Petrophysical Evaluation of Hydrocarbon Potential of "OMA" Field, Niger Delta

Olarewaju Modupe Abayomi[1], Osisanya O Wasiu[2]*, Korode A Isaac[3], Ibitoye T Abel[4]

[1]*Department of Applied Geophysics, Federal University of Technology, Akure, Ondo State, Nigeria.*

[2]*Department of Physics, University of Benin, Benin City, Edo state, Nigeria.*

[3,4]*Department of Petroleum Engineering and Geosciences, Petroleum Training Institute, Effurun, Nigeria.*

**Corresponding Author Email: wasiu.osisanya@uniben.edu*

Abstract*: The goal of this study is to maximize hydrocarbon reserves by evaluating reservoirs using derived petrophysical parameters, a common practice in the oil and gas industry. In order to complete this task, data (logs) from three Niger Delta onshore wells (OMA01, OMA02, and OMA 03) were used. Gamma-ray, resistivity, and neutron-density well logs were used in this study for lithology identification, fluid delineation, and hydrocarbon identification. Petrel and Rokdoc software were used for lithology identification and petrophysical analysis computation. The qualitative analysis revealed that the wells drilled through various lithologies contained sand and shale intercalations. Three in WellOMA01, Four in WellOMA02, and Two in WellOMA03, reservoirs were delineated. The field's petrophysical analysis was also produced. Shale's volume varies from 10% to 24%, its porosity from 14% to 26%, and its water saturation from 16% to 53%, while its permeability was relatively high. The highest hydrocarbon saturation (84%) was found in RES 01 from WellOMA03. The "OMA" field study revealed that there is a sizably high potential for hydrocarbons.

***Keywords*: Hydrocarbon, Lithology, Well, Reservoirs, Log, Nigeria**

I. INTRODUCTION

The information found in well log data is one crucial component of exploration geophysics that complements earlier data acquisition (wire line data). Well logging is the process of meticulously documenting the geological formations that the well has drilled through. In Alsace, France, the Schlumberger brothers invented the geophysical well logging technique in 1927 (Schlumberger, 1982; 1989). In order to log, either samples are brought to the surface for visual inspection (geological logs, such as cuttings logs, core-logging, or petro-physical logs), or physical measurements are taken using equipment lowered into the hole (geophysical logs) (Asquith, 1982; Teama and Nabawy, 2016). The formations are exposed to well-bore immediately after the well is drilled. One of the most effective and crucial tools for characterization of reservoir rock is the petrophysical analysis of well logs. Petrophysical characteristics, such as lithology, porosity, water saturation, permeability, and saturation, affect the productivity of wells in hydrocarbon-bearing reservoirs (Al-Ruwaili and Al-Waheed, 2014; Alao, et al., 2013, Osisanya et al., 2021). The process of using borehole measurements to evaluate the properties of subsurface formations is known as formation evaluation in the context of this petrophysics framework (Lyaka and Mulibo, 2018; Amigun and Odole, 2013). To complete this task, well log data including gamma ray, density, neutron porosity, photoelectric effect values, and resistivity (Features an ensemble cast, LLS, and MSFL) logs were used. In cases where several wells are available, it is a key tool for linking stratigraphy, defining reservoir properties of a formation, calibrating seismic data, and correlating lithology in addition to providing information about the petrophysical characteristics of the subsurface formation. Information derived from well logs is helpful for aptat estimation of reservoir hydrocarbon (oil & gas) quantities and formation evaluation (Asquith and Krygowski2004). Petrophysical characteristics such as lithology, porosity, water saturation, permeability, and saturation affect the productivity of wells in hydrocarbon-bearing reservoirs. Petrophysics, also known as formation evaluation, is the process of assessing the properties of subsurface formations using borehole measurements. Similar research was done by Short and Stauble, (1967), who described the Niger Delta's general geology. The Tertiary deltaic fill of the Niger Delta is represented by a strongly diachronous sequence, according to research on the origin of the Niger Delta basin. Identification of the chemical and physical characteristics of rocks and the fluids they contain is known as formation evaluation. The goals of a formation evaluation are to assess whether commercial quantities of hydrocarbons exist in formations that the wellbore has penetrated, to identify the static and dynamic properties of productive reservoirs, to find minute amounts of hydrocarbon that could be extremely important from an exploration standpoint, and to compare a given interval in one well to the corresponding interval in another well. One of the many sources of information used in the evaluation of a formation is wireline logs. The wireline logs and subsurface layers produced by petrophysical analysis are revealed in this research work, along with their potential and a detailed layout. It also demonstrates how estimated petrophysical parameters might be applied to the estimation of formations' hydrocarbon potentials in the study area. It will also be used as a reference tool for academics, particularly for students who have little to no experience interpreting well logs. It will show them how to conduct petrophysical analysis. In order to ascertain a field's hydrocarbon potential, this research aimed to estimate the petrophysical analysis of the field. Reducing the likelihood of discovering a viable reservoir that produces well is one of the key challenges in the oil and gas sector. In order to address this issue, a thorough description of the reservoir's physical characteristics, including net/gross, porosity, permeability, water saturation, and hydrocarbon saturation, must be made. The goal of the study was to analyze the "OMA" field using petrophysical methods. The aforementioned goal will be accomplished by identifying possible hydrocarbon zones, calculating the reservoirs' petrophysical parameters and plotting the neutron log against the density log.

II. LOCATION OF THE STUDY

'OMA' field is situated in southern Nigeria's Niger Delta basin (Fig. 1). The Niger Delta basin is situated in West Africa along the continental margin of the Gulf of Guinea, between latitudes 3º and 6 º N and longitudes 5º and 8 º E. This basin is extremely intricate, has significant economic value, and is home to a highly productive petroleum system. One of Africa's largest subaerial basins is the Niger delta basin.

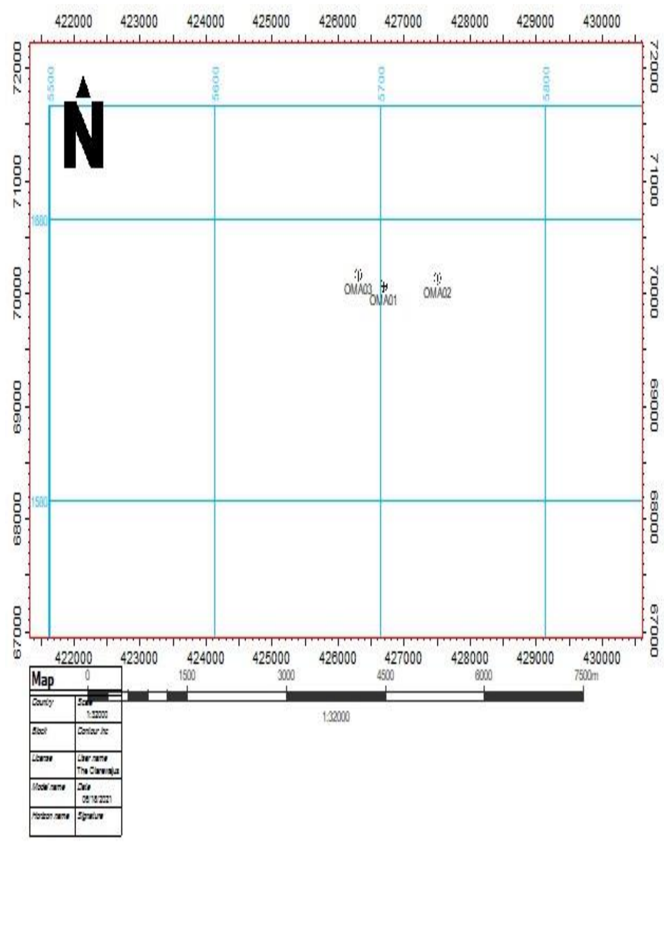

Fig.1: Basemap of "OMA" field, Niger Delta showing well location.

Geology of Niger Delta

The Niger delta is located between latitudes 3°N and 6°N and longitudes 5°E and 8°E on the continental edge of the Gulf of Guinea. It was created at a rift junction where the south Atlantic opened up beginning in the late Jurassic and lasting into the Cretaceous. The geology of southern Nigeria and southwest Cameroon defines the Niger Delta Province's onshore area (Fig. 2). The Benin flank, an east-northeast trending hinge line south of the West African basement massif, forms the northern boundary. The Cretaceous outcrops on the Abakaliki High and the Calabar flank, which forms a hinge line with the nearby Precambrian, define the northeastern boundary. The Cameroon volcanic line, which forms the eastern limit of the Dahomey basin, defines the province's offshore boundary. An area of about 300,000 km^2 is covered by the province.

Regional Settings

In equatorial West Africa, the Niger Delta basin (Fig. 2) is located on the continental edge of the Gulf of Guinea. It is a clastic fill measuring approximately 12,000 meters, with a sub-aerial portion covering 75,000 km (Doust and Omatsola, 1990). The three arm so far triple junction is where the Niger Delta complex emerged. When the African and South American plates split during the Albian era, this triple junction was created (DoustandOmatsola,1990, Whiteman, 1982,). Two of the arms that followed Nigeria's southwest and southeast coasts collapsed to form South Atlantic continental margins, while the third failed arm formed the Benue Trough. According to Evamy, etal., (1978), the progradation of the Niger Delta began in the Eocene and has persisted to the present. This is most likely due to epeiorogenic movements along the flanks of Benin and Calabar. Strata were deposited along a progradation margin that was unsteady. Later, it was discovered that this was caused by paralic deposition into a series of depobelts that succeeded one another in time and space, resulting in a regular step-like southward progression of the delta known as "escalator regression." A significant sea transgression that occurred in the Paleocene put an end to the proto-development delta's (Weber and Daukoru,1975). The sea gradually moved southward after that, and the Eocene saw a regressive phase. The modern Niger Delta, which is Eocene to Recent in age, was formed as a result of the regressive phase, which has persisted up to the present but is frequently interrupted by generally minor transgressions. Massive, monotonous marine shale makes up the majority of the Niger Delta basin. This grade ascends into the typical paralic portion of the delta, which is composed of interbedded shallow marine fluvial sands, silts, and clays. A large, non-marine unit makes up the uppermost portion of the sequence. These are known as the Akata, Agbada and the Benin Formation, respectively (Short and Stauble,1967). Strong diachrony characterizes these three lithostratigraphic units. However, large-scale syn sedimentary features in the subsurface, like growth faults, roll-over anticlines, and diapirs, have a significant impact on the Cenozoic Niger Delta complex (Evamy et al, 1978). However, large-scale syn sedimentary features in the subsurface, like growth faults, roll-over anticlines, and diapirs, have a significant impact on the Cenozoic Niger Delta complex (Evamy et al, 1978).

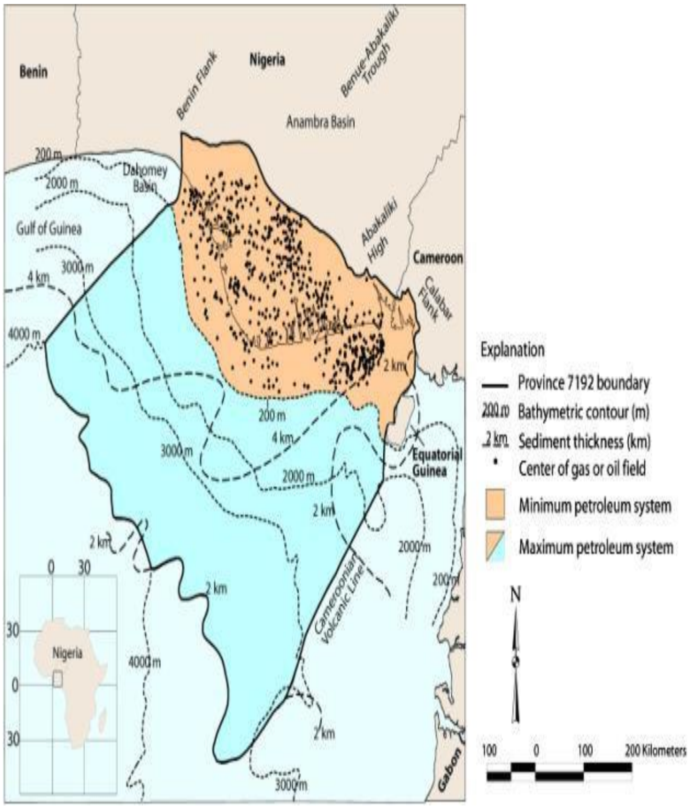

Fig. 2. Map of Niger Delta showing Province outline (maximum petroleum system) and key structural features (After Tuttle et al,1999)

III. STRATIGRAPHY AND STRUCTURAL FRAMEWORK

The Niger Delta basin is made up of an overall regressive clastics sequence with a maximum thickness of 9,000 to 12,000 meters, covering an area of about 75,000 km^2. A balance between subsidence and sedimentation rates allowed the delta to form. The tectonics of the basement and the structural configuration (Fig. 2) appear to have had an impact on the resulting sedimentation patterns. The Tertiary Niger delta developed within the context of regional tectonic and stratigraphic framework of the associated drift systems. The Niger delta developed as a series of depo-centers that crossed the edge of the continent and reached the oceanic crust. There have been identified at least three significant depositional cycles that range from the early Cretaceous to the Cenozoic. The Santonian compression event brought the initial cycle to an end, beginning in the mid-Cretaceous Albian. The subsequent cycle started with the Santonian/Campanian transgression and continued through the regressive phase of the late Cretaceous. A multiplex known as the third mega-cycle began with the widespread Paleocene transgression and continued throughout the Cenozoic upgradation of the Niger delta. The focus of hydrocarbon exploration in the basin is this Cenozoic progradation. Seven parallel, fault-bounded depositional belts, which grew progressively younger from north to south as a result of syn-sedimentary tectonics typical of progradation occurring along with the Cenozoic sediment buildup. See Table 1 for a breakdown of the depobelt architecture, which is overprinted by the same stratigraphic sequence (from top to bottom). i Continental coarse-clastic Benin Formation. ii Paralic, transitional to marine, interbedded sandstone and shale of the Agbada. iii. Massive, marine shale section of the Akata Formation.

Table 1: Geological sequence of Niger Delta (modified after Short and Stauble, 1967)

Formation		Age
Benin Formation		Oligocene-Pleistocene
Agbada Formation	Ogwashi-Asaba Formation	Oligocene-miocene
Akata Formation	Ameki Formation	Eocene

IV. MATERIALS AND METHODS

The Basemap, Well-logs, and Checkshot survey data processed using the Petrel2014 (Schlumberger) software were used to aid in the proper delineation of the hydrocarbon in the "OMA" field. The potential for subsurface hydrocarbons is revealed by using the well logs. Additionally, the neutron-density crossplots of the wells in the field were computed using the RokDoc6.1.4.1089 (IkonScience) software.

Methodology

There are two primary approaches to interpreting well-logging data: Both qualitative and quantitative interpretations are possible.

Lithology and Reservoir Delineation from Well Logs

The lithologies that the wells penetrated were identified using the gamma ray and spontaneous logs. A sand unit can be identified by a sharp deflection to the left of the logs, while a shale unit can be identified by a sharp deflection to the right. Based on the response of the resistivity and lithology logs signature, the reservoir was identified. A hydrocarbon-bearing reservoir can be identified by low gamma ray log signature and correspondingly high resistivity.

Porosity Determination

The proportion of voids to the total volume of a rock is known as the porosity of that rock. Using the equation, Schlumberger (1989) estimated the porosity of the rock formation from the density log.

$$\emptyset = \frac{(\rho_{mat} - \rho_b)}{(\rho_{mat} - \rho_{fl})} \qquad \text{Eqn. 1}$$

where

ρ_{mat} = density of rock matrix given as 2.65 g/cm3,

ρ_b = bulk density obtained from the density log

ρ_{fl}= density of water given as 1 g/cm3.

Determination of Water and Hydrocarbon Saturation

The water saturation (S_w) was estimated from the deep resistivity log. The relationship between the resistivity log and the water saturation (Asquith and Krygowski, 2004) is given as;

$$S_w = R_0/R_t \qquad \text{Eqn. 2}$$

where,
S_w= water saturation,

R_0 = Resistivity of rock that is 100 percent saturated with water, R_t = True resistivity in reservoir.

The Hydrocarbon saturation of the reservoir was obtained from the water saturation by using the equation (Okwoli et al., 2015)

Sh = (100 – Sw) % Eqn 3

where
SH = hydrocarbon saturation,

SW = water saturation.

V. RESULTS AND DISCUSSION

The three wells in the OMA field studied (OMA01, OMA02, and OMA 03) were all subjected to a petrophysical analysis. Cross plots, depth plots, histograms, and well sections were used to present the study's findings. Fig. 3 shows the wells in the well section. Gamma ray, resistivity, neutron, and density well logs were all used in the study.

Petrophysical Analysis of Well Oma01

Three (3) reservoirs with a net-gross ratio of 0.58 to 0.86 were identified from Table 2. The top of the reservoirs across the well had a range of 3556.81 meters to 3875.04 meters, while the base had a range of 3665.08 meters to 3921.45 meters. It can be deduced that more than 50% of the reservoirs are sand units in this well and were formed from sandstone. With the aid of wireline logs, distributions of porosity, water saturation, reservoir thickness, and permeability were created in each of these delineated zones. The well OMA 01 estimated the clean zone at 35 API and the shale zone at 75 API; the shale baseline was also used at 70 API. Water saturation (Sw) was estimated to be between 0.28 and 0.52 ohm-m, while the formation resistivity (R) was chosen at 100% water saturation (3.86 ohm-m). A total of 191.57 m is the pay zone for the three hydrocarbon bearing zones. Additionally, the estimated porosity and permeability values for the oil zones were obtained. The oil zones appear to have been much more porous and permeable, as indicated by the mean estimated values for porosity, permeability, and water saturation of 25%, 1164.09md, and 40%, respectively. The estimated water saturation (Sw) ranges from 28 to 53 percent, indicating that the well's hydrocarbon saturation is roughly 60 percent. Because of their good porosity and water saturation, reservoirs 2 and 3 are considered to be good despite having a relatively low permeability.

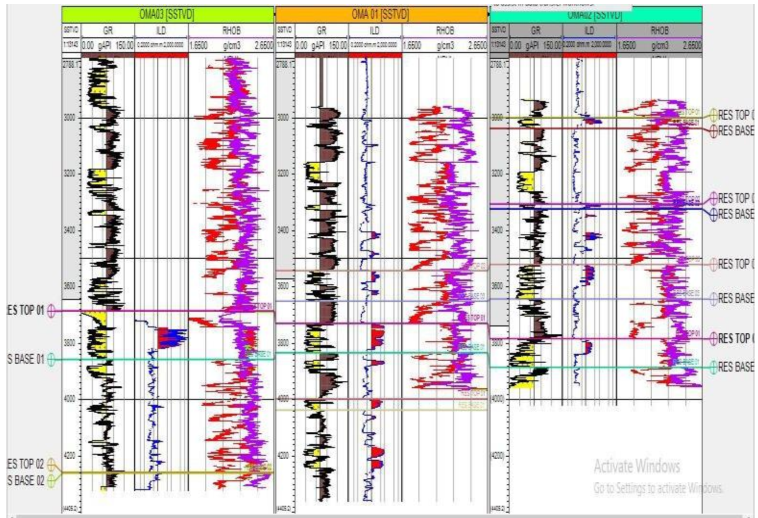

Fig. 3: Well Section

Table 2: Comprehensive result for hydrocarbon potential of WELLOMA01

	RES 01	RES 02	RES 03
TOP (metres)	3556.81	3743.96	3875.04
BASE (metres)	3665.08	3848.15	3921.45
GROSSTHICKNESS (metres)	108.27	104.19	46.41
NET THICKNESS (metres)	62.53	90.1	38.94
NET/GROSS	0.58	0.86	0.84
GAMMA RAYINDEX	0.43	0.24	0.26
VOLUME OFSHALE	0.24	0.10	0.12
POROSITY FROM DENSITYLOG	0.21	0.20	0.19
POROSITY FROM NEUTRONLOG	0.30	0.24	0.24
NEUTRON-DENSITYPOROSITY	0.26	0.22	0.22
EFFECTIVE POROSITY	0.20	0.20	0.19
RESISTIVITY OF 100% WATER	3.86	3.86	3.86
RESISTIVITY OF UNINVADED ZONE	13.81	47.10	25.63
WATER SATURATION	0.53	0.28	0.39
HYDROCARBONSATURATION	0.47	0.72	0.61
FORMATION FACTOR(F)	44.35	23.84	40.55
IRREDUCIBLEWATER SATURATION	0.09	0.10	0.12
PERMEABILITY (mD)	1868.43	1075.76	548.07

Depth plot of WellOMA01

The relationship between shale volume, porosity, and water saturation is depicted in Fig. 4 as depth plots in relation to defined reservoirs. Porosity is seen to decrease as depth increases. Reservoir 02's volume of shale was observed to have a lower percentage than other reservoirs, and the water saturation is low throughout the pay zones.

Neutron-Density Cross plot of Well OMA01

Fig. 5 below displays the neutron-density porosity cross-plot, where the the Rokdoc program was used. A gamma ray calibration is created from the cross-plot that more accurately depicts the lithology of the wells in relation to the neutron-density cross-plot. The gamma ray log has a range of 0 to 150 API, with each range denoting a different color. While the neutron porosity ranges from 0 to 60%, the density porosity ranges from 1.65-2.65g/em. The concentrated points suggest the presence of distinct facies connected to depositional and/or ordia genetic controls. Lower gamma ray counts (15-30 API) are more concentrated between 0-34 percent neutron porosity and 2.0-2.65 g/cm^3 in the density porosity, indicating the formation of pores and stones. Higher gamma ray counts (75-90 API) are indicative of the intercalation of sandstone and calcite (limestone), and as we move upward, we have the formation of dolomite.

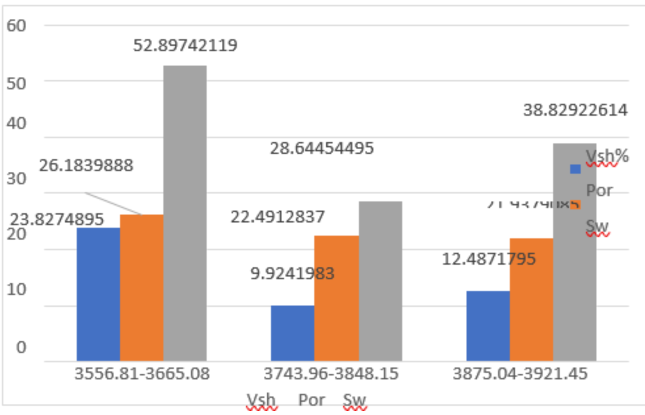

Fig. 4: Depth plot of Wel lOMA01

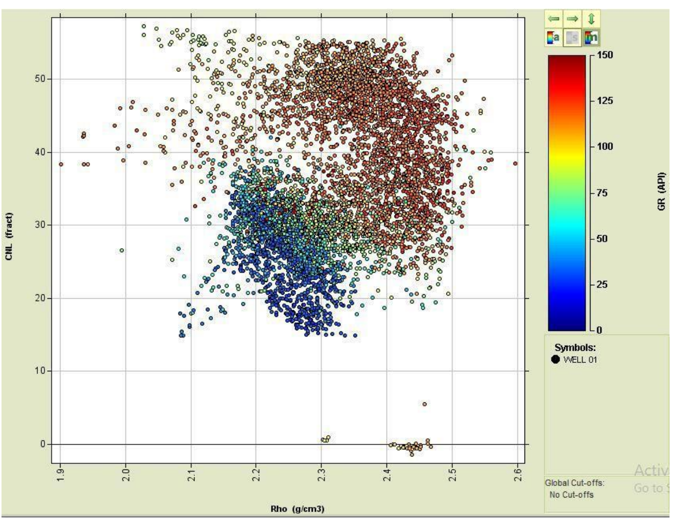

Fig. 5: Crossplot of Well OMA 01

Petrophysical Analysisof Well Oma02

Four (4) reservoirs were identified from Table 3 with a net-gross ratio of 0.82 to 0.97. In the reservoirs, the top values ranged from 3014.99 to 3799.1 meters, while the base values ranged from 3053.14 to 3900.71 meters. It can be assumed that more than 90% of the sandstone used to form the reservoirs in this well. Wireline logs were employed in each of these delineated zones to develop the distribution of porosity, water saturation, reservoir thickness, and permeability. The estimated clean zone according to WELLOMA02 was 35 API, the estimated shale zone was 95 API, and the shale baseline was also 70 API. The resistivity of formation (R) was chosen to be 1.49 ohm-m at 100 percent water saturation, while the water saturation (Sw) was predicted to be between 0.18 and 0.37 ohm-m. Additionally, the estimated porosity and permeability values for the oil zones were obtained. The oil zones appear to have been much more porous and permeable, with mean estimated values for porosity, permeability, and water saturation of 24 percent, 987 md, and 26 percent, respectively. Reservoir 1 has extremely high levels of water saturation, porosity, and permeability, measuring 26 percent, 2003 millimeters, and 19 percent, respectively. This reservoir turns out to be the most porous and highly permeable of all the defined hydrocarbon zones of the entire reservoir, closely followed by reservoir 2 with porosity, permeability, and water saturation values of 24%, 726md, and 18%, respectively. The estimated water saturation (Sw) ranges from 18 to 37 percent, indicating that the well is approximately 80 percent saturated in hydrocarbons.

Table 3: Comprehensive result for hydrocarbon potential of WELLOMA02

	RES 01	RES 02	RES 03	RES 04
TOP (metres)	3014.99	3321.56	3535.74	3799.1
BASE (metres)	3053.14	3338.46	3658.27	3900.71
GROSS THICKNESS (metres)	38.15	16.9	122.53	101.61
NET THICKNESS (metres)	36.95	16.16	100.41	93.14
NET/GROSS	0.97	0.96	0.82	0.92
GAMMA RAYINDEX	0.35	0.36	0.36	0.27
VOLUME OFSHALE	0.13	0.13	0.15	0.11
POROSITY FROM DENSITYLOG (ϕ�)	0.24	0.26	0.21	0.19
POROSITY FROM NEUTRONLOG (ϕ�)	0.27	0.20	0.25	0.24
NEUTRON-DENSITY POROSITY(ϕ�−�)	0.26	0.24	0.23	0.22
EFFECTIVE POROSITY (ϕ���)	0.23	0.21	0.20	0.19
RESISTIVITY OF 100%WATER (��)	1.49	1.49	1.49	1.49
RESISTIVITY OF UNINVADED ZONE (��)	41.62	45.60	14.58	10.83
WATER SATURATION(��)	0.19	0.18	0.32	0.37
HYDROCARBON SATURATION($�_h$)	0.81	0.82	0.68	0.63
FORMATION FACTOR(F)	14.40	17.96	19.54	20.89
IRREDUCIBLEWATER SATURATION ($�_i$��)	0.08	0.09	0.10	0.10
PERMEABILITY	2003.06	726.344	733.57	484.32

Depth plot ofWellOMA02

In Fig. 6, depth plots in relation to defined reservoirs show the relationship between shale volume, water saturation, and porosity. It has been found that porosity declines with depth. In comparison to other reservoirs, reservoir 01's volume of shale was also observed to have a lower percentage, and the water saturation level is low throughout the pay zones.

Neutron-Density Cross plot of Well OMA 02

Fig. 7, which displays the neutron-density porosity cross-plot, was produced using the Rokdoc program. In order to better understand the lithology of the wells in relation to the neutron-density cross-plot, a gamma ray calibration is created from the cross-plot. The ranges of the gamma ray log, from 0-150API, correspond to different color codes. The density porosity ranges from 1.62 to 2.65 g/em, while the neutron porosity is between 0 and 60%. The concentrated points show the presence of distinctive facies that are influenced by depositional and/or diagenetic controls. The lower gamma ray counts (15-30 API) are more concentrated between neutron porosity values of 13–33 percent and 2.1-2.35 g/cm'in the density porosity, indicating pure sandstone formation, while the higher gamma ray counts (70–90 API) are indicative of intercalation of sandstone and calcite (limestone), and as we move higher, we have the dolomite formation.

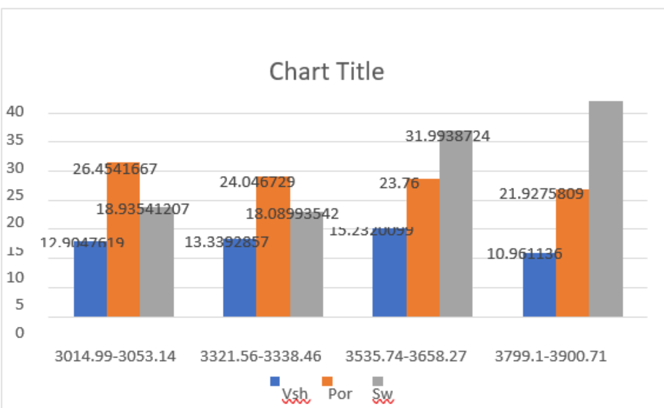

Fig. 6: Depth plot of WellOMA02

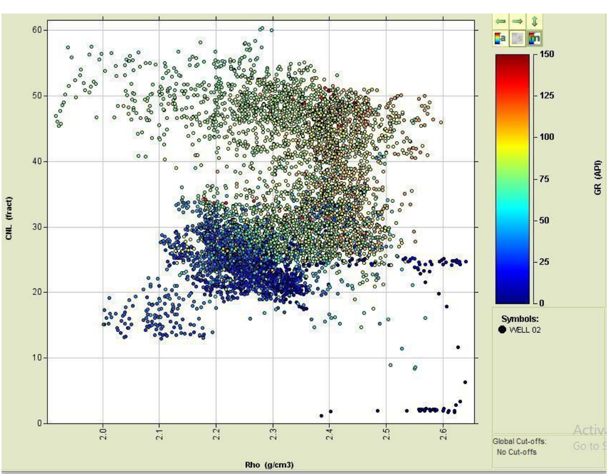

Fig. 7: Crossplot ofWellOMA02

Petrophysical Analysisof Well Oma03

Two (2) reservoirs with a net-gross ratio of 0.95 to 1.00 were identified from well OMA 02, as shown in Table 4. While the range values for the base were 3869.60 m - 4273.22 m, those for the top across the reservoirs were 3697.44 m - 4270.21 m. This suggests that sandstone made up more than 98 percent of the reservoir in this well. The distribution of porosity, water saturation, reservoir thickness, and permeability were developed in each of these delineated zones using wireline logs. While 70 API was used as the shale baseline, WELL OMA 03 estimated the clean zone to be 25 API and the shale zone to be 95 API. The water saturation (Sw) was estimated to be between 0.16 and 0.30 ohm-m, and the resistivity of formation (R) at 100 percent water saturation was chosen at 4.12 ohm-m. The two hydrocarbon bearing zone has a 167.17 million pay zone overall. Additionally, the estimated porosity and permeability values for the oil zones were obtained. The average estimated values for porosity, permeability, and water saturation of 19%, 8934.38md, and 23%, respectively, imply that the oil zones were not particularly porous but were rather highly permeable. With values of 24 percent, 17853.12 md, and 16 percent, respectively, Reservoir 1 has extremely high levels of porosity, permeability, and water saturation. Of the two clearly defined hydrocarbon zones in the entire reservoir well, this reservoir is found to be the most porous and highly permeable. Reservoir 2 has extremely low values for porosity, permeability, and water saturation, which are 14 percent, 15.63 millimeters, and 30 percent, respectively. The estimated water saturation (Sw) values, which range from 16 to 30 percent, indicate that the well is approximately 50% saturated with hydrocarbons.

Table 4: Comprehensive result for hydrocarbon potential of WELLOMA03

	RES 01	RES 02
TOP (metres)	3697.44	4270.21
BASE (metres)	3869.6	4273.22
GROSSTHICKNESS(metres)	172.16	3.01
NET THICKNESS (metres)	164.16	3.01
NET/GROSS	0.95	1.00
GAMMA RAYINDEX	0.27	0.29
VOLUME OFSHALE	0.10	0.20
POROSITYFROM DENSITYLOG	0.24	0.14
POROSITYFROM NEUTRONLOG	0.24	0.15
NEUTRON-DENSITYPOROSITY	0.24	0.14
EFFECTIVE POROSITY	0.21	0.13
RESISTIVITY OF100%WATER	4.12	4.12
RESISTIVITY OF UNINVADED ZONE	151.74	47.20
WATER SATURATION	0.16	0.30
HYDROCARBONSATURATION	0.84	0.70
FORMATION FACTOR(F)	24.04	56.31
IRREDUCIBLEWATER SATURATION	0.10	0.16
PERMEABILITY	17853.12	415.63

Depth plot ofWellOMA03

The relationship between porosity water saturation and volume of shale is illustrated in Fig. 8 as depth plots with respect to delineated reservoirs. It is observed that the porosity decreases with depth. The volumeofshaleinreservoir01 was also seen to have the lower percentage compared to the second reservoir and the water saturation is low in reservoir1 than in reservoir 2.

Neutron-Density Cross plot of Well OMA 03

In Fig. 9, the neutron-density porosity cross-plot is displayed. Software by Rokdoc was used. The cross-plot is used to generate a gamma ray calibration that more accurately depicts the lithology of the wells in relation to the neutron-density cross-plot. The gamma ray log has a range of 0-150 API, with each range denoting a different color. The density porosity is between 1.6 and 2.65 g/em, while the neutron porosity is between 0 and 60%. The grouped points show that there are distinct facies that are connected to depositional and/or diagenetic controls. The region between 10–33% neutron porosity and 2.1-2.33 g/cm' in the density porosity is where the lower gamma ray counts (0–25 API) are more concentrated, indicating the formation of pures and stones, while the region between 20–50% neutron porosity and 2.18–2.52 g/cm' in the density porosity has the higher gamma ray count (75–100 API).

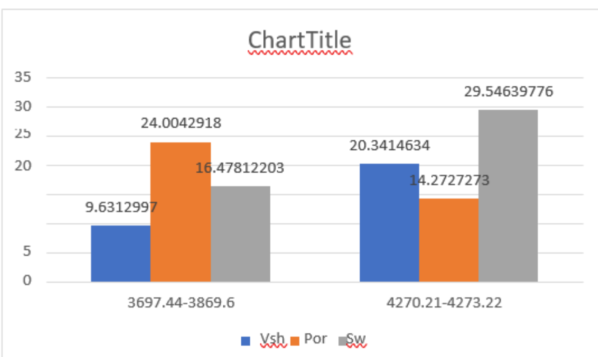

Fig. 8: Depth plot of Well OMA 03

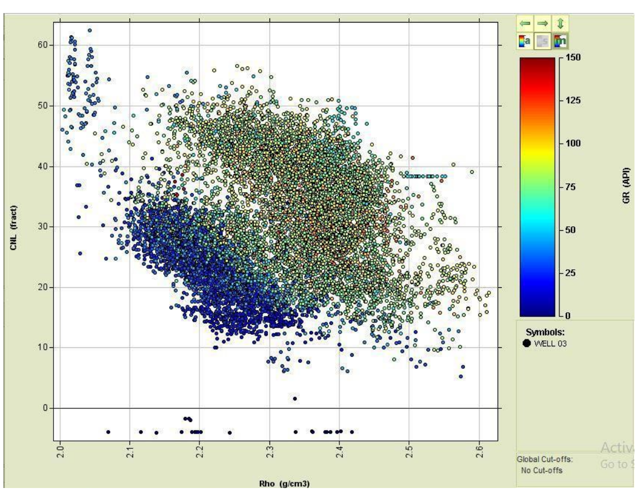

Fig. 9: Cross plot ofWellOMA03

VI. CONCLUSION AND RECOMMENDATION

Conclusion

Wireline log data from three wells' well logs were successfully analyzed using well log methods in "OMA Field," Nigeria's onshore Niger Delta. The three wells under study's composite well logs showed that the Niger Delta formation's sandstone and shale constitute the local geology, which contains all of the reservoir. The following petrophysical parameters were used to assess the reservoir's potential for the wells: porosity, water saturation, hydrocarbon saturation, permeability, irreducible water saturation, reservoir thickness (payzone), volume of shale, and net to gross ratio. The defined values for the oil-bearing zones' porosity and permeability range from 14% to 25% and 415.03mD to 17853.12mD respectively. Water saturation varies across wells from 18 to 52 percent, hydrocarbon saturation varies from 47 to 82 percent, irreducible water saturation varies from 8 to 16 percent, net thickness varies from 3.01 m to 164.16 m, gross thickness varies from 3.01 m to 172.16 m, and net/gross ratio varies from 0.58 to 1.00. All of the wells under study encountered oil in their formations, and some reservoirs also encountered gas, according to the distribution of these estimated parameters derived from the log interpretation. Some of the reservoirs' low porosity/low permeability results from a relatively constrained reservoir section. With the exception of the second reservoir in wellOMA03, which has low porosity, permeability, and water saturation and is therefore not sufficient for economic viability, the hydrocarbon potential of the wells can be adjured to be sufficient for viability.

Recommendation

It is advised that all of the reservoirs defined in this work, with the exception of the second reservoir in well OMA 03, be taken into consideration for exploitation based on the petrophysical analysis obtained from this project. To improve the description and analysis of each reservoir, seismic data should be used, and more developmental wells should be drilled for better well recovery.

REFERENCES

[1] Al-Ruwaili, S.A, and Al-Waheed, H.H (2004). Improved Petrophysical Methods and Techniques for Shaly Sands Evaluation," paper SPE 89735 presented at the 2004 SPE. International Petroleum Conference in Puebla.

[2] Alao, P.A., Ata, A.I, Nwoke, C.E. (2013). Subsurface and petrophysical studies of shalysand reservoir targets in apete field, Niger Delta, in: Int Sch Res Notices, Hindawi Publishing Corporation, p11, https://doi.org/10.1155/2013/102450

[3] Amigun, J. O., Odole, O. A. (2013). Petrophysical properties evaluation for reservoir characterisation of Seyi oil feld (Niger-Delta). Int J Innov Appl Stud 3:756–773

[4] Asquith G (1982) Basic well log analysis for geologists, pub by the American association of petroleum geologists, Tulsa, Oklahoma, USA, p 216

[5] Asquith,G, Krygowski, D. (2004).Basic Well Log Analysis. AAPG Methods in Exploration Series, 16. Manchester, United Kingdom.2, pg.23-59.

[6] Evamy,B.D., Haremboure,J., Kamerling,P., Knaap,W.A., Molloy,F.A., Rowlands,P.H. (1978).

HydrocarbonhabitatofTertiaryNigerDelta:AmericanAssociationofPetroleum GeologistsBulletin, v.62, p. 77-298

[7] Lyaka AL, Mulibo GD (2018) Petrophysical analysis of the Mpapai well logs in the east Pande exploration block, southern coast of Tanzania: geological implication on the hydrocarbon potential. Open J Geol 8:781–802

[8] Okwoli E., Obiora D.N., Adewoye O., Chukudebelu J.U., Ezema P.O. (2015) Reservoir Characterization and Volumetric Analysis Of "Lona" Field, Niger Delta, Using 3-D Seismic And Well Log Data. Petroleum & Coal 57(2) 108-119, 2015 Osisanya, W.O; Alile, O.M; Eze, S.U; Ibitoye, T.A and Oyanameh, O.E (2021): Hydrocarbon Play Assessment of "Oswil" Field, Onshore Niger Delta Region. Journal of Geological Research | Volume 03 | Issue 01 | January 2021.

[9] Schlumberger, (1982). Log Interpretation, Principles and Application. Schlumberger Wireline and Testing: Houston, 1989, TX. 21-89.

[10] Schlumberger (1989) Log Interpretation, Principles and Application. Schlumberger Wireline and Testing, Houston.

[11] Short, K.C, Stauble, A. (1967). Outline of Geology of Niger Delta: American Association of Petroleum Geologists, Bulletin, v.51, pg. 761-779.

[12] Teama, M. A., Nabawy, B. S. (2016). Petrophysical evaluation of the hydrocarbon potential of the lower cretaceous Kharita clastics, North Qarun oil feld, Western Desert, Egypt. J Afr Earth Sci 121:62–71

[13] Tuttle, W.L.M., Charpentier, R. R., Brownfield,M.E. (1999).The Niger Delta petroleum system; Niger Delta province, Nigeria, Cameroon and Equatorial Guinea, Africa USGS, Denver, Colorado, open file report, world energy project.

[14] Weber,K.J., Dakoru,E.M. (1975).Petroleum Geology of the Niger Delta: Proceedings of the Nineth World Petroleum Congress.Vol. 2, Geology: London, Applied Science Publishers Ltd., pg. 210-221

[15] Whiteman, A. (1982). Nigeria:PetroleumGeology.ResourcesandPotential:London,Grahamand Trotman, pg. 110-160