International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Petro physics And Petroleum Evaluation of Wells Nat-05 and Nat-06, Agbada Formation, Niger Delta, Nigeria

ADIELA U.P, [1]. & & AYODELE MOSES OYEWOLE [2]

[1] Department of Petroleum Engineering, Nigerian Agip Oil Company, Port Harcourt

[2] Department of Geology, University of Port Harcourt, Port Harcourt, Nigeria

ABSTRACT

This study is on the evaluation of petrophysical parameters of the reservoir sand bodies and their transmissivity using well logs of six well, Niger Delta. These parameters have been used to determine the reservoirs potential and quality prevalent in the study area. The petrophysical parameters of the reservoir A ranges from 32-22%, 5024-116.2md, 20-14% and 86-80% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h). Its transmissivity ranges from 50,952mdft-648,148mdft. The petrophysical parameters of the reservoir B ranges 30-18%, 1997.8 – 166.5md, 30-14% and 86-70% for porosity (□), permeability, water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Its transmissivity ranges from 14,935-87,806mdft. The petrophysical parameters of the reservoir C ranges from 14-17%, 79.9-22.4md, 20-19% and 81-80% for porosity, permeability water saturation (S_w) and hydrocarbon saturation (S_h) respectively. Based on Schlumberger standard, the values indicate that reservoir A has both excellent porosity and permeability with highest transmissivity. Both porosity and permeability in reservoir B are very good while it transmissivity is lower than reservoir A. Reservoir C has fair porosity and moderate permeability, but has least transmissivity. The reservoirs bulk volume water (BVW) values calculated are close to constant resulted that the reservoirs are homogenous and at irreducible water saturation.

INTRODUCTION

The potential and performance of reservoirs depend on both engineering and petrophysical parameters. The engineering parameters are rock compressibility, reservoir storativity, transmissivity, etc, while the fundamental petrophysical parameters are porosity, permeability, and fluid saturation. The relationships among these properties are used to identify and characterize reservoirs.

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 .

Reserve estimation therefore, is based on the field wide distribution of these reservoir properties. Due to the intense petroleum exploration and exploitation activities in the Niger Delta region during the last two decades, vast amount of data have been accumulated from which it had been possible to establish the historical reconstruction and evolution of the Niger Delta basin

LOCATION OF STUDY

The field under study is located in the offshore Niger Delta but the co-ordinates of the location of this field were concealed due to proprietary reasons.

OBJECTIVES OF STUDY

This research is aimed at evaluating the reservoir potential of the field to achieve the following objectives:

- ✓ To determine the petrophysical characteristics of sand bodies.
- ✓ To estimate and compare porosity, permeability and hydrocarbon distribution within the field.

SEDIMENTOLOGY ANDSTRATIGRAPHY OF NIGER DELTA

The lithostratigraphic build-up of the Niger Delta basin was accompanied by synsedimentary tectonics normal to the progradation, resulting in a series of parallel, fault-bounded depobelts, which become progressively younger from north to south as the delta progrades southward (Stacher, 1995). These depobelts are: Northern depobelt, greater

Ughelli, central swamp, coastal swamp and the offshore depobelt (Figure 2.6).

According to Short and Stauble (1967), Frankl and Cordry (1967), and Avbovbo (1978), the lithostratigraphy of Niger Delta is represented by three (3) major diachronous formations stretching in age from Paleocene to recent and comprising from base to top - the Akata, Agbada and Benin Formations; the formations were placedbeneath marine, transitional (paralic) and continental environments respectively(figure 2.7) .

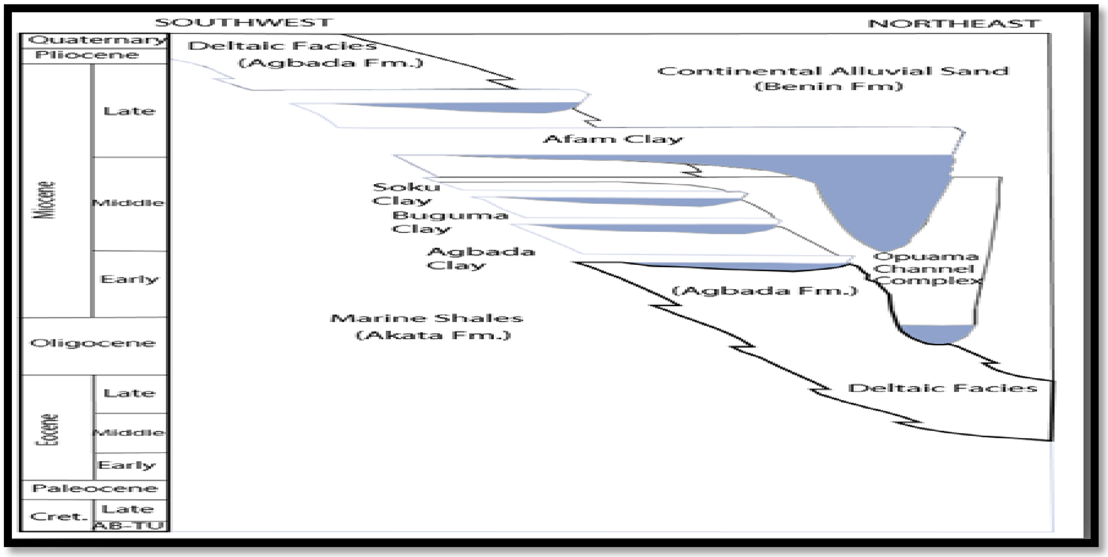

Figure 1 : The Niger Delta lithostratigraphic section showing the three lithologic units (Adapted from Doust and Omatsola, 1990).

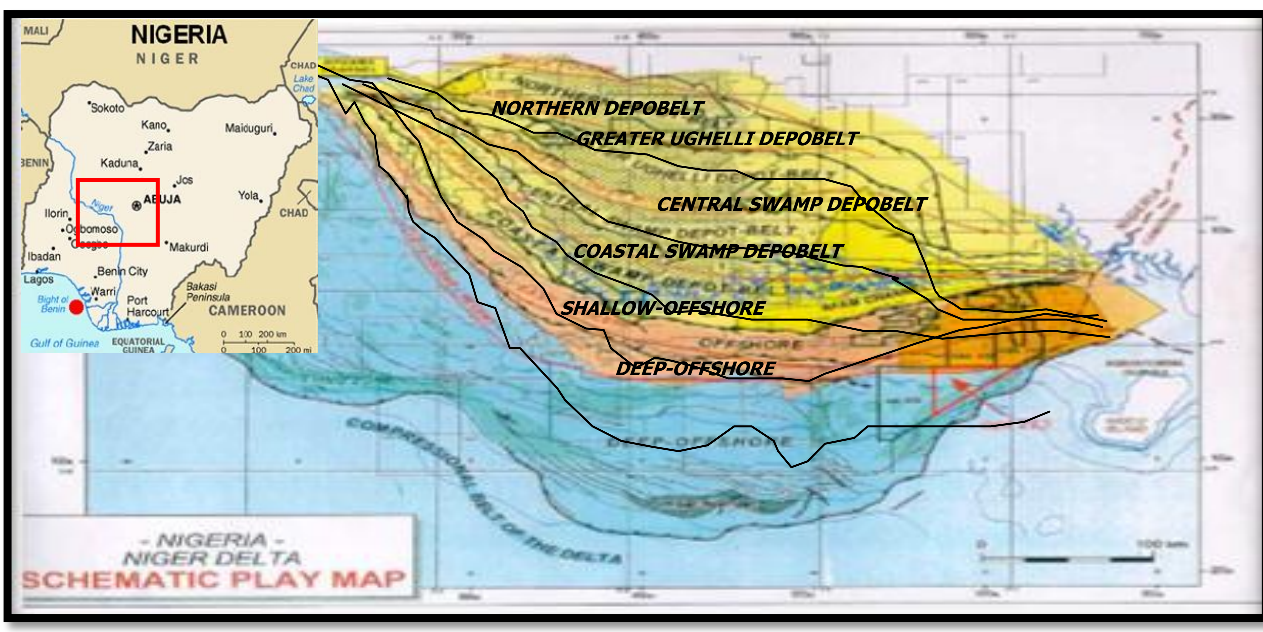

Figure 2.7: Showing Niger Delta Depobelts and Spatial Distribution of Studied Wells (Modified from Reijers, 1997)

Figure 2: Showing Niger Delta Depobelts and Spatial Distribution of Studied Wells (Modified from Reijers, 1997)

AKATA FORMATION

According to Short and Stauble, (1967)Akata Formation, the lowermost lithological division of the Niger Delta consists of basically marine shales with clay and silt intervals in places. This Lithostratigraphic unit is taken as the prodelta megafacies of the Niger Delta complex, formed during lowstand when terrestrial organic matters and clays were conveyed to deep water areas chiefly epitomized by low energy conditions and oxygen deficiency (Stacher, 1995).The Akata Shale is under-compacted and over-pressured (Merki, 1972).

According to Beka and Oti (1995), turbidity currents likely deposited the turbidity sands within the upper Akata Formation of the Niger Delta. The Akata Formation ranges in age from Paleocene – Recent and grades into the Agbada Formation.

AGBADA FORMATION

The Agbada Formation overlies the Akata Formation and underlies the Benin Formation. It is the second of the three strongly diachronous Niger Delta multifaceted formations(Short and Stauble, 1967; Frankl and Cordry, 1967). The interbeded shales supposedly taken as source rocks for son_ _ _ the petroleum pools and fields in these areas (Evamy 1978).The Agbada Formation spans over 3500 m (11,500 ft.) in thickness. (Corredor et al, 2005).The thickness of Agbada Formation ranges from 1,000 ft (Merki, 1972), 10,000 ft (Short and Stauble, 1967) and 9.600 ft – 14,000 ft thick in the middle section of the delta, it thins out in the delta margin direction (Weber and Daukoru 1975). The age of the Agbada Formation is in between Eocene to Recent.

BENIN FORMATION

The BeninFormation lies uppermost in the Niger Delta lithostratigraphy and it is made up of very poorly consolidated sandstones, with little shale lenses, coals and conglomerates from continental and delta plain. According to Allen (1965), the thickness of the Benin Formation lies within 2000m. Oemkens (1974) established the factthat the late Quartenary post-glacial transgressive deposits take place locally inside the upper 0-30m of the Benin

Formation in lower delta plainsof the study area.

According to Omatsola and Cordry (1976), acomparatively thick clay unit casuallydenoted as the 'Afam Clay Member' and assumedas a submarine canyon fill; occur within the basal unit of the Benin Formation in places. Thus, the Benin Formation is fundamentally fluvial in source and comprises unconsolidated, immense, and porous freshwater-bearing sands with restricted shale interbeds. The age of the Benin Formation ranges from Miocene to Recent.

LITERATURE REVIEW

The Niger Delta basin has been intensively studied, mostly by the oil industry and academia in recent time because of its economic value as a petroliferous province. Most of the workers have investigated and summarized the basic geology, evolution and structural setting, sequence stratigraphy, biostratigraphy, lithology and depositional environment of the basin. Other studies include production characteristics and field development strategies. Some of the workers and their contributions about the Niger Delta are discussed below.

Reyment (1965) and Hosper (1965) described the basement configuration of the Niger Delta on the basic of geophysical data. They suggested that the bulk of the younger Tertiary portion of the delta sequence overlies Cretaceous oceanic crust.

Allen (1965) observed that the modern Niger Delta is a combination of a wave and tide-dominated delta, whose geometry is actuate – estuarine – irregular.

Studies carried out by Stoneley (1966), Short and Stauble (1967), Wright (1968 & 1970) and Merki (1972) showed that differential loading of under compacted shales at the base of the Tertiary Delta initiated the formation of growth faults in Niger Delta sediments.

Murat (1970), Burke and Whiteman (1972) found that the Niger Delta is located at the intersection of the triple junction from which the rifting and separation of the African plate from North America plate was initiated in the middle Cretaceous. Later studies by Nwachukwu (1972), Uzuakpunawa (1974), and Olade (1975 & 1978) further supported this view.

Weber and Daukoru (1975) proposed that faults serve as pathways for hydrocarbon migration from the source rocks. The views of Doust and Omatsola (1990) supported the building of the Niger Delta on a collapsed continental margin as observed by earlier workers.

Davies and Ethridge (1975) used sandstone composition while Friedman (1961)

e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

used textural analysis to arrive at their environmental interpretations. Other workers back up the SP/GR log interpretations with data on mineralogy, micro- fauna, sedimentary structures from cores and ditch cutting. Selly (1978), Adedokun (1981) used electric logs, textural analysis and petrographic data to study depositional environment.

Omoboriowo and Soronnandi-Ononiwu,(2011) , Omoboriowo, A.O, et al (2012).Omoboriowo, and Edidem, (2011) , Amajor and Agbaire (1984) used electric logs and side wall core description data to interpret depositional environment. Keltech et al. (1990) used gamma ray, compensated neutron and density logging suite and isopach maps for environmental structures. Scotchman (1990) used gamma ray log, induction log and seismic section to interpret depositional environment.

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.

PETROPHYSICAL QUANTITATIVE ANALYSIS OF WELL NAT-05

CALCULATION OF POROSITY (Ø)

Reservoir A

USING FORMULA:

$$\phi_{Den} = \left(\frac{p_{ma-}p_{blog}}{p_{ma-}p_{f}}\right) - V_{sh} \times \left(\frac{p_{ma} - p_{sh}}{p_{ma-}p_{f}}\right)$$

Where ϕ_{Den} = porosity derived from density log

ρ_{ma} = Density of matrix = 2.65g/cm^3

ρ_{blog} = Bulk density value on density log =2.11g/cm^3

ρ_f = 1.0g/cm^3

V_{sn} = volume of shale = 0.20

ρ_{sn} = 2.30g/cm^3

By Substitution,

$$\phi = \left(\frac{2.65 - 2.11}{2.65 - 1.0}\right) - 0.20 \times \left(\frac{2.65 - 2.30}{2.65 - 1.0}\right)$$

$$\phi = \left(\frac{0.54}{1.65}\right) - 0.20 \times \left(\frac{0.35}{1.65}\right)$$

$$\phi = 0.33 - 0.20 \text{ x } 0.212$$

$$\phi = 0.33 - 0.042$$

ϕ = 0.29 or 29%

Reservoir B

$$\phi_{\text{Den}} = \left(\frac{p_{ma} - p_{b\log}}{p_{ma} - p_f}\right) - V_{sh} \times \left(\frac{p_{ma} - p_{sh}}{p_{ma} - p_f}\right)$$

ϕ_{Den} = porosity derived from density log

ρ_{ma} = Density of matrix = 2.65g/cm^3

ρ_{blog} = Bulk density value on density log =2.26g/cm^3

ρ_f = 1.0g/cm^3

V_{sn} = volume of shale = 0.25

ρ_{sn} = density of shale = 2.32g/cm^3

By Substitution,

$$\phi = \left(\frac{2.65 - 2.26}{2.65 - 1}\right) - 0.25 \times \left(\frac{2.65 - 2.32}{2.65 - 1}\right)$$

$$\phi = \left(\frac{0.39}{1.65}\right) - 0.25 \times \left(\frac{0.33}{1.65}\right)$$

ϕ = 0.236 – 0.25 x 0.2

ϕ = 0.236 – 0.05

ϕ = 0.19 or 19%

CALCULATION OF FORMATION FACTOR

Using Humble's formula for unconsolidated formations, typical of Niger Delta Sandstones,

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

Where F= Formation Factor

Ø = Porosity

For Reservoir B, where $\phi = 29\%$

$$F = \frac{0.62}{29^{2.15}} = \frac{0.62}{1393.7} = 0.00044$$

For Reservoir B, where $\phi = 19\%$

$$F = \frac{0.62}{19^{2.15}} = \frac{0.62}{1561.5} = 0.0011$$

CALCULATION OF IRREDUCIBLE WATER SATURATION (Swirr)

Reservoir A

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

Where F = 0.00044

By substitution,

$$\text{Swirr} = \left(\frac{0.00044}{2000}\right)^{1/2}$$

$$\text{Swirr} = (0.00000022)^{1/2}$$

Swirr = 0.00045

International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Reservoir B

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

Where F = 0.0011

By substitution,

$$Swirr = \left(\frac{0.0011}{2000}\right)^{1/2}$$

$$= (0.00000055)^{1/2}$$

Swirr = 0.00074

Therefore, Swirr at reservoir A = 0.00045 and Swirr at reservoir B = 0.00074

CALCULATION OF PERMEABILITY (K)

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

Reservoir A

Where ϕ = 0.29 and Swirr = 0.00045

$$K = \frac{0.136 \times 0.29^{4.4}}{(0.00045)^2}$$

$$K = \frac{0.136 \times 0.00431}{2.025 \times 10^{-7}}$$

$$K = \frac{0.000586}{2.025 \times 10^{-7}} = 2895md$$

Reservoir B

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

Where ∅ = 0.19 and Swirr = 0.00074

$$K = \frac{0.136 \times 0.19^{4.4}}{(0.00074)^2}$$

$$K = \frac{0.136 \times 0.000671}{5.48 \times 10^{-7}}$$

$$K = \frac{0.0000913}{5.48 \times 10^{-7}} = 166.5md$$

CALCULATION OF TRANSMISSIVITY

Transmissivity (T) = Permeability x Reservoir's thickness

Reservoir A

Where permeability = 2895md and reservoirs' thickness = 129 feet

Transmissivity (T) = 2895 x 129 = 373 455md ft

Reservoir B

Transmissivity (T) = permeability (K) x reservoir thickness

Where Permeability = 166.5md reservoirs thickness = 90ft

Transmissivity = 166.5 x 90 = 14985mdft

CALCULATION OF WATER SATURATION (S_w)

Water saturation (S_w) = $\left(\frac{Ro}{Rt}\right)^{1/2}$

Where Ro = Resistivity of water bearing rock

Rt = True resistivity of the rock.

Reservoir A

Where Ro =3.241ohm-metres and Rt=599.438 ohm-metres

$$S_w = \left(\frac{3.241}{99.438}\right)^{1/2} = (0.0326)^{1/2} = 0.18$$

Reservoir B

Where Ro = 2.268 ohm-metres and Rt = 2.4.428 ohm-metres

$$S_w = \left(\frac{2.268}{24.428}\right)^{1/2} = (0.0928)^{1/2} = 0.30$$

CALCULATION OF HYDROCARBON SATURATION (S_H)

$S_H + S_w = 1$

$S_H = 1 - S_w$

Reservoir A

Where $S_w = 0.18$

$S_H = 1 - 0.18$

$S_H = 0.82$

Reservoir B

Where $S_w = 0.30$

$S_H = 1 - 0.30$

$S_H = 0.70$

CALCULATION OF BULK VOLUME OF WATER (BVW)

Bulk volume water (BVW) = Porosity (Ø) x saturation water (S_w)

Reservoir A

Where ϕ = 0.29 and $S_w = 0.18$

Bulk volume water (BVW) = 0.29 x 0.18 = 0.052

Reservoir B

Where ϕ = 0.19 and $S_w = 0.30$

Bulk volume water (BVW) = 0.19 x 0.30 = 0.057

RESULTS AND INTERPRETATION

Table 1 PETROPHYSICAL QUANTITATIVE ANALYSIS of WELL NAT-05

Reservoirs	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ϕ (%)	Swirr	SW (%)	SH (%)	BVW	K (MD)	T(mdft)
A	129	129	103.5	0.802	29	0.00045	18	82	0.052	2895	373,455
B	90	90	80	0.889	19	0.00074	30	70	0.057	166.5	14,985

Table 2 PETROPHYSICAL QUANTITATIVE ANALYSIS OF WELL NAT-06

Reservoirs	Thickness (ft)	Gross Thickness of Sands(ft)	Net Thickness of Sands(ft)	N/G Ratio	ϕ (%)	Swirr	S_W (%)	S_H (%)	BVW	K (MD)	T(mdft)
A	120	120	109.5	0.912	22	0.0006	19	81	0.042	424.6	50952
B	90	90	81.5	0.910	18	0.0007	18	82	0.032	175.5	15795
C	86	86	77	0.895	17	0.0008	20	80	0.034	79.9	6871.4

CHARACTERISTICS OF RESERVIORS OF WELL NAT-05

There are two hydrocarbon reservoirs found in the wells . These are reservoirs A and B. Reservoir A occurs at the interval of 5693 – 5822ft (1735-1775m) and has a gross (G) and net (N) thickness of sand, 129ft (39.3m) and 103.5ft (31.5m) respectively with N/G ratio of 0.8; water saturation (S_w) of 18% and hydrocarbon saturation (S_h) of 82%; porosity (ø) and permeability (K) of 29% and 2895md respectively while its transmissivity is 373455mdft (Table 4). Therefore, the reservoir has very good porosity and excellent permeability.

Reservoir B occurs at the interval of 7672 – 7762ft (2338-2366m) and has a gross (G) and net (N) thickness of sand, 90ft (27.4m) and 80ft (24.4m) respectively, with N/G ratio of 0.9; water saturation (S_w) of 30% and hydrocarbon saturation (S_h) 70%, porosity (ø) and permeability (K) of 19% and 166.5md respectively. Its transmissivity is 14985mdft.

Therefore, the reservoir has both good porosity and permeability.

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 far much greater than the reservoir B, this means that the hydrocarbon in reservoir A will flow easier to the well bore than B.

CHARACTERISTICS OF RESERVIORS OF WELL NAT-06

There are three hydrocarbon reservoirs (A, B and C) observed in 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 5). 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 NAT-06.

TABLE 3: RESERVOIR SAND/SHALE PERCENTAGE CALCULATIONS FOR WELLS.

International Journal of Research
Available at https://edupediapublications.org/journals
e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

WELL NAT-05		
RESERVOIRS	**% SAND**	**% SHALE**
A	80	20
B	75	25
WELL NAT- 06		
RESERVOIRS	**% SAND**	**% SHALE**
A	50	50
B	80	20
C	85	15

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 reservoir sand bodies have three hydrocarbon reservoirs A, B and C)of which only reservoir A cuts across the six wells.

In reservoir A, both porosity and permeability are excellent while its transmissivity is the highest. The hydrocarbon saturation ranges 86 – 80%.

In reservoir B, both porosity and permeability are very good. The hydrocarbon saturation ranges 86-70% while its transmissivity is the second among the three reservoirs.

Reservoir C has fair porosity and moderate permeability. The hydrocarbon saturation ranges 81-80%. Its transmissivity is the least.

With these petrophysical values, 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 these reservoirs are homogenous and at irreducible water saturation.

The quality of the reservoirs in terms of porosity, permeability and transmissivity decreases down the depth. Therefore, it can be concluded that the hydrocarbon potential and productivity of the reservoir sands can be classified in decreasing order of arrangement as A, B and C. The reservoir A in in both wells is the best in terms of hydrocarbon production and hydrocarbon in such wells can easily migrate to the wellbore as compared to other two reservoirs.

In the course of this research work, nine empirical formulas relating depth, porosity, permeability, and irreducible water saturation were generated. These equations will serve as a guide to estimate the value of permeability and porosity at various depths. The formulas between the depth (d) and porosity (∅**)** are:

(1) $D = 289.52\ \emptyset^{-1}$ Where: D = depth in feet and ∅= Porosity (%)

(2) $D = 88.25\ \emptyset^{-1}$ Where: D = depth in metres

While the formulas between the porosity (∅**)** and depth (d) can be derived from the equation 1 and 2 as:

(3) $\emptyset = 289.52\ D^{-1}$ Where: D = depth in feet and ∅= Porosity (%)

(4) $\emptyset = 88.25\ D^{-1}$ Where: D = depth in metres

REFERENCES

Adedokun, O. (1981). Petrology, provenance and depositional environments of the reservoir sandstone of Ossu-

Amajor, L. and D. Agbaire (1984). Depositional history of the reservoir sandstones, Akpor and Apara oilfield, Eastern Niger Delta, Nigeria: Journal of Petroleum Geology.

Amajor, L. and F . Lebekmo (1990). The Vicking (Albian) Reservoir Sandstones of central and south-centra Alberta, Canada. Part 1 Geometry and Depositional History: Journal of Petroleum Geology 13 (3), p. 315 – 328.

Beka, F. and M. Oti (1995). The distal Offshore Niger Delta: from tier prospects of a mature petroleum province, in, Oti, M.M., and Postina, G., eds., Geology of Deltas: Rotterdam, A.A. Balkema, p. 237-241.

Benkhelil, J. and M. Guiraud (1980). La Benoune (Nigeria): une chaine intracontinentale de style atlasique. C.R. Acad. Sci., Paris 290, p.1517-1520.

Burke, K. and B. Durotoye (1970). The Quartenery in Nigeria. African Geology Ibadan, p. 325-348.

e-ISSN: 2348-6848
p-ISSN: 2348-795X
Volume 04 Issue 13
October 2017

Burke, K. (1972). Longshore rift submarine canyons and submarine fans in development of Niger Delta, American Association of Petroleum Geologists, Bulletin 56 : 1975-1983.

Burke, K. (1976). Development of Graben Associated with the initial ruptures of the Atlantic Ocean. Tectonophysics 36, p. 93-112.

Burke, K.; Dessauvagie, T. and A. Whiteman (1971). Opening of the Gulf of Guinea and geological history of Benue depression and Niger Delta. Nature Physical Science, 233, p. 51-55.

Billman, G. (1992). Offshore stratigraphy and paleontology of the Dahomey (Benin) Embayment, West Africa. MAPE bulletin, V. 7, No. 2, p. 121-130.

Bilotti, F. and J. Shaw (2001). Modeling the comprehensive toe of the Niger Delta as a critical taper wedge (abs), American Association of Petroleum Geologists Annual Meeting programme, 10:1903.

Bilotti, F. and J. Shaw (2005). Deep water Niger Delta field and thrust belt modeled as a critical taper wedge: The influence of elevated basal fluid pressure on structural styles: American Association of Petroleum Geologists, 89:1475-1491.

Omoboriowo, A.O. Edidem, G.T Sorronnadi, G.C 2011. Foraminifera Biostratigraphy and Paleoenviroment of the ETOP Well, Deep Offshore, Niger Delta, Nigeria. *International Journal of Science and Emerging Technology, Vol. 2, No. 3. pp. 87 – 94*

Omoboriowo, A.O, Chiadikobi, K.C. Chiaghanam, O.I (2012) Depositional Environment and Petrophysical Characteristics of “LEPA” Reservoir, Amma Field, Eastern Niger Delta, Nigeria International Journal of Pure and Applied Sciences and Technology Vol 10(2) pp. 38-61