

Hydrocarbon Generative Windows Determination Using Geomathematical Model: Case Study from Ogbogede Field, Niger Delta, Nigeria

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Abstract

Oil and gas generative windows of source rocks in Niger Delta have been determined by applying a mathematical model to geotemperature data from the wells of Ogbogede oil field. GR and Resistivity log signatures show that the Benin and Agbada Formations comprises massive sands with clay intercalations while the Agbada Formation comprises alternate sequence of sandstones and shales. The geothermal gradients for the field range from 1.4°C/100m to 2°C/100m with an average of 1.8°C/100m and standard deviation of 0.2°C/100m. Geotemperature analysis of shales of the Agbada Formation varies from 58.92°C-107.6°C, indicating that they are thermally mature and within the oil generative window, at depths varying approximately from 1833.30 m to 5166.67m. The gas window occurs from 5166.67 m to 11000 m. This work has provided a mathematical method of source rock evaluation to compliment geochemistry. The outcome is a very important tool, which can be applied to other fields and sedimentary basins in hydrocarbon exploration.

Keywords: Hydrocarbon Generative Windows, Geotemperature data

1. Introduction

Organic matter in sedimentary rocks generates petroleum under favorable temperature conditions. Temperature increases with depth and plays a very important role in hydrocarbon generation. Hyne (1984) notes that a minimum temperature of 50°C is necessary for the generation of crude oil under average sedimentary condition Selley (1996) shows that significant crude oil generation occurs between 60°C and 120°C, and significant gas generation between 120°C and 225°C, and that above 225°C the organic matter is spent and only carbon remains as graphite.

Albrecht et al. (1976), Cooper (1977), Hunt (1979), and Alexander et al. (1979) showed through geochemical studies, that hydrocarbon generation is promoted by high subsurface temperatures. This observation corresponds to the predictions of chemical reaction-rate theory in Waples (1981) and Allen and Allen (2002).

On the other hand, Lopatin (1971) and many others believe that time and temperature are the important factors in hydrocarbon generation and destruction. Lopatin (1971) developed a "Time-Temperature Index" of maturity (TTI) to calculate the thermal maturity of organic material in sediments. His method has been widely applied in oil exploration and basin analysis. Ziegler and Spotts (1978), and MacMillan (1980) applied Lopatin's technique in the study of Californian Basins and Rocky Mountains Basin of Colorado respectively. Waples (1980, 1981) used the same technique for petroleum exploration and to construct geologic models for depositional and tectonic histories of the geologic sections. Onwuemesi and Egboka (2007), and Odumodu (2009) applied the Lopatin's method in the study of petroleum prospect of Anambra Basin of Nigeria and the hydrocarbon studies of the Calabar Flank respectively.

The integrated basin modeling and hydrocarbon maturation history of Ghadames Basin, north Africa in Underdown and Redfern (2007, 2008) applied vitrinite reflection (Ro) calibration data which were compared to the calibrated values obtained using vitrinite reflection (% Ro) algorithm of Sweeney and Burnham (1990). This is based on chemical kinetic model that uses Arrhenius rate constant to calculate vitrinite elemental composition as a function of temperature and time and is the most widely used model for Ro calibration in basin modeling application.

Early studies of the Niger Delta Basin (Short and Stauble, 1967) subdivided the basin into three formations namely the Akata (base), the Agbada (middle), and the Benin (top) Formations. These formations represent the prograding depositional facies that are distinguished mostly on the basis of their sand-shale ratios. The Akata Formation comprises mostly marine shale sequences and lowstand turbidite sand. The Agbada Formation comprises alternating sequences of sandstone and shale and is interpreted as a cyclic paralic sequence comprising marine and fluvial deposits. The Benin Formation comprises continental, massive sands with clay

intercalations (Short and Stauble, 1967; Evamy et al, 1978; Weber, 1987; Reijers et al, 1996; Anakwuba et al, 2008; Akpunonu et al, 2008; Akpunonu, 2008).

The early works on the Niger Delta in Short and Stauble (1967) identified the Akata Shale as the source rock and the Agbada Formation as the reservoir sequence. Nevertheless, the recent works by Evamy et al (1978), Ekweozor and Okoye (1980), Ejedawe (1981), Ekweozor and Daukoru (1992), Frost (1997), Reijers et al (1996), and Ako et al, (2004) document the Akata and lower Agbada Formations as constituting the major source rocks of the Niger Delta. Geotemperature analysis of the Agbada Shale beds in Akpunonu et al (2008, 2009), shows that the shales of the Agbada Formation from top to bottom in the swamp and onshore fields are thermally mature to generate oil. Temperature and burial depth are major contributory factors in the maturation of the source beds within the oil and gas generative windows (Underdown and Redfern, 2007, 2008; and Akpunonu, 2002, 2008).

In the present study, an equation is derived from geotemperature equation of Akpunonu et al (2008, 2009) to calculate the depths where oil and gas generation occurred. The objective of the research is to provide a mathematical method of source rock evaluation to compliment geochemistry and to determine the oil and gas generative windows in Niger Delta from the Ogbogede On-Shore Field.

2. Methodology

The materials used in order to accomplish the objectives of the study are the gamma-ray logs (GR), resistivity logs (LLD & LLSD), neutron/density logs (RHOB/NPHL), sonic logs, and caliper logs from Ogbogede 1 – 4 Wells. Borehole information on bottom-hole temperatures (BHT) of wells OGB-1, OGB-2, OGB-3, and OGB-4 as well as the mean annual surface temperature of the entire region (Table 1) was also provided. The bottom-hole temperatures were corrected using Fertl Wichmann method (Fertl and Wichmann, 1977) or where circulation time was not known, using empirical factor derived from the temperature correction curve of Jones (1975). Details on the correction procedure have been described in Deming (1989). The fundamental approach to the study starts with quantitative well log interpretation. GR log and resistivity logs were combined to interpret lithologic sections of the from the wells. These litho-sections were drawn using a vertical scale of 1cm: 100m (Figures 3a-d & 4a-d).

The source rock potential analysis focuses on the shale units of Agbada Formation because all the wells terminated there and none penetrated into Akata Formation. The sand and shale packages of Agbada Formation are carefully delineated and the shale units are properly defined and numbered for maturation potential evaluation Figures 5a-d, shows the shale units of the Agbada Formation identified and numbered for temperature analysis to assess their thermal maturation potentials.

3. Geothermal Gradient

The depth at which oil and gas windows occur in a basin according to Adesida and Ojo (2004), Forest et al (2005) and Akande et al (2007) depends on the heat or geothermal gradient of the field. Therefore, the first step taken in the determination of the hydrocarbon generative windows in Ogbogede Field is the determination of geothermal gradients of the field. This is followed by the evaluation of hydrocarbon generative potential of petroleum source rock of the field. Geothermal gradient according to Hyne (1984) is defined as the increase of temperature with depth. The mathematical expression of geothermal gradient in Akpunonu et al (2009) is as in equation (1):

$$G = \Delta T / \Delta H \quad (1)$$

Where

ΔT = difference between mean annual surface & bottom hole temperatures

ΔH = difference in depth between surface & bottom hole temperatures

G = geothermal gradient

The mean annual surface temperature of the Niger Delta is 27°C, measured at depth of 18.29m (60ft) to avoid the weathered materials on the surface (Akpunonu et al; 2008). Table 2 shows the computed geothermal gradients for wells 1 – 4 in the Ogbogede Field.

The average geothermal gradient in the entire field is calculated from the equation

$$G_a = \frac{\sum \Delta T / \Delta H}{N} \quad (2)$$

Where

G_a = average geothermal gradient.
 N = the number of wells in the field.

To ensure that the value obtained from the above equation represents the geothermal gradient of the entire field, the standard deviation is calculated with the formula below:

$$S = \sqrt{\frac{\sum (G - G_a)^2}{N}} \quad (3)$$

Akpunonu, et al; 2008

Where S = standard deviation
 G = geothermal gradient
 G_a = average geothermal gradient
 N = no of wells in the field

There are four (4) wells in the field. Therefore the average geothermal gradient (G_a) of the field as calculated from equation (2) above is 1.8°C/100m, while the standard deviation (S) as calculated from equation (3) above is 0.2°C/100m.

4. Geotemperature Analysis and maturity status of Shales in the Agbada Formation.

The temperature variation with depth will give a linear function as in equation (4) below.

$$T_d = Gd + C \quad (4)$$

Where T_d = temperature at any depth
 d = depth of interest
 G = geothermal gradient
 C = constant (mean annual surface temperature)

Combining equations (1) and (4) and substituting for G in (1)

$$T_d = (\Delta T / \Delta H \times d) + C \quad (5)$$

[Akpunonu (2008) and Akpunonu et al (2008)]

Where T_d = temperature at the target depth
 ΔT = difference between mean annual surface & bottom hole temperatures
 ΔH = difference in depth between surface & bottom hole temperatures
 d = target depth or depth of interest
 C = constant (mean annual surface temperature)

The maturity of source rock of Agbada Formation in is evaluated by calculating the temperature of shale units at various depths in the four well sections using equation (5) above. Tables 3, 4, 5, and 6 are the temperature of the shales at various depths. Graphical plots of computed temperatures versus depth are shown in Figs. 6a - d.

5. Determination Of Oil And Gas Windows.

To determine the depth at which oil/gas starts and a stop generating in the field, an equation is derived from the geotemperature equation (5) above (Akpunonu, 2008; Akpunonu et al., 2008):

$$\{T_d = (\Delta T / \Delta H \times d) + C\}$$

Since geothermal gradient $G = \Delta T / \Delta H$ and average geothermal gradient

$$G_a = \frac{\sum \Delta T / \Delta H}{N} \quad (2)$$

$$\begin{aligned} T_d &= (\Delta T / \Delta H \times d) + C \\ T_d &= (G_a \times d) + C \\ &= (G_a \times d) + C \\ G_a \times d &= T_d - C \end{aligned}$$

$$d = T_d - C$$

$$\frac{1}{G_a} \quad (6)$$

Where d = the target depth

T_d = temperature at the target depth

C = constant (mean annual surface temperature)

G_a = average geothermal gradient.

Selley (1996) shows that oil generation starts at 60°C and stops at 120°C, while gas generation begins at 120°C and stops at 225°C, and that above 225°C hydrocarbon irreversibly transforms into graphite (pure carbon).

From equation (6) above, if

$T_d = 60^\circ\text{C}$ and $G_a = 1.8^\circ\text{C}/100\text{m}$, then $d = 1833.3 \text{ m}$. (6013.2 ft)

If $T_d = 120^\circ\text{C}$ and $G_a = 1.8^\circ\text{C}/100 \text{ m}$, then $d = 5166.7 \text{ m}$. (16946.8 ft)

If $T_d = 225^\circ\text{C}$, and $G_a = 1.8^\circ\text{C}/100\text{m}$, then $d = 11000 \text{ m}$ (36,000 ft)

Above 11000 m (36000 ft) metagenesis will take place and hydrocarbon will be destroyed.

6. Result and Discussion

6.1 Hydrocarbon Generation Model

Figure (7) shows the stratigraphic units of the Niger Delta (Akata, Agbada, and Benin) and the model of oil and gas windows using data from the Ogbogede Field. In the zone of catagenesis oil and gas are produced while in the metagenesis zone the organic matter/kerogen is transformed to graphite

This model shows that oil generation in the Niger Delta starts at the depth of about 1833.3m (6012ft) in the lowermost part of the Benin Formation and extends through the Agbada Formation to a depth of about 5166.7m (16947ft) at the topmost part of the Akata Formation. Gas generation occurs from about 5166.7m (16947ft) to 11000m (36080ft) within the Akata Formation. From about 11,000m (36,080ft), the hydrocarbon irreversibly transforms to graphite (carbon) up to the basement at a depth of about 12000m. The result shows that oil generation in the field has a ceiling at 1833.3m (6013ft) and a floor at 5166.7m (16,947ft) while gas generation has a ceiling and a floor at 5,166.7m (16,947ft) and 11,000m (36,080ft) respectively. Although the oil ceiling is in the lower Benin Formation, oil does not cook there because of the absence of organic matter (kerogen) as it is believed that shale unit within the Benin Formation does not have enough organic matter content to generate crude oil. The gas window begins from the upper Akata Formation, which is the gas ceiling and boundary between the oil and gas windows. The floor is located at the lower Akata Formation where gas generation stops and hydrocarbon irreversibly begins to transform into graphite. The over maturity and destruction of the organic matter and kerogen from 11000 m (36,080ft) may be attributed to deep burial and very high temperatures close to the basement complex.

6.2 Lithology

The Niger Delta Basin has a sedimentary fill of about (39,360ft) 12,000m (Weber and Daukoru, 1975; Avbovbo, 1978; Evamy et al, 1978; Whiteman, 1982; Stacher, 1994; Reijers et al, 1996; Owoyemi and Willis, 2006; and Magbagbeola and Willis, 2007). Short and Stauble (1967) subdivides the basin into three lithostratigraphic units namely Akata, Agbada and Benin Formations. Short and Stauble (1967) notes that Agbada Formation is about 2,300m (7,544ft) thick while Akpunonu (2002) inferred from seismic stratigraphic and log interpretations that it is about 2,350m (7,708ft) thick. The quantitative log interpretation in this study shows that Benin Formation is about 2,262.5m (7,421ft) while Agbada Formation is about 2,200m (7,216ft) in the Ogbogede Field. The stratigraphic model constructed in this study (Fig. 7) has estimated the thickness of Agbada and Benin Formations at about 4,463m (14,638.6ft) while the Akata Formation is about 7,537m (24,721ft).

The hydrocarbon generative windows in the Niger Delta have been evaluated using from geotemperature and wireline log analysis of OGB-1, OGB-2, OGB-3, and OGB-4 in the Ogbogede On-shore Field of western Niger Delta. The maturation potential of the source rock is evaluated in terms of lithology and temperatures. These are interpreted from the wireline logs obtained from the wells.

Only the Benin and the Agbada Formations are recognized from the well logs during the quantitative interpretation (Figures 3a-d). In all the wells, the Benin Formation is recognized by low gamma counts and high resistivity readings of fresh water, while the Agbada Formation is recognized by high gamma and low resistivity readings. The Benin Formation is interpreted to have been deposited in fluvial and coastal environments (Short

and Stauble, 1967; Ekweozor and Daukoru, 1992; Reijers et al, 1996; and Ajaegwu et al, 2008). The thickness of the formation varies but the average thickness as interpreted from the logs is about 2,262.5m. It lies conformably on the Agbada Formation. The results of the log interpretation show that Benin and Agbada Formations have their boundaries at about 2,240m in well OGB-1, 2,280m in well OGB-2, 2,315m in well OGB-3 and 2,225m in well OGB-4; and at about 2,262.5m on the average (Figures 3a-d). The sand bed that overlies the very first thick shale bed is recognized as the base of Benin Formation and is identified as "Base of Fresh Water Sand" (BFWS). The Agbada Formation begins with the first thick shale bed that underlies the BFWS and continues to the total depths of the wells. It comprises alternate sequence of sandstone and shale. The log analysis shows an increase in shale alternation over sandstone, which suggests a decrease in sand/shale ratio. Both the thickness and its boundary with the Akata Formation could not be determined in this work because all the wells used terminated in the Agbada Formation. However, the average thickness has been inferred to be about 2300m to 2350m (Short and Stauble, 1967, Akpunonu, 2002).

Figures 3a-d shows the litho- sections recognized in the wells. In OGB-1, the Agbada Formation comprises ten (10) shale (sh) units, eight (8) clean sands, and six (6) dirty sands. In well OGB-2, eight (8) shale units, five (5) clean sands, and one (1) dirty sand are identified. In Well OGB-3 eighteen (18) shale units, thirteen (13) clean sands, and eight (8) dirty sands are identified ; while in well OGB-4, four (4) shale , one (1) clean sand, and two (2) dirty sand packages were recognized (Table 8). Shale unit 5 (sh₅) is missing in OGB-1, while shale unit 6 (sh₆) in well OGB-1 is missing in well OGB-2. In well OGB-3, sh₁ – sh₃ are not recorded, while sh₃, sh₅, sh₆ and sh₇ are missing in well OGB-4. The absence of these shale units is evidence of fault cuts which in Tearpock and Bischke (1991) is indication of growth faults.

6.3. Temperature Analysis

Organic matter in sedimentary rocks generates petroleum under favorable temperature conditions. Temperature therefore plays the most important role in maturation of source rocks and oil and gas generation. Temperature usually increases with depth and the rate of increase with depth (geothermal gradient) is a prerequisite in the source rock potential evaluation. The geothermal gradients in wells OGB-1, OGB-2, OGB-3 and OGB-4 determined from equation (1) are 1.4°C/100m, 1.7°C/100m, 2.0°C/100m, and 1.9°C/100m respectively. The average geothermal gradient and standard deviation calculated from equations (2) and (3) are 1.8°C/100m and 0.2°C/100m respectively. Because of the low value of the standard deviation, the average value (1.8°C/100m) has been used in this study as the geothermal gradient for the field.

From equation (5), the temperature of the shale units at various depths in the wells were calculated and the values were recorded in Tables 3, 4, 5, and 6. The temperature of the source rocks in wells OGB-1, OGB-2, OGB-3, and OGB-4 are summarized in Table (7) and range from 58.92°C to 76.42°C, 66.44°C to 85.48°C, 74.00°C to 107.60°C, and 70.32°C to 75.45°C respectively. The graphical plots of the above values with respect to depths in figures 6a-d confirmed the linear relationship of temperature with depth and authenticate equation (5). Since oil generation begins from 50°C (Hyne, 1984), or from 60°C (Selley, 1996), the above temperature values show that oil generation is possible from the shale beds of Agbada Formation in Ogbogede Field. This implies that these shales are thermally matured, and can generate crude oil if they contain enough kerogen.

7. Conclusion

There are many oil and gas fields in the Niger Delta, but little or no considerations are given to depths where oil and gas are generated within the basin. In the present study, the hydrocarbon generative windows of Ogbogede Onshore Field in Niger Delta have been determined with geomathematics modeled from geotemperature analysis.

The geotemperature equations used in this study to evaluate the degree of thermal maturity of the source rocks in the Niger Delta show that the Agbada Formation is the main oil source rock while the Akata Formation generates more of gas. The use of this mathematical model for source rock evaluation and oil/gas window evaluation has provided a cheaper and faster method of hydrocarbon source rock evaluation to compliment petroleum geochemical methods of source rock evaluations in frontier and even mature petroliferous basins.

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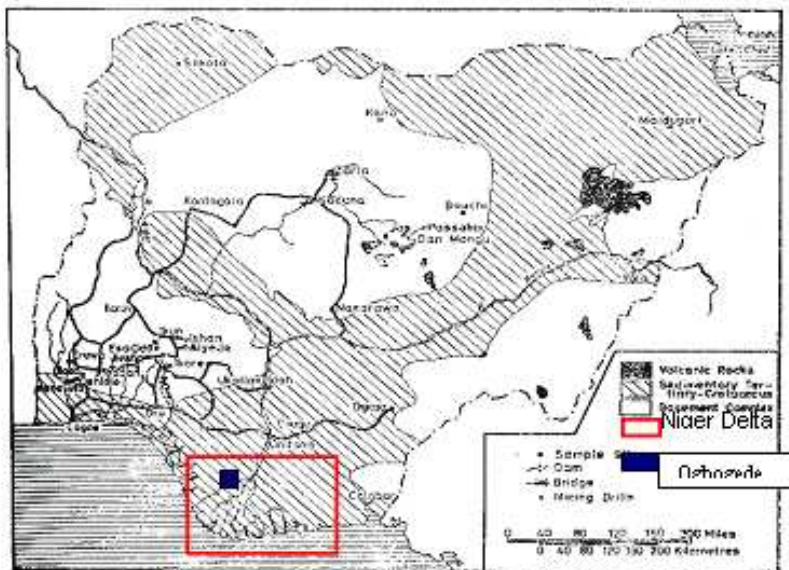


Fig. 1: Geologic Map of Nigeria showing Niger Delta (Modified from Whiteman, 1982)

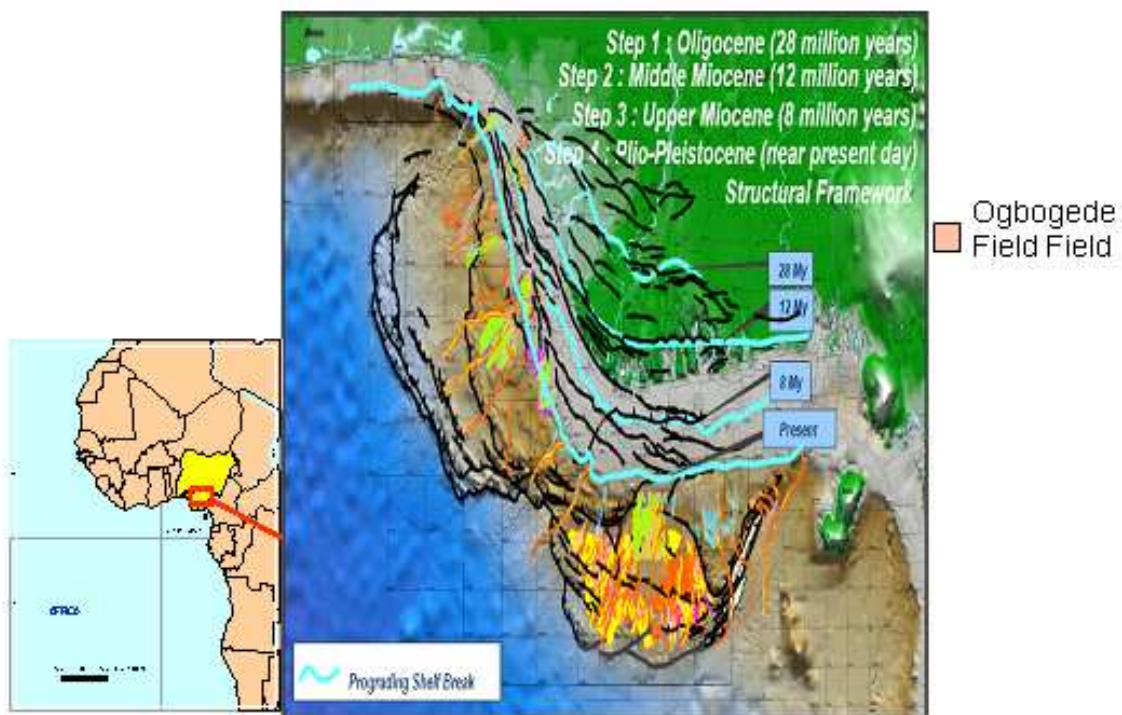


Fig. 2: Location map of Niger Delta (Adopted from Akpuxonu et al, 2008)

OGBOGEDE ONSHORE OIL

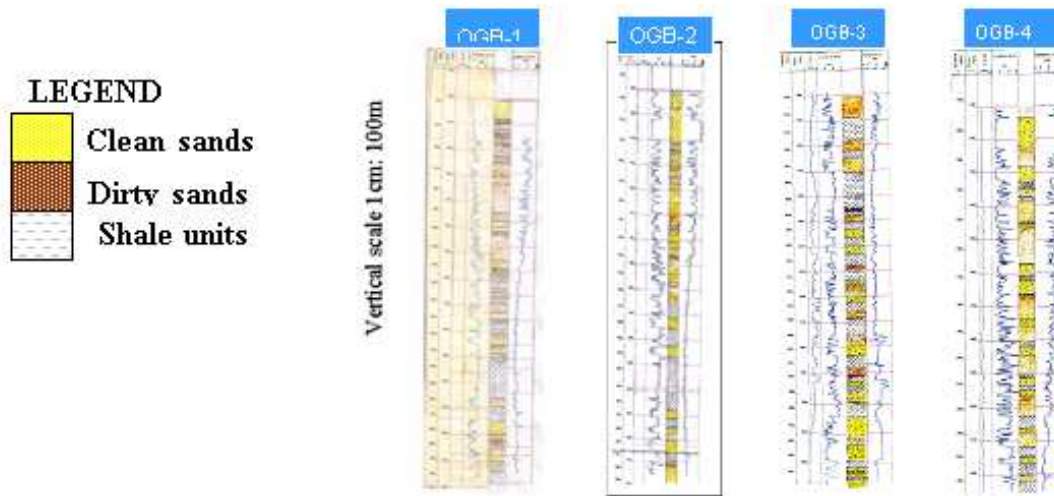


Fig. 3a-d: Lithologic sections of the wells OGB-1, OGB-2, OGB-3, and OGB-4 interpreted from a combination of gamma ray and resistivity logs

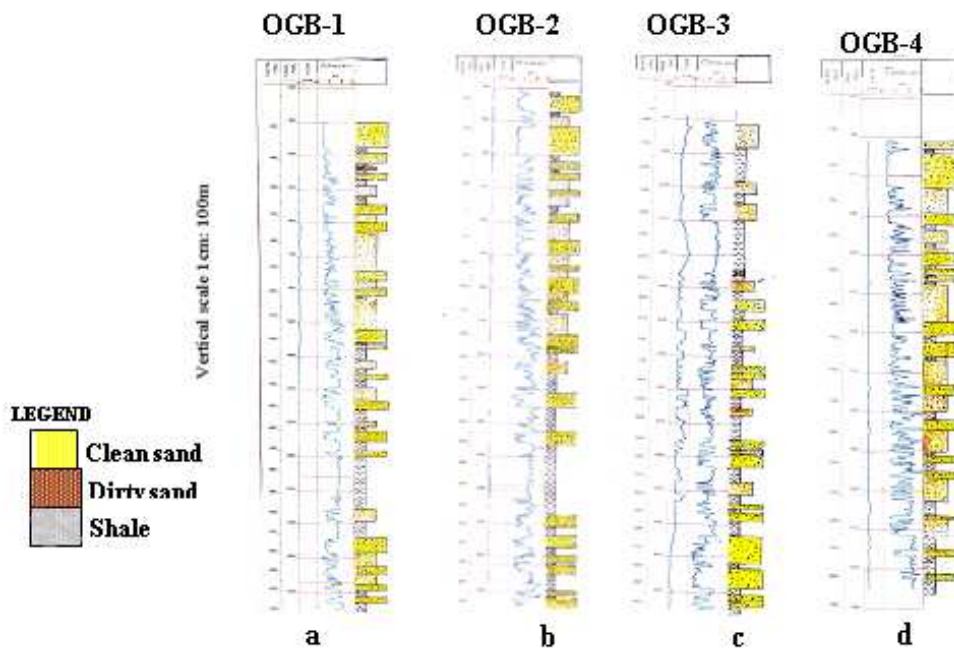


Fig. 4a-d: Block type lithologic sections of wells OGB-1, OGB-2, OGB-3, & OGB-4 arranged in panel, interpreted from gamma ray composite logs.

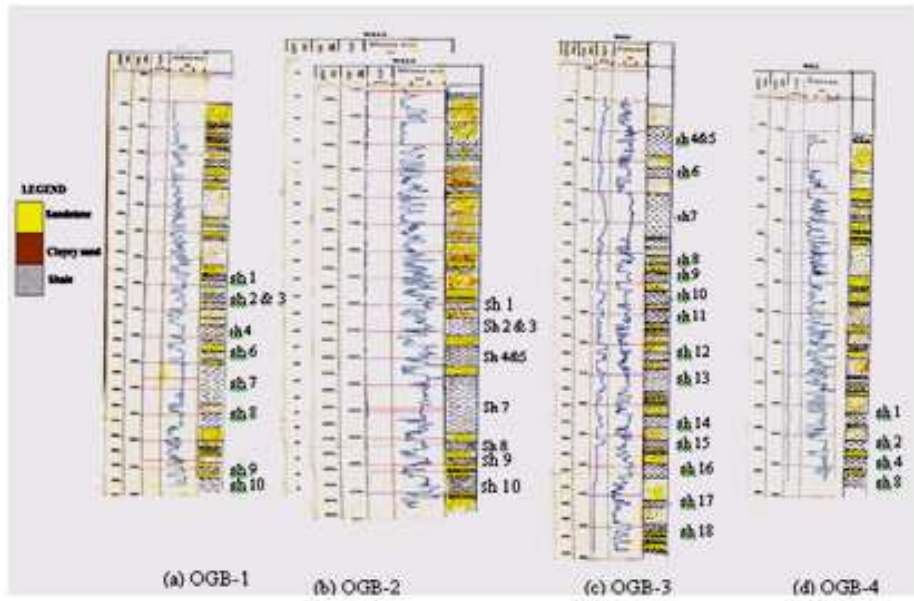


Fig. 5a-d: The shale units of Agbada Formation in wells OGB-1, OGB-2, OGB-3 & OGB-4

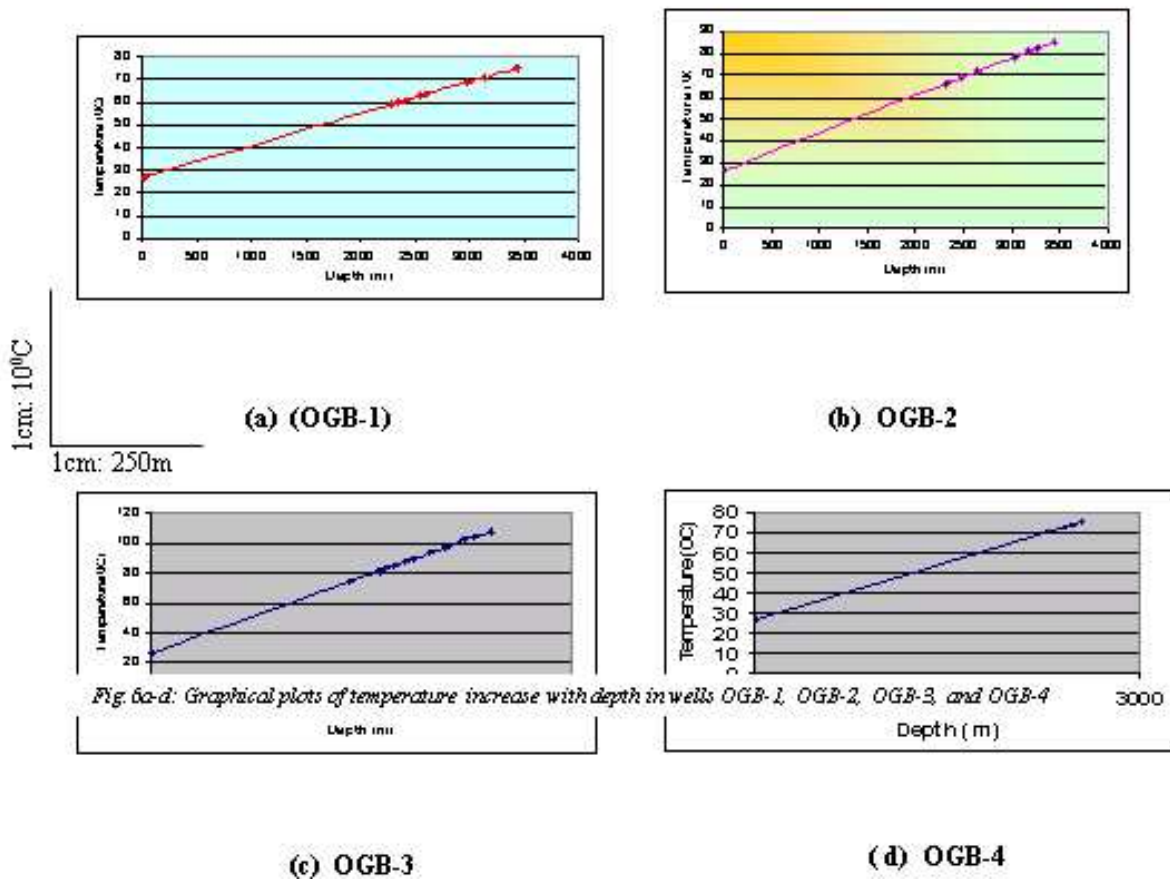


Fig. 6a-d: Graphical plots of temperature increase with depth in wells OGB-1, OGB-2, OGB-3, and OGB-4

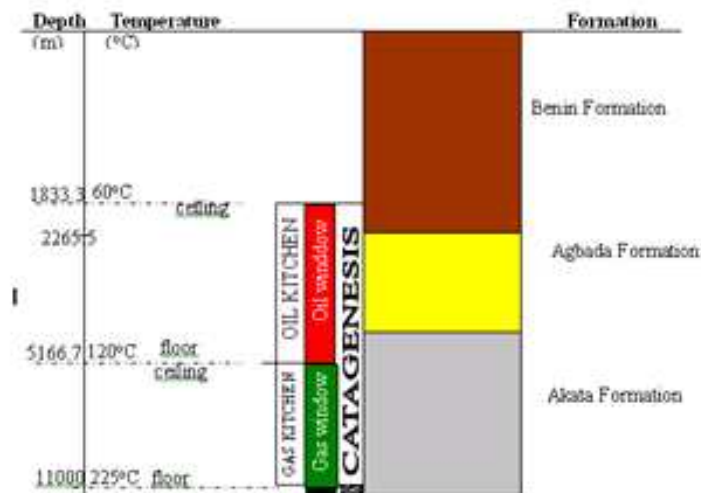


Fig. 7: Schematic diagram showing hydrocarbon generative windows and metagenesis in Ogbogede Field Niger Delta Basin

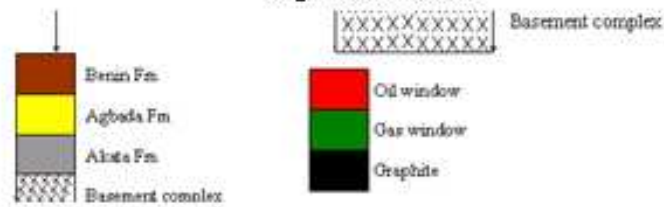


Table 1: Bottom Hole Temperature and Depths of Formations.

WELL	DEPTH (m)	BHT (°C)	SURFACE TEMPERATURE (°C)
OGB-1	3530	75	27
OGB-2	3540	87	27
OGB-3	4450	115	27
OGB-4	2540	76	27

Well	Bottom hole temp (BHT) $t_2(^{\circ}\text{C})$	Mean annual surface temp. $t_1(^{\circ}\text{C})$	Depth to BHT $d_2(\text{m})$	Depth of surface temp. $d_1(\text{m})$	Temp. difference ΔT ($t_2 - t_1$)	Depth difference ΔH ($d_2 - d_1$)	Geothermal gradient ($G = \Delta T / \Delta H$) ($^{\circ}\text{C}/100\text{m}$)
OGB-1	75	27	3530	18.29	48.0	3511.71	1.4
OGB-2	87.8	27	3540	18.29	60.0	3521.71	1.7
OGB-3	115	27	4450	18.29	88.0	4431.71	2.0
OGB-4	76	27	2540	18.29	49.0	2521.71	1.9

Table 2: Computed values of geothermal gradients of the wells

Table 3: Computed temperature values of shale in well OGB-1:

Shale unit	Depth (m)	Thickness (m)	Geothermal gradient $^{\circ}\text{C}/100\text{m}$	Constant ($^{\circ}\text{C}$)	Temperature at d T_d ($^{\circ}\text{C}$)
Sh-1	2240-2280	40	1.4	27	58.92
Sh-2	2335-2355	20	1.4	27	60.00
Sh-3	2375-2410	35	1.4	27	60.74
Sh-4	2510-2560	50	1.4	27	62.84
Sh-5	2585-2610	25	1.4	27	63.54
Sh-6	2740-2988	248	1.4	27	68.83
Sh-7	3050-3140	90	1.4	27	70.96
Sh-8	3410-3440	30	1.4	27	75.16

Table 4: Computed temperature values of shale in well OGB-2

Shale unit	Depth (m)	Thickness (m)	Geothermal gradient $^{\circ}\text{C}/100\text{m}$	Constant ($^{\circ}\text{C}$)	Temperature at d $(T_d)^{\circ}\text{C}$
Sh-1	2280-2320	40	1.7	27	66.44
Sh-2&3	2360-2470	110	1.7	27	68.99
Sh-4&5	2530-2645	115	1.7	27	71.97
Sh-7	2700-3045	345	1.7	27	78.77
Sh-8	3110-3180	70	1.7	27	81.06
Sh-9	3230-3270	30	1.7	27	82.59
Sh-10	3360-3440	50	1.7	27	85.48

Table 5: Computed temperature values of shale in well OGB-3

Shale unit	Depth (m)	Thickness (m)	Geothermal gradient $^{\circ}\text{C}/100\text{m}$	Constant ($^{\circ}\text{C}$)	Temperature at d $(T_d)^{\circ}\text{C}$
Sh-1	2220 - 2280	60	1.9	27	70.32
Sh-8	2360 - 2410	50	1.9	27	72.79
Sh-9	2425 - 2475	50	1.9	27	74.03
Sh-10	2510 - 2550	40	1.9	27	75.45

Table 6: Computed temperature values of shale in well OGB-4

Wells	Temperature range (°C)	Geothermal gradient (°C/100m)
OGB-1	58.92 - 76.42	1.40
OGB-2	66.44 - 85.48	1.70
OGB-3	74.00 - 107.60	2.00
OGB-4	70.32 - 75.45	1.90

Table 7: Summary of temperature ranges of shale from wells in the Ogbogede On-shore Field

• Shale unit	Depth (m)	Thickness (m)	Geothermal gradient (°C/100m)	Constant (°C)	Temperature at d (T _d) °C
Sh-1	2315-2360	45	2.0	27	74.00
Sh-7	2440-2710	270	2.0	27	81.20
Sh-8	2740-2790	50	2.0	27	82.80
Sh-9	2850-2890	40	2.0	27	84.80
Sh-10	2960-3025	65	2.0	27	87.50
Sh-11	3040-3115	65	2.0	27	89.50
Sh-12	3270-3320	50	2.0	27	93.40
Sh-13	3400-3500	100	2.0	27	97.00
Sh-14	3670-3730	60	2.0	27	102.60
Sh-15	3800-3840	40	2.0	27	103.80
Sh-16	3940-4030	90	2.0	27	107.60

Table 8: Lithologic units of Agbada Formation interpreted from well logs in Ogbogede On-shore Field

Well	OGB-1	OGB-2	OGB-3	OGB-4
No of shale units	10	8	18	4
No of clean sand packages	8	5	13	1
No of dirty sand packages	6	1	8	2

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