Source Rock Evaluation in The Lake Chad Area of the Bornu Basin, Nigeria

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Abstract

Source rock evaluation of the Lake Chad area of the Bornu Basin which contains a comparatively thicker sedimentary succession based on interpreted seismic and gravity data was undertaken in this study. A total of twenty-nine shale samples from three wells (Kutchali-1, Faltu-1 and Herwa-1) were analysed to arrive at the bulk geochemical properties, organic matter particles and vitrinite reflectance (VR) data of the strata penetrated by the wells. The Lake Chad area appears to contain the main ingredients required to make a rich source rock with over 96% of the total organic carbon (TOC) values being in the range of 0.63-2.88 wt% and over 95% having T_{max} greater than 435°C in most of the sampled intervals. The variation of Tmax and VR with depth in the wells reveals irregular decreases or subtle decreasing trends that are suggestive of cooling in the basin's thermal history probably as a result of uplift and erosion. The uplift could have been caused by epeirogenic movement or by folding related to the Santonian inversion witnessed by the West African Rift Subsystem. In terms of hydrocarbon generation potential, most of the samples have HI values greater than 50 mgHC/g TOC, but generally less than 200 mgHC/g TOC. These HI values suggest dominance of Type III with less Type II Kerogen; thus, a predominantly predominantly gas prone area. A study of some bulk geochemical parameters (TOC, T_{max} and HI) of the three study wells has revealed that the succession penetrated by one of them (Faltu-1 well) contains several potential gas source intervals and two potential oil source intervals with the latter probably lying between 2500 m and 3000 m depth.

Keywords: Source rock; Bornu Basin; Kutchali; Bulk geochemistry; Fika Shale

Introduction

Following the discovery of oil in parts of the mega-Chad Basin that fall within the neighbouring countries of Chad and Niger Republics (i.e the Termit Basin) in the seventies, the Nigerian National Petroleum Corporation, a parastatal of the Federal Government of Nigeria, was encouraged to carry out oil exploration in Bornu Basin which is the Nigerian sector of the mega-Chad Basin. The mega-Chad Basin covers all the rift basins associated with the West and Central African Rift System (WCARS) [1] which lie within the confine of the ancient inland Chad Basin. The exploration involved acquisition of 33,642 km of 2-D seismic lines and sinking 23 wells which provided subsurface materials for detailed studies including source rock evaluation. Unfortunately, the exploration campaign was unsuccessful as only uneconomic gas find was reported.

Recently there is renewed interest by the Federal Government to revisit the basin. This calls for re-evaluation of the prospectively of the different areas of the basin. Evaluation of potential source rock is an important parameter to be considered in reviewing and isolating the most auspicious area for further work. Previous workers, notably, Olugbemiro, Obaje, Moumouni and Alalade and Tyson [2-5] have evaluated potential source rocks in some parts of the basin, although the selection of materials for the analysis appears haphazard. These works have been reviewed in Adekoya [6] suggesting that the basin contain sufficient hydrocarbon generation elements. In the present study, source rock evaluation is focused on the north-eastern portion of the Bornu Basin where a thick sedimentary cover, possibly the thickest in the basin, is speculated on the basis of magnetic and gravity data interpretation and well log information [7,8]. Borehole cuttings were selected from three wells-Kutchali-1, Herwa-1 and Faltu-1-in the area for organic geochemical studies. The purpose is to shed more light on source rock availability in that part of the basin believed to have high prospective potential for hydrocarbon discovery, more so thtat the area is very close to the oil-producing Termit Basin of Chad and Niger Republics.

Geological setting

The geological setting of the Bornu Basin is similar, to a large extent to other rift basins in the West and Central African Rift systems (WCARS) that are petroleum producing. They were all either a product of strike-slip or extensional forces that brought about the mechanical separation of African and South American crustal blocks during the Early Cretaceous [9-11]. The study of the geology of the Bornu Basin has received considerable attention mainly because of its presumed hydrocarbon potential, ground water exploration and its position in relation to the connection of the Tethys Sea with the Atlantic Ocean during the Cretaceous [12-20].

Stratigraphy

The Precambrian Basement Complex constitutes the bedrock on which sediments ranging in age from Mesozoic to the Quaternary have been deposited in the Bornu Basin, which is one of the rift basins associated with the WCARS [1]. The sedimentary fill of the basin is divided into six defined lithostratigraphic units and two unnamed units (Figure 1). The oldest named unit, the Bima Formation, consists of sparsely fossiliferous, poorly sorted, cross-stratified, fine- to coarse-grained arkosic sandstones interlayered with clay/shale, which are interpreted as fluvial and lacustrine deposits [17,21]. These continental
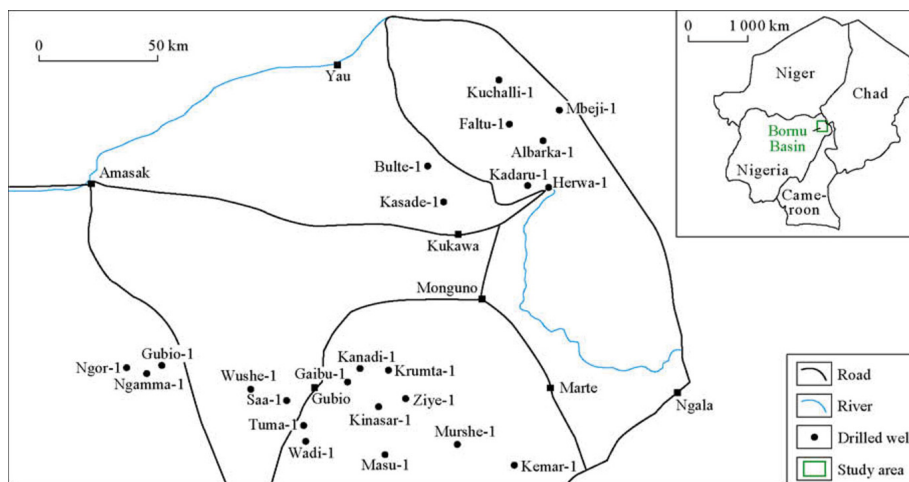
Figure 1: Map of the Bornu Basin showing the location of drilled wells in the basin and three areas of thick sedimentary deposits in the basin marked as depression A, B and C (Modified after Olabode [7]). The focus of this study is on depression A occurring in the area around the Lake Chad.

System	Series	Stage	Formation	Lithology	Average thickness/m	Thickness from seismic data/m	Outcrop Description
Quaternary			Chad		400	800 (Average)	Variegated clays with sand interbeds
Tertiary			Kerri-Kerri		130		Iron rich sandstone and clay covered by plinth of laterite
Cretaceous	Upper	Maastrichtian	Gombe		315	0–1 000	Sandstone, siltstone and clay with coal beds. Fossils, bivalve impressions and *Cruziana lebana purren*
		Senonian	Fika		430	0–900	Shale, dark gray to black, gypsiferous with limestone beds
		Turonian	Gongila		420	0–800	Alternating sandstone and shale with limestone beds
		Cenomanian	Bima		3 050	2 000	Sandstone, gravelly to medium grained, poorly sorted and highly feldspathic
	Lower	Albian	Unnamed	???		3 600	Seismically transparent sequence, monolithologic sequence inferred
			Unnamed			0–3 000	Piedmont alluvial fans early rift sediments
Precambrian			Basement				

Sandstone █ Shale ﹌ Unconformilty

Figure 2: Stratigraphic Units in the Bornu Basin [17,25].

sediments were deposited directly on the seismically defined two unnamed units (also observed in outcrop, Avbovbo [17] that were likely deposited during the Aptian-Albian early rift stage or rift phase I of Genik [1,20] or syn-rift phase I of Popoff [22]. Regional extensional events during the Cenomanian marked the onset of marine transgression in the basin [2,17,20], which some authors claimed to have led to the deposition of Yolde Formation. A short-lived regressive phase of the transgression period led to the deposition of the Gongila Formation. Sediments of this formation consist of basal limestone and overlying sandstone-shale alternating sequence. Some authors prefer to merge the two formations (Yobe and Gongila) together as the Gongila Formation (Figure 2) Marine transgression predominated throughout most of the Turonian and reached its peak in the late Turonian to Senonian, when sediments of Fika Formation were deposited in an open marine environment [3,4,23]. This formation conformably rests on the Gongila Formation and consists of blue to black, thick-bedded shales, which sometimes contain gypsum, and thin interbedded siltstones and sandstones. According to Alalade [8] the upper part of Fika Formation was deposited under an oceanic anoxic event. Following the Santonian Squeeze event recorded in the basins of WCARS, there was an uplift

and erosion in the basin. This event was followed by the deposition of Gombe Formation lying unconformably on the Fika Formation. Gombe Formation consists of alternating siltstones, clays, and sandstones that become ferruginous towards the top. This formation is interpreted to have been deposited in an estuarine to deltaic environment during the Maastrichtian [4,17]. The last rifting phase in the Chad Basin during the late Maastrichtian to Paleocene resulted in development of a series of NE-SW horst and graben structures. This phase was followed by a long period of non-deposition [4,20]. The long unconformity period elapsed with the deposition of Kerri-Kerri Formation, probably in a continental (lacustrine) environment during the Neogene. The Kerri-Kerri Formation consists of loose coarse- to fine-grained, cross-bedded shaly sandstones. The youngest formation, Chad Formation, also of continental origin, comprise fine- to coarse-grained sandstones with intercalated sandy clay, clay and diatomite deposited during the Pliocene. The central and southern parts of the Chad Basin experienced widespread of volcanic activities in the late Tertiary to recent [24].

Methodology

A total of 29 samples were carefully selected from three wells-Kuchali-1; Herwa-1 and Faltu-1 located in the Lake Chad area of the Bornu Basin for this study [25]. One major factor that guided the sample selection was detailed visual sedimentologic studies of all the cuttings of the wells to eliminate samples with poor organic matter content i.e. sands, marl and clay. The selected samples were assigned to different formations based on the interpretation carried out by Olabode [7] using the lithological characteristics derived from the well logs.

The samples were sieve-washed under running water to remove drilling contaminants, dried and pulverized. One gram of powdered sample was decarbonated with HCl and utilized for total organic carbon (TOC) analyses using a LECO-CS 244 carbon analyser.

After the TOC analysis, the Rock-Eval pyrolysis was performed on the samples utilizing 100 mg of powdered borehole cuttings and was done using a GEO-IMT-2005 instrument. Ground sediment samples were heated in an inert atmosphere at 300°C to liberate hydrocarbons which have been generated but not expelled from the source rock (S1). Further heating to 650°C led to the generation of all further potential hydrocarbons from the sample (S2). The temperature at the peak of S2 marks the Tmax. The quantity of hydrocarbons was measured by using an external standard method, built into the Rock-Eval data system. A response curve for the instrument's FID detector was calibrated in mg (oil)/gram (rock) using known IFP standards. The hydrogen index (HI) was determined as the yield of reduced products of pyrolysis (S2) relative to the TOC (mg HC/g TOC) while the oxygen index (OI), which is the yield of the oxygen and bound organic carbon (S3) deduced from the relation S3/ (S1+S2).

Result

Bulk geochemistry

Twenty-nine samples from three wells (Kutchali-1 (7), Faltu-1 (11), and Herwa-1(11)) were analysed to arrive at the bulk geochemical properties of the strata penetrated by the wells (Tables 1 and 2). Since evaluation of a rock has to be based on integration of multiple parameters to ascertain availability of source rock in a basin the plot of TOC, HI and $T_{max.}$ against depth for each of the three wells was made (Figures 3-5).

Organic particles and vitrinite reflectance value

The organic particles contained in selected samples and their corresponding vitrinite reflectance data obtained for Kutchali -1, Faltu -1 and Herwa-1 are displayed in Figures 6-8 respectively.

Kutchali-1: Only three samples picked at depths of 1890 m, 2190 m

Age	Formation (Olabode et al.)	Lithology	Depth (m)	TOC (wt.%)	S1 mg/g	S2 mg/g	S3 mg/g	HI=S2/TOC × 100	OI=S3/ (S1+S2)	PI=S1/ (S1+S2)	Tmax	S2/S3	S1/TOC × 100
Herwa-1													
U. Santonian -Campanian	Fika	Shale	2000	0.63	0.19	0.59	0.83	94	132	0.24	432	0.71	30.16
U. Santonian-Campanian		Shale	2250	1.1	0.32	1.37	1.09	125	99	0.19	436	1.26	29.09
Santonian-L. Campanian		Shale	2350	0.8	0.14	0.79	1.37	99	171	0.15	436	0.58	17.5
Santonian-L. Campanian		Shale	2550	0.82	0.3	1.01	1.12	123	137	0.23	441	0.9	36.59
Coniacian		Shale	2700	0.76	0.17	0.88	1.09	116	143	0.16	427	0.81	22.37
Coniacian		Shale	2850	0.72	0.23	0.81	0.98	113	136	0.22	437	0.83	31.94
Coniacian		Shale	3250	0.18									
Coniacian		Shale	3400	0.66	0.2	0.37	0.65	56	98	0.35	380	0.57	30.3
Cenomanian -Turonian	Yolde/Gongila	Shale	4000	0.74	0.23	0.91	0.71	123	96	0.2	439	1.28	31.08
Albian and Older	Bima	Shale	4200	0.63	0.2	0.78	0.87	124	138	0.2	443	0.9	31.75
Albian and Older		Shale	4550	1.1	0.35	0.82	1.24	75	113	0.31	384	0.66	31.82
Faltu-1													
Santonian-L. Campanian	Fika	Shale	1560	0.78	0.07	0.3	0.88	38	112	0.19	429	0.3	8.94
Santonian-L. Campanian		Shale	1700	0.68	0.05	0.26	0.66	38	97	0.16	434	0.4	7.33
Coniacian		Shale	1940	0.76	0.04	0.11	0.61	14	80	0.27	431	0.2	4.18
Coniacian		Shale	2140	0.64	0.05	0.26	0.52	41	82	0.16	431	0.5	5.24
Coniacian		Shale	2220	0.93	0.07	0.84	0.47	90	51	0.08	435	1.8	7.84
Turonian	Gongila	Shale	2340	0.86	0.05	0.71	0.49	83	57	0.07	434	1.4	6.9

Cenomanian-L. Turonian	Yolde	Shale	2420	1.18	0.04	0.46	0.69	39	58	0.08	428	0.7	7.85
Albian		Shale	2460	0.65	0.06	1.05	0.38	162	59	0.05	439	2.8	7.53
Albian and Older		Shale	2560	1.62	0.09	4.53	0.46	280	28	0.02	445	9.8	5.79
Albian and Older		Shale	2920	2.88	0.3	7.38	0.7	256	24	0.04	443	10.5	5.84
Albian and Older		Shale	3120	0.8	0.1	0.68	0.62	86	78	0.13	441	1.1	13.75
Kutchali-1													
Santonian-L. Campanian	Fika	Shale	1890	0.92	0.12	0.56	0.38	61	41	0.18	432	1.47	13.04
Santonian-L. Campanian		Shale	1950	1.09	0.28	0.98	0.44	90	40	0.22	432	2.23	25.69
Santonian-L. Campanian		Shale	2070	0.77	0.14	0.6	0.33	78	43	0.19	438	1.82	18.18
U. Coniacian		Shale	2190	0.92	0.22	0.82	0.5	89	54	0.21	441	1.64	23.91
U. Coniacian		Shale	2220	0.72	0.12	0.61	0.39	85	54	0.16	440	1.56	16.67
U. Coniacian		Shale	2280	0.8	0.09	0.56	0.3	70	38	0.14	439	1.87	11.25
Turonian	Gongila	Shale	2790	0.83	0.43	1.31	2.31	158	278	0.25	421	0.57	51.81

Table 1: TOC and Rock-Eval pyrolysis data for three wells in the Nigerian sector of Chad Basin.

Depth (m)	Vitrinite reflectance (%Ro)	Standard deviation	Count	Confidence (95%)
1890	0.60	0.04	3	0.10
2190	0.80	0.06	6	0.06
2790	0.88	0.05	6	0.05

Table 2: Vitrinite reflectance data to determine source rock status of some strata penetrated by Faltu-1 well.
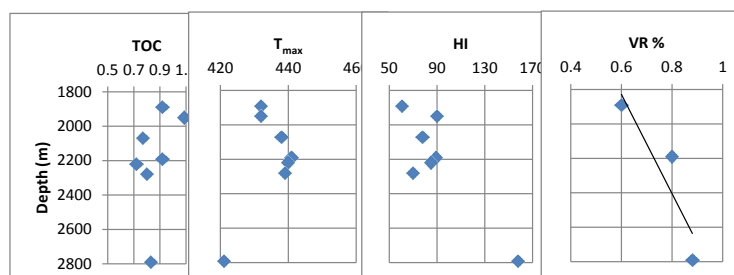

Figure 3: A plot of bulk geochemical and vitrinite reflectance data to determine source rock status of some strata penetrated by Kutchali- 1 well, Bornu Basin, Nigeria. A=TOC Vs Depth, B=Tmax Vs depth, C=HI vs Depth and C=VR% vs Depth.
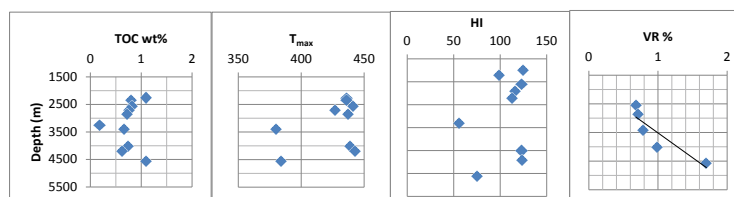

Figure 4: A plot of bulk geochemical and vitrinite reflectance data to determine source rock status of some strata penetrated by Herwa - 1 well, Bornu Basin, Nigeria.
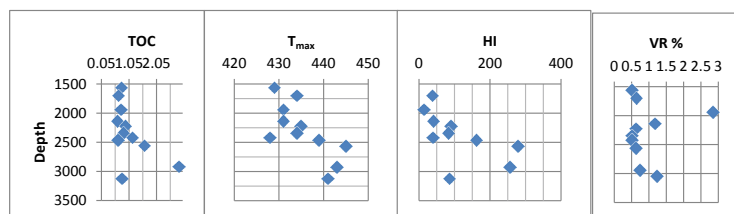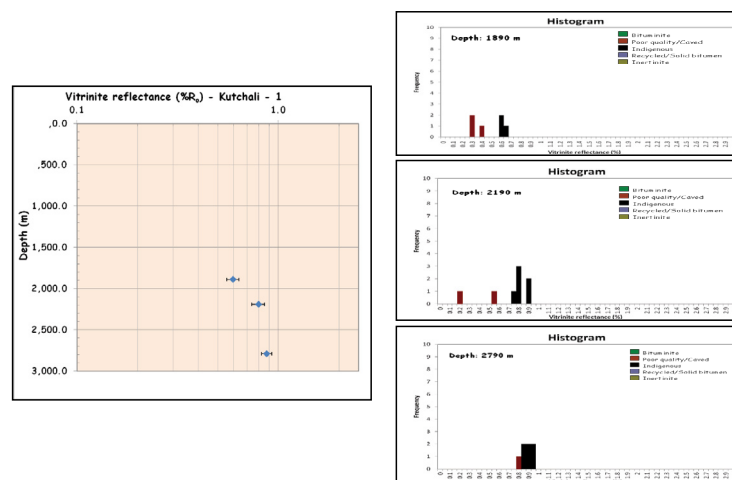

Figure 5: A plot of bulk geochemical and vitrinite reflectance data to determine source rock status of some strata penetrated by Faltu - 1 well, Bornu Basin, Nigeria.

Figure 6: Whole rock vitrinite reflectance results for Kutchali-1. A. Depth plot of vitrinite reflectance, B. Histogram plots for the organic matter particles and vitrinite reflectance values obtained at different depths in the well.
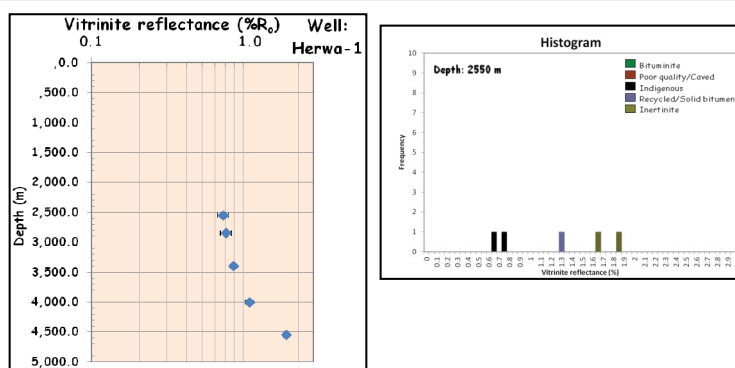
Figure 7: Vitrinite reflectance plots for Herwa- 1 well.
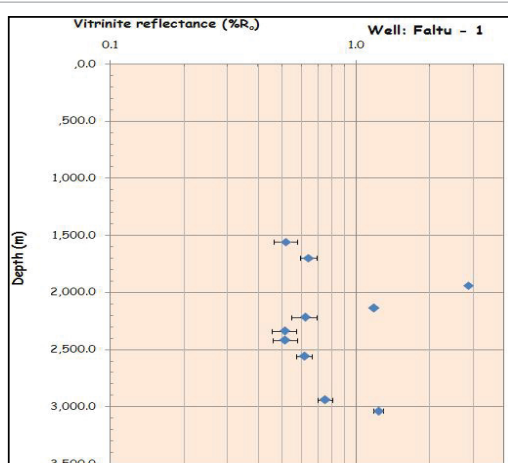
Figure 8: Vitrinite reflectance values for Faltu- 1 well.

and 2790 m were analysed in Kutchali-1 well (Figure 6). These samples were composed of powdered siltstone, carbonate grains and mudstone that had low organic matter content. Many particles were small and of poor quality. The most commonly occurring particle type was inertinite while a few particles appeared to be charred. Vitrinite was present in trace to low quantities and differentiation of primary from recycled vitrinite was often difficult. Only a few particles embedded in rock fragments were unequivocally deemed to be primary and used for this determination. There was no appreciable matrix bitumen stain while in a few samples the stain was light. Under blue light excitation, very low liptinite content was revealed. There were few algal cysts, which occasionally occurred as primary component that fluoresced yellow. However, one excellent trilete spore fluoresced light orange to mid orange with low intensity. Caved particles and some potentially drilling materials introduced as artifacts were present in all the sample. The vitrinite reflectance (VR) values obtained for the three samples were 0.60%Ro, 0.80%Ro and 0.88%Ro (Figure 6). Thermal maturation in the different samples from the various depths was assessed as early to peak oil window mature and late peak oil window mature (Table 3).

Herwa-1: Five ditch cutting samples selected at the following depths: 2550 m, 2850 m, 3400 m, 4000 m and 4550 m, were subjected to vitrinite reflectance study. The samples were composed of mudstone and siltstone with moderate organic matter content dominated mostly by recycled particles of vitrinite, inertinite and coaly contaminants (Table 4) (Figure 7). Primary vitrinite was present at a relatively low quantity and was at most times difficult to distinguish from recycled organic matter. The VR obtained from the study were 0.68%Ro, 0.71%Ro, 0.79%Ro, 0.99%Ro and 1.70%Ro varying from the shallowest to the deepest level. Mineral matrix was lightly stained with bitumen.

One tenuispore and orange spore fluoresced light orange with low to moderate intensity in a few samples while in other samples there was no convincing organic matter that shows flourescence. Some specimens in the samples exhibited artifacts of tiny pollen grains that showed flourescence. In others, trace spores fluoresced mid to dark orange with weak intensity. Hematite was present in some samples. Thermal maturation of the samples was considered to be at least peak oil window, late oil window and wet gas/condensate zone mature. The vitrinite reflectance values increase downhole (Figure 4d).

Faltu-1: In Faltu-1 well, ten ditch cutting samples were selected for vitrinite reflectance evaluation. They were picked at the following depths: 1560 m, 1700 m, 1940 m, 2140 m, 2220 m, 2340 m, 2420 m, 2560 m, 2940 m and 3040 m. The samples were made up of mudstone, silstone and shale with low to moderate organic matter content. They were dominated by inertinite and recycled vitrinite with subordinate contribution from primary vitrinite (Figure 8). Primary vitrinite was present as very small lenses and stringers that are high reflecting and poor to fair in quality often with degraded surfaces. There was abundance of phytoclasts that appear coal-like. Bituminite was occasionally present in few samples while liptinite was present in low amounts. Spore and trace spores fluoresced yellow-orange and light orange with moderate intensity, respectively. Hematite was fairly common and mineral matrix had light bitumen staining. The VR values attained for the sampled depths were 0.52%Ro, 0.64%Ro, 2.85%Ro, 1.18%Ro, 0.62%Ro,

Depth (m)	Vitrinite reflectance (% Ro)	Standard deviation	Count	Confidence (95%)
2550	0.68	0.05	2	0.48
2850	0.71	0.06	3	0.14
3400	0.79	0.03	4	0.05
4000	0.99	0.05	4	0.09
4550	1.7	0.06	2	0.56

Table 3: Vitrinite reflectance result.

Depth/Sample number (m)	Vitrinite reflectance (%Ro)	Standard deviation	Count	Confidence (95%)
1560	0.52	0.06	6	0.06
1700	0.64	0.05	6	0.05
1940	2.85	0	1	0
2140	1.18	0	2	0.03
2220	0.62	0.07	6	0.08
2340	0.51	0.06	11	0.04
2420	0.52	0.06	11	0.04
2560	0.62	0.04	13	0.03
2940	0.75	0.05	13	0.03
3040	1.23	0.06	11	0.04

Table 4: Vitrinite reflectance plots for Herwa-1 well.

0.51%Ro, 0.52%Ro, 0.62%Ro, 0.75%Ro and 1.23%Ro from the upper to the lower depths. These data indicate that the thermal maturation of the samples is dry gas zone, moderate to early oil window mature, late oil window and wet gas/condensate zone mature. The VR values exhibit irregularities with increasing depth.

Source rock potential

The level of maturity of the tested sections of the three wells derived from a plot of HI against T_{Max} is displayed in Figure 9. To examine all lines of evidence based on available data, the kerogen potential and van Krevelen diagrams were plotted (Figure 10). Figure 9 reveals that the samples from the three wells fall between immature and mature (oil window) zone. While most Kutchali and Herwa samples plotted close to the margin of mature oil window zone with the immature zone, the Faltu samples concentrate largely in the mature zone.

As revealed by the van Krevelen diagram in Figure 10 the source rock for the Kutchali samples is Type II but very close to type III margin whereas the kerogen potential diagram (S_2 vs TOC) indicates type III kerogen which is gas prone. Herwa samples reveal type III kerogen indicating gas prone source rock like its Kutchali samples whereas those of Faltu show that they contain type II/III kerogen capable of generating both oil and gas.

Discussion

Source rock evaluation in each of the three wells

In this section, emphasis shall be laid on depth of sampling in each well in the Bornu Basin.

Kutchali well: Within the section studied in Kutchali well, the TOC is far above the 0.5 wt% threshold for hydrocarbon generation [25]. All the TOC values vary between 0.7 wt% and 1.1 wt% (Figure 4) (Table 1), indicating a fair source-rock generative potential (Figure 10). Recent data on TOC values from some Kutchali samples published by Alalade [8] also support a fair to very good source rock potential based on the obtained TOC values that range from 0.64-2.0 wt%. However, these values are still less than those recorded in the neighbouring oil producing Termit Basin with TOC ranging from 1-30 wt% with averages of 2-3 wt% [20].

The organic matter type in a source rock dictates the nature of hydrocarbon products. To know this important parameter, the following indicators are commonly used: van Krevelen plot, kerogen potential diagram and HI values. van Krevelen plot of samples from Kutchali-1 (Figure 10a) suggests type II kerogen with only one sample at the boundary of type III/II; However, the kerogen potential diagram (Figure 10b) indicates a gas prone type III kerogen.
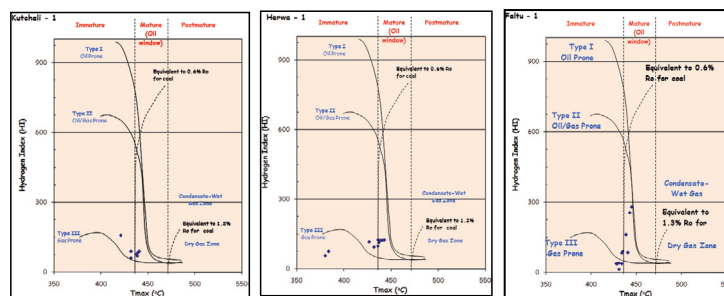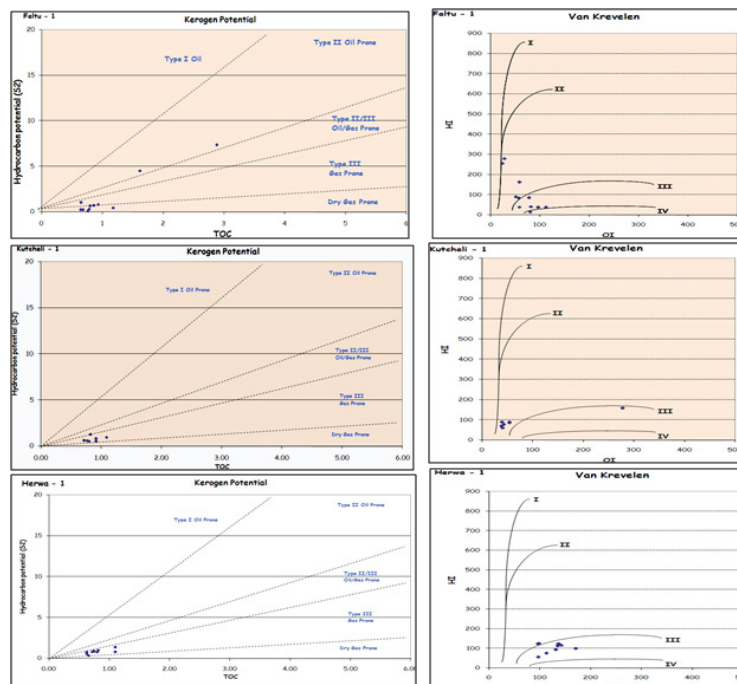

Figure 9: Plots showing type of kerogen and their level of maturation in three wells from the Chadian sector of the Bornu Basin, Nigeria.

Figure 10: Plots showing hydrocarbon generation potential plots(A) (modified after Ghoria) and Van Krevelen diagrams (B)for three wells: Faltu- 1, Kutchali- 1 and Mbeji- 1 in the Lake chad area of the Bornu Basin.

The HI values obtained from the well dominantly range between 61 and 90 with only one sample reaching 158. According to McCarthy [26], HI value of between 50 and 200 will lead to the generation of gas, which suggests that all the samples tested in Kutchali-1 are capable of generating gas. The maturity level of the organic matter as determined by the HI vs T_{max} plot (Figure 9) and VR values (Figure 6) falls within the mature oil window although a few samples are immature, several authors recommend 435°C T_{max} as marking the onset of hydrocarbon generation, but McCarthy [26] put it at 440°C for type III kerogen. If the Tmax threshold value of 440°C is accepted for type III kerogen, then only Kutchali samples from depths below 2000 m (Figure 3b) which fall within the oil window (Figure 9) can generate gas.

Herwa-1 well: The organic matter richness of the sediments in Herwa-1 were determined using TOC values. The TOC values of the tested section of the well vary from 0.6 to 1.1 wt% (Table 1) implying that the sediments are sufficiently rich in organic matter for hydrocarbon generation. According to Peters (1986) the TOC values of between 0.5 and 1.0 wt% indicate a fair source-rock generative potential and from 1.0 to 2,0 wt% reflect a good generative potential.

All the samples analysed except two in Herwa-1 well have HI values greater than 100 mgHC/gTOC but not more than 150 mgHC/gTOC (Table 1), which, according to Peters [25], suggest a gas prone organic matter. Similarly, the kerogen potential diagram (Figure 10) also shows the plot of the samples in type III kerogen gas prone zone. However, the HI vs T_{max} and the Krevelen plots suggest that the organic matter in the source rock facies is composed mainly of Type II/III (oil/gas prone) kerogen (Figures 9a and 10a). This shows that the source for the organic matter contents is predominantly from the terrestrial environment. Figure 9b also reveals that most samples are oil window mature while a few are immature.

Thermal maturity level of the organic matter suggests that two of the samples having lower T_{max} at deeper levels (Figure 4) might have

suffered cooling attributable to uplift/exhumation as shown by the plot of T_{max} against depth (Figure 4).

Faltu-1 well: The results derived from the bulk geochemical analysis of samples from Faltu-1 well are displayed in Figure 5. TOC values derived from Faltu-1 well suggest that the well penetrated several organic rich beds (Table 2) (Figure 5a). All the values range from 0.64-2.88 wt% which are well above the 0.5 wt% threshold for HC generation. Organic rich facies of good source rock generative potential (TOC>1.0 wt%, Peters [25]) even occur at depth of about 3000 m, which is probably below the Fika Shale in the stratigraphic succession penetrated by the Faltu-1 well. Two samples from the well at depths of 2560 m and 2920 m have HI values of 280 and 256 mgHC/gTOC, respectively (Table 1) with corresponding T_{max} values of above 435°C. This suggests that the sections contain types II/III and II kerogen which has genetic potential for generating both oil and gas. Both the Krevelen and kerogen potential plots (Figure 10) also confirm the Faltu kerogen to be type II (oil prone) and type III (gas prone). The thermal maturity level of the Faltu kerogen (Figure 9) indicates the type II kerogen is mature within the oil window and is oil/gas prone while the type III kerogen is immature. Therefore, based on the three parameters of TOC, T_{max} and HI defined by Peters [25] and their variation with depth (Figure 5), several potential gas source intervals and two potential oil source intervals can be distinguished in Faltu-1 well. It can be reasonably inferred from Figure 5 that the potential oil source intervals probably lie between 2500 m and 3000 m depth in the well.

Organic matter (kerogen) type and hydrocarbon generation potential

The close relationship between organic matter and the type of hydrocarbon it can generate is well documented [25-28]. A plot of HI versus OI (van Krevelen diagrams) and S_2 vs TOC used in this study show that most of the examined samples in the three wells consist of type III kerogen, which are capable of generating gas [27]. However,

two samples in Faltu-1 well recoding HI above 200 and type II kerogen have genetic potential for oil (Figure 10). One sample falls very close to the margin of Type II/III kerogen (Figure 10b). This sample is also capable of generating oil and gas.

Source rock evaluation on a stratigraphic basis and in relation to other African basins

The stratigraphic subdivision used in this study is based on Olabode [7]. Of the three wells (Kutchali -1, Herwa-1 and Faltu-1) studied in the Lake Chad area, all the samples identified as Bima Formation (Table 1) are mature (T_{max}>435°C), except for one sample in Herwa-1 at a depth of 4550 m where the T_{max} is 384°C. Similarly, Yolde Formation (Table 1) is considered mature (within the oil window) in all the wells. But the sample analysed in Faltu-1 well in this formation at a depth of 2420 m is immature (T_{max} is 428C) (Table 1). Samples were obtained from Gongila Formation in two wells (Faltu-1, (2340 m) and Kutchali-1 (2790 m)). The formation is thermally mature in Faltu-1 while it is immature in Kutchali-1 (T_{max} is 421C). Majority of the samples analysed from the three wells in the Lake Chad area of the basin are from Fika Formation. This formation is thermally mature or very close to being mature in most of the wells having T_{max} values >430°C. In Herwa-1 well low T_{max} values (380°C) was recorded for the same formation at depths 3400 m. even though higher T_{max} values were obtained at shallower depths (Table 1). Such a decrease in T_{max} at deeper depths as observed in Bima and Fika Formations suggests cooling

Petroleum generation potential of any strata is directly related to its volume, organic richness and thermal maturity [26,27]. This study is concerned only with about the organic richness and maturity. Organic richness is a function of the amount and type of the organic matter in the sediments. In the three wells studied, samples of Gombe Formation, which are mainly reworked sediments deposited after the Santonian squeeze in the basin are predominantly sandstone and marl. Similarly, the Tertiary succession in the area of study consists of clay and sand. The implication of this is that, apart from the issue of type and maturity of organic matter, the Campano-Maastrichtian and Tertiary sediments of the study area in the Bornu Basin lack sufficient organic matter that could generate hydrocarbon and so were excluded from geochemical studies. This is in contrast to other oil producing rifts basins of WCARS such as the close by the Termit Basin that contains Cretaceous, as well as Tertiary lacustrine and marine source rocks and the Interior Sudan Basins where sediments of over 5,486 m with inter-bedded organic rich shale are recorded in the Tertiary [20,29]. In the complex rift systems of East Niger, both the Cretaceous marine shales and Oligocene lacustrine shales serve as source rocks [30].

Organic matter maturation, tectonism and oil generation window

In all the wells studied, the T_{max} values do not show any consistent variation with depth while the VR values tend to display increase with depth in Kutchali and Herwa but are irregular in Faltu (Figures 3-5). However, a close study of the T_{max} variation with depth reveals noteworthy decreases at some levels. For example, in Kutchali there appears to be a decrease in T_{max} from 440°C at a depth of 2220 m down to 421°C at 2800 m depth (Table 1) (Figure 3) but the Herwa T_{max} plot shows 3 irregular decreases at 2600 m, 3450 m and 4500 m depths (Figure 4). The irregularities displayed by the Faltu T_{max} plot (Figure 5) reveal 2 subtle increasing and decreasing trends each. The first decreasing trend involves a decrease from T_{max} of 435°C at 2220 m depth to 428C at 2420 m depth and the second from 445°C at 2560 m to 441°C at 3120 m. The T_{max} decreases or irregular distribution with

depth in the wells suggest cooling which can be occasioned by several geological factors including uplift leading to unconformities, faults, changes in geothermal gradients and contamination from migrated oils and bitumen [25,31]. According to Sahagian [32] a back-stripping study of the Chad Basin and Benue Trough suggests a better affinity between the Benue Trough and the Bornu Basin than between the Chad Basin and the Bornu Basin. The subsidence of the Benue Trough is dominated by early cretaceous rifting and rapid fault-bounded subsidence. He also observed that the post-faulting thermal subsidence history was interrupted by compressional folding in the Late Cretaceous, which correlates with the Santonian squeeze of Genik [20]. The Late cretaceous folding must have caused uplift resulting in the cooling suggested by the irregular T_{max} history of the study area because the deposition of the studied sections predated the Santonian squeeze [24].

The "onset of oil generation window" delineated in this work probably occurs below 2000 m depth as suggested for Kutchali well. This is in agreement with the findings of Thomas [33] who estimated the threshold of the "oil window" in the Bornu Basin to be at a depth of 2000 m which correlates somewhat with the Genik's [20] suggestion of 2500-4000 m "oil window" in the rift basins of the West African Rift Subsystem that includes the Bornu Basin. A shallower "oil window" of 1522 m has been recommended by Nwankwo and Ekine [34] on the basis of geothermal gradient studies of the Bornu Basin. Such a "shallow oil window" will lie below the intra-Maastrichtian unconformity in the wells studied.

Conclusion

1. The conventional source rock evaluation tools using TOC and Rock-Eval pyrolysis of selected source rock intervals of the Cretaceous succession in the Lake Chad area presumably containing the thickest sediments in the Bornu Basin indicates a generally fair to moderately good amount of organic matter with TOC in the range of 0.63-2.88 wt%.

2. HI vs T_{max} plots, supported by van Krevelen and S_2 vs TOC plots, to determine the kerogen types and their maturity show that the dispersed organic matter in the source rock facies is composed mainly of Type III gas prone kerogen with subordinate Type II/III (oil/gas prone) kerogen. This shows that the source for the organic matter contents is predominantly derived from terrestrial environment.

3. The variation of Tmax and VR with depth reveals irregular decreases or subtle decreasing trends that are suggestive of cooling in the basin's thermal history probably as a result of uplift and erosion. The uplift could have been caused by epeirogenic movement or by folding related to the Santonian squeeze of Genik [1].

4. A careful study of some bulk geochemical parameters (TOC, Tmax and HI) of the three study wells (Kutchali-1, Herwa-1 and Faltu-1) has revealed that the succession penetrated by the Faltu well contains several potential gas source intervals and two potential oil source intervals with the latter probably lying between 2500 m and 3000 m depth.

5. The onset of "oil generating window" probably occurs in parts of the Lake Chad area (the study area) below 2000 m depth based on the assumption of McCarthy [26] that type III kerogen can only become mature if subjected to Tmax of 440°C.

6. Tertiary sequences in the study area, unlike those of the neighbouring rift basins (e.g. Termit Basin), are predominantly clay, marl and sandstone that are deficient in organic matter for hydrocarbon generation.

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