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SOURCE ROCK MATURITY EVALUATION IN THE COASTAL SWAMP DEPOBELT, WESTERN NIGER DELTA BASIN

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ABSTRACT

Hydrocarbon generating potential and maturity status on eleven non-composited shale samples retrieved from 1390 – 3466m (4560 – 11370ft) depth interval of the KB-1 well located in the Coastal Swamp depobelt in the Niger Delta Basin using conventional Rock-Eval techniques has been done in this study to expand knowledge on the source rock status of the Niger Delta Basin. A range of 0.09 – 1.16wt % (av. 0.78wt %) recorded for Total Organic Carbon (TOC), indicate fair to good potential source rock. The production index (PI), genetic potential (GP) and hydrogenindex (HI), ranges from 0.05 – 0.2 (av. 0.12), 0.2 – 0.51 (mg/g) (av. 0.31mg/g) and 21 – 44 (mgHC/gTOC)(av. 27mgHC/gTOC)respectively. Calculated vitrinite reflectance and T_{max}*range from 0.45 – 0.53 (0.50) and 408 – 430°C (av. 419°C), indicates immature source sediments. HI calibration constrained with* S_2/S_3 *indicates a dominance of type IV non-source organic matter. Cross plots of HI vs OI refined and confirmed type IV kerogen as dominant species. A flat PI trend withno decrease of increase with depth is unusual and difficult to explain, but may be probably due to the effect of impregnation by migrated hydrocarbons from older sequences which may have masked the expected trend for the well. Maturity indices from this study, thus far shows that the sediments of the Agbada Formation in the section of the well and in this aspect of the Coastal Swamp Depobelt though have potential to generate hydrocarbon, containspent and immature organic matterthat cannotgenerate any form of hydrocarbon.*

Keywords: *Coastal Depo Belt, Calculated vitrinite, Hydrogen Index, Niger Delta, Source Rock Maturity*

INTRODUCTION

Debates on the source sediments of the Niger Delta oil has been on four over three decades. Different worker have presented their finding and,their views are products of the stratigraphic perspectives. Vast amount of data have been utilized to speculate and assert these positions. Although extensive studies on these thematic aspect of the Basin has been on for so long,controversies and divers views still exist among workers on the actual source sedimentsof the Niger Delta hydrocarbon resource.

A literature survey of classic works of Frankl and Cordry, (1967), Short and Stuable, (1967), Reed, (1969),Lambert-Aikhionbare, (1984), Lambert-Aikhionbare and Ibe, (1984),Evamy et al. (1978),Ekweozor et al. (1979), Ekweozor and Okoye, (1980), Nwanchukwu and Chukwura, (1986), Bustin, (1988), Doust and Omatsola, (1990) reveal divergent views of these workers on the sources sediments of the Niger Delta Basin. Variable organic matter contribution has been postulated based on geochemical data. These include, Cretaceous shale that possibly occurs at the base of the delta stratigraphic pile, the deep marine Akata shale Formation and the interbedded marine shale intervals present in the Agbada Formation, as co-sources of the Niger Delta oil (Weber and Daukoru, 1975; Evamy et al. 1978; Ekweozor and Okoye, 1980; Ekweozor and Daukoru, 1984; Lambert-Aikhionbare and Ibe, 1984; Doust and Omatsola, 1990; Stacher, 1995; Frost, 1977; Haack et al., 1997).

So far, two schools of thought can be clearly distinguished on the subject matter. Frankl and Cordry (1967), Short and Stuable (1967) and Reed (1969), later supported by Lambert-Aikhionbare (1984) and Lambert-Aikhionbare and Ibe, (1984)leeds the first school. They asserts that the interbedded marine shale of the Agbada Formation are prominent in the hydrocarbon generation equation in the Niger Delta. Weber and Dakoru (1975), Evamy et al. (1978) who belong to the Second school of thought favored the Akata shale as the major source sediments, and presented the Agbada shale as essentially immature sediments. This view was later supported and strengthened by Ekweozor and Okoye (1980) and Ekweozor and Daukoru (1984).

Although several studies have reported total organic contents in the Agbada shale as potential source sediments, Evamy et al. (1978),Stacher, (1995), Osokpor et al. (2016), Osokpor and Osokpor (2017) noted that the shale intervals within the Agbada Formation were generally immature in various parts of the delta and rarely reach thicknesses sufficient to produce a world-class oil province compared to the Akata Shale Formation that is volumetrically sufficient to generate substantial oil for a world class oil province.

Variable contributions have also been advanced for the hydrocarbon although their relative contribution to the hydrocarbon accumulation may be different (Ejedawe and Okoh, 1981, Ejedawe et al., 1984). With respect to the quantity of organic matter recorded in this present study which indicates a good potential, the application of further geochemical techniques such as the T_{max}, hydrogen index, vitrinite reflectance, and production index etc. to ascertain the quality of the preserved organics and the corresponding maturity state of these organics in the sediments retrieved from KB-1 well located in the Coastal Swamp Depo belt forms the focus of this study and motivated by the inconclusive and non-agreement on the actual source sediments of the Niger Delta Basin.

Geologic Setting

The Niger Delta Basin (Fig. 1) which has prograded south-westward since the Eocene to present is situated in the Gulf of Guinea (Klett et al., 1997) on the trailing edge of the African plate margin (Doust and Omatsola, 1990).the Niger Delta ranks as one of Africa`s leading petroleum provinces, with over 5000 oil wells and 34.5 billion barrels of recoverable oil and

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93.8 trillion cubic feet of recoverable gas as at 1999, (Petroconsultants, 1996a), (Klett et al. 1997). The Niger Delta Basin is characterized by depobeltswhich are large megastructural units within the delta and known to control the regressive form of the delta, thus forming an area of some 300,000 km^2 (Kulke, 1995), and a sediment thickness of over 10 km in the basin centre (Kaplan and others, 1994) hostingsediment volume of about 500,000 km^3(Hospers, 1965).

Proximal stratigraphic profile of the Niger Delta Basin reveals that proximal facies of the Delta rest unconformably on the distal sedimentary facies components of the Benin Flank at depth (Osokpor and Ogbe, 2018).

A typical off-lap sequence divided into three main chronostratigraphic units (Short and Stauble, 1967; Reijers, 2011) comprising time equivalent proximal-to-distal prograding facies (Akata, Agbada and Benin Formations)occur as the three main lithostratigraphic unitsin the Niger Delta Basin (Short and Stauble, 1967). Outcropping sediments of Eocene age occur in the northern fringes while sediments deposited along the present coastlines of the Niger Delta Basin are of Recent (Avbovbo, 1978b; Short and Stauble, 1967). Oligocene and Miocene age deposits of the Ogwashi-Asaba and Benin Formations occur as surface deposits in limited areas and much of the age determination is uncertain.

The Akata Formation with a thickness range of from 600m to 6000m occurs as the bottomset consists of over 90% prodelta marine shale and less than 10% sandstone (Short and Stauble, 1967). Its age ranges from Eocene to Recent. The Agbada Formation with a thickness range of 3000m to 4500m and a diachronous age range of Eocene to Recent (Short and Stauble, 1967; Whiteman, 1982) represents the foreset of the Niger Delta. It is comprised of delta front lithofacies consisting mostly shoreface and channel sand deposits with minor shale in the upper parts and sand and shale alternations of almost equal proportion in the lower part. The Benin Formation composed of over 90% thick sequences of continental sands and gravels with clay intercalations occur as delta plain lithofacies (Short and Stauble, 1967). Variable thickness, which generally exceed 2100m and an Oligocene – Recent age range (Whiteman, 1982) has been recorded for the Benin Formation.

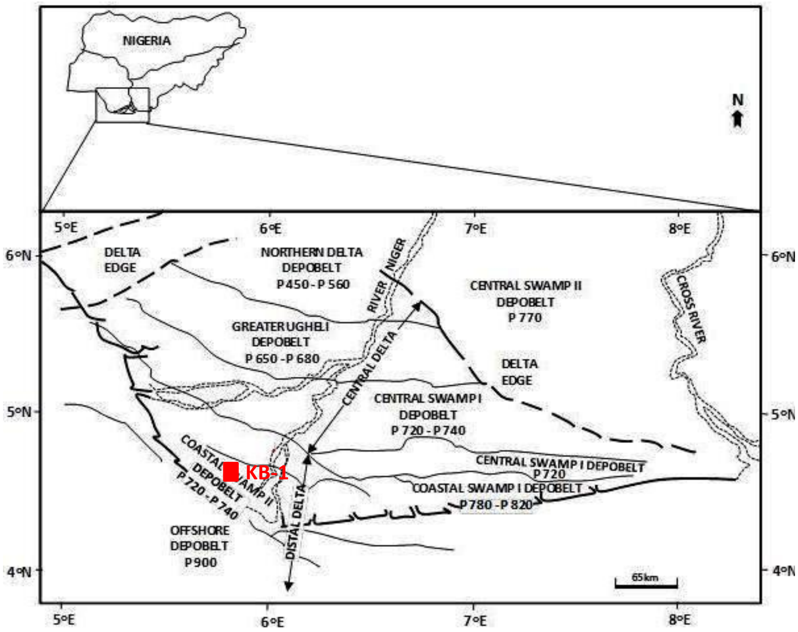

Figure 1: Map of Niger Delta Basin showing the location of KB-1 well in the Coastal Swampdepobelt (Modified after Doust and Omatsola 1990).

MATERIALS AND METHODS

Geochemical Analysis

Organic geochemical analyses of total organic carbon (TOC) and Rock-Eval pyrolysis of eleven non-composited ditch cutting samples from a depth range of 1390 – 3466m (4560 – 11370ft) spanning Late Oligocene to Early Miocene age (Osokpor, 2013), was done to ascertain total organic matter content (TOC), maturation state and source rock hydrocarbon generative potential of samplesretrieved from well KB-1. Sampling factors considered include facies characteristics, resolution and intervals of interest.

Total Organic Carbon (TOC)

Total organic carbon (TOC) (% C_{org}) determination was carried out using an ELTRA CS800 Carbon and Sulphurdeterminator as a first step inidentifying potential source from non-source rock, as finer grained facies are expected to have greater TOC content (Hunt, 1996; Huc, 1988). Hunt, (1979) established the lower TOC limit for effective shale source sediments to generate hydrocarbon as 0.5 wt. % and 0.3 wt. % for carbonates respectively. A linear proportionality had been shown to exist between the quantity of oil generated in any given volume of source rock and its organic carbon content (Tissot and Welte, 1984).

Samples due for analysis were initially pulverization using an automated rock pulverizer,and then sieved through a 25 µm sieve and 0.1g of each sample was weighed out (against a standard: 0.1015 – 0.0985gm). Measured samples were then fed into the CS analyzer and analyzed for 50secs each. This Analysiswas performed at the Fugro Robertson Limited (FRL) Petroleum Geochemistry Laboratory in Llandudno, United Kingdom.

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Rock-Eval Analysis

Rock-Evalpyrolysis up to 550°C in order to obtain geochemical attributes of the sediments was carried out on eleven non-composite samples from the KB-1 well within a depth range of 1390 – 3466m (4560 – 11370ft). This involved passing a stream of helium through 100mg of pulverized rock sample that has been initially heated to 300°C, and programmed to increase at 25°C/min, up to 550°C (Espitalie et al. 1977).

In analyzing the sediments, each sample was pulverized and 100g of each pulverized sample was sieved through a 25µm mesh screen. Each sample was weighed (dependent on TOC) and fed into a Vinci Tech Rock-Eval 6 analyzer interfaced with a Nelson Analytical 760 to an IBM PC/XT computer and analyzed for 50 seconds at the Petroleum Geochemistry Laboratory of Fugro Robertson in Llandudno, United Kingdom.

RESULTS AND DISCUSSION

The results for the primary data sets (total organic carbon, rock-evaldata) and derived vitrinite values are presented in Table 1.The range and average values of pyrolysates and their derivativesare presented in Table 2

Quantity of Organic Matter

Total organic carbon concentration (TOC) range from 0.09 – 1.16 wt. % (av. 0.71) (Tables 1 and 2). These values satisfy the requisite threshold value of 0.5 wt. % TOC for siliciclastics to generate hydrocarbon and classified as fair to good (Peters et al. 2006) (Table 3, Fig. 2). A percentage TOC classification, presents 9.1% as poor, 63.3% as fair and27.3% as good (Fig. 2). Assertions made by Conford, (1986) that although the percentage total organic matter present in sediments is a vital requirement for hydrocarbon generation, the quality of organic matter(Tissot and Welte, 1984; Hunt, 1979; North, 1985; Jarvie, 1991), is a pivotal factor controlling hydrocarbon generation in sedimentary basins, was considered.

Soluble/extractible organic matter (SOM) value range of 321 – 48,726, (av. = 18,942) (Table 2) was recorded for the samples. An obvious impregnation by oil from other sources, probably from migrated hydrocarbon is indicated by these values.

The hydrocarbon genetic potential represented by S_2, a measure of hydrocarbon derived by cracking the kerogen until only residual non-generating carbon remains and provides a means of source rock organic matter evaluation to generate further hydrocarbons (Tissot and Welte, 1984; Hunt, 1979), ranged from 0.16 – 0.45 (av. 0.26).A comparison of these values with the general criteria of Peters and Cassa (1994), the samples present an S_1 andS_2 classification of 100%, indicatinglow and poor potential source rocks (Fig. 3).

Table 1: Calculated Vitrinite reflectance (R_c) of selected samples, Rock-Eval parameters, Total organic carbon (Measured TOC) from KB-1 well, Coastal Swampdepobelt. (R_c= calculated Vitrinite reflectance, TOC^X = measured TOC, ND = not determined)

S/N	Depth (FT)	Depth (M)	S_1	S_2	S_3	T_{max}°C	HI	OI	PI	TOC wt %	S_1/TOC	S_1+S_2	S_2/S_3	R_c
1	4560	1390	0.05	0.21	1.79	411	27	229	0.05	0.78	0.06	0.26	0.12	ND
2	5190	1581	0.04	0.16	1.70	410	21	227	0.20	0.75	0.05	0.2	0.09	ND
3	5310	1618	ND	0.01	0.05	501	1.0	0.7	ND	0.90	ND	ND	ND	ND
4	5370	1637	0.05	0.24	1.81	414	30	223	0.17	0.81	0.06	0.29	0.01	ND
5	5670	1728	0.04	0.24	1.80	408	32	247	0.14	0.73	0.05	0.28	0.13	ND
6	6210	1893	0.04	0.24	1.80	416	28	214	0.14	0.09	0.44	0.28	0.13	ND
7	6570	2003	0.03	0.22	1.22	424	43	239	0.12	0.51	0.09	0.25	0.18	0.47
8	8250	2515	0.05	0.33	1.68	423	44	224	0.13	0.75	0.07	0.38	0.20	0.45
9	10470	3118	0.06	0.45	1.71	430	42	160	0.12	1.06	0.06	0.51	0.26	0.58
10	10650	3283	0.05	0.38	1.62	424	33	140	0.12	1.16	0.04	0.43	0.23	0.47
11	11370	3466	0.08	0.42	1.60	427	39	148	0.16	1.08	0.07	0.50	0.26	0.53

Table 2: Range and Average Values of Pyrolysates and their Derivatives

Pyrolysates	Range	Average
S_1 (mg/g)	0.03 – 0.08	0.04
S_2 (mg/g)	0.16 – 0.45	0.26
S_3 (mg/g)	1.22 – 1.81	1.53
T_{max} (°C)	408 - 430	419
Derivatives		
GP (mg/g)	0.2 – 0.51	0.31
PI	0.05 – 0.2	0.12
HI (mgHC/gTOC)	21 – 44	27
OI	140 – 247	186
R_c	0.45 – 0.53	0.50
Organic matter concentration parameters		
TOC (wt.%)	0.09 – 1.16	0.78
SOM (PPM)	321 – 48,726	18,942
BR (mg Extract/g TOC)	0.40 – 45.12	17. 30

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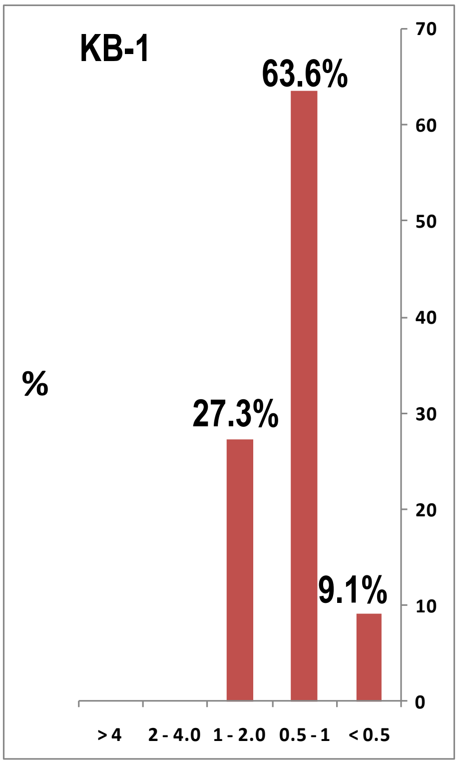

Figure 2: Percentage classification of Total Organic Matter in the KB-1 well section.

Table 3: Hydrocarbon generative potential of KB-1 well based on TOC, S_1, S_2 and bitumen ratio (after Peters et al. 1996)

Potential (quantity)	TOC (wt.%)	KB-1 (%)	S_1	KB-1 (%)	S_2	KB-1 (%)	Bitumen (ppm)	KB-1 (%)
Poor	<0.5	9.1	<0.5	100	<2.5	100	<500	20
Fair	0.5 – 1	63.6	0.5–1	0	2.5–5	0	500-1000	0
Good	1 – 2	27.3	1–2	0	5–10	0	1000-2000	20
Very Good	2 – 4	0	2–4	0	10–20	0	2000-4000	0
Excellent	> 4	0	> 4	0	>20	0	>4000	60

Table 4: Percentage Kerogen types based on HI and S_2/S_3 values and corresponding expected hydrocarbon product generated from the well section

Kerogen (quality)	Hydrogen Index (mg HC/gTOC)	KB-1 (%)	S_2/S_3	KB-1 (%)	Main product at peak maturity
I	>600	0	>15	0	Oil
II	300 - 600	0	10 – 15	0	Oil
II/III	200 - 300	0	5 – 10	0	Oil/gas
III	50 - 200	0	1 – 5	0	Gas
IV	< 50	100	< 1	100	None

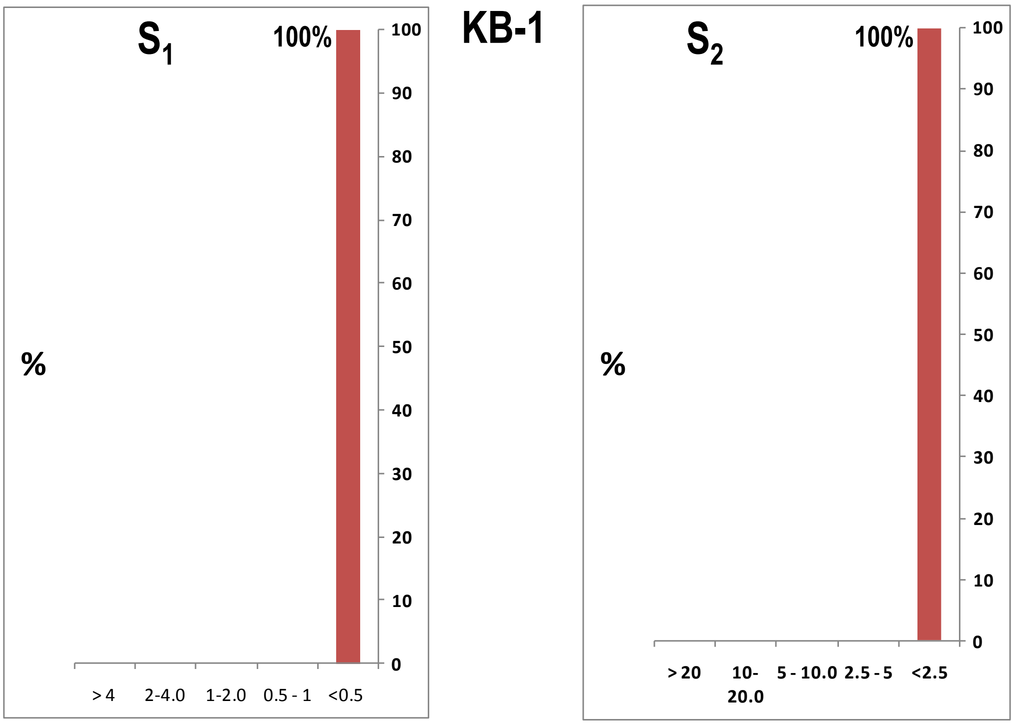

Figure 3: Percentage S_1 and S_2 classification of organic matter in the KB-1 well section

Kerogen Quality

The kerogen quality of the samples were appraised HI to obtain insight on the convertibility of the kerogen present in the samples (Robert and Cordell, 1980; Tissot and Welte, 1984.

Samples from KB-1 Well have HI values ranging from 21 to 44mgHC/gTOC with an average value of 27mgHC/gTOC (Tables 2 and 4, Fig. 3); these are below 50mgHC/gTOC which is characteristic of organic matter considered as inert (carbonized) (Hunt, 1979; Peters, 1986; Bordenave, 1993), and thus are classed as type IV kerogen. This interpretation is strengthened by the cross plot of HI versus OI for the samples, in which all samples plot within the type IV kerogen region (Fig. 5.).

The range of HI, and HI versus OI values which indicated that the shales are inert, was further verified and ascertained by a cross plot of hydrocarbon potential (S_2) versus TOC (Fig. 6) for this well. This shows that the shales have potential to generate dry gas, a characteristic exhibited by inert organic matter. Furthermore, a cross plot of HI versus Tmax also shows that the shales have no potential to generate reasonable hydrocarbon but dry gas (Fig.7).

The S_2/S_3 values for this well range from 0.01 to 0.26 with an average value of 0.15. All of these values fall within the inert class of kerogen (Peters and Cassa, 1994) and is consistent with the HI based classification above.

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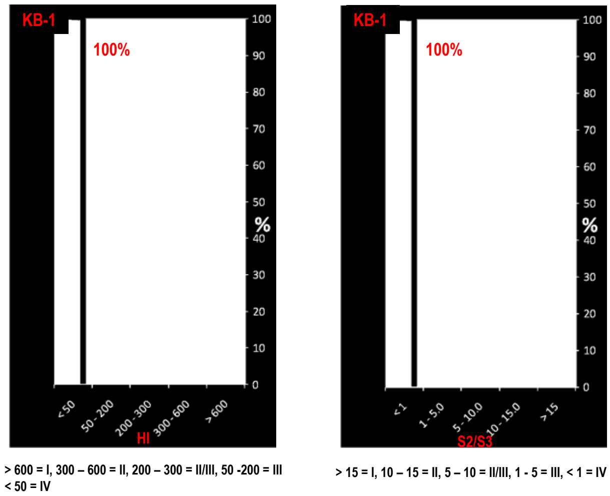

Figure 4: Percentage HI and S_2/S_3 classification of organic matter in the KB-1 well section.

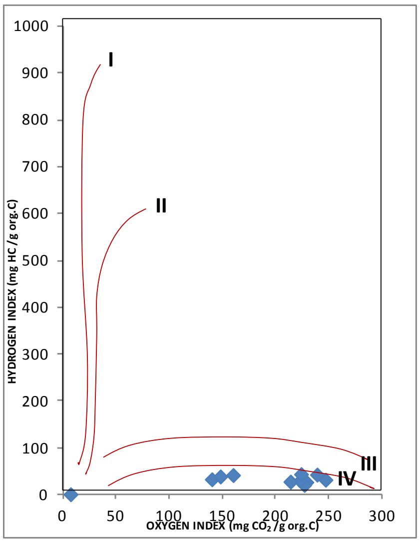

Figure 5: Cross plot of hydrogen index versus oxygen index showing the various kerogen types present in KB-1 well, (*Modified after van Krevelen, 1961*).

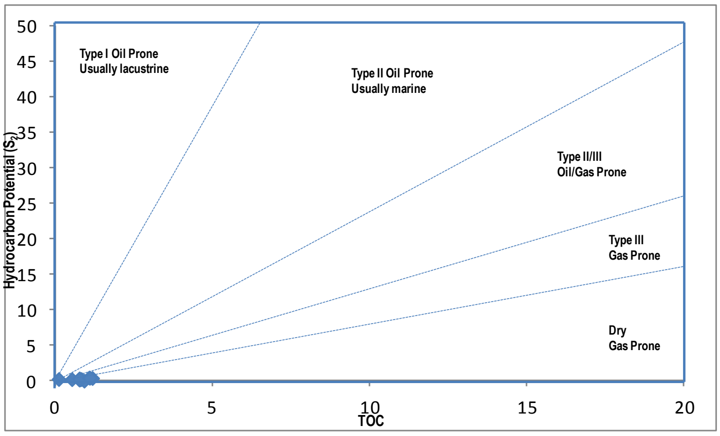

Figure 6: Cross plot of hydrocarbon potential versus TOC for KB-1 well showing the hydrocarbon generative potential of the various kerogen types present in the samples.

Cross plot of HI versus T_{max}(Fig. 7) affirmed the interpretation derived from the HI and HI versus OI cross plots (Fig.5) and hence is in agreement with the type IV classification of kerogen for the well section under study (Fig. 4).

The hydrocarbon generative potential (TOC vs S_1+S_2) (Fig. 8) of the sediments has been calibrated with the general framework for the evaluation of generative potential for source rocks (Dow, 1977; Peters, 1986). This indicates a gas source organic matter type consistent withother source parameters obtained from kerogen classification parameters shown above. GP values for the KB-1 Well range from 0.2 to 0.52 with an average of 0.31mg/g.

The range of hydrogen index (HI) values adopted for interpretation in this present study are based on suggestion of Peters (1986), that the onset of thermal maturity Vitrinite reflectance of 0.6% is equivalent to a $T_{max}$of 435°C and modified T_{max} benchmark of 430°C advanced by Mukhopadhyay et al. (1995), (Fig. 7).

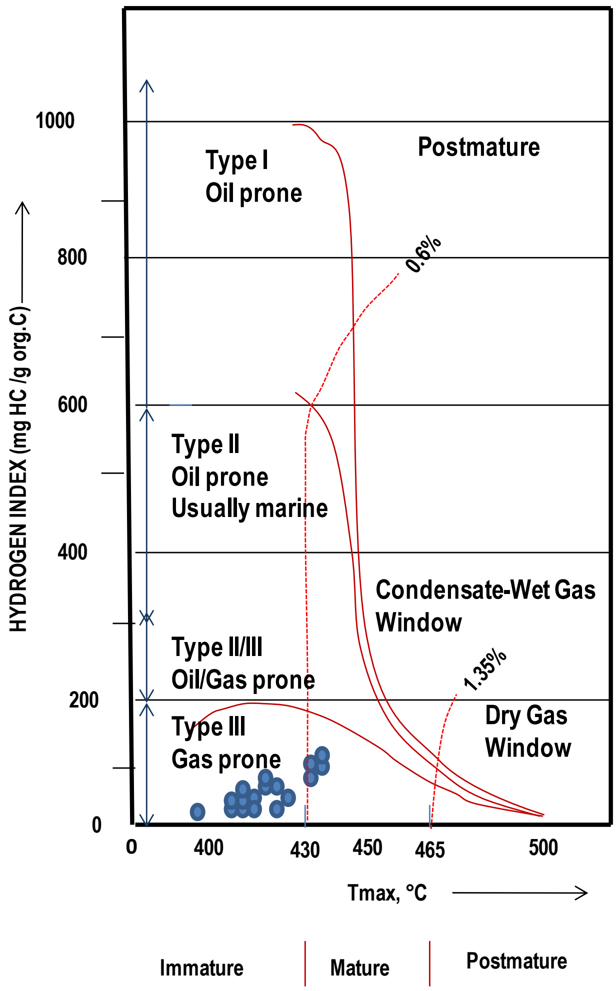

Figure 7: Plot of hydrogen index (HI) versus Tmax for KB-1 well, showing the kerogen types and their respective hydrocarbon generative potentials (*Modified after Mukhopadhyay et al. 1995*).

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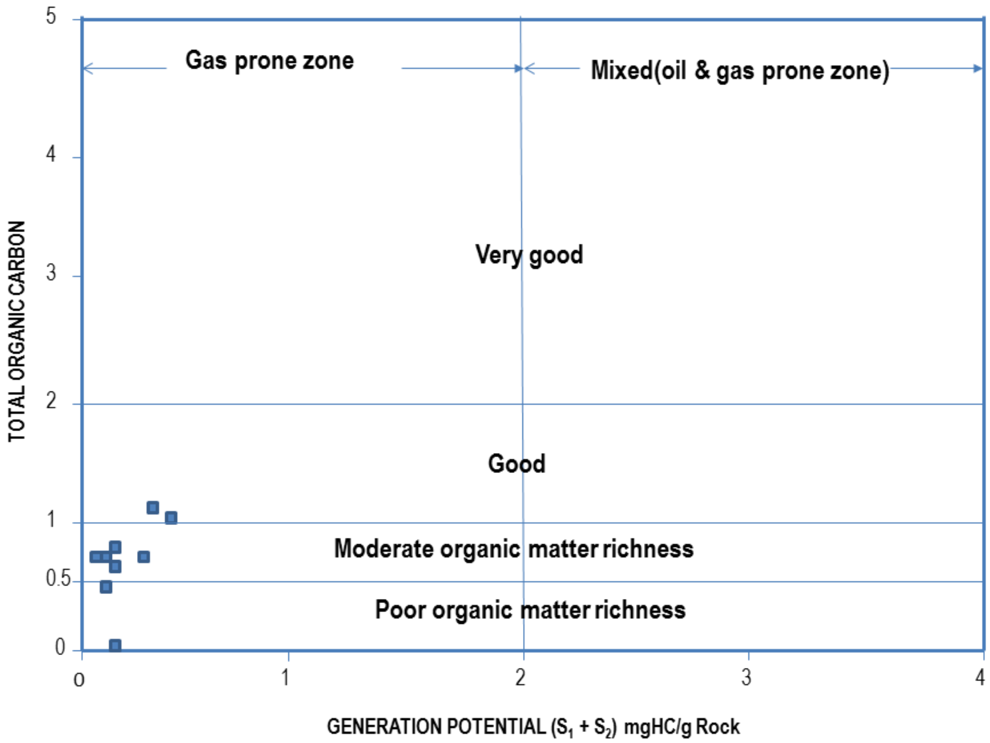

Figure 8: Cross plot of TOC versus generation potential to show the generic potential of samples from KB-1 well *(Modified after Akande et al. 2005)*

Thermal maturity (T_{max})

Thermal maturity evaluation of source sediments elucidates the maturity state of potential source sediments. It is affected by parameters such as organic matter composition, mineral matter content, presence of free hydrocarbon, burial depth and age (Tissot and Welte, 1984).

Maturity status of the sediments was inferred from the T_{max} (°C), Vitrinite reflectance (R_c) parameters, calculated production index (PI) and bitumen ratio. T_{max} values (Table 1), range from 408 to 430, with an average of 419, (Table 2) and indicate immaturesource sediments (Dow, 1977; Peters, 1986; Miles, 1989; Peters and Cassa, 1994). Cross plot of HI versus T_{max}(Fig. 7) further affirm the state of maturity of the sediments. Comparing these data with the maturation benchmark of Mukhopadhyay et al. (1995) and Peters and Cassa (1994), the sediments from this well are considered immature, and thus have neither generated any form of hydrocarbon.

Production index (PI) ranges from 0.05 to 0.2, with an average value of 0.12 (Table 2). The PI data displays an abnormal trend contrary to expected trend (Baker, 1972), and also show no correlation (Fig. 9a) with depth.In general PI values of pyrolysates are expected toincrease with depth (Baker, 1972; Peters and Cassa, 1994), which impliesgeothermal maturation, cracking of kerogen, thermal vaporization and cracking of asphaltenes which causes the S_2component to continuouslychange to $S_1$and thus results in an increase in PI.

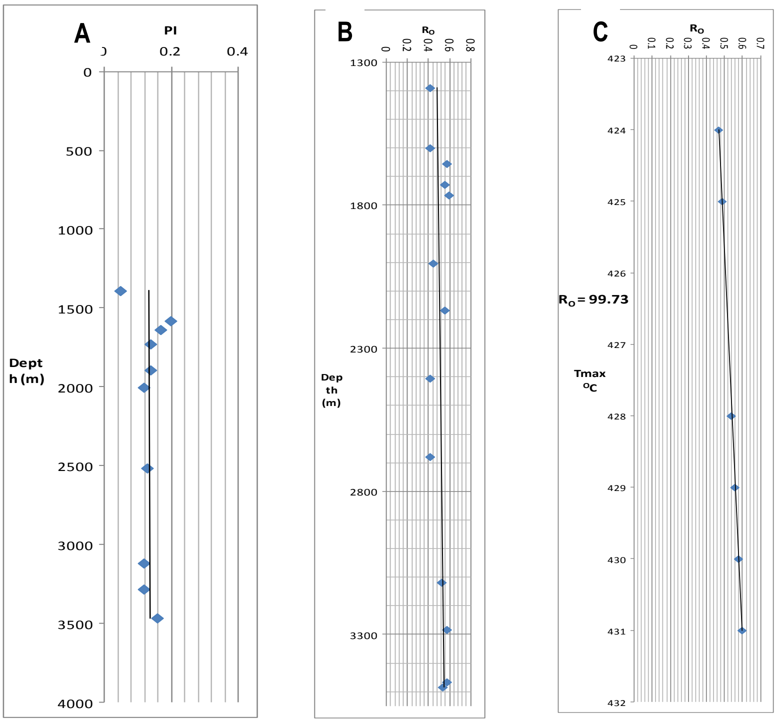

Figure 9(A - C): (A) Cross plots of production index (PI) versus depth (m), (B) Cross plot of calculated Vitrinite reflectance (R_c) versus depth and (C) Cross plots of calculated Vitrinite reflectance R_c versus T_{max}showing very high correlation of R_c with T_{max}, compared to moderate correlations derived for $R_c$versus depth for the KB-1 well.

Calculated vitrinite reflectance values for the well range from 0.45 to 0.53, with an average value of 0.50. This was achieved using derived formula(Jarvie et al. 2001b) (Table 2). A maximum value of 0.53 was attained at the maximum depth of 3466m (Table 1). This value falls outside the 0.65 and 0.90 benchmark for early to peak oil generation (Peters and Cassa, 1994), thus strengthens earlier results derived for the thermal alteration of the sediments. (Fig. 9b). A depth versus calculated vitrinite reflectance cross plot for the well (Fig. 9b), revealed a poor linear correlation (R^2) of 28.09%, indicatingthe geothermal energy that sediments have been exposed to was not solely dependent on depth index, but on such indices as time and also probably effects of episodic basin tectonic-sedimentary uplifts in the subsurface (Lopatin, 1971).

A high linear correlation of 99.81% in contrast to the above observation is revealed by a T_{max} versus $R_c$cross plot (Fig. 9c). Similar trends were observed by Teichmuller and Durand (1983) in type III kerogen and humic coals from the Douala Basin, Cameroun.

The transformation ratio which is the ratio of:

$$\frac{\text{Extractible bitumen}}{\text{Total organic carbon}},$$

insource rocks, has been variously used in determining organic maturity (Peters and Moldowan, 1993). Values of this ratio ranges from near-zero in near-surface sediments to approximately 250mg/gTOC

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at peak hydrocarbon generation. A decrease of this value at greater depth occurs due to conversion of bitumen to gas (Peters et al. 2005). The application of this technique as a maturity index (Miles, 1989), dictates that gas- and oil-prone kerogen hardly exceeds 50mg/gTOC at any level of thermal maturity. Considering the anomalously high values of the ratio derived from this study (Table 2), and other maturation parametrs measured from same purpose thus far, an obvious indication of contamination by migrated hydrocarbon or man-made products is visible (Peters et al. 2005). Plots of SOM versus total organic carbon were done to further verify the source potential of the shale samples and also to possibly unravel any form of contamination (Fig. 10). All the samplesplot within the field of oil impregnation, although the position of values from the lower sections of the well point to higher levels of organic maturity. Some samples plot outside the region of impregnation which is less than 1000 ppm extract, also indicative of increasing source rock quality

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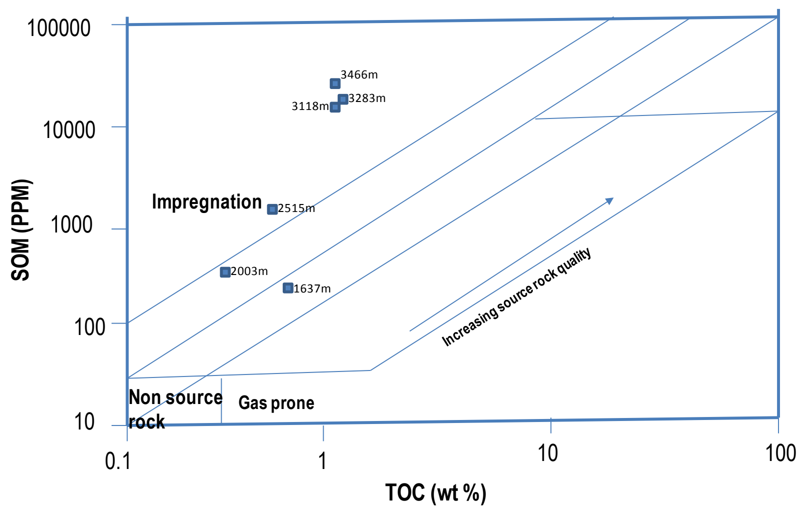

Fig. 10: Cross plot of soluble organic matter (SOM) versus total organic carbon (TOC) revealing bitumen impregnation in most of the samples from KB-1 well.
(Devised by Hunt, 1979 and modified after Le Tran and Philippe, 1993)

CONCLUSION

A comprehensive organic geochemical analyse have been carried out on subsurface shalesamples from the KB-1 well located in the Coastal swamp depo belt of the Niger Delta Basin in order to ascertain the source rock generating potential. Despite the average potential presented by some of the sample that were geochemically examined, none of the samples in the range of samples tested were geothermally matured enough to generate any form of hydrocarbon in the area of study. Measured TOC values indicate deposition of the sediments in shallow water settings were the organic matter were probably derived from near-shore terrestrial environment and have also probably been exposed to different mechanisms of degradation in shallow water, characteristic of sections of the Agbada Formation, hence yielding types III and IV kerogen. Geochemical data from this study shows that the shale intervals of the Agbada Formation, though have some potential to generate hydrocarbon, are thermally immature and thus have not generated any form of hydrocarbon in this well area

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