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PETROLEUM AND PETROPHYSICAL CHARACTERISTICS OF APO WELL, X FIELD, NIGER DELTA. NIGERIA

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ABSTRACT
The quality of the hydrocarbon reservoirs the study well in terms of porosity, permeability and transmissivity decreases down the depth, therefore, it can be concluded that hydrocarbon potential and productivity of the reservoirs sand can be classified in decreasing order of arrangement as A, B and C. Hence, the reservoir A in well is the best in terms of hydrocarbon production and has highest transmissivity. The reservoirs bulk volume water (BVW) values calculated and are close to constant resulted that the reservoirs are homogenous and at irreducible water saturation. Therefore, the reservoirs of the study area can be said to be prolific in terms of hydrocarbon production and they will produce water free hydrocarbon due to the fact that all the reservoirs are homogenous and at irreducible water saturation

INTRODUCTION
Reservoir characterization is the continuing process of integrating and interpreting geological, geophysical, petrophysical, fluid and performance data to form a unified, consistent description of a reservoir and produce a geological model that can be used to predict the distribution of reservoir properties throughout the field. It can also be defined as the quantification, integration, reduction and analysis of geological, petrophysical, seismic and engineering data.

This research work is on the application of wire line logs to identify and quantify hydrocarbon reserves and evaluate rock properties in part of the offshore Niger Delta. The petrophysical analyses of the wireline logs provide reservoir characteristics (porosity, permeability and fluids saturation). Quantitative determination of fluid transmissivity (layer thickness times permeability) will be an added advantage to further characterize reservoir rocks. Integrating these two parameters would guide and provide a good knowledge of the potential of porous media and enhance exploration and development of the reservoir rocks.

LOCATION OF STUDY
The field under study is pseudo-named "X'' field. The field is located in the offshore Niger Delta, but the co-ordinates of the location of this field were concealed due to proprietary reasons.

STRATIGRAPHY OF THE NIGER DELTA BASIN
The established Tertiary sequence in the Niger Delta consists, in ascending order, of the Akata, Agbada, and Benin Formation. The strata composed an estimated 8,535 m (28000 ft) of section at the approximate depocenter in the central part of the delta.

AKATA FORMATION
The Akata Formation which is the basal unit of the Cenozoic delta complex is composed mainly of marine shales deposited as the high energy delta advanced into deep water (Schlumberger, 1985). It is characterized by a uniform shale development and the shale in general is dark grey, while in some places it is silty or sandy and contains especially in the upper part of the formation, some thin sandstone lenses (Short & Stauble, 1967).

The Akata Formation probably underlies the whole Niger Delta south of the Imo Shale outcrop of the Paleocene age from Eocene to Recent (Short & Stauble, 1967). The Akata Formation has been penetrated in most of the onshore fields between 12,000 and 18,000 ft (~3,700 – 5,500 m) and in many of the offshore fields between 5,000 and 10,000 ft (~1,530 – 3050 m); however, the maximum thickness of the Akata Formation is believed to average 20,000 ft (~7,000 m).

For all practical prospecting purposes, the top of the Akata Formation is the economic basement for oil; however, there may be potential for gas dissolved in oil field waters under high pressure in the deeper formation (Schlumberger, 1985).

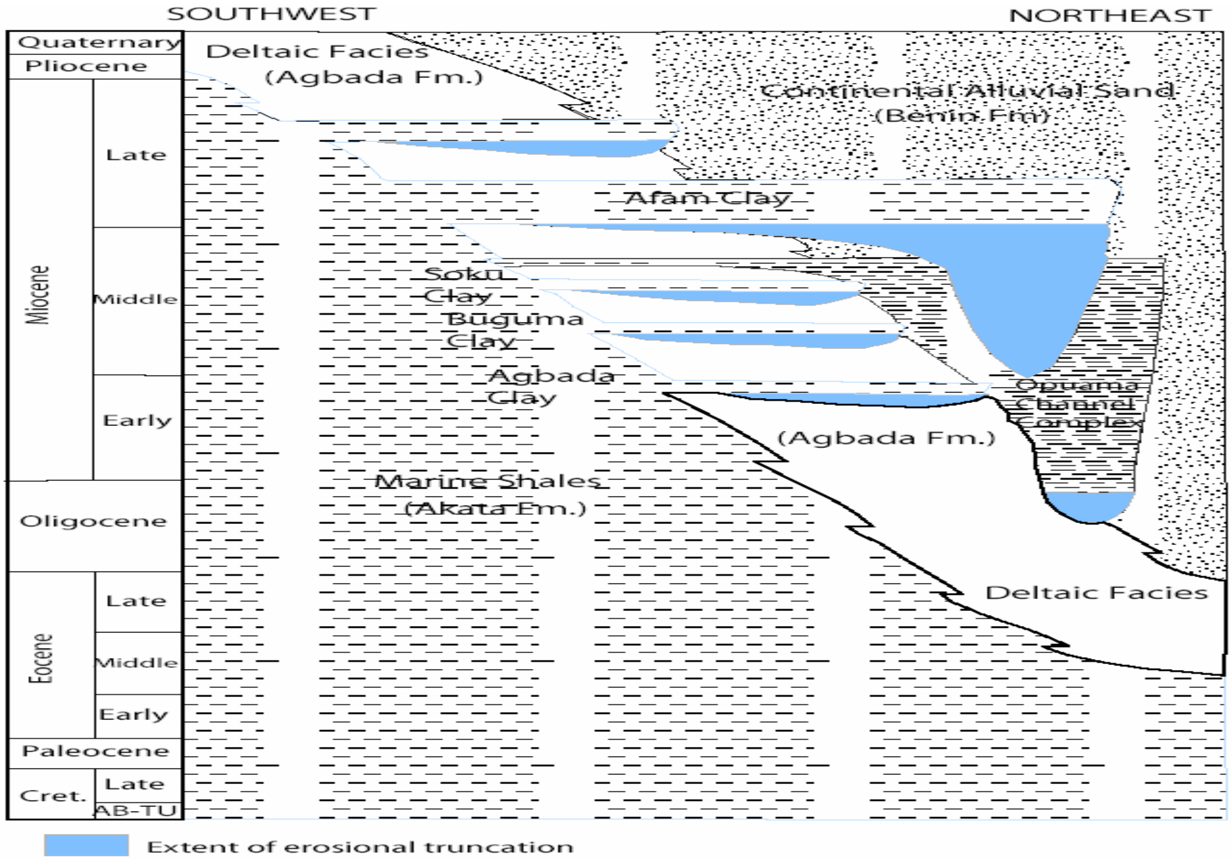


Figure 1: Stratigraphic column showing the three formations of the Niger Delta (Doust and Omatsola, 1990).

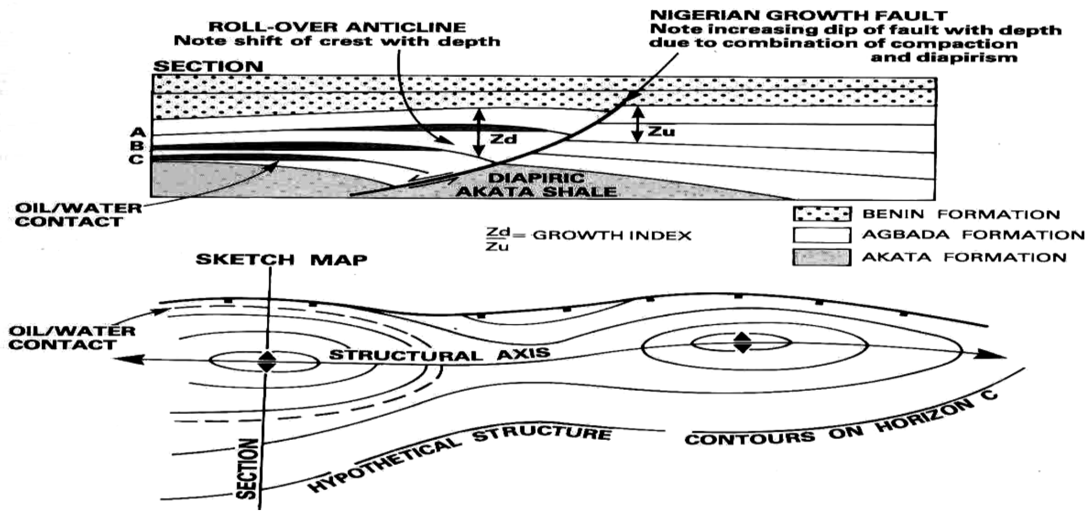
STRUCTURES OF THE NIGER DELTA BASIN

The delta sequence is deformed by syn-sedimentary faulting and folding. Evamy et al. (1978) described the main structural features of the Niger Delta as growth faults and roll over anticlines associated with these faults on their downthrown (i.e. seaward) side.

GROWTH FAULTS

Growth faults are faults that offset an active surface of deposition. It is characterized by thicker deposits in the downthrown block relative to the up thrown block. The growth fault planes exhibit a marked flattening with depth as a result of compaction. Thus a curved, concave-upward fault plane is developed, which continues at a low angle.

The ratio of the thickness of a given stratigraphic unit in the downthrown block to that of the corresponding unit in the up-thrown block is termed the 'growth index' which in Nigeria can be as high as



2.5m.

Figure 2: Schematic section showing a map of simple growth Fault and rollover anticline (After Schlumberger, 1985).

AGBADA FORMATION

The Agbada Formation is a paralic succession of alternating sandstones and shales, whose sandstone reservoirs account for the oil and gas production in the Niger Delta (Nwachukwu and Odjegba, 2001).

The formation consists of an alternating sequence of sandstones and shales of delta-front, distributary-channel, and deltaic-plain origin. The sandstones are medium to fine-grained, fairly clean and locally calcareous, glauconitic, and shelly. The shales are medium to dark grey, fairly consolidated, and silty with local glauconite.

The sand beds constitute the main hydrocarbon reservoirs while the shale beds present form the cap rock. These shale beds constitute important seals to traps and the shales interbedded with the sandstones at the lower portions of the Agbada Formation are the most effective delta source rocks (Schlumberger, 1985). Petroleum occurs throughout the Agbada Formation of the Niger Delta.

Maximum thickness of the formation is 3,940m (12,000ft) at the central part of the delta, and thins northward and toward the northwestern and eastern flanks of the delta. The formation is poorly developed or absent north of the Benin city-Onitsha-Calabar axis. The age of the Agbada Formation varies from Eocene to Pliocene/Pleistocene.

BENIN FORMATION

The Benin Formation consists of predominantly massive highly porous, freshwater-bearing sandstones, with local thin shale interbeds, which are considered to be of braided-stream origin. Mineralogically, the sandstones consist dominantly of quartz and potash feldspar and minor amounts of plagioclase. The sandstones constitute 70 to 100% of the formation. Where present, the shale interbeds usually contain some plant remains and dispersed lignite.

Benin Formation attains a maximum thickness of 1,970m (6,000ft) in the Warri-Degema area, which coincides with the maximum thickness (i.e. depocenter) of the Agbada Formation. The first marine foraminifera within shales define the base of the Benin Formation, as the formation is non-marine in origin (Short and Stauble, 1967). Composition, structure, and grain size of the sequence indicate deposition of the formation in a continental, probably upper deltaic environment. The age of the formation varies from Oligocene (or earlier) to Recent.

METHODOLGY

Different methods of study as applied to wireline well logs interpretation within the available materials have been adopted for the evaluation of reservoir sands in this research work. The approach involves both quantitative and qualitative interpretation. Qualitative interpretation entails visual analysis of the log shapes for the identification of reservoir sands and hydrocarbon bearing sands. Quantitative interpretation involves estimation of reservoir parameters and interrelationship between them.

The instrumentation necessary for borehole logging is housed in a cylindrical metal tube known as *sonde*. Sondes are suspended in the borehole from an armoured multi-core cable. During logging, the sonde is gradually pulled up from the borehole bottom at a certain speed. The data are recorded on magnetic tape as analogue or digital signal was be display on photographic paper. The different logs used for the research work are Gamma ray log, Resistivity logs, Compensated Bulk Density log and Porosity log. The wireline logs were used in the interpretation and calculation of the various functions and parameters of the reservoir sands

RESULTS AND INTERPRETATION

Petrophysical Quantitative Analysis

Total of three hydrocarbon reservoirs were identified and evaluated and the each petrophysical properties were calculated as follows;

CALCULATION OF FORMATION FACTOR

Using Humble's formula for unconsolidated formations typical of Niger delta sandstones,

$$F = \frac{0.62}{\phi^{2.15}}$$

Reservoir A

Where $\phi = 22$

$$F = \frac{0.62}{22^{2.15}} = \frac{0.62}{769.5} = 0.0008$$

Reservoir B

Where $\phi = 18$

$$F = \frac{0.62}{18^{2.15}}$$

$$F = \frac{0.62}{18^{2.15}} = \frac{0.62}{499.8} = 0.00124$$

Reservoir C

Where $\phi = 17$

$$F = \frac{0.62}{\phi^{2.15}} = \frac{0.62}{17^{2.15}} = \frac{0.62}{442} = 0.0014$$

Calculation of Irreducible Water Saturation (Swirr)

$$Swirr = \left[\frac{F}{2000}\right]^{1/2}$$

Where F= formation factor

Reservoir A

Where F = 0.00081

$$\text{Swirr} = \left[\frac{0.00081}{2000}\right]^{1/2} = \left(4.05\times10^{-7}\right)^{1/2}$$

Swirr = 0.00064

Reservoir B

Where F = 0.00124

$$\text{Swirr} = \left[\frac{F}{2000}\right]^{1/2}$$

$$\text{Swirr} = \left[\frac{0.00124}{2000}\right]^{1/2} = \left(6.2\times10^{-7}\right)^{1/2} \quad = 0.000787$$

Reservoir C

Where F= 0.0014

$$\text{Swirr} = \left[\frac{F}{2000}\right]^{1/2} \quad = \left[\frac{0.0014}{2000}\right]^{1/2} = \left(7\times10^{-7}\right)^{1/2}$$

Swirr = 0.000837

Calculation of Permeability (k)

Reservoir A

$$K = \frac{0.136\times\phi^{4.4}}{(Swirr)^2}$$

Where ϕ = 0.22 and Swirr = 0.00064

$$K = \frac{0.136\times0.22^{4.4}}{(0.00064)^2}$$

$$K = \frac{0.136\times0.00128}{4.096\times10^{-7}}$$

$$K = \frac{1.739\times10^{-4}}{4.096\times10^{-7}} \quad = 424.6\text{md}$$

K= 424.6md

Reservoir B

Where ϕ = 0.18 and Swirr = 0.00064

By substitution,

$$K = \frac{0.136\times0.18^{4.4}}{(0.00064)^2}$$

$$K = \frac{0.136\times0.000529}{4.096\times10^{-7}}$$

$$K = \frac{7.19\times10^{-5}}{4.096\times10^{-7}} \quad = 175.5\text{ md}$$

Reservoir C

Where $\phi = 0.17$ and Swirr = 0.000837

By substitution,

$$K = \frac{0.136 \times 0.17^{4.4}}{(0.000837)^2}$$

$$K = \frac{0.136 \times 0.000411}{7 \times 10^{-7}}$$

$$K = \frac{5.59 \times 10^{-5}}{7 \times 10^{-7}} = 79.9\text{md}$$

Permeability (K) for reservoirs A, B, C, is 424.6md, 175.5md and 79.9md respectively.

Calculation of Transmissivity

Transmissivity (T) = Permeability (K) x Reservoir's thickness

Reservoir A

Where Permeability (K) = 424.6md and Reservoir's thickness = 120ft

Transmissivity = 424.6 x 120 = 50952mdft

Reservoir B

Where Permeability = 175.5md and Reservoir's thickness = 90ft

Transmissivity = 175.5 x 90 = 15795 mdft

Reservoir C

Where permeability (K) = 79.9md and reservoir's thickness = 86ft

Transmissivity (T) = 79.9 x 86 = 6871.4mdft

Transmissivity at reservoirs A, B, C, is 50952mdft, 15795mdft and 6871.4mdft respectively.

Calculation of Water Saturation (S_W)

Water saturation (S_w) = $\left(\frac{Ro}{Rt}\right)^{1/n}$

Reservoir A

Where n = 2

Ro = resistivity of water bearing rock = 2.939 ohm-metres

Rt = True resistivity of the rock = 85.550 ohm-metres

$$S_w = \left(\frac{2.939}{85.55}\right)^{1/2} = (0.0344)^{1/2}$$

$S_w = 0.19$

Reservoir B

Where Ro = 3.042 ohm-metres and Rt = 90.307 ohm-metres

$$S_w = \left(\frac{3.042}{90.307}\right)^{1/2} = (0.034)^{1/2} = 0.18$$

Reservoir C

Where Ro = 3.342 ohm-metres and Rt = 83.508 ohm-metres

$$S_w = \left(\frac{3.342}{83.508}\right)^{1/2} = (0.04)^{1/2} = 0.20$$

Calculation of Hydrocarbon Saturation (S_H)

$S_H + S_w = 1, \quad \therefore S_H = 1 - S_w$

Reservoir A

Where $S_w = 0.19, \quad \therefore S_H = 1 - 0.19 = 0.81$

Reservoir B

Where $S_w = 0.18, \quad \therefore S_H = 1\text{-}0.18 = 0.82$

Reservoir C

Where $S_w = 0.20, \quad \therefore S_H = 1\text{-}0.20 = 0.80$

Calculation of Bulk Volume Water (BVW)

Reservoir A

Where $\phi = 0.22$ and $S_w = 0.19$

Bulk volume water = porosity X saturation water = 0.22 x 0.19 = 0.042

Reservoir B

Where $\phi = 0.18$ and $S_w = 0.18$

Bulk volume water = 0.18 x 0.18 = 0.032

Reservoir C

Where $\phi = 0.17$ and $S_w = 0.20, \quad \therefore$ Bulk volume water = 0.17 x 0.20 = 0.03

The reservoir B is found at the interval of 7673 – 7761ft (2339-2366m) and has a gross (G) and net (N) thickness of sand, 88ft (26.8m) and 70.5ft (21.5m) respectively, with N/G ratio of 0.80; water saturation (S_w) of 14% and hydrocarbon saturation (S_h) of 86%, porosity (ø) and permeability (K) of 25% and 997.8md respectively. Its transmissivity is 87806mdft. (Table 1).

Therefore, reservoir B has very good porosity and very good permeability.The formation bulk volume water values calculated are nearly constant (Table 1) and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore can produce water – free hydrocarbon. The transmissivity in reservoir A is higher than of B.

TABLE 1: PETROPHYSICAL QUANTITATIVE ANALYSIS OF WELL

Depth Top	Depth Bottom	Thickness (ft)	Gross Thickness of Sands(ft)	N/G Ratio	ϕ (%)	Swirr	S_W (%)	S_H (%)	BVW	K (MD)	T(mdft)
5579	5699	120	120	0.912	22	0.0006	19	81	0.042	424.6	50952
5797	5887	90	90	0.910	18	0.0007	18	82	0.032	175.5	15795
6379	6465	86	86	0.895	17	0.0008	20	80	0.034	79.9	6871.4

CHARACTERISTICS OF RESERVIORS OF APO WELL

There are three hydrocarbon reservoirs (A, B and C) observed in the well. Reservoir A occurs at the interval of 5579ft – 5699ft (1700-1737m) and has a gross (G) and net (N) thickness of sand, 120ft (36.5m) and 109.5ft (33.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 19% and hydrocarbon saturation (S_h) of 81%, porosity (ø) and permeability (K) of 22% and 424.6md respectively (Table 1). Its transmissivity is 50952mdft. Therefore, reservoir A has both very good porosity and permeability.

Reservoir B occurs at the interval of 5797 – 5887ft (1767-1794m) and has a gross (G) and net (N) thickness of sand, 90ft (27.4m) and 81.5ft (24.8m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%, porosity (ø) and permeability (K) of 18% and 175.5md respectively. Its transmissivity is 15795mdft. Therefore, the reservoir has good porosity and very good permeability.
In reservoir C, the hydrocarbon occurs at interval of 6379 – 6465ft (1944-1971m) and has a gross (G) and net (N) thickness of sand, 86ft (26.2m) and 77ft (23.4m) respectively; with N/G ratio of 0.9; water saturation (S_w) of 20% and hydrocarbon saturation (S_h) of 80%, porosity (ø), permeability (K) and transmissivity are 17%, 79.9md and 6871.4mdft respectively. Therefore, the reservoir C has both good porosity and permeability but its transmissivity is the lowest.

The formation bulk volume water values calculated are nearly constant and this shows that the reservoir is homogeneous and is at irreducible water saturation (S_{wirr}) and therefore, can produce water-free hydrocarbon. The transmissivity in reservoir A is highest among the reservoirs in well.

TABLE 2: RESERVOIR SAND/SHALE PERCENTAGE CALCULATION

APO WELL		
RESERVOIRS	**% SAND**	**% SHALE**
A	50	50
B	80	20
C	85	15

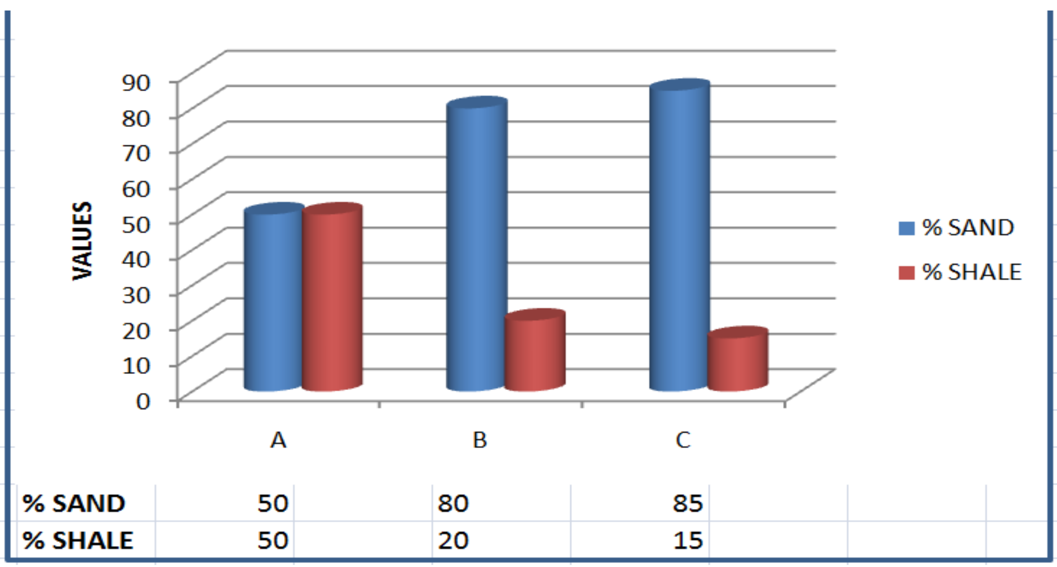


Fig. 3: Graph of reservoir sand / shale percentage for Apo well .

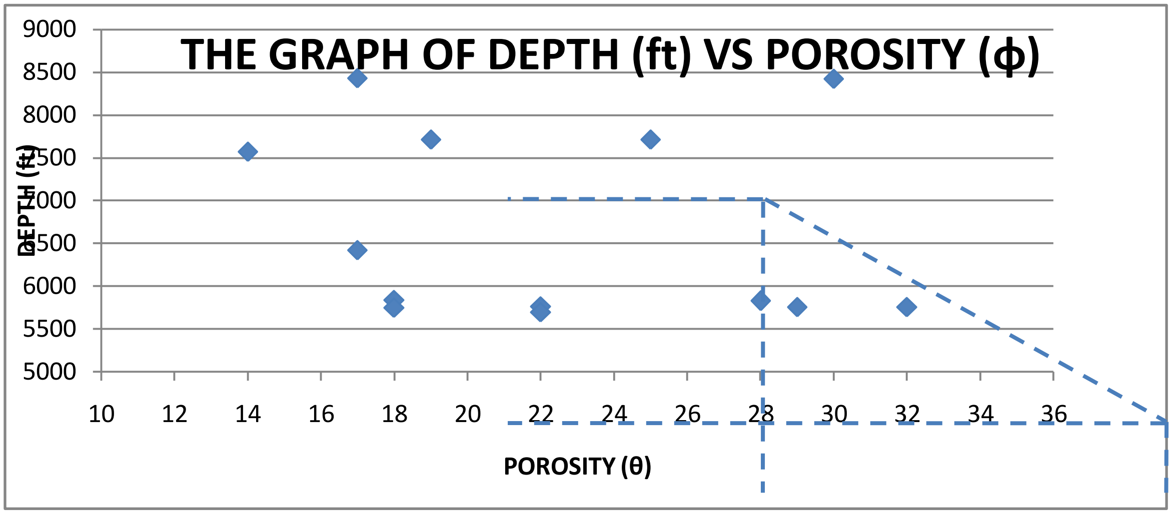


Fig. 4: The graphs showing relationship between depth and porosity.

TABLE 3: SHOWING

RELATIONSHIP BETWEEN POROSITY AND PERMEABILITY

Ø(%)	$Ø^{4.4}$	**B = (0.136x$Ø^{4.4}$)**	**K (md)**
0.32	6.65×10^{-3}	0.000904	5024
0.29	4.31×10^{-3}	0.000586	2895
0.28	3.69×10^{-3}	0.000502	2092
0.25	2.24×10^{-3}	0.000305	997.8
0.22	1.28×10^{-3}	0.000174	424.6
0.19	6.71×10^{-4}	0.0000912	166.5
0.18	5.29×10^{-4}	0.0000719	116.2
0.17	4.11×10^{-4}	0.0000559	79.9
0.14	1.75×10^{-4}	0.0000238	22.4

DISCUSSION AND CONCLUSION

The reservoirs for the discovered hydrocarbons in the study area are sandstones within the Agbada Formation. Petrophysical evaluation was carried out on the geophysical wireline logs. A total of three hydrocarbon reservoirs were identified and evaluated.

The petrophysical parameters of reservoir A range from 32-22%, 5024-116.2md, 20-14% and 86 – 80% for porosity (ø), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. From the Dresser standard, the porosity (ø) ranges from excellent to very good, while the permeability (K) is excellent. Its transmissivity ranges from 50952mdft–648148 mdft.

The petrophysical parameters of the reservoir B range from 30-18%, 1997.8 -166.5md, 30-14% and 86 – 70% for porosity (ø), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h), respectively. Its transmissivity ranges from 14935 – 87806mdft. From the Dresser standard, the porosity (ø) ranges from very good to good, while its permeability (K) ranges from excellent to good.

The petrophysical parameters of the reservoir C ranges from 14-17%, 79.9 – 22.4md, 20-19%, 81-80% for porosity (ø), permeability (K), water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Its transmissivity ranges 8449 to 1993.6mdft. From the Dresser standard, the porosity (ø) ranges from good to fair while its permeability (K) ranges from good to moderate.

The reservoirs bulk volume water (BVW) values calculated are close to constant, this indicates that the reservoir are homogenous and at irreducible water saturation. Therefore, reservoirs can produce water – free hydrocarbon. When a reservoir is at irreducible water saturation, water saturation (S_w) will not move because it is held on grains by capillary pressure. The petrophysical parameters show a gradual decrease from the top to bottom of the wells, reflecting increase in compaction with depth. The porosity, permeability and transmissivity also followed the same trend.

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