Quest Journals
Journal of Research in Environmental and Earth Sciences
Volume 9 ~ Issue 3 (2023) pp: 07-19
ISSN(Online) :2348-2532
www.questjournals.org

Research Paper

Reservoir Quality Prediction in a Muddy Deepwater Submarine Fan System of "AFUN" Field Niger Delta Nigeria

Yemisi. C. Ajisafe
Department of Geology, Ekiti State University, Ado-Ekiti

ABSTRACT
The study was carried out to predict parameters controlling the reservoir quality of deepwater submarine fan deposits of "AFUN"Field and their impact on the temporal and spatial distribution of turbidites. This was with a view to illustrating how factors such as rock properties control reservoir quality of deep marine deposits.The study involved description of the lithology using Gamma Ray and resistivity logs. This was followed by correlation of the lithology across the six wells in the study area. The petrophysical analysis involved the generation of both the static properties of the reservoir such as Porosity (ϕ), Volume of shale (V_{sh}), Water Saturation (S_w), Net-to-Gross (NTG) and fluid type. The porosity and permeability (the determinant of reservoir quality index) were calculated from the core data of the two cored wells (AF-4 and AF-4ST1) by plotting the values from routine core analysis. These properties served as viable determinants to obtaining an adequate reservoir modelling. Well log correlation shows that the sand/shale ratio obtained is about 3:7. There is intercalation of sand and shale with the sand occurring as relatively thin units of about 1.53 – 12.20m. while the shale occursas thick units of 6.10 – 106.75m. The thickness of the reservoirs (C4, F1 and G1) ranges from 4.27m to 53.38m, while effective porosity ranges from 7% to 26%.Permeability ranges from 107.33 to 1643.41 mD, water saturation ranges from 46% to 90% and net to gross ranges from 10% to 70%. The average porosity values of the reservoirs that were analysed are 21%, 28% and 27% indicating that the reservoirs have good storage capacity. Results from porosity and permeability cross-plot show that lithofacies type play a significant control on reservoir quality. The study has represented a significant insight into the factors controlling reservoir quality of deepwater turbidites. This helped in understanding of reservoir distribution and continuity which could be useful for the development of the field.
KEYWORDS: *Reservoir quality, Submarine fan, Rock properties, Petrophysical analysis, Effective porosity.*

Received 06 Mar., 2023; Revised 17 Mar., 2023; Accepted 19 Mar., 2023 © The author(s) 2023. Published with open access at www.questjournals.org

I. INTRODUCTION

The quality of a reservoir is defined by its hydrocarbon storage capacity and deliverability. The hydrocarbon storage capacity of reservoirs is characterized by the effective porosity and the size of the reservoir, whereas the deliverability is a function of the permeability. Effective porosity is the percentage volume of interconnected pores in a rock. The remaining space in the rock is occupied by the framework or matrix of the rock and, if present, non-connected pore space. The permeability of a rock is a measure of the rock's ability to transmit fluid. Permeability, measured in Darcy, is a function of the size, shape, and distribution of the pore channels in the rock, the type and number of fluids present, the fluid flow rate, the length and cross-sectional area of the rock, and the pressure differential across the length of flow [1].

With the quest for hydrocarbon prospects in frontier deepwater settings characterized by complex rock fabric variation and structural complexities, detailed reservoir characterization is essential for accurate field management and production optimization.Thispaper provides detailedevaluation of reservoir characteristics and their implications in reservoir quality of the challenging deep water depositional environment with thin-bedded turbidite sequence which is necessary for developing effective reservoir characterization programs of such deposits.This study therefore predicts parameters controlling the reservoir quality of deepwater submarine fan deposits of "AFUN" Field and their impact on the temporal and spatial distribution of the reservoir quality and heterogeneity.The study area, "AFUN" Field, lies within the deep offshore Niger Delta at a water depth of about990-1117 m (Figure 1). The study area is located within the Gulf of Guinea at the Western Inner Fold Thrust Belt of the delta toe divided into lobes by the Charcot fracture zone. The lobes are characterised by numerous fracture zones [2]. "AFUN" Field covers an area extent of approximately 812 km^2 and has six oil wells drilled. The sediments have been deposited during Early to Late Miocene [3].

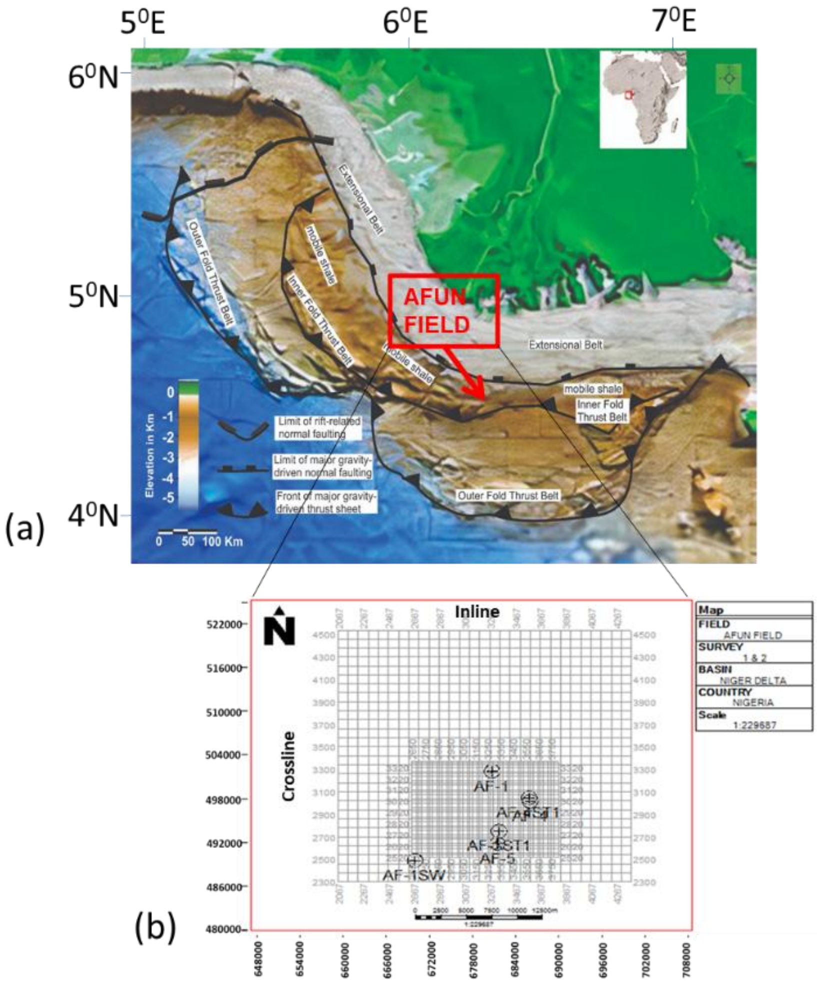


Figure 1: Map showing the location of the study area [2]

II. GEOLOGY OF THE STUDY AREA

The Niger Delta is located in the Gulf of Guinea on the margin of West Africa (Figure 2). This oil and gas province is located in southern Nigeria between Latitudes 4^0N and 6^0N and Longitudes 3^0E and 9^0E [4] as indicated in figure 1 – the location map of the study area. The offshore boundary of the Niger Delta province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin) to the west, and the two-kilometer sediment thickness contour or the 4000-meter bathymetric contour in areas where sediment thickness is greater than two kilometers to the south and southwest. The province covers about 300,000 km2 and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) petroleum system (Figure 2). The Niger Delta is a regressive sequence of clastic sediments developed in series of offlap cycles [5]. The base of the sequence consists of massive and monotonous marine shales. These grade into interbedded shallow-marine and fluvial sands, silts, and clays, which form the typical paralic facies portion of the delta [5]. The uppermost part of the sequence is a massive non-marine sand section. Figure 3 shows the established Cenozoic sequence in the Niger delta consists, in ascending order of the marine shales (Akata Formation), paralic clastics (Agbada Formation), and continental sands (Benin Formation) [6]. This mechanism, called the escalator regression model, postulated that the base of the Benin Formation in any of the six depobelts is coeval with the Agbada Formation in the adjacent depobelt to the south. This principle implies an abrupt shift in the age of the base of the Benin Formation across the bounding faults of depobelts and had been used to define the Northern limit of the Northern Delta depobelt [7]. [8] discussed in detail the sedimentology, growth faults dynamics and hydrocarbon accumulation in the Niger Delta. [9]; [10] also, studied the hydrocarbon potentials of the Niger Delta using well data. [11] discussed lithofacies relations in the late Quaternary period. The importance of longshore drift and submarine canyons and fans in the development of the basin has been emphasized by [12].Massive accumulations of turbidites and other deep-water deposits may result in the formation of submarine fans. Sedimentary models of such fan systems typically are subdivided into upper, mid, and lower fan sequences each with distinct sand-body geometries, sediment distributions, and lithologic characteristics [13]; [14]; [15]. Turbidite deposits typically occur in foreland basins.Most faults in the Niger Delta are listric and normal. Oil and gas are mainly trapped by rollover anticlines and fault closures. Features associated with compressional or wrench movements have not been observed in the shallow Niger Delta except in the toe-thrust zone at the base of the slope. Alsoshale diapir are present in offshore on the continental slope (Figure 4).In general, deepwater basins are unique compared with other petroleum basins because of: (1) their recent generation and migration of petroleum (during the last 5–10 million years), and (2) the fact that all elements of theirpetroleum systems work together from the initial evolution of the basin and are inextricably linked (their reservoirs are deposited with growing structures etc.) [16].

In the Nigeria deepwater region, basement is composed of oceanic crust; thus, no hydrocarbons generated from favourable non-marine synrift sequences are available for entrapment [17].The source rock potential of the deep offshore Niger Delta from marine sequences (Upper Cretaceous and Tertiary source rocks) [18]; [19]; [20].Due to the appreciable distance from the sediment source, the main depositional regime is regarded to be marine shales with shelf-fed turbidites as principal reservoirs.Submarine fans and turbidite systems are now accepted as major petroleum reservoirs in many sedimentary basins of the world. These reservoirs are produced from a variety of structural, stratigraphic and combination traps (Figure5).

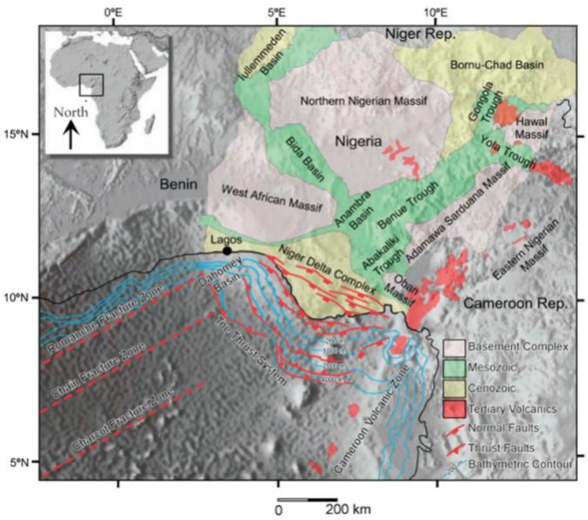


Figure 2: A Geological Map showing the Niger Delta [21]

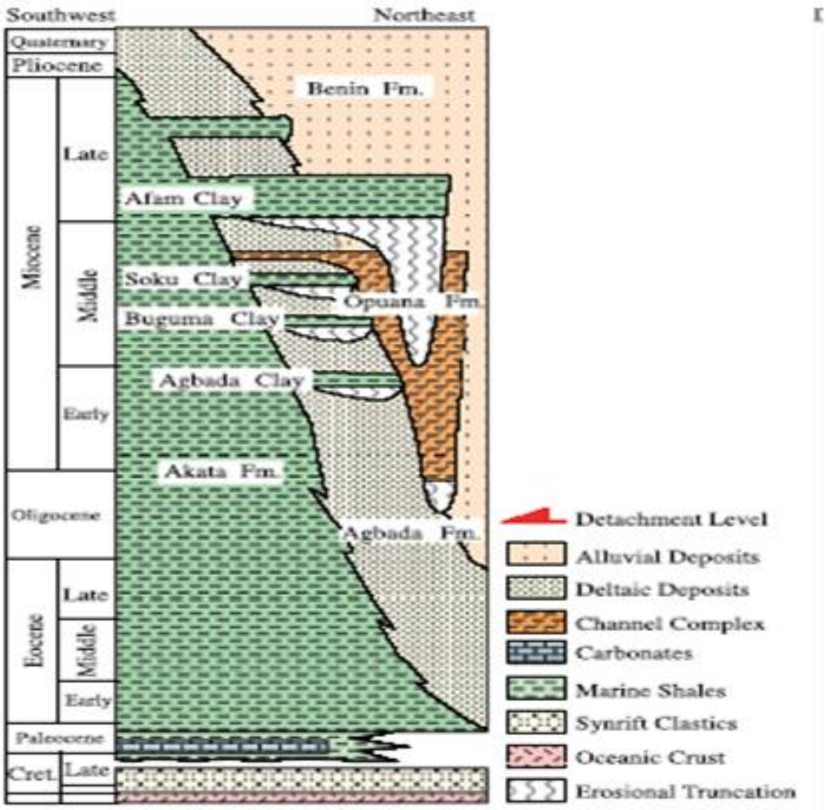


Figure 3: Stratigraphy of the Niger Delta[22]

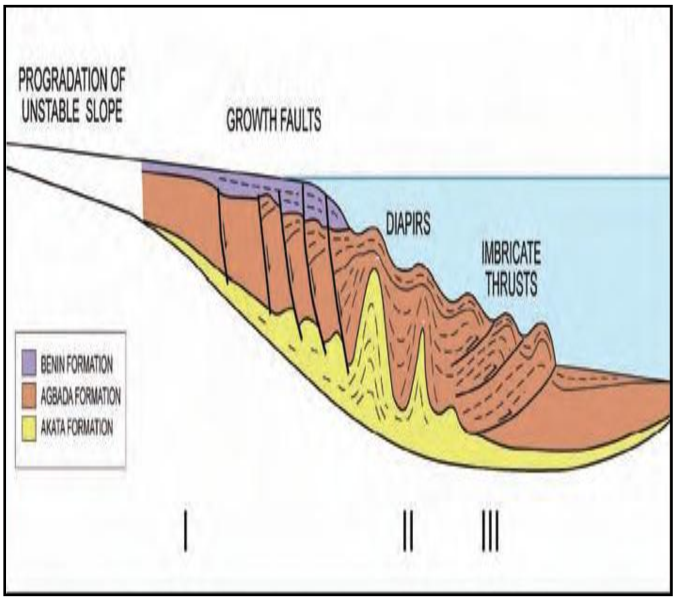


Figure 4: Image showing the Structures in Niger Delta[23]

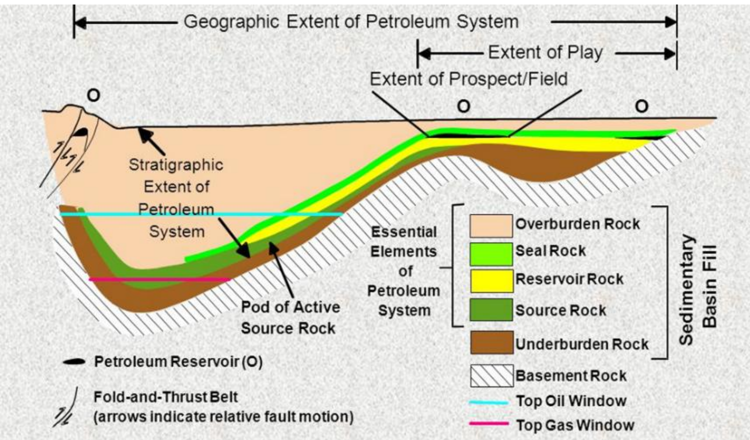


Figure 5: Cross section of petroleum system: Foreland Basin example [24]

III. METHODS OF STUDY

The datasets available for this study include Six wells drilled (AF-1, AF-SW1, AF-3ST1, AF-4, AF-4ST1 and AF-5);Five wireline logs (Gamma Ray, Resistivity, Neutron, Density and Sonic logs);Checkshot (for all the six wells),Deviation data (indicate 3 Deviated and 3 Vertical wells)Biostratigraphic data from AF-SW1well and Core data from AF- 4ST1 and AF-4 wells drilled within "AFUN" Field, Niger Delta.The data analyses were done using the Petrel software. LAS file of logs was imported into the software. The following procedures were adopted to interpret the data:

(a) Petrophysical Analysis

The purpose of petrophysical analysis is to quantitatively evaluate the wireline logs available for each of the wells and obtain values that reflects the properties of the rock and fluid. Data from the wells were vetted for various anomalies such as missing sections, depth mismatch and missing log curves so as to validate the quality of the data. Overall the log quality is acceptable, although there were areas where editing and synthetic curve generations were carried out using AF-5 checkshot. Shale volume was estimated from Gamma Ray log using Larinovo-Tertiary model [25]. The minimum clean sand value (GR_{min}) is taken as 10 API and the maximum shale value as 90 API representing the bulk of the data and ignoring insignificant tails. Petrophysical interpretation was carried out for all the sands mapped in the entire wells as well as three hydrocarbon bearing reservoir sands of interest, namely C4 – sand, F1 – sand, and G1 – sand. The wireline logs from all the wells were used to obtain both the static properties of the reservoir such as porosity (ϕ), volume of shale (V_{sh}), water saturation (S_w), net-to-gross (NTG), and fluid type. The fluid type was inferred from the neutron and density logs. Typically, gas effect is indicated by a significant lowering of the neutron and density porosity giving rise to a separation like "ballooning" look. This separation was observed from one of the reservoirs (i.e. F1), therefore oil was inferred as the fluid type for the other two reservoirs. The results of this interpretation would serve as a viable determinant toobtaining an adequate volumetric estimation and reservoir modelling. Although the whole well petrophysical analysis were done by Techlog software but the intervals of interest were further cross checked using manual computation.

(b) Determination of Gross and Net Sand Reservoir Thickness

Gross reservoir thickness interval is the interval covering shale and sand within a reservoir. Net thickness of sand is the interval covering only sand within a reservoir. It is called net productive sand. The gross reservoir thickness was determined by knowing interval covering both sand and shale within the reservoir studied using gamma ray log signature. Net sand thickness was determined by subtracting the interval covering the shale from gross reservoir thickness. Well log datasets were used in this analysis to generate rock properties using these formulae:

Gross sand thickness(GST) = Base of sand – Top of sand (1)

Net sand thickness(NST) = GST – Shale (2)

(if shale is present in the formation and if not **NST** will be the same as **GST)**

Net-to-gross (NTG) = (NST/GST) (3)

(c) Shale Volume (V_{sh}) Determination

Shale volumes were evaluated using GR log by applying Larionov Tertiary Rock method. GR curves were used in the evaluation because all the 6 wells have GR curves and Neutron/ Density pair. Larionov method was chosen because it suitable for Tertiary Niger Delta rocks and is widely used in the industry. The applied equations are as follows:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \qquad (4)$$

[25] Tertiary rocks method:

$$V_{sh} = 0.083(2^{(3.7 x I_{GR})} - 1) \qquad (5)$$

where: I_{GR} = gamma ray index, GR_{log} = gamma ray reading of formation, GR_{min} = minimum gamma ray (clean sand or carbonate), GR_{max} = maximum gamma ray (shale), V_{sh} = volume of shale

The minimum clean sand value (G_{Rmin}) is taken as 10 API and the maximum shale value as 90 API representing the bulk of the data and ignoring insignificant tails.

(d) Porosity Determination

Porosity log (density log to be precise) was used to calculate the porosity. Density-derived porosity (porosity from density log), $\emptyset_D$ is computed using the equation:

$$\emptyset_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \qquad (6)$$

where: ρ_{ma} = Density of matrix material (2.648 gm/cm^3 for sandstone), ρ_b = Bulk density (read from the density log), ρ_f =Fluid density (1.1 gm/cm^3)

The criteria for classifying porosity given by [26] are:

$\emptyset < 0.05 = Negligible$; $0.05 < \emptyset < 0.1 = Poor$; $0.1 < \emptyset < 0.15 = Fair$; $0.15 < \emptyset < 0.25 = Good$; $0.25 < \emptyset < 0.30 = Very\ good$; $\emptyset > 0.30 = Excellent$

The formula used to compute the effective porosity is as follows:

$$\emptyset_{eff} = \emptyset_{total}\, x(1 - Vsh) \qquad (7)$$

(e) Water Saturation and Hydrocarbon Saturation Determination

Water saturation was estimated from Archie's equation as given in equation 8. In order to estimate water saturation from this method, formation water resistivity (R_w) and True formation resistivity (R_t) need to be estimated. R_w is usually estimated in a clean water-bearing interval (water leg) while R_t is estimated in hydrocarbon bearing zones using deep resistivity reading. Therefore, S_w (Archie's equation) was then estimated using the estimated R_w, R_t and computed Φ; local correction factor or tortuosity factor (a) of 0.62 was assumed; saturation exponent (n) of 2 was also assumed; and cementation exponent (m) of 2.15. These values commonly apply to reservoirs in the Niger Delta. The equations used are highlighted as follows:

According to [27]:

$$S_w = \left[\frac{(ax R_w)}{(R_t x \emptyset^m)}\right]^{\frac{1}{2}} \qquad (8)$$

$$S_h = 1 - S_w \qquad (9)$$

where: S_w= Water saturation, S_h = Hydrocarbon saturation, R_t = True formation resistivity (that is, deep induction), R_w= resistivity of formation water at formation, $\emptyset$ = porosity, n = saturation exponent, m = cementation factor, a = tortuosity factor

(f) Irreducible Water Saturation

This describes the water saturation at which all the water is adsorbed on the grains in a rock or is held in capillaries by capillary pressure. Because production of water in a well can affect a prospect's economics, it is important to know the bulk volume of water and whether the formation is at irreducible water saturation (S_{wirr}). At irreducible water saturation, water does not move and the relative permeability to water is zero. Hence, water saturation varies from 100% to a small value but never goes to zero because some water held in capillaries cannot be displaced. The following is the equation used in calculating S_{wirr}:

$$S_{wirr} = \left(\frac{F}{2000}\right)^{\frac{1}{2}} \qquad (10)$$

where: F = formation factor

(g) Bulk Volume of Water (BVW)

This is the product of water saturation and porosity corrected for shale:

$$BVW = S_w\, x\, \Phi_{eff} \qquad (11)$$

If values for BVW calculated at several depths within a formation are consistent, then the zone is considered to be homogeneous and at irreducible water saturation. Therefore, hydrocarbon production from such zone should be water free.

(h) Permeability Determination

[28]can be employed in determining permeability. The equation is stated below:

$$K = \left(250x\frac{\emptyset^3}{S_{wirr}}\right)^2 \quad \text{(Medium-gravity oils)} \quad (12)$$

where: K = permeability in millidarcy, S_{wirr} = irreducible water saturation

Practical oil filed rule of thumb for classifying permeability [26]: Poor to Fair = 1.0 to 14 mD; Moderate = 15 to 49 mD; Good = 50 to 249 mD, Very good = 250 to 1000 mD; >1 Darcy = Excellent.

(i) Reservoir Quality Index and Flow Zone Indicator Application

Flow Zone Indicator (FZI) as presented by [29]. Flow zone indicator is a unique and useful value to quantify the flow character of a reservoir and offers a relationship between petrophysical properties at small scale (core plugs) and large scale (well bore level). In addition, FZI improves reservoir description [30].

The equation is given as:

$$FZI = \frac{RQI}{PMR} \quad (13)$$

Where, reservoir quality index, $$RQI = 0.0314\sqrt{\frac{K}{PHIE}} \quad (14)$$

And pore-to-matrix ratio $$PMR = \frac{PHIE}{1-PHIE} \quad (15)$$

K is permeability in mD and PHIE is porosity in fraction.

IV. RESULTS AND DISCUSSION

Reservoir Property

The results of the studied well analysis suggest that the reservoirs are well developed and typical of turbidite depositas expressed by the mixed sand-mud flows from the facies proportion of the reservoirs delineated in the study area as shown in figure 6. This was evidence from the lithostratigraphic panel, it can be deduced that there is reservoir discontinuity and lateral facies change, that is, thickening and thinning of reservoir (some reservoir pinch out from sand to shaly sand). It can also be deduced from the well correlation that the reservoir series are characterized by both lateral and vertical heterogeneities (figure 7). The reservoirs could be said to have been smeared by the continuous shale layers that occur between the sand bodies in the study area. The three horizons mapped, namely C4-sand, F1-sand and G1-sand chosen were well developed hydrocarbon bearing sands within the Lowstand Systems Tract (LST). The reservoirs studied has their thicknesses ranging from 4.27m to 53.38 m.effective porosity range from 7% to 26%, water saturation range from 46% to 90% and net to gross ranges from 10% to 70% (Table 1).

C4 Reservoir

C4 reservoir has a gross thickness ranging from 6.15 to 100.36m, net thickness ranges from 0 to 7.80m, and the net-to-gross thickness (N/G) ranges from 0 to 0.64. Also, C4 reservoir also has porosity ranging from 0.16 to 0.25 with an average porosity value of 0.21. The waterand hydrocarbon saturation have average values of 46% and 54% respectively (Table 2). The porosity values obtained within C4 reservoir show a good rating. The hydrocarbon saturation indicates a high proportion of hydrocarbon to the quantity of water within the reservoir. Hence C4 reservoir is an oil reservoir (Figure8).

F1 Reservoir

It has a gross thickness ranging from 7.53 to 52.91m, net thickness ranging from 1.87 to 37.31m and net-to-gross thickness (N/G) ranging from 0.13 to 0.75. F1 reservoir also has porosity ranging from 0.19 to 0.32 with an average porosity value of 0.28. The water and hydrocarbon saturation have average values of 36 % and 64 % respectively (Table 3). The porosity values obtained in F1 reservoir are good values. The hydrocarbon saturation indicates a high

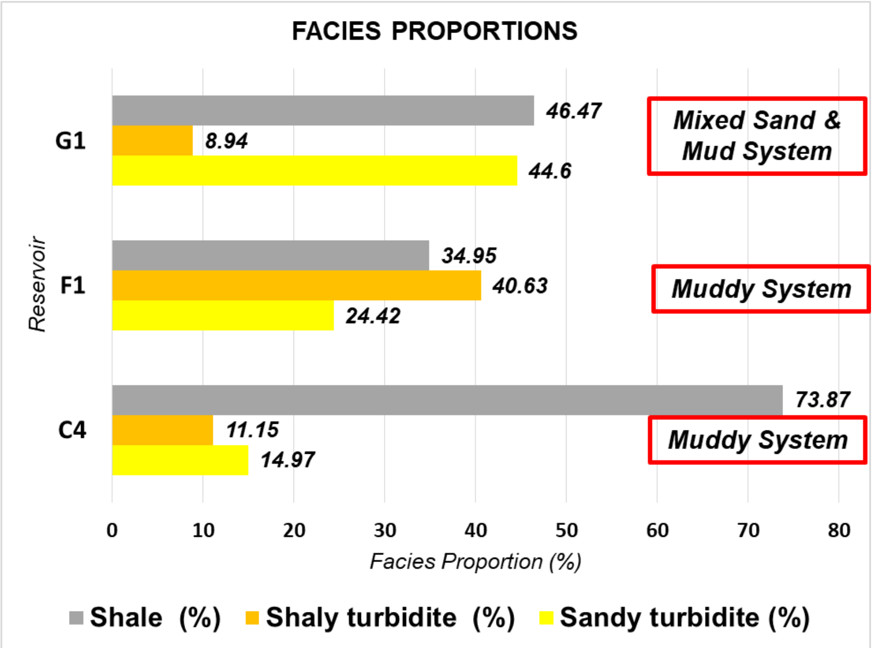


Figure 6: Facies Proportion of the Reservoirs

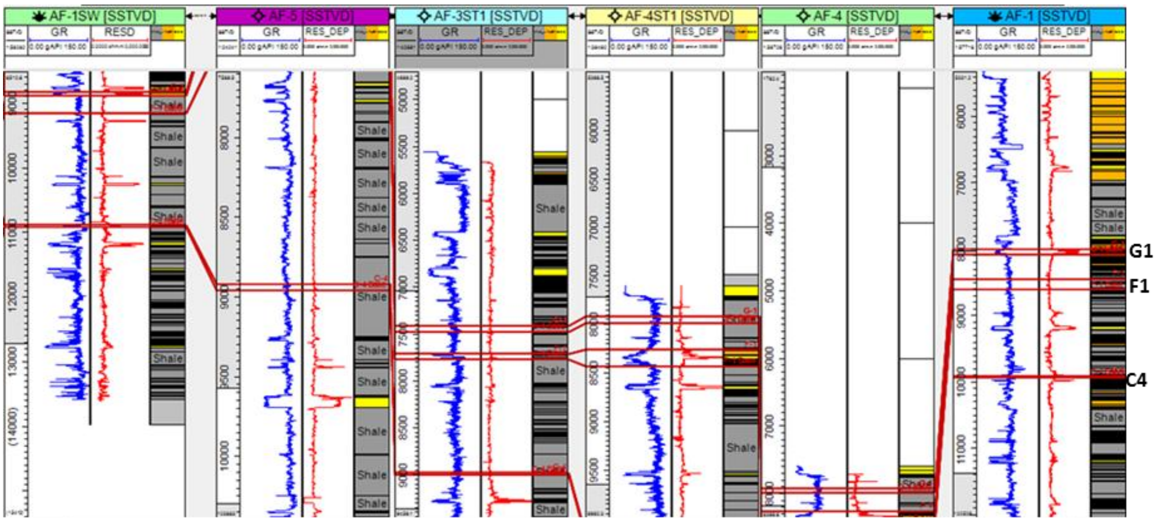


Figure 7: Sand to sand correlation (G1, F1 & C4)

Table 1: Summary of the computed petrophysical parameters obtained for the wells

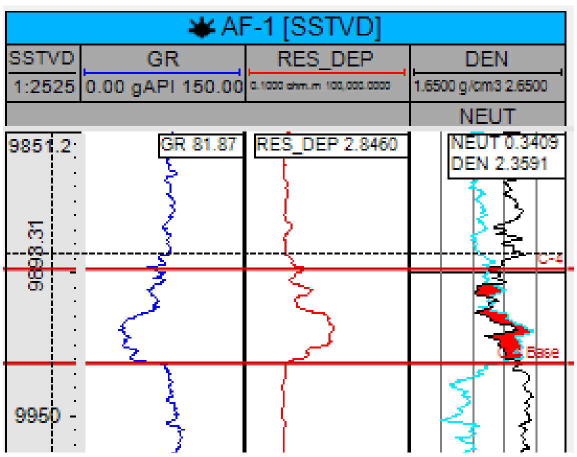
SANDS	TOP		CONTACT (TVDSS)			BASE		GROSS SAND	NET SAND	GROSS PAY	NET PAY	ϕ	SW	NTG	REMARKS
	MD (m)	TVDSS (m)	GOC	OWC	GWC	MD (m)	TVDSS (m)	(m)	(m)	(m)	(m)	dec	dec	dec	
	AF-1														
G-4	2080.0	-2055.4	-	-	-	2106.9	-2082.4	27.0	17.8	27.0	17.8	0.29	0.36	0.66	OIL
G-1	2464.4	-2439.9	-	-	-	2488.5	-2463.9	24.1	23.1	24.1	23.1	0.31	0.17	0.96	OIL
E-2	2752.6	-2728.0	-	-	-	2773.8	-2749.1	21.2	9.5	21.2	9.5	0.21	0.47	0.45	OIL
E-1	2812.3	-2787.5	-	-	-	2836.7	-2811.9	24.4	15.4	24.4	15.4	0.21	0.27	0.63	OIL
C-4	3043.4	-3018.3	-	-	-	3053.8	-3028.7	10.3	6.6	10.3	6.6	0.21	0.22	0.64	OIL
C-3	3064.5	-3036.4	-	-	-	3072.7	-3047.6	8.2	6.9	8.2	6.9	0.19	0.46	0.85	OIL
	AF-4														
I	2505.3	-2480.6	-	-	-	2483.7	-2483.7	3.0	3.0	3.0	3.0	0.27	0.50	0.98	GAS
F-1	2543.5	-2518.9	-2548.3		-	2571.8	-2571.8	53.0	34.4	29.4	19.1	0.29	0.25	0.65	GAS
	AF-4ST1														
I	2504.4	-2479.7	-	-	-	2507.4	-2482.8	3.0	2.9	3.0	2.9	0.25	0.48	0.98	GAS
F-1	2542.9	-2518.2	-	-2547.4	-	2594.9	-2570.2	52.0	33.8	29.1	18.8	0.27	0.26	0.65	OIL
E-4	2650.9	-2626.1	-	-	-	2667.8	-2643.1	16.9	15.1	16.9	15.1	0.28	0.14	0.89	OIL
E-2	2945.2	-2906.7	-	-2908.9	-	2958.2	-2917.5	10.7	7.9	2.2	2.1	0.26	0.32	0.74	OIL
X-C2	3261.1	-3145.3	-	-	-	3267.6	-3150.1	4.8	0.6	4.8	0.6	0.17	0.41	0.12	OIL
C-2	3276.8	-3156.9	-	-	-	3282.9	-3161.4	4.5	4.4	4.5	4.4	0.21	0.36	0.97	OIL
C-1	3298.9	-3173.2	-	-	-	3314.1	-3184.5	11.3	7.3	11.3	7.3	0.18	0.37	0.65	OIL
	AF-5														
G-2	2102.1	-2076.2	-	-	-2077.4	2104.0	-2078.1	1.9	1.9	1.2	1.2	0.31	0.52	0.99	GAS
C-1	3040.6	-2864.7	-	-	-	3060.1	-2881.6	16.9	2.4	16.9	2.4	0.21	0.30	0.14	OIL
B-2	3119.8	-2933.9	-	-	-	3145.6	-2956.6	22.6	22.4	22.6	22.4	0.30	0.17	0.99	OIL
	AF-3ST1														
C-4	2845.8	-2821.0	-	-	-	2860.7	-2835.9	14.8	9.6	14.8	9.6	0.28	0.14	0.65	OIL
C-2	2912.6	-2887.8	-	-	-	2918.5	-2893.8	5.9	5.4	5.9	5.4	0.27	0.22	0.90	OIL
	AF-1SW														
G-2	2674.2	-2649.7	-	-	-	2688.3	-2663.8	14.1	13.8	14.1	13.8	0.30	0.14	0.98	OIL
G-1	2698.9	-2674.5	-	-	-	2715.4	-2691.0	16.5	16.1	16.5	16.1	0.29	0.17	0.98	OIL
E-4	2834.5	-2810.1	-	-	-	2841.7	-2817.3	7.2	7.0	7.2	7.0	0.28	0.19	0.97	OIL
E-2	3096.6	-3072.2	-	-	-	3105.1	-3080.6	8.4	2.6	8.4	2.6	0.22	0.36	0.31	OIL
E-1	3132.0	-3107.5	-	-	-	3142.1	-3117.6	10.1	9.9	10.1	9.9	0.27	0.10	0.98	OIL
C-4	3329.7	-3305.3	-	-	-	3335.8	-3311.4	6.1	3.4	6.1	3.4	0.20	0.29	0.55	OIL
B-2	3410.2	-3385.8	-	-	-	3427.4	-3403.0	17.2	16.0	17.2	16.0	0.19	0.23	0.93	OIL

MD: Measured depth, TVDSS: True vertical depth sub-sea, GOC: Gas-oil-contact, GWC: Gas-water-contact, OWC: Oil-water-contact, ϕ: Porosity, S_W: Water saturation, NTG: Net-to-gross

Table 2: Summary of the Computed Petrophysical Parameters obtained for C4Reservoir

Well Identifier	Top (MD, m)	Base (MD, m)	Gross Thickness (m)	Net Sand (m)	N/G (Sand)	Vshale	Øeff	Sw	K (mD)
AF-1	3043.4	3053.8	10.4	6.6	0.63	0.42	0.20	0.62	501.3
AF-1SW	3329.7	3335.8	6.1	3.4	0.56	0.67	0.22	0.57	250.04
AF-3ST1	2845.8	2860.7	14.8	9.6	0.65	0.58	0.24	0.41	718.7
AF-4ST1	3261.1	3267.6	4.8	0.6	0.13	0.87	0.16	0.99	188.33

MD: Measured Depth, NTG: Net-to-gross, $V_{shale:}$ Volume of Shale, ϕ_T: Total Porosity,ϕ_{eff}: Effective Porosity, S_W: Water Saturation



Possible hydrocarbon charge

Figure 8: Log Plots for C4 Reservoir showing the Neutron and Density Crossovers which may indicate that the Hydrocarbon Type as Oil

*Corresponding Author: Yemisi. C. Ajisafe

Table 3: Summary of the Computed Petrophysical Parameters obtained for F1 Reservoir

Well Identifier	Top (MD, m)	Base (MD, m)	Gross Thickness (m)	Net Sand (m)	N/G (Sand)	Vshale	Øeff	Sw	K (mD)
AF-4	2543.5	2570.8	52.3	34.4	0.65	0.24	0.28	0.25	1546
AF-4ST1	2542.9	2594.9	52.0	38.8	0.75	0.30	0.27	0.38	1643.41

MD: Measured Depth, NTG: Net-to-gross, $V_{shale:}$ Volume of Shale**,** ϕ_T: Total Porosity, ϕ_{eff}: Effective Porosity, S_W: Water Saturation

proportion of hydrocarbon to the quantity of water within the reservoir. Hence F1 reservoir is a gas reservoir as evidenced from balloon shape of the neutron- density plot (Figure 9).

G1 Reservoir

This reservoir cuts across all the wells. Its gross thickness ranges from 16.43 to 24.41m, the net thickness is between 3.93 and 22.89m and the net to gross thickness (N/G) ranges from 0.20 to 0.95. G1 reservoir has porosity ranging from 0.24 to 0.32 with average porosity of 0.27. The average water saturation (S_w) is 26%, while the hydrocarbon saturation (S_h) 74% (Table 4). The porosity values of G1 reservoir are good and indicative of porous sandstone. The water saturation and hydrocarbon saturation reveal that both hydrocarbon and water are present in the reservoirs with the hydrocarbon having a higher ratio. Hence G1 reservoir is an oil unit based on neutron and density crossover (Figure 10).

Reservoir Quality Prediction

Figure 11 shows a plot of porosity and logarithm of permeability obtained from conventional core analysis of two cored wells in "AFUN" field. The figure shows a lot of scatter and some samples of same porosity but different permeability values. This reveals a fact that porosity is not the only parameter that can explain permeability variation. This can be attributed to the existence of more than one rock type in the reservoir, where each rock type has fluid flow properties different from the other.The correlation shows no significant value of regression. Hence the low value of regression indicating poor correlation between the two parameters.FZI technique was employed for better correlation of the rocks with similar fluid flow properties.This gives an insight about the pore geometry by dividing the rock types into different hydraulic flow units (Figure 12). Four hydraulic flow units in the reservoir were delineated. It implied that each unit is precipitated at certain geological conditions and has fluid flow properties different from the other unit. From this plot of FZI where regression value is greater than 0.6 and hence indicates very strong correlation between the two parameters. Consequently upon this, estimated permeability obtained from the well log analysis were compared with core permeability. The zone of high interval of permeability indicates reservoir of high quality.The reservoir quality of "AFUN" field have been found to depreciate with increasing depth.

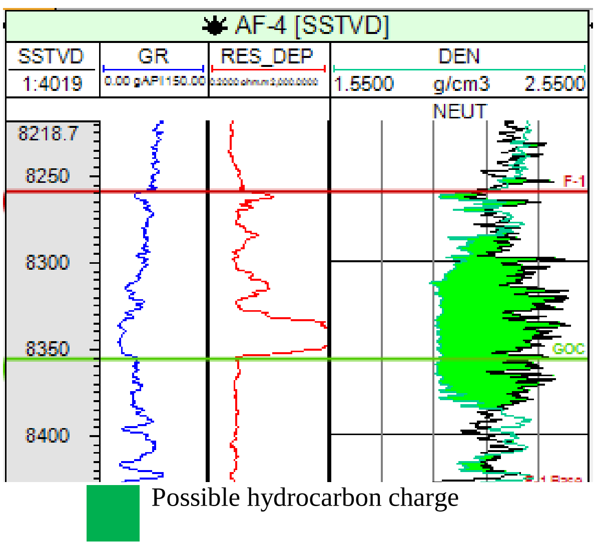


Figure 9: Log Plots for F1 Reservoir showing the Neutron and Density Crossovers which may indicate that the Hydrocarbon Type as Gas

Table 4: Summary of the Computed Petrophysical Parameters obtained for G1 Reservoir

Well Identifier	Top (MD, m)	Base (MD, m)	Gross Thickness (m)	Net Sand (m)	N/G (Sand)	Vshale	Øeff	Sw	K (mD)
AF-1	2464.4	2488.5	24.1	19.3	0.80	0.31	0.25	0.39	1213
AF-1SW	2698.6	2715.4	16.5	1.65	0.10	0.75	0.13	1	404.1
AF-4	2518.77	2571.11	52.34	37.32	0.65	0.24	0.28	0.25	957
AF-4ST1	2518.14	2571.00	52.86	28.65	0.54	0.31	0.27	0.63	776.74

MD: Measured Depth, NTG: Net-to-gross, $V_{shale:}$ Volume of Shale, ϕ_T: Total Porosity, ϕ_{eff}: Effective Porosity, S_W: Water Saturation

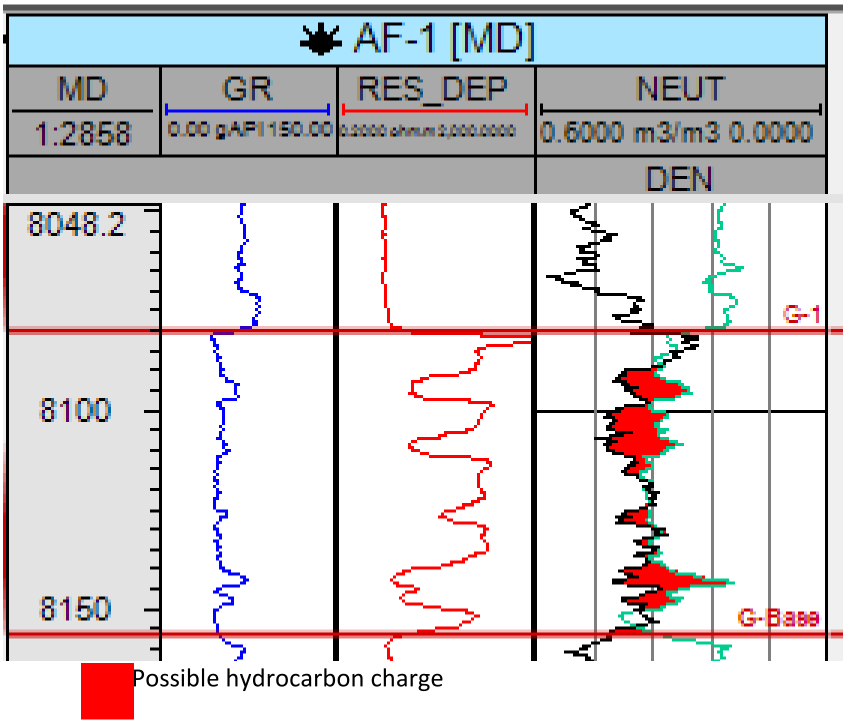


Figure 10: Log Plots for G1 Reservoir showing the Neutron and Density Crossovers which may indicate that the Hydrocarbon Type as Oil

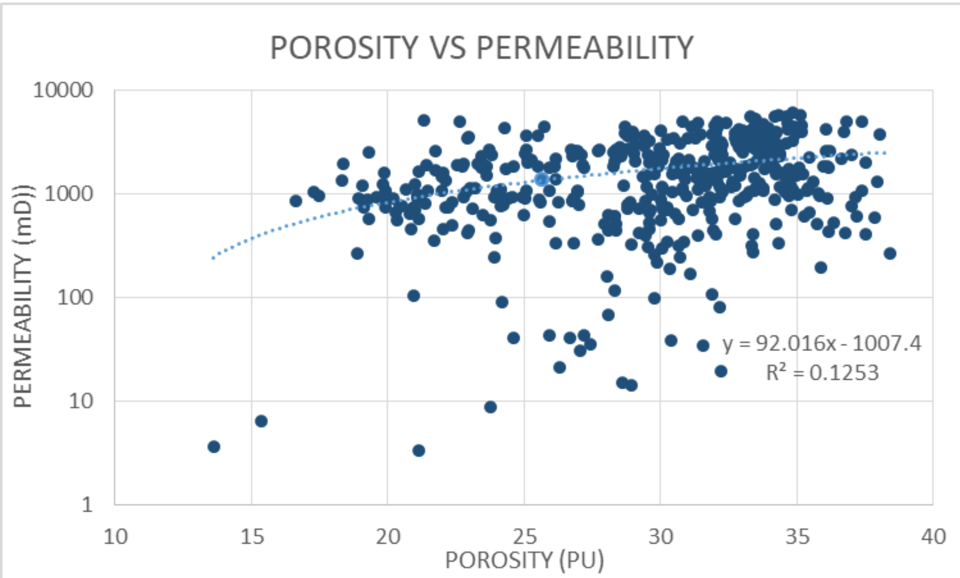


Figure 11: Correlation of Core Permeability and Core Effective Porosity

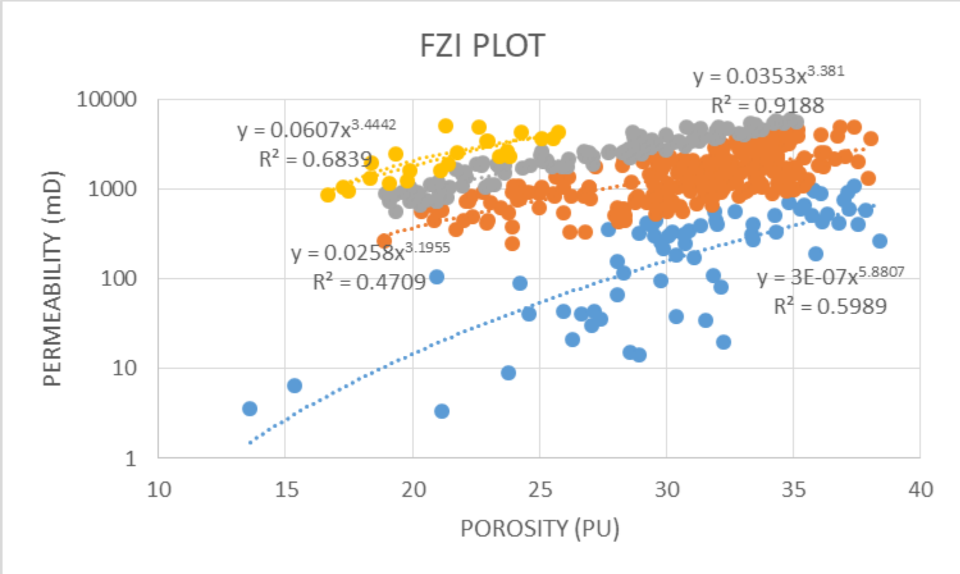


Figure 12: Permeability-Porosity cross plots for wells AF-4ST1 and AF-4 with four correlation lines drawn based onFlow Zone Indicator values

V. CONCLUSIONS

The study was carried out in order to predict the reservoir quality of deepwater submarine fan system of "AFUN" Field, Niger Delta.Wells in the study area were correlated to estimate the petrophysical properties of the turbiditedeposits. Petrophysical parameters such as porosity and permeability determined the quality of the reservoir. Routine core data analysis were used for correlation of porosity and permeability of the reservoirs.This correlation can be usedto predict the quality of the reservoirs for development of the field.Further study should be carried out by incorporating petrophysical analysis. The relationship between porosity, permeability and lithofacies can be further improved for better reservoir characterization.

REFERENCES

[1]. Worden, R. and Morad, S. (2009). Quartz cementation in oilfield ssandstones: a review of the key controversies. In: Worden, R. and Morad, S. 9eds) Quartz Cementation in Sandstones Blackwell Publishing Ltd., Oxford, 29, 1- 20

[2]. Corredor, F., Shaw, J. and Suppe, J. (2005). Shear fault-bend folding, deep water Niger Delta, In: J. Shaw, C. Connors, and J. Suppe, eds., Seismic Interpretation of Contractional fault-related folds: AAPG Studies in Geology 53, 87– 92.

[3]. Reijers, T. J.A., Petters, S. W., Nwajide, C. S. (1997) The Niger Delta Basin, in Selley, R.C, ed, African Basin-sedimentary Basin of the world 3: Amsterdam, Elsevier Science, p. 151 – 172

[4]. Nwachukwu, J. I. and Chukwura, P. I. (1986). Organic matter of Agbada Formation, Niger Delta, Nigeria. American Association of Petroleum Geologists, Bulletin, 70, 48-55.

[5]. Evamy, D. W., Haremboure, J., Kamerling, P., Knaap, W. A., Molloy, F. A. and Rowlands, P. H. (1978): Hydrocarbon habitat of Tertiary Niger Delta. AAPG Bulletin, 62 (1), pp. 1–39.

[6]. Knox, G. J. and Omatsola, E. M. (1989): Development of the Cenozoic Niger Delta in terms of the "escalator regression" model and Impact on hydrocarbon distribution; in W. J. M., van der Linden et al., eds, 1987 Proceedings KNGMG Symposium on Coastal Lowlands, geology, and Geotechnology: Dordrecht, the Netherlands, Klumer Academic Publishers, pp. 181–202.

[7]. Ekweozor, C. M. and Daukoru, E. M. (1994): Northern Delta depobelt portion of the Akata-Agbada, petroleum system, Niger Delta, Nigeria; in L. B. Magoon and W. G. Dow, eds, The petroleum system - from source to trap: AAPG Memoir, pp. 599–613.

[8]. Weber, K. J. and Daukoru, E. M. (1975): Petroleum Geology of the Niger Delta; Proceedings of the Ninth World Petroleum Congress, Tokyo, Japan, 2, pp. 209–221.

[9]. Short, K. C. and Stauble, A. J. (1967): Outline of the Geology of Niger Delta. AAPG Bulletin, 51, pp. 761–779.

[10]. Avbovbo, A. A. (1978). Tertiary Lithostragraphy of the Niger Delta. AAPG, 62 (2), pp. 295–300.

[11]. Oomkens, E. (1974): Lithofacies relations in the late Quaternary Niger Delta complex. Sedimentology, 2, pp. 195–222.

[12]. Burke, K. (1972): Longshore drift, submarine canyons, and submarine fans in development of NigerDelta AAPG Bulletin, 59 (3), pp. 414–419.

[13]. Mutti, E. and Ricci Lucci, F. (1975). Turbidite facies and facies associations. In: Examples of Turbidite Facies and Associations from Selected Formations of the Northern Apennines. IX Int. Congress of Sedimentology, Field Trip A-11, 21–36.

[14]. Normark, W.R. (1978). Fan valleys, channels, and depositional lobes on modern submarine fans: Characters for recognition of sandy turbidite environments. American Association of Petroleum Geologists Bulletin, 62 (6), 912–931.

[15]. Walker, R. G. (1978). Deep-water sandstone facies and ancient submarine fans: model for exploration for stratigraphic traps. American Association of Petroleum Geologists Bulletin, 62 (6): 932–966

[16]. Weimer, P. and Slatt, R. M. (2004). Petroleum systems of deepwater settings, SEG/EAGE Distinguished Instructor Short Course, Distinguished Instructor Series; 7, 423-427.

[17]. Thomas D. (1995). Exploration gaps exist in Nigeria's prolific delta. Oil and Gas Journal, 66-71.

[18]. Haack, R.C., Sundaraman, P. and Dahl, J. (1997). Niger Delta Petroleum System. "Petroleum Systems of the South Atlantic Margin", Hedberg Research Symposium, Rio de Janeiro, 16-19 November, extended abstract 144 p.

[19]. Stephens, K. D., Clark, J. D. and Gardiner, A. R. (1997). Outcrop-based stochastic modeling of turbidite amalgamation and its effects on hydrocarbon recovery. Petroleum Geoscience, 7, 163–172.

[20]. Haack, R. C., Sundararaman, P., Diedjomahor, J. O., Gant, N. J. and Dahl, J. (1998). Niger Delta Petroleum Systems. Extended Abstracts AAPG International Conference and Exhibition, November 8-11, 1998 Rio de Janeiro, p. 936-937.

[21]. Onuoha, K. M. (1999). Structural features of Nigeria's coastal margin: An assessment base on age data from wells. Journal of African Earth Sciences, 29 (3), p. 485–499.

[22]. Lawrence, S. R., Munday, S. and Bray, R. (2002). Regional geology and geophysics of the eastern Gulf of Guinea (Niger Delta to Rio Muni). The Leading Edge, 21, (11), p. 1112–1117.

[23]. Ojo, A. O. (1996). Pre-drill prospect evaluation in deep water Nigeria. Nigerian Association Petroleum Explorationists Bulletin, 11: 11-22.

[24]. Magoon, L. B., and Dow, W. G., (1994). The petroleum system. In: Magoon, L.B., and Dow, W.G., eds. The Petroleum System - from Source to Trap: American Association of Petroleum Geologists Memoir 60, 3-23.

[25]. Larionov, V. V. (1969). Borehole Radiometery. Moscow, U.S.S.R., Nedra, p.115 – 121.

[26]. Baker, H. I. (1992). Advanced wireline and MWD procedures manual: B.H.I technical publications group. AAPG Bulletin, 84 (2), 250–265.

[27]. Archie, G.E. (1942). Introduction to petrophysics of reservoir rocks. American Association of Petroleum Geologists Bulletin, 34(5), 943-961.

[28]. Wyllie, M. R. J. and Rose, W. D. (1950). Some theoretical considerations related to the quantitative evaluations of reservoir rocks from electric log data: Journal of Petroleum Technology; 189, 105 -110.

[29]. Amaefule, J. O., Altunbay, M., Tiab, D., Kersey, D. G., Keelan, D. K. (1993). Enhanced reservoir description using core and log data to identify hydraulic flow units and predict permeability in uncored intervals/wells. In SPE Annual Technical Conference and Exhibition, 3-6 October, Houston, Texas.

[30]. Alhashmi, N. F., Torres, K., Faisal, M., Segura Cornejo, V., Bethapudi, B. P., Mansur, S., Al-Rawahi, A. S. (2016). Rock typing classification and hydraulic flow units definition of one of the most prolific carbonate reservoir in the onshore Abu Dhabi In: SPE Annual Technical Conference and Exhibition, 26-28 September, UAE. Dubai. SPE- 181629-MS.