Petroleum Potential of Paleogene-Neogene Age Sediments in Well TN-1, Western Niger Delta Basin, Nigeria.

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ABSTRACT

Petroleum potential of Paleogene-Neogene sediments from the western Niger Delta Basin as penetrated by the well TN-1 has been carried out using Rock-Eval techniques, with a view to assessing source rock potentials and maturity status of sections of the Agbada and Akata Formations penetrated in the well. Total organic carbon analyses of the sediments was carried out using an ELTRA CS800 carbon-sulphur determinator, while Rock-Eval pyrolysis was performed with a Vinci Tech Rock-Eval 6 analyzer.

Hydrocarbon generative potential based on TOC (1.15 – 16.11w %), S1 (0.15 – 10.04) and S2 (0.79 – 107.7), show good to excellent source rocks. TOC vs GP show good to very good source rocks. The hydrogen index (HI) range from 62 – 671 mgHC/gTOC indicating types I – III kerogen, while Kerogen typing based on S_2/S_3, HI vs OI and HI vs Tmax (°C), class kerogen form the well section as oil-prone to inert. T_{max} (°C) ranges from 416 - 431°C indicating thermally immature sediments, while calculated vitrinite reflectance ($R_{c)}$ range from 0.47 – 0.6%, indicating immature to marginally mature source rocks. Maturity profile of the well section based on T_{max} and $\%R_c$ show that the Agbada Formation in this well location has not entered into the OGW, while the Akata Formation at a depth of about 1000 m below the base of the Agbada Formation is only marginally mature.

(Keywords: Niger Delta, petroleum generation, Akata Formation, Agbada Formation, source rock maturity)

INTRODUCTION

The Niger Delta Basin stands as Africa`s leading petroleum basin, haven been the focus of hydrocarbon exploration since 1937. As at present, the Niger Delta is covered by a dense grid of 2D and 3D seismic data and well over 5000 oil wells has been drilled across the Delta. Huge quantities of liquid and gaseous hydrocarbon have been recovered from the Niger Delta and vast amount of data concerning the basin has become available, and hence becoming a maturing basin. During the early years of exploration in the Niger Delta, uncertainties existed as to whether the Akata and/or Agbada Formations were the actual source of hydrocarbon in the Delta (Ejedawe, 1981; Ejedawe et al., 1984).

The Akata and Agbada Formations are products of two contrasting depositional environments and as such the organic matter contents are expected to poses different geochemical characteristic. When organic matter is deposited, it undergoes diagenetic processes alongside the sediments in which they are incorporated. The quantity and quality of organic matter preserved during diagenesis of sediments ultimately determines the petroleum-generating potential of the rock.

Various factors play a role in the preservation of organic matter during sedimentation and burial, (Demaison and Moore, 1980; Emerson, 1985; Meyers, 1987), although the relative importance of these factors remains controversial and probably differs between depositional environments (Peters et al. 2005). The geological formations (Akata and Agbada Formation) in the Niger Delta Basin believed to have generated hydrocarbon are characteristically deposited in different depositional settings. While the Agbada is deposited in shallow marine (inner – outer neritic), the Akata is solely of deep marine origin formed in bathyal to basin floor settings. The geochemical integrity of persevered organic matter is to a large extent a function of the environment of deposition in terms of bathymetric constraints, hence organic matter generated in deep water settings have a higher chance of better preservation due to anoxicity (Damaison and Moore, 1980) constraints with a tendency of sourcing liquid hydrocarbon.

Sediments (carbonate and shale) in which appreciable amounts of hydrogen-rich organic matter have been incorporated and that have the potential to generate or have generated significant amount of hydrocarbon are termed petroleum source rocks (Hunt, 1996; Peters et al. 2005). The type of hydrocarbon generated from potential source rocks that have undergone catagenesis is dependent on the kerogen type.

This study examines the hydrocarbon generating potential of organic-rich shale samples from the Akata and Agbada Formations in the Coastal Depobelt, in order to ascertain the maturation state of each formation. Such information would be of importance to researchers and explorationist and also clarify uncertainties regarding the actual source rocks of the Niger Delta oil.

GEOLOGIC SETTING

The Niger Delta Basin is situated in southern Nigeria along the West African coast at the site of a Cretaceous triple junction and lies between longitudes 5° and 8°E and latitudes 3° and 6°N within the coastal area of the Gulf of Guinea and covers an area of about 75, 000km^2 with an overall regressive fill of about 12,000m (Doust and Omatsola, 1990; Reijers, 1996) (Figure 1).

It is the main petroleum province in Nigeria in terms of proven reserves which is currently estimated at 34.5 billion barrels of crude and 93.8 trillion cubic feet of gas. The Niger Delta Basin has built out over a crustal tract on the trailing edge of the African continental margin and adjacent oceanic crust since the Eocene (Evamy et al., 1978) forming successive depobelts that represent the most active portion of the delta at each stage of its development, and can be classified as a marginal sag basin based on the Kingston et al. (1983) basin classification model.

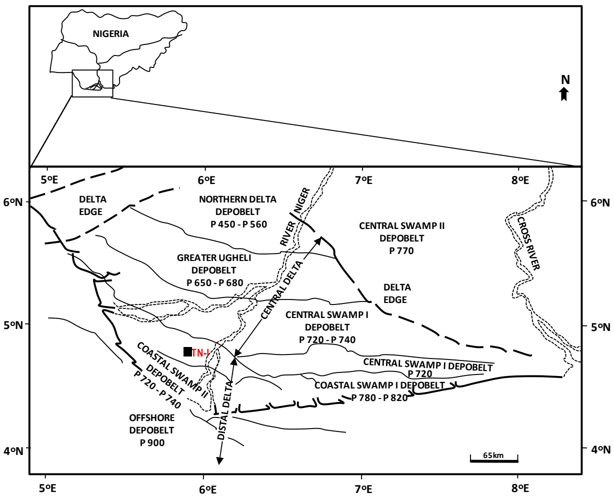


Figure1: Map of the Niger Delta Basin Showing the Various Depobelts (Modified from Doust and Omatsola, 1990).

A three-fold lithostratigraphic age-dichroneous subdivision, into the Akata, Agbada and Benin Formations (Short and Stauble, 1967), reflect the main sedimentary regressive megasequence (Doust & Omatsola, 1989; Morgan, 2003). Although the sedimentary wedge is dominated by prograded material, it contains major transgressive marine sequences that contribute to making its geology complex (Osokpor, 2002, 2013). The Akata Formation which is conventionally viewed as the principal source of hydrocarbon in the Niger Delta has accumulated in deep marine environment and consists of parallel-laminated, basin-floor, pro-delta, over pressured marine mud with an estimated thickness of 3 – 4 km (Doust and Omatsola, 1989; Haack et al., 2000).

The tectonic evolution and setting of the Niger Delta is related to the evolution of the Benue Trough and the tectonic framework of the continental margin along the West Africa equatorial coast, where it is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zones and ridges subdivide the margin into individual basins, and in Nigeria, form the boundary faults of the Cretaceous

Benue-Abakaliki Trough, which cuts far into the West African Shield (Olade, 1975; Tuttle et al. 2006). Subsidence along the north-south oceanic transform fault later controlled the location of the main axis of subsidence of the Niger Delta. The Chain Fault line coincides with the Benin Hinge Line of the Western Niger Delta. Its eastern flank is marked by a similar but more complex feature, the Calabar Flank that is the subsurface continuation of the Oban Massif comprising NW-SE trending structures such as the Ikang Trough, the Ituk High and the Calabar Hinge Line (Whiteman, 1982).

Generally, the evolution of the Niger Delta Basin is controlled by pre- and synsedimentary tectonics as described by Evamy et al. (1978), Ejedawe (1981), Knox & Omatsola (1987) and Stacher (1995). As rifting tectonics diminished in the Late Cretaceous, the Niger Delta was initiated, following which synsedimentary gravity tectonics became the primary deformational mechanism initiated by shale mobility which induced internal deformation. This mechanism has been ascribed to the loading of under compacted and over-pressured prodelta and delta-slope clays (Akata Formation), by higher density delta front sands (Agbada Formation) and delta slope instability induced by lack of lateral, basin-ward support for the under compacted delta-slope clays. The Benin Formation overlying the Delta is not affected by these features, because gravity tectonics has stopped in the five depobelts recognized before the Benin Formation was deposited (Reijers, 2011).

Eocene outcrops occur south of the Benin Flank in the northern fringes of the Delta, while Recent outcrops are along the present coastlines (Short and Stauble, 1967). Surface evidence of Oligocene and Miocene deposits is limited and much of the age determination is uncertain (Whiteman, 1982). The approximate surface boundaries of the Eocene – Recent sediments in the Niger Delta Basin have been indicated in Hospers (1971).

The Niger Delta Basin stratigraphy shows a typical off-lap sequence (Reijers, 2011), broadly divided into three main age-dichroneous lithostratigraphic units as stated above, comprising time equivalent proximal-to-distal prograding facies. The Akata Formation occurs as the bottomset and consists of over 90% prodelta marine shale and less than 10% of sandstone and has an Eocene to Recent age. The Agbada Formation represents the foreset of the Niger Delta and is comprised of delta front lithofacies consisting mostly shore face and channel sand deposits with minor shale in the upper parts and an alternation of sand and shale of almost equal proportion in the lower part. Its thickness ranges from about 3000m to 4500 m, while its age ranges from Eocene to Recent in the northern and offshore areas. The topset Benin Formation is an upper delta plain lithofacies that consists of over 90% massive continental sands and gravels with clay intercalations. It has variable thickness, which generally exceed 2100m and ranges in age from Oligocene – Recent (Whiteman, 1982).

MATERIALS AND METHODS

Sampling and Geochemical Analysis

Detailed geochemical analyses involving total organic carbon (TOC) and Rock-Eval pyrolysis of twenty (20) representative samples from a depth range of 2109 – 4167 m along hole (6920 – 13670 ft), was carried out to determine (and ascertain) maturation state and petroleum generative potential of the sediments retrieved from the well TN-1. Sampling was based on facies characteristics, resolution and intervals of interest.

Total Organic Carbon

Total organic carbon (TOC) (% Corg) was determined using an ELTRA CS800 Carbon and Sulphur determinator as a first step to discriminating potential and non-potential source rock. Sampling for TOC analysis in the well was done based on facies, as it is expected that finer grained facies holds a higher TOC potential (Hunt, 1996; Huc, 1988), and generally 0.5 wt. % and 0.3 wt. % of TOC represent the lower limit for an effective shale and carbonate source rock respectively (Hunt, 1979). Tissot and Welte (1984) had shown that the quantity of oil generated in any given volume of source rock is linearly proportional to its organic carbon content.

In determining the TOC values for the samples, all samples selected for analysis were pulverized using an automated rock pulverizer. Pulverized samples were sieved through a 25 µm sieve and 0.1g of each sample was weighed out (against a standard: 0.1015 – 0.0985 gm) and processed for further analysis. Processed samples were fed into the TOC analyzer and analyzed for fifty second each. The analyses were carried out at the Fugro Robertson Limited (FRL) Petroleum Geochemistry Laboratory in Llandudno, North Wales United Kingdom.

Rock-Eval Analysis

The Rock-Eval analysis involves the pyrolysis of pulverized samples up to 550°C. This technique of evaluating source rock maturity (Espitalie et al., 1977), involves passing a stream of inert gas (helium gas) through 100mg of pulverized rock heated initially at 300°C, programmed to increase at about 25°C/min, up to 550°C.

In analyzing the samples, 100g of each sample due for analysis was pulverized and sieved through a 25µm mesh screen. The required weight of each sample, which is dependent on the TOC value of each sample, was weighed out and analyzed using a Vinci Tech Rock-Eval 6 analyzer interfaced through a Nelson Analytical 760 to an IBM PC/XT computer at the Fugro Robertson Petroleum Geochemistry Laboratory in Llandudno, North Wales United Kingdom.

RESULTS AND DISCUSSION

Organic Richness

The result of the organic matter concentrations for the various samples from the well is shown in Table 1, while the range and average values are shown in Table 2a. TOC values ranges from 1.15 to 16.11 with an average value of 7.39 wt% (Table 2a). The values indicate that all samples satisfied the required threshold value of 0.5 wt% TOC for clastic rocks to generate petroleum, and range from fair to excellent in terms of potential to generate hydrocarbon (Table 3).

The shale from the well is thus classified as having a moderate to high potential, having the capacity to generate petroleum (Dow, 1977; Hunt, 1978; Tissot and Welte, 1984). While the adequate amount of organic matter present in sediments is a vital prerequisite for the generation of hydrocarbon (Conford, 1986), one of the most important factor controlling the generation of hydrocarbon is the quality of organic matter which is a measure of the hydrogen content of the organic matter (Tissot and Welte, 1984; Hunt, 1979; North, 1985; Jarvie, 1991).

The soluble/extractible organic matter (SOM) of the samples ranges from 290 to 56,729, with an average value of 20,528 (Table 4). These figures indicate that the shales from the lower sections of the well (Figure 2) have source rocks with good potentials to generate hydrocarbon (Peters and Cassa, 1994) and classed as adequate by Hunt and Meinert (1954).

Organic Matter type (Kerogen Quality)

The values of rock-eval parameters S_1, S_2 and S_3, are shown in Table 1. S_1 represents any free hydrocarbons in the rocks and accounts for the material in the C_7 – C_{32} range that either was present at the time of deposition or was generated from the kerogen since deposition, excluding heavy molecular weight resin and asphaltene fractions which are liberated during higher temperatures of S_2 cycle (Hunt, 1978; Peters, 1986; Miles, 1989).

The S_1 values for the well, range from 0.15 – 10.04, with an average value of 1.86 (Table 2). Comparing these data with the general criteria for describing the potentials of source sediments (Peters and Cassa, 1994), 30% of the samples is classed as poor, 10% as fair, 30% as good, 20% as very good while 10% as excellent (Figure 3).

The S_2 values of the samples range from 0.79 – 107.7 with an average value of 39.39 (Table 2). The S_2 represents the fraction of the genetic potential, i.e. the residual potential which has not yet been used to generate hydrocarbons. It is generated by cracking the kerogen until only residual non-generating carbon remains and thus provides a measure of the source rock organic matter to generate further hydrocarbons (Tissot and Welte, 1984; Hunt, 1978).

When compared with the general criteria of Peters and Cassa (1994), 10%, 5%, 15% and 60% of the samples are classed as poor,

Table 1: Measured Total Organic Carbon (TOC), Rock-Eval Pyrolysis Parameters, and Calculated Vitrinite Reflectance (Rc) of Selected Intervals from Well TN-1, Western Niger Delta.

Geologic Unit	S/N	DEPTH (FT)	DEPTH (M)	S1	S2	S3	Tmax°C	HI	OI	PI	TOC^X wt %	S1/TOC	S1 + S2	S2/S3	R_c
Agbada	1	6920	2109	0.17	0.76	3.06	424	65	262	0.18	1.17	0.15	0.93	0.25	0.47
Agbada	2	7370	2246	0.15	0.71	2.70	416	62	235	0.17	1.15	1.00	0.86	0.26	ND
Akata	3	11,000	3353	10.04	96.11	5.02	430	671	35	0.10	14.32	0.70	106.15	19.15	0.58
Akata	4	11,480	3499	0.3	8.11	1.88	429	381	88	0.04	2.13	0.14	8.41	4.31	0.56
Akata	5	11,510	3508	0.17	3.25	1.43	425	141	62	0.05	2.30	0.07	3.42	2.27	0.49
Akata	6	11,780	3591	2.66	93.6	3.50	429	586	22	0.03	15.96	0.17	96.22	26.73	0.56
Akata	7	11,810	3600	2.45	72.3	2.36	431	609	20	0.03	11.87	0.21	74.79	30.65	0.60
Akata	8	11,900	3627	2.22	77.00	3.02	429	607	24	0.03	12.68	0.18	79.17	25.48	0.56
Akata	9	12,020	3664	1.33	35.32	1.75	431	461	23	0.04	7.67	0.17	36.65	20.18	0.60
Akata	10	12,230	3728	3.09	41.58	2.14	428	622	32	0.07	6.68	0.46	44.67	19.42	0.54
Akata	11	12,290	3746	5.65	107.7	3.28	428	668	20	0.05	16.11	0.35	113.32	32.83	0.54
Akata	12	12,320	3755	1.14	28.00	2.19	428	230	18	0.04	12.16	0.09	29.13	12.78	0.54
Akata	13	12,680	3865	0.43	11.00	1.71	429	312	49	0.04	3.52	0.12	11.41	6.42	0.56
Akata	14	13,010	3965	0.55	15.00	2.09	430	398	56	0.04	3.76	0.15	15.53	7.17	0.58
Akata	15	13,130	4002	1.53	46.11	2.20	430	575	27	0.03	8.02	0.19	47.64	20.96	0.58
Akata	16	13,160	4011	1.67	47.50	2.42	428	571	29	0.03	8.31	0.20	49.12	19.61	0.54
Akata	17	13,430	4093	0.51	15.80	1.46	430	392	36	0.03	4.02	0.13	16.26	10.79	0.58
Akata	18	13,550	4130	1.19	29.80	2.55	428	515	44	0.04	5.78	0.21	30.97	11.68	0.54
Akata	19	13,640	4157	0.23	3.80	1.60	431	196	83	0.06	1.92	0.12	4.020	2.37	0.60
Akata	20	13,670	4167	1.74	54.40	2.28	431	660	28	0.03	8.24	0.20	56.12	23.85	0.60

(TOCX = Measured TOC, ND = Not Determined, Rc = Calculated Vitrinite Reflectance)

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

PYROLYSATES	WELL TN-1	
	Range	Average
S_1 (mg/g)	0.15 – 10.04	1.86
S_2 (mg/g)	0.79 – 209.27	46.62
S_3 (mg/g)	1.43 – 5.02	2.43
Tmax (°C)	416 - 431	428
Derivatives		
GP (mg/g)	0.86 – 219	48.48
PI	0.03 – 0.18	0.05
HI (mgHC/gTOC)	62 – 1461	499
OI	18 – 262	60
R_c	0.47 – 0.6	0.56
Organic matter concentration parameters		
TOC^X (wt %)	1.15 – 16.11	7.39
SOM (PPM)	290 – 56, 729	20, 528
BR (mg Extract/g TOC)	0.25 –10.50	3.44

Table 2b: Results of Extraction of Soluble Organic Matter for Well TN-1.

Sample No.	S.O.M (ppm)	TOC (Wt.)	S.O.M/TOC (mg extract/gTOC)
TN-1 2109	290	1.17	0.25
TN-1 2192	923	3.12	0.30
TN-1 2246	947	3.11	0.30
TN-1 2356	1, 025	1.87	0.55
TN-1 2438	1, 132	3.37	0.34
TN-1 2502	1, 610	2.98	0.54
TN-1 2548	7, 428	2.63	2.82
TN-1 3499	22, 342	2.13	10.50
TN-1 3627	56, 621	12.68	4.50
TN-1 4011	48, 644	8.31	5.85
TN-1 4130	48, 640	5.78	8.42
TN-1 4167	56, 729	8.24	6.89
MEAN	20, 528		3.44
RANGE	290 – 56,729		0.25 – 10.50

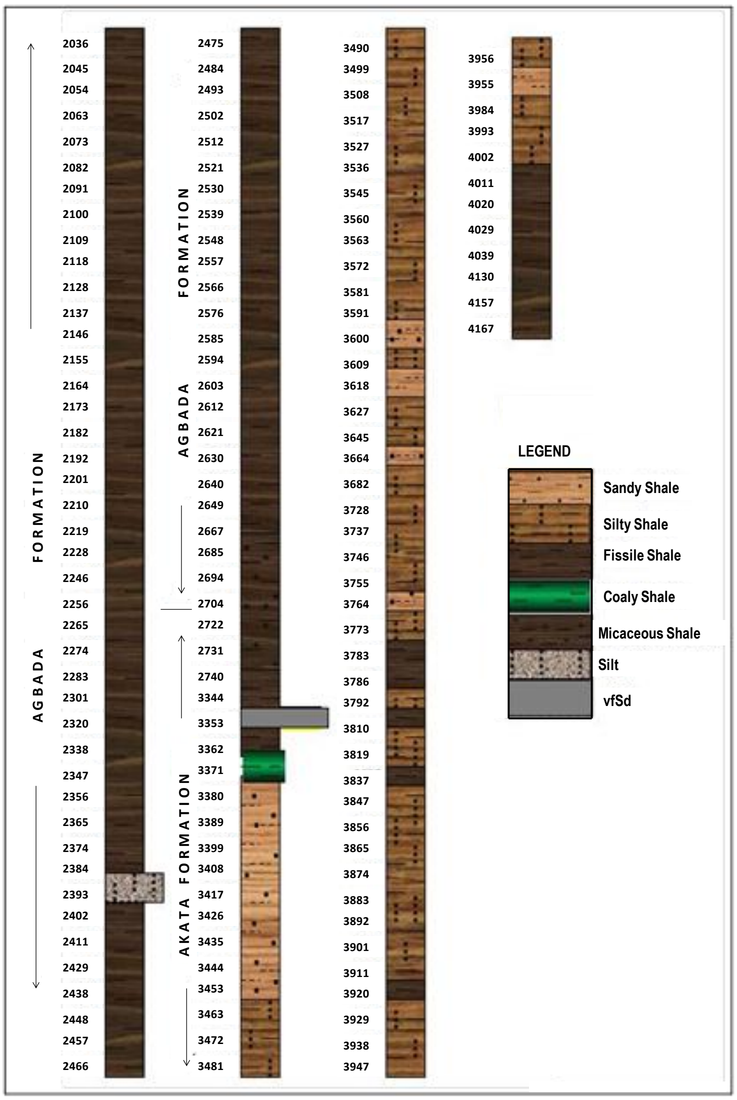
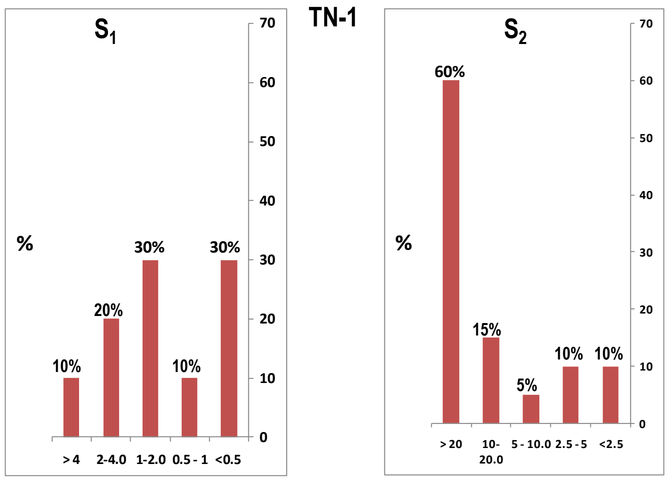
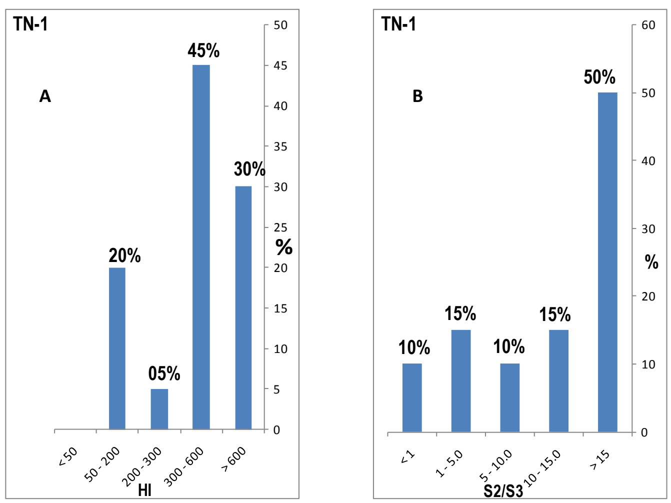


Figure 2: Lithostratigraphic Section of Well TN-1.



S_1: <0.5 = poor, 0.5-1.0 = fair, 1-2.0 = good, 2-4.0 = very good, >4 = excellent
S_2: <2.5 = poor, 2.5-5 = fair, 5.0-10 = good, 10-20 = very good, >20 = excellent

Figure 3: Comparative Pyrolysis S1 and S2 Values from Well TN-1 with the General Criteria for Describing Source Rock Potentials (Modified after Peters and Cassa, 1994).



> 600 = I, 300 – 600 = II, 200 – 300 = II/III, 50 -200 = III
< 50 = IV

> 15 = I, 10 – 15 = II, 5 – 10 = II/III, 1 - 5 = III, < 1 = IV

Figure 4: Comparative Pyrolysis HI and S2/S3 Values From Well TN-1 with the General Criteria for Describing Source Rock Potentials (Modified after Peters and Cassa, 1994).

good, very good and excellent, respectively against 30%, 30%, 20% and 10% derived from S_1 based classification (Figure 2), while the 10% derived for the fair category remained unchanged.

The hydrogen index (HI) ranges from 62 – 671 mgHC/gTOC (Table 2), and have an average value of 436.1 mgHC/gTOC. The range of HI values points to types I, II and III kerogen. Four samples (TN2109, TN2246, TN3591 and TN4157) have HI values of 65, 62 141 and 196 mgHC/gTOC, respectively (Table 1), indicating gas prone source material. All other samples from this well have HI values ranging from 230 to 671 mgHC/gTOC above the 200 mgHC/gTOC benchmark for gas prone organic matter, thus indicating that the kerogen are capable of generating oil and gas (Hunt, 1979; Peters, 1986; Bordenave, 1993).

Evaluating the distribution of the kerogen type from the HI values, 20% are classed as type III, 5% as type II/III, 45% as type II, while 30% are type I (Figure 4a). The oil prone types make up 75% of the total kerogen present in the well, while 25% accounts for oil and gas generative types. This shows that the sediments from the well have a far higher potential to generate liquid hydrocarbon than gas. Cross plot of HI versus OI (Figure 5) confirms the kerogen classification (type I, II, III) derived from the HI values above. The plot of Hydrocarbon potential versus TOC.

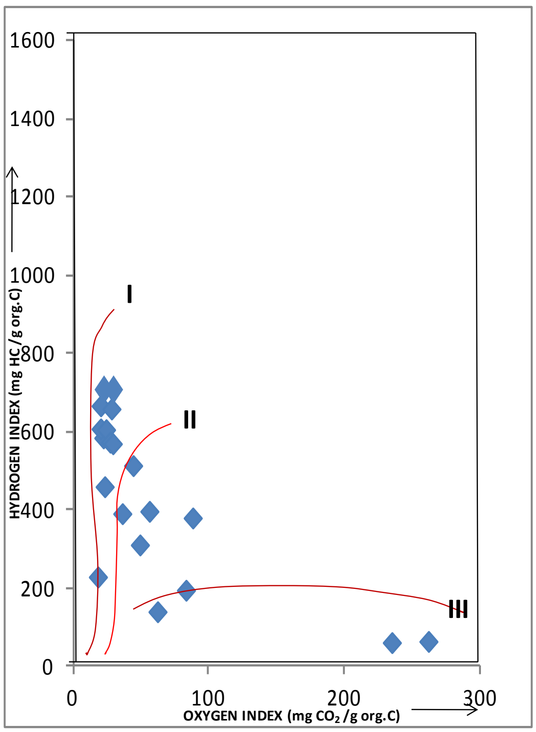


Figure 5: Cross Plot of Hydrogen Index (HI) Versus Oxygen Index (OI) Showing the Various Kerogen Types Present in Well TN-1, (Modified after van Krevelen, 1961).

Figure 6 further confirms that the shale samples from well TN-1 have potential to generate more oil than gas. Further oil generative potential of these samples were confirmed by plotting HI versus T_{max} (Figure 7), which shows that majority of the values plot within the oil prone domain (Peters, 1986).

The S2/S3 values ranged from 0.25 to 32.83, with an average value of 14.86 (Table 2). Fifty percent (50%) of these values are above 15, and thus are classed as type I kerogen.

Fifteen percent (15%) each range between 10 and 15 and between 1 and 5, and are classed as types II and III kerogen, while those classed as types II/III and IV make up 10% each (Figure 4). These interpretations are consistent with standards of Peters (1986) and Peters and Cassa (1994).

A summation of generic forms shows that 65% of the kerogen is oil prone, 10% is oil and gas prone, 15% gas prone, while 10% is composed of inert materials. A 20% and 5% up-scaling, 30% and 5% down-scaling is observed for the types I, II/III, and types II and III kerogen species with an introduction of a 10% inert class, when compared with the percentage distribution derived from the HI evaluations. In general this interpretation is consistent to a large extent with those derived from the HI interpretations above, but with a total 10% down scaling of the mainly oil prone and an introduction of 10% inert kerogen species, while the oil and gas prone (type II/III) species remained unchanged.

Source richness plots of HI versus TOC (fig. 7) indicate that over 50% of the samples plot within the oil-prone fields, about 40% plot in the fair oil field, while less than 10% of the sample plots within the gas source rock field.

Thermal maturity (T_{max})

Measured thermal maturity provides an indication of source rock maturity. This factor is influenced by source rock characteristics such as compositional organic matter type and the presence of excess free hydrocarbon coupled with such factors like mineral matter content, depth of burial and age of sediments (Tissot and Welte, 1984).

The evolutionary thermal maturity of the sediments from the well was deduced from the T_{max} (°C), production index (PI) and calculated vitrinite reflectance (%R_c). The T_{max} values for the well (Table 2a) range from 416 to 431°C with an average of 428°C. These indicate that the shales range from immature to transitionally early mature, but on the average are immature in line with interpretations given by Dow (1977), Peters (1986) and Miles (1989).

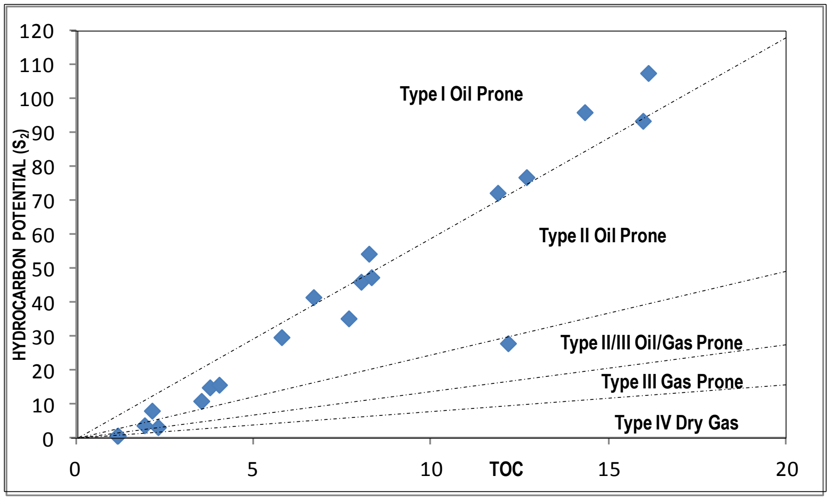


Figure 6: Cross Plot of Hydrocarbon Potential Versus TOC for Well TN-1 Showing Hydrocarbon Generative Potential of the Various Kerogen Types Present in the Samples.

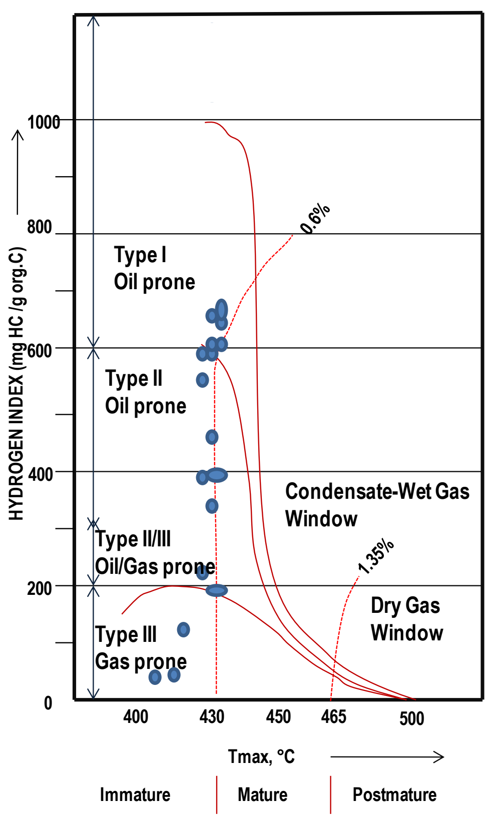


Figure 7: Plot of Hydrogen Index (HI) Versus Tmax for Well TN-1, Showing the Kerogen Types and their Respective Hydrocarbon Generative Potentials (Modified after Mukhopadhyay et al. 1995).

A cross plot of HI versus T_{max} (Mukhopadhyay et al. 1995) (Figure 8) further highlighted the state of maturity of the sediments. Applying the Mukhopadhyay et al. (1995) maturation model in which the upper temperature limit of early hydrocarbon generation is set at 430°C in contrast with 435°C advanced by Peters and Cassa (1994), the maturity window is seen to adjust upward to accommodate two samples from two depth intervals (4157 m and 4167 m) with R_c of 0.6 and T_{max} of 431°C each, as mature, thus can be said to have generated hydrocarbon. Based on HI value of 196 mgHC/gTOC, (composed of type III kerogen), sediments from 4157m ah may have generated gas, while those from 4167 with HI value of 660 mgHC/gTOC, composed of type I kerogen, may have generated oil.

The production index (PI), range from 0.03 to 0.18 with 0.05 as an average value, (Table 2). The PI data for the well show abnormal trends in deviation from expected trend as noted by Baker (1972). Cross plots of the PI versus depth, show a good correlation of 80.37% (Fig. 8), but with PI values decreasing with depth. According to Baker (1972) and Peters and Cassa (1994), PI value of pyrolysates increases with depth, implying that an increase in PI is mainly due to thermal cracking of kerogen and to a lesser extent, to thermal vaporization and cracking of asphaltenes which causes the S_2 signal to progressively transform to S_1.

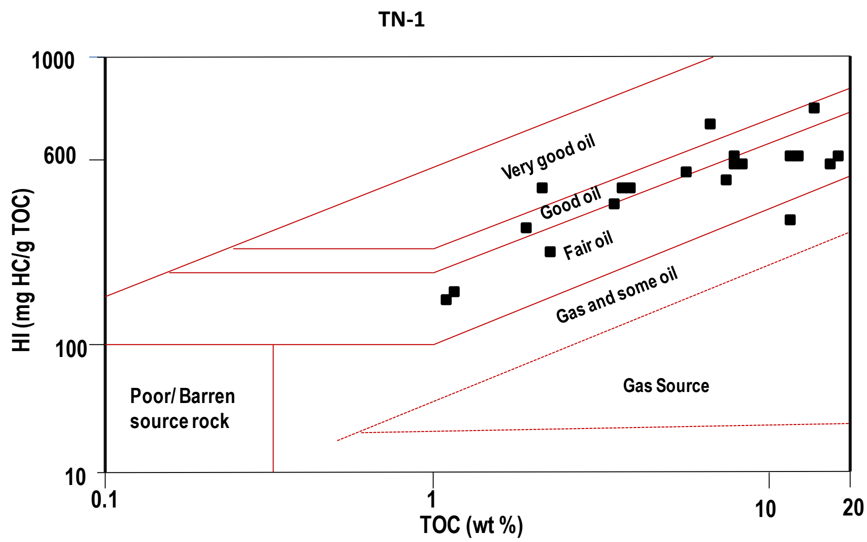


Figure 8: Source Richness Plots for Sediments of Well TN-1, Western Niger Basin (Adapted from Jackson et al. 1985).

The PI trends from the well interval is here interpreted as probably due to the effect of impregnation that emanated from the migration of generated hydrocarbons from deeper stratigraphic levels in the basin which, have thus masked the true signal expected from the samples.

Calculated vitrinite reflectance values (Jarvie et al. 2001b) range from 0.47 to 0.6, with an average value of 0.56 (Table 2a). A reflectance value of 0.6 was attained at 4156 m below the surface (Table 1). This value correlates with the upper limit of early thermal Immaturity of Peters and Cassa, 1994 (Table 3), thus placing the oil generating window at a depth below 4156 m, hence the sediments at deeper horizons may have generated hydrocarbons.

Cross plot of T_{max} versus R_c for the well (Figure 9), revealed a very high linear correlation (R^2) of 99.73% for the well section. Similar linear correlation trend was observed in type III kerogen and humic coals from the Douala Basin, Cameroun by Teichmuller and Durand (1983).

Although calculated vitrinite values for the lower section of the well attained the R_c 0.6 (Table 3), expected for the upper limit of early maturity (Peters and Cassa, 1994), the corresponding T_{max} values (431°C) for these depth interval fell short of the minimum value (435°C) designated as the onset of maturity (Peters and Cassa, 1994) (Table 3C).

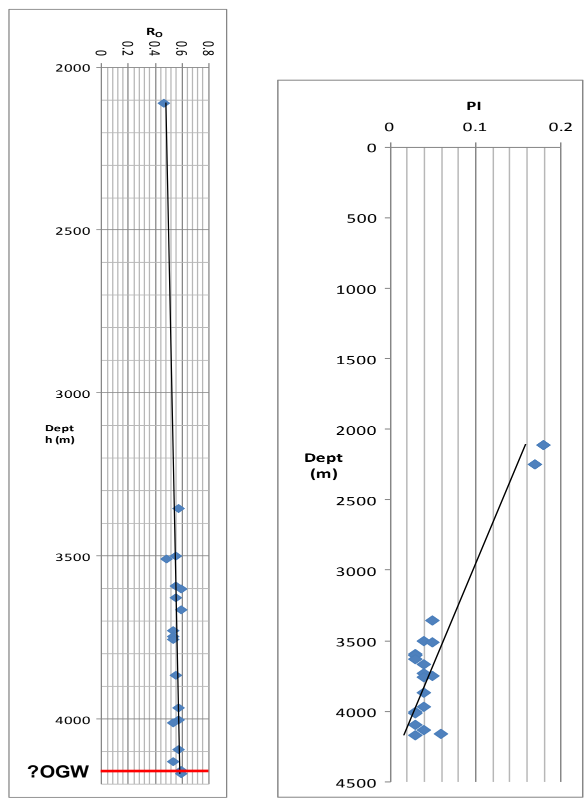


Figure 9: Cross Plot of Calculated Vitrinite Reflectance (R_c) Versus Depth and Production Pndex (PI) for Well TN-1 Showing the Depth in Meters of the Oil Generating Window (OGW) at R_c Values of 0.60 and the Anomalous PI Trend for Well TN-1.

Table 3: Comparative Source Rock Evaluation Parameters for Well TN-1 (After Peters and Cassa, 1994).

(A)

Source Rock Potential									
Potential (quantity)	TOC (wt. %)	TN-1 (%)	S1	TN-1 (%)	S2	TN-1 (%)	Bitumen (ppm)	TN-1 (%)
Poor	<0.5	0	<0.5	30	<2.5	10	<500	8.3
Fair	0.5 – 1	0	0.5–1	10	2.5–5	10	500-1000	16.7
Good	1 – 2	15	1–2	30	5–10	5	1000-2000	25
Very Good	2 – 4	20	2–4	20	10–20	15	2000-4000	0
Excellent	> 4	65	> 4	10	>20	60	>4000	50

(B)

Source Rock Quality					
Kerogen (quality)	Hydrogen Index(mg HC/gTOC)	TN-1 (%)	S2/S3	TN-1 (%)	Main product at peak maturity
I	>600	30	>15	50	Oil
II	300 - 600	45	10 – 15	15	Oil
II/III	200 - 300	5	5 – 10	10	Oil/gas
III	50 - 200	20	1 – 5	15	Gas
IV	< 50		< 1	10	None

(C)

MATURATION				
Maturity	R_o (%)	TN-1 (%)	T_{max} (°C)	TN-1 (%)
Immature	0.20 – 0.60	100	< 435	100
Mature:				
Early	0.60 – 0.65	0	435 – 445	0
Peak	0.65 – 0.90	0	445 – 450	0
Late	0.90 – 1.35	0	450 – 470	0
Post-mature	> 1.35	0	> 470	0

Evaluating the hydrocarbon generating potential of the well section based on Peters and Cassa, (1994) T_{max} model for hydrocarbon generation, the T_{max} values for the well section indicates that the sediments within the objective interval of study has not generated hydrocarbon. At a depth of 1000 m below the base of the Agbada Formation within the Akata Formation, the Akata Formation has barely entered the oil generating window, it is obvious that the Agbada Formation present at a higher stratigraphic level could not have generated hydrocarbon contrary to views and uncertainties across the academic and earth science community.

CONCLUSION

Rock-Eval pyrolysis studies of well TN-1 in the western Niger Delta Basin show that the sediments have adequate organic matter composed mainly of type I and II kerogen and thus have good hydrocarbon generating potential.

Although it is widely believed that the Agbada Formation may have generated hydrocarbon, hence viewed by many as one of the source of the oil resource in the Niger Delta, maturity indices from this study has shown overwhelmingly that the Agbada Formation has not entered the oil-generating window, hence is immature. At the interface depth between the Agbada and Akata Formations, a T_{max} of < 430°C and *Rc* <0.60 was attained.

The Akata Formation on the other hand, showed positive indication of maturation at depths ranges below 4167 m subsea, thereby pointing to the formation as the sole source rock in this area of the basin.

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