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RESEARCH ARTICLE

GEOMECHANICAL AND PETROPHYSICAL PROPERTIES OF "X$_{RO}$" OIL FIELD IN THE CENTRAL SWAMP DEPOBELT PART OF THE NIGER DELTA; ENHANCING RESERVOIR CHARACTERIZATION AND FLUID IDENTIFICATION

Bassey, Richard E., Akpabio, Idara O.

Department of Physics, University of Uyo, Uyo
****Corresponding Author Email: mbetohenry@gmail.com***

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ABSTRACT

The study presents a comprehensive analysis of well log data from the "XRO" oil field in the Central Swamp Depobelt of the Niger Delta. Logs analyzed include gamma ray, resistivity, neutron, density, and sonic, which were used to determine lithology and pore fluid content. Geomechanical properties (e.g., bulk modulus, shear modulus, Young's modulus, Poisson's ratio, Vp/Vs ratio) and petrophysical parameters (e.g., porosity, permeability, water saturation, shale volume, bulk volume of water) were computed using Interactive Petrophysics v4.6. Two distinct reservoir sands were identified across five wells (RO5–RO9), each exhibiting unique geomechanical and petrophysical characteristics. Net pay thicknesses ranged from 234.51 ft to 993.57 ft across sand units. For example, in RO5, sand units 1 and 2 had porosity of 0.386 and 0.338, and permeability of 91.36 mD and 73.11 mD respectively. High resistivity values across most reservoirs indicate hydrocarbon presence, except in RO8's sand unit 1, where low resistivity suggests brine. The integration of these parameters enhances reservoir characterization and supports efficient hydrocarbon development strategies.

KEYWORDS

Fluid Identification, Geomechanical Properties, Hydrocarbon Exploration, Lithological Composition, Petrophysical Analysis..

1. INTRODUCTION

The risk of hydrocarbon exploration and extraction is substantial, particularly in identifying viable drilling locations. To reduce these hazards, it is necessary to define a reservoir's lithology and pore fluid composition.

Poor core sample quality and preservation techniques have led to some issues relating to poor prediction of reservoir properties and lithofacies from core analysis. (Olurunniwo et al., 2019). Seismic or well log data generated from such core information in most cases leads to correlations that are faulty. With the aforementioned challenge in place, for optimized development and production to be achieved a detailed quantitative petrophysical evaluation is usually required, especially in the highly heterogeneous environments like the paralic successions of the Agbada Formation of the Niger Delta (Kiakojury et al., 2018; Anyiam et.al., 2018). This study attempts to resolve this impasse in predicting the reservoir properties and lithofacies by employing the use of well log data and petrophysical studies. Regional and detailed reservoir scales that enable evaluation of lithology and pore fluid variations have been achieved using cross-plotting or statistical techniques (Lamont et al., 2008; Cao et al., 2022).

The travel of seismic waves through rocks has made it possible for rock physics to describes the physical properties of a reservoir such as compressibility, porosity and rigidity; these properties would affect how seismic waves flow through rocks (Close et al., 2016). To develop a theory that may help predict these properties in seismic, an attempt is made to establish a relationship between these material properties and the observed seismic response (Austin et al., 2018).

As a result, using rock physics in conjunction with seismic features allows for the prediction of reservoir properties, such as lithologies and pore fluids. This strategy reduces the hazards associated with exploration and is especially useful in uncharted territory (Foster et al., 2010).

A quantitative rock physics study is performed in an attempt to give a solution to this problem by removing the uncertainties that typically follow conventional methodologies in estimating lithology and differentiating pore fluids using well logs. The goal of this research is to use rock physics analysis of well log data to distinguish lithology and pore fluid characteristics.

1.1 Location And Geology Of The Study Area

The study area is situated within the Niger Delta, specifically in the 'X$_{RO}$' field located within the Central swamp depobelt part of the Niger Delta, as depicted in figure 1.

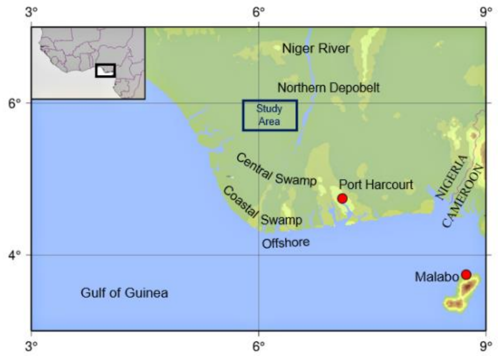

Figure 1: Map of the Niger Delta showing study area

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Geographically, the Niger Delta is nestled along the continental margin of the Gulf of Guinea, spanning latitudes between 3^0N and 6^0N and longitudes between 5^0E and 8^0E (Murat, 1972).

The surrounding area of approximately 75,000 square kilometers is predominantly categorized as 'tertiary,' with sediment thickness ranging from 9,000 meters to 12,000 meters, forming a clastically regressive sequence (Evamy et al., 1978).

The stratigraphic units within the Niger Delta can be classified into three major formations: the Akata formation, Agbada formation, and Benin formation, each indicative of distinct depositional environments (Short and Stauble, 1967). These formations collectively shape the subsurface lithostratigraphy, with the Agbada formation serving as the primary reservoir for hydrocarbons due to its favorable geological characteristics (Frankl and Cordry, 1967). The oil is seen to belong to the Akata-Agbada group (Atat et al., 2020c; Akpabio et al., 2023a). The Agbada formation remains the main oil reservoir in the Niger Delta (Weber and Daukoro, 1975; Doust and Omatsola, 1990; Akpabio and Ojo, 2018).

2. Theoretical Framework

Analyzing petrophysical and geomechanical properties from well logs involves a variety of mathematical formulas and equations. These formulas help in determining key parameters such as porosity, permeability, water saturation, hydrocarbon saturation, modulus, etc. Below, we will explore the most commonly used formulas.

2.1 Petrophysical Properties

2.1.1 Porosity Calculation

a. Density Log (RHOB): The density log measures the bulk density of the formation. The porosity (ϕ) can be calculated using the following formula:

$$\phi_d = \frac{\rho_{matrix} - \rho_{log}}{\rho_{matrix} - \rho_{fluid}}$$

where:

- ρ_{matrix} is the matrix density (depends on lithology).
- ρ_{log} is the density log reading.
- ρ_{fluid} is the fluid density.

b. Neutron Porosity Log (NPHI)

The neutron porosity log measures the hydrogen index of the formation which is influenced by the fluids in the pore spaces. The porosity can be calculated using:

$$\phi_n = \frac{H_f - H_m}{H_f - H_0}$$

where:

- ϕ_n is the neutron porosity.
- H_f is the hydrogen index of the fluid in the pore space.
- H_m is the hydrogen index of the matrix (rock).
- H_0 is the hydrogen index of the formation.

c. *Sonic Log (DT)*

The sonic log measures the travel time of sound waves through the formation. The porosity can be calculated using:

$$\phi_{\Delta t} = \frac{\Delta t_{ma} - \Delta t_b}{\Delta t_f - \Delta t_{ma}}$$

where:

- Δt_{ma} is the matrix slowness.
- Δt_b is the bulk slowness (measured from the sonic log).
- Δt_f is the fluid slowness.

2.1.2 Water Saturation Calculation

a. Archie Equation

The Archie equation is widely used for calculating water saturation (S_w) in clean (non-shaley) reservoirs. It is given by;

$$S_w = \left(\frac{aR_w}{\phi^m R_t}\right)^{\frac{1}{n}}$$

Where,

- R_w is the resistivity of the formation water.
- R_t is the true resistivity of the formation (measured from the resistivity log).
- ϕ is the porosity.
- a, m, and n are empirical constants (typically $a = 1$, $m = 2$, and $n = 2$).

b. Waxman-Smits Equation

For shaley reservoirs, the Waxman-Smits equation is preferred for water saturation which is given as;

$$\frac{1}{R_t} = \frac{\phi^m}{R_w}\left(\frac{1 - S_w^n}{S_w^n}\right) + \frac{Q_v B}{R_w}$$

where:

- R_t: True resistivity of the formation.
- R_w: Resistivity of the formation water.
- ϕ: Porosity of the formation.
- m: Cementation exponent.
- n: Saturation exponent.
- V_{sh}: Volume fraction of shale.
- Q_v: Cation exchange capacity per unit total pore volume.
- B: Equivalent conductance of the clay counterions.

2.1.3 Permeability Calculation

Permeability (k) can be estimated using various empirical relationships. One common method is the Coates equation:

$$k = \phi^2 \cdot (1 - S_{wirr})$$

where:

- ϕ is the porosity.
- S_{wirr} is the irreducible water saturation (often assumed to be 0.3).

2.1.4 Shale Volume Calculation

Shale volume (V_{sh}) is crucial for accurate petrophysical analysis. It can be calculated from Larionov equation using the gamma ray log (GR):

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

Where,

- GR_{log} is the measured gamma ray value.

- GR_{min} is the minimum gamma ray value (clean sand).

- GR_{max} is the maximum gamma ray value (shale).

2.1.5 Bulk Volume of Water (BVW)

This is the percentage of the total rock volume that is occupied by water.

The bulk volume of water (BVW) is calculated as:

$$BVW = Sw \times \Phi$$

where:

- ϕ is the porosity
- S_w is the water saturation.

2.1.6 Hydrocarbon Saturation

Hydrocarbon saturation (S_h) is calculated as:

$S_h = 1 - S_w$

2.2 Geomechanical Properties

2.2.1 Bulk Modulus (K)

The bulk modulus is the measure of a material's resistance to uniform compression. It is defined as the ratio of the infinitesimal pressure increase to the resulting relative decrease of the volume. The bulk modulus can be calculated using the compressional wave velocity (V_p), shear wave velocity (V_s), and bulk density of the rock. The formula is;

$$K = \rho\left(V_p^2 - \frac{4}{3}V_s^2\right)$$

2.2.2 Shear Modulus (G)

Shear Modulus (G) is the material's resistance to shear deformation. It is defined as the ratio of shear stress to shear strain.. In the context of well logs, the shear modulus can be calculated using the shear wave velocity (V_s) and the bulk modulus of the rock. The formula is;

$$G = \rho V_s^2$$

2.2.3 Poisson's Ratio

This is a measure that indicate how a material deforms when a compressive force is applied. It is also the ratio of the transverse strain to the corresponding axial strain and can be estimated using velocities of compressional (V_p) and shear waves.(V_s)

$$\nu = \frac{V_p^2 - 2V_s^2}{2(V_p^2 - V_s^2)}$$

These equation help in understanding the geomechanical behaviour of reservoirs without the need for destructive core sample test (Koefoed, 1995).

2.2.4 Young's Modulus (E)

This is the measure of the rocks stiffness, defined as the ratio of stress to strain in the elastic region of the rock's stress-strain curve, and can be estimated from sonic logs using the following formula;

$$E = \frac{\rho \cdot V_p^2 \cdot (1-\nu)}{(1+\nu)\cdot(1-2\nu)}$$

where:

- ρ is the bulk density.
- V_p is the compressional wave velocity.
- ν is the Poisson's ratio.

These formulas are fundamental in geomechanical and petrophysical analysis and are widely used in the oil and gas industry to interpret well logs and characterize reservoir properties.

3. MATERIALS AND METHOD

The five oil wells (RO5, RO6, RO7, RO8, RO9) used in this research of the X_{RO} field in the Niger Delta basin focuses on using composite well logs such as density, sonic, gamma ray, neutron, resistivity logs. Interactive Petrophysics (IP) v.4.6 software is used in processing and analyzing these data. The suite of logs generated from the software includes gamma ray, density, neutron and other necessary data. The research workflow is presented in figure 2 . Data were prepared and loaded with the software (IP) and the shale, sand lithologies were identified;

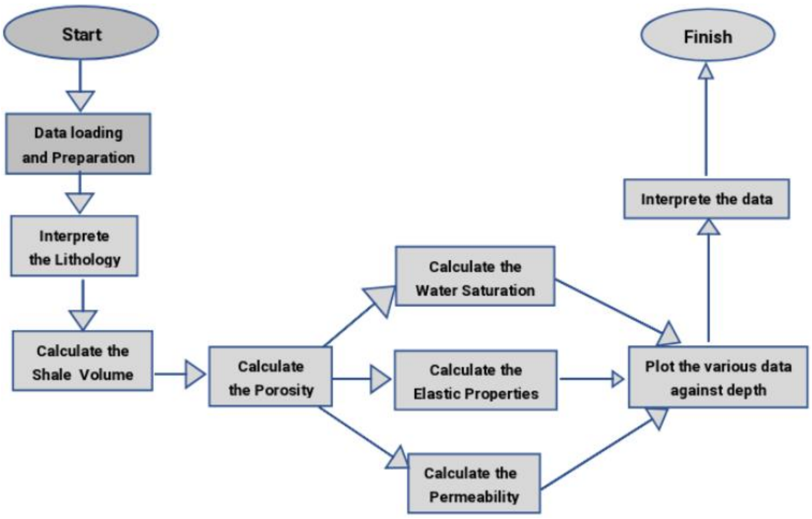

Figure 2 : Research Workflow Chart of the Study

4. Results and Discussion

The results from the processing of the IP software with their respective discussions are presented in the suite of logs represented in figures 3 (Well R05), figures 4 (Well RO6), figures 5 (Well RO7), figures 6 (Well RO8) and figure 7 (RO9). They are shown below;

4.1 WELL RO5

The measured, calculated and computed data provided in figure 3 offers a detailed insight into the petrophysical and geomechanical properties of reservoir sands 1 and 2 within well RO5.

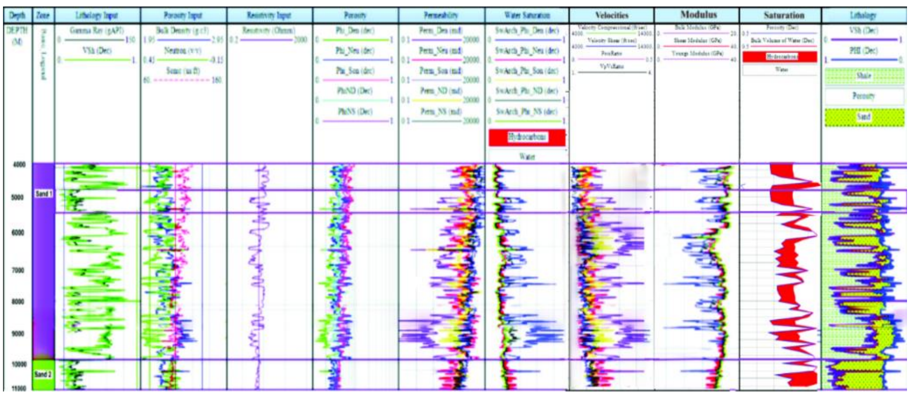

Figure 3: Basic log, Petrophysical and Geomechanical Properties of Well RO5 showing two sand units.

The mean value of gamma ray, neutron and resistivity for sand 1 corresponds to 27.105API, 0.321dec and 46.28ohm.m. For sand 2, their values corresponds to 38.963API, 0.430dec and 34.832ohm.m. In sand 1, the netpay interval ranged from 4876.31ft to 5471.23ft with a net thickness of 594.92ft. In sand 2, the analysis was done from 9921.56ft to 1091.13ft which had a netpay of 993.57ft. The curve results are shown in figure 3.

The density value is within the range 2.215 to 2.831g/cc with a mean value of 2.523g/cc. The permeability value is in the range of 81.34md to 101.38md with a mean value of 91.36md for sand 1. For sand 2, the mean of the density and permeability is 2.302g/cc and 73.106md respectively. Sand 1 has a porosity value ranging from 0.259 to 0.513dec with a mean value of 0.386dec. For sand 2, the porosity value range from 0.2771 to 0.405dec with a mean value of 0.338dec. Water saturation and volume of shale values in sand 1 have their mean values to be 0.339dec and 0.129dec respectively.

For geomechanical parameters, the bulk modulus and shear modulus have their mean to be 11.523GPa and 4.832GPa in sand 1 respectively suggesting potentially different lithological composition or compactness. The mean values of Young's modulus in sand 1 and 2 are 11.356GPa and 20.368GPa which indicate differences in rock stiffness and mechanical behaviour.

The following petrophysical parameters indicated high values and they are given as ; neutron, sonic, porosity, permeability (in sand 1 while moderately high in sand 2). In sand 1 and sand 2, the values of resistivity are moderately high, bulk volume of water is moderately high in sand 1 while the same property is low in sand 2. Also the volume of shale in sand 2 is low while sand 1 shows value that indicate moderately high.

In the geomechanical properties, the following properties indicated low values; bulk modulus, shear modulus, velocity compressional, velocity shear, across both reservoir sand unit and only Young's modulus showed moderately high in sand 1 but high in sand 2. Vp/Vs ratio in both sands indicate high values with various levels of discrepancies, poisson ratio indicating high values in both sand 1 and sand 2.

The similarities and differences noticed in the values of the sand units in both reservoirs can serve as indicators and provide a lead as to the behavior of the well during the different stages of work in the well i.e. it provides information to the driller on well stability, hydraulic fracturing, blowout, collapse, cracks etc.

With the volume of shale in sand 1 showing low and moderately high in sand 2, it gives a pointer as to the shale content within the reservoir as this affect the permeability of the formation. The high permeability in sand 1 and moderately high permeability value in sand 2 offers additional information that a low shale volume and high permeability of sand 1 makes it a more clean and excellent reservoir for its storage and productivity as it favors higher production. With a high porosity value in sand 1 and sand 2, it provides a good signal for good/high fluid storage, but a low water saturation value gives a pointer that the formation is an excellent hydrocarbon storage unit with bulk volume of water being moderately high on sand 1 and low in sand 2.

Density values are low for the two sand units and neutron values showing high indicates high hydrogen content which translate to high hydrocarbon content. With resistivity being a good fluid indicator, a moderately high resistivity value in the two sand units would suggest that the hydrocarbon contained as fluid in the reservoir is oil.

4.2 WELL RO6

The delineation of various parameters as shown in the distinct petrophysical and geomechanical properties demonstrated in reservoir sands 1 and 2 is shown in figure 4**.** The depth of Well RO6 has a range of about 6886.12ft to 7992.38ft with a netpay thickness of about 606.23ft for sand 1 and depth ranging from 8358.14ft to 8651.83ft for sand 2 with a netpay thickness of about 293.09ft.

Mineral deposition and composition between the two reservoirs (i.e. sand units) is suggested by the density values which ranges from 2.920 to 2.314g/cc with a mean value of 2.302g/cc in sand 1 and 1.916 to 2.904g/cc in sand 2 giving a mean of 2.410g/cc. Gamma ray measurement values provide a good insight into the mineralogy and lithology of the two reservoirs with sand 1 ranging from 24.012 to 25.980API with an average of 24.996API and sand 2 ranging from 21.824 to 36.000 API with an average of 28.912 API. The resistivity value which indicate variations in fluid content and lithology ranges from 33.84 to 48.36 ohm.m in sand 1 with an average of 40.10ohm.m. In sand 2, the range goes from 36.40 to 53.84 ohm.m with a mean of 45.12ohm.m showing change in fluid content and lithology. The porosity value of sand 2 range from 0.110 to 0.316dec with a mean of 0.213dec. This represent a higher porosity value when compared to that of sand 1 which ranges from 0.060 to 0.342dec with an average of 0.201dec suggesting potentially higher reservoir quality and fluid content. On the bulk volume of water, sand 1 has a range of 0.083 to 0.105dec with a mean of 0.094dec and sand 2 ranges from 0.079 to 0.281dec with a mean value of 0.101dec. The difference or variation in the bulk water volume reflects the differences in reservoir flow content and saturation..

For the geomechanical aspect of the reservoir suggesting potential variation in lithological composition, the bulk modulus value for sand 1 ranges from 9.976 to 13.948GPa having a mean of 11.962GPa. The bulk modulus value within the two reservoirs show some similarities in their strength and compactness. The values of Shear and Young's modulus in sand 1 reservoir range from 2.307 to 5.703GPa with a mean of 4.035GPa and 8.945 to 15.021GPa with a mean of 11.983GPa respectively are higher compared to sand 2 indicating differences in rock stiffness and mechanical behaviour. For shear and compressional velocities where both reservoir exhibit similar trends which reflect consistent lithological properties and compaction levels. The variability in volume of shale and VpVs ratio is somewhat higher in sand 2 as compared in sand 1 suggesting differences in rock texture between the two reservoirs.

Geomechanically observing the values gotten from the two sand units i.e. Sand 1 and sand 2, the following properties/parameters indicated low values when calculated, computed or measured, and they are velocity compressional, velocity shear, bulk modulus, shear modulus while poisson ratio, Youngs modulus and VpVs ratio all have values that are considered high.

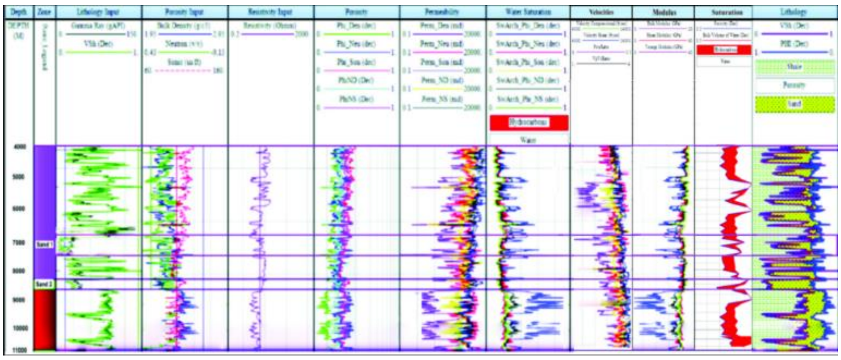

Figure 4: Basic log, Petrophysical and Geomechanical Properties of Well RO6 showing two sand units.

Coincidentally, the geomechanical values of the two identified sand units have slight variations but show some similarities in their range of classification as either low or high.

Petrophysically, the following parameters indicated low values; gamma ray, density, volume of shale, water saturation, bulk volume of water, while the following properties indicated values ranging from moderately high to high and they are; sonic, porosity, resistivity and neutron with permeability giving values that are moderately high in sand 1 and high in sand 2. This means that the high Young's modulus values in the two sand units is indicative of formation that is brittle thereby favoring hydraulic fracturing. The high porosity value favors fluid accumulation and low water saturation is indicative of the presence of hydrocarbons. A low to moderately high permeability value in sand 1 is indicative of a tight sandstone reservoir which when hydraulically fractured due to its brittleness would increase the permeability value with secondary porosity measures introduced as a result of the fracturing. With low water saturation indicative of high hydrocarbon presence/saturation. A moderate to high resistivity values in the two sand units which is a good fluid indicator suggest that the pore spaces is largely occupied by oil.

4.3 WELL RO7

This well has two sand units with depth ranging from about 4021.52ft to 4336.30ft in sand 1 with a netpay of 314.78ft and range of 5748.71ft to 5983.22ft in sand 2 with a netpay of 234.51ft.

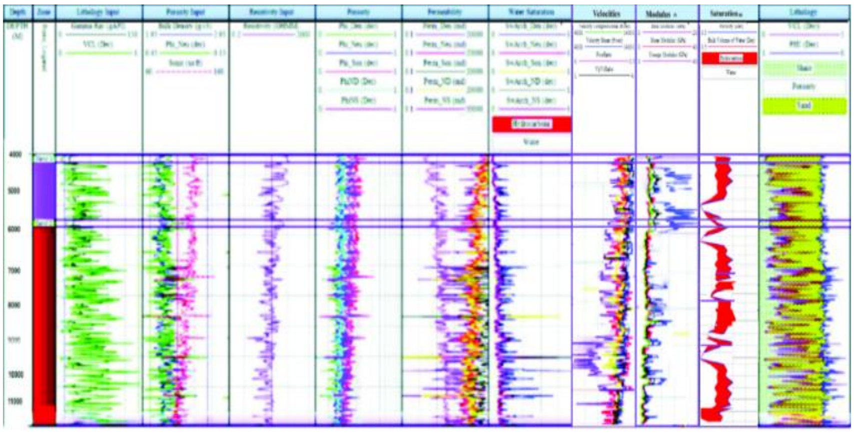

Figure 5: Basic log, Petrophysical and Geomechanical Properties of Well RO7 showing two sand units

The geomechanical and petrophysical properties of the two sand unit as measured, calculated, computed and discussed is shown in figure 5. The mean value of gamma ray, neutron and resistivity for sand 1 corresponds to 35.449API, 0.301dec and 95.08ohm.m. For sand 2, their values corresponds to 39.923API, 0.317dec and 47.92ohm.m.

The density value is within the range 2.100 to 2.300g/cc with a mean value of 2.141g/cc. The permeability value is in the range of 9.837mD to 31.215mD with a mean value of 20.526md for sand 1. For sand 2, the mean of the density and permeability is 2.148g/cc and 77.652md respectively. Sand 1 has a porosity value ranging from 0.167 to 0.329dec with a mean value of 0.296dec. For sand 2, the porosity value range from 0.208 to 0.328dec with a mean value of 0.289dec. Water saturation and volume of shale values in sand 1 have their mean values to be 0.305dec and 0.151dec respectively.

For geomechanical parameters, the bulk modulus and shear modulus have their mean to be 12.044GPa and 4.910GPa in sand 1 respectively suggesting potentially different lithological composition or compactness. The mean values of Young's modulus in sand 1 and 2 are 12.963Gpa and 13.916Gpa which indicate differences in rock stiffness and mechanical behaviour.

The geomechanical parameters discussed in this well are bulk modulus, shear modulus, velocity compressional, velocity shear and poisson ratio where all the mentioned parameters have values that are considered low while others like Vp/Vs ratio and Young's modulus have values considered to be high for the two sand units.

Petrophysically, the following properties are considered to be low and they are; density, gamma ray, volume of shale, water saturation and bulk volume of water. Properties with high values include neutron (which suggest high hydrogen content) sonic, porosity, permeability and resistivity. The implication of the values gotten from the geomechanical and petrophysical properties suggest that the high porosity value in the two sand units signifying high accumulation capabilities with low volume of shale signifying a clean sandstone formation. The two units have excellent fluid flow capabilities with high permeability values. A low bulk volume of water and low water saturation values suggest that the two sand units within the well have high potential for hydrocarbon content. The discrepancies noticed in the values of resistivity in sand 1 and sand 2 serve as a fluid indicator as the value of resistivity in sand 1 is considered to be very high suggesting the presence of gas while the value of resistivity in sand 2 which is moderately high is suggesting the presence of oil.

In summary, for well RO7, it is suggested that sand 1 is filled with fluid suspected to be gas guided by the values of the petrophysical parameters while sand 2 is filled with fluid suspected to be oil.

With a low bulk modulus and low shear modulus, it suggest that both sands have a high degree of compressibility and can likely support hydraulic fracturing due to its britleness.

4.4 WELL RO8

The distinct values of petrophysical and geomechanical properties as delineated by the analysis of the various parameters is gotten from reservoir sands 1 and sand 2 within well RO8 as shown in figure 6. This well has two sand units with depth ranging from about 8156.35ft to 8576.81ft in sand 1 with a netpay of 420.46ft and range of 11212.14ft to 11532.42ft in sand 2 with a netpay of 320.28ft.

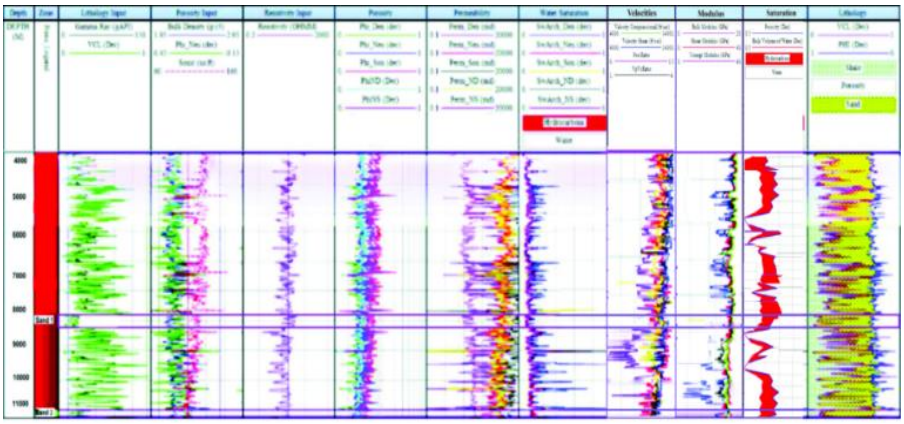

Figure 6: Basic log, Petrophysical and Geomechanical Properties of Well RO8 showing two sand units.

The description of the geomechanical and petrophysical parameters provide deep insight into the picture of the well to guide drillers while working on the well from start to finish. The petrophysical properties which is highlighted below indicates low values in sand 1 and sand 2 and they are; gamma ray, density, volume of shale, neutron (which is low in sand 1 but high in sand 2), water saturation (which is high in sand 1 and low in sand 2) with similar behavior playing out in the bulk volume of water within the two sand units. For sand 1, resistivity is low while the value of resistivity is high in sand 2. Other properties that have high values in both sand units included sonic, porosity, and permeability.

Geomechanically the parameters that read low in the two reservoirs include; bulk modulus, shear modulus, velocity compressional, velocity shear while high values were gotten from Vp/Vs ratio, Young's modulus and poisson ratio.

The implications of the values gotten from the parameters in the two sand units has it that sand 1 with high porosity value have excellent storage. Sand 1 also have high water saturation, high bulk volume of water, and low neutron value (i.e. low hydrogen content) signalling low hydrocarbon content. With resistivity being a good fluid indicator, a low resistivity value attempts to suggest that the fluid in the sand unit is low in hydrocarbon but saturated with water **(Brine)** in sand 1.

For sand 2, having high neutron, high permeability, high resistivity with low water saturation, low bulk volume of water and low volume of shale suggesting a high presence of hydrocarbon with low water saturation. The resistivity value showing high suggest that the fluid contained in sand 2 of well RO8 is high in hydrocarbon suggesting the presence of oil.

4.5 WELL RO9

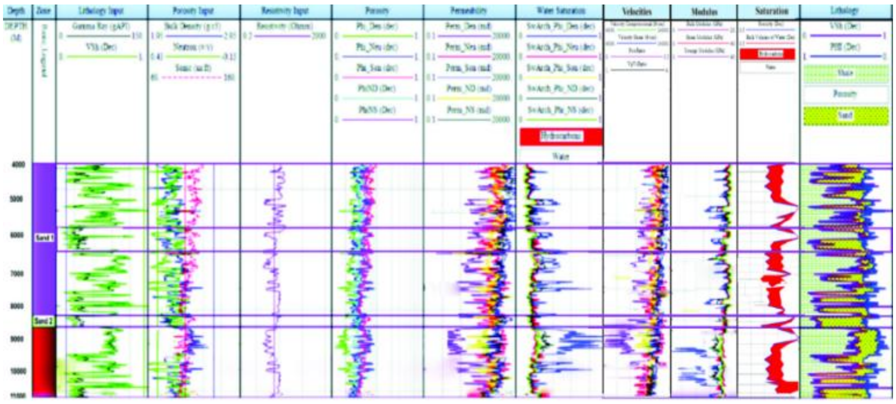

Figure 6: Basic log, Petrophysical and Geomechanical Properties of Well RO9 showing two sand units.

The data provided in figure 6 takes us into some petrophysical and geomechanical properties of reservoir sands 1 and 2 within well RO9. The rock composition and fluid content is provided by the density and resistivity values. In sand 1, the density ranges from 2.282 to 2.564g/cc with a mean of 2.423g/cc. Resistivity in the first sand unit i.e. Sand 1 varies from 103.727 to 110.513ohm.m with a mean of 107.12ohm.m where as in sand 2 it is from 45.62 to 53.10ohm.m with a mean value of 49.36ohm.m. Parameter which measure pore pressure variation indirectly such as gamma ray and neutron measurement have their ranges in sand 1 from 9.996 to 46.274API and have their mean to be 28.135API. In sand 2, the range is from 8.112 to 36.258API having a mean of 22.135API to represent gamma ray measurement while neutron measurement range from 0.211 to 0.413dec with a mean of 0.312dec in sand 1 and 0.340 to 0.866dec with a mean value of 0.613dec in sand 2.

For geomechanical parameters such as shear and bulk modulus which are indicative of varying rock stiffness and certain mechanical behaviours, sand 1 has a mean value of 5.604GPa while sand 2 has a value of 6.032GPa as the mean of shear modulus. For bulk modulus, sand 1 has 12.962GPa as its mean while sand 2 is 13.215GPa. Insights into seismic response and rock elasticity is largely controlled by Young's modulus and velocity measurements. The mean of Youngs modulus in sand 1 is from 13.004GPa while that of sand 2 is 14.024GPa. Velocity compression in sand 1 ranges from 9762.313 to 10244.121 ft/sec with a mean value of 10003.217ft/sec while that of sand 2 ranges from 9062.561 to 10875.109ft/sec with a mean of 9968.835ft/sec. For velocity shear values, it has a range of 4882.135 to 5181.389ft/sec for sand 1 with a mean of 5031.762ft/sec while that of sand 2 ranges from 4996.213 to 6728.517ft/sec with a mean of 5862.365ft/sec. Sand 1 and 2 display different water saturation and porosity values. The water saturation values ranges from 0.098 to 0.328dec with a mean value of 0.213dec in sand 1 while 0.251 to 0.395dec represents the range for sand 2 with a mean value of 0.323dec. The range of the porosity values is from 0.256 to 0.354 dec with a mean value of 0.305dec.

The differences in the lithology between the two sand units can be attributed to the higher acoustic value and slightly lower density values in sand 1 when compared to sand 2 which can equally provide insight into the mineral composition of the reservoir. The history of compaction within the sand units may suggest variances in variation within the different sand units as demonstrated in the difference in the neutron levels which could indicate discrepancies in hydrogen content, porosity or lithology among the sands.

The materials ability to withstand uniform compression as demonstrated in the different values of bulk modulus which shows that both sands have very close or similar bulk modulus characteristics with sand 2 showing higher mean values overall. For the materials ability to withstand shear deformation as presented by shear modulus values. It shows that both sand units show similar trends in shear modulus with sand 2 showing higher values the across the whole formation which is quite similar to that which was observed in bulk modulus.

With an overview of the results offered by the different parameters (measured and calculated) in sand units 1 and 2, it can be stated that petrophysically the following parameters offer low values for sand 1 and sand 2 and they are density, gamma ray, volume of shale, water saturation and bulk volume of water while the following parameters which have moderate to high values are represented as neutron, sonic, porosity, permeability with resistivity showing very high values.

Geomechanically, parameters such as bulk modulus, shear modulus, velocity compressional, velocity shear all indicated low values in the two sand units while VpVs ratio, Youngs modulus and poisson ratio all indicated high values. With a high porosity and permeability value, it is indicative of a formation that has high accumulation of fluid which flows easily. Neutron value being high suggesting high hydrogen content which translates to high potential for hydrocarbon content. With a low density value, it suggest a formation that is relatively compressible and a low volume of shale is indicative of a clean sandstone formation. With a low water saturation value and low bulk volume of water, it is indicative that the fluid that fills the porous and permeable formation is majorly hydrocarbons.

Also, with a low bulk and shear modulus values; it confirms that the two sand units are uniformly and shearly compressible. High values of VpVs ratio, Young's modulus and poisson ratio are indicative of formations that are ductile showing that the well has a high level of stability which can enable it withstand drilling activities without a possible blowout or deformation of any sort.

As a parameter with high fluid predictor, resistivity which is very high in sand 1 suggest a hydrocarbon formation filled with gaseous fluid while a moderately high resistivity of sand 2 is indicative of a formation filled with oil.

5. CONCLUSION

Geomechanical and petrophysical properties of rocks provide essential information for a wide range of applications from resource extraction to environmental management, and their studies continue to evolve with advancements in measurement techniques and analytical methods. The delineation of the different wells in X_{RO} field into the various reservoirs defines most of the reservoirs as being highly porous and highly permeable with most of the reservoir supporting hydraulic fracturing activities to encourage enhanced oil recovery. Most of the wells exhibit high hydrocarbon potential due to their low water saturation levels.

The integration of the results of various geomechanical and petrophysical properties leading to the characterization of the reservoirs reveal that Well RO5 has strong potential for storing *oil* in reservoir sand 1 and *oil* in reservoir sand 2, Well RO6 has strong potential for storing *oil* in reservoir sand 1 and *oil* in sand 2 while Well RO7 is expected to store *gas* in sand 1 and *oil* in reservoir sand 2. Also, due to the integration of the various parameters, Well RO8 is likely to produce *water(brine)* in sand unit 1 and *oil* in sand unit 2. Finally strong indications of *gas* is expected in sand 1 while *oil* is expected in sand 2 for Well RO9.

The values provided by the results of the geomechanical and petrophysical properties provide a strong reason for proceeding with well exploitation activities as the picture generated from the analysis has reduced the initial risk providing the driller with the idea of what to expect at various depth and planning ahead to avoid unpleasant consequences.

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