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PETROPHYSICAL PROPERTIES AND VOLUME ESTIMATION OF HYDROCARBON RESOURCES IN X FIELD, ONSHORE NIGER DELTA: A RESERVOIR CHARACTERIZATION STUDY

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ABSTRACT

A reservoir characterization study was conducted on three wells located in X Field, situated in the Onshore region of the Niger Delta. A suite of conventional digital well logs was utilized to identify hydrocarbon-bearing reservoirs, determine reservoir petrophysical parameters, and infer the depositional environment. The study delineated four hydrocarbon-bearing reservoirs, labeled A, B, C, and D, with porosity estimates ranging from 25% to 27%, and permeability values varying from 1863.22md to 2759.78md. These results suggest that the reservoirs have good storage capacity and permit free flow of fluids, consistent with prior research in the Niger Delta. The water saturation values, ranging from 43% to 70% for Well X and 53% to 94% for Well Y, indicate the presence of significant hydrocarbon in reservoir C, while Well Z did not contain any hydrocarbon. The estimation of oil and gas resources indicated that Well X contains 1.11 X 10^5 barrels/acre of oil and 5.16 X 10^7 cubic feet/acre of gas, while Well Y contains 4.43 X 10^6 cubic feet of gas. The analysis of the volume of shale (0.15-0.19) revealed that the reservoirs range from slightly shaly sand to shaly sand. Based on the log motifs, the study suggests that the reservoirs are mainly fluvial channel deposits, and the rapid alternation of thin beds of sand and shale indicates deposits of delta progradation and river floodplain deposits.

Keywords: Reservoir characterization, Hydrocarbon-bearing zones, Digital well logs, Petrophysical parameters, Depositional environment, Niger Delta

INTRODUCTION

Reservoir characterization is the continuing process of integrating and interpreting geological, geophysical, petrophysical, fluid and performance data to form a unified, consistent description of a reservoir (Halderson and Damsleth, 1993). The description can be qualitative or quantitative.

Reservoir characteristics include pore and grain-size distributions, reservoir permeability and porosity, facies distribution, depositional environment, and basin description.

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; core and log data, well-test data, tracer and production data, and in some instances, 2D-and 3D-seismic data; vertical seismic profiles, wellbore tomography, and outcrop analogs. Ideally, all the different sources of data should be included in a final reservoir description. If more information is used, the reservoir description is better.

Petrophysical log interpretations used for the characterization of reservoir sands are very useful and important tools for selecting, planning and implementing operationally sound supplementary recovery schemes. These logs are commonly used in exploration for the correlation of sand bodies, isopach and structural mappings, and for the determination of certain physical properties of rocks such as porosity, permeability, lithology identification and possibly pore geometry. The evaluation of reservoir rocks in terms of their porosity, water saturation and permeability determinations, enhances the ability to predict abnormally pressured zones, to estimate hydrocarbon reserves and reservoir bed thickness, and to distinguish between gas, oil and water bearing strata, by observing their electrical resistivity and relative permeability values (Hilchie, 1990; Schlumberger, 1996; Uguru *et a*l., 2002)

The principal goal of reservoir characterization is to outsmart nature to obtain higher recoveries with fewer wells in better positions at minimum cost through optimization (Halderson and Damsleth , 1993) Moreso, the understanding of the depositional setting of a field is fundamentally important in the determination of reserves and in the design of optimum reservoir management proceedures. Sands deposited in different depositional environments are characterized by different sand body trend, shape, size, and heterogeneity. This tends to show that the physical characteristics of clastic reservoir rocks reflect the response of a complex interplay of processes operating in depositional environments.

Hence, the reconstruction of depositional environments in clastic successions provides optimum framework for describing and predicting reservoir quality distribution. Also, knowledge of depositional environment of reservoirs through accurate description/interpretation of wire line logs and possibly other data allows for a better understanding of reservoir characteristics and hence its quality for optimal utilization of the embedded resources.

This study involves the reservoir characterization of hydrocarbon-bearing zones in the X Field onshore in the Niger Delta region, which is a major oil and gas-producing region in Nigeria (Akpan et al., 2018). Reservoir characterization is an essential process in the exploration and production of oil and gas, and it involves the identification and assessment of the physical properties and characteristics of subsurface reservoir rocks (Raza et al., 2020). Digital well logs, which are records of measurements taken during drilling and completion of oil and gas wells, are commonly used to obtain information about the subsurface reservoir rocks (Hunt et al., 2013). The information obtained from reservoir characterization can guide decision-making in the oil and gas industry and improve the efficiency and profitability of hydrocarbon production (Tavakoli et al., 2017).

The objectives of the study are:

1. To identify hydrocarbon-bearing reservoirs in three wells located in the X field onshore, Niger Delta.
2. To calculate the petrophysical properties of these reservoirs, including porosity, permeability, and water saturation.
3. To deduce the depositional environment of the reservoirs.
4. To estimate the oil and gas resource volumes in the identified reservoirs.

The study aim at, determining reservoir depths and thicknesses in the wells, classify reservoir sands and their depositional environment from

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the log motifs, making detailed use of available wireline logs data to delineate the hydrocarbon bearing reservoirs in the field, correlation of Reservoir sand Integration of all the available data to evaluate the production potential of the well.

The relevance and contribution of this study are significant for several reasons. Firstly, it provides valuable information for the oil and gas industry, which can use the data to make informed decisions on exploration and production activities. Secondly, it contributes to our understanding of the geology of the Niger Delta region and the processes that led to the formation of the reservoirs. Thirdly, it demonstrates the effectiveness of conventional digital well logging techniques for reservoir characterization, which can be applied in other geological settings. Overall, this work provides important insights into the geology and hydrocarbon potential of the Niger Delta region and contributes to our broader understanding of petroleum geology.

Location and Literature Review of the Study Area

The Niger Delta forms one of the world's major hydrocarbon provinces and it is situated on the Gulf of Guinea on the west coast of central Africa (Southern Nigeria). It covers an area within longitudes 4^{o}E– 9^{o}E and latitudes 4^{o}N - 9^{o}N (Figure 1). It is composed of an overall regressive clastic sequence, which reaches a maximum thickness of about 12 km (Evamy *et al*, 1978). The Structural map (Figure 2) of the Study area shows the location of the three wells (X, Y and Z) within the study area. The wells are located on one side of the major fault.

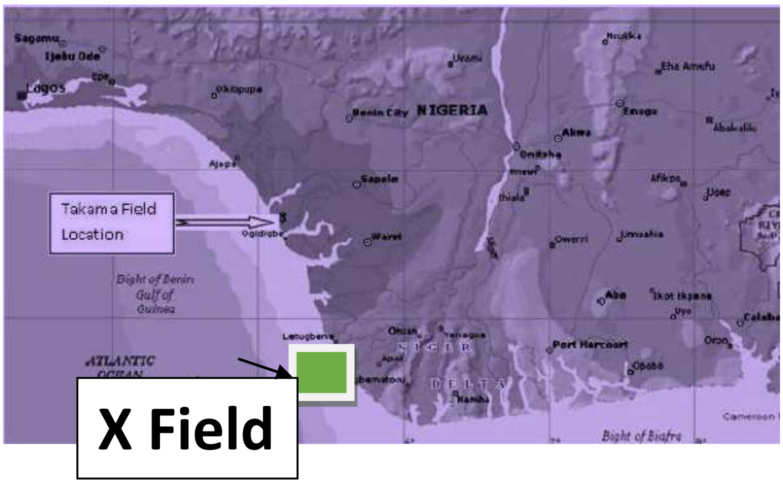

Figure 1: Location/ map of the study area

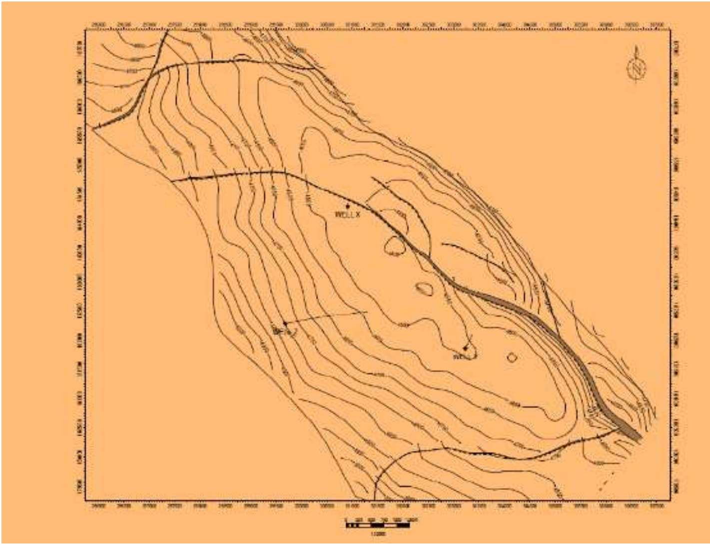

Figure 2: Structural Map of the Study Area

In the study area, Shell Petroleum Nigeria Limited has documented detailed work on the integration and interpretation of wireline logs, seismic, core, and biofacies data (not publicly accessible due to confidentiality). However, for the purpose of this review, information on the Niger Delta has been gathered from various published studies, including those by Short and Stauble (1967), Weber (1971), Weber and Daukoru (1975), Evamy et al. (1978), Reijers (1996), Selley (1997), and others.

The search for hydrocarbon products has led to an extensive study of the Niger Delta depocenters, particularly after an unsuccessful search in the Cretaceous sediments of the Benue Trough (Doust, 1989; Doust and Omatsola, 1990). The Agbada Formation is the primary source of oil and gas in the Niger Delta, with known reservoir rocks ranging in age from Eocene to Pliocene (Evamy et al., 1978). The reservoirs are predominantly composed of sandstones and unconsolidated sands that are often stacked, with thickness ranging from less than 15 meters to greater than 45 meters (Evamy et al., 1978). The thickness variation is strongly controlled by growth faults, with the reservoirs thickening towards the fault within the down-thrown block (Weber and Daukoru, 1975).

The primary reservoirs in the Niger Delta are described as Miocene parallic sandstones with 40% porosity, 2 darcy permeability, and a thickness of 100 meters (Edwards and Santogrossi, 1990). The most important reservoir types are point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels, with the grain size of the reservoir sandstone being highly variable (Kulke, 1995). Fluvial sandstone tends to be coarser than their delta front counterparts, point bars fine upward, and barrier bars tend to have the best grain sorting. The sandstone is nearly unconsolidated, with some containing a minor component of argillo-silicic cement (Kulke, 1995).

Depositional environment and lithofacies interpretation have been carried out by several researchers, including Allen (1965), Oomkens (1974), and Selley (1997). Weber (1971) analyzed various lithofacies from log data and demonstrated that the oil-bearing reservoir of the delta is made up of marine clay, barrier foot sediment, barrier bar sediments, tidal channel fill sediment, and transgressive sediments.

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Lithostratigraphy of Niger Delta:

The Niger Delta lithostratigraphy comprises of a sequence of sedimentary rocks that were deposited over time, including the Benin Formation, Agbada Formation, and Akata Formation. The Benin Formation consists of sandstone, shale, and minor limestone, while the Agbada Formation is made up of sandstone and shale with intercalations of coal. The Akata Formation is primarily composed of shale with minor sandstone and limestone. These formations are important hydrocarbon reservoirs in the Niger Delta region.

Depobelts

Five major depobelts are generally recognized, each with its own sedimentation, deformation, and petroleum history (Figure 3 and 4). Doust and Omatsola (1990) described three depobelt provinces based on structure. The northern delta province, which overlies relatively shallow basement, has the oldest growth faults that are generally rotational, evenly spaced, and increases their steepness seaward.

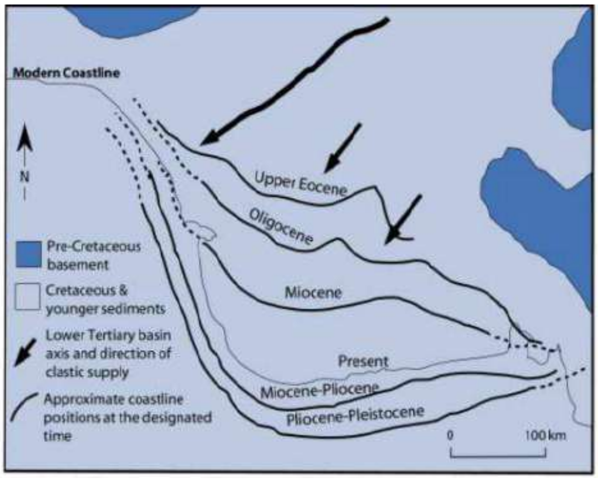

Figure 3: Progradation of the Niger Delta coastline since 35Ma (Modified from Whiteman, 1982)

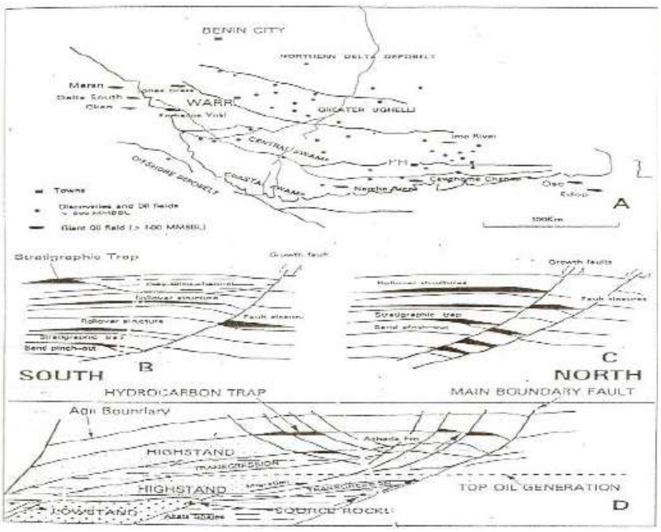

Figure 4: Niger Delta Depobelts, Sequence Stratigraphic Model and relations to hydrocarbon occurrence (After Selly, 1997)

The central delta province has depobelts with well-defined structures such as successively deeper rollover crests that shift seaward for any given growth fault. Last, the distal delta province is the most structurally complex due to internal gravity tectonics on the modern continental slope.

MATERIALS AND METHOD

Availability of Data

The study utilized data collected from Shell Petroleum Development Company (S.P.D.C) in Nigeria, including digital well logs (gamma ray, resistivity, density, and neutron), field structural maps, well deviation data, and well headers. This data was imported into the Petrel software for analysis.

Methods

The wireline log signatures were used to identify hydrocarbon-bearing reservoirs and calculate petrophysical parameters such as porosity, water saturation, net reservoir thickness, gross reservoir thickness, and net to gross thickness ratio. Additionally, fluid contacts were delineated. The methods employed included delineation of reservoir units using gamma ray logs (Schlumberger, 1989), determination of reservoir properties using petrophysical calculations (Archie, 1942; Asquith and Krygowski, 2004), and interpretation of the results (Asquith and Krygowski, 2004).

Wireline Logs

Wire-line logging is one of the necessary methods for earth scientists to understand the subsurface formations. There are so many types of wireline logs, but for the purpose of this study, gamma ray, resistivity, density and neutron logs were used.

Gamma Ray Log

The Gamma ray (GR) log is a geophysical measurement that records the natural radioactivity of rock formations. It results from the decay of naturally occurring uranium, thorium, and potassium isotopes. In this study, the Gamma ray log was utilized, which provides information on the radioactivity of all three elements combined. While shale deposits typically exhibit the highest levels of radioactivity, it is no w recognized that the simplistic interpretation of the Gamma ray log as a "shale log" is inadequate (Etu-Efeotor, 1997). The Gamma ray log can be used to determine reservoir thickness, indicate lithology, correlate wells, estimate shale volume, and infer the depositional environment of reservoir sands.

Resistivity Log

Resistivity logs are used to measure the resistivity of sedimentary rocks in ohm-metres, which helps to identify the presence of water or hydrocarbons in the rocks. The higher the water content, the lower the resistivity, while hydrocarbons have high resistivity. Resistivity logs are essential for formation evaluation, as they can be used to correlate wells, identify fluid contacts, and determine water saturation. However, clay minerals and certain other minerals can reduce the difference in resistivity between hydrocarbons and formation water. Some resistivity logs measure conductivity instead of resistivity.

Compensated Formation Bulk Density Log (FDC)

The density log is a well log that provides a continuous record of the bulk density of a formation. This log measures the overall density of a rock, which includes both the solid matrix and the fluid present in the pore space. The tool used to generate the density log has a

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shallow depth of investigation, and therefore, the fluid present in the pore space is assumed to be mud filtrate with a density of either 1.0 (fresh) or 1.1 (salt) (Rider, 2002). The unit of measurement for density log is in gramme per centimetre cube (g/cm3). The deflection of the log to the right indicates high density compacted material, while a deflection to the left indicates low density uncompacted material. In hydrocarbon-bearing reservoir sands, the bulk density reading is usually high in oil-bearing zones and lower in gas-bearing zones. This log was used in this research to determine porosity values of sand bodies, draw bed boundaries due to its good resolution, and estimate reservoir quality based on the separation between the neutron and density logs.

Compensated Neutron Porosity Log (CNL)

The neutron log provides a continuous record of a formation reaction to fast neutron bombardment. It is quoted in terms of neutron porosity unit, which is related to the formation hydrogen index, an indication of its richness in hydrocarbon (Rider, 2002). Neutron log is a log response primarily related to hydrogen concentration but also affected by mineralogy and borehole effects. The neutron log does not distinguish between the hydrogen in the pore fluids (i.e., water, oil, gas), in water of crystallization, or water bound to solid surfaces. In clean oil-filled or water-filled formations the apparent porosity reading at the neutron log reflects the amount of liquid-filled pore volume. Neutron log is used with other porosity information. The neutron log is useful to ascertain the presence of gas and determine mineralogy and shaliness. The tool contains a continuously emitting neutron source and either a neutron- (n-n tool) or a gamma-ray detector. High energy neutrons from the source are slowed down by collisions with atomic nuclei. The hydrogen atoms are by far the most effective in the slowing down process because their mass is nearly equal to that of the neutron. Thus, the distribution of the neutrons at the time of detection is primarily determined by the hydrogen concentration. A deflection of neutron porosity log to the right indicates a small amount of hydrogen nucleus in the formation thus lower value of reading. On the other hand, a deflection to the left indicates a small a high amount of hydrogen nuclei in the formation.

Depending on the tool type, detection is made of either;

1. Thermal neutrons

2. Gamma rays, generated when thermal neutrons are captured by thermal-neutron absorbers in the formation (primarily chlorine) or

3. Epithermal neutrons (neutrons having energies higher than thermal).

Neutron curves are scaled in American Petroleum Institute (API) units or in terms of apparent porosity. The neutron log can be recorded in open or cased liquid-filled well bores. There is a maximum hole size limitation in empty holes for running tools in which the detector does not contact the formation wall

In this study, the neutron log in combination with density log was used to delineate fluid contact and to recognise reservoir quality rock based on separation between density and neutron log.

Density/Neutron Combination

The combination of neutron and density logs takes advantage of the fact that lithology has opposite effects on these two porosity measurements. The average of neutron and density porosity values is usually close to the true porosity, regardless of lithology. Another advantage of this combination is the "gas effect." Gas, being less dense than liquids, translates into a density-derived porosity that is too high. Gas, on the other hand, has much less hydrogen per unit volume than liquids: neutron derived porosity, which is based on the amount of hydrogen, is too low. If both logs are displayed on compatible scales, they overlay each other in liquid-filled clean formations and are widely separated in gas-filled formations. Density-neutron logs give porosity as their primary information.

Estimation of Petrophysical Parameters

This involves the use of empirical formulae to estimate the Petrophysical properties of the formations intersected by the wells. The reservoirs were identified through the use of gamma ray and resistivity tools. These reservoirs were further characterized quantitatively to arrive at the desired parameters, which include: volume of shale, formation factor, porosity, water saturation, permeability.

Net/Gross

The gross reservoir thickness H, of the Well 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 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, hshale, within the reservoir sands were obtained and therefore, subtracted from the gross reservoir thickness.

Hence, Net reservoir thickness, h = H - hshale, and Net/Gross = h/H, was obtained for all the reservoirs in the Wells.

Volume of Shale (VSH) Estimation

The gamma ray log was used to calculate the volume of shale by first determining the gamma ray index using the formula according to Asquith and Gibson, 1982

$$I_{GR} = \frac{GR_{LOG} - GR_{MIN}}{GR_{MAX} - GR_{MIN}} \qquad (1)$$

Where,

I_{GR} = gamma ray index

GR_{LOG} = gamma ray reading of formation from log

GR_{MIN} = minimum gamma ray (clean sand)

GR_{MAX} = maximum gamma ray (shale)

Then the volume of shale was then calculated by applying the gamma ray index in the appropriate volume of shale equation defined for tertiary rocks:

$$V_{sh} = 0.083[2^{(3.7 \times I_{GR})} - 1.0] \qquad (2)$$

Where,

V_{sh} = volume of shale

I_{GR} = gamma ray index.

Porosity

The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity, and then the neutron-density porosity was estimated using the neutron derived porosity and the density derived porosity.

The Wyllie equation for density derived porosity is given as:

$$\phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \qquad (3)$$

ϕ_D = density derived porosity

ρ_{ma} = density of rock matrix

ρ_b = bulk density (obtained from the log)

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ρ_{fl} = density of fluid occupying rock pore spaces.

Then the neutron-density (ϕ_{N-D}) porosity was derived using the root mean square formula as follows

$$\phi_{N-D} = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}} \quad (4)$$

Where,

ϕ_{N-D} = neutron-density porosity

ϕ_D = density derived porosity

ϕ_N = neutron derived porosity

Formation Factor

This was achieved using the following equation:

$$F = \frac{a}{\phi^m} \quad (5)$$

Where,

F = formation factor

a = tortuosity factor = 0.62

ϕ = porosity

m = cementation factor = 2.15

Formation Water Resistivity

Using the Archie's equation that related the formation factor (F) to the resistivity of a formation at 100% water saturation (Ro) and the resistivity of formation water (Rw), the resistivity of the formation water was estimated as:

$$R_W = \frac{R_0}{F} \quad (6)$$

Water Saturation

Determination of the water saturation for the uninvaded zone was achieved using the Archie's equation given below:

$$S_w^2 = \frac{F \times R_W}{R_T} \quad (7)$$

From equation 2.5, $F = \frac{R_0}{R_W}$

Hence $$S_w^2 = \frac{R_0}{R_T} \quad (8)$$

Where,

S_w = water saturation of the uninvaded zone

R_0 = resistivity of formation at 100% water saturation

R_T = true formation resistivity

Hydrocarbon Saturation

This was obtained directly by subtracting the percentage water saturation from 100.

That is;

$$\% S_h = 100 - \% S_w \quad \text{or} \quad S_h = 1 - S_w \quad (9)$$

Where, Sh is the hydrocarbon saturation (expressed as a percentage or as a fraction).

Hydrocarbon Pore Volume (HCPV)

The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This was calculated as the product of neutron-density porosity and hydrocarbon saturation as shown below:

$$HCPV = \emptyset_{N-D} \times (1 - S_w) \quad (10)$$

$$HCPV = \emptyset_{N-D} \times (S_h) \quad (11)$$

Irreducible Water Saturation

The irreducible water saturation was calculated using the following relationship:

$$S_{wi} = \left(\frac{F}{2000}\right)^{1/2} \tag{12}$$

Where,

S_{wt}= irreducible water saturation

F = formation factor.

Permeability

This was based on the relationship between permeability, porosity, and irreducible water saturation. The relationship is expressed as:

$$k^{1/2} = 70\frac{\phi_e^2\,(1 - S_{wt})}{S_{wi}} \tag{13}$$

Where

K is permeability in millidarcy (mds)

ϕe is effective Porosity and

Swi is irreducible water Saturation

Use of Log Shapes to Determine Lithology and Environment

Depositional environment analysis was conducted using the log motifs obtained from the interpretation of the logs. The rapid alternation of thin beds of sand and shale indicated deposits of delta progradation and river floodplain deposits. The shapes of gamma ray logs are important for determining the sediment character and depositional environment of reservoirs. Log patterns can be established by introducing a shale baseline to the log and can be used to identify different depositional energies. The basic log patterns associated with gamma ray logs include funnel-shaped, bell-shaped, cylindrical/ blocky, serrated, and cylindrical/serrated (Figure 5). The funnel-shaped log indicates coarsening upward sequences and a deltaic or shallow marine progradation environment. The bell-shaped log shows upward fining and indicates river deposits, such as fluvial channel sands and point bars. The cylindrical or block-shaped log indicates constant energy level during deposition and suggests thickly bedded and lithologically uniform sandstones in tidal channel barrier bars, fluvial channel sand, incised valley fills, low sinuosity distributary channels, and beaches. The serrated log indicates rapid alternation of thin beds of sandstone and shales and suggests marshy or swampy areas, lagoon, delta front, and fluvial flood plain. The cylindrical/serrated log shape indicates a combination of deltaic progradation and river flood plain deposits.

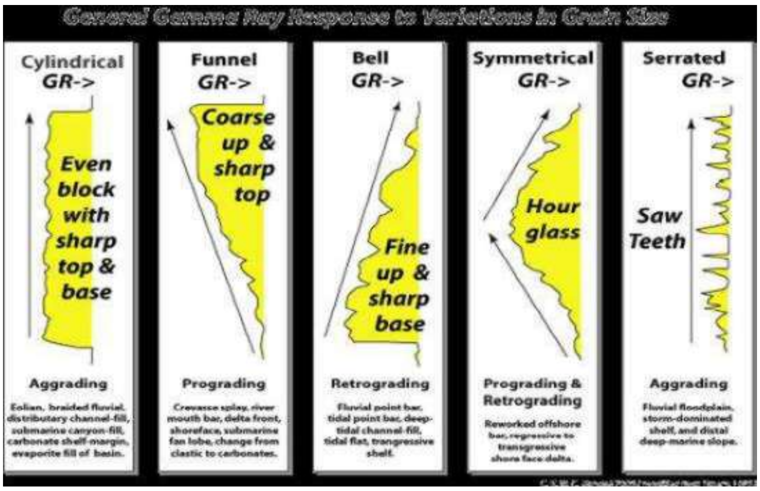

Figure 5 General Gamma ray response to variation in grain size (Emery, 1996)

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Correlation of Reservoir Sands

Stratigraphic correlation is the process of identifying and matching lithologic units such as reservoir sands or marker sealing shales across a region of the subsurface. This is a crucial task for petroleum geologists, who use a variety of materials including cores, drill cuttings, and logs for the task. While cores are expensive and drill cuttings are not always reliable for depth matching, logs are always available for every well and are therefore heavily relied upon for correlation. Several types of logs can be used for correlation, but the most commonly used ones include the gamma ray, spontaneous potential, resistivity, Sonic, Density, and Neutron logs. It is important to use only one type of log for a particular correlation, rather than a mixture of different types of logs at the same time. However, another type of log can be used to cross-check the section for a separate correlation. For example, gamma ray logs can be used for correlating a number of wells, and the obtained section can be cross-checked by using the resistivity logs of the same wells within the same intervals for another correlation section.

RESULTS

Log Characteristics of the Wells

The electrical logs (Gamma-ray, resistivity, neutron, and density) were examined for three wells, and sandstone reservoirs were easily identified on the logs (Figure 6 and 7). The resistivity log showed higher readings in the sandstone reservoirs, possibly due to fluid-hydrocarbons. The neutron-density curve indicated gas or oil-bearing reservoirs based on the porosity values and the separation of the two curves.

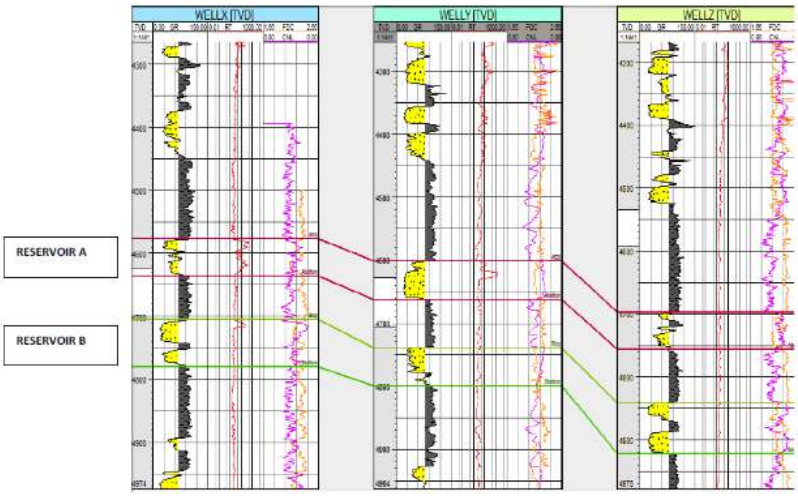

Figure 6 Log Response for Reservoir A and B

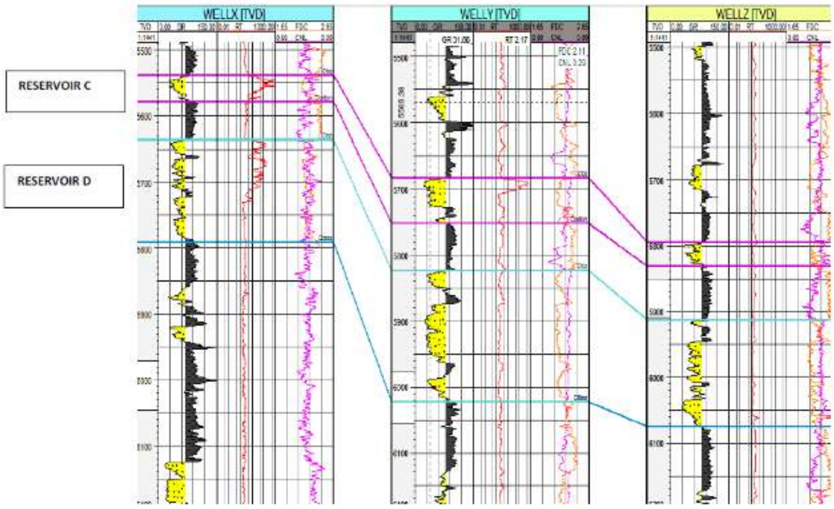

Figure 7 Log Response for Reservoir C and D

Definition of Reservoir Boundary

The reservoirs in the wells were qualitatively identified using the log signatures by eliminating the shale beds. Beds with high gamma-ray low resistivity, high density and high neutron readings indicated shale and were thus eliminated. The reservoir zones were also quantitatively identified by shale volume, porosity and fluid content through the use of some empirical equations already mentioned in materials and methods. Based on qualitative and quantitative interpretation, 4 hydrocarbon bearing reservoirs were delineated and were called A, B, C and D as shown in the Tables 1, 2, 3 respectively.

Table 1 Reservoir depth and thickness for Well X

Reservoir	Top (ft)	Bottom (ft)	Gross thickness (ft)
A	4577.16	4636.78	59.62
B	4703.87	4779.34	75.47
C	5540.06	5580.33	40.27
D	5636.55	5790.00	153.45

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Table 2: Reservoir depth and thickness for Well Y

Reservoir	Top (ft)	Bottom (ft)	Gross thickness (ft)
A	4606.03	4669.83	63.80
B	4746.18	4807.42	61.24
C	5726.55	5799.56	73.01
D	5874.11	6081.29	207.18

Table 3 Reservoir depth and thickness for Well Z

Reservoir	Top (ft)	Bottom (ft)	Gross thickness (ft)
A	5350.52	5420.17	69.65
B	5520.84	5614.70	93.86
C	6645.46	6689.91	44.45
D	6787.98	6988.46	200.48

Hydrocarbon Types and Fluid Contact

Hydrocarbon types were defined in the reservoirs based on the evidence drawn from the neutron-density log signatures at their corresponding depths. A balloon shape typified gas, while tracking together of the two curves indicated oil in the reservoirs. Resistivity log was used to determine the extent of hydrocarbon thickness in the reservoir and these points were determined by means of visual evidence and through interpreted results of saturation from logs. The fluid contacts observed in different reservoirs for wells X and Y are shown in Tables 4 and 5. Well Z does not contain hydrocarbon.

Table 4 Fluid contacts for Well X

Reservoirs	Type of contact	Contact (ft)
A	Oil-water	4627.84
B	Gas-water	4720.23
C	Gas-oil, oil-water	5564.70, 5575.50
D	Gas-oil, oil-water	5650.17, 5728.71

Table 5 Fluid contacts for Well Y

Reservoirs	Type of contact	Contact (ft)
A	Gas-water	4636.73
B	No hydrocarbon	---
C	Gas-water	5752.90
D	No hydrocarbon	-----

Petrophysical Result Summary

The petrophysical parameters for Wells X, Y and Z and the four hydrocarbon bearing reservoirs are summarized in Tables 6, 7, 8 and 9

Table 6 Petrophysical Parameters for Well X

Reservoir	Top (Ft)	Bottom (Ft)	Thickness (Ft)	N/G	Vshale	ϕ	ϕ_e	S_w	S_h(%)	K(md)
A	4577.16	4636.78	59.62	0.76	0.24	0.29	0.22	0.43	57	1438.61
B	4703.87	4779.34	75.47	0.86	0.14	0.23	0.20	0.70	30	908.49
C	5540.06	5580.33	40.27	0.88	0.12	0.22	0.19	0.37	63	652.48
D	5636.55	5790.00	153.45	0.86	0.14	0.30	0.26	0.43	57	4789.40

Table 7 Petrophysical Parameters for Well Y

Reservoir	Top (Ft)	Bottom (Ft)	Thickness (Ft)	N/G	Vshale	ϕ	ϕ_e	S_w	S_h(%)	K(md)
A	4606.03	4669.83	63.80	0.94	0.06	0.27	0.25	0.62	38	3179.71
B	4746.18	4807.42	61.24	0.86	0.14	0.29	0.25	0.93	7	3711.67
C	5726.55	5799.56	73.01	0.83	0.17	0.26	0.22	0.53	47	1746.01
D	5874.11	6081.29	207.18	0.82	0.18	0.27	0.22	0.94	6	1906.86

Table 8 Petrophysical Parameters for Well Z

Reservoir	Top (Ft)	Bottom (Ft)	Thickness (Ft)	N/G	Vshale	ϕ	ϕ_e	S_w	S_h(%)	K(md)
A	5350.52	5420.17	69.65	0.73	0.27	0.26	0.19	0.92	8	971.34
B	5520.84	5614.70	93.86	0.84	0.16	0.24	0.20	0.93	7	1192.55
C	6645.46	6689.91	44.45	0.85	0.15	0.29	0.25	0.98	2	3711.67
D	6787.98	6988.46	200.48	0.79	0.21	0.27	0.21	0.97	3	1583.08

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Table 9 Petrophysical Parameters for reservoirs A, B, C and D

Petrophysical data	A	B	C	D
Thickness (Ft)	64.36	76.86	52.58	187.04
Net/ Gross	0.81	0.85	0.85	0.82
V-shale	0.19	0.15	0.15	0.18
Porosity	0.27	0.25	0.26	0.27
Permeability (md)	1863.22	1937.57	2036.84	2759.78
Water Saturation	0.53	0.70	0.45	0.43
Hydrocarbon Saturation (%)	47	30	55	57
Hydrocarbon pore volume	0.11	0.08	0.14	0.15
Vol. of Oil Resources(barrels/acre)	4.06×10^4	------	4.22×10^3	5.90×10^3
Vol. of Gas Resources (Cuft/ acre)	3.15×10^6	7.46×10^5	2.98×10^2	1.05×10^7

DISCUSSION

Interpretation of Petrophysical Results

The results of the study were interpreted based on the works of distinguished scholars in the field, including Etu-Efeotor (1997), Rider (1986), as well as Davies (2002). These esteemed authors have made significant contributions to the discipline, and their works were relied upon to provide insight and understanding into the findings of the study. By drawing upon the insights of these respected scholars, the results were interpreted in a thorough and professional manner that adds to the body of knowledge within the field.

Interpretation of Petrophysical Results of Well X

The average shale content (v-shale) of the reservoirs in well X is between 0.12 and 0.24 which indicates that the reservoirs are slightly shaly sand to shaly sand. The average porosity (22-30%) suggests that the reservoirs in well X have very good porosity which decreased slowly with depth. While the permeability values (652.48-4789.40md) show that the reservoirs have very good to excellent permeability which is in line with that of the Niger Delta (Weber, 1975). The average water saturation (43-70%) indicates that reservoirs A, C and D with low water saturation values are hydrocarbon bearing while reservoir B with water saturation of 70% is mainly water bearing with little accumulation of hydrocarbon. Well X contains both oil and gas with oil in reservoir A, C and D while reservoir B is mainly gas. The volume of oil in well X is $1.11x10^5$ barrels/acre and it also contains $5.16x10^7$ cubic feet/acre of gas.

Interpretation of Petrophysical Results of Well Y

The average shale volume (0.06-0.18) for the reservoirs in Well Y suggest that reservoir A is a clean sand, C and D are shaly sand reservoirs while B is a slightly shaly sand reservoir. The average porosity (26-29%) and permeability (1746.01md-3711.67md) values indicates that the reservoirs have very good porosity and permeability values good enough to permit free flow of fluid. However, the average water saturation (53-94%) indicates that most of the reservoirs are mainly water bearing with significant hydrocarbon accumulation in reservoir C (47%). Furthermore, well Y contains only gas accumulating in reservoir A and C. The volume of gas resources in well Y is $4.43x10^6$ cubic feet/acre

Interpretation of Petrophysical Results of Well Z

The volume of shale content (0.15-0.27) suggests that the reservoirs B, C and D are shaly sand reservoirs while A is a very shaly sand reservoir. The average porosity (24-29%) and permeability (971.34-3711md) indicates that the reservoirs have very good porosity and permeability values to permit free flow of fluid. The average water saturation (92-98%) indicates that all the reservoirs are mainly water bearing indicating that it does not contain significant amount of hydrocarbon.

Interpretation of Petrophysical Results of Reservoir A

Reservoir A ranges in thickness from 59.62ft to 69.65ft being thickest in well Z. it has an average thickness of 64.36ft. Its average volume of shale (0.19) and net/gross (0.86) shows that it is a shaly sand reservoir. Moreso its porosity and permeability values are good enough to store and transmit fluid. The water saturation for this reservoir range from 43% in Well X to 62% in Well Y indicating that it contains significant accumulation of hydrocarbon in these wells while it does not contain hydrocarbon in well Z. Moreso, reservior A contains both oil and gas and having 4.06 X 104 barrels/acre and 3.15x106 cubic ft /acre of oil and gas respectively.

Interpretation of Petrophysical Results of Reservoir B

This reservoir has an average thickness of 76.86ft and it is also thickest in well Z. Its volume of shale (0.15) suggests that it is a slightly shaly sand reservoir. Reservoir B with porosity values of 23-29% and permeability values (908.49-3711md) is sufficiently porous and permeable for the accumulation of hydrocarbon. The reservoir contains only hydrocarbon in Well X while Well Y and Z, having high water saturation of 93% does not contain any significant accumulation of hydrocarbon. The volume of gas resources in reservoir B is about 7.46x105 cubic feet/acre.

Interpretation of Petrophysical Results of Reservoir C

Reservoir C range in thickness from 40.27feet to 200.48ft. It has an average thickness of 52.58ft. The volume of shale analysis indicates that reservoir C, just like reservoir B, is a slightly shaly sand reservoir. The average permeability and porosity values of 1312.40md and 26% respectively, suggest that

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it has very good porosity and excellent permeability to store and transmit fluid. Moreso, this reservoir contains only gas in Well Y and contains oil and gas in Well X. The volume of oil and gas reservoir in reservoir C are 4.22x103 barrels/acre and 2.98x106 cubic ft/acre of oil and gas respectively.

Interpretation of Petrophysical Results of Reservoir D

This reservoir is the thickest reservoir in the study area. It ranges in thickness from 153.45ft in Well X to about 207.48ft in well Z with an average thickness of 187.04ft. The average volume of shale for this reservoir indicates that it is a shaly sand reservoir. The average porosity (27%) and permeability (2759.78md) suggests that this reservoir have good porosity and excellent permeability. In reservoir D, only Well X contains hydrocarbon (gas and oil), well Y and Z with high water saturation values for reservoir D does not contain hydrocarbon. This reservoir contains $5.9x10^3$ barrels/acre of oil and 1.05x107 cubic feet/acre of gas.

Reservoir Description and Evaluation

Reservoir characterizations of these sand bodies were made possible by the careful study of well log responses. The study examined the vertical sequence of lithologies of the sand bodies, trend of data and log interpretation.

Four main reservoirs were identified in the wells. They were identified qualitatively with the aid of log signatures. Net/gross was used to define the proportion of the intervals that were considered to be reservoirs as it aided in the understanding of the sand. This ratio is unit less and reflects the overall quality of a zone not minding its thickness. It indicated areas/units where sand deposition is concentrated and where better reservoirs quality is to be found with variation in the quality of sand. The net/gross values (Figure 8a) for the reservoirs indicated the presence of quality reservoir rocks in the study area.

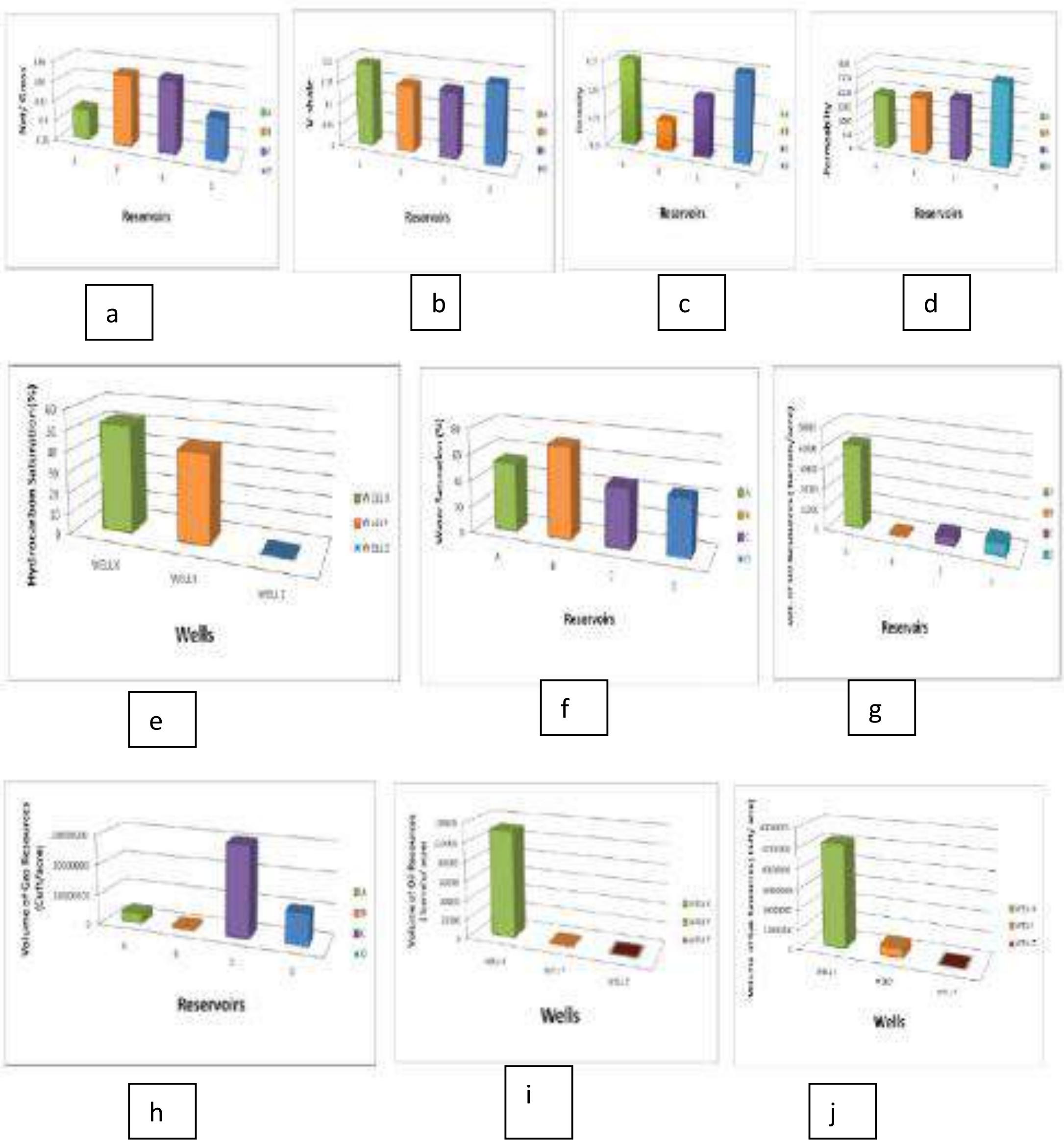
The average volume of shale for reservoirs (Figure 8b) varies. Their values indicate that the reservoir A and D are shaly sand reservoirs while reservoirs B and C are slightly shaly sand reservoirs (Davies, 2002). This suggests that reservoir B and C are slightly cleaner than reservoir A and D as seen from their net/gross values. Moreso, reservoir A and D have average volume of shale of 0.19 and 0.18 respectively, which suggest that they are above the limit of 15% that can affect water saturation values (Hilchie, 1978). Porosity within the wells was observed generally to decrease with depth. Porosity only slowly decreases with depth because of the younger age of the sediment and the coolness of the deltaic complex. The porosity values obtained fall within the stipulated porosity range for sand and sandstone reservoir (Schlumberger, 1989) and they are also in line with that of the Niger Delta. Edward and Santogrossi (1990) describe the primary Niger delta reservoirs as Miocene parallic sandstone with 40% porosity, 2 darcy permeability and a thickness of one hundred metres. The porosity values (figure 8c) for the reservoirs in the study area interpreted from Etu- Efeotor (1997) and are considered very good for hydrocarbon accumulation. The average permeability values (Figure 8d) for the reservoirs varies and are observed to be generally high. The permeability values suggest that they are good enough to permit free flow of fluid.

The average water saturation (Figure 8f) for the reservoirs in the wells suggest that well X and Y contains significant accumulation of hydrocarbon especially in reservoirs A and C while well Z (figure 8e) does not contain hydrocarbon This could be due to the fact that well X and Y were drilled at the crest of the dome while well Z was drilled directionally away at the flank of the structure as seen from the structural map.

There was also a lateral variation (increase) in water saturation from well X to well Z and the water saturation values was found to be high for reservoir B and D in the wells . However, due to the fact no other form of analysis was undertaken to support the result of this work, there was no advance for the specific causes of the trend in the water saturation values.

Moreso, the average water saturation values (Figure 8f) for the reservoirs was seen to gradually decrease with depth, reservoirs A, C and D following the trend except for reservoir B being highly saturated with water.

The volume of oil and gas resources indicates that reservoir A has the highest oil resources (figure 8g) while reservoir C has the highest gas resources (Figure 8h). Moreso, Well X contains the highest hydrocarbon resources in it as seen from (figure 8i and 8j) respectively.



a b c d

e f g

h i j

Figures 8a-8i. (a) Average Net/Gross Values for the Reservoirs in X field. **(b),** Average Volume of shale Values for the Reservoirs in X Field. **(c)**, Average porosity Values for the Reservoirs in X field. **(d)**, Average permeabilty Values for the Reservoirs in X field. **(e)**, Average hydrocarbon Saturation for the Wells in X field. **(f),** Average Water Saturation for

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the reservoirs in X field. **(g),** Volume of oil resources for the reservoirs in X field. **(h),** Volume of gas resources for the reservoirs in X field. **(i,)** Volume of oil resources for the Wells in X field. **(8j),** volume of gas resources for the Wells in X field.

Depositional Environment and Correlation of Reservoir Sand

Based on the works of Emery (1996), the characteristic log motifs were used to infer the depositional environment of the sands. Reservoir A and B (Figure 9) have a blocky or cylindrical signature indicative of a relative constant energy during deposition which suggest a thickly bedded sandstone which is lithologically uniform with none or very few thin non shaly interbeds. This can be interpreted as fluvial channel sands in the outer deltaic parts.

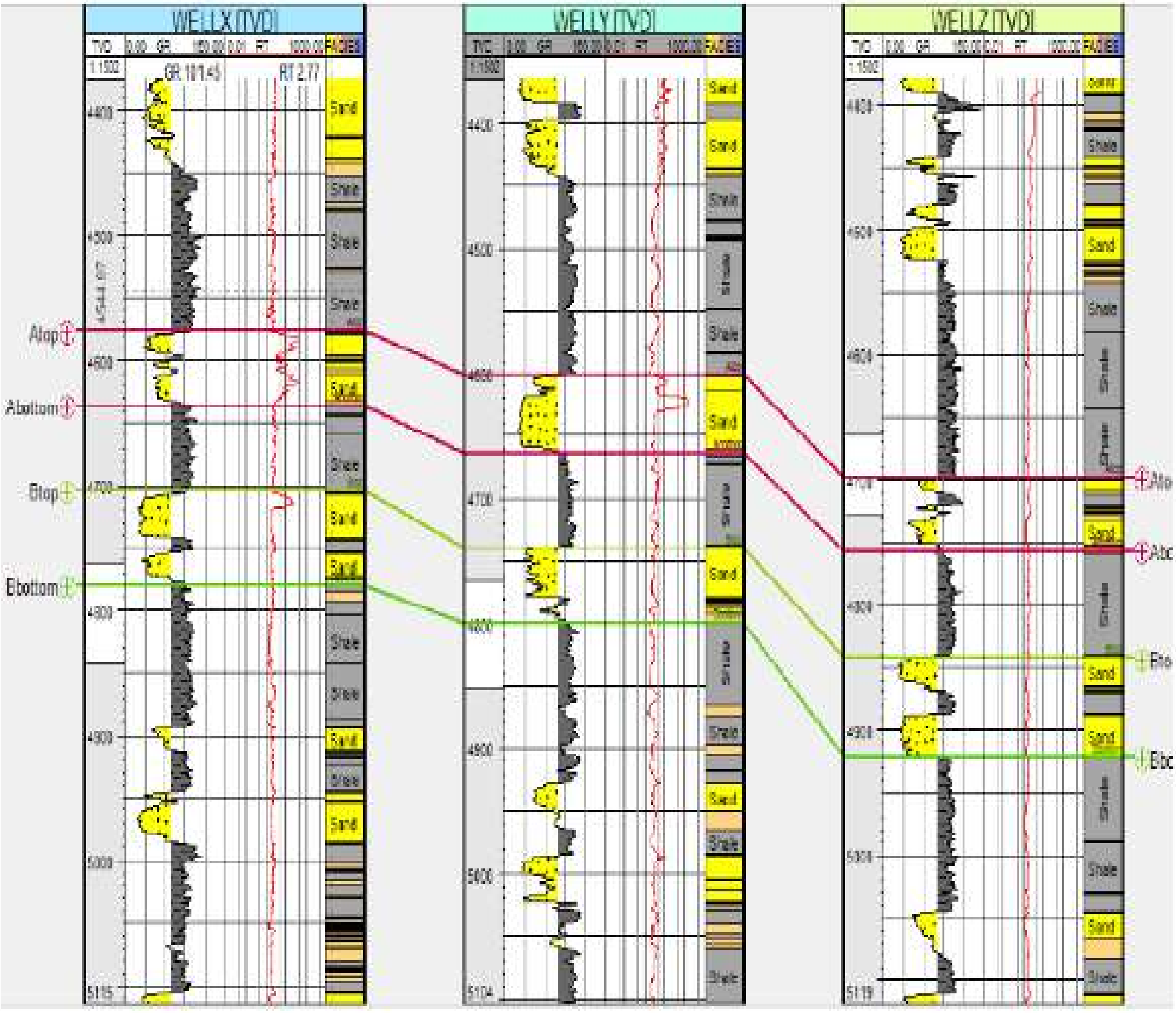

Figure 9 Correlation of Reservoir A and B

Reservoir C (figure 10) show a funnel shaped pattern interpreted as a coarsening upward sequence representing upward increase in depositional energy. This upward flaring indicates that the sand coarsen upwards and these are typical of deltaic progradation. Reservoir D (figure 10) was interpreted from its blocky and serrated log motifs.

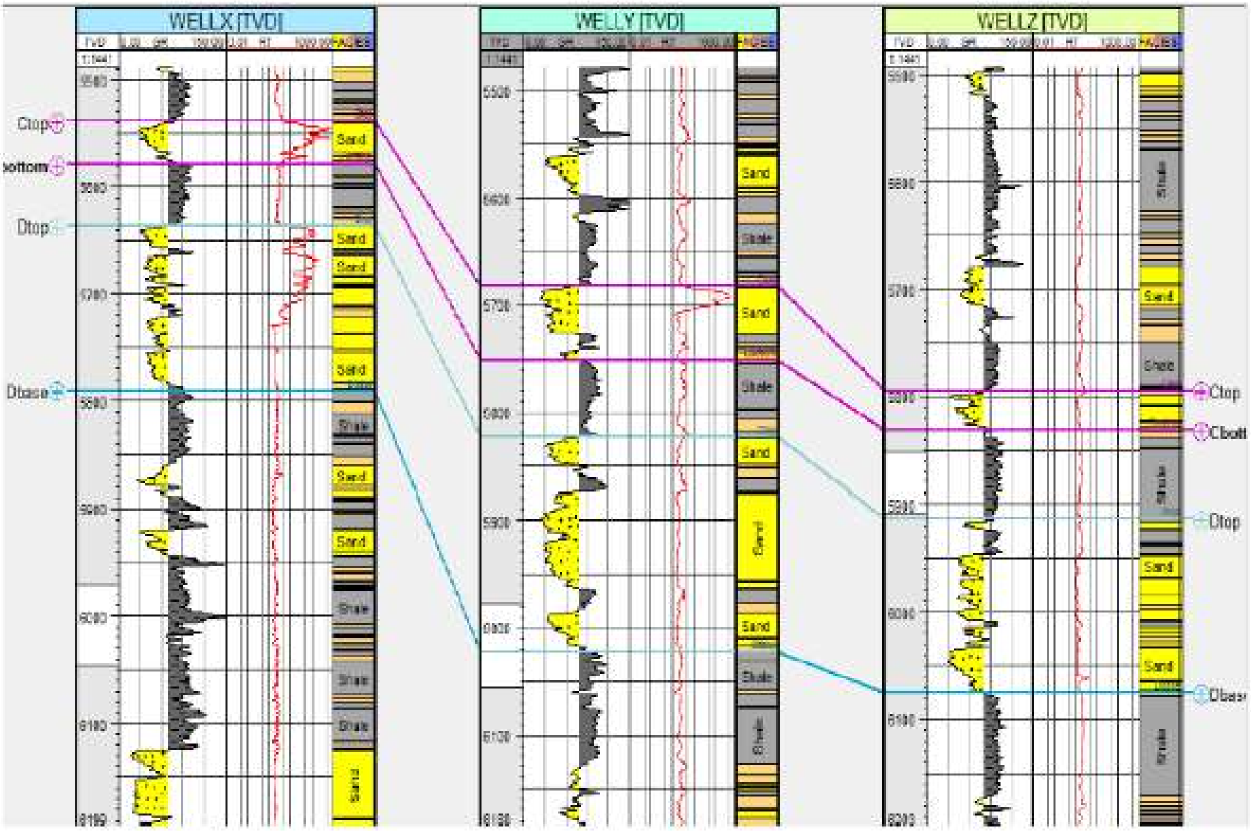

Figure 10 Correlation of reservoir C and D

This serrated shaped Indicates rapid alternation of thin beds of sand and shale typical of a fluvial flood plain. Based on the combination of its blocky and serrated nature, it can be inferred that the reservoir D consists of the deposits of deltaic progradation and river flood plain. All the reservoirs were encountered in the three wells. The grain size of reservoir sand is highly variable with fluvial channel sandstone tending to be coarser than the delta front counterparts. Much of the sandstone is nearly unconsolidated; some with a minor component of argillo-silico cement (Kulke, 1995).

CONCLUSION AND RECOMMENDATION

Conclusion

This study aimed to characterize the reservoirs in the X field using petrophysical data derived from wireline logs. A conventional suite of digital well logs was employed to identify hydrocarbon-bearing reservoirs, compute reservoir petrophysical parameters, and infer depositional environments. After a thorough analysis of the log responses, the vertical sequence of lithologies of the sand bodies, and the data trend for the wells, the following conclusions were drawn.

Four hydrocarbon-bearing reservoirs were delineated from the wells in the field, ranging in thickness from 52.58ft-187.04ft, with reservoir D being the thickest. These reservoirs' porosity and permeability suggest that they are capable of retaining and transmitting a free flow of fluid, while the volume of shale analysis indicates that they range from shaly sand to slightly shaly sand reservoirs.

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Additionally, reservoirs A and B are fluvial channel deposits, reservoir C is typical of deltaic progradation deposits, while reservoir D consists of deltaic progradation and fluvial flood plain deposits. Well X and Y contain hydrocarbon, while well Z does not. Reservoirs A, C, and D contain significant accumulation of hydrocarbon, with reservoir A having the highest volume of oil resources and C having the highest volume of gas resources. Reservoir B is mainly water-bearing.

In summary, this study provides valuable insights into the characterization of the reservoirs in the X field, contributing to a better understanding of their petrophysical properties and depositional environments. These findings could aid in optimizing hydrocarbon exploration and production activities in the area.

Recommendation

Based on the findings of this research, the following recommendations have been made to guide future researchers and further hydrocarbon exploration in the X field.

1. In order to reduce uncertainties associated with field development, more wells should be drilled in the field to further confirm what the three wells have shown.

2. Decision on economic production of hydrocarbon from the wells should not be based solely on electric log responses, but should consider evidence obtained from integrated study using biofacies, core, seismic, wireline logs and other techniques used in reservoir characterization.

3. The nature of data storage and preservation by the oil companies make quality data acquisition difficult, hence I wish to recommend that the geology department should liase with operating oil and gas companies to foster researches and release industrial data for different research works.

4. Further studies should be conducted to investigate the potential of additional reservoirs in the area that may have been overlooked in this study.

5. Given the heterogeneity of the reservoirs in the X field, it is recommended that reservoir modeling and simulation be carried out to obtain a better understanding of the flow behavior of fluids in the reservoirs, which could aid in optimizing production strategies.

6. The use of advanced petrophysical technologies such as nuclear magnetic resonance (NMR) and dielectric logging could be explored in future studies to provide more accurate and detailed information on reservoir properties.

7. Environmental impact assessments should be carried out before drilling new wells in the field to ensure that exploration and production activities are carried out in an environmentally sustainable manner.

8. Finally, it is recommended that collaborations and partnerships be fostered between academic researchers and industry players in the oil and gas sector to encourage knowledge sharing and the application of cutting-edge technologies in hydrocarbon exploration and production.

If these recommendations are implemented, they could help to further optimize hydrocarbon exploration and production activities in the X field, reduce uncertainties associated with field development, and ensure that environmental sustainability is considered in all exploration and production activities.

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