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Assessment of Well Log Correlation and Petrophysical Characterization of D1 Reservoir Sands in the OKW Field, Southeastern Niger Delta, Nigeria

Nsikan M. Akpan, Thomas A. Harry*, Itoro G. Udo, Camillus E. Etim, Nsidibe I. Akata

Abstract

Accurate reservoir characterization is fundamental to reserve estimation, hydrocarbon recovery optimization, and field development planning in clastic petroleum systems. This study presents an integrated well-log correlation and petrophysical evaluation of the D1 reservoir interval within the OKW Field, offshore southeastern Niger Delta, Nigeria, with the objective of assessing reservoir continuity, reservoir quality, and hydrocarbon potential. Wireline log data comprising gamma-ray, resistivity, neutron, density, sonic, and spontaneous potential logs from OKW 1, OKW 7 and OKW 10 were interpreted using a combination of stratigraphic correlation, neutron-density cross-plot analysis, and quantitative petrophysical evaluation. Gamma-ray correlation established the lateral continuity of the D1 sandstone unit across the field, confirming a regionally extensive reservoir package within the upper Agbada Formation. Cross-plot analysis successfully discriminated shale, brine-bearing sands, and hydrocarbon-bearing sands, thereby improving lithological and fluid characterization. Petrophysical results reveal significant variability in reservoir quality among the studied wells. OKW 1 exhibits a gross reservoir thickness of 210.70 ft, net-to-gross ratio of 0.97, effective porosity of 32%, permeability of 1,874.46 mD, water saturation of 36%, hydrocarbon saturation of 64%, and net pay thickness of 45 ft. OKW 7 records the highest effective porosity (37%) and permeability (3,651.06 mD), but its high water saturation (76%) and low hydrocarbon saturation (24%) indicate a predominantly water-bearing reservoir. OKW 10 represents the most prospective interval, with a gross thickness of 235.53 ft, effective porosity of 36%, permeability of 3,622 mD, low water saturation of 20%, hydrocarbon saturation of 80%, bulk volume water of 0.07, and net pay thickness of 137.61 ft. Comparative reservoir ranking indicates that OKW 10 possesses the most favorable combination of reservoir quality and hydrocarbon charge, followed by OKW 1, whereas OKW 7 is limited primarily by excessive water saturation despite excellent rock properties. The results demonstrate that hydrocarbon prospectivity within the D1 reservoir is controlled not only by porosity and permeability but also by fluid distribution and structural compartmentalization. This study provides the first integrated multi-well assessment of the D1 reservoir interval in OKW Field and establishes a quantitative framework for reservoir appraisal and future field development in offshore Niger Delta sandstone reservoirs.

✉ Thomas A. Harry: thomasharry@aksu.edu.ng

Department of Geology, Akwa Ibom State University, Ikot-Akpaden, Akwa Ibom State, Nigeria

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1.0 Introduction

Reservoir characterization is the foundation of any reliable assessment of hydrocarbon prospectivity, recoverable reserves, and production strategy. In clastic basins such as the Niger Delta, where reservoir heterogeneity is controlled by depositional architecture, growth faulting, shale dynamics, and fluid substitution effects, accurate interpretation of wireline logs is essential for identifying reservoir boundaries, estimating reservoir quality, and evaluating pay zones.

Traditionally, core analysis has been regarded as the most direct method for reservoir characterization because it provides physical measurements of porosity, permeability, grain framework, pore geometry, and mineralogical composition. However, core availability is often limited by cost, operational constraints, and sampling bias. Consequently, wireline logs remain the most widely available and operationally practical source of subsurface information, particularly in mature deltaic provinces with large numbers of wells but incomplete core coverage.

The Niger Delta is one of the world's most prolific hydrocarbon provinces (Evamy et al. (1978) and is characterized by a thick Tertiary sedimentary wedge deposited within a regressive deltaic system. Its principal petroleum-bearing unit, the Agbada Formation, comprises interbedded sandstones and shales deposited in fluvial, deltaic, shoreface, and shallow marine settings (Doust (1989); Doust and Omatsola, 1990). Reservoir properties in this setting are strongly influenced by sediment supply, compaction, diagenesis, depositional facies, and structural compartmentalization (Tuttle et al. (1999). In such a complex system, log-based petrophysical analysis provides a practical and powerful means of discriminating sand from shale, estimating fluid content, and predicting reservoir productivity (Harry et al. (2022a, 2022b).

The OKW Field is located in the offshore southeastern Niger Delta and contains reservoir sands within the D1 section of the Agbada Formation. The field presents a useful case study because the reservoir intervals are accessible through multiple wells and the available log suite permits comparative interpretation across fault blocks and sand bodies (Harry & Akata, 2019). The present study focuses on the integration of well log correlation and petrophysical analysis to improve understanding of reservoir continuity, reservoir quality, and hydrocarbon occurrence within the D1 sand units. The central aim is to determine the extent to which conventional wireline logs can be used to establish reservoir geometry, quantify rock and fluid properties, and identify intervals with the strongest hydrocarbon potential.

Although several studies in the Niger Delta have applied well-log analysis to evaluate reservoir properties, many of them emphasize either single-well petrophysical estimation, regional stratigraphic description, or general hydrocarbon prospectivity (Abraham et al. (2019). The present study differs by integrating well-log correlation, lithology and fluid discrimination, and quantitative petrophysical evaluation within a multi-well framework for the D1 reservoir sands of the OKW Field. This approach allows the study to move beyond isolated parameter estimation and assess reservoir continuity, lateral variability, fluid distribution, and relative well prospectivity across the field. A further contribution of the work is its demonstration that excellent rock properties alone do not guarantee commercial hydrocarbon potential, as shown by the contrast between high-porosity, high-permeability but water-bearing intervals and intervals with lower water saturation and stronger hydrocarbon charge. By ranking the studied wells using both rock-quality indicators and saturation-based pay criteria, the study provides a practical and reproducible workflow for reservoir appraisal in data-limited offshore Niger Delta sandstone reservoirs. The novelty of this study therefore lies in its integrated, multi-well evaluation of the D1 reservoir sands in the OKW Field, where reservoir continuity, lithological variability, petrophysical quality, fluid saturation, and well ranking are jointly assessed to support more reliable reservoir appraisal and field-development decisions.

1.1 Study aim and objectives

The study aims to provide an integrated well-log-based assessment of the D1 reservoir sands in the OKW Field, with emphasis on reservoir continuity, lithological variability, petrophysical quality, and hydrocarbon potential. Specifically, the work seeks to correlate the D1 sandstone interval across selected wells using gamma-ray and associated log signatures in order to establish reservoir continuity and stratigraphic equivalence. It also applies log-based cross-plot techniques to discriminate lithologies and identify fluid types within the reservoir interval. In addition, key petrophysical parameters, including shale volume, porosity, permeability, water saturation, hydrocarbon saturation, net reservoir thickness, and net-to-gross ratio, are estimated to quantify reservoir quality and productive potential. By comparing these properties across the studied wells, the paper identifies the most prospective reservoir interval within the field. Ultimately, the study provides a reproducible log-based workflow for reservoir appraisal in the Niger Delta and similar clastic petroleum systems.

2.0 Geological Setting

The OKW Field is situated offshore southeastern Nigeria within the Niger Delta Basin, approximately 45 to 50 km offshore and in shallow water depths. The field lies within OML 67 and forms part of the petroleum province hosted by the Tertiary Niger Delta sequence. Structurally, the field is divided into fault blocks, reflecting the strong influence of syn-sedimentary growth faulting and rollover deformation typical of the delta (Short & Stauble, 1967). The Niger Delta Basin is a large regressive delta complex that developed through the interaction of sediment supply from the Niger-Benue catchment and long-term tectonic subsidence along the continental margin (Anyiam & Uzuegbu (2020). The basin is conventionally subdivided into three major lithostratigraphic units: the Akata Formation, the Agbada Formation, and the Benin Formation (Essien & Okon, 2017; Harry et al, 2017). The Akata Formation comprises marine shale and is considered the principal source rock (Asuaiko et al, 2022; 2024). The Agbada Formation is the main petroleum-bearing unit and contains alternating sandstone and shale successions deposited in deltaic to shallow marine settings (Figure 1). The Benin Formation is dominantly continental and consists largely of coastal plain sands.

The OKW Field reservoirs investigated in this study belong to the D1 section of the Agbada Formation and are represented by Plio-Pleistocene sandstone bodies. These sands are important reservoir intervals because they are commonly porous and permeable, but their quality may vary laterally and vertically due to shale intercalation, invasion effects, and facies heterogeneity. Understanding these variations is essential for reliable reservoir appraisal.

Figure 2 shows the location map of OKW field situated on the South Eastern section of Niger Delta sedimentary province while Figure 3 shows the studied well locations. Syn-sedimentary faulting defines the Niger Delta Depobelts, which represent different units with unique sedimentation and petroleum histories. The structural complexity of the northern, central, and distal delta provinces varies depending on the overlaying basement and growth faults (Reijers, 2011; Fazli Khani and Back, 2012).

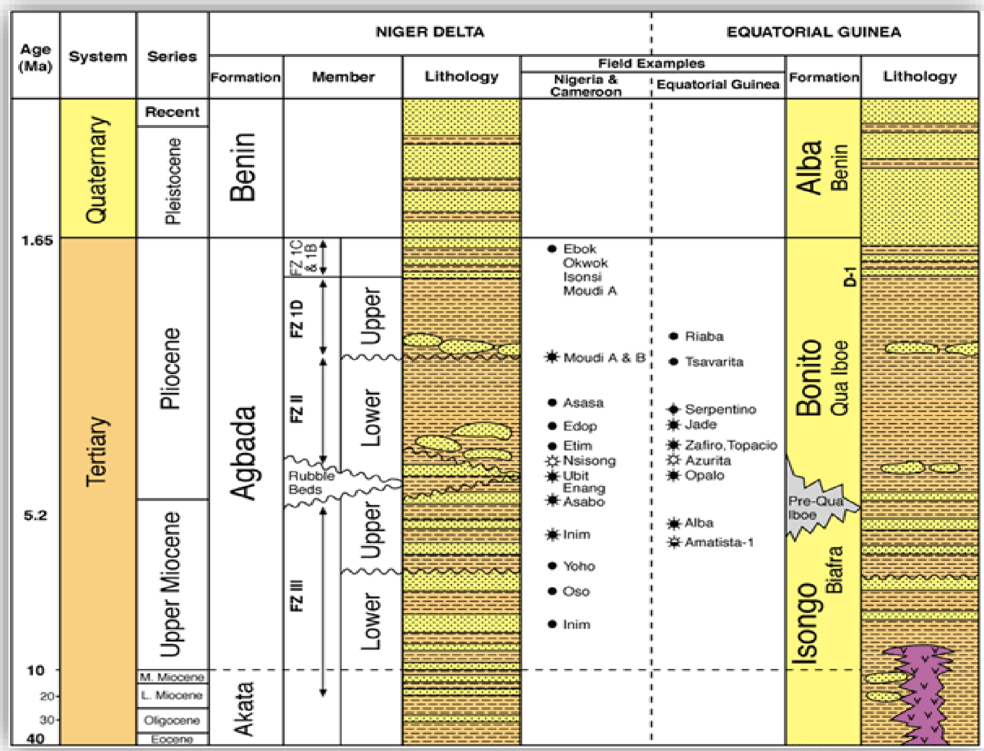

Figure 1: Stratigraphic framework of the Niger Delta Basin

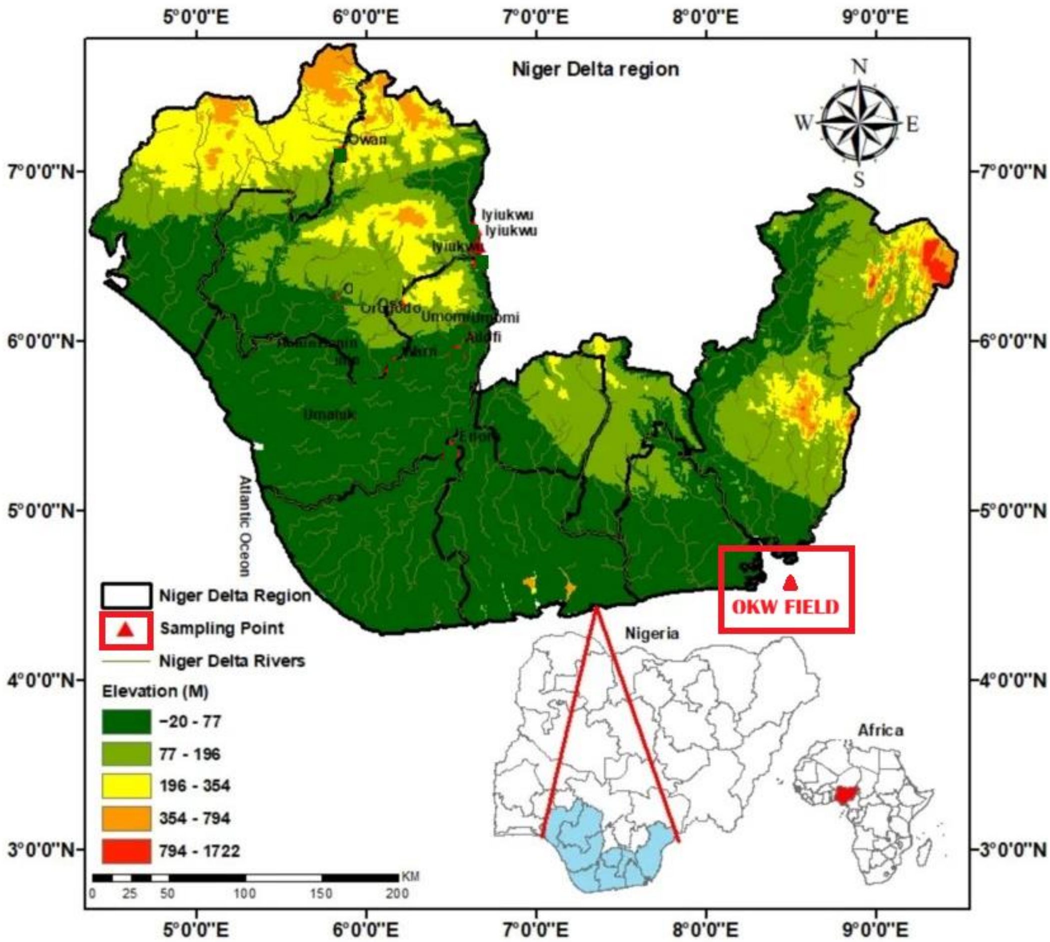

Figure 2: Location Map of OKW field, Niger Delta Basin

The research is centered on the OKW Field region (Figure 4) of Nigeria's Akwa Ibom State, which is located in the country's south. The field is located 45 kilometers off the coast of Nigeria, where the bottom is 35 to 50 meters deep. The OKW field was discovered in 1967 as a result of a joint venture between the Nigerian National Petroleum Corporation (NNPC) and Mobil Producing Nigeria. The field is separated into three major fault blocks, namely Fault Block 1, Fault Block 2, and Fault Block 3, and is characterized by Plio - Pleistocene age sandstones known as Lower D Sands, which may be found at subsea drill depths ranging from 914.4 to 1,219.2 m.

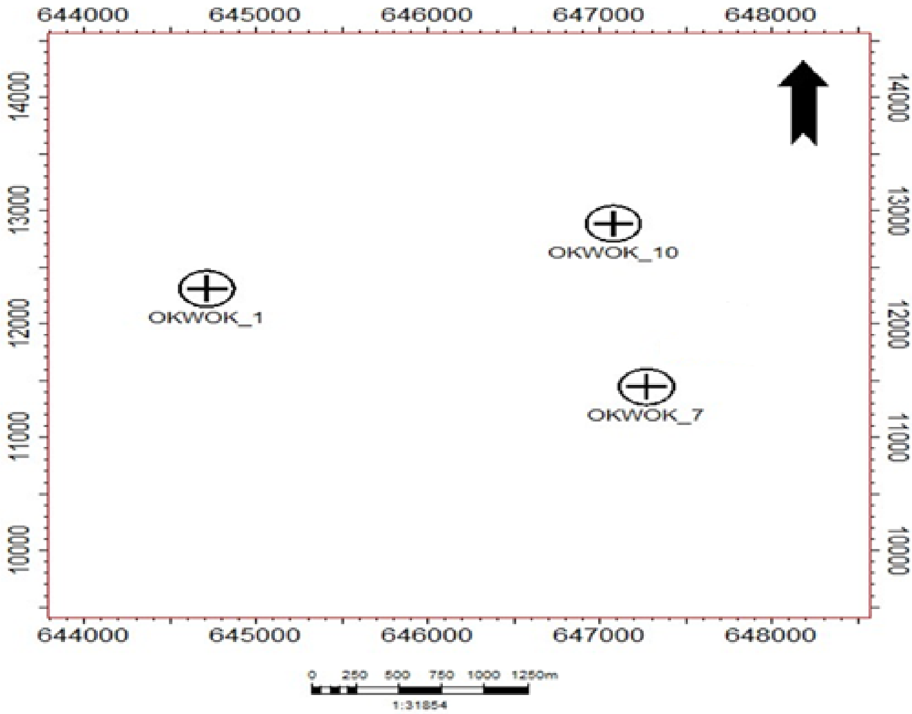

Figure 3: Location of the wells in the study area

3.0 Materials and Method

3.1 Data Used

This study utilized wireline log datasets acquired from four wells within the OKW Field, namely OKW 1, OKW 7, and OKW 10. The available logging suite comprised gamma-ray (GR), resistivity, neutron, density, spontaneous potential (SP), sonic, and photoelectric logs where available. These datasets formed the primary source of subsurface information and were used for lithological interpretation, reservoir correlation, fluid identification, and quantitative petrophysical evaluation. The combination of multiple log types enabled a comprehensive characterization of the D1 reservoir interval and provided the basis for assessing reservoir continuity, rock quality, and hydrocarbon potential across the field.

3.2 Well Correlation

Well correlation was undertaken to establish the lateral continuity and stratigraphic relationships of the D1 reservoir interval across the study area. Gamma-ray (GR) log signatures were employed as the principal correlation tool because of their effectiveness in distinguishing shale-rich intervals from relatively clean sandstone units. Low gamma-ray responses were interpreted as sandstone-dominated intervals, whereas elevated gamma-ray values were associated with shale-rich sections. Correlation was achieved by identifying distinctive sand motifs, marker horizons, and characteristic log patterns that could be traced between wells. The resulting correlation framework facilitated the evaluation of reservoir continuity, variations in reservoir thickness, and the distribution of potential shale barriers or baffles that may influence fluid flow and reservoir compartmentalization. Furthermore, the correlation provided valuable insight into the depositional architecture and stratigraphic organization of the D1 reservoir sands within the OKW Field.

3.3 Data Compilation, Quality Control (QC) and log interpretation

The methodology for geological log interpretation and correlation involves a systematic approach to analyse and integrate well log data for a comprehensive understanding of subsurface geology. The initial step includes compiling a dataset of geological well logs, encompassing gamma-ray, resistivity, neutron, density, and sonic logs, from the target well and nearby wells. Following data compilation, a thorough quality check is performed to address issues such as missing values, outliers, and data inconsistencies. Ensuring proper depth alignment among logs from different wells is crucial for accurate correlation. Basic log responses were then utilized to identify lithological boundaries, such as shale, sandstone, limestone, and other formations. Standard correlation techniques, including visual inspection of log signatures, cross-plotting, and statistical analyses, were applied to establish correlations between logs from different wells.

Marker horizons or key stratigraphic features are identified to serve as tie points for correlation. Paleo-environmental factors, such as depositional environments and sedimentary facies, were considered to refine correlations and provide geological context. Structural information derived from logs is incorporated to enhance correlation accuracy, particularly in areas with structural complexities. The interpreted geological log data and correlation results were then synthesized to develop a cohesive understanding of subsurface geology.

3.2 Petrophysical Analysis

Petrophysical analysis plays a pivotal role in the assessment of subsurface reservoirs in the oil and gas industry. Understanding the lithology and fluid type within a reservoir is essential for optimizing exploration and production strategies.

3.2.2 Water Saturation

Water saturation can be obtained from formation factor as follows (El-Bagoury, 2020):

$$F = \frac{R_o}{R_w} \quad 1$$

where R_o is the resistivity of formation, R_w is the resistivity of saturating water and F is the formation factor. If hydrocarbon is present, the resistivity of formation is R_t and water saturation is less than 100%. But

$$F = \frac{R_o}{R_w} = \frac{a}{\phi^m} \quad 2$$

where a is a is the tortuosity or lithology factor, ϕ is the porosity, m is the cementation factor. a varies from 0.6 – 2.0 depending on texture, m varies from 1 – 3 according to the type of sediment. Water saturation can be deduced from Archie equation as (Gomaa et al., 2022):

$$Sw^n = \frac{R_o}{R_t} \quad 3$$

From (2):

$$R_0 = \frac{aR_w}{\phi^m} \quad 4$$

From (3) and (4) we have

$$S_w = \sqrt[n]{\frac{aR_w}{R_t\,\phi^m}} \quad 5$$

where S_w is water saturation; a is the tortuosity or lithology factor; R_w is the formation-water resistivity; R_t is the true formation resistivity of the uninvaded zone; ϕ is porosity; m is the cementation exponent; and n is the saturation exponent. For clean sandstone reservoirs, a is commonly taken as 1, while m and n are commonly approximated as 2 in the absence of core-derived calibration (Telford et al., 1990).

3.2.3 Bulk Volume of Water

The bulk volume of water (BVW) in a reservoir is simply the product of the water saturation (S_w) times the porosity (ϕ), or stated mathematically:

$$BVW = S_w \times \phi \quad 6$$

It is often one of the most important parameters that we can use to evaluate a reservoir's potential. This is true because bulk volume water indicates whether or not a reservoir is at irreducible water saturation (S_{wirr}).

3.2.4 Volume of Shale

The Gamma Ray log is particularly useful for defining shale beds when the spontaneous potential log is distorted. The GR log reflects the proportion of Shale and in many regions can be used qualitatively as a Shale indicator. The bed boundary is picked at a point midway between the maximum and minimum deflection of the anomaly.

There are various ways of determining the volume of Shale (V_{sh}) in a Shaly Formation (Schlumberger, 1987). In a shaly, porous, and permeable zone, the volume of shale (Vsh) can be estimated from the deflections of the GR curve.

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad 7$$

where I_{GR} = Gamma Ray Index (dimensionless): a normalized value ranging from 0 to 1. It indicates the relative shale content of a formation. I_{GR} = 0 represents a clean (shale-free) formation. I_{GR} = 1represents a pure shale formation. GR_{log} = measured gamma ray log value: the gamma ray reading recorded by the logging tool at a specific depth (units: API units (American Petroleum Institute units). GR_{min} = minimum gamma ray value: the lowest gamma ray reading observed in the interval, representing a clean sandstone, limestone, or dolomite with negligible shale content (units: API units). GR_{max} = maximum gamma ray value: the highest gamma ray reading observed in the interval, representing a shale or clay-rich formation (units: API units)

$$V_{sh} = 0.08(2^{(3.71 I_{GR})} - 1) \quad 8$$

V_{sh} = Volume of shale: the estimated fraction or percentage of shale present within the rock formation. It is dimensionless and typically expressed as a decimal (0–1) or percentage (0–100%). For example, V_{sh} = 0.25 corresponds to 25 % shale.

3.2.5 Porosity

Porosity can be calculated from sonic logs using the Wyllie time average in equation 9.

$$\phi_w = \frac{\Delta t_{log} - \Delta t_{max}}{\Delta t_{ft} - \Delta t_{max}} \quad 9$$

where Δt_{log} is the reading on the sonic log in µs/ft Δt_{max} is the transit time of the matrix material (about 55.5 µs/ft) Δt_{ft} is the transit time of the saturating fluid (about 189 µs/ft for fresh water).

3.2.6 Permeability

Permeability is a measure of fluid transmissibility in rock and is an important topic in formation appraisal and hydrocarbon production from reservoirs. To estimate permeability from other petrophysical properties, many techniques such as intelligent algorithms have been devised. Permeability computation was done by the software called interactive Petrophysics using Timur's equation (equation 10).

$$K = a \frac{\phi^b}{S_{wi}^c} \quad 10$$

where K = permeability (mD), ϕ = porosity and S_{wirr} = reservoir irreducible water while a, b and c are constants with the following values: a = 8581, b = 4.4 and c = 2. Because of the efficiency and convergence challenges associated with artificial neural networks, researchers have been inspired to utilize hybrid methodologies for network optimization, in which the artificial neural network is paired with heuristic algorithms.

3.4 Petrophysical Calculations

Quantitative petrophysical evaluation was performed to determine the reservoir properties of the D1 sandstone interval. Key reservoir parameters estimated from the log data included volume of shale (Vsh), total porosity (PHIT), effective porosity (PHIE), water saturation (Sw), hydrocarbon saturation (Sh), bulk volume of water (BVW), permeability, net reservoir thickness, and net-to-gross ratio (N/G). Volume of shale was calculated from gamma-ray responses using standard shale-index relationships appropriate for Tertiary clastic reservoirs. Porosity was determined using density and sonic log responses, while effective porosity was obtained after correcting for shale content. Water saturation was estimated using Archie's clean-sand model, which relates formation resistivity to porosity and formation water resistivity. Hydrocarbon saturation was subsequently calculated as the fraction of pore volume not occupied by water. Permeability was estimated using empirical relationships based on porosity and irreducible water saturation, including Timur's equation. Net reservoir thickness and net-to-gross ratios were derived from the interpreted reservoir intervals and used as indicators of reservoir quality and productivity potential. To distinguish productive reservoir zones from non-pay intervals, petrophysical cut-off values were applied. A shale volume cut-off of 0.40, effective porosity cut-off of 0.15, and water saturation cut-off of 0.50 were adopted. Intervals satisfying these criteria were classified as potential pay zones, whereas intervals failing to meet one or more of the thresholds were considered non-productive.

3.5 Reservoir Interpretation Workflow

The reservoir interpretation workflow followed a systematic and integrated approach designed to ensure consistency and reliability in reservoir evaluation. The process began with the identification of gross sandstone intervals based on characteristic log motifs and gamma-ray responses. These intervals were subsequently correlated across the study wells to establish reservoir continuity and stratigraphic equivalence. Lithological interpretation was then refined using gamma-ray signatures and supported by neutron-density cross-plot analysis for fluid and lithology discrimination. Following lithological characterization, petrophysical parameters were computed and evaluated using the established cut-off criteria to identify productive reservoir sections. Finally, the interpreted reservoir properties were compared among the wells to assess variations in reservoir quality, rank hydrocarbon prospectivity, and identify the most favorable reservoir compartments within the OKW Field. This integrated workflow provided a robust framework for reservoir characterization and facilitated a comprehensive understanding of the D1 reservoir system.

4.0 Results

4.1 Well correlation and reservoir continuity

The correlation of the D1 sand interval across the selected wells shows that the reservoir sands are laterally continuous across the OKW Field, although thickness and shale content vary from well to well. The main reservoir interval is recognized consistently in OKW 1, OKW 7, and OKW 10, confirming that the D1 unit forms a regionally mappable reservoir package.

The gamma-ray log signature demonstrates that the sand bodies are interbedded with shale streaks of variable thickness. These shale intervals likely reflect depositional heterogeneity and may act locally as baffles to fluid flow. The correlation also suggests that the reservoir is compartmentalized by faulting and facies changes, which is consistent with the structural style of the Niger Delta. The well correlation between the three wells OKW 1, 7 and 10 based on their top and basal depths (Table 1), with an emphasis on the sandstone units as shown in Figures 4 and 5. The correlation was carried out to prove the continuity and link of these units between the four wells based on the gamma ray log character. The sand motifs were used as the basis for the correlation. The optimization of hydrocarbon recovery systems might benefit from this connection, which is essential for comprehending the heterogeneity of the reservoir. The correlation results add to a thorough knowledge of the subsurface properties of the OKW Field and provide useful information for reservoir appraisal.

4.2 Petrophysical summary of OKW 1

OKW 1 intersects a sandstone reservoir of gross thickness 210.70 ft (Table 2), from 2986.28 ft to

3196.98 ft. The net reservoir thickness is 204.56 ft, giving a net-to-gross ratio of 0.97. The low shale volume indicates a relatively clean sand body. Total porosity is 0.34 and effective porosity is 0.32, showing excellent reservoir storage capacity. Permeability is 1874.46 mD, indicating very favorable fluid flow potential. Water saturation is 0.36, while hydrocarbon saturation is 0.64. The reservoir is interpreted as gas-bearing with a water contact near 3041 ft and a net pay thickness of 45 ft. Overall, OKW 1 exhibits strong reservoir quality and productive hydrocarbon potential.

4.3 Petrophysical summary of OKW 7

OKW 7 penetrates a sandstone reservoir of gross thickness 195.06 ft, from 3202.6 ft to 3397.66 ft. The net reservoir thickness is 184.88 ft and the net-to-gross ratio is 0.95, indicating a thick and largely sand-dominated interval. Total porosity is 0.39 and effective porosity is 0.37, both of which are very favorable. Permeability is 3651.06 mD, suggesting excellent transmissibility (Table 3). However, water saturation is high at 0.76, with hydrocarbon saturation of only 0.24. The bulk volume of water is 0.28, which is consistent with a water-rich interval. The reservoir is therefore interpreted as wet, and no clear fluid contact or net pay was assigned. Although the rock framework itself is of good quality, the fluid occupancy significantly reduces commercial attractiveness.

4.4 Petrophysical summary of OKW 10

OKW 10 intersects a sandstone reservoir of gross thickness 235.53 ft, from 3134.39 ft to 3369.92 ft. The net reservoir thickness is 212.55 ft, and the net-to-gross ratio is 0.90. Volume of shale is low at 0.10, indicating a clean reservoir sand. Total porosity is 0.38 and effective porosity is 0.36, showing high storage capacity. Permeability is 3622 mD, which is also highly favorable (Table 4).

Water saturation is low at 0.20 and hydrocarbon saturation is 0.80. Bulk volume of water is 0.07, indicating limited water occupancy and a strong hydrocarbon signal. The interval is interpreted as gas-bearing, with a gas-water contact at approximately 3272 ft and a net pay thickness of 137.61 ft. Among the interpreted wells, OKW 10 appears to be the most promising hydrocarbon-bearing interval.

4.5 Comparative Reservoir Assessment

The comparative evaluation reveals clear differences in reservoir performance among the studied wells. OKW 1 and OKW 10 both exhibit favorable reservoir characteristics, particularly in terms of relatively low water saturation and high hydrocarbon saturation, indicating good hydrocarbon-bearing potential. Among the evaluated wells, OKW 10 shows the strongest overall prospectivity because it combines good reservoir thickness, high effective porosity, favorable permeability, low water saturation, and the highest hydrocarbon saturation. OKW 1 also demonstrates strong reservoir quality and remains a potentially productive interval, although its hydrocarbon potential is slightly lower than that of OKW 10. In contrast, OKW 7 presents a different reservoir condition. Although it exhibits excellent porosity and permeability, the interval is dominated by high water saturation and relatively low hydrocarbon saturation. This indicates that good rock quality alone is insufficient to guarantee commercial productivity where the pore spaces are largely occupied by water. From a production perspective, OKW 7 is therefore less attractive than OKW 1 and OKW 10. Based on the integrated assessment, OKW 10 is ranked as the most prospective reservoir interval, followed by OKW 1, while OKW 7 ranks lowest because of its water-bearing character. This comparison confirms that reservoir quality must be evaluated using both rock properties and fluid saturation parameters. High porosity and permeability may indicate favorable storage and flow capacity, but they do not necessarily translate into commercial pay if water saturation is excessive and hydrocarbon saturation is low.

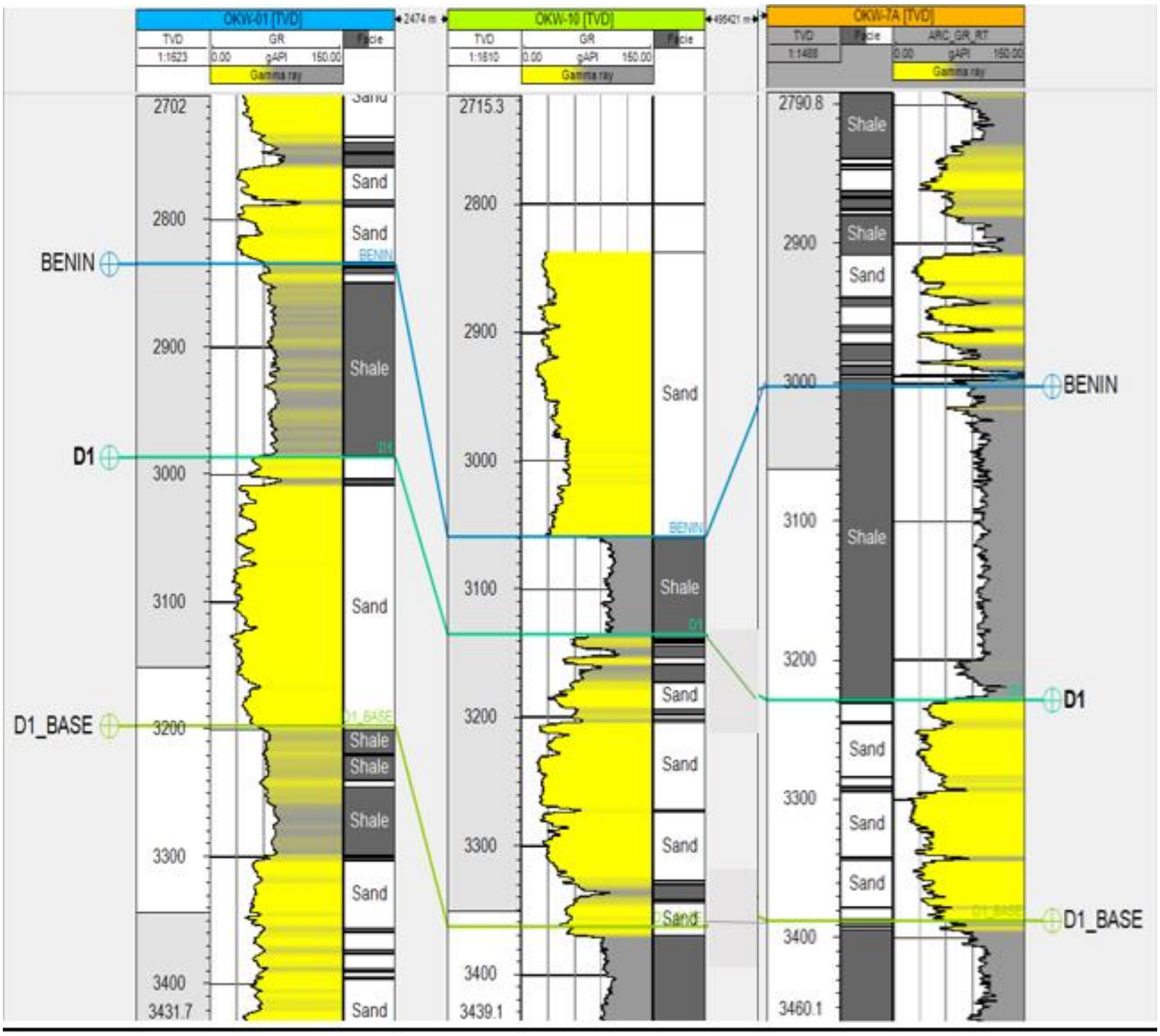

Figure 4: Well log correlation with a 60° API Gamma Ray sand cut-off

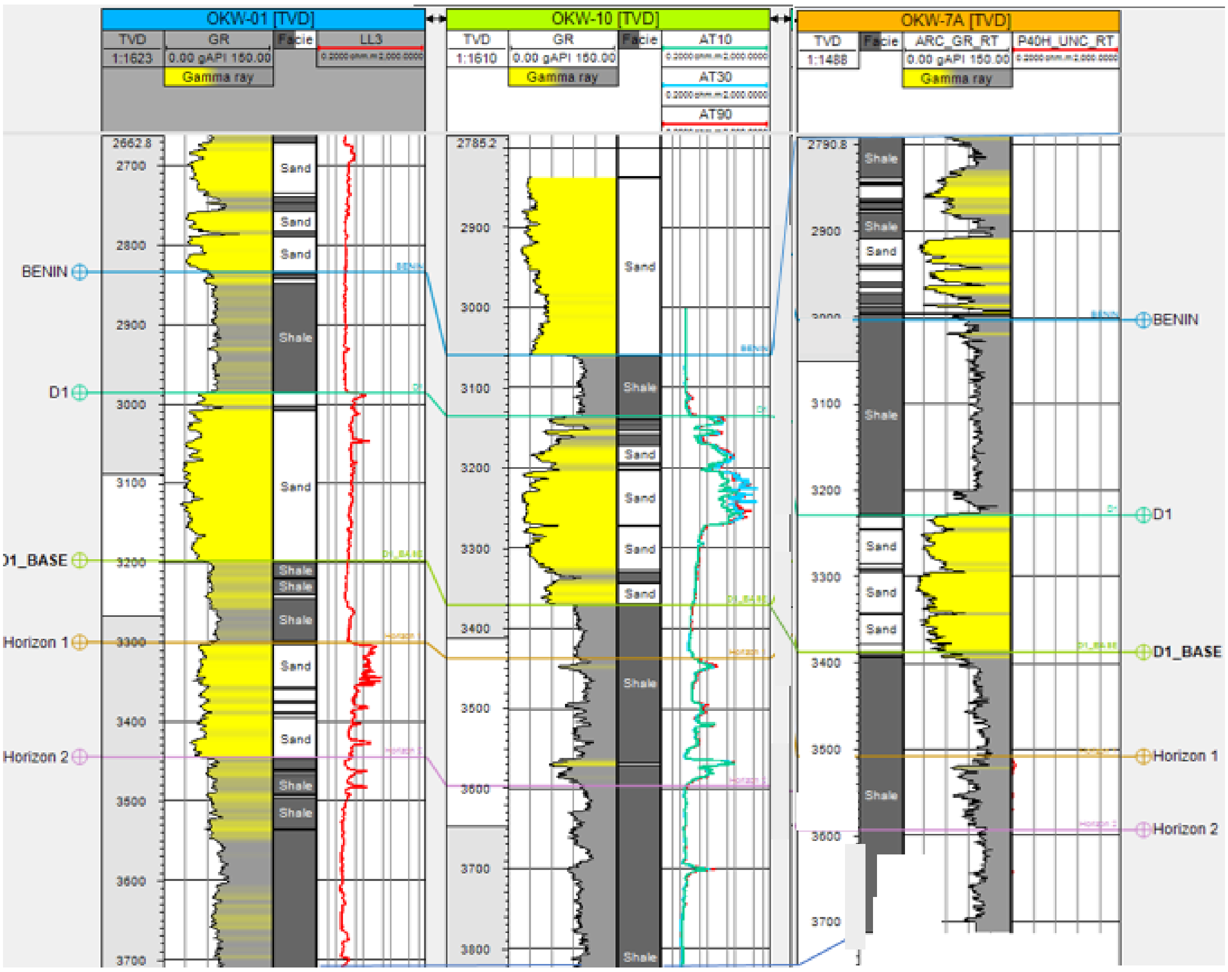

Figure 5: Well logs showing Gamma, lithofacies and Resistivity Logs

Table 1: Table showing the Location and depths of studied Wells

Well identifier	Surface	X	Y	Depth	MD
	Benin	644713	12317	-2760	2831.58
OKW-1	D-1	644713	12317	-2914	2986.28
	D-1 Base	644713	12317	-3125	3196.98
	Benin	647270	11452	-2957	3039.7
OKW-7	D-1	647270	11452	-3120	3202.6
	D-1 Base	647270	11452	-3315	3397.66
	Benin	647079	12916	-2686	2988.35
OKW-10	D-1	647077	12890	-2805	3134.39
	D-1 Base	647074	12847	-2993	3369.92

Table 2: Petrophysical Summary of OKW 1

Sand Top (ft)	2986.28
Sand Bottom (ft)	3196.98
Gross Sand/Thickness (ft)	210.70
Net Thickness (ft)	204.56
Net to Gross (N/G)	0.97
Volume of Shale (Vshale)	0.09
Total Porosity (PHIT)	0. 34
Effective Porosity (PHIE)	0.32
Permeability (mD)	1874.46
Water Saturation (Sw)	0.36
Hydrocarbon Saturation (Sh)	0.64
Water Saturation in the Invaded/Flushed Zone (Sxo)	0.82
Bulk Volume of Water (BVW)	0.12
Hydrocarbon Fluid Type	GAS, WATER
Fluid Contact	WUT* - 3041
Net Pay Thickness (ft)	45

Table 3: Petrophysical Summary of OKW 7

Sand Top (ft)	3202.6
Sand Bottom (ft)	3397.66
Gross Sand/Thickness (ft)	195.06
Net Thickness (ft)	184.88
Net To Gross (N/G)	0.95
Volume of Shale (Vshale)	0.087
Total Porosity (PHIT)	0.39
Effective Porosity (PHIE)	0.37
Permeability (mD)	3651.06
Water Saturation (Sw)	0.76
Hydrocarbon Saturation (Sh)	0.24
Water Saturation in the Invaded/Flushed Zone (Sxo)	0.95
Bulk Volume of Water (BVW)	0.28
Hydrocarbon Fluid Type	Wet
Fluid Contact	None
Net Pay Thickness	None

Table 4: Petrophysical Summary of OKW 10

Sand Top (ft)	3134.39
Sand Bottom (ft)	3369.92
Gross Sand/Thickness (ft)	235.53
Net Thickness (ft)	212.55
Net to Gross (N/G)	0.90
Volume of Shale (Vsh)	0.10
Total Porosity (PHIT)	0.38
Effective Porosity (PHIE)	0.36
Permeability (mD)	3622
Water Saturation (Sw)	0.20
Hydrocarbon Saturation (Sh)	0.80
Water Saturation in the Invaded/Flushed Zone (Sxo)	0.72
Bulk Volume of Water (BVW)	0.07
Hydrocarbon Fluid Type	Gas, Water
Fluid Contact	GWC* @3272
Net Pay Thickness (ft)	137.61

5.0 Discussion

The assessment of well-log correlation and petrophysical evaluation of the D1 reservoir sands reveal that the interval represents a laterally continuous but internally heterogeneous sandstone body within the OKW Field. Gamma-ray correlation confirms that the D1 sand can be traced across OKW 1, OKW 7, and OKW 10, indicating that it forms a mappable reservoir package within the Agbada Formation. However, variations in gross thickness, shale content, net reservoir thickness, and fluid saturation show that the reservoir is not uniform across the field. This heterogeneity is consistent with the depositional and structural complexity of the Niger Delta, where deltaic sand bodies are commonly modified by shale intercalations, facies changes, and growth-fault-related compartmentalization.

The petrophysical results indicate that the D1 reservoir generally has very good to excellent rock quality. OKW 1 records an effective porosity of 32% and permeability of 1,874.46 mD, while OKW 7 has the highest effective porosity and permeability values of 37% and 3,651.06 mD, respectively. OKW 10 also shows excellent reservoir properties, with effective porosity of 36% and permeability of 3,622 mD. These values suggest that the D1 sands possess strong storage capacity and good fluid transmissibility. The high net-to-gross ratios further indicate that the reservoir interval is largely sand-dominated, although the presence of shale streaks may locally reduce vertical connectivity and influence fluid flow.

Despite the generally favorable rock properties, the wells show marked differences in fluid saturation and hydrocarbon potential. OKW 10 is the most prospective well, with low water saturation of 20%, high hydrocarbon saturation of 80%, bulk volume water of 0.07, and net pay thickness of 137.61 ft. This combination of thick reservoir development, excellent porosity, high permeability, low water occupancy, and strong hydrocarbon saturation indicates a highly favorable pay interval. OKW 1 also shows good hydrocarbon potential, with water saturation of 36%, hydrocarbon saturation of 64%, and net pay thickness of 45 ft. Although its reservoir quality is strong, its lower net pay and higher water saturation make it less attractive than OKW 10.

In contrast, OKW 7 demonstrates that good rock quality alone does not guarantee commercial hydrocarbon prospectivity. Although it has the highest porosity and permeability among the studied wells, its water saturation of 76% and hydrocarbon saturation of only 24% indicate that the reservoir interval is dominantly water-bearing. This contrast is important because it shows that reservoir evaluation must integrate both rock properties and fluid-saturation parameters. Porosity and permeability describe the capacity of the reservoir to store and transmit fluids, but water saturation and hydrocarbon saturation determine whether that capacity is occupied by commercially valuable hydrocarbons.

The contrasting fluid distribution among the wells may reflect differences in structural position, proximity to fluid contacts, hydrocarbon charge, or compartmentalization within the reservoir (Akindulureni et al., 2018). OKW 10 may occupy a more favorable structural or stratigraphic position within the hydrocarbon column, whereas OKW 7 may lie closer to the water leg or within a less effectively charged compartment. Shale interbeds and growth faults may also have influenced reservoir connectivity, creating local variations in pressure communication and fluid distribution. These interpretations are consistent with the known complexity of Niger Delta reservoirs, where laterally continuous sand bodies may still show significant differences in fluid content from one well to another.

The comparative reservoir ranking therefore places OKW 10 as the most favorable development candidate, followed by OKW 1, while OKW 7 is considered less prospective because of its high water saturation. This ranking has practical implications for field development. OKW 10 should be prioritized for further appraisal, completion planning, and possible production optimization. OKW 1 remains a viable hydrocarbon-bearing interval but may require more careful evaluation of pay thickness and water production risk. OKW 7 should be treated cautiously, as development without further validation may result in high water production and reduced economic value.

Overall, the results demonstrate the value of combining well-log correlation, lithological interpretation, and quantitative petrophysical analysis for reservoir appraisal. The D1 reservoir sands in the OKW Field are laterally persistent and generally of high rock quality, but hydrocarbon prospectivity is controlled primarily by the distribution of fluids within the reservoir. The study therefore highlights the need to evaluate reservoir quality and pay potential jointly, rather than relying on porosity and permeability alone. Further integration of core data, pressure information, fluid samples, and seismic interpretation would help validate the log-derived results and improve understanding of reservoir connectivity, compartmentalization, and development potential.

6.0 Conclusion

This study has demonstrated the effectiveness of well log correlation and petrophysical interpretation in characterizing D1 reservoir sands in the OKW Field, offshore southeastern Niger Delta. The D1 interval is laterally continuous across the investigated wells, but reservoir quality varies significantly due to differences in shale content, porosity, permeability, and fluid saturation.

OKW 10 is the most promising reservoir in the dataset, with high net thickness, low shale content, excellent effective porosity, high permeability, low water saturation, and strong hydrocarbon saturation. OKW 1 is also a strong hydrocarbon-bearing interval, while OKW 7 is more water-bearing despite its good rock framework.

The study confirms that careful integration of gamma-ray correlation and quantitative petrophysical estimation can provide a reliable basis for reservoir appraisal in data-limited settings. The results support the view that the OKW Field contains productive sandstone reservoirs within the D1 section of the Agbada Formation. However, the findings should be further validated with core data, fluid analysis, and pressure information to improve confidence in the final reservoir model.

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