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Porosity And Permeability Trend In Agbami-Field Using Well Log, Offshore, Niger Delta

Juliet E. Emudianughe, P. M. Eze and Sunday Urah

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Abstract: The need to provide comprehensive information on the reservoir characteristics of the offshore Agbami (ATA) oil field, Niger Delta, prompted the present study, which was designed to determine the porosity and permeability trends of three delineated formations across two wells and their relationships with compaction in the field. A well log suite consisting of gamma-ray, resistivity, neutron and density logs from two wells was used in the analysis. The well correlation study revealed stratigraphic continuity in the formations with varying degrees of thickness, which suggested the presence of faults. The results also indicated a shale volume range of 9% to 30%, which indicated a good fraction of clean sandstone in the formations. Over 20% formation porosity was observed indicating a very good ability to accommodate hydrocarbon fluids in the field. The study essentially determined reservoir properties such as lithology, depositional environments, shale volume, porosity (Φ), permeability (K), compaction trend and hydrocarbon fluid saturation, among others from well logs, which are variables that determine reservoir quality. The lithology of the wells was determined using a gamma-ray log. The high kick signatures of the gamma-ray delineate the shale intervals. Due to its highly conductive nature, shale lithology cause resistivity to shift to the far left. Porosity is generally high in all reservoirs, indicators for the volume of shale are low, water saturation is low, and permeability is high.

Keywords: *Porosity, permeability, recoverability, rock property*

Juliet E. Emudianughe
Department of Earth Sciences, Federal University of Petroleum Resources, Effurun, Delta State, Nigeria
Email: emudianughe.juliet@fupre.edu.ng
Orcid id: 0000-0002-5617-6203

P. M. Eze
Department of Earth Sciences, Federal University of Petroleum Resources, Effurun, Delta State, Nigeria
Email: ezeprosper98@gmail.com
Orcid id: 0000-0002-1217-4599

Sunday Utah*
Department of Earth Sciences, Federal University of Petroleum Resources, Effurun, Delta State, Nigeria
Email: utah.Sunday@fupre.edu.ng
Orcid id: 0000-0002-2481-2332

1.0 Introduction

A reservoir rock's potential and performance can be assessed through certain characteristics such as porosity, permeability (k), water saturation (SW), rock particle sizes and shapes, degree of compaction, cementation, and matrix quantity (Worden *et al*, 2018). Porosity and permeability are the two most important characteristics of every reservoir. The fractional/percentage of the total volume occupied by pores or voids is known as porosity. It's a measure of the volume of fluid a rock unit can contain. Porosity values in reservoirs typically range from 5% to 30%, however, the majority of reservoirs have porosity values between 10% and 20% (Selley and Morrill, 1983).

The continuum recording of well formation parameters over the subsurface depth is known as a well log. Well logging is used to determine the physical qualities of undisturbed rocks and the fluid content. Formations resistivity, radioactivity, electron density, neutron, acoustic transit, and lithology are among the metrics computed from these logs. Sonic log which is designated as tlog, is an acoustic wave travel time per one foot of rock formation. Specific acoustic time measurements have been related to the porosity of the subsurface formations. The interval transit time for an acoustic wave to travel through the formation is dependent upon lithology and porosity. Hence porosity logs can be derived from sonic logs. Density recording employs the principle of gamma-ray scattering in a formation when it is irradiated by a gamma-ray source. It, however, measures only the primary and secondary porosity. The amount of hydrogen index across a rock formation is measured by the neutron log. As a result, in clean formations with hydrocarbon-filled pores, the degree of liquid-filled porosity is reflected in the neutron log (Chilingar, et *al*, 1988).

Permeability is a second degree of petrophysical parameter and it is a significant factor in the effective characterization and good hydrocarbon field development (Onyekonwu and Ekpoudom, 2004. As a result, a precise understanding of its distribution in the reservoir is crucial for predicting production performance. Oil recovery is influenced by variation in permeability during primary depletion. These parameters can be directly measured from core data. However, because these parameters must be calculated from logs, analyzing only the well logs without the core data is frequently associated with uncertainty. Several factors that can affect the permeability of a formation include pore sizes, amount of clay minerals and distribution, rock matrix and rock particle grain size (Balan and Mohaghegh, 1995). So many permeability models has been proposed by several researchers to determine permeability in unevaded zones of the reservoir with the use of well logs, based on the degree of similarity between the petrophysical properties of the rock formations (Tixier, 1949., Coates and Dumanoir, 1981., Yao, 2003 and Osborne, 2004). This study will focus on the porosity and permeability trend in two formations of ATA5 and ATA7 wells in parts of the Agbami field.

1.1 The study area

The area of study is the Agbami field and is located about 1500m off the central Niger Delta. The location map of the area is shown in Fig. 1. The study area exhibits one of the classical examples of oil-producing fields in the Niger Delta with fault-related problems concerning hydrocarbon reservoirs.

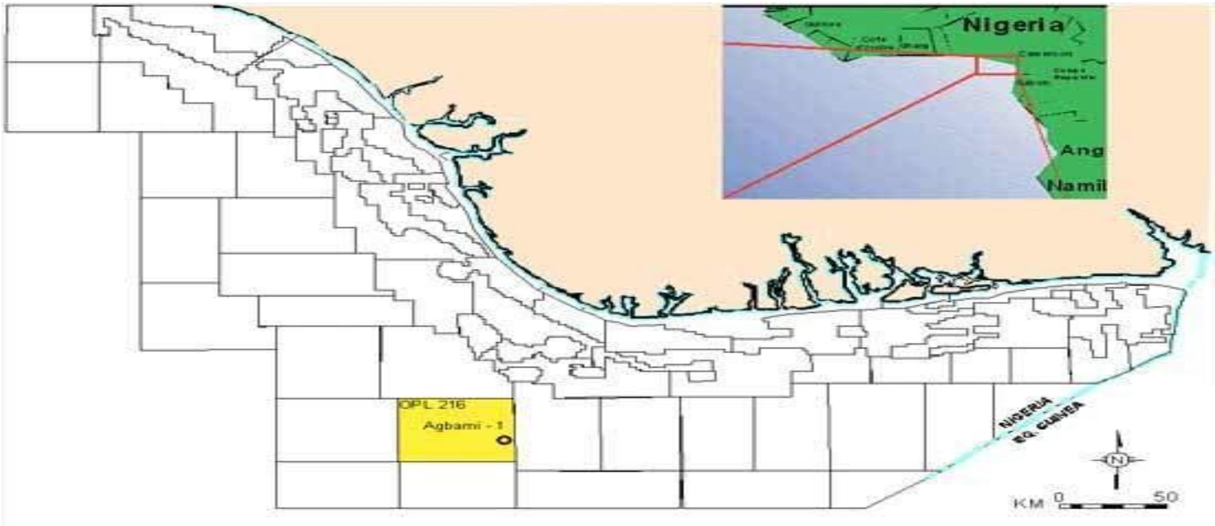
The Niger Delta depression is divided into three main formations; Akata, Agbada and the Benin formations (Nwachukwu and Odjegba, 2001), demonstrating prograding depositional facies that are notable mostly based on the sand-shale ratio (Tuttle *et al*., 1999).

The Akata formation is of marine origin and is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt (Omatsola *et al*, 2001). Whiteman (1982) suggested that the Akata formation may be about 6,500 m (21,400 ft) thick, while Doust and Omatsola (1990) suggested that the thickness ranges from 2000m (6600 ft) at the most distal part of the delta to 7000 m (23,000 ft) beneath the continental shelf.

The Agbada Formation overlies the Akata formation, and it is an alternating sequence of sandstones and shale beddings, whose sandstone reservoirs account for oil and gas production in the delta (Nwachukwu and Odjegba, 2001). The Agbada Formation is over 3700m thick (Reijers 1996).

The Benin formation consists of the top portion of the Niger Delta depression, from the northern Benin-Onitsha area to beyond the coastline

(Short and Stuable, 1967). Shallow parts of the formation are composed entirely of non-marine sand deposited in alluvial or upper coastal plain environments during the progradation of the delta (Doust and Omatsola, 1989).



Fi g. 1:. Agbami oil field (Onikoyi etal, 2014).

Keelan (1982) analysed the characterization of certain rock properties such as porosity, permeability, grain density, and capillary pressure, and showed how these properties varied with the geological factors such as depositional environments. Log motifs were used to describe the paleo environment of deposition for hydrocarbon-bearing sands in areas (Rider, 2002). He noted that the shape of spontaneous potential and gamma-ray signatures are reliable indicators for inferring prevailing lithologies. Selley (1976), proposed a relatively simple method to distinguish clastic depositional environment using the gamma-ray curve and the presence or absence of glauconite and carbonaceous material. Amaefule *et al* (1993) stated that factors that enhance reserves and improve productivity depend on established relationships among core-derived parameters and on the log-derived attributes. This theoretically relationship can be used as input variables to calibrate logs for improved reservoir characterization. After an intensive appraisal, Kehinde (2011) alluded that a detailed understanding of reservoir drive mechanism and reservoir characterization can provide information for the optimization of a reservoir management strategy and the development of short and long-term work programs.

2.0 Materials and Method

Fig. 2 presents the research workflow. Well logs data was employed in this study using the Schlumberger PETREL platform. In order to avoid challenges associated with data interpretation, a series of checks were performed on the data to eliminate poor data spots. Hydrocarbon pay zones, hydrocarbon fluid type and contacts of ATA5 and ATA7 wells were identified using the high resistivity log signatures and the Neutron-Density overlay Technique (see Figs. 3 and 4). First and second-degree rock parameters were calculated for the Agbami field using the logs from Gamma ray Log (GR)., Resistivity Log (LLD), Density Log (RHOB) and equation models. The stratigraphic correlation across the two wells was done using the gamma-ray signatures.

Water saturation was derived using the method reported by Archie (1942), who stated that the experimental water saturation of a clean formation can be evaluated in terms of its true resistivity expressed as equation 1

$$S_W = \left[\frac{F\,Rw}{Rt}\right]^{1/n} \qquad (1)$$

Since $= \frac{R_0}{R_W}$, then $R_0 = FR_W$. Therefore, by substitution for R_W , equation 1 becomes,

$$S_W = \left[\frac{R_0}{Rt}\right]^{1/n} \qquad (2)$$

where F is the formation factor., R_W is the resistivity of the formation of water., R_T is the true resistivity obtained from the deep reading tool, Ro is the resistivity of the formation when it is 100% saturated with water with resistivity Rw (Schlumberger, 1989), S_W is water saturation and n is the saturation exponent (commonly 2.0)

Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbons. It is usually determined by the difference between unity and water saturation in fe567ractions. It is given by:

$$S_H = 1 - S_W \qquad (3)$$

where S_H is the hydrocarbon saturation, S_W is the water saturation., 1 = Unity.

The formation factor of a porous formation within the target depth interval was determined using humble' formula for unconsolidated formations (equation 4),

$$F = {}^{a}/_{\Phi}{}^{m} \qquad (4)$$

where: F is the formation factor, Φ is the porosity, 'a' is the tortuosity constant and m is an exponent called cementation factor m = exponent called cementation factor

For sands; $F = {}^{0.62}/_{\Phi}{}^{2.15}$ (5)

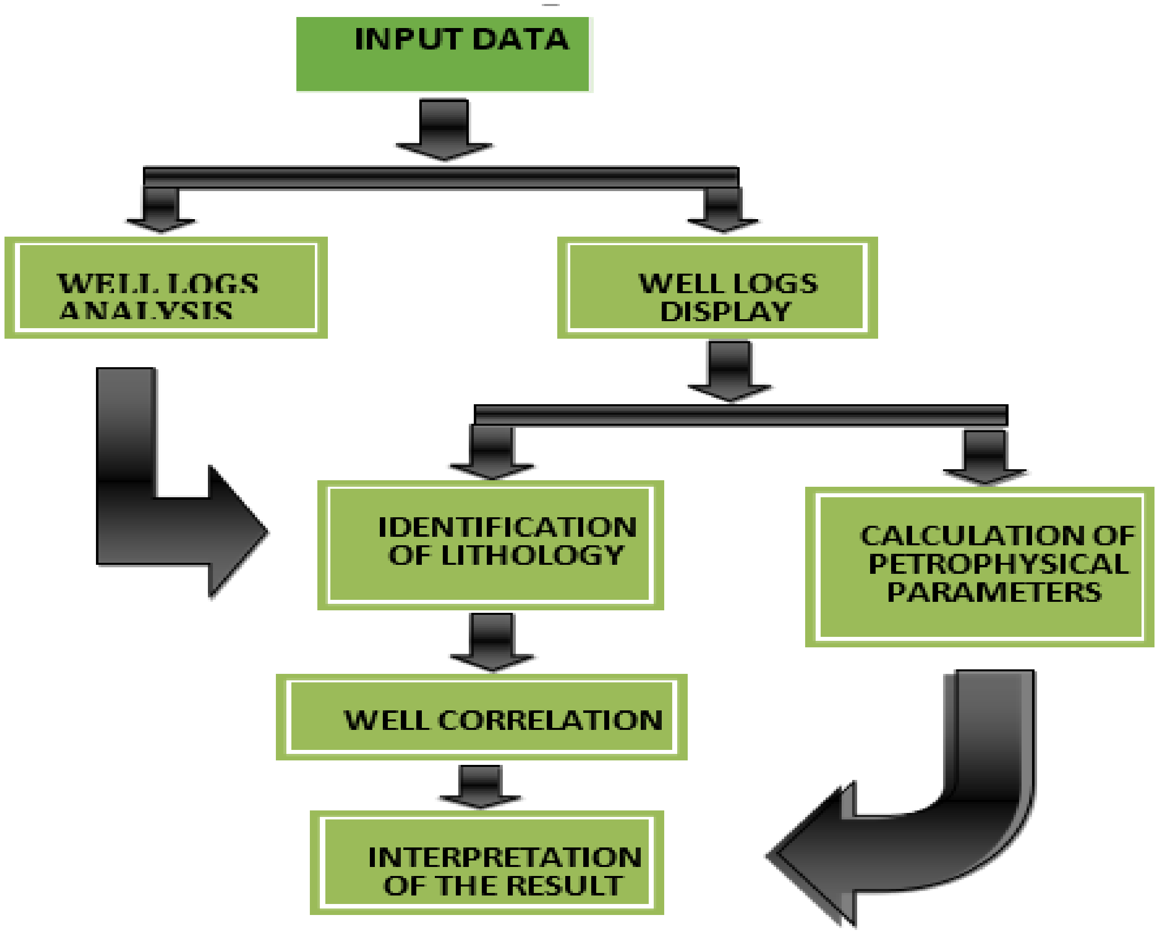


Fig. 2: Showing study Workflow.

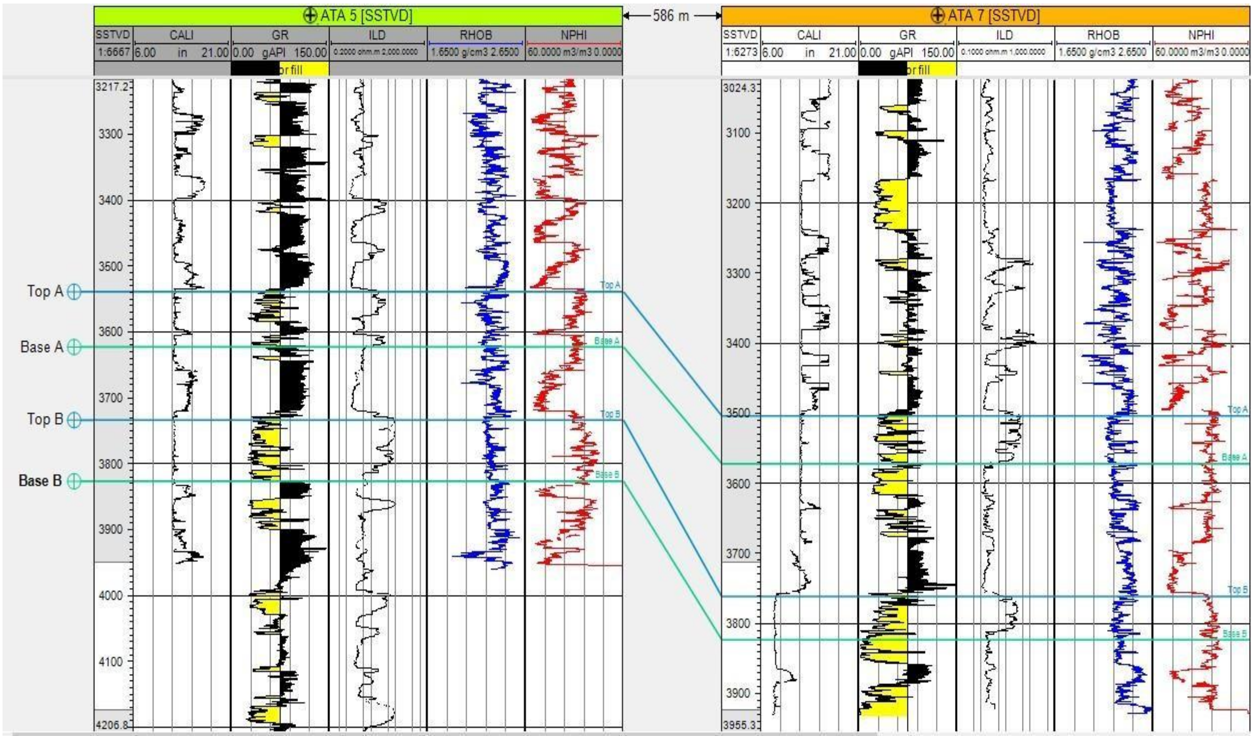


Fig. 3: Showing Delineated payzones of Ata 5 and Ata 7 Well

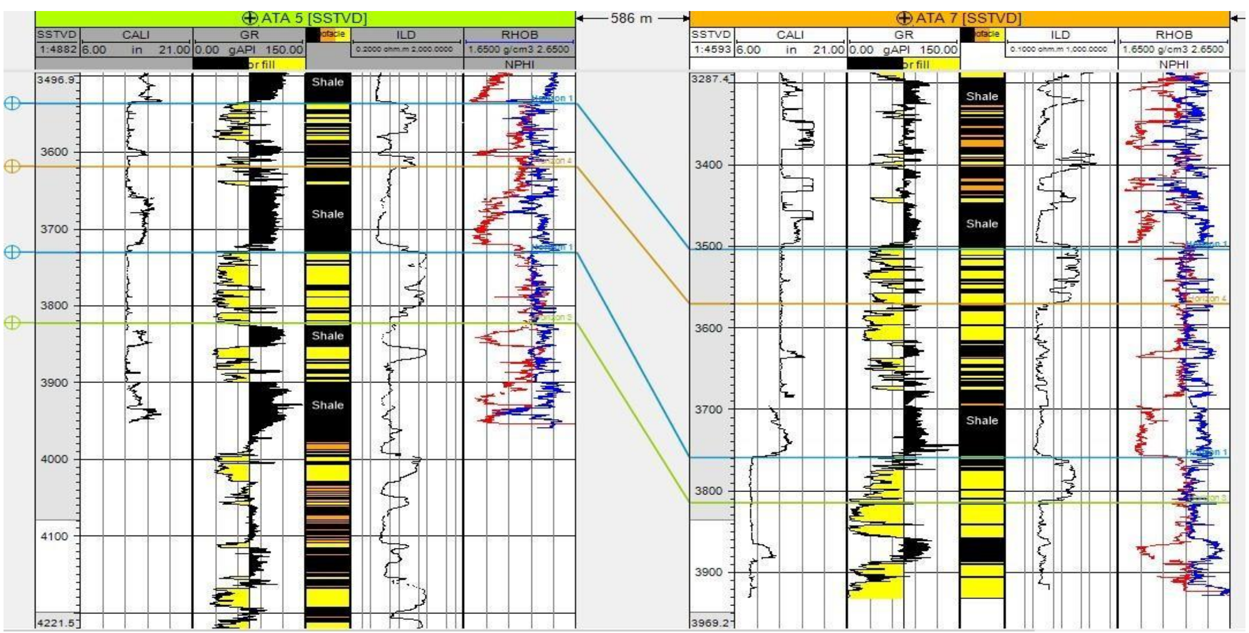


Fig. 4: Hydro fluid type identification of Ata 5 and Ata 7 well

The volume of shale in unconsolidated tertiary rocks is given by:

$V_{SH} = 0.33\ (2^{(2 \times Igr)} - 1.0)$ (6)

where: V_{SH} is the volume of the shale and I_{GR} is the gamma-ray index,

$$I_{gr} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (7)$$

The porosity is derived from the bulk density of clean liquid-filled formations when the matrix density, ρ_{ma}, and the saturating fluid density, ρ_f, are known

$$\Phi den = \frac{\rho ma - \rho b}{\rho ma - \rho f} \quad (8)$$

where: Φden is the density derived porosity, ρma is the matrix density ($2.65 g/cm^3$). ρb is the formation bulk density, ρf is fluid density ($0.85 g/cm^3$ for oil and $1.1\ g/cm^3$ for water).

According to Schlumberger (1989), the irreducible water saturation (Swirr) can be expressed according to equation 9

$$Swirr = \left[\frac{F}{2000}\right]^{0.5} \quad (9)$$

where Swirr is the irreducible water saturation and F is Formation factor

Tixier equation was used for the determination of permeability (K) , expressed as equation 10

$$K^{1/2} = \frac{250\ \Phi^{3}}{Swirr} \quad (10)$$

where: Φ is the Porosity.

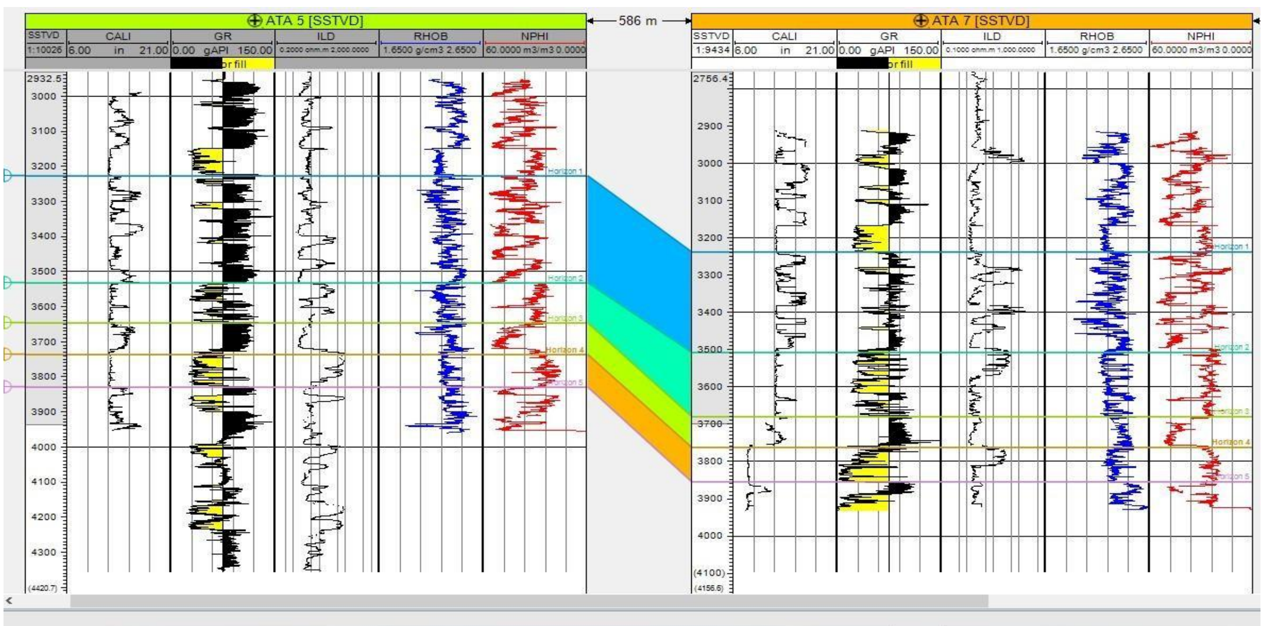


Fig. 5: Well correlation, Ata 5 and Ata 7 Well

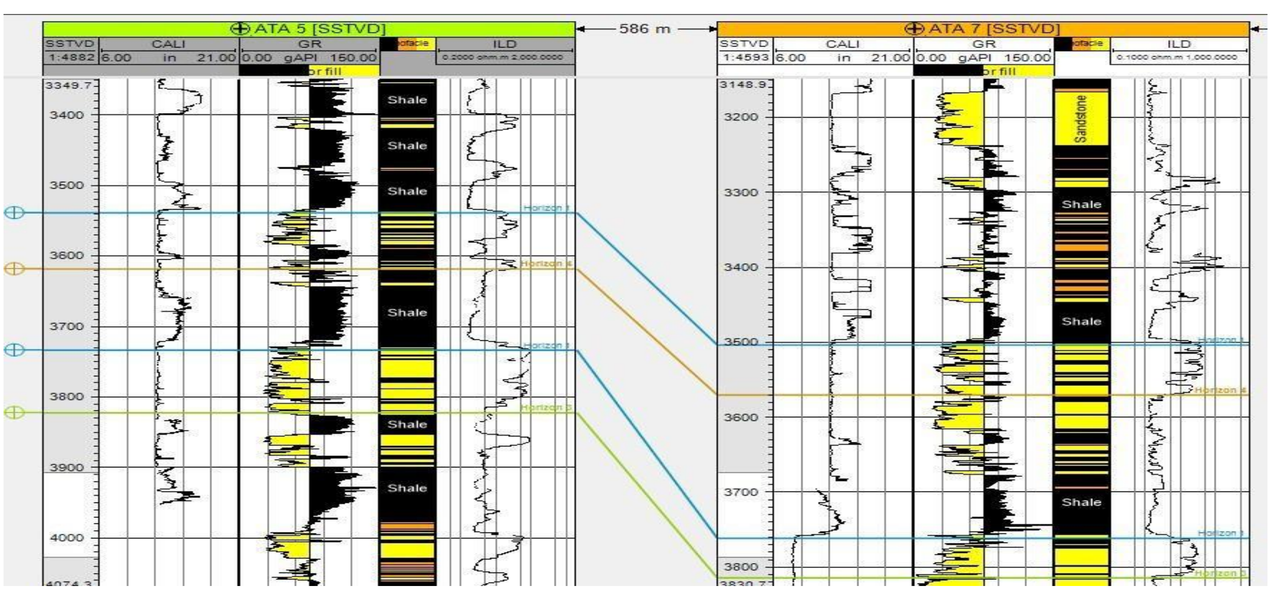


Fig. 6: Rock facie formation Of Ata 5 and Ata 7 Well

3.0 Results and Discussion

Rock properties results of the subzones (as seen by the measured depth) for formation A and B of ATA5 well are presented in Table1. Formation A of the ATA5 well which is characterised by sandstone and shale sequential beddings (53.13 – 95.32API) has low to moderate volume of shale (13.34%, 55.84% and 22.12%), very good porosities (24.51%, 20.14% and 24.11%) with good and effected ability to accommodate hydrocarbon fluid (Levorsen 1967), high recoverability indices as inferred by the NTG (86.66%, 44.16% and 77.88%) and good hydrocarbon saturation (66.64%, 14.97% and 66.08%). Formation A of ATA5 well also exhibits an excellent degree of hydrocarbon flow (high permeability values). The porosity across formation A infers a normal compaction trend as it decreases with depth (Mode et al, 2013).

Formation B of the ATA5 well is characterized majorly by cleaner sandstones (44.42-47.84 API), showing a similar trend with very good porosities (23.33 – 21.54%), magnificent hydrocarbon saturations (80.27% - 65.05%) and excellent flow paths (>1000 mD). The decreasing porosity with depth, like formation A, also indicates the normal compaction trend (Mode et al, 2013).

Table 1: Reservoir properties estimates for Formations A and B of ATA5 well

Well	ATA5A	ATA5A	ATA5A	ATA5B	ATA5B
Start MD (m)	3558.05	3604.20	3627.13	3752.06	3796.47
GR(API)	53.13	95.32	64.13	44.42	47.84
Porosity (%)	24.51	20.14	24.11	23.33	21.54
EffPorosity(%)	21.50	9.52	19.32	21.53	19.28
Vsh (%)	13.34	55.84	22.12	8.83	12.40
NTG (%)	86.66	44.16	77.88	91.17	87.60
Sw (%)	39.36	85.03	33.92	19.73	34.95
Sh (%)	60.64	14.97	66.08	80.27	65.05
Swirr (%)	8.50	10.48	8.33	8.54	9.50
K	1963.70	1430.49	1879.19	1764.908	1565.86

Table 2 presents the results of petrophysical evaluations of the subzones (as seen by the measured depth) for formation A and B of ATA7 well. Formation A which is characterized by clean sandstone beds (30.94 – 55.14API), has low shale volume, very good porosities (25.31%, 24.40%, and 24.18 %) (Levorsen 1967),very good recoverability indices as inferred by the NTG of over 80%, good hydrocarbon saturations (69.39%, 66.02% and 49.42%) and excellent degree of hydrocarbon flow (high permeability values). The porosity across formation A infers a normal compaction trend as it decreases with depth (Mode et al, 2013).

Formation B is of ATA7 well which is also characterized by clean sandstones (30.94-50.00API) showing a similar trend with good porosities (>20%), and good hydrocarbon saturations (48.25% - 61.39%) and excellent permeabilities (Levorsen 1967, Baker 1992). The decrease in porosity with depth, like formation A, also indicates the normal compaction trend (Mode *et al*, 2013).

Table 2: Rock properties estimates for formations A and B of ATA7 well

Well	ATA7A	ATA7A	ATA7A	ATA7B	ATA7B
Start MD (m)	3545.84	3566.05	3591.00	3801.50	3842.08
GR(API)	42.54	51.30	55.14	50.00	30.94
Porosity (%)	25.31	24.40	24.18	20.18	22.06
EffPorosity(%)	23.58	21.53	21.08	17.90	20.15
Vsh (%)	7.54	14.85	16.43	12.78	5.81
NTG (%)	92.46	85.15	83.57	87.22	94.19
Sw (%)	30.61	33.98	50.58	38.61	51.75
Sh (%)	69.39	66.02	49.42	61.39	48.25
Swirr (%)	7.98	8.82	8.78	10.57	9.52
K	2041.61	1965.33	1934.10	1434.18	1644.82

Table 3 presents the mean (averages) results for formations A and B for ATA5 and ATA7 wells. The low Shale volume (<31%) and the high NTG (64.08% min and 90.70% max) across the four formations are indicative of Clean sandstone beds with negligible shale volume The porosity (≥21.12%) rates the reservoirs very good (Levorsen 1967), excellent ease for hydrocarbon flow (>1000 mD) (Bake, 1992). See Tables 3. Using a water saturation cut-off of 60%, the formations clearly show good hydrocarbon fluid volume of over 40% saturation.

The steady decrease in the porosity with an increase in depth infer the normal compaction trend.

Table 3: Average Rock properties estimates for Formations A and B of ATA5 and ATA7 wells

Well	ATA5A	ATA5B	ATA7A	ATA7B
Start MD (m)	3558.05	3752.06	3545.84	3801.06
Porosity (%)av	22.92	22.43	24.63	21.12
EffPorosity(%)av	16.78	20.40	22.06	19.12
Vsh (%)av	30.43	10.21	12.94	9.29
NTG (%)av	69.57	89.79	64.68	90.70
Sw (%)av	52.77	27.33	38.38	45.18
Sh (%)av	47.23	72.67	61.62	54.82
Swirr (%)av	9.10	9.03	8.53	10.04
K(mD)av	1757.46	1665.38	1980.34	1539.50

Depositional environment

By comparing the gamma-ray signature to typical log patterns, the depositional environments of the formation sand masses were inferred as inner fan channels of deep sea settings using the modified Malcom Rider Log motif (Fig.7).

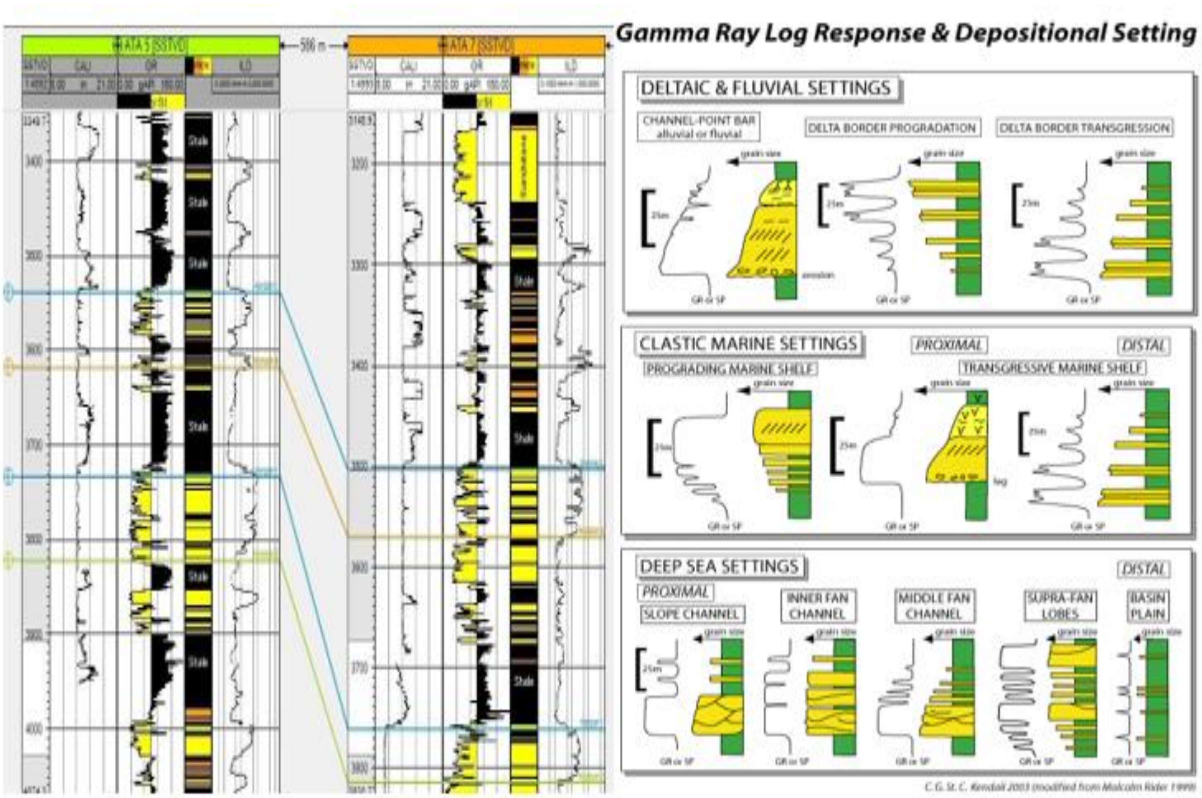


Fig. 7. Showing the sand beddings from the agbami field and the Modified Malcom Rider Log Motiff

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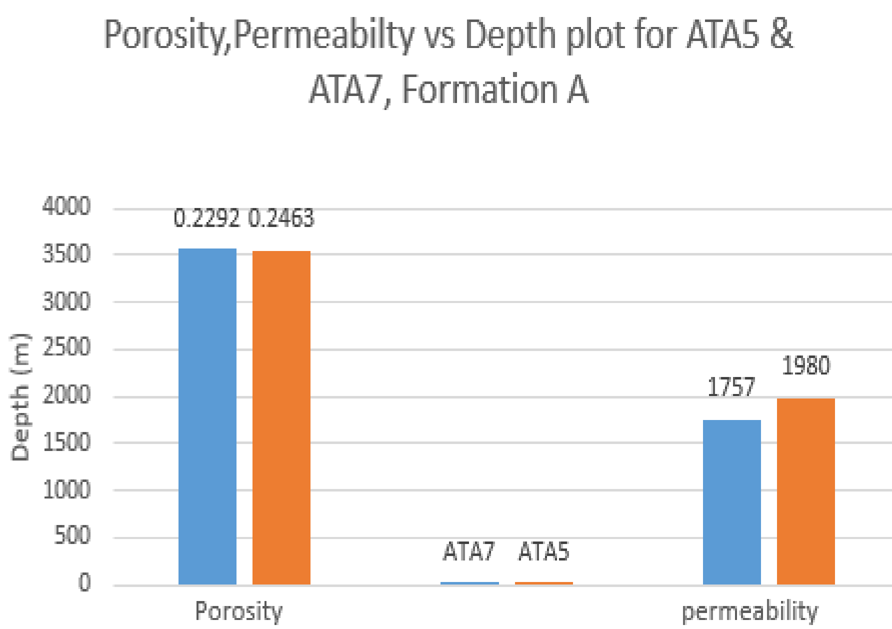

Fig. 8: Showing the permeability and porosity distribution for Reservoir A across ATA5 and ATA7

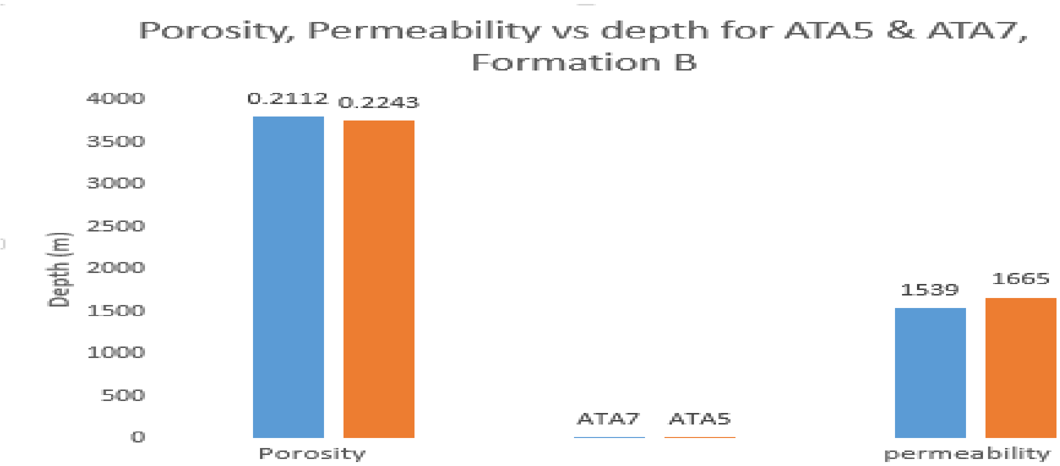

Fig. 9: Permeability and porosity distribution for Reservoir B across ATA5 and ATA7

Figs. 8 and 9 present the distribution of permeability and porosity across ATA5 and ATA7 over formations A and B. With the parameters decrease with an increase in depth indicating a normal compaction trend of the study area.

4.0 Conclusion

Rock formation property studies have been successfully done using well log data in the Agbami field to assess reservoir properties and their connection. The zones of interest were marked and the degree of similarity noted across the two wells. The well correlation revealed stratigraphic continuities of sand units over the field and varies in thickness with some sand units occurring at greater depth than their adjacent units, indicating the complexity of the field. The petrophysical parameters calculated include total/effective porosity, water saturation, permeability, net-to-gross and volume of shale. The results obtained show volume of shale values range from 9% to 30% is indicative of huge amount clean sands in the formations and the fraction of shale in the reservoirs is quite low. The average porosity is greater than 20% which means the reservoirs very good with good to excellent ease for fluids (oil and gas) recoverability. The Agbami field sedimentation is characterized with the normal compaction trend.

Based on the interpretation of the Agbami field, Niger Delta, more exploitation for hydrocarbon can be carried out within Agbami oil field. However, coring should be done in order to validate the result of the wireline logging.

5.0 Acknowledgment

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