Reservoir Characterization using Petrophysical Evaluation of W-Field, Onshore Niger Delta

ABSTRACT

Reservoir characterization of W-field, onshore Niger Delta was carried out using petrophysical evaluation of well logs. Three reservoir sand intervals (A, B, C) were identified and correlated across four wells (W1, W2, W3, W4) in W-field using the gamma ray, while the fluid identification of each reservoir was achieved using the resistivity log. The reservoir C interval was selected and utilized for petrophysical interpretation was penetrated at depths 11741-11945ft, 11933-12173ft, 11658-11847ft and 11926-12095ft across all wells respectively.The average values of gross thickness, volume of shale, effective porosity, total porosity, permeability, water saturation and hydrocarbon saturation of the delineated reservoir sand are 200.5ft for gross thickness, 18% for shale volume, 21% for effective porosity, 26% for total porosity, 1071.74mD for permeability, and 28% for water saturation and 77% for hydrocarbon saturation. Petrophysical evaluation revealed that porosity and permeability are very good to excellent in the field. The reservoir is classed as clean sands based on the high net to gross ratio (>70%) and the low shale volumes (<30%). Consequently, the low value of shale volume, low value water saturation, high value of hydrocarbon saturation and the good porosity and permeability properties of the reservoir of interest suggets economical and commercial quality and viability of the wells within this field.

Keywords: Reservoir Characterization; Petrophysical Evaluation; Fluid Identification; Hydrocarbon Saturation

1. INTRODUCTION

Characterizing the reservoir is a process which describes various properties in reservoirs using all the available data to provide reliable reservoir geologic models for accurate prediction of the performance of a reservoir [1]. [2] described reservoir characterization as a process that involves the integration of various qualities and quantities of data in a consistent way to describe the reservoir properties of interest in inter well locations**.**

The studies on depositional facies and reservoir characterization of Usani Field 1, Niger Delta using 3-D seismic, well logs and cores was carried out by [3]. Eight reservoirs were mapped at depth intervals of 2886m to 3533m with their thicknesses ranging from 12m to 407m. Petrophysical results showed that porosity of the reservoirs ranged from 14% to 28%; permeability, from 245.70 md to 454.7md; and water saturation values from 21.65% to 54.50%. The model served as a basis for establishing facies model in the field [3].
Integrated reservoir characterization of “XOX” Field in the southern Niger Delta was done by [4]. Four faults were mapped and five horizons studied, for the purpose of carrying out 3-D

subsurface structural interpretation. The study showed that the 'XOX'-field bears a considerable amount of 129,931,627.6 million square cubic feet (MMSCF) of gas in-place and about 173,579,727.3 million barrels (MMBSTB) of oil reserve which could be exploited for commercial purposes.

[5] carried out formation evaluation and reservoir characterization of a field in Niger Delta using 3-D seismic and well logs. The method adopted involves delineation of lithologies from the gamma ray log, identification of reservoirs from the resistivity log, well correlation, determination of petrophysical parameters, horizon and fault mapping, time to depth conversion, attribute analysis and reserve estimation. One reservoir was mapped, having porosity values ranging from 0.19 to 0.46 and permeability values from 14.53mD to 496.61mD. The Sw values range from 5.6% in well A, 6% in well B and 24% in well C. The reserve estimate for the reservoir is 40.1mmbls. The result of this analysis has proved that the integration of attribute analysis with structural interpretation is a reliable and efficient way of carrying out formation evaluation and reservoir characterization. It has also enhanced hydrocarbon exploration for optimal well placement and reserve estimation.

[6] carried out an integrated interpretation of seismic and well log data over "Y" Field in the Niger Delta area of Nigeria. Their aim was to characterize reservoir rocks using quantitative seismic attributes and petrophysical properties. Three reservoirs were mapped at depth range of 1524 to 1800 m, with thicknesses of 10- 45 m. Porosity of the reservoirs ranged from 30- 40 %, water saturation 30-45 % and hydrocarbon saturation 65-80 %. Seismic attribute maps revealed presence of hydrocarbons in the identified sands. Their study concluded that seismic attributes could be used to predict reservoir rock properties and characterize reservoir.
The aim of the study to characterize quantitatively reservoirs in W-Field, Onshore Niger Delta by identifying, correlating well logs and carrying out a petrophysical evaluation of reservoir rocks in this field. The petrophysical parameters to be evaluated includes effective porosity, permeability, shale volume, net to gross and hydrocarbon saturation

2. LOCATION OF THE STUDY AREA

W-Field is located in Bayelsa state between longitudes 6°14′40″E to 6°33′38″E and latitudes 4°50′10″N to 4°58′22″N in the coastal swamp depobelt, onshore Niger Delta. The field lies in OML28 and is owned and operated by Shell Petroleum Corporation. Figure 1 shows the location of the oilfield and the exploration wells drilled.

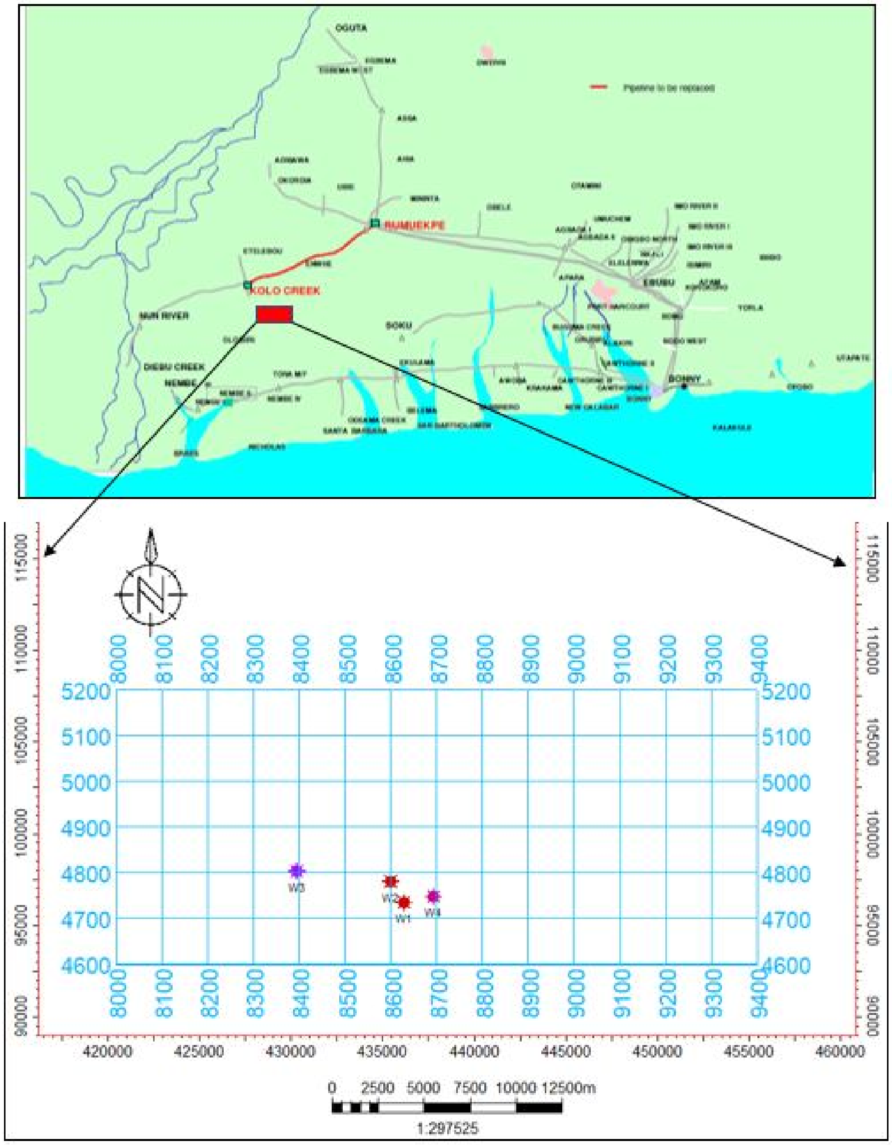

Figure 1: Map showing the location of W-field and the wells drilled

3. GEOLOGY OF THE STUDY AREA

The Niger Delta is located in the Gulf of Guinea on the West Coast of Africa. It lies between latitudes $4^0$3'N to $5^0$2'N. and longitudes 3^0E to 9^0E [7,8]. The delta was formed in late Jurassic time as the failed arm of the triple junction, during the extensional rifting that separated the South America and Africa plate with the evolution of the South Atlantic Ocean, [9] Whiteman (1982). It has an area extent of about 300,000-km^2 [10] (Kulke, 1995) and 500,000-km^3 volume of sediment [11] (Hospers, 1965). The sediments in the depocentres are 10-12 km thick [12(Kaplan *et la.,* 1994). [10,13] Kulke (1995), Ekweozor and Daukoru (1994) proposed one petroleum system for the delta. However, its formation and regional tectonic history can be deduced from the geologic formations in the basin.[14] Short and Stauble (1967) distinguished the sequence stratigraphy of the Tertiary Niger Delta into three

lithostratigraphic units. These include progradational deltaic facies known as Akata Formation, delta front facies that is the paralic Agbada Formation and continental Benin Formation.
Akata Formation is the basal unit of the delta [15] Avbovbo (1978). It is Paleocene in age, and as well the source rock of the delta [13,16] Weber and Daukoru, 1975); [Ekweozor and Daukoru (1975). The formation is composed predominantly of under compacted thick shale, lenses of sandstones, turbidities sand and a small amount of silt with 20% sand and 80% shale**[17] (**Evamy *et al*., 1978). In addition, it consists of abundant planktonic and benthonic foraminifera, which are present in all depobelts. The formation has an estimated thickness of 7000m [18] (Doust and Omatsola, 1990). Its lateral equivalent in the North-Eastern zone is the Imo Shale while in offshore areas it outcrops in diapirs [15] (Avbovbo, 1978).

Agabda Formation overlies the Akata Formation. It is Eocene in age and the major reservoir unit of the delta[19] (Weber *et al.,* 1978). The upper portion comprises sand with only minor shale interbeds while the lower portion comprises sand-shale intercalations, with the shale sequence forming the cap rock in the delta. This shale is dominant in all depobelts. The sequence has 60% sand and 40% shale[17] (Evamy *et al.,* 1978). Also, it has an estimated thickness of 3700m [20] (Reijers, 1996). The lateral equivalent of the upper part of Agbada formation is the Ogwashi-Asaba Formation, which outcrops around Ogwashi and Asaba, Southern Nigeria [18] (Doust and Omatsola, 1990) while the Ameki Formation is the lateral equivalent of the lower part of the formation.

Benin Formation is Oligocene in age. It is the uppermost part of the unit and it overlies the Agbada Formation. Itconsists mostly of continental sands with 90% sand and 10% shale [17] (Evamy *et al.,* (1978). The thickness of the formation is about 2100m [9] (Whiteman, 1982). The stratigraphic columns, as well as the formations in Niger Delta (Figure 2)

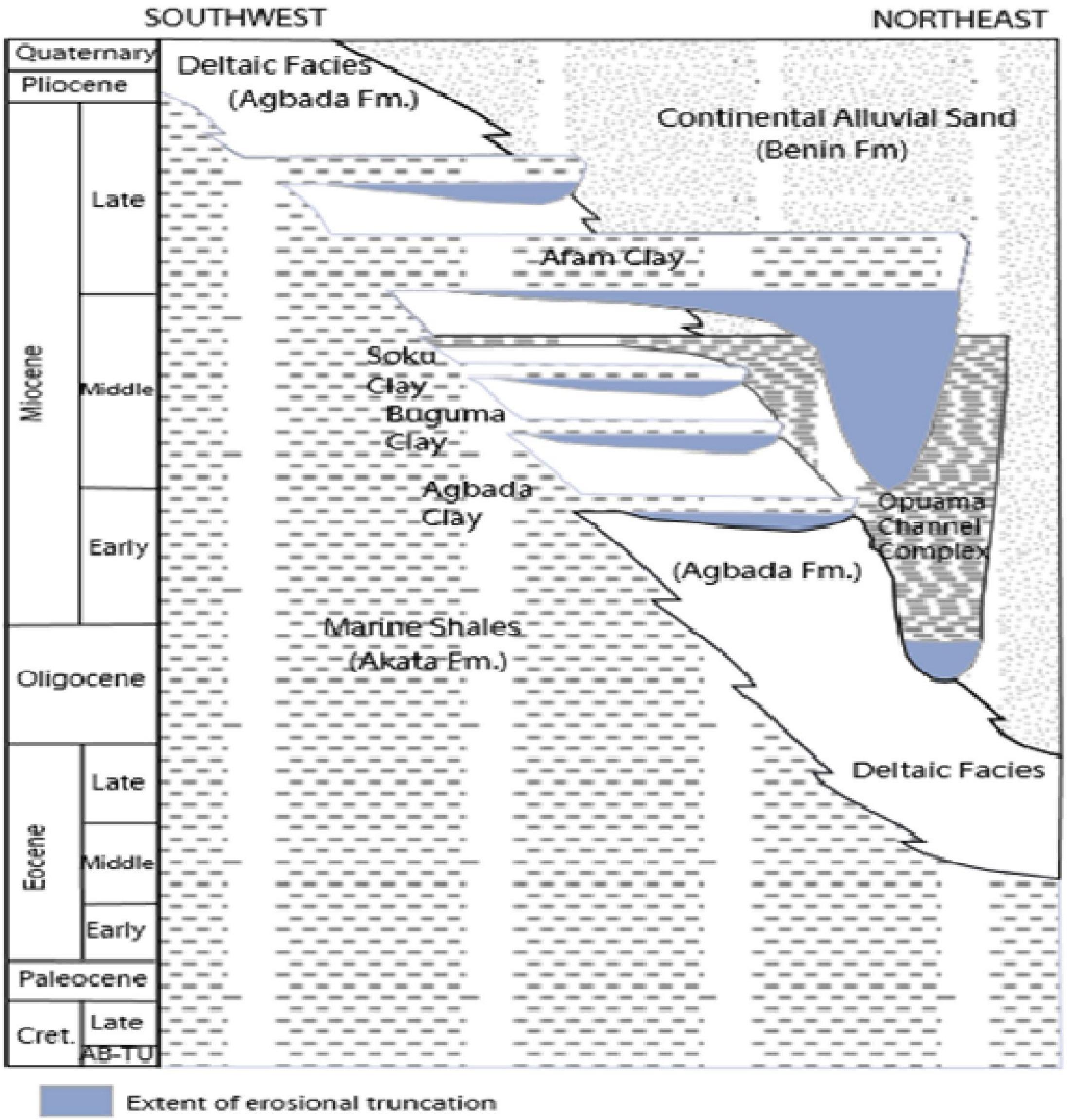

Figure 2: Lithostratigraphy showing the formations in Niger Delta**[18] (**Doust and Omatsola, 1990)

4. MATERIALS AND METHODS

Data utilized for this research includes; 3-D seismic data in segy format, well data (well header, well logs, well deviations) in LAS format and a checkshot in ASCII format. The seismic data covers an area of 840 sqkm and four (4) wells were provided. Table 1 shows details on the well data provided for the study. Details on the data provided are enumerated in subsequent headings.The well header holds information regarding the exact geographic locations of the wells in time and space. Also, the total well drilled depth, the well reference datum and the well names are all included in the well header data file. Well headers were provided for all wells.

The well deviation contains information regarding the original well trajectory. The deviation data contains the measured depth, the dip and the azimuth for each well. It is the information contained in the deviation file that aids in the conversion from measured depth (MD) to true vertical depth (TVD). Well deviations were available for all four wells (W-1, W-2, W-3, W-4). Well logs were provided for all wells in ASCII format (Table 1). The well logs available included gamma ray (GR), deep resistivity (LLD), density (RHOB), neutron (NPHI) and sonic (DT) (for only W1) (Table 1). The logs were used for lithologic identification, reservoir identification, fluid discrimination, seismic well tie and hydrocarbon volumetric estimation. The log depths were provided in feet, GR in GAPI, LLD in Ohm.m, RHOB in g/cm^3, NPHI in m^3/m^3 and sonic in μs/ft.

Table 1: Data inventory showing the wells information utilized for this study

Wells Logs	W1	W2	W3	W4
Well Header	YES	YES	YES	YES
Well Deviation	YES	YES	YES	YES
GR log	YES	YES	YES	YES
Resistivity Log	YES	YES	YES	YES
Density Log	YES	YES	YES	YES
Neutron Log	YES	YES	YES	YES
Sonic Log	YES	NO	NO	NO
Checkshot	YES	NO	NO	NO

1.3 Petrophysical Evaluation

To quantify the volume of hydrocarbons found within the identified reservoir prospects, petrophysical evaluation was conducted using well logs. These properties include; shale volume, porosity, water saturation and permeability were estimated using the empirical formulas stated in Table 2.

5. RESULTS AND DISCUSSION

From the four wells, three reservoirs (A, B and C) were identified and picked across the wells. The sands (colour coded yellow) are capped by shale (colour coded black) (Figure 3). These reservoirs were identified using gamma ray and resistivity logs. Several serrations are found within the sands on the GR log(which was set at 0-150 gAPI, with zero at the left and 150 at the right side of the gamma ray tract while the mid-point (75 gAPI) is considered the sand/shale cutoff) indicating the presence of shales. The left side deflections of the established cut-off from the gamma ray curve indicated sands while deflections to the right of the curve are termed shales. Reservoir C was utilized in this study for petrophysical interpretation based on high thickness, hydrocarbon presence in all wells and availability of logs for computation. Petrophysical logs generated for the four wells are presented in Figures 4 - 7 respectively. The petrophysical properties estimated includes shale volume, porosity, net to gross, permeability and water saturation.

Table 2 : Empirical formulas of shale volume, porosity, water saturation and permeability

Petrophysical parameters	Empirical formulas	
Volume of Shale (Vsh)	$I_{GR} = \dfrac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$ I_{GR} = Gamma ray index describes a linear response to shale content GR_{log} = Log reading at the depth of interest GR_{min} = Gamma Ray value in a nearby clean sand zone GR_{max} = Gamma Ray value in a nearby shale [21]	$.\mathbf{V_{SH}} = \mathbf{0.083} * \left(\mathbf{2^{(3.7*I_{GR})}} - \mathbf{1}\right)$ $V_{SH} = Volume of shale$ $I_{GR} = Gamma ray index$[22]
Porosity Estimation	$\emptyset_T = \dfrac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}}$ $\emptyset_T = Total porosity$ $\rho_{ma} = Matrix density$ = 2.65 $\rho_{bulk} = Bulk density reading read from density log$ $\rho_{fl} = Fluid density$ (0.74 $for gas$, 0.9 $for oil and$ 1.0 $for water$)	Øe = $(1 - V_{SH}) \times \emptyset_T$ $\emptyset_e = Effective porosity$ $\emptyset_T = Total porosity$ $V_{SH} = Shale volume$[23].
Permeability Estimation	$K(mD)$ = 307 + 26552($\emptyset_e^2$) – 34540 $(\emptyset_e \times S_w)^2$ $K(mD) = Permeability in milli Darcy$ $\emptyset_e = effective porosity$ $S_w = water saturation$ [24]	
Water Saturation	$S_w = \sqrt{\dfrac{R_o}{R_t}}$ $S_w = Water\ saturation$ $R_o = Resistivity\ of\ the\ oil\ leg$ $R_t = True\ resistivity\ reading$ [25].	
Hydrocarbon saturation	$S_H = 1 - S_w$ $S_H = Hydrocarbon saturation$, $S_w = Water saturation$ [26].	
Net-To-Gross	$\text{Net} - \text{to} - \text{gross} = \dfrac{\text{NT}}{\text{GT}} \times 100$ $NT = Net thickness$, $GT = Gross thickness$	

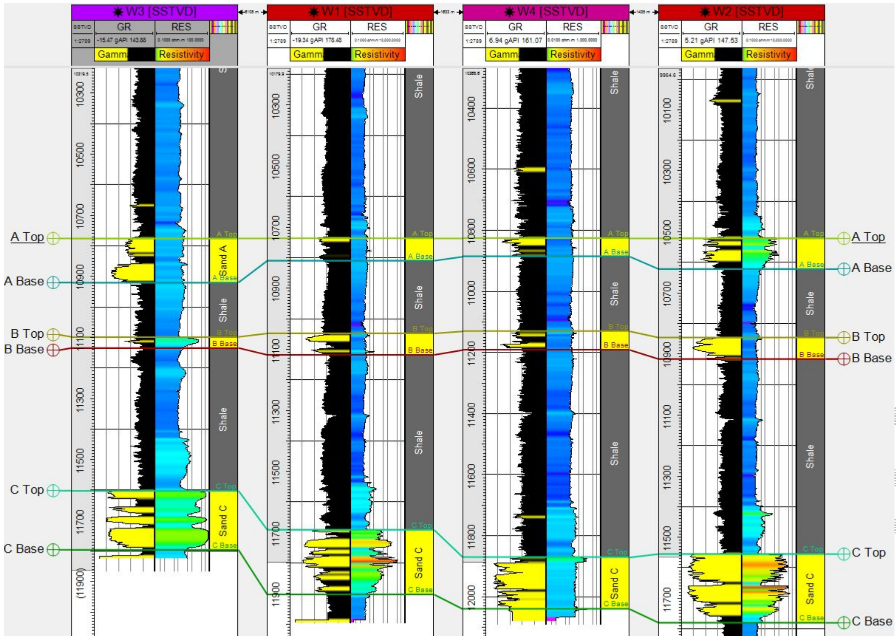

Figure 3: Well section window showing correlation of A, B and C reservoir sand bodies

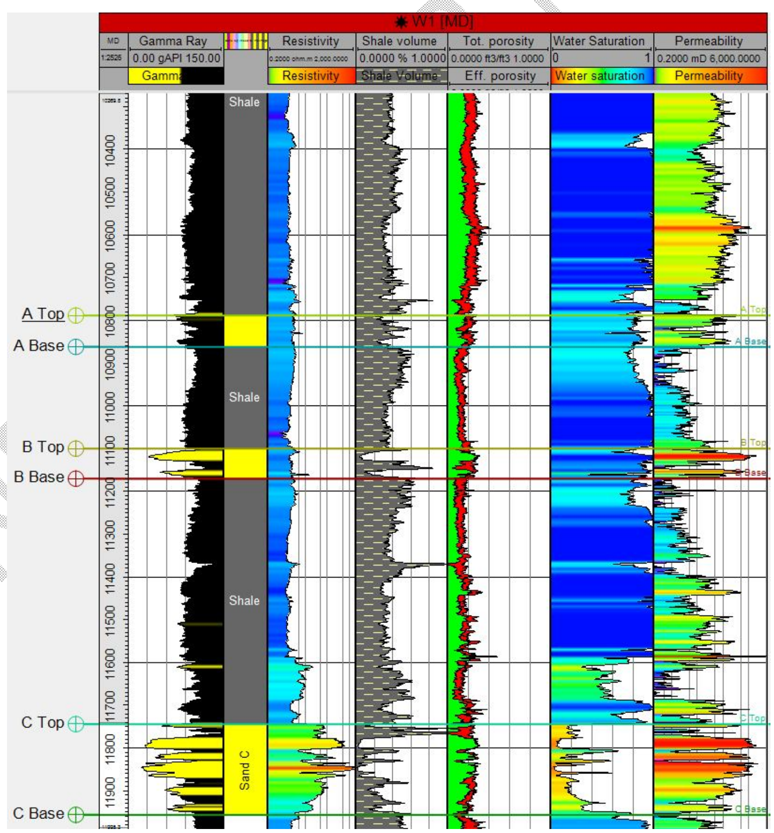

Figure 4: Petrophysical logs for three reservoir intervals in W1 well

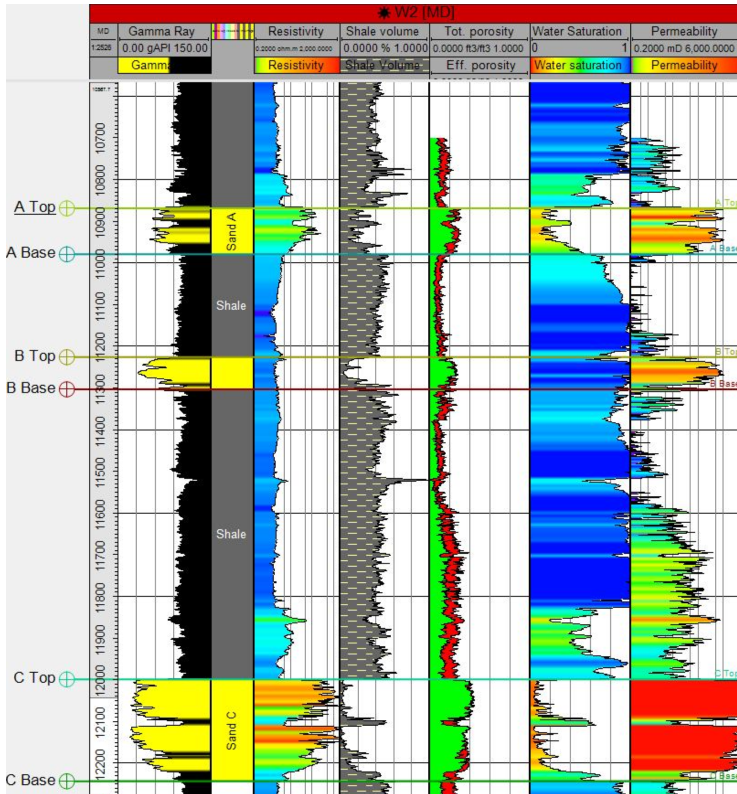

Figure 5: Petrophysical logs for three reservoir intervals in W2 well

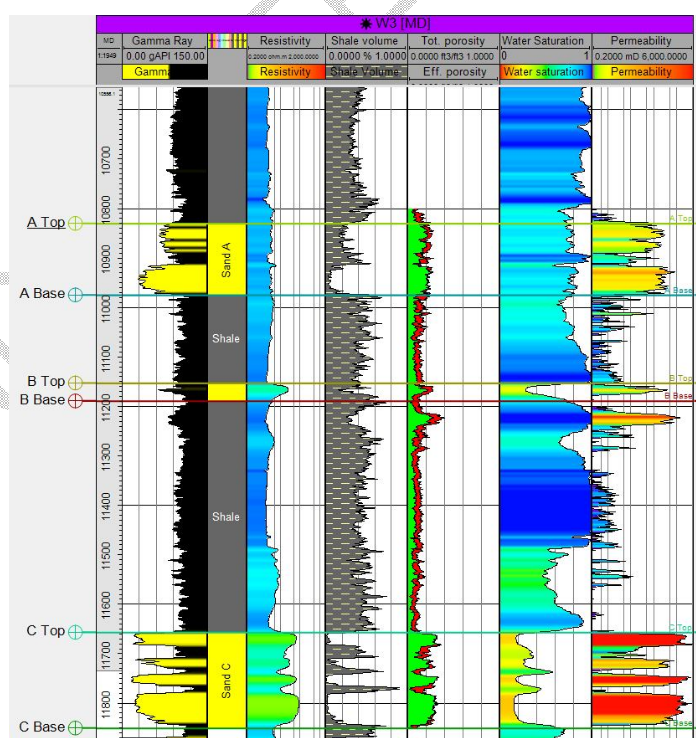

Figure 6: Petrophysical logs for three reservoir intervals in W3 well

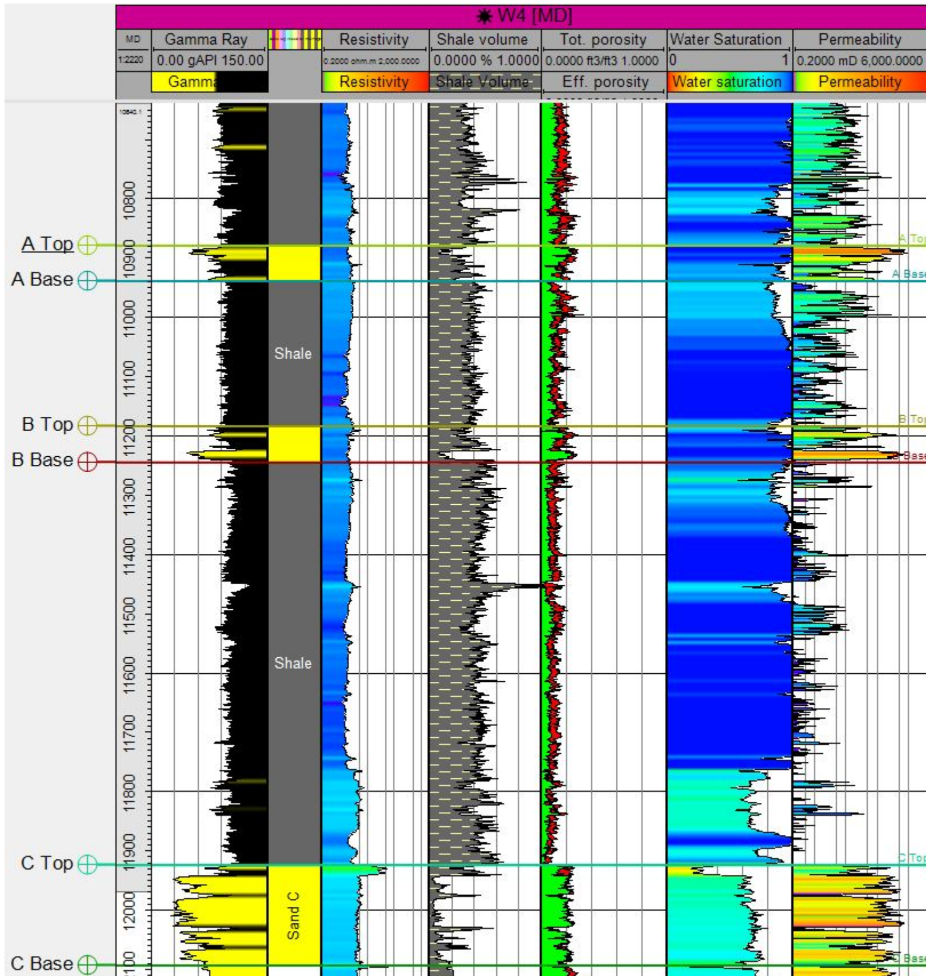

Figure 7: Petrophysical logs for three reservoir intervals in W4 well

Gross Thickness

The gross thickness of a reservoir is the entire thickness from the top of the reservoir to the base of the reservoir (Figures 4-7). The thickness of the reservoirs varies from one well to the other across the field. The thickness of reservoir C is 204ft in W1 well, 240ft in W2, 189ft in W3 and 169ft in W4 well (Table 3 and Figure 8). The average gross thickness of reservoir C is 200.5ft for the four wells. The gross thickness of the wells shows that W2 well has the highest thickness while W4 has the lowest thickness. These results show that the reservoir sands are of sufficient thickness to accumulate hydrocarbons in economical quantities.

Shale Volume (Vsh)

Shale volume is the percentage of shale contained within the reservoir (Figures 4-7). The higher the shale content the poorer the reservoir quality to yield hydrocarbons. This is because shales act as barrier to the flow of hydrocarbons. In reservoir C, shale volume is 23% in W1, 18% in W2, 16% in W3 and 15% in W4 well (Table 3 and Figure 9). On average, shale volume thickness is 18% suggesting that about 18% of the average gross thickness of reservoir C in the four wells is occupied by shale.

Net to Gross

The net to gross is the ratio of the thickness of the clean sand (net sand thickness) divided to the total gross thickness of the reservoir. The net to gross gives an indication of the total amount of the reservoir section that can be produced. The larger the net to gross value (in percentage), the better the quality of the reservoir. For Reservoir C, net to gross ratio is 77% in W1, 82% in W2, 84% in W3 and 85% in W4 well (Table 3 and Figure 9). The average net to gross ratio for reservoir C is 82% (Table 3).This result shows that on average, over 82% of the entire gross thickness of the reservoir C can produce if they contain hydrocarbons.

Porosity

Total porosity is the sum total of both the interconnected pores and the isolated pore spaces (Figures 4-7). The porosity relevant for hydrocarbon production is the effective porosity. The effective porosity is the sum of all the interconnected pore throats. In this study, the total and effective porosity of reservoir C are 24% and 17% for the W1 well, 29% and 26% for W2 well, 26% and 21% for the W3 well and 24% and 20% for the W4 well (Table 3 and Figure 9). The average total and effective porosity for reservoir C is 25.75% and 21% respectively (Table 3). According to [26] Rider (1986), porosity measurements <5% are negligible, between 5-10% are poor, >10-20% are good, >20-30% are very good and >30 are excellent. Based on this classification scheme which is globally accepted for porosity classification, the total porosity recorded from reservoir C are classed as very good to excellent while effective porosity recorded for C are classed as good to excellent.

Permeability

Permeability is the ability of fluids to flow through a reservoir rock. Figures 4 - 7 shows the permeability measurements calculated in this study. The results of permeability for reservoir C are 410mD in W1 well, 2932.1mD in W2, 810.54mD in W3 and 134.33mD in W4 well (Table 3). On average, permeability value is 1071.74mD in reservoirs C (Figure 10). [26] Rider (1986) classification of reservoir quality based on permeability values are as follows; < 10mD (poor to fair), >10-50 mD (moderate), >50-250 mD (Good), >250-1000 mD (very good) and >1000 mD (excellent). Based on this classification scheme, reservoir C can be classed as very good to excellent reservoirs because they have average permeability values ranges between 250-1000mD and >1000mD except for well W4 that good only. These results show that all the reservoirs in the field have good to excellent permeability values which are necessary requirements for hydrocarbon flow and production in economical quantities.

Fluid saturation

The fluids saturation in the reservoirs were determined using the Archie's equation and the logs generated are presented in Figures 4-7. Water saturation estimated for reservoir C is 2% in W1 well, 12% in W2, 21% in W3 and 58% in W4 well (Figure 9). This accounts for an equivalent hydrocarbon saturation of 98%, 88%, 79% and 42% in W1, W2, W3 and W4 wells respectively (Table 3). W1 has the highest hydrocarbon and lowest water saturation whiile W4 has the lowest hydrocarbon and highest water saturation measurements. The average hydrocarbon and water saturation values for reservoir C are 77% and 28% respectively (Table 3).

Fluid type

In a reservoir rock, three types of fluids are commonly found in the pores. The fluids can either be gas, oil, water (fresh or brine) or a combination of two or the entire three fluid phases. The resistivity log was used to determine the presence of oil and water in the reservoirs because oil is much more resistive and water is less resistive. Hence a sharp increase in the resistivity log measurement indicated the presence of an oil water contact in the reservoir. In this study, reservoir C is oil bearing in well W1, W2 and W3 while oil and water bearing in W4 (Table 3). These results show that the reservoir C in all the wells are hydrocarbon bearing and can be produced.

Table 3: Results of petrophysical evaluation estimated for Reservoir C in four wells

Well	Reservoir Interval (MDft)	Gross thickness ft	Shale volume (%)	Net to Gross (%)	Total Porosity (%)	Effective Porosity (%)	S_W (%)	Permeability (mD)	S_H (%)	Fluid type
W1	11741-11945	204	23%	77%	24%	17%	2%	410	98%	Oil
W2	11933-12173	240	18%	82%	29%	26%	12%	2932.1	88%	Oil
W3	11658-11847	189	16%	84%	26%	21%	21%	810.54	79%	Oil
W4	11926-12095	169	15%	85%	24%	20%	58%	134.33	42%	Oil and Water
Mean		200.5	18%	82%	25.75%	21%	28%	1071.74	77%	

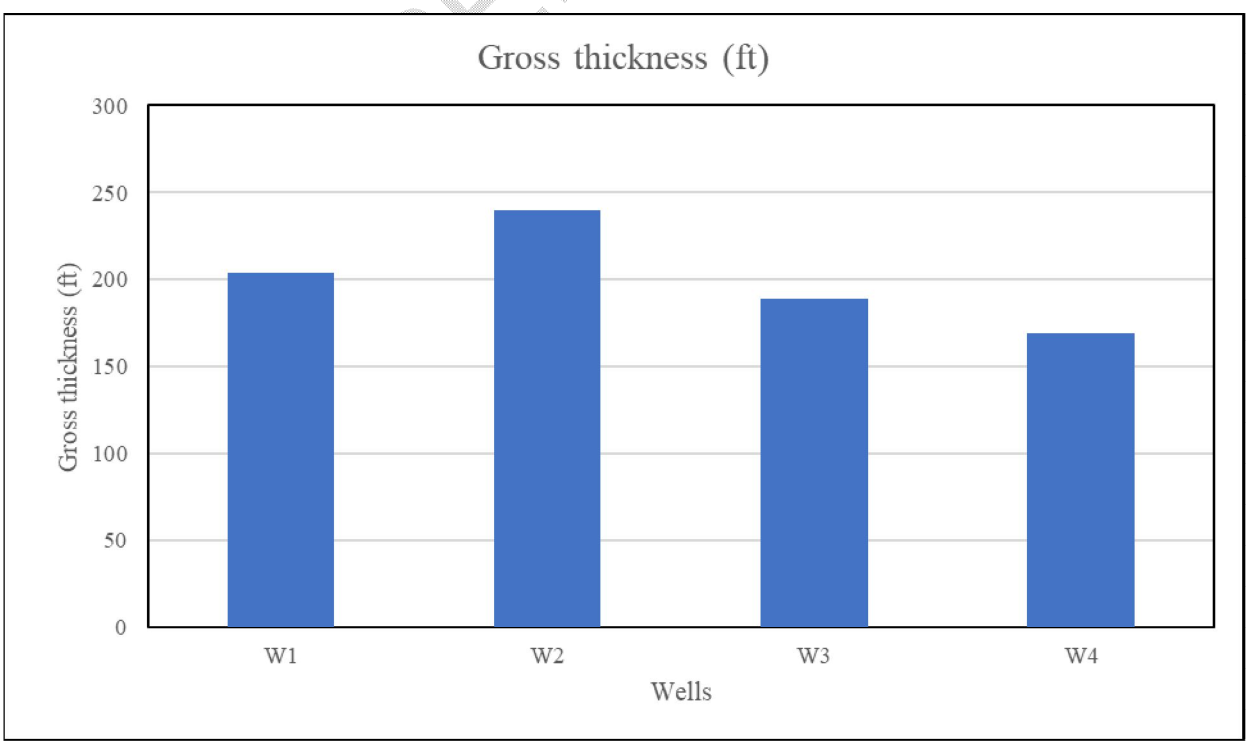

Figure 8: A plot of gross thicknesses for reservoir C sand across all wells

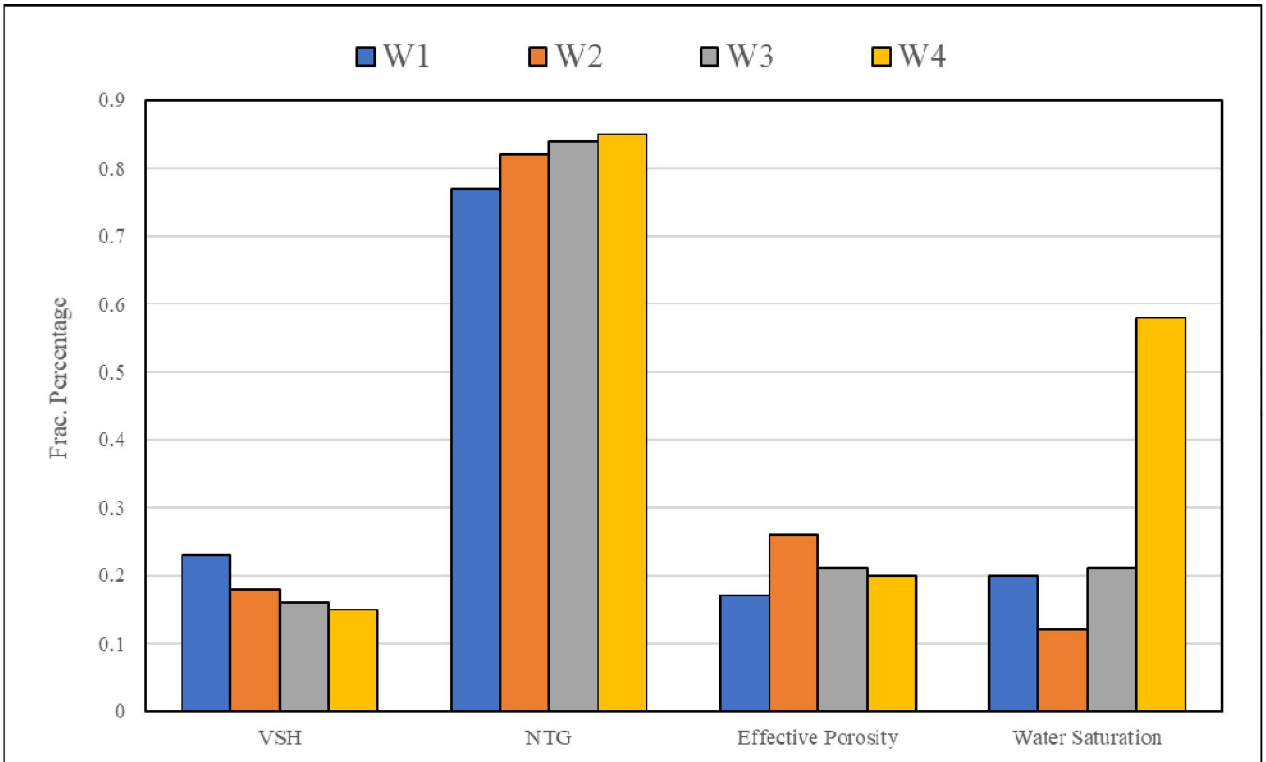

Figure 9: A plot of shale volume, net to gross ratio and porosity for reservoir C sand across all wells

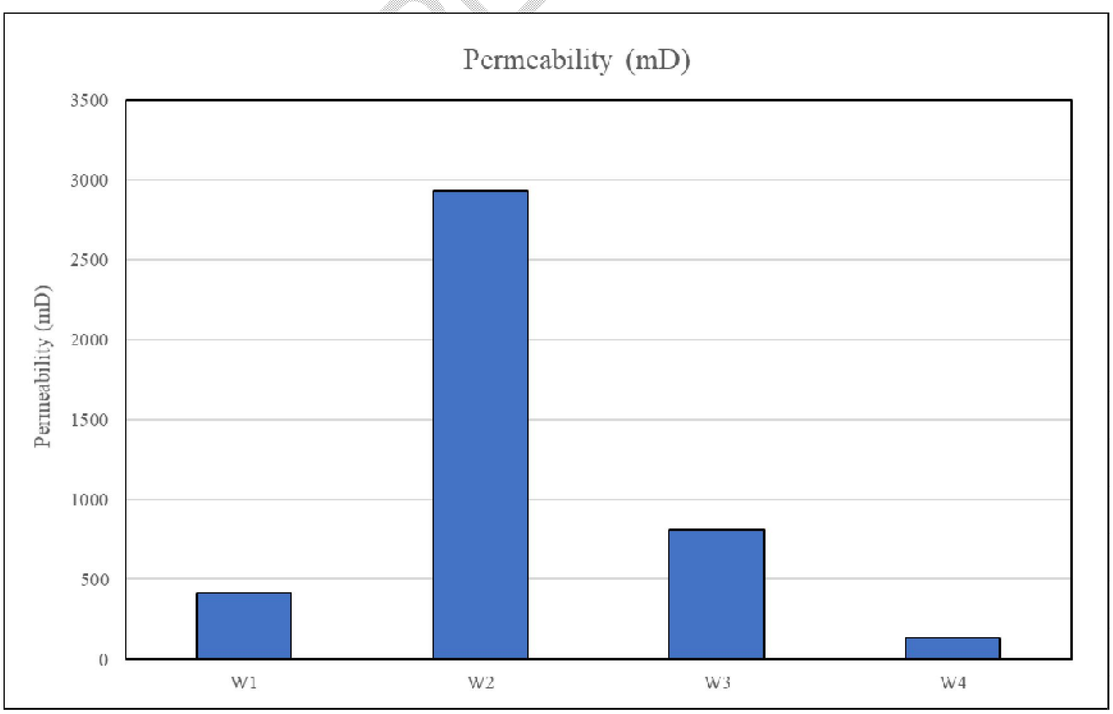

Figure 10: A plot of permeability for reservoir C sand across all wells

6. CONCLUSION

Three representative reservoir intervals (A, B, C) were identified and correlated across four wells (W1, W2, W3, W4) in W-field. The reservoir C interval was selected and utilized for the petrophysical interpretation. The results for petrophysical properties were presented in Table 3 and Figures 8 – 10. The gross thickness of the reservoirs ranged from 169 to 240 ft with an average of 200.5ft. Average shale volume and net to gross (NTG) ratio for the reservoir are 0.18 (18%) and 0.82 (82%) respectively. Generally, shale volume is < 30% and NTG exceeds 70% for reservoir C in all wells suggesting that the reservoir is clean enough for hydrocarbon production. On average total and effective porosity recorded are 0.26 (26%) and 0.21 (21%) respectively (Table 3). This result falls within 21-30% of Riders classification scheme, which classes the reservoir as having very good porosity. The results of permeability ranged from 134.33 to 2932.1 mD with an average of 1071.74 mD (Table 3). Based on [13] classification scheme, the reservoir is classed as having very good to excellent permeability values. Results of water saturation shows that the reservoir sand is hydrocarbon bearing with average water saturation value of 28% with an equivalent 77% hydrocarbon saturation (Table 3).

Petrophysical evaluation revealed that porosity and permeability are very good to excellent in the field. The reservoir is classed as clean sands based on the high net to gross ratio (>70%) and the low shale volumes (<30%). Therefore, the reservoir is hydrocarbon-bearing reservoir.

References

[1]. Jong SL. Reservoir Properties Determination using fuzzy logic and neural networks from well data in offshore Korea, J. Petroleum Sci. Eng. 2005;49:182-192.

[2]. Ezekwe JN, Filler SL. “Modelling Deepwater Reservoirs,” paper SPE 95066 presented at the 2005 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, U.S.A. 2005;9:12.

[3]. Aigbadon GO, Okoro AU, Una CO, Ocheli A. Depositional facies model and reservoir characterization of USANI field 1, Niger delta basin, Nigeria. International Journal of Advanced Geosciences. 2017;5(02):57-68.

[4]. Aigbedion I, Dawodu F. Integrated reservoir characterization of “XOX” field in the southern Niger Delta, Nigeria. Journal of Geography, Environment and Earth Science International. 2016:8(04):1-10.

[5]. Abe SJ, Olowokere MT. Reservoir characterization and formation evaluation of some parts of Niger Delta using 3-D seismic and well log data.Research Journal in Engineering and Applied Sciences. 2013;2(04):304-307.

[6]. Ajisafe YC, Ako BD. 3-D seismic attributes for reservoir characterization of Y Field Niger Delta, Nigeria. IOSR Journal of Applied Geology and Geophysics. 2013;1(02):23-31.

[7]. Turtle MLW, Charpentier RR, Brownfield ME. The Niger Delta petroleum system: Niger Delta Province, Nigeria, Cameroun, and Equatorial Guinea, Africa. U.S.G.S. Open file Report. 1999;50–54.

[8]. Adeoti LA, Kolade A. Afinotan I. Fluid prediction using AVO analysis and forward modelling of deep reservoirs in Faith field, Niger Delta, Nigeria. Arabian Journal of Geosciences. 2014;8(6):4057–4074.

[9]. Whiteman A. Nigeria: its petroleum geology, resources, and potential: London, Graham, Trotman. 1982;394.

[10]. Kulke H. Nigeria, in, Kulke, H., ed.Regional Petroleum Geology of the World. Part II: Africa, America, Australia and Antarctica. Berlin, Gebrüder Borntraeger. 1995;143-172.

[11]. Hosper J. The Geology of the Niger Delta Area, in the Geology of the East Atlantic Continental Margin, Great Britain, Institute of Geological Science, Report. 1965;70(16): 121-141

[12]. Kaplan L. Fundamentals of geology. 3-d seismic horizons and inversions. The leading Edge. 1997;15:1090

[13]. Ekweozor CM, Daukoru EM. Petroleum source bed evaluation of tertiary Niger Delta. American Association of Petroleum Geologists Bulletin. 1984;70:48-55,

[14]. Short KC, Stauble AJ. Outline of Geology of Niger Delta. Am. Assoc. Petr. Geol. Bull., 1967;51(5): 761–779

[15]. Avbovbo AA. Tertiary lithostratigraphy of the Niger Delta. American Association of Petroleum Geologists Bulletin. 1978;62(2):295-306.

[16]. Weber KJ, Daukoru EM. Petroleum geology of the Niger Delta. Ninth World Petroleum Congress. Tokyo. 1975;2:202–221,

[17]. Evamy BD, Haremboure J, Knaap P, Molloy FA, Rowlands PH. Hydrocarbon habitat of tertiary Niger Delta. *American association of petroleum geologist. Bulletin.* 1978;62:1–39

[18]. Doust H, Omatsola E. Niger Delta, in J.D. Edwards, and P.A. Santogrossi, Divergent/passive margin basins: American Association of Petroleum Geologists Memoir. 1990;48:201–238

[19]. Weber KJ, Daukoru EM, Mandl G, Pilaar WF, Lehner F. The role of Faults in Hydrocarbon Migration and Trapping in Nigerian Growth Fault Structures: Offshore Technology Conference 10, Paper OTC 3356, 1975;2643–2653.

[20]. Reijers TJ. Selected Chapters on Geology. SPDC Corporate Reprographic Service, Warri, Nigeria. 1996;194.

[21]. Asquith G, Gibson D. Basic well log analysis series. 1982;2(3):12-18.

[22]. Larionov VV. Borehole radiometry, national electric drag racing association, Moscow, Soviet Union. 1969

[23]. Toby D. Well logging and formation evaluation burlington: Gulf Professional Publishing (Elsevier) USA. 2005.

[24]. Owolabi OO, Longjohn TF, Aijenka JA. An empirical expression for permeability in unconsolidated sands of the eastern Niger delta.Journal of Petroleum Geology. 1994;17(1):111-116.

[25]. Asquith G, Krygowski D. Basic well log analysis: American association of petroleum geologist. Methods in Exploration. 2004;16:31-35.

[26]. Rider MH. Geological interpretation of well logs. Blakie, Glasgow, and London-John Wiley and Sons, New York. 1986.