Source Rock Assessment and Hydrocarbon Prospects of Anambra Basin: Salient Indications for Maturity.

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ABSTRACT

This paper presents the results of successful application of organic geochemical analysis in evaluating the hydrocarbon potentials of the Campanian-Paleocene shale sections in the Anambra Basin Southeastern Nigeria. Twenty-eight representative outcrop samples from four major formations within the basin were randomly collected (Nkporo, Enugu, Mamu, and Nsukka Formation). The result shows variation in TOC (total organic content) values across the formations in the basin from 0.5-5.08wt%. The Tmax varies from 421-439^{0}C independently with age of the formations across the Anambra Basin. The Tmax result of five shale samples collected from Mamu ranges from 431-433^{0}C. The result of ten shale samples from Nkporo ranges from 424-439^{0}C, the result of six Enugu Shale samples ranges from 425-434^{0}C, and the result of seven shale samples collected from Nsukka ranges from 421-433^{0}C.

These results show that Mamu Formation which is the youngest has completely mature, and attained the depth range for oil generating window while the remaining formations have not completely and wholly attained such depth range requires for hydrocarbon generation due to their Tmax values that are below 431^{0}C. However some sections of the formations have attained the depth range for oil generation. Variation in maturity among the formations across the basin can be tied to lateral variation in deposition of sediments within the basin and variation in the rate of subsidence across the basin. Hence, younger formation (Mamu) that was deposited in the zone that experienced rapid subsidence rate appears matured because it was able to get to favorable depth of maturity compare to older formations (Nkporo and Enugu Shale) that were deposited along the zones that experienced very slow rate of subsidence in the basin. However, some few portions of Nkporo and Enugu are mature because little parts of the formations were deposited or overlapped into zones of active subsidence.

(Keywords: subsidence rate, Anambra Basin, oil generating window, maturity, source rock)

INTRODUCTION

The study area is located within the southern Anambra Basin covering parts of Anambra State, Enugu State, Imo State, and Abia State. The Anambra Basin is located between Latitudes 5^{0}00'N to 8^0 00'N and Longitudes 6^0 30'E to 8^0 00'E (Figure 1).

Adeigbe and Salufu (2010) and Akande et al. (2011) accessed the potential source rocks in the Lower Benue Trough (Anambra Basin) and observed that Mamu Formation is the only important source rock with good potential for oil and gas. Odoh et al. (2009) did a detailed review of previous geophysical studies on Anambra Basin and compared it with genetic analysis of geologic system. They were able to observe three major geothermal gradient zones in the basin; high (41-31^{0}C/km), intermediate (31-27^{0}C/km), and low (27-24^{0}C/km). They likened the presence of thermal gas profusion in the basin to be associated with high geothermal gradient zone. Thus, they suggested that oil could be found in the low geothermal zone.

However, this present work is aimed at evaluating the potential for oil generation of shale units in the Anambra Basin from Campanian-Paleocene sediments and the maturity of organic matter as a preliminary indication for establishing the existence of petroleum potential in Anambra Basin, using geological and geochemical studies of the basin; and to study reason Mamu Formation that is younger in age, is mature compare to Enugu Shale and Nkporo Shale that are older in the basin.

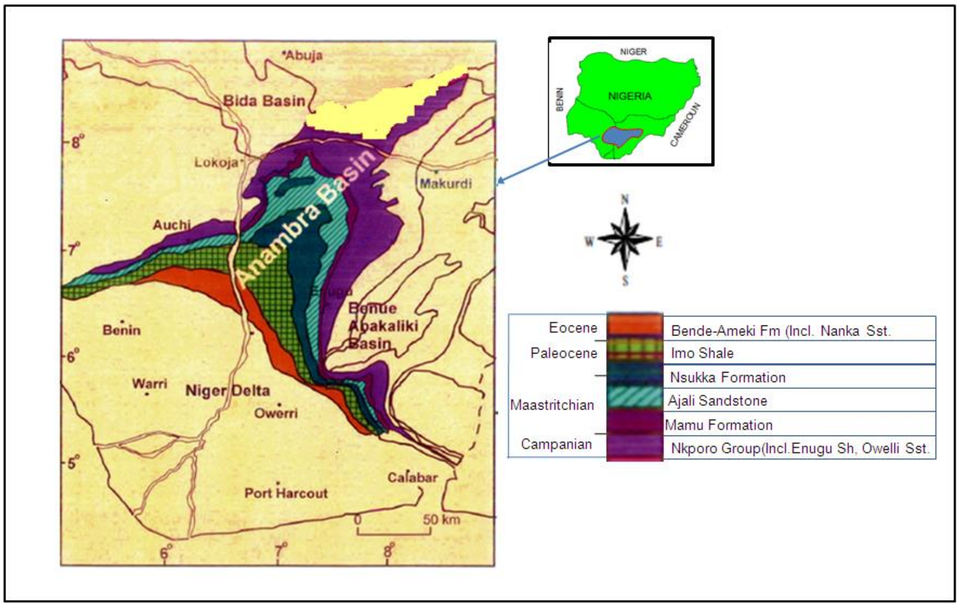

Figure 1: Regional Stratigraphy of Anambra Basin and Location of Study Area.

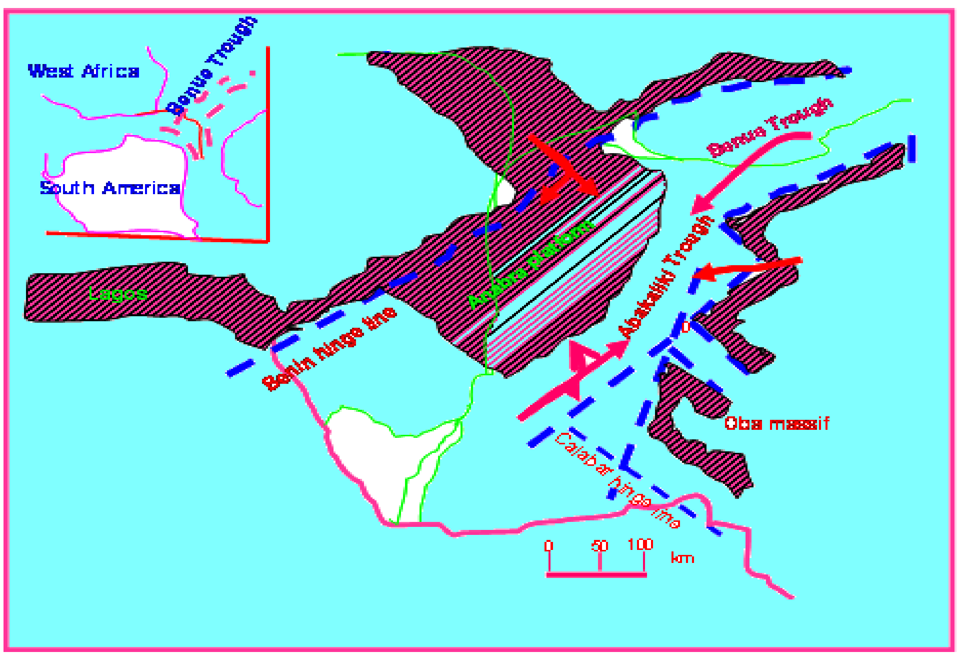

Figure 2: Tectonic Map of the South Eastern Nigeria (Modified after Murat, 1972).

Regional Geology and Stratigraphic Setting

In the Early Cretaceous times tectonic activities started in the Southern Nigeria thus, separated Africa plate from South American and led to the opening of the Atlantic (Benkhelil, 1987). This resulted in the development of the Benue Trough which stretched in a NE-SW direction and resting unconformably upon the Pre-Cambrian Basement Complex (Kogbe, 1989).

In the Santonian times, the Southern Nigeria (south-east and some parts of south-south Nigeria) experienced another tectonic event. The tectonic event caused uplift of Abakaliki Anticlinurium (Figure 2), pre-Santonian sediments (first and second cycle sediments) were uplifted. Thus Anambra Basin was created in the east (Figure 2) Marine transgression and regression favored deposition of Campanian-Maastritchian sediments in Anambra Basin.

The first marine transgression took place in Anambra Basin after the end of Santonian tectonism. Subsequently, Nkporo Group (Nkporo Shale, Enugu Shale, and Owelli Sandstone) was deposited by the marine transgression into the basin (Reyment, 1965; Nwajide, 1990; and Obi, 2000).

Nkporo Shale is predominantly deposited in the extreme eastern and northern parts of the basin (Figure 1) while its lateral equivalent, Enugu Formation is predominantly restricted to the center of the basin. Nkporo Group is laterally graded upward to deltaic Mamu Formation. Mamu Formation comprises intercalation of mudstone, sandstone, siltstone, and coal seams. Mamu Formation laterally passes upward unto Ajali Sandstone (marginal marine sediments). Ajali Sandstone is poorly sorted sandstone with mudstone and clay. Ajali Sandstone graded vertically upward unto Nsukka Formation (Figure 1).

At the end of Maastritchian, there was another marine transgression that caused marine incursion in the Paleocene that led to deposition of Imo Shale. Marine regression followed the transgression that caused deposition of Imo Shale, thus caused deposition of Bende-Ameki/Nanka Formation in the south-western part of the basin. Bende-Ameki Formation graded upward to Ogwashi-Asaba Formation (Oligocene/Miocene) which is an equivalent of Niger Delta (Akande et al., 2011).

MATERIALS AND METHODS

Twenty-eight outcrop samples of shale were collected from Nkporo Shale, Enugu Shale, Mamu Formation, and Nsukka Formation across Anambra Basin. The shale samples were crushed and 100mg of each shale sample was weighed into oven. 1ml HCl was added to the weighed shale samples in crucible to remove carbonates. The samples were allowed to drain off HCl for about 5hrs and later transferred into an oven at temperature of 60^0C and left overnight. The following day, TOC (Total Organic Content) were then measured using a LECO device.

Rock-eval at elevated temperature of ca. 600^0C and pyrolysis were carried out. The S_1 (hydrocarbon already generated within the source rock) was determined, S_2 (residual petroleum potential) was determined, S_0 (gas), and temperature at which the maximum in S_2 response was measured as Tmax. The values of the measured Tmax were used to compute the vitrinite reflectance (%VRo) and values of parameter gotten during pyrolysis to compute TOC respectively, using the below equations:

$$\%VRo = 0.01803Tmax - 7.16 \qquad \textbf{(1)}$$

Where %VRo= calculated vitrinite reflectance

$$TOC = \frac{(0.83(So+S1+S2)+S4)}{10(\%wt)} \qquad \textbf{(2)}$$

The computed TOC values and measured S1, and S2 were used to compute hydrogen index (HI) and production index (PI), using Equation (3) and (4), respectively.

$$HI = \frac{S2}{TOC} \times 100 \qquad \textbf{(3)}$$

$$PI = \frac{S1}{(S1+S2)} \qquad \textbf{(4)}$$

The above measured and computed results were analyzed and used to determine the hydrocarbon generation potential, type of kerogen of the shale units of the formations in the Anambra Basin.

RESULTS AND DISCUSSION

The result of seven outcrop shale samples, collected from Nsukka Formation in Anambra basin shows that the TOC ranges from 0.5-18.67 (wt%), vitrinite reflectance (%VRo) ranges from 0.42-0.63, Tmax ranges from 421-433^0C, hydrogen index (HI) ranges from21-162 (mg/gTOC), and production index (PI) ranges from 0.02-0.13 (Table 1).

The result of TOC of five shale samples from Mamu across Anmbra Basin ranges from 1.45-6.1(wt%), vitinite reflectance ranges from 0.6-0.63, Tmax ranges from 431-433^0C, hydrogen index ranges from106-206(mg/gTOC), and production index ranges from 0.02-0.09 (Table 1). The TOC result of six shale samples of Enugu Shale collected randomly across Anambra Basin ranges from 0.74-2.95(wt%), vitrinite reflectance ranges from 0.49-0.65, Tmax ranges from 425-

434^{0}C, hydrogen index ranges from 39-159(mg/gTOC), and production index ranges from0.04-0.1 (Table 1).

Samples of shale from Nkporo Shale show that the TOC result ranges from 0.97-5.75(wt%), vitrinite reflectance ranges from 0.47-0.67, Tmax ranges from 424-439^{0}C, HI ranges from 31-294(mg/gTOC), and PI ranges from 0.02-0.08 (Table 1).

Table 1: Result of Rock-Eval Pyrolysis for Shale Samples Randomly Collected across Anambra Basin.

S/N	Formations	TOC (wt%)	S1 (mg/g)	S2 (mg/g)	Tmax (0C)	%VRo	HI (mg/gToc)	PI
1	Nsukka	0.5	0.03	0.21	421	0.42	42	0.13
2	Nsukka	0.85	0.03	0.26	430	0.58	31	0.1
3	Nsukka	1.05	0.07	0.71	432	0.62	68	0.09
4	Nsukka	3.19	0.19	5.16	433	0.63	162	0.04
5	Nsukka	18.67	0.43	18.25	431	0.6	98	0.02
6	Nsukka	1.22	0.02	0.26	432	0.62	21	0.07
7	Nsukka	1.6	0.07	0.74	430	0.58	64	0.09
8	Mamu	4.73	0.3	11.87	433	0.63	251	0.02
9	Mamu	3.79	0.33	9.86	432	0.62	260	0.03
10	Mamu	5.08	0.24	9.96	431	0.6	196	0.02
11	Mamu	6.1	0.27	11.62	432	0.62	194	0.02
12	Mamu	1.45	0.09	1.53	432	0.62	106	0.06
13	Enugu	2.34	0.05	1.29	434	0.65	55	0.09
14	Enugu	2.95	0.07	1.29	427	0.53	42	0.04
15	Enugu	2.77	0.07	1.91	425	0.49	69	0.05
16	Enugu	0.71	0.03	0.63	431	0.6	89	0.04
17	Enugu	2.04	0.09	0.8	425	0.49	39	0.05
18	Enugu	0.74	0.07	1.18	428	0.54	159	0.1
19	Nkporo	1.26	0.05	0.7	435	0.67	56	0.07
20	Nkporo	5.75	0.38	18.91	432	0.62	294	0.07
21	Nkporo	1.05	0.03	0.43	428	0.54	41	0.02
22	Nkporo	1.83	0.07	1.32	431	0.6	72	0.08
23	Nkporo	1.59	0.1	0.84	430	0.58	56	0.07
24	Nkporo	3.21	0.01	3.56	434	0.65	111	0.03
25	Nkporo	0.97	0.07	0.3	439	0.74	31	0.03
26	Nkporo	1.33	0.04	1.18	432	0.62	89	0.06
27	Nkporo	2.29	0.03	1.18	424	0.47	48	0.04
28	Nkporo	1.07	0.03	1.1	425	0.49	36	0.07

Organic Matter Content and Kerogen Type

The result of Rock-Eval Pyrolysis shows that the twenty eight shale samples obtained from Nsukka Formation, Mamu Formation, Enugu Shale and Nkporo Shale within Anambra Basin varies from 0.5-18.67wt% (Table 1).

This observation shows that the organic carbon content of the four formations studied in Anambra Basin are adequate enough for the formations to be potential source rocks according to Tissot and Welta (1984) classification of potential source rock using TOC value. However the result of the vitrinite reflectance and T_{max} show that all the five shale samples from the Mamu Formation have 0.6% and above vitrinite reflectance and Tmax of 431^0C and above (Table 1) which are the indication for mature source rock and geothermally mature source rock respectively that has attained oil generating window according to Demiason and Moore (1980) classification of mature source rock.

However, apart from Mamu Formation, Nkporo result shows that six out of ten shale samples and for Nsukka Formation, four samples out of six samples, fall within the mature source rock and thermally mature source rock (Table 2) that can generate hydrocarbon in the basin. The remaining shale samples from Nsukka Formation, Enugu Shale and Nkporo Shale that are below 0.6% vitrinite reflection and T_{max} value below 431^0C are immature source rocks (Table 2) according to Tissot and Welta (1984) Classification and Dimiason and Moore (1980), respectively.

Table 2: Interpreted Result of Rock-Eval Pyrolysis for Shale Samples in Anambra Basin.

S/N	Formations	TOC	Tmax (0C)	%VRo	S1+S2	Source Rock	Maturity	%Maturity	Hydrocarbon yield
1	Nsukka	0.5	421	0.42	0.24	Fair	Immature		Gas potential
2	Nsukka	0.85	430	0.58	0.29	Fair	Immature		Gas potential
3	Nsukka	1.05	432	0.62	0.78	Good	Mature	57.14	Gas
4	Nsukka	3.19	433	0.63	5.35	V. good	Mature		Oil
5	Nsukka	6.1	431	0.6	18.68	Excellent	Mature		Oil
6	Nsukka	1.22	432	0.62	0.28	Good	Mature		Gas
7	Nsukka	1.6	430	0.58	0.81	Good	Immature		Gas potential
8	Mamu	4.73	433	0.63	12.17	V. good	Mature		Oil
9	Mamu	3.79	432	0.62	10.19	V. good	Mature		Oil
10	Mamu	5.08	431	0.6	10.2	Excellent	Mature	100	Oil
11	Mamu	6.1	432	0.62	11.89	Excellent	Mature		Oil
12	Mamu	1.45	432	0.62	1.62	Good	Mature		Gas
13	Enugu	2.34	434	0.65	1.34	V. good	Mature		Gas
14	Enugu	2.95	427	0.53	1.36	V. good	Immature		Gas potential
15	Enugu	2.77	425	0.49	1.98	V. good	Immature	33.3	Gas potential
16	Enugu	0.71	431	0.6	0.66	Fair	Mature		Gas
17	Enugu	2.04	425	0.49	0.89	V. good	Immature		Gas potential
18	Enugu	0.74	428	0.54	1.25	Fair	Immature		Gas potential
19	Nkporo	1.26	435	0.67	0.75	Good	Mature		Gas
20	Nkporo	5.75	432	0.62	19.29	Excellent	Mature		Oil
21	Nkporo	1.05	428	0.54	0.46	Good	Immature		Gas potential
22	Nkporo	1.83	431	0.6	1.39	Good	Mature		Gas
23	Nkporo	1.59	430	0.58	0.94	Fair	Immature	60	Gas potential
24	Nkporo	3.21	434	0.65	3.57	Fair	Mature		Oil
25	Nkporo	0.97	439	0.74	0.37	Fair	Mature		Gas
26	Nkporo	1.33	432	0.62	1.22	Good	Mature		Gas
27	Nkporo	2.29	424	0.47	1.21	V. good	Immature		Gas potential
28	Nkporo	1.07	425	0.49	1.13	Good	Immature		Gas potential

The variation in the TOC values (Table 1) across the Anambra Basin among Nsukka Formation, Mamu Formation, Enugu Shale, and Nkporo Shale is as a result of fluctuation in availability of organic materials from the source of organic materials into parts of the Anambra Basin during the time of deposition/sedimentation, due to proximity and unfavorable conditions of preservation during the time of deposits/sedimentation. Parts of the basin that are well supplied with abundant organic materials and with favorable preservative conditions for supplied organic materials as at the time of deposition of sediments in the basin are very rich in organic matter thus, having high TOC while those areas that are far away from the source of organic material or close but lack favorable preservative conditions are starved of organic matter, are generally characterized by lower TOC values.

The plot of HI (Hydrogen Index) against T_{max} (Figure 3) according to the method of Baskin (1997) shows that four samples out of five from Mamu Formation are plotted in portion of Kerogen type II while the remaining one is plotted at Kerogen type III portion. This occurrence is as a result of high value of HI and T_{max} ($\geq 431^0$C) of the four shale samples and low value of HI and T_{max}($<431^0$C) exhibited by the remaining (one) shale sample out of five respectively (Figure 3). This observation indicates that larger portion of Mamu Formation is oil prone while little portion is gas prone (Table 2).

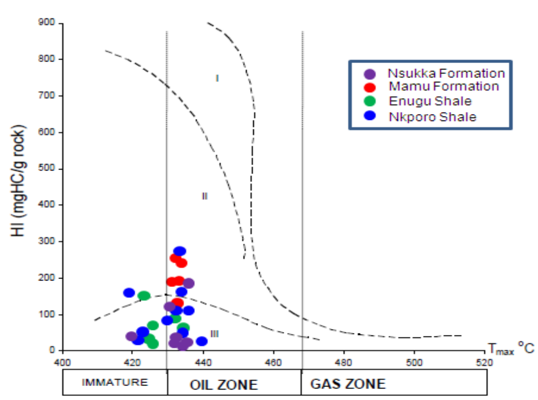

Figure 3: Plot of HI vs Tmax for Kerogen Type Classification for Nsukka, Mamu, Enugu, and Nkporo in Anambra Basin.

The plot of S_1+S_2 against vitrinite reflectance (Figure 4) confirms the fact earlier established by the plot of HI against T_{max} after the method of Baskin's (1997). This observation shows that the organic material that is found in the source rock of the Mamu Formation has two sources, marine and terrestrial sources. However, the marine source predominates, that is why the source is more of type II (oil prone) and very little gas (Figure 3, Figure 4, and Table 2).

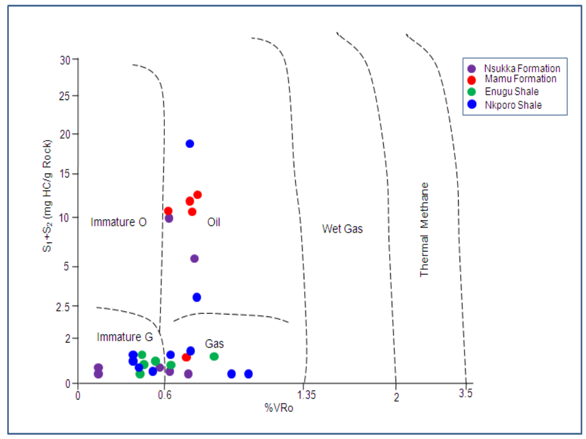

Figure 4: Hydrocarbon Yield Curve for Nsukka, Mamu, Enugu, and Nkporo in Anambra Basin.

The plot of HI against Tmax values for the six shale samples from Enugu Shale after the method of Baskin's (1997) shows that four of the samples are plotted in immature portion while the remaining two samples fall within type III Kerogen, meaning gas prone (Figure 3).

Similarly, the plot of S_1+S_2 against $\%VR_0$ indicates that four of the samples are immature while two are gas prone (Figure 4). This predominant occurrence of immaturity in Enugu Shale is an indication that Enugu Shale has not attained thermal maturity (Tmax is less than 431^0C) and the two are plotted at type III (Figure 3) and (Table 2). This suggests that pocket of Enugu Shale is mature, gas prone. This is as a result of thermal maturity attainment and low hydrocarbon index, and low S_1+$S_{2,}$ which are associated with Enugu Shale.

Three samples out of the seven shale samples of Nsukka Formation have HI below 100mg Hc/g rock and T_{max} below 431^0C. These observations indicate immature source rock while the remaining four shale samples have T_{max} value

431^0C and above (Table 1 and Table 2), indicating mature source rock. Two out of four mature source rock of Nsukka have above 100mgHc/g rock HI values, that is the reason they are plotted in Kerogen type II while the remaining two have HI below 100mgHc/g of rock thus they are plotted at Kerogen type III (Figure 3). That is, they are oil prone and gas prone respectively. The oil prone shale of Nsukka Formation is as a result of organic material which was sourced from a marine environment thereby caused high S_1+S_2 values ($\geq$2.5mgHC/g rock) while the gas prone must have been sourced from terrestrial environment thus resulting to low S_1+S_2 less than 2.5mgHc/g rock (Figure 4).

The plot of HI against T_{max} for Nkporo Shale after the method of Baskin's (1997) shows that two shale are type II (oil prone) and four are type III that is, gas prone (Figure 3). These observations tally with the plot of S_1+S_2 against T_{max} (Figure 4).

Maturity Model for Source Rocks in Anambra Basin

Variation in maturity (Table 2) in the twenty-eight shale samples selectively collected at random across the four formations in the Anambra Basin, the shale samples of Mamu Formation that are younger to Enugu Shale and Nkporo and even Nsukka Shale that is younger than Enugu Shale show high level of maturity compare to the older formations in the basin. This observation suggests that a pattern of deposition of sediments in Anambra Basin was almost lateral while very few portions of each formation in the basin is laid vertically succeeding other at the edge of each formation.

At the time of deposition of the older formations (Nkporo, Enugu Shales), Late Campanian, the basin's rate of subsidence was slow, thus Nkporo Shale and Enugu Shale were unable to attain that suitable depth that would have made them attained the stage of thermal maturity that would have led to catagenesis (OGW). In the Maastrichtian period, Mamu Formation started depositing into the basin such that largest portion of Mamu was deposited laterally in a manner that is not directly on top of the older formations earlier deposited into the basin. However, small portions of Mamu (Edge bed) was deposited and laps on top of Nkporo Shale and very small portion lapse on top of Enugu Shale.

During this period, Maastrichtian, the rate of subsidence in the basin was rapid (Figure 5). However, the subsidence rate varies across the basin. Some portion of the basin experienced rapid rate of subsidence while some were very slow.

All the sediments of Mamu Formation were favorable to have deposited in zone or part of the basin that experienced rapid subsidence, thus Mamu was able to attain the depth range that was favorable for catagenesis temperature range. This is the reason all the Mamu Formation samples are mature, that is, have reached oil generating window (OGW). However, Enugu Shale, was unfavorable to have deposited in the part of the basin that experienced low rate of subsidence. This caused largest part of Enugu shale not to have attained the depth range that favor catagenesis temperature ranges except for little part of Enugu Shale that lapse with the edge of Mamu Formation (Figure5) that was deposited in favorable part of the basin that experienced rapid subsidence rate. That is the reason two shale samples out of the six shale samples from Enugu Shale are mature (Table 2).

Similarly, almost more than half of Nkporo Shale was deposited in favorable part of the basin that later experienced rapid subsidence in the Maastrichtian (Figure 5), this enabled them to attain depth range that favored catagenesis temperature range (oil generating window). This is the reason six shale samples out of the ten samples are mature (Figure 3 and 4, and Table 2) while the remaining four samples are those that are deposited in the unfavorable part of the basin that still continued to experience low rate subsidence from Campanian time to Maastrichtian.

The basin continued to experience rapid subsidence most especially in the part of the basin where Mamu was deposited from Middle Maastrichtian to Late of Maastrichtian. During Late Maastrichtian times, Ajali Sandstone and Nsukka Formation were deposited directly on top of Mamu Formation where the basin experienced rapid subsidence, thus half of Nsukka Formation was able to attain the depth range that favored catagenesis temperature range. That is the reason more than half of the samples are mature. At the end of Maastrichtian, Anambra Basin seized to experience rapid subsidence in all the portions of the basin and the rate of subsidence generally became very low. Thus the remaining part of Nsukka that was deposited in the Early Paleocene could not attain the depth range that favors catagenesis temperature range that would have caused them to reach oil generating window. That is the reason three samples of Nsukka Formation are immature (Table 2) because they fall in that portion of Nsukka that was deposited during Early Paleocene.

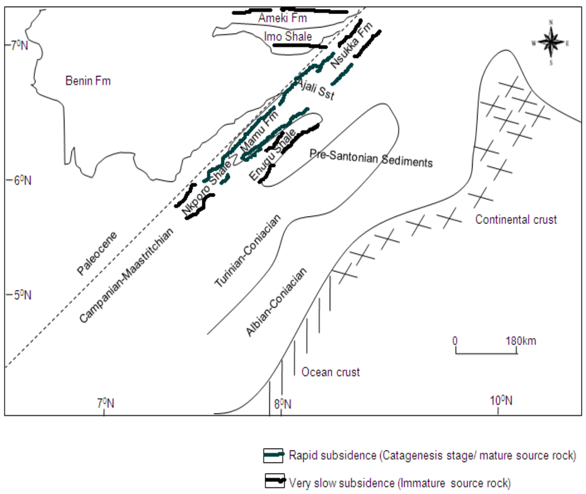

Figure 5: Model for Potential Source Rocks Maturity in the Anambra Basin.

CONCLUSION

The present study has shown that there is a great prospect for hydrocarbon in the Anambra Basin. However, great attention should be focused on Mamu Formation and on the zones where rapid subsidence occurred in the basin during period of deposition of the other three formations in order to optimally explore those portions of Nkporo Shale, Enugu and Nsukka Formation that have attained oil generating window and their migration paths, using 2D and 3D seismic with sophisticated inversion model.

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SUGGESTED CITATION

Salufu, S.O. and T.F. Ogunkunle. 2015. "Source Rock Assessment and Hydrocarbon Prospects of Anambra Basin: Salient Indications for Maturity". *Pacific Journal of Science and Technology*. 16(1):336-344.

Pacific Journal of Science and Technology