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Determination of Organic Matter Richness for Agbada Formation, Osioka South Area, Western Niger Delta, Nigeria

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ABSTRACT
The study determined organic richness of Agbada formation located in the Osioka area of Western Niger Delta. Thirty (30) Core samples from a well in Oil Mining Lease, OML 65 were subjected to geochemical analysis to determine the total organic carbon content (TOC) and soluble organic matter (SOM) levels. The TOC values were between 1.60w% - 1.80w% with a mean value of 1.6503w%, while the SOM values ranged from 0.0027% to 1.514894% with a mean value of 0.3347%. The values were above the standard minimum threshold of source rock hydrocarbon generation potential. The minimum threshold TOC value in the Niger Delta is 0.5% compared to higher values obtained from the Agbada formation. The mean SOM value of 0.3347% was also indicative of good hydrocarbon source rock potential for the 30 core samples studied. The transformation ratio (TR) was 0.1969 compared to the minimum threshold value of 0.16. The core samples from the studied depth slice were therefore regarded as good organic matter richness for hydrocarbon source rock.

Keywords: *Agbada formation, core samples, hydrocarbon source rocks, organic matter richness.*

1. INTRODUCTION

The Niger Delta is considered among the world's best studied delta provinces. There are three lithostratigraphic units recognized in the Niger Delta namely Akata, Agbada and Benin Formations [1]. Source rock of the Niger Delta hydrocarbon has been a subject of controversy. [1] and [2] proposed the shale of the paralic Agbada Formation as the source rocks, while [3] and [4] argued that in most parts of the delta, the Agbada Formation is immature and suggested the source rock to be the marine shale of Akata Formation which are more matured. There has been much discussion about the source rock for petroleum in the Niger Delta (e.g. [5]; [6]; [7]; [8]; [9]; [10]). Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation and the marine Akata shale, and a Cretaceous shale ([3]; [5]; [11]; [7]; [4]; [8]; [10]; [12]; [13]; [14]).

The Agbada Formation has intervals that contain organic-carbon contents sufficient to be considered good source rocks (see data in [7]; [15]). The intervals, however, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the delta ([5]; [12]).

Based on organic-matter content and type, [5] proposed that both the marine shale (Akata Formation) and the shale interbedded with paralic sandstone (lower Agbada Formation) were the source rocks for the Niger Delta oils.

[9] in a detailed source-rock study on side-wall core and cuttings from the Agbada-Akata transition or uppermost Akata Formation, concluded that there are no rich source rocks in the delta. With respect to oil potential, Bustin claims that the poor source-rock quality has been more than compensated by their great volume, excellent migration pathways, and excellent drainage. The oil potential is further enhanced by permeable interbedded sandstone and rapid hydrocarbon generation resulting from high sedimentation rates. The total organic-carbon (TOC) content of sandstone, siltstone, and shale in his study is essentially the same (average of 1.4 to 1.6% TOC). The content, however, seems to differ with age of the strata—a trend of decreasing content with decreasing age (average of 2.2% in the late Eocene compared to 0.9% in Pliocene strata). Bustin's Eocene TOC average compares well with the averages of 2.5% and 2.3% obtained for Agbada-Akata shales in two wells [16]. [7] report TOC values from 0.4 to 14.4% in the both onshore and offshore paralic sediments. [15] report values as high as 5.2% in paralic shales from the western part of the delta. The higher TOC contents are limited to thin beds and are only easily recognized in conventional cores ([10]).

The aim of this study was to determine the organic matter richness for Agbada Formation in terms of amount of organic carbon content and extractable organic matter from a depth slice within Oil Mining Lease, OML 65, in the Osioka area of the Niger Delta region using thirty (30) core samples. Figure 1 shows the location map of the studied area.

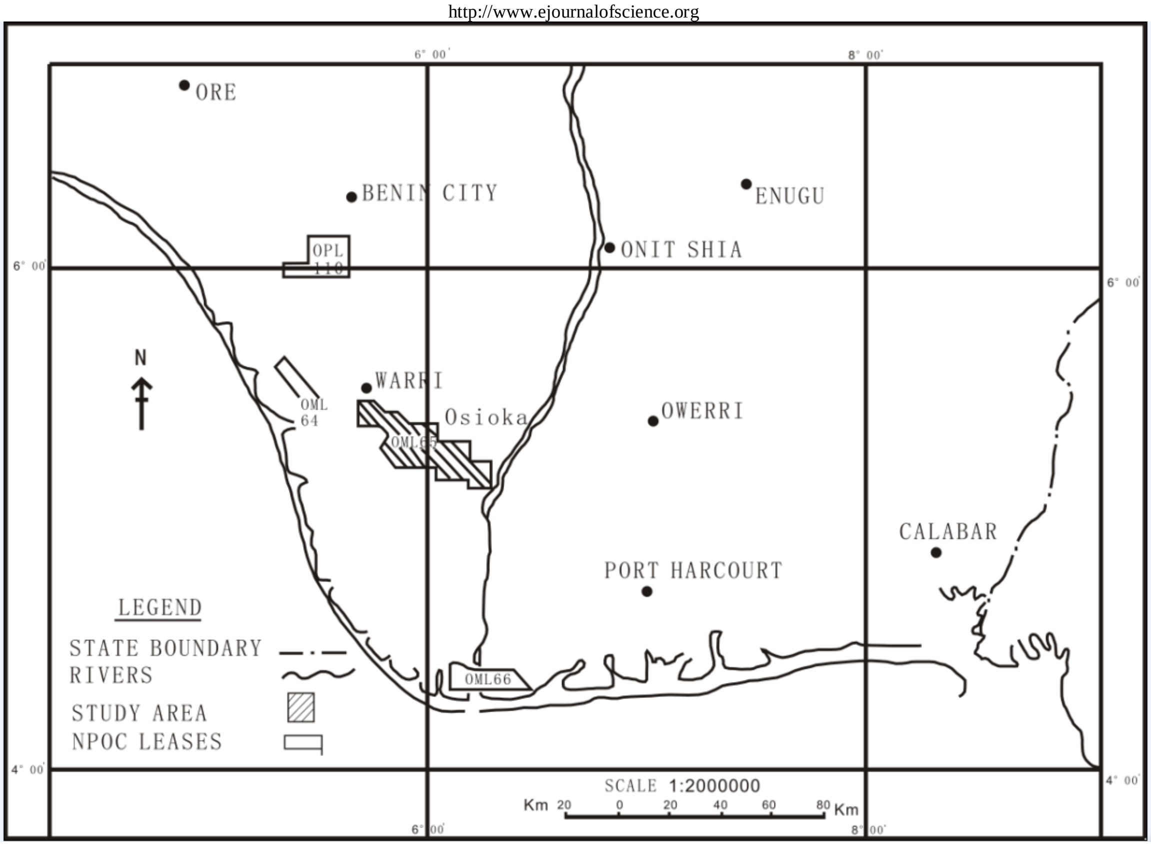

Fig 1: Location Map of study Area

1.1 Geology of the Niger Delta

The Niger Delta, situated at the apex of the Gulf of Guinea on the west coast of Africa, covers an area of about 75 000 km^2. The geology of the tertiary Niger Delta province has been described by several workers ([1]; [17]; [3]; [18]; [5]; [10]; [19]). Basement tectonics related to crucial divergence and translation during the late Jurassic and Cretaceous continental rifting probably determined the original site of the main rivers that controlled the early development of the Delta. The Cenozoic development of the delta is also believed to have taken place under approximate isostatic equilibrium. The main depocenter is thought to have been at the triple junction between the continental and oceanic crust where the delta reached a main zone of crustal instability. The Niger Delta is a large arcuate delta of the destructive, wave-dominated type and is composed of an overall regressive clastic sequence which reaches a maximum thickness of about 12 km in the basin centre.

The Delta's sediments show an upward transition from marine pro-delta shales (Akata Formation) through a paralic interval (Agbada Formation) to a continental sequence (Benin Formation). These three sedimentary environments, typical of most deltaic environments, extend across the whole delta and ranges in age from early tertiary to resent. A separate member, the Afam clay member, of the Benin formation is recognized in the eastern part of the delta and is considered as an ancient valley fill formed in Miocene sediments. The formations are strongly diachronous [20] and cut across the time stratigraphic units which are characteristically S-shaped in cross-section. Most economically exploitable hydrocarbon in the delta is believed to be trapped within the Agbada formation. Virtually all the hydrocarbon accumulations in the Niger Delta occur in the sands and sandstones of Agbada Formation where they are trapped by rollover anticlines related to growth fault development ([21]; [22]; [23]).

2. METHODOLOGY

2.1 Sample Preparation

The thirty (30) core samples were recovered from an interval of an appraisal well within the Osioka south area of the Western Niger Delta. The core samples were selected and oven dried and grounded. The core samples were subjected to a geochemical analysis in order to determine their organic matter richness and subsequently their petroleum generation potential.

2.2 Method of Evaluation

The evaluation process involved analysis and interpretation of source rock parameters such as the amount of organic carbon content and extractable organic matter, in order to determine the organic richness of the studied core samples. The core samples were recovered from an interval of an appraisal well within the Osioka area of the Western Niger Delta complex.

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2.2.1 Determination of Total Organic Carbon (TOC) Content

The samples were added to a mixture of H_2SO_4 and aqueous Potassium dichromate ($K_2Cr_2O_7$). After complete oxidation from the heat of solution and external heating, the excess $K_2Cr_2O_7$ (in oxidation) was titrated against ferrous ammonium sulphate. The difference between initial and residual $K_2Cr_2O_7$ is a measure of organic content of sample.

2.2.2 Extraction and Fractionation of Soluble Organic Matter (SOM) from the core samples

This was done to determine source rock potential, maturity and depositional environment. The significance of this was that extraction and the determination of yield of soluble organic matter (SOM) allowed for identification of hydrocarbon rich sediments, while the ratio of soluble organic matter (SOM) to the total organic carbon (TOC) giave an indication of the maturity status of hydrocarbon generating potential of the source rock.

2.2.3 Transformation Ratio

The transformation ratio was investigated as a comparative measure between the values of SOM and those of TOC. It was expressed as the ratio of the extractable soluble organic matter to total organic content (SOM/TOC). It served as a quantitative analysis index of maturity and was used to determine the level of maturity of the sediments to produce hydrocarbons.

3. RESULTS

3.1 Total Organic Carbon Content (TOC)

The total organic carbon content (TOC) of the thirty (30) core samples analyzed ranged between 1.60wt% - 1.80wt% with a mean value of 1.6503%. Figure 2 shows the titre and TOC as a function of depth of sample. For detail of the titre and TOC value see appendix 1. From Figure 2, there was fairly general increase in TOC as depth of burial increased. Similarly, as depth of burial increased, there was a general increase in titre values between depths of burial 2770m and 2800m and almost remained constant between depths of burial 2800m and 2920m.

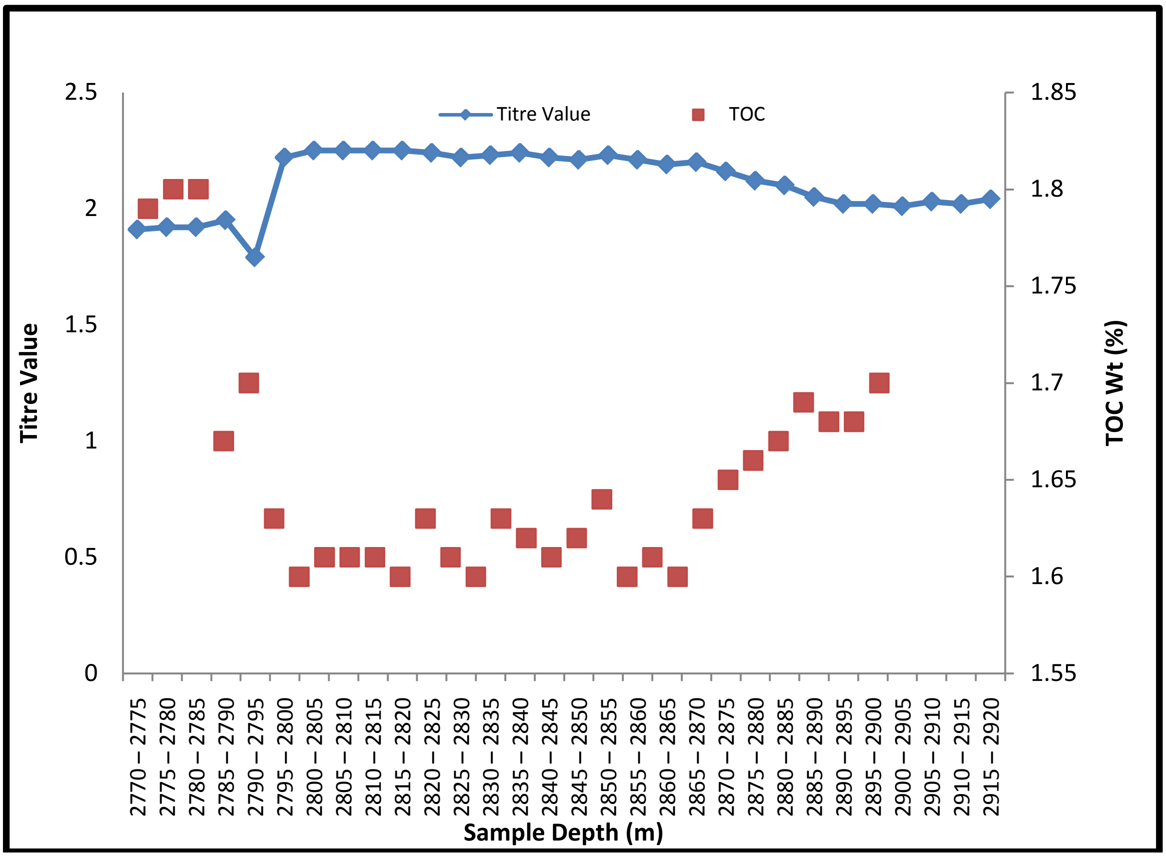

Fig 2: Titre Value and TOC as a function of depth

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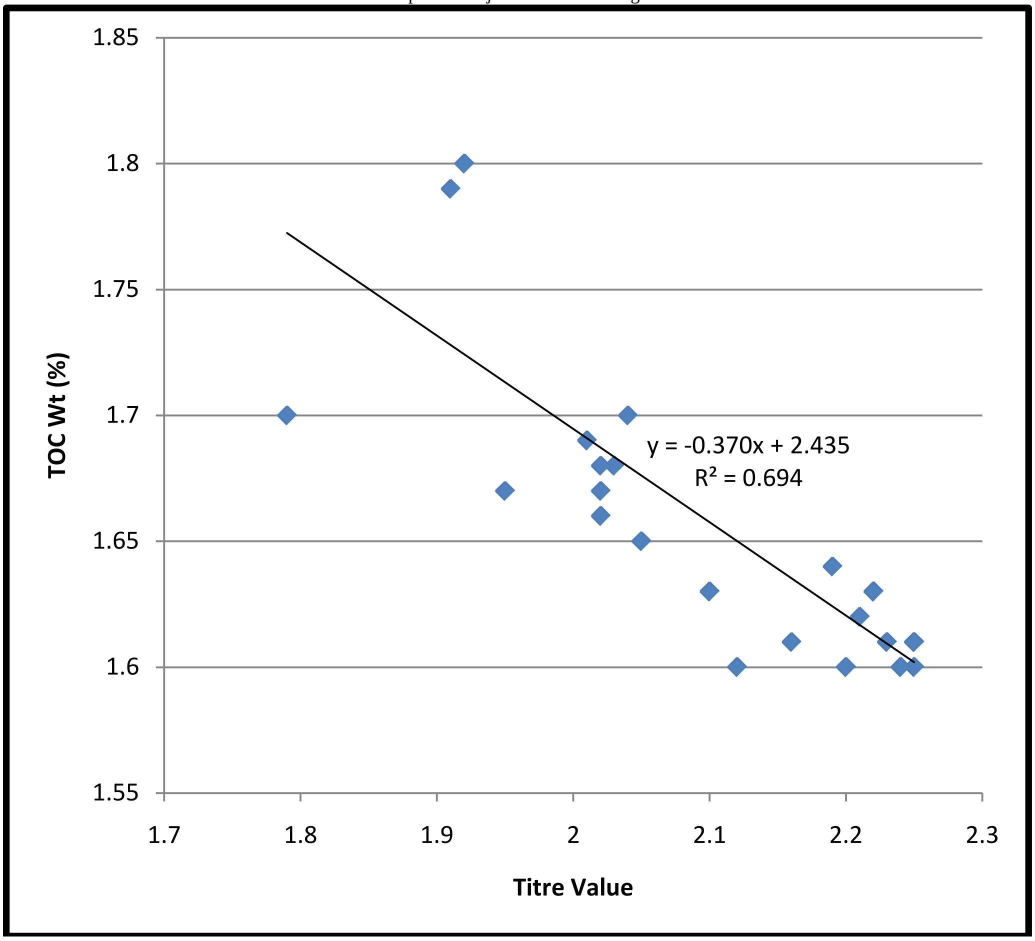

Fig 3: TOC as function of Titre Value

From figure 3, it was revealed that there was a strong correlation between TOC and titre values since $R^2 = 0.694$. The total organic carbon content for the 30 well core samples analyzed ranged between 1.60% - 1.80% with an average TOC value of 1.6503wt%. These values are in agreement with the 0.4 – 4.4% range previously reported by [7] for the Agbada Formation in the Niger Delta. It has been established from various studies that TOC of 0.5% is the standard minimum threshold value for source rock to generate hydrocarbon. Therefore an average TOC value of 1.6503% for the 30 samples studied was well above the minimum threshold for hydrocarbon source rock generation.

[24] stated that the ability of a rock to generate and expel hydrocarbon is dependent on the quantity of organic matter present. The quantity of organic matter present in a rock can be evaluated and classified using the total organic carbon content (Philip et al, 1986) as indicated in Table 2.

Table 1: TOC and corresponding source rock grade

TOC (WT %)	Source Rock Grade
< 0.5%	Poor
0.5% - 1.0%	Fair
> 1.0%	Good

From the data in Table 1, it was deduced that all the 30 samples analyzed had total organic carbon content greater than the threshold value of 0.5%. Hence, the source rock was rated as good organic richness and hence good for hydrocarbon generation.

3.2 Extractable Soluble Organic Matter (SOM)

The thirty (30) samples were subjected to extractable soluble organic matter (SOM) analysis and the values obtained are shown in appendix 2. Figure 4 shows the relationship between SOM, weight of extract and sample depth.

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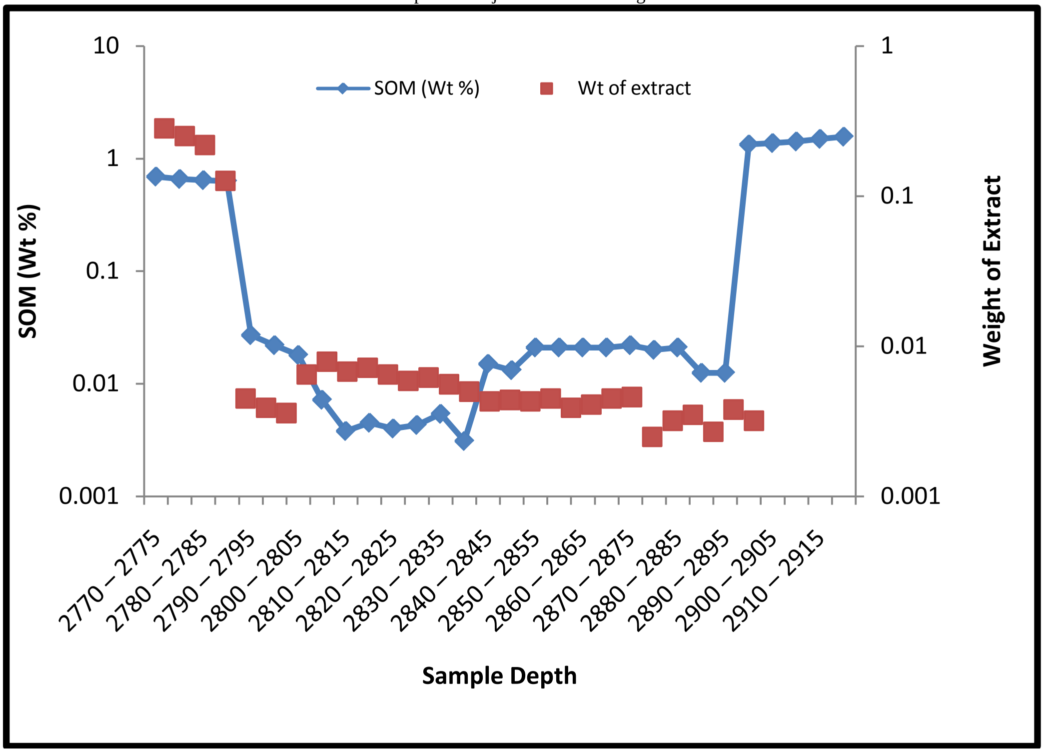

Fig 4: SOM and Weight of Extract as a function of Sample Depth

From Figure 4, the extractable soluble organic matter (SOM) showed a pattern similar to that of the total organic carbon content in appendix 2. The SOM values increased with depth of burial. The value of SOM ranged from 0.0027% to 1.5148% with an average of 0.3347%. [25] have shown that soluble organic matter content in the range of 0.15% - 3.36% is high. The average SOM value for the 30 core samples analyzed was within this range and thus interpreted as having high organic matter richness and hence good for hydrocarbon generation.

3.3 Transformation Ratio (TR)

Figure 5 compared the TOC, SOM and TR values for 30 samples analyzed. There was a fairly general increase in TOC, SOM and TR as depth of burial increased. From figure 5, the mean transformation ratio was 0.1969. According to [25], values of transformation ratios between 0.002 and 0.016 indicate no hydrocarbon source rock generation and that the standard threshold value of transformation ratio is 0.16. The mean transformation ratio of 0.1969 was far above the standard threshold value required for hydrocarbon source generation, implying that the core samples were good in organic matter richness and hence good hydrocarbon source rocks. For details of the TOC, SOM and TR values obtained see appendix 3. From Figure 6, there was a fairly general increase in SOM and TR values as the TOC values increased.

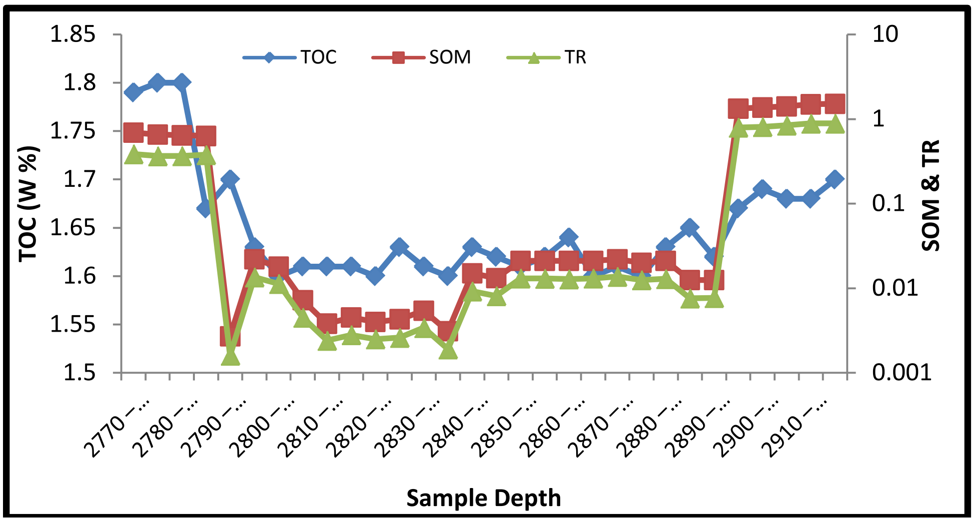

Fig 5: TOC, SOM, and TR as a function of Sample Depth

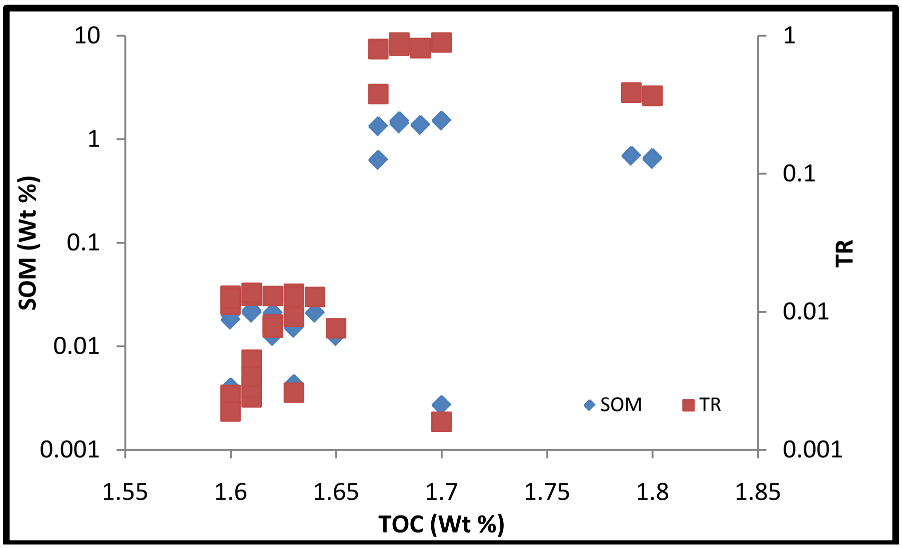

Fig 6: SOM and TR as a function of TOC

4. DISCUSSIONS

Two criteria viz. organic matter richness and degree of maturation were used for the determination of the hydrocarbon source rocks. Determination of organic richness was based on the amount of organic carbon content and extractable organic matter. Total organic carbon content ranging from 1.60w% - 180wt%m with a mean value of 1.6503 % were relatively high and was within the range expected in the Niger Delta area [6]. The extractable organic matter also tends to increase as the depth of burial increased. The values obtained were interpreted to be high (SOM values of 0.0027% - 1.5148%, mean value of 0.3347%). The transformation ratio (TR) values were observed to fluctuate with highest value recorded at 2915m-2920m depth. The ratio SOM/TOC in the sediments was a measure of the transformation of kerogen into hydrocarbon. It was low in immature sediments, but increased sharply in mature ones [26]. Although initially, high values at 2770m-2790m depth were recorded, this decreased and then rose sharply at 2895m-2900m depth. This suggested that the sediment penetration probably vary from immature at the top to mature at depth. [25] have stated that values between 0.002-0.016 indicated no hydrocarbon source rock generation. The mean value of TR for the 30 studied core samples exceeded this threshold. Therefore, the samples can be said to be fairly mature and hence good hydrocarbon source rock material.

5. CONCLUSIONS

The result of the various analyses carried out within the studied sedimentary section showed that the samples exhibited the qualities of good source rock. The TOC values ranged from 1.60%-1.80% with an average of 1.6503%. According to [27], the TOC of a sediment is the basic parameter which is required to interprete any other geochemical information obtained by other methods. Therefore, good source rocks have high TOC values. The average TOC value for the 30 studied core samples was in agreement with the 0.4-4.4% range reported by [7]) for the Niger Delta source rocks. It is generally accepted that good shaly source rock of liquid petroleum should normally have a minimum average TOC of 1 – 2wt%. It is reasonable to conclude that the sampled section has the optimum Kerogen concentration to produce petroleum. This view is based on the values of extractable soluble organic matter. The maturity status of the sediments show a fairly good agreement with the views of [1] and [2] that the shales of the paralic Agbada Formation are source rocks in the Niger Delta. Contrary to the views of [3] and [4] that in most parts of the delta, the Agbada Formation is immature as to be the source rock.

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APPENDICES

Appendix 1

S/No.	Depth interval (m)	Titre Values	TOC (Wt %)	Rating
1	2770 – 2775	1.91	1.79	Good
2	2775 – 2780	1.92	1.80	Good
3	2780 – 2785	1.92	1.80	Good
4	2785 – 2790	1.95	1.67	Good
5	2790 – 2795	1.79	1.70	Good
6	2795 – 2800	2.22	1.63	Good
7	2800 – 2805	2.25	1.60	Good
8	2805 – 2810	2.25	1.61	Good
9	2810 – 2815	2.25	1.61	Good
10	2815 – 2820	2.25	1.61	Good
11	2820 – 2825	2.24	1.60	Good
12	2825 – 2830	2.22	1.63	Good
13	2830 – 2835	2.23	1.61	Good
14	2835 – 2840	2.24	1.60	Good
15	2840 – 2845	2.22	1.63	Good
16	2845 – 2850	2.21	1.62	Good
17	2850 – 2855	2.23	1.61	Good
18	2855 – 2860	2.21	1.62	Good
19	2860 – 2865	2.19	1.64	Good
20	2865 – 2870	2.20	1.60	Good
21	2870 – 2875	2.16	1.61	Good
22	2875 – 2880	2.12	1.60	Good
23	2880 – 2885	2.10	1.63	Good
24	2885 – 2890	2.05	1.65	Good
25	2890 – 2895	2.02	1.66	Good
26	2895 – 2900	2.02	1.67	Good
27	2900 – 2905	2.01	1.69	Good
28	2905 – 2910	2.03	1.68	Good
29	2910 – 2915	2.02	1.68	Good
30	2915 – 2920	2.04	1.70	Good

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Appendix 2

S/No.	Depth interval (m)	Weight of sample	Weight of extract	SOM (W %)
1	2770 – 2775	20	0.2824	0.6923
2	2775 – 2780	20	0.2515	0.6587
3	2780 – 2785	20	0.2187	0.6435
4	2785 – 2790	20	0.1263	0.6315
5	2790 – 2795	20	0.0045	0.0270
6	2795 – 2800	20	0.0039	0.0220
7	2800 – 2805	20	0.0036	0.0180
8	2805 – 2810	20	0.0065	0.0072
9	2810 – 2815	20	0.0079	0.0038
10	2815 – 2820	20	0.0068	0.0045
11	2820 – 2825	20	0.0072	0.0040
12	2825 – 2830	20	0.0065	0.0043
13	2830 – 2835	20	0.0059	0.0054
14	2835 – 2840	20	0.0062	0.0031
15	2840 – 2845	20	0.0056	0.0150
16	2845 – 2850	20	0.0050	0.0132
17	2850 – 2855	20	0.0043	0.0210
18	2855 – 2860	20	0.0044	0.0210
19	2860 – 2865	20	0.0043	0.0210
20	2865 – 2870	20	0.0045	0.0210
21	2870 – 2875	20	0.0039	0.0220
22	2875 – 2880	20	0.0041	0.0200
23	2880 – 2885	20	0.0045	0.0210
24	2885 – 2890	20	0.0046	0.0125
25	2890 – 2895	20	0.0025	0.0125
26	2895 – 2900	20	0.0032	1.3345
27	2900 – 2905	20	0.0035	1.3737
28	2905 – 2910	20	0.0027	1.4189
29	2910 – 2915	20	0.0038	1.4965
30	2915 – 2920	20	0.0032	1.5648

Appendix 3

S/No.	Depth interval (m)	TOC (W %)	SOM (W %)	TR = SOM/TOC
1	2770 – 2775	1.79	0.6923	0.3868
2	2775 – 2780	1.80	0.6587	0.3659
3	2780 – 2785	1.80	0.6435	0.3675
4	2785 – 2790	1.67	0.6315	0.3781
5	2790 – 2795	1.70	0.0027	0.0016
6	2795 – 2800	1.63	0.0220	0.0135
7	2800 – 2805	1.60	0.0180	0.0113
8	2805 – 2810	1.61	0.0072	0.0045
9	2810 – 2815	1.61	0.0038	0.0024
10	2815 – 2820	1.61	0.0045	0.0028
11	2820 – 2825	1.60	0.0040	0.0025
12	2825 – 2830	1.63	0.0043	0.0026
13	2830 – 2835	1.61	0.0054	0.0034
14	2835 – 2840	1.60	0.0031	0.0019
15	2840 – 2845	1.63	0.0150	0.0092
16	2845 – 2850	1.62	0.0132	0.0081
17	2850 – 2855	1.61	0.0210	0.0131
18	2855 – 2860	1.62	0.0210	0.0130
19	2860 – 2865	1.64	0.0210	0.0128
20	2865 – 2870	1.60	0.0210	0.0131
21	2870 – 2875	1.61	0.0220	0.0137

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22	2875 – 2880	1.60	0.0200	0.0125
23	2880 – 2885	1.63	0.0210	0.0129
24	2885 – 2890	1.65	0.0125	0.0076
25	2890 – 2895	1.62	0.0125	0.0077
26	2895 – 2900	1.67	1.3345	0.7991
27	2900 – 2905	1.69	1.3737	0.8128
28	2905 – 2910	1.68	1.4189	0.8446
29	2910 – 2915	1.68	1.4965	0.8908
30	2915 – 2920	1.70	1.5148	0.8911

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