*IOSR Journal of Applied Physics (IOSR-JAP)*
*e-ISSN: 2278-4861. Volume 3, Issue 4 (Mar. - Apr. 2013), PP 66-71*
*www.iosrjournals.org*

# Estimation of Water Saturation Using a Modeled Equation and Archie's Equation from Wire-Line Logs, Niger Delta Nigeria

Agbasi, Okechukwu Ebuka
*University of Uyo, Uyo*
*Namdie, Inyang University of Uyo, Uyo*
*Ibout Johnson, University of Uyo, Uyo*

***Abstract:*** *Well log data from wells located in the X fields of the Niger Delta Basin were used in the determination of some Petrophysical characteristics of the reservoir sands. Well log data were obtained from sonic, gamma-ray, matrix density and resistivity logs. The Petrophysical characteristics investigated were porosity, water saturation, tortuosity and permeability. The results of the analysis revealed the presence of different sand and shale units. The thickness of each sand unit was highly variable, ranging between 6.1 and 21.5 m. Average porosities vary between 25.0 and 72.0 percent and generally decreasing with depth. A modeled water saturation showed a better value for water saturation (calculation) for non-Archie media.The correlation between the modeled water saturation method (using a different value of cementation factor m and tortuosity a as given by some literature) gives a weaker correlation for the non-Archie media while the Archie media gives a stronger correlation when compared with the Archie equation. The average water saturation of these units varied between 5.0 and 64.0 percent. These values are generally high for the sand units in varying wells. Similarly, the average permeability values varied between 22.0 and 70.0 mD. The results of this study will enhance the proper characterization of the reservoir sands and a better estimation of hydrocarbon saturation.*

## I. Introduction

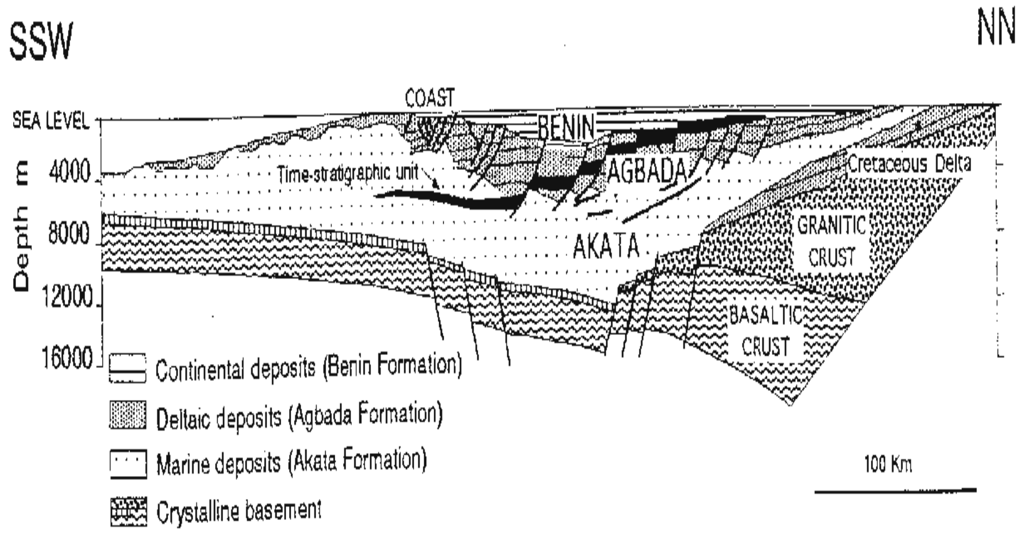
Intheevaluationofaclasticreservoir,thepresenceofclayparticlesorshalewithinthesandisaparameterwhich mustbeconsidered.Shalinessisknowntoaffectbothformationcharacteristicandloggingtoolresponse.Carbonates,nonclasticreservoirs,arecharacteristicallylimestoneanddolomite.Theirimportanceasreservoirsrocksshouldnotbeunderestimated.Approximately,50%ofhydrocarbonreservoiriscarbonaterocks( Schlumberger,1985).Wellloggingtoolsrespondprimarilytothechemicalnature ofmatrixandporefluids.

InhispioneeringworkArchie( Archie,1950)setsoutthefundamentalsofrocktypeclassification.Anyporous networkisrelatedtoitshostrockfabric,thereforepetrophysicalparameter,suchasporosity(Φ),permeability(K)andsaturation(S),foranygiven(typeofrock)arecontrolledbyporesizesandtheirdistributionandinterconnection.Thegoalofreservoircharacterizationistopredictthespatialdistributionofsuchpetrophysicalparameteronafieldscale.Archie(Archie,1950)statedthatabroadrelationshipexistsbetweenporosityandpermeabilityofaformation.Petrophysicsalsorefertothecarefulandpurposefuluseofrockphysicsdataandtheoryintheinterpretationofreservoirgeophysicsobservation(Lucia, 1983).

ThispaperaimedatcomputingandevaluatingthePetrophysicalparametersintheNigerDeltausinggeophysicalwelllogdata.

### Geology/Location Of Study

The Cenozoic Niger Delta is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of the continents of South America and Africa in the late Jurassic (Whiteman,1982). Subsidence of the African continental margin and cooling of the newly created oceanic lithosphere followed this separation in early Cretaceous times. Marine sedimentation took place in the Benue Trough and the Anambra Basin formed-Cretaceous onwards. The Niger Delta started to evolve in early Tertiary times when clastic river in put increased (Doust, and Omatsola,1990).Generally the delta prograded over the subsidizing continental-oceanic lithospheric transition zone, and during the Oligocene spread on to oceanic crust of the Gulf of Guinea (Adesida, Reijers and Nwajide, 1997).




Stratigraphic succession, subsidence and progradational cycle model of Niger Delta (Nuhu 2009)

The weathering flanks of out-cropping continental basement sourced the sediments through the Benue-Niger drainage basin. The delta has since Paleocene times prograded a distance of more than 250km from the Benin and Calabar flanks to the present delta front (Evamy, Hammering,Kmoap and Rowlands, 1978). Thickness of sediments in the Niger Delta averages 12km covering a total area of about 140,000km$^2$.

The Stratigraphic sequence of the Niger Delta comprises three broad lithostratigraphic units namely, (1) a continental shallow massive sand sequence – the *Benin Formation*, (2) a coastal marine sequence of alternating sands and shales–the *Agbada Formation* and (3) a basal marine shale unit-the *Akata Formation.*

The Akata Formation consists of clays and shales with minors and intercalations. The sediments were deposited in pro delta environments. The sand percentage here is generally less than 30%.

The Agbada Formation consists of alternating sand and shales representing sediments of the transitional environment comprising the lower delta plain (mangrove swamps, floodplain, and marsh) and the coastal barrier and fluviomarine realms. The sand percentage within the Agbada Formation varies from 30 to 70%, which results from the large number of depositional off lap cycles. A complete cycle generally consists of thin fossil ferrous transgressive marine sand, followed by an off lap sequence which commences with marine shale and continues with laminated fluviomarine sediments followed by barrier sand/or fluviatile sediments terminated by another transgression (Weber,1972 ;Ejedawe,1989).

The Benin Formation is characterized by high sand percentage (70 – 100%) and forms the top player of the Niger Delta depositional sequence. The massive sands were deposited in continental environment comprising the fluvial realms (braided and meandering systems) of the upper delta plain.

## II. Material And Method

The data collected from the field in the Niger Delta is related geological data, routine core analysis (permeability, porosity, cementation exponent, saturation exponent) and well logging data, including gamma ray, resistivity, density and neutron logs which were collected and reviewed.

Well logging interpretation provides the output of log analysis in term of reservoir parameter. Quick look log interpretation is generally used in formation evaluation using well logs. This interpretation method provides the information which help geologists, geophysicists, reservoir engineers and drilling engineers in short time. Basically, it relies on overlays of logs, interpretation charts, or graphic methods such as cross plots to minimize methods requiring detailed calculation.

The interpretation can derive porosity, water saturation from available well logging data. The zones of reservoir can be identified by many parameters. The permeability is determined from permeability – porosity relationship from core analysis of the corresponding well.

Zone of reservoir is determined by gamma ray and resistivity logs. Make cross plot GR to separate shale and sand lines. Resistivity log is fundamental in formation evaluation because hydrocarbons do not conduct electricity. Therefore, the well logs are split into interval of porous and non-porous rock, permeable and non-permeable rock or shaly and clean sand rock.

The clean sands and sandstones are determined by GR log are low radioactive
because GR log records the abundance of the radioactive isotopes of thorium, uranium and potassium. They are usually concentrated in shales and less concentrated in sandstones, so high GR reading can be observed normally and can be used as regional marker because shale is deposited in wide area.

Resistivity curve can indicate hydrocarbon in porous and permeable rock.
The sonic tool is selected to calculate the porosity in a good borehole condition. The Sonic log is used as porosity method, the equation to calculate the porosity based on the
sonic log is as follows:

$$\phi = \frac{V_p}{V_b} = \frac{V_b - V_s}{V_b}$$

Where $\phi$ = fractional porosity
$V_p$ = Pore Volume
$V_b$ = Bulk Volume
$V_s$ = Gain Volume

Formation factor can obtain $R_w$. When a given zone is water bearing that $R_t$ reverts to the water bearing resistivity ($R_o$). Therefore, a number of water zones can be plotted
depth versus Rw from calculation

$$F = \frac{R_o}{R_w}$$

F = formation resistivity factor or simply formation factor
$R_o$ = resistivity of rock when water saturation is 1 (100% saturated)
$R_w$ = resistivity of saturating water

$$F = \frac{a}{\phi^m}$$

$\Phi$ = porosity
*a* = empirical constant (default = 1)
m = cementation exponent (default = 2)

For determination of water saturation of a clean sand formation we use the following equations

$$S_w{}^n = \frac{R_o}{R_t}$$

$S_w$ = water saturation
$R_t$ = resistivity of rock when Sw< 1

Combining the above equations gives Archie's equation, the most fundamental equation in well logging.

$$S_w{}^n = \frac{aR_w}{R_t\phi^m} = \frac{FR_w}{R_t}$$

Practical average Archie's Equation general equation for finding water saturation is

$$S_w{}^n = \left[\frac{0.62 \times R_w}{\phi^{2.15} \times R_t}\right]^{1/2}$$

Using proper m relationship determines permeability in the reservoirs. In-situ porosity versus logarithm of permeability can be plotted, and the relationship can predict more accuracy and be divided by facies and/or formation.

$$k = \frac{q\mu L}{A\Delta P}$$

k = permeability of reservoir

## III. Result And Discussion

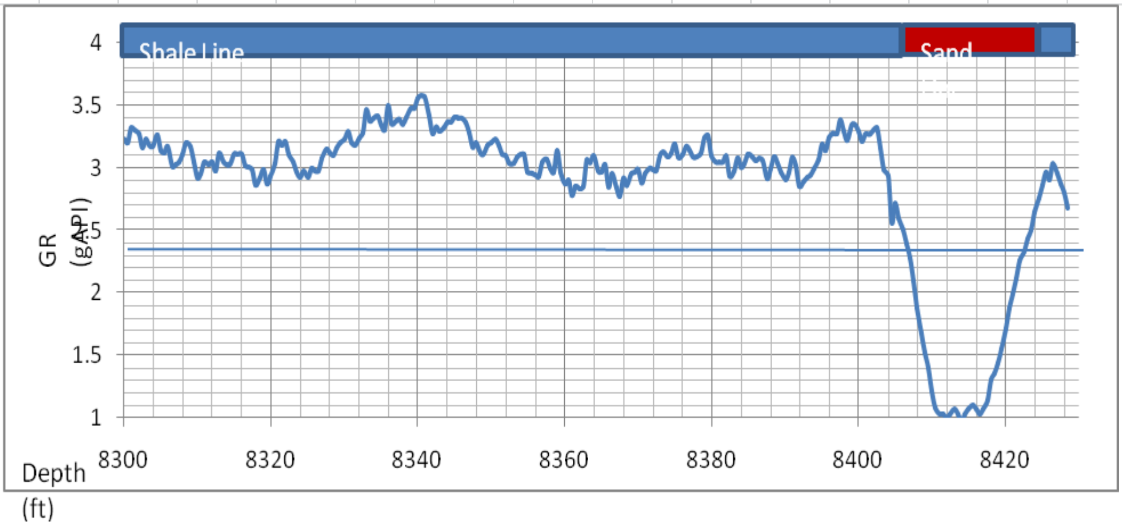
The analysis of the wells, each of which is divided into three zones based on the porosity of each zone. In each zones of the wells, the formation of the wells was determined using the plot of Depth versus Gamma log. High gamma reading indicates shale formation while low gamma reading indicates sand formations.

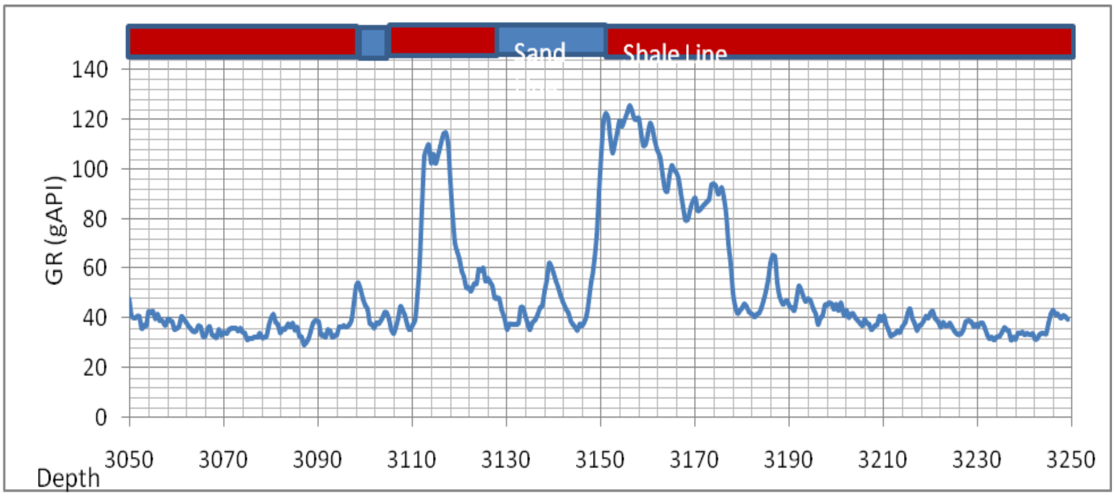
Porosities within the field are observed general to decrease with depth. The estimated average porosity value ranges between 0.82 and 0.22, decreasing with depth. These low porosity values may be attributed to mainly grain size and sorting effects within the reservoir sands. (Pickett,1960; Beard, and Weyl, 1973 and Scherer, 1987). All the sand units investigated are confined within the Agbada Formation. The varying shale contents and the depths of burial may have contributed, though to a minor extent, to the decrease in porosity. The porosity values are however considered to be fairly good for hydrocarbon accumulation.

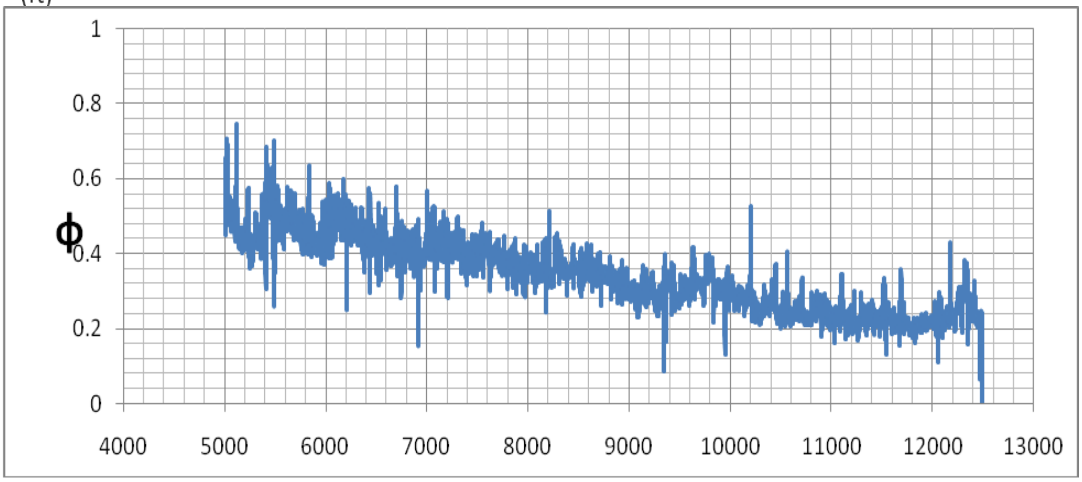
Average water saturation of the sand units vary between 0.05 and 0.52 for cementation factor (m = 1.8) and 0.05 and 0.64 for cementation factor (m = 2.0). These average water saturation values are observed to increase with depth. The average permeability values for the values for the various sand units vary between 0.70 and 0.27, for m = 1.8 and between 0.22 and 0.65, for m = 2.0. The thickness of the sand units is highly variable for both sand and shale formation. The sand thickness for well 1 is between 13 – 32ft, well 2 between 20ft, well 3 between 32 – 60ft, well 4 between 45 – 47 ft, well 5 between 50ft, well 6 between 18 – 39ft, well 7 between 20 – 50ft, well 8 between 60 – 80ft and well 9 between 26 – 100ft.

For Archie media the water saturation values for both the Archie and modeled equation, the correlation between both of them are strongly related having values of 0.99997 – 0.99999, while for non-Archie media they are less related having values of 0.99992 – 0.99995.

| Shale | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Well 1.1 | 7550 - 758 | 109.11 | 1.91 | 143.75 | 0.40 | 2.08 | 0.42 | 0.14 | 0.86 | 2.50 | 0.42 | 0.16 | 0.84 | 9.66 |
| Well 1.2 | 7800.5 - 78 | 108.17 | 2.61 | 130.40 | 0.39 | 2.12 | 0.41 | 0.15 | 0.85 | 2.57 | 0.41 | 0.16 | 0.84 | 10.09 |
| Well 1.3 | 10590 - 10 | 95.22 | 2.81 | 140.16 | 0.30 | 2.67 | 0.34 | 0.23 | 0.77 | 3.43 | 0.34 | 0.26 | 0.74 | 13.41 |
| Sand | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
| Well 1.1 | 7628 -7660 | 119.03 | 32.11 | 53.77 | 0.48 | 1.81 | 0.47 | 0.11 | 0.89 | 2.11 | 0.47 | 0.12 | 0.88 | 7.750529 |
| Well 1.2 | 7848 - 788 | 102.84 | 11.28 | 52.03 | 0.35 | 2.30 | 0.38 | 0.17 | 0.83 | 2.83 | 0.38 | 0.19 | 0.81 | 11.00862 |
| Well 1.3 | 10607 - 10 | 85.39 | 22.18 | 31.20 | 0.22 | 3.45 | 0.27 | 0.37 | 0.63 | 4.72 | 0.27 | 0.44 | 0.56 | 17.45787 |
| Shale | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
| Well 2.1 | 5100 -5148 | 123.29 | 2.00 | 88.91 | 0.51 | 1.74 | 0.49 | 0.10 | 0.90 | 2.00 | 0.42 | 0.12 | 0.88 | 15.33 |
| well 2.2 | 5255 - 529 | 114.77 | 3.05 | 87.32 | 0.44 | 1.92 | 0.45 | 0.12 | 0.88 | 2.26 | 0.37 | 0.14 | 0.86 | 17.78 |
| well 2.3 | 5860 - 592 | 104.83 | 2.70 | 89.09 | 0.37 | 2.23 | 0.39 | 0.16 | 0.84 | 2.72 | 0.32 | 0.20 | 0.80 | 22.38 |
| Sand | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
| Well 2.1 | 5032 -5064 | 113.36 | 1.92 | 33.20 | 0.43 | 1.96 | 0.44 | 0.13 | 0.87 | 2.32 | 0.37 | 0.15 | 0.85 | 18.37 |
| well 2.2 | 5205 -5245 | 110.66 | 250.56 | 32.52 | 0.41 | 2.03 | 0.43 | 0.13 | 0.87 | 2.43 | 0.35 | 0.16 | 0.84 | 19.50 |
| well 2.3 | 5670 - 573 | 94.57 | 1.76 | 26.81 | 0.29 | 2.68 | 0.33 | 0.23 | 0.77 | 3.42 | 0.26 | 0.29 | 0.71 | 27.97 |
| | | | | | | | | | | | | | | |
| Shale | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
| Well 3.1 | 4900 - 493 | 147.65 | 9.86 | 86.79 | 0.69 | 1.36 | 0.61 | 0.06 | 0.94 | 1.46 | 0.55 | 0.07 | 0.93 | 8.22 |
| well 3.2 | 7020 - 703 | 114.89 | 9.02 | 96.96 | 0.44 | 1.92 | 0.45 | 0.12 | 0.88 | 2.26 | 0.37 | 0.14 | 0.86 | 17.94 |
| well 3.3 | 7410 - 748 | 107.38 | 9.54 | 76.94 | 0.39 | 2.33 | 0.41 | 0.21 | 0.79 | 2.96 | 0.33 | 0.28 | 0.72 | 37.73 |
| Sand | DEPTH (ft) | SONIC (µs | RT(Ωm) | GR (gAPI) | ϕ | a, m = 1.8 | K | Sw | Sh | a, m = 2 | K | Sw | Sh | % |
| Well 3.1 | 4854.5 - 48 | 123.91 | 115.79 | 37.95 | 0.51 | 1.71 | 0.50 | 0.10 | 0.90 | 1.96 | 0.42 | 0.11 | 0.89 | 14.50 |
| well 3.2 | 6653 - 670 | 106.92 | 63.69 | 38.39 | 0.39 | 2.31 | 0.40 | 0.19 | 0.81 | 2.89 | 0.33 | 0.24 | 0.76 | 28.21 |
| well 3.3 | 7320 - 740 | 106.77 | 34.82 | 36.73 | 0.38 | 2.21 | 0.40 | 0.16 | 0.84 | 2.70 | 0.33 | 0.20 | 0.80 | 23.31 |






## IV. Conclusion

Petrophysical analysis was carried out for all the identified hydrocarbon intervals, from the eight wells studied in the Niger Delta Fields using suites of geophysical well logs. From the analysis of the geological logs comprising gamma-ray and electrical resistivity, the total porosity in the hydrocarbon bearing zone was found to range from 25.0% to 75.0% and the water saturation range from 5.0 to 64.0%. Good well-to-well lithology correlation was established across the fields studied .The researcher found that the bulk of the hydrocarbon encountered in the Niger Delta basin was found to be within a depth range of 2,050 – 11,620ft (624.84 – 3,541.78m) as compared to the values gotten by Falebita. 2003 (about 1,200 – 3,650m) and Aigbedion, I., 2007 (about 2,510 – 3,887m). The hydrocarbon reservoirs were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta, Nigeria. This study was carried out to find out if the petrophysical parameters computed in the field will encourage deeper drilling in the area of study.

One of the most important tasks in reservoir engineering is characterizing different parameters of the reservoir. Water saturation is a parameter which helps evaluating the volume of hydrocarbon in reservoirs. Determination of this parameter started from 1942 by integrating some well logs in clean sandstones. After that, many scientists introduced some equations to validate this procedure in shaly sands and carbonates (Lucia, 1983). To treat the problem of dependency of water saturation estimation on core analysis in previous works, other scientists proposed using rock physics and arrived at improved models of water saturation estimation. More recently, interpreters have used seismic attributes to evaluate water saturation values directly or estimating proper rock physical properties such as tortousity which are useful in water saturation estimation process.

## Reference


[1]. Adesida, A.A., Reijers T.J.A, Nwajide C.S. (1997) Sequence stratigraphic framework of the NigerDelta. Paper presented at the AAPG international conference and exhibition, Vienna, Austria

[2]. Aigbedion, I., (2007). Reservoir Fluid Differentiation case study from the Oredo Field. International, Journal of Physical Sciences, 2 (6): 144-148.

[3]. Archie, G.E., (1950) Classification of Carbonate Rocks and Physical Consolidations. AAPG Bulletin, 36.

[4]. Doust, H., Omatsola, E. (1990). Niger Delta in divergent/passive margin basins, in J. D. Edwards. and P. A. Santogrossied, eds., Am. Assoc. Petrol. Geol. Memoir, 48: 201-238.
[5]. Ejedawe, J.E. (1989) The Eastern Niger Delta: geological evolution and hydrocarbon occurrences. SPDC Internal Report, Exploration Note 89. 002
[6]. Evamy, D.D., P. Hammering, W.A. Kmoap and P.H. Rowlands, (1978). Hydrocarbon habitat of the tertiary Niger Delta. American Association of 1-3. Petroleum, Geologist Bulletin, 62(2): 1-10.
[7]. Falebita, B. (2003). Deep drilling in the Niger Delta.Nape bulletin.Vol 10(1).
[8]. Lucia, F.G., (1983). Petrophysical parameters estimated from virtual description of carbonate rocks. Journal of petroleum technology, Canada, 32: 49 -53
[9]. Nuhu, G.O (2009). Geology and mineral resources of Nigeria. Lecture notes on Earth science series, Volume 120. SpingerVerleg Berlin. pp. 109 – 116.
[10]. Pickett, E. (1960). The use of acoustic logs in the evaluation of sandstones reservoir. Geophysics, 21(#3): 250 – 274.
[11]. SchlumbergerEducational Services. 1985. "Log Interpretation Principles/Applications". Schlumberger Manual.
[12]. Weber, K.J. (1972). "Petroleum Geology of the Niger Delta". 9th World Petroleum Congress: Tokyo, Japan. 2:207-221.
[13]. Whiteman, I.K. (1982). Fundamental of Reservoir Engineering,4th ed. University of Oklahoma Press, Norman, 426pp.