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GEOPHYSICAL LOGS ANALYSIS FOR FORMATION EVALUATION: A CASE STUDY OF "ODOKOKO" FIELD, COASTAL SWAMP DEPOBELT, NIGER DELTA

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Abstract

The logs were used to identify the sand intervals which are potential commercial hydrocarbon bearing reservoirs. A cut off of 43 API was used for sand, 65API for shaly sand and 85 for sandy shale in the Cross plotting technique and the unsupervised neural network process of Petrel. Four sands of possible reservoir quality were identified. Their porosities range from 23% to 34%, permeability from 2104 to 16361 md and hydrocarbon saturation from 66 - 98 percent. The shale volume was found to be in the range of 3 - 31 percent and net to gross from 0.69 - 0.97. The porosity- permeability relationship is near perfectly logarithmic with correlation coefficients (R^2) ranging from 0.98 to 0.99. The Bulk Volume Hydrocarbon (BVH) was found to be a good hydrocarbon indicator and also has a strong quadratic relationship with the acoustic impedance at the wells with correlation coefficients (R^2) ranging from 0.553 to 0.837. The sands studied are potential high quality reservoirs.

***Keywords**: Geophysical logs; porosity; permeability; Bulk Volume hydrocarbon; Acoustic impedance; reservoirs.*

1. Introduction

The "Odokoko" field in the Coastal Swamp depobelt of the Niger Delta, Basin consists of-sands and shale formations.The mostly unconsolidated formations consist of sands ranging from fluvial(channel) to fluvio-marine (Barrier Bar sands), while shales are generally fluvio-marine or lagoonal. Formation evaluation is mostly based on geophysical logs [1]. Petrophysical parameters like lithology, fluid content, porosity, water saturation, hydrocarbon saturation and permeability are derived using geophysical welllog data. It is usually done to delineate the reservoir sands and asses their commercial viability by evaluating petrophysical parameters and consequently the volume of hydrocarbon in place and its producibility. In the work of [2], it was demonstrated that petrophysical parameters such as porosity (φ), permeability (K) and saturation (S), for any given rock type are controlled by pore sizes and their distribution and interconnection. He stated that a broad relationship exists between porosity and permeability of a formation. He stated that a broad relationship exists between porosity and permeability of a formation. The goal of reservoir characterization is to predict the spatial distribution of such petrophysical parameters on a field scale. This paper presents the results of studies of the petrophysical evaluation of the "Odokoko" field in the Coastal Swamp Depobelt of the Niger Delta Basin, and determining the porosity permeability relationship of the field using geophysical well log data. It presents a detailed qualitative and quantitative estimation of the reservoir and the fluids in it. This includes the lithology, porosity, permeability and hydrocarbon saturation. The Bulk Volume Hydrocarbon (BVH) is the product of effective porosity and hydrocarbon saturation. Its usefulness as a hydrocarbon indicator and relationship to acoustic impedance was determined in this study. These are results useful for locating and estimating the economic prospects of the reservoir(s) intercepted by the wells.

2. Geology and Stratigraphy of the Niger Delta

The Niger Delta consists of three major lithostratigraphic units: the Akata, Agbada and Benin formations. The Oligocene- Holocene Benin Formation is a loose fresh water bearing sand with occasional lignite and clay goesdown to a depth of 2,286 m. The Agbada Formation is made up of alternating sands and shales. The sands are mostly encountered at the upper parts while shales are found mostly at the deeper parts. The Agbada Formation is thickest at the centre of the Delta and is over 3700m and are Eocene-Holocene [3]. This is the seat of most known oil reservoirs in the Niger Delta. The Akata Formationthought to be at the base of the delta is Palaeocene- Holocene facies of marine origin and composed of thick shale sequences (potential source rock), turbidite sand (potential reservoir in deep water) and minor amounts of clay and silt. It is estimated that the formation is up to 7000m thickin the central part of the delta. The marine shale is typically over pressured [4].

The Niger delta oil province is characterized by approximately east-west trending syn-sedimentary faults and folds. These syn-sedimentary faults are called growth faults and the anticlines associated with themare called roll-over anticlines [5].

3. Materials and methods

Suites of Five geophysical well logs were obtained from SPDC in Nigeria, recorded at various locations within the "Odokoko" field, Niger Delta basin. A sample of these well logs is shown in Fig.2. Petrel® software: the Petrel software is a Schlumberger owned window PC software application designed to analyse oil reservoir data from multiple sources.

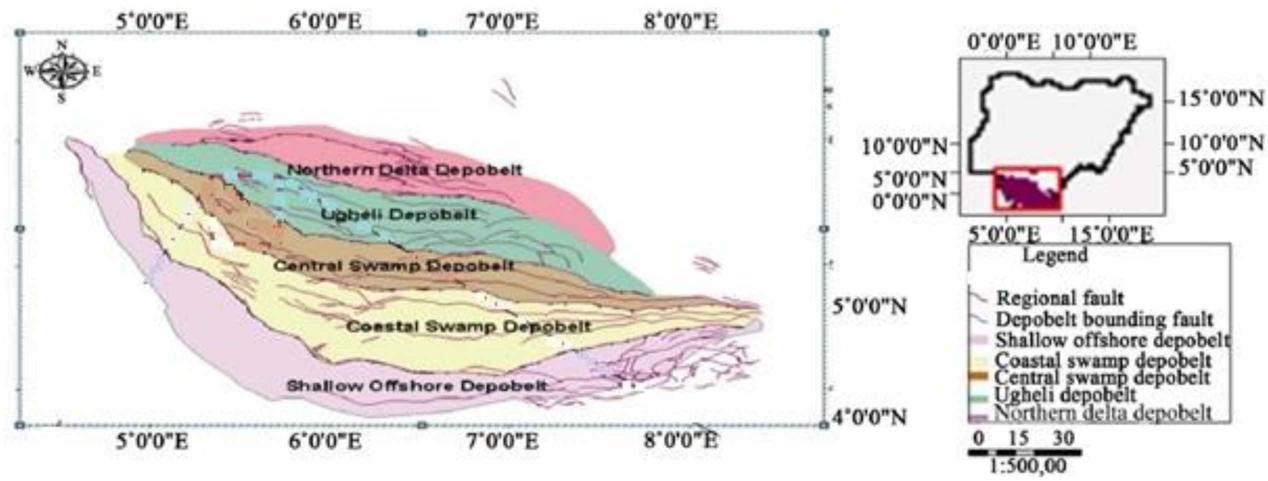


Fig 1 Map of Nigeria showing depobelts in the Niger Delta [6]

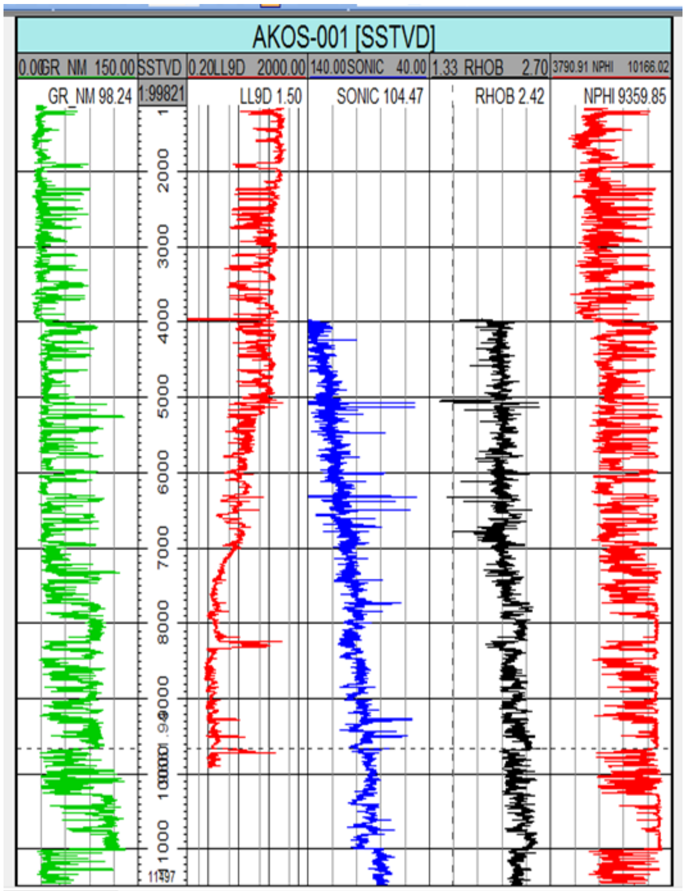
3.1. Qualitative analysis

The suite of geophysical well logs were evaluated to determine sand/shale lithology pattern, differentiate the hydrocarbon/non-hydrocarbon zones of the area penetrated by the wells.

3.1.1. Sand/shale lithology

Sand and shale bodies were delineated from the gamma ray log signatures. Sand bodies were identified by deflection to the left due to the low concentration of radioactive minerals in it and shale to the right due to the high concentration of radioactive minerals in it. This enables differentiation between sand, shaly sand, sandy shale and shale using the train estimation model process of Petrel to generate the lithology log. This is indicated by yellow for sand, orange for shaly sand, light grey for sandy shale and dark grey for shale colourations. The cross plot technique was also used for lithologic identification. A cut off of 80API gamma ray was used for classification of sands and shales and cross plotted with sonic, density and neutron porosity logs respectively.

3.1.2. Differentiation of hydrocarbon and non-hydrocarbon bearing zones



A combination of the gamma ray and resistivity logs were used to differentiate between the hydrocarbon and non-hydrocarbon bearing units. The resistivity and gamma ray logs are shown in tracks 1 and 2 of Fig. 2 respectively. The scale increases from left to right, the values depending on the log type and scale of data acquisition. The gamma ray log is used to indicate the sand and shale bodies within the formation. Hydrocarbon saturated zones in the sand bodies were identified by the deflection on the Laterolog Deep resistivity log. It is a well established fact that hydrocarbon is more resistive than formation waters. Increase in resistivity is indicated by deflections to the right on the resistivity log. Crossplots of BVH vs Acoustic (Impedance AI), porosity vs AI and water saturation vs AI were also performed.

Fig. 2. Typical suite of well logs in Odokoko field
GR_NM- Gamma Ray Log; LL9D-Resistivity Log; SONIC-Sonic log; RHOB-Density Log; NPHI-Neutron-Porosity Log

3.2. Quantitative interpretation

This involves the use of empirical formulae to estimate the petrophysical parameters such as porosity, permeability, volume of shale and hydrocarbon saturation.

3.2.1. Determination of volume of shale (V_{sh})

The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step in determining the volume of shale from a gamma ray log is the calculation of the gamma ray index using equation 1:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} = \quad (1)$$

where: I_{GR} = Gamma ray index; GR_{log} = Gamma ray reading of the formation; GR_{min} = minimum gamma ray (clean sand); GR_{max} = maximum gamma ray (shale). All these values are read off within a particular reservoir.

Having obtained the gamma ray index, the volume of shale is calculated using the [7] formula (equation 2),

$$V_{sh} = 0.083(2^{3.7 \times I_{GR}} - 1.0) \quad \text{(Tertiary consolidated sand)} \quad (2)$$

3.2.2. Determination of porosity (Ø)

Porosity is defined as the percentage of voids to the total volume of rock. The Formation density log was used to determine Formation porosity. The Formation porosity was determined by substituting the bulk density readings obtained from the density log and volume of shale within each reservoir into equation 3 [7]

$$\emptyset_{eff.} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} - V_{sh}(\frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}) \quad (3)$$

where: $\emptyset_{eff}$ is the effective porosity; ρ_{ma} is the matrix density = 2.65gm/cm^3 (sandstone); ρ_{fl} is the fluid density= 1.1gm/cm^3 (fluid density); ρ_b = formation bulk density.

The criteria for classifying porosity given is:
Ø <0.05= Negligible, 0.05< Ø<0.1= Poor, 0.1 Ø<0.15= Fair, 0.15< Ø<0.25%= Good, 0.25<Ø<0.30 = Very good, Ø>0.30 = Excellent.

3.2.3. Determination of compressional velocity (V_p)

This is the velocity of compressional seismic waves within a rock, ie velocity of acoustic wave in rock. It is estimated from the sonic log

$$V_p = 10^6/\Delta T\ (\mu sec/ft) \quad (4)$$

where: ΔT=corrected conic travel time in µsec/ft.

3.2.4. Determination of acoustic impedance

The Acoustic impedance values of the lithologies intercepted by the wells were calculated using the equation below.

$$AI = V_b * \rho_b \quad (5)$$

where: V_b =velocity of acoustic wave in rock = $10^6/\Delta T$ (µsec/ft); ρ_b = Density log value in gm/cc.

3.2.5. Estimation of water saturation

Water saturation of the un-invaded zone was determined using the [2] equation;

$$S_w{}^2 = \frac{F \times R_w}{R_t} \quad (6)$$

But $F = \frac{R_o}{R_w}$ (7)

Thus, $S_w{}^2 = \frac{R_o}{R_t}$ (8)

where: S_w= water saturation of the un-invaded zone; R_o= resistivity of formation at 100% water saturation; R_t= true formation resistivity (log readings); F = formation factor.
Irreducible water saturation is determined using [9]

$$S_{wirr} = \sqrt{\frac{F}{2000}} \quad (9)$$

3.2.6. Hydrocarbon saturation (S_h)

This is the percentage of pore volume in a formation occupied by hydrocarbons. It is obtained by subtracting the value obtained for water saturation from 100%.
i.e., S_h = (100 – Sw) % [2] (10)
where: S_h = hydrocarbon saturation; S_w = water saturation.

3.2.7. Permeability (K)

The ability of a rock to transmit fluid is referred to as permeability. It is related to porosity but not always dependent on it. It is controlled by the size of the connecting passages (pore throats or capillaries) between pores. It is measured in darcies or millidarcies. The permeability is obtained from the equation given by the Wyllie and Rose in [8].

$$k = [\frac{250 \times \emptyset^3}{\boldsymbol{S_{wirr}}}]^2 \quad (11)$$

where S_{wirr} is the irreducible water saturation

A practical oil field rule of thumb for classifying permeability:
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.

3.2.8. Determination of bulk volume hydrocarbon (BVH)

The BVH is the product of hydrocarbon saturation and effective porosity. It is an aggregate of three well log properties; gamma ray, density and resistivity logs. These logs enable the determination of lithology, porosity and water saturation. Accurate determination of these properties enables determination of good reservoir prospects as well as reliable reservoir characterisation. The BVH combines the strengths of these properties in order to deploy the synergy which exists among them for more accurate and reliable reservoir prediction and characterisation.

$$BVH = \emptyset_{eff.} \times S_h \quad (12)$$

BVH values >0.15 =good reservoir.

4. Results and discussion

The results of the study are presented in figures (3-8) and tables (1 -3) while the interpretation of results is presented both qualitatively and quantitatively.

4.1. Qualitative interpretation

For the log interpretation shown in Fig. 2, its litho-stratigraphic correlation furnishes knowledge of the general stratigraphy of the study field. Four lithologies were identified using the gamma ray log; **sand, shaly sand, sandy shale and shale**. The colour code for the lithology log are, yellow for sand, orange for shaly sand, light grey for sandy shale and dark grey for shale.

Correlating sand bodies of potential reservoir interest in this field was an uphill task. The gamma ray, resistivity, sonic, density and neutron logs showed great variations between wells even for those very close to each other. This is probably because the wells are located in areas with complicated faulting. The absence of some sands in some of the wells also indicate an unconformity in the area.

4.2. Well Correlation/Reservoir identification

Correlation was necessary to determine lateral continuity or discontinuity of reservoir facies in the field in order to properly delineate reservoir extent. Reservoir identification was done using gamma ray log signatures as markers and lithology indicators with a shale volume cut off of 20% and Laterolog Deep resistivity was used to identify potential reservoirs. The reservoir correlation panel is displayed in Fig 3. The alternation of sands and shale in various proportions and thicknesses within the evaluated depth conforms to that of the Agbada formation. The evaluated depth and the thicknesses of the various overlaying shale units, suggest a comfortable room for accumulation of matured hydrocarbon-prospective sequence in the studied area. From the correlation panel, there are stratigraphic discontinuities which may have been caused by faulting and or pinchouts in the area.

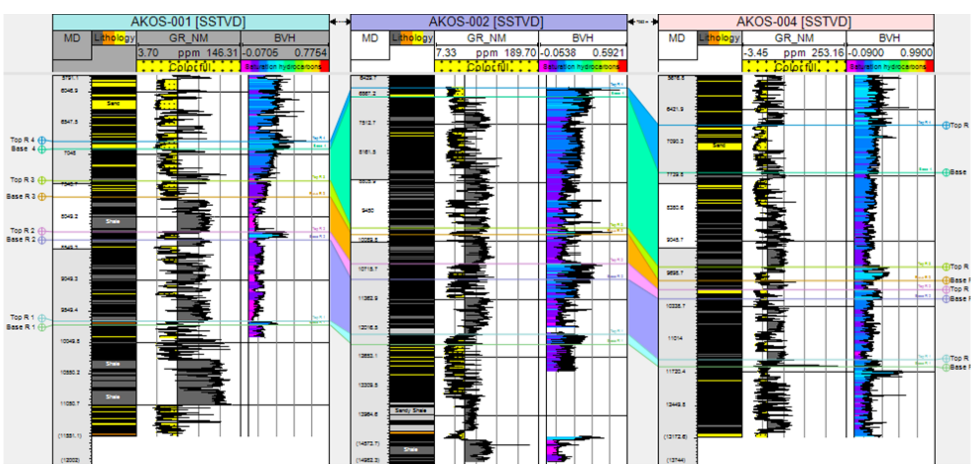
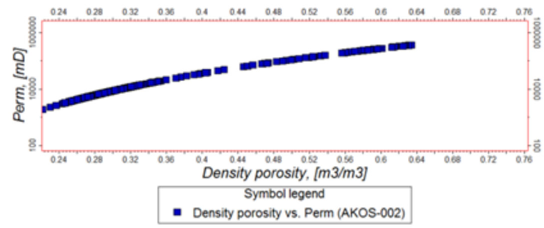
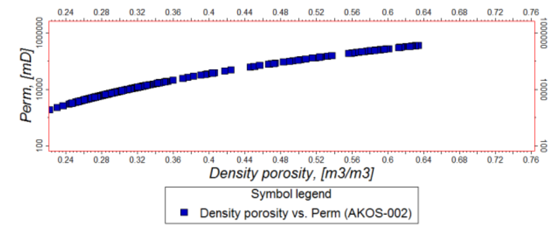


Fig.3. Well correlation panel showing the Top and Base of the interpreted reservoir sands.

4.3. Porosity - permeability relationship

The permeability of the Formations were determined using equation (11). It ranged from 2104 - 16361 md. The permeability values show excellent permeability. Figs. 4a-care sample porosity - permeability plots. It shows a perfectly correlated logarithmic relationship between the porosity and permeability. Permeability was found to be highest in Akos 001 and least in Akos 004. This may be as a result of more clay volumes present in the sand at well Akos 004.





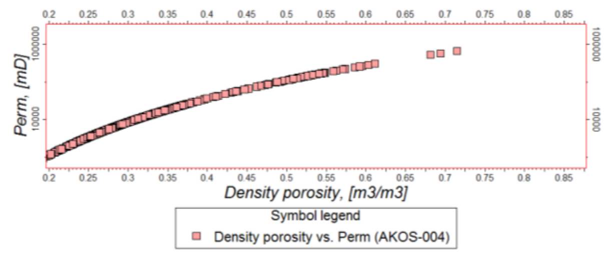


Fig 4 (a-c). Porosity permeability relationship in Akos 001,002 and 004

Table 1. Porosity Permeability relationships of the wells in the study area

Wells	Porosity-permeability relationship	Correlation coefficient (R^2)
AKOS 001	Log K=5.59 φ + 2.31	0.99
AKOS 002	Log K=5.36 φ + 2.30	0.99
AKOS 004	Log K=6.17 φ + 2.07	0.98

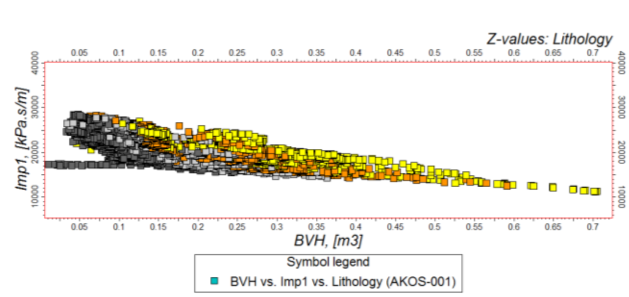
4.4. BVH-AI relationships of the wells in the study area

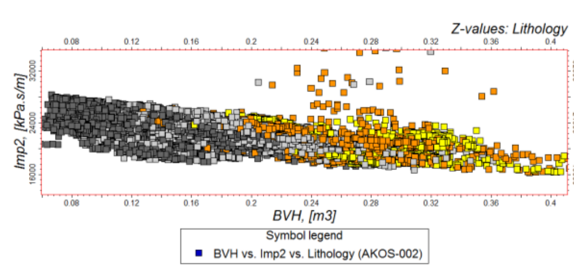
The BVH was determined using equation 12.

Table 2. Comparison of correlation coefficients of the crossplots of AI vs porosity, AI vs water saturation and AI vs BVH

Parameter	Correlation coefficient, R^2			
	Akos 001	Akos 002	Akos 004	Average
Acoustic Impedance (Z) vs porosity	-0.76	0.033	-0.63	-0.4533
Acoustic Impedance (Z) vs Water saturation	0.81	0.04	0.25	0.367
Acoustic Impedance (Z) vs BVH	0.837	0.553	0.714	0.701

The impedance tends to increase with decreasing BVH and increasing shaliness probably due to decreasing effective porosity as seen in figure 5.





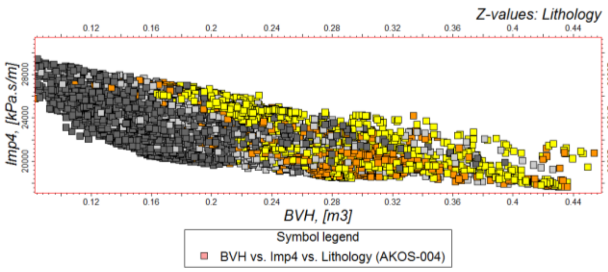


Figure 5. Crossplots of BVH and P-impedance colored by lithology

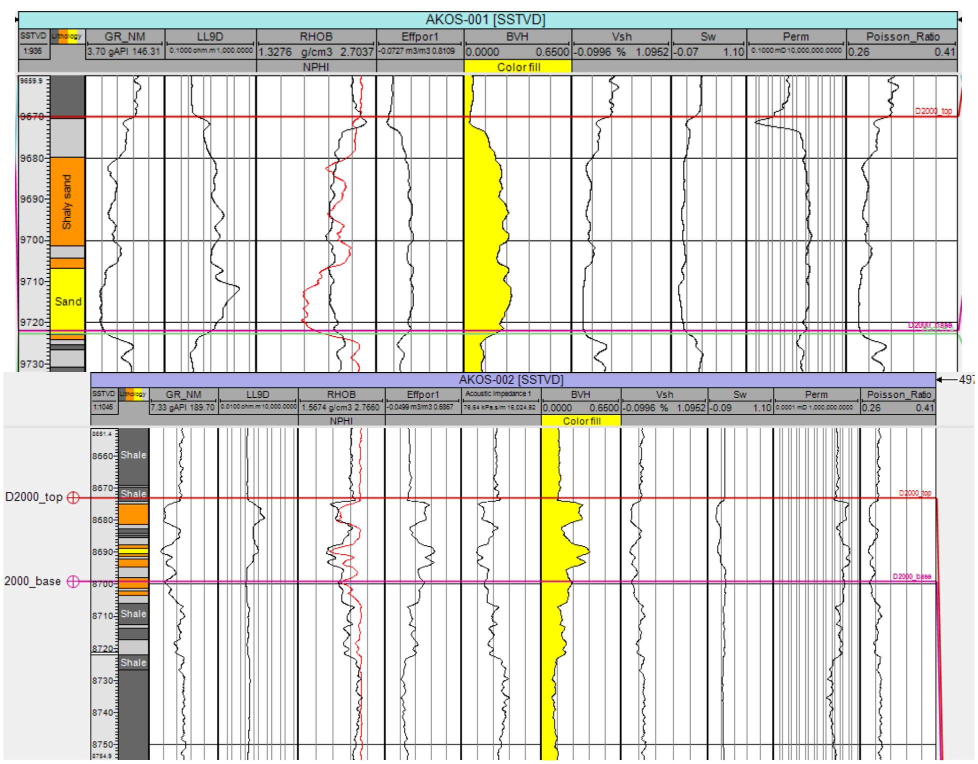
Table 3. BVH-AI relationships of the wells in the study area

Wells	BVH-Acoustic impedance relationships	*R2*
AKOS 001	AI=26056.1-32230.9BVH +1588.7BVH2	0.837
AKOS 002	AI= 27218.7-40537.9 BVH + 1283.3 BVH2	0.553
AKOS 004	AI= 30775.5-48787.2BVH + 466417.1 BVH2	0.714

The correlation coefficients, R^2, values displayed in Table 3 shows clearly that the BVH and acoustic impedance, AI, have a strong quadratic relationship.

4.5. BVH as hydrocarbon indicator

Figures 6 displays the results of petrophysical analysis. The BVH shows a potential as a good hydrocarbon indicator. It corroborates gamma ray, resistivity and Poisson ratio logs indicating hydrocarbon presence in sand D_2000. As can be seen in Fig. 7, intervals of high BVH coincides with sand and shaly sand lithologies, high effective porosity, high permeability, low water saturation, low shale volume, and low Poisson ratio. All these are indicative of good reservoir prospect sands in the three wells displayed.



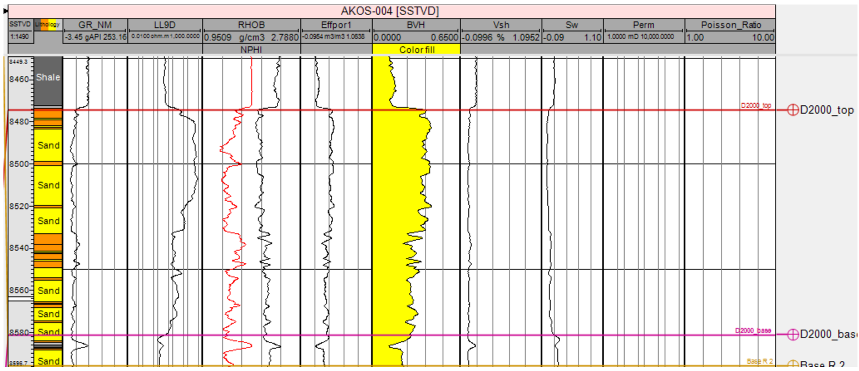


Fig 6. Results log for the D_2000 reservoir showing the BVH as a hydrocarbon indicator in agreement with Gamma ray, resistivity and poisson ratio logs, BVH values averaging 0.26 in Akos 001, 0.27 in Akos 002 and 0.29 in Akos 004

4.6. Quantitative interpretation

Following is a description of key petrophysical parameters for each reservoir intercepted by the wells arranged in stratigraphic order.

4.4.1. Reservoir 4

Table 4 shows the result of some computed petrophysical parameters for reservoir 4 It has a gross thickness ranging from 87 to 730 feet and the average net-gross ratio (N/G) is 0.94.

The average porosity in the three wells which intercept reservoir 4 is 0.31. This is an excellent porosity value. The average permeability is 10655md, an excellent value that permits the free flow of fluid within the reservoir. The hydrocarbon saturation is 0.89 on average, hence reservoir 1 is a hydrocarbon saturated reservoir with potential for high recovery factor. It has an average BVH of 0.26. This implies that sands having BVH of 0.26 or greater are potentially good reservoirs in the study area.

4.6.2. Reservoir 3

Some computed petrophysical parameters for reservoir 3 are shown in Table 4. It has a gross thickness ranging from 98 to 301 feet and the average net-gross ratio (N/G) is 0.93.

The average porosity across the three wells within which reservoir 3 is encountered is 0.29. This is a very good porosity value. The average permeability is 5366 md, an excellent value that permit the free flow of fluid within the reservoir. The hydrocarbon saturation indicates a high proportion of hydrocarbon (0.87 average) to the quantity of water within the reservoir. Hence reservoir 2 is a hydrocarbon saturated reservoir. It has an average BVH of 0.24. This implies that BVH of 0.24 or greater are potentially good reservoirs in the study area and that reservoir 3 has less than reservoir 4 if they have the same areal extent.

4.6.3. Reservoir 2

Table 4. show the result of some computed petrophysical parameters for this reservoir. It has a gross thickness ranging from 104 to 134 feet, and the average net to gross ratio (N/G) is 0.94.

It has an excellent porosity value averaging 0.32. The average permeability is 13.312 darcies, an excellent value. The hydrocarbon saturation indicates a high proportion of hydrocarbon (0.94 average) to the quantity of water within the reservoir. It has an average BVH of 0.28. This implies that reservoir 2 has greater potential than reservoir 4and 3 if they have the same areal extent.

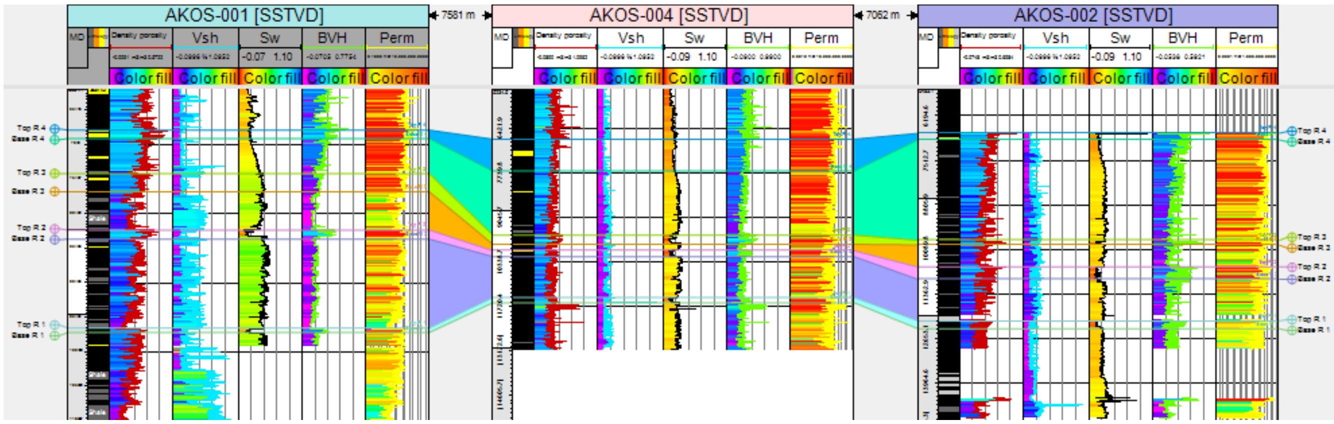


Fig. 7. Typical results logs including lithologic section for "Odokoko"field, Niger Delta. Quantity of water within the reservoir.

4.6.4. Reservoir 1

Some computed petrophysical parameters for reservoir 1 are displayed in table 2. It has a gross thickness ranging from 58 to 174 feet, and the average net to gross ratio (N/G) is 0.96.

The average porosity across the three wells incepting reservoir 1 is 0.31. This is an excellent porosity value. The average permeability is 12.168 darcies, indicating free flow of fluid within the reservoir. The hydrocarbon saturation of 0.95 average, to the quantity of water within the reservoir implies reservoir 1 is a hydrocarbon saturated reservoir. It also has an average BVH of 0.28.

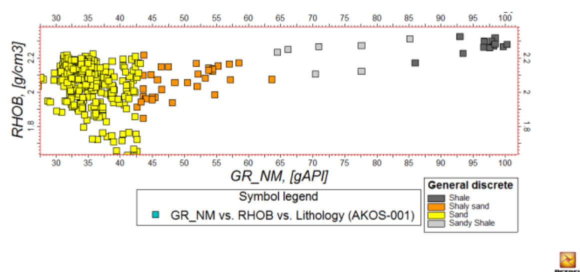
Table 4 Petrophysical Analysis of 'Odokoko' field showing field average values.

	THICKNESS (ft)				NET TO GROSS				POROSITY (φ)				Shale volume (Vsh)			
WELLS	R4	R3	R2	R1	R4	R3	R2	R1	R4	R3	R2	R1	R4	R3	R2	R1
AKOS 001	132	301	104	58	0.94	0.86	0.87	0.97	0.30	0.23	0.33	0.31	0.06	0.14	0.13	0.03
AKOS 002	87	98	282	174	0.97	0.97	0.98	0.96	0.31	0.32	0.34	0.31	0.03	0.03	0.02	0.04
AKOS 004	730	206	134	99	0.92	0.96	0.97	0.96	0.31	0.32	0.29	0.3	0.08	0.04	0.03	0.04
AVERAGE	316	202	173	110	0.94	0.93	0.94	0.96	0.31	0.29	0.32	0.31	0.06	0.07	0.06	0.04

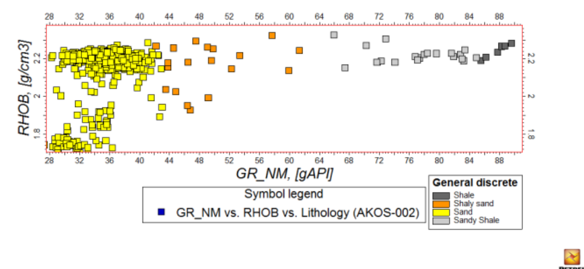
	Water saturation (Sw)				Hydrocarbon Saturation (Sh)				Bulk volume Hydrocarbon (BVH)				Permeability (k)			
WELLS	R4	R3	R2	R1	R4	R3	R2	R1	R4	R3	R2	R1	R4	R3	R2	R1
AKOS 001	0.13	0.34	0.11	0.05	0.87	0.66	0.89	0.95	0.2453	0.13055	0.25552	0.28567	9848	2104	14242	9836
AKOS 002	0.09	0.03	0.02	0.04	0.91	0.97	0.98	0.96	0.2736	0.30109	0.32654	0.2857	9677	1694	16361	10528
AKOS 004	0.11	0.03	0.04	0.05	0.89	0.97	0.96	0.95	0.2538	0.29798	0.27005	0.2736	12440	12300	9332	16141
AVERAGE	0.11	0.13	0.06	0.05	0.89	0.87	0.94	0.95	0.26	0.24	0.28	0.28	10655	5366	13312	12168

4.7. Crossplot analysis

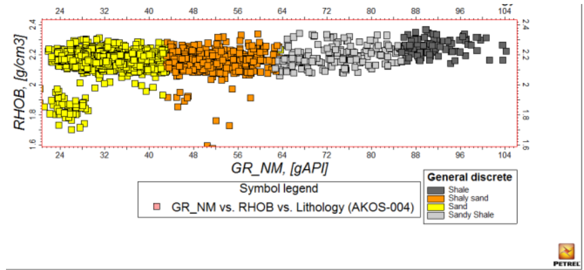
The cross plots in fig.8(a-i) show that clay proportions were increasing from Akos 001 to 002 and 004 having the highest clay volume. From the relative positions of the wells, the clay volume is increasing westwards. This may indicate that the sediments are transported from the east and deposited westwards becoming finer with depth.



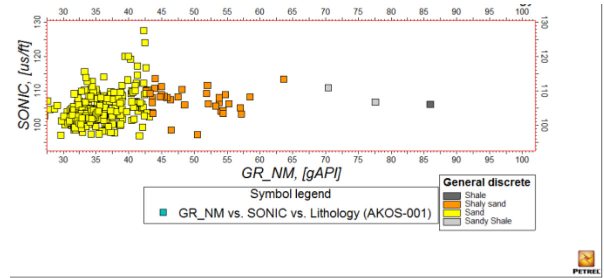
a. Gamma ray - density cross plot for Akos 001



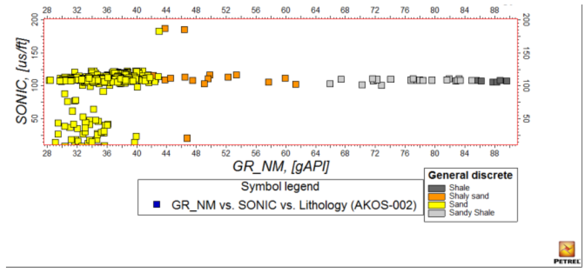
b. Gamma ray - density cross plot for Akos 002



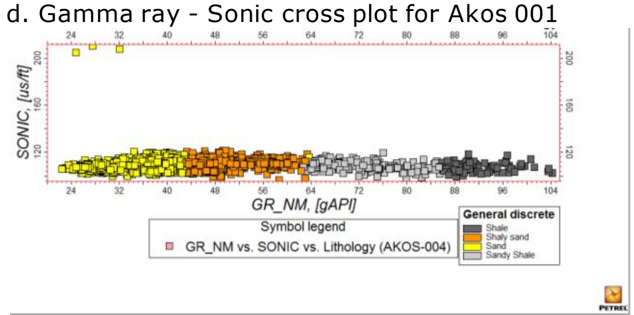
c. Gamma ray - density cross plot for Akos 003



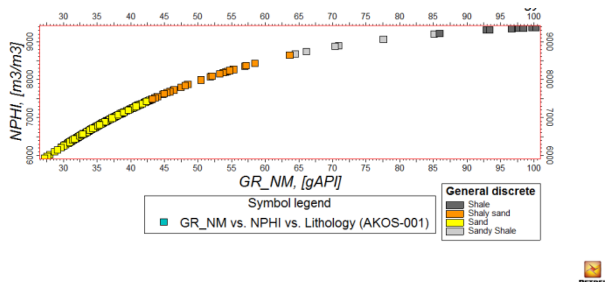
d. Gamma ray - Sonic cross plot for Akos 001



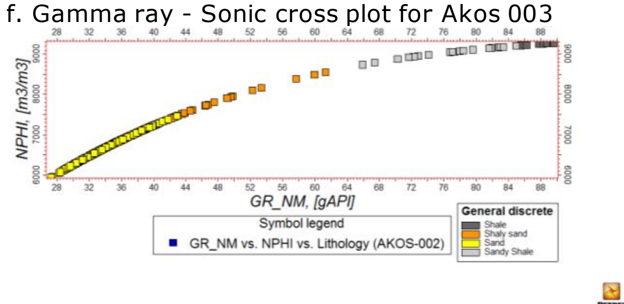
e. Gamma ray - Sonic cross plot for Akos 002



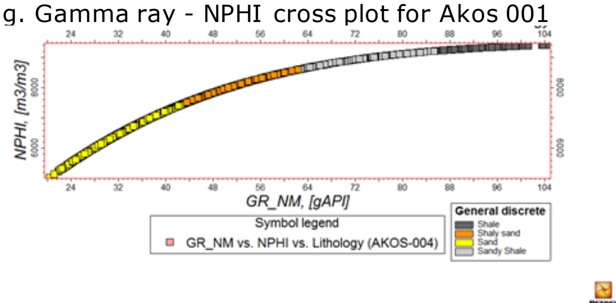
f. Gamma ray - Sonic cross plot for Akos 003



g. Gamma ray - NPHI cross plot for Akos 001



h. Gamma ray - NPHI cross plot for Akos 002



i. Gamma ray - NPHI cross plot for Akos 003

Fig. 8 (a-i) Cross plot technique for lithologic identification for Odokoko field for Akos 001, 002and 004 wells

5. Conclusion

All the reservoirs encountered have excellent porosity and permeability values. Their gross thicknesses range between 110 and 316 feet, net to gross values greater than 0.80, and high hydrocarbon saturation greater than 0.89 on average, implies excellent hydrocarbon pore volume for hydrocarbon accumulation in commercial quantity. The permeability values were of excellent value. The BVH is found to have a strong quadratic relationship with acoustic impedance and is a good hydrocarbon indicator. Based on this study, the "Odokoko" field contains high quality reservoirs.

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