Journal of Engineering and Technology (JET),
Volume 2, Issue 1, Page 90-103, 2026

TOC and SOM Analyses of Anambra Basin Mamu Shale Outcropped at Okpekpe, South-South Nigeria

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ABSTRACT

The Mamu Formation of the Anambra Basin is a significant stratigraphic unit with potential hydrocarbon source rock characteristics. This study evaluates the Total Organic Carbon (TOC) and Soluble Organic Matter (SOM) content of Mamu shale outcrops at Okpekpe, South-South Nigeria, to assess their organic richness and hydrocarbon generation potential. Fourteen shale samples (R1- R14) were analyzed, revealing TOC values ranging from 0.22% to 2.67%, with an average of 1.41%. SOM concentrations varied between 805 ppm and 3,321 ppm, averaging 1,947 ppm. The results indicate that some samples (R5, R8, R11, R13) possess good to excellent TOC values (>2%), suggesting significant hydrocarbon potential. A moderate positive correlation ($R^2 \approx 0.5$) between TOC and SOM implies that organic matter quantity influences hydrocarbon yield. This study contributes to understanding the source rock potential of the Mamu Formation in the Anambra Basin.

Keywords— **Anambra Basin, Hydrocarbon potential, Mamu Formation, Okpekpe, Total organic carbon**

I. INTRODUCTION

The Anambra Basin is a Cretaceous sedimentary basin in southeastern Nigeria, forming part of the broader Benue Trough system. This basin hosts the Mamu Formation, which consists of coal-bearing shales, sandstones, and siltstones [1]. The formation is considered a potential source rock due to its organic-rich facies. Total Organic Carbon (TOC) and Soluble Organic Matter (SOM) are critical geochemical parameters for evaluating source rock quality [2]. It is a significant hydrocarbon and coal-bearing basin, with the Mamu Formation being one of its key stratigraphic units. Previous studies [3], [4] have reported varying organic richness in the Mamu Formation, but detailed outcrop-based geochemical data from Okpekpe remain limited. In his evaluation of the Upper Cretaceous (Maastrichtian Mamu

Formation) hydrocarbon potential in the Anambra Basin, [5] concluded that the coal and shale samples were thermally immature to marginally mature for the production of petroleum (Fig. 1).

[6] described the lower Maastrichtian coals of the Mamu Formation as containing modest inertinites and liptinites and moderate to high huminite concentrations. Earlier research in the Anambra Basin has mostly concentrated on the middle and eastern flank or east of the River Niger. By assessing the hydrocarbon generation potential of Maastrichtian Mamu Shales at Imiegba and surrounding areas on the Benin Flank of the South-Western Anambra Basin, as well as the organic abundance, kinds, and quality of organic matter, this study advances geoscientific research. In order to evaluate the source rock potential of the samples taken from shale outcrops, geochemical methods such as Rock-Eval pyrolysis and Total Organic Carbon (TOC) measurement were used. A more thorough knowledge of the hydrocarbon prospectivity of the entire Anambra Basin is facilitated by the results, which offer insightful information about the Mamu Formation's potential for petroleum generation in this hitherto unexplored region. This study focuses on the TOC and SOM analyses of Mamu shale outcrops at Okpekpe, South-South Nigeria, to assess their hydrocarbon potential and evaluate the economic potentials.

A. Regional Geology of the Anambra Basin

The Benue-Abakaliki Trough's formation, which is associated with the division of Africa, South America, and the opening of the South Atlantic, most likely marked the beginning of tectonism in Southern Nigeria in the late Jurassic to early Cretaceous [7]. The NE-SW trending Abakaliki Anticlinorium was created when the Abakaliki Trough was reversed by Santonian compressional folding [8]. The Benin Flank, the southern extension of the Anambra Basin, which was formed by post-Santonian rifting [9], joins the Okitipupa structure westward (Fig. 1). The Coal Measure, which shows a significant regression of the late Cretaceous Sea, and the Nkporo Group, which represents a significant marine transgression, are sediments of the Benin Flank [1]. The Mamu Formation belongs to Middle–Upper Maastrichtian, this consists of Dark gray, fissile organic-rich shales with Interbedded coal seams. This makes a potential hydrocarbon source rock. Present within it are kaolinite and quartz. The coal seam consists of sandy mudstones with carbonaceous and ferruginous materials [10].

According to [3], Mamu Formation is of transitional depositional settings indicating deltaic to paralic environment, with evidence of fluvio-lacustrine and shallow marine influences (Fig. 2). Palynological studies indicate a humid, tropical climate with abundant terrestrial organic matter. The formation is highly rich in Total Organic Carbon (TOC) signifying good to excellent hydrocarbon potential. The kerogen type revealed a mixed Type II/III, which suggests terrestrial and marine organic input.

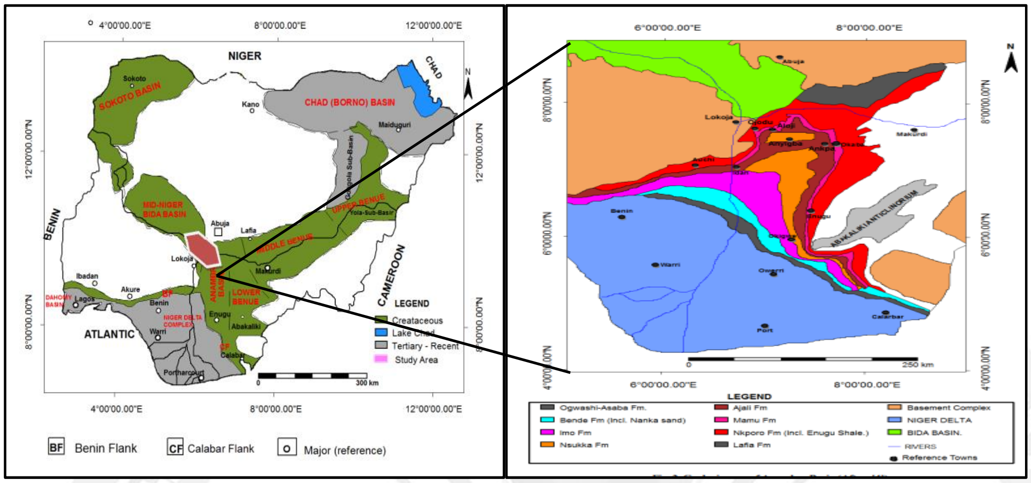

Fig. 1: Geological map of Nigeria and Anambra Basin

Fig. 2: The Mamu coal measures overlain by the Ajali sandstone around Imiegba - Okpekpe hill environment within the Anambra Basin

B. Stratigraphy

The Anambra basin's stratigraphy consists of Campanian–Maastrichtian Units, Enugu/Nkporo Formation is constituted with shales of marine sediment. This forms the basal unit overlying the basement complex. The Nkporo Shales are prodelta shales with subordinate sands and limestone, and their lateral counterparts, the Enugu Shales and Owelli Sandstones, make up the Campanian basal layers in the southeast.

Table 1: The Stratigraphic Sequences in Anambra basin [1]

Age	Basin		Stratigraphic Unit					
Danian			Nsukka Formation					
Maastrichtian	Anambra Basin	Coal Measure	Ajali Formation Mamu Formation					
Campanian		Nkporo Fm	Nkporo Shale	Enugu Shale	Owelli Ss	Afikpo Ss	Otobi Ss	Lafia Ss
Santonian	Southern Benue Trough		Awgu Formation					

Seating on the Enugu/ Nkporo shale is Mamu Formation (Lower Coal Measures), consisting of coal-bearing shales and sandstone deposit otherwise call paralic deposit [11]. On top of this, is continental Ajali Sandstone made of fluvial deposit (Table 1). The Nsukka Formation (Upper Coal Measures) consist shale/sandstone, while the Imo Formation consists of marine shales. They were both deposited during Paleocene–Eocene period (Table 1). The Nkporo Shale gives way to the Lokoja-Basange Sandstone Formation on the Benin Flank [21]. The stratigraphy of the Anambra Basin is shown in Table 1 [1].

II. MATERIALS AND METHODS

A. Study Area

The study area is positioned around Okpekpe community, within the Anambra Basin (Fig. 3). The research region is located between latitudes 07°10'11.9" N and 07°11'27.2" N and longitudes 06°25'54.4" E and 06°26'51.4" E. within the Edo State, Anambra Basin Nigeria. The study area is situated at Imiegba village and along the Okpekpe-Imiegba Road (Fig. 3). The geology of the area is a reflection of the African and South American plates' separation [12].

The Anambra Basin originated during the Santonian tectonic episode (~84 Ma) as a result of the compressional deformation of the Benue Trough, which shifted sedimentation westward. It is a synclinal depression bounded by the Abakaliki Anticlinorium (east), The Niger Delta hinge line (south), with The Precambrian Basement Complex at the northwest. The basin evolved as a failed rift arm of the South Atlantic opening, accumulating over 6,000 m of Cretaceous to Tertiary sediments.

Journal of Engineering and Technology (JET),
Volume 2, Issue 1, Page 90-103, 2026

Fig. 3: Map of the Study Area (retrieved from Goggle, 2025)

B. Sample Preparation

Twenty fresh shale samples were carefully collected and carefully stored in airtight containers to prevent oxidation and avoid contamination. The samples were then crushed and grinded to a fine powder (<200 mesh, ~74 µm) to ensure homogeneity. Each sample was further acid treated to remove inorganic carbonates using hydrochloric acid (HCl, 6M) at 60°C for 24 hours, followed by rinsing with deionized water and drying (60°C) in consonance with [13].

C. Total Organic Carbon (TOC) Analysis

The TOC of the sample is measured using LECO combustion-based methods [14]. The Instrument was calibrated using a certified standards involving potassium hydrogen phthalate) for calibration. Then, a 50 –100 mg of acid-treated shale powder was weighed into a crucible and heated to 900 –1000°C in an oxygen-rich environment. The Organic carbon is oxidized to CO_2, and measured by an infrared (IR) detector to record the TOC as weight percentage (wt%).

$$TOC = \frac{(0.083 \text{ x } S2) + S1 + RC}{0.85}\ wt\% \qquad (1)$$

Where:

S1 = volatile hydrocarbons released at temperature up to 300°C.

S2 = hydrocarbons from kerogen at temperature up to 650°C signifies

RC = residual carbon from oxidation step).

D. Soluble Organic Matter (SOM) Extraction methods

SOM includes free hydrocarbons and bitumen that are extracted using organic solvents such as Soxhlet Extraction. A fresh shale sample of 10–20 g was pulverized to very fine powder and prepared for solvent Selection using Chloroform ($CHCl_3$) or Dichloromethane (DCM:MeOH, 93:7) for efficient extraction. The sample was placed in a thimble and refluxed with solvent for 48–72 hours [13]. The solvent was later evaporated under nitrogen flow, then the extracted bitumen weighed. The SOM content is calculate using equation:

$$\mathrm{SOM}\left(\frac{\mathrm{mg}}{\mathrm{g}}\right)=\frac{\text{Extracted Mass (mg)}}{\text{Sample Weight (g)}} \qquad (2)$$

III. RESULTS

A. TOC Content

The TOC results of the samples under study range from 0.22 to 2.67 with mean value of 1.48% weight. As classified by research works of [2], samples R9, R10 and R16 have their TOC values fall within (<0.5%) indicated poor samples, while samples R1, R2 and R5 values range from (0.5–1.0%) signifies Fair TOC values. Also, samples R3, R4, R7, R12, R14, R18, R19 and R20 have TOC (1.0–2.0%) values indicating good quality. Samples R5, R9, R11, R13, R15 and R17 displayed very good qualities with their TOC values greater than 2, this indicates about 70% of these samples have TOC values ranging from good to very good values for hydrocarbon potential (Table 2).

IV. DISCUSSION

The SOM results revealed samples R4, R5, R7, R8, R11, R13, R15, R16, R17 and R19 to contain high SOM about >2000 ppm, while samples R1, R2, R6, R9, R11, R12 and R18 displayed moderate SOM values between 1000 and 2000 ppm (Table 2). Only sample R3, R14 and R20 showed low SOM with less than 1000 ppm (Figure 4). This indicates the sample has high hydrocarbon potential with 70 percent of the samples under study revealing high SOM values..

Table 2: The TOC and SOM values for the samples under study

S/N	SAMPLES	TOC VALUES	SOM VALUES
1	R1	0.55	1123
2	R2	0.77	1566
3	R3	1.33	905
4	R4	1.23	2345
5	R5	2.43	3244
6	R6	0.97	1653
7	R7	1.11	2633
8	R8	2.38	3218
9	R9	0.32	1687
10	R10	0.22	2180
11	R11	2.67	1468
12	R12	1.29	1016
13	R13	2.66	3321
14	R14	1.78	805
15	R15	2.38	3185
16	R16	0.31	2098
17	R17	2.64	3223
18	R18	1.15	1128
19	R19	1.98	2568
20	R20	1.67	855
Mean Value		1.48	2011
Minimum		0.22	805
Maximum		2.67	3321

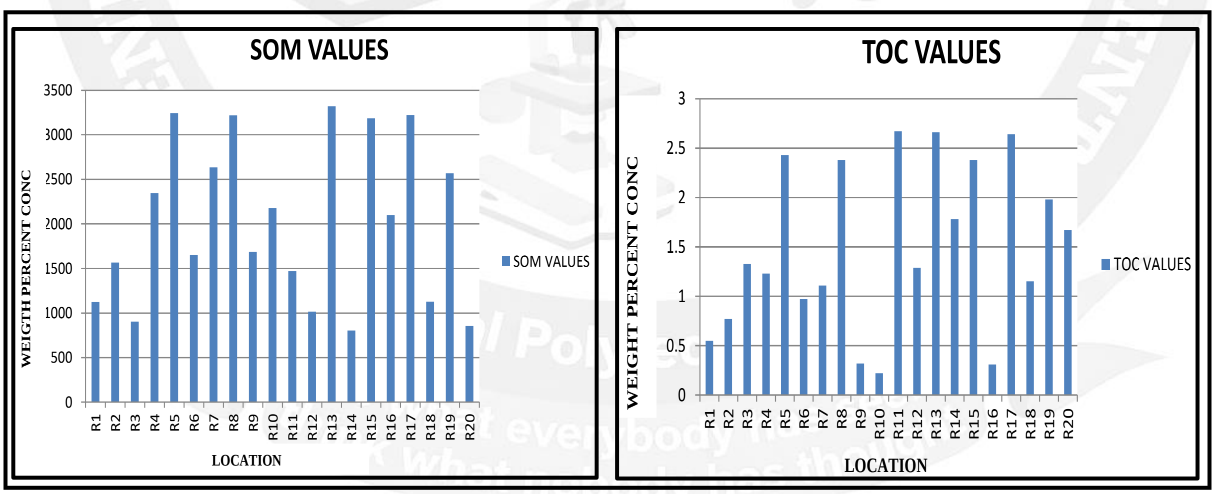

Fig. 4: Plots of SOM and TOC of the samples specifying their spatial distribution

A. Source Rock Potential

[15] in his research work, reported that the estimation of SOM content is predicated on TOC content that has been deposited for over 100 years. The conversion of TOC to SOM based on the content of carbon in organic matter is assumed to have its sources from the mixture of various compounds consisting of different carbon contents that constitute the SOM [16]. Samples R5, R8, R11, and R13 exhibit very good TOC values (>2%), this indicates high hydrocarbon generation potential. The SOM data support these findings, with high extractable organic matter in corresponding samples. Based on the result, samples R9 and R10 have poor TOC values; these probably represent less favorable source intervals [17].

Also these results were compared with the research work of [4], it was observed the TOC values from this study aligned with previous findings with their TOC values range from 0.5 to 3.0% for Mamu shales. However, SOM concentrations from this study show higher values than those reported by [3], this suggest local variability in organic facies present in this study area. This implies the Hydrocarbon Exploration in this study area signifies the Mamu Formation at Okpekpe contains sections with good to excellent source rock quality [18].

A Pearson correlation analysis was conducted to examine the relationship between total organic carbon (TOC) and soil organic matter (SOM). The results indicated a moderate positive correlation ($r = 0.486$) between TOC and SOM, with a 95% confidence interval ranging from 0.056 to 0.764. This suggests that increases in TOC are generally associated with increases in SOM. However, some samples (R3, R11, R14) deviate, possibly due to variations in organic matter present in them (Fig. 5). The high TOC and SOM values suggest significant hydrocarbon generation capacity in comparison with other Basins such as Akata Shale in Niger Delta basin, but with higher terrestrial influence [19], [21].

Although the lower bound of the confidence interval is close to zero, the interval does not include zero, indicating that the relationship is statistically significant at the 5% level. The scatter plot further illustrates an overall upward trend in SOM with increasing TOC. The spread of data points and presence of possible outliers imply that factors other than TOC also contribute to variations in SOM. These findings shows that TOC ss a primary constituent of SOM, while there are other additional environmental and management factors influencing soil organic matter content [20].

The Spearman's rank correlation coefficient between total organic carbon (TOC) and soil organic matter (SOM) was 0.342, with a 95% confidence interval ranging from –0.132 to 0.689. This value suggests a weak positive monotonic relationship between TOC and SOM. This means that, in general, higher TOC values tend to be associated with higher SOM values, although the relationship is not strong. However, the confidence interval includes zero, indicating that this relationship is not statistically significant at the 5% level. The scatter plot supports this finding, showing a mild upward trend but with substantial variability in SOM at given TOC values and possible deviations from a perfect monotonic pattern.

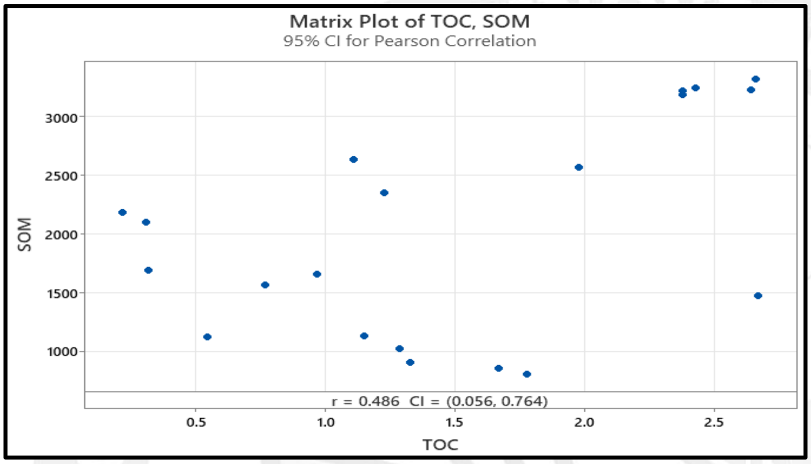

Fig. 5: Matrix scatter plot correlation signifying the behaviours of the sample to oil source production

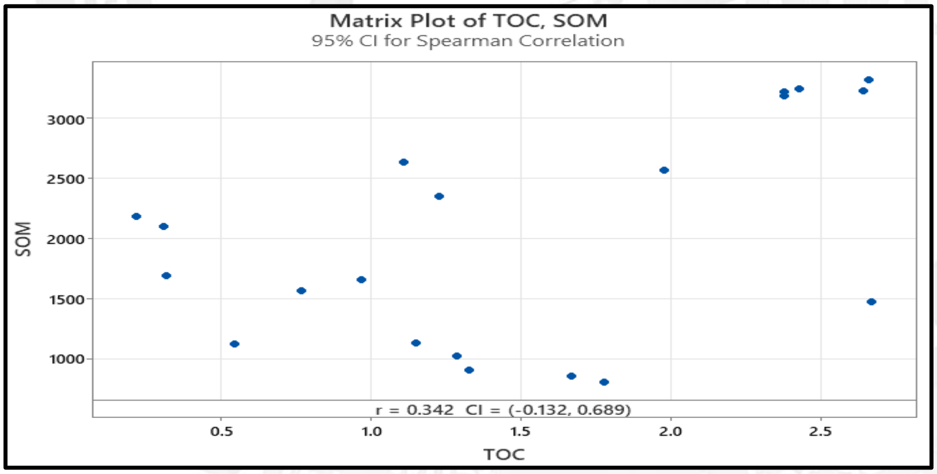

Fig. 6: Matrix plots based on spearman correlation

The weaker Spearman correlation compared to the Pearson correlation (r = 0.486) suggests that the relationship between TOC and SOM is more linear than monotonic and that the rank-order association is less pronounced (Fig. 6). This could be due to the presence of outliers which diminishes the strength of the monotonic relationship. The Pearson result provides stronger evidence of a statistically significant association between TOC and SOM, likely due to the direct proportionality inherent in their chemical relationship. Nevertheless, the reduced Spearman correlation highlights variability in the rank-order relationship, possibly arising from outliers, data clustering, or other soil characteristics influencing SOM independently of TOC.

B. Simple Linear Regression between TOC and SOM

A simple linear regression analysis was performed on the shale samples to evaluate the predictive relationship between total organic carbon (TOC) and soluble organic matter (SOM). The regression equation obtained was:

$$SOM = 1225 + 527.1 \times TOC \qquad (3)$$

The slope coefficient for TOC (527.1, SE = 223) was statistically significant ($t = 2.36$, $p = 0.030$), indicating that, on average, a one-unit increase in TOC is associated with an increase of approximately 527 units in SOM. The intercept (1225) represents the estimated SOM when TOC is zero (Table 3).

The model's coefficient of determination ($R^2 = 23.64\%$) suggests that TOC explains about 24% of the variation in SOM, while the adjusted R^2 (19.40%) accounts for the number of predictors in the model (Table 5). The relatively low R^2 value indicates that the majority of SOM variation is due to other factors not included in the model. The predicted R^2 (6.44%) is notably lower, suggesting that the model's predictive ability for new data is limited (Table 5). The overall regression model was statistically significant, ($p = 0.030$), meaning that TOC is a significant predictor of SOM at the 5% level. However, the standard error of the regression ($S = 815.671$) is relatively large compared to the mean SOM values, indicating substantial unexplained variability. The fitted line plot shows a positive slope, consistent with the earlier Pearson correlation result ($r = 0.486$), but the scatter of points around the line and potential outliers suggest that a single linear predictor may not fully capture the relationship between TOC and SOM (Figure 7).

Table 3: Correlation coefficients table

Term	Coef	SE Coef	T-Value	P-Value	VIF
Constant	1225	380	3.22	0.005	
TOC	527	223	2.36	0.030	1.00

	TOC
SOM	0.342

Model Summary

Table 4 summary of the model

S	R-sq	R-sq(adj)	R-sq(pred)
815.671	23.64%	19.40%	6.44%

Analysis of Variance

Table 5: Analysis of variance

Source	DF	SS	MS	F	P
Regression	1	3707815	3707815	5.57	0.030
Error	18	11975742	665319		
Total	19	15683557			

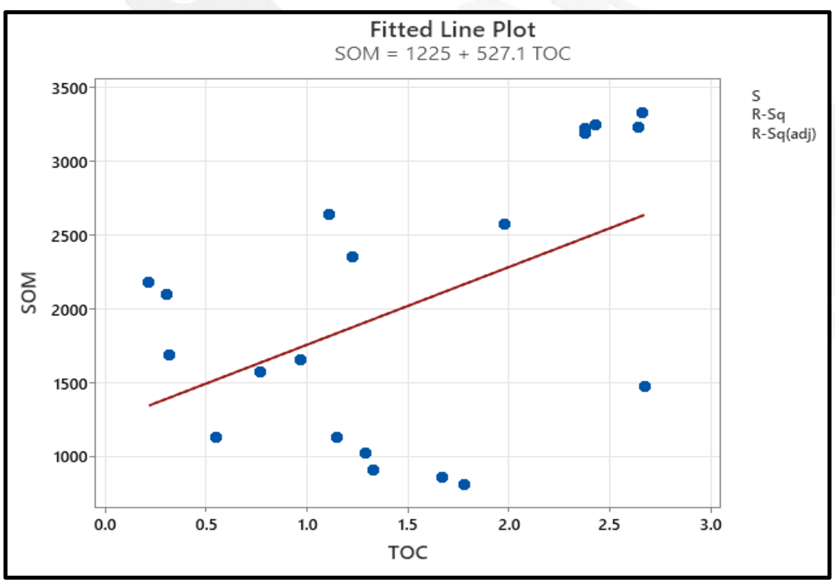

Fig. 7: -Bivariate plot of TOC against SOM, the fitted line plot shows a positive slope

V. CONCLUSION

The Anambra Basin's Mamu Formation at Okpekpe is a key stratigraphic unit with substantial hydrocarbon potential due to its organic-rich shales and transitional depositional setting. This has variable TOC (0.22–2.67%) and SOM (805–3,321 ppm). Four samples (R5, R8, R11, R13) exhibit very good TOC, indicating significant hydrocarbon potential. A moderate TOC-SOM correlation suggests organic quantity influences hydrocarbon yield. Its geochemical and sedimentological characteristics align with a passive margin tectonic setting, influenced by felsic provenance and intense weathering. Further subsurface geochemical and petrophysical studies are needed to evaluate kerogen type and thermal maturity in order to fully assess its petroleum system and avoid possible chemical weathering that might have affected the exposed outcrops. To learn more about the organic matter's source input and thermal maturity history, more research is advised, including biomarker analysis. potential for producing carbon from the Maastrichtian Mamu Shales at Imiegba and surrounding areas on the Benin Flank of the South-Western Anambra Basin, assessing the organic matter's kinds, richness, and quality.

ACKNOWLEDGEMENT

This study recognises the contribution of University of Ibadan Geochemistry Laboratory for their supports. We also acknowledge every person that contributed directly and indirectly to this research work.

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