IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG)
e-ISSN: 2321–0990, p-ISSN: 2321–0982.Volume 9, Issue 5 Ser. I (Sep. – Oct. 2021), PP 55-61
www.iosrjournals.org

Petrophysical Evaluation of Reservoirs of the X-Field, offshore, Niger Delta, Nigeria

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Abstract
Understanding reservoir quality is very fundamental in the development of an oil and gas field. This study was aimed at evaluating the distribution of petrophysical properties across the X-field. Wireline log for four wells were critically investigated and five reservoir sand units were defined. Computations were made for parameters such as volume of shale, water saturation, hydrocarbon saturation, density porosity and permeability using exiting principles and equations. Results revealed that most of the reservoir units had volume of shale values not significant enough to hinder primary recovery of hydrocarbon except for RES 05 in well 01, and RES 01, RES 02, and RES05 in well 02 which exhibit a volume of shale higher than 0.55.Water saturation values discloses that RES 01 and RES 03 in well 01, and RES 03 in well 05 are areas of interest because they exhibit a high hydrocarbon saturation. Majority of the reservoirs displays a good to excellent porosity values except for well RES 05 in well 03 which is negligible. Likewise, permeability values ranging from 2.36 -735.79mD. The reservoirs were seen to thin out in a basin ward direction which needs to be considered in making field decisions.

Keyword *Lithofacies, Shaliness, Basinward*

Date of Submission: 30-09-2021 Date of Acceptance: 14-10-2021

I. Introduction

Reservoir management plays a key role in optimizing hydrocarbon recovery. To understand the characteristics of hydrocarbon reservoirs, it is essential to build good reservoir models. These models help to enhance hydrocarbon recovery by aiding volumetric calculations and providing an understanding of the reservoir architecture and heterogeneity which is a major factor controlling fluid flow (Jackson, 2011). It encompasses a wide range of activities which includes contouring reservoir characteristics manually, to the development of computer-based 3D models which are usually made of numerous grid cells, and incorporate well log, analogue and seismic data (Hurst *et al*., 2000).

Accuracy of reservoir models are guided by the level of geologic complexities the model can capture. Reservoir modelling entails the distribution of reservoir properties such as volume of shale, porosity, permeability, and water saturation, guided by statistic or geologic principles. (Jensen *et al*, 2000).

The aim of this study is to evaluate the distribution of petrophysical properties of reservoirs of the X-field. The objective of this work is to define the net to gross thickness of the reservoir units, estimate porosity for each reservoir across wells, estimate permeability of each reservoir across well, estimate water saturation, and predict reservoir performance.

II. Study Area Location and Geology

The area of study, X-field, is located 120km southeast of the Niger Delta Basin, and extends to about 60km^2 (Figure 1). It is owned by Shell Nigeria Exploration and Production Company. The Niger Delta Basin lies on the Gulf of Guinea and is between longitudes 3^0E and 9^0E and latitudes 4^0N and 7^0N (Whiteman, 1982). In accordance with the oil and gas industry confidentiality policy, the detailed location of the field was not disclosed.

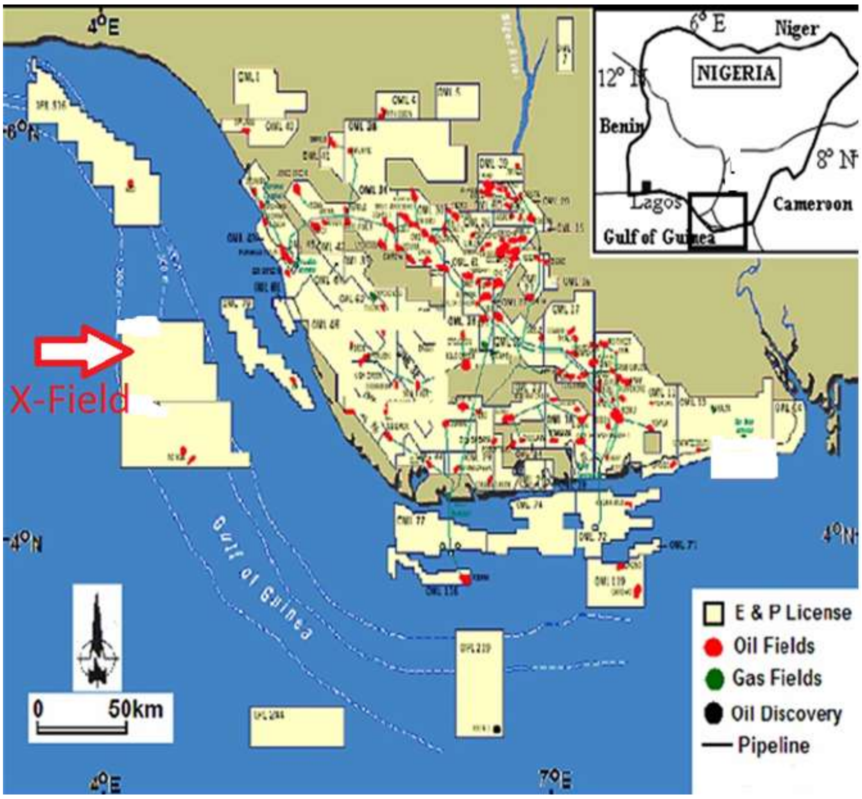

Figure 1: Map of the Niger Delta showing the location of the study area (adapted from Nton & Esan, 2010)

The stratigraphy of the Tertiary Niger Delta is characterized of the Akata Formation, the Agbada Formation, and the Benin Formation in an ascending manner (Figure 2). At the approximate depocentre of the central part of the Niger Delta Basin, these formations are estimated to be about 28,000ft thick (Avbovbo, 1978).

The Akata Formation is overlain by the Agbada Formation and is characterized by an even shale development. According to Short & Stauble (1967), these shales which are medium to dark grey, variably medium hard or soft, and partly sandy or silty are undercompacted and are likely to encompass lenses of unusually high-pressured siltstone or fine-grained sandstone.

The Agbada Formation is underlain and overlain by both the Akata Formation and the Benin Formation respectively, it is characterized by an alternation of sandstone and shale beds which were suggested by Avbovbo (1978) to be of the delta front, distributary channel and deltaic plain origin.

The Benin Formation is the topmost and is underlain by the Agbada Formation and is of a non-marine origin. It is characterized mainly by massive freshwater bearing sandstone exhibiting high porosity, and local tinny shale interbeds which are believed to be of a braided river origin. These sandstones are dominantly composed of quartz, potash feldspar and negligible quantity of plagioclase, and could signify point-bar deposits, channel fill, and natural levee while the shales may signify back swamp deposits and oxbow fills (Avbovbo, 1978; Short & Stauble, 1967).

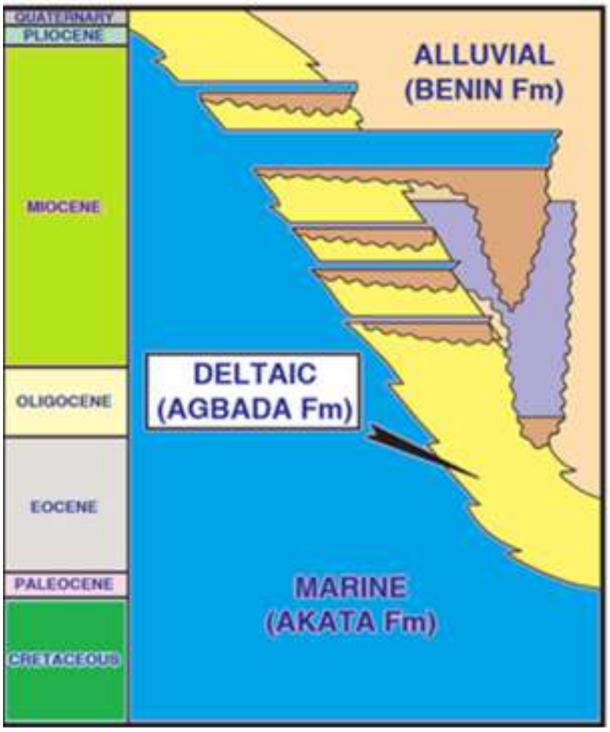

Figure 2: Illustration of the Niger Delta stratigraphy showing the three formations and their geologic ages (adapted from Short & Stauble, 1967).

III. Methodology

Wireline log datafor four wells was used for this study. Following a critical analysis of the log data, genetic units were identified within the various wells, and potential reservoir tops and reservoir bottoms were identified and correlated across the wells. (Figure 3) Petrophysical parameters such as gamma ray index, volume of shale, density porosity, water saturation, net-to-gross thickness, effective porosity, irreversible water saturation, and permeability for the various reservoir sections were determined by reading values directly from the logs, and computations made with existing principles and equations.

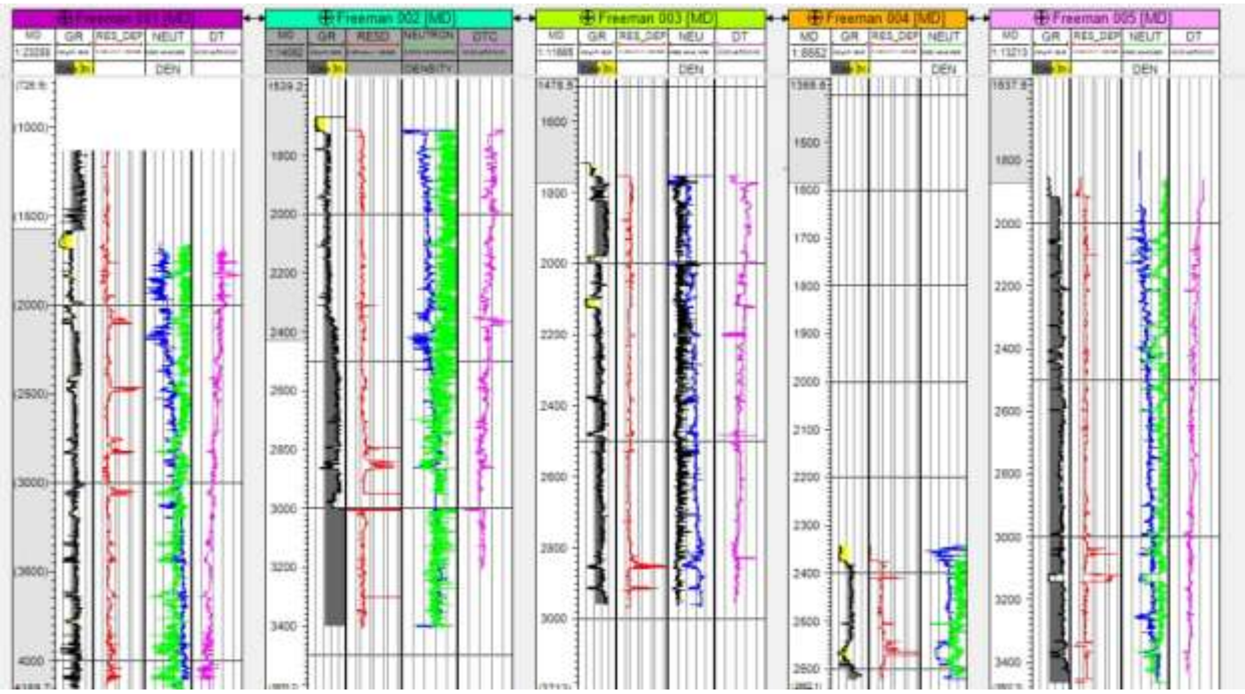

Figure 3: Well log data for wells of the X-field

Using the equation 1 and 2 as defined by Larionov 1969, the Gamma ray index (IGR) was first calculated and then inputted to determine the volume of shale (V_{sh}). This method gives an estimate of the degree of shaliness of the reservoir units.

Gamma Ray Index (IGR) = GR_{log}-GR_{min}/GR_{max}-GR_{min} Equation 1

Volume of Shale (V_{sh}) = $0.083[2^{3.7IGR} - 1]$ Equation 2

Where,

GRlog = Gamma ray of the zone of interest

GRmin = Least Gamma ray in formation of interest

GRmax = Maximum gamma ray reading in formation of interest

IGR = Gamma Ray Index

V_{sh} = Volume of shale

Density porosity was calculated for various units with the use of bulk density readings from the log. This was achieved using equation 3 as defined by Rider 1986.

Ǿdensity = ρma – ρb/ ρma-ρf Equation 3

Where,

Ǿd = Density porosity

ρb = Bulk density

ρma = Matrix (grain) density

ρf= Fluid density

Asquith and Gibson 1982 explain that for electrode tools such as Dual Laterolog it is essential to utilize a salt-based drilling mud to derive exact true resistivity (Rt) while for Dual Induction tools fresh water saturated mud is required. Hence, the matrix (grain) density (ρma) was presumed as that of sand (2.65 g/cm3), while the fluid density (ρf) was presumed to be that of fresh water-based mud (1.0 g/cm3). The water saturation and hydrocarbon saturation for the various reservoir unit was determined using equation 4 and 5 after Archie 1942.

$(S_w)^n = R_o / R_t$ Equation 4

Where n = 2

Formation Factor (F) = a/$Ǿ^{m}$

Where a = 0.62, m = 2.15

Hydrocarbon saturation for the reservoir units were estimated from the water saturation values using equation 5

$S_w + S_h = 1$ Equation 5

Reservoir net-to-gross was calculated using equation 6 where the gross thickness is the difference between the base of reservoir and top of reservoir while net thickness is the difference between the gross thickness and the non-reservoir thickness.

Net-to-Gross = Net thickness/ Gross thicknessEquation 6

Permeability was calculated using equations 9 and10 following the general expression by Willey and Rose 1950.To determine permeability(K) of the reservoir units, it was necessary to derive the effective porosity ($Ǿ_{eff}$) and irreversible water saturation (S_{wirr}) for these formations. This was achieved with equation 7 and equation 8 after Asquith and Krygowski 2004.

$Ǿ_{eff}$ = Ǿ(1-Vsh) Equation 7

S_{wirr} = Ǿ x Sw/$Ǿ_{eff}$Equation 8

Permeability (K) = $(93 \text{ x } Ǿ^{2.2}/S_{wirr})^2$ for oilEquation 9

Permeability(K) = $(79 \text{ x } Ǿ^{2.2}/S_{wirr})^2$for gas Equation 10

IV. Results and Discussion

Wireline log data for 4 wells of the X-field located offshore the Niger Delta area of Nigeria was used for this study. A combined investigation on the gamma ray, resistivity, and neutron density logs led to the definition of five reservoir sands, RES 01, RES 02, RES 03, RES 04, and RES 05 (Figure 4).

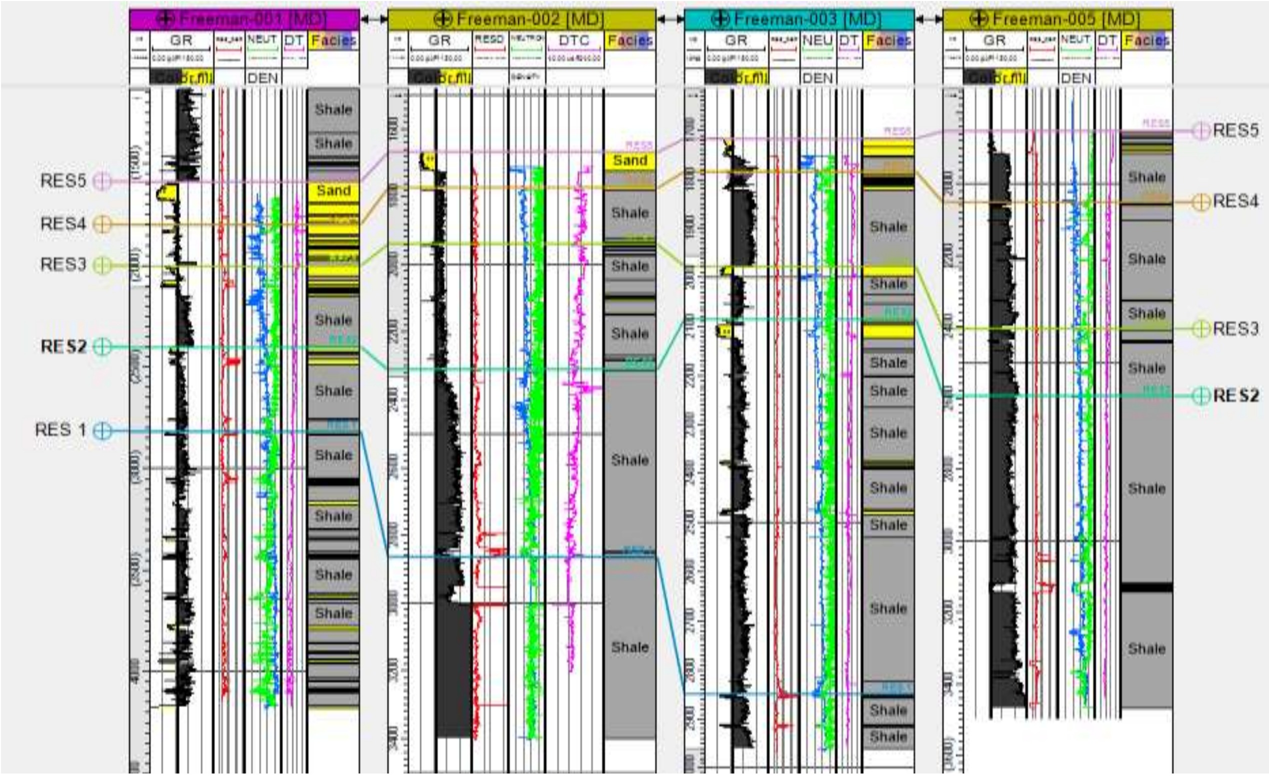

Figure 4: Well log correlation showing the different reservoir tops and genetic units

In each well, parameters such as the gamma ray index, volume of shale, water saturation, density porosity, effective porosity, irreversible water saturation, and permeability were calculated for each of these reservoir units present.
Results for the petrophysical analysis for the various well is displayed in Table1, 2, 3, and 4. In well 01, well 02, and well 03 five reservoir units were identified, while only two of these reservoir units were seen in well 05.

Well 01

This well displayed a net-to-gross ranging from 0.61-0.94, net pay sand values (13-165m) high enough to support production. The volume of shale which ranges from 0.2002- 0.7133 is not significant enough to hinder production. Density porosity which ranges from 24- 38% indicates very good porosity for production. Two hydrocarbon bearing reservoirs were found. They are RES 01 and RES 03. A gas-water contact was found between 2497m – 2820 while an oil-water contact was seen at 2154-2391m.

Table 1: Petrophysical properties of reservoirs in well 01

Well 01	Depth(m)	Gamma Ray Index (IGR)	(Volume of Shale (Vsh)	Gross Sand(m)	Net sand(m)	Net- to Gross (NTG	Density Porosity	Effective Porosity (Øeff)	Water Saturation	Hydrocarbon Saturation	Formation Factor(F)	Irreversible Water Saturation(Swirr)	Permeability K(mD)	Remark
RES 01	2820-2834	0.6680	0.3795	14	13	0.93	0.24	0.1489	0.13	0.87	14.33	0.2095	27.1	Gas
RES 02	2391-2497	0.4773	0.2002	106	70	0.66	0.27	0.2159	0.99	0.01	10.35	1.238	15.79	Water
RES 03	2000-2154	0.7069	0.4282	154	94	0.61	0.28	0.1601	0.23	0.77	9.57	1.3466	16.609	Oil
RES 04	1789-1981	0.8431	0.6426	192	165	0.859	0.25	0.089	0.65	0.35	12.21	0.9831	15.78	Water
RES 05	1580-1696	0.8793	0.7133	116	109	0.94	0.38	0.1089	0.65	0.35	4.96	1.221	126.22	Water

Well 02

This well exhibited a net-to-gross ranging from 0.71-1.0, net pay sand (4-57m) displays values high enough to support production. The volume of shale for RES 04 and RES 03which are 0.5304 and 0.5942 are not significant enough to hinder production. However, RES01, RES 02, and RES 05 exhibit high volume of shale values that could hinder production. Density porosity which ranges from 23- 30% indicates very good porosity for production. Two hydrocarbon bearing reservoirs were found. They are RES 01 and RES 03 at depths ranging from 2668m-2725m and 1932m-1946m. A gas-water contact was found between RES 01 and RES 02, and an oil-water contact between RES 02 and RES 03.

Table 2: Petrophysical properties of reservoirsin well 02

Well 02	Depth(m)	Gamma Ray Index (IGR)	(Volume of Shale (Vsh)	Gross Sand(m)	Net sand(m)	Net- to Gross (NTG	Density Porosity	Effective Porosity (Øeff)	Water Saturation	Hydrocarbon Saturation	Formation Factor(F)	Irreversible Water Saturation(Swirr)	Permeability K(mD)	Remark
RES 01	2668 - 2725	0.9091	0.7768	57	57	1.0	0.28	0.062	0.58	0.42	9.57	2.619	4.39	Water
RES 02	2308 - 2312	0.9333	0.8320	4	4	1.0	0.30	0.050	--	--	8.25	---	------	Water
RES 03	1932 - 1946	0.7778	0.5304	14	10	0.71	0.24	0.1127	0.64	0.36	13.33	1.3629	6.430	Water
RES 04	--	0.8163	0.5942	--	--	--	0.24	0.097	0.91	0.09	13.33	2.256	2.356	Water
RES 05	1668 - 1725	0.9545	0.8832	57	57	1.0	0.23	0.027	--	--	14.61	----	----	Water

Well 03

This well display a net-to-gross ranging from 0.49-0.89, net pay sand (7-37m) displays values high enough to support production. The volume of shale which ranges from 0.2750 to 0.5580, is not significant enough to hinder production. Density porosity ranging 32-53% indicates an excellent porosity for production except for RES 05 which is negligible. All reservoir units were water bearing.

Table 3: Petrophysical Properties of reservoirs in well 03

Well 03	Depth(m)	Gamma Ray Index (IGR)	(Volume of Shale (Vsh)	Gross Sand(m)	Net sand(m)	Net- to Gross (NTG	Density Porosity	Effective Porosity (Øeff)	Water Saturation	Hydrocarbon Saturation	Formation Factor(F)	Irreversible Water Saturation(Swirr)	Permeability K(mD)	Remark
RES 01	2848-2858	0.5690	0.2755	10	7	0.7	0.32	0.2318	--	--	7.18	---	--	Water
RES 02	2083-2123	0.6154	0.3210	40	34	0.85	0.53	0.3531	0.88	0.12	2.43	1.2959	735.79	Water
RES 03	1677-1996	0.7949	0.5580	19	19	1.0	0.42	0.1856	0.92	0.08	4.0	2.0818	79.158	Water
RES 04	1784-1821	0.2973	0.0953	37	18	0.49	0.32	0.2895	--	--	7.78	--	--	Water
RES 05	1717-1754	0.7500	0.4881	37	37	0.89	0.01	0.005	--	--	12370.62	--	--	Water

Well 05

This well exhibited a net-to-gross ranging from 0.84-0.87, net pay sand (41-45m) displays values high enough to support production. The volume of shale ranging from 0.2578 – 0.3400 is not significant enough to hinder production. Density porosity ranges 16-33% indicates a good to excellent porosity for production. One hydrocarbon bearing reservoirs was found, RES 02 at depths ranging from 2541m-2594m. An oil-water contact was found between RES 02 and RES 03

Table 4: Petrophysical properties of reservoirs in well 05

Well 05	Depth(m)	Gamma Ray Index (IGR)	(Volume of Shale (Vsh)	Gross Sand(m)	Net sand(m)	Net- to Gross (NTG	Density Porosity	Effective Porosity (Øeff)	Water Saturation	Hydrocarbon Saturation	Formation Factor(F)	Irreversible Water Saturation(Swirr)	Permeability K(mD)	Remark
RES 02	2541-2594	0.6333	0.3400	53	45	0.84	0.33	0.2178	--	--	6.72	---	---	Water
RES 03	2340-2387	0.5493	0.2578	47	41	0.87	0.16	0.1190	0.16	0.78	31.88	0.215	22.684	Oil

V. Conclusion

Petrophysical evaluation of the X-field was carried out using well log data for four wells. Lithofacies delineated were majorly sand and shale bodies. The sand bodies are the major reservoirs within the field. Five reservoir sections were defined.Net-to-gross values display reservoirs thinning out in a basinward direction from well 01 to well 05. This needs to be considered in making decisions for future well placement and field development.

Most of the reservoir units had volume of shale values not significant enough to hinder primary recovery of hydrocarbon except for RES 05 in well 01, and RES01, RES02, and RES05 in well 02 which exhibit a volume of shale higher than 0.55.

Water saturation values reveals that RES 01 and RES 03 in well 01, RES 03 in well 05 are areas of interest because they exhibit high hydrocarbon saturation.

Majority of the reservoirs displays a good to excellent porosity values except for well RES 05 in well 03 which is negligible. Likewise permeability values range from 2.36 -735.79mD.

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Ikomi, Misan Kelvin, et. al. "Petrophysical Evaluation of Reservoirs of the X-Field, offshore, Niger Delta, Nigeria."*IOSR Journal of Applied Geology and Geophysics (IOSR-JAGG),* 9(5), (2021): pp 55-61.