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Integrated Petrophysical Evaluation of Reservoir Quality and Hydrocarbon Potential Using Thickness-Weighted Metric from Well Logs from the Niger Delta

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Integrated Petrophysical Evaluation of Reservoir Quality and Hydrocarbon Potential Using Thickness-Weighted Metric from Well Logs from the Niger Delta.

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Abstract

Evaluating reservoir quality and hydrocarbon potential in complex deltaic systems continues to pose significant challenges for petroleum geoscientists, especially when dealing with unconventional and marginal reservoirs. Our research focuses on a detailed petrophysical analysis of two wells from the Niger Delta Basin. We combined standard log-derived parameters with thickness-weighted metrics specifically porosity thickness (Φ·H) and oil-filled porosity thickness (ΦSo·H) extracted directly from LAS well log data. We systematically analyzed gamma ray, resistivity, neutron porosity, and density logs to map lithology, pinpoint reservoir zones, and calculate key parameters including porosity (Φ), water saturation (Sw), shale volume (Vcl), and net-to-gross ratio (N/G). Based on our lithological and petrophysical analysis, we identified five distinct reservoir zones in each well. Our findings show that Zones 1, 3, and 5 across both wells display excellent reservoir properties. Porosity values range from 24.8% to 40.3%, water saturation

drops as low as 5.5%, and N/G ratios consistently exceed 0.6. These zones also show remarkably high Φ·H values (reaching 43.81 ft) and ΦSo·H values (up to 41.39 ft), suggesting substantial pore volume and hydrocarbon storage potential. In stark contrast, Zones 2 and 4 show poor reservoir characteristics with low N/G ratios (<0.02), high water saturation (>44%), and virtually negligible thickness-weighted metrics, making them unsuitable prospects. Our work proves that thickness-weighted metrics deliver a more reliable and physically meaningful assessment of reservoir performance than traditional parameters used in isolation. By incorporating Φ·H and ΦSo·H, we've developed a scalable, quantitative approach for ranking reservoirs and estimating hydrocarbons in challenging deltaic settings.

Keywords: Petrophysical evaluation; Thickness-weighted metrics; LAS well logs; Hydrocarbon pore volume; Reservoir characterization; Niger Delta.

Introduction

The accurate characterization of subsurface reservoirs is fundamental to hydrocarbon exploration and production (Volokitin & Khabarov, 2010). In mature hydrocarbon provinces such as the Niger Delta, the increasing complexity of reservoir architecture necessitates the adoption of advanced petrophysical techniques capable of capturing both vertical and lateral heterogeneity (Deabl et al., 2021). Traditional reservoir evaluation methods rely heavily on parameters such as porosity, permeability, and fluid saturation; however, these parameters, when considered independently, often fail to adequately represent the integrated storage and flow capacity of the reservoir system (Sharif, 2024).

The challenge is particularly pronounced in deltaic systems, where rapid facies transitions, interbedding of sands and shales, and structural compartmentalization introduce significant variability in reservoir properties over short spatial scales (Chukwuemeka et al., 2025). As highlighted in previous studies, the Niger Delta Basin is characterized by stacked sedimentary sequences formed through progradational processes, resulting in complex stratigraphic and structural traps that control hydrocarbon accumulation (Kuye & Hampson, 2023).

Fluid saturation, particularly the ratio of hydrocarbons to water within the pore spaces, is another critical factor in petrophysical evaluation (Omoja et al., 2026). However, unconventional reservoirs often exhibit mixed wettability, where both oil and water are present, complicating the use of conventional resistivity logs to estimate fluid saturation accurately (Knackstedt et al., 2013). In such cases, advanced techniques like nuclear magnetic resonance (NMR) logging or dielectric logging may be employed to improve the accuracy of saturation estimates (Herlinger, 2019; Bassey, 2015).

Despite advancements in petrophysical techniques, several challenges remain in the evaluation of unconventional reservoirs (Sarhan, 2025). One of the primary challenges is the accurate measurement of porosity and permeability in tight formations (Shabani et al., 2022; Osman et al., 2025). The presence of micro-porosity, combined with the low permeability of the reservoir rock, makes it difficult to obtain representative measurements using traditional well logging tools (Ejaita & Omonefe, 2026). Core analysis, while more accurate, is time-consuming and expensive, and may not always be feasible for large-scale reservoir studies (Zhang et al., 2020).

Another challenge is the accurate determination of fluid saturation in unconventional reservoirs (Nabawy, 2025). Mixed wettability, where both oil and water are present in the pore spaces, can complicate the interpretation of resistivity logs (Sneider et al., 1978). Advanced techniques such as NMR or dielectric logging can improve the accuracy of saturation measurements, but these methods are also more expensive and require specialized expertise (Nikolaev & Kazak, 2019).

To address these limitations, this study adopts thickness-weighted petrophysical metrics specifically porosity-thickness ($\Phi \cdot H$) and oil-filled porosity-thickness ($\Phi So \cdot H$) as primary indicators of reservoir quality and hydrocarbon potential. These parameters integrate rock and fluid properties across reservoir intervals, thereby providing a more physically meaningful representation of storage capacity and producibility.

Geological Setting

Figure 1 shows a small portion of the Niger Delta Basin where Wells 01 and 02 are located. Both wells sit in a highly productive area that's famous for its substantial hydrocarbon reserves. The grid system on the map helps show exactly where these wells are positioned, which makes it easier to plan subsurface exploration and assessment work. Beyond being crucial to Nigeria's energy

industry, the Niger Delta ranks among the world's largest deltas. It was created over time as sediment from the Niger River accumulated where it flows into the Atlantic Ocean. This massive delta covers roughly 75,000 square kilometers, and in certain locations, the sediment layers can be as thick as 12 km (Sneider et al., 1978).

The lithology of the Niger Delta is characterized by a complex arrangement of sandstones, shales, and siltstones deposited in varying depositional environments, which include fluvial, deltaic, and marine settings (Figure 2) (Momta et al., 2015). The lithological sequence is stratified into three primary formations that define the geological architecture of the Niger Delta Basin:

The Benin Formation is the uppermost layer and is composed of continental deposits from fluvial processes (Olabode & Mohammed, 2016). It primarily consists of unconsolidated sandstones interbedded with clay, representing a depositional environment dominated by rivers and floodplains. The Benin Formation ranges from the Oligocene to the present day and extends to depths of approximately 2000 meters (Reijers, 2011). Its sands are often non-hydrocarbon-bearing, but they provide structural support for the overlying formations (Olabode, 2006).

The Agbada Formation is the primary reservoir-bearing unit of the Niger Delta. It consists of an alternating sequence of sandstones and shales, deposited in deltaic and shallow marine environments (Overare et al., 2024; Plumley, 1992). The sandstones in the Agbada Formation serve as the primary hydrocarbon reservoirs, while the shales function as both source and cap rocks, trapping hydrocarbons within the formation (Reijers, 2011). This formation’s thickness can exceed 3,500 meters, and it is the most economically significant due to its oil and gas-bearing zones. The Agbada Formation dates from the Eocene to the present, reflecting millions of years of sedimentation driven by the Niger River (Reijers et al., 1997).

The Akata Formation is the deepest lithological unit of the Niger Delta and is composed primarily of marine shales. These shales were deposited in deep marine settings during the early stages of the delta’s formation and are thought to act as the main hydrocarbon source rock for the overlying reservoirs (Haack et al., 2000). The Akata Formation ranges from the Paleocene to the present and can reach thicknesses of more than 6,000 meters in some areas. Its organic-rich shales were deposited during periods of low oxygen levels in marine waters, leading to the preservation of organic matter essential for hydrocarbon generation (Reijers et al., 1997).

The Niger Delta is an archetypal example of a wave-dominated deltaic system, where sediment deposition is influenced by fluvial input, wave action, and longshore currents (Omonefe et al., 2020). The Niger River, one of Africa's largest, has been the primary agent of sediment transport, depositing vast amounts of detritus that have accumulated in the delta over millions of years. These depositional processes have created a diverse array of environments, each contributing to the region's complex stratigraphy and petroleum system (Ejaita & Omonefe, 2026).

The delta is dissected by a complex network of distributary channels, forming classic fluvial-deltaic systems. These systems deposit coarse-grained sandstones in proximal regions, gradually transitioning to finer sediments such as shales and siltstones toward the distal portions of the delta. These fluvial deposits form the core of the reservoir rock within the Agbada Formation (Huang et al., 2025). During periods of low sea level, the river's energy deposited larger, coarser sediments, while higher sea levels allowed for more fine-grained deposition (Kiss et al., 2022).

The distal portions of the Niger Delta extend offshore into the shallow marine environment, where finer sediments, such as silts and clays, are deposited by longshore currents and tidal processes. The transition from deltaic to marine deposition is reflected in the lithology of the Agbada and Akata Formations, with alternating layers of sandstone and shale indicating fluctuating sea levels and changing depositional environments (Allen, 1970). These transitions are key in understanding the vertical and lateral facies changes within the reservoir (Ezeh et al., 2016).

Over geologic time, the Niger Delta has grown seaward through a process called progradation, where sediments build outward from the continent toward the ocean. This process has created a stacked sequence of sedimentary deposits, with older layers buried beneath younger sediments (Konyukhov, 2008). Each depositional cycle represents a phase of delta growth, influenced by factors such as sea-level change, sediment supply, and tectonic activity. These progradational sequences are responsible for the multi-layered hydrocarbon reservoirs found in the Niger Delta (Bello et al., 2026).

The formation of the Niger Delta is intricately linked to the tectonic evolution of the West African margin. The development of the delta began in the late Cretaceous and has continued through to the present, driven by the interplay of tectonics, sediment supply, and sea-level changes (Bonne, 2014):

The Niger Delta Basin formed as part of a passive continental margin following the separation of the African and South American plates during the early Cretaceous (Stoneley, 1966). As the Atlantic Ocean opened, the crust along the West African margin began to subside, creating accommodation space for sediment deposition. This subsidence, combined with sediment influx from the Niger River, facilitated the accumulation of thick sedimentary sequences (Doust & Omatsola, 1989).

The Niger River, along with its numerous tributaries, has been the primary source of sediment for the delta (Spina et al., 2025). Over millions of years, the river has transported vast amounts of sediment from the interior of the African continent to the deltaic plain. The fluvial processes associated with the river have built the delta outward, creating a range of depositional environments from terrestrial to deep marine. As the delta has evolved, sediment supply has varied, influencing the size and nature of the deposits in different parts of the basin (Allen, 1970).

The organic-rich shales of the Akata Formation, buried deep within the delta, were subjected to high temperatures and pressures over millions of years, converting the organic matter into hydrocarbons. These hydrocarbons then migrated upward through porous rock formations into the sandstones of the Agbada Formation, where they became trapped by impermeable shale layers. This process created the complex petroleum system of the Niger Delta, which includes source rocks, reservoir rocks, and trapping mechanisms (Olatunji, 2023).

The Niger Delta is a world-class hydrocarbon province with complex geological and depositional features. Its lithology, dominated by the Benin, Agbada, and Akata Formations, represents a range of depositional environments from fluvial-deltaic to deep marine (Deigh, 2024). The ongoing tectonic activity, sediment supply, and subsidence have driven the evolution of the delta, making it a key region for oil and gas exploration. The wells located in the study area aim to tap into these hydrocarbon-rich formations, contributing to Nigeria’s continued role as a major oil-producing nation delta (Spina et al., 2025).

Theoretical Review

Understanding petrophysical properties through well log analysis forms the backbone of effective reservoir characterization (Omoja et al., 2026). When we examine properties like porosity, water saturation, and net-to-gross ratios, we're essentially looking at how good the reservoir rock is - can

it hold hydrocarbons? Will it produce well? These properties tell us everything we need to know about storage capacity and production potential. This review digs into the fundamental theory behind these crucial petrophysical concepts and walks through their calculations, complete with the relevant formulas.

Take porosity, for example. It's simply a way to measure all those empty spaces within rock - we calculate it as the ratio between pore volume and total volume. For reservoir engineers, porosity is absolutely essential because it directly tells us how much fluid the rock can actually hold, whether that's water, oil, or gas. Porosity is derived from well logs such as Neutron Porosity (NPHI) and Bulk Density logs (Asquith et al., 2004).

$$\Phi = \frac{V_p}{V_t} \quad (1)$$

Where:

(Φ) = Porosity (fraction or percentage)

(V_p) = Volume of pores (voids)

(V_t) = Total volume of the rock

For density log-derived porosity (Φ_d)

$$\Phi_d = \frac{\rho_m - \rho_b}{\rho_m - \rho_f} \quad (2)$$

Where:

(ρ_m) = Matrix density (g/cc) (typically around 2.65 g/cc for sandstone)

(ρ_b) = Bulk density from the log (g/cc)

(ρ_f) = Fluid density (g/cc) (typically around 1.0 g/cc for water)

Water saturation is the fraction of the pore space that is occupied by water. It is a critical parameter for determining the amount of hydrocarbons present in a reservoir (Sam-Marcus et al., 2018). Water saturation is usually estimated using resistivity logs and the Archie equation.

$$S_w^n = \frac{a \cdot R_w}{\phi^m \cdot R_t} \quad (3)$$

Where:

- (S_w) = Water saturation (fraction or percentage)

- (R_w) = Formation water resistivity (ohm-m)

- (R_t) = True resistivity of the formation (ohm-m) from the resistivity log

- (ϕ) = Porosity (fraction)

- (a) = Tortuosity factor (typically assumed as 1)

- (m) = Cementation exponent (usually between 1.8 and 2)

- (n) = Saturation exponent (typically assumed as 2)

The Archie equation assumes a clean (non-shaly) formation. For shaly formations, corrections like the Simandoux or Dual Water models are often used to account for the additional conductivity due to the clay content (Ibrahim et al., 2022).

The net-to-gross ratio is the fraction of the total interval that consists of reservoir-quality rock. It is a measure of the proportion of the zone that can effectively contribute to fluid flow (Egbele et al., 2005). This ratio is particularly useful in formations where the reservoir rock is interbedded with non-reservoir rock, such as shale.

$$\frac{\text{Net Thickness}}{\text{Gross Thickness}} = \frac{\text{Reservoir Quality Thickness}}{\text{Total Thickness of the Zone}} \quad (4)$$

Net-to-gross ratio (N/G) is dimensionless and typically ranges from 0 to 1. Higher values indicate better reservoir quality (Asquith et al., 2004).

The volume of clay is an important parameter, particularly in shaly formations, as it affects the reservoir's ability to store and transmit fluids. The Gamma Ray (GR) log is often used to estimate the volume of clay in the formation (El-Sawy et al., 2026).

$$V_{cl} = 0.33 \times \left(2^{3.7 \cdot \left(\frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}\right)} - 1\right) \quad (5)$$

Where:

- (GR_{log}) = Gamma Ray log reading in the zone of interest

- (GR_{min}) = Minimum Gamma Ray reading (clean sand baseline)

- (GR_{max}) = Maximum Gamma Ray reading (shale baseline)

Hydrocarbon pore-volume are measures of the volume of hydrocarbons in the reservoir. It is calculated by multiplying porosity ((Φ)), oil saturation ($(S_o = 1 - S_w)$), and net thickness (Ahmed et al., 2019).

$$\Phi S_o H = \Phi \cdot (1 - S_w) \cdot H \quad (6)$$

Where:

- (Φ) = Porosity (fraction)

- (S_o) = Oil saturation (fraction)

- (H) = Net thickness (ft or m)

Hydrocarbon pore-volume provides an indication of the hydrocarbon storage capacity of a reservoir (El-Sawy et al., 2026).

The porosity-height product is used to quantify the storage capacity of the reservoir. It is the product of the average porosity and the net thickness (Anovitz & Cole, 2015).

$$\Phi H = \Phi \cdot H \quad (7)$$

Where:

- (Φ) = Average porosity of the zone

- (H) = Net thickness

This product is important for volumetric calculations and assessing the overall hydrocarbon potential of the reservoir.

Water cut is the fraction of water in the total produced fluids from the reservoir, while oil cut is the fraction of oil in the produced fluids. These are important production parameters in evaluating the performance of the reservoir (Kamal et al., 2023).

$$WC = \frac{Q_w}{Q_o + Q_w} \quad (8)$$

Where:

- (Q_w) = Water production rate

- (Q_o) = Oil production rate

$$OC = 1 - WC \quad (9)$$

The resistivity index is used to quantify the increase in resistivity due to the presence of hydrocarbons in the pore space (Jahanpanah & Tavakoli, 2026).

$$I_r = \frac{R_t}{R_0} \quad (10)$$

Where:

- (R_t) = True formation resistivity

- (R_0) = Formation resistivity when fully saturated with water

This ratio is used to determine the hydrocarbon saturation when applied with Archie's equation.

The petrophysical analysis of reservoir rocks involves the use of well logs such as Gamma Ray, Resistivity, Neutron Porosity, and Bulk Density logs to calculate key parameters like porosity, water saturation, and net-to-gross ratio (Senosy et al., 2020). These parameters are fundamental in evaluating the reservoir's storage and production potential, with each property governed by well-established theoretical formulas (Omoja et al., 2026). The application of these formulas allows for a comprehensive interpretation of the reservoir characteristics, enabling geoscientists and engineers to assess the feasibility and profitability of hydrocarbon extraction.

Materials and Methods

Data and Software

This study employed conventional well log datasets from two wells, hereafter referred to as Well 1 and Well 2, located within the Niger Delta Basin. The available datasets (Table 1) comprised well header information, well deviation data, and digital wireline logs. The well headers provided essential metadata, including well name, reference datum, total drilled depth, and spatial location. Deviation data, where available, contained measured depth, inclination, and azimuth information required for trajectory assessment and depth correction.

Petrophysical interpretation was performed using Interactive Petrophysics v3.4, a standard well log analysis software used for log editing, reservoir zonation, lithological interpretation, cross-plotting, and petrophysical parameter estimation. The input logs were supplied in ASCII format and included gamma ray, deep resistivity, bulk density, neutron porosity, and sonic logs. Log depths were recorded in feet, gamma ray values in API/GAPI, resistivity in ohm-m, bulk density in g/cm³, and neutron porosity in fractional units (Figure 3a and b).

The integrated log suite was used for reservoir identification, lithological discrimination, fluid typing, porosity estimation, shale volume calculation, water saturation estimation, net-to-gross evaluation, and thickness-weighted reservoir ranking.

Log Quality Control and Data Preparation

Prior to interpretation, the digital logs were imported into Interactive Petrophysics and inspected for completeness, depth consistency, curve availability, and anomalous readings. The log curves were checked visually to identify missing intervals, spurious spikes, unrealistic values, and depth mismatch between curves. Where necessary, minor log editing and curve conditioning were carried out to improve interpretability while preserving the original character of the dataset.

The wells were analysed using measured depth as the primary depth reference. For Well 2, where deviation data were available, the deviation survey supported the assessment of well trajectory and depth positioning. For Well 1, where deviation data were not available, interpretation was based on the supplied depth-referenced logs. All reservoir zones were identified consistently across the available log intervals using gamma ray, resistivity, density, and neutron responses.

Lithological Identification and Reservoir Zonation

Lithological discrimination was primarily based on the gamma ray log because gamma ray response is sensitive to shale content. Intervals with low gamma ray readings were interpreted as cleaner sand-dominated units, whereas intervals with high gamma ray readings were interpreted as shale-rich units. Sand and shale baseline values were established separately for each well to account for local log response variation.

For Well 1, the clean sand baseline was defined at approximately 22 API, while the shale baseline was defined at approximately 90 API. For Well 2, the clean sand baseline was defined at approximately 25 API, while the shale baseline was defined at approximately 100 API. A gamma

ray cut-off was then applied between the clean sand and shale baselines to separate reservoir-quality sand intervals from shale-dominated intervals.

Reservoir zones were selected where the gamma ray response indicated sand-rich intervals and where the resistivity and porosity logs supported potential hydrocarbon-bearing conditions. Five reservoir zones were identified in each well. The gross thickness of each zone was defined from the top and base of the selected interval, while net sand thickness was determined from the cumulative thickness of intervals satisfying the clean sand and reservoir-quality criteria.

Shale Volume Estimation

The volume of shale was estimated from the gamma ray log using the gamma ray index method. This approach normalizes the gamma ray response between the clean sand and shale baselines established for each well. The gamma ray index was calculated as:

$$\left[I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}\right] \quad (11)$$

where $(I_{GR})$is the gamma ray index, $\left(GR_{log}\right)$ is the gamma ray reading at a given depth, (GR_{min}) is the clean sand gamma ray baseline, and (GR_{max}) is the shale gamma ray baseline.

For this study, the gamma ray index was used as an approximation of shale volume:

$$[V_{sh} = I_{GR}] \quad (12)$$

where (V_{sh}) is the estimated shale volume. Intervals with lower(V_{sh}) values were interpreted as cleaner reservoir sands, whereas higher (V_{sh}) values indicated increased shale content and poorer reservoir quality.

Porosity Estimation

Porosity was estimated using density and neutron porosity logs. The density-derived porosity was calculated from the bulk density log using:

$$\left[\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}\right] \quad (13)$$

where (ϕ_D) is density porosity, (ρ_{ma}) is matrix density, (ρ_b) is bulk density from the log, and $\left(\rho_f\right)$ is fluid density.

The neutron porosity log provided an independent porosity estimate. To improve reliability, density and neutron porosity responses were compared across each reservoir interval. Where both curves showed consistent behaviour, an average effective porosity was computed as:

$$\left[\phi = \frac{\phi_D + \phi_N}{2}\right] \quad (14)$$

where (ϕ) is the average porosity and (ϕ_N) is neutron porosity. This combined porosity estimate was used for subsequent saturation and thickness-weighted calculations.

Fluid Identification and Hydrocarbon Discrimination

Fluid identification was performed by integrating deep resistivity, density, and neutron porosity responses. Intervals with low gamma ray, favourable porosity, and elevated deep resistivity were interpreted as potential hydrocarbon-bearing reservoirs. Water-bearing zones generally exhibit lower resistivity because formation water is conductive, whereas hydrocarbon-bearing intervals typically show higher resistivity due to the non-conductive nature of hydrocarbons.

Neutron-density log separation was used to support fluid discrimination. Large separation between neutron and density porosity curves may indicate gas effects, whereas smaller separation within high-resistivity sand intervals may suggest oil-bearing reservoirs. This interpretation was used qualitatively to support hydrocarbon identification prior to quantitative saturation estimation.

Water Saturation and Hydrocarbon Saturation Estimation

Water saturation was estimated using Archie's equation, which is commonly applied to clean sandstone reservoirs:

$$\left[S_w = \left(\frac{aR_w}{\phi^m R_t}\right)^{1/n}\right] \quad (15)$$

where (S_w) is water saturation, (a) is the tortuosity factor, (R_w) is formation water resistivity, (ϕ) is porosity, (m) is the cementation exponent, (R_t) is true formation resistivity, and (n) is the saturation exponent.

Hydrocarbon saturation was then calculated as:

$$[S_h = 1 - S_w] \quad (16)$$

For oil-bearing intervals, oil saturation was expressed as:

$$[S_o = 1 - S_w] \quad (17)$$

where (S_o) is oil saturation. These saturation values were computed for each reservoir zone and used to estimate the hydrocarbon-bearing pore volume.

3.8 Net-to-Gross Ratio Estimation

The net-to-gross ratio was calculated to evaluate the proportion of reservoir-quality sand within each gross reservoir interval. Net thickness was defined as the cumulative thickness of clean, porous, and potentially hydrocarbon-bearing sand. Gross thickness was defined as the total thickness between the top and base of each reservoir zone.

The net-to-gross ratio was calculated as:

$$\left[N/G = \frac{H_{net}}{H_{gross}}\right] \quad (18)$$

where (N/G) is the net-to-gross ratio, (H_{net}) is net reservoir thickness, and $\left(H_{gross}\right)$ is gross reservoir thickness. Higher net-to-gross values indicate better reservoir development and greater sand dominance, whereas lower values indicate shale-prone or non-reservoir intervals.

Thickness-Weighted Reservoir Quality Metrics

The main analytical contribution of this study is the use of thickness-weighted petrophysical metrics to rank reservoir quality and hydrocarbon potential. Two metrics were computed for each reservoir zone: porosity–thickness and oil-filled porosity–thickness.

Porosity–thickness was calculated as:

$$[\phi \cdot H = \phi \times H_{net}] \quad (19)$$

where $(\phi \cdot H)$ represents the total pore-volume indicator, (ϕ) is average porosity, and (H_{net}) is net reservoir thickness.

Oil-filled porosity–thickness was calculated as:

$$[\phi S_o \cdot H = \phi \times S_o \times H_{net}] \quad (20)$$

where $(\phi S_o \cdot H)$ represents the oil-filled pore-volume indicator, (ϕ) is average porosity, (S_o) is oil saturation, and (H_{net}) is net reservoir thickness.

These metrics were calculated for each identified reservoir zone in both wells. The $(\phi \cdot H)$ metric was used to evaluate total reservoir storage capacity, while $(\phi S_o \cdot H)$ was used to evaluate hydrocarbon-bearing storage capacity. Zones with high porosity, high net thickness, low water saturation, and high net-to-gross ratio were ranked as the most prospective reservoir intervals.

Reservoir Ranking Workflow

Reservoir zones were ranked using an integrated petrophysical workflow. First, gamma ray logs were used to identify sand-prone intervals and define reservoir zones. Second, porosity was estimated from density and neutron logs. Third, deep resistivity logs were used to support fluid identification and water saturation estimation. Fourth, net thickness and net-to-gross ratio were calculated for each zone. Finally, the thickness-weighted metrics $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ were computed and used to compare reservoir performance between zones and wells.

Reservoir intervals with high $(\phi \cdot H)$ and high $(\phi S_o \cdot H)$ values were interpreted as having better reservoir quality and stronger hydrocarbon potential. Conversely, intervals with low net-to-gross ratio, high water saturation, and negligible thickness-weighted values were classified as poor or non-prospective reservoir zones.

Results and Discussion

Lithostratigraphic Correlation

The lithostratigraphic correlation of the two wells provides insight into the vertical and lateral distribution of the subsurface units within the study area. The correlation panel presented in Figure 4 shows broadly consistent lithological units across the wells, indicating lateral continuity of the main stratigraphic intervals. The deeper intervals are characterised by progressively thicker shale units, which may reflect a transition towards more shale-dominated successions associated with the deeper parts of the Niger Delta stratigraphy.

Five reservoir zones were identified across the wells based on the integrated interpretation of gamma ray, resistivity, density, and neutron porosity logs. These zones were further evaluated using conventional petrophysical parameters and thickness-weighted metrics to determine their reservoir quality and hydrocarbon potential.

Petrophysical Evaluation of Well 1

The petrophysical results for Well 1 are presented in Table 2 and Figure 5. Five reservoir zones were identified between 8776 ft and 9452 ft. The zones were evaluated using gross thickness, net thickness, net-to-gross ratio, average porosity, average water saturation, average clay volume, porosity–thickness $(\phi \cdot H)$, oil-filled porosity–thickness $(\phi S_o \cdot H)$, and clay-volume–thickness $(V_{cl} \cdot H)$.

Zone 1: 8776–8965 ft

Zone 1 has a gross thickness of 189 ft and a net thickness of 108.5 ft, giving a net-to-gross ratio of 0.574. This indicates that more than half of the interval consists of reservoir-quality sand. The average porosity is 24.8%, suggesting good storage capacity, while the average water saturation of 28.9% indicates moderate hydrocarbon saturation. The average clay volume of 20.1% suggests some shale influence, which may affect permeability. However, the high $(\phi \cdot H)$ value of 26.87 and $(\phi S_o \cdot H)$ value of 19.09 confirm that this zone has good pore-volume capacity and significant hydrocarbon potential.

Zone 2: 8965–9084 ft

Zone 2 has a gross thickness of 119 ft but only 2 ft of net reservoir thickness, resulting in a very low net-to-gross ratio of 0.017. Although the average porosity is 18.0%, the high water saturation of 46.5% and very low net thickness significantly reduce its reservoir potential. The $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values are 0.36 and 0.19, respectively, indicating negligible hydrocarbon storage capacity. This zone is therefore interpreted as non-prospective.

Zone 3: 9084–9154 ft

Zone 3 displays favourable reservoir characteristics, with a net-to-gross ratio of 0.743 and a net thickness of 52 ft within a gross interval of 70 ft. The average porosity is 26.9%, while the water saturation is very low at 6.8%, indicating high hydrocarbon saturation. The average clay volume

of 12.6% is relatively moderate and does not significantly reduce the reservoir quality. The $(\phi \cdot H)$ value of 13.99 and $(\phi S_o \cdot H)$ value of 13.04 confirm that this zone has strong hydrocarbon-bearing capacity. Zone 3 is therefore one of the most prospective intervals in Well 1.

Zone 4: 9154–9360 ft

Zone 4 has the poorest reservoir quality in Well 1. Although the gross interval is 206 ft thick, the net reservoir thickness is only 0.5 ft, giving an extremely low net-to-gross ratio of 0.002. The average porosity is 16.7%, and the water saturation is high at 46.6%. The very low $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values of 0.08 and 0.04, respectively, indicate negligible reservoir storage and hydrocarbon capacity. This interval is therefore classified as non-reservoir or non-prospective.

Zone 5: 9360–9452 ft

Zone 5 shows good reservoir potential, with a gross thickness of 92 ft and a net thickness of 59.5 ft, corresponding to a net-to-gross ratio of 0.647. The average porosity is 26.8%, indicating good pore-volume capacity. The average water saturation of 28.1% suggests moderate hydrocarbon saturation, while the average clay volume of 12.6% indicates relatively clean reservoir conditions. The $(\phi \cdot H)$ value of 15.93 and $(\phi S_o \cdot H)$ value of 11.45 support the interpretation of Zone 5 as a productive hydrocarbon-bearing interval.

Zones 1, 3, and 5 represent the most favourable reservoir intervals in Well 1. Zones 2 and 4 show poor reservoir potential due to low net thickness, low net-to-gross ratios, and high water saturation.

Petrophysical Evaluation of Well 2

The petrophysical results for Well 2 are presented in Table 3 and Figure 6. Five reservoir zones were identified between 7300 ft and 8580 ft. Compared with Well 1, Well 2 generally shows higher porosity values and stronger thickness-weighted hydrocarbon indicators, particularly in Zones 3 and 5.

Zone 1: 7300–7400 ft

Zone 1 has a gross thickness of 100 ft and a net thickness of 48 ft, resulting in a net-to-gross ratio of 0.480. The average porosity is high at 40.3%, suggesting excellent pore-volume capacity. The low water saturation of 10.0% indicates strong hydrocarbon saturation, while the clay volume of 10.5% suggests relatively clean reservoir conditions. The $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values of 19.34 and 17.40, respectively, indicate significant hydrocarbon storage potential.

Zone 2: 7400–7723.5 ft

Zone 2 has a gross thickness of 323.5 ft but a net thickness of only 6 ft, giving a net-to-gross ratio of 0.019. Although the average porosity is high at 41.8%, the very limited net thickness substantially reduces its reservoir significance. The average water saturation of 25.3% is moderate, but the low $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values of 2.51 and 1.88, respectively, indicate limited

Zone 3: 7723.5–7821.5 ft

Zone 3 is one of the best reservoir intervals in Well 2. It has a gross thickness of 98 ft and a net thickness of 91.5 ft, producing a very high net-to-gross ratio of 0.934. The average porosity is 36.7%, indicating excellent storage capacity, while the low water saturation of 12.2% suggests strong hydrocarbon saturation. Although the clay volume is 18.4%, the high net thickness and high porosity compensate for the shale content. The $(\phi \cdot H)$ value of 33.62 and $(\phi S_o \cdot H)$ value of 29.51 confirm that Zone 3 has very strong hydrocarbon potential.

Zone 4: 7821.5–8459.5 ft

Zone 4 has a very large gross thickness of 638 ft but only 6.25 ft of net reservoir thickness, resulting in a very low net-to-gross ratio of 0.010. Although the average porosity is high at 42.9%, the water saturation is also high at 44.5%, and the effective reservoir thickness is very limited. The low $(\phi \cdot H)$ value of 2.68 and $(\phi S_o \cdot H)$ value of 1.49 indicate poor hydrocarbon storage capacity. This zone is therefore interpreted as non-prospective.

Zone 5: 8459.5–8580 ft

Zone 5 is the most prospective interval in Well 2. It has a gross thickness of 120.5 ft and a net thickness of 111.25 ft, giving a high net-to-gross ratio of 0.923. The average porosity is 39.4%, indicating excellent reservoir storage capacity, while the very low water saturation of 5.5% indicates strong hydrocarbon saturation. The average clay volume of 12.5% suggests manageable shale content. The $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values of 43.81 and 41.39, respectively, are the highest among all evaluated zones, confirming Zone 5 as the most favourable hydrocarbon-bearing interval in the study.

For well 01, the bar chart shows that Zones 3 and 5 appear to be the most promising for hydrocarbon extraction, given their high N/G ratios, moderate porosity, low water saturation, and low clay content. Zones 2 and 4, on the other hand, present less favorable conditions due to their low N/G ratios and high water saturation levels (Figure 7).

Zones 3 and 5 appear to be the most promising for hydrocarbon extraction in Well 02, given their high N/G ratios and moderate porosity. However, the high water saturation in these zones may pose a challenge. Zone 2, despite having a low N/G ratio, exhibits high porosity and moderate water saturation, making it a potentially interesting zone for further investigation. Zone 4, with its low N/G ratio, high water saturation, and very low porosity, appears the least favorable for hydrocarbon extraction (Figure 8).

5. Comparative Reservoir Ranking

The comparative evaluation of both wells shows that reservoir quality is controlled not only by porosity but also by net thickness, water saturation, and net-to-gross ratio. In Well 1, Zones 1, 3, and 5 exhibit the best reservoir characteristics, with Zone 1 having the highest $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values. Zone 3, although thinner than Zone 1, has very low water saturation and a high

net-to-gross ratio, making it highly prospective. Zone 5 also shows good hydrocarbon potential due to its favourable porosity, net thickness, and moderate water saturation.

In Well 2, Zones 3 and 5 clearly dominate the reservoir ranking. Zone 5 has the highest $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values in the entire study, indicating the greatest hydrocarbon-bearing storage capacity. Zone 3 also shows excellent reservoir quality due to its high net-to-gross ratio, high net thickness, and low water saturation. Zone 1 is also prospective, although its net-to-gross ratio and thickness-weighted values are lower than those of Zones 3 and 5.

Zones 2 and 4 in both wells are consistently poor reservoir intervals. Although some of these zones display moderate to high porosity, their very low net-to-gross ratios and limited net thickness result in weak $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ values. This demonstrates that porosity alone is not sufficient for reservoir evaluation. A zone may have high porosity but still possess poor reservoir potential if the effective net thickness is small or if water saturation is high.

6. Discussion of Thickness-Weighted Metrics

The results demonstrate the importance of thickness-weighted petrophysical metrics in reservoir evaluation. Conventional parameters such as porosity, water saturation, and clay volume provide useful information at the interval scale, but they do not fully capture the cumulative storage capacity of a reservoir. By integrating porosity, oil saturation, and net thickness, the $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ metrics provide a more realistic measure of reservoir quality and hydrocarbon potential. The $(\phi \cdot H)$ metric reflects the total pore-volume capacity of each reservoir zone, while $(\phi S_o \cdot H)$ provides a more direct indication of hydrocarbon-filled pore volume. This distinction is important because zones with high porosity may not necessarily contain significant hydrocarbons if water saturation is high or net thickness is low. For example, Zones 2 and 4 in Well 2 have high porosity

values but low ($\phi S_o \cdot H$) values due to their limited net thickness and relatively high water saturation.

The strongest hydrocarbon potential is observed in Well 2, particularly in Zones 3 and 5. These zones combine high porosity, high net-to-gross ratio, low water saturation, and large net thickness. In contrast, Well 1 shows more moderate reservoir development, with Zones 1, 3, and 5 representing the main prospective intervals. The results therefore suggest that Well 2 contains better-developed reservoir sands and stronger hydrocarbon-bearing capacity than Well 1.

The integrated interpretation confirms that thickness-weighted metrics improve reservoir ranking by combining both rock quality and fluid saturation with reservoir thickness. This provides a more robust basis for identifying productive zones and prioritising intervals for further development or detailed reservoir modelling.

7. Conclusion

This study quantitatively evaluated reservoir quality and hydrocarbon potential in two wells from the Niger Delta Basin using conventional petrophysical parameters and thickness-weighted metrics. A total of 10 reservoir zones were identified, comprising five zones in Well 1 and five zones in Well 2. The interpretation was based on net thickness, net-to-gross ratio, average porosity, water saturation, shale volume, porosity–thickness ($\phi \cdot H$), and oil-filled porosity-thickness ($\phi S_o \cdot H$).

In Well 1, Zones 1, 3, and 5 represent the main prospective intervals. Zone 1 recorded the highest pore-volume indicator in the well, with a net thickness of 108.5 ft, net-to-gross ratio of 0.574, average porosity of 24.8%, water saturation of 28.9%, ($\phi \cdot H$) of 26.87 ft, and ($\phi S_o \cdot H$) of 19.09 ft. Zone 3 also showed strong reservoir quality, with the highest net-to-gross ratio in Well 1 at 0.743, average porosity of 26.9%, very low water saturation of 6.8%, and ($\phi S_o \cdot H$) of 13.04 ft.

Zone 5 recorded a net-to-gross ratio of 0.647, average porosity of 26.8%, and $(\phi S_o \cdot H)$of 11.45 ft. In contrast, Zones 2 and 4 are poor reservoir intervals, with net-to-gross ratios of only 0.017 and 0.002, and very low $(\phi S_o \cdot H)$ values of 0.19 ft and 0.04 ft, respectively.

In Well 2, Zones 3 and 5 are the most productive reservoir intervals. Zone 5 is the best-performing zone in the entire study, with a net thickness of 111.25 ft, net-to-gross ratio of 0.923, average porosity of 39.4%, very low water saturation of 5.5%, $(\phi \cdot H)$ of 43.81 ft, and $(\phi S_o \cdot H)$ of 41.39 ft. Zone 3 also shows excellent reservoir potential, with a net thickness of 91.5 ft, net-to-gross ratio of 0.934, average porosity of 36.7%, water saturation of 12.2%,$(\phi \cdot H)$ of 33.62 ft, and $(\phi S_o \cdot H)$ of 29.51 ft. Zone 1 is also favourable, with average porosity of 40.3%, water saturation of 10.0%, and $(\phi S_o \cdot H)$ of 17.40 ft. Zones 2 and 4 are less prospective because their net-to-gross ratios are very low, at 0.019 and 0.010, despite having high porosity values above 41%.

Comparatively, Well 2 has better reservoir quality than Well 1. The highest oil-filled porosity–thickness value in Well 2 is 41.39 ft, compared with 19.09 ft in Well 1. This indicates that the best reservoir interval in Well 2 has more than twice the hydrocarbon-bearing pore-volume capacity of the best interval in Well 1. The results also show that high porosity alone does not guarantee good reservoir performance. For example, Zones 2 and 4 in Well 2 have high porosity values of 41.8% and 42.9%, respectively, but their low net thickness and low net-to-gross ratios reduce their hydrocarbon potential.

The quantitative ranking indicates that the most prospective intervals are Well 2 Zone 5, followed by Well 2 Zone 3, Well 1 Zone 1, Well 2 Zone 1, Well 1 Zone 3, and Well 1 Zone 5. The study confirms that $(\phi \cdot H)$ and $(\phi S_o \cdot H)$ provide stronger reservoir ranking indicators than porosity alone because they combine storage capacity, hydrocarbon saturation, and effective reservoir thickness. Therefore, Well 2 Zones 5 and 3 should be prioritised for further reservoir evaluation, production testing, and field development planning. This study introduces a quantitative,

thickness-integrated framework for reservoir evaluation, bridging classical petrophysics with modern data-driven analysis.

DECLARATIONS

Consent for Publication

All authors have read and approved the final version of the manuscript titled "Integrated Petrophysical Evaluation of Reservoir Quality and Hydrocarbon Potential Using Thickness-Weighted Metric from Well Logs from the Niger Delta" and consent to its publication. The authors confirm that the manuscript does not contain any individual person's data, images, or personal clinical information requiring additional consent for publication.

Competing Interests

The authors declare that they have no competing financial or non-financial interests that could have influenced the work reported in this manuscript.

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Availability of Data and Materials

The well log dataset used in this study was acquired from **Frandee Consulting Services, Yenagoa**, through authorized academic access. The data are not publicly available due to access and confidentiality restrictions. However, derived datasets generated during the present study, including processed well logs, interpreted reservoir zones, petrophysical results, tables, Figures, and images, are available from the corresponding author upon reasonable request.

Authors' Contributions

Dr. Francis Omonefe, conducted the petrophysical data processing and quantitative analysis, performed reservoir zonation, calculated the thickness-weighted metrics, interpreted the well log results, prepared the Figures and tables, and drafted the original manuscript.

Dr. Edeye Ejaita conceptualized the study, acquired the well log dataset, contributed to the geological and petrophysical interpretation, supported the structural and reservoir analysis, and reviewed and revised the manuscript.

Arekumo ThankGod assisted with data validation, software implementation, quality control of the well log interpretation, and verification of the petrophysical modelling outputs.

All authors reviewed, edited, and approved the final version of the manuscript.

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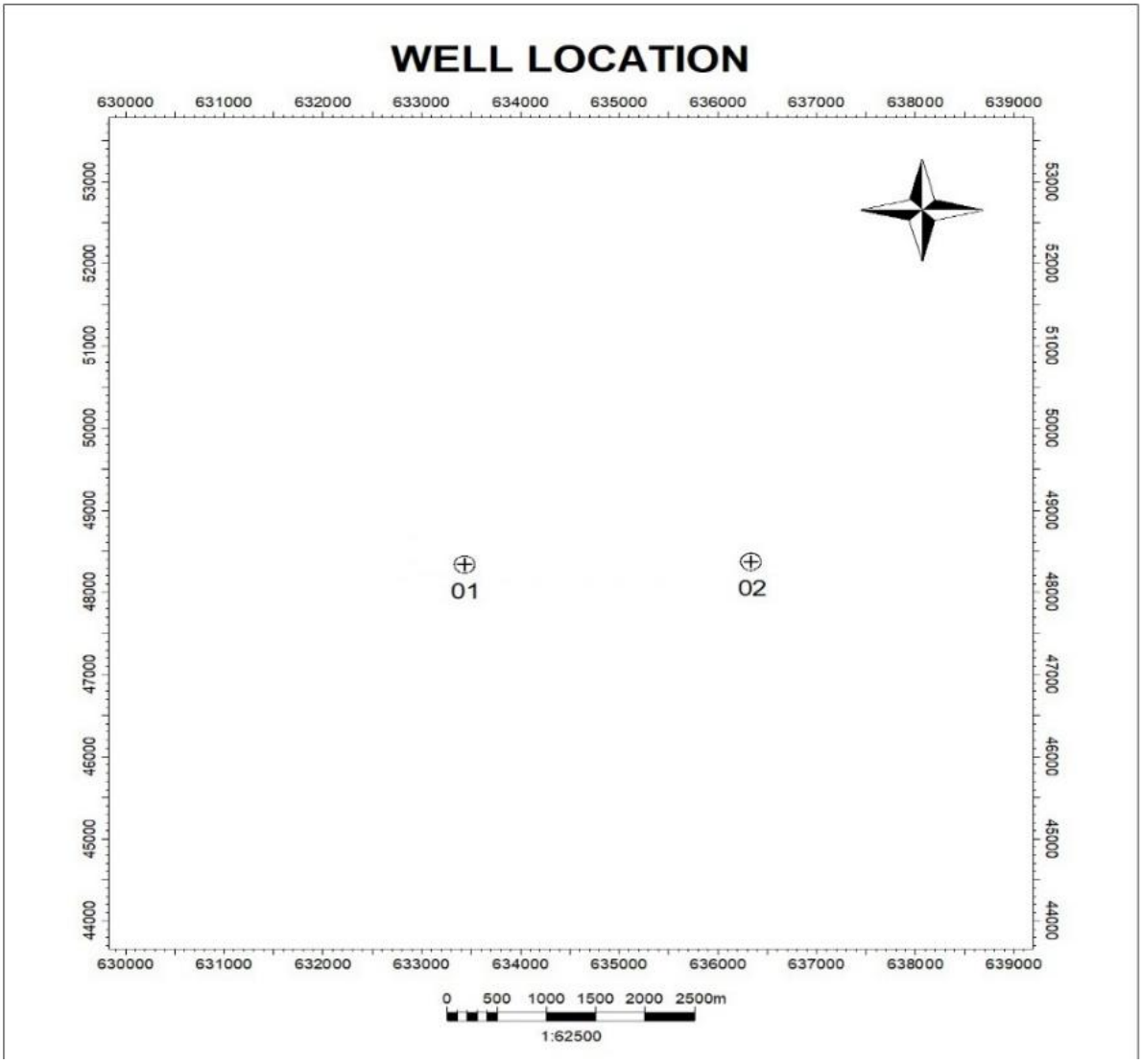
803 Figures



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805 Figure 1: Map of the field.

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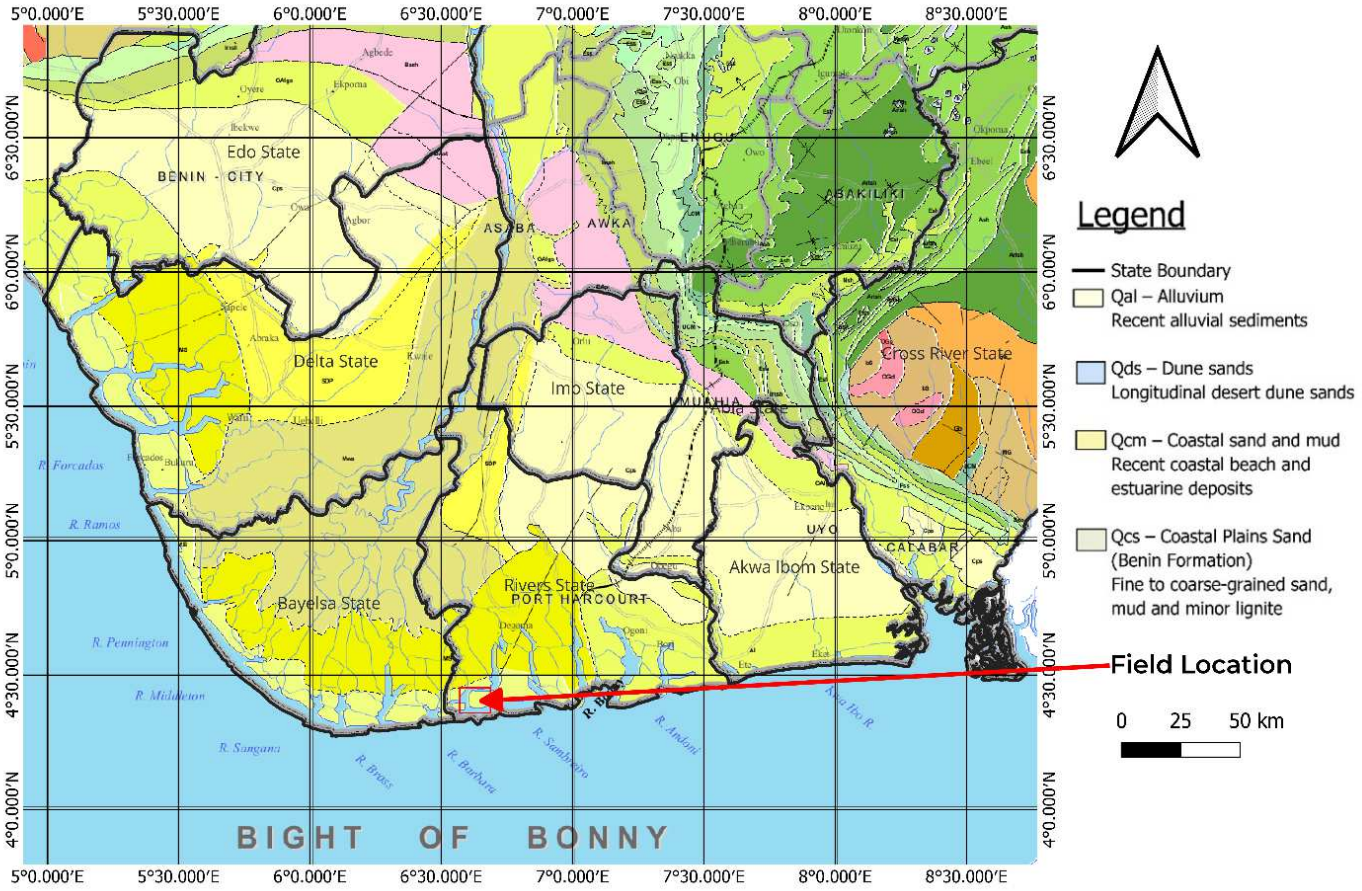

Figure 2: Litho-Structural map of the Niger Delta.

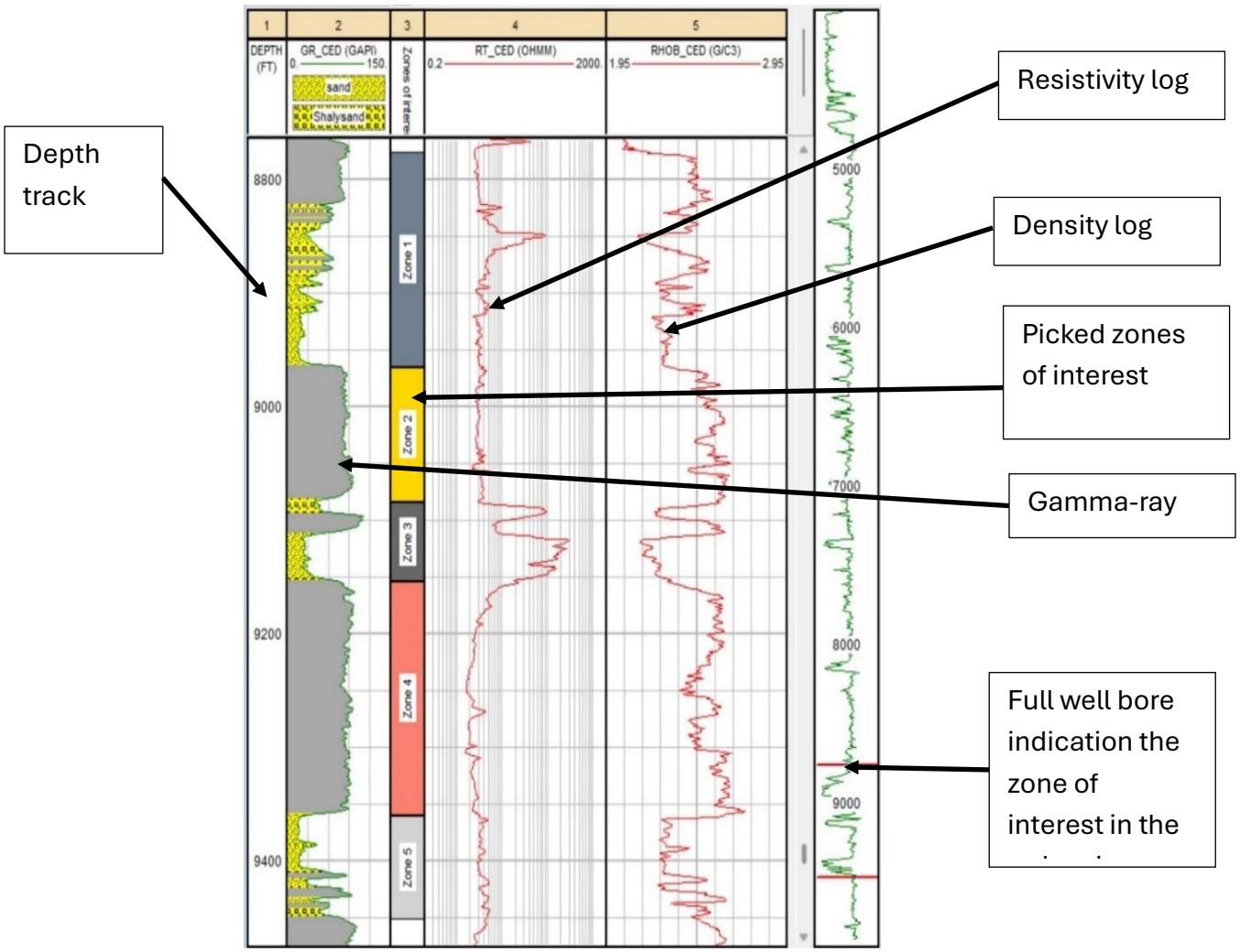

Figure 3a: Input logs for well 1

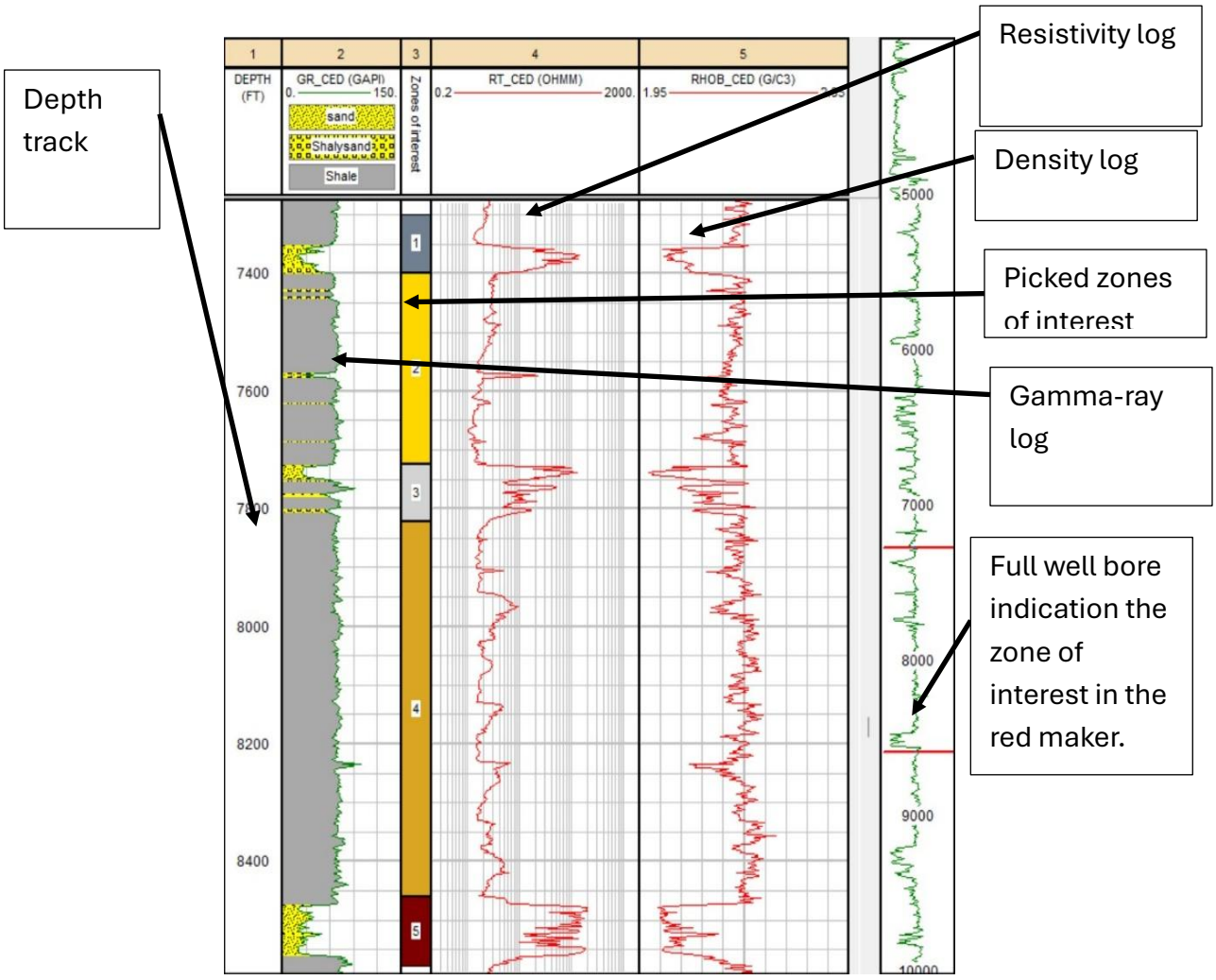

Figure 3b: Input logs for well 2

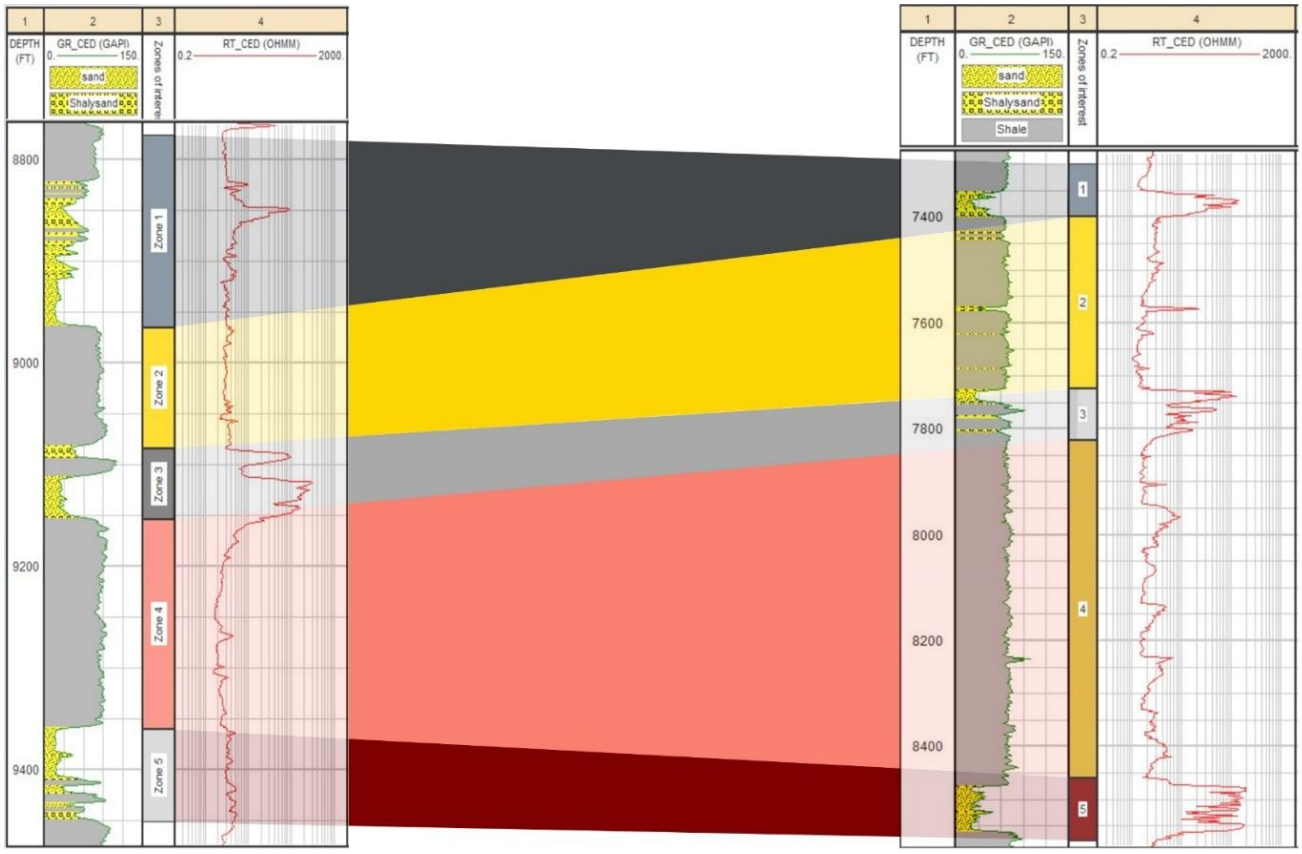

Figure. 4. Correlation panel showing the typical subsurface bedding and lithostratigraphic continuity across the study area.

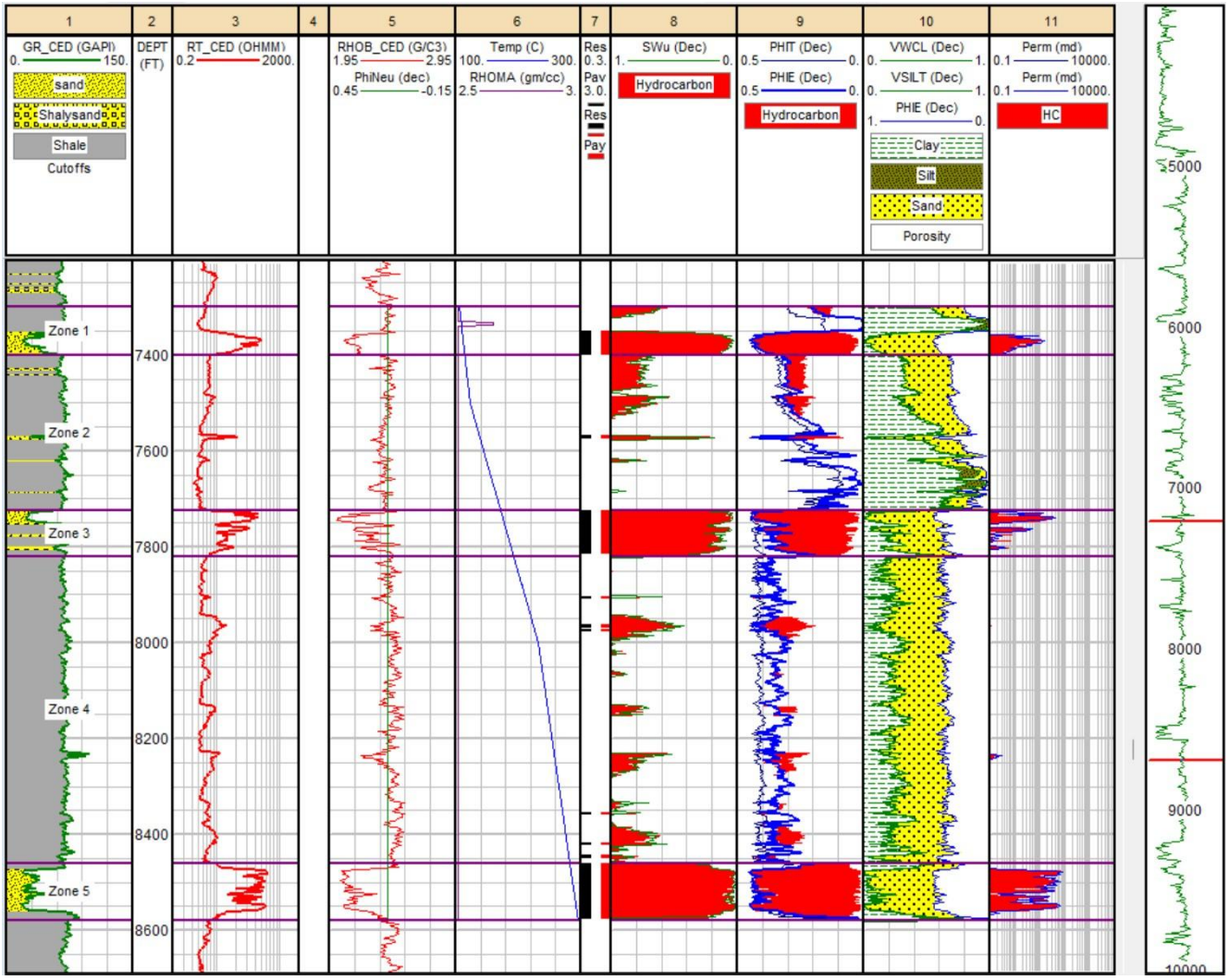

Figure 5. Petrophysical interpretation results for Well 1.

hydrocarbon-bearing capacity. This zone is therefore considered to have poor reservoir potential.

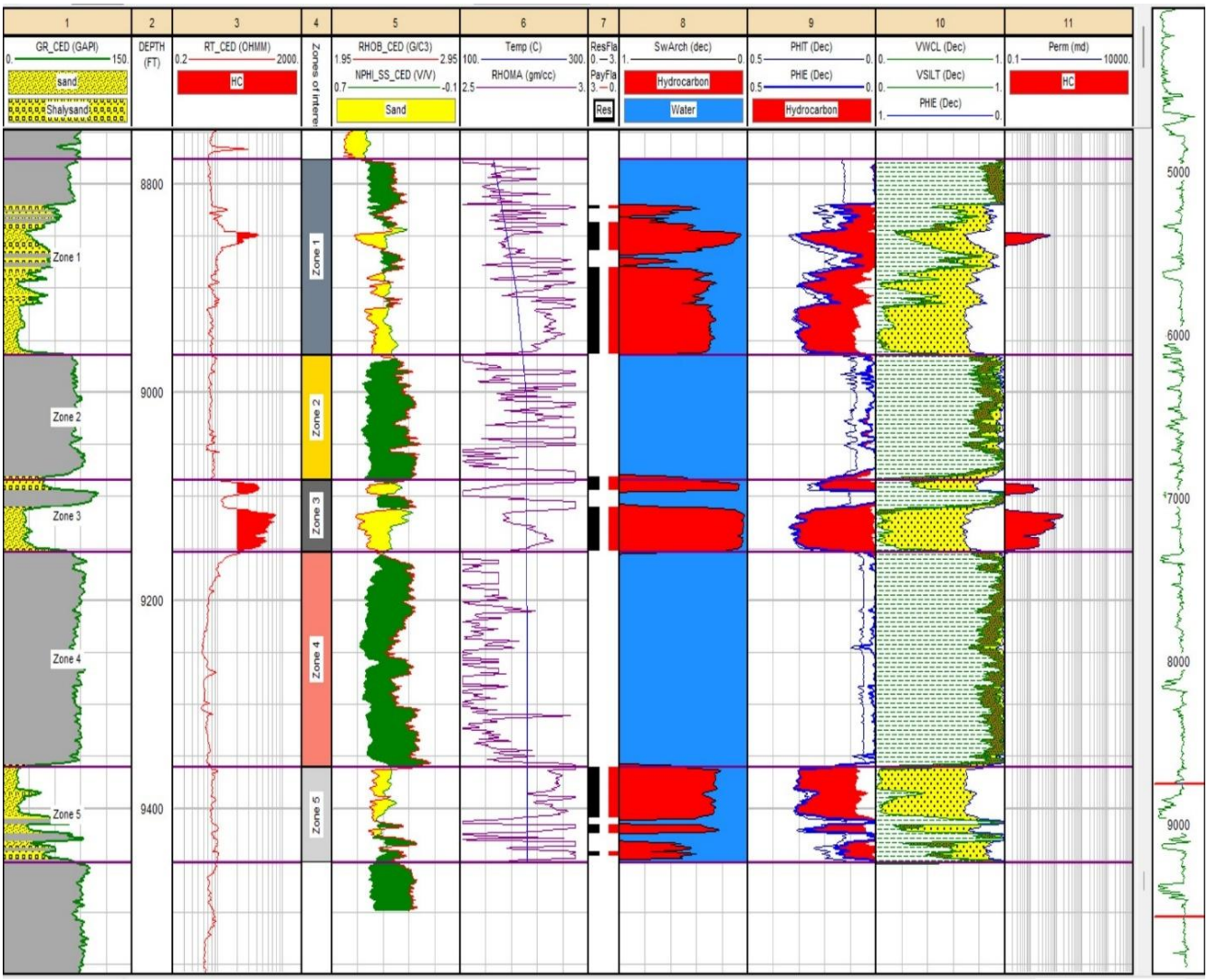

Figure 6. Petrophysical interpretation results for Well 2.

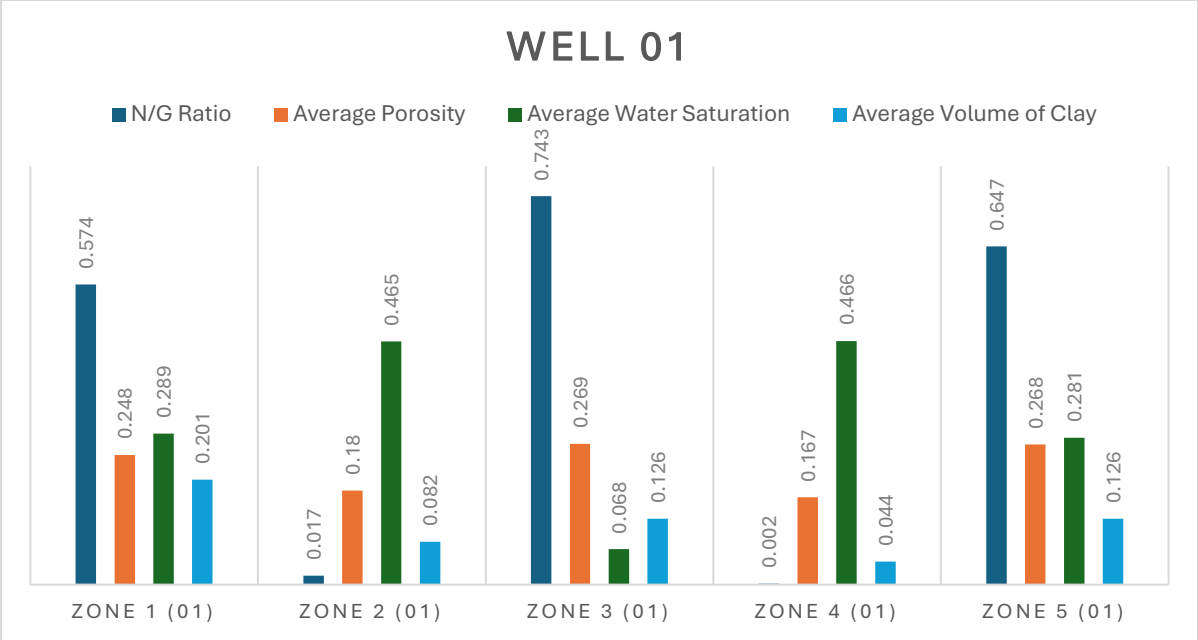

Figure.7: Bar chart showing Petrophysical results across all 5 Zone for well 1

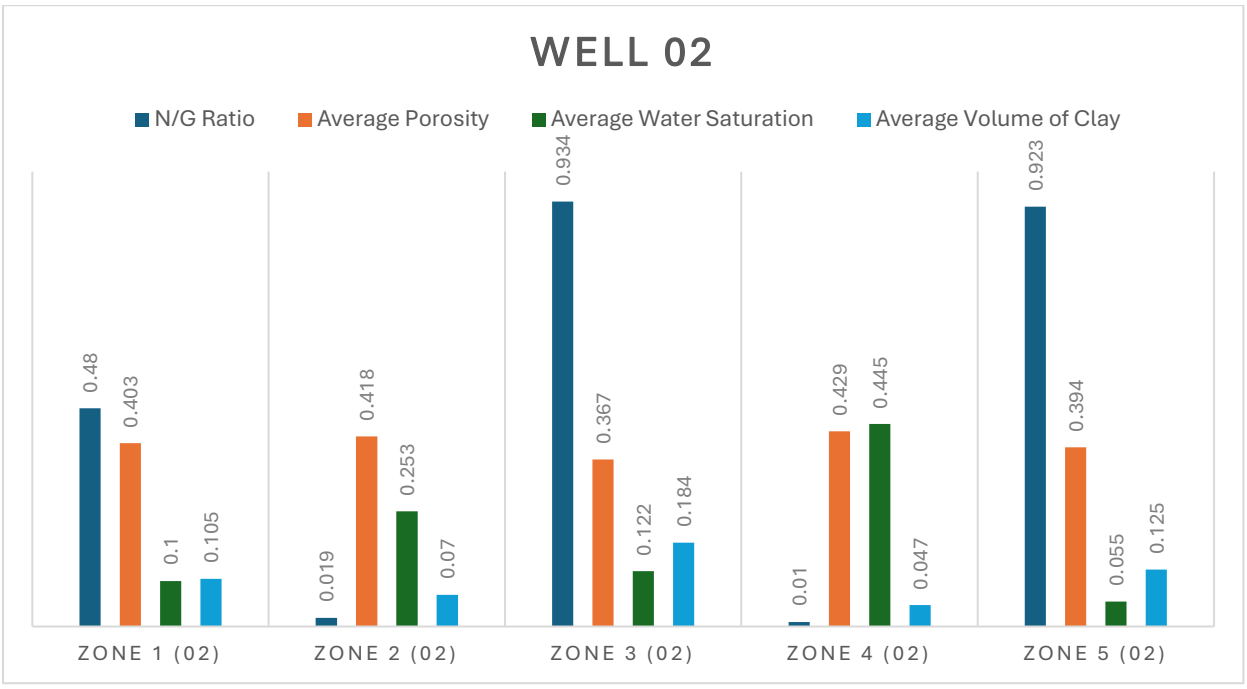

Figure. 8: Bar chart showing Petrophysical results across all 5 Zone for well 2

Tables

Table 1. Data inventory of the well log datasets used in this study

Dataset / Log Type	**Well 1**	**Well 2**
Well header	Available	Available
Well deviation	Not available	Available
Gamma ray log	Available	Available
Deep resistivity log	Available	Available
Bulk density log	Available	Available
Sonic log	Available	Available
Neutron porosity log	Available	Available

Table 2. Petrophysical results for Well 1

Well	Zone Name	Units	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	$\phi \cdot H$	$\phi S_o \cdot H$	$V_{cl} \cdot H$
01	Zone 1	ft	8776	8965	189	108.5	0.574	0.248	0.289	0.201	26.87	19.09	21.8
01	Zone 2	ft	8965	9084	119	2	0.017	0.18	0.465	0.082	0.36	0.19	0.16
01	Zone 3	ft	9084	9154	70	52	0.743	0.269	0.068	0.126	13.99	13.04	6.58
01	Zone 4	ft	9154	9360	206	0.5	0.002	0.167	0.466	0.044	0.08	0.04	0.02
01	Zone 5	ft	9360	9452	92	59.5	0.647	0.268	0.281	0.126	15.93	11.45	7.51

Table 3. Petrophysical results for Well 2

Well	Zone Name	Units	Top	Bottom	Gross	Net	N/G	Av Phi	Av Sw	Av Vcl	$\phi \cdot H$	$\phi S_o \cdot H$	$V_{cl} \cdot H$
02	Zone 1	ft	7300	7400	100	48	0.48	0.403	0.1	0.105	19.34	17.4	5.03
02	Zone 2	ft	7400	7723.5	323.5	6	0.019	0.418	0.253	0.07	2.51	1.88	0.42
02	Zone 3	ft	7723.5	7821.5	98	91.5	0.934	0.367	0.122	0.184	33.62	29.51	16.8
02	Zone 4	ft	7821.5	8459.5	638	6.25	0.01	0.429	0.445	0.047	2.68	1.49	0.29
02	Zone 5	ft	8459.5	8580	120.5	111.25	0.923	0.394	0.055	0.125	43.81	41.39	13.9