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Depth-dependent variation in porosity and permeability: An integrated multi-well wireline log analysis of the Gabo Field

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ABSTRACT: This study presents an integrated Depth-Dependent Permeability and Porosity trend characterisation of the Gabo Oil Field, located in the onshore Niger Delta, using wireline logs from five wells (GABO-18, GABO-14, GABO-15, GABO-17, and GABO-19). The primary objective was to evaluate depth-dependent trends in two key reservoir properties, porosity (Φ) and permeability (K), in the Gabo oil Field within a laterally continuous reservoir unit identified between 2358 m and 2568 m. Results indicate a general improvement in reservoir quality with depth, characterised by increasing porosity and permeability. The fractional porosity ranges from 0.03% t0 0.32% across the five wells, reflecting variable but moderate to good reservoir quality. Permeability ranges from 0.01 to 2259.69 mD, reflecting possible heterogeneity in the pore structure and connectivity within the identified interval. These trends are attributed to depositional facies changes, diagenetic enhancement, and possibly overpressure preservation. The study highlights GABO-17 and GABO-18 as the most promising wells for hydrocarbon production due to their superior petrophysical properties. The findings contribute to a refined understanding of reservoir heterogeneity and sweet-spot identification in deltaic systems.

Keywords: Depth-dependent trends, Gabo Field, Niger Delta, permeability, porosity, reservoir quality, wireline logs.

INTRODUCTION

Porosity and permeability are essential petrophysical parameters that determine fluid storage and flow capacity in hydrocarbon reservoirs (Okon *et al*., 2021; Abraham *et al*., 2022; Tiab and Donaldson, 2015). Accurately describing their vertical and lateral distribution is crucial for accurate reservoir modelling, production projection, and ultimate recovery prediction. In elastic reservoirs, these parameters generally display systematic depth-dependent trends due to the gradual impacts of mechanical compaction and chemical diagenesis, which limit pore space and alter pore-throat geometry with increasing burial (Paxton *et al*., 2002; Bjørlykke, 2014; Eltom *et al*., 2023; Zhang *et al*., 2024). Furthermore, depth-dependent temperature variations influence the thermal conductivity and geothermal gradients, which in turn govern the maturity and the sealing capacity of caprocks (Allen and Allen, 2013; Beardsmore and Cull, 2001; Vasseur *et al*., 1995). Consequently, understanding these depth-dependent trends is vital for accurately ranking reservoir zones by their heterogeneity and predicting where high-quality preferential flow paths exist within a stratigraphic framework.

Establishing predictive, field-wide links between permeability (k), porosity (ϕ), and depth remains a challenging task (Corbett and Potter, 2004; Ehrenberg and Nadeau, 2005; Rajput and Pathak, 2025). Core-derived measurements provide direct but limited and costly data points (Amaefule *et al*., 1993; Lindsay *et al*., 2023). Consequently, a crucial aspect of formation evaluation is integrating continuous wireline log data, such as Gamma ray, density, and Resistivity logs, with core-calibrated transformations (Asquith and Krygowski, 2004; Crain, 2002). These thorough analyses enable high-resolution extrapolation of key petrophysical parameters across uncored intervals and between wells, supporting the creation of more accurate 3D reservoir models (Asquith and Krygowski, 2004).

An excellent case study for examining these depth-dependent patterns is the Gabo Field, a siliciclastic reservoir in Nigeria's Niger Delta (Short and Stäuble, 1967; Reijers *et al*., 1997; Iheaturu *et al*., 2022). Preliminary findings reveal significant diversity in reservoir quality across distinct structural blocks and stratigraphic units (Edwards and Santogrossi, 1990; Aigbedion and Iyayi, 2007). Determining the primary factors on porosity-permeability evolution in this field, hence, requires a thorough, multi-well investigation of log data; in the absence of comprehensive core data, wireline logs offer a dependable way to infer these characteristics. This study examines variations in porosity and permeability with depth within a correlated reservoir unit using gamma-ray (GR), resistivity (RXO), and density (RHOB) logs from five wells. The goal of the analysis is to find depth-dependent patterns that can direct field development plans, completion tactics, and well placement.

MATERIALS AND METHODS

Study area

The Gabo Field is situated between latitudes 4°19′N and 5°50′N and longitudes 5°30′E and 6°10′E in the Central swamp Depobelt of the Niger Delta, where three major subsoil formations have been identified. Figure 1(a) shows the Niger Delta and the study area's location; Figure 1(b) illustrates the distribution of wells within the study area. These three formations, Figure 2 - Agbada, Akata, and Benin - were deposited in marine, transitional, and continental environments, respectively (Owoyemi, 2004; Igbinigie and Aigbadon, 2025; Ilevbare *et al*., 2025). The Agbada formation, over 3700 meters thick and mainly composed of sandstone at the top with shaley intercalations, and mostly shale with sandstone intercalations at the bottom, is the primary hydrocarbon-bearing unit in the Niger Delta basin and hosts the Gabo oil field (Oluyemoh, 2023). Studies indicate that the Akata formation, primarily made up of marine shale with sandy and silty beds laid down as turbidites and continental slope channel fills, serves as the source rock. Lastly, the Benin formation, about 2,100 meters thick and consisting of continental sands and gravels, is the main groundwater-bearing formation in the Niger Delta basin (Short and Stäuble, 1967; Edwards and Santogrossi, 1990; Corredor *et al*., 2005; Omietimi, 2022; Abdulmajeed *et al*., 2025).

Well logs

A set of well logs (including Gamma Ray, Resistivity, Spontaneous Potential, and Density logs) was acquired from Shell Nigeria Limited for this study. For reference, the logs have been assigned the identifiers GABO-18, GABO-14, GABO-15, GABO-17, and GABO-19, as detailed in Table 1. Logs include GR (for litho logy and Vsh), deep resistivity (for fluid saturation), and density (for porosity). The reservoir unit of interest, labelled "Horizon 1," was correlated across all wells and spans depths from 2358 to 2568 m, with thicknesses ranging from 50 to 86 m.

To achieve the objectives set out for this research work. The materials used involved the availability and analysis/evaluation of composite wireline logs using Petrel software. The log types include gamma ray logs, resistivity logs, density logs, and Spontaneous potential logs. Gamma rays log helps to measure the natural radioactivity in the formations, resistivity logs are used in identifying hydrocarbon saturation vs. water saturation in a formation, and density logs are used in porosity detection.

Porosity (Φ)

Computed from density logs using the matrix and fluid densities for clean sandstone. The porosity ϕ of a Formation can be obtained from the Bulk density if the mean density of the rock matrix and that of the fluids it contains are known (Dresser Atlas, 1979). The bulk density, ρ_b, of a formation can be written as a linear contribution of the density of the rock matrix, ρ_{ma}, and the fluid density, ρ_f, with its present in proportions (1- Φ) and Φ, respectively:

$$\rho_b \phi = (1-\phi)\rho_{ma} + \phi\rho_f \quad (1)$$

When solved for porosity, we get.

$$\phi = \frac{\rho_{ma}-\rho_b}{\rho_{ma}-\rho_f} \quad (2)$$

In (1) and (2), ρ_b is the bulk density of the formation, ρ_{ma} is the density of the rock matrix, ρ_{fl} is the density of the fluids occupying the porosity, and Φ is the porosity of the rock. Common values of matrix density (in g/cm³) are Quartz sand - 2.65, Limestone - 2.71, Dolomite - 2.87, and shale - 2.8.

Permeability (K)

Derived from the Coates and Dumanoir (1973) model, incorporating porosity and irreducible water saturation.

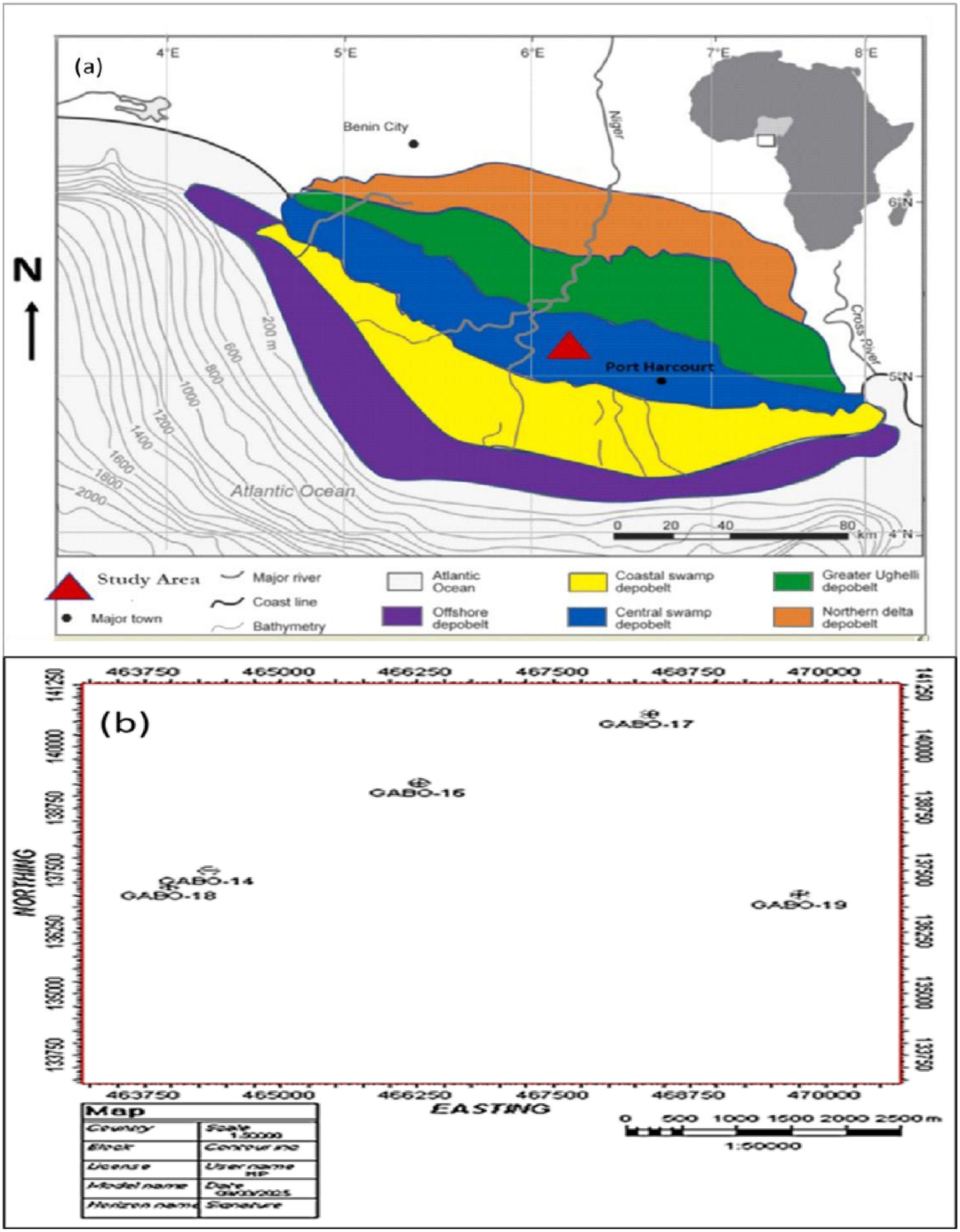

Figure 1. (a) Illustrates the Niger Delta and the study Area (Modified after Horsfall *et al*., 2024). **(b)** Base map of the study area showing the position of the wells.

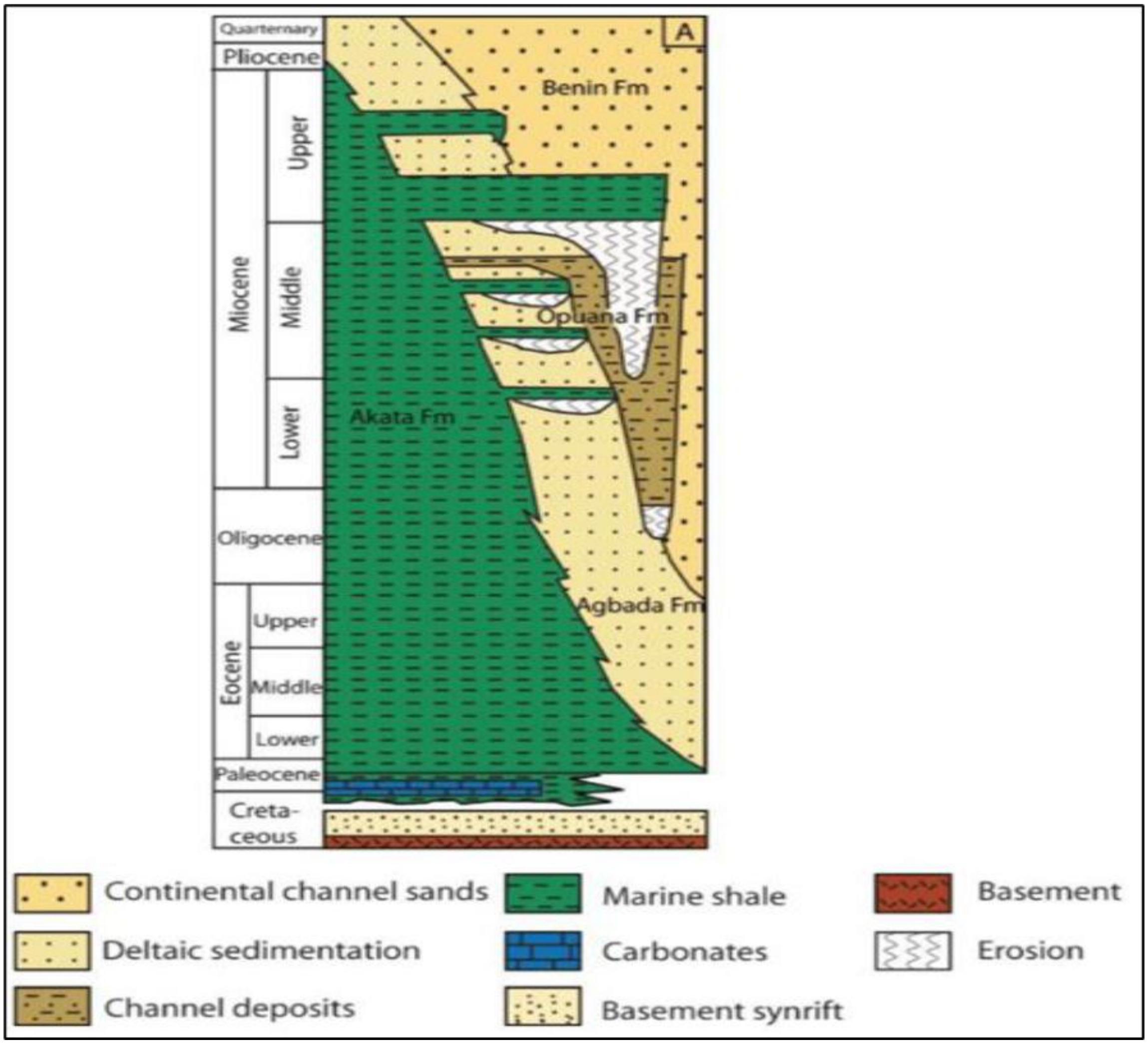

Figure 2. Stratigraphic column showing Benin, Agbada, and the Akata formation. (modified after Kouadio *et al*., 2020).

Table 1. Sorting index for different classes of sorting (Omoboriowo *et al*., 2012).

Sorting	Sorting index
Extremely well-to-well-sorted	0.70
Very well to well-sorted	0.77
Well sorted	0.84
Well, to moderately sort	0.87
Moderately sorted	0.91
Moderately to poorly sorted	0.95
Poorly sorted	1.00

Davies *et al*. (2019) identified Van Baaren's model as a reliable empirical approach for predicting permeability, while RGPZ and Timur's models overestimate permeability and Berg's model underestimates it (measured in millidarcies, mD) within Niger Delta reservoir rocks. Accordingly, this research adopted Van Baaren's model (presented in Equation 3) to estimate the permeability of the target reservoir.

$$K\ (mD) = 10 D_d^2 \phi^{3.64+m} C^{-3.64} \quad (3)$$

In this model, D_d (dominant grain size in microns), ϕ (fractional porosity), m (cementation exponent), and C (sorting index) are key inputs. The sorting index ranges from 0.7 for well-sorted to 1.0 for poorly sorted grains. The cementation exponent retains values used in prior water saturation models, and the grain size is fixed at 316 microns, following Akpan *et al*. (2016).

Estimating C remains the main challenge. Van Baaren's chart (Van Baaren, 1979), as shown in Table 1, aids this process. As the Agbada Formation (which is the principal

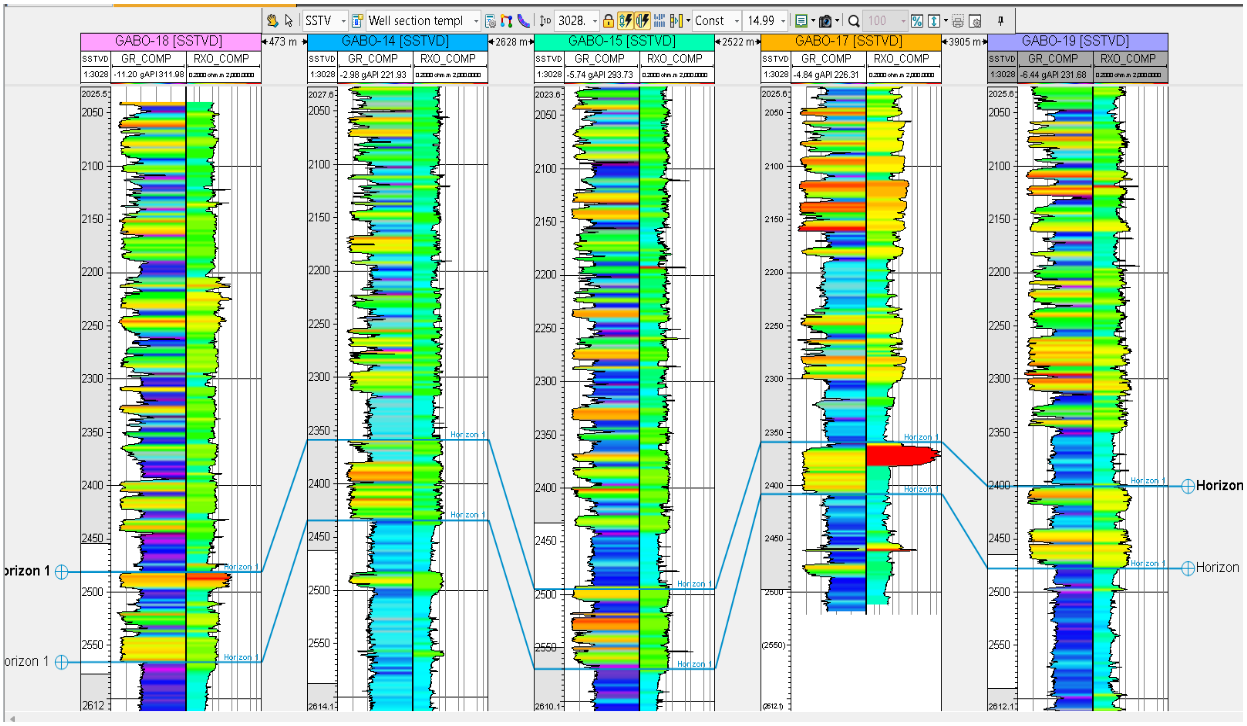

Figure 3. Correlated well logs.

Table 2. Reservoir interval and thickness.

Well name	Top (m)	Base (m)	Reservoir thickness (m)
GABO-18	2481	2567	86
GABO-14	2358	2433	75
GABO-15	2493	2568	75
GABO-17	2358	2408	50
GABO-19	2401	2476	75

reservoir in the Niger Delta) is moderately to poorly sorted (Omoboriowo *et al.*, 2012), sorting indices were assigned using Van Baaren's framework.

Well correlation

Well correlation across GABO 14, GABO 15, GABO 17, GABO 18, and GABO 19 was performed to establish the lateral continuity of stratigraphic units and to identify reservoir intervals across the field, using gamma-ray and deep resistivity logs, which provided consistent lithological signatures confirming lateral continuity of the reservoir unit (Horizon 1).

Using the signatures from the gamma ray log, the predominantly sandy formation was identified as a possible reservoir unit, as seen from the available well logs. These units were then affirmed as possible reservoirs from the signature of the deep resistivity log, which can identify the presence of hydrocarbons with the measured resistivity in the formation of interest. This will aid in the identification and correlation of a reservoir unit across the field of interest.

RESULTS

The results obtained from the data analysed are presented in this subsection. The correlated well logs are shown in Figure 3. This led to an estimated range of depths for the reservoir of interest, as from the 5 analysed wells, as shown in Table 2. After estimating the key petrophysical reservoir variables (porosity and permeability) based on the analysed well logs, these variables were plotted against the identified depth interval of the reservoir to examine their trends with depth. These plots are shown in Figure 4, and the permeability-porosity for the five wells combined was plotted, as presented in Figure 5.

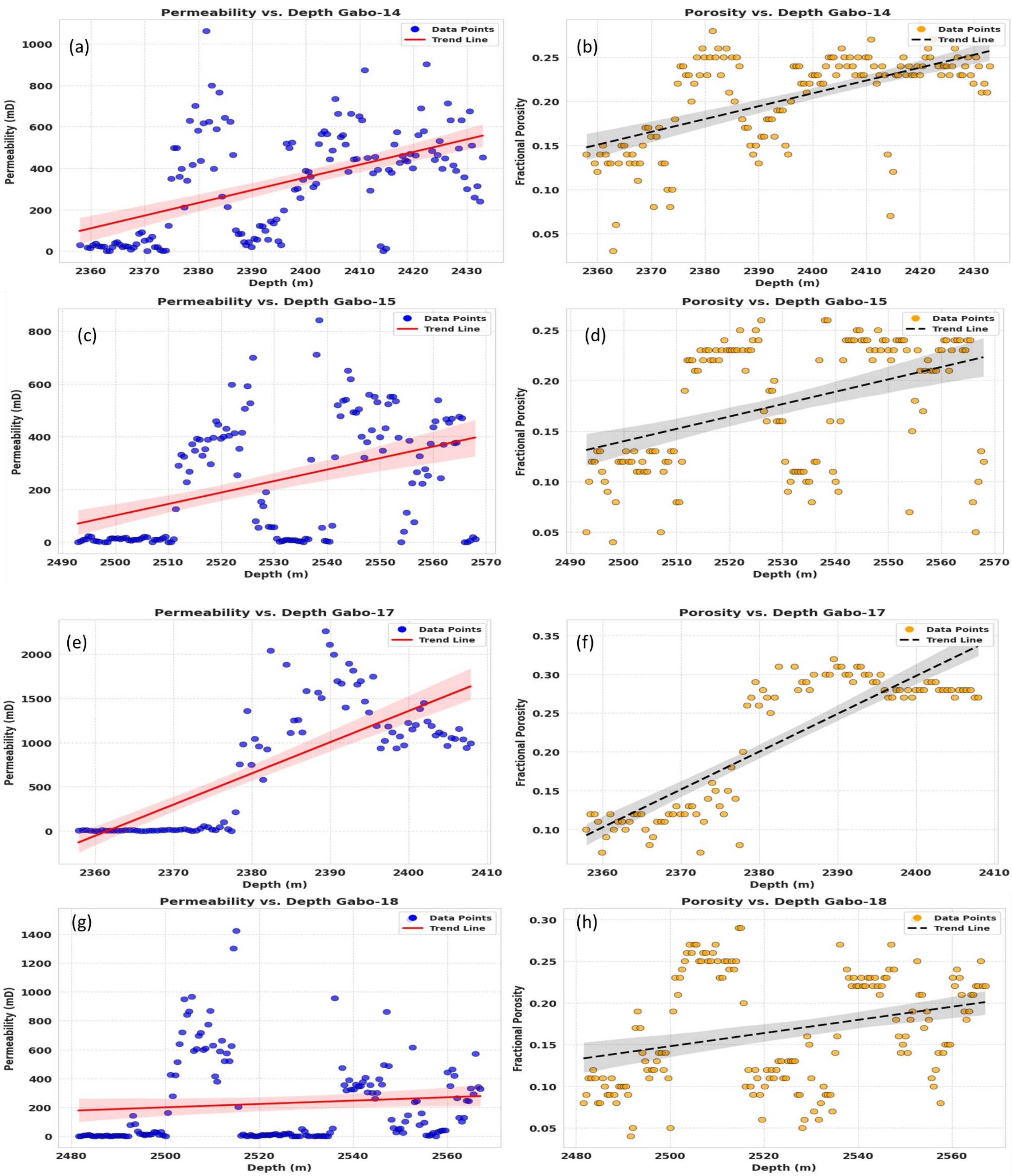

Figure 4. (a) Permeability vs Depth, (b) Fractional Porosity vs Depth Gabo-14, (c) Permeability vs Depth, (d) Fractional Porosity vs Depth Gabo-15, (e) Permeability vs Depth, (f) Fractional Porosity vs Depth Gabo-17, (g) Permeability vs Depth, (h) Fractional Porosity vs Depth Gabo-18.

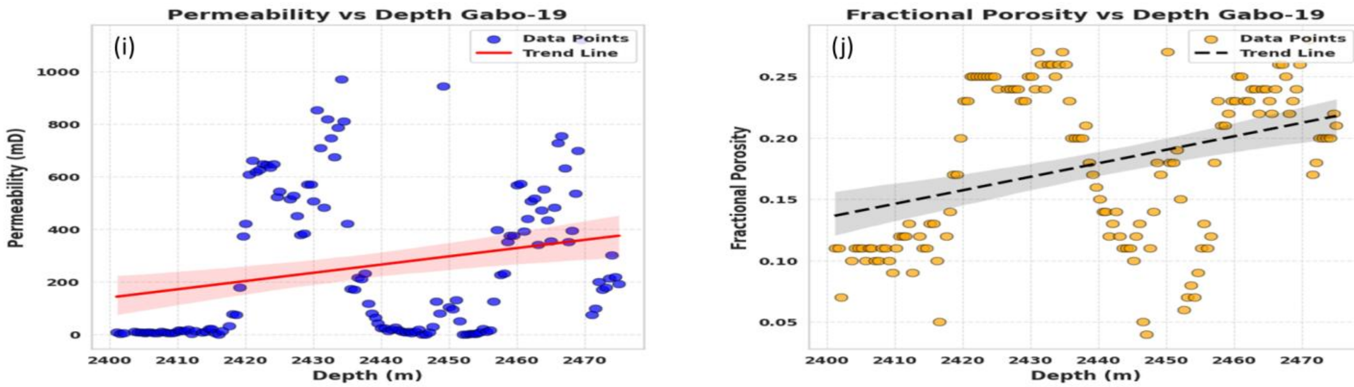

Figure 4 Contd. (i) Permeability vs Depth, **(j)** Fractional Porosity vs Depth Gabo-19.

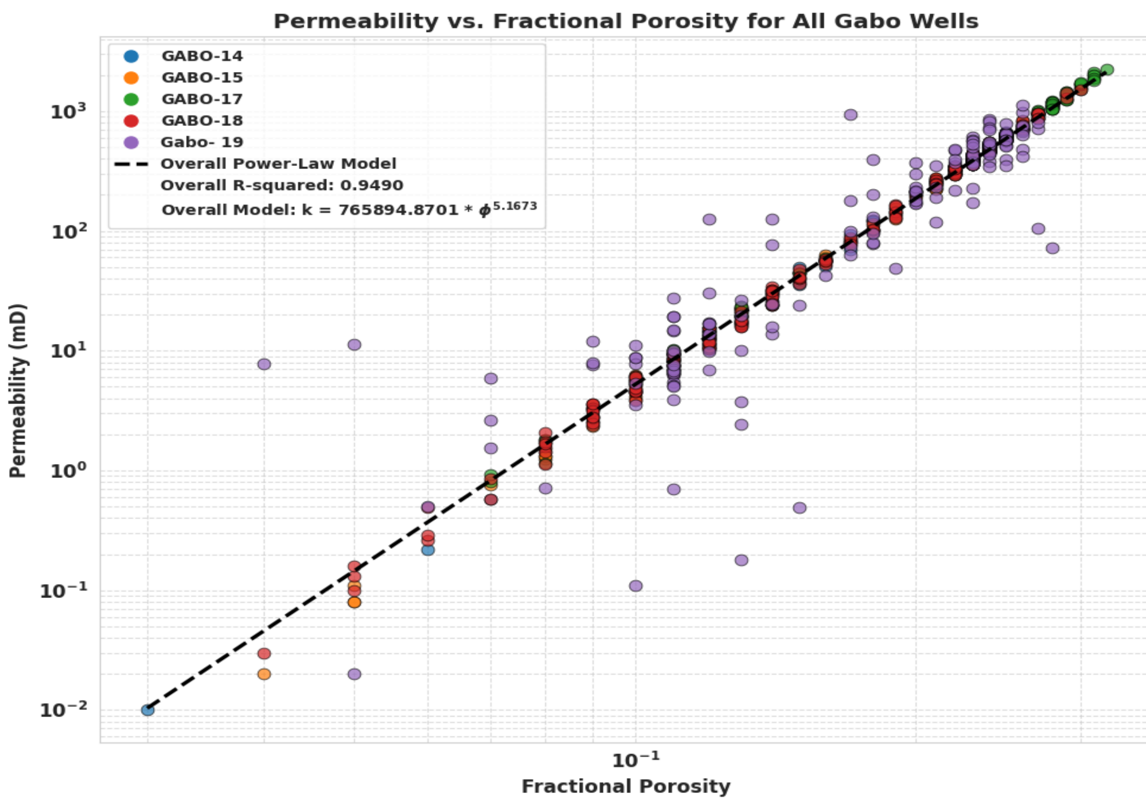

Figure 5. Illustrate Permeability vs porosity for all the wells in Gabo Field, with overall power-law model trend line and R-Squared value of 0.9490, of which $K = 765894.8701 \times \varphi^{5.16713}$ represent the modelled equation for Gabo Field.

Reservoir geometry and correlation

The gamma-ray logs display uniformly low API values across all wells, indicative of a laterally extensive sandy succession typical of the Agbada Formation. Resistivity responses show distinct hydrocarbon-bearing intervals, validating clean sand units with minimal shale influence.

Closer examination reveals subtle but important intra-reservoir variations. GABO 18 shows the thickest development (86 m), which suggests its location within a more proximal depositional belt, likely a shoreface to delta-front system. GABO 17, though thinner (50 m), displays the cleanest and highest-quality sand body, evidenced by its unusually high basal porosity and permeability. This

Table 3. Estimate range of fractional porosity and permeability.

Parameters		GABO- 18	GABO-14	GABO-15	GABO-17	GABO-19
Depth (M)	Top	2481	2358	2493	2358	2401
	Base	2567	2433	2568	2408	2476
Fractional Porosity	Min.	0.04	0.03	0.04	0.07	0.04
	Max.	0.30	0.28	0.26	0.32	0.28
Permeability (mD)	Min.	0.03	0.01	0.02	0.81	0.02
	Max.	1501.60	1062.94	842.59	2259.69	1119.72

suggests localised diagenetic enhancement or a higher-energy depositional facies. These interpretations integrate with sedimentological models of the Niger Delta, where lateral facies transitions and channel-mouth bar geometries produce variable sand-body thickness but maintain continuity across well clusters (Reijers *et al*., 1997; Arochukwu *et al*., 2023). The correlation thus confirms:

1. a regionally continuous reservoir,
2. moderate thickness variation driven by depositional architecture,
3. improved reservoir quality downdip (notably in GABO 17 and GABO 18), and
4. consistent hydrocarbon saturation across all wells.

A continuous reservoir unit Horizon 1 (Figure 3) was identified across all wells, with top depths ranging from 2358 to 2493 m and base depths from 2408 to 2568 m (Table 2). The unit thickness varies from 50 (GABO-17) to 86 m (GABO-18), indicating a moderately thick, laterally extensive sand body, typical of shoreface or delta-front deposits in the Niger Delta (Reijers *et al*., 1997; Arochukwu *et al*., 2023).

Petrophysical property ranges

The estimated permeability and porosity parameters across the five wells are summarised in Table 3.

Depth-dependent trends

Analysis of cross-plots is shown in Figure 4. The red trend lines and shaded confidence intervals reveal the following trends with depth: Porosity, Figure 4 (b, d, f, h, j) show an unexpected increase with depth, contrary to typical compaction trends. Permeability, Figure 4 (a, c, e, g, i) increase significantly with depth, reflecting better pore connectivity and reservoir quality.

In GABO-17, porosity increases from the top of the reservoir (10.71%) to the base (28.00%), representing a massive improvement in storage capacity over a span of only ~43 meters. The permeability in GABO-17 jumps from a nearly 7.94 mD at the top to a prolific 1123.29 mD at the base. Similar multi-fold increases are seen in all other wells (e.g., GABO-19 increases from 7.79 to 412.92 mD). This result confirms that the base of these reservoir units in the Gabo Field contains significantly cleaner, coarser, and more porous sandstones than the top, likely representing a progradational or diagenetically enhanced sequence (Petter and Steel, 2006; Bjørlykke, 2014; Iheaturu *et al*., 2022). Gabo-19 reveals two high-permeability "sweet spots”, one in the middle section (approx. 2420–2435 m) and another towards the base (2460–2475 m), where values peak above 1000 mD.

Permeability-fractional porosity plots

The plots for the GABO well series (14, 15, 17, 18, and 19), as shown in Figure 5, illustrate the fundamental Permeability-Porosity (*k*-*ϕ*) relationship, which is the cornerstone of reservoir characterisation. The results are linear in log (permeability) vs. porosity, which is common in clean, well-sorted sandstone reservoirs, indicating a strong exponential relationship between porosity and permeability (Beard and Weyl, 1973; Enaworu, 2024; Wu *et al*., 2023). The modelled Equation of permeability and porosity is given by $K = 765894.8701 \times \varphi^{5.16713}$ This implies that permeability can be estimated using porosity information in the absence of core and well log data.

DISCUSSION

Porosity anomaly

The results obtained in this study exhibit trends that are consistent with, yet in some cases exceed, published porosity and permeability relationships for Niger Delta reservoirs. The observed increase in porosity with depth contrasts with the classical mechanical compaction trend but matches findings by Bloch *et al*. (2002), Bjørlykke and Jahren (2012), and Wang *et al*. (2024), who documented secondary porosity creation and overpressure-related porosity preservation in deeply buried sandstones.

Table 4. Porosity and permeability variation from top to base of the reservoir.

Well	Top Depth (Avg m)	Base Depth (Avg m)	Porosity at Top (%)	Porosity at Base (%)	Permeability at Top (mD)	Permeability at Base (mD)
GABO-18	2487.6	2561.1	10.24	18.24	16.22	198.78
GABO-14	2364.1	2427.6	13.05	23.73	29.26	483.07
GABO-15	2498.5	2562.7	10.82	19.86	10.63	301.38
GABO-17	2361.2	2404.7	10.71	28	7.94	1123.29
GABO-19	2406.9	2470	10.71	22.43	7.79	412.92

As porosity increases from 0.10 to 0.28, permeability increases by several orders of magnitude, reaching values over 1,000 mD. Rock quality improves with higher porosity (Tiab and Donaldson, 2015; Amaefule *et al*., 1993). The increase in porosity with depth may be attributed to secondary porosity development through diagenetic processes like feldspar dissolution (Bjørlykke and Jahren, 2012; Bloch *et al*., 2002; Li *et al*., 2024), and/or the presence of overpressure zones that inhibit compaction (Paxton *et al*., 2002; Shi *et al*., 2024). This phenomenon has been documented in other Niger Delta reservoirs, where overpressure and diagenetic alteration commonly preserve or enhance porosity at depth (Weber and Daukoru, 1975; Igili and Ndubueze, 2024).

Permeability enhancement

Permeability range (0.25 to 2.6 mD) suggests a tight to low-permeability reservoir, possibly a tight sandstone or a poorly sorted formation (Holditch, 2006; Wang *et al*., 2024). The positive correlation between permeability and depth aligns with improved sorting, coarser grain sizes, and possible fracture-enhanced flow in deeper zones (Paxton *et al*., 2002; Bloch *et al*., 2002). In the Niger Delta, deeper channel sands commonly exhibit these characteristics, enhancing reservoir quality (Reijers *et al*. 1997). Permeabilities exceeding 1000 mD in GABO-17 and GABO-18 classify these intervals as excellent reservoirs (Tiab and Donaldson, 2015; Amaefule *et al*., 1993), indicating high flow capacity favourable for commercial production.

Permeability values exceeding 1000 mD in GABO 17 and GABO 18 significantly surpass the typical range (10–500 mD) reported for most Niger Delta shoreface sands (Amaefule *et al*., 1993; Igili and Ndubueze, 2024). This integrates with global cases of diagenetically enhanced deep reservoirs (Wu *et al*., 2023; Zhang *et al*., 2024). The exponential porosity and permeability relationship observed in all wells is also in agreement with earlier models for clean sandstones (Beard and Weyl, 1973; Pittman, 1992) and supports recent findings by Enaworu (2024) and Lindsay *et al*. (2023) regarding pore system efficiency and grain sorting. Overall, the Gabo Field exhibits superior deep reservoir quality compared to regional averages, making it a high-potential development target.

Permeability-porosity plot

For the Gabo Field wells combine plot, it was noticed that when plotted on a semi-log scale (Log k vs. Linear ϕ), the data points generally form a diagonal trend. This suggests a power-law relationship, often expressed as:

$$k = A \times \varphi^B \quad (4)$$

Which are characteristics of a clean, well-sorted, typical of high-quality sandstone reservoirs in the Niger Delta. The lack of significant scattering suggests a relatively homogeneous but slightly heterogeneous reservoir facies with consistent pore-throat geometry (Nelson, 1994; Tiab and Donaldson, 2015). This trend indicates that as the volume of pore space increases, the pathways for fluid flow increase exponentially. This is typical of clastic reservoirs, where the primary control on flow is the size and interconnectivity of the pores, and they are used to define hydraulic flow units for permeability prediction (Amaefule *et al*., 1993).

Points with high ϕ (>0.20) and high k (>100 mD) represent the "sweet spots" of the reservoir, likely clean, well-sorted sandstones with minimal clay content (Tiab and Donaldson, 2015; Pittman, 1992). While points with low ϕ and k likely correspond to shaly intervals or highly cemented zones where pore throats are constricted (Nelson, 1994; Bjørlykke, 2014). Permeability increases exponentially with an increase in porosity in rock.

Well-specific performance

GABO-17 and GABO-18 exhibit the most favourable petrophysical characteristics of high porosity (up to 0.32), high permeability (up to 2259.69 mD. These wells are prioritised for production (Table 4).

Conclusion

This integrated multi-well analysis reveals clear depth-dependent petrophysical trends in the Gabo Field reservoir. The general improvement in reservoir quality with depth, higher porosity, and permeability, highlights the potential of deeper intervals for hydrocarbon production. The anomalous increase in porosity with depth suggests significant diagenetic or pressure-related influences that warrant further investigation using core and seismic data. Based on these outcomes, GABO 17 and GABO 18 represent the most promising wells for development and should be prioritised for deeper completions between 2490–2570 m. The study provides a reliable petrophysical foundation for optimising future drilling and reservoir management in the Gabo Field. This integrated multi-well study successfully characterised depth-dependent porosity and permeability trends within Horizon 1 of the Gabo Field, revealing several key findings:

1. Porosity increases with depth, ranging from ~10% near the top to over 28% at the base in some wells, indicating significant secondary porosity or overpressure preservation.
2. Permeability increases exponentially with depth, reaching values exceeding 2000 mD in GABO 17 and GABO 18, confirming excellent fluid-flow capacity in deeper intervals.
3. A strong porosity–permeability relationship exists across all wells, suggesting a homogeneous, clean sandstone system with efficient pore-throat connectivity.
4. Well correlation confirms a continuous reservoir with moderate thickness variation but consistent lithological signatures across the field.
5. Comparative evaluation shows that the Gabo Field reservoir exceeds regional and global averages in deep-reservoir quality.

CONFLICT OF INTEREST

The authors declare that they have no conflict of interest.

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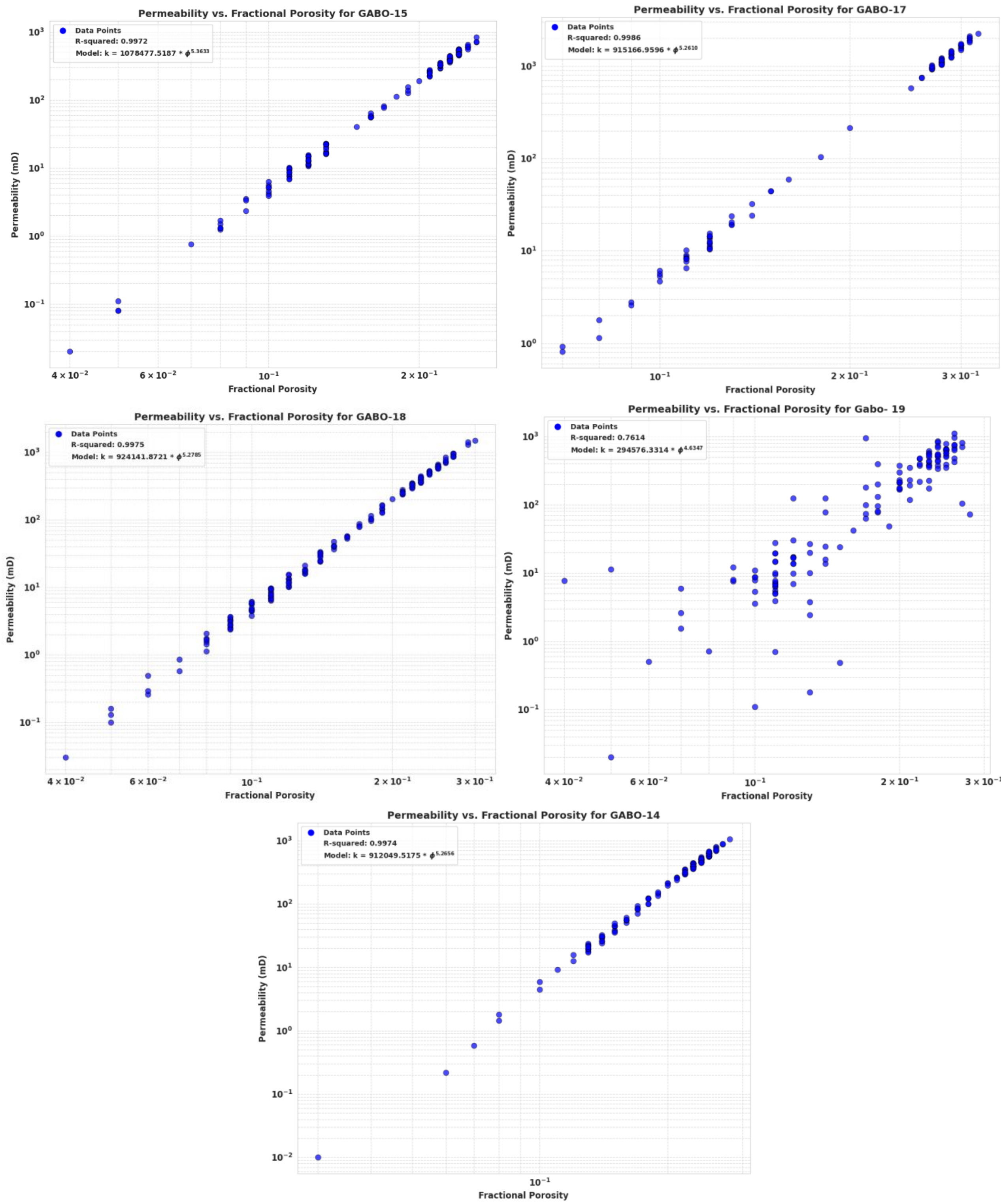
Appendix



Appendix Figure 1. (a) Illustrate permeability vs porosity for Gabo-14, which indicates a good linear correlation between permeability and porosity. (b) Illustrate permeability vs porosity for Gabo-15, with a good correlation. (c) Illustrate permeability vs porosity for Gabo-17, which also shows a perfect linear correlation. (d) illustrate permeability vs porosity for Gabo-18, it also indicates a linear correlation and (e) Illustrate permeability for Gabo-19, this suggests a slight linear correlation with a reasonable scatter.