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Research Paper

Petrophysical Evaluation of Gabo Field Niger Delta

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ABSTRACT
Petrophysical evaluation of the "Gabo'' Field, Niger Delta, was undertaken with the aim of carrying out a detailed reservoir characterization of the field. Seven wells were correlated across the field to delineate the lithology and establish the continuity of reservoir sands as well as the stratigraphy of the area. The reservoir tops and bases were identified using gamma-ray, resistivity, neutron, and density logs. They were correlated across the seven wells. Four sand bodies marked Reservoirs A, B, C and D were delineated and correlated across the six wells. petrophysical analysis based on available well logs indicates that the hydrocarbon-bearing sands have good petrophysical properties. The sands have relatively fair to good reservoir quality and are continuous across most wells in the "Gabo" field. The average shale volume is 0.09 – 0.18, and some of these reservoir sands are very clean with clay content as low as 0.08. The net reservoir thickness ranges from 29ft – 140ft. The effective porosity varies from 13% – 25%. There is variation in the water saturation with the lowest value observed at 40%.

KEYWORDS: *Petrophysical, reservoir, hydrocarbon, porosity and water saturation.*

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I. INTRODUCTION

Oil and gas in the Niger Delta are principally produced from sandstones and unconsolidated sands predominantly in the Agbada formation. Several geological and geophysical investigations have been performed in the Niger Delta basin starting about fifty years ago for oil and gas prospecting (Aizebeokhai and Olayinka, 2011; Cobbold et al., 2009). The basin has preserved thick sedimentary deposits and prominent geological features favorable for petroleum generation, migration, and entrapment from the onshore through the continental shelf and to the deep-water terrains. It is the largest basin in the West African continental margin and is noted among the major prolific deltaic oil and gas accumulations. The Niger Delta has proven ultimate recoverable reserves of approximately 26 billion barrels (26 bbl) of oil and an underevaluated, but vast gas resource base (Ekweozor and Okoye 1980). In order to characterize the "Gabo" field, composite well logs (which include the Gamma Ray, Resistivity, Neutron, and Density logs) were examined and interpreted with a view to unraveling the hydrocarbon in place. This is necessary as reservoir systems have been recognized as complex. The complexity is reflected in the depositional mechanism, depositional environment, external morphology and geometry, sand distribution and reservoir quality of the deposits (Stow et al., 1999; Caers et al., 2001; Strebelle, 2002).

II. GEOLOGICAL SETTING AND STRATIGRAPHY

The "Gabo" field is located within the Niger delta, Nigeria. The field is situated within latitudes 4° 19′ 00" N and 5° 50′ 00" N and Longitudes 5° 30′ 30" E and 6° 10′ 00" E. The base map of the area showing the seismic lines and well locations is shown in Figure 1. The base map indicates the relative positions of the wells in the field as well as political boundaries, company leases and other pertinent information relating to exploration within the field. The Niger Delta Basin is characterized by three main lithostratigraphic units, the Akata, Agbada, and Benin Formation from the oldest to the youngest (Short and Stauble, 1967). Figure 2 shows sediment deposition in the tertiary prograding Niger Delta Basin is complicated by depositional patterns restricted to series of fault-controlled sub-basins, referred to as depobelts that strike northwest to southeast, sub-parallel to the present shoreline (Knox and Omatsola, 1989). The depobelts were associated with increasing deltaic sediment loads that forced underlying marine shale to move upward and basinward. The depobelts represent different offlapping siliciclastic sedimentation cycles in the Niger Delta (Stacher, 1995). Each depobelt is a separate unit defined by a break in the regional dip of the prograding delta, and is bounded landward and basinward by growth faults and counter regional faults or growth faults of the next seaward belts respectively (Evamy et al.,1978; Doust and Omatsola,1990).

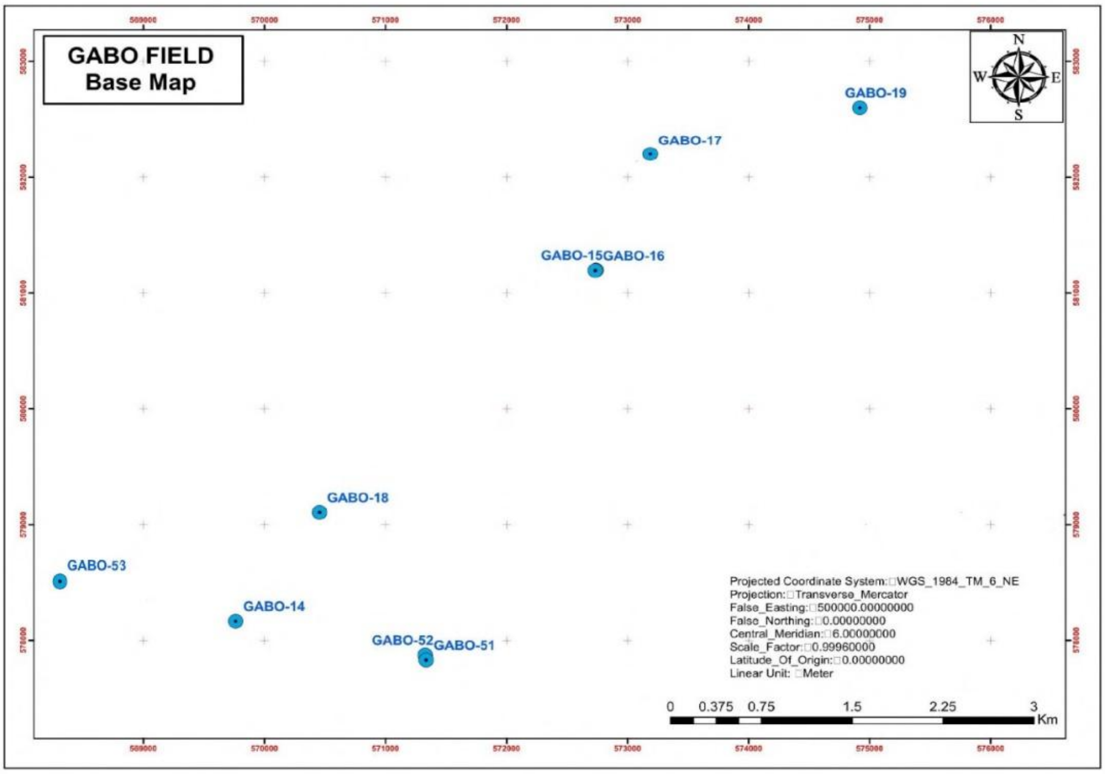

Figure 1: Base map of Gabo field, Niger Delta showing well locations

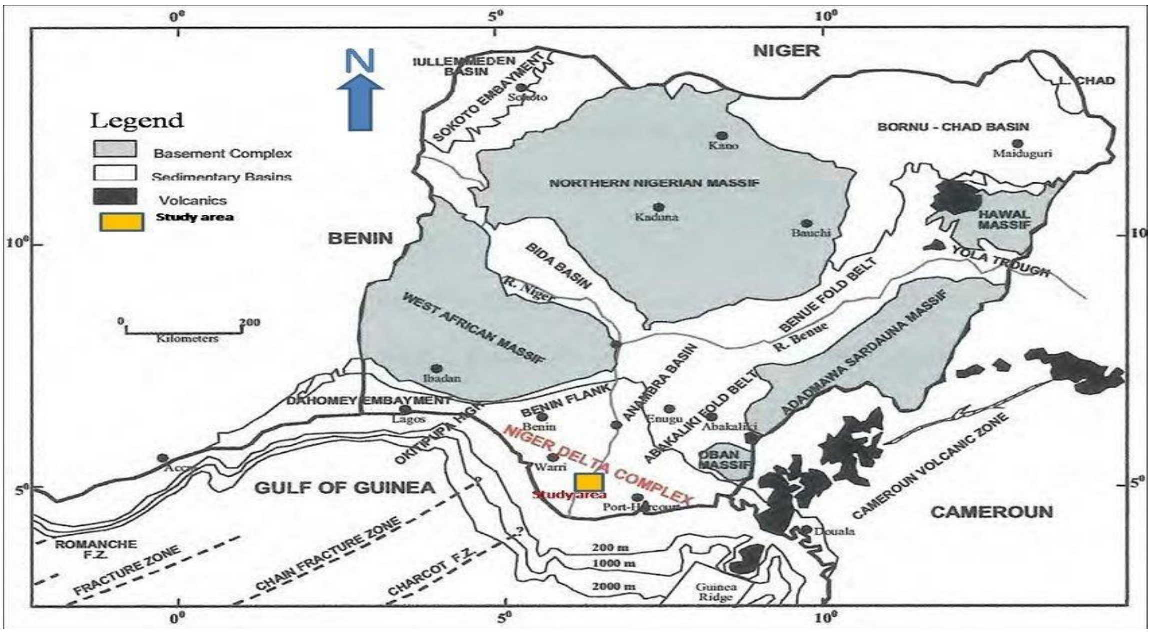

Figure 2: Map of Nigeria, showing Niger delta basin and the location of the studied area (modified after Whiteman,1982)

III. MATERIAL AND METHODS

The main steps involved in the interpretation of well-log data include data importation, quality control and petrophysics (Figure 3). Well logs in LAS Format, which comprises gamma ray, resistivity, neutron, and density logs were used for the well log analysis. These data are: (1) Well-log data of seven wells; Gabo-17, Gabo-19, Gabo-15, Gabo-16, Gabo-14, Gabo-18 and Gabo-52.

3.1 Methodology: The logs were used for the lithological interpretation of the formations and the log correlations in the study area. The well log evaluation has been achieved using Paradigm Geolog-7.

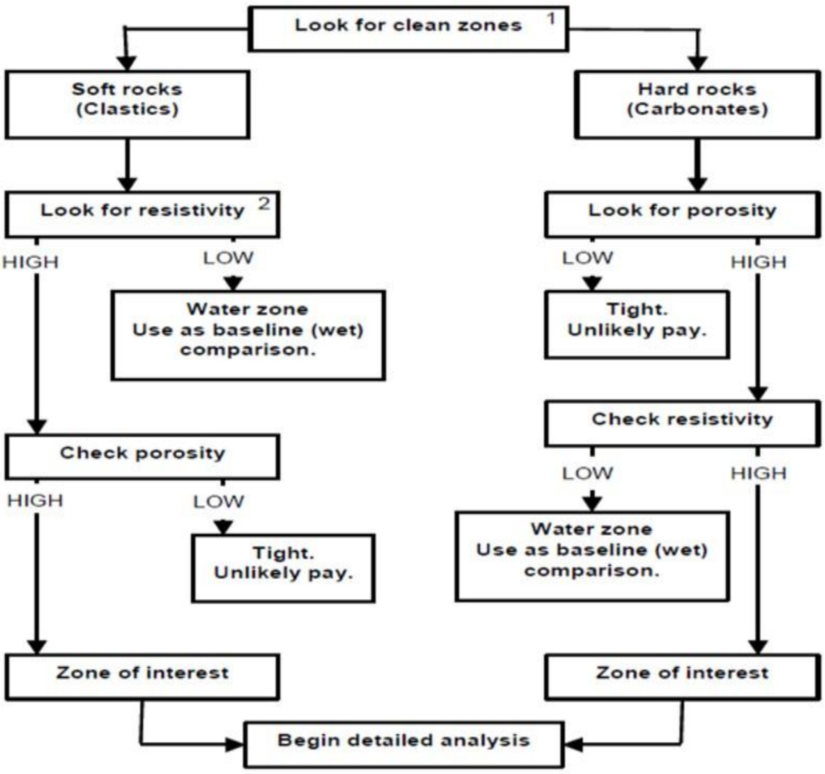

Figure 3: Workflow for petrophysical evaluation

IV. RESULTS AND DISCUSSION

4.1 Lithologic Interpretation

Figures 4.1a-4.1g shows the interpreted lithology of the studied wells. Gabo-17 (Figure 4.2a) covers the depth range of 1750m to 2500m and the rock units delineated are alternation of sand and shale units. The sand unit decreases in thickness with depth while the shale unit's increases. The sand units are composed of thin shale intercalations. The delineated stratigraphy is typical of Agbada formation comprising an alternation of sand and shale layers (Short and Stauble, 1967). Gabo-19 (Figure 4.1b) has a similar lithologic sequence like Gabo-17 comprising an alternation of sand and shale units. The shale units increase with thickness with depth and there is a corresponding decrease in sand units with depth. The sand is dirty and comprises thin inter bedding shale. Four reservoirs exist at depth 2343m, 2419m, 2456m, and 2638m. The well covers a depth range of 1738m to 2530m subsea GABO-16. GABO-15, GABO-14, GABO-18, and GABO-52 (Figures 4.1c-g) are similar to GABO-17 and GABO-19. The same sequence of stratification of sand and shale lithology units exists.

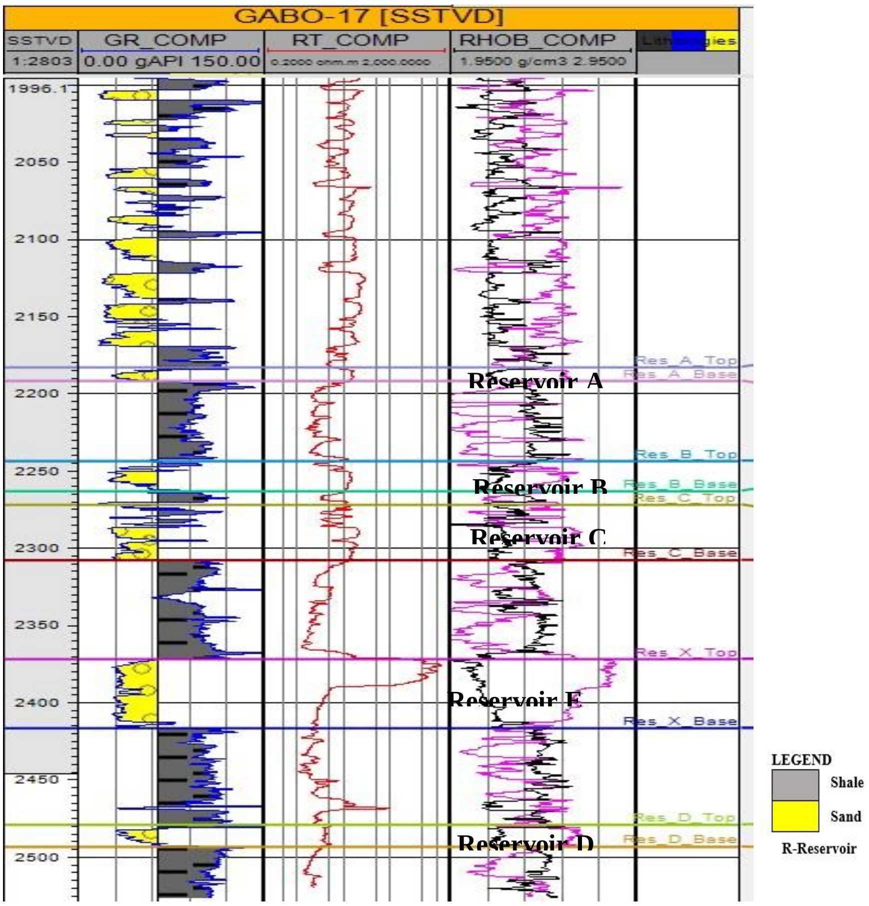

Figure 4.1a: Lithology Interpretation of Gabo-17

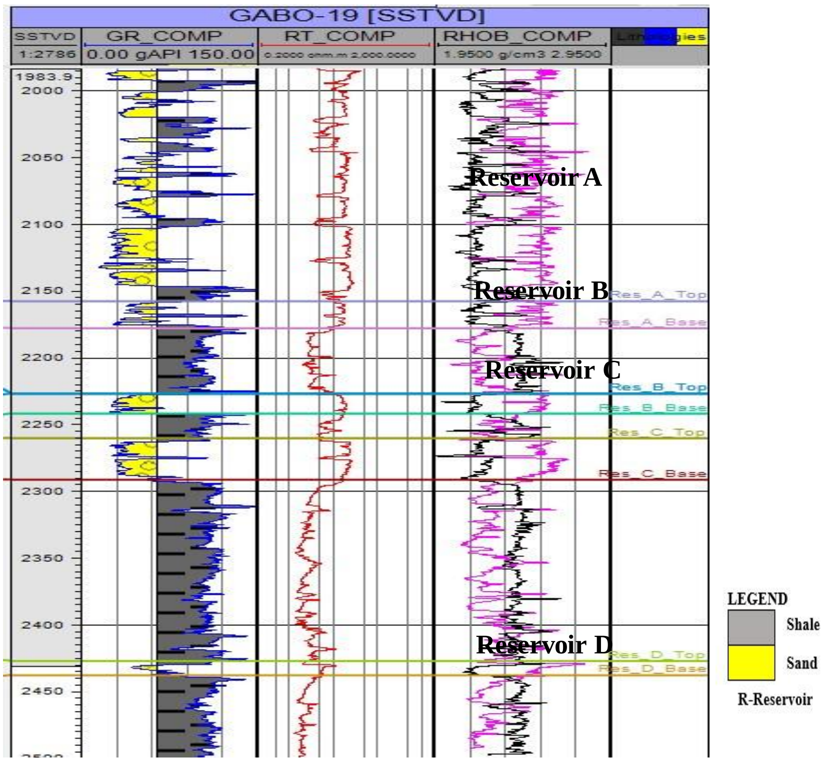

Figure 4.1b: Lithologic Interpretation of Gabo-19

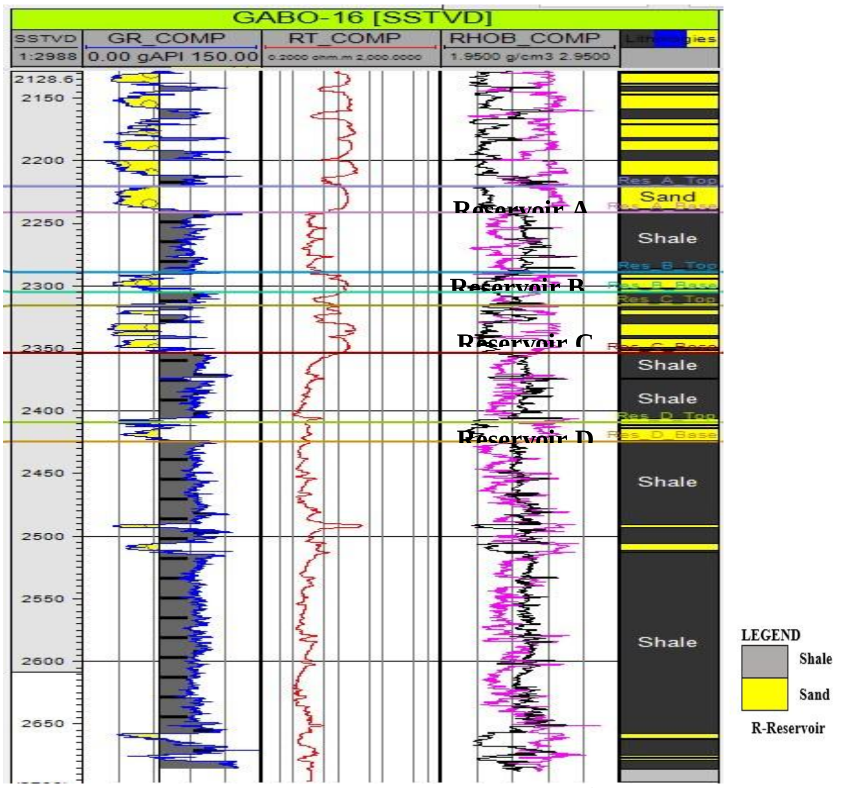

Figure 4.1c: Lithologic Interpretation of Gabo-16

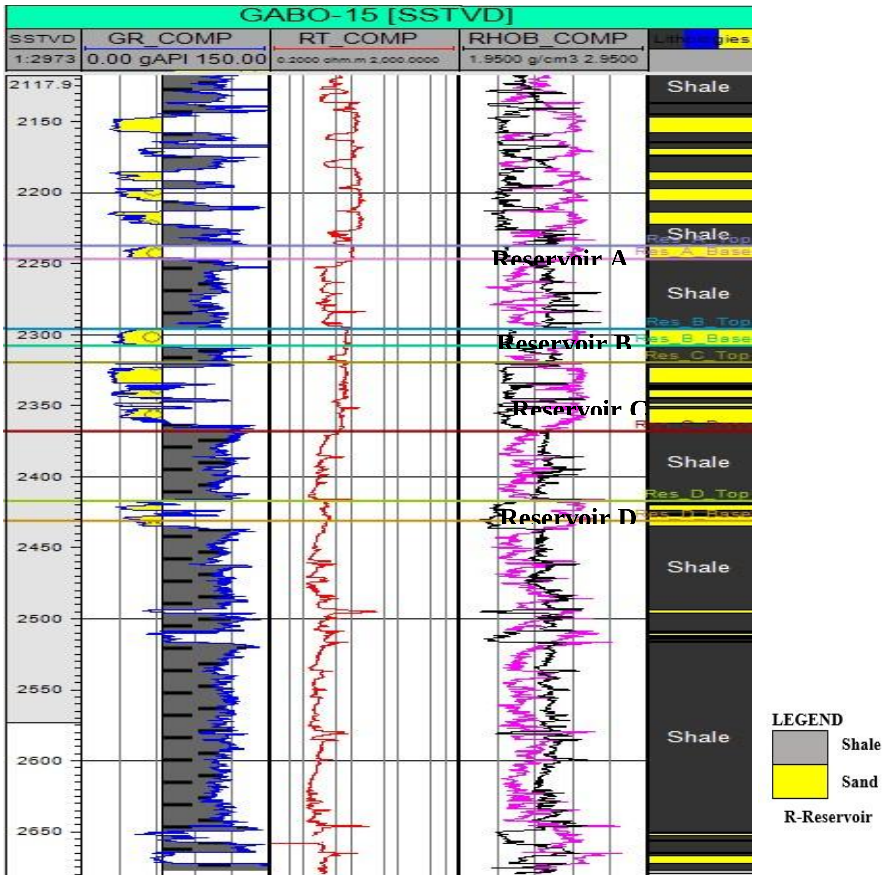

Figure 4.1d: Lithologic Interpretation of Gabo-15

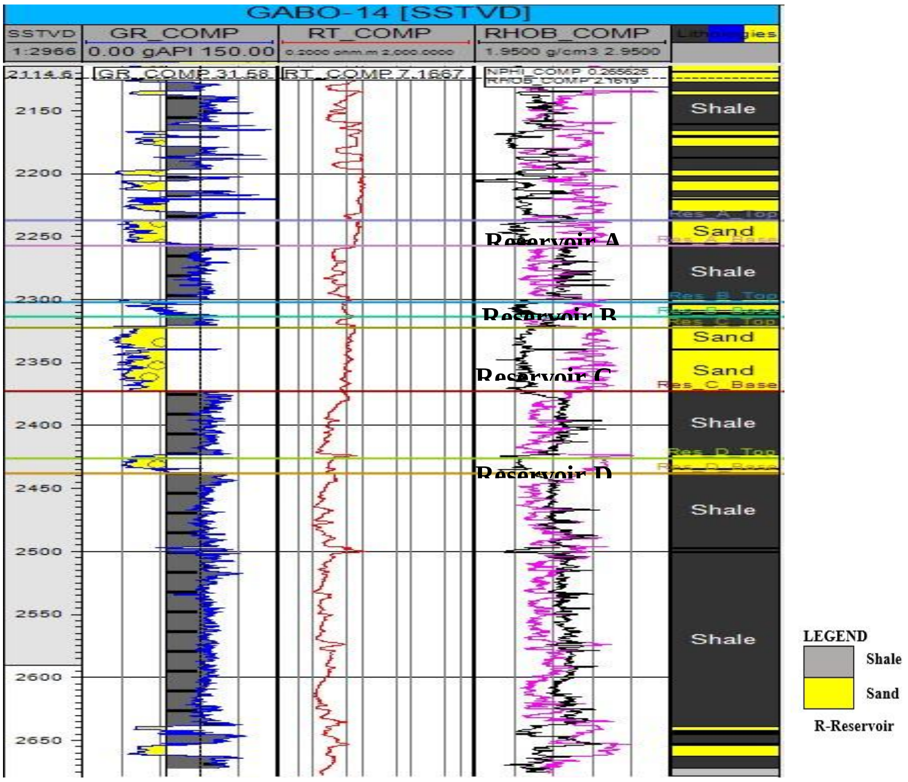

Figure 4.1e: Lithologic Interpretation of Gabo-14

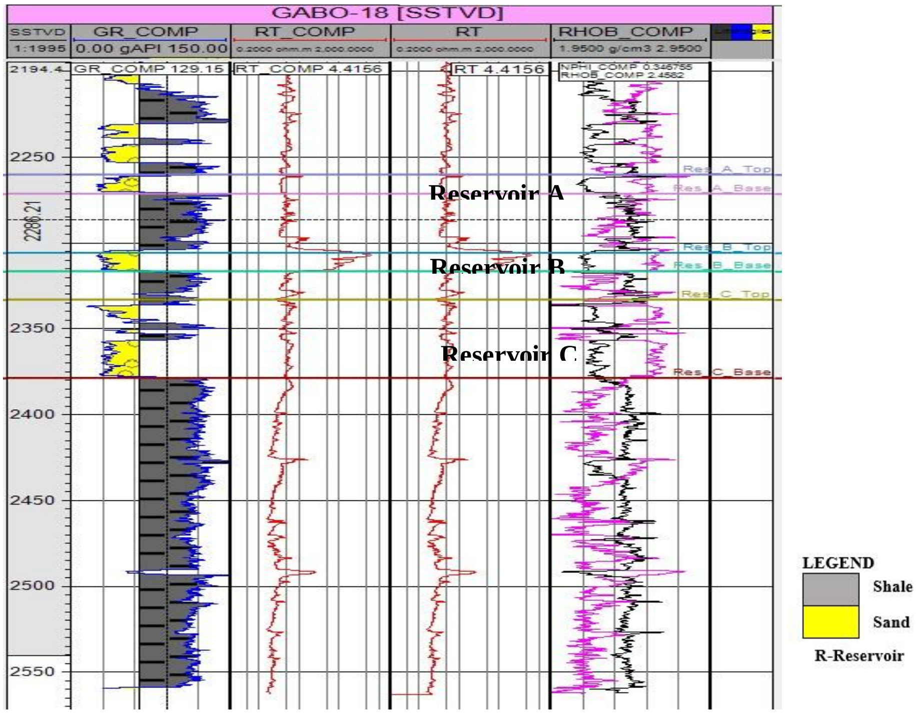

Figure 4.1f: Lithologic Interpretation of Gabo-18

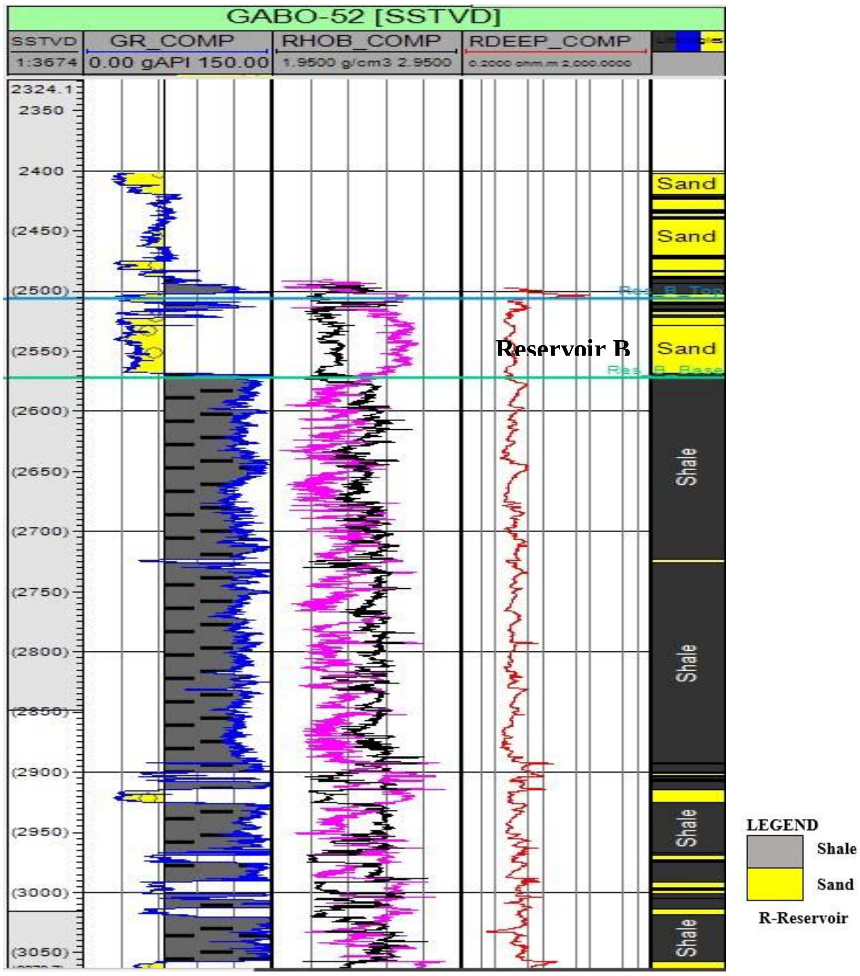

Figure 4.1g: Lithologic Interpretation of Gabo-52

4.2 Delineated Reservoirs and Well Correlation

Figure 4.2 depicts the stratigraphic correlation panel of the studied wells. Five reservoirs were delineated in Gabo-17 namely Reservoir-A, Reservoir-B, Reservoir-C, Reservoir-D, and Reservoir-E within the depth interval of 2311m and 2732m across the entire wells; however only Reservoir-B was identified in Gabo-52 and Reservoir-A, Reservoir-B and Reservoir-C were identified Gabo-18. Four of the delineated reservoirs cut across the wells. Gas fluid were identified in Gabo-17, Gabo-19 Gabo-16, Gabo-15 Gabo-14, Gabo-18 and Gabo-52.

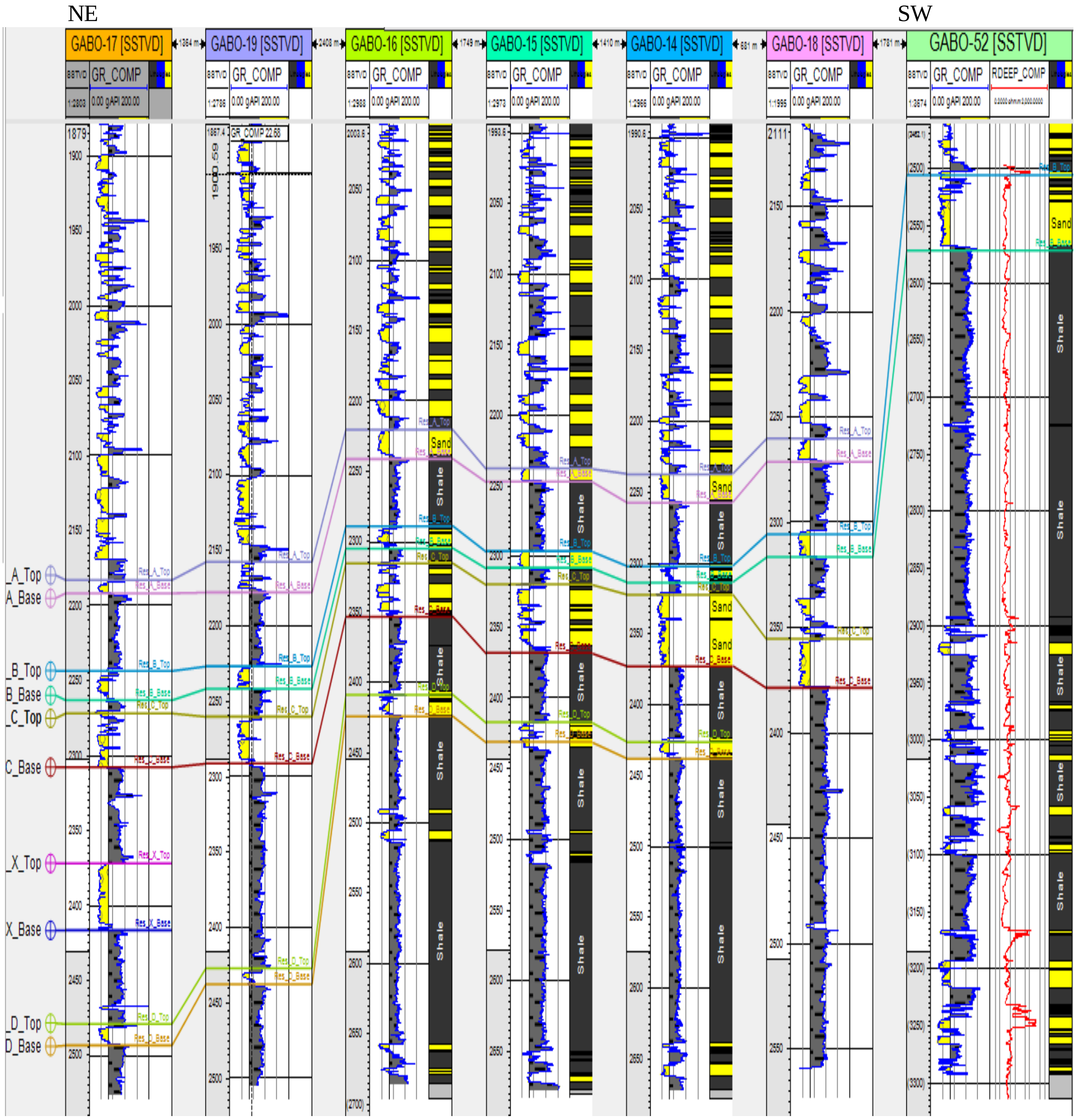

Figure 4.2: Well Correlation Panel of the Reservoirs A, B, C, and D across the studied wells

4.3 Computed Petrophysical Properties

The computed petrophysical parameters for the observed five reservoirs are shown in Table 4.1a - 4.1d. The five reservoirs occur at various depths respectively in GABO-17; (2193 m), (2254 m), (2282 m), (2382 m) and (2489 m) respectively in GABO-19; (2342m), (2419m), (2456m), and (2638 m) in GABO-16; (2401 m), (2482 m), (2513 m), and (2621m) in GABO-15; (2446m), (2511m), (2537m), and (2645 m) in GABO-14: (2311 m), (2377 m), (2397 m), and (2502 m) in GABO-18: (2449 m), (2502 m), and (2558 m) in GABO-52; (2780) designated as R1, R2, R3, R4, and RX were mapped and analysed across the wells.

Table 4.1a: Summary of Average Computed Petrophysical Parameters for Reservoir A

Wells	Gross (ft)	Net (ft)	NTG	Vsh	Φ	SW	SH
Gabo-17	28	20	0.69	0.11	0.25	0.52	0.48
Gabo-19	77	45	0.59	0.13	0.24	0.65	0.35
Gabo-16	78	60	0.76	0.09	0.24	0.40	0.60
Gabo-15	39	32	0.80	0.12	0.24	0.60	0.40
Gabo-14	67	56	0.83	0.12	0.24	0.60	0.40

Table 4.1b: Summary of Average Computed Petrophysical Parameters for Reservoir B

Wells	Gross (ft)	Net (ft)	NTG	Vsh	Φ	SW	SH
Gabo-17	75	31.5	0.42	0.12	0.24	0.58	0.42
Gabo-19	56	44	0.79	0.11	0.23	0.80	0.20
Gabo-16	58	26	0.45	0.12	0.22	0.49	0.51
Gabo-15	48	41	0.84	0.11	0.24	0.65	0.35
Gabo-14	41	12	0.29	0.12	0.24	0.65	0.35

Table 4.1c: Summary of Average Computed Petrophysical Parameters for Reservoir C

Wells	Gross (ft)	Net (ft)	NTG	Vsh	Φ	SW	SH
Gabo-17	124	73	0.58	0.16	0.22	0.60	0.40
Gabo-19	104	84	0.80	0.13	0.20	0.80	0.35
Gabo-16	151	78	0.50	0.13	0.13	0.48	0.52
Gabo-15	176	104	0.59	0.12	0.24	0.85	0.25
Gabo-14	170	140	0.82	0.18	0.23	0.82	0.28

Table 4.1d: Summary of Average Computed Petrophysical Parameters for Reservoir D

Wells	Gross (ft)	Net (ft)	NTG	Vsh	Φ	SW	SH
GABO-17	44	28	0.63	0.10	0.24	0.65	0.35
GABO-19	43	13	0.30	0.08	0.22	0.65	0.35
GABO-16	71	33	0.46	0.14	0.25	0.80	0.20
GABO-15	69	35	0.50	0.16	0.24	0.80	0.20
GABO-14	40	25	0.63	0.09	0.245	0.95	0.15

The computed petrophysical parameters are also presented in log form in figures 4.3 – 4.6 for Gabo 17, 19, 16 and 15 respectively. The petrophysical properties are plotted in track 4 of the log panel, the values of the properties vary with depth.

In GABO-17, Reservoir A has a subsea true vertical depth (TVDSS) of about 7201 ft (2195 m), and 7229ft (2204 m) at the top and base respectively. The reservoir gross interval thickness is 28.33 ft (8.63 m), net-thickness 19.5 ft (5.95 m) and the net-to-gross (N/G) ratio is 0.69. The effective porosity is 25%, water saturation is 69%, hydrocarbon saturation 31%, and the volume of shale is 11%. From the calculated parameters, the reservoir has good thickness with moderate net-to-gross, low volume of shale and good porosity value; hence, Reservoir A is a moderately good hydrocarbon-bearing reservoir.

In GABO-19, Reservoir A has reservoir gross interval thickness of 77ft (23 m), net thickness 45 ft (19.71 m) and a net-to-gross (N/G) ratio of 0.59. The effective porosity is 22%, water saturation is 90%, hydrocarbon saturation is 10%, and the volume of shale is 13%. From the calculated parameters (table 4.1 a- 4.4 d), the reservoir has good thickness with good net-to-gross, low volume of shale, good porosity value, and very low hydrocarbon saturation; hence, Reservoir A is a poor hydrocarbon reservoir.

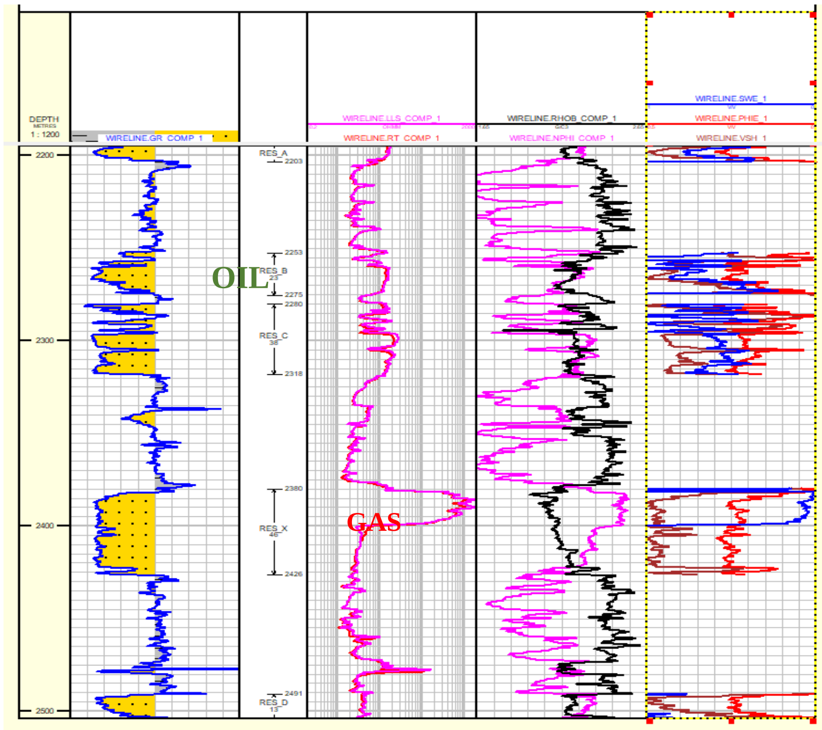

Figure 4.3: Computed Reservoir parameters across Gabo-17

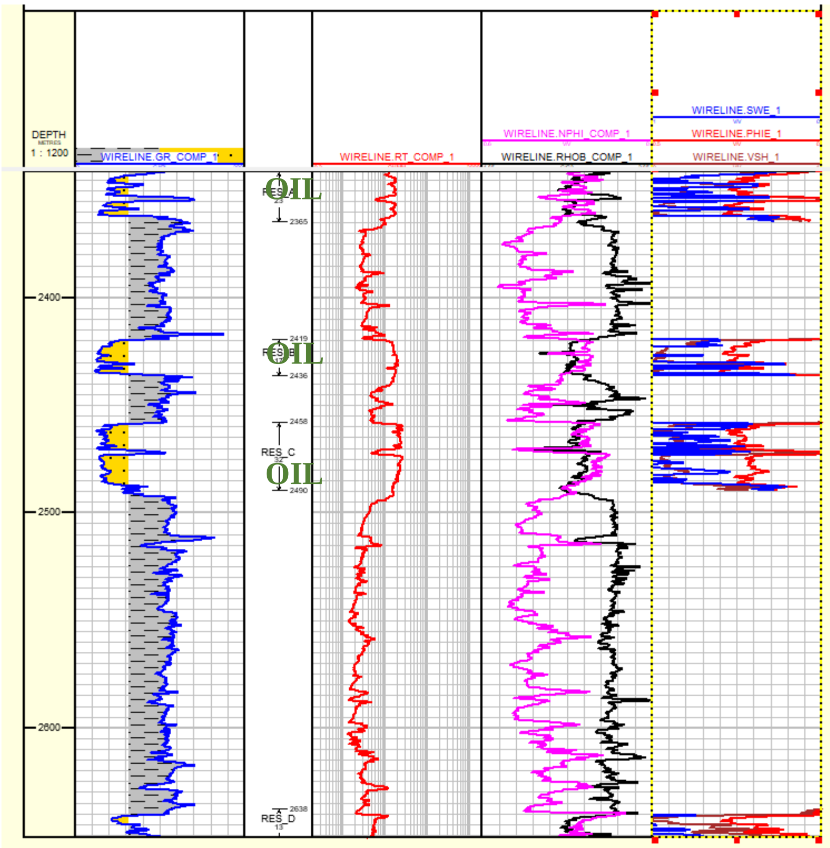

Figure 4.4: Computed Reservoir parameters across Gabo-19

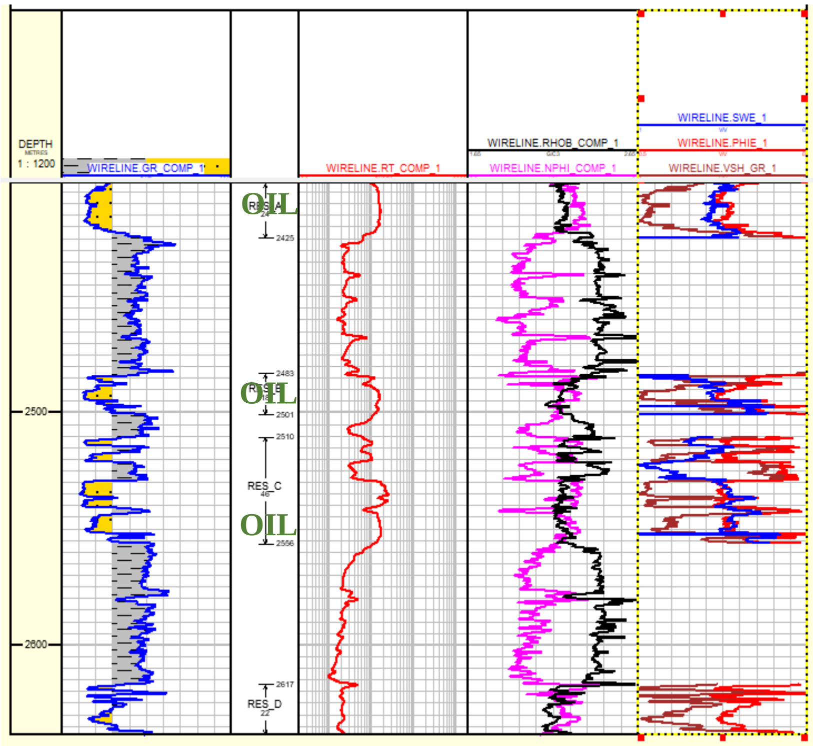

Figure 4.5: Computed Reservoir parameters across Gabo-16

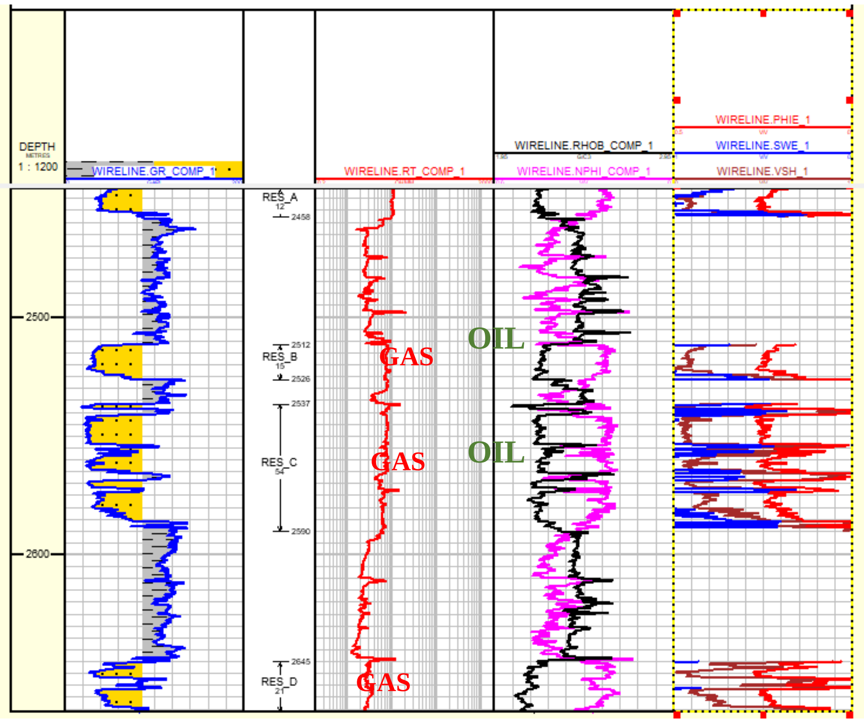

Figure 4.6: Computed Reservoir parameters across Gabo-15

In Gabo-16, Reservoir A has reservoir gross interval thickness of 78ft (24 m), net thickness 60ft (18.29 m) and a net-to-gross (N/G) ratio of 0.76. The effective porosity is 24%, water saturation is 55%, hydrocarbon saturation 45% and the volume of shale is 9%. From the calculated parameters, the reservoir has good pay thickness with good net-to-gross, low volume of shale, good porosity value and moderately high hydrocarbon saturation.

In GABO-15, Reservoir A has gross interval thickness of 39ft (12m), net thickness of 32ft (9.76m) and a net-to-gross (N/G) ratio of 0.80. The effective porosity is 24%, water saturation is 93%, hydrocarbon saturation 7% and the volume of shale is 12%. From the calculated parameters, the reservoir has a good pay thickness with high net-to-gross, low volume of shale, good porosity value, and good permeability but with a moderately low hydrocarbon saturation; hence, Reservoir A is a poor reservoir.

In GABO-14, Reservoir A has reservoir gross interval thickness of 66ft (20.12m), net thickness of 56ft 17.07m) and a net-to-gross (N/G) ratio of 0.83. The effective porosity is 24%, water saturation is 93%, hydrocarbon saturation 7% and the volume of shale is 12%. From the calculated parameters, the reservoir has a good pay thickness with high net-to-gross, low volume of shale, good porosity value, and good permeability but with a moderately low hydrocarbon saturation; hence, Reservoir A is a poor reservoir.

V. CONCLUSIONS

The lithologies in the GABO field have been delineated across seven wells; the log analysis performed in this study shows that the reservoir sand units of 'GABO' field contain significant accumulation of hydrocarbons from the attribute analysis. petrophysical analysis based on available well logs indicates that the hydrocarbon bearing sands have good petrophysical properties. The sands have relatively fair to good reservoir quality and are continuous across most wells in GABO field. The average shale volume is 0.09 to 0.18, and some of these reservoir sands are very clean with clay content as low as 0.08. The net reservoir thickness ranges from 29ft to 140ft. The effective porosity varies from 0.13 to 0.25. There is variation in the water saturation with the lowest value observed at 40.

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