

Integration of Borehole Geophysical Data and 3D Seismic Data in Reservoir Characterization

A S Ekine M¹, Uche-Collins G Ubaku²

¹ Professor Emeritus, Department of Physics, University of Port Harcourt, Choba. East-west road Rivers state, Nigeria.

² Student, Department of Physics, University of Port Harcourt, Choba. East-west road Rivers state, Nigeria.

Corresponding Author: asekin2001@yahoo.co.uk

Abstract: - This research involves the Integration of Borehole Geophysical Data and 3D Seismic Data in Reservoir Characterization. Data from the “Goko” field was obtained and analyzed using Petrel software package. The reservoir was identified at an approximate depth of the top at about 3537.5 feet. The quality of the reservoir was determined using petrophysical parameters like porosity and permeability. The reservoir was found to have an average porosity of about 0.22408 which gives about 22.408%. The permeability was obtained at an average value of about 1485.828. This gives Very Good porosity and an excellent permeability. Hence the reservoir quality has been identified to be a good one. The lateral extent of the reservoir was obtained by determining the horizon of interest in terms of its depth from the surface, area and geometry. The reservoir was found to be an anticline structure as shown in figures 3.5.2 Fault and horizon Interpretation on Inline 5741, 3.5.3 Fault and horizon Interpretation on Inline 5641, and 3.6.1 Interpreted Horizons, fault sticks and wells across inline 5820. The STOIP estimation shown using equation 2.9 gave the volume of hydrocarbon that can possibly be found in the reservoir. With values of about fifty-six million stock-tank barrel (**56,167,045.24 Stock Tank Barrel (STB)**), the reservoir is seen as a possible rich source of hydrocarbon that is good enough for exploration.

Key Words: —*Bore hole, Geophysical data, 3D Seismic data, Reservoir.*

I. INTRODUCTION

Reservoir characterization is an integrated process whereby several data such as seismic, well log, check shots etc. and several geoscientific principles are used, to unravel the nature and quality of the reservoir (Ezekwe and Filler, 2005). The quantity of the natural resources of the subsurface is known in the process, which will be a good guide to the management of the asset to make important decisions which will enhance productivity and maximize profit. Depending on what an exploration team is targeting, several parameters can be determined during reservoir characterization. An Exploration and Production (E&P) team will be strictly targeting Hydrocarbon. A potential hydrocarbon reservoir has a great deal of uncertainty associated with it in terms of locating it, determination of its depth, and estimating its quantity (Nwankwo, 2014). This uncertainty is largely due to the complex nature of the Subsurface.

A geophysicist uses several available data to create a model, or what looks like an “educated guess” in describing the structure of the rocks in the subsurface, Gadallah and Fisher, (2009).

The aim of an exploration team in the Exploration and Production Company is basically to locate a reservoir that will yield a rich source of hydrocarbon whose outcome will be of a great economic benefit. Reservoir characterization can be carried out for several geophysical or petrophysical parameters in a given reservoir. This can vary from the hydrocarbon history, potential, depth, lateral extent, quality, volume among others. Whatever the aim of exploration is, it is of great importance to channel all efforts towards exploring and producing hydrocarbon in an economic, safe, and environmentally friendly manner. There is no E&P Company operating in the oil industry that does not want to maximize profit from an exploration outfit. To explore for hydrocarbon, several departments work together, in order to generate the needed data, to process it, and to characterize the Reservoir.

A very important aspect of hydrocarbon exploration is Reservoir characterization (Odai and Ogbe, 2010). It informs management of the outcome of an exploration project. When properly done, it can serve as an early warning in a case where the field is not rich enough. During reservoir characterization,

Manuscript revised April 21, 2021; accepted April 22, 2021.

Date of publication April 24, 2021.

This paper available online at www.ijprse.com

ISSN (Online): 2582-7898

the diverse tools, disciplines and knowledge are integrated which all work towards obtaining a better understanding of the Reservoir (Enaworu, 2014). According to (Schlumberger, 2015) the better a reservoir is understood, the better the possibility of optimizing its potential. This can be obtained by integrating well log and 3D seismic data (Ameloko and Owoseni, 2015).

II. MATERIAL AND METHODS

As we characterize the reservoir in the field also called the “G” field, a number of processes are included and two major sets of data are used: Geophysical well log data and 3D seismic data. The processes involved in this work are outlined in the workflow diagram shown below:

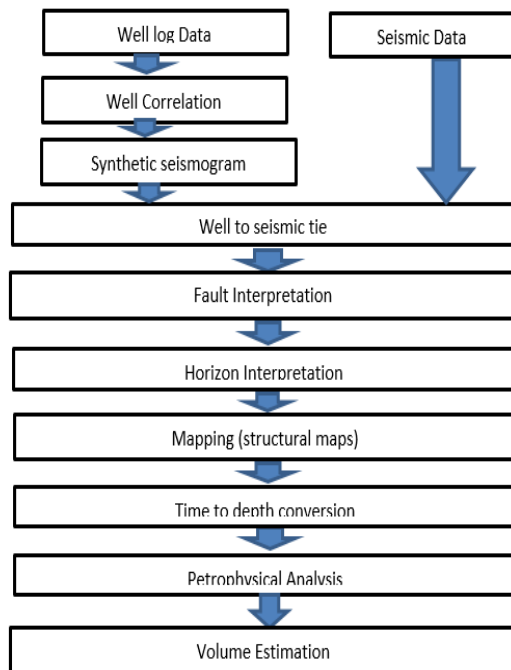


Fig. 1. Workflow diagram

A. Types of Data Used

The types of data used in this project are majorly grouped into two, namely (i) Well log Data and (ii) Seismic Data. The choice of these sets of data is born out of the fact that for a proper reservoir characterization, there is a great need to integrate these two sets of data.

1. Well Log Data

The well log data used in this project include the following;

- Gamma Ray log
- Density log
- Neutron porosity log
- Resistivity log
- Sonic log
- Caliper log
- SP log

Each of the mentioned log gives a unique signature which helps in the determination of the petro physical parameters used in this project.

The gamma ray log, which are as a result of the penetration of radiation penetrating the rock formation, helps in the determination of the volume of shale and sand in the well. This is in line with the formula shown below:

$$V_{sh} \text{ Linear } (V_{sh_gr_1}) = \frac{GR - GR_{CL}}{GR_{SH} - GR_{CL}} \quad 2.0$$

Where;

V_{sh} = volume of shale

GR = Gamma ray log reading in the zone of interest (API units)

GR_{CL} = Gamma ray log reading in 100% clean zone

GR_{SH} = Gamma ray log reading in 100% shale zone

Also the density log gives us the signatures of the variation in density based on the bulk density, which indicates the spaces between the rock formations. It is combined with the neutron-porosity log to give the possible location of oil or gas-bearing zones. Higher readings of the density log indicates the possible presence of shale and lower readings indicate the presence of sands where the possibility of locating oil is high. The opposite is the case for the neutron-density log, and where there is a cross between the density log and the neutron log it indicates the possible presence of gas.

The resistivity log gives the level of resistance the rock formation gives to the flow of electric current. Higher readings show the presence of formations with a higher possibility of obtaining hydrocarbon. But lower readings show the presence of water due to the conductivity of water. The caliper log is used to indicate the nature of the walls of the well. It shows where there may be a relatively change in the well diameter. A slight change in the diameter may affect the logging readings. The sonic log gives the travel-time of sound as it passes through the different rock formations. Then the SP log gives the response of the rock formation to the conductivity of charges.

High conductivity indicates the possible presence of either shale or non-oil formations. But lower conductivity readings indicate the possible presence of oil-bearing formations or sands.

2. Seismic Data

The seismic data used in this research is a 3D seismic data. Generally all seismic data are recorded in time. The need to convert it to depth arises and this was done by converting the time to depth during seismic-to-well tie.

B. Quality Assessment (QA)/ Quality Control (QC) of Data

The data was obtained from the “Goko” field of the Niger Delta region in Nigeria. Some wells were identified out of which four wells were considered to have sufficient information for the attainment of the objectives of this research. The field is 210 km², Fields: G Inline range: 5577 to 5850, Xline range: 1495 to 1750, Inline/Xline interval: 25m, Time: -2100 to -3100ms, Wavelet type: Zero phase, Polarity: SEG Reverse having the four wells labeled A, B, C, and D. A synthetic seismogram was generated using the generated wavelet and the reflection coefficient. This seismogram was matched with the seismic data in an iterative process to obtain the seismic-to-well tie. The four wells are shown in the figure below:

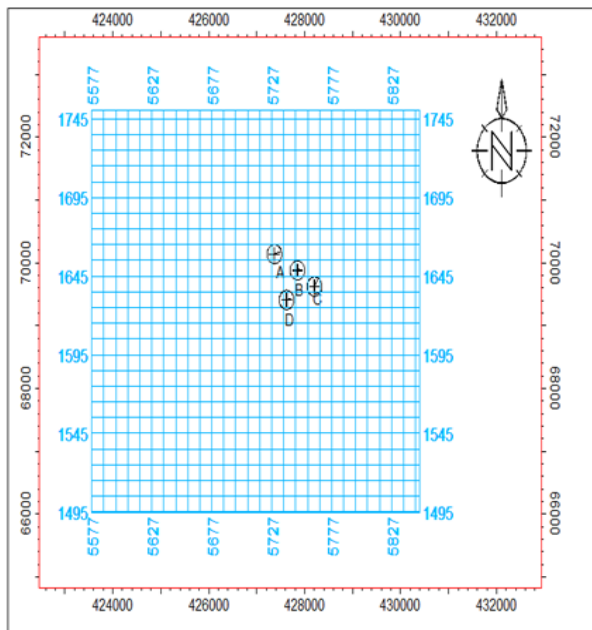


Fig. 2.1. The Area covered.

C. Petro physical Evaluation

Carrying out the petro physical evaluation will yield the following data ; the volume of shale, the porosity, the water saturation of the formation, the ratio of the sand to the thickness of the reservoir also known as Net-To-Gross(NTG) and the permeability. The following parameters are to be determined;

Volume of shale; this is the term used to describe a rock composed of clay, silt, and bound water. Shale is usually more radioactive than sand, it is obtained in terms of the gamma ray log. The formula used is given below, Larionov(1969);

$$VSH = 0.083^{((2.37 * IGR) - 1)} \tag{2.1}$$

Where;

VSH= volume of shale

IGR=Gamma Ray Index

$$IGR = \frac{(GR - GR_{min})}{(GR_{max} - GR_{min})} \tag{2.2}$$

1. Estimation Of Porosity

Porosity, is a phenomena that tells of the measure of reservoir storage capacity, this is also the proportion of the total rock volume that is void and filled with fluids in a given reservoir. Porosity is normally expressed in such fractional units/decimal or as a percentage (%), in some cases.

$$\Phi = \frac{(\delta_{ma} - \delta_b)}{(\delta_{ma} - \delta_{fl})} \tag{2.3}$$

Where,

Φ = Porosity from density log.

δ_{ma} = Matrix density (2.65 g/cm³).

δ_b = Bulk density value on Density log (as obtained using the measurement tool)

δ_{fl} = Density of fluid (1 g/cm³)

also,

$$\Phi = \frac{2.65 - \rho_{bulk}}{2.65 - 1} \tag{2.4}$$

2. Estimation of Water Saturation

Every good hydrocarbon reservoir should have less water saturation than hydrocarbon saturation. Water Saturation is the amount of pore volume filled by water in fraction or percentage. But hydrocarbon saturation refers to the percentage or fraction of the amount of the pore volume filled by hydrocarbon in the reservoir.

Water saturation was estimated using equation 2.5 after Udegbunam and Ndukwe (1988). This equation for hydrocarbon saturation is applicable to the Niger Delta environment. Water saturation is given as;

$$S_{w_ud} = \frac{0.082}{\Phi} \quad 2.5$$

Where;

S_{w_ud} = Water saturation of Udegbunam and Ndukwe (1988).

Φ = Porosity

3. Estimation of Hydrocarbon Saturation

Hydrocarbon saturation will be estimated for using the equation 3.6. It is denoted as S_H . This was done after the value of water saturation had been obtained then subtracted from 1. The outcome is the hydrocarbon saturation. This is the fraction or percentage of pore volume of a reservoir which is filled with hydrocarbon. Hydrocarbons are highly resistive. Therefore, a reservoir sand with high resistivity shows that hydrocarbon is present.

$$S_H = 1 - S_{w_ud} \quad 2.6$$

Where,

S_{w_ud} = Water Saturation (from equation 3.5 above)

S_H = Hydrocarbon Saturation

4. Estimation of Net To Gross (NTG)

The Net to Gross (NTG) of a given formation is the ratio of the (net) thickness of reservoir sand (without shale) to that of the total (gross) thickness of sand in the given formation. This can be estimated to be the productive part (that has hydrocarbon) of the reservoir sand without shale. NTG was estimated in the given equation 3.7 below.

$$NTG = \text{If } (GR < 75, 1, 0) \quad 2.7$$

From this, it implies that if the Gamma Ray (GR) is less than 75 API, Net to Gross (NTG) will yield a value of 1, and otherwise it is zero if GR is greater than 75. The software computes and records the values for the net to gross, and then the average of the net to gross of the reservoir sand at each depth is calculated for and taken to be the net to gross value of the particular reservoir estimated for.

Net to Gross is also given as;

$$NTG = \text{If } (\Phi \leq 0.2 \text{ And } VSH \geq 0.2, 0, 1) \quad 2.7.1$$

NTG = Net to Gross

VSH = volume of shale

Which implies that if the porosity is less than or equal to 0.2 and the volume of shale is greater than or equal to 0.2, the NTG will be 0. Hence the porosity must be greater than 0.2 and volume of shale must be less than 0.2 to obtain a value of 1.

5. Estimation of Permeability

This is the capacity of a reservoir rock to allow fluid to flow; hence the permeability is a measure of how freely a formation allows fluid to pass through it. The Permeability is given as a function of the interconnectivity of the pore volume. A rock must have interconnected pore spaces to be seen as permeable. Permeability is measured in units of darcy or millidarcy and is denoted by the symbol K.

Permeability is given as stated by Owolabi et al., (1994) in estimation of reservoir permeability;

$$K = 307 + 26552 ((\Phi)^2) - 34540 ((\Phi S_{w_ud})^2) \quad 2.8$$

Where;

Φ = Porosity

K = Permeability

S_{w_ud} = Water Saturation (from equation 3.5 above)

From these equations we will obtain the values that can be used to determine the quality of the reservoir and the volume of hydrocarbon in the reservoir

D. Volume estimation

The volume of hydrocarbon in the reservoir referred to as the Stock Tank of Oil Initially in Place (STOIPP) is given with the formula below:

$$STOIPP = \frac{Ah * \Phi * NTG * (1 - S_w) * 7758}{FV} \quad 2.9$$

Where:

A = the area of the identified horizon

H = the height of the reservoir

Φ = reservoir porosity

7758 = the conversion factor of a barrel

FV = the formation volume factor

III. RESULTS

The well correlation was carried out using four wells which are labeled A, B, C and D: From well “A”, the top of the reservoir was obtained at a depth of about 3460ft. The base was obtained at about 3580ft. This was correlated with well B, C and D whose tops were obtained at a depth of about 3512.5ft, 3495ft and 3490ft. Respectively. The base of these wells was obtained at about 3610ft, 3645ft and 3620ft respectively. The gamma ray signatures indicate a reasonably high reading suggesting the presence of high amounts of shale at the top of these wells. These also show the possible presence of hydrocarbon in these wells (as shale mostly acts as a seal to the hydrocarbon in the formation). The Gamma ray log shows a lower reading slightly below the shale region, which indicates the presence of sand where the hydrocarbon is found. The resistivity log signatures indicates a higher value at the point where the Gamma ray log reading is low (where there is sand), the high resistivity is an indicator of hydrocarbon against water (as both of them show high gamma ray readings), but the resistivity is higher in well “A” than the others, implying that there is a higher potential for hydrocarbon in well “A” than the others-hence the choice of well “A” for the well tie. Figure 4.1 below shows the correlated wells and their respective well log signatures.

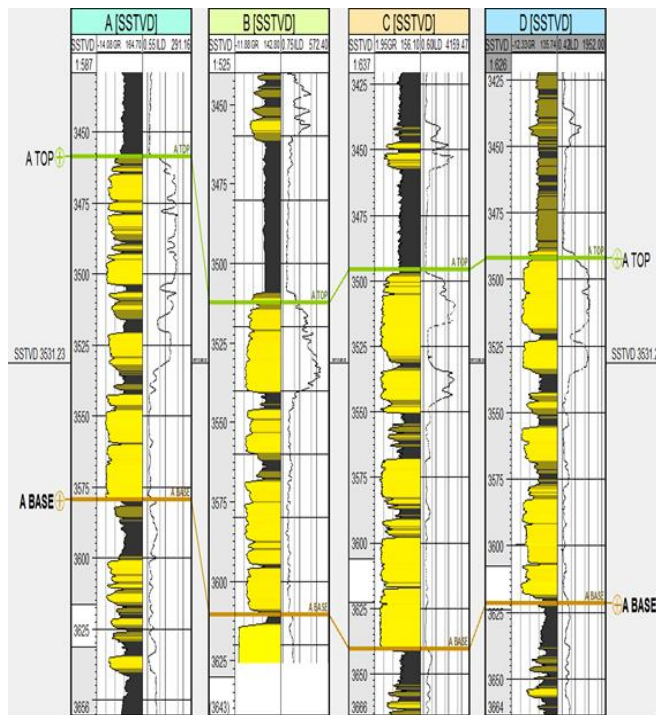


Fig. 3.1. Well Correlation

A. Seismic To Well Tie Results

The well-to seismic tie results shown in figure 4.2 below gives the synthetic seismogram generated which was used to match the crest to crest and through to through in the seismic section and the well logs. The reservoir top was identified at a depth of about 3460ft as viewed from inline 5741, this corresponds to the well log signature and seismic trace just below horizon 2. The reservoir Top was identified as traced on an inline 5741 along the well “A” column as shown in fig 3.2.1.

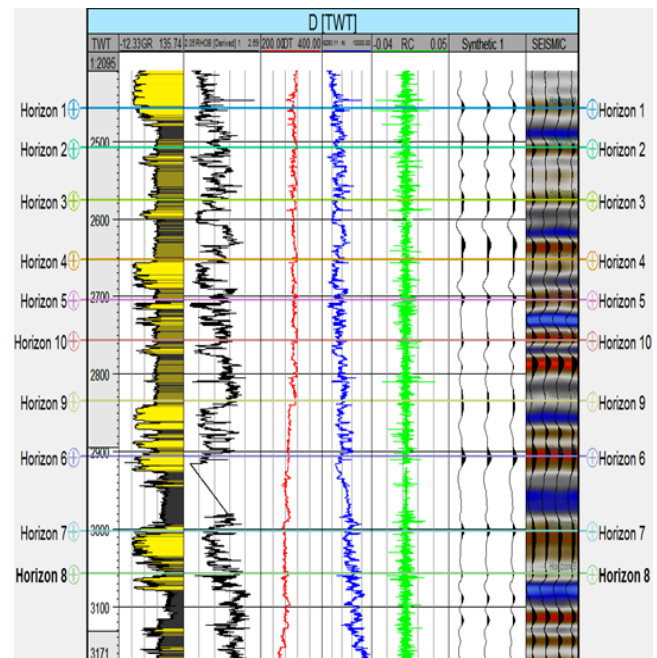


Fig.3.2. Well-to-Seismic tie using Synthetic seismogram generated in the “G” field

B. Results of Petro physical Evaluation

The oil zone was identified (as shown in figure 3.3), which is the hydrocarbon zone was identified at about 3457.5ft to about 3625ft, the base of the reservoir is at about 3658ft; the top of the reservoir is at 3457.5ft for well “A”, 3512.5ft for well “B”, 3495ft for “C” and 3492ft for “D”. These values form the top of the reservoir. The well logs within this region shows a high resistivity, a high proportion of sand having as compared to shale, the shale zone lies above the sand zone in line with the well log analysis. The Oil Water Contact (OWC) was identified from well “A” at about 3534ft, well “B” about 3542.3ft, well “C” about 3552ft, and well “D” 3538ft. The base of the reservoir is at about 3780ft for well “A”, 3610ft for well “B”, 3638ft for well “C”, and 3622ft. The petrophysical parameters were also identified based on the four wells identified: The figure below shows these identified values.

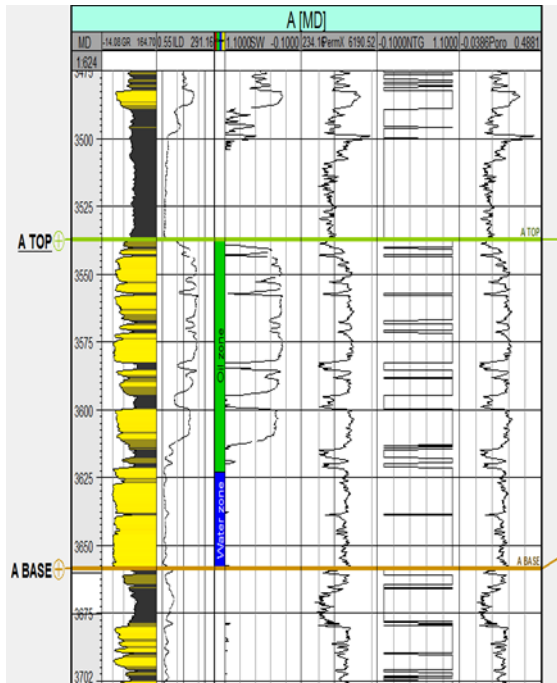


Fig.3.3. Petrophysical Evaluation on well A

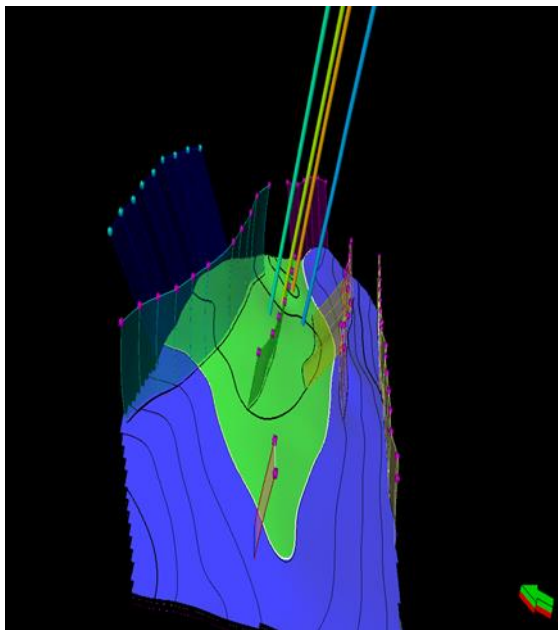


Fig. 3.4. 3D Section of the reservoir contacts

IV. DISCUSSION

From well A, an average porosity of 0.23035 was obtained. Well B, C and D gave an average porosity of 0.185797, 0.238698 and 0.241483 respectively. In general, we obtained an average porosity of 0.224082 in the identified reservoir. The

permeability obtained from well A is 1542.767. Well B, C and D gave 1106.038, 1612.515 and 1681.993 respectively. The reservoir permeability is about 1485.828. The saturation of water for well A, B, C and D are 0.55, 0.33, 0.46 and 0.25 respectively. Generally the saturation of water is 0.862808 for the chosen reservoir.

With a height of 47ft, an area of 2380.28 Acre; the Net-To-Gross values of 0.842569 was obtained in reservoir A, 0.890223 was obtained in reservoir B, 0.864809 in reservoir C and 0.85363 in reservoir D. the average value of 0.862808 was obtained as the NTG of the chosen reservoir.

V. CONCLUSION

During the petrophysical evaluation, with an average porosity of 0.22408, the reservoir has a Very Good porosity. With an average permeability of 1485.828, this shows an excellent permeability. With a very good and an excellent porosity and permeability, the identified reservoir shows a high chance of bearing hydrocarbon. With an identified area of about 2380.28 acres and a thickness of about 47 square feet, hence the volume of hydrocarbon obtained.

The STOIP estimation shown using equation 2.9 gave the volume of hydrocarbon that can possibly be found in the reservoir. With values of about fifty-six million stock-tank barrel (56,167,045.24 Stock Tank Barrel (STB)), the reservoir is seen as a possible rich source of hydrocarbon that is good enough for exploration.

REFERENCES

- [1]. A. A. Ameloko and A. M. Owoseni (2015); Hydrocarbon reservoir evaluation of X- field, Niger Delta using seismic and petrophysical data, International Journal of Innovation and Scientific Research Vol.15 No.1, pp.193-201.
- [2]. A.A.P.G Bulletin 2008. Pp. 30 – 32 Lambert, A. (2011); the Niger Delta Complex Basin, Journal of Petroleum Geology, 1(2), 78 – 98 Muslime, B.M., and Moses. A.O.
- [3]. A.A.P.G memoir 60; Tulsa, 599 -614 Evamy, B.D., Haremboure, J., Kamerling, P., Molloy, F.A., and Rowland, P.H. (1978); Hydrocarbon habitat of tertiary Niger Delta;
- [4]. Akinwumi, F. V., Arochukwu, E. C., and Abdul-Kareem, A. S. (2004); “Managing Uncertainties in Hydrocarbon-in-place Volumes in a Northern Depobelt Field, Niger Delta, Nigeria” paper SPE 88880, presented at the 28th Annual SPE International Technical Conference and Exhibition in Abuja, Nigeria, August 2-4.

- [5]. Asquith, N. (2004); Basic Well Log Analysis for Geologists. A.A.P.G. Methods in Exploration. Tulsa, Oklahoma, No. 16. Pp. 12 – 135.
- [6]. Asquith, G., and D. Krygowski, (2004); Basic Well Log Analysis: AAPG Methods in Exploration 16, p.31-35
- [7]. Balarabe, H.J. (2003); Interpretation of Madu field 3D Seismic Data and Prospect Generation, A Paper Delivered at a Technical Section to Exploration/Asset Department Texaco Overseas Petroleum Company of Nigeria.
- [8]. Barrell, Joseph, (1914); the strength of the earth's crust: Jour Geology, v.22, p. 214.
- [9]. Charlou, J. L., and J. P. Donval (1993); Hydrothermal methane venting between 12oN and 26oN along the Mid-Atlantic Ridge, J. Geophys. Res., 98, 9625-9642.
- [10]. Charlou, J. L., J. P. Donval, Y. Fouquet, P. Jean-Baptist, and N. Holm (2002); Geochemistry of high H₂ and CH₄ vent fluids issuing from ultramafic rocks at the Rainbow hydrothermal field (36o14'N, MAR), Chem. Geol., 184, (1-2), 37-48.
- [11]. C. N. Nwankwo, J. Anyanwu and S. A. Ugwu (2014); Integration of Seismic and Well Log Data for Petrophysical Modeling of Sandstone Hydrocarbon Reservoir in Niger Delta. Scientia Africana, Vol. 13 (No.1), ISSN 1118 – 1931. Pp186-199.
- [12]. Dillon, W. P., M. W. Lee, and K. Fehllalen (1993); Gas hydrates on the Atlantic continental margin of the United States – controls on concentration, in Future of Energy Gases, U.S. Geological Survey Professional Paper. 1570, pp. 313-330, edited by D.G.Howell, U.S. Govern. Print. Office, Washington (D.C.).
- [13]. Doust, H., Omatsola, M. E.: (1990); Niger Delta, In J. D. Edwards, P. A Santogrossi (eds.), Divergent/passive margin basins, American Association of Petroleum Geologists (AAPG), p. 239–248.
- [14]. Duchesne, M., and P. Gaillot, (2011); did you smooth your well logs the right way for seismic interpretation? Journal of Geophysics and Engineering, 8, 514523.
- [15]. Edgar, J., and M. van der Baan, (2011); how reliable is statistical wavelet estimation? Geophysics, 76, V59V68.
- [16]. Ekine A.S. and Ibe A.A (2013); Delineation of Hydrocarbon Bearing Reservoirs from Surface Seismic and Well Log Data (Nembe Creek) in Niger Delta Oil Field. IOSR Journal of Applied Physics (IOSR-JAP) e- ISSN: 2278-4861. 4(3): 26-30.
- [17]. Ekweozor, C.M. and Dankoru, E.M.(1994); North Delta depobelt portion of the Akata – Agbada (1) Petroleum System, Niger Delta, Nigeria, in Magon, L.B., and Dow, W.G., eds. The petroleum system from source to trap.
- [18]. Enaworu Efeoghene (2014); Evaluating Uncertainty in the Volumes of Fluids in Place in an Offshore Niger Delta Field. Journal of Emerging Trends in Engineering and Applied Sciences (JETEAS) 5(2): 144-149 © Scholarlink Research Institute Journals, 2014.
- [19]. Eshimokhai, S. and Akhirevbulu, O.E.(2012); Ethiopian Journal of Environmental Studies and Management EJESM Vol. 5 no.4 (Suppl.2).
- [20]. Ezekwe, J. N., and Filler, S. L.(2005); “Modelling Deepwater Reservoirs,” paper SPE 95066 presented at the 2005 SPE Annual Technical Conference and Exhibition held in Dallas, Texas, U.S.A., 9 – 12 October.
- [21]. Godwin Emujakporue, Cyril Nwankwo and Leonard Nwosu: (2012); Integration of Well Logs and Seismic Data for Prospects Evaluation of an X Field, Onshore Niger Delta, Nigeria International Journal of Geosciences, 2012, 3, 872-877, September 2012.
- [22]. Dave Hale and Andrew Munoz; (2012); Automatically tying well logs to seismic data, Center for Wave Phenomena, Colorado School of Mines, Golden, CO 80401, USA. CWP-725.
- [23]. Klett, T. R., Ahlbrandt, T. S., Schmoker, J. W. & Dolton, J. L. (1997); Ranking of the world's oil and gas provinces by known petroleum volumes: U.S. Geological Survey Open-file Report-97-463, CD-ROM.
- [24]. Kulke, H.: (1995) Nigeria, In, Kulke, H., Ed., Regional Petroleum Geology of the World. Part II: Africa; America; Australia And Antarctica: Berlin, Gebrüder Borntraeger, Pg. 143-172.
- [25]. Kutcherov V.G., A.Yu. Kolesnikov, T.I. Dyuzheva, L.F. Kulikova, N.N. Nikolaev, O.A. Sazanova, V.V. Braghkin (2010): Synthesis of Complex Hydrocarbon Systems at Temperatures and Pressures Corresponding to the Earth's Upper Mantle Conditions. Doklady Akademii Nauk, 433 (3), 361–364.
- [26]. Lambert-Aikhionbare, D. O., and Ibe, A.C., (1984); Petroleum source-bed evaluation of the Tertiary Niger Delta: discussion: American Association of Petroleum Geologists Bulletin, 68, 387-394.
- [27]. L. Adeoti, E.A. Ayolabi and P.L. Jame (2009); An Integrated Approach to Volume of Shale Analysis: Niger Delta Example, Orire Field. World Applied Sciences Journal 7 (4): 448-452.
- [28]. L. P. Dakes (2001); The Practice of Reservoir Engineering, Revised edition. Elsevier Radarweg 29, P.O Box 211, 1000 AE Amsterdam, Netherlands.
- [29]. Mamdouh R. Gadallah and Ray Fisher (2009); Exploration Geophysics, Springer-Verlag Berlin Heidelberg. 1120 Nantucket Drive, Houston, TX 77057 and 14203 Townshire Drive, Houston, TX 77088, USA mgadallah@comcast.net and rfisherosu@sbcglobal.net.
- [30]. Odai L.A and Ogbe D.D. (2010); Building and Ranking of Geostatistical Petroleum Reservoir Models, MSc. Thesis, Unpublished, AUST, December.
- [31]. O. I. Horsfall, E. D. Uko, and I. Tamunobereton-ari (2013); Comparative analysis of sonic and neutron-density logs for porosity determination in the South-eastern Niger Delta Basin,

- Nigeria. American Journal of Scientific and Industrial Research, doi:10.5251/ajsir.2013.4.3.261.271.
- [32]. Orife, J. M. & Avb o, A. A. (1982); Stratigraphy and the unconformity traps in Niger Delta. American Association of Petroleum Geologist Memoire; Vol. 32, p. 265.
- [33]. Owolabi O.O, Longjohn T.F, Ajiienka J.A (1994); An empirical expression for permeability in unconsolidated sands of eastern Niger Delta: Journal of Petroleum Geology, 17(1): 111-116.
- [34]. P.I. Edigbue¹; A.A. Komolafe²; A.A. Adesida and O.J Itamuko (2014); Hydrocarbon reservoir characterization of “Keke” field, Niger Delta using 3 seismic and petrophysical data. American Journal of Scientific and Industrial Research.
- [35]. Reservoir Characterization and Paleo- Stratigraphic imaging over Okari Field, Niger Delta using neural networks; The Leading Edge, 1(6), 650 -655.
- [36]. Rider M, (1986); the Geological Interpretation of Well Logs. Blackie, Glasgow, 151-165.
- [37]. Sales, J. K.: (1997); Seals strength versus trap closures-a fundamental control on the distribution of oil and gas. In: R. C. Surdam, (ed.), Seals trap and petroleum system. American Association of Petroleum Geologists Memoir; Vol. 67, pp.57–83.
- [38]. Schlumberger Oil Servicing Co.: Techlog Interactive Suite 2010 Help Manual.
- [39]. Schlumberger, (1989); Log Interpretation, Principle and Application: Schlumberger Wireline and Testing, Houston Texas, pp. 21 – 89.
- [40]. Short, K. C. & Stauble, A. J. (1967); Outline of Geology of Niger Delta. American Association of Petroleum Geologists Bulletin; Vol. 51, p. 761–779.
- [41]. Stacher, P. (1995); Present Understanding of the Niger Delta Hydrocarbon Habitat, In, Oti, M. N., and Postman Eds., Geology of Deltas: Rotterdam, A. A., Balkema, Pg. 257-267.
- [42]. Tuttle, M.L.W., Charpentier, R.R., and Brownfield, M.E. (1990); Tertiary Niger Delta (Akata-Agbada) Petroleum System (No. 701901), Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa, in USGS, ed., The Niger Delta Petroleum System: Niger Delta Province, Nigeria, Cameroon, and Equatorial Guinea, Africa: Denver, Colorado, U.S. Department Of The Interior. S. Geological Survey.
- [43]. Uko, E D (1996); Thermal modeling of the Northern Niger delta. Unpublished Ph. D. Thesis, Rivers State University of Science and Technology, Port Harcourt.
- [44]. Udegbunam E.O and Ndukwe K, (1988); Rock Property Correlation for hydrocarbon producing sand of the Niger Delta sand, Oil and gas J.
- [45]. Wan Qin, (1995); Reservoir Delineation using 3-D Seismic Data of the Ping Hu Field, East China, Unpublished MSc thesis, University of Colorado Boulder pp 6-8.
- [46]. Weber, K. J. & Daukoru, E. M. (1975); Petroleum geology of the Niger Delta: Proceedings of the 9th World Petroleum Congress, Vol. 2, And Geology: London, Applied Science Publishers, Ltd., p. 210–221.