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Petrophysical Evaluation and Depositional Environments of Reservoir Sands in an Oil Producing Field, Onshore Niger Delta, Nigeria

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ABSTRACT: Optimal hydrocarbon recovery depends strongly on predicting the reservoir quality and reservoir drive mechanism, and this could be achieved by petrophysical analysis. This research evaluated the petrophysical properties of reservoir sands in an Oil producing Field, onshore Niger delta, Nigeria using petrophysical techniques. Results from the Petrophysical evaluation, showed that the average porosity values of the reservoirs ranged between 0.15 and 0.24 while average water saturation for the three reservoirs ranged from 19% to 44%. Reservoir D_3000 has the largest accumulation of about 952 MMSTB while reservoir D_1000 gave the least accumulation of about 727MMSTB. The environment of deposition was interpreted using gamma-ray log motif. Reservoir D_1000 shows a blocky gamma ray motif that suggests deposition from a steady energy, which can likely be a channel deposits. Reservoir D_2000 sands showed an obvious funnel shape gamma ray log motif by it coarsening upward attribute, which can likely be interpreted as a shore face environment. Reservoir D_3000 is the deepest and the thickest of the three reservoir sands, the gamma ray log motif displayed a blocky shape which can likely be interpreted as bar deposits and channel sands. This study reveals that Channel Sands, Bars and Shore face are good sites for exploration and production of hydrocarbon.

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Analyzing the spatial variability of saturating reservoir fluids (hydrocarbon) is an important aspect of oil and gas production. Petrophysical analysis is needed to guide production and well placements, well paths for optimal hydrocarbon recovery. The key factor controlling variation in strata patterns and facies distribution is the environment of deposition. Depositional environment identification is strongly tied to a proper description of core samples (Attia et al., 2015). This description focuses on sedimentary structures, mineralogical composition, grain size distribution, and textural features (Kessler and Sachs, 1995). Unfortunately core samples are rarely available, hence the use of Gamma-ray log motif, a globally accepted method as a suitable alternative (Chow et al., 2005; Farrell et al. ,2013).Depositional environment tend to influence the grain size of sediment, sorting even their distribution pattern, (Sakura, 2002). They also exercise certain level of dominance over the petrophysical properties of the reservoir, (Wyllie et al., 1956). Therefore, this paper employed petrophysical analysis to evaluate the reservoir properties of the Sands in an oil producing field, onshore Niger delta, Nigeria.

MATERIALS AND METHOD

Location and Geology of the Study Area: The study location is an onshore oil producing field within the

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Southeastern part of the Central swamp depobelt in the Niger Delta Basin. (Fig. 1a) shows map of the study area while (Fig. 1b) shows well location in the study area.

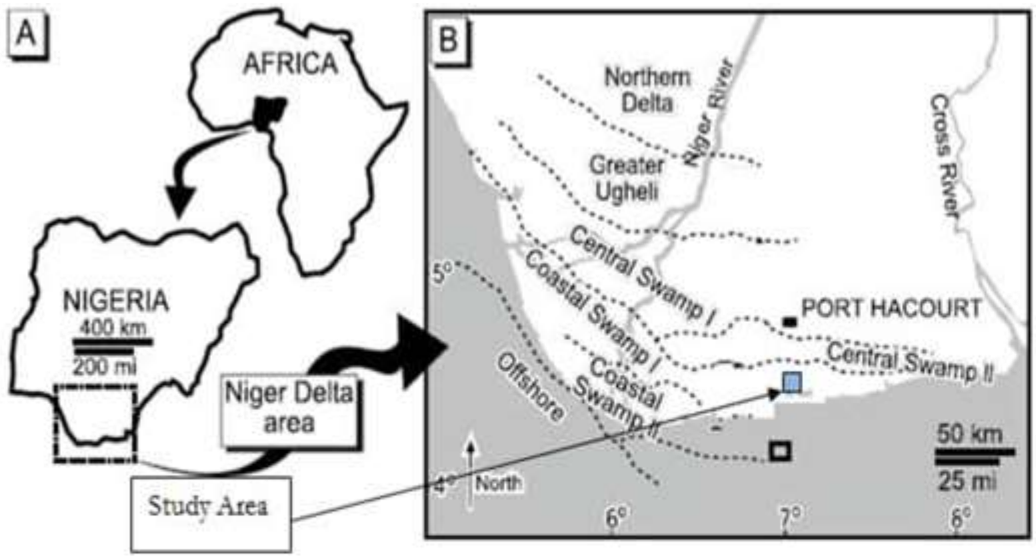

Fig 1: Map showing the study area

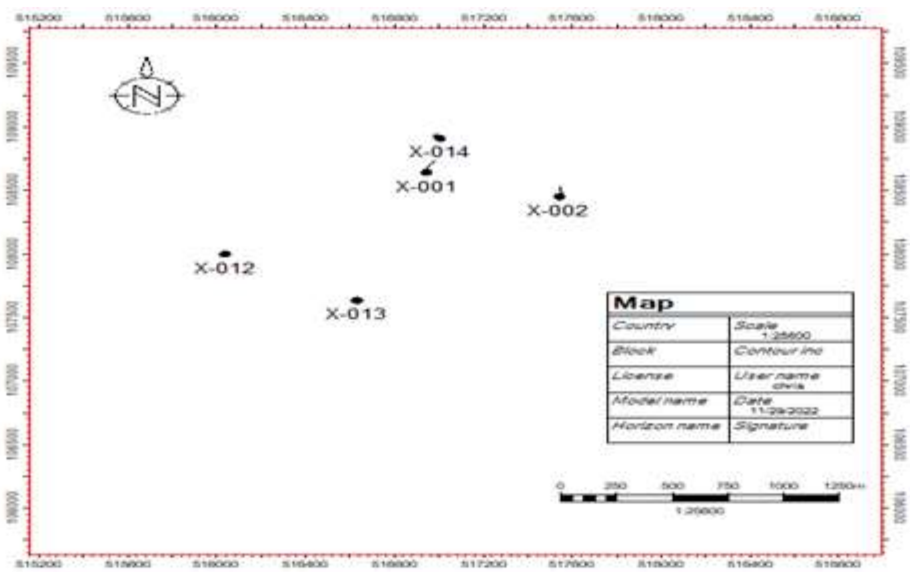

Fig 2: Base Map of the field showing well locations.

The Niger Delta basin resulted from a failed rift junction during the separation of the South American plate from the African plate and consequently, the opening of the South Atlantic (Reijers et al. 1997). During the late Cretaceous, rifting ceased completely in the delta. (Lehner and De Ruiter 1977). Gravity tectonism became the main deformational process. Three formations make up the Niger Delta province; the formations are recognized primarily by their lithologic type. They include; the poorly compacted, deep marine shales of the Akata Formation, the paralic sands of the Agbada Formation and the Continental sand of the Benin Formation. The Akata Formation occupies the lower part of the region. The Agbada formation consists mainly of sands with shale intercalations, especially at the base, where it overlies the Akata formation; it constitutes the main hydrocarbon reservoir in the Niger Delta Basin. Finally, the last formation of the Delta that occupies the topmost region, indeed the youngest of the three is the Benin formation (Short and Stauble (1967), Reijers, et al. (1997), Ozumba, (2013), Owoyemi, and Willis (2006)). Suite of wire line logs namely gamma ray, neutron, density, caliper and sonic logs were used to correlate, evaluate the reservoir petrophysical properties and infer the depositional environments.

Methods: Well correlation was done using the gamma-ray (GR) log as suggested by Shabeer and Sarfraz, (2016). Facies analysis was done based on the gamma-ray, density and neutron logs promptly, and three lithofacies types were identified, which are clean sand, shaly sand, and shale. The three reservoirs of interest were correlated across the five wells to give a clear view of sand distribution in the study area. Though a sand top file was supplied for the purpose of this research, the depths proposed by the data were cross-checked with the correlation done, using Gamma-ray, resistivity, neutron, and density logs to ensure that the right depths were picked as the top and base of the reservoirs of interest. The deflection of the Gamma-ray log to the left implied that we were dealing with a reservoir while a zone, where the gamma-ray log deviated towards the right was considered a shale zone. The first task in the interpretation of the spontaneous potential log is to ascertain the sand/shale baseline which was well established. The log showed normal (negative) SP deflection which suggested the presence of a permeable zone in places where the gamma-ray log deviated to the left while in areas where the gamma-ray log moved towards the right indicating a shaly area, the spontaneous potential log showed a reverse (positive) SP deflection suggesting an impermeable region (shale). It is important to note at this point that spontaneous potential log is greatly influenced by the salinity of both interstitial water and drilling mud. Therefore, caution should be exercised when it is employed to tell sand and shale zones as that was kept in mind while doing this analysis.

Petrophysical evaluation: The volume of shale was determined using the empirical formula proposed by Larionov (1969) for tertiary rock, given as; $Vsh = 0.083(2^{3.7*I_{GR}} - 1)$. (Schlumberger 1974) suggested that gamma-ray index (I_{GR}) can be derived from a gamma-ray log and gave a relationship between them as:

$$I_{GR} = \left(GR_{\log} - GR_{min} \middle| GR_{max} - GR_{min}\right)$$

Where: I_{GR}= Gamma-ray index; GR_{log} = Gamma-ray reading of the formation; GR_{min} = Minimum Gamma-ray reading (Sand baseline); GR_{max} = Maximum Gamma-ray reading (Shale baseline)

Porosity was also determined using the formula by Asquith and Krygowski (2004).

$$(\emptyset T) = (\rho_{ma} - \rho b)|(\rho_{ma} - \rho f)$$

Where: $(\emptyset T)$ = Density porosity; ρ_{ma} = Matrix density; ρb = bulk density; ρf = Fluid density

Effective Porosity:

$$\varphi_{eff} = (1 - Vsh) * PoroT$$

Where: φ_{eff}= Effective porosity; Vsh = Volume of shale; $PoroT$ = Total porosity

Water saturation was derived from the formula by Udegbunam and Amaefule (1988). It has a relationship with hydrocarbon saturation (S_h) since the sum of both parameters must equal one.

$$Sw + Sh = 1$$

Therefore,

$$Sh = 1 - Sw$$

$$Sw\_ua = 0.082/PoroT$$

Where: Sw_ua = Water saturation; $PoroT$ = Total Porosity

The entire **reservoir thickness** otherwise known as gross reservoir thickness is estimated from the top to the base of the reservoir.

Hence,

$$\text{NTG} = 1 - Vsh$$

Where: NTG = Net to gross; Vsh = Volume of shale

Irreducible water saturation and permeability were calculated from Schlumberger (1974). Also called critical water saturation, the irreducible water saturation is the quantity of water a porous and permeable formation can hold without producing water.

$$S_{wirr} = (F/2000)^{1/2}$$

Where: S_{wirr}= Irreducible water saturation; F = Formation factor given as $0.81/\varphi^2$ (for most sandstone reservoirs)

Permeability

$$K = 304 + 26552\varphi^2 - 34540(\varphi Sw)^2$$

Where: K = Permeability; φ = Porosity; Sw= Water saturation

$$RQI = 0.0314\sqrt{\frac{Perm\ X}{\varphi eff}}$$

Where: $Perm\ X$ = Horizontal permeability; φeff = Effective Porosity

$$FZI = \frac{RQI}{Q_z}$$

Where: RQI = Reservoir quality index; Q_Z = Pore volume to grain ratio

Given as:

$$Qz = \frac{\varphi eff}{1 - \varphi eff}$$

The depositional environment was interpreted based on the gamma ray log motifs for the identification of depositional environment proposed by Chow et al. (2005) and Cant, (1992).

RESULTS AND DISCUSSION

Petrophysical Evaluation: From the stratigraphic correlation (Figure 3), reservoir sands D-1000 and D_2000 with minor shaly sand intercalations were laterally extensive, cutting across the five wells in the field, while reservoir sand D_3000 did not cut through wells X-002 and X-014 as a result of a major fault that cuts through the reservoirs. The average values for the petrophysical properties of reservoir sand (D_1000, D_2000 and D_3000) across the field are tabulated as shown below (Table 1-3). Results from the Petrophysical evaluation, revealed that the average porosity values of the reservoirs ranged between 0.20 and 0.225 while average water saturation for the three reservoirs ranged from 21% to 40% respectively. Reservoir D_3000 has the largest accumulation of about 952 MMSTB while reservoir D_1000 gave the least accumulation of about 727MMSTB. The porosity and permeability values (Table 1-3) across all the reservoir sands showed a noticeable decrease in values at deeper stratigraphic intervals. The overall quality of the reservoir sands generally depreciated with increasing depth regardless of their net-to-gross ratios.

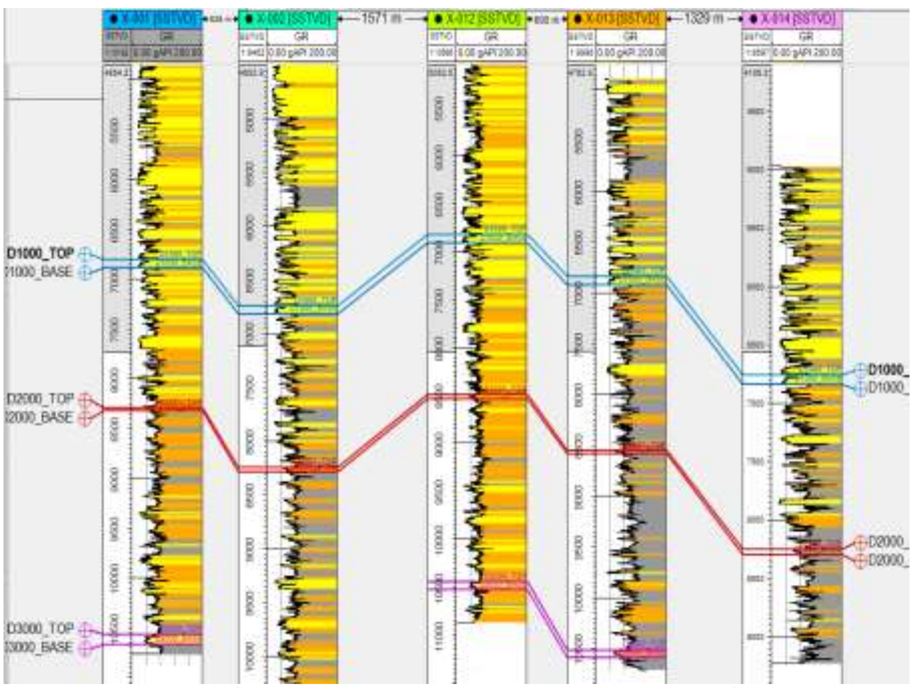

Fig 3: Stratigraphic correlation of reservoir sands D-1000, D_2000 and D_3000 across the five wells in the study area.

Table 1: Average Petrophysical Properties for Reservoir D_1000

Wells	Depth(ft)		Gross Thickness(Ft)	Net-to-Gross	Volume of Shale	Porosity	Permeability (mD)	Water Saturation
	Top	Bottom						
X001	6800.8	6882.8	82	0.99	0.01	0.24	9499	0. 20
X002	6738.34	6813.27	74.93	0.98	0.02	0.22	8479	0. 21
X012	6819.1	6907.2	88.1	0.97	0.03	0.23	9019	0. 19
X013	6835	6919	84	0.94	0.06	0.20	8469	0. 22
X014	6754.5	6834.4	79.9	0.96	0.04	0.21	6230	0. 24

STOIIP = 727 MMSTB

Depositional environment: In the absence of core, the lithofacies identification was done using the gamma-ray log, density and neutrons cross plots. Three lithofacies types were identified; from Figure 4, clean sand facies showed a blocky gamma ray log motif, as it positions steadily at the zero mark at gamma ray track. The density log reduced significantly thereby moving to the left of the neutron log. The shaly sand facies showed the gamma ray log gradually moving away from zero, an indication that it is not as clean as the clean sand facies, there was also a gradual drift of the density log towards the right. Finally, the shale lithofacies showed a complete drift of the gamma ray log towards the shale region as it moves to the right, and the density- neutron cross plot showed a balloon shape, as the density increases towards the right while the neutron log increases towards the left. According to Mene and Okengwu (2020), gamma ray log does not only play a fundamental role in the identification of lithology, it also attempt to predict depositional environment. Table 4 lists the likely depositional environment per gamma ray log shape, while (Figure 5 – Figure 7) show the Gamma ray log curve shape for all the reservoirs, which aided the prediction made on the depositional environment in line with the characterization proposed by chow et al. (2005) and Cant (1992). The shape of the gamma-ray log curve of reservoirs D_1000 (Figure 5) and D_3000 (Figure 7) show close resemblance, except for the low energy sediment deposited on top of the blocky steady energy deposits of reservoir D_3000. Reservoir D_2000 on the other hand showed quite a different outlook from the other two with its coarsening upward sequence (Figure 6).

Table 2: Average Petrophysical Properties for Reservoir D_2000

Wells	Depth(Ft)		Gross	Net-to-	Volume	Porosity	Permeability	Water
	Top	Bottom	Thickness (Ft)	Gross	of Shale		(mD)	Saturation
X001	8289.2	8317.1	27.9	0.99	0.01	0.19	7230	0. 27
X002	8240.71	8283.29	42.58	0.98	0.02	0.17	6230	0. 27
X012	8490.14	8534.4	44.26	0.96	0.04	0.16	7510	0. 24
X013	8547.01	8580.66	33.65	0.93	0.07	0.17	5230	0. 26
X014	8246.62	8292.37	45.75	0.65	0.35	0.15	4130	0. 30

STOIIP=872 MMSTB

Table 3: Average Petrophysical Properties for Reservoir D_3000

Wells	Depth(Ft)		Gross	Net-to-	Volume	Porosity	Permeability	Water
	Top	Bottom	Thickness (Ft)	Gross	of Shale		(mD)	Saturation
X001	10561.71	10663.79	102.08	0.97	0.03	0.22	78479	0. 29
X012	10441.9	10523.93	82.03	0.95	0.05	0.19	4200	0. 39
X013	10514.68	10587.84	73.16	0.93	0.07	0.18	3479	0. 44

STOIIP=952 MMSTB

Reservoir D_1000 with an average thickness of about 83ft and porosity values 0.22 is the shallowest of the three reservoirs under study; it shows a blocky gamma ray log curves (Figure 5) that suggests deposition from a steady energy, which can be said to be channel deposits. Reservoir D_2000 has an average thickness of about 39ft and porosity values 0.17. From Figure 6, we see that the sand shows an obvious funnel shape gamma ray log curve by its coarsening upward attribute. This reservoir had low energy deposits at some time which were later overlaid by high energy coarser deposits. Leaving the cleaner sediments at the top while the shaly sand remained at the base. This may likely be interpreted as shoreface environment. Figure 7 shows reservoir D_3000, as the deepest and the thickest of the three sands with an average thickness of about 86ft and porosity values 0.19. It shows a blocky gamma ray log motif predominantly, but with low energy deposits at the top and base of the block. This can be interpreted as a combination of bar deposits and channel sands.

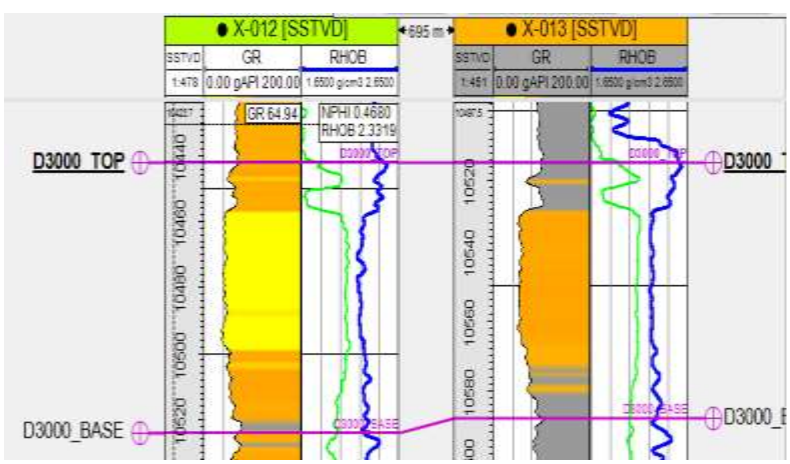

Fig 4: Gamma ray log and density – neutron cross plot

Table 4: Depositional environment prediction by Gamma Ray log motif modified from (Chow et al.2005) and (Cant 1992).

Reservoir	Gamma ray log curve shape	Characteristics	Inferred Depositional environment
D_1000	Cylindrical/Box	A consistent vertical trend with sharp top and base	Fluvial channel, Prograding delta distributries, tidal sand
D_2000	Funnel	A coarsening upward trend with a sharp top	Shoreface, river mouth bar or delta front
D_3000	Cylindrical/Box	A consistent vertical trend with reduced energy at the top and base	Fluvial channel, Prograding delta distributries

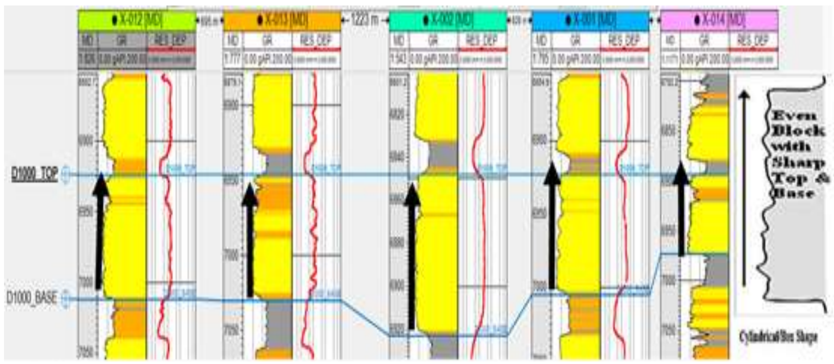

Fig 5: Reservoir D_1000 Showing Cylindrical/box Shape Log Motif

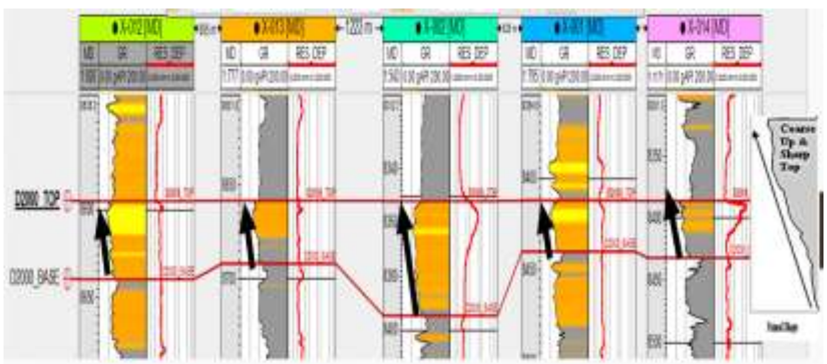

Fig 6: Reservoir D_2000 Showing Funnel Shape Log Motif

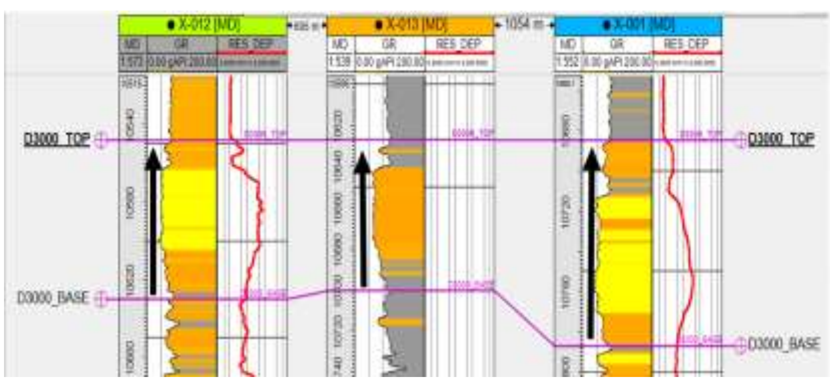

Fig 7: Reservoir D_3000 Showing Cylindrical/box Shape Log Motif

Conclusion: The petrophysical evaluation carried out on the reservoir sands revealed that the Channel Sands, Bars and Shore face exhibited good to excellent reservoir properties. Hence, are good locations for the exploration and production of hydrocarbon. The depositional environment has a major control on the reservoir properties.

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