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Petrophysical Analysis of Reservoirs in Well-*Y*, Coastal Swamp Depobelt, Niger Delta Basin, Nigeria

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Abstract

The present study presents the interpretation of well log data obtained from a well-*Y* drilled on the coastal swamp depobelt of Niger Delta Basin, Nigeria. The petrophysical analysis of the well-*Y* identified four (4) hydrocarbon-bearing reservoirs namely RES-A, RES-C, RES-D, and RES-E. The net sand thickness of the identified reservoirs varies from 12.69ft in RES-D sand to 103.45ft in RES-E sand. The effective porosity values of the reservoirs range from 0.18 in RES-D to 0.2 in RES-A and RES-C reservoirs, while NTG values range from 0.51 in RES-D to 1.0 in RES-A and RES-C reservoirs. The values of water saturation computed range from 22% in RES-E to 80% in RES-C sand. The porosities of the identified reservoir sands are very good for hydrocarbon production, also the reservoirs have good to very good permeability values. The water saturation values of RES-III and RES-IV are 25% and 22% respectively, which indicate high hydrocarbon saturation. The generated petrophysical parameters from the well log data analyses indicate that reservoir RES-IV is the thickest, and has the highest hydrocarbon saturation. Reservoirs RES-D and RES-E would be more prolific than others because of their thicknesses and saturation of hydrocarbon.

Keywords: Reservoir; Hydrocarbon; Niger Delta Basin; Porosity; Hydrocarbon Saturation

1.0 Introduction

The essence of oil and gas exploration is to identify and establish suitable reservoir formations with commercial accumulation and thereafter characterize the reservoir as accurately as possible to evaluate the hydrocarbon reserve (Omoboriowo *et al*., 2012; Osinowo *et al*., 2017). Initial understanding of the reservoir properties (porosity, permeability, water saturation, thickness, and area extent of the reservoir) is crucial in determining the hydrocarbon potential of any basin because they serve as necessary and important inputs for reservoir volumetric/economic analysis (Obiora *et al*., 2016). The evaluation of reservoir rocks in terms of their porosity, water saturation, and permeability determinations, enhances the ability to estimate hydrocarbon reserves and reservoir bed thickness, and to distinguish between gas, oil, and water-bearing strata, by observing their electrical resistivity and relative permeability value (Schlumberger *et al*., 1998; Osinowo *et al*., 2017). Well, logs data provide reliable downhole geological information useful for evaluating the hydrocarbon potential of rock formations and apt at estimating hydrocarbon (oil and gas) quantities in a reservoir (Asquith and Gibson, 1982; Asquith and Krygowski, 2004). The present study focuses on the delineation of hydrocarbon-bearing formations, discrimination of formation fluids, and also hydrocarbon saturation in the reservoirs using petrophysical characteristics of the identified reservoirs sands.

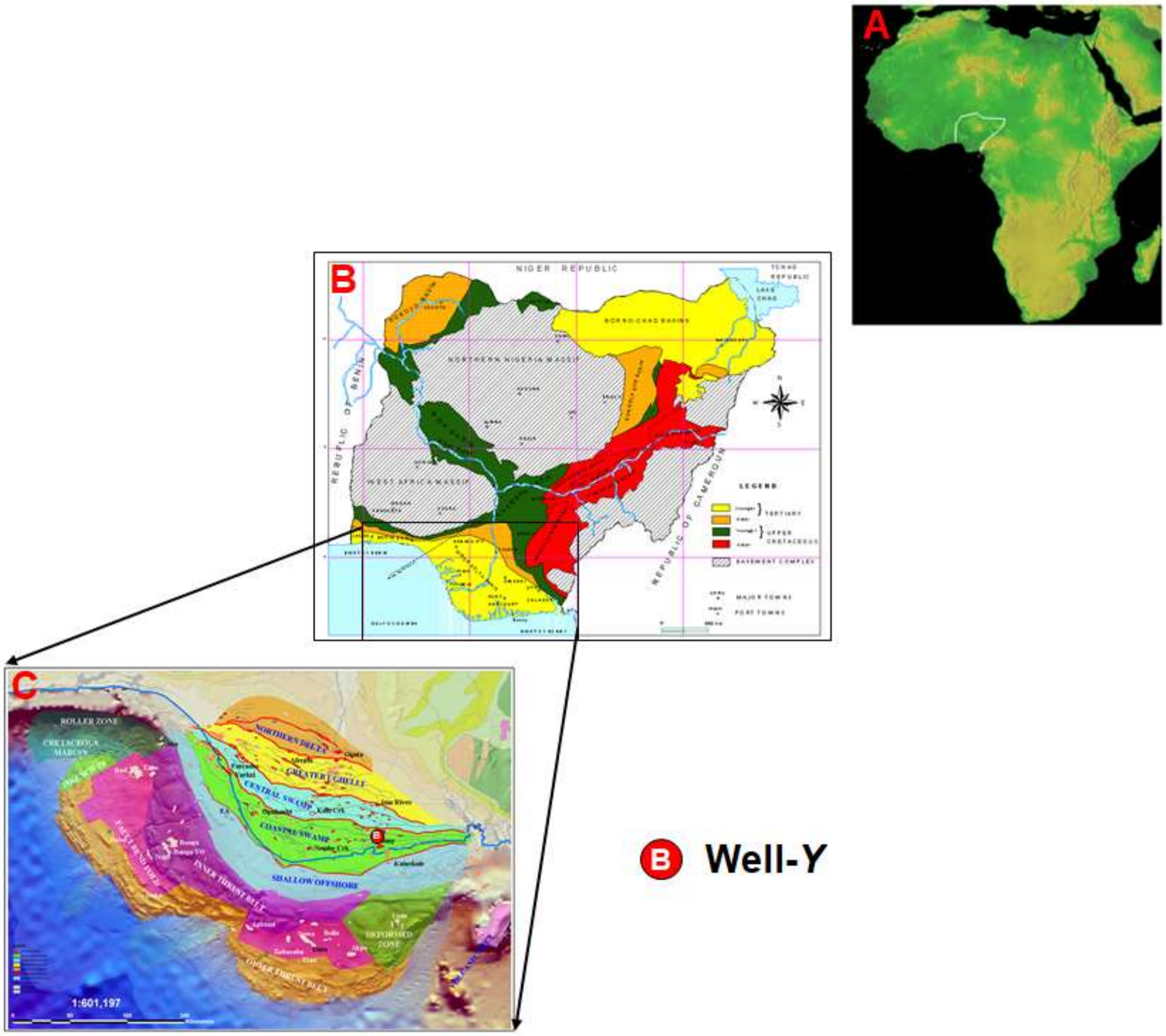

Figure 1: (A) Map of Africa showing Nigeria (B) Location of Niger Delta on the map of Nigeria (modified from Ejedavwe *et al*., 2002). (C) Location of studied Well-*Y* on the coastal swamp depobelt of the Niger Delta map.

2.0 Geologic Setting

The Niger Delta Basin is ranked as the sixth-largest oil producer in the world (Oluwajana, 2018; Ogbe, 2021). The basin is situated in the south of Nigeria along the western part of the African plate coast at the site of a Cretaceous triple junction between latitude 4^{o} and 6^{o} N and longitude 3^{o} and 9^{o} E (Figure 1).

The Niger Delta complex is a regressive offlap sequence that prograded across the southern Benue trough and spread out onto cooling and subsiding oceanic crust, which had formed as Africa and South America separated (Petters, 1991). Continental-margin collapse structures exerted an important control on depositional and stratigraphic patterns on the wedge of clastic sediments of the Niger Delta Basin (Owoyemi and Willis, 2006). The structure and stratigraphy are intricately related within the basin, with the development of each dependent on the interplay between sediment supply and subsidence (Lewis *et al*., 2014).

The sedimentary fill is usually divided into three diachronous formations (Eocene – Recent); namely the undercompacted, overpressured marine Akata Formation, paralic Agbada formation, and continental fluviatile Benin formation (Figure 2). The three Formations are interfingering facies equivalents representing pro-delta, delta front, and delta-top respectively. The Akata Formation is typically overpressured and made up of pro-delta shales with occasional turbidite sands. It also provides the detachment horizon for large growth faults that define depobelts (Adeogba *et al*., 2005). The Agbada Formation overlies the Akata Formation and is composed mainly of sand but with some shale, into an alternation of sandstone and shale, deposited under paralic conditions (Mode and Anyiam, 2007). The Benin Formation is predominantly nonmarine sandstone, whereas the Agbada Formation consists of neritic sandstone and mudstone (Adeogba *et al*., 2005).

The deltaic-front sands of the Agbada Formation account for the bulk of the Niger Delta hydrocarbon production. Reservoir sands of the Agbada Formation were deposited at the interplay between the lower deltaic plain and marine sediments of the continental shelf. (Odedede, 2018). Most primary reservoirs were Miocene-aged paralic sandstones with 40% porosity, 2 Darcy permeability, and thickness of about 300 feet.

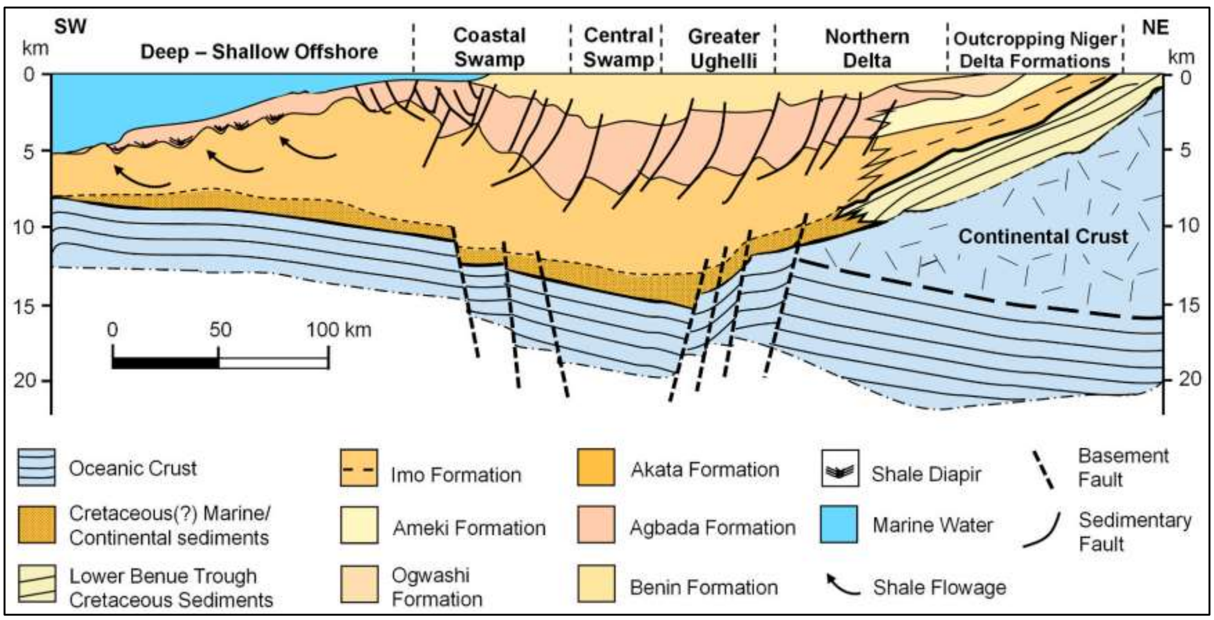

Figure 2: The schematic stratigraphic dip section of the Cenozoic Niger Delta Basin shows the position of the various depobelts with the three diachronous lithostratigraphic formations and associated depositional structures (Modified from Ogbe, 2021).

3.0 Materials and Methods

The well log data was loaded into petrel™2014software for analysis and interpretation after the data had been quality controlled by setting up logs in preferred layouts (e.g., caliper, gamma-ray, density, and deep resistivity logs; Figure 2).

This study adopted petrophysical calculations by Asquith and Gibson (1982) and Asquith and Krygowski (2004), which involve delineation of reservoir units and determination of petrophysical attributes of the reservoir sands identified on the wireline logs. The initial approach for this study involves lithologic delineation based on the deflection of the gamma-ray log, resistivity, and density log. A deep resistivity log was used to discriminate fluids in identified sandbodies. high resistivity response within sand bodies is interpreted as possible hydrocarbon-bearing.

Petrophysical parameters namely volume of shale, gross thickness, net sand thickness, net-to-gross ratio, porosity, permeability, water saturation, and hydrocarbon saturation were computed using the appropriate formula.

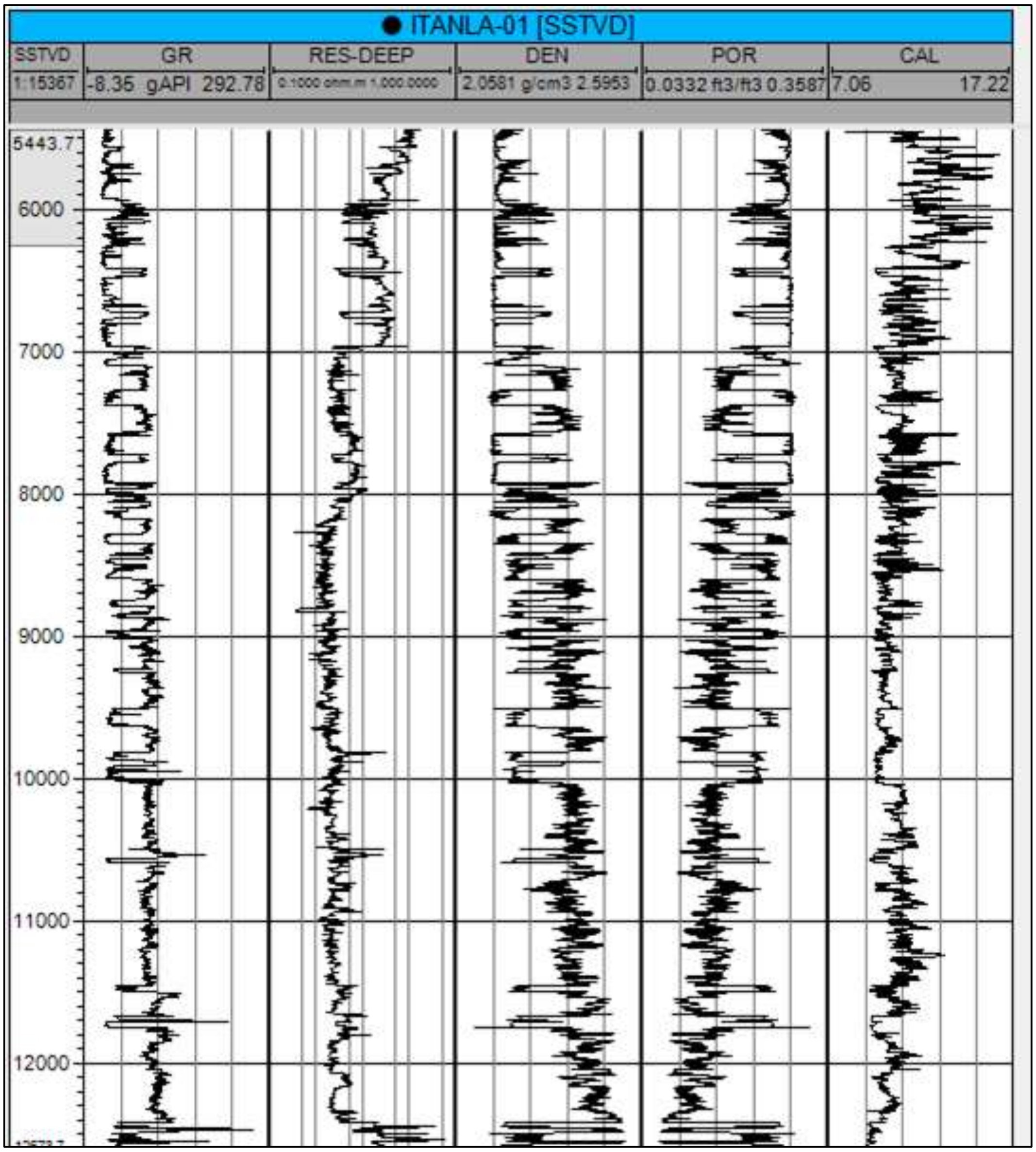

Figure 3: An uninterpreted suite of composite well log display of Well-*Y* in preferred layouts

3.1 Computation of Petrophysical Parameters

3.1.1 Determination of Gross Thickness

The Gross Thickness is the total thickness of the reservoir calculated by subtracting the depth value of the top of the reservoir from the base.

Gross Thickness = Base of Reservoir - Top of Reservoir…………………. (1)

3.1.2 Determination of Net Thickness

The Net thickness is the thickness of sand units in the reservoir.

Net Thickness = Gross Thickness - Shale interval thickness……………… (2)

3.1.3 Determination of Net-to-Gross Ratio

This is the ratio of the Net thickness to the Gross thickness of the reservoir interval.

$$\text{NTG} = \frac{\text{Net}}{\text{Gross Thickness}} \ldots\ldots\ldots\ldots\ldots (3)$$

3.1.4 Determination of Volume of Shale

The volume of shale was calculated from the gamma-ray log. The first step was to determine the gamma-ray index (I_{GR}) as follows;

$$I_{GR} = \frac{GR_{\log} - GR_{min}}{GR_{\max} - GR_{min}} \ldots\ldots\ldots (4)$$

Where;

I_{GR} is Gamma-ray index

GR_{log} is a Gamma-ray reading of the formation

GR_{min} is Minimum gamma-ray reading (Clean sand)

GR_{max} is the Maximum gamma-ray reading (Shale)

These parameters were deduced from the reservoirs units of interest and having obtained the gamma-ray index, the volume of shale was calculated from the I_{GR} using the Larinov (1969) Equation for Paleogene-Neogene (formerly Tertiary) rocks:

$$V_{shale} = 0.083(2^{3.7 \times I_{GR}} - 1) \ldots\ldots\ldots\ldots (5)$$

3.1.5 Determination of Porosity

Porosity can be defined as the percentage of voids to the total volume of rock. Porosity can be calculated using density, neutron, and sonic logs. It was calculated in this project density log (using matrix density, fluid density, and observed log density).

$$\phi_{den} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}} \ldots\ldots\ldots\ldots (6)$$

Where;

ρ_{ma} is the matrix density =2.65gm/cm^3 (Sandstone);

ρ_{fl} is the fluid density = 1.09gm/cm^3 (Fluid density with default brine);

ρ_b is the Formation bulk density

3.1.6 Determination of Effective Porosity

This accounts for the removal of shale volume from the total porosity. It is calculated using the equation below:

$$\phi_{eff} = \phi_{den} * (1 - V_{shale}) \ldots\ldots\ldots (7)$$

3.1.7 Determination of Formation Factor

The formation factor was computed using the Archie Equation below;

$$F = \left(\frac{a}{\phi^m}\right) \ldots\ldots\ldots\ldots\ldots\ldots (8)$$

Where:

F is Formation factor;

ϕ is Porosity;

a is constant (0.62);

m is cementation factor (2.15 for sand).

3.1.8 Determination of Irreducible Water Saturation

When a formation's bulk volume water is constant, a zone is at irreducible water saturation and vice versa. This parameter was computed using the equation below;

$$S_{wirr} = \left(\frac{F}{2000}\right)^{1/2} \ldots\ldots\ldots\ldots\ldots\ldots (9)$$

Where:

S_{wirr} is Irreducible water saturation;

F is the Formation factor

3.1.9 Determination of Permeability (K)

Permeability is the measure of a formation to transmit fluids. The permeability was calculated for the reservoirs using the equation below;

$$K_{oil}^{1/2} = \frac{250\,\emptyset^3}{S_{w_{irr}}} \ldots\ldots\ldots\ldots\ldots (10)$$

$$K_{gas}^{1/2} = \frac{79\,\emptyset^3}{S_{w_{irr}}} \ldots\ldots\ldots\ldots\ldots (11)$$

Where;

S_{wirr} is the irreducible water saturation;

K_{gas} is the permeability of gas fluid;

K_{oil} is the permeability of oil fluid

3.1.10 Determination of Water Saturation

The water saturation for the uninvaded zone was estimated using the following Archie's equations.

$$S_w{}^2 = \frac{F \times Rw}{R_t} \ldots\ldots\ldots\ldots\ldots\ldots (12)$$

$$F = \frac{R_o}{R_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots (13)$$

$$S_w{}^2 = \frac{R_o}{R_t} \ldots\ldots\ldots\ldots\ldots\ldots\ldots (14)$$

Where;

S_w is water saturation of the uninvaded zone;

R_o is the resistivity of formation at 100% water saturation;

F is Formation Factor and R_t is true formation resistivity

3.1.11 Determination of Hydrocarbon Saturation

This is the percentage of pore volume in a formation occupied by hydrocarbons. It is estimated by subtracting the value obtained for water saturation from 100%.

$$S_H = (100 - S_w)\ \% \ldots\ldots\ldots (15)$$

Where;

S_H is the hydrocarbon saturation;

S_w is the water saturation;

4.0 Results and Discussion

Four (4) of the permeable formations, designated RES-A, RES-C, RES-D, and RES-E showed remarkably high resistivity responses indicating hydrocarbon-bearing sandstone units. The summary of calculated petrophysical parameters obtained through the analyses of well logs of four (4) hydrocarbon-bearing reservoirs intercepted in the studied well is presented in Table 1.

The hydrocarbon-bearing reservoirs (RES-A, RES-C, RES-D, and RES-E), were encountered at 9,865-12,538ft TVDSS in the well-*Y*, and have a gross thickness of 53ft, 38ft, 25ft, and 121ft respectively (Figures 4 and 5; Tables 1).

The results reveal reservoir RES-A has a net sand thickness of 53ft, net to gross ratio of 1.0, a volume of shale of 0.13, total porosity of 0.23, effective porosity of 0.20, water saturation of 66%, and hydrocarbon saturation of 34%. Reservoir RES-C has net sand of 38ft, net to gross of 1.0, a volume of shale of 0.12, total porosity of 0.23, effective porosity of 0.20, water saturation of 80%, and hydrocarbon saturation of 20%. Reservoir RES-D has a net sand thickness of 12.69ft, net to gross of 0.51, the volume of shale of 0.17, total porosity of 0.22, effective porosity of 0.18, water saturation of 25%, and hydrocarbon saturation of 75%. Reservoir RES-E has a net sand thickness of about 103ft, net to gross of 0.86, a volume of shale of 0.15, total porosity of 0.23, effective porosity of 0.19, water saturation of 22%, and hydrocarbon saturation of 78%.

All the reservoir sands in the studied well have very good porosities essential for hydrocarbon production. The reservoirs also have good to very good permeability values. The water saturation values of RES-III and RES-IV are 25% and 22% respectively, which indicate high hydrocarbon saturation. The generated petrophysical parameters from the well log data analyses generally indicate reservoir RES-IV as the thickest and have the highest hydrocarbon saturation.

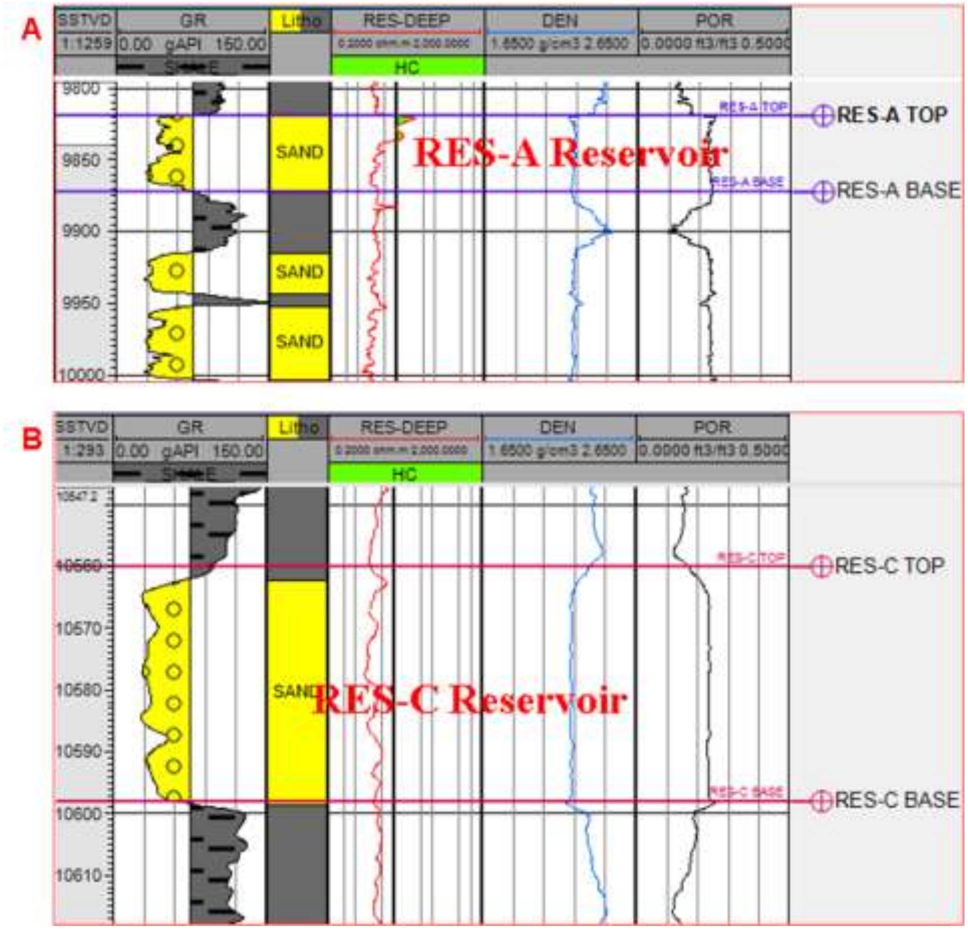

Figure 4: Well log signatures of studied interval in Well-*Y* and the identified reservoir, (a) RES-A and (b) RES-C

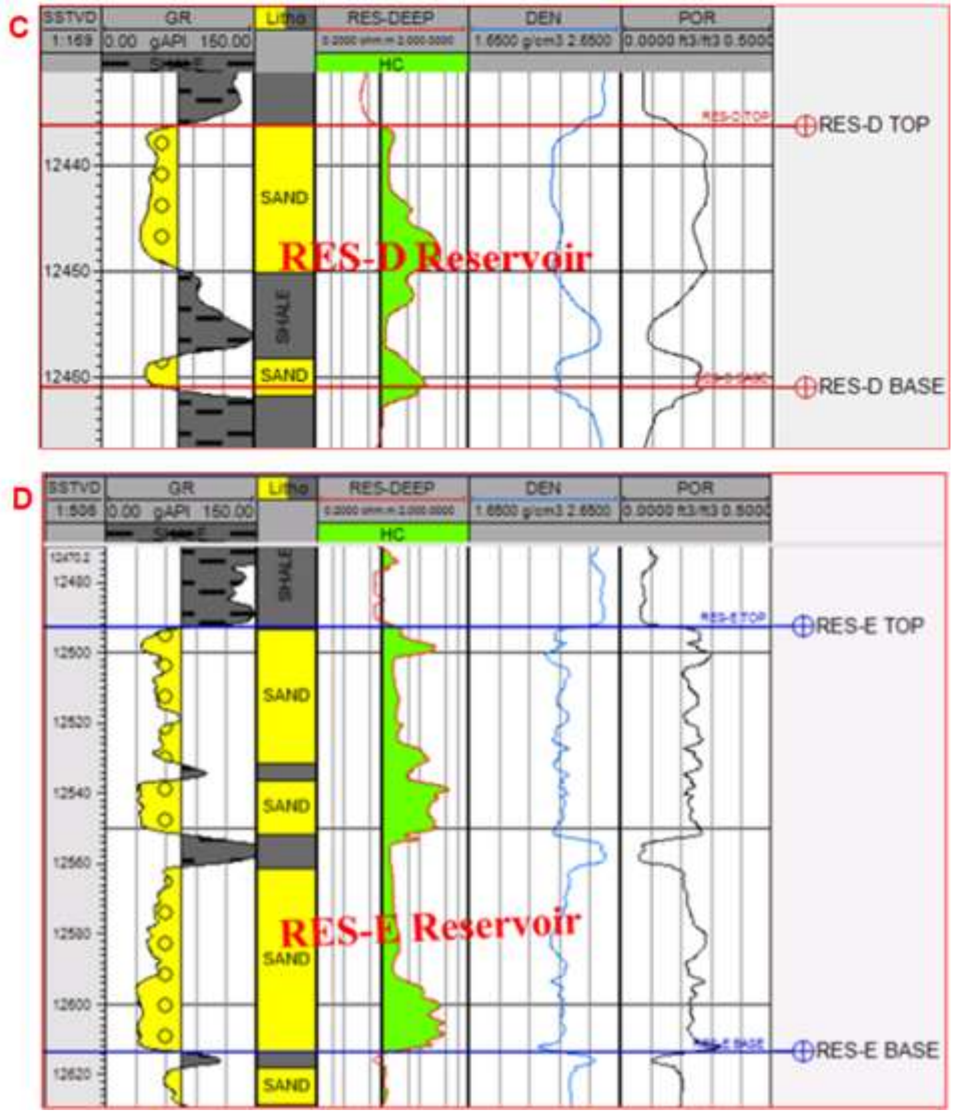

Figure 5: Well log signatures of studied interval in Well-*Y* and the identified reservoirs, (a) RES-D and (b) RES-E

Table 1: Calculated Petrophysical Data for Well-*Y*

Petrophysical Parameters	**RES-A**	**RES-C**	**RES-D**	**RES-E**
Top (ft)	9, 865	10, 606	12, 482	12, 538
Base (ft)	9, 918	10, 644	12, 507	12, 659
Gross Thickness (ft)	53.0	38.0	25.0	121.0
Net Sand Thickness (ft)	53.0	38.0	12.69	103.45
Net-to-Gross Ratio	1.0	1.0	0.51	0.86
Volume of Shale	0.13	0.12	0.17	0.15
Porosity	0.23	0.23	0.22	0.23
Effective Porosity	0.2	0.2	0.18	0.19
Permeability-gas(mD)	94.0	95.0	59.0	86.0
Permeability-oil (mD)	943	953	592	866
Water Saturation (%)	66.0	80.0	25.0	22.0
Hydrocarbon Saturation (%)	34.0	20.0	75.0	78.0

5. 0 Conclusions

This study has evaluated the hydrocarbon potential of well-*Y* located on the coastal swamp depobelt of Niger Delta Basin, Nigeria. The petrophysical analysis of the well-*Y* identified four (4) hydrocarbon-bearing reservoirs namely RES-A, RES-C, RES-D, and RES-E. The net sand thickness of the reservoirs varies from 12.69 ft in RES-D sand to 103.45ft in RES-E sand. The effective porosity values of the reservoirs range from 0.18 in RES-D to 0.2 in RES-A and RES-C reservoirs, while NTG ranges from 0.51 in RES-D to 1.0 in RES-A and RES-C reservoirs. The values of water saturation computed range from 22% in RES-E to 80% in RES-C sand.

The porosities of the identified reservoir sands are very good for hydrocarbon production, also the reservoirs have good to very good permeability values. The water saturation values of RES-III and RES-IV are 25% and 22% respectively, which indicate high hydrocarbon saturation. The generated petrophysical parameters from the well log data analyses indicate that reservoir RES-IV is the thickest, and has the highest hydrocarbon saturation. Reservoirs RES-D and RES-E would be more prolific than others because of their thicknesses and saturation of hydrocarbon. The study is expected to contribute to the planning of the production life of the field where well-*Y* was drilled.

6.0 Acknowledgements

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