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## Petroleum Source Rock Characterization of the Pindiga Formation Exposed at Pantami Stream, Gongola Sub-Basin, Northern Benue Trough, Nigeria

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### Abstract

The hydrocarbon potential of the Pindiga Formation exposed at the Pantami Stream section within the Gongola Sub-basin of the Northern Benue Trough, Nigeria, was evaluated through an integrated lithostratigraphic, organic geochemical, and carbonate petrographic approach in order to constrain source rock quality, organic matter characteristics, depositional environment, and thermal maturity. Detailed field-based lithostratigraphic logging revealed a stratigraphic succession dominated by shale, limestone, and minor gypsum interbeds, indicative of deposition within a predominantly marine depositional system influenced by relatively low-energy conditions and episodic evaporitic input. Six representative shale samples were subjected to Rock-Eval pyrolysis for the determination of Total Organic Carbon (TOC), kerogen type, generative potential, and thermal maturity parameters, while six limestone samples were analyzed petrographically to characterize microfacies and infer carbonate depositional conditions. The geochemical results show TOC values ranging from 1.2 to 2.4 wt.%, reflecting moderate organic matter richness and suggesting a fair to good source rock potential. Hydrogen Index (HI) values ranging from 133 to 225 mg HC/g TOC indicate the predominance of mixed Type II/III kerogen, suggesting the presence of both oil-prone and gas-prone organic matter with mixed marine and terrestrial affinities. Tmax values between 421 and 430°C indicate immature to early mature thermal conditions, implying that the studied interval has not yet attained optimal thermal maturity for significant hydrocarbon generation. Carbonate petrographic analysis reveals predominantly micritic limestones classified as mudstone and wackestone, consistent with deposition in low-energy marine environments favorable for organic matter preservation. The association of fine-grained argillaceous facies, micritic carbonate microfacies, and moderate organic enrichment suggests conditions conducive to source rock development. Overall, the results demonstrate that the Pindiga Formation possesses fair to good hydrocarbon source rock potential; however, greater burial depth and enhanced thermal maturation would be required for optimum hydrocarbon generation and expulsion. These findings reinforce the petroleum prospectivity of the Pindiga Formation within the Northern Benue Trough and provide insights into its source rock evaluation framework.

### Keywords

Organic Geochemistry;  
Rock-Eval Pyrolysis;  
Pindiga Formation;  
Petroleum Geology;  
Northern Benue Trough

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## 1.0 INTRODUCTION

The Benue Trough is a major intra-continental sedimentary basin in Nigeria, formed during the Early Cretaceous (Aptian-Albian) as part of the tectonic evolution associated with the opening of the South Atlantic Ocean (Burke et al., 1971; Genik, 1993). It extends for about 1000 km northeast-southwest and is approximately 150km wide, running from the Niger Delta in the south to the Chad Basin in the northeast (Nwajide, 2013). Structurally, the trough is regarded as part of the West and Central African Rift System (WCARS) and represents a major failed arm of a triple junction related to the separation of the African and South American plates (Benkhelil, 1989).

The Trough is generally subdivided into three major sectors – the Lower Benue Trough, Middle Benue Trough, and Upper Benue Trough (Gongola and Yola sub-basins) – each containing thick successions of Cretaceous to Paleogene sediments. These successions are composed of continental sandstones, marine shales, carbonates, and coal beds, reflecting complex depositional environments and multiple marine transgressions and regressions (Petters, 1982; Zaborski et al., 1997).

Interest in the petroleum potential of the Benue Trough dates back to the early 20th century when surface bitumen seeps and oil-stained sandstones were first reported (Cratchley & Jones, 1965). Systematic exploration began in the 1950s, with the Shell D'Arcy Petroleum Company conducting the first reconnaissance geological mapping and geophysical surveys (Offodile, 1976). Despite initial optimism, early drilling results were

inconclusive, partly due to the complex tectonic and structural settings of the basin.

In recent decades, however, advances in geochemical and basin modeling techniques have renewed interest in the hydrocarbon generation potential of the Benue Trough. Several studies have identified organic-rich shales, particularly within the Bima, Yolde, Pindiga, and Fika Formations, as potential source rocks (Obaje et al., 1999; Akande et al., 2005).

The Pindiga Formation, especially in the Gongola Sub-basin, has been recognized for its alternating shales, limestones, and sandstones, suggesting a favorable depositional environment for the preservation of organic matter (Owolabi & Akande, 1992; Obaje, 2009). Exploration efforts have intensified with the Nigerian National Petroleum Corporation (NNPC) and other agencies conducting aeromagnetic surveys, seismic investigations, and geochemical sampling in the Upper Benue Trough. These efforts are driven by the need to diversify Nigeria's petroleum sources beyond the Niger Delta, where mature source rocks and discovered reserves are already declining (Abubakar, 2014; NNPC, 2020).

Despite the growing body of work on the Benue Trough, data from the Gongola Sub-basin, particularly the Pantami Stream Section, remain sparse and underexplored. Previous studies have mainly focused on regional geology, with limited detailed organic geochemical and petrographic assessments of the Pindiga Formation, which are essential for evaluating its source rock potential and hydrocarbon generation capability.

This research, therefore, aims to assess the source rock potential of the Pindiga Formation in the Pantami Stream Section through an integrated study of its lithostratigraphic succession, organic geochemistry, and carbonate petrography. Such an approach will contribute to a better understanding of the hydrocarbon prospectivity of the Gongola Basin and provide valuable data to support ongoing and future exploration efforts in the Benue Trough.

The studied locations were selected due to their excellent exposure and/or features and the coordinates of the exact locations were established using global positioning system (GPS). The fieldwork started at Pantami stream at coordinates; Latitude: 10°16'2.41392" N and Longitude: 11°9'44.4924" E, Other observed features on the field includes features such as the dip angle which is indicative of tectonism, possible mineralogy, strike direction, bed thickness, degree of sorting and elevation, these were recorded on the field notebook.

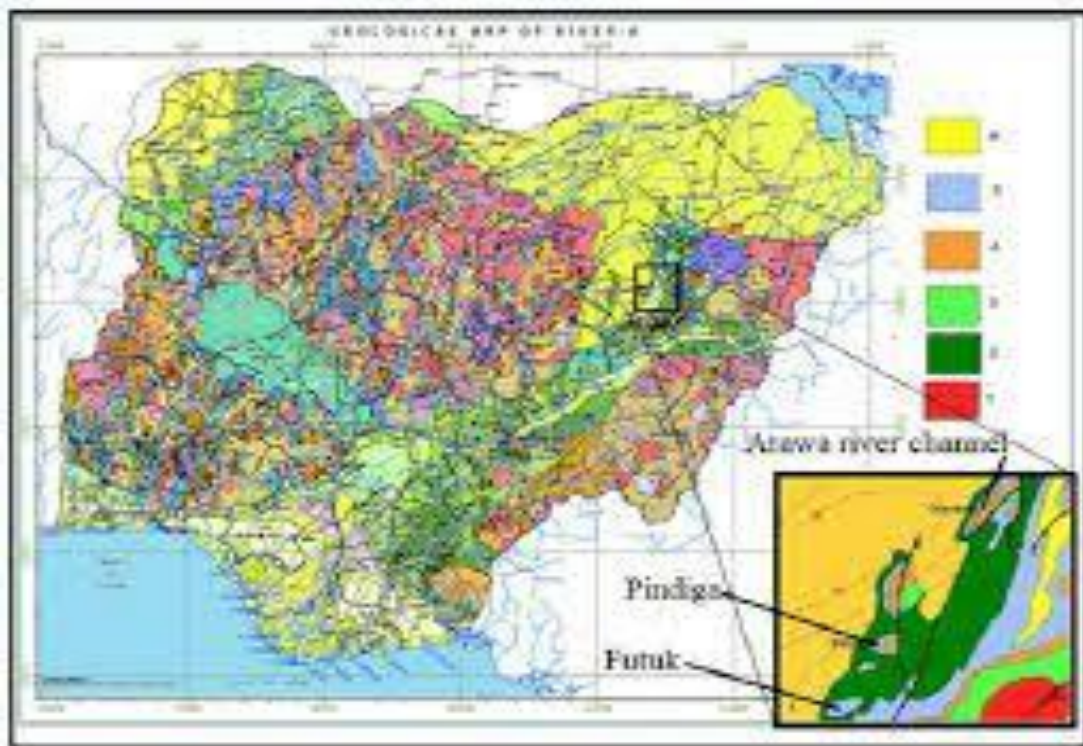


Figure 1 Geological map of Nigeria showing location of the study area

The Benue Trough is an important sedimentary basin in Nigeria, formed as a result of the early Cretaceous rifting associated with the opening of the South Atlantic Ocean during the breakup of Gondwana. It is an elongated, NE-SW trending intracontinental rift basin extending over 1,000 km in length and about 150 km in width, covering a significant portion of central and northeastern Nigeria (Benkhelil, 1989).

The trough is structurally and geologically complex, characterized by multiple episodes of subsidence, sedimentation, and deformation, which have significantly influenced its hydrocarbon potential. The Benue Trough is commonly divided into three sub-basins based on structural and depositional differences:

- **Northern Benue Trough** - Includes the Gongola and Yola sub-basins, which contain thick sequences of continental, transitional, and shallow marine sediments deposited during the Cretaceous.
- **Central Benue Trough** - A structurally complex section with major folds and faults, recording significant deformation.
- **Southern Benue Trough** - Linked to the Anambra Basin and the Niger Delta, serving as a

transition zone between inland basins and the deltaic system.

The Northern Benue Trough, where the Gongola Sub-basin is located, has received significant attention due to its thick sedimentary sequences and potential for hydrocarbon accumulation. Studies indicate that the basin contains over 5,000 meters of sedimentary fill, with multiple petroleum system elements such as potential source rocks, reservoirs, and structural traps (Guiraud, 1990; Obaje, 2009).

The Gongola Sub-basin, specifically, is known for its well-preserved stratigraphic succession ranging from fluvial to shallow marine deposits, providing an excellent field setting for sequence stratigraphic studies. The evolution of the sub-basin has been controlled by both tectonic subsidence and eustatic sea-level changes, leading to the deposition of key formations such as the Bima, Yolde, Pindiga, and Gombe Formations (Dike, 2002; Zaborski, 1998). Understanding these depositional environments and their relationship to petroleum system elements is essential for hydrocarbon exploration in the region.

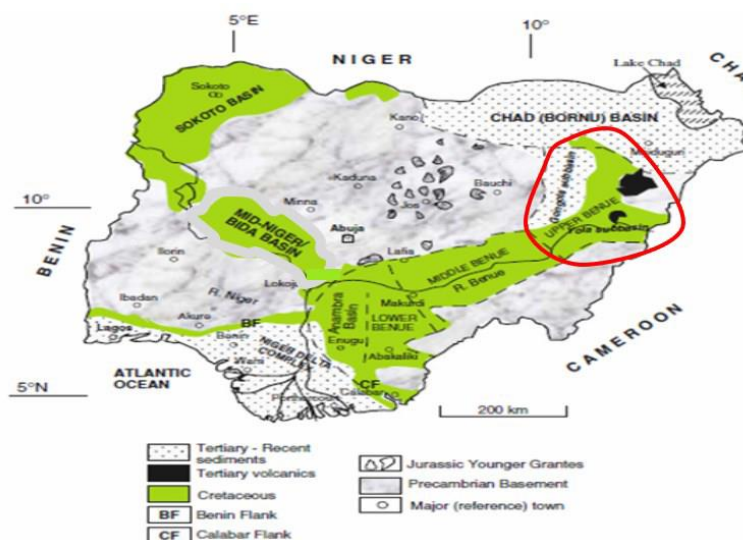


Figure 2 Map of Nigeria showing Northern Benue Trough

## 2.2 Stratigraphy and Depositional Framework

The stratigraphy of the Gongola Sub-basin records a complex history of Cretaceous sedimentation controlled by tectonics, eustatic sea-level changes, and climatic conditions. The sedimentary fill within this sub-basin consists predominantly of continental, transitional, and shallow marine deposits, deposited in response to successive

episodes of rifting, subsidence, and marine incursions (Carter et al., 1963; Zaborski, 1998).

The stratigraphic framework of the region comprises several key formations, including the Bima, Yolde, Pindiga, Gombe, and Kerri-Kerri Formations, which represent a complete sedimentary cycle from fluvial to marine environments.

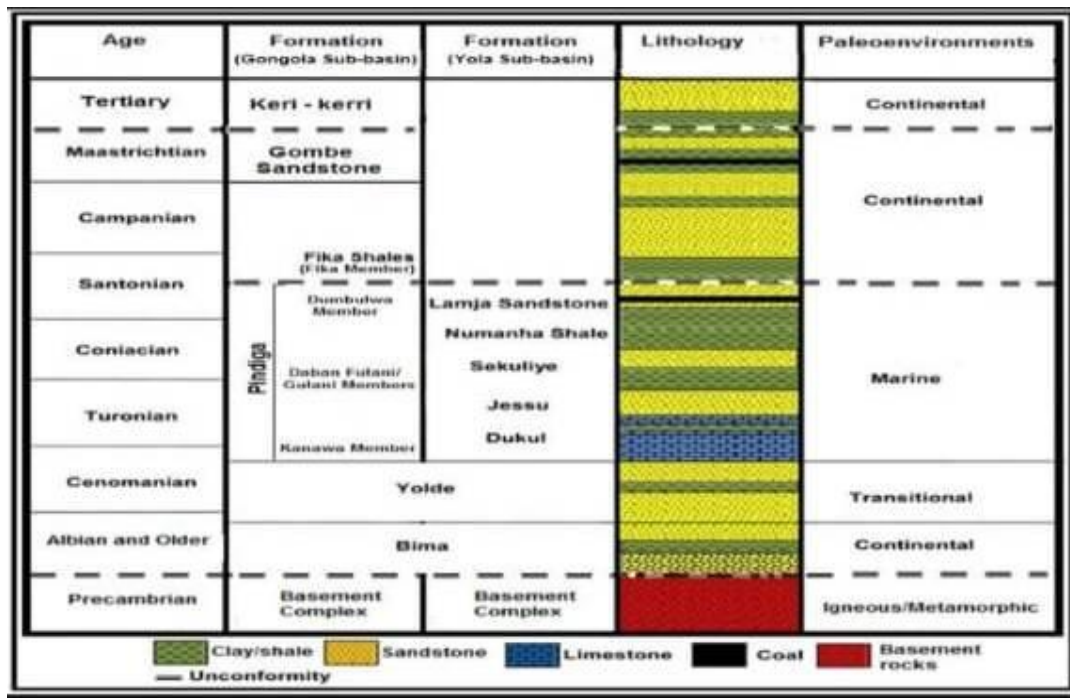


Figure 3 Stratigraphic chart for the Cretaceous-Tertiary sequences of the Gongola Basin (Bello et al., 2023).

## 3.0 MATERIALS AND METHODS

### 3.1 MATERIALS

The following materials were used during the field mapping and reservoir assessment:

1. **Topographic Map:** This was a primary reference tool during field activities. Major geological features, such as outcrops, boundaries, and elevations, were recorded directly onto the map. The map provided a spatial context for

the study area and helped navigate the terrain.

2. **Field Notebook:** Document detailed observations, measurements, and findings in the field. This included descriptions of rock types, structures, and any anomalies observed. The notebook served as a permanent record for later analysis and interpretation.

3. **Global Positioning System (GPS):** The GPS plays a critical role in locating specific points on the Earth's surface. It was used to trace boundaries, record elevations, and capture latitude and longitude coordinates. The GPS ensured accurate spatial referencing of samples and outcrops.
  4. **Compass-Clinometer:** Primarily used to measure the strike and dip of geological structures, such as bedding planes and faults. It also provided directional guidance during field traverses, ensuring accurate orientation and mapping.
  5. **Sample Bags (Polythene Bags):** Used to store and transport rock and sediment samples collected from various locations within the study area. The bags ensured that samples remained uncontaminated and well-organized for laboratory analysis.
  6. **Hand Lens:** Essential for examining small mineral grains and textures that are not visible to the naked eye. The hand lens provided a magnified view, aiding in the identification of mineral composition and rock fabric.
  7. **Measurement Tape (30m):** Employed to measure the dimensions of geological features, such as the length, width, and height of outcrops or sections. This tool was crucial for quantifying the scale of structures and stratigraphic units.
  8. **Geological Hammer:** This tool was used to break rocks and extract fresh samples from outcrops. It allowed for the collection of representative samples while minimizing weathering effects.
  9. **Camera:** Used to capture high-quality photographs of outcrops, samples, and geological structures in their natural setting. These images provided visual documentation of field conditions, including bedding planes, lithological changes, and structural features.
- 3.2.1 **Desk Study**  
Related literatures to the work were reviewed at the preliminary stage of the research before the field work. This review also continues throughout the stages of the work.
  - 3.2.2 **Fieldwork Methodology**  
When logging the section, the following steps/options were used as follows:
    1. Establish a measured section: from base to top of exposure, marking stratigraphic metres (e.g., 0 m at base of section).
    2. Describe lithology bed-by-bed: noting rock type (shale, mudstone, gypsum and limestone), colour, grain size, bed thickness, bounding surfaces, any erosional or sharp contacts.
    3. Record sedimentary structures: e.g., cross-bedding (planar, trough), hummocky cross stratification, ripple lamination, massive bedding, bioturbation. For example: herringbone cross-bedding, tabular cross beds.
    4. Note vertical facies changes (coarsening upward / fining upward, retrogradation/progradation patterns).
    5. Create lithostratigraphic log: A graphic column illustrating bed thicknesses, lithologies, structure symbols, facies associations. Useful for visualising the section.

In this study, field work was conducted to examine sections of the Pindiga formation along Pantami stream section. During the fieldwork, roads and footpaths were traversed to access well-exposed outcrops and sedimentary exposures within the study area. A detailed stratigraphic logging of the region was performed, and sediment characteristics, including variations in grain size, were analyzed using grain size charts.

Representative rock samples were collected using sledge hammer and were labelled properly using the masking tape and marker from each of the beds. A total of 15 rock samples (Eight shale and seven limestone samples) were collected out of which six (6) limestone samples were selected for carbonate petrography and four (4) shale samples were also selected for organic geochemistry

All the Samples were characterized by good sedimentary rock exposure, where various stratigraphic lithologies were very visible aiding the identification, logging and description of the lithologic units that make up the exposures. The exposures were logged and described on the basis of their lithologies, texture and colour on the field. Primarily, the field descriptions include;

1. Lithology
2. Colour and colour changes
3. Bioturbations
4. Structures and
5. Textures as observed.

## 4.0 DISCUSSION OF RESULT

### 4.1 LITHOSTRATIGRAPHIC SUCCESSION

Detailed stratigraphic logging across certain meters of exposed strata including structures, facie description and sampling.

When logging the section, the following steps/options were used and you should consider something similar:

1. Establish a measured section: from base to top of exposure, marking stratigraphic metres.
2. Describe lithology bed-by-bed: noting rock type (sandstone, shale, siltstone, claystone, limestone), colour, grain size, bed thickness, bounding surfaces, any erosional or sharp contacts.
3. Record sedimentary structures: e.g., cross-bedding (planar, trough), hummocky cross stratification, ripple lamination, massive bedding, bioturbation. For example: herringbone cross-bedding, tabular cross beds.
4. Note vertical facies changes (coarsening upward / fining upward, retrogradation/progradation patterns).
5. Create lithostratigraphic log: A graphic column illustrating bed thicknesses, lithologies, structure symbols, facies associations. Useful for visualising the section.

#### 4.1.2 Facies description

A= Light grey shale, fissile, laminated, disintegrated.

B= Limestone, hard crystalline, grey to white.

C= Muddy limestone, capped with thin layer of gypsum, light brown,

D= Glauconitic limestone, Greenish to grey, hard crystalline.

E= Limestone wrapping gypsum occurring as elongated nodules.

F= Ferrugised layer (shale) indicating surface exposure.

G= Ferrugised silty to fine grained sandstone associated with muds and thalassinoides burrows.

H= Mudstone, containing ferrugised faults

I= Ferrugised mudstone, siltstone, highly bur



Plate 1: Sample S1 - Grey to light grey, fissile shale



Plate 2: Sample S2 - Contains black organic matter



Plate 3: Sample S3 - Fissile, laminated shale



Plate 4: Sample S4 limestone enriched with glauconit



Plate 5: Sample S6 Light grey shale, fissile, laminated, disintegrated



Plate 5: Sample S7 Limestone wrapping gypsum occurring elongated nodules



Plate 6: Sample S9 - Limestone, hard crystalline



Plate 6: Sample S11 Fissile light grey presences of thallassi



Plate 7: Sample S12 Ferrugined layer with presences of thalassinoides burrows



Plate 7: Sample S13 Ferrugined highly burrowed silt mudstone



**Figure 5 Sedimentary Graphic Log of the Pindiga Formation along Pantami Stream Section**

### Legend/Key

Lithologies	Symbols
Shale	Horizontal planar lamin
Limestone	Nodules and concretions
Gypsum/Anhydrite	Horizontal burrows

#### 4.1 INTERPRETATION OF THE SEDIMENTARY LOG OF THE PINDIGA FORMATION

Three distinct facies were identified; Shale Facies (P1), which includes a gypsum-bearing subfacies, Fine-Grained Sandstone Facies (P2), and Limestone Facies (P3). These facies represent variations in depositional environments, sediment composition, and diagenetic processes.

The sedimentary log of the Pindiga Formation along Pantami Stream Section reveals a

succession dominated by shale, limestone, gypsum, and ferruginized sediments, which aligns with the work of Zaborski (1998), who described this formation as a fully marine deposit marking a major transgressive phase in the Gongola Sub-basin. The facies associations in the log indicate a transition from offshore marine conditions with low-energy deposition to more restricted marine settings influenced by diagenetic processes and bioturbation. Marine settings with prolonged exposure to seawater. The presence of fine to medium-grained gypsum beds within the limestone units

suggests episodes of high salinity, possibly due to evaporative conditions in a restricted marine setting, similar to what has been observed in other parts of the Benue Trough (Dike, 2002). Additionally, the hard crystalline limestones and muddy limestone facies

indicate varying degrees of carbonate diagenesis, with some sections experiencing early cementation, which aligns with Zaborski's (1998) interpretation of the Pindiga Formation as a carbonate-dominated unit influenced by periodic fluctuations in water chemistry

## 4.2 CARBONATE PETROGRAPHIC ANALYSIS

### SAMPLE ID S2

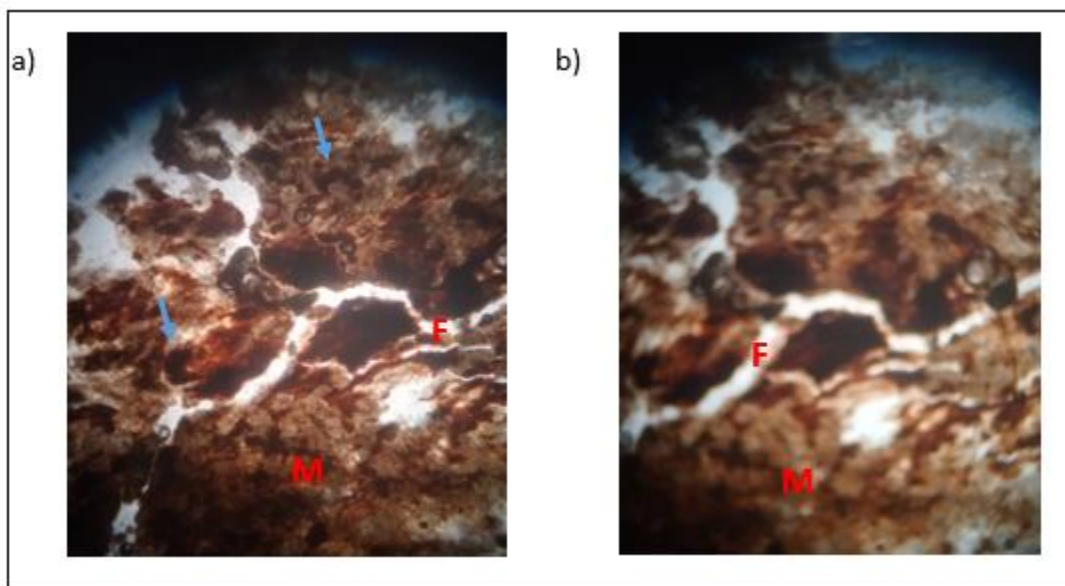


Plate 1: Photomicrographs of part of Sample S2 (a) Plane Polarized Light View (b) Cross Polarized Light View. Micrite (M), Calcite-filled Fractures (F), Irregular voids (Blue Arrows)

#### S2:

The thin section analysis reveals a fine-grained carbonate rock dominated by a micritic matrix. The texture is clearly mud-supported, with few, if any, identifiable skeletal grains in contact. This suggests deposition in a low-energy marine environment, likely below wave base, where fine carbonate mud could accumulate with minimal current agitation.

The brownish background material is interpreted as micrite, and it appears to constitute the majority of the rock fabric. Some portions of the matrix show signs of mild recrystallization, likely indicating early diagenetic processes, but the micritic texture is still largely preserved. The presence of dark, irregular voids and patches suggests that the rock has undergone some degree of dissolution, leading to the development of

moldic or vuggy porosity. These voids are irregular and are scattered throughout the micrite, consistent with the removal of once-present skeletal fragments or peloids. Additionally, white, vein-like features cutting through the matrix evident in Plates 5 and 7 are likely calcite-filled fractures, indicating later-stage cementation during diagenesis.

Overall, the lack of abundant visible grains (less than 10% of the rock volume), the dominance of micritic matrix, and the mud-supported fabric strongly support the classification of this limestone as a Wackestone in the Dunham classification scheme. There is no visible evidence of original

grain binding by organisms, which further supports this classification. Diagenetic features such as dissolution, cementation, and fracture development also suggest a complex post-depositional history, but they do not obscure the primary depositional fabric

#### 4.3 ORGANIC GEOCHEMICAL ANALYSIS

Organic geochemistry analysis of Six (6) shale samples was analyzed using the rock eval pyrolysis to evaluate the hydrocarbon potential, type and maturity of organic matter within rocks (source rocks)

**Table2; showing results obtained from the analysis**

Sample ID	TOC (%)	S (%)	S1 (mg/g)	S2 (mg/g)	HI (mg HC/g TOC)	OI (mg CO <sub>2</sub> /g TOC)	Tmax (°C)
S1	1.3	0.6	0.2	1.8	138	75	422
S4B	1.6	0.8	0.3	2.6	163	70	424
S6	1.8	0.9	0.4	3.1	172	66	426
S10A	2.0	1.0	0.5	3.6	180	58	428
S12A	2.4	1.3	0.8	5.4	225	42	430
S14	1.2	0.5	0.2	1.6	133	78	421

**Table3: Showing Interpretation of the Results**

Sample	TOC	S2	HI	Tmax	Interpretation
S1	1.3	1.8	138	422	<b>Poor source rock</b> , immature, gas-prone.
S4B	1.6	2.6	163	424	<b>Poor–Fair source</b> , immature to early mature, mixed kerogen.
S6	1.8	3.1	172	426	<b>Fair source</b> , approaching oil window.
S10A	2.0	3.6	180	428	<b>Fair–Good</b> , low maturity, better potential.
S12A	2.4	5.4	225	430	<b>Good source</b> , early mature, Type II/III kerogen.
S14	1.2	1.6	133	421	<b>Poor source</b> , immature.

## 1. Description of Rock-Eval Pyrolysis Results

The analytical parameters obtained from six representative samples (S1, S4B, S6, S10A, S12A, and S14) include Total Organic Carbon (TOC), S<sub>1</sub>, S<sub>2</sub>, Hydrogen Index (HI), Oxygen Index (OI), and Tmax.

Parameter	Range	Description
TOC (wt.%)	1.2 - 2.4	Indicates moderate organic matter content across samples.

S1 (mg HC/g rock)	0.2	-	0.8
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Represents free hydrocarbons already generated; values are relatively low, suggesting limited expulsion.

S2 (mg HC/g rock)	1.6	-	5.4
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Indicates hydrocarbon generation potential; ranges from fair (S<sub>2</sub> < 2) to good (S<sub>2</sub> > 5).

HI (mg HC/g TOC)	133	-	225
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Reflects hydrogen richness and kerogen type; values suggest mixed Type II-III kerogen (oil-gas prone).

OI (mg CO <sub>2</sub> /g TOC)	42 - 78	Shows the oxygen content; moderate values indicate oxidized or terrestrial organic input.	
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Tmax (°C)	421 - 430	Indicates thermal maturity; all samples are in the immature to early-mature stage of hydrocarbon generation.	
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## 2. Summary of Observations by Sample

### S12A

Highest TOC (2.4%) and S<sub>2</sub> (5.4 mg HC/g rock). HI = 225 mg HC/g TOC; OI = 42 mg CO<sub>2</sub>/g TOC.

Best organic richness and highest oil-prone potential.

Tmax = 430°C → at the onset of oil window.

### S10A, S6, S4B

TOC (1.6-2.0%), S<sub>2</sub> (2.6-3.6), HI (163-180). Moderate quality with mixed Type II/III kerogen.

Tmax (424-428°C) → early maturity, possible incipient hydrocarbon generation.

### S1 and S14

Lowest TOC (1.2-1.3%), S<sub>2</sub> (1.6-1.8), HI (133-138), OI (75-78).

Poor to fair organic richness, gas-prone Type III kerogen.

Tmax (421-422°C) → immature.

## 3. Implications of the Results

### (a) Source Rock Quality

TOC values (1.2-2.4%) indicate that the Pindiga Formation contains moderately rich organic matter, capable of generating hydrocarbons if sufficiently matured.

S<sub>2</sub> values reveal that hydrocarbon generation potential varies from poor (S1, S14) to good (S12A), implying heterogeneous organic content across the formation.

### (b) Kerogen Type and Hydrocarbon Potential

The HI-OI relationship places the samples mostly within Type II/III kerogen fields on the Van Krevelen diagram.

Type II kerogen (S12A, S10A) → oil-prone.

Type III kerogen (S1, S14) → gas-prone.

This suggests that the Pindiga Formation organic matter originated from mixed marine algal and terrestrial plant material.

The implication is that the formation can generate both oil and gas, with oil dominance in richer intervals.

### (c) Thermal Maturity

max (421-430°C) indicates immature to early-mature stage of organic evolution.

The S12A sample (430°C) lies at the threshold of oil generation.

Other samples (<428°C) are still immature but could mature with deeper burial.

This implies that in the present burial depth, the Pindiga Formation has limited hydrocarbon

generation, but deeper parts of the basin may have reached the main oil window.

#### (d) Depositional Environment

Moderate OI values (42-78) and mixed HI suggest deposition in a marine-deltaic to shallow marine environment, with periodic terrestrial organic influx under suboxic conditions.

This environment favored moderate preservation of organic matter but not highly reducing conditions typical of very rich marine shales.

#### (e) Petroleum Potential

Overall, the data indicate fair to good potential for hydrocarbon generation.

The best intervals (S12A, S10A, S6) could yield liquid hydrocarbons (oil) if buried to greater depths or subjected to higher geothermal gradients.

The poorer samples (S1, S14) likely contribute dry gas or inert carbon under deeper burial.

### 4. Geological and Exploration Implications

#### 1. Potential Source Rock

The Pindiga Formation can be regarded as a potential source rock with mixed oil and gas-generating potential, especially in the lower carbonate and shale-rich intervals represented by samples like S12A.

#### 2. Maturity Window

Current maturity levels show that the unit is not yet at optimum oil generation depth in the Pantami Stream area.

However, deeper structural lows in the Gongola Basin could reach the main oil window, enhancing exploration interest.

#### 3. Exploration Target

Focus exploration on areas of higher TOC and S<sub>2</sub>, and deeper sub-basins where Tmax exceeds 435°C.

Integrate these results with petrographic and sedimentological data to delineate facies with better organic preservation.

#### 4. Correlation with Carbonate Petrography

The moderate organic content and mixed kerogen types align with carbonate-shale alternations in the Pindiga Formation, which can trap organic matter in low-oxygen, lagoonal, or restricted marine settings.

### 5. Overall Interpretation

The Pindiga Formation in the Pantami Stream section shows:

Moderate organic carbon content (TOC up to 2.4%),

Mixed Type II/III kerogen indicating both marine algal and terrestrial origins,

Fair to good hydrocarbon potential (S<sub>2</sub> up to 5.4 mg HC/g)

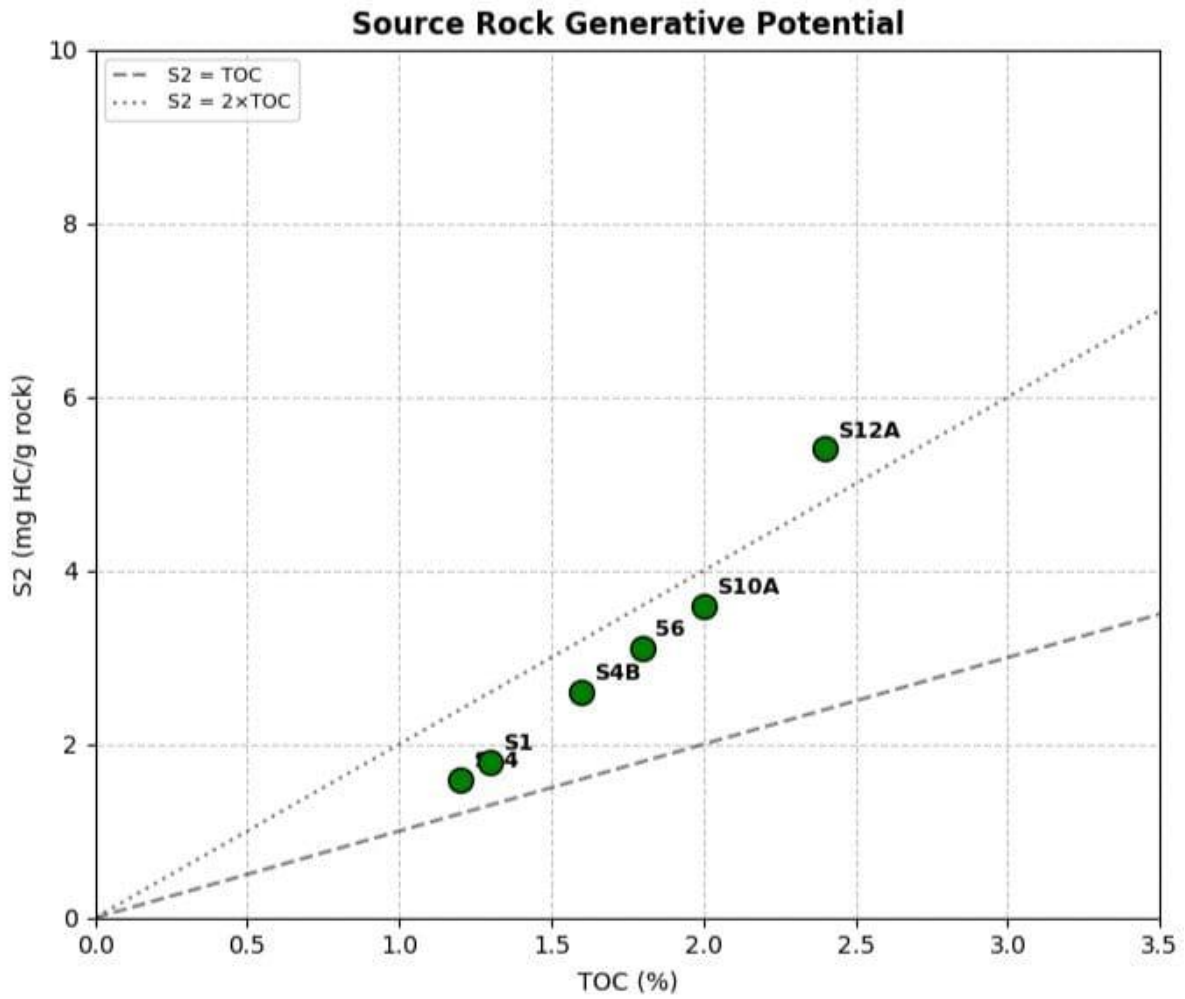
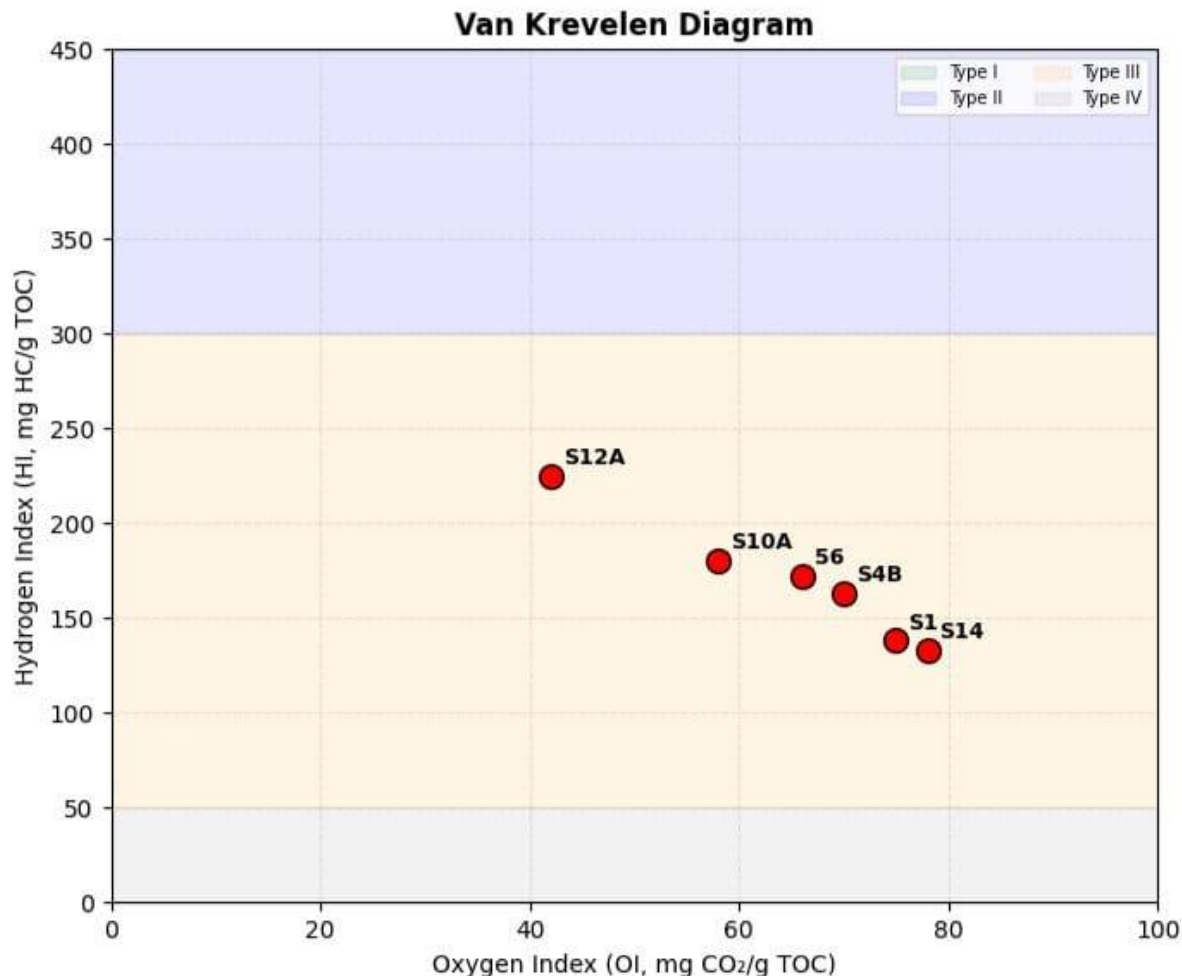


Figure 6  $S_2$  (mg HC/g rock) is the quantity of hydrocarbons that can be generated from kerogen on pyrolysis — it is a direct measure of generative potential.

TOC (%) is the amount of organic carbon in the rock. Plotting  $S_2$  vs TOC checks how much hydrocarbon potential exists per unit organic carbon and whether organic matter is productive and hydrogen-rich.



**Figure 7 Van Krevelen Diagram: HI vs OI.**

### 1) Van Krevelen (HI vs OI) – interpretation

What the plot shows (concept):

The Van Krevelen diagram displays Hydrogen Index (HI) on the vertical axis vs Oxygen Index (OI) on the horizontal axis.

HI (mg HC / g TOC) is a proxy for the hydrogen richness of the organic matter – higher HI → more H-rich, more oil-prone.

OI (mg CO<sub>2</sub> / g TOC) reflects oxygen content – higher OI → more oxygenated, more

influence from terrestrially derived, oxidized organic matter (tends toward gas-prone).

T<sub>max</sub> values (421-430 °C) and PI ~ 0.10-0.13 suggest immature → early mature overall; S12A (T<sub>max</sub> = 430 °C) sits at the onset of the oil window, so its position with high HI is likely primary (original kerogen composition) rather than the product of

Best organic richness and highest oil-prone potential.

T<sub>max</sub> = 430°C → at the onset of oil window.

S10A, S6, S4B

TOC (1.6-2.0%), S<sub>2</sub> (2.6-3.6), HI (163-180).

Moderate quality with mixed Type II/III kerogen.

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Lowest TOC (1.2-1.3%), S<sub>2</sub> (1.6-1.8), HI (133-138), OI (75-78).

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The S12A sample (430°C) lies at the threshold of oil generation.

Other samples (<428°C) are still immature but could mature with deeper burial.

This implies that in the present burial depth, the Pindiga Formation has limited hydrocarbon generation, but deeper parts of the basin may have reached the main oil window.

#### (d) Depositional Environment

Moderate OI values (42-78) and mixed HI suggest deposition in a marine-deltaic to shallow marine environment, with periodic terrestrial organic influx under suboxic conditions.

This environment favored moderate preservation of organic matter but not highly reducing conditions typical of very rich marine shales.

#### (e) Petroleum Potential

Overall, the data indicate fair to good potential for hydrocarbon generation.

The best intervals (S12A, S10A, S6) could yield liquid hydrocarbons (oil) if buried to greater depths or subjected to higher geothermal gradients.

The poorer samples (S1, S14) likely contribute dry gas or inert carbon under deeper burial.

### 4. Geological and Exploration Implications

#### 1. Potential Source Rock

The Pindiga Formation can be regarded as a potential source rock with mixed oil and gas-generating potential, especially in the lower

carbonate and shale-rich intervals represented by samples like S12A.

## 2. Maturity Window

Current maturity levels show that the unit is not yet at optimum oil generation depth in the Pantami Stream area.

However, deeper structural lows in the Gongola Basin could reach the main oil window, enhancing exploration interest.

## 3. Exploration Target

Focus exploration on areas of higher TOC and S<sub>2</sub>, and deeper sub-basins where T<sub>max</sub> exceeds 435°C.

Integrate these results with petrographic and sedimentological data to delineate facies with better organic preservation.

## 4. Correlation with Carbonate Petrography

The moderate organic content and mixed kerogen types align with carbonate-shale alternations in the Pindiga Formation, which can trap organic matter in low-oxygen,

Intelagoonal, or restricted marine settings.

## 5.1 CONCLUSION

The lithostratigraphic study of the pindiga formation along pantami stream section revealed a fully marine conditions confirming previous interpretation by zaborski (1998) and other researchers. The identification of key sedimentary structures such as bioturbation and ferruginized layers highlight the complex depositional of these formation, shaped by fluctuating sea levels, sediment supply variations and post depositional diagenetic processes. The finding from this field work

align with sequence stratigraphic models, demonstrating gradual shallowing towards the overlying Gombe Formation

The petrographic examination of samples S2, S3, S7, and S9 reveals a suite of fine-grained, mud-supported carbonate rocks deposited in predominantly low-energy marine environments. Samples S2, S3, and S7 are best classified as **Wackestones**, characterized by a dominant micritic matrix, subordinate grain content (<10-15%), and evidence of early diagenetic processes such as recrystallization, dissolution, and cementation. Subtle features such as laminated zones, possible bioturbation, and localized porosity in S7 indicate slight variations in depositional energy or microbial activity, though not sufficient to alter the overall mud-supported fabric. In contrast, Sample S9 exhibits an even finer micritic texture with virtually no allochems or skeletal grains, supporting its classification as a **Mudstone**. Collectively, these samples suggest deposition in a calm, subtidal to lagoonal or open-shelf setting below wave base, where fine carbonate muds accumulated under minimal hydrodynamic influence. The presence of dissolution-related porosity and calcite cement further reflects moderate diagenetic modification, yet the preservation of primary micritic textures across all samples indicates limited post-depositional alteration and a consistent, low-energy sedimentary regime.

The Organic Geochemical assessment of the Pindiga Formation in the Gongola Sub-basin reveals that the formation possesses favorable characteristics for hydrocarbon generation. The Total Organic Carbon (TOC) content indicates fair to good organic richness across the analyzed samples. Rock-Eval pyrolysis results demonstrate moderate to good generative potential, with Hydrogen Index (HI) values suggesting a predominance

of Type II and Type III kerogen, capable of generating both oil and gas.

**Thermal maturity** indicators such as Tmax and vitrinite reflectance (Ro) confirm that the formation has reached the early to peak oil window. This level of maturity, coupled with suitable kerogen types, supports the idea that the Pindiga Formation has experienced sufficient burial and heating for hydrocarbon generation, particularly in the deeper parts of the basin.

**The depositional environment** interpreted as marginal marine to deltaic with low oxygen conditions, further enhanced the preservation of organic matter. These results confirm the Pindiga Formation as a viable source rock, deserving of further exploration and modeling within the Gongola Basin.

#### **Conclusion:**

Sample **S12A** shows the **highest hydrocarbon potential** and early maturity, making it the best prospect among the set. Most other samples are **marginal to fair source rocks**, predominantly gas-prone and immature to early mature.

## **5.2 RECOMMENDATIONS**

1. Basin Modeling: Conduct 2D and 3D basin modeling to better understand the thermal evolution and timing of hydrocarbon generation and expulsion in the Pindiga Formation.
2. Drilling and Coring: Acquire core samples from subsurface wells to validate surface-based geochemical findings and extend the maturity profile to deeper stratigraphic intervals.
3. Extended Biomarker Studies: Perform biomarker (GC-MS) and isotopic analyses to refine kerogen typing, correlate source rocks with oils, and reconstruct depositional environments.
4. Lateral Facies Mapping: Use sequence stratigraphy and seismic interpretation to map lateral facies changes and locate organic-rich zones across the basin.
5. Integration with Reservoir Analysis: Correlate source rock quality with nearby reservoir units (e.g., Gombe Sandstone) to evaluate complete petroleum systems.

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