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RESEARCH ARTICLE

RESERVOIR QUALITY AND PERFORMANCE ASSESSMENT USING WELL LOGS FROM A PRODUCING NIGER DELTA FIELD

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ABSTRACT

The current investigation is focused on determining porosity and permeability, among other parameters, in a producing Niger Delta field in the Coastal Swamp Depositional Belt. Well logs like gamma ray logs, resistivity logs, caliper logs, density logs, and compressional wave logs in digital format were utilized in this study. The methodology began by filtering logs to eliminate erroneous spikes that might affect the accuracy of the outcomes. Identifying reservoir zones of interest and establishing correlations between wells were key steps in this work. These correlations revealed the consistency of shale and sand packages across the field. Finally, petrophysical characteristics were computed through empirical relationships. Results reveal that reservoirs exhibit an average gross thickness of 50 to 329 ft, a net thickness of 40 to 213, a net-to-gross ratio of 0.496 to 0.924, a shale volume of 0.054 to 0.429, an average total porosity of 0.256 to 0.407, an effective porosity of 0.202 to 0.404, water saturation of 0.036 to 0.431, and permeability of 2108 to 4932 millidarcy (md). Results also showed the reservoir units have fair-to-good porosity, exceptional permeability, and good-to-excellent net-to-gross characteristics. Overall, the comprehensive petrophysical analytical technique has increased confidence in discovering hydrocarbon by giving additional useful information into the reservoir quality distribution of the field.

KEYWORDS

Niger Delta, Well Logs, Gamma ray, Porosity and Permeability.

1. INTRODUCTION

The accurate description of reservoirs is an important component of oil and gas production, as well as prediction (Ibekwe et al., 2023). Reservoir description integrates critical subsurface analyses to develop a comprehensive picture of a reservoir's potential, as well as its challenges. It helps identify how reservoir properties will likely behave in different circumstances. As demand for hydrocarbon rises coupled with a decline in production from mature fields, there is urgent need to come up with improved and robust reservoir characterizations (Horsfall et al., 2017). On the other hand, the process of estimating petrophysical properties involves assessing attributes such as water and hydrocarbon saturation, effective porosity, and shale content. The main goal of the well-log analysis is to estimate the amounts of gas, oil, and water that are present in the reservoir formation based on the raw log data.

The quality and performance of a reservoir refers to the capacity of rock pore system to create and store sizable amounts of hydrocarbon fluids. Reservoir quality is related to reservoir productivity. Reservoir quality and performance depends largely on porosity and permeability among other properties. Porosity and permeability are the most significant physical properties of the reservoir rock. Under appropriate trap conditions, porous and permeable rock permits the migration and accumulation of petroleum. Both are geometric properties that influence structural and compositional behavior (composition) reservoir rocks. These parameters are difficult to anticipate since they have been impacted by both the initial depositional and diagenetic processes. Nonetheless, reservoir quality can be predicted to a degree by integrating sediment petrological and diagenetic investigations, but these procedures are extremely expensive. Petrophysical evaluation from well logs provide an alternative means of estimating reservoir properties. Accurate reservoir appraisal and classification can provide a theoretical foundation for sandstone reservoir exploration and development. The recommended assessments for reservoir research and classification evaluation are typically suggested to be physical attributes (Liu et al., 2021).

Well logging is an excellent method for determining reservoir parameters. It is a geophysical technique that uses a down-hole instrument called a sonde (source and detector) to evaluate the formation and quantify reservoir properties while drilling (Kobr, 2021). Log measurements, when properly calibrated, can reveal the majority of petrophysical properties. Poor data quality and availability, challenges in estimating shale volume, complex porosity and permeability estimation, problems with fluid identification and saturation, the impact of overburden and stress, formation damage and compaction, a lack of integration with other data sources, inadequate calibration and validation, technological limitations, and environmental and operational factors are some of the challenges faced by petrophysical evaluation from logs in the Niger Delta (Akpan et al., 2022; Opiriyabo et al., 2018). This study aims to examine reservoir quality and performance in the X field, Onshore Niger Delta, by applying recently updated formula for petrophysical evaluation using state of the art tools. The objectives of this study are to identify reservoir units, conduct well correlation across the field and conduct petrophysical evaluation to estimate reservoir parameters including net-pay thickness, porosity, shale volume, and hydrocarbon saturation. A suite of wire-line

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logs, including resistivity, density, gamma ray, and compressional wave velocity logs, were used in this work to evaluate petrophysical properties. The procedure applied are as follows; the lithologies were defined, reservoirs and fluid types were identified, wells were correlated, and petrophysical parameters of the identified reservoirs were determined.

2. Location and Geology of The Study Area

The study area (X field) lies in the Coastal Swamp Depositional belt of the Niger Delta Basin, which is in the Gulf of Guinea on the West African boarder (see Figure 1a, b and c). The Niger Delta Basin has boundaries defined in the east by the Cameroon Volcanic Line, in the west by the Dahomey Basin, and in the south by the 4000m bathymetric contour (Onuoha, 1999). The Niger Delta Basin is located at the southern end of the Benue Trough, which is a failed arm of a rift that stopped rifting in the Late Cretaceous. The basin's structures and strata have been influenced by pre- and syn-sedimentary tectonics related to the interplay of sediment supply and subsidence rates (Knox and Omatsola,1987). The geologic sequence of the Niger Delta Basin is an upward-coarsening regressive association of Cenozoic clastics. This sequence is 39,370 feet thick and is made up of three lithostratigraphic units. According to research in 1994, these units are the diachronous marine shales of the Akata Formation (source rock), interstratified sandstones, siltstones, and shales of the paralic Agbada Formation (source and reservoir rocks), and continental alluvial sands and clays of the Benin Formation (overburden rocks) (Ekweozor and Daukoru, 1994). Also, the thickness of the hydrocarbon reservoirs varies from less than 45 feet to a few feet with thicknesses greater than 150 feet (Weber and Daukoru, 1975).

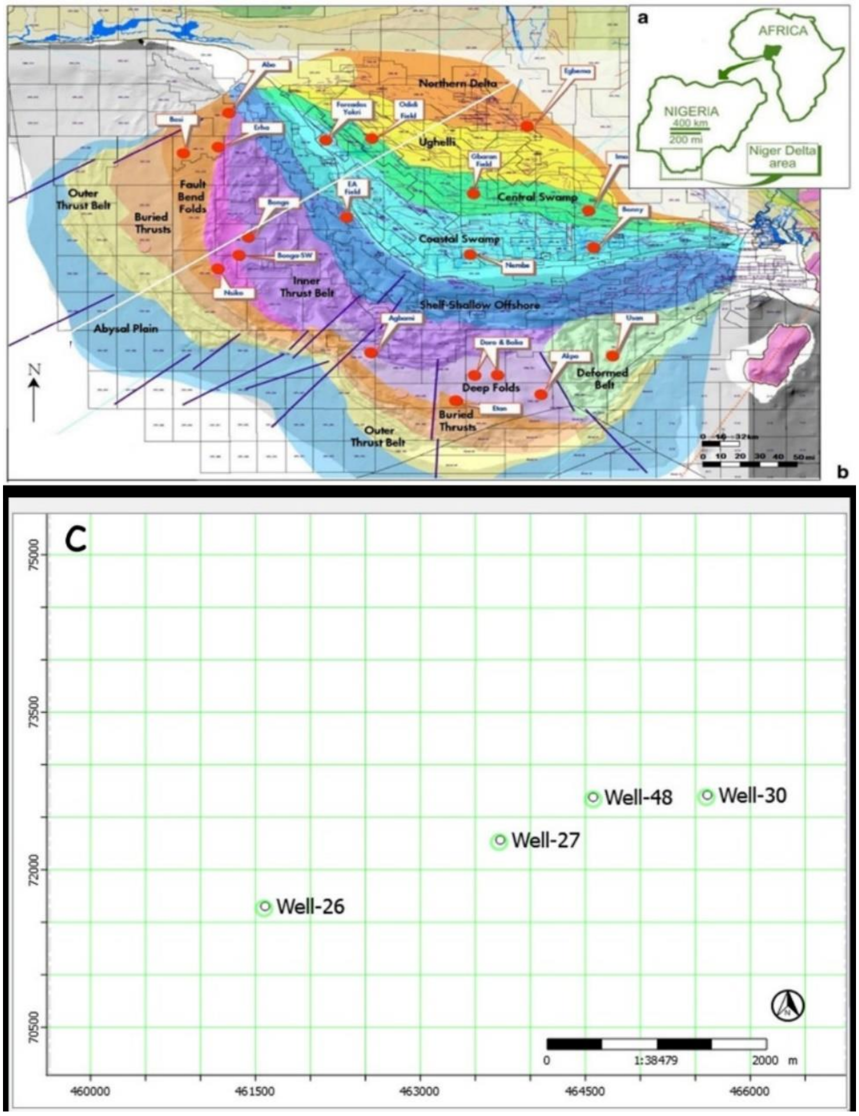

Figure 1: (a) Location of Niger Delta along the west coast of Africa. (b) Depositional Belt map with the Niger Delta Basin (after Ejedawe et al. 2007). (c) The Basemap of the Wells in the Field.

3. Materials and Methods

The data used in this work is a suite of well log data from an X. The X field, renamed for this study for proprietary reasons, is a marginal oil and gas field. The available logs include gamma ray log, resistivity, caliper, density and sonic log. The wells are Well 26, Well 27, Well 30, and Well 48. Formation evaluation was done using Rokdoc software.

3.1 Determination of Reservoirs Zones of Interest

Finding the zones with a low volume proportion of shale is the initial step, as these areas, also known as "clean zones," are more likely to generate stored hydrocarbons. The resistivity and gamma ray logs have frequently been used to achieve this purpose. While resistivity logs were utilized to distinguish between zones holding hydrocarbons and those not, since hydrocarbons are non-conductors, the gamma ray (GR) log in the reservoir units indicates the amount of shale. Low shale volume indicates hydrocarbon bearing zones and vice versa.

3.2 Determination of Gamma Ray Index

Shale volume V_{sh} of the rock can still be estimated linearly from the gamma ray log, which is still the prime choice for obtaining shaliness indication. This index takes into account minimum gamma ray (GR) value (cleanest zone), the maximum GR value (most shaly zone), and the value of the study area or depth. The gamma ray log is commonly used to calculate the gamma ray index using the Asquith and Gibson formula, as shown in equation 1 (Asquith and Gibson, 1982):

$$I_{GR} = GR_{\log} - GR_{\min} / GR_{\max} - GR_{\min} \tag{1}$$

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).

3.3 Determination of Volume of Shale

According to researchers, shale is a heterogeneous rock that is rich in clay and has a varying quantity of organic matter and clay minerals, primarily illite, kaolinite, chlorite, and montmorillonite (Mehana and El-monier,2016). Shale has a severe impact on the petrophysical characteristics of the formation, lowering the reservoir's effective and total porosity and permeability (Kamel and Mohamed, 2006). Furthermore, shale's presence raises questions about how to accurately estimate oil and gas reserves and evaluate formations (Abudeifa et al., 2016). The most accurate method for estimating the volume of shale (Vsh) is to use logging metrics that are predominantly sensitive to shale, specifically gamma ray and spontaneous potential (SP). This technique uses the gamma ray index to determine the volume of shale. The gamma ray index was used to determine the volume of shale.

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

where: $V_{s?}$=volume of shale and I_{GR}= gamma ray index.

3.4 Determination of Total Porosity

Total porosity is defined as all pore space containing fluids (water, oil, or gas), The density log is the best approach to calculate total porosity. The porosity was calculated using the Wyllie equation to estimate the density derived porosity (Wyllie and Rose, 1950). Equation 3 shows the Wyllie equation for density-derived porosity.

$$\Phi_T = \rho_{ma} - \rho_b / \rho_{ma} - \rho_f \tag{3}$$

where ρ_f is the fluid density (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water), ρ_{ma}= 2.65 g/cc is the is the grain density (normally determined from laboratory measurements on core material) and ρ_b is the density log measurement.

3.5 Determination of Formation Factor

The formation resistivity factor (F) is determined by the kind of matrix (sandstone, limestone, dolomite, etc.) and the porosity of the zone of interest. It is the ratio of the resistivity of a water-filled rock (Ro) to the resistivity of that water (Rw). Several equations that have the general expression in equation 4 have been developed to relate formation factor to porosity.

$$F = a / \phi^m \tag{4}$$

where, F = formation factor; a = tortuosity factor = 0.62; Ø = porosity and m = cementation factor = 2.15

3.6 Determination of Formation Water Resistivity

Researcher defined formation water as water that saturates the formation rock but is uncontaminated by drilling mud (Schlumberger, 1996). The higher the temperature at a given salinity, the lower the resistivity, therefore the water resistivity at any formation temperature may be predicted from the water resistivity at another formation temperature if both the temperature and temp8erature offsets are known. The resistivity of the formation water was determined using Archie's equation, which coupled the formation factor (F) to the resistivity of a formation at 100% water saturation (Ro) and the resistivity of formation water (R_w).:

$$R_w = R_o / F \tag{5}$$

3.7 Determination of Water Saturation (S_w)

The fraction of pore space containing water is termed water saturation (S_w). Determination of the water saturation for the uninvaded zone was achieved using the Archie equation given (Archie, 1941).

$$S_w^{\ 2} = (F \times R_w) / R_T \tag{6}$$

But, $$F = R_o / R_w \tag{7}$$

Thus, $$S_w^{\ 2} = R_o / R_T \tag{8}$$

Where S_w=Water Saturation of the uninvaded zone, R_o=resistivity of formation at 100% water saturation; R_T= true formation resistivity.

3.8 Determination of Hydrocarbon Saturation

Hydrocarbon saturation is one minus water saturation. This was calculated by deducting the percentage of water saturation from 100.

Thus $$S_h = 1 - S_w \tag{9}$$

$$S_h\% = 1 - S_w\% \tag{10}$$

where: S_h is the hydrocarbon saturation (expressed as a fraction or as percentage).

3.9 Calculation of Irreducible Water Saturation

The fraction of a reservoir pore volume occupied by water at maximal hydrocarbon saturation is known as irreducible water saturation. It represents water that has not been displaced by hydrocarbons because it is confined in small pore spaces and narrow interstices by sticking to rock surfaces. Equation 12 was used to compute the irreducible water saturation.

$$S_{wirr} = \sqrt{\frac{F}{2000}} \tag{12}$$

where: S_{wirr} = Irreducible Water Saturation; F = Formation Factor.

3.10 Determination of Permeability

Permeability (k) is the ease with which a fluid of a certain viscosity can flow through a formation. Fluids flow more easily through high permeability materials than low permeability materials. The Darcy (d), or more often the millidarcy (md), is a practical unit for permeability. Owolabi et al. (1994) applied multiple-regression analysis to the available data-sets of Eastern Niger Delta unconsolidated sands to generate an empirical expression for predicting permeability. Equation (13) from Owolabi et al., was utilized to estimate permeability in this investigation (Owolabi et al., 1994).

$$K = 307 + 26,552\Phi^2 - 34,540(\Phi S_{wirr})^2 \tag{13}$$

where S_{wirr} is irreducible water saturation and Φ is porosity

3.11 Determination of Net Thickness

Net thickness is the thickness of reservoir-quality lithology (often sand) in the unit. It is the reservoir column that is occupied solely by reservoir formations (e.g., sand) and is devoid of non-reservoir formations (e.g., shale). It is computed using Equation 14:

$$h = H - V_{sh} Total \tag{14}$$

Where H = Gross Thickness, V_{sh} Total = column of the reservoir that is occupied by reservoir formation.

3.12 Determination of Net to Gross Ratio (NTG)

This is the ratio of the entire pay footage divided by the reservoir interval's total thickness, or the net reservoir thickness to the gross reservoir thickness. The depositional environment paints a picture of the overall sand/shale ratio (high N/G) or low N/G richness of the reservoir interval, as well as the type of interbedding that occurs between high- and low-quality rocks. Equation (14) is used to determine the thickness of the net/gross reservoir (h), and Equation (15) is used to determine the net to gross ratio.

$$\text{Net/Gross} = \frac{\text{h}}{\text{H}} \tag{15}$$

3.13 Determination of Effective Porosity

When determining the economic feasibility of rocks or sediments as oil or gas reservoirs, effective porosity is critical. The porosity of a rock that contributes to fluid flow through the rock is represented by effective porosity. Typically, effective porosity is computed by modifying total porosity by shale volume calculations. Dresser (1979) was used to adjust total porosity to get effective porosity (equation 16).

$$\Phi_{eff} = \Phi_T - \left(\Phi_{sh} \times V_{sh}\right) \qquad (16)$$

where Φ_{eff} is effective porosity, Φ_T is the total porosity, Φ_{sh} is the porosity log reading in a shale zone and V_{sh} is the volume of shale.

4. Results and Discussion

4.1 Reservoir Zones of Interest and Well-To-Well Correlation

The initial phase was to identify reservoir units and correlate wells throughout the field. Three probable hydrocarbon-bearing zones were delineated throughout the wells using a combination of gamma ray and resistivity logs. The general stratigraphy of the study field is revealed via well correlation. The correlation panel for the three sand bodies across the four wells in the field of study is shown in the well section window in Figure 2. Three (3) sand bodies identified were correlated through the four wells as reservoir Sand A, Sand B and Sand C. The wells revealed a shale/sand/shale sequence representative of Niger Delta deposits. The analysis reveals that each sand unit stretches the length of the field, varies in thickness, while some units are shallower or deeper than adjacent units, implying that reservoir intervals are rather continuous laterally.

4.2 Petrophysical Curves and Tables

Figure 3 displays Well-27 well curves of estimated reservoir values in Sand A. Fig. 4, 5, 6, and 7 represent well curves of predicted reservoir properties in Sand A, B, and C for Wells 26, 27, 48, and 30 respectively. Measured depth (MD), Gamma ray (GR), Resistivity (RES), Lithology (LITH), Net-to-gross (NTG), total porosity (POR), water saturation (Sw), hydrocarbon saturation (Sh), permeability (PERM), volume of shale (Vsh), and effective porosity (POREFF) are shown from left to right in the panel. It should be noted that their arrangement varies, but each incorporates all of the attributes indicated. The average petrophysical evaluation for the Sand A, B, and C reservoirs of Well-26 is summarized in Table 1. The mean petrophysical analysis for the Sand A, B, and C reservoirs of Well-27 is summarized in Table 2. The mean petrophysical evaluation for the Sand A, B, and C reservoirs in Well-30 is presented in Table 3. The average petrophysical evaluation for the Sand A, B, and C reservoirs of Well-48 has been compiled in Table 4. A constant pattern in all of the Reservoir intervals indicate that they all have low gamma ray, relatively high resistivities, low water saturation, high hydrocarbon saturation, high Net-to-gross, and relatively high total and effective porosity.

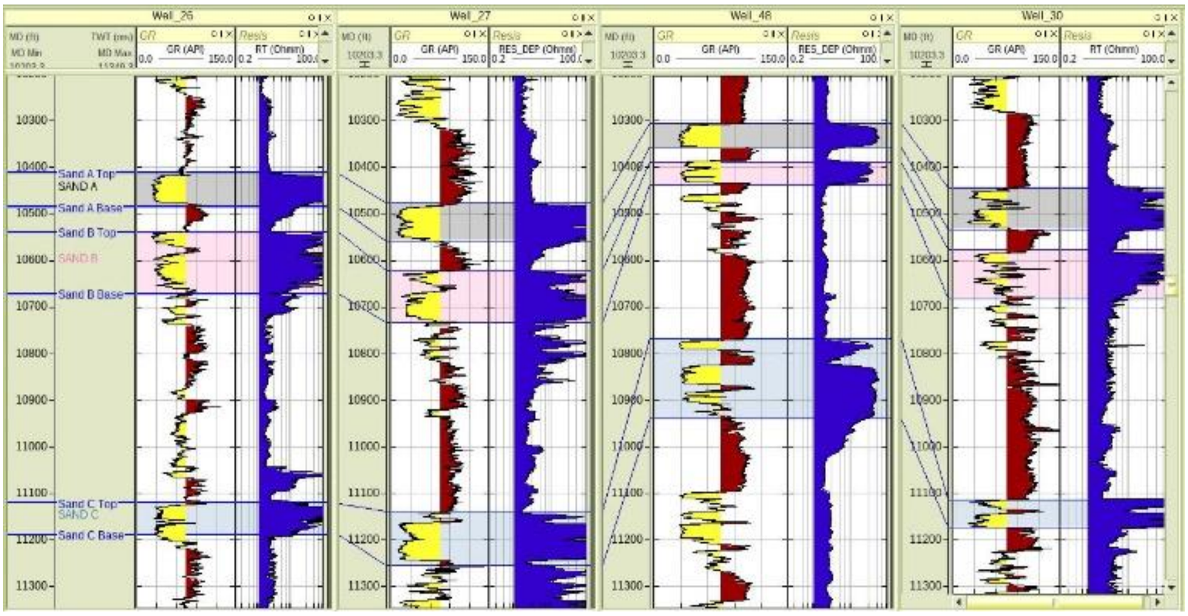

Figure 2: Well correlation panel for 3 reservoirs across the four wells.

4.3 Petrophysical Analysis

Reservoirs containing hydrocarbons have been detected using both qualitative and quantitative methods. The quantitative analysis includes calculating for parameters like shale volume, water saturation, and effective porosity, while the qualitative analysis involves scanning well logs for hydrocarbon reservoir signatures like low gamma ray, low SP, high resistivity, and a cross-plot of neutron and density logs (gas reservoirs), if available.

The average petrophysical evaluation for Well-26 within the reservoirs of interest which are Sand A, B, and C is summarized in Table 1. The volume of shale readings in this well ranged from 0.174 to 0.344, and this implies that the quantity of shale in the reservoirs is quite low. Thus, the inferred reservoir is characterized by a larger sand deposit than shale and is consequently hydrocarbon saturated. The average total porosity was 0.292 (29.2%), indicating that the reservoir units are of significant-to-good quality. The permeability of the reservoir units ranges from 2612 to 2685 mD, which simply connotes that there is outstanding reservoir flow. Usually, permeability of a rock must be more than 100 mD in order for it to be considered as a hydrocarbon reservoir without stimulation (Rider, 1986; Schlumberger, 1996). The reservoir hydrocarbon saturation varies from 0.938 to 0.964, indicating that only a tiny portion of the voids are saturated with water. The results of this are high hydrocarbon production and saturation. The reservoir's net to gross ratio, which varies from 0.496 to 0.729 (49.6 to72.8%), indicating that it contains sands in addition to other types of rock. These results confirm that the reservoir has significant permeability and is practically porous with linked pores. This indicates that there is a high concentration of exploitable hydrocarbons in the reservoirs.

The average shale volume in Well-27 (Table 2) ranges from 0.229 to 0.337. The notably low volume of shale suggests that there is more sand than shale in the reservoirs, indicating a low shale proportion. The range of average values for total porosity is 0.211 to 0.270 (21.1% to 27.0%). Researcher's report that the porosities are good if they are between 25% and 30% (Baker, 1992). The reservoirs have an average permeability of 2848 mD. In addition researchers described the permeability as excellent in his qualitative description if it is above 1000 mD (Rider, 1986). The classification criteria for porosity and permeability are shown in Tables 5 and 6, respectively. Saturation of the hydrocarbon reservoir ranges from 0.917 to 0.954 and this means that, in comparison to the resulting hydrocarbon saturation, the fraction of vacant spaces filled with water is small. The net to gross ratio ranges from 0.605 to 0.800, indicating that the reservoir contains more sands than other rock types. Generally, Sand H has high hydrocarbon content that makes it very viable for production.

In Well-48 (Table 3), the net thickness (thickness of reservoir-quality lithology) is between 40 and 48 ft which is sufficiently thick enough to accommodate hydrocarbons. The net-to-gross ranges from 0.648 to 0.923 and indicates that the column of the reservoir that is occupied by reservoir sand formation is quite high. Average volume of shale is between 0.106 and 0.429 and indicates that fraction of shale contained in the reservoirs is relatively low. The total and effective porosity are between 0.299 and 0.407 and connotes a good-to-excellent reservoir porosity. Permeability is excellent with values ranging from 2998 to 4932 mD. Water saturation is low with values ranging from 0.059 to 0.103 and means that there is sufficient hydrocarbon in the reservoir.

The reservoir in Well 30 (Table 4) has an average net thickness between 37 and 61ft, a net-to-gross ratio between 0.519 and 0.625 (51.9 to 62.5%), am average shale volume of 0.065, an average total porosity between 0.265 and 0.321 (26.5 to 32.1%), a water saturation between 0.321 and 0.431 (32.1 to 43.1%), and a permeability between 2108 and 2620 mD. On the whole, these qualities result in a productive hydrocarbon reservoir that can both produce and store a hydrocarbon supply that is both economically and environmentally feasible.

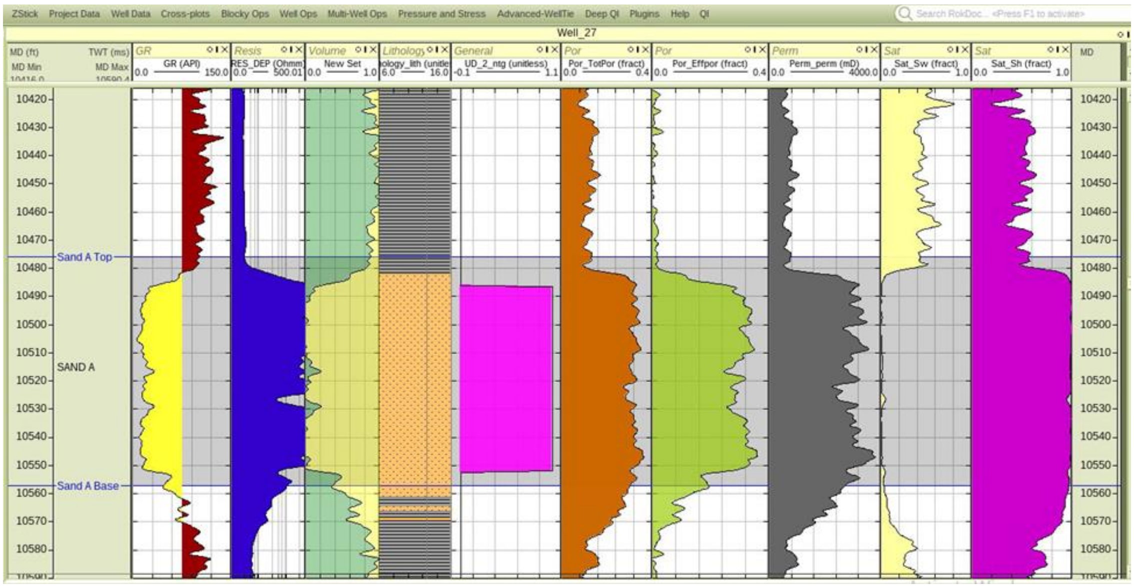

Figure 3: Well curves showing the reservoir properties in Sand A for Well-27

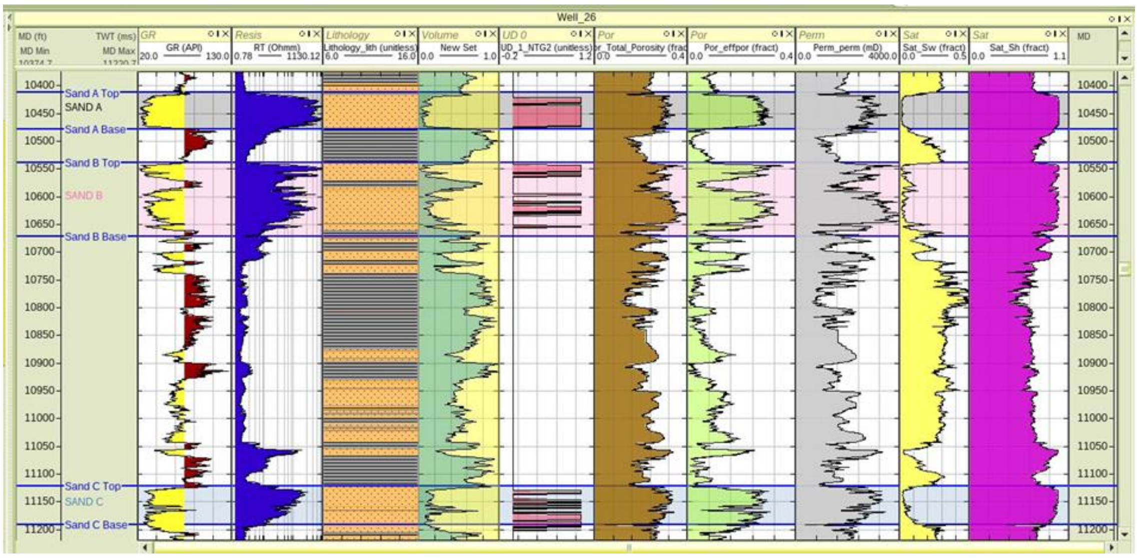

Figure 4: Well curves showing the reservoir properties in Sand A, B, and C for Well-26

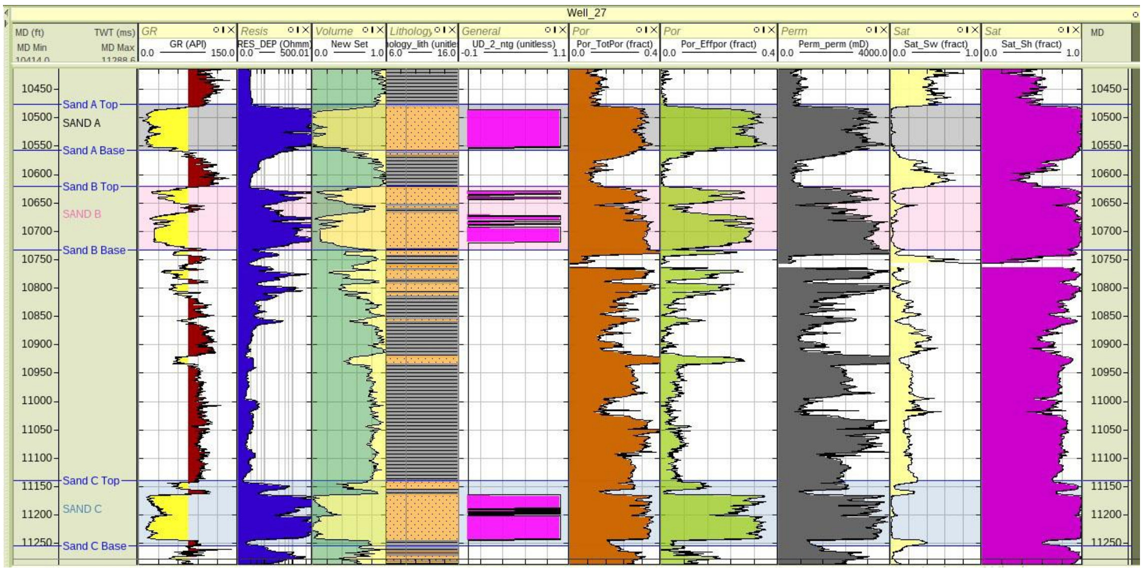

Figure 5: Well-27 well curves displaying the properties of the reservoir in Sand A, B, and C

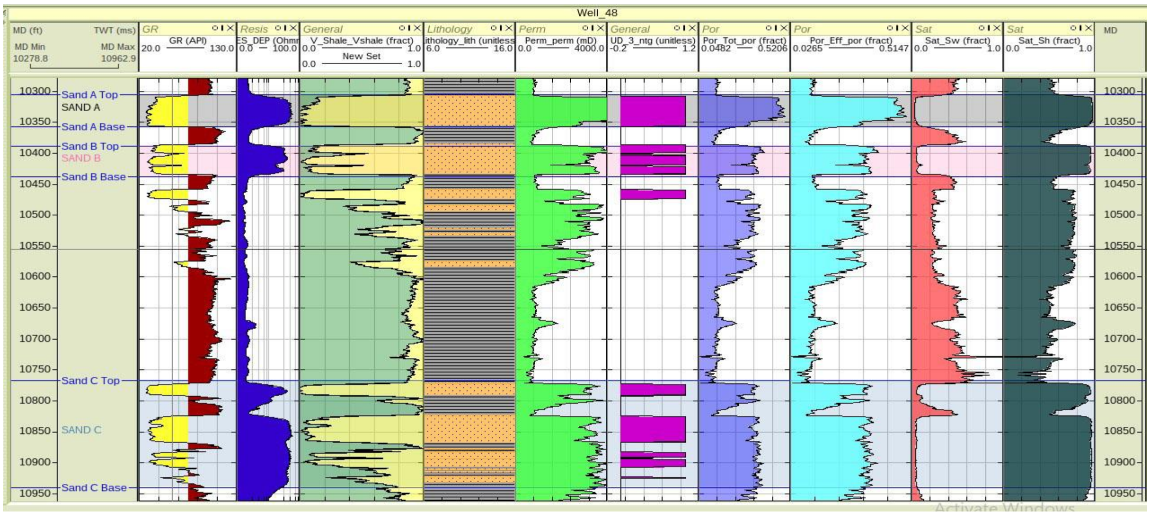

Figure 6: Well curves showing the reservoir properties in Sand A, B, and C for Well-48

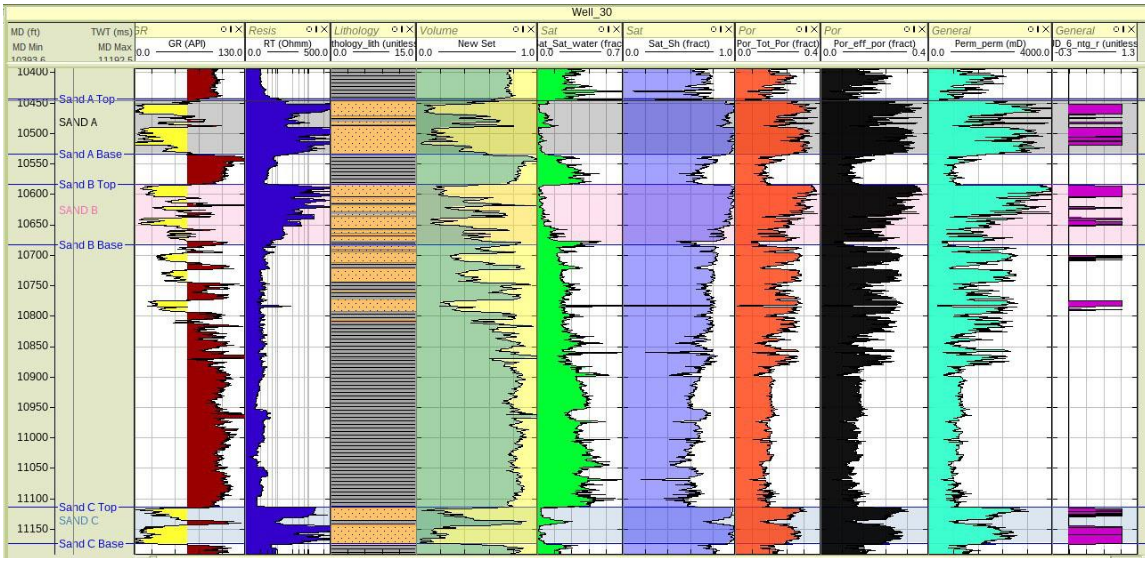

Figure 7 Combined Well curves for Well-30 illustrating reservoir properties in Sand A, B, and C

Table 1: Summary of the estimated petrophysical parameters from Sand A, B and C for Well 26

Well 26 (Reservoir Rock Summary)											
Reservoir Zone	**Top depth (ft)**	**Bottom Depth (ft)**	**Gross Thickness (ft)**	**Net Thickness (ft)**	**N/G**	**Av. Vsh.**	**Av. Tot Por**	**Av. Eff Por**	**Av. Sw.**	**Av. Sh.**	**Perm**
Sand A	10412	10478	66	48	0.7293	0.1740	0.2924	0.2447	0.0355	0.9645	2617
Sand B	10539	10672	133	94	0.7109	0.3444	0.2928	0.2017	0.0619	0.9381	2685
Sand C	11122	11191	69	34	0.4964	0.2487	0.2911	0.2223	0.0562	0.9437	2612

Table 2: Summary of the estimated petrophysical parameters from Sand A, B and C for Well 27

Well 27 (Reservoir Rock Summary)											
Reservoir Zone	**Top depth (ft)**	**Bottom Depth (ft)**	**Gross Thickness (ft)**	**Net Thickness (ft)**	**N/G**	**Av. Vsh.**	**Av. Tot Por**	**Av. Eff Por**	**Av. Sw.**	**Av. Sh.**	**Perm**
Sand A	10475	10557	82	66	0.8001	0.2292	0.3044	0.2700	0.0461	0.9539	2839
Sand B	10620	10733	113	68	0.6051	0.3372	0.3066	0.2111	0.0634	0.9366	2866
Sand C	11139	11254	115	79	0.6872	0.2998	0.3022	0.2376	0.0830	0.9169	2833

Table 3: Summary of the estimated petrophysical parameters from Sand A, B and C for Well 48

Well 48 (Reservoir Rock Summary)											
Reservoir Zone	**Top depth (ft)**	**Bottom Depth (ft)**	**Gross Thickness (ft)**	**Net Thickness (ft)**	**N/G**	**Av. Vsh.**	**Av. Tot Por**	**Av. Eff Por**	**Av. Sw.**	**Av. Sh.**	**Perm**
Sand A	10305	10357	52	48	0.9238	0.1062	0.4075	0.4043	0.0586	0.9414	4932
Sand B	10388	10438	50	40	0.8019	0.2012	0.3228	0.3167	0.0828	0.9171	3149
Sand C	10438	10767	329	213	0.6484	0.4287	0.3115	0.2985	0.1033	0.8967	2998

Table 4: Summary of the estimated petrophysical parameters from Sand A, B and C for Well 30											
Well 30 (Reservoir Rock Summary)											
Reservoir Zone	**Top depth (ft)**	**Bottom Depth (ft)**	**Gross Thickness (ft)**	**Net Thickness (ft)**	**N/G**	**Av. Vsh.**	**Av. Tot Por**	**Av. Eff Por**	**Av. Sw.**	**Av. Sh.**	**Perm**
Sand A	10443	10533	90	47	0.5193	0.0546	0.2891	0.2793	0.3231	0.9453	2620
Sand B	10584	10682	97	61	0.6248	0.0825	0.2687	0.2556	0.4310	0.9174	2365
Sand C	11113	11173	59	37	0.6198	0.0621	0.2566	0.2468	0.3218	0.9378	2108

Table 5: Criteria for classifying Porosity (Baker, 1992)	
Average Porosity values (%)	**Qualitative Description**
< 5	Very insignificant
5 – 10	Insignificant
10 – 15	Fairly Significant
15 –25	Significant
25 – 30	Good
Φ > 30	Excellent

Table 6: Qualitative Evaluation of Permeability (Rider, 1986)	
Average Permeability Value (mD)	**Qualitative Description of Permeability**
< 10.5	Poor
15–50	Moderate
50 – 250	Good
250 – 1000	Very Good
> 1000	Excellent

5. Concluding Remarks

Using well data, thorough petrophysical analyses were carried out, improving knowledge of the qualities and characteristics of the reservoir. The X field is situated in the Niger Delta's Coastal Swamp Depositional Belt. Twelve distinct lithofacies were found in the field, and they were further examined using certain empirical formulas to find petrophysical characteristics that might be used to better comprehend the performance and quality of the reservoir. The reservoir sand and seal sequence continuity of the field is good, according to well log correlation of the field. According to the petrophysical assessment, the reservoir units have excellent permeability and significant-to-excellent porosity. The finding of this study is consistent with the studies of previous researchers in 2018 and 2022. The X field reservoirs can be considered to be a prolific hydrocarbon system. The application of robust petrophysical methods has provided more details as per the reservoir quality and performance while also reducing uncertainty in the prediction of reservoirs. The limitation of the study was that at the time of this study, core data was unavailable which could serve as ground truth data for calibrating and validating petrophysical measurements obtained from well logs. Future research in the areas should incorporate core samples to validate the petrophysical analysis from logs.

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