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SUBSURFACE TEMPERATURES, GEOTHERMAL GRADIENTS AND HYDROCARBON STUDIES IN THE CALABAR FLANK

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ABSTRACT

Data gathered from seven exploratory wells were used to estimate geothermal gradients in the Calabar flank. Geothermal gradients vary between 34° C / km to 51° / km with an average value of 43.5 ° C / km. The deeper formations such as the Awi Formation, the Nkalagu Formation and the Nkporo Shale records very high geothermald gradient values. These high geothermal gradients could result from nearness to the basement, volcanic emplacement or due to overpressuring usually associated with shales. The Benin Formation recorded lower geothermal gradient values which may have been caused by the free movement of groundwater in these continental sandstones. Geothermal gradient in the Calabar flank is higher on the Ituk high, while lower values were observed on the Ikang trough and the Ikpe platform. Hydrocarbon maturation studies suggest the Ameke Formation ($R_o\% < 0.3$) and the Imo Shale ($R_o\% = 0.39 - 0.58$) as being thermally immature and also reveal the Nkporo Shale ($R_o\% = 0.70 - 1.02$) and the Nkalagu Formation ($R_o\% = 0.82 - 1.42$) as having the potential to generate liquid hydrocarbon, while the Mfamosing Limestone ($R_o\% = 1.43 - 2.13$) is inferred as a likely gaseous hydrocarbon precussor. The presence of volcanic fragments in some of the sediments suggests possible thermal alteration of pooled hydrocarbons.

KEYWORDS: Geothermal gradients, Hydrocarbon maturation, Bottom hole temperatures. Time temperature index

INTRODUCTION

Temperature and time plays a very important role in the maturation of organic matter into hydrocarbons. Bottom hole temperatures gotten from geophysical logs of petroleum exploratory wells are commonly used for geothermal and heat flow studies. However, several corrections are necessary before they can be utilized for geothermal and maturation studies.

This study deals with the temperature and geothermal history of the Calabar flank with a view to assess its potential for significant hydrocarbon accumulations. The geothermal gradients were evaluated using the least square techniques. Lopatin – Waples modeling method, a technique which integrates time and temperature information in estimating maturation were utilized. The calculated Time – temperature index (TTI) values were then correlated with other maturation Indices such as vitrinite reflectance (R_o %)

STRUCTURAL AND GEOLOGIC SETTING

The Calabar flank is a sedimentary basin bordering South-eastern Nigeria's continental margin. It is at right angle to the major rift faults of the Benue Trough. It is also a down faulted margin that borders the Niger Delta on the South-eastern side and adjoins the NW-SE trending Oban massif. The Oban massif bound it to the north, Abakaliki trough to the north-west while the Cameroun volcanic line bounds the extension to the South-east. (Figure 1)

The stratigraphic succession in the Calabar flank has been described by several workers such as Reyment (1965), Murat (1972), Kogbe (1975), Adeleye and Fayose (1978), Odumodu (1994) and many others. A geological map of the Calabar flank is shown in Figure 2.

The stratigraphic fill in the Calabar flank (Table 1) starts from the basal fluvial grits and calcareous arkosic sandstones of the Awi Formation, which rests unconformably on weathered Precambrian Crystalline Basement Complex rocks (Adeleye and Fayose, 1978). The Awi Formation is probably of Aptian age. The Albian Mfamosing Limestone overlies the Awi Formation. Overlying the Mfamosing Limestone is the Cenomanian – Turonian Nkalagu Formation, which is made up of a sequence of alternating dark grey shales with intercalations of thin calcareous limestone bands. This formation includes the Eze –Aku Shale, the Awgu Shale and the alternating shales and limestones of the Odukpani Formation. Some fragments of volcanic bodies have been found in the Nkalagu Formation at Anua-1 and Ikono-1 wells. The Nkalagu Formation is unconformably overlain by the Campanian – Maastrichtian Nkporo Shale. Tertiary to Recent sediments including the Imo Shale, the Ameke Formation and the Benin Sandstone overlies the Nkporo Shale.

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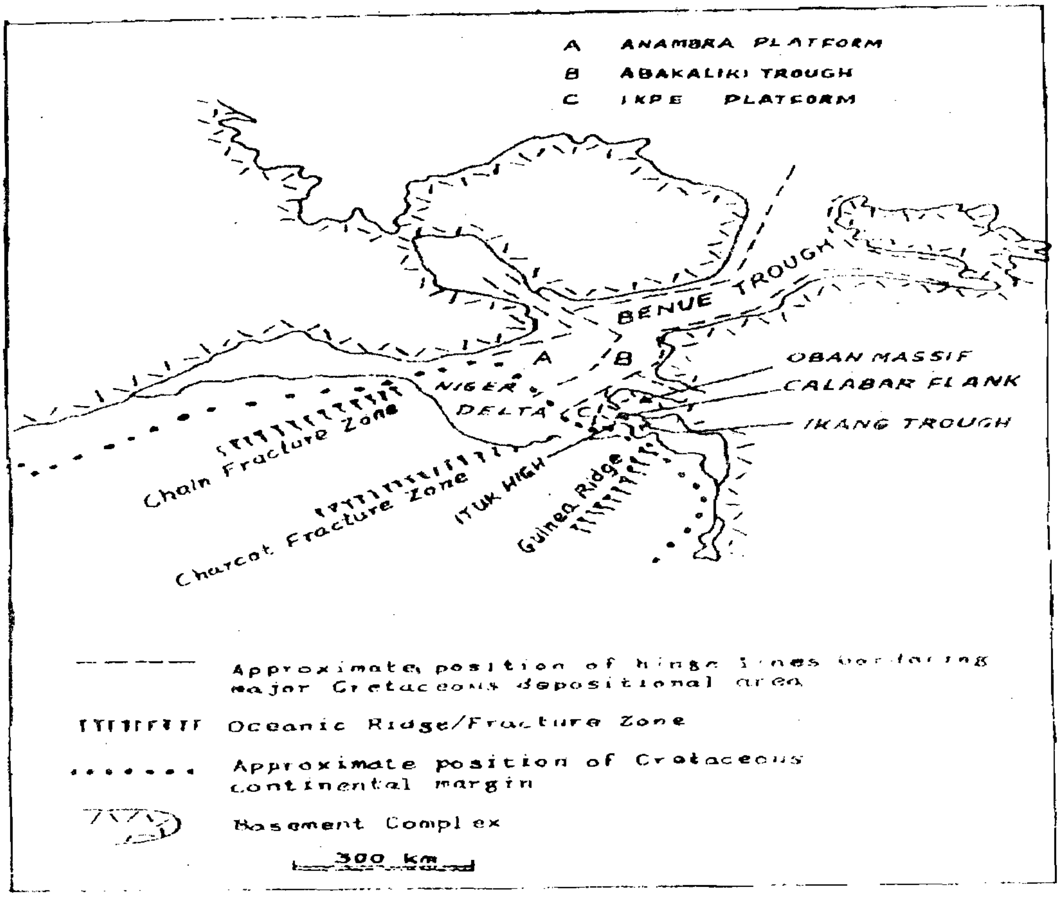


Figure 1 : Structural framework of the Calabar flank and adjacent areas (Adapted from Reijers and Petters, 1987)

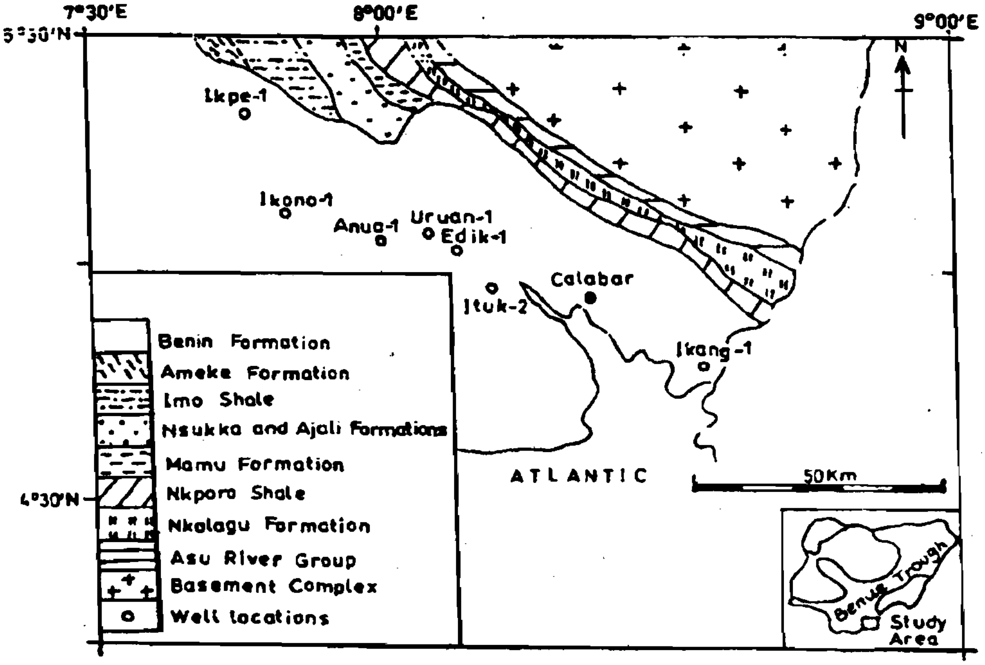


Figure 2 : Geologic sketch map of the Calabar flank with well locations

Table 1: Stratigraphic sequence in the Calabar flank. Compiled from Reyment, 1965; Dessauvagie, 1968; Fayose, 1978; Ramanathan and Kumaran,1981; Petters And Ekweozor,1982.

	Age	Formation		Lithologic Description	Environment
TERTIARY	Oligocene To Recent	Benin Fm.		Pebbly sands and gravel	Continental
	Eocene	Ameki Fm		Medium grained pebbly sandstone Clayey sandstones, calcareous silts, Clays and thin limestones	Paralic
	Paleocene	Imo Shale		Clayey Shale, clay- ironstone bands, Thin sandstone and sandy limestone Bands	Shallow Marine
CRETACEOUS	Campano-Maastrichtian	Nkporo Shale		Friable to flaggy carbonaceous shales with bands of marly and Silty to sandy shales and mudstones	Marine
	Coniacian	Awgu Shale	Nkalagu Fm		
	Cenomanian	Ezeaku Shale	Nkalagu Fm	Alternating dark grey shales with intercalations of thin calcareous Limestone bands	Marine
	Turonian	Odukpani Formation			
	Albian	Asu River Group	Mfamosing Limestone	Limestones with interbedded shales	Marine
	Aptian	Asu River Group	Awi Formation	Basal fluvial grits and calcareous arkosic sandstones	Fluvio-Deltaic
	Precambrian	Basement Complex		Weathered crystalline metamorphosed rocks	

METHOD OF STUDY

TEMPERATURE AND GEOTHERMAL GRADIENT VARIATIONS

Geothermal gradient can be defined as an increase in temperature resulting from a corresponding increase in depth. Bottom hole temperatures (BHT) gotten from geophysical logs of petroleum exploratory wells are commonly used for geothermal and heat flow studies. However several corrections are necessary before a reasonable interpretation of temperature data can be made. Bottom hole temperatures are usually lower than static formation temperatures because of drilling disturbances such as the circulation of drilling mud.

A method commonly used for correcting bottom hole temperatures (BHT) is the Horner technique (Chapman et al, 1984). It involves plotting the bottom hole temperatures according to the equation.

$T_B(t) = T_{B\alpha} + A \log(t_c + t_e / t_e)$ ------------ (1)

Where $T_{B(t)}$ = the time dependent BHT

$T_{B\alpha}$ = the true formation temperature

t_c = the circulation time

t_e = the elapsed time since circulation

A = a constant

By plotting $\log(t_c + t_e / t_e)$ against $T_B(t)$, one can estimate $T_{B\alpha}$ as the ordinate intercept on the abscissa axis. This method was utilized by Chapman et al (1984) for the temperature data from Uinta Basin. Nwachukwu (1976) applied a modified Lachenbruch – Brewer equation to correct bottom hole temperatures (BHT) for drilling effects. However this method requires multiple determinations of bottom hole temperatures at the same depth so as to use this correction procedure to obtain equilibrium temperature. The magnitude of differences between observed bottom hole temperatures BHT and corrected temperatures as discussed in some studies ranges from 5° C (Handique and Bharali, 1981) to 10 ° C and 20 ° C (Chapman et al, 1984). Handique and Bharali (1981) suggested that well log BHT are about 5° C lower than static formation temperature.

Leblanc et al (1981) suggested a method of correcting bottom hole temperatures based on Middleton (1979) curve matching techniques whereby thermal stabilization curves derived from an assumed thermal diffusivity are superimposed on actual data to estimate a true formation temperature. Leblanc's correction is done using the following relation.

$$BHT(o, t) = Tm + \Delta T\,(e^{-a^2} / 4kt) \quad \ldots\ldots\ldots\ldots 2$$

Where $\Delta_T = T_f - T_m$

Tm = the temperature of the drilling mud

T_f = the formation temperature

a = the drill hole radius

k = the formation rock matrix diffusivity

t = the total time of mud circulation at the depth of measurement.

However, neither the Horner's plot or Leblanc's method could be applied to this study because of lack of basic data as stated above that are required for these corrections.. The geothermal gradients at the various well sites as well as the average geothermal gradient were obtained by use of least square fit to the bottom hole temperatures (BHT) data.

HYDROCARBON MATURATION

The maturation of buried organic matter into hydrocarbons is largely a function of the temperature history of the sediment (Lopatin, 1971; Hunt, 1979 and Waples, 1980). The present day temperatures were used to estimate the paleotemperature. The estimated paleotemperatures were then superimposed on already established burial history curves. (Figure 3). The degrees of maturation of organic matter in sediments were then calculated using Lopatin – Waples time temperature index (TTI) of maturity as given in equation.

$$TTI = \sum_{nMin}^{nMax} (\Delta T_i)(r_i^n) \ldots\ldots\ldots\ldots 3$$

Where ΔTi = Residence times and

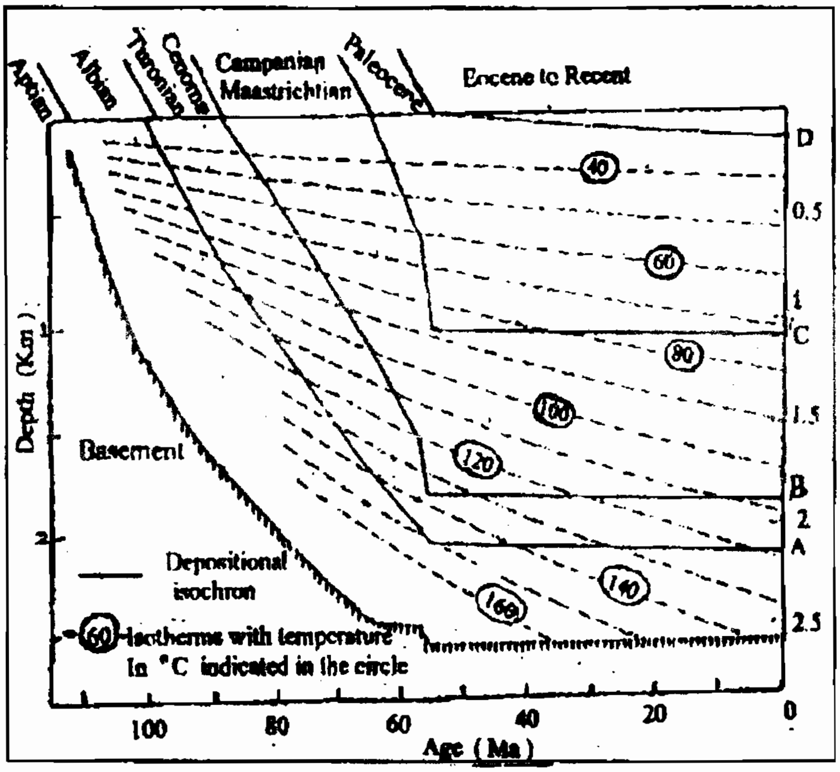
r_i^n = temperature coefficient of the rate of maturation and $_n$max and $_n$min are respectively the index values of the highest and lowest temperature intervals encountered.

Organic maturation were evaluated for the Calabar flank, using the Lopatin – Waples modeling approach

RESULTS AND DISCUSSION

Temperature versus depth plot for the various wells as well as a generalized temperature depth plot for the Calabar flank are shown in Figures 4 and 5. A large variation in temperature and geothermal gradient values were observed in the Calabar flank. (Table 2, Figure 6). These variations are influenced by well position with respect to nearness to a source of heat such as basement, depth of burial of the sediment / formation and the hydraulic flow system. A summary of the geothermal gradient distribution in the Calabar flank is given in Table 2 and Figure 6. The Awi Formation has a temperature gradient that ranges from 34.1 to 62.5 °c / km (Table 2). The high temperature gradient observed in the formation is to a large extent been influenced by high temperatures diffusing from the basement. The lower temperature value observed in the Benin Formation resulted from convection currents set up by the free movement of groundwater in the continental sandstones of the Benin Formation. The Nkalagu Formation is another formation that recorded a high thermal gradient value that ranges from 48.7 to 66.9 °c / km. The high thermal gradient observed in the formation might have been influenced by some volcanic bodies lying within the sediments at Anua-1 and Ikono-1 wells. The Nkporo Shale has a variable thermal gradient ranging from 33.3 to 94.7 ° C / km. The high thermal gradient recorded in the Nkporo Shale could result from over pressuring often associated with shales. It can as well be induced by volcanics lying directly beneath the shales.

(a)



E = Top of [illegible] Formation
B = Top of Nkalagu Formation
D = Top of Imo Shale
A = Top of Mfamosing Limestone
C = Top of Nkporo Shale

(b)

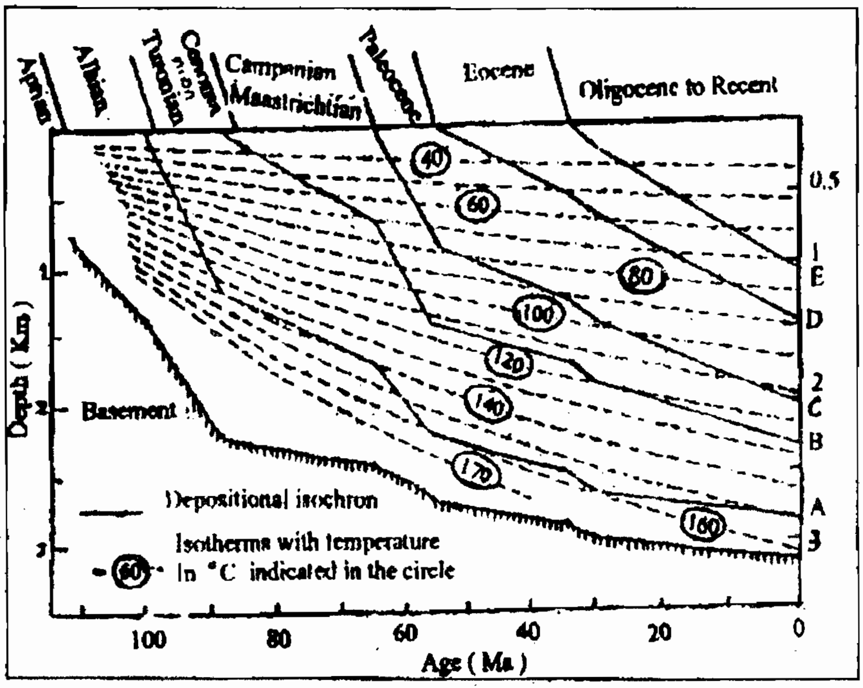
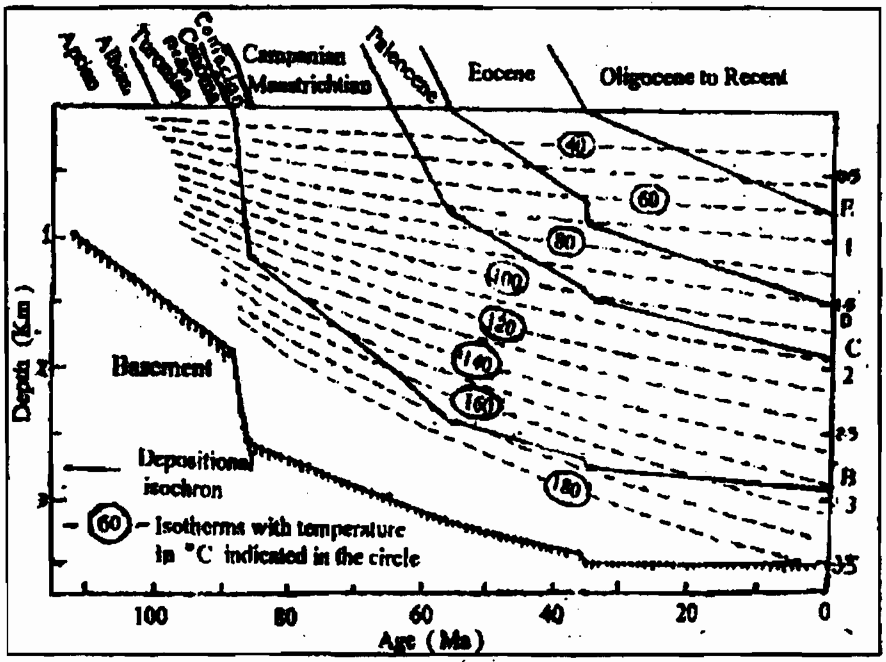


Figure 3 : Time / Temperature / Depth plot for (a) Ikpe – 1 and (b) Uruan – 1 wells

(c)



E = Top of Ameke Formation
D = Top of Imo Shale
C = Top of Nkporo Shale
B = Top of Nkalagu Formation
A = Top of Mfamosing Limestone

(d)

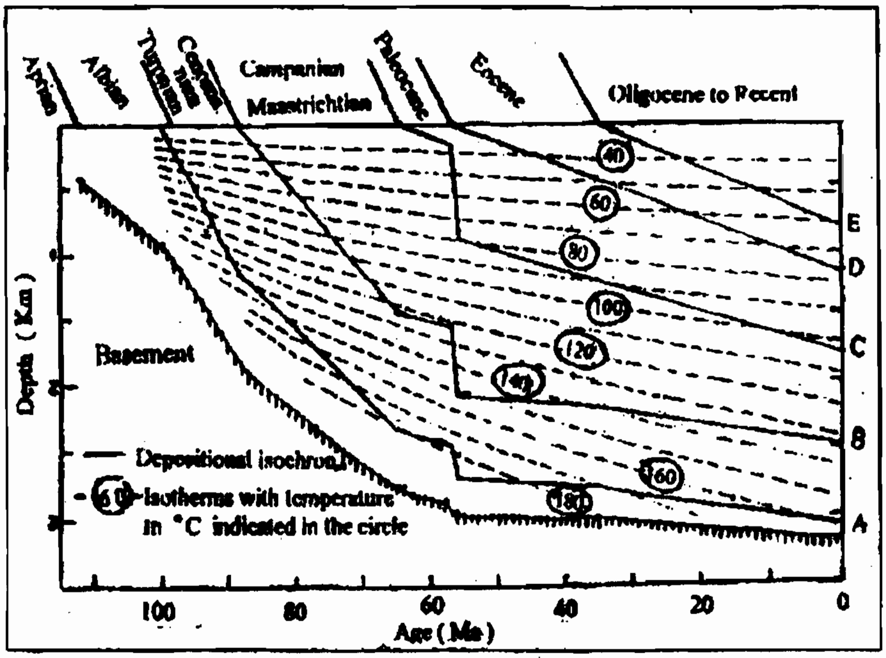


Figure 3 : Time / Temperature / Depth plot for (a) Anua – 1 and (b) Ituk – 2 wells

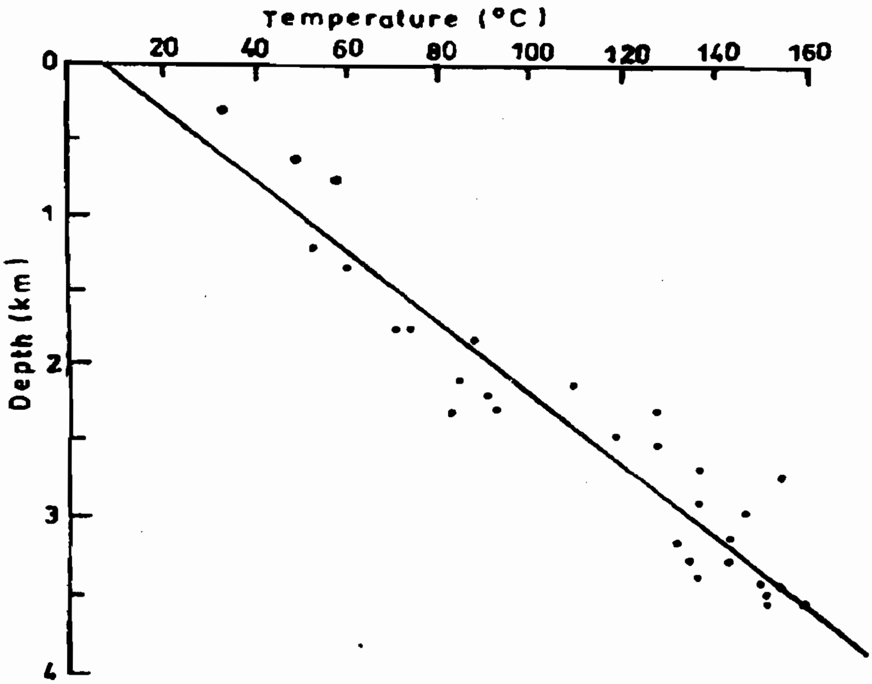


Figure 4 : Bottom Hole Temperatures (BHT) versus Depth plot for all wells

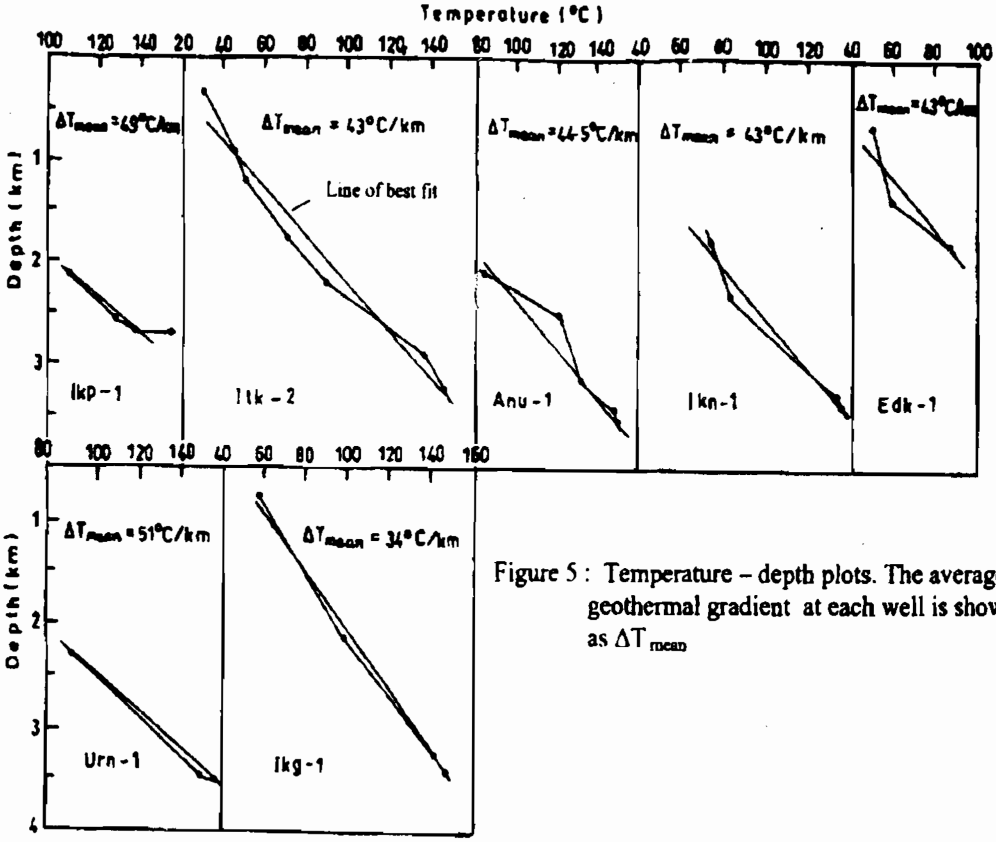


Figure 5 : Temperature – depth plots. The average geothermal gradient at each well is shown as ΔT_{mean}

The geothermal gradient in the Calabar flank increases in a north-easterly direction from the Niger delta to the Oban massif (Figure 7), which is in consonance with the earlier projections of Niger Delta based studies of Nwachukwu (1976) and Avbovbo (1978). The geothermal gradient is higher on the Ituk high but decreases towards the Ikpe platform and Ikang trough (Figure 7).

Possible source rocks for hydrocarbon maturation in the Calabar flank include the shales and limestones of the Mfamosing Limestone, the Nkalagu Formation, the Nkporo Shale, the Ameke Formation and the Imo Shale. The result of hydrocarbon maturation which was empirically calculated is given in table 3. The calculated TTI values were converted to vitrinite reflectance (R_o %) values using table 4. The result of organic maturation of the source rocks (Table 3), suggests that the Ameke Formation ($R_o\% < 0.3$) and the Imo Shale ($R_o\% = 0.39 - 0.58$) in the Calabar flank as immature source rocks while the Nkporo Shale ($R_o\% = 0.70 - 1.02$) and Nkalagu Formation ($R_o\% = 0.82 - 1.42$) are mature enough to generate hydrocarbons. The Mfamosing Limestone ($R_o\% = 1.43 - 2.13$) is also considered to be within the light oil and condensate (Wet gas) preservation deadline.

Table 2: Summary of Geothemal Gradient variations in the Calabar flank

Wells / Formations	Ikpe-1	Ikono-1	Anua-1	Uruan-1	Edik-1	Ituk-2	Ikang-1
Benin Formation	–	–	–	–	–	21.8	–
Ameke Formation	–	–	–	–		22.9	29.6
Imo Shale	–	–	–	–	15.0	35.2	38.4
Nkporo Shale	–	–	94.7		–	46.0	33.3
Volcanics	–	54.7	65.6		–	–	–
Nkalagu Formation	–		–	48.7	–	66.9	–
Mfamosing Limestone	45	17.7	–		–	25.6	–
Awi Formation	62.5	–	–		–	34.1	–
Basement	–	–	–	131.1	–	–	–

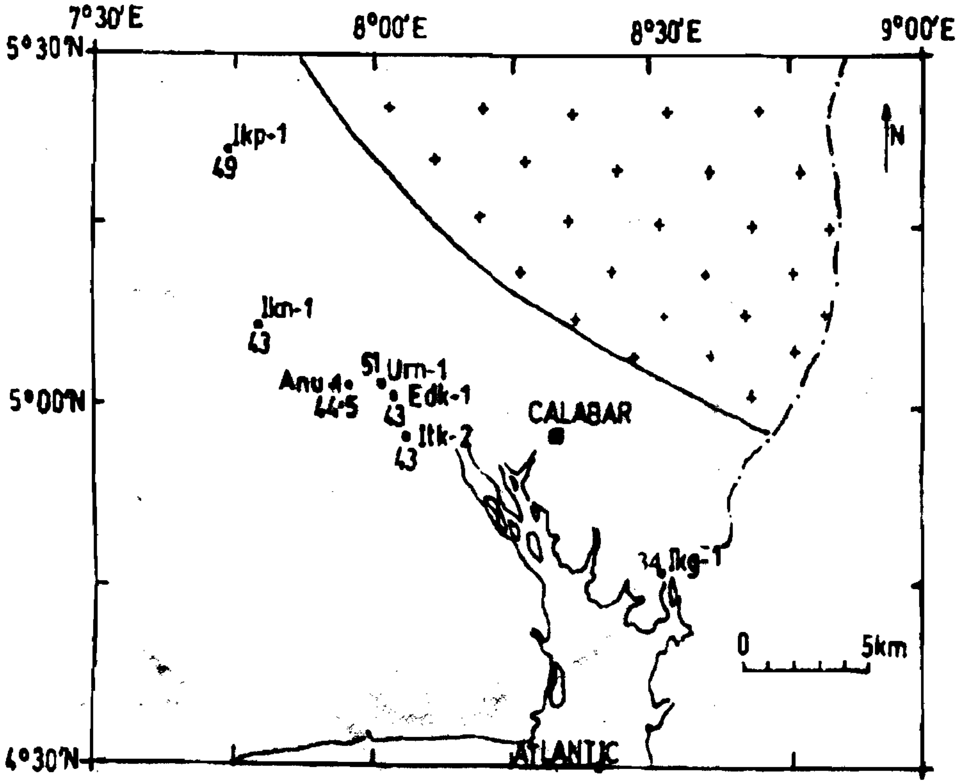


Figure 6 : Grad T variations across the Calabar flank (values are in °C / Km).

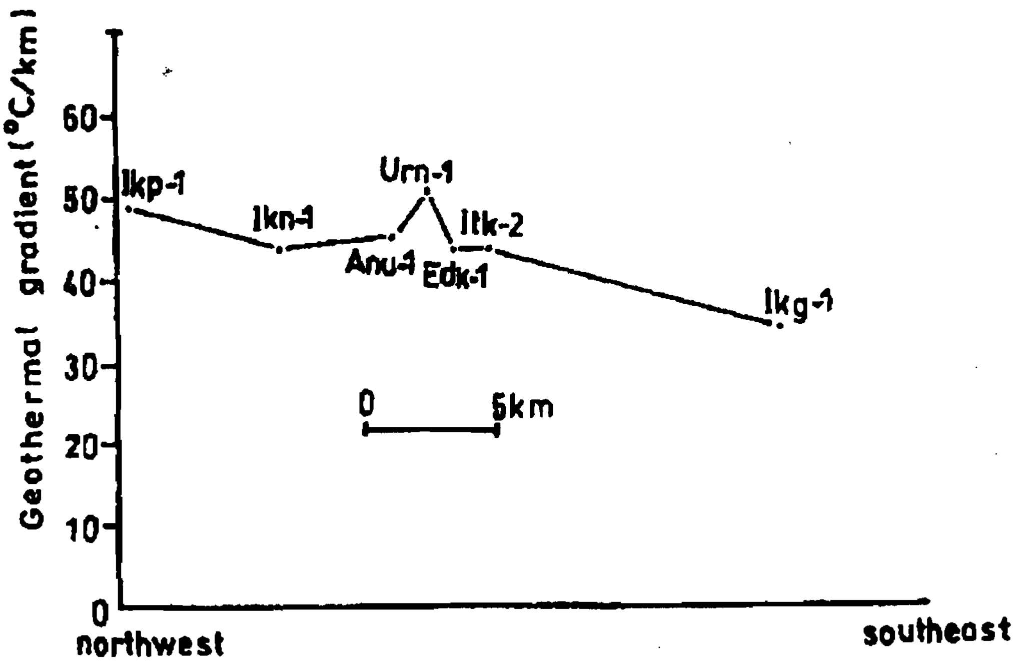


Figure 7 : Geothermal gradient variations along northwest – southeast direction

CONCLUDING REMARKS

Geothermal gradients in the Calabar flank varies from 34 °C / Km to 51°C/Km with an average value of 43.5 °C/Km. Geothermal gradients are generally higher for the deeply buried formations such as the Awi Formation, the Nkalagu Formation and the Nkporo Shale. Such factors such as closeness to basement, volcanic emplacement, overpressuring often associated with shales may have influenced this high thermal stress. Lower thermal gradient values occur within the Benin Formation and this can be attributed to the free movement of groundwater in the continental sandstone. Geothermal gradients in the Calabar flank generally increases in a northeasterly direction from the Niger Delta to the Oban Massif. The geothermal gradients in the Calabar flank is generally higher on the Ituk high than at the Ikpe platform than the Ikang trough.

Hydrocarbon maturation modeling which has been evaluated for the Calabar flank by superimposing paleotemperatures on already established burial history curves suggests that some of the source rocks have undergone proper temperature conditions and requisite exposal time for the maturity status to be attained. This study has shown that the Ameke Formation ($R_o\% < 0.3$) and the Imo Shale ($R_o\%$ = 0 39 - 0 58) are thermally immature. The Nkporo Shale ($R_o\%$ = 0.70 – 1.02) and Nkalagu Formation ($R_o\%$ = 0.82 – 1.42) has been revealed as having the potential to generate liquid hydrocarbon, while the Mfamosing Limestone ($R_o\%$ = 1.43 – 2.13) has the capacity for light oil and wet gas generation. However, all the wells drilled in the Calabar flank were dry wells except at Ikono – 1 well where little gas was encountered. The non discovery of oil in the Calabar flank is still a mystery. Absence of suitable traps and possible migration of generated hydrocarbons out of the flank to the adjoining Niger Delta could be possible explanations of this problem. Other possible ideas about this issue might be the conversion of generated oil to gas due to high temperatures associated with volcanic bodies that were emplaced within the sediments.

One limitation encountered in this study was the lack of some basic data required for the correction of bottom hole temperatures (BHT) to static formation temperature. This lack therefore necessitated using the raw data without corrections. This may result to an underestimation in the maturation status of the source rocks because bottom hole temperatures are usually lower than static formation temperatures. It is therefore recommended that more data should be made available for future studies.

Table 3: Calculated TTI values with their Equivalent Vitrinite reflectance (R_o %) values for the Ikpe -1, Anua-1, Ituk-2, and Uruan -1 wells, all in the Calabar flank.

Wells	Ikpe-1 well		Anua-1 well		Ituk-2 well		Uruan-1 well		
Maturation Indices / Formation	TTI Values	R_o % Values	TTI Values	R_o % Values	TTI Values	R_o % Values	TTI Values	R_o % Values	Remarks/I nterpretati on.
Ameke Formation	–	–	0.625	< 0.3	0.968	< 0.3	0.172	< 0.3	Immature
Imo Shale	–	–	8.766	0.58	5.235	0.53	1.169	0.39	Immature
Nkporo Shale	0.357	< 0.3	80.028	1.02	26.956	0.76	20.194	0.70	Mature
Nkalagu Formation	36.435	0.82	352.124	3.54	99.668	1.10	231.689	1.42	Mature
Mfamosing Limestone	238.071	1.43	–	–	1,064.00	2.06	1277.631	2.13	Light Oil and wet gas

Table 4: Correlation of TTI with threshold values of hydrocarbon generation and preservation. (After Waples, 1980)

Stage	TTI	R^0	TAI
Onset of oil generation	15	0.95	2.65
Peak of oil generation	75	1.00	2.90
End of oil generation	160	1.30	3.20
Light oil (API<40^0) Preservation deadline	500	1.75	3.60
Oil (API<50) Preservation deadline	1000	2.00	3.70
Condensate (Wet Gas) preservation deadline	15000	2.20	3.70
Dry Gas Methane	>65.000	4.50	>4.00

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