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Reservoir characterization of an x-field, offshore Niger Delta, Nigeria, using well data

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Petrophysical parameters of an oil field in the Niger Delta, Nigeria, were analyzed and characterized using well log data. The well log data were used to determine the hydrocarbon depth (2757 to 3591 m) and lithology of the field. Shale volume (V_{sh}) was calculated using linear and Larinov equations while the Archile equation was used to determine the water saturation. The study revealed water saturation of 0.035 to 0.426 and good porosity range of 0.105 to 0.152. The bulk volume of water ranged from 0.005 to 0.049 while the bulk volume of hydrocarbon ranged from 0.067 to 0.130. Hydrocarbon saturation of 0.574 to 0.965 was estimated across the reservoirs. The estimated value of moveable hydrocarbon saturation ($S_{hmov.}$) is less than 0.70 and was therefore inferred to be moveable. The well-seismic tie revealed synthetic and antithetic growth faults, roll-over anticlines, back-to-back and collapse crests as the major faults in the area, trending NW-SE. The model horizon obtained for the field shows that the eastern part of the field with maximum contour closures corresponds to the area with maximum hydrocarbon accumulation.

Key words: Petrophysical properties, characterization, hydrocarbon saturation, moveable hydrocarbon, shale volume, lithology, hydrocarbon potential.

INTRODUCTION

As the energy demand of the world continues to grow due to improved standard of living associated with technological advancements and breakthroughs, so also are the challenges associated with exploration and development of new oil fields. As a result, oil exploration has gradually shifted to more challenging environments. There is therefore the need to reduce exploration uncertainty and maximize recovery, if supply is to meet up with demand. This need has therefore engendered a multidimensional approach to reservoir evaluation, which combines geophysics, geology, petrophysics, reservoir engineering and geostatistics for detailed evaluation of reservoir properties.

Reservoir characterization is a technique that involves quantitative distribution of reservoir properties, such as facies distribution, porosity, permeability, fluids saturations, etc. This technique has gained significant relevance as well as attracted remarkable research efforts in the last decades. The study has since evolved as a technique which integrates seismic derived

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information, well logs, pressure tests, cores and other engineering and geoscience data to provide adequate information required for reservoir modelling aimed at field development and reservoir management. This way, maximum recovery is guaranteed and uncertainties in production forecast are reduced (Jahns, 1966; Haldorsen and Damsleth, 1993; Phillips, 1996; Johnston, 2004).

In this study we characterize the reservoirs of an oil field (X-Field) that is located offshore, west of Niger Delta, Nigeria. This is important in order to evaluate the hydrocarbon prospect of the field with a view for the field development and proper management of the reservoirs. The field is located in a relatively challenging environment where the exploitation uncertainty needs to be reduced for gainful economic oil recovery (EOR) of the hydrocarbon reserve.

Geology of the study area

The study area is located in NW-SE trending Miocene depocenters in a wave-dominated Niger Delta depositional environment (Figure 1). The reservoir units occur as part of the Agbada formation and comprise of stacked shallow marine fluvial-deltaic sediments separated by major marine shale units (Poston et al., 1981). The underlying Eocene-Oligocene Akata marine shales are the likely sources of the hydrocarbons to the reservoirs. The onshore portion of the Niger Delta Province is delineated by the geology of Southern Nigeria and Southwestern Cameroon. The northern boundary is the Benin Flanks, an East-Northeast trending hinge line south of the West Africa basement massif. The northeastern boundary is defined by outcrops of the Cretaceous Abakaliki High and further East-Southeast by the Calabar Flank-a hinge line bordering the adjacent Precambrian. The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey Basin to the west, and the 2 km sediment thickness contour or the 4 km bathymetric contour (in areas where sediment thickness is greater than 2 km) to the south and southwest. The province covers 300,000 km^2 and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) petroleum system (Ejedawe et al., 1984; Tuttle et al., 1999).

MATERIALS AND METHODS

Three wells identified as Well A, Well B and Well C and the seismic data acquired from an offshore X-field in the Niger Delta of Nigeria were used for this study. The study utilized Petrel Version 2014.1 and Interactive Petro-physical software to characterize the petrophysical properties of the reservoirs in the field.

The well logs from the three wells were arranged into vertical profiles against common measured depths to show systematic vertical variations of the sedimentary sequence across the different log types at corresponding depths. The resistivity logs were correlated with gamma ray logs for lithological investigation due to their distinguishing behaviours in sand and shale formations. In the well log traces (Figure 2), the yellow interval is sand while the dark grey interval is shale. Six sand bodies were mapped as horizons 1, 2, 3, 4, 5, 6 and 7 for each correlated reservoir across the wells. The log scale for resistivity was set at a range of 0.2 to 2000 Ωm while that of gamma ray log, ranges between 0 and 150 which fitted the extent of the data (Figure 2).

Typical log responses associated with the various lithologies described by Jurgen (2015) were used for the qualitative identification of inter-facies units. Qualitative analysis of the well logs resulted in characterization of the subsurface stratigraphy into well log facies of depositional environments.

Interactive Schlumberger Petro-physical software was used to compute the shale volume of all the reservoirs in the three wells from the Gamma ray logs by maintaining the log response in the clean sand and shale zone.

To define the net pay and other petrophysical parameters, the cut-off was set as ≤ 0.5 for water saturation, ≥ 0.1 for porosity and ≤ 0.5 for volume of shale. Using formation parameters generated from log data and basic regional information applicable to the Niger Delta Province enabled determination of other reservoir parameters such as reservoir thickness, net-to-gross (NTG) ratio, volume of shale (V_{sh}) in the clastic reservoirs, movable hydrocarbon saturation and non-movable hydrocarbon saturation. All these were in order to evaluate the hydrocarbon potentiality of the field.

Faults and horizons were picked from the seismic data to find the formation boarder on both the cross-line and inline section. The seismic slices were both picked on the inline and cross-line to improve accuracy and to provide a check for the other line picks. All the slices were on the time domain

RESULTS AND DISCUSION

A summary of the characterization of the reservoirs in each of the three wells are as shown in Tables 1 to 3.

Well A has porosity ranges of 0.105 to 0.152 while the bulk volume of water of hydrocarbon-bearing zones ranges from 0.005 to 0.034 (Table 1). The grain size of the sand is fine to very fine-grain (Fertl, 1987). The analysis shows that each of the sand units extends through the field at various thicknesses. Well B however has porosity range of 0.111 to 0.117 with a bulk volume of water that ranges from 0.007 to 0.049 while Well C has a porosity of 0.133 with 0.0130 bulk volume of water.

Six hydrocarbon bearing reservoirs were identified and located within 2757 to 3591 m (Figure 2). The average petrophysical values for each reservoir are as shown in Tables 1 to 3. Water saturation ranges from 0.041 to 0.426 while hydrocarbon saturation ranges from 0.574 to 0.965.

Abrupt changes observed in the overall log pattern with associated change in individual log implied changes in the lithology or stratigraphic boundary. The volume of shale reveals the lithology of the reservoir rock type while the porosity depends on degree of uniformity of grain size, the shape of the grains, the method of deposition, the manner of packing and the effects of compaction during or after deposition. The lithology of the wells revealed by the gamma ray logs shows that the formations contain varying proportions of sand and shale.

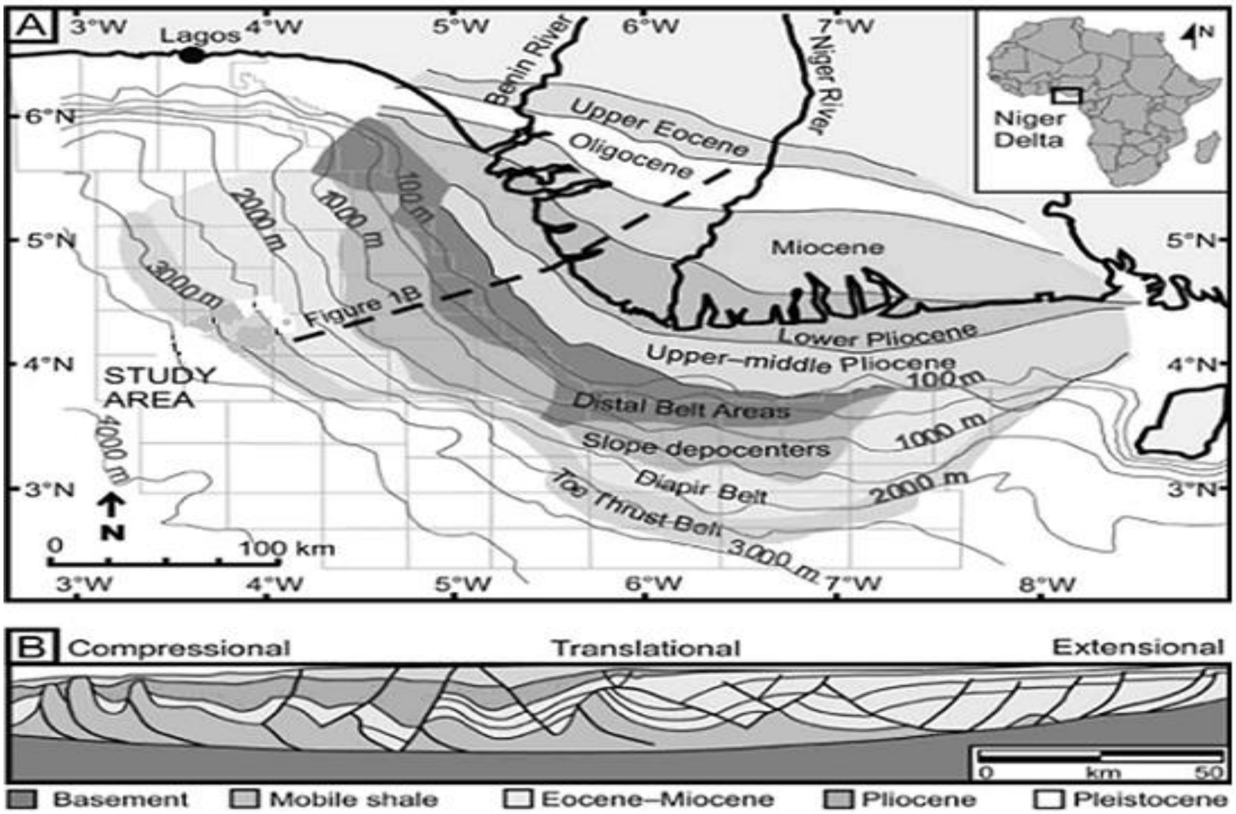

Figure 1. The Niger Delta Complex.
Source: Cohen and McClay (1996).

As such, qualitative analysis was based on the dominance of shale or sand as indicated by their corresponding log responses at any depth within the formation. The volume of shale is low within the hydrocarbon-bearing zone. Hence the low volume of shale (0.027 to 0.371) indicates good productive zone with clean sand distribution. For Well A, Reservoir 1 is hydrocarbon bearing within the depth of 3488 m with a gross thickness of 56.7 m and net pay thickness of 23 m. Reservoir 2 is hydrocarbon bearing within a depth of 3327 m with a gross thickness of 209 m and net pay thickness of 18 m. Reservoir 3 is considered to be fresh water reservoir as evidenced from the corresponding well log traces of Figure 2. The cut-off applied eliminates unproductive (not significant) zone. Reservoir 4 is hydrocarbon bearing within a depth of 2857 m with a gross thickness of 410 m and net pay thickness of 119 m. Reservoir 5 is hydrocarbon bearing within a depth of 2843 m with a gross thickness of 14 m and net pay thickness of 2.7 m. Reservoir 6 is hydrocarbon bearing within a depth of 2757 m with a gross thickness of 86 m and net pay thickness of 35 m.

For Well B, Reservoir 1 is hydrocarbon bearing within a depth of 3575 m with a gross thickness of 53 m and net pay thickness of 21 m. Reservoir 2 is hydrocarbon bearing within a depth of 3399 m with a gross thickness of 175 m and a net pay thickness of 17 m. Reservoir 3 is hydrocarbon bearing within a depth of 3380 m, a gross thickness of 18 m and net pay thickness of 2.7 m. This reservoir is sufficient for oil and gas exploration. Reservoir 4, reservoir 5 and reservoir 6 are considered to be fresh water reservoirs.

For Well C, only one hydrocarbon bearing reservoir, corresponding to reservoir 1 was identified and located within a depth of 3591 m with gross thickness of 49 m and a net thickness of 29.3 m (Figure 2). Reservoir 2, 3, 4, 5 and 6 are considered to be fresh water reservoirs. The cut-off values indicated an unproductive zone (not significant). This could be observed when small amount of shale decreases the rock resistivity much more than in a (deep) reservoir with saline formation water. Figures 3 to 5 show the variation of depth with hydrocarbon saturation for each of the reservoirs (R1, R2, R3, R4, R5 and R6) of Well A, Well B and Well C, respectively.

The reservoir petrophysical features are good indicators of hydrocarbon accumulation, especially in the oil bearing zone with low water saturation (Table 1). This result fairly agrees with that obtained by Akpan et al. (2017) where hydrocarbon saturation of 68% was obtained at depths of 3533 to 3850 m.

From Well A, it was observed that there was a shale increase from top of the formation down to a depth of

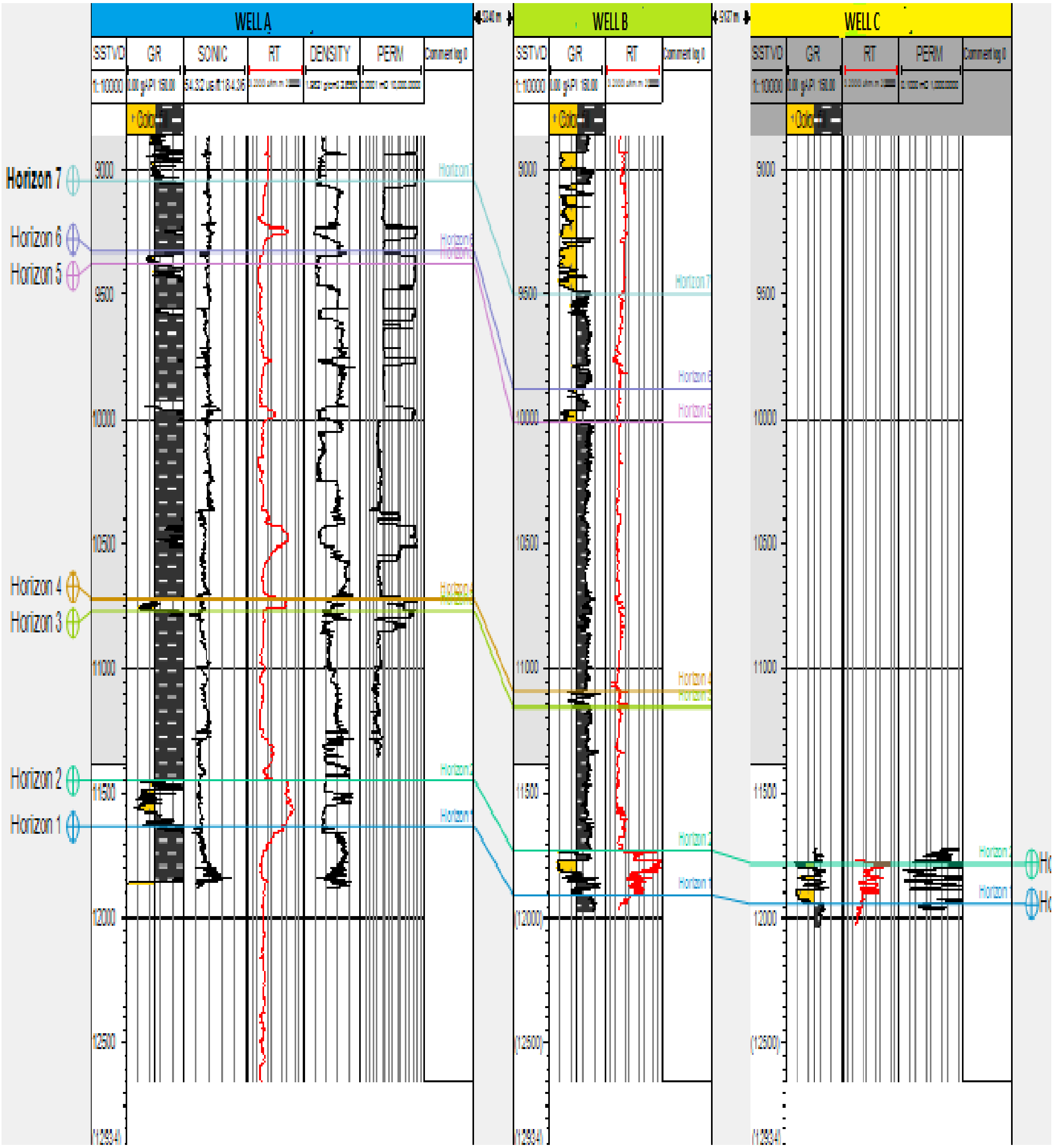

Figure 2. Log traces of the three wells.
Source: Authors 2023

2843 m, which corresponds to an unproductive zone. The resistivity increases from a depth of 3490 m to a depth of 3545 m which correspond to a gamma ray log decrease within same range. Major oil accumulation depth varies from 3504 m to about 3539 m as could be seen from the log track in Figure 2. Resistivity below the depth 3284 m (2.47-2.64 Ohm-metre) indicates a very high salinity which gives a strong contrast to mud filtrate resistivity.

Table 1. Petrophysical parameters of Well A.

Reservoir	D(m)	GPT (m)	NPT (m)	NGR (m)	V_{sh} (%)	Φ (%)	S_w (%)	S_h (%)	S_{xo} (%)	$S_{hmov.}$ (%)	$S_{hnon\text{-}mov.}$ (%)	BVW (%)	BVH (%)	F (%)	τ (%)
1	3488	56.7	23	0.406	2.7	11.4	4.1	95.9	52.8	48.69	47.2	0.5	10.9	76.9	8.8
2	3279	209	18	0.086	15.2	10.5	14.6	85.4	68.0	53.5	31.9	1.8	9.0	90.7	9.5
3	3267	12	-	-	-	-	-	-	-	-	-	-	-	-	-
4	2857	410	119	0.290	13.4	13.4	23.8	76.2	75.0	51.2	25.0	2.9	10.2	55.7	7.5
5	2843	14	2.7	0.193	11.2	11.2	30.1	69.9	78.7	48.6	21.3	3.4	7.8	79.7	8.9
6	2757	86	35	0.407	15.2	15.2	14.6	85.4	68.1	53.5	31.9	2.2	13.0	43.3	6.6

Source: Authors 2023

Table 2. Petrophysical parameters of Well B

Reservoir	D (m)	GPT (m)	NPT (m)	NGR (m)	V_{sh} (%)	Φ (%)	S_w (%)	S_h (%)	S_{xo} (%)	$S_{hmov.}$ %)	$S_{hnon\text{-}mov.}$ (%)	BVW %)	BVH (%)	F (%)	τ (%)
1	3575	54	21	0.389	2.7	11.3	3.5	96.5	51.1	47.6	48.9	0.7	10.9	78.3	8.8
2	3399	176	17	0.097	0	11.7	42.6	57.4	84.3	41.79	15.69	4.9	6.7	73.1	8.5
3	3380	19	2.8	0.147	37.1	11.1	36.2	63.8	81.6	45.41	18.39	4.0	7.1	81.16	9.0
4	3050	330	-	-	-	-	-	-	-	-	-	-	-	-	-
5	3010	132	-	-	-	-	-	-	-	-	-	-	-	-	-
6	2895	114	-	-	-	-	-	-	-	-	-	-	-	-	-

Source: Authors 2023

Table 3. Petrophysical parameters of Well C

Reservoir	D (m)	GPT (m)	NPT (m)	NGR (m)	V_{sh} (%)	Φ (%)	S_w (%)	S_h (%)	S_{xo} (%)	$S_{hmov.}$ (%)	$S_{hnon\text{-}mov.}$ (%)	BVW (%)	BVH (%)	F (%)	τ (%)
1	3591	49	29	0.592	**8.7**	**13.3**	**8.8**	**91.2**	**61.5**	52.7	38.5	**1.3**	**12.1**	56.5	7.5
2	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

D, Depth; GPT, Gross Pay Thickness; NPT, Net Pay Thickness; NGP, Net Gross Ratio; $V_{sh,}$ Volume of Shale; Φ, Porosity; S_w, Water Saturation; S_h, Hydrocarbon Saturation; S_{xo}, Mud Filtrate Saturation; $S_{hmov.}$, Movable Hydrocarbon Saturation; $S_{h\ non\text{-}movable}$ - Non-Movable Hydrocarbon Saturation; τ, Tortuosity; F, Formation Factor; BVH, Bulk Volume of Hydrocarbon; BVW, Bulk Volume of Water.
Source: Authors 2023

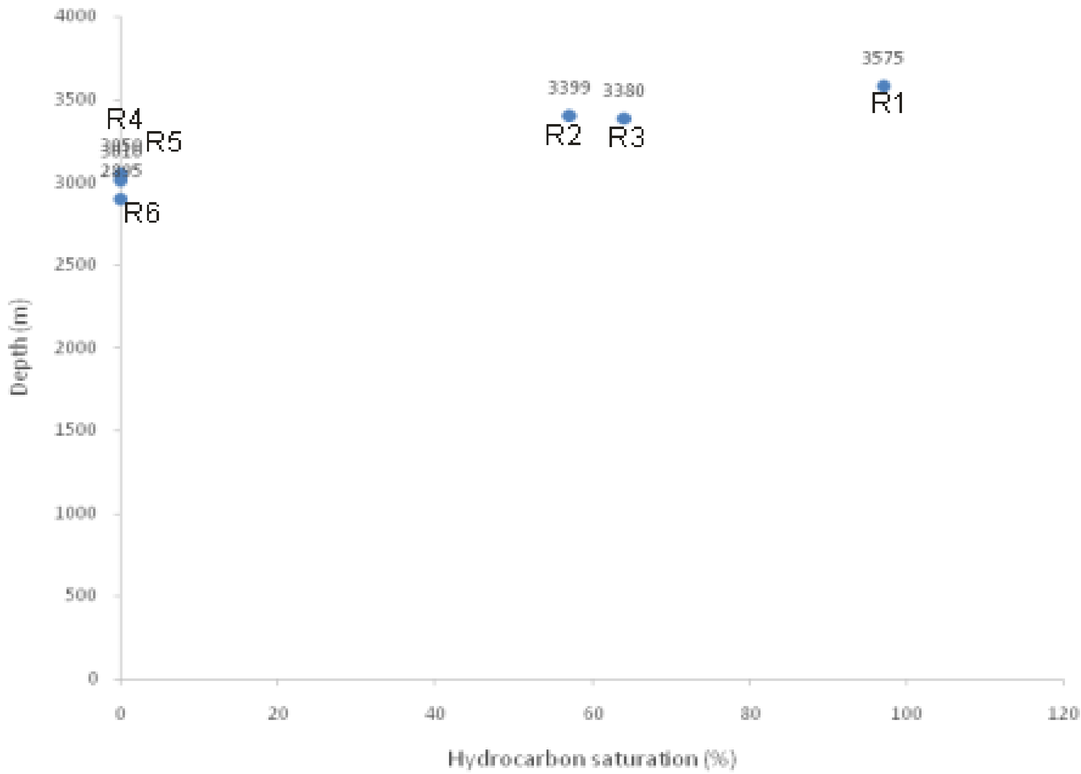

Figure 3. Depth versus hydrocarbon saturation plot of Well B.
Source: Authors 2023

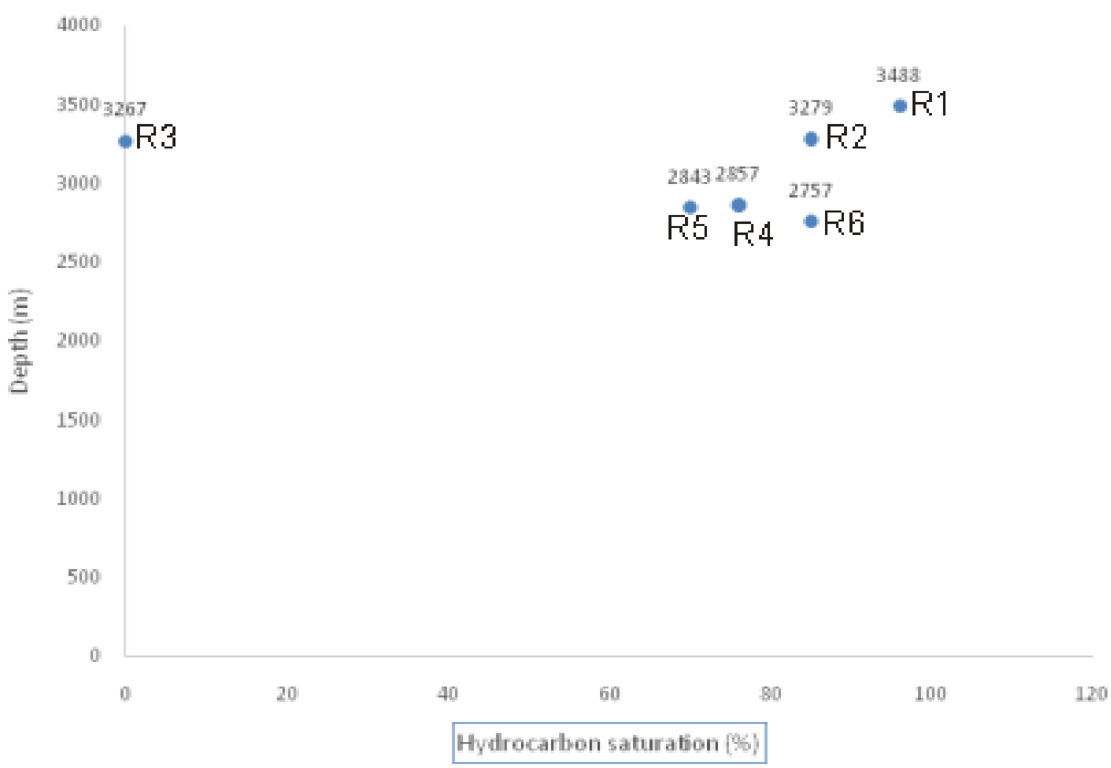

Figure 4. Depth versus hydrocarbon saturation plot of Well A.
Source: Authors 2023

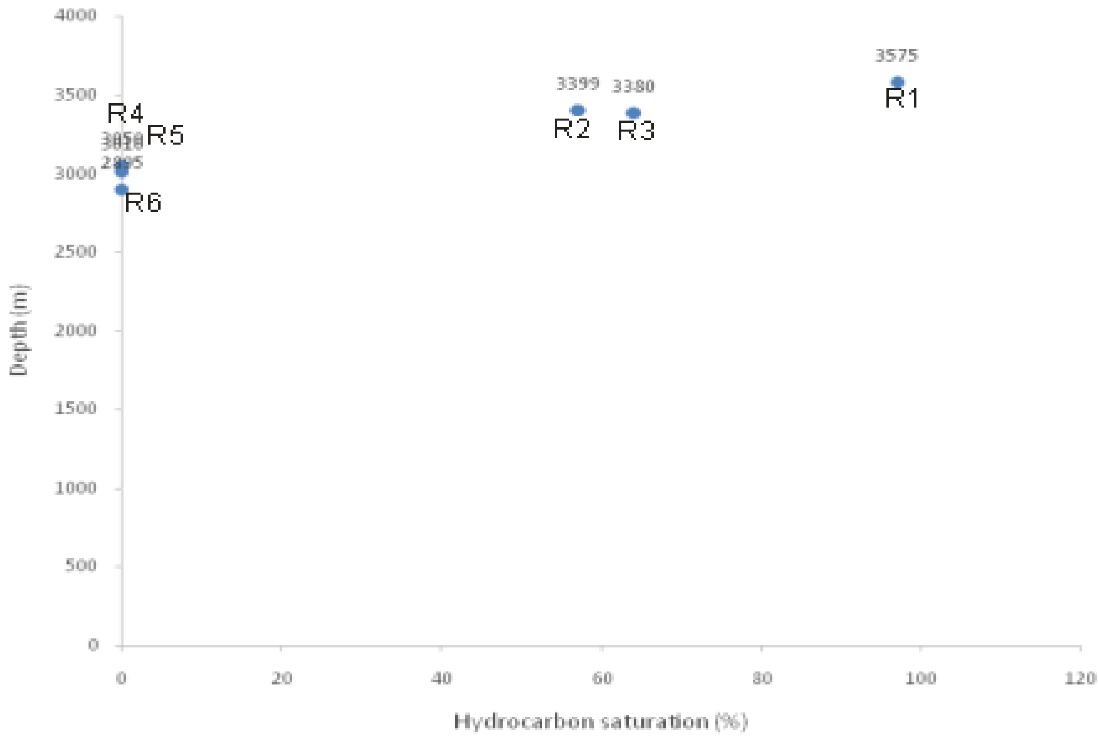

Figure 5. Depth versus hydrocarbon saturation plot of Well C.
Source: Authors 2023

This increase of resistivity originated from a decrease of water saturation because porosity is constant. In Well B, the resistivity increases from a depth of 1362 m to a depth of 1824 m which corresponds to a gamma ray log decrease within same range. Major oil accumulation depth ranges between 1362 m and 1910 m, with a small quantity appearing to have been trapped within 3588 m to 3601 m as seen in the log track in Figure 2. Resistivity below the depth 2176 m is very low (1.2 to 2.63 Ohm-metre) indicating a very high salinity and a strong contrast to mud filtrate resistivity. It was observed that from a depth of 3576 m downward, the resistivity increases by a factor of about 8 Ohms. This part is probably the transition zone, from 1361 to 1989 m. The reservoir is above the transition zone, which clearly indicates reservoir homogeneity and invasion as a result of permeability. This increase in resistivity was caused by a decrease in water saturation because porosity is constant.

In Well C, the resistivity increases from a depth of 3590 m to a depth of 3628 m which corresponds to a gamma ray log decrease within the same range. Major oil accumulation depth varies from 3590 m to about 3639 m as seen from the log track in Figure 2. Resistivity below the depth of 3628 m (1.9 to 3.8 Ohm–metre) indicates a very high salinity which gives strong contrast to mud filtrate resistivity. This increase in resistivity was caused by a decrease in water saturation because porosity is constant. The results from these wells conform to similar study by God'swill and Jonathan (2019) with the assertions of hydrocarbon depth that ranges from 3580 to 3670 m.

Figure 6 typically shows the seismic section of Well A. The numbers in the seismic section indicate the thickness (Z) of the faults. The major fault orientation in the study area is NW-SE trending and was commonly noted as synthetic and antithetic growth faults, roll-over anticlines, back-to-back and collapse crests. The work of Aigbedion and Hafiz (2016) which showed faults of assisted anticline structures that served as structural traps to hydrocarbon source rocks at Fareed field, Western Niger Delta attests to this result.

Figure 7 shows the model horizon of the field obtained. The figure shows a trend towards increasing thickness in a certain downward direction (right hand side). Therefore, the eastern part of the model horizon with maximum contour closures corresponds to the area of maximum hydrocarbon accumulation.

Conclusion

Well log and seismic data have been used to characterize the reservoir parameters of an X-field in the Niger Delta of Nigeria and to determine its hydrocarbon potentiality. Shale volume of hydrocarbon-bearing zones was used

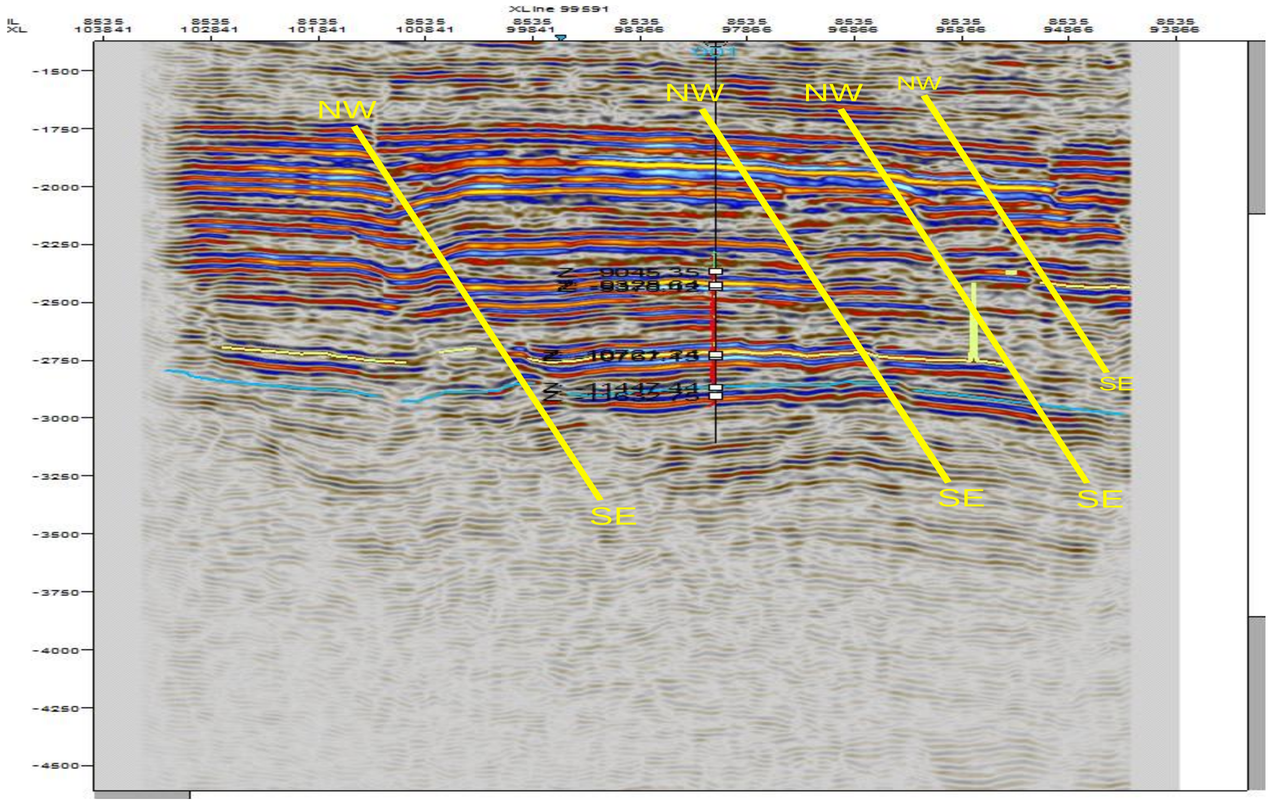

Figure 6. Seismic section of Well A.
Source: Authors 2023

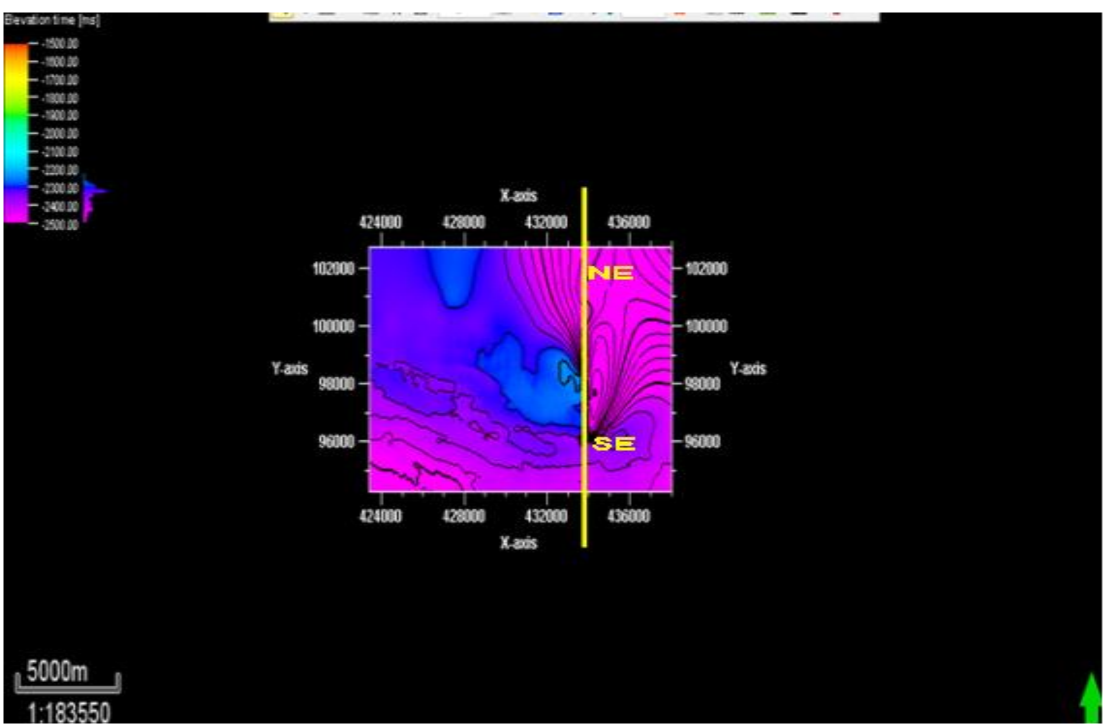

Figure 7. Model horizon of the field.
Source: Authors 2023

to characterize the shale distribution in each reservoir and to distinguish between the movable and non-movable hydrocarbons. The percentage of movable hydrocarbons in the reservoirs ranged from 41.8 to 53.5%. The hydrocarbon depths in the reservoirs ranged from 2757 to 3591 m while the hydrocarbon saturation ranged from 57.4 to 96.5%. It could therefore be concluded that the reservoirs of the field have good hydrocarbon prospect, with reservoir 1 of Well B being the most productive reservoir (with hydrocarbon saturation of 96.5%). This result is in close agreement with that of Imikanasua et al. (2022) on determination of reservoir quality in field "D" in Central Niger Delta, using well log data. It is also in agreement with that obtained by Boris et al. (2023) on petrophysical characterization and 3D seismic interpretation of reservoirs in the Baris Field, onshore Niger Delta Basin.

CONFLICT OF INTERESTS

The authors have not declared any conflict of interests.

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