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The significance of temperature and geothermal gradient to hydrocarbon occurrence: case study of Bara oilfield, western Niger delta, Nigeria

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ABSTRACT

The significance of temperature and geothermal gradient in relation to hydrocarbon occurrence in the BARA Field, western Niger Delta was studied using bottom hole temperature logs. The average depth to the floor of the oil generative window (7182.3m) shows that commercial hydrocarbon accumulation still lies below the final drilled depth in the field. The average geothermal gradient of 1.74 °C /100m shows that the field is thermally mature for commercial accumulation of hydrocarbon. This is evidenced in the occurrence of hydrocarbon in the wells drilled within the field. The geothermal gradient decreases radially from the centre of the field to the edges based on the position of the five wells in the field, this is confirmed by the average thermal conductivity which tends to increase radially from the centre to the edges. Areas with high shale percentage show high geothermal gradient values while areas with high sand percentage show low geothermal gradient values. Significant hydrocarbon occurrence lies below the top of the calculated depth of oil ceiling (3508.89m) and within the oil generative window of the worldwide catagenesis range (50°C to 200°C). Rapid change in geothermal gradient occurs in intervals where there are hydrocarbon accumulation showing that, changes in geothermal gradient can be used to enhance exploration activities. The occurrence of hydrocarbon within the oil generative window in terms of temperature and depth, suggests that adjacent shales of the Agbada Formation are possible source rock.

Introduction

Geothermal gradient is the persistent rise in temperature with depth within the earth. It is expressed as the change in temperature in degrees centigrade or fahrenheit per depth (°C /100m or °F / 100ft).

Temperature has a great influence on hydrocarbon generation from organic matter and kerogen in particular. It is believed that hydrocarbon is generated from kerogen – the precursor of petroleum, by thermo catalytic cracking. The degree of generation of hydrocarbon from this process is regulated by time, temperature, pressure and catalyst; of which temperature is considered the most important.

The type of hydrocarbon found in a place has a relationship with the geothermal gradient and temperature of the area, because each hydrocarbon type (oil, gas or condensate) has been known to occur or form at a particular temperature from kerogen (Land, 1967). However, it is pertinent to note that the kerogen type also determines the nature of the hydrocarbon.

The oil window is known to occur at a particular temperature range within a basin. Organic matter increase in maturity with depth of burial and since temperature increases with depth, it follows then that hydrocarbon generation from organic matter increases with temperature until the metagenetic stage where no more hydrocarbons is generated, but the organic matter is turned into graphite by condensation of the aromatic components with methane. In exploring for oil and gas in wildcat areas, it is important to know if the rock has passed through this generation stage, and the depth where generation started, peaked and terminated. Such data alone, may not pinpoint the location of economic petroleum, since they are affected by migration and trapping. However, it does bracket the depth ranges in which mature source beds occur and thus indicate the most likely subsurface zones to prospect for oil and gas (Hunt, 1979).

Measurement of geothermal gradient in an area can help locate potential hydrocarbon reservoir. Since hydrocarbon containing rocks have lower thermal conductivity (hydrocarbon is a non conductor), the thermal gradient within such rocks are abnormally high when compared with normal subsurface thermal gradient. Such anomaly extends well beyond the boundaries of the reservoir (Mufti, 1978). The geothermal gradient of the Niger Delta has been studied by various researchers such as Evamy et al., 1978; Ejedawe et al., 1984; Ejedawe, 1981; Ekweozor & Okoye, 1980; Akpabio, et al., 2003 and others. Ejedawe et al (1984) and Akpabio et al., (2003) studied the distribution and variation of geothermal gradient in the Niger Delta through continuous temperature logs. Their studies indicated regional geothermal gradient increase from the central portion of the delta northwards with intermediate value southwards on both the Benin and the paralic Agbada Formation. The geothermal gradient was found to increase linearly with depth from the Benin Formation to the Akata Formation (Akpabio et al., 2003). This work aims at studying the significance of temperature and geothermal gradient to the occurrence of hydrocarbon within the BARA oilfield, western Niger Delta. A relationship will be established between hydrocarbon occurrence and temperature as well as geothermal gradient, and probable reason for temperature and geothermal gradient variation within the field.

Location

The study area, BARA oilfield is located within the western area of the Niger Delta basin (figure 1). The wells under study

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are operated by Shell Petroleum Development Company Limited (SPDC). The field name, BARA is not the real name of the oilfield. The original name is not used here for proprietary reason.

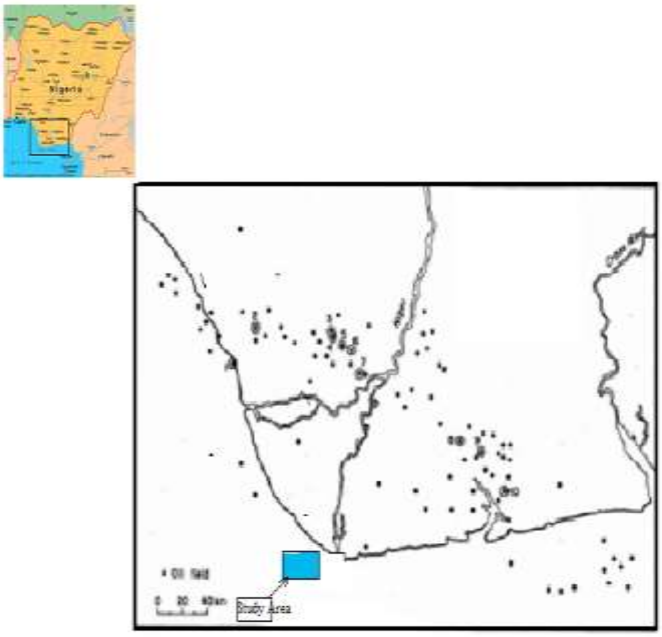

Fig. 1 Oil fields in Nigeria (Adapted from Weber, 1971)

Geologic setting of the Niger delta

The formation of the Niger Delta sedimentary basin started in the Early Tertiary time, as the fourth stage in the development of the southern Nigerian sedimentary basins (Etu - Efeotor, 1997) following the opening of the South Atlantic Ocean during the Early Cretaceous time. The dominant process in this stage was regression, which led to the deposition of thick sedimentary piles that form the modern delta during the Eocene.

The tectonic history and the evolution of the Niger Delta sedimentary basin have been reported in the work of Short and Stauble, 1967, Doust and Omatsola, 1990). The Niger Delta basin is situated in the Gulf of Guinea on the coast of West African continental margin (figure 1).

The basin evolved following the separation of African and South American plates during the Early Cretaceous times. This was followed by the opening of the South Atlantic Ocean and several episodes of transgressions and regressions accounted for the sedimentary units in both the Cretaceous and Tertiary Southern Nigerian sedimentary basins.

Stratigraphically, the subsurface sedimentary sequences of the Niger Delta are made up of basically lithofacies of three distinct environments of deposition: continental, transitional and marine. The Akata Formation (marine shale) underlying the Agbada is believed to be the major source rock. The Agbada Formation comprises of a sequence of interbedded sand/sandstone and shale occurring in almost equal proportion. The Agbada sandstone forms the reservoir unit, where there is a huge accumulation of hydrocarbon. The Benin Formation is the continental unit, comprising of massive continental sands with minor shale streaks and lignite, overlying the Agbada Formation. The delta has prograded through time for a distance of more than 300 km from the apex to the present delta nose (Doust and Omatsola, 1990). It is segmented into several geomorphological units, displaying a concentric arrangement often referred to as depobelt, which started with the oldest Northern Delta depobelt to the offshore depobelt.

Materials and methodology

Five wells (figures 2, 3, & 4) each with gamma ray, resistivity, temperature and geothermal gradient logs were used for this study. The datasets were provided by Shell Petroleum Development Company, Port Harcourt.

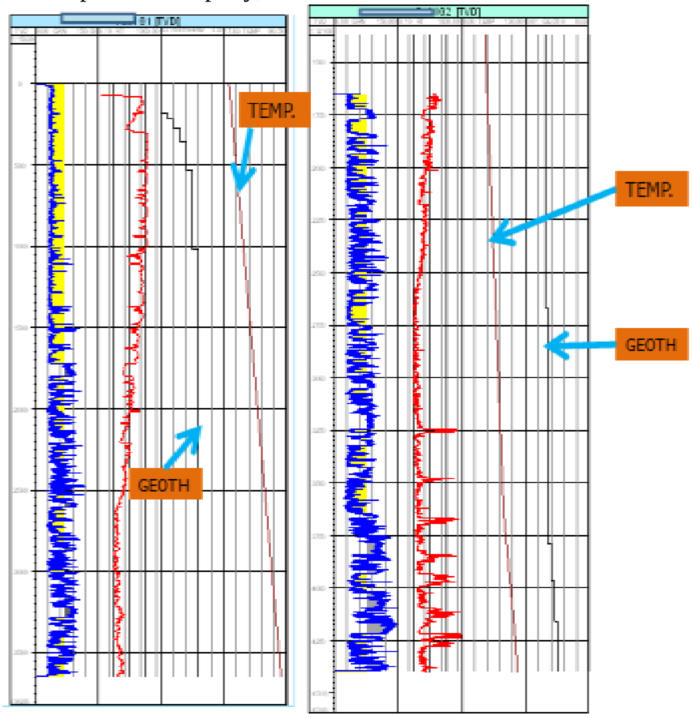

Figure 2: Well Logs Showing Temperature and Geothermal Gradient for Wells 1 and 2.

NOTE: GEOTH – Geothermal Gradient; TEMP – Temperature.

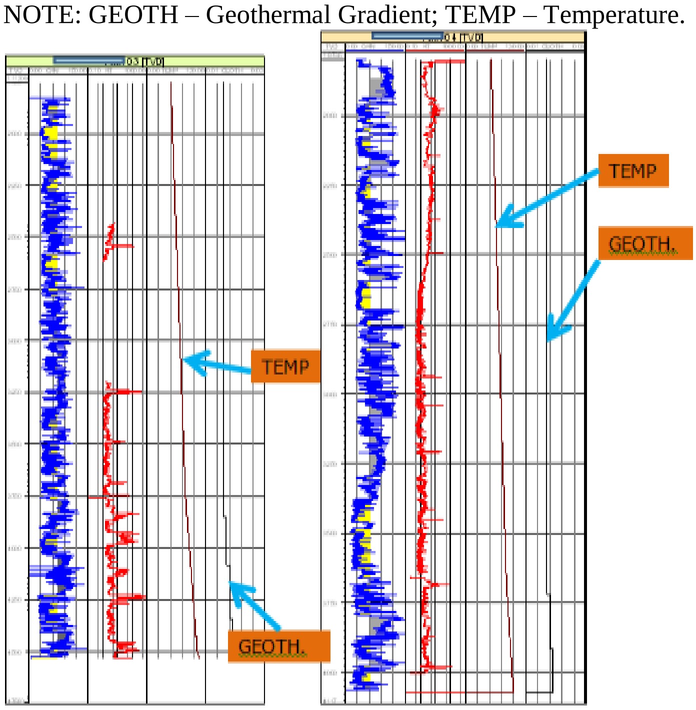

Figure 3: Well Logs Showing Temperature and Geothermal Gradient for Wells 3 and 4.

NOTE: GEOTH – Geothermal Gradient; TEMP – Temperature

Methodology

The sand and shale sequences in the study area were recognized on well log based on the gamma ray signatures. Increasing gamma ray values to the right beyond 100^{0} API show an environment that is made up of majorly fine grained pelitic rocks such as clay or shale. The minimum gamma ray trend signifies sandy intervals. The type of fluid present in the rock was determined from resistivity logs.

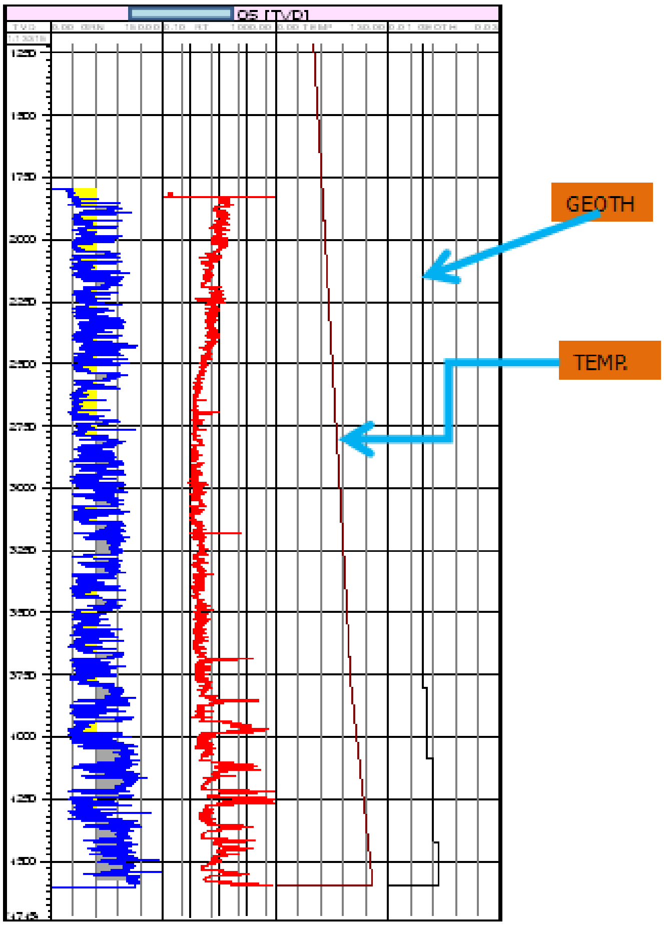

Figure 4: Well Log Showing Temperature and Geothermal Gradient for Well 5.

The geothermal gradient calculated for each depth was performed using the relation:

$$\text{Geothermal gradient} = \frac{T^{o}_{formation} - T^{o}_{surface}}{\text{Depth}}$$

Where $T^0_{formation}$ is the measured temperature reading from the logs, and $T^o_{surface}$ is the ambient temperature which is taken to be 25^{o}c, since the area lies in the tropics. The depth is the depth of measurement of temperature.

The oil kitchen threshold temperature for each well was determined using the age of the source rock in the field (the Agbada and upper Akata formation). The age of the source rock was imputed into the formula:

$T = 164.4 – 19.39 \ln t$.

Where **t** is the age in million year of the source rock, T is the threshold temperature of oil generation (Pigott, 1985). The age of the source rock in the field (the Agbada and upper Akata formation is Eocene which is 55.8 million years (Short and Stauble, 1967).

The depth to top and floor of the oil kitchen was calculated using the formula:

$$Doc = \frac{100(T - Ts)}{dt/dz}$$

Where Doc is the depth to the oil ceiling in meters, T is the temperature at the top of oil ceiling in degree centigrade was determined from equation 2 above, Ts is the average ambient surface temperature which is taken as 25^{o}c in this study, dt/dz is the average geothermal gradient of the well in ^{O}c /100m (Pigott, 1985).

Ten fixed depth points were chosen for the five wells and the geothermal gradient of each at that depth was taken and converted to the metric value (^{o}c /100m) by multiplying the calculated geothermal gradient at that depth by 100. The values were contoured for each depth point using the base map of the field (figures 5, 6).

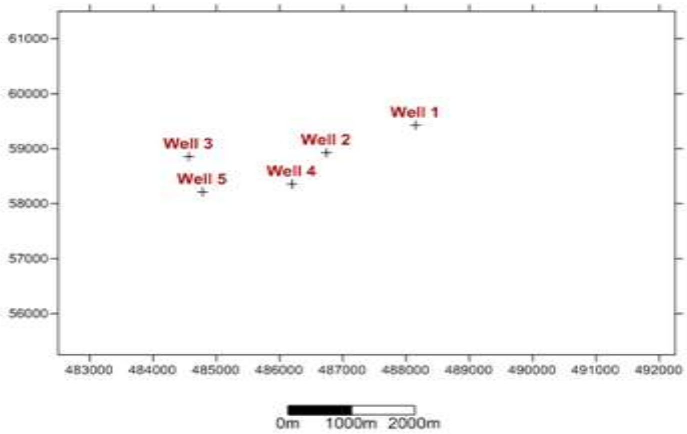

Figure 5: Base map of the area

Results And Interpretation

Lateral Geothermal Gradient Variation

The ten points chosen for the five wells show a radial decrease in geothermal gradient from wells 2 and 4 outwards (figure 6, 7). The first few points where all the wells penetrated the depth of mapping clearly shows this. At depth 3243.98m, the geothermal gradient for wells 2 and 4 which is at the centre of map (field) is higher than for well 1,3,and 5 which are at the edges of the map (field), based on the five wells. The average geothermal gradients of the five wells (table 1) calculated from the slope of temperature plot against depth, also show an increase towards the centre of the field based on the five wells.

Table 1: Calculation of Average Geothermal Gradient

Well No.	Temperature difference (^{o}C)	Depth difference (m)	Avg. Geoth. Grad. (^{O}C/100m)
1	53.91	3250	1.66
2	51.19	3000	1.71
3	35.1	2000	1.76
4	49.85	2750	1.81
5	53.21	3000	1.77

The thermal conductivity shows a relative increase towards the edges of the field based on the five wells; this also supports the radial increase in geothermal gradient towards the centre of the field.

Heat flows in most basins arise from some combination of at least the following four principal influences: variation in mantle heat flow, variation in conductivity and heat generation in the sedimentary succession, variation in the heat generation of the crystalline basement, and heat redistribution by migration of meteoric formation water.

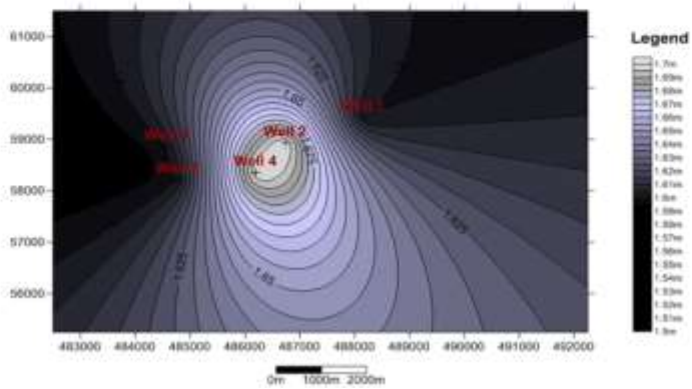

Figure 6: Map of geothermal gradient at 3243.99m for wells 1 – 5

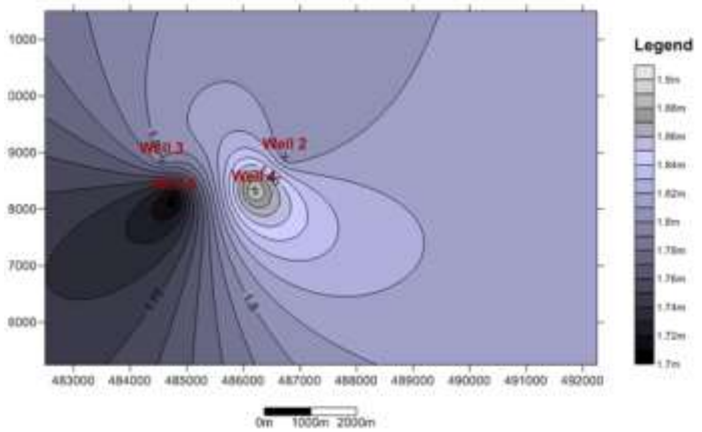

Figure 7: Map of geothermal gradient at 3940.45m

The most probable causes for the radial variation in geothermal gradient in the area are the conductivity of the various rocks, heat generation in the sedimentary succession and heat redistribution by migration of formation water (meteoric water.)

The shale and sand percentages (figure 2, 3 and 4), show that wells 2, 4 and 5 have the highest shale percentage. Shale has a lower thermal conductivity than sand. Therefore, heat can be trapped by shale than sand thus increasing the geothermal gradient in such area.

Evamy et al., (1978) observed a low geothermal gradient in areas with high sand percentage and high geothermal gradient in areas with high shale percentage.

The highest average geothermal gradient is observed in well 4 followed by well 5, decreasing to the lowest in well 1 with the lowest shale percentage. This confirms that the thermal conductivities of the lithologies within the field are responsible for the increase in geothermal gradient toward the centre. Well 5 occurs towards the southern part of the field (figure 5) and thus justified for the high shale percentage indicating a marine depositional setting. The low geothermal gradient at the edge of the field may be attributed to cooling effect of the convectional current of meteoric water from the upper portion of the well. The high geothermal gradient of wells 2 and 4 can also be due to internal heat generated within the sedimentary succession in the area. Heat can be generated through radioactivity when there is disintegration of radioactive elements Makhous et al (1997). Exceptional high pressure can also result in increase in temperature since collision between the molecules of the fluid increases hence increase in heat (Chilingar et al, 2005).

The area might also be closer to a possible intrusion within the position of the two wells or a hot spot occurring within the basement lying below the area occupied by the wells with higher geothermal gradient.

Vertical Variation in Temperature

Maps of constant temperature variation with depth for the five wells (figures 8 to 12), show that the temperature at 78.8^{o}C was encountered at shallower depth in wells 2 and 4 than in wells 3, 1 and 5. This depicts a higher heat flow in wells 2 and 4 area within the field.

Traditionally, geothermal gradient or temperature increases with depth (figures 2, 3, 4 & 8) as a result of mantle heat flow transmitted through earth materials to the surface where temperature is low. The quantity of heat transferred to a particular portion of the earth material lying above the mantle should be the same at a particular level within the earth, if the same quantity of heat is transmitted from the mantle and the earth material is homogenous.

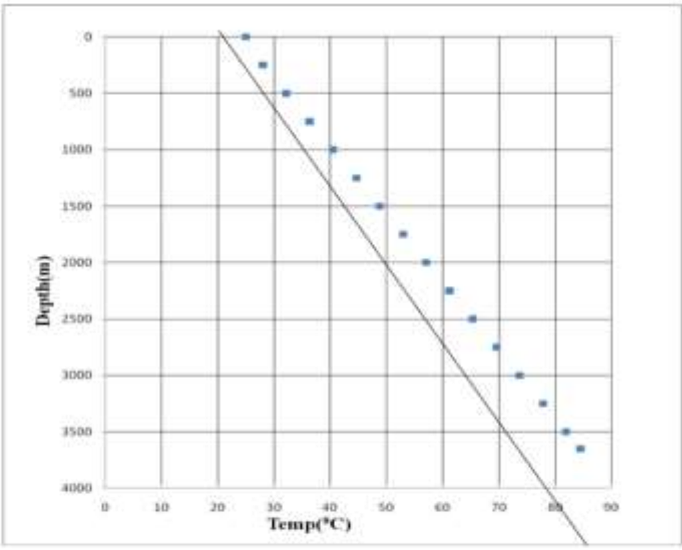

Figure 8: Well 1 plot of temperature against depth. Average geothermal gradient is 1.66 ^{o}C/100m

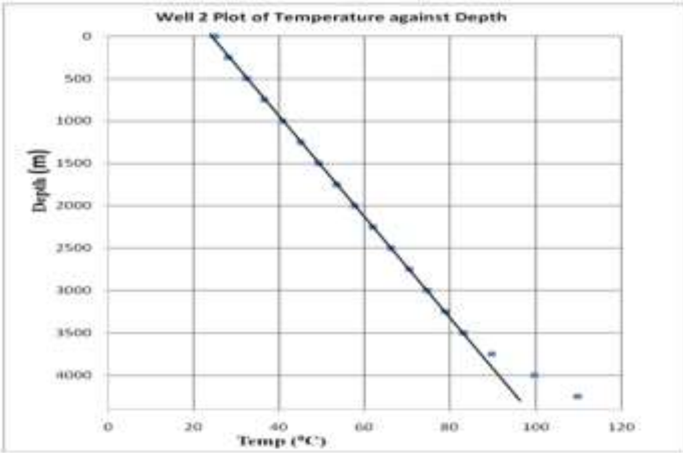

Figure 9: Well 2 plot of temperature against depth. Average geothermal gradient is 1.71 ^{o}c/100m

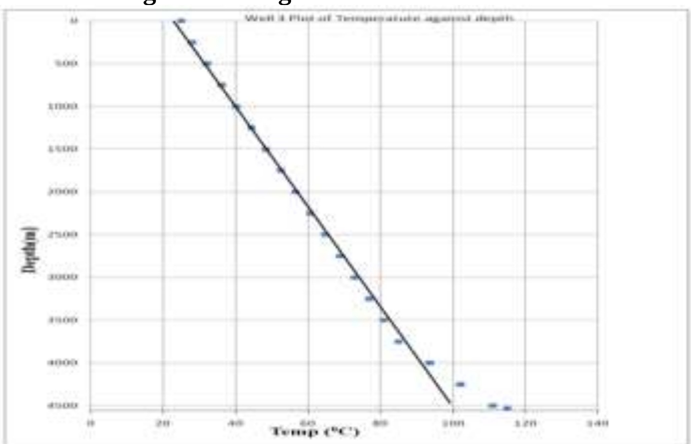

Figure 10: Well 3 plot of temperature against depth. Average geothermal gradient is 1.76 ^{o}c/100m

The difference in depth encountered at the 110^{o}C isotherms by the five wells (table 2), shows that there is additional effect to mantle heat flow influencing the vertical heat flow in the field. This may be due to a possible hot spot below the position of wells 2 and 4, more heat generation within the sedimentary succession or nearby crystalline basement, possible igneous intrusion, a possible fracture below or a cooling effect of meteoric water at the edges of the field (wells 1, 3 and 5). It might also result from the difference in the thermal conductivity of earth material in the sedimentary succession within the area.

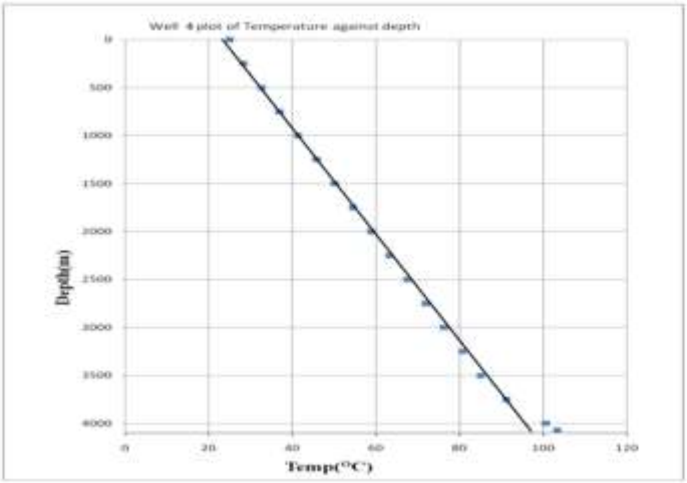

Figure 11: Well 4 plot of temperature against depth. Average geothermal gradient is 1.81 °c/100m

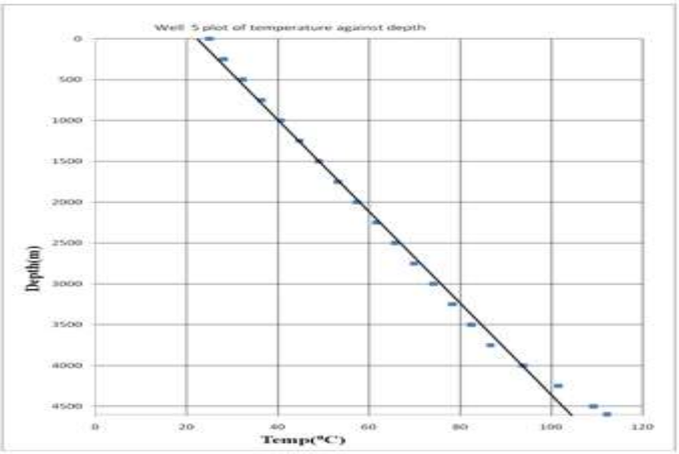

Figure 12: Well 5 plot of temperature against depth. Average geothermal gradient is 1.77°C/100m

Table 2: Constant temperature variation with depth: temperature at 110 °C

Well Number	Temperature (°C)	Depth of temperature (m)
1	110	-
2	110	4255.01
3	110	4479.65
4	110	-
5	110	4525.52

Hydrocarbon Occurrence

Hydrocarbon occurrence entails its generation, expulsion, migration, entrapment and preservation.

The organic theory of petroleum origin is based on the accumulation of hydrocarbon from living things, and its formation by the action of heat on biologically formed organic matter (kerogen). Hydrocarbon is derived from life in two part ways: it may be formed from dead organism with hydrocarbon molecules and those formed by bacteria activity and low temperature chemical reactions in unconsolidated sediments.

Secondly, it may originate from kerogen when it is heated to high enough temperature to crack and release hydrocarbon. About 80 - 90% of petroleum is formed from this pathway (Hunt, 1979). Organic diagenesis is the biological, physical and chemical alteration of organic debris with a pronounced effect of temperature within the range from 0 - 50°C (122° F), and leads to the formation of kerogen.

Catagenesis is the stage where increasing temperature cause kerogen to be converted to bitumen and then bitumen to oil, condensate and gas. Temperature range is from 50° C (122°F) to 200°C (392°F). The generation of petroleum from organic matter is a two step process involving bitumen as an intermediate, that is, kerogen to bitumen to oil and gas plus residue.

Kerogen is formed from the decarboxylation (breaking down of complex organic molecules), deamination, polymerization and reduction of bio molecules. These processes also lead to the formation of bitumen as stated earlier. Bitumen consists largely of biological markers such as normal paraffins, isoprenoids, steranes, triterpanes and porphyrins, some of which are found in petroleum. It also contains nitrogen, sulphur and oxygen (NSO).

The generation of petroleum from organic matter is a rate controlled reaction which is principally dependent on temperature according to the Arrhenenius equation;

$K = Ae^{-(Ea/Rt)}$.

Where k is the reaction rate constant related to change in concentration of parent substance and product, A is the frequency factor, E is the activation energy, R is the gas constant, T is the temperature in degrees Kelvin.

From the above equation, it is obvious that the rate of hydrocarbon generation from organic matter depends mainly on temperature, since the other parameters are constant.

In catagenesis stage, all the hydrocarbons C1 through C40 are formed in larger amount than in other stages. Heavy oil fractions are formed first followed by cracking of these fractions to yield light oil and gases as temperature rises.

The generation of gases and cracking of heavy hydrocarbon molecules and bitumen's already formed from diagenesis stage, creates localised overpressures that force the hydrocarbons out of the source rocks. At the metagenetic stage, only methane is formed in significant amount with eventual formation of graphite-like molecules from the condensation and polymerization of aromatics.

Oil generation windows are a vertical representation of the oil generation interval, normally expressed in terms of temperature range, the lowest been the top and the highest the base.

The top of the initial oil generation window in the Niger Delta was set at 140° C and has moved upward to shallower depth and temperature of about 95°C due to time effects on potential source rock which expose them to prolonged effects of temperature (Ejedawe et al., 1984). This must have resulted in the maturation of some parts of Agbada Formation.

Ekweozor and Okoye (1980) shows that the top of the oil kitchen was located at an average depth of 3375m and 2900m in onshore and offshore wells respectively through the study of Oleanes. They also show that the kerogen of the source rocks were mainly of humic and mixed varieties and are thus prone to the generation of more gas. However, Aikhiombare et al (1984) shows that type II kerogen is the dominant organic matter in the Niger Delta , and thus have potential to generate both oil and gas but with more oil than gas. Combining the above two proposals about the kerogen type in the Niger Delta, we can say that both type II and III kerogen are abundant in the Niger Delta which has capacity to produce both gas and oil.

The average top of oil ceiling (top of oil window) in this study is 3508.89m and the depth to the oil floor (base of oil window) is 7182.3m giving the thickness of the oil kitchen to be 3673.3m. The shallowest hydrocarbon in the field, based on the five wells, was found at 2565m in well 2. However, this may be due to organic diagenesis and / or migration. Significant occurrence of hydrocarbon lies within the top and floor of the oil window. Since the deepest encountered hydrocarbon at 4550m in well 5, still lies far below the floor of the observed oil generating window; commercial accumulation may be expected at deeper depth in the field.

The entire hydrocarbon occurring in the field under study lies below and within the top of the oil kitchen proposed for Niger Delta by Ekweozor and Okoye (1980) for both onshore and offshore wells. This shows that their source rocks could be the adjacent shale of the lower Agbada formation or top of Akata Formation from where they might have migrated through available growth faults. In terms of temperature, all the hydrocarbon occurrence lie above 70^{o}C which is within the range of catagenesis (50^{o}C – 200^{o}C), justifying the possibilities of the adjacent shale as source rock.

Temperature Rise in Relation to Hydrocarbon Accumulation

Hydrocarbons have low thermal conductivity just like shales. This reduces the rate of heat transfer through hydrocarbon bearing rocks, such that temperature will be relatively higher below such reservoirs. Most of the hydrocarbon accumulation in the wells has relative increase in temperatures that nearly coincide and sometimes coincide with the oil-water contacts of the hydrocarbon intervals at 3502m, 3700m, 4141m, 4235.6m; 5 at 3868m, 3989.7m 4146.4m, 4267.2m, 4372.1m and 4 at 3696m, 3987.4m (figures 2, 3 & 4). From 3780m to 3875m, there is a rapid rise in temperature which is related to hydrocarbon occurrence or shale with low thermal conductivity occurring above the interval (figures 8, 9, 10, 11 & 12).

Anomalous Geothermal Gradients Related to Hydrocarbon Accumulation.

Anomalous geothermal gradient rise which may be related to hydrocarbon occurrence as explained in the case of temperature was also observed in some of the wells. These anomalous rises in geothermal gradient may be related to lateral occurrence of hydrocarbon in the wells at these depths, or the occurrence of hydrocarbon above or below them. From the above, we can infer that temperature changes have a relationship with the accumulation of hydrocarbon.

Comparison of Results

The geothermal gradient for the five wells ranges from 0.1 to 2^{O}C / 100m. The lowest values occur at the upper sections of the wells while the highest values occur at the deeper sections, corresponding to the continental Benin and paralic Agbada and probably a little of Akata Formations respectively. This is in agreement with the results of Akpabio et al., (2003), who discovered that geothermal gradient increases with depth linearly from the Benin Formation to the Akata Formation.

The shale percentages in relation to geothermal gradient also correlate with the result of Evamy et al, (1978) which shows that areas with high shale percentage have high geothermal gradient when compared with areas of low shale percentage.

Summary And Conclusions

The significance of temperature and geothermal gradient in relation to hydrocarbon occurrence of BARA oilfield in the western Niger Delta was studied using bottom hole temperature logs. In summary, the study shows that the average top of the oil generative window in the field is 3508.89m and the depth to the oil floor is 7182.3m, giving the thickness of the oil kitchen to be 3673.3m.

The average geothermal gradient of 1.74^{o}C / 100m shows that the field is thermally mature for commercial accumulation of hydrocarbon. This is evidenced in the occurrence of hydrocarbon in wells drilled by the operators of the field.

Conclusion

The study reveals that, the temperature and geothermal gradient of the field increase toward the centre. Commercial hydrocarbon occurs below calculated top of oil generative window, meaning that adjacent shale of the Agbada formation also contributed to hydrocarbon occurrence. Commercial accumulations of hydrocarbon still lie below the maximum drill depth in the field. Areas with high shale percentage have higher geothermal gradient while areas with low shale percentage have lower geothermal gradient. Hydrocarbon accumulations sometimes have a relationship with relative rise in temperature. Rise in geothermal gradient may be related to hydrocarbon accumulation or difference in thermal conductivity of the material above that rise. The geothermal gradient range agrees with that of previous works carried out in the Niger Delta Basin.

Recommendation

Based on observations from this study, it is pertinent to recommend that geothermal gradient measurement of fields be studied and plotted, so that the curve anomaly is properly studied for probable accumulation of hydrocarbon. Furthermore, the floor of oil generative window of fields should be evaluated in detail in order to have an in-depth knowledge of the hydrocarbon source rocks of the studied part of the Niger Delta.

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