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PETROPHYSICAL EVALUATION OF ETERIEVA FIELD, NIGER DELTA, NIGERIA, USING WELL LOGS DATA

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ABSTRACT

Hydrocarbon exploration and development rely heavily on understanding the characteristics of subsurface reservoirs. Petrophysical evaluation emerges as a crucial tool in this endeavor, aiming to quantify the essential properties of these reservoirs using well log data. Through the utilization of Petrel 2017 software, this study conducted 3D seismic analysis, well log interpretation, to gauge the hydrocarbon production potential of reservoirs. The geophysical logs used comprise gamma ray log, resistivity log, density and neutron logs etcetera. Sandstone and shale lithology were delineated within the Eterieva field which is a distinctive quality of the Agbada formation. The objective was to pinpoint potential hydrocarbon reservoirs, analyze their configuration, estimate reservoir properties, and evaluate overall reservoir capacity within the Eterieva Field, located in the Niger Delta Basin by amalgamating geological and geophysical data. The result showed that C reservoir in the Eterieva Field has a net thickness of about 176.5ft, an average Effective Porosity of 26%, Total Porosity of 30%, Permeability of 2239.70mD, Water Saturation of 47% and Hydrocarbon Saturation of about 53%. Its payzone thickness and shale volume are 129.73ft and 14% respectively. The C reservoir is basically made up of oil and water with an OWC at an average depth of about 6552.4ft. This nature of the petrophysical parameters reveals that the reservoir is of good quality and hence, viable for exploitation. The findings of this endeavor provide valuable insights for the sustainable management of the region's hydrocarbon assets while enhancing our comprehension of the basin's geological intricacies

1. Introduction

Beneath the Earth's surface lie valuable natural resources, necessitating the use of diverse geophysical techniques to unveil potential hydrocarbon deposits and essential minerals. These methods, crucial to the oil and gas sectors, include seismic, magnetic, and gravity surveys. Seismic techniques are particularly instrumental in petroleum exploration, while magnetic and gravity surveys aid in identifying areas of interest. Oil and gas exploration aims to assess field potential, identify viable accumulation sites, and locate structural or stratigraphic traps conducive to economic development.

The Earth's subsurface harbors a treasure trove of natural resources, including hydrocarbons and essential minerals. Unveiling these resources necessitates the use of diverse geophysical techniques (Ugwu & Okengwu, 2013). Seismic, magnetic, and gravity surveys are crucial tools in the oil and gas sector (Amin et al., 2014).

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Among these, seismic methods play a central role in petroleum exploration, while magnetic and gravity surveys aid in pinpointing areas with high potential for hydrocarbon deposits (Telford et al., 1976).

Structural traps, notably, are pivotal in hydrocarbon exploration, though many have already been discovered and exploited, posing challenges to further development. Seismic and well log data serve as valuable exploration tools, facilitating the identification of structural and stratigraphic features such as faults, anticlines, and hydrocarbon reservoirs, thereby enabling accurate subsurface mapping.

In our research, we focus on conducting petrophysical evaluation and analysis of the Eterieva field in the Niger Delta basin. Seismic surveys, employing reflection or refraction methods on land or sea, yield data that are subsequently interpreted to enhance understanding of subsurface structures. This interpretation process involves extracting geological information from seismic data, integrating various datasets such as seismic sections, check shot data, and well logs, and constructing a geological model of the subsurface.

LOCATION

The research area is situated offshore of the Niger Delta Basin in Nigeria as shown in figure 1. The Niger Delta Basin is an extensive sedimentary basin found in West Africa, particularly in Nigeria, and stretching into certain regions of neighboring countries.

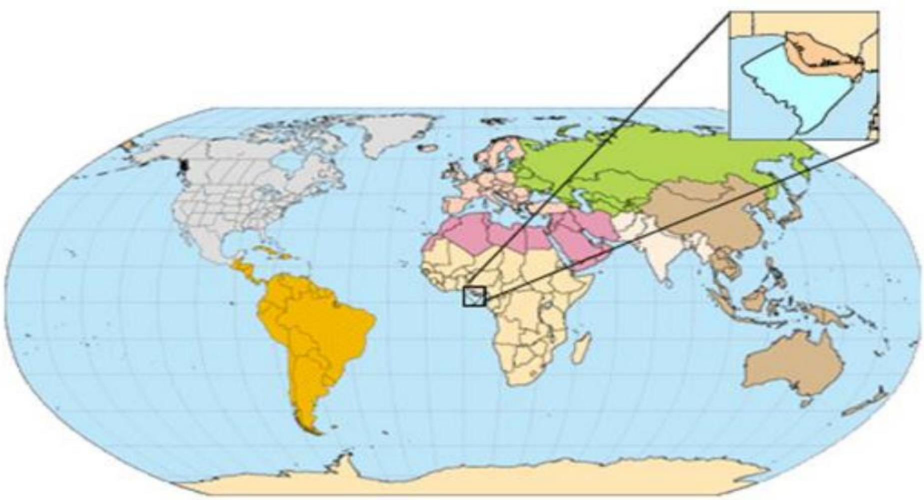


Figure 1: Location of the Niger Delta basin on the world map (Tuttle et al, 1999)

GEOLOGY OF STUDY AREA

The Niger Delta Basin, located in Southern Nigeria, is a prominent geological feature and Africa's largest delta, ranking third globally in size (Doust & Omatsola, 1990). Spanning roughly 70,000 square kilometers, the basin owes its formation to the Niger River's discharge into the Gulf of Guinea (Short & Stauble, 1967). Its geological history can be traced back to the Cenozoic Era, approximately 66 million years ago, when sediments transported by the Niger River and its tributaries began accumulating, forming layers that constitute the extensive sedimentary basin we see today (Reyment, 1965).

The Niger Delta basin is characterized by a diversity of depositional environments, encompassing fluvial (river-dominated), deltaic (formed by river deltas), estuarine (areas where freshwater and saltwater mix), and marine settings (Tuttle et al., 1999). As the Niger River reaches the ocean, its velocity decreases, causing the suspended sediments to settle and accumulate, gradually building the deltaic environment (as shown in figure 2). This ongoing process of sediment deposition has resulted in the continuous progradation (outward growth) of the delta into the sea (Agbamu, 2007).

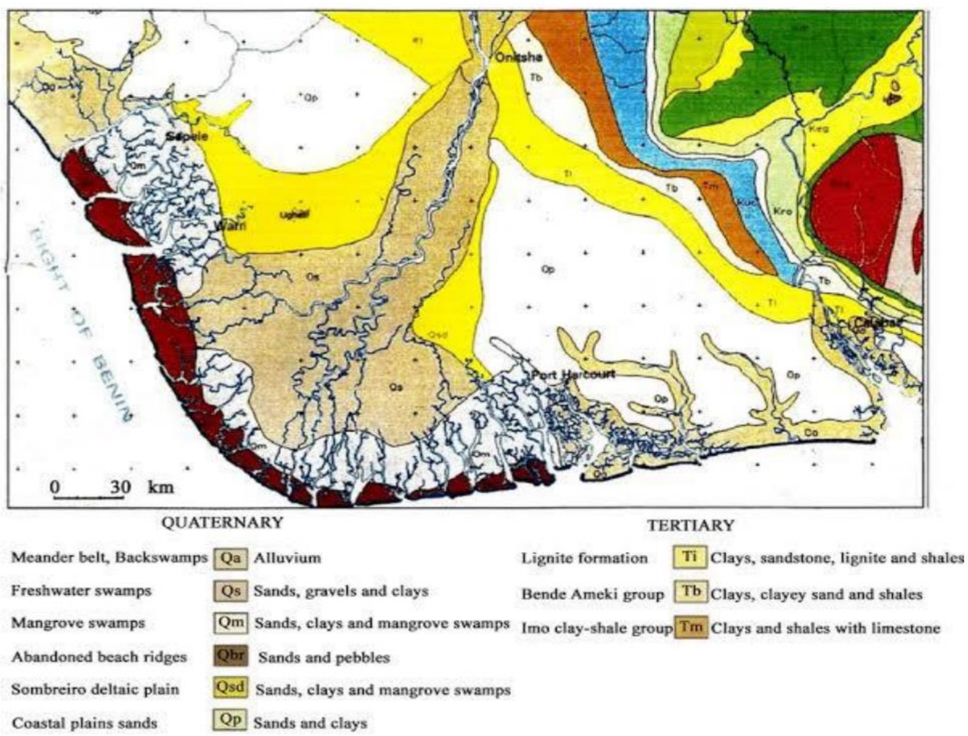


Figure 2: Geologic map of the Niger Delta Basin

STRUCTURAL PATTERN OF THE NIGER DELTA

The Niger Delta Province's onshore regions display geological features unique to southern Nigeria and southwestern Cameroon. The province is bounded to the north by the east-northeast trending Benin Flank and to the south by the West Africa baseline, with its northeastern limit defined by Cretaceous outcrops on the Abakaliki high. The province's eastern extent is bounded by the Calabar flank hinge line (east-southeast), the eastward-extending Cameroon volcanic line offshore, and the Dahomey Basin's western edge, where sediment thickness exceeds 2km or bathymetry reaches 4000m. With an area of approximately 300,000 km², the province encompasses the geological extent of the Agbada-Akata Petroleum System within the Tertiary Niger Delta.

STRATIGRAPHY - The Niger Delta Basin is characterized by a thick clastic wedge, reaching depths of 9,000 to 12,000 meters and occupying an area of nearly 75,000 square kilometers (Short & Stauble, 1967). Three primary formations define the basin's stratigraphy, each reflecting distinct depositional environments and sand-shale ratios:

Akata Formation (Base): The formation consists mainly of marine-derived source rocks, characterized by thick shale layers, turbiditic sandstone reservoirs, and smaller amounts of claystone and siltstone. Deposited during the Paleocene to Recent epoch, the Akata Formation represents periods of low sea level, characterized by low energy, oxygen-deficient deep-water environments where terrestrial organic matter and clays accumulated. Notably, this formation exhibits high overpressure zones and extends across the entire delta with a total thickness of up to 6,000 meters (Evamy et al., 1978).

Agbada Formation: Lying above the Akata Formation, this formation represents a significant petroleum reservoir in the Niger Delta. Deposited during the Eocene to Recent epoch, the Agbada Formation comprises approximately 3,700 meters of paralic siliciclastics. This formation represents the deltaic segment of the sequence, characterized by clastic deposits in delta-front, delta-topset, and fluvio-deltaic environments (Weber & Daukoru, 2005).

Benin Formation: The topmost formation, consisting of continental deposits ranging from Eocene to Recent. Primarily of alluvial origin, the Benin Formation reaches thicknesses of around 2,000 meters in coastal plain sands (Avbovbo, 1978).

The Niger Delta Basin exhibits a characteristic deltaic morphology with a network of distributaries, tidal channels, and levees. However, the basin's structural and tectonic framework plays a critical role in hydrocarbon exploration and development (Akande et al., 2014). The Niger Delta Basin comprises several sub-basins, including the Benin, Agbada, and Anambra basins, separated by structural highs and fault systems. These features significantly influence the migration and entrapment of hydrocarbons within the basin (Nwajide & Chukwueke, 2011). Growth faults are a prominent structural feature within the Niger Delta Basin. These faults arise due to variations in sediment compaction rates and tectonic activity. They create structural traps where hydrocarbons accumulate beneath impermeable sedimentary layers. Notably, the thick sedimentary deposits originated during the rifting events associated with the ancient West Africa Rift System (Séran et al., 2012). The basin's structural evolution has been substantially influenced by salt tectonic processes. The presence of mobile salt layers within the basin has resulted in the formation of salt diapirs and other related structures. These structures can act as effective hydrocarbon traps by creating impermeable barriers that prevent oil and gas from migrating further (Xiao et al., 2014). The basin's overall formation is attributed to a combination of subsidence and sediment accumulation. Subsidence is driven by two primary factors: Sediment Loading - the weight of accumulating sediments exerts pressure on the underlying strata, causing the basin to subside;

Tectonic Processes - the opening of the Atlantic Ocean triggered tectonic activity that contributed to basin subsidence (Sengupta et al., 2013). The interplay of these geological processes – sedimentary deposition, burial, and tectonic activity – has created favorable conditions for the formation and preservation of hydrocarbon reservoirs within the Niger Delta Basin, making it a basin with significant oil and gas potential.

MATERIALS AND METHOD

For this investigation, the PETREL workstation, an interpretation tool by Schlumberger was used and the most up-to-date seismic interpretation technology was utilized. The dataset made available for this study were; Structural analysis of the Niger Delta basin was conducted using an integrated dataset consisting of post-stacked 3D seismic, well data (logs, basemap, check-shots), and geological mapping. The process is summarized in figure 3 below

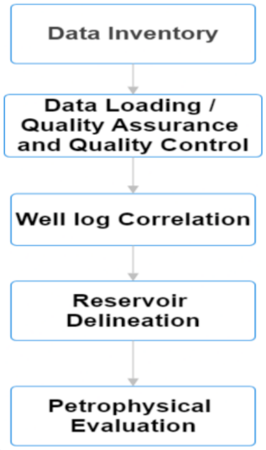


Figure 3: the study workflow

DATA LOADING, QUALITY ASSURANCE AND QUALITY CONTROL: The seismic data was imported in SGY format first, after which the wells were loaded one at a time with the LAS File containing the well data; the directional data (ASC File) for the deviated wells and Checkshots data were then loaded for the various wells. A data quality testing was conducted to assess the quality and determine the availability of specific data, like well logs.

WELL LOG CORRELATION: A detailed well log correlation was done. This involved assessing whether the underground sequence in multiple locations shares similar geological age or positioning. The process entailed examining log intervals from various wells visually to identify comparable features across different locations. After recognizing and labeling the rock layers (strata), Petrel well correlation function provides a clear platform to display logs and encourage discoveries. Each well's stratigraphic analysis is presented in its dedicated panel within the Petrel user interface, and a unified correlation among the five wells is computed. Gamma ray and resistivity logs were used to identify and correlate reservoirs across the wells. The wireline logs from the wells were analyzed using PETREL software to characterize the reservoirs. Gamma ray, resistivity, and density/neutron logs helped in identifying hydrocarbon sands and assess reservoir quality. Neutron/density log data indicated that water, oil, and gas were the main fluids in the reservoirs.

PETROPHYISICAL EVALUATION: Petrophysical properties evaluated include:

Water saturation, a crucial metric for evaluating hydrocarbon reservoir productivity, represents the proportion of pore space occupied by water within a rock. Geophysicists commonly employ Archie's equation to calculate this value, leveraging rock resistivity, formation water resistivity, and porosity.

$$S_w = \left(\frac{a * R_w}{R_t * \emptyset^m}\right)^{\frac{1}{n}}$$

Where:

- S_w is the water saturation; a is the tortuosity factor; R_w is the resistivity of the formation water; R_t is the true resistivity of the rock; φ is the porosity of the rock; m is the cementation exponent; n is the saturation exponent.

Porosity of the reservoir rock – Reservoir rock porosity, representing the percentage of void spaces within the rock's bulk volume, is a critical parameter. This value indicates the rock's capacity for fluid storage and movement, with pore size and distribution also influencing fluid mobility. The porosity of the reservoir rock was computed as shown in the following equation;

$$\Phi_{TD} = \frac{(\rho ma - \rho b)}{(\rho ma - \rho f)}$$

Where:

$\Phi_T = \Phi_{TD}$ = Total Porosity estimated from density log; ρma = Matrix (or grain) density;

ρb = Bulk density (as obtained from the tool and hence includes porosity and grain density); ρf = Density of the fluid

With the above computation, the effective porosity was then determined using the equation given below:

$$\Phi_e = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)} - \left[V_{sh} * \frac{(\rho_{ma} - \rho_{sh})}{(\rho_{ma} - \rho_f)}\right].$$

Where:

Φ_e = Effective porosity; P_{sh} = Density of shale

The ability of fluids to flow through a reservoir is primarily controlled by permeability, a vital petrophysical property. Permeability increases with improving porosity, grain size, and packing efficiency, particularly in sandstone reservoirs, enhancing fluid flow and reservoir productivity. Wyllie and Rose equation is used to calculate for permeability and is denoted by:

$$\Phi_e = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_f)} - \left[V_{sh} * \frac{(\rho_{ma} - \rho_{sh})}{(\rho_{ma} - \rho_f)}\right].$$

Where; K = permeability; Swirr = irreducible water saturation; Φ =porosity

Volume of shale refers to the proportion or percentage of shale within a rock formation. It represents the amount of shale present relative to the total volume of the rock. This is an important parameter in petrophysical studies, as it can impact various properties of the rock, such as porosity, permeability, and hydrocarbon potential.

$$Vsh_{LinearGRindex} = \text{IGR} = \frac{GR_{Log} - GR_{Sand}}{GR_{Shale} - GR_{Sand}}$$

Where: IGR is the gamma ray index; GR_{log} is the Gamma Ray Log reading of the formation; GR_{sand} is the Gamma Ray for a complete sand matrix zone; GR_{shale} is the Gamma Ray for a complete shale zone

The volume of shale is computed by applying Larionov's (1969) equation to the gamma ray index, providing an accurate estimate for tertiary clastic reservoirs.

$Vsh = 0.083*[2^{(3.7*IGR)} - 1]$

NTG ratio measures the proportion of economically productive reservoir rock, calculated from net pay zone thickness and overall well depth. The net-to-gross ratio characterizes reservoir quality by comparing net pay zones to total reservoir thickness. Gross thickness is defined as the total depth of the well, from top to base, whereas net thickness represents the cumulative sum of net pay zones identified through detailed petrophysical log evaluation.

Hydrocarbon saturation captures the proportion of pore volume of a deposit that is filled with hydrocarbons is known as hydrocarbon saturation. By deducting the water saturation value from 100%, it was calculated.

$S_h = (100 - S\mathbf{w})\ \%$

RESULTS AND DISCUSSION

The gamma ray log distinguished the shale from the sand units, having a lithology cut off of about 60 units; minimum and maximum gamma ray reading as 10 and 110 respectively. The resistivity log delineated the hydrocarbon bearing interval of the reservoir across the well. The fluid contained in the reservoir units are basically oil and water as this is clearly expressed in neutron and density logs.

WELL CORRELATION: The reservoirs were correlated across the five wells, but C reservoir show greatest lateral extent of hydrocarbon saturation across the wells (figure 4).

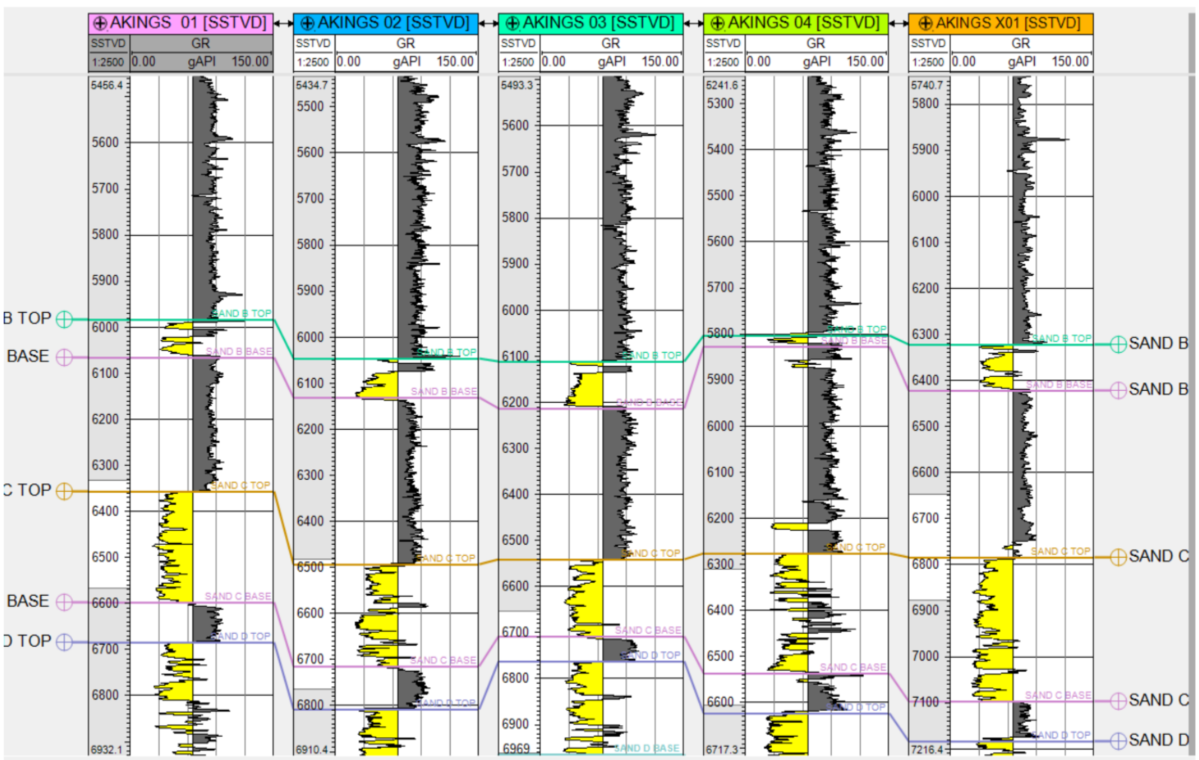
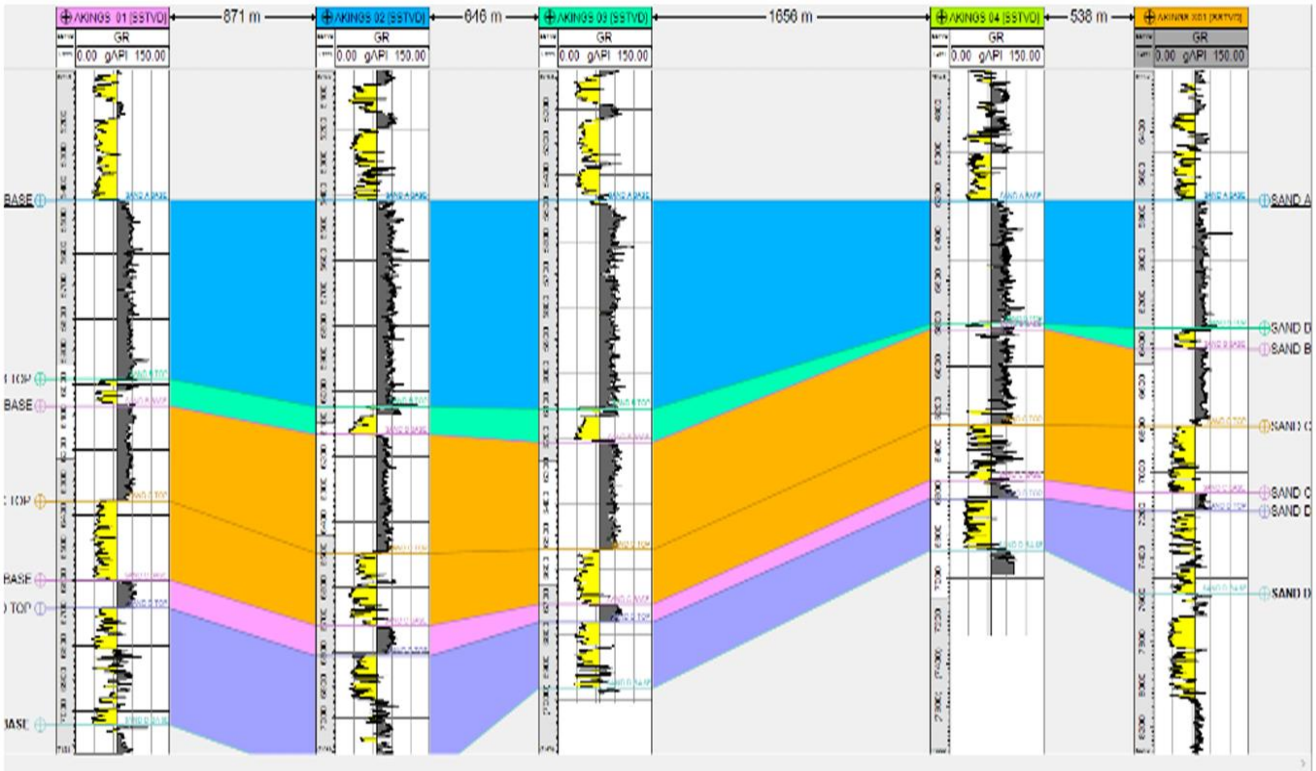


Figure 4: Well correlation panel showing the reservoirs

This research work focused on characterization of C reservoir because it had the greatest thickness and showed the greatest lateral extent of hydrocarbon presence across the wells. The tops of the C reservoir in Akings 01, Akings02, Akings 03 and Akings 04 wells have average depth of 6366ft, 6501ft, 6546ft and 6276ft respectively, while the bases of the reservoir are 6593ft, 6709ft, 6714ft



and 6536ft respectively. The hydrocarbon saturation of reservoir C is highest in Akings 04 well and lowest in Akings 02 well. The pay-zone thickness ranges from 64.17ft to 202.22ft across the reservoir. The displacement observed between the wells as shown in the correlation panel is indicative of faults within the Formation (figure 5 below)

Figure 5: Correlation panel showing the relative distance between the wells

The properties of the reservoir C show variation in petrophysical parameters like effective and total porosity, permeability, shale volume, water saturation and hydrocarbon saturation across the wells as shown by figures 6, 7, 8 and 9. The values of the properties of C reservoir across the wells are summarized in table 1.

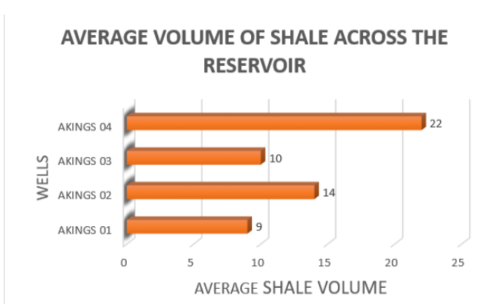


Fig 6: chart showing the average shale volume

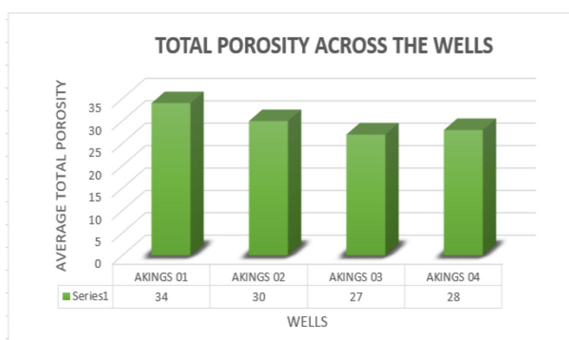


Fig 7: chart showing the average total porosity across the wells

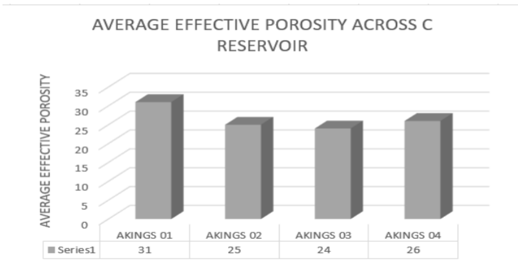


Fig 8: chart showing the average effective porosity

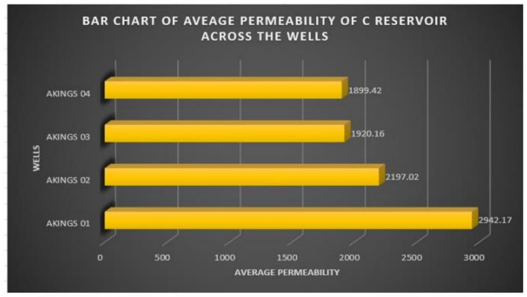


Fig 9: chart showing the average permeability

Table 1: summary of the petrophysical properties of C reservoir across the wells

Wells	Reservoir Top(ft)	Reservoir Base(ft)	Gross Thickness (ft)	NTG	Net Thickness (ft)	Shale Volume	Total Porosity	Effective Porosity	Water Saturation	Hydrocarbon Saturation	Permeability	Fluid Type	Fluid Contact	Payzone Thickness
AKINGS 01	6366.66	6592.66	226.26	1.0	226.26	0.09	0.34	0.31	0.28	0.72	2942.17	oil & water	6550.78	184.12
AKINGS 02	6501.27	6708.94	207.67	0.91	207.67	0.14	0.30	0.25	0.63	0.37	2197.02	Oil & water	6565.17	63.9
AKINGS 03	6546.02	6714.19	168.17	0.98	168.17	0.1	0.27	0.24	0.58	0.42	1920.16	Oil & water	6614.91	68.89
AKINGS 04	6274.90	6536.09	259.74	0.74	103.90	0.22	0.28	0.23	0.38	0.62	1899.42	Oil & water	6474.95	202.02
AVERAGE	6422.21	6637.97	215.46	0.91	14.97	0.14	0.30	0.26	0.47	0.53	2239.70	_____	6551.45	129.73

CONCLUSION

The C reservoir in the Eterieva Field has a net thickness of about 176.5ft, an average effective porosity of 26 percent, total porosity of 30 percent, permeability of 2239.70mD, water saturation of 47 percent and hydrocarbon saturation of about 53 percent. Its payzone thickness and shale volume are 129.73ft and 14 percent respectively. The C reservoir is basically made up of oil and water with an OWC at an average depth of about 6552.4ft. This nature of the petrophysical parameters reveals that the reservoir is of good quality and hence, viable for exploitation.

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