WELL COMPLETION REPORT

WEST WHIPTAIL-1

VOLUME 2
INTERPRETIVE DATA

GIPPSLAND BASIN
VICTORIA

ESSO AUSTRALIA PTY LTD

Compiled by Andy Zannetos and Sheryl Sazenis
November 2004

WELL COMPLETION RPEORT
WEST WHIPTAIL-1

VOLUME 2:

INTEPRETATIVE DATA

TABLES

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WELL COMPLETION RPEORT
WEST WHIPTAIL -1

VOLUME 2:

INTEPRETATIVE DATA (cont'd)

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1. **COMPOSITE WELL LOG**

APPENDICIES

1. **MDT ANALYSIS**
2. **QUANTITATIVE FORMATION EVALUATION**
3. **HYDROCARBON FINGERPRINT ANALYSIS**

I. WELL INDEX SHEET

WELL & RIG DATA

WELL NAME: West Whiptail – 1
OPERATOR: Esso Australia Pty Ltd
CLASSIFICATION: New Field Wildcat

SURFACE LOCATION							GENERAL	
LATITUDE		**LONGITUDE**		**UTM CO-ORDS**			**Rig Name:**	Ensco 102
DEG:	38	DEG:	147	NORTH:	5758030.22		**Basin:**	Gippsland Basin
MIN:	19	MIN:	30	EAST:	544121.32m		**Status:**	Plugged and Abandon Oil Well
SEC:	29.150S	SEC:	17.167E	Geodetic Datum: Zone / Meridian :	GDA 94/MGA94 Zone 55, CM 147°E			

Rig on location:	00:30 hours, 8 May 2004	**Total Depth (Driller):**	1539mRT
Spudded Well:	23:00 hours, 10 May 2004	**Total Depth (Logger):**	1535mRT
TD Reached:	09:00 hours, 20 May 2004	**RT to Sea level:**	39m
Rig Released:	15:30 hours, 5 June 2004	**RT to Seafloor:**	78m
Trap Style:	Structural trap	**Datum:**	MSL
		Seismic:	G01

Cuttings Samples: 5m and 30m intervals from 150 to 1539mRT.

Hole Size (inch)	Hole TD (m)	Casing Size (inch)	Shoe Depth (m)
36”	123	30 x 20 x 13.375"	120.4
12 1/4"	750	9.625”	745

Abandonment Plugs	
1a	1365 – 1539
1b	1191 – 1365
1c	1017 – 1191
1d	843 – 1017
1e	669 – 843
2	110 – 170

WEST WHIPTAIL –1 FORMATION TOPS

Age	Formation	Measured Depth (mRT)	Depth (mTVD)	Depth (mSS)
OLIGOOENE-MIOCENE	Top Lakes Entrance Fm	835.6	835	-796.5
PALEOCENE-EARLY EOCENE	Latrobe Group (TOL)	1179.0	1177.3	-1138.7
PALEOCENE-EARLY EOCENE	Top Coarse Clastics	1185.3	1183.6	-1145.0
PALEOCENE-EARLY EOCENE	Top N1.0	1406.3	1403.5	-1364.9
PALEOCENE-EARLY EOCENE	Top N1.1	1409.7	1406.9	-1368.3
PALEOCENE-EARLY EOCENE	Base N1.4	1417.7	1414.9	-1376.3
PALEOCENE-EARLY EOCENE	Total Depth	1539.0	1493.1	-1496.5

WIRELINE LOGS

Suite / Run	Type of Log	Interval (mRT)	BHT °C / Time since circ.(Hrs)
1/1	PEX-HALS-DSI-HNGS-LEHQT	77.6 – 1529.0	72.0/10.4
1/2	MDT-GR-LEHQT	Aborted at 1241	N/a
1/3	MDT-GR-LEHQT(pressures and samples)	1364.0 – 1470.0	69.0/42.3
1/4	CSAT-GR	1264 – 100.0	N/a

II. INTRODUCTION

The West Whiptail-1 well is located approximately 1.4 km WSW of Whiptail-1A. The location lies in 38 meters of water, within the VIC/L1 license area of the Gippsland Basin (Figure 1). The West Whiptail-1 well was designed to provide data on the lateral extent of the Whiptail and Mulloway discoveries within the fluvial "N" sand reservoirs of the intra Latrobe (lower N.asperus age) (Figure 2). A closure was mapped between the Mulloway and Whiptail discoveries with a range of potential contacts in the main N1.1/N1.3 sands of between 1375-1389m. Definition of the position of the contact would enable a better assessment of the oil resource within the overall Whiptail complex which includes Mulloway, West Whiptail, Whiptail and East Whiptail closures (Figure 3).

The West Whiptail1 near field wildcat well was spud on 10th May and drilled to a total depth of 1539 MD by the jack-up drilling rig *Ensco 102*. The well was subsequently P&A'ed and the rig released on 5th June, 2004.

III. SUMMARY OF WELL RESULTS

A comparison of prognosed versus actual formation tops penetrated in West Whiptail 1 is summarised in Table 1, and the relevant stratigraphy is summarised in Figure 2. The prognosed stratigraphy was based on adjacent wells Whiptail 1A and Mulloway 1.

Analysis of the wireline logging suite indicates the well intersected a total of 4.5m of gross hydrocarbon bearing sand (4.25m net oil) within the N1.1 sand. The hydrocarbons were located within the prognosed fluvial sequence of the lower N.asperus of the Latrobe Group over the interval 1409.7m to 1414.2m measured depth. The N1.3 sand was intersected at 1417.7m measured depth and was water wet.

The N1.1 intersected in West Whiptail-1 well from pressure data is interpreted to have an OWC at 1380mSS. The intervening shale between the N1.1 and N1.3 sands is interpreted to be a local base seal and has prevented migration of oil into the N1.3. Plotting pressure points from the West Whiptail 1 well gives an OWC at 1380mSS (Figure 4).

Analysis of sample recovered from the hydrocarbon sand in West Whiptail-1 shows that it is a 43° API oil similar to Whiptail 1A.

IV. GEOLOGICAL DISCUSSION

OVERVIEW

Exploration in the Gippsland basin has historically focussed on the upper Latrobe, most of the large fields are Top Latrobe closures sealed by overlying Lakes Entrance Formation marine shales. Some large intra-Latrobe fields are also present such as the Tuna T-1 and Halibut/Cobia reservoir that are sealed by coastal plain shales. Within the greater Barracouta, Whiting and Snapper area there are several medium to small size intra-Latrobe hydrocarbon accumulations sealed by coastal plain shales and each of these fields has produced oil from the M.diversus section and above.

The G01 Northern Fields 3D seismic survey was partly aquired to progress delineation of the Whiptail complex. The survey extends across all four of the closures within the complex and includes the West Whiptail 1A and Mulloway 1 wells.

REGIONAL SETTING

The initial formation of the Gippsland Basin was associated with rifting and subsidence that extended along the southern margins of Australia during the Jurassic to Early Cretaceous. During this period, deposition of predominantly volcanoclastic successions occurred in alluvial and fluvial environments, in NE trending en-echelon graben systems (Otway and Strzelecki groups). A phase of structuring and localised uplift of the Strzelecki Group occurred around 100-95Ma.

A renewed phase of Late Cretaceous (approximately 90 Ma) rifting coincided with the onset of Tasman seafloor spreading to the east of Tasmania. This resulted in the rapid development of extensional basins in the Gippsland area, with active extensional faults oriented WNW/ESE (oblique to the earlier extensional event). A thick (overall coarsening-up) succession was deposited in these tectonically active depocentres (Emperor-Golden Beach Groups). Initial rift deposition included marine and lacustrine shales in distal parts of the basin, while deltaic successions and alluvial fans developed along basin margins. The rift fill succession gradually evolved into a fluvial-dominated system. The upper parts of the Golden Beach Group (eg. Kipper sub-volcanic reservoir section) were predominantly braided fluvial to delta plain in character. As the northward migrating Tasman spreading centre passed by the Gippsland Basin around 85-80Ma, the eruption of mafic volcanics and emplacement of related intrusions occurred across the Gippsland Basin. These volcanics form the topseal for several hydrocarbon accumulations (eg. the Kipper volcanics).

IV. GEOLOGICIAL DISCUSSION (cont'd)

The active rift phase in the Gippsland Basin ceased at approximately 80 Ma, as the Tasman Rift proceeded to migrate further northwards towards Queensland. From this time onwards, the Gippsland Basin evolved into essentially a failed arm of the Tasman Rift system. The Latrobe Group was deposited in this sag phase basin setting, with fault controlled subsidence continuing until the Late Paleocene. Most of the Latrobe Group was deposited in a non-marine setting behind a NE-SW tending beach-barrier complex. As sedimentation rates declined, the strandline moved to the northwest, depositing thin Eocene-aged glauconitic green sands over a wide area (Gurnard Formation).

Two major phases of canyon cutting occurred during the Tertiary. The Early Eocene Tuna/Flounder Channel was cut and then filled with predominantly marine sediments of the Flounder Formation. The Marlin Channel was cut during the Middle Eocene and partially filled with distal marine sediment of the Turrum Formation. Erosion associated with the top of Latrobe Group unconformity resulted in the formation of many of the hydrocarbon traps in the basin.

The end of the Latrobe Group is marked by deposition of marl and calcareous siltstone of the Lakes Entrance Formation in response to continued marine transgression in the Oligocene. Prograding limestone and calcareous siltstone wedges of the Gippsland Limestone result in the formation of the present day shelf.

Compressional events in the late Eocene to mid-Miocene caused selective inversion of faults around the basin and the establishment of the major ENE-WSW anticlinal trends in the basin.

STRATIGRAPHY

The stratigraphic section intersected is very close to predicted and is shown in Figure 2. A thick succession of limestones and marls of the Gippsland Limestone and the Lakes Entrance Formation overly a thick Latrobe clastic package down to the fluvial "N" sand reservoirs (lower N.asperus age).

IV. GEOLOGICIAL DISCUSSION (cont'd)

STRUCTURE

West Whiptail is one of four discrete *en echelon* closures which comprise an E-W oriented hangingwall anticlinal trend referred to as the Whiptail Complex. The Whiptail Complex is the product of oblique inversion of E-W oriented normal faults during Eocene - Miocene compression. Interpretation of post-Latrobe Group stratigraphy indicates West Whiptail and Whiptail share a common structural history.

PRESSURE DATA

The N1.1 intersected in West Whiptail-1 well from pressure data is interpreted to have an OWC at 1380mSS. The intervening shale between the N1.1 and N1.3 sands is a local base seal and has prevented migration of oil into the N1.3. Plotting pressure points from the West Whiptail 1 well gives an OWC at 1380mSS (Figure 4). Comparing West Whiptail 1 and Whiptail 1A pressures shows similar drawdown for sands above, within and below the main N reservoirs. This indicates good pressure communication between sands and no indication of any stratigraphic isolation between the N1.1 or the N1.3 between the wells

HYDROCARBON DISTRIBUTION

The West Whiptail 1 well intersected one 4.6m gross oil column within the N1.1 reservoir. The N1.3 reservoir was water wet.

A fill and spill model was used to explain the hydrocarbon distribution within the complex (Fig 6). A local base seal is interpreted to extend across W. Whiptail and Whiptail. Oil migration is interpreted to occur via the fault between W. Whiptail and E. Whiptail. The N1.1 in the Whiptail and West Whiptail closures fill first before preferntially spilling to E. Whiptail and then towards Barracouta. The N1.3 in West Whiptail does not fill as it is in a migration shadow with no cross cutting fault and a saddle point towards Whiptail closure that is deeper than the N1.1 saddle between Whiptail and E. Whiptail. This explains HPW in West Whiptail which is at 1377.5m tvdss. The contact from pressure data gives an OWC depth of 1380m tvsSS.

IV. GEOLOGICIAL DISCUSSION (cont'd)

TIME INTERPRETATION

The time interpretation of the Whiptail Complex was conducted on the G01A 3D migrated full stack. Significant horizons included five Miocene surfaces, Top Latrobe Group, Mid N Asperus Coal Marker, Lower N Asperus Coal Marker and the Barracouta M1 equivalent.

Three wells (Mulloway-1, Whiptail-1A and Barracouta-3) were tied to the seismic data using synthetic seismograms. The Lower N Asperus Coal Marker was interpreted on the peak to trough zero crossing that was interpreted to mark the top of the coastal plain seal and the base of overlying fluvial sandstone.

The five Miocene horizons were used as control for depth conversion. The lowermost of these (HVC4) cuts down into the lower velocity marls of the Lakes Entrance Formation in a N-S oriented channel over the West Whiptail Prospect. Two Miocene horizons (HVC2 and HVC2a) represent the top and base surface of an interpreted Miocene clastic unit observed in offset wells.

Tuning analyses of the G01A 3D migrated full stack indicate the seismic wavelet has adequate bandwidth to resolve events at the top and base of the reservoir to a thickness of 14 - 21 ms (20 - 30 Hz Ricker Wavelet 90° Phase Shift). Below 14 - 21 ms the seismic wavelet can detect the top and base of the reservoir but can no longer resolve its thickness. Based on interval velocities measured in the wells a 14 - 21 ms isochron equates to a thickness of 22 - 33 metres implying the reservoir is beneath resolution at both existing well locations. At the West Whiptal-1 location the N1.1-N1.4 reservoir is interpreted to be below peak tuning and therefore has been assessed as the arithmetic average of the gross reservoir observed at Mulloway-1 and Whiptail-1A (19 metres).

Similar analysis indicates the seismic trough overlying the peak which represents the coastal plain interbedded coal and shale unit is also below tuning thickness over most of the Complex. The isochron from the peak-trough zero crossing to the trough-peak zero crossing is approximately constant at 18 ms and the trough appears to exceed tuning thickness only south of the Whiptail-1A well.

V. GEOPHYSICAL DISCUSSION

GEOPHYSICAL DATA

The West Whiptail prospect was originally identified on 2D seismic data. Subsequent 3D surveys (G88A, G99A and G01A) confirmed the presence of a discrete TWT closure located between the Whiptail and Mulloway discoveries. The seismic data quality of both G99A and G01A surveys exhibits improved multiple suppression and signal-to-noise ratios compared to previous 2D and 3D data.

DEPTH CONVERSION

Although the Whiptail Complex is located within an area of relatively low lateral velocity gradients, individual closures within the Whiptail Complex are of low strutural relief.

High Density Velocity Analysis was used to evaluate whether the TWT West Whiptail closure is valid in the depth domain. High density 3D volumes of velocity data are interpreted data generated by the contractor processing centre using picking algorithms to identify the semblance maxima which derive from primary reflections. An expert processor provides manual interpretation of the velocity field for control of the picking. The success of the process is dependent on the quality of the expert interpretation as well as the ability of the algorithm to discriminate primary reflections from multiples and converted waves.

High Density Velocity Analyses were provided by VERITAS (Singapore). The input data was preprocessed by Kirchoff 3D prestack time migration and radon multiple filtering. All four depth conversion techniques performed indicated that the West Whiptail-1 location was within closure.

The West Whiptail 1 well came in very close to prediction. The Top of coarse clastics was 1m low to prediction while the main N1.1 reservoir was 3.3m deep to prediction. Some of this depth error is attributed to the well walking to the east and intersecting the N1.1 at a slightly deeper point on the depth map.

The predicted tops were based on the Model B structure map which was considered the most likely structural form before drilling the well (40% weighting).

FORMATION RESERVOIR TOPS

Formation/ Zone	MtvDSS			mMDRT
	Predicted	Actual	Difference	
Top Lakes Entrance Fm	-787.0	-796.5	9.5 low	835.6
Latrobe Group (TOL)	-1139.0	-1138.7	0.3 high	1179
Top Coarse Clastics	-1144.0	-1145.0	1.0 low	1185.3
Top N1.0	-1360.0	-1364.9	4.9 low	1406.3
Top N1.1	-1365.0	-1368.3	3.3 low	1409.7
Total Depth	-1500.00	-1496.5	3.5 high	1539.0

Table 1.

FIGURES

GIPPSLAND BASIN LOCATION MAP

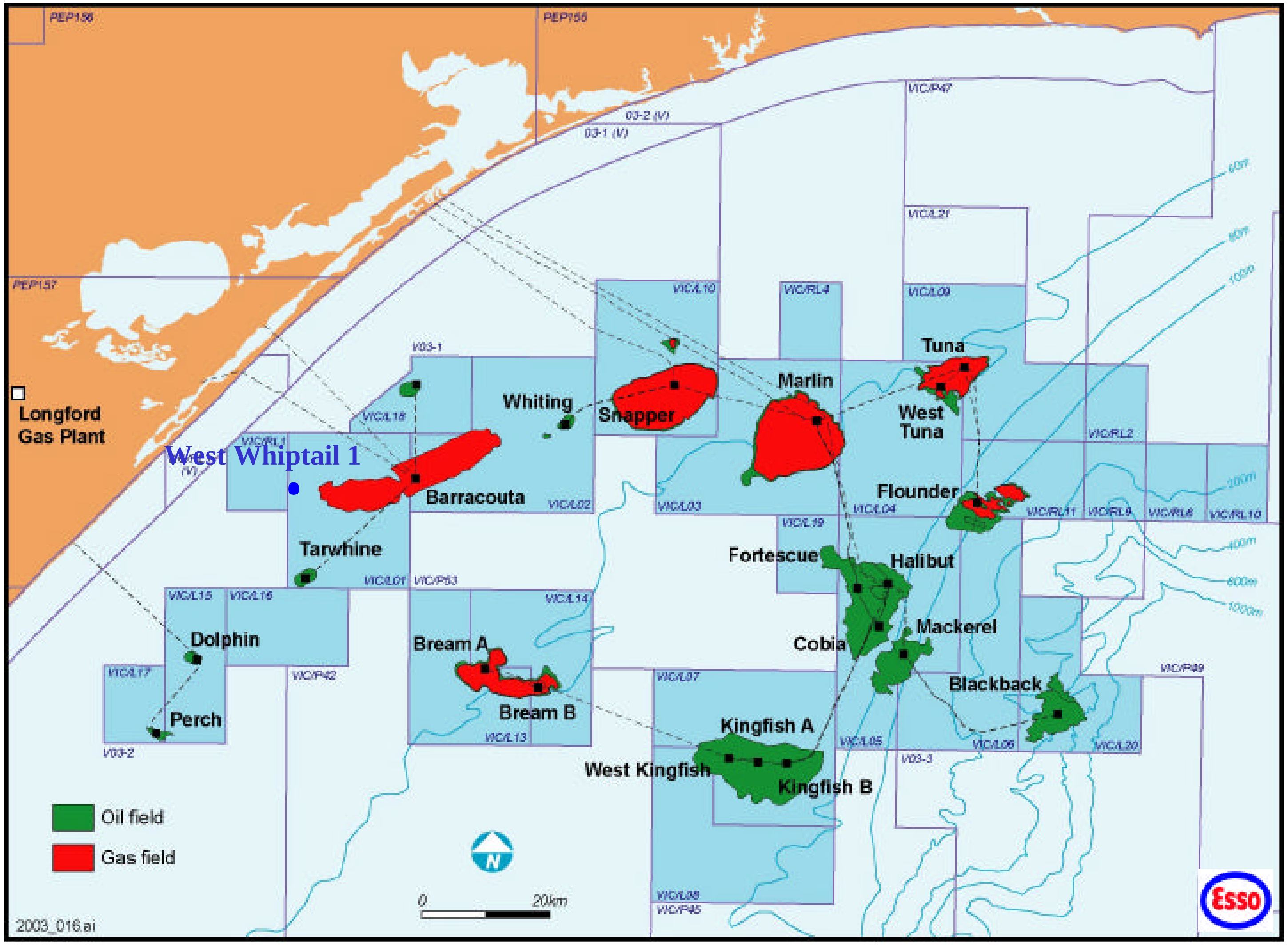


FIGURE 1

WEST WHIPTAIL-1
STRATIGRAPHY

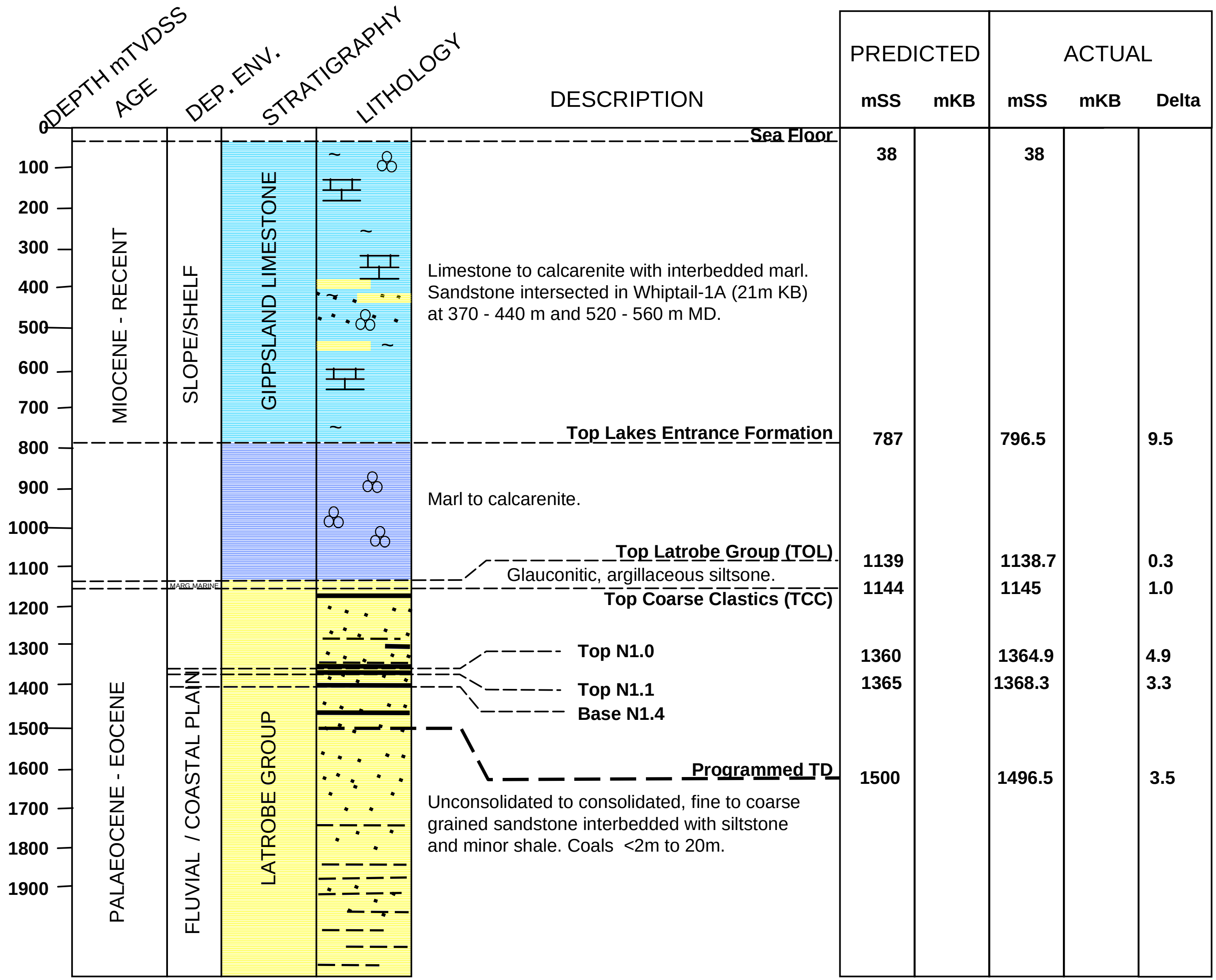


FIGURE 2

WHIPTAIL COMPLEX N1.1 POST-DRILL STRUCTURE

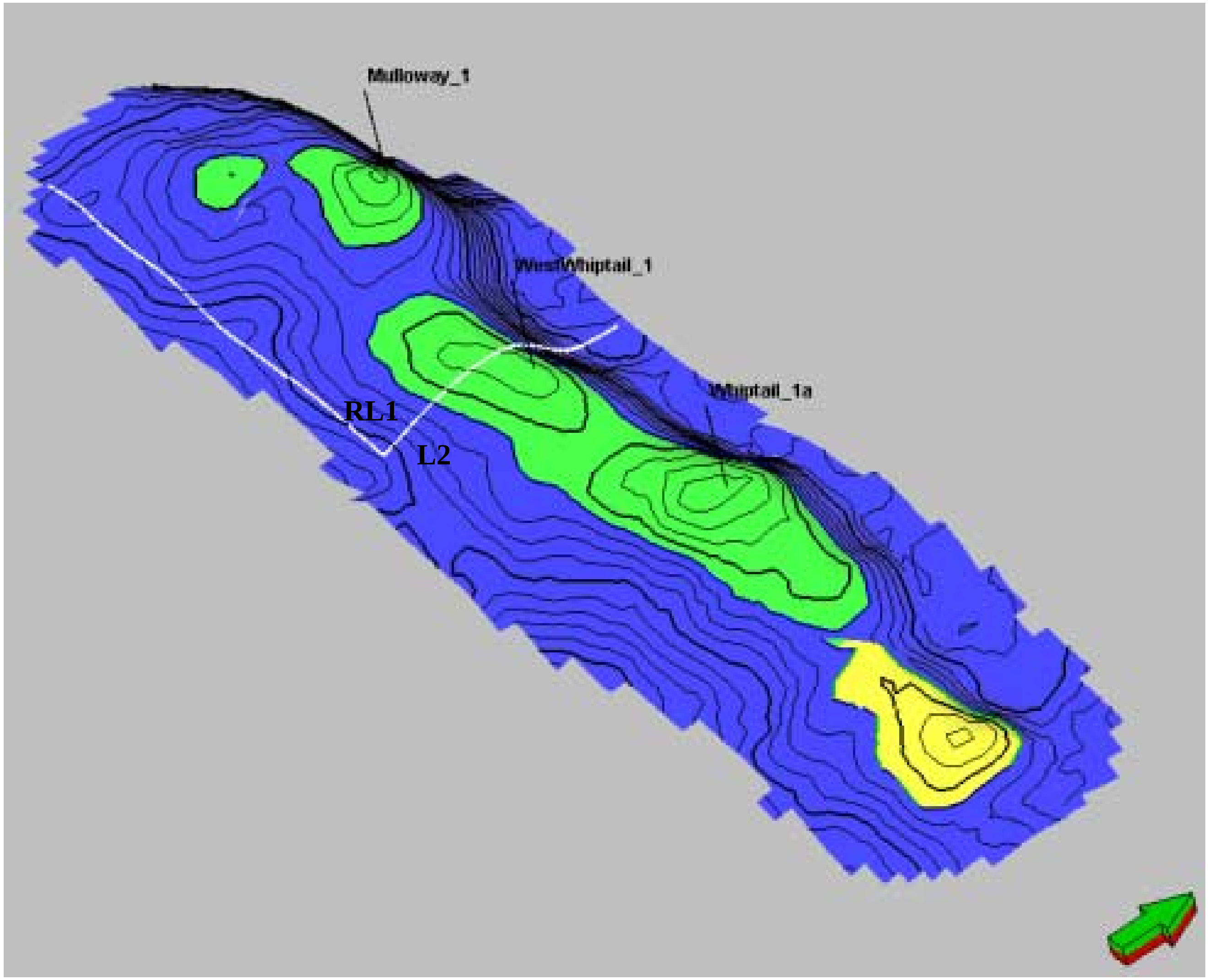


FIGURE 3

WEST WHIPTAIL 1 AND WHIPTAIL 1 MDT PRESSURES

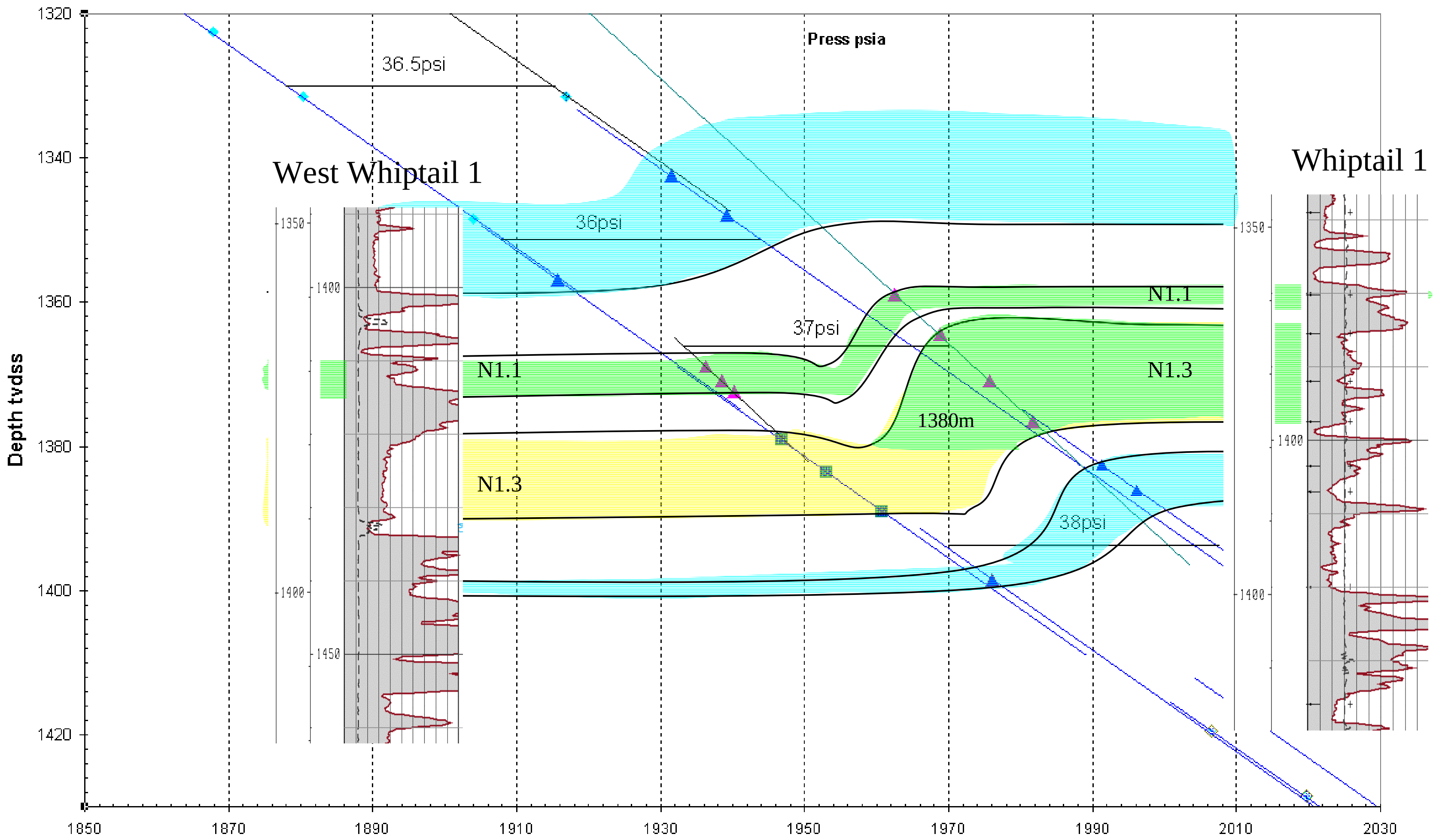


FIGURE 4

WHIPTAIL COMPLEX COMPARTMENT DEFINITION

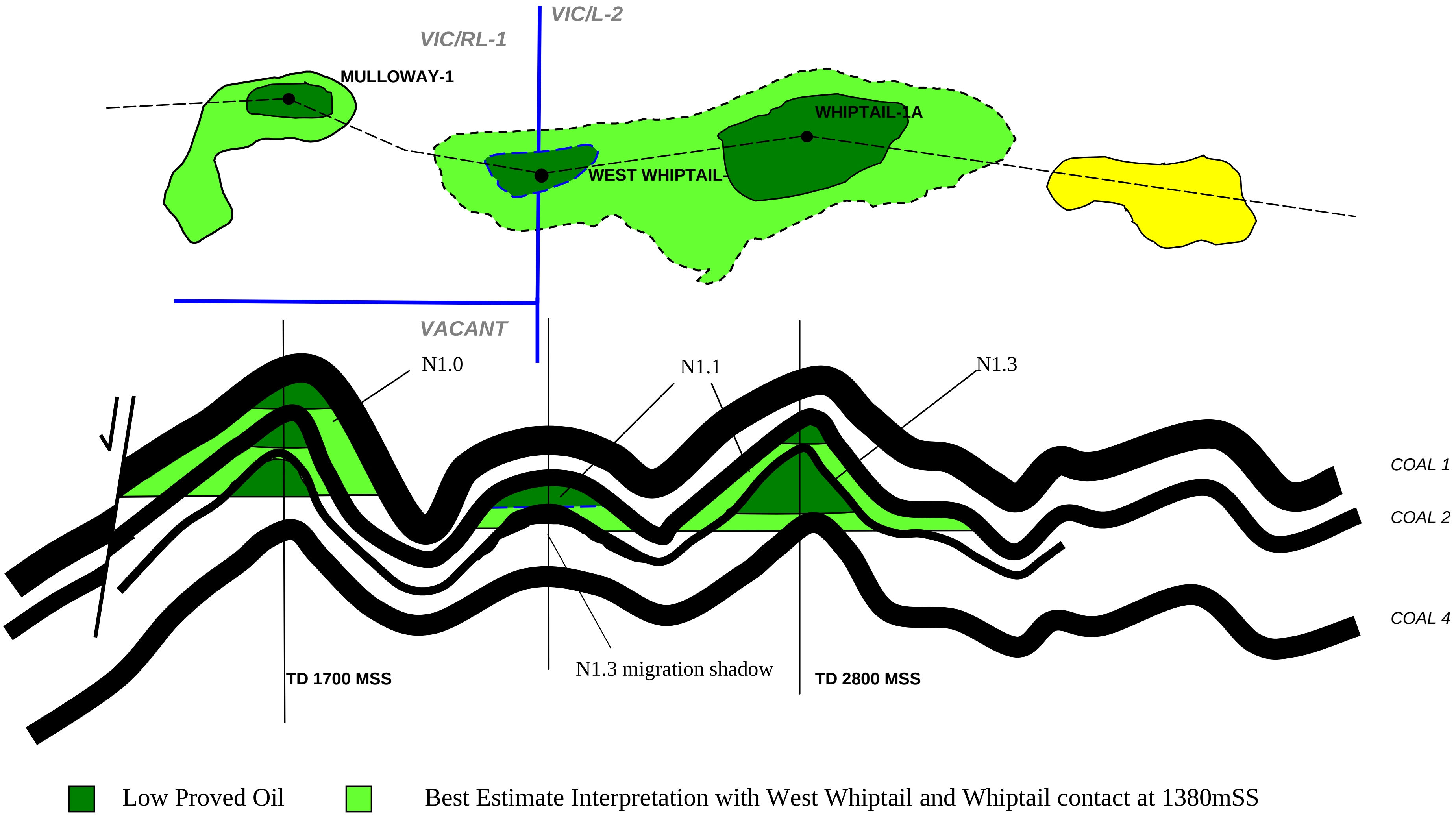
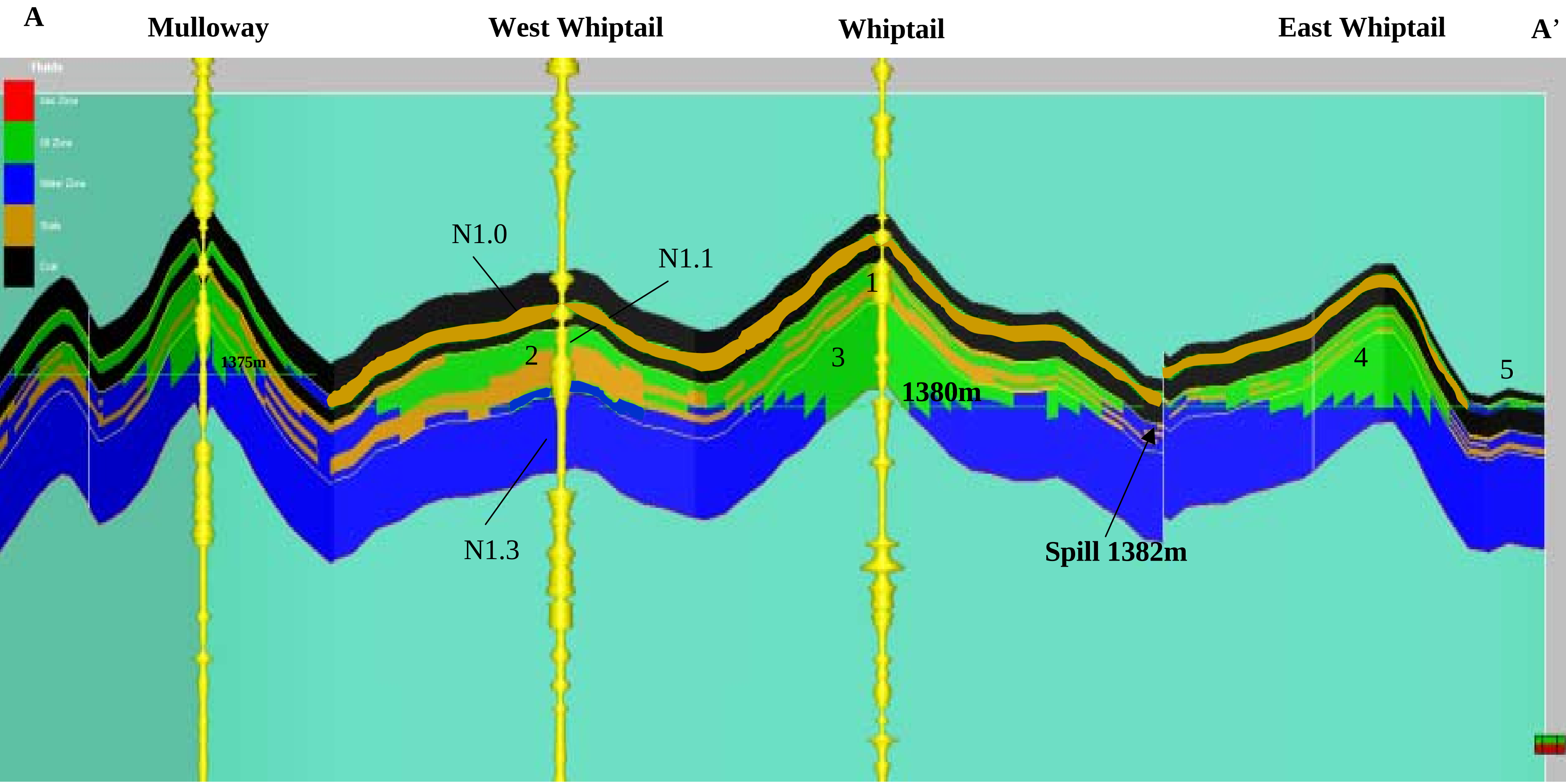


FIGURE 5

WHIPTAIL COMPLEX FILL AND SPILL MODEL



1-5 Fill and Spill order - local N1.1 base seal extends across W. Whiptail and Whiptail N1.1 fills across both closures before spilling to N1.3 in Whiptail via fault or breakdown of base seal on eastern flank of Whiptail. Then spills to East Whiptail then spills to Barracouta.

FIGURE 6

WEST WHIPTAIL 1 SYNTHETIC TIE

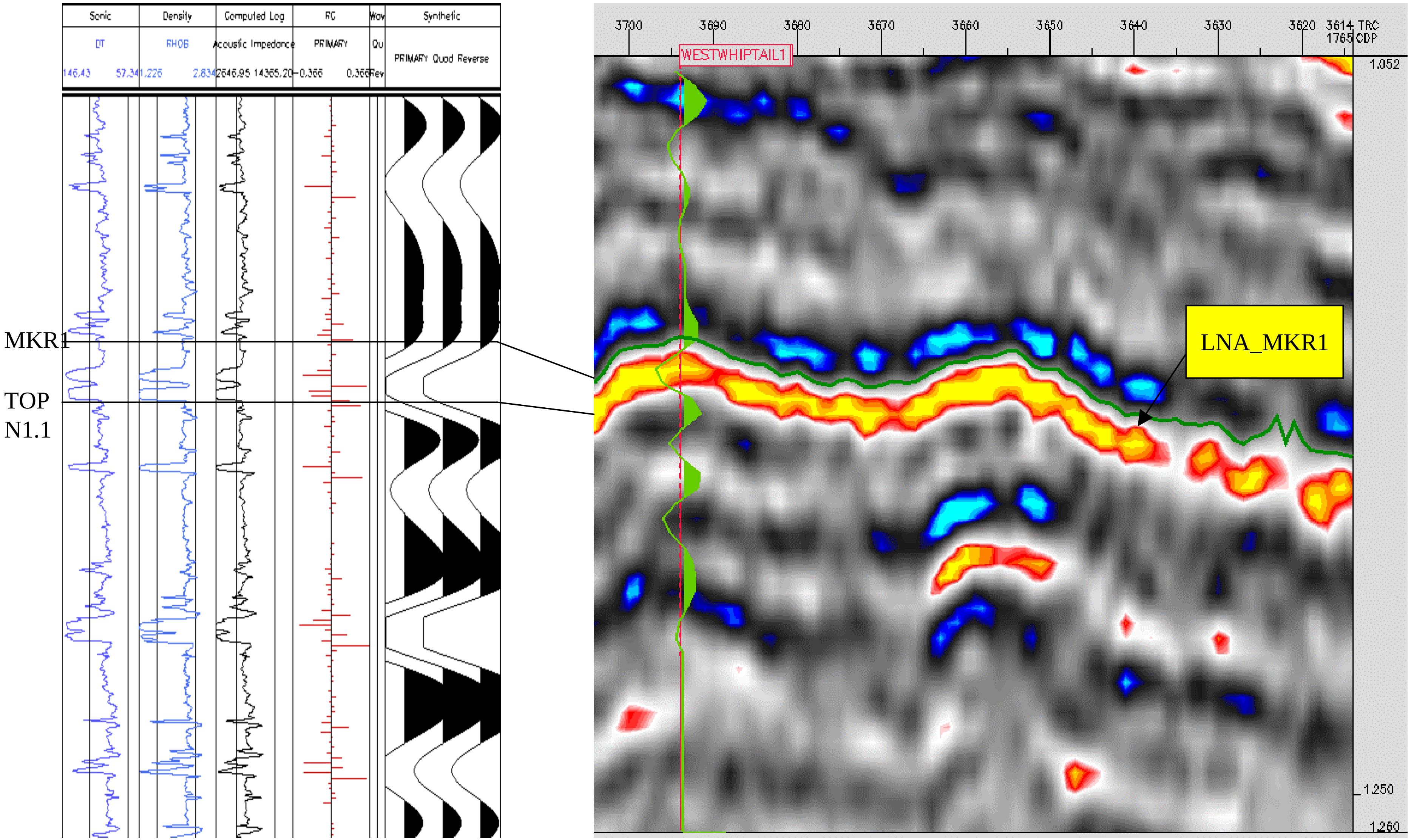


FIGURE 7

ATTACHMENT 1

COMPOSITE WELL LOG

ESSO AUSTRALIA RESOURCES LTD.

WELL COMPLETION LOG Scale - 1:200

WEST WHIPTAIL -1

Gippsland Basin, Victoria
Concession: VIC/L1

POST-DRILL (surface) **LOCATION:**	Latitude: 38º 19' 29.150"S Longitude: 147º 30' 17.167"E AMG X: 544,121.32 mE AMG Y: 5,758,030.22 mN Datum: GDA94 (GRS80) Projection: MGA/ UTM Zone 55 (S)	**COMPILED BY:**	Sheryl Sazenis
		DRAFTED BY:	Andrew Hodgson
		DRILLED BY:	ENSCO 102
ELEVATION:	G.L.: -78.0m R.T.: 39.0m Water Depth: 39.0m	**TOTAL DEPTH:**	1539m MDRT
		PLUGGED BACK T.D.:	117m MDRT
DATES:	Spudded: 10/05/2004 Rig Released: 05/06/2004 I.P. Established: Plugged & Abandoned *(Initial production)*	**CLASSIFICATION:**	Near Field Wildcat
		STATUS:	Plugged & Abandoned

SERVICE COMPANIES:

DRILLING CONTRACTOR:	ENSCO Australia (ENSCO 102)	PRODUCTION TESTING:	Not tested
LWD/MWD:	No MWD run	DIVERS:	Global Offshore ROV
GYRO SURVEYING:	Scientific Drilling International / Anderdrift	MUD LOGGING:	Geoservices
CORING:	No cores cut	PRESSURE RECORDING:	Schlumberger
WIRELINE LOGGING:	Schlumberger	WELL VELOCITY SURVEY:	Schumberger
CEMENTING:	Dowell Schlumberger	MUD ENGINEERING:	Baroid Australia
CASING:	Weatherford Australia	LINER:	Not run

LEGEND

2.7m NOS
Ø = 17%
Sw = 32%

LOG ANALYSIS DATA
NS - Net Sand
NOS - Net Oil Sand
NGS - Net Gas Sand
Sw - Water Saturation

SHOW OR STAIN

HYDROCARBON CUT

Sw - Water Saturation

No Rec.
CORE
Rec.

PERFORATED INTERVAL

PLUG

MUD DATA
Ø - Porosity
Snd - Sand
MW - Mud Weight
FV - Funnel Velocity
PV - Plastic Velocity
YP - Yield Point
Gel - Gel Strength
pH - Acidity/Alkalinity
WL - Water Loss
Cl - Chloride
Ca - Calcium
Sol - Solids
H2O - Water
Oil -Oil

SST RECOVERED SIDE WALL CORE LITHOLOGY

SST - Sandstone	CLST - Claystone
SLST - Siltstone	LMST - Limestone
MST - Mudstone	ML - Marl
SH - Shale	COAL - Coal

SIDE WALL CORE - NO RECOVERY

SST RECOVERED MSCT

MSCT – NO RECOVERY

FIT

P2/11 MDT PRETEST SUITE/RUN/SEAT NUMBER

S11/2 MDT SAMPLE SUITE/RUN/SAMPLE NUMBER

P2/40 MDT VERTICAL/HORIZONTAL PERMEABILITY TEST

PACKER

BRIDGE PLUG

FLUORESCENCE

GAS SHOW

OIL PRODUCTION

GAS PRODUCTION

INTERPRETED OIL PRODUCTION

INTERPRETED GAS PRODUCTION

INTERPRETED WATER PRODUCTION

WATER PRODUCTION

CONDENSATE PRODUCTION

INTEPRETED CONDENSATE BEARING

DSTG DST WITH GAS RECOVERED

DSTO DST WITH OIL RECOVERED

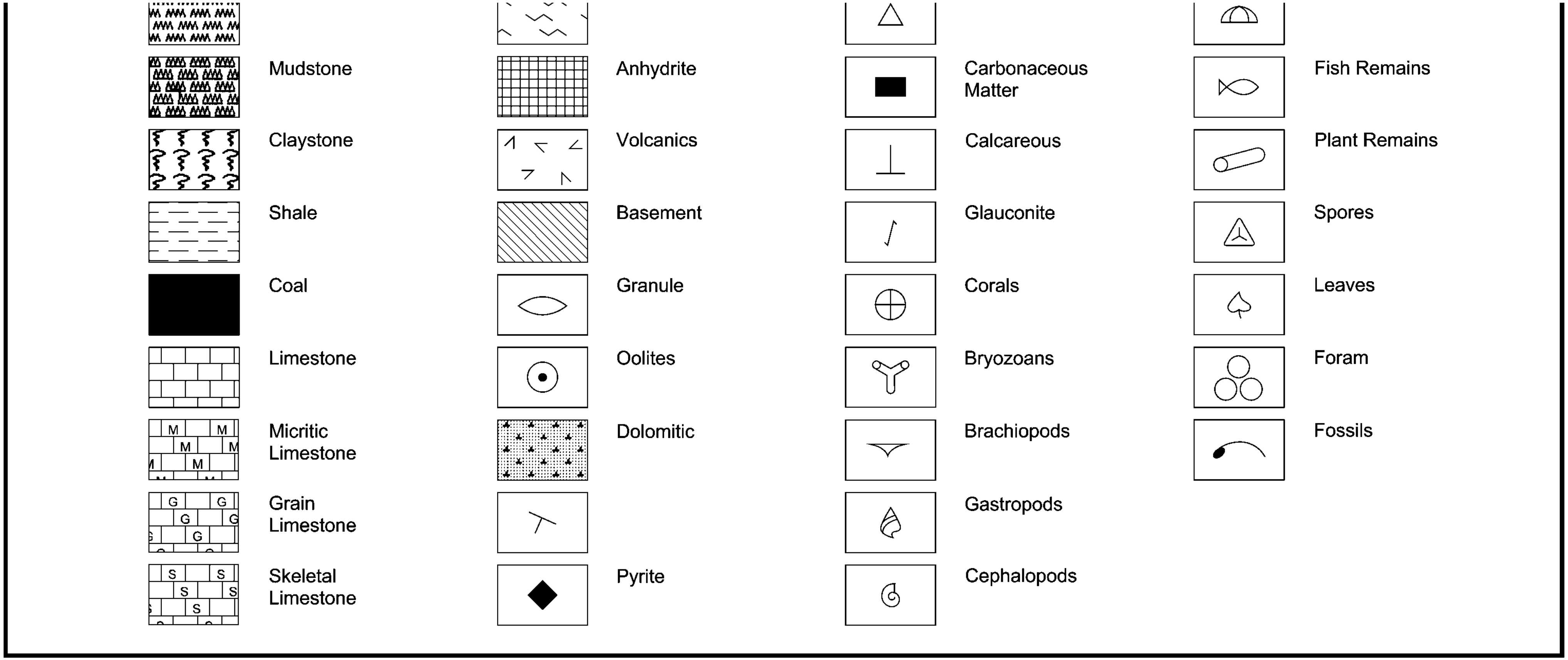
SURVEY POINT

13-3/8" CASING SHOE

MUD

LITHOLOGICAL SYMBOLS

Sandstone	Dolomite	Mica	Pelecypods
Siltstone	Marl	Chert	Echinoids



LOGGING AND SURVEYING

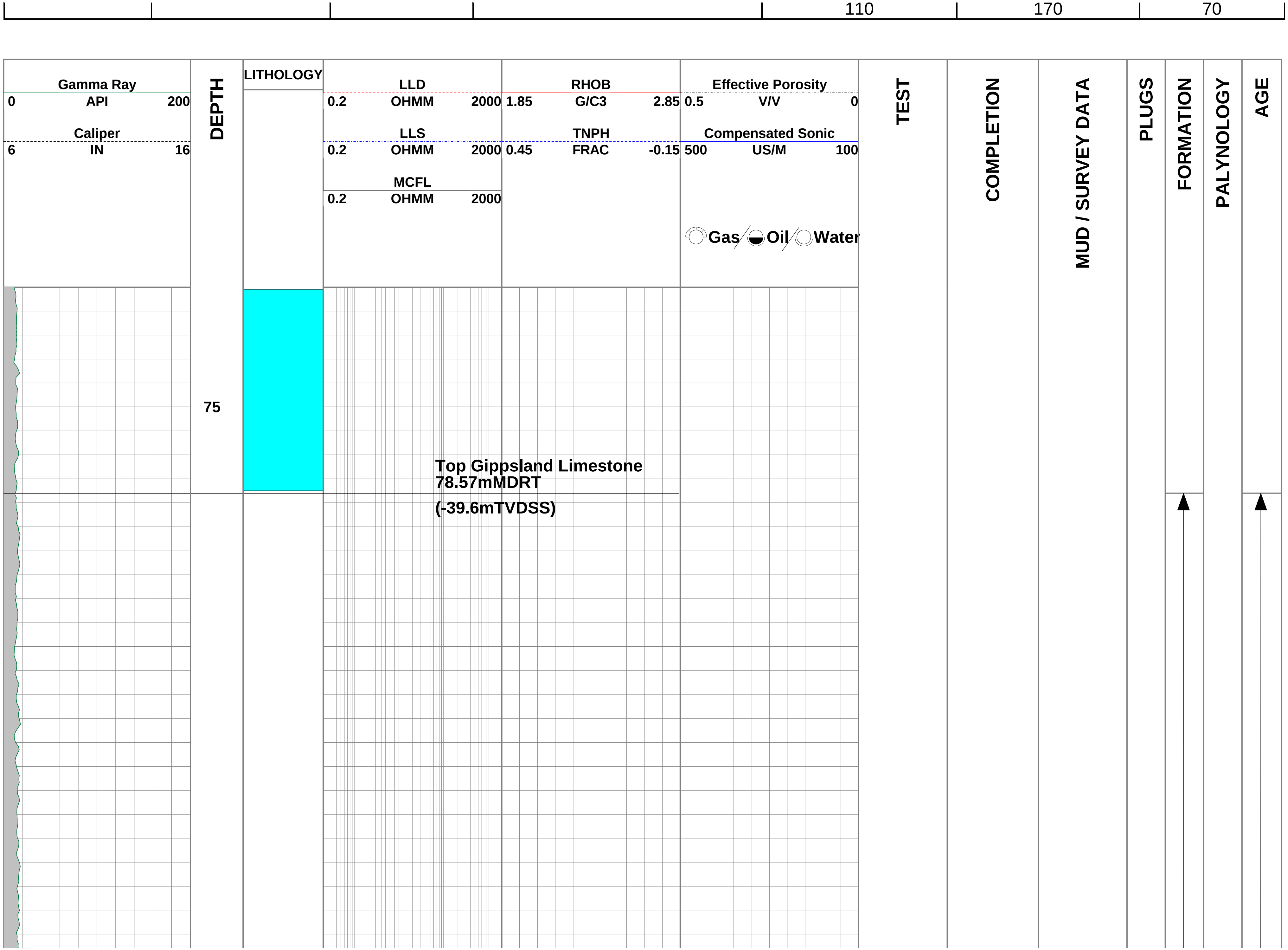
Log Suite #1	Interval (mMDRT)	Survey	Interval (mMDRT)
RUN #1 PEX-HALS-DSI-HNGS-LEHQT	1529m - 77.6m 1480m - 1380m Repeat Section 1529m - 1100m PEX Logged in high-resolution mode. 1100m - 745m PEX Logged in normal resolution mode. 1529m- 745m DSI P & S in upper dipole mode 745m - 77.6m DSI in P & S mode GR run to Sea floor 77.6m	GYRO Scientific drilling International Anderdrift	104m – 1521.9m 93m - 1445m
RUN #2 MDT-GR-LEHQT	MDT could not pass 1241m due to bridging of the hole, Run aborted.		
RUN #2A MDT-GR-LEHQT (pressures and samples)	20 Stations measured. 4 Pump-outs. 4 pre-tests Tight. 16 pre-tests Good. 1 x pump-out sampled: 4 x MPSR, 1 suspect MPSR and 1x1gallon samples collected . 2 x Pump-outs LFA analysis only. 1		

	x Pump-out too tight for LFA analysis.		
RUN #3 CSAT-GR	1264m - 100m 50m stations		

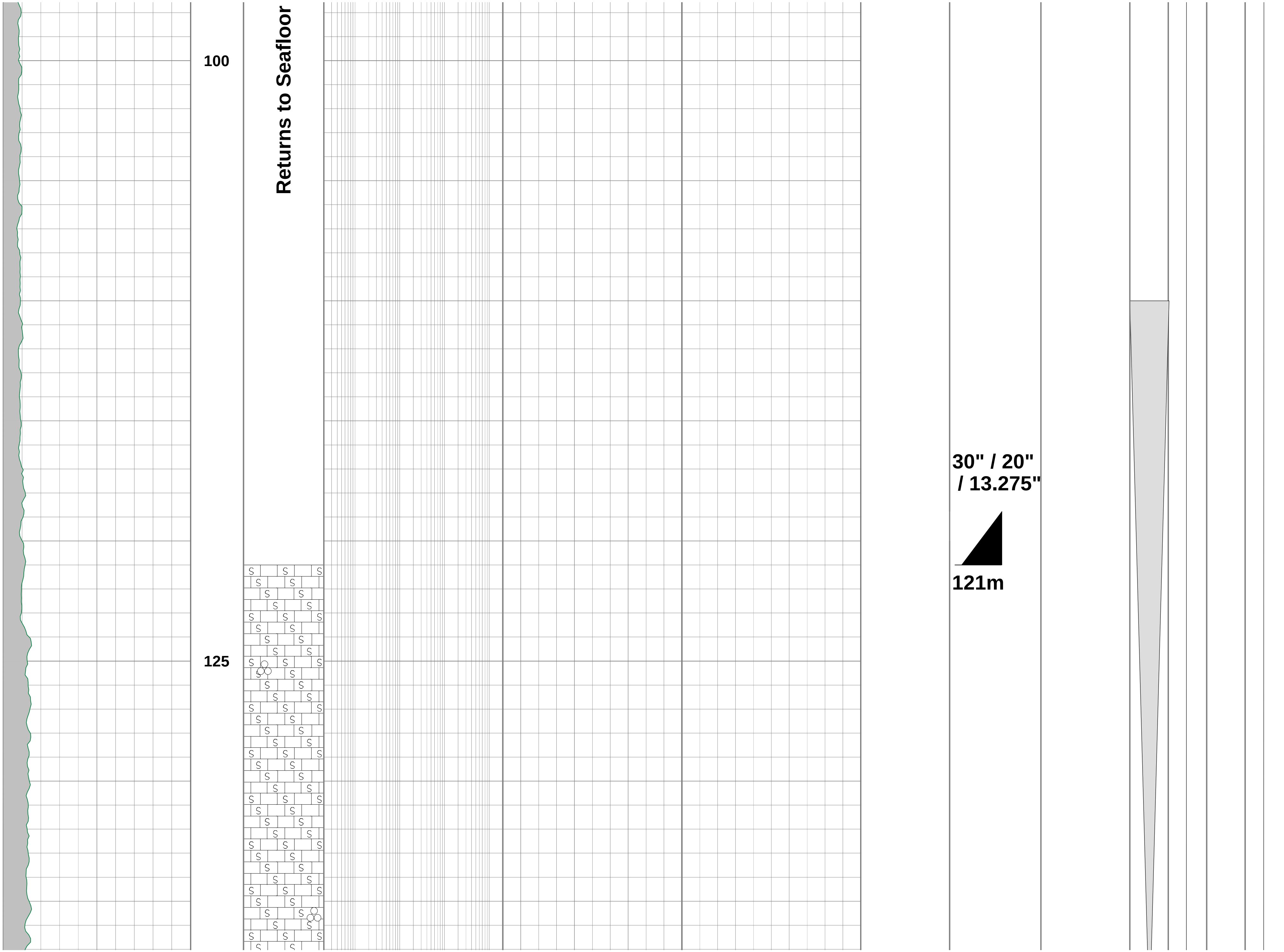
WELL DATA				
Date	20/05/2004 - 21/05/2004	21/05/2004	22/05/2004	22/05/2000
Run	1	2	2A	3
Log	PEX-HALS-DSI-HNGS-LEHQT	MDT-GR-LEHQT	MDT-GR-LEHQT	CSAT-GR
Depth Driller	1539m	1539m	1539m	1539m
Depth Logger	1529m	Log did not reach bottom	Log did not reach bottom	Log did not reach bottom
Bottom Log Interval	1526.7m	Run aborted at 1241m	1470m lowest depth pre-tested	1264m Lowest depth station
Top Log Interval	77.6m GR and DSI logged to ML	Run aborted at 1241m	1364m	100m
Casing Driller	745m	745m	745m	745m
Casing Logger	745.5m	745.5m	745.5m	745.5m
Casing Size	9 5/8"	9 5/8"	9 5/8"	9 5/8"
Casing Weight	47 lb/ft	47 lb/ft	47 lb/ft	47 lb/ft
Bit Size	8 1/2"	8 1/2"	8 1/2"	8 1/2"
Type of Fluid in Hole	KCl/PHPA/Polymer/Glycol	KCl/PHPA/Polymer/Glycol	KCl/PHPA/Polymer/Glycol	KCl/PHPA/Polymer/Glycol
Density	9.95 ppg	9.95 ppg	10.2 ppg	10.2 ppg
Rm @ Measured Temp.	0.117 @ 19°C	0.117 @ 19°C	0.1233 @ 25.5°C	N/a
Rmf @ Measured Temp.	0.097 @ 21°C	0.097 @ 21°C	0.099 @ 21.6°C	N/a
Rmc @ Measured Temp.	0.143 @ 21°C	0.143 @ 21°C	0.1334 @ 26.2°C	N/a
Max. Recorded Temp.	72.0°C	Log did not get to bottom	70.9°C @ 1419m	N/a
Equipment / Location	unit 571, VEA	unit 571, VEA	unit 571, VEA	unit 571, VEA
Recorded By	Greg Ruthven / Justin Bell	Greg Ruthven / Justin Bell	Greg Ruthven / Justin Bell	Greg Ruthven / Justin Bell
Witnessed By	Mike Woodmansee	Mike Woodmansee	Mike Woodmansee	Greg O'Niell

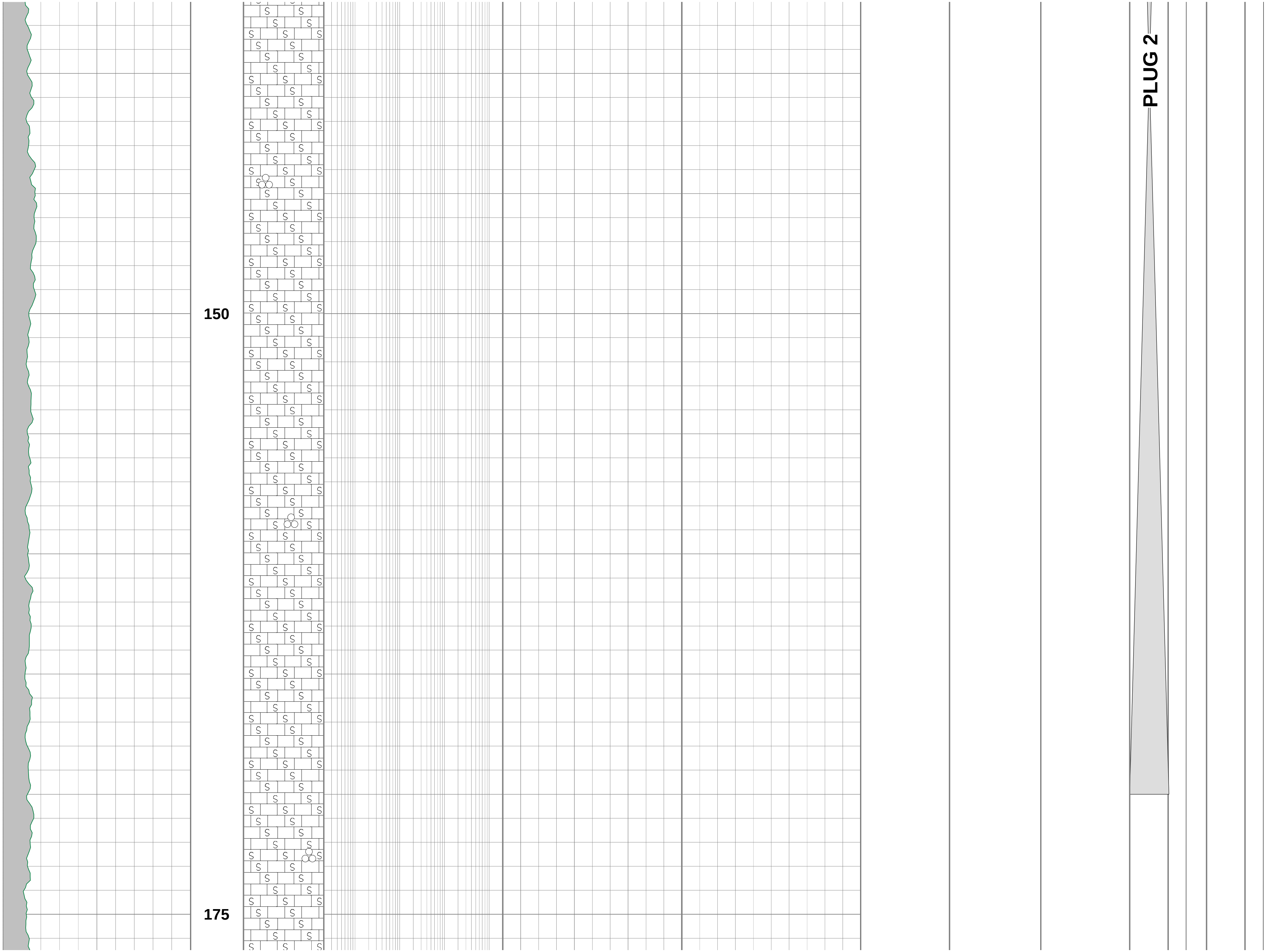
CORES			PERFORATIONS		
From (mMDRT)	**To (mMDRT)**	**Rec %**	**From (mMDRT)**	**To (mMDRT)**	**Shots/ft**
No cores were cut	---		No perforations		

CASING				PLUGS		
Size	**Set @ (mMDRT)**	**Sx Cmt**	**Formation**	**From (mMDRT)**	**To (mMDRT)**	**Sx Cmt**
30”/20”/ 13.375”	121.0	1084	Gippsland Limestone	1365	1539	197
9.625”	745	738	Gippsland Limestone	1191	1365	208
				1017	1191	252
				843	1017	222
				669	843	222



110
170
70
Gamma Ray
0 API 200
Caliper
6 IN 16
DEPTH
LITHOLOGY
LLD
0.2 OHMM 2000
LLS
0.2 OHMM 2000
MCFL
0.2 OHMM 2000
RHOB
1.85 G/C3 2.85
TNPH
0.45 FRAC -0.15
Effective Porosity
0.5 V/V 0
Compensated Sonic
500 US/M 100
Gas
Oil
Water
TEST
COMPLETION
MUD / SURVEY DATA
PLUGS
FORMATION
PALYNOLOGY
AGE
75
Top Gippsland Limestone
78.57mMDRT
(-39.6mTVDSS)


100
125
Returns to Seafloor
30" / 20"
/ 13.275"
121m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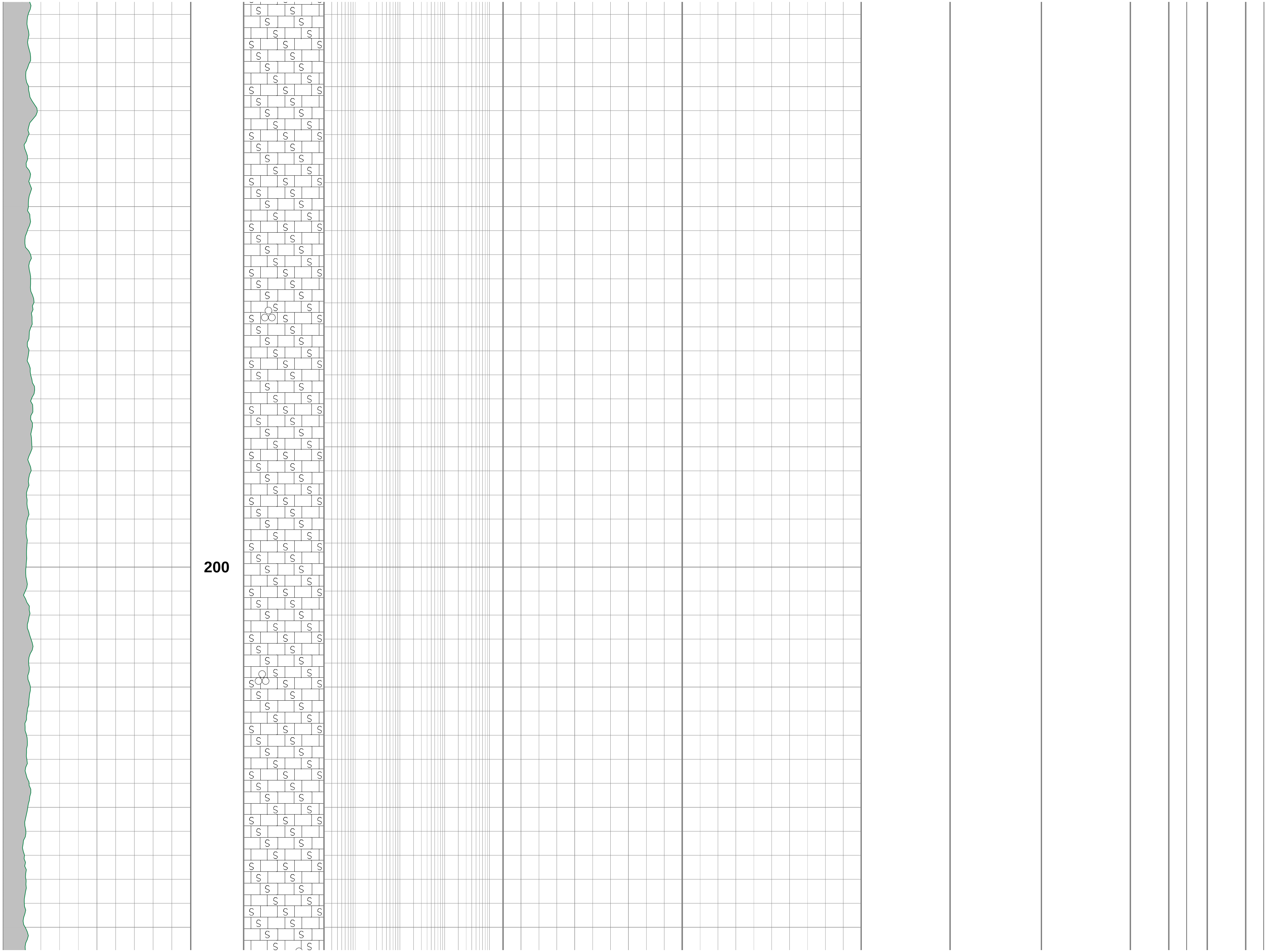
175
PLUG 2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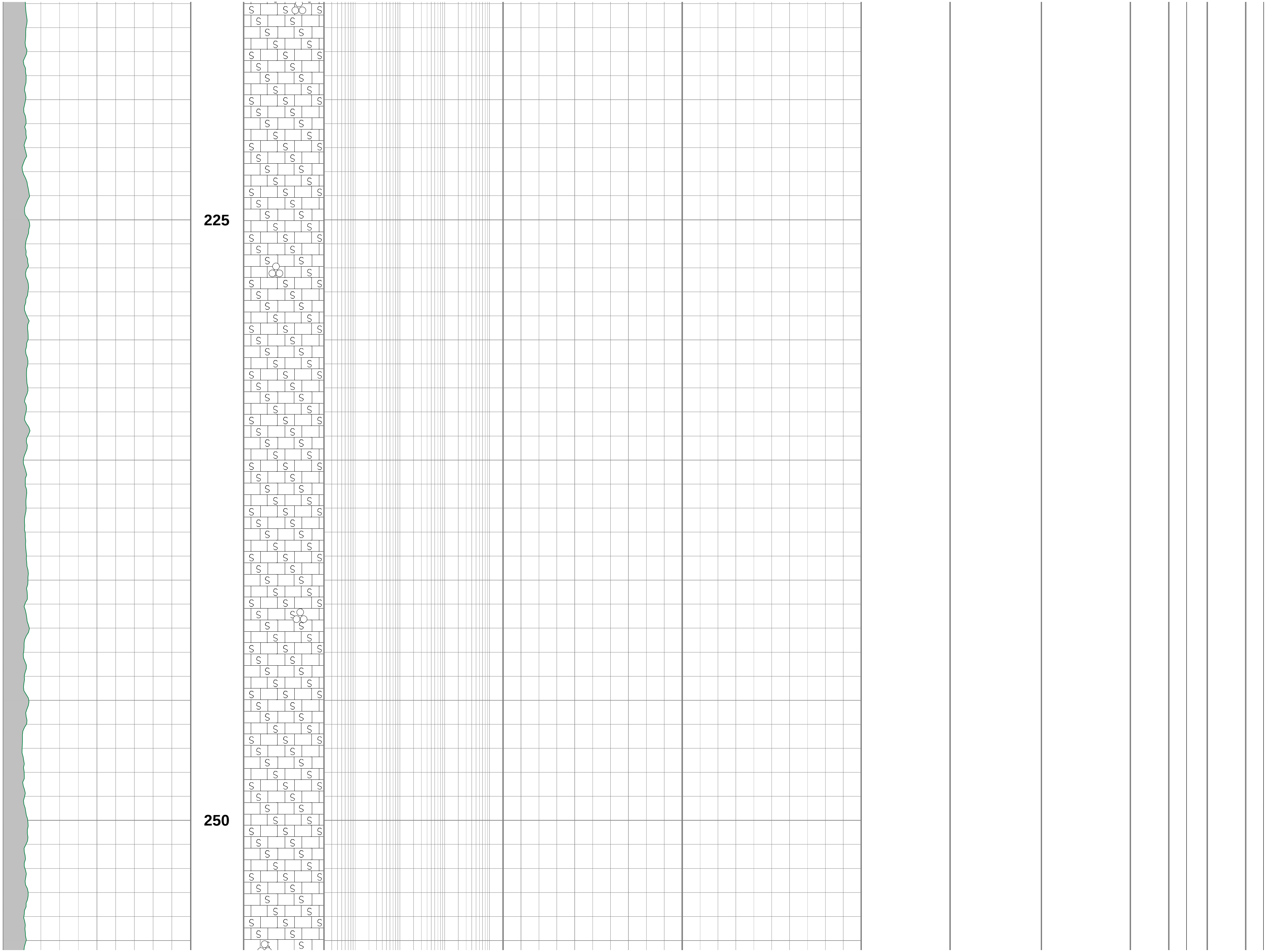
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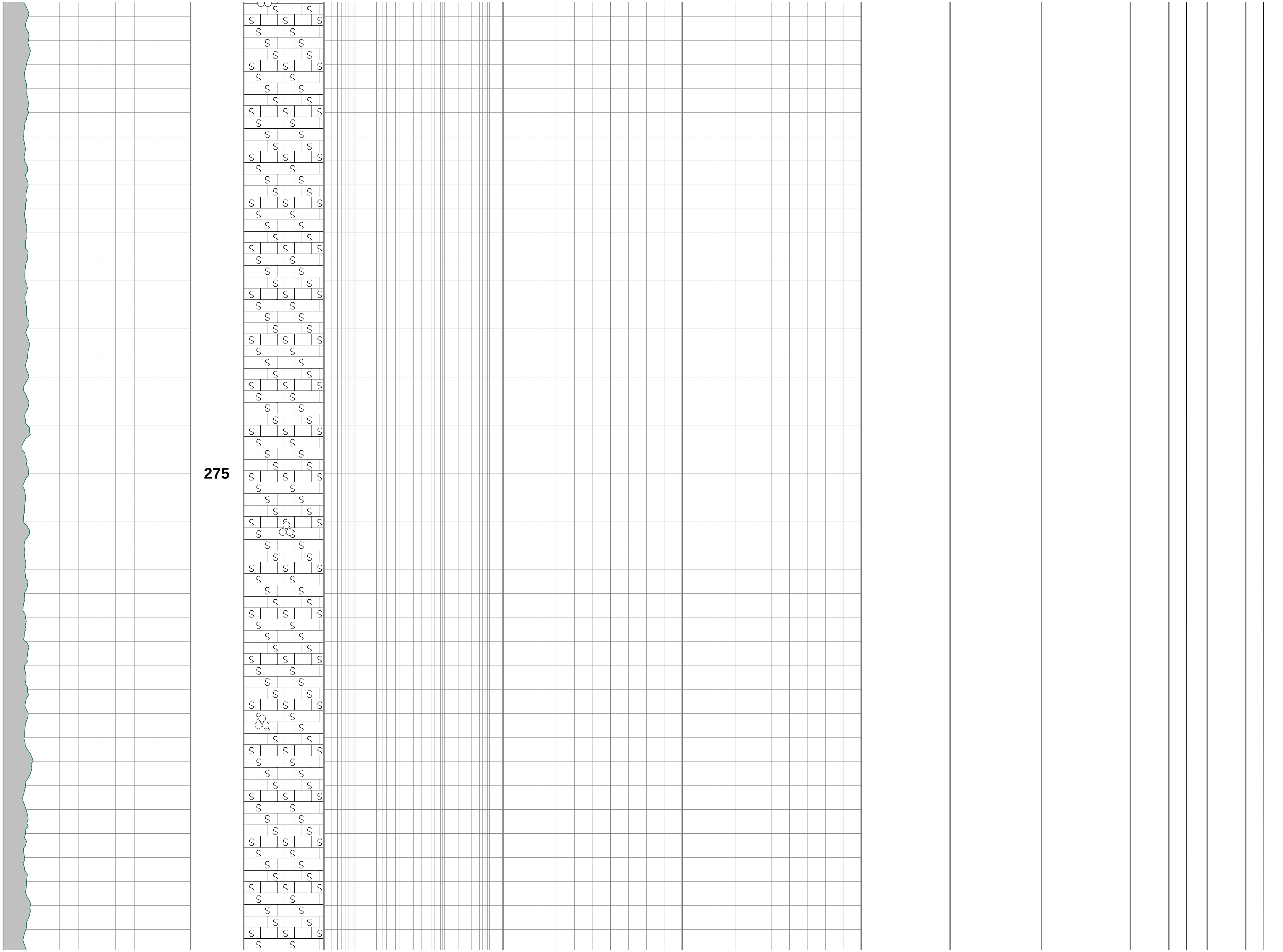
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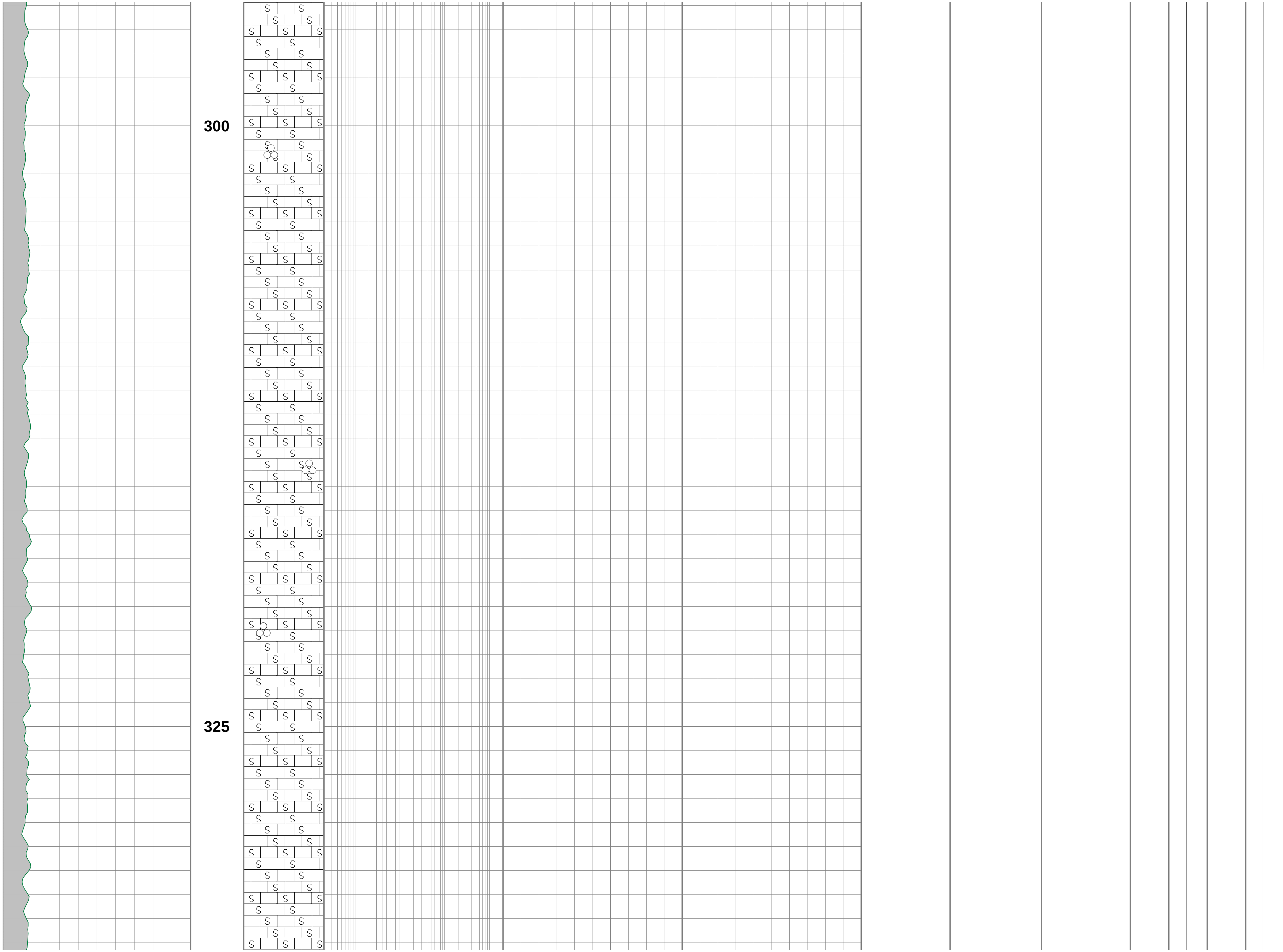
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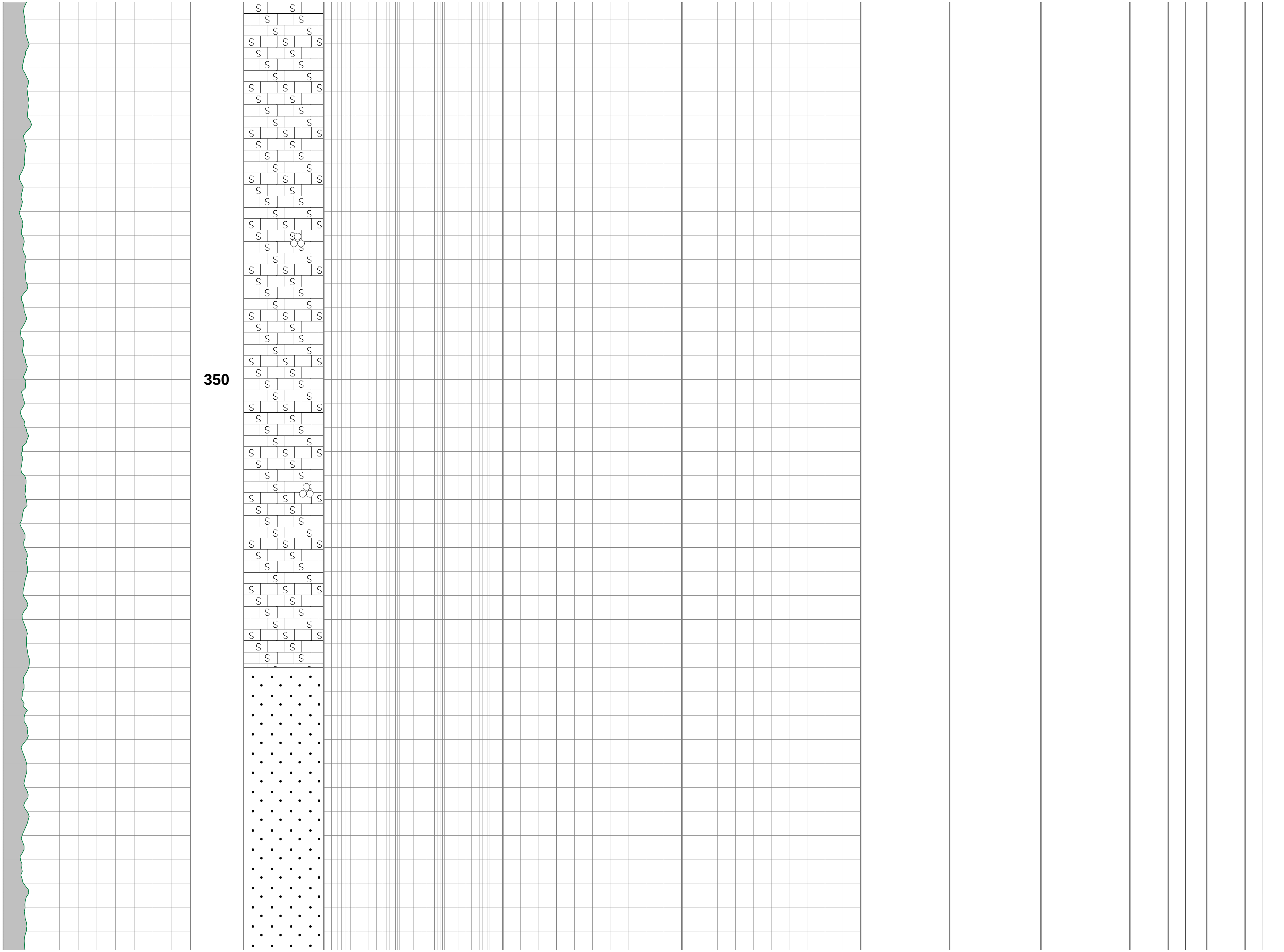
325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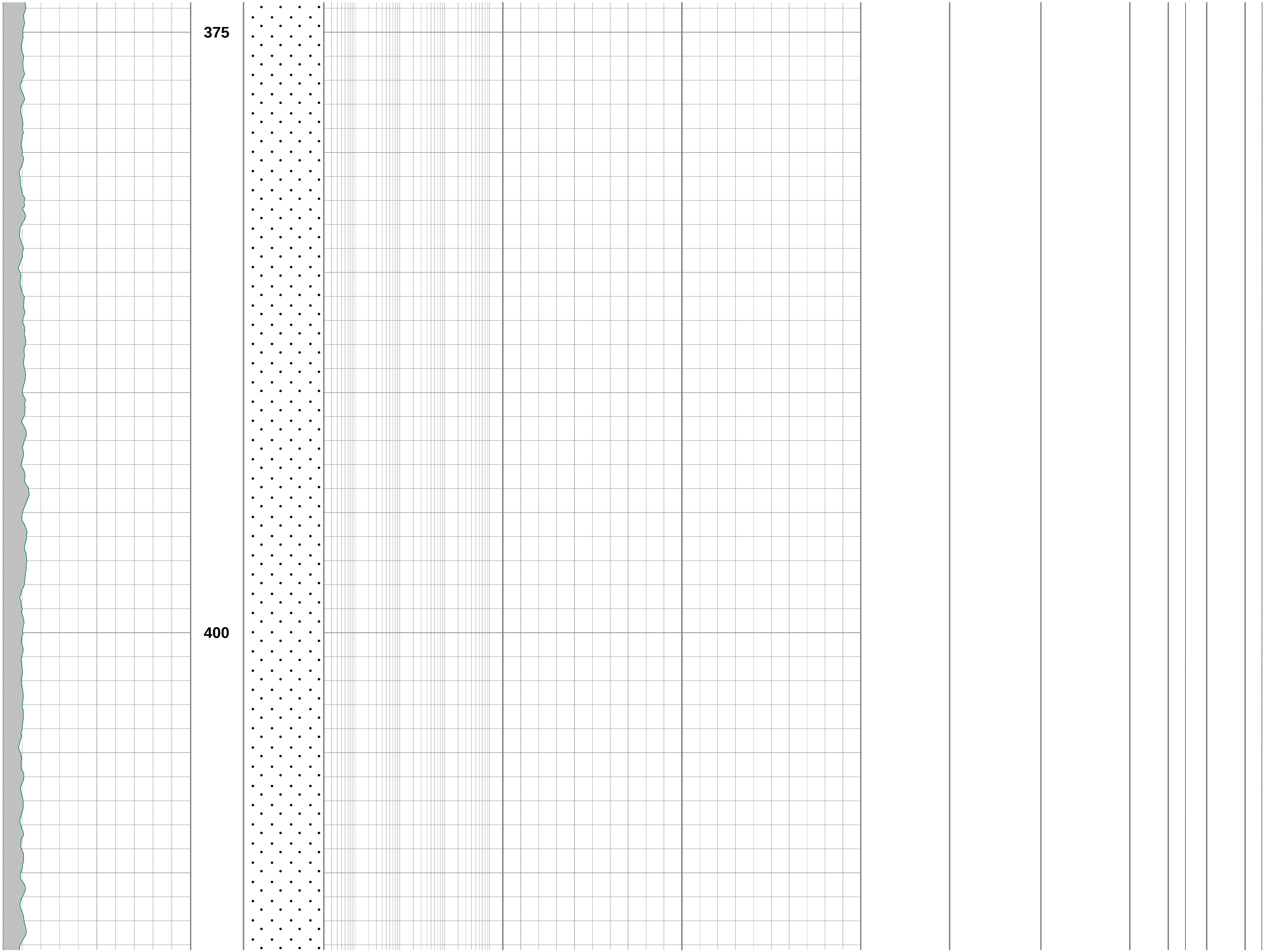
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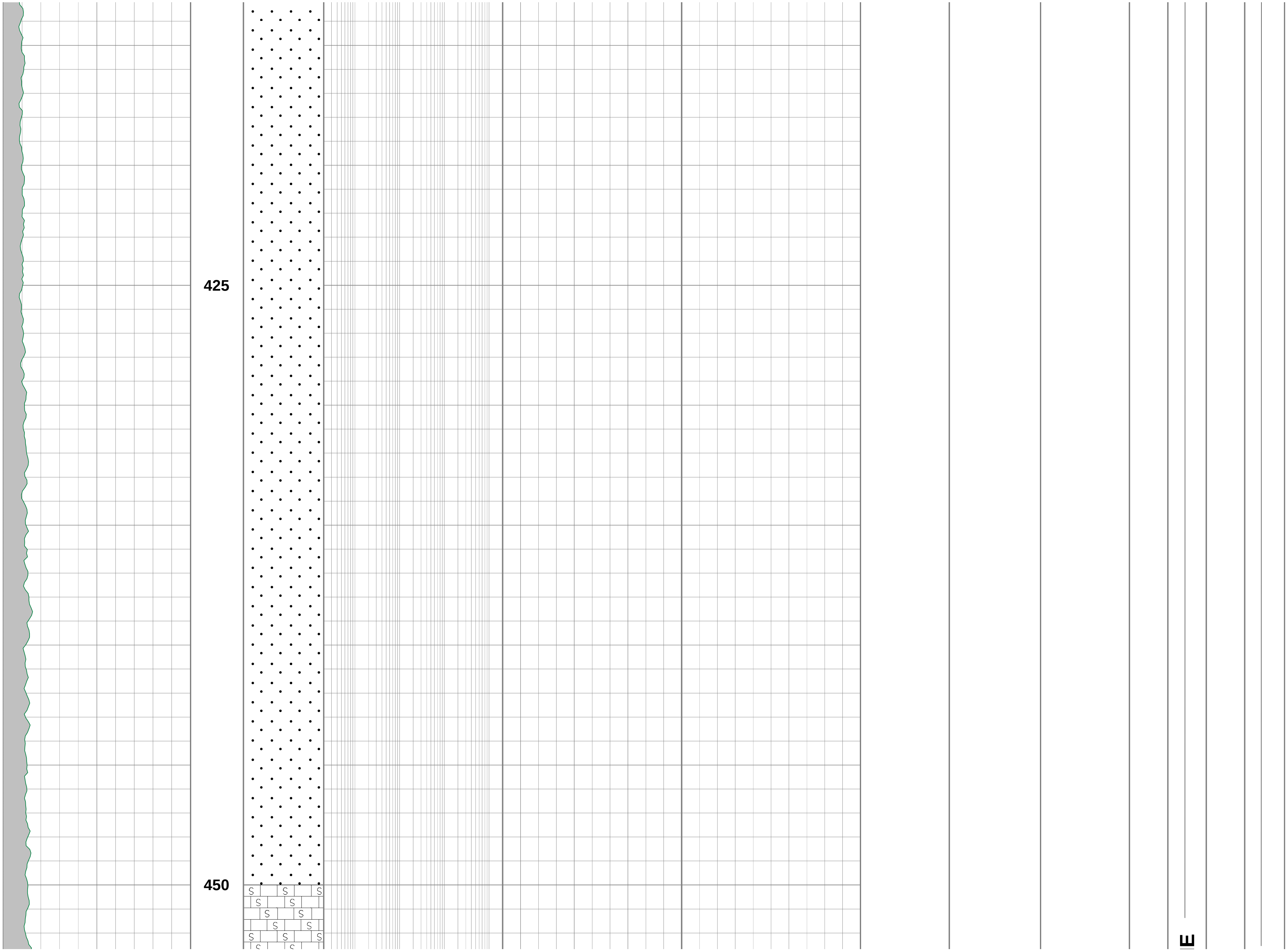
400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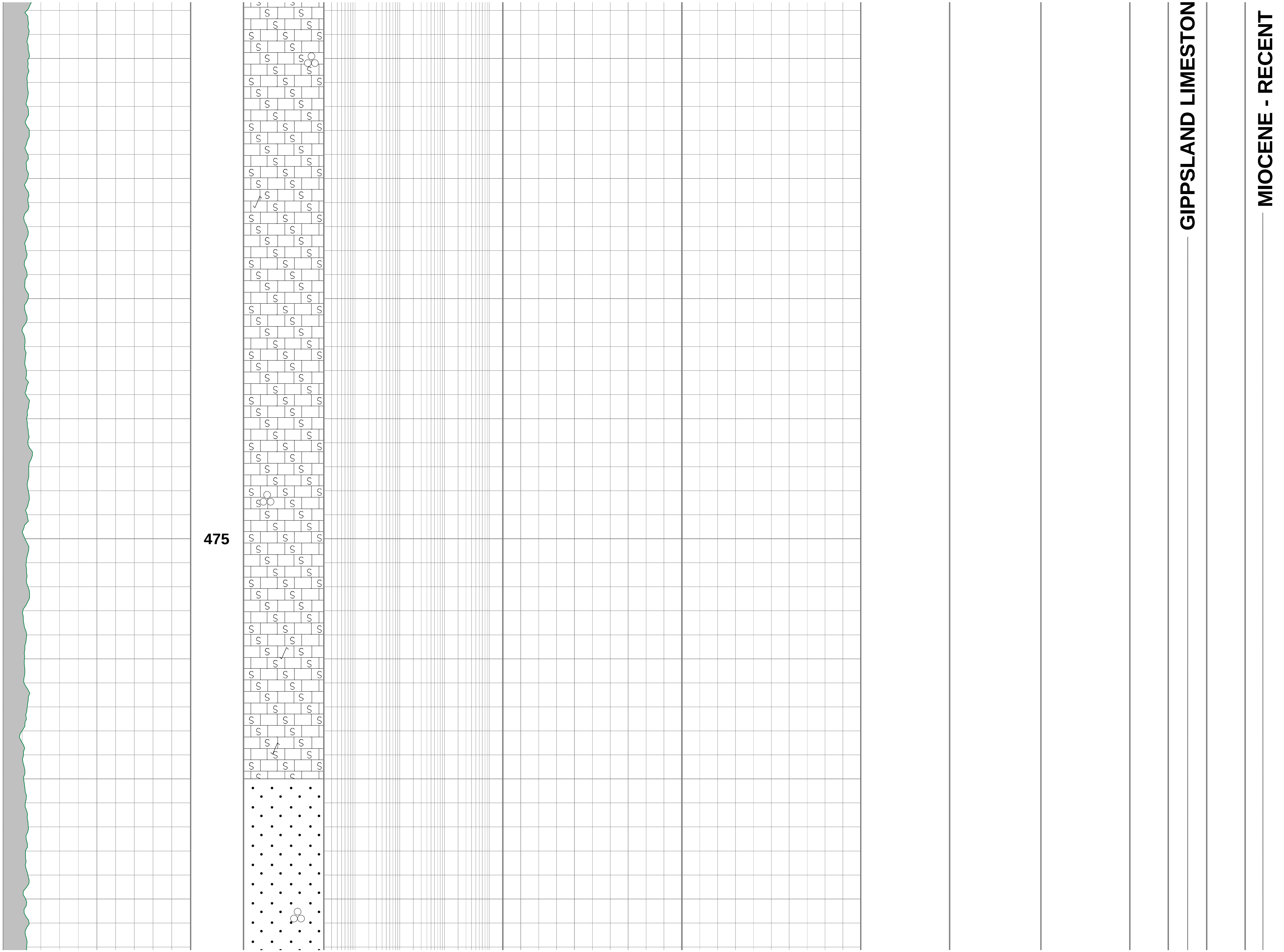
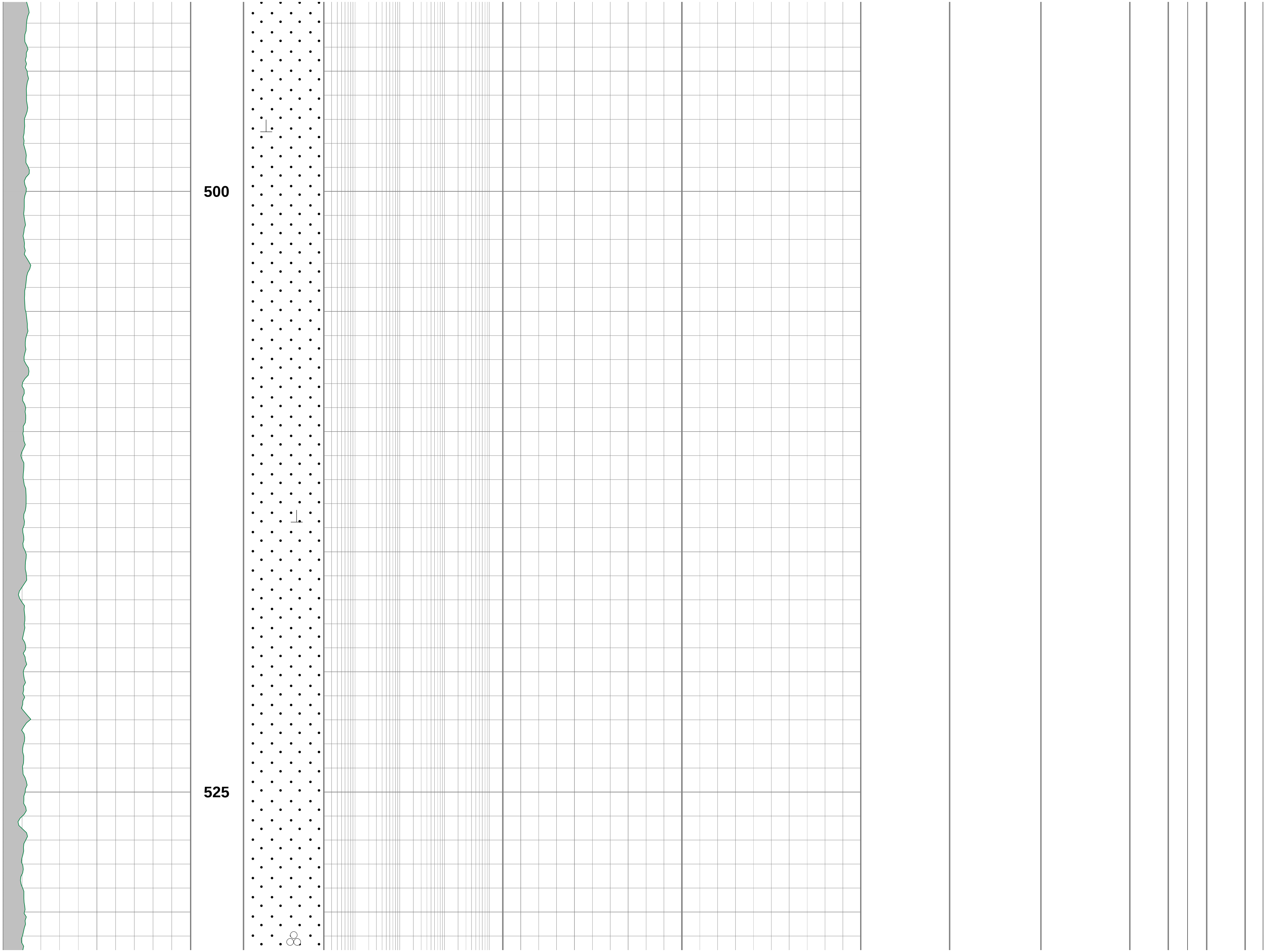

475
GIPPSLAND LIMESTON
MIOCENE - RECENT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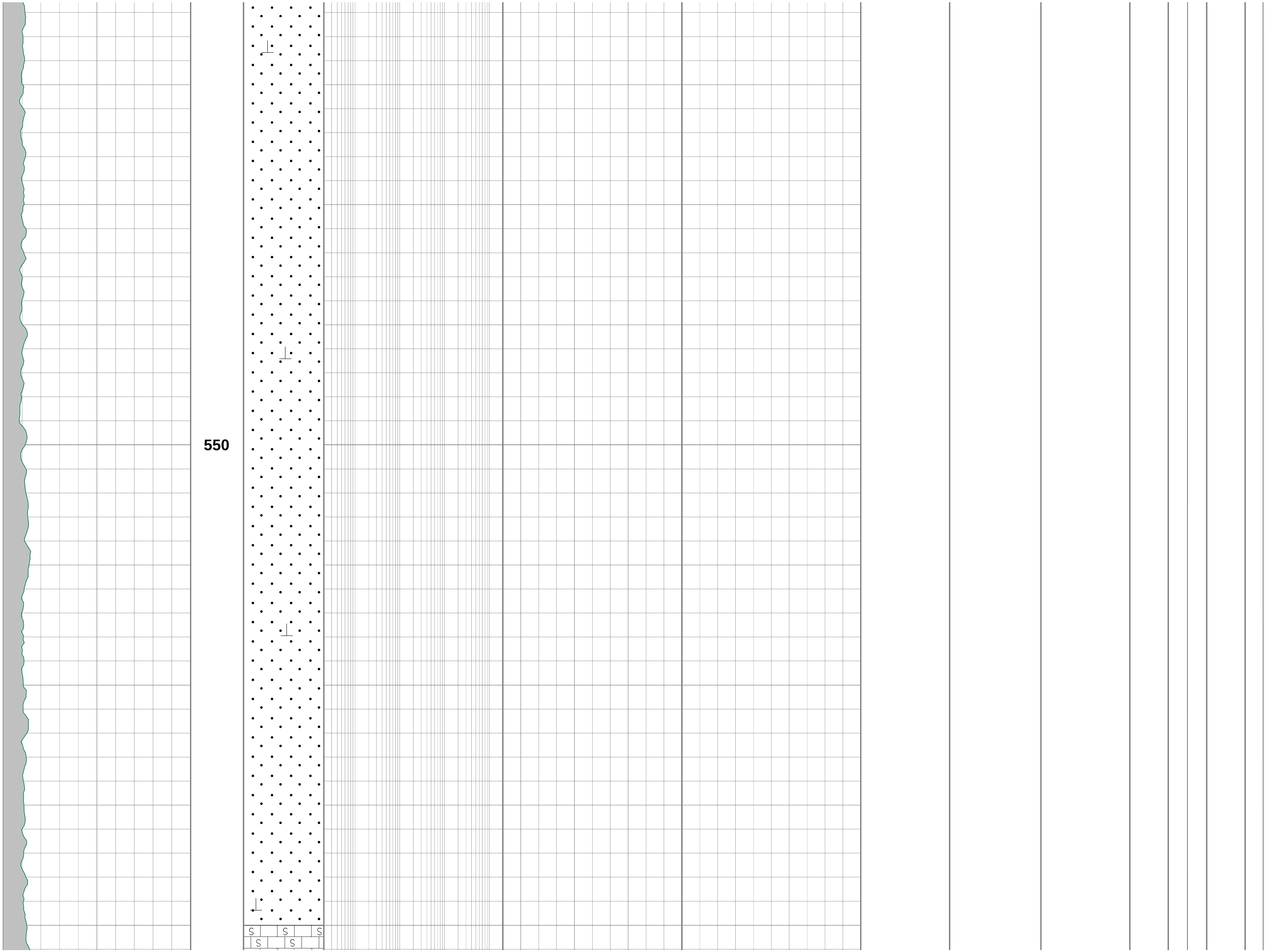
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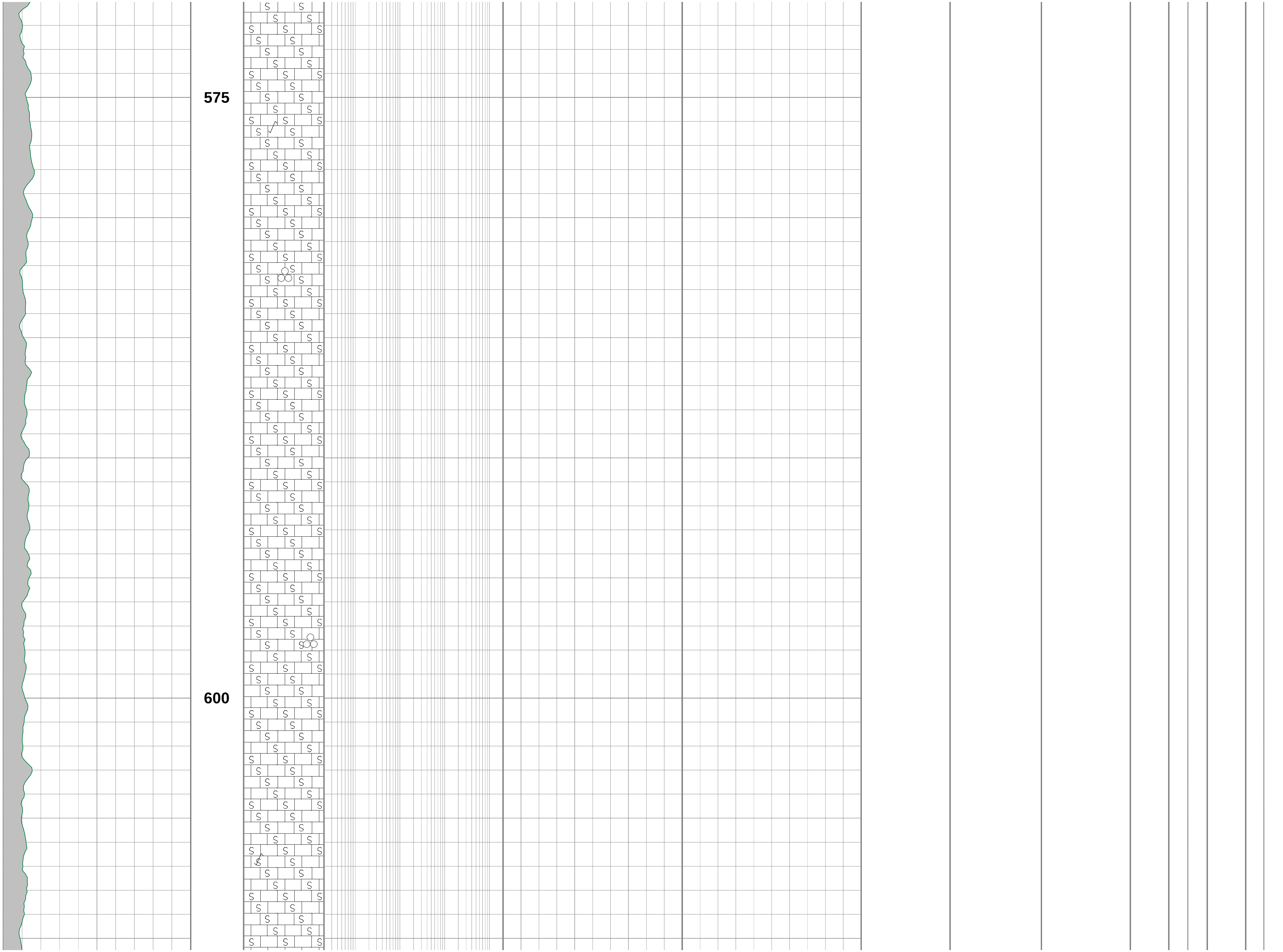
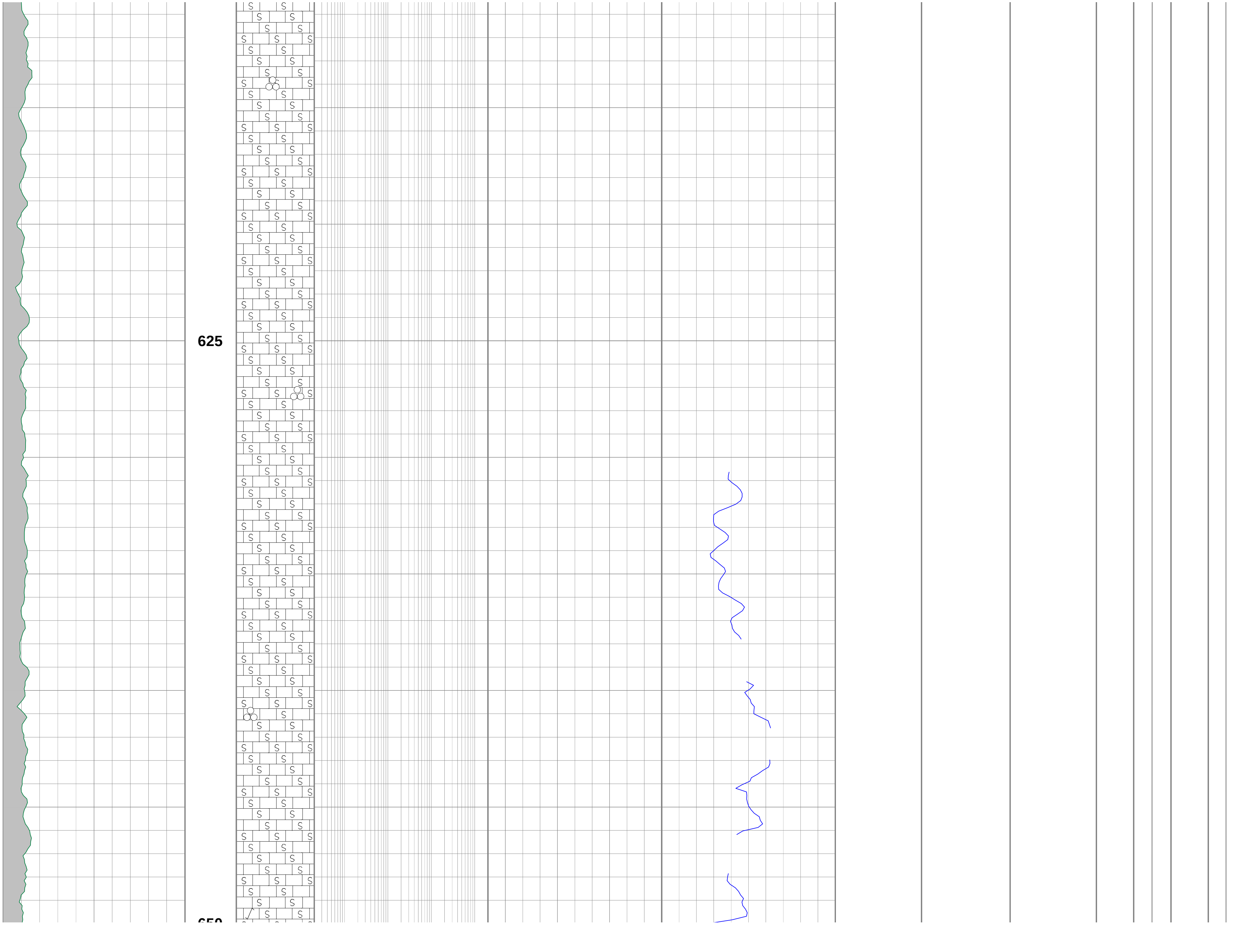

575
600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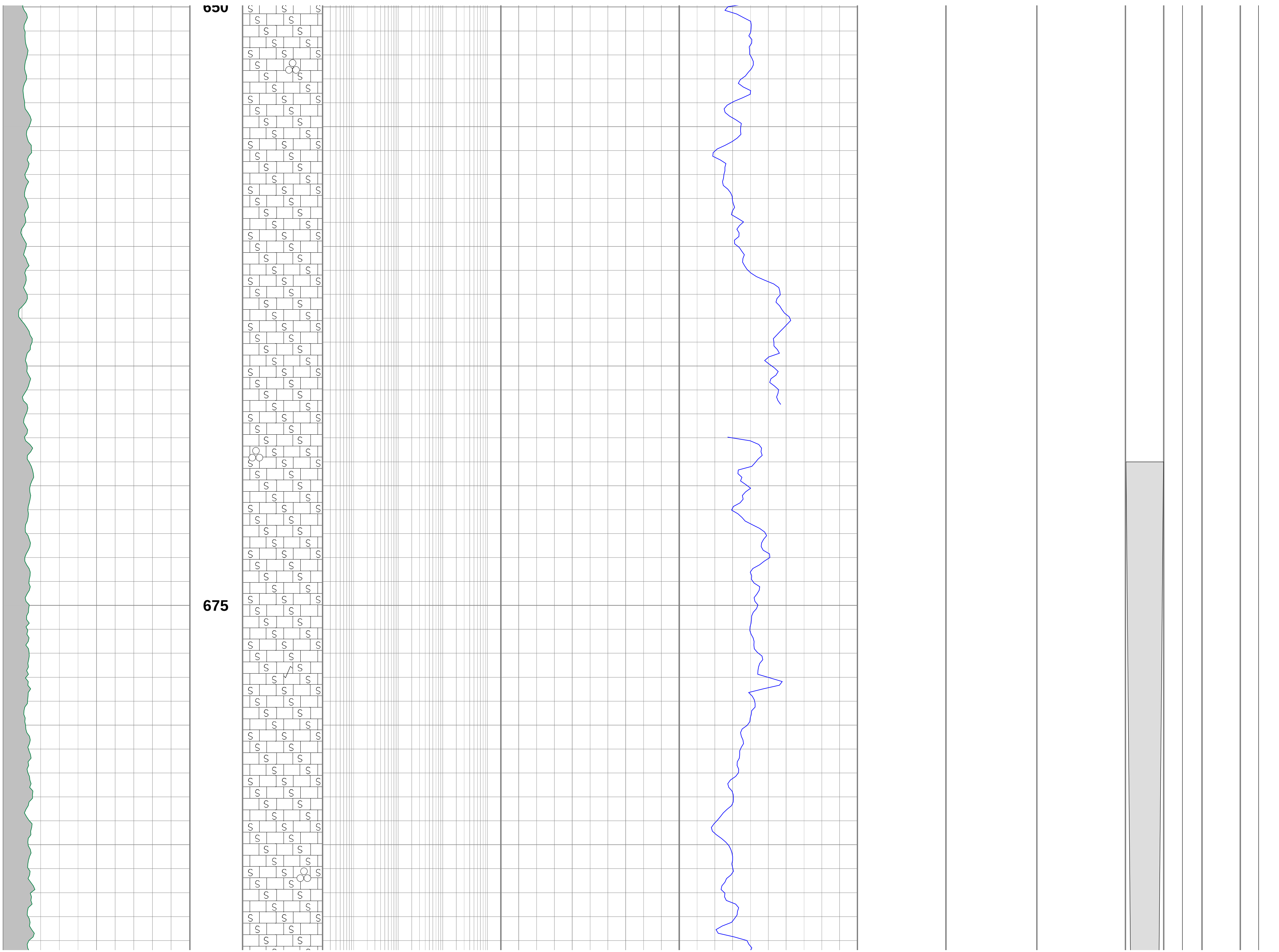
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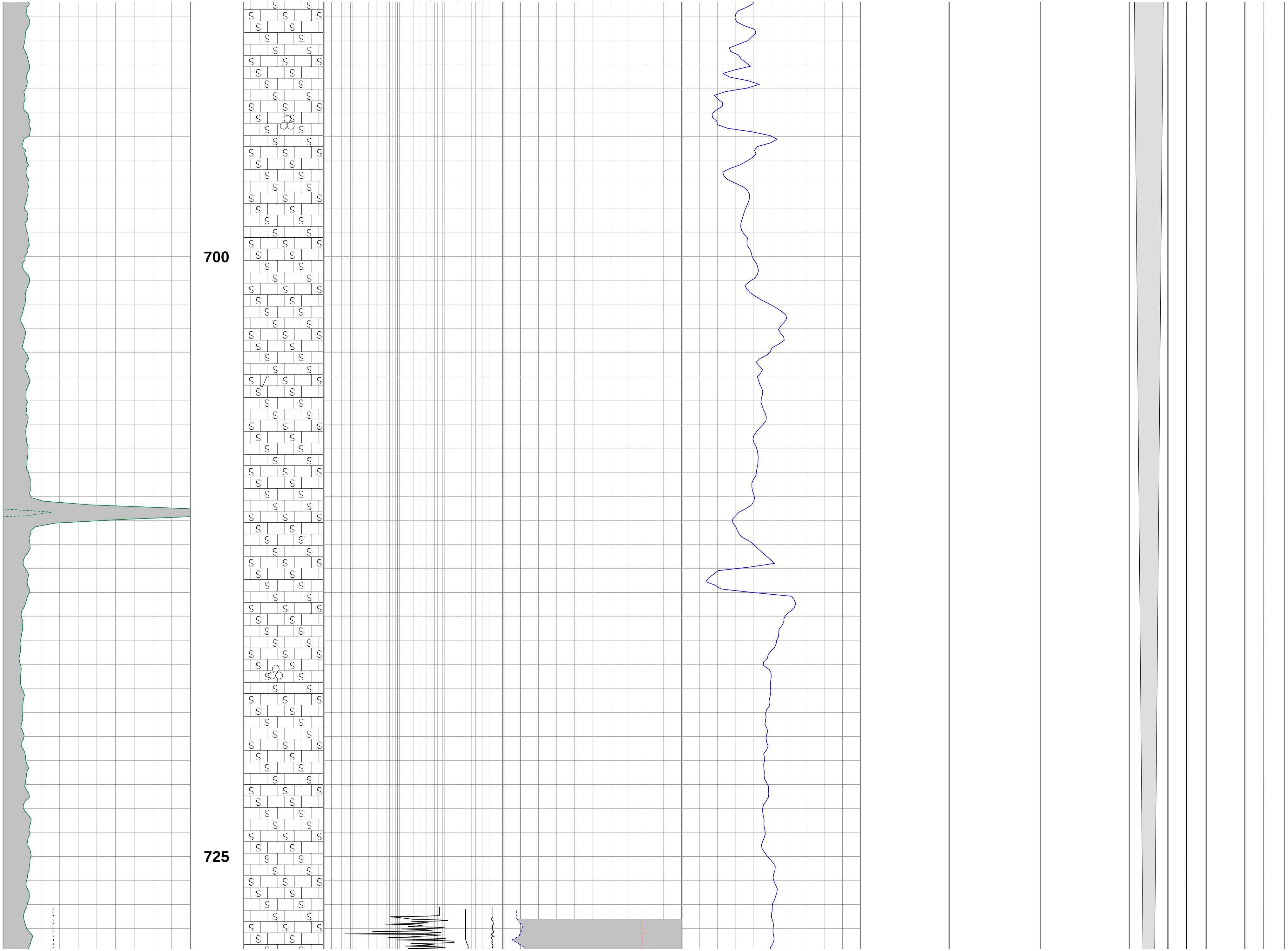
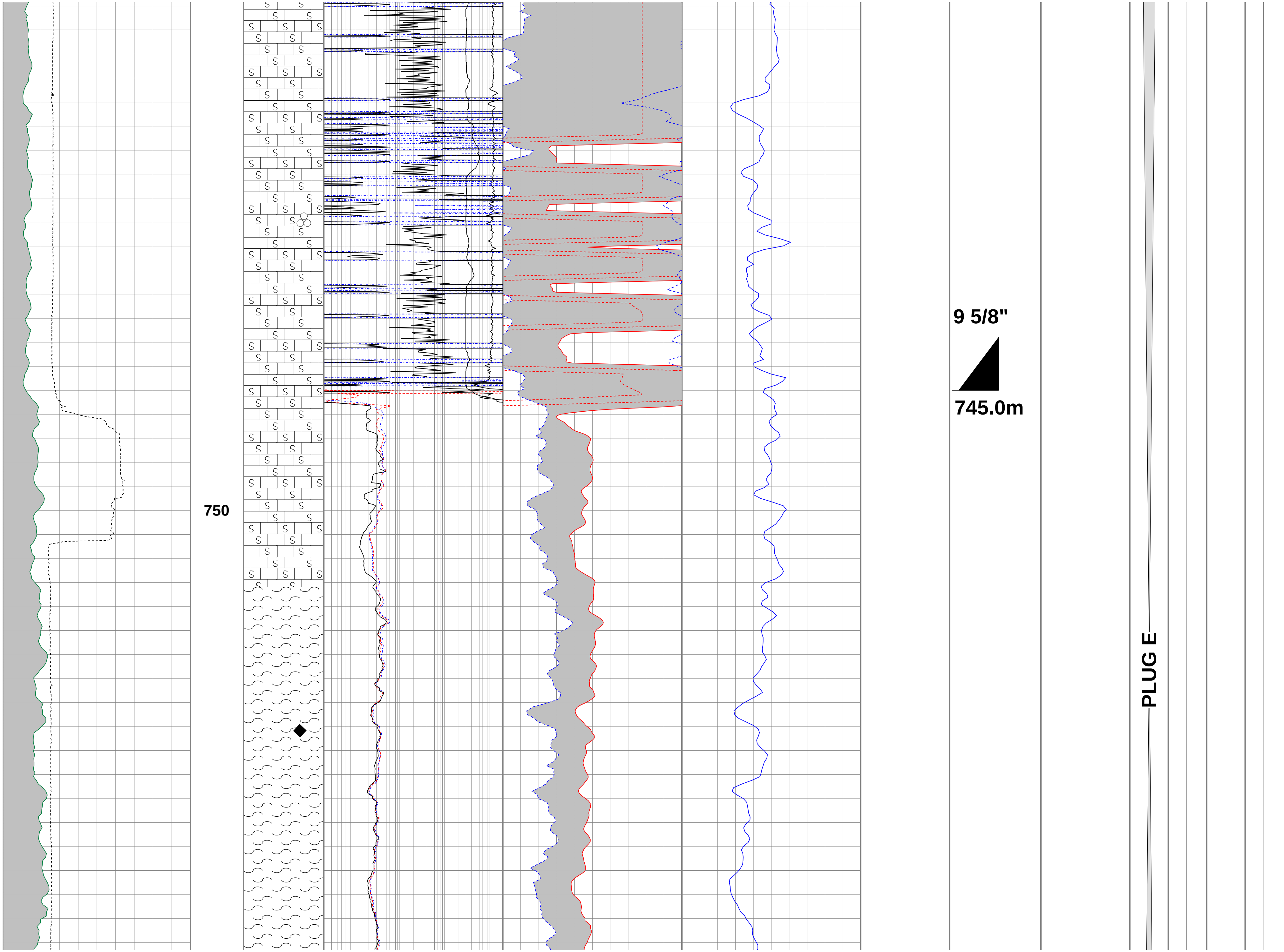
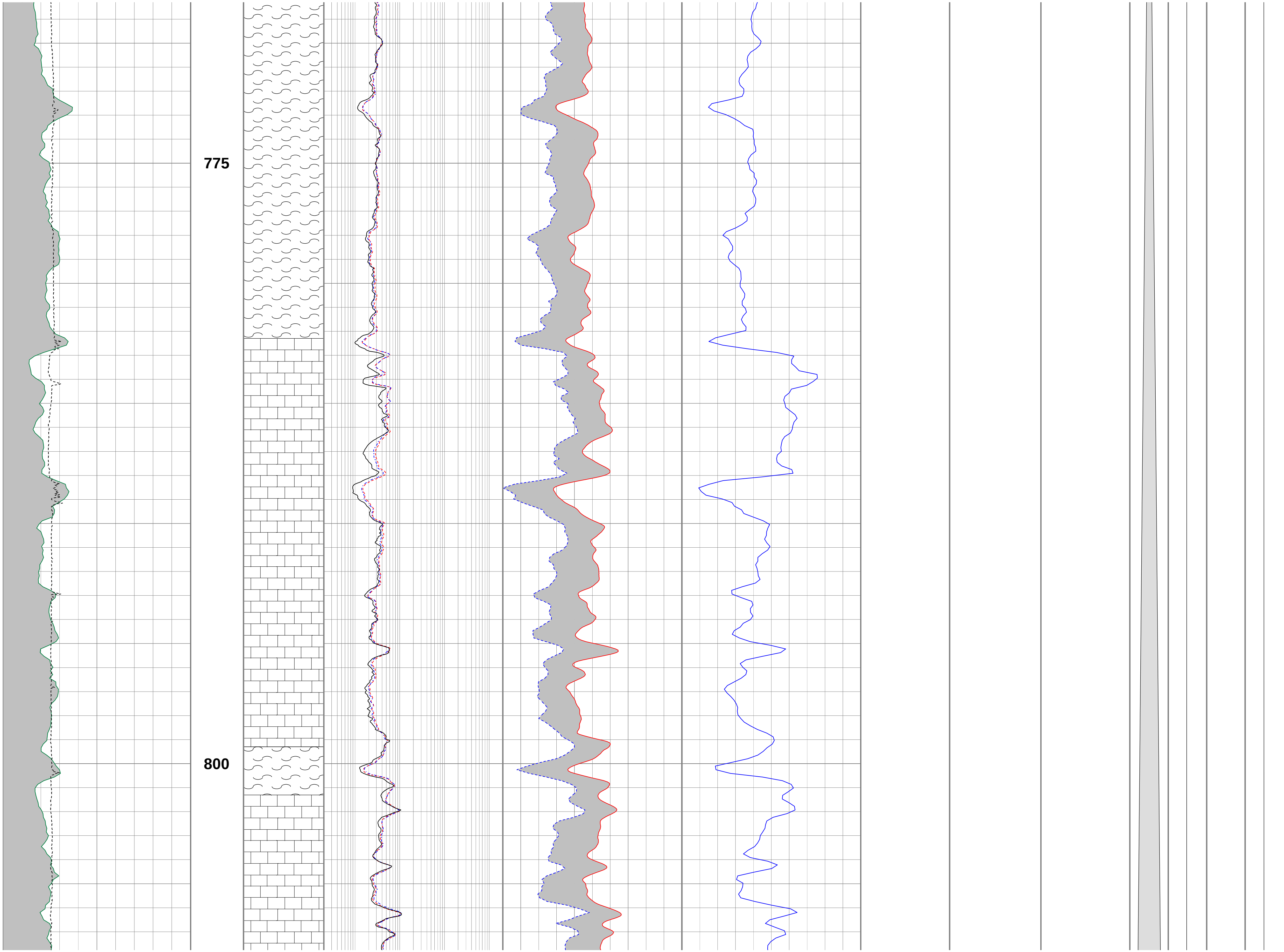
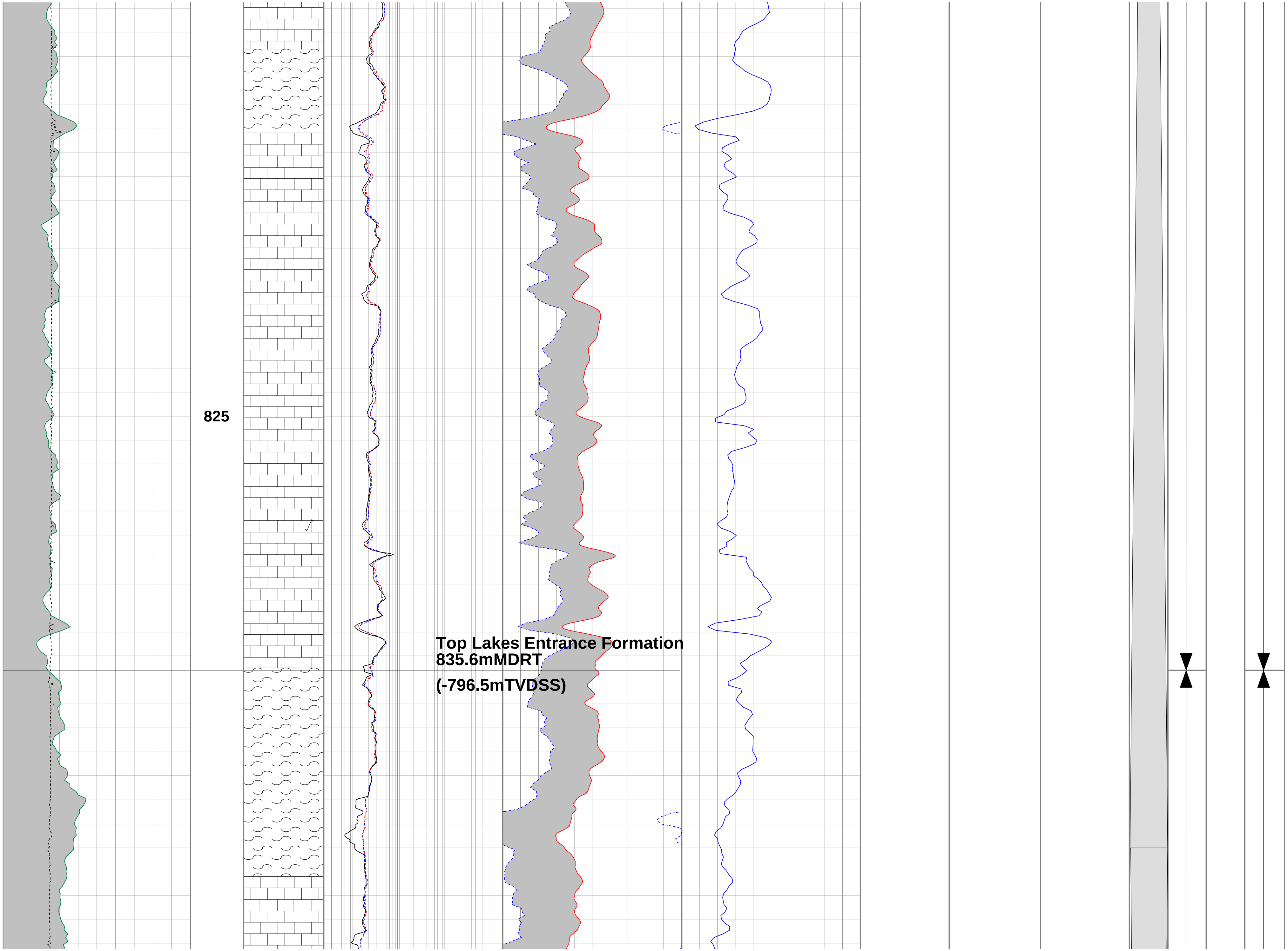
675

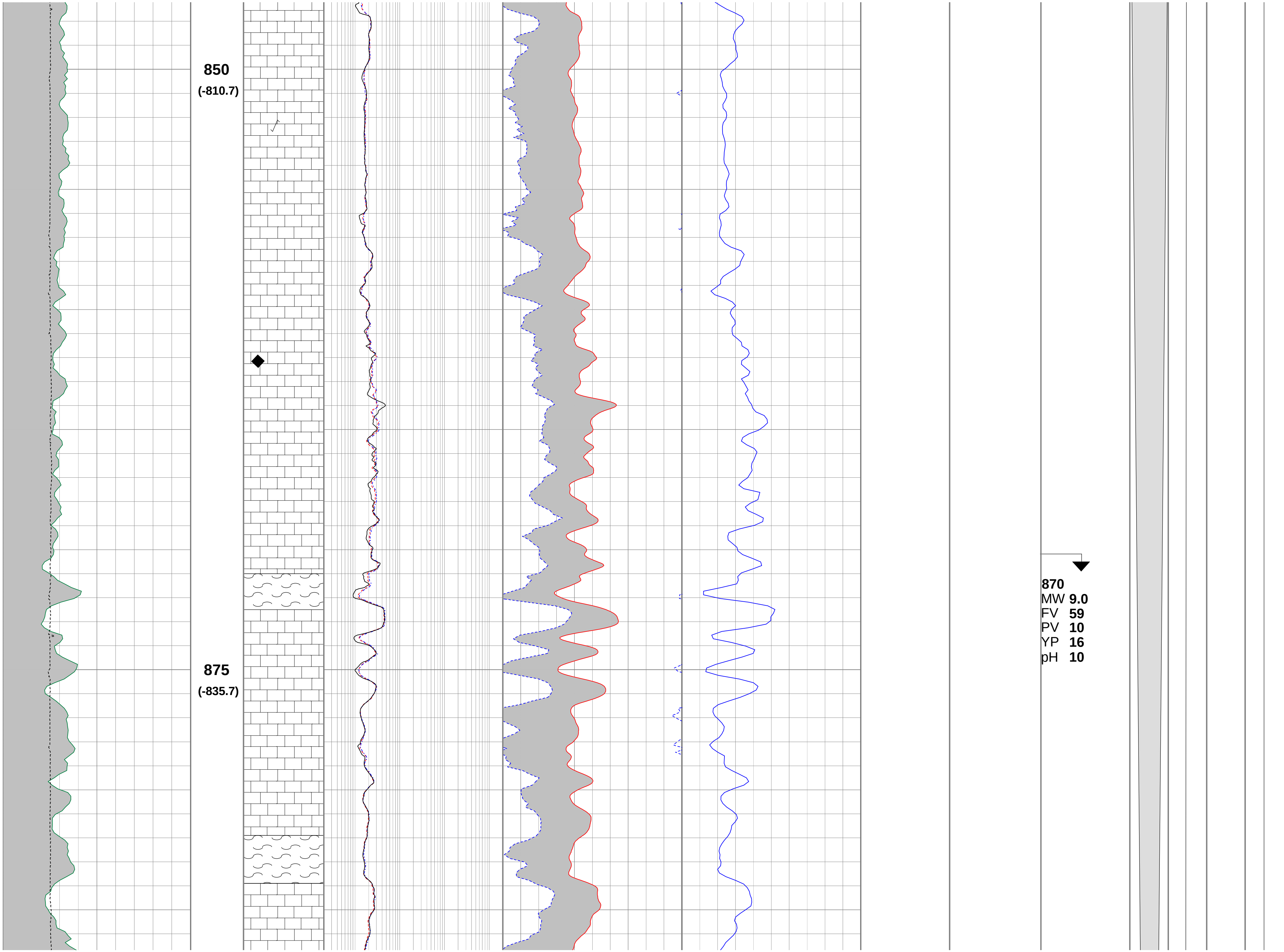


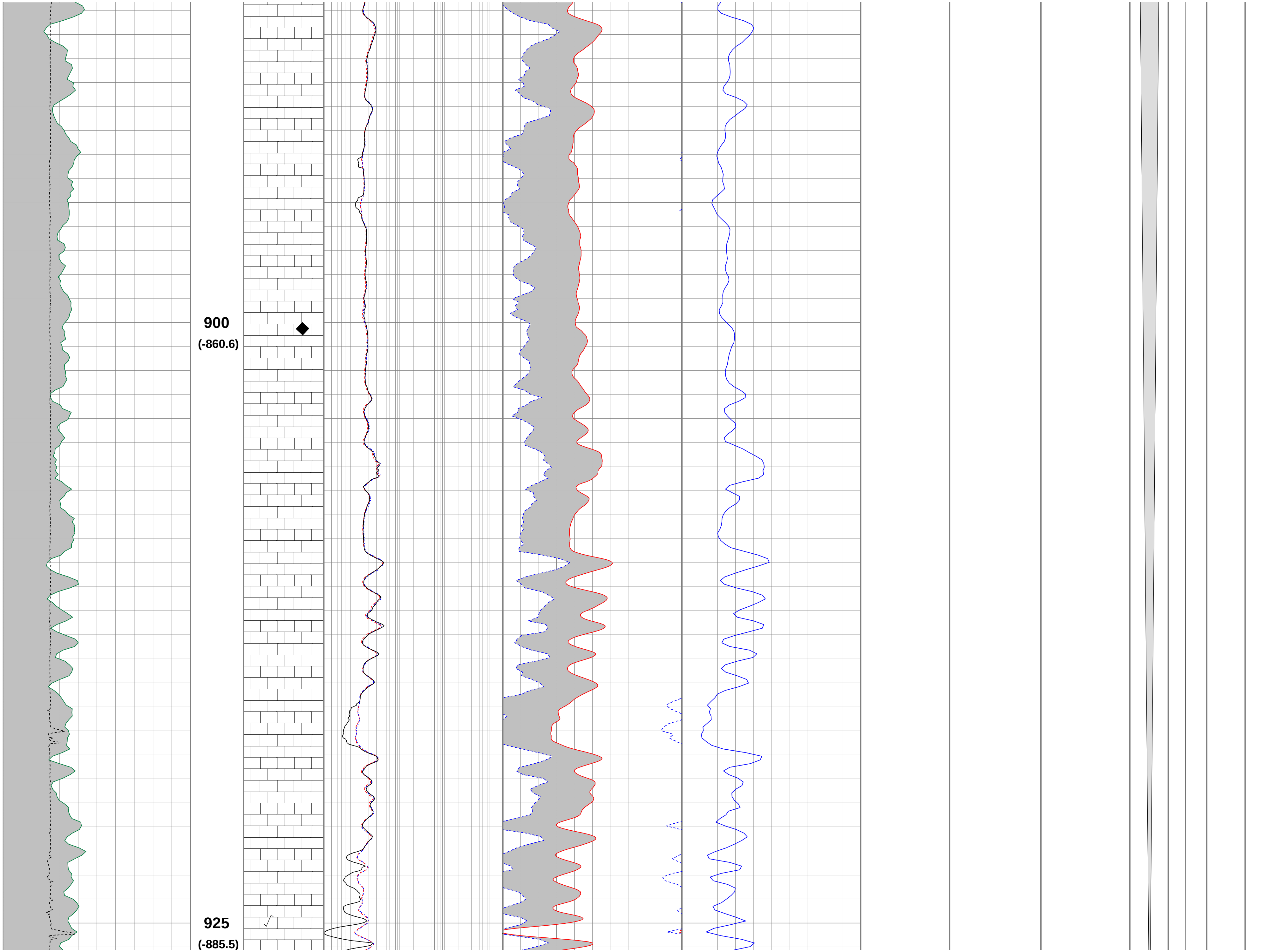
700
725

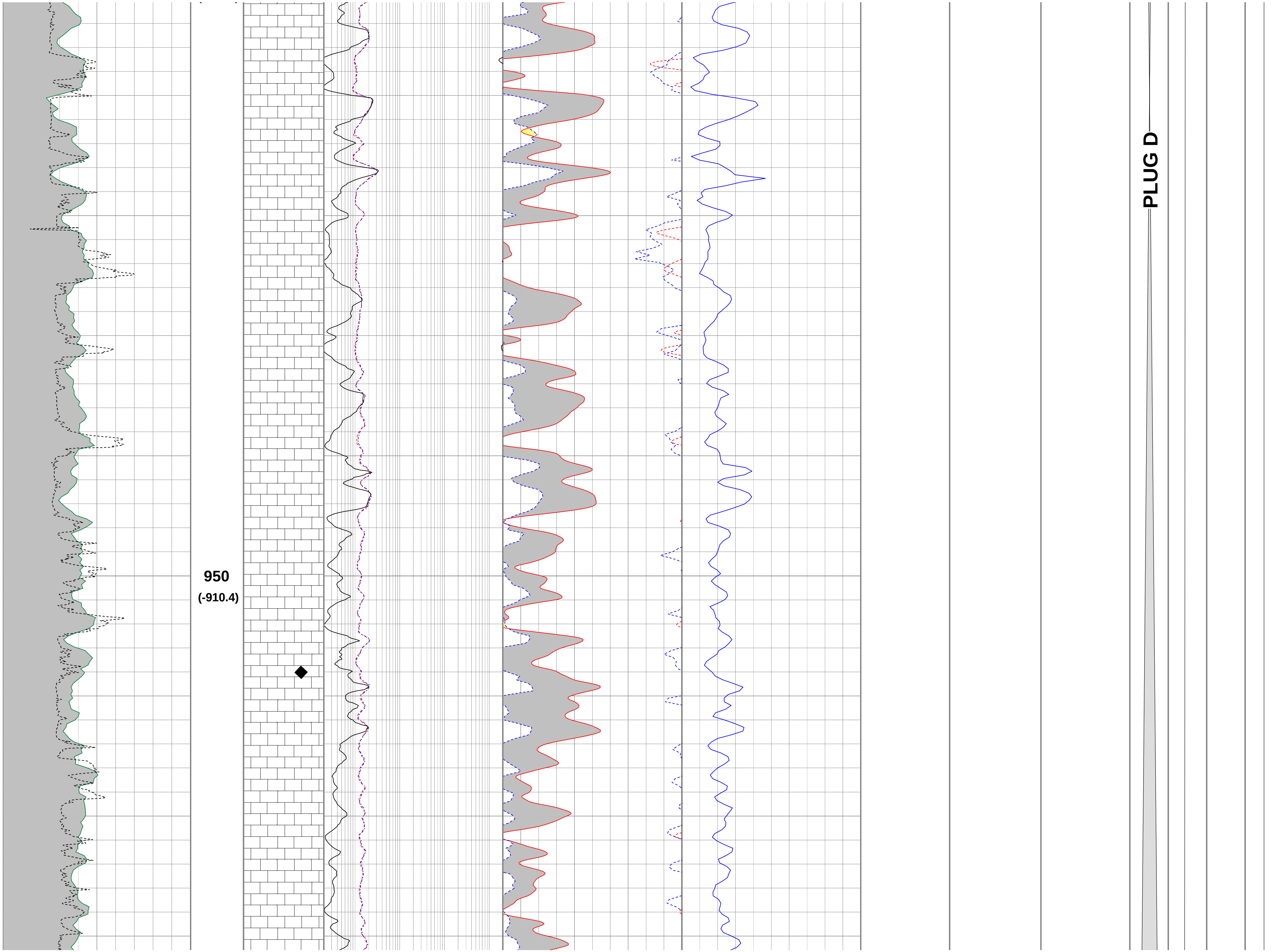

750
9 5/8"
745.0m
PLUG E

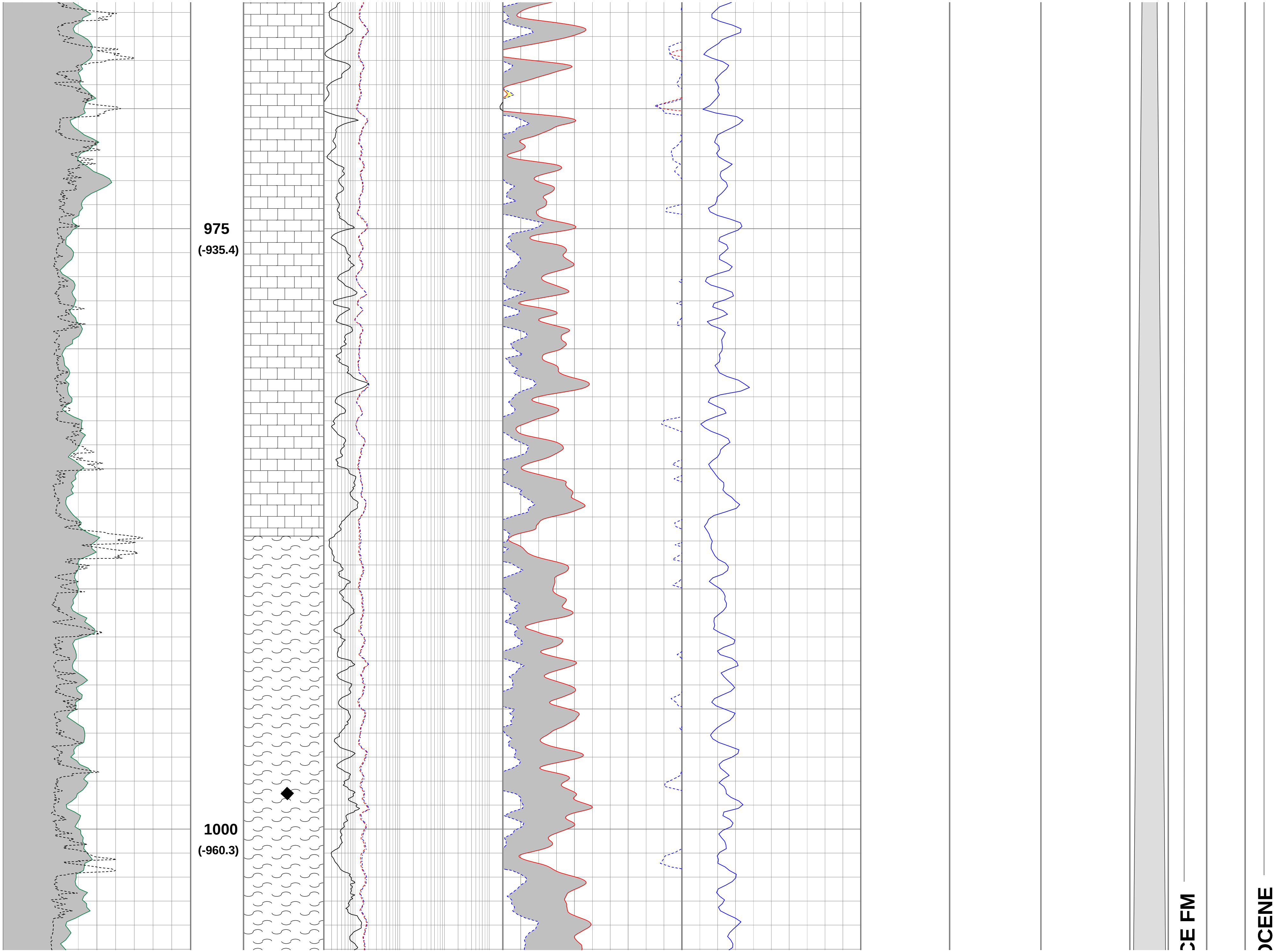

775
800

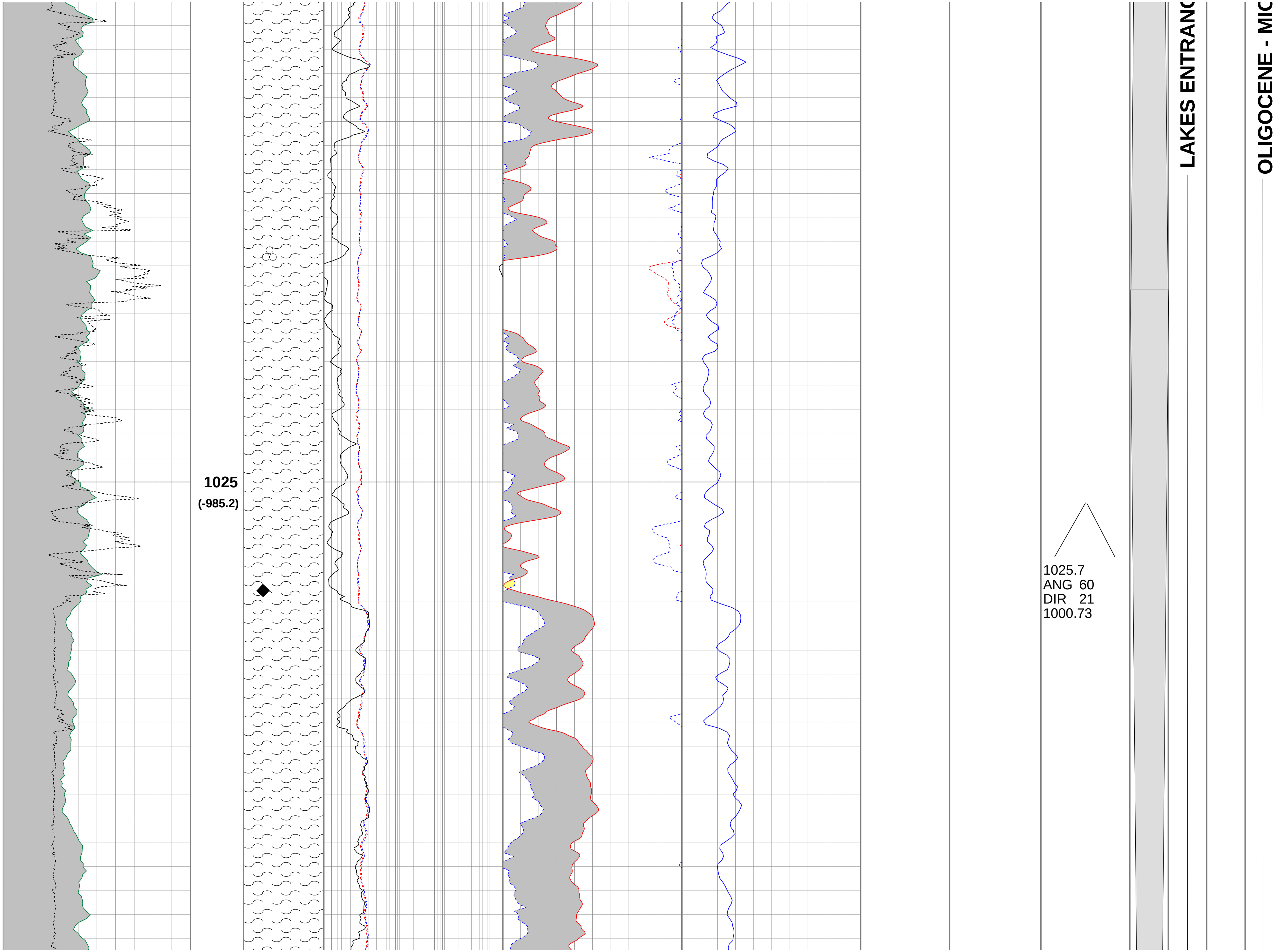

825
Top Lakes Entrance Formation
835.6mMDRT
(-796.5mTVDSS)

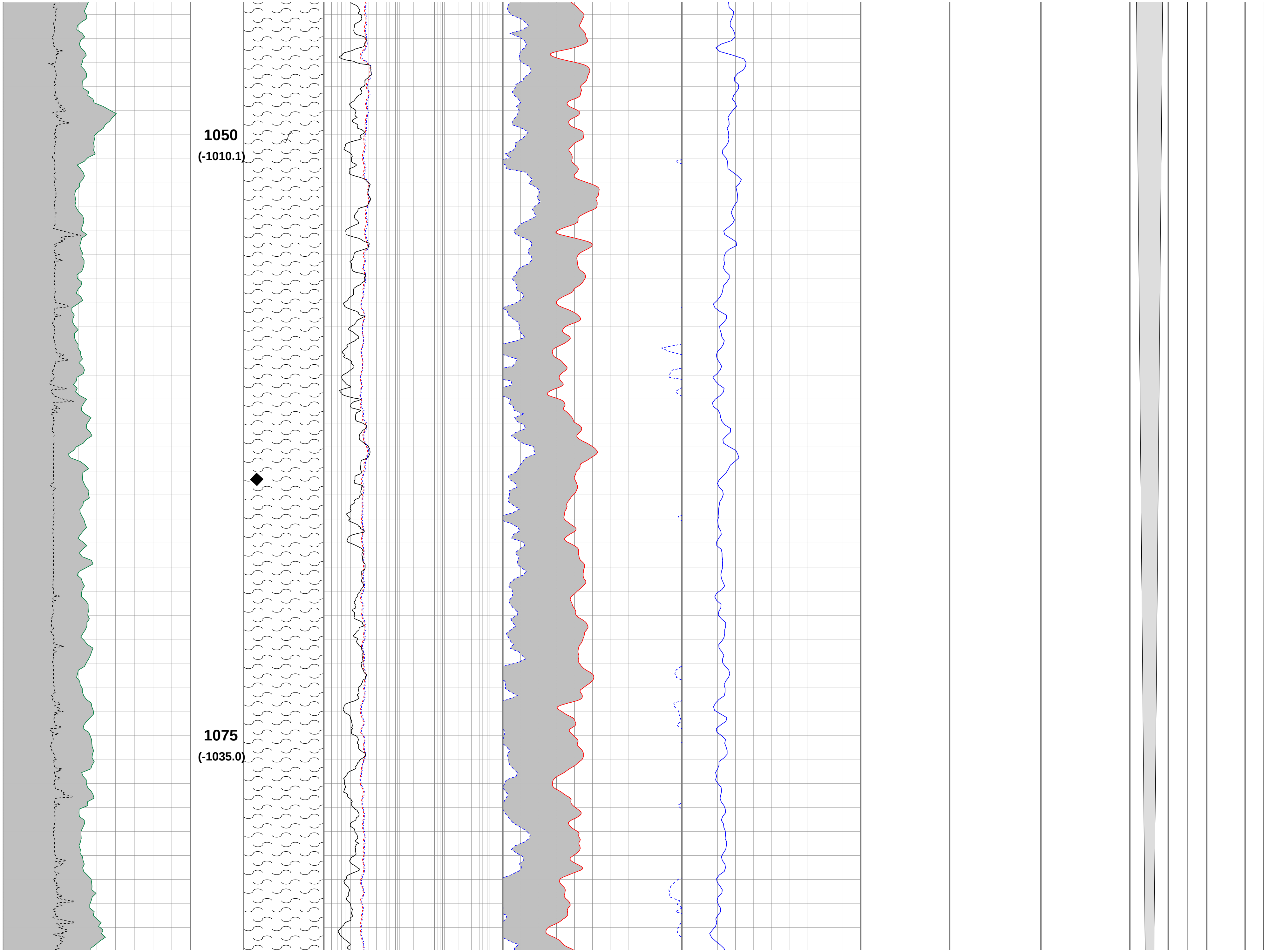

850
(-810.7)
875
(-835.7)
870
MW 9.0
FV 59
PV 10
YP 16
pH 10

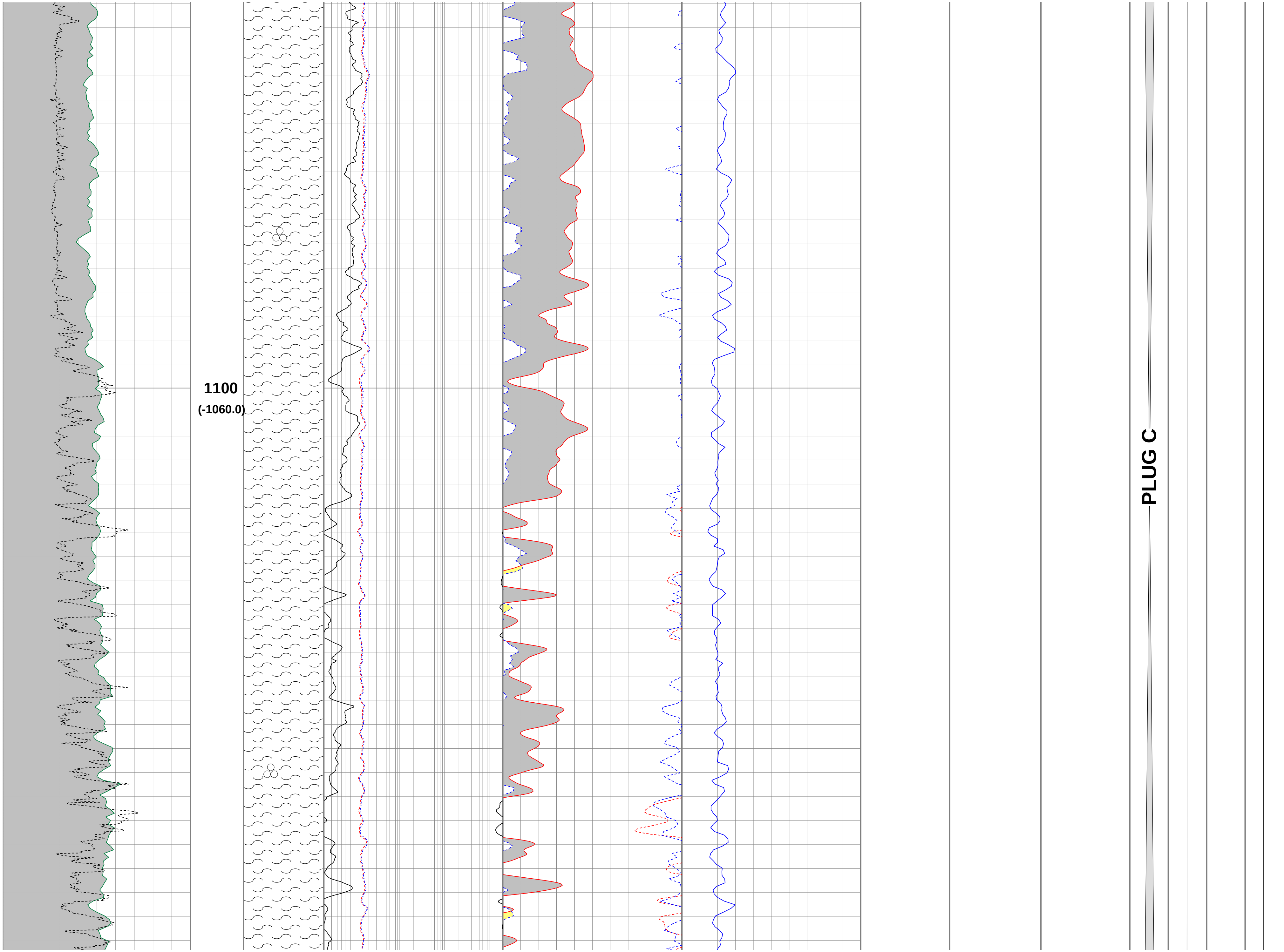

900
(-860.6)
925
(-885.5)

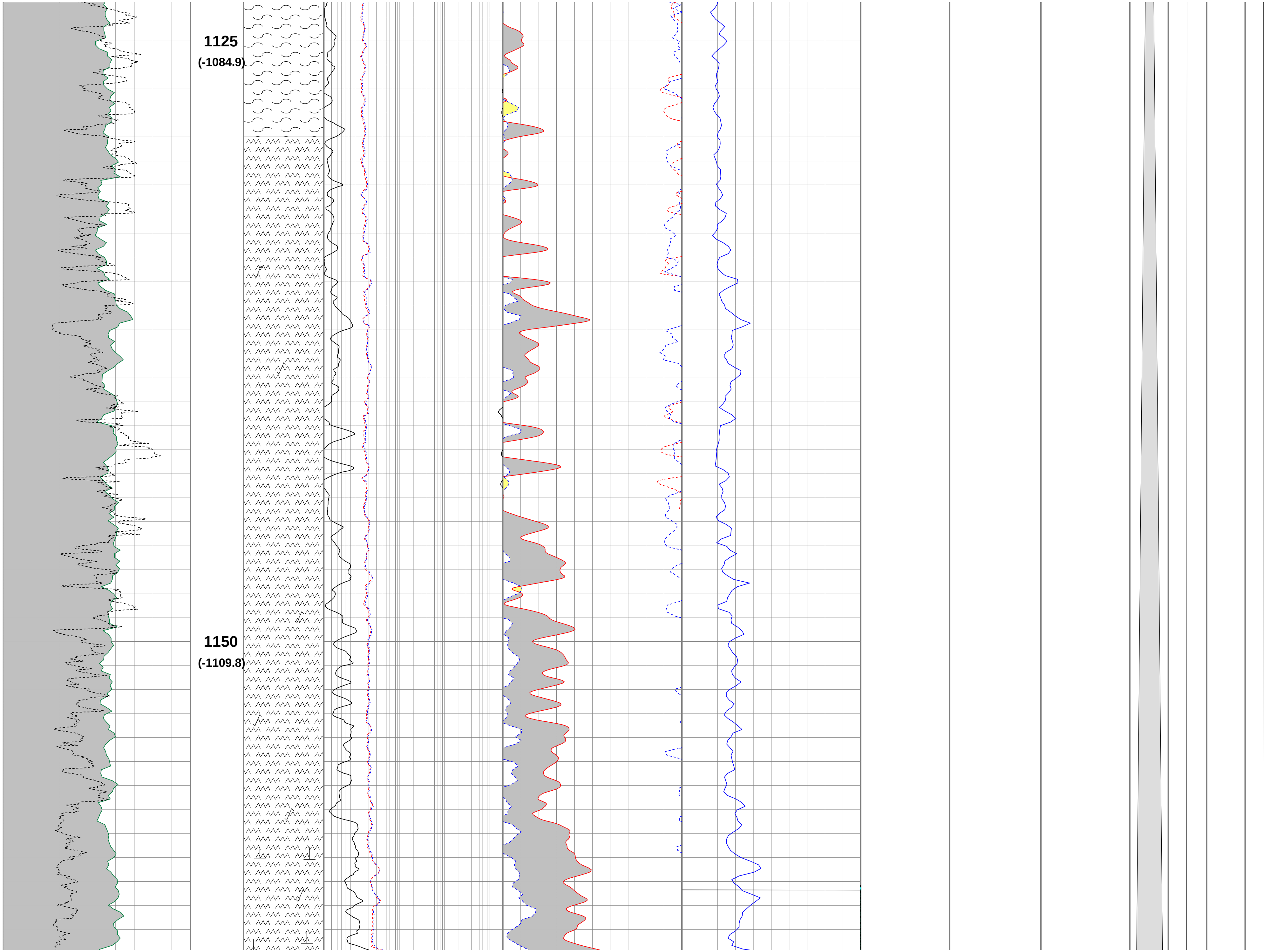

950
(-910.4)
PLUG D

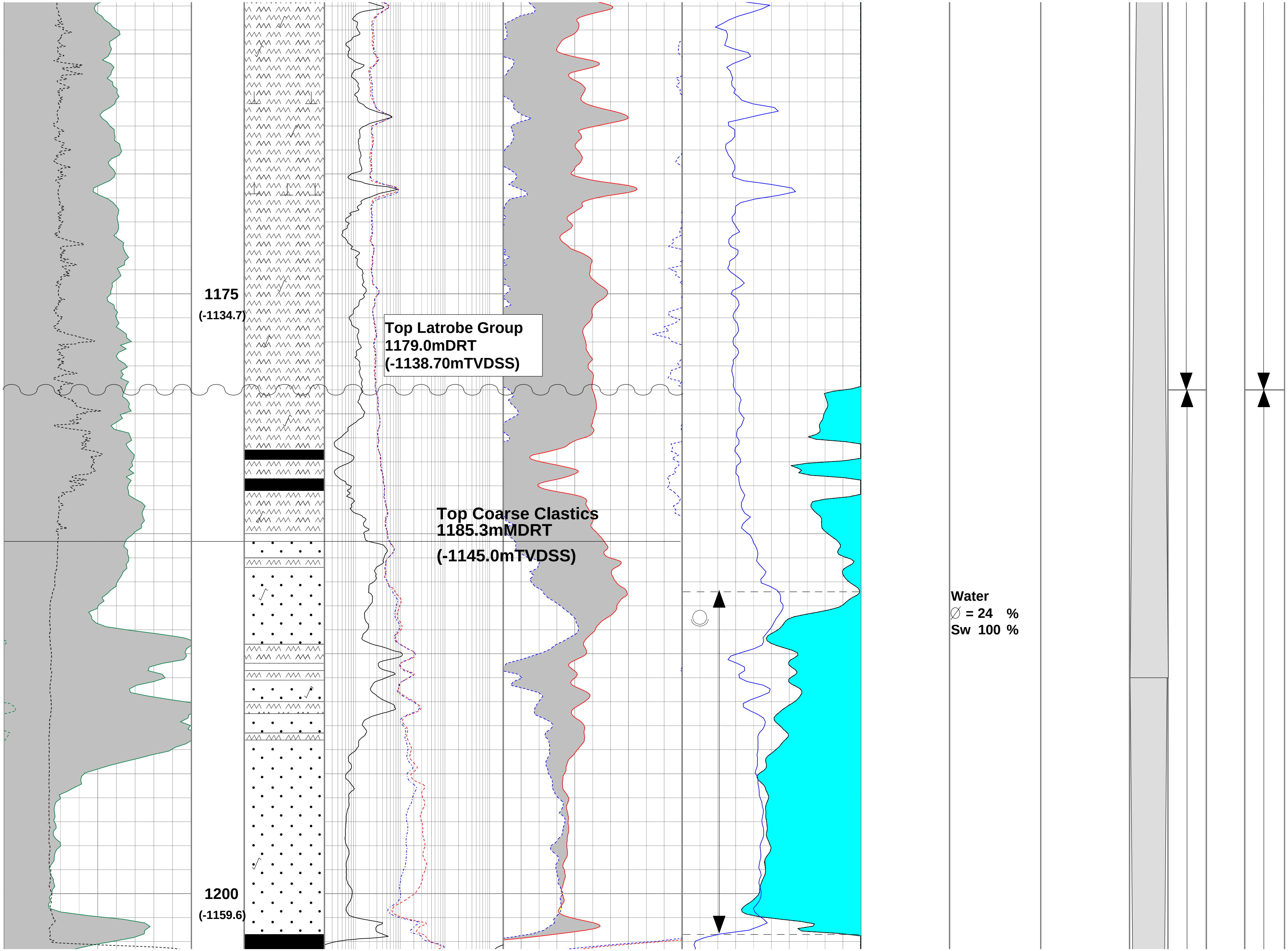

975
(-935.4)
1000
(-960.3)
CE FM
OCENE


1025
(-985.2)
1025.7
ANG 60
DIR 21
1000.73
LAKES ENTRANC
OLIGOCENE - MIC

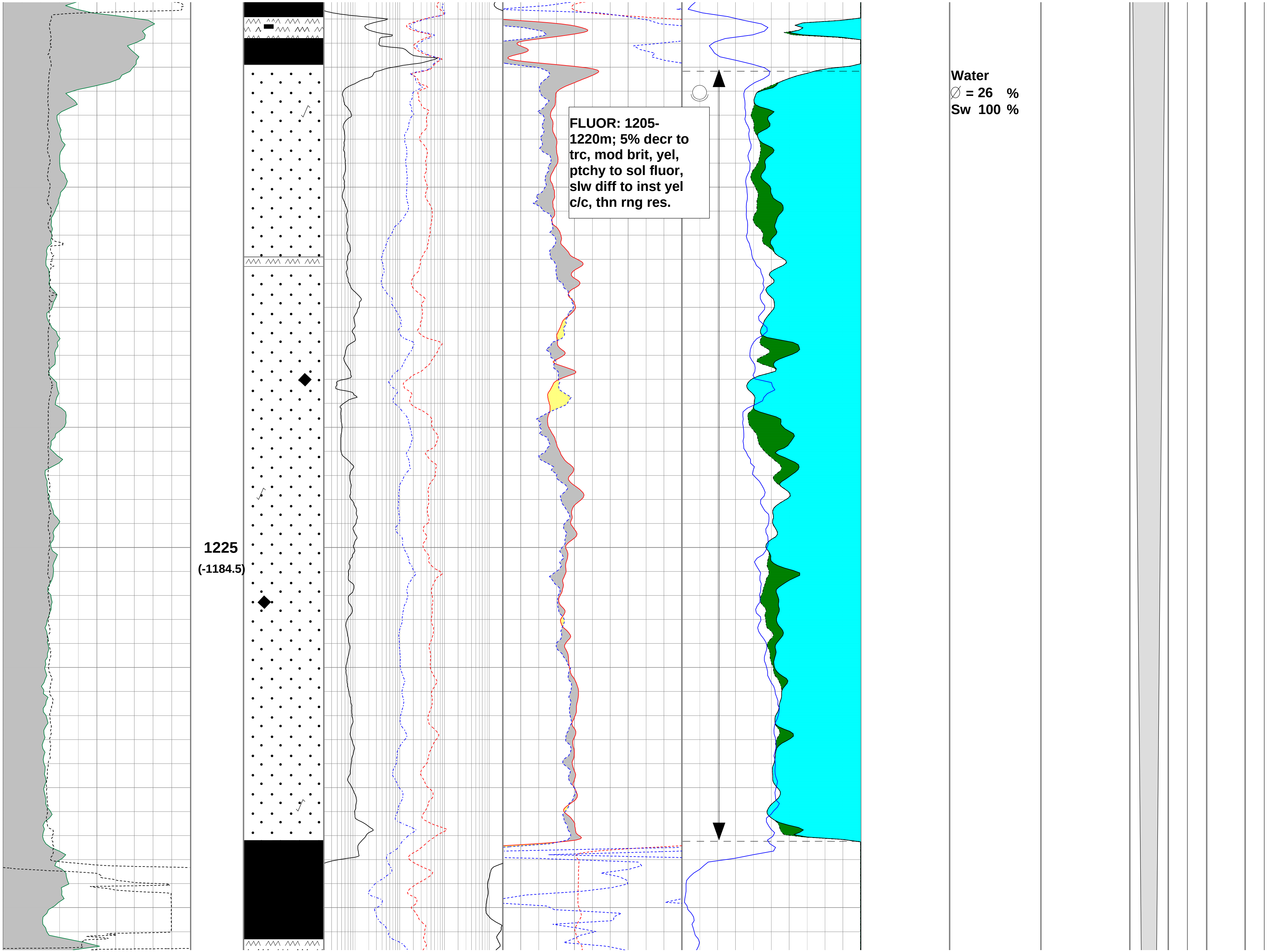

1050
(-1010.1)
1075
(-1035.0)

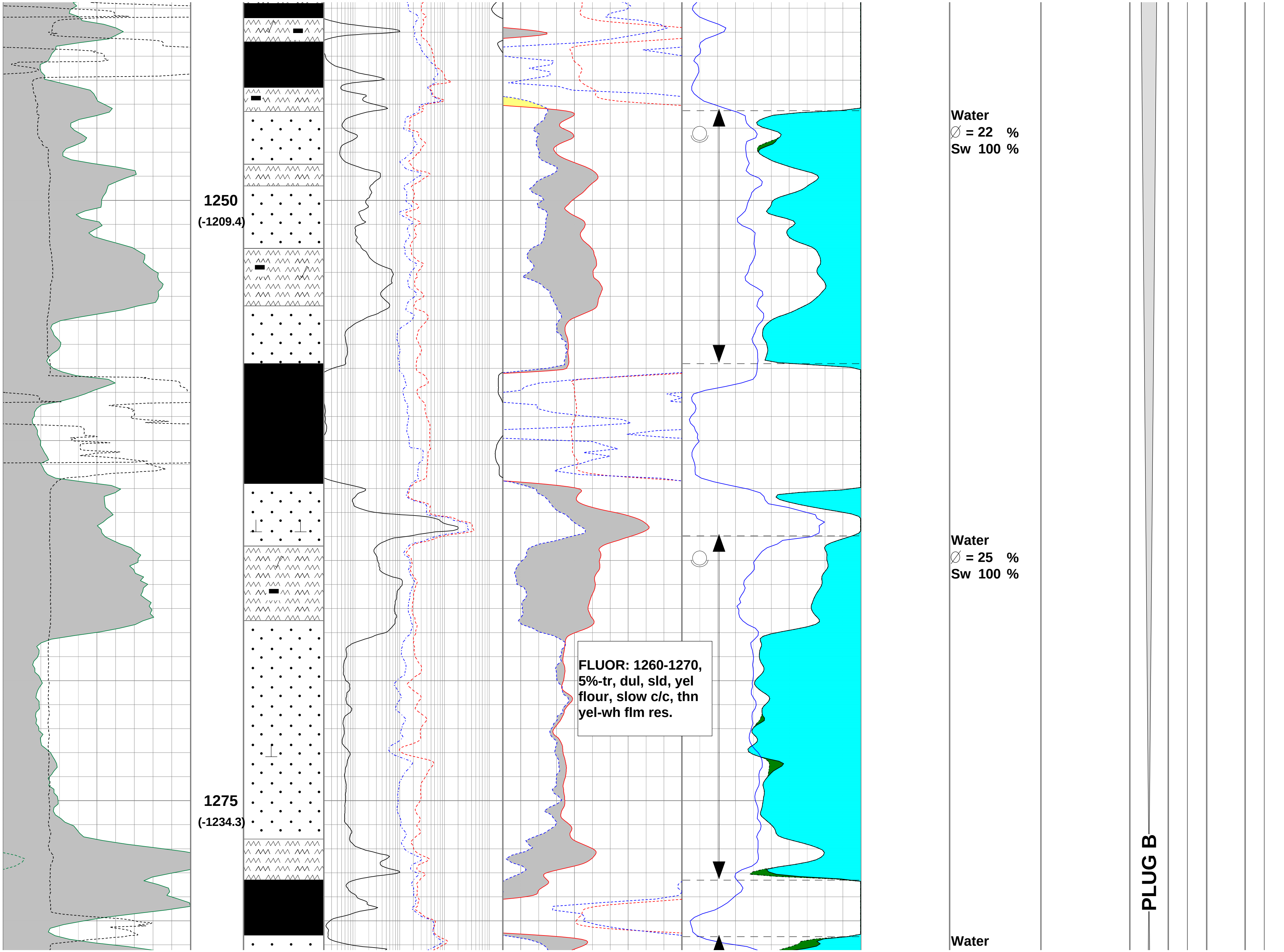

1100
(-1060.0)
PLUG C

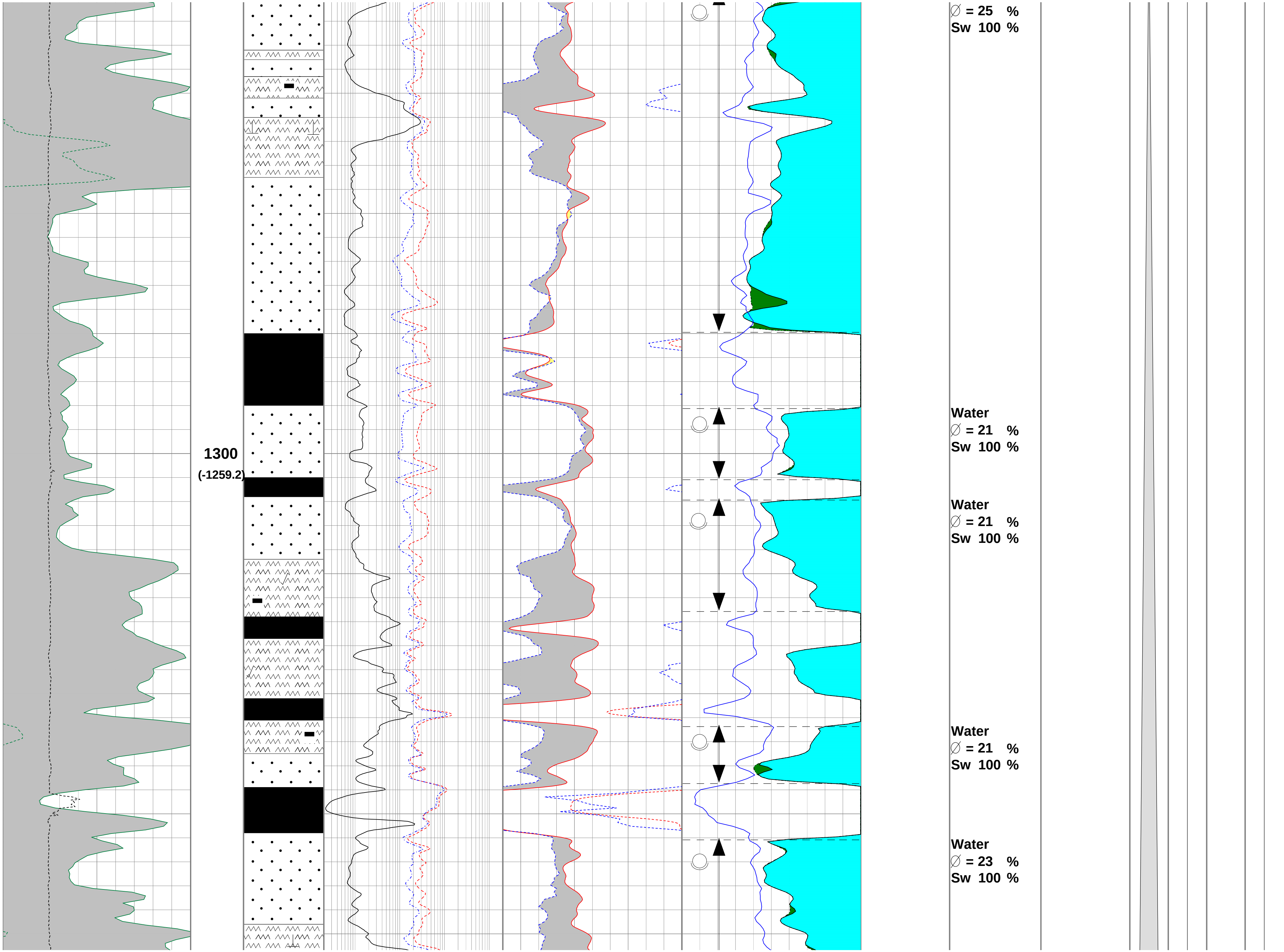

1125
(-1084.9)
1150
(-1109.8)

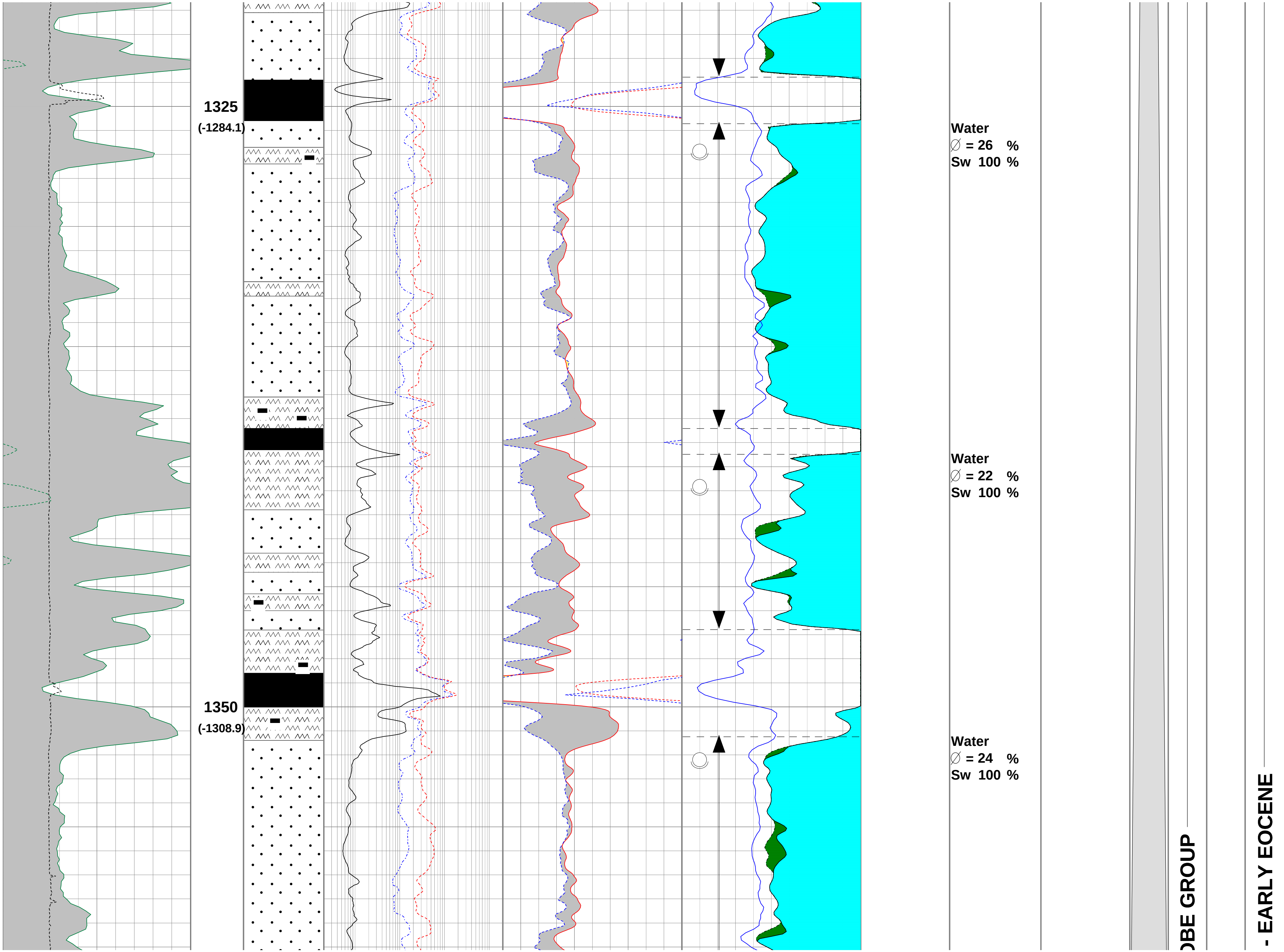


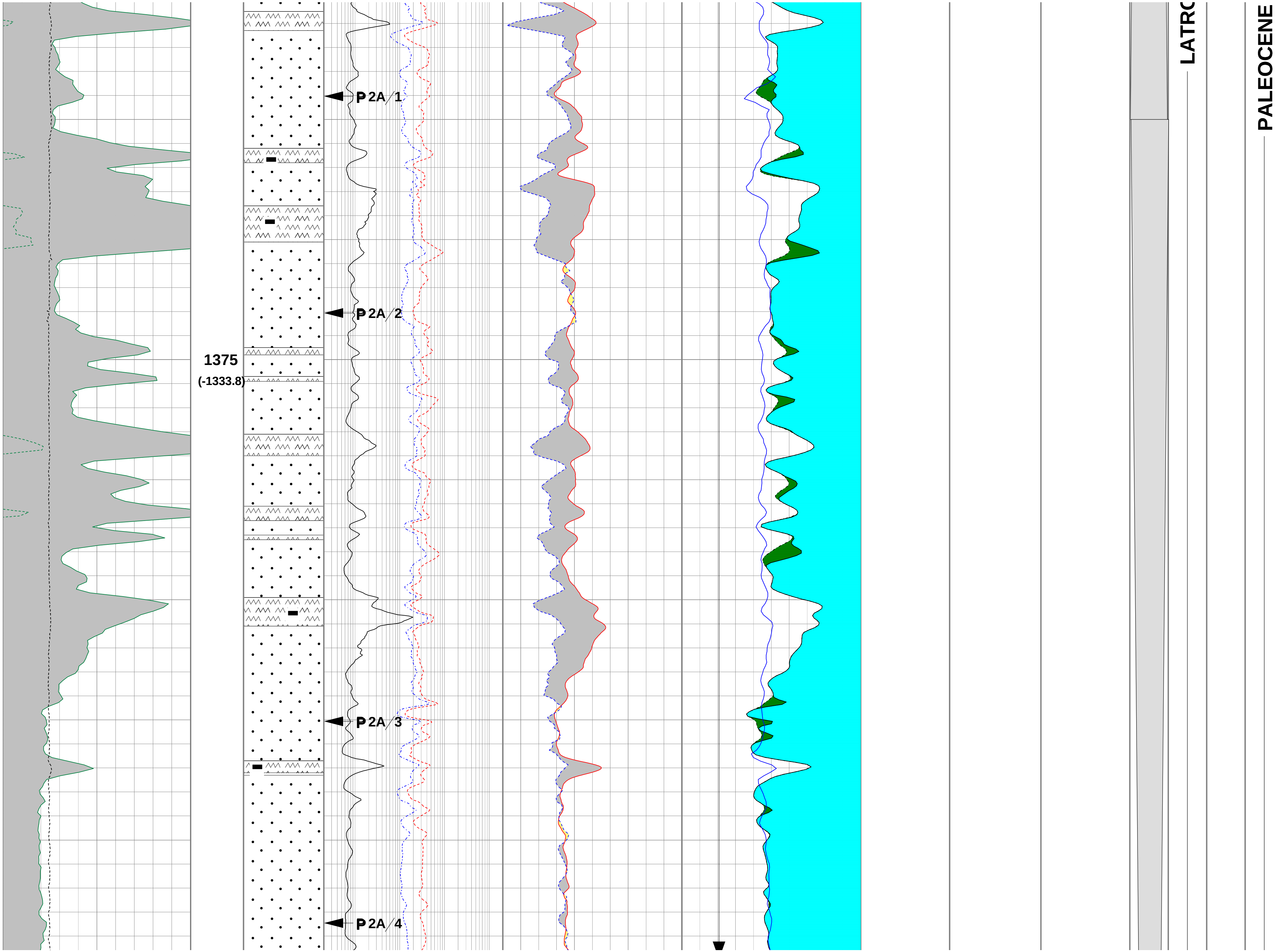
1175
(-1134.7)
Top Latrobe Group
1179.0mDRT
(-1138.70mTVDSS)
Top Coarse Clastics
1185.3mMDRT
(-1145.0mTVDSS)
Water
∅ = 24 %
Sw 100 %
1200
(-1159.6)

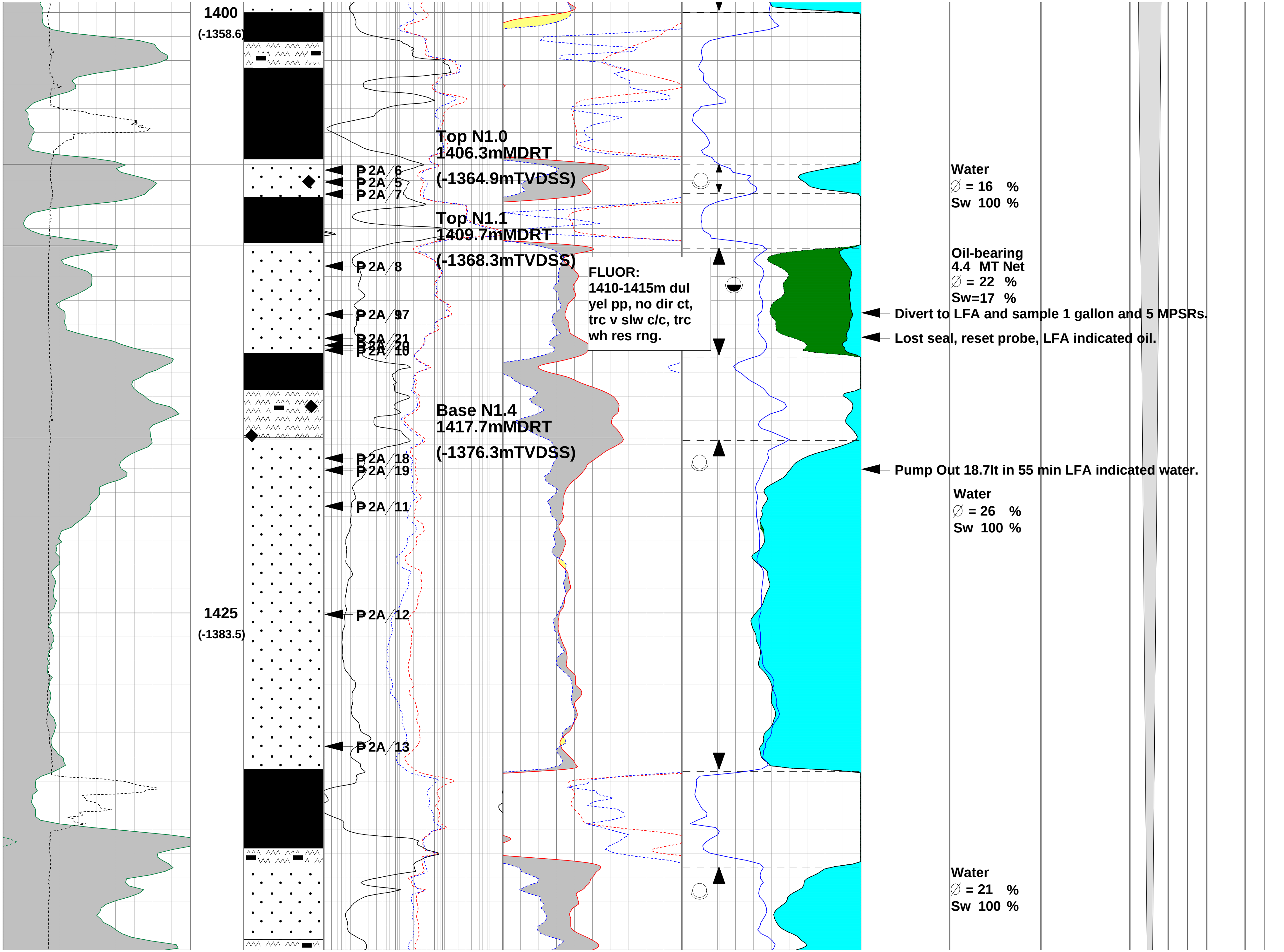

1225
(-1184.5)
FLUOR: 1205-1220m; 5% decr to trc, mod brit, yel, ptchy to sol fluor, slw diff to inst yel c/c, thn rng res.
Water
∅ = 26 %
Sw 100 %

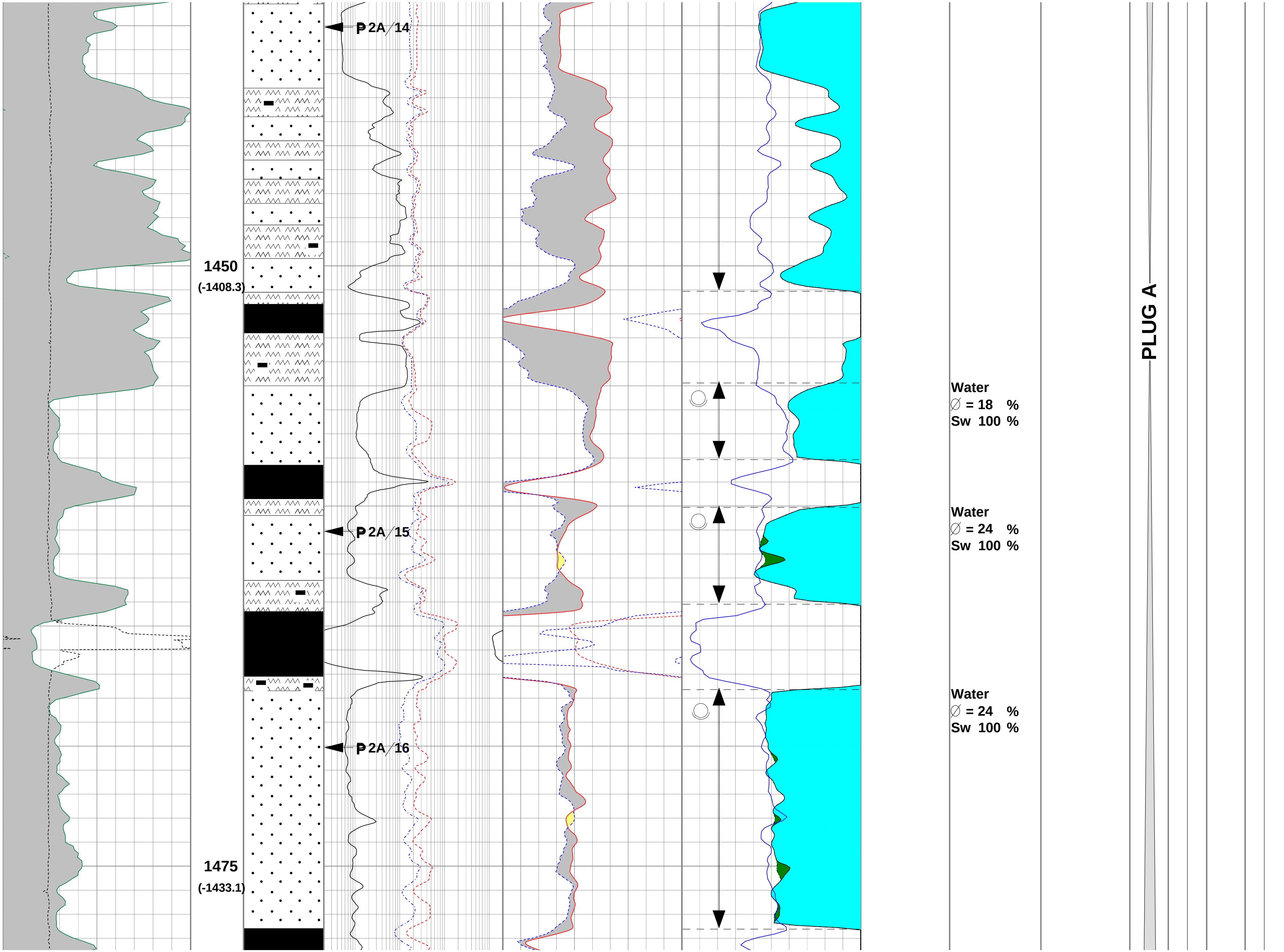

1250
(-1209.4)
1275
(-1234.3)
FLUOR: 1260-1270, 5%-tr, dul, sld, yel flour, slow c/c, thn yel-wh flm res.
Water
∅ = 22 %
Sw 100 %
Water
∅ = 25 %
Sw 100 %
Water
PLUG B

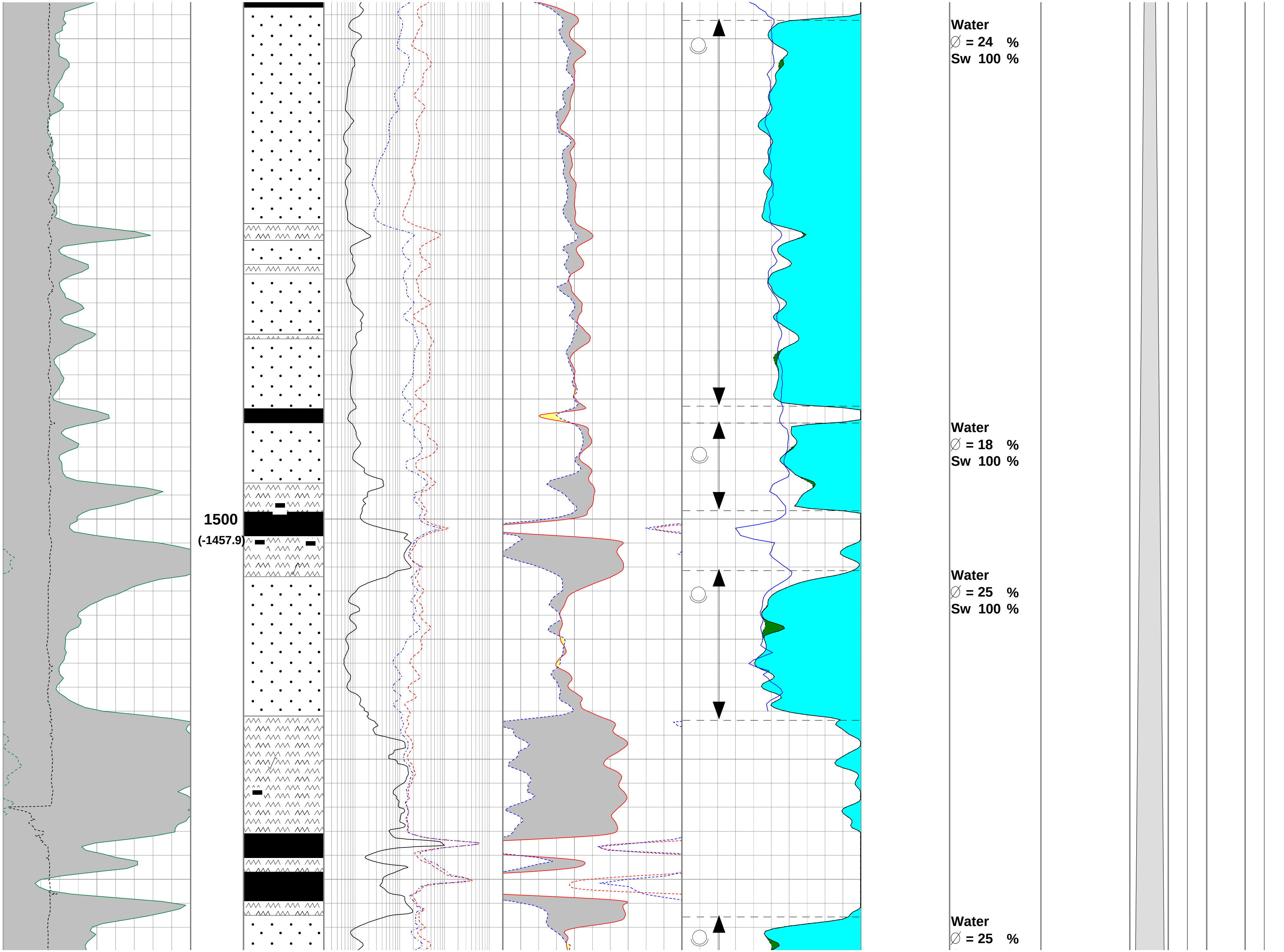

1300
(-1259.2)
∅ = 25 %
Sw 100 %
Water
∅ = 21 %
Sw 100 %
Water
∅ = 21 %
Sw 100 %
Water
∅ = 21 %
Sw 100 %
Water
∅ = 23 %
Sw 100 %

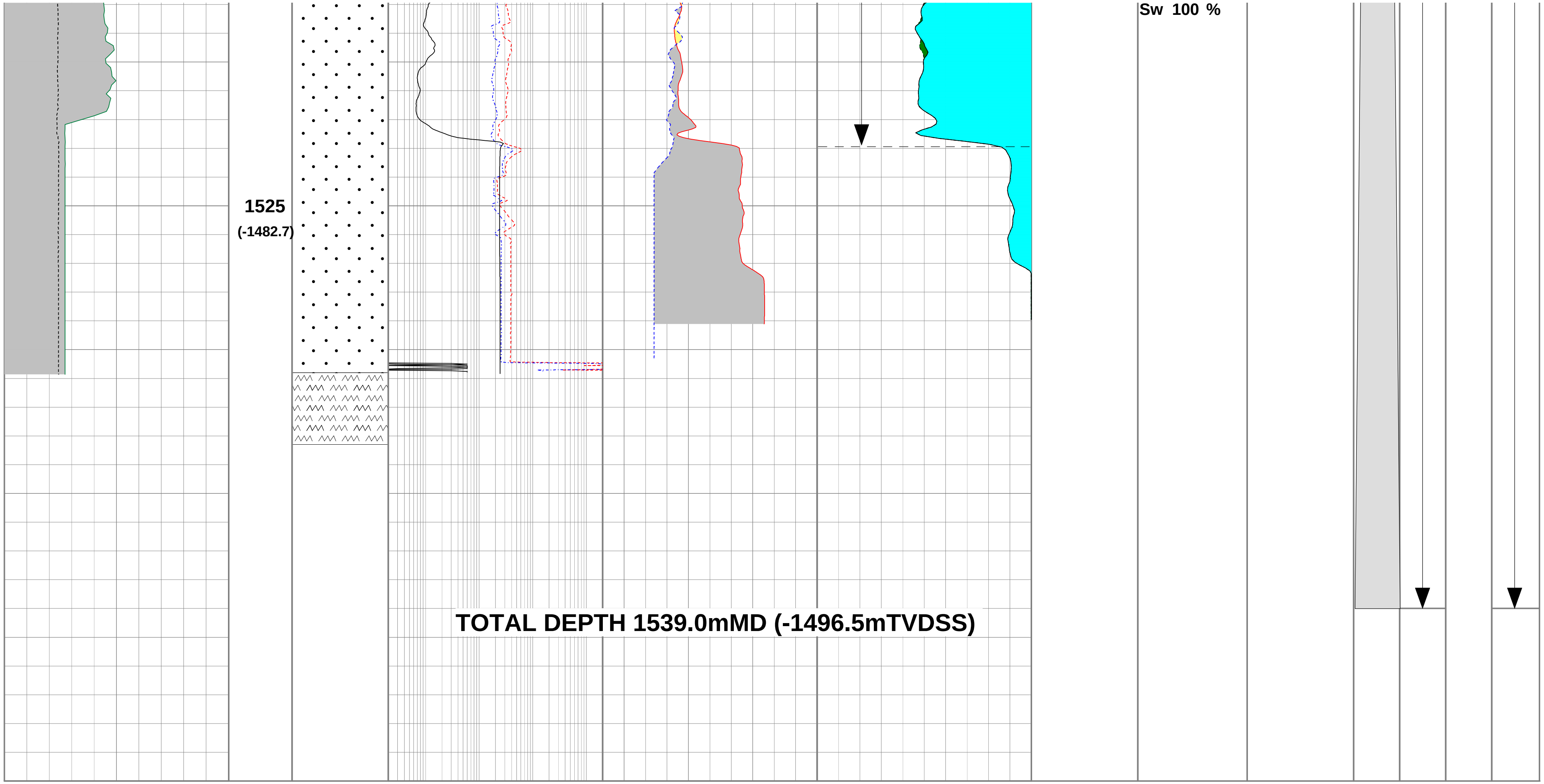

1325
(-1284.1)
1350
(-1308.9)
Water
∅ = 26 %
Sw 100 %
Water
∅ = 22 %
Sw 100 %
Water
∅ = 24 %
Sw 100 %
OBE GROUP
- EARLY EOCENE


P 2A/1
P 2A/2
1375
(-1333.8)
P 2A/3
P 2A/4
LATRO
PALEOCENE


1400
(-1358.6)
Top N1.0
1406.3mMDRT
(-1364.9mTVDSS)
P 2A/6
P 2A/5
P 2A/7
Top N1.1
1409.7mMDRT
(-1368.3mTVDSS)
P 2A/8
P 2A/17
P 2A/21
P 2A/20
P 2A/10
FLUOR:
1410-1415m dul
yel pp, no dir ct,
trc v slw c/c, trc
wh res rng.
Base N1.4
1417.7mMDRT
(-1376.3mTVDSS)
P 2A/18
P 2A/19
P 2A/11
P 2A/12
P 2A/13
1425
(-1383.5)
Water
∅ = 16 %
Sw 100 %
Oil-bearing
4.4 MT Net
∅ = 22 %
Sw=17 %
Divert to LFA and sample 1 gallon and 5 MPSRs.
Lost seal, reset probe, LFA indicated oil.
Pump Out 18.7lt in 55 min LFA indicated water.
Water
∅ = 26 %
Sw 100 %
Water
∅ = 21 %
Sw 100 %


1450
(-1408.3)
1475
(-1433.1)
Ᵽ 2A/14
Ᵽ 2A/15
Ᵽ 2A/16
Water
∅ = 18 %
Sw 100 %
Water
∅ = 24 %
Sw 100 %
Water
∅ = 24 %
Sw 100 %
PLUG A


1500
(-1457.9)
Water
∅ = 24 %
Sw 100 %
Water
∅ = 18 %
Sw 100 %
Water
∅ = 25 %
Sw 100 %
Water
∅ = 25 %



Esso Australia Pty Ltd

Well:	West Whiptail-1		
Date:	22 May 2004	Geologist-Engineer:	Mike Woodmansee
Tool Type:	(MDT-GR-LEHQT)	KB (metres):	39.0
Gauge Type:	CQG	Probe type:	Large
Pressure units:	psia	Temperature units:	Deg C

Sample No	Depth mMD	Depth mTVDSS	Strain Gauge Hydro Before	Strain Gauge Reservoir	Strain Gauge Hydro After	Quartz Gauge Hydro Before	Quartz Gauge Reservoir	Quartz Gauge Hyd After	Comments	Mobility
1	1364.00	1322.50	2424.40	1858.20	2424.80	2434.36	1867.84	2434.21	20cc drawdown	15860.0
2	1373.00	1331.50	2440.90	1871.10	2441.20	2450.29	1880.38	2450.05	20cc drawdown	118.6

3	1390.00	1348.50	2471.00	1894.80	2471.00	2480.09	1903.99	2480.02	20cc drawdown	14665.0
4	1398.40	1356.90	2485.90	1906.50	2484.90	2494.99	1915.67	2494.87	20cc drawdown	767.2
5	1407.00	1365.50	2501.12			2510.20			tight retrace move up 0.5m	
6	1406.50	1365.00	2500.10			2509.28			5cc drawdown, tight retract	
7	1407.50	1366.00	2501.80			2511.04			1500psi pressure limited draw down, tight retract	
8	1410.50	1369.00	2507.00	1926.80	2506.90	2516.19	1936.18	2516.13	10cc drawdown	2362.2
9	1412.50	1371.00	2510.50	1929.10	2510.40	2519.70	1938.40	2519.61	20cc drawdown	193.2
10	1414.00	1372.50	2513.20	1930.80	2512.90	2522.38	1940.13	2522.15	20cc drawdown, slow but ok	4.1
11	1420.50	1379.00	2524.50	1937.40	2524.40	2533.72	1946.78	2533.62	20cc drawdown	252.7
12	1425.00	1383.50	2532.40	1943.60	2532.20	2541.62	1953.00	2541.55	20cc drawdown	3803.0
13	1430.50	1389.00	2542.00	1951.30	2542.10	2551.27	1960.67	2551.24	20cc drawdown	2084.0
14	1440.00	1398.50	2559.00	1966.70	2558.50	2568.18	1976.03	2568.16	20cc drawdown	506.0
15	1461.00	1419.50	2596.10	1997.00	2596.00	2605.40	2006.43	2605.27	20cc drawdown	3363.0
16	1470.00	1428.50	2612.20	2010.30	2612.10	2621.50	2019.67	2621.37	20cc drawdown	4115.0
17	1412.50	1371.00	2510.70	1929.40	2510.30	2519.31	1938.47	2519.32	20cc drawdown, divert to LFA and then sample 1 gallon followed by 4 MPSR, plus one malfunctioned MPSR. Total 5 MPSR's.	
18	1418.50	1377.00	2519.70		2119.20	2529.22		2529.28	10cc drawdown, tight	
19	1419.00	1377.50	2520.70	1935.60	2520.40	2580.08	1945.19	2530.06	10cc, Diverted flow through LFA after 55min and 18.7lt pumped LFA indicated water.	116.0
20	1413.80	1372.30	2511.40	1931.50	2511.40	2520.76	1940.99	2520.74	20cc drawdown. Attempt pumpout but formation to tight	1.3
21	1413.50	1372.00	2510.80	1930.30	2510.50	2520.19	1939.82	2520.54	20cc drawdown, lost seal, reset probe, LFA indicated oil.	71.4

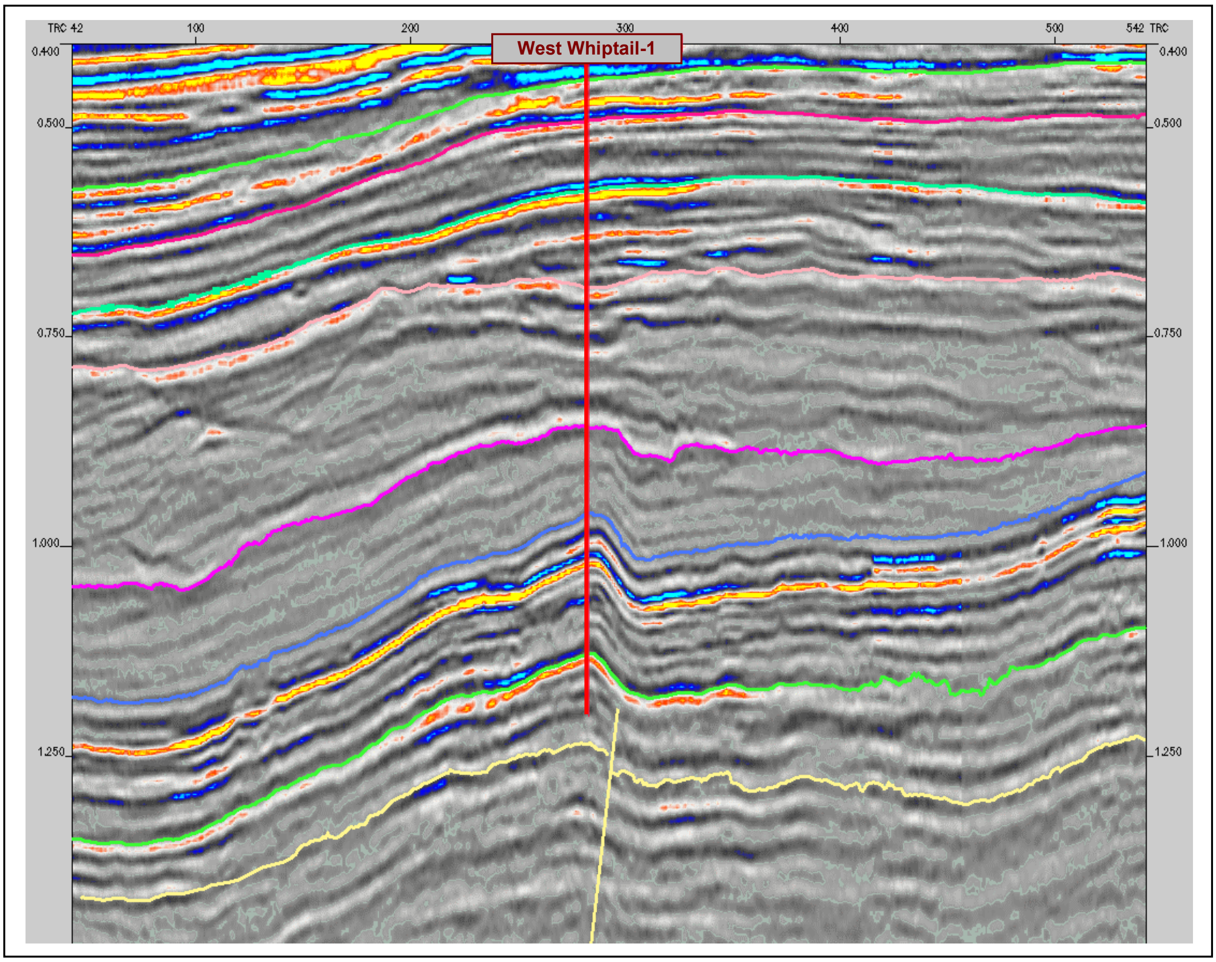
APPENDIX 1

MDT ANALYSIS

Esso Australia Pty Ltd
Exploration Department

West Whiptail 1

Wireline Formation Testing Report



Petrophysicists: Andrew Miller and Kumar Kuttan

October 2004

Contents

Summary

Schlumberger's Modular Formation Dynamics Tester (MDT) was used to obtain formation pressures and fluid samples in the West Whiptail 1 well. A total of 16 pressure and 5 fluid tests were attempted. Only 13 of the pressure tests were successful and hydrocarbon samples from one oil zone were successfully recovered.

The pressure data indicates that there are at least 5 aquifer pressure systems and one oil system in the interval from 1322.5m tvdss down to 1428.5m tvdss (1364 to 1470m mdkb) over which measurements were taken. A single oil zone was identified in the interval 1368.5 to 1372.9m tvdss (1409.8 to 1414.3m mdkb). No other hydrocarbon zones are present as indicated by hydrocarbon show, petrophysical and wireline formation testing analysis.

All of the aquifers in the interval are drawn down by approximately 88 psi from the original basin gradient as a result of production in the basin. The positions of the 5 water gradients vary up to 2 psi.

An OWC was interpreted at 1381m tvdss using a water gradient from the water sand that extends from 1376.3 to 1390m tvdss (1417.7 to 1431.5m mdkb) and a PVT derived oil gradient. This suggests the presence of a 13m oil column at the well location. However, a pump-out from the top of the water sand at 1377.6m tvdss (1419m mdkb) only recovered formation water suggesting that the coal from 1372.9 to 1374.1m tvdss (1414.3 to 1415.8m mdkb) is probably a base seal for the oil sand. As there is very little difference in the positions of the water gradients above and below the oil system it is highly likely that the OWC is at or very close to 1381m tvdss.

1.0 Operational Summary

Schlumberger's MDT (Modular Formation Dynamics Tester) was deployed in the West Whiptail 1 near field wildcat well to obtain formation pressures and fluid samples. The MDT tool was configured and run with the following modules:

- 1 X Multi-chamber Multi-sample Module (MRMS) (Original plan - two modules)
- One 1-gallon Modular Sample Chamber (MRSC)
- Live Fluid Analyser (LFA)
- Pump-out module (MRPO_UD)
- Single-probe Module (MRPS)

Two runs were made with the MDT tool. When the MDT was being run in the hole it hung up at 1241m in a large washout. Several attempts were made to pass the washout at various speeds but were unsuccessful. Three further attempts were made by opening the probe above the washout to rotate the tool then running in at 1200ft/hr. These attempts were also unsuccessful and the tool was pulled out of the hole. A wiper trip was performed and the tool was run in the hole successfully.

A total of 16 pressure tests were attempted. Thirteen were successful and three were tight. MDT data results are listed in Table 1.1. A total of 6 MPSR (450cc each) oil samples were taken for PVT analysis at 1371m tvdss (1412.5m mdkb) after a "pump-out". The results of this "pump-out" and fluid sampling are shown in Table 1.2. Additional "pump-outs" were done at 1372.1m tvdss (1413.5m mdkb) and 1377.6m tvdss (1419m mdkb) for fluid identification. The "pump-out" at 1372.1m tvdss (1413.5m mdkb) indicated the presence of reservoired oil, whereas the "pump-out" at 1377.6m tvdss (1419m mdkb) indicated formation water.

2.0 Pressure Data Observations and Interpretation

Figure 2.1 shows a plot of the pressure data recorded from 1322.5m tvdss down to 1428.5m tvdss (1364 to 1470m mdkb). It also includes pressure data from Whiptail 1A and Mulloway 1 for comparison.

The pressure data indicates that there are at least 5 aquifer pressure systems and one oil system in the interval over which measurements were taken. The oil bearing zone extends from 1368.4 to 1372.9m tvdss (1409.8 to 1414.3m mdkb) as shown in Figure 2.2. All the aquifer systems are drawn down by 88 psi from the original basin as a result of production in the basin. The positions of the 5 interpreted water gradients show variations in pressure of up to 2 psi.

For the purpose of identifying the aquifer systems and determining fluid contacts, the established water gradient of 1.42 psi/m for the basin was used. An oil gradient of 1.11 psi/m as determined from the PVT analysis of oil sample taken at 1371m tvdss (1412.5m mdkb) was used for the oil system.

Using the water gradient from the water sand that extends from 1376.3 to 1390m tvdss (1417.7 to 1431.5m mdkb) and the PVT determined oil gradient, an OWC contact of 1381m tvdss was interpreted from the pressure data. This also suggested the presence of a 13m oil column at the well location. However, a pump-out at 1377.6m tvdss (1419m mdkb) only recovered formation water (pumped 18.7 litres of water, with no indications of oil on the live fluid analyser and increasing water resistivity) suggesting that the oil system has a base seal which is probably the coal that extends from 1372.9 to 1374.1m tvdss (1414.3 to 1415.8m mdkb).

As there is very little difference between the positions of the water gradients above and below the oil sand, it is postulated that the actual OWC for this oil sand is likely to be at or close to 1381m tvdss.

Table 1.1 MDT Data Summary

ESSO AUSTRALIA PTY LTD
Well: West Whiptail-1
Date: 22-May-04
Tool Type (MDT-GR-LEHQT)
Gauge Type: CQG
Pressure units (psia, psig) psia

Near vertical Well
Maximum Inclination 8 deg
Hole angle offset -2.5m to TVD

Geologist-Engineer: Mike Woodmansee / Greg O'niell
KB (metres): 39.0
Probe type: Large
Temperature units: Deg C

Point No	Reeves Depth mMD	Schlumberger Depth mMD	Reeves Depth mTVDSS	Schlumberger Depth mTVDSS	Strain Gauge PSIG Hydrostatic Before	PPG	Reservoir	PPG	Quartz Gauge PSIA Hydrostatic Before	PPG	Reservoir	PPG	Temp	Strain hyd after	Qtz hyd after	Mobility Ratio	Comments
1		1364.00		1322.50	2424.40	10.8	1858.20		2434.36	10.8	1867.84		63.10	2424.80	2434.21	15860.0	20cc drawdown
2		1373.00		1331.50	2440.90	10.8	1871.10		2450.29	10.8	1880.38		63.80	2441.20	2450.05	118.6	20cc drawdown
3		1390.00		1348.50	2471.00	10.8	1894.80		2480.09	10.8	1903.99		64.20	2471.00	2480.02	14665.0	20cc drawdown
4		1398.40		1356.90	2485.90	10.8	1906.50		2494.99	10.8	1915.67		65.00	2484.90	2494.87	767.2	20cc drawdown
8		1410.50		1369.00	2507.00	10.7	1926.80		2516.19	10.8	1936.18		66.50	2506.90	2516.13	2362.2	10cc drawdown
9		1412.50		1371.00	2510.50	10.7	1929.10		2519.70	10.8	1938.40		66.80	2510.40	2519.61	193.2	20cc drawdown
10		1414.00		1372.50	2513.20	10.7	1930.80		2522.38	10.8	1940.13		67.30	2512.90	2522.15	4.1	20cc drawdown, slow but ok
11		1420.50		1379.00	2524.50	10.7	1937.40		2533.72	10.8	1946.78		67.40	2524.40	2533.62	252.7	20cc drawdown
12		1425.00		1383.50	2532.40	10.7	1943.60		2541.62	10.8	1953.00		67.60	2532.20	2541.55	3803.0	20cc drawdown
13		1430.50		1389.00	2542.00	10.7	1951.30		2551.27	10.8	1960.67		67.90	2542.10	2551.24	2084.0	20cc drawdown
14		1440.00		1398.50	2559.00	10.7	1966.70		2568.18	10.8	1976.03		68.00	2558.50	2568.16	506.0	20cc drawdown
15		1461.00		1419.50	2596.10	10.7	1997.00		2605.40	10.8	2006.43		68.30	2596.00	2605.27	3363.0	20cc drawdown
16		1470.00		1428.50	2612.20	10.7	2010.30		2621.50	10.8	2019.67		68.60	2612.10	2621.37	4115.0	20cc drawdown

Table 1.2 Fluid Sample Summary

West Whiptail-1							
A. Sample Identification							
Run/seat number	#/#	17	17	17	17	17	17
Sample depth (1371m tvdss)	md m rkb	1412.5	1412.5	1412.5	1412.5	1412.5	1412.5
Pretest volume	cc	20 ccs	n/a	n/a	n/a	n/a	n/a
Chamber size	cc/litre/gallon	1 gallon	450cc	450cc	450cc	450cc	450cc
Chamber serial number	#	19	478	494	1178	1695	1760
Probe type		Large	Large	Large	Large	Large	Large
Choke size		n/a	n/a	n/a	n/a	n/a	n/a
B. Sampling History							
Date	dd/mm/yy	22/5/04	22/5/04	22/5/04	22/5/04	22/5/04	22/5/04
Initial hydrostatic	psia	2519.32	2519.32	2519.32	2519.32	2519.32	2519.32
Tool Set	hh:mm	5:10	n/a	n/a	n/a	n/a	n/a
Pretest start	hh:mm	5:11	n/a	n/a	n/a	n/a	n/a
Initial form'n pressure (pretest)	psia	1938.47	1938.47	1938.47	1938.47	1938.47	1938.47
Pretest end	hh:mm	5:12	n/a	n/a	n/a	n/a	n/a
Pretest duration	*hh:mm*	*0:01*	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Pumpout start	hh:mm	5:13	*n/a*	*n/a*	*n/a*	*n/a*	*n/a*
Pumpout end	hh:mm	6:10	*6:25*	*6:45*	*6:53*	*6:59*	*7:03*
Pumpout duration	*hh:mm*	57min/20min					
Pumpout volume	litres	1 gallon	450cc	450cc	450cc	450cc	450cc
LFA indication	colour	green	green	green	green	green	green
Interpreted fluid at LFA	-	oil	oil	oil	oil	oil	oil
Final resisitivity at probe	ohm-m	0.595	0.7603	0.5495	0.693	0.7003	0.695
Chamber open	hh:mm	6:10	6:38	6:48	6:55	7:00	7:06
Minimum sampling pressure	psia	800	1770.0	1770.0	1770.0	1770.0	1770.0
Final formation pressure	psia						
Seal chamber	hh:mm	6:25	6:45	6:53	6:59	7:03	7:09
Chamber fill time	*hh:mm*	*15min*	*7min*	*5min*	*4min*	*3min*	*3min*
Tool retract	hh:mm	not retracted	not retracted	not retracted	not retracted	not retracted	7:12
Final hydrostatic	psia	n/a	n/a	n/a	n/a	n/a	2519.4
Total time	*hh:mm*	*1:15*	*0:20*	*0:08*	*0:06*	*0:04*	*0:09*
C. Sample Downhole Temperature And Resistivity							
At sample depth (AMS)	degC	67.2	67.2	67.2	67.2	67.2	67.2
Rm@sample depth (AMS)	ohm-m						
F. Mud Filtrate Properties							
Rmud @ degC	ohm-m@degC		0.1233/25.5c	0.1233/25.5c	0.1233/25.5c	0.1233/25.5c	0.1233/25.5c
K+ ion calculated from KCL%	ppm		0	0	0	0	0
Chlorides titrated	ppm		0	0	0	0	0
pH			0	0	0	0	0
Tritium	DPM						
G. General Calibration							
Reported mud weight	ppg	10.2	10.2	10.2	10.2	10.2	10.2
Calculated hydrostatic	*psia*		*2455*	*2455*	*2455*	*2455*	*2455*

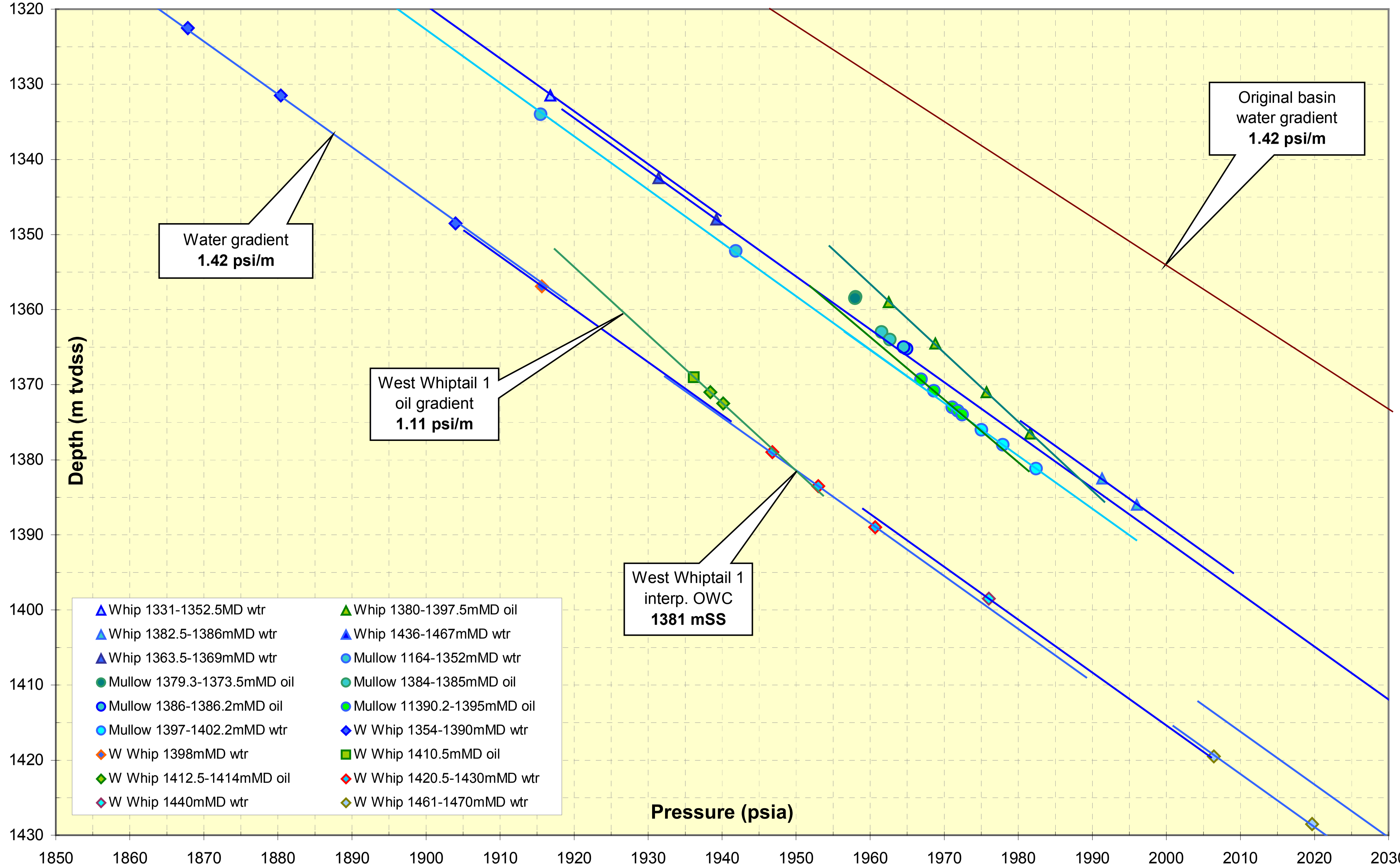


Fig. 2.1 - Plot of Whiptail-1, Mulloway-1A and West Whiptail 1 pressure data

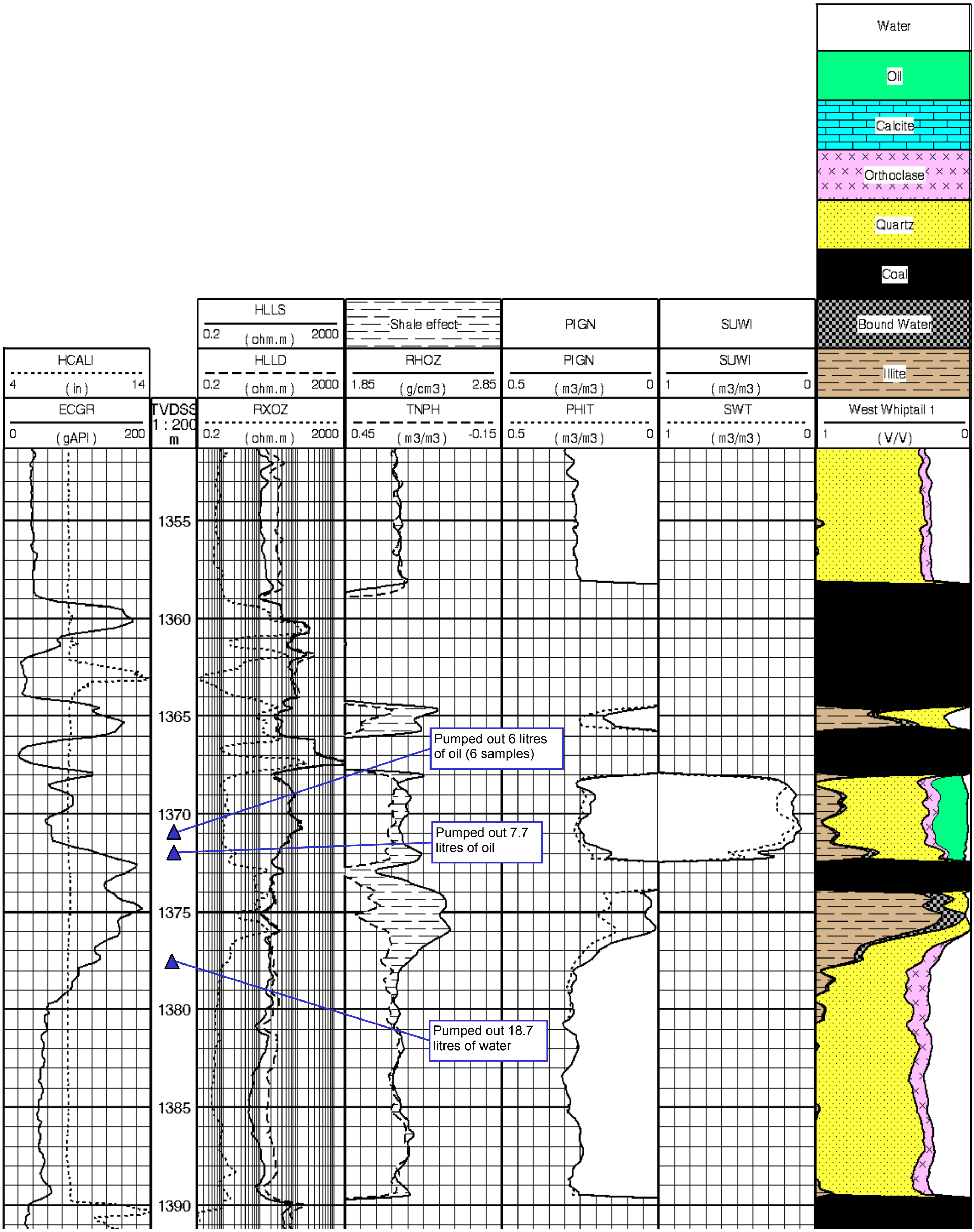


Fig. 2.2 - Wireline logs and ELAN+ model results

Appendix 1 - Calculation of Oil Gradient from PVT Data

Density of oil at bubble point (216 psig) and reservoir temperature (153 deg F or 67.2 deg. C) = 0.7664 g/cc (page 1 of West Whiptail 1 PVT Report by Petrolab).

Compressibility of oil at reservoir pressure (1924 psig) and reservoir temperature (153 deg. F or 67.2 deg. C) = 0.9847 (Constant Mass Study, page 20, West Whiptail 1 PVT Report by Petrolab).

Density of oil at reservoir pressure (1924 psig) and reservoir temperature (153 deg. F or 67.2 deg. C) = 0.7664/0.9847 = 0.7783 g/cc.

Oil gradient at reservoir pressure and temperature:

=0.7783*1.426 = 1.11 psi/m

Note: *The pressure and temperature used during the PVT analysis varies from that measured in the borehole as follows:*

	Source	
	MDT	**Esso to Petrolab**
Pressure (psig)	1929.1	1924
Temp (deg C)	66.8	67.2

The data used by Petrolab for the PVT analysis were provided by the Esso Reservoir Engineering group. The effect created by these small variations on the calculated oil gradient is considered to be negligible.

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SUMMARY OF RESULTS

CONSTANT MASS DATA :

Reservoir Temperature (°F)	:	153
Saturation Pressure (psig)	:	216
Thermal Expansion of Saturated Oil		
@ 153 °F AND 216 PSIG (*10^4/°F)	:	4.87
(*10^4/°C)	:	8.77
Compressibility of Saturated Oil		
@ 153 °F AND 216 PSIG (*10^6/psi)	:	10.80

SATURATED OIL @ 153 °F AND 216 PSIG :

Oil density (gm/cc)	:	0.7664
Specific Volume (ft^3/lb)	:	0.0209
Viscosity (cp)	:	1.28

RESIDUAL OIL :

API Gravity @ 60 °F	:	43.0
Formation Volume Factor	:	1.045
Density @ 153 °F (gm/cc)	:	0.7751
Viscosity @ 0 °F (cp)	:	1.46
Pour Point (°C)		9
Flash Point (°C)		< 15
Wax Content (wt %)	:	8.8

RESERVOIR OIL @ 153 °F AND 1924 PSIG :

Solution GOR (SCF/Bbl)	:	**Rs**	**41**
Formation Volume Factor (Resbbl/STbbl)	:	**Bo**	**1.052**

SATURATED OIL @ 153 °F AND 216 PSIG :

Solution GOR (SCF/Bbl)	:	**Rs**	**41**
Formation Volume Factor (Resbbl/STbbl)	:	**Bo**	**1.063**

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Well : West Whiptail # 1	File : E - 24014

CONSTANT MASS STUDY
@ 153 °F
Using Bottom Hole Reservoir Fluid in Cylinder # L-405

Pressure (psig)		Relative Volume (V/Vsat) (1)	Oil Compressibility (x10^-6)(psig^-1) (2)	Y Function (psig^-1) (3)	Thermal Expansion (x10^-4)(°F^-1) (4)	Oil Viscosity (Centipoise) (4)
3000		0.9771	6.56		4.06	1.64
2500		0.9805	6.94		4.16	1.57
1924	* *	0.9847	7.40		4.27	1.50
1500		0.9880	7.88		4.38	1.45
1000		0.9923	8.58		4.53	1.38
750		0.9945	9.00		4.62	1.35
500		0.9969	9.60		4.72	1.32
216	*	1.0000	10.80		4.87	1.28
215		1.0026		1.78		1.28
210		1.0155		1.84		1.29
200		1.0376		2.13		1.29
180		1.0901		2.22		1.30
160		1.1620		2.16		1.31
140		1.2583		2.10		1.32
120		1.3922		2.04		1.33
100		1.5859		1.98		1.34
80		1.8854		1.92		1.36
60		2.3978		1.86		1.37
40		3.4581		1.79		1.39
0						1.46

* Saturation Pressure

* * Reservoir Pressure

(1) Barrels at indicated pressure per barrel at saturation pressure
(2) Oil Compressibility = - (1/V) * (dV/dP)
(3) Y Function = (Psat - P) / (P)*(V/Vsat-1)
(4) Thermal Expansion = - (1/V) * (dV/dT)

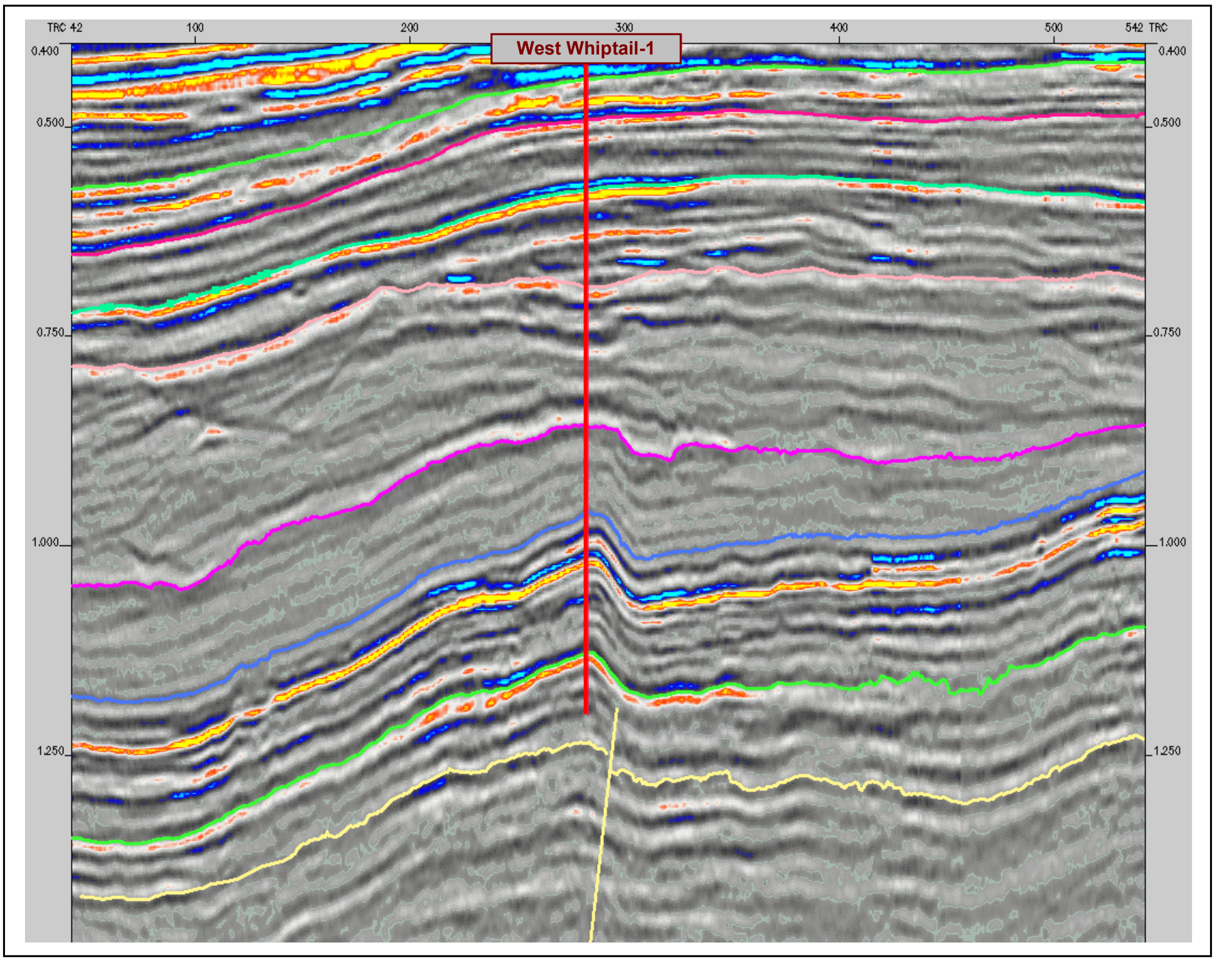
APPENDIX 2

QUANTITATIVE FORMATION EVALUATION

Esso Australia Pty Ltd
Exploration Department

West Whiptail 1

Quantitative Petrophysical Interpretation



Petrophysicists: Andrew Miller and Kumar Kuttan

October 2004

Contents

1.0 Introduction

1.1 General

The West Whiptail 1 near field wildcat exploration well, located in VIC/L1 (see Fig. 1.1) was drilled to test the hydrocarbon potential of Palaeocene to Eocene aged Intra-Latrobe Group fluvial reservoirs in a closure located between the Whiptail and Mulloway discoveries along the Barracouta anticlinal trend. The well was spudded on the 10th of May 2004 and was drilled to a total depth of 1539mRT (Driller) 1529mRT (Logger) and plugged and abandoned. The primary objective of this quantitative petrophysical interpretation was to evaluate the reservoirs for porosity, water saturation and net pay.

Note: All depths quoted in this report are logged mRT unless otherwise specified.

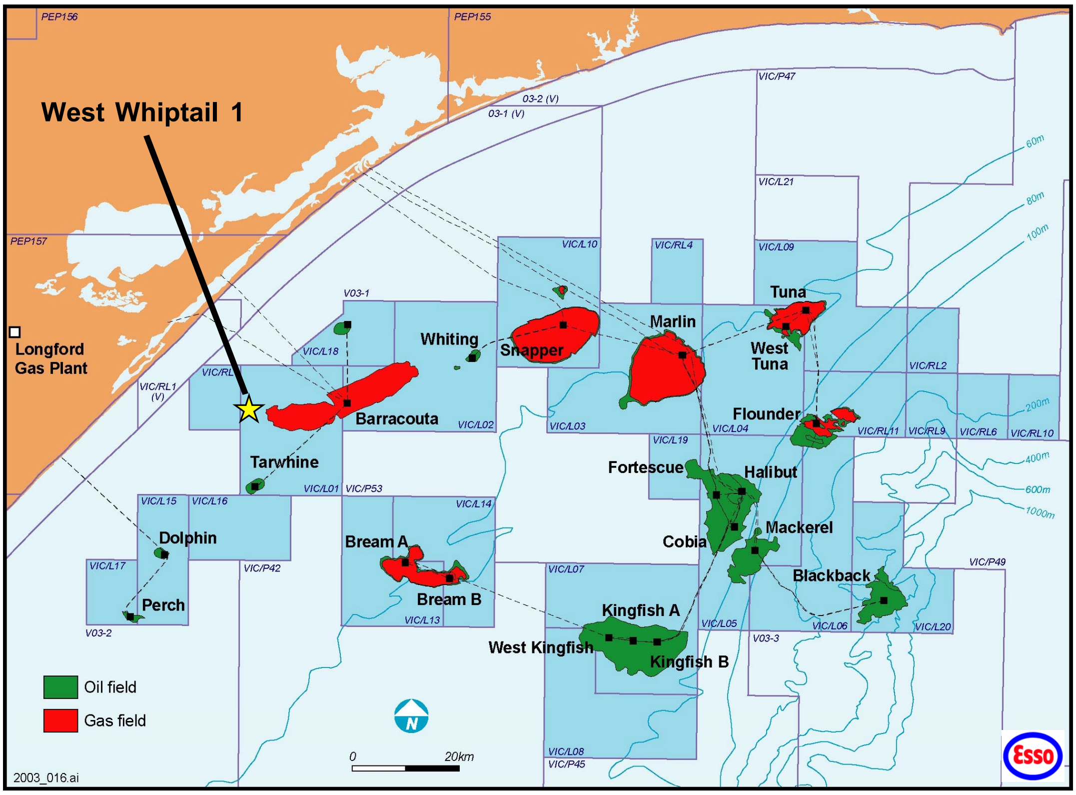


Figure 1.1 - West Whiptail 1 location map

2.0 Data

2.1 Wireline Logs

The logs run in the well are listed in Table 2.1.

Table 2.1 - Summary of Wireline Logs

Survey /Log	Company	Top (m MDRT)	Bottom (m MDRT)
Gyro Survey	Scientific Drilling	0.0	1521.9
Suite 1: Run at 1526.7m MDRT			
HALS-PEX-HNGS-DSI	Schlumberger	745.5 GR, DSI to surface	1526.7
MDT-GR	Schlumberger	1364.0	1440.0
CSAT-GR	Schlumberger	99.9	1265.0

2.2 Logging Suite 1

The PEX density-neutron, resisitivity and GR logs were acquired in high-resolution mode from 1526.7m to 1100m at 1800ft/hr, after which logging speed increased to 2100ft/hr up to the casing shoe at 745.5m. DSI and GR logs were recorded from the casing shoe to sea bed at 2800ft/hr. A repeat section was logged from 1480m to 1380m as per EAL request. The only problem encountered with the logging job was failure of the Schlumberger computer to store data. Vision files were displayed on screen as normal. Troubleshooting was performed by re-booting the computer. Ran back into the hole and re-logged repeat section.

2.3 Mud Data

Table 2.2 Summary of mud properties

Property	Value
Mud Type	KCL / PHPA / Glycol
Mud Weight	9.95 ppg
Rm	0.117 ohm.m @ 19°C
Rmf	0.097 ohm.m @ 21°C
Rmc	0.143 ohm.m @ 21°C
BHT	72 °C

2.4 Log Quality

The overall data quality of the density-neutron and sonic logs and the MDT pressure data appear to be good and the calibration data appear to be acceptable. However, the GR logs including the HCGR (HNGS GR that has been corrected for the potassium in the mud) recorded with the various logs appear to be high (~40 API) in the sands.

Also, all sands in the well show some separation between the bulk density (RHOZ) and TNPH curves. The separation suggests that these sands are either shaly or have complex mineralogy. Nearby fields (eg. Mulloway, Barracouta) show that in these reservoirs, the predominant mineral is quartz with low clay content and some feldspars.

The RXOZ log is generally of acceptable quality over most of the logged intervals, except over shales where it indicates an 'invasion' profile. The apparent 'invasion' profile is probably due to poor pad pressure over the shales, which have become soft as a result of hydration by the mud.

The wellsite compressional sonic log from the DSI (DT4P) showed that there were numerous intervals above 607m of around 3-4m each with no data recorded.

2.5 Data Processing

The standard resolution (6 inch sample rate) was selected for the final petrophysical evaluation. The RHOZ log was chosen as the base log for depth matching purposes. The TNPH, HLLD, HLLS, RXOZ and DT4P were then depth matched to the RHOZ log. No corrections or bulk shifts were applied to any of the logs. No environmental corrections were applied to any of the log data.

3.0 Interpretation

3.1 Methodology

Schlumberger's Geoframe ELAN+ module was used to determine mineral volumes, Total Porosity, (PHIT), Effective Porosity (PHIE or PIGN), Total Water Saturation (SWT) and Effective Water Saturation (SUWI). Net reservoir and net pay were then calculated using a PHIE cut-off of 0.12 (12%).

The ELAN+ model and input parameters are described in Appendix 1.

3.2 Logs Used

The primary logs used in this interpretation were HLLD (deep resistivity), POTA (Potassium curve derived from the spectral gamma ray), RHOZ (bulk density) and TNPH (thermal neutron porosity). A temperature log was created using the data in Table 3.1.

Table 3.1 Temperate data

Depth (m)	Temperature (^{O}C)
48	10
1539	72

The maximum temperature used in creating the temperature curve was obtained from the maximum recorded temperature from the HALS-PEX-HNGS-DSI log.

All coal and carbonaceous shaly units were identified using a coal flag (FLAG_COAL).

3.3 Formation Water Salinity

An apparent formation water salinity (FWS) curve was created using the Rwa salinity method with inputs of m=2, a=1 and BHT=72^{O}C. This curve was used to quantify salinity in sandy intervals within the borehole. All sands appear to contain fresh connate water. The base of the fresh water wedge is not seen in the well and is expected to lie below the TD of 1529m.

It has been shown by K. Kuttan *et al* (*Freshwater Influx in the Gippsland Basin: Impact on Formation Evaluation, Hydrocarbon Volumes and Hydrocarbon Migration*, APPEA Journal, 1986) that the connate water in the hydrocarbon bearing intervals occurring within the freshwater wedge is significantly more saline than that of the surrounding aquifers.

For the West Whiptail 1 petrophysical evaluation, a salinity of 25K ppm was used for the hydrocarbon zone within the fresh water wedge. For the zones with fresh connate water, the apparent salinity from the Rwa calculation of 1 kppm was used.

3.4 Hydrocarbon Type

Using a combination of density-neutron crossover effect, RFT recoveries, and mud log and cuttings shows, the hydrocarbon type present in the reservoirs was identified. The MDT pressure testing and sampling indicated that there was only one oil-bearing zone over the logged interval. For the ELAN+ analysis, a hydrocarbon density of 0.7 g/cc was used.

3.5 Results

Except for a single thin hydrocarbon bearing sand in the interval 1410 to 1414.5m all other reservoir quality sands are water bearing. Average effective porosities range from 14% to 29% with the majority being over 20%. The hydrocarbon in the reservoir interval is interpreted to be oil. This is based on MDT pressure data and down hole LFA analysis results.

In this sand, the average effective porosity ranges from 15% to 26% and the effective water saturation ranges from 4% to 18% (see Figure 3.1).

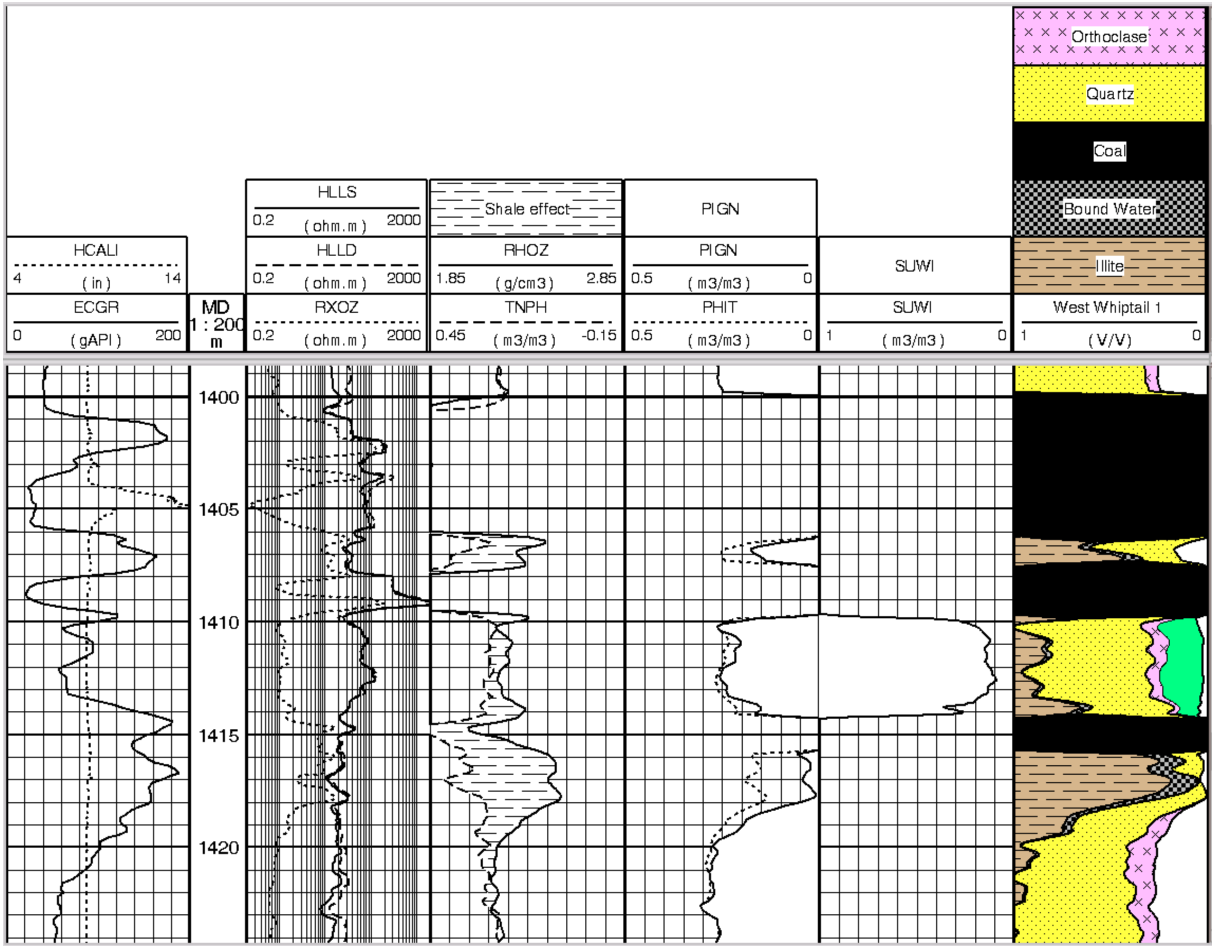


Figure 3.1 - Results from ELAN+ model for the interval 1400 to 1425 m.

1400m - 1425m
All of the sands throughout this interval are considered to be water-bearing, except for an oil-bearing interval between 1410 - 1414.5m. The sand shows an average PHIE of 20% and an average effective water saturation of 10%.

4.0 Net Reservoir and Net Pay

4.1 General

Net reservoir and net pay were determined using an effective porosity cut-off of 12%. The total net oil pay in West Whiptail 1 is estimated to be 4.43m. Table 4.1 is a summary of the results of the analysis.

Table 4.1 Petrophysical Summary 1187 - 1522 m

Top depth (m)	Bottom depth (m)	Gross thickness (m)	Net thickness (m)	Net/gross ratio	Mean VCL (m3/m3)	Mean PHIE (m3/m3)	Mean SWE (m3/m3)	Comments	Net pay
1187.36	1201.64	14.280	13.330	0.933	0.199	0.240	1.000	Water-bearing	
1205.11	1237.18	32.070	32.000	0.998	0.060	0.260	1.000	Water-bearing	
1246.21	1256.74	10.530	8.830	0.839	0.274	0.218	1.000	Water-bearing	
1263.91	1278.25	14.340	11.240	0.784	0.166	0.250	1.000	Water-bearing	
1280.60	1294.89	14.290	13.780	0.964	0.228	0.250	1.000	Water-bearing	
1298.07	1301.03	2.960	2.820	0.953	0.053	0.205	1.000	Water-bearing	
1301.88	1306.52	4.640	4.530	0.976	0.289	0.206	1.000	Water-bearing	
1311.31	1313.68	2.370	1.970	0.831	0.410	0.211	1.000	Water-bearing	
1316.03	1323.72	7.690	7.490	0.974	0.224	0.227	1.000	Water-bearing	
1325.66	1338.35	12.690	12.450	0.981	0.088	0.256	1.000	Water-bearing	
1339.43	1346.73	7.300	7.220	0.989	0.381	0.215	1.000	Water-bearing	
1351.19	1399.94	48.750	47.330	0.971	0.134	0.237	1.000	Water-bearing	
1406.28	1407.48	1.200	0.700	0.583	0.534	0.158	1.000	Water-bearing	
1409.78	1414.29	4.510	**4.430**	0.982	0.166	0.216	0.170	**Oil-bearing**	Y
1417.76	1431.54	13.780	13.230	0.960	0.051	0.263	1.000	Water-bearing	
1435.56	1451.00	15.440	9.600	0.622	0.284	0.208	1.000	Water-bearing	
1454.82	1458.01	3.190	3.000	0.940	0.077	0.182	1.000	Water-bearing	
1460.00	1464.03	4.030	4.030	1.000	0.112	0.244	1.000	Water-bearing	
1467.59	1477.56	9.970	9.920	0.995	0.042	0.244	1.000	Water-bearing	
1479.18	1495.24	16.060	16.060	1.000	0.041	0.238	1.000	Water-bearing	
1495.94	1499.59	3.650	3.580	0.981	0.134	0.182	1.000	Water-bearing	
1502.09	1508.32	6.230	5.700	0.915	0.080	0.253	1.000	Water-bearing	
1516.51	1522.88	6.370	6.000	0.942	0.051	0.251	1.000	Water-bearing	

Net thickness is based on PHIE cutoff of 0.12 volume per volume.
Depth Reference = mRT.
Mean PHIE, Mean VCL, mean SWE is of net thickness interval.
Y = yes, N = no.

Appendix 1

ELAN+ Model and Parameters

A-1 ELAN+ Model

The Schlumberger ELAN+ West Whiptail 1 model input parameters are described below. This model uses the Dual Water Archie equation saturation model for determining water saturation in both the invaded and uninvaded zones. A basic mineralogy of pure calcite was used for the interval above 1179m that comprises the Lakes Entrance Formation. Below 1179m, illite is used to represent all shale volumes and quartz to represent all sand volumes.

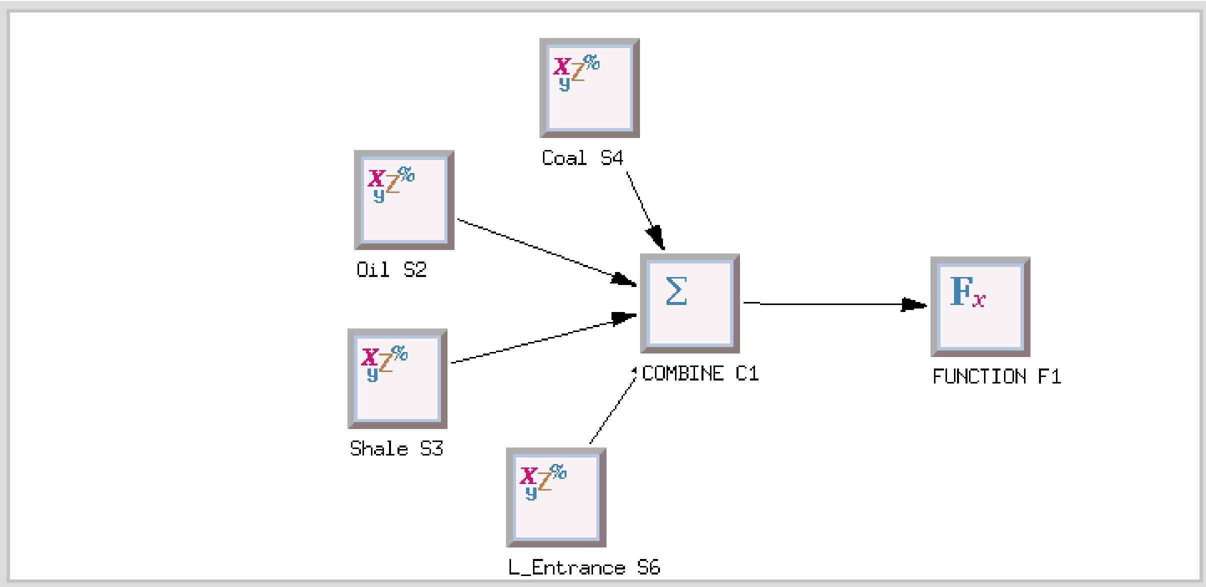


Figure A1.1 details the ELAN+ process definition.

Table A1.3 lists the parameters used over the entire borehole. A value of -999.25 in all tables indicates a null value.

A 1.1 Elan Process Definitions

Process: SOLVE2 "Oil"

Equations	Volumes
RHOB	QUAR
NPHI	ORTH
CUDC_DWA	ILLI
WWK	XWAT
CT1	UWAT
	XOIL
	UOIL

Constraints applied:
WaterBaseMud_SXO_gt_SW
User constraints: gas_cutoff = if(GR_CH >= 60, 0, 1)
(xgasconstraint, XOIL <= gas_cutoff)
(ugasconstraint, UOIL <= gas_cutoff)
Constraint Zones: Bottom Top
1530.8580(m) 1160.0000(m)

Process: SOLVE3 "Shale"

Equations	Volumes
RHOB	QUAR
NPHI	ORTH
WWK	ILLI
	XWAT
	UWAT

Constraint Zones: Bottom 1530.8580(m) Top 1160.0000(m)

Process: SOLVE4 "Coal"

Equations	Volumes
RHOB	COAL

Constraint Zones: Bottom 1530.8580(m) Top 1160.0000(m)

Process: SOLVE6 "L_Entrance"

Equations	Volumes
RHOB	CALC

Constraint Zones: Bottom 1530.8580(m) Top 1160.0000(m)

Process: COMBINE1 "COMBINE"

Order SOL.2 → SOL.3 → SOL.4 → SOL.6
Combine Method:
"Fm" 5022.5000(m) Internal Average
"Lakes_Entran" 3868.1104(m) Sol.6
Probability Functions:
Probability (SOL.6,0)

Probability (SOL.4, PRB4_CH)

prob3 = linear(ILLI_VOL.SOL.3, 0.3, 0, 0.5, 1)
probability (SOL.3, prob3)

Process: FUNCTION1 "FUNCTION"

Outputs: VCL, SXWI, SWT, SUWI, PIGN, PHIT
User-defined Function/n:
swt_cmp = if((PRB4_CH>0), 1, (UWAT_VOL + XBWA_VOL) / (UWAT_VOL + XBWA_VOL + UOIL_VOL))
output (SWT, swt_cmp)

A 1.2 Elan Channels

	Compound Name Spec	WEST WHIPTAIL 1
TEMP_CH	TEMP;*	TEMP@ELANInput;4 .WELLEDIT [A963818]
RHOB_IFAC_CH	IFRH;*	
NPHI_IFAC_CH	INPH;*	
RHOB_CH	RHOZ;*	RHOZ@ELANInput;11 .WELLEDIT [A963805]
NPHI_CH	TNPH;*	TNPH@ELANInput;12 .WELLEDIT [A963859]
CUDC_CH/RT_CH	HLLD;*	HLLD@ELANInput;12 .WELLEDIT [A963850]
WWK_CH	POTA;*	POTA@DataFunction;1 .DF [A966276]
PRB2_CH	FLAG_RHOH;*	FLAG_RHOH@ELANInput;1 .WELLEDIT [A963816]
PRB3_CH	PRB3;*	
PRB4_CH	FLAG_COAL;*	FLAG_COAL@ELANInput;2 .WELLEDIT .WELLEDIT
PRB6_CH	PRB6;*	
M_CH	MXP;*	
N_CH	SXP;*	

A 1.3 Elan+ Model Parameters

Parameter	Value	Parameter	Value
RHOB_QUAR	2.650 (g/cm3)	RHOB_CALC	2.710 (g/cm3)
RHOB_ORTH	2.570 (g/cm3)	RHOB_ILLI	2.780 (g/cm3)
RHOB_KAOL	2.620 (g/cm3)	RHOB_FELD	2.520 (g/cm3)
RHOB_COAL	1.200 (g/cm3)	RHOB_XOIL	0.700 (g/cm3)
RHOB_UOIL	0.700 (g/cm3)	RHOB_XGAS	0.098 (g/cm3)
RHOB_UGAS	0.098 (g/cm3)	RHOB_XBWA	1.000 (g/cm3)
NPHI_QUAR	-0.018 (m3/m3)	NPHI_CALC	0.000 (m3/m3)
NPHI_ORTH	-0.010 (m3/m3)	NPHI_ILLI	0.247 (m3/m3)
NPHI_KAOL	0.450 (m3/m3)	NPHI_FELD	-0.006 (m3/m3)
NPHI_COAL	0.500 (m3/m3)	NPHI_XWAT	1.000 (m3/m3)
NPHI_UWAT	1.000 (m3/m3)	NPHI_XOIL	1.000 (m3/m3)
NPHI_UOIL	1.000 (m3/m3)	NPHI_XGAS	0.123 (m3/m3)
NPHI_UGAS	0.123 (m3/m3)	NPHI_XBWA	1.000 (m3/m3)
DT_QUAR	55.500 (us/m)	DT_CALC	47.800 (us/m)
DT_ORTH	69.007 (us/m)	DT_ILLI	60.000 (us/m)
DT_KAOL	91.318 (us/m)	DT_FELD	69.007 (us/m)
DT_COAL	121.920 (us/m)	DT_XWAT	220.000 (us/m)
DT_UWAT	0.000 (us/m)	DT_XOIL	240.000 (us/m)
DT_UOIL	0.000 (us/m)	DT_XGAS	0.000 (us/m)
DT_UGAS	289.999 (us/m)	DT_XBWA	189.000 (us/m)
CUDC_ILLI	-999.250 (mS/m)	CUDC_KAOL	-999.250 (mS/m)
GR_QUAR	20.000 (gAPI)	GR_CALC	11.000 (gAPI)
GR_ORTH	200.000 (gAPI)	GR_ILLI	190.000 (gAPI)
GR_KAOL	98.000 (gAPI)	GR_FELD	250.000 (gAPI)
GR_COAL	40.000 (gAPI)	GR_XWAT	0.000 (gAPI)
GR_UWAT	0.000 (gAPI)	GR_XOIL	0.000 (gAPI)
GR_UOIL	0.000 (gAPI)	GR_XGAS	0.000 (gAPI)
GR_UGAS	0.000 (gAPI)	GR_XBWA	0.000 (gAPI)
WWK_QUAR	0.000 (kgf/kgf)	WWK_CALC	0.000 (kgf/kgf)
WWK_ORTH	0.102 (kgf/kgf)	WWK_ILLI	0.030 (kgf/kgf)
WWK_COAL	0.000 (kgf/kgf)	WWK_XWAT	0.000 (kgf/kgf)
WWK_UWAT	0.000 (kgf/kgf)	WWK_XOIL	0.000 (kgf/kgf)
WWK_UOIL	0.000 (kgf/kgf)	WWK_XBWA	0.000 (kgf/kgf)
CT1_QUAR	0.000	CT1_CALC	0.000
CT1_ORTH	0.000	CT1_ILLI	0.000
CT1_KAOL	0.000	CT1_FELD	0.000
CT1_COAL	0.000	CT1_XWAT	0.000
CT1_UWAT	0.000	CT1_XOIL	1.000
CT1_UOIL	-0.200	CT1_XGAS	1.000
CT1_UGAS	-0.800	CT1_XBWA	0.000
CT2_QUAR	0.000	CT2_CALC	0.000
CT2_ORTH	0.000	CT2_ILLI	0.000
CT2_KAOL	0.000	CT2_FELD	0.000
CT2_COAL	0.000	CT2_XWAT	0.000
CT2_UWAT	0.000	CT2_XOIL	1.000
CT2_UOIL	-0.800	CT2_XGAS	0.000
CT2_UGAS	0.000	CT2_XBWA	0.000
CT3_QUAR	0.050	CT3_CALC	0.000
CT3_ORTH	-1.000	CT3_ILLI	0.000
CT3_KAOL	0.000	CT3_FELD	-1.000
CT3_COAL	0.000	CT3_XWAT	0.000
CT3_UWAT	0.000	CT3_XOIL	0.000
CT3_UOIL	0.000	CT3_XGAS	0.000
CT3_UGAS	0.000	CT3_XBWA	0.000
ARHOB_ILLI	2.780 (g/cm3)	ARHOB_KAOL	2.620 (g/cm3)
WCLP_ILLI	0.154 (m3/m3)	WCLP_KAOL	0.058 (m3/m3)
CBWA_ILLI	-0.999 (mS/m)	CBWA_KAOL	-999.250 (mS/m)
CECA_ILLI	0.200 (meq/g)	CECA_KAOL	0.090 (meq/g)
RMF	0.086 (ohm.m)	MST	-999.250 (degC)
RWT	-999.250 (degC)	SALIN_ISOL	-999.250 (ppk)
SALIN_PARA	-999.250 (ppk)	SALIN_XWAT	-999.250 (ppk)
SALIN_UWAT	-999.250 (ppk)	SALIN_XIWA	-999.250 (ppk)
SALIN_UIWA	-999.250 (ppk)	SALIN_XOIL	0.000 (ppk)
SALIN_UOIL	0.000 (ppk)	SALIN_XGAS	0.000 (ppk)
SALIN_UGAS	0.000 (ppk)	SALIN_XSFL	-999.250 (ppk)
SALIN_USFL	-999.250 (ppk)	CT1_ZP	0.000
CT2_ZP	0.000	CT3_ZP	0.000
RHOB_UNC_ZP	0.027 (g/cm3)	NPHI_UNC_ZP	0.015 (m3/m3)
DT_UNC_ZP	2.250 (us/m)	GR_UNC_ZP	2.250 (gAPI)
WWK_UNC_ZP	0.002 (kgf/kgf)	CT1_UNC_ZP	0.015
CT2_UNC_ZP	0.015	CT3_UNC_ZP	0.015
VOLS_UNC_ZP	0.015 (m3/m3)	RHOB_UNC_WM	1.000
NPHI_UNC_WM	1.000	DT_UNC_WM	0.700
CUDC_UNC_WM	0.600	GR_UNC_WM	0.500
WWK_UNC_WM	0.500	CT1_UNC_WM	0.200
CT2_UNC_WM	1.000	CT3_UNC_WM	0.700
VOLS_UNC_WM	1.000	RHOB_IFAC_ZP	1.000
NPHI_IFAC_ZP	1.000	A_ZP	1.000
N_ZP	2.000	C_DWA	0.000
M_DWA	2.000	BVIRR	0.015 (m3/m3)

Appendix 2

MDT Data Summary

A-2 MDT Data Summary

ESSO **AUSTRALIA PTY LTD**
Well: West Whiptail-1
Date: 22-May-04
Tool Type (MDT-GR-LEHQT)
Gauge Type: CQG
Pressure units (psia, psig) psia

Near vertical Well
Maximum Inclination 8 deg
Hole angle offset -2.5m to TVD

Geologist-Engineer: Mike Woodmansee / Greg O'niell
KB (metres): 39.0
Probe type: Large
Temperature units: Deg C

Point No	Reeves Depth mMD	Schlumberger Depth mMD	Reeves Depth mTVDSS	Schlumberger Depth mTVDSS	Strain GaugePSIG Hydrostatic Before	PPG	Reservoir	PPG	Quartz GaugePSIA Hydrostatic Before	PPG	Reservoir	PPG	Temp	Strain hyd after	Qtz hyd after	Mobility Ratio	Comments
1		1364.00		1322.50	2424.40	10.8	1858.20		2434.36	10.8	1867.84		63.10	2424.80	2434.21	15860.0	20cc drawdown
2		1373.00		1331.50	2440.90	10.8	1871.10		2450.29	10.8	1880.38		63.80	2441.20	2450.05	118.6	20cc drawdown
3		1390.00		1348.50	2471.00	10.8	1894.80		2480.09	10.8	1903.99		64.20	2471.00	2480.02	14665.0	20cc drawdown
4		1398.40		1356.90	2485.90	10.8	1906.50		2494.99	10.8	1915.67		65.00	2484.90	2494.87	767.2	20cc drawdown
8		1410.50		1369.00	2507.00	10.7	1926.80		2516.19	10.8	1936.18		66.50	2506.90	2516.13	2362.2	10cc drawdown
9		1412.50		1371.00	2510.50	10.7	1929.10		2519.70	10.8	1938.40		66.80	2510.40	2519.61	193.2	20cc drawdown
10		1414.00		1372.50	2513.20	10.7	1930.80		2522.38	10.8	1940.13		67.30	2512.90	2522.15	4.1	20cc drawdown, slow but ok
11		1420.50		1379.00	2524.50	10.7	1937.40		2533.72	10.8	1946.78		67.40	2524.40	2533.62	252.7	20cc drawdown
12		1425.00		1383.50	2532.40	10.7	1943.60		2541.62	10.8	1953.00		67.60	2532.20	2541.55	3803.0	20cc drawdown
13		1430.50		1389.00	2542.00	10.7	1951.30		2551.27	10.8	1960.67		67.90	2542.10	2551.24	2084.0	20cc drawdown
14		1440.00		1398.50	2559.00	10.7	1966.70		2568.18	10.8	1976.03		68.00	2558.50	2568.16	506.0	20cc drawdown
15		1461.00		1419.50	2596.10	10.7	1997.00		2605.40	10.8	2006.43		68.30	2596.00	2605.27	3363.0	20cc drawdown
16		1470.00		1428.50	2612.20	10.7	2010.30		2621.50	10.8	2019.67		68.60	2612.10	2621.37	4115.0	20cc drawdown

APPENDIX 3

Hydrocarbon Fingerprint Analysis

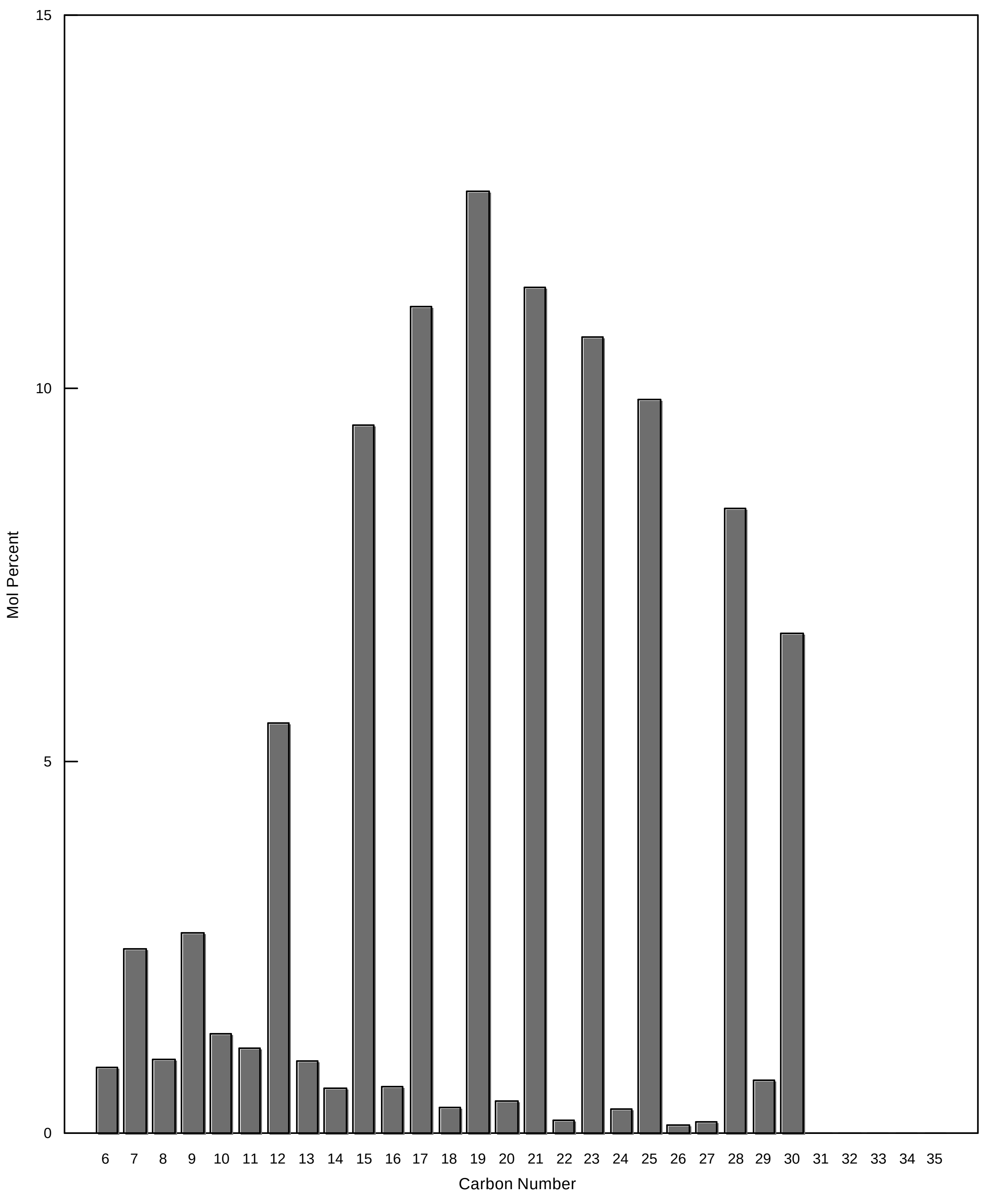
PETROLAB

Company : Esso Australia Limited	Page : 1 of 2
Well : West Whiptail 1	File : E - 24014

FINGERPRINT ANALYSIS
BY CAPILLARY GAS CHROMATOGRAPHY
On Extracted Oil from Cuttings of Depth 1405-1410 mMD

Component		Mol %
Hexanes minus	C6-	0.26
Hexanes	C6	0.89
Heptanes	C7	2.47
Octanes	C8	1.00
Nonanes	C9	2.69
Decanes	C10	1.35
Undecanes	C11	1.14
Dodecanes	C12	5.50
Tridecanes	C13	0.98
Tetradecanes	C14	0.62
Pentadecanes	C15	9.50
Hexadecanes	C16	0.63
Heptadecanes	C17	11.08
Octadecanes	C18	0.36
Nonadecanes	C19	12.64
Eicosanes	C20	0.44
Heneicosanes	C21	11.35
Docosanes	C22	0.18
Tricosanes	C23	10.67
Tetracosanes	C24	0.34
Pentacosanes	C25	9.83
Hexacosanes	C26	0.11
Heptacosanes	C27	0.16
Octacosanes	C28	8.38
Nonacosanes	C29	0.72
Triacontanes	C30	6.71
Hentriacontanes	C31	0.00
Dotriacontanes	C32	0.00
Tritriacontanes	C33	0.00
Tetratriacontanes	C34	0.00
Pentatriacontanes Plus	C35+	0.00
TOTAL		100.00

FINGERPRINT ANALYSIS
BY CAPILLARY GAS CHROMATOGRAPHY
On Extracted Oil from atmospheric flash of sample in cylinder # 1405-1410 mMD



PETROLAB

Company : Esso Australia Limited	Page : 1 of 2
Well : West Whiptail 1	File : E - 24014

FINGERPRINT ANALYSIS
BY CAPILLARY GAS CHROMATOGRAPHY
On Extracted Oil from Cuttings of Depth 1410-1415 mMD

Component		Mol %
Hexanes minus	C6-	0.76
Hexanes	C6	0.53
Heptanes	C7	2.90
Octanes	C8	1.78
Nonanes	C9	5.48
Decanes	C10	2.28
Undecanes	C11	2.21
Dodecanes	C12	9.33
Tridecanes	C13	1.06
Tetradecanes	C14	1.23
Pentadecanes	C15	10.72
Hexadecanes	C16	0.73
Heptadecanes	C17	12.16
Octadecanes	C18	0.57
Nonadecanes	C19	11.58
Eicosanes	C20	0.28
Heneicosanes	C21	9.46
Docosanes	C22	0.17
Tricosanes	C23	0.21
Tetracosanes	C24	8.20
Pentacosanes	C25	0.13
Hexacosanes	C26	7.43
Heptacosanes	C27	0.11
Octacosanes	C28	0.08
Nonacosanes	C29	0.05
Triacontanes	C30	6.05
Hentriacontanes	C31	4.51
Dotriacontanes	C32	0.00
Tritriacontanes	C33	0.00
Tetratriacontanes	C34	0.00
Pentatriacontanes Plus	C35+	0.00
TOTAL		100.00

FINGERPRINT ANALYSIS
BY CAPILLARY GAS CHROMATOGRAPHY
On Extracted Oil from atmospheric flash of sample in cylinder # 1410-1415 mMD