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RESEARCH ARTICLE

PETROPHYSICAL EVALUATION OF WELL LOG DATA TO ANALYSE RESERVOIR PROPERTIES IN OGBA FIELD, NIGER DELTA, NIGERIA

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ABSTRACT

This study evaluates the petrophysical characteristics of Ogba Field in the Niger Delta Basin, Nigeria, using well log data (gamma ray, resistivity, neutron, and density logs) from two wells (Ogba-1 and Ogba-2) and core data from Ogba-4ST. The research quantifies key petrophysical parameters including shale volume, total porosity, water saturation, permeability, and net-to-gross ratios to understand reservoir properties. Results show that Ogba-1 generally exhibits lower shale content (Vsh 0.19–0.21), higher porosity (0.17–0.22), lower water saturation (0.02–0.14), and higher permeability (1851–2931 mD) compared to Ogba-2, indicating high reservoir quality. Well correlations reveal laterally continuous sand bodies interbedded with shale layers typical of a fluvio-deltaic depositional environment. Integration of well log and core data confirms distributary channel to mouth bar systems with periodic tidal influence. The study provides a practical workflow for reservoir characterization in data-limited siliciclastic settings of the Niger Delta.

KEYWORDS

Petrophysical evaluation, well log analysis, reservoir characterization, Niger Delta Basin.

1. INTRODUCTION

When assessing the potential of hydrocarbon reserves, petrophysical study is essential (Asquith and Krygowski, 2004). Using this analytical method, the viability of extracting hydrocarbons from the reservoirs is assessed by examining rock characteristics such porosity, permeability, and saturation. Petrophysical analysis, with the use of sophisticated instruments and methods, can offer important information on the type and amount of hydrocarbons found in a reservoir. In addition, it helps determine the best drilling and finishing methods, identify possible production zones, and estimate the reservoir's overall recovery rate.

The economic potential of a reservoir can only be maximized by making well-informed decisions during the development and production phases with the help of these crucial pieces of information. Petrophysical analysis is a vital technique for assessing reservoirs and has shown great advantages for the energy sector. Although Petrophysics studies the characteristics of rocks and how they interact with hydrocarbons, reservoir evaluation determines a reservoir's capacity to generate gas and oil. Additionally, engineers and geoscientists can integrate these two fields to make well-informed choices about production, recovery, and reservoir development plans (Doveton, 2019). Petroleum engineering and geology investigations depend on the use of petrophysical techniques for efficient reservoir characterization (Asquith and Krygowski, 2004). Knowing the different characteristics of reservoir rocks is crucial for modern hydrocarbon exploration and production in order to maximize resource extraction. Through the analysis of rock and fluid parameters, these petrophysical techniques allow for precise reservoir modelling and assessment. Additionally, a number of studies emphasized the need of petrophysical analysis in characterizing reservoirs. In order to effectively model and characterize reservoirs, for example, in two studies both stress the significance of comprehending rock attributes (Tiwari et al., 2019; Mavko et al., 2020).

The use of petrophysical analysis for reservoir evaluation has significantly increased in recent years (Tiab and Donaldson, 2015). The physical characteristics of the reservoir rocks, primarily porosity, permeability, and saturation, are measured and analyzed using a variety of methods and instruments. Its use has significantly increased the success of oil and gas exploration and production, and it has been shown to be a very accurate and successful tool for evaluating reservoirs (Rider, 2015). Furthermore, the development of artificial intelligence and machine learning has further transformed petrophysical analysis by accurately forecasting key petrophysical parameters. Thus, using these technologies to analyze large datasets will result in reservoir evaluations that are quicker and more accurate (Zhang et al., 2022).

In order to evaluate a reservoir, its attributes must also be quantified in geological models with less uncertainty, which is essential for exploration and production. Assessing the porosities and saturations of reservoir rocks, as well as depth correlations, requires well-log readings. Log data has been acknowledged as a useful source of geological information in recent years. Analogous to how eyes and instruments view surface outcrops, enabling geologists to deduce subsurface rock qualities (Asquith and Krygowski, 2004). Logging is a method that complements laboratory investigations on rock samples by measuring a variety of physical parameters linked to the geological and petrophysical features of penetrated strata (Reijers et al., 1997).

Moreover, well logs offer a distinct viewpoint on the subsurface geology by revealing information about the fluid that is present in the reservoir rock's pores. A permanent and ongoing record of the physical properties of the rock, molded by physical, chemical, and biological processes during deposition and geological history, log data is still available even though it may be distorted or incomplete. The goals of log interpretation should be the same as those of laboratory core analysis, depending on clear connections between log readings and relevant rock parameters. A

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quantitative depiction of reservoir dynamics and characteristics is made possible by combining well logs, seismic data, and geological data; this is essential for improved production and profitable reservoir development.

In reservoir development initiatives, characterizing the reservoir requires merging logs and well information. Thickness and reservoir extent are important factors (Thomas, 1995). The determination of reservoir thickness is based on volumetric analysis, which depends heavily on well logs, especially resistivity and gamma ray logs. The seismic approach records data from subterranean rocks by non-invasive means, allowing for indirect readings. Finding horizons and measuring the characteristics of the hydrocarbon-bearing zone are made possible by seismic pictures, which are made up of traces that capture reflections from rock layer borders.

By combining all available data and using accurate interpretation, subsurface petroleum geology aims to identify and produce oil and gas reserves. In order to exploit proven deposits and explore undiscovered hydrocarbons, subsurface geophysical maps are crucial (Smith-Rouch et al., 1996). A primary goal of evaluating reservoir geology is to investigate how reservoir heterogeneities affect reservoir behaviour. Because of lithologic variation and sedimentary deposition, reservoir heterogeneity is determined by the distribution of porosity and permeability. This is further exacerbated by chemical processes linked to diagenesis and mechanical processes related to deformation.

2. Location And Geological Setting

An Ogba field in Nigeria's onshore Niger Delta region serves as the study location (Figure 1). The Niger Delta Basin lies between latitudes 40N and 60N and longitudes 30E and 90E in southern Nigeria (Klett et al., 1997). The Akata, Agbada, and Benin Formations make up the tripartite lithostratigraphy of the Niger Delta Basin, which is reputed to be a hydrocarbon-rich zone. As the principal source rock, deep sea shales make up the Akata formation. The primary reservoir is the Agbada formation, which is made up of alternating layers of sand and shale that were deposited in fluvio-deltaic environments. Continental sands and gravels that were deposited in a riverine setting make up the Benin formation (Doust and Omatsola, 1990; Evamy et al., 1978; Ekweozor and Okoye, 1980; Nwachukwu and Chukwurah, 1986; Short and Stäuble, 1967).

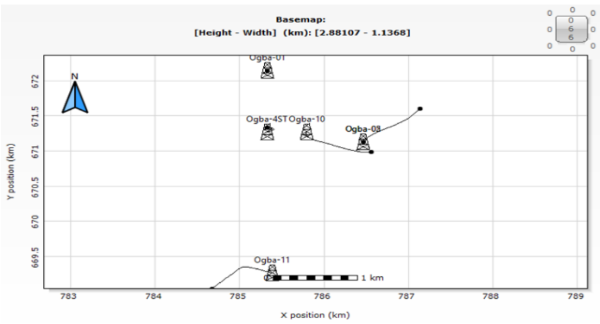

Figure 1: A Base map for Ogba wells showing the distribution of the wells within the area.

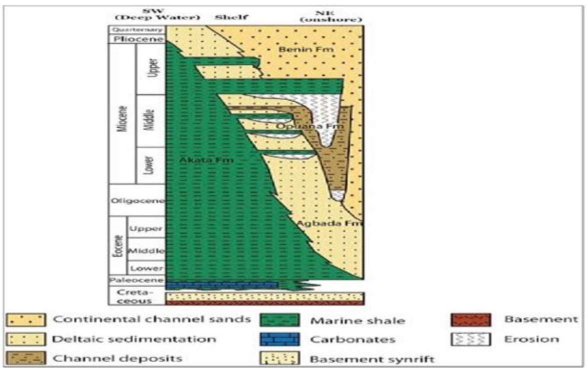

Figure 2: Stratigraphic column showing the three formations of the Niger Delta [H. Doust, and E. Omatsola, P.M. Shannon, and N. Naylor].

3. Materials And Methods

Well log data from the Niger Delta's Ogba Field, an onshore field, was used in this investigation. Gamma Ray (GR) logs, neutron/porosity logs, density logs, resistivity logs for two (2) wells, and the core analysis report of Ogba 4ST are among the data that are available. These were crucial in figuring out the distribution of reservoirs and lateral continuity in the research area. The data set came from a Port Harcourt field that was owned and run by Ansett Integrated Services Limited. The data was processed and interpreted using Schlumberger Techlog industrial software.

3.1 Methodology

Data was quality-checked and sorted into acceptable formats for Techlog software and was also used for, Data QC, well correlation, Net to gross, and petrophysical analysis. After loading the data into the respective software a sum of 2 wells with the log suits mentioned above were identified and utilized for this research which include OGBA 1 and OGBA 2. Well logs were available, Gamma Ray log in gAPI unit, Deep Resistivity in Ohm.m, Density in g/cm3, and Neutron in m3/m3.

3.1.1 Data Quality Control (QC)

This process began with the importation of relevant well log data into Schlumberger Techlog software. The datasets were provided in LAS (Log ASCII Standard) format, which contained depth-based measurements such as:

a) Gamma Ray (GR) logs are analyzed to identify clean and shaly formations, typically by establishing a baseline and computing shale indicators, which is measured in API units. Clean sandstone reserves show low GR values, but shale deposits show high GR readings because of the high levels of gamma radiation they produce because of their clay mineral concentration. Because of this disparity, the GR log is the main tool used to determine the dimensionless Volume of Shale (Vshale), a crucial metric for assessing reservoir quality, and to identify lithology.

The Gamma Ray Index formula, IGR = (GR_log - GR_min) / (GR_max - GR_min), is used to quantitatively determine Vshale. The baseline values for clean sand and pure shale are denoted by GR_min and GR_max, respectively. To account for intricate shale distribution patterns, empirical non-linear equations like Larionov's model are frequently used to modify this initial linear estimate. The resulting Vshale value serves as the basis for all further petrophysical study and is crucial for figuring out net pay, adjusting porosity measurements, evaluating permeability, and precisely computing water saturation in shaly sand reservoirs.

b) Resistivity logs help detect hydrocarbon-bearing zones due to the higher resistivity signature in such intervals. A vital tool in petrophysical evaluation, the resistivity log (measured in Ω·m) aids in determining the kind of fluid present in the reservoir. Zones 22 that contain water exhibit low resistivity, whereas zones that contain hydrocarbons exhibit high resistivity. Resistivity and porosity logs are merged using Archie's equation to determine water saturation (Sw) and, consequently, hydrocarbon saturation (Sh = 1-Sw).

This makes resistivity essential for:

- Differentiating oil/gas from water zones,
- Quantifying fluid saturations,
- Defining pay zones and reservoir quality.

Archie's Equation (Clean Formations)

$$S_w^n = \frac{aR_w}{\phi^m R_t}$$

where:

- Sw= water saturation
- Rw= resistivity of formation water (Ω·m)
- Rt= true formation resistivity from log (Ω·m)
- ϕ= porosity
- a= tortuosity factor
- m= cementation exponent
- n= saturation exponent.

c) Density and Neutron logs are interpreted together to infer lithology and porosity. The crossover between these logs helps in distinguishing gas zones from liquid-filled formations. The porosity from the Density log is calculated using the formula:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Where:

- ρb= bulk density from the log (kg/m^3 or g/cm^3)
- ρma= matrix density (e.g., sandstone = 2.65 g/cm^3)
- ρf= fluid density (e.g., water ≈ 1.0 g/cm^3, oil ≈ 0.8 g/cm^3, gas ≈ 0.2 g/cm^3)
- ϕD= density porosity (fraction, unitless).

The Density–Neutron pair is a diagnostic tool for gas detection and lithology in addition to porosity estimation. The neutron porosity and density curves overlap in pristine formations, suggesting reliable pore space measurement. Nonetheless, a distinctive crossover effect is seen in gas-bearing zones, where the porosity is larger in the neutron log and lower in the density log. Because of this behaviour, the porosity pair is crucial for accurately determining porosity as well as for locating hydrocarbon gas zones and distinguishing between non-reservoir shales and reservoir sands.

3.1.2 Data Import

This is the first stage after data quality control which involves loading of well data into the Techlog environment. This includes digital log curves (such as GR, resistivity, density, neutron), well trajectory files, core data, and lithological descriptions. The software supports multiple data formats including LAS, DLIS, and CSV. The project file was created and imported the data into designated workspaces using the "Well Data Manager" or dedicated data loaders, where depth-matching and unit checks are also configured.

3.1.3 Well Correlation and Reservoir Delineation

After loading the data into the software, then further proceeded to correlate the wells (Field scale analysis), by using tops and marker horizons. Using Techlog's correlation panel, we established a stratigraphic framework by matching key geological markers across the wells. Lithofacies distributions are visualized and tied to well log responses. The multi-well correlation reveals lateral continuity of the reservoir units and help to define the areal extent of productive intervals. structural offsets or unconformities are accounted for during interpretation.

Table 1: Well data inventory for the 2 wells utilized in this research

WELL	GR Log	Density & Neuron Log	Resistivity Log	Pressure	Deviation Data
Ogba-01	YES	YES	YES	NO	YES
Ogba-02	YES	YES	YES	NO	YES
Ogba-05	YES	NO	NO	NO	YES
Ogba-04ST	YES	NO	NO	NO	YES

WELL	GR		RES		NPHI		RHOB		SONIC	
	Start(ft)MD	Stop(ft)MD	Start(ft)MD	Stop(ft)MD	Start(ft)MD	Stop(ft)MD	Start(ft)MD	Stop(ft)MD	Start(ft)MD	Stop(ft)MD
Ogba-01	1000.5	10885	1000.5	10885	1000.5	10885	1000.5	10885	1000.5	10885
Ogba-02	1001	10722.5	1001	10722.5	1001	10722.5	1001	10722.5	-	-

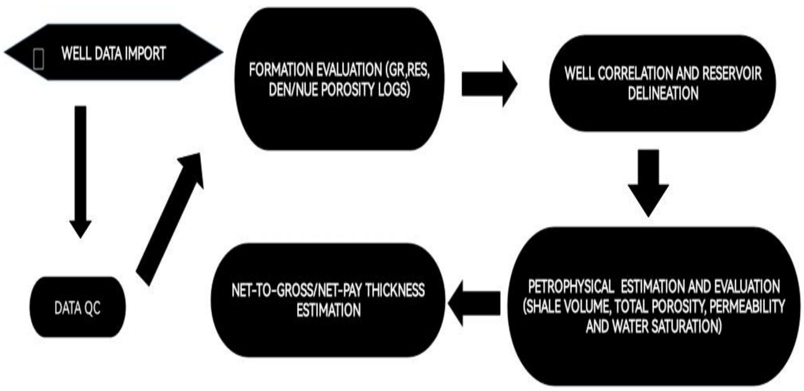

Figure 3: Project Workflow for Formation Evaluation and Petrophysical Analysis adapted in this study

4. Results

This chapter presents the results of the work of the petrophysical properties of Ogba 1 and Ogba 2 from the wells logs below is the summary table of the Ogba 1and Ogba 2 showing the thickness parameter the porosity the water saturation and net-to- Gross parameter used in calculating the volume of hydrocarbon in a reservoir volume of hydrocarbon in a reservoir.

Table 2: Summary result of Ogba-01

General summary table result Ogba-01

S/N	Well	Zones	Flag Name	Top	Bottom	Reference unit	Gross	Net	Net to Gross	Av_Porosity	Av_Water Saturation
1	Ogba-01	Sand A1	PAY	7935.284	8040.851	Ft	105.567	99.851	0.951	0.191	0.091
2	Ogba-01	Sand A2	PAY	8068.271	8128.595	Ft	60.324	48.095	0.851	0.165	0.093
3	Ogba-01	Sand A3	PAY	8143.676	8319.163	Ft	175.487	154.824	0.902	0.202	0.086

Table 2 (Cont): Summary result of Ogba-01

General summary table result Ogba-01											
S/N	**Well**	**Zones**	**Flag Name**	**Top**	**Bottom**	**Reference unit**	**Gross**	**Net**	**Net to Gross**	**Av_Porosity**	**Av_Water Saturation**
4	Ogba-01	Sand A4	PAY	8331.502	8465.86	Ft	134.358	114.358	0.881	0.19	0.089
5	Ogba-01	Sand A5	PAY	8475.457	8568.685	Ft	93.228	93.228	1	0.19	0.112
6	Ogba-01	Sand B1	PAY	8579.652	8629.009	Ft	49.356	47.348	0.959	0.196	0.12
7	Ogba-01	Sand B2	PAY	8645.461	8656.429	Ft	10.968	6.5	0.684	0.182	0.145
8	Ogba-01	Sand B3	PAY	8707.155	8748.285	Ft	41.13	33	0.802	0.199	0.13
9	Ogba-01	Sand C1	PAY	8772.963	8807.238	Ft	34.275	31	0.941	0.218	0.115
10	Ogba-01	Sand C2	PAY	8826.433	8864.82	Ft	38.388	31.5	0.821	0.197	0.138
11	Ogba-01	Sand C3	PAY	8907.321	8955.306	Ft	47.984	45	0.938	0.148	0.157
12	Ogba-01	Sand D4	PAY	8988.21	9040.308	Ft	52.098	48.098	0.923	0.196	0.138
13	Ogba-01	Sand D5	PAY	9080.066	9129.423	Ft	49.356	38.5	0.821	0.163	0.055
14	Ogba-01	Sand D6	PAY	9151.358	9188.375	Ft	37.017	36.875	0.996	0.197	0.102
15	Ogba-01	Sand D7	PAY	9197.973	9240.474	Ft	42.501	35.001	0.847	0.214	0.126
16	Ogba-01	Sand D8	PAY	9263.78	9314.507	Ft	50.727	30	0.601	0.186	0.083
17	Ogba-01	Sand D9	PAY	9358.379	9450.236	Ft	91.857	75.5	0.833	0.187	0.045
18	Ogba-01	Sand E1	PAY	9494.107	9542.093	Ft	47.985	22.485	0.5	0.199	0.117
19	Ogba-01	Sand E2	PAY	9602.417	9628.466	Ft	26.049	17	0.691	0.143	0.064
20	Ogba-01	Sand E3	PAY	9653.144	9832.744	Ft	179.601	157.356	0.91	0.184	0.122
21	Ogba-01	Sand E4	PAY	9867.019	9917.746	Ft	50.728	44.981	0.926	0.203	0.027
22	Ogba-01	Sand E5	PAY	9939.682	9967.102	Ft	27.42	10	0.474	0.132	0.161
23	Ogba-01	Sand E6	PAY	9997.264	10057.59	Ft	60.324	57.736	0.957	0.177	0.139
24	Ogba-01	Sand E7	PAY	10095.98	10122.02	Ft	26.049	16.024	0.654	0.145	0.134
25	Ogba-01	Sand E8	PAY	10134.36	10180.98	Ft	46.614	44	0.944	0.182	0.302
26	Ogba-01	Sand E9	PAY	10204.28	10234.45	Ft	30.162	19.5	0.729	0.16	0.335

Table 3: Summary result of Ogba-02

General summary result Ogba-02											
S/N	**Well**	**Zones**	**Flag Name**	**Top**	**Bottom**	**Reference unit**	**Gross**	**Net**	**Net to Gross**	**Av_Porosity**	**Av_Water Saturation**
27	Ogba-02	Sand A1	PAY	7964.075	8182.063	Ft	217.988	181.925	0.883	0.145	0.115
28	Ogba-02	Sand A2	PAY	8213.597	8264.323	Ft	50.727	42.823	0.903	0.152	0.096
29	Ogba-02	Sand A3	PAY	8280.775	8306.824	Ft	26.049	26.049	1	0.131	0.128
30	Ogba-02	Sand A4	PAY	8323.276	8516.587	Ft	193.311	128.811	0.739	0.137	0.112

Table 3 (Cont): Summary result of Ogba-02											
General summary result Ogba-02											
S/N	**Well**	**Zones**	**Flag Name**	**Top**	**Bottom**	**Reference unit**	**Gross**	**Net**	**Net to Gross**	**Av_Porosity**	**Av_Water Saturation**
31	Ogba-02	Sand A5	PAY	8552.232	8593.362	Ft	41.13	36.862	0.896	0.159	0.09
32	Ogba-02	Sand B1	PAY	8602.96	8637.234	Ft	34.274	32.774	1	0.144	0.109
33	Ogba-02	Sand B2	PAY	8650.944	8676.993	Ft	26.049	24.549	0.942	0.155	0.115
34	Ogba-02	Sand B3	PAY	8697.559	8727.721	Ft	30.162	23.441	0.96	0.143	0.12
35	Ogba-02	Sand C1	PAY	8756.512	8819.577	Ft	63.065	53.065	0.913	0.15	0.106
36	Ogba-02	Sand C2	PAY	8834.658	8860.707	Ft	26.049	17	0.872	0.121	0.063
37	Ogba-02	Sand C3	PAY	8988.21	9045.792	Ft	57.582	50	0.868	0.144	0.141
38	Ogba-02	Sand D4	PAY	9066.356	9100.632	Ft	34.275	27	0.831	0.126	0.171
39	Ogba-02	Sand D5	PAY	9119.825	9136.277	Ft	16.452	2.175	0.284	0.113	0.152
40	Ogba-02	Sand D6	PAY	9155.472	9200.715	Ft	45.243	35.5	0.807	0.156	0.157
41	Ogba-02	Sand D7	PAY	9226.764	9266.522	Ft	39.759	32.5	0.88	0.147	0.169
42	Ogba-02	Sand D8	PAY	9288.458	9328.217	Ft	39.759	28	0.855	0.145	0.188
43	Ogba-02	Sand D9	PAY	9367.976	9428.3	Ft	60.324	19.5	0.746	0.124	0.206
44	Ogba-02	Sand E1	PAY	9465.316	9527.012	Ft	61.695	49	0.835	0.152	0.151
45	Ogba-02	Sand E2	PAY	9601.046	9649.03	Ft	47.984	30.5	0.719	0.125	0.124
46	Ogba-02	Sand E3	PAY	9677.821	9782.018	Ft	104.196	86.179	0.851	0.131	0.161
47	Ogba-02	Sand E4	PAY	9801.211	9831.373	Ft	30.162	16	0.564	0.15	0.159
48	Ogba-02	Sand E5	PAY	9853.309	9875.245	Ft	21.937	0	0.023		
49	Ogba-02	Sand E6	PAY	9923.223	9984.917	Ft	61.694	52.917	0.887	0.128	0.103
50	Ogba-02	Sand E7	PAY	10112.43	10132.98	Ft	20.557	18.072	1	0.167	0.246
51	Ogba-02	Sand E8	PAY	10165.9	10193.32	Ft	27.42	0	0.869		

4.1 Reservoir Properties

4.1.1 Lithology

Lithologic interpretation was primarily based on Gamma Ray (GR) logs, supported by resistivity and density–neutron data. The GR log effectively distinguished between sandstone and shale intervals, with low GR values (20–50 API) indicating clean, high-quality sands and high GR values (80–120 API) representing shaly zones. The Ogba Field is characterized by sand–shale interbedding, typical of fluvio-deltaic depositional settings within the Agbada Formation of the Niger Delta Basin. High resistivity readings confirmed hydrocarbon-bearing sands, while low resistivity reflected water-bearing zones.

i Volume of shale: In order to account for shale influences, the Volume of Shale was calculated from GR logs using both linear and Larionov Tertiary equations. Higher Vsh values in units E1 and E7 suggest shaly or transitional intervals, while cleaner sand units (E3–E6) reveal lower shale volumes and improved reservoir quality. The results show Vsh values between 0.10 and 0.35 (10–35%).

The linear method is given as:

$$V_{sh} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

Where:

- GR_{log}= gamma ray reading of the formation
- GR_{min}= minimum GR value (clean sand baseline)
- GR_{max}= maximum GR value (shale baseline)

For Tertiary Niger Delta formations, the Larionov Tertiary equation is often preferred:

$$V_{sh} = 0.083 \times (2^{3.7 \times I_{GR}} - 1)$$

where $I_{GR}$is the gamma ray index.

Results show that the volume of shale varies between 0.10 and 0.35 (10–35%) across the correlated sand units. Lower Vsh values correspond to cleaner reservoir sands (E3–E6), while higher values indicate shaly or transitional zones (E1, E7). This variation influences porosity and permeability, as shale content reduces effective pore space and connectivity.

ii Porosity: In order to refine estimates and identify the presence of gas, porosity was calculated using density-derived porosity calculations and cross-plots between density and neutron logs. The porosity ranges from 0.22 to 0.30 (22–30%), indicating high-quality reservoir sands; clean, well-sorted sands have higher porosity, while shaly or compacted intervals show lower values.

The density-derived porosity was calculated using:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Where:

- ρ_{ma}= matrix density (2.65 g/cc for sandstone)
- ρ_b= bulk density from log
- ρ_f= fluid density (1.0 g/cc for formation water)

Cross-plot analysis between neutron and density porosity logs was used to refine the estimates and identify gas effects.

The calculated porosity values for the Ogba Field reservoirs range between 0.22 and 0.30 (22–30%), which falls within the typical range for good-quality Niger Delta sandstone reservoirs. Clean, well-sorted sands show higher porosity values, while shaly intervals and compacted sands exhibit reduced porosity.

iii Permeability: Permeability estimation was carried out empirically from the porosity-permeability relationship, using the Wyllie-Rose correlation given by:

$$k = a \times \phi^b$$

Where:

- k= permeability (mD)
- ϕ= porosity (fraction)
- a, b= formation constants (for Niger Delta sands, $a = 1000$and $b = 3$are commonly used)

The computed permeability ranges from 150 mD to over 1200 mD, indicating excellent reservoir quality in the cleaner sand units. Zones with higher shale content show lower permeability due to reduced intergranular pore connectivity.

Overall, the reservoir exhibits moderate to high porosity and permeability, suggesting good potential for hydrocarbon production, especially in the E3–E6 sand units, which display high resistivity, low gamma ray readings, and favorable petrophysical properties.

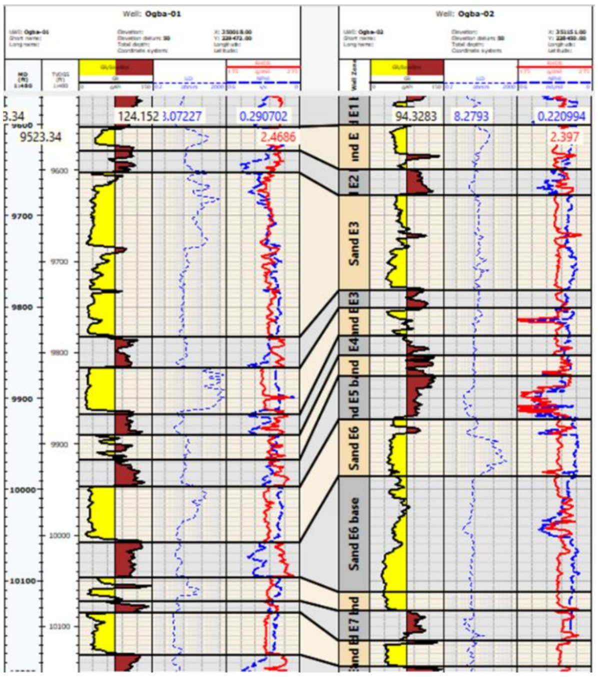

Figure 4: Hydrocarbon reservoir unit (e.g Sand A, B etc.)

To identify the hydrocarbon-bearing zones and assess their lateral continuity, a thorough well-log correlation and petrophysical investigation were performed on the Ogba-01 and Ogba-02 wells. Within the Agbada Formation, seven (7) different sand bodies were found, ranging in depth from roughly 9,500 feet to 10,100 feet TVDSS. The designations for these sand units were E1 through E7.

According to the correlation, the majority of the sand units are laterally continuous between the two wells; fault displacement and depositional alterations are responsible for some thickness and quality variations. The hydrocarbon potential of clean sand intervals was ascertained by integrating the gamma-ray, resistivity, neutron, and density logs. Overall, the sands have good petrophysical qualities; the most promising reservoir characteristics are seen in Sands E2 through E6.

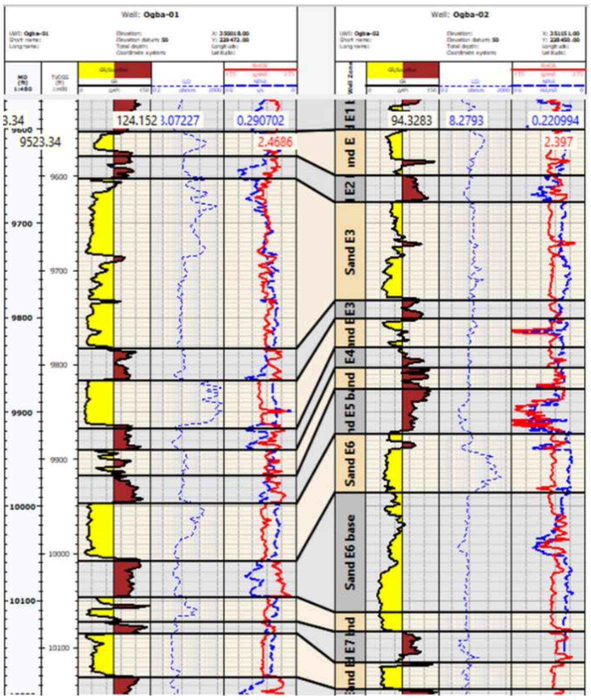

Figure 5: The gamma-ray, resistivity, neutron, and density logs 2 wells.

4.1.2 E1 Sand

E1 is found in Ogba-01 between 9,540 and 9,600 feet and in Ogba-02 between 9,530 and 9,590 feet. The gamma-ray log shows interbedded shale streaks in a somewhat shaly sand. Permeability (k) varies from 200 to 300 mD, porosity (ϕ) is 0.18, and the average volume of shale (Vsh) is approximately 0.28. The interval is probably a transition zone or water-bearing, according to moderate resistivity measurements. Although the sand is laterally consistent throughout both wells, it is a reservoir of questionable quality that was most likely deposited in a marginally marine environment with low energy.

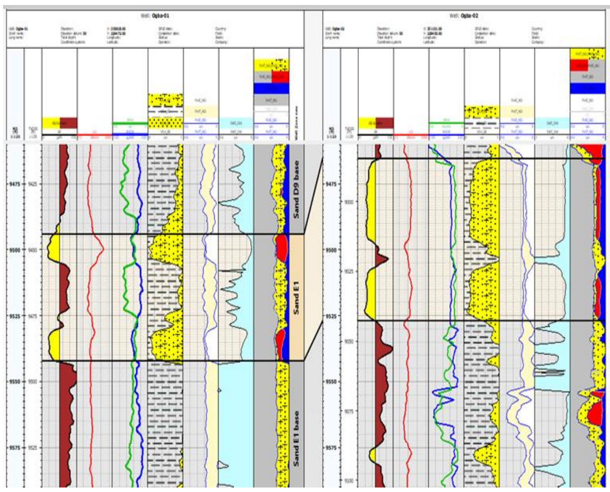

Figure 6: Sand E1 Both wells.

4.1.3 Sand E2

Directly below Sand E1, Sand E2 is located between 9,610 and 9,660 feet in Ogba-01 and 9,600 and 9,660 feet in Ogba-02. It displays a clean, hydrocarbon-bearing sandstone with a sharp upper contact and low gamma-ray with high resistivity responses. Excellent reservoir quality is indicated by the shale volume (Vsh) of roughly 0.15, the average porosity of 0.27, and the permeability exceeding 600 mD. One of the most productive reservoirs in the Ogba Field, the unit is laterally continuous across both wells and was probably deposited in a shoreface or distributary channel environment.

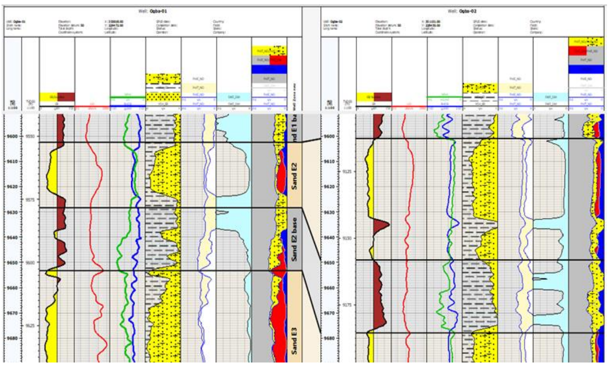

Figure 7: Sand E2 Both wells

4.1.4 Sand E3

Sand E3 is found in Ogba-01 between 9,690 and 9,770 feet and in Ogba-02 this thick, well-developed sandstone. The presence of hydrocarbons is confirmed by the high resistivity and low gamma-ray responses. Excellent reservoir quality is indicated by the shale's volume (Vsh) of around 0.18, porosity of 0.26–0.29, and permeability of 900–1,000 mD. The unit's designation as a major productive interval is supported by its great lateral continuity and probable high-energy channel-mouth bar environment of deposition.

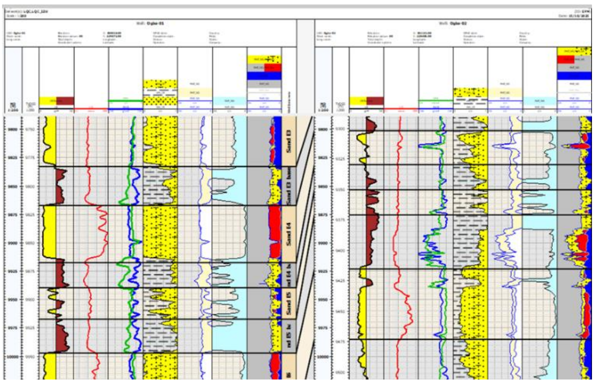

Figure 8: Sand E3 Both wells

4.1.5 Sand E4/E5 (Interval of Merger)

Occur between 9,830 and 9,920 feet in Ogba-01 and 9,820 and 9,910 feet in Ogba-02, respectively, are the combined or composite intervals that comprise Sands E4 and E5. The log signatures reveal a heterogeneous reservoir with alternating thin layers of sand and shale. According to petrophysical characteristics, the average permeability is between 400 and 600 mD, the porosity is 0.25, and the Vsh is 0.22. Although the interbedded shales may somewhat decrease effective permeability, the resistivity response indicates the presence of hydrocarbons. When hydraulically connected to cleaner sands, this period can be characterized as a moderately decent reservoir that can contribute to production.

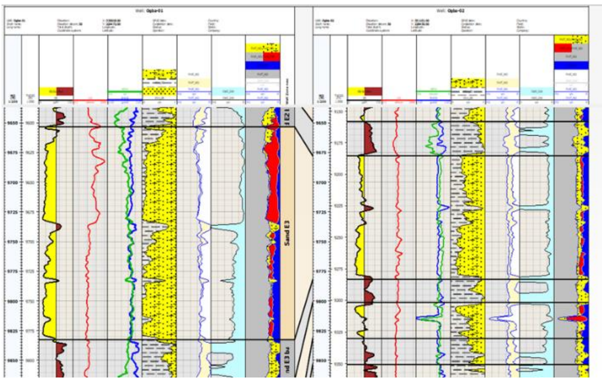

Figure 9: Sand E4 and E5 Both wells.

4.1.6 Sand E6

Sand E6 is found in Ogba-01 between 9,950 and 10,020 feet, and in Ogba-02 between 9,950 and 10,030 feet. With very low gamma-ray values and high resistivity, which confirm substantial hydrocarbon saturation, it is the cleanest and best-developed sandstone in both wells. Excellent reservoir quality is indicated by the volume of shale (Vsh) being less than 0.10, the average porosity being 0.30, and the permeability exceeding 1,200 mD. The unit represents the primary pay zone of the Ogba Field and was most likely deposited in a high-energy channel environment.

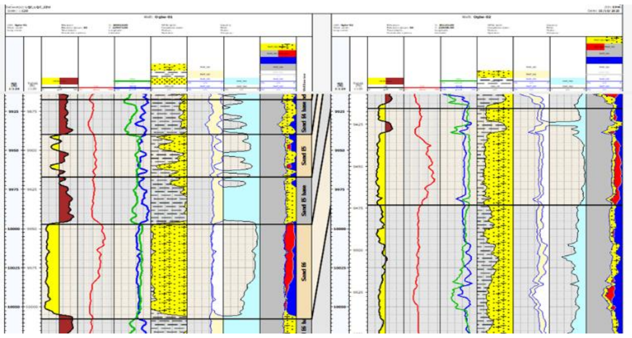

Figure 10: Sand E6 Both wells.

4.1.7 Sand E7

Sand E7, the lowest reservoir unit, is located in Ogba-01 between 10,050 and 10,100 feet, and in Ogba-02 between 10,040 and 10,100 feet. This thin, slightly shaly sandstone has a permeability of 150–250 mD, a porosity of 0.15, and a Vsh of approximately 0.25. The reservoir is categorized as tight or marginal-quality due to the moderate resistivity response, which suggests wet or residual hydrocarbon conditions. This gap probably serves as a base seal for the fertile sands that lie on top of it.

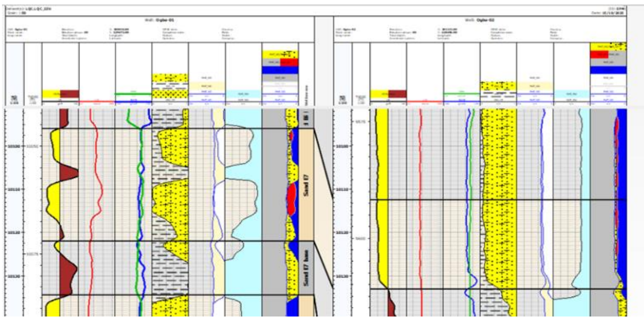

Figure 11: Sand E7 Both wells.

4.2 Cross plots (Depth VS GR, Vshale, Porosity, Permeability. Depth VS Sonic, Density etc)

The correlation between log-derived metrics and reservoir attributes with depth in the Ogba-01 and Ogba-02 wells was examined using cross plots. To find lithologic changes, assess reservoir quality, and verify log interpretations, these graphical tools—such as Depth vs. Gamma Ray (GR), Depth vs. Volume of Shale (Vsh), Depth vs. Porosity, Depth vs. Permeability, and Depth vs. Sonic/Density—were employed. A better grasp of reservoir heterogeneity and continuity is provided by the plots, which show the vertical and lateral distribution of lithology, shale content, and important petrophysical features within the Agbada Formation of the Niger Delta.

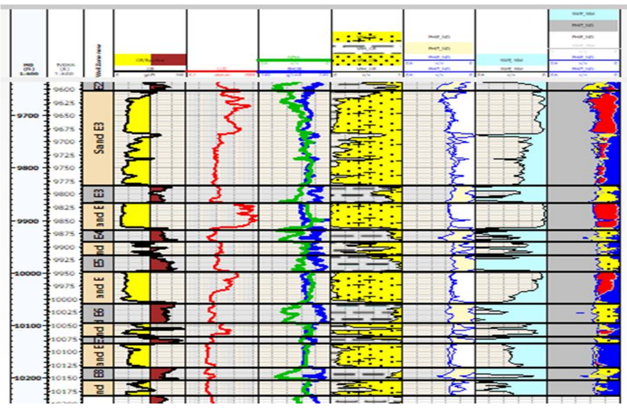

Figure 12: Cross Plot

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4.2.1 Depth vs. Gamma ray (GR) plot (Fig. 12)

Interbedded sand-shale sequences characteristic of deltaic to fluvio-deltaic habitats are indicated by the GR plots, which show alternating low and high readings. Higher readings in E1 and E7 indicate shaly, non-reservoir intervals, whereas clean sand units (E2–E6) exhibit low GR values (<60 API), indicating adequate reservoir quality. This pattern points to progradational deltaic cycles, in which shaly marine or overbank deposits alternate with distributary channels dominated by sand.

4.2.2 Depth vs. Volume of Shale (Vsh) Plot (Fig. 12)

Low shale volumes (<0.20) in sands E2–E6 indicate clean, high-quality reservoirs, while greater Vsh (>0.25) in E1 and E7 indicate transitional or sealing layers. These Vsh-depth plots reflect the GR patterns. These differences are a result of changes in depositional energy, with low-energy delta-front conditions producing shalier zones and high-energy mouth-bar or distributary settings producing cleaner sands.

4.2.3 Depth vs. Porosity (Fig. 12)

Because to compaction and diagenesis, porosity gradually decreases with depth, ranging from 0.10 to 0.25. Sands E2, E3, and E6 have higher porosities (>0.20), which are indicative of high-quality reservoirs connected to clean, well-sorted sands. Sand E6 exhibits good porosity despite deeper burial, indicating that the primary pore structures have been retained. This pattern is consistent with the Agbada Formation's fluvio-deltaic depositional hypothesis.

4.2.4 Depth vs. permeability plot (Fig. 12)

Permeability has a positive correlation with porosity and ranges from 150 mD to >1200 mD. Sands E2, E3, and E6 have the highest permeability values (>800 mD), indicating superior hydrocarbon potential and reservoir linkage. In E1 and E7, lower permeability (<300 mD) is associated with compacted, shaly intervals that have a reduced flow capacity. These patterns encourage deposition in mouth-bar and high-energy channel settings.

5. Discussion

Four main reservoir sands (A–D) with low GR, high resistivity, and good lateral continuity are identified by the correlation between Ogba-01 and Ogba-02, which creates a consistent stratigraphic framework. The Agbada Formation's typical deltaic to shallow marine environments are where the sands were deposited. In comparison to Ogba-02, Ogba-01 shows thicker, cleaner, and more resistant sands, suggesting superior reservoir quality, most likely as a result of improved sorting and increased depositional energy. The slightly thinner, shalier sands found in Ogba-02, on the other hand, show lateral facies diversity within the same depositional system. The reservoirs are hydrocarbon-bearing and laterally continuous overall, with Sands A and B exhibiting the best hydrocarbon saturation, permeability, and porosity. These results validate a productive reservoir system that is regionally widespread and appropriate for additional petrophysical and volumetric analysis.

5.1 Petrophysical variation within the reservoir

The lithologic composition, depositional energy, and diagenesis of Sands E1–E7 show distinct vertical and lateral differences in reservoir quality, according to the petrographic results. While E4–E5 sands have a higher shale concentration and somewhat worse quality, E1–E3 sands are comparatively clean and porous. Higher porosity levels in upper sands (particularly in Well 1) indicate greater sorting and less compaction. Porosity ranges from 10% to 25%. Clean, porous sands have the highest permeability, which ranges from 150 to 800 mD. Superior reservoir properties, such as increased porosity, permeability, and lower water saturation, are typically displayed by Ogba-01, suggesting improved hydrocarbon storage and flow capacity. These variances show the field's overall continuity of productive zones despite lateral heterogeneity.

5.2 Petrophysical evaluation and reservoirs characterization

The E1–E7 sands are primarily clean to moderately shaly sandstones interbedded with sealing shales, according to a thorough log investigation (GR, resistivity, density, neutron, and sonic). Water saturation (Sw) is between 0.25 and 0.45, hydrocarbon saturation (Sh) is between 0.55 and 0.75, permeability is between 150 and 800 mD, porosity is between 10 and 25%, and Vsh is between 0.10 and 0.30. The main productive intervals are found to be sands E1–E3, which are distinguished by their high resistivity, low shale content, and robust porosity–permeability relationships. Because to cementation and compaction increasing depth, deeper sands (E4–E5) exhibit lower quality. The Ogba Field reservoirs have good hydrocarbon potential overall, according to the integrated petrophysical analysis, with E2–E6 being the most prospective units for commercial production and field development planning.

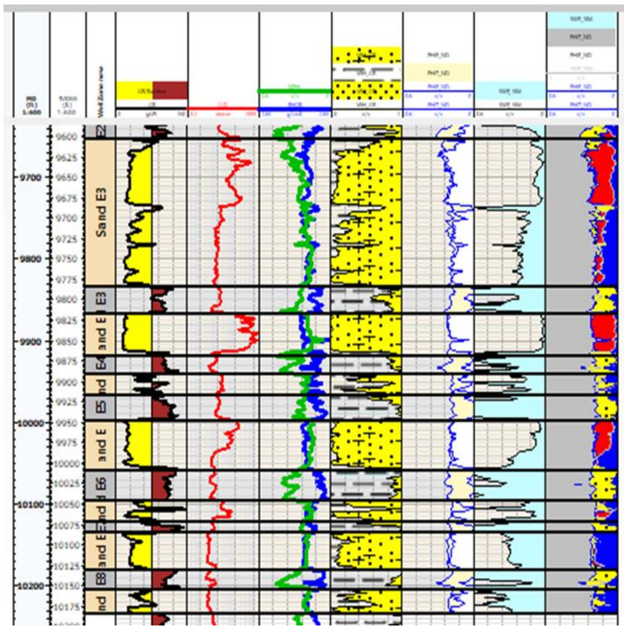

Figure 13: Petrophysical and reservoirs characterization showing oil in E sands.

5.3 Reservoir delineation and well correlation

5.3.1 Well Correlation and Reservoir Mapping

The lateral and vertical continuity of reservoir sands (E1–E7) across four wells—Ogba-01, Ogba-02, Ogba-05, and Ogba-4ST—is established by the Ogba Field's well correlation and reservoir mapping. The study uses gamma-ray and resistivity logs to identify zones that contain water and hydrocarbons, as well as clean sandstones and shale layers. Thin shale interbeds that serve as flow barriers divide the laterally continuous recognised sand groups, according to the correlation. A laterally broad yet heterogeneous reservoir system inside the Ogba Field is confirmed by slight differences in thickness and log responses, which point to modest facies or structural alterations.

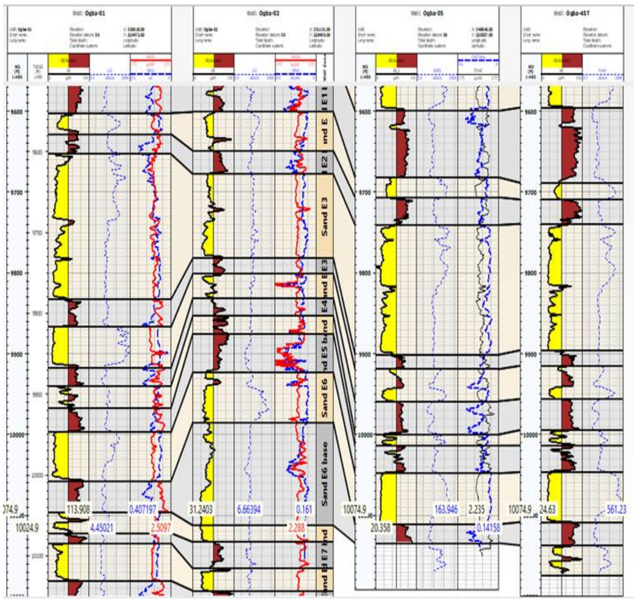

Figure 14: E sand Well correlation of Ogba-1, Ogba-2, Ogba-5 and Ogba-4st.

These correlations are important from a petrophysical perspective because they:

- Describe the structure of reservoirs and the size of productive zones.
- Offer the framework for modelling the porosity, permeability, and saturation of cross-well properties.
- Assist in locating possible compartmentalization and updip and downdip fluid connections.

- Encourage the incorporation of quantitative petrophysical characteristics into the geological model, such as water saturation, effective porosity, and shale volume.

According to the logs, Ogba-01 and Ogba-02 exhibit greater resistivity in important sand units (such as Sands E3–E6), suggesting the presence of potential hydrocarbon-bearing zones. Ogba-05 and Ogba-04ST, on the other hand, have thinner sand growth and lower resistivity, suggesting that the sands are less clean or water-bearing and may be found downdip. Both lateral shifts in reservoir quality and structural placement within the field are reflected in these variations.

All things considered, the connection paints a clear picture of the distribution and quality trends of the reservoirs throughout the Ogba Field. In order to characterize hydrocarbon potential and maximize field development, it provides a basis for further petrophysical analysis, reservoir modelling, and volumetric estimation.

5.3.2 Interpretation of depositional environments

Interpretation of the depositional environment from log patterns (blocky, funnel, and bell forms) suggests a fluvio-deltaic system typical of the Agbada Formation in the Niger Delta. High-energy channel fills are represented by blocky patterns, mouth bar deposits that are coarsening upward are indicated by funnel shapes, and channel abandonment or crevasse splay deposits are suggested by bell shapes. Cycles of transgressive and regressive events are represented by the sand-shale alternations. All things considered, the Ogba reservoirs were formed in a deltaic environment influenced by tides, where fluvial, wave, and marine processes combined to create stacked units of sandstone that contained hydrocarbons and were interbedded with efficient shale seals.

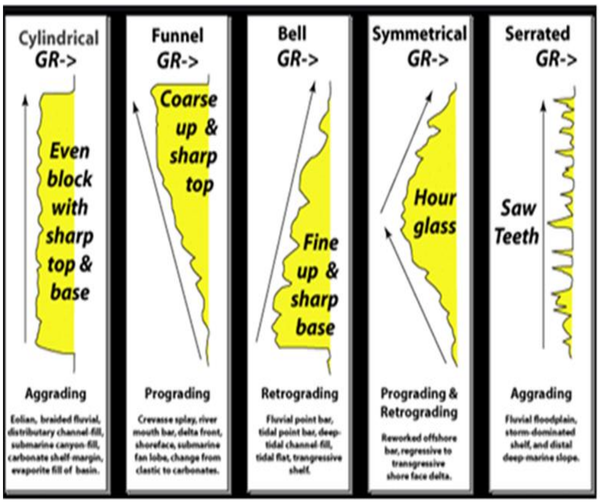

Figure 15: Gamma-ray responses and their corresponding depositional environment prediction (Emery and Myers 1996).

6. Conclusion

The petrophysical and geological analyses demonstrate that Sands E2, E3, and E6 constitute the main reservoir intervals in the Ogba Field, characterized by good porosity, high permeability, and low shale content. These sands are laterally continuous and exhibit strong correlation across the studied wells, suggesting favourable connectivity and hydrocarbon potential. The upper (E1) and lower (E7) units, in contrast, are predominantly shaly and serve as possible cap or transition zones. Therefore, there is a need to conduct a detailed petrophysical evaluation of well data to further analyse reservoir properties, providing reliable inputs for reservoir characterization, heterogeneity assessment, and volumetric estimation. This will enhance the accuracy of reservoir models and support effective field development planning

Recommendations

Acquire Core Data and Laboratory Measurements

Core analysis (porosity, permeability, grain density, and capillary pressure) should be carried out to calibrate and validate well log interpretations. This will improve the accuracy of derived petrophysical parameters such as effective porosity, permeability, and water saturation.

Integrate Advanced Log Interpretation Techniques

Advanced interpretation methods such as multi-mineral analysis, cross-plot modeling, and quantitative interpretation (QI) should be adopted to reduce uncertainties in shale volume estimation and fluid typing.

Use High-Resolution Logging Tools

Incorporating high-resolution tools like NMR (Nuclear Magnetic Resonance), Formation MicroImager (FMI), and Spectral Gamma Ray logs can enhance the identification of thin beds, detect complex lithologies, and differentiate between movable and bound fluids.

Perform Petrophysical Modeling and Sensitivity Analysis

A detailed petrophysical model should be constructed to quantify the relationships among porosity, permeability, and saturation. Sensitivity analysis will help determine how variations in these properties influence reservoir performance and volumetric estimates.

Integrate Petrophysical and Geological Data

Petrophysical results should be integrated with core description, sedimentological, and structural data to better define facies distribution, heterogeneity, and reservoir connectivity across the field.

Continuous Quality Control and Re-evaluation

Regular re-evaluation of petrophysical parameters is recommended as new wells are drilled or new data become available. This iterative process ensures consistent and reliable inputs for reservoir characterization and field development

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