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Multi-Well Reservoir Heterogeneity and Flow Unit Characterization Using Wireline Logs, RQI, and FZI in the Niger Delta Basin, Nigeria.

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Abstract

Reservoir heterogeneity and hydraulic flow unit characterization constitute critical parameters in optimizing hydrocarbon recovery within structurally and stratigraphically complex depositional systems such as the Niger Delta Basin. This study investigates reservoir quality, compartmentalization, and flow unit architecture in the offshore QUAC Field, Niger Delta, Nigeria, through an integrated petrophysical evaluation of wireline log datasets acquired from three wells: QUAC-1, QUAC-2, and QUAC-3. The workflow incorporated gamma-ray, neutron-density, sonic, and resistivity logs to quantitatively estimate shale volume (Vsh), porosity, and permeability, while hydraulic flow units were delineated using the Reservoir Quality Index (RQI) and Flow Zone Indicator (FZI) techniques. Four principal reservoir zones were identified and classified on the basis of distinct lithological and petrophysical characteristics. Computed shale volume values range from 0.12 to 0.45, indicating moderate to high vertical heterogeneity across the reservoir succession. RQI and FZI values cluster between 0.09–0.18 and 0.90–1.12, respectively, suggesting the predominance of moderate-quality hydraulic flow units. Neutron-density crossplot analysis reveals the occurrence of multiple hydraulic flow units governed by depositional facies variability and post-depositional diagenetic modifications. Among the delineated intervals, Zone 2 across all wells represents the cleanest, most laterally extensive, and hydrocarbon-saturated reservoir unit with enhanced reservoir continuity and favorable petrophysical attributes. Conversely, Zone 3 consistently exhibits poor reservoir quality, characterized by elevated shale volume values ranging from 0.38 to 0.45, thereby functioning as a potential flow barrier and non-reservoir interval. The integration of multi-log petrophysical analysis with hydraulic flow unit classification provides a robust framework for understanding reservoir heterogeneity and compartmentalization, thereby supporting efficient reservoir management and strategic hydrocarbon field development.

Keywords

Fluid saturation;
Hydrocarbon reservoirs;
Reservoir Quality Index;
Flow Zone Indicator;
Compartmentalization

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1. Introduction

The characterization of subsurface reservoirs is fundamental to optimizing hydrocarbon exploration and production (Alpay, 1972). Understanding reservoir heterogeneity and flow unit characterization is critical for predicting fluid movement, optimizing well placement, and enhancing recovery strategies (Alpay, 1972; Agbasi et al., 2020; Hosseinzadeh and Tavakoli, 2024; Mishra et al., 2025). As petroleum reservoirs are inherently complex, their properties vary significantly across different spatial scales due to depositional environments, diagenetic alterations, and structural modifications (Prochnow et al., 2022; Mishra et al., 2025). These variations impact porosity, permeability, and fluid saturation, influencing hydrocarbon productivity.

Reservoir heterogeneity refers to the spatial variation in rock properties that control fluid movement and storage within the subsurface (Hosseinzadeh and Tavakoli, 2024). These variations can be observed at multiple scales, from the pore level to field-wide distributions. Heterogeneity arises due to depositional facies changes, diagenetic modifications, and structural deformation, making it a key consideration in reservoir management (Jika et al., 2020). In the Niger Delta and other prolific hydrocarbon basins, reservoir heterogeneity is commonly observed in fluvial, deltaic, and deepwater turbidite systems, where sand body connectivity and permeability contrasts significantly influence hydrocarbon recovery (Agbasi et al., 2020). If heterogeneity is not adequately characterized, it may lead to inefficient well placement, poor sweep efficiency, and unoptimized production strategies (Omoja and Obiekezie, 2021; Prochnow et al., 2022;

Hosseinzadeh and Tavakoli, 2024; Mishra et al., 2025).

Flow unit characterization is a crucial step in reservoir evaluation, as it defines zones of similar fluid flow behavior within a reservoir. Flow units are determined based on permeability trends, porosity distributions, lithofacies, and depositional environments, allowing geoscientists and reservoir engineers to segment the reservoir into meaningful hydraulic units (Olotu et al., 2020; Hosseinzadeh and Tavakoli, 2024; Nordin et al., 2024; Mishra et al., 2025). The identification of flow units helps in predicting connectivity, optimizing recovery techniques, and improving well completion strategies. Flow units are classified based on geological and petrophysical parameters, with the most widely used techniques including Flow Zone Indicator (FZI), Lorenz plots, and stratigraphic layering approaches. These methods allow for the differentiation of high-permeability pathways and baffles or barriers that influence hydrocarbon migration (Oyeyemi et al., 2018; Fajana, 2020; Khalili, and Ahmadi, 2023; Munther and Sahaab, 2024).

Despite advancements in reservoir characterization techniques, challenges persist in accurately defining heterogeneous reservoirs and mapping flow units (Elnaggar et al., 2018; Mishra et al., 2025). Variations in sandstone, shale, and carbonate formations create ambiguous log responses, requiring advanced log interpretation techniques (Darling, 2005). Diagenetic effects such as cementation, dissolution, and clay mineral transformations can alter porosity and permeability, complicating petrophysical analysis (Aminian et al., 2003; Odedede, 2018). Borehole washouts, mud invasion, and

formation damage may introduce artifacts in wireline log responses, requiring data correction and quality control (Adelu et al., 2019). Overcoming these challenges requires a multidisciplinary approach, integrating geophysical, geological and petrophysical techniques.

To address these complexities, the integration of wireline log data provides a robust approach to evaluating reservoir heterogeneity and flow unit characterization, ensuring optimized hydrocarbon recovery strategies. Understanding reservoir complexity, compartmentalization, and fluid flow behavior is essential for improving production efficiency and reservoir management (Ali et al., 2019; Shah et al., 2021; Hossain et al., 2022; Ebraheem et al., 2025). In this study, we utilized wireline logs to demonstrate the effectiveness of wireline log interpretation in defining flow units, assessing petrophysical properties, and enhancing reservoir performance. By leveraging advanced log interpretation techniques, oil and gas operators can maximize recovery, reduce operational risks, and optimize field development strategies.

2. Geology of the study area

The QUAC field is situated within OML-X, an offshore block in the Niger Delta Basin of Nigeria, located in the Gulf of Guinea. This region is renowned for its substantial hydrocarbon reserves and intricate geological

evolution. The precise locations of the wells within the QUAC field are depicted in Figure 1, where they are marked in red on the Niger Delta map. The Niger Delta Basin is one of Africa's most prolific petroleum provinces, hosting extensive accumulations of oil and gas within its diverse stratigraphic formations (Reijers et al., 1997; Agbasi et al., 2023; Diab et al., 2023).

The geological development of Nigeria's coastal sedimentary basins is categorized into three primary depositional cycles (Reijers et al., 1997). The first cycle commenced with a marine incursion during the Albian period and extended to the Santonian period, resulting in the deposition of thick marine sediments (Reijers et al., 1997; Austin et al., 2018; Osung et al., 2024). The second cycle initiated the formation of the Niger Delta during the Eocene epoch and continues into the present, driven by the accumulation of deltaic and marine sediments transported by rivers (Reijers et al., 1997; Osung et al., 2024). During the late Quaternary period, sedimentation patterns were periodically disrupted by uplift and erosion, leading to recurring episodes of channel incision and infilling. These processes played a crucial role in the formation of submerged canyons, which have significantly influenced the current depositional environment of the Niger Delta (Reijers et al., 1997; Agbasi et al., 2023; Osung et al., 2024).

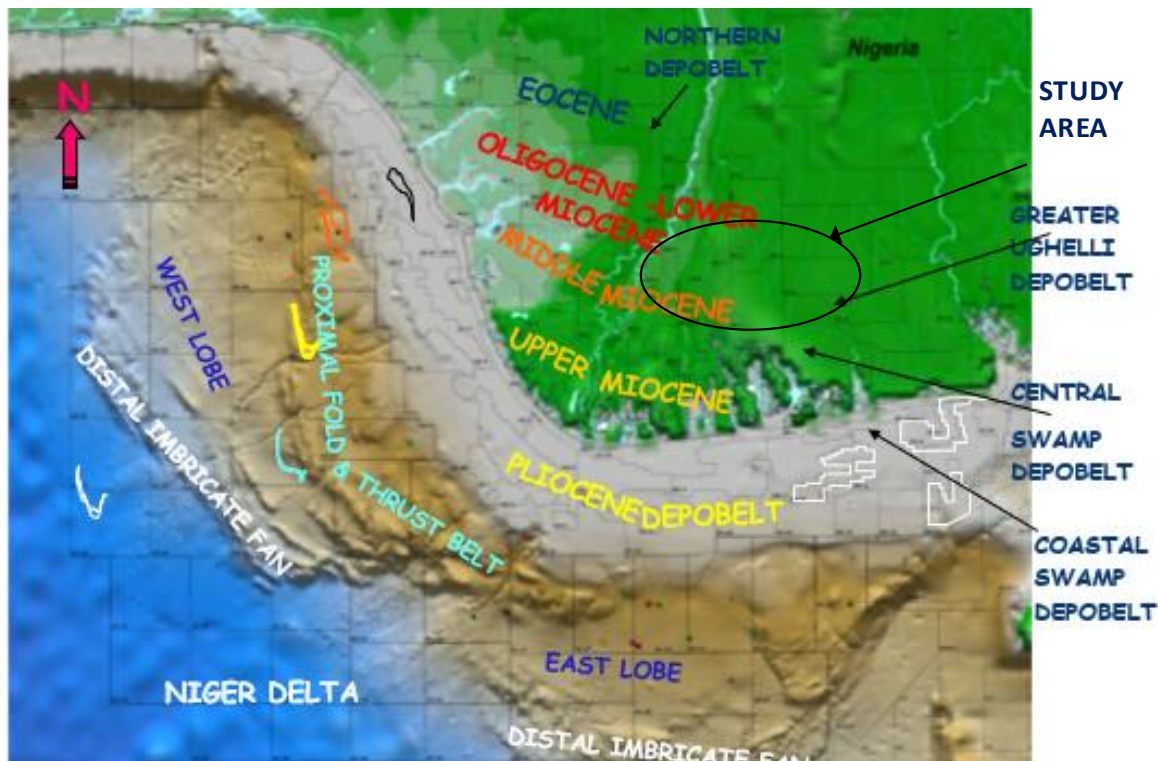


Figure 1. Geologic map of the Niger Delta Region showing the study area (Reijers 1997)

The Niger Delta is characterized by three primary lithofacies, forming a regressive sequence of deltaic and marine clastic deposits (Reijers et al., 1997). The Agbada Formation, composed of interbedded sand and shale in a paralic sequence, is overlain by the Benin Formation, which consists predominantly of continental sands (Reijers et al., 1997). Beneath these, the Akata Formation consists of coastal shale and serves as the primary hydrocarbon source rock, while the Agbada Formation functions as the main reservoir unit. Within the Niger Delta Basin, six major depobelts have been identified, including the offshore megastructure, Coastal Swamp I and II, Central Swamp, Great Ughelli, and Northern Delta. These depobelts were formed by successive episodes of deposition and structural evolution, leading to the

accumulation of substantial petroleum resources (Osung et al., 2024).

To evaluate spatial variability in porosity and permeability within reservoir intervals, well log interpretation is integrated with core data. Lithofacies variations significantly influence fluid flow and reservoir quality, making it essential to assess the distribution of sand and shale units. Studies have established a correlation between grain size and bulk volume of water, which aids in classifying five key lithofacies: coarse-grained sand, medium-grained sand, fine-grained sand, very fine-grained shale, and silty shale (Okoli and Agbasi, 2021). Each lithofacies exhibits distinct petrophysical properties, influencing reservoir performance, fluid migration, and hydrocarbon recovery.

A thorough understanding of lithofacies distribution and reservoir intervals in the Niger Delta is crucial for identifying high-potential hydrocarbon zones, ultimately improving hydrocarbon recovery and production efficiency. The integration of geological, petrophysical, and geophysical data enhances reservoir characterization, enabling more accurate exploration, development, and optimization of hydrocarbon resources in the region (Darling, 2005).

3. Materials and methods

The methodology employed in this study aims to evaluate reservoir heterogeneity, define flow units, and assess compartmentalization across three wells (QUAC-1, QUAC -2, and QUAC -3) using wireline log data. The analysis integrates petrophysical measurements such as gamma-ray, neutron porosity, resistivity, sonic velocity, and density logs to characterize reservoir quality and shale volume. Various analytical techniques and mathematical formulations are utilized to quantify key reservoir properties, enabling a comprehensive assessment of reservoir behavior (Torres et al., 2010; Islam et al, 2013; Abdelwahhab and Raef, 2020; Munther and Sahaab, 2024; Ebraheem et al., 2025).

Wireline log data were obtained for QUAC-1, QUAC-2, and QUAC-3, covering depths from approximately 4800 ft to 11650 ft. The logs used in this study include:

- **Gamma-ray logs (GR):** To determine lithology and shale content.
- **Neutron and density logs:** To evaluate porosity and fluid saturation.
- **Resistivity logs:** To identify hydrocarbon-bearing zones.
- **Sonic logs:** To assess rock compaction and porosity trends.

The acquired log data were processed to remove noise, correct for environmental effects, and standardize depth scales and was analyzed using interactive petrophysics software. The logs were calibrated using standard industry techniques to ensure consistency in interpretation across all three wells.

3.1. Petrophysical Parameter Calculation

The reservoir properties were evaluated using established petrophysical equations below (Schlumberger, 1974; Torre et al., 2010; Abdelwahhab and Raef, 2020):

3.1.1. Shale Volume Estimation

Shale volume (V_{sh}) was determined using multiple methods, including gamma-ray, neutron, density, and resistivity-based approaches.

3.1.2. Gamma-ray-derived shale volume

$$V_{sh} = \frac{GR_{log} - GR_{clean}}{GR_{shale} - GR_{clean}}$$

[1]

where: GR_{log} = gamma-ray reading of the formation, GR_{clean} = gamma-ray reading of clean sandstone, GR_{shale} = gamma-ray reading of pure shale (Schlumberger, 1974; Asquith et al., 2004).

A similar method was applied to refine shale volume estimates using neutron, density, and resistivity logs. Water saturation (S_w) was computed using Archie's equation.

3.1.3. Porosity Determination

The total and effective porosity of the formations were computed using neutron and density logs.

Density porosity (ϕ_d) was calculated using the equation proposed by Schlumberger (1974):

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

[2]

where: ρ_{ma} = matrix density (2.65 g/cm³ for sandstone), ρ_b = bulk density from logs, ρ_f = fluid density (assumed 1.0 g/cm³ for water).

3.1.4 Permeability Determination

Permeability (k) was estimated empirically from porosity and irreducible water saturation based on Timur (1968) as explained by Aneth et al, (2018) the most widely applied empirical relationship for sandstone reservoirs (such as in the Niger Delta)

$$K = a \frac{\phi^b}{S_{wi}^c} \quad [3]$$

where:

- k = permeability (in millidarcies, mD)
- ϕ = effective porosity
- S_{wi} = irreducible water saturation
- a, b, c = empirical constants determined

For typical sandstone reservoirs in the Niger Delta, the constants are often taken as: a=0.136, b=4.4, c=2

Neutron porosity (ϕ_n) was extracted directly from neutron logs. Effective porosity (ϕ_e) was estimated by correcting total porosity (ϕ_t) for shale content (Dresser, 1979):

$$\phi_e = \phi_t(1 - V_{sh}) \quad [4]$$

where V_{sh} is the shale volume fraction.

3.1.5. Compartmentalization Analysis

Reservoir compartmentalization was evaluated by analyzing variations in density, porosity, and resistivity across the wells to assess differences in lithology, compaction, and fluid distribution. Differences in shale volume between zones were examined to determine the extent of shaliness and its impact on permeability and porosity. Disruptions in fluid

contact levels were also assessed to identify potential barriers to fluid flow, which could indicate compartmentalization caused by structural or stratigraphic variations (Buckman et al., 2019; Shah et al., 2021; Hossain et al., 2022; Ebraheem et al., 2025). These analyses provided critical insights into reservoir quality variations and fluid distribution, aiding in the identification of optimal hydrocarbon-bearing intervals.

Flow Unit Characterization through parameters such as the Reservoir Quality Index (RQI) and Flow Zone Indicator (FZI) offers a means to classify rock intervals into hydraulically similar groups (Asquith et al., 2004). These indicators reflect how pore geometry and permeability interact to influence flow, thus providing a bridge between static log-derived properties and dynamic reservoir performance.

Cross-well comparisons were conducted to determine formation heterogeneity, helping to define lateral continuity of reservoir units. Clean reservoir zones were identified based on low gamma-ray readings, indicating minimal shale influence. Density and porosity trends were analyzed to evaluate compaction effects and their implications for fluid storage capacity (Ekpo et al., 2017; Hossain et al., 2022). Resistivity values were examined to distinguish between hydrocarbon-bearing and water-saturated intervals, providing a clearer understanding of fluid movement and potential production zones.

Result and Discussion

4.1. Reservoir Quality and Lithological Variability in QUAC-1

The petrophysical analysis of QUAC-1 reservoirs reveals significant variations in density, gamma-ray response, porosity,

resistivity, sonic velocity, and shale volume estimates as shown in Table 1 and Figure 2. These variations indicate differences in lithology, fluid content, and reservoir quality, which are critical for evaluating hydrocarbon potential. The well was subdivided into four (4) stratigraphic zones based on depth and log responses. Zone 1 is generally shaly-sandy with modest porosity of about 10%, an average Vsh of 0.3 and a density of 2.52g/cc, and it's assumed not to be a high-quality reservoir due

to its values, which may reduce the reservoir's effective porosity and permeability. Zone 2 appears cleaner, with higher resistivity (R_t), with an average of $30 \Omega\cdot m$, moderate porosity of about 13-14%, and Vsh of 0.3. Zone 3 is shalier with a Vsh of about 0.45, low porosity of 9% and low R_t , mostly non-productive under current assumptions. Zone 4 has some cleaner sands and high resistivity values ranging from 5 to $80 \Omega\cdot m$, Zone 4 is assumed to be a potential hydrocarbon-bearing formation.

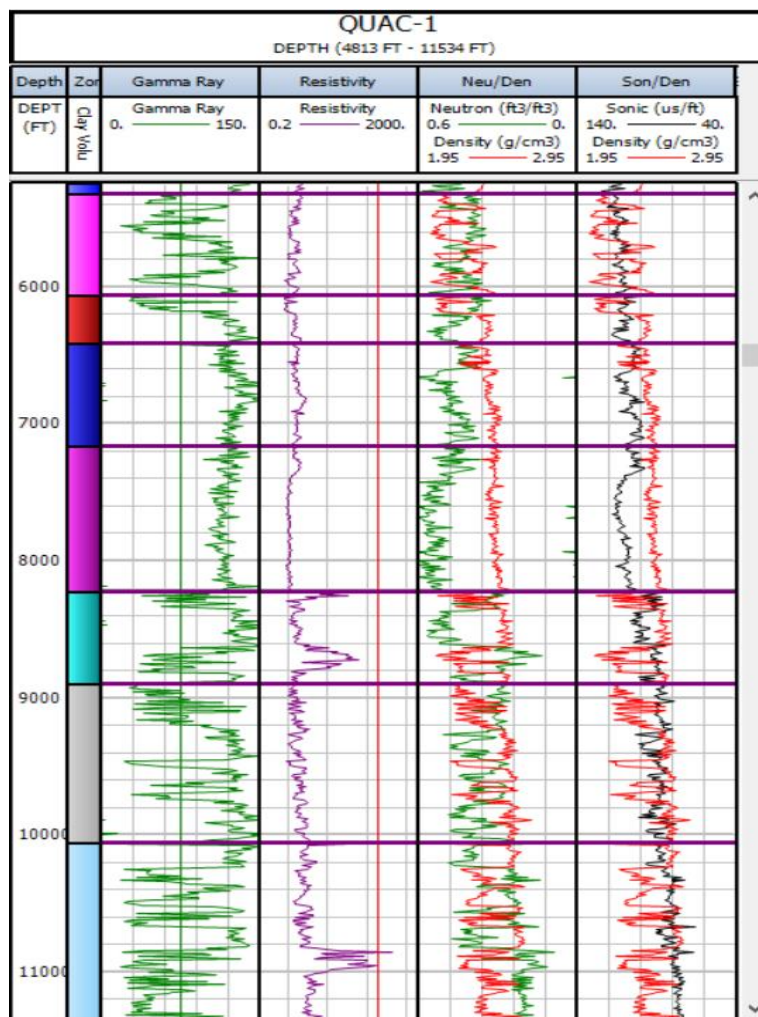


Figure 2. Petrophysical Characteristics and Shale Volume Distribution of QCAU-1

Table 1. Average petrophysical Properties and Shale Volume Estimates for QUAC-1

Zones	Resistivity $\Omega \cdot m_{avg}$	VshGR (Avg)	Density g/cc_avg	Porosity φ_{avg} (%)	Permeability K (mD)	RQI	FZI
1 4183- 6600	12	0.30	2.5	10	1.3	0.11	1.0
2 6500- 8200	30	0.95	2.1	13.5	4.2	0.175	1.12
3 8200- 10200	8	0.45	2.7	9	0.8	0.095	0.96
4 10200- 11534	25	0.25	2.3	13	3.6	0.164	1.10

For QUAC-1, Zone 1 has low porosity and low effective hydrocarbon saturation, Zone 2 demonstrates partial hydrocarbon saturation potential with moderate porosity and resistivity value, and Zone 3 is predominantly shaly, with low effective porosity and permeability. Hence, not a good reservoir. While zone 4 could be hydrocarbon-bearing.

4.2. Reservoir Quality and Lithological Variability in CAU-2

The petrophysical properties and shale volume estimates of CAU-2 across the four well zones provide crucial insights into the reservoir characteristics and their implications for hydrocarbon potential. The results from Table 2 and Figure 3 reveal variations in density, gamma ray, neutron porosity, resistivity, sonic velocity, and shale volume indicators, which help in evaluating the reservoir quality and

shale content distribution across the three wells.

Similar to QUAC-1, the density values for zone 1 range between 2.09 g/cm³ and 2.48 g/cm³, with a mean of 2.32 g/cm³ and an average resistivity of 18 $\Omega \cdot m$, indicating moderate compaction and lithological consistency. Gamma ray readings, which serve as an indicator of shale content, have an average of 0.2, reflecting a mix of clean reservoir sandstones and shaly intervals with porosity of 12.5%. Zone 2 has a better reservoir characteristic with Vsh of 0.12, average resistivity of 40 $\Omega \cdot m$ and density less than 2.3. The low resistivity value in zone 3, with an average of 7 $\Omega \cdot m$, implies a significantly higher shale presence with Vsh of 0.40. These variations suggest that zone 3 is the most shale-prone. Zone 4 has similar lithological features to zone 2, with an average resistivity of 25 $\Omega \cdot m$, Vsh 0.18, indicating a potential reservoir-bearing formation.

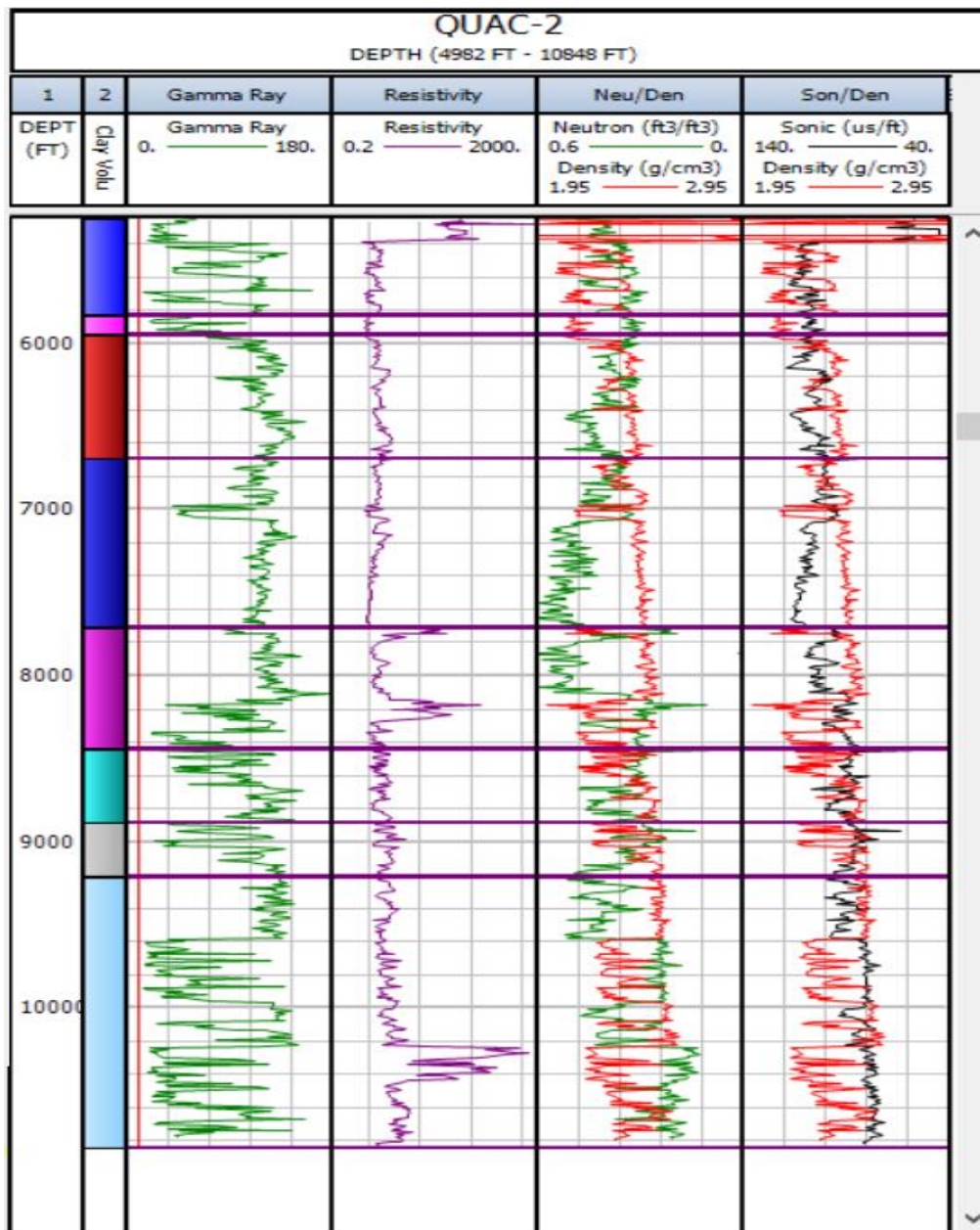


Figure 3. Petrophysical Characteristics and Shale Volume Distribution of CAU-2 Reservoir

Table 2. Average petrophysical Properties and Shale Volume Estimates for CAU-2

Zones	Resistivity $\Omega \cdot m_{avg}$	VshGR (Avg)	Density g/cc_avg	Porosity φ_{avg} (%)	Permeability K (mD)	RQI	FZI
1 4892- 6100	18	0.20	2.3	11	2.6	0.153	1.24
2 6100- 7700	40	0.12	2.05	12.5	3.0	0.155	1.08
3 7700- 9500	7	0.40	2.55	9	0.9	0.09	0.9
4 9500- 10840	25	0.18	2.15	12	4.0	0.16	1.10

In QUAC-2, zone 1 showed moderate porosity, zone 2 has good reservoir potential with moderate porosity and resistivity. Zone 3 is water-filled, shaly, low reservoir quality, while zone 4 has moderate reservoir quality with a potential pay zone.

4.3. Reservoir Quality and Lithological Variability in CAU-3

CAU-3 was analyzed across the 4 zones, with varying depths and petrophysical properties, as shown in Table 3. The density values across the three wells indicate variations in lithological composition and fluid content. Zone 1 exhibited a density range between 2.18 g/cm³ and 2.38 g/cm³, with an average of 2.29 g/cm³, suggesting a mixture of sandstone and shale with an average Vsh of 0.25 and an average resistivity value of 15 $\Omega \cdot m$. Zone -2 had a slightly narrower range between 2.23 g/cm³ and 2.30 g/cm³, averaging 2.27 g/cm³,

indicating a more consistent lithology with slightly lower compaction.

Its resistivity value and Vsh are 30 $\Omega \cdot m$ and 0.18, respectively, with 13% porosity. Zone 3 presented a broader density range from 2.22 g/cm³ to 2.46 g/cm³, with a mean of 2.40 g/cm³, suggesting variations in compaction and mineralogical composition. Vsh value of 0.38 and low resistivity value of 9 $\Omega \cdot m$ further substantiate lithological variations, suggesting increased shale content and a tight water-bearing formation, which implies lower reservoir quality. Zone 4 suggests a comparatively less compact formation, potentially indicating a higher porosity zone with an average Vsh of 0.2, average resistivity of 30 $\Omega \cdot m$ and porosity of about 13%. These variations suggest that zone 4 has relatively higher porosity, making it a potential candidate for enhanced fluid flow and hydrocarbon accumulation.

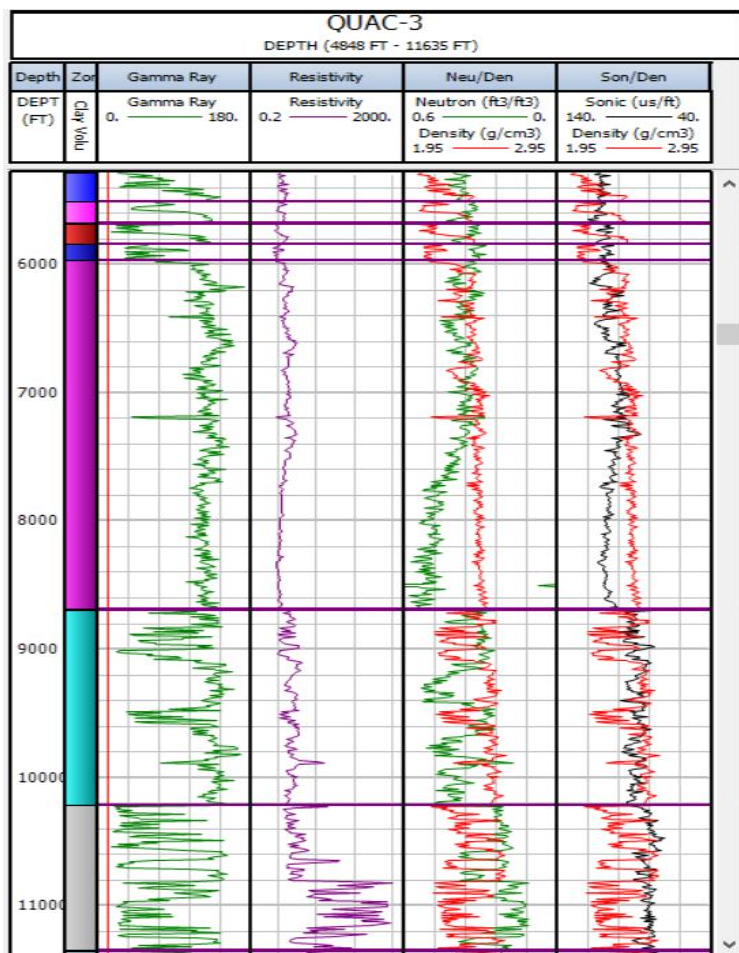


Figure 4. Petrophysical Characteristics and Shale Volume Distribution of QUAC-3

Table 3. Average Petrophysical Properties and Shale Volume Estimates for CAU-3

Zones	Resistivity $\Omega \cdot m_{avg}$	VshGR (Avg)	Density g/cc_avg	Porosity φ_{avg} (%)	Permeability K (mD)	RQI	FZI
1 4848- 6200	15	0.25	2.4	11	2	0.14	1.10
2 6200- 8700	30	0.18	2.10	13	5	0.17	1.10
3 8700- 10200	9	0.38	2.50	7	1	0.10	0.95
4 10200- 11635	30	0.2	2.15	13	4	0.17	1.12

For QUAC-3, zone 1 showed moderate porosity, likely water-wet in average parts, and zone 2 demonstrated better reservoir intervals with moderate porosity. Zone 3 is characterized by lower reservoir quality and water saturation, while zone 4 has good sand intervals, moderate porosity, and a good hydrocarbon zone.

4.4. Heterogeneity and Flow Zone Indicator across the wells

The three wells show alternating sand/shale layers characteristics of deltaic/Agbada formation deposition, lateral continuity of good sands occurs, while vertical heterogeneity of interbeds of shale and silt is common. Shale volume (Vsh) ranges from 0.12 to 0.45, indicating variable heterogeneity.

Cleanest zones ($V_{sh} \leq 0.20$) occur in Zone 2 of all wells, with resistivity varying from 7 to 40 $\Omega\cdot m$, with higher R_t correlating to potential hydrocarbon zones. Zones 3 tend to be shaly, acting as barriers to flow. The general pattern suggests moderate to high vertical heterogeneity but laterally persistent flow units. Computed Reservoir Quality Index cluster between (0.09 to 0.18) and Flow Zone Indicator cluster between (0.9 to 1.12) values reveal moderate-quality flow units that recur laterally across the wells with comparable hydraulic behavior (Odedede, 2018; Omoja and Obiekezie, 2021; Hosseinzadeh and Tavakoli, 2024). Zone 2 in all wells represents the most promising and laterally continuous reservoir interval, while Zone 3 acts as a non-reservoir or barrier (Figs. 5, 6, 7) (Hosseinzadeh and Tavakoli, 2024).

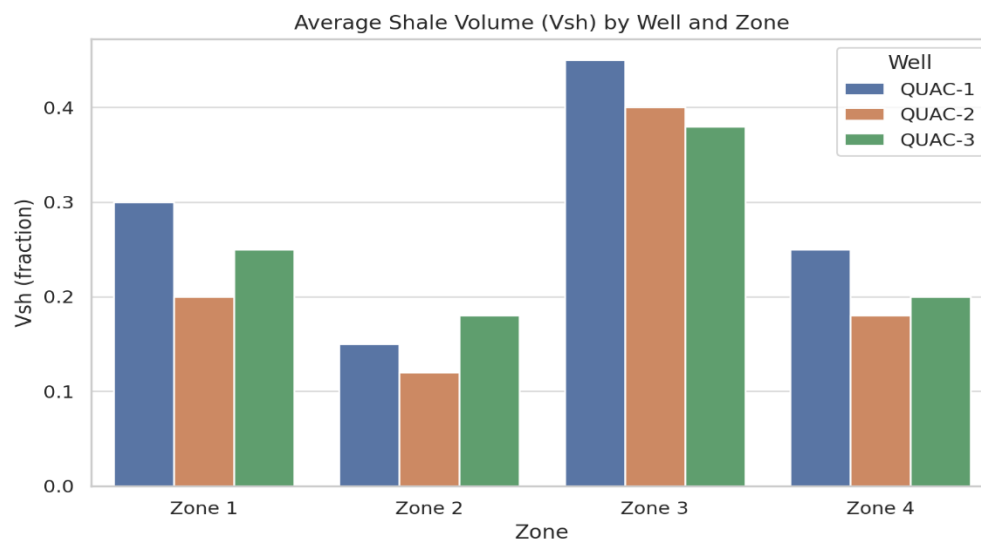


Figure 5. Showing the average shale volume

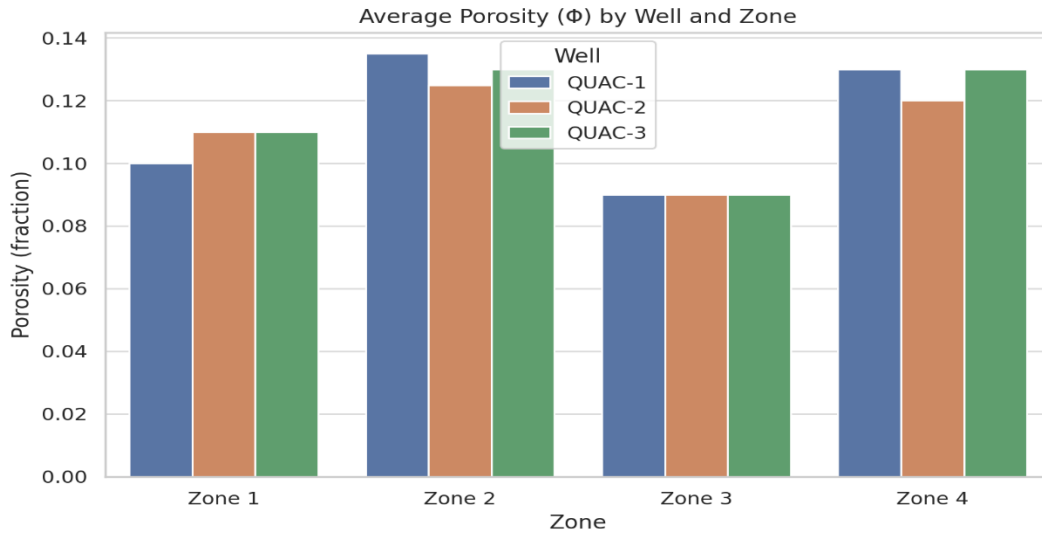


Figure 6. Barplot of average porosity.

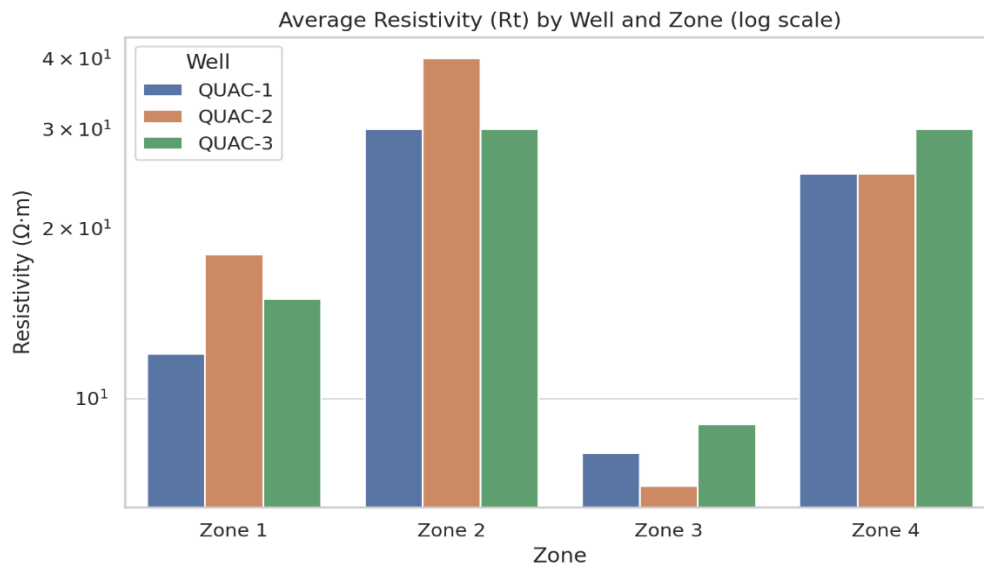


Figure 7. Bar plot of the average resistivity

The neutron-density crossplots (Figs. 8,9, and 10) across the three wells demonstrate reservoir heterogeneity resulting from variable depositional and diagenetic controls within the Niger Delta Basin (Figs. A, b, c) (Odedede, 2018; Omoja and Obiekezie, 2021; Hosseinzadeh and Tavakoli, 2024). The cross-plot with different colors indicating various zones within the reservoir to estimate total porosity and determine the rock type by comparing their responses. Each point on the graph represents a specific formation in relation to reservoir compartment analysis and flow unit characterization.

Porosity was estimated by the distance of points from the cross-plot trend line. Points that deviate significantly suggest high porosity formations, while those near the line indicate lower porosity. Since different lithologies exhibit characteristic responses on the cross-plot. Clean sandstones plots in a specific area, while shaly sands plot differently due to the presence of clay, affecting density and neutron readings. Colour coding from overlay gamma ray with blue/light blue indicate low GR likely clean formation,

magenta/green indicate mixed lithology while brown/red indicates shaly zones. The plots shows a porosity variation across different zones across the three wells.

QUAC-2 shows significant scatter and overlap of lithologies, indicating greater lateral and vertical heterogeneity compared to QUAC-1 and QUAC-3. From their Lithologic character, QUAC-1 and QUAC-3 display cleaner sands and more uniform compaction trends, pointing to better-defined flow units and better reservoir performance. QUAC-2 heterogeneity and shale interbedding will result in compartmentalization and reduced flow connectivity.

The neutron-density cross plots so far confirm the multi-layered and compositionally diverse nature of the reservoir system. The field consists of multiple flow units with distinct petrophysical properties, a characteristic deltaic depositional environment dominated by interbedded fluvial and shallow marine facies (Omoja and Obiekezie, 2021; Shah et al., 2021; Hossain et al., 2022; Munther and Sahaab, 2024; Ebraheem et al., 2025).

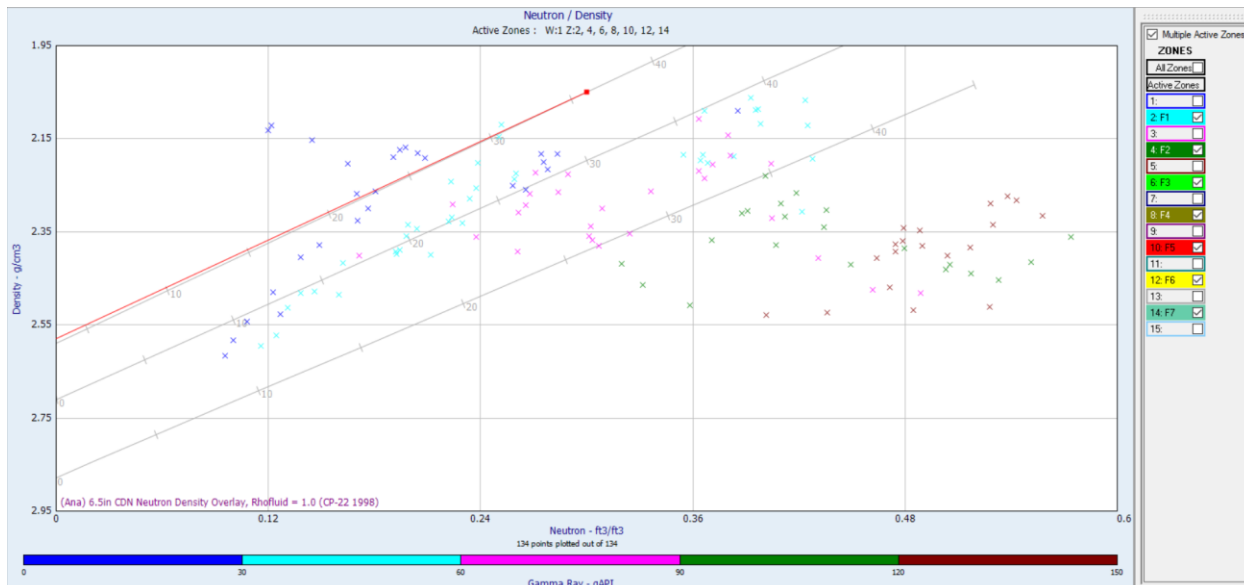


Figure 8. Cross plot of Neutron Density for well QUAC-1

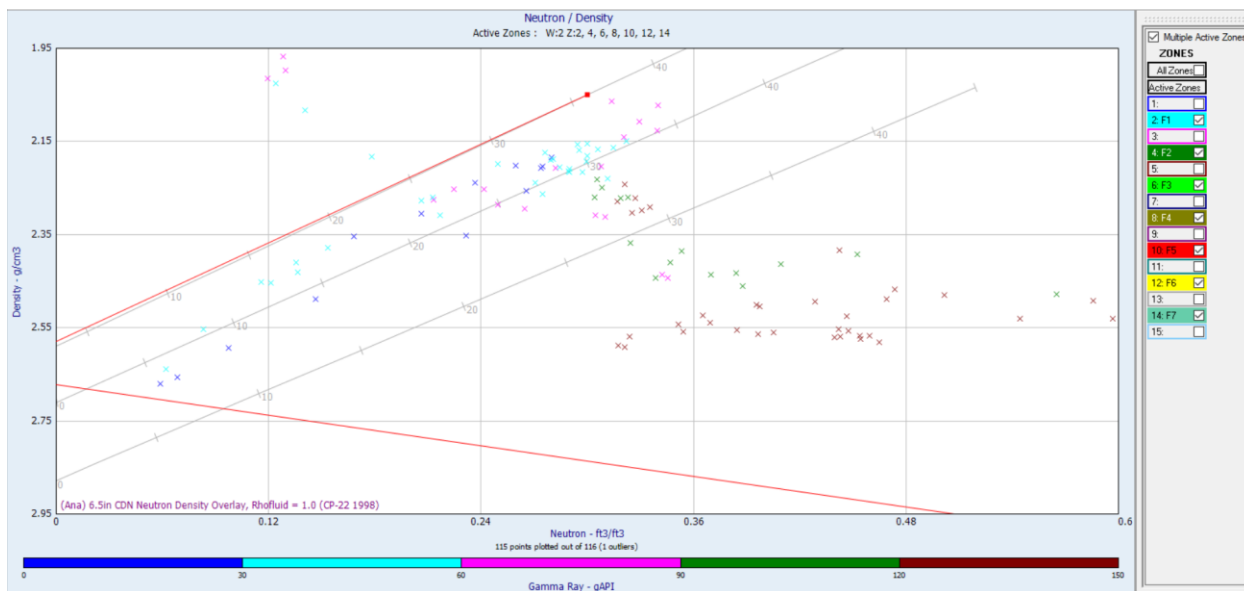


Figure 9. Cross plot of Neutron Density for well QUAC-2

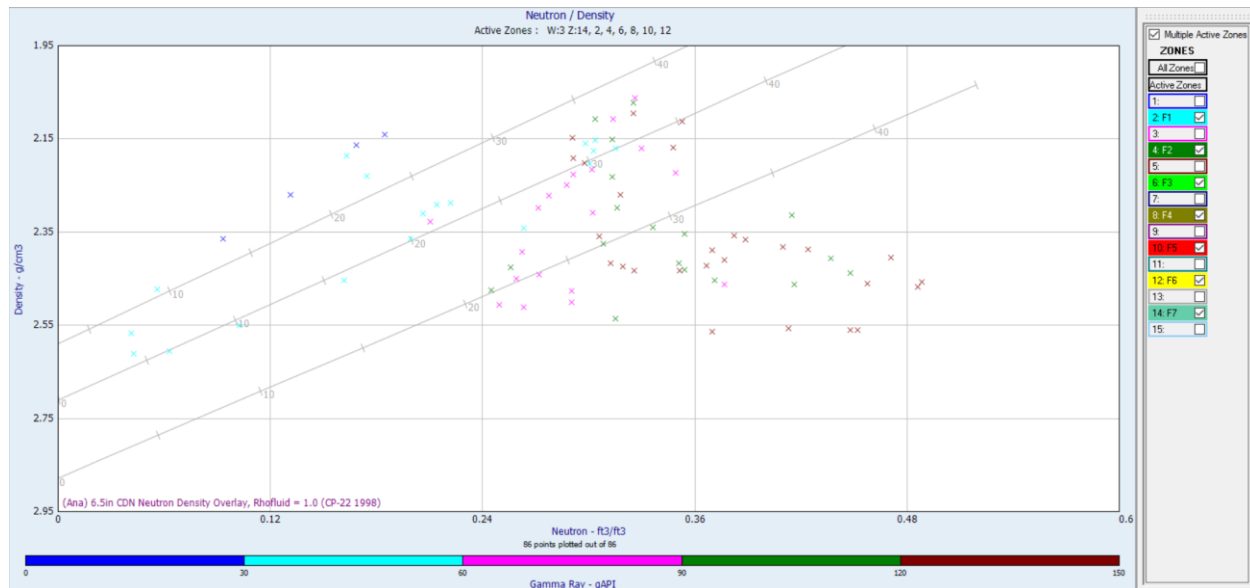


Figure 10. Cross plot of Neutron Density for well QUAC-3

5. Conclusion

The integration of petrophysical and crossplot analyses across the three wells in the QUAC field has effectively delineated reservoir heterogeneity and characterized distinct flow units within the Niger Delta Basin. The results demonstrate that the studied reservoirs are composed of interbedded sand and shale sequences, typical of deltaic Agbada Formation depositional environments, exhibiting both vertical and lateral heterogeneity. Shale volume and porosity variations highlight multiple reservoir facies with differing fluid storage and flow capacities.

Across the wells, Zone 2 consistently exhibits the best reservoir quality, with low shale content ($V_{sh} \leq 0.20$), moderate porosity ($\approx 13\%$), and high resistivity (25-40 $\Omega \cdot m$), indicating potential hydrocarbon-bearing intervals. Zone 4 also displays moderate reservoir potential, whereas Zone 3 is dominantly shaly, low in porosity, and non-productive. The RQI and FZI results confirm

that the flow units range from moderate to good quality, with similar hydraulic behavior across the wells, suggesting partial lateral continuity of productive sands and moderate compartmentalization due to shale intercalations. Neutron-density crossplots further reveal distinct lithological scatter and compaction trends, supporting the interpretation of multiple flow units with varying degrees of connectivity and diagenetic influence. QUAC-2 exhibits the highest degree of heterogeneity and potential compartmentalization, while QUAC-1 and QUAC-3 show better-defined and laterally continuous flow units.

The study showed that reservoir heterogeneity in the QUAC field is primarily controlled by depositional layering and shale interbedding, while the identified flow units provide a framework for improved reservoir modeling, production forecasting, and well placement optimization in the Niger Delta

Basin. Future studies could incorporate seismic data for 3D heterogeneity mapping.

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