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Petrophysical Analysis of Some Hydrocarbon Reservoirs in Eastern Niger Delta Basin Using Well Logs

Oki, Austin Oyinkuro[1*] and Opukumo, Alfred Wilson[1].
[1] Department of Geology, Niger Delta University, Bayelsa State, Nigeria
*Corresponding author: ustin_oki@yahoo.com.

Abstract:
Petrophysical parameters were investigated on sandstone reservoirs of three wells in X-Field of Eastern Niger Delta basin with the aim of assessing the quality of the reservoir rock units for hydrocarbon production. Well logs were used for different parameters: Gamma-ray and Neutron logs for lithology identification; Resistivity log for Fluid-type discrimination; Density log for Porosity determination. A total of three reservoir sands (A, B and C) were identified and correlated across all three wells using Gamma-Ray logs. Average values for Gross thickness, Shale volume, Net thickness, Net to Gross, Effective porosity, Water saturation and Permeability for all three reservoirs were estimated using Petrel software. Gross thickness of A, B and C were 91.33, 214.66 and 206.66ft, respectively. Shale volume thicknesses were 17.38, 12.62, and 35.95 ft for A, B, and C, respectively. For Net thickness, A, B and C had 45.33, 203.99 and 173.52 ft, respectively. Net to Gross ratio for reservoir A, B and C were 0.78, 2.18 and 0.82, respectively. The average Total and Effective porosity for A were 0.32 and 0.25 %, 0.32 and 0.25 % for B and 0.30 and 0.25 % for C, respectively. Permeability values read 2538.6, 2591.33 and 2211.66 mD in A, B and C, respectively. Water saturation in A, B and C were 1.64, 0.55 and 0.42 %, respectively.Logs correlation showed a good agreement of lithology types from Gamma ray and Neutron logs, indicating accuracy and applicability of the plots in delineating lithology from well logs. Despite Resistivity logs showing all three reservoirs as hydrocarbon bearing coupled with lowShale volumes and enough Gross thicknesses to be able to reserve economic quantities of hydrocarbon, porosity values appearedinsufficient for them to be termed good reservoirs.

Keywords: *Petrophysical properties, Well logs, Petrel, Hydrocarbon*

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I. Introduction

Hydrocarbon reservoirs are rocks that are sufficiently porous and permeable to store and transmit hydrocarbons to extraction wells, as such, the potential and performance of a reservoir lies primarily in the influence of its reservoir properties. An effective reservoir management programme requires a good knowledge of the character of the reservoir, this includes the structure of the reservoir and distribution of fluids within it. This information aids in building reservoir models to provide reliable quantitative performance forecasts.

Reservoir characterization involves the determination of reservoir properties such as Porosity, Permeability, Shale Volume and Water Saturation using available data to generate reliable reservoir models for accurate reservoir performance predictions[1][2][3][4]. Porosity is the ratio, fraction or percentage of the total volume of a rock occupied by voids (pores), it depends on factors such as the type of rock and grain packing. Porosity determines the storage capacity of a reservoir rock. It ranges generally from less than 1 % to 40 % in rocks. In crystalline rocks such as granite, porosity could be as low as 1 %, in a carbonate rock like dolomite is ranges between 2 % to 6 %, in shales it ranges between 8 % and 29 %, although most shales have a porosity of less than 15 %. Sandstone has the highest porosity of 10 % to 35 %, this is so because individual sand and mineral grains don't fit closely together.Porosity can either be Total; which is the ratio of total void volume (whether connected or not) to the bulk volume, or Effective; which is the ratio of the volume of connected voids available for fluid to flow to the bulk volume. Results of early research by[5] showed reservoir porosities within the range of 15 % to 35 % using well logs in the Niger Delta. [6] showed porosity values ranging from 10 % to 25 % in the Northeastern Niger Delta.Permeability has to do with the ability of a reservoir rock to allow the flow of fluids through it, it is a function of the interconnectivity of pore volume, as such, a rock can be said to be permeable if it has an effective porosity. Permeability can either be Effective, Absolute or Relative. Effective permeability is the ability of fluids to pass through the pore spaces of a rock,in the presence of other fluids. Absolute permeability is when the medium is fully saturated with one fluid. Relativepermeability is the ability of a particular rock to allow the flow of a particular fluid through it.Empirical models are based on the correlation between permeability, porosity, and irreducible water saturation. Irreducible water being a function of rock characteristics. Some of the most widely used models include [7] [8] [9] [10] [11]. Most of these models assume certain values for cementation factor and/or saturation exponent and are applicable to clean sand formations where conditions of residual water saturation exist.Fluid saturation is the fraction or percentage of pore space occupied by a particular fluid, a reservoir could be saturated by water (S_W) or hydrocarbons ($1 - S_W$) depending on its constituent fluid type. To determine the hydrocarbon saturation of a Formation the Water Saturation (S_W) must be known, a wrong estimation of the Water Saturation would result in inaccurate hydrocarbon reserve prediction[12]. Shale Volume distribution is one of the most important factors considered in Formation evaluation, since shale reduces effective porosity and permeability of the reservoir [13]. It causes uncertainties in Formation evaluation and could prevent proper estimation of hydrocarbon reserves [14].

Reservoir modelling is often associated with uncertainties due to inadequate understanding of reservoir properties leading to poor performance predictions. Reservoir properties are determined primarily by two techniques, either directly from core sample measurements in the laboratory or indirectly from wireline log measurements. Several researchers have successfully employed well log data for the determination of petrophysical properties of reservoir rocks.

This study is however based on the determination of petrophysical properties of a reservoir using well logs from the Eastern Niger Delta region of Nigeria, the study is borne out of the need to understand the character of reservoir in the area for more efficient Formation evaluation.

II. Materials and Methods

(i) Geology of study area

The location of study lies within the Niger Delta sedimentary basin of Southern Nigeria (Fig. 1). The Niger Delta basin is a prolific hydrocarbon province in West Africa.It is a clastic wedge with a thickness of 12 km at the centre spanning over a 75, 000 Sqkm area [15] [16]. It is bound on the Northwest by the Benin flank, on the East by the Calabar flank and extends into the Atlantic on the South [17]. The thick assemblage of sediments of the basin was developed by the side of a failed arm of a triple junction “RRR” system during the breakup of the South American and the African plates, which resulted in the opening of the Atlantic during the Late Jurrasic[18]. The basin is comprised of a single petroleum system known as the Akata-Agbada petroleum system, driven by a source rock, reservoir and seal all of which are generally accepted to have formed in the Mid Eocene [19].

Three lithostratigraphic units have been identified in the prograding Niger Delta, they are the Akata Formation representing a marine depositional environment with characteristic dark grey thick overpressured shales with plant remains. It is known to be the potential source rock of the Akata-Agbada petroleum system. Overlying the Akata Formation is the Agbada Formation, comprised of a sequence of sandstones and shales characteristic of transitional or deltaic depositional environment. The sandstones of the Agbada Formation are known to serve as good hydrocarbon reservoirs due to their porosity and pore connectivity. The uppermost and youngest lithostratigraphic unit is the Benin Formation.It consists chiefly of sandstones with a few intercalations of shales. The deposits of the Benin Formation depict a continental depositional environment. Very few hydrocarbon accumulations have been associated with the Benin Formation [20] [21][22].

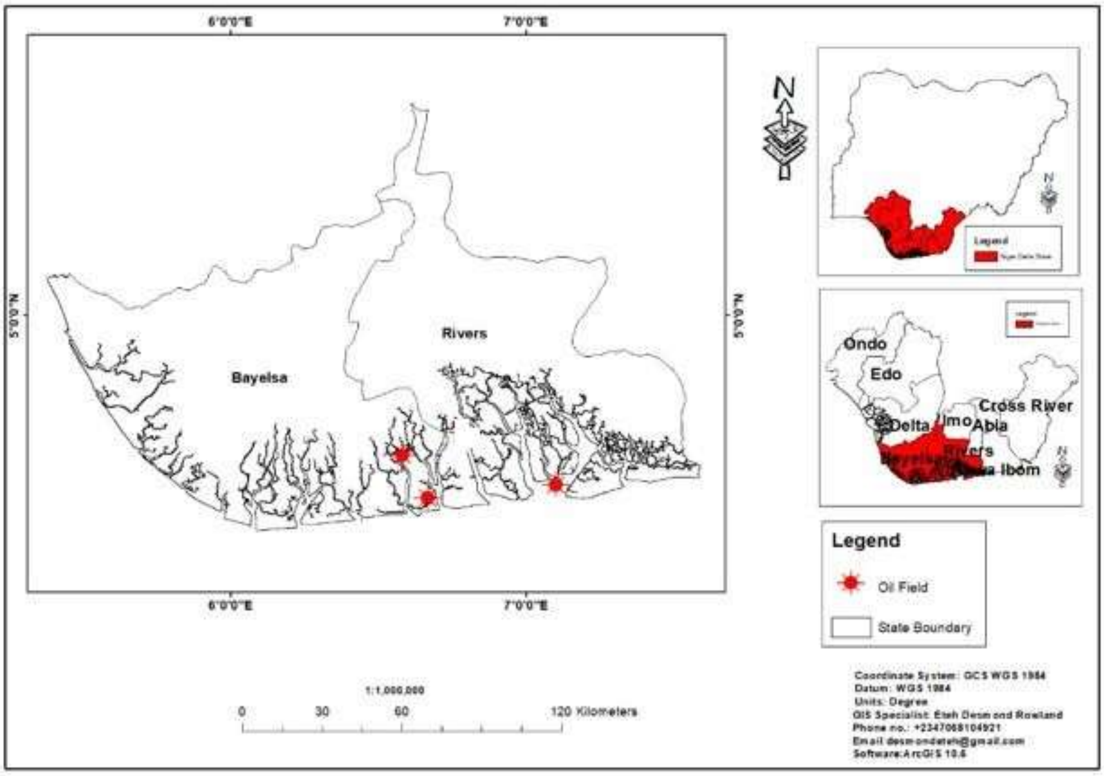

Fig. 1 Map of study area

(ii) Study design

Log data from three wells (F1, F2, F3)in Field “X” in the Eastern Niger Delta Basin was used for this study. Logs used include Gamma-ray, Resistivity, Neutron and Density.Log information were provided for depths of 5800ft to 7400ft for F1, 5800ft to 7400ft for F2 and 5800ft to 7000ft for F3, as such, F1 and F2 had similar depths, both deeper than F3. Schlumberger’s Petrel 2014 version interpretation software was used to load, QC and analyze data. Lithologic discrimination was done using Gamma-ray and Neutron logs, water and hydrocarbon saturation was done using Resistivity log and reservoir porosity was determined using Density log.

III. Results and Discussion

(i) Lithofacies analysis

Lithology identification was achieved with the aid of the gamma ray log. The sand baseline and the shale baseline were determined for each of the wells. The sand baseline was selected as the highest mode GR occurrence at the lower spectrum while the shale baseline was selected as the highest mode GR occurrence at the higher spectrum. The sand/shale cutoff was selected as the mid-point between the sand baseline and the shale baseline for each well. Gamma ray values which deflect to the left of the established cutoff indicated clean sand while deflections to the right of the cutoff indicated shales. On this basis, lithology was identified across all the wells. The lithology identification was supported by the behavior of the neutron-density crossing. The neutron and density logs either overlap or cross in sandy intervals while in shales, there is a wide separation between these two logs. The larger the crossing between the neutron and density logs, the better the quality of the sand. After defining the lithologies based on color codes (yellow for sand, black for shale), the gamma ray motif was then used for correlation based on recognizable trends.

The results for the lithologies and correlation across all 3 wells is presented in Fig 2. Gamma ray logs revealed two lithologies of sand and shale from top to bottom in the three wells (Wells 1-3 represented in the Table 1 as F1-3). A total of three reservoirs (A, B and C) were identified and correlated across to other wells (Fig. 2). The reservoirs are bounded by layers of shales which serve as both seals and source rocks.Tables 1-3 show the results of petrophysical properties estimated for reservoir sands identified across the field using Petrel.

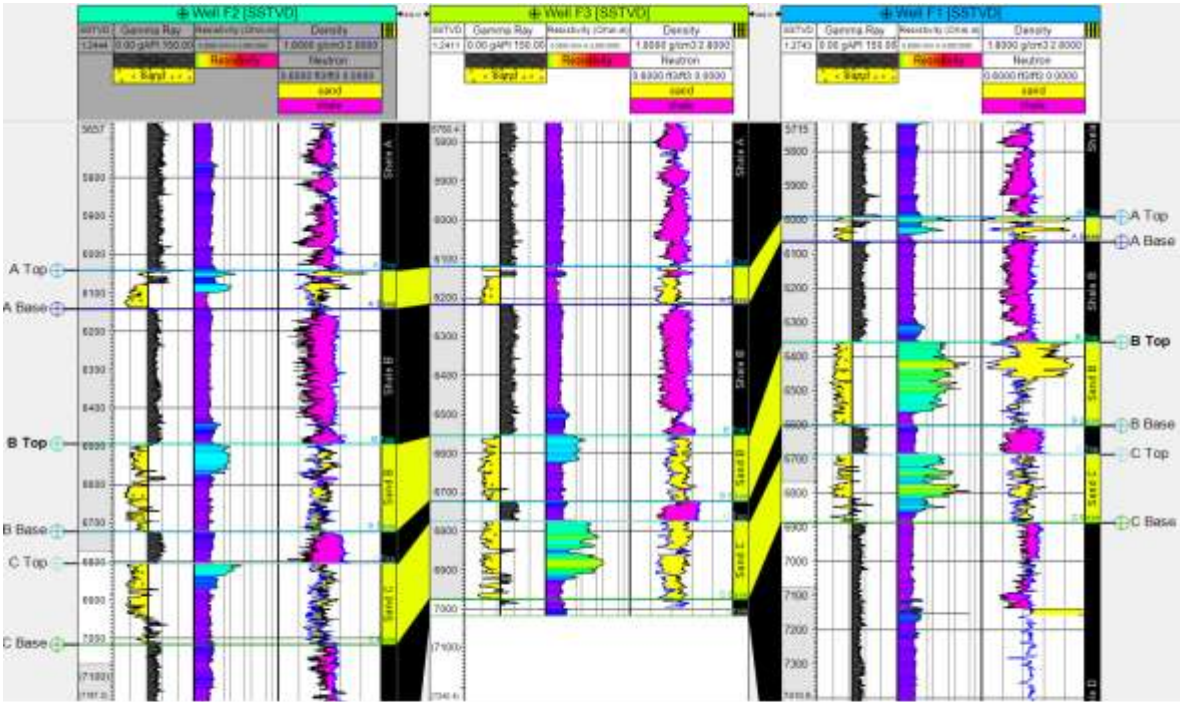

Fig.2 Sand and shale lithologies identified and correlated across the field.

(ii) Gross thickness

The gross thickness of a reservoir is the entire thickness from the top to the base of the reservoir. The thickness of the reservoirs varies from one well to the other across the field. The thickness of reservoir A is 68 ft in W1 well, 105 ft in W2, and 101 ft in W3 (Tables 1 to 3). Reservoir B has a thickness of 240 ft in W1 well, 225 ft in W2, and 179 ft in W3 well. Similarly, Reservoir C had varying thicknesses across all three wells. The thickness of reservoir C is 211ft in W1 well, 213 ft in W2 and 196ft in W3 well. On average, gross thickness of reservoir A is 91.33ft, 214.66ft for reservoir B and 206.66ft for reservoir C, respectively. The average gross thickness of the reservoirs show that reservoir B has the highest thickness while reservoir A has the lowest thickness. These results show that the reservoir sands are of sufficient thickness to hold hydrocarbons in economic quantities.

Table 1: Results of petrophysical evaluation for Sand A reservoir correlated across all 3 wells

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale thickness (ft)	Net thickness (ft)	NTG	Total porosity	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Saturation	Permeability (mD)	Fluid Type	Fluid Contact (ft)	Pay Thickness (ft)
F1	6070-6138	68	0.22	14.96	53.04	0.78	0.32	0.26	0.00035	0.00054	0.50	3014	Gas/Oil/Water	GOC=6114ft	44.00
														OWC=6123ft	9.00
F2	6730-6840	105	0.21	22.05	82.95	0.71	0.30	0.24	0.00037	0.00044	0.42	2313	Gas/Oil/Water	GOC=6775ft	45.00
														OWC=6798ft	23.00
F3	6959-7060	101	0.15	15.15	85.85	0.85	0.35	0.27	0.00042	0.00062	1.00	2289	Water	WUT	
Avg.		91.33	0.19	17.38	45.33	0.78	0.32	0.25	0.00038	0.00053	1.64	2538.6			94.50

Table 2: Results of petrophysical evaluation for Sand B reservoir correlated across all 3 wells

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale thickness (ft)	Net thickness (ft)	NTG	Total porosity	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Saturation	Permeability (mD)	Fluid Type	Fluid Contact (MDft)	Pay Thickness (ft)
F1	6430-6670	240	0.07	16.8	232.42	0.96	0.30	0.20	0.00032	0.000409	0.28	3222	Gas/Oil/Water	GOC=6537 ft	107.00
														OWC=6639ft	102.00
F2	7225-7450	225	0.03	6.75	214.49	0.91	0.37	0.3	0.00054	0.000442	0.68	2354	Oil/Water	OWC=7312ft	87.00
F3	7408-7587	179	0.08	14.32	165.06	0.94	0.29	0.26	0.00044	0.000522	0.70	2198	Oil/Water	OWC=7486ft	78.00
Avg.		214.66	0.06	12.623	203.99	2.81	0.32	0.25	0.0005	0.000457	0.55	2591.33			124.67

Table 3: Results of petrophysical evaluation for Sand C reservoir correlated across all 3 wells

Wells	Reservoir Interval (MDft)	Gross thickness (ft)	Shale volume	Shale thickness (ft)	Net thicknes s (ft)	NTG	Total porosit y	Effective Porosity	Formation Factor	Irr. Water Saturation	Water Satura tion	Permeabilit y (mD)	Fluid Type	Fluid Contact (ft)	Pay Thickness (ft)
F1	6759-6960	211	0.18	37.98	163.18	0.82	0.31	0.26	0.00052	0.00035	0.30	2247	Oil Water	OWC=6920ft	161.00
F2	7557-7770	213	0.19	40.47	181.44	0.81	0.29	0.24	0.00058	0.00047	0.72	2045	Oil Water	OWC=7585ft	28.00
F3	7636-7832	196	0.15	29.40	175.95	0.85	0.30	0.26	0.00033	0.00049	0.24	2343	Oil Water	OWC=7781ft	145.00
Avg		206.66	0.17	35.95	173.52	0.82	0.3	0.25	0.00047	0.00043	0.42	2211.66			111.33

GDT – Gas Down To; WUT – Water Up To; OWC – Oil Water Contact; GOC – Gas Oil Co

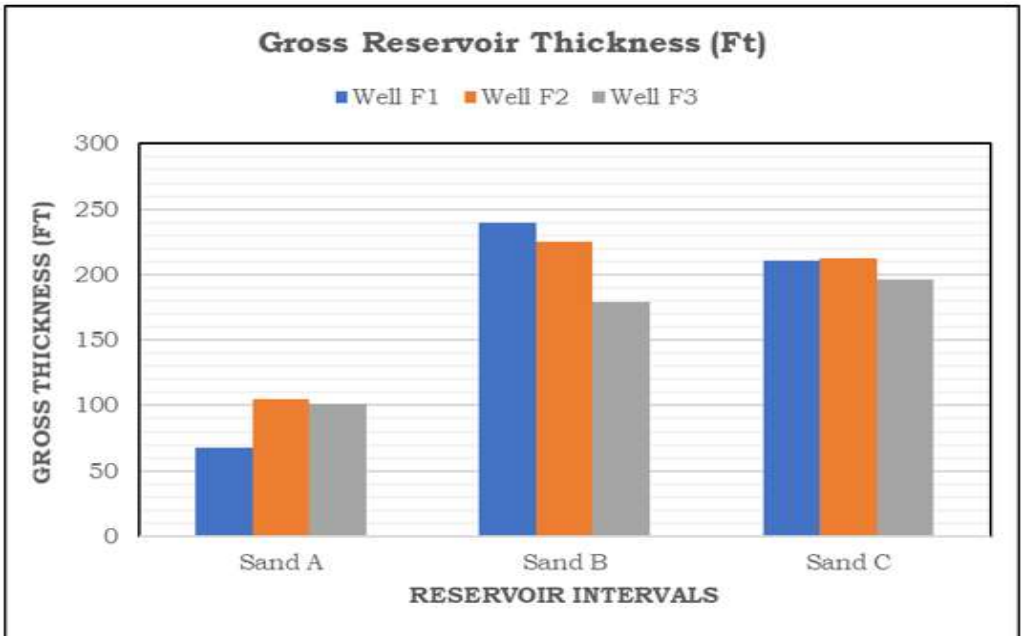

Fig. 3: Average gross thickness for three reservoir intervals in wells W1-3

(iii) Shale volume (Vsh)

Shale volume is the amount of shale contained within the reservoir. The higher the shale content the poorer the reservoir quality to yield hydrocarbons. This is because shale acts as a barrier to hydrocarbon flow. In Reservoir A shale volume is 0.22 in W1, 0.21 in W2 and 0.15 in W3 well. In reservoir B, shale volume is 0.07, 0.03, and 0.08 in wells W1, W2 and W3,respectively. Meanwhile shale volume in reservoir C is 0.18 in W1 well, 0.19 in W2 well and 0.15 in W3 well, which translates to a shale thickness inReservoir A of 14.96 ft, 22.05 ft and 15.15 ft in wells W1, W2, and W3, Reservoir B wells 1, 2 & 3 had shale thicknesses of 16.8 ft, 6.75ft, 40.47ft and Reservoir C had shale thicknesses of 37.98 ft, 40.47 ft and 29.40 ft in W1, W2 and W3, respectively. On average, shale volume thickness is 17.38 ft in Reservoir A, 12.62 ft in Reservoir B and 35.95 ft in Reservoir C.

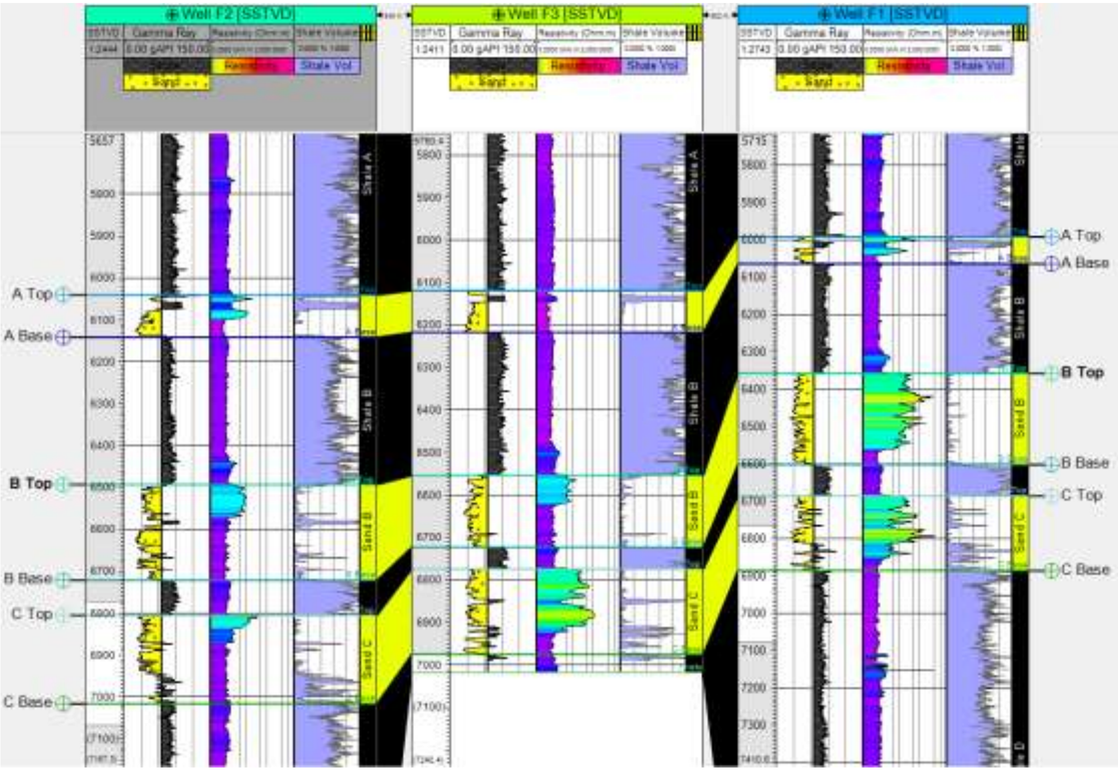

Fig. 4: Shale volume calculated for three reservoir intervals and correlated across all three wells

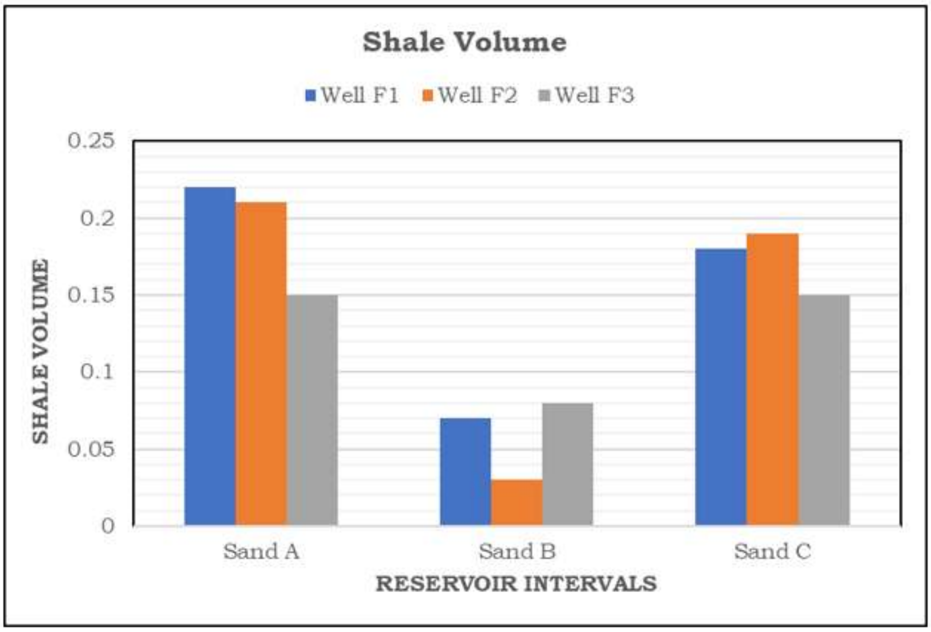

Fig. 5: Average gross thickness for three-reservoir intervals in wells W1-3

(iv) Net thickness

The reservoir Net Thickness is the proportion of the clean sand in the reservoir. It is obtained after the Shale volume is removed from the Gross thickness of the reservoir. The Net Thickness for Reservoir A in wells W1, 2 and 3 are 53.04 ft, 82.95 ft and 85.85 ft, respectively. Reservoir B has Net thicknesses of 232.42 ft, 214.49 ft and 165.06 ft for wells W1, 2 and 3. Reservoir C has a Net thickness of 163.18 ft for well W1, 181. 44 ft for well W2 and 175.95 ft for well W3. The average Net thickness for Reservoir A, B and C are 45.33 ft, 203.99 ftand 173.52 ft.

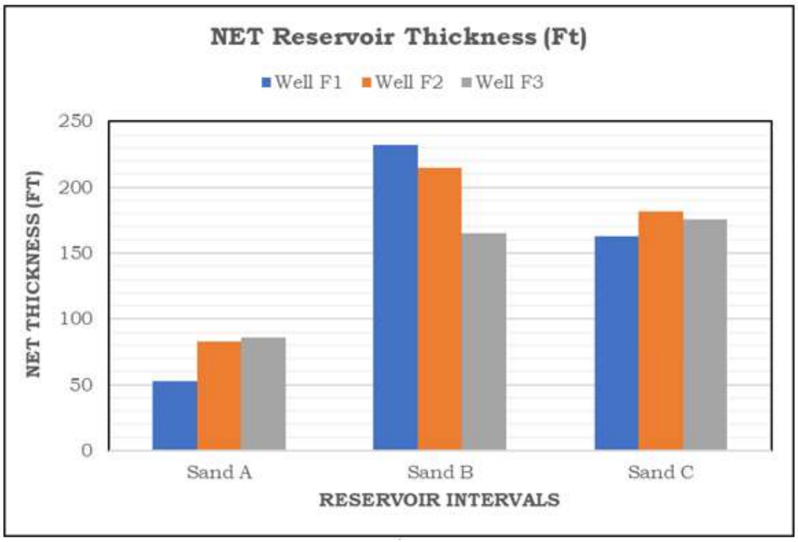

Fig. 6: Average Net Reservoir thickness for three reservoir intervals in wells W1-3

(v) Net to Gross

The Net to Gross is the thickness of the clean sand (net sand thickness) divided by the total gross thickness of the reservoir. The Net to Gross gives an indication of the total amount of the reservoir section that can produce fluids. The larger the Net to Gross value (in percentage), the better the quality of the reservoir. For Reservoir A, Net to Gross ratio is 0.78% in W1, 0.71 % in W2 and 0.85 % in W3 well. For Reservoir B, the value of Net to Gross is 0.96 %, 0.91 % and 0.94 % in wells W1, W2 and W3,respectively. Similarly, for Reservoir C, the net to gross has values of 0.82% in W1, 0.81 % in W2 and 0.85 % in W3 well. The average net to gross ratio for reservoir A, B and C are 0.78 %, 2.18 % and 0.82 % respectively.

(vi) Porosity

Total porosity is the sum total of both the interconnected pores and the isolated pores. The Effective porosity is the sum of all the interconnected pore throats, it is the porosity relevant in hydrocarbon production. The estimated Total and Effective Porosities are 0.32 %, 0.30 %, 0.35 % and 0.26 %, 0.24 %, 0.27% in W1, W2 and W3 wells, respectively for Reservoir A. For Reservoir B, Total and Effective Porosities are 0.30 % and 0.20 % for well W1, 0.37 % and 0.30 % for W2, 0.29 % and 0.26 % for well W3. Similarly, for Reservoir C, Total Porosity is 0.31 %, 0.29% and 0.30% while Effective Porosity is 0.26 %, 0.24 % and 0.26 % for wells W1, W2 and W3, respectively. The average Total and Effective porosities for Reservoir A are 0.32 % and 0.25 %. 0.32 % and 0.25 % for Reservoir B and 0.30 % and 0.25 % for Reservoir C, respectively. Reservoir classification based on porosity according to [23] placesporosity measurements less than 5 % as negligible, between 5-10 % as poor, 11 - 20% as good, 20- 30% as very-good and more than 30 as excellent. Based on this classification scheme, the Total and Effective porosity recorded from Reservoirs A, B and C not sufficient for good reservoirs.

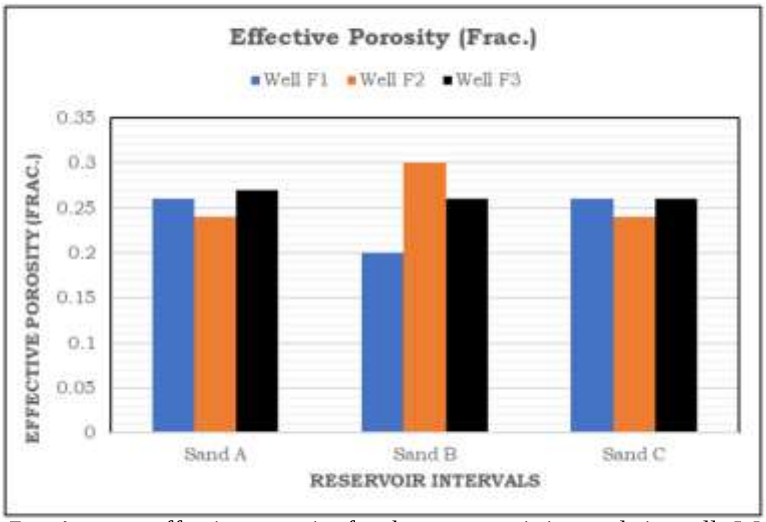

Fig. 7: Average effective porosity for three reservoir intervals in wells W1-3

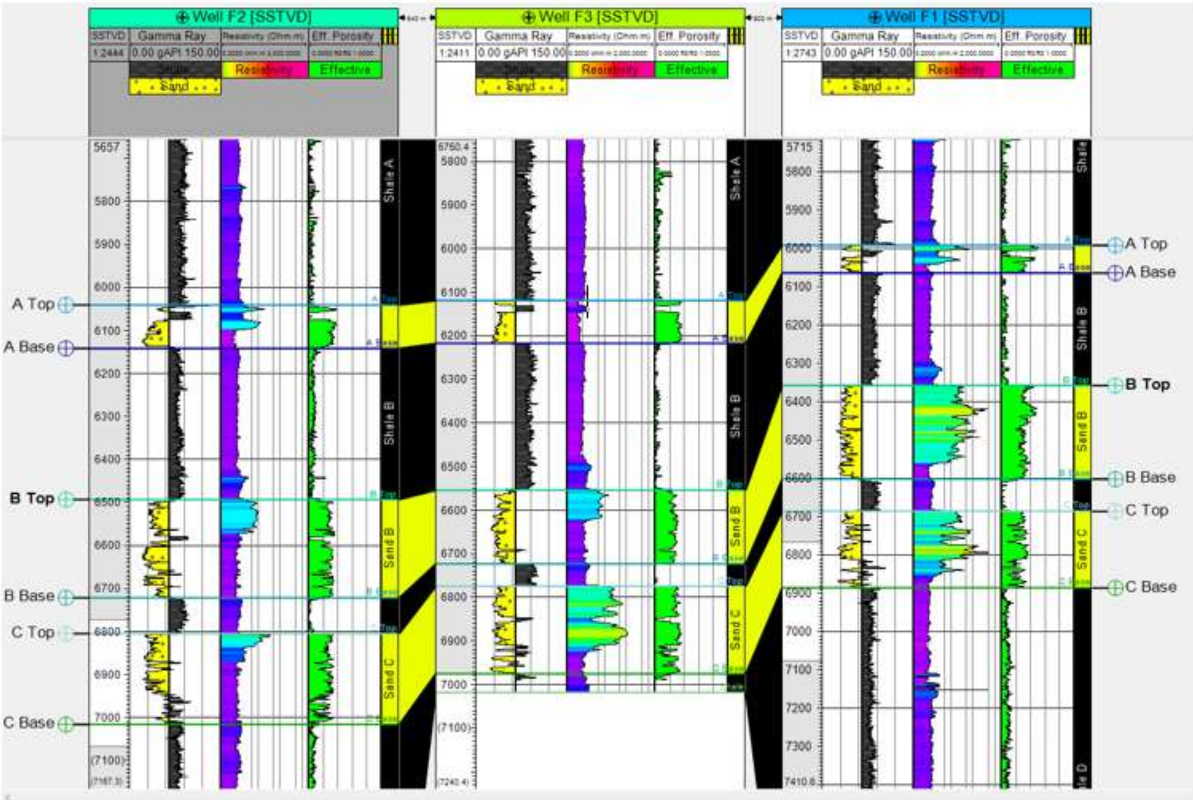

Fig. 8: Effective Porosity calculated for three reservoir intervals in wells W1-3

(vii) Fluid type

In a reservoir rock, three types of fluids are commonly found in the pores. The fluids can either be gas, oil, water (fresh or brine) or a combination of two or the entire three fluid phases. The resistivity log was used to determine the presence of oil and water in the reservoirs because oil is much more resistive, and water is less resistive. Hence a sharp increase in the resistivity log measurement indicated the presence of an oil–water contact in the reservoir. Density and neutron is also used to determine gas, oil and water. A decrease in density and an increase neutron contrast is an indication of a gas zone while a decrease in neutron and a small increase in density record indicate oil or water bearing zone.In this study, Reservoir A is gas, oil and water bearing in wells W1, W2 and oil and water bearing in well W3. Reservoir B is gas, oil and water bearing in W1, oil and water bearing in W2 and W3 well. Meanwhile, in Reservoir C, wells W1, W2 and W3 are oil and water bearing. These results show that all the reservoir intervals are hydrocarbon bearing.

(viii) Water Saturation

The WaterSaturation in the reservoirs were determined using the Archie's equation. Water Saturation calculated for Reservoir A is 0.50 % in W1 well, 0.42 % in W2 and 1.0% in W3 well. For Reservoir B, Water Saturation is 0.28 % in W1, 0.68% in W2 and 0.55 % in W3 well. While in Reservoir C, Water Saturation values are 0.3 %, 0.72 % and 0.24 % in wells W1, W2 and W3,respectively. Average Water Saturation in Reservoir A, B and C is 1.64 %, 0.55 % and 0.42 %, respectively. These results show that Reservoir A has the highest Water Saturation while Reservoir C has the least Water Saturation.

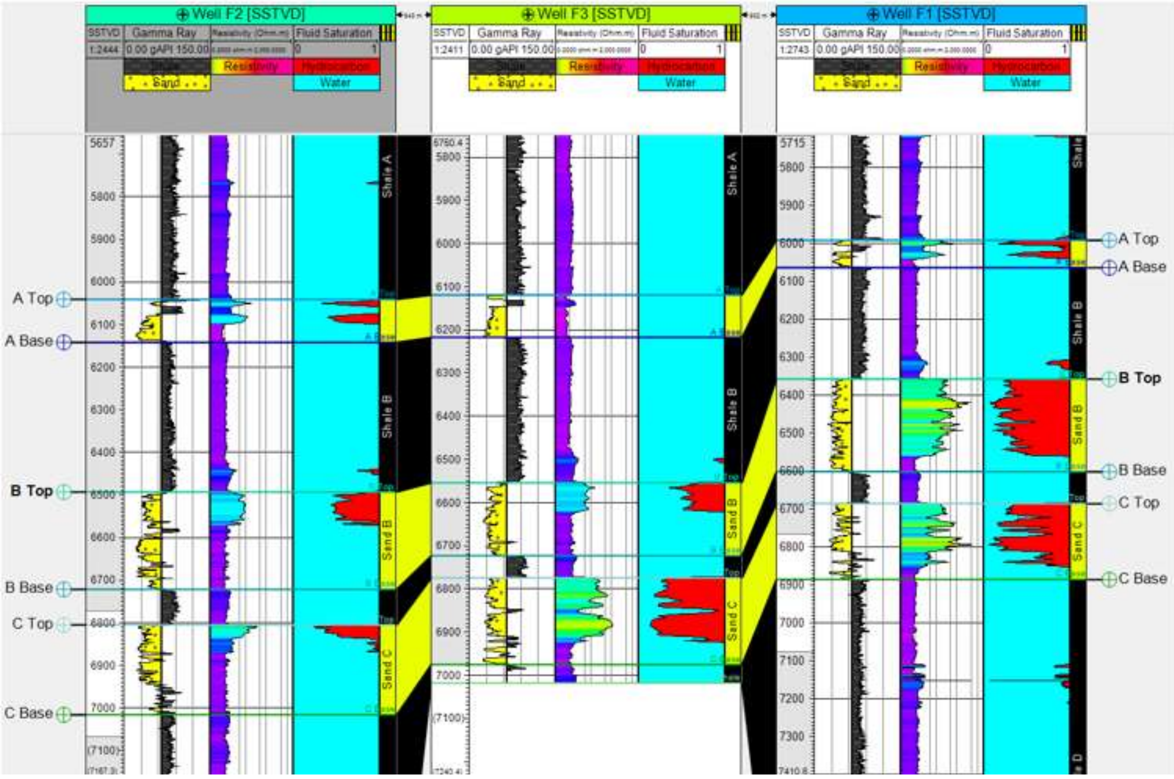
Fig. 9: Fluid saturation (Water and oil) calculated for three reservoir intervals in wells W1-3

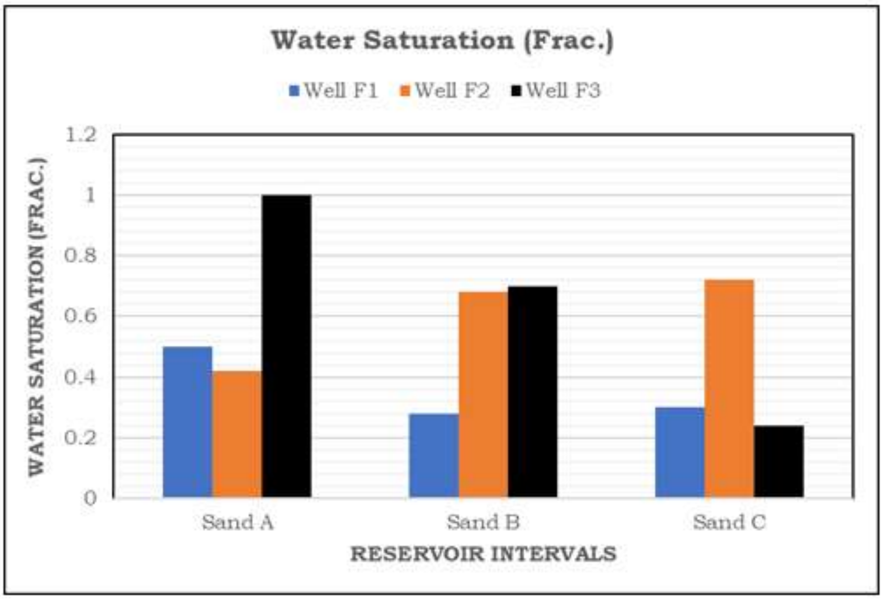

Fig. 10: Water Saturation calculated for three reservoir intervals in wells W1-3

(ix) Permeability

Permeability is the ability of fluids to flow through a reservoir rock. Results show the Permeability for Reservoir A is 3014 mD in W1 well, 2313 mD in W2 and 2289 mD in W3 well. For Reservoir B, permeability is 3222 mD, 2354mD and 2198 mD in W1, W2 and W3 wells, respectively. Meanwhile for Reservoir C, permeability values are 2247 mD, 2045 mD and 2343mD in wells W1-3 respectively. On average, permeability values are 2538.6 mD, 2591.33 mD, and 2211.66mD in Reservoirs A, B, and C, respectively.

[23] classification of reservoir quality based on permeability values are as follows; < 10mD (poor to fair), >10-50 mD (moderate), >50-250 mD (Good), >250-1000 mD (very good) and >1000 mD (excellent). Based on this classification scheme, Reservoir's A, B and C can be classed as excellent reservoirs, as such, they are capable to allow flow of hydrocarbon to wells in economic quantities.

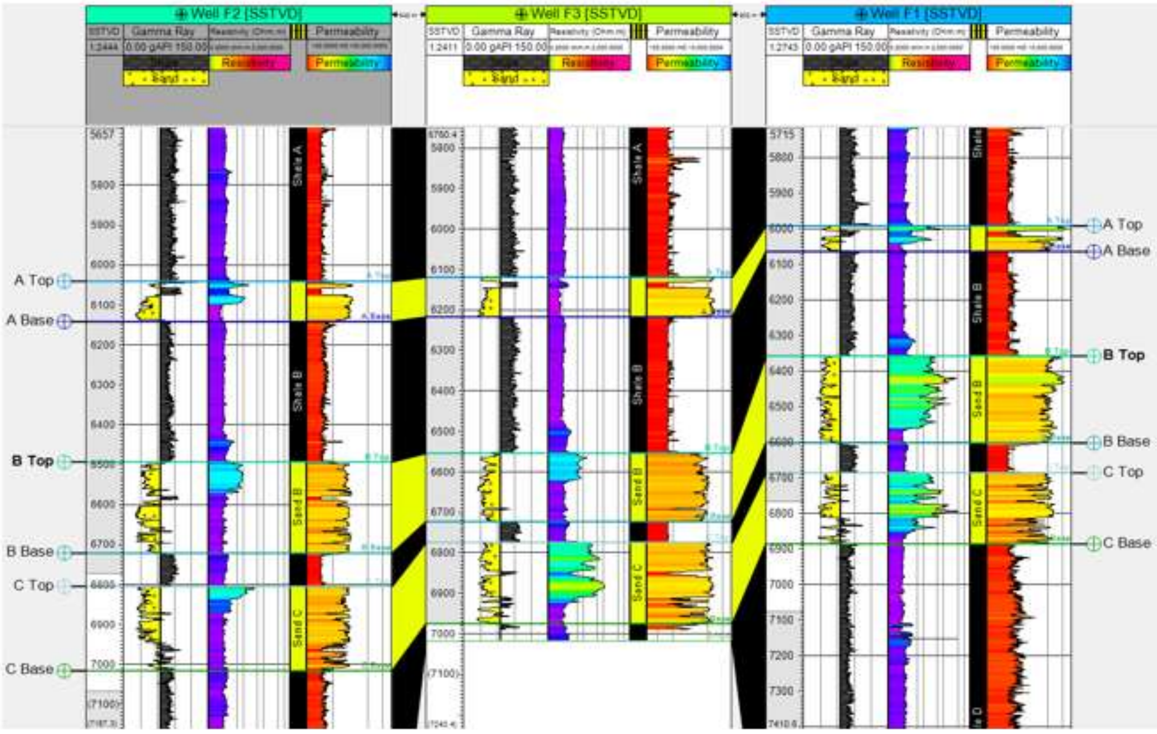

Fig. 11: Permeability calculated for three reservoir intervals in wells W1-3

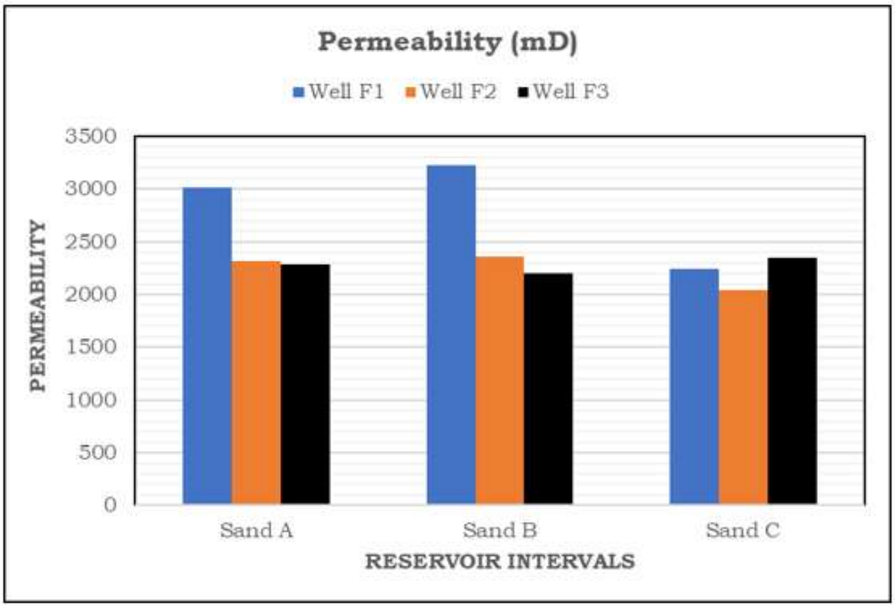

Fig. 12: Permeability calculated for three reservoir intervals in wells W1-3

IV. Conclusions

In this study, the petrophysical characteristics of three reservoir sands (A, B, and C) were analyzed using well logs obtained from three hydrocarbonwells (W1, W2, and W3) in X-field in the Eastern Niger Delta Basin. Consequently, the following conclusions have been drawn.

Results from Gamma ray logsand Neutron logs showed a good correlation of lithologies in the three wells. This demonstrates accuracy and applicability of the plots in delineating lithology from well logs.

For the three reservoir sands (A, B, and C) identified, B is most proficient to yield high amounts of hydrocarbon because of its low Shale volume and consequent high Net thickness. However, reservoir classification based on porosity according to [23] places the Total and Effective porosity recorded from A, B and C not sufficient for good reservoirs.

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