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PETROLEUM GENERATIVE POTENTIALS AND MATURATION STUDIES OF UPPER CRETACEOUS SEDIMENTS WITHIN AFIKPO SYNCLINE, SOUTH EASTERN NIGERIA

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ABSTRACT

The present study assessed the petroleum potential of the upper Cretaceous stratigraphic interval within the Afikpo Basin. This basin has remained under-investigated relative to the neighbouring Anambra Basin and the prolific Niger Delta. Sixteen shale samples obtained from the stratigraphic interval were subjected to Total Organic Carbon determination (TOC) and Rock-Eval pyrolysis. The results of the TOC determination range from 0.97 to 13.80 wt% (an average of 4.14 wt%), indicating a fair to excellent level of organic enrichment for hydrocarbon generation. The genetic potential (S1 + S2) of the shales ranges from 0.47 to 8.26 mg HC/g rock. This suggests that the shales have poor to excellent generative potential for hydrocarbons. Meanwhile, the bivariate plot of S2 against TOC shows that most of the samples analyzed have poor to fair petroleum generative potential, except samples Ok-4 and OK-7 that exhibit good generative potential. Furthermore, Hydrogen Index (HI) for the shales ranges from 16 to 101 mgHC/g TOC (an average of 36.25 mgHC/g TOC). Thirteen samples have HI below 50 mgHC/gTOC, suggesting Type IV kerogen, while three samples have HI above 50 mgHC/gTOC, suggesting Type III-prone kerogen that is capable of generating gas. Type IV kerogens have little or no hydrocarbon potential and are primarily inert organic matter in the form of polycyclic aromatic hydrocarbons. The thermal maturity (Tmax) values of the shales range from 401 to 429 °C (mean = 410 °C), indicating that the shales are thermally immature. The plots of Tmax against HI further affirm the thermal immaturity of the sediments. In conclusion, shales within the upper Cretaceous interval exposed in the study areas generally have good organic matter with poor generative potential for gas and low thermal maturity.

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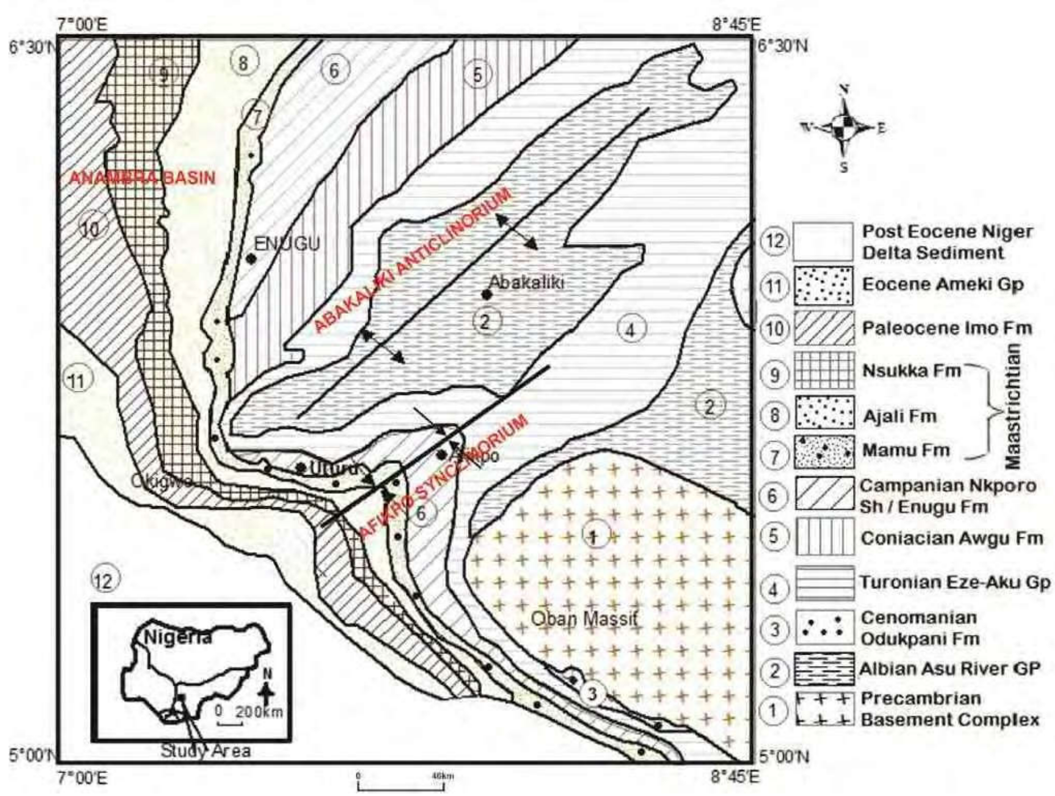
1. INTRODUCTION

Afikpo Syncline in the southern Benue Trough has remained poorly understood relative to other sub-basins in the southern Benue Trough in respect of the database on petroleum-generating potentials. Despite numerous previous works focused on the sedimentology, biostratigraphy, and other aspects of the basin's geology (Umeji, 2010; Igwe *et al.*, 2015; Okoro *et al.*, 2016; Ameh *et al.*, 2016; Mode *et al.*, 2018), there is a lack of emphasis on the petroleum generative potentials of the syncline and its maturation level for hydrocarbon generation. More so, in view of its proximity to the Niger Delta oil province and the Anambra Basin, where hydrocarbons are being generated. The Afikpo Syncline, together with the neighbouring Anambra Basin, formed flexural basins in relation to the Abakaliki Anticlinorium following the Santonian Orogeny within the southern Benue Trough (Fig. 1). Sedimentation within the syncline commenced during the upper Cretaceous, with its deposits unconformably overlying the compressionally folded pre-Santonian deposits. These sequences include the Enugu Shale, Nkporo Shale, Ajali Sandstone, Mamu Formation, and Nsukka Formation. Several authors have reported the petroleum potentials of the upper Cretaceous sediments, with more emphasis on the Anambra components of the Southern Benue Trough. Notable among them are Ekwezor and Gormly (1983), Nwachukwu (1985), Ojo *et al.* (2009), Akande *et al.* (2015), Dim *et al.* (2018), Chiadikobi and Chiaghanan (2018a and 2018b), Okwara *et al.* (2019), and Madukwe *et al.* (2023).

Ekwezor and Gormly (1983) observed that the shales of the late Cretaceous to early Tertiary penetrated by the Akukwa _2 have a poor to very good level of organic matter that is derived from humic and mixed sources. The infrajacent Nkalagu Formation and Nkporo Shales within the Anambra Basin are identified as the best source beds for petroleum generation. Also, Unomah and



Ekweozor (1993) assessed the petroleum potentials of the Campanian Nkporo Formation in the southern Benue Trough, reporting similar Total Organic Carbon values across regions. The Nkporo Group has fair to excellent organic enrichment with Type III/IV kerogen, whereas the Enugu Shale is mature.

Additionally, Ojo *et al.* (2009) reported fair to good organic matter and potentials for gas generation upon thermal maturity for dark grey shales within the Campanian to Maastrichtian Enugu Formation. Chiadikobi and Chiaghanan (2018b) likewise reported that source rocks in the Nkporo Group have fair to very good organic enrichment. The Nkporo sediments have Type III/IV kerogen, and the Enugu Shale has Type II/III kerogen. Meanwhile, the Nkporo sediments range from immature to marginally mature, whereas the Enugu shales exhibit maturity. According to Adeleye *et al.* (2017), coaly sediments of the Mamu Formation have a fair to excellent level of organic matter for hydrocarbon generation. Akande *et al.* (2015) supported that sub-bituminous sediments of the Mamu Formation have an excellent level of organic matter with Type III gas-prone kerogen. However, Madukwe *et al.* (2023) revealed that the Nkporo and Awgu Shales shales within the southern Benue Trough have a Co/Ni ratio greater than 0.1, suggesting oil source rocks with more marine-derived sources.

Most of the aforementioned contributions on the petroleum potentials of the Upper Cretaceous sediments have focused on the Anambra Basin component of the southern Benue Trough, whereas, very little investigations is conducted on the petroleum potentials of the Upper Cretaceous interval of the Afikpo Syncline. This has constituted the basis for this research. Additionally, the research covers new outcrop locations that include Nguzu Edda, Ekoli and Asaga Amangwu. These areas have not been fully assessed for their petroleum potential. This study, however, aimed to assess the petroleum potential of some outcrop sediments from the Upper Cretaceous interval exposed within the Afikpo Syncline.

Geological Settings

The Afikpo Syncline, the Anambra Basin, and the tectonically flipped Abakaliki Anticlinorium constitute the southern extension of the Benue Trough (Petters and Ekwezor, 1982a), a large depression. Also within the trough is the Calabar Flank, which is situated in the far east of the basin. The 'X'-shaped basin formed over the Basement Complex of Nigeria and is oriented in Northeast-Southwest (NE-SW) and Northwest-Southeast (NW-SE) (Short and Stauble, 1967). According to Nwachukwu (1972) and Nwajide and Reijers (1997), the Benue Trough formed from the undeveloped arm of the triple-ridge system, that resulted from the drifting of the South America and Africa plates during the early Mesozoic era. Crustal stretching and downwarping in the southern Atlantic accompanied the formation process, leading to the development of coastal basins. King (1950) previously suggested that the emergence of the basin is believed to be correlated with forces linked to the separation of the South American and African plates. The process leading to the evolution of the Benue Trough (Burke *et al.*, 1970; Nwachukwu, 1972; Olade, 1975; Wright, 1981; Petters, 1978; Benkhelil, 1982). According to Wright (1981), the Benue Trough has been an extensional feature since Early Cretaceous. It is considered a failed arm of a rift-rift-rift (RRR) triple junction that formed during the development of the South Atlantic. This is in agreement with the reports of Burke *et al.* (1970).

Olade (1975) related the formation of the trough to the emergence of a plume of mantle in the contemporary Niger Delta region. The plume emergence resulted in the doming and rifting in the Benue region, and subsequent development of rift-rift-rift (RRR) triple junction. The concurrent volcanic activity led to the formation of the Abakaliki pyroclastics from the Aptian to early Albian age. In the middle and late Albian age, the trough underwent an intense subsidence and sediments of the Asu River Group were deposited, coinciding with the process of rifting.

Worldwide eustatic sea level changes, local diastrophism, and basin tectonics mainly control sedimentation within the trough. The initial sediments found in the Benue Trough were pyroclastics from the Aptian-Albian period, specifically located in the southern region of the trough (Uzuakpunwa, 1974). This unit forms the onset of deposition in the Albian-Cenomanian (Petters, 1978) and was subsequently overlain by sediments of the Asu River Group, which is about 3000m. The Asu River group consists of shales, sandy shales, micaceous sandstones, and lenses of limestones. Increased marine influence during the Cenomanian period led to the formation of the Odukpani Formation, as indicated by the presence of transgressive coastline carbonates (Petters, 1978). Subsequently, during the late Cenomanian age, there was a retreat of the Asu River Group, marked by the occurrence of folding and erosion (Machens, 1973; Offodile, 1976; Wright, 1981). The Turonian age exhibited transgression characteristics (Petters, 1978), which validate the presence of two distinct unconformities that separate the Turonian-Coniacian sequence in the southern region. Following this major episode of transgression, there was the deposition of the transitory Eze-Aku Group and the marine Awgu Shale. Sediments recorded in the Eze-Aku Group include calcareous sandstones, shelly limestones, siltstones, and calcareous shales. The Eze-Aku Group consists of calcareous shales, siltstones, thin sandy or shelly limestones, and calcareous sandstones. The Eze-Aku Group penetrates the Awgu Formation, characterized by predominantly dark shales interbedded with limestone bands. Widespread Santonian movements interrupted this depositional cycle, folding the sediments and causing magmatic activity and lead-zinc mineralization to occur simultaneously.

Following the Santonian tectonic event, the sea receded into the Anambra Basin, resulting in the displacement of the depositional axis and the sinking of the basin. The basin predominantly experienced the accumulation of terrestrial deposits. The Campanian-Maastrichtian sequence, as described by Petters (1978), comprises the shallow marine Nkporo Shale, Enugu Shale, Mamu Formation, Ajali Formation, and Nsukka Formation (Fig. 2). The southern region experienced a transgression phase during the Paleocene. During the Eocene, sediments accumulated in the Anambra Basin, and simultaneously, the Niger Delta expanded in a southern direction, reaching towards the Gulf of Guinea (Petters, 1978).

Ekwezor and Gormly (1983) observed that the

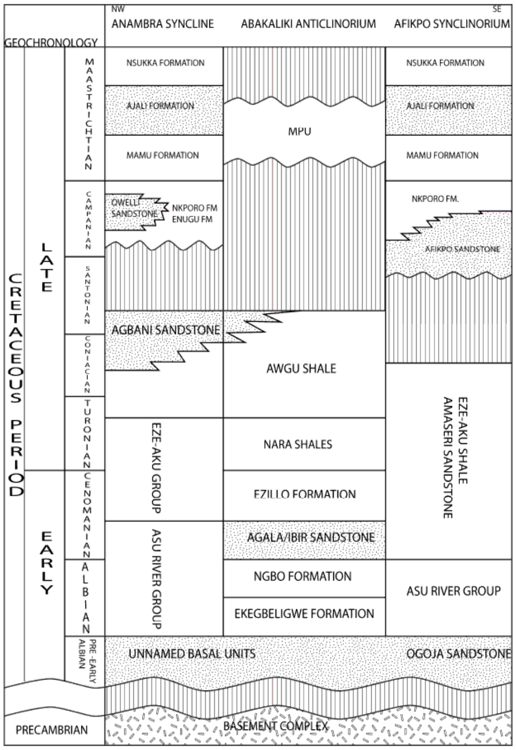


Fig. 1: Geological map of Nigeria showing the Afikpo Syncline within the southern Benue Trough (modified after Hoque, 1976).

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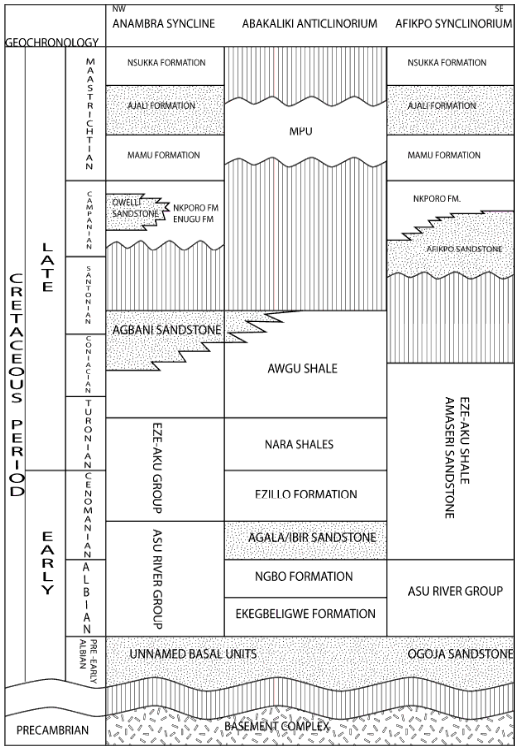

Fig 2: Stratigraphic column of the Southern Benue Trough (Nwajide, 2005).

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Material and Methodology

Fieldwork was carried out within sediments of the Upper Cretaceous exposed at Nguzu-Edda, Asaga Amangwu, and Ekoli (along the Okwenkwu-Ekoli road). Two outcrop sections were investigated within Nguzu-Edda. These include the Nguzu Hill outcrop along the Nguzu-Owutu road and the Nguzu stream outcrop within Nguzu town. One section each was investigated within Asaga Amangwu and Ekoli (along the Okwenkwu-Ekoli road). The fieldwork involves comprehensive logging at each location, section measurements, descriptions of beds, and the collection of fresh representative samples. The beds were described based on lithologic characteristics that include textural and mineralogical composition, sedimentary structures, and fossil contents. Carefully selected samples were subjected to analyses that included total organic carbon (TOC) and Rock-Eval pyrolysis. The analyses were performed at the Stratochem Laboratory, Canada.

Total Organic Carbon

Seventeen shale samples were recovered from the fieldwork and subjected to Total Organic Carbon (TOC) analysis. Espitalié *et al.* (1977, 1985) demonstrated the standard technique used in the procedures. The samples were pulverized and analyzed by means of a LECO C230 analyzer.

Initially, 20mg of each sample was pulverized and weighed into a stainless steel crucible. The samples were thereafter treated with hydrochloric acid (HCl) for carbonate removal and washed using distilled water. Afterwards, the samples were dried and placed into the furnace for adequate combustion. This process enables the determination of organic carbon richness within the samples.

Rock-Eval Pyrolysis

Sixteen samples were pyrolyzed to determine the organic richness, maturity level, Hydrogen Index (HI) and kerogen type using the Rock-Eval II instrument as described by Espitalié *et al.* (1977). At first, 30–40 g of each sample was heated to 300°C for 3–4 minutes, followed by controlled pyrolysis at a rate of 25 °C per minute in a helium environment, until reaching a temperature of 600°C. The purpose of this process was to obtain values for S_1, S_2, S_3, and thermal maturity. When organic matter is heated without oxygen, it produces organic compounds. Pyrolysis provides a direct measurement of the hydrocarbons that have previously been produced in the rock (S_1) and the hydrocarbons which are capable of being produced from the kerogen through thermal cracking (S_2). The sum of the values of S_1 and S_2 indicate the overall capacity of the rock to generate hydrocarbons (Dymann *et al.*, 1996). Also, the S_2 and S_3 values are been normalized to the amount of organic carbon, resulting in computed Hydrogen (mg HC/g TOC) and Oxygen indices (mg CO_2/g TOC).

Results

The results of the Total Organic Carbon (TOC) analyses conducted on the sixteen (16) shale samples range from 0.97 to 13.80 wt%, with an average TOC value of 4.14 wt% (Table 1). The Ekoli section exhibits the highest concentrations of organic carbon, with TOC values averaging greater than 7.39 wt% (Table 1). Asaga samples recorded the lowest concentration of TOC, with an average of 1.62 wt%. Also, the genetic potential of S_1+S_2, in the study areas ranges from

Table 1: Result of the Rock–Eval pyrolysis of samples of the Nkporo Formation exposed at Asaga Amangwu, Ekoli, and Nguzu-Edda

S/N	Sample Number	Location	TOC (wt%)	S_1 (mgHC/g rock)	S_2 (mgHC/g rock)	S_3 (mgHC/g rock)	S_1+S_2 (mgHC/g rock)	Tmax (°C)	HI (mgHC/g TOC)	OI (mgHC/g TOC)	PI
1	Ok-2	Ekoli Outcrop	3.26	0.18	0.55	1.94	0.73	405	17	60	0.25
2	Ok-3		6.96	0.18	2.46	5.23	2.64	410	35	75	0.07
3	Ok-4		13.80	0.34	7.80	11.19	8.14	411	57	81	0.04
4	OK-5		5.02	0.18	1.84	3.12	2.02	401	37	62	0.09
5	OK-7		7.91	0.27	7.99	5.28	8.26	420	101	67	0.03
6	UZ-1	Nguzu Hill	2.95	0.06	0.81	2.06	0.87	409	27	70	0.07
7	UZ-2		2.01	0.05	0.52	1.16	0.57	414	26	58	0.09
8	UZ-3		2.46	0.06	0.46	1.59	0.52	405	19	65	0.12
9	UZ-4		2.54	0.07	0.53	1.44	0.60	407	21	57	0.12
10	UZ-5		2.50	0.07	0.41	1.62	0.48	401	16	65	0.15
11	UG-5		2.60	0.07	0.80	1.73	0.87	416	31	67	0.08
12	UG-13		2.56	0.13	0.59	1.39	0.72	401	23	54	0.18
13	UG-18		6.12	0.16	2.30	3.07	2.46	403	38	50	0.07
14	UGZ-1	Nguzu Stream	4.28	0.11	3.32	3.58	3.43	429	78	84	0.03
15	UGZ -8		2.20	0.09	0.38	1.30	0.47	403	17	59	0.19
16	AS-1	Asaga Amangwu	2.26	0.08	0.86	0.65	0.94	420	38	29	0.09
17	AS-3		0.97								
Average			4.14	0.13	1.98	2.90	2.11	409.69	36.25	62.55	0.10

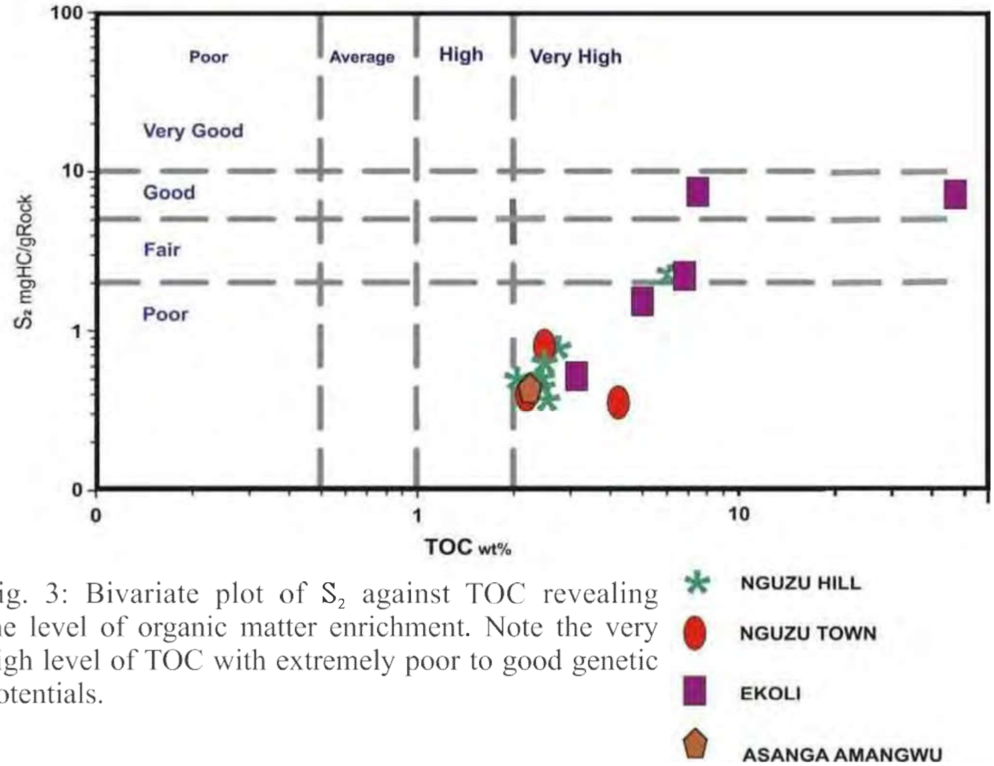

Fig. 3: Bivariate plot of S_2 against TOC revealing the level of organic matter enrichment. Note the very high level of TOC with extremely poor to good genetic potentials.

0.47 mg HC/g to 8.26 mg HC/g rock. Ekoli samples have the highest concentration of S_1+S_2, ranging from 0.73 to 8.26 mg HC/g rock (with an average of 4.36 mg HC/g rock), while UGZ-8 has the lowest concentration of S_1+S_2 at 0.47 mg HC/g rock. Generally, the Hydrogen Index (HI) values are very low, and they range from 16 to 101 mg HC/g TOC.

Only three samples have HI values above 50 mgHC/g TOC, the remaining thirteen samples have HI values that fall below 50 mgHC/g TOC. The Thermal Maturity (Tmax) values of the shales range from 401°C to 429°C (mean = 410°C). Sample UGZ-1 from the Nguzu stream channel recorded the highest Tmax value (429°C), while samples OK-5, UZ-5, and UG-13 recorded the lowest value of 401°C.

Discussion

Organic Matter Richness

Organic matter concentration in potential source rocks directly correlates with the quantity of hydrocarbon generated from the organic matter disseminated in the shale (Tissot and Welte, 1984). Sediments collected in areas with high productivity of organic materials are typically highly concentrated in organic matter. Peters and Cassa (1994) categorized the Total Organic Carbon (TOC) content of a rock as poor, fair, good, very good, or excellent. All the samples analyzed have TOC values above 2.0 wt%, except AS-03. This level of concentration indicates a very good to excellent level of organic enrichment for hydrocarbon generation (Peters and Cassa, 1994; Hunt, 1996). However, sample AS-03 indicates a fair level of organic matter concentration. The plot of the TOC against S_2

supports the organic richness and further indicates a fair to excellent potential of the source rock (Fig. 3).

Genetic Source Potentials ($S_1 + S_2$)

The genetic potential (S_1+S_2) defines the overall quantity of petroleum that a source rock can generate (Tissot and Welte, 1984). Tissot and Welte (1984) classified genetic potential ($S_1 + S_2$) less than 2 mg HC/g rock to connote little to no oil potential. A $S_1 + S_2$ of 2 to 6 mg HC/g rock means that the generative potential is moderate to fair, and a hydrocarbon yield of more than 6 mg HC/g rock means that the source rock potential is good to excellent. Consequently, only samples OK-4 and OK-7 have good to excellent generative potentials, while samples OK-3, OK-5, UG-18, and UGZ-1 have fair to moderate generative potential. The remaining samples that have less than 2 mg HC/g rock have poor generative potential. The plot of S_2 against TOC also confirms this (Fig. 3).

Hydrogen Index and Kerogen Type

Though the amount of organic matter in a rock is typically calculated by measuring the amount of organic carbon, Akande *et al.* (2015) reported that hydrogen, not carbon, is the reaction's limiting factor in the petroleum-forming process. Only the bonded hydrogen in organic molecules plays a role in the processes that generate petroleum, necessitating the analysis of carbon. The higher the hydrogen contents in a source rock, the greater the tendency to generate oil. Generally, all the samples have a Hydrogen Index (HI) value below 200 (mgHC/g TOC) suggesting Type III gas-prone to Type IV kerogens (Fig. 4 and Fig. 5). These kerogen types are complemented by the cross plots of Hydrogen Index (HI) against Oxygen Index (OI) and Hydrogen Index (HI) versus Thermal Maturity (Tmax). Due to the extremely low HI value, the majority of the samples plot within the weak gas zone (Fig. 4) and Type III gas-prone to Type IV kerogen (Fig. 5), respectively. Meanwhile, Peters and Cassa (1994) classified HI values below 50 mgHC/g TOC as Type IV kerogen. The thirteen samples that have HI below 50 mgHC/gTOC suggest type IV kerogen, while the three samples with HI above 50 mgHC/gTOC suggest Type III gas-prone kerogen. Type IV kerogen is universally discarded due to its debatable potential as a hydrocarbon. It has no potential for hydrocarbons and has mainly inert organic content in the form of polycyclic aromatic hydrocarbons. Kerogens are hydrogen-deficient components, among which is inertinite, that undergo direct oxidation by thermal maturation, including processes like fire (charcoal) or biological and sedimentological recycling. During deposition, recycled or extremely oxidized organic matter dominates the sediments. Resins and waxes from non-biological sources contribute to their derivation and are present in rocks deposited in an arid environment.

Thermal Maturity (Tmax)

The Tmax value corresponds to the temperature at which the highest quantity of hydrocarbons is generated in the laboratory during pyrolysis. Hydrogen content in the rock and its maturity level are related to hydrocarbon formation by pyrolysis. As the source rocks mature, their hydrogen content decreases, requiring more energy to expel hydrocarbons. All the samples studied have values below the minimum threshold for hydrocarbon generation, as illustrated by

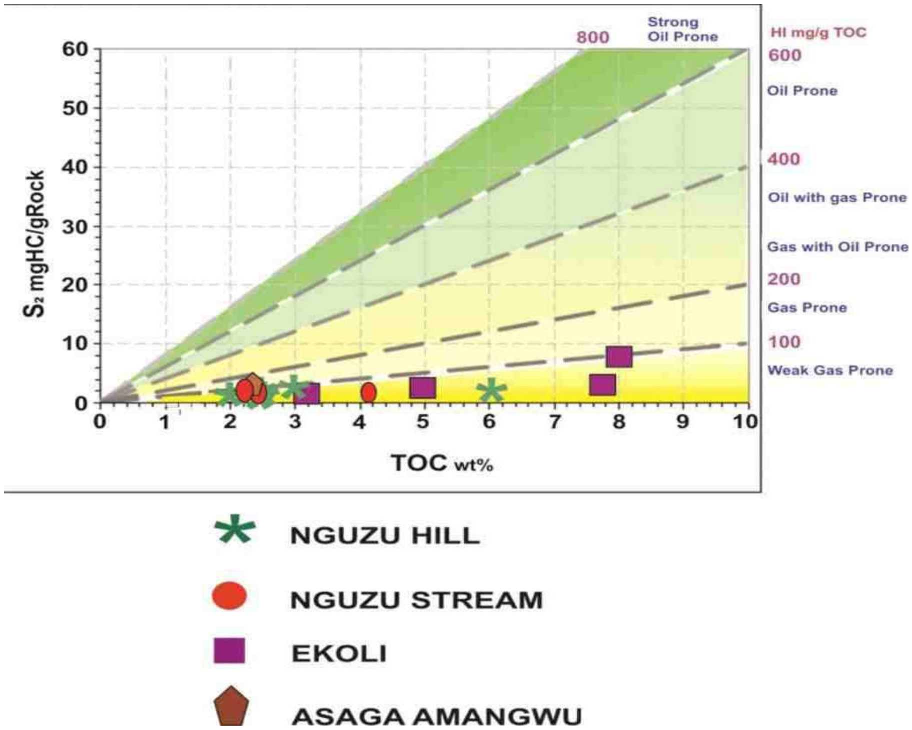

Fig. 4: Bivariate plot of S_2 against TOC indicating that the source rocks are capable of generating weak gas

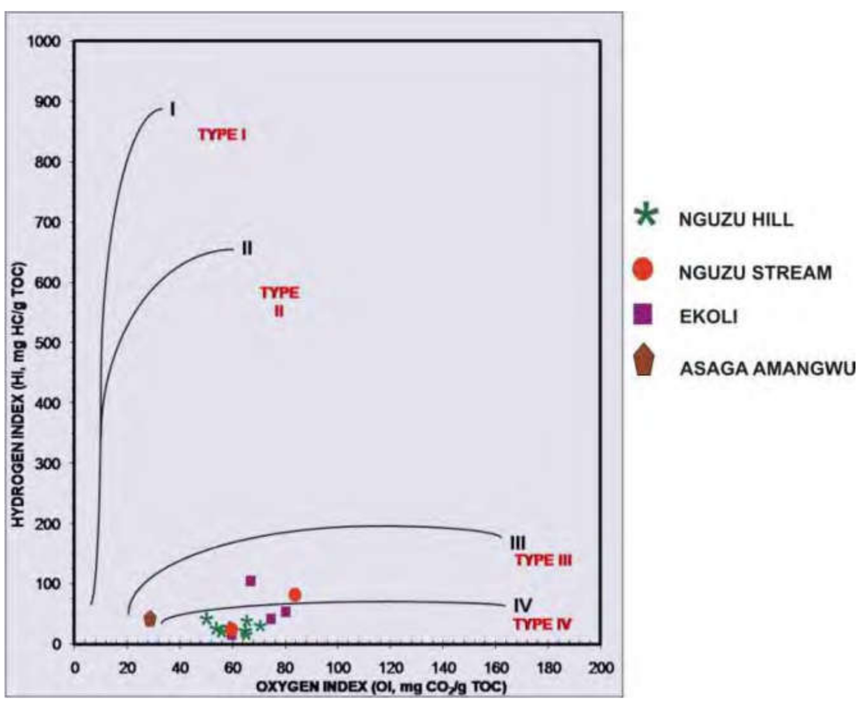

Fig. 5: Bivariate plot of Hydrogen Index against Oxygen Index indicating Type III to Type IV kerogens for the source rocks.

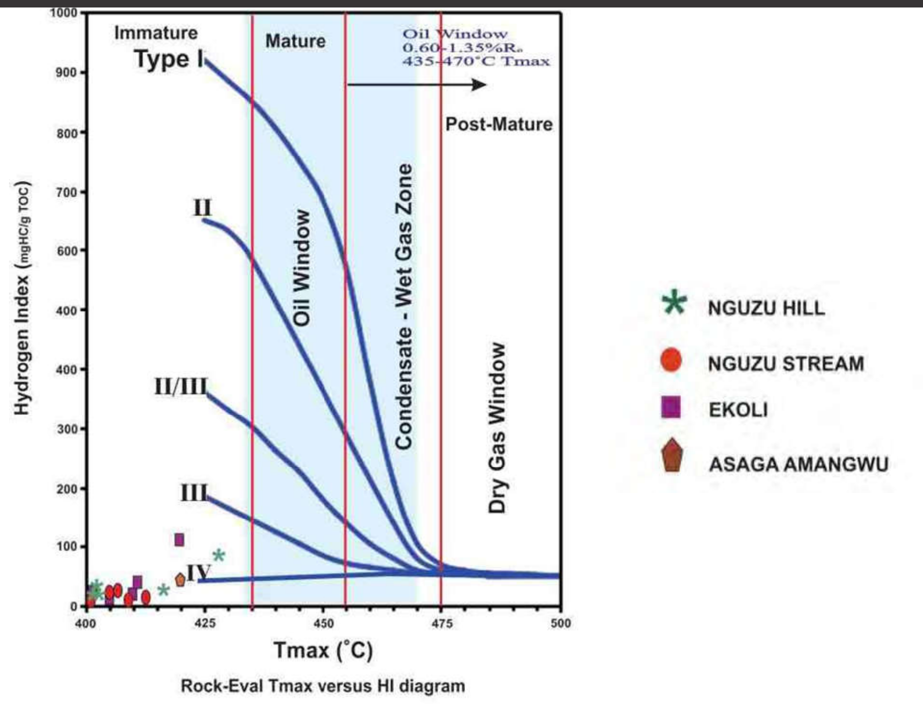

Fig. 6: Bivariate plot of Hydrogen Index against Tmax, suggesting that the samples falls within Type III and Type IV kerogens and are all thermally immature.

Peters and Cassa (1994), and are therefore all considered thermally immature. The bivariate plots of Tmax against HI (Fig. 6) and PI against Tmax further complement the thermal immaturity.

CONCLUSION

Source rocks exposed at Nguzu-Edda, Ekoli, and Asaga Amangwu in the upper Cretaceous stratigraphic interval of the Afikpo Syncline exhibit fair to excellent organic matter enrichment and are presumed to be capable of generating petroleum. However, the genetic source potential indicates that the source rocks have poor to excellent potential for petroleum generation. Meanwhile, the preponderance of Type IV kerogen (approximately 81%) within the sediments indicates no potential for hydrocarbon generation, while a subordinate amount of Type III kerogen (approximately 19%) suggests capability for gas generation. Type IV kerogen also signifies a high level of oxidation in the sediments, as likewise reflected in the oxygen index values. Based on the thermal maturity values and the bivariate plots of HI against Tmax, it is observed that the source rocks are thermally immature.

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