The main oil source formations of the Anambra Basin, Southeastern Nigeria

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Abstract

Anambra basin is one of the basins in Nigeria, habouring the largest deposit of sub-bituminous coal and lignite. Oil seepages have also been reported from parts of the basin. The potential of the coal and other formations as source rock for the oil seepages is yet to be fully understood. This study therefore aims at identifying the source rocks and the geochemical composition of the oil seepage. Detailed lithologic profiles were carried out on the following geological formations: Asu River, Eze-Aku, Awgu shale, Nkporo Shale, Enugu Shale, Mamu, Imo and Ameki Formations and fifty samples were selected. Organic geochemical analysis involving Total Organic Carbon content (TOC), Rock-Eval pyrolysis, and Gas chromatography (GC) were carried out.

The Asu River, Eze-Aku, Awgu shale, Nkporo, Enugu, Mamu shale, Mamu coal, Imo and Ameki Formations, have average TOC values of 0.68, 2.74, 3.26, 2.28, 3.23, 1.98, 56.05, 1.34, and 1.70 wt%, respectively. This indicates that both shale and coal have adequate organic matter to generate hydrocarbon. The plot of TOC against Hydrogen index (HI) suggests that the coal samples are of type III/IV kerogen while that of the shale sample suggest type II/III kerogen (mixed environment).

The level of thermal maturity as estimated from the plot of Tmax against production index (PI) suggest that the shales range from immature to marginally mature source rock while the coal is of low level conversion. The GC result indicates that the *n*-alkanes and isoprenoids in the oil seepage samples are completely depleted while steranes are seriously altered. Regular steranes {C_{27}aaR, C_{28}aaR and C_{29}aaR} and C_{29}, C_{30}, C_{31} Hopanes are all consumed up, but Diasteranes {C_{27}Dbas, C_{27}DbaR} and 25-Norhopanes (C_{28}, C_{29}) are relatively high. This suggests that the oil seepage is highly biodegraded and on level 9 of Peter and Moldowen (PM) scale.

The geochemical analyses of some selected samples showed that there are high organic richness in Eze-Aku, Awgu, Nkporo, Mamu (Coal) and Enugu Formations,and Awgu Shale could be regarded as the main oil source formation of the Anambra basin.

Keywords: Source rock, Organic matter, Anambra Basin, Biomarker and Oil seep.

Introduction

The Anambra basin (Fig 1) is a cretaceous basin with a total sediment thickness of about 9km, presents an ideal geo-reactor for all manner of complex chemical reactions that can lead to the formation and occurrence of economically viable hydrocarbon deposits. It is also characterized by enormous lithologic heterogeneity in both lateral and vertical extension derived from a range of paleoenvironmental settings ranging from Campanian to Recent (Akaegbobi, 2005).

The roughly triangular shaped Anambra basin covers an area of about 40,000 sq.km, located in south central part of Nigeria. Extending northwards in the Lower Benue River.

Several authors have demonstrated the usefulness and organic petrologic methods in assessing the generative potentials and characteristics of source rocks in the basin (Peters 1986; Baskin 1997; Akande et al., 1988; Ojo and Akande 2002).

Mainly organic-rich rocks were selected from three wells located in the Anambra basin, and also some outcrop samples from different locations were picked, in order to determine the hydrocarbon source potential of the basin.

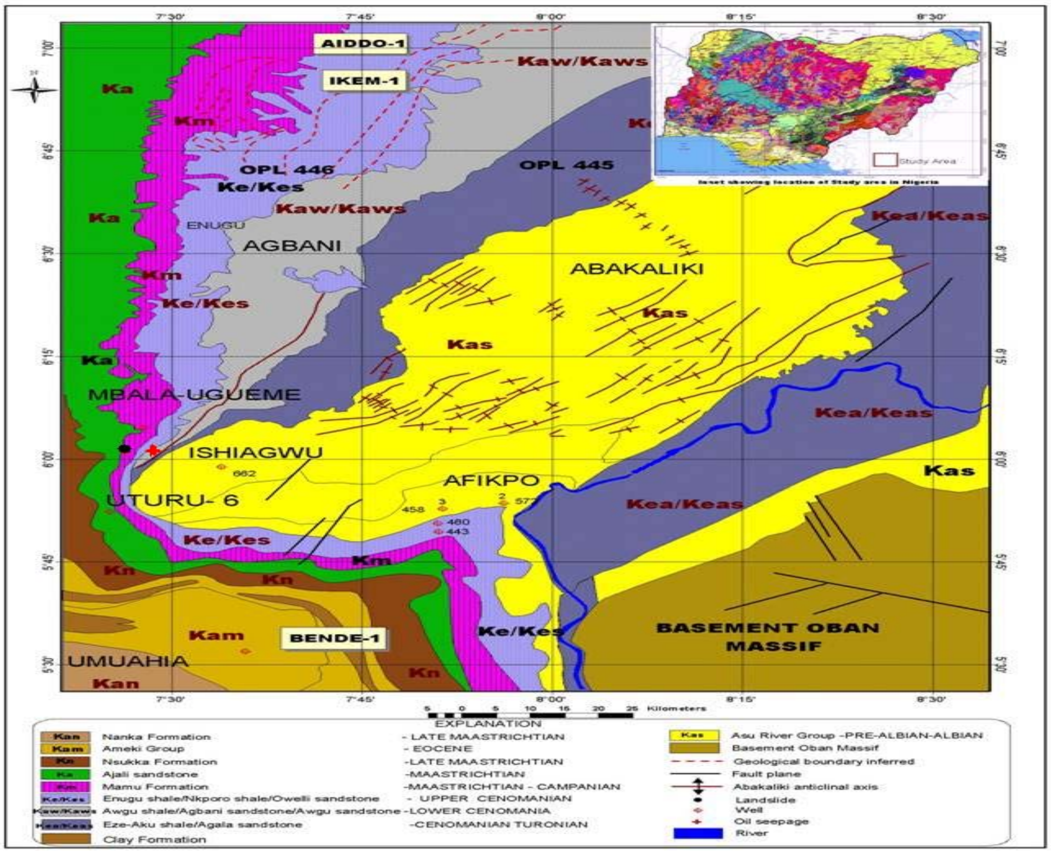

Fig. 1: Geological map of the Anambra Basin

2. Stratigraphic overview

The stratigraphic history of the region is characterized by three sedimentary phases (Short and Stauble, 1967; Murat, 1972; Obi et al., 2001) during which the axis of the sedimentary basin shifted. These three phases were: (a) the Abakaliki-Benue phase (Aptian-Santonian), (b) the Anambra-Benin phase (Campanian-Mid Eocene), and (c) the Niger Delta phase (late Eocene-Pliocene). The more than 3000m of rocks comprising the Asu River Group and the Eze-Aku and Awgu Formations, were deposited during the first phase in the Abakaliki-Benue Basin , the Benue Valley and the Calabar Flank. The second sedimentary phase resulted from the Santonian folding and uplift of the Abakaliki region and dislocation of the depocenter into the Anambra platform and Afikpo region. The resulting succession comprises the Nkporo Group, Mamu Formation, Ajali Sandstone, Nsukka Formation, Imo Formation and Ameki Formation. The third sedimentary phase credited for the formation of the petroliferous Niger Delta, commenced in the Late Eocene as a result of a major earth movement that structurally inverted the Abakaliki region and displaced the depositional axis further to the south of the Anambra Basin (Obi et al., 2001), Reyment (1965) undertook the first detailed study of the Southern Nigeria sedimentary basin, and he proposed many of the lithostratigraphic units in the region.

3. Methods

Two main methods were employed for the purpose of achieving the objectives of this study. They are detailed geological field mapping and laboratory studies. Samples were obtained at different stratigraphic positions along the profiles. Fifty samples of shale and coal units were sampled with oil seepage sample were labeled, then stored in calico bags, for further laboratory studies.Measurements, photographs including rough sketches were also made on the field as thus;

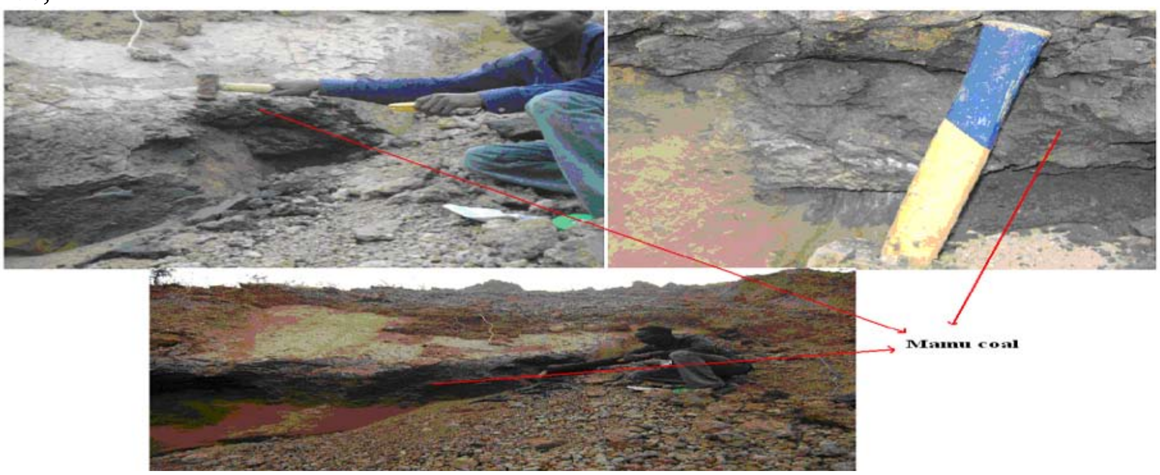

Fig 2: The coal bed at landslide in Ugwueme

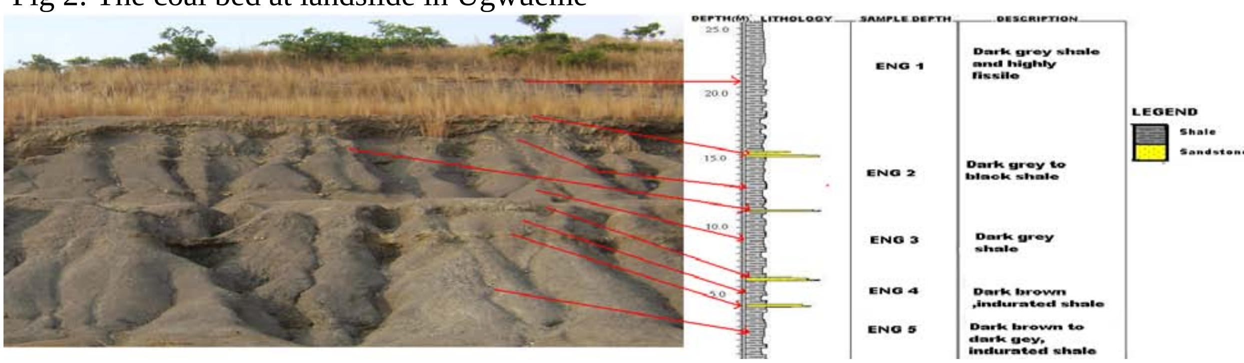

Fig.3: Lithologic section of the Enugu formation exposed near Gariki along Enugu-Port Harcourt Expressway

Fig.4: The oil seepage spreads on the water surface

The geochemical analysis involves the Total Organic Carbon (TOC), Rock eval pyrolysis, and Gas chromatography

3.1. ***Total Organic Caron (TOC) Determination***

Fifty samples were selected for preliminary total organic carbon content determination using Walkley Black Wet Oxidation method. 0.5g of each of the pulverized samples were subjected to chromic oxidation following the procedure of Walkley and Black (1965).This assessment served as preliminary screening for further detailed Rock-Eval analysis and to determine the organic richness of the source rocks.

3.2. ***Rock Eval Pyrolysis***

Rock- Eval Pyrolysis is frequently performed only on samples with a TOC content greater than about 0.5%.Therefore the fifty samples were screened and further analyzed by Rock-Eval Pyrolysis to determine the hydrocarbon generation potential, maturity, type of kerogen and Hydrogen richness (HI) using a Rock-Eval II pyrolyser machine.The samples were heated in an inert atmosphere to 550°C using a special temperature programmed.

3.3. ***Biomarker Analysis***

The GC/MS were carried out on a HP5890GC coupled with HP5970A.M.S.D.Helium was used as carrier gas with oven temperature programmed from 80°C (2 min hold) to 290°C at 4°C/min.The mass spectrometer was operated at electron energy of 70eV,an ion source temperature of 250°C,and separator temperature of 250°C. Terpanes and steranes were identified on m/z 191 and 217 respectively. The compound on m/z 191 and 217 mass chromatograph were identified according to the previously reported mass spectra and relative retention times at The State Key Laboratory of Organic Geochemistry, Chinese Academy of Sciences in China.

4. Results and Discussion

4.1. ***Total Organic Carbon (TOC*****)**

The quantity of organic matter expressed as total organic carbon is a measurement of the organic richness of sedimentary rocks (Jarvie, 1991).i.e. the measurement of the amount of organic matter present in a rock are expressed as TOC values in weight present of the dry rock.

The table 1 below shows variable TOC values .The amount of organic carbon is usually measured as Total Organic Carbon (TOC).

This analysis shows that the TOC of the samples range from 0.49 to 56.05 wt.%.(Table 2),and for a clastic rock to act as a good source rock, its organic matter content should be greater than 0.5% (Tissot and Welte 1984).and just one out of the samples analyzed has TOC lesser than 0.5% .

The table 1.0 above, shows that there is a general increase in TOC value from Asu River shales, of average 0.68%, average of 2.74% in Eze-Aku Shale, average of 3.26% in Awgu Shale, average of 3.23% in Enugu shale, average of 2.28% in Nkporo shale, average of 1.98% in Mamu Shale, average of 1.34% in Imo, and average of 1.7% in Ameki formation. This suggests a general increase in TOC from the more marine Asu River Group formation to the more terrigenous sediments of the Mamu formation as corroborated by Ekweozor (1982).

This increase in organic richness towards the younger formation was correlative with a decrease in the preponderance of Planktonic Foraminifera (Peters 1978) and an increase in the abundance of coarse terrigenous clastic particles and coal beds; a trend towards less marine conditions.The level of maturity of these samples will be dependent on depth of burial and geothermal gradient of the basin.

Table 1.organic geochemical analysis

Sample no	Sample type	TOC (wt. %)	S1 (mgHC/g	S2 (mgHC/g	S3 (mgHC/g	GP(S1+ S2)	Tmax(°C)	PI	HI (mgHC/g	OI	PC	S2/S3	RC	S1/TOC ×100
OKP 18	Core	0.79	0	0	0.18	0	500	0	0	23	0	0	0.79	0
OKB 20	Core	0.58	0.01	0.04	0.17	0.05	493	0.15	7	29	0.01	0.24	0.57	1.72
OKP 10	Core	0.66	0.01	0.03	0.11	0.04	488	0.18	5	17	0.01	0.27	0.65	1.52
OKC 18	Core	0.55	0.01	0.04	0.17	0.05	550	0.13	7	31	0.02	0.24	0.53	1.82
OKC 2	Core	0.49	0	0.05	0.16	0.05	525	0.07	10	33	0.01	0.31	0.48	0
OKP 3	Core	0.78	0	0.02	0.18	0.02	393	0.19	3	23	0.02	0.11	0.76	0
ETANI	Outcrop	0.92	0.1	0.12	0.21	0.22	459	0.46	13	23	0.04	0.57	0.88	10.87
EZE 1	Outcrop	2.3	0.04	1.92	0.92	1.96	439	0.02	83	40	0.16	2.08	2.1	1.74
EZE 2	Outcrop	3.1	0.19	4.87	0.88	5.06	434	0.04	155	28	0.42	5.53	2.94	6.13
EZE 3	Outcrop	2.5	0.12	2.47	0.9	2.59	443	0.04	203	21	0.27	2.74	2.32	4.8
EZE 4	Outcrop	3.09	0.28	3.05	0.98	3.33	431	0.08	99	32		3.11		9.06
AWG1	Outcrop	3.6	0.82	8.29	1.4	9.11	435	0.09	229	38	0.76	5.92	2.98	22.78
AWG2	Outcrop	3.1	0.37	6.47	1.33	6.84	431	0.05	208	42	0.57	4.87	2.92	11.94
AWG 3	Outcrop	3.4	0.69	7.62	1.38	8.31	432	0.06	245	27	0.69	5.52	2.94	20.29
AWG 4	Outcrop	3.3	1.21	7.67	5.25	8.88	439	0.14	233	59		1.46		36.67
AWG 5	Outcrop	2.9	0.37	6.43	2.42	2.65	438	0.05	228	85		2.65		12.75
ENG 1	Outcrop	3.26	0.14	3.34	0.2	3.48	431	0.04	102	6	0.33	16.7	2.93	4.29
ENG 2	Outcrop	3.51	0.07	1.81	1.03	1.88	426	0.04	52	29	0.16	1.76	2.97	2
ENG 3	Outcrop	3.5	0.15	3.21	0.18	3.36	428	0.04	92	34	0.28	17.83	2.95	4.29
ENG 4	Outcrop	2.86	0.06	1.43	0.98	1.49	426	0.04	50	42	0.12	1.46	2.51	2.1
ENG 5	Outcrop	3.69	0.13	3.34	0.93	3.47	433	0.04	91	36	0.29	3.59	3.02	3.52
ENG 6	Outcrop	3	0.07	3.27	0.81	3.34	430	0.02	109	27		4.03		2.33
ENG 7	Outcrop	3.32	0.09	0.7	1.89	0.79	431	0.1	21	57		0.37		2.71
ENG 8	Outcrop	2.69	0.08	0.7	1.99	0.78	429	0.11	26	74		0.35		2.97
NKP1	Outcrop	3.09	0.04	1.33	0.32	1.37	426	0.03	43	10	0.17	4.16	2.92	1.29
NKP2	Outcrop	2.34	0.08	4.33	1.83	4.41	418	0.02	185	78.2	0.37	2.37	2.07	3.42
NKP3	Outcrop	2.51	0.06	1.58	1.25	1.64	420	0.04	63.2	50	0.14	1.26	2.14	2.39
NKP 4	Outcrop	1.3	0.02	0.3	0.27	0.32	427	0.01	22	20	0.03	1.11	0.98	1.53
NKP 5	Outcrop	1.52	0.02	0.35	0.28	0.37	431	0.03	22	18	0.03	1.29	1.2	1.32
NKP 6	Outcrop	3.02	0.06	1.97	1.28	2.03	432	0.04	65	42	0.17	1.54	2.89	1.99
NKP 7	Outcrop	1.57	0.01	0.47	0.77	0.48	425	0.02	30	49		0.61		0.64
NKP 8	Outcrop	2.9	0.05	0.88	2.29	0.93	427	0.05	34	88		0.38		1.72
MAM 1	outcrop	2.39	0.07	3.76	0.63	3.83	428	0.02	160	26.8	0.32	5.97	2.11	2.92
MAM 2	outcrop	1.96	0.03	3.56	1.43	3.59	415	0.01	179.8	72.2	0.3	2.49	1.75	1.53
MAM 3	outcrop	2.45	0.09	1.68	1.37	1.77	423	0.1	70	56.9	0.15	1.23	2.23	3.67
MAM 4	Outcrop	2.72	0.05	0.65	1.63	0.7	428	0.07	24	60		0.4		1.84
MAM 5	Outcrop	2.67	0.05	0.88	1.5	0.93	424	0.05	33	56		0.59		1.87
MAM 6	Outcrop	1.34	0.08	2.55	0.94	2.63	425	0.03	190	70		2.71		5.97
MAM 7	Outcrop	1.22	0.03	0.63	1.24	0.66	418	0.05	52	102		0.51		2.46
MAM 8	Outcrop	1.07	0.02	0.55	1.06	0.57	426	0.04	51	99		0.52		1.87
COAL MF	outcrop	56.05	2.03	150.16	5.48	152.19	437	0.01	268	10	13.17	27.4	42.88	3.62
IMS 1	outcrop	1.6	0.01	0.14	0.36	0.15	430	0.07	9	22	0.01	0.39	1.37	0.63
IMS 2	outcrop	1.23	0.01	0.12	0.42	0.13	427	0.07	10	35	0.01	0.29	1.01	0.81
IMS 3	outcrop	1.16	0.01	0.14	0.52	0.15	425	0.06	12	45	0.01	0.27	0.95	2.56
IMS 4	Outcrop	1.51	0.04	0.53	1.62		426	0.07	35	107		0.33		2.65
IMS 5	Outcrop	1.2	0.01	0.12	0.42		428	0.07	11	39		0.29		0.83
AMEK 1	outcrop	1.56	0.04	0.16	2.9	0.2	386	0.2	10	186	0.02	0.05	1.39	2.56
AMEK2	outcrop	1.5	0.04	0.14	2.5	0.18	383	0.2	8	170	0.01	0.06	1.32	2.67
AMEK 3	Outcrop	1.78	0.07	0.65	1.13	0.72	410	0.1	18	39		0.58		3.93
AMEK 4	Outcrop	1.96	0.04	0.59	1.56	0.63	414	0.06	22	58		0.38		2.04

4.2. ***Organic Matter Type***

Petroleum is a generative product of organic matter disseminated in the shale and therefore the quantity of hydrocarbon directly correlated with organic matter concentration of the potential source rocks (Tissot & Welte, 1984).

Agagu (1978) showed that the source rocks in the lower Benue Trough with high organic richness include the shales of Eze-Aku, Awgu, Nkporo and Imo formations.

According to generalized guidelines for source rock interpretation (after ocean curve geosciences limited) (Table 3); Hydrogen indices below 50mgHc/gTOC indicate the absence of significant amounts of oil-generative lipid materials and confirm the kerogen as mainly type IV.

Hydrogen indices between 50 – 250 mgHc/gTOC contain type III kerogen, while those above 250 contain substantial amounts of type II macerals.

Therefore Asu-River Group (ranges 0-13;average 7.5 mgHc/gTOC), Imo Shale (ranges 9-35;average 15.4 mgHc/gTOC) and Ameki Formation(ranges 8-22;average 14.5mgHc/gTOC) (Table 1),because they have hydrogen indices below 50mgHc/gTOC.

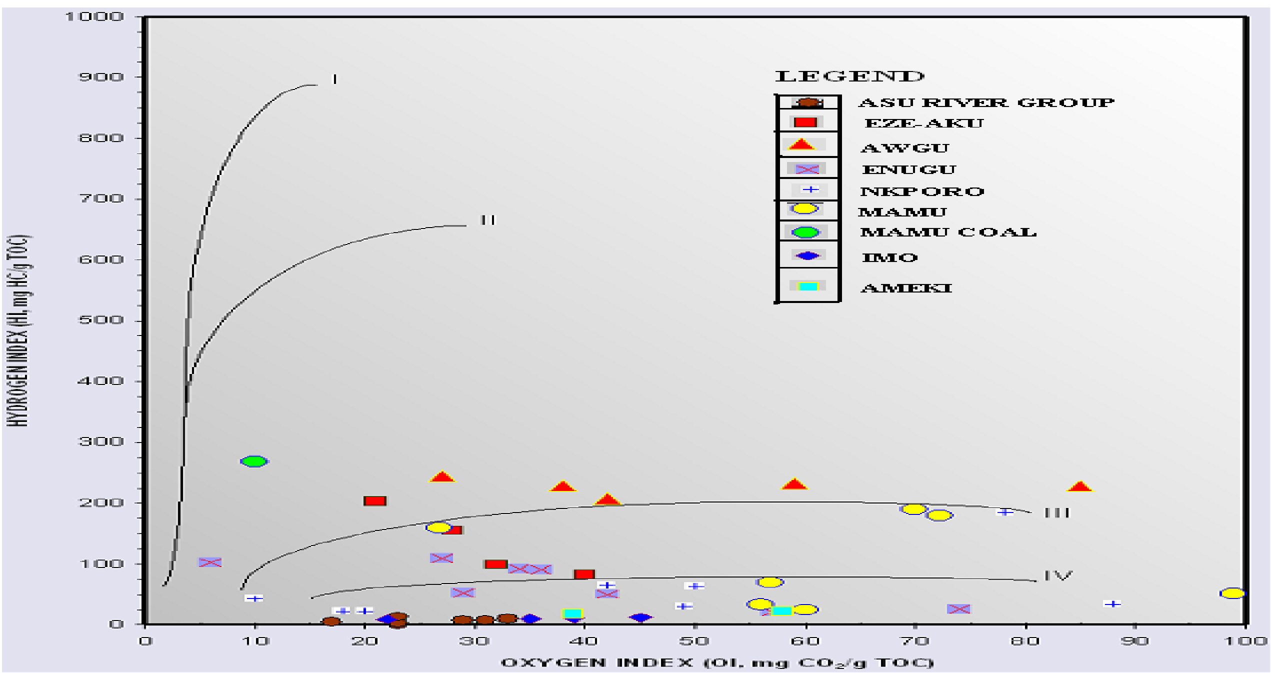

Fig 5. Kerogen type.

The plot of S2 Vs TOC shows that Awgu shale is of mixed type II-III Kerogen (Oil-gas-prone), Eze-Aku, Enugu, Mamu, and part of Nkporo shales are type III kerogen (Gas prone).
While Asu, Imo, and Ameki are type IV Kerogen (Inert)

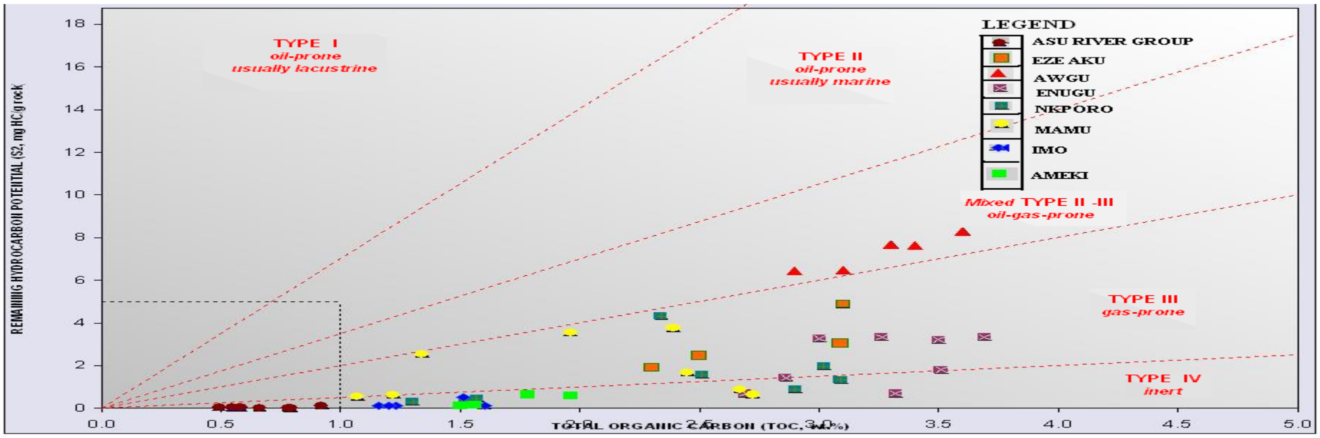

Fig 7: The plot of Remaining Hydrocarbon potential against Total Organic Carbon.

Oil Seepage

The N-alkanes are typically the major peaks on gas chromatograms of mature oils and bitumens.The distribution of N-alkanes depends on organic source type, thermal maturity, expulsion, migration and biodegradation. The biodegraded oils commonly lack n-alkanes, but still show pristane, phytane, and other isoprenoids .No N-alkanes and isoprenoids exist.

The *m/e* 217 (steranes) chromatograms as showing in the fig above, indicates that steranes are seriously altered. Regular steranes C_{27}aaR, C_{28}aaR, and C_{29}aaR are consumed up.Diasteranes can be seen (C_{27}DbaS, and C_{27}DbaR).The removal of steranes from the oil seepage biodegradation might have occurred after or before complete removal of hopanes (Seifert and Moldowan, 1979).

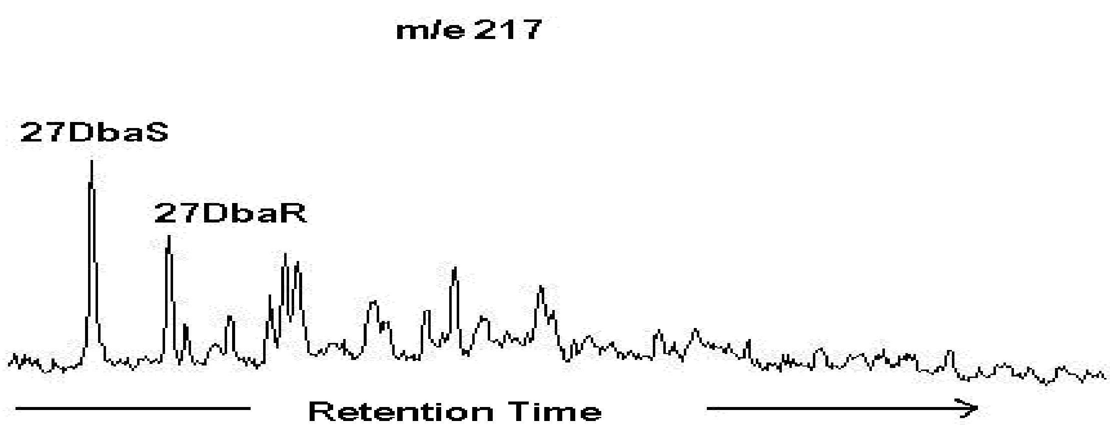

Fig.7 Showing the distribution of Steranes

(Winters and Williams, 1969).The bacteria selectively metabolize the n-alkanes, followed by the isoprenoid alkanes, pristine and phytane (Bailey, Jobson, and Rogers, 1973).

Fully biodegraded bitumen are those that show complete removal of n-alkanes and isoprenoid alkanes ;while partly biodegraded samples are those that show removal of some or all n-alkanes and some isoprenoid alkanes

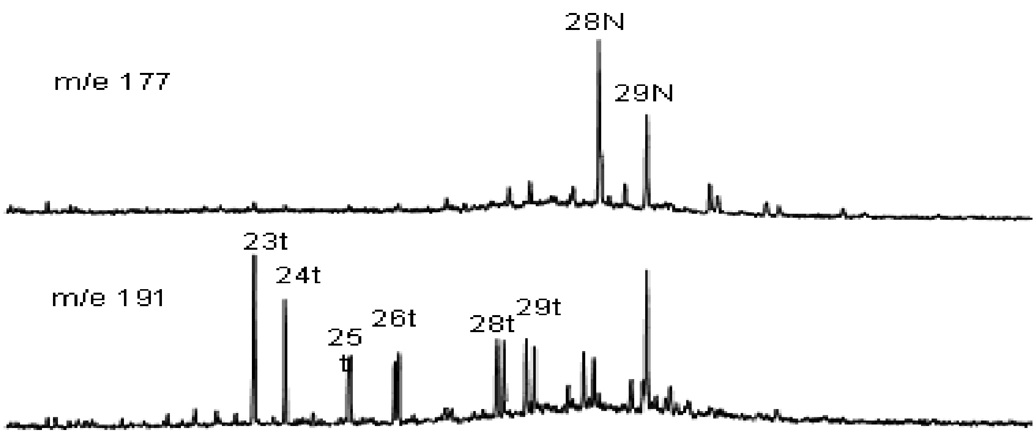

Fig.8.Showing distribution of Hopanes.

Therefore according to the mass chromatogram representatives in fig.7 and 8, the oil seep is The *m/e* 177 and 191 mass chromatogram representatives showing in the above shows that C29, C30, C31 hopanes are all consumed up.25-Norhopanes (C_{28}, C_{29}) are high and since there is high proportion of 25-Norhopanes, it indicates that, the oil seep should be very seriously biodegraded because 25-Norhopanes are only found in severely biodegraded crudes, due to selective removal of methyl groups by bacteria. It should be of PM level 9 on Peters and Moldowan scale (abbreviated as PM level; Peters et al, 2005)

5. CONCLUSION

The Total Organic Carbon (TOC) analysis of the Asu-River Group Shale, Eze-Aku shale, Awgu shale, Nkporo shale, Mamu shale, Imo and Ameki shale reveal that the shale can serve as a good source rock having attained the threshold of 0.5wt. % required for petroleum source rocks.

The values of Hydrogen Indices; and plot of HI against OI reveals that the Shales contained mostly of type III organic matter which can generate mainly gas and little oil.

The level of maturity of these formations dependent on the depth of burial and geothermal gradient of the basin, and the stratigraphic units in this basin had been exposed in some part to maximum depths, and the high temperature had predisposed the viable petroleum source units to gas generation in some parts of the basin. In conclusion the shales are barely matured based on the Tmax and transformation values. Most of the Shales in Anambra Basin are immature to early mature except Awgu shale and Eze-Aku shale that are mature (oil window),while the Asu River shale are under late catagenetic stage which is condensate and dry gas.

The plot of Hydrogen Index against Oxygen Index inferred that Awgu Shale is of type II Kerogen that is oil prone, and Awgu Shale is older than the Sandstone(Agbani Sandstone) in which the oil seepage occurs, therefore Awgu Shale may be the source of the oil seepage, and the main oil source formation of the Anambra Basin.

The Gas Chromatograms indicated that there is no N-alkane, the sterane is seriously altered, and there is high proportion of 25-Norhopanes which determined that the oils seepage has been partly biodegraded.

Based on my study, Anambra Basin is therefore considered to be of good petroleum potential, although it may not be of commercial quantity.

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