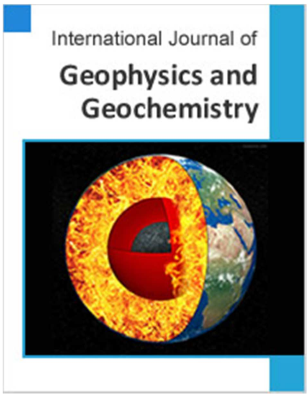
International Journal of Geophysics and Geochemistry
2017; 4(6): 73-82
http://www.aascit.org/journal/ijgg
ISSN: 2381-1099 (Print); ISSN: 2381-1102 (Online)

American Association for Science and Technology



Keywords
Porosity,
Permeability,
Water Saturation,
Hydrocarbon Saturation,
3D Seismic,
Faults,
Petrophysical and Structural

Received: October 5, 2017
Accepted: November 1, 2017
Published: December 5, 2017

3D Seismic Interpretation and Petrophysical Analysis of "Olu Field" Onshore Niger Delta

Samuel Onyekuryu*, Oluoma Chinonyerem Fortune, Adikwu Stephen Onum, Okoro Eze Martins, Obaje Enejo Christian

Department of Geology, Federal University of Technology Owerrri, Imo State, Nigeria

Email address
samuel.onyekuru@futo.edu.ng (S. Onyekuryu)
*Corresponding author

Citation
Samuel Onyekuryu, Oluoma Chinonyerem Fortune, Adikwu Stephen Onum, Okoro Eze Martins, Obaje Enejo Christian. 3D Seismic Interpretation and Petrophysical Analysis of "Olu Field" Onshore Niger Delta. *International Journal of Geophysics and Geochemistry.* Vol. 4, No. 6, 2017, pp. 73-82.

Abstract
In this study, seismic interpretation and petrophysical evaluation of the "Olufield" Onshore Niger Delta, was carried out using 3D seismic and well log data with a view to identify potential hydrocarbon reservoirs in the study area. Structural and stratigraphic interpretation was done on seismic sections while lithologic interpretation and petrophysical analysis was done with well log. The Fourteen (14) Faults that was mapped and seen on the time structural map include growth structures, synthetic faults, and counter regional antithetic faults. A total of four horizons (H1, H2, H3 and H4) were mapped and used to understand the stratigraphic complexity of the study area. Three hydrocarbon bearing sands were discovered with a good porosity ranging from 0.14 to 0.28. Result shows that the three reservoirs harbor considerable volumes of hydrocarbon enough to make an affirmative business decision

1. Introduction

The great demand for energy has placed both pressure and greater challenge to increase energy supply in Nigeria. The risk factor associated with the probability of hydrocarbon presence in any basin has been reduced due to the advancement in computational technology. In Nigeria oil is the major revenue base for national development and as such greater efforts is demanded from both the Government and the research institutions to ensure that this non-renewable resource is adequately tapped [1].

The Niger Delta province of Nigeria has accumulation of oil and gas in commercial quantity, which is produced from the pore spaces of reservoir rocks usually sandstone. The formation is characterized by alternating sandstone and shale units varying in thickness from 100ft to 1500ft [2-3]. The sand in this formation is mainly hydrocarbon reservoir with shale providing lateral and vertical seal. The most important tools used to explore for undiscovered hydrocarbons and to develop proven hydrocarbon reserves are reservoir characterization and subsurface geological mapping. As a field is developed from its initial discovery, a large volume of well, seismic and production data are obtained. With the integration of these data sets, the accuracy of the subsurface interpretation is improved through time.

3D seismic interpretation often requires extrapolating well data far from the area of interest, crossing faults, sequence boundaries and other discontinuities [4].

In order to characterize the "Olu field", 3D seismic sections and composite well logs (which include the Gamma Ray, Resistivity, Sonic and Neutron Density logs) were examined and interpreted with a view to unravel the hydrocarbon in place.

1.1. Background of Study

Seismic reflection surveys are used in exploration for oil and gas, coal and the study of the earth's deep crustal layers. For Successful exploration, information integration is required from several disciplines and it is seismic interpretation which brings them together [5].

Reservoir rocks, their porosity and permeability are the most important physical properties with respect to storage and transmission of fluids. Knowledge of these two properties for any hydrocarbon reservoir together with the fluid properties is required for efficient development, management and prediction of future performance of the oil field.

Seismic interpretation is the extraction of subsurface geologic information from seismic data. It is the thoughtful procedure of separating the seismic wavelet from noise and various kinds of defects. Simply defined, seismic interpretation is the science (and art) of inferring the geology at some depth from the processed seismic record.

Seismic energy is reflected from interfaces where the acoustic properties of the rock change. These interfaces follow sedimentary boundaries created at the time of deposition of the sediments. While modern multichannel data have increased the quantity and quality of interpretable data, proper interpretation still requires that the interpreter draw upon his or her geological understanding to pick the most likely interpretation from the many "valid" interpretations that the data allow.

The seismic record contains two basic elements for the interpreter to study. The first is the time of arrival of any reflection (or refraction) from a geological surface. The actual depth to this surface is a function of the thickness and velocity of overlying rock layers. The second is the shape of the reflection, which includes how strong the signal is, what frequencies it contains, and how the frequencies are distributed over the pulse. This information can often be used to support conclusions about the lithology and fluid content of the seismic reflector being evaluated.

The interpretation process can be subdivided into three interrelated categories: structural, stratigraphic and lithologic. Structural seismic interpretation is directed toward the creation of structural maps of the subsurface from the observed three-dimensional configuration of arrival times. Seismic sequence stratigraphic interpretation relates the pattern of reflections observed to a model of cyclic episodes of deposition. The aim is to develop a chronostratigraphic framework of cyclic, genetically related strata. Lithologic interpretation is aimed at determining changes in pore fluid, porosity, fracture intensity, lithology, and so on from seismic data.

Petrophysical characteristics of reservoir rocks include porosity, permeability, water saturation, hydrocarbon saturation, formation water resistivity and formation factors. These properties are determined by grain size, grain shape, and degree of compaction, amount of matrix, cement composition, type of fluid present and saturation of different fluids. Among these properties porosity, permeability and fluid saturation are the most important and can be measured using standard procedures.

For scientific and economic purposes, laboratory data of high accuracy and reliability for both the fluids and the rocks that contain them are extremely useful information evaluation. However such data cannot be acquired very quickly, hence the operators in the field need a method of acquiring the fundamental properties of the rocks and their fluid contents for a quick management decision making. This requirement is easily satisfied by the use of geophysical wireline logs. Recent reservoir evaluation involves the study of well cuttings, cores, well log data, formation micro scanner (FMS) images and drill stem tests.

However, the wireline log is basically used for this work in integration with seismic sections. The well logs used include Gamma Ray, Density, Neutron, Sonic and Resistivity logs. The main petrophysical parameters evaluated in this work are porosity, permeability, water and hydrocarbon saturation as well as sand/shale percentages of these reservoirs.

The knowledge of the reservoir dimension is an important factor in quantifying producible hydrocarbons [6]. Among the needed information includes the thickness and areal extent of the reservoir. These parameters are important because they serve as veritable inputs for reservoir volumetric analysis, i.e. the volume of hydrocarbon in place [7]. It is therefore imperative that they are determined with reasonable precision. Precise determination of reservoir thickness is best obtained from well logs especially, using the gamma ray and resistivity logs [8]. Because all oil and gas produced today come from accumulations in the pore spaces of lithologies like sandstones, limestones or dolomites, the gamma ray log can come in handy to help in lithology identification, i.e. to differentiate between the reservoir rock (sand) and the embedding shale [8].

If core data is available, other lithologies like limestone or dolomites can be identified [9]. The resistivity log on the other hand can be used for determining the nature of interstitial fluid i.e. differentiating between (saline) water and hydrocarbon in the pore spaces of the reservoir rocks. Since these logs are recorded against depth, the hydrocarbon-bearing interval can be determined. Accurate mapping of the lateral dimension of the reservoir on the other hand, can be obtained from well logs, where abundantly available, or direct hydrocarbon indicators [10]. To use well logs to map the lateral dimension of the reservoir, the gas-oil and oil- water contacts are located on structure maps [11]. This process can be seriously hampered when, as is usually the case, limited borehole information from wells is available.

Also, in mapping reservoir boundaries, studies of geologic structures that can hold hydrocarbon in place must be considered. Hydrocarbons are found in geologic traps, that is, any combination of rock structure that will keep oil and gas from migrating either vertically or laterally [12]. These traps can either be structural, stratigraphic or a combination of both. Structural traps can serve to prevent both vertical and lateral migration of the connate fluid [11]. Examples of these include anticlines and flanks of salt domes. Stratigraphic traps include sand channels, pinchouts, unconformities and other truncations [13]. According to [2], majority of the traps in the Niger delta are structural and to locate them, horizons are picked and faults mapped on seismic inlines and crosslines to produce the time structure map. This can reveal the structures that can serve as traps for the hydrocarbon accumulations. It is then possible to deduce the relevant petrophysical parameters from well logs, for the computation of the volume of hydrocarbon in place.

1.2. Statement of the Problem

One of the major challenges in reservoir geophysics is the integration of all available data for characterization of the pay zone and the reduction of uncertainty in interpretation. An actual reservoir can only be developed and produced once, and mistakes can be tragic and wasteful. It is essential to model the reservoir as accurate as possible in order to calculate the reserves and to determine the most effective way for optimum recovery.

Integrated 3D seismic interpretation techniques hence, allows for 3D visualization of the subsurface, enhancing understanding of reservoir heterogeneities for improved hydrocarbon recovery rates.

1.3. Justification

The integration of 3D seismic interpretation with quantitative petrophysical evaluation of the available field data will provide the necessary information to intelligently judge the risks and opportunities involved in winning new hydrocarbon prospects from an old abandoned field using improved techniques.

1.4. Aim and Objectives

The aim of this study is to identify potential hydrocarbon reservoirs in the study area by integrating 3D seismic and petrophysical data.

The objectives of this study include to:

1. Delineate hydrocarbon-bearing sands from well-log correlation and analysis.
2. Carry out well-to-seismic tie in order to establish a relationship between the seismic and well log data.
3. Map faults and horizons in order to understand the structural framework andtrapping mechanisms in the field
4. Evaluate petrophysical properties including volume of shale (V_{sh}), effective porosity ($Ø_e$), net to gross ratio (N/G), water saturation (S_w), hydrocarbon saturation (S_h) etc.
5. Estimate the hydrocarbon volumes in the identified reservoir zones.

1.5. Scope of the Study

This study focuses on the integration of 3D seismic and well-log data in the evaluation of petrophysical properties of hydrocarbon reservoirs in "Olufield" onshore Niger Delta. It includes the identification and delineation of the structural and stratigraphic traps within "Olufield" from seismic data, which also aided in the mapping of the subsurface geology of the area.

The well log data was used to produce accurate correlation of the wells that penetrated the reservoir sands. The GR and resistivity logs helped in distinguishing the sand-shale sequence within the wells which in turn helped in differentiating permeable from non-permeable intervals, thereby defining bed boundaries. The resistivity and porosity log helped in delineating the fluid content of the reservoir formation and to identify the Gas-Oil contact as well as Oil-Water contacts across the field.

1.6. Geology of the Study Area

The "Olu field" lies within the Coastal Swamp Depobelt of the Niger Delta oil province (Figure 1). It is located within longitude 05˚41′27″E to 05˚42′05″E and latitude 05˚51′55″N to 05˚52′03″N on the western part of Niger Delta.

The field contains thirteen onshore wells from which ten wells were selected specifically for the purpose of this study. The field is operated by Shell Petroleum Development Company of Nigeria (SPDC). The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta province [14]. The delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development from the Eocene to the present, [2]. The depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2, a sediment volume of 500,000 km^3 [15], and a sediment thickness of over 10 km in basin depocenter [16].

The Niger Delta Province contains only one identified petroleum system [17-18]. This system is referred to as the Tertiary Niger Delta (Akata-Agbada) Petroleum System. The maximum extent of the petroleum system coincides with the boundaries of the province. The Benin Formation which is the upper delta-top lithofacies has been described as coastal plain sands. The Benin formation consists predominantly of massive, highly porous, fresh-water sand stones with shale/clay interbeds. These sediments represent upper delta-plain deposits, so that the gravels and sandstones represent braided streams, point-bar channel fills, while shales and clays may represent back swamp-deposits [19]. The Agbada Formation consists of interbedded sand and shales with a thickness of about 300 – 4,500 meters [20]. The sandy parts constituted the main hydrocarbon reservoirs, while the shales form the seal (cap) rock [19]. The Formation is rich in microfauna at the base decreasing upwards thus indicating and increasing rate of deposition in the delta front. The sandy parts of the formation are known to constitute the main hydrocarbon reservoirs of the Niger Delta oil fields and the shales constitute seals to the reservoirs. The Agbada

Formation gets younger down delta from northeast to southwest. It is widely agreed to be of Eocene age, although Agbada facies is being laid at the present day on the inner continental shelf within the landward units of mangrove swamp and brackish water environment [3]. The Akata Formation is a marine prodelta megafacies, mainly composed of marine shales with locally sandy and silty beds thought to have been laid down as turbidities and continental slope channel fills. The prodeltaic shales are plastic, low density, overpressured, shallow marine to deep water. As defined by paleontological evidence, the marine shales of Akata Formation range in age from Paleocene in the proximal partsof the delta to Recent in the distal offshore. The formation is said to be the main source rock or Niger Delta complex.

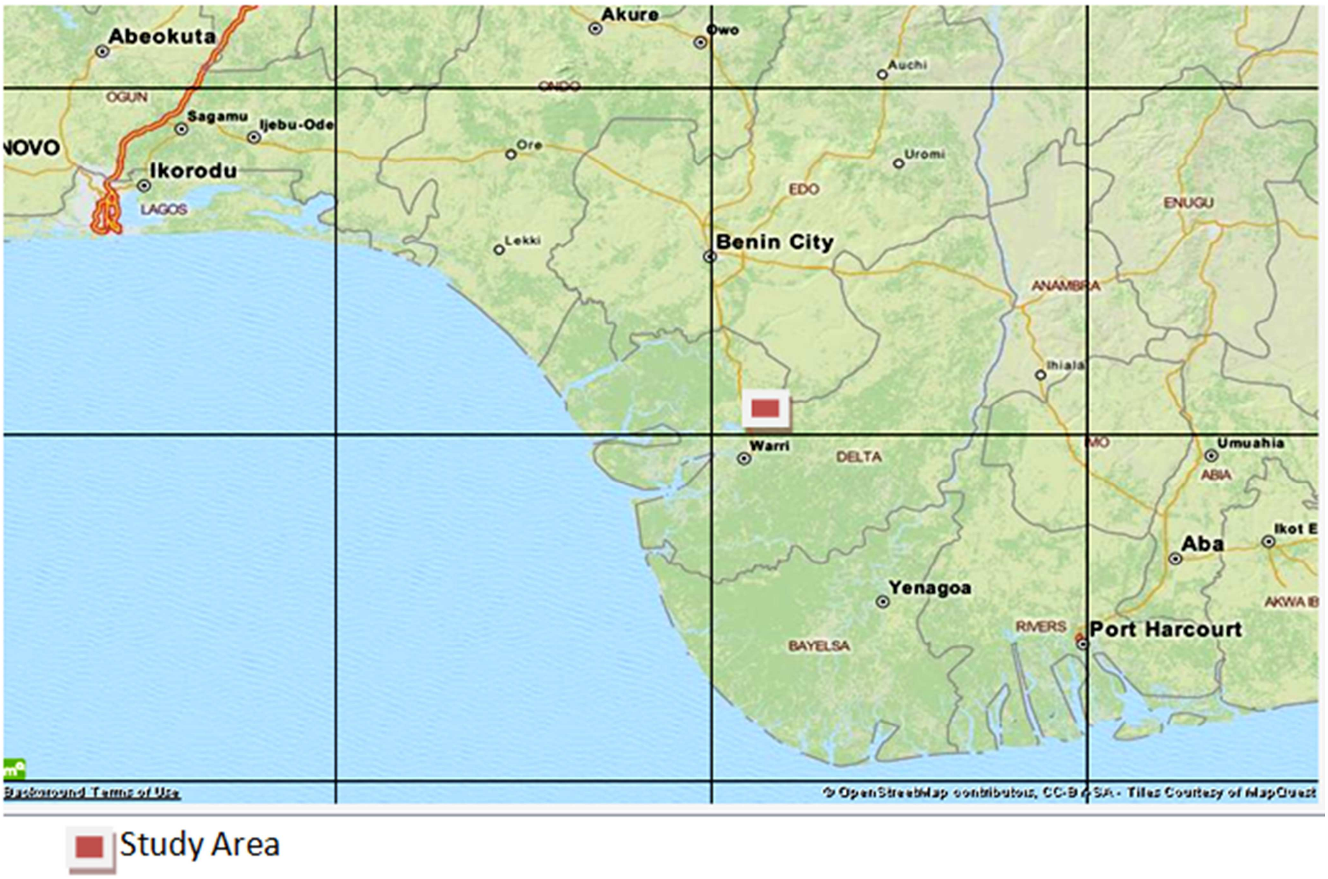


Figure 1. *Geological map of Niger Delta showing the study area (Modified from Google Earth).*

2. Methodology

The data used for this work was compiled by Shell Petroleum Development Company of Nigeria (SPDC) Port Harcourt in line with the Department of Petroleum Resources (D.P.R.) and the federal government's policy on education urging multinational companies operating in Nigeria to support academic research. The compiled dataset include well heads and well deviation data, composite log suites from ten wells in the "Olu Field", Central Swamp depobelt, logged with gamma ray, neutron, sonic, density and resistivity logs, 3D seismic volume covering the study area and checkshot data.

Software tools used for the interpretation include Petrel 2013. MS Excel, Notepad and MS Power Point. Figure 2. Shows the worklow of the interpretation

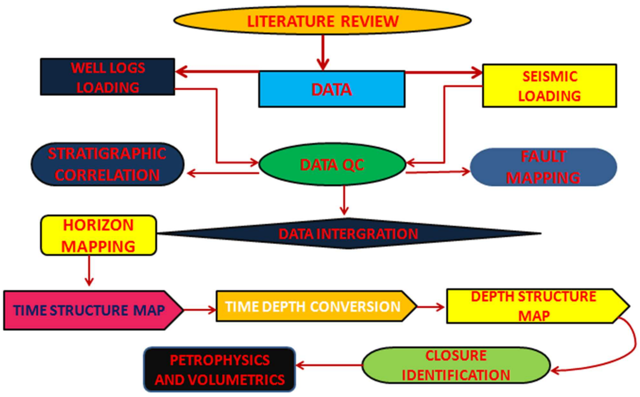


Figure 2. *Workflow chat.*

2.1. Determination of Shale Volume

The volume of shale, which is the percentage of shale contained in a sandstone or heterolithic reservoir, was calculated using the [21] equation for Tertiary rocks:

$$V_{sh} = 0.083*(2^{3.7*IGR}-1)$$

Where I_{GR} is the gamma ray index and is given by:

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

GR_{log} is the gamma ray reading of the formation, GR_{min} is the minimum gamma ray reading (sand baseline) and GR_{max} is the maximum gamma ray reading (shale baseline).

2.2. Determination of Total Porosity and Effective Porosity.

Total and effective porosity was estimated from the density, neutron, and sonic logs. It is generally accepted among geoscientists that porosity calculation from bulk density logs is more accurate [22-25]. To calculate the porosity (Ø), we used the rock matrix density, ρma, the fluid density, ρf, and the bulk density, ρb. The average rock density in the sandstones research reports is 2.66gcm^{-3}. The average rock density in the shales is 2.65gcm^{-3}. The fluid density depends on whether the well encounterred water or hydrocarbons. This was determined by the electrical resistivity log. The hydrocarbon density was calculated from composition and phase considerations, oil = 0.80 gcm^{-3} and gas = 0.6 gcm^{-3}. The water density used was 1 gcm^{-3}. Porosity was determined from the formula [26]:

$$\emptyset_{density} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$$

Where ρ_{ma} = matrix (or grain) density, ρ_f = fluid density and ρ_b = bulk density (as measured by the tool and hence includes porosity and grain density.

Effective porosity was calculated using the equation given below:

$$\emptyset_e = (1-V_{sh})*Por\_den$$

2.3. Water Saturation Estimation

In order to calculate the saturation of the fluid content of the reservoir sands, the formation water saturation was first computed by using the [21] for water saturation given as:

$$S_w=(FR_w/R_t)^{1/n}$$

Where n is the saturation exponent (usually 2), R_w is the formation water resistivity and R_t is the true rock resistivity (i.e. resistivity of the uninvaded zone), and F is the formation factor. The formation factor was determined using the Humble's formula for unconsolidated sands, given as:

$$F=0.62/(\emptyset^{2.15})$$

Where 0.62 is a constant value for the tortuosity factor and was used in this algorithm for unconsolidated Tertiary rocks of the Niger delta.

2.4. Net Pay Estimation

The determination of net pay is a required input to calculate the hydrocarbon pore feet, F_{HCP}, at a wellbore and its input to the overall reservoir original oil in place (OOIP) or original gas in place (OGIP) calculations. The total F_{HCP} at a well is the point-by-point summation over the reservoir interval with. The top and base of the reservoir interval are defined by geologists on the basis of core description and log characteristics. The hydrocarbon pore feet is given as:

$$F_{HCP} = \sum_{i=1}^{i=m} h_{ni}\emptyset_t(1 - S_W)_t$$

2.5. Determination of Permeability

Estimates of permeability can be made from empirical equations. Permeability is controlled by such factors as pore size and pore-throat geometry, as well as porosity. Permeability values for the reservoir zones were determined by relating formation factor (F) to irreducible water saturation using the equation [8]

$$S_{wi}^2 = \frac{F}{2000}$$

The widely used [27] equation which relates permeability to irreducible water saturation and porosity was then applied only in hydrocarbon-bearing zones. The equation is given below:

$$K = 100\,x\,\frac{\emptyset^2 x(1 - S_{wi})}{S_{wi}}$$

Where K = permeability in millidarcies, ϕ = effective porosity as a bulk volume fraction and S_{wi} = irreducible water saturation.

2.6. Hydrocarbon Volumetric Calculation

Deterministic estimation of the volume of hydrocarbon in place involves the application of one or more simple equations that describes the volume of hydrocarbon filled pore space in the reservoir and the way that volume will change from the reservoir to the surface. We considered the weighted mean hydrocarbon saturation of the net pay section and estimated the hydrocarbon in place. This quantity is the Oil in Place, abbreviated to OIIP which is given as:

$$OIIP = GRV *N/G* \phi*(1 - S_{wi})$$

Where GRV is the Gross Rock Volume, the product of reservoir area and individual zone thickness, N/G is the net to gross (interval ratio). ϕ and S_{wi} are the corrected porosity and interstitial water saturation respectively. OIIP was converted into recoverable reserve in terms of stock tank oil initially in place (STOIIP) by applying three additional factors.

$$STOIIP = (7758 * GRV * N/G * (-S_{wi}))/FVF$$

Where FVF is the formation volume factor estimated from the production data.

Recoverable reserve (N) is given as:

$$N = STOIIP * RF$$

Where RF is the Recovery factor which depends on drive mechanism, permeability, reservoir depth and hydrocarbon viscosity. RF was estimated using the equation below:

$$RF = \frac{100(1 - S_{wi} - S_{or})}{1 - S_{wi}}$$

Where S_{wi} is the irreducible water saturation and S_{or} is the oil saturation.

Incorrect porosity value and water resistivity (R_w) can introduce significant error in reserve estimation. The resistivity-porosity cross plot was used to estimate the water cut which showed clearly if the reservoir would be producible or not by taking a quick glance at the cluster of points whether it is below or above the 60% water saturation line.

3. Results

3.1. Interpretation of Well Logs

Correct interpretation of well logs is critical to any reservoir evaluation and characterization. Log correlation provides the basis for the determination of reservoir geometry and architecture [27]. The wells in "Olu" field were arranged and interpreted according to spatial distributions in the well field which arranged the wells according to affinity and not with respect to well numbers. A type log (Olu-002) was chosen for loop-tying the wells. This correlation type log shows a complete (unfaulted) interval of sediments representative of the thickest and stratigraphically deepest sedimentary section penetrated by the wells within the field. Lithological correlation in the study area revealed three reservoir intervals, namely D_sand, E_sand and F_sand (Figure 3). Delineation of these sand units have been aided by the combination of several logs including resistivity, gamma ray, neutron and density logs.

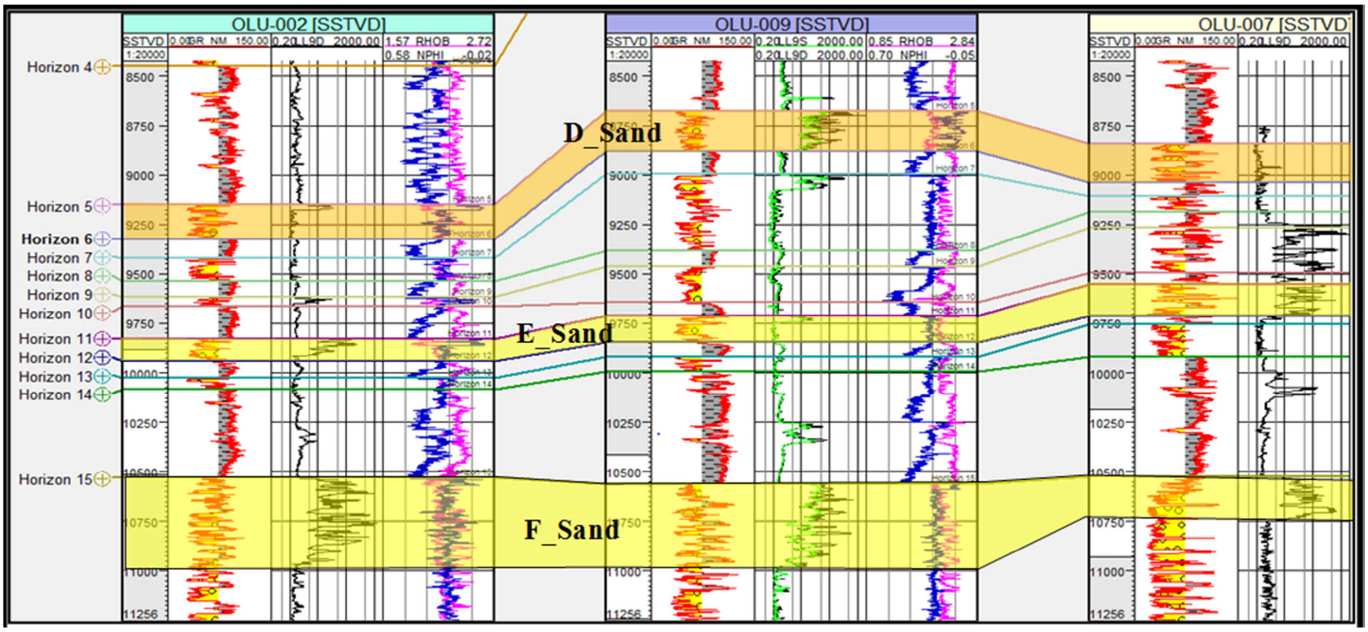


Figure 3. *Correlation Panel showing the delineated sand units in some of the wells.*

3.2. Fault and Horizon Mapping

Fault picking on the seismic cube was carried out in order to delineate the geological structural trend in the study area. A total of fourteen faults were mapped and labeled F1 to F14 (Figure 4), showing the structural complexity of the study area. Some of these faults are listric faults which are typical of the Niger Delta growth structures with the "spoon"shapes. Faults 2, 4 and 5 are structure building, synthetic faults, while faults 10, 11, 12 and 13 are counter regional, antithetic faults. The mapped faults were used to capture the strati-structural styles and controls relative to the sediment supply rate in the accommodation spaces created by the displacements of the faults (Figure 4). The faults also helped us understand how structures affected the subsurface stratigraphy in the study area. The structure of the field indicated major growth faults and antithetic faults which forms the major structural trap types identified in the Niger Delta by [2].

In mapping the horizons, faults and other structural plays prevalent in the field were thoroughly obeyed, so as to have a robust and accurate representation of the subsurface geology of the study area.

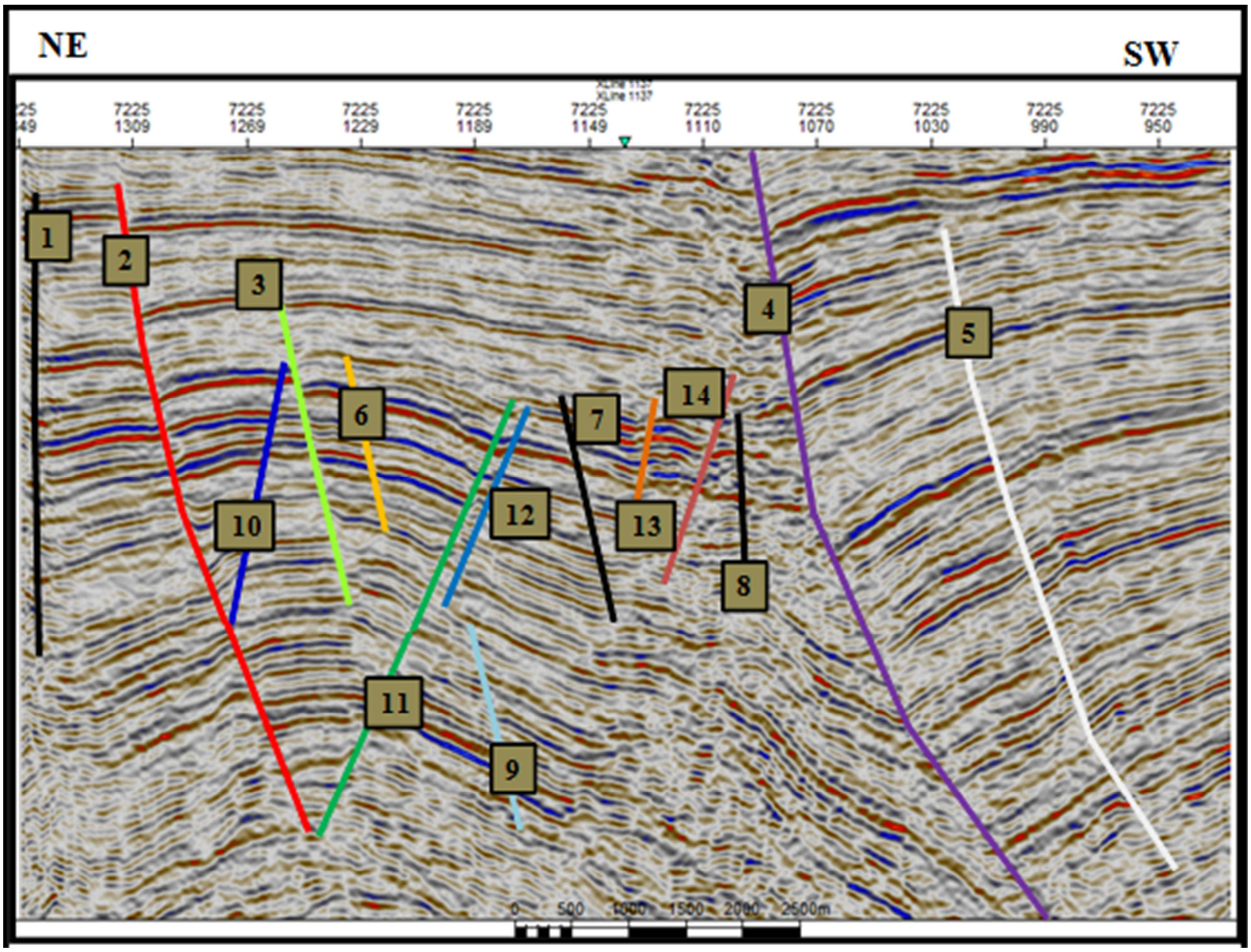


Figure 4. *Interpretation of Faults showing structural complexities.*

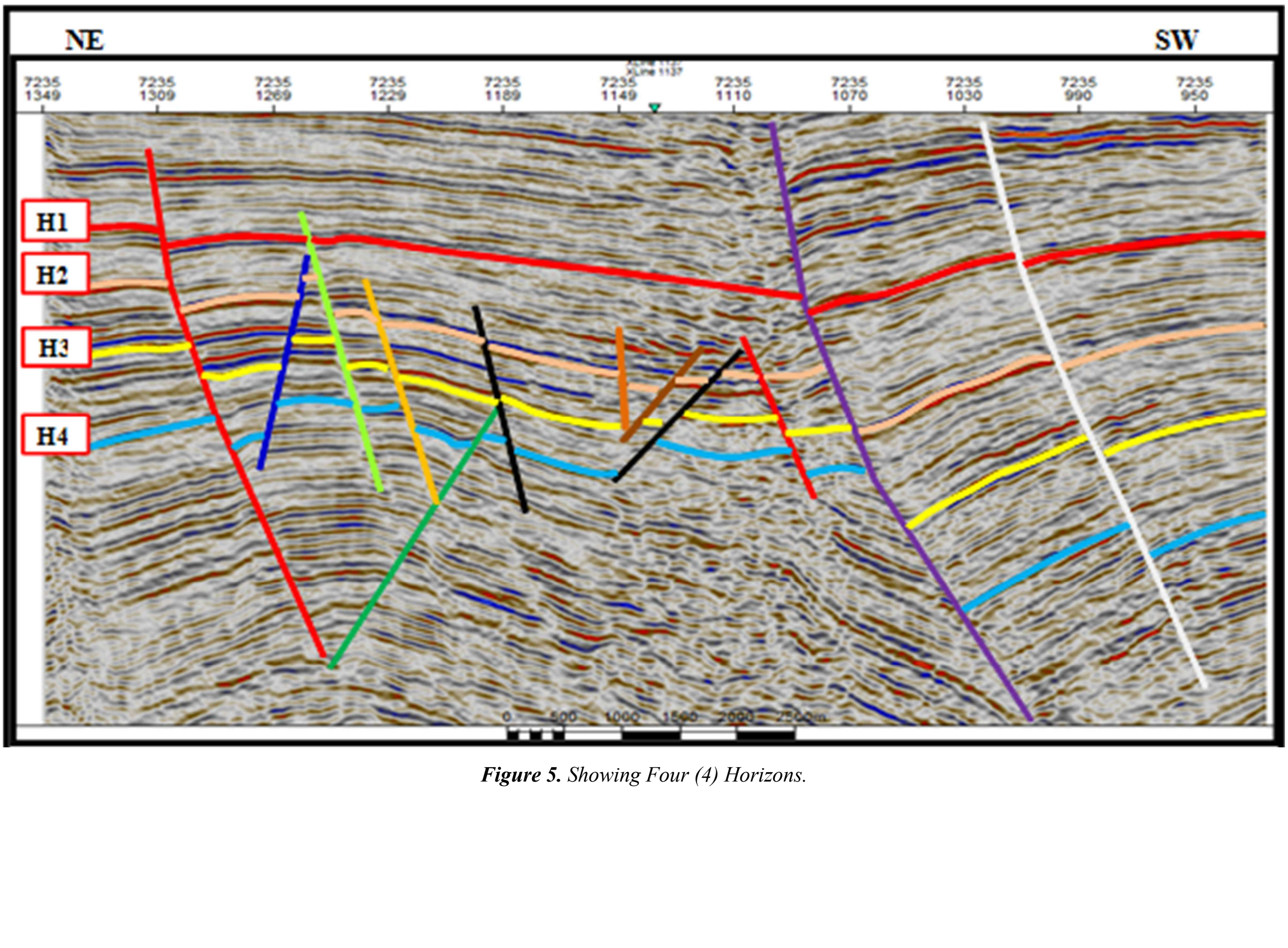


Figure 5. *Showing Four (4) Horizons.*

3.3. Petrophysical Evaluation

Permeable reservoir sands were distinguished from the impermeable shales using a combination of log suites including resistivity, density, neutron and caliper logs. The subsurface lithology in the study area was interpreted using the natural gamma ray, which is used for distinguishing between clean sands formations and shaly formations. The more impermeable zones indicate shale intervals with high concentration of clay minerals which decrease the effective porosity and permeability. Permeable zones are likely to be one of the dominant mineralogies (sandstone/limestone/dolomite), but in this study sandstones are the only dominant mineralogy in permeable zones.

A total of three reservoir zones were delineated in the study area using three of wells with the best quality log suites. The reservoir zones are designated D_Sand, E_Sand and F_Sand respectively (Figure 5).

3.4. Estimated Petrophysical Properties

Logs of the determined petrophysical parameters for each of the three wells are shown in Figure 6. Table 1 to Table 3 are summary of the average petrophysical results for the evaluated reservoir sands.

The petrophysical analysis revealed F_Sand to be the most viable reservoir unit with average net thickness as high as 81 ft. All the three reservoirs exhibited good petrophysical attributes with high effective porosity and hydrocarbon saturation except in Olu-007 well where the D Sand reservoir tested 98% water.

The reservoirs are clean sands with high net to gross ratios and low volume of shale resulting in high effective porosities and low water saturation.

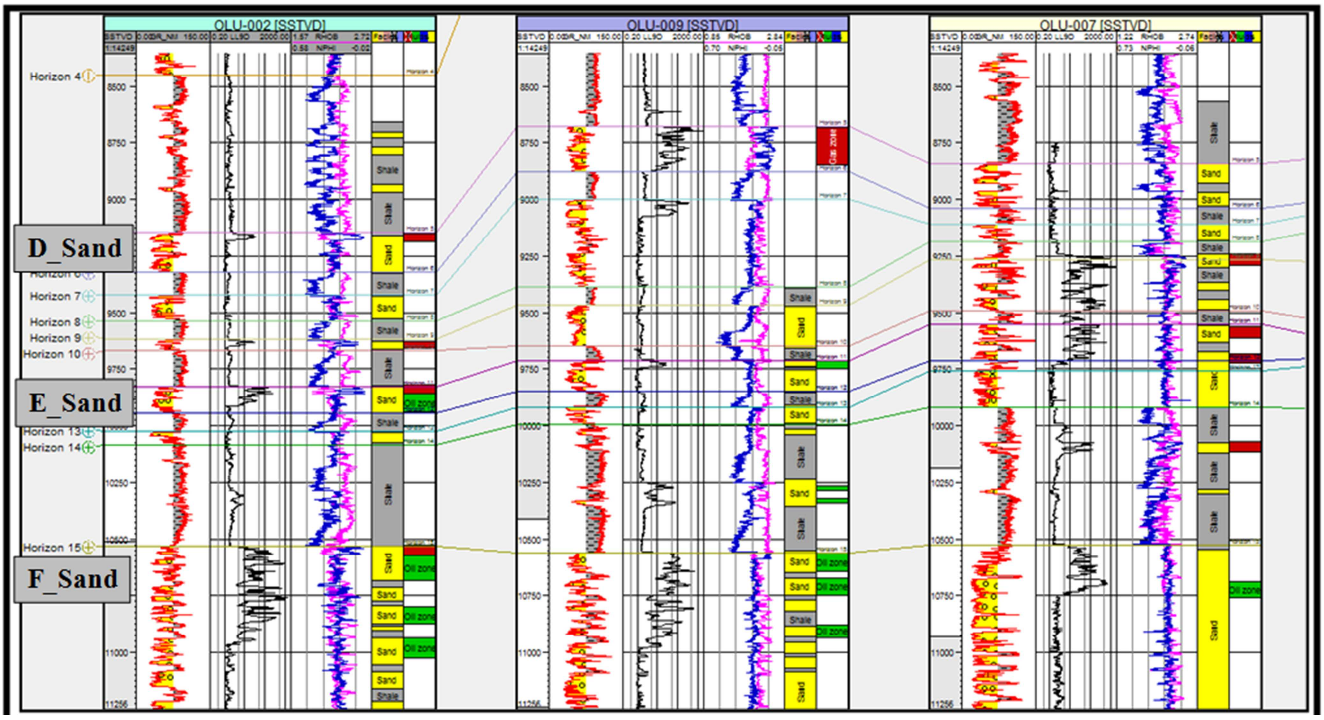


Figure 6. *Showing Reservoirs zones across the wells.*

Table 1. *Average Petrophysical results for Olu002.*

Parameters	Reservoirs		
	D_SAND	**E_SAND**	**F_SAND**
TOP (ft)	9206	9869	10591
BASE (ft)	9232	10018	10734
GROSS (ft)	26	149	143
NET (ft)	20	82	69
NTG	0.76	0.55	0.48
V_{SH}	0.24	0.45	0.52
Øe	0.28	0.17	0.14
S_W	0.37	0.46	0.19
S_h	0.63	0.53	0.81

Table 2. *Average Petrophysical results for Olu009.*

Parameters	Reservoirs		
	D_SAND	**E_SAND**	**F_SAND**
TOP (ft)	8738	9777	10610
BASE (ft)	8939	9915	10802
GROSS (ft)	202	138	192
NET (ft)	133	79	106
NTG	0.66	0.57	0.55
V_{SH}	0.34	0.43	0.45
Øe	0.23	0.17	0.16
S_W	0.20	0.87	0.16
S_h	0.80	0.13	0.84

Table 3. *Average Petrophysical results for Olu007.*

Parameters	Reservoirs		
	D_SAND	E_SAND	F_SAND
TOP (ft)	8890	9602	10721
BASE (ft)	8975	9687	10801
GROSS (ft)	85	85	80
NET (ft)	58	52	68
NTG	0.68	0.61	0.85
V_{SH}	0.32	0.39	0.15
Øe	0.19	0.18	0.27
S_W	0.98	0.17	0.20
S_h	0.02	0.83	0.80

4. Discussion

Volumetric methods attempt to determine the amount of oil-in-place by using the size of the reservoir as well as the physical properties of its rocks and fluids. Then a recovery factor (RF) is assumed, using assumptions from fields with similar characteristics. The stock tank oil initially in place (STOIIP), or the gas initially in place (GIIP), is multiplied by the recovery factor to arrive at a reserve estimate. The recovery factors for gas cap fields (typical of the Olufield) is usually within the range of 15-25% for solution gas drive, gas cap drive and water drive saturated reservoirs and is usually the first estimate for a new discovery until other production mechanisms have been observed in the field [28].

A simple weighted average among the major oil provinces gives an average recovery factor of 22% which is well within the range of the solution gas drive reservoirs. By analogy, the overall recovery factor for the bulk of the world's conventional oil reserves would at best be about 20% [29]. For the sake of this work however, a recovery factor of 20% is employed.

The oil reserve and gas reserve could be computed from the formulae below:

Oil Reserve = $((7758*A*h*S_o*Ø)/B_o)*RF$

Gas Reserve = $((43560*A*h*S_g*Ø)/B_g)*$ RF

Where

7758 = conversion factor from acre-ft to bbl

43560 = conversion factor from acre-ft to ft^3

Ø = average effective porosity of the reservoir (fractional)

A= Area of the field

h= net reservoir thickness

S_o = average oil saturation (fractional).

S_g = Hydrocarbon saturation (gas) fractional.

B_o = Formation oil volume factor = 1.2 bbls/STB

B_g = Formation gas volume factor = 0.005 cuft/scf

RF = Recovery factor (fractional)

The Area of the field gas reserve is approximately $29km^2$, which equals 7125 acres.

A summary of the computed hydrocarbon volumes in the evaluated reservoir sands for each of the three wells is presented in Table 4 to Table 6.

Table 4. *Volume calculation summary report sheet for the three reservoirs in Olu002-well.*

Reservoir Name	STOIIP MBBL)	GIIP (BCF)	Recoverable Oil @ 20% MBBL)	Recoverable Gas @ 80% (BCF)
D_Sand	-	219	-	175
E_Sand	216	264	43	211
F_Sand	282	150	56	120

Table 5. *Volume calculation summary report sheet for the three reservoirs in Olu009-well.*

Reservoir Name	STOIIP MBBL)	GIIP (BCF)	Recoverable Oil @ 20% MBBL)	Recoverable Gas @ 80% (BCF)
D_Sand	-	1.5	-	1.2
E_Sand	80.4	-	16.1	
F_Sand	656	-	131	-

Table 6. *Volume calculation summary report sheet for the three reservoirs in Olu007-well.*

Reservoir Name	STOIIP MBBL)	GIIP (BCF)	Recoverable Oil @ 20% MBBL)	Recoverable Gas @ 80% (BCF)
D_Sand	-	-	-	-
E_Sand	-	482	-	385
F_Sand	676	-	135	-

From the tables above, it is readily observed that the three reservoirs contain considerable volumes of hydrocarbon enough to make an affirmative business decision.

5. Conclusion

3D Seismic interpretation and petrophysical evaluation of "Olu Field" located in the central swamp Depobelt, Onshore Niger Delta, have been attempted in this study. The intergrated cross-disciplinary approach adopted has led to the successful delineation of hydrocarbon reservoirs within the study area. These include the D_Sand, E_Sand and F_Sand reservoirs. Petrophysical properties evaluation and volumetric assessments of these high quality reservoir sands revealed that these prospects contain economically viable amounts of oil and gas for affirmative business decision.

The quality conscious, multidisciplinary approach has enabled quantitative interpretation of reservoir architecture, lithology prediction and prospect identification and has also improved our understanding of the subsurface geological framework of the study area.

Recommendation

Deeper horizons indicate that the seismic datasets used are characterized by poor imaging with increasing depth. Hence reacquisition and/or processing should be done to improve seismic data quality for better imaging and interpretation/ Mapping.

Core samples and core photo should be provided for effective lithologic andpetrophysical interpretation of the given data in the study area

References

[1] Adaeze, I. U., Onyekuru, S. O. and Iwuagwu, C. J. (2012). Petrophysical evaluation of uzek well using well log and core data, Offshore Depobelt, Niger Delta, Nigeria. Pelagia Research Library, Advances in Applied Science Research, (5): 2966-2991.

[2] Doust, H. and Omatsola, E. (1990). Niger Delta, in, Edwards, J. D., and Santogrossi, P. A., eds., Divergent/passive Margin Basins, AAPG Memoir 48: Tulsa, American Association of Petroleum Geologists, pp. 239-248.

[3] Short, K. C. and Stauble, J. (1967). "Outline geology of the Niger delta," *AAPGBulletin*, vol. 51, no. 5, pp. 761–779.

[4] Sheriff, R E. and Geldart, L. P., (1982). Explorational Seismology, Vol. 1, Cambridge University Press. Cambridge. 253pp.

[5] Chopra. S and Huffman A. R. (2006). Velocity determination for pore-pressure prediction. The Leading Edge, December 2006 Vol. 25, No. 12 © 2006 Society of Exploration Geophysicists. pg. 1502.

[6] Schlumberger (1989) Schlumberger log principles and applications.

[7] Ejedawe, J. E. (1989). "The Eastern Niger Delta: Geological Evolution and Hydrocarbon Occurrences," SPDC Internal Report Exploration Note 89.002.

[8] Asquith, G. and Krygowski, D., 2004. Basic Well Log Analysis. AAPG Methodsin Exploration Series, 16. Manchester, United Kingdom. 2, pp. 23-59.

[9] Keelan, D. K. and McGinley, D. C. (1979). Application of Cation Exchang Capacity in a Study of the Shannon Sand of Wyoming. Paper KK presented at the SPWLA Annual Symposium, p. 1-5.

[10] Brown, A. R. and Wright, R. M., 1984. Mapping of producible gas sand in the North Sea. Geophysics, pp. 4-14.

[11] Coffen, J. A., 1984. Interpreting seismic data: Penwell Publishing Company, Tulsa Oklahoma. pp. 39-118.

[12] Tearpock, D. J., and Bischke, R. E. (2003). Applied Subsurface Geological Mapping with Structural Methods, Prentice Hall publishers, New Jersey, pp. 265.

[13] Ejeh, I. O. (2010). Sedimentary Fill Modeling: Relationships to Sequence Stratigraphy and Its Implications for Hydrocarbon Exploration in the Niger Delta, Nigeria. The Pacific Journal of Science and Technology, V. 11. No. 1, p. 502-509.

[14] Klett, T. R., Ahlbrandt, T. S., Schmoker, J. W., and 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.

[15] Hospers, J. (1965). "Gravity Field and Structure of the Niger Delta, Nigeria, West Africa". *Geological Society of American Bulletin:* Vol. 76, pp. 407-422.

[16] Kaplan, A., Lusser, C. U., Norton, I. O., 1994, Tectonic map of the world, panel 10: Tulsa, American Association of Petroleum Geologists, scale 1:10,000,000.

[17] Kulke, H. (1995). "Nigeria": Kulke, H., (ed.), Regional Petroleum Geology of theWorld. Part II: Africa, America, Australia and Antarctica: Berlin, Gebrüder Borntraeger, pp. 143-172.

[18] Ekweozor, C. M., and Daukoru, E. M, 1994, Northern delta depobelt portion of theAkata-Agbada (!) petroleum system, Niger Delta, Nigeria.

[19] Weber, K. J. (1971). "Sedimentological aspects of oil fields in the Niger delta,"*Geologie en Mijnbouw*, vol. 50, pp. 559–576.

[20] Weber, K. J. and Daukoru, E. M. (1975). Petroleum geology of the Niger Delta Proceedings of the Ninth World Petroleum Congress, volume 2, Geology: London, Applied Science Publishers, Ltd., pp. 210-221.

[21] Archie, G. E., 1950. Introduction to Petrophysics of reservoir rocks. AAPG Bulletin, Tulsa, 34 (5): 943-961.

[22] Rider, M. (2006). The geological interpretation of well logs. Progress Press Co. Ltd, Malta, p. 43-67.

[23] Calderon, J. E. and Castagna, J. (2007). Porosity and lithologic estimation usingrock physics and multi-attribute transforms in Balcon Field, Colombia. P. 142-150.

[24] Issler, D. R. (1992). A new approach to shale compaction and stratigraphicrestoration, Beaufort-Mackenzie Basin and Mackenzie Corridor, northern Canada, *American Association of Petroleum Geologists Bulletin*, 76 (8), p. 1170–1189.

[25] Horsfall, O. I., Uko E. D. and Tamunobereton-ari, I. (2013). Comparative analysis of sonic and neutron-density logs for porosity determination in the Southeastern Niger Delta Basin, Nigeria, *American Journal of Scientific and Industrial Research*, 4 (3), p. 261-271.

[26] Wyllie M. R. J., Gregory A. R. and Gardner L. W. (1956). Elastic wave velocities inheterogeneous and porous media. *Geophysics* 21, p. 41-7.

[27] Coates, G. R., and Denoo, S. (1981). The producibility answer product: Schlumberger Technical Review, v. 29, no. 2, p. 54–63.

[28] Davies, D. K. (2002). Foundation of Petrophysics. Petroskills Training, Vol B, p. 7.

[29] Sandrea, I. and Sandrea, R. (2007). Global Oil Reserves – Recovery factors leavevast targets for EOR technologies. Oil and Gas Journal, Part 1 & 2.