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Petroleum Generation Potentials and Expulsion Efficiency of Shales from Pindiga Formation, Northern Benue Trough

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Abstract

This study integrates lithofacies analysis, Rock-Eval pyrolysis and mass-balance expulsion modelling to evaluate the petroleum generation potential of Cretaceous shales of the Pindiga Formation around Pindiga village, Gongola Sub-basin, Northern Benue Trough, Nigeria. Seven lithofacies were recognized from the measured succession: black carbonaceous shale, dark grey laminated shale, bioclastic limestone, calcareous shale, silty shale, ripple-laminated sandstone and cross-bedded sandstone. Their vertical association records offshore shelf to delta-front and shoreface sedimentation during a Cenomanian-Santonian marine transgressive-regressive cycle. Six representative shale samples were analysed for total organic carbon and pyrolysis parameters. TOC values range from 1.2 to 2.8 wt.% with a mean of 2.02 wt.%, indicating good to very good organic richness. Hydrogen Index values of 180-340 mg HC/g TOC and Oxygen Index values of 30-50 mg CO_2/g TOC indicate mixed Type II/III kerogen, reflecting combined marine algal and terrestrially derived organic inputs. Tmax values of 430-439 °C and Production Index values of 0.072-0.115 place the studied shales from immature/early mature levels into the early oil window. Generated petroleum potential ranges from 2.36 to 10.42 mg HC/g rock. Material-balance calculations, using an initial HI baseline of 420 mg HC/g TOC, indicate expulsion efficiencies of 16.7-23.6% in the mature samples. The results demonstrate that the Kanawa Member shales constitute an effective but incompletely expelled source-rock interval, capable of charging adjacent sandstone reservoirs while retaining significant hydrocarbons within the shale matrix, thereby suggesting additional unconventional tight-shale resource potential in the Pindiga Formation and wider Gongola Sub-basin petroleum system under favourable burial conditions locally and regionally.

Keywords

Pindiga Formation;
Rock-Eval pyrolysis;
Expulsion efficiency;
Type II/III kerogen;
Northern Benue Trough.

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1. INTRODUCTION

Hydrocarbon exploration in the West and Central African Rift System (WCARS) has produced significant discoveries in rift-related basins such as the Muglad Basin of Sudan and the Termit Basin of Niger Republic. In Nigeria, the Benue Trough represents a major NNE-SSW-trending intracontinental Cretaceous rift that extends for more than 1000 km from the Niger Delta margin toward the Chad Basin. The trough is commonly subdivided into Southern, Central and Northern sectors, with the Northern Benue Trough comprising the Gongola and Yola sub-basins.

The Gongola Sub-basin has long been regarded as an inland frontier petroleum province because of its complex structural history, discontinuous outcrop control and limited subsurface data. However, the discovery of hydrocarbons within the Kolmani River area has renewed interest in the petroleum systems of the Northern Benue Trough. A viable petroleum system requires organic-rich source rocks that have attained adequate thermal maturity and have expelled sufficient hydrocarbons to charge adjacent reservoirs. Therefore, source-rock evaluation must go beyond organic richness and kerogen typing to include the efficiency of petroleum generation and primary expulsion.

The Cenomanian-Santonian Pindiga Formation records a major marine transgression over the continental Bima Group and transitional Yolde Formation. Its lower Kanawa Member is characterized by dark carbonaceous shale and interbedded limestone, and has been recognized as a key potential source interval in the Gongola Sub-basin. Previous studies have described its organic richness, depositional setting and regional petroleum significance, but quantitative constraints on expulsion efficiency remain limited. This study therefore integrates lithofacies analysis, Rock-Eval pyrolysis and material-balance expulsion modelling to assess the source-rock quality, maturity status and hydrocarbon expulsion efficiency of Pindiga Formation shales around Pindiga village, Gombe State, Nigeria.

2. GEOLOGICAL AND STRATIGRAPHIC SETTING

The Upper Benue Trough developed during Early Cretaceous rifting associated with the separation of the African and South American plates. Regional extension, strike-slip movement and subsidence produced a series of pull-apart depocentres, including the Gongola Arm. The stratigraphic succession begins with the Aptian-Cenomanian Bima Formation, which consists mainly of continental alluvial and braided-river sandstones and conglomerates resting unconformably on the Precambrian Basement Complex.

The Bima Formation is overlain by the Cenomanian Yolde Formation, a transitional-marine unit composed of alternating sandstone, siltstone and mudstone deposited in deltaic to shallow-marine settings. Continued marine transgression during the late Cenomanian to Santonian led to deposition of the Pindiga Formation, a marine-dominated succession composed of shale, limestone, calcareous shale and subordinate sandstone. The lower Kanawa Member contains organic-rich black shale and limestone intervals, while the overlying Dumbulwa Member records more mixed siliciclastic-carbonate sedimentation. Post-Santonian compression folded and locally faulted the succession before deposition of the Maastrichtian Gombe Sandstone and the Paleogene Kerri-Kerri Formation.

3. MATERIALS AND METHODS

3.1 Field Mapping and Sample Collection

Field mapping was carried out around Pindiga village, Gombe State, within the coordinate range N9°58'00"-N10°00'00" and E10°56'30"-E10°58'45". Traverses were conducted along stream channels, cattle tracks and accessible agricultural exposures to identify relatively fresh shale outcrops. Lithologic attributes, bed thicknesses, sedimentary structures and stratigraphic relationships were recorded, while structural attitudes were measured using a compass-clinometer. Sample locations were georeferenced using a handheld GPS referenced to the WGS 1984 datum. Six representative shale samples, labelled YL1-YL6, were collected, sealed in polythene bags and submitted for geochemical analysis.

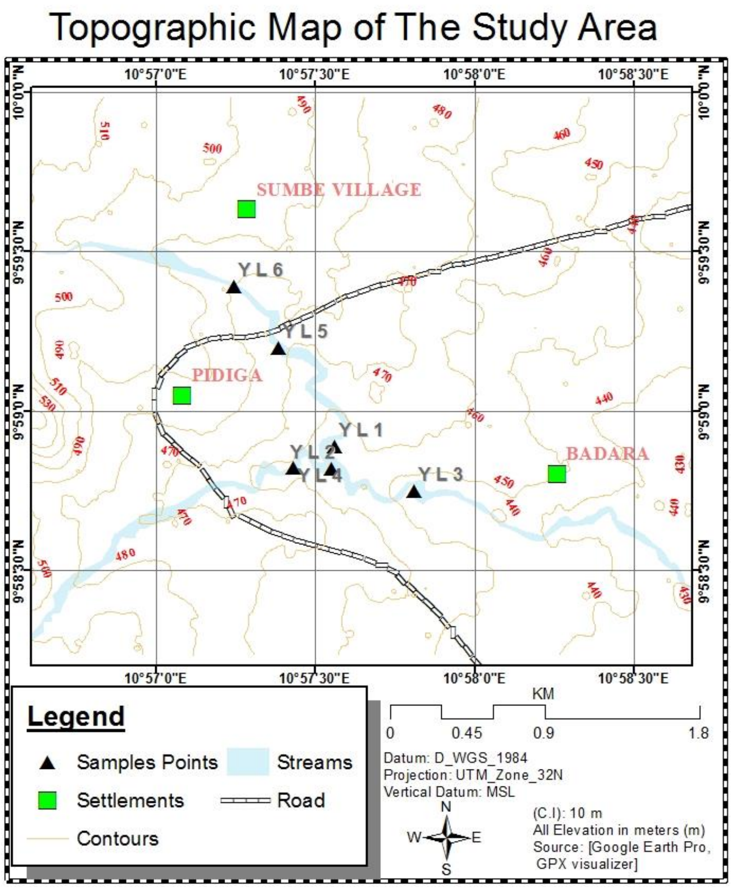

Figure 1. Topographic and sample-location map of the Pindiga study area.

3.2 Lithofacies Logging

A measured lithologic section was constructed to define the vertical facies architecture of the Pindiga Formation at the studied locality. Lithofacies were differentiated using lithology, colour, grain size, sedimentary structures, carbonate content, organic matter abundance, fossil content and facies stacking pattern. Facies were subsequently grouped into facies associations that reflect the main depositional environments represented in the section.

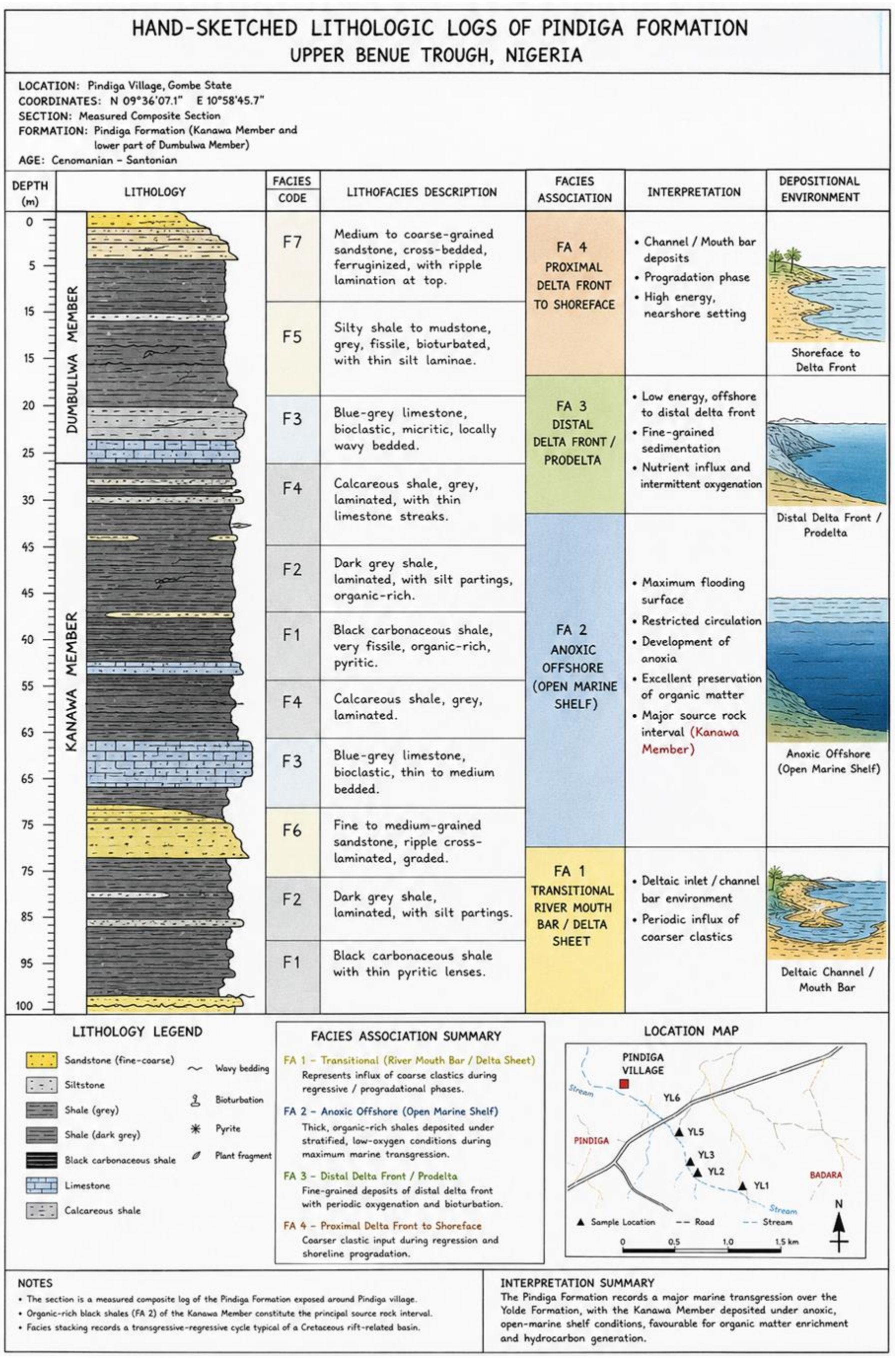

Figure 2. Composite hand-sketched lithologic log and facies-association interpretation of the Pindiga Formation around Pindiga village.

3.3 Laboratory Analysis and Geochemical Calculations

The shale samples were cleaned, dried and pulverized to a homogeneous powder. Total Organic Carbon (TOC) was determined after removal of inorganic carbonate using 10% hydrochloric acid, followed by combustion of the decarbonated residue in a carbon analyser. Rock-Eval pyrolysis was used to determine free hydrocarbons (S1, mg HC/g rock), remaining generative potential (S2, mg HC/g rock), carbon dioxide yield (S3, mg CO_2/g rock) and Tmax, the temperature of maximum S2 generation.

Derived geochemical parameters were calculated using standard relationships: Hydrogen Index, HI = (S2/TOC) x 100; Oxygen Index, OI = (S3/TOC) x 100; Genetic Potential, GP = S1 + S2; and Production Index, PI = S1/(S1 + S2). Hydrocarbon expulsion efficiency was estimated using the material-balance approach of Cooles et al. (1986), with an assumed original Hydrogen Index baseline of 420 mg HC/g TOC based on immature equivalent source-rock trends within related depocentres.

4. RESULTS AND DISCUSSION

4.1 Lithofacies and Depositional Interpretation

Seven lithofacies (F1-F7) were identified in the measured section. These facies define a vertical transition from organic-rich offshore shale to increasingly silt- and sand-prone delta-front and shoreface deposits, indicating a marine transgressive-regressive depositional cycle.

Facies F1: Black Carbonaceous Shale

F1 consists of black to dark-grey, fissile, organic-rich shale with thin lamination and local pyrite. The lack of intense bioturbation and the presence of pyrite indicate deposition under oxygen-deficient bottom-water conditions. This facies represents an anoxic offshore shelf setting during maximum flooding and forms the principal source-rock interval of the Kanawa Member.

Facies F2: Dark Grey Laminated Shale

F2 comprises dark grey laminated shale with occasional silt partings. Suspension settling under low-energy conditions produced the fine lamination, while minor silt influx indicates intermittent distal clastic input. The facies is interpreted as a distal offshore shelf deposit with moderate organic-matter preservation.

Facies F3: Bioclastic Limestone

F3 is represented by blue-grey to light-grey, locally fossiliferous bioclastic limestone. The limestone records periods of reduced terrigenous input and enhanced carbonate productivity in an open marine shelf environment.

Facies F4: Calcareous Shale

F4 consists of grey calcareous shale with thin limestone streaks. The mixed carbonate-siliciclastic character indicates fluctuating sediment supply in an offshore-transition setting.

Facies F5: Silty Shale

F5 is composed of silty shale to mudstone with thin siltstone laminae and local bioturbation. Increased silt content and biogenic reworking suggest deposition in a distal delta-front to prodelta environment affected by episodic sediment delivery.

Facies F6: Ripple-Laminated Sandstone

F6 consists of fine- to medium-grained sandstone with ripple cross-lamination, grading and local parallel lamination. It reflects mouth-bar or deltaic channel-bar deposition under moderate-energy flow conditions.

Facies F7: Cross-Bedded Sandstone

F7 comprises medium- to coarse-grained sandstone with cross-bedding, ripple lamination and locally erosional contacts. The facies record proximal delta-front to shoreface sedimentation associated with shoreline progradation and higher-energy sediment transport.

Table 1. Rock-Eval pyrolysis parameters and derived mass-balance data for Pindiga Formation shales.

Sample ID	TOC (%)	Sulfur (%)	HI (mg HC/g TOC)	OI (mg CO2/g TOC)	Tmax (°C)	S1 (mg/g)	S2 (mg/g)	GP (mg/g)	PI	EE (%)
YL1	2.4	0.9	320	35	438	1.0	7.68	8.68	0.115	20.3
YL2	2.8	1.1	340	30	436	0.9	9.52	10.42	0.086	16.7
YL3	1.6	0.6	240	40	432	0.3	3.84	4.14	0.072	-
YL4	2.1	0.8	300	35	439	0.8	6.3	7.1	0.113	23.6
YL5	1.2	0.5	180	50	430	0.2	2.16	2.36	0.085	-
YL6	2.0	0.7	280	40	437	0.7	5.6	6.3	0.111	-

4.2 Organic Richness and Generative Potential

TOC values range from 1.2 to 2.8 wt.% with an average of 2.02 wt.%. Based on standard source-rock screening criteria, the analysed shales are good to very good in organic richness. Samples YL1, YL2 and YL4 exceed 2.0 wt.% TOC and therefore represent the richest intervals, whereas YL5, with 1.2 wt.% TOC, still falls within the good source-rock category. S2 values of 2.16-9.52 mg HC/g rock and GP values of 2.36-10.42 mg HC/g rock indicate fair to good residual petroleum potential, with the highest values recorded in YL2 and YL1. The enrichment is consistent with deposition under restricted marine conditions that favoured organic matter preservation during the Cenomanian-Santonian transgression.

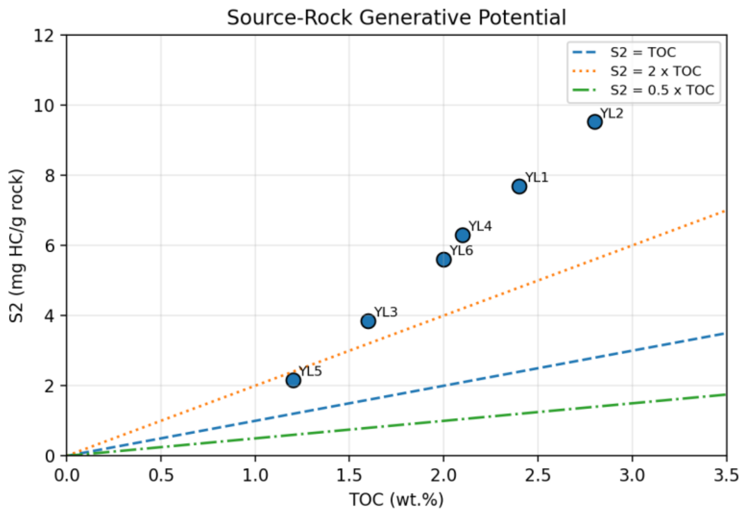

Figure 3. Source-rock generative potential plot showing the relationship between TOC and S2 for the analysed Pindiga shale samples.

4.3 Organic Matter Type and Kerogen Quality

Hydrogen Index values range from 180 to 340 mg HC/g TOC, while Oxygen Index values range from 30 to 50 mg CO_2/g TOC. On the modified van Krevelen diagram, most samples plot within the Type II/III kerogen field, indicating mixed marine algal and terrestrial organic matter. Samples YL1, YL2 and YL4 have relatively higher HI values and stronger oil-prone tendencies, whereas YL5 is more gas-prone due to its lower HI. This mixed kerogen assemblage is consistent with marine shelf deposition influenced by periodic fluvial input from adjacent continental source areas.

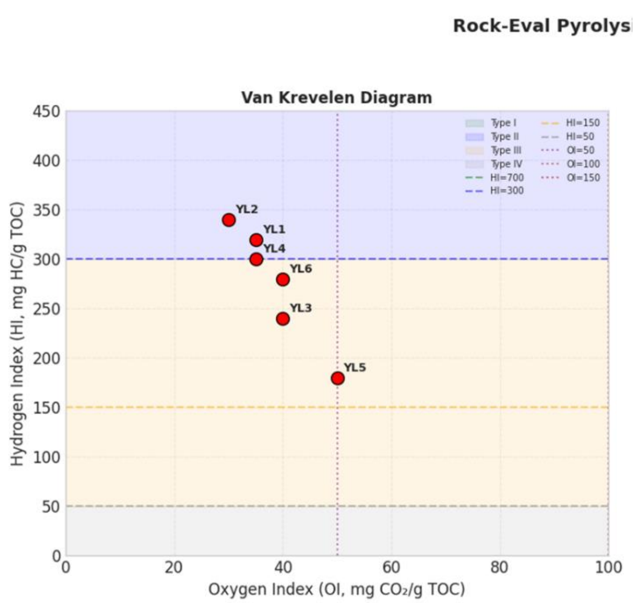

Figure 4. Modified van Krevelen diagram showing mixed Type II/III kerogen in the Pindiga Formation shale samples.

4.4 Thermal Maturity and Hydrocarbon Generation

Tmax values vary from 430 to 439 °C. Samples YL3 and YL5, with Tmax values of 432 °C and 430 °C respectively, are immature to early mature. Samples YL1, YL2, YL4 and YL6, with Tmax values of 436-439 °C, have entered the early oil window. Production Index values of 0.072-0.115 indicate early-stage conversion of kerogen to generated bitumen. The maturity pattern suggests that the exposed Pindiga shales are close to the onset of effective hydrocarbon generation, while more deeply buried equivalents may have attained higher maturity levels and greater petroleum charge potential.

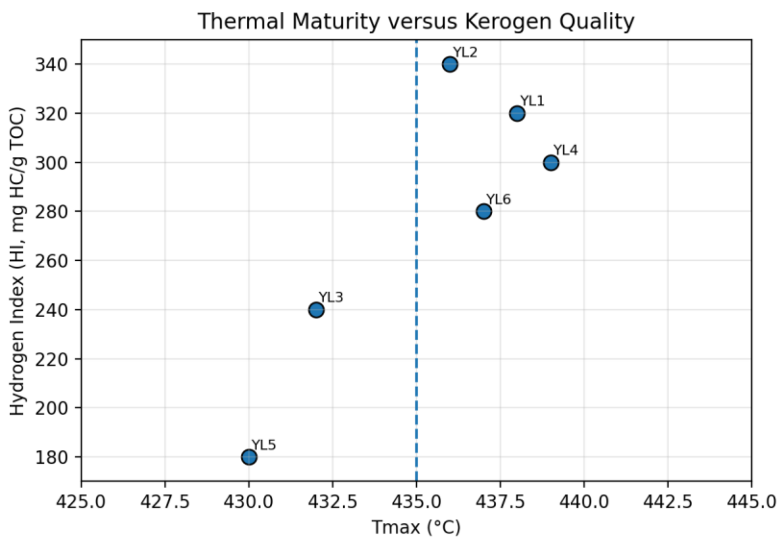

Figure 5. Thermal maturity versus kerogen-quality plot for Pindiga Formation shale samples.

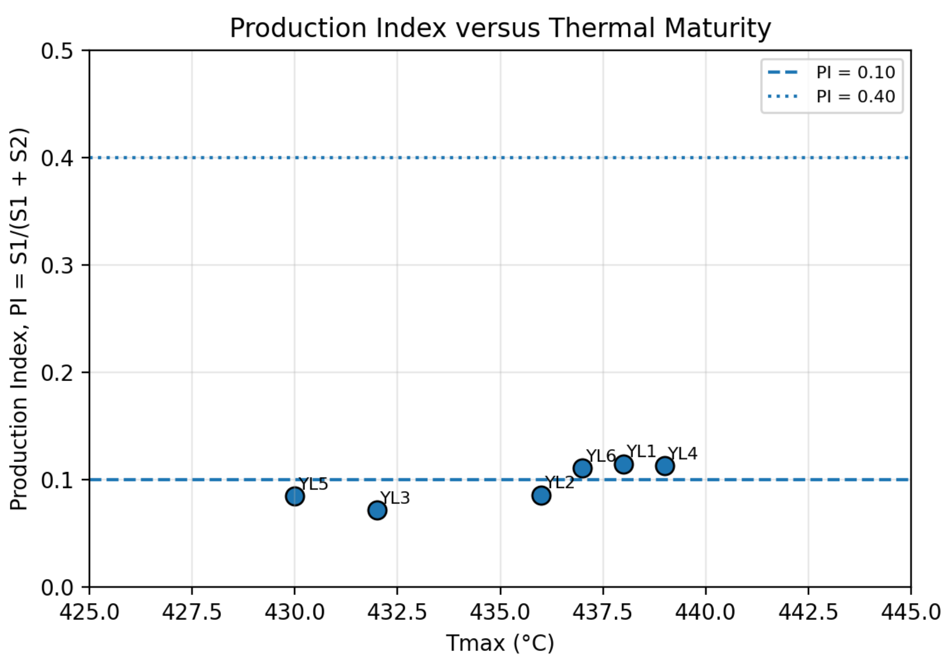

Figure 6. Production Index versus Tmax plot showing early-stage hydrocarbon generation within the studied shale samples.

4.5 Hydrocarbon Expulsion Efficiency

Material-balance modelling indicates that primary expulsion has commenced in the mature samples. Computed expulsion efficiencies are 20.3% for YL1, 16.7% for YL2 and 23.6% for YL4. These values indicate low to moderate expulsion efficiency. The relatively limited expulsion is attributed to the early-oil-window maturity level and the low permeability of the shale matrix, which delays primary migration until generated fluids exceed the pore-storage and fracture-initiation threshold. Consequently, a portion of generated hydrocarbons may have charged adjacent sandstone carrier or reservoir units, while a larger proportion remains retained within the source-rock fabric.

The implication is twofold. First, the Kanawa Member of the Pindiga Formation is capable of acting as an effective conventional source rock where burial and maturation are sufficient. Second, the high retained-hydrocarbon fraction suggests possible unconventional tight-shale potential, especially in deeper, less weathered and more mature parts of the Gongola Sub-basin.

4.6 Regional Petroleum-System Significance

The studied shales show geochemical similarities to Cretaceous marine source intervals in other WCARS basins, including mixed Type II/III kerogen, moderate to good TOC and early to peak oil-window maturity in favourable depocentres. However, the Northern Benue Trough is structurally heterogeneous, and maturity may vary considerably over short distances because of differential burial, Santonian deformation and local heat-flow anomalies. Focused source-rock mapping, maturity modelling and subsurface calibration are therefore required to reduce exploration risk and to distinguish effective kitchens from marginally mature outcrop analogues.

5. CONCLUSION

The Pindiga Formation shales around Pindiga village contain seven lithofacies grouped into offshore shelf, distal delta-front/prodelta, mouth-bar and shoreface depositional associations. The most organic-rich facies is the black carbonaceous shale of the Kanawa Member, deposited under anoxic offshore marine conditions during maximum flooding. Rock-Eval data show TOC values of 1.2-2.8 wt.% (mean = 2.02 wt.%), indicating good to very good organic richness.

HI values of 180-340 mg HC/g TOC indicate mixed Type II/III kerogen capable of generating both oil and gas. Tmax values of 430-439 °C and PI values of 0.072-0.115 place the studied samples between immature/early mature conditions and the early oil window. Expulsion efficiency values of 16.7-23.6% for mature samples indicate incomplete primary migration. Thus, the Pindiga Formation is a credible source-rock interval with capacity to charge adjacent sandstone reservoirs, while retaining significant hydrocarbons that may support unconventional shale-resource potential in more deeply buried and thermally mature parts of the Gongola Sub-basin.

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