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## RESERVOIR EVALUATION OF "T-X" FIELD (ONSHORE, NIGER DELTA) FROM WELL LOG PETROPHYSICAL ANALYSIS

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### ABSTRACT

*Three wells A1, A2 and A3 were identified on the 'T-X' field in onshore Niger Delta. A comprehensive petrophysical analysis on one of the wells (well A1) was carried out in order to come up with physical properties such as shale volume, porosity ( $\Phi$ ), permeability (K), fluid saturation, and net pay thickness, among others for future development planned of the oil field.*

*A well log data from this field have been examined and analyzed. The logs include gamma ray (used for the identification of lithology), resistivity and porosity logs (used for delineating hydrocarbon bearing reservoirs). Wireline log analysis was employed in the characterization of the reservoirs in the well studied; the hydrocarbon sands were delineated by the use of gamma ray, resistivity and density/neutron from which the reservoir quality were determined. Fluid types defined in the reservoirs on the basis of neutron/density log signatures were basically water, oil and gas. Eighteen (18) reservoirs (AR1 to AR18) were identified, among which twelve (12) are hydrocarbon-bearing reservoirs. Permeability and porosity values range between 1-6206md and 6-28% respectively. Water saturation recorded between 15-100% in the identified reservoirs which indicated that the proportion of void spaces occupied by water varied from low to high values, thus, indicating both low and high hydrocarbon saturation. Plot of hydrocarbon saturation and porosity showed a linear trend and strong linear relationships between permeability and porosity was also observed in all the reservoirs identified indicating that they are permeable and have pores that are strongly interconnected. This study has really demonstrated that petrophysics has a vital role to play in reservoirs characterization.*

*Keywords: Reservoir sands, petrophysical properties, reservoir quality, Lithology and Wireline logs.*

### INTRODUCTION

Effective description of reservoirs is the key to efficient reservoir management. Typically, data from various sources are utilized to describe reservoir in terms of pore space, distribution, and geological attributes. These sources include cores, logs, well test and production data. Sneider and King (1978) have discussed the integration of core data and log data in formation evaluation. A reservoir is a subsurface rock that has effective porosity and permeability which usually contains commercially exploitable quantity of hydrocarbon. Reservoir characterization is undertaken to determine its capability to both store and transmit fluid. Amafulé (1988) defined reservoir characterization as 'combined efforts aimed at discretizing the reservoir into subunits, such as layers and grid blocks and assigning values to all pertinent physical properties to these blocks'. Hence, characterization deals with the determination of reservoir properties/parameters such as porosity ( $\Phi$ ), permeability (K), fluid saturation, and Net Pay thickness. Estimates of lithology, fluid content, and porosity are indispensable. Also in the evaluation of clastic reservoirs such as obtained in the Niger Delta, shaliness which is a measure of the cleanliness of the reservoir is a parameter to be considered as it can give a wrong impression of estimated petrophysical values like porosity and hydrocarbon saturation when

they are not corrected for (Aigbedion and Iyayi, 2007). The uses of exploratory wells that are drilled through prospective geological structures have been of greater assistance in evaluating the hydrocarbon potential of so many locations. In order to know the quantity of hydrocarbon accumulation in reservoir rocks (sandstone, limestone or dolomite), some basic petrophysical parameters must be evaluated. These parameters include porosity, thickness and extent of formation, hydrocarbon saturation and permeability. Logs ranging from electrical, nuclear and acoustic have been in use for deriving these parameters. According to Asquith and Krygowski (2004) well logs are used to correlate zones suitable for hydrocarbon accumulation, identify productive zones, determine depth and thickness of zones, distinguish between gas, oil and water in a reservoir and to estimate hydrocarbon reserves.

The role of well evaluation in petroleum exploration and production is well appreciated when one determine its petrophysical parameters of a reservoir because reservoir quality was strongly influenced by the grain sizes in the reservoir where these parameters are high (Dressor, 2004). The porosity and permeability increased with increasing in reservoir quality. These are essential for both economic evaluations of the reservoir and production planning of an optimum recovery method.

However, this project work is aim at utilizing a suite of borehole geophysical wire lines logs for the evaluation of the hydrocarbon potential of an oil field in onshore, Niger Delta with the objectives to: Identification of the reservoirs in well A1, lithologic identification and interpretation of exploratory well A1 and estimation of petrophysical properties such as porosity, hydrocarbon saturation, thickness and permeability of the identified reservoir

**Description of the Study Area**

The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province as defined by Klett *et al.*, (1997). The province contains only one identified petroleum system (Kulke, 1995; Ekweozor and Daukoru, 1994). This system is related to as the Tertiary Niger Delta (Akata –Agbada) Petroleum System, with majority of which lies within the borders of Nigeria, with suspected or proven

access to Cameroon and Equatorial Guinea. It occupies an area enclosed by the geographical grids of latitude 5.30 and 5.40N and longitude 6.00 and 6.20E. The Delta is rich in both oil and gas. Three (3) main formations have been noted in the subsurface of the Niger Delta (Frank and Cordy, 1967). They are the Benin, Agbada and Akata Formations which were deposited in continental, transitional and marine environments, respectively.

The field location was stated as occurring in the onshore southwestern Niger delta. The field has three wells log data that include well 1, well 2 and well 3 drilled to an average depth of 2,700 m. Figure 1 is the base map of the study area, showing the three wells in the field and some of the seismic lines. For the purpose of this work, one of the exploratory well (well A1) was evaluated. This well belongs to an active oil company in Niger Delta and the new names given to the fields are valid only in this work.

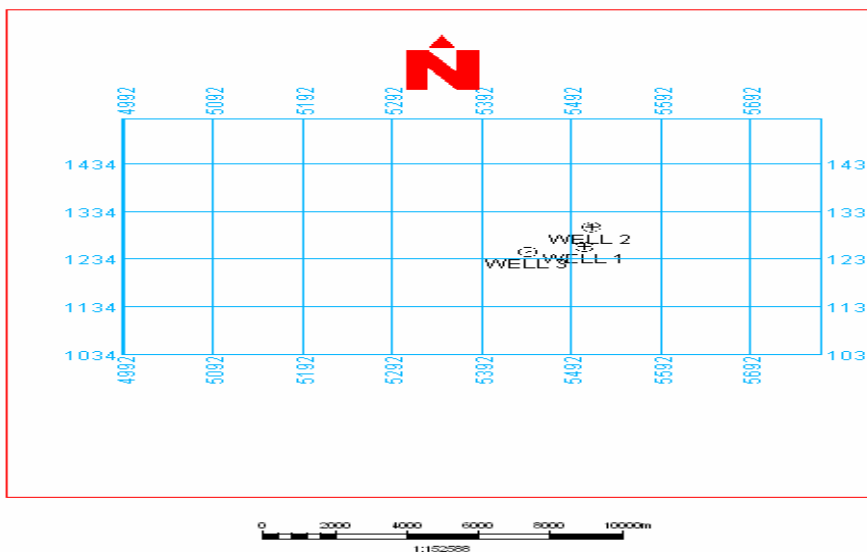


Figure 1: Study Location and Base map of the Study Area

**Geological Settings of the Study Area**

The Niger Delta is situated in the Gulf of Guinea and extends throughout the Niger Delta Province. From Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1994). These depobelts form one of the largest regressive deltas in the world with an area of about 300,000 km<sup>2</sup> (Kulke, 1995), a sediment volume of 500,000 km<sup>3</sup>, and a sediment thickness of over 10 km in the basin depocenters, (Kaplan, 1994).The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon (Doust and Omatsola, 1994). The northern boundary is the Benin Flank an east-northeast trending hinge line south of the West Africa basement massif

(Avbovbo, 1978). The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further east-south-east by the Calabar Flank-a hinge line bordering the adjacent Precambrian (Figure 2).

The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey Basin (the eastern-most West African transform-fault passive margin) to the west, and the two kilometer sediment thickness contour or the 4000-meter bathymetric contour in areas where sediment thickness is greater than two kilometers to the south and southwest (Amfulde, 1988). The province covers 300,000 km<sup>2</sup> and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum System.

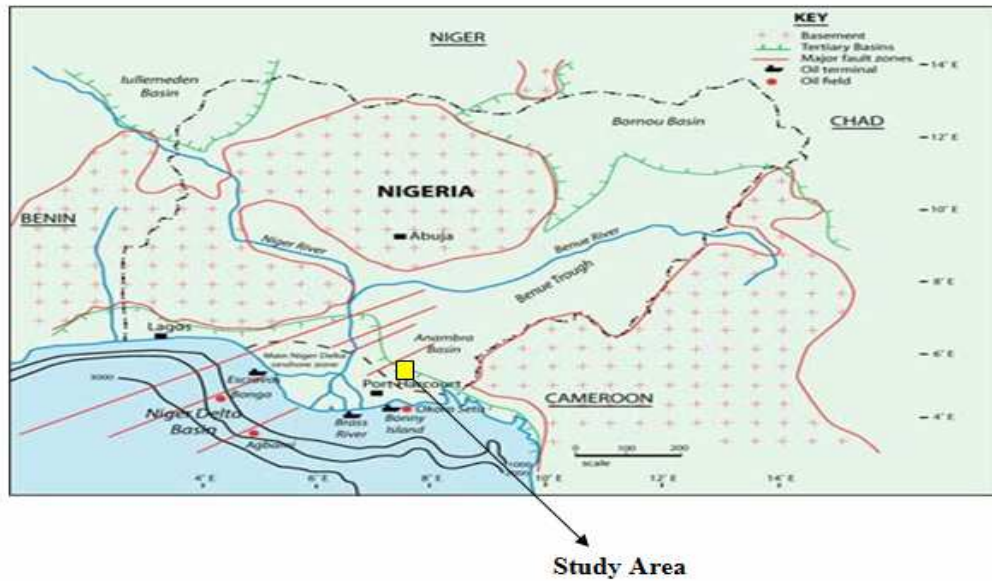


Figure 2: Map of Niger Delta showing the Study Area (modified after Jane and Whaley 2008)

**Stratigraphy**

The Niger Delta Basin covers an area of about 300,000 km<sup>2</sup> and is composed of an overall regressive clastic sequence that reaches a maximum thickness of 9,000 to 12,000m (29,500 to 39,400 ft). The Niger Delta is divided into three formations, representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios (Figure 3). The Akata Formation at the base of the delta is of marine origin and is composed of thick shale sequence (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt. Beginning in the Paleocene and through the Recent, the Akata Formation formed during low stands when terrestrial organic matter and clays were transported to deep water areas

characterized by low energy conditions and oxygen deficiency (Stacher, 1995). The formation underlies the entire delta, and is typically over pressured. The approximate range of the thickness is about 6,000m (Paul, 2003). Deposition of the overlying Agbada Formation, the major petroleum-bearing unit, began in the Eocene and continues into the Recent. The formation consists of paralic siliciclastics over 3,700meters thick and represents the actual deltaic portion of the sequence. The clastics accumulated in delta-front, delta-top set, and fluvio-deltaic environments. The Agbada Formation is overlain by the third formation, the Benin Formation, a continental latest Eocene to Recent deposit of alluvial and upper coastal plain sands that are up to 2,000m thick, (Avbovbo, 1978).

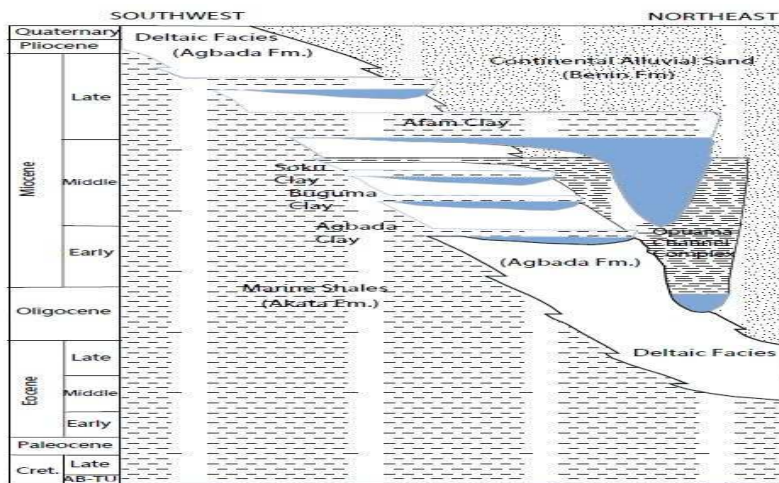


Figure 3: Stratigraphic columns showing the three formations of the Niger Delta. (After Shannon and Naylor 1989)

**Tectonics and Structure**

The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins, and, in Nigeria, form the boundary faults of the Cretaceous Benue-Abakaliki Trough, which cuts far into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic Ocean. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous, (Lehner and De Ruiter, 1977). In the region of the Niger Delta, rifting diminished altogether in the Late Cretaceous. After rifting ceased, gravity tectonism became the primary deformational process. Shale mobility induced internal deformation and occurred in response to two processes (Kulke, 1995). First, shale diapirs formed from loading of poorly compacted, over-pressured, prodelta and delta-slope clays (Akata Formation) by the higher density delta front sands (Agbada Formation). Second, slope instability occurred due to a lack of lateral, basinward, and support for the under-compacted delta-slope clays (Akata Formation). For any given depobelts, gravity tectonics were completed before deposition of the Benin Formation and are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults (Evamy, 1978). These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.

**Theoretical Background**

To achieve the objectives set out for this project work. The materials used involved the availability and analysis/evaluation of composite wireline logs. The log types include gamma ray logs, resistivity logs and combination of neutron/density logs. Gamma rays log help to measure the natural radioactivity in the formations. It can also be used for identifying

lithologies and correlating sandstone zones which are free of shale.

**Estimation of Petropysical Parameters**

The reservoir zones were qualitatively identified using the log signatures by way of eliminating the shale beds and compact beds. Beds with high gamma ray, low resistivity, low density, and high neutron readings indicated shale (Schlumberger Ltd., 1972). The reservoir zones were also quantitatively identified by shale volume, porosity, and fluid content determinations through the use of some empirical equations stated in this chapter.

**Porosity**

Porosity ( $\phi$ ) is defined as the pore volume per unit volume of formation or rock. It is also the percentage of the total volume of the rock that is occupied by pores (Asquith and Krygowski, 2004):

$$\phi = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_{fl}) \dots\dots\dots 3.1$$

Where,

$\phi$  = porosity derived from density log

$\rho_{ma}$  = matrix (or grain) density

$\rho_b$  = bulk density (as measured by the tool and hence includes porosity and grain density)

$\rho_{fl}$  = fluid density.

Effective porosity was estimated according to equation 3.2

$$\phi_e = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \times \{V_{sh} \times (\rho_{ma} - \rho_{sh}) / (\rho_{ma} - \rho_{fl})\} \dots \text{equation 3.2}$$

where,

$\phi_e$  = Effective porosity

$\rho_{sh}$  = Density of shale

$V_{sh} \times (\rho_{ma} - \rho_{fl})$  = Clay Bound Water

( $\rho_{ma} = 2.65\text{g/cc}$ ,  $\rho_{fl} = 1.0\text{g/cc}$ ,  $\rho_{sh} = 2.6\text{g/cc}$ )

According to Rider (1986), Table 1 gives a better explanation of porosity description of reservoirs.

**Table 1: Qualitative Evaluation of Porosity**

Percentage Porosity (%)	Qualitative Description
0-5	Negligible
5-10	Poor
15-20	Good
20-30	Very Good
>30	Excellent

**4.12 Permeability**

Permeability (K) is a measure of the ease with which a fluid of given viscosity can flow through a formation. Tables 2 describe permeability range within a particular formation. It is a function of the

connectivity of the pores and thereby a function of the effective porosity. It is useful for the evaluation of the producibility of a reservoir. Its unit is darcy (d) or millidarcy (md) for practical uses; 1md = 10<sup>-3</sup>d

**Table 2: Qualitative Evaluation of Permeability**

Average K Value (md)	Qualitative Description
<10.5	Poor to Fair
15-50	Moderate
50-250	Good
250-1000	Very Good
>1000	Excellent

**Net/ Gross**

The gross reservoir thickness H, of the well A1 was determined by looking at tops and bases of the reservoir sands across the well. The net thickness which is the thickness of the reservoir was determined by defining bases for non reservoir and reservoir sands using the gamma ray log. This was carried out by drawing a shale baseline and sand baseline on the gamma ray log. The thicknesses of the shale,  $h_{shale}$ , within the reservoir sands were obtained and therefore, subtracted from the gross reservoir thickness. Hence, Net reservoir thickness,  $h = H - h_{shale}$ , and Net/Gross=  $h/H$ , was obtained for all the reservoirs in the well A1.

**Volume of Shale**

The maximum and minimum of gamma ray were used to compute shale volume as shown in equation 3.1.

$$V_{sh} = \frac{GR_{log} - GR_{min}}{(GR_{max} - GR_{min})}$$

$$V_{sh} = \frac{GR_{log} - GR_{min}}{(GR_{max} - GR_{min})} \text{ (linear)}$$

$$V_{sh} = 0.5 \times V_{sh} / (1.5 - V_{sh}) \text{ (steiber)}$$

$$GR_{min} = 20API \quad GR_{max} = 153API$$

where,

$V_{sh}$  = Volume of shale

$GR_{log}$  = Gamma ray log reading of formation

$GR_{min}$  = Gamma ray matrix (Clay free zone)

$GR_{max}$  = Gamma ray shale (100% Clay zone)

**Saturation**

The saturation of a reservoir is the fraction of its pore volume that is occupied by the fluid considered. In formation evaluation, water saturation ( $S_w$ ) is that percentage or fraction of the pore volume that contains the formation water while hydrocarbon saturation ( $S_h : S_o$  or  $S_g$ ) is that fraction of the pore volume that is not occupied by the formation water. Simply put, it is the fraction of the pore volume that is being filled with hydrocarbons and can be calculated as;

$$S_h = 100 - S_w \% \quad S_h = 1 - S_w$$

Archie equation was used to calculate the water saturation as shown was used to calculate the effective water saturation due to its wide-scale applicability in the Niger Delta

$$R_o = F \times R_w$$

$$F = \frac{a}{\phi^n}$$

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

$$S_w = (F \times \frac{R_w}{R_t})^{1/n}$$

$$S_w = \sqrt[n]{(a \cdot R_w / \phi_e^m \times R_t)}$$

$$(a = 1.0, m = 1.6, n = 2)$$

where,

$R_t$  = True Resistivity,  $R_w$  = Water resistivity

$\phi_e$  = Effective porosity,  $S_w$  = water saturation

$a$  = Archie's exponent,  $m$  = cementation factor

$n$  = Saturation exponent, Hydrocarbon saturation is the fraction of pore volume occupied by hydrocarbon and it is dependent on water saturation.

$$S_h = 1 - S_w$$

Where,

$S_w$  = water saturation

$S_h$  = Hydrocarbon saturation.

**Bulk Water Volume**

The product of formation's water saturation ( $S_w$ ) and its porosity ( $\Phi$ ) is the bulk water volume (BWV).

$$BWV = S_w \times \Phi$$

Where,

BWV= Bulk water volume

$S_w$  = Water saturation

$\Phi$  = Porosity

**RESULTS AND DISCUSSION**

**Log Characteristics of Well A1 Reservoirs**

The gamma ray log of the studied well was interpreted for lithology identification. Within the study intervals, the lithology was dominated by alternating sand and shale, the sand occurring at the top, middle and base of the log whereas the shale occur more frequently as the logging deepens. However, core data and core cuttings may be needed before the final verification is done; and these were not included in the data. Therefore, to minimize uncertainties in interpretation, lithology type has been narrowed down to sand and shale lithology. In differentiating the fluids saturating the reservoir, well A1 was studied and Eighteen (18) different reservoirs were encountered. The reservoirs sand marked AR1, AR2, AR3, AR4, AR5, AR6, AR8, AR11, AR12 and AR15 are probably hydrocarbon bearing that records high resistivity values while reservoir sands AR7, AR9, AR10, AR13, AR14, AR16, AR17 and AR18 are not hydrocarbon bearing evidenced from the resistivity log signatures that records low resistivity values within these intervals. All available electrical logs (gamma, spontaneous potential, resistivity, neutron and density) for well A1 were examined. They show that the reservoirs were easily identified on the logs. The gamma ray log shows that well A1 reservoir sandstone has a low gamma ray reading unit.

The resistivity log was generally characterized by relatively higher resistivities where the gamma ray was low, indicating sand (Figure 4). This may be in part a reflection of the sandstone's contained fluid-hydrocarbons (Dressor, 2004). On the neutron-density curve in Figure 4, this depicts gas bearing effect superimposed on the lithology effect as evidenced by the divergence of the two curves. The neutron log shows a very low porosity because of the low hydrogen density of the gas and because the neutron log has a reverse scale, this low porosity causes the neutron log trace to move to the right (Rider, 1999).

**Identified Reservoirs**

The sandstone and shale base lines SSBL and SHBL are chosen from the gamma ray log and a cut-off line is drawn midway between the SSBL and SHBL. The zones where the gamma ray log is below the cut-off are considered to be reservoirs in the well sections. Other areas of the gamma ray log above the cut-off line are considered as non- reservoirs.



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Based on the qualitative and quantitative interpretations, eighteen (18) reservoirs were identified and located in the well A1 (Figure 4). These reservoirs were labeled reservoir AR1, AR2, AR3, AR4, AR5, AR6, AR7, AR8, AR9, AR10, AR11, AR12, AR13, AR14, AR15, AR16, AR17 and AR18 respectively.

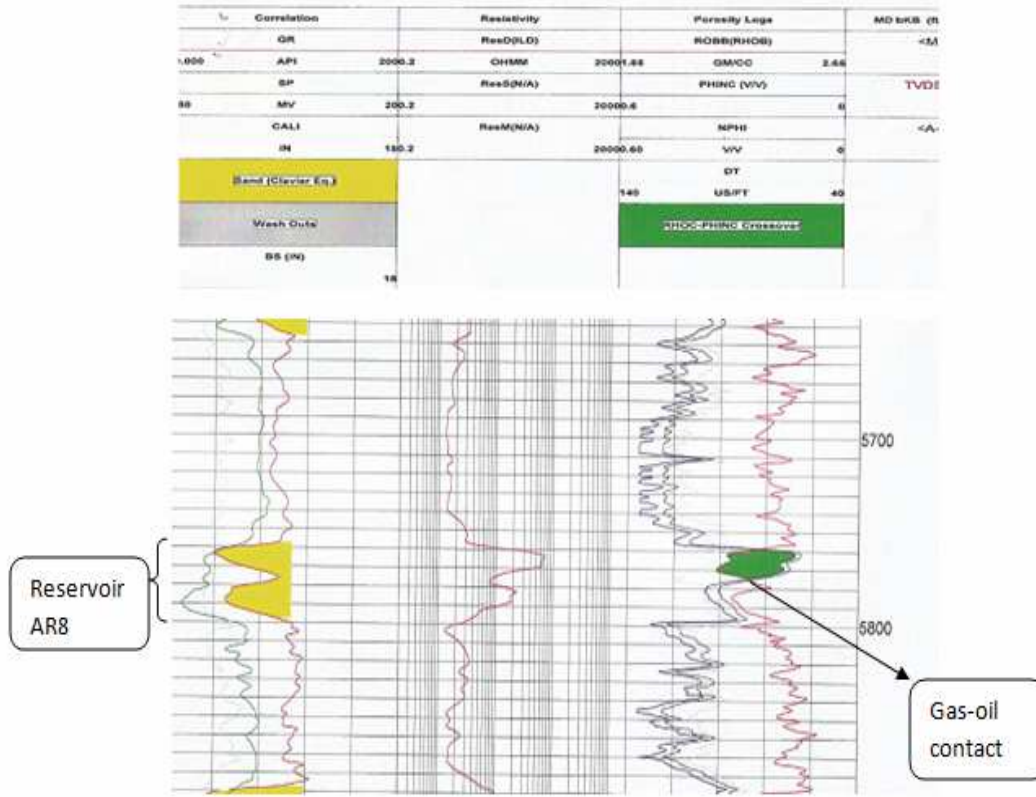


Figure 4: Gas-Oil Contact (GOC) in Reservoir AR8 (5758-5800ft)

**Table 3: Results of the Petrophysical Analysis of Well A1**

Reservoir	Top ft AH	Base ft AH	GR API	V <sub>sh</sub> %	φ <sub>eff</sub> %	S <sub>w</sub> %	S <sub>h</sub> %	Pay	K(md)	BWV%
AR1	4633	4745	93	28.86	23.68	51.00	49.00	5	2243	27.32
AR2	4864	4886	73	18.09	20.17	35.60	64.40	20	825	7.18
AR3	4982	5081	87	25.29	24.18	47.80	52.20	13	2556	11.56
AR4	5176	5192	47	7.83	24.56	34.70	65.30	25	679	6.78
AR5	5283	5320	57	11.38	28.10	42.80	57.20	16	6206	11.93
AR6	5400	5416	110	41.10	18.09	16.60	83.40	41	397	2.98
AR7	5450	5646	113	43.66	15.99	64.70	35.30	2	194	10.35
AR8	5758	5800	66	14.98	22.86	26.60	73.40	37	1354	5.81
AR9	5888	6100	120	50.25	13.57	60.00	40.00	7	70	8.14
AR10	6148	6179	73	18.09	23.89	97.80	2.20	0	2368	23.36
AR11	6309	6321	47	7.83	26.31	62.50	37.50	3	4323	16.44
AR12	6653	6900	123	53.36	11.25	18.50	81.50	40	22	2.08
AR13	7065	7123	94	29.48	18.79	83.30	16.70	0	531	15.65
AR14	7164	7290	100	33.48	16.72	83.40	16.60	0	256	13.94
AR15	7550	7630	103	35.63	16.86	15.30	84.70	45	269	2.58
AR16	7690	7809	83	23.08	17.08	97.80	2.20	0	222	15.98
AR17	8483	8532	110	41.10	13.08	100.0	0.00	0	56	13.08
AR18	8656	8828	126	56.68	6.83	86.40	13.60	0	1	5.90

The Table above presents the results of the digitization, evaluation of petrophysical parameters and related reservoir properties carried out in Well A1. All Petrophysical properties were determined for only the hydrocarbon bearing sandstones units of the basin. These reservoirs are eighteen in number and they include: reservoir sand AR1.....AR18 as shown in the Table above.

**Fluid Contacts**

The resistivity log was used to determine the extent of hydrocarbon thickness in the reservoirs. A combination of the Neutron-Density log was used to confirm the contact points, and they were located in the well A1 reservoirs by means of visual inspection and through interpreted results of saturations from the logs. The Gas/Oil contacts are picked at the point below which gas crossover on the shale and matrix corrected density neutron log disappears for example

in reservoir AR8 (Figure 4). The Oil/Water contact was picked in reservoir AR15(Figure 5).From Figure 6, it was noted that high porosity with high hydrocarbon saturation means that gas is present in the reservoir termed as Gas Saturation ( $S_g$ ) while the porosity and permeability relationship (Figure 7) showed that the higher the porosity the higher the permeability and vice versa.

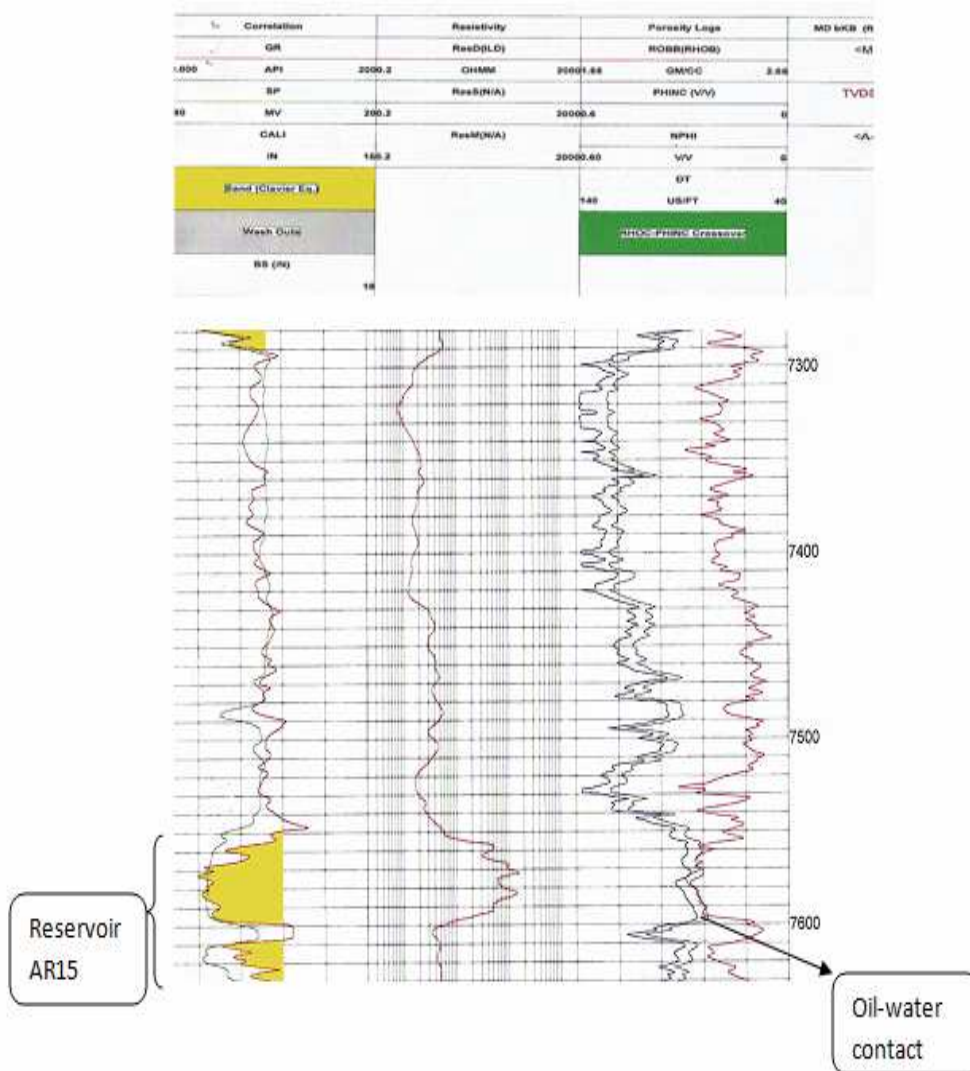


Figure 5: Oil-Water Contact (OWC) in Reservoir AR15 (7550-7629ft)

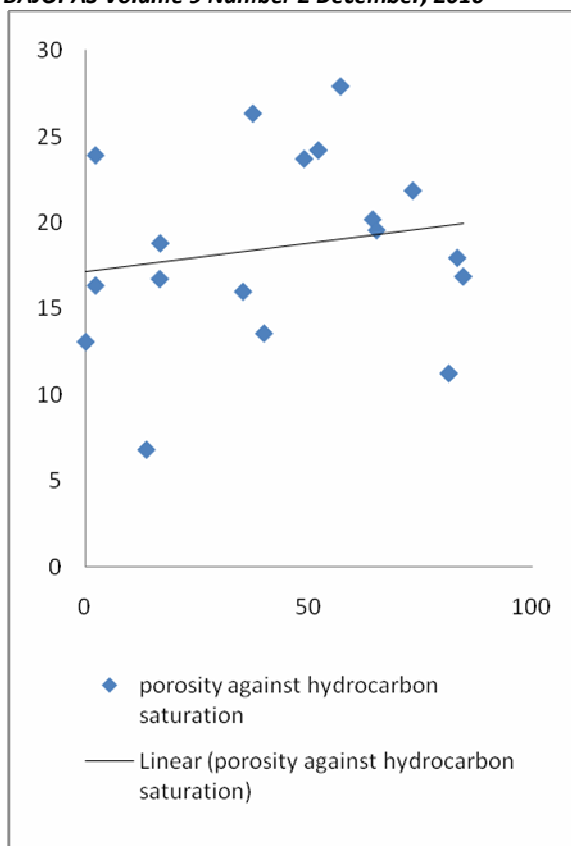


Figure 6:  $\Phi$  and  $S_h$  Graph of Selected Reservoirs in Well A1 Well A1

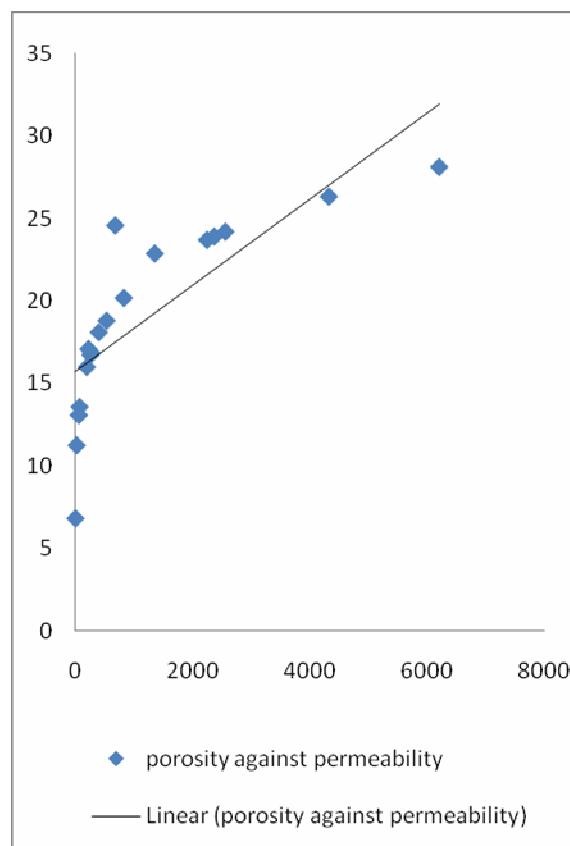


Figure 7:  $\Phi$  and K Graph of Selected Reservoirs in

**CONCLUSION AND RECOMMENDATION**

Neutron, density, gamma ray and resistivity logs were employed in the analysis of eighteen (18) reservoirs in well A1. The correlation of these reservoirs depicts that the subsurface stratigraphy is that of sand shale interbedding. The interpretation of the well A1 reservoir sand bodies was carried out with integration of well log responses. It was observed that the lithologies characterizing the well are sand, shale and sand with shale intercalations. The proportion of the shale compared to that of sand units increased with depth as this is typical of Agbada formation. The log analysis performed in this study shows that the reservoir sand units of well A1 contain significant accumulations of hydrocarbon. The delineated zones of interest (eighteen in number) have an average net sand thickness of between 12m – 209m, average effective porosity in the range of 0.068 to 0.28 and hydrocarbon saturation ranging from 0 to 85% which are favorable indicators for commercial hydrocarbon accumulation. The quality of the reservoirs is determined by the average permeability values of 1 to 6206md, and the porosity value was also between 6.83 to 28 percent. From the porosity and permeability graph (Figure 6), it was stated that the higher the porosity the higher the permeability and vice versa. Consequently, petrophysical evaluation of the reservoirs showed that the porosity ranges from

very poor to excellent while the permeability varies from poor to excellent. The water saturation value ranges from 15 to 100%, while the hydrocarbon saturation of the well ranges from 0 to 85%. From the value of the bulk volume of water, the reservoirs are at irreducible water saturation, implying that the reservoirs can produce water-free hydrocarbon. The result of the formation evaluation shows that reservoir zones AR1, AR3, AR5, AR7, AR9 and AR15 contain oil, reservoirs AR2, AR4, AR6, AR8, AR11 and AR12 contain gas while reservoirs AR10, AR13, AR14, AR16, AR17 and AR18 are water filled. The contact between the oil and water (Oil water contact- OWC/Free Water Level) is at a depth of 6670ft.

In order to have better understanding of the lithology, reservoir geometry and hydrocarbon accumulation within well A1, core samples, biostratigraphy and seismic data should be integrated for a better understanding of the field as the significant of integrating petrophysical evaluation and seismic interpretation for the planning program is to give a well-articulated exploration data in petroleum prospecting (Ologe *et al.*, 2014). Oil companies should therefore be generous in releasing data to improve the research output of the researchers. Decisions on economic production of hydrocarbons from the well A1 should not be based solely on electrical log responses but should also consider evidence obtained from other techniques.



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