



(RESEARCH ARTICLE)



INTEGRATED PETROPHYSICAL CHARACTERIZATION AND HYDROCARBON POTENTIAL ASSESSMENT OF RESERVOIRS IN EMERALD FIELD, NIGER DELTA BASIN, NIGERIA

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Magna Scientia Advanced Research and Review, 2026, 18(01), 173–181

Publication history: Received on 04 September 2026; revised on 11 October 2026; accepted on 13 October 2026

Article DOI: <https://doi.org/10.30574/msarr.2026.18.1.0204>

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ABSTRACT

Understanding variations in reservoir quality is essential for evaluating the hydrocarbon potential of the Niger Delta. This study investigated these variations in Emerald Field by integrating petrophysical parameters derived from well logs across six wells: RBK-15, RBK-07, RBK-10, RBK-13, RBK-17 and RBK-04. Gamma-ray, deep resistivity, bulk-density and neutron-porosity logs were analysed using Petrel software to identify reservoir intervals and estimate shale volume, effective porosity, water saturation, hydrocarbon saturation, permeability and net-to-gross ratio (NTG). Water saturation was evaluated using the Simandoux model to account for the influence of shale on resistivity-based estimates. The identified reservoir intervals range from 199 to 266 ft in gross thickness, but their petrophysical properties vary considerably. Mean effective porosity ranges from 0.13 to 0.24, while mean hydrocarbon saturation varies from 0.74 to 0.91 and NTG from 0.55 to 0.83. These differences are reflected in the integrated assessment of the wells. RBK-17 has the most favourable combination of effective porosity, model-derived permeability and NTG, whereas RBK-15 records the highest mean hydrocarbon saturation and lowest mean water saturation. In contrast, RBK-07 exhibits comparatively less favourable characteristics, including higher shale volume and lower effective porosity and NTG. The findings show that reservoir quality in Emerald Field varies between wells and cannot be adequately assessed using a single petrophysical parameter. Integrating these indicators provides a more balanced basis for identifying favourable reservoir intervals and guiding further appraisal. Nevertheless, independent permeability measurements and production data are needed to determine whether the estimated reservoir potential translates into effective production performance.

Keywords: Emerald Field; Petrophysical Characterization; Simandoux Model; Reservoir Quality; Hydrocarbon Potential.

1 INTRODUCTION

The Niger Delta Basin is a major petroleum province characterized by a thick Tertiary siliciclastic succession comprising the Akata, Agbada and Benin formations. The Agbada Formation, consisting predominantly of interbedded sandstones and shales, contains the principal reservoir intervals of the Niger Delta petroleum system [1]. Depositional variability and structural deformation in the reservoir rocks of the Delta have produced considerable heterogeneity in reservoir thickness, continuity and petrophysical properties, making accurate characterization important for evaluating reservoir quality and hydrocarbon distribution [2,3].

Petrophysical characterization provides a quantitative means of evaluating this heterogeneity through parameters such as shale volume, effective porosity, permeability, fluid saturation and net-to-gross ratio. Integration of these properties from well-log data has been widely applied to reservoir evaluation in the Niger Delta, where studies have demonstrated significant variations in reservoir quality both vertically and between wells [4–7]. Archie's relationship remains fundamental to resistivity-based water-saturation estimation [8], while regionally derived empirical relationships such as that of Owolabi et al. [9] provide a basis for estimating permeability in unconsolidated Niger Delta sands. These approaches emphasize the importance of integrating multiple petrophysical indicators when assessing reservoir quality rather than relying on a single property.

Emerald Field has previously been investigated using integrated seismic and well-log data. Kalu et al. [10] identified three hydrocarbon-bearing reservoirs, Emy A, Emy B and Emy C, from four wells and reported porosity of 10–29%, hydrocarbon saturation of 0.75–0.84, shale volume of 0.24–0.33 and net-to-gross ratios of 0.72–0.93. Their results established the hydrocarbon-bearing character of the field but also demonstrated variability in its reservoir properties [10]. Further evaluation of reservoir quality across additional wells is therefore necessary to determine the extent of interwell variability and to identify the reservoir intervals with the most favourable combination of storage, flow and hydrocarbon-bearing characteristics.

The present study aims to integrate well-log-derived petrophysical parameters to characterize the reservoirs of Emerald Field and assess their hydrocarbon-bearing potential. Specifically, it evaluates shale volume, effective porosity, water saturation, hydrocarbon saturation, estimated permeability and net-to-gross ratio to establish variations in reservoir quality and identify the relatively more favourable reservoir intervals within the field.

2 GEOLOGICAL SETTING OF THE STUDY AREA

The Niger Delta Basin is a major Cenozoic sedimentary basin on the Gulf of Guinea and comprises several depobelts, including the Coastal Swamp depobelt in which Emerald Field is located. Its Tertiary succession consists principally of the Akata, Agbada and Benin formations. The Akata Formation comprises predominantly marine pro-delta shales, the Agbada Formation consists of paralic interbedded sandstones and shales and forms the principal reservoir-bearing succession, while the Benin Formation is dominated by continental sands and sandstones [1,3]

The reservoir succession in Emerald Field therefore occurs within the heterogeneous sandstone–shale architecture characteristic of the Agbada Formation. Previous work on the field identified hydrocarbon-bearing reservoir units using integrated seismic and well-log data [10]. The present study evaluates six wells within the field to assess the petrophysical characteristics and reservoir-quality variations of the identified reservoir intervals.

3 MATERIAL AND METHODS

3.1 Data and Well Log Preparation

The study used wireline-log data from six wells in Emerald Field: RBK-15, RBK-07, RBK-10, RBK-13, RBK-17 and RBK-04. The available logs included gamma ray (GR), deep resistivity (R_t), bulk density (RHOB) and neutron porosity. The logs were depth-matched and quality-controlled, with anomalous spikes removed using Petrel proprietary software. Reservoir intervals were delineated primarily from relatively low GR and higher resistivity responses and subsequently correlated between wells.

A well-to-seismic tie was also performed using density and sonic logs to generate acoustic impedance and a synthetic seismogram. The resulting correlation coefficient was ≥ 0.80 , allowing integration of the well data with the seismic framework and interpretation of the structural setting and lateral continuity of the reservoir intervals.

3.2 Shale-Volume Estimation

Shale volume (V_{sh}) was calculated from the gamma-ray log. The gamma-ray index was first determined as:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (1)$$

where GR_{min} and GR_{max} represent the clean-sand and shale baselines, respectively. Since the studied reservoirs are Tertiary siliciclastic rocks, the Larionov relationship for Tertiary formations was applied [11]:

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

The calculated values were constrained to the range 0–1.

3.3 Effective-Porosity Estimation

Density-derived porosity was calculated using:

$$\Phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (3)$$

where ρ_{ma} is matrix density, ρ_b is bulk density and ρ_f is pore-fluid density. A sandstone matrix density of 2.65 gcm^{-3} was adopted. Effective porosity was then calculated by correcting for shale volume according to Asquith *et. al.* [12]:

$$\phi_e = \phi_D(1 - V_{sh}) \quad (4)$$

3.4 Water and Hydrocarbon Saturation

For this study, the Simandoux model [13] was therefore used to account for the shale contribution in estimating water saturation, rather than applying the clean-sand Archie equation directly [8], since the reservoir rocks of the Niger Delta are commonly characterized as shaly sandstones, in which shale contributes additional electrical conductivity and can affect resistivity-based saturation estimates [14].

Water saturation (S_w) was calculated using:

$$\frac{1}{R_t} = \frac{\phi_e^m S_w^n}{a R_w} + \frac{V_{sh} S_w}{R_{sh}} \quad (5)$$

For $n = 2$, the equation was rearranged as:

$$S_w = \frac{a R_w}{2 \phi_e^m} \left[\sqrt{\left(\frac{V_{sh}}{R_{sh}} \right)^2 + \frac{4 \phi_e^m}{a R_w R_t}} - \frac{V_{sh}}{R_{sh}} \right] \quad (6)$$

where R_t is true formation resistivity, ϕ_e is effective porosity, V_{sh} is shale volume, R_{sh} is shale resistivity, R_w is formation-water resistivity, a is the tortuosity factor, m is the cementation exponent and n is the saturation exponent. The adopted values were $R_w = 0.20 \Omega m$, $a = 1.45$, $m = 1.65$ and $n = 2$. R_t , V_{sh} , ϕ_e and R_{sh} were obtained from the corresponding well-log analyses. Calculations were restricted to the identified reservoir intervals and constrained to the range 0–1.

Hydrocarbon saturation S_h was calculated from:

$$S_h = 1 - S_w \quad (7)$$

3.5 Permeability Estimation

Permeability was estimated using the empirical relationship developed by Owolabi *et al.* [9] for unconsolidated sands of the Eastern Niger Delta:

$$K = 307 + 26,552 \phi_e^2 - 34,540 (\phi_e S_{wi})^2 \quad (8)$$

where K is permeability (mD), ϕ_e is effective porosity and S_{wi} is irreducible water saturation, expressed as fractions.

Since core-derived S_{wi} was not available, S_{wi} was estimated using the formation-factor relationship adopted in the study:

$$F = \frac{a}{\phi_e^m} \quad (9a)$$

$$S_{wi} = \sqrt{\frac{F}{2000}} \quad (9b)$$

where F is formation factor, a is the tortuosity factor and m is the cementation exponent. Values of $a = 1.45$ and $m = 1.65$ were adopted for this study.

3.6 Net-to-Gross and Reservoir-Quality Assessment

Net reservoir thickness was determined by applying appropriate cut-off values to V_{sh} , ϕ_e and S_w . An interval was considered net reservoir where it satisfied the adopted criteria:

$$V_{sh} \leq V_{sh,cut}, \phi_e \geq \phi_{e,cut}, S_w \leq S_{w,cut} \quad (10)$$

Where $V_{sh,cut} = 0.35$, $\phi_{e,cut} = 0.12$ and $S_{w,cut} = 0.6$. These thresholds were adopted for the present study based on the petrophysical characteristics of the field and published cutoff practices in Niger Delta reservoirs [4,7,15].

The net-to-gross ratio was subsequently calculated as:

$$NTG = \frac{H_{net}}{H_{gross}} \quad (11)$$

where H_{net} and H_{gross} are the net and gross reservoir thicknesses, respectively.

Reservoir quality and hydrocarbon-bearing potential were evaluated by integrating V_{sh} , ϕ_e , estimated K , S_w , S_h and NTG. This integrated approach was used to identify variations in reservoir quality between the six wells rather than relying on any single petrophysical parameter.

4 RESULTS

4.1 Reservoir Identification and Distribution

Reservoir intervals were identified from characteristic low gamma-ray and relatively high resistivity responses and correlated across the six wells, as summarized in Table 1. The identified intervals occur at depths between 11,488 and 12,855 ft, with gross thicknesses ranging from 199 to 266 ft. RBK-17 contains the shallowest reservoir interval, with a top depth of 11,488 ft, whereas RBK-10 records the deepest reservoir base at 12,855 ft. RBK-13 contains the thickest identified reservoir interval (266 ft), while RBK-15 has the thinnest (199 ft). These variations in reservoir depth and gross thickness demonstrate differences in the distribution and thickness of the identified intervals across Emerald Field.

Table 1: Reservoir intervals identified across the six wells in Emerald Field

Well	Top (ft)	Base (ft)	Gross thickness (ft)
RBK-15	11,499	11,698	199
RBK-07	12,597	12,810	213
RBK-10	12,629	12,855	226
RBK-13	12,564	12,830	266
RBK-17	11,488	11,695	207
RBK-04	12,344	12,578	234

4.2 Petrophysical Properties of the Identified Reservoirs

4.2.1 Petrophysical Properties of the Identified Reservoirs

The identified reservoir intervals were evaluated using shale volume (V_{sh}), effective porosity (ϕ_e), water saturation (S_w), hydrocarbon saturation (S_h), model-derived permeability (K) and net-to-gross ratio (NTG). The calculated parameters exhibit considerable variability among the six wells, indicating differences in lithological composition, pore-space characteristics, fluid saturation and net-reservoir proportion across Emerald Field.

The pointwise shale-volume values range from approximately 0.00 to 0.99, while effective porosity ranges from 0.00 to 0.37. Water saturation ranges from 0.01 to 0.90, and hydrocarbon saturation ranges from 0.10 to 0.99 across the identified reservoir intervals. Model-derived permeability varies from approximately 304 to 3,940 mD, indicating substantial variation in the estimated flow characteristics of the reservoirs.

At the well scale, mean shale volume ranges from 0.21 to 0.39, while mean effective porosity ranges from 0.13 to 0.24. Mean water saturation varies from 0.09 to 0.26, and mean hydrocarbon saturation ranges from 0.74 to 0.91. Mean model-derived permeability ranges from 910.81 to 1,985.38 mD, while NTG varies from 0.55 to 0.83.

RBK-17 records the lowest mean shale volume (0.21), the highest mean effective porosity (0.24), the highest mean model-derived permeability (1,985.38 mD) and the highest NTG (0.83). RBK-15 also exhibits favourable petrophysical characteristics, with mean effective porosity of 0.20, estimated permeability of 1,465.75 mD, mean hydrocarbon saturation of 0.91 and NTG of 0.75. In contrast, RBK-07 has the highest mean shale volume (0.39), the lowest mean effective porosity (0.13), the lowest mean model-derived permeability (910.81 mD), the lowest mean hydrocarbon saturation (0.74) and the lowest NTG (0.55). The remaining wells exhibit intermediate values across these parameters, although their relative characteristics differ according to the property considered.

Overall, the results demonstrate substantial variation in reservoir properties across Emerald Field. The integrated distribution of shale volume, effective porosity, fluid saturation, estimated permeability and NTG provides a basis for comparing reservoir quality and assessing the relative hydrocarbon-bearing potential of the identified intervals. The well-by-well summary of these petrophysical parameters is presented in Table 2.

Table 2: Summary of petrophysical parameters for the identified reservoirs in Emerald Field

Well Name	V_{sh}		Φ_e		S_w		S_h		K (mD)		NTG
	Range	Mean	Range	Mean	Range	Mean	Range	Mean	Range	Mean	
RBK-15	0.00–0.99	0.28	0.00–0.33	0.20	0.02–0.26	0.09	0.74–0.98	0.91	304.38–3113.54	1465.75	0.75
RBK-07	0.00–0.99	0.39	0.00–0.28	0.13	0.05–0.88	0.26	0.12–0.95	0.74	303.85–2398.99	910.81	0.55
RBK-10	0.00–0.99	0.32	0.00–0.28	0.16	0.04–0.90	0.25	0.10–0.96	0.75	303.74–2392.44	1066.85	0.61
RBK-13	0.00–0.99	0.29	0.00–0.29	0.16	0.02–0.80	0.15	0.20–0.98	0.85	303.75–2475.85	1096.96	0.68
RBK-17	0.00–0.99	0.21	0.00–0.37	0.24	0.03–0.79	0.16	0.21–0.97	0.84	304.52–3939.82	1985.38	0.83
RBK-04	0.00–0.99	0.33	0.00–0.28	0.15	0.01–0.63	0.12	0.37–0.99	0.88	303.76–2311.27	1012.12	0.59

5 DISCUSSION

5.1 Reservoir Heterogeneity and Quality Variation

The petrophysical results reveal appreciable vertical and interwell heterogeneity in Emerald Field. Although reservoir intervals were identified in all six wells, their gross thicknesses range from 199 ft in RBK-15 to 266 ft in RBK-13, while their tops occur at depths between 11,488 ft in RBK-17 and 12,629 ft in RBK-10. These differences indicate that the identified intervals vary in thickness and stratigraphic position across the study area. However, gross thickness alone does not establish reservoir quality because the proportion of sandstone, effective pore space and fluid distribution may differ substantially within intervals of comparable thickness according to Anyiam *et al.* [16].

The well-averaged petrophysical properties further demonstrate this variability. Mean shale volume ranges from 0.21 in RBK-17 to 0.39 in RBK-07, whereas mean effective porosity ranges from 0.13 in RBK-07 to 0.24 in RBK-17. The contrasting values suggest that lithological composition and effective pore-space development contribute to differences in reservoir quality. RBK-17 combines the lowest mean shale volume with the highest mean effective porosity, whereas RBK-07 exhibits the opposite pattern. This inverse relationship is consistent with previous petrophysical studies reporting a reduction in effective porosity with increasing shale volume [17].

The observed heterogeneity is consistent with the variable sandstone–shale architecture commonly associated with the Agbada Formation. Previous studies in the Niger Delta have documented variations in reservoir properties and stratigraphic architecture that affect reservoir continuity and management [2,3]. In Emerald Field, the differences among the six wells indicate that field-wide averages would conceal potentially important local variations. Reservoir

evaluation should therefore preserve well-specific and, where data permit, depth-dependent property variations rather than assume uniform reservoir characteristics across the field.

5.2 Integrated Assessment of Reservoir Quality

Reservoir quality is best evaluated by integrating indicators of storage capacity, fluid-flow capacity, lithological composition and the proportion of the interval satisfying the adopted net-reservoir criteria [18]. In this study, effective porosity provides an indication of the pore space available for fluid storage, while estimated permeability provides a model-based indication of potential flow capacity. Shale volume helps characterize lithological cleanliness, and water saturation provides an estimate of the fraction of pore space occupied by water. Considered together, these parameters offer a more informative basis for comparing the wells than any single parameter considered in isolation.

On the reported mean values, RBK-17 exhibits the most favourable combination of these indicators. Its mean effective porosity of 0.24, estimated permeability of 1,985.38 mD, water saturation of 0.06 and shale volume of 0.21 collectively suggest comparatively favourable storage and potential flow characteristics. Its reported NTG of 0.83 also indicates a relatively high proportion of net reservoir within the gross interval, subject to verification of the cutoff and thickness calculations. RBK-15 is another comparatively favourable well, with mean effective porosity of 0.20, estimated permeability of 1,465.75 mD and water saturation of 0.12.

RBK-10 and RBK-13 show intermediate characteristics, with mean effective porosity of 0.16 in both wells. Their mean estimated permeabilities are 1,066.85 and 1,096.96 mD, respectively, while mean water saturation is 0.13 in RBK-10 and 0.16 in RBK-13. Although these values suggest potentially useful reservoir properties, the relatively higher water saturation in RBK-13 may reduce the proportion of pore space occupied by hydrocarbons compared with a reservoir of similar porosity and lower water saturation.

RBK-04 and RBK-07 present different limitations. RBK-04 has the highest reported mean water saturation of 0.22 and the lowest mean hydrocarbon saturation of 0.78, suggesting less favourable fluid occupancy than in the other wells. RBK-07 has the highest mean shale volume (0.39), the lowest mean effective porosity (0.13) and the lowest reported mean estimated permeability (910.81 mD). These properties collectively indicate comparatively less favourable reservoir characteristics. Nevertheless, well-level averages should not be taken to imply that every interval within these wells is poor quality; individual depth intervals may exhibit more favourable properties than the overall mean.

The comparison illustrates why reservoir ranking should be based on multiple parameters. A thick interval may contain substantial shale or limited effective pore space, while an interval with lower gross thickness may possess more favourable storage and flow characteristics. The integrated results therefore support a differentiated assessment of reservoir quality across Emerald Field, while recognizing that the ranking remains dependent on the reliability of the petrophysical models and net-reservoir criteria used.

5.3 Hydrocarbon-Bearing Potential

The reported mean hydrocarbon saturation ranges from 0.78 in RBK-04 to 0.94 in RBK-17. When considered alongside effective porosity and estimated permeability, these values suggest that the identified intervals have varying degrees of petrophysical hydrocarbon-bearing potential. RBK-17 presents the strongest combination of the reported indicators, with the highest mean effective porosity and estimated permeability, the lowest mean water saturation and the highest mean hydrocarbon saturation. RBK-15 also displays a favourable combination of storage and estimated flow properties, together with a mean hydrocarbon saturation of 0.88.

In contrast, RBK-04 has a mean hydrocarbon saturation of 0.78 and mean water saturation of 0.22. This combination indicates a relatively greater proportion of water-filled pore space, based on the reported saturation estimates. RBK-07 has a mean hydrocarbon saturation of 0.88, but its comparatively high shale volume and low effective porosity suggest that its hydrocarbon-bearing potential should not be judged from saturation alone. The distinction is important because, according to Ibe & Oyewole [19], high hydrocarbon saturation alone does not establish the volume of hydrocarbons in place or predict production performance, which also depend on reservoir volume and geometry, effective porosity, permeability and hydrocarbon mobility.

The results can be compared with the earlier Emerald Field study by Kalu et al. [10], which reported hydrocarbon saturation of 0.75–0.84, porosity of 10–29%, shale volume of 0.24–0.33 and NTG of 0.72–0.93. The present study evaluates six wells and reports a broader range of well-averaged properties, particularly for shale volume, effective porosity and hydrocarbon saturation. These differences may reflect variations in the wells and intervals evaluated, as well as differences in data processing, parameter estimation and cutoff selection. Direct numerical comparison should therefore be made cautiously unless the two studies used consistent definitions, equations and reservoir-selection criteria.

The inferred hydrocarbon-bearing potential should not be interpreted as confirmation of commercial producibility or recoverable reserves. Water saturation is estimated from petrophysical relationships, and the permeability values are model-derived rather than independently measured from core samples. Furthermore, the available analysis does not establish dynamic reservoir behaviour through production history, pressure data or fluid-property measurements. The results are therefore most appropriately used to identify and compare potentially favourable intervals and to guide further appraisal, rather than to make definitive claims about commercial development.

5.4 Implications for Reservoir Characterization and Development

The interwell variations identified in Emerald Field have implications for reservoir correlation, static modelling and the prioritization of further appraisal. The differences in shale volume, effective porosity, saturation and estimated permeability indicate that the six wells should not be represented by a single set of field-wide petrophysical properties. Instead, reservoir models should preserve the observed spatial and vertical variability to the extent supported by the well data. Correlation of reservoir units should also consider stratigraphic position and log-response patterns, rather than relying on gross thickness alone.

The reported results identify RBK-17 and RBK-15 as comparatively favourable candidates for further investigation based on their combined petrophysical characteristics. RBK-10 and RBK-13 display intermediate properties, while RBK-04 and RBK-07 exhibit specific limitations associated with fluid saturation and shale content or effective porosity, respectively. This ranking should be treated as a preliminary petrophysical screening rather than a definitive development ranking. The distinction matters because a well-scale average may conceal vertical variations in reservoir quality; consequently, intervals should also be assessed individually to identify poorer-quality sections within otherwise favourable wells and potentially promising sections within wells with less favourable average properties [20].

Confidence in the interpretation would be strengthened by validating the model-derived permeability against core measurements, where available, and comparing the saturation estimates with independent fluid or pressure evidence. The net-to-gross calculation should also be checked against the stated net-reservoir cutoff and the corresponding net and gross thicknesses. These checks are important because uncertainties in petrophysical parameter selection and cutoff application can influence net-reservoir identification and the resulting assessment of reservoir quality; sensitivity analysis is therefore important for evaluating the robustness of well comparisons and rankings [21].

Overall, the study provides a comparative petrophysical basis for delineating reservoir intervals and assessing relative reservoir quality across Emerald Field. Its principal contribution is the demonstration that reservoir quality and inferred hydrocarbon-bearing potential vary among the six wells and are best evaluated through an integrated set of indicators. Further geological correlation, petrophysical validation and dynamic reservoir data would be required to establish reservoir connectivity, production performance and commercial potential.

6 CONCLUSION

This study has shown that the six investigated wells in Emerald Field do not exhibit uniform reservoir characteristics. Although reservoir intervals were identified in every well, differences in shale content, effective porosity, fluid saturation, estimated permeability and net-to-gross ratio reveal meaningful variations in reservoir quality across the field. RBK-17 and RBK-15 emerge as the most favourable wells in the integrated assessment, but their strengths differ. RBK-17 combines the highest mean effective porosity, estimated permeability and NTG with the lowest mean shale volume. RBK-15, on the other hand, has the highest mean hydrocarbon saturation and lowest mean water saturation. These differences demonstrate why reservoir evaluation should consider the combined behaviour of petrophysical parameters rather than use hydrocarbon saturation or any single property as the sole basis for ranking wells. RBK-07 exhibits comparatively less favourable characteristics across several of the evaluated parameters. The study provides a useful petrophysical basis for comparing reservoir quality and identifying intervals that warrant further investigation. However, the permeability values are empirical estimates, and the saturation results depend on the adopted model and input parameters. Consequently, the findings establish relative hydrocarbon-bearing potential rather than confirmed production performance or recoverable reserves. Further work should focus on validating the estimated permeability against core data where available, integrating pressure and production information, and refining reservoir correlation and continuity across the field. Such investigations would help determine whether the favourable petrophysical characteristics identified in RBK-17 and RBK-15 translate into effective reservoir performance and would support more reliable decisions on appraisal and development.

STATEMENTS ON COMPLIANCE WITH ETHICAL STANDARDS

Acknowledgments

The authors are especially grateful to the group of researchers in the geophysics option of Physics department, faculty of Science, Rivers State University, Nigeria, for their support during this research.

Disclosure of conflict of interest

The authors declare that there is no conflict of interest in this research work.

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