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Analysing the Influence of Depositional Processes on Shale Volume andReservoir Performance

Azubuike-Ijomah Kelechi[1] and Ugwueze Charles Ugwu[2]

1,2Department of Geology, University of Port Harcourt, Nigeria
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ABSTRACT

The studied area has three wells; X1, X2, and X3, with different observed lithological alternation of sand and shale (Zone Pattern 1, Zone Pattern 2, and Zone Pattern 3) in a progressive pattern, and this was defined to be in accordance to relative sea-level at the time of deposition. Two oil-bearing reservoirs were observed; in zone pattern 1 and zone pattern 3. The volume of shale and true porosity calculation formulas were modified (after Thomas and Steiber, 1975) to consider the relationship of gamma, neutron, and density logs, while the Simandoux equation was applied for water saturation calculation, and thereafter permeability was calculated. Zone pattern 1 had a calculated shale volume percentage range of 11-18 which is a low fraction, with a total porosity percentage range of 17 - 30 and a permeability range of 250mD- 1275mD, suggestive of a very good reservoir. Zone pattern 3 had a 15-65 shale volume percentage range, a porosity percentage range of 0.8-12, and a permeability range of 12mD-120mD. From the interpreted result, we observed a gradual decrease in Porosity and Permeability with an increase in shale volume, thus a direct relation between the volume of sand and permeability, and an inverse relationship between the volume of shale and permeability.

INTRODUCTION

Different Depositional processes are peculiar in producing unique features like grain size distribution, sedimentary structures, etc., which hence generates variations in textural properties and reservoir quality (Nichol, 2009). Most reservoir sands contain some percentage of shaliness, and this constitutes some degree of effect. This effect depends on the amount of shale content in the formation hence the estimation of the volume of shale (Vsh) is very important. The volume of shale (Vsh) is very vital in petrophysical analyses, to characterize the reservoir and estimate its hydrocarbon potential, thus effective in the accurate evaluation of other petrophysical parameters like effective porosity, saturation, and Net-to-Gross.

The study zone of this research work is within 3000m-4000m of the Agbada formation. Petroleum in the Niger Delta is drilled from unconsolidated sandstones predominantly in the Agbada Formation. The features of the Agbada Formation reservoirs are controlled by the depositional environment and depth of burial. The facies have an alternation of sandstones and shale which are a result of differential subsidence, variation in sediment supply, and shift in the delta depositional axis. The Agbada formation was laid down under a variety of environmental conditions as defined by Short and Stauble (1967), stressing further that the composition and rhythm encountered in a drilled well, will depend mainly on the location of the well with respect to positions of the coastlines prevailing at the times of deposition, growth faulting, regional subsidence, etc.

Analysing the percentage of shale to sand in the Agbada formation, the environment of deposition is considered to be paralic to transitional (Boggs, 2006). The alternations of sand and shale sediments reflect periods of high and low-energy sea-level changes, with fluctuations in sediment supply and current velocity. The Agbada Formation is a paralic sequence of the delta front, distributary channel, and deltaic plain mega facies. The sandstones or sands have a combination of very coarse to very sand, slightly consolidated but majorly of the unconsolidated calcareous matrix. They are often poorly sorted except where sands grade into shales. Lignite streaks are common, and shales of brackish water to marine fauna.

A number of methods have been developed to estimate the volume of shale (Vsh) from different logging data such as gamma ray, spontaneous potential, and porosity logs. The earliest attempts were focused on developing a model based on the distribution of clays, whether as shale in laminated or dispersed in the pore space of the sandstone. Based on petrographic examination of various cores, De Witte L. (1950) concluded that the distributions of clays are more common in dispersed than laminated. Researchers later on also recognized that laminated clays are not typical in many areas and dispersed clay models are more representative of the shaly sand formation. Hossin (1960) developed a model based on the relationship between Vsh and total porosity. In shaly sand, the wetted shale, Vsh, is replacing some space of total porosity (φ). In the other words, Vsh is analogous to φ and the wetted-shale conductivity. Leveaux and Poupon (1971) developed a model based on field data from Indonesia where the reservoir rock has fresh formation water and a high degree of shaliness.

The minerals contained in shales are distributed in silts, clays, cementing materials, and organic matter. The common minerals include clay minerals, feldspars, calcite, mica, quartz, pyrites, iron oxides, and organic carbon. Clays and quartz are the main minerals constituting about 57% and 25% by weight, respectively of the rock. Shales vary in colour ranging from white through red and green to grey and black depending on mineralogical composition and depositional environment. They are characteristically water sensitive (susceptible to hydration and swelling when in contact with water), with low strength and low permeability.

The importance of Shale in the petroleum industry is seen in its role as source rock in petroleum generation, could serve as seal rock in both structural and stratigraphic traps, and also as reservoirs in fractured shales for secondary production of oil and gas. The major problems observed include; its volume affecting fluid flow in reservoirs, slow rate of penetration, and wellbore instability, which also generally increase the cost of drilling a well.

SIGNIFICANCE OF THE STUDY

Depositional processes like eustatic changes in sea level and tectonic movements affect lithologic facies and boundaries, as there are fluctuations in sediment supply resulting in different alternations of sand and shale ratio, which contributes to reservoir performance. The volume of shale (Vsh) is however the most basic reservoir property among other petrophysical (effective porosity, Net to Gross, permeability, and water saturation) properties that identify the quantity of shale present in hydrocarbon reservoirs, and hence very vital in evaluating the hydrocarbon potential, to aid management decision on investment in the field development. This work, therefore, focuses on applying different modified Shale volume calculations, Simandoux plus other modified Petrophysical equations that consider shale volume, and able to analyze its petrophysical influence on reservoir performance.

LOCATION OF STUDY AREA

The study area 'X-Field' is located within the central swamp of the South-Eastern Niger Delta (Fig 1). It is part of the NNPC/Shell joint venture (JV). The Niger Delta is a large Delta in West Africa, and within Nigeria it is located in the Gulf of Guinea, discharging at the Atlantic Ocean. The Basin lies between latitudes 3^o and 6^o N and longitudes 5^o and 8^oE within the Gulf of Guinea continental margin in equatorial west Africa.

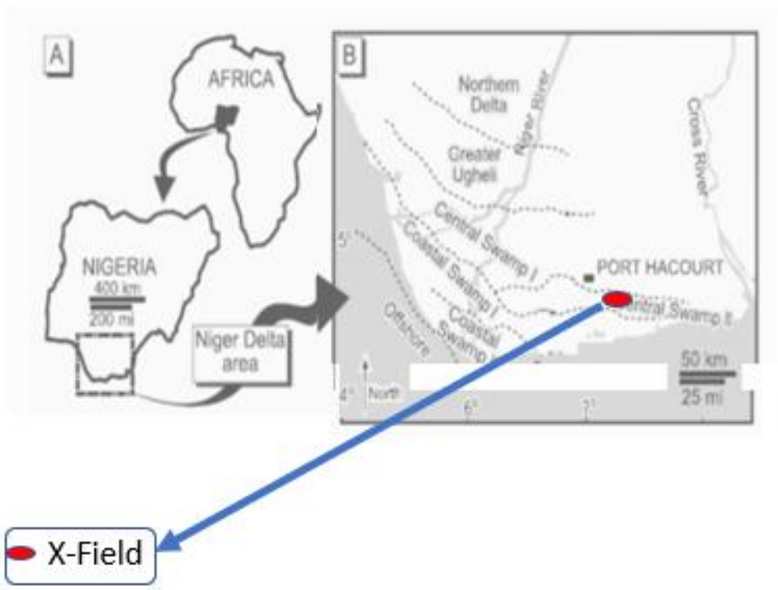

Fig 1: Location Map of Study Area within Niger Delta (modified after Ahiarakwem et. al., 2012).

DEPOSITIONAL PROCESSES AND STRATIGRAPHY OF THE NIGER DELTA

The Niger Delta depositional environment has different facies variations as a product of energy, wave-dominated, constructional, arcuate-lobate tropical delta, with three distinct facies belts; continental top facies, paralic delta front, and Marine prodelta facies, which were modeled based on paleoenvironment, sedimentology, and stratigraphy (Reijers, 2011). Sediment was dispersed at different durations of transgressive/regressive eustatic sea-level changes and subsidence, locally influencing sediment accumulation (Fig.2). The delta-wide shale markers formed at high inflection flooding of the long-term eustatic sea-level curve while erosional channels associated of downdip turbidites formed at low inflection points, also a range of heterogenous fine to coarse siliciclastics formed during progradational to aggradation sea-levels.

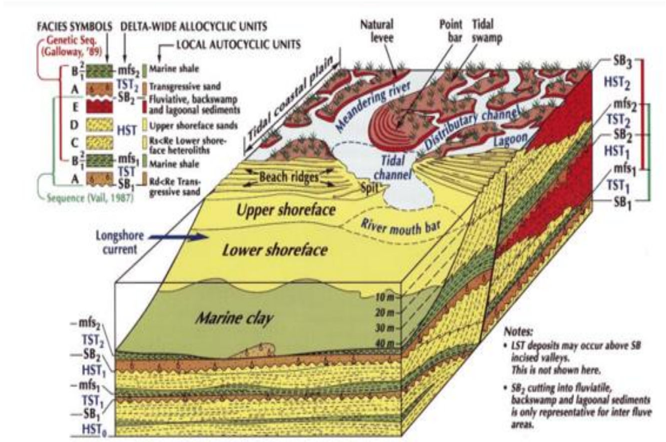

Fig.2: Geomorphology and Cyclic sedimentation of Niger Delta (Modified after Weber, 1971).

According to Short and Stauble (1967), the sedimentology of the Niger Delta can be divided into three lithostratigraphic units. They include the following:

- The Akata Formation (Paleocene-Recent): This forms the basal portion of the succession, and constitutes marine shale with silty and sandy interbeds (Whiteman,1982). It ranges from 600m to over 6000m(2000-20,000ft) in thickness.
- The Agbada Formation (Eocene-Recent): This overlies the Akata formation and is characterized by paralic to marine coastal and fluvial-marine deposits which has a composition of sandstones and shale organized into coarsening-upward off-lap cycles (Weber, 1971). It has a thickness ranging from 300m to 4500m(1000-15,000ft), (Weber and Daukoru, 1975).
- The Benin Formation (Oligocene): This is the upmost segment of the sequence and entirely non-marine sand, composed of continental and fluvial sands, gravel, and back swamp deposits with a ranging thickness of 0 to 2,100m(0-7,000ft).

The emergence of the Niger Delta basin is controlled by allocyclic and autocyclic processes (Fig.3); the autocyclic cycle forms from redistribution energy within a depositional system as seen in channel meandering or switching and delta avulsion, while allocyclic cycles is an outcome of adjustments in sedimentary system sequel to external causes such as eustatic sea level change, tectonic basin subsidence, and climate change. The Autocyclic cycles are superposed on allocyclic cycles. As reviewed by Reijers (2011), the Niger Delta sedimentary basin has a sedimentological structure with a greater effect on local and delta-wide sea-level cyclicity and delta tectonics. Niger Delta basin is accordingly recognized as being of mixed processes of different interactions of sea level changes, tide, wave, fluvial influx, and storm.

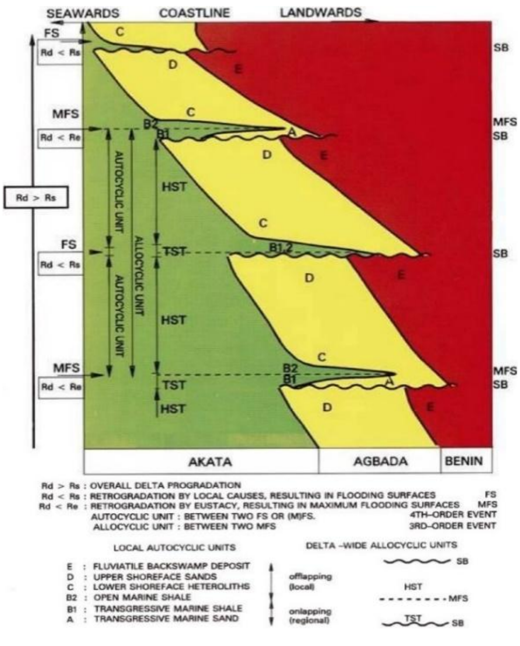

Fig.3: Allocyclic and Autocyclic control processes on Niger Delta (Reijers, 2011).

The Niger Delta stratigraphic fill of sea-level movements and sediment packages (Fig.4) formed entirely within the Cenozoic-Tejas megacycle ‘T’, (Sloss, 1963). This megacycle was further broken into seven worldwide second-order supercycles (TA1, TA2, TA3, TA4 between 66.8 and 29.3 Ma, and TB1, TB2, TB3 between 29.3 Ma and today) by updated work by Exxon group and other researchers. This resultant eleven mega-sequences of the Niger Delta were formed from global eustatic movements, local delta tectonics, allocyclic and autocyclic sedimentation processes.

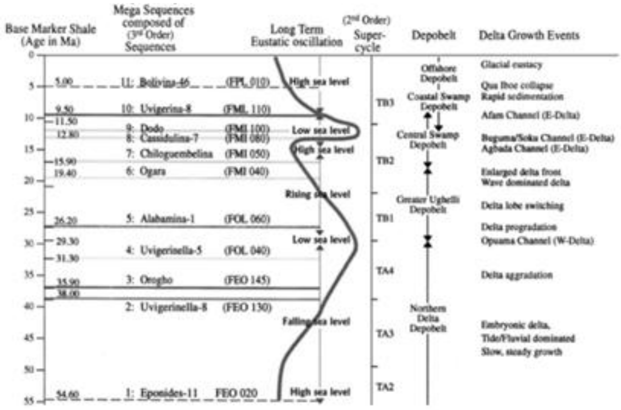

Fig.4: Sea-Level movement phases of Niger Delta Evolution (Reijers, 2011).

LITERATURE REVIEW

Shale are fine-grained laminated sedimentary rocks with predominance of silt and clay (Table 1) as the detrital components (Krumbein and Sloss, 1963). They are formed from silts and clays that have been deposited and compacted or hardened into rocks.

Shale is described as fissile clastic sedimentary rocks formed from the transportation, deposition, and compaction of detrital materials of silt and clay. Fissility is defined as the property of a rock to split easily along thin closely spaced (< 10mm approximately) parallel layers (Ingram, 1953). The fissility of clay is plastic, and its main distinguishing characteristic from other sedimentary rocks.

Shales characteristically contain fine-grained silt and clay particles (< 0.063mm). They are therefore classified as silty shale or clay shale, depending on whether silts or clays dominate the constituents of the rock. Silty shale and clay shale may collectively be called argillaceous shales. Occasionally, shales may also contain appreciable amounts of sand, in which case they may be called sandy shale or arenaceous shale.

Table 1: Grain size description of sediments to define Shale.

Grain-Size	Sediment Name	Rock Name
> 2.00mm	Gravel	Conglomerate (Brescia if grains are angular)
2.00 –0.06mm	Sand	Sandstone
0.06 – 0.002mm	Silt	Siltstone (33% of clay fraction) Mudstone (33-66% of clay fraction)
<0.002mm	Clay	Claystone (>66% of clay fraction)

The classification of shales like other sedimentary rocks should reflect the observable features and environment of deposition. Accordingly, shales are classified on the basis of texture, mineralogical composition, type of cementation/cementing materials, depositional environment, organic matter content, and strength (Krumbein and Sloss, 1963; Boggs, 1995).

On the basis of texture, the most common types of shales are silty shale (silt dominant) and clay shale (clay dominant). These two types of shales are also called argillaceous shales. Occasionally, shales may also contain appreciable amounts of sand in which case they may be called sandy shale (arenaceous shale).

Shale may form in any environmental condition in which sediment is abundant and water energy sufficiently low to allow the settling of suspended fine silt and clay. They are particularly characteristic of marine environments adjacent to major continents where the sea floor lies below the storm wave but they can also form in lakes (lacustrine/continental) and deltaic (transitional/marginal) environments (Porter et. al., 1980). Silts and clays when newly deposited from suspension in water undergo compaction due to the continuous accumulation of other sediments above them, and the compaction affects and reduces the porosity.

Shales may be classified as quartzose, feldspathic, or micaceous shale depending on the predominance of the mineral’s quartz, feldspar, or mica, respectively, in the rock after appropriate XRD analysis (Pettijohn, 1957). The dominant type of cementing material is silica, iron oxide, and calcite or lime. Accordingly, shales may be classified as siliceous, ferruginous, or calcareous (sometimes also called limy), respectively.

The sedimentary environment of any sedimentary rock (including shale) is a natural geographical entity in which sediments are accumulated and later changed to rock (Reineck and Singh, 1980). Three depositional sedimentary environments are recognized namely, continental, transitional or marginal, and marine. Each depositional environment has various subdivisions. Shales are generally deposited in lacustrine (continental), deltaic (transitional), and marine depositional environments and may correspondingly be classified as such; that is, lacustrine, deltaic, and marine shales (Compton, 1977; Boggs, 1995).

Lacustrine deposits are characterized by a mixture of clay, silt, and sands; inorganic carbonate precipitates; and various freshwater invertebrate organisms including bivalves, ostracods, gastropods, diatoms, and various plant deposits. Most lake deposits are less than 10m thick. Deltaic deposits are generally paralic (consisting of orderly sequences of shales and sandstones formed as a result of alternating marine transgressions and regressions). They are also characterized by shallow depth and concentration of kaolinite/illite/montmorillonite clay minerals. Deposits of the marine environment are characterized by homogenous rock sequences (non-paralic), great depth, oxygen deficiency, and concentration of illite/montmorillonite clay minerals. Shales of marine depositional environments are generally darker in colour and richer in marine planktonic fossils than shales deposited in lacustrine and deltaic environments.

METHOD OF STUDY

The available data consisted of three different wells and the wireline logs data available for this work: Gamma-ray (GR), Resistivity, and Density logs. Sidewall sample description data for one of the wells was available. This Data was provided by SPDC, Port Harcourt. The Techlog software was used to import, analyze and interpret the results.

The method of data interpretation for this work followed the format as shown in Fig.5:

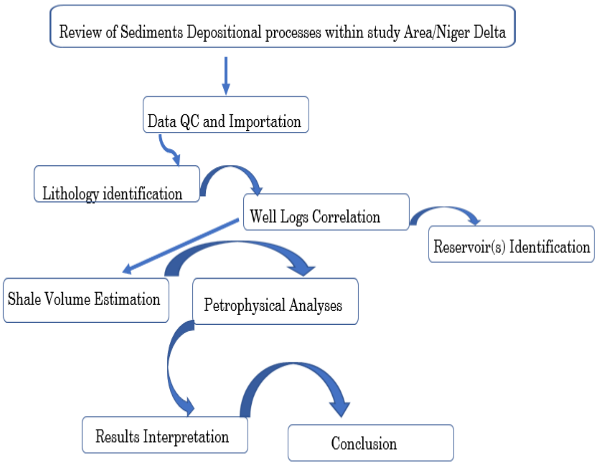

Fig. 5: Pictorial view of study method as applied in this work.

The lithology identification (Fig. 6) was done using the gamma-ray log signatures complimented with the resistivity readings. The gamma-ray logs were measured in API between 0-150. The sands (API 75-150) have low radioactive minerals and deflect to the left, shaly sand is interpreted as API50-75, while the shale log signature (API 0-50), deflects to the right as it has high radioactive minerals.

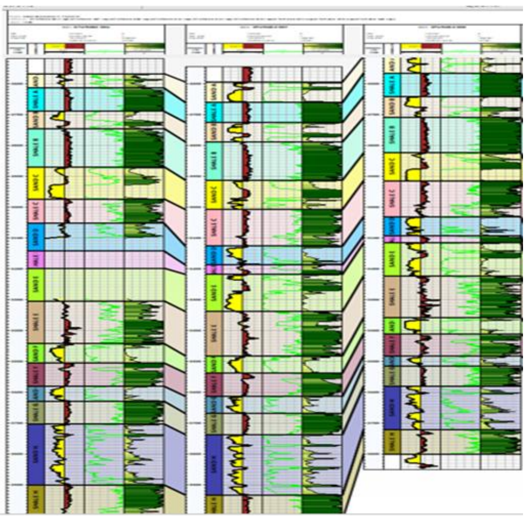

Fig. 6: Well logs Correlation and Lithology identification

The volume of shale was calculated using the Larionov (1969) non-linear relationship for Tertiary rocks:

$Vsh=0.083(2^{3.7(I_{sh})}$ ……………………1

Where:

I_{sh} (Igr)= Gamma ray index

The Igr was determined on the Gamma-ray log using the formula proposed by Asquith and Gibson, (1982):

$Igr = \frac{GRlog - GRmin}{GRmax - GRmin}$ ………………………………….2

Where:

GRlog = Gamma-ray value at the depth of interest

GRmin = Gamma-ray value in a nearby clean sand zone

GRmax = Gamma-ray value in a nearby shale zone

A modification was applied to create an empirical relationship that applies gamma ray, neutron, and density logs readings in calculating shale volume (after Thomas and Steiber, 1975).

$V_{sh} = (V_{sh1} + V_{sh2})/2$ ………………………….. 3

Where:

$V_{sh1}=0.083(2^{3.7(I_{sh})} - 1)$ ….as above in Eqn 1

$Vsh2 = \frac{\phi D - \phi N}{(\phi D)sh - (\phi N)sh}$ ……………………………4

To be able to calculate V_{sh} using Eqn 4, we had to calculate for Density derived and Neutron derived porosity formulas.

$\phi D = \frac{\rho ma - \rho b}{\rho ma - \rho f}$ ……………………………….5

$\phi N = \phi S_{xo}\phi_{Nmf} + (1-S_{xo})\phi_{Nhc} + Vsh\phi Sh + (1-\phi-Vsh)\phi_{Nma}$ ……………………………….6

ϕD= Density derived porosity

ϕN= Neutron-derived porosity

ϕD(sh)= Density porosity corrected for shale

ϕN(sh)= Neutron porosity corrected for shale

The true porosity ϕ was thereafter calculated, thus correcting for shale.

$\phi = \frac{\rho ma - \rho b}{\rho ma - \rho f} - Vsh\ X\ \frac{\rho ma - \rho b}{\rho ma - \rho f}$ …………………. 7

For water saturation, the Gus Archie's equation (Eqn8) was initially used but since research shows that it works better with clean sand, we had to apply the Simandoux equation (Eqn 10) to fit well for the Shale content in the reservoirs

$Sw = \sqrt[n]{\frac{FRw}{Rt}}$ ………………………………….8

$$F = \frac{a}{\phi^m}$$ ………………………………….9

…………10 $$\frac{1}{R_t} = \frac{S_w^2}{F \times R_w (1 - V_{SH})} + \frac{V_{SH} \times S_w}{R_{SH}}$$

Where :

Sw= Water Sauration

Rw = Resistivity of formation waters

Rt = True formation resistivity

RsH= Resistivity of Shale

VsH=Volume of Shale

n= Saturation exponent

F= Formation resistivity factor

In soft formations: a=0.81, m=2.0, or a=0.62, m=2.15

In hard formations: a=1.0, m=2.0

Permeability was calculated using the relationship equation between Porosity, Flow zone indicator and Permeability:

$$K = \frac{\phi\ X\ (FZI)^2\ X\ \frac{\phi}{(1-\phi)^2}}{(0.0314)^2} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots 11$$

Where :

ϕ = True porosity

FZI = Flow zone indicator.

FZI is assumed here as 1 (after Manika Prasad, 2003).

From the previously used Simandoux equation for water saturation calculation, we were confident to calculate the Hydrocarbon saturation from the water saturation relationship (Eqn 12), since the volume of shale has earlier been fit in. u

Shc = 1 – Sw ……………………………….12

RESULTS AND INTERPRETATION

The lithologic analyses based on a detailed description of the gamma-ray log signatures showed an alternation of sand and shale in a progressive pattern which was defined according to relative sea-level at the time of deposition. There were three different lithologic zone patterns observed (Table 2). The first (zone Pattern 1) observed was a pattern of shale and sandstone interbedding, following a coarsening upward pattern and this predicts an onset of relative sea-level rise after a fall. The second (zone pattern 2) observed lithologic pattern zone had more of shale sediments, with a small percentage of sand units characterized by finning and thinning upward trend. This is seen to be in accordance with the relative rise in sea level, progressive supply of sediments as sediment accumulation is forced towards the basin margin, and also transgression as turbidity current reduces (Armstrong and Braisier 2005). The third (zone pattern 3) zone had an increased percentage of sand in shale with an aggradational and upward finning, thinning of beds which predicts a landward shift as the sea level rises.

Using the radioactivity logs in relation to other available logs, two oil-bearing reservoirs were observed; in zone pattern 1 and zone pattern 3. The zone pattern 1 had a calculated shale volume percentage range of 11-18 which is a low fraction, with total porosity percentage range of 17- 30 and permeability range of 250mD-1275mD, suggestive of a very good reservoir. The zone pattern 2 had highest gamma ray readings, with highest shale volume percentage range of 35-90, the porosity percentage ranged between 0.5-10 and permeability of 0.02-0.09mD. The zone pattern 3 had 15-65 shale volume percentage range, a porosity percentage range of 0.8-12 and permeability range of 12mD-120mD. Though this zone is an oil-bearing reservoir, but the estimation shows it is not a good one as the porosity and permeability values could affect the reservoir performance potential.

Table 2: Categorized Lithologic Zone Patterns

Lithologic Zone	**Shale Volume (%)**	**Porosity (%)**	**Perm (mD)**
Zone Pattern 1	11-18	17-30	250-1275
Zone Pattern 2	35-90	0.5-10	0.02-0.09
Zone Pattern 3	15-65	0.8-12	12-120

For the two reservoirs; in zone Pattern 1, the water saturation had an average of 22% with average hydrocarbon saturation of 78% compared to zone pattern 3, with average water saturation of 75% and hydrocarbon saturation of 35%.

CONCLUSION

Though there are different enhancement technology carried out on oil recovery, there is however a great need to understand the influence of depositional processes and volume of shale on the lithology of the area, as this would determine the productivity and the potential of the reservoir.

From the interpreted result, we observed a gradual decrease in porosity and permeability with an increase in shale volume, thus a direct relation between the volume of sand and permeability, and an inverse relationship between the volume of shale and permeability. Shale lithology was observed to be denser than sandstone attributed to the undergone plastic compaction or deformation, unlike sandstone which is of elastic compaction/deformation. The quality of a reservoir is related to the facies type and its distribution, as this has a great influence on the porosity and permeability.

From this study, the appropriate reservoir for further recovery exploration is zone Pattern 1, which has a lower shale volume range of 11-18%, Porosity range of 17-30%, and Permeability range of 250-1275mD as compared with zone Pattern 3 of 15-65% shale volume range, Porosity range of 0.8-12% and permeability range of 12-120mD. The fluid flow capability of the reservoir is directly dependent on the pore network, which is a product of porosity and permeability, and this further reveals zone pattern 3 to be a poor reservoir as though its amount of oil saturation content, there would be a great restraint to flow for recoverable oil. The reservoir flow parameters are controlled by porosity and permeability impact, which is influenced by pore characteristics like shape, size, and connectivity of the pore system for a better flow pathway.

With more available data like Seismic data, Biofacies data, Core photos, and area coverage extent of the reservoir, this work could further be extended for depositional environment interpretation and calculation of oil initially in place/recoverable oil.

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