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SOURCE ROCK GEOCHEMISTRY OF THE PALEOGENE STRATA IN BENDE-UMUAHIA AND ITS ENVIRONS, NIGER DELTA BASIN, SOUTHEASTERN, NIGERIA

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Abstract

Source rock geochemistry of the paleogene (Imo and Ameki Formations) strata in Bende- Umuahia and its environs, Niger Delta Basin, southern eastern Nigeria was assessed for its hydrocarbon play using walkley black wet oxidation and rock-eval pyrolysis techniques. The total organic carbon (TOC) average values for Imo and Ameki Formation are 0.86wt% and 0.74 wt%, this indicates a fair petroleum potential and organic matter concentration. The generative potential (GP) average value of 0.38mg Hc/g for the two formations studies indicates that the organic matter quality is poor. The result of hydrogen index (HI) shows a studied area that is basically type IV Kerogen. The average T_{max} value for Imo Formation was 408.8ºC ad 410.8ºC for Ameki Formation, which suggest that the studied area is thermally immature. The average vitrinite reflectance (RO) values for Imo and Ameki Formation, which are 0.59R_o and 0.32R_o respectively also suggests that the area studied is thermally immature.Theplots of Rock-Eval s2 versus Toc and hydrogen index versus oxygen index indicates that the studied area is basically type IV Kerogen, while the plots of production Index versus T_{max} and Hydrogen index versus T_{max} indicates thermally immature for the area. Source rock geochemistry of type IV Kerogen, Thermally immature and fair petroleum potential can be assigned to the area studied.

Keywords: *Source Rock Geochemistry; Rock-Eval; Total Organic Carbon; Kerogen; Imo and Ameki Formation.*

1. Introduction

Niger Delta is a Cenozoic gross offlap clastic succession built out atop the Anambra Basin and forms part of the western African miogeocline that spread out onto the cooling and subsiding oceanic crust generated as the African and the South American lithospheric plates separated [1].

The systematic and consistent pattern of development of Niger Delta was such that, taken in a gross stratigraphic sense, three distinct vertically stacked lithologic units- Akata (Marine facies), Agbada (transitional, paralic facies) and Benin (Continental) have been, and are still been, constructed. The total sediment thickness is up to 12km beneath the upper and lower deltaic plain [1]. The outcropping units of the Cenozoic Niger Delta are Imo Formation (Paleocene-Early Eocene) which is blue –grey shales with sand lenses, marls, and fossiliferous limestones, sandstone members- Ebenebe, Umuna and Igbaku sandstones; shales with foraminifera and ostracods. Ameki group (Eocene- Early Oligocene) which comprises (a) Nsugbe Formation- mainly sands, with some conglomerate bands, (b) Nanka Formation-calcareous clays and silts with thin shelly limestones, rich in foraminifera (c) Ameki Formation-calcareous clays and silts with thin shelly limestone, rich in foraminifera, mainly sands, minor silt and clay intercalations. The Ogwashi- Asaba Formation (Oligocene- Miocene) comprises of clays, silts and sandstones with thin to thick lignite seams [1-3]. The geologic map of the study area is shown in Fig. 1.

The objective of the present study is aimed at investigating the hydrocarbon potential of the outcropping shale units of the Cenozoic Niger Delta within the Umuahia-Bende axis which will help to:

1. Determine the quality of the source rock of the paleogene strata exposed in the Bende-Umuahia axis,
2. Determine and evaluate the thermal and hydrocarbon generation potential of the organic rich sediments of paleogene strata exposed in the Bende-Umuahia axis.

The deductions from the study will provide information necessary to optimize exploration activities in the Niger Delta Basin with a view of improving on past investigation/assessment in the study area.

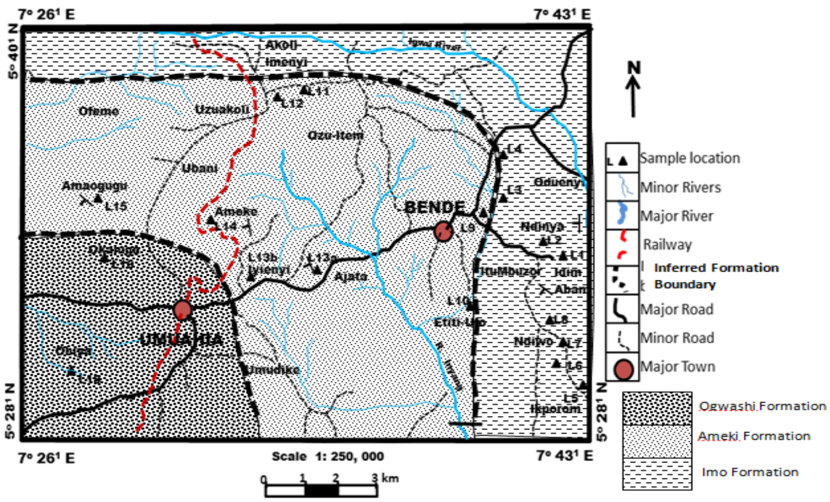

Fig. 1. Geologic map of the study area

2. Geological setting and stratigraphy of the area

The cenozoic strata of the Niger Delta Basin are N-S to NW-SE striking units comprising Imo (Middle Paleocene- early Eocene), Ameki (Early to late Eocene), Ogwashi (Oligocene-Early Miocene), and Benin Formation (Miocene to recent); [4-5] (Fig. 2).

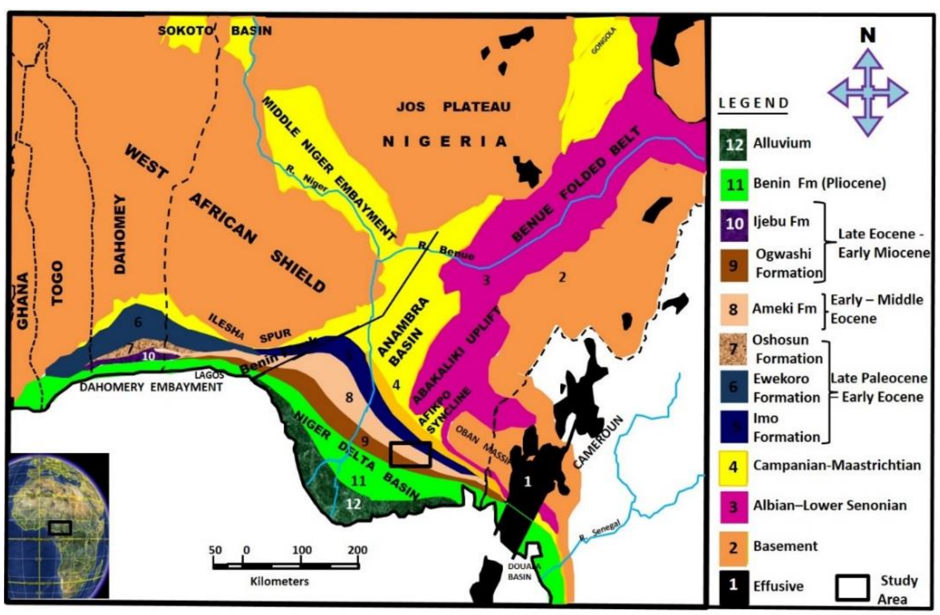

Fig. 2. The Cenozoic succession of the Niger Delta Basin (*after* [4-5])

The Imo Formation consist of thick blue to grey shales and mudstones,with occasional thin bands of calcareous sandstones and limestone, about 1000m thickness, [6]. The formation is exposed at Bende town, extending from Oduenyi village to Ndiwo junction, along Ndiwo-Ikporom road cut. This is overlain by Ameki Formation which consists of alternating shales, sandyshales, clay, sandstones, and fine-grained fossiliferous sandstone with thin bands of limestone [6-7]. At Itumbuzor in Bende, the formation directly overlies the Imo Formation and terminates westward around Isiadu Ameke and Amaogugu where it is completely buried by the overlying Ogwashi Formation [4,8]. The Ogwashi Formation [9], consists of alternating coarse grained sandstones, light coloured clays of continental Origin, with Lignite seams. The formation is overlain by the alluvial deposits of Benin Formation. These Cenozoic succession up-dip of the Niger- Delta have been correlated to the subsurface down-dip formations [3,10] Fig. 3, and since there are no stratigraphic breaks, the formation in the up-dip and down-dip constitute the Niger delta basin [4], according to the rules of stratigraphic nomenclature [2,6,11] Table 1.

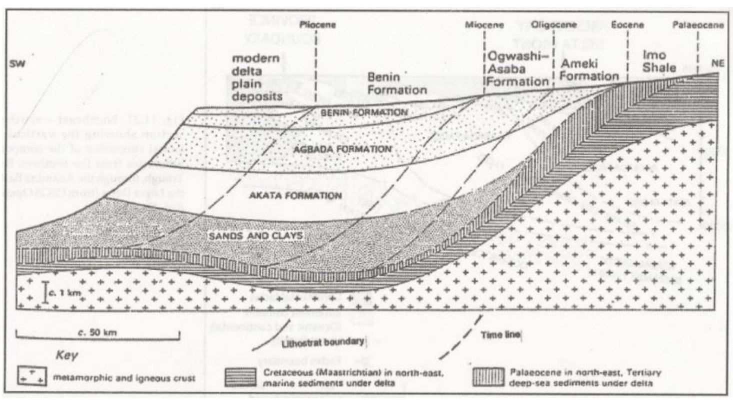

Fig 3. Stratigraphic equivalencies between the outcropping and the subsurface Niger Delta (*after* [3])

Age			Group	Niger Delta Basin (This Study) Down-dip	Niger Delta Basin (This Study) Up-dip
Quaternary				Alluvium	
NEOGENE	Pliocene		Benin Group	Benin Formation	Benin Formation
NEOGENE	Miocene		Benin Group	Benin Formation	Benin Formation
PALEOGENE	Oligocene		Ameki Group	Upper Agbada Formation	Ogwashi Formation
PALEOGENE	Eocene	L	Ameki Group	Upper Agbada Formation	Ogwashi Formation
PALEOGENE	Eocene	M	Ameki Group	Lower Agbada Formation	Ameki Fm/ Nanka Sand/ Nsugbe Sst
PALEOGENE	Eocene	E	Ameki Group	Lower Agbada Formation	Ameki Fm/ Nanka Sand/ Nsugbe Sst
PALEOGENE	Paleocene		Imo Group	Akata Formation	Imo Fm/ Umuna Sst/ Ebenebe Sst
PALEOGENE	Danian		Imo Group		
LATE CRETACEOUS	Late Maastrichtian		Coal Measures Group	Major Unconformity	Major Unconformity

Major Unconformity

Table 1. Stratigraphic column of Niger Delta Basin (*modified after Frankyl and Cordry* [10])

3. Previous work

Source rock geochemistry studies in the Niger Delta Basin and Late Cretaceous Anambra Basin has the undertaken by various workers, these workers includes Chiaghanam *et al.* [12], studies the palynofacies and kerogen Analysis of Upper Cretaceous (Early-Campanian to Maastrictian) Enugu Shale and Mamu Formation in Anambra Basin, Southeastern, Nigeria. The source rock potential and thermal maturity of the Eocene Nanka Formation in Anambra Basin: An Appraisal of Ogbunike reference locality, SE, Nigeria was carried out by Chiaghanam *et al.* [13]. Palynology, source rock potential and thermal maturity of Eocene Nanka Formation in Anambra basin: An investigation of Agulu Lake, S.E. Nigeria [14]. Source rock and thermal maturation of Campanian Enugu Shale in Anambra Basin, S.E. Nigeria. Anozie *et al.* [15]. The Depositional environments, Organic richness and petroleum generating potential of the Campanian to Maastrictitian Enugu Formation were done by Ojo *et al.* [16]. Ogala [17] studies hydrocarbon potential of the Upper Cretaceous coal and shale units in the Anambra Basin. source rock maturation studies using vitrinite reflectance and geothermal data from six wells in Gaba and Wabi, fields, onshore Niger delta, was done by Didei and Akana [18]. Geochemical investigation of potential source rocks for Agbada Formation, Osioka South Area, Western Niger Delta was studies by Nyantakyi *et al.* [19]. Source Rock characterization of Agbada Formation in well Z, offshore, Niger Delta Asadu *et al.* [20].

The present study attempts to provide information on the hydrocarbon potential and thermal maturation of the study area, since little or no work has been done on its source rock geochemistry.

4. Materials and methods

Ten shale samples recovered from the outcropped Imo and Ameki Formation in the study are selected for Total organic content determination and Rock eval pyrolysis which was aimed towards:
a) Determining the quantity, or amount of organic matter.
b) Determining the quality, or type of organic matter
c) Determining the thermal maturity, or extent of burial/heating [21].

Total Organic Carbon (TOC): The ten shale samples were subjected to preliminary total organic carbon content determination by using Walkley Back wet oxidation method, which involves subjecting 0.5g of each pulverized samples to chromic oxidation using the principles of Walkley and Black [22]. This served as a preliminary step towards carrying out rock- eval pyrolysis analysis.

Rock-eval Pyrolysis: The samples were subjected to rock-eval pyrolysis using the principles and procedures according to Espitalie *et al.* [22] and Stach *et. al.* [23]. The samples were heated in an inert atmosphere to 550°C using a special temperature programme. The parameters/results obtained from the analysis include;

1) First Peak ((S_1) hydrocarbon generated at the temperature of 300°C.
2) Second Peak (S_2) hydrocarbon yield from cracking of Kerogen and heavy kerogen in the rock sample at the temperature of range of 300-550°C.
3) Third Peak (S_3) carbon dioxide (CO_2) generated during the process of thermal cracking of kerogen.
4) T_{max} which is the value of thermal maturity and corresponds to the Rock eval pyrolysis oven temperature (°C) at maximum S_2 generation [25].
5) Production or productivity index [$PI = S_1/(S_1 + S_2)$].
6) Hydrogen index [$HI = (S_2/Toc) \times 100$.mg HC /gToc]
7) Oxygen index [$OI = (S_3/Toc] \times 100$.mg CO_2/g Toc].
8) Calculated vitrinite reflectance (R_o).

5. Results and discussion

Research has shown the importance of organic geochemical methods in assessing the generative potential and characteristics of source rocks [15,21,24-27]. In this work, the petroleum potential (quantity), Kerogen type (quality) and level of thermal maturity of the analysed samples of the paleogene (Imo and Ameki Formation) were discussed based on rock-eval pyroysis and total organic carbon.

Organic Matter Richness: Total organic carbon content (TOC) and Rock-eval analysis were carried on 10 shale samples that are presumed to be source rocks with 5 samples each from Imo Formation and Ameki Formation. The Total organic carbon in a source rock comprises three base components. (a) organic carbon in a retained hydrocarbons as received in the laboratory, (b) organic carbon that can be converted to hydrocarbon, called convertible carbon [28] or reactive or labile carbon [29]; and (c) carbonaceous organic residues that will not yield hydrocarbon because of insufficient hydrogen commonly referred to as inert carbon [15,17,28-29].

The total organic carbon (Toc) ranges from 0.18 to 1.43 wt% with an average value of 0.86 wt% for Imo Formation, and 0.40 to 1.22 wt% with an average value of 0.74 wt% for Ameki Formation (Table 2a and 2b). This indicates a fair Petroleum potential and Organic matter concentration for the studied area [21,30-31].

The quality of the source rock in the studied area is confirmed by the pyrolysis -derived generative potential (G.P. = $S_1 + S_2$). The rock-eval pyrolysis revealed that the total hydrocarbon generative potential ranges from 0.17 to 0.63 mg HC/g rock with an average value of 0.38 Mg HC/g rock for Imo Formation and 0.19 to 0.55 mg HC/g rock with as average valve of 0.38 mg HC/g rock for Ameki Formation. This indicates that the organic matter quality for the studied area is poor. S_1 measures hydrocarbon shows as the amount of free hydrocarbon that can be volatilized out of the rock without cracking the kerogen (mg HC/g rock). S_1 increases at the expense of S_2 with maturity while S_2 measures the hydrocarbon yield from cracking of kerogen (mg Hc/g rock) and heavy hydrocarbon and represents the existing potential of a rock to generate petroleum [21].

Table 2a. Results of geochemical analysis for Imo Formation

Station Name	Station no.	Sample Type	Formation	TOC	Rock-Eval S1	S2	S3	Tmax (^{O}C)
OKWANKA STREAM	L1	OUTCROP	*IMO*	1.34	0.05	0.54	0.56	432
INYIAKWU STREAM	L2	OUTCROP	*IMO*	0.54	0.07	0.14	0.29	416
OKOTU JUNCTION	L4	OUTCROP	*IMO*	0.18	0.06	0.11	0.25	344
NDIWO/IKPOROM ROAD	L6	OUTCROP	*IMO*	1.43	0.11	0.17	0.44	438
NDIWO JUNCTION	L8	OUTCROP	*IMO*	0.82	0.13	0.37	0.42	414
				0.86	**0.08**	**0.27**	**0.39**	**408.8**

	Ro	HI	OI	S2/S3	S1/TOC	PI	GP S1+S2
OKWANKA STREAM	0.62	40	42	1.0	4	0.08	0.59
INYIAKWU STREAM	0.33	26	54	0.5	13	0.33	0.21
OKOTU JUNCTION	0.97	60	137	0.4	33	0.35	0.17
NDIWO/IKPOROM ROAD	0.72	40	103	0.4	26	0.39	0.28
NDIWO JUNCTION	0.29	45	52	0.9	16	0.26	0.63
	0.59	**42.2**	**77.6**	**0.64**	**18.4**	**0.28**	**0.38**

Table 2b. Result of geochemical analysis for Ameki Formation

Station Name	Station no.	Sample Type	Formation	TOC	Rock-Eval S1	S2	S3	Tmax (^{O}C)
OKWANKA STREAM	L1	OUTCROP	*Ameki*	0.54	0.08	0.47	1.22	429
INYIAKWU STREAM	L2	OUTCROP	*Ameki*	0.75	0.04	0.37	0.35	415
OKOTU JUNCTION	L4	OUTCROP	*Ameki*	0.71	0.07	0.49	1.11	413
NDIWO/IKPOROM ROAD	L6	OUTCROP	*Ameki*	1.22	0.05	0.22	1.02	386
NDIWO JUNCTION	L8	OUTCROP	*Ameki*	0.40	0.08	0.11	1.31	411
				0.74	**0.06**	**0.33**	**1.00**	**410.8**

	Ro	HI	OI	S2/S3	S1/TOC	PI	GP S1+S2
OKWANKA STREAM	0.56	87	227	0.4	15	0.15	0.55
INYIAKWU STREAM	0.31	49	47	1.1	5	0.10	0.41
OKOTU JUNCTION	0.27	69	157	0.4	10	0.13	0.50
NDIWO/IKPOROM ROAD	0.21	18	84	0.2	4	0.19	0.27
NDIWO JUNCTION	0.24	28	329	0.1	20	0.42	0.19
	0.32	**50.2**	**168.8**	**0.44**	**10.8**	**0.20**	**0.38**

The hydrogen index (HI) values range from 26 to 60mg Hc/g Toc, with an average value of 42.2 mg HC/g Toc for Imo Formation, and 18 to 87 mg HC/g Toc, with average of 50.2HC/g TOC for Ameki Formation. This indicates a source rock that cannot expelled oil or gas at peak maturity and a type IV Kerogen, with atomic H/C of < 0.7 and S_2/S_3 of <1 [21,32], however, the average value for Ameki Formation falls at the boundary and may be regarded as type III Kerogen.

Type of organic matter

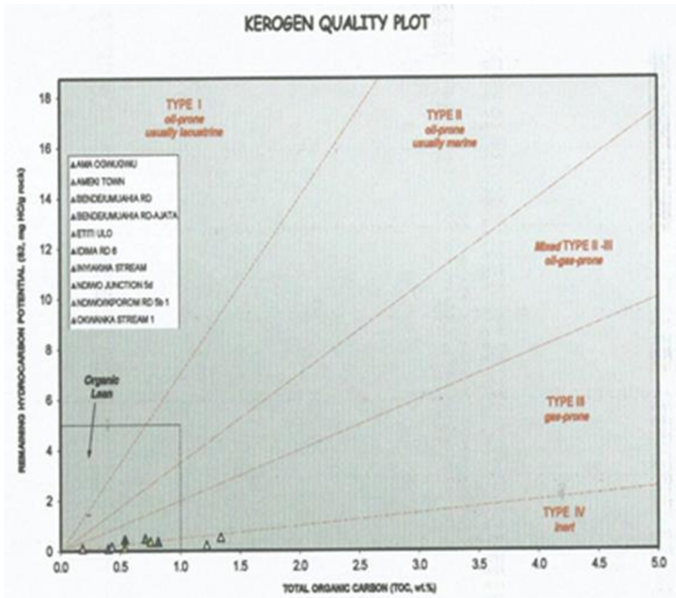

Fig 4. Plot of Rock-eval S_2 versus TOC

The types of organic matter in sediments of the studied area were analyzed using rock-eval pyrolysis. The ten shale samples assessed by rock-eval pyrolysis are basically of type IV Kerogen, which those not expel oil or gas at the peak of maturity and can be regarded as being inert. The plot of Rock-eval S_2 versus Toc (Figure 4) describes the hydrocarbon potential of the samples. The plot reveals that the samples analyzed have minimum value required for quality source rock. The relationship between the hydrogen index (HI) versus oxygen index (OI) (Figure 5) suggests a Kerogen Type IV organic matter which are predominantly inert.

Thermal maturity of organic matter

Thermal maturity or extent of burial heating provides an indication of the maximum paleo temperature reached by a source rock [17]. The thermal maturation of Niger Delta Basin has been studied by authors [18-20]. The degree of Thermal maturity of Paleogene strata of the studies area was assessed using pyrolysis-derived parameters such as vitrinite reflectance (Ro), production index, Rock-eval and T_{max} which measures thermal maturity and corresponds to the rock eval, pyrolysis oven temperature (°C) at maximum S_2 generation [21]. The T_{max} value represents the temperature at which the largest amount of hydrocarbon is produced in the laboratory when a whole rock sample undergoes a pyrolysis treatment [15]. The T_{max} value in the studied area ranges.

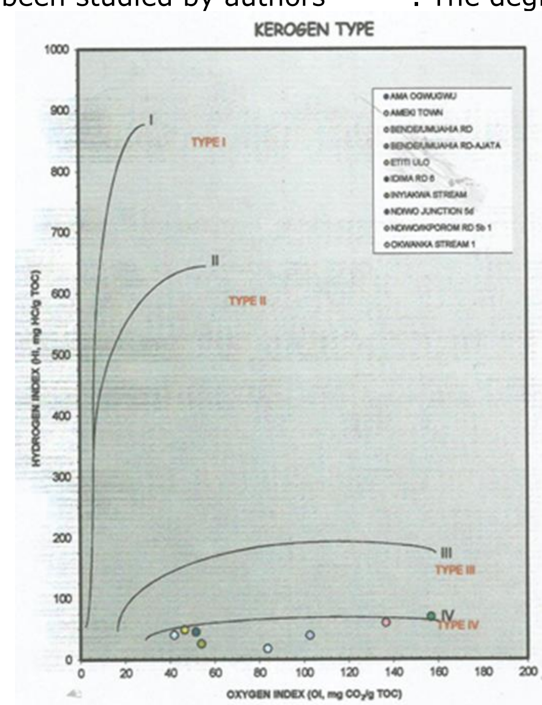

Fig 5. Plot of Hydrogen Index versus Oxygen Index

From 344°C to 438°C with an average valve of 408.8°C for Imo Formation, while 386°C to 429°C with an average valve 410.8 °C was recorded for Amaki Formation. This indicates that the studies samples stage of thermal maturity for oil is still immature. The calculated vitrinite reflectance (R_o) value which increases during thermal maturation due to complex, irreversible aromatization reaction [21], ranges from 0.29 to 0.97 R_o with an average valve of 0.59 R_o for Imo Formation and ranges from 0.21 to 0.56 R_o

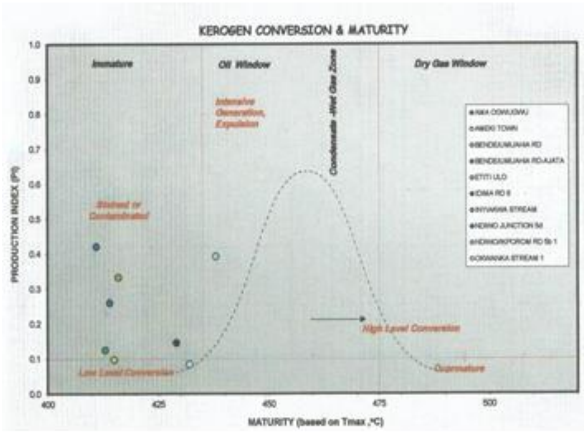

Fig. 6: Plot of production index (PI) against maturity (Based on Tmax)

with an average valve of 0.32 R_o for Ameki Formation. The average valve for R_o in the studied area suggests that stage of thermal maturity for oil is immature. The result of vitrinite reflectance (R_o) in the studies area shows that the Thermal alteration index will range between 1.5 to 2.6. Thermal alteration index (TAI) is a numerical scale based on thermally induced colour changes in spores and pollen [21].

The Plot of production index (PI) against maturity (Based on Tmax) as shown in Fig 6. and plot of hydrogen index [HI (S2/Toc x 100, mg/g Toc] against maturity (Tmax) as shown in Fig 7. Suggests that the studied area are basically type IV Kerogen, meaning a "dead carbon" showing low atomic H/C (about 0.5-0.6)and low to high O/C (≤ 0.3). It also shows that the studied area are basically immature (level of thermal maturation) except for sample location L 6 (Ndiwo/ Ikpeoram road) that falls within the thermally matured /oil window range.

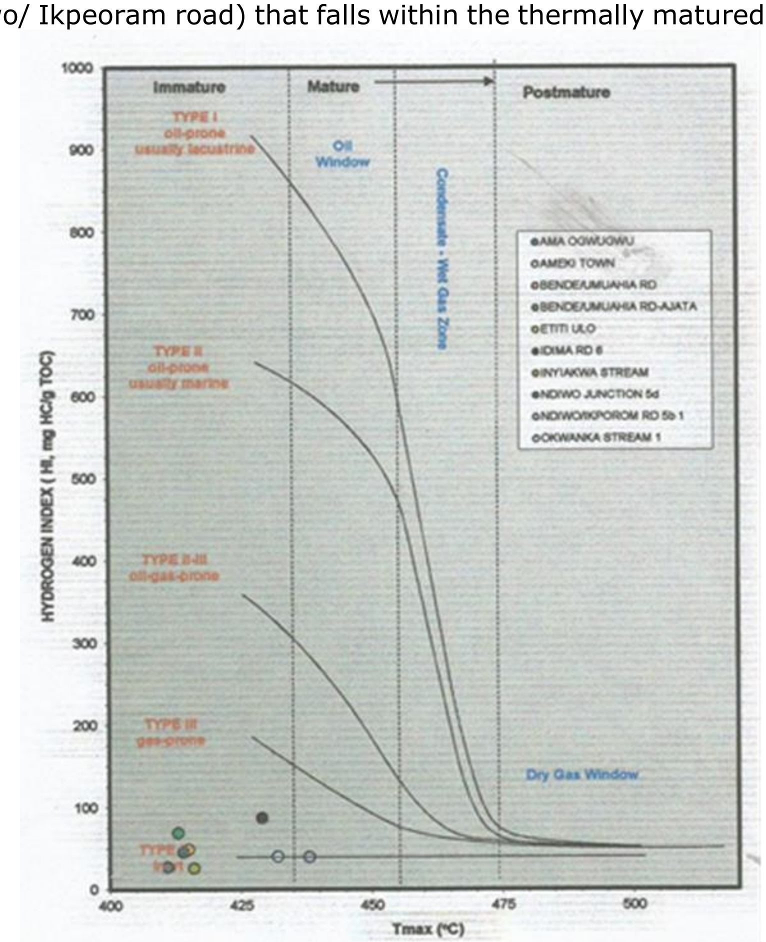

Fig 7. Plot of Hydrogen Index versus T_{max}

6. Conclusion

This study has shown that the shale of peleogene strata (Imo & Ameki Formations) in the Bende Umuahia and its environs in the Niger-Delta Basin, South-Eastern Nigeria has a Total

Organic Carbon whose petroleum potential is fair, with poor organic matter quality. The hydrogen index value that is basically type IV Kerogen. The T_{max} and Vitrinite reflectance results all indicates that the studied area is thermally immature, except for L6 which can be regard as being a type III. kerogen and thermally matured.

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