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Petrophysical Analysis of XYZ Field, South-East, Niger Delta Using Well Logs

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ABSTRACT

The Niger Delta is a prolific oil province within the West African subcontinent. Exploration activities have been concentrated in the onshore part of this basin but as the delta becomes better understood exploration influences are gradually being shifted to the offshore. This study essentially helps understand the physical properties of the reservoir units of the XYZ field in Niger Delta Basin. PETREL Software and suites of seven geophysical well log data and pressure data obtained from an active oil company in Nigeria, recorded at various locations within the XYZ field, Niger Delta basin was used for this work. The petrophysical analysis was carried out on seven wells using geophysical wireline logs and pressure data to evaluate the reservoir potentials of the XYZ field in the south east Niger Delta. The main petrophysical parameters include; estimation of volume of shale, net to gross, porosity, fluid identification, water saturation and net pay thickness. The Wireline logs employed in this work include Gamma Ray, Density, Neutron log and Resistivity log. Two reservoirs designated P0.5 and P1 were delineated and correlated across wells in the field using the gamma ray logs and resistivity logs. The following procedures were followed for the data analysis; Well data import, Well Normalization, well log Analysis and correlation, Identification of reservoirs, differentiation of hydrocarbon and non-hydrocarbon bearing zones and Petrophysical Analysis. The analysis revealed that the reservoir sand bodies have good reservoir characteristics as shown by their petrophysical properties with an average porosity ranging from 0.30-0.36, average water saturation ranging from 0.08-0.3. The net/gross of the reservoirs is between 0.06-0.6. Wells B1, A5X, A4X, A8X(P0.5) reservoir are oil and gas bearing, well A4X(P1) reservoir is gas bearing, well A8X(P1) reservoir is oil bearing and well B1(P1) reservoir is a wet sand. The petrophysical properties of reservoirs in XYZ field suggest a good reservoir quality which is satisfactory for further exploration and production.

1. Introduction

Petrophysical characteristics of reservoir rocks include porosity, permeability, water saturation, hydrocarbon saturation, formation water resistivity and formation factors.

These properties are determined by grain size, grain shape, and degree of compaction, amount of matrix, cement composition, type of fluid present and saturation of different fluids. Among these properties' porosity, permeability and fluid saturation are the most important and can be measured using standard procedures. For scientific and economic purposes, laboratory data of high accuracy and reliability for both the fluids and the rocks that contain them are extremely useful information evaluation (Harry and Akata, 2019a). However, such data cannot be acquired very quickly, hence the operators in the field need a method of acquiring the fundamental properties of the rocks and their fluid contents for a quick management decision making. This requirement is easily satisfied by the use of geophysical wireline logs.

Recent reservoir evaluation involves the study of well cuttings, cores, well log data, formation micro scanner (FMS) images and drill stem tests. The wireline log is basically used for this work. The well logs used include Gamma Ray, Density, Neutron and Resistivity logs. The main petrophysical parameters evaluated in this work are estimation of volume of shale, net to gross, porosity, fluid identification, water saturation and net pay thickness of these reservoirs. This work focuses on correlating the reservoirs across the well, to delineating hydrocarbon bearing reservoir, and to improve the understanding of hydrocarbon distribution in the reservoir. The study area is located within the offshore area of Niger Delta (between longitudes 3° (500,088 mE) and 9° E (1,165,306 mE), and between latitudes 4° (442,007 mN) and 6° N (666,735 mN) belonging to an active oil producing company in Nigeria. The seven wells; B1, A1, A4X, A5X, A8, A8X, A8Y provided are aligned in the west to the east part of the study area (Fig. 1).

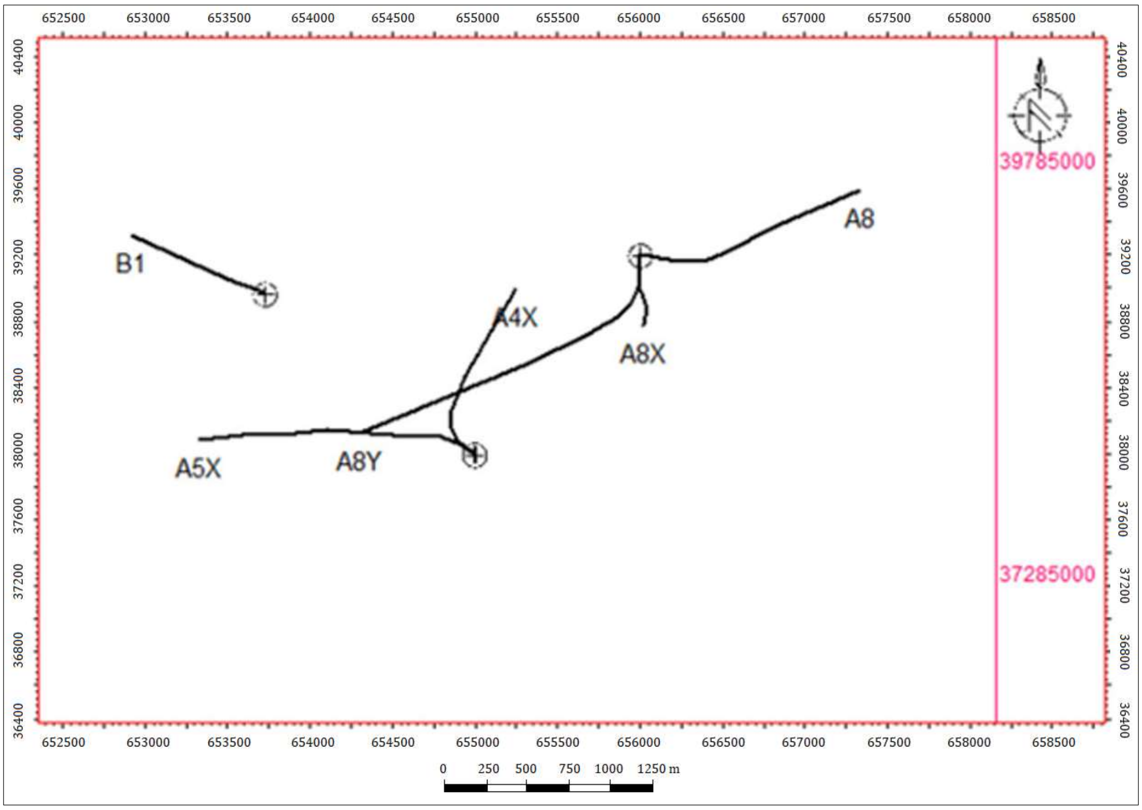

Fig. 1. Base map of the study area

2. Geology of Study Area

This study will be conducted using data from XYZ field in the Niger Delta Basin. The Niger Delta is located in the Gulf of Guinea on the margin of West Africa between latitudes 3° and 6° N and longitude 5° and 8° E near the west coast of Nigeria with the access to Cameroon (Fig. 2). The Niger Delta sits at the southern end of the Benue trough, which corresponds to a failed arm of a triple rift (Avbovbo, 1978; Corredor et al., 2005).

It is one of the largest prolific petroleum producing regressive deltas in the world (Doust and Omatsola, 1990). It has a sub-aerial area of about 75,000 km^2, a total area of 300,000 km$^{2.}$ and sediment fill of 500,000 km^2.Rifting in this basin started in the late Jurassic and ended in the mid Cretaceous. As rifting continued, several faults were formed, of which many were thrust faults.

Also, at this time we had the deposition of the syn-rift sands and then shales in the late cretaceous which shows that there was a regression in the early basin. By this time the basin was undergoing extension by high angle normal faults and fault block rotation. Then at beginning of the Paleocene there was a large transgression which deposited the Akata Formation and in the Eocene the Agbada Formation was deposited. This caused the underlying shale Akata Formation to be squeezed into shale diapirs, followed by the deposition of the Benin Formation above the Agbada Formation. The sediment fill has depth range of about 9-12 km.

2.1. Stratigraphy of the Niger Delta Basin

The established Tertiary sequence in the Niger Delta consists, in ascending order, of the Akata, Agbada, and Benin Formations (Fig. 3). The strata composed an estimated 8,535 m (28000 ft) of section at the approximate depocenter in the central part of the delta. The Akata Formation which is the basal unit of the Cenozoic delta complex is composed mainly of marine shales deposited as the high energy delta advanced into deep water (Schlumberger, 1985). It is characterized by a uniform shale development and the shale in general is dark grey, while in some places it is silty or sandy and contains especially in the upper part of the formation, some thin sandstone lenses (Schlumberger, 1985).

The Akata Formation probably underlies the whole Niger Delta south of the Imo Shale outcrop of the Paleocene age from Eocene to Recent (Short and Stauble, 1965). The Akata Formation has been penetrated in most of the onshore fields between 12,000 and 18,000 ft (~3,700- 5,500 m) and in many of the offshore fields between 5,000 and 10,000 ft (~1,530-3050 m); however, the maximum thickness of the Akata Formation is believed to average 20,000 ft (~7,000 m). For all practical prospecting purposes, the top of the Akata Formation is the economic basement for oil; however, there may be potential for gas dissolved in oil field waters under high pressure in the deeper formation (Schlumberger, 1985). The Agbada Formation is a paralic succession of alternating sandstones and shales, whose sandstone reservoirs account for the oil and gas production in the Niger Delta (Nwachukwu et al., 1995). The formation consists of an alternating sequence of sandstones and shales of delta-front, distributary-channel, and deltaic-plain origin.

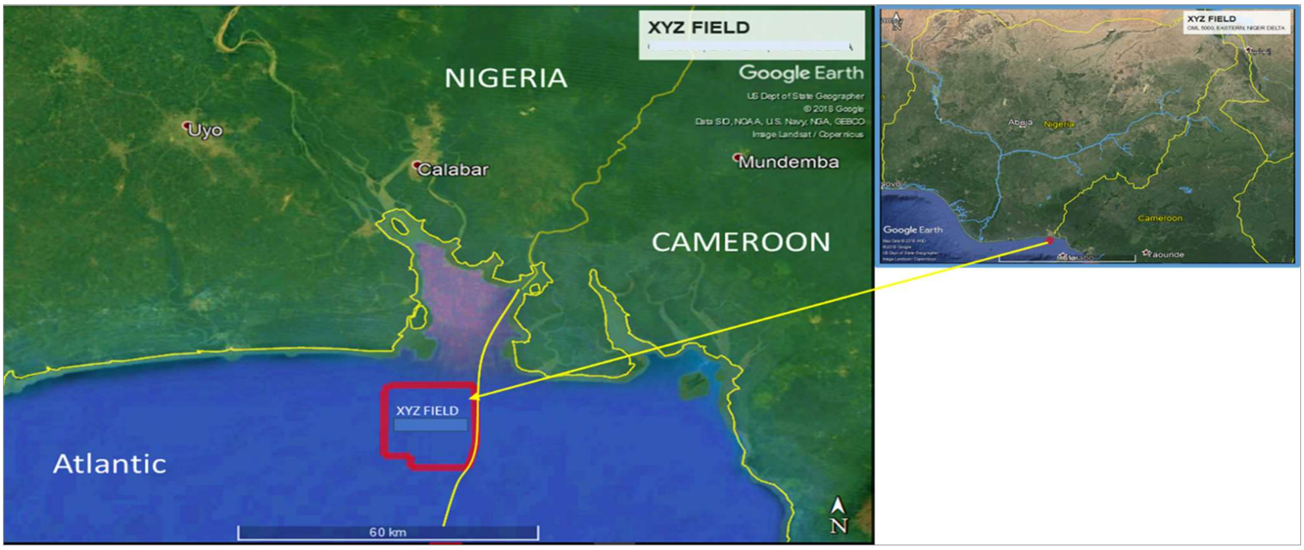

Fig. 2. Map of study area showing the XYZ field

The sandstones are medium to fine-grained, fairly clean and locally calcareous, glauconitic, and shelly. The shales are medium to dark grey, fairly consolidated, and silty with local glauconite. The sand beds constitute the main hydrocarbon reservoirs while the shale beds present form the cap rock. These shale beds constitute important seals to traps and the shales interbedded with the sandstones at the lower portions of the Agbada Formation are the most effective delta source rocks (Schlumberger, 1985) (Fig. 4).

Petroleum occurs throughout the Agbada Formation of the Niger Delta. Maximum thickness of the formation is 3,940m (12,000ft) at the central part of the delta, and thins northward and toward the northwestern and eastern flanks of the delta. The formation is poorly developed or absent north of the Benin City-Onitsha-Calabar axis. The age of the Agbada Formation varies from Eocene to Pliocene/Pleistocene.

The Benin Formation consists of predominantly massive highly porous, freshwater-bearing sandstones, with local thin shale interbeds, which are considered to be of braided-stream origin. Mineralogically, the sandstones consist dominantly of quartz and potash feldspar and minor amounts of plagioclase. The sandstones constitute 70 to 100% of the formation. Where present, the shale interbeds usually contain some plant remains and dispersed lignite. Benin Formation attains a maximum thickness of 1,970 m (6,000ft) in the Warri-Degema area, which coincides with the maximum thickness (i.e. depocenter) of the Agbada Formation. The first marine foraminifera within shales define the base of the Benin Formation, as the formation is non-marine in origin (Short and Stauble, 1965).

Composition, structure, and grain size of the sequence indicate deposition of the formation in a continental, probably upper deltaic environment. The age of the formation varies from Oligocene (or earlier) to Recent. The delta sequence is deformed by syn-sedimentary faulting and folding. Evamy et al. (1978) described the main structural features of the Niger Delta as growth faults and roll over anticlines associated with these faults on their downthrown (i.e. seaward) side (Fig. 5).

2.2. Growth faults

Growth faults are faults that offset an active surface of deposition. It is characterized by thicker deposits in the downthrown block relative to the upthrown block. The growth fault planes exhibit a marked flattening with depth as a result of compaction. Thus, a curved, concave-upward fault plane is developed, which continues at a low angle.

The ratio of the thickness of a given stratigraphic unit in the downthrown block to that of the corresponding unit in the up-thrown block is termed the growth index" which in Nigeria can be as high as 2.5m. The main boundary fault separates megastructures which represent major breaks in the regional dip of the delta (Evamy et al., 1978; Stacher, 1995).

3. Background of the Study

The Niger Delta Basin is considered as one of the most prolific hydrocarbon provinces in the world. With recent giant oil discoveries there is an increasing demand of hydrocarbon products to meet global needs in the 21st century. Despite the fall in global oil prices, there is however a need for an increase in exploration of other fields with a view to increasingly support reservoir appraisal, development and thus optimise hydrocarbon production from the basin.

Petrophysical analysis is crucial for understanding the characteristics and properties of a reservoir to enhance development and production. Well log analysis and interpretation are one of the most useful techniques in evaluating the petrophysical parameters of a reservoir, linking stratigraphy and correlating lithology where there are more than one well available. Petrophysical analysis can thus be used to study the lateral continuity or extent of the physical properties of a reservoir when seismic data is not available (Adeoye and Enikanselu, 2009).

These petrophysical parameters include; estimation of volume of shale, net to gross, porosity, fluid identification, water saturation and net pay thickness. Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation.

It is necessary to delineate the hydrocarbon reservoirs and evaluate them because they are the zones of interest for hydrocarbon exploitations (Adewoye et al., 2013). It is also necessary to use technological and economical viable methods in the exploration and exploitation for hydrocarbon because the oil business is capital intensive. This thus mitigates failure in hydrocarbon exploration.

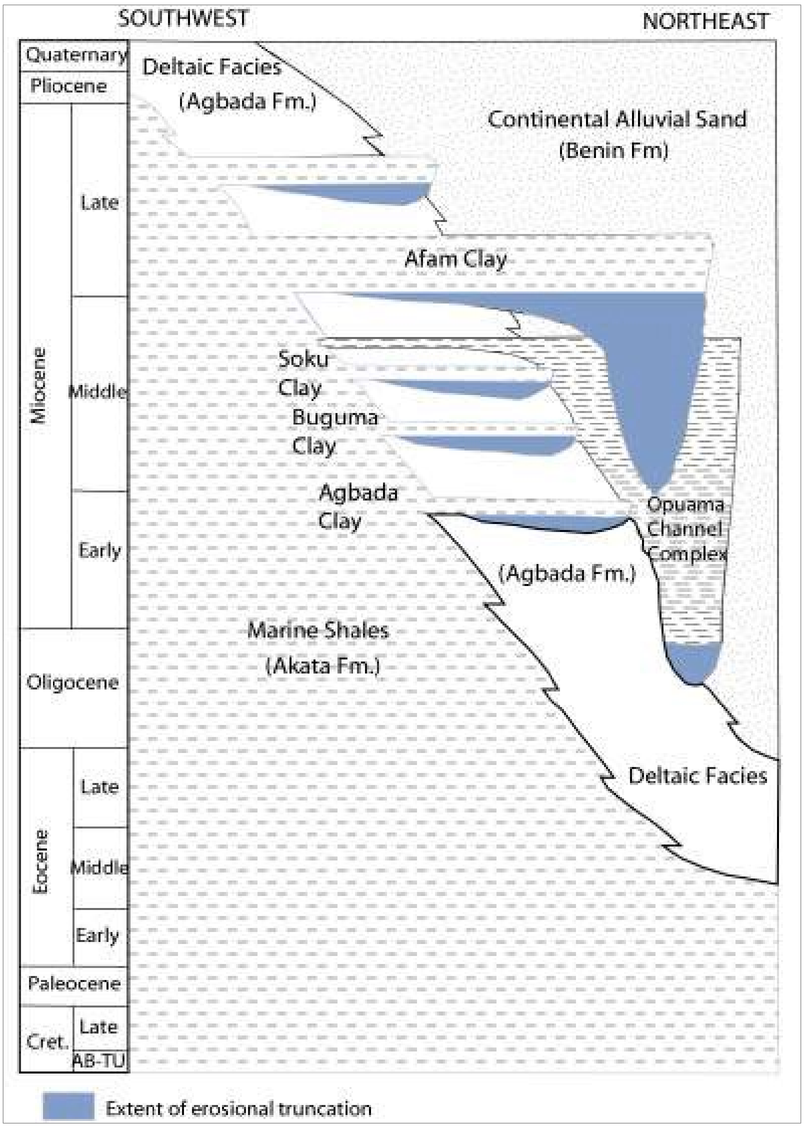

Fig. 3. Stratigraphic column showing the three formations of the Niger Delta

4. Materials and Methods

4.1. Materials

Petrel software, Suites of Geophysical Well Log Data (Gamma Ray, Compensated Bulk Density Log, Compensated Neutron Porosity Log and Resistivity Log from seven wells) and Pressure Data were provided by an active oil company in Nigeria for this study.

4.2. Methods

The following methods were applied in the study;

4.2.1. Data analysis

After the necessary data QC, using PETRELTM 2014, the following procedures were followed for the data analysis; Well data import, Well Normalization, well log Analysis and correlation, Identification of reservoirs, differentiation of hydrocarbon and non-hydrocarbon bearing zones and Petrophysical Analysis.

4.2.2. Well data import

The sequence of the well data import begins with the well headers and logs. The well header file contains the well name, surface location of the wells (2D-XY coordinate system), Rotary table (RT), the top depth and bottom depth. This will allow the display of well position on the base map. Since some of the wells were deviated wells, the deviation data was imported followed by the logs (gamma ray, resistivity, density and neutron) for all the wells.

4.2.3. Well Normalization

The wells were normalized by setting a scale range for each of the log tracts, the gamma ray log scale was set from 1-150 API, resistivity log was scaled from 0.2-2000ohm meter, Density log was scaled from 1.65-2.65g/cm3, the neutron porosity log was scaled from -0.15-0.45.

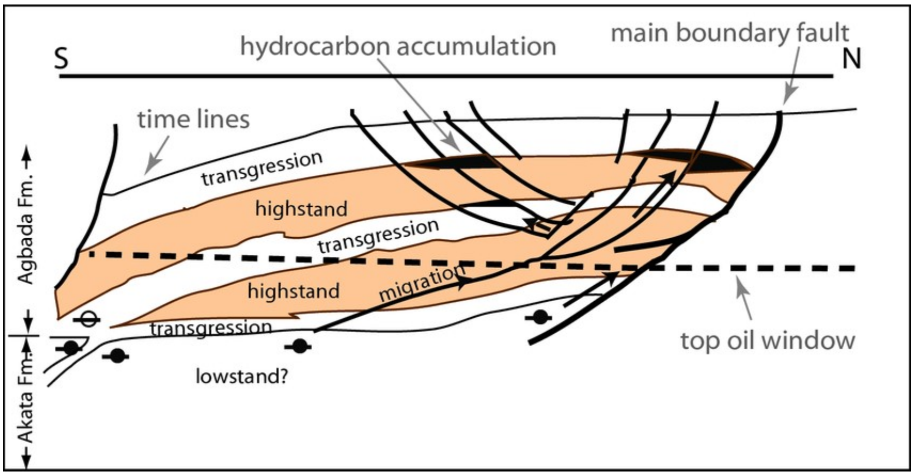

Fig. 4. Sequence stratigraphy model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon traps related to growth faults

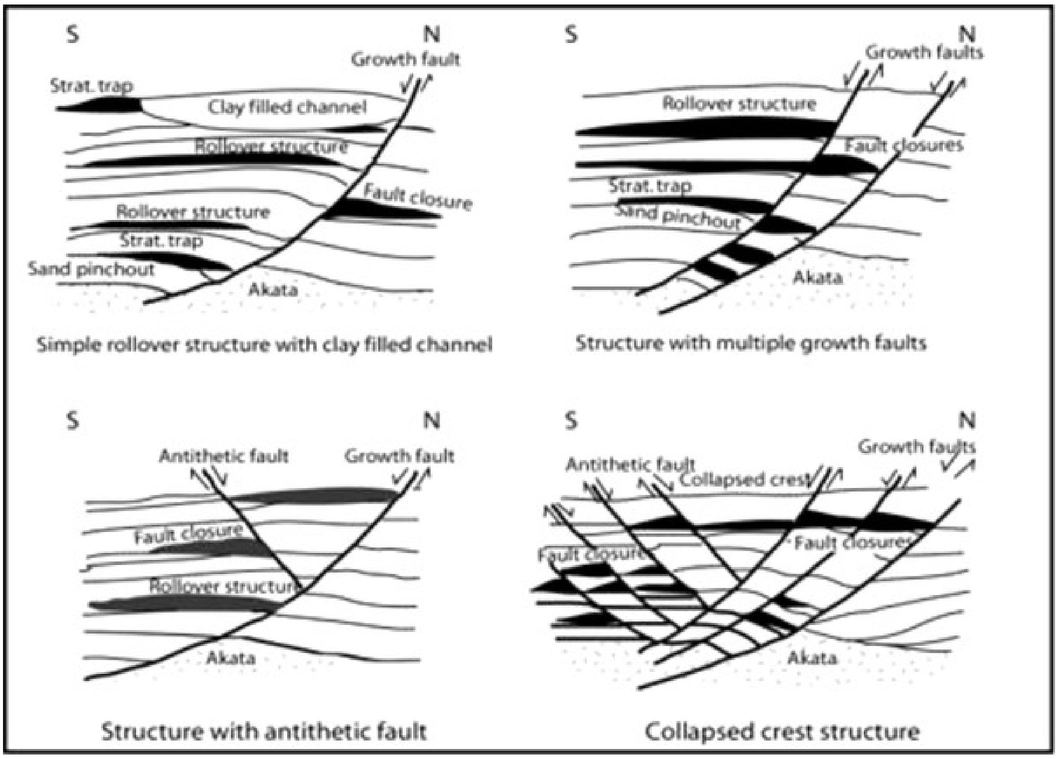

Fig. 5. Principal types of oil-field structures in the Niger Delta with schematic indications of common trapping configurations (Doust and Omatsola, 1990)

4.2.4. Well log analysis and correlation

The wells were displayed on a Map window using the Petrel software. A strike-line running from West -East was taken and the wells were being displayed on the well section window in that order. Correlation was carried out using the lithology log (Gamma ray log), the resistivity was used to check the fluid contents present within the formation i.e. hydrocarbon or water.

Hydrocarbons were initially delineated on well logs with the aid of gamma ray and deep resistivity logs. The essence was to test for the availability of hydrocarbon at the location of each exploratory well which will provide control for reservoir distribution prediction (Harry and Akata, 2019b). The entire formation was considered, and a good agreement was observed of their continuity with the extent of the well location.

The Gamma Ray log is a measurement of the natural radioactivity of the formations. In sedimentary formations the log normally reflects the shale content of the formations. This is because the radioactive elements tend to concentrate in clays and shales.

Clean formations usually have a very low level of radioactivity, unless radioactive contaminant such as volcanic ash or granite wash is present or the formation waters contain dissolved radioactive salts.

The density log is a continuous record of a formation 's bulk density. This is the overall density of a rock including solid matrix and fluid enclosed in the pores. Since the tool has a shallow depth of investigation, the fluid is assumed to be mud filtrate with a density of 1.0 (fresh) or 1.1 (salt). The presence of mixed matrix leads to possible errors in the assumption of matrix density.

Low density interstitial clays will especially result in overestimated porosity. The neutron log provides a continuous record of a formation reaction to fast neutron bombardment. It is quoted in terms of neutron porosity units, which are related to formation hydrogen index as indication of its richness in hydrogen (Rider, 1986).

Resistivity, which is the inverse of conductivity, is the specific resistance of a material to the flow of current. The resistivity of a formation depends on the electrical conductivity of the rock materials within the formation, the nature of the formation water (fresh or salt), other fluid like oil or gas contained in it (Harry et al., 2018). Also, the conductivity of water is a function of temperature because the lighter the temperature, the lower the resistivity.

Well log interpretation involves choosing the best model from the given data so as to obtain results which are geologically plausible. Well log interpretation is often qualitative and quantitative. The qualitative interpretation has to do with the use of models, which represent the Characteristic log responses to formation parameters.

4.2.4.1. Net/Gross

The gross reservoir (sand) thickness 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 basis for non- reservoir (shale) and gross reservoir sands using the gamma ray log. This was carried out by drawing a shale baseline and sand baseline on the gamma ray log (Equation 1).

$$NTG = \frac{Net\ sand}{gross\ sand} \tag{1}$$

where; Net sand is gross sand-shale streak and Gross sand is reservoir top- reservoir base.

4.2.4.2. Volume of shale

The gamma ray log was used to compute shale volume as shown in Equation 2.

$$Vsh = \frac{GRlog - GRmin}{GRmax - GRmin} \tag{2}$$

where; *Vsh* is volume of shale, *GRlog* is Gamma Ray Log reading of formation, *GRmin* is Gamma Ray Matrix (Clay free zone) and *GRmax* is Gamma Ray Shale (100% Clay zone).

4.2.4.3. Porosity

Porosity is the percentage of the total volume of the rock that has pore spaces, whether the pores are connected or not. Total porosity denoted by the Greek word phi (Ø) was calculated from density-neutron log as shown in the following relationship:

$$Ø = \frac{(ðma\ -\ ðb)}{(ðma\ -\ ðfl)} \tag{3}$$

where; Ø is porosity derived from density log, *ðma* is matrix (or grain) density, *ðb* is bulk density (as measured by the tool and hence includes porosity and grain density) and *ðfl* is fluid density.

4.2.4.4. Water saturation

Archie clean sand equation was used to calculate the water saturation as shown in Equation 4 (Archie's clean sand equation).

$$S_W = \frac{R_o}{R_t}\wedge(1/n) \tag{4}$$

where; R_o is resistivity of rock filled with water, R_t is resistivity of suspected oil zone and *N* is saturation exponent (generally 2).

4.3. Fluid contact identification

The reservoir interval was subdivided based on fluid type (i.e. Gas-Oil Contact (GOC) marked in green, Oil-Water Contact (OWC) marked in red to account for differences in thickness of the fluid type. The approaches used are the resistivity, density, neutron log and pressure-depth plot.

An increase in resistivity reflects hydrocarbon in the formation but this is limited to the exact kind of fluid. The neutron/density logs with low readings indicates the presence of oil and when there is a balloon effect or a significant reduction in neutron/density reading it indicates the presence of gas. Fluid contacts were also determined following the change in the pressure-depth gradient of well A8X.

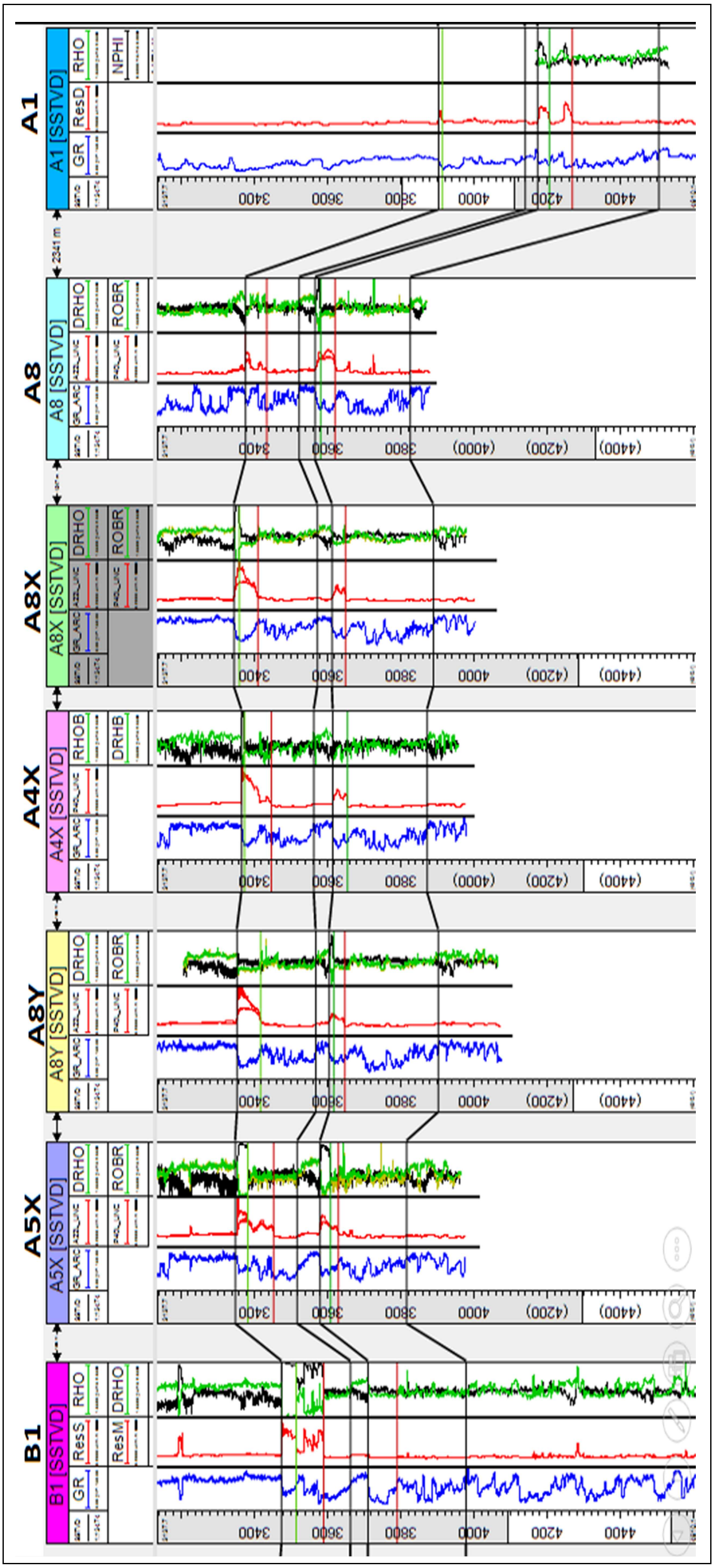

Fig. 6. Well section window showing electrical logs and correlation across the well

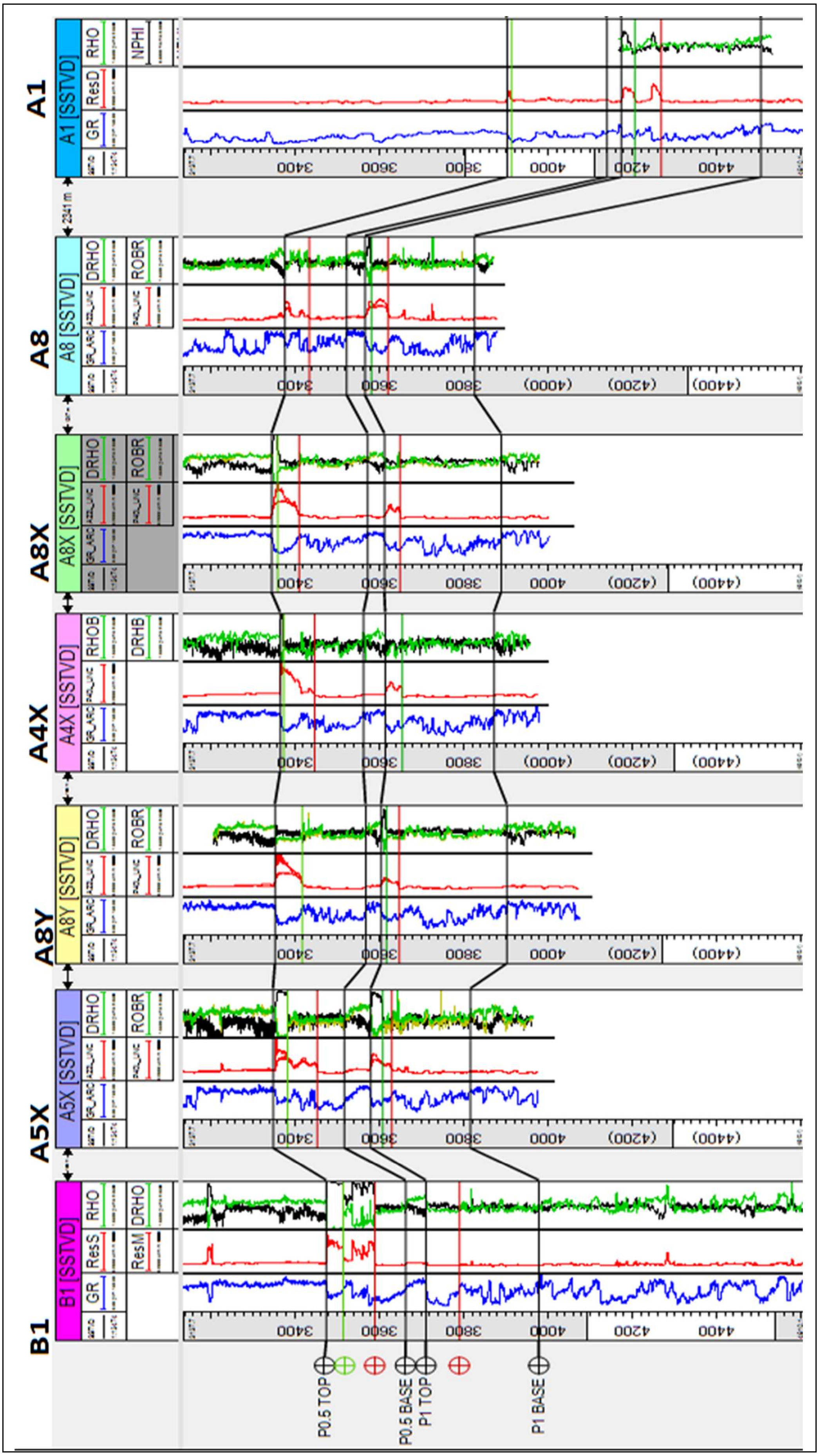

Fig. 7. Reservoir top and base and their hydrocarbon contact

5. Results and Discussion

We have applied the above described methodology to the sand bodies of the Agbada Formation and the results are categorized into different sections. To study the petro-physical characteristics of reservoir zones (P0.5 and P1) the dominant lithology present in the zone of interest is identified and then petrophysical analysis is performed to estimate the porosity, water-hydrocarbon saturations, net pay thickness, net-to gross ratio, which show the variations of petrophysical parameters and hydrocarbon potentials within the reservoir sands and among different reservoir sand bodies (i.e. vertically and laterally).

5.1. Well log interpretation and correlation

All available electrical logs (gamma, resistivity, neutron, and density) for the seven wells in the area of study were examined as shown in Fig. 6. The lithology (sand and shale) were identified using the Gamma ray log signatures. The gamma ray log shows sandstone as a low gamma ray reading unit and shale as high gamma ray reading unit. The resistivity log shows relatively higher resistivity indicating a sandstone contained with hydrocarbons while shale partings show low resistivity readings. In the neutron-density log, a significant reduction or balloon effect depicts gas bearing zone superimposed on the lithology as evidenced by the divergence of the log curves. Also, minor influence on the separation of the two log curves indicates oil-bearing reservoir. Two sand bodies P0.5 and P1 were delineated and correlated based on the strikeline correlation in Fig. 7 across the field in order to determine the continuity and equivalence of lithologic units for the reservoir sand and shales of seven wells in the study area as shown in Fig. 7.

5.2. Hydrocarbon-Bearing zones and contact identification

Hydrocarbon-bearing zones of the seven wells were identified by using Gamma ray, resistivity, neutron and density logs. These zones were identified depending on the very high values of the resistivity logs comparing to water-bearing zones, low values of Gamma ray log, very low density and neutron log response as shown in Fig. 8. The hydrocarbon contact was delineated from the neutron-density cross-over and the interception of the pressure-depth plot at similar depths as shown in Figs. 9a and 9b. Also, they were correlated across the wells.

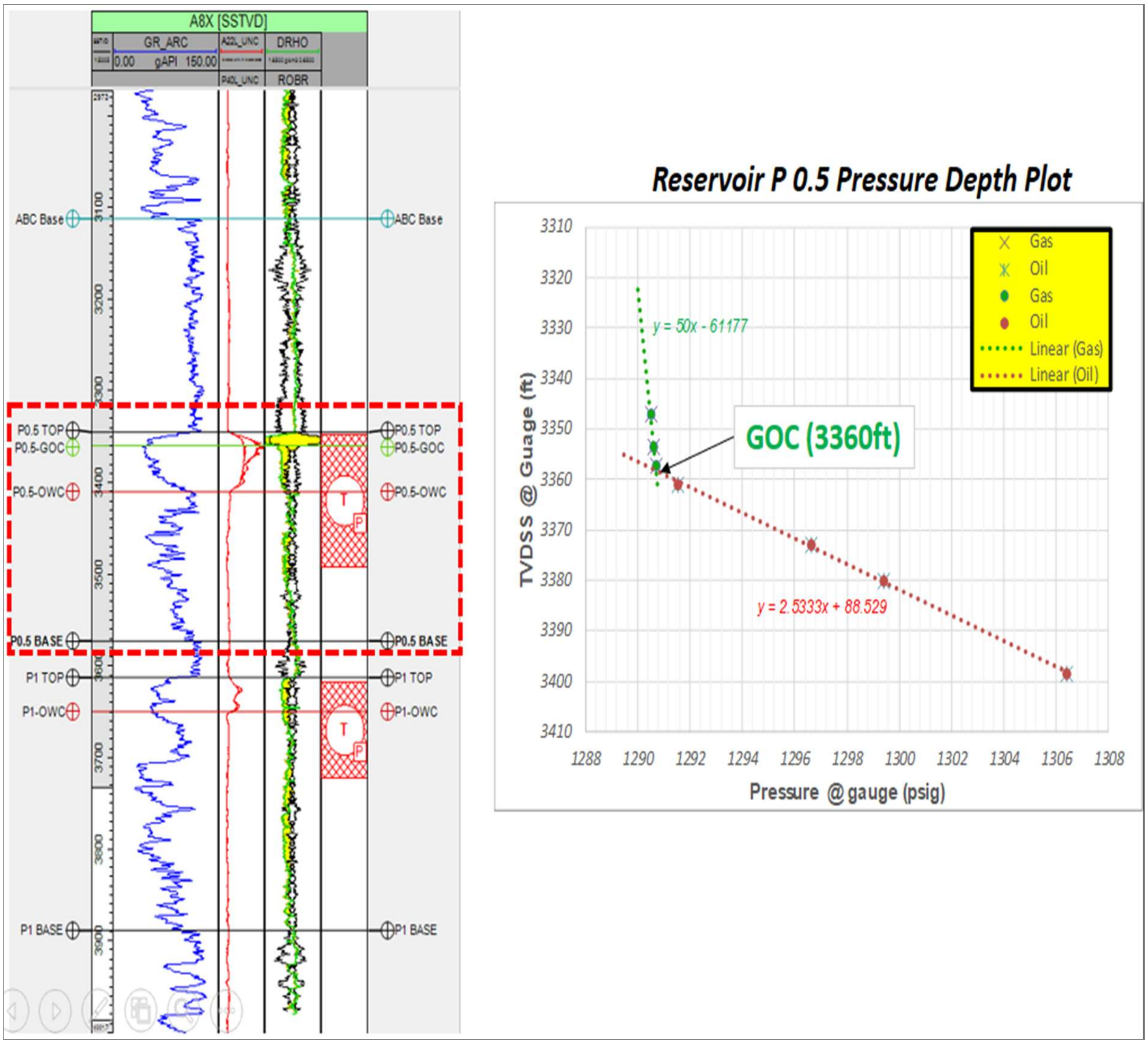

Fig. 9a. Gas-Oil Contact (GOC) of Well A8X

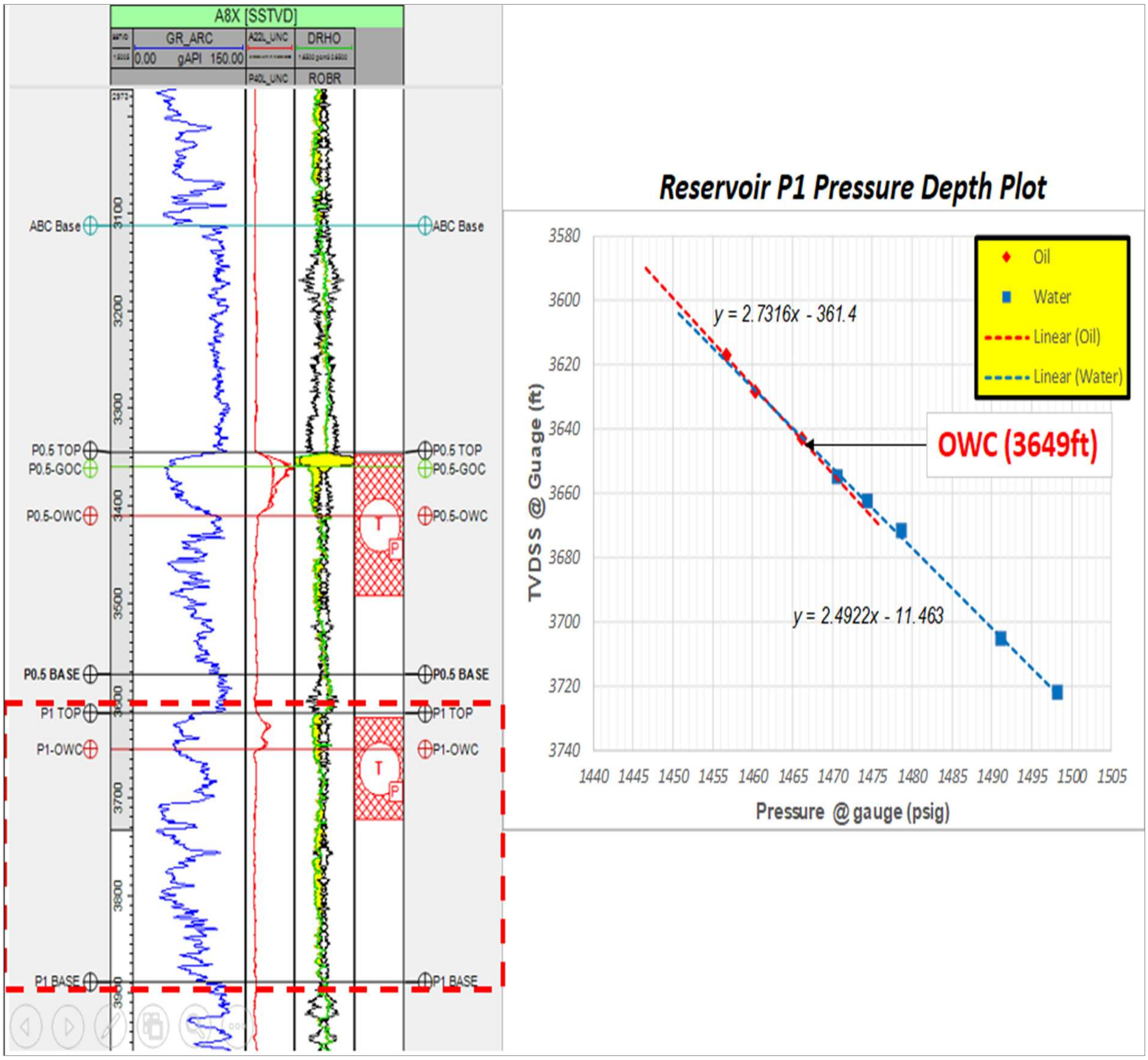

Fig. 9b. Oil-Water Contact (OWC) for Well A8X

5.3. Analysis of petrophysical parameters Reservoir P0.5

5.3.1. Reservoir P0.5

Table 2 shows the summary result of the petrophysical parameters for reservoirs, which cuts across well B1 to A1. The reservoirs were penetrated at depths of 3475-3665 meters in well B1, 3356-3518m in well A5X, 3353-3568 m in well A8Y, 3365-3563 m in well 4X, 3345-3573 m in Well A8X, 3376-3523 m in wellA8, and 3903-4140m in wellA1.The fluid types identified in this reservoir is gas, oil and water. The Net/gross value obtained shows the ratio of sand to shale in the reservoir is high indicating a clean sand reservoir. The porosity value obtained across the wells within Reservoir P0.5 shows a good to very good reservoir rating based on the porosity description table of Rider (1986).

The water saturation revealed the proportion of void space occupied by water in the reservoirs based on the calculations made, which shows that water saturation of the reservoirs is low, thus, high hydrocarbon saturation. Hence, comparing these properties on a bar chart as shown in Fig. 9a, it is evident that Reservoir P0.5 is a hydrocarbon saturated reservoir and has a good reservoir quality.

5.3.2. Reservoir P1

Table 3 shows the summary result of the petrophysical parameters for reservoirs, which cuts across well B1 to A1. The reservoirs were penetrated at depths of 3711-3969 meters in well B1, 3580-3816 m in well A5X, 3605-3905m in well A8Y, 3615-3872 m in well 4X, 3613-3889 m in well A8X, 3566-3826 m in wellA8, and 4174-4504 m in wellA1. The fluid types identified in this reservoir is gas, oil and water. The Net/gross value obtained shows the ratio of sand to shale in the reservoir is high indicating a clean sand reservoir.

The porosity value obtained across the wells within ResevoirP1 shows a very good reservoir rating based on the porosity description table of Rider (1986).

The hydrocarbon saturation for all the well except well B1 indicates a high proportion of hydrocarbon to the quantity of water within the reservoir. Hence, comparing these properties on a bar chart as shown in Fig. 9b, it is evident that the wells in Reservoir P1 is a hydrocarbon saturated reservoir except the well B1 which is a wet sand.

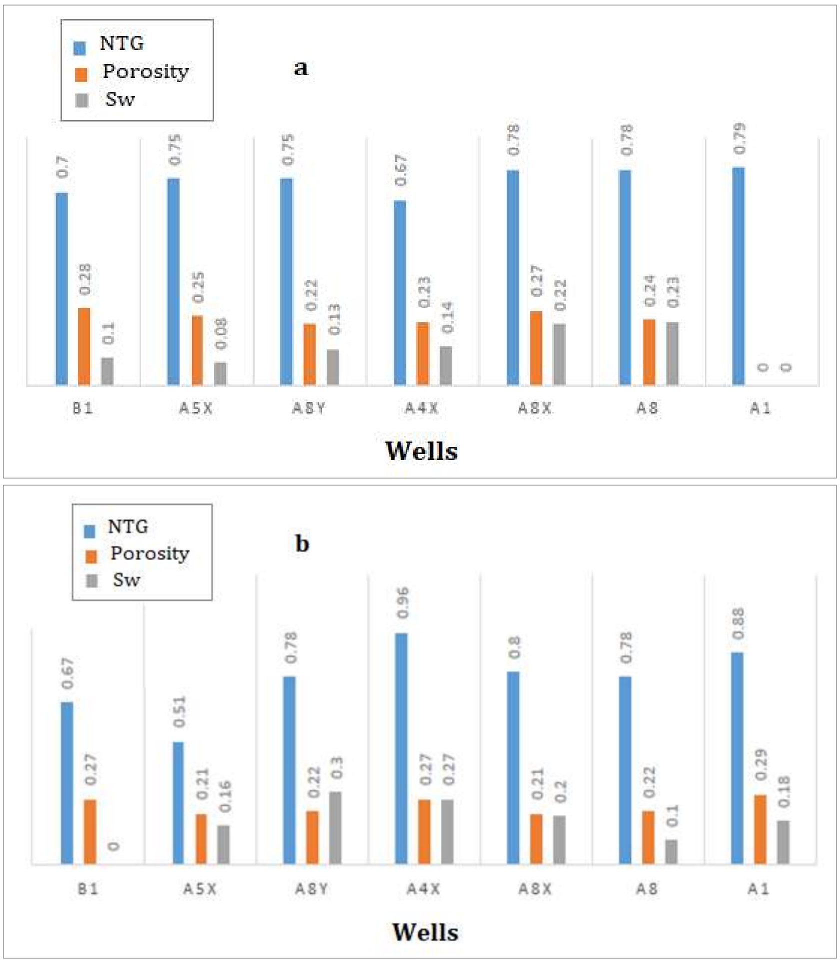

Fig. 10. a) Petrophysical results for Reservoir P0.5 and b) petrophysical results for Reservoir P1

Table 2. Summary result for the petrophysical parameters of Reservoir P0.5

Well	Top (ft)	Base (ft)	Gross sand thickness (ft)	Contact		Pay thickness		NTG	Porosity (Ø)	Sw
				Nature	Value (ft)	Net pay gas (ft)	Net pay oil (ft)			
B1	3475	3665	190	GWC	3590	115	0	0.7	0.28	0.095
A5X	3356	3518	162	GOC OWC	3384 3453	28	69	0.75	0.25	0.084
A8Y	3353	3568	215	OWC	3417	0	64	0.75	0.22	0.13
A4X	3365	3563	198	GOC OWC	3373 3447	8	74	0.67	0.23	0.14
A8X	3345	3573	228	GOC OWC	3360 3410	15	50	0.78	0.27	0.22
A8	3376	3523	147	OWC	3434	0	58	0.78	0.24	0.23
A1	3903	4140	237	OWC	3913	0	10	0.79		

Table 3. Summary result for the petrophysical parameters of Reservoir P1

Well	Top (ft)	Base (ft)	Gross sand thickness (ft)	Contact		Pay thickness		NTG	Porosity (Ø)	Sw
				Nature	Value (ft)	Net pay gas (ft)	Net pay oil (ft)			
B1	3711	3969	258	WET SAND	-	-	-	0.67	0.27	
A5X	3580	3816	236	GOC OWC	3608 3630	28	22	0.51	0.21	0.16
A8Y	3605	3905	300	GOC OWC	3617 3647	12	30	0.78	0.22	0.3
A4X	3615	3872	257	OWC	3655	0	40	0.96	0.27	0.27
A8X	3613	3889	276	GOC	3650	0	37	0.8	0.21	0.2
A8	3566	3826	260	GOC OWC	3581 3662	15	81	0.78	0.27	0.3
A1	4174	4504	331	GOC OWC	4253 4268	79	15	0.88	0.297	0.18

6. Conclusion

To study the hydrocarbon potential of XYZ field of the Niger Delta Basin, petrophysical analysis was carried out on seven wells. The lithology's (sand and shale) were identified, a good lithological correlation was established across the field studied, two reservoirs (P0.5 and P1) were found to be in the Agbada Formation which is in conformity with the geology of Niger Delta Basin. The analysis revealed that the reservoir sand bodies have good reservoir characteristics as shown by their petrophysical properties with an average porosity ranging from 0.30-0.36, average water saturation ranging from 0.08 0.3. The net/gross of the reservoirs is between 0.06-0.6. The well B1, A5X, A4X, A8X(P0.5) reservoir are oil and gas bearing, well A4X(P1) reservoir is gas bearing, well A8X(P1) reservoir is oil bearing and well B1(P1) reservoir is a wet sand. The petrophysical properties of reservoirs in XYZ field suggest a good reservoir quality which is satisfactory for further exploration and production.

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