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EVALUATION OF THERMAL MATURATION INDICES IN SEDIMENTARY BASINS: IMPLICATIONS TO HYDROCARBON POTENTIALS IN BORNU BASIN NIGERIA

Cyril N. Nwankwo and Leonard I. Nwosu

University of Port Harcourt Nigeria

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Abstract

Effort is made in this study to establish the hydrocarbon potential of the Bornu Basin by analyzing the thermal maturation indices in 14 exploratory Wells in the area. The time-temperature index, virtrinite reflectance and maturation index were modeled to establish the thermal maturity condition of the basin, based on established geothermal gradient, subsurface temperature and burial history. The estimated TTI values derived from Lopatin's method was compared with the measured Ro to validate the accuracy of the findings. The results show that sediments from late Santonian units in the basin have reached sufficient thermal maturity to generate hydrocarbons. The peak of the maturation at about 3920 m when TTI is 68.8 and Ro of 1.33, occurs at about 99.5 Ma. The onset of maturation is defined by TTI of 15 at sediment of 3920m occurs at 108 Ma.

Keywords: Maturation indices; Lopatin; vertrinite reflectance; hydrocarbon; Chad Basin.

1. Introduction

Various methods have been developed for calculating maturity levels of organic source rocks, when oil generation occurred and at what depth or temperature it occurred. Some of these thermal maturation indicators in sedimentary rocks are virtrinite reflectance (Ro), paleotemperature, oil-window concept, Time-Temperature Index (TTI) etc. Accurate assessment of these parameters help in reducing exploration risks, especially in Bornu Basin Nigeria where several attempts of discovering hydrocarbon of commercial value have not been fruitful despite discoveries in other areas within the Chad Basin. The maturation of hydrocarbons is the slow thermodynamic conversion of organic matter (kerogens) in source rocks into oil and gas, which then migrate to more porous reservoir rocks. This maturation process is mainly influenced by local temperature and the duration of thermal event; and these are in turn controlled by rates of subsidence and sedimentation.

Virtrinite is the organic matter (remains of wood plant) commonly found in sedimentary rocks. Loss of volatile components and graphitization of carbon during burial, results to an increase in the optical reflectivity of virtrinite. Vertrinite reflectance, Ro is therefore a measure of the percentage of light reflected from samples in kerogen (example, oil) in order to determine source rock maturity. It is commonly found to be in the range of 0.2 to 2.0 for potential hydrocarbon source rocks while significant hydrocarbons are however, produced only from rocks with virtrinite reflectance in the range of 0.65 and 1.30 [1]. The Time-Temperature Index method developed by Lopatin [2] has become a house hold model to basin maturity analysis in the last few decades though not without some criticisms [3]. The method which is defined as the sum of the products of weighting factors and residence time of such units for every 10 °C interval corroborates with other parameters which relate to oil generation to devise a model that could predict the thermal conditions under which hydrocarbons could be generated and preserved. Lopatin's method has been used in the present study to understand the thermal maturity and hydrocarbon generation potential of the study area.

The important relationship between temperature, petroleum generations and heat flow in sedimentary rocks during burial necessitates the determination of the paleotemperature and hence the thermal potential for maturation of such strata. Piggot [4] presented a model for assessing the source rock maturity of a sedimentary basin. The oil ceiling, or depth of intense oil generation, is defined as the depth below the diagenetic zone of buried sediment at which oil generation begins to increase substantially, while the depth and associated temperature at which oil is no longer generated and gas begins to dominate (metagenesis zone) is known as the oil floor. These two depths bound the oil generative window (zone of catagenesis). This concept of sediment maturity estimate has been applied for the Bornu Basin [5].

Various attempts of drilling productive wells in Bornu Basin have necessitated the application of different maturity modeling techniques that are vital in assessing the geological factors that are essential for petroleum generation and accumulation in the basin. This study therefore, attempts to synthesize the results of various thermal history analyses to assess the maturation level of the lithostratigraphic units in the basin. The computed values from the different modeling techniques were compared in order to predict if the thermal conditions under which hydrocarbons are generated and preserved have been attained by Bornu Basin sediments. The result could be a guide for subsequent exploratory work in the basin.

2. Geologic History of Chad Basin

Chad basin is centered on Lake Chad at the elevation of 200m to 500m above sea level [6]. It is concentrated within the large area of West Africa. The basin is the largest inland basin in Africa and covers a total area of about 2,335,000 km^2 [7-8], and extends to Nigeria, Niger Republic, Cameroon, Chad Republic and Central Africa Republic (Figure 1).

During early Cretaceous when African and South American lithospheric plates separated and the Atlantic opened, a rift system was developed mostly in the Benue trough. That was said to be the origin of Chad Basin [9]. The basin experienced initial extensional tectonics with intermittent periods of less influential compressive tectonism and magmatism. Santonian Cretaceous sediments were also deposited within this rift system.

Bornu Basin is the Nigerian sector of the Chad Basin and covers about 152,000 Km^2 of territory of Borno, Bauchi, Plateau and Kano States put together. It makes up 6.5% of the whole basin and falls between longitudes 11° 45′E and 14° 45′E, and latitude 9° 30′N and 13° 40′N [10-11]. The range of the altitude is from 300m within the lake to about 530m at the western margin, along a distance of about 240km [12]. The basin developed at the intersection of many rifts especially, in the extension of the Benue trough. The most common structural features in the basin are horsts and grabens, buried hills and intrusive volcanic [13]. Majority of the Faults in the basin are tensional and basement involved, which terminate beneath a regional angular unconformity at the boundary between the Cretaceous and Tertiary [13-14].

The basin contains about 4.65 km of marine and continental sediments made up of the Bima Sandstone, Gongila Formation, Fika Shale, Kerri Kerri and Chad Formations. The Bima

Formation composed of feldspathic, coarse grained sandstones with occasional shale interbeds. It is the oldest stratigraphic unit in the area (Albian to Cenomanian), and lies on the basement complex. The Gongila Formation is a transitional sequence and overlies the continental Bima Sandstone conformably. It represents the first marine sediment in the Cretaceous basin and consists of thin to moderately thick inter beds of shale, silty sandstone and sandstone. Fika Formation is made up of blue-black, fissile, fossiliferous, argillaceous sandstones with irregular limestone layers. The formation is Turonian to Maestrichtian in age. The Kerri-Kerri Formation is of Paleocene age, and represents an unconformable continental sequence of flat lying grits, sandstone and clays. An unconformity is observed between Fika and Kerri-Kerri Formations [16-17]. Chad Formation is the youngest stratigraphic unit in the basin and consists mainly of fine to coarse grained sands, siltstones, diatomite, clays and blue-grey shales.

The basin is rimmed by crystalline basement rocks mainly of granitic and gneissic compositions with some mica schists. Basalts, minor basic and acidic intrusions (particularly of

Tertiary age) occur commonly within parts of the basin as sills and plugs. These intrusions (sill and plugs) on Tertiary rocks could change the heat flow and temperature [18].

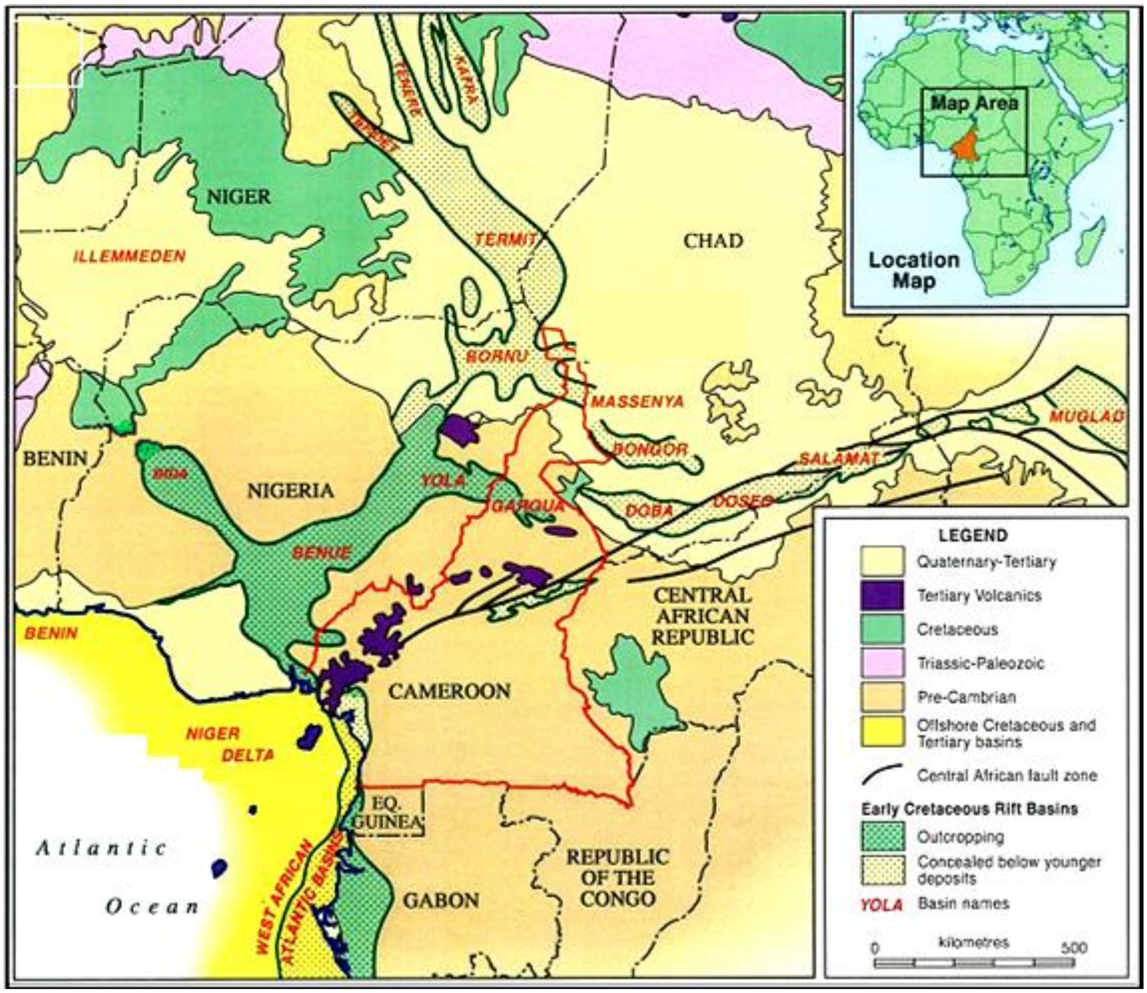

Figure 1. Regional map showing the location of Chad and other neighboring basins [15].

3. Materials and methods

The sedimentary layer of 14 deeper oil wells drilled in the study area were decompacted utilizing 'back-stripping' method in order to determine the geology and maturation history of sediments deposited at earlier times (Figure 2) [19]. In order to construct the temperature grid of the geologic model, the variation of heat flow or geothermal gradient with time, the thickness of each sedimentary layer as a function of time, and conductivities as a function of time and depth were determined [18, 20]. The near surface temperature at time t, and depth z were computed utilizing Sclater and Christie [21] expression:

$$T(t,z) = T_{surface} + \int_{o}^{z} \frac{Q(t)dz}{K(t,z)} \qquad (1)$$

where K(t,z) is the conductivity as a function of time and depth; $T_{sufarce}$ is the surface temperature and Q(t) is the heat flow. We integrate equation 1 numerically for each layer after establishing how the conductivity varies with depth for the lithologies from the conductivity, porosity and depth relationships. A surface temperature of 27°C has been assumed to be constant throughout the time interval covered by the reconstruction.

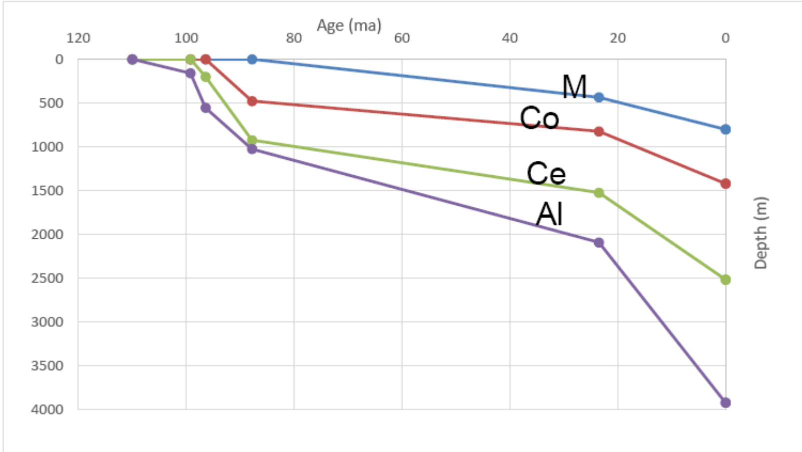

Figure 2. Burial history of Murshe-1 Well. M = Miocene, Co = Coniacian, Ce= Cenomanian, Al = Albian

In calculating the degree of thermal maturation of a given sedimentary basin, Royden *et al.* [22] established the hydrocarbon thermal alteration parameter C to be related to temperature by the following relation:

$$C = \ln \int_0^t 2^{T(t,z)}/10dt \qquad (2)$$

where T(t,z) is temperature as a function of time t, and t is in million years. This relationship is based on the observation that the reaction rate for thermal alteration of organic sediments doubles for every 10°C increase in temperature. Oil generation process started at C value of 10 and is essentially complete when it is greater than 16 [23].

Several workers [22, 24-25] have proposed equations relating temperature and virtrinite reflectance. Reflectivity is generally accepted as a measure of thermal alteration of organic matter, and is assumed to increase with temperature and time. Middleton [24] expressed the virtrinite reflectance (R_o) as

$$(R_0)^{5.5} = 3.4 \, x \, 10^{-6} \int_0^t \exp[0.069\, T(t)dt \qquad (3)$$

where R_o is expressed in %, T in °C and t in million years (Ma).

It is generally accepted that crude oil generation occurs for reflectivity values between 0.6% and 1.5%. Gas generation takes place for R_o between 1.5% and 3.0%; and at values greater than 3.0%, rocks are graphitic, and without any hydrocarbons. Immature sediments have R_o values range between 0.21 and 0.59. Virtrinite reflectance scale has been calibrated from field studies in oil and gas provinces and by other maturity provinces. Plots of R_o measurements against depth provide enough information on the thermal history of the basin. The normal pattern is a linear relationship with depth indicating a continuous time-invariant geothermal gradient. Combining R_o values with other maturation indices is a sure way of testing the potentiality of a reservoir.

3.1 Lopatin Maturation Index

Lopatin [2] developed a simple model by which the effect of both temperature and time could be taken into account in calculating the organic materials in sediments. To accomplish this, Lopatin in determining the maturation index of source rocks simplified the Arrhenius equation (which states that chemical reaction rates increase exponentially with increasing temperatures) by replacing the thermodynamic variables in the equation with a simple constant r. This constant reflects the increase in reaction rate that results from increasing temperature [26]. By accepting the rule that chemical reaction rates double for every 10°C rise in temperature [27], a value of two was selected for r, and in order to estimate the differrence in reaction rate between two temperatures, r is raised to power n of 10°C increment. This relationship can be expressed algebraically as:

$$\gamma = r^n \qquad (4)$$

where γ is maturation rate factor and n is temperature (°C)/10. γ describes the instantaneous rate at which oil is generated; that is the exponential dependence of maturity on temperature.

Lopatin indexed the temperature variable n so that n = 0 over the temperature interval 100 – 110°C. The other intervals were assigned index values as shown in Table 1.

Table 1. Temperature factors for different temperature intervals (modified from Wapples [27]

Temp. Interval (°C)	Temp. Index (n)	Maturation rate factor
20-30	-8	r^{-8}
30-40	-7	r^{-7}
40-50	-6	r^{-6}
50-60	-5	r^{-5}
60-70	-4	r^{-4}
70-80	-3	r^{-3}
80-90	-2	r^{-2}
90-100	-1	r^{-1}
100-110	0	1
110-120	1	r^{1}
120-130	2	r^{2}
130-140	3	r^{3}

Wapples had observed that onset of oil generation is at TTI value of 15 while the generation ends when it is 160. Upper limit for wet gas corresponds to a TTI value of 1,500. Assuming a constant rate of temperature change, equation 4 can be integrated over time t_{n1} and t_{n2} to yield the corresponding incremental time temperature index (TTI_n) given by Wood [3]:

$$TTI_n(t_{n1}\ to\ t_{n2}) = \frac{10}{q_n}\left\{\frac{1}{\ln(r)}\left(r^{\left[\left(\frac{tn2}{10}\right)-10.5\right]} - r^{\left[\left(\frac{tn1}{10}\right)-10.5\right]}\right)\right\} \qquad (5)$$

where n is the number of stratigraphic intervals, TTI_n is the time-temperature index for the interval defined by $t_{n1}\ and\ t_{n2}$ and T_{n1}, T_{n2}; $q_n = (T_{n2} - T_{n1})^2/(t_{n2} - t_{n1})$; t_{n1} is the starting age of interval n, t_{n2} is the ending age of interval n. T_{n1} is the starting temperature (°C) of interval n while T_{n2} is the ending temperature (°C) of the interval.

Since maturation effects on the organic maturity of a given sediment is given by the sum of the maturities acquired in each interval, it follows that

$$TTI = \sum_{n=1}^{n=max} TTI_n = \sum_{n=1}^{n=max} \Delta T_n r^n \qquad (6)$$

where ΔT_n is the length of time (in million years) spent in each temperature interval traversed by the sedimentary unit layer. That is ΔT for a particular interval is the age difference between when the sediment enters that interval and the age at which it enters the next interval. The temperature history of the basin was then constructed by specifying the subsurface temperature for every depth throughout the time interval covered. Using the surface temperature and geothermal gradient data, the temperature grid with equally spaced isotherms (10°C) parallel to the earth surface was constructed (Figure 3).

By utilizing equation 6 under the Arrenius equation assumption, TTI values were then calculated for the geologic model having four sediment horizons and a simple temperature grid of constant geothermal gradient. The temperature grid is just a series of equally spaced lines of constant depth. The isotherms (dashed lines) represent the subsurface temperature as a function of time. The constructed burial history (Figure 2) curves and temperature grids are pasted together (Figure 4). The intersection of the burial history curve with each isotherm is then marked out. These points define the time and temperature intervals that were used in the calculation of TTI and the set of lines forms the basis of Lopatin's geologic reconstruction.

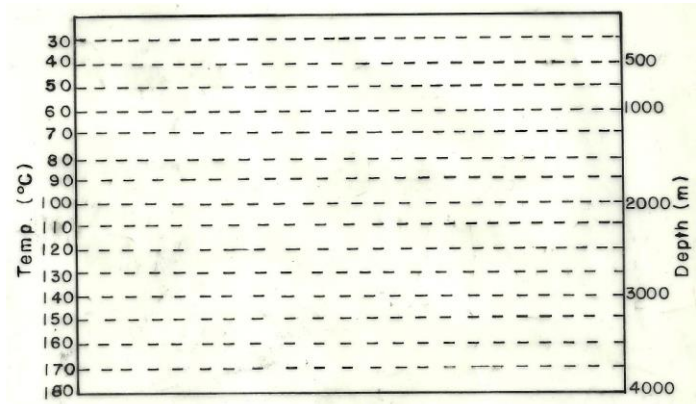

Figure 3. Subsurface temperature grid that assumes a constant surface temperature of 27°C and geothermal gradient of 34°C/Km

Figure 4. Isomaturity lines on a geological reconstructed model.

4. Results and discussion

The variation of burial depth with geologic age for a representative well in Chad basin (Figure 2) shows a continual deposition of the Cretaceous sediment from about 110 Ma when it was first deposited until the top of Fika shale and bottom of Chad Formation respectively where unconformities of unspecified time durations took place. The distribution of temperature in the basin shows that the values are higher at the northeastern and south-western axes than at the center where most of the wells are located [20]. The higher temperatures can be related to the tectonic uplifts, faults or sedimentation rates. Thus, faster sedimentation reduces temperature at depth.

The values of R_o and the thermal alteration parameter, C obtained in this study using equations 2 and 3 indicate prospect for hydrocarbon generation and accumulation in the basin, and the values exhibit normal and constant geothermal gradient through time. However, below the depths of 3.8 km for the Herwa-1 and 3.1 km for the Mbeji-1 wells, R_o values rose significantly higher. This region must therefore be area of high concentration of gaseous hydrocarbons. R_o values obtained also exhibit increasing trend with depth, temperature and age (Figures 5 to 7). A range value of 0.21 to 1.58 % was computed for the entire basin while the thermal alteration index values range from 5.7 to 15.2.

Ro values vary between 0.65 and 1.37 within the sediments oil generative window while it rose up to 1.58 in Herwa-1 well. This range correlates with a paleotemperature range of 77.7 to 146.3°C, and 176.3°C respectively (Table 2). These values indicate oil prospect in all the Wells and likely gas accumulation towards the basement for Herwa-1and Mbeji-1 Wells. For age intervals where the sediments were deemed immature, Ro values range between 0.21 and 0.59. Correspondingly, the maturation index, C varies between 9.9 and 15.2. TTI values vary between 14.8 and 116.8 where the sediments are presumed mature and have the potential of generating oil. The onset of the thermal maturation when TTI value of 15 and a C value of 10 are considered stays close to 80°C isotherm. Palumbo *et al.* [1] had observed that typical hydrocarbons are produced for TTI range of 15 to 160 within the oil generative window. For TTI values less than 15, no hydrocarbons are produced, and for values higher than 160 all of the oil have been expelled from the source rock.

Most values of the thermal maturity index calculated within the oil generative window in this study lie between 12 and 14. It is therefore possible that the oils in the basin are light and hence must have been expelled.

The results of the thermal maturity values (Table 3) show that horizons A and B in the basin are immature (TTI<15) and hence do not generate hydrocarbon. However, older sediments (horizons C and D) with total TTI values greater than 15 are mature and capable of producing oil.

Table 2. Maturation indicators for wells in Chad Basin, Nigeria

S/N	Wells	Depth (m)	Age (Ma)	Temp (°C)	R_o (%)	Index, C
1	Al-Barka-1	1710-3450	87.2-99.8	118-132	1.00-1.19	12.6-13.6
2	Herwa-1	1525-4700	86.5-108.0	81-176	0.63-1.58	10.1-15.2
3	Kanadi-1	1550-2905	86.5-97.0	84-134	0.62-0.82	10.3-11.3
4	Kasadi-1	1430	86.2	87	0.67	10.4
5	Kemar-1	1775	87.4	91	0.71	10.71
6	Krumta-1	1990-2935	88.6-97.3	94-128	0.74-1.16	10.9-13.5
7	Masu-1	1790-3085	87.5-98.2	98-131	0.62-0.88	10.0-12.1
8	Mbeji-1	1650-3715	86.9-102.0	95-156	0.75-1.11	10.9-13.3
9	Murshe-1	1695-3920	88.5-99.2	79-124	0.62-0.85	9.9-11.7
10	Ngor N-1	1795-3385	85.8-99.1	94-161	0.75-1.36	11.0-14.3
11	SA-1	1728-2382	86.3-88.9	86-108	0.67-0.88	10.4-11.9
12	Tuma-1	1510-3216	86.1-95.9	80-136	0.61-1.21	10.0-14.0
13	Wadi-1	1455-3210	86.3-95.8	98-131	0.61-1.2	9.9-13.6
14	Ziye-1	1720-3350	87.2-99.6	79-128	0.61-1.16	9.9-13.5

Table 4 shows how computed TTI values for the basin compare with Ro at any given temperature and age. Ro and TTI values measured from geologic models show that several important stages of oil generation and preservation have their values lie between 0.62 and 117 respectively. Figure 8 is the combined burial and thermal history for Kanadi-1Well, which is a representative of the basin. All these results points to the possibility of discovering oil in commercial quantity in the basin if necessary precautions are put in place.

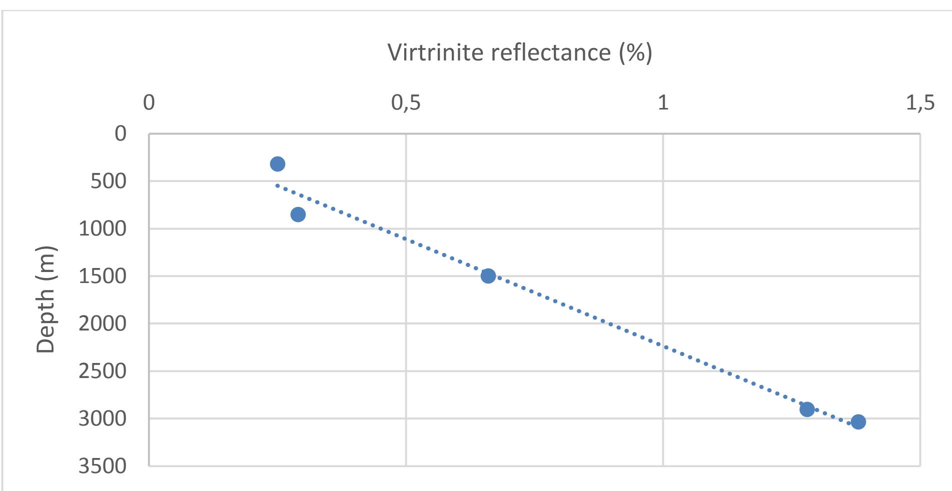

Fig. 5. Depth vs Virtrinite reflectance variation for Kanadi-1 Well

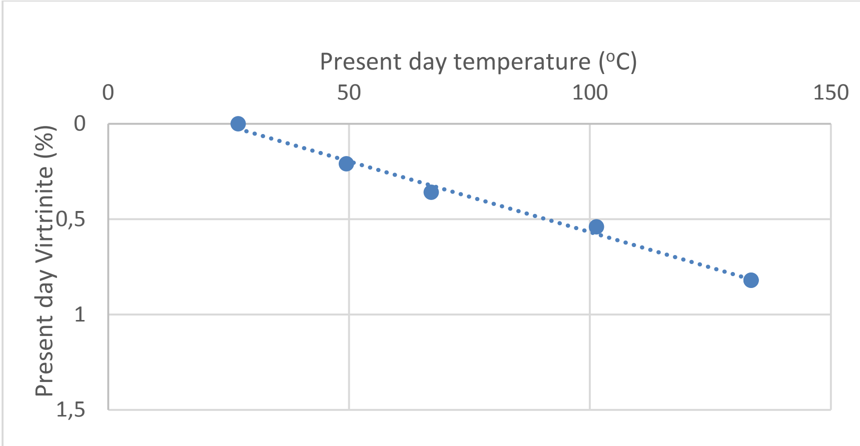

Fig. 6. Temperature vs Virtrinite reflectance variation for Kanadi-1 Well

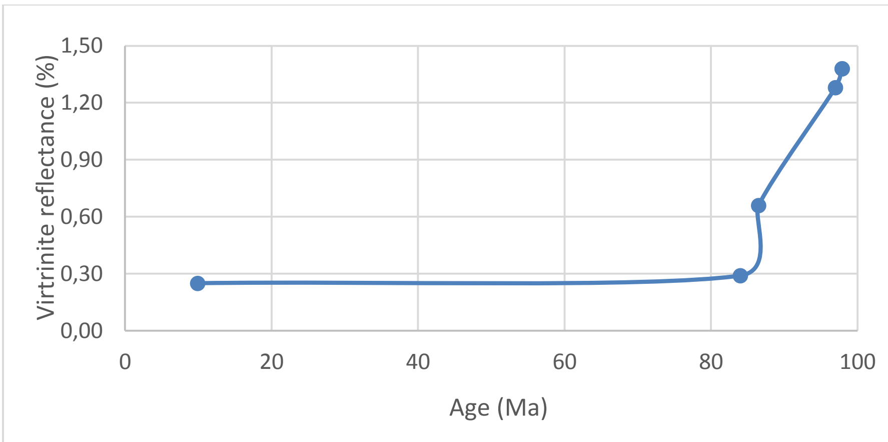

Figure 7. Age Vs Virtrinite reflectance variation for Kanadi-1 Well

Table 3. Calculated present TTI values

Temp. interval, °C	Index value	Temp. factor	Time factor (mil. y)	TTI	Total TTI
Horizon A					
20-30	-8	0.004	35.0	0.140	0.140
30-40	-7	0.008	34.0	0.272	0.412
40-50	-6	0.016	10.0	0.160	0.572
Horizon B					
20-30	-8	0.004	6.0	0.024	0.024
30-40	-7	0.008	4.5	0.036	0.060
40-50	-6	0.016	44.0	0.704	0.764
50-60	-5	0.031	25.0	0.775	1.539
Horizon C					
20-30	-8	0.004	2.5	0.010	0.010
30-40	-7	0.008	3.0	0.024	0.034
40-50	-6	0.016	3.5	0.056	0.090
50-60	-5	0.031	9.5	0.295	0.385
60-70	-4	0.063	25.0	1.575	1.960
70-80	-3	0.125	28.0	3.500	5.460
80-90	-2	0.250	8.5	2.125	7.585
90-100	-1	0.500	7.5	3.750	11.335
100-110	0	1.000	5.5	5.500	16.835
110-120	1	2.000	5.5	11.000	27.835

Temp. interval, °C	Index value	Temp. factor	Time factor (mil. y)	TTI	Total TTI
Horizon D					
30-40	-7	0.008	0.9	0.007	0.053
40-50	-6	0.016	2.0	0.032	0.085
50-60	-5	0.031	8.0	0.248	0.333
60-70	-4	0.063	12.5	0.788	1.121
70-80	-3	0.125	15.0	1.875	2.996
80-90	-2	0.250	16.7	4.175	7.171
90-100	-1	0.500	15.3	7.650	14.821
100-110	0	1.000	8.0	8.000	22.821
110-120	1	2.000	3.0	6.000	28.821
120-130	2	4.000	4.0	16.000	44.821
130-140	3	8.000	3.0	24.000	68.821
140-150	4	16.00	1.5	48.000	116.821
150-160	5	32.00	5.0	160.0	276.821
160-170	6	64.00	2.5	160.0	436.821

Table 4. Correlation of TTI with Ro values

Ro	TTI	Temp (°C)	Age (Ma)	Depth (m)
0.19	0.085	50	19.8	750
0.33	0.333	60		1000
0.43	1.121	70	23.5	1250
0.62	2.996	80	87.9	1500
0.71	7.171	90	95.2	1750
0.82	14.821	100	96.3	2000
0.92	22.821	110	97	2250
1.03	28.821	120		2500
1.19	44.821	130	98.2	2750
1.33	68.821	140	99.5	3000
1.38	116.821	150	102	3250
1.46	276.821	160	105.4	3500
1.58	436.821	170	108	3750

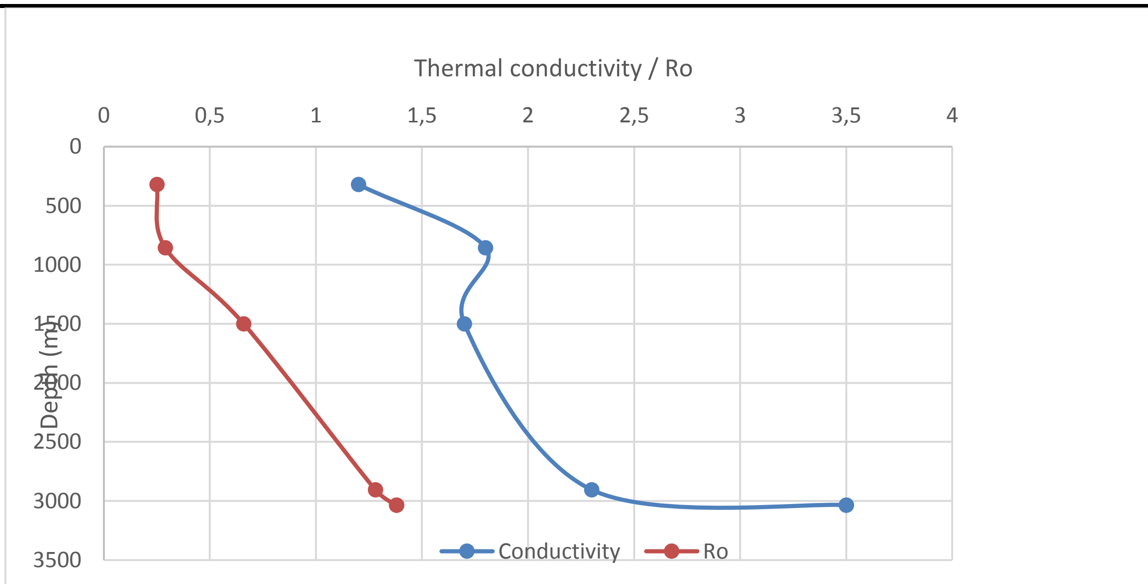

Figure 8. Combined burial and thermal history variation for Kanadi-1 Well, (a) Thermal conductivity/Ro versus Depth

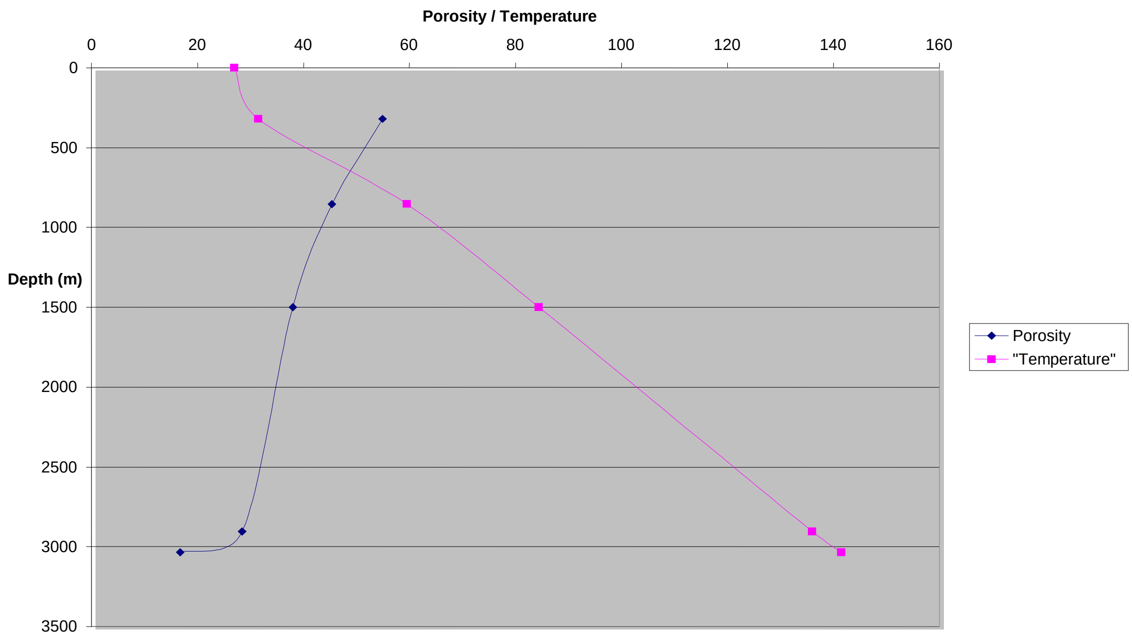

Figure 8. Combined burial and thermal history variation for Kanadi-1 Well, (b) Porosity/Temperature versus depth

5. Conclusion

Modeling of TTI, virtrinite reflectance and thermal alteration parameter in this study shows that Bornu Basin is thermally mature and therefore has the potential of generating and preserving hydrocarbons. TTI modeling is based on estimated average geothermal gradient of 34 °C/Km while virtrinite reflectance was modeled from temperature data. The thermal history analysis reveals that effective petroleum source rocks are the upper Cretaceous (Santonian to Turonian) shales. Tertiary shale, which may be high in organic content, may have not been subjected to favourable burial and thermal condition required for petroleum generation. A higher level of organic maturity of kerogens is expected in the northeast and southwest regions where the sedimentation histories are higher.

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*Corresponding author E-mail: Cyril.nwankwo@uniport.edu.ng