SPE-207086-MS

# Assessing Bypassed Hydrocarbons

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This paper was prepared for presentation at the Nigeria Annual International Conference and Exhibition held in Lagos, Nigeria, 2 - 4 August 2021.



## Abstract

Hydrocarbons are bypassed in known fields. This is due to reservoir heterogeneities, complex lithology, and limitations of existing technology.

This paper seeks to identify the scenarios of bypassed hydrocarbons, and to highlight how advances in reservoir characterization techniques have improved assessment of bypassed hydrocarbons.

The present case study is an evaluation well drilled on the continental shelf, off the West African Coastline. The targeted thin-bedded reservoir sands are of Cenomanian age.

Some technologies for assessing bypassed hydrocarbon include Gamma Ray Spectralog and Thin Bed Analysis. NMR is important for accurate reservoir characterization of thinly bedded reservoirs.

The measured NMR porosity was 15pu, which is 42% of the actual porosity. Using the measured values gave a permeability of 5.3mD as against the actual permeability of 234mD.

The novel model presented in this paper increased the porosity by 58% and the permeability by 4315%.

## Introduction

Large volumes of hydrocarbons are known to have been bypassed on a macroscopic and microscopic scale in known fields. This is mainly due to reservoir heterogeneities and complex lithology. Hydrocarbon bypassed on a macroscopic scale should not be confused with hydrocarbon bypassed on a microscopic scale. The aforesaid is the immobile oil trapped in the reservoir pores by viscous and capillary forces and cannot be displaced by water. Hydrocarbon bypassed on a macroscopic scale may be due to limitations of existing technology.

In the context of harder-to-find reserves and rise in development cost, it is vital that hitherto bypassed hydrocarbons are accessed and assessed during drilling and development phases, respectively. This paper seeks to identify the various scenarios of bypassed hydrocarbons, and to highlight how tools evolution and advances in reservoir characterization techniques have greatly improved assessment of hitherto bypassed hydrocarbons.

A reservoir of 1 square mile (640 acres), that has an oil column 200 ft thick, a porosity of 20%, and water saturation of 10% and an oil formation volume factor ($B_0$) of 1.2 contains:

$$\begin{aligned} 7758 \times 640 \times 200 \times 0.2 \times (1-0.1) / 1.2 \quad &= 148.95\, million\, bbls \\ &= \$7.45\, billion\, (@\$50/bbl) \end{aligned}$$

An error of 1ft in depth/thickness is worth +/- \$34.9 M, an error of 1% in water saturation is worth +/- \$80.4 M, and an error of 1% in porosity is worth +/- \$370 M. This underscores the need for accurate reservoir characterization, and the impact of bypassed hydrocarbons on the entire reservoir economics.

The present case study is on an evaluation well drilled on the continental shelf, off the West African Coastline (Figure 1). The targeted thin-bedded reservoir sands are of Cenomanian age (Feng et al 2010). In addition to basic formation evaluation services, Nuclear Magnetic Resonance (NMR) service was deployed to significantly improve the confidence in interpretation of the reservoir fluids.

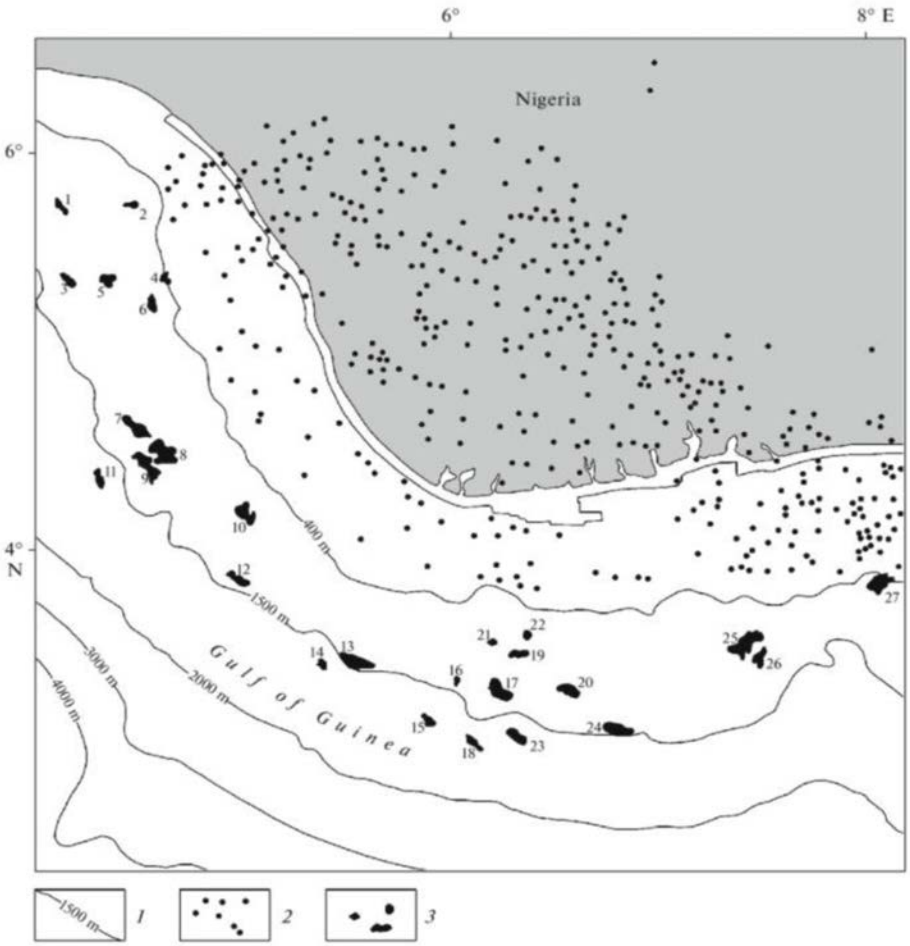


**Figure 1—Schematic map of oil-and-gas-bearing of Nigerian continental margin. Compiled by A. Zabanbark and L.I. Lobkovsky (2017) from materials [6, 11, 12, 18–21]. (1) Water depth isobaths, m; (2) coastal plain and shallow-water hydrocarbon fields; (3) petroleum fields on continental slope. Numbers on the map, names of fields. (1) Adje; (2) Abo; (3) Bosi; (4) Erha North; (5) Erha;(6) Oyo; (7) Bonga NW, (8) Bonga; (9) Bonga SW; (10) Aparo; (11) Nsiko; (12) Uge; (13) Agambi; (14) Ikija; (15) Etan;(16) Bilah; (17) NNWA, Doro; (18) Lura, (19) Bolia; (20) Hota; (21) Sehki; (22) N'Golo; (23) Egina; (24) Akpo; (25) Usan;(26) Ukot; (27) Okpok.**

## Methodology

Some technologies for assessing bypassed hydrocarbon include Gamma Ray Spectralog to enhance shale volume estimation and definition of clay type and volume; and laminated Sand Shale Analysis, which has proven very reliable for assessing bypassed hydrocarbon. The use of NMR is important for accurate reservoir characterization of low resistivity pay zones, like thinly bedded reservoirs. Only NMR provides accurate porosity measurement in complex lithology reservoir.

Conventional gamma ray tools do not differentiate the gamma rays into its three main naturally occurring radioactive elements - Potassium, Uranium, and Thorium. They read only the total gamma ray and thus cannot differentiate radioactive sands from shales. Radioactive sands are caused by the presence of Uranium, which could result from the decay of organic remains.

Gamma Ray Spectralog starts out the same as the standard gross gamma ray count log. Gamma rays from the formation are counted in a detector system. However, there is an added level of sophistication. The gamma ray photon is captured by the detector and a flash of light is emitted. It strikes the photo cathode knocking off electrons. This signal or electrical pulse is amplified by the photomultiplier. The resulting voltage spike, proportional to the gamma ray, is measured and then distributed in the channel corresponding to that voltage. In this way, the voltage amplitude converted into counts is accumulated in the corresponding channel to each distinct element. Once the concentrations of elements are determined, some specific minerals and clay typing can be defined, together with a more accurate shale volume result (Gadeken et al, 1991).

Accurate determination of shale content ensures better indication of reservoir production potential, better definition of clay type and volume, quantitative definition of natural gamma radiation, grain size and mineral identification, and aids fracture detection.

Figure 2 shows a comparison between the total gamma ray reading (green curve and shading) and the Potassium-Thorium log (black dashed curve) reading (total gamma ray minus the Uranium content). As seen above, the actual shale volume is far less than the volume determined by the total gamma counts. Much of the radioactivity is attributed to the presence of Uranium in the sands. The Potassium-Thorium (KTH) log shows that this is a clean sand reservoir with high hydrocarbon potential.

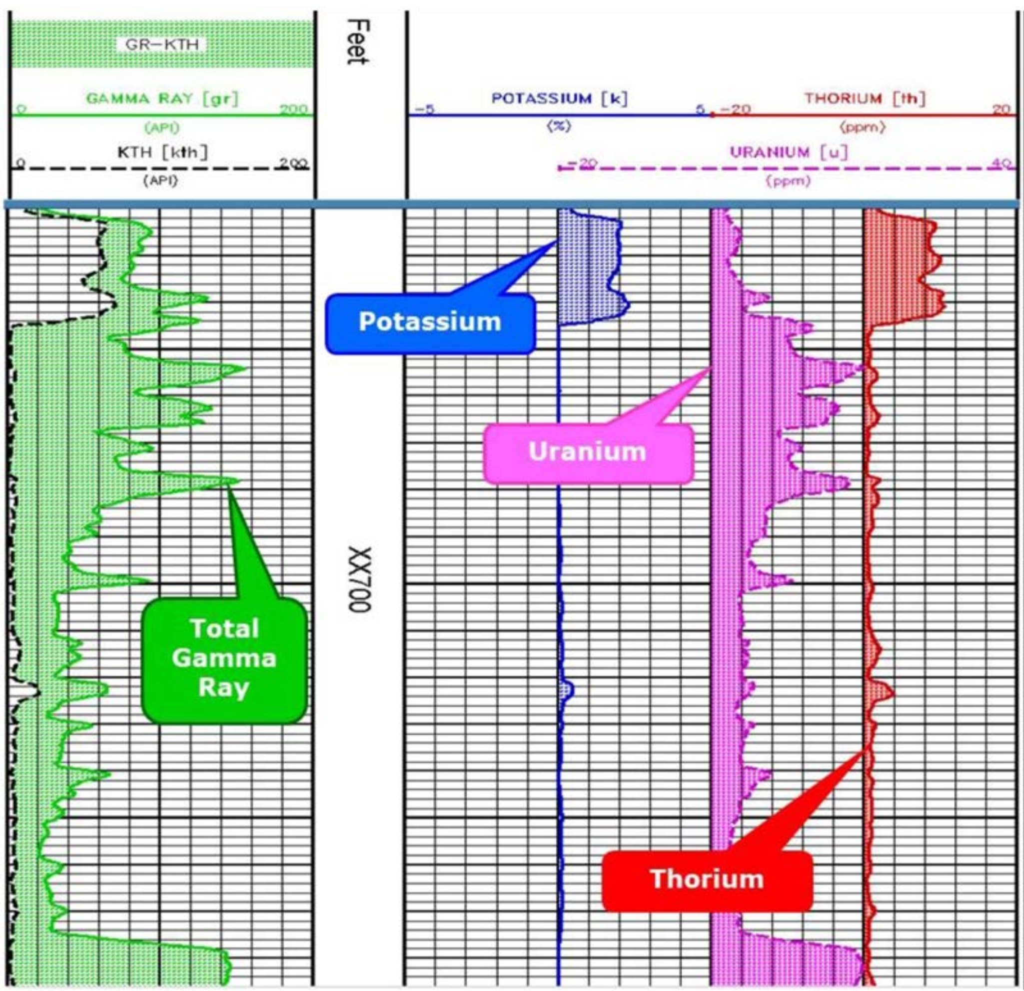


Figure 2—Gamma Ray Spectralog showing over-estimated shale volumes (green shading).

The Laminated Shaly Sand Analysis (LSSA) technique is a log analysis model specifically designed for the evaluation of thin-bedded (Figure 3), low-resistivity sand-shale sequences using vertical resistivity data along with conventional horizontal resistivity data and various porosity and shale indicator methods (Lee et al., 2018). LSSA uses Vertical Resistivity ($R_V$) and Horizontal Resistivity ($R_h$) readings from Multi-component resistivity devices to compute the sand fraction resistivity ($R_{sd}$) and the volume of laminated shale ($V_{lam}$). The Multi-component resistivity devices do not measure each individual sand lamina's resistivity. The Model combines the multi-component resistivity data with porosity measurements from Nuclear Magnetic Resonance to derive the Bulk Volume Hydrocarbon ($BV_{HC}$) of the sand fraction within an interval.

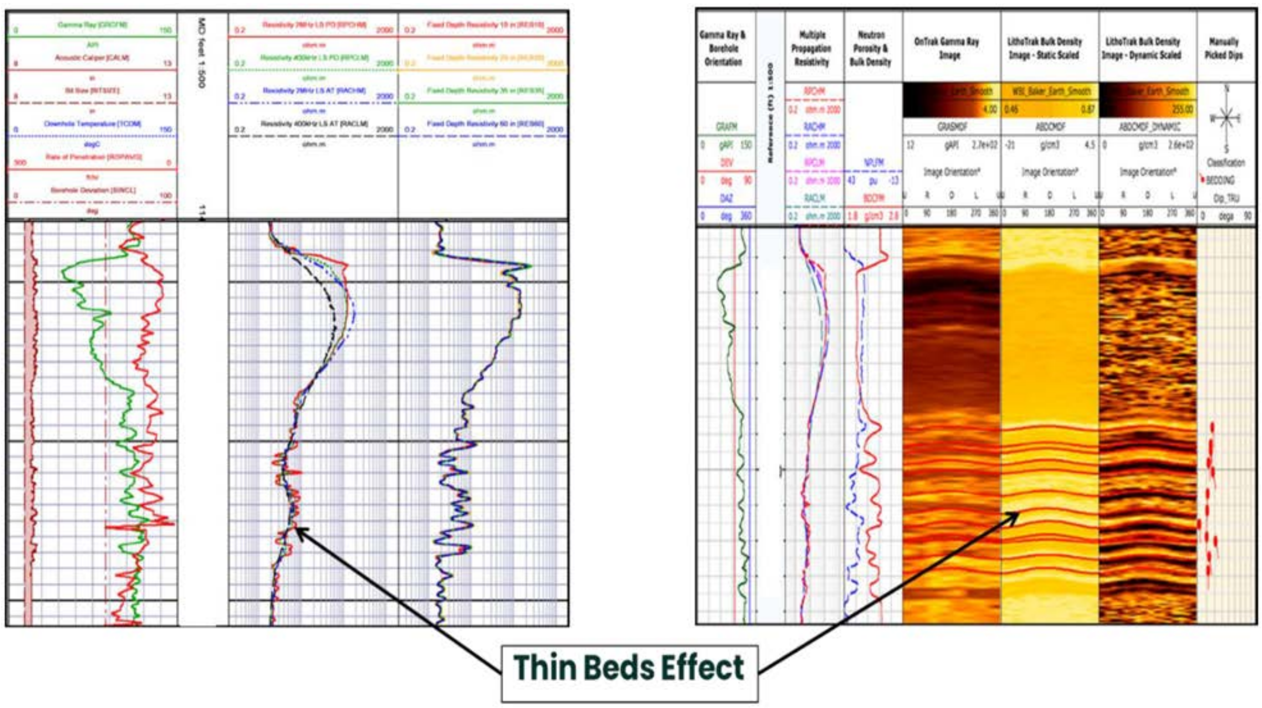


**Figure 3—Thin beds identified by the difference in reading between the phase difference and attenuation logs in logging-while-drilling (LWD) log, and confirmed by LWD images.**

Before the advent of LSSA also referred to as the Tensor Model, Thomas-Stieber had designed several equations to resolve the volume of the different types of shales found in rocks. The equations covered Laminated, Dispersed and Structural Shales. Vlam from the Thomas-Stieber model is entirely dependent on a volumetric relationship between the volume of shale and total porosity; the geometry of the bedding had no significance. The Tensor Model is entirely dependent on the geometry of the sand-shale lamina, also referred to as the macroscopic electrical anisotropy of the formation. The convergence of the volume of shale from the Tensor Model and Thomas Stieber's laminated shale volume provides a cross-validation and additional stability that either model may lack alone in laminated sand-shale sequences (Figure 4).

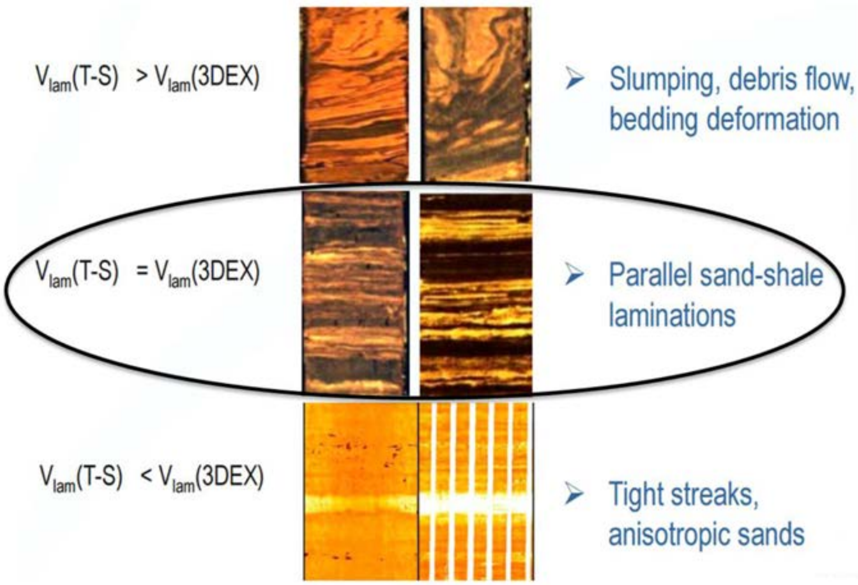


**Figure 4—Comparison of volume of laminated shale from the Tensor Model and Thomas Stieber laminated shale volume in three different formation types. Notice the convergence in the laminated sand-shale sequence.**

Nuclear Magnetic Resonance (NMR) Measures relaxation of hydrogen nuclei in fluids. It is purely an electromagnetic measurement with no nuclear sources. NMR measurements give lithology independent fluid-filled porosity, fluid type, pore size, and textural information of the formation. The readings are compartmentalized into the different sources of formation porosity (Figure 5) – Clay Bound Water (CBW), Bulk Volume Irreducible (BVI or Irreducible Bound Water, and Bulk Volume Movable (BVM). No other tool gives compartmentalized porosity in real time.

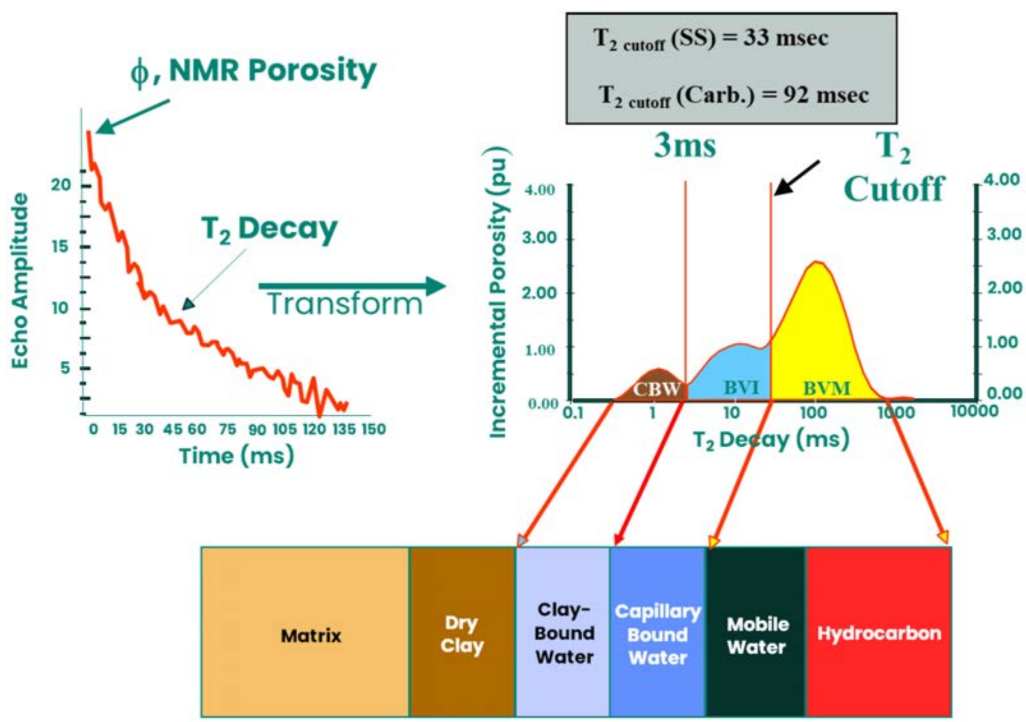


**Figure 5—NMR compartmentalized porosity.**

The novelty approach for assessing bypassed hydrocarbon is a combination of NMR porosity with laminated shale volume computed from the tensor model (Eqns. 1 and 2). This advanced technique aids accurate determination of porosity of individual sand laminae in thin-bedded sand shale sequences. With this technique, hydrocarbon volumes are accurately determined and no hydrocarbon is bypassed.

**Isotropic Laminar Sand Resistivity Component**

$$R_{sd} = R_n \cdot \frac{R_v - R_{sn}}{R_h - R_{sn}} \tag{1}$$

**Isotropic Laminar Shale Volume**

$$V_{lam} = \frac{R_{sd} - R_v}{R_{sd} - R_{sh}} \tag{2}$$

$R_{sh}$ is estimated from log data in massive shale intervals

Where $R_{sd}$ is the resistivity of the sand, $R_h$ is the horizontal resistivity of the formation, $R_v$ is the vertical resistivity of the formation, $R_{sh}$ is the resistivity of the shale, and $V_{lam}$ is the volume of laminated shale.

The NMR tool has an average vertical resolution of 4ft, which is larger than the thickness of most laminated sand shale sequences. Rather than measure the sand or shale properties, the tool measures approximately 4ft of formation comprising sand and shale sequences as a single unit. The readings are neither representative of the sand nor the shale beds. To accurately determine the sand properties, we employ the novel NMR thin bed analysis equations presented in Equations 3 – 6 (modified from Ostroff et al, 1999).

$$MPHE_{Sand} = \frac{MPHE - \left(Vsh_{lam} \cdot MPHE_{Shale}\right)}{1 - Vsh_{lam}} \tag{3}$$

$$MBVI_{Sand} = \frac{MBVI - \left(Vsh_{lam} \cdot MBVI_{Shale}\right)}{1 - Vsh_{lam}} \tag{4}$$

$$MBVM_{Sand} = MPHE_{Sand} - MBVI_{Sand} \tag{5}$$

Where $MPHE_{sand}$ is the effective porosity of the sand, $MPHE_{shale}$ is the effective porosity of the shale, MPHE is the bulk effective porosity reading from the NMR tool, and MBVI is the bulk irreducible water reading from the NMR tool. $Vsh_{lam}$ is the volume of laminated shale, $MBVI_{sand}$ is the irreducible water volume in the sand, $MBVI_{shale}$ is the irreducible water volume in the shale, and $MBVM_{sand}$ is the total movable volume in the sand.

Equations 3 to 5 above are used to accurately determine the sand effective porosity, sand irreducible water volume and total movable volume in thinly laminated sands interbedded with thin shales. The individual sand and shale beds are too small to be resolved by the NMR tool. The tool measures the entire formation as a single body and determines a single reading that is usually about 50% of the actual sand porosity.

Coates-Timur Model :

$$k_{Sand} = \left(\frac{MPHE_{Sand}}{C}\right)^a \cdot \left(\frac{MBVM_{Sand}}{MBVI_{Sand}}\right)^b \tag{6}$$

Where default parameters are: C=10, a = 4 & b = 2

Using the bulk properties readings from the NMR tool and the modeled readings from the laminated sand –shale permeability equation (Eqn. 6, modified from Timur [1968] and Ahmed et al [1991]) will show a remarkable increase in sand permeability ($K_{sand}$).

## Case study

The study area is a Niger Delta ultra-deepwater field located in over 1,000m-deep waters in the Gulf of Guinea, approximately 145km off the coast of Nigeria (Figure 6). Niger Delta Deepwater is comprised of giant deep-water fields, which are some of the largest and highest quality in Africa. All the fields have high quality reservoirs and produce light, sweet crude oil. The field is a faulted anticline with complicated geological characters. The sedimentary Facies of the reservoir is deep-water Turbidite fan, and the lithology of the reservoir is fine-coarse sandstone, which is mainly composed of quartz and feldspar. The reservoir is shallow buried, loose cemented, and weak compacted leading to medium-high porosity and high permeability. Primary intergranular pore forms the main reservoir spaces. The formation fluid is medium oil with low viscosity (Yuan et al, 2020).

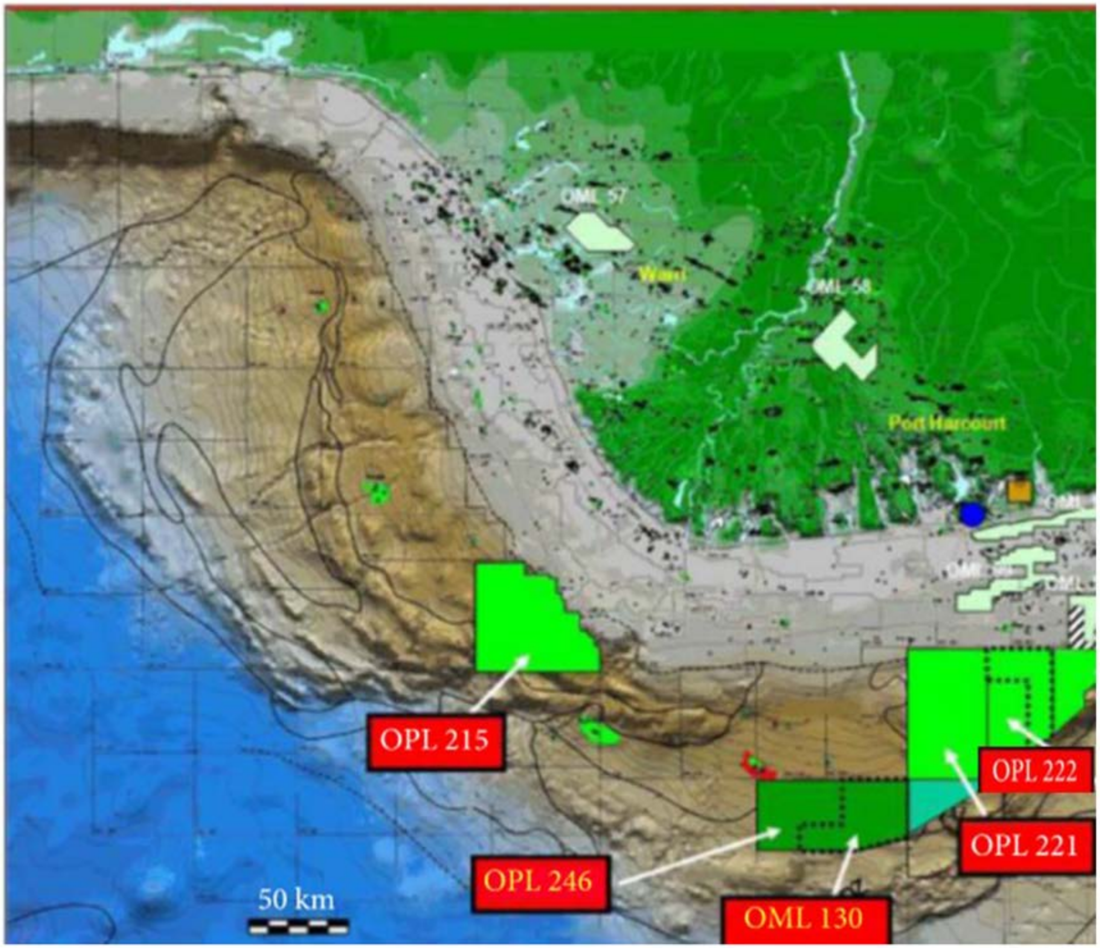


**Figure 6—Location of the study area.**

Formation and evolution of the Niger Delta basin is related to Atlantic cracking and later continuous spreading since the Mesozoic era. Continental rift and passive continental margin basins induced by separation of the African Plate from the North American and South American Plate and the extension of the Atlantic superimpose further geologic signatures on the Niger Delta. The basin experienced three tectonic evolution stages: pre-rifting, rifting and passive continental margin. The Niger Delta Basin is a non-salt basins composed of the Benin, Agbada and Akata Formations (Figure 7).

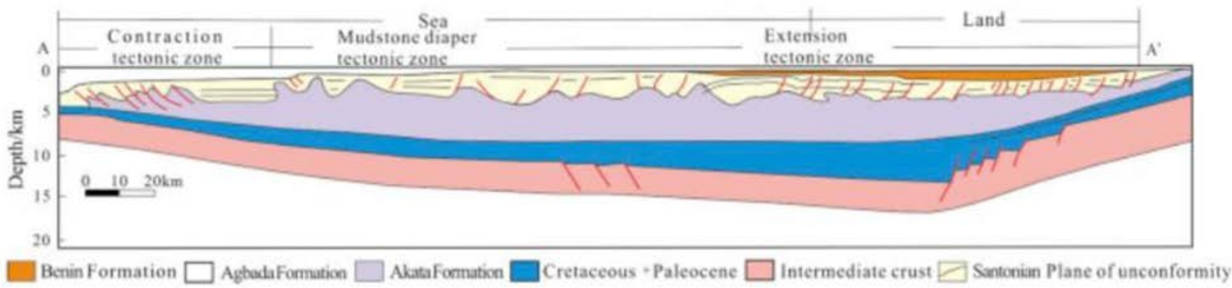


**Figure 7—Geological section of Niger Delta Basin.**

Akata Formation is part of the Tertiary Niger Delta (Akata-Agbada) petroleum system located in the Niger Delta Province, of Nigeria at the Gulf of Guinea, Atlantic Ocean. The upper Akata Formation is cited to be a primary source rock, providing Type II/III kerogen (Owoyemi, 2004), and a potential target in deep water offshore and possibly beneath currently producing intervals onshore. The clays are typically over-pressured due to the absence of enough porous sediments during compaction and are about 3,000 meters vertical depth below mean sea level.

The Agbada Formation dates back to Eocene in age. It is a marine Facies defined by both freshwater and deep-sea characteristics. This is the major oil and natural gas-bearing Facies in the Niger Delta basin. The hydrocarbons in this layer formed when this layer of rock became subaerial and was covered in a marsh-type environment rich in organic content. It is estimated to be 3,700 meters thick. The Benin Formation is Oligocene and younger in age. It is composed of continental flood plain sands and alluvial deposits. It is estimated to be up to 2,000 meters thick (Tuttle et al, 2015).

## Result and Discussion

When NMR tool is passed through a Thin Bedded Formation in the study well, the measured effective porosity (MPHE) is 15pu, which was only about half of the actual effective porosity (35pu) of the sand (MPHEsand). Using the tool measured effective porosity and irreducible bound water, gave a permeability of 5.3mD as against the actual permeability of 234mD computed with values derived from the correct thin bed analysis model (Figure 8).

Fit-for-purpose models are invaluable in the assessment of bypassed hydrocarbons. The novel thin bed analysis model presented in this paper increased the sand porosity by 58% and the sand permeability by 4315%. This underscores the need for application of the right models in reservoir characterization of unconventional reservoirs.

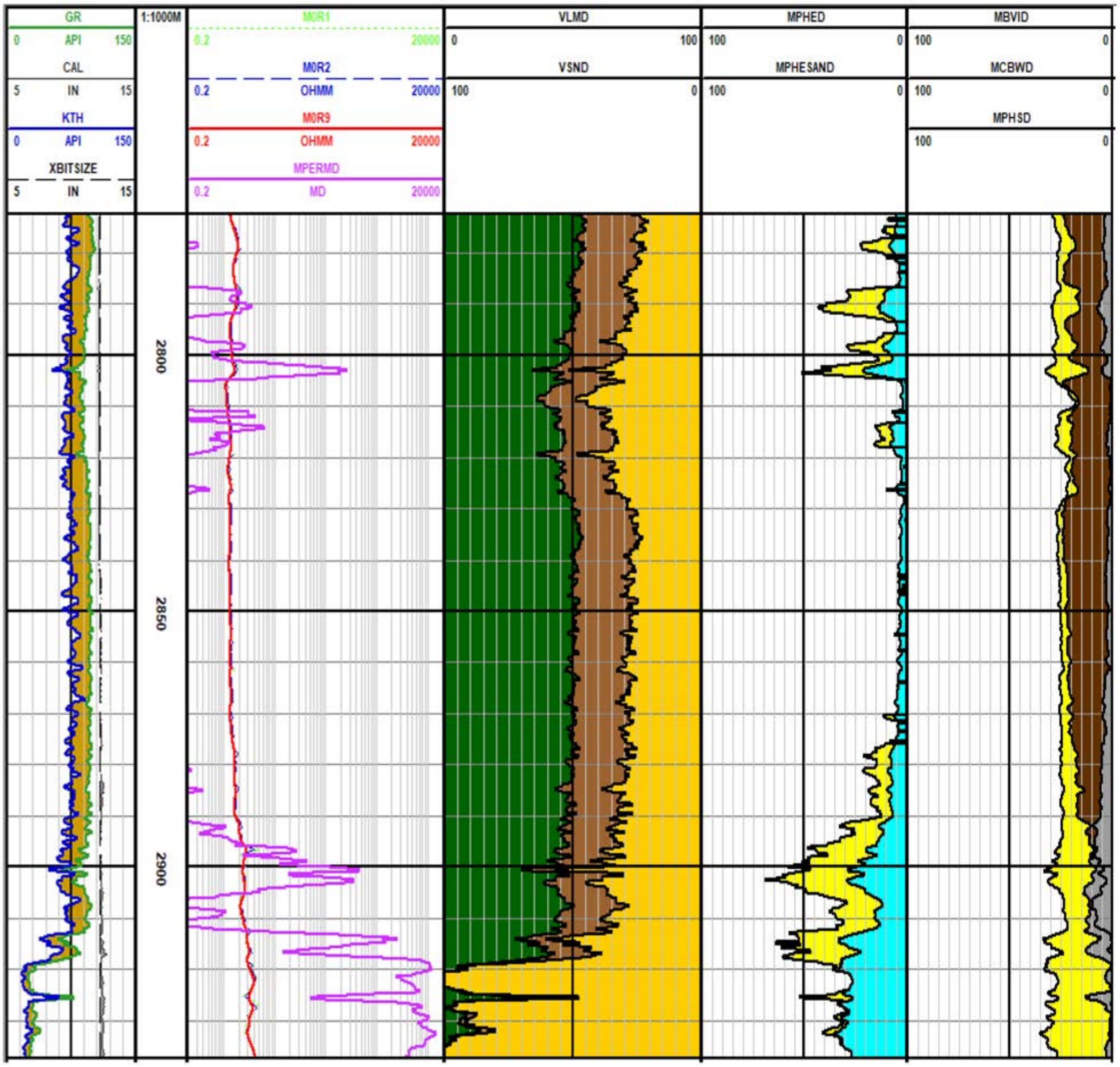


**Figure 8—Tensor model and NMR Thin Bed Analysis Result.**

## Conclusion

Tools evolution and advances in reservoir characterization techniques have greatly improved assessment of hitherto bypassed hydrocarbons. The computed porosity and permeability of the sand fraction of the reservoirs as well as the estimated bulk movable volume of hydrocarbon indicate that the reservoir sands are far more prolific than hitherto thought. This study has therefore contributed to the understanding of hydrocarbon resource potential within the study area.

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