



Integrated Geochemical and Multivariate Statistical Examination of Source Rocks in the Sokoto and Anambra Basins, Nigeria: Implications for Hydrocarbon Prospectivity

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To cite this article:

Lukman Musa Adamu, Nuhu George Obaje, Okafor Pudentiana Ngozi, Umar Mohammed Umar. Integrated Geochemical and Multivariate Statistical Examination of Source Rocks in the Sokoto and Anambra Basins, Nigeria: Implications for Hydrocarbon Prospectivity. *Petroleum Science and Engineering*. Vol. 4, No. 2, 2020, pp. 39-50. doi: 10.11648/j.pse.20200402.11

Received: May 21, 2020; Accepted: June 4, 2020; Published: June 15, 2020

Abstract: The LECO and Rock–Eval pyrolysis for 7 shale and 3 coal samples, as well as, multivariate statistical analysis have been used to probe source rock characteristics, correlation between the assessed parameters (S1, S2, S3, HI, S1 + S2, OI, PI, TOC) and the impact of changes in the Tmax on the assessed parameters in the Sokoto Basin and Anambra Basin of northwestern and southeastern Nigeria respectively. The geochemical results show that 93% of the samples have TOC values greater than the minimum limit value (0.5 wt %) required to induce hydrocarbon generation from source rocks. Meanwhile, the Dukamaje and Taloka shales are found to be fair to good source rock for oil generation with slightly higher thermal maturation. The source rocks are generally immature through sub-mature to marginal mature with respect to the oil and gas window, while the potential source rocks from the Anambra Basin are generally sub-mature grading to mature within the oil window. The analyzed data were approached statistically to find some relations such as factors, and clusters concerning the examination of the source rocks. These factors were categorized into type of organic matter and organic richness, thermal maturity and hydrocarbon potency. In addendum, cluster analysis separated the source rocks in the study area into two groups. The source rocks characterized by HI >240 (mg/g), TOC from 58.89 to 66.43 wt%, S1 from 2.01 to 2.54 (mg/g) and S2 from 148.94 to 162.52 (mg/g) indicating good to excellent source rocks with kerogen of type II and type III and are capable of generating oil and gas. Followed by the Source rocks characterized by HI <240 (mg/g), TOC from 0.94 to 6.68 wt%, S1 from 0.14 to 0.72 (mg/g) and S2 from 0.14 to 3.36 (mg/g) indicating poor to good source rocks with kerogen of type III and are capable of generating gas. However, Pearson's correlation coefficient and linear regression analysis shows a significant positive correlation between TOC and S1, S2 and HI and no correlation between TOC and Tmax, highly negative correlation between TOC and OI and no correlation between Tmax and HI.

Keywords: Anambra Basin, LECO, Multivariate Statistical, Rock–Eval Pyrolysis, Sokoto Basin

1. Introduction

Presently data set are being gathered through surveys to enable extensive appraisal of the oil and gas possibilities in the frontier basins of Nigeria by the Nigerian government

through the Nigerian National Petroleum Corporation and other investors. These basins include the Anambra Basin, Benue Trough, Bida Basin, Chad Basin (Nigerian sector), Dahomey Basin and Sokoto Basins (Figure 1). The oil and gas potency in the basins will depend on the fortune of the elements that make up the petroleum system. The elements

include organically rich, mature source rocks and their volumes, porous and permeable reservoir rocks and seal lithologies, effective generation, expulsion and migration into reservoirs, availability of trapping mechanisms and timing of generation, expulsion and migration in relation to other events. At the centre of the petroleum system is the availability of organically rich, mature source rocks. Source rocks for petroleum generation are usually shales, carbonates and coals.

The northwestern Nigeria Sokoto Basin occupies the geographical Sokoto State, and parts of Zamfara and Kebbi State, covers about 20% of the northeastern region of Nigeria. It is considered as one of the promising basins in the country with good potential oil and gas deposits with area of about 60,000 km² and is also the least studied basin in Nigeria [1-3]. Potential hydrocarbon source rocks exposed in outcrops and stratigraphic sections in the Sokoto Basin, and a preliminary assessment of the hydrocarbon prospectivity using the organic geochemical tools (LECO and Rock-Eval pyrolysis analysis) had earlier been studied [1, 2]. They identified the source to be mainly the carbonaceous Dukamaje and/or Taloka shales. These methods are used in determining the thermal maturation of kerogen. Behar *et al.* [4] defined the thermal parameters based on which maximum temperature (T_{max}) can be used to model the proportions of the oil window. Thermal maturity of sediments can be ascertained with production of graph that plots T_{max} values versus HI. In this study, we used both geochemical and statistical analyses for evaluating the source rocks in the northwestern Sokoto Basin.

In this study, both geochemical and statistical analyses were used for evaluating the source rocks and discriminate the maturity and hydrocarbon potentialities of the northwestern Lower and Middle Maastrichtian source rocks in the northwestern Sokoto Basin and the Campanian-Maastrichtian source rocks in the Anambra Basin. This work has studied the geochemical properties of organic material, thermal maturation and affluence of hydrocarbon in order to square up the petroleum potency of the source rocks. The intention of this study is to set up indices for a unified appraisal of organic material for petroleum potency evaluation and pivot on multivariate statistical analysis and cross-plots of TOC, and parameters of Rock-Eval pyrolysis. With speculative and analytical examination, we anticipate to uncover that the utility of seven (7) parameters (S₁, S₂, S₃, S₁+S₂, HI, OI, PI, TOC) increase as the thermal maturity of organic materials increase during the initial stage of thermal maturation. In addendum, this study is to style the affinities between organic material and thermal maturity.

2. Geological / Stratigraphy Setting

The discussion on the geological setting focuses on the Sokoto Basin being the south-eastern portion of the larger Iullemeden Basin. The Iullemeden Basin covers northwestern Nigeria, most parts of Niger Republic, Benin Republic, Mali, Algeria and Libya. This geological setting hosts

the appraised carbonaceous shale deposits (Figures 1, 2, 3, 4).

2.1. The Northwestern Sokoto Basin

Kogbe [5, 6] carried out a work on geology of the south-eastern (Sokoto) sector of the Iullemeden Basin and produced a detailed geological map of the Sokoto Basin. Obaje [7] worked on the Foraminiferal biostratigraphy and paleoenvironment of the Sokoto Basin of NW Nigeria. Obaje, [8] in his book titled 'The Geology and Mineral Resources of Nigeria' give a detailed stratigraphic description of the formations within the basin.

The main lithologies of the northwestern Sokoto Basin range in chronology from Pre-Maastrichtian to Eocene [6-8, 3] (Figure 4). The stratigraphic rock units comprise continental and marine sediments (Figure 4). The Pre-Maastrichtian part is represented by siliciclastics Gundumi-Ilo Formation. This formation is wholly grits and clays that constitute the Pre-Maastrichtian 'Continental Intercalaire' which rest unconformably on the Pre Cambrian basement rocks of the northwestern Nigeria (Figure 4). The Pre-Maastrichtian Gundumi-Ilo Formation also unconformably underlies the Rima Group which comprise of the Taloka, Dukamaje and Wurno Formations. The Lower Maastrichtian Taloka Formation is composed mainly mudstone and friable sandstones and shales with coal seams, and is overlain conformably by Middle Maastrichtian marine Dukamaje Formation (Figure 4) composed mainly of fossiliferous, calcareous and shales. The Dokamaje Formation is overlain conformably by Upper Maastrichtian Wurno Formation. The continental sandstone of the Wurno Formation are overlain unconformably by Paleocene units of Sokoto Group (Figure 4). The Paleocene units comprise the Dange, Kalambaina and Gamba Formations. The Dange Formation (Lower Paleocene) composed of mainly marine shales. Kalambaina Formation represents a calcareous sequence. Gamba Formation consist of mainly marine shales, and it is uncoformably overlain by Eocene continental Gwandu Formation (Figure 4) which forms the Eocene Continental Terminal.

2.2. The Anambra Basin

The Anambra Basin is sometimes seen as an integral unit of the Lower Benue Trough (Figure 1 and Figure 3). During the Santonian, upheavals (epeirogenic) movements, these sediments experience flexure and uplifted into the Abakaliki-Benue Anticlinorium [9] with synchronous subsidence of the Anambra Basin and the Afikpo sub-basins to the northwest and southeast of the folded belt respectively [9-11]. The Abakaliki Anticlinorium later served as a sediment disbandment centre from which sediments were shifted into the Anambra Basin and Afikpo Syncline. The Cameroon basement complex, Oban Masif and southwestern Nigeria basement craton also served as sources for the sediments of the Anambra Basin [12]. Post-deformational sedimentation in the Lower Benue Trough, therefore, constitutes the Anambra Basin.

After the development of the Anambra Basin following the

Santonian epeirogeny, the Campanian-early Maastrichtian transgression deposited the Nkporo Group (i.e the Enugu Formation, Owelli Sandstone, Nkporo Shale, Afikpo Sandstone, Otobi Sandstone and Lafia Sandstone) as the basal unit of the basin, unconformably overlying the Awgu Formation. This was followed by the Maastrichtian regressive event during which the coal measures (i.e. the Mamu, Ajali and Nsukka Formations) were deposited. The Enugu and the Nkporo Shales represent the pro-delta fossiliferous facies of the Late Campano-Maastrichtian depositional cycle [8]. Deposition of the sediments of the Nkporo/Enugu Formations reflects a funnel-shaped shallow marine setting that graded into channeled low-energy marshes. The coal-bearing Mamu Formation and the Ajali Sandstone accumulated during this epoch of overall regression of the Nkporo cycle. The Mamu Formation occurs as a narrow strip trending north-south from the Calabar Flank, swinging west around the Ankpa plateau and terminating at Idah near the River Niger [8, 13, 14]. The Ajali Sandstone marks the height of the regression at a time when the coastline was still concave. The converging littoral drift cells governed the sedimentation and are reflected in the tidal sand waves which are characteristic for the Ajali Sandstone [15, 13, 16, 11, 17, 18].

3. Samples and Methods

Ten selected shale and coal rock ditch and field samples from Dukamaje and Taloka Formations of the northwestern Sokoto Basin and Enugu and Mamu Formations of the Anambra Basin (Table 1) were analyzed for total organic carbon, and Rock-Eval pyrolysis. The LECO TOC content and Rock-Eval pyrolysis analyses were made partly in the laboratories of Geo-data GmbH Garbsen and partly at BGR Hannover, both in Germany through the instrumentality of the 2nd author (NGO). The Analyses were performed on 70 mg to 100 mg crushed whole rock samples, heated to 600°C in a helium atmosphere, using a LECO and Rock-Eval 6 unit.

Multivariate statistical analysis was applied to evaluate the source rock potentiality and clarify the relationship between petroleum potential and maturity. The results obtained for studied samples were statistically analyzed using cluster analysis (hierarchical cluster analysis), Factor analysis, K-independence sample T-tests, linear regression and Pearson's correlation by SPSS 15.0 [19].

3.1. Cluster Analysis

Cluster analysis is based on a matrix measuring the differences between each parameter of each sample. Two basic types of cluster analyses are known: K-Means and hierarchical types. For K-means analysis, it is necessary to define the number of groups into which the samples/parameters are to be classified, while hierarchical cluster analysis enables the grouping of the samples or parameters without any previous classification [20]. These differences are squared. By adding the individual matrices, a

summed matrix is obtained. In the case when the values of the parameters are essentially different, they should preliminarily be standardized, in order that in the final matrix each parameter becomes an equal share. Based on the final matrix, a dendrogram is constructed, which involves all samples or parameters being classified into groups on the basis of all data taken into consideration [21].

3.2. Factor Analysis

According to [22], the statistical method used for combining a large number of data into a considerably smaller number of factors, representing groups of initially mutually linearly dependent parameters containing the same amount of information as their constituent parameters is known as Factor analysis. The values of the coefficients preceding the parameters, marked as loadings, define the significance of a particular parameter in the characterization of an analyzed group of samples. The significance of a particular factor is defined by its characteristic value and percent of variance [23, 24]. In order to determine the relationship between the parameters for the sake of classification of the samples, an interdependence diagram of two factors may be constructed [25]. In the case when the parameters are defining factors reflecting certain types of reaction characteristic for the investigated group of samples, the course of these processes and their mutual agreement can be proven by constructing corresponding correlation diagrams of these factors [25].

3.3. Pearson's Correlation Coefficient and Linear Regression

El-Nady and Lotfy, [20] described Pearson's correlation coefficient as a statistical measure of the strength of a linear relationship between paired data. The correlation coefficient can range from -1 to +1, with -1 indicating a perfect negative correlation, +1 indicating a perfect positive correlation, and 0 indicating no correlation at all. (A variable correlated with it will always have a correlation coefficient of 1). Linear regression is the next step after correlation. It is used when we want to predict the value of a variable based on the value of another variable. The variable we want to predict is called the dependent or outcome variable. The variable we are using to predict the other variable's value is called the independent or the predictor variable [20].

4. Results and Discussion

4.1. Geochemical Methods

In order to examine the organic carbon content and source rock maturity different factors including quality and quantity of organic matter, generating potentialities, type of organic matter and thermal maturation were considered.

4.1.1. Quality and Quantity of Organic Matter

The organic carbon richness of the rock samples (TOC %), is important in the examination of sediments as a source for petroleum. Tissot and Welte [26-34] presented a scale for the

assessment of source rocks potency, based on the TOC% and Rock-Eval pyrolysis data, such as S1 and S2. The procured data set in Table 1 show that the total organic carbon content values for the northwestern Sokoto Basin source rocks are between 0.94 and 7.00 wt % indicating fair to good source rocks. While the values for the Anambra Basin source rocks are between 2.46 and 66.43 wt % indicating good to excellent source rocks. This assumption is validated by the plot of

TOC (wt %) versus S2 (Figure 5a). Also, the plot of S1 versus TOC (Figure 5b) according to [35], can be used to discriminate between indigenous (autochthonous) and nonindigenous (allochthonous) hydrocarbons. This relation points that all of the studied rock samples for the Sokoto and Anambra Basins source rocks were characterized by autochthonous hydrocarbons showing that oil in the studied source rocks originate from within the studied basins.

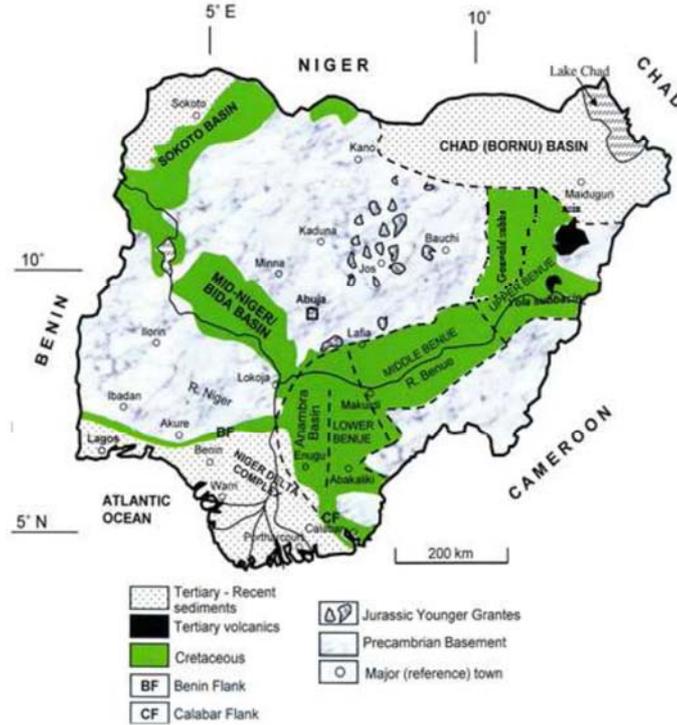


Figure 1. Generalized Geological sketch map of Nigeria showing the major geological components; Basement, Younger Granites, and Sedimentary Basins [8].

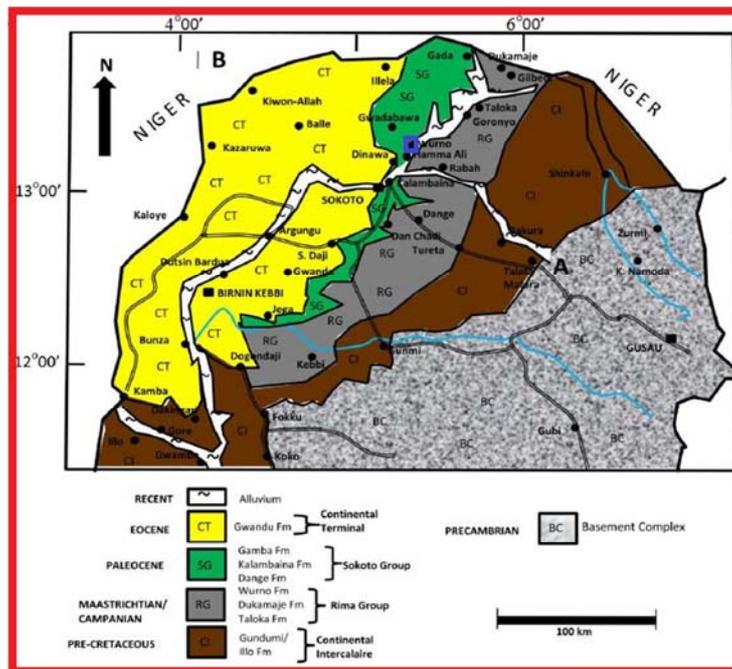


Figure 2. Generalized geological map of the Nigerian sector of the Iullemeden Basin (Sokoto Basin) showing where samples of the Dukamaje shale were collected [3].

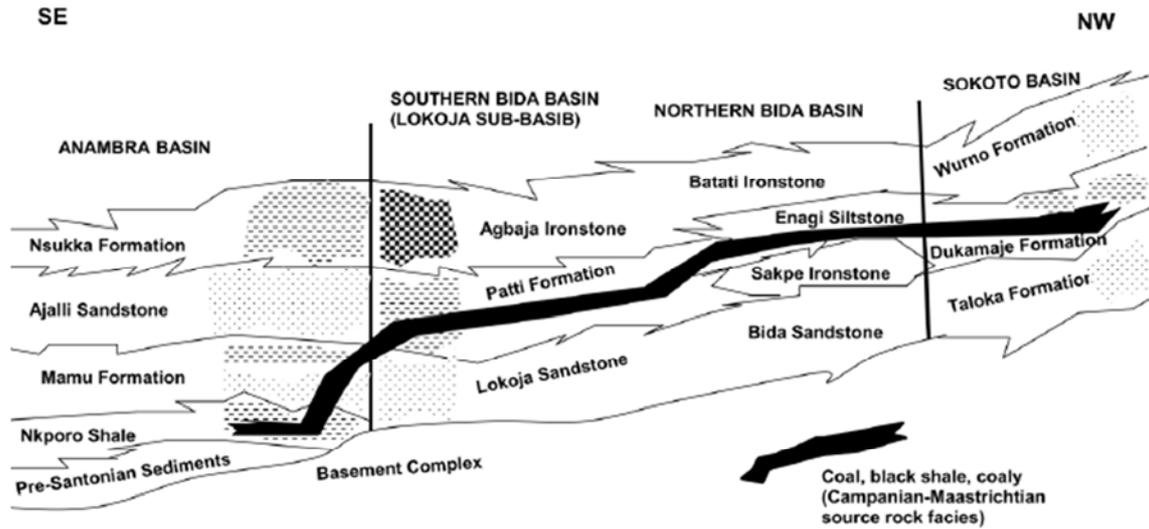


Figure 3. Stratigraphical cross-section and source rock development (coal, black shale, coaly) is a continuous linear belt from the Anambra Basin in the south through the Bida Basin in the middle to the Sokoto Basin in the northwest [1].

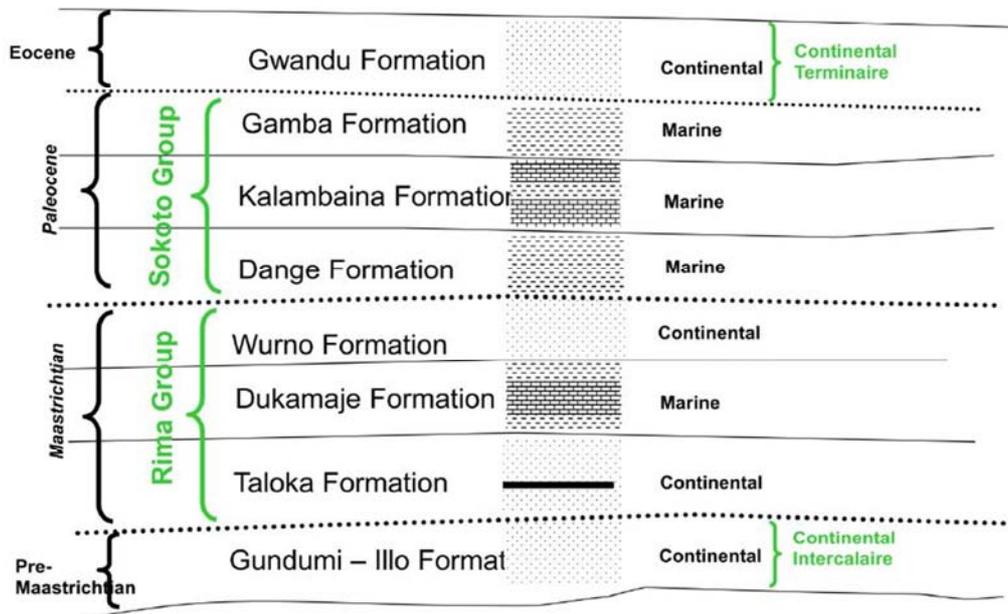


Figure 4. Stratigraphic successions in the Nigerian sector of the Iululmedden Basin (Sokoto Basin) [8].

Table 1. Carbon determination (LECO) and Rock-Eval pyrolysis of the source rock samples from northwestern Sokoto and Anambra Basins, Nigeria.

	SAMPLE ID									
	DKM1.8M	DKM2.5M	DKM3.0M	DKM3.2M	TLKL2	TLKL4	IBEA	OKOBO	ESHAL1	ONY
TOC (wt %)	3.28	2.46	2.52	0.94	6.68	1.28	61.89	58.89	2.46	66.43
S1 (mg Hc/g rock)	0.47	0.37	0.23	0.23	0.72	0.14	2.17	2.54	0.05	2.01
S2 (mg Hc/g rock)	3.36	2.59	1.09	0.23	3.04	0.14	148.94	151.95	0.97	162.52
S3 (mg CO ₂ /g rock)	0.73	0.5	1.35	0.38	5.12	0.5	6.28	10.89	0.9	2.46
HI (mg Hc/g TOC)	102	105	43	24	46	11	241	258	39	245
OI (mg CO ₂ /g TOC)	22	20	54	40	77	39	10	18	37	4
PI	0.12	0.13	0.17	0.5	0.19	0.5	0.01	0.02	0.05	0.01
Tmax (°C)	418	416	407	*413	427	*312	421	421	410	430

*PI Production Index S1/(S1+S2).

*HI Hydrogen Index (mg Hc/g TOC).

*OI Oxygen Index (S3×100)/TOC (mg CO₂/g TOC).

* Tmax (°C) Uncertain.

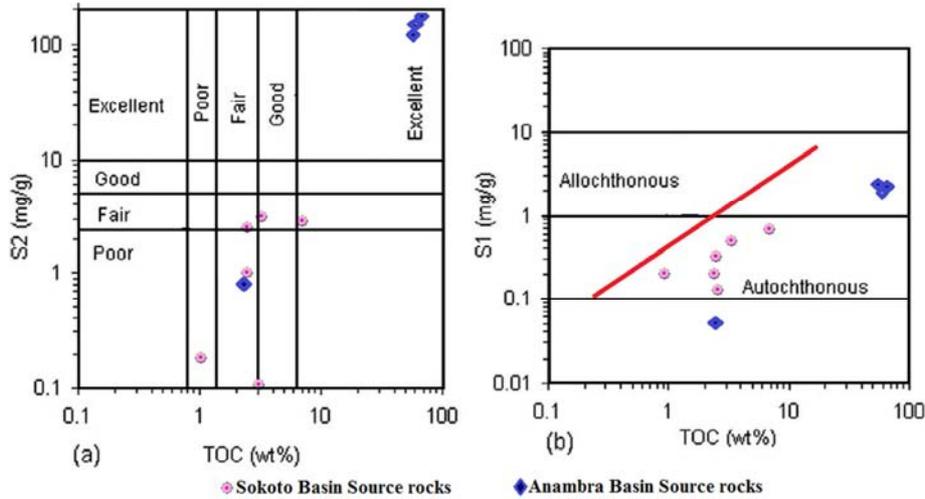


Figure 5. Quality and quantity of organic matter of Sokoto and Anambra Basins source rocks, Nigeria.

4.1.2. Generating Potency

The generation potency of a source rock is identified using the results of pyrolysis analysis. The genetic potency (GP) is the sum of the values S1 and S2. According to [36] source rocks with a GP <2, from 2 to 5, from 5 to 10 and >10 are considered to have poor, fair, good, and very good generation potency, respectively. The relationship between (S1+ S2) and TOC [37]. (Figure 6a) shows that the Sokoto Basin (Dukamaje and Taloka shales) source rocks are considered as fair to good source potential except few samples that are considered as poor source potential while the Anambra Basin source rocks are considered as good to excellent source potential. On the other hand, the plot of TOC (wt %) versus HI mg/g (Figure 6b) shows that the Sokoto and Anambra Basins source rocks are non-oil or gas source rocks.

4.1.3. Genetic Organic Matter

In petroleum prospectivity, the initial genetic type of organic matter of a particular source rock is essential for the prediction of oil and gas potential. Waples [32, 33, 37-41] used the hydrogen index values (HI) to differentiate between the types

of organic matter. Hydrogen indices <150 mg/g indicate a potential source for generating gas (mainly type III kerogen). Hydrogen indices between 150 and 300 mg/g contain more type III kerogen than type II and therefore are capable of generating mixed gas and oil but mainly gas. Kerogen with hydrogen indices >300 mg/g contains a substantial amount of type II macerals and thus are considered to have good source potential for generating oil and minor gas. Kerogen with hydrogen indices >600 mg/g usually consists of nearly type I or type II kerogen, they have excellent potential to generate oil.

In this study, we used [42, 43] kerogen type diagram which represents the plot TOC versus S2 (Figure 7a). This diagram shows that the Sokoto Basin source rocks are characterized by kerogen of type III, while the Anambra Basin source rocks are characterized by type II and type III. Based on pyrolysis data kerogen classification diagrams were constructed using the HI versus OI plot as opined by [44], popularly used to determine the kerogen type (Figure 7b). The results show that the analyzed Sokoto Basin samples are generally plotted under type III kerogen, while the analyzed Anambra Basin samples are plotted in kerogen of type III and type II.

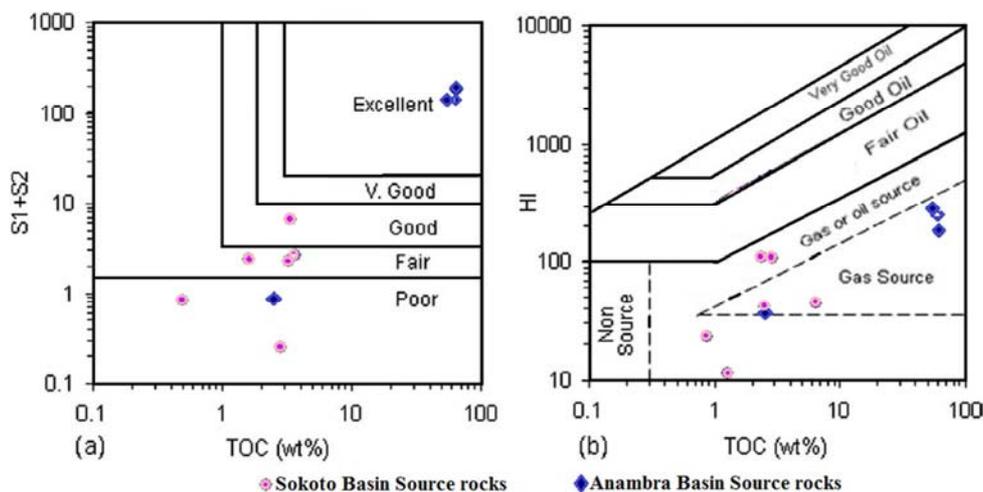


Figure 6. Generating potency of Sokoto Basin and Anambra Basins source rocks, Nigeria.

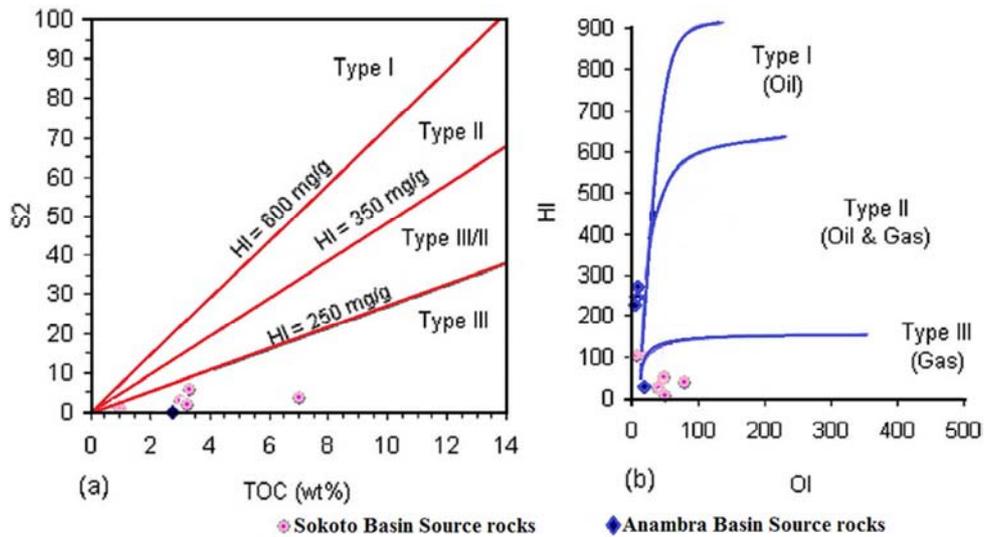


Figure 7. Genetic type of organic matter of Sokoto Basin and Anambra Basin source rocks, Nigeria.

4.1.4. Thermal Maturation

According to [26, 34, 45-49], the generation of petroleum from the organic matter during its burial history is a part of the overall process of thermal metamorphism of organic matter. The concentration and distribution of hydrocarbons inhibited in a particular source rely on both the type of the organic matter and its degree of thermal alteration [26, 29, 31, 33, 34, 42]. In the present study, the thermal maturity level of the source rocks has been unraveled by the examination of the geochemical parameters as Rock-Eval pyrolysis “Tmax”, production index “PI” [36, 50]. Peters [28, 50, 51, 52] reported that oil generation from source rocks began at Tmax=435–465°C. Production index “PI” between 0.2 and 0.4, the organic matters are in immature stage when “Tmax” has a value less than 435°C, and “PI”

less than 0.2 and the gas generation from source rocks began at “Tmax” 470°C, and production index “PI” more than 0.4. Based on pyrolysis data kerogen classification diagrams were constructed using the HI versus Tmax plot as carried out by [50, 53] which is used to determine the kerogen type and maturity (Figure 8a). The results show that the analyzed Sokoto Basin samples are generally plotted in the immature zone of type III kerogen, while the analyzed Anambra Basin samples are plotted in the immature zone grading to marginally mature zone with kerogen of type III and type II. The plot of Tmax versus PI diagram [28, 37, 53] (Figure 8b) indicates that the Sokoto Basin source rocks are immature source rocks while, the Anambra Basin source rocks grade from immature to marginally mature.

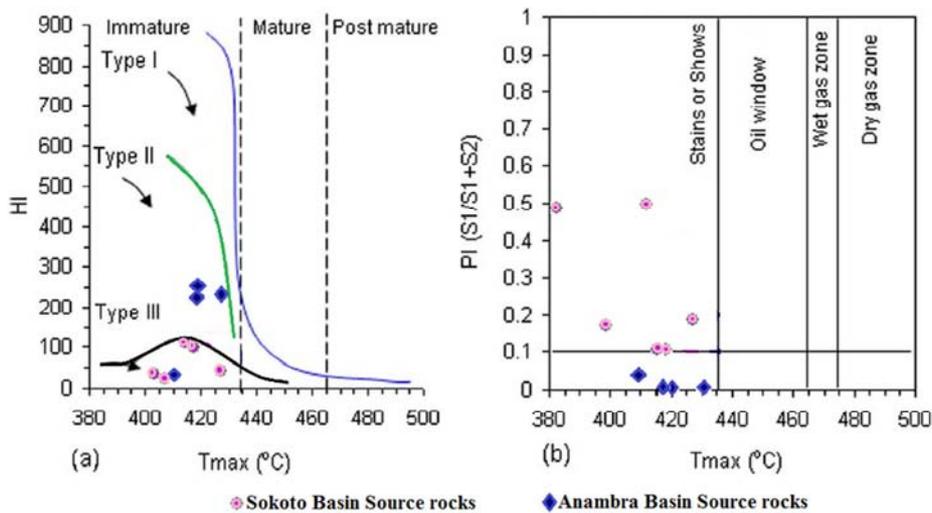


Figure 8. Thermal maturation of Sokoto and Anambra Basins source rocks, Nigeria.

4.2. Statistical Methods

In this study, the multivariate statistical analysis was employed. The multivariate statistical analysis is the construction of cluster analysis (hierarchical cluster analysis),

Factor analysis, K-independence sample T-tests, Pearson’s correlation and linear regression.

4.2.1. Cluster Analysis

The set of 9 source parameters (Tmax, HI, OI, PI, S1, S2,

S3, TOC, S1 + S2) were subjected to hierarchical cluster analysis using the standard method, which was proven to be the most reliable according to the up-to-date organic geochemical investigations [20, 32, 33, 34]. Based on the different HI values, the samples were distinguished into two main clusters. The first one (cluster I) of high HI values greater than 240 mg/g and the second (cluster II) of HI values lower than 240 mg/g. However, the samples of cluster II of comparable HI values have showed variability in other parameters like TOC, S1, S2 and Tmax. The resulting dendrogram (Figure 9) showed two types of clusters which reflect two types of source rocks. Cluster I that represents

Anambra Basin source rock is found to be a fair source rock for oil generation with slightly higher thermal maturation and characterized by HI ranging from 241 to 258 mgHC/g. TOC reflecting that these source rocks were characterized by kerogen type II and III. Cluster II mainly represents Dukamaje Formation with subordinate Taloka Formation and Enugu Shale which are characterized by HI ranging from 11 to 105 mgHC/g. TOC reflecting kerogen type III. By applying K-means cluster analysis on the same set of source parameters, the results showed that all samples belong to cluster II except for three samples (IBEAGWA, OKOBO, ONYEAMA A) which belong to cluster I (Table 2).

Table 2. Average Linkage (Between Groups).

Agglomeration Schedule							
Stage	Cluster Combined		Coefficients	Stage Cluster First Appears		Next Stage	
	Cluster 1	Cluster 2		Cluster 1	Cluster 2		
1	1	2	18.328	0	0	7	
2	4	9	246.363	0	0	4	
3	7	10	352.649	0	0	5	
4	3	4	455.777	0	2	6	
5	7	8	539.191	3	0	9	
6	3	5	1688.193	4	0	7	
7	1	3	5656.849	1	6	8	
8	1	6	14472.914	7	0	9	
9	1	7	69498.513	8	5	0	

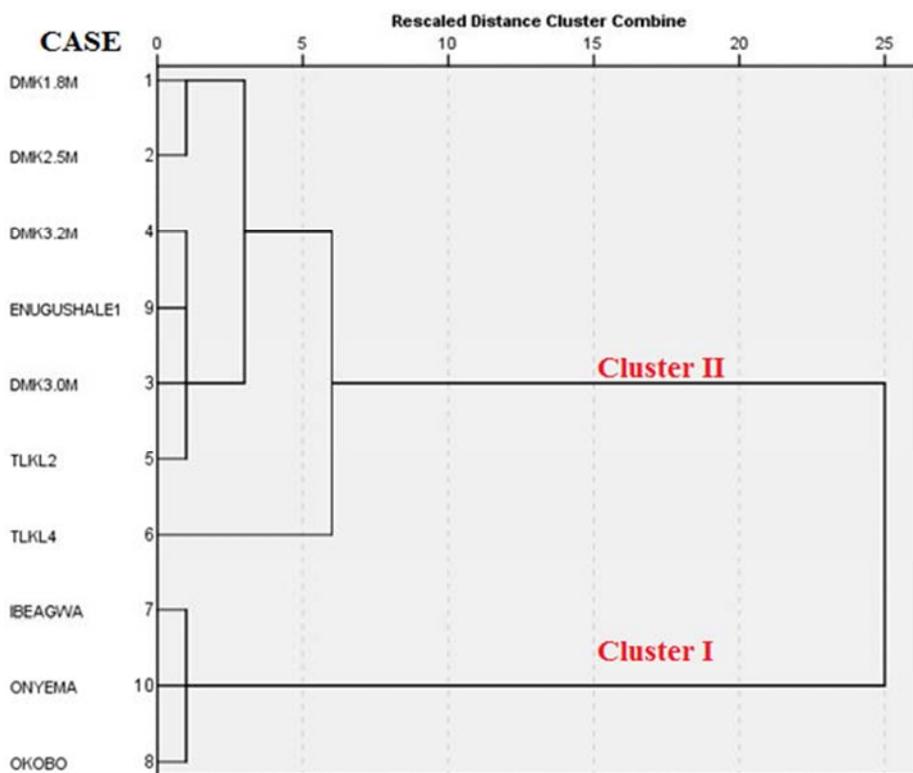


Figure 9. Hierarchical cluster analysis dendrogram using average linkage (between groups).

4.2.2. Factor Analysis

To get a more detailed classification of the source rock potential in the study area, a factor analysis of the source parameters was carried out using principle component analysis (Table 3 and Table 4). According to up-to-date

organic geochemical investigations, this method has been shown to be the most convenient [50, 54]. Employing factor analysis on Rock-Eval pyrolysis variables shows three distinct factors affecting the evaluation of source rocks (Table 3). Factor 1 includes variables TOC, S1, S2 which ascertain the organic richness and hydrocarbon potency of

source rocks and also HI which square up the type of organic matter that characterizes source rocks. Factor 2 and Factor 3 include variables PI and Tmax, which reflect the maturity of source rocks. In totality, factor analysis shows that evaluating the source rocks rely on determining hydrocarbon potency,

organic richness, type of organic matter, and thermal maturity. Correlating the results derived by application of factor and cluster analyses methods; corroborate the existence of two distinct source rock types.

Table 3. Correlation matrix of the parameters in the studied source rocks.

		TOC	S1	S2	S3	HI	OI	PI	TMAX
Correlation	TOC	1.000	.969	.998	.702	.951	-.655	-.602	.359
	S1	.969	1.000	.969	.833	.956	-.575	-.599	.402
	S2	.998	.969	1.000	.703	.955	-.676	-.590	.343
	S3	.702	.833	.703	1.000	.693	-.152	-.481	.330
	HI	.951	.956	.955	.693	1.000	-.749	-.713	.467
	OI	-.655	-.575	-.676	-.152	-.749	1.000	.444	-.157
	PI	-.602	-.599	-.590	-.481	-.713	.444	1.000	-.667
	TMAX	.359	.402	.343	.330	.467	-.157	-.667	1.000
Sig. (1-tailed)	TOC		.000	.000	.012	.000	.020	.033	.154
	S1	.000		.000	.001	.000	.041	.034	.125
	S2	.000	.000		.012	.000	.016	.036	.166
	S3	.012	.001	.012		.013	.338	.080	.176
	HI	.000	.000	.000	.013		.006	.010	.087
	OI	.020	.041	.016	.338	.006		.099	.332
	PI	.033	.034	.036	.080	.010	.099		.018
	TMAX	.154	.125	.166	.176	.087	.332	.018	

a. Determinant=6.994E-010.

Table 4. Total Variance of the parameters in the studied source rocks Explained.

Component	Initial Eigen values			Extraction Sums of Squared Loadings			Rotation Sums of Squared Loadings ^a
	Total	% of Variance	Cumulative %	Total	% of Variance	Cumulative %	Total
1	5.616	70.201	70.201	5.616	70.201	70.201	4.984
2	1.084	13.549	83.750	1.084	13.549	83.750	3.034
3	.865	10.807	94.558	.865	10.807	94.558	2.647
4	.279	3.485	98.042				
5	.139	1.735	99.778				
6	.017	.207	99.985				
7	.001	.012	99.997				
8	.000	.003	100.000				

4.2.3. Pearson’s Correlation Coefficient and Linear Regression Analyses

According to the correlation coefficient can range from -1 to +1, with -1 indicating a perfect negative correlation, +1 indicating a perfect positive correlation, and 0 indicating no correlation at all. (A variable correlated with it will always have a correlation coefficient of 1).

In this study, employing Pearson’s correlation analysis shows a strong positive correlation between TOC and S1 and S2 (Table 5, Figure 10a and 10f) indicates the contribution of S1 and S2 from TOC. Furthermore, highly positive correlation between TOC and HI (Figure 10d), highly negative correlation with oxygen index (Figure 10b) and little to no correlation between TOC and Tmax (Figure 10e) and PI indicate that the maturity of source rocks is independent of the amount of organic matter [23]. Highly positive correlation between S1 and S2 (Figure 10f) and also between S2 and HI in addition to no correlation between Tmax and HI (Figure 10c) illustrate that the highest HI occurs at certain maturities and does not occur in stages of less maturity or over maturity. Highly negative reverse correlation between HI and OI was also shown (Figure 10b).

5. Conclusions

Integrated LECO, Rock–Eval pyrolysis and multivariate statistical analysis are examined to investigate the level and time of hydrocarbon generation and expulsion of shale and coal successions in northwestern Sokoto and Anambra Basins, they showed that the northwestern Sokoto Basin source rocks are poor to good source rocks with kerogen of type III and are capable of generating gas. The Anambra Basin source rocks are good to excellent source rocks with kerogen of type III and type II and are capable of generating oil and gas. Employing Hierarchical cluster analyses on the studied samples shows two clusters reflecting two types of source rocks. Cluster I are source rocks characterized by HI >240 (mg/g), TOC from 58.89 to 166.43 wt %, S1 from 2.01 to 2.54 (mg/g) and S2 from 148.94 to 162.52 (mg/g) indicating good to excellent source rocks with kerogen of type III and type II and are capable of generating oil and gas. Cluster II are source rocks characterized by HI <240 (mg/g), TOC from 0.94 to 6.68 wt %, S1 from 0.14 to 0.72 (mg/g) and S2 from 0.14 to 3.36 (mg/g) indicating poor to good source rocks with kerogen of type III and are capable of

generating gas. Employing factor analysis on Rock–Eval pyrolysis variables indicates that there are three factors affecting the evaluation of source rocks. Factor 1 includes variables TOC, S1, S2 which determine the organic richness and hydrocarbon potentiality of source rocks and also HI which determine the type of organic matter that characterizes source rock. Factor 2 and Factor 3 include variables PI and Tmax which reflect the maturity of source rocks. Pearson’s correlation analysis shows a strong positive correlation between TOC and S1 and S2 indicates the contribution of S1

and S2 from TOC. Furthermore, highly positive correlation between TOC and HI, highly negative correlation with oxygen index and no correlation between TOC and Tmax and PI indicate that the maturity of source rocks is independent of the amount of organic matter. Highly positive correlation between S1 and S2 and also between S2 and HI in addition to, no correlation between Tmax and HI illustrate that the highest HI occurs at certain maturities and doesn’t occur in stages of less maturity or over maturity. Highly negative reverse correlation between HI and OI was also shown.

Table 5. Linear regression coefficients of the parameters in the studied source rocks.

Model	Unstandardized Coefficients		Standardized Coefficients	T	Sig.
	B	Std. Error	Beta		
(Constant)	12.497	11.205		1.115	.381
S1	21.343	12.898	.706	1.655	.240
S2	.298	.065	.763	4.624	.044
S3	-1.657	.721	-.200	-2.298	.148
HI	-.115	.094	-.394	-1.223	.346
OI	-.015	.110	-.011	-.136	.904
PI	-17.000	9.769	-.109	-1.740	.224
TMAX	-.010	.021	-.012	-.464	.688

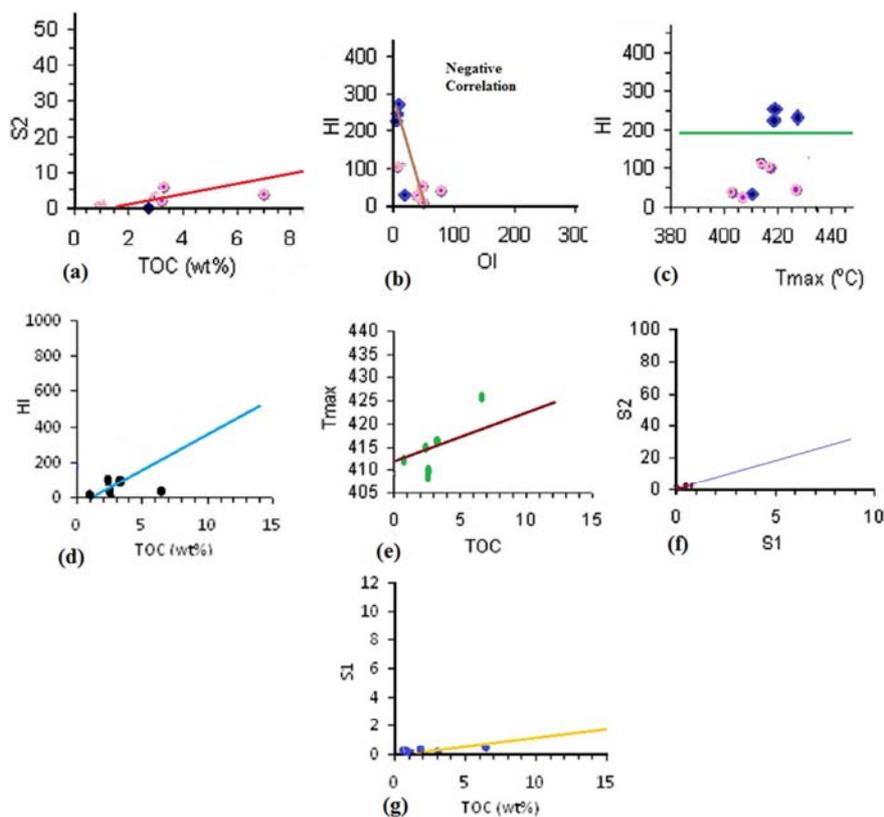


Figure 10. Pearson’s correlation coefficient of the studied samples.

Acknowledgements

Great acknowledgments goes to the Nigerian National Petroleum Corporation through the office of the NNPC Chair in Basinal Studies, Ibrahim Badamasi Babangida University, Lapai, Nigeria and the Sokoto State Government for supporting different aspects of the Sokoto Basin hydrocarbon

prospectivity evaluation.

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