070	1,419	0	2,380	11,664
Recovery Factor to Date, %	12%	10%	24%	8%	0%	14%	12%
Expected Ultimate Recovery, e^3m^3	12,811	9,011	7,759	7,245	2,713	10,859	50,399
Expected Ultimate Recovery Factor, %	55%	49%	62%	41%	55%	63%	53%
OBIP, e^3m^3	23,300	18,500	12,600	17,700	4,900	17,300	94,300

- Infill wells are included
- P108 North wells are included

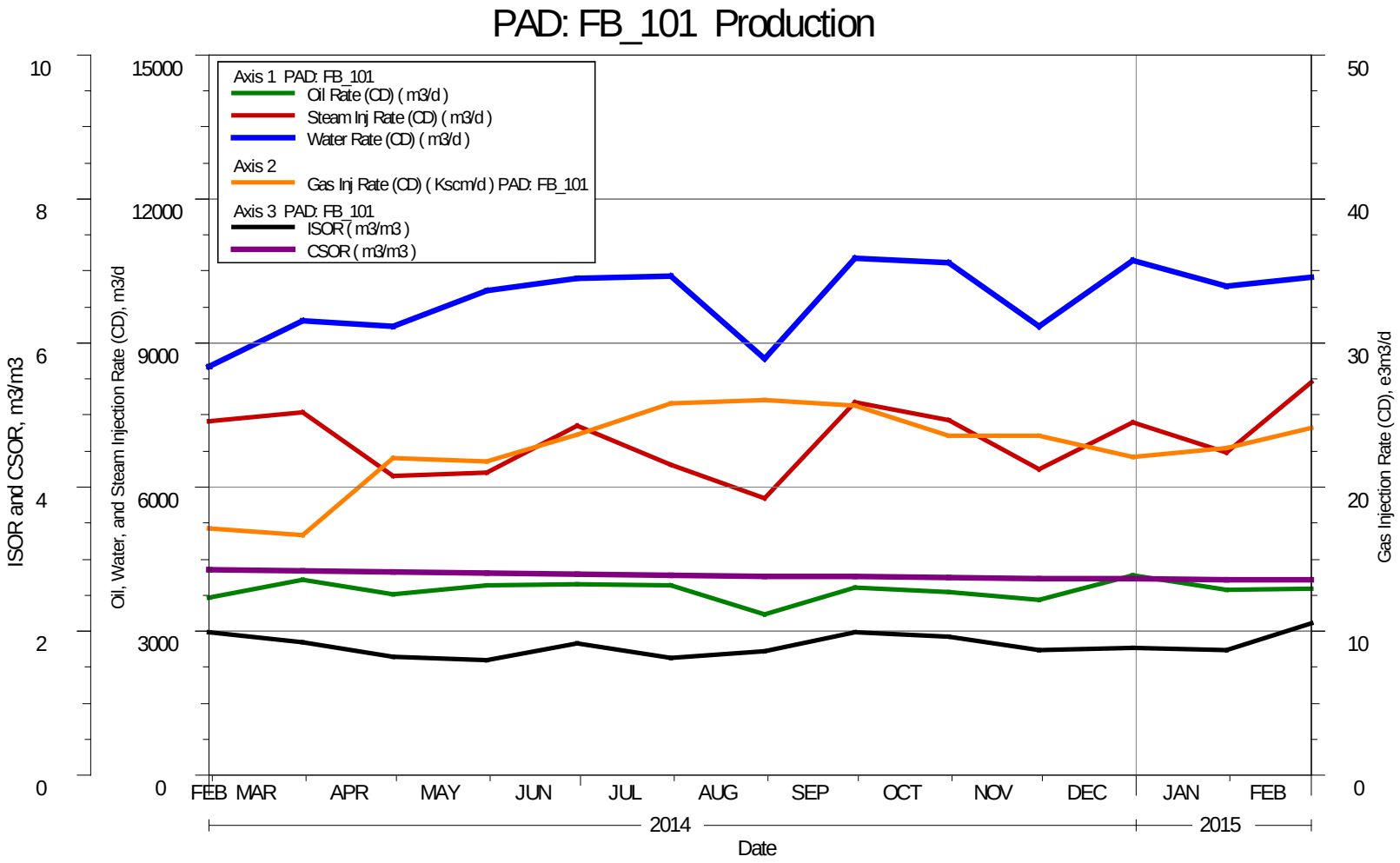
Pad 101 Performance

- Pad 101
  - Most mature pad
  - 19 wells on production
    - 10 well pair producers and 9 infills
  - Monthly steam chamber pressures:
    - Average: 2,200 kPag
    - Range: 2,181 kPag – 2,221 kPag
  - Performance as of Feb 28, 2015:
    - Cumulative steam injected is 28,783,914 m3
    - Cumulative oil produced is 10,626,247 m3
    - Cumulative SOR = 2.71 m3/m3
    - Recovery Factor of 46%
  - Pad Learnings
    - Infill wells have shown varying degrees of interference effects on the existing well pairs and have improved performance and lowered SOR
    - Interactions between wells and offsetting pads is important in understanding performance

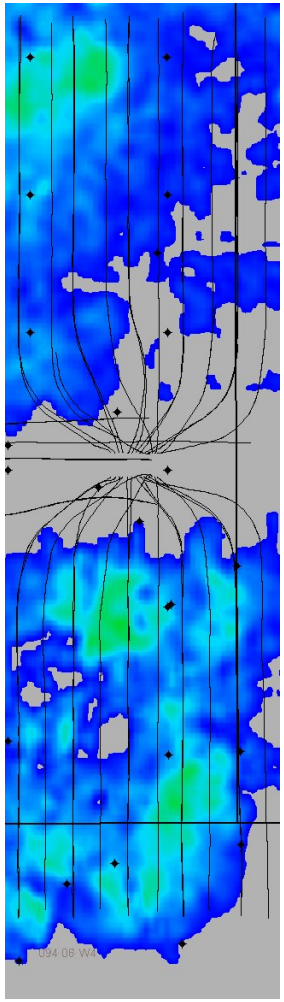
Pad 101 Performance



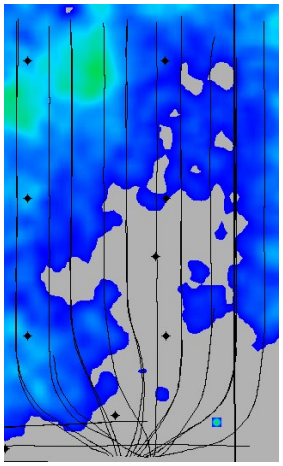
Pad 101 Performance



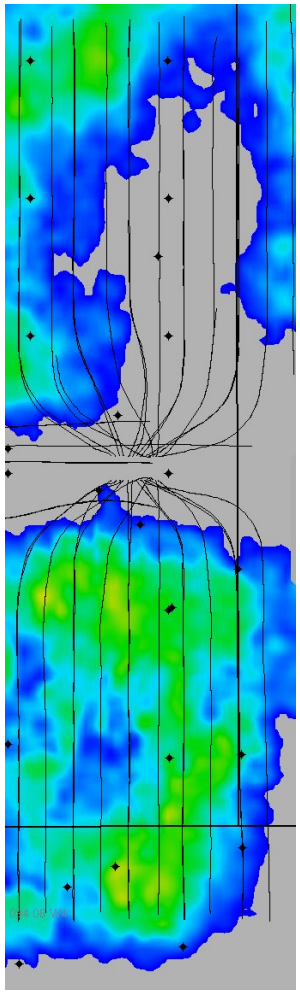
Pad101 Performance - 4D Seismic Time Delay



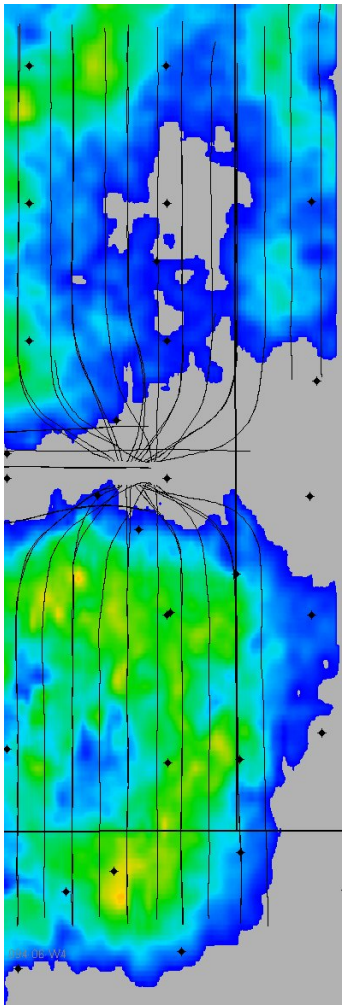
2006



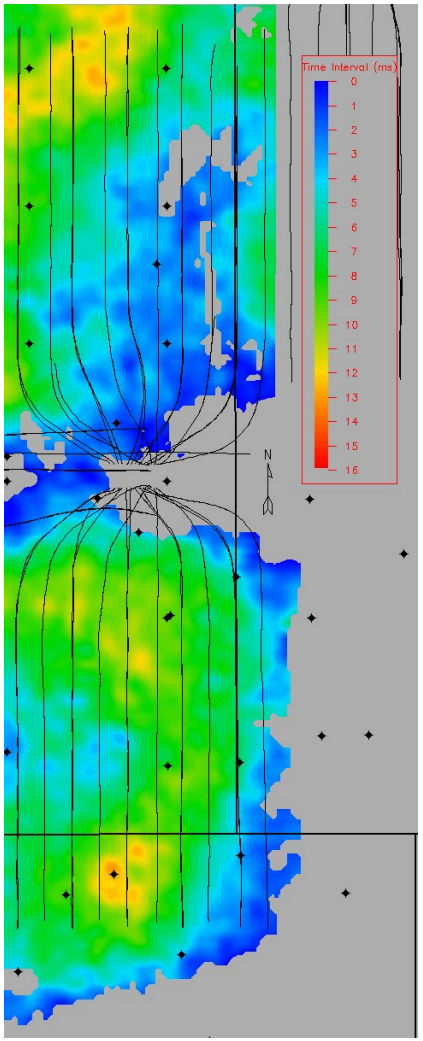
2007



2009



2010



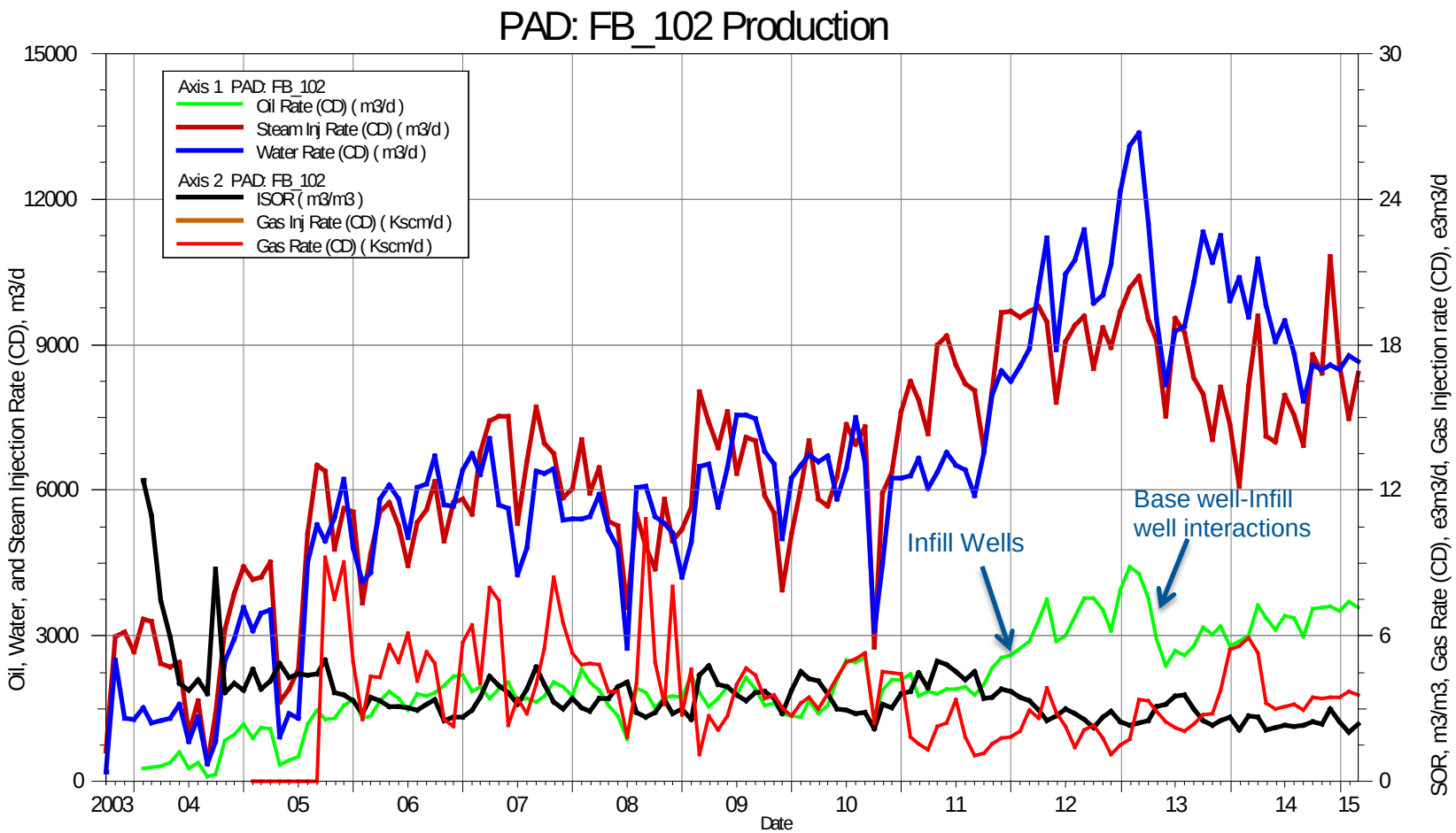
2012

SUNCOR

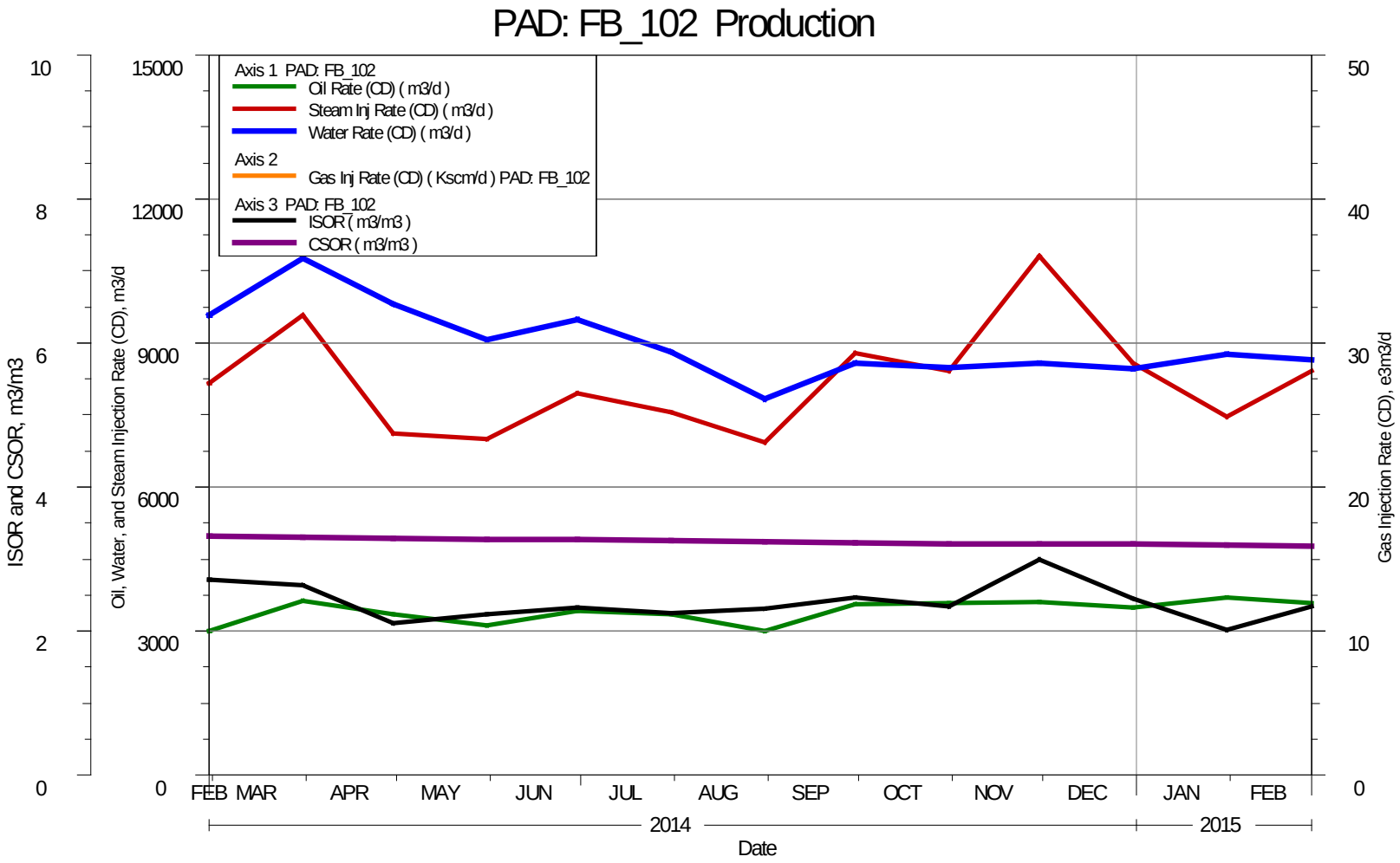
Pad 102 Performance

- Pad 102
  - Mature pad
  - 18 wells are currently on production
    - 9 well pair producers and 9 infills
  - Monthly steam chamber pressures:
    - Average: 2,279 kPag
    - Range: 2,255 kPag – 2,306 kPag
  - Performance as of Feb 28, 2015:
    - Cumulative steam injected is 26,749,840 m3
    - Cumulative oil produced is 8,415,239 m3
    - Cumulative SOR = 3.18 m3/m3
    - Recovery Factor of 36%
  - Pad Learnings
    - Infill wells have shown varying degrees of interference effects on the existing well pairs and have improved performance and lowered SOR
    - Interactions between wells and offsetting pads is important in understanding performance
    - Geological complexities can cause performance issues (mud layer running across north part of pad)

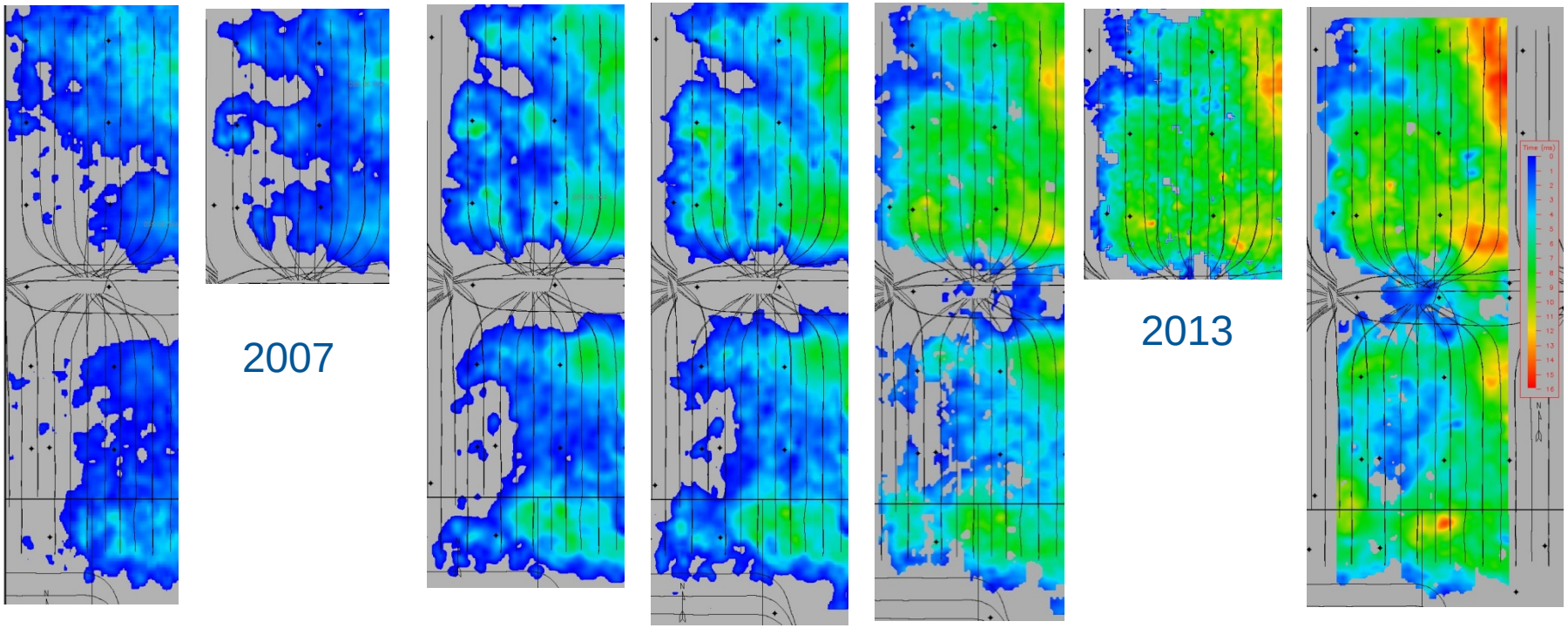
Pad 102 Performance



Pad 102 Performance



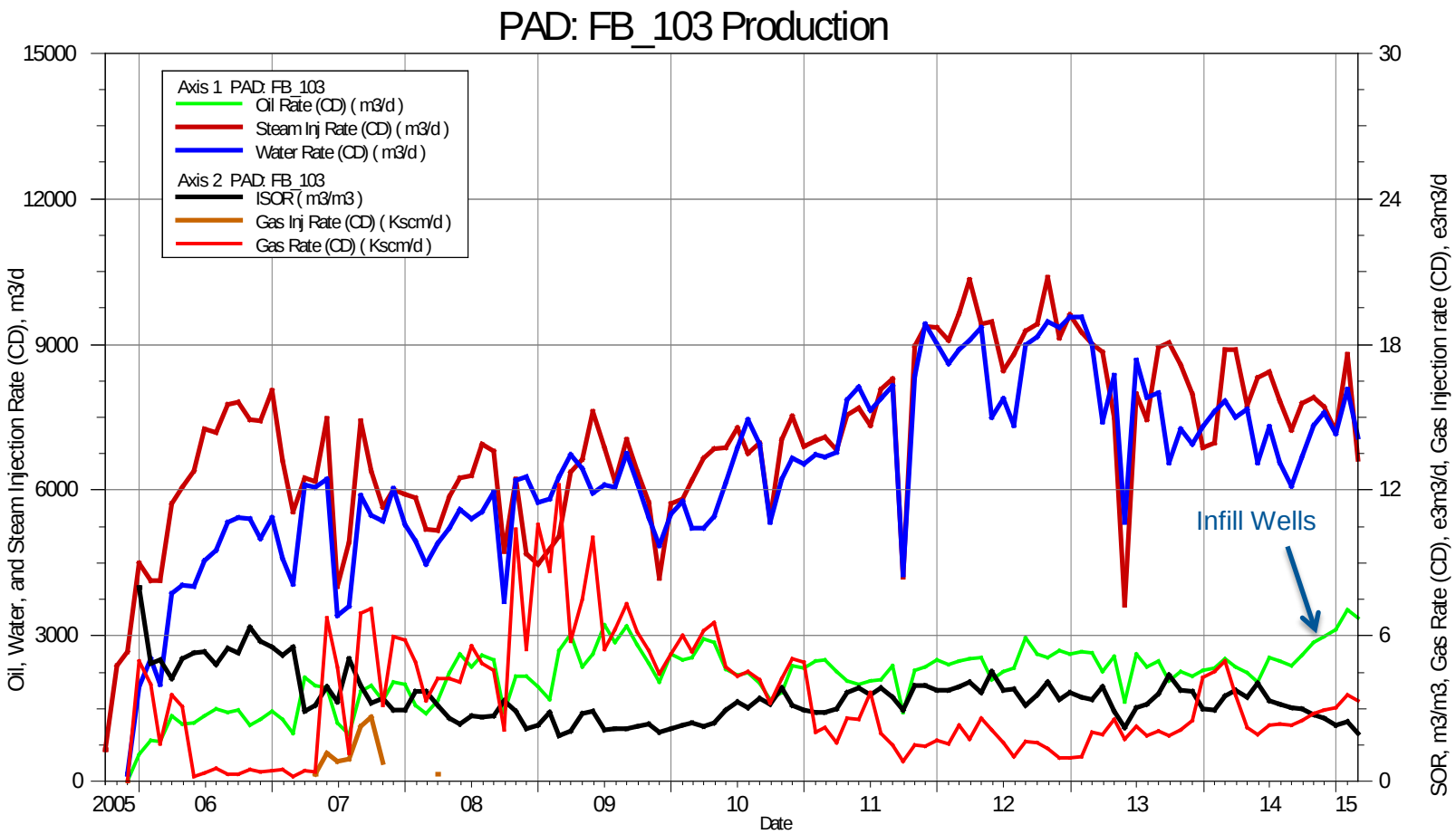
Pad 102 Performance - 4D Seismic Time Delay



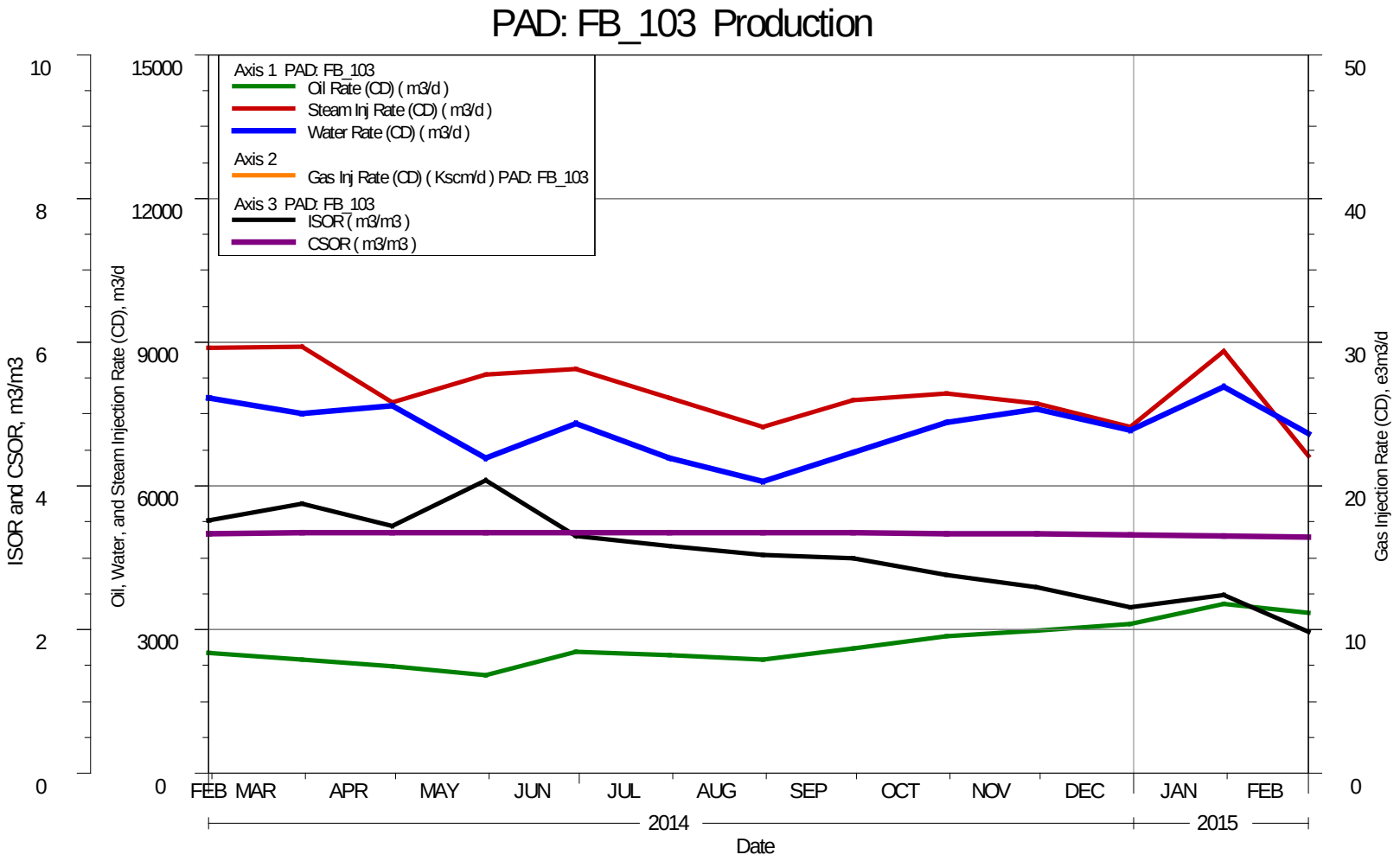
Pad 103 Performance

- Pad 103
  - Mature pad
  - 16 wells are currently on production
    - 11 well pair producers and 5 infills
  - Monthly steam chamber pressures:
    - Average: 2,314 kPag
    - Range: 2,263 kPag – 2,360 kPag
  - Performance as of Feb 28, 2015:
    - Cumulative steam injected is 24,161,225 m3
    - Cumulative oil produced is 7,355,485 m3
    - Cumulative SOR = 3.28 m3/m3
    - Recovery Factor of 37%
  - Pad Learnings
    - Infill wells have shown varying degrees of interference effects on the existing well pairs and have improved performance and lowered SOR
    - Infill well temperatures vary greatly, 3N7 encountered steam chamber and requires suspension, 3N4 very cold required extensive steam injection to startup
    - Geological complexities can cause performance issues

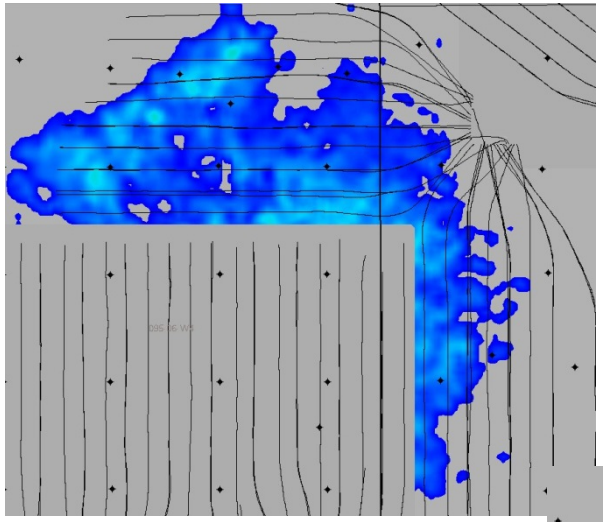
Pad 103 Performance



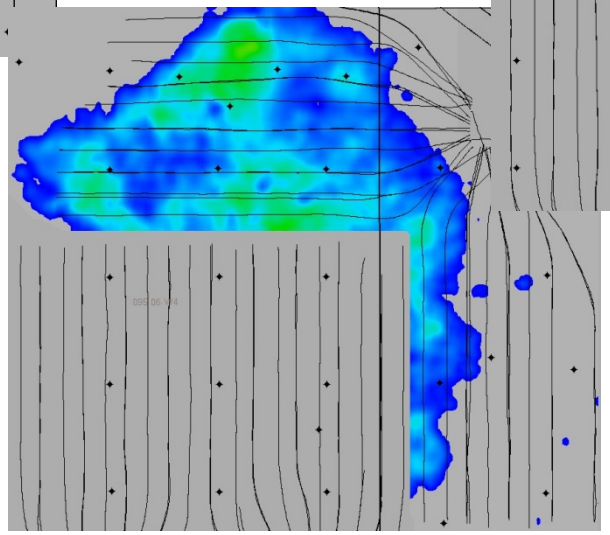
Pad 103 Performance



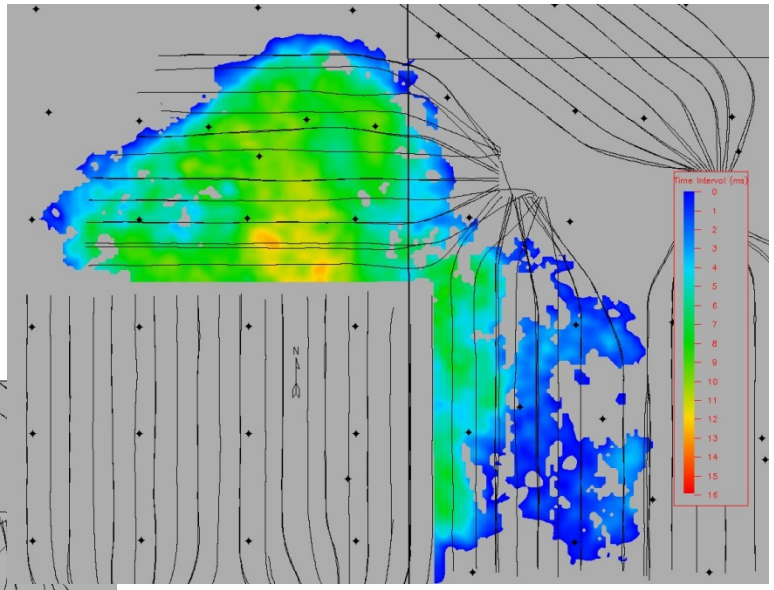
Pad 103 Performance - 4D Seismic Time Delay



2007



2009

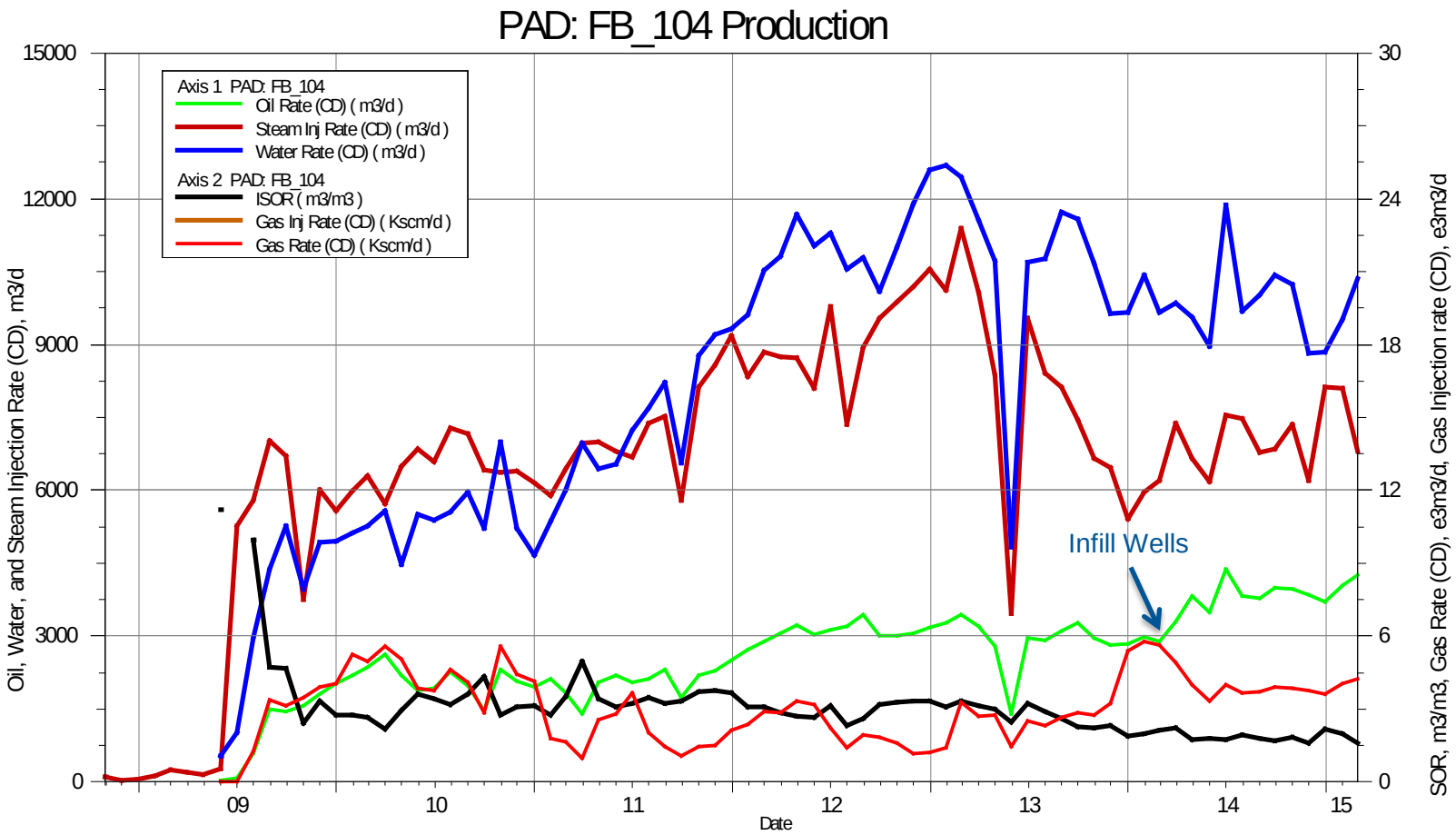


2012

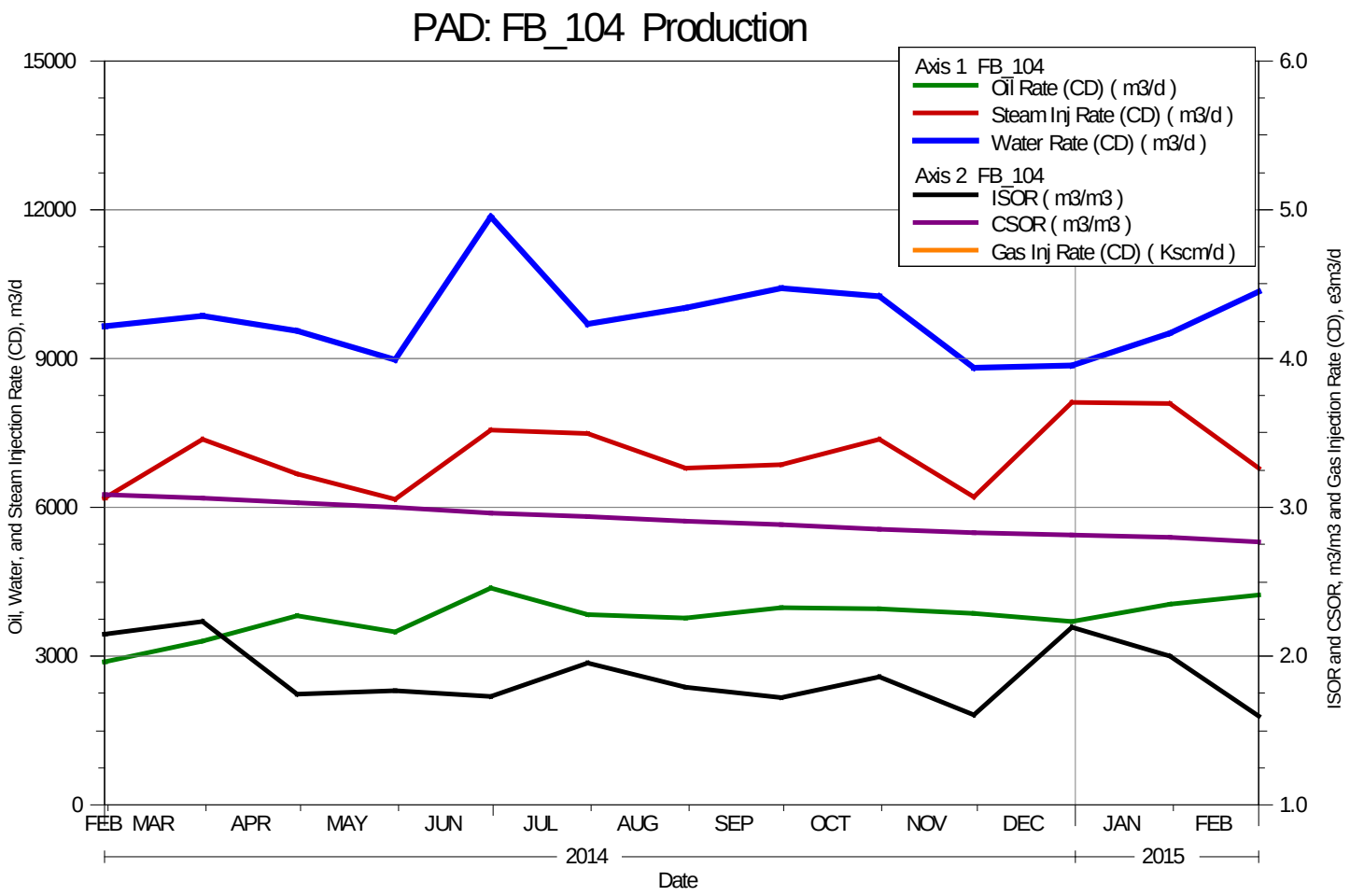
Pad 104 Performance

- Pad 104
  - 15 wells are currently on production
    - 10 well pair producers and 5 infills
  - North Infill wells first oil April 2014
  - Monthly steam chamber pressures:
    - Average: 2373 kPag
    - Range: 2320 kPag - 2440 kPag
  - Performance as of Feb 28, 2015:
    - Cumulative steam injected is 15,431,984 m3
    - Cumulative oil produced is 5,570,341 m3
    - Cumulative SOR = 2.77 m3/m3
    - Recovery Factor of 30%
  - Pad Learnings
    - Infill well temperatures generally colder than Pad 101, 102, and 103 infills due to 6 year difference in age of pad
    - Geological complexities can cause performance issues (south part of Pad 104 has slower steam growth)

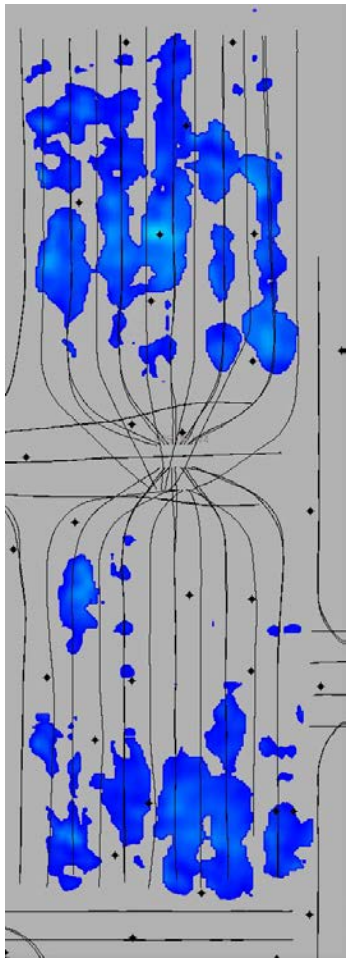
Pad 104 Performance



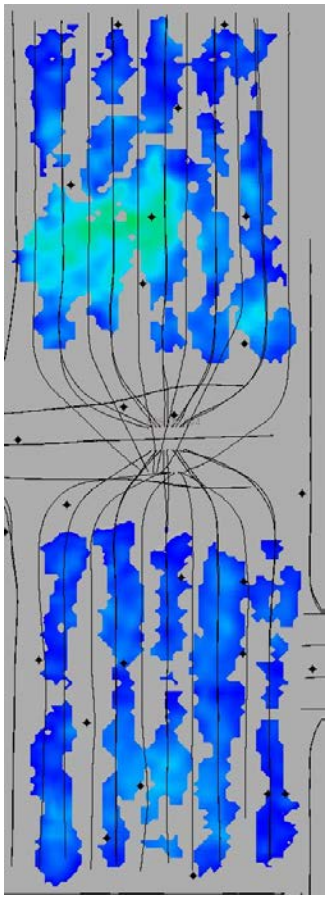
Pad 104 Performance



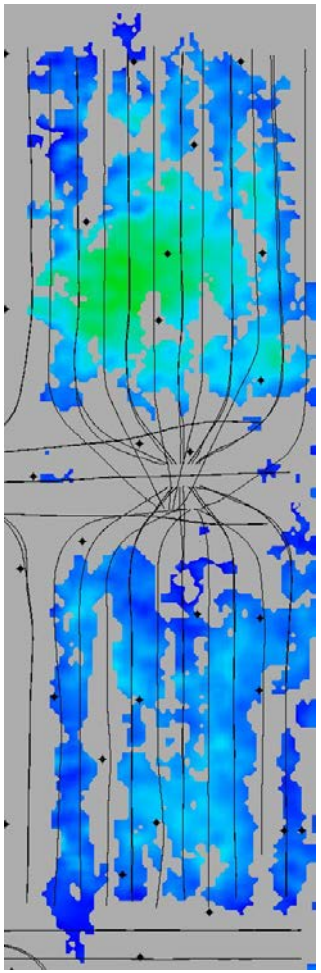
Pad 104 Performance - 4D Seismic Time Delay



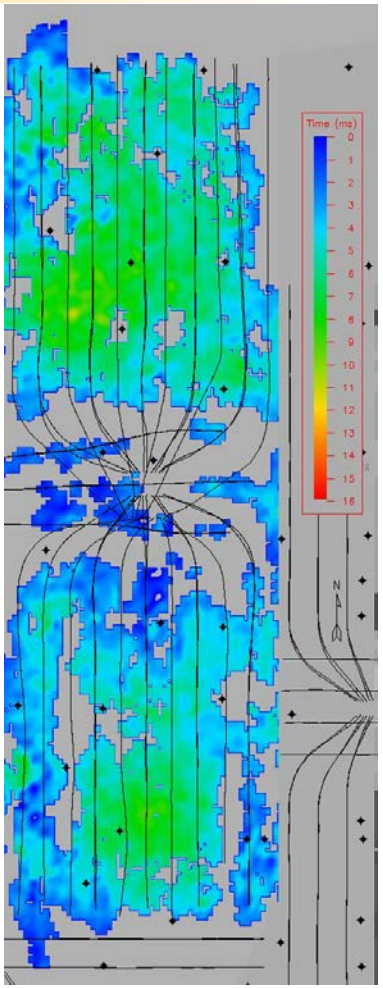
2010



2011



2012



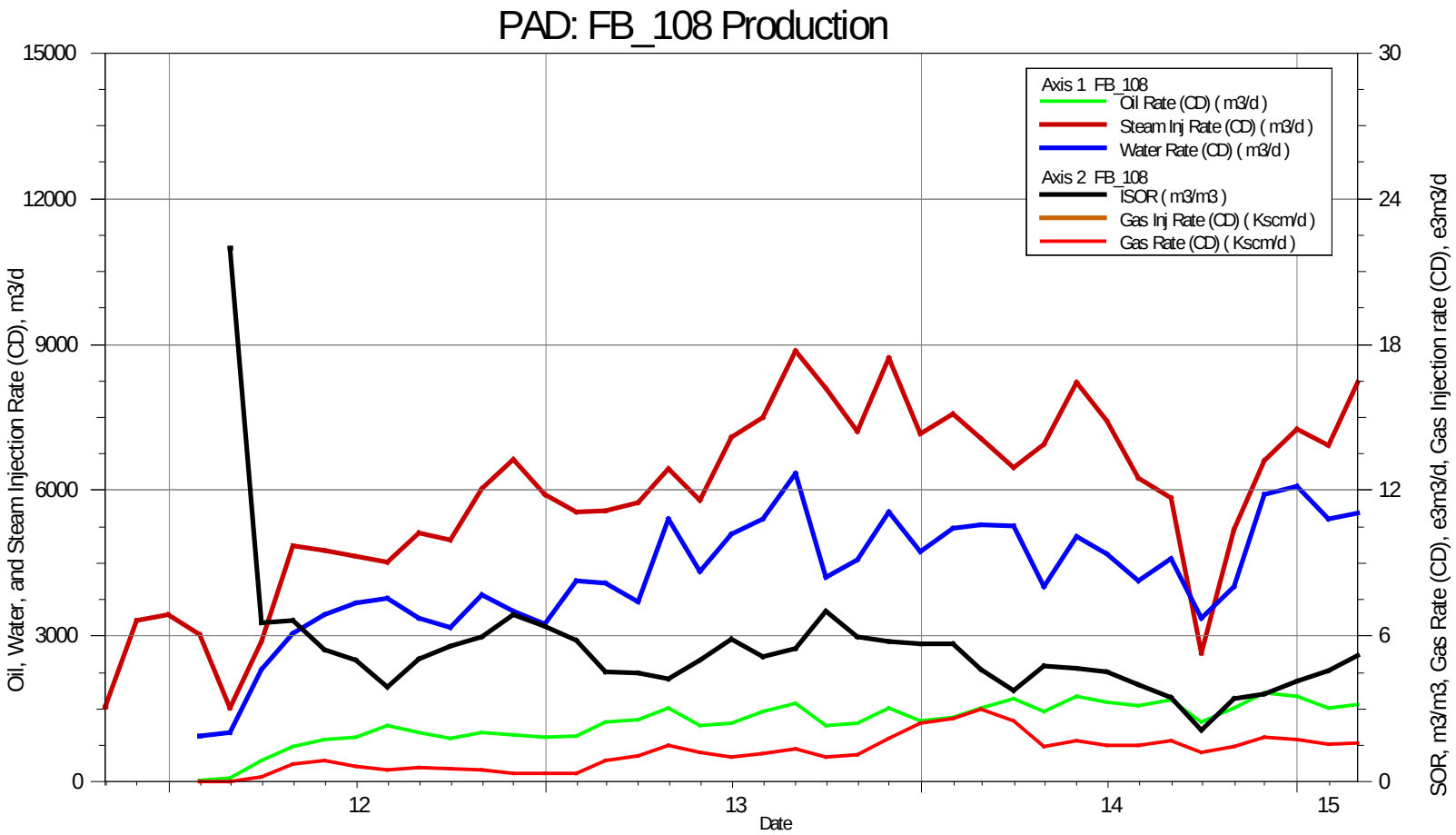
2013

SUNCOR

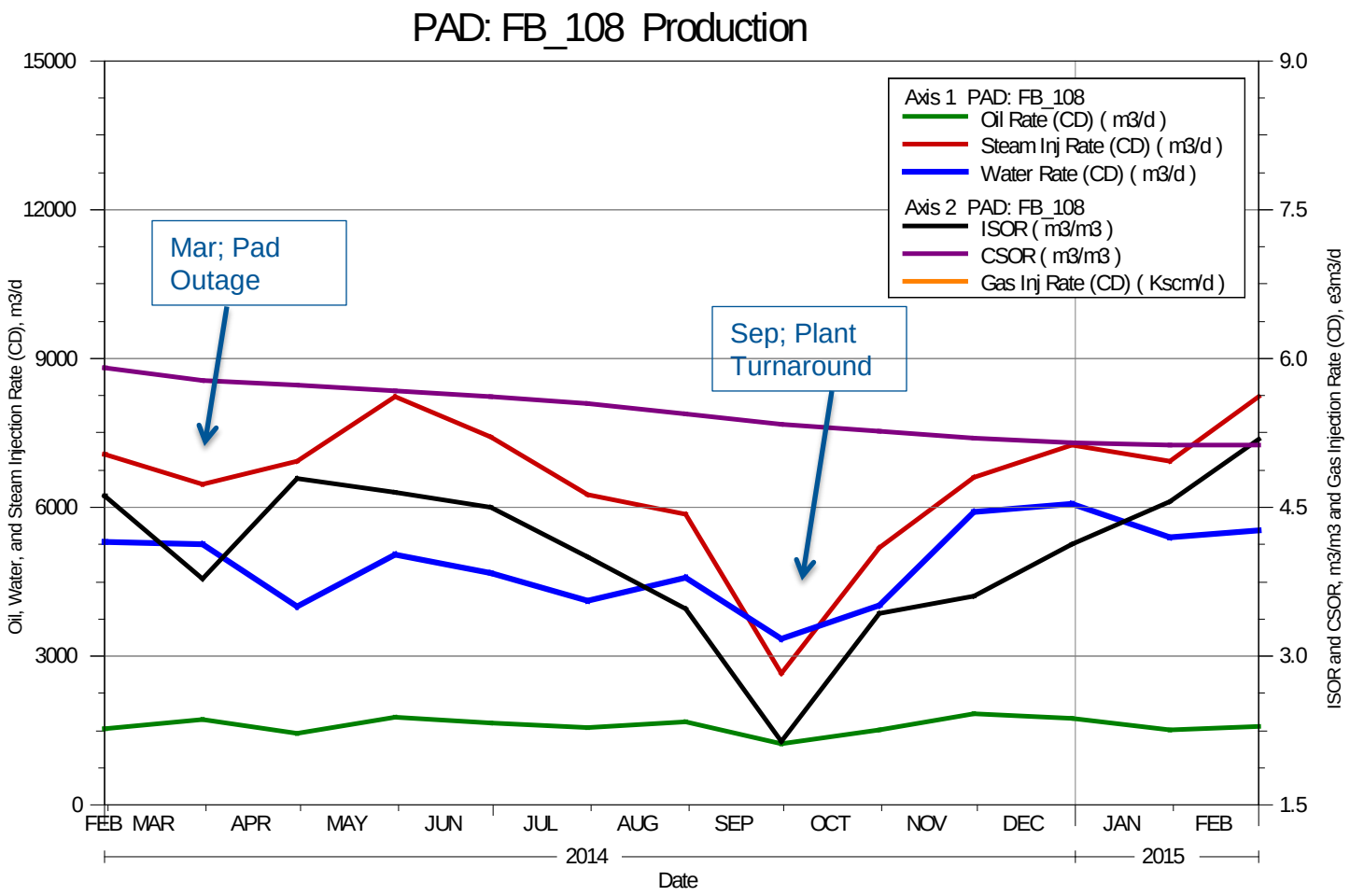
Pad 108 Performance

- Pad 108
  - 11 wells currently on production
  - 2 well pairs and one infill first steam in Oct 2014, planned first oil for April 2015
  - Steam chamber pressures:
    - Average over period: 2562 kPag
    - Range over period: 2457 kPag - 2720 kPag
  - Performance as of Feb 28, 2015:
    - Cumulative steam injected is 7,283,824 m3
    - Cumulative oil produced is 1,418,938 m3
    - Cumulative SOR = 5.13 m3/m3
    - Recovery Factor of 8%
  - Pad Learnings
    - Interactions with offset more mature pads causing some challenges with steam chamber conformance
    - Geological complexities can cause performance issues

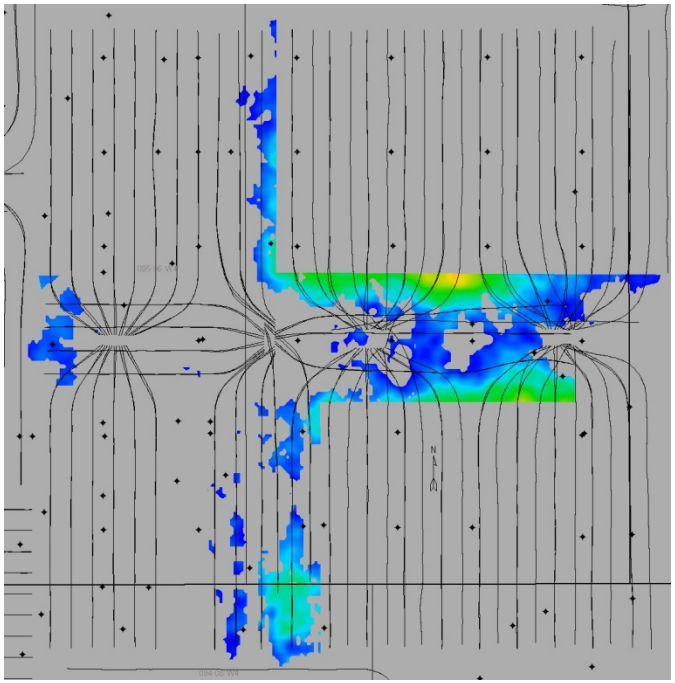
Pad 108 Performance



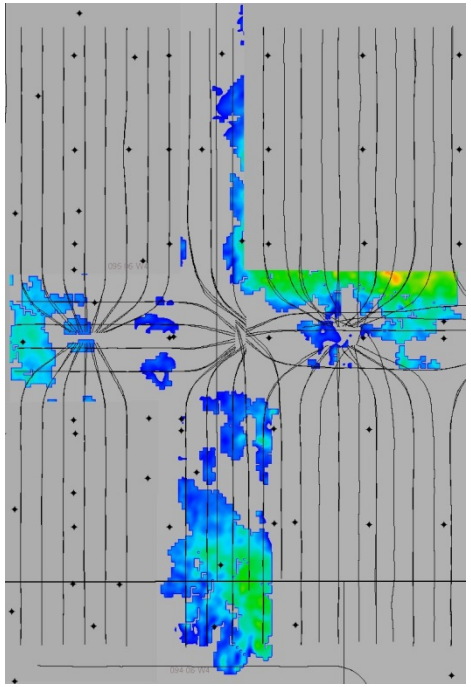
Pad 108 Performance



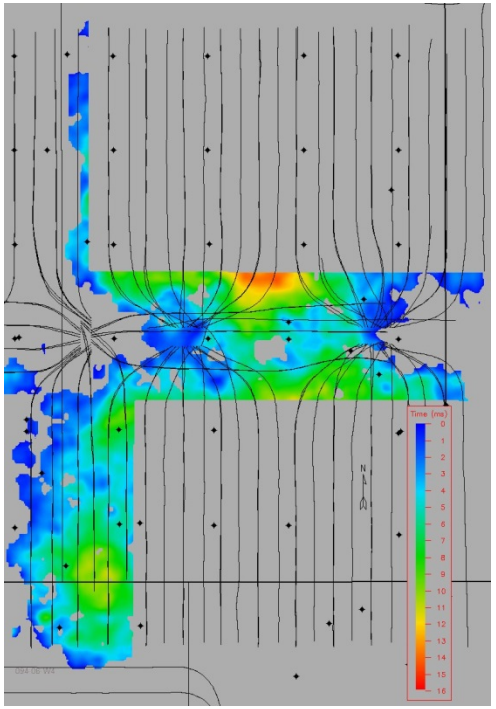
Pad 108 Performance - 4D Seismic Time Delay



2012



2013



2014

Future Plans – Well and Pad Abandonments

- Do not anticipate abandonment of any SAGD pads within the next 5 years
- Well Abandonments
  - 1P6
  - 1P3, 8P4 and 2P9 are potential future abandonments

Steam Injection Properties

- Approved MOP of currently producing pads:
  - 4040 kPag (251 ^{o}C) during circulation
  - 3570 kPag (243 ^{o}C) during SAGD
- Average monthly casing injection pressure during Feb 2015 (as measured by blanket gas) was 2443 kPag (225 ^{o}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

Summary of Key Learnings

- Infill Performance and Operation
- Bullheading
- Pad 101 NCG Pilot
- Operating Pressure Strategy
- Operating Strategy and Optimal Subcool Management

Summary of Key Learnings

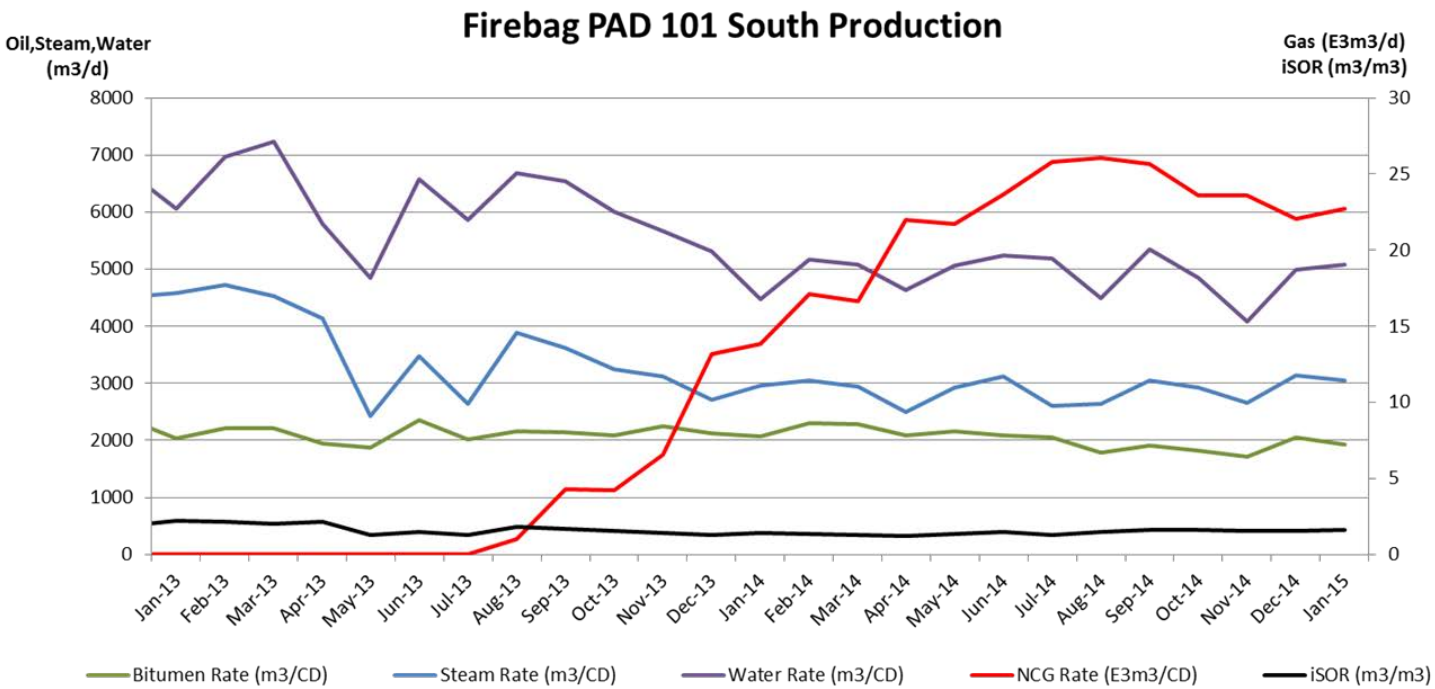
- Infill Performance
  - Bottom hole temperatures vary greatly well to well
  - Mobility and conformance greatly influence steam requirement
  - Tailored well completions based on preliminary temperature surveys
    - Equip well for bull heading, steam past ESP, no steam
    - Target hot / cold zones for production / injection
  - Select wells required multiple steaming cycles
  - Generally stable production once in SAGD mode
  - Infill / base well interaction needs to be managed to optimize performance at a chamber level
  - 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)

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
  - Purpose is to heat the reservoir between injector and producer
  - Historically circulation startup wells at Firebag have leaked off a material portion of circulated steam
  - By not taking returns, bullheading:
    - Requires less cumulative steam
    - Achieves the same reservoir heating as circulation
    - Reduces CSOR and thus emissions / bbl produced
  - Pads with Bullheading Start Up: 105, 107, 108, 116, 104/103 Infills
  - 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
  - Oil rate continues to be maintained against steam reductions
  - Significant NCG partial pressure effects have not been observed
  - NCG return production is not significant enough with current injection rates to be empirically substantiated. Reliable sampling is a challenge. Continue monitoring effort as co-injected NCG cumulative volumes become larger



2014 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	0.58%
	100.00%

Summary of Key Learnings

- Operating Pressure Strategy
  - Steam prioritized to be directed towards younger pads
  - Balance steam chamber pressures between Pads as much as possible
  - Utilize the available steam
  - Pressure drop from wellhead to reservoir varies resulting in different chamber pressures across the field
  - Reduction in chamber pressures as needed to bring new pads online

Summary of Key Learnings

- Operating Strategy and Sub-cool Management
  - Operate SAGD well pairs with target of 20°C reservoir subcool
  - Temperature measured in all producers at the ESP intake
    - Some pads use 6 point thermocouples or fibre temperature data to assess subcool along the horizontal wellbore
  - Low rate steam tests measure reservoir pressure monthly
  - Adjust pump speeds regularly to maintain subcool target
  - Manage reservoir fluid levels below injectors to avoid flooding
  - Reduces risk of steam coning
  - Improved pump reliability
  - Infill wells operated at higher subcool in some cases to manage interaction with base well pairs
  - Proactively allocate steam placement to utilize energy efficiency

Steam Strategy

- Operating Pressure
  - Operating pressures ranged from 1900-3000 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

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- Geoscience
- Surface Heave and Cap Rock Integrity
- Drilling and Completions
- Artificial Lift
- Instrumentation in Wells
- 4-D Seismic
- Scheme Performance
- **Future Plans**

Future Plans – Regulatory Applications

- Filed Applications

Directive 23 Applications	Description	Date submitted	Date Approved	Approval
Pad 123	Nine wellpairs	24-Sep-13	15-Jul-14	8870BBB
Pad 121	Eighteen wellpairs	6-Jan-14	5-Aug-14	8870CCC
Pad 122	Eighteen wellpairs	6-Jan-14	5-Aug-14	8870CCC
Directive 78 Amendments	**Description**	**Date submitted**	**Date Approved**	**Approval**
Firebag Fieldwide bullheading		18-Sep-13	23-Jan-14	8870XX
Tie-In of Plant 91/92 PWTs to VRU		13-Feb-14	5-Mar-14	8870XX
Directive 81 Compliance		12-Feb-14	8-Apr-14	8870YY
Start-up Chemical Injection	Pad 110 & 115	14-Feb-14	1-May-14	8870ZZ
P1P6 Re-drill	Pad 101	15-May-14	12-Jun-14	8870AAA
Water Cooling Expansion		18-Jun-14	8-Sep-14	8870DDD
Water Mobility Tests		7-Jul-14	23-Oct-14	8870EEE
Pad 111 Amendments		10-Nov-14	18-Dec-14	8870FFF
Water Injectivity Tests		27-Oct-14	19-Dec-14	8870GGG
Downhole Electrical Heater	Pad 109	3-Feb-15	13-Mar-15	8870HHH

- Future Applications
  - Geoscience and Reservoir Development teams are continuing work to determine optimum depletion plans for next sustaining pads in two potential areas
  - Continuing work on NCG co-injection next phase development

Future Plans - Drilling Activities

- Completed Drilling
  - Pad 104 Infill commenced drilling in June 2014, finished September 2014
  - Pad 109 finished drilling April 2014
  - Pad 112 finished drilling January 2014
  - Pad 114 finished drilling August 2014
- Drilling In Progress
  - Pad 118 commenced drilling in Q4 2014, anticipated finish Q4 2015

2015 Drilling: Re-entered & Re-drilled Wells

- The following wells were re-entered or re-drilled during the reporting period:

Well	Re-entry/Re-drill	Reason
P1P6 (Pad 101)	Re-drill (P1P6 abandoned)	• Well shut-in due to a suspected liner failure • New well, P1P6B, was drilled with a horizontal leg offset 80m to the east of P1P6 well to improve performance and increase recovery • Currently on production

Future Plans – Drilling Activities

- Future Drilling
  - Coreholes/observation wells will be drilled as necessary to:
    - Adequately delineate the resource
    - Monitor SAGD operations
    - Further cap rock integrity analysis
    - Hydrogeology analysis
    - Water disposal analysis

Future Plans – Testing

- Pad 104 North Chemical Co-Injection Test
  - Application was approved in Mar 2013
  - Test planned for Q2 2015
  - Three injectors: 4S2, 4S3 and 4S4
- Pad 110 Chemical Co-Injection Test
  - Canceled
- Pad 115 Chemical Soak – 15WP6 & 15WP7
  - Executed in Q3 2014, under evaluation
- Electrical Pre-heat in 10P7 (canceled) - moved to Pad 109
  - Planned for Q3 2015 in one well (Pad 109)

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

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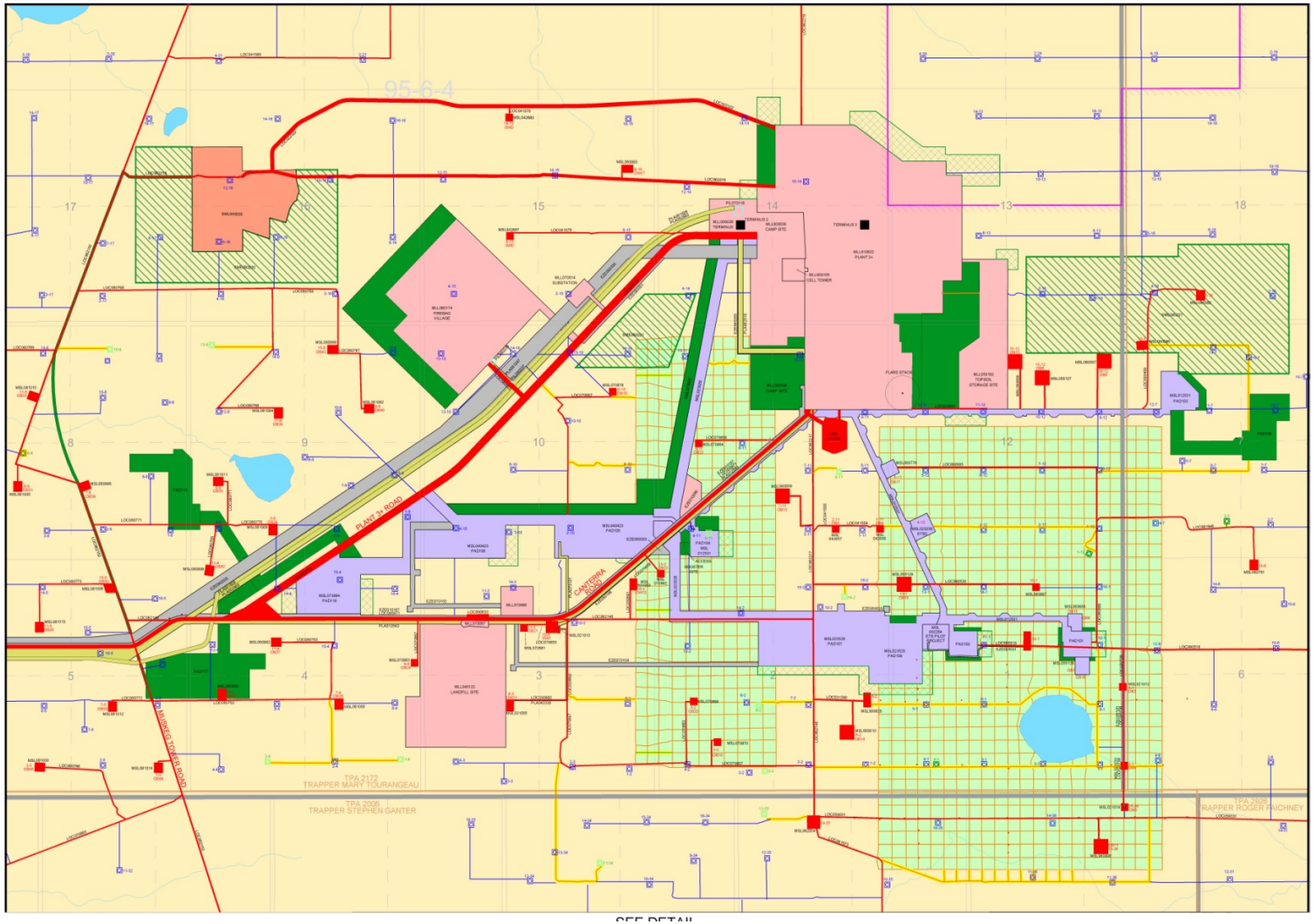
- **Operations and Facility Performance**
- Measurement and Reporting
- Water Production, Injection and Usage
- Sulphur Production
- Environmental Performance
- Future Plans

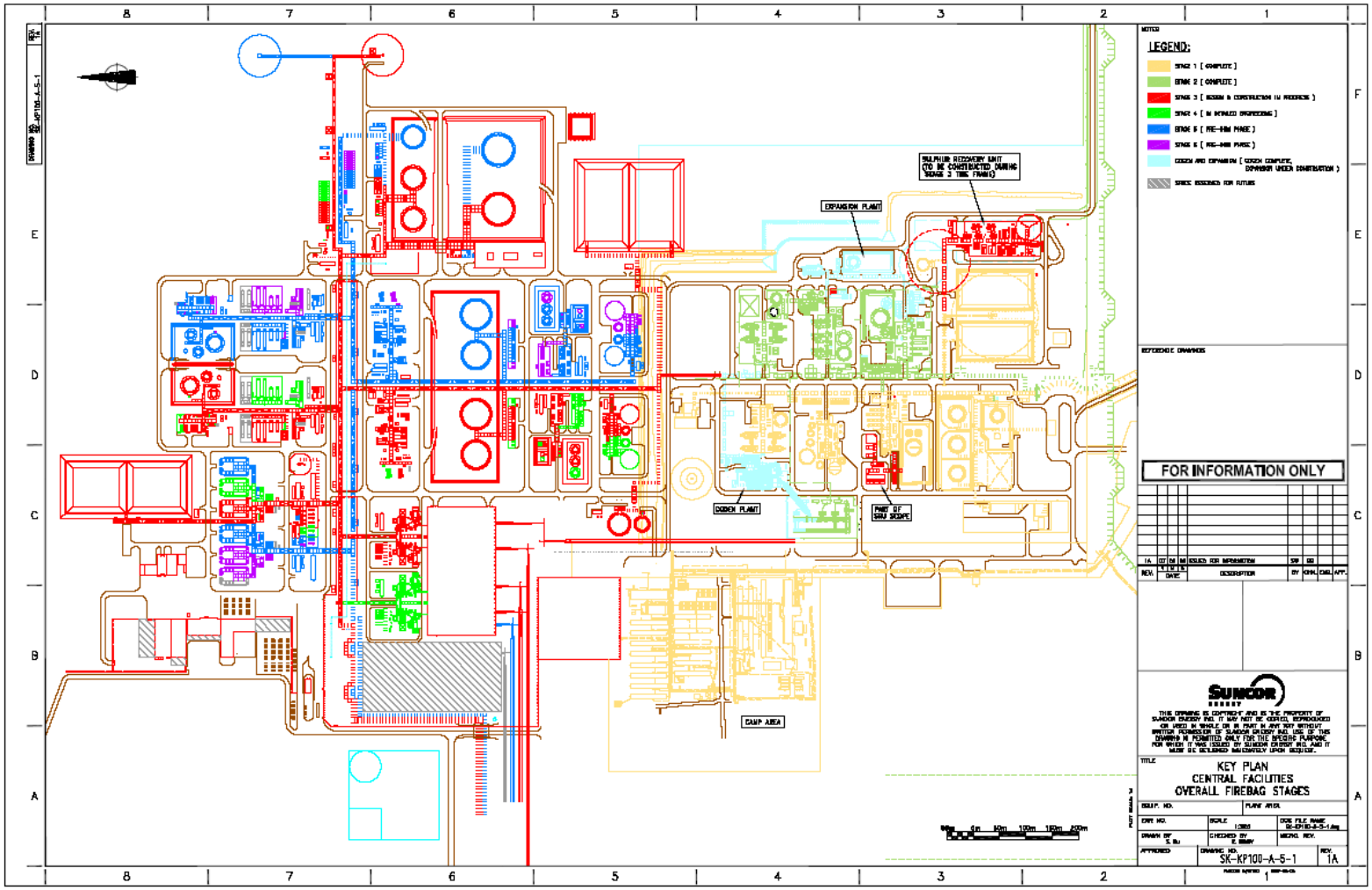
Firebag Project Site

Site Survey Plan

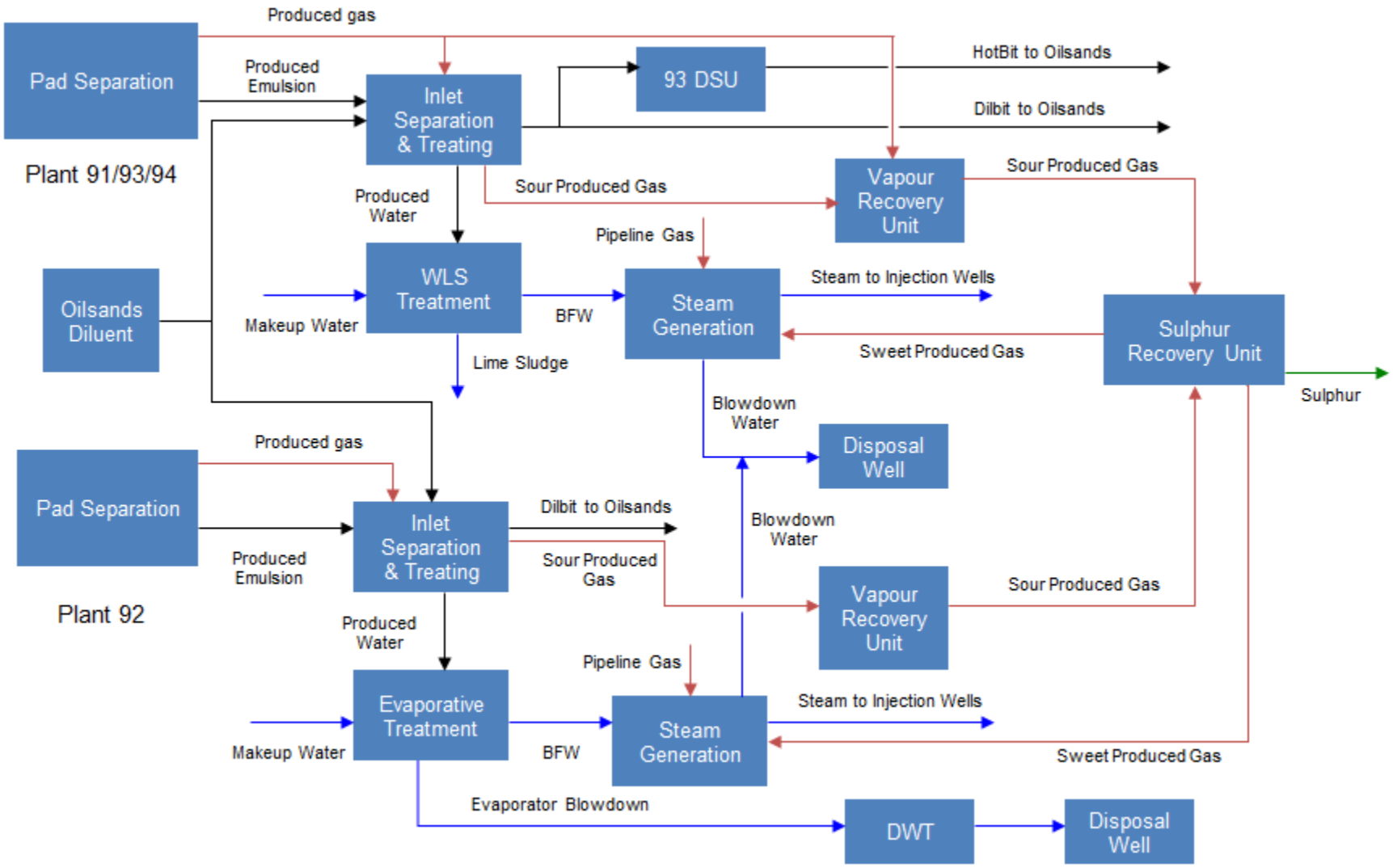


SEE DETAIL

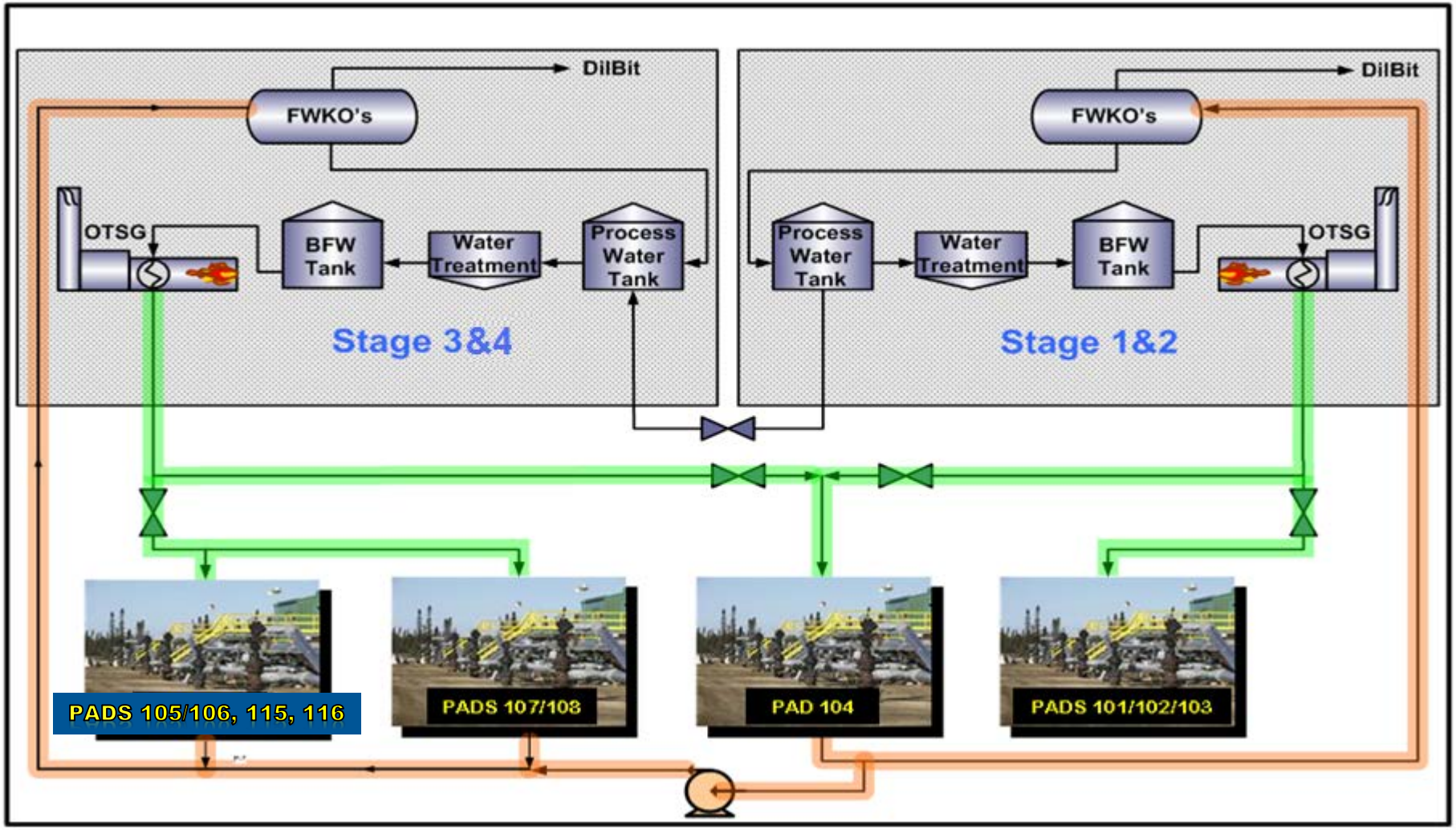
Firebag Site Layout



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
PAD 104
PADS 101/102/103

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

Oil Treatment Risks and Opportunities

- All Plants
  - Chemical Usage Optimization
  - Improvement in Produced water cooler run time on Plant 91
  - Ongoing operation improvement to reduce venting incidents
  - Ongoing treatment of utility water system to prevent biological corrosion

- Plant 93/94
  - Improvement in MBF operations resulted in benefits in 2014

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
  - Positive results from chemical cleaning to remove scale
  - Success with internal mechanical changes
  - Extending run times between chemical cleanings

- 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
- 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

- Reduction of gas to the SRU by optimization of the blanket gas and additional cooling in plants 93/94/DSU

	Overall Recovery, %	SRU Recovery, %	Incinerator Emissions , tonnes/day	Overall SO2 Emissions, tonnes/day
2012	93.4	95.1	0.30	-
2013	95.2	96.7	0.20	-
2014	97.3	97.6	0.17	0.53

Pads/Gathering Technologies

- Currently: 10 Pads and 157 Producing Wells
- New Pads: Pad-115, Pad-104 & Pad-103 Infill, Pad-108 North
- Future Pads: 109, 110, 111, 112, 114, 117 and 118 by 2018 (Firebag development program)
- Produced emulsion from Pads 1 to 4 is transferred to Plant-91/92
- Booster pumps to transfer some of the emulsion from Pads-101-104 to Plant-93/94
- Produced emulsion from Pads 105, 106, 107, 108, 116 is transferred to Plant-93/94

Produced Water (PW) Quality

PW Quality (averages)			
	Plant 91	Plant 92	Plant 93 & 94
pH (pH units)	9.1	10.6	7.1
Turbidity (NTU)	26.4	17.8	99.5
Reactive Silica (mg/L)	248	273	263
Bitumen in Water (ppm)	1.8	3.0	1.9
Dissolved Ca (mg/L)	5.4	2.4	1.9
Dissolved Mg (mg/L)	1.1	0.6	1.0
Dissolved Hardness CaCO3 (mg/L)	18.0	8.2	9.0

Boiler Feed Water (BFW) Quality

	Plant 91	Plant 92	Cogen (HRSG)	Plant 93/94
Total Dissolved Solids (mg/L)	1200	180	410	2900
Reactive Silica (mg/L)	45	4	12	42
Dissolved Chloride (mg/L)	180	18	48	570
Dissolved Sodium (mg/L)	478	53.8	167	1140
Dissolved Potassium (mg/L)	22.2	2.3	6.9	94
Alkalinity (mg/L)	457	113	210	814
pH (pH units)	10.1	9.9	9.6	9.9
Dissolved Oxygen (DO)	Note 1			Note 2

Note 1: DO not measured. DO is close to zero or zero because of oxygen scavenger dosing.

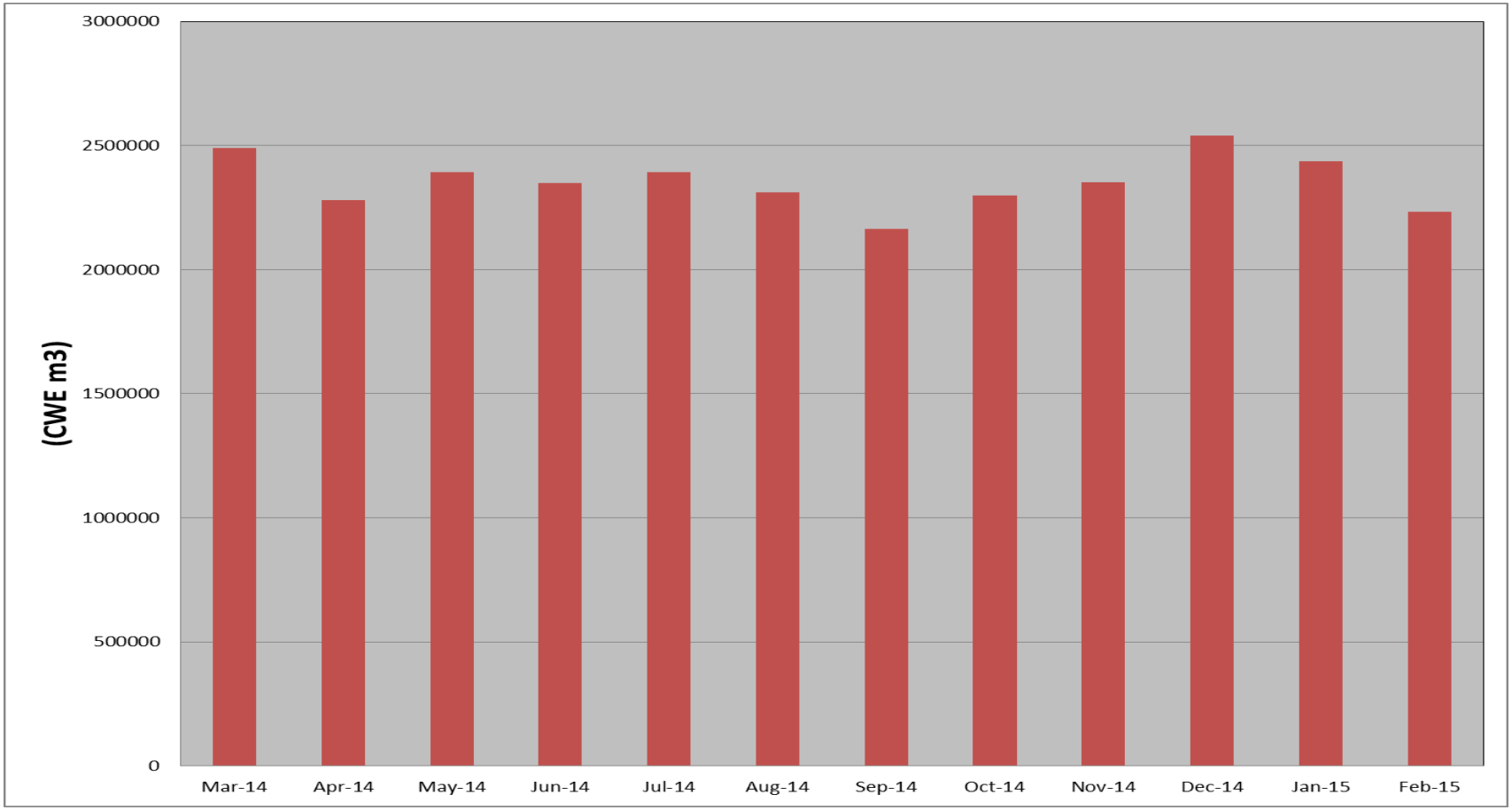
Note 2: DO was 0 ppb to 4.5 ppb before oxygen scavenger dosing. DO is zero after oxygen scavenger dosing was started in Nov/Dec 2014.
DO < 7ppb (spec)

Plant Improvements

- Optimized operation of the Free Water Knockout (FWKO) and Deoiling to ensure onspec Basic Sediment & Water (BS&W) in Dilbit and Oil in Water
- Plant 92 Expansion Treater nuclear interface level control
- Improved the foaming issue in Amine unit significantly by continuous skimming of water from stripper column reflux drum. Project ongoing to automate skimming and water make up
- Improved the performance of steam traps to handle extra generated steam condensate in pads and reduce water hammering and erosion issue in Pad-116 and 108
- New Boiler Feed Water (BFW) transfer line from 91/92 to 93/94
- Optimized steam generation capacity during steam long situations to maximize energy efficiency by operating in their most efficient combustion zones
- Chemical cleaning program on 92 Evaporators
- Reduction in SOR assisted with higher DilBit production

Steam Injected

From March 2014 to February 2015, Firebag injected on average 77,365 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-14	75.6	76.9	77.7	73.8	77.2	74.1	77.5
Apr-14	76.3	78.5	78.6	74.1	75.1	74.5	73.8
May-14	75.7	77.6	77.8	74.3	76.7	75.1	75.2
Jun-14	76.5	78.1	77.4	73.5	74.4	73.8	74.4
Jul-14	75.0	78.3	78.6	73.5	74.0	71.5	74.0
Aug-14	72.5	78.3	77.7	73.6	73.8	72.2	71.5
Sep-14	75.8	78.0	79.1	70.9	73.4	72.1	73.2
Oct-14	76.9	77.2	78.3	73.4	72.5	67.9	72.7
Nov-14	75.4	78.6	78.3	73.1	75.1	74.3	74.0
Dec-14	74.9	78.3	79.1	74.7	75.4	74.6	74.9
Jan-15	75.9	77.9	78.6	73.2	73.4	73.4	73.6
Feb-15	74.8	77.7	77.9	72.3	72.3	72.1	73.1
Average:	**75.5**	**78.0**	**78.3**	**73.4**	**74.4**	**73.0**	**74.0**

Notes of Steam Qualities

- For Plant 91, the quality can be run to a maximum of 80% on any individual pass, which means the average must be lower than 80% due to the spread of pass qualities. Plant 91 is specifically prone to particulate hardness excursions and the quality must be cut to 75% and then 70% to protect the boiler tubes on occasions. This happens frequently enough to account for the low quality below.

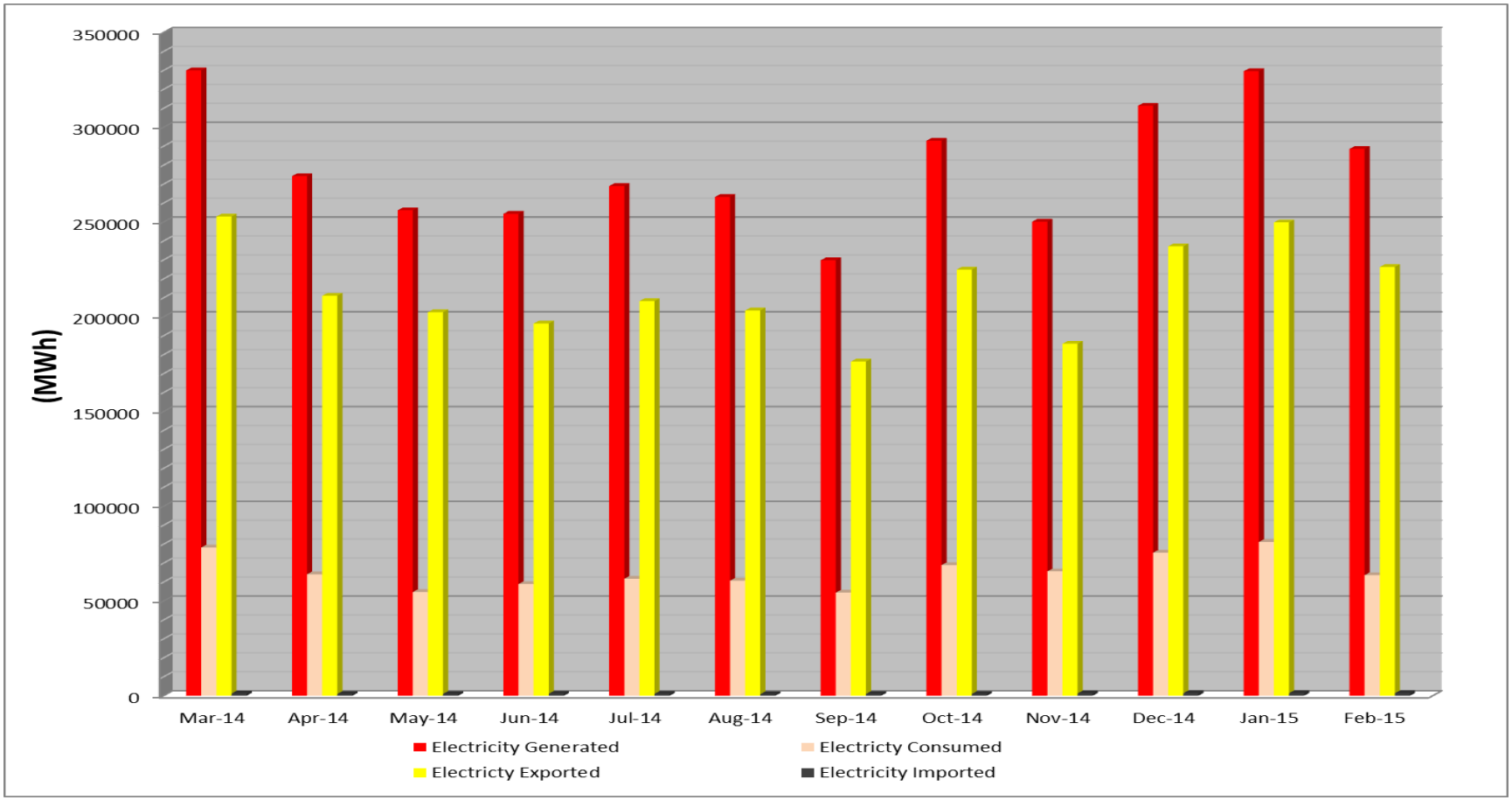
- For Plant 92, the quality can be run to a maximum of 80% on any individual pass, which means the average must be lower than 80% due to the spread of pass qualities.

- For the Plant 91 Cogeneration unit, the quality can be run to a maximum of 80% on any individual pass, which means the average must be lower than 80% due to the spread of pass qualities, however tighter pass control on this cogeneration unit allows a higher average quality than Plant 92.

- For all Plant 93 and 94, the design is for 75% average

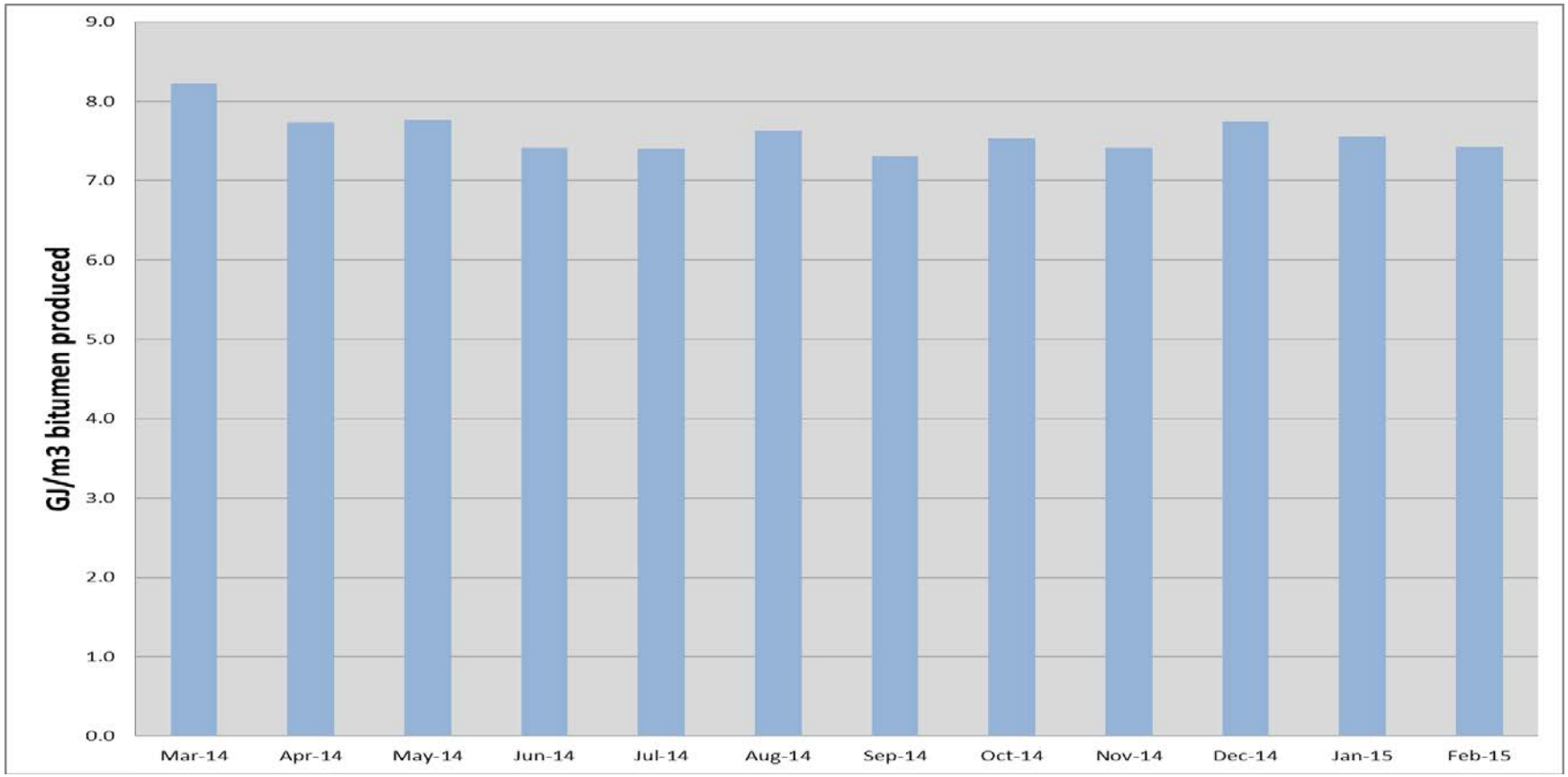
Electricity Generation/Consumption

From March 2014 to February 2015, Firebag generated 3,349 GW-hours of electricity, with 2,574 GW-hours being exported for sale



Energy Intensity

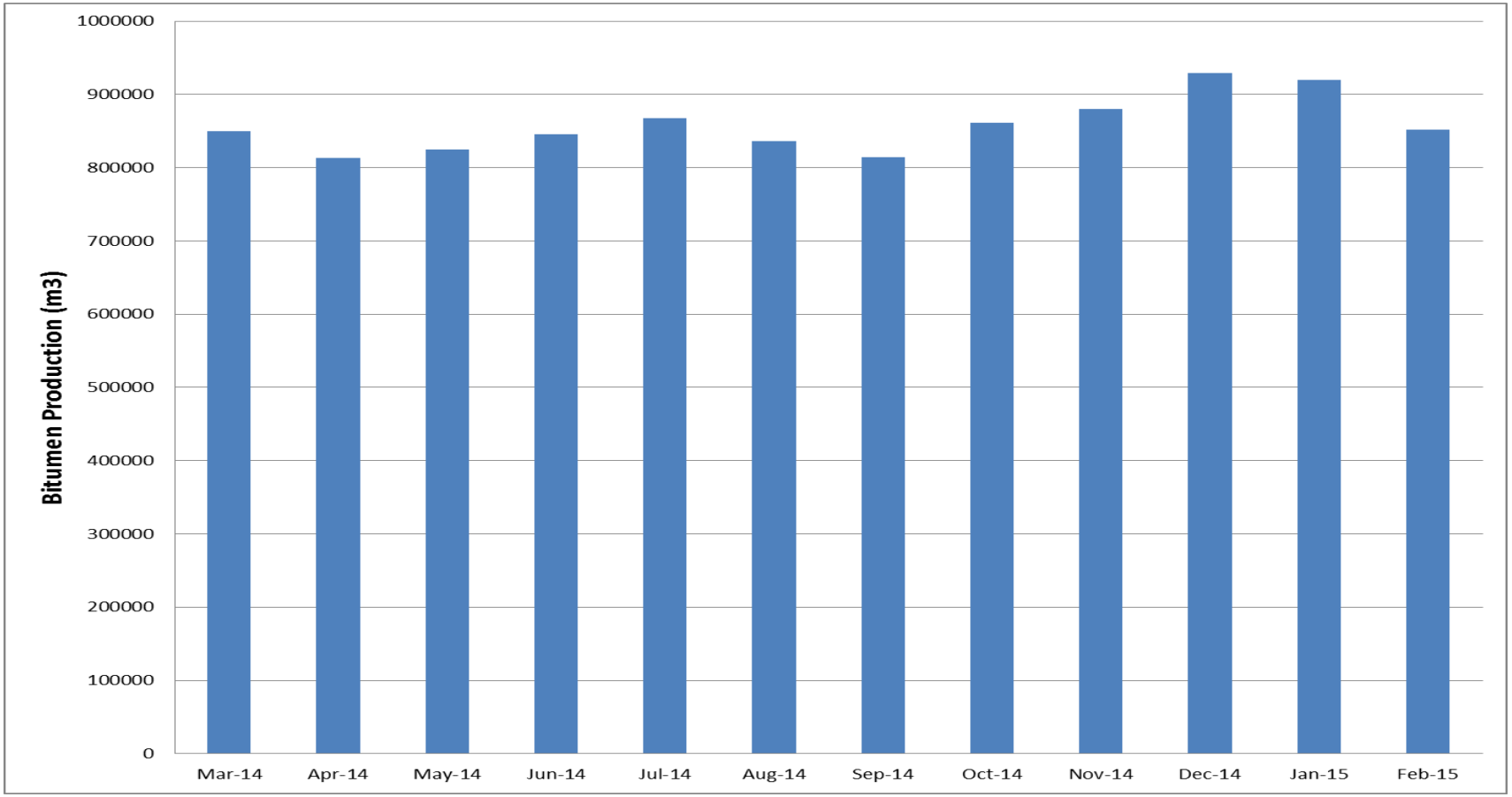
Firebag's average energy intensity was 7.6 GJ per m3 of production, from March 2014 to February 2015



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

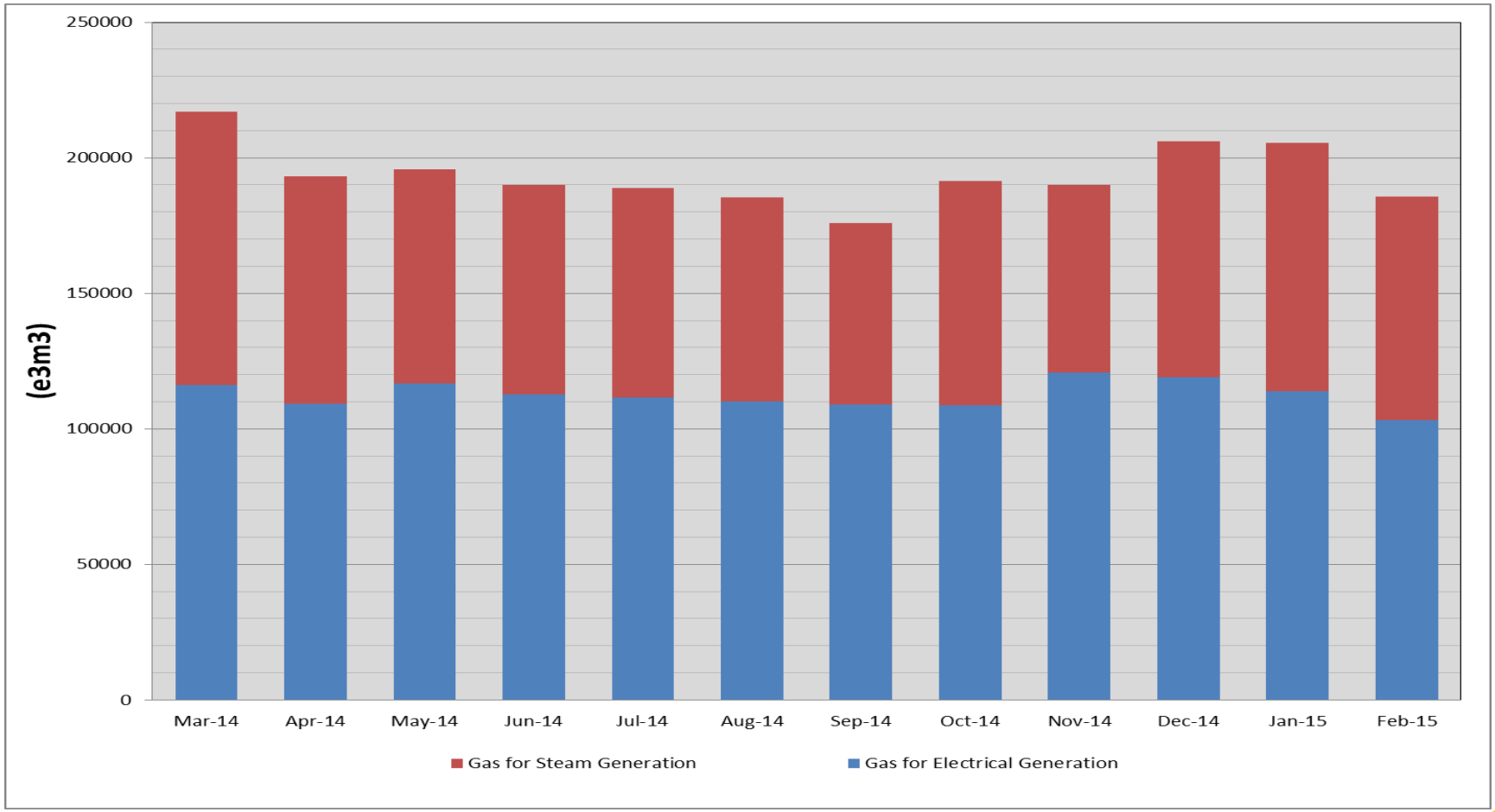
Monthly Bitumen Production

Firebag averaged 28,201 m3/day (177,398 BPD) of production from March 2014 to February 2015



Purchased Gas Usage

Firebag used on average 6,590 e3m3 of natural gas per day, from March 2014 to February 2015



Facility Environmental Performance

Emissions Parameter	Mar 2014 - Feb 2015
Solution Gas Produced (e^3m^3)	10,422.8
Solution Gas Flared (e^3m^3)	154.5
Solution Gas Vented[1] (e^3m^3)	0.49
Solution Gas Recovery	98.5%
Total Gas Flared (e^3m^3)	344.9
Total Gas Vented[3] (e^3m^3)	99.3
H_2S Emissions[2] (kg)	6084.2

[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 2014 – Dec 2014
2014 GHG Emissions (tonnes CO_2e) Calendar Year	4,903,185.2
2014 GHG Emission Intensity (tonnes CO_2e/m^3) Calendar Year	0.35

❖CO_2e is based on AENV SGER Reporting for the 2014 calendar year

Table of Contents

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

Measurement, Accounting and Reporting Plan (MARP)

- Firebag MARP approved June 2010
- Fifth MARP update submitted to the AER in February 2015
- MARP details all the requirements in Directive 42
- Firebag formed an Enhanced Production Audit Program (EPAP) and MARP team in January 2013
  - Team made up of representatives from each discipline who have tasks associated with MARP and EPAP
  - Team meets monthly to ensure tasks are being completed to remediate the deficiencies from the EPAP audit, and other measurement deficiencies identified through the monthly meetings

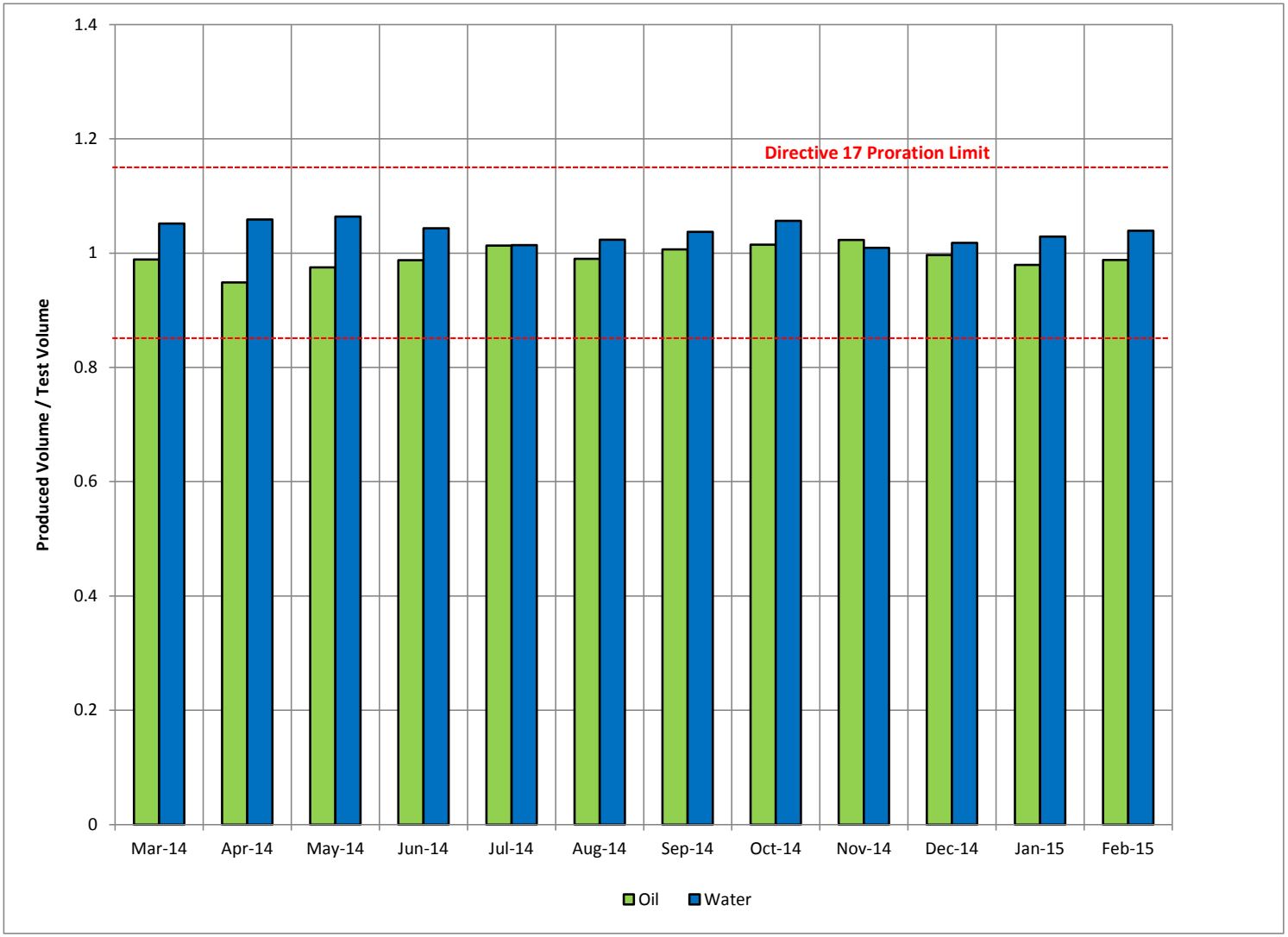
Estimating Well Production & Steam Injection Volumes

- 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

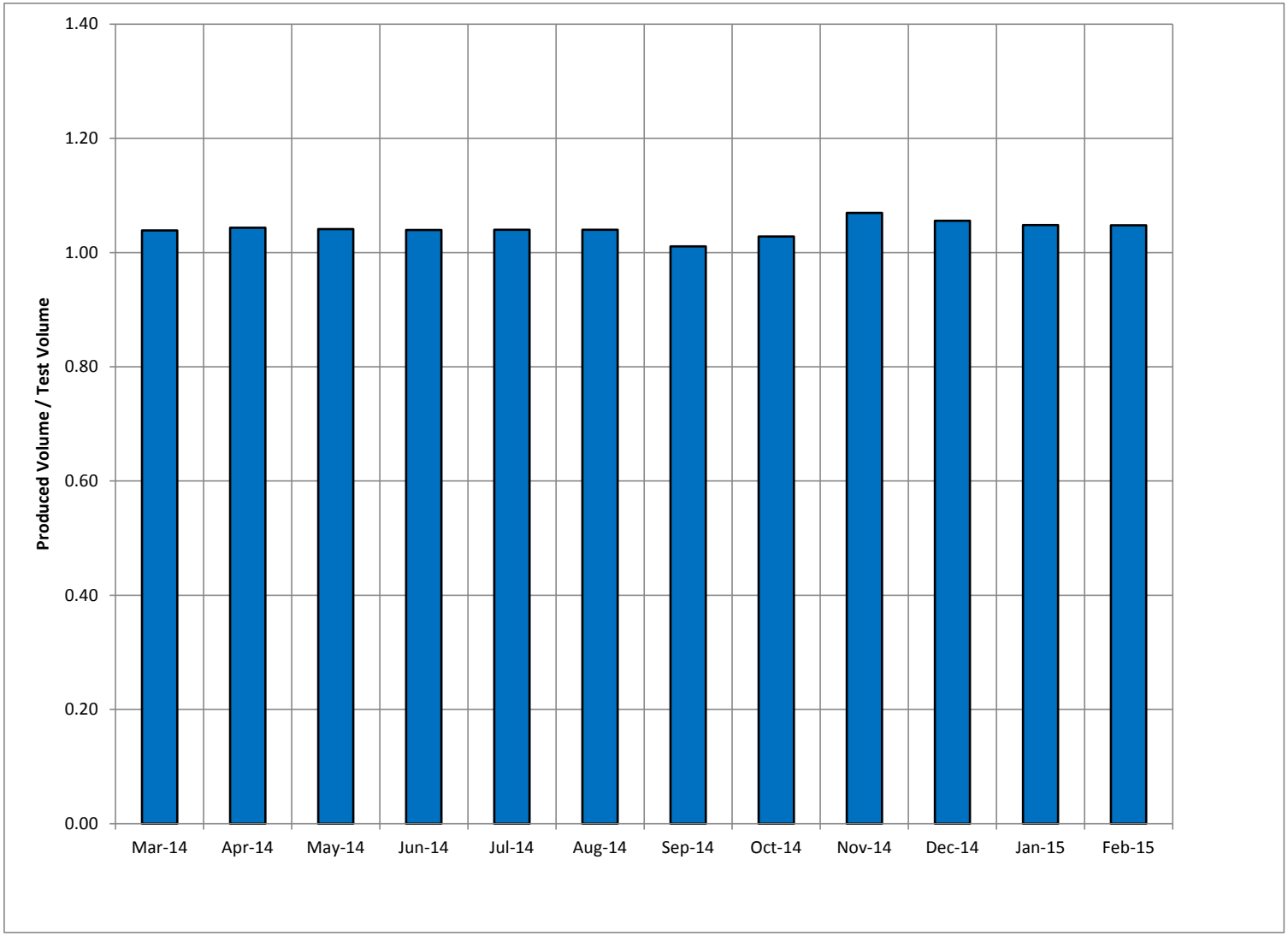
- Dec. 16, 2011 received approval for Multiphase Flow Meter (MPFM) on Pad 105 and future developments
- Fit for purpose Well Production Test software (WPT)
- MPFM now present on Pads 101 infills, 102 infills, 103 infills, 104 infills, 105, 106, 108 North, 115, 116

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

Water Sources

- Primary makeup water source for process operations is two wastewater streams from Oil Sands Base Plant:
  - Reverse Osmosis (RO) Water
    - The total volume of RO water used from March 2014 to February 2015 was 855,373 m^3 (2014 calendar year usage was 875,434 m^3)
  - Pond Effluent Water (PEW)
    - The total volume of PEW used from March 2014 to February 2015 was 126,084 m^3 (2014 calendar year usage was 133,690 m^3)

Pond Effluent Water (PEW) Water Quality

- Source of PEW (Tailings Water) is from Pond 7 at Oil Sands Base Plant

Parameters	Units	Average	Comments
Total Dissolved Solids	**mg/L**	2390	Suitable for processing in WLS, Skim Tanks, MBF and Utility Water.
Total Supsended Solids	**mg/L**	68.6	Suitable for process in WLS and Utility Water. Potential issues with pump mechanical seals.
pH	**mg/L**	8.3	
Chlorides	**mg/L**	504	Potential issues/pitting on stainless steel components.
HCO3 Alkalinity	**mg/L**	823	
Hardness (as CaCO3)	**mg/L**	131	Suitable for processing in WLS. Chemical dosing required for Utility Water systems.
Oil and Grease (O&G)	**mg/L**	32.1	O&G needs to be reduced for BFW, but low enough for Utility Water systems.
Total Organic Content (TOC)	**mg/L**	38.6	Similar/lower than existing process streams.
C6-C10 HC	**mg/L**	0.04	
Ammonia	**mg/L**	11.1	

Water Usage

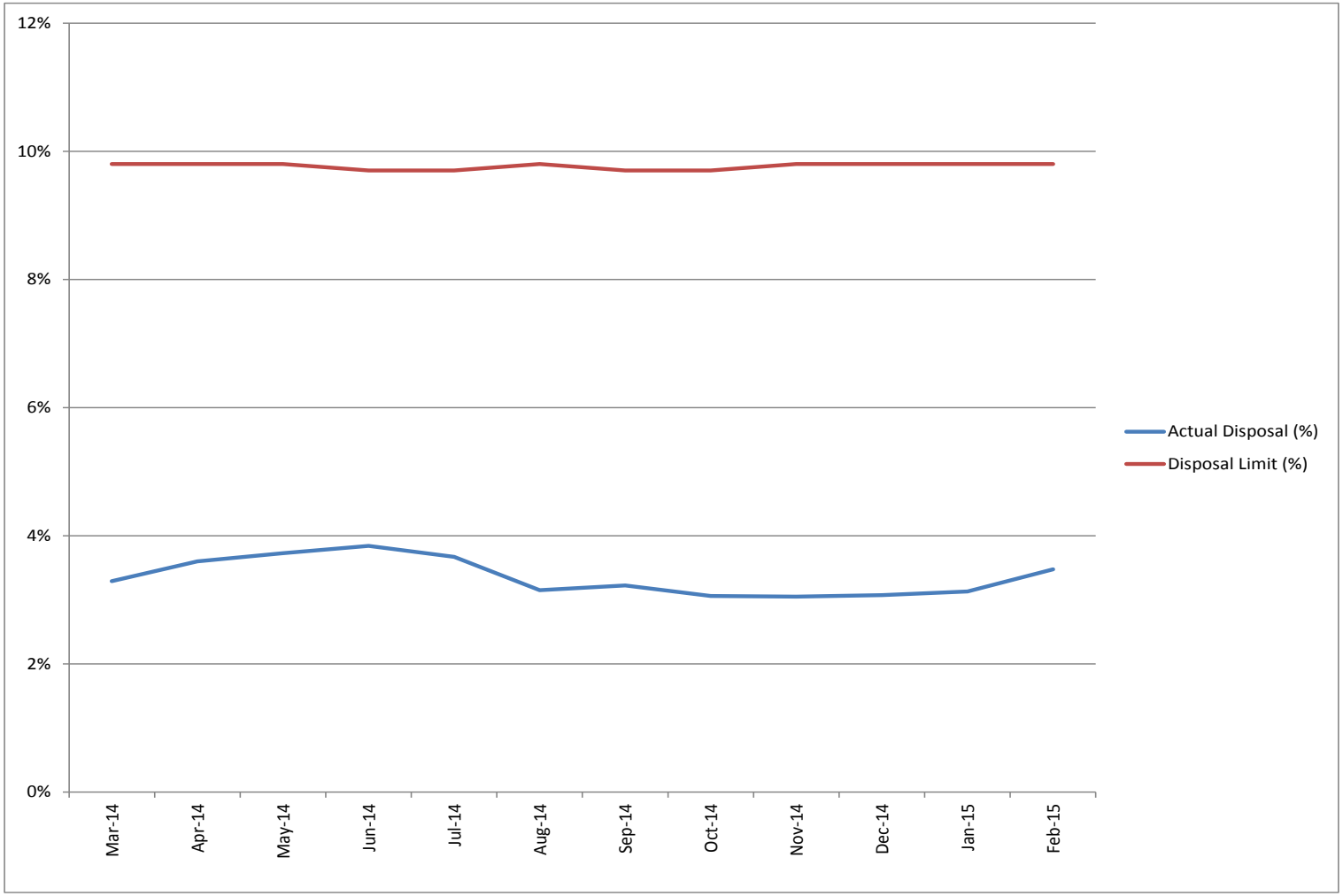
- Site runoff water (rainfall and snow melt) is routed to the site process ponds and reused in the process

- A total of 76,572 m^3 of storm water runoff water was diverted for process use from March 2014 to February 2015 (for the 2014 calendar year, usage was 75,983 m^3; 1,032 m^3 for the Stages 1/2 area and 74,951 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 as back-up supply for up to 620,500 m^3 annually. The well was not used in 2014 or 2015 year-to-date

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. 9487F (March 27, 2013)

Water Balance For Firebag Injection Facility

WATER BALANCE FOR FIREBAG INJECTION FACILITY															
	Fresh Water						Steam	Produced Water						Disposal	Imbalance
	FW1	FW2	FW3	FW4	FW5	FW6	INT	PW1	PW3	PW8	PW4	PW5	PW6	DIT	Injection
	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	Facility
Mar-14	95442.86	39458.51	39458.51	24171.91	21503.89	0.00	2456664.53	2599105.21	0.00	112884.30	140860.99	129756.97	0.00	82135.40	2.0%
Apr-14	88527.26	31623.14	31623.14	21503.89	24115.78	0.00	2255143.17	2465117.95	0.00	115785.80	129756.97	182247.31	0.00	84852.00	1.6%
May-14	90795.24	41577.00	41577.00	24115.78	23673.66	0.00	2365828.24	2489110.29	0.00	114237.40	182247.31	158522.00	0.00	88889.50	1.2%
Jun-14	101564.00	55638.57	55638.57	23673.66	24112.52	0.00	2319105.54	2504580.36	0.00	119224.90	158522.00	156429.18	0.00	91993.50	2.7%
Jul-14	119982.81	64529.23	64529.23	24112.52	23881.71	0.00	2367121.22	2494397.86	0.00	120392.80	156429.18	160812.91	0.00	87428.60	1.2%
Aug-14	81864.90	47098.08	47098.08	23881.71	21491.17	0.00	2287090.39	2471068.12	0.00	120270.90	160812.91	133124.56	0.00	97902.30	2.8%
Sep-14	101127.70	47120.82	47120.82	21491.17	22933.32	0.00	2133970.51	2405368.27	0.00	116496.80	133124.56	191677.09	0.00	100781.20	3.5%
Oct-14	95967.50	95967.50	95967.50	22933.32	23516.48	0.00	2267970.53	2540686.54	0.00	162391.60	191677.09	231195.66	0.00	72996.90	3.2%
Nov-14	75401.50	44844.93	44844.93	23516.48	23974.07	0.00	2325781.27	2472852.99	0.00	124314.80	231195.66	159563.45	0.00	71862.20	3.4%
Dec-14	69542.50	35401.30	35401.30	23974.07	23267.75	0.00	2508935.47	2638702.14	0.00	134586.40	159563.45	125809.50	0.00	75808.60	0.8%
Jan-15	73104.20	37139.55	37139.55	23267.75	24115.29	0.00	2408332.14	2630590.14	0.00	134128.00	125809.50	149652.32	0.00	78400.10	2.0%
Feb-15	64799.20	41080.07	41080.07	24115.29	24123.22	0.00	2204896.12	2456703.69	0.00	121304.80	149652.32	196767.21	0.00	81398.50	2.4%

Water Balance For Overall Firebag Facility

WATER BALANCE FOR OVERALL FIREBAG FACILITY															
	Fresh Water						Steam	Produced Water						Disposal	Imbalance
	FW1	FW2	FW3	FW4	FW5	FW6	INT	PW1	PW3	PW8	PW4	PW5	PW6	DIT	Scheme
	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	(m3)	
Mar-14	95866.66	0.00	0.00	24171.91	21503.89	0.00	2456664.53	2571647.25	0.00	75979.32	140860.99	129756.97	0.00	92006.30	2.0%
Apr-14	88874.66	0.00	0.00	21503.89	24115.78	0.00	2255143.17	2426253.85	0.00	69746.70	129756.97	182247.31	0.00	92374.40	1.6%
May-14	91201.24	0.00	0.00	24115.78	23673.66	0.00	2365828.24	2458121.87	0.00	73169.95	182247.31	158522.00	0.00	99374.50	1.3%
Jun-14	102007.80	0.00	0.00	23673.66	24112.52	0.00	2319105.54	2467120.83	0.00	71724.91	158522.00	156429.18	0.00	102477.70	2.8%
Jul-14	120392.91	0.00	0.00	24112.52	23881.71	0.00	2367121.22	2453388.95	0.00	70143.42	156429.18	160812.91	0.00	97079.20	1.3%
Aug-14	82151.10	0.00	0.00	23881.71	21491.17	0.00	2287090.39	2423575.47	0.00	70734.75	160812.91	133124.56	0.00	107232.00	2.6%
Sep-14	101469.70	0.00	0.00	21491.17	22933.32	0.00	2133970.51	2362514.93	0.00	65999.09	133124.56	191677.09	0.00	108767.50	3.6%
Oct-14	96259.90	0.00	0.00	22933.32	23516.48	0.00	2267970.53	2457100.78	0.00	70143.42	191677.09	231195.66	0.00	81951.70	3.4%
Nov-14	75828.10	0.00	0.00	23516.48	23974.07	0.00	2325781.27	2429369.77	0.00	71931.38	231195.66	159563.45	0.00	81189.00	3.5%
Dec-14	69963.80	0.00	0.00	23974.07	23267.75	0.00	2508935.47	2589795.05	0.00	77595.94	159563.45	125809.50	0.00	84313.40	0.8%
Jan-15	73534.20	0.00	0.00	23267.75	24115.29	0.00	2408332.14	2580142.62	0.00	74484.50	125809.50	149652.32	0.00	88026.10	2.1%
Feb-15	65185.90	0.00	0.00	24115.29	24123.22	0.00	2204896.12	2410935.22	0.00	68192.66	149652.32	196767.21	0.00	89164.80	2.5%

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 (°C)
March-2014	1,367	1111	4423	49
April-2014	766	1026	4840	44
May-2014	801	1267	5045	44
June-2014	819	1311	5047	49
July-2014	807	1231	4997	52
August-2014	671	705	4557	51
September-2014	660	758	4548	54
October-2014	638	631	4476	50
November-2014	613	598	4463	47
December-2014	612	510	4334	52
January-2015	624	629	4303	51
February-2015	699	1047	4692	52

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 (°C)
March-2014	860	867	4,607	49
April-2014	565	895	4,812	43
May-2014	535	1,082	4,997	43
June-2014	581	1,137	5,015	49
July-2014	553	1,070	4,972	52
August-2014	473	592	4,543	50
September-2014	476	603	4,544	53
October-2014	459	547	4,499	49
November-2014	393	492	4,474	47
December-2014	370	381	4,359	52
January-2015	438	450	4,360	50
February-2015	482	871	4,752	51

Waste Management – Disposal

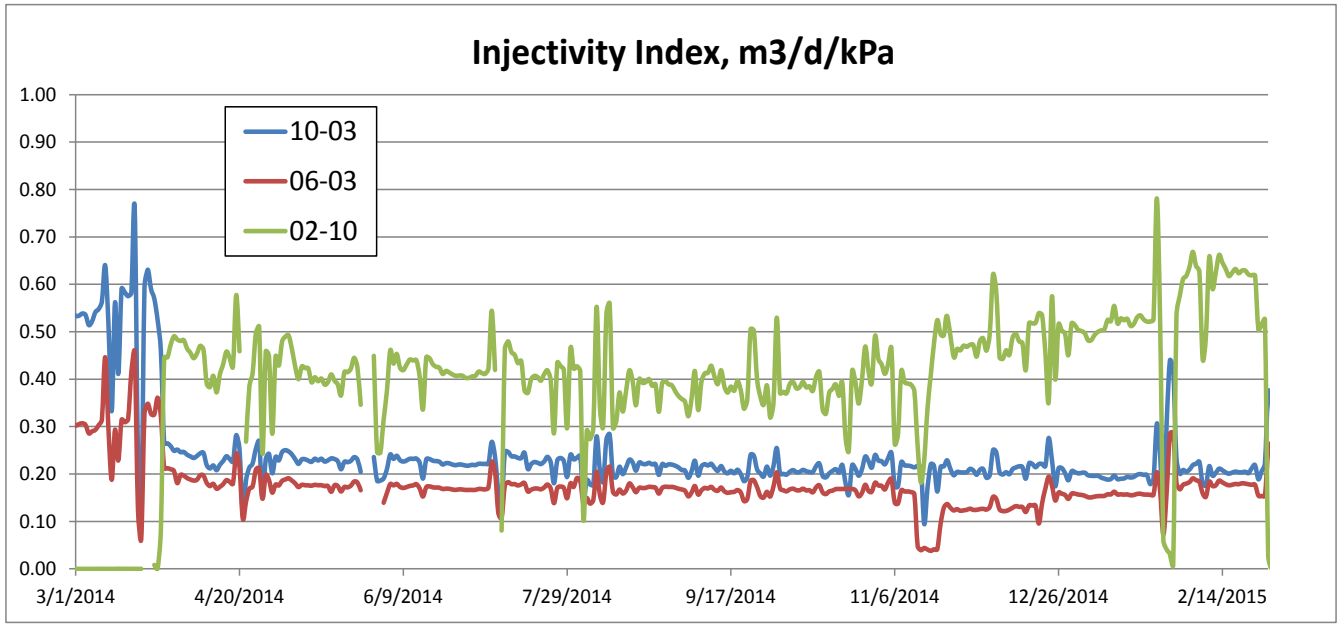
Disposal Information – 100/02-10-095-06W4

(data shown is averaged across the month)

Month	Injection Rate (Sm3/day)	Wellhead Pressure (kPa-g)	Downhole Pressure (kPa-g)	Injection Temperature (°C)
March-2014	423	419	4723	49
April-2014	1498	1076	5174	44
May-2014	1532	1318	5046	44
June-2014	1666	1358	4881	49
July-2014	1461	1273	5378	52
August-2014	1247	749	4926	51
September-2014	1331	791	4929	54
October-2014	1258	660	4860	50
November-2014	1389	651	4845	47
December-2014	1507	517	4708	52
January-2015	1467	531	4692	51
February-2015	1726	960	5083	52

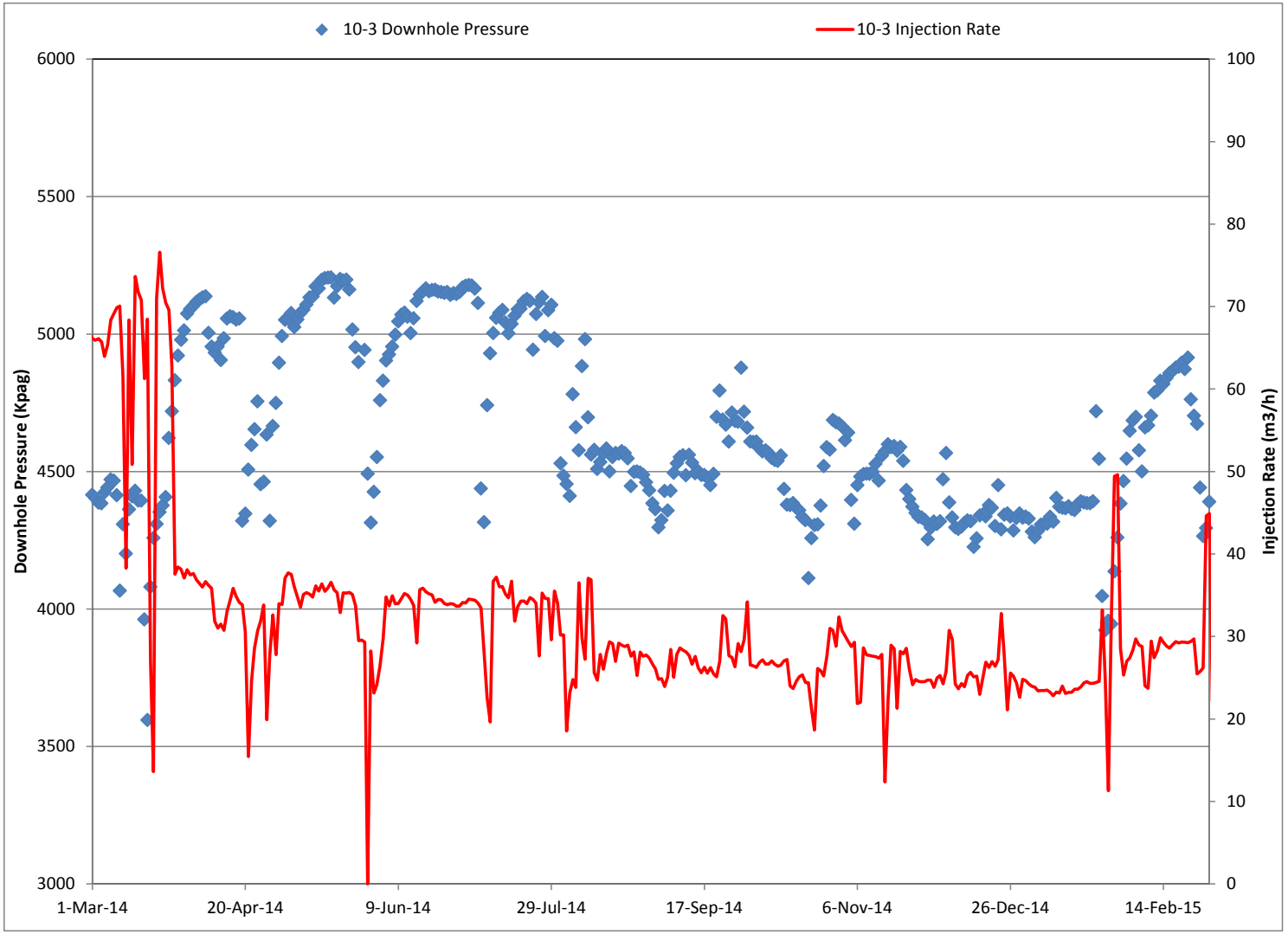
Waste Management – Disposal

- Downhole pressure and performance at 6-03 & 10-03 locations impacted by 2-10 start-up due to high permeability within trough
- The three disposal wells share a common surface pipeline, and the surface injection pressure at each location tends to follow a similar trend based on operating pressure
- Calculating injectivity index for each well, it is shown that 2-10 has a significant impact on the other two disposal wells – but otherwise the injectivity indexes at 10-3 and 6-03 are relatively consistent over the reporting period.



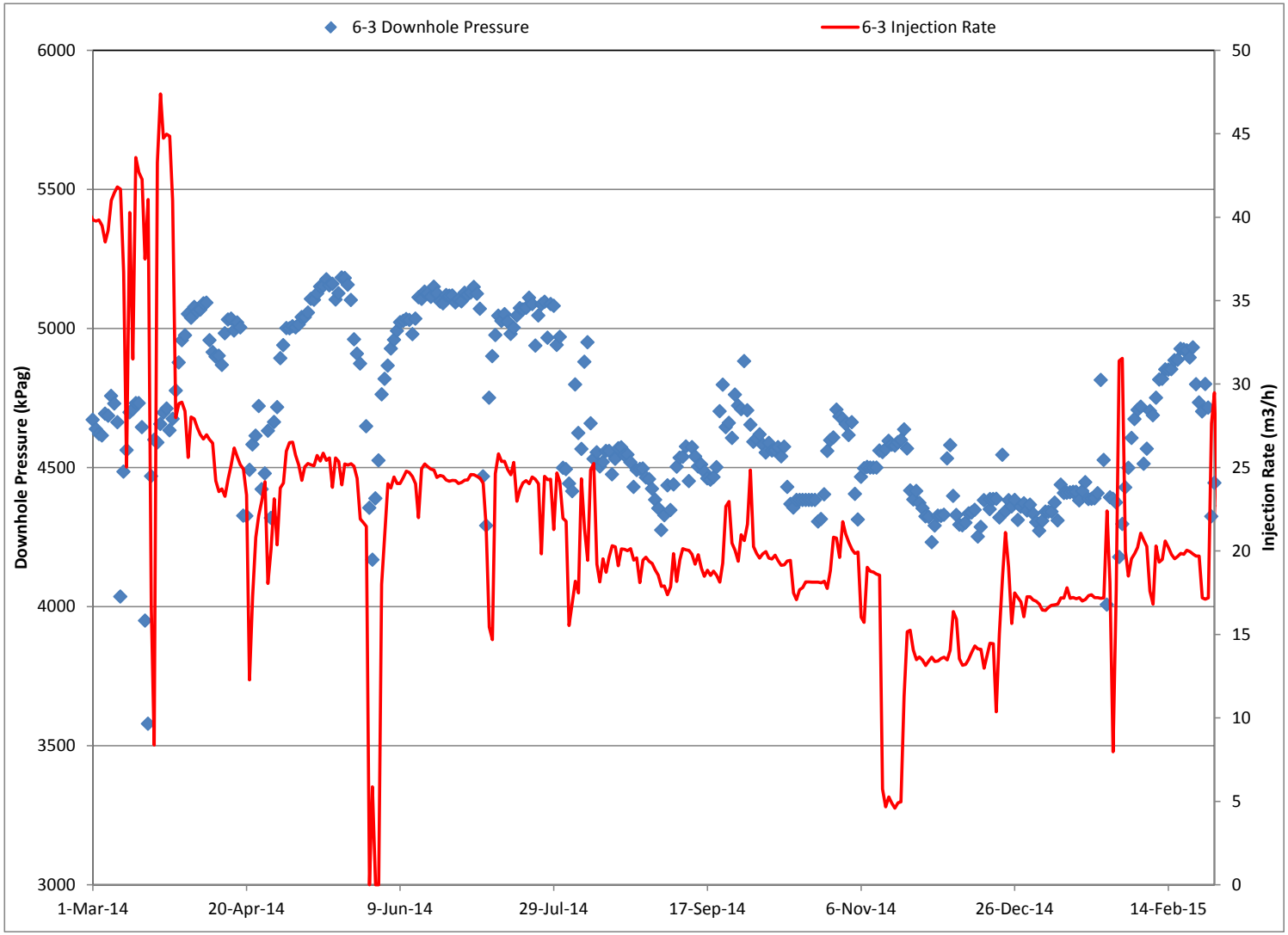
Waste Management – Disposal

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



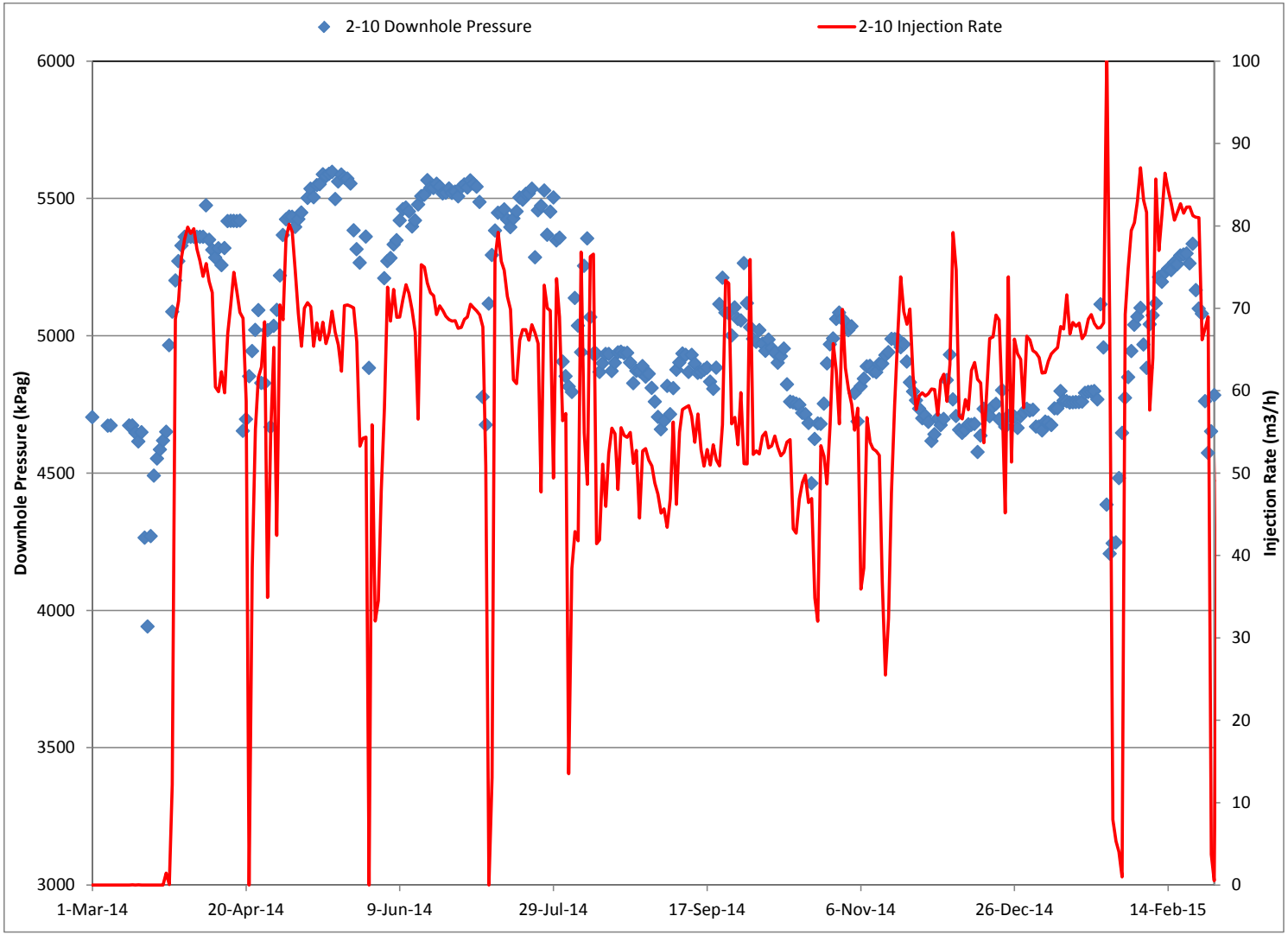
Waste Management – Disposal

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



Waste Management – Disposal

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

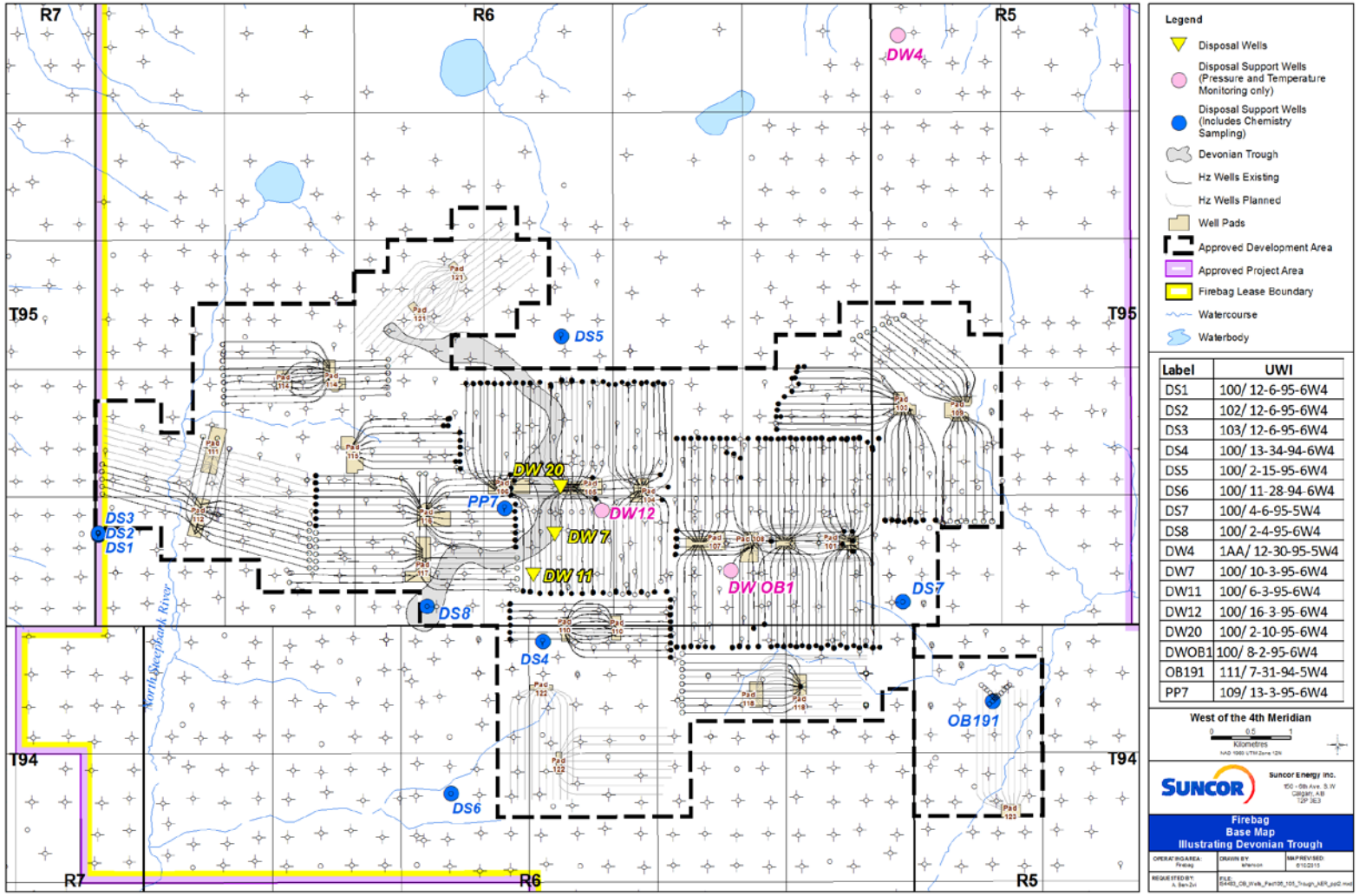


Waste Management – Disposal

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)*

Water Disposal and Monitoring Locations



Label	UWI
DS1	100/ 12-6-95-6W4
DS2	102/ 12-6-95-6W4
DS3	103/ 12-6-95-6W4
DS4	100/ 13-34-94-6W4
DS5	100/ 2-15-95-6W4
DS6	100/ 11-28-94-6W4
DS7	100/ 4-6-95-5W4
DS8	100/ 2-4-95-6W4
DW4	1AA/ 12-30-95-5W4
DW7	100/ 10-3-95-6W4
DW11	100/ 6-3-95-6W4
DW12	100/ 16-3-95-6W4
DW20	100/ 2-10-95-6W4
DWOB1	100/ 8-2-95-6W4
OB191	111/ 7-31-94-5W4
PP7	109/ 13-3-95-6W4

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Devonian Trough at Firebag

- The Devonian trough (informal name) is a structural sag resulting from collapse above an area of enhanced Prairie Formation anhydrite dissolution.
- Subsidence related to trough development affected all the supra-Keg River section up to and including the lower McMurray 2. This suggests collapse was complete before lower McMurray 3 deposition. Onset of collapse is more difficult to time.
- Located on the north and east sides of an Upper Keg River buildup that defines the west side of the Firebag basin.
- Suncor maps the trough extent through a combination of wells and 3D seismic data.
- Disposal and monitoring occur in wells both within and beyond the Devonian trough (see map on previous slide).
- A more comprehensive discussion on the Devonian trough is available in the Suncor Firebag 2012-2013 Annual Disposal Monitoring Report. Data obtained since submission of that report have not resulted in any change to Suncor's interpretation of the feature.

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Pressure Increase within the Slave Point Fm.

- A Slave Point pressure increase has been observed at DW12, underlying Pad 105, approximately 500 metres east of disposal wells.
- Suncor interprets this pressure increase as response to a combination of disposal activity and startup of nearby SAGD pads.
- Suncor does not view the Slave Point pressure increase at DW12 as being significant to ongoing SAGD or disposal operations, but will continue to monitor pressure and assess any impact.
- Supporting data and greater detail on the pressure increase are available in Suncor's SIR response to the 2014 Annual Deep Well Monitoring Report.

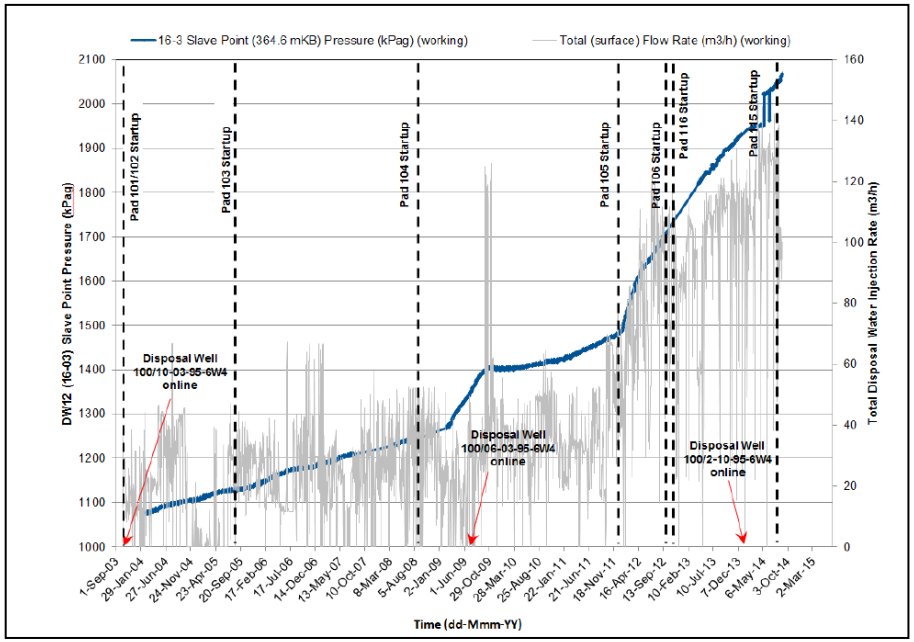

Figure 6, extracted from SIR response to the 2014 Annual Deep Well Monitoring Report

Waste Management – Disposal

- During the reporting period, the following was completed:
  - Drilled DS8 for testing and monitoring program
  - Completed, tested and sampled chemistry at DS7 and DS8
  - Re-sampled chemistry at DS1, DS2, DS3, DS4, DS5, DS6 and PP7
  - 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
  - Future drilling locations and testing programs will be based on learnings from the data acquired
- Numerical modeling, based on all data acquired to date, is ongoing

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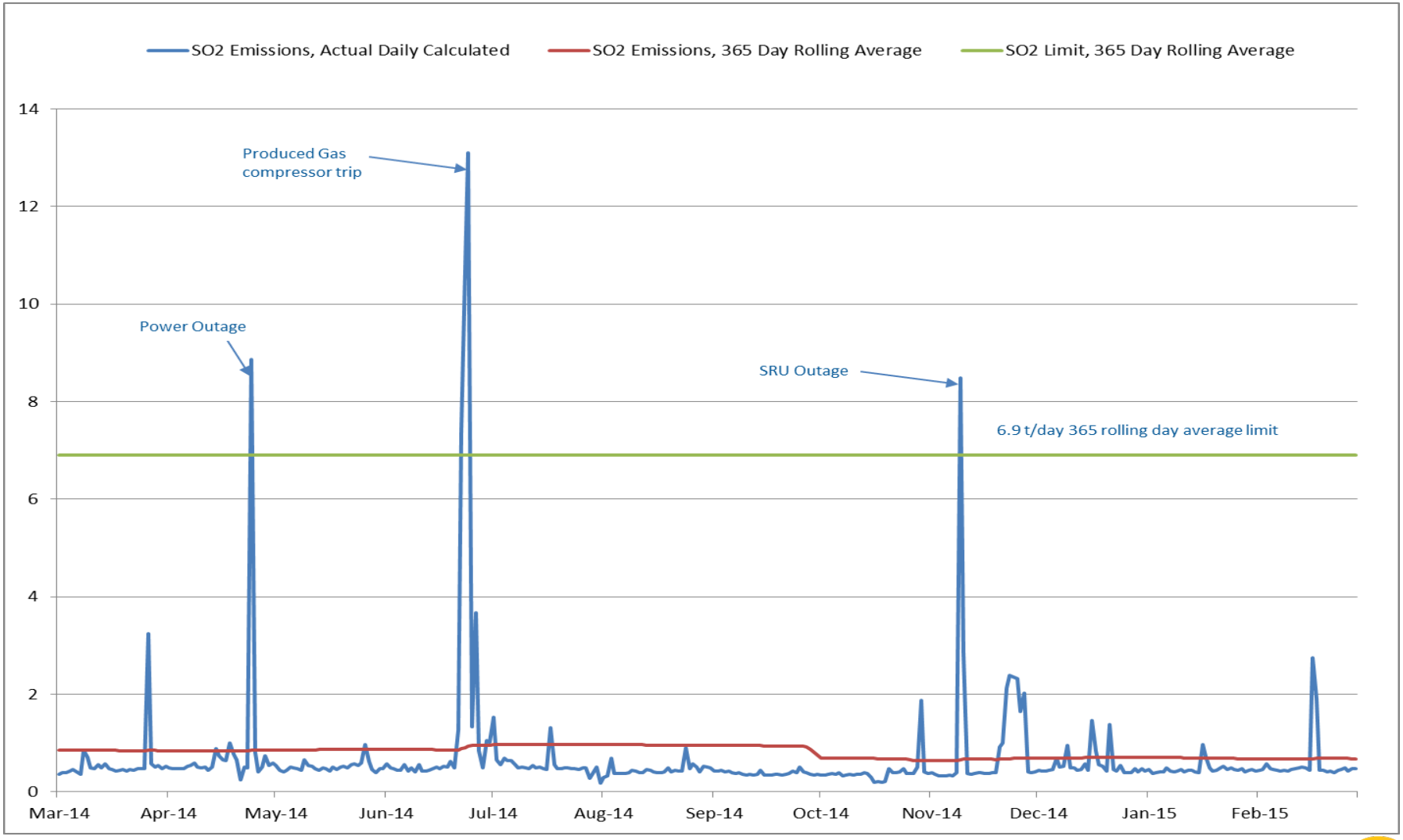
- Future Plans

Sulphur Recovery

	Average Inlet Sulphur (tonnes/day)	Sulphur recovery (%)	Sulphur Balance (%)	Acid Gas Flared (e3m3)	Sulphur Flared (tonnes)
Q2 2014	10.38	95.4	1.6	316.9	22.42
Q3 2014	9.92	97.7	1.3	6.92	1.57
Q4 2014	10.93	96.6	0.5	86.15	14.84
Q1 2015	11.78	97.9	0.6	4.47	2.16

- Regulatory requirement of > 95.9% sulphur recovery per calendar quarter for inlet rates > 10-50 tonnes/day
- Sulphur recovery rates in 2014 and 2015 year-to-date have consistently been above these requirements except for Q2 2014
- Sulphur Recovery rates in Q2 2014 were not within the limits due to the Produced Gas Compressor reliability and regional power interruption

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 = 0.68 tonnes/day
- SO_2 Total = 247.5 tonnes
- Average Inlet H_2S Concentration = 5.5%

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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 Occurences	Reference Number(s)	Date of Occurrence	Details of Occurrence	Suncor Actions
SRU Stack Top Exceedance	4	282089, 282029, 282557, 288530	March 26, 2014, March 27, 2014, April 9, 2014, August 19/20, 2014	Stack top temperature (STT) exceeded the limits as outlined in Section 3 (Table 3.1) of the EPEA approval four times during this reporting period.	Suncor has implemented corrective actions reflective of each of the root causes. Electrical/instrumentation personnel have assisted with the repairs of each the pressure transmitter failures which have been idenfitied as a root causes in the majority of the STT exceedances.
NOx CEMS Exceedance	5	283182, 287672, 290454, 291536, 294903	April 25, 2014, August 2, 2014, October 7, 2014, November 3, 2014, February 13, 2015	There were five events where Nox limits were exceeded on the cogeneration units (194-5000, 193-5000 (two), Plant 91, 191-5000).	Suncor continues to address each of the Nox exceedance events on a case by case basis and implement corrective actions accordingly. If required, a vendor is engaged to provide expert advise and guidance on actions moving forward.
SO2 Exceedance	1	285085	May 26, 2014	There was one event where SO2 exceeded the EPEA approval limits (133 kg/h) for a one hour average due to a pressure build up in the group seperators on four pads. This excess pressure resulted in flaring from the SRU during the initial influx of increased flow.	Suncor currently has several action items under development related to the SRU operation and performance. For this particular incident, the additional flow was due to a portable air compressor failure on Pad 104. The air compressor was replaced and no further issues have been identified.
Disposal/Retention Pond Breach	2	283975, 296229	March 21, 2014 and March 22, 2015	There were two events where the disposal and retention pond liners were compromised as determined by leak detection sump monitoring.	Suncor continues to provide updates to the AER for the retention pond liner. A plan is currently under development based on the results of the most recent liner leak survey (March 2015).
Industrial Runoff Release	4	283028, 283129, 295914, 296456	April 21, 2014, April 23, 2014, March 14, 2015 and March 28, 2015	Suncor had four events of uncontrolled releases of surface water to the environment. All four incidents were tested and met pump-off parameter requirements for pH, chlorides and O&G.	Suncor continues to work on addressing weak point within the berm and ditching systems onsite. Suncor roads and grounds personnel continue to monitor the berm systems on a regular basis with specific attention during spring runoff and high rainfall events. Projects for improvement of the ditching systems continue to be assessed with particular attention to the key areas for concern.
Low Risk Non Compliance - late reporting	1	20150393	February 18, 2015	Late reporting of an uncontrolled release of Disposal Water Treatment (DWT) Filtrate at the Suncor Firebag facility and subsequent notification of low risk noncompliance.	Suncor will review and update the reporting procedure to ensure they reflect the latest requirements of the AER. Suncor will then review this procedure with the 8 remaining/new plant shift supervisors to ensure they understand the importance of following the Suncor reporting requirements that have been established by AER.

Regulatory – AER Compliance Items

	Number of Occurences	Reference Number(s)	Date of Occurrence	Details of Occurrence	Suncor Actions
Monthly Well Testing	3	VSD	September 30, 2014, February 28, 2015 and February 28, 2015	The VX meter on 116WP9 was down for repair and as a result Suncor was unable to meet the requirement for the production well to have one valid testing hour for every 20 hours the well is in operation. The installed insulation around the VXTM meter was different than what was designed and installed on other VXTM meters used at the Firebag site causing the VXTM meter on Pad 115 to overheat. Large flucuations between the production rates on the Pad 108 production wells caused issues with the test separator at Pad 108. As a result, 5 of the 6 well tests were invalid.	Suncor will continue tracking the test hours when the VX is taken down for maintenance. This tracking of hours will lead to potential issues being flagged early enough to allow for work to be done to obtain required testing hours. Once with insulation was removed the meter functioned properly. Redesigned insulation has been ordered and work progresses to install the updated insulation. Suncor Production, Process and Reliabliity Engineering groups are working together to determine the root cause of these testing issues. Sunor continues trialling tests of running the test separator at different pressures and other means to reduce multiphase flow on this well to obtain valid tests.
Venting	75	DDS System, 281896, 283552		There have been 75 venting incidents reported to the AER during the reporting period using the DDS system as well as perfomrance issues challenges with the Plant 91 and 92 Produced Water Tank scrubber systems, including two fires on March 23, 2014 and May 4, 2014 resulting in the implemetation of a new temporary scrubber system.	Suncor continues to work on reducing the number and duration of venting incidents. The approved plan to connect the Produced Water Tanks in the Plant 91 and 92 to the VRU will address oustanding performance challenges and is under construction with an expected completion date in June 2015.
Sulphur Recovery Not Met	1	VSD	30-Jun-14	Suncor Firebag is required to recover 95.9% of the inlet Sulphur produced based on a 10 tonnes/ day inlet volume. Calculations for Q2, 2014 show Firebag recovered 95.4% Sulphur Recover with an average inlet Sulphur rate of 10.3 tonnes/day. Two root causes were identified - disconnection from Millenium Substation in April 2014 and malfunctioning of the produced gas compressors in the SRU - June 2014.	Suncor continues to work through the action plan provided in the VSD.
Firebag Pipeline Licensing Compliance Project		Multiple Pipeline License VSDs	Submitted over the course of 2014 and early 2015 Suncor	On its own initiative, Suncor conducted a detailed review of its historical AER licensing details for above-ground pipelines at Firebag. The review identified licensning discrepencies and non-compliances reuslting in multiple VSD submissions to the AER Authorizations group. VSDs included unlicensed surface lines, not constructed surface lines, discontinuations, MOP changes, and various administrative corrections (i.e. location, FC corrections, lengths, mapping corrections, and audit documentation).	To date all identified compliance matters have been disclosed and VSD amendment approvals received from the AER. A final issue was raised with the AER, but Suncor is awaiting gas analysis results to routinely lower its current licensed H2S for a produced gas pipeline and facility license at Pad 104 prior to submitting a final application. As identifed in the various VSDs, to address the causes of the non-compliances Suncor has established a records managment system that will better capture all required records and ensure more thorough review by Suncor's regulatory approval group during handover.

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

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Future Plans

- 91/92/Pads 101 & 102 Turnaround May 2015
- 93/94 and Pads Turnaround ~ September 2016
- Installation of additional Produced Water Coolers on 93/94
- Water Treatment pilot facility ~ 2017

Key growth and sustaining project timelines

- Additional 93/94 PWC target Q3 2015
- Pad 110 (15 Wells) Q1 2015
- Pad 109 (15 Wells) Q4 2015
- Pad 104S Infills (6P) Q3 2015
- Pad 117 (14 Wells) 2016
- FB debottleneck project 21KBPD expansion target Q2 2021

Appendix A
2015 Appendix to AER Subsurface Section

May 7, 2015
Reporting Period: March 1, 2014 to February 28, 2015

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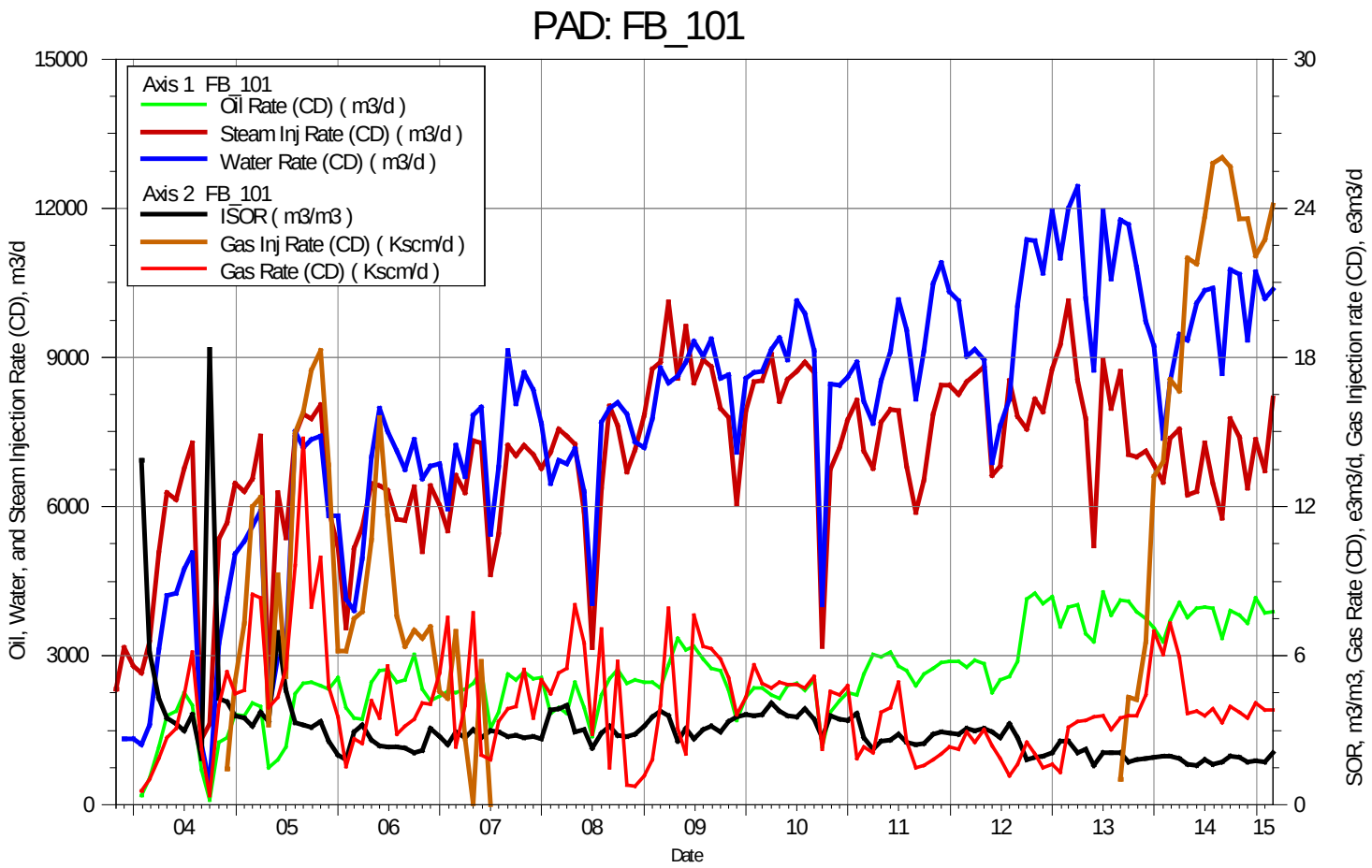
Pad Produced & Injected Fluids Plots



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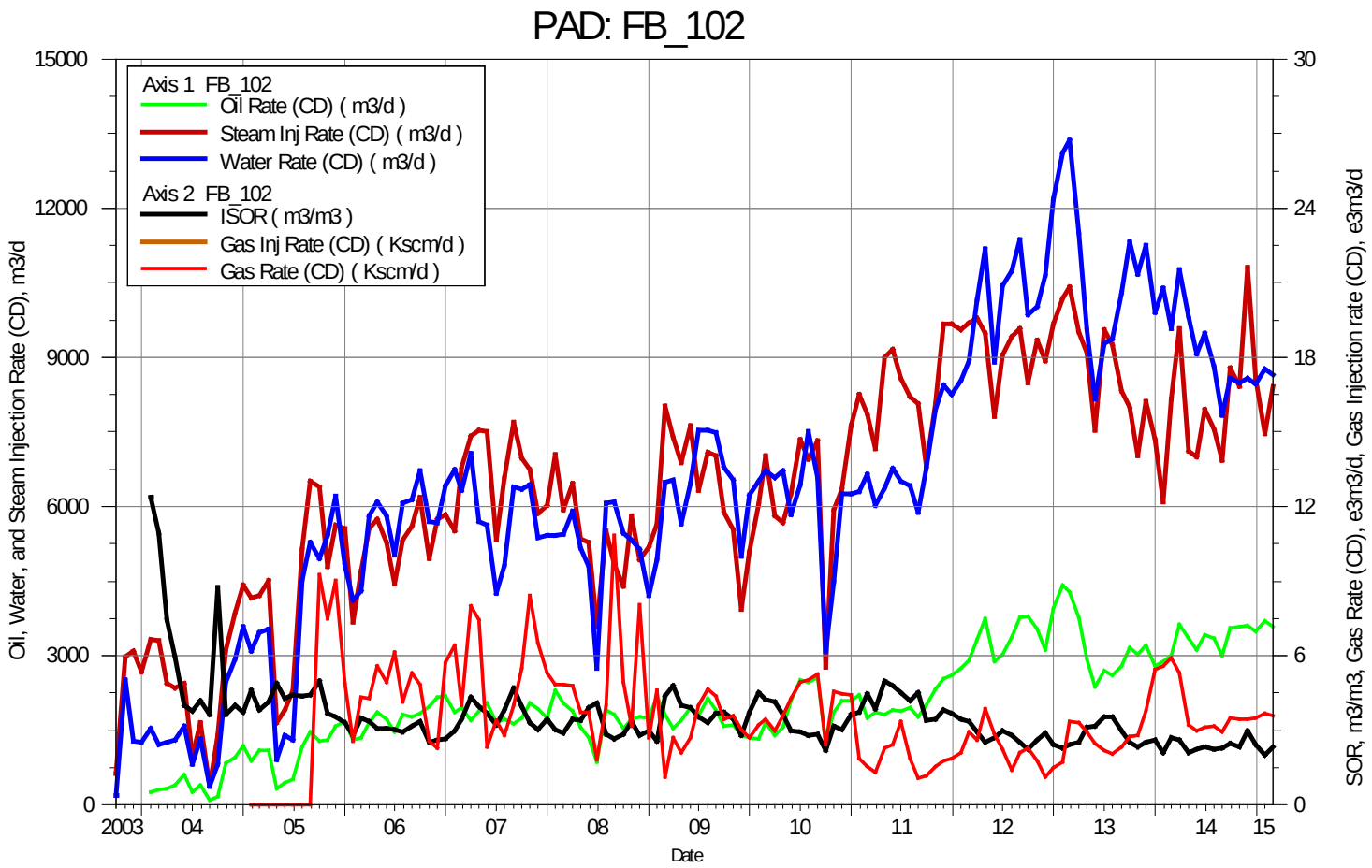

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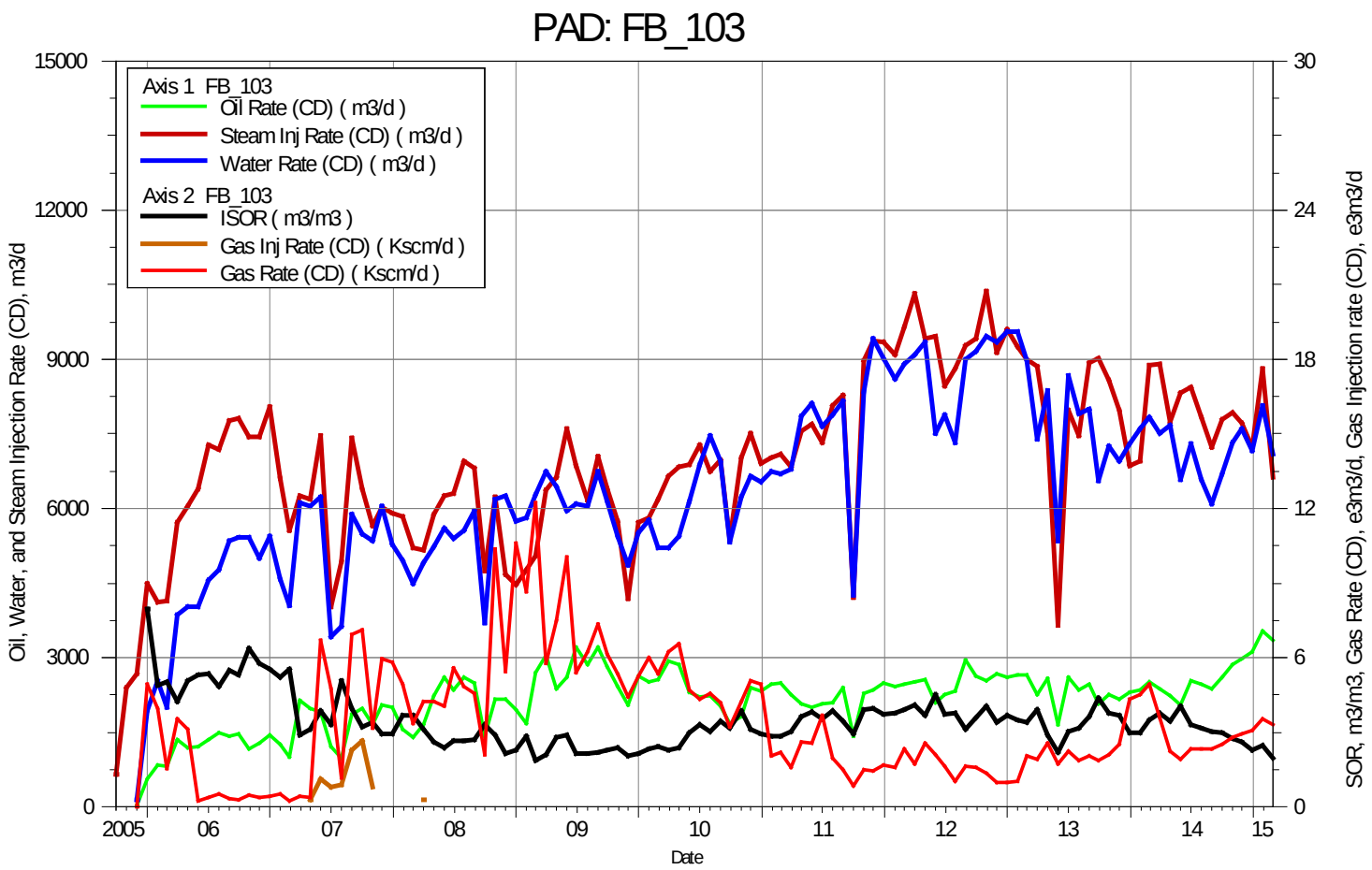

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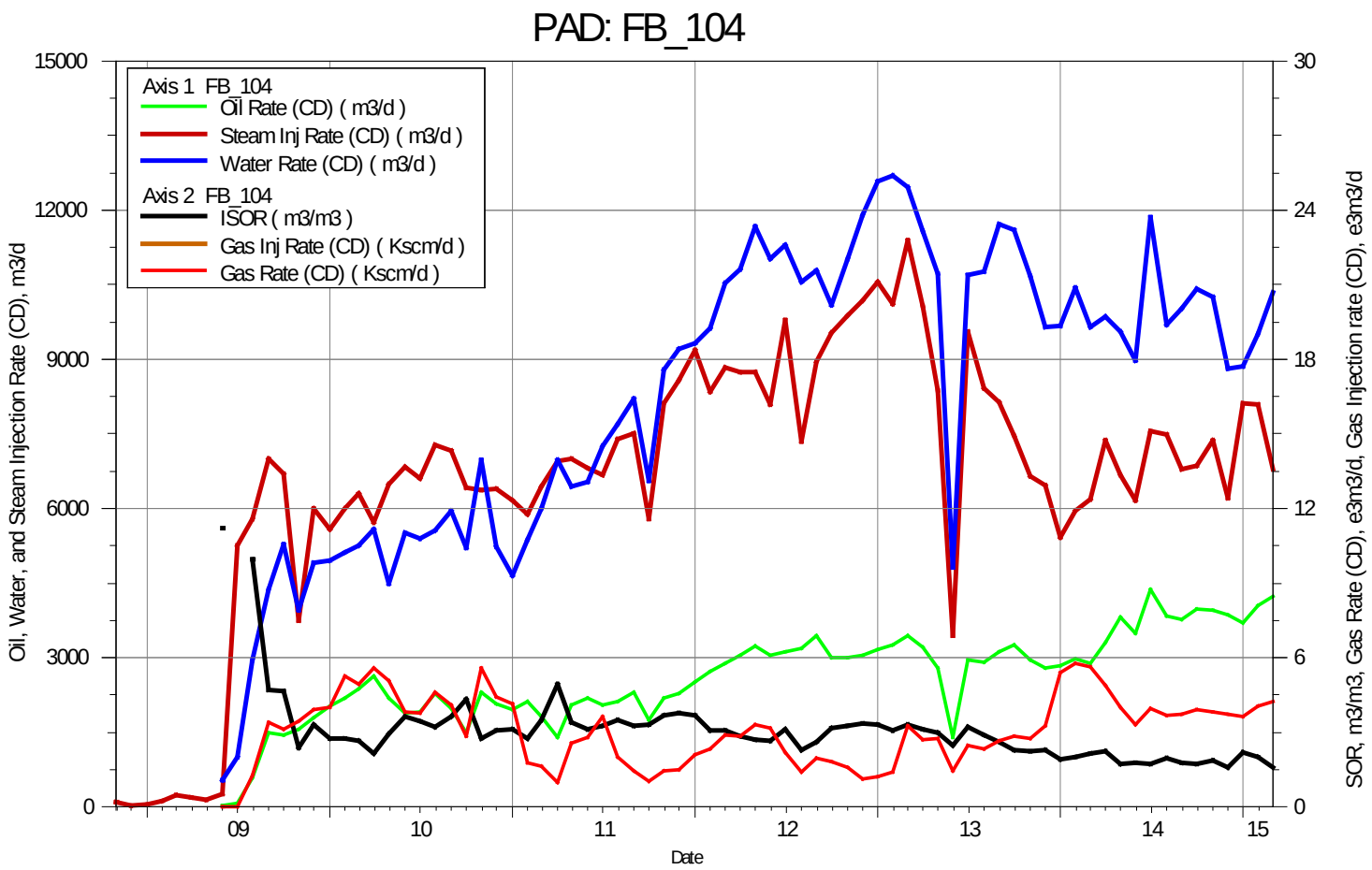

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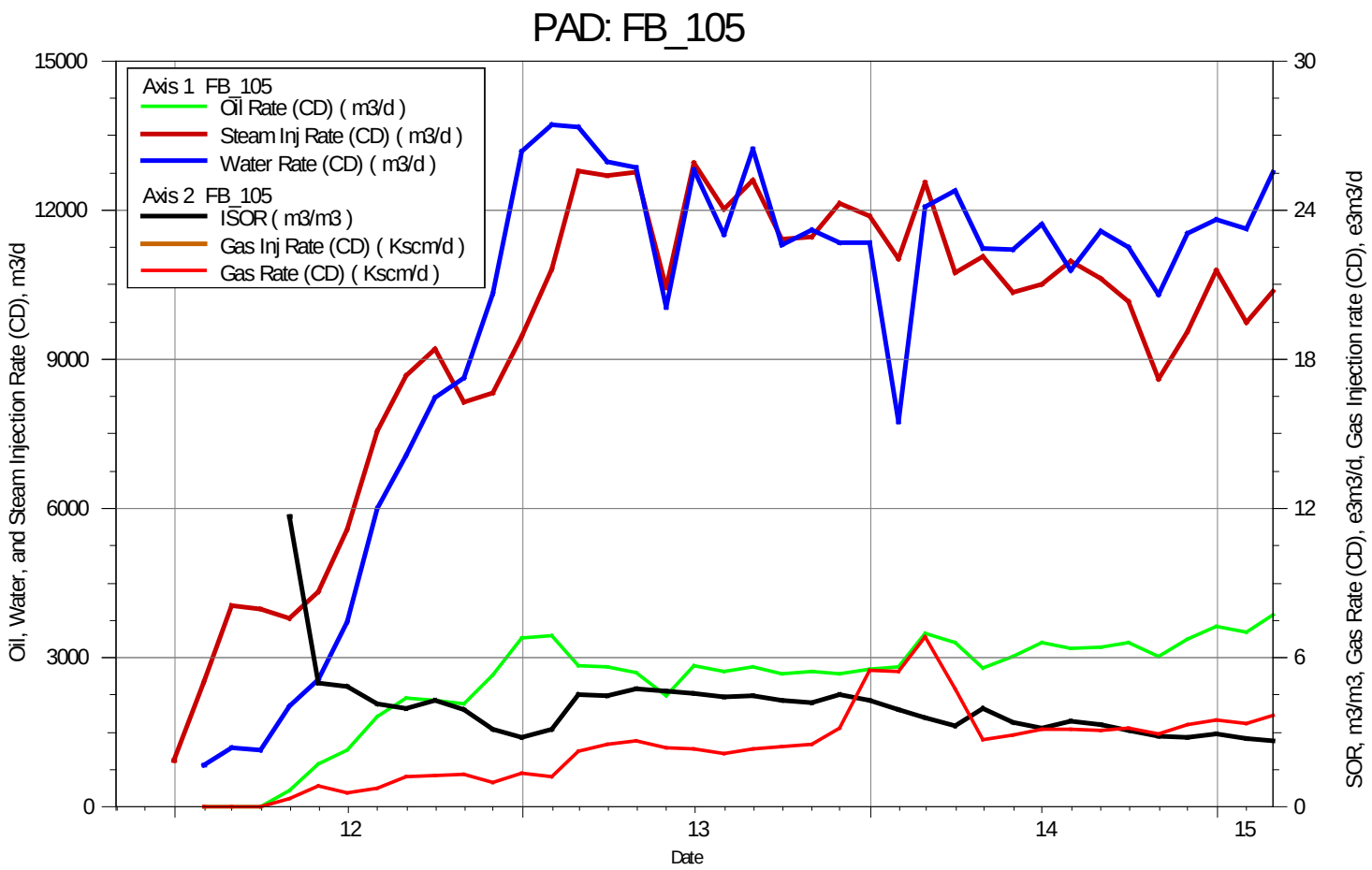

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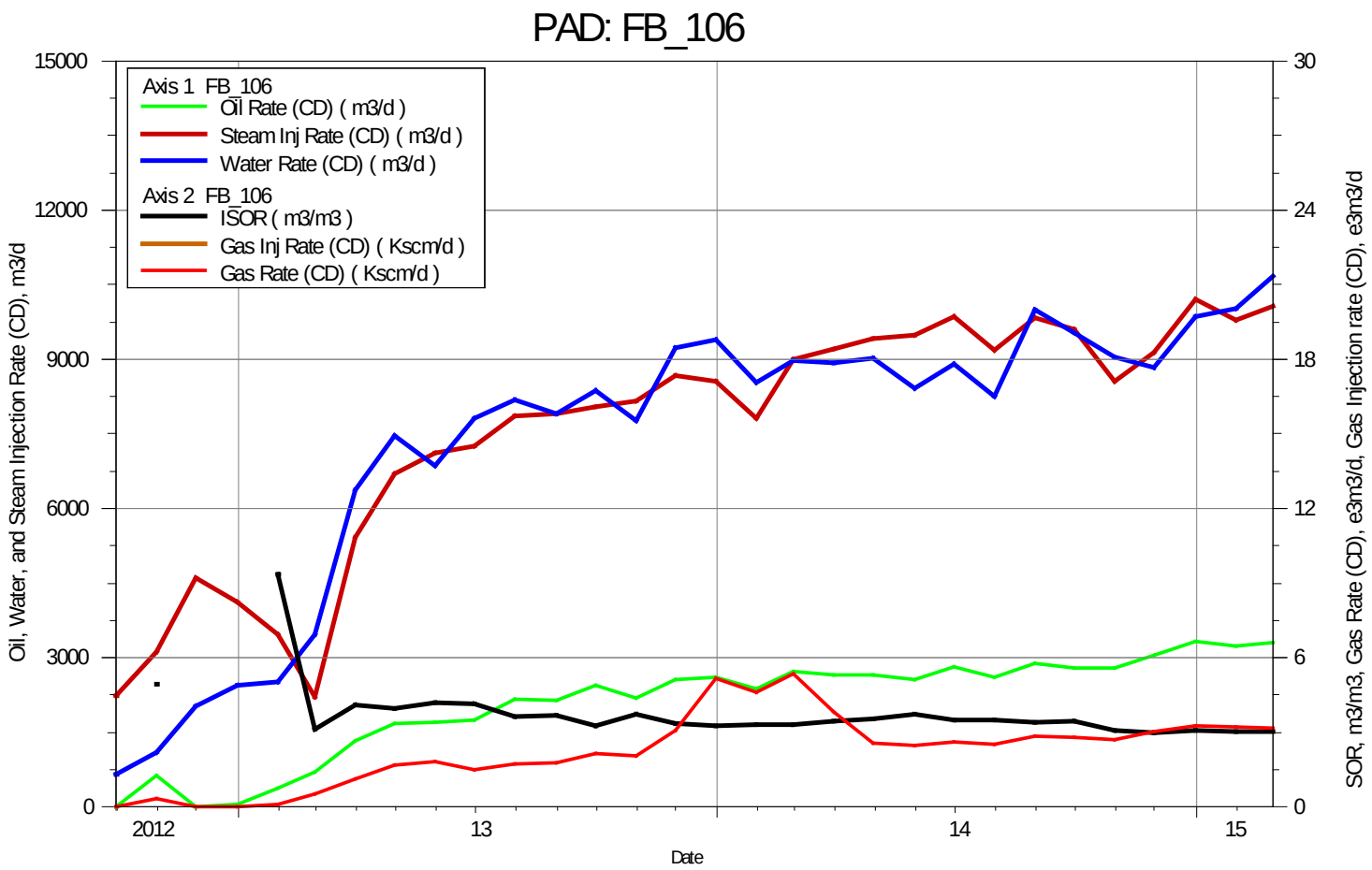

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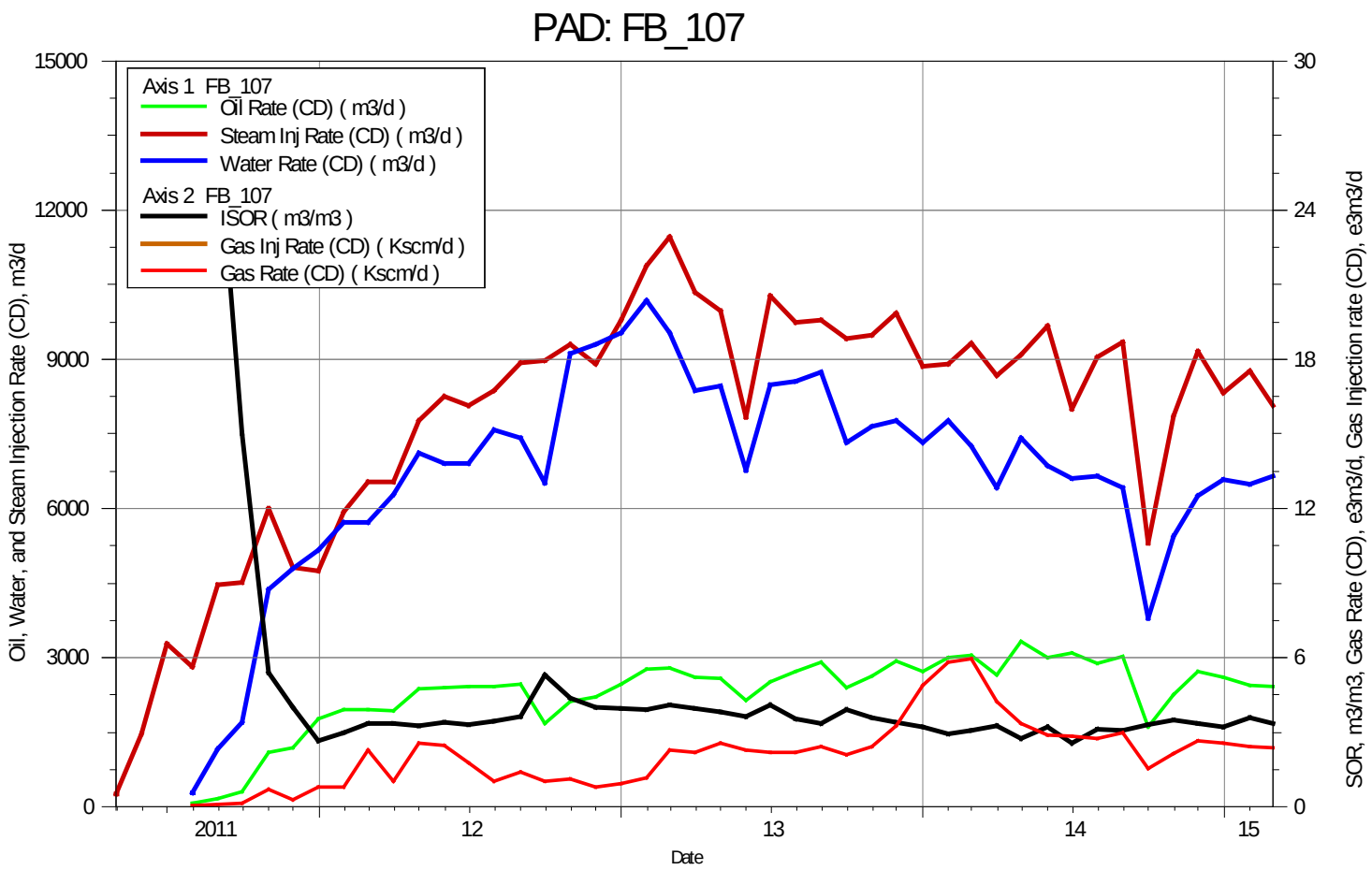

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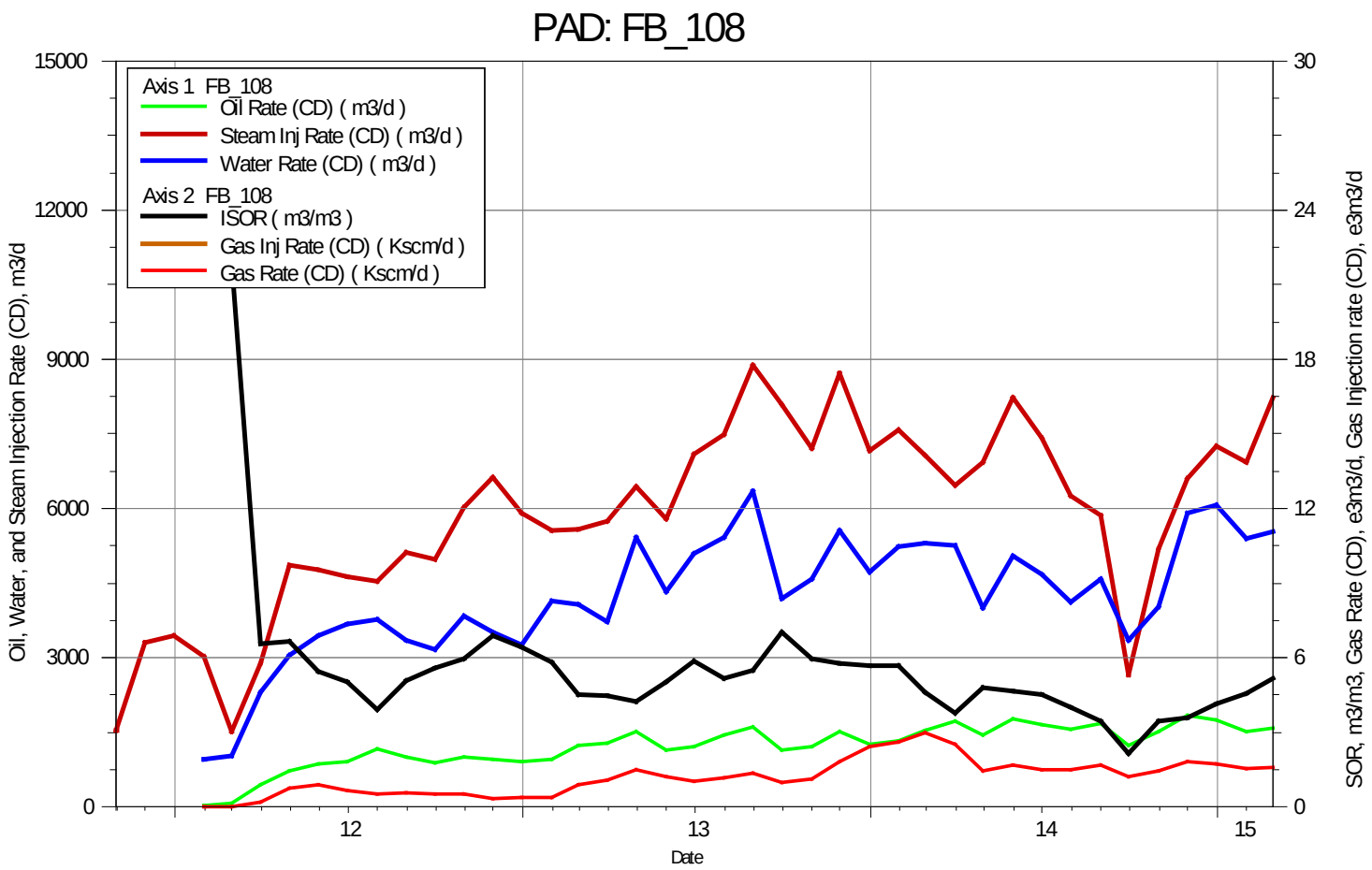

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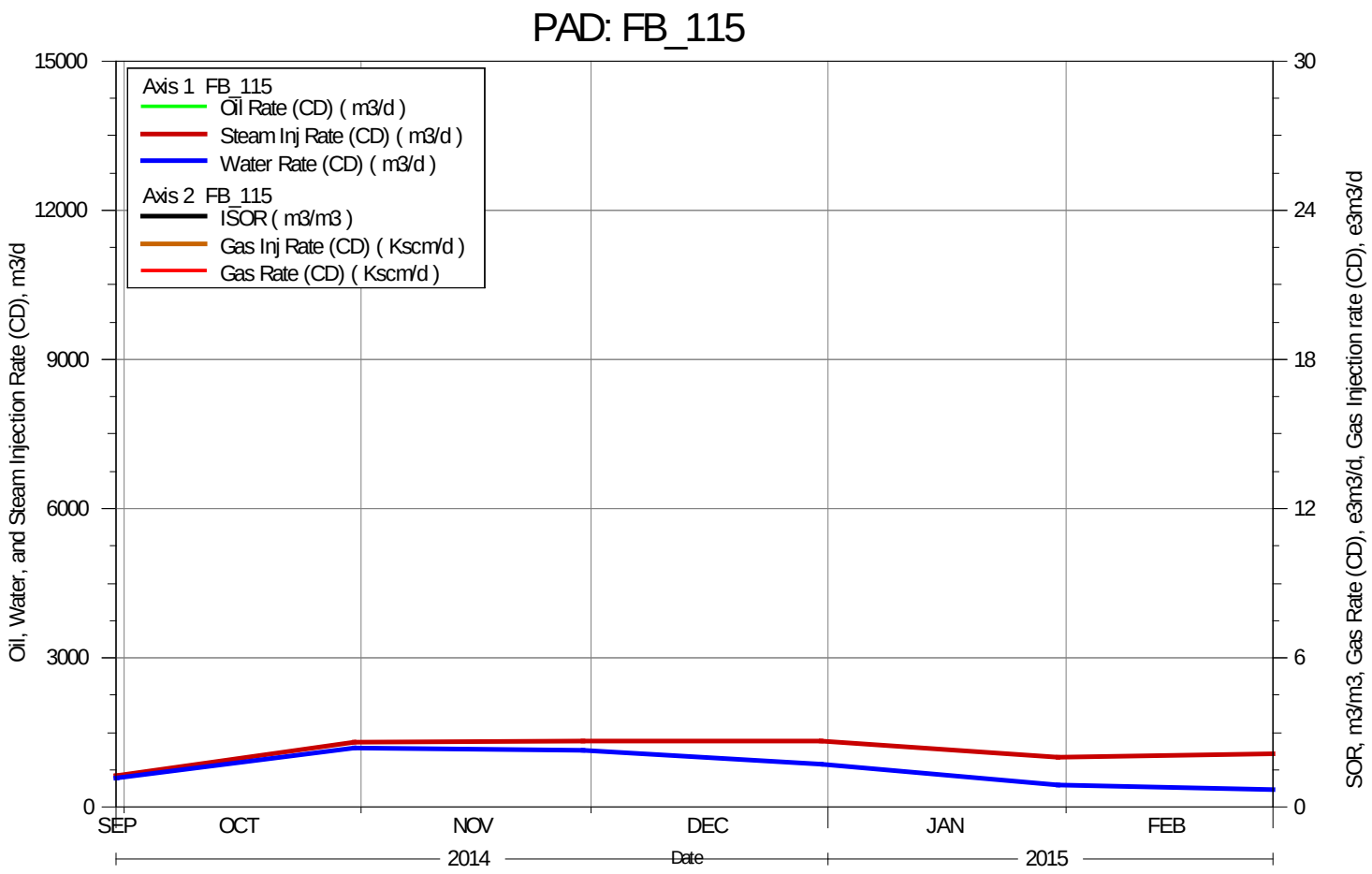

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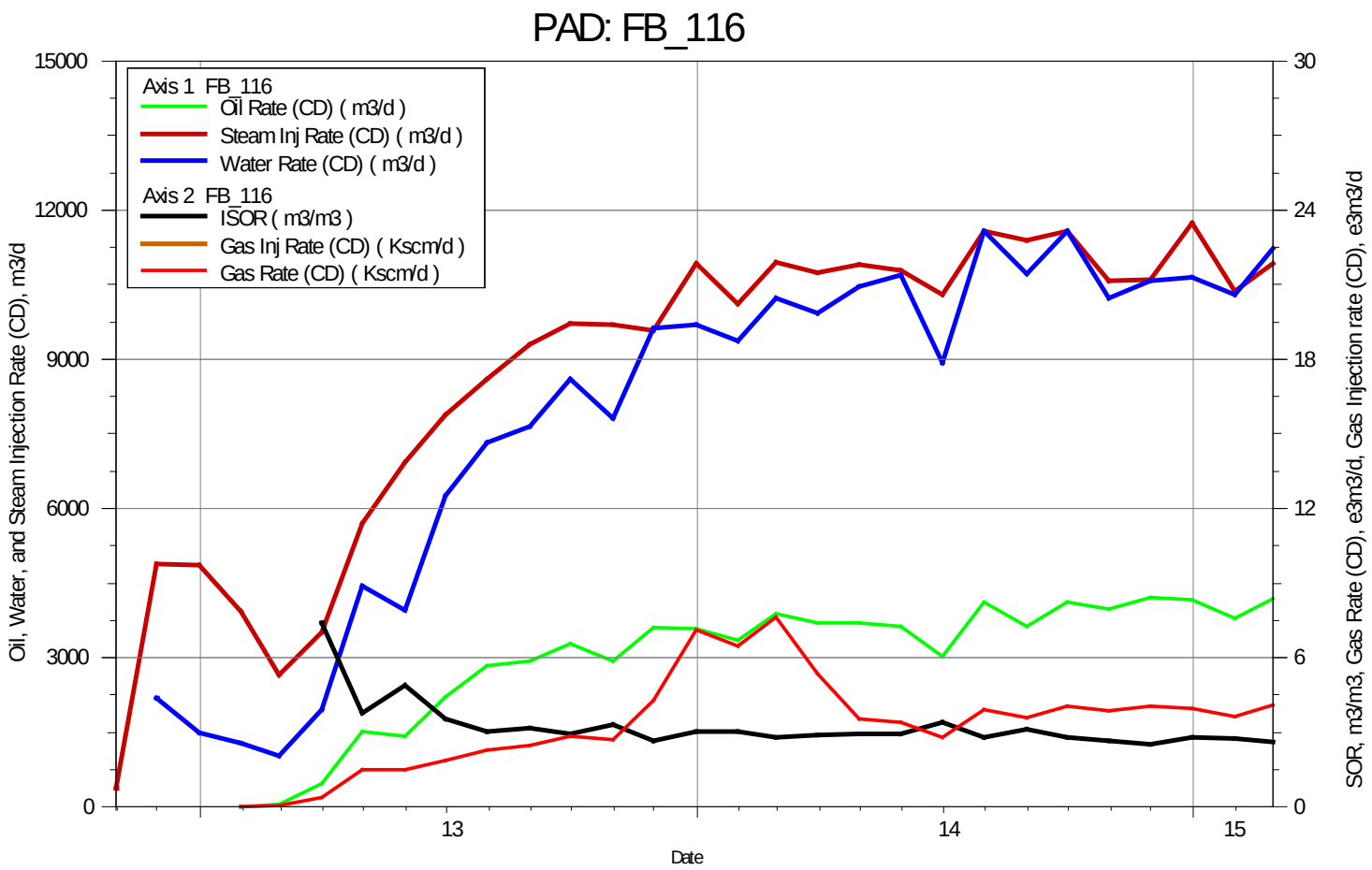


SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
DS1	00/12-06-095-06W4/0	P112P12_planned	512 m SW	262.6
DS2	02/12-06-095-06W4/0	P112P12_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	P110P10	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 OB1	02/10-01-095-06W4/0	P8P1 P8P2	69.5 m S 32.6 m N	311.5m MD 315.9m MD
ETS OB3	00/01-11-095-06W4/0	P8P13B P814B	57m E 37m W	315.0m MD 316.0m MD
ETS OB4	02/01-11-095-06W4/0	P7P6 P7P7	24.4 m E 79.8 m W	323.0m MD 315.0m MD
OB DW12	00/16-03-095-06W4/0	P5P12	14 m W	320.9
OB DW4	1AA/12-30-095-05W4/0	P9P15_planned	3550 m N	288.6
OB10	00/13-01-095-06W4/0	P8N15_planned P2S1 P2P1	38 m E 91.5 m W 91.5 m W	328 m MD 319.55 m MD 326.59 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB101	00/02-09-095-06W4/0	P116S3 P116P4	41 m S of horizontal 21.6 m N of horizontal	287.9m MD 293.9m MD
OB102	02/09-04-095-06W4/0	P116P9 P116P10	24.3 m S of horizontal 65.2 m N of horizontal	304m MD 309.7m MD
OB103	00/02-17-095-06W4/0	P115P1 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
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	P116P11	2025 m SW of build	307.5m 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

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB122	00/09-02-095-06W4/0	P7NP10_planned	1.0 m S	315.4 m MD
		P8P9	50.1 m S	315.4 m MD
		P8P8	49.4 m N	315.4 m MD
OB123	02/15-02-095-06W4/0	P7P3	47.0 m E	323.7 m MD
		P7P4	42.9 m W	326.0 m MD
		P8P10	135.8 m N	319.1 m MD
OB124	04/04-01-095-06W4/0	P8P5	56.6 m E	313.9 m MD
		P8P4	50.1 m W	313.3 m MD
OB125	00/02-02-095-06W4/0	P7P12	43.8 m E	325.6 m MD
		P7P11	47.4 m W	324.3 m MD
OB126	00/07-02-095-06W4/0	P7P12	42.2 m E	325.8 m MD
		P7P11	45.1 m W	325.1 m MD
OB127	04/08-02-095-06W4/0	P8P6	45.5 m E	312.9 m MD
		P8P5	46.0 m W	315.3 m MD
OB128	05/08-02-095-06W4/0	P7P9	96.3 m E	327.2 m MD
		P8P6	155.6 m W	314.0 m MD
		P8P7	200.6 m S	315.9 m MD
OB129	10/11-02-095-06W4/0	P4P7	77.4 m E	319.1 m MD
		P4P6	82.9 m W	326.1 m MD
OB13	10/07-11-095-06W4/0	P7S2	16.8 m W	322.66m MD
		P7P2	14.9 m W	322.7m MD
		P7P1	74.2 m E	318.5m MD
OB130	02/09-03-095-06W4/0	P5P14	78.7m E	324.7 m MD
		P5P13	58.8 m W	324.8 m MD
OB131	10/01-10-095-06W4/0	P5P8	95.2 m S	311.3 m MD
		P5P10	5.0 m N	311.3 m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
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_planned	1475.8 m NE	276.9 m MD
OB138	00/07-09-095-05W4/0	P9P1_planned	2765.3 m E	274.5 m MD
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
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
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

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
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
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	P123P9_planned	42 m E	278
OB202	00/13-29-094-05W4/0	P123P9_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	P109P15	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
OB27	00/05-04-095-06W4/0	P116P12	559 m S of horizontal	296.2m MD
OB28	00/07-04-095-06W4/0	P116P11	400m SW of ICP	315.75m MD
OB29	00/07-05-095-06W4/0	P116P12	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

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB30	00/15-05-095-06W4/0	P116P14 P116P13	63.4 m SW of toe 87.6 m NW of toe	285.5m MD 288m MD
OB31	00/06-08-095-06W4/0	P116P19 P115P1	750 m NW of toe 795 m SW of ICP_PLAN	275.75m MD 275.5m MD
OB32	00/11-08-095-06W4/0	P115P1	476 m W of horizontal	277m MD
OB33	00/13-08-095-06W4/0	P115P1	868 m W of horizontal	270.5m MD
OB34	00/03-09-095-06W4/0	P116P19 P116P18	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	P115P12 P115P11	92.6 m NW of ICP_PLAN 119 m SW of ICP_PLAN	285m MD 285m MD
OB36	00/11-09-095-06W4/0	P115P9	206.5 m N of horizontal	286.4m MD
OB37	00/11-04-095-06W4/0	P116P12 P116P10	218 m SE of ICP 585 m SW of ICP	294.3m MD 306.2m MD
OB38	00/11-05-095-06W4/0	P116P12	557 m SW of toe	288m MD
OB39	00/07-08-095-06W4/0	P116P19 P115P1	320 m NW of toe 539 m SW of ICP_PLAN	281.2m MD 280.6m MD
OB4	02/01-01-095-06 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 P115P9	132.7 m W of horizontal 229 m N of horizontal	291m MD 288.4m MD
OB42	00/13-04-095-06W4/0	P116P15 P116P16	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 P115P9	383 m NW of toe 658 m N of horizontal	292.2m MD 289.2m MD
OB44	00/01-05-095-06W4/0	P116P12	1065 m S of horizontal	296.4m MD
OB45	00/03-05-095-06W4/0	P116P12	1191 m SW of toe	285.6m MD
OB47	05/16-03-095-06W4/0	P5P13 P5P14	16.2m W of ICP 121.5m E of ICP	329m TVD 574m MD
OB48	02/11-06-095-06W4/0	P116P12	2229 m SW of toe	274.8m MD
OB49	00/13-06-095-06W4/0	P116P14	2582 m W of toe	262.8m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
OB5	00/15-36-094-06W4/0	P1S6 P1P6	1.5 m E 0.6 m W	310.21 m MD 316.71 m MD
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
OB69	00/11-35-094-06W4/0	P7S9	365.5 m SW of toe	320.1m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
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
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

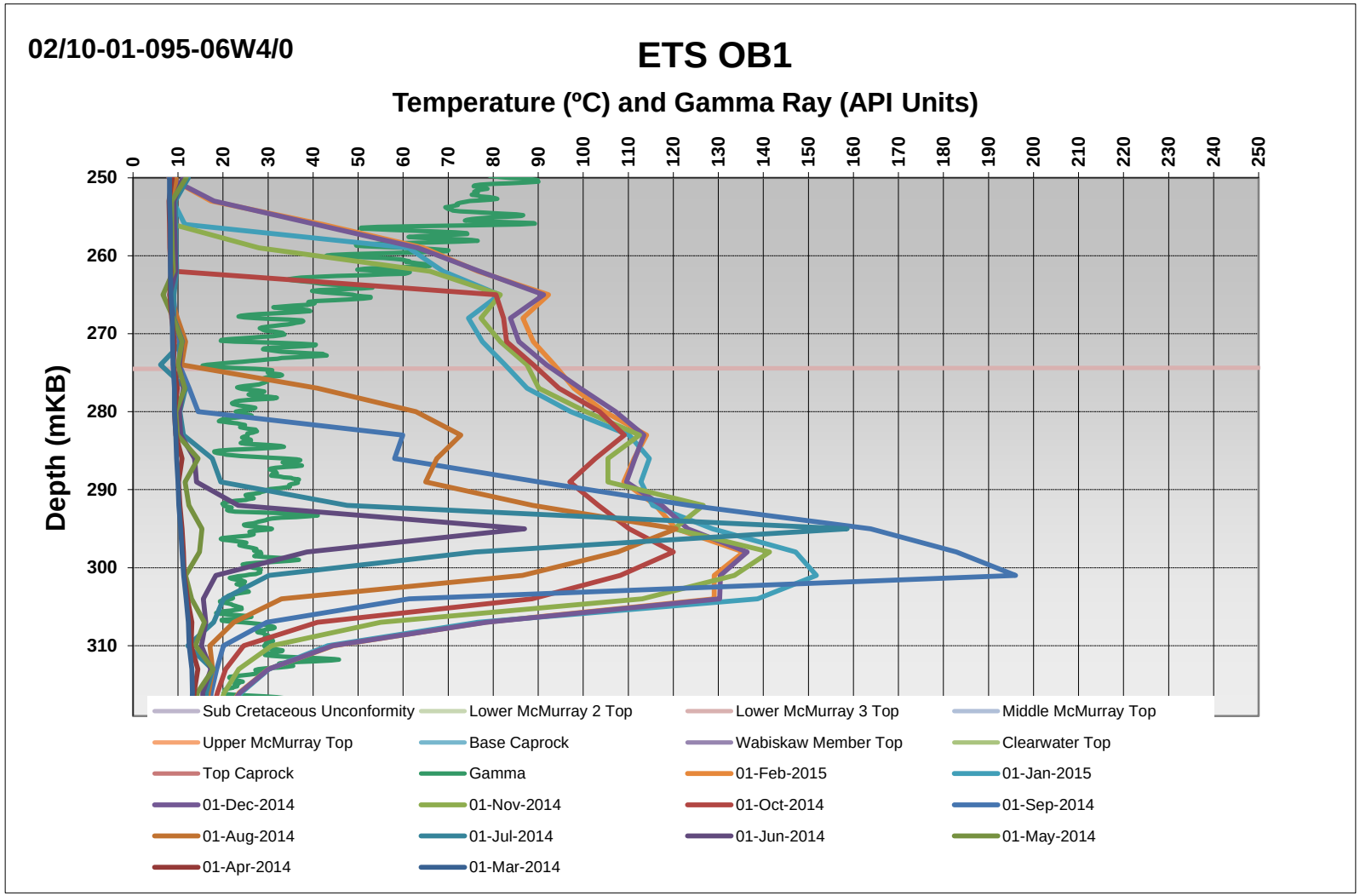
SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
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
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	P115P1 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	P115P1 P6P1 P16P19	1023.8 m NW of horizontal 1729 m NW 1633 m N	294.2m MD 290.7m MD 287.6m MD

SAGD Observation Well Positioning

Well Name	UWI	Proximity Relative to	Lateral Proximity To	Vertical Proximity To
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	04/15-10-095-06W4/0	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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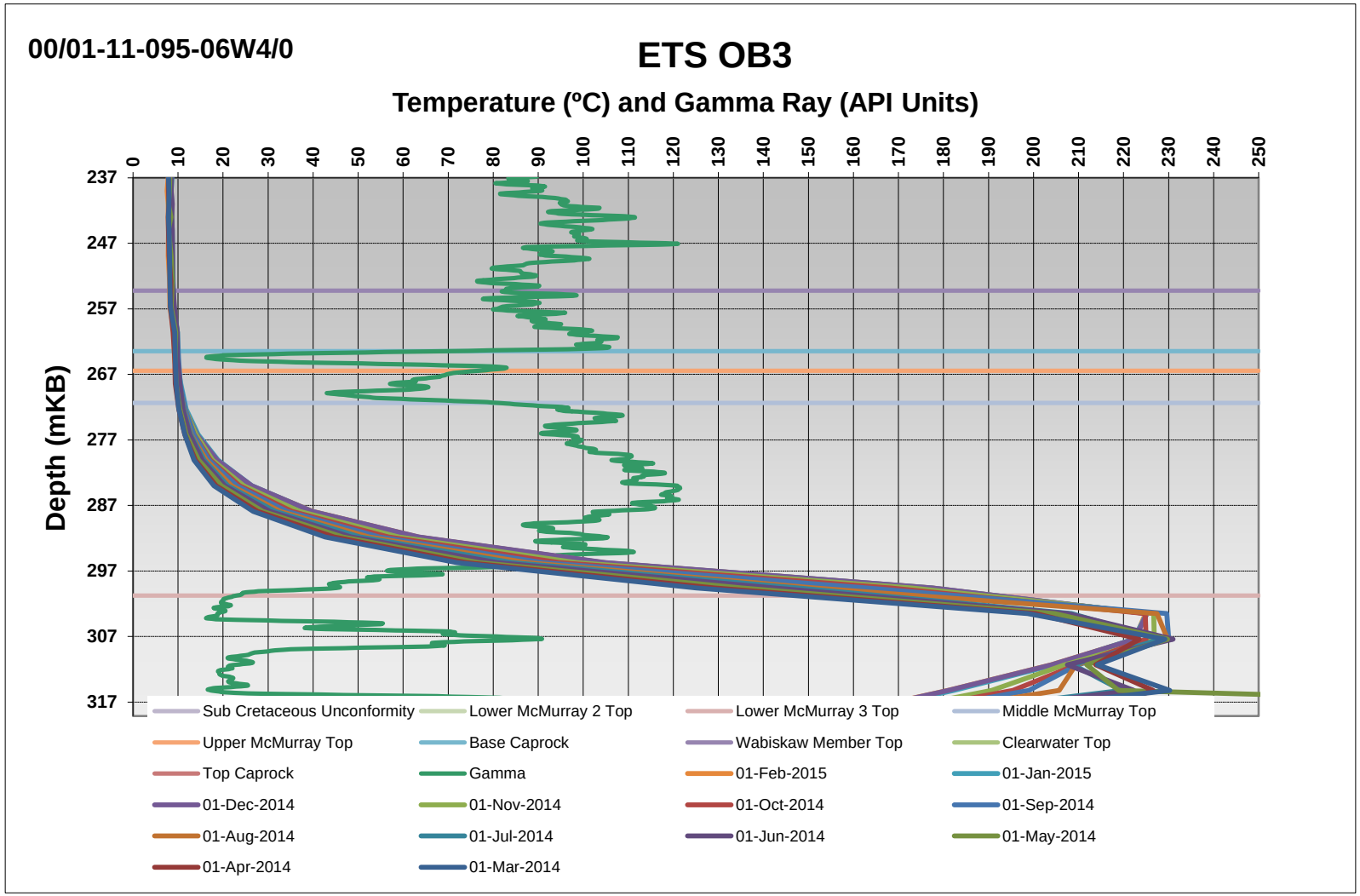
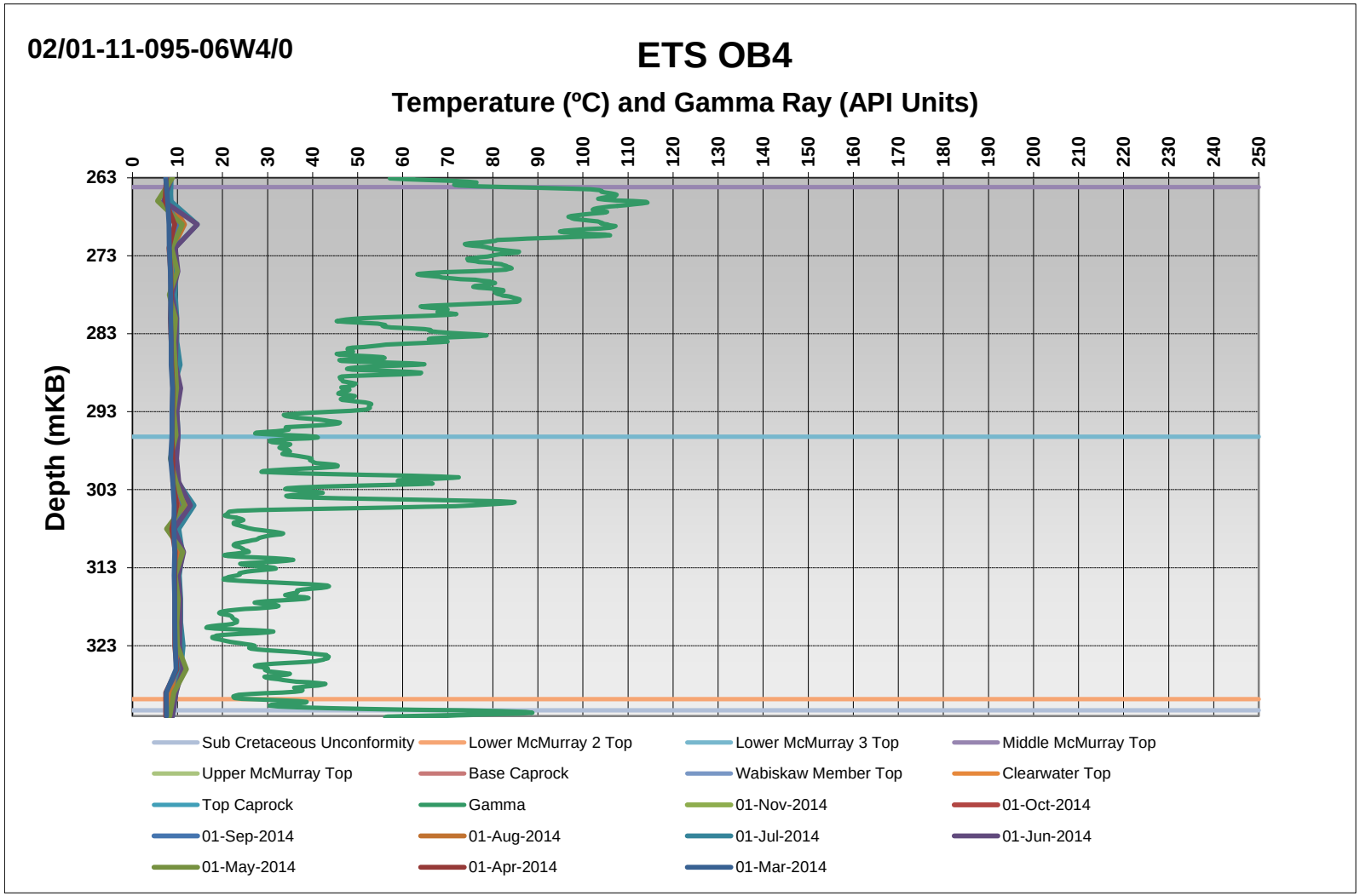


Piezometer Plots & Temperature vs Depth Plots



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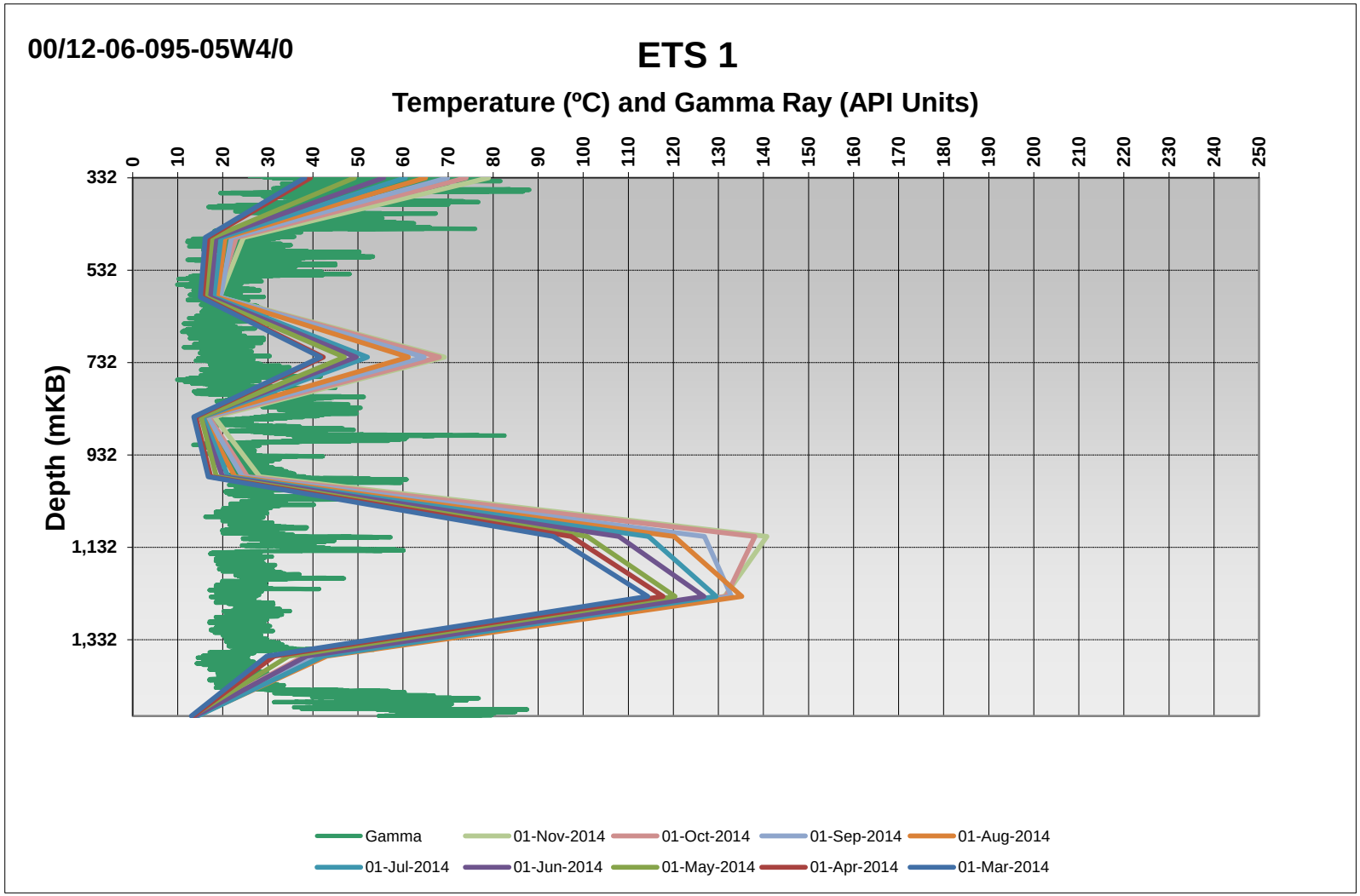

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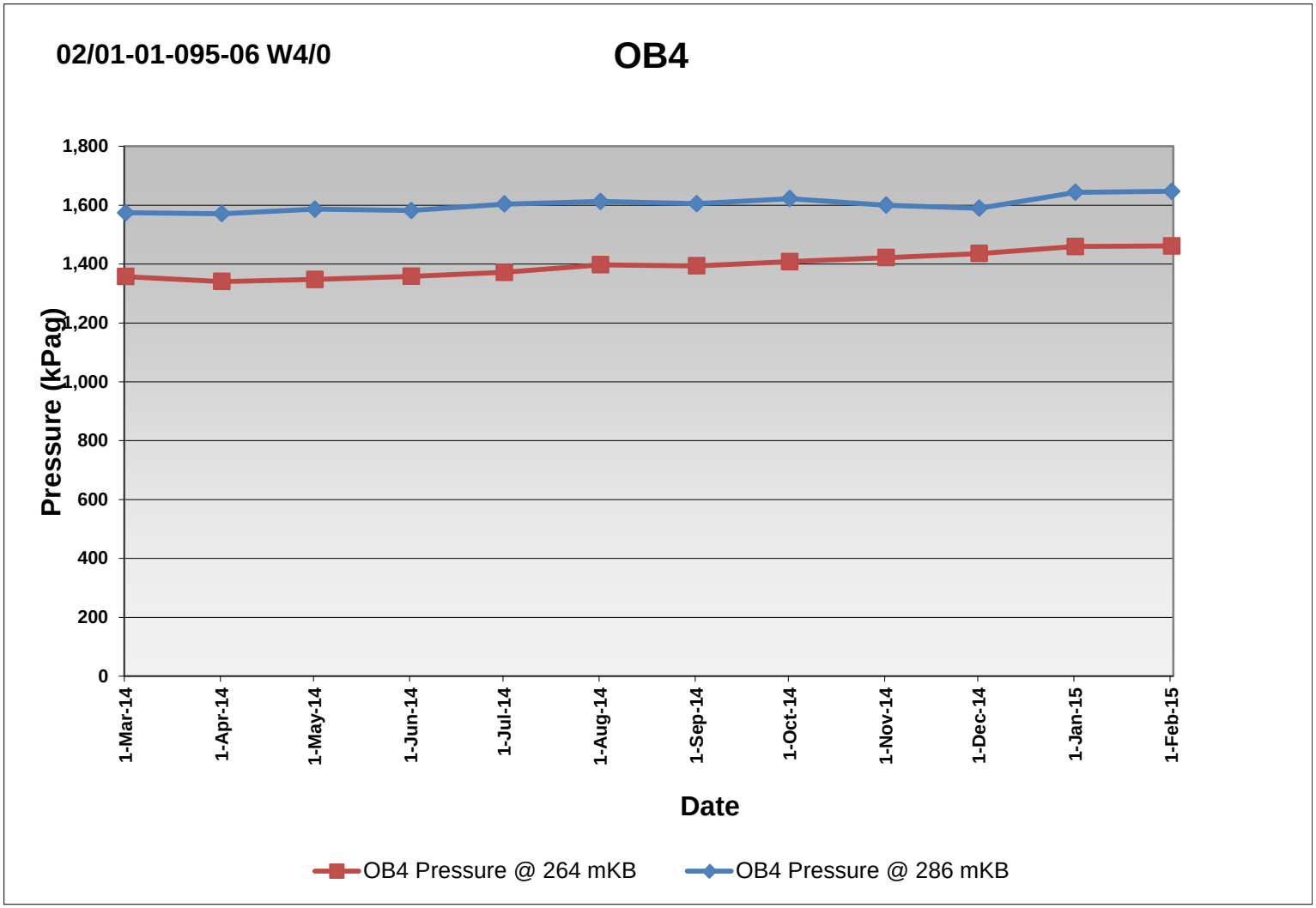
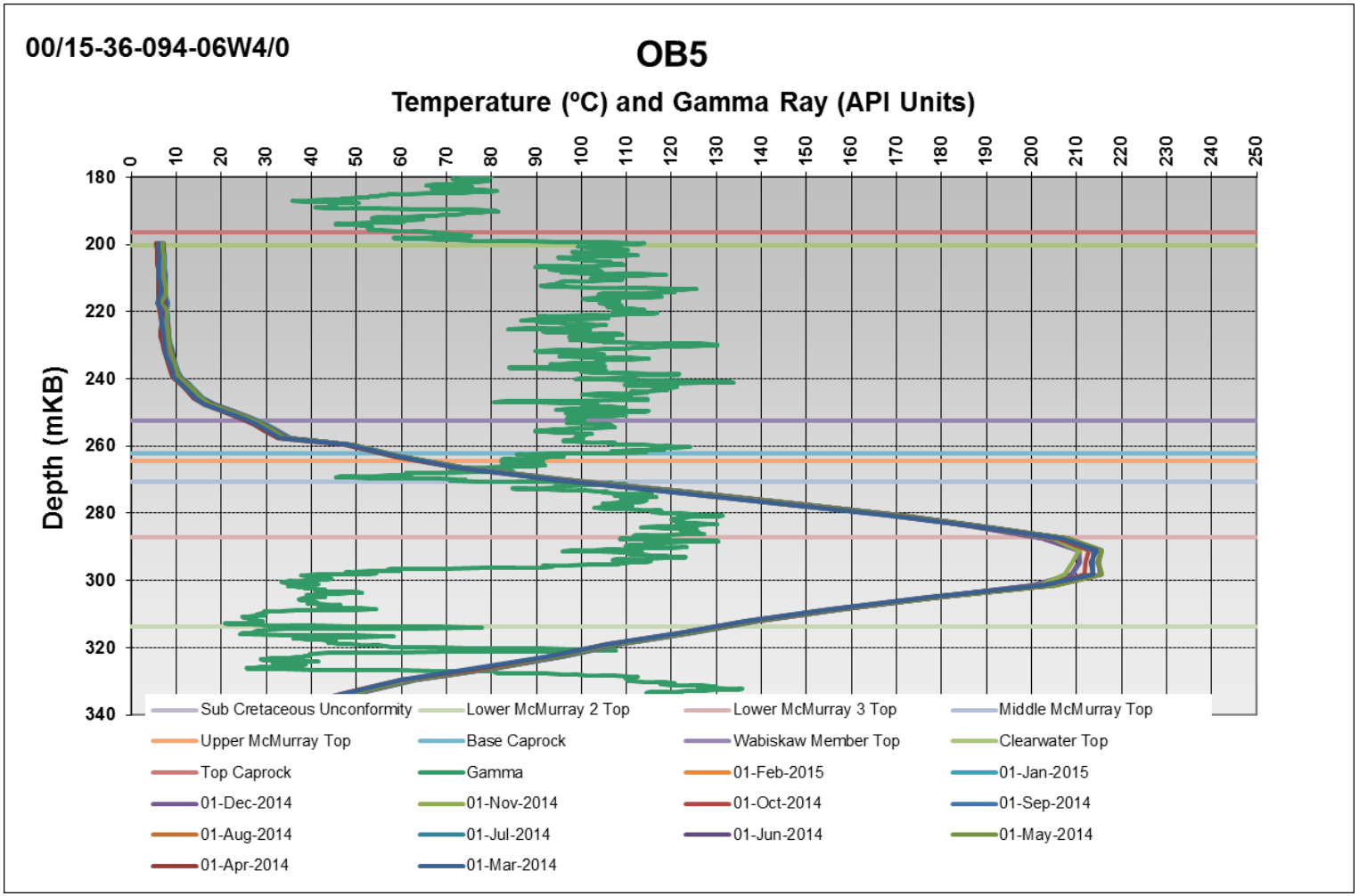


Piezometer Plots & Temperature vs Depth Plots



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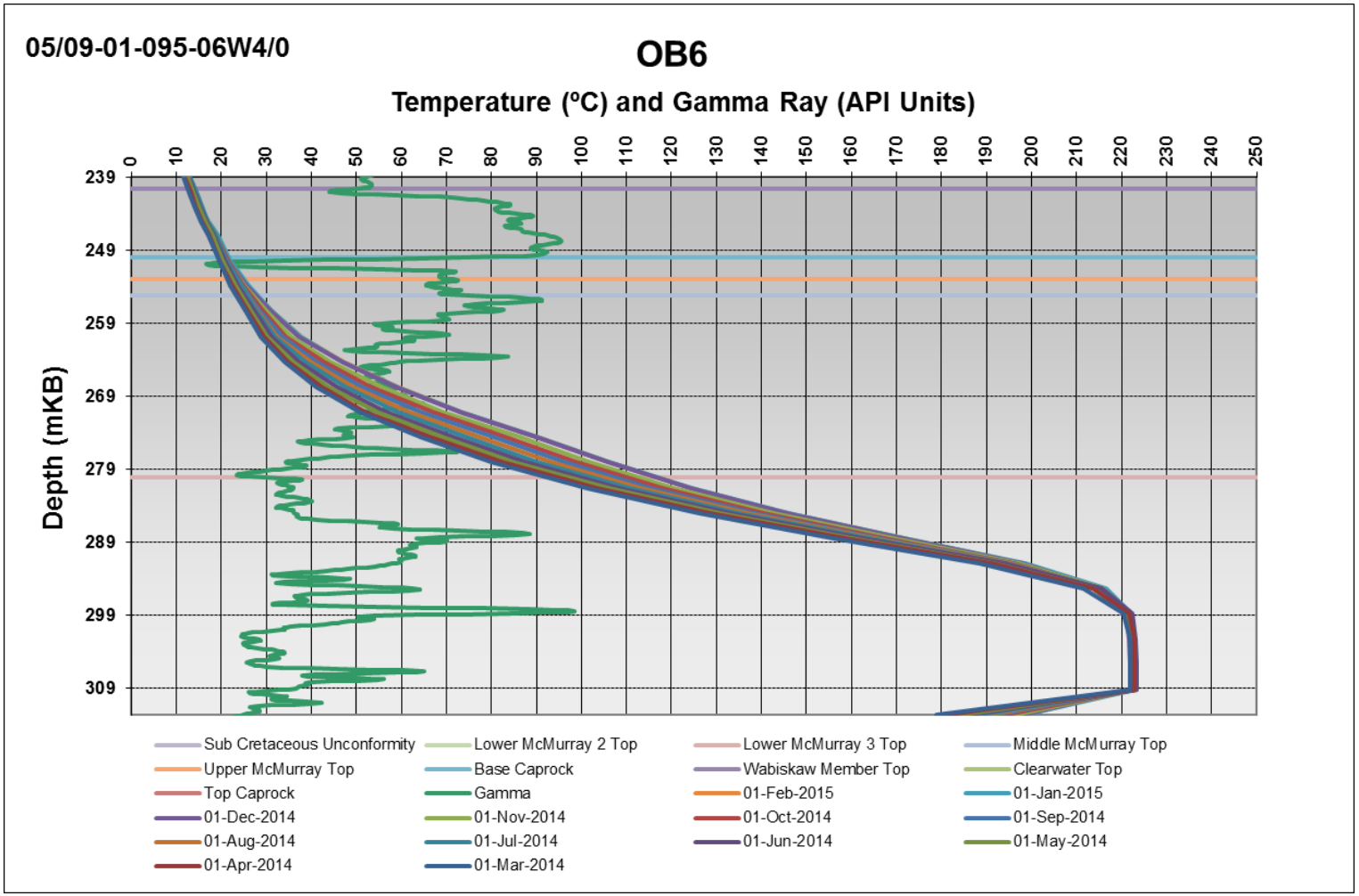
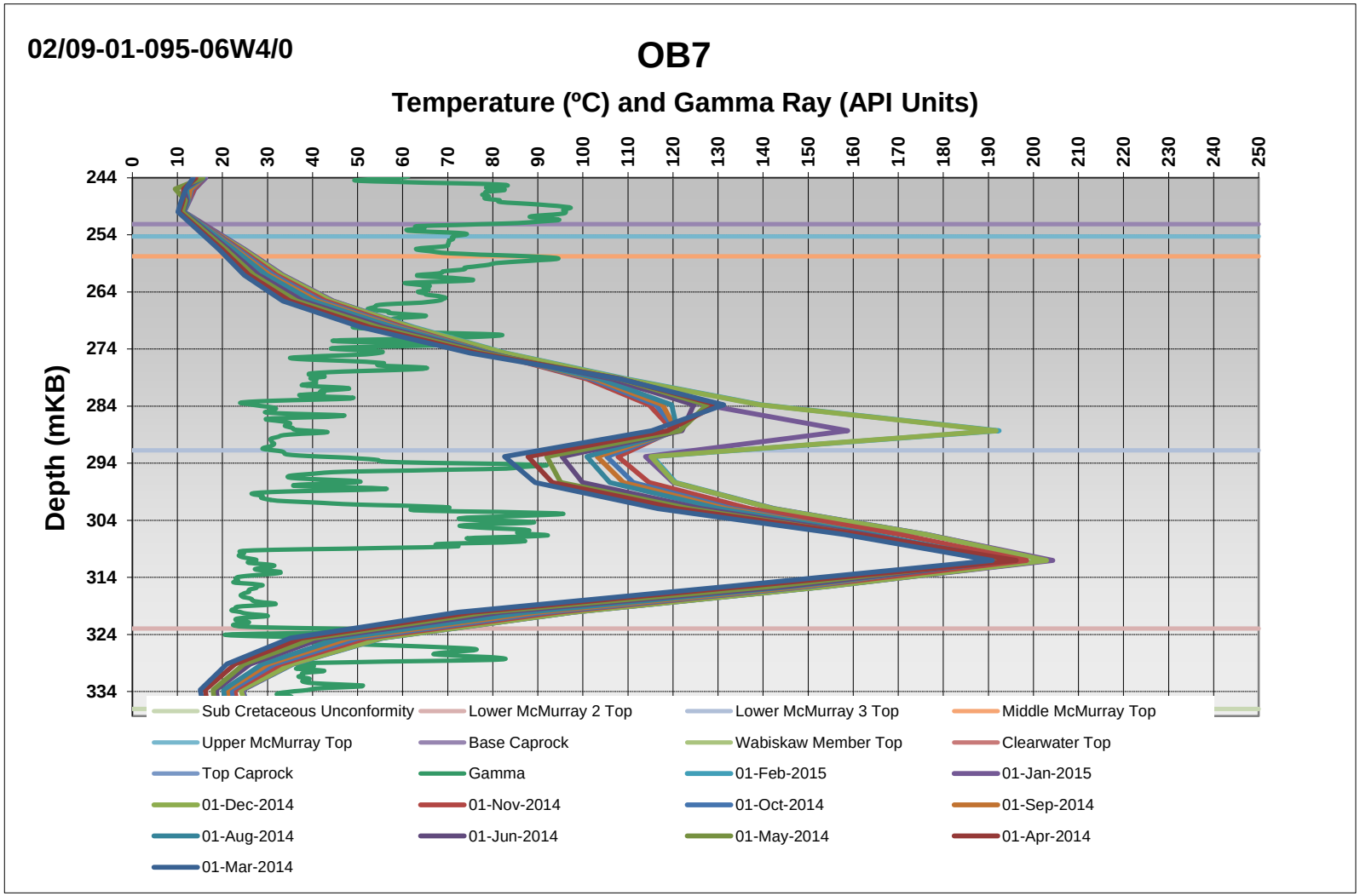
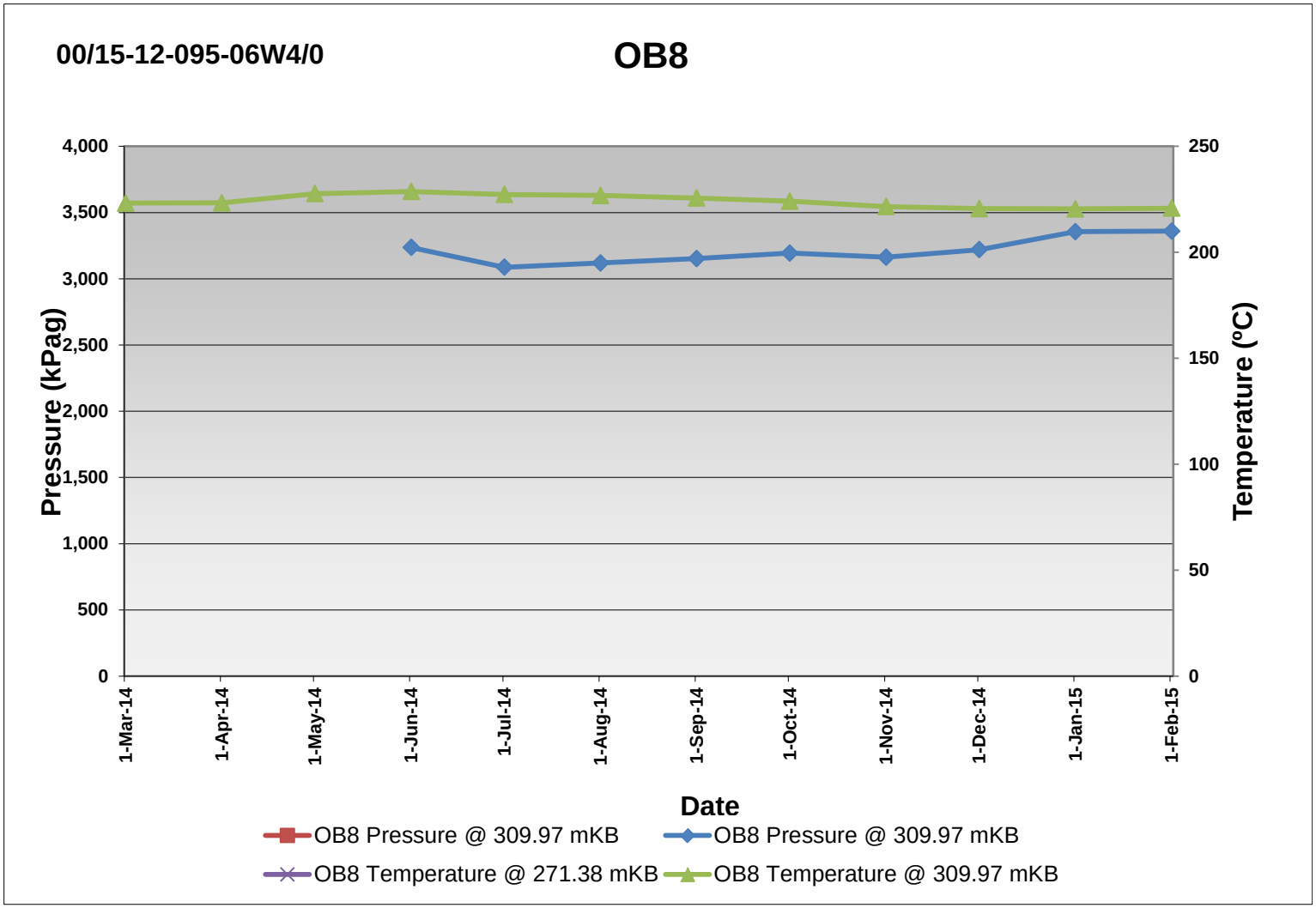


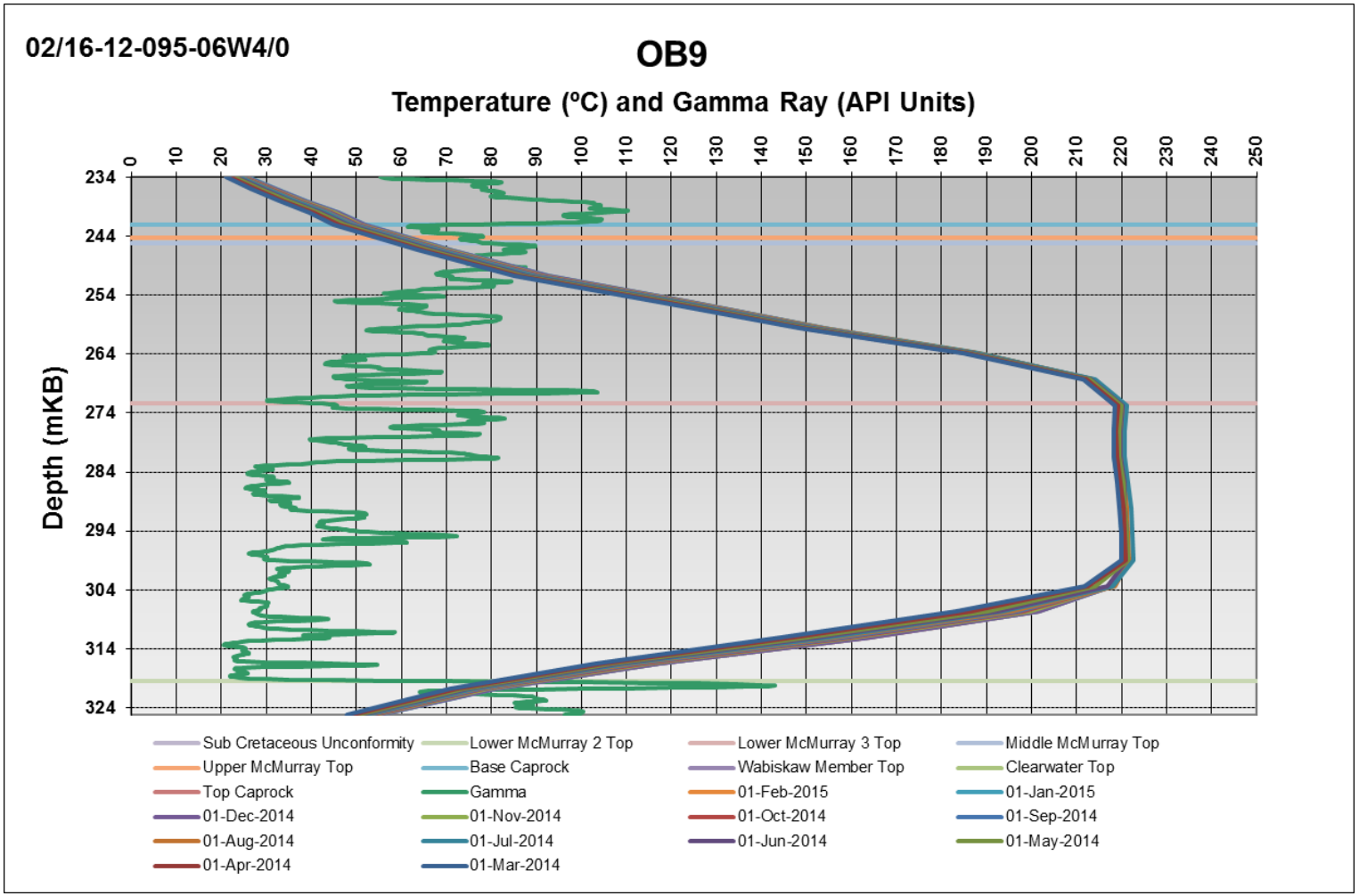
Piezometer Plots & Temperature vs Depth Plots



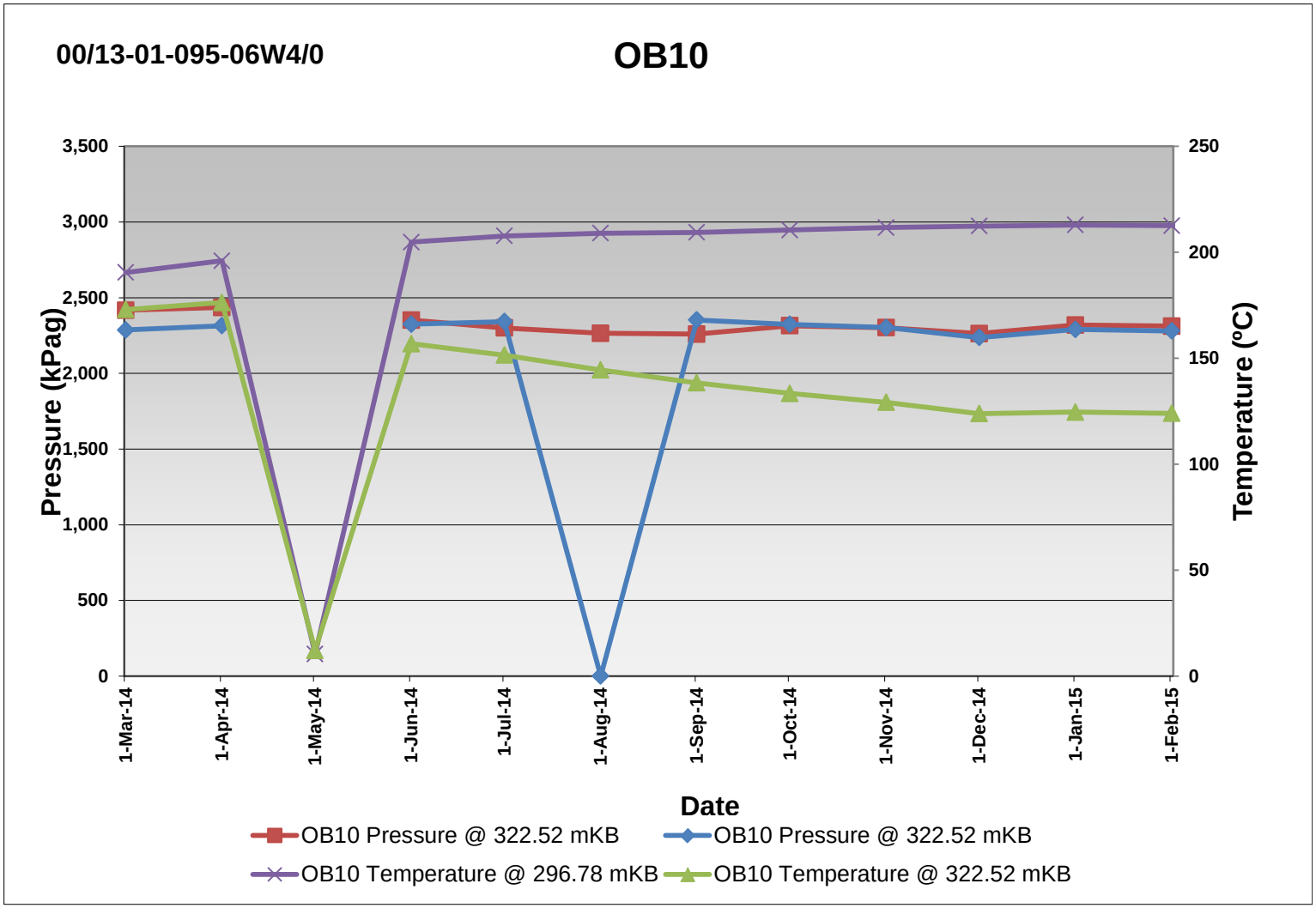
Piezometer Plots & Temperature vs Depth Plots



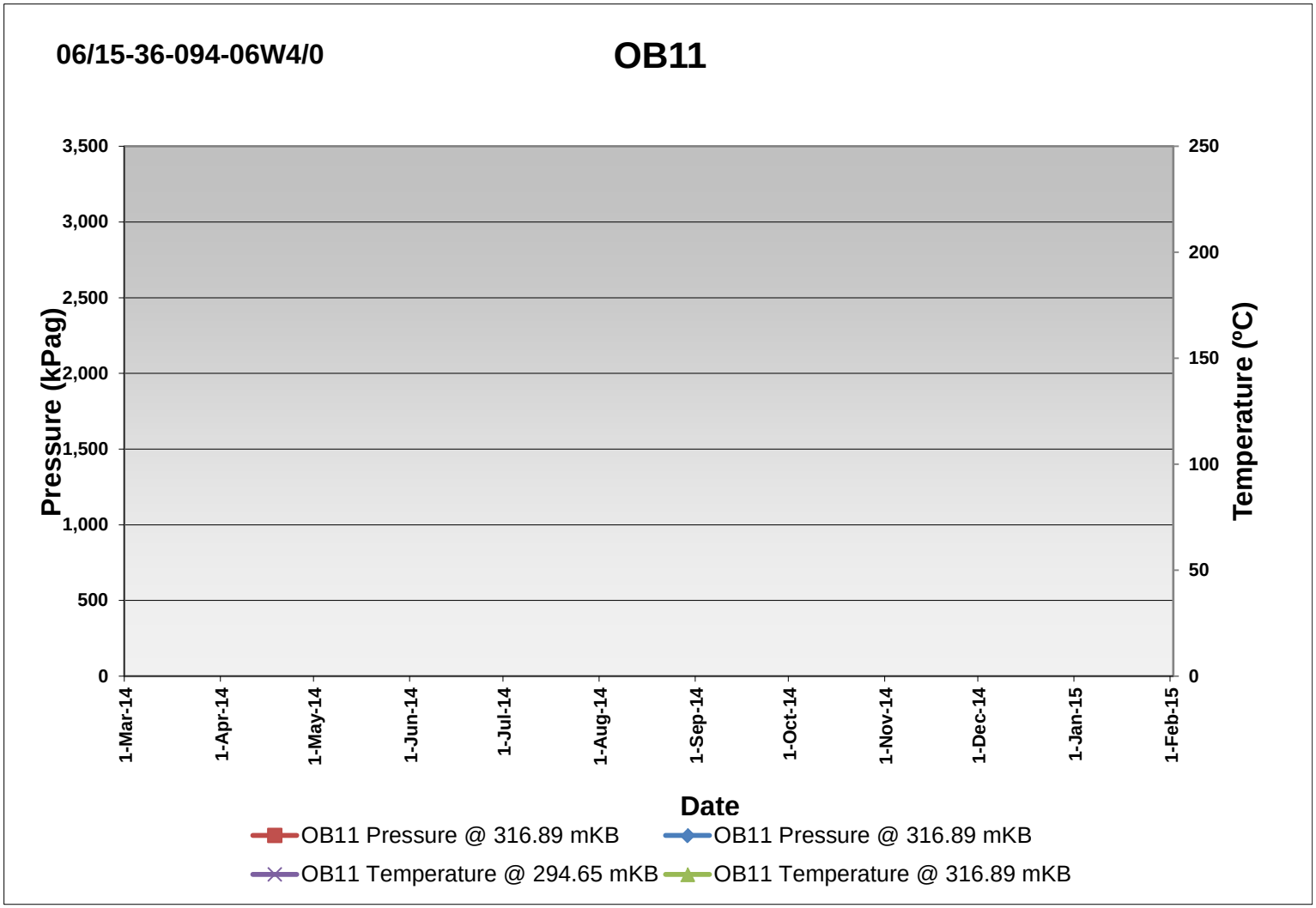
Piezometer Plots & Temperature vs Depth Plots



Piezometer Plots & Temperature vs Depth Plots



Piezometer Plots & Temperature vs Depth Plots



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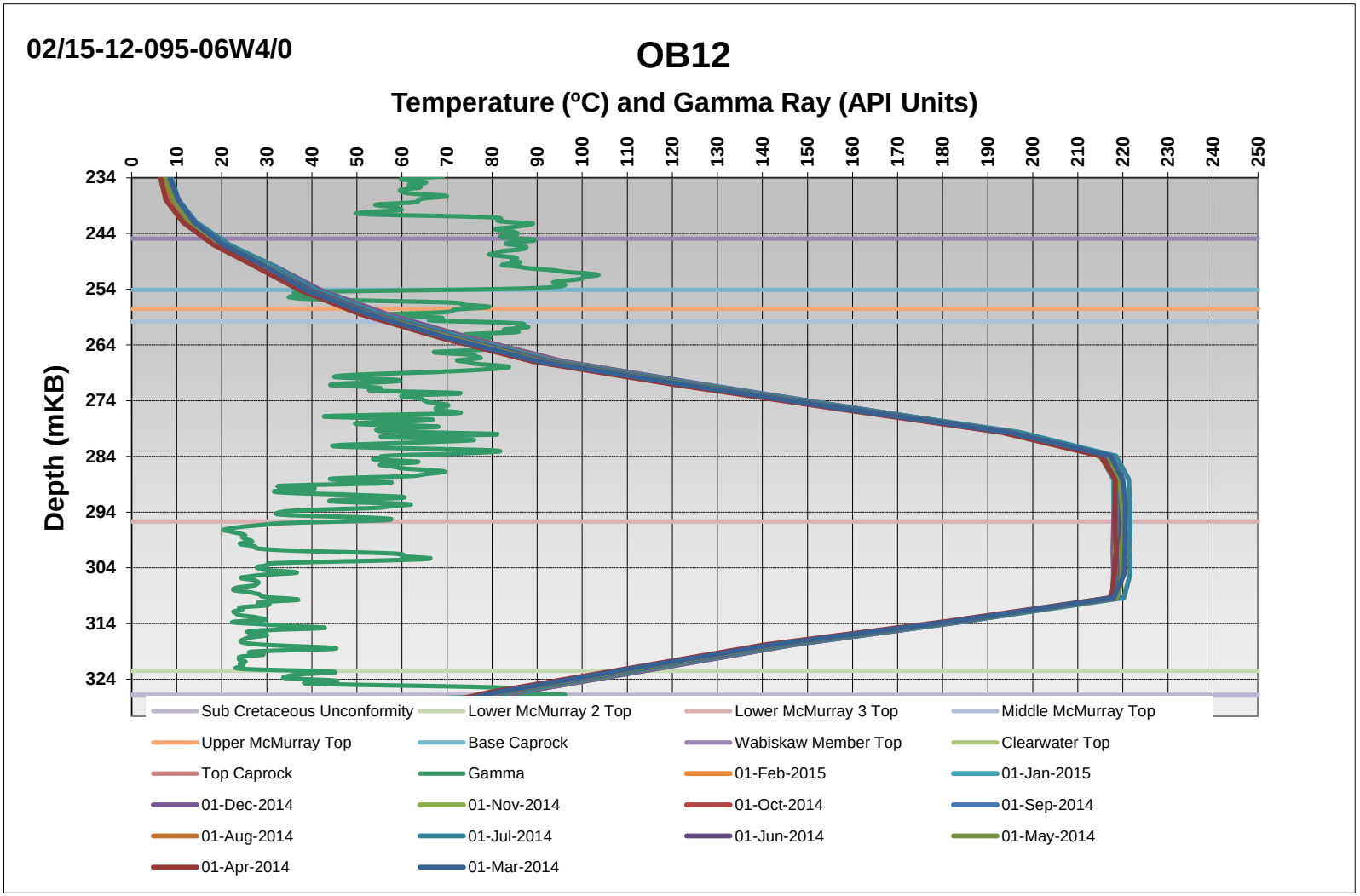

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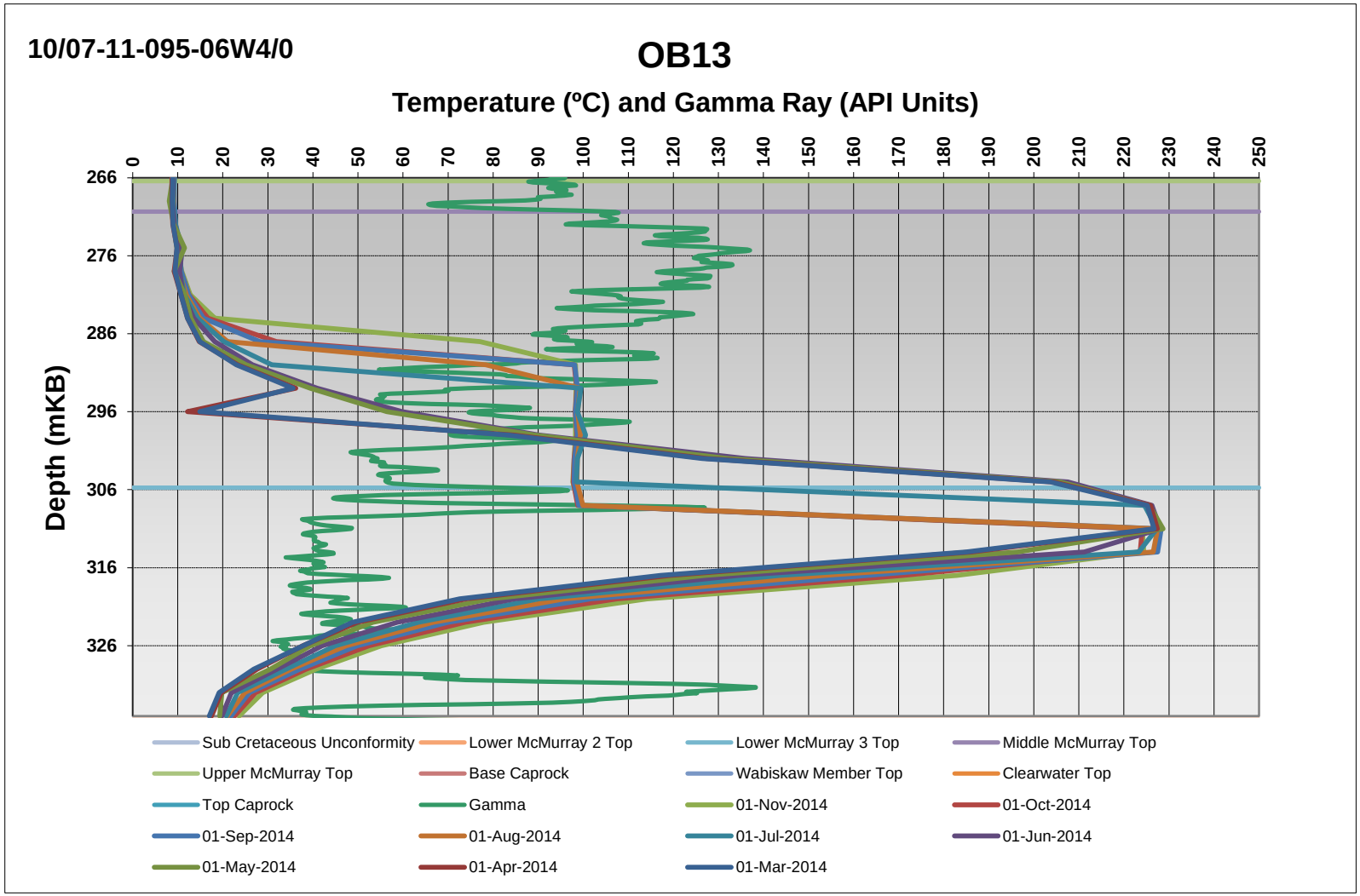

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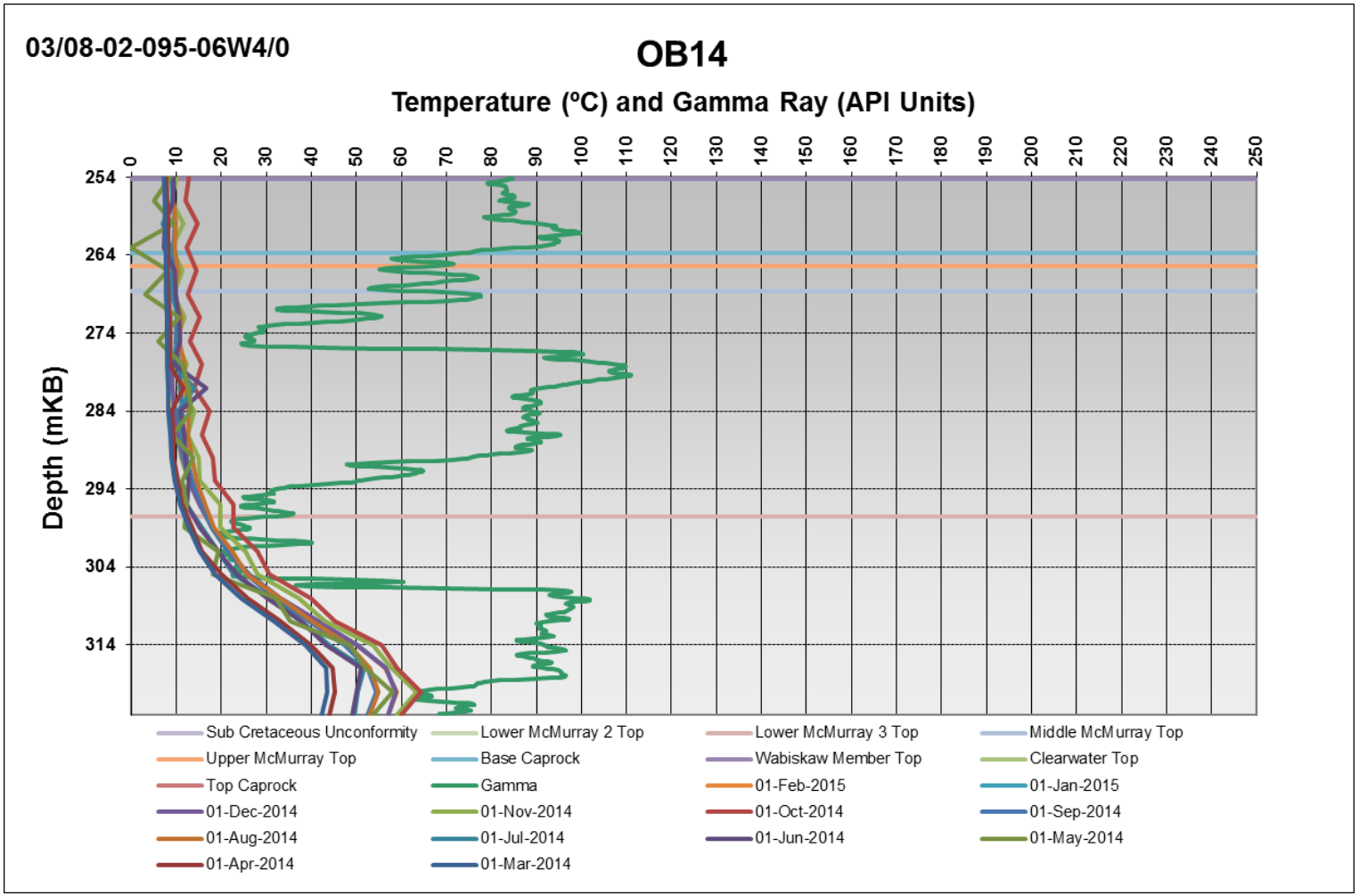

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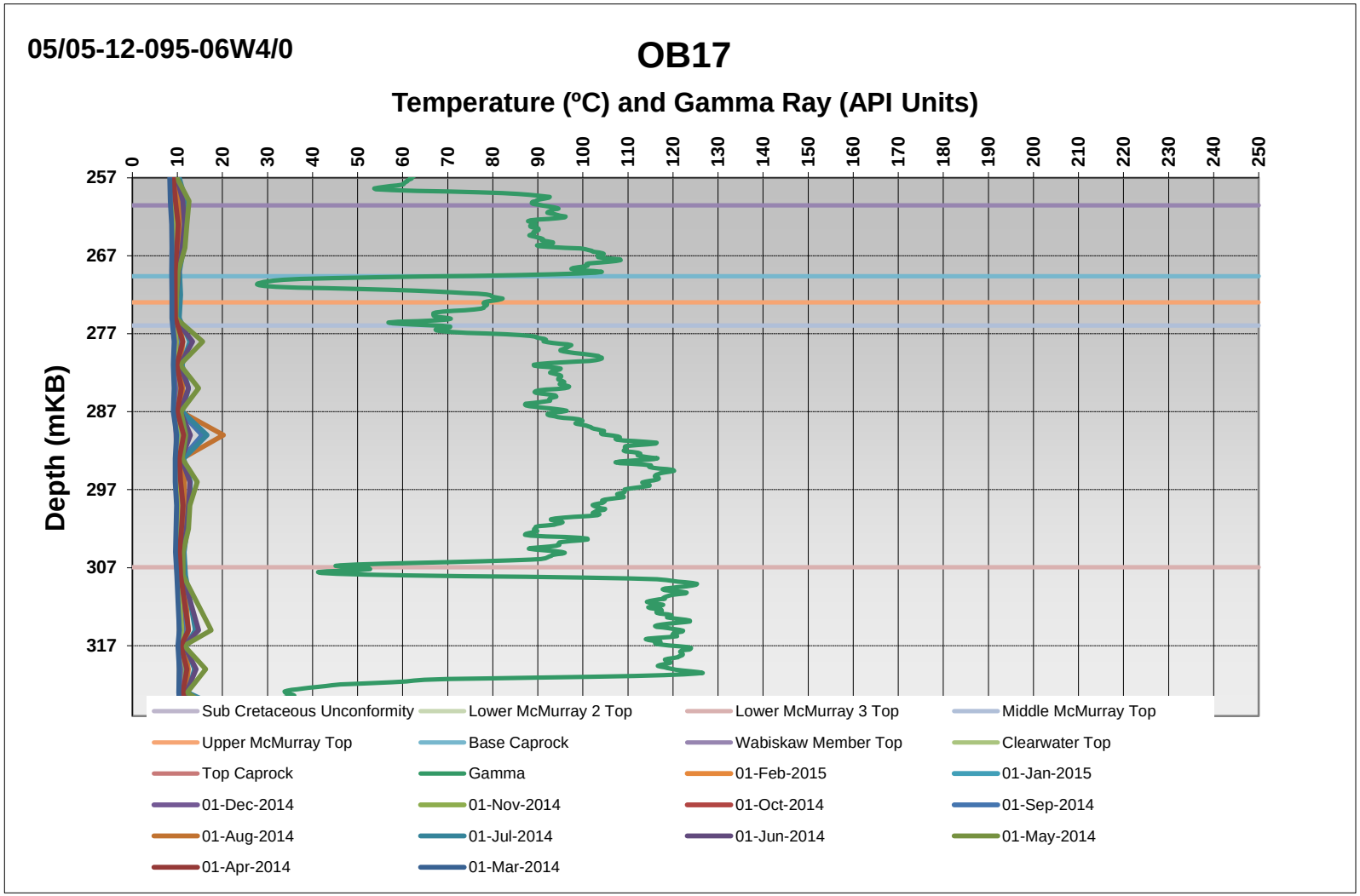

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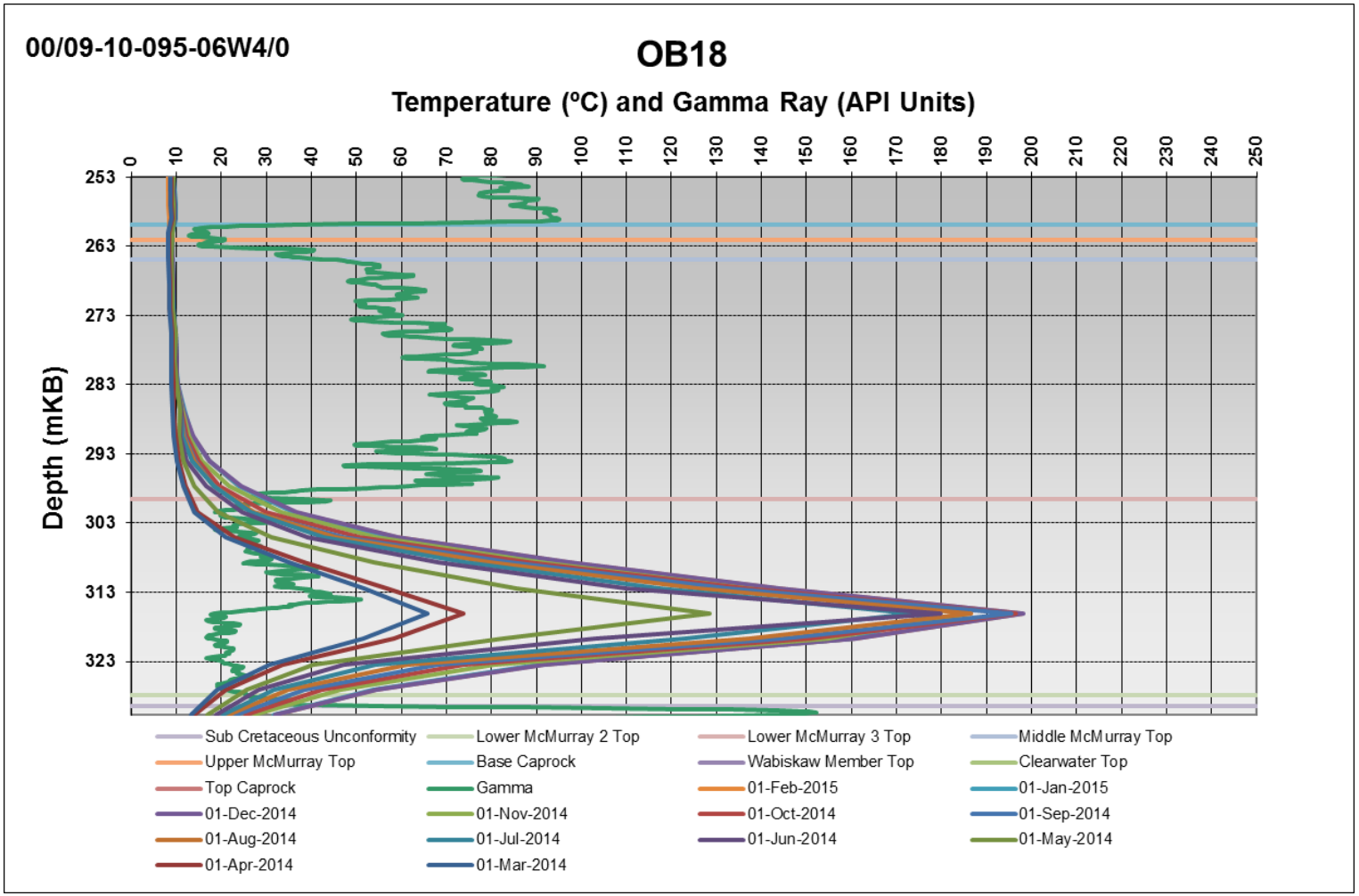

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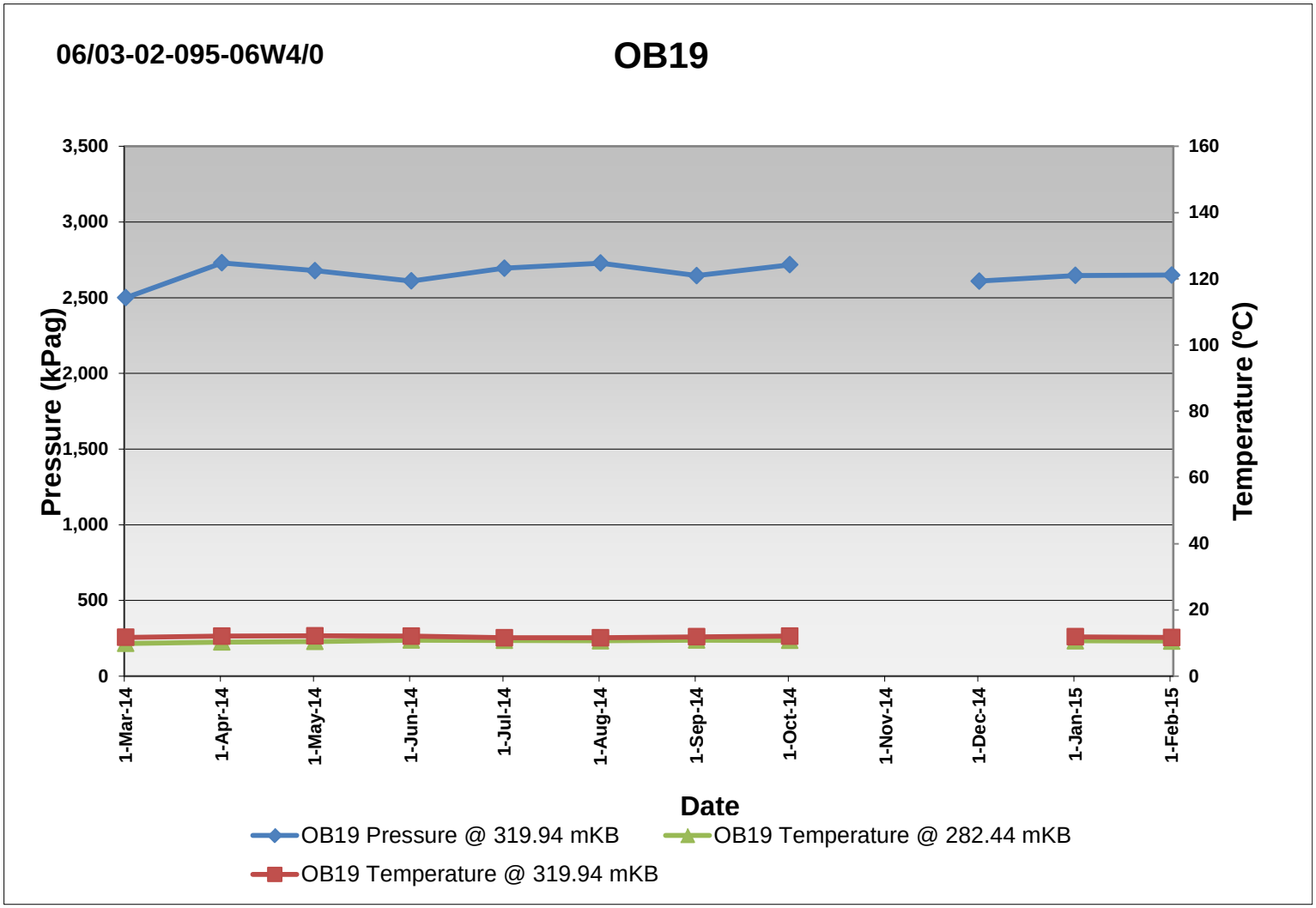

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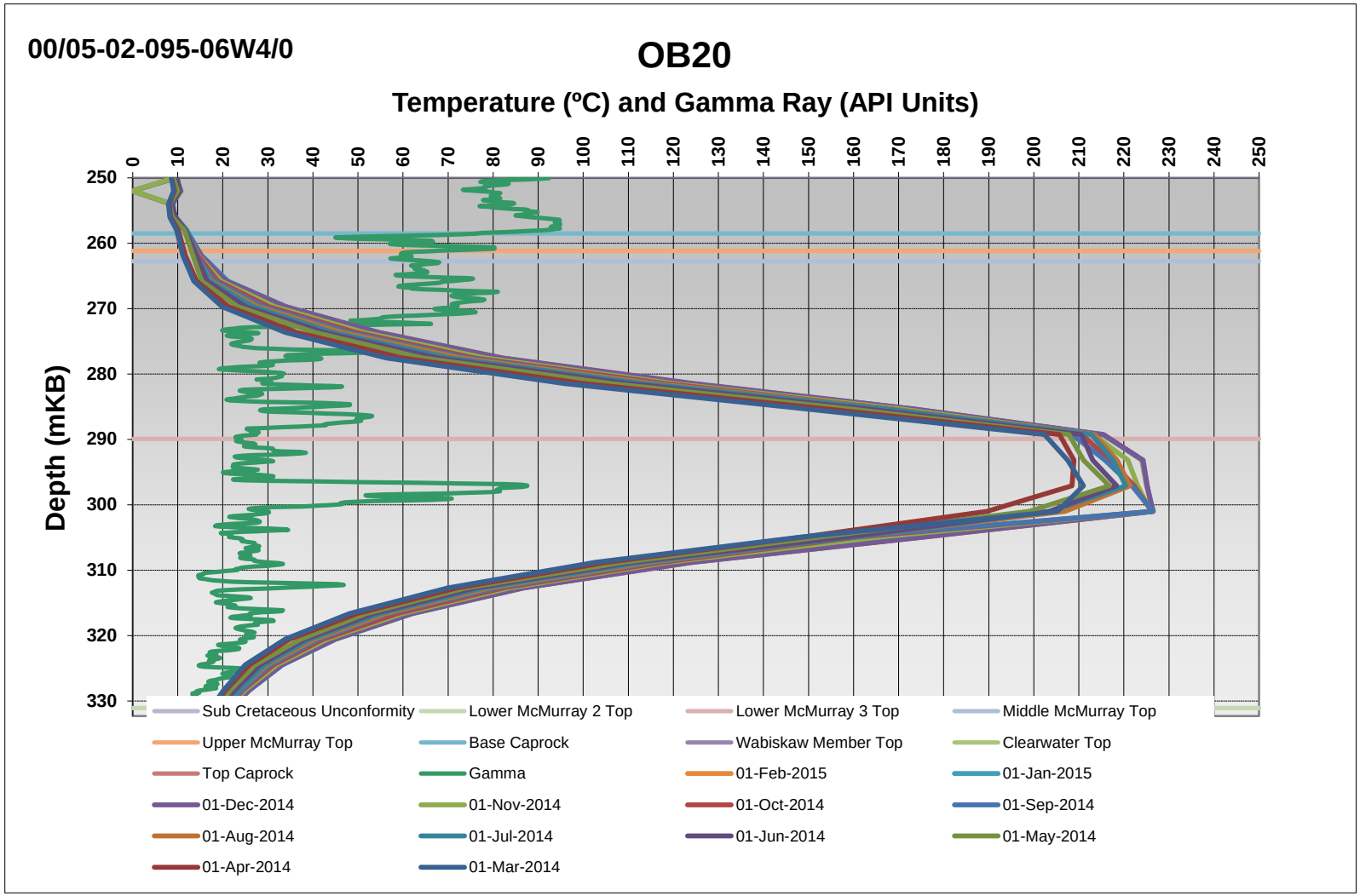

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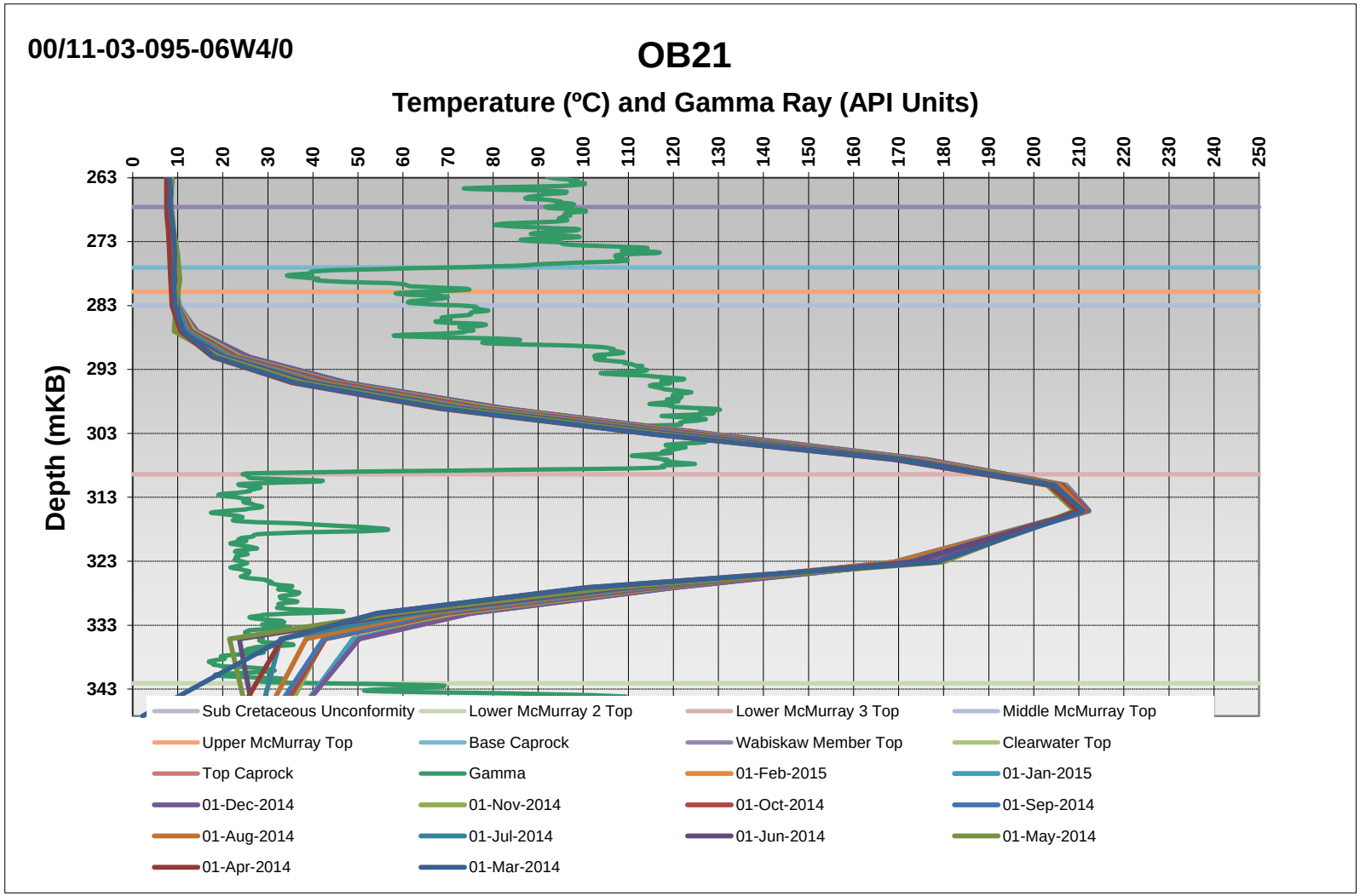

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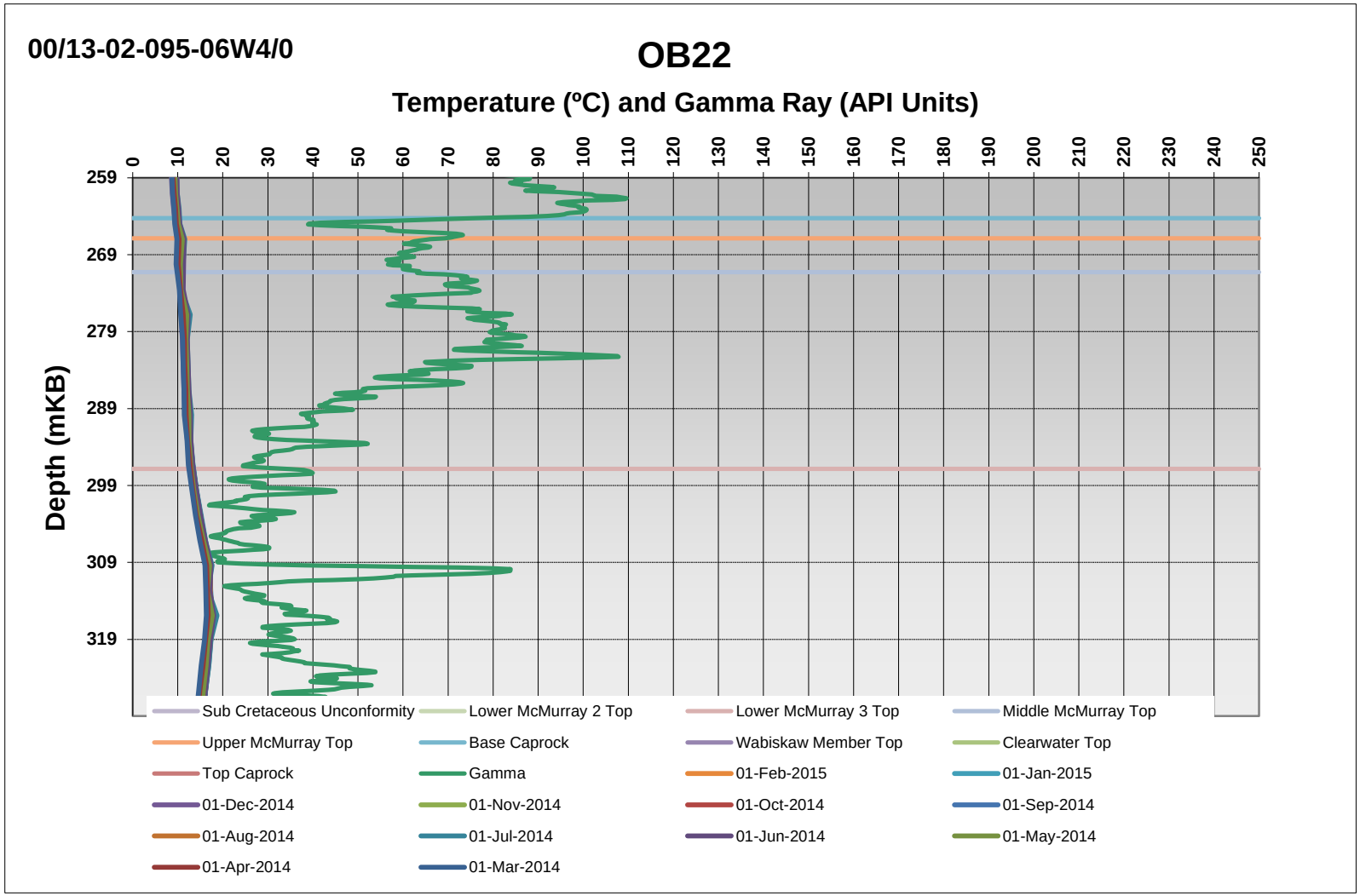

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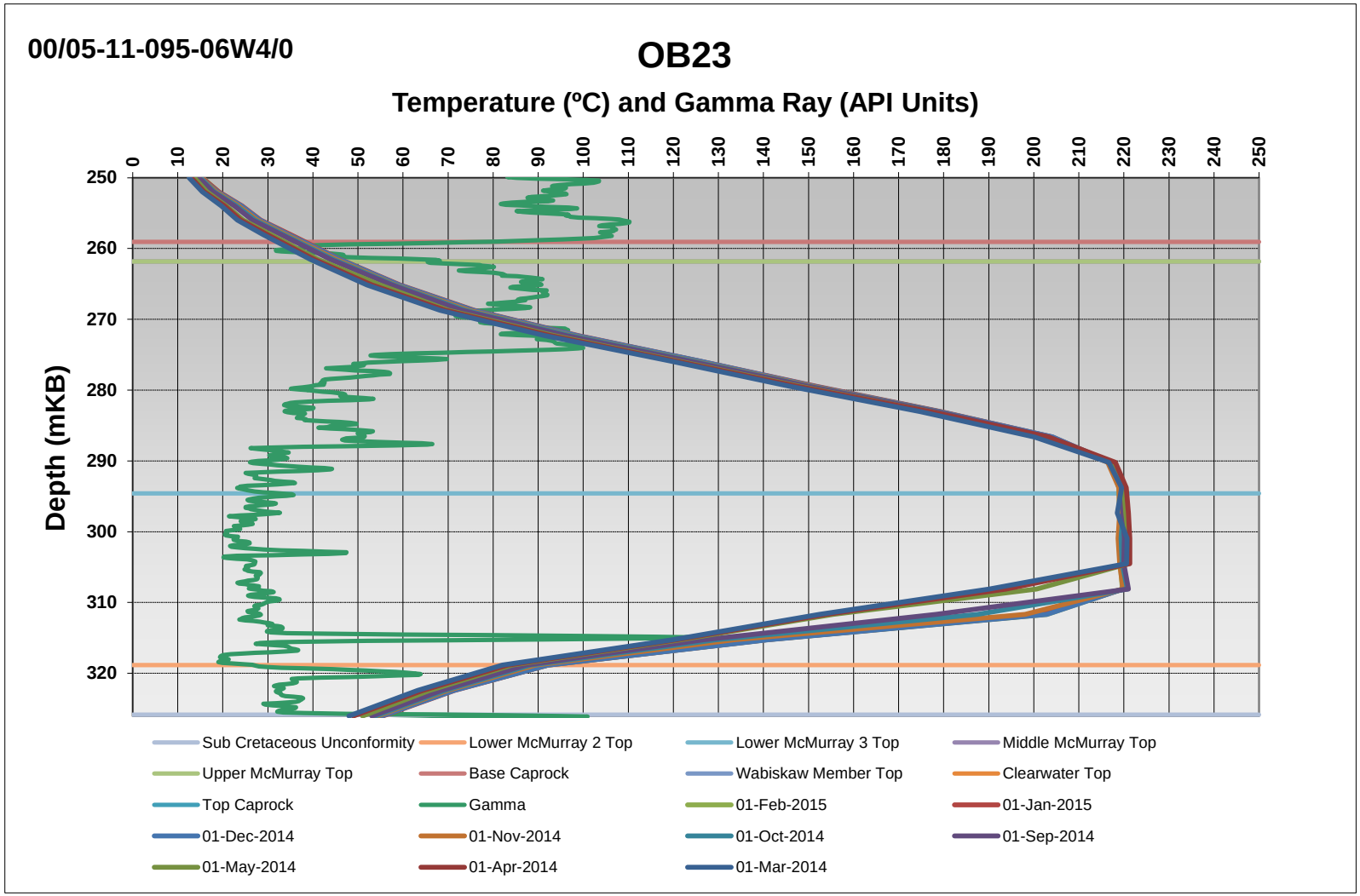

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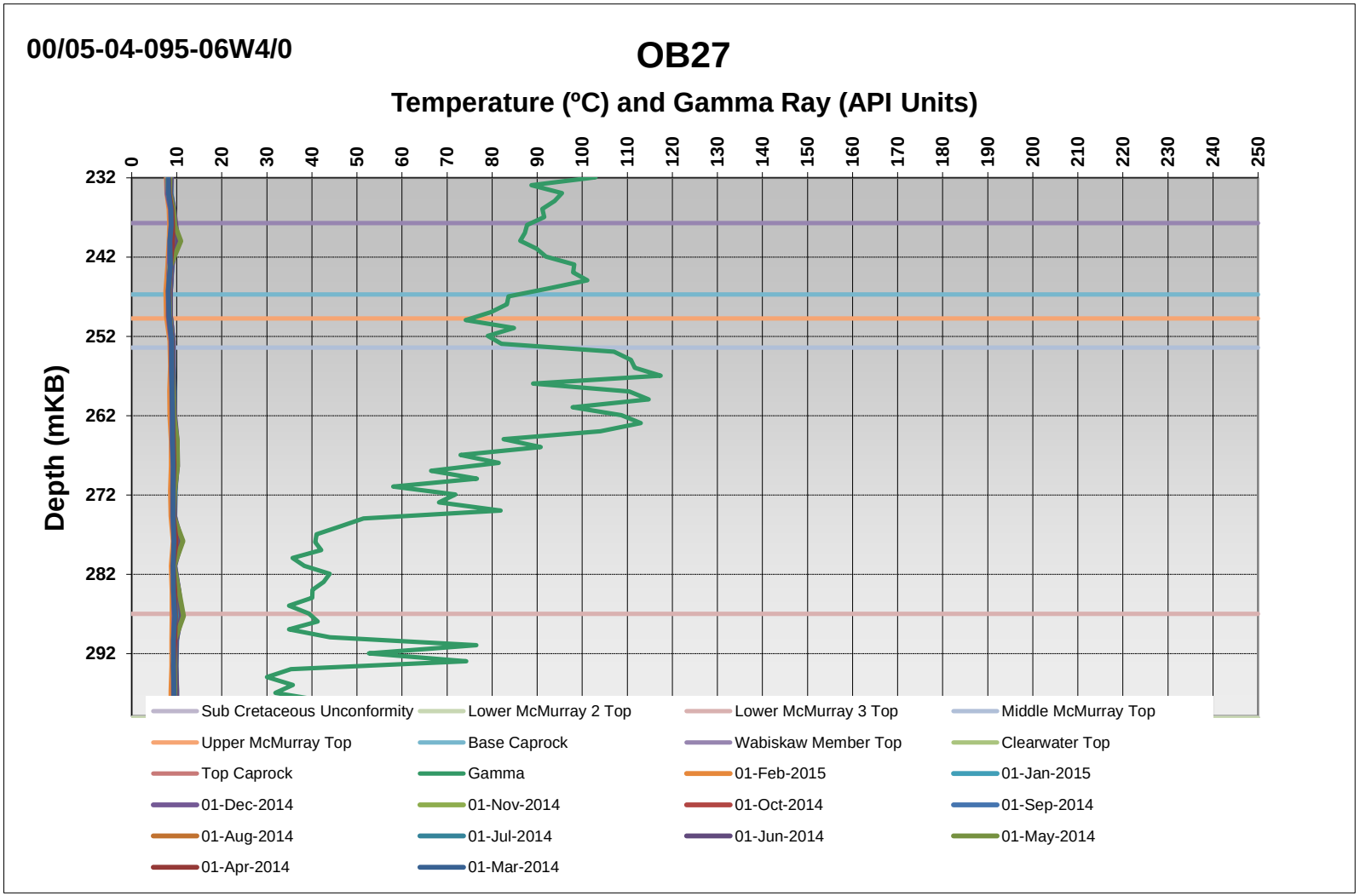

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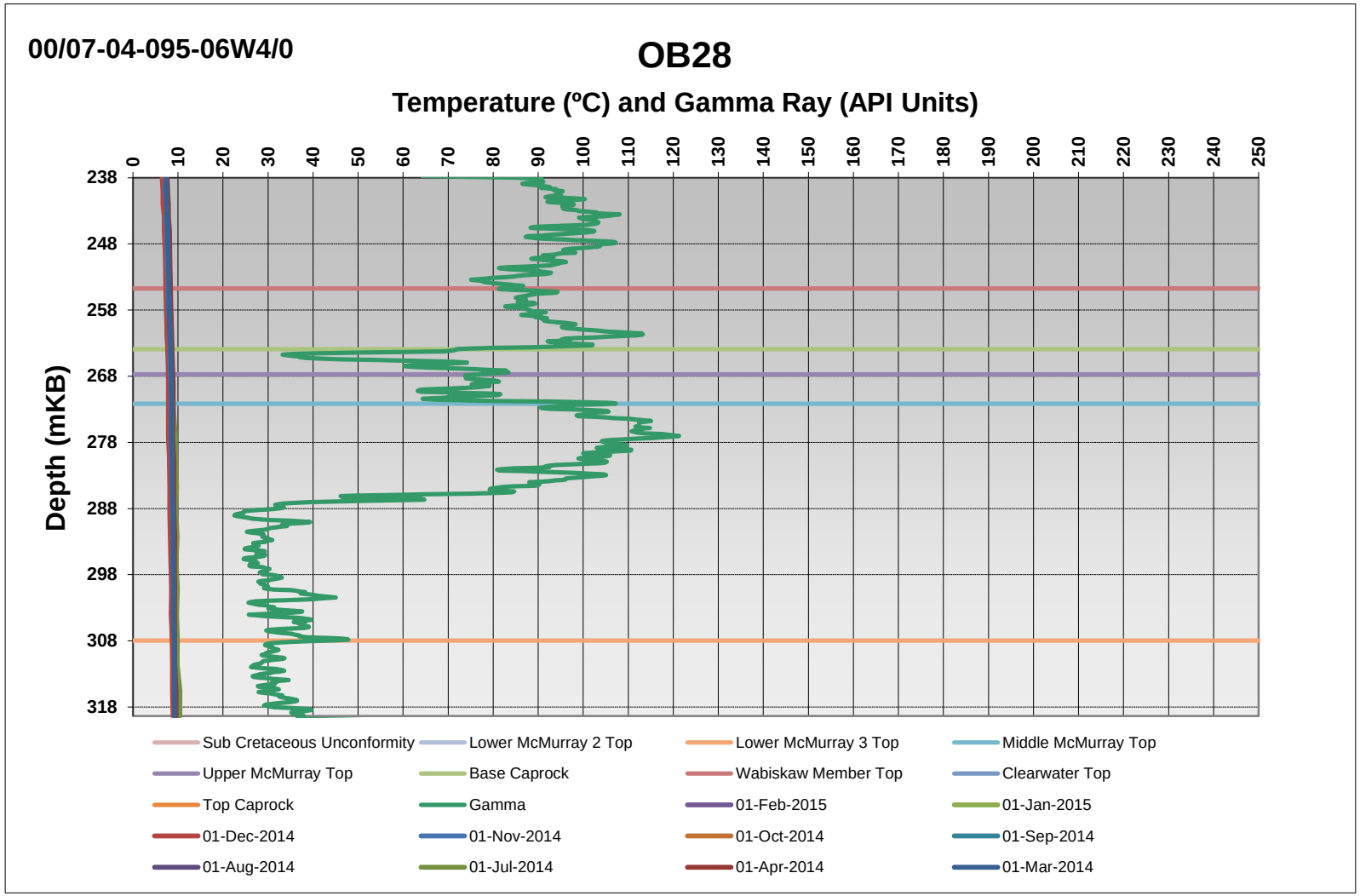

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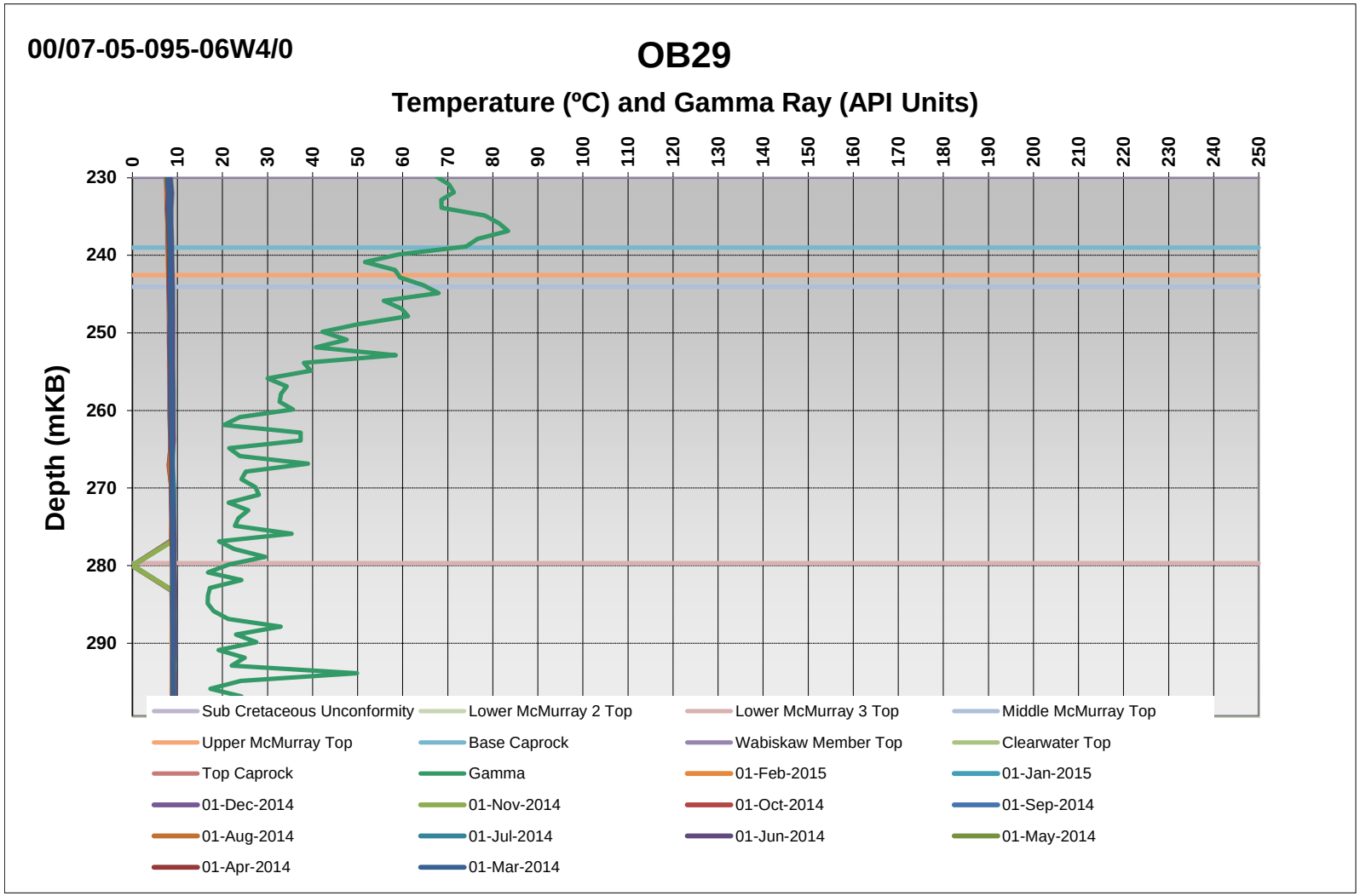

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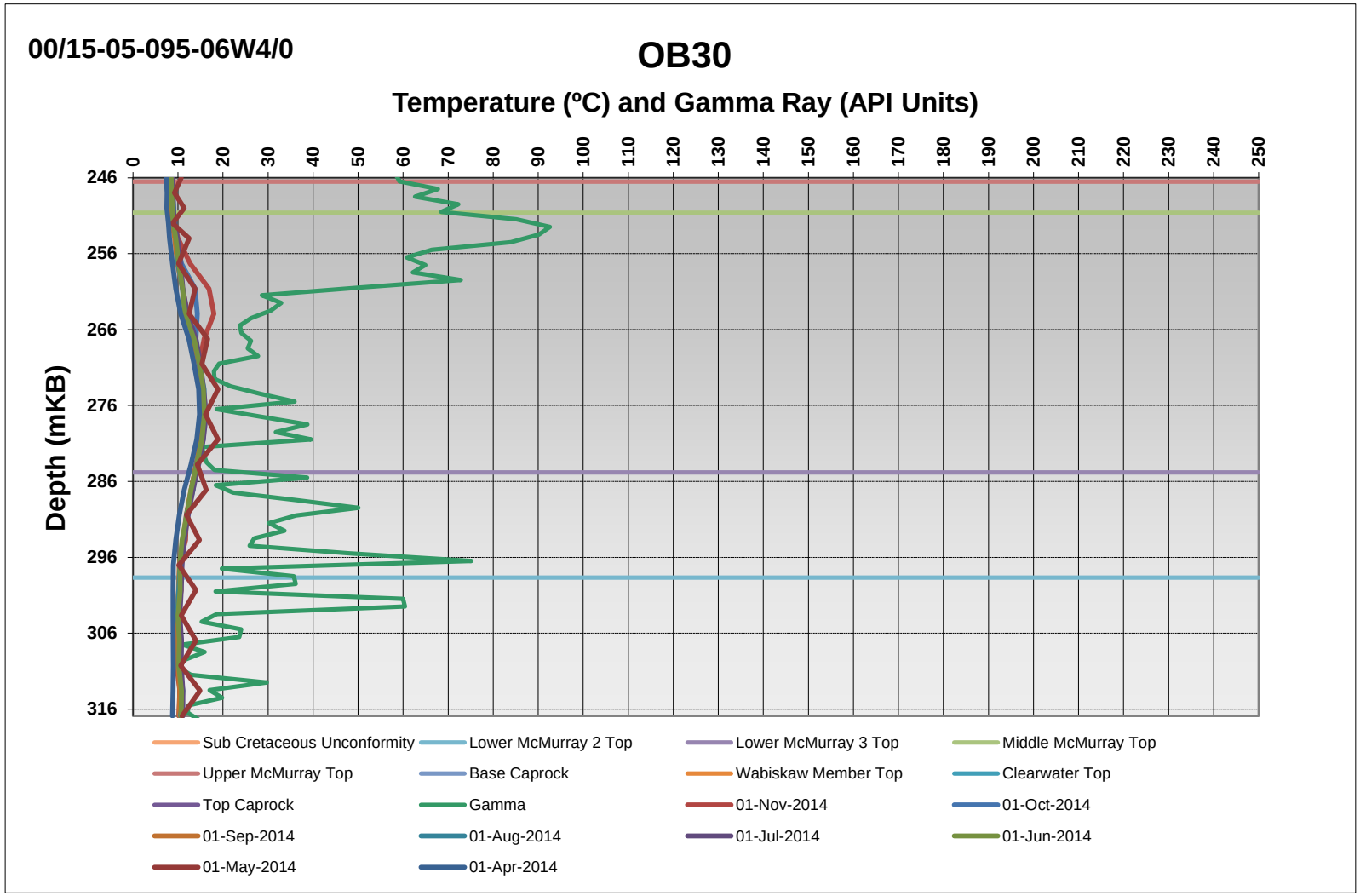

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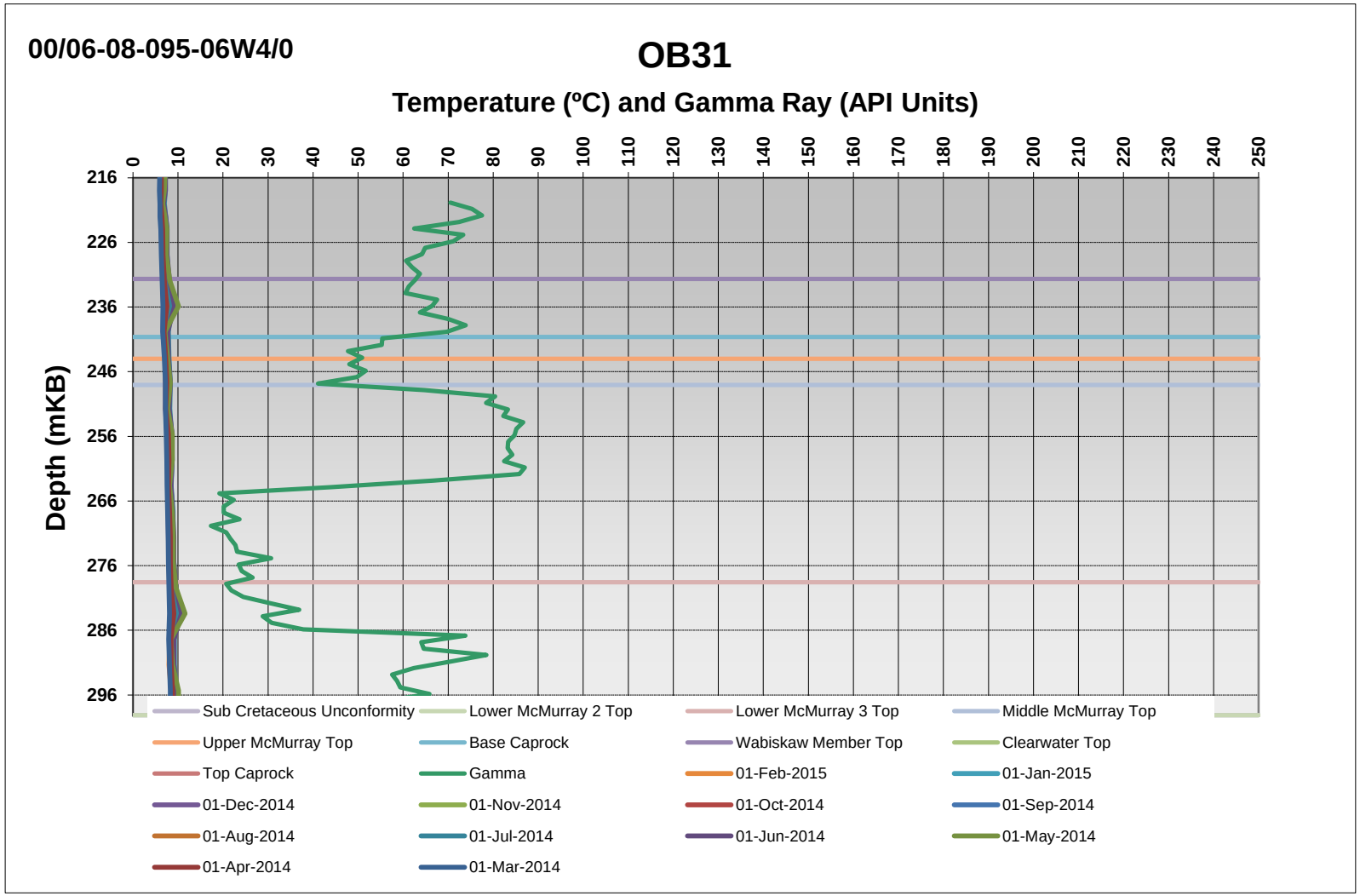

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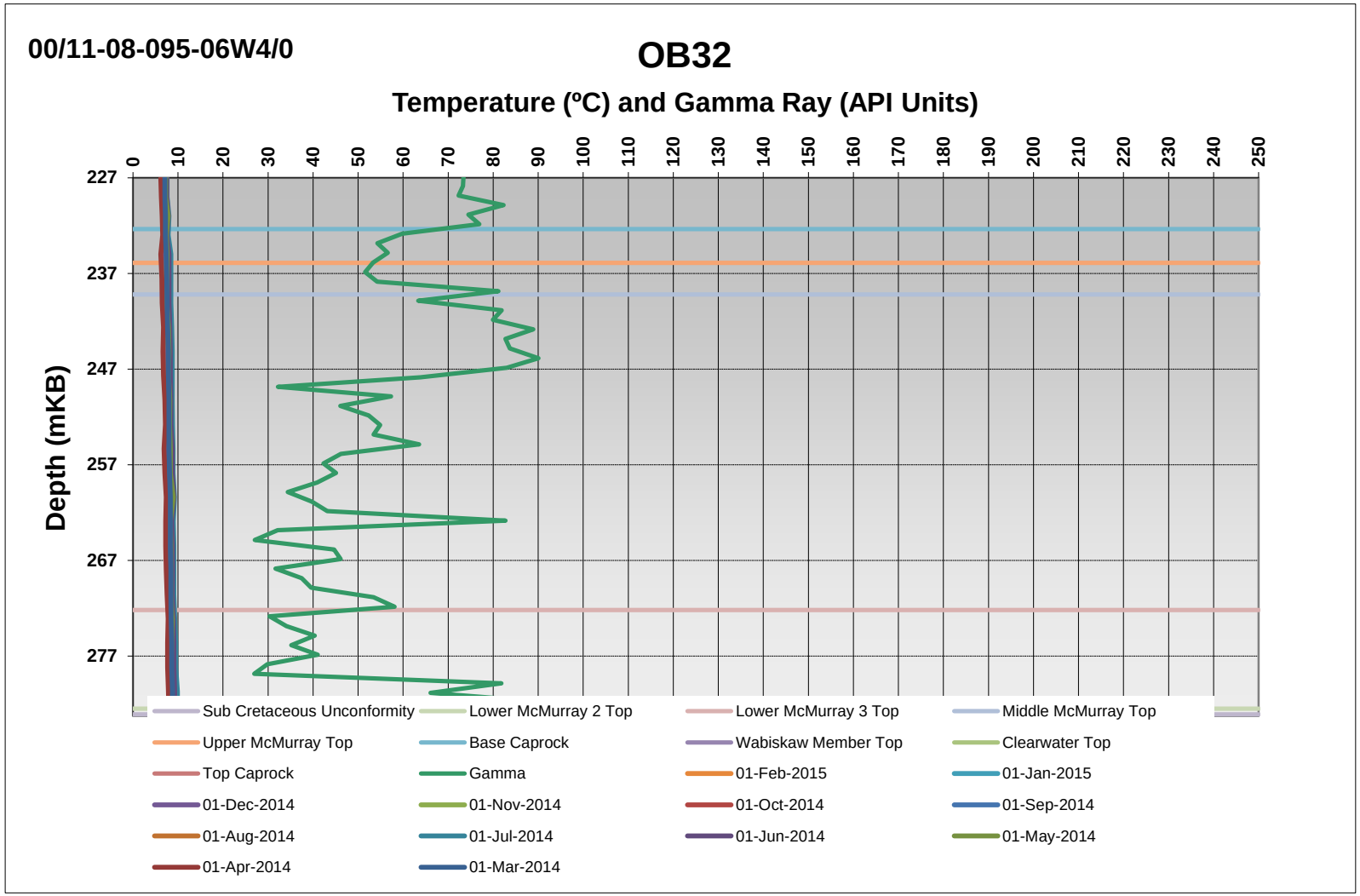

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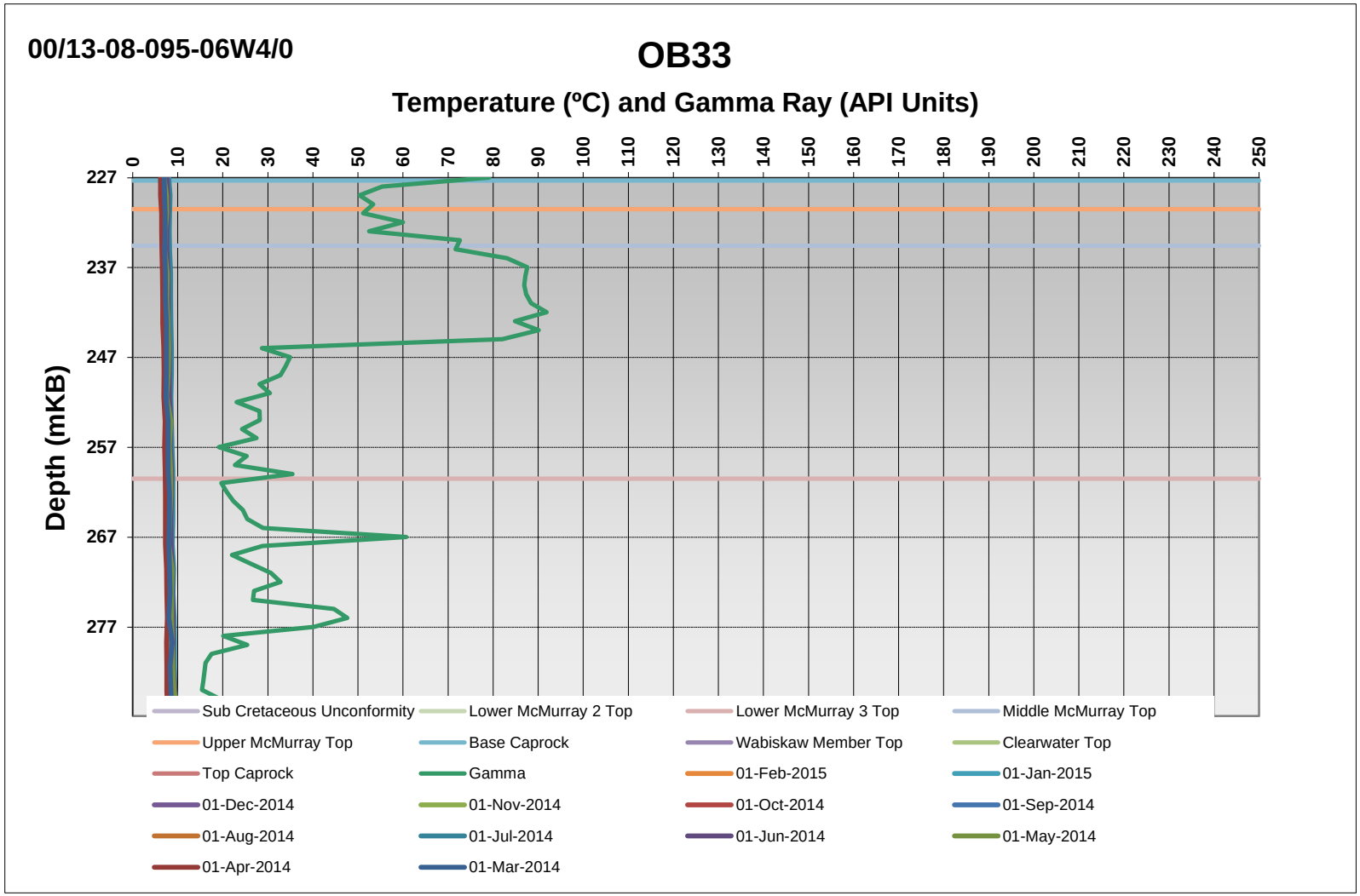

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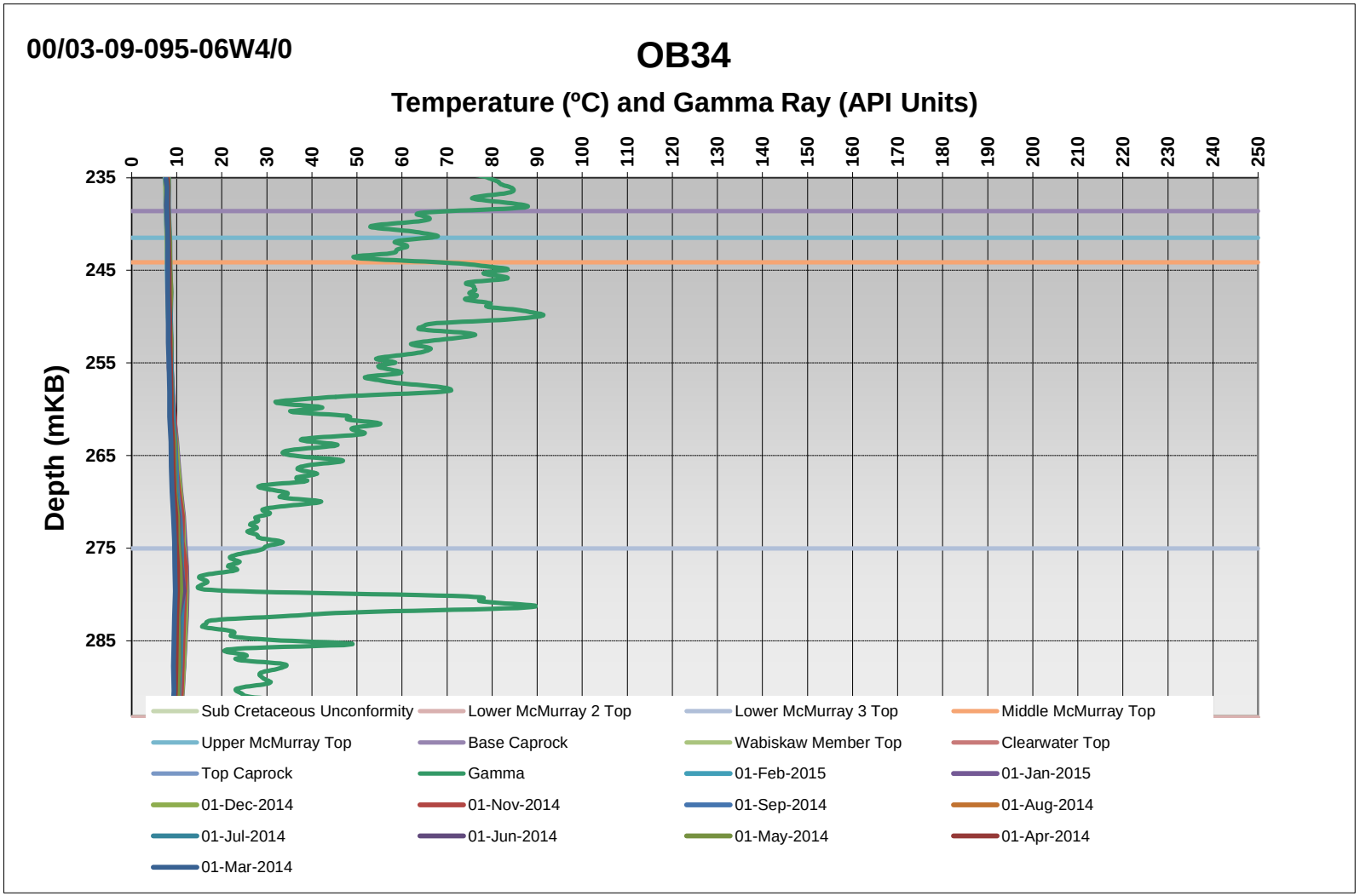

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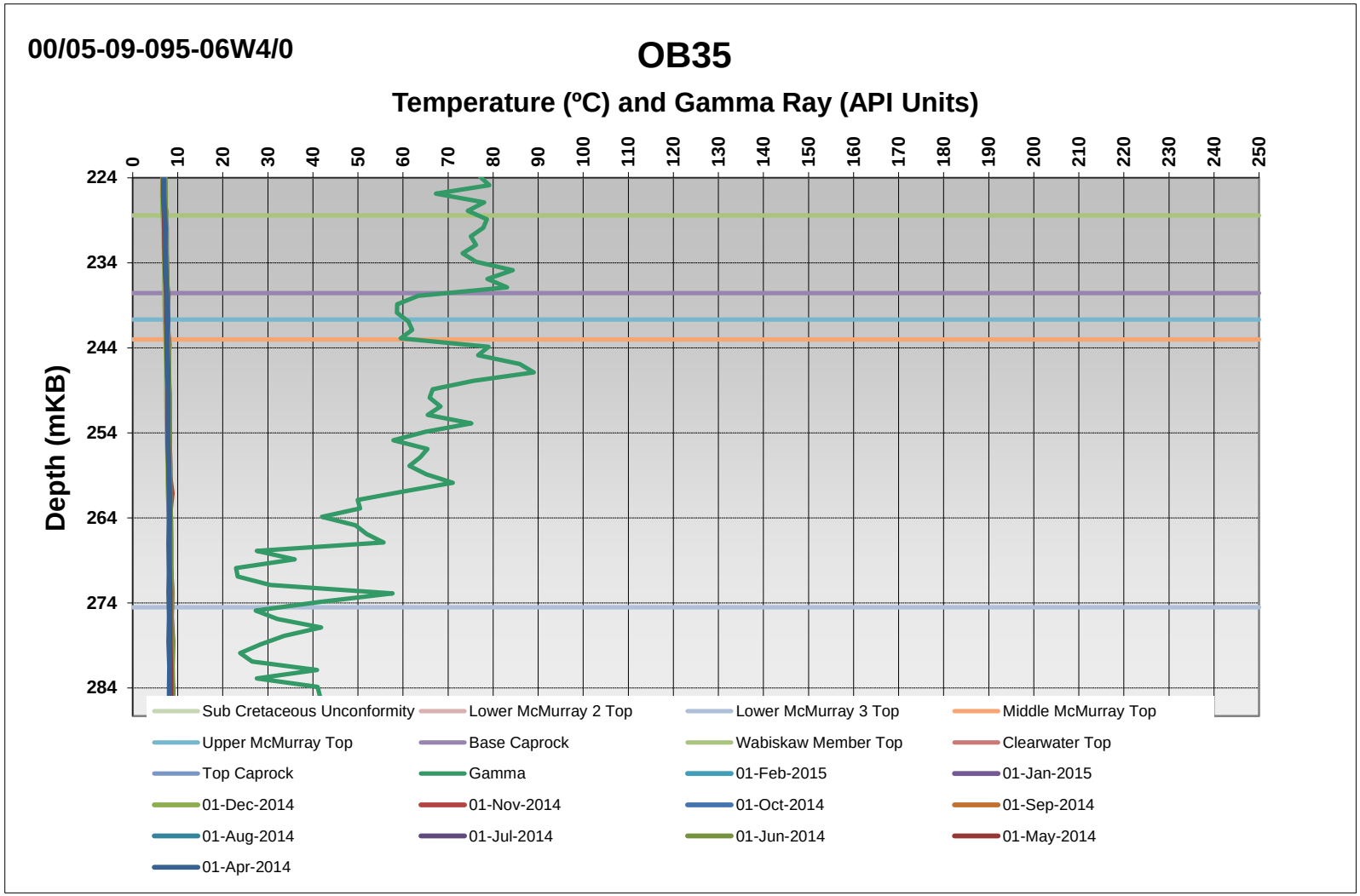

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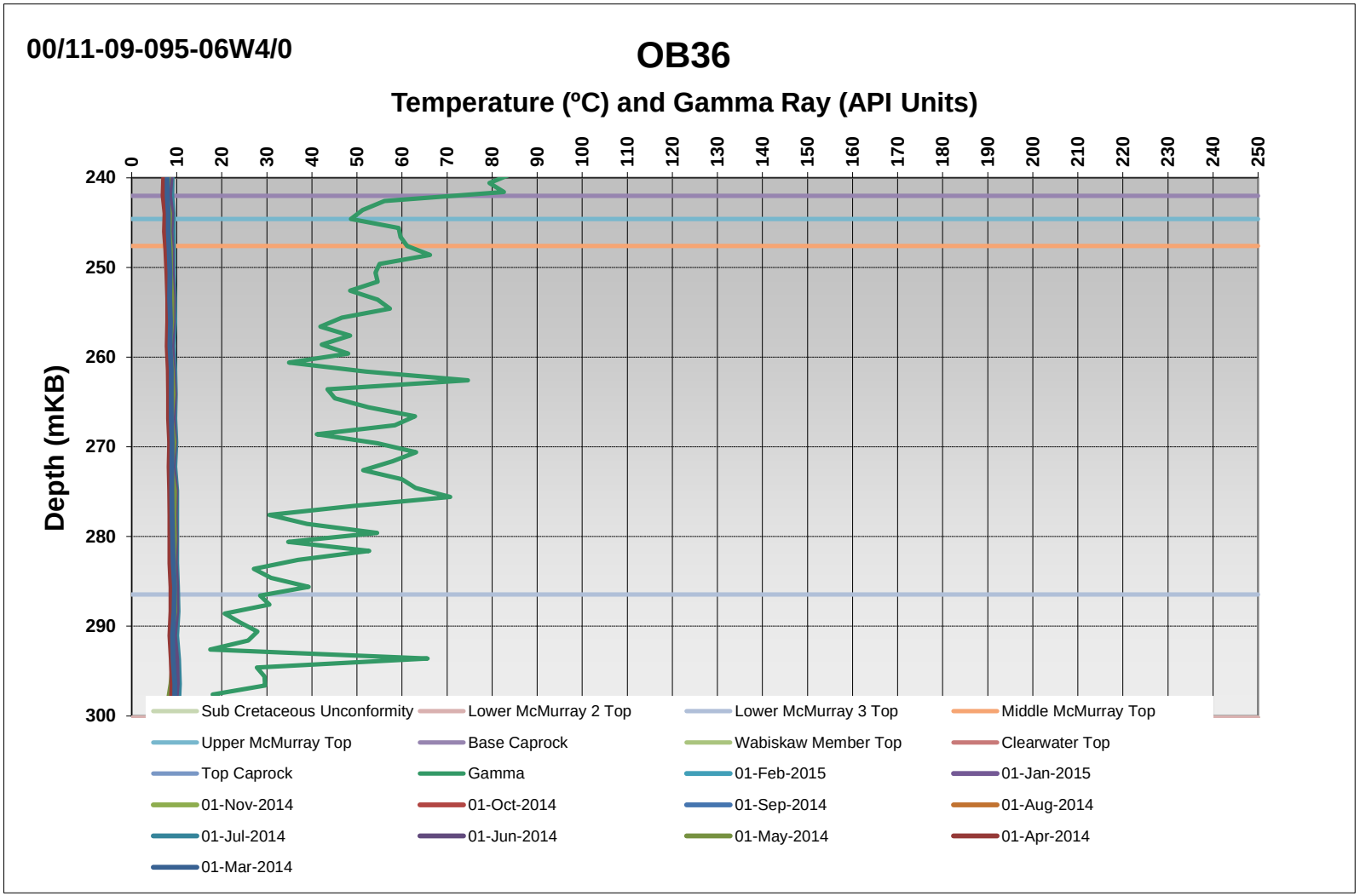

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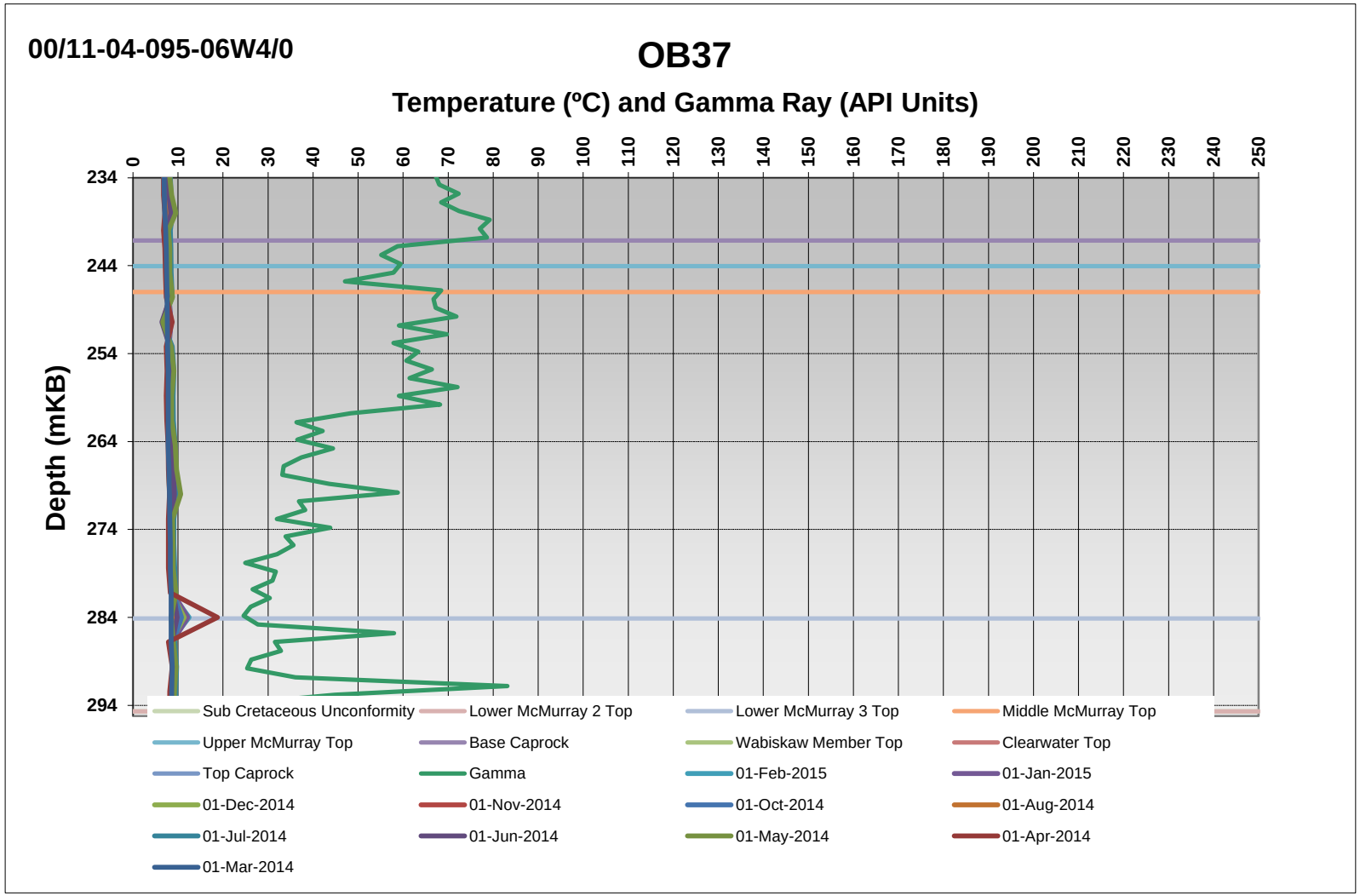

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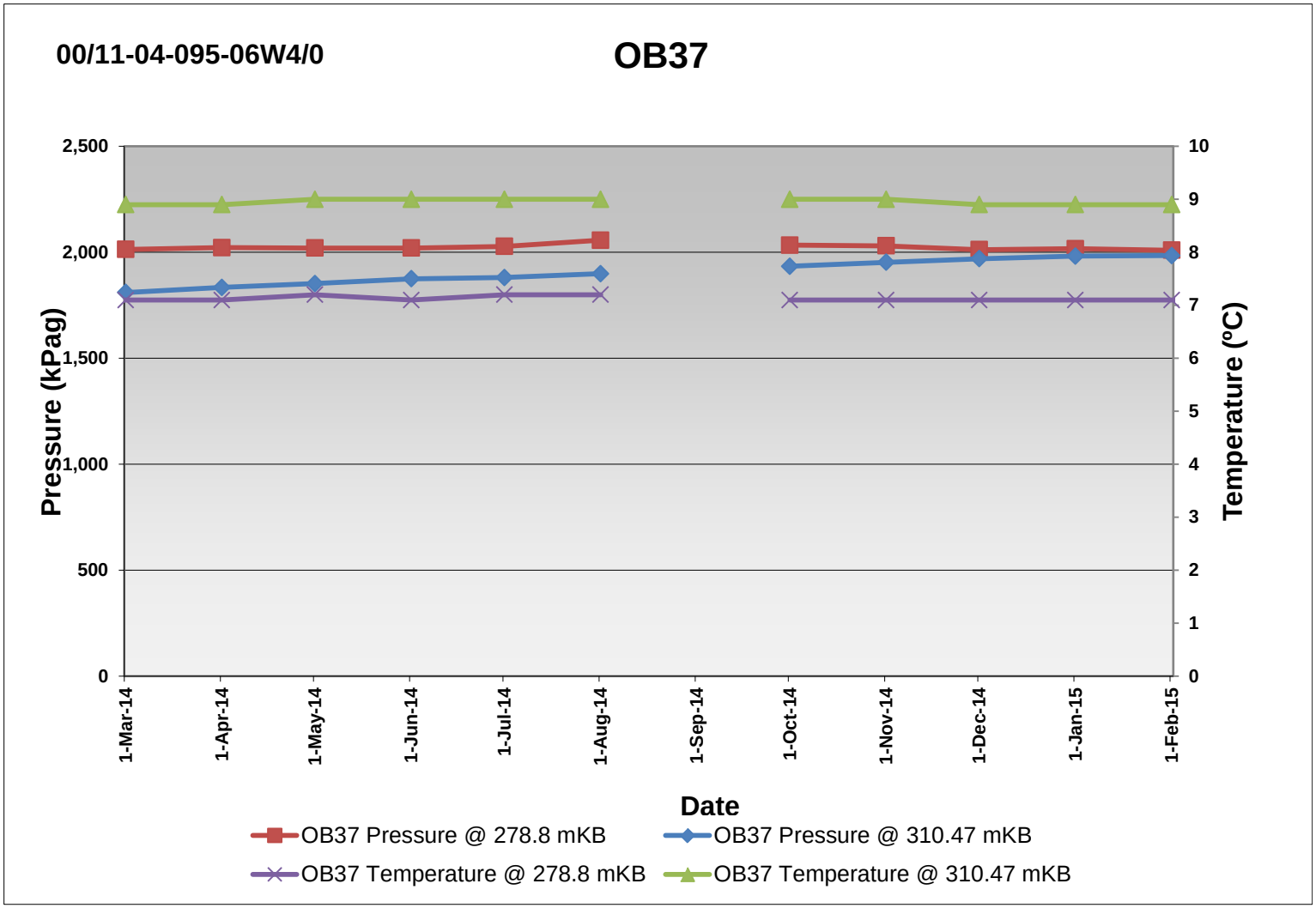

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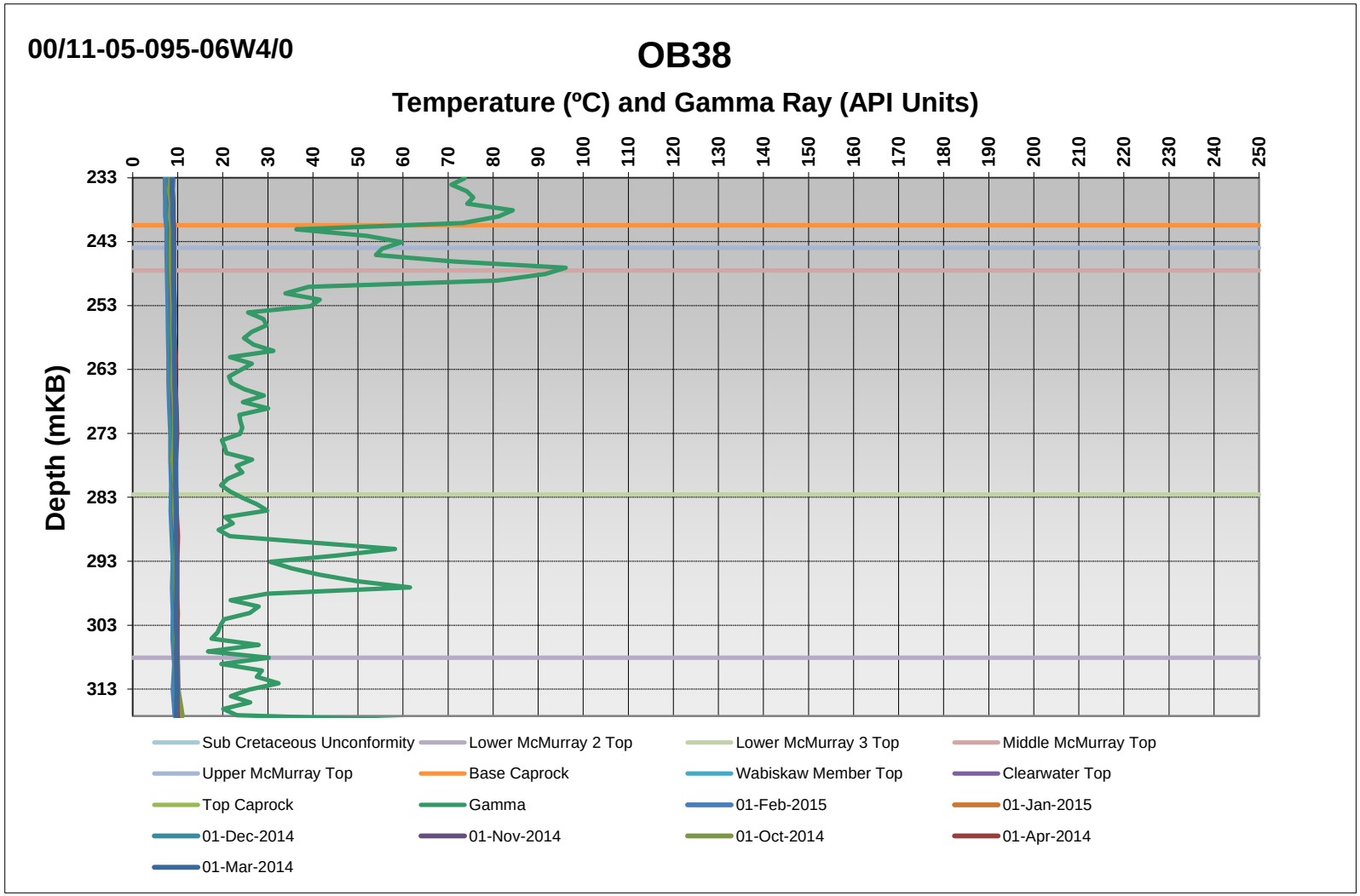

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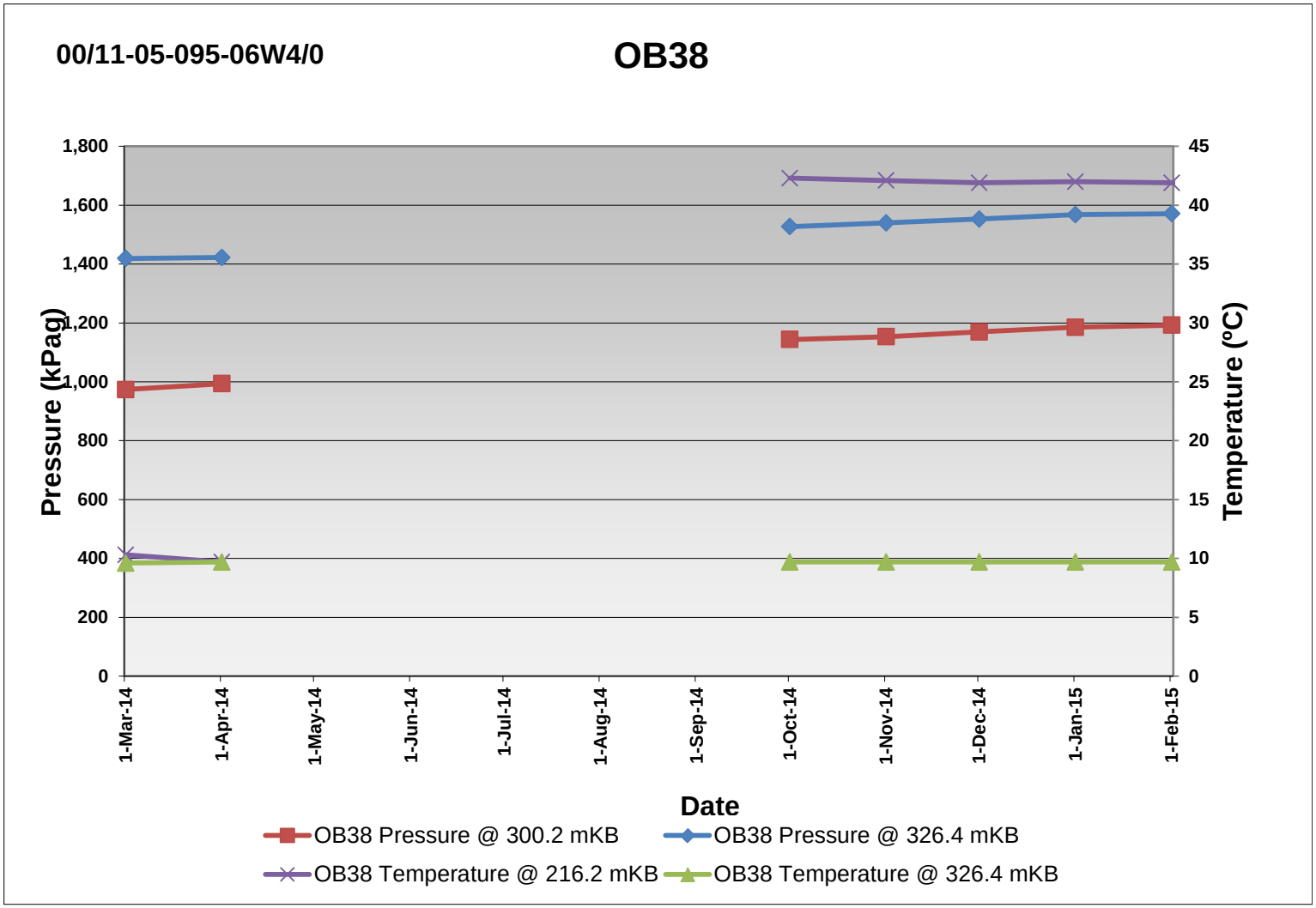

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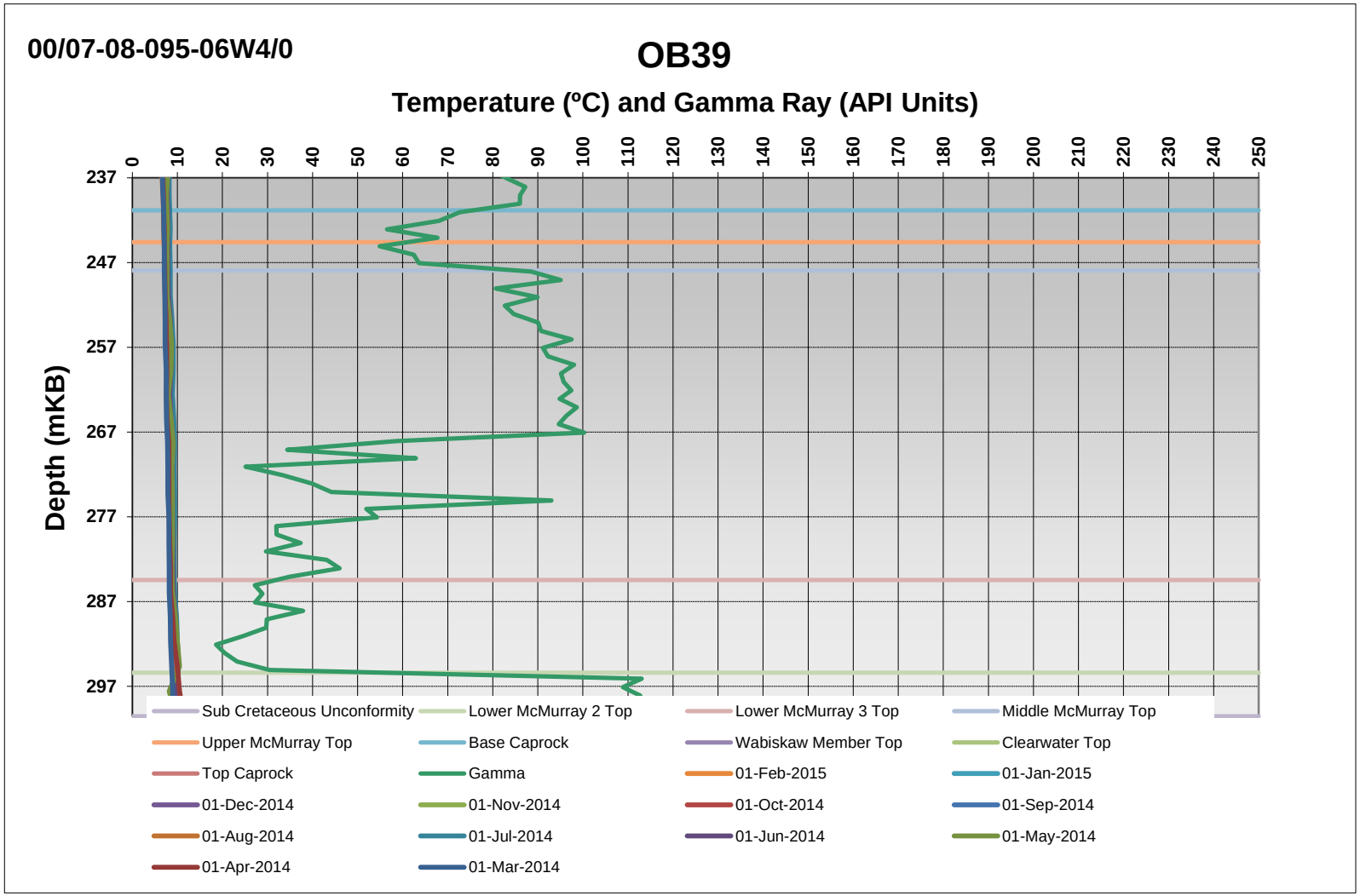

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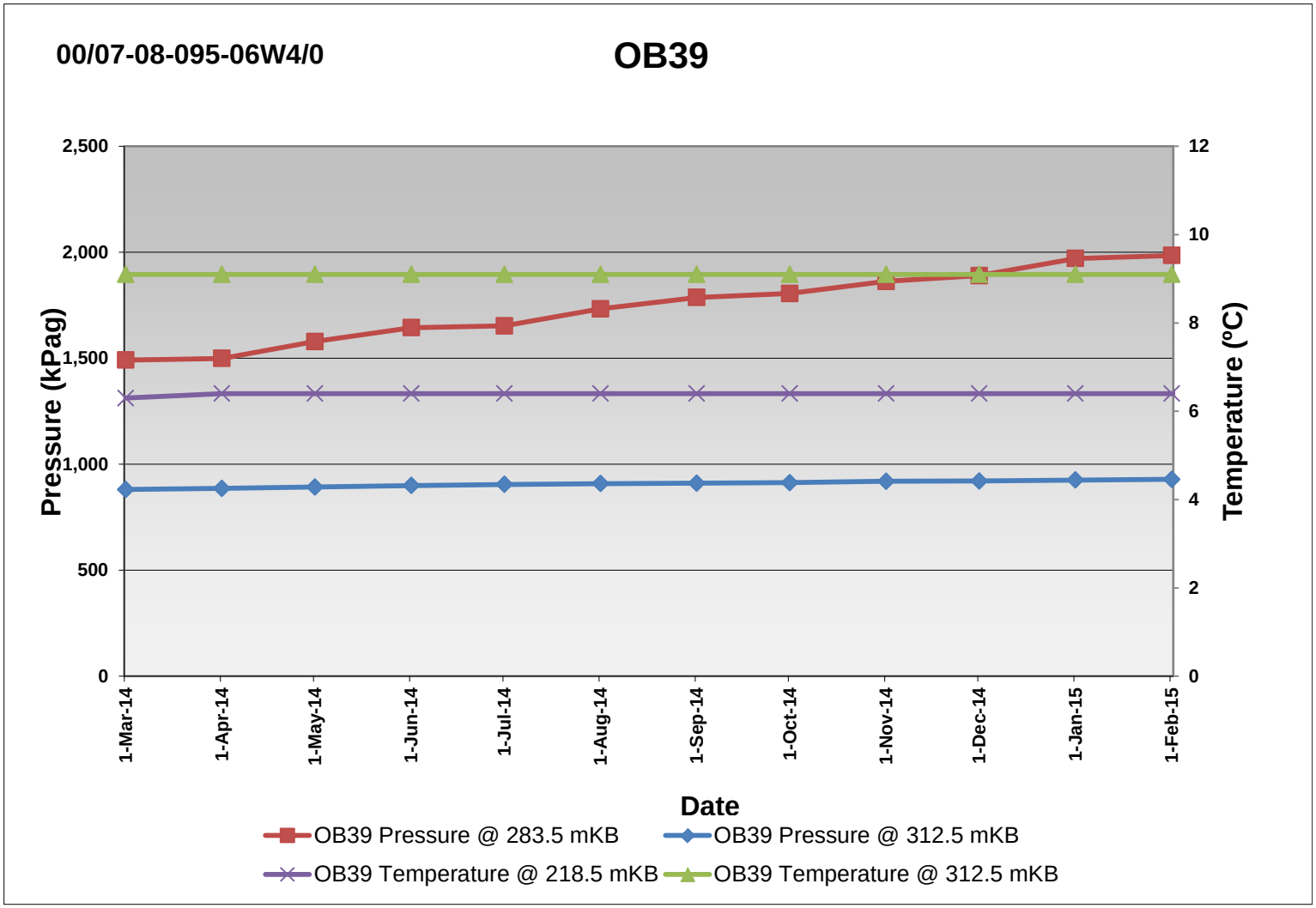

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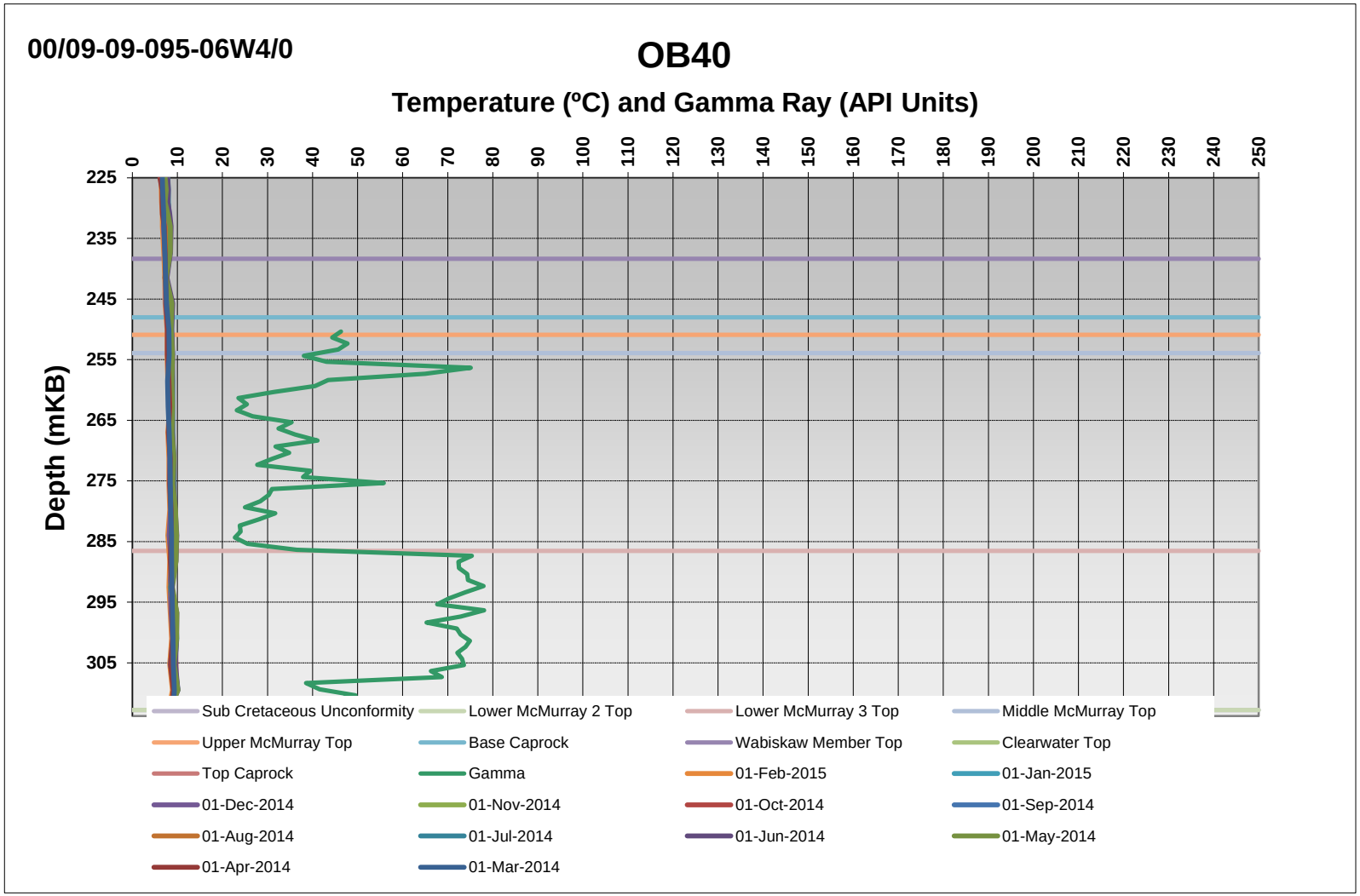

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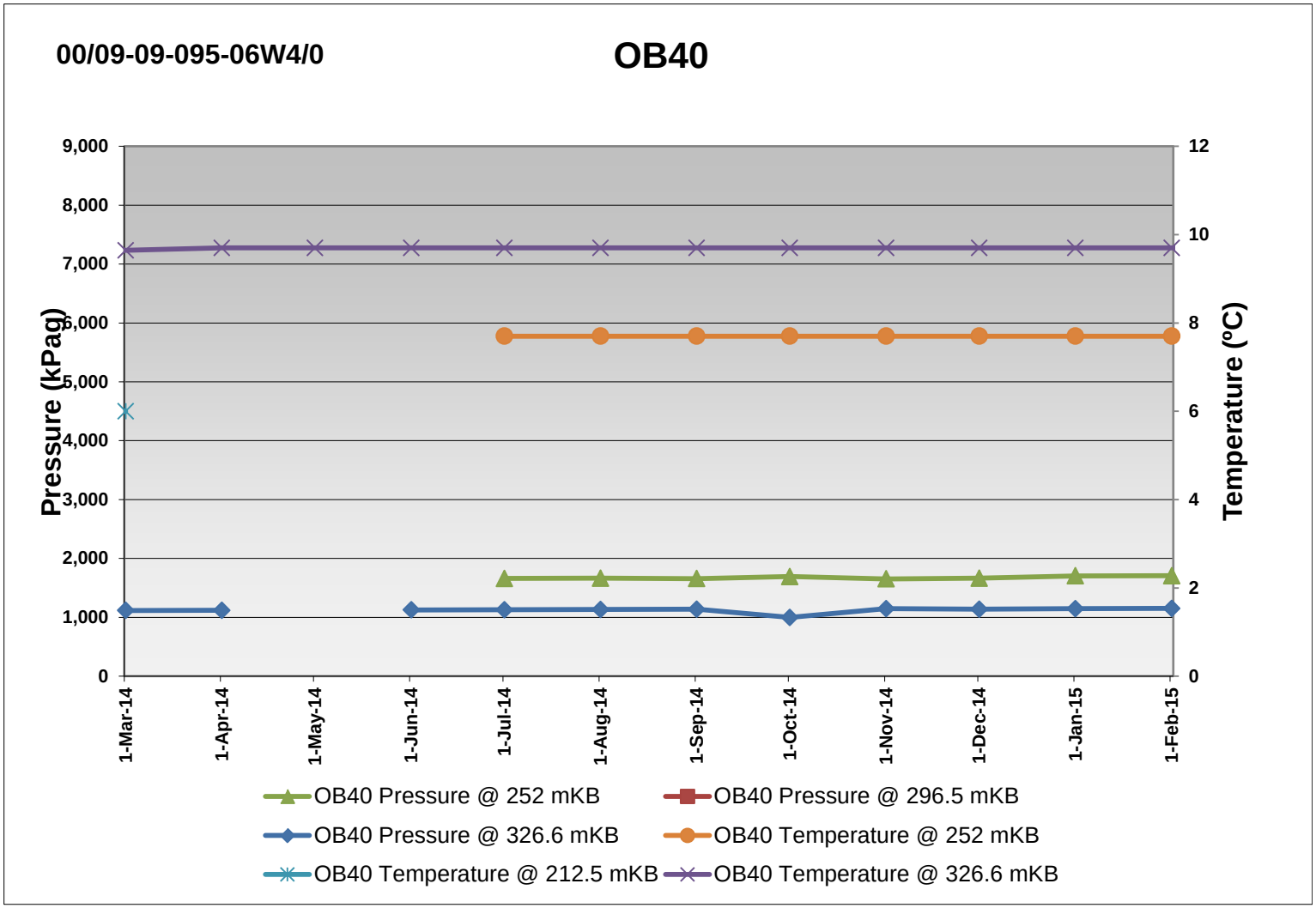

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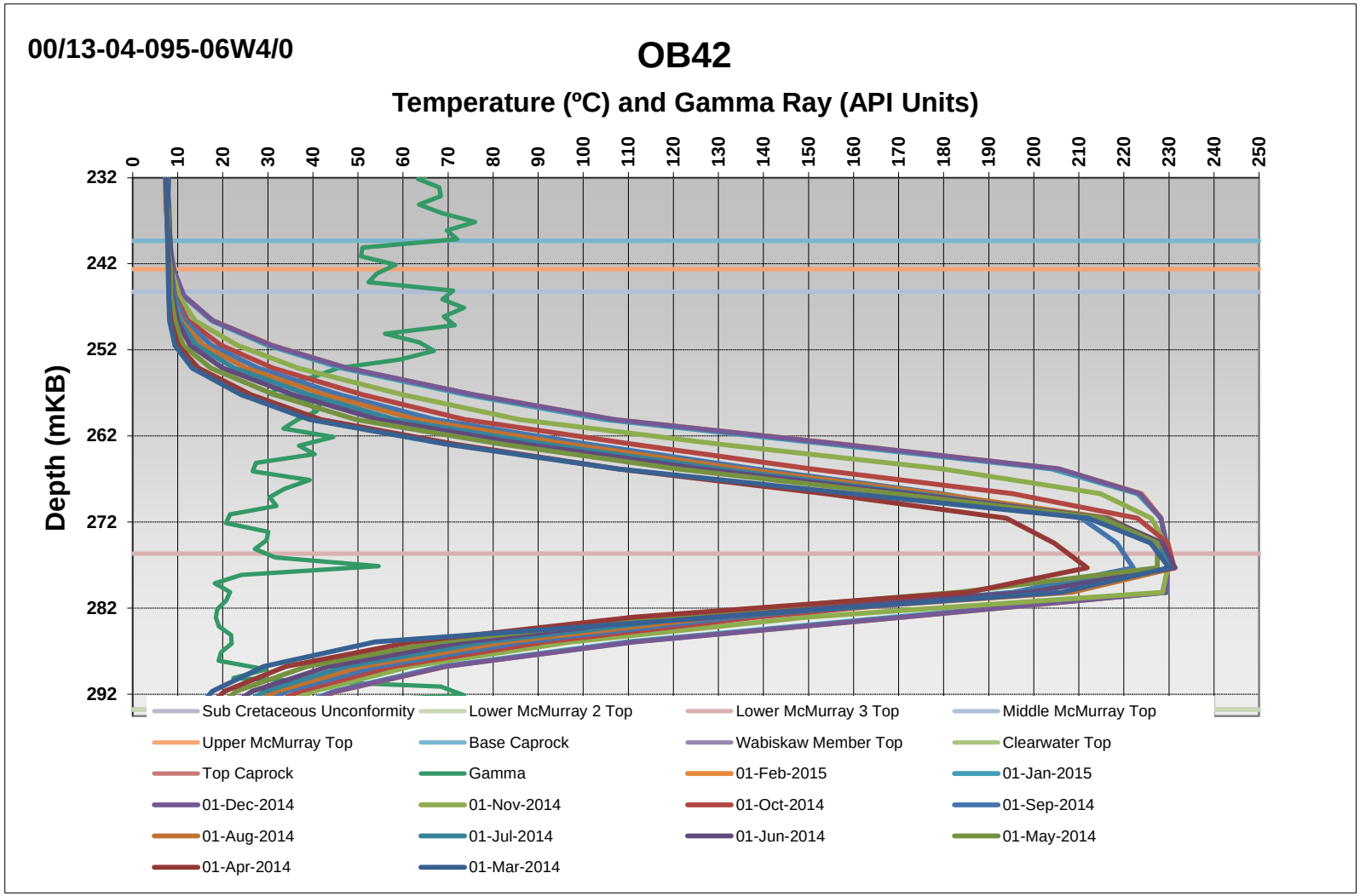

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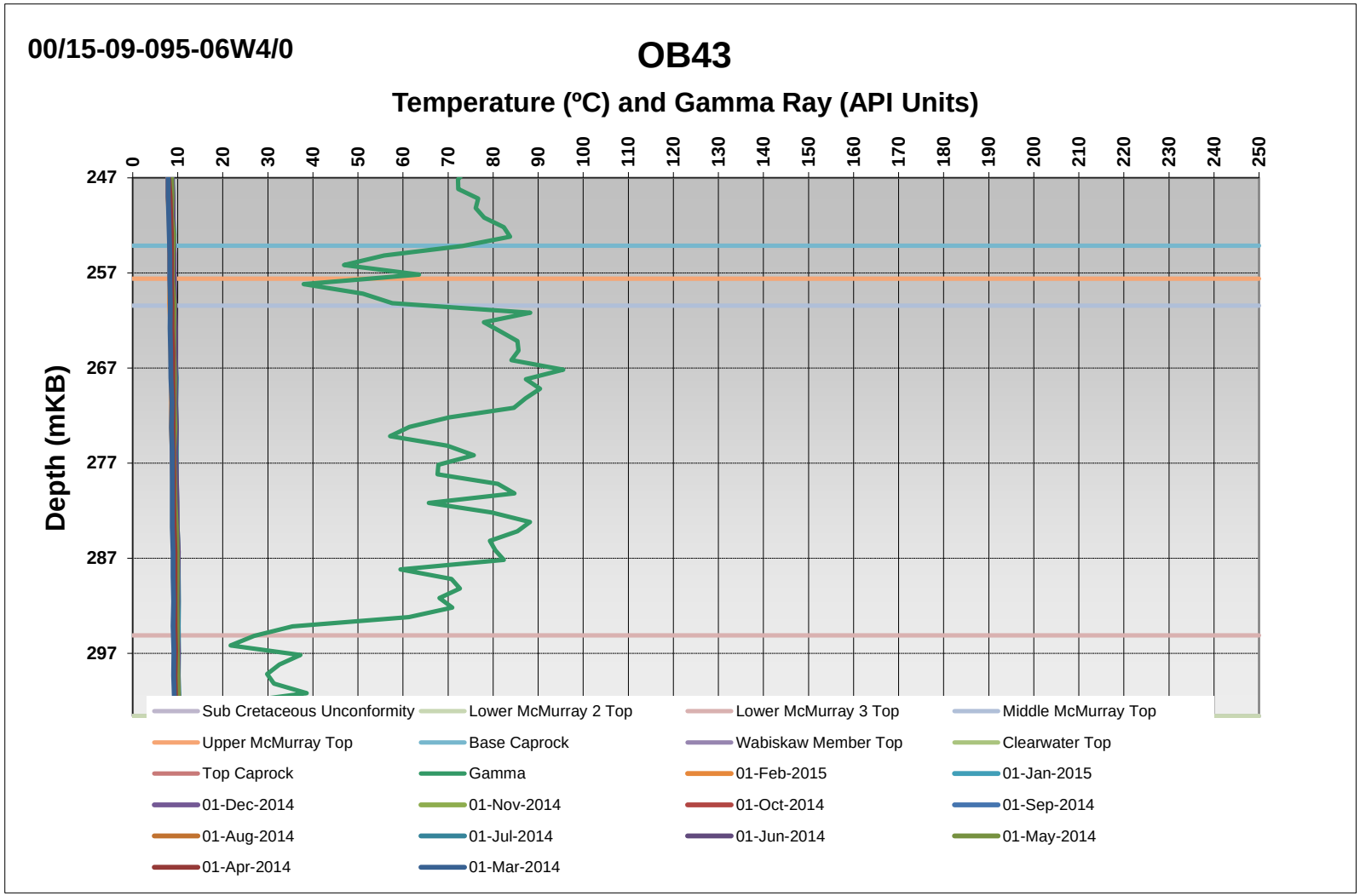

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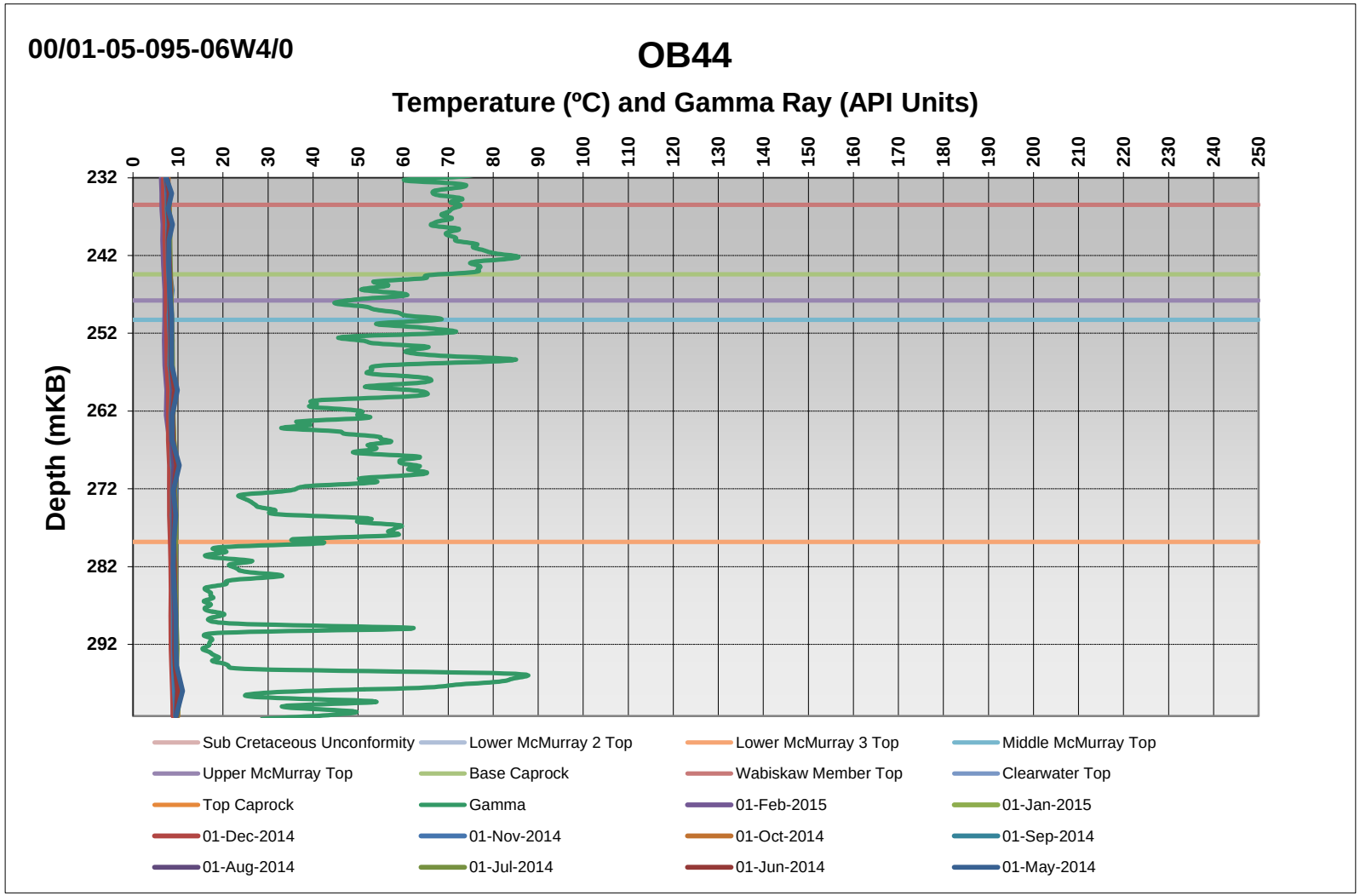

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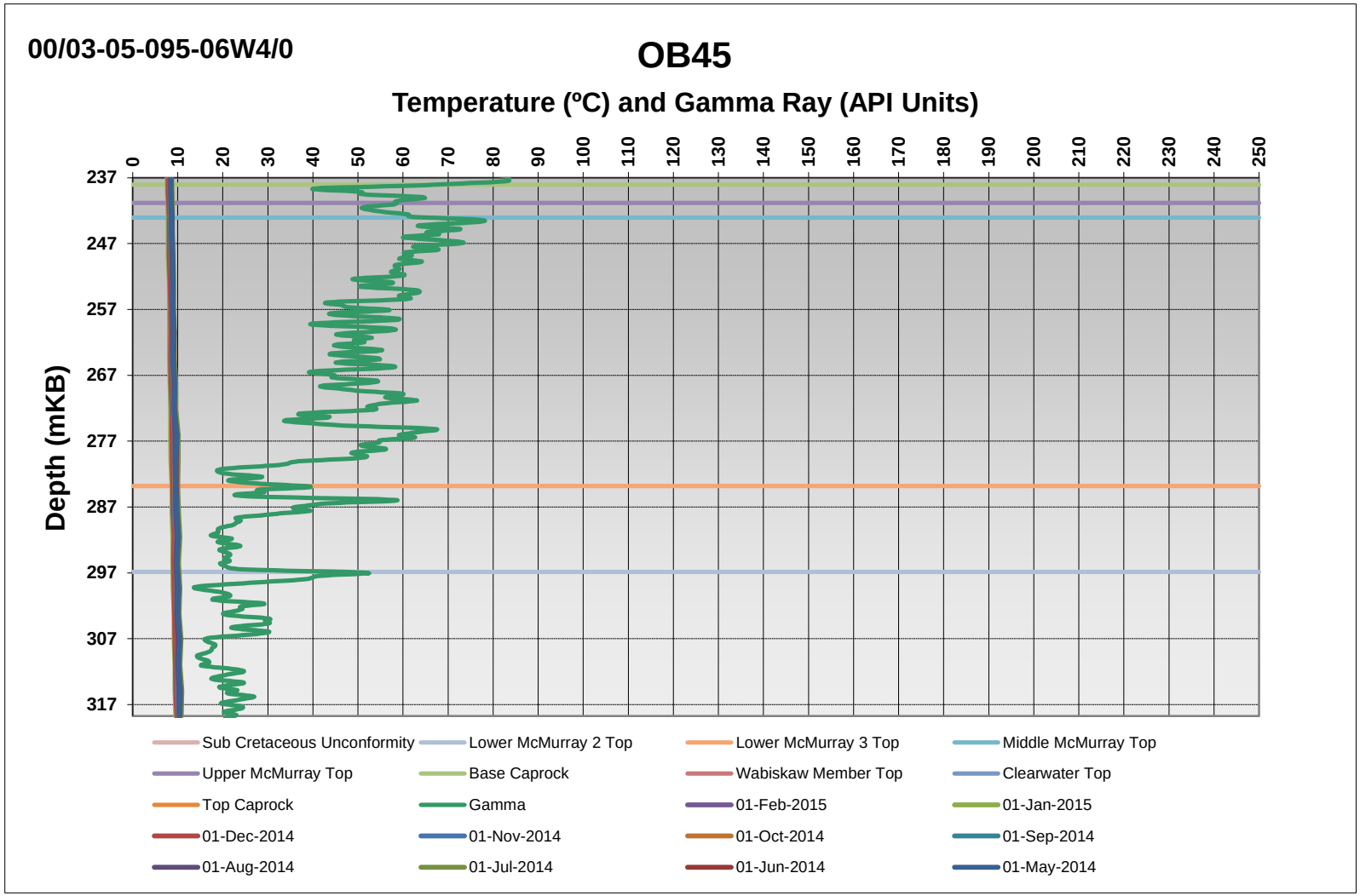

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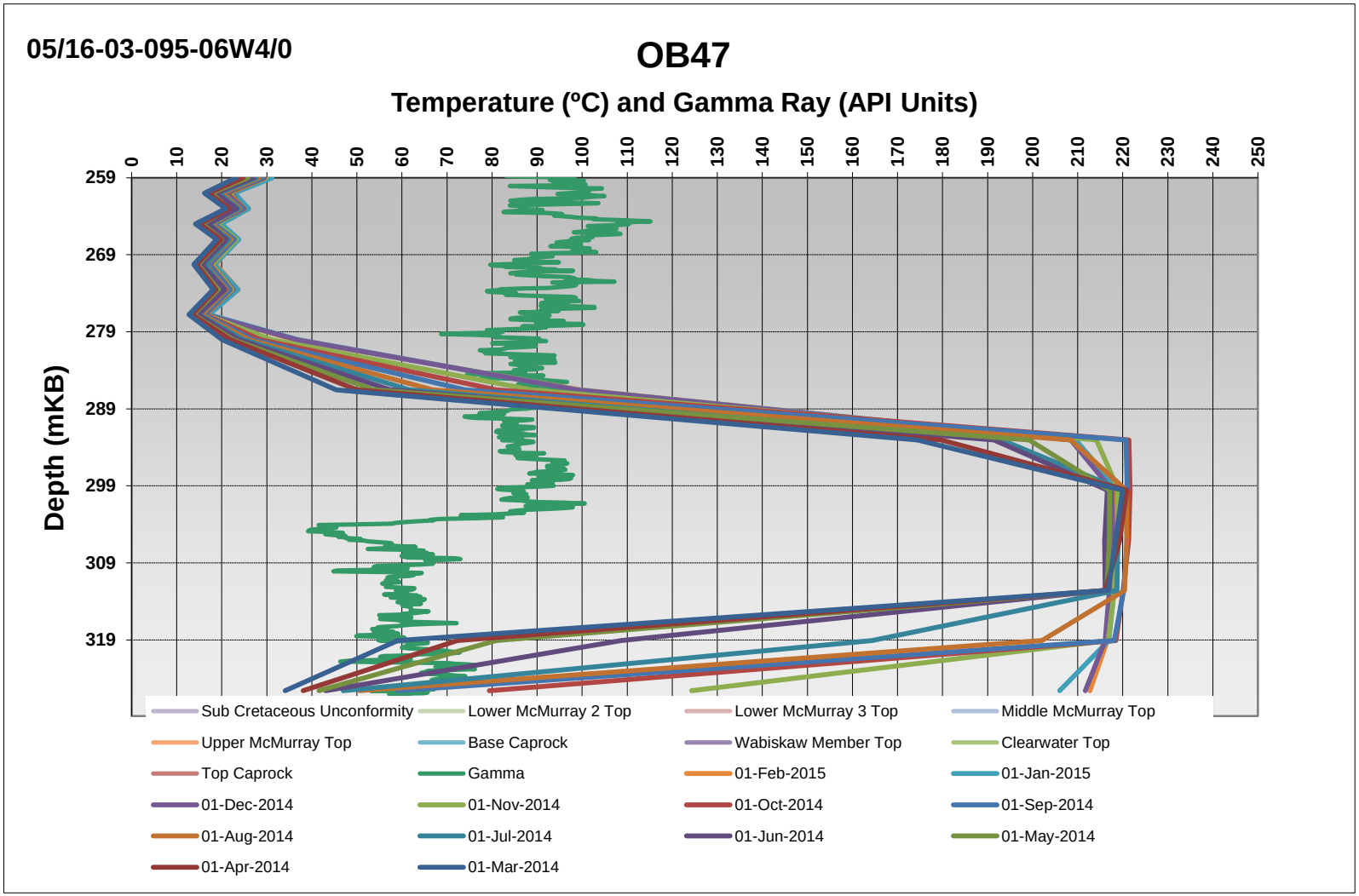

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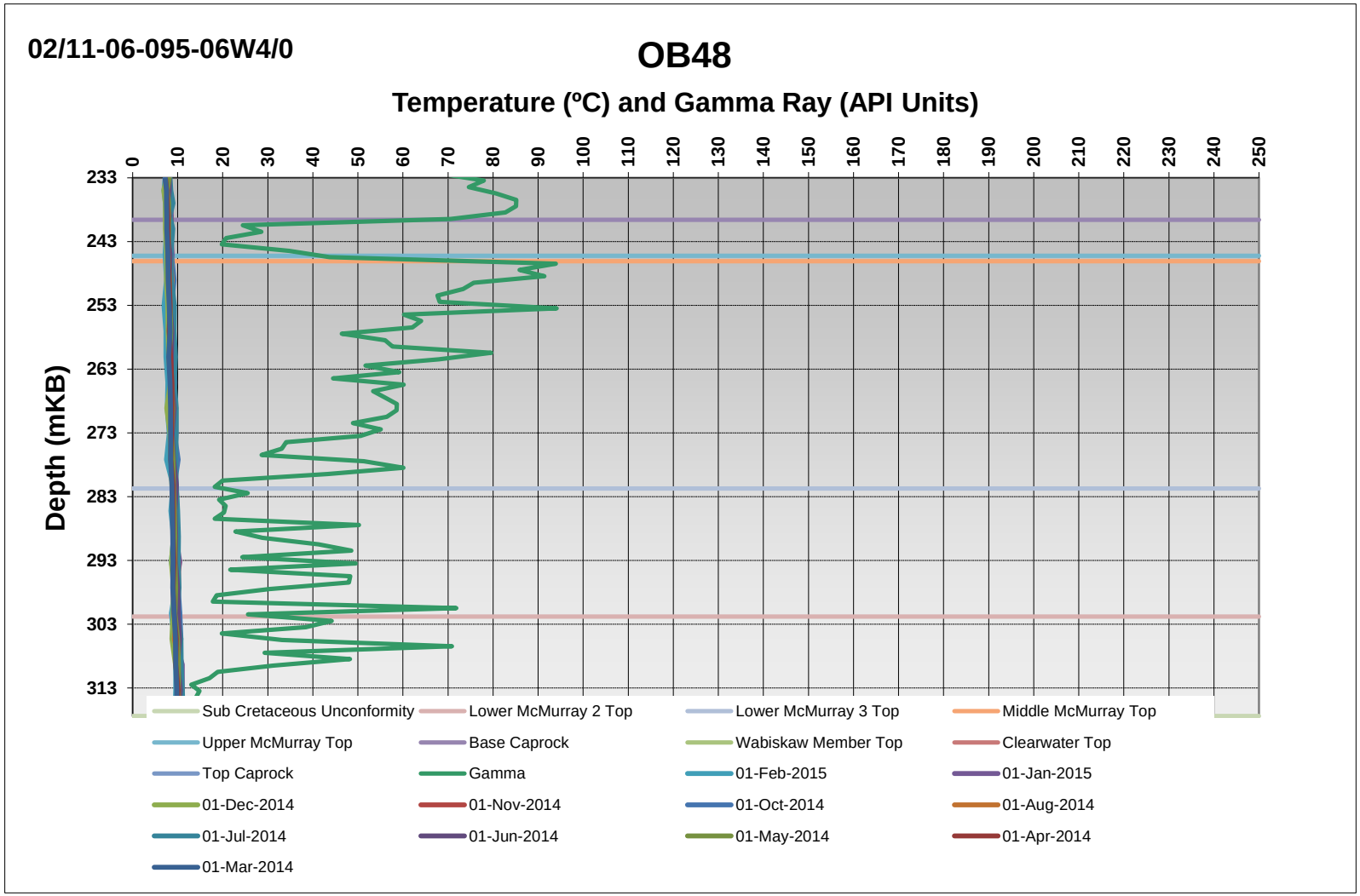

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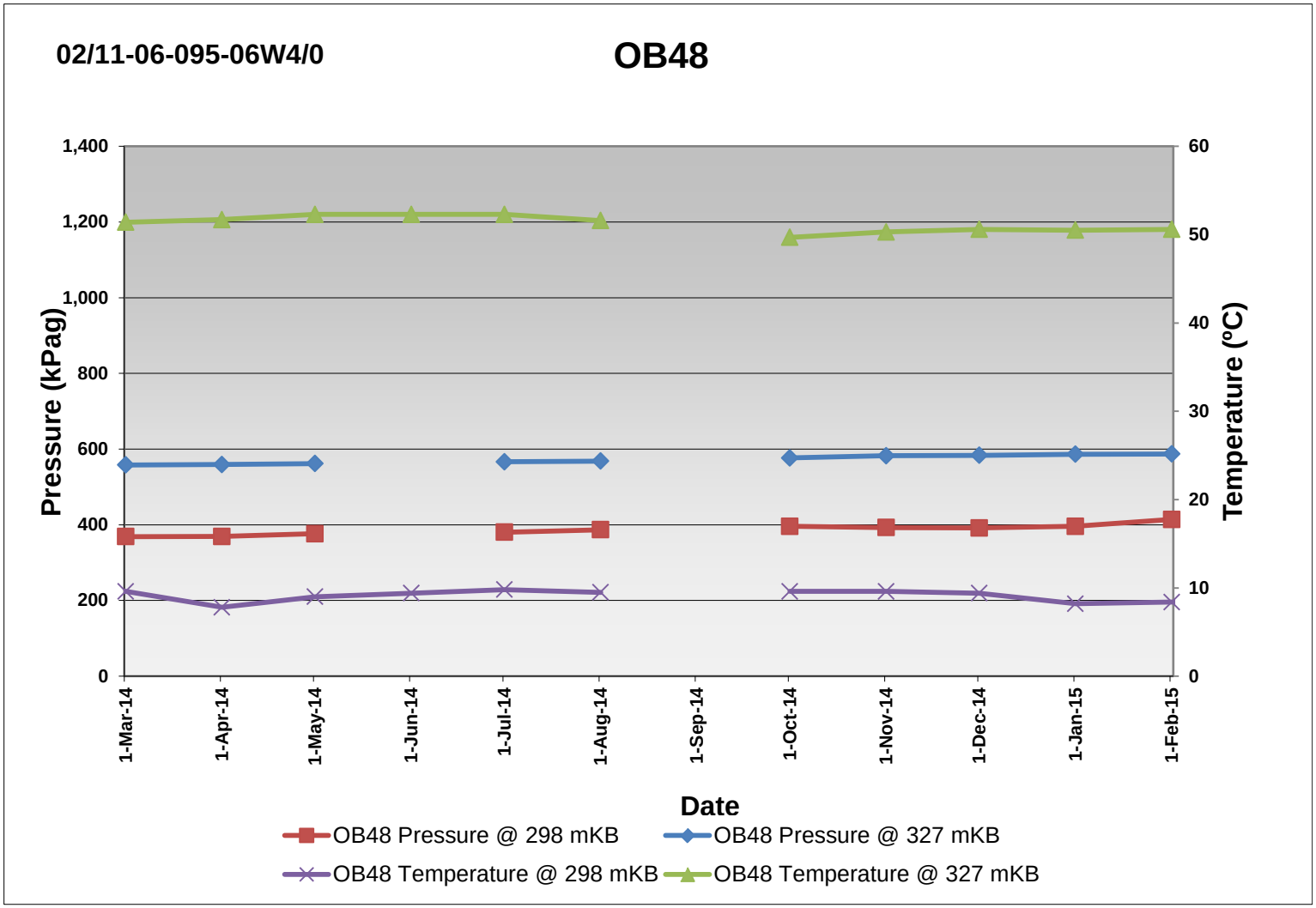

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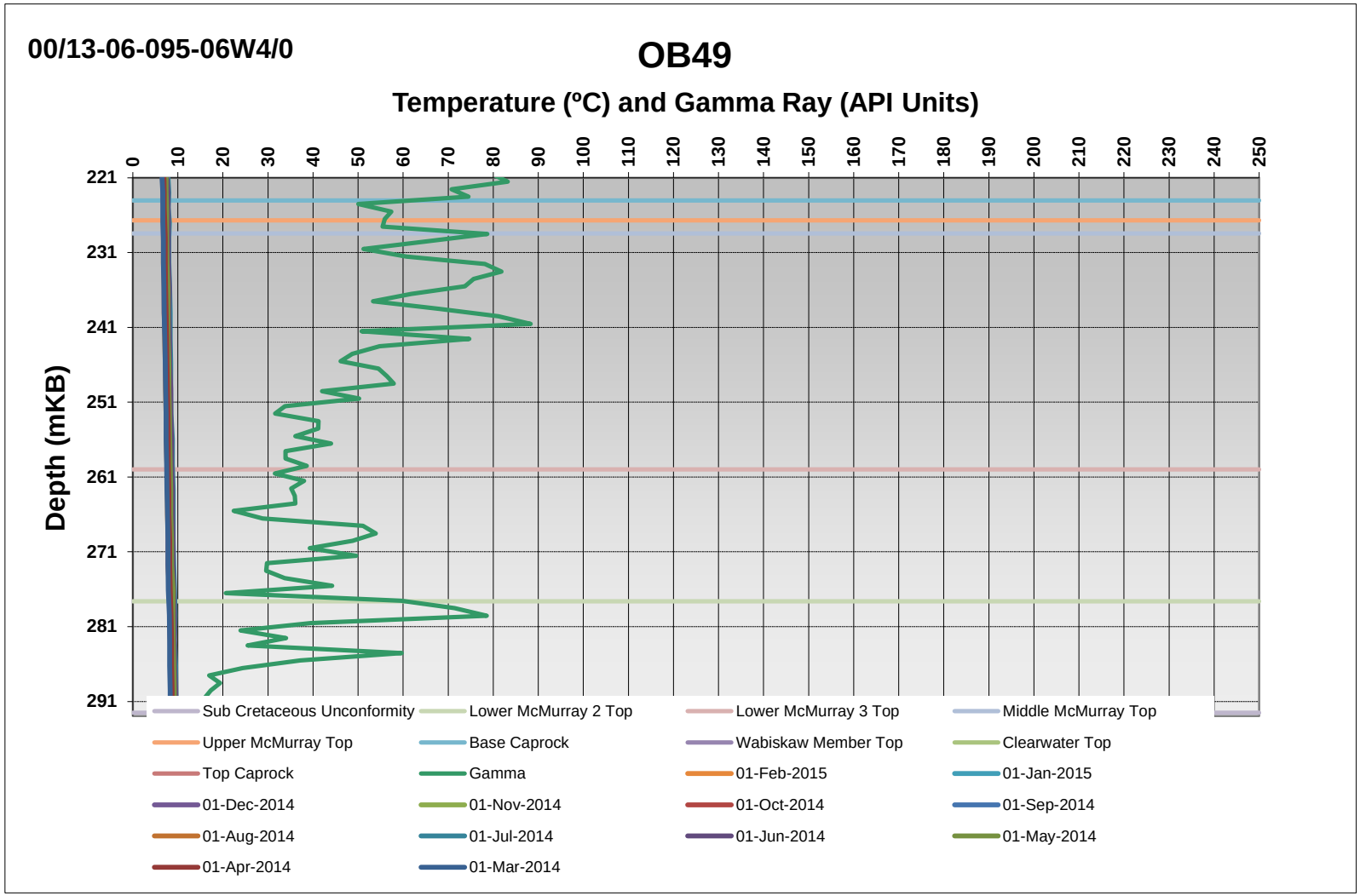

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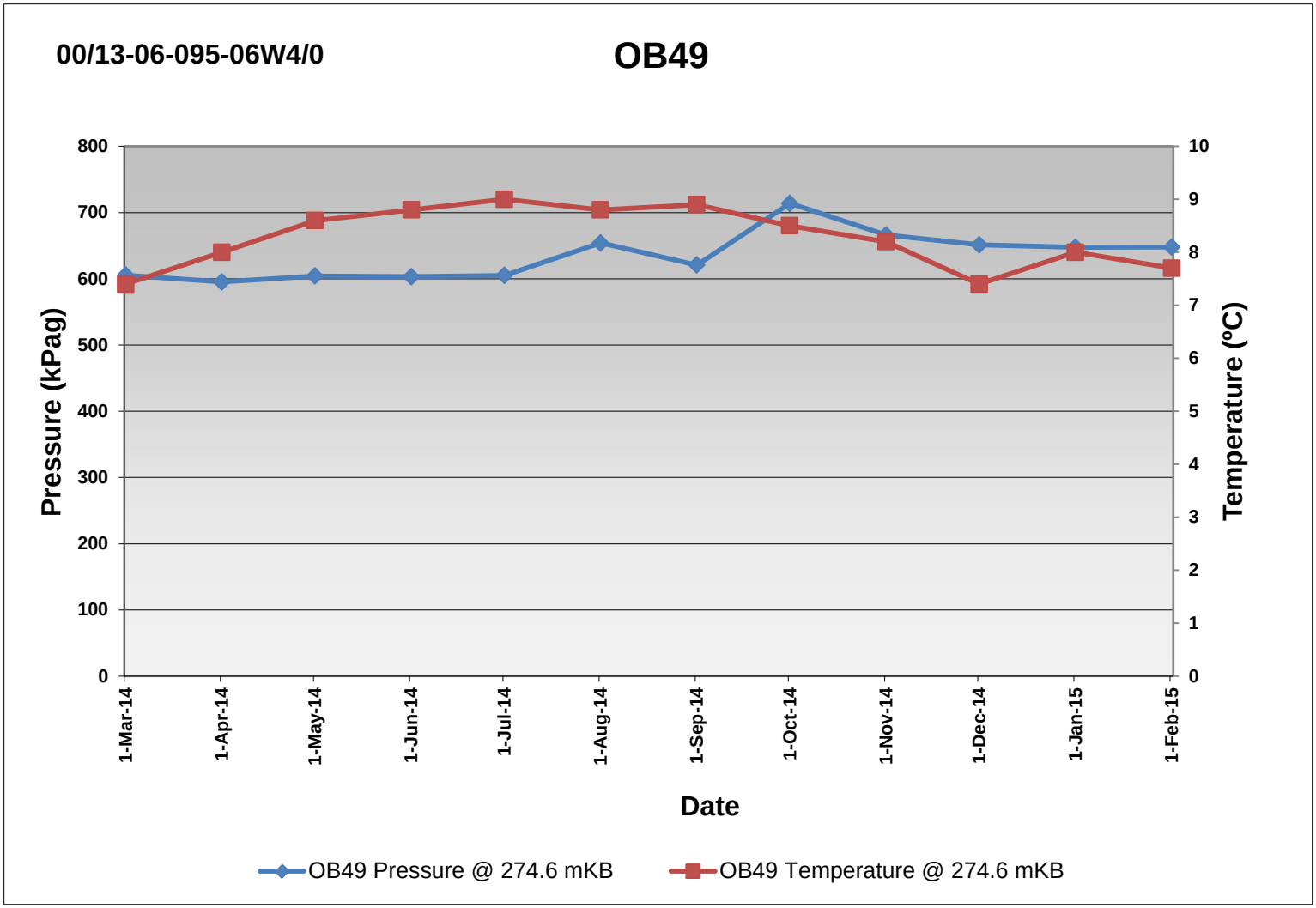

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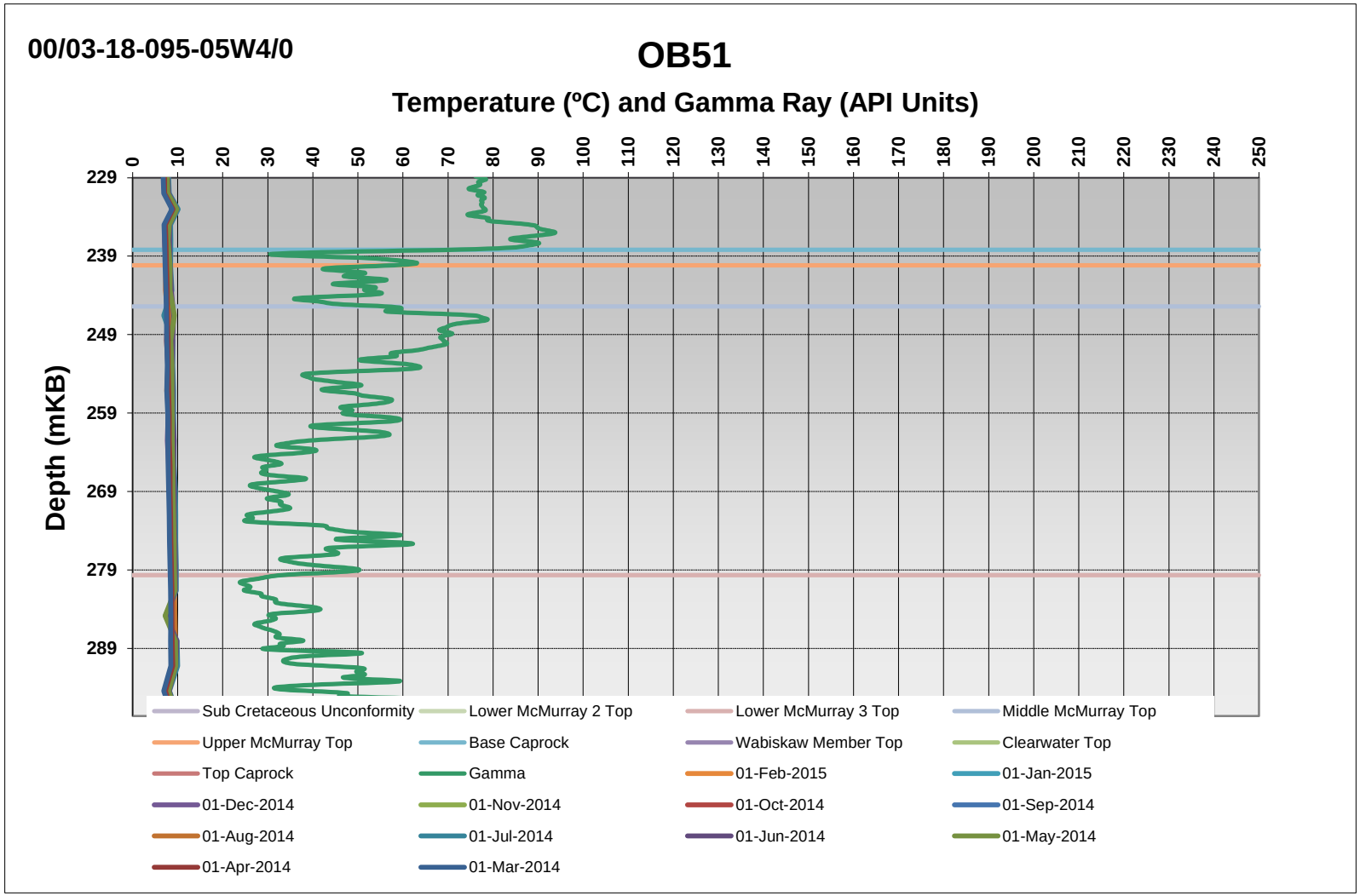

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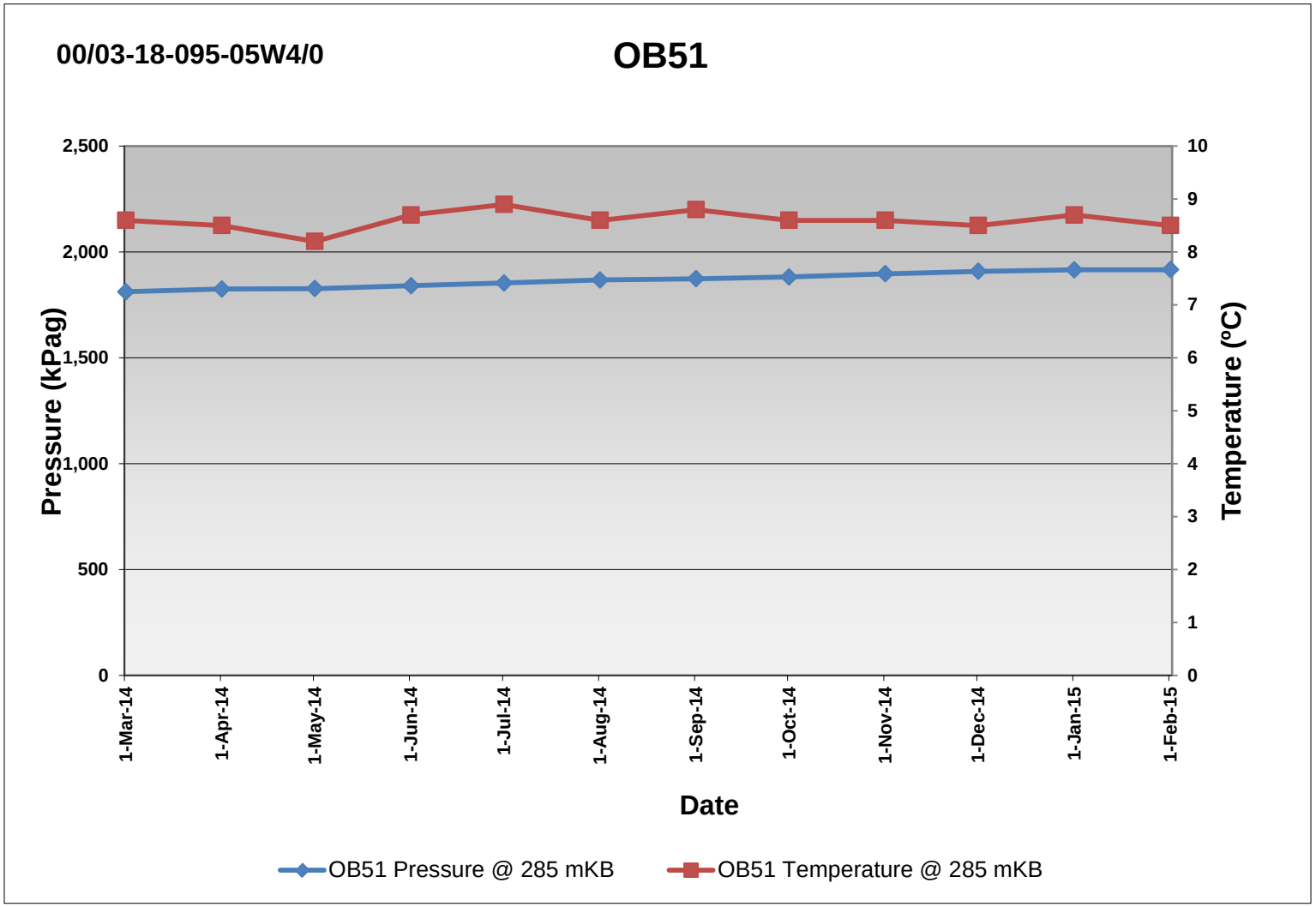

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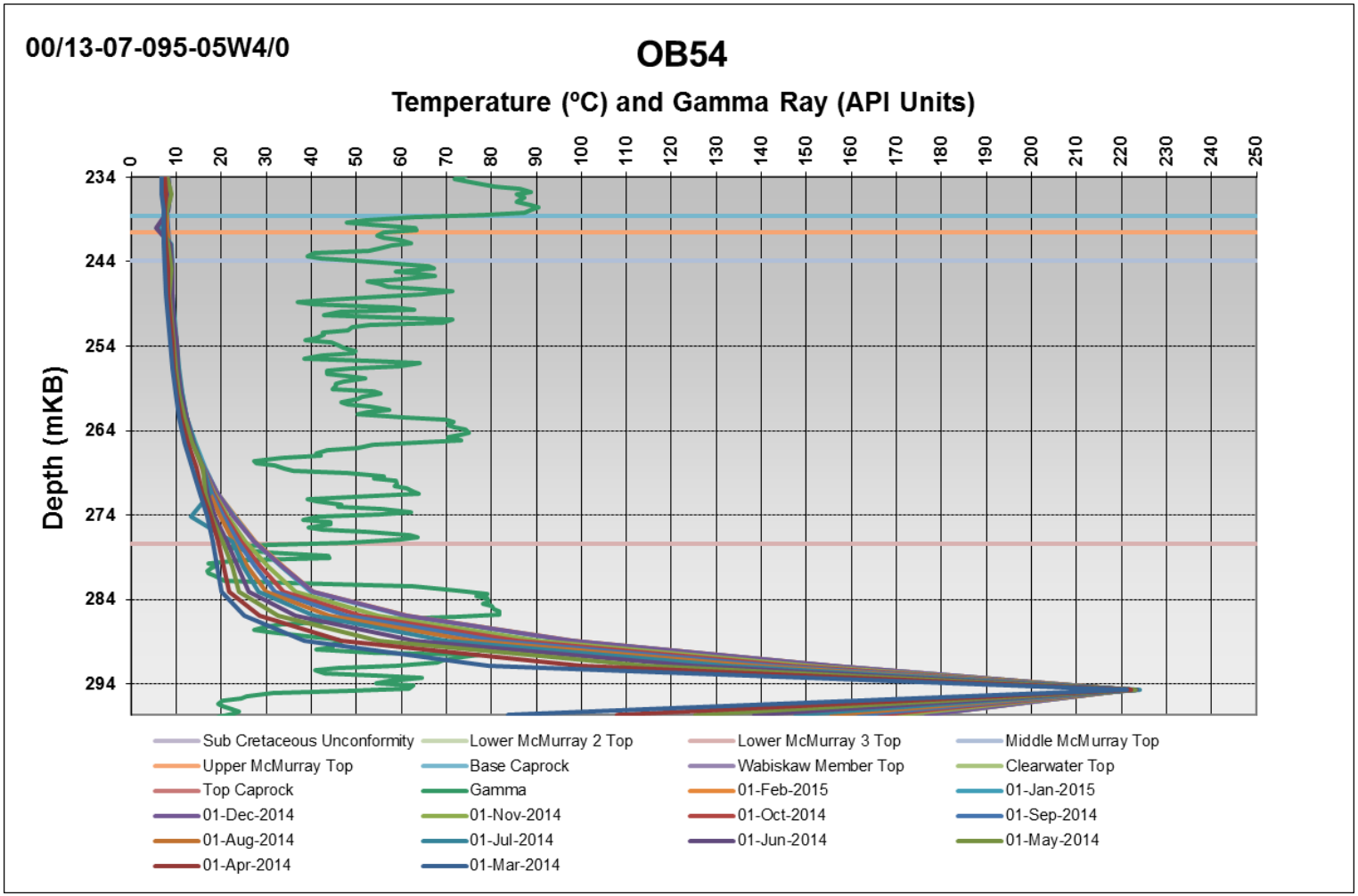

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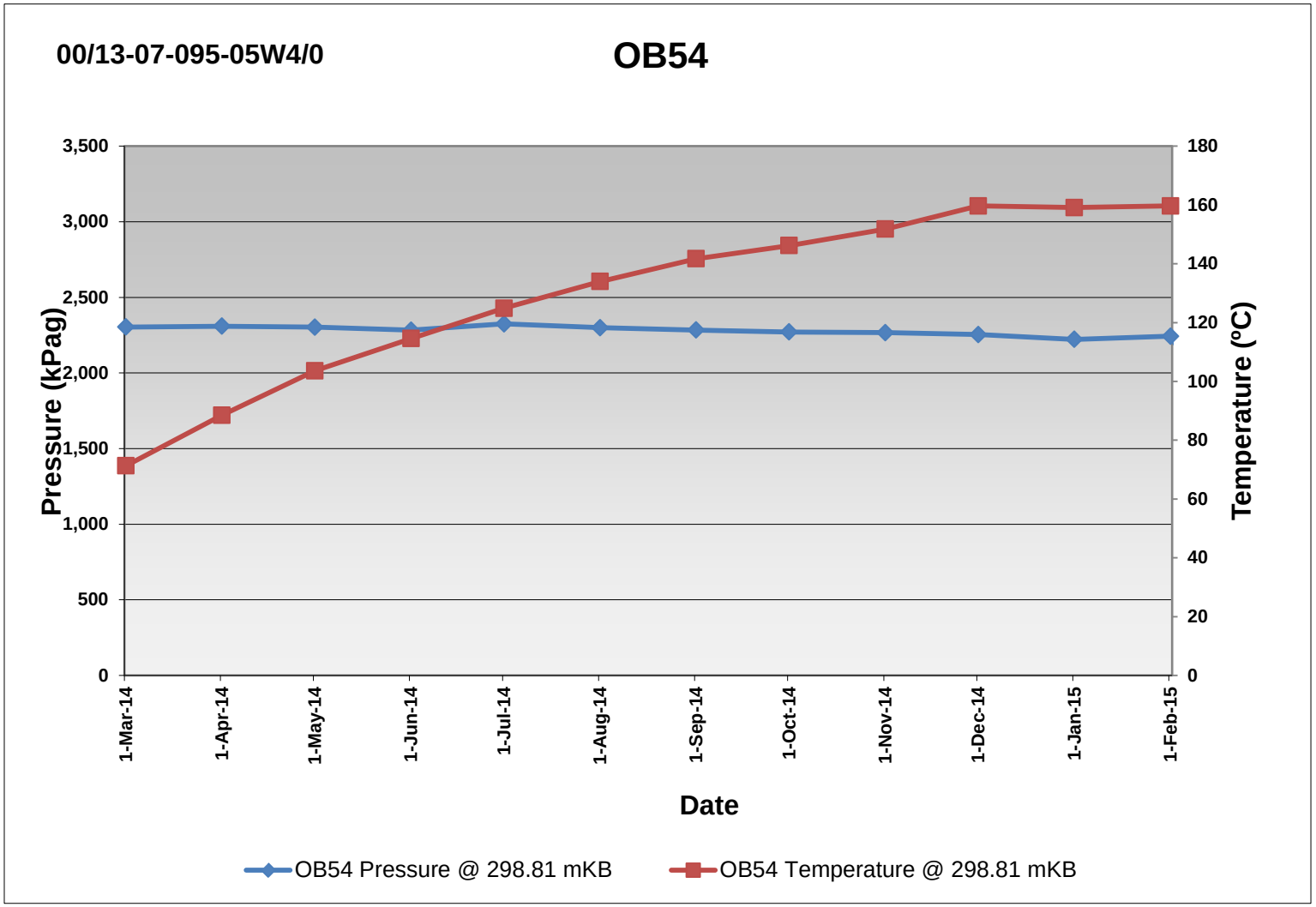

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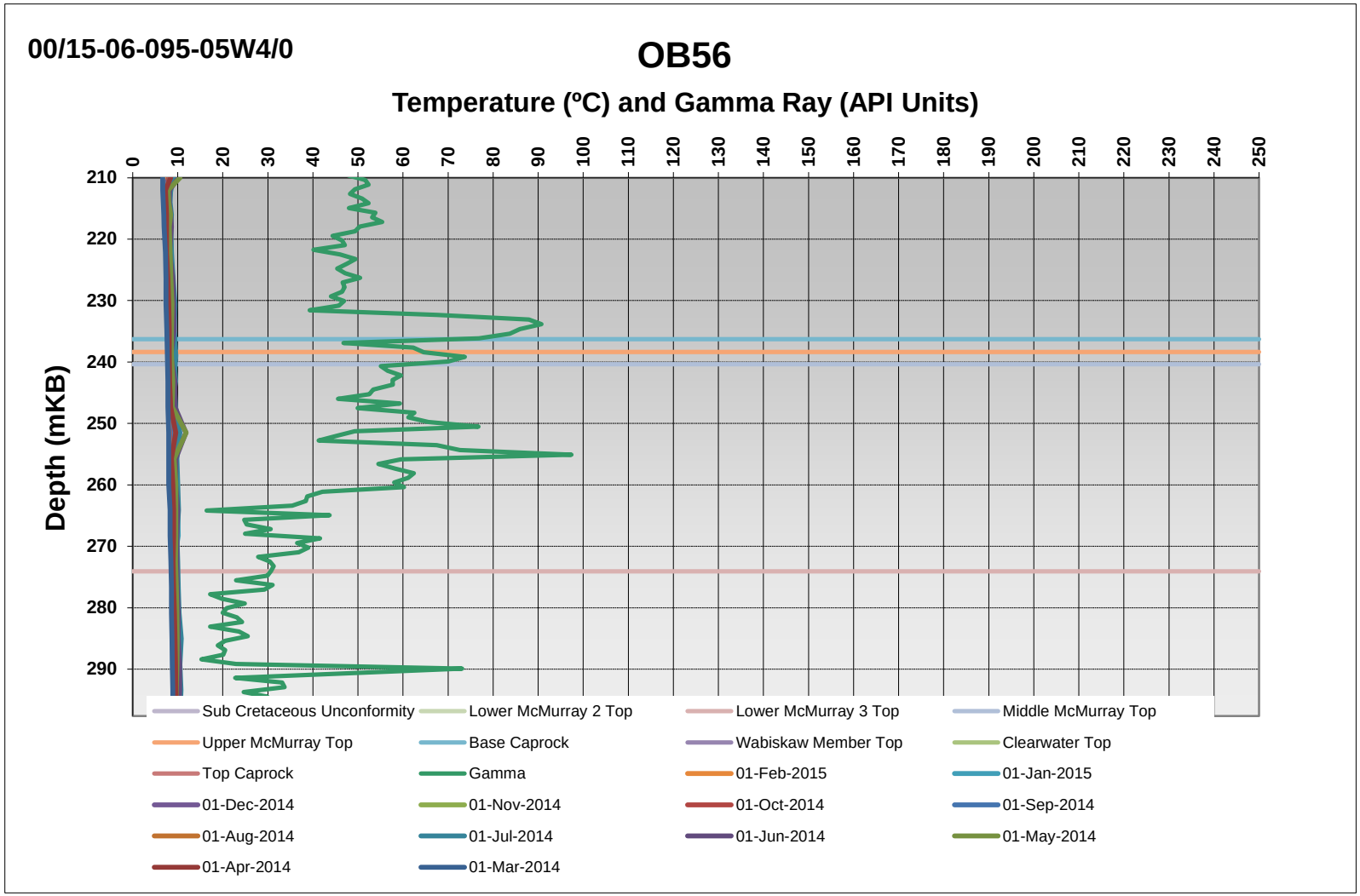

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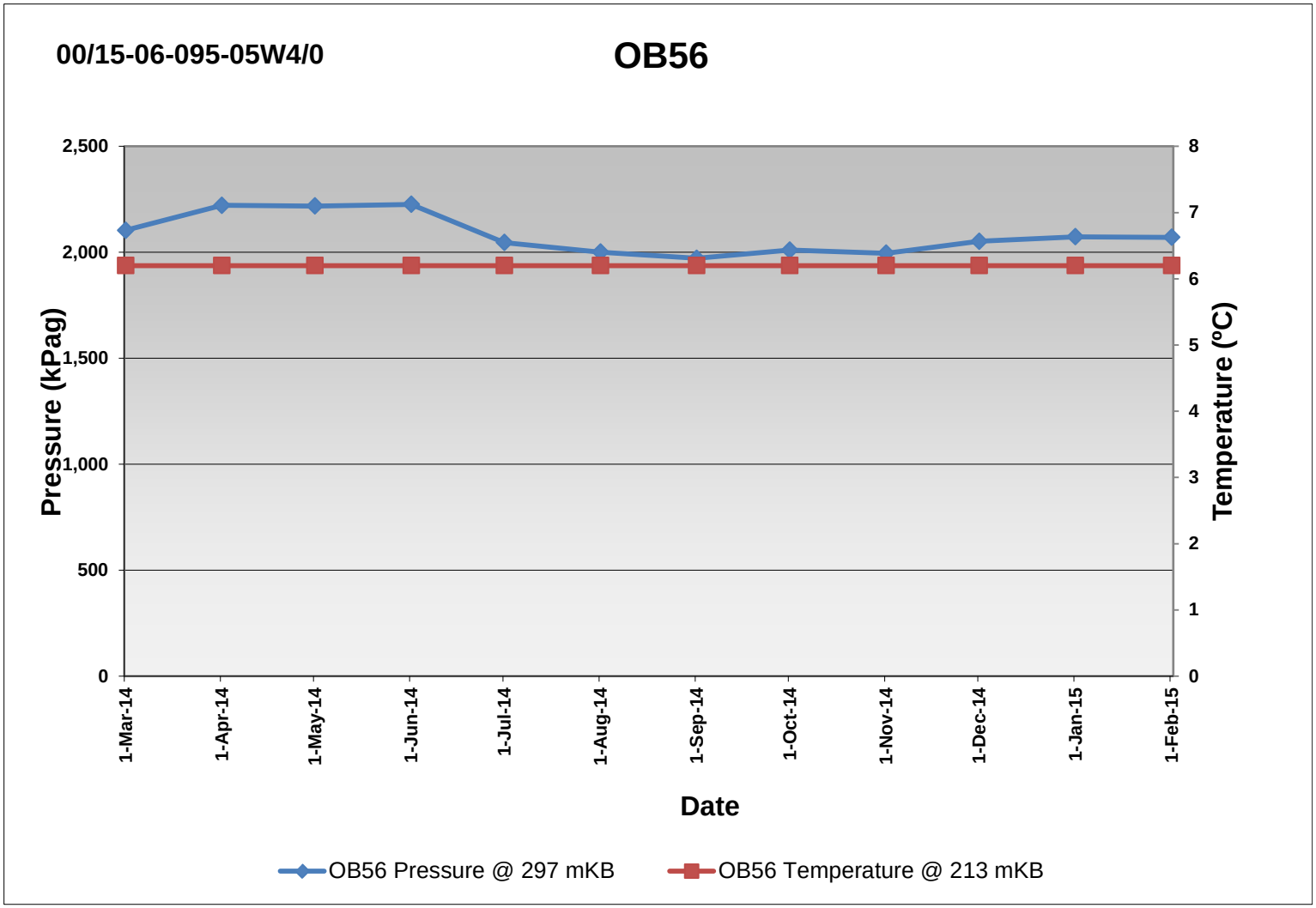

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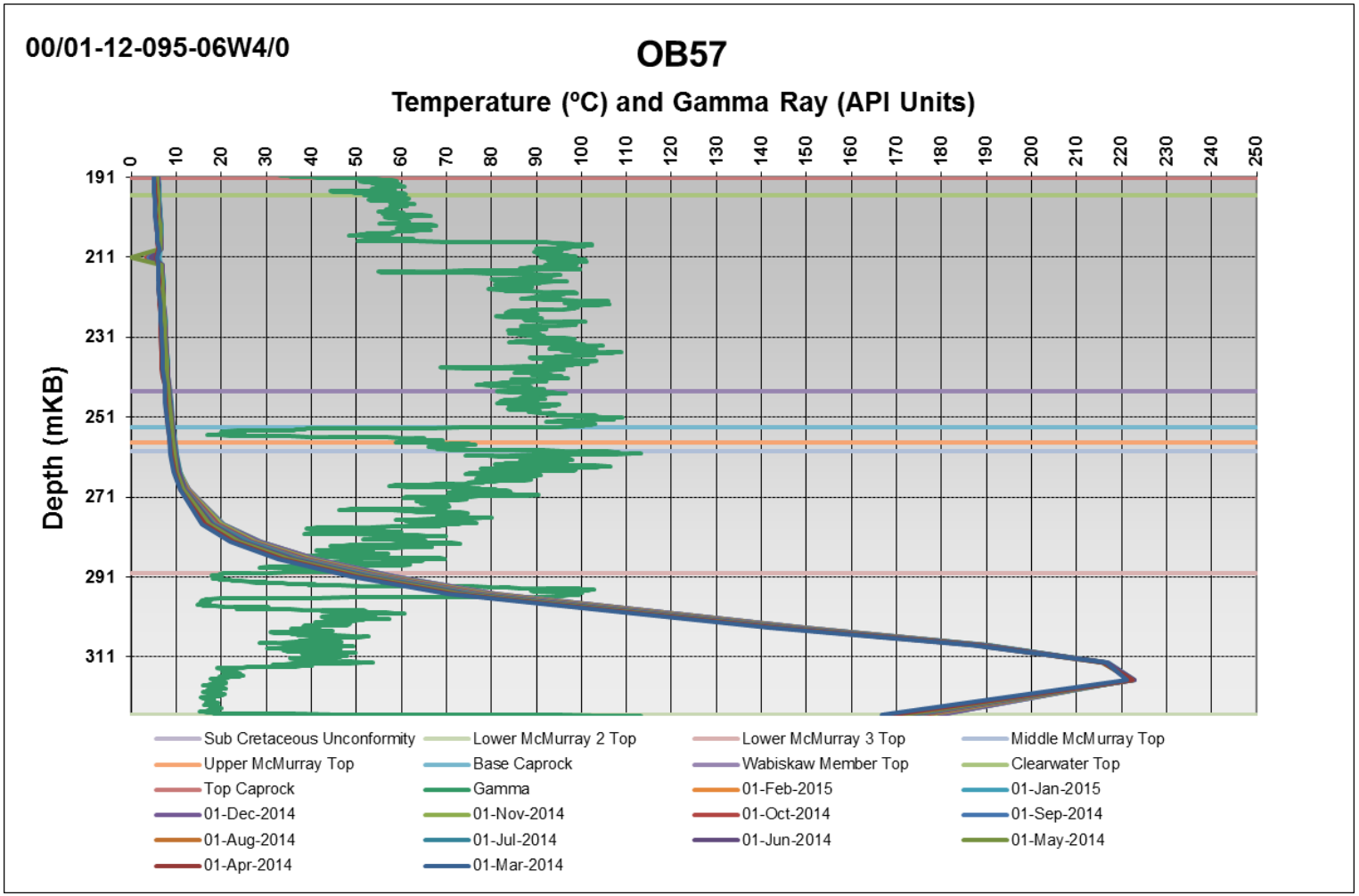

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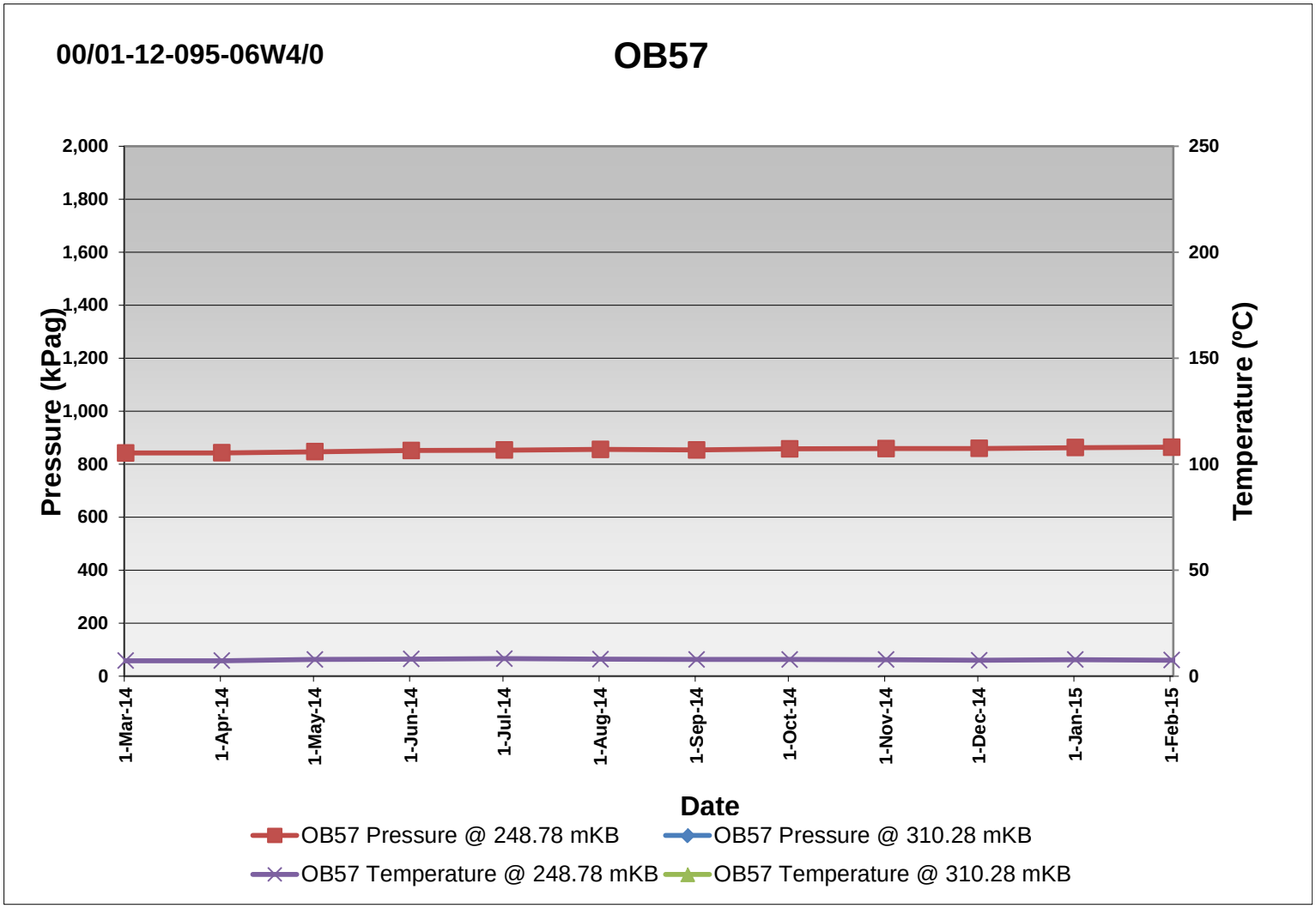

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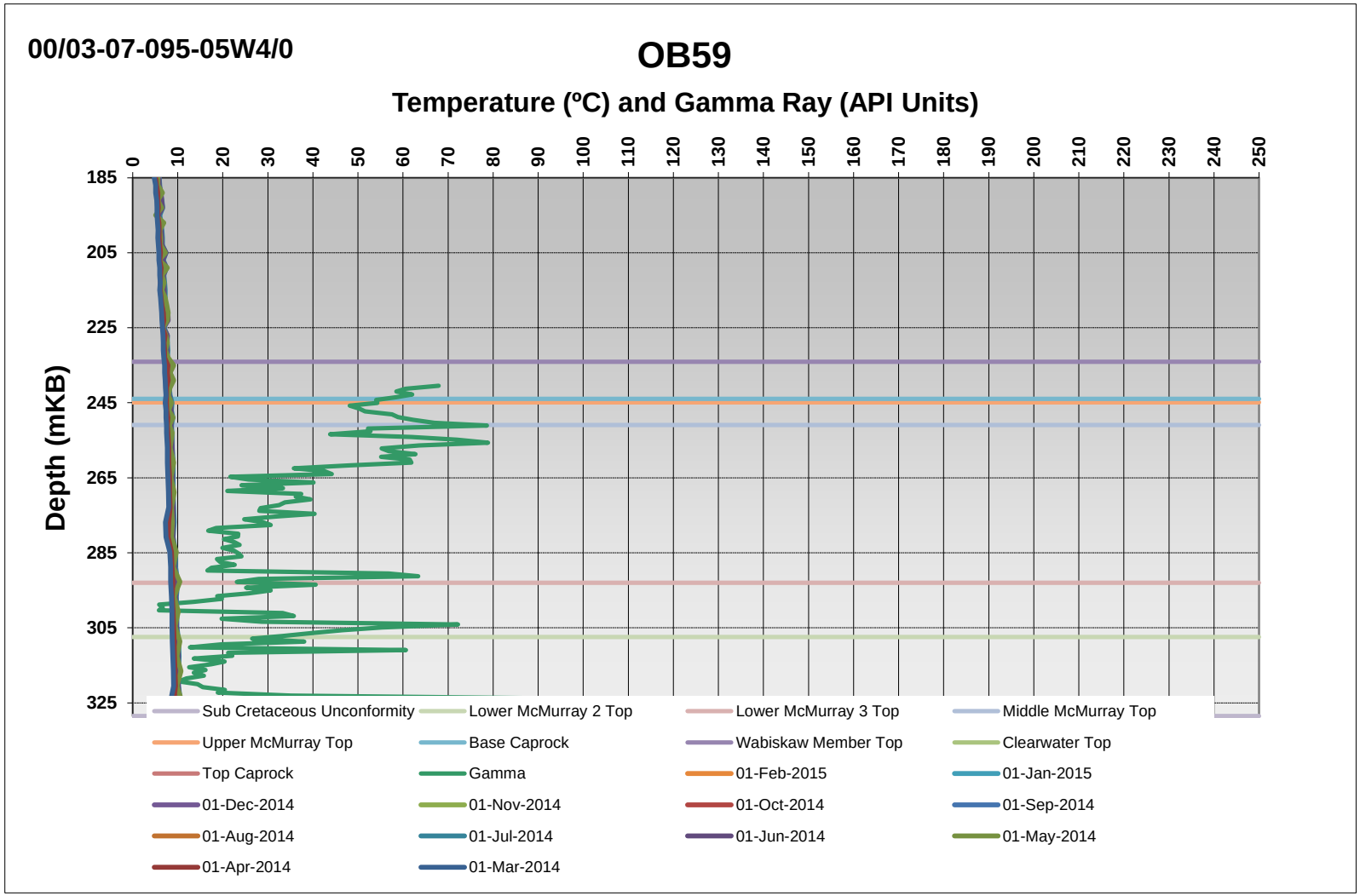

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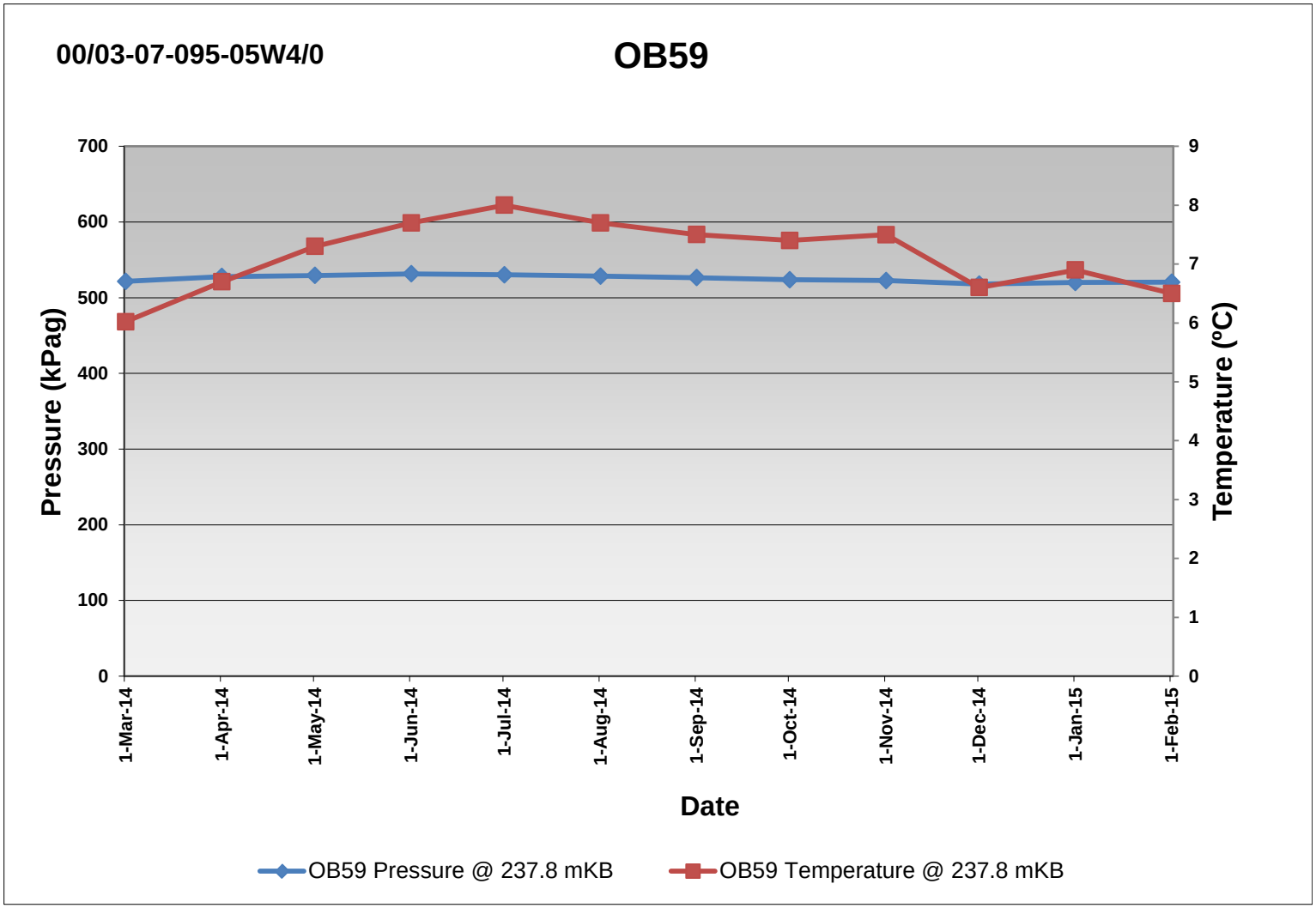

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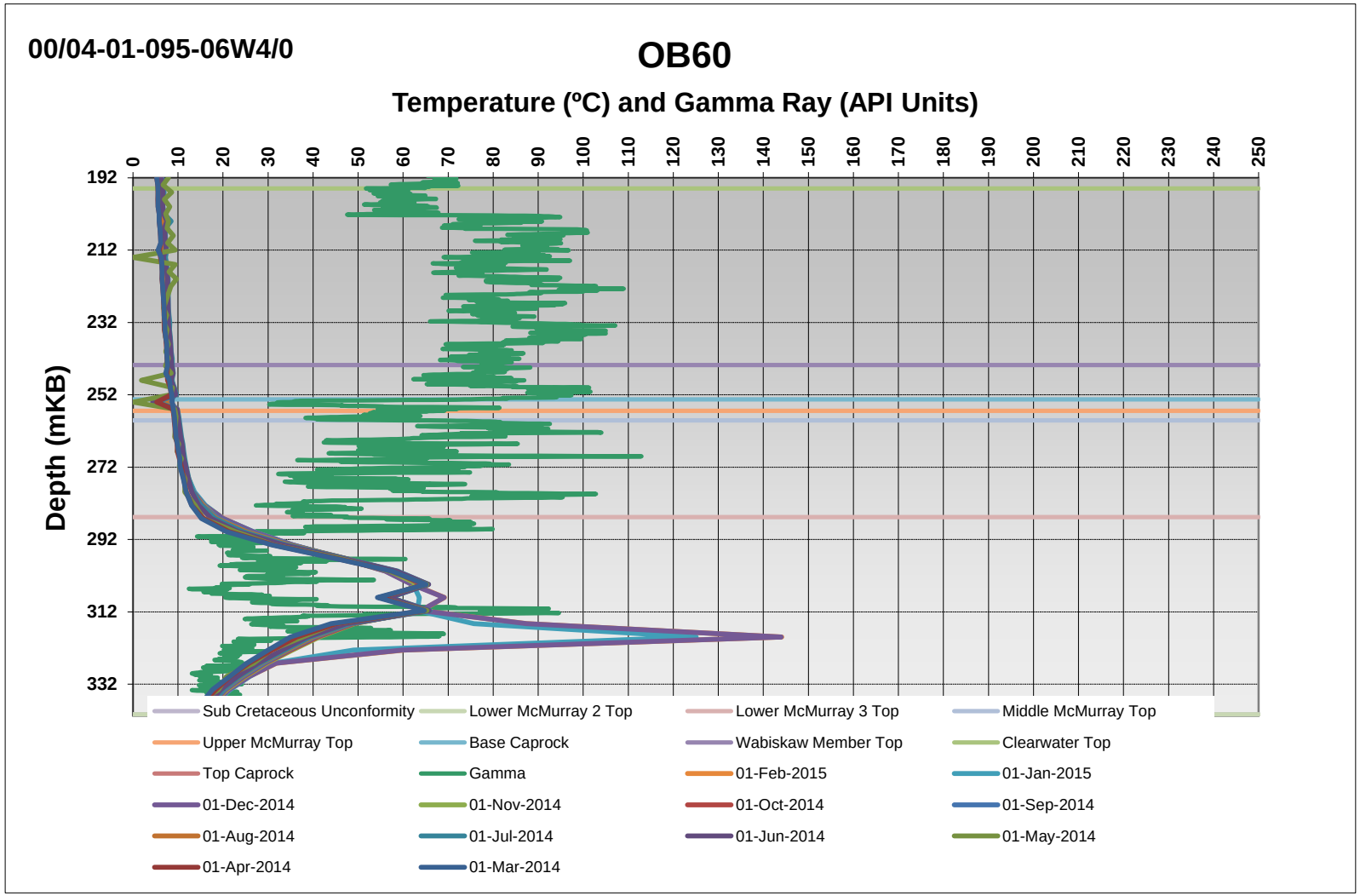

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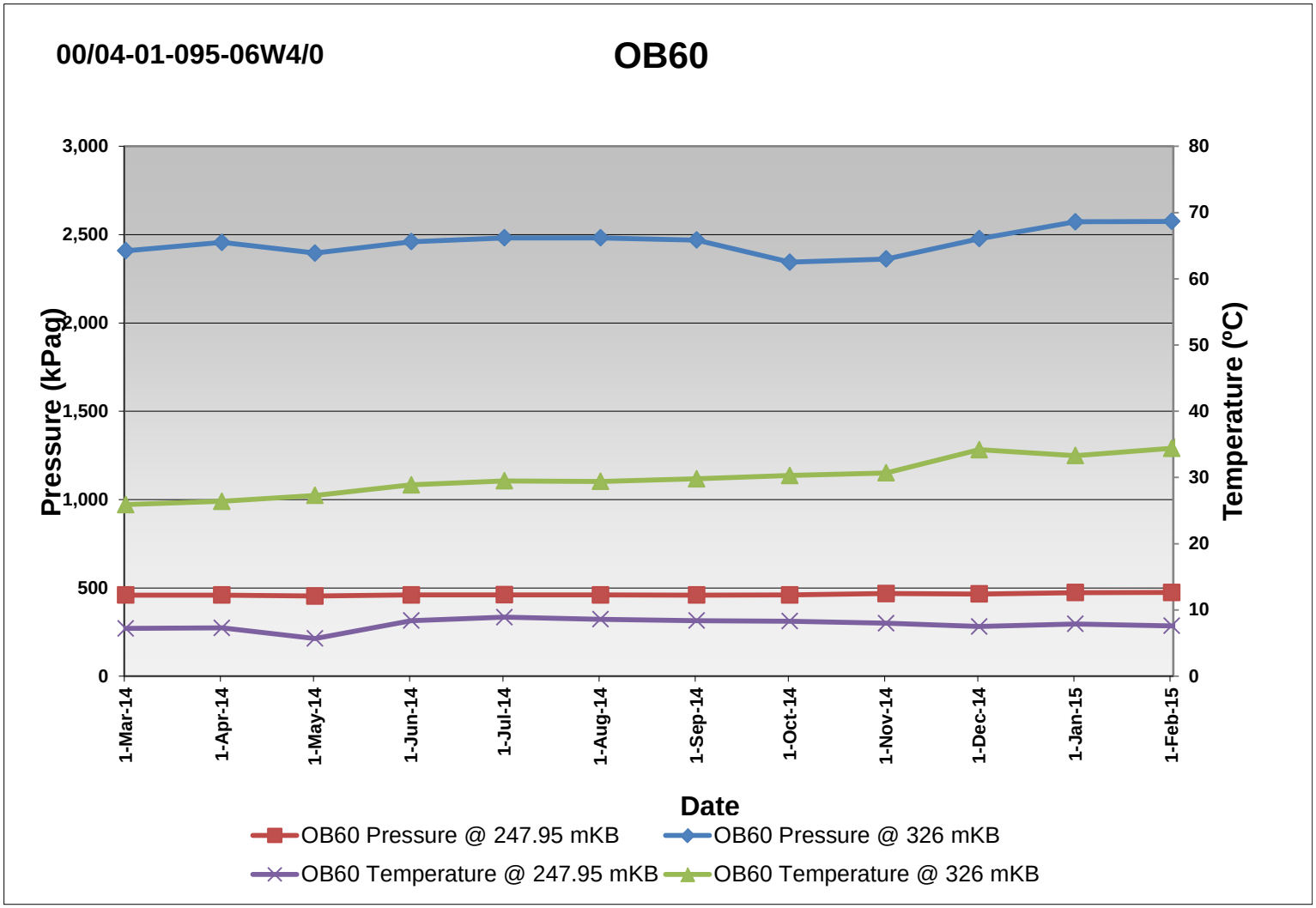

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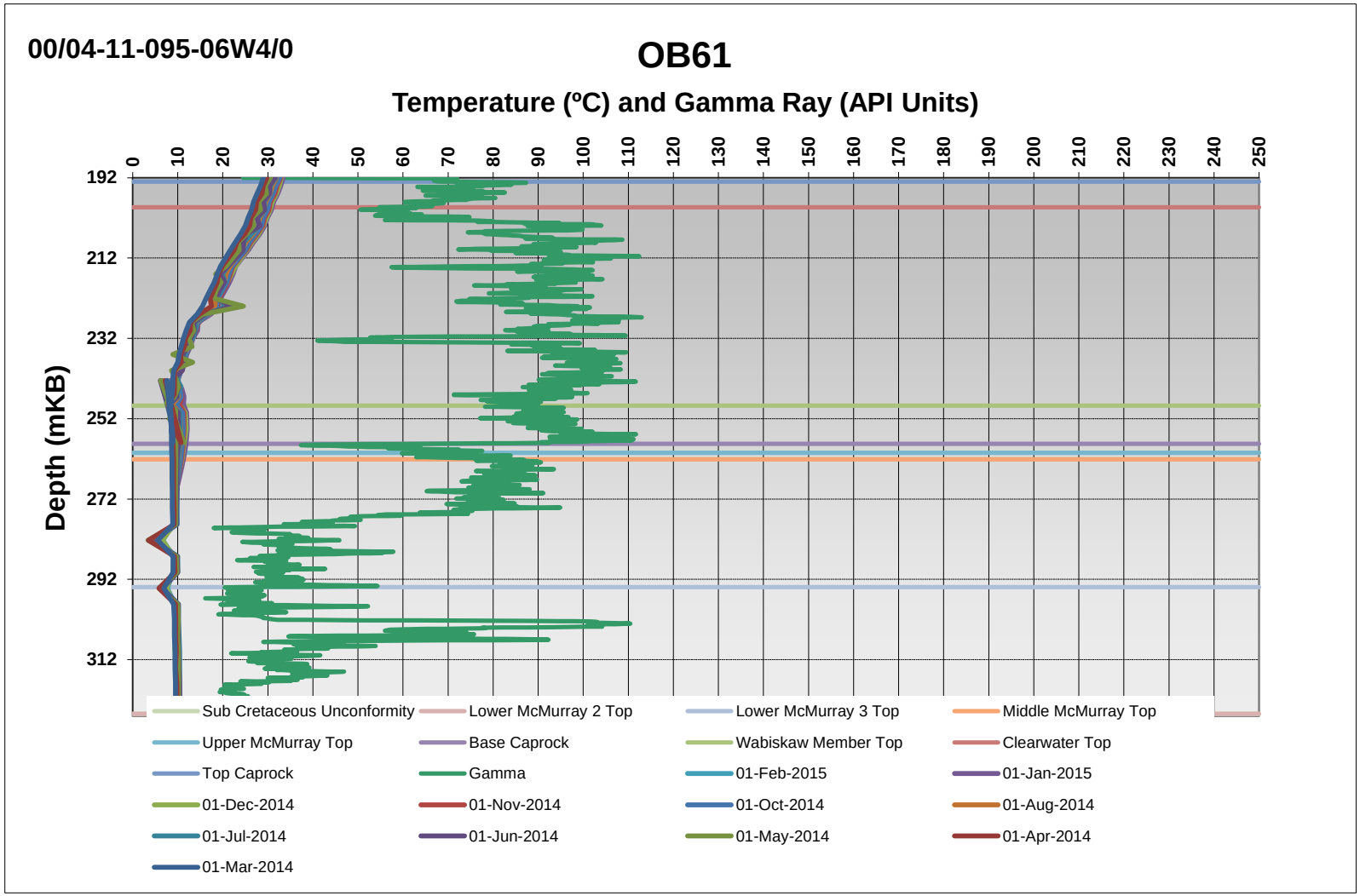
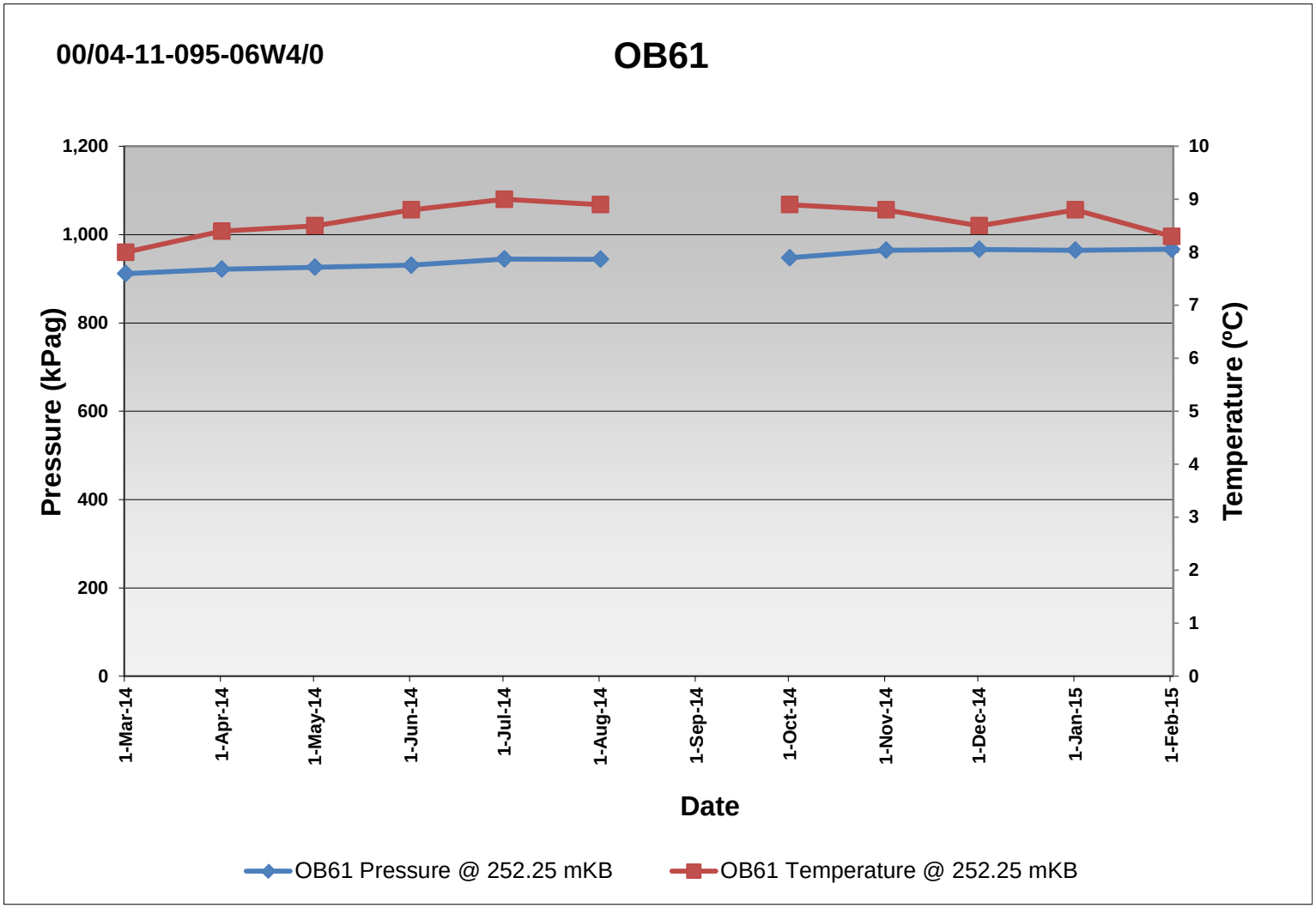


Piezometer Plots & Temperature vs Depth Plots



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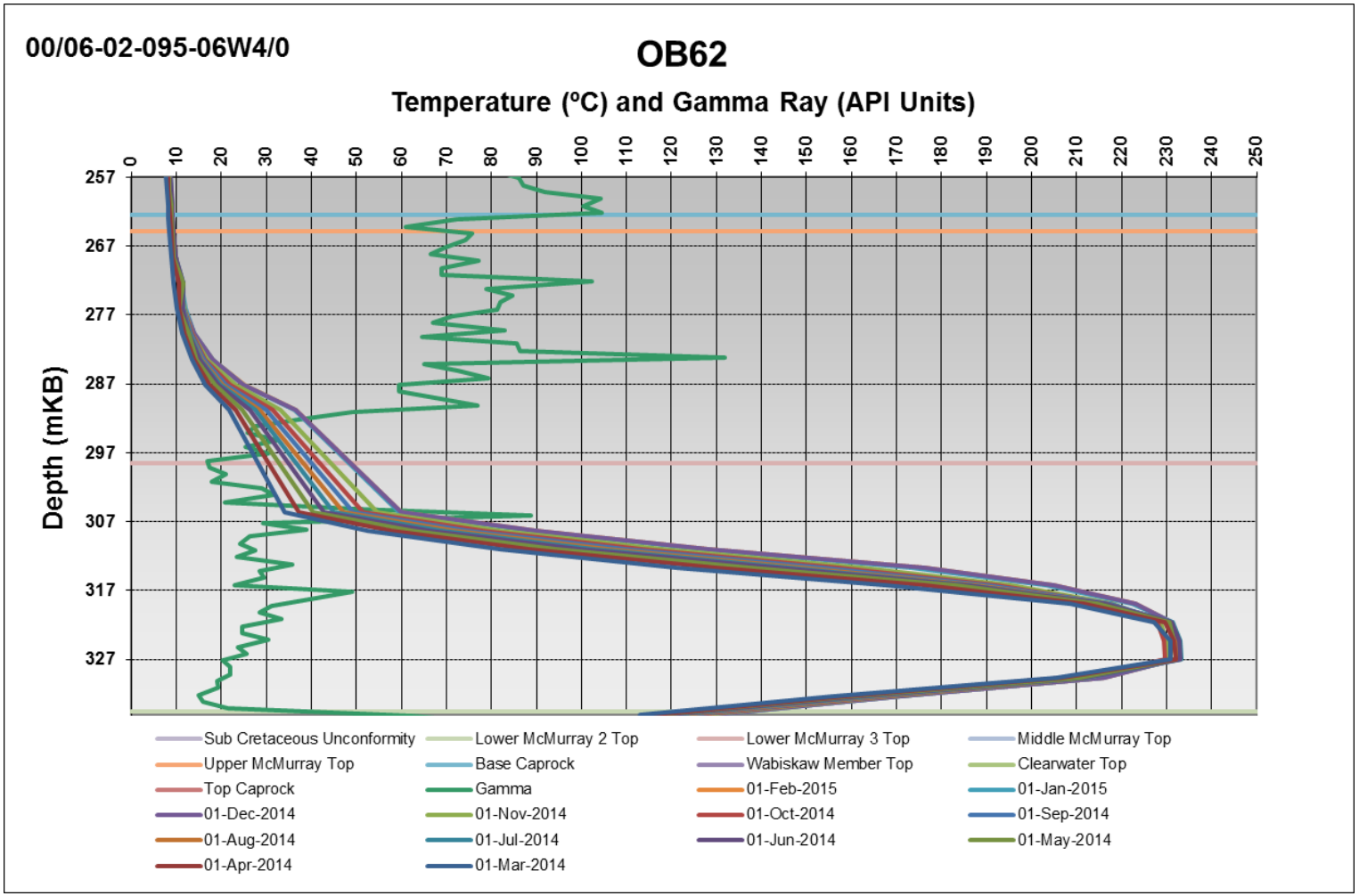

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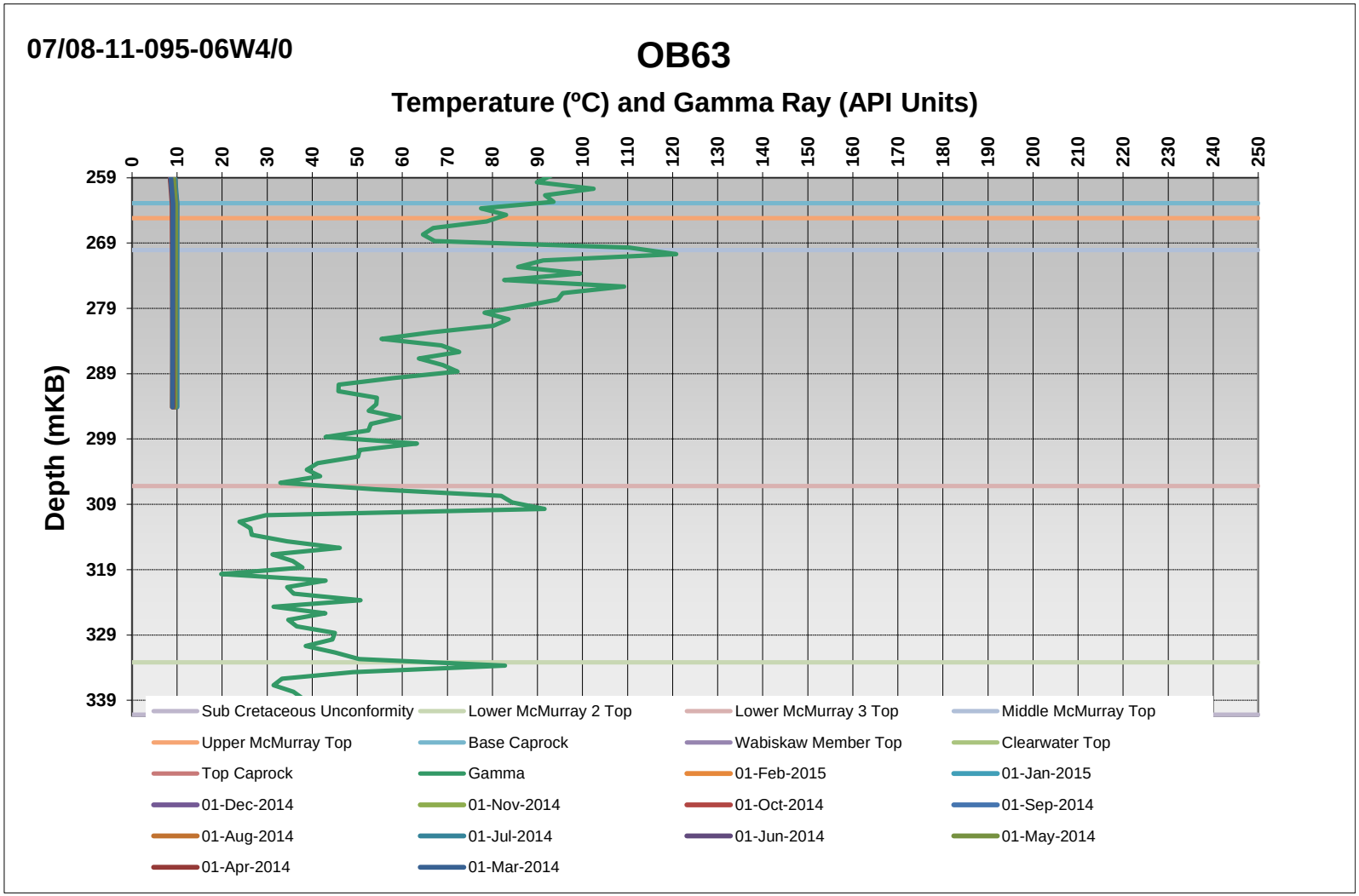

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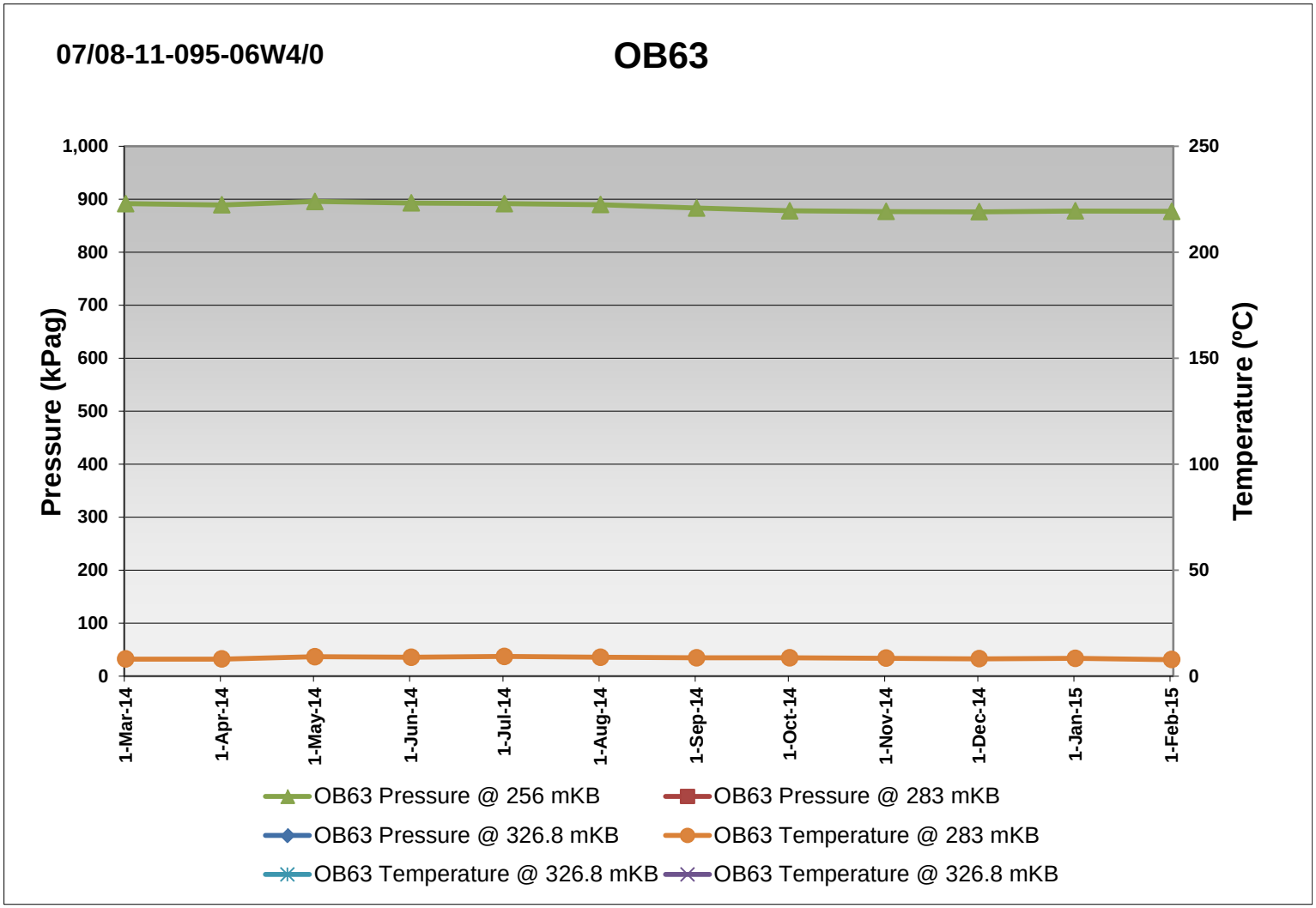

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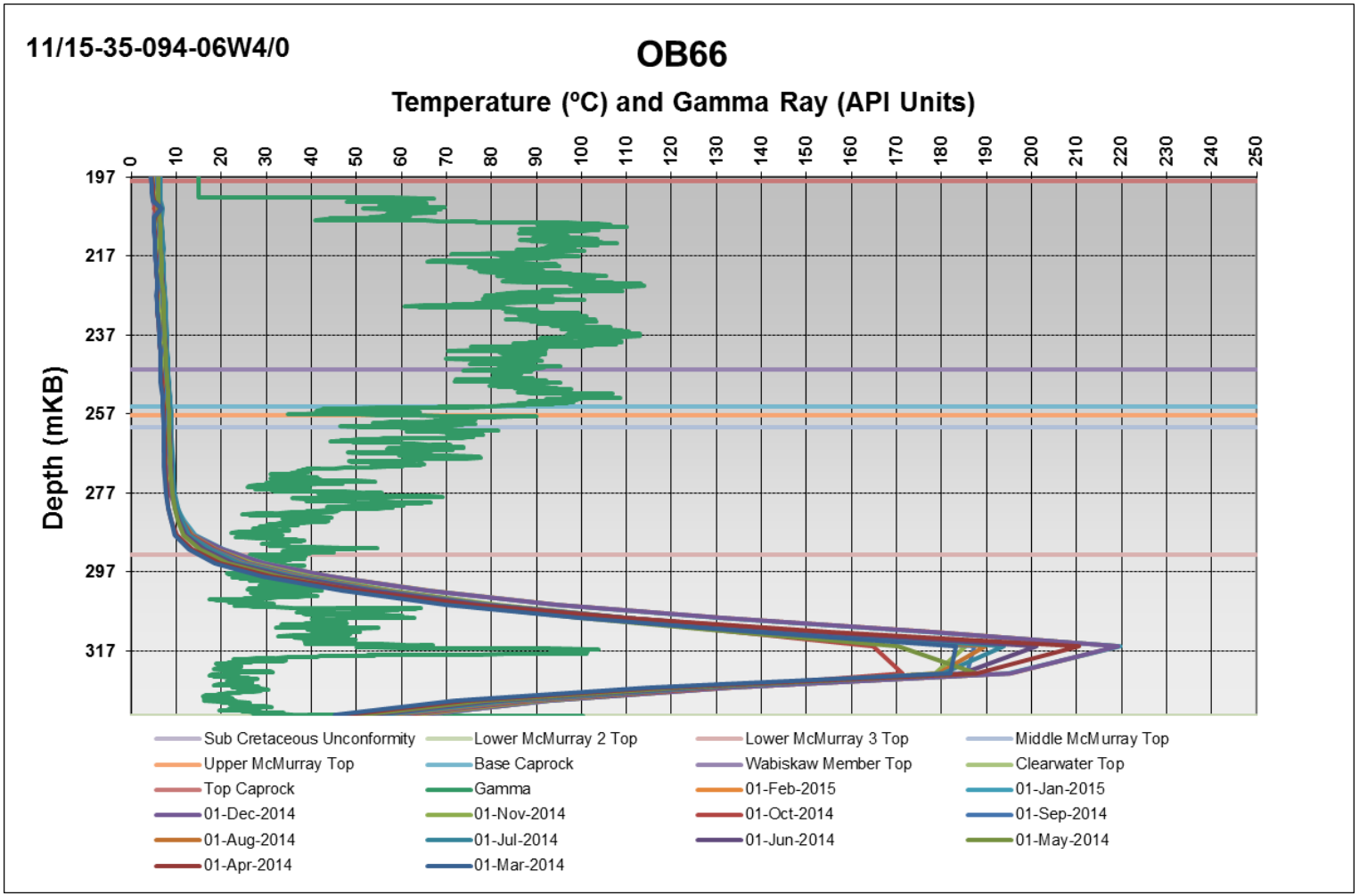

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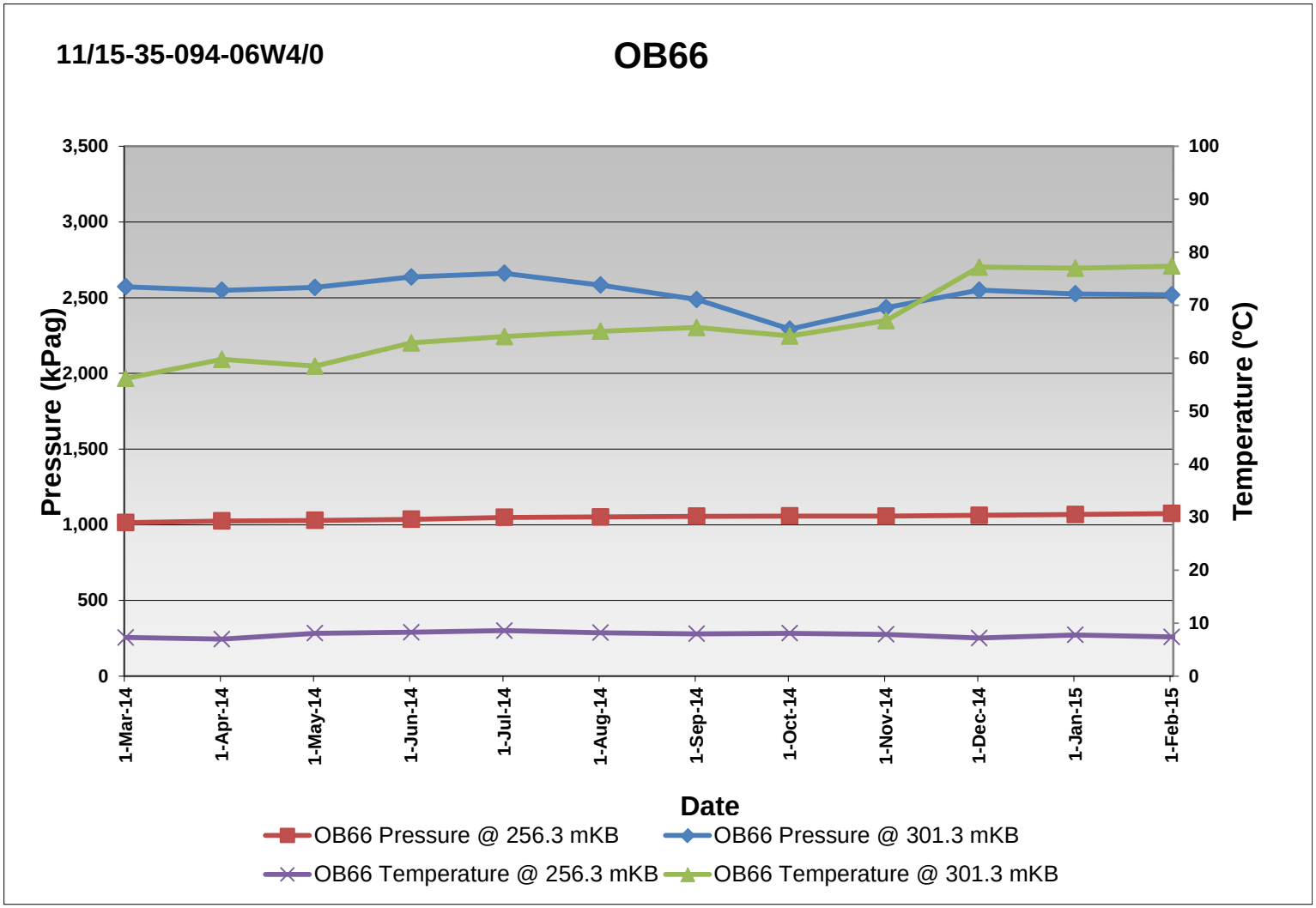

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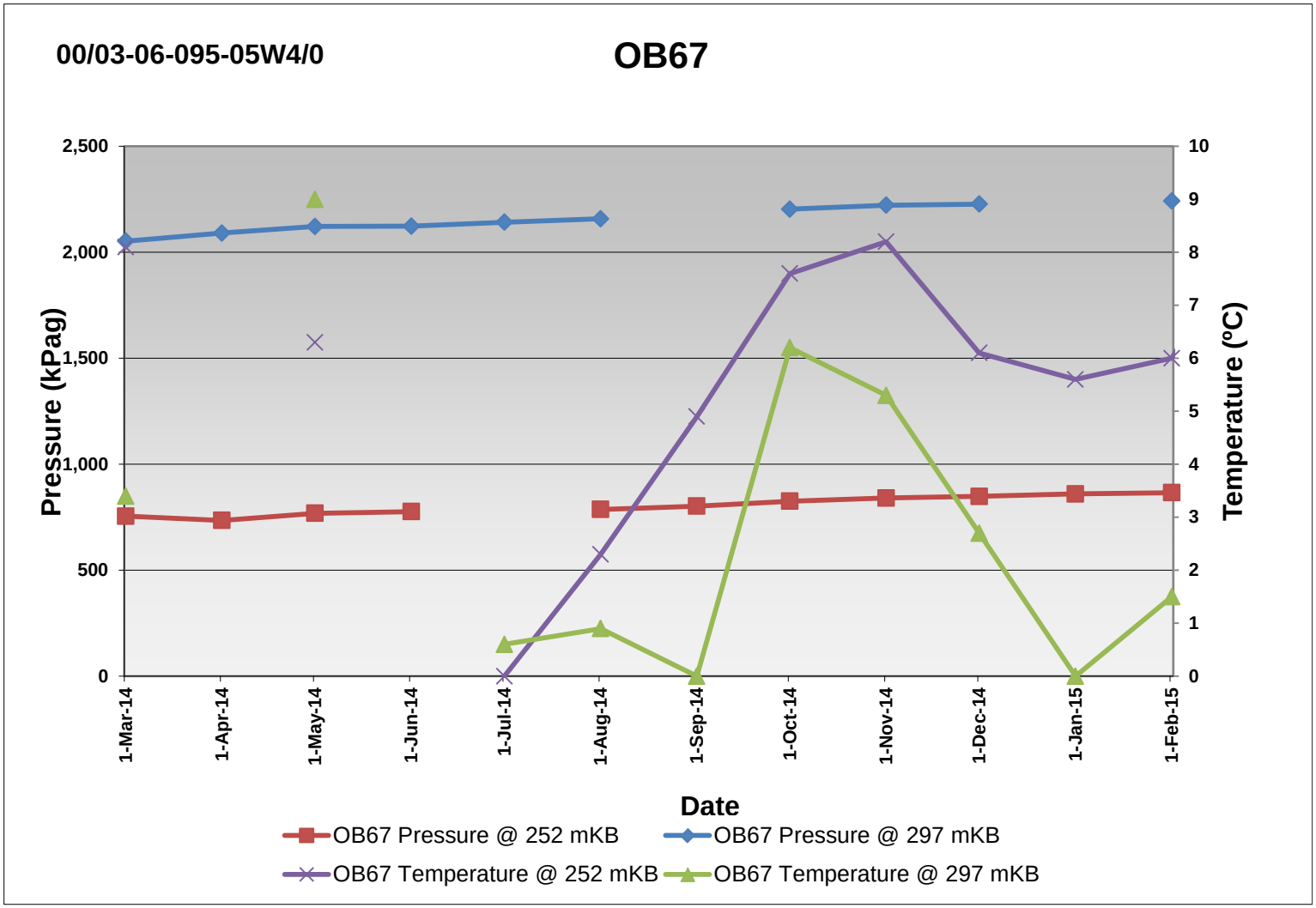

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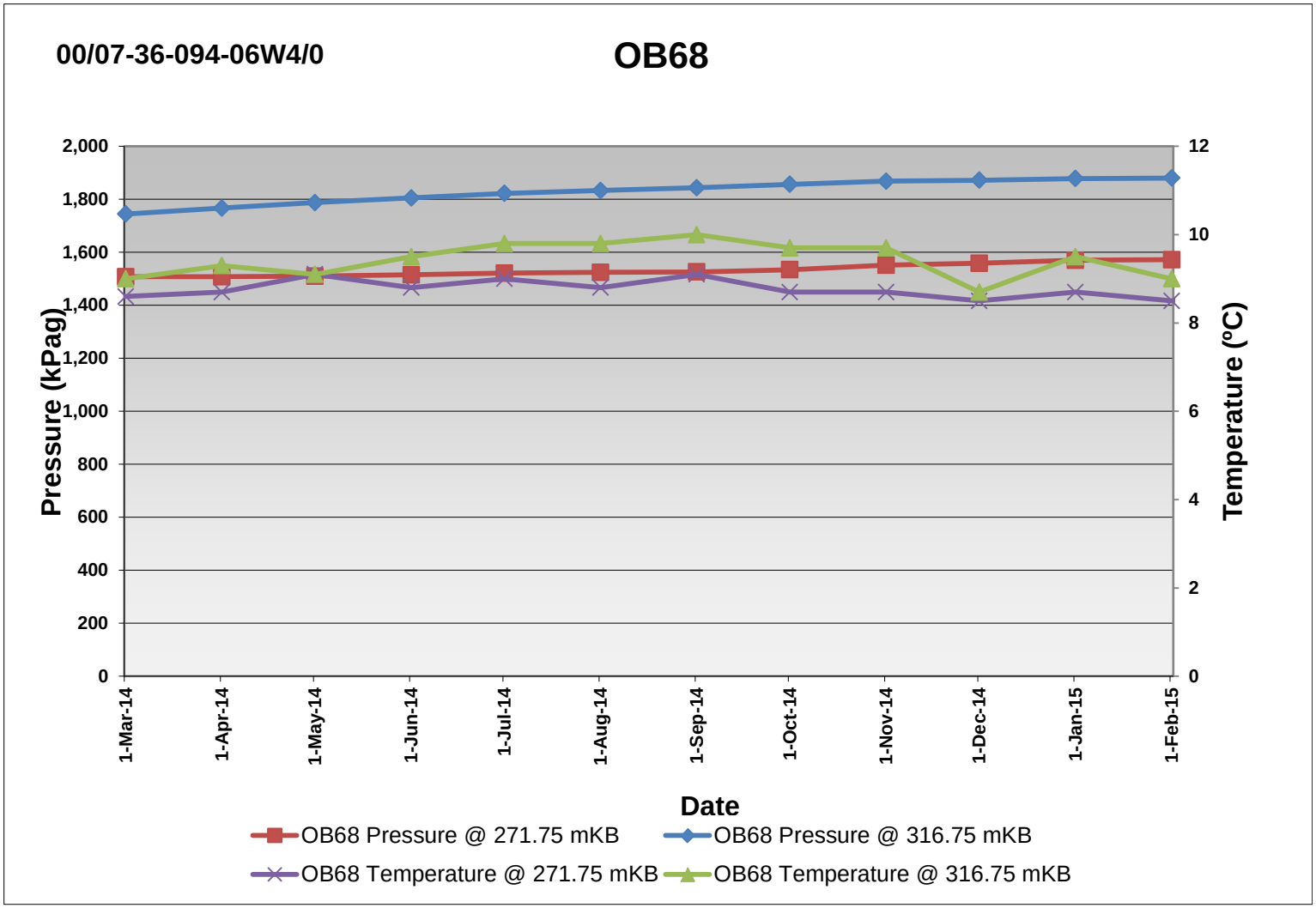

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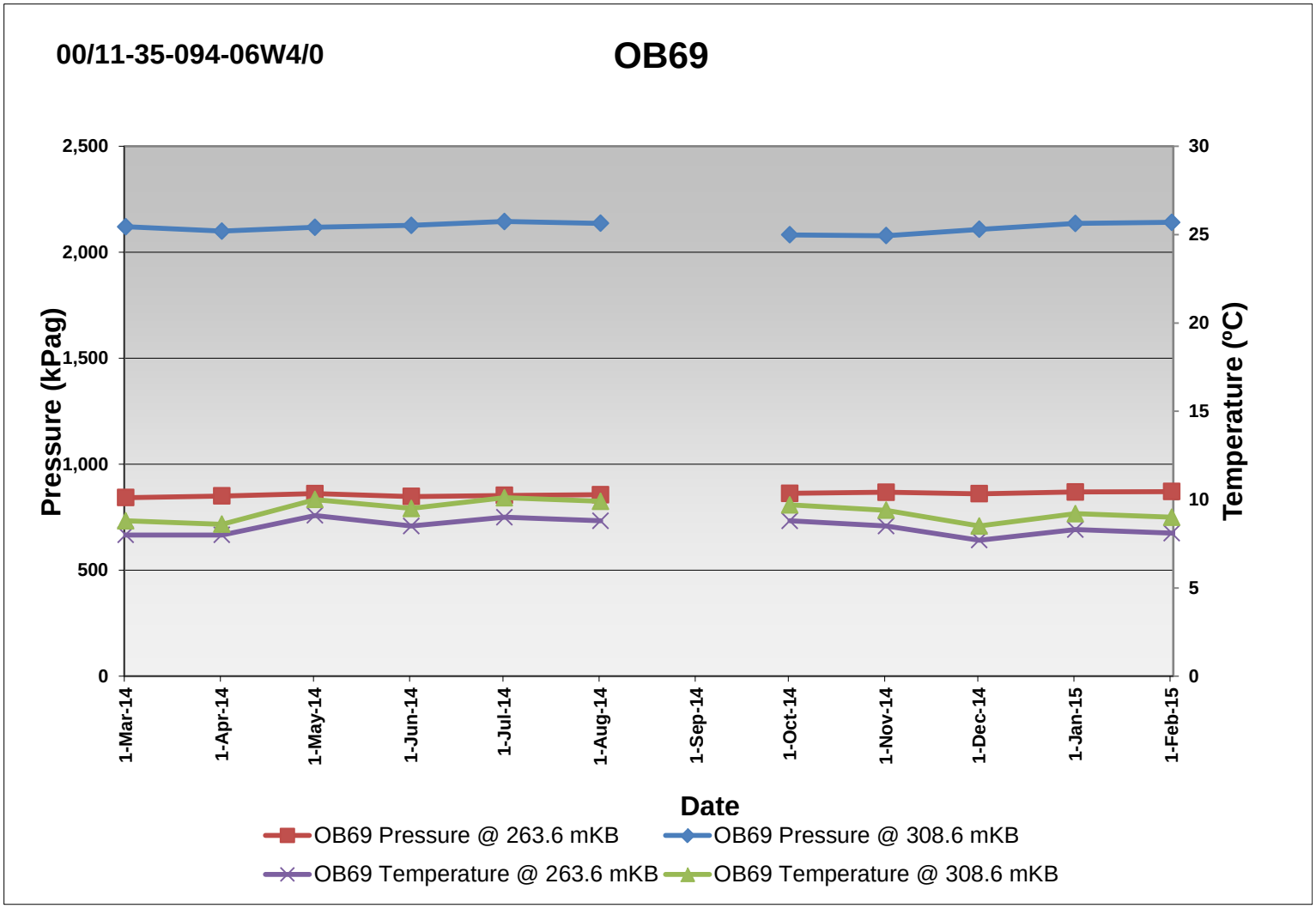

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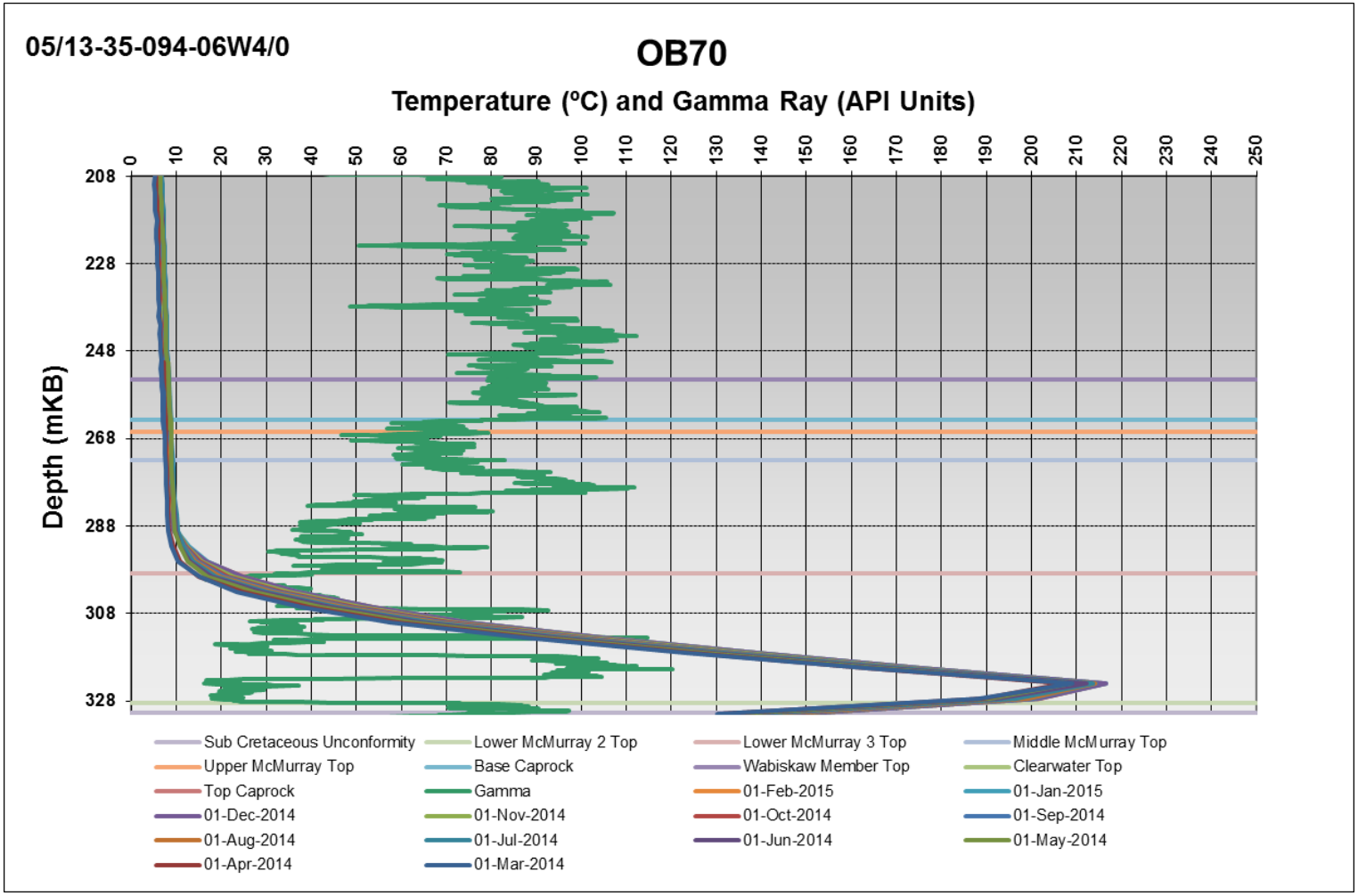

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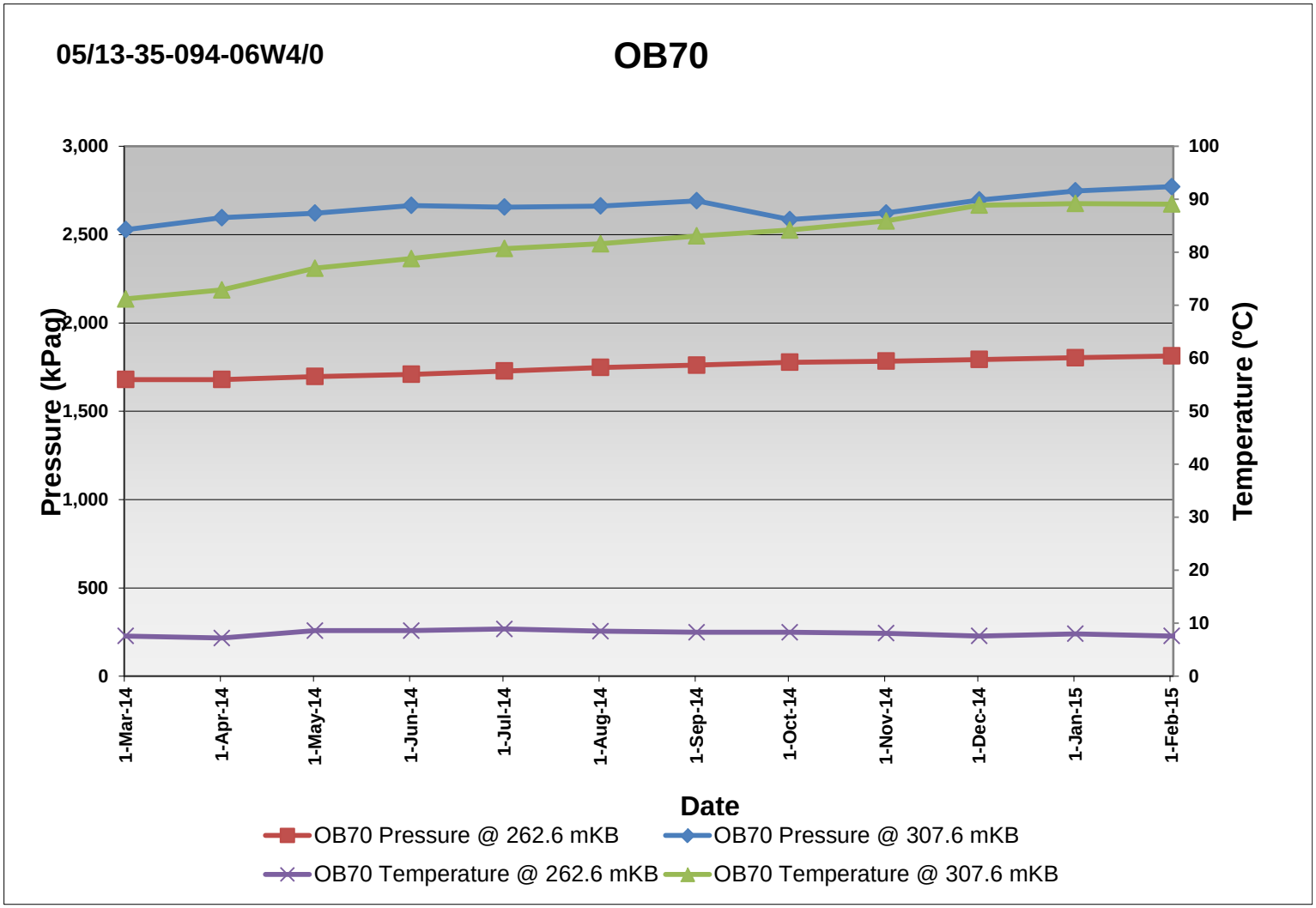

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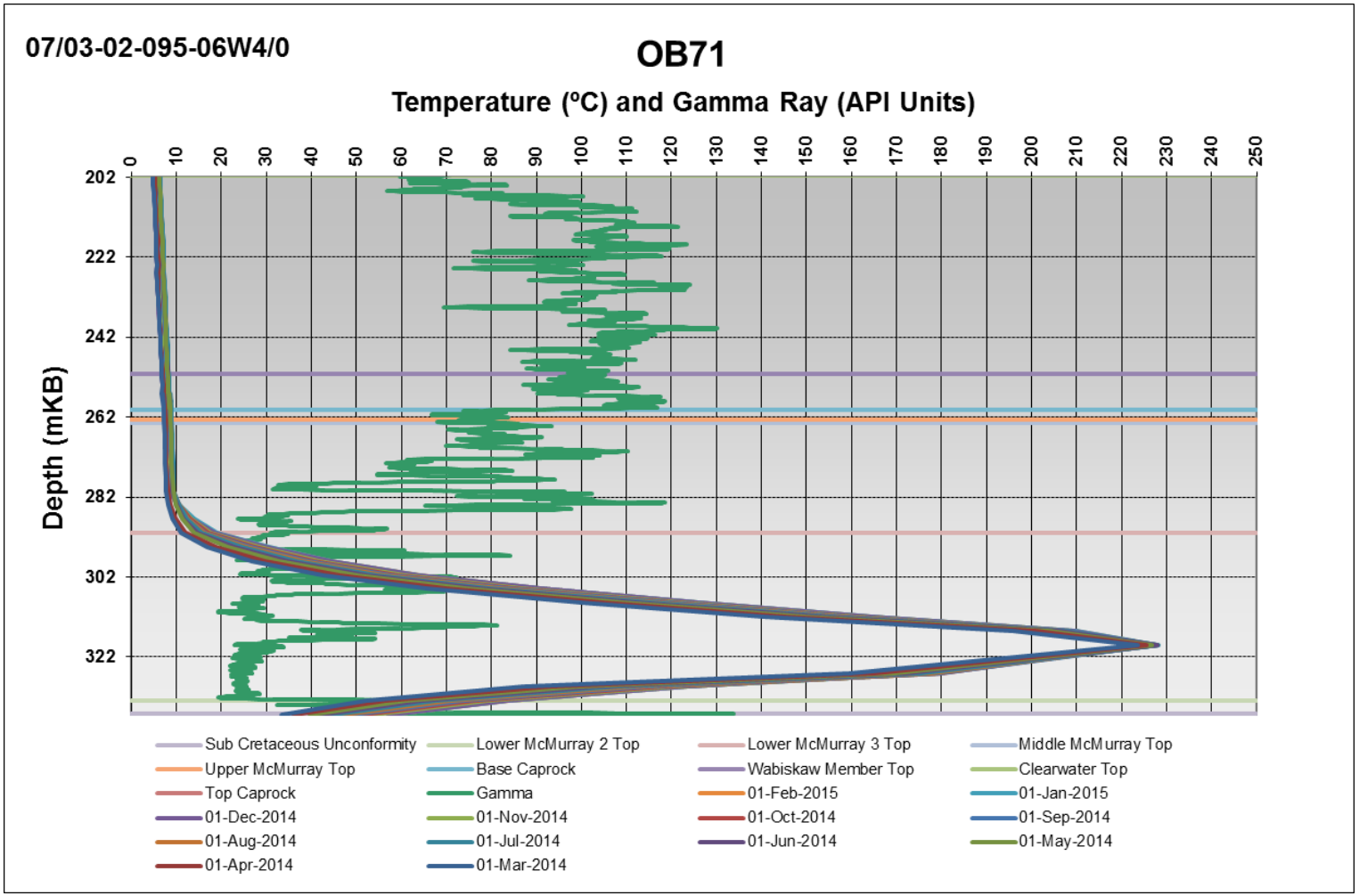

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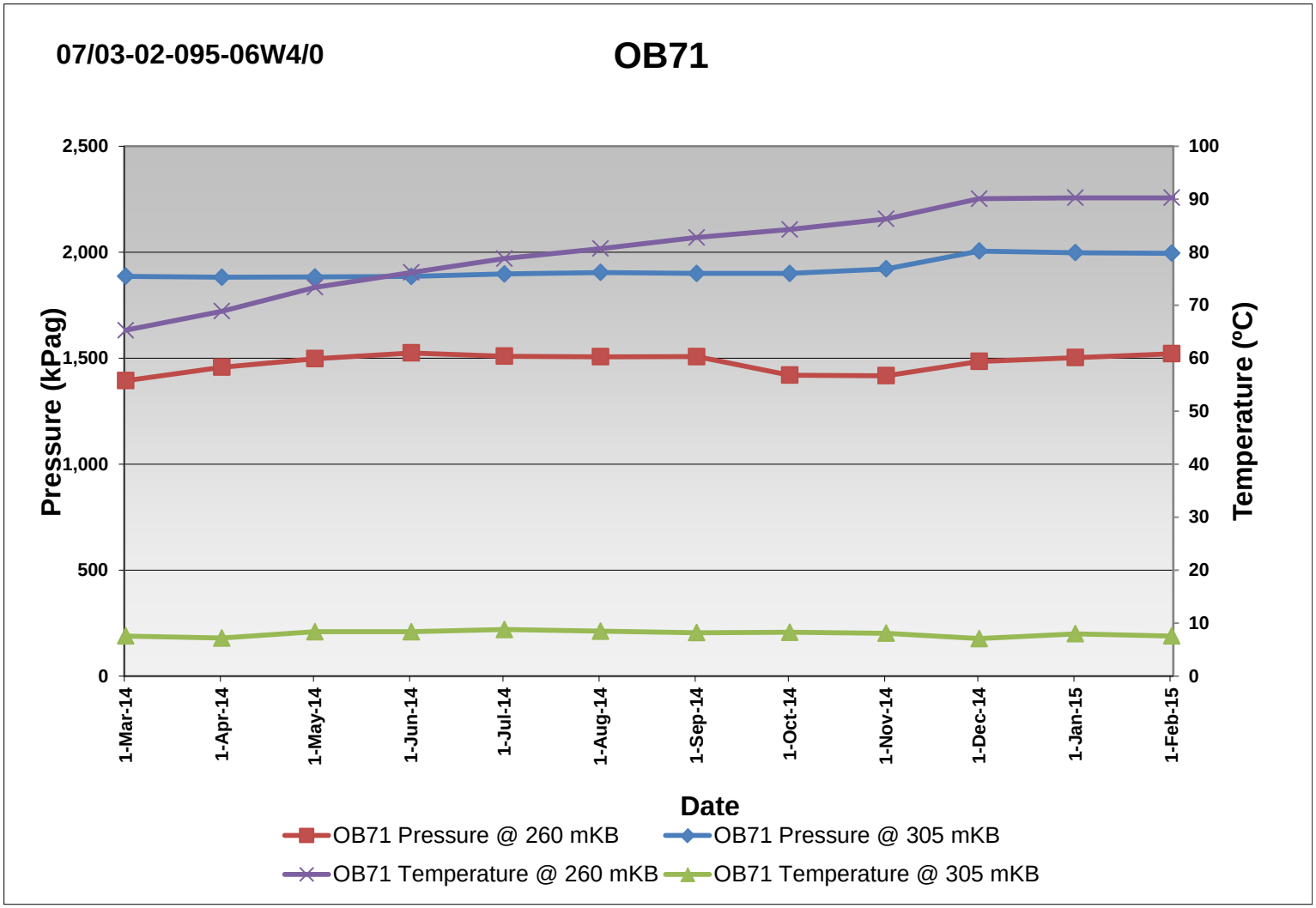

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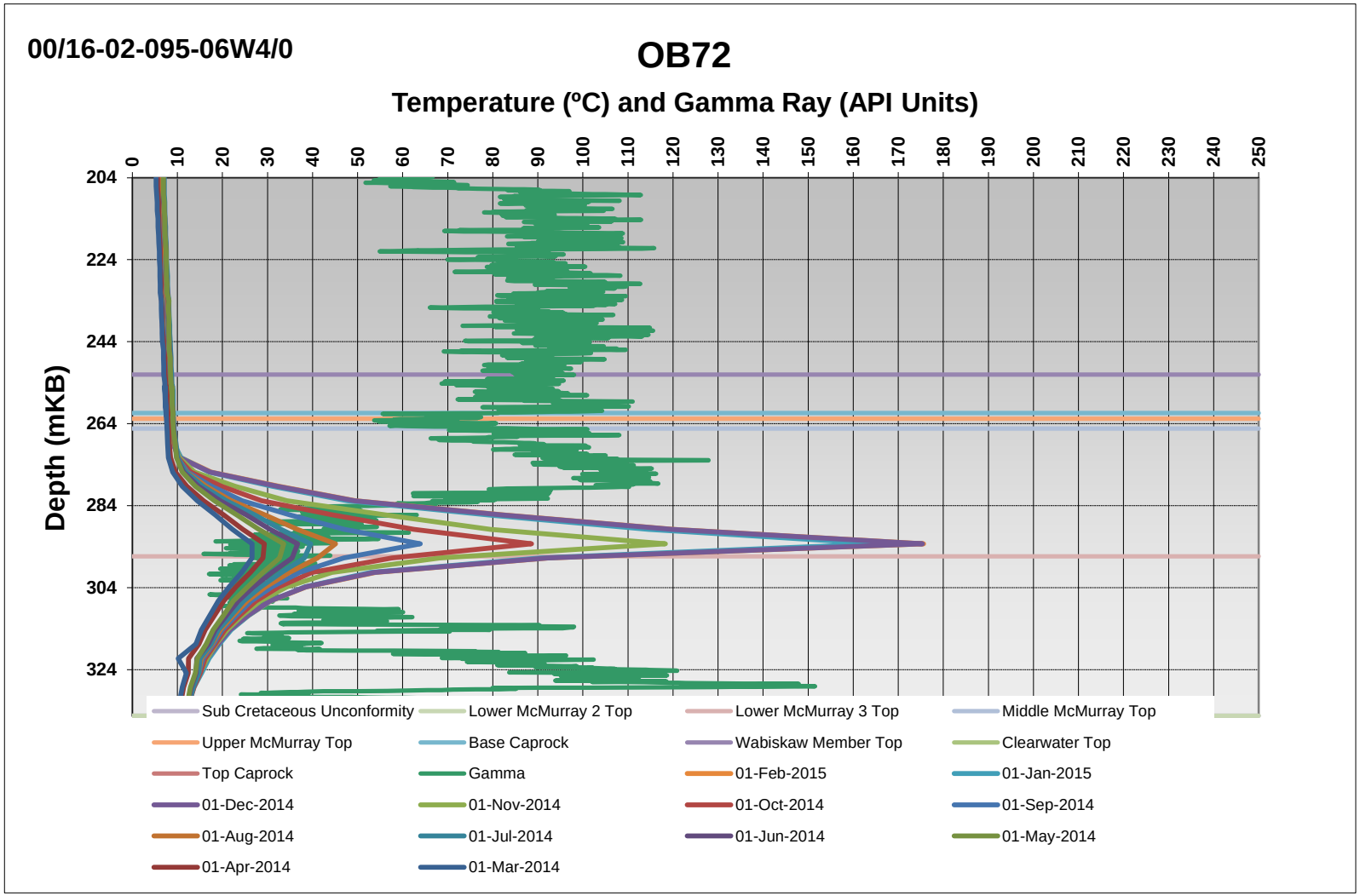

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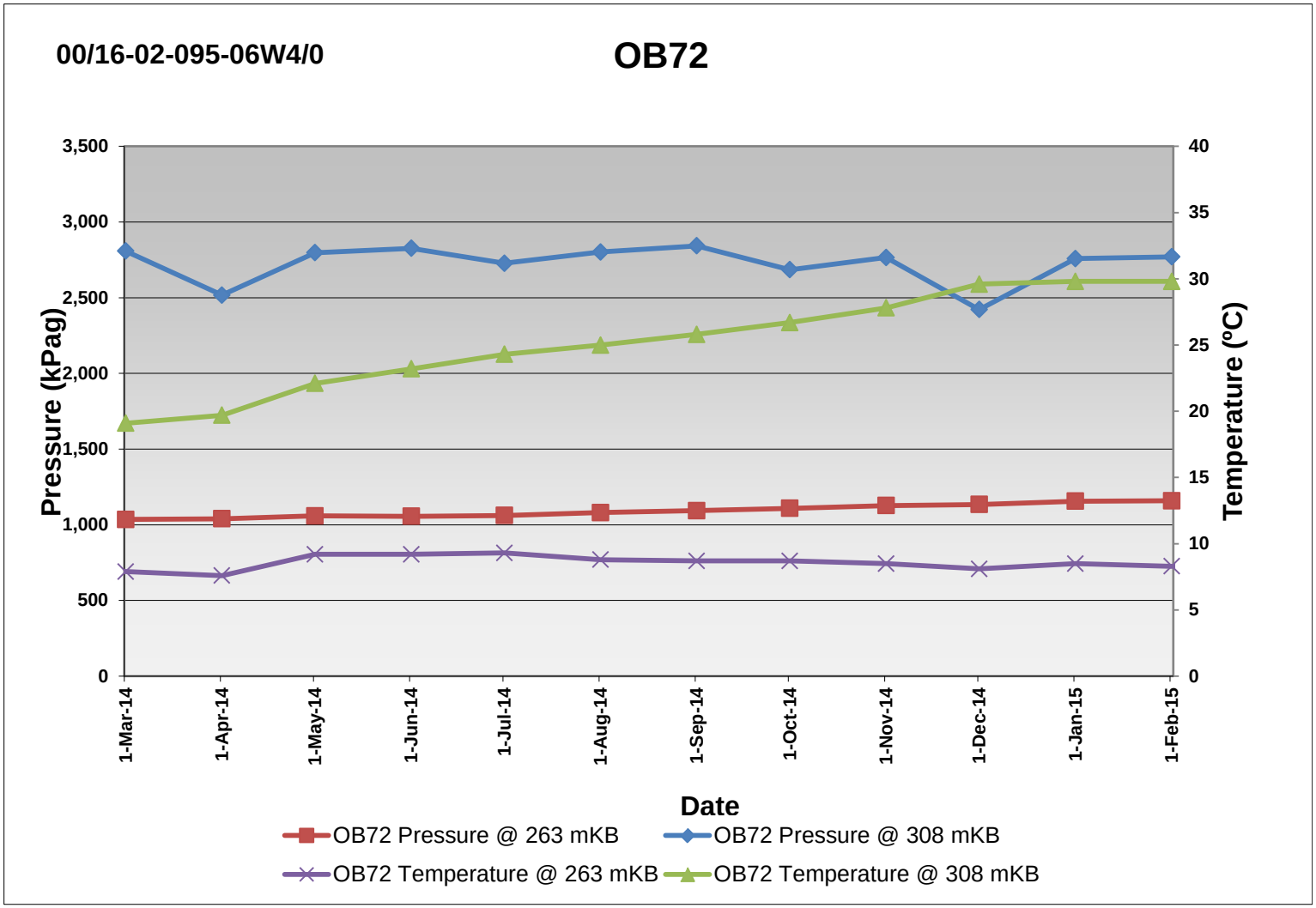

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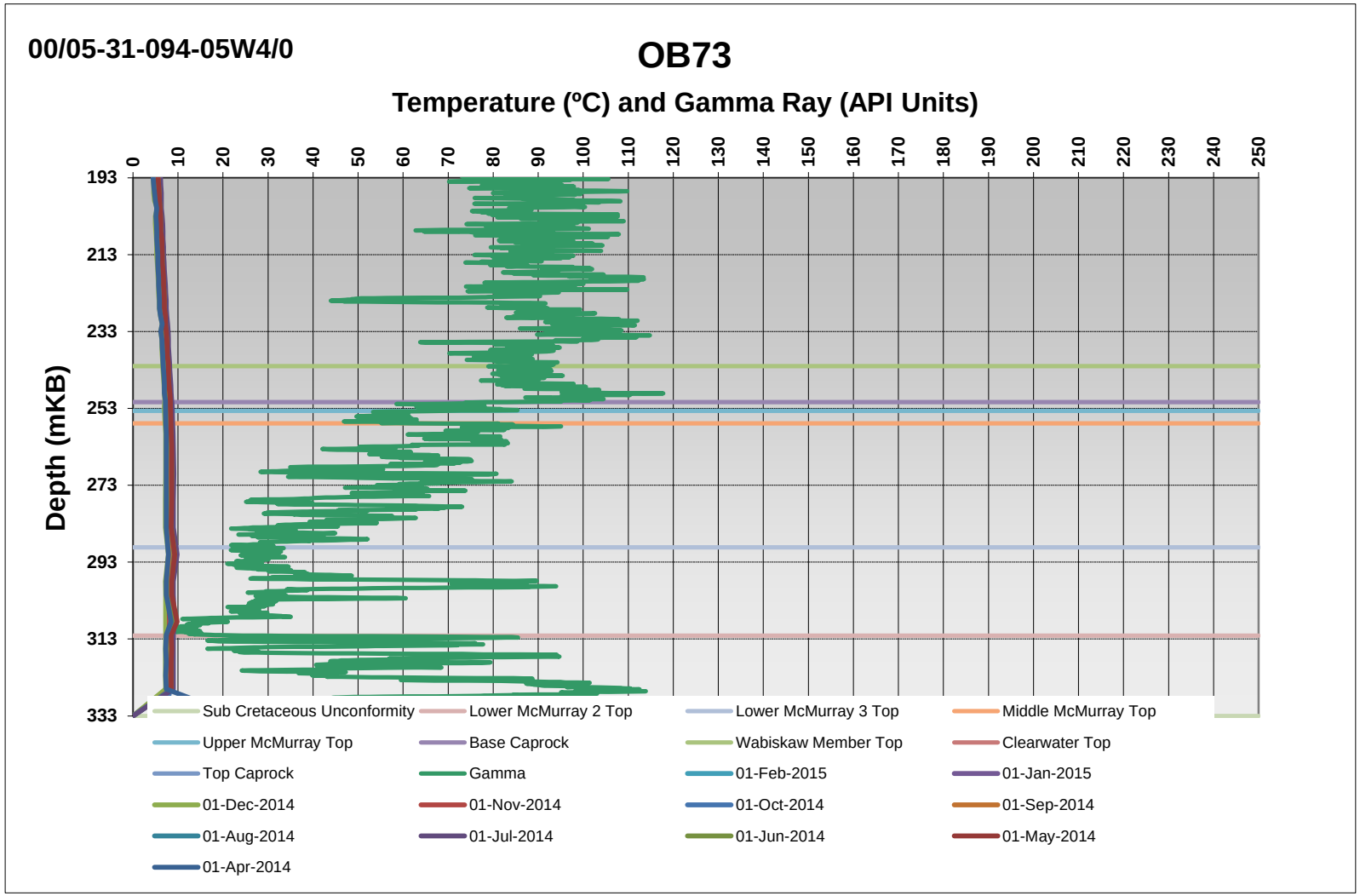

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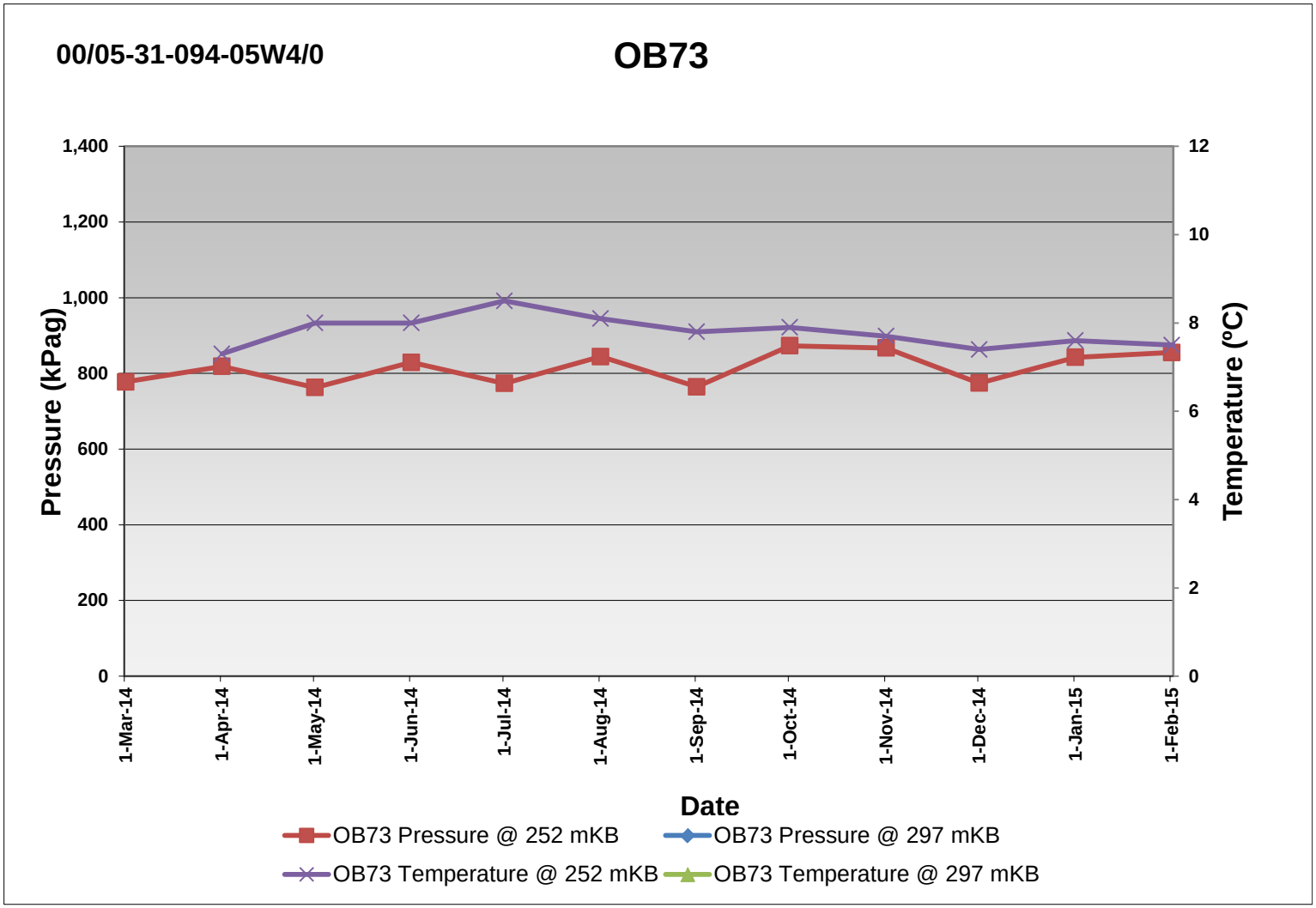

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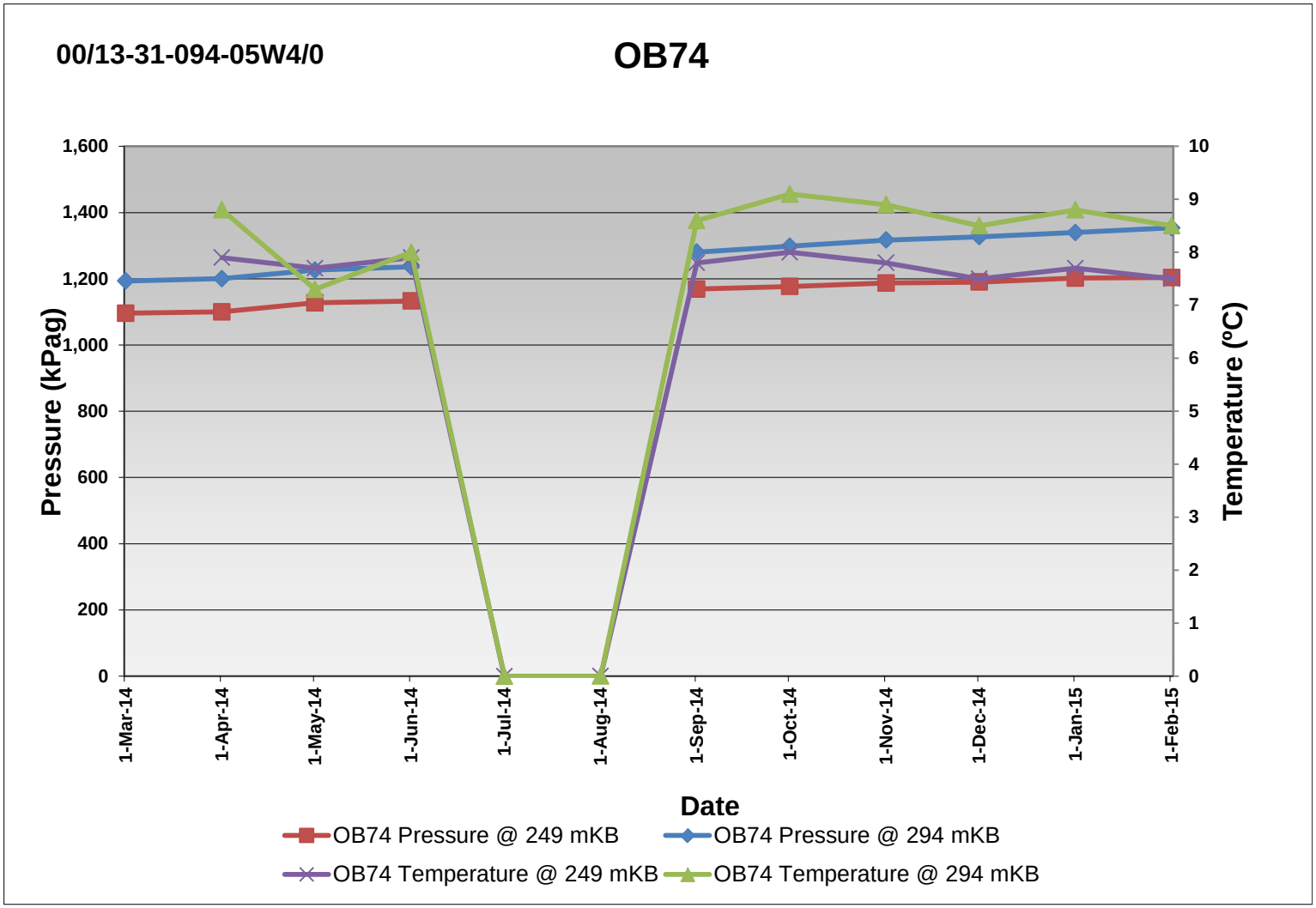

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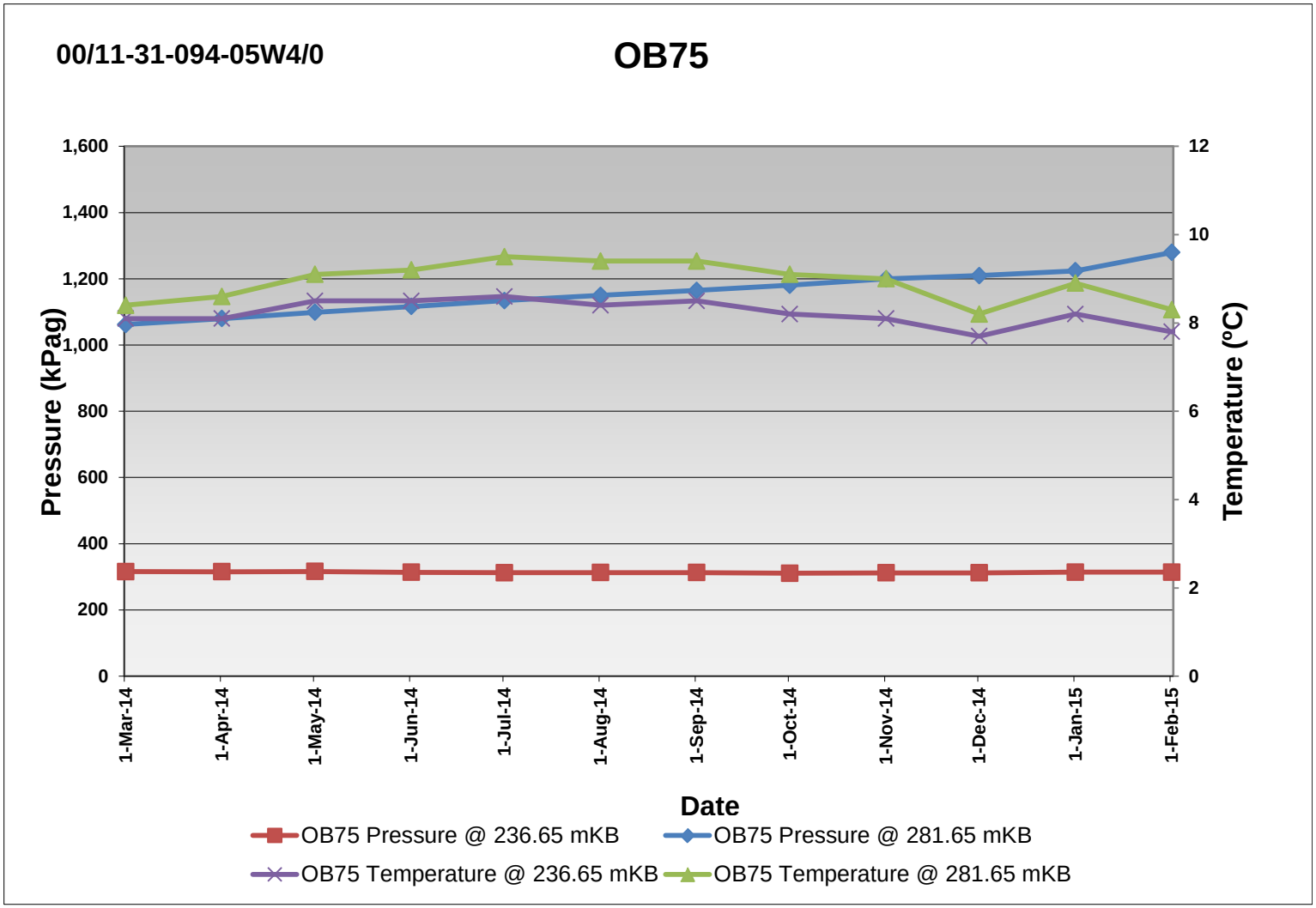

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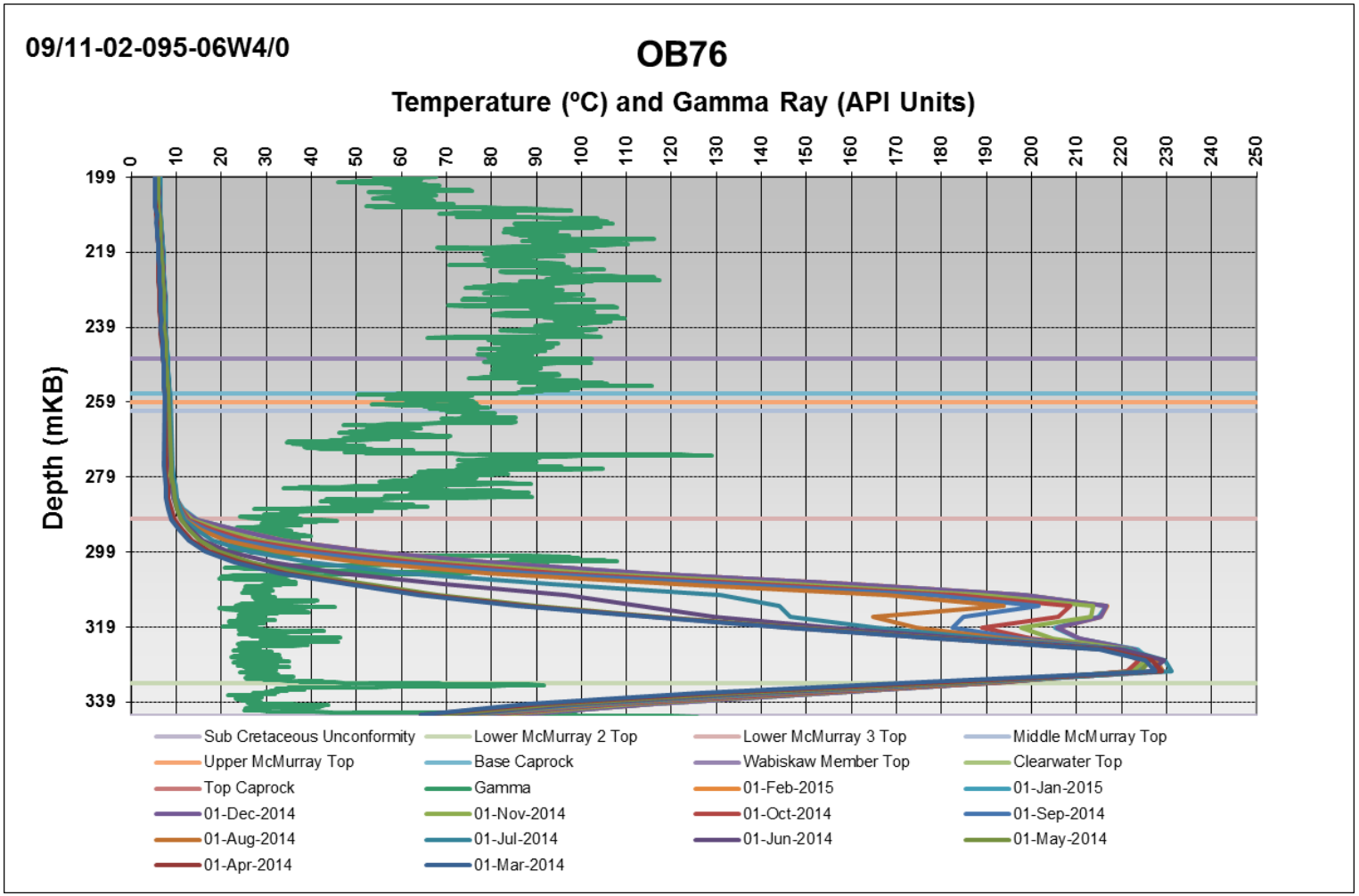

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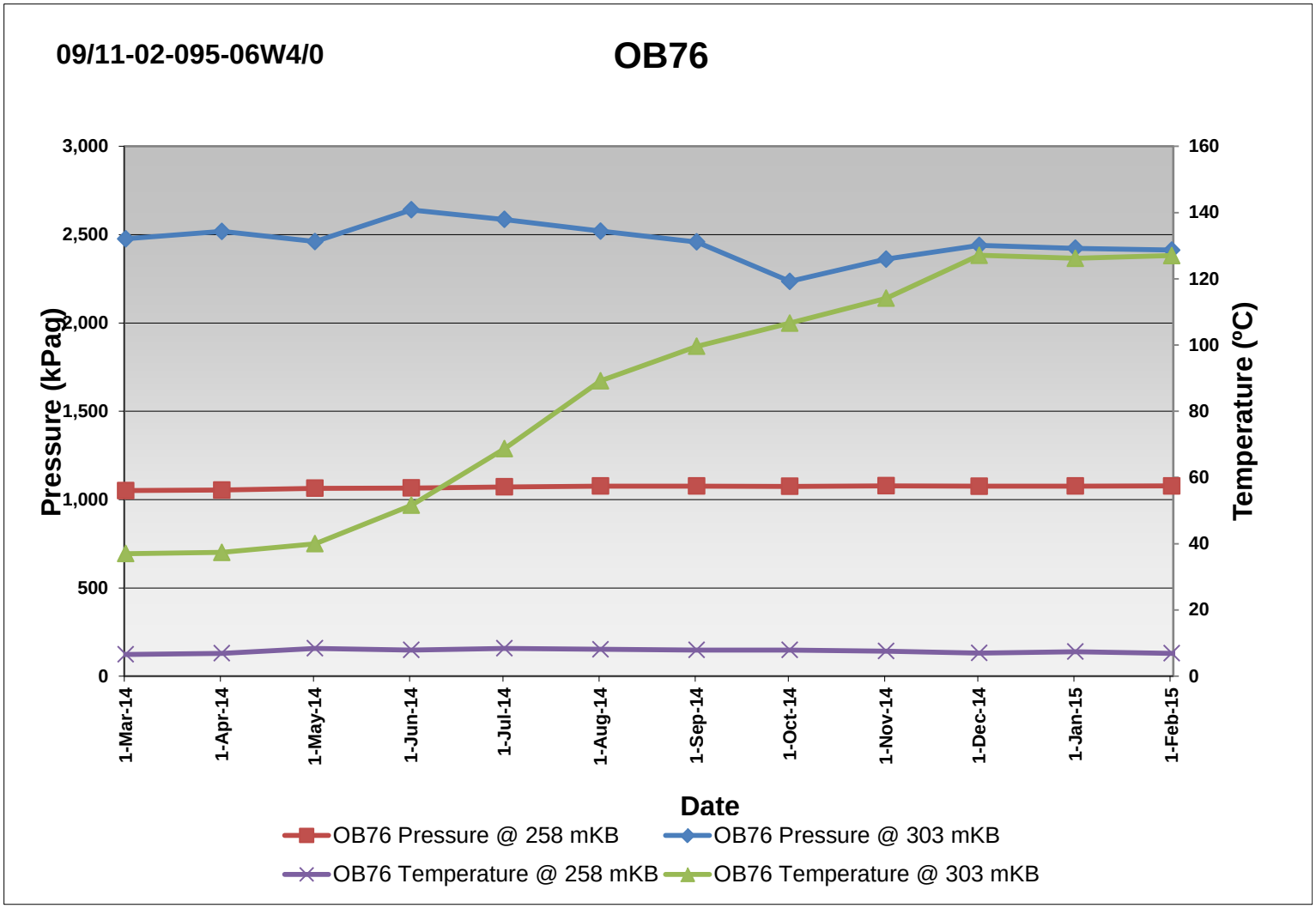

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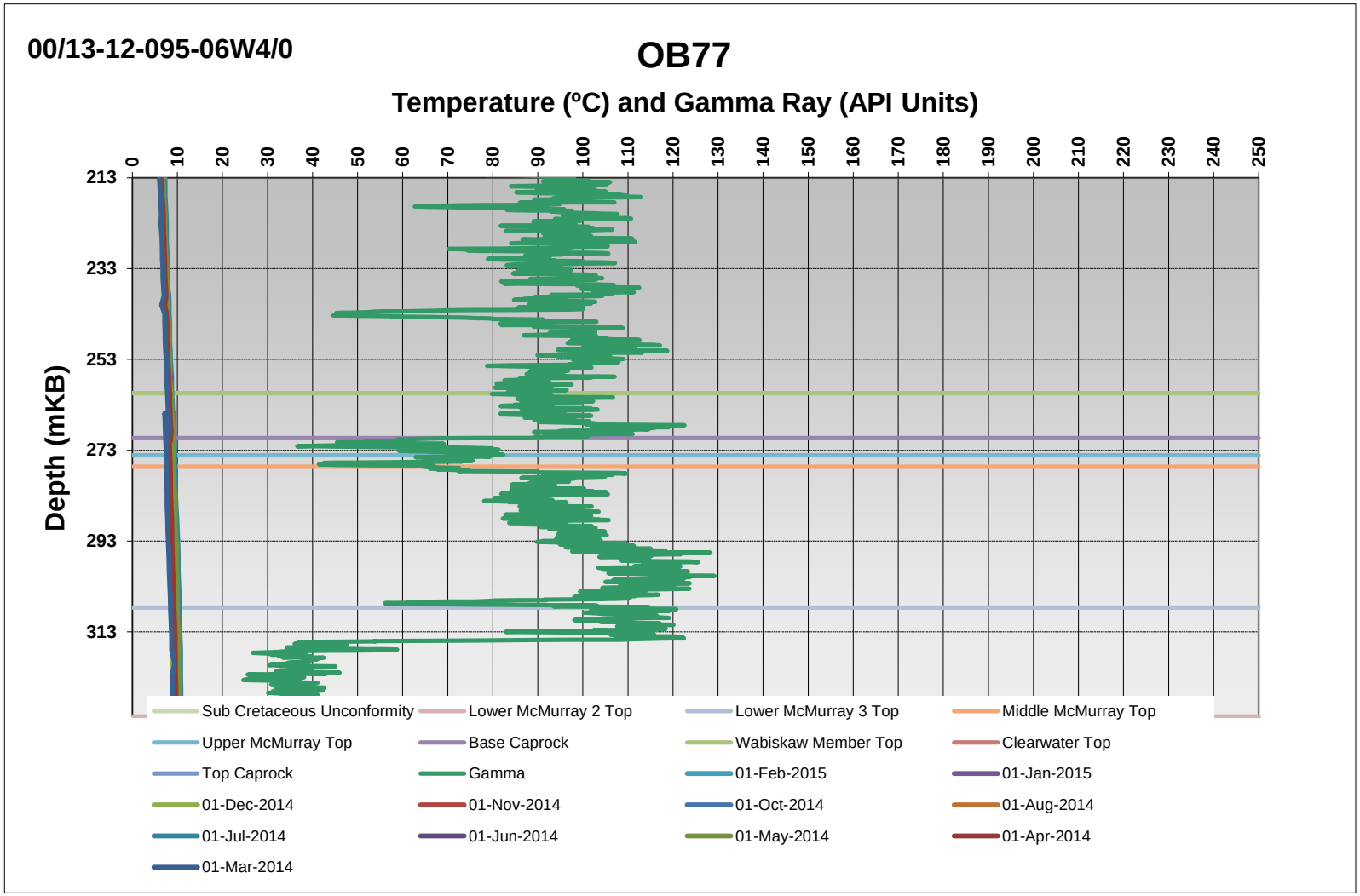

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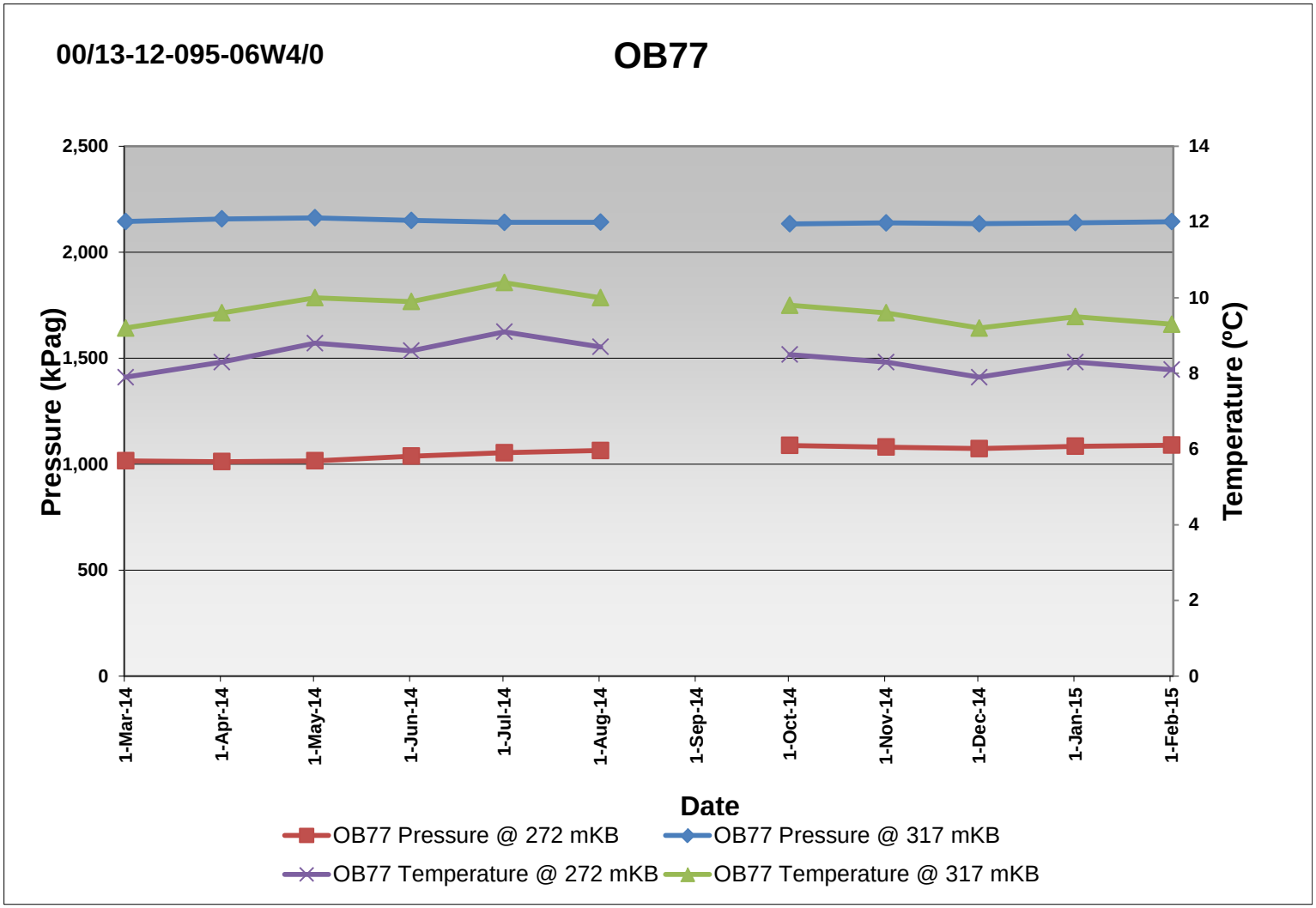

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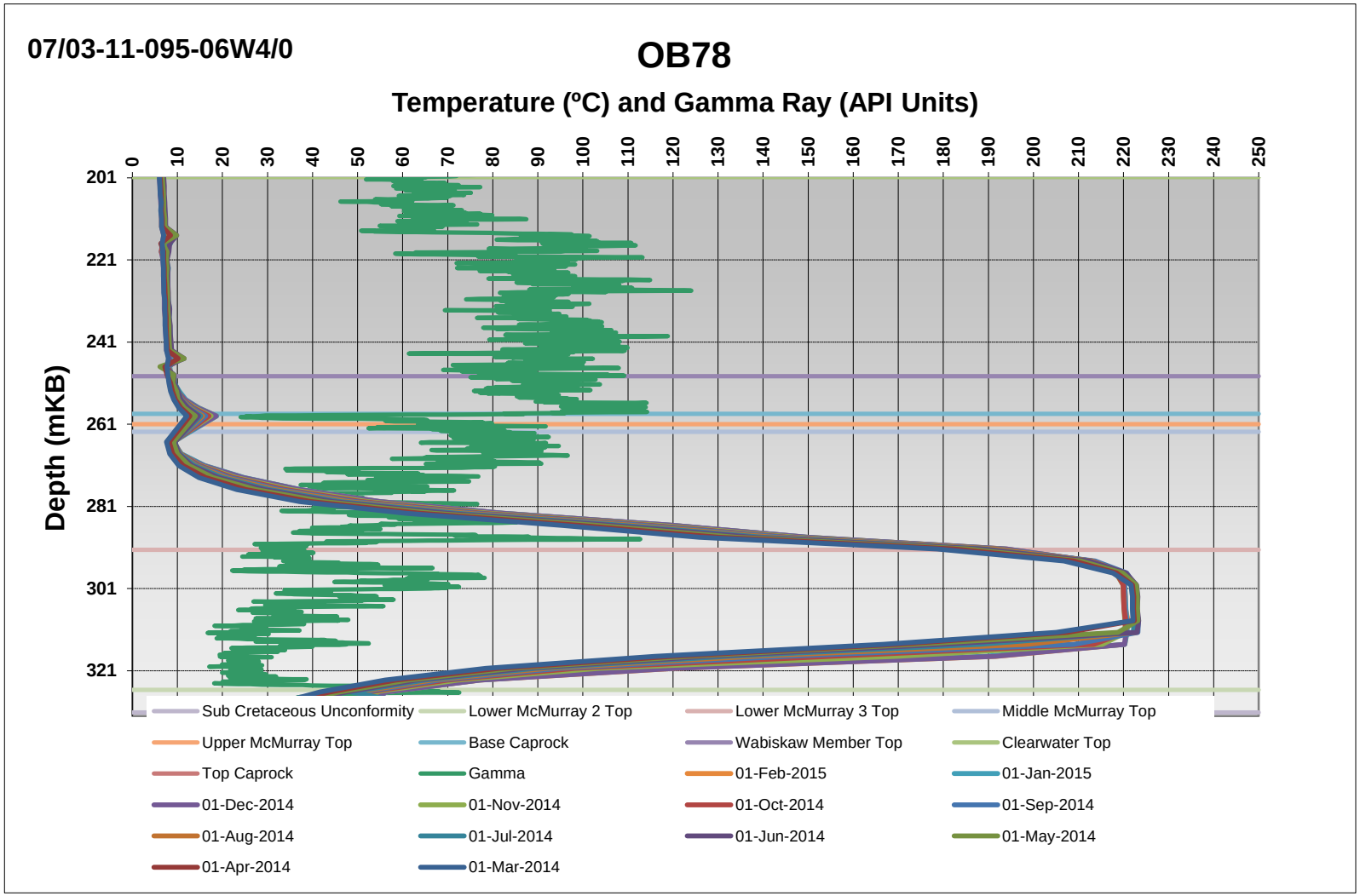

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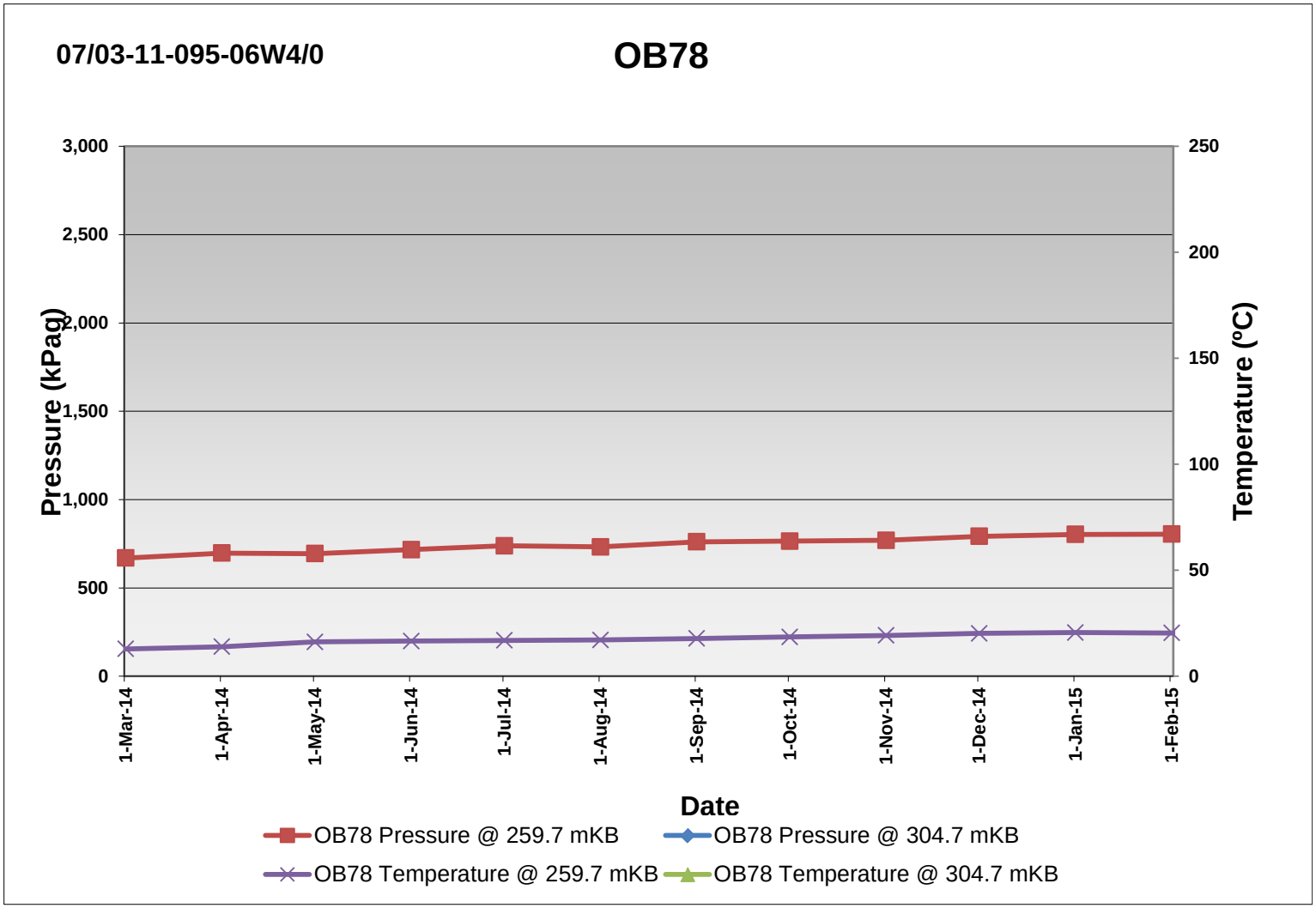

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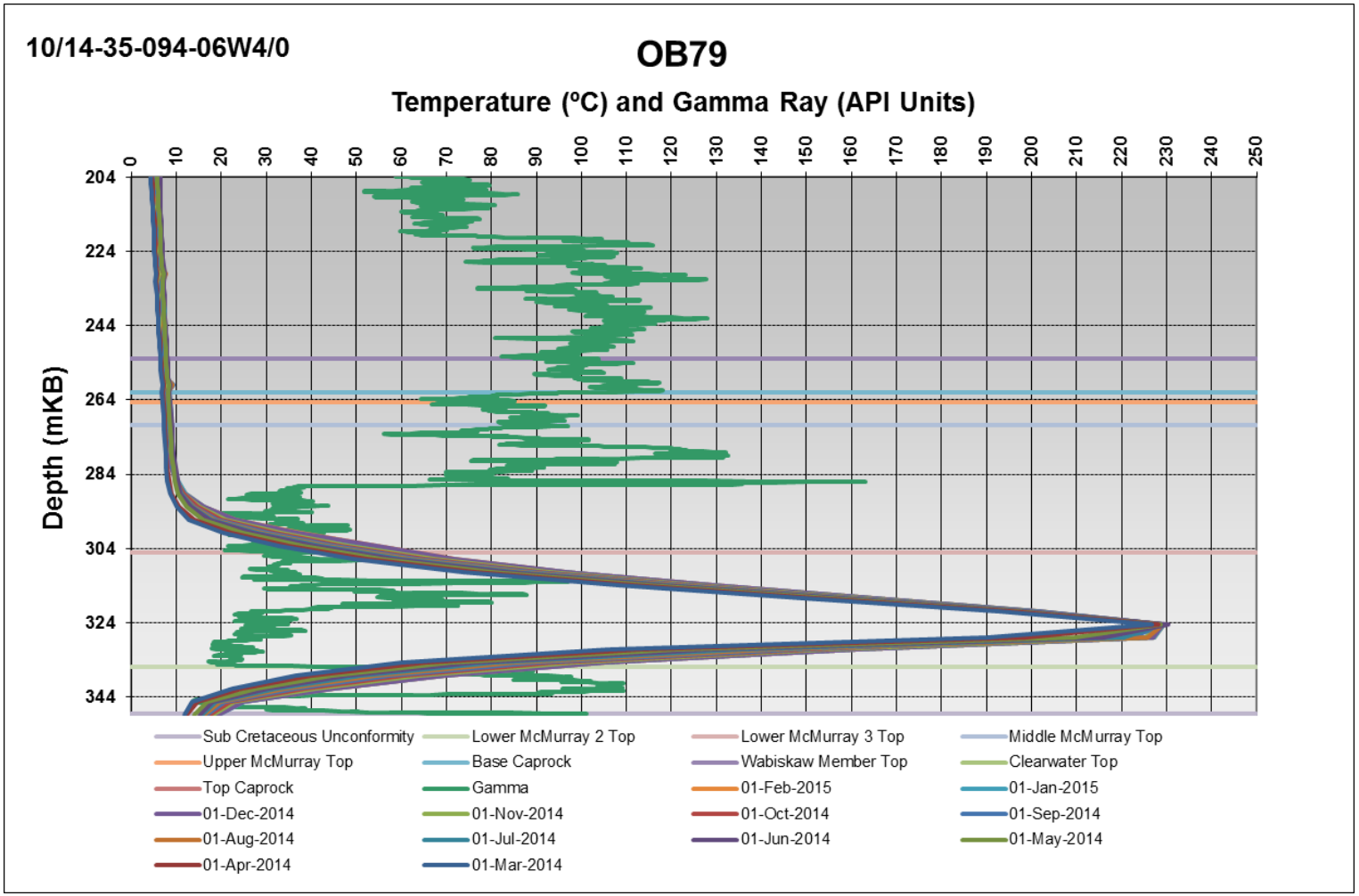

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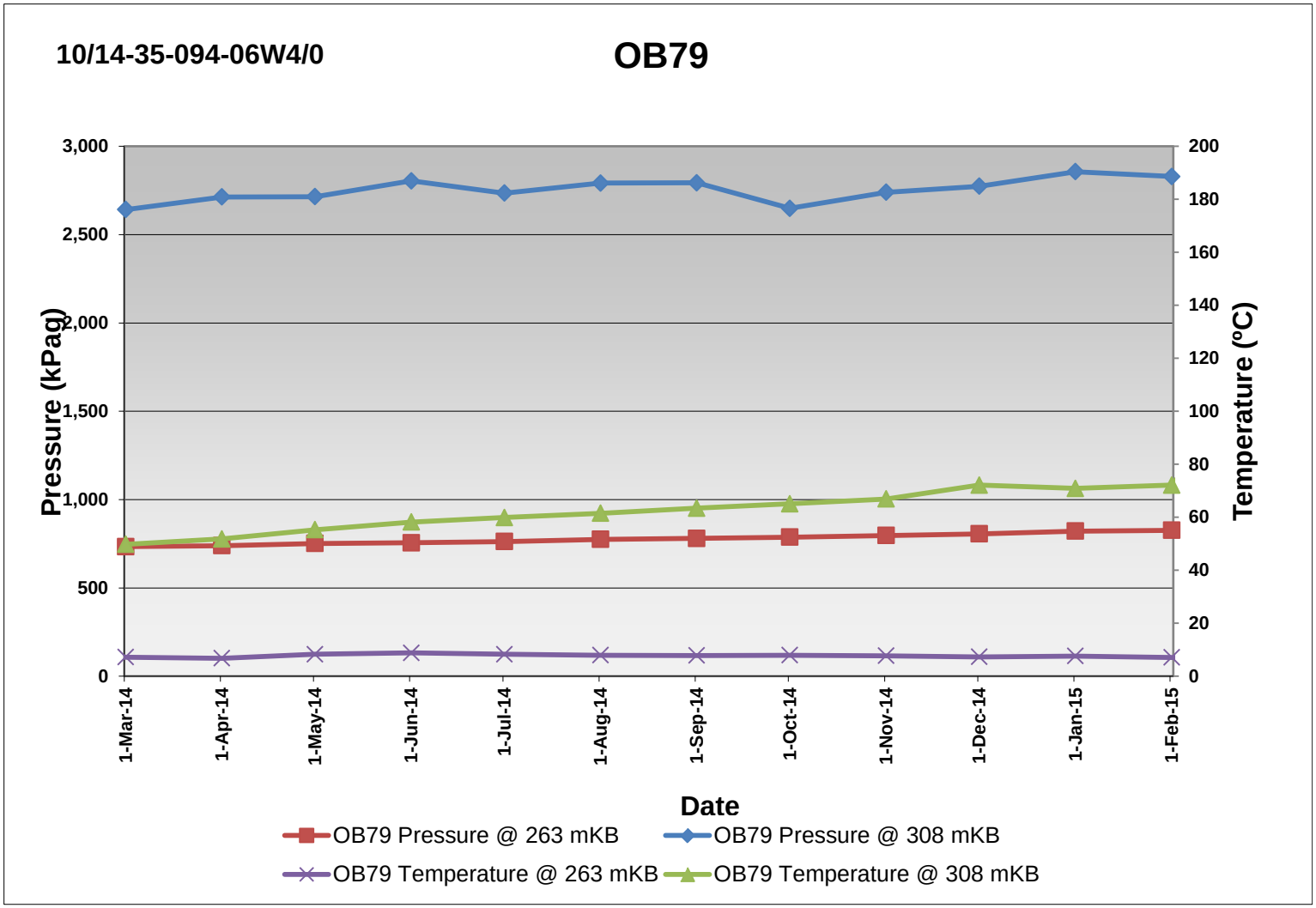

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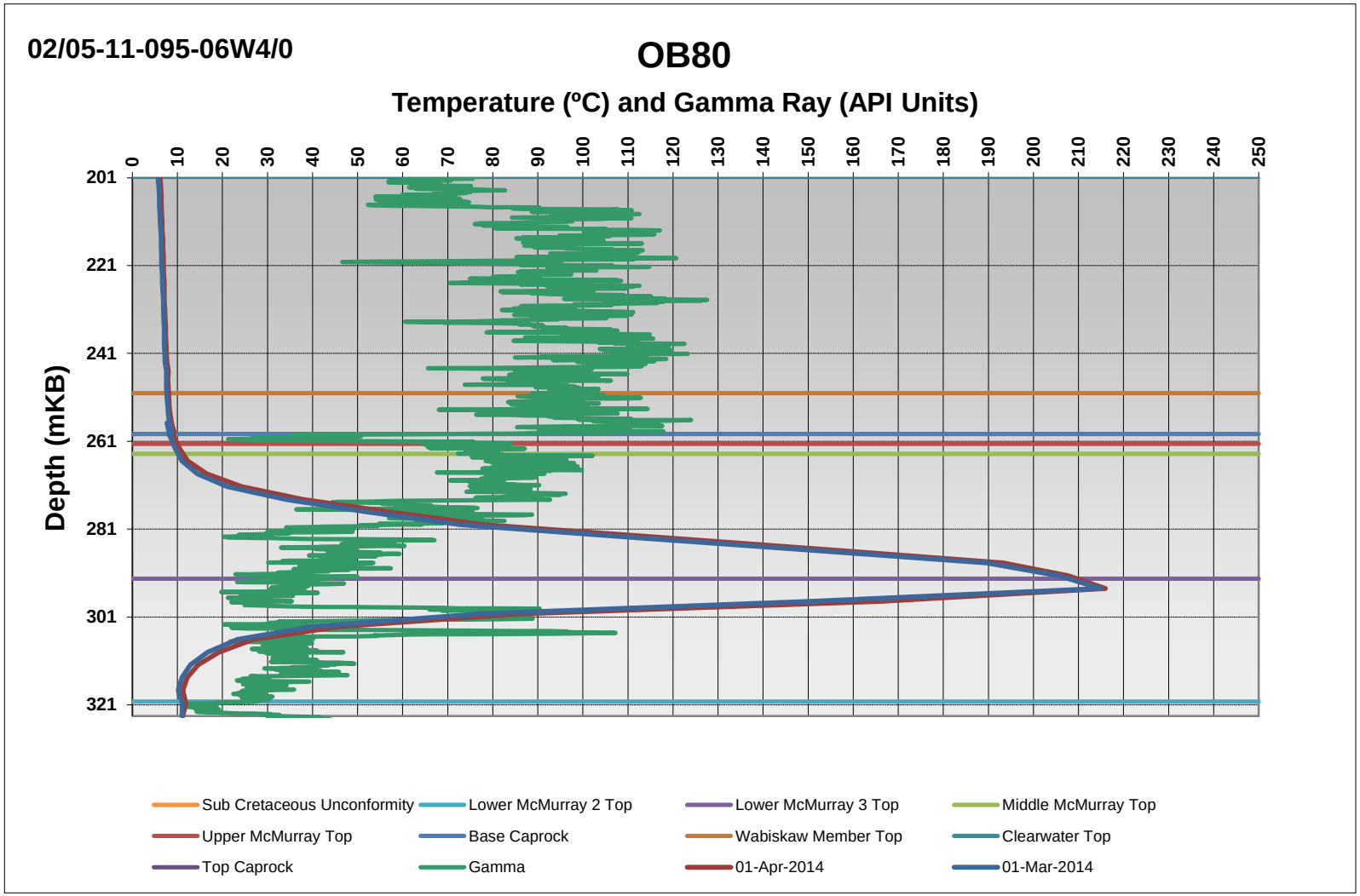

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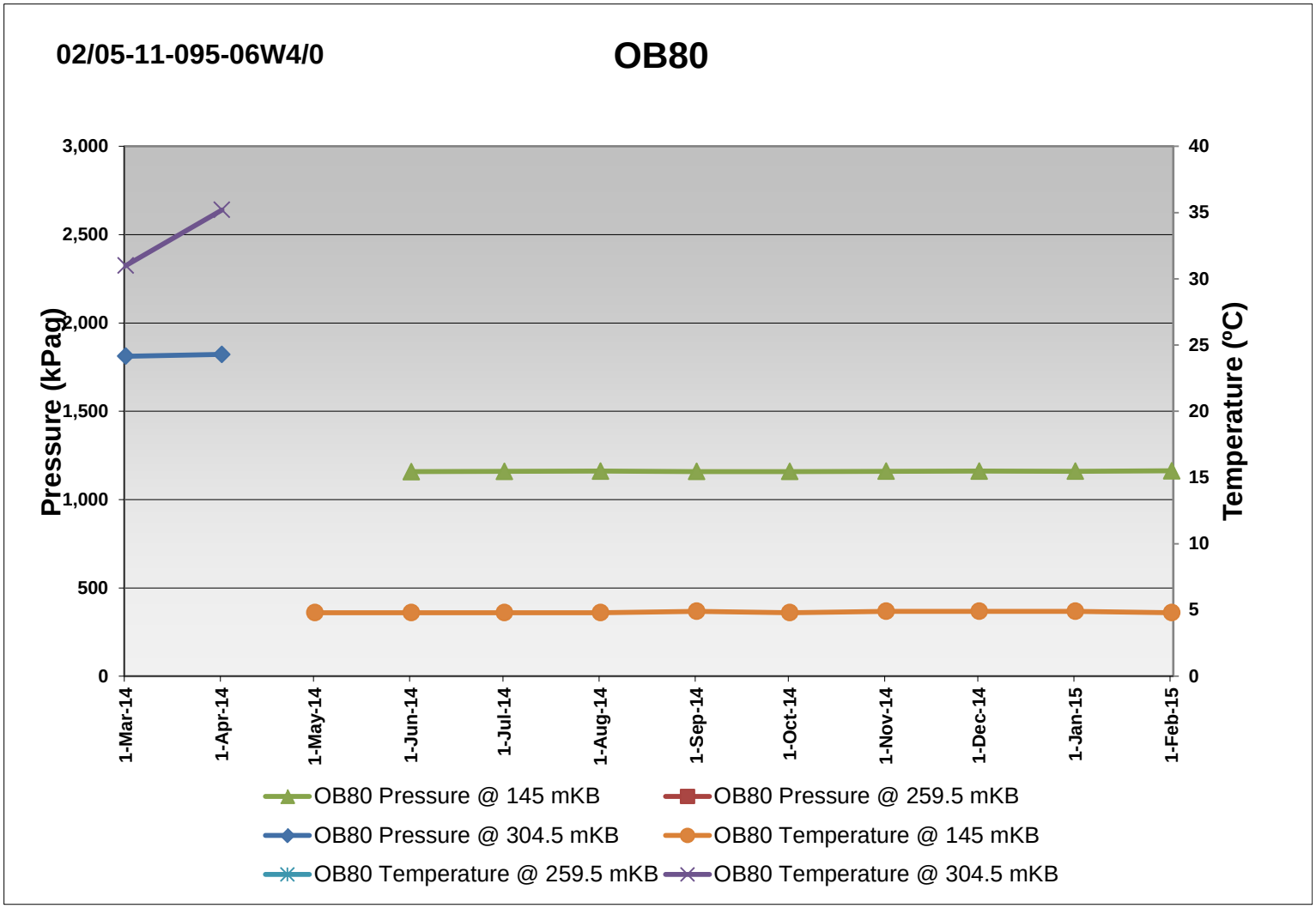

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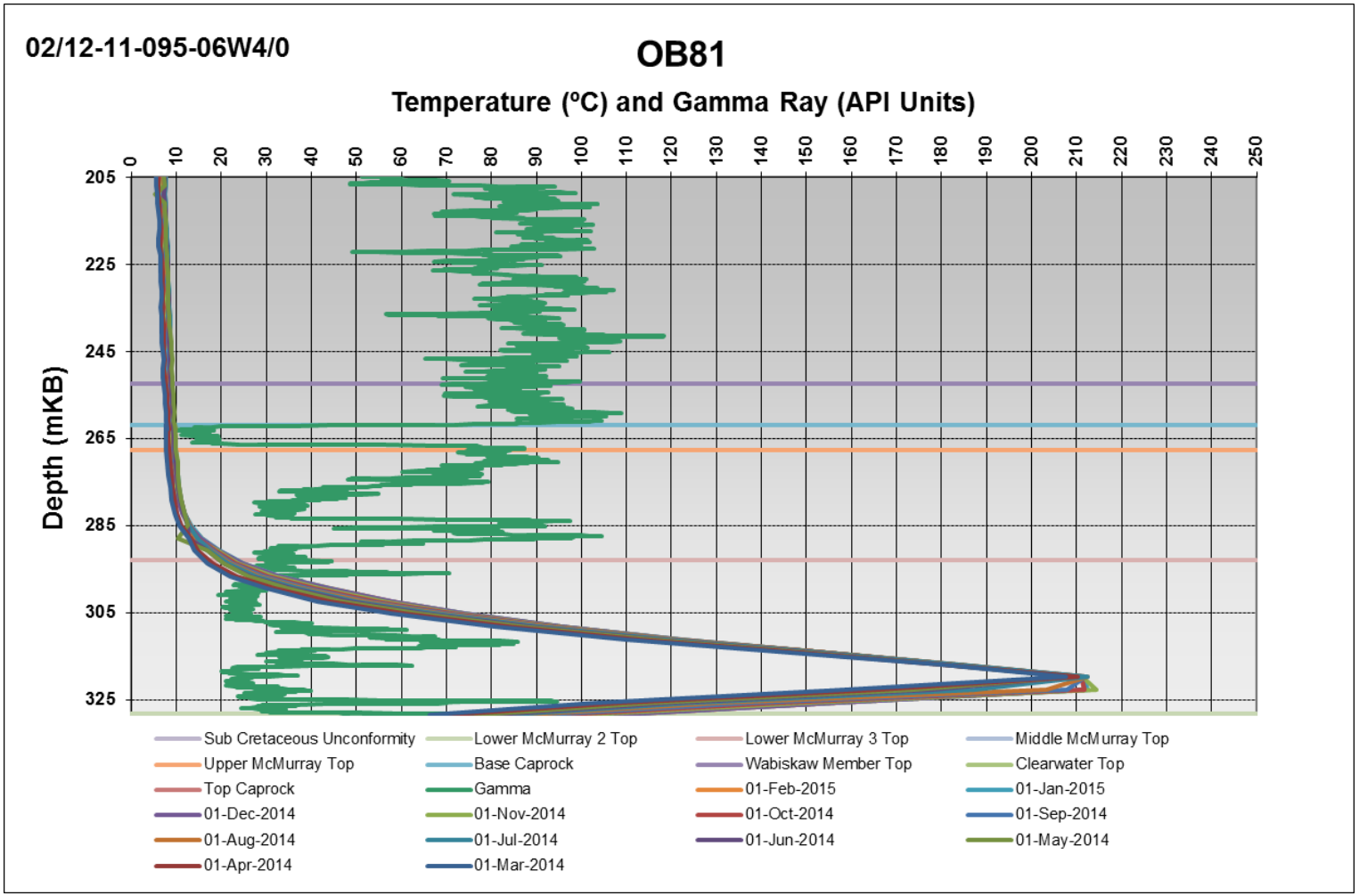

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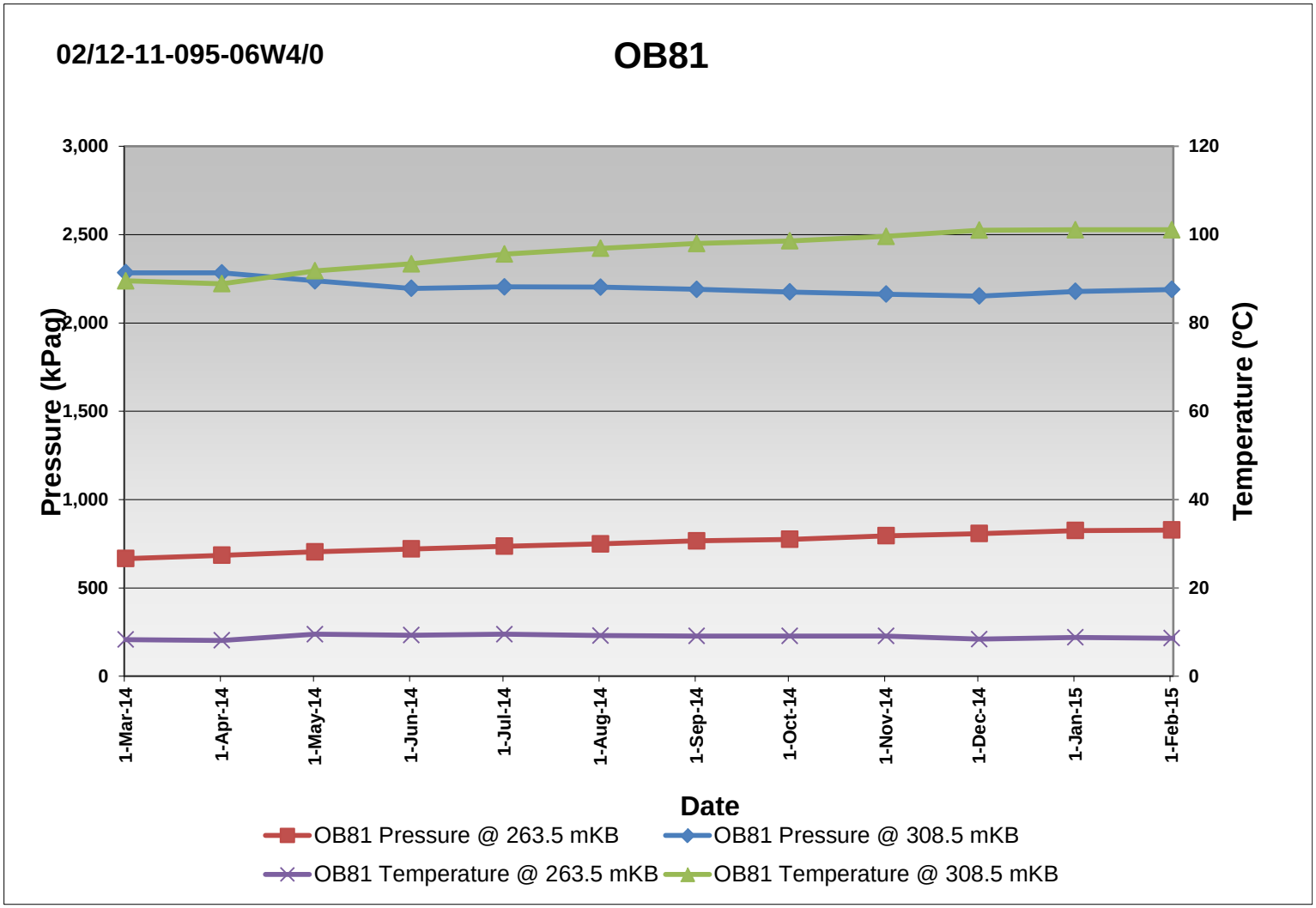

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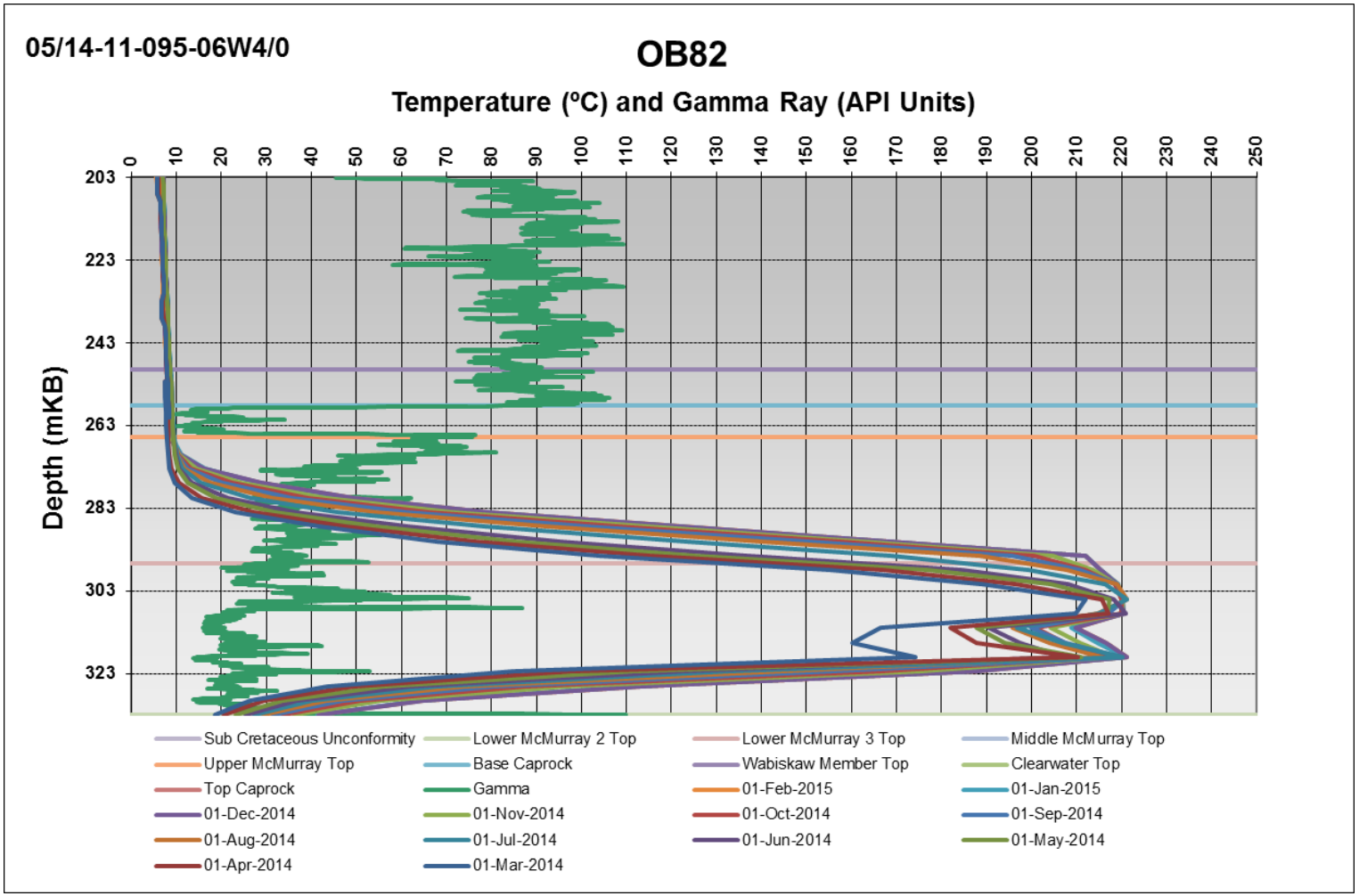

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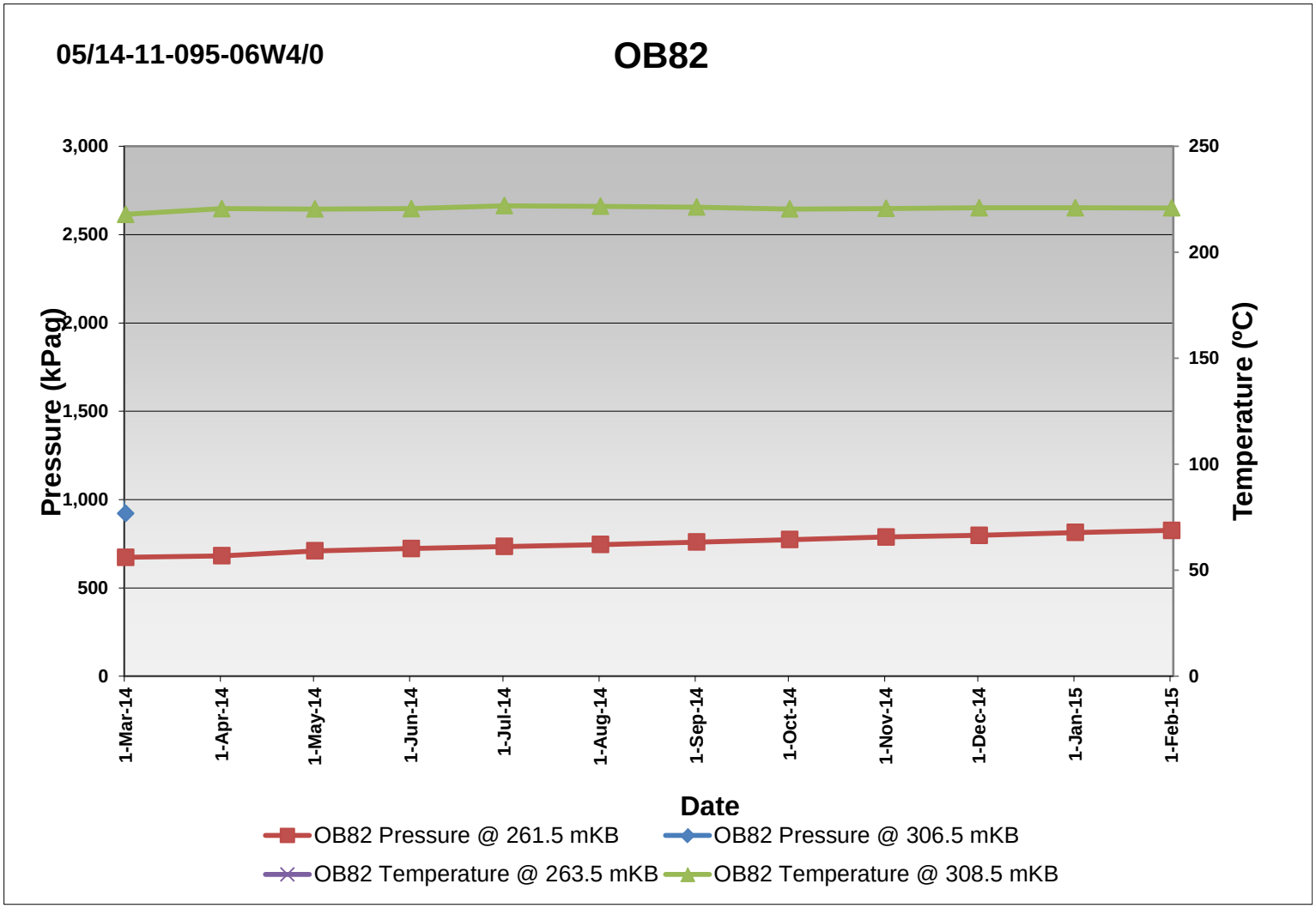

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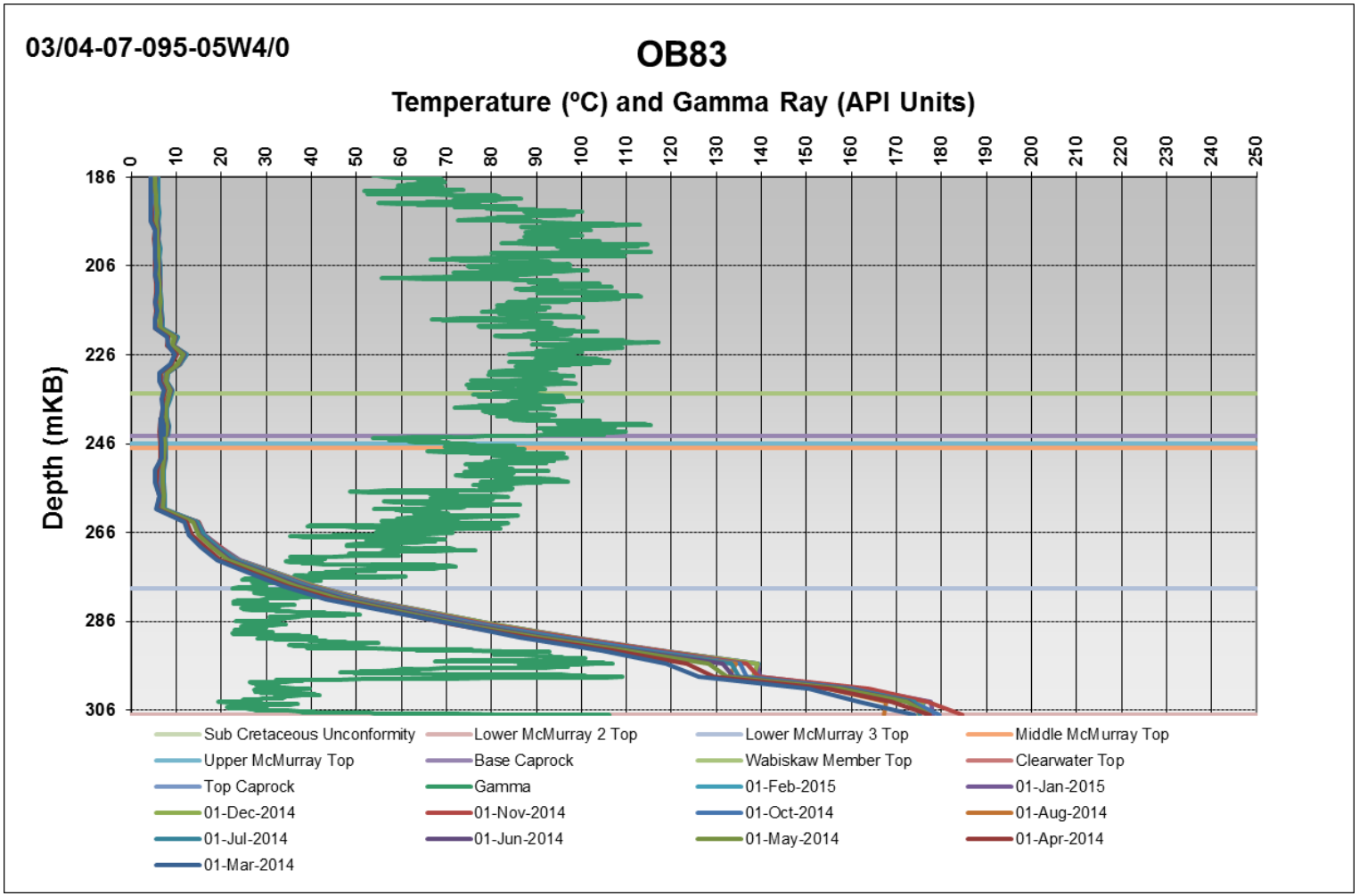

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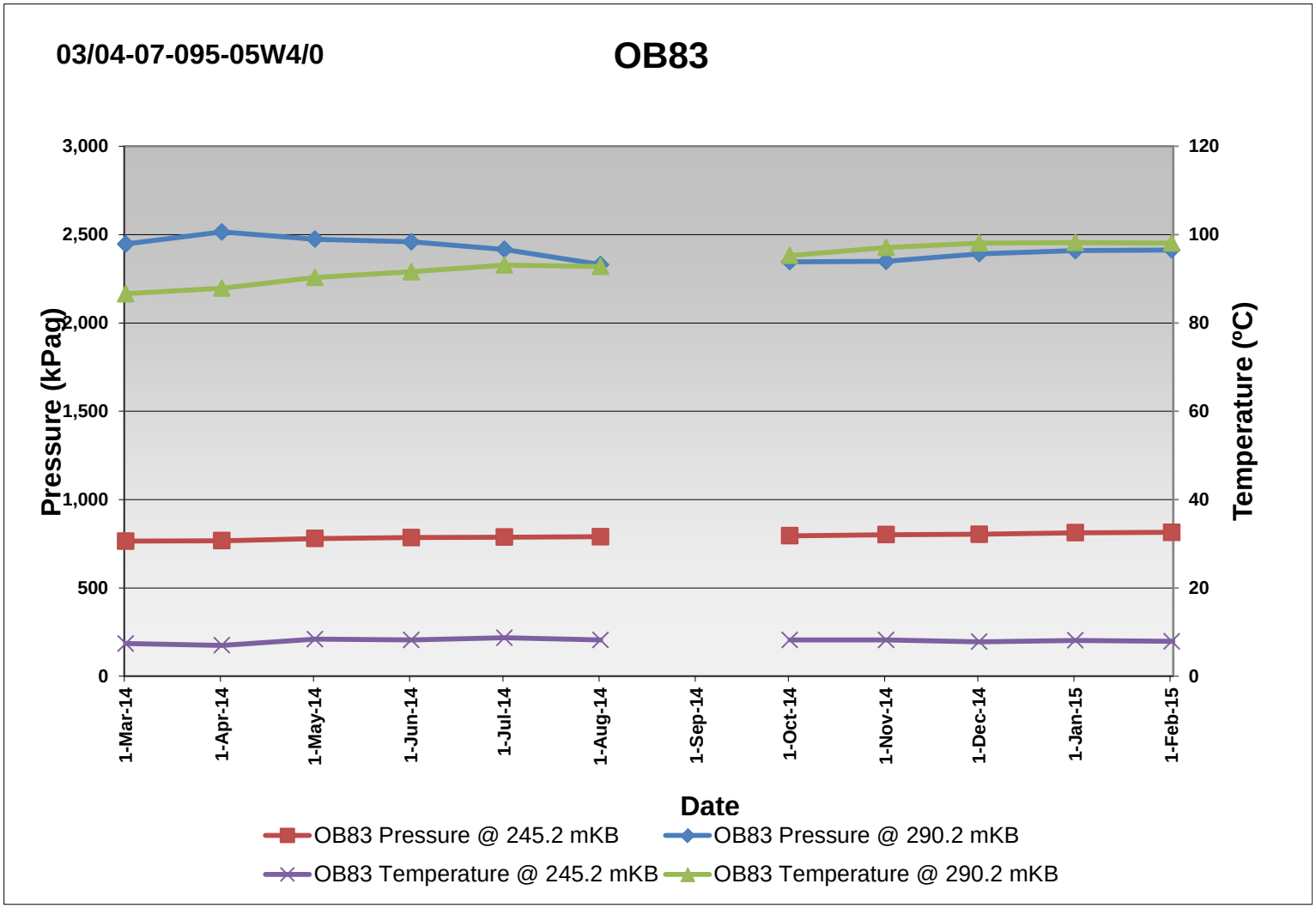

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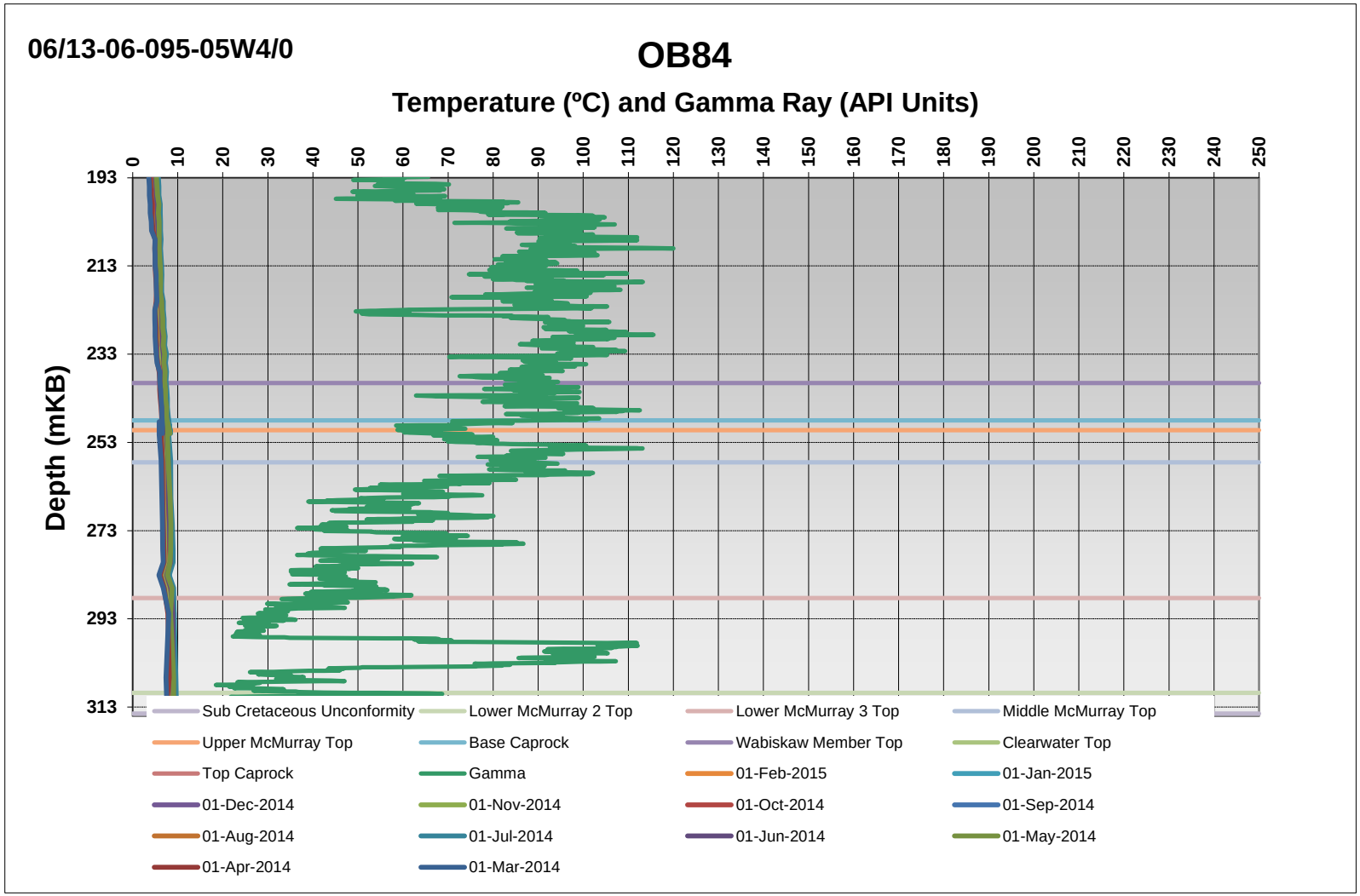

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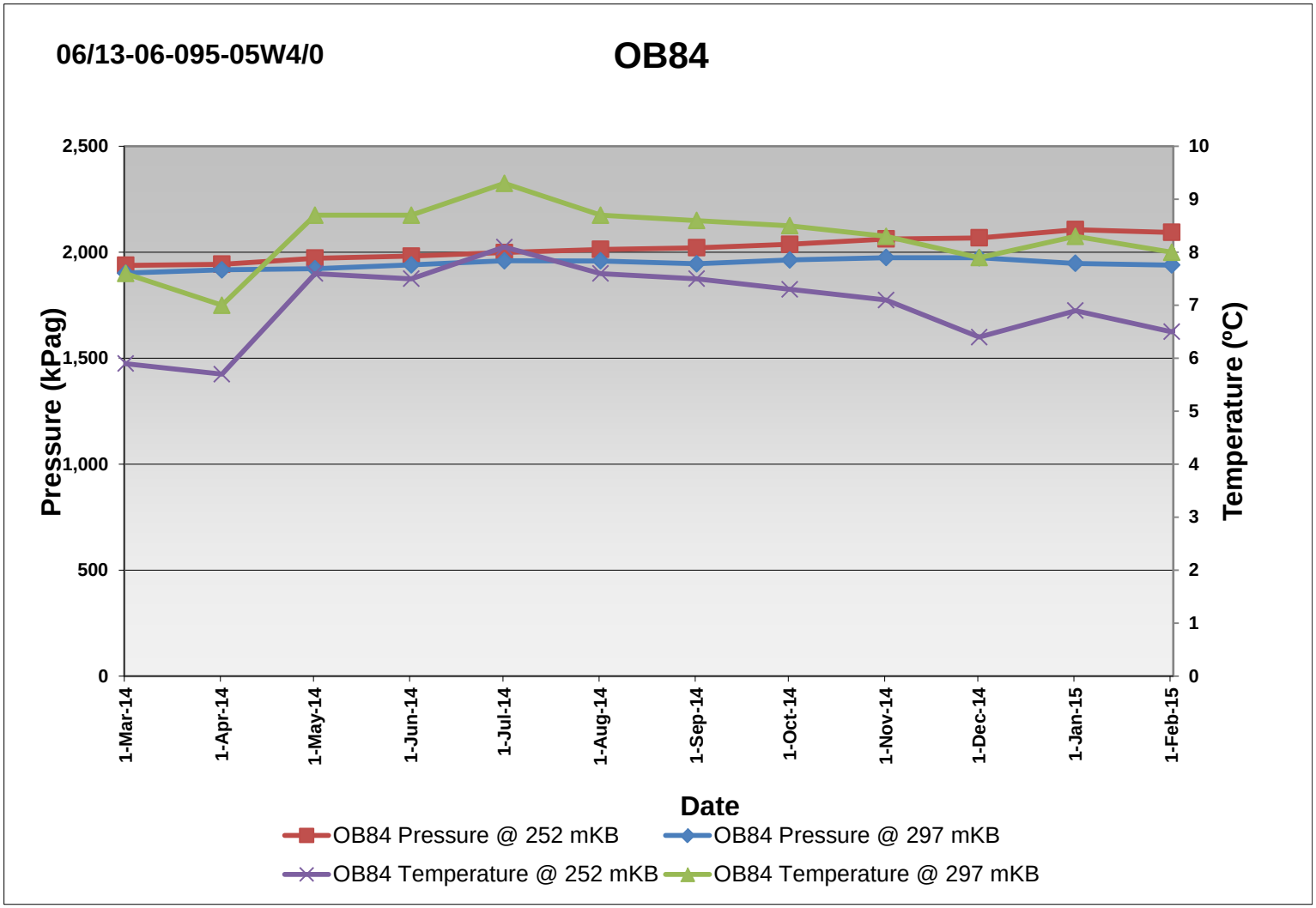

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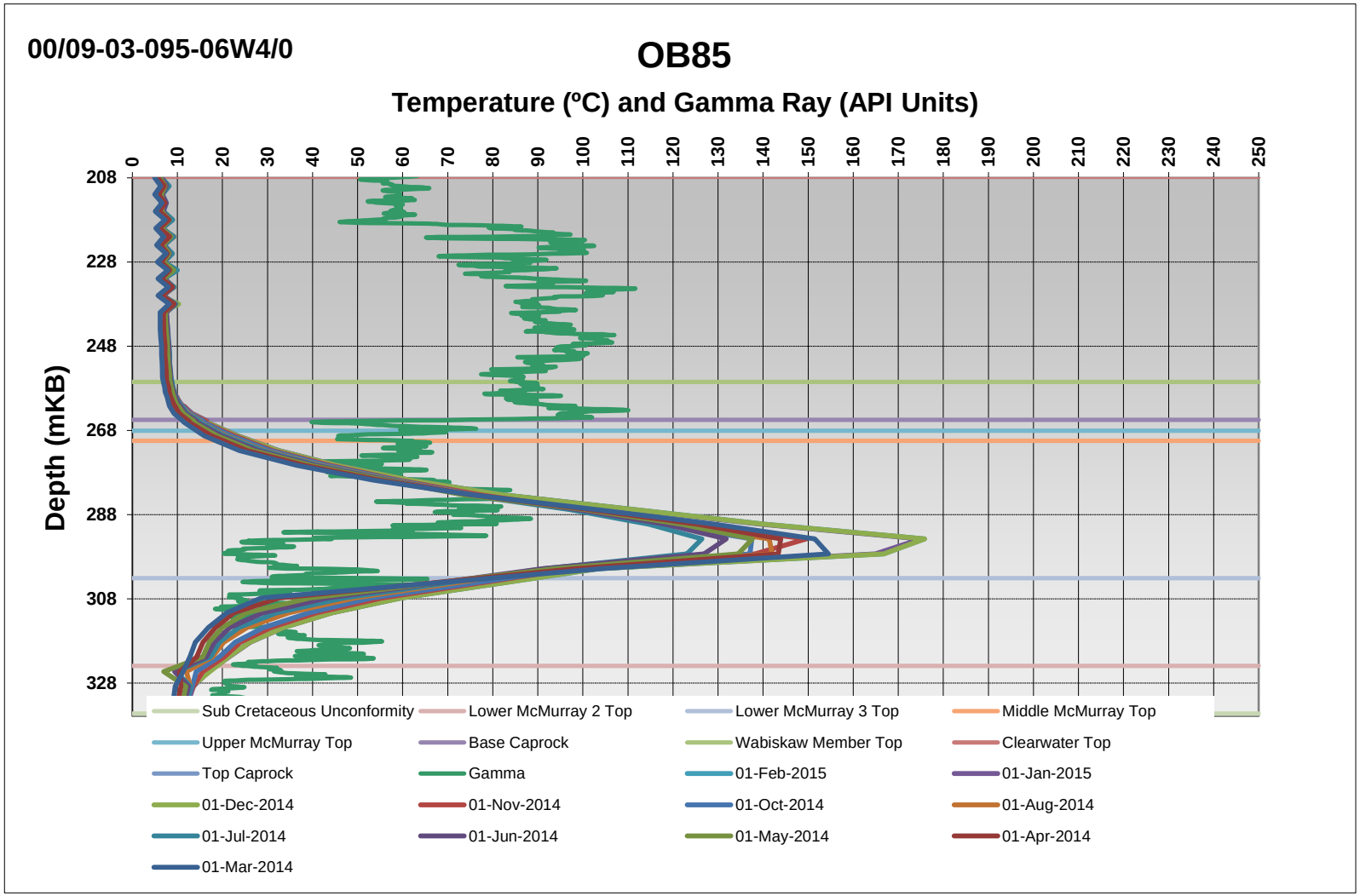

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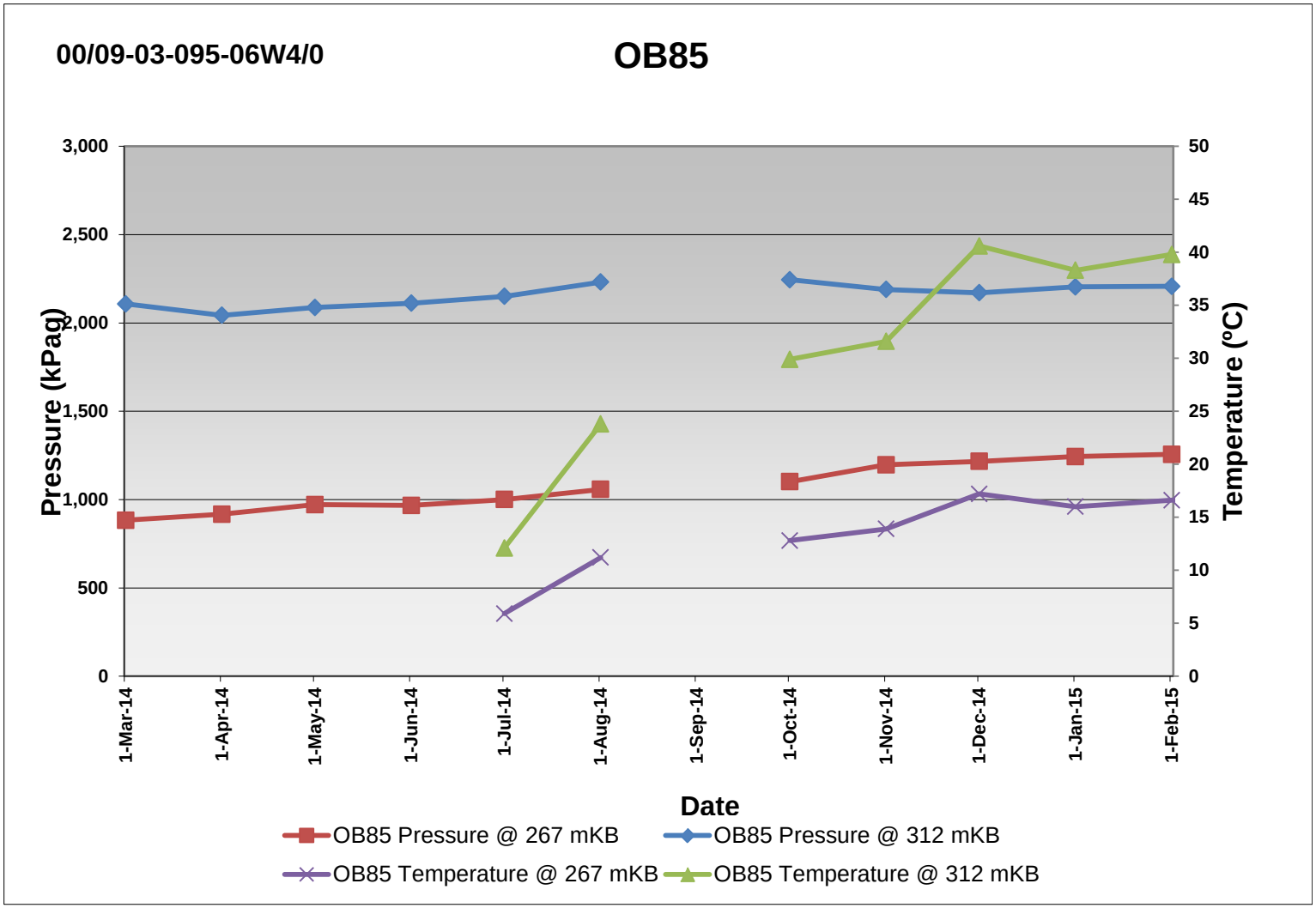

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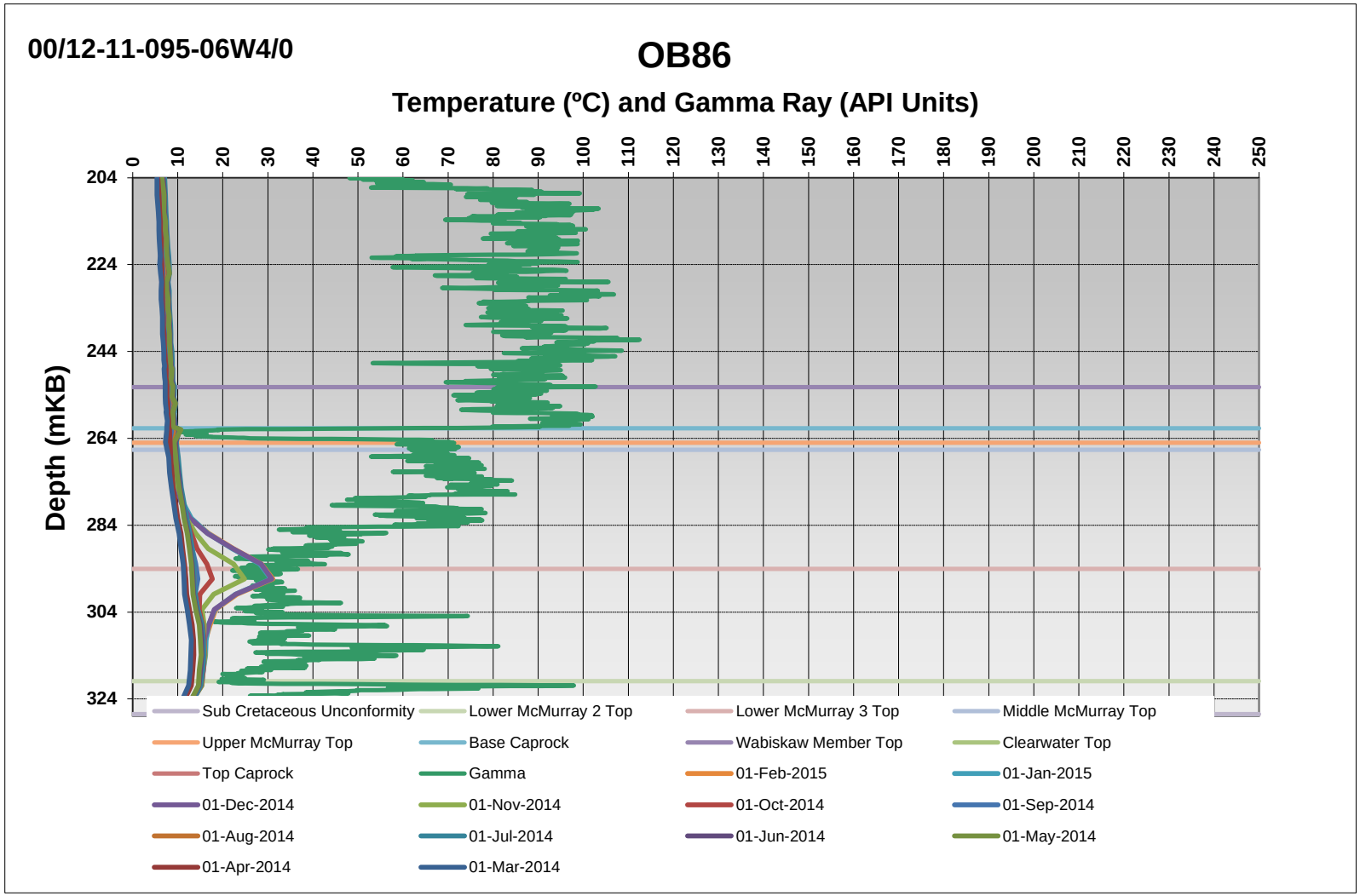

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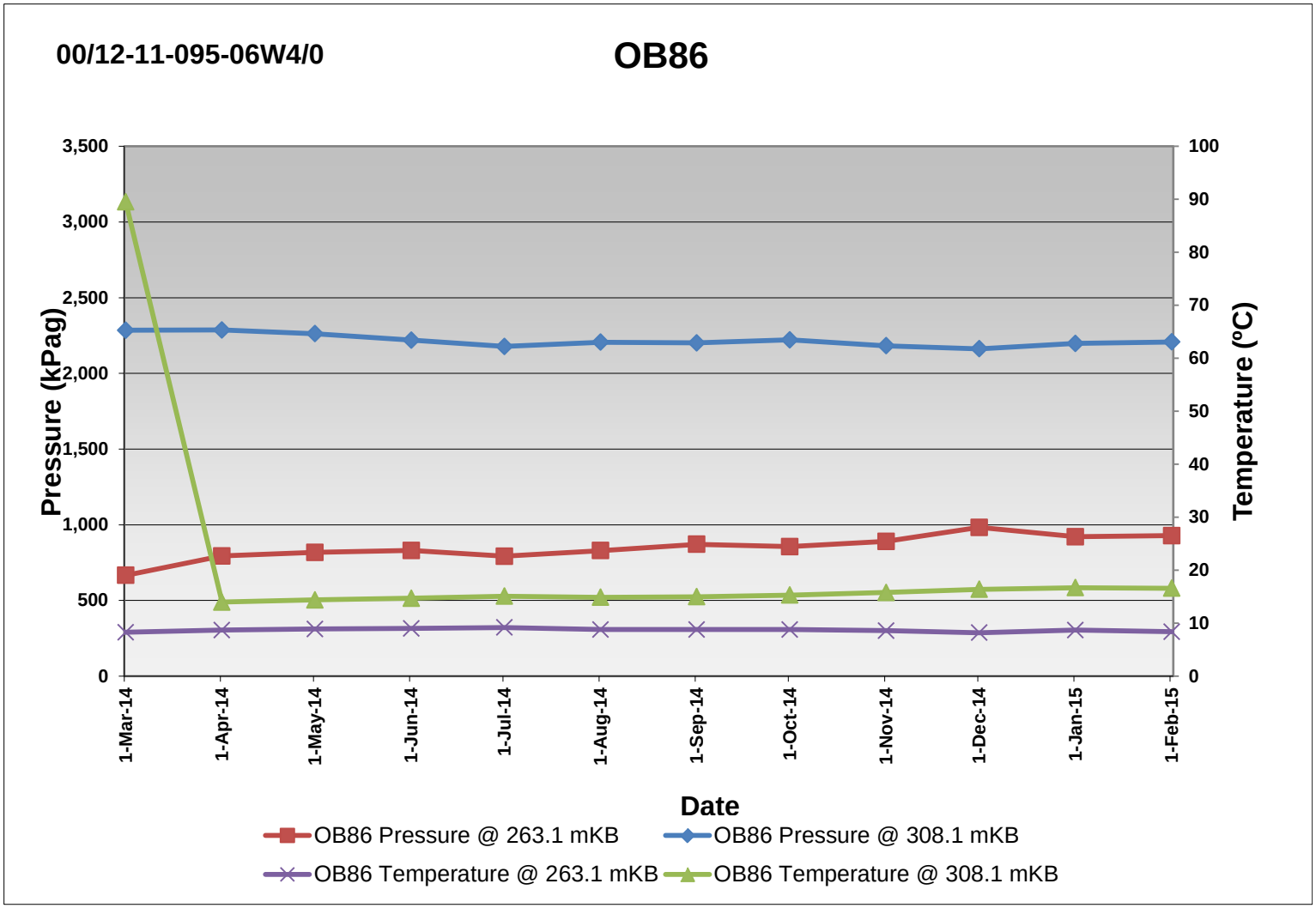

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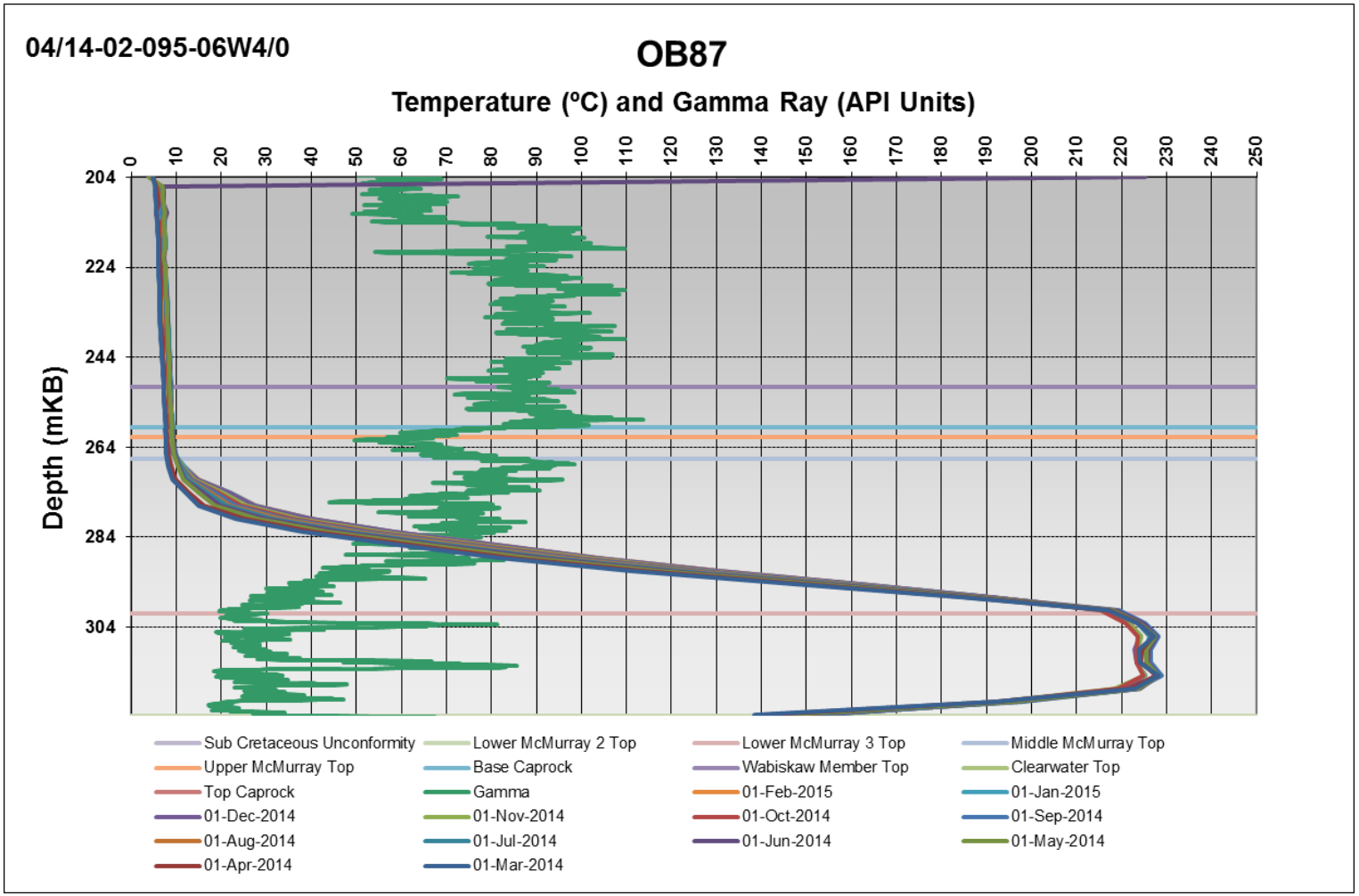

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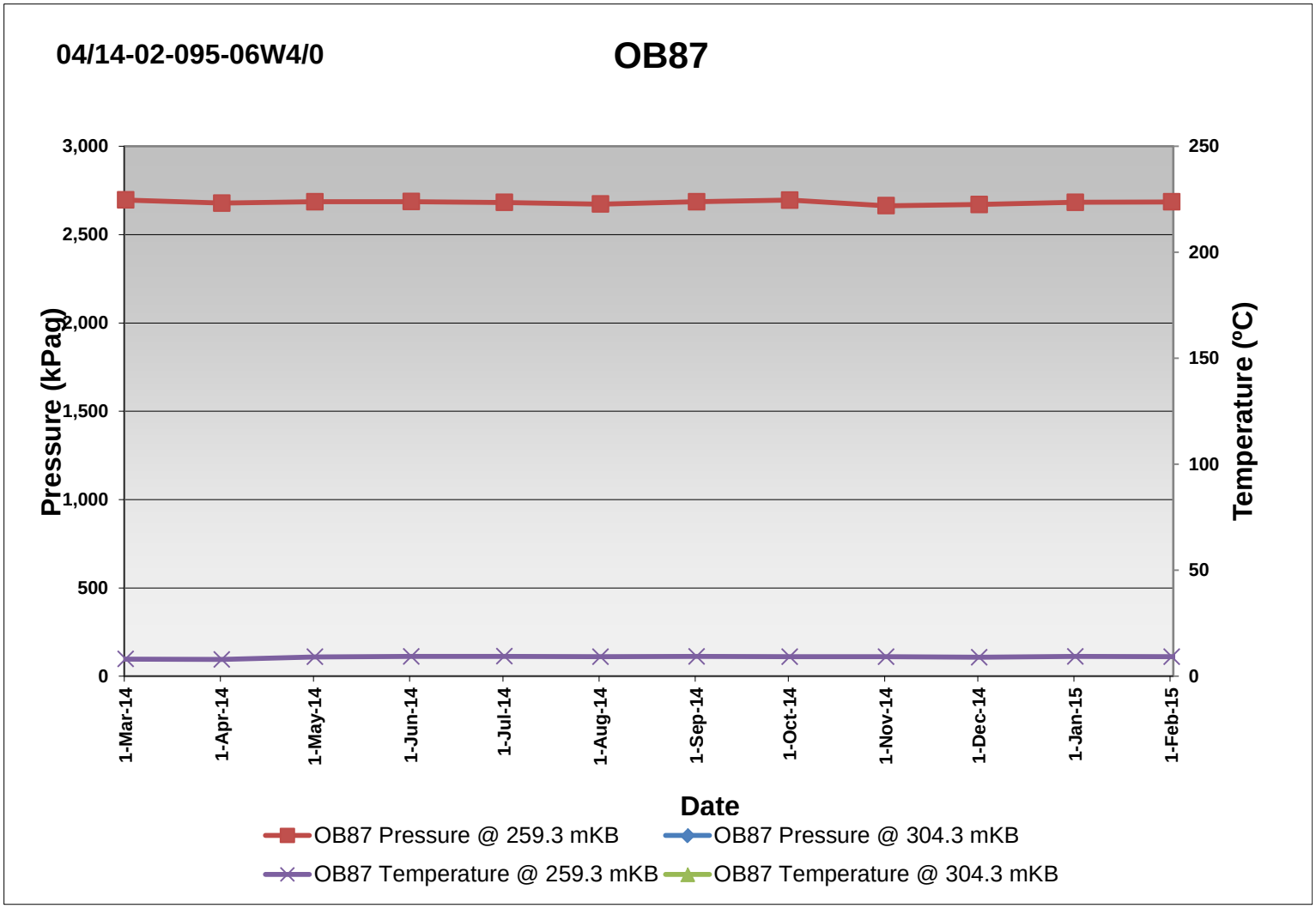

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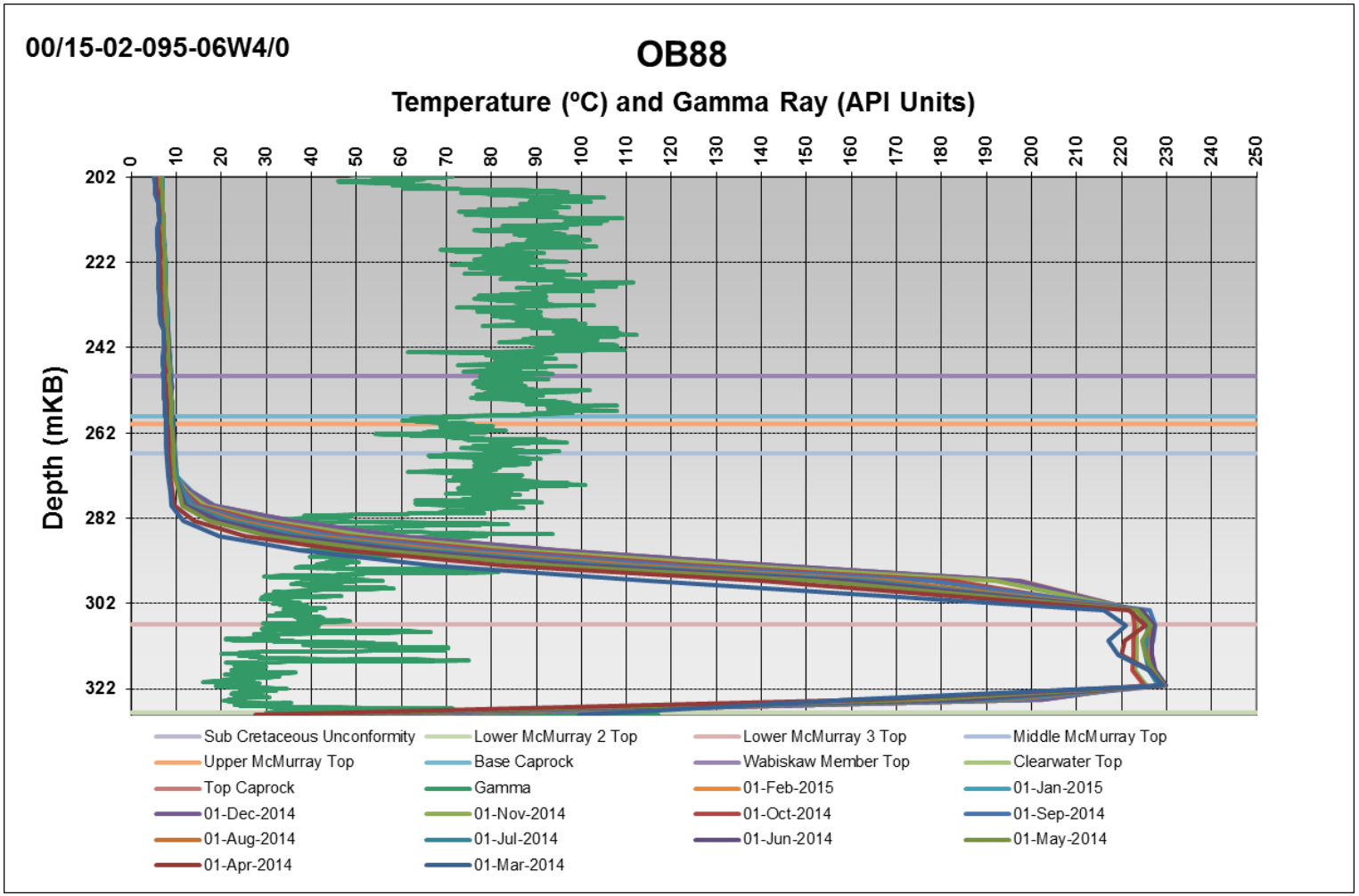

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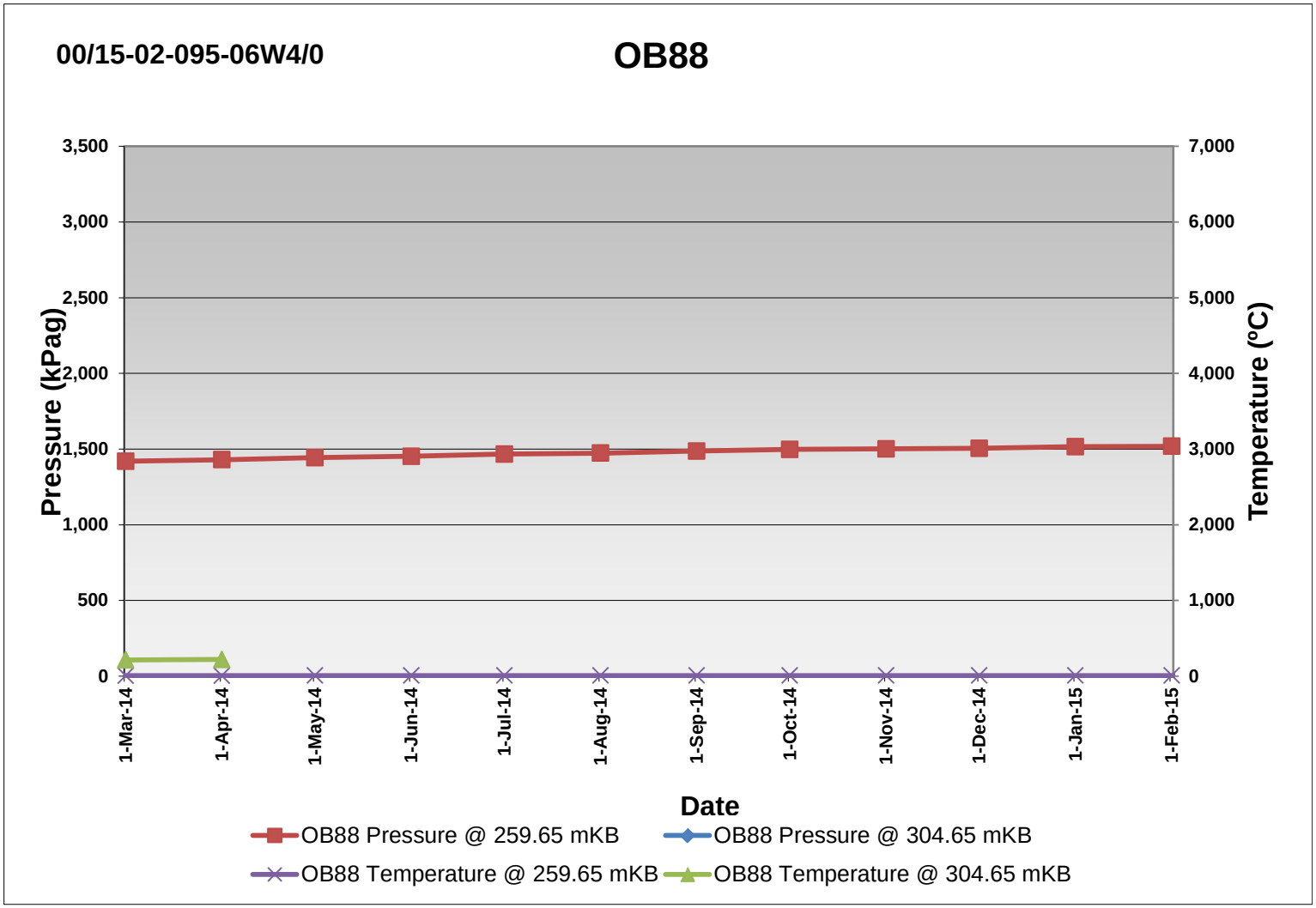

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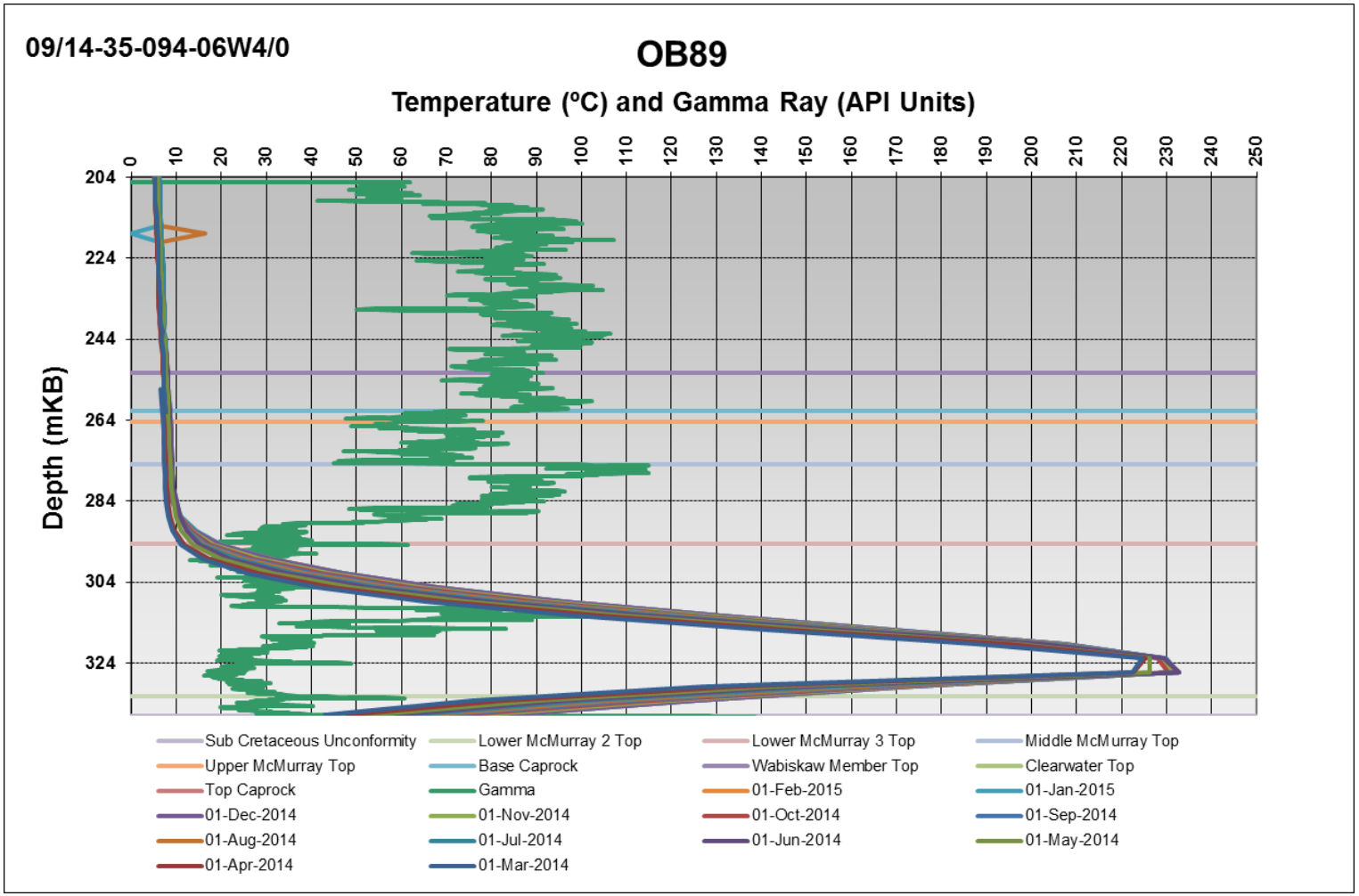

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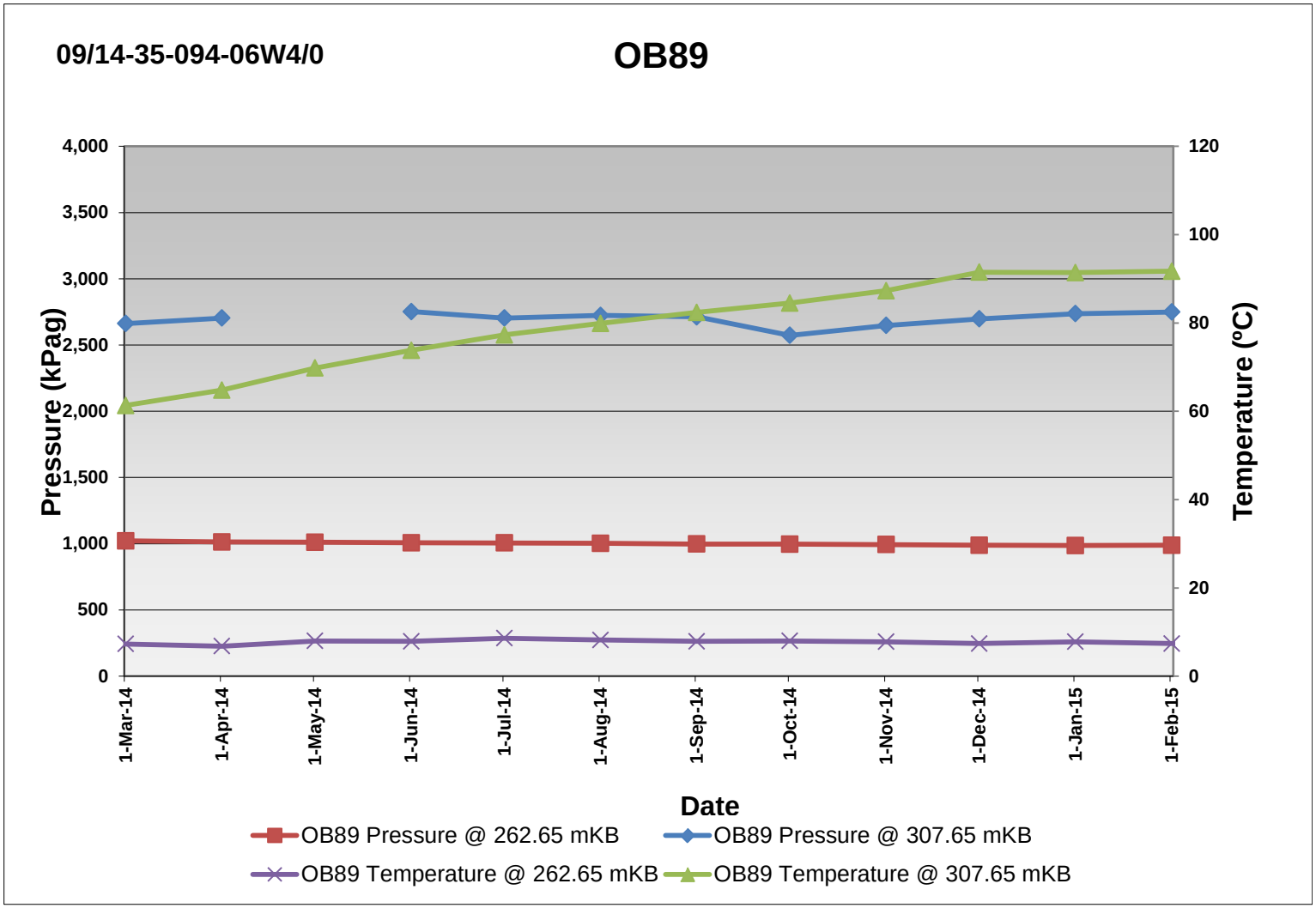

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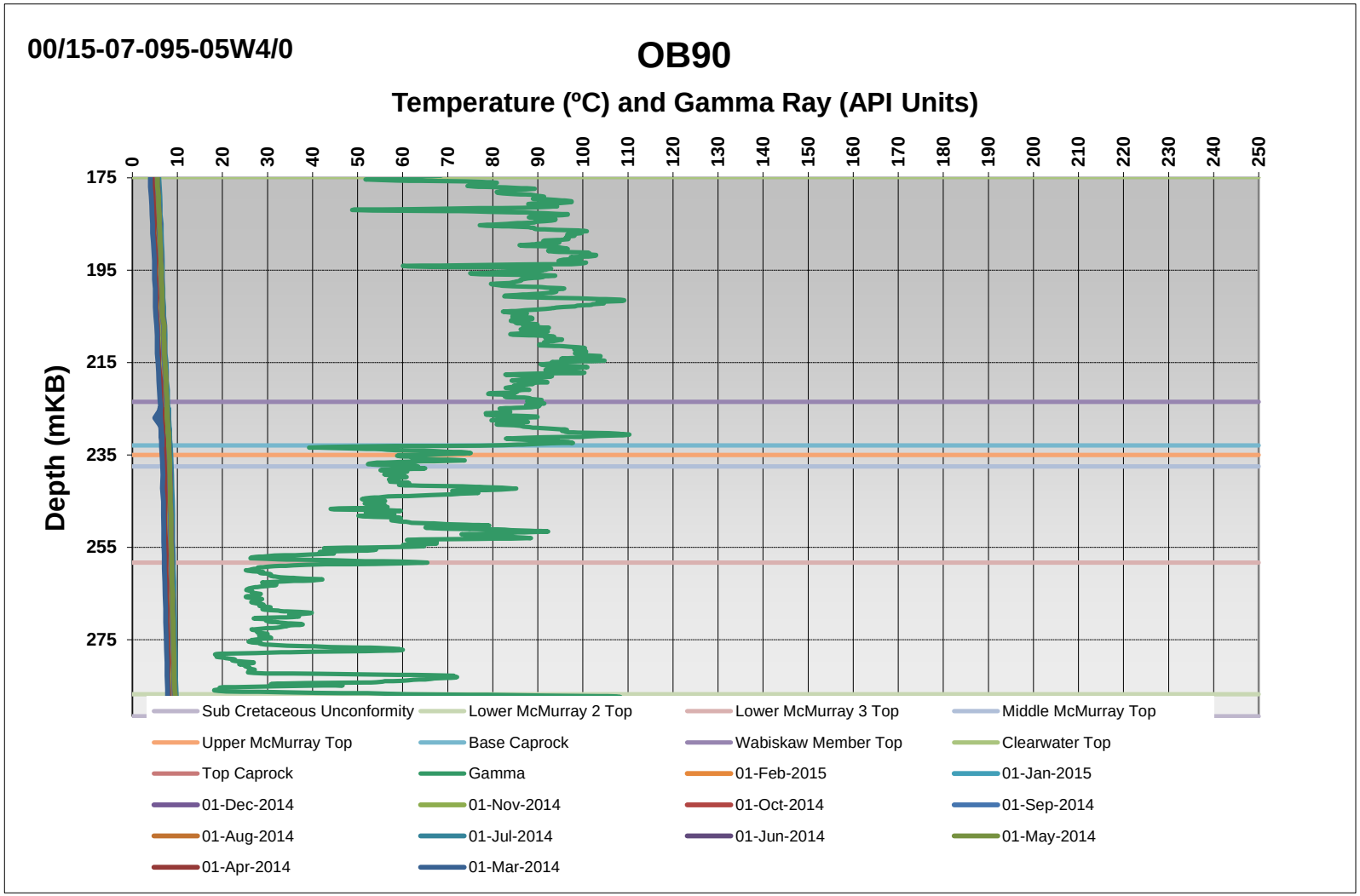

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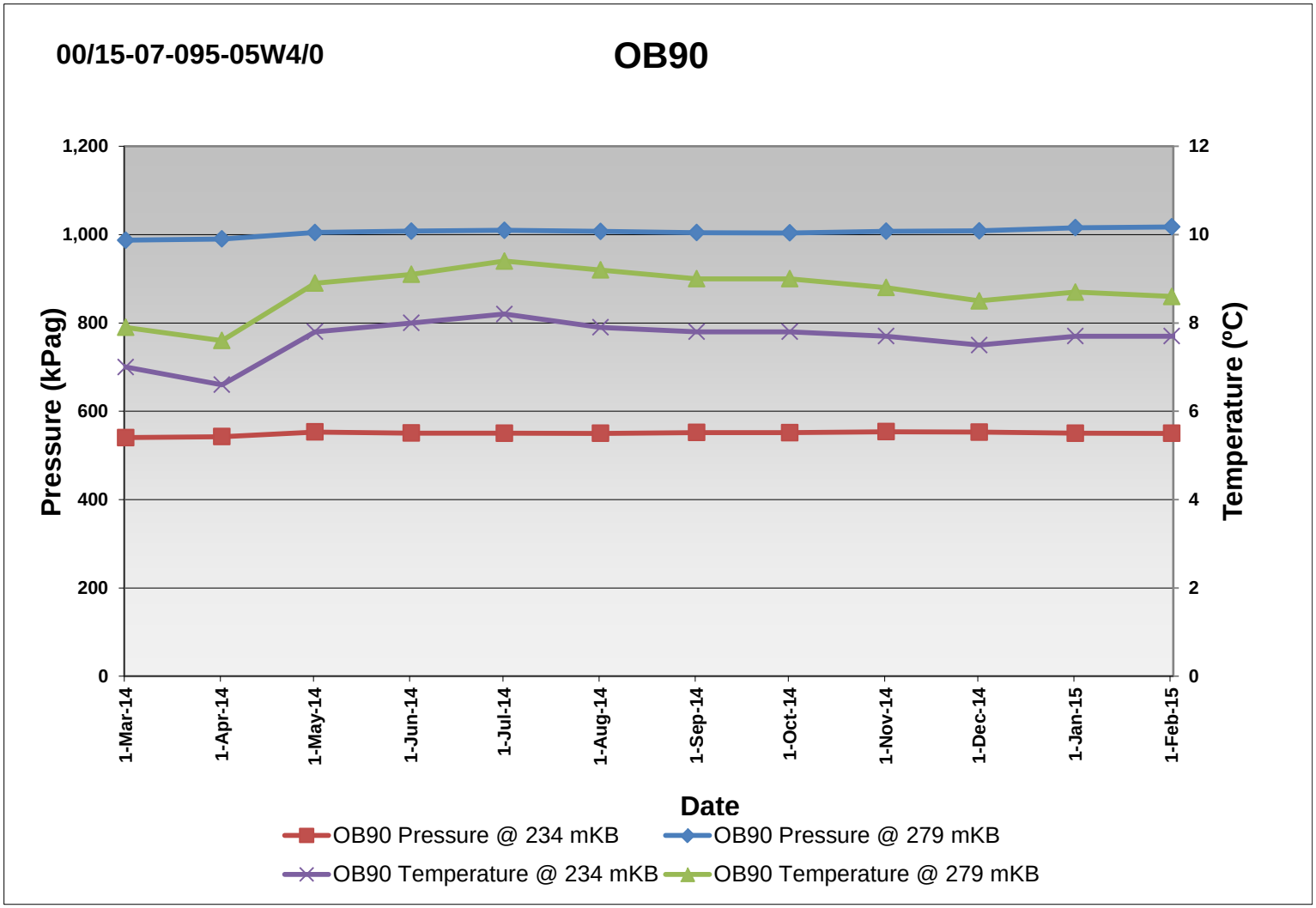

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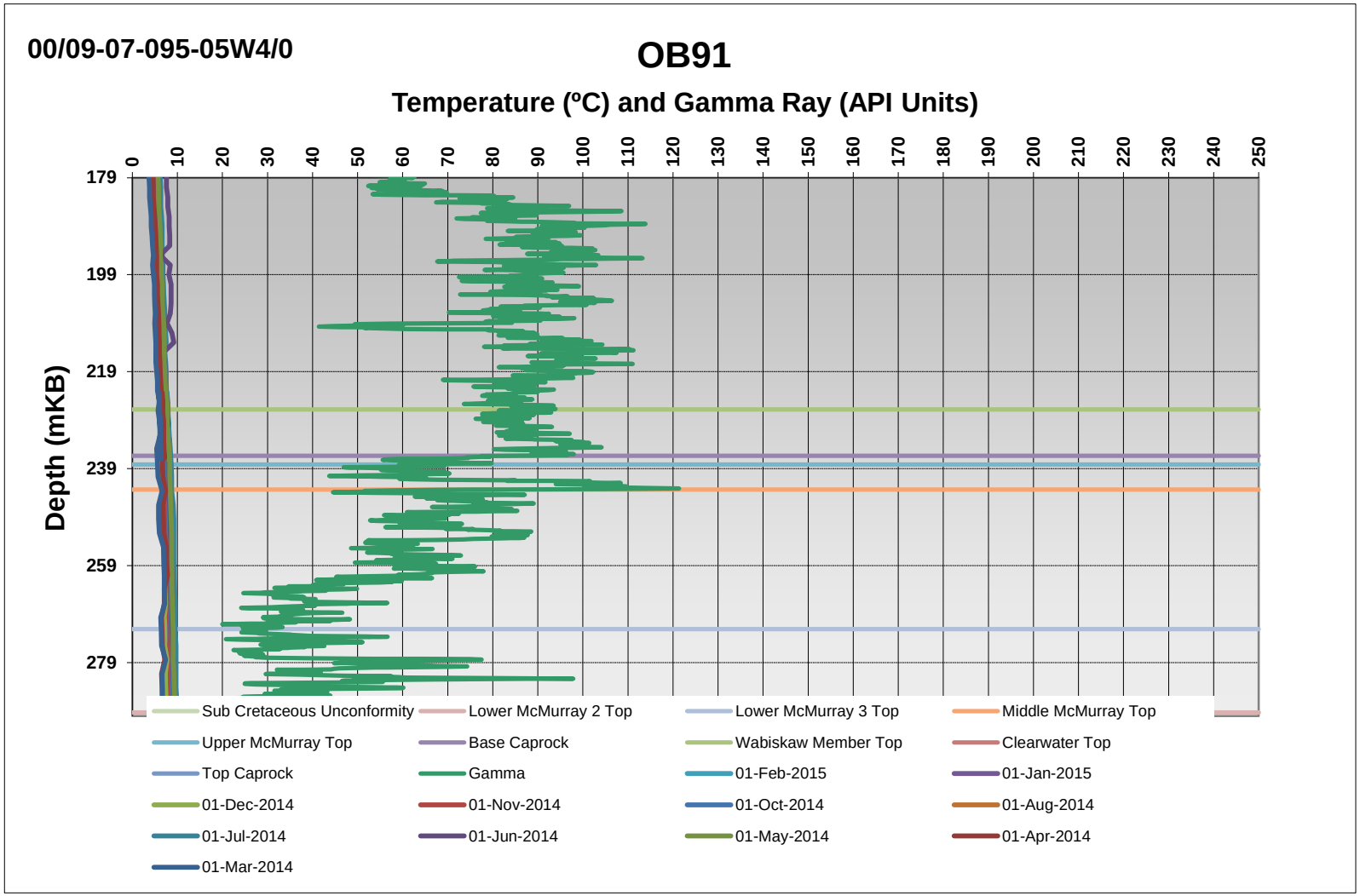

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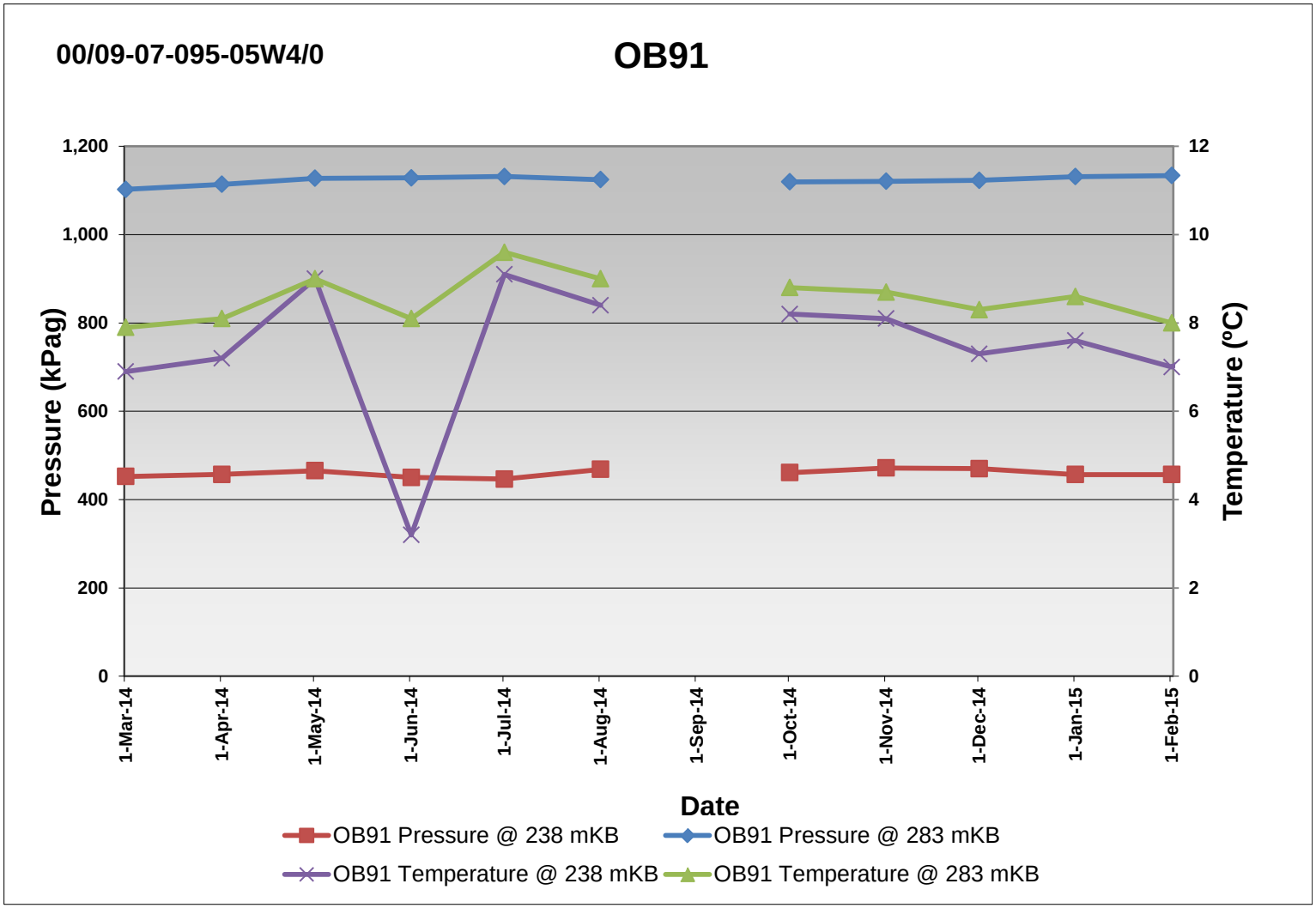
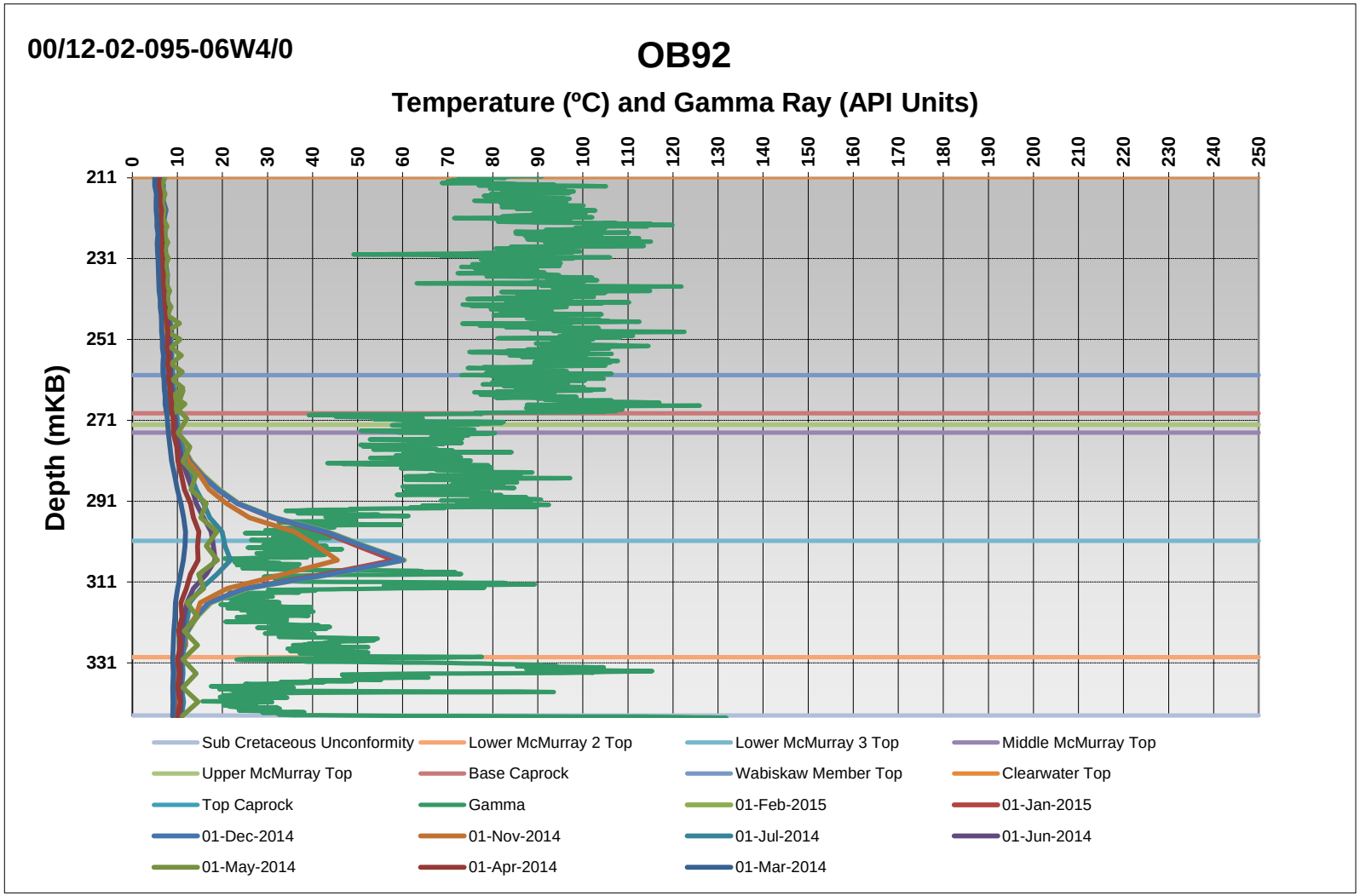


Piezometer Plots & Temperature vs Depth Plots



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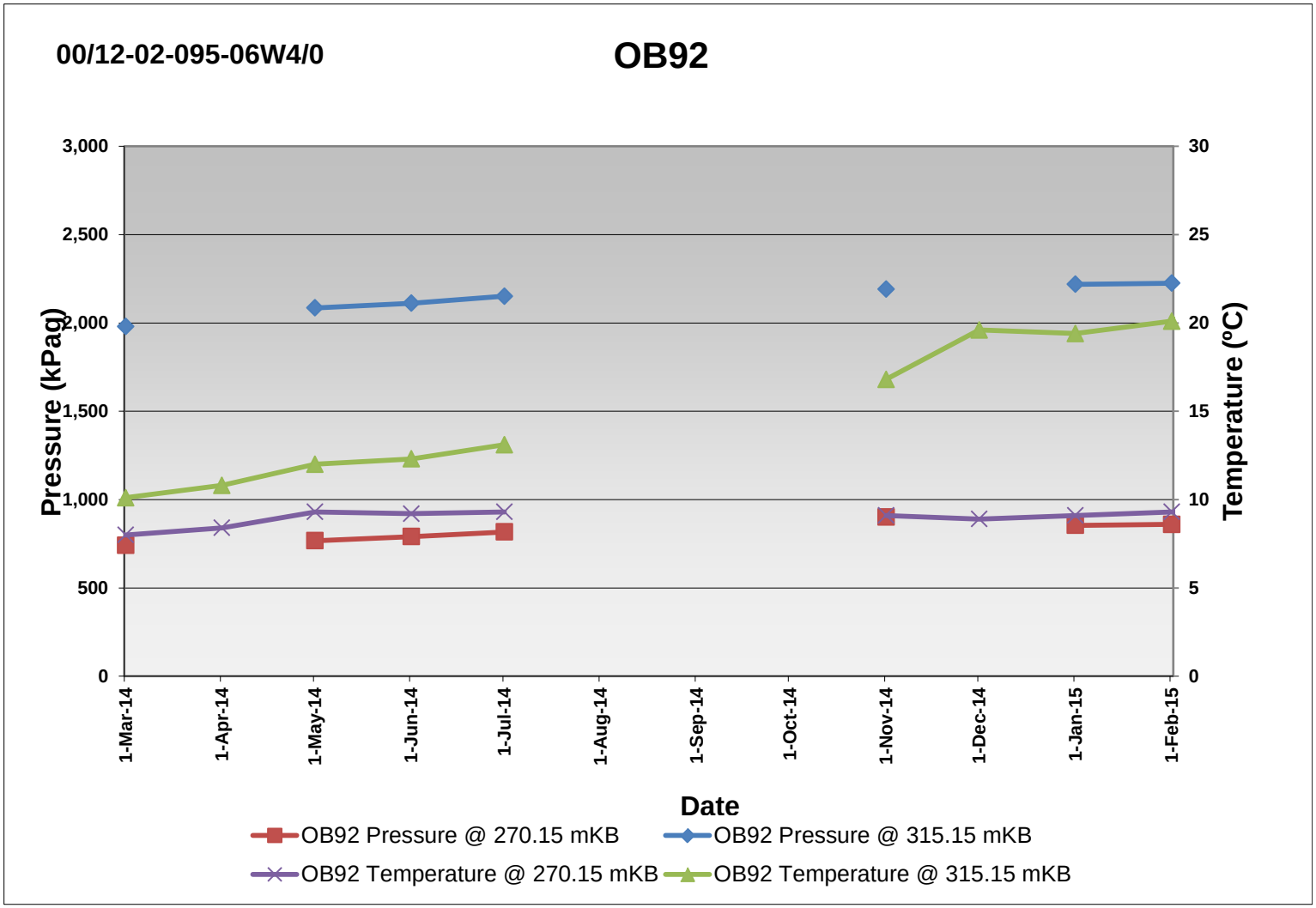

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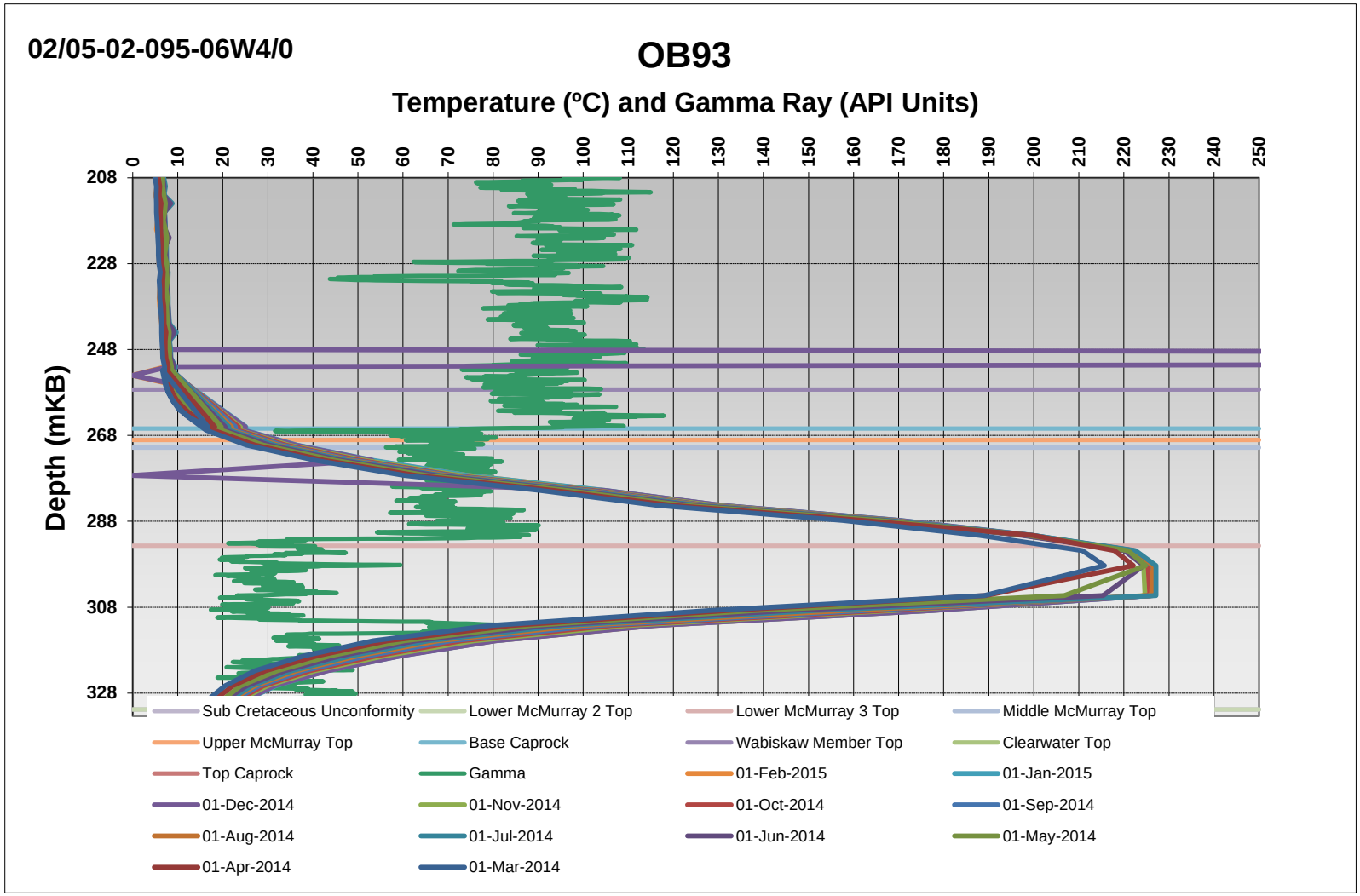

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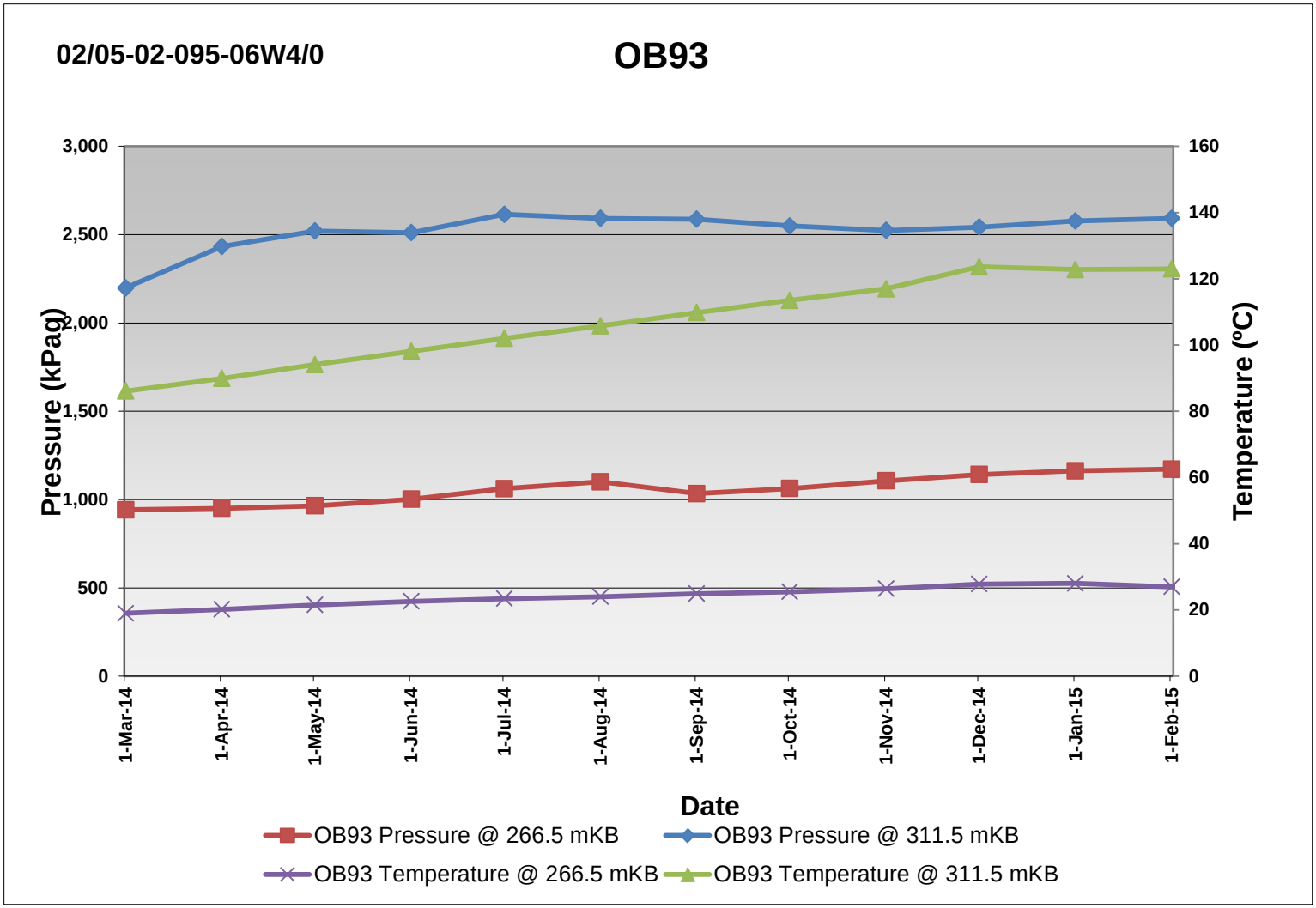

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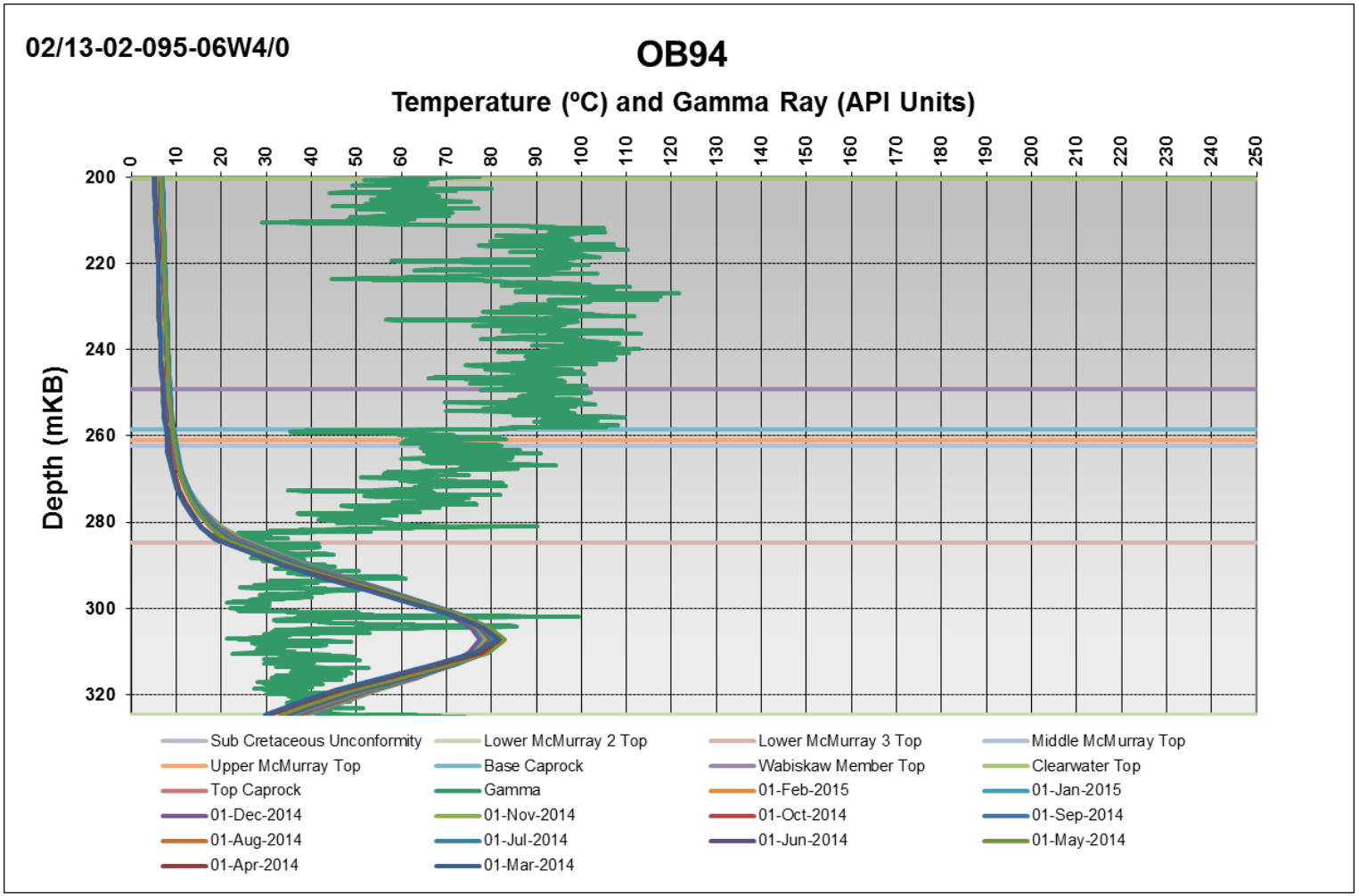

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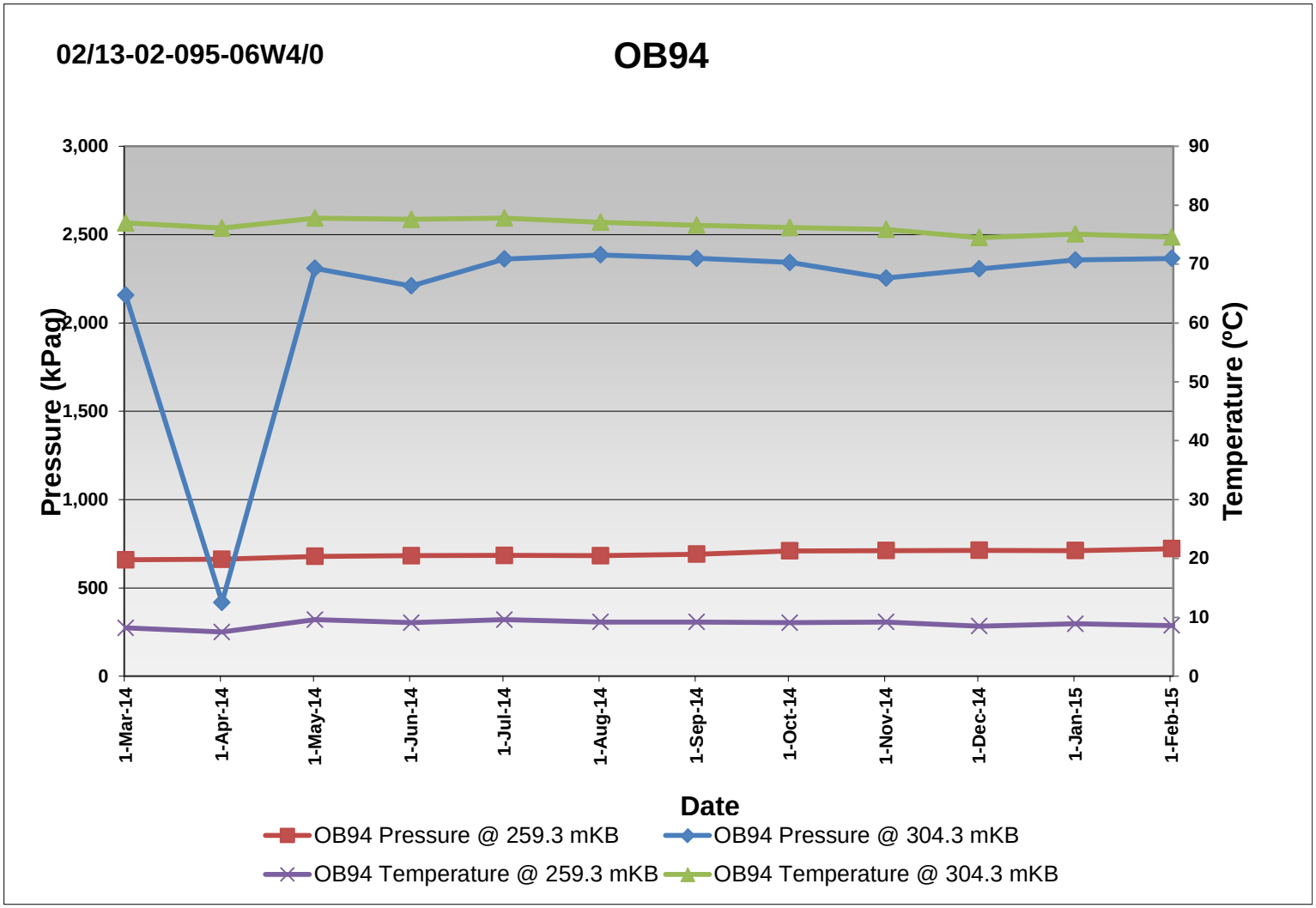

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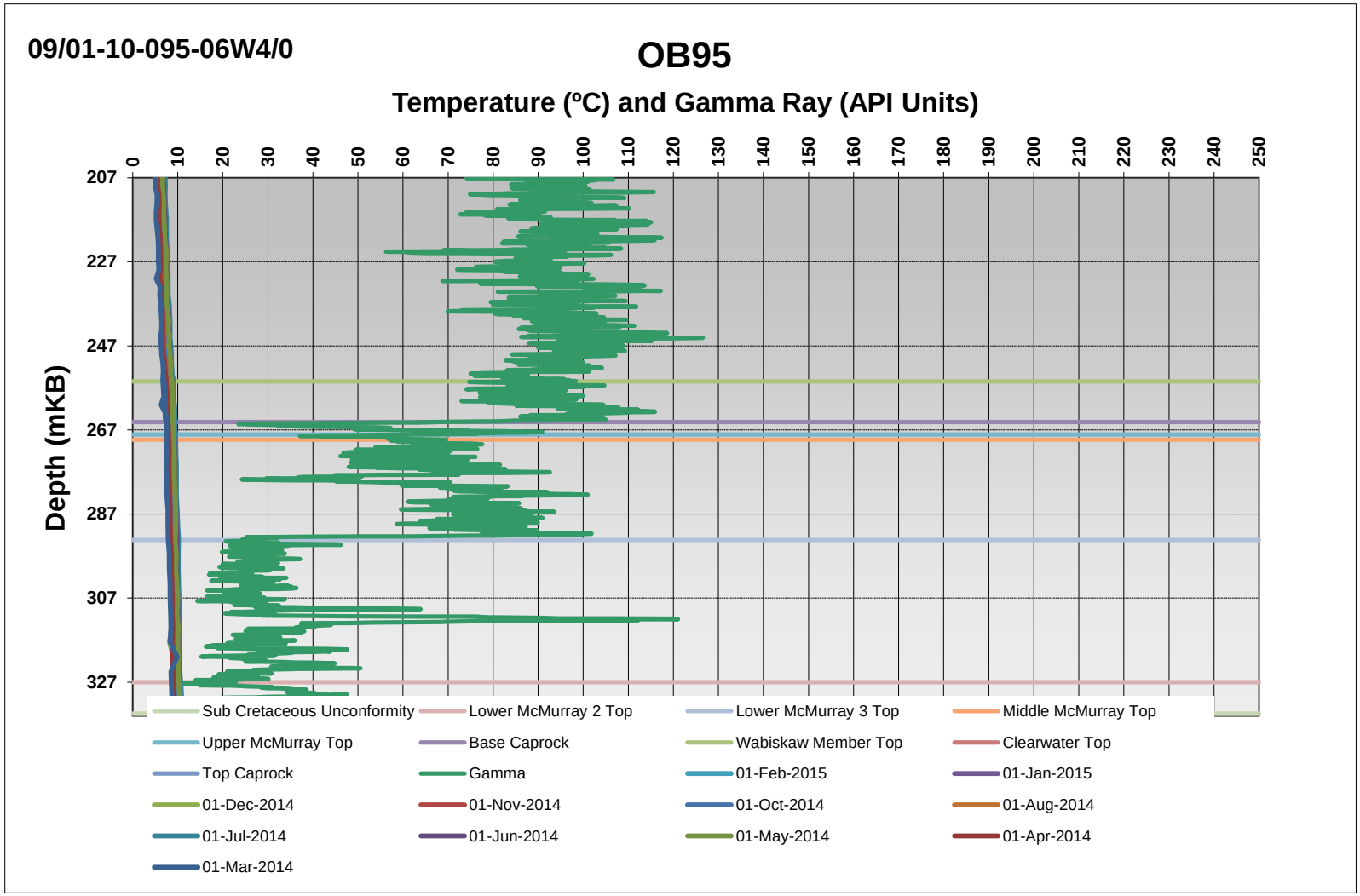

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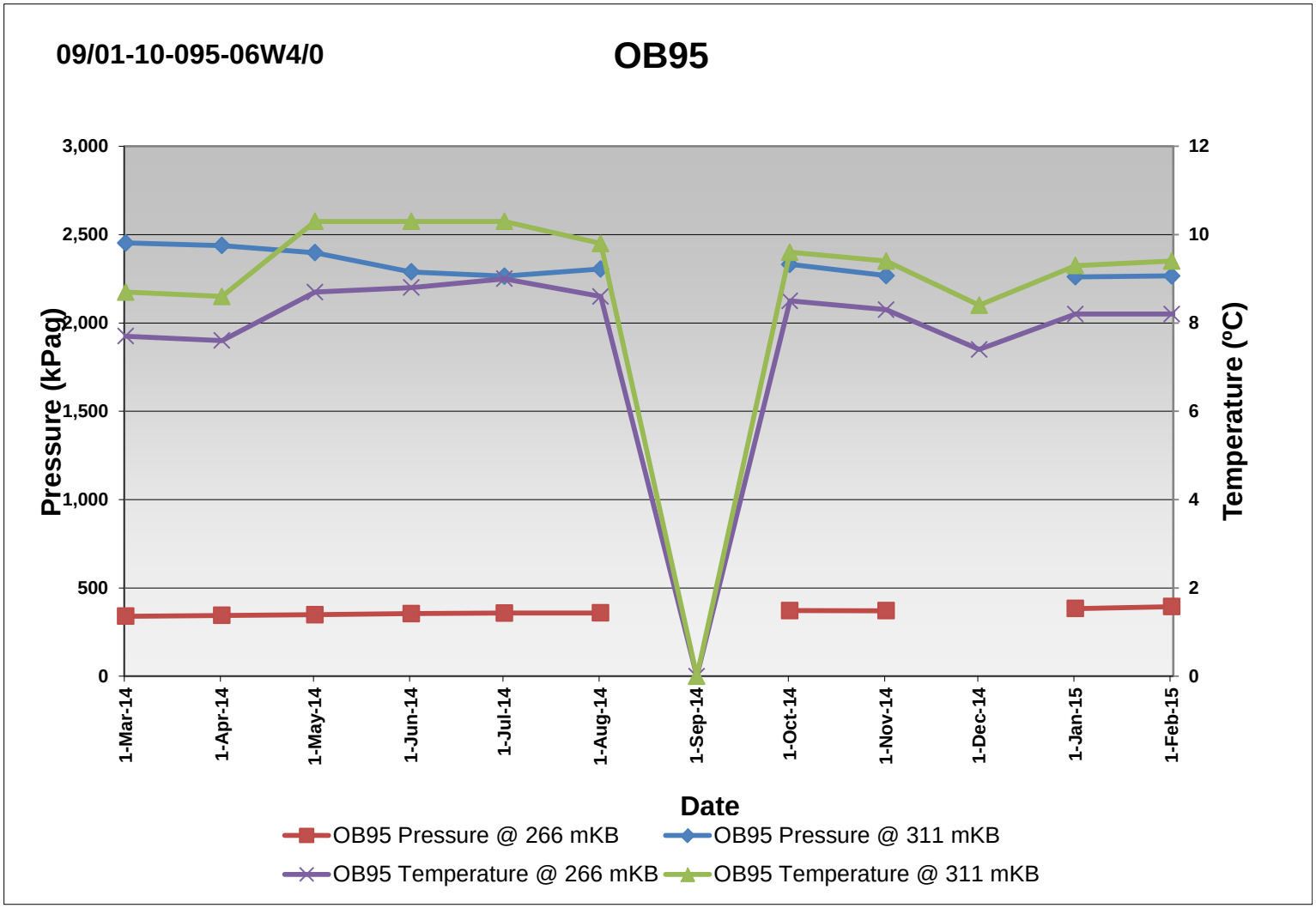

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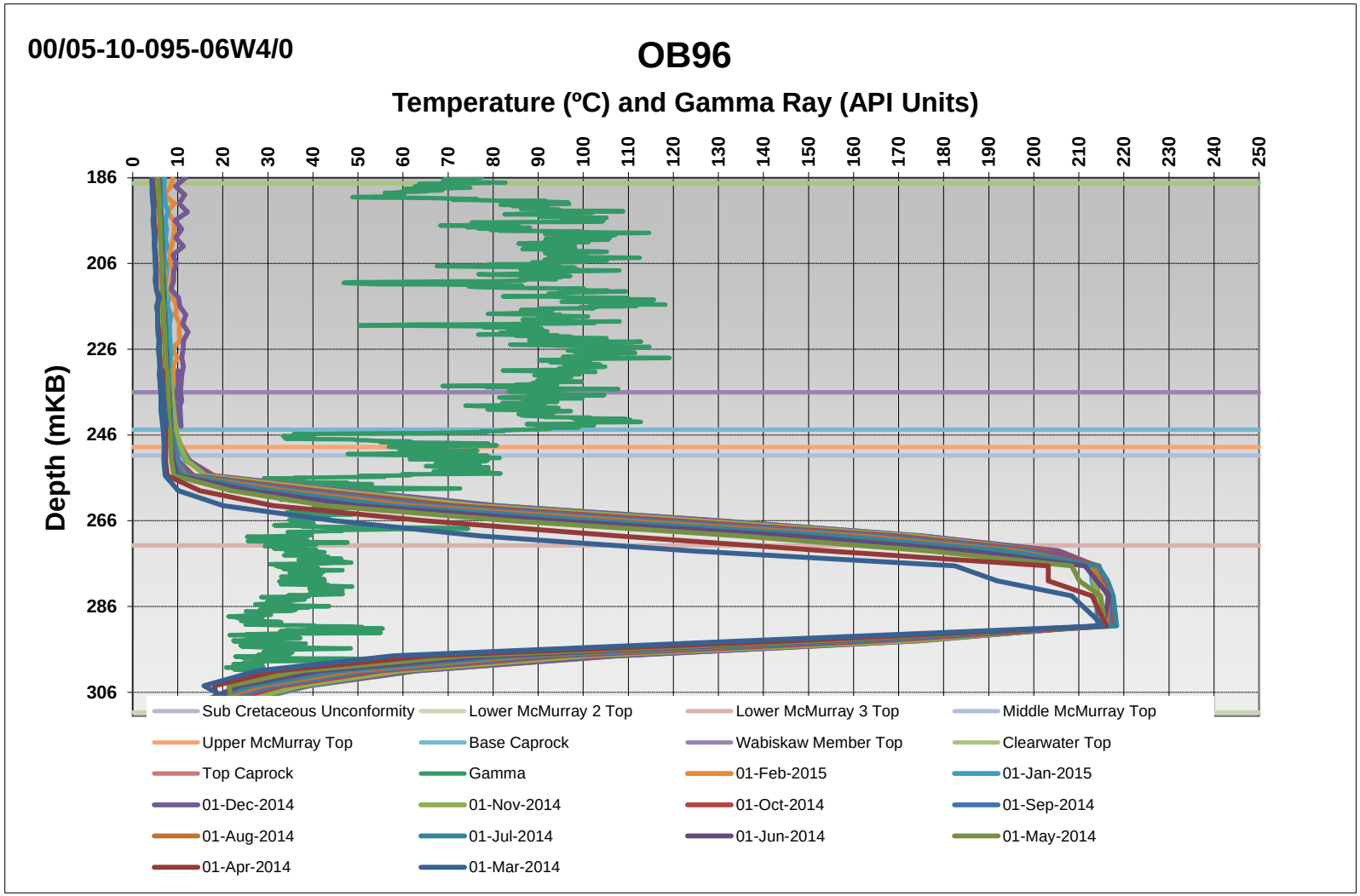

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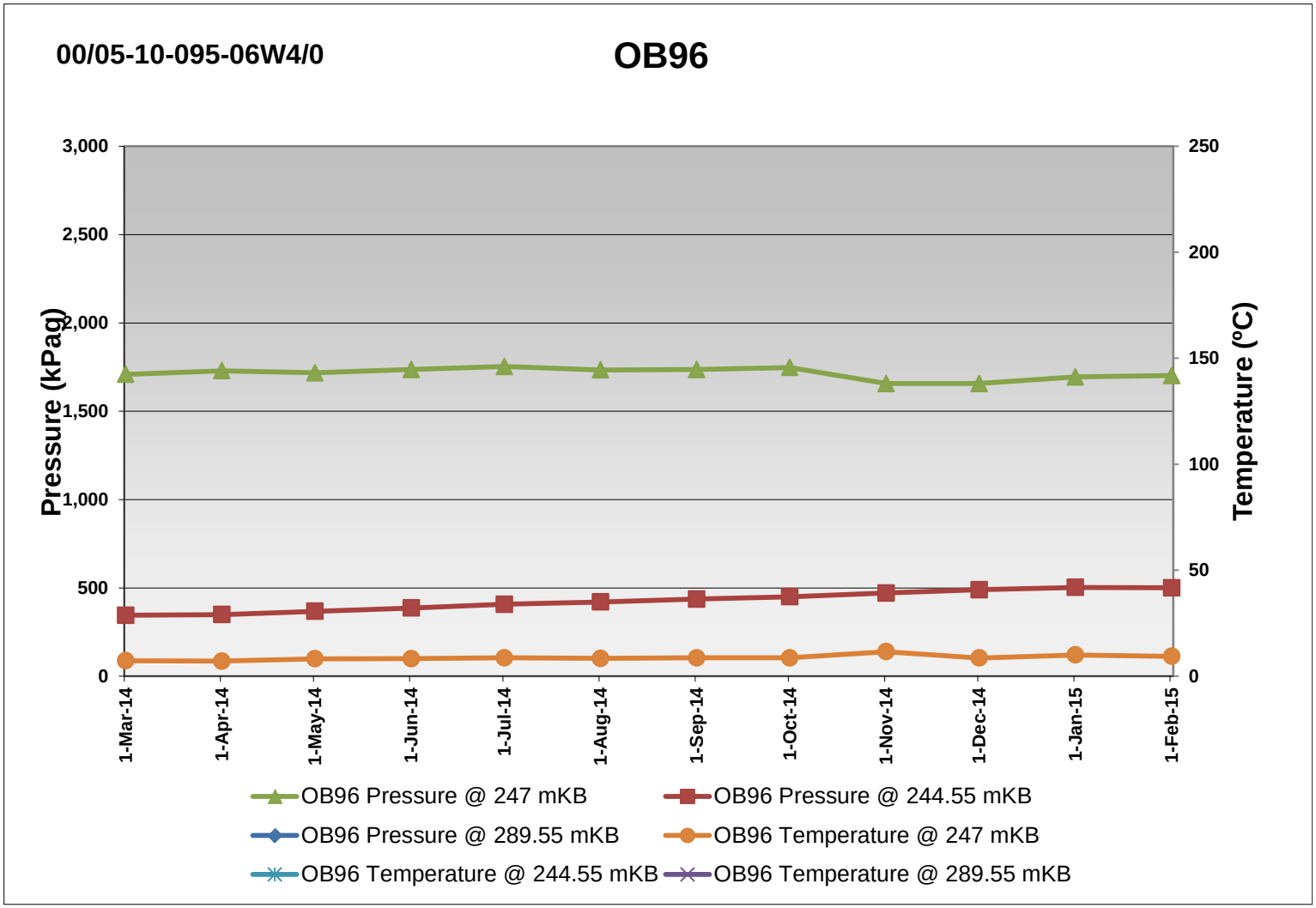

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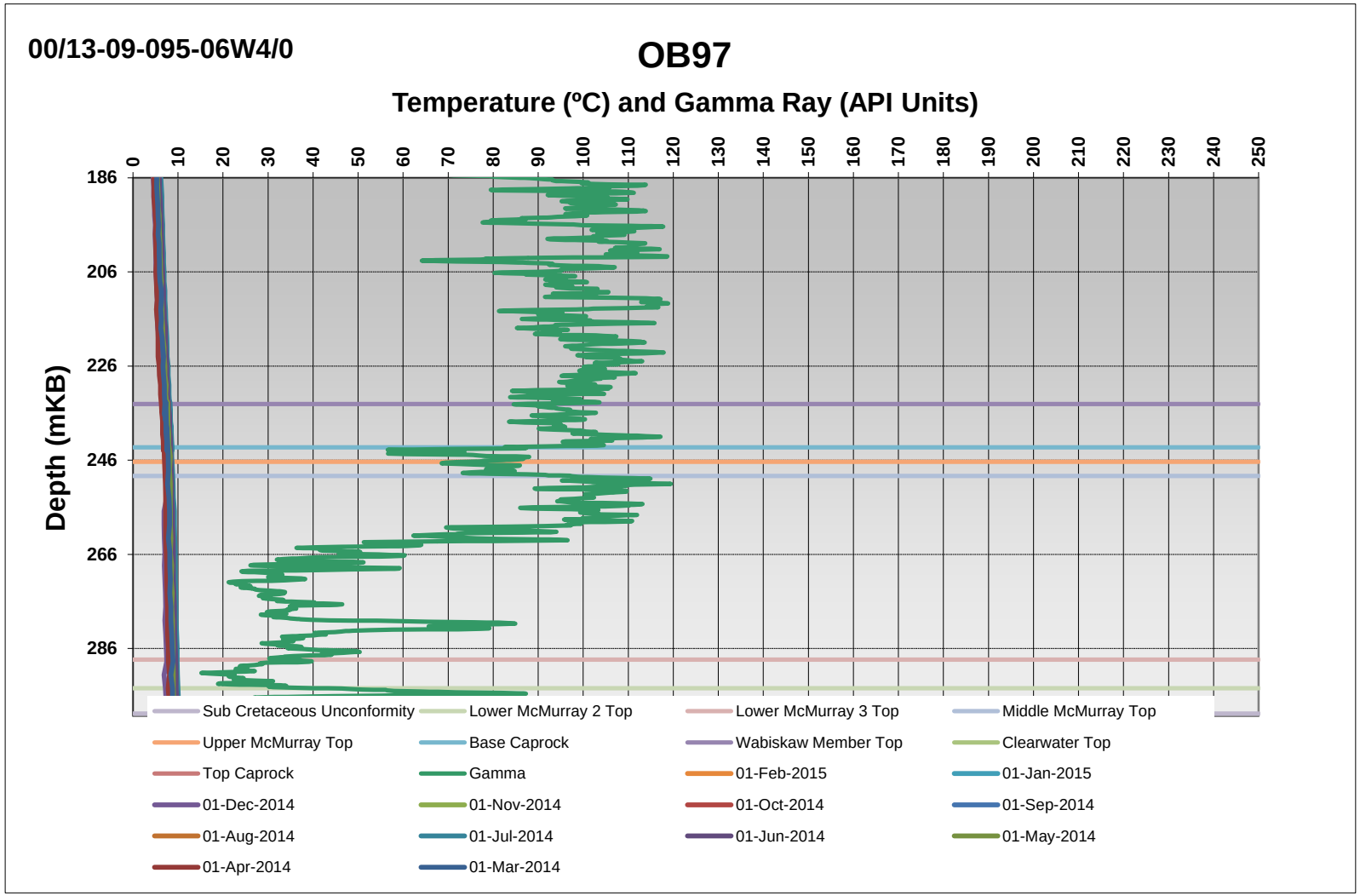

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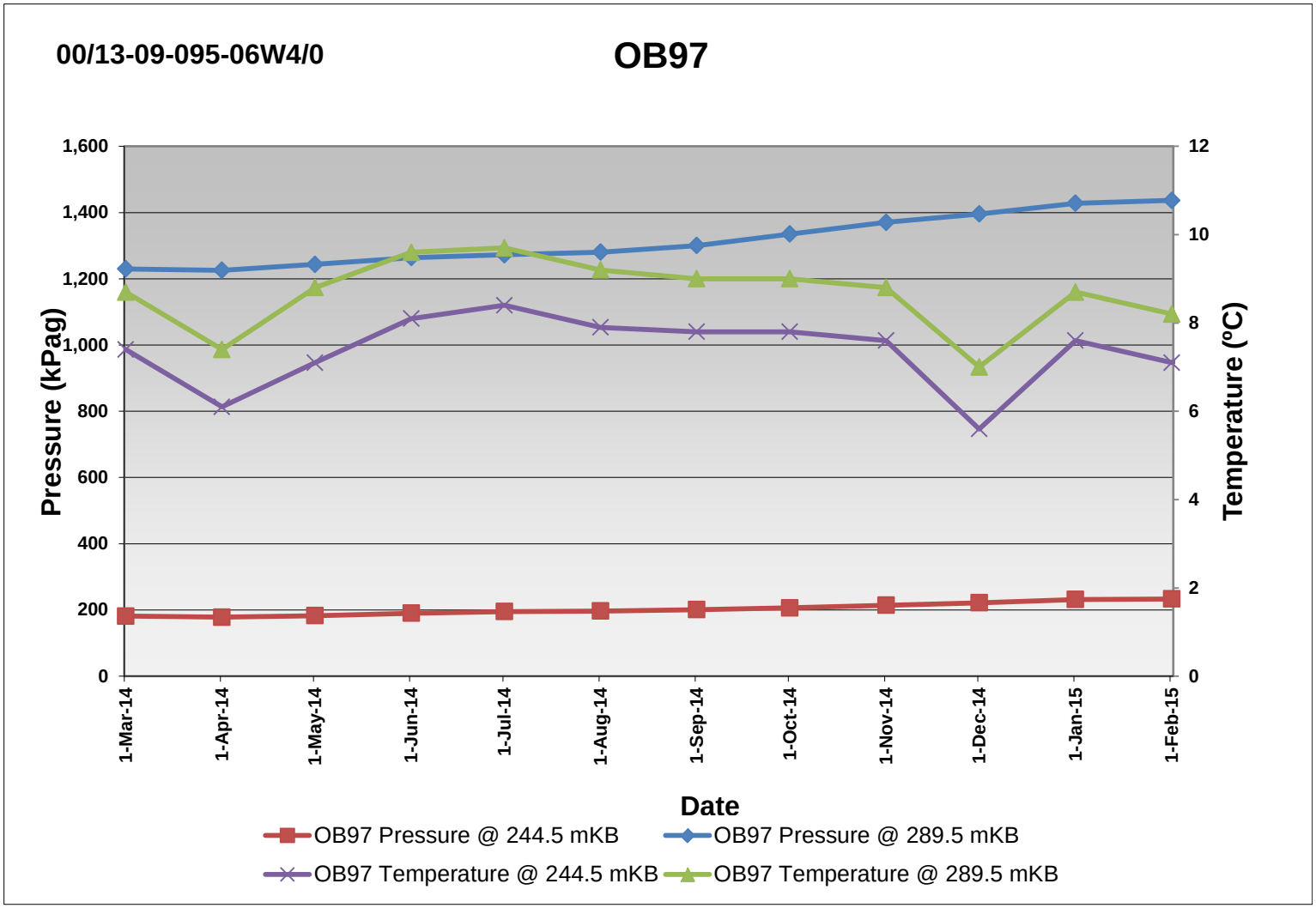

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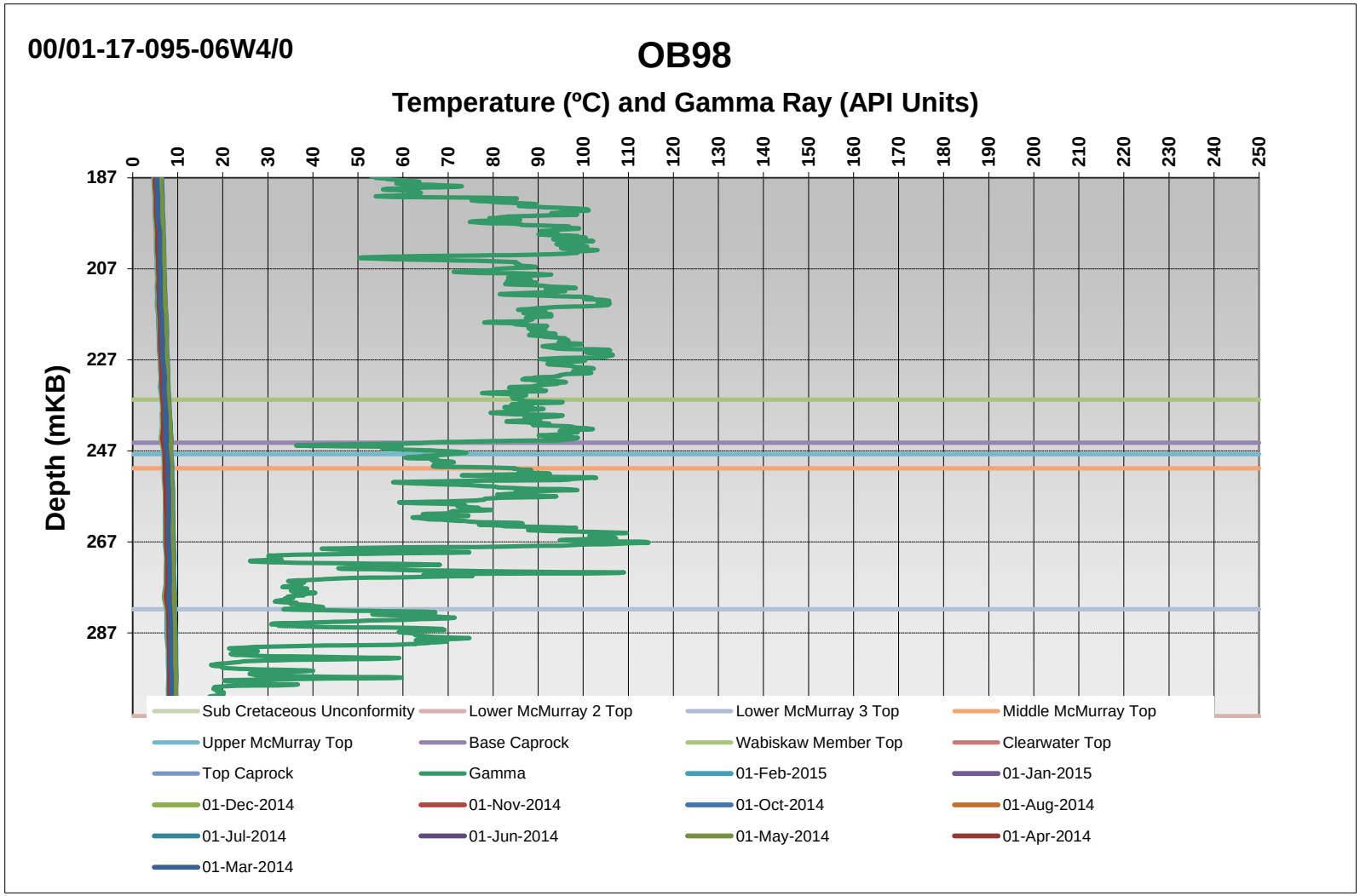

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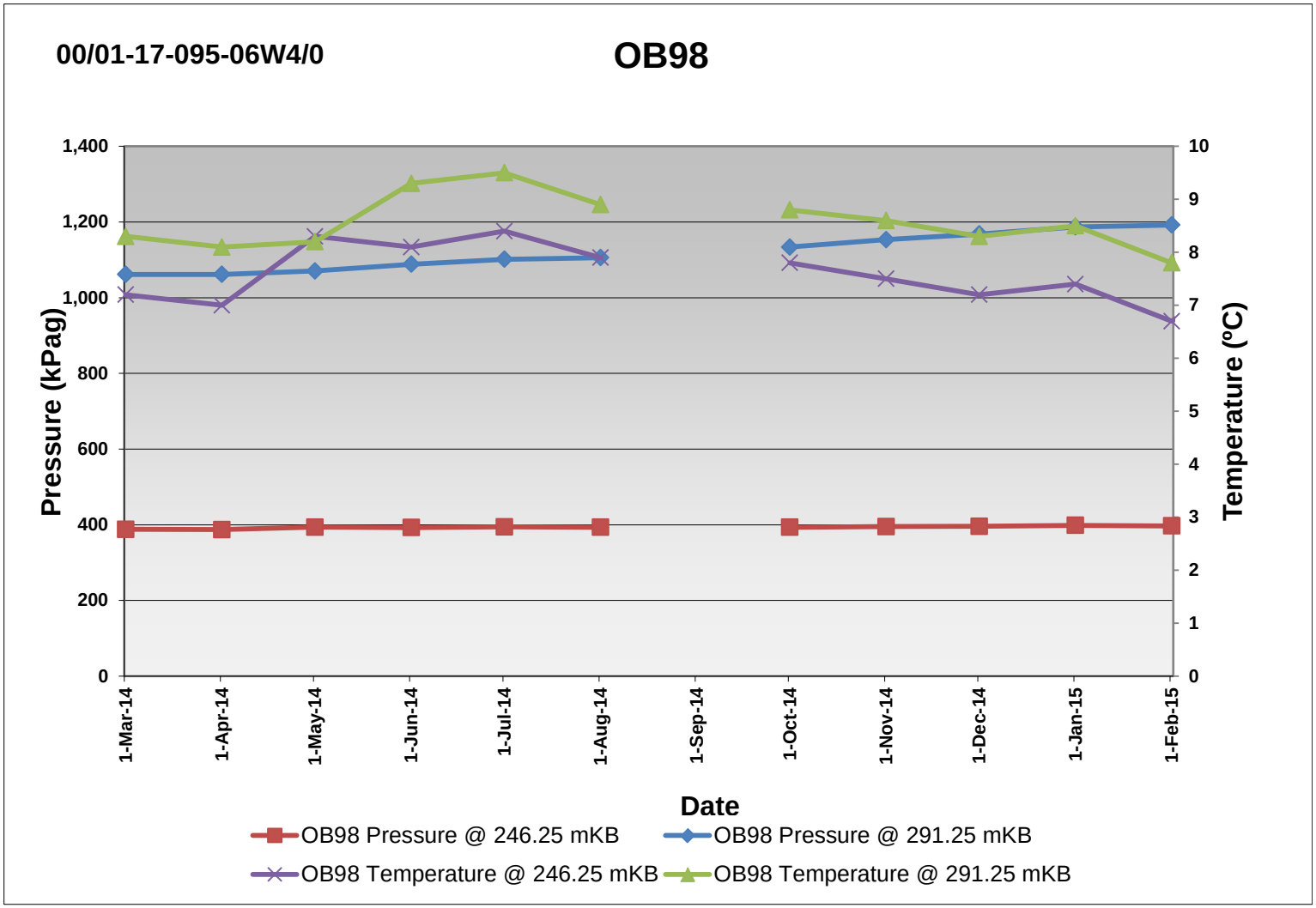

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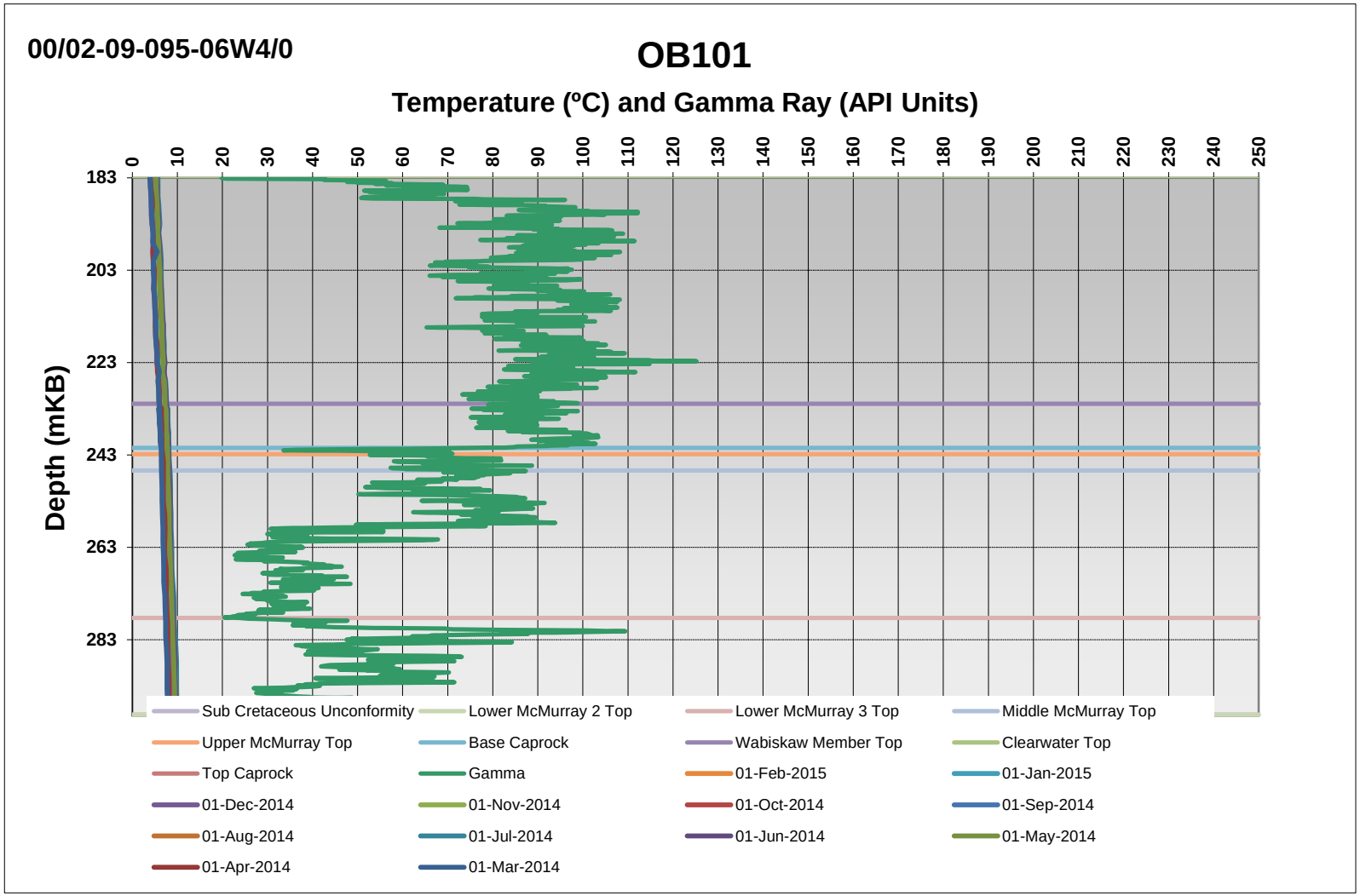

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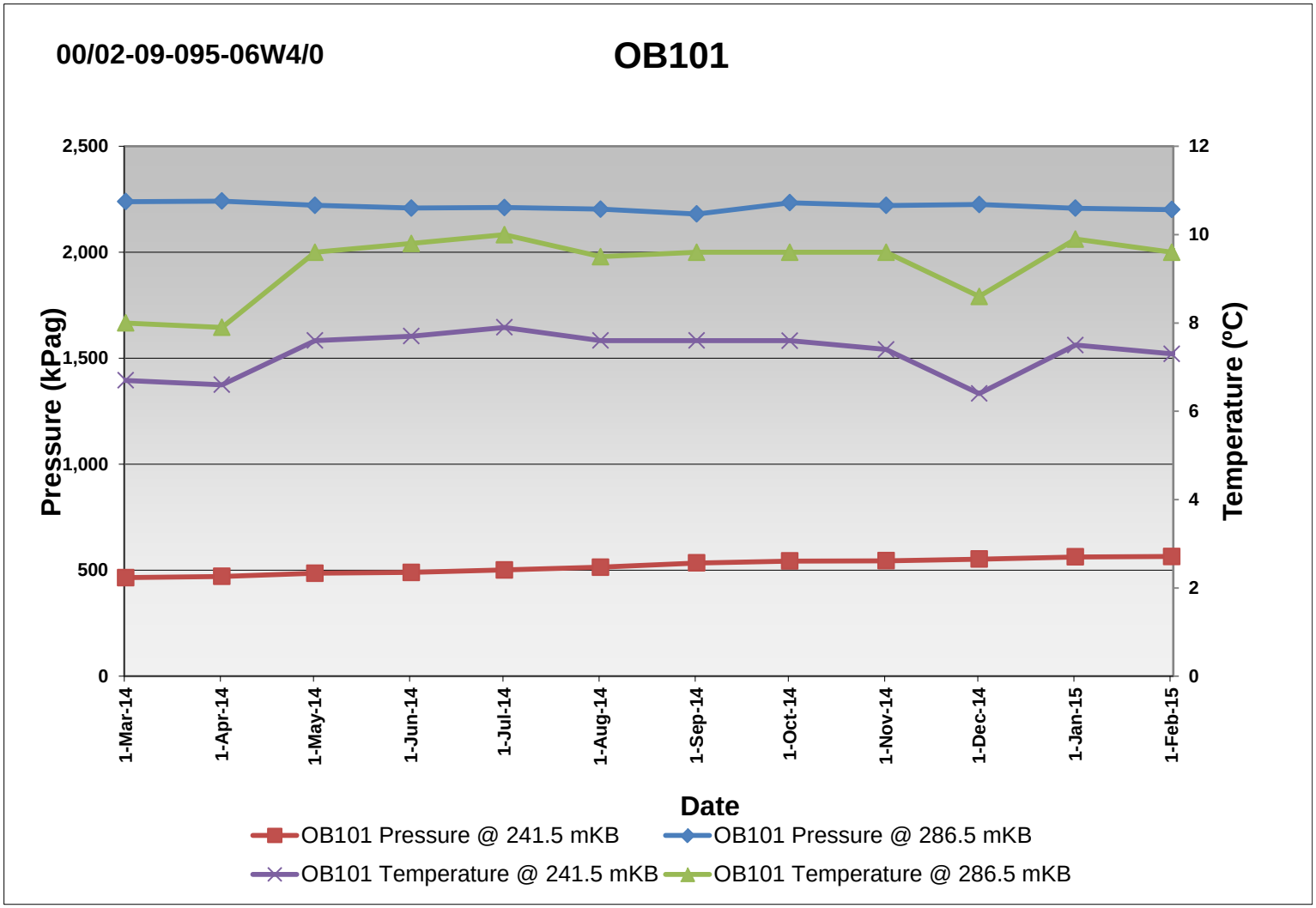

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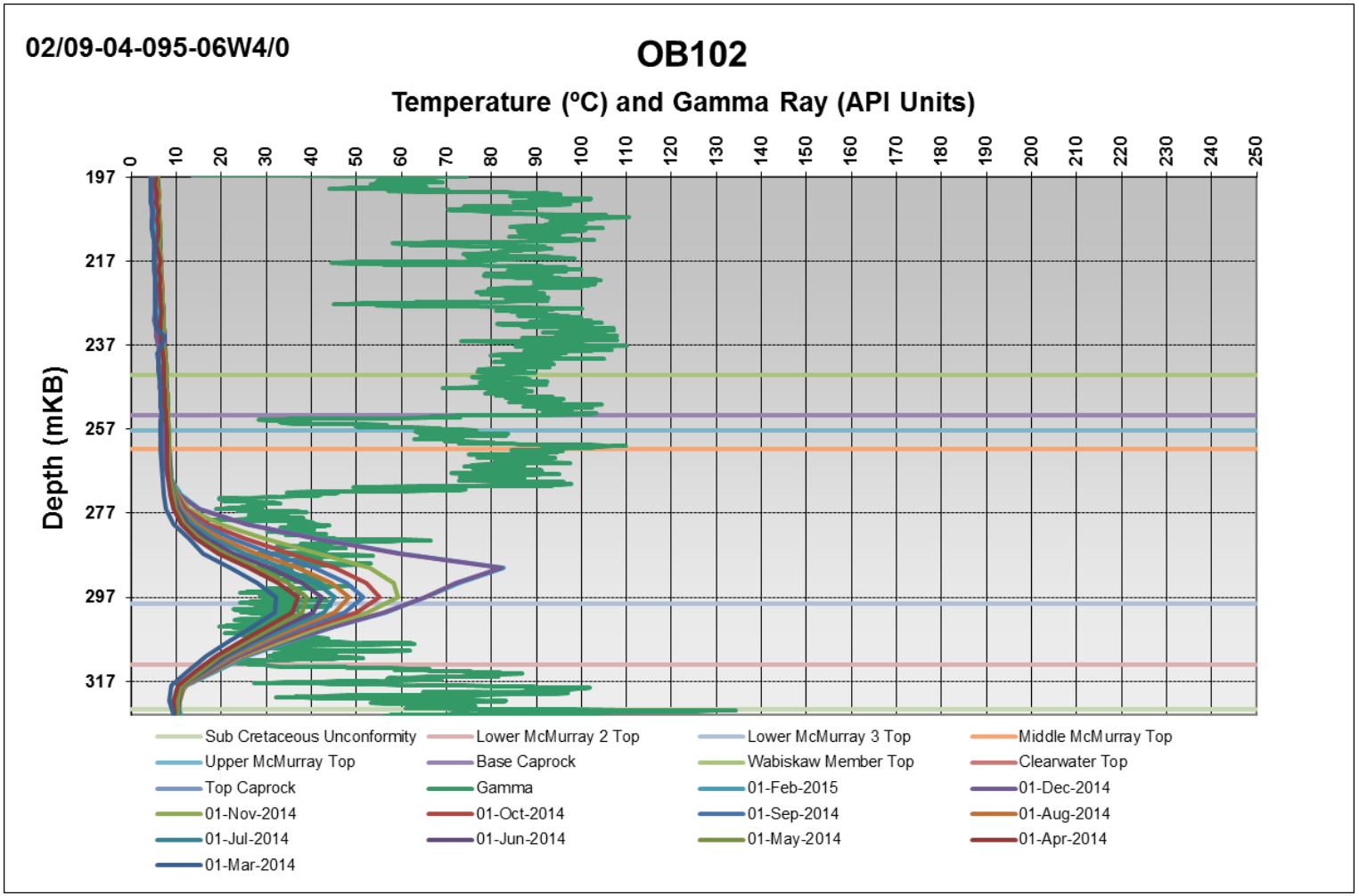

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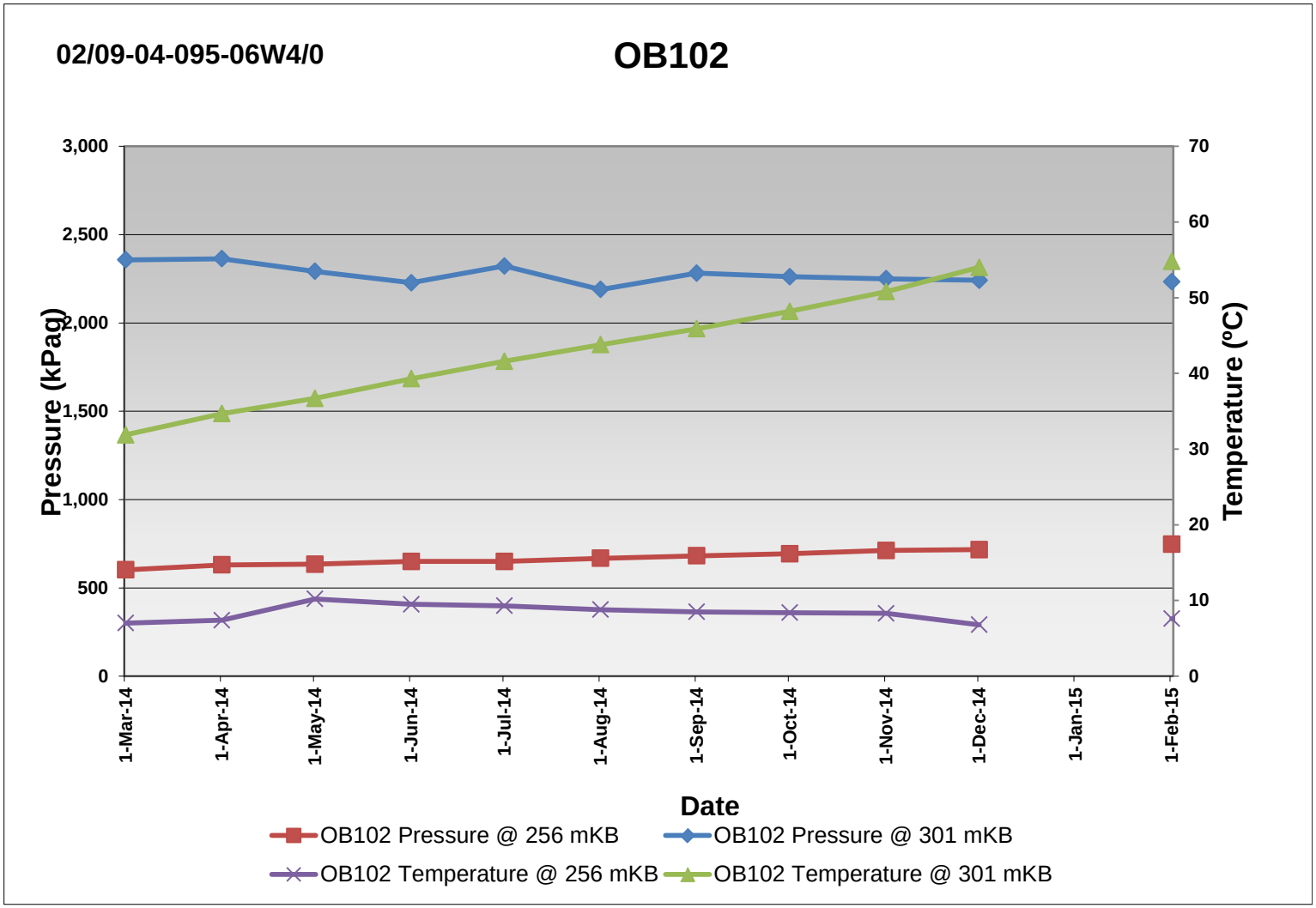

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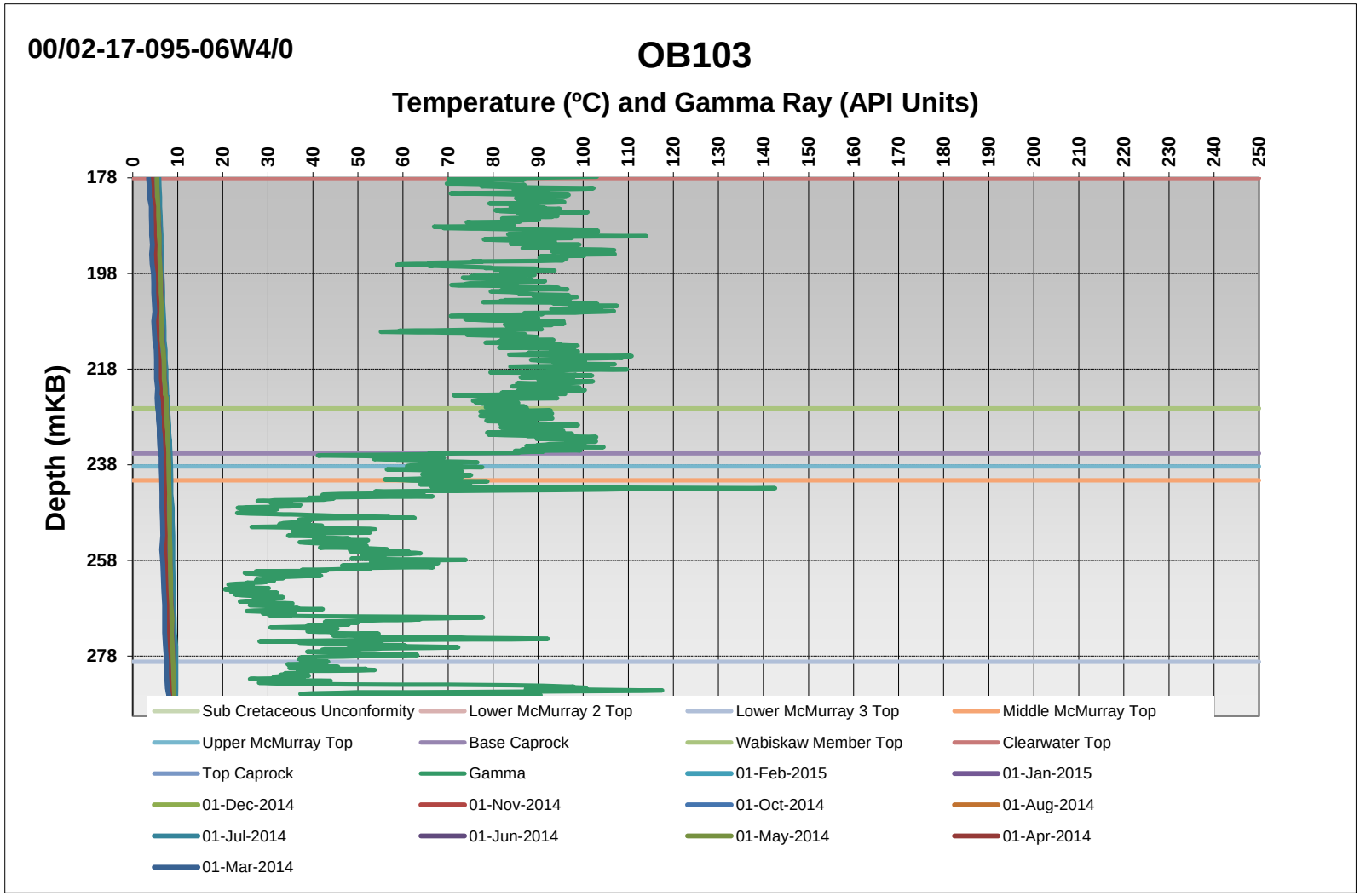

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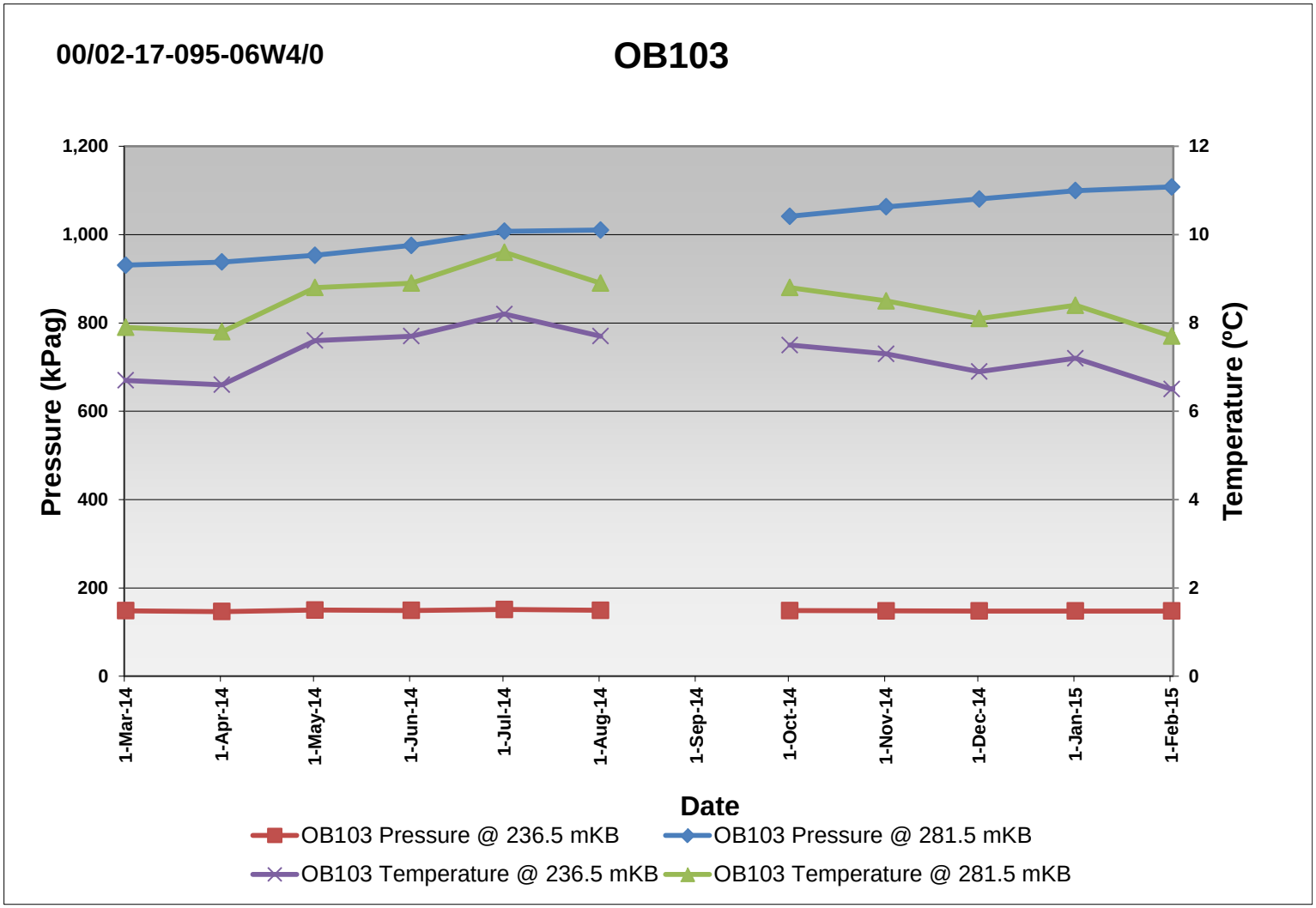

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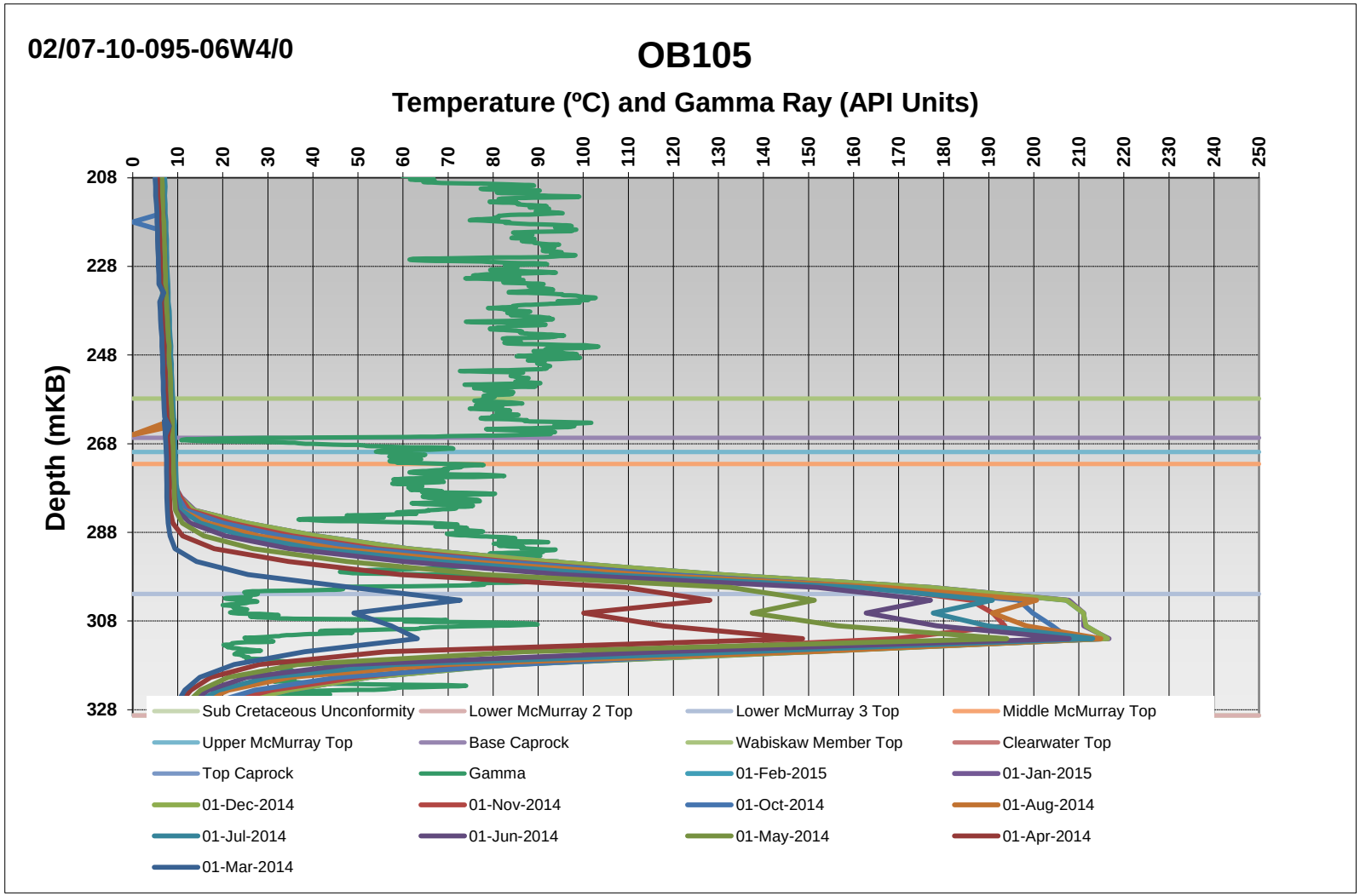

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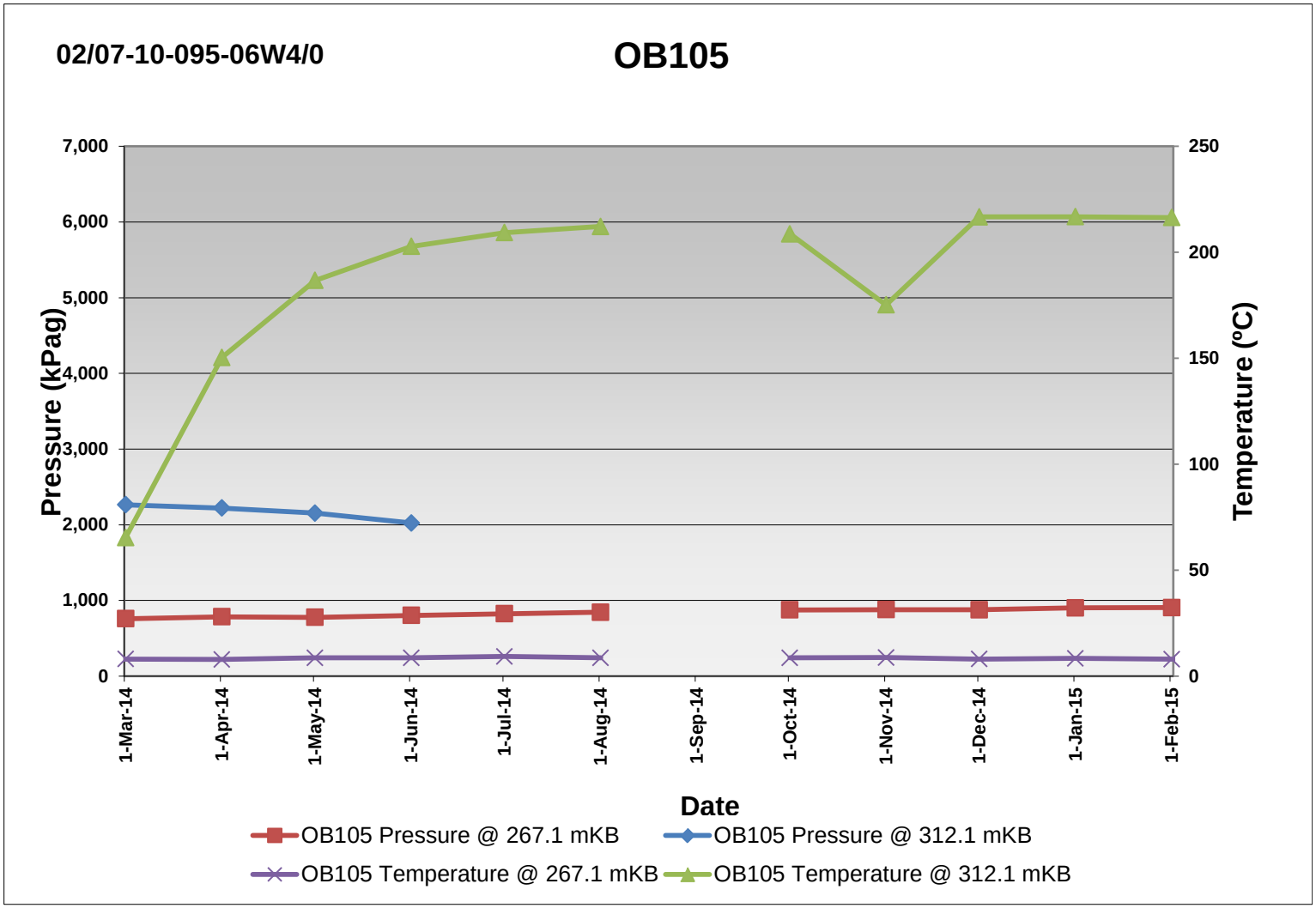

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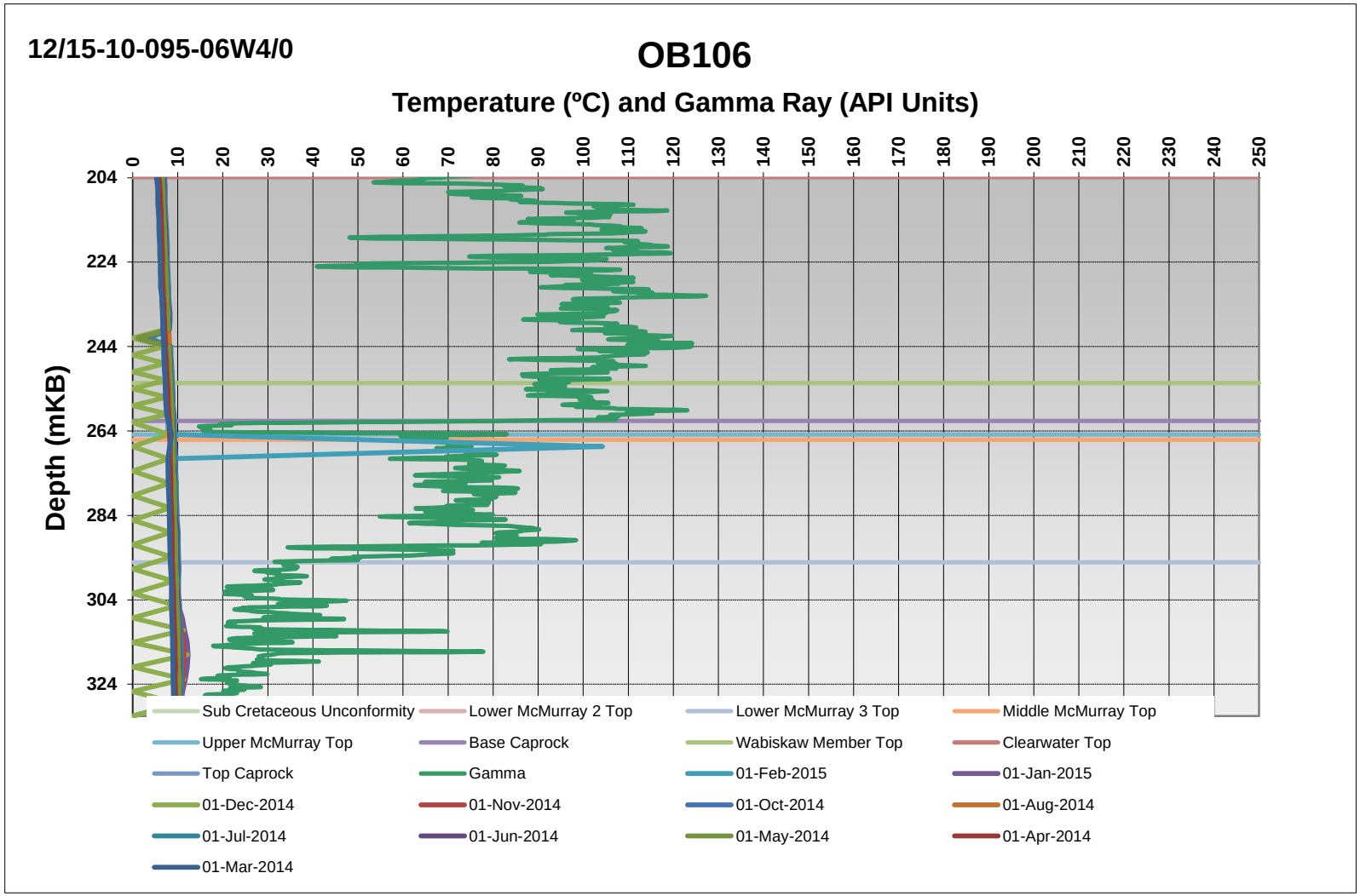

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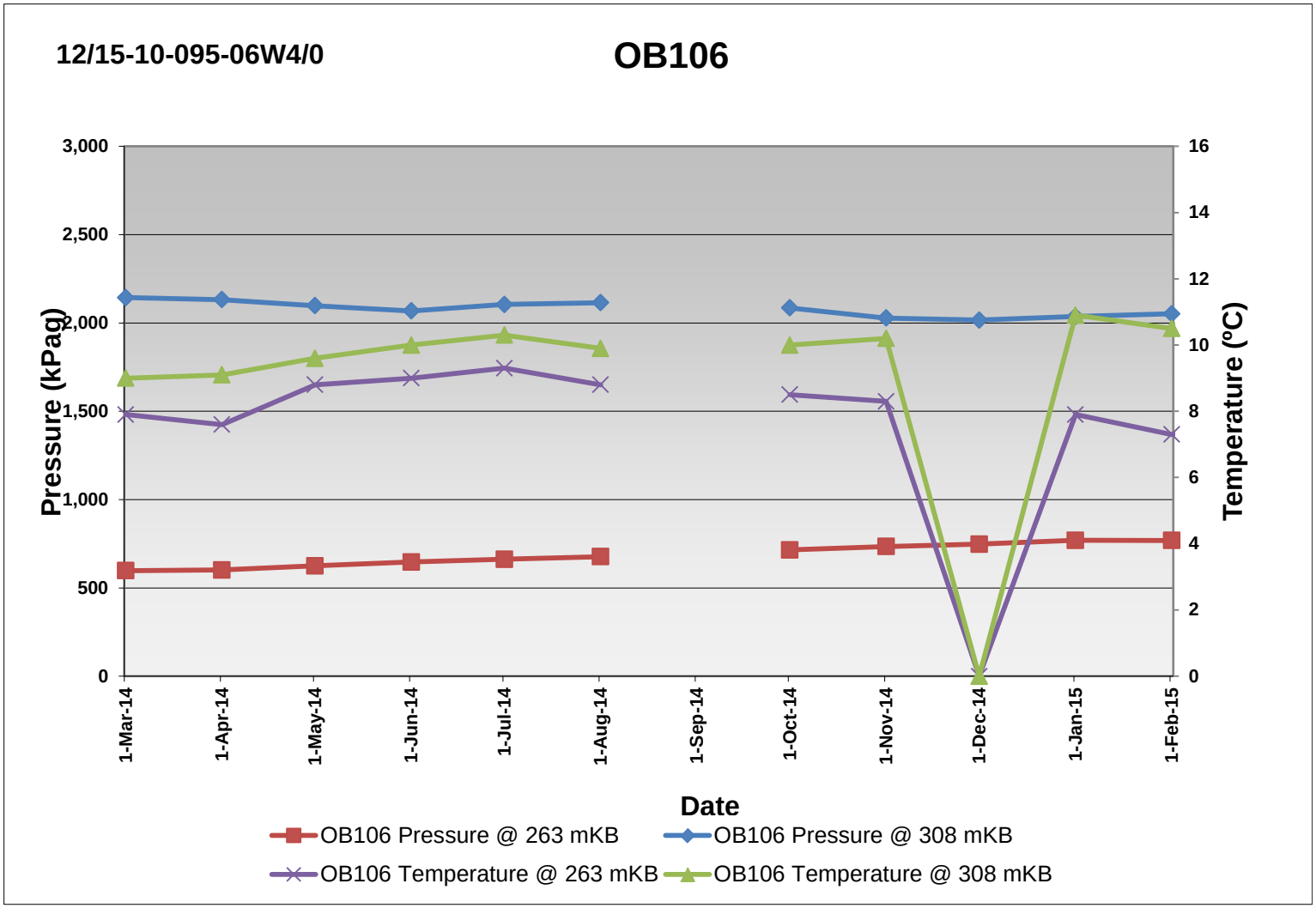

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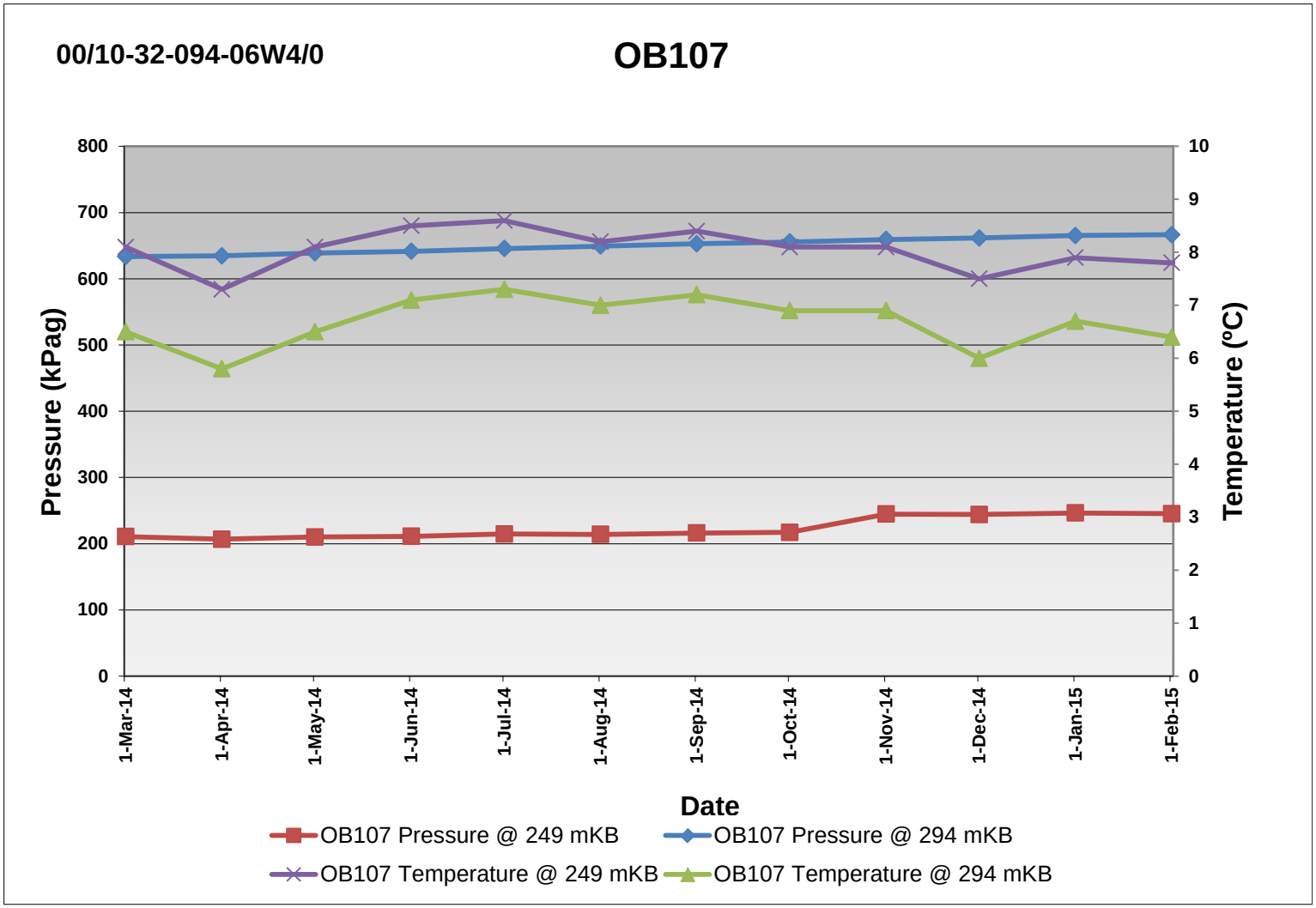

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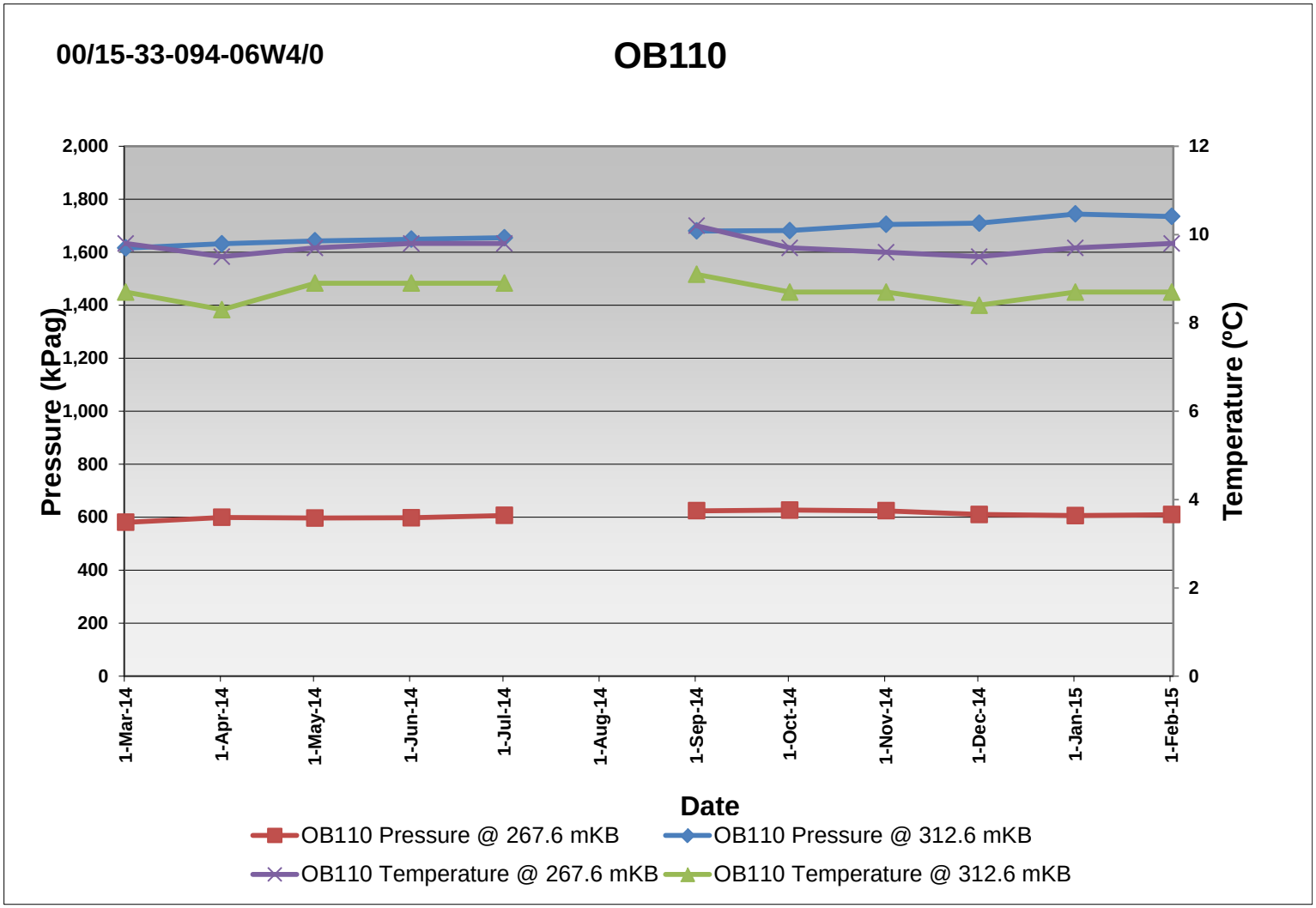

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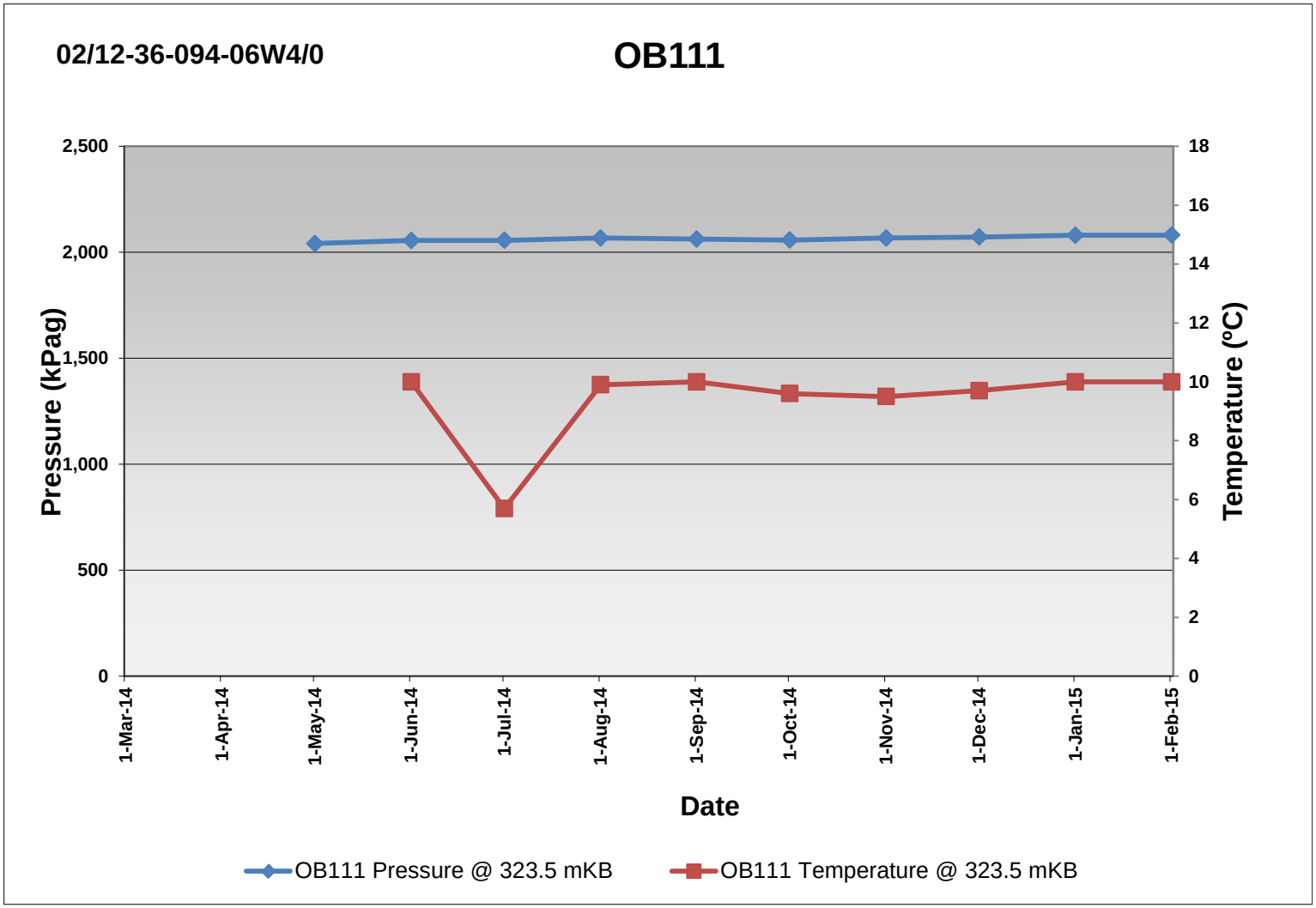

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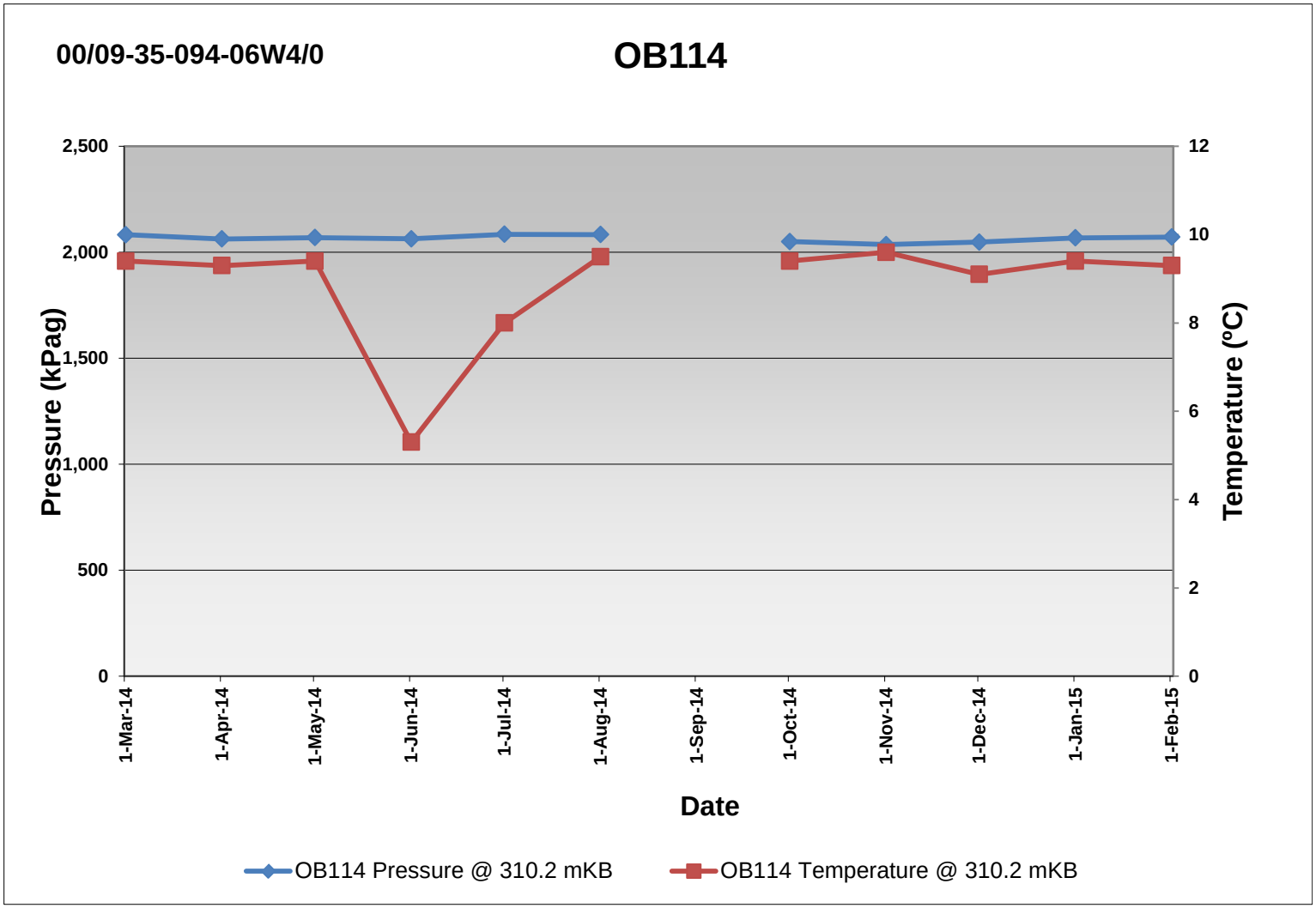

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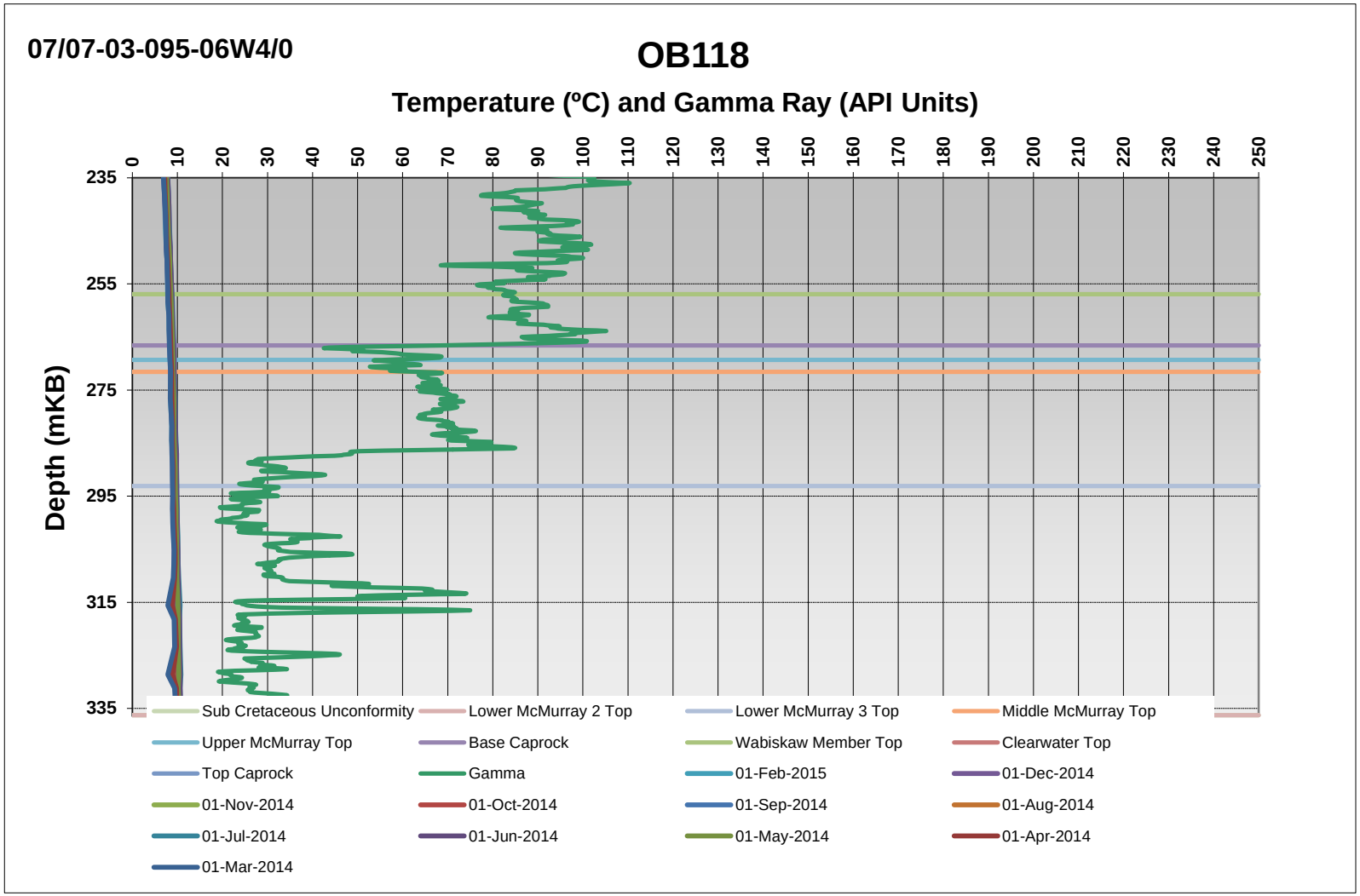

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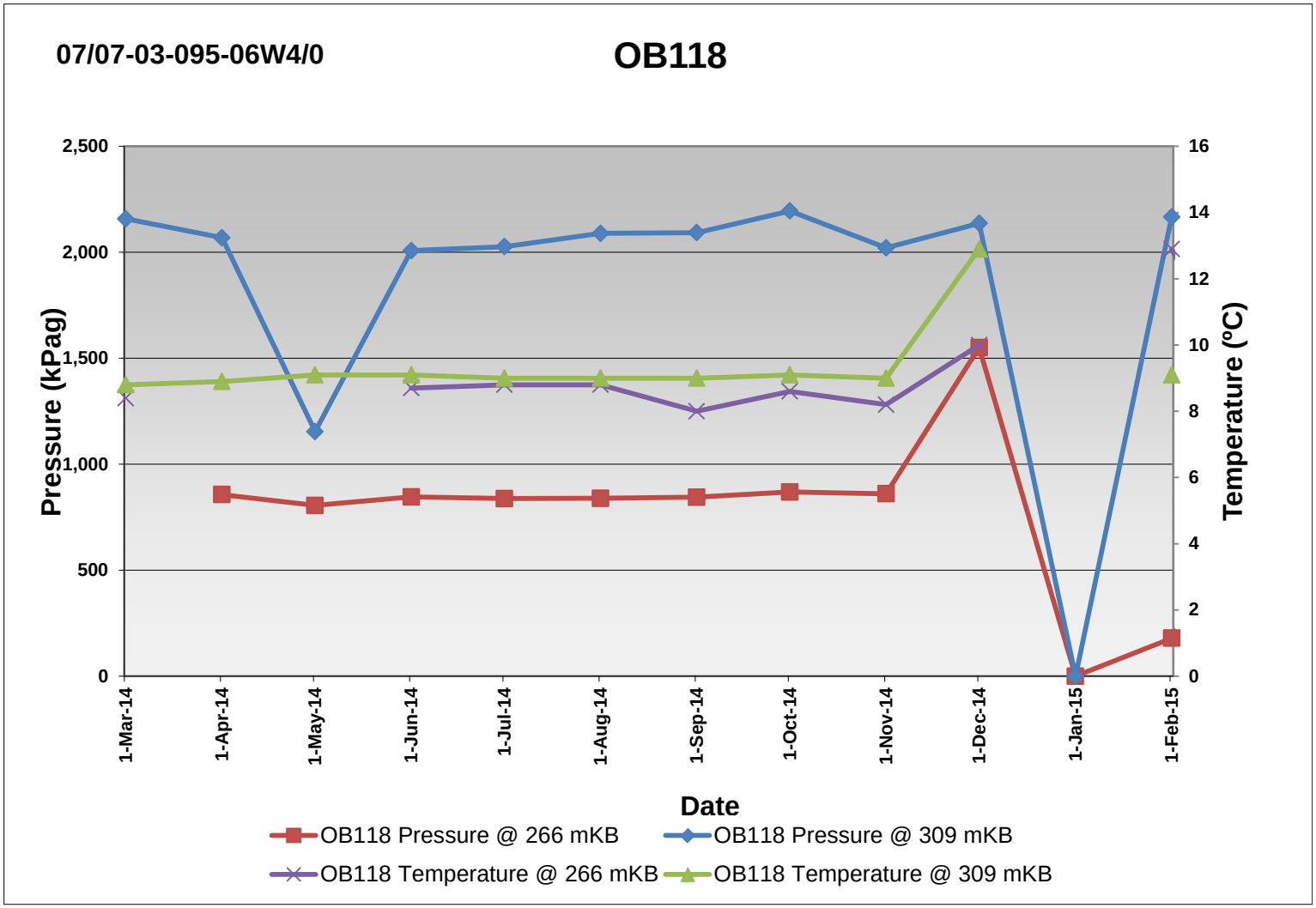

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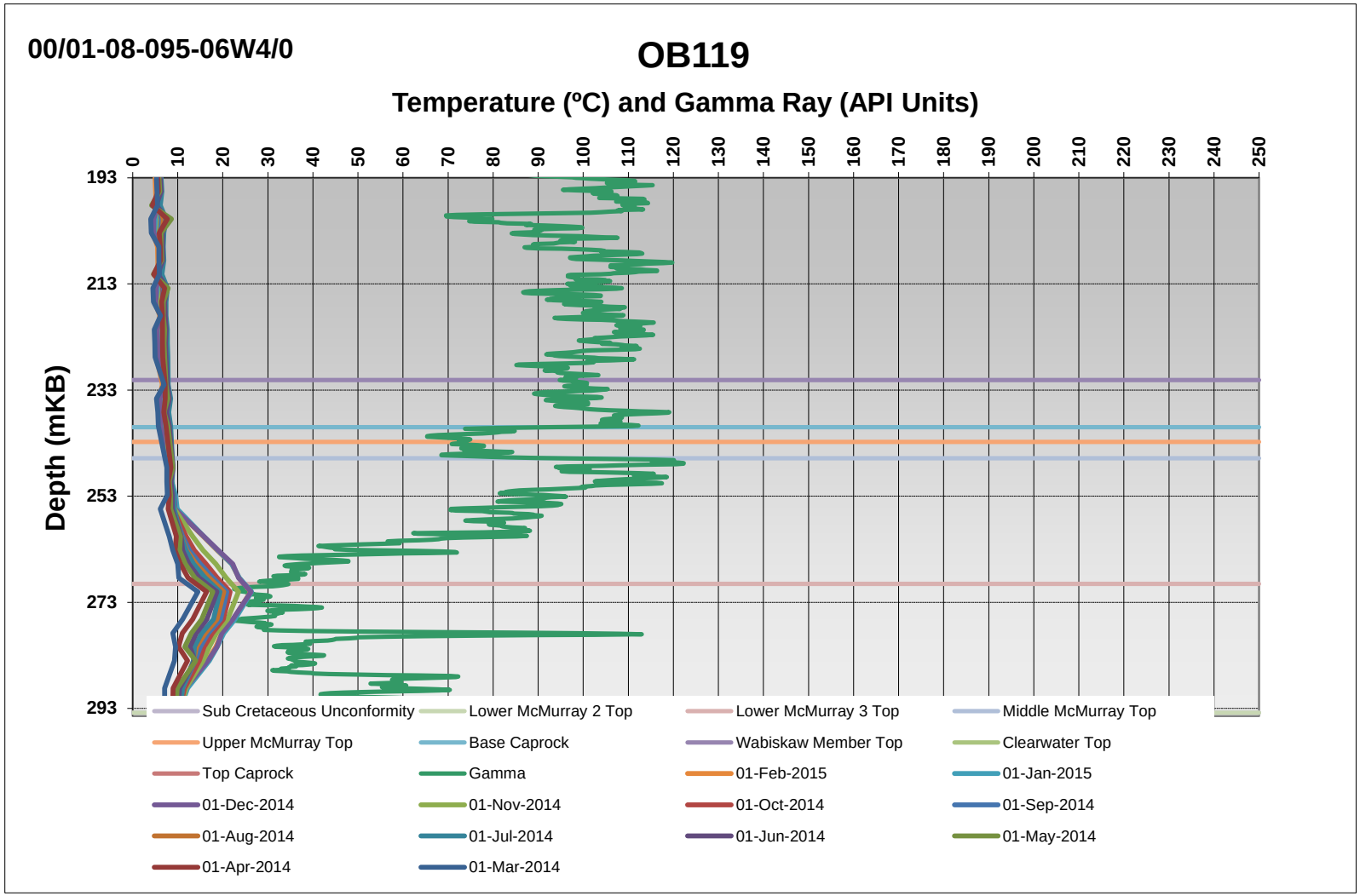

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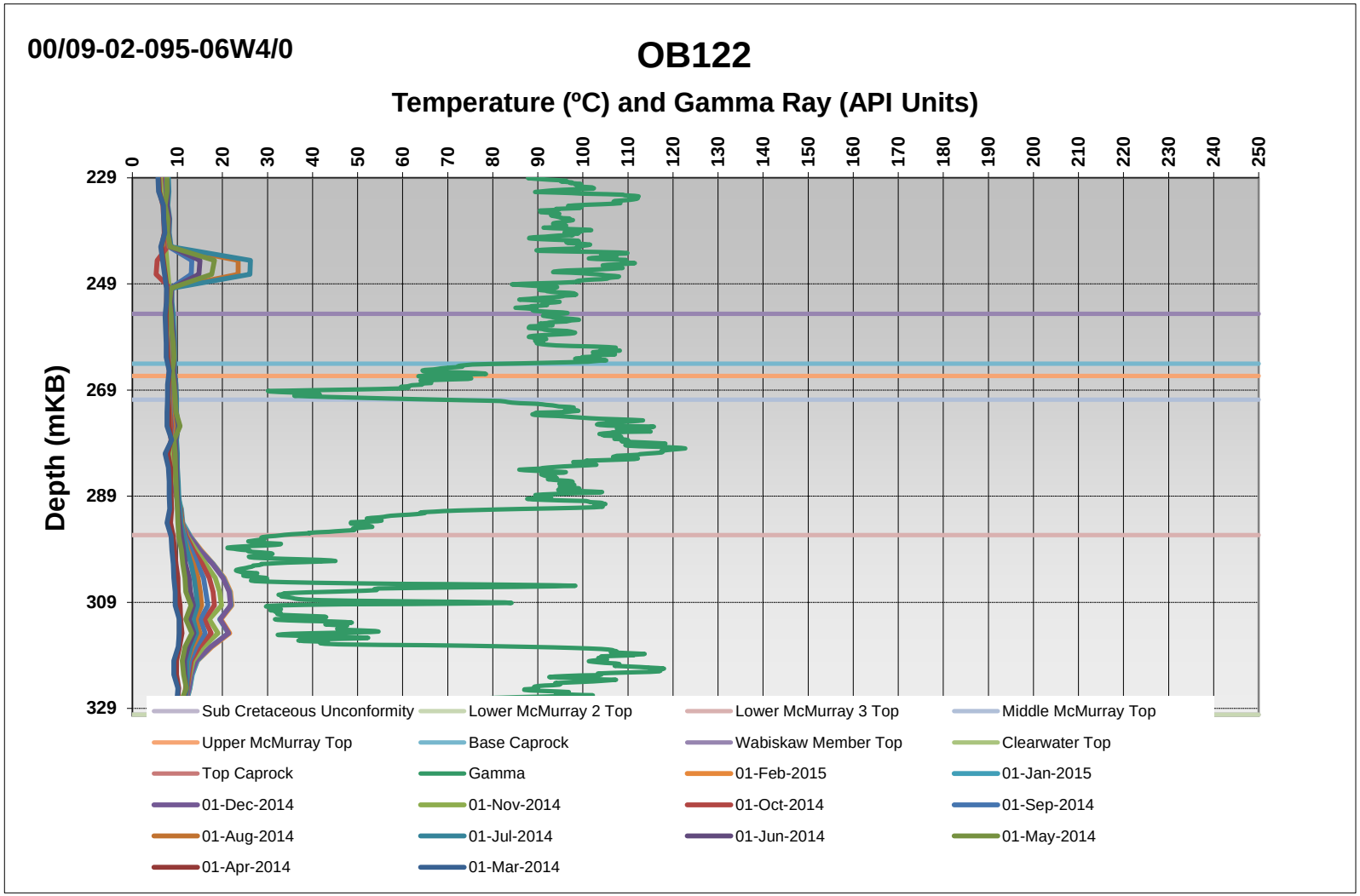

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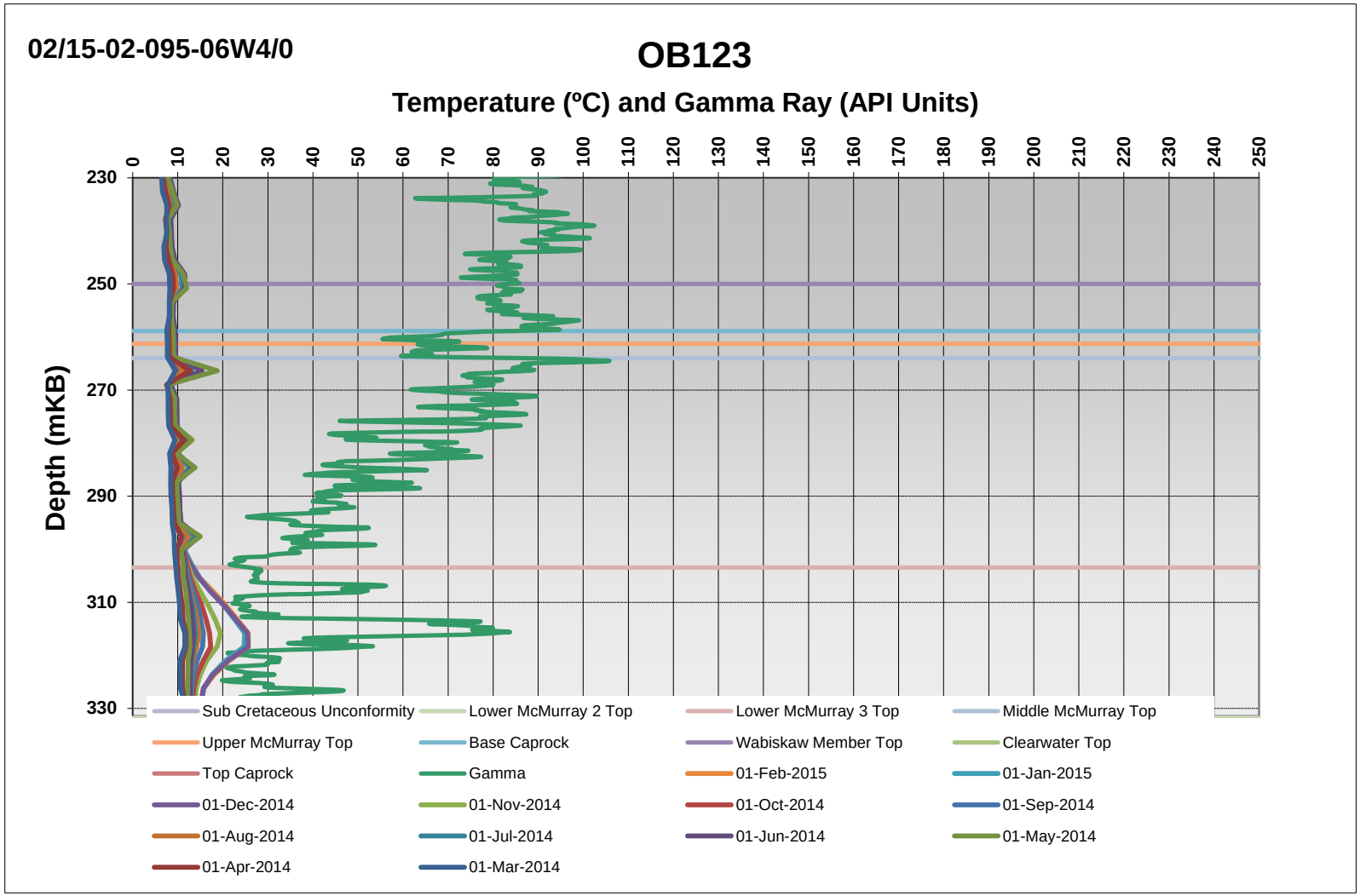

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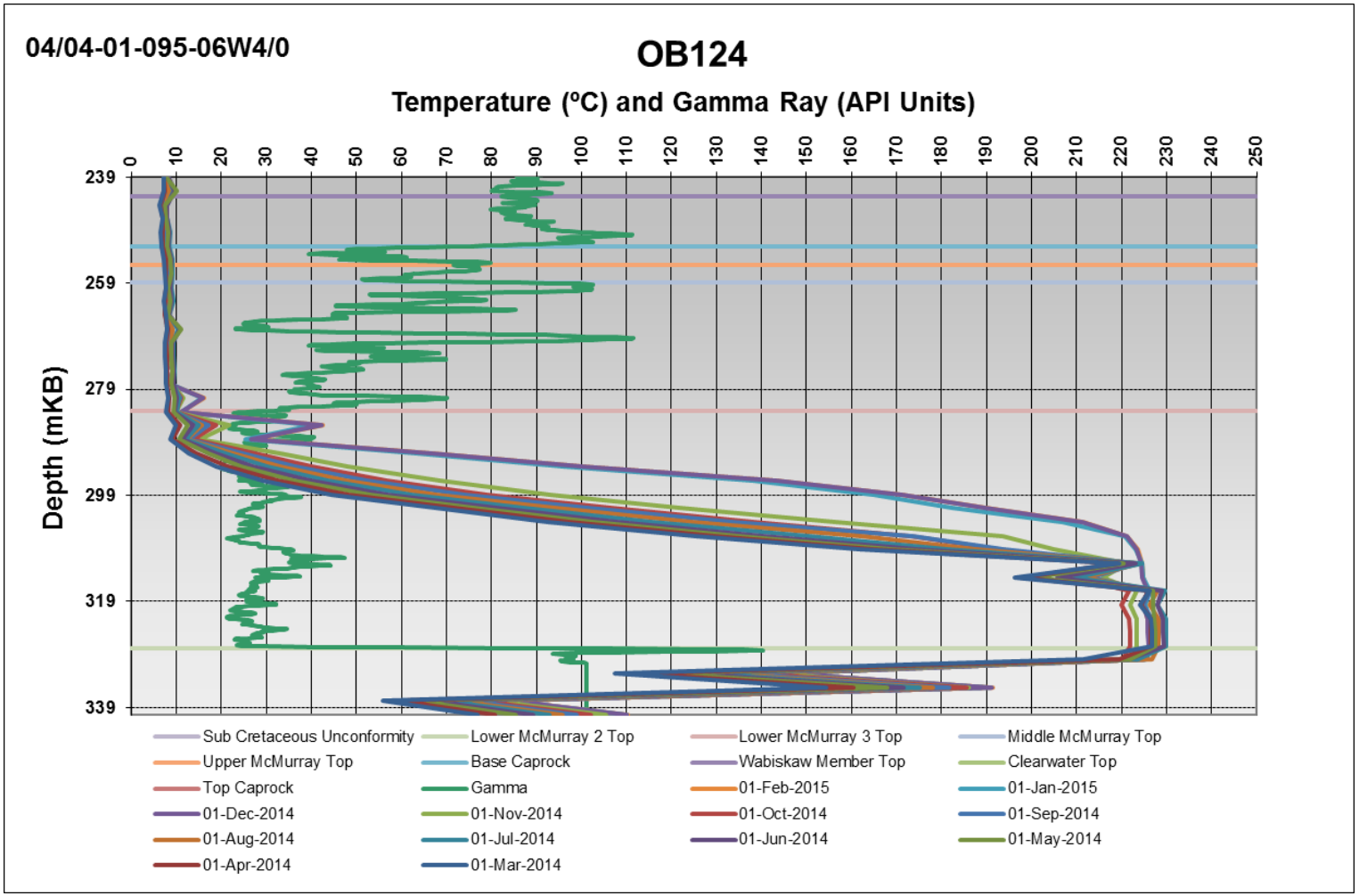

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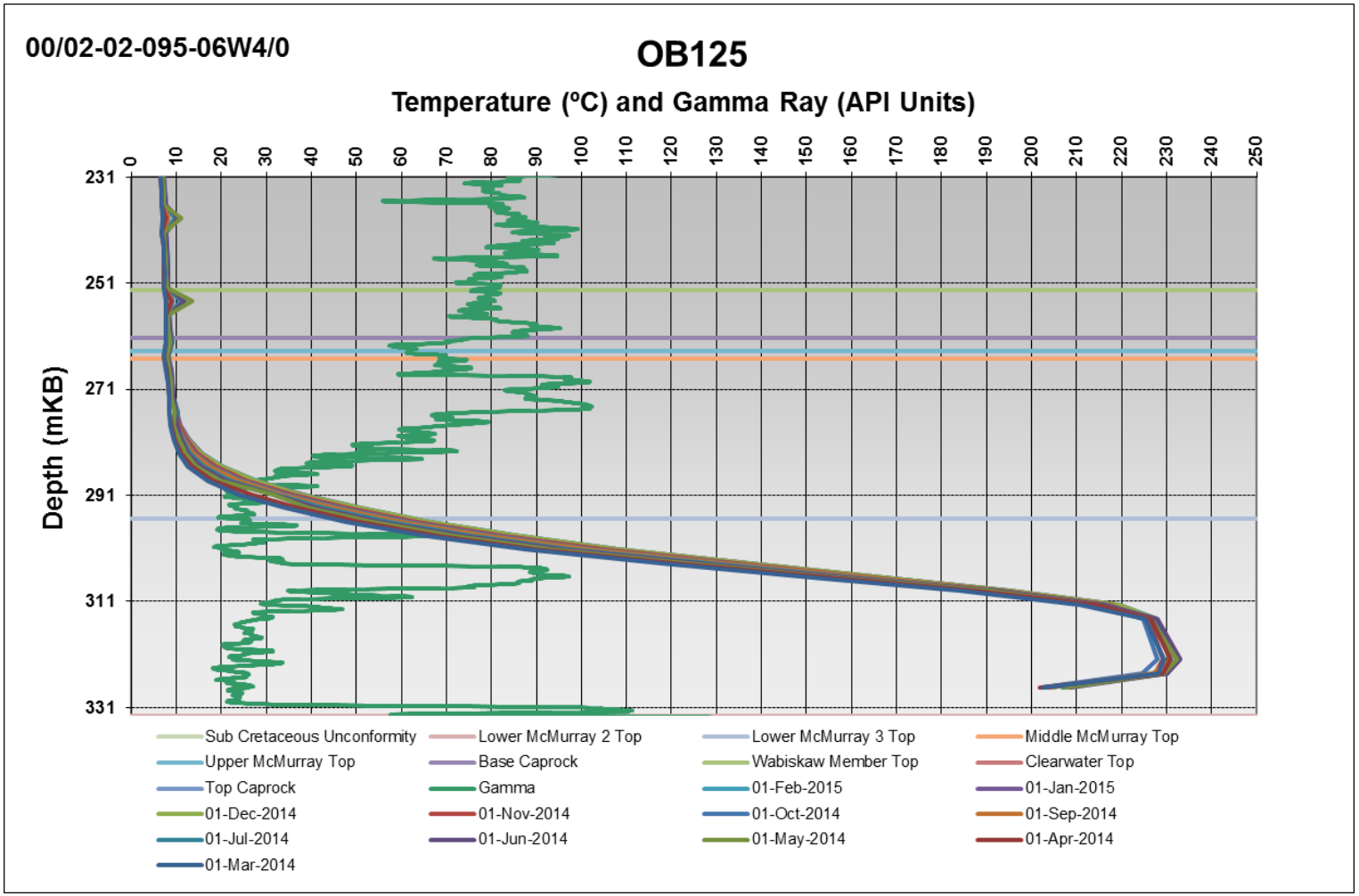

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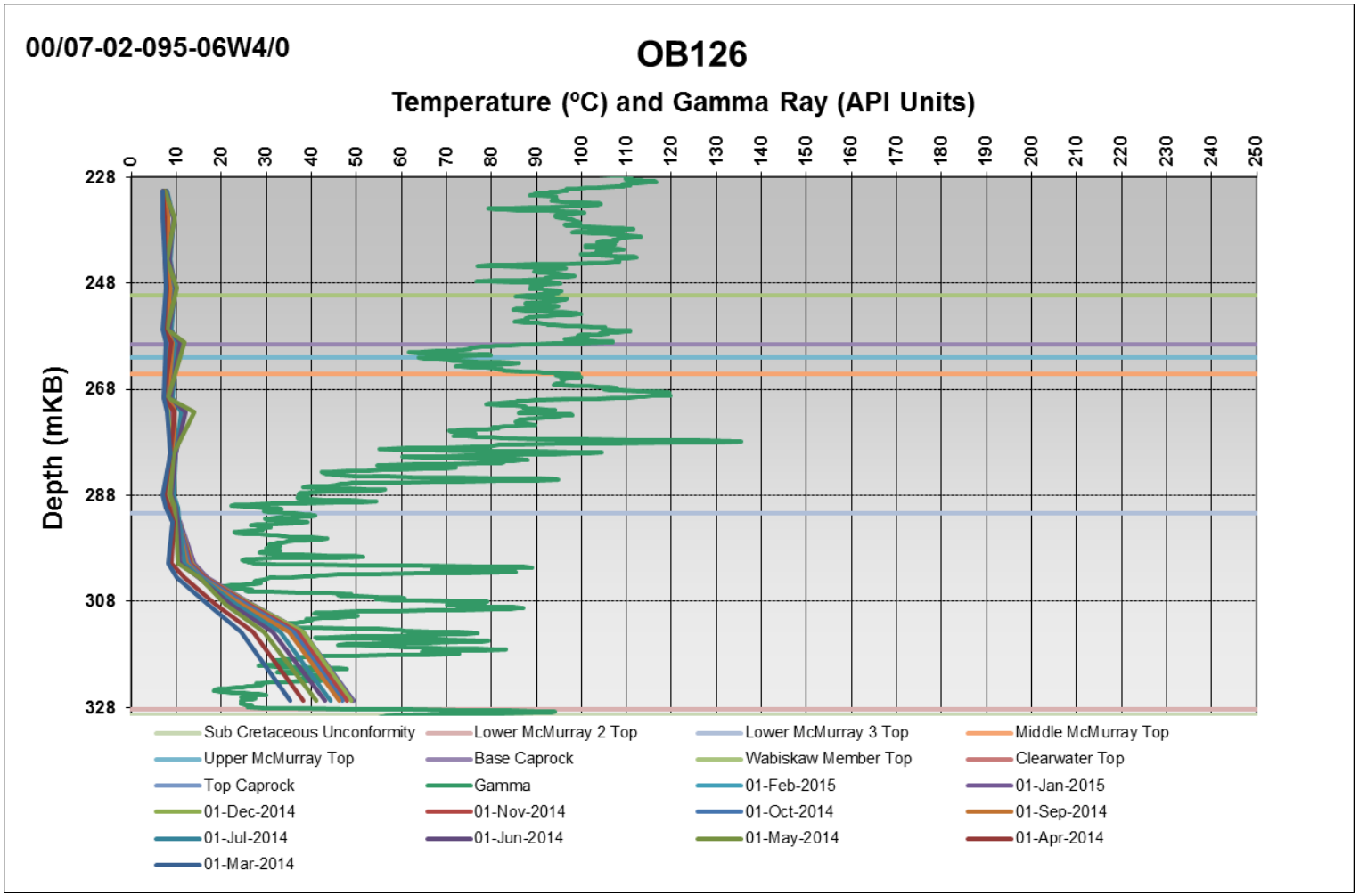

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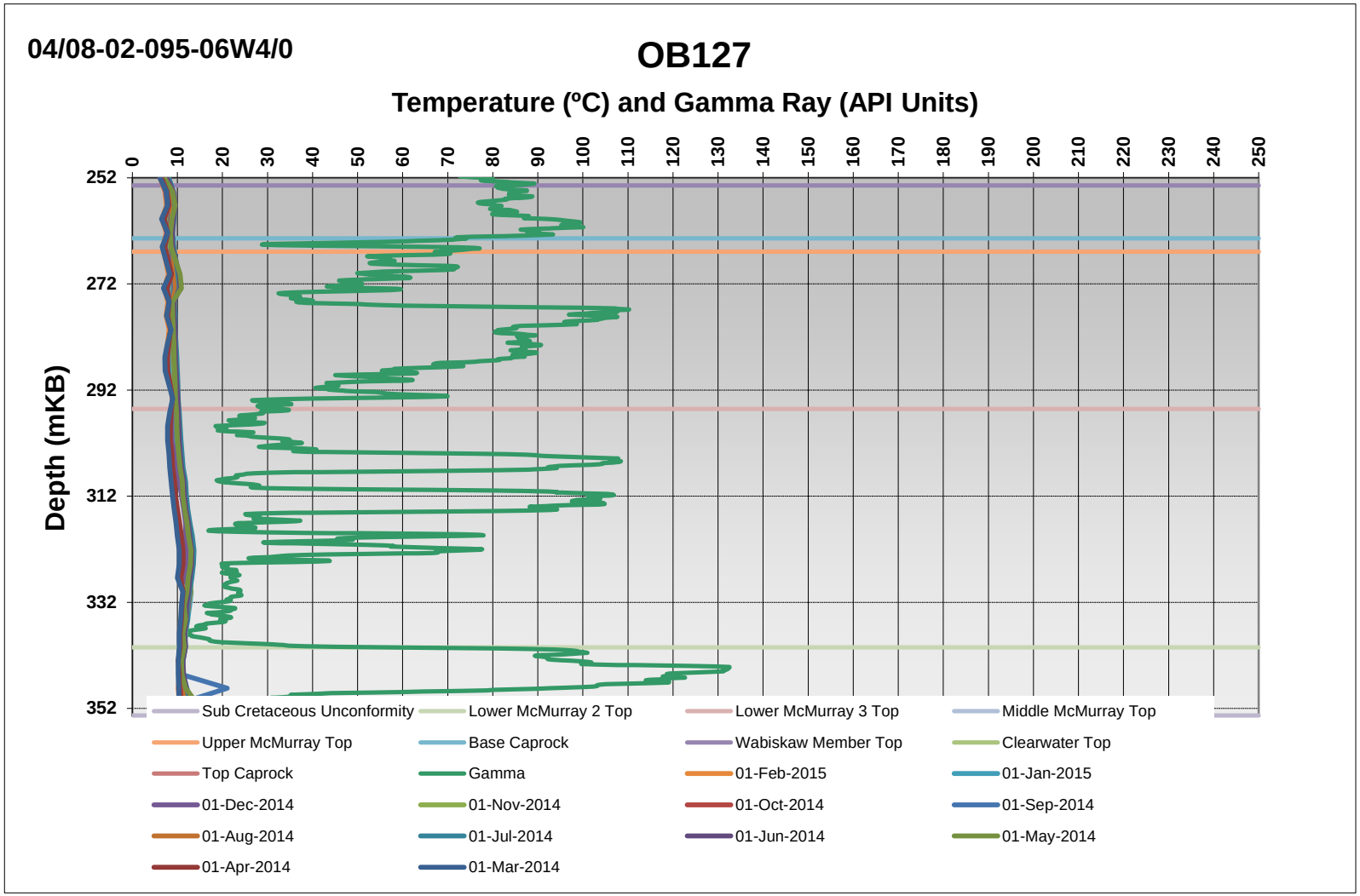

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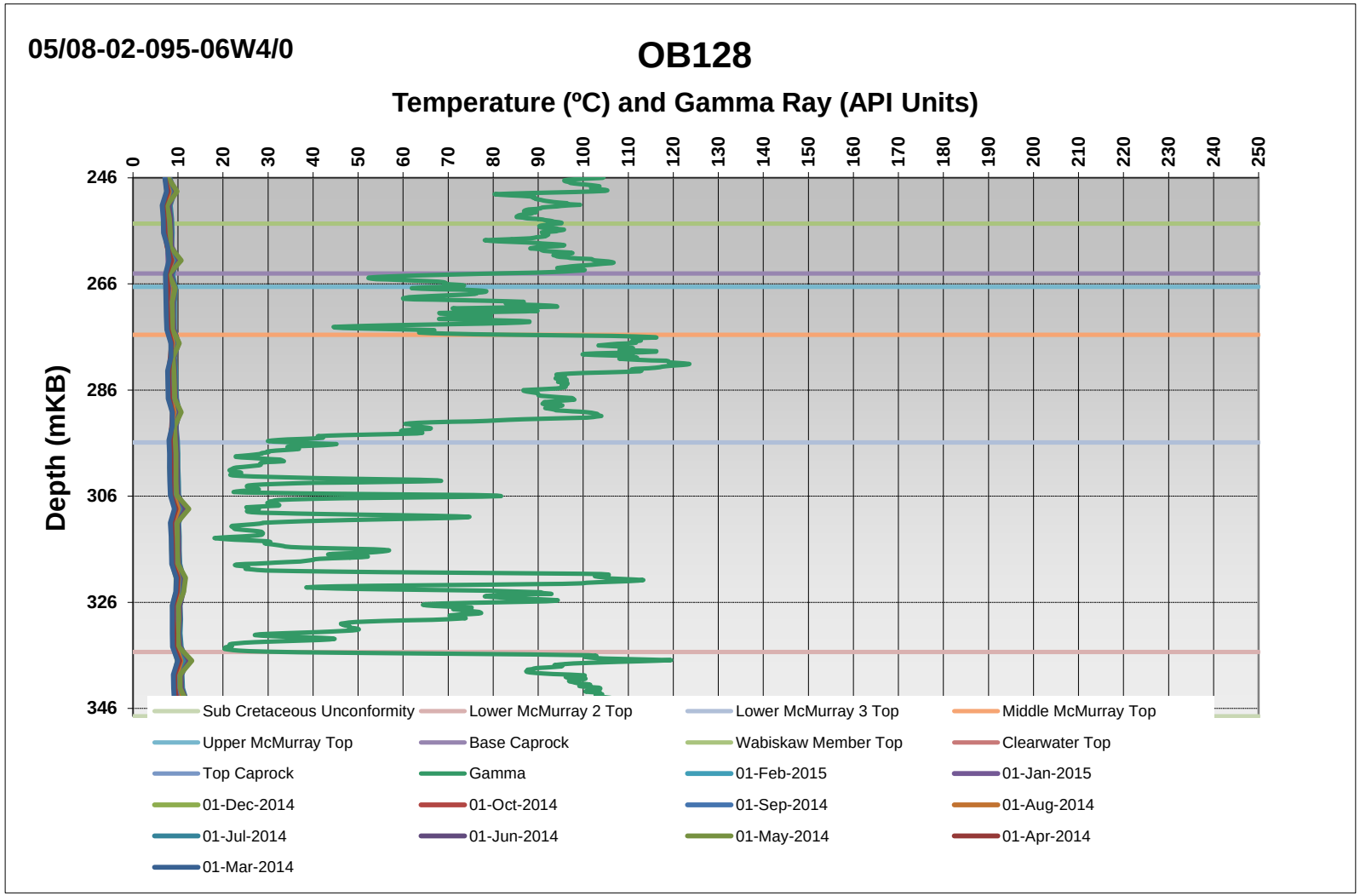

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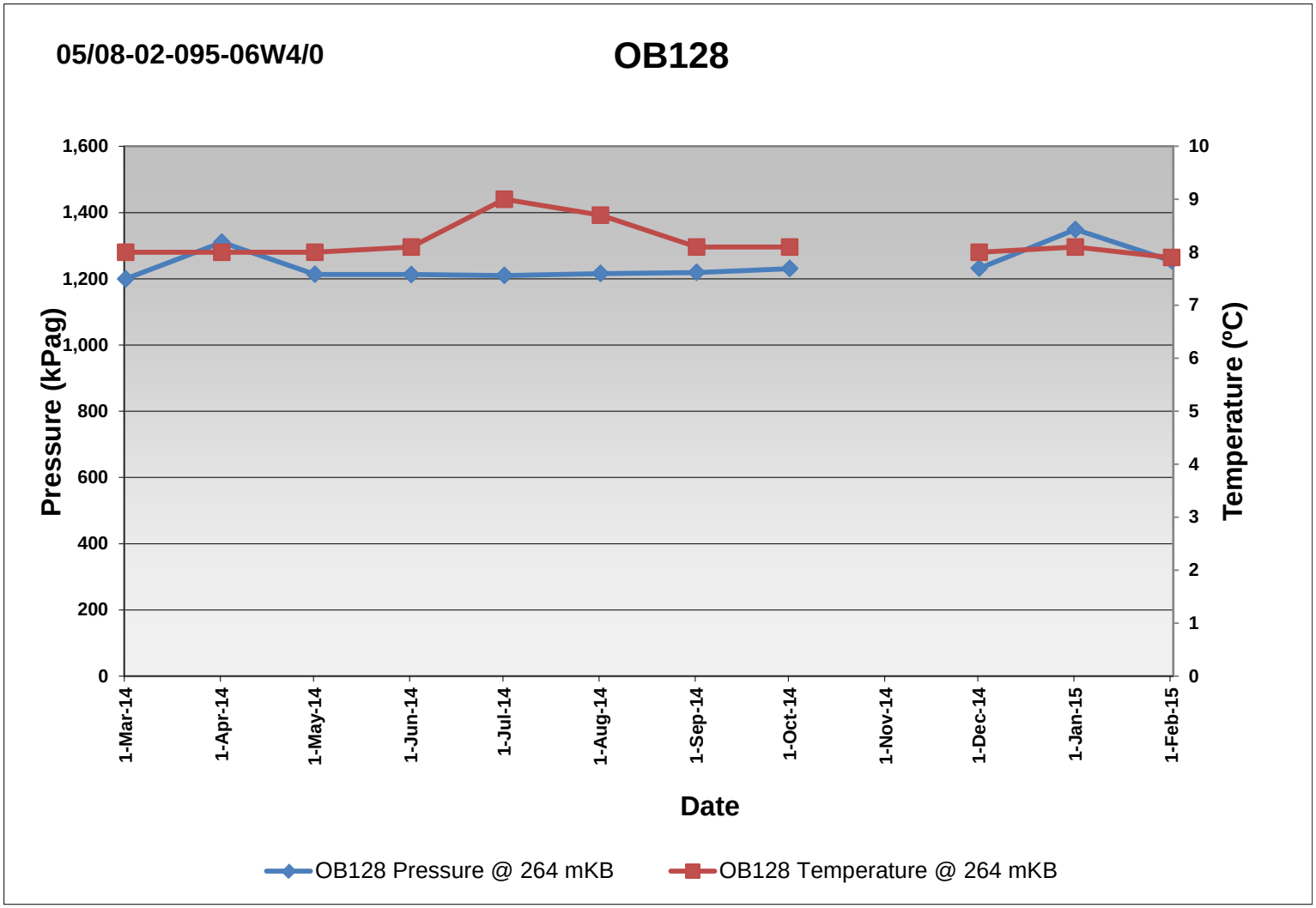

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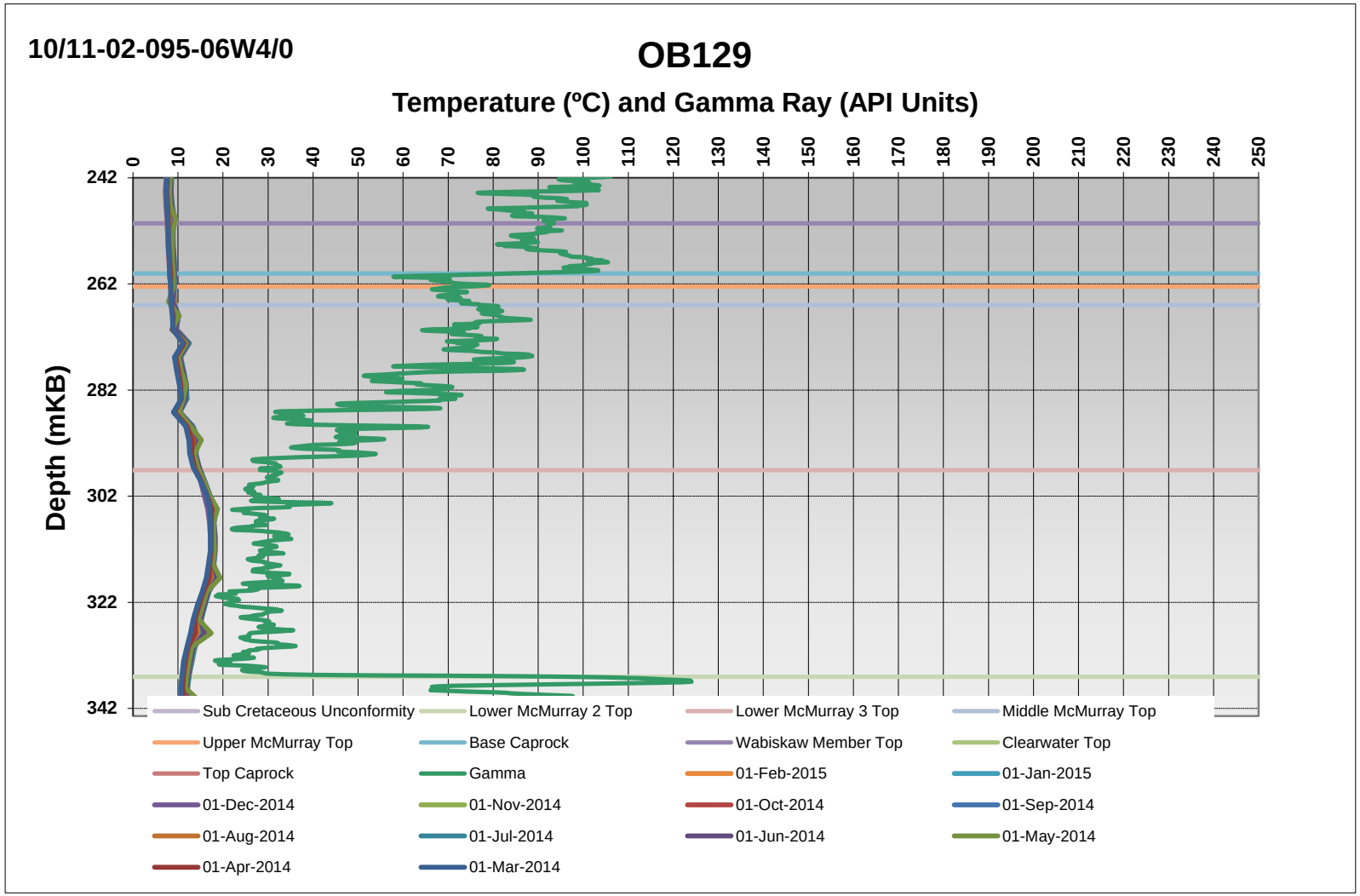

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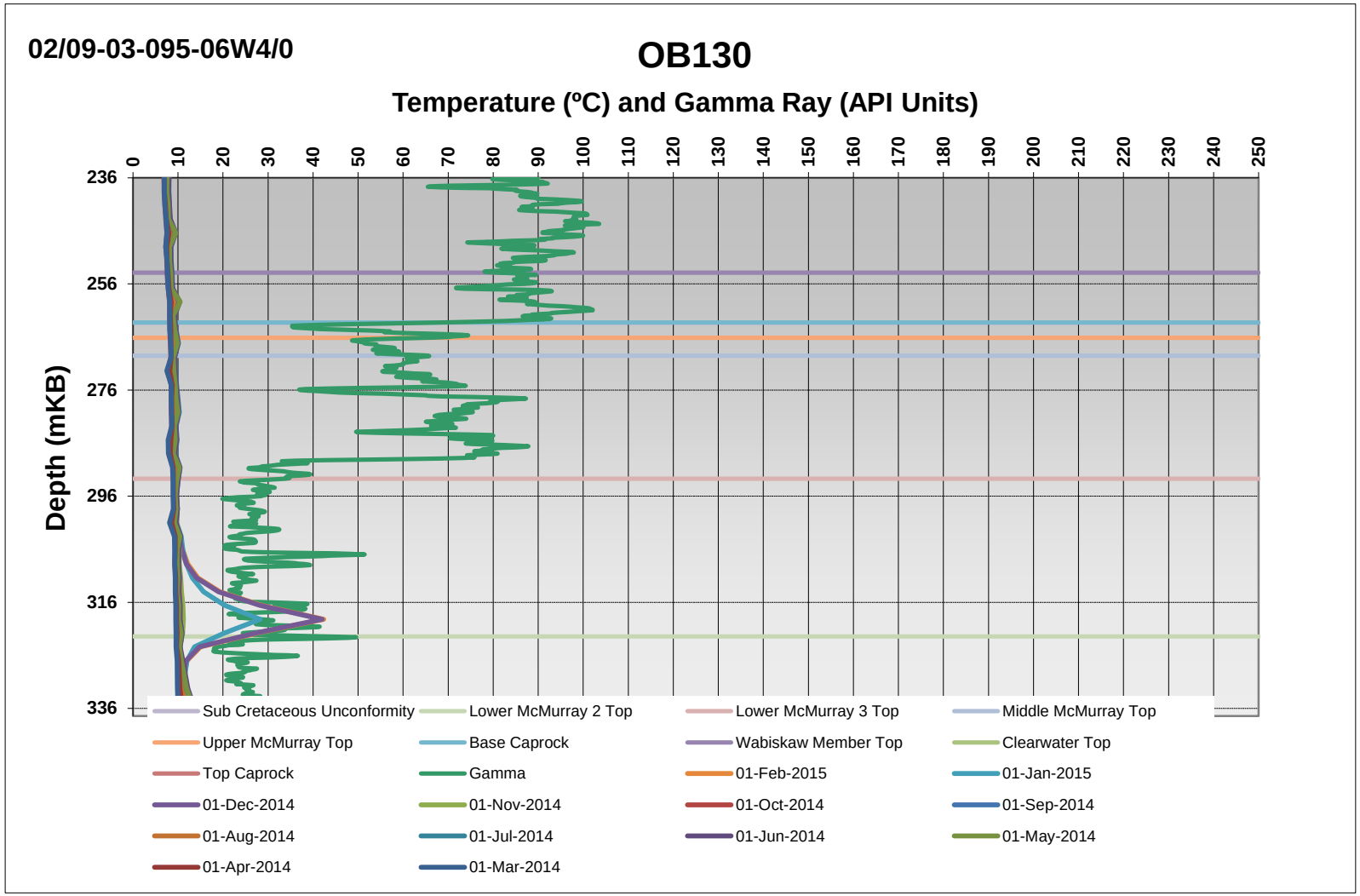

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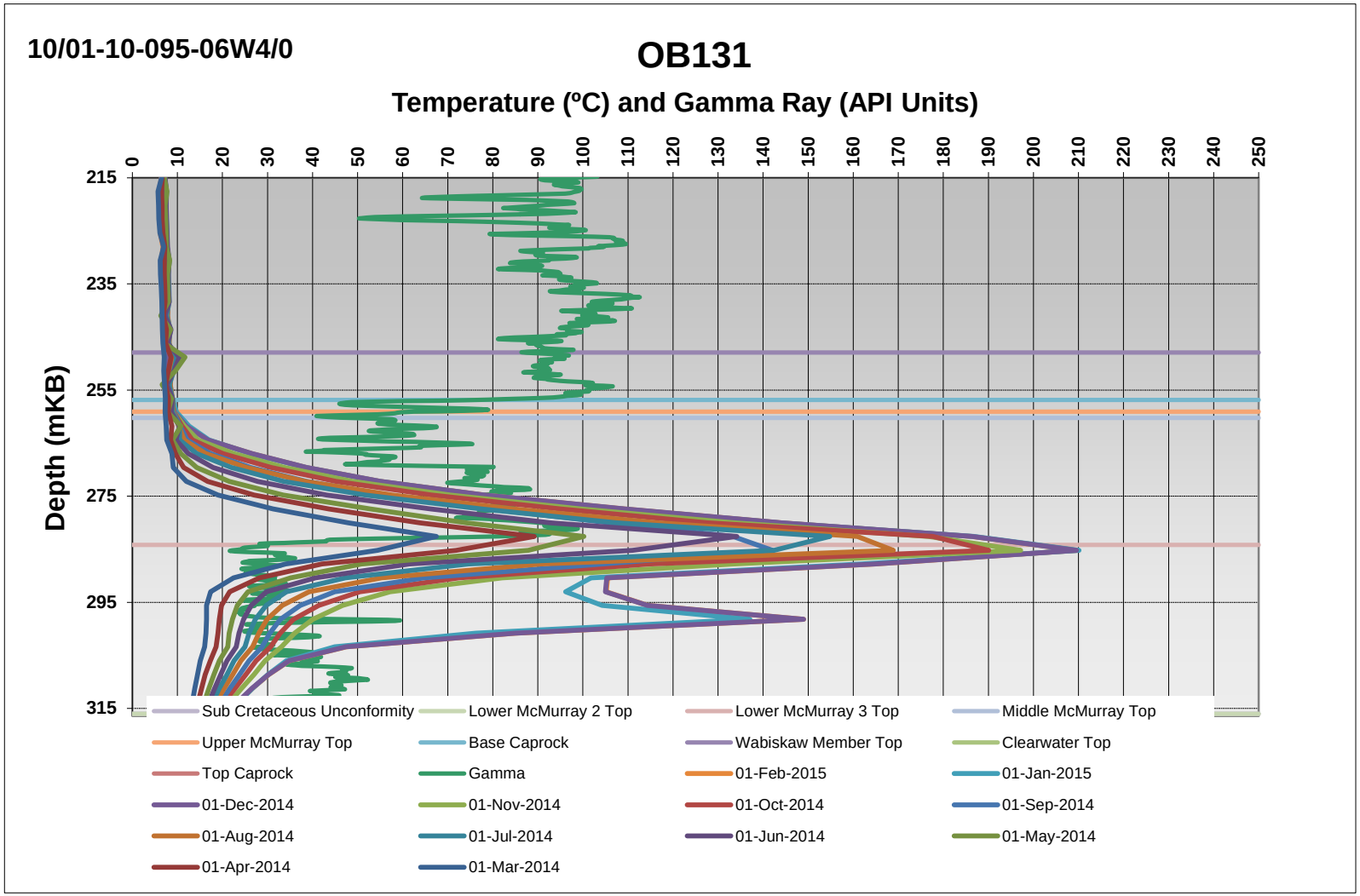

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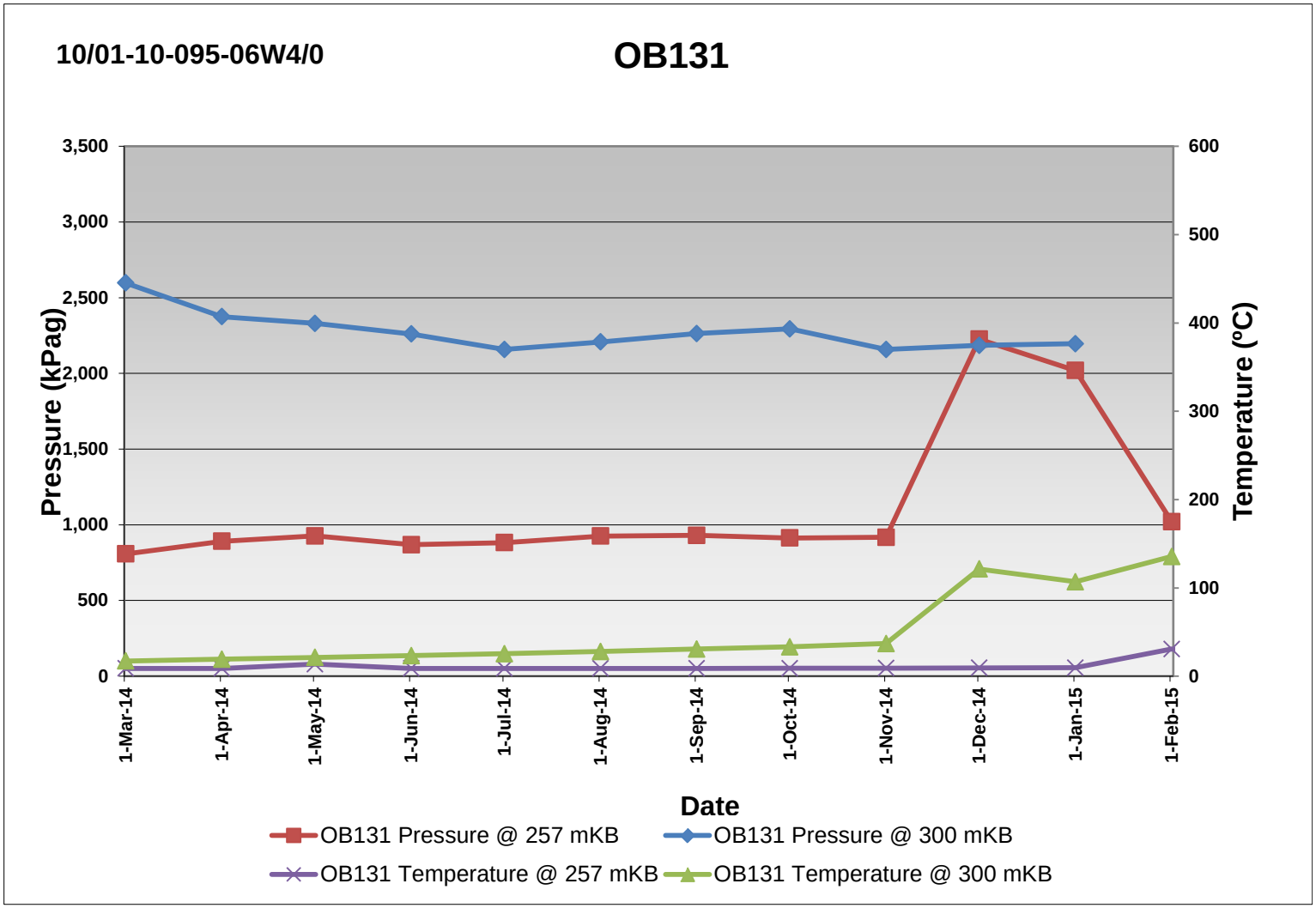

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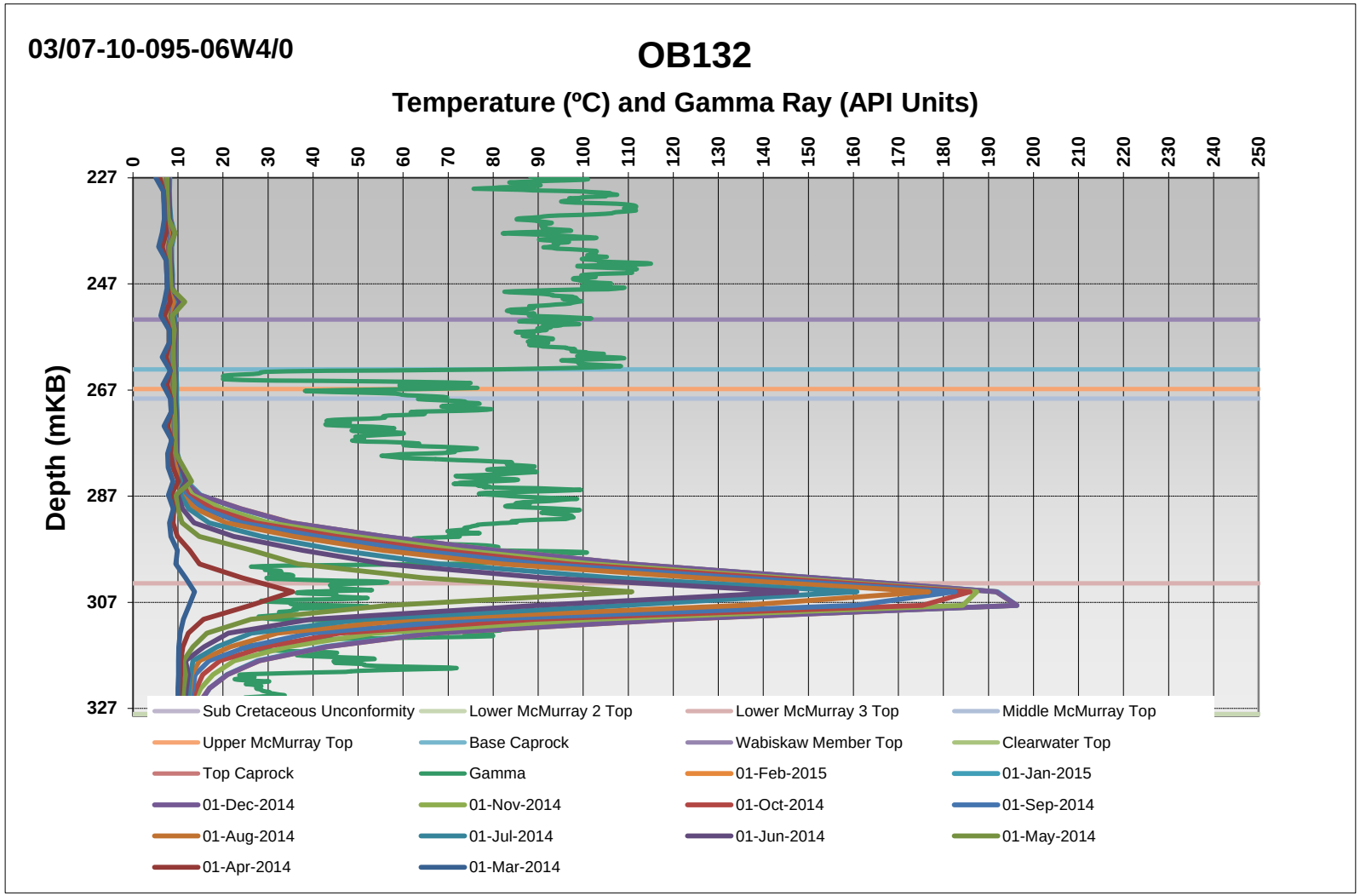

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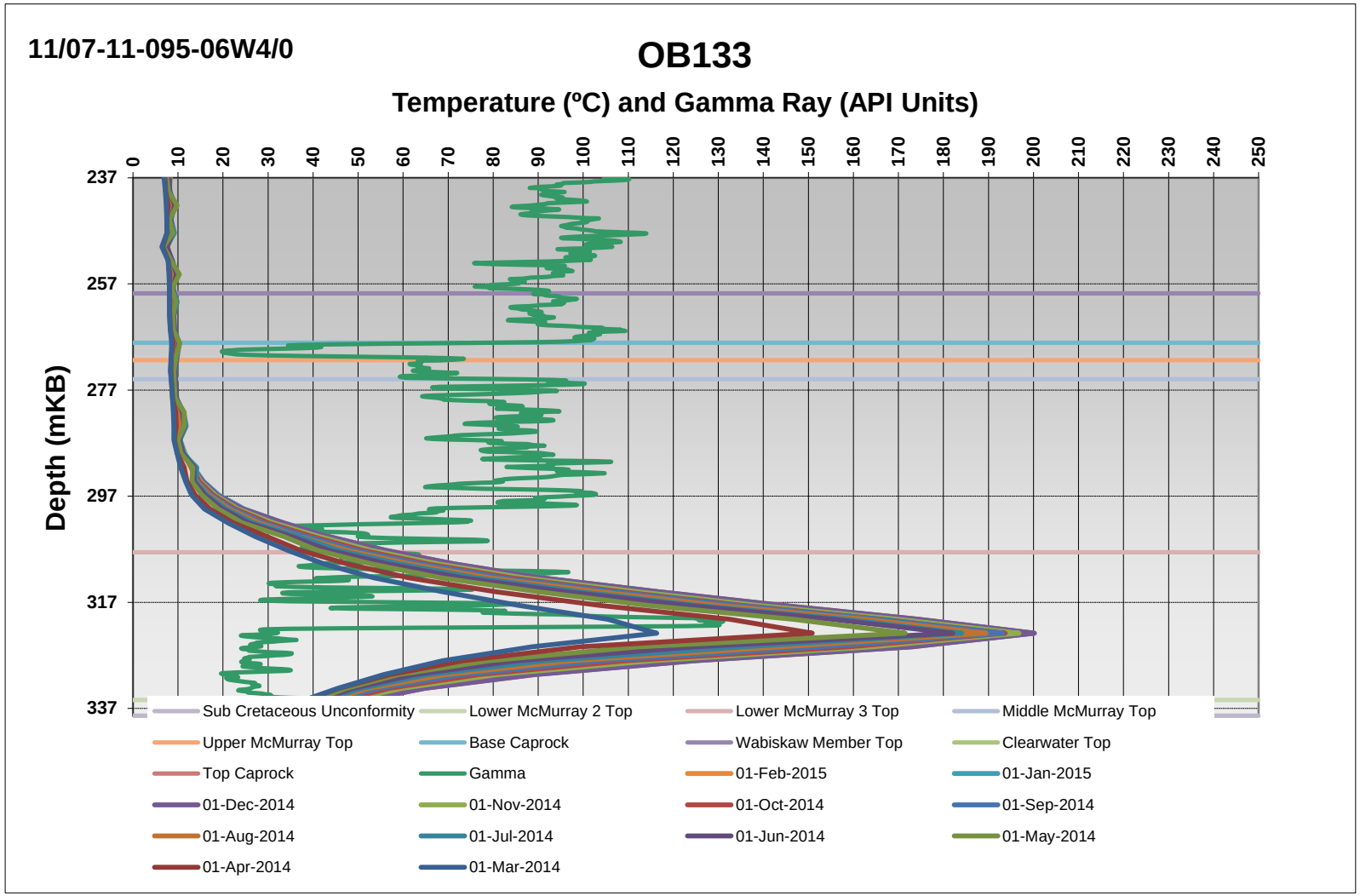

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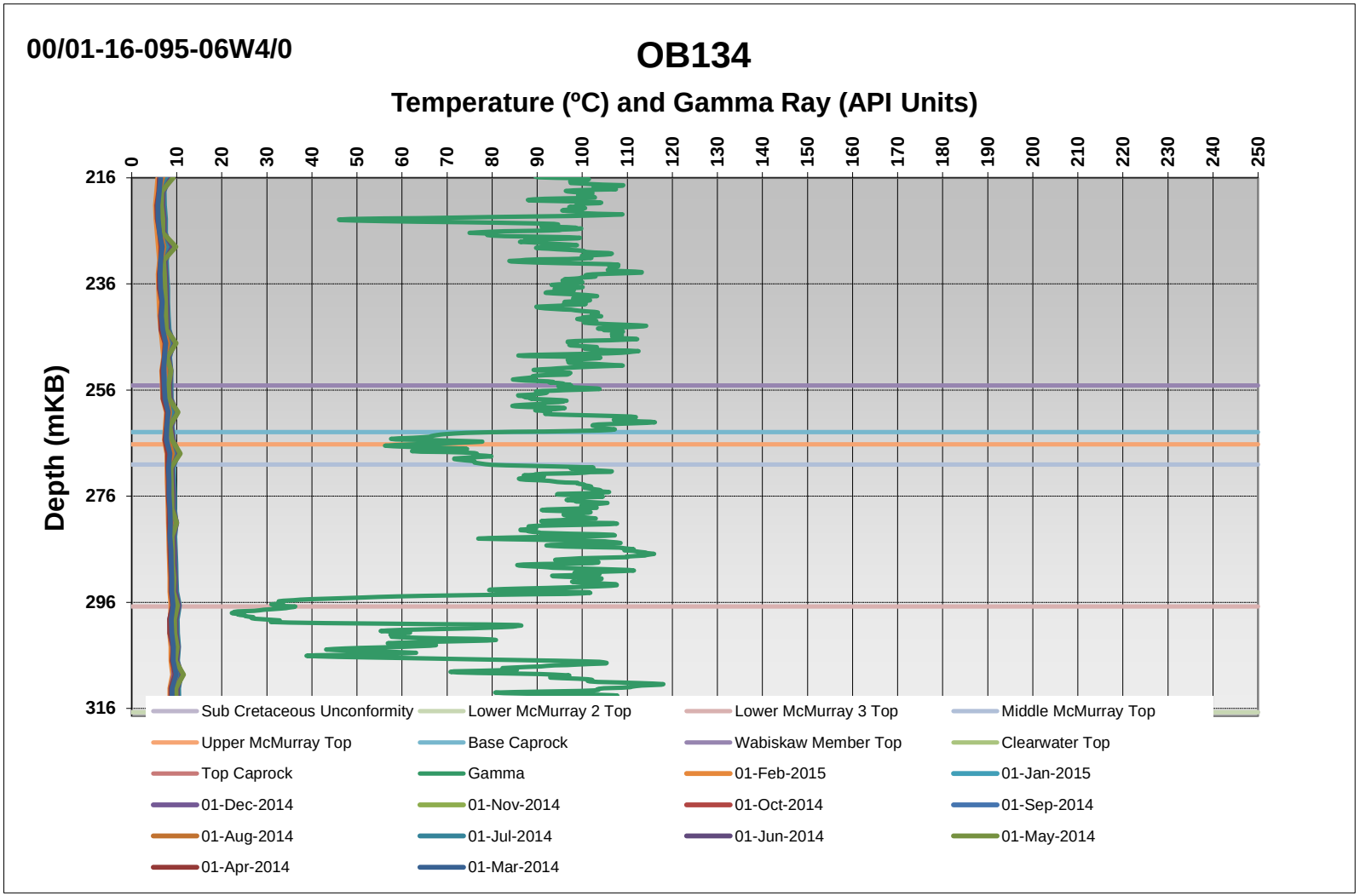

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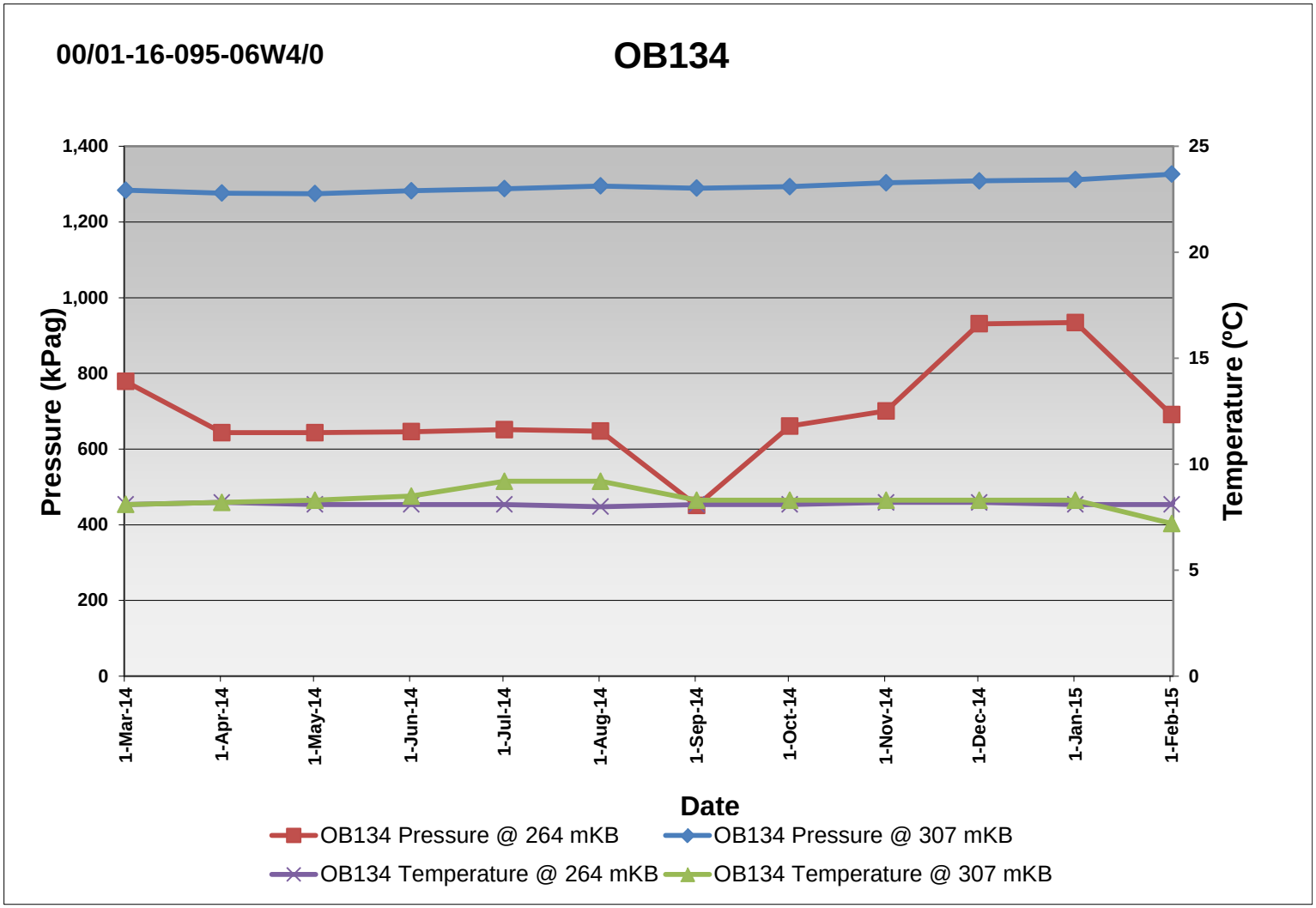

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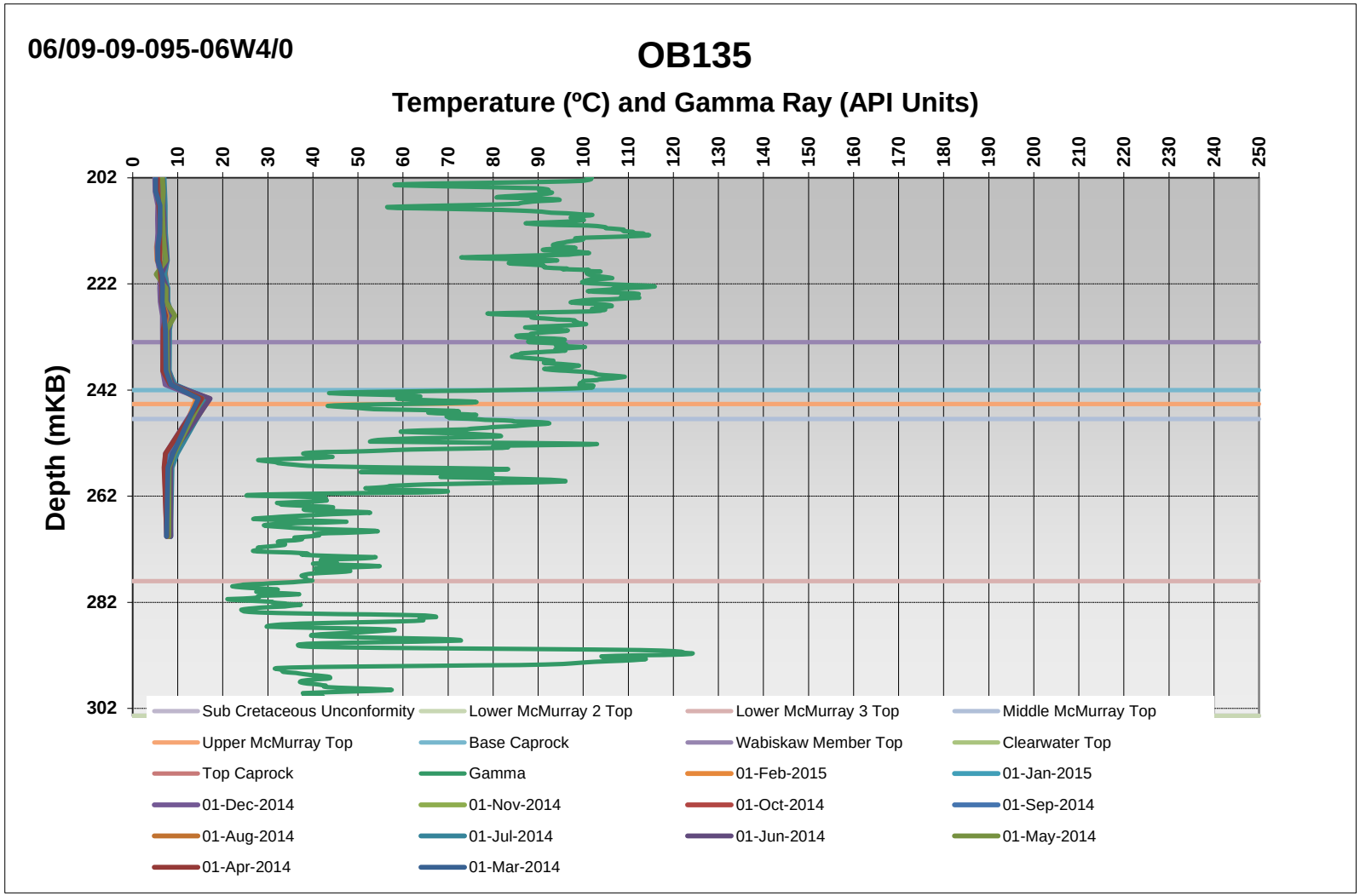

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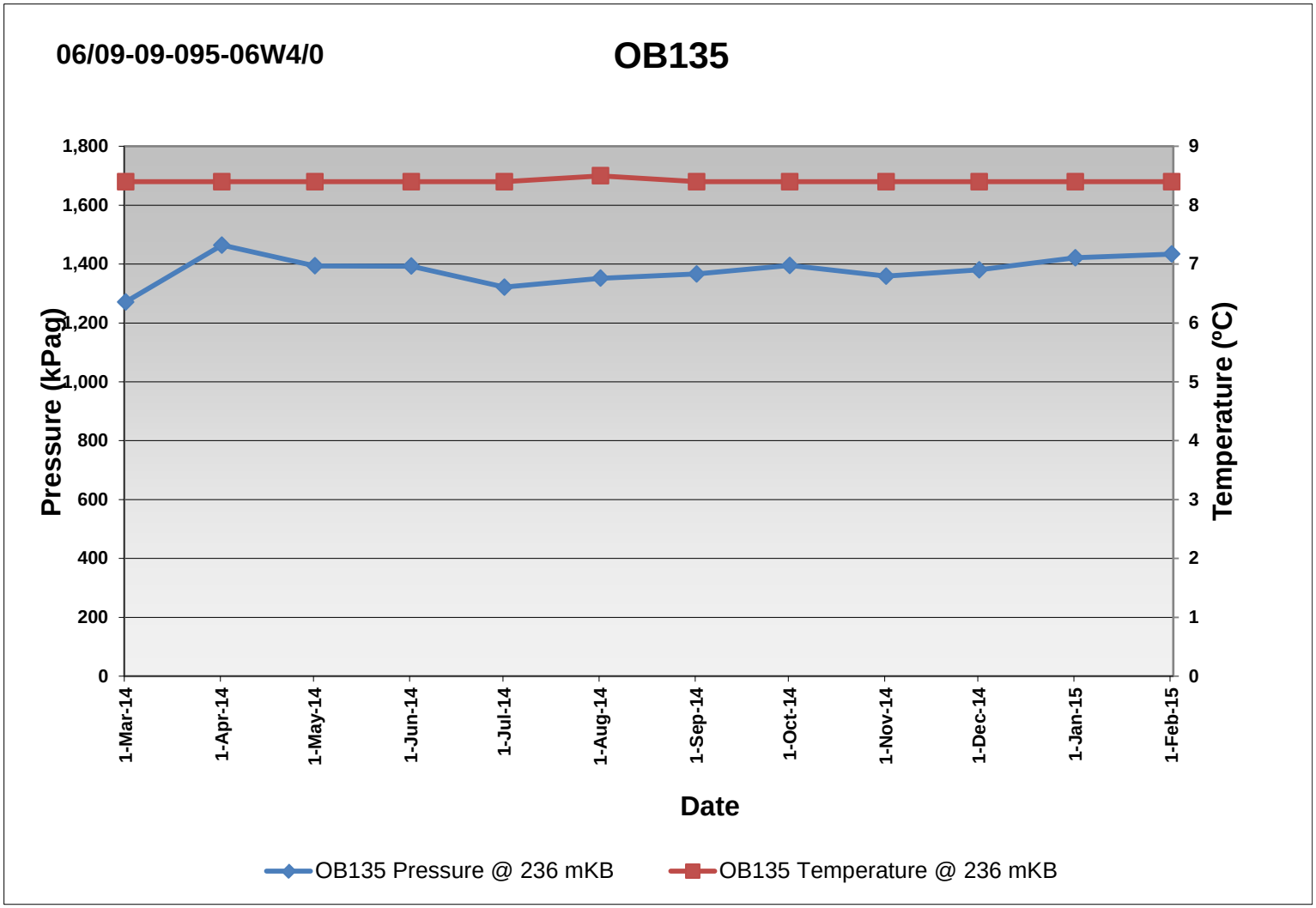

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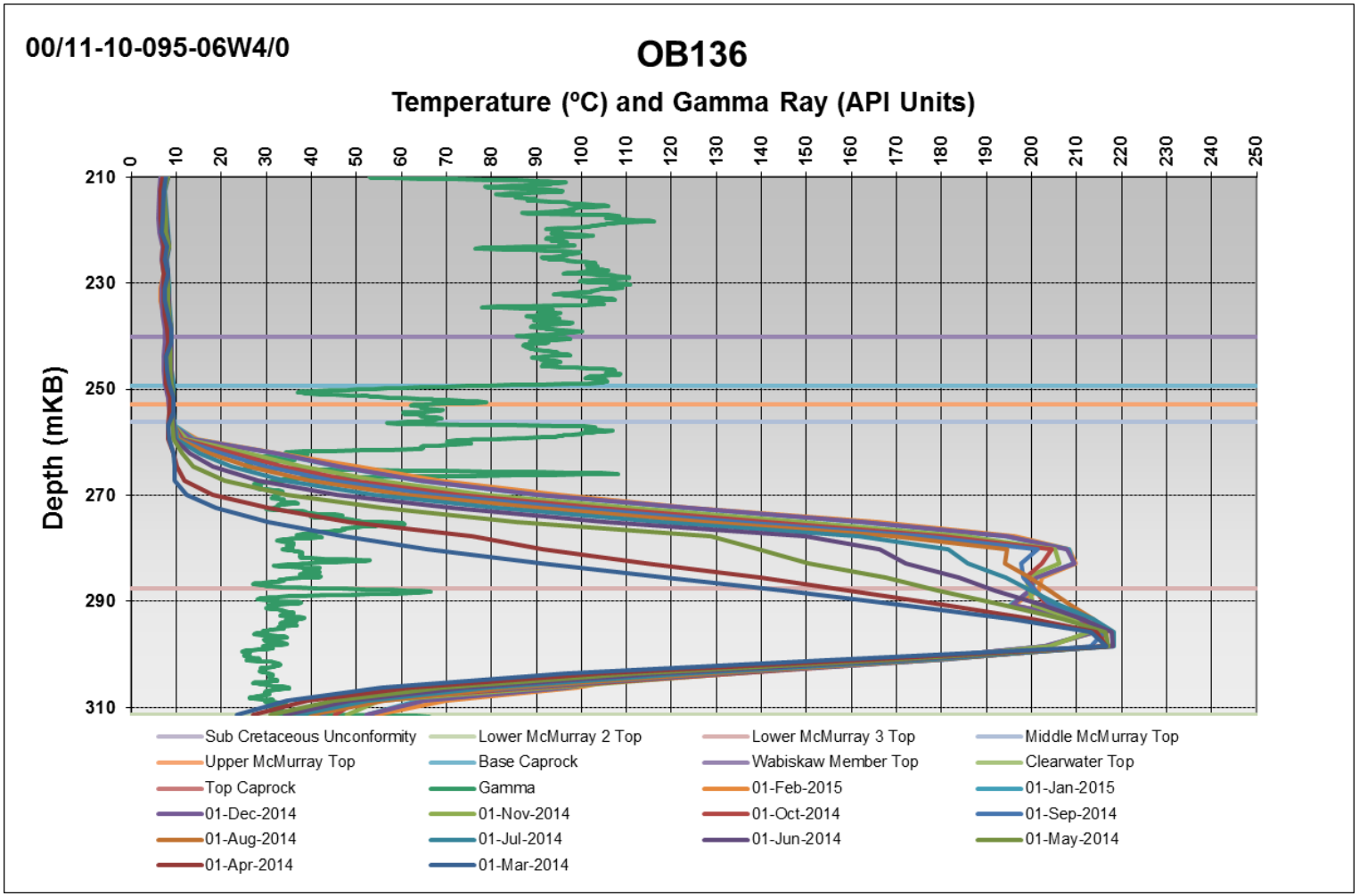

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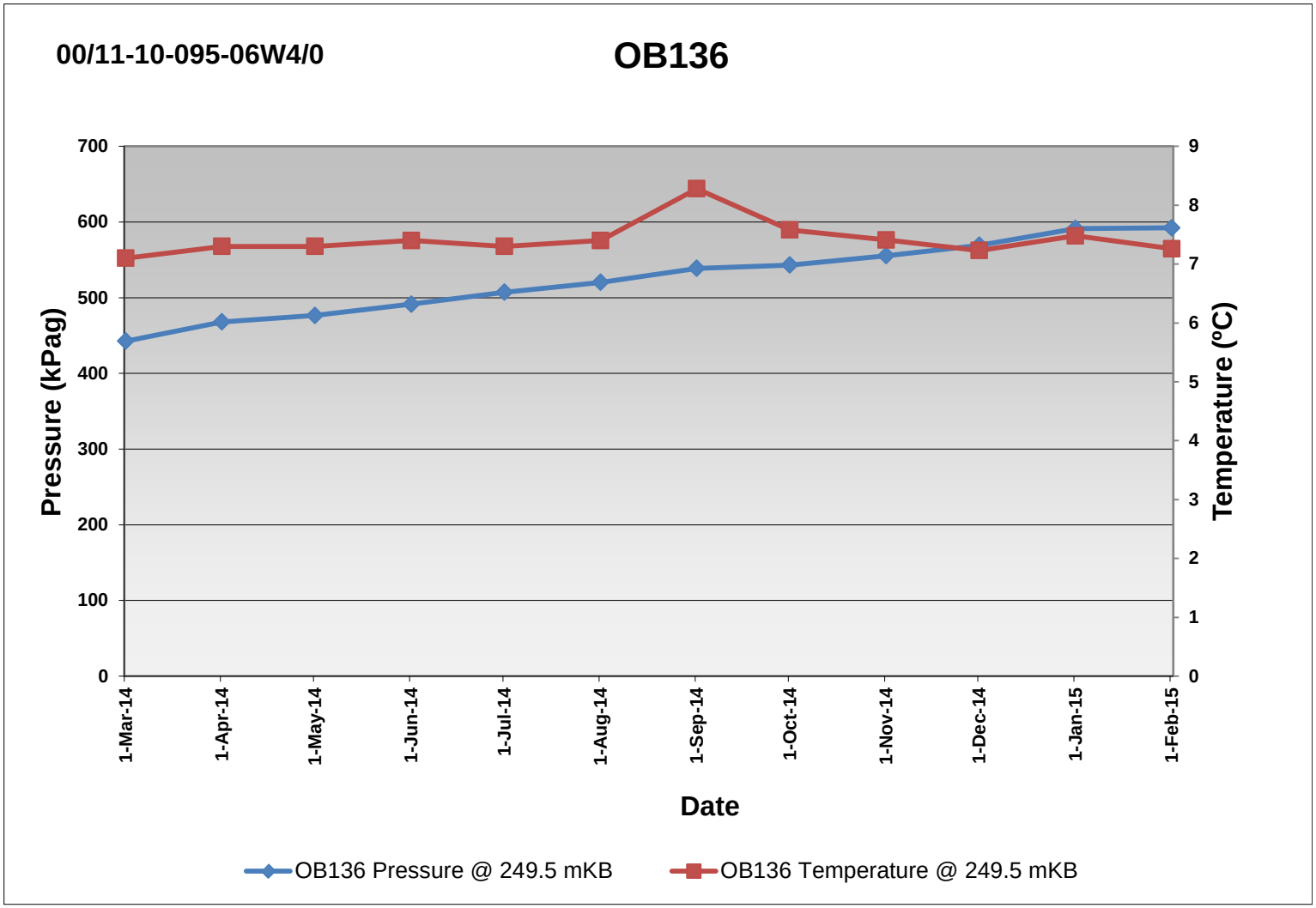
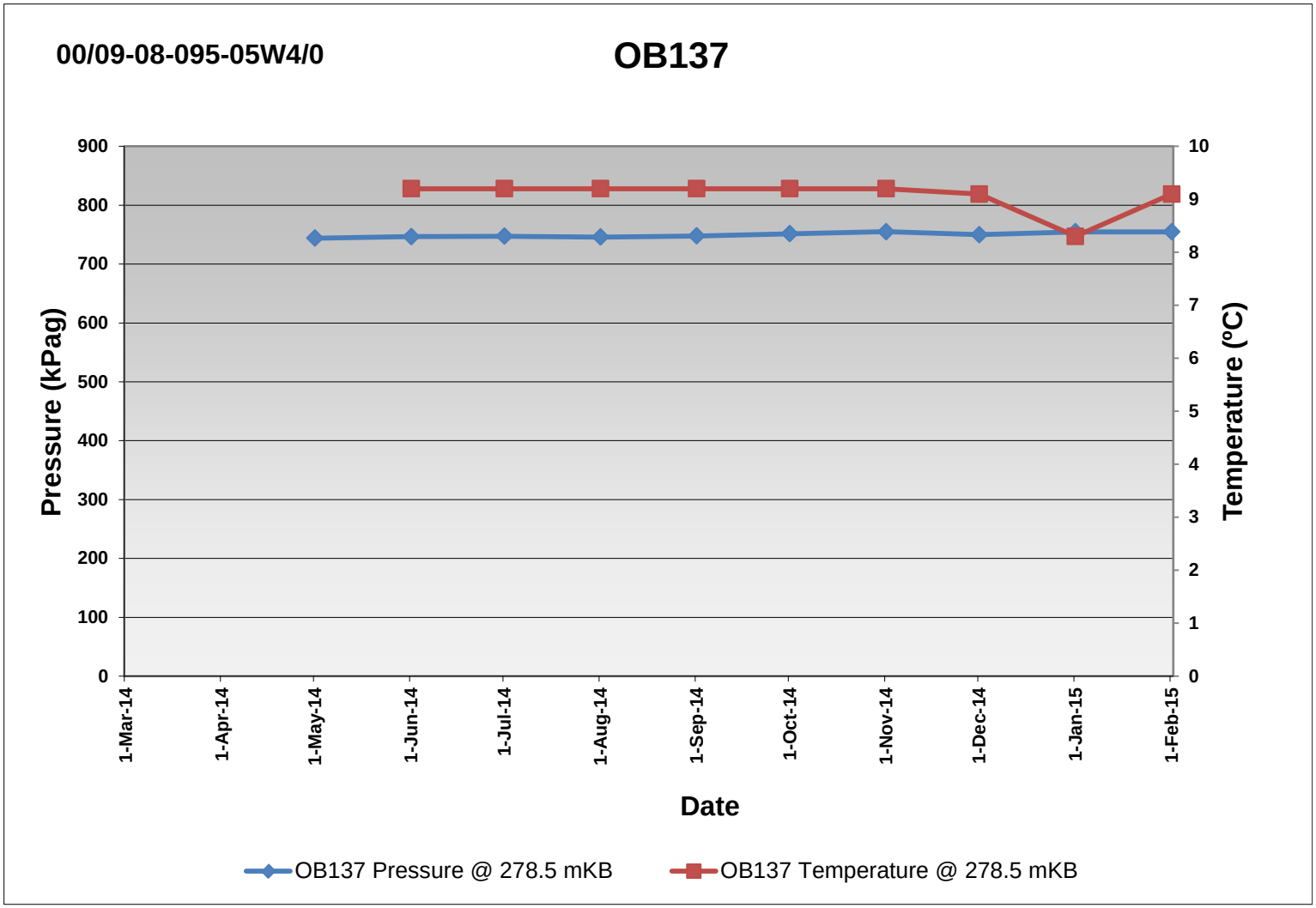


Piezometer Plots & Temperature vs Depth Plots



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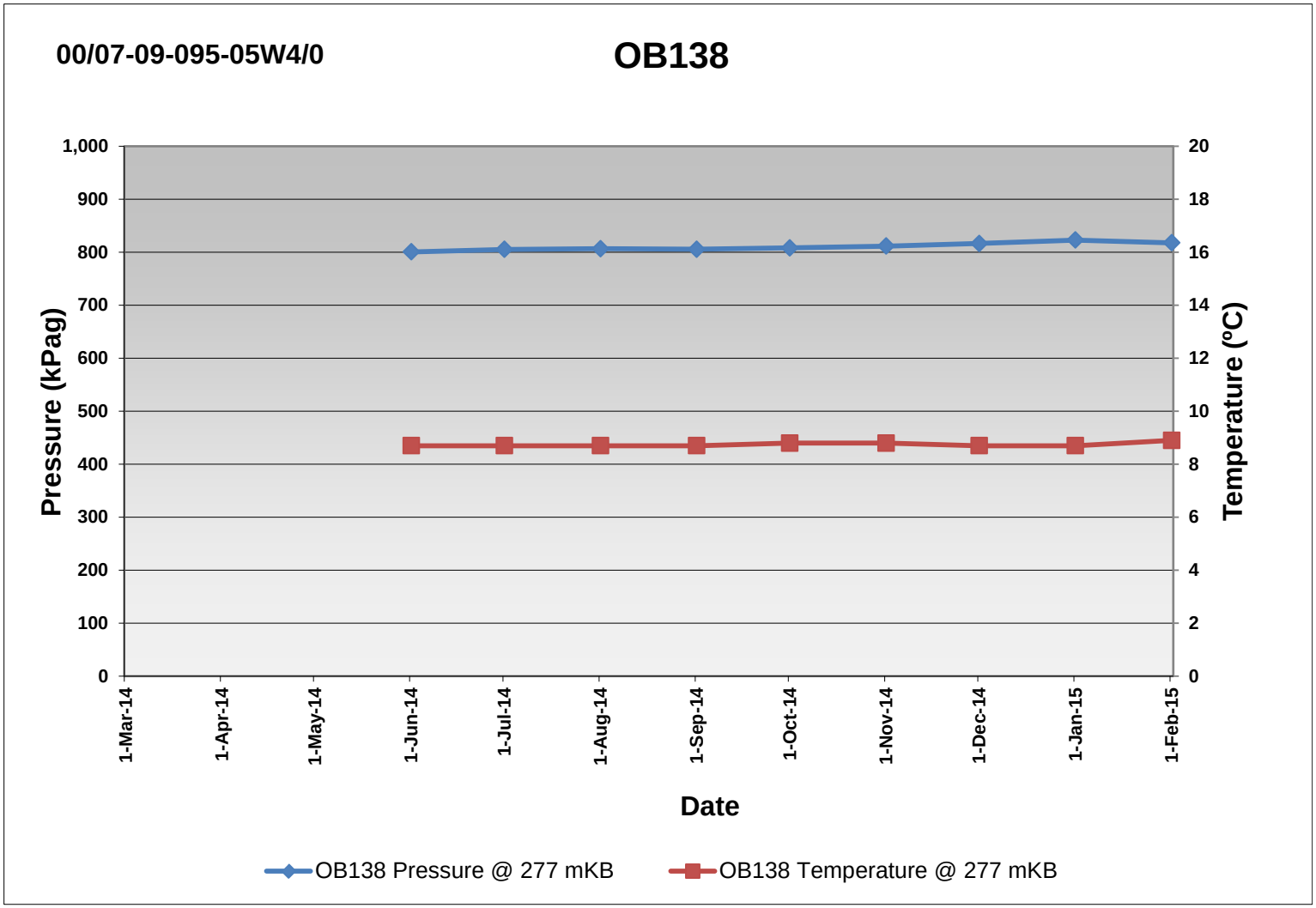

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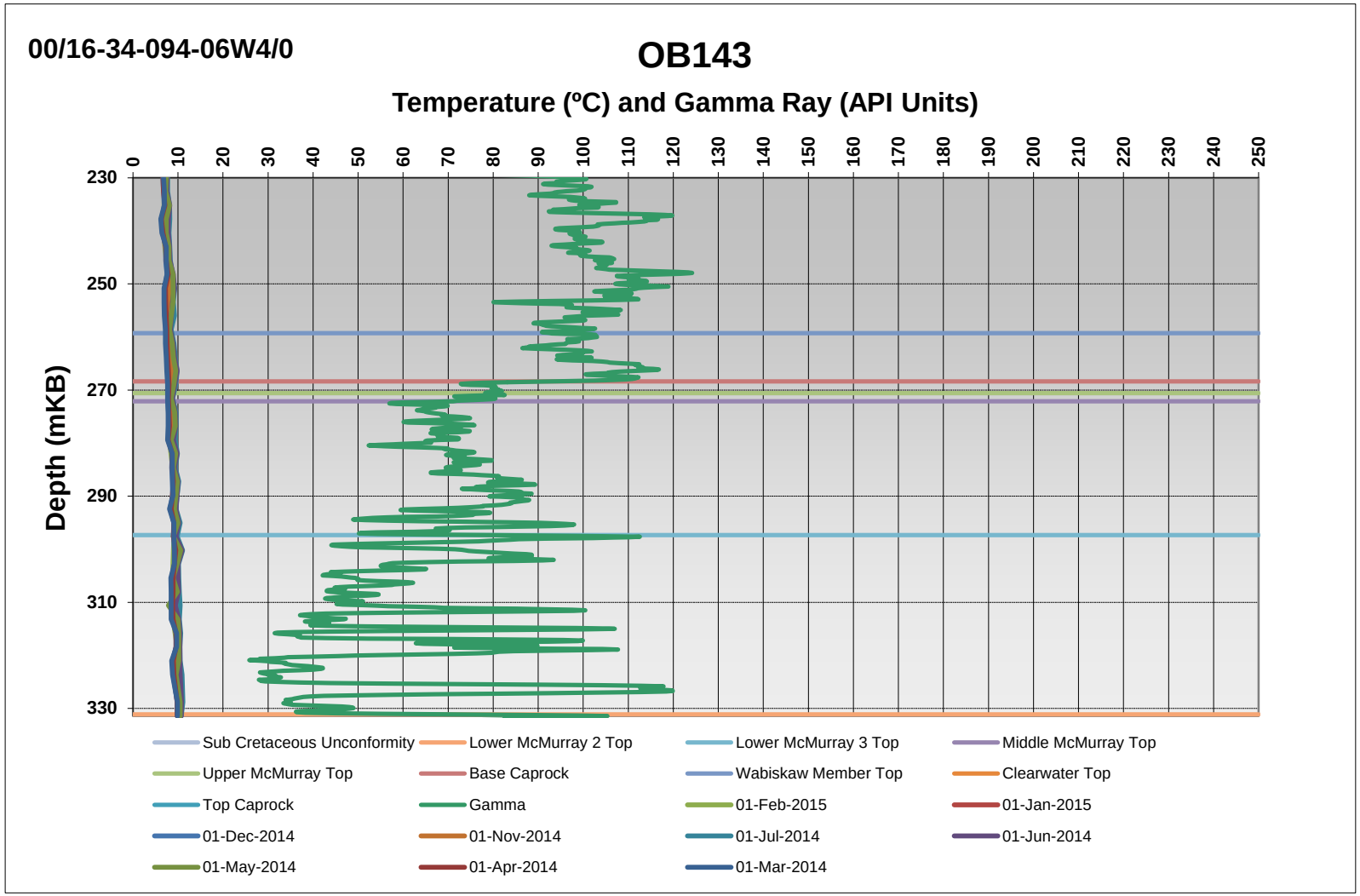

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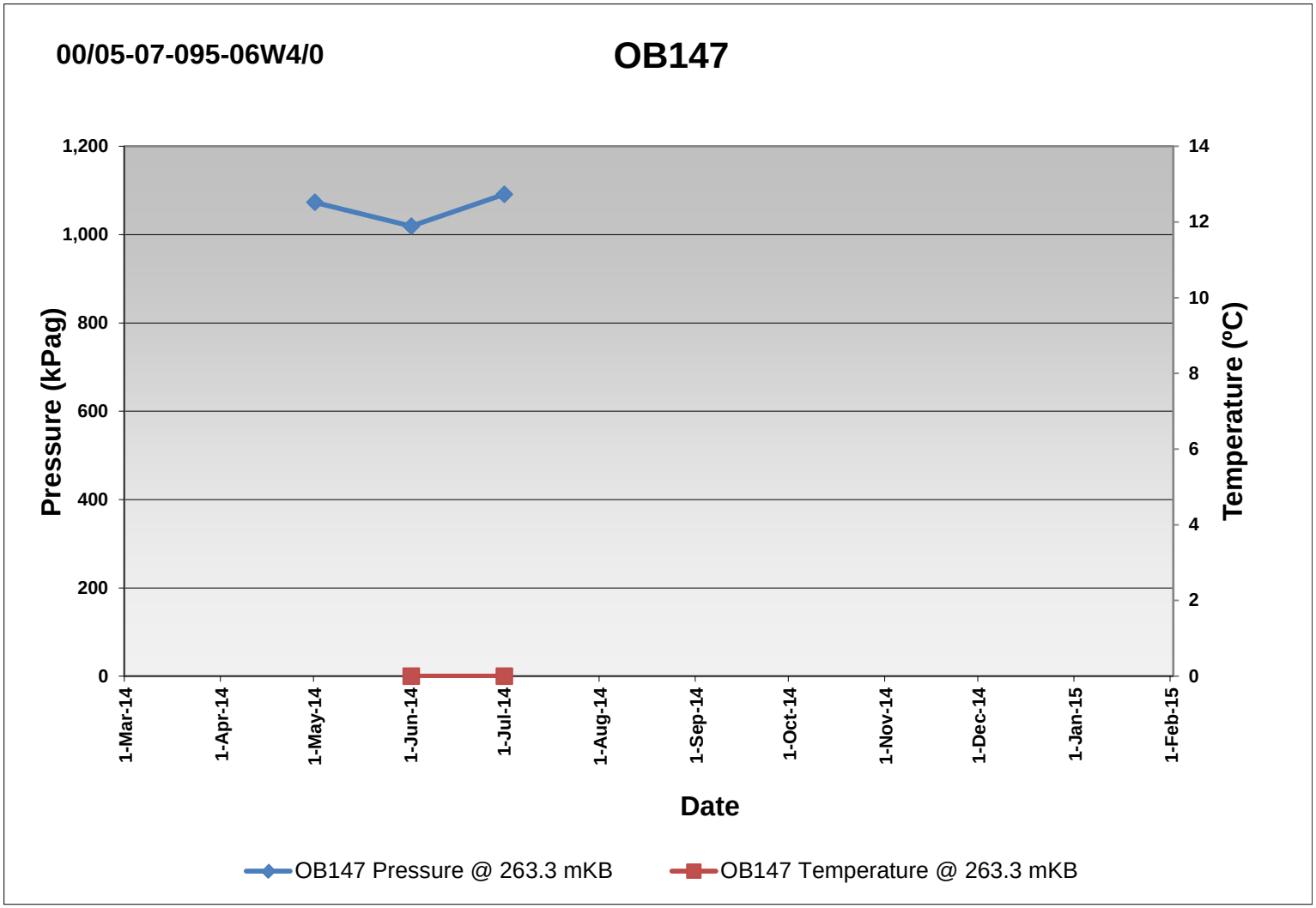

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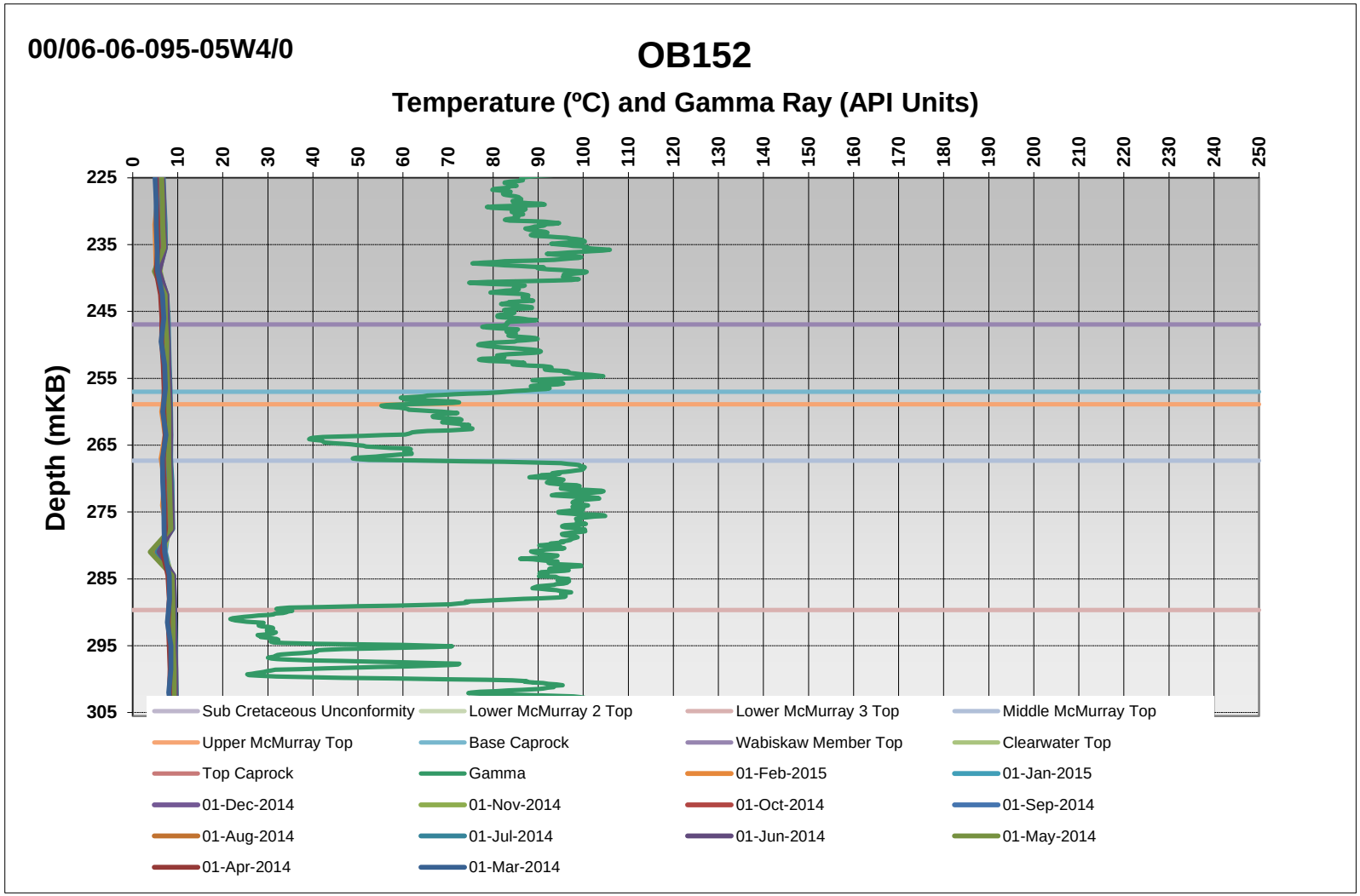

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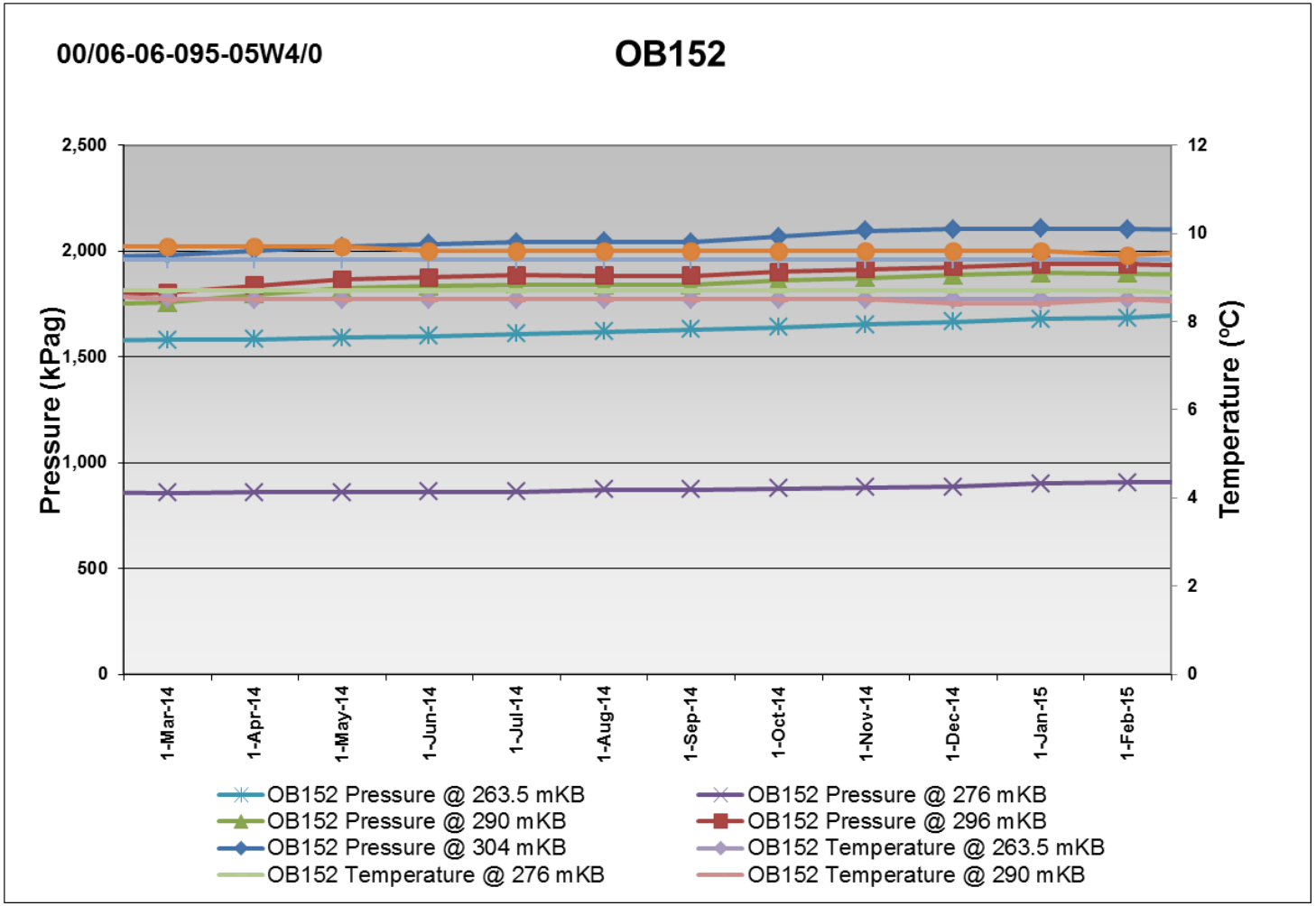

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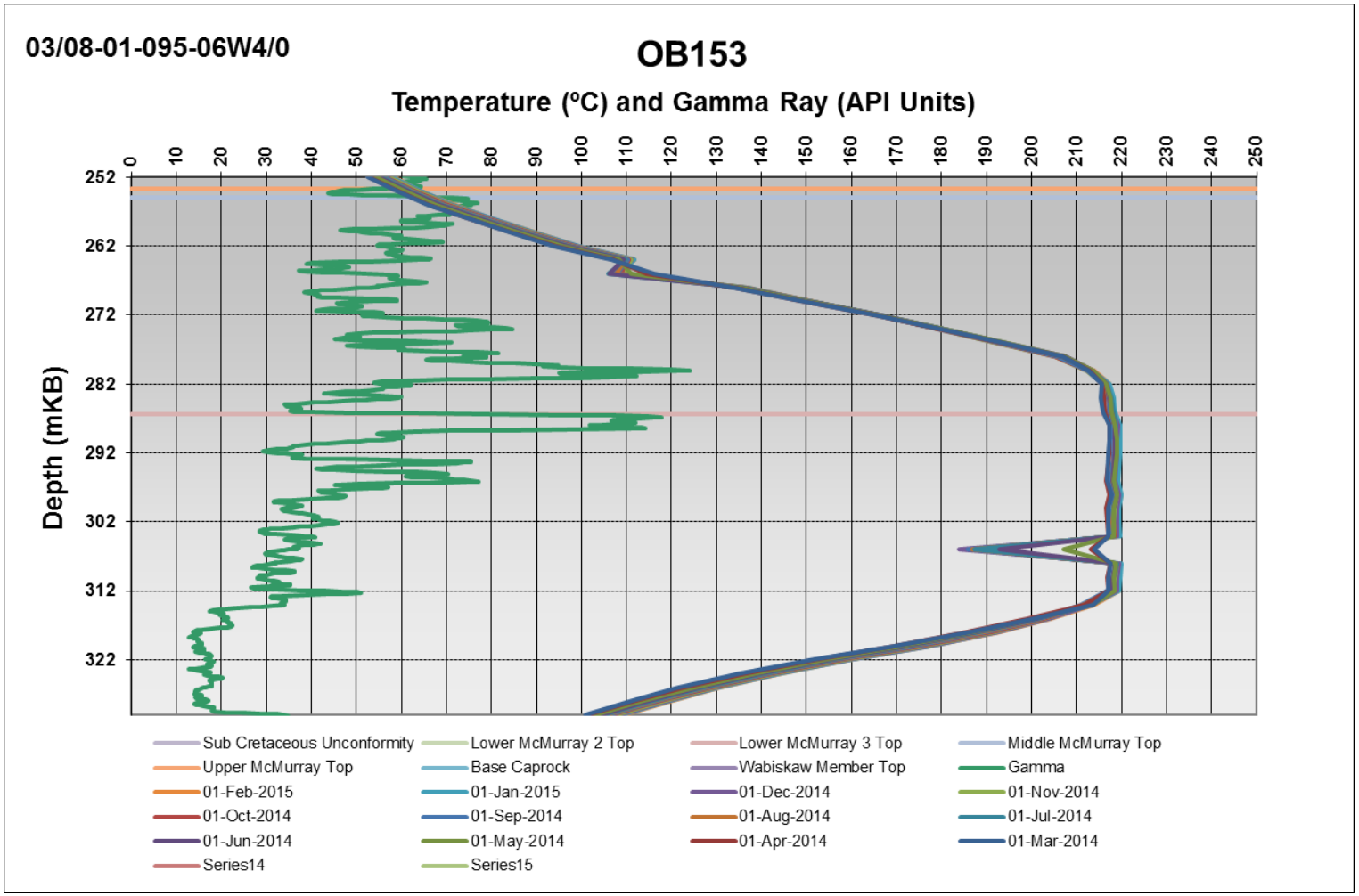

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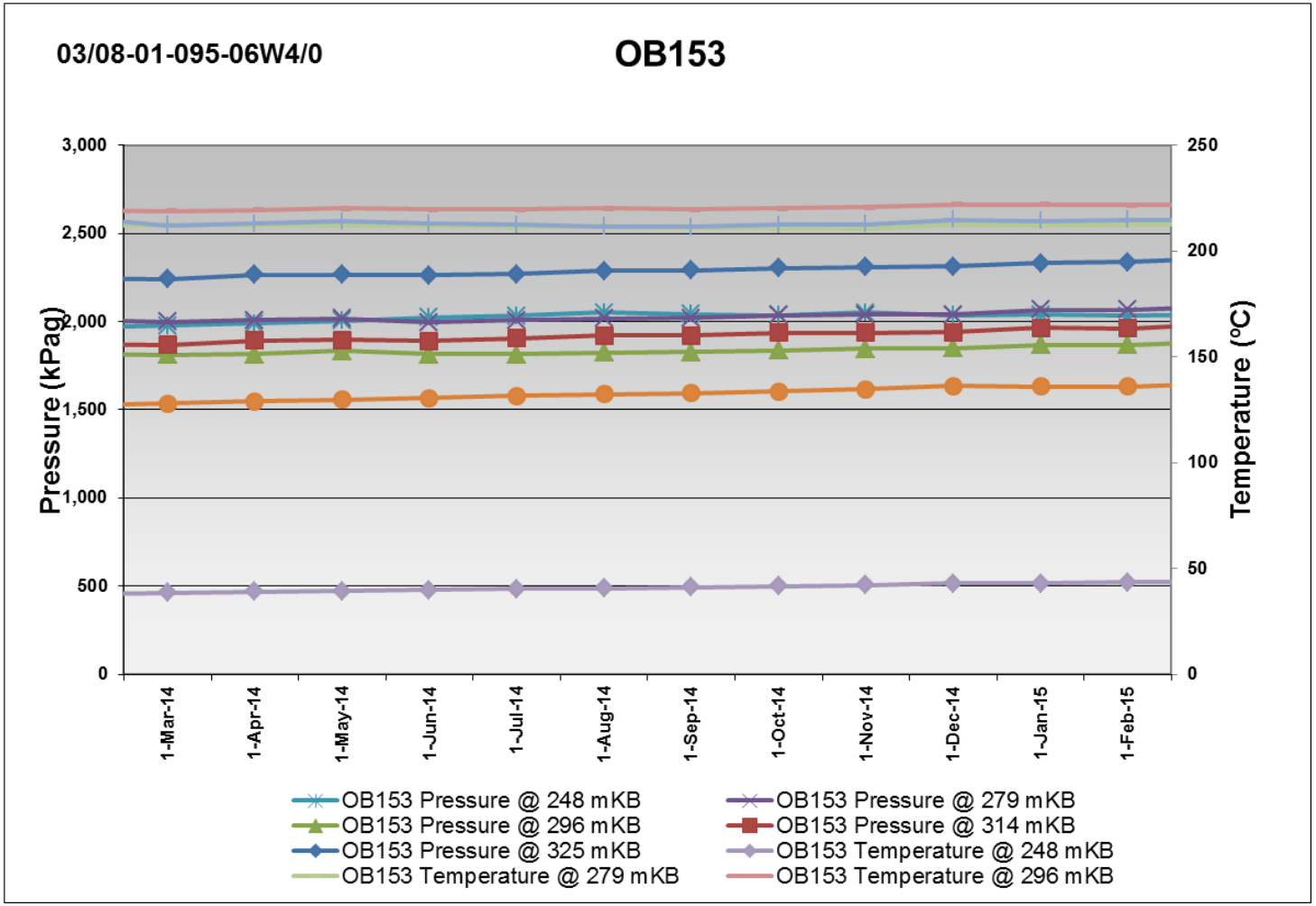

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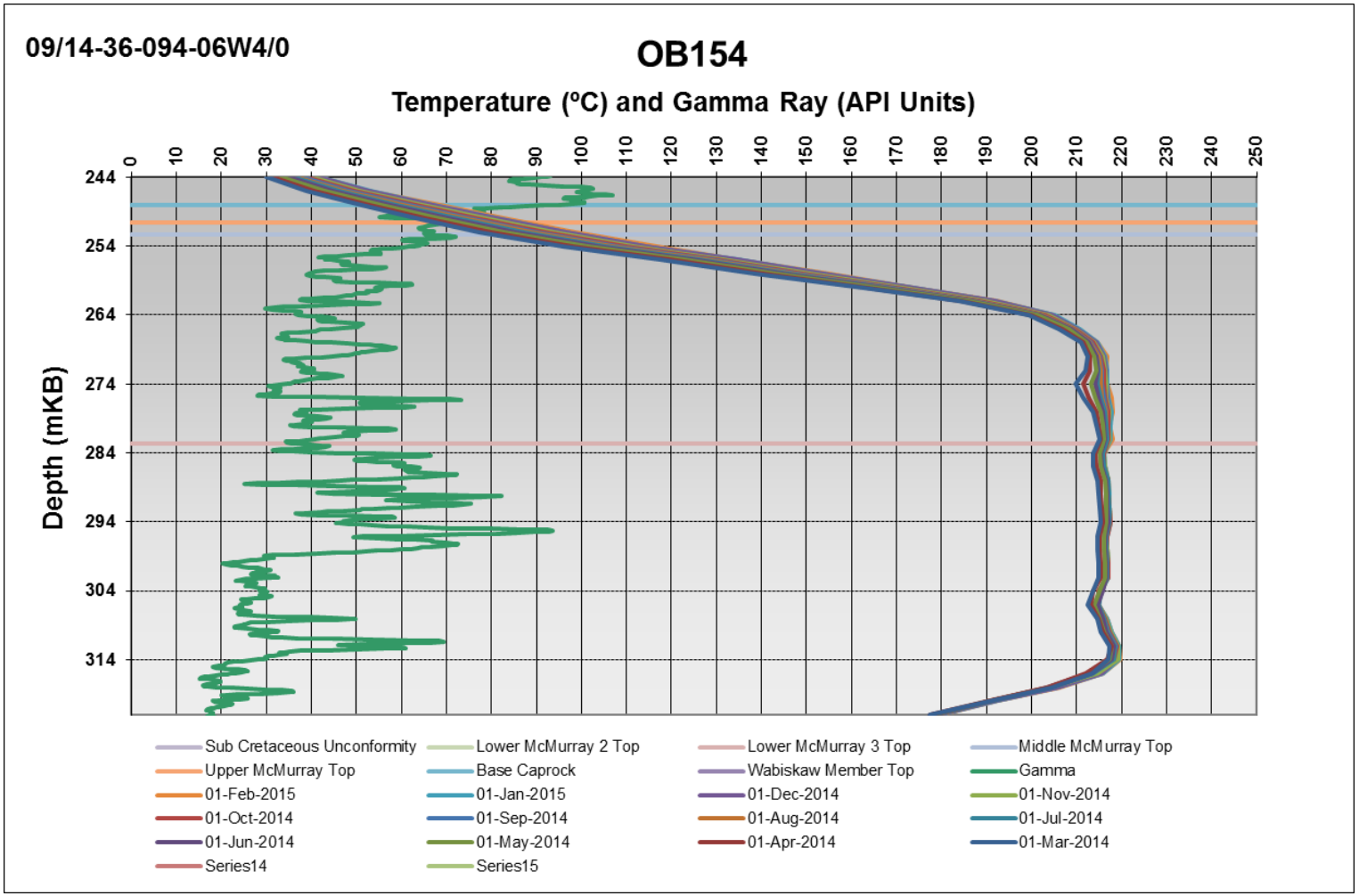

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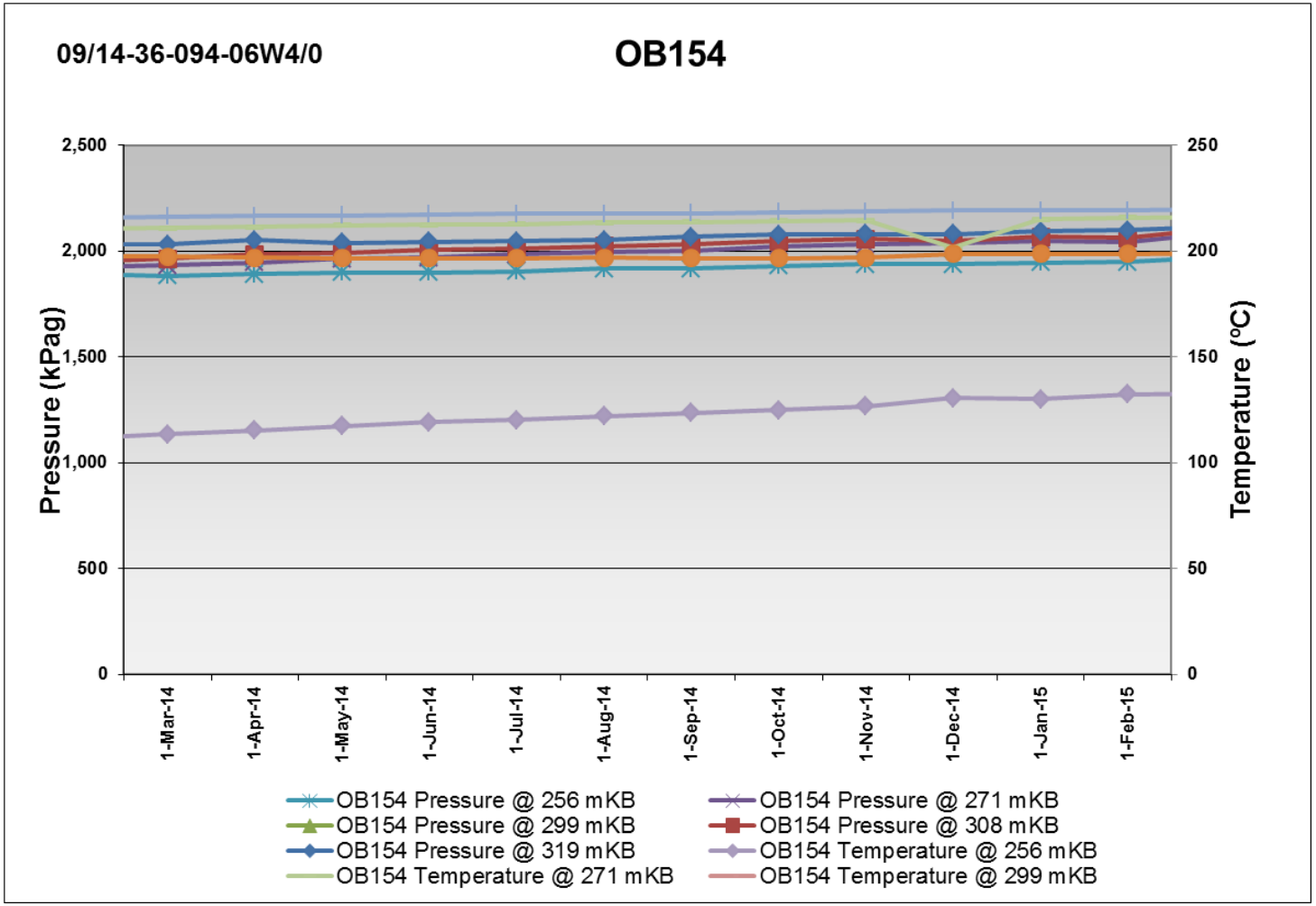

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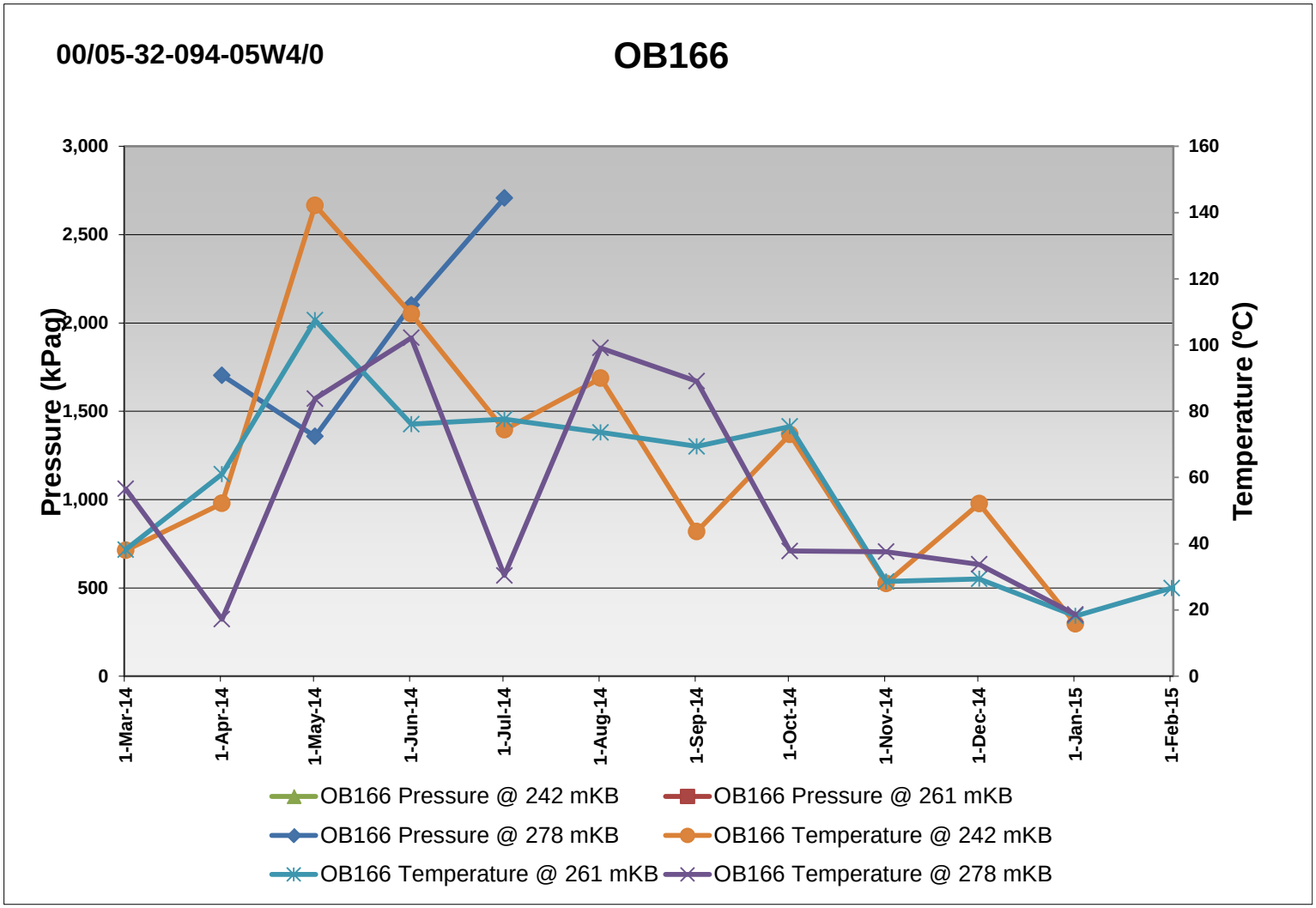

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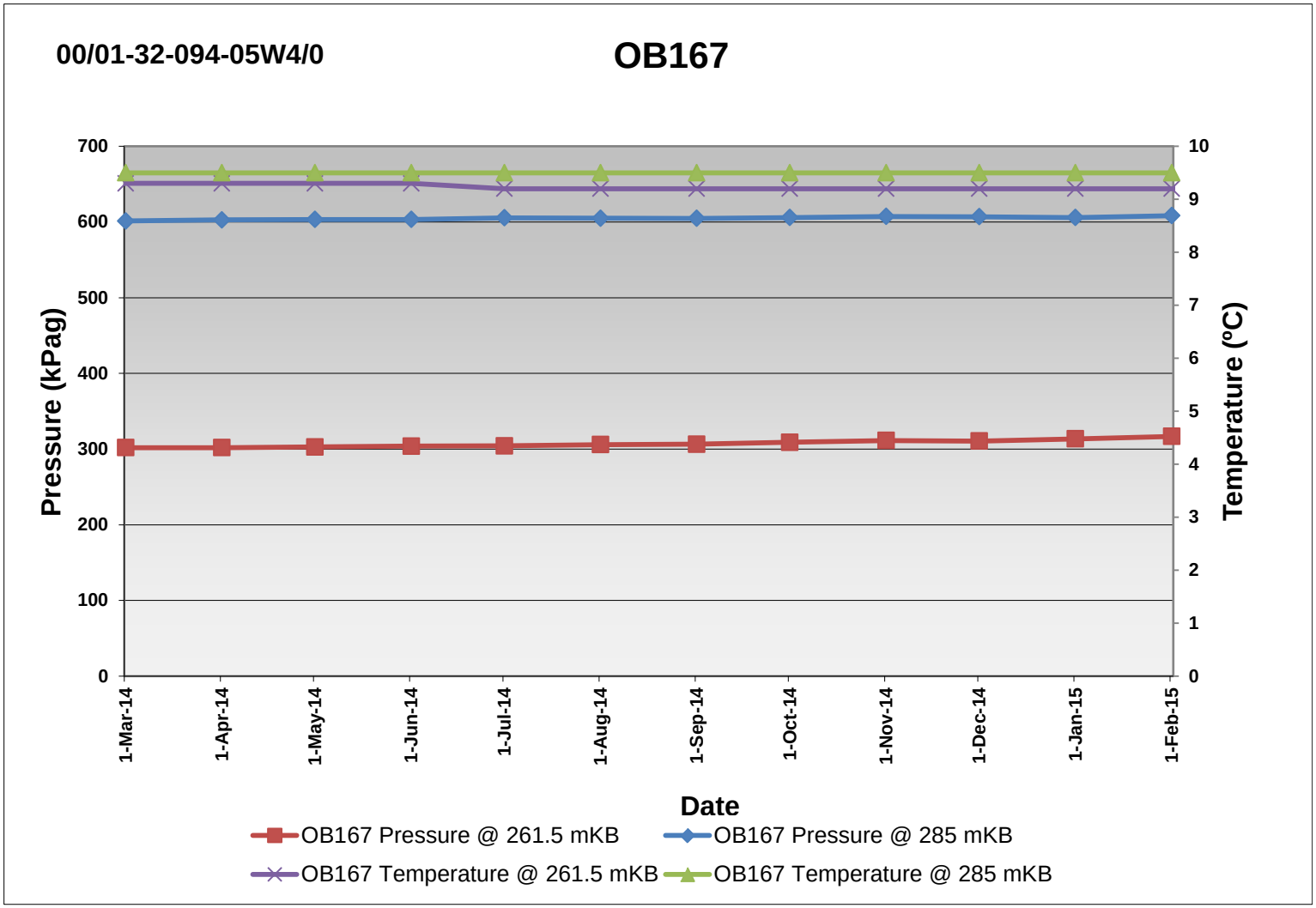

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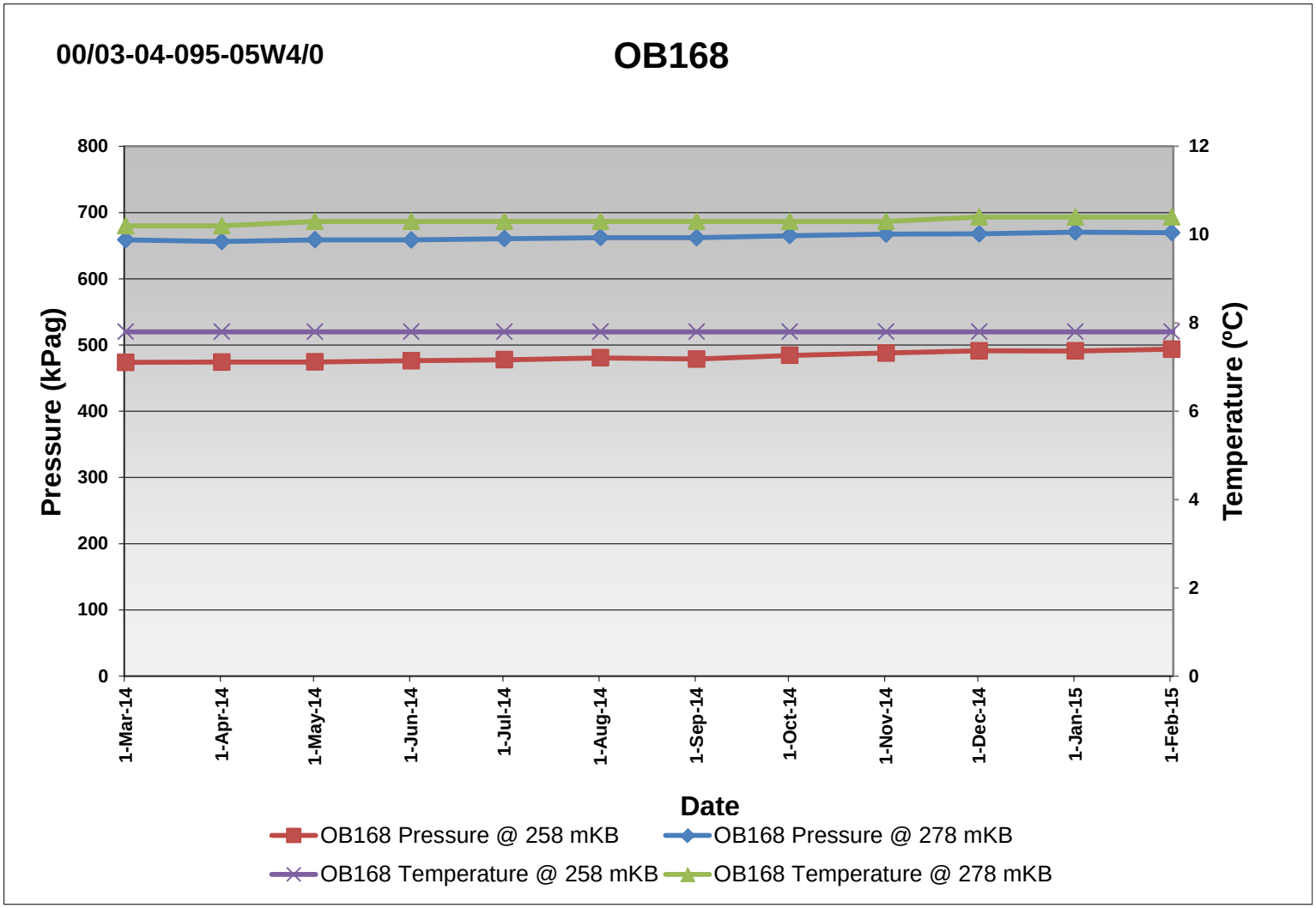

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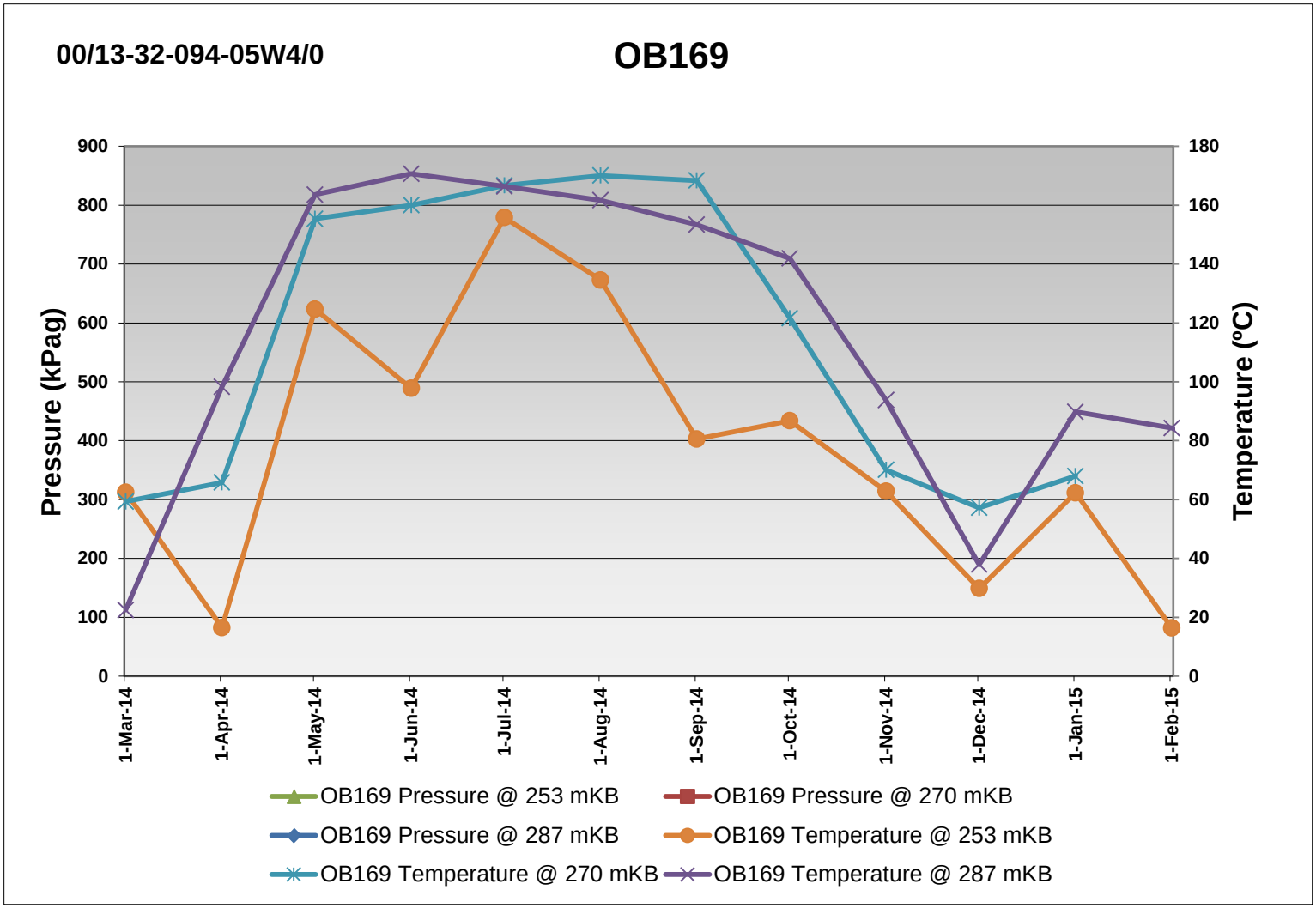

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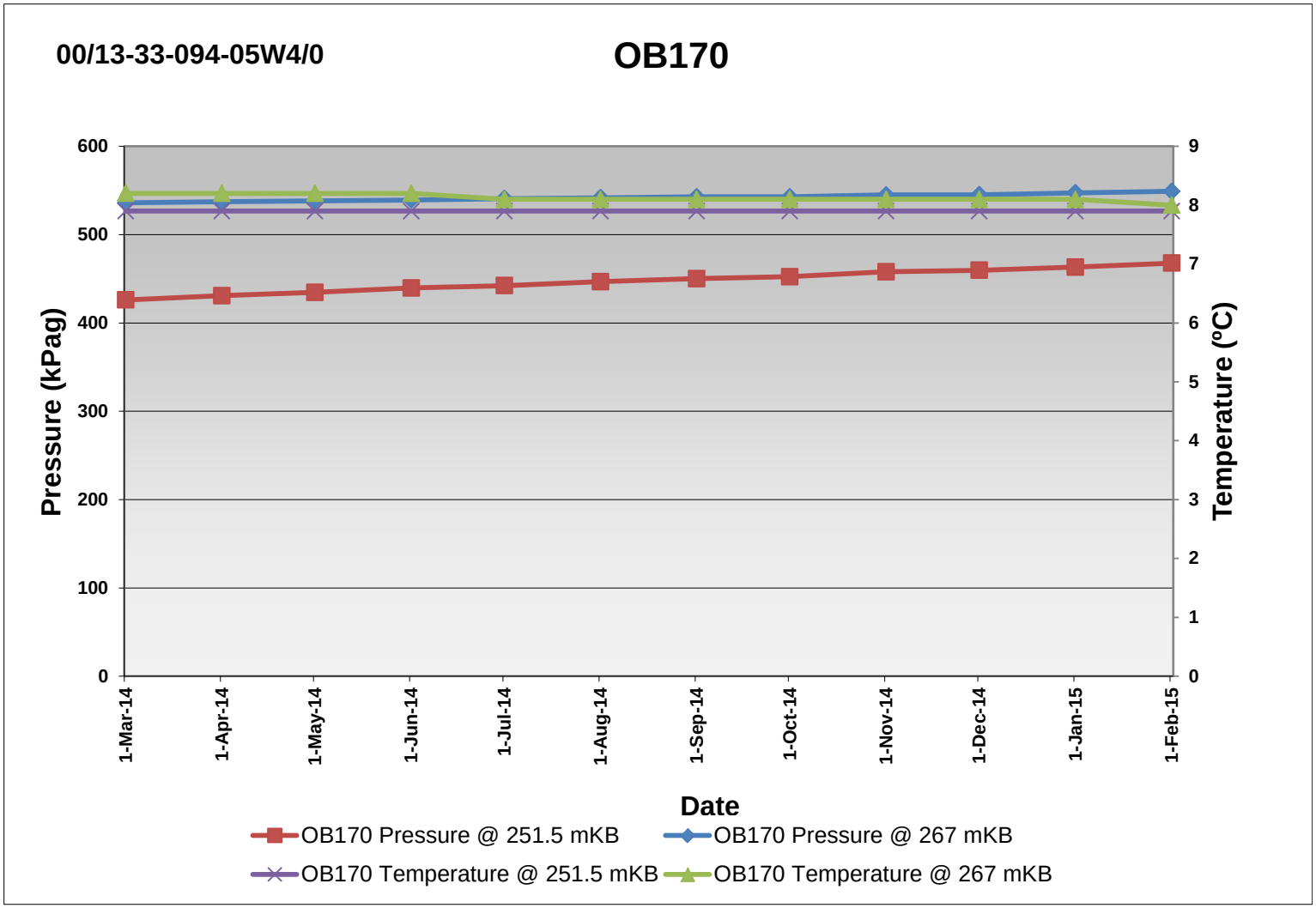

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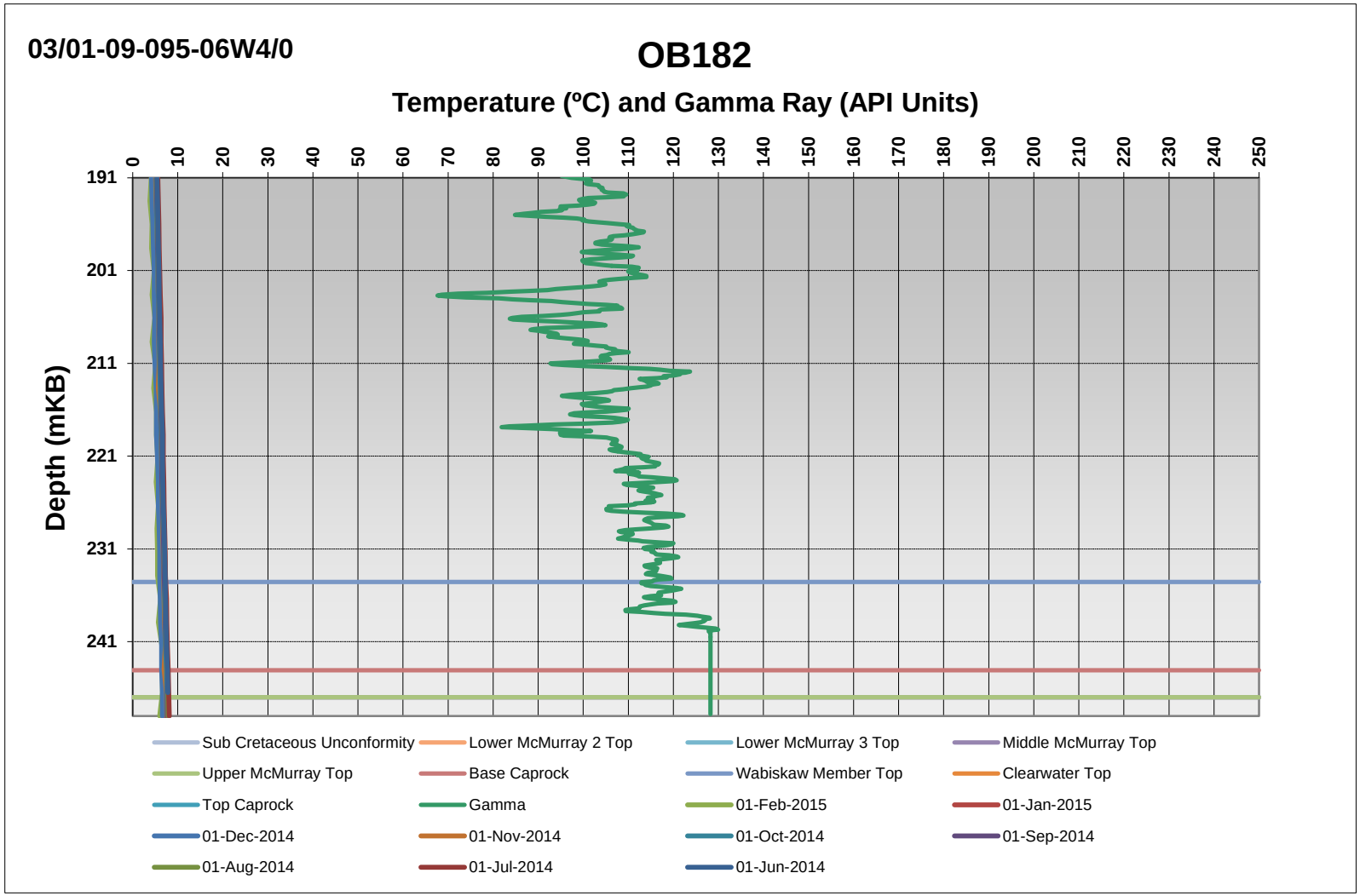

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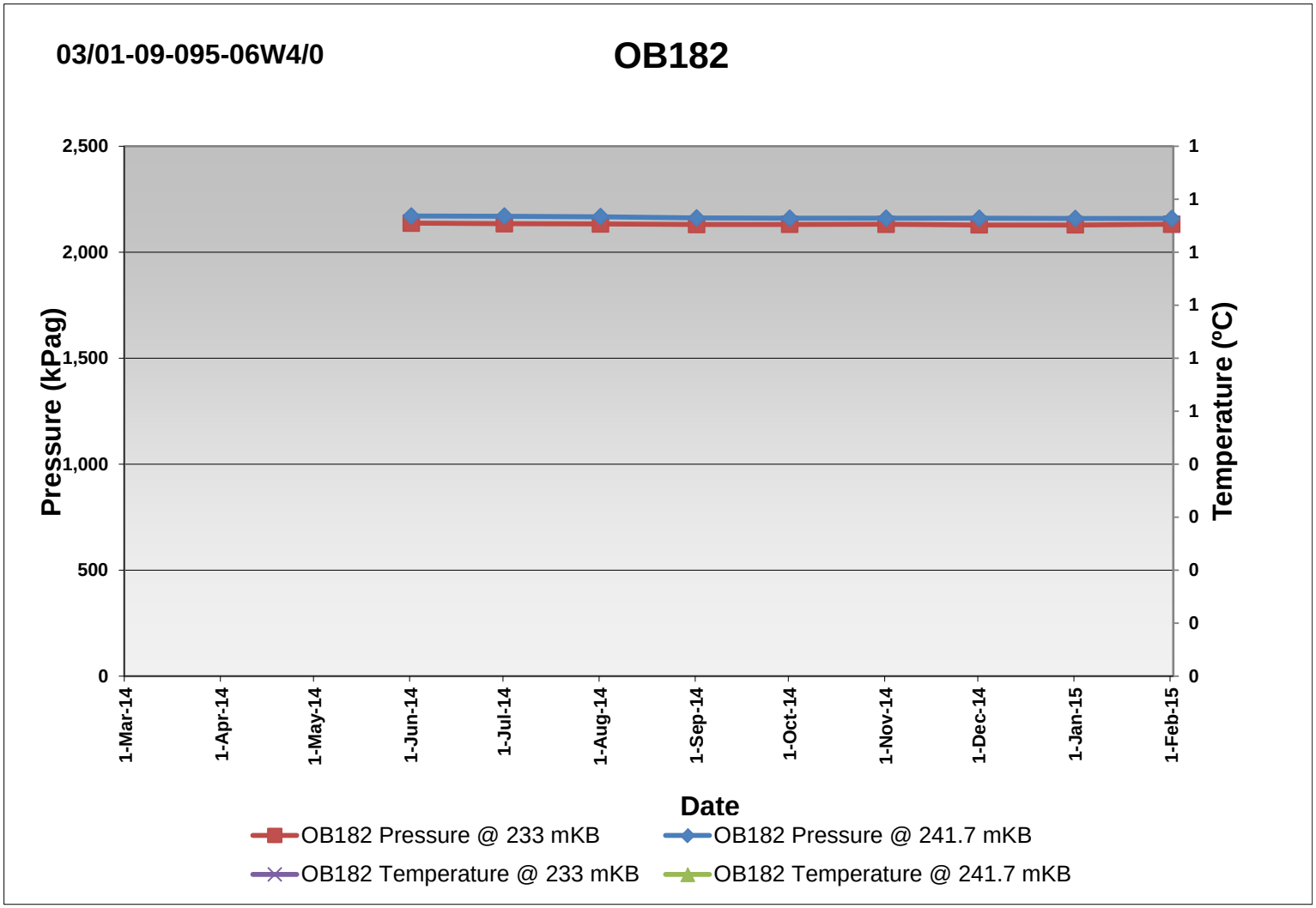

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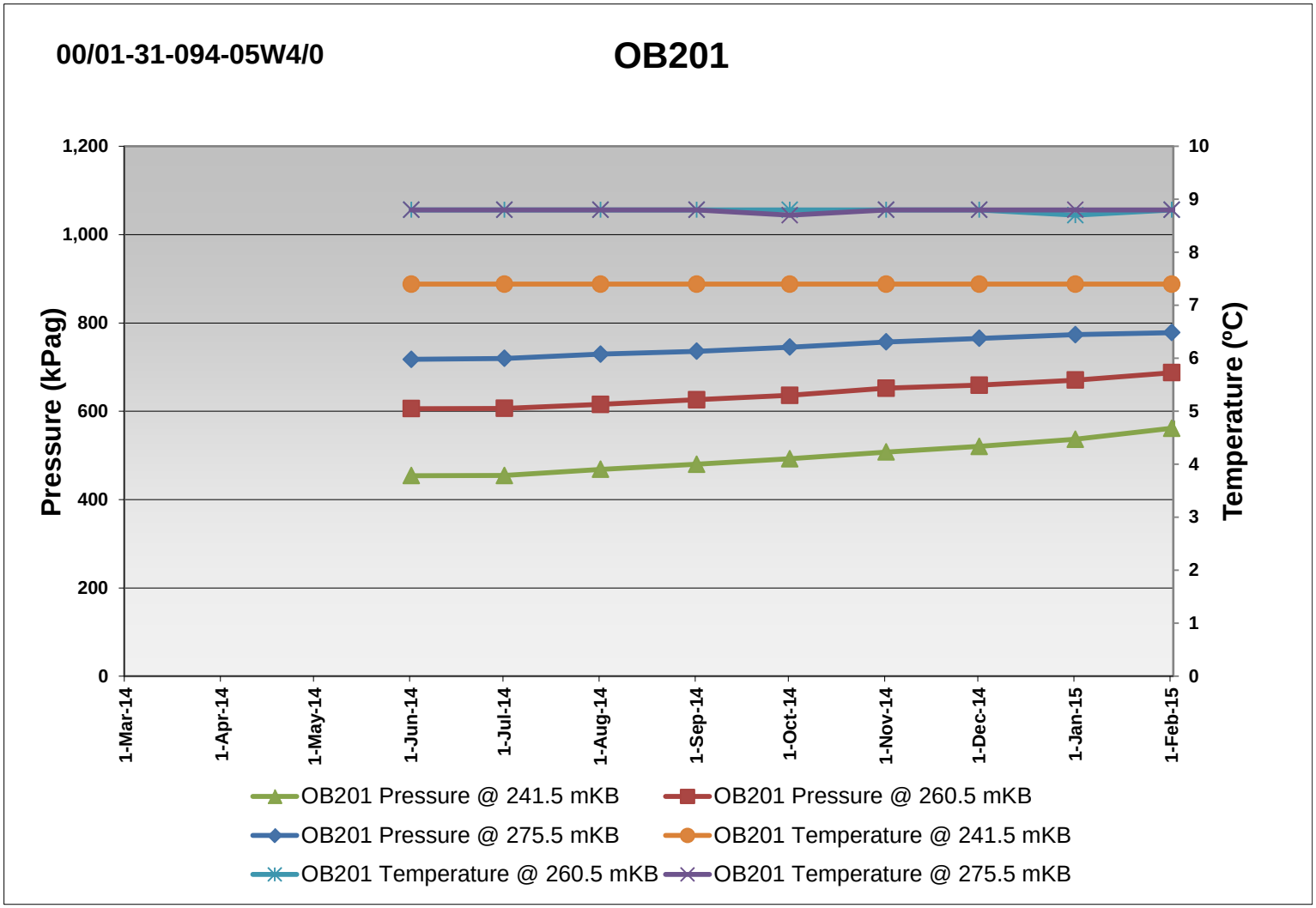

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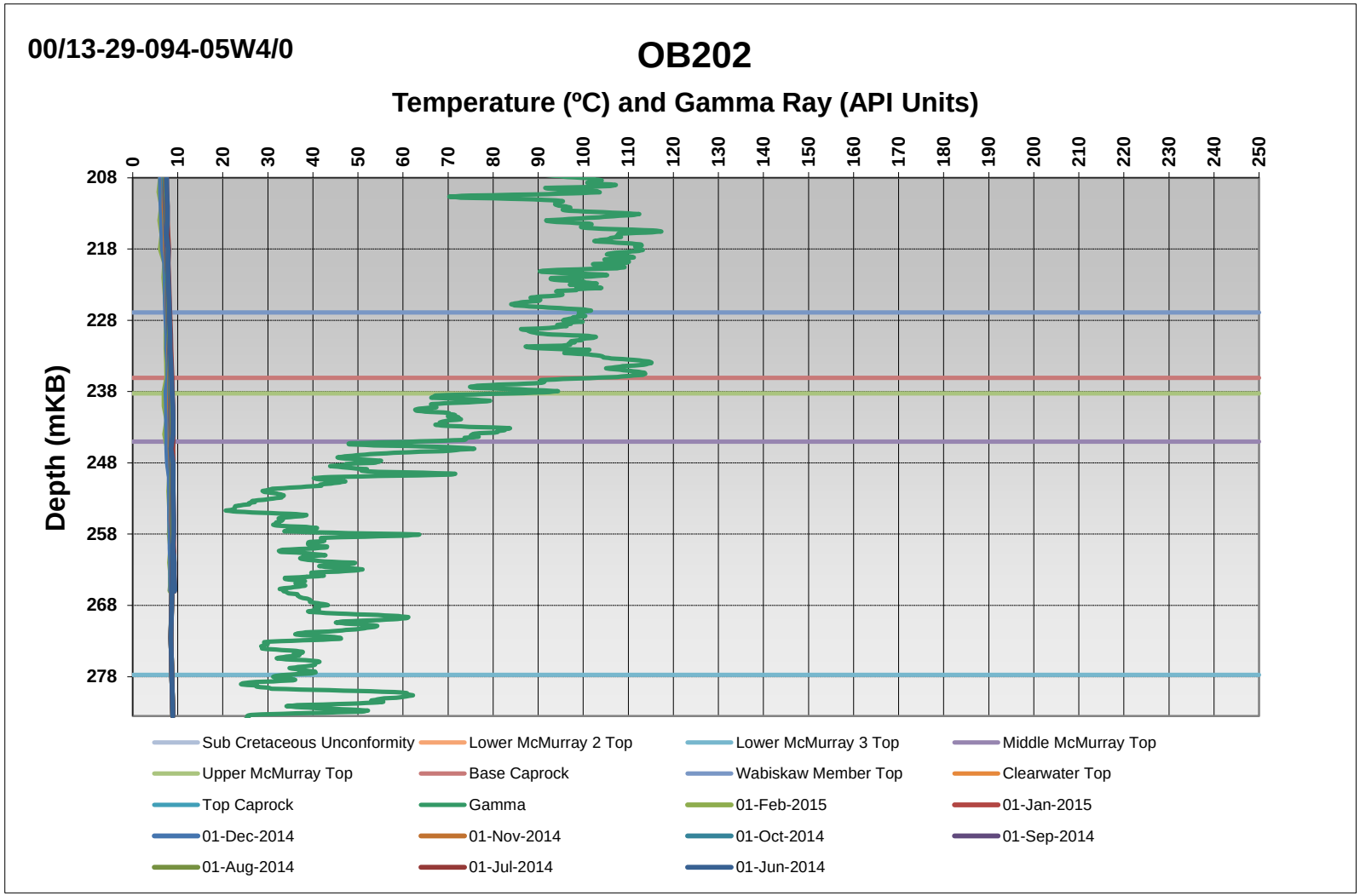

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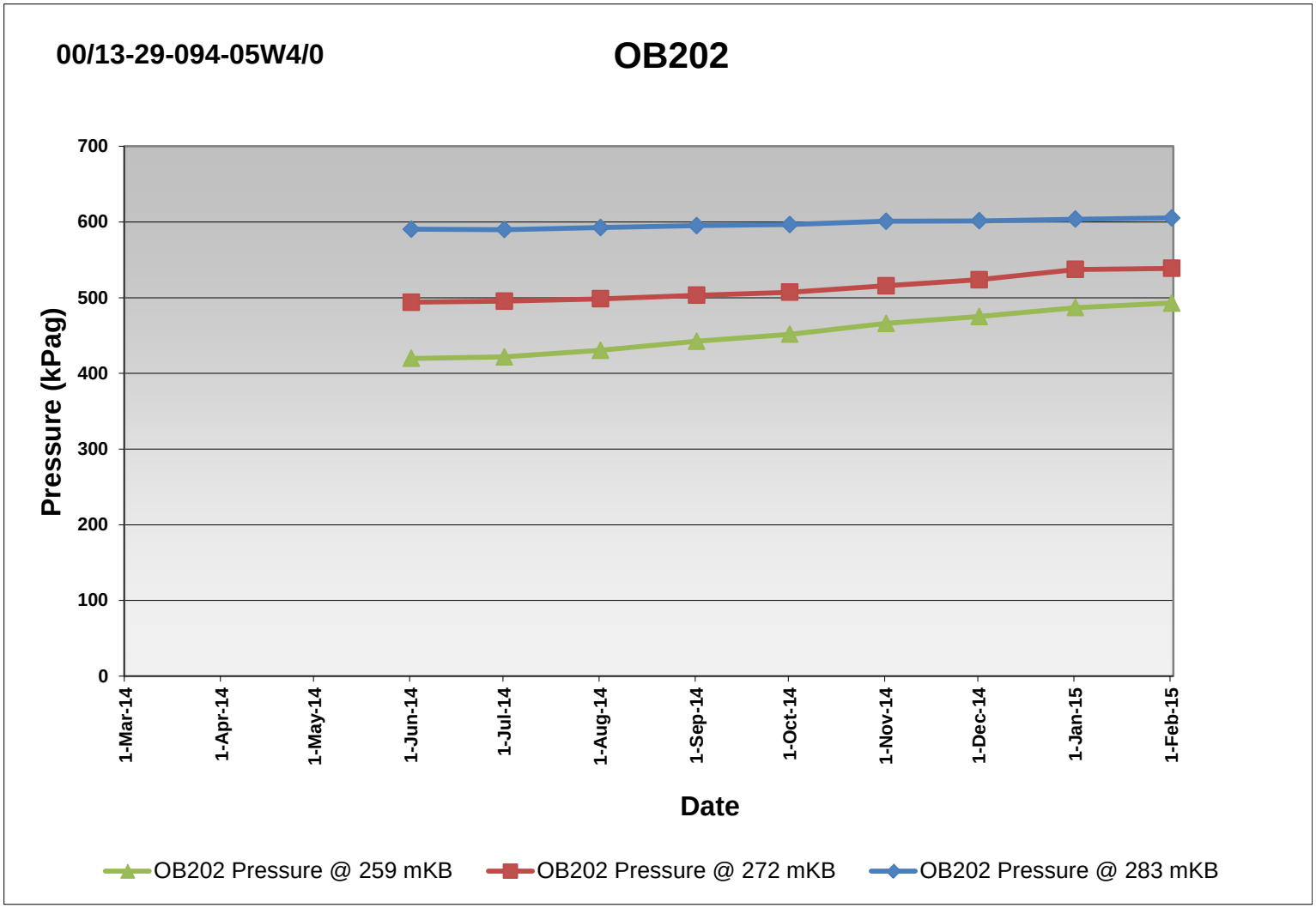

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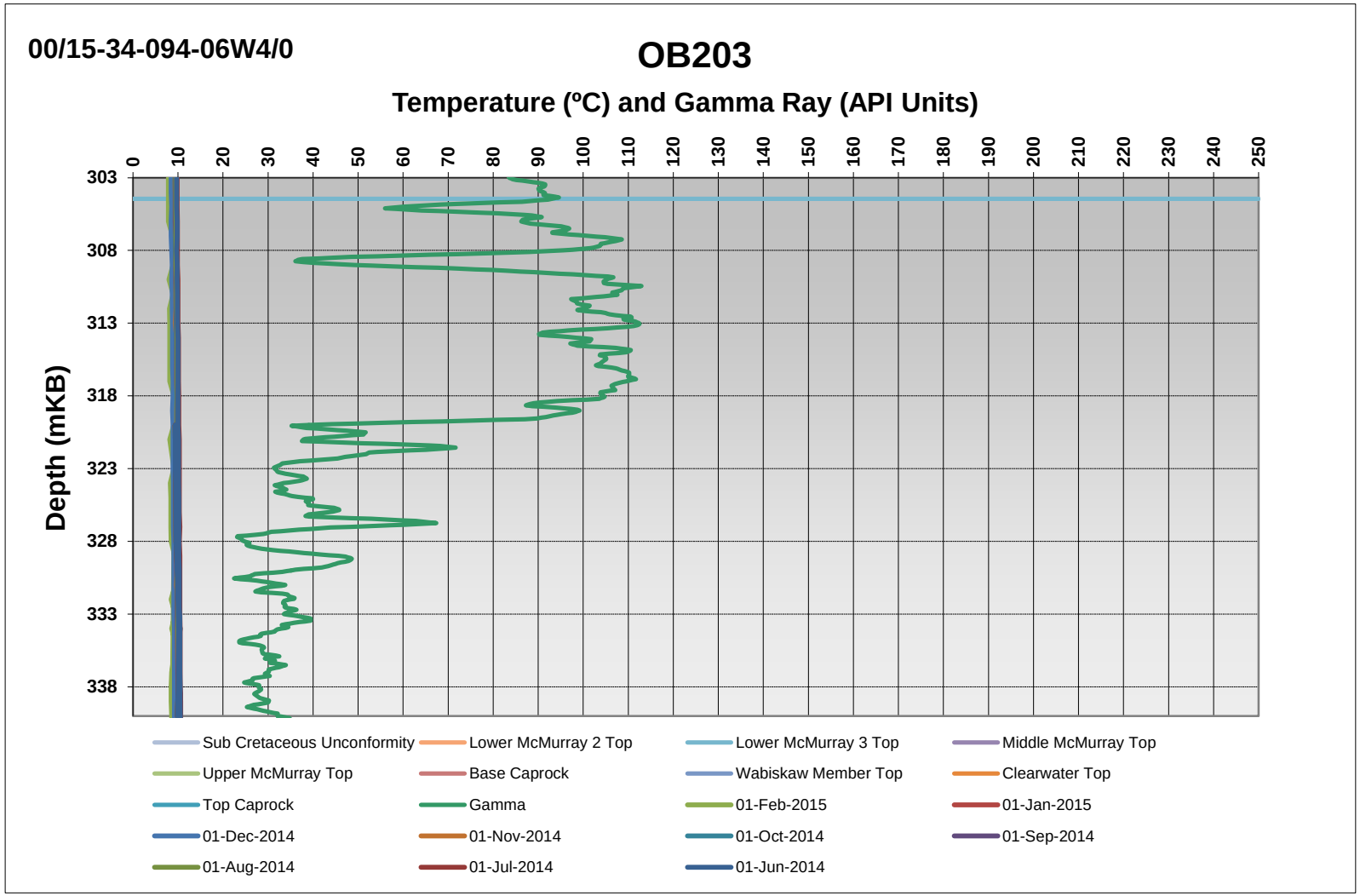

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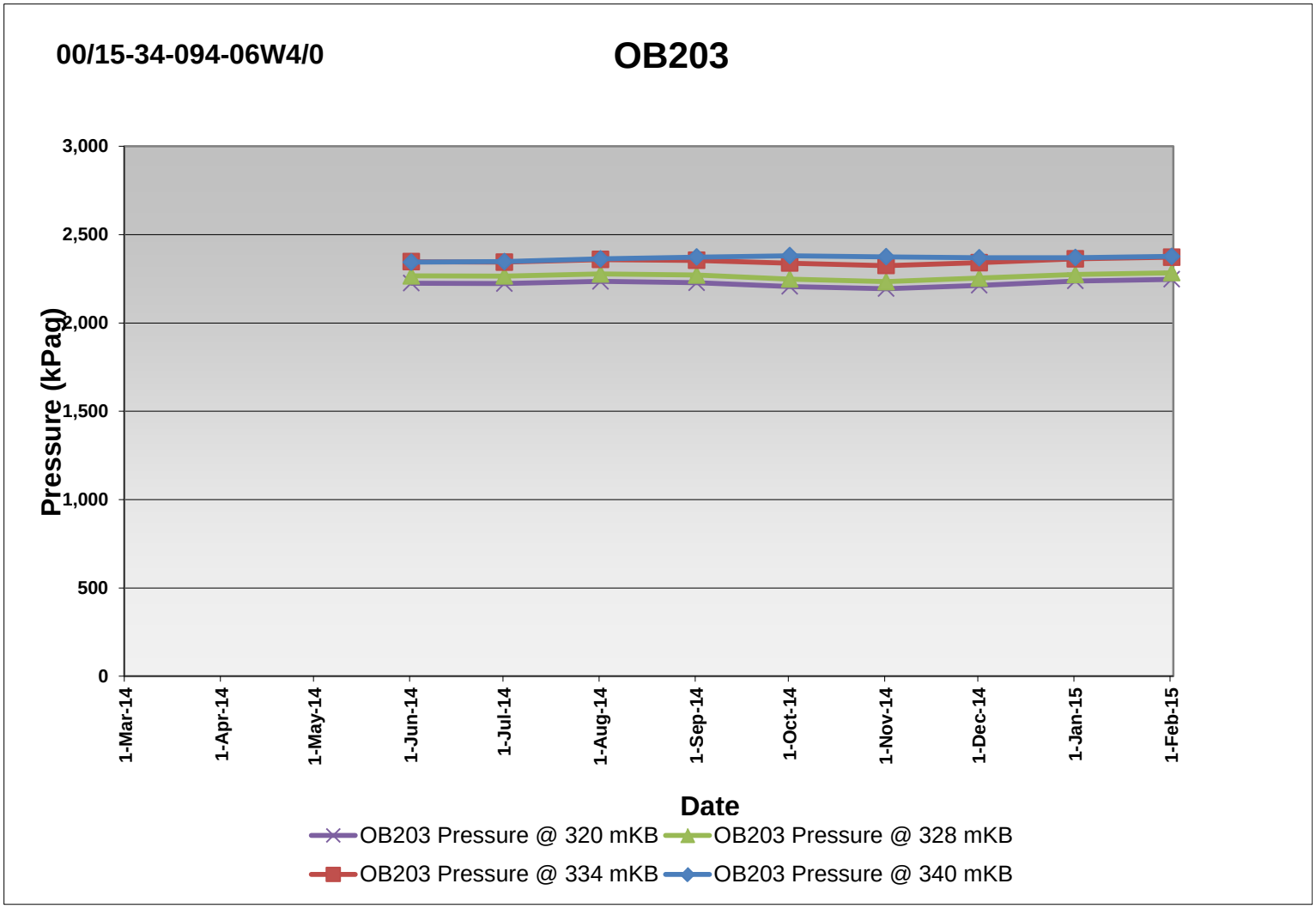

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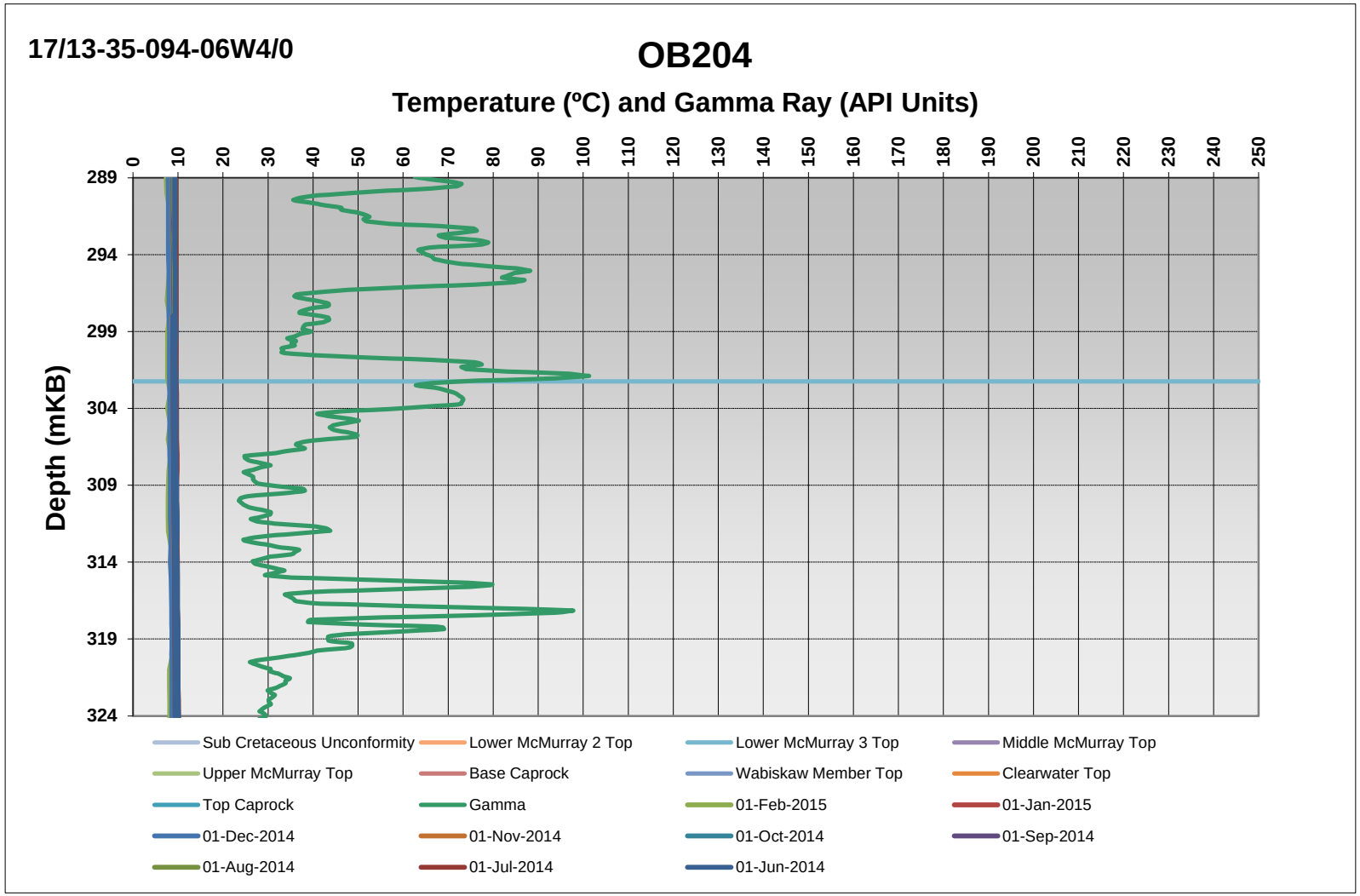

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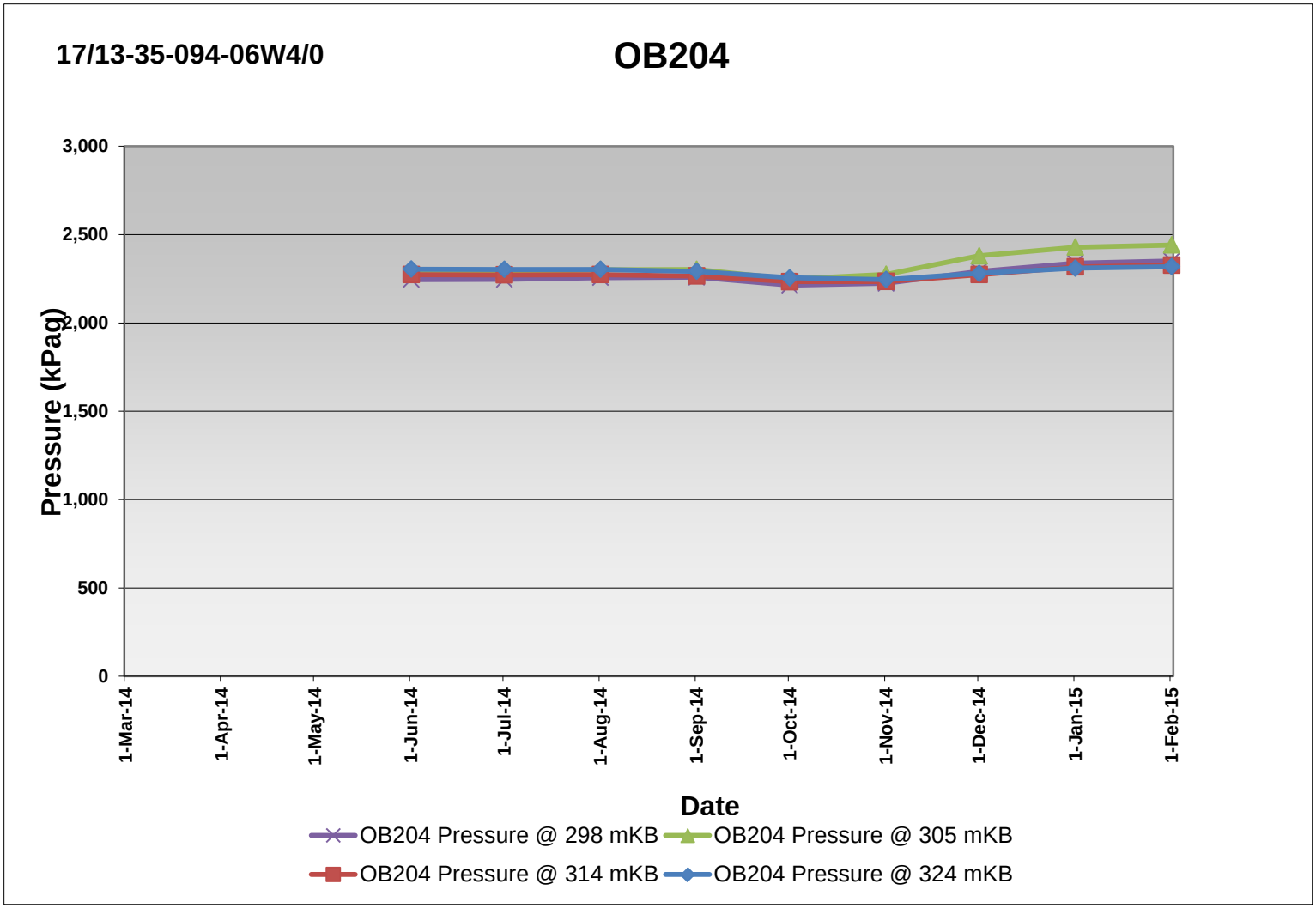

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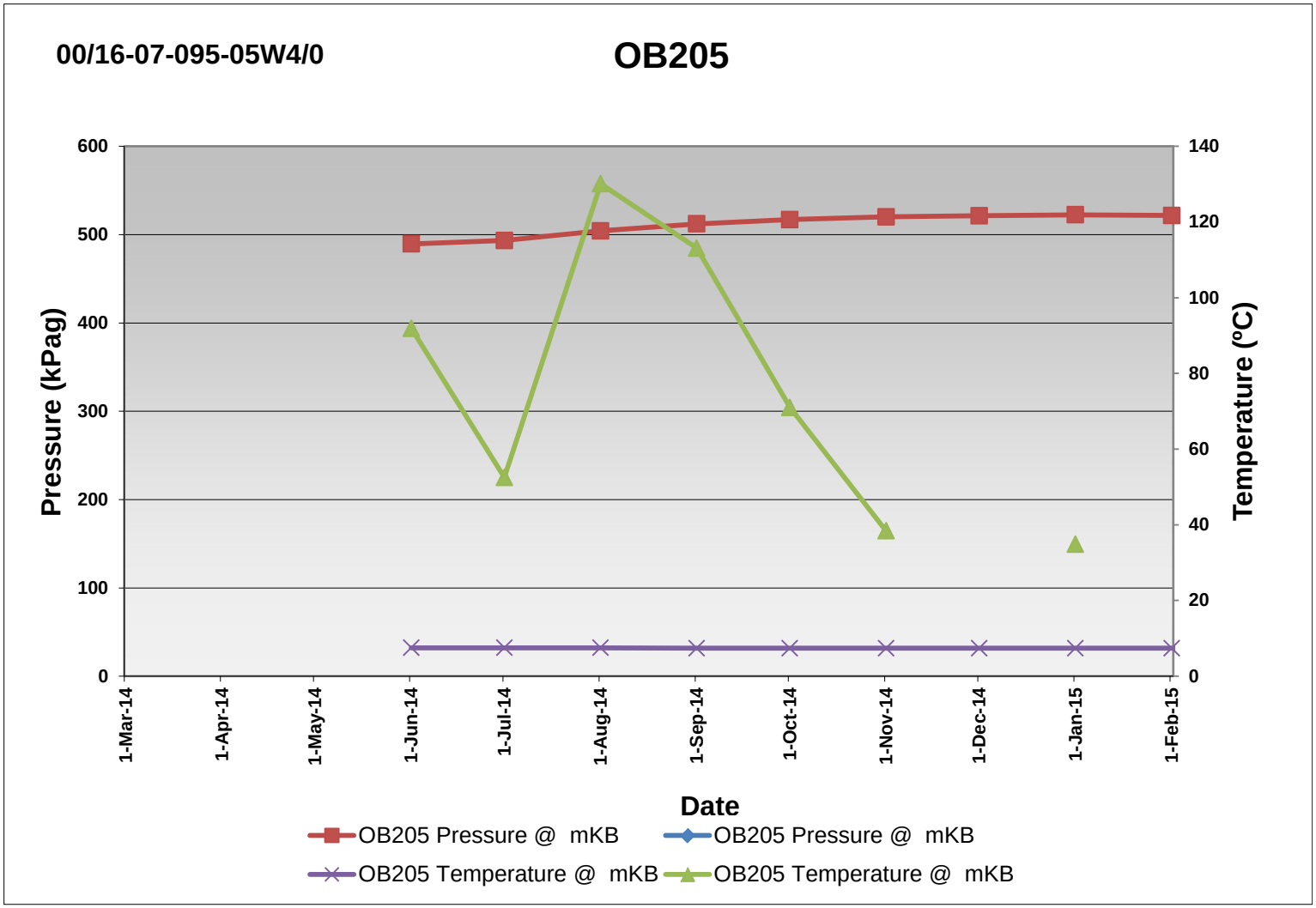

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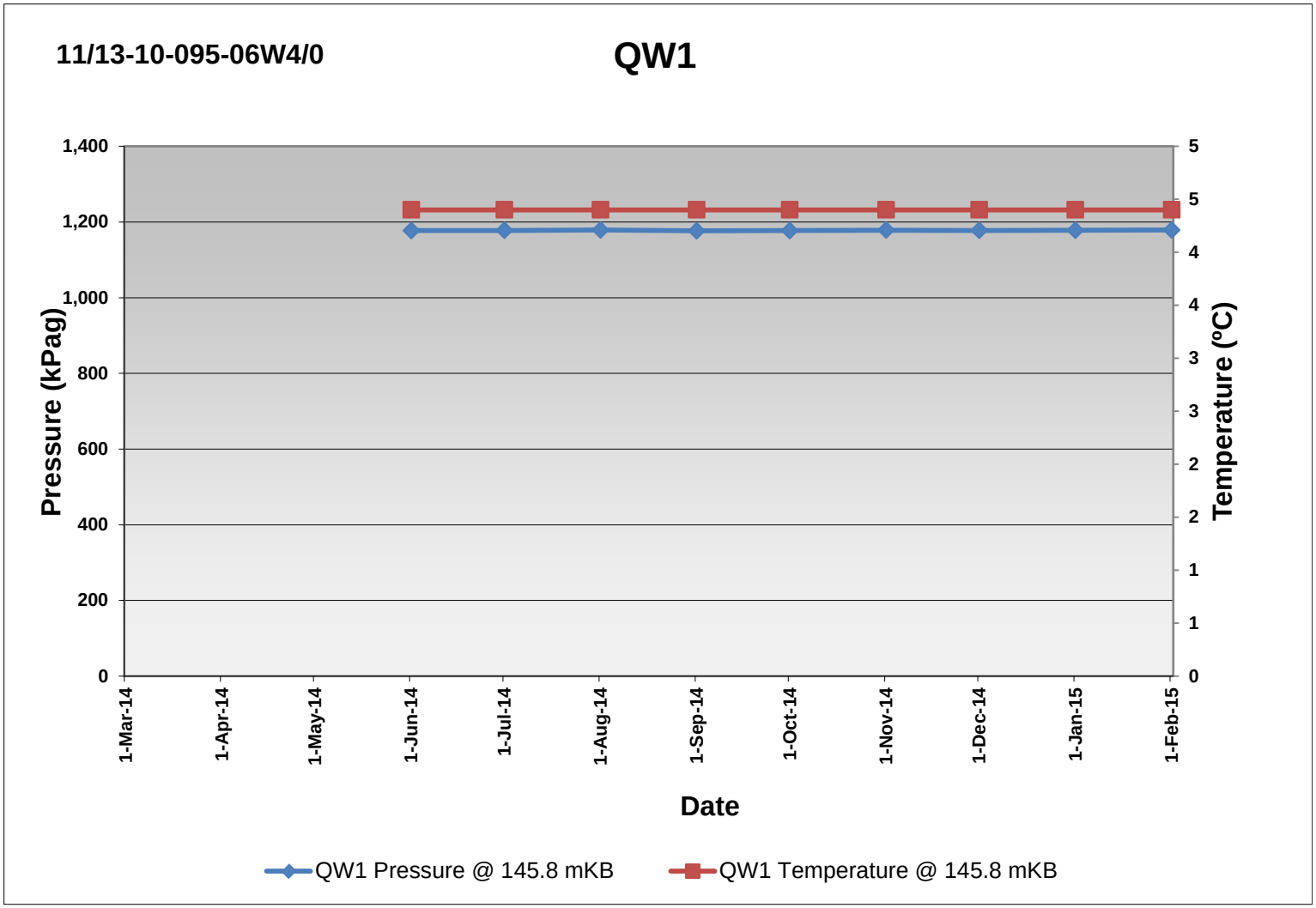

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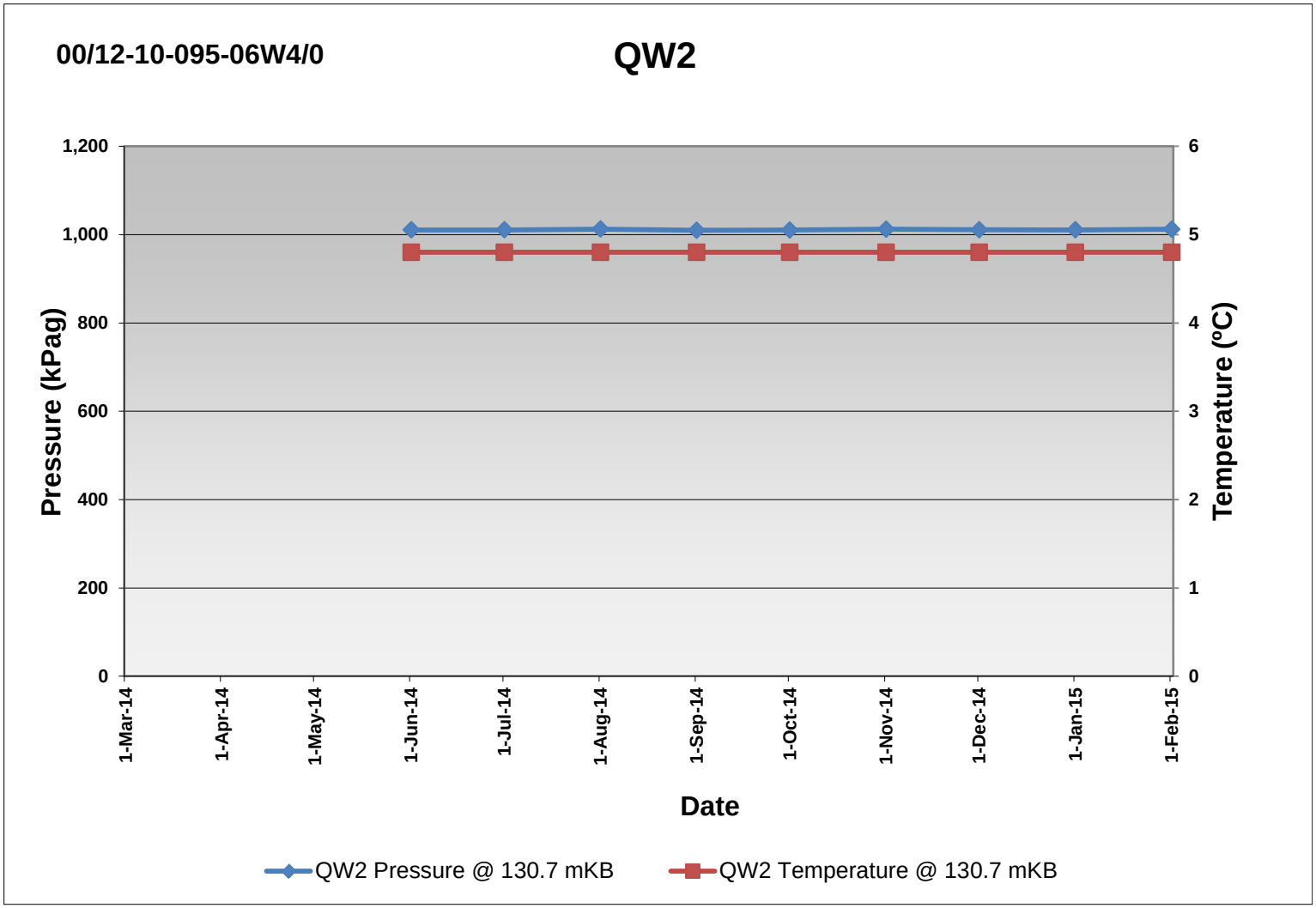

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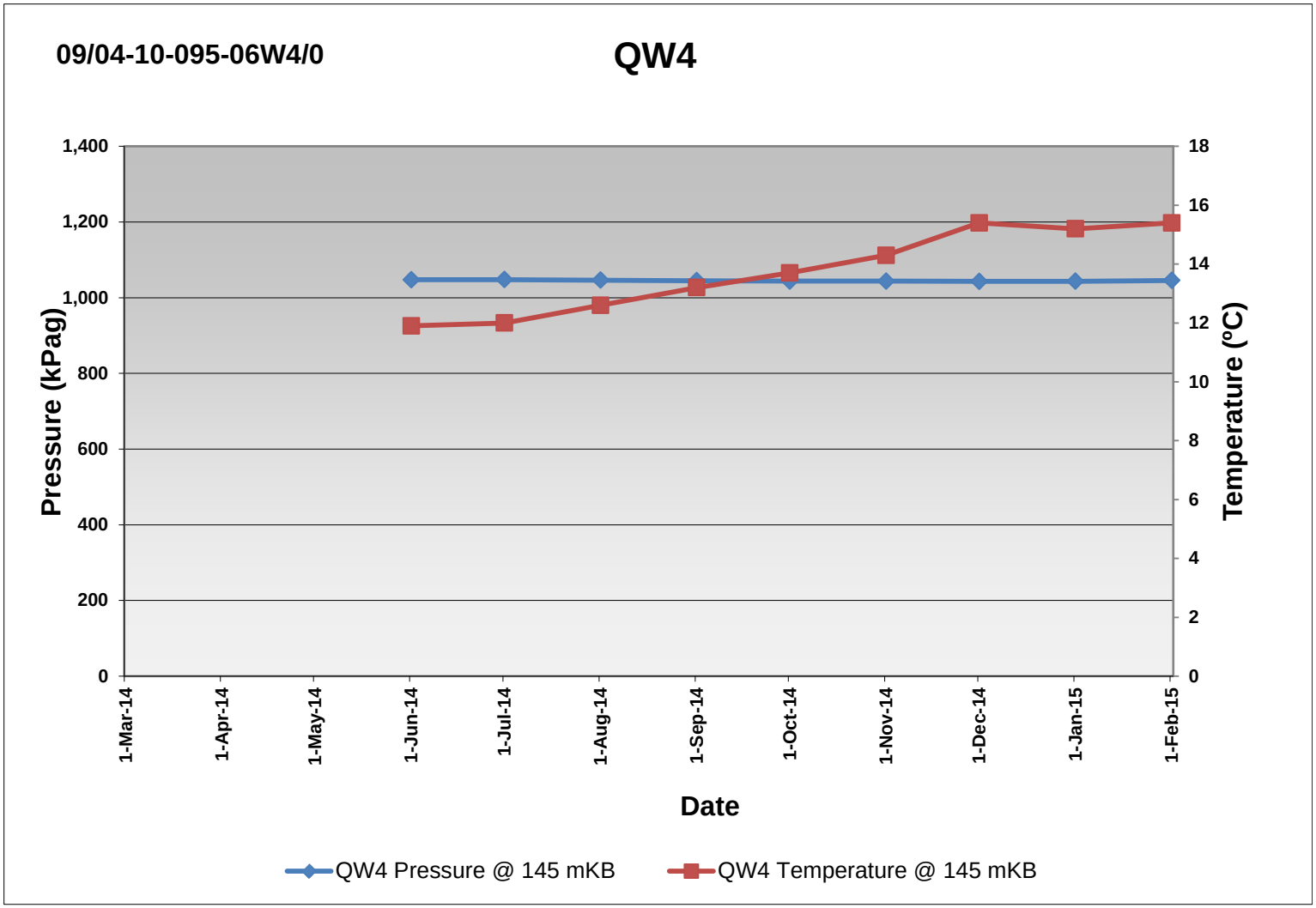

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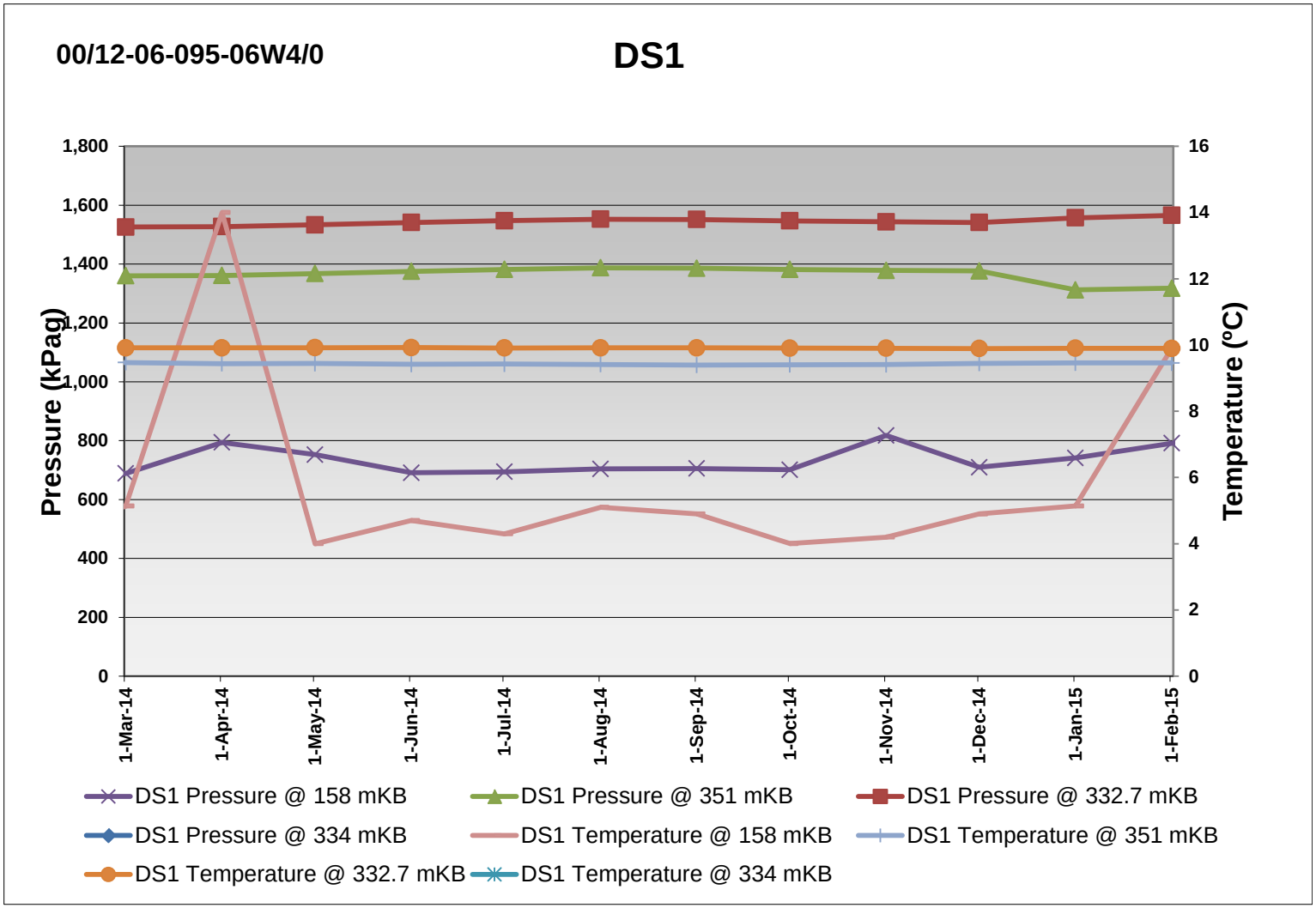

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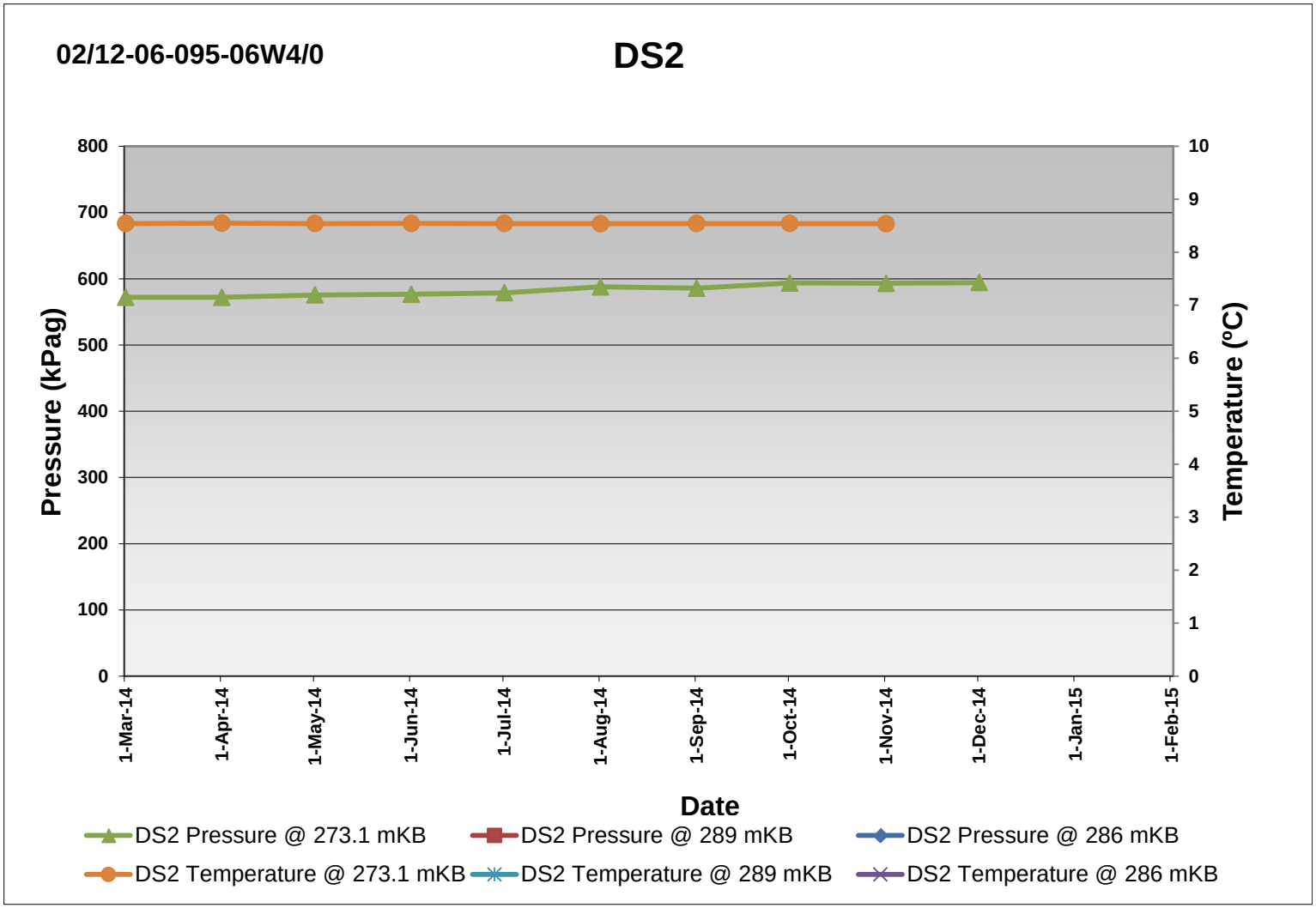

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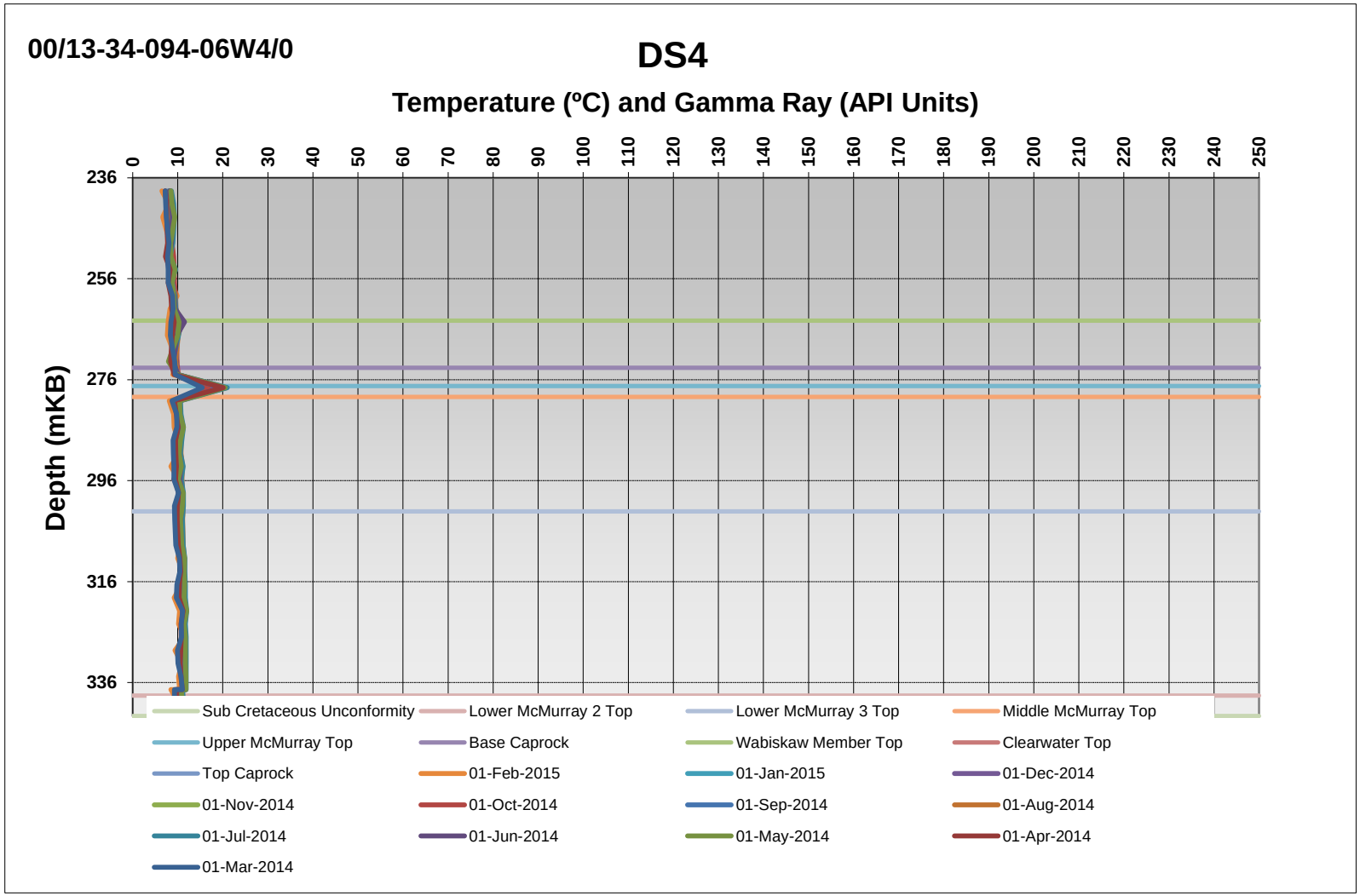

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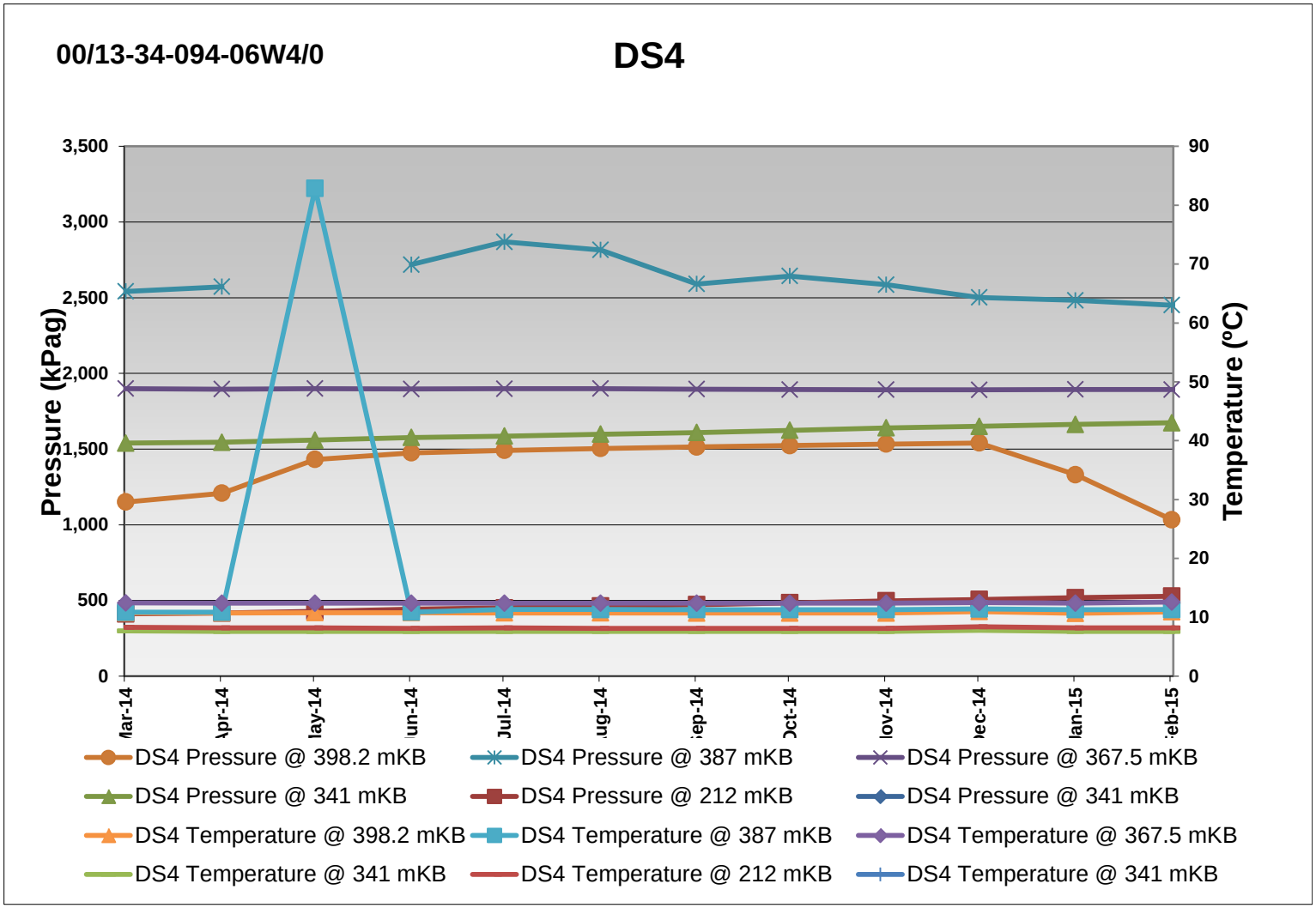

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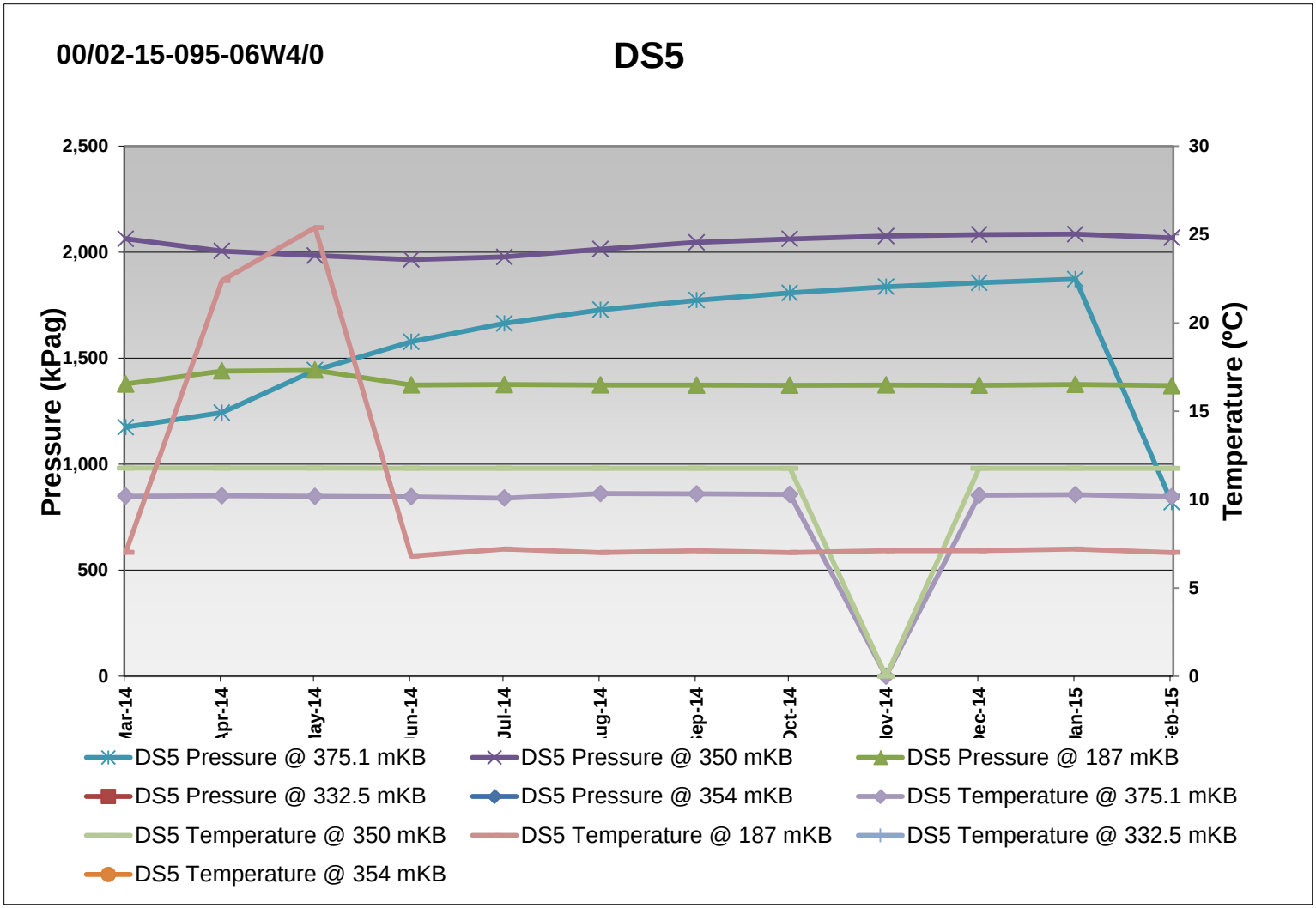

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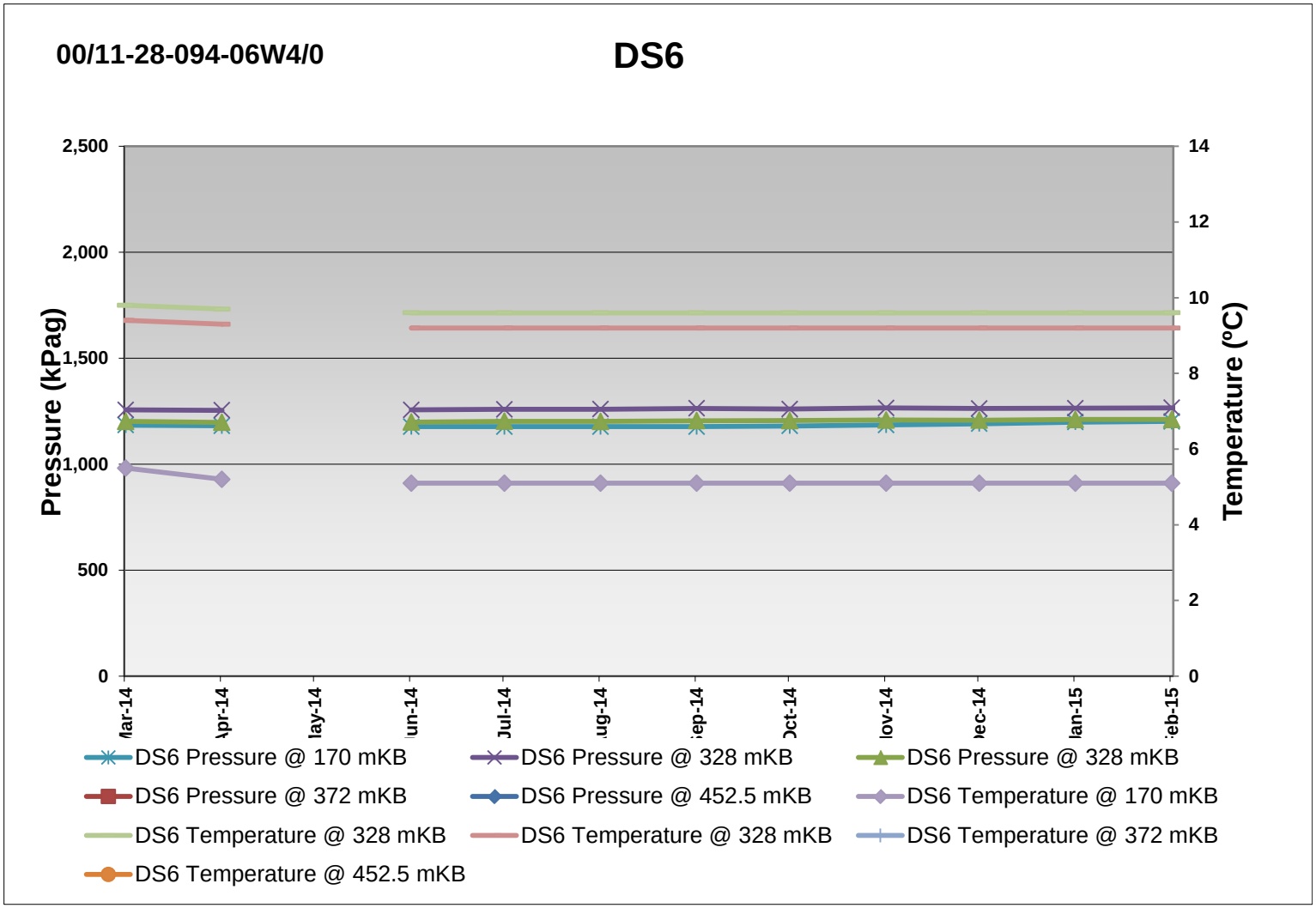

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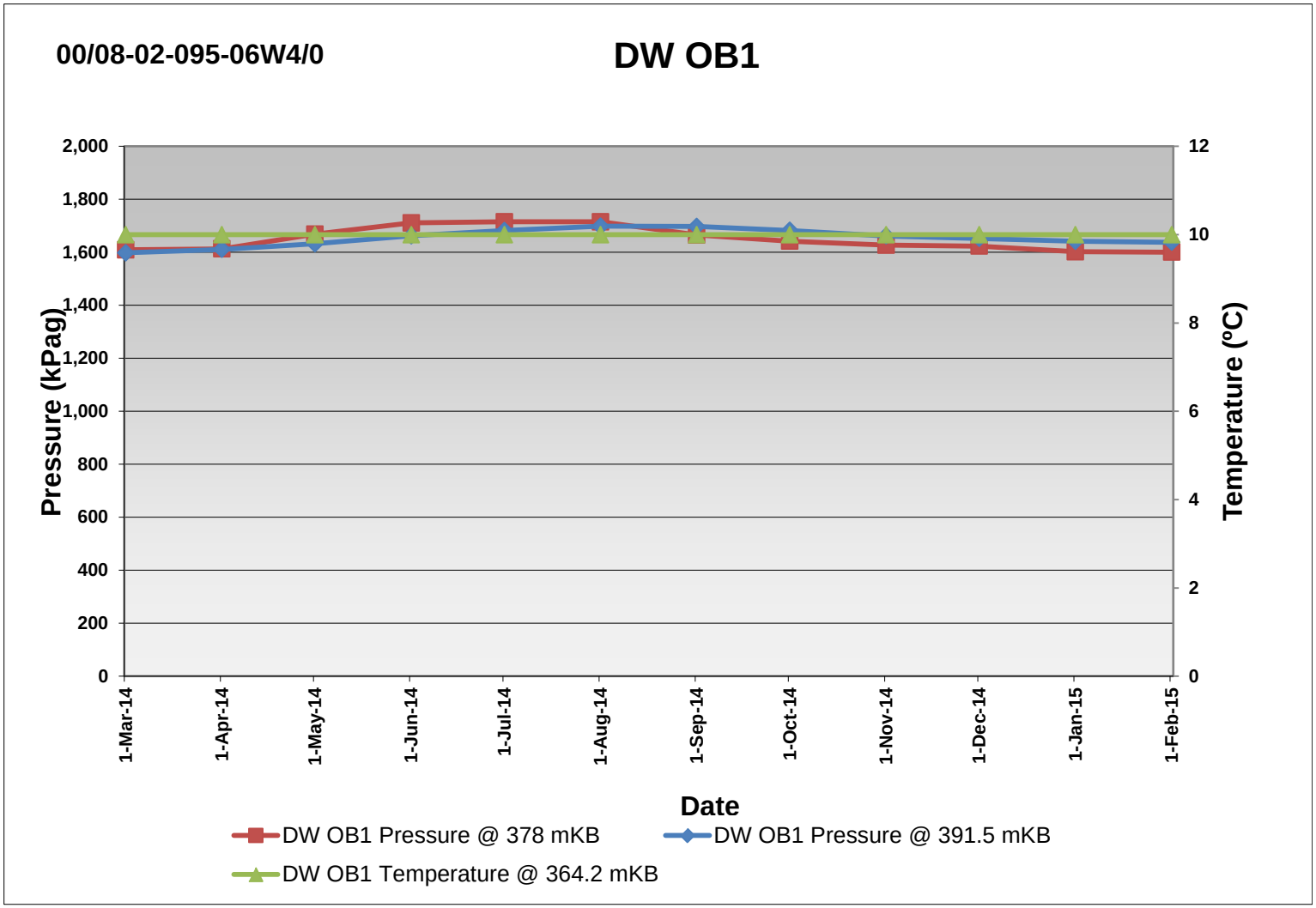

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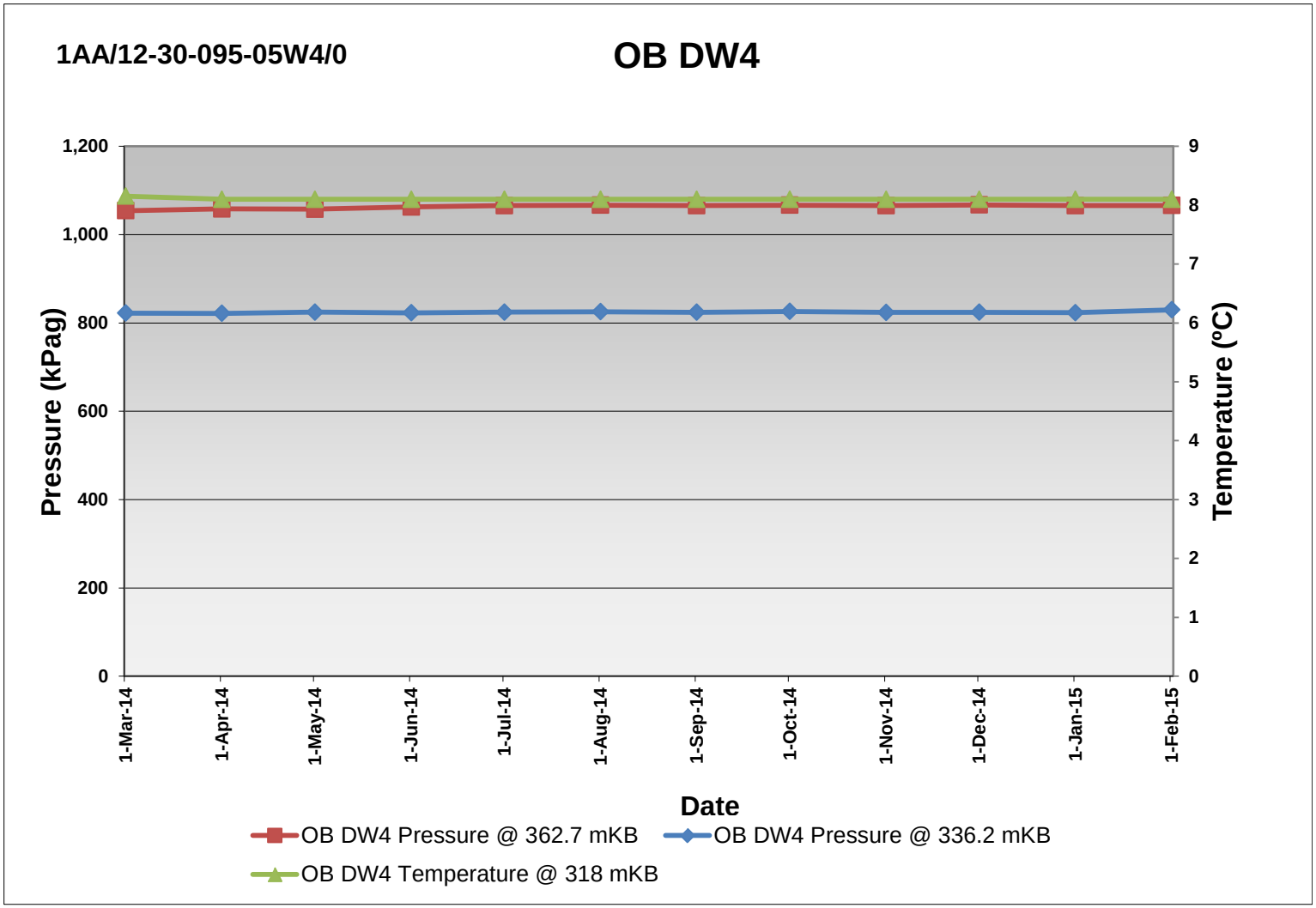

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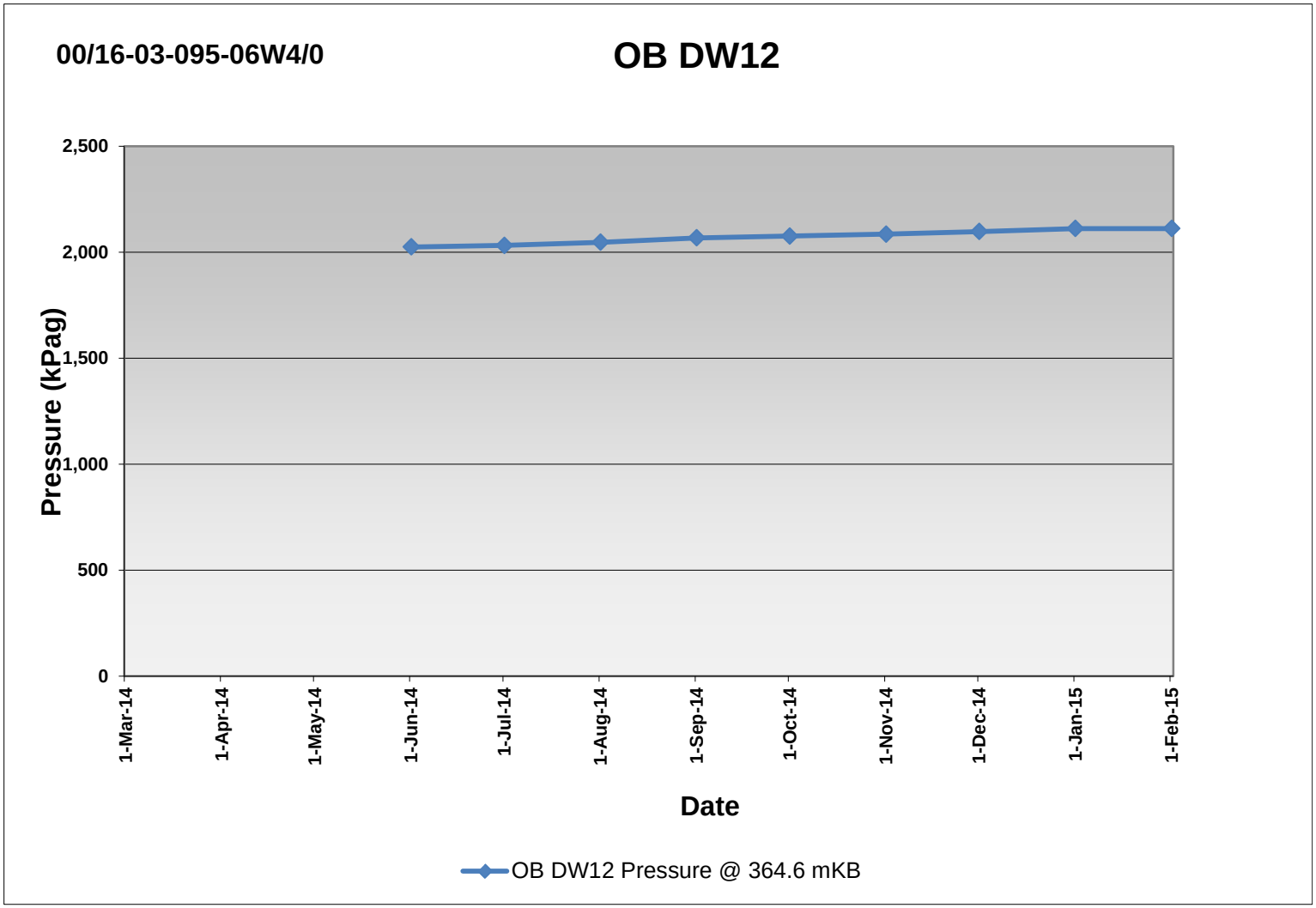

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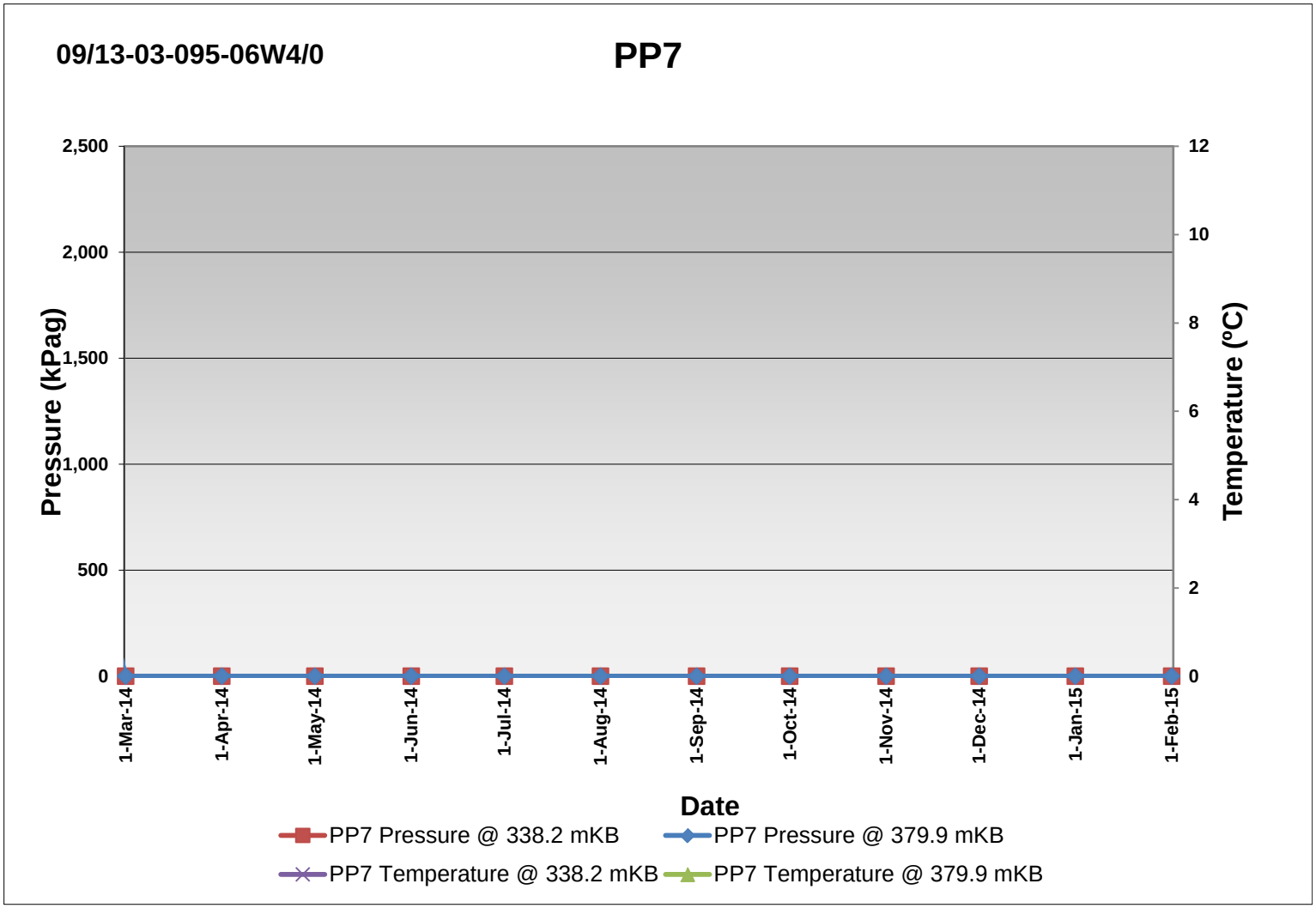

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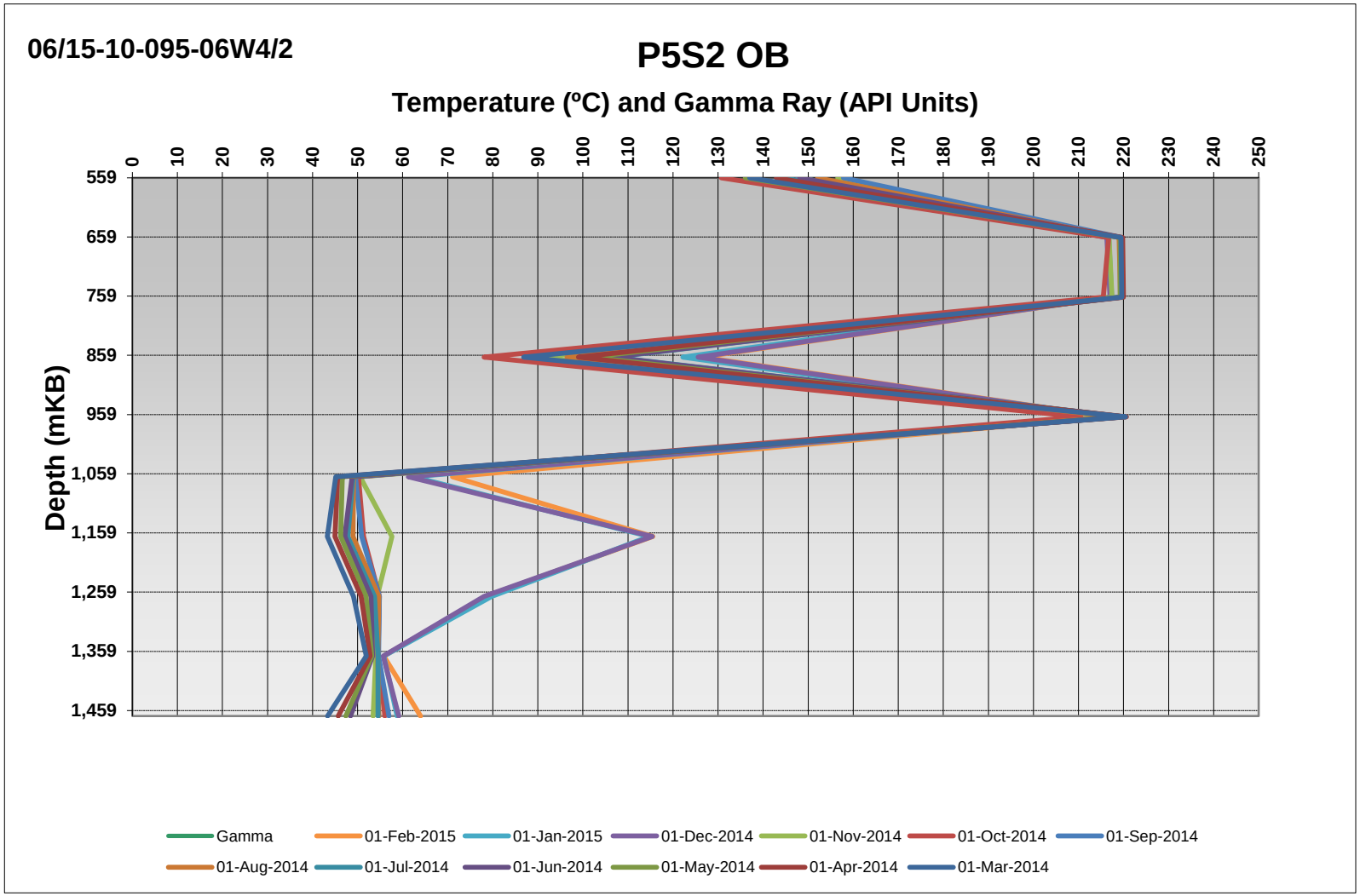

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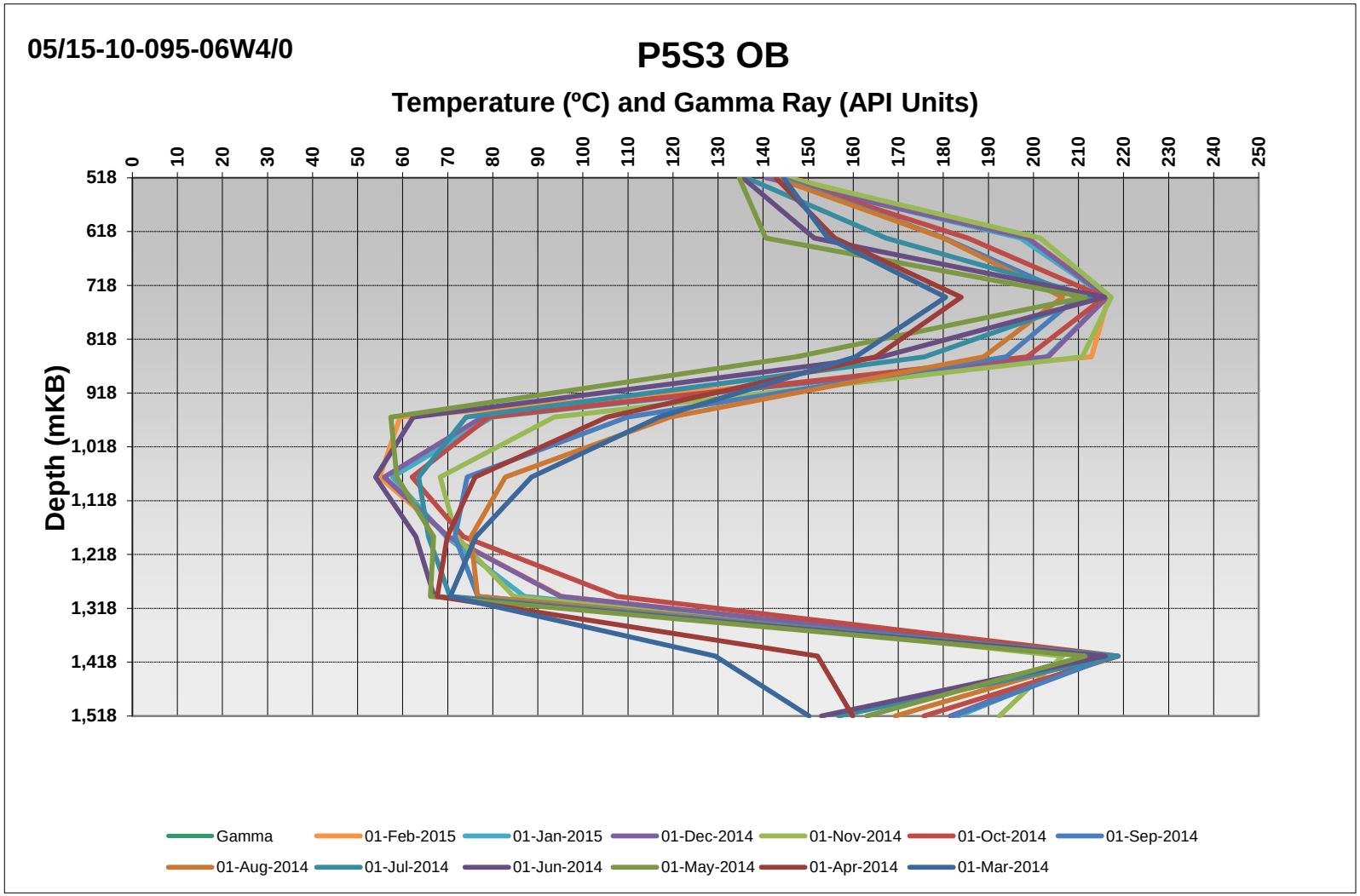

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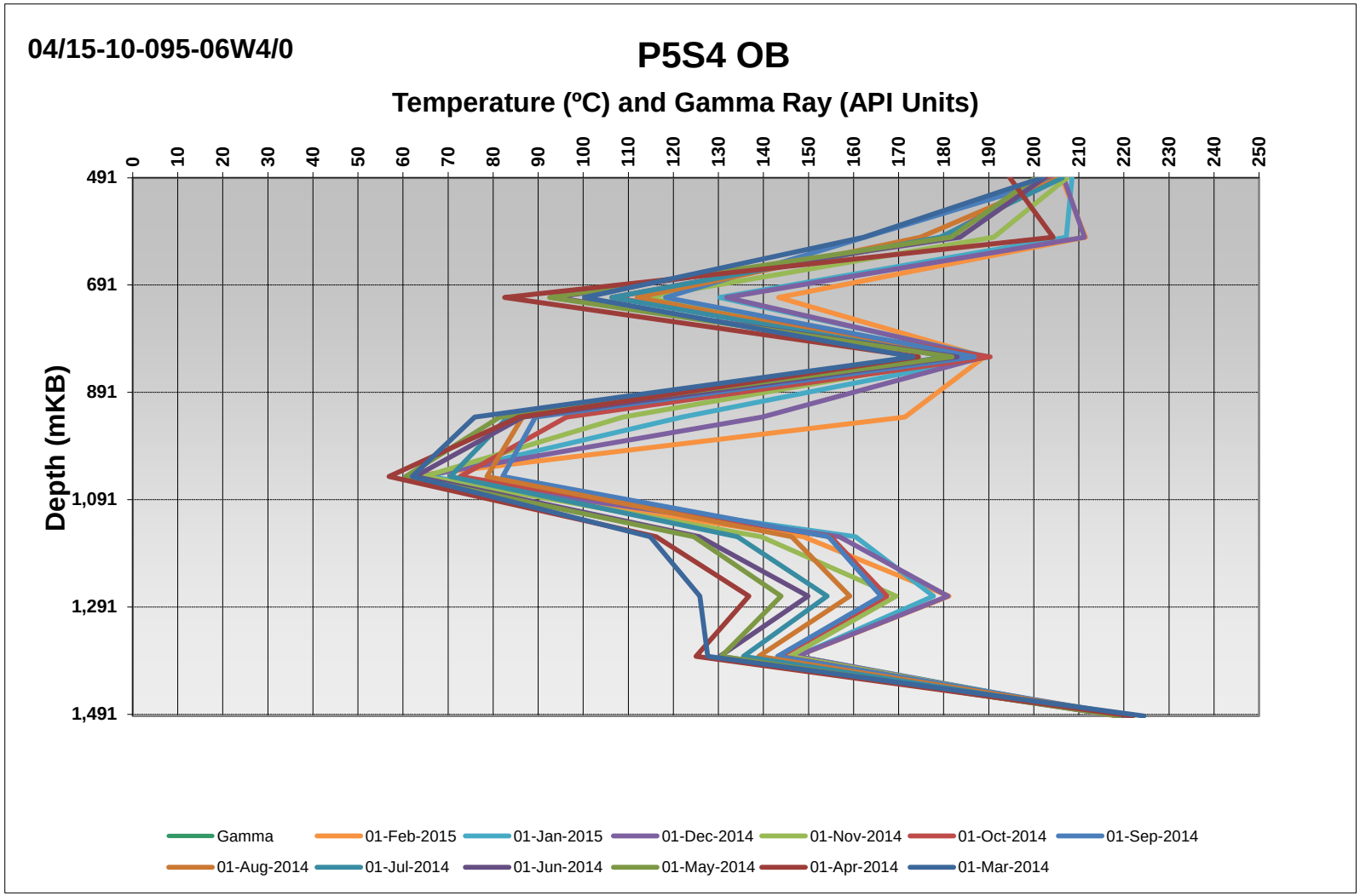
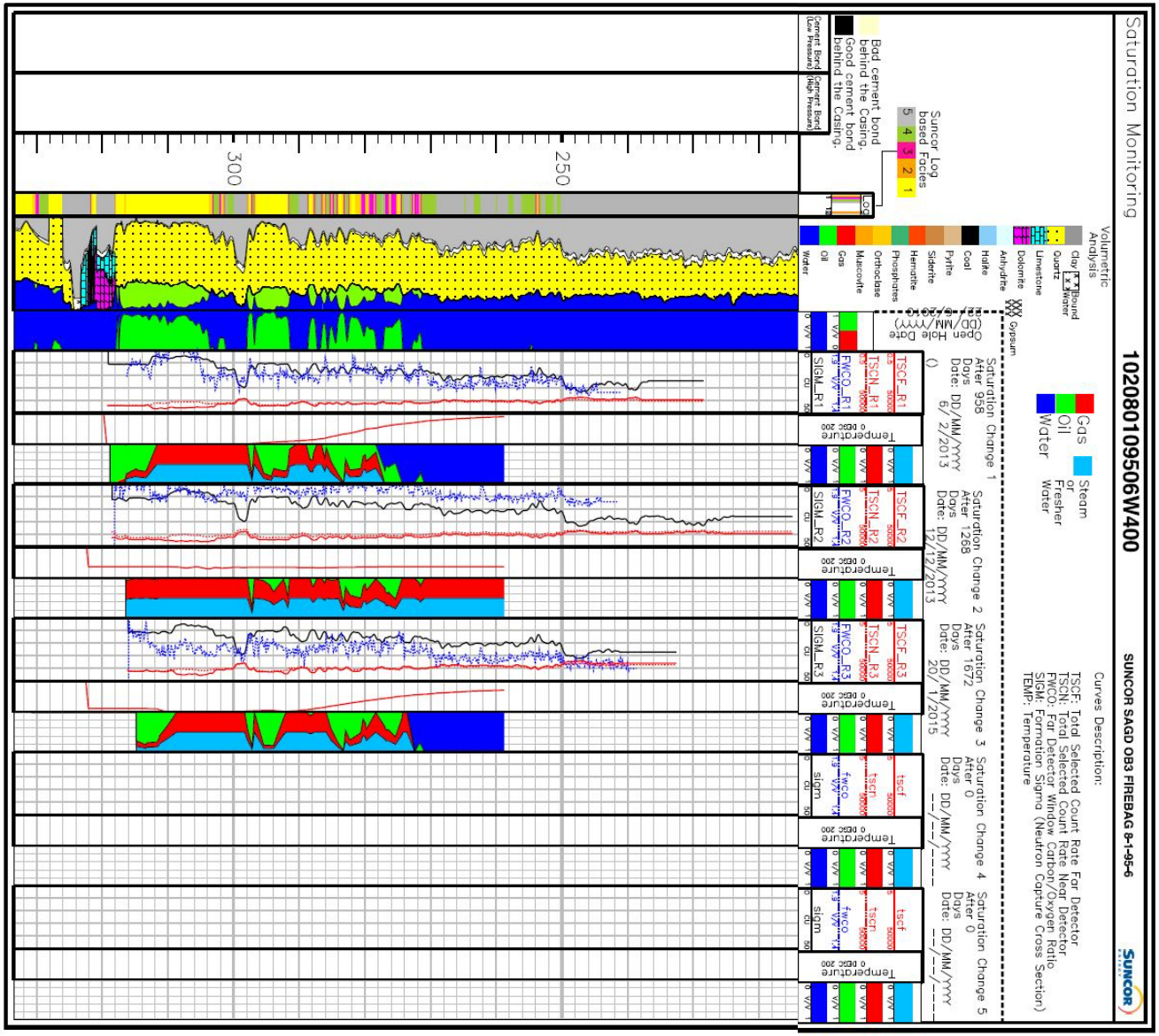


Appendix - RST Logs



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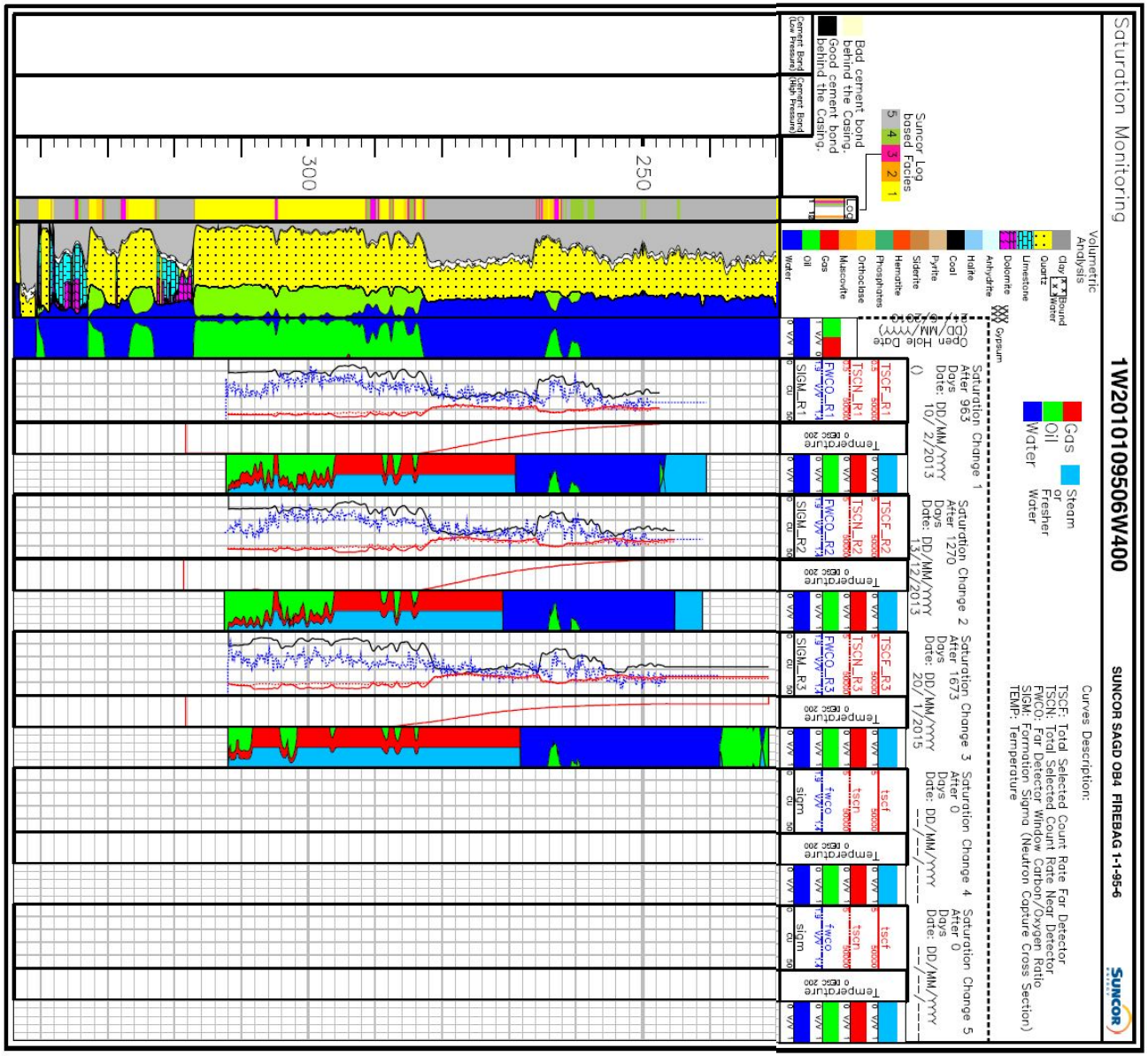

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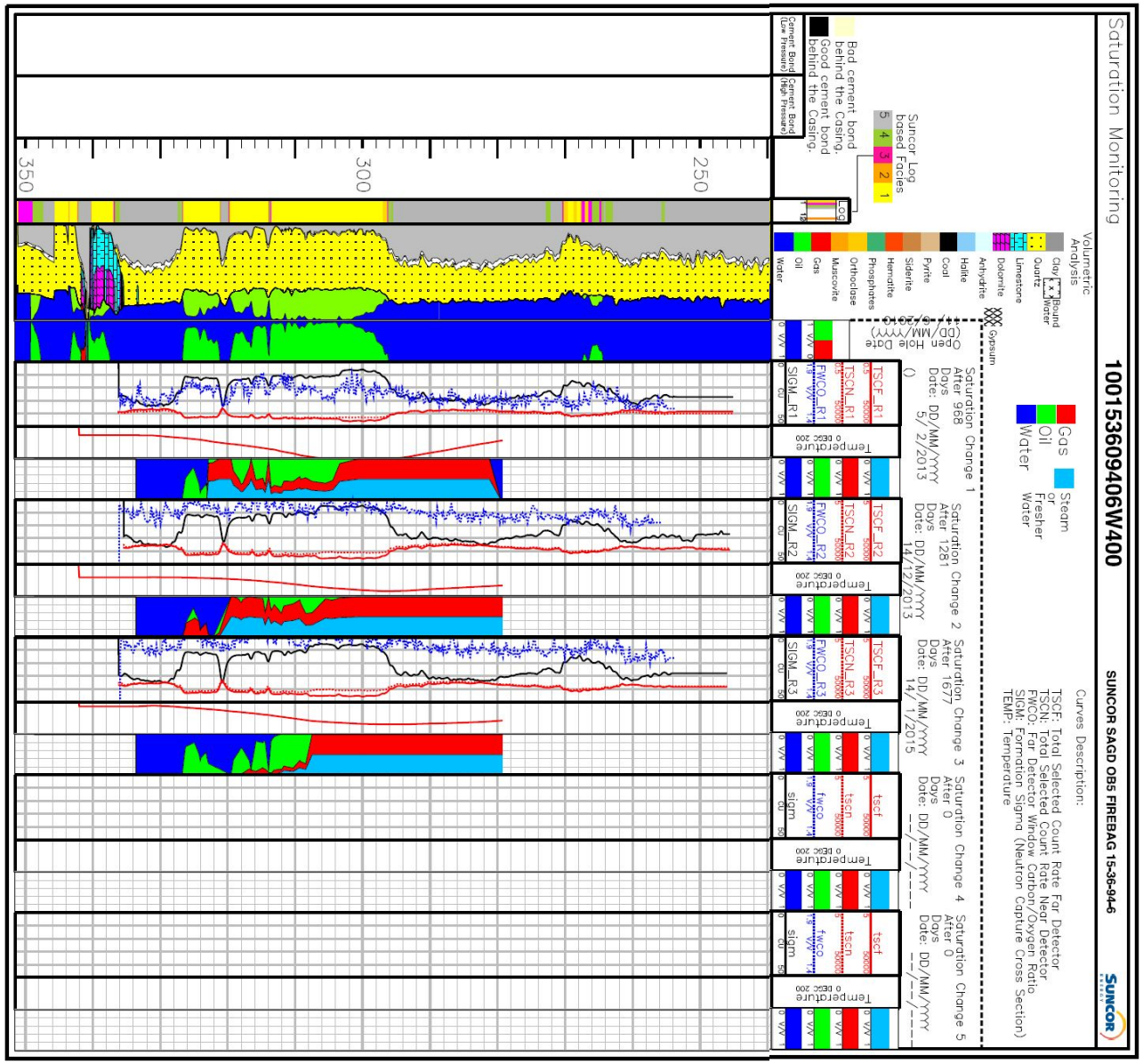

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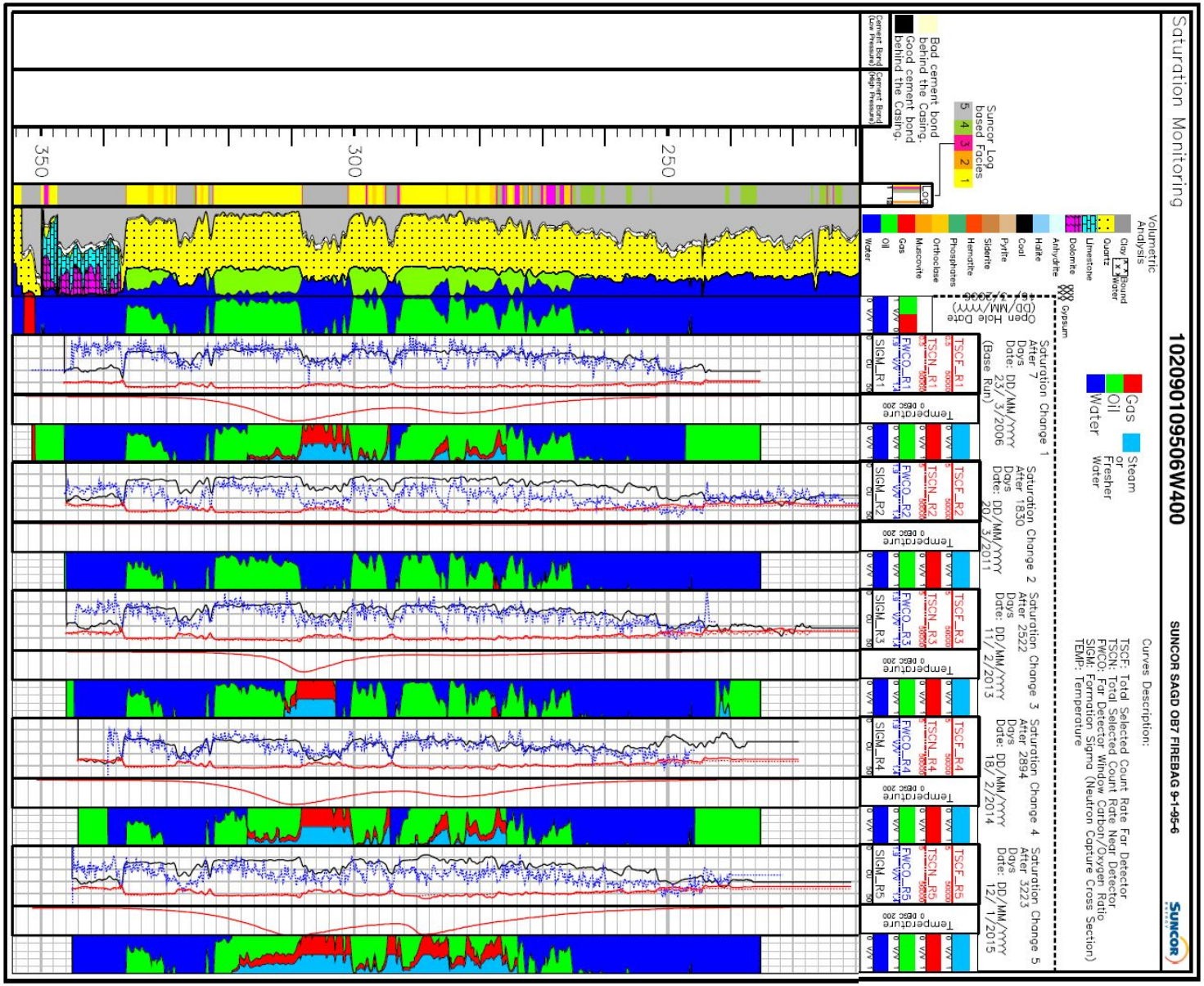

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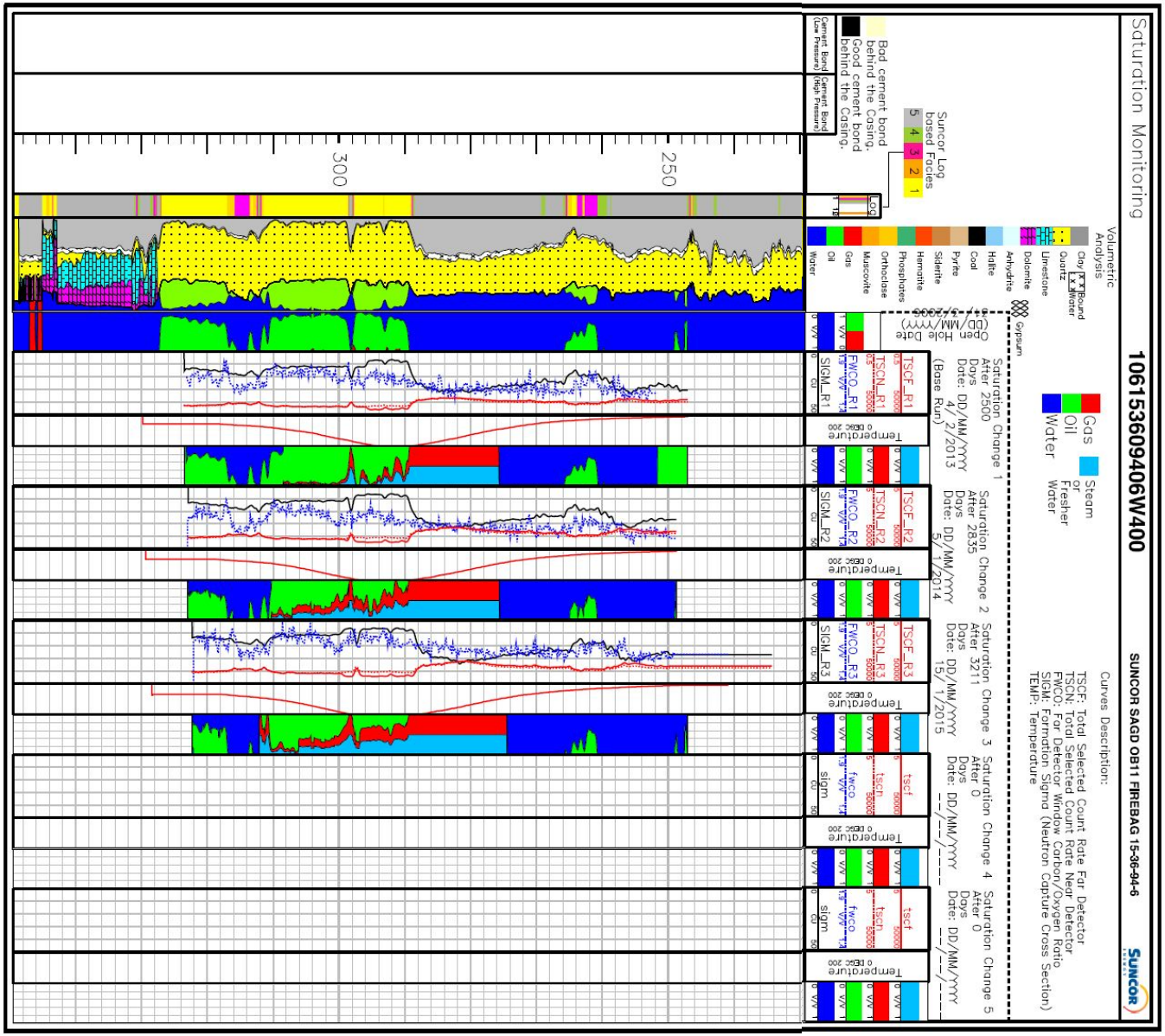

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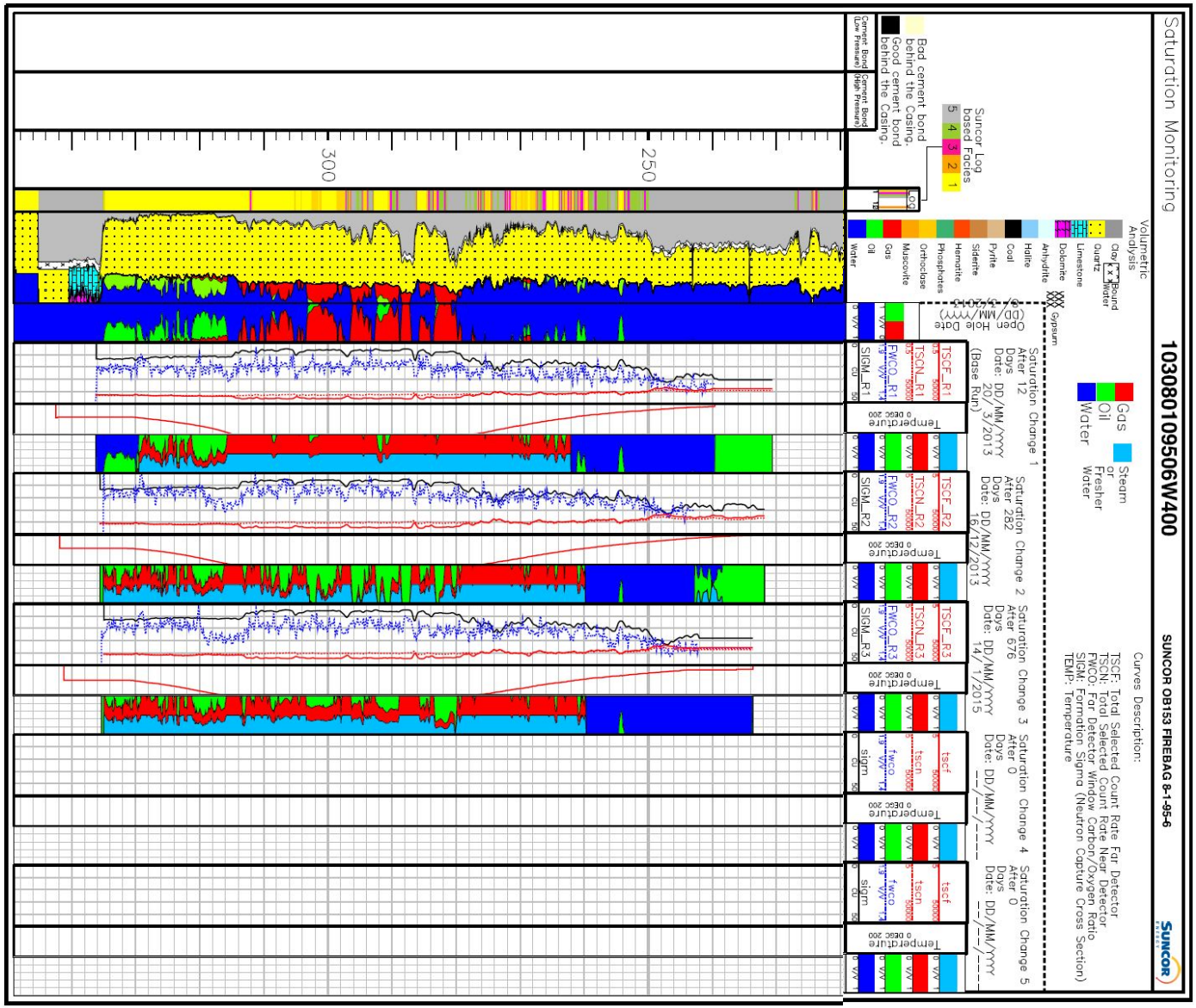

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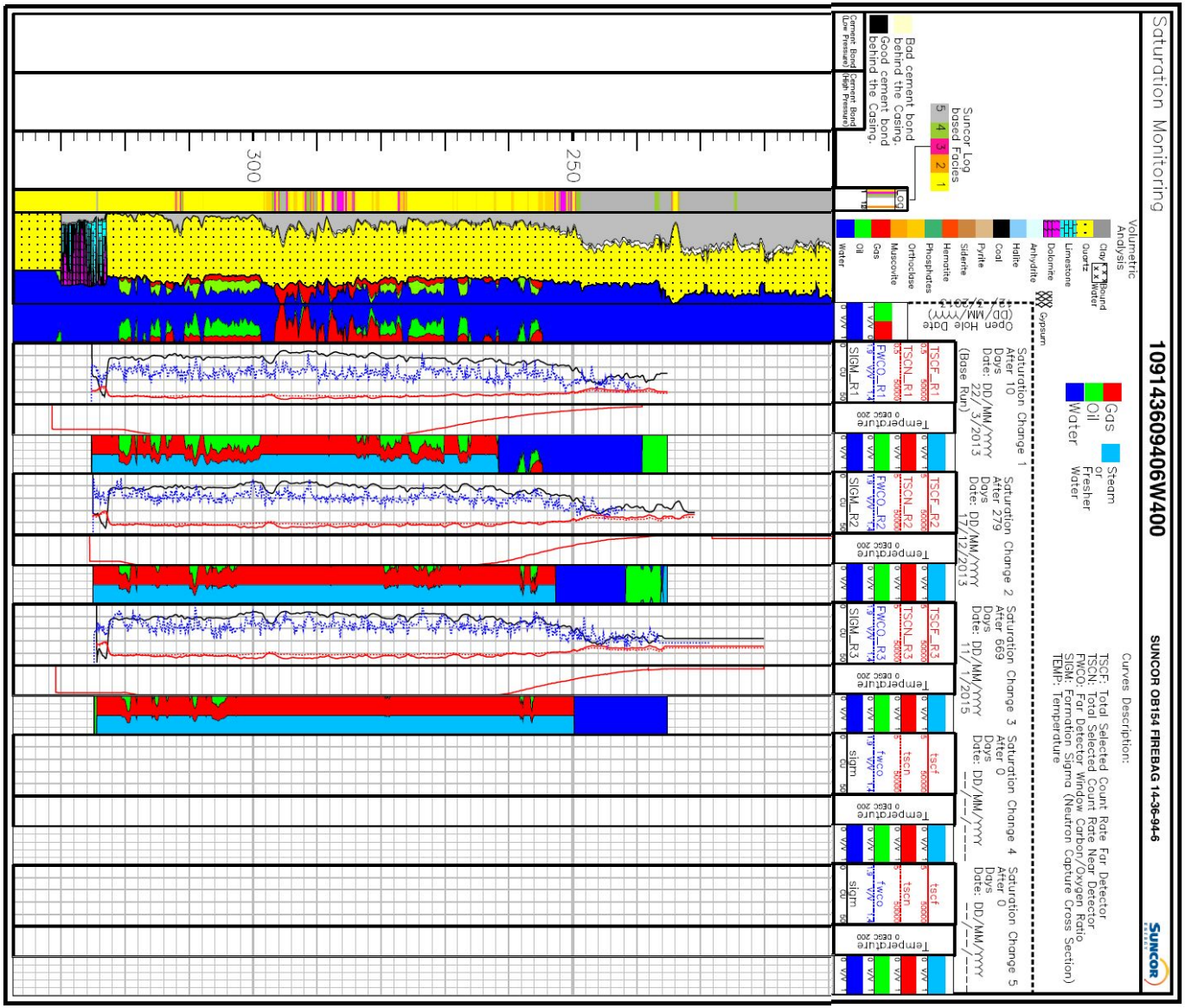

Appendix B
2015 Appendix to AER Surface Section

May 7, 2015
Reporting Period: March 1, 2014 to February 28, 2015

SUNCOR

Water Balance For Firebag Injection Facility

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

Fresh Water

- FW1: Receipt Stream into the Injection Facility. Firebag receives water from the Suncor Oilsands site (AB OS 0077189) and from surface runoff (AB RO). Firebag also has a source water wells (AB WI 100151109506W400 and AB WI 100151409506W400), however it was not used in 2014. In 2015, Make-up water wells were operating from March 2015.
- FW2: Receipt Stream into the Injection Facility. Fresh Water Transfer from the Oil Battery to the Injection Facility within the scheme.
- FW3: Disposition Stream from the Injection Facility to the Oil Battery. Freshwater transferred to the oil battery (AB BT 0078417), in the deoiling unit for cooling purposes.
- FW4: Fresh water tank opening inventory. This volume is carried forward from last month's closing inventory.
- FW5: Fresh water tank closing inventory. This volume takes into consideration levels in Fresh water tanks.
- FW6: "Fresh" water streams used for purposes other than utilities or injection , such as drilling, potable use, and sludge pond losses. Freshwater that never returns.
- FW7: Freshwater vented from the evaporators and lost (if that is occurring). If an evaporator vent collection system exists so under normal operation, no fresh is vented from the evaporators FW7 would be blank/zero.

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 oil battery (AB BT 0078417). This includes produced water from the wells, plus (PW8) the water that was sent from the injection facility to the oil battery for utility and cooling purposes.
- 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 and ponds.
- INVOP (PW4): Water tank opening inventory. This volume is carried forward from last months closing inventory.
- Util (PW7) = The remaining water vented from the evaporators and lost (if that is occurring). If an evaporator vent collection system exists so under normal operation, no water is vented from the evaporators PW7 would be blank/zero.
- PLTUSE (PW6) = "Produced" water streams used for purposes other than utlilties or injection , such as drilling, potable use, and sludge pond losses. Freshwater that never returns.
- INJ (DIT): Water injected to the three disposal wells (AB WI 100060309506W400, AB WI 100100309506W400 and AB WI 100021009506W400).

Water Balance For Overall Firebag Facility

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

Fresh Water

- FW1: Receipt Stream into the Firebag Scheme. Firebag receives water from the Suncor Oilsands site (AB OS 0077189) and from surface runoff (AB RO). Firebag also has a source water wells (AB WI 100151109506W400 and AB WI 100151409506W400), however it was not used in 2014. In 2015, Make-up water wells were operating from March 2015. Water Received from Diluent into Firebag
- FW4: Fresh water tank opening inventory. This volume is carried forward from last month's closing inventory.
- FW5: Fresh water tank closing inventory. This volume takes into consideration levels in Fresh water tanks.
- FW7: Freshwater vented from the evaporators and lost (if that is occurring). If an evaporator vent collection system exists so under normal operation, no fresh is vented from the evaporators FW7 would be blank/zero.

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): 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 and ponds.
- INVOP (PW4): Water tank opening inventory. This volume is carried forward from last months closing inventory.
- Util (PW7): The remaining water vented from the evaporators and lost (if that is occurring). If an evaporator vent collection system exists so under normal operation, no water is vented from the evaporators PW7 would be blank/zero.
- INJ (DIT): Water injected to the three disposal wells (AB WI 100060309506W400, AB WI 100100309506W400 and AB WI 100021009506W400), Utility Steam to Flare, Trucked Out Water and Water in DilBit/Hot Bit.

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