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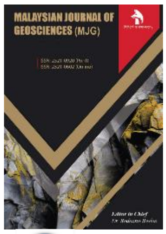

RESEARCH ARTICLE

PETROPHYSICAL ANALYSIS FOR PROSPECT IDENTIFICATION IN BOK FIELD, ONSHORE NIGER DELTA BASIN USING WELL LOG DATA

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ABSTRACT

Well log data acquired from three wells (BOK – 14, BOK - 16 and BOK - 19) from an onshore Niger Delta field (BOK) where used to carry out petrophysical analysis of the field to determine the prospectivity of the field. The *Petrel software 2014™* was used for the petrophysical analysis and prospect identification. The petrophysical analysis revealed four hydrocarbon bearing reservoir sand formations with volume of shale ranging from 13.09% to 22.95%, effective porosity ranging from 19.24% to 24.23, 13% to 22.85%, net to gross ranging 38.66% to 75.40% and hydrocarbon saturation of 54.85% to 72.53%. From the petrophysical properties computed after the detailed petrophysical analysis from the well log data, it was evident that the identified reservoirs in BOK field had very good to excellent petrophysical properties ranges and were therefore prolific, holding great prospects for hydrocarbon fluid saturation which could be exploited for profitable use.

KEYWORDS

Well Log Data, BOK Field, Onshore Niger Delta Basin, Petrophysical Analysis, Prospect Identification, Hydrocarbon Fluid Saturation, Profitable Use.

1. INTRODUCTION

Reservoir characterization for increased oil recovery is constantly needed to meet the growing global demand for petroleum. There is still a lot of oil in existing fields because recovery rates are low, but it is unlikely that the number of fresh discoveries of massive conventional oil fields will be sufficient to supply these demands over time. Existing fields will provide the majority of future oil output. Information from the fields of geology, geophysics, and reservoir engineering will surely be integrated into the science of reservoir characterization. The study of the physical and chemical characteristics of rocks and the fluids they contain is known as petrophysics. The oil and gas industry depends heavily on the definition of petrophysical parameters such as permeability, fluid saturation, area extent, reservoir thickness, and porosity. The majority of the hydrocarbons generated in the Niger Delta basin come from deposits in the pores of permeable and porous rock formations. These pores are determined by the rock's porosity, a crucial petrophysical parameter. Fluid saturation, which measures the amount of gas, water, or oil in the rock's pore spaces, is crucial for figuring out how the fluids are distributed throughout the reservoir. The amount of hydrocarbon reserves contained in the reservoir is determined by the porosity and hydrocarbon saturation. All of these demonstrate how important it is to determine these petrophysical parameters when assessing the hydrocarbon volume and prospectivity of any given field. Numerous other properties, like the rock's mineralogy, pore size, and the type of fluid itself, affect these parameters. Some of these properties may be constant in a homogeneous reservoir while they may differ greatly in a heterogeneous reservoir. Well logs and three-dimensional seismic data are integrated to describe the reservoir in reservoir development projects where understanding the reservoir's thickness and area is crucial.

The aim of this study is to evaluate the petrophysical parameters and determine the prospectivity potential of the BOK field in the onshore Niger Delta basin. The objectives are;

- Log correlation: Log motifs as displayed on the gamma ray log was used to correlate reservoir of similar trend across the wells to show the lateral extent of the reservoir from the available wells in the BOK field.
- Petrophysical analysis: Qualitative and quantitative interpretation to identify porous and permeable beds on the log, determine pore fluid (water and oil bearing zones), calculation of the porosity, permeability, shale volume and the hydrocarbon saturation of the zones of interest.
- Prospectivity prognosis: To infer from calculated petrophysical characteristics if the BOK field offers excellent prospects for comprehensive volumetric evaluation which would be the focus of a complementing future investigation.

This study is beneficial as it would provide the asset managers of the BOK field with subtle information for characterizing reservoirs in the field. The direct prediction of hydrocarbon reservoirs will then be aided by the outcome of the study; ultimately, this will assist the asset managers in lowering risk and uncertainty and preparing them for additional BOK field development plans in the future. A couple of studies around the subject theme of this study have been carried out in both the onshore and offshore Niger Delta basin fields, a few of these studies are presented; Aigbogun and Mujakperuo, (2000) used well log data to evaluate an onshore Niger Delta field. They provided suites of geophysical well logs for three wells for the

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purpose of evaluating the formation, and the sandstone and shale lithology delineated within the logged interval was a distinctive quality of the Agbada formation.

According to the petrophysical parameters of the reservoirs delineated, the shale volume ranges between 0.034 and 0.15, the porosity and permeability values range between 26% and 31% and 1947.08mD and 2541.99mD, and the water saturation ranges between 44% and 98%. Other studies of a similar nature include those conducted in the Niger Delta basin's "X-Y" field, and in the Baze field, onshore Niger Delta basin (Ihianle et al., 2013; Salami et al., 2018). The lead author has also carried out studies in offshore and onshore Niger Delta basin around the same subject matter (Ohakwere-Eze and Adizua, 2014; Adizua and Oruade, 2018A and 2018B; Adizua and Emuoborohwo, 2024).

He equally investigated petrophysical properties of the NEMA field with the integration of core data and subsequently established a correlation pattern for core derived and well log derived petrophysical properties in Adizua and Uzu (2024); Adizua and Odu (2025). The slight departure between the current study and previous studies is the integration of the 3D seismic dataset of the BOK field, which offers a more holistic opportunity to perform advanced volumetric computations leveraging on the structural maps that would be produced from the 3D seismic data, thereby promoting the opportunity for a comprehensive economic appraisal of the BOK field which will be the focus of a complementary future study.

2. Location of The Field, Geological Settings and Characteristics

BOK field is located in the onshore Niger Delta basin between longitude 6^0 34′52.2676′′E to 6^0 47′53.3275′′E and latitude 5^0 13′0.2201′′N to 5^0 19′3.7854′′N. The Niger Delta province encompasses Nigeria, Cameroon and Equatorial Guinea. Known as the Tertiary Niger Delta (Akata-Agbada) petroleum system in Nigeria, the province is located in West Africa's Gulf of Guinea and has a single petroleum system. Targeted from structural traps, the Agbada Formation is the primary source of oil and gas extraction in the region (Ekweozor and Okoye, 1980; Kulke, 1995). As the south Atlantic began to open up, beginning in the late Jurassic and ending in the mid-cretaceous, the Niger Delta basin was created by a failed rift junction during the separation of the South American and African plates (Burke et al., 1972; Whiteman, 1982).

The Niger River, which has the third-largest drainage area in Africa and the ninth-largest in the world, provided sediments for the delta (Rangeley, 1994). The overall area of the Niger Delta is 300,000km^2, its sub-aerial is around 75,000km^2, and its sediment fill is 500,000km^2. A group of researchers identified three lithostratigraphic units in the Tertiary portion of the Niger Delta representing prograding depositional facies that are distinguished from one another mostly on the basis of their sand-shale ratios ranging in age from Paleocene to Recent (Avbovbo, 1978; Doust and Omatsola, 1990; Short and Stauble, 1967; Kulke, 1995). They include the Akata, Agbada and Benin Formations.

2.1 Akata Formation (Marine shale)

The Niger Delta basin's base, or the base beneath the entire delta, is home to the marine-derived Akata Formation. It is made up of silty beds and sand, which were laid down as turbidites and continental-slope channel fills, but it also contains marine shale, which is a possible source rock. Although the exact thickness of this sequence is unknown, it may exceed 7000 meters at the delta's center. Its formation age ranges from the Eocene to the present. Usually, the marine shale sequence is typically over-pressured.

2.2 Agbada Formation (Paralic Clastic)

The Niger Delta's hydrocarbon-prospective sequence is formed by the Agbada Formation, which sits on top of the Akata Formation. The primary hydrocarbon reservoirs in the delta oilfields are made up of the sandy portion of an alternation of sands, sandstone, and siltstones. Shale is particularly crucial for reservoir seals. The paralic sequence, which spans the Eocene to Pleistocene in age, is found in all depobelts, much like in marine shales. This lithofacies reaches a maximum thickness of more than 3000m.

2.3 Benin Formation (Continental Sands)

The Benin Formation, the basin's topmost region and third lithostratigraphic unit, sits atop the Agbada Formation. It is made up completely of non-marine sand that spans in age from Oligocene to Recent and in thickness from 0-2000m. After deltaic deposition shifted southward into a new depobelt, it was deposited in alluvial or upper coastal plain settings. The three Niger Delta basin formations are depicted in a stratigraphic column in Figure 1, and the BOK field's approximate location is displayed on a map of Nigeria that includes the Niger Delta region in Figure 2.

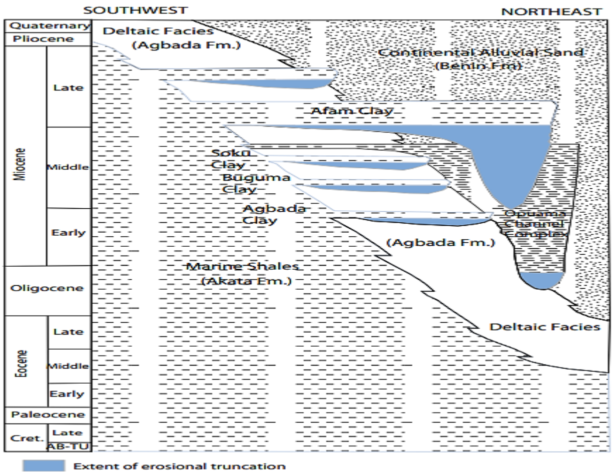

Figure 1: Stratigraphy showing the formations in Niger Delta (Doust and Omatsola, 1990).

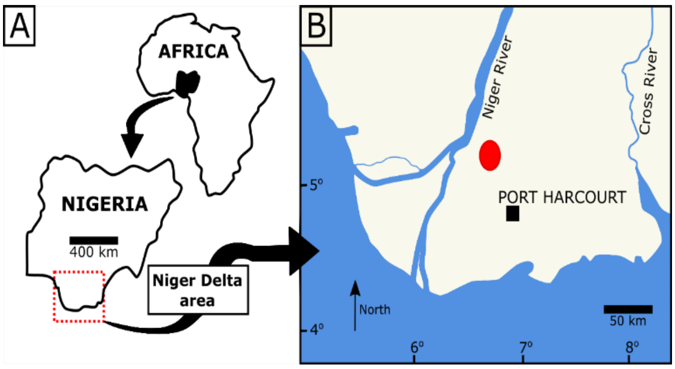

Figure 2: Map of Africa showing the position of Nigeria and also showing the location of the Niger Delta Basin.

3. Overview of Geophysical Well Logging/Logs: Classifications and Applications

Techniques for well logging can yield subsurface geological information. A log is a continuous recording of a set of curves indicating different formation properties that are penetrated in wells, plotted against depth. A geophysical log is created by continuously recording a geophysical parameter along a borehole. Because geophysical sampling during drilling (cutting sampling) leaves a very imperfect record of the formation encountered, geophysical well logging is required. Mechanical coring is a slow and costly method of bringing entire formation samples to the surface. The outcome of coring is clear-cut. It requires interpretation to elevate a record to the level of geological or petrophysical experience, logging is exact and ambiguous. But with experience, calibration, and computers, logs bridge the gap between cuttings and cores. The (physical) principle of measurement can be used to classify geophysical logging techniques. There are two basic kinds: Tools that measure parameters or properties provided by the formation or by the interaction of the formation and the borehole fluid without the need of a source (such as spontaneous potential or gamma rays) are known as passive tools. Tools that monitor the reaction to a signal, pulse, radiation, or current—that is, the outcome of a contact with the material nearby—are known as active tools. They usually consist of one or more detectors (such as acoustic, density, neutron, and resistivity logs) and a source. Logs from a thorough well logging process can reveal information about the following:

i. Is a reservoir present?
ii. Potential reservoir depth.
iii. The reservoir's thickness.
iv. The reservoir's lithology.
v. The reservoir's porosity.
vi. The reservoir's size.
vii. Content of fluid.
viii. Guidelines for reservoir production.

4. Petrophysical Parameters of Interest and Their Computational Empirical Models

The main petrophysical parameters of interest to this study which were used to evaluate the reservoir prospectivity of BOK are listed below and briefly explained;

- Porosity
- Water/Hydrocarbon saturation
- Shale volume
- Permeability

4.1 Porosity

The volume of the pore space divided by the volume of the rock that contains the pore space is the definition of a formation's porosity. The issue of whether or not the pores are connected is disregarded by this definition of porosity. Effective porosity is inter-granular porosity that is interconnected. Ineffective pores are those that are obstructed in some manner (by silt, clay particles, etc.). Porosity is a non-dimensional parameter expressed as a fraction or percentage.

$$\text{Porosity } (\varphi) = \frac{Volume\ of\ pore\ space}{Total\ volume\ of\ rock} * 100 \quad (1)$$

Porosity can be determined indirectly from logs (density, neutron and acoustic logs).

Acoustic porosity may be estimated from the Wyllie Rose time average equation; $\varphi_s = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_{fl} - \Delta t_{ma}}$ (2)

where Δt_{log}=sonic log reading, Δt_{ma}=matrix transit time, Δt_{fl}=pore fluid transit.

Porosity from neutron-density log; $\varphi_{N-D} = \frac{\varphi_N + \varphi_D}{2}$ (3)

where φ_N= neutron porosity, φ_D= density porosity.

Density log; $\varphi = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}$ (4)

4.2 Water saturation (S_w)

Water saturation is defined as the volume fraction of the pore space occupied by water expressed in fraction or percentage.

$$S_w = \frac{Formation\ water\ occupying\ pores}{Total\ pore\ space\ in\ the\ rock} \quad (5)$$

Water saturation is obtained indirectly from resistivity log using (Archie, 1942) model;

$$S_w = [\frac{R_0}{R_t}]^{1/n} \quad (6)$$

where R_0 = F*R_w

And F = $\frac{a}{\varphi^m}$

Therefore $S_w = \sqrt[n]{\frac{a * R_w}{R_t * \varphi^m}}$ (7)

F = formation resistivity factor ($\frac{a}{\varphi^m}$), φ = porosity, a = tortuosity factor (0.62 - 2.45), m = cementation factor (1.0 - 2.15), R_w = Resistivity of the formation water, R_t = True resistivity, R_0 = Resistivity of 100% water saturated rock.

Where there is no knowledge of local parameters the following values can be used; n = m = 2.0, a = 1.0.

The hydrocarbon saturation is the fraction of pore volume in a formation occupied by oil and gas. It is obtained by subtracting the computed water saturating in a reservoir from one (1). The hydrocarbon saturation is given as;

$$S_h = 1 - S_w \quad (8)$$

where; S_w = water saturation and S_h = hydrocarbon saturation.

4.3 Shale volume

This is the portion of the reservoir rock that is made up of shale (clay) (Cannon, 2016). The volume of shale in porous reservoirs can be determined using gamma ray logs since shale is more radioactive than sand. To calculate the volume of shale from a gamma ray log, the first step is to calculate the gamma ray index. Here is a list of the steps involved:

Read the gamma ray activity associated with the zone of interest (GR_{zone}).

Select a clean shale-free zone and read(GR_{clean}).

Select a zone 100% shale and read (GR_{shale}).

$$I_{GR} = \frac{GR_{zone} - GR_{clean}}{GR_{shale} - GR_{clean}} \quad (9)$$

where; I_{GR} = Gamma ray index, GR_{zone} = Gamma ray reading of formation, GR_{clean} = Minimum gamma ray (clean sand or carbonate), GR_{shale} = Maximum gamma ray (shale).

Larionov (1969) equation for tertiary reservoir rock was used to calculate the shale volume from gamma ray index:

$$V_{sh} = 0.083*[2^{(3.7*I_{GR})} - 1] \quad (10)$$

where V_{sh} = shale volume.

4.4 Permeability (K)

The ease with which fluids can pass through a formation is measured by its permeability. The millidarcy (mD) or Darcy (D) is the unit of permeability. Since virtually no information regarding the permeability of formations can be obtained via geophysical well logging surveys, certain empirical relations that link porosity and permeability have been presented.

The Timur (1968) model yields;

$$K = \frac{0.136\varphi^{4.4}}{Sw_{irr}^{2}} \quad (11)$$

Employing the equation of Owolabi *et al.* (1994), the permeability (K) can be calculated from;

For oil;

$$K = 307.0 + 26552.0\,(\emptyset_E^{\,2}) - 34540.0\,(\emptyset_E * S_{wirr})^2 \quad (12)$$

For gas;

$$K = 30.7 + 2655\,(\emptyset_E^{\,2}) - 3454\,(\emptyset_E * S_{wirr})^2 \qquad (13)$$

where; S_{wirr} = irreducible water saturation

Irreducible water saturation also called critical water saturation. It defines the maximum water saturation that a formation with a given permeability and porosity can retain without producing water.

$$S_{wirr} = \sqrt{\frac{F}{2000}} \qquad (14)$$

where: $F = \frac{0.81}{\emptyset^2}$, in most sandstone reservoir is the Formation factor.

5. Materials and Methods

5.1 Materials (Data Sets and Processing/Analysis/Computational Tools)

Well data (well header, suites of logs, well trajectory, checkshot) were used to carry out this study. Table 1 show details of the well data acquired and analysed in the course of the study.

Table 1: Description of well log data and header parameters used for the study

DATA SET/WELLS	BOK - 14	BOK – 16	BOK - 19
Well header	YES	YES	YES
Well trajectory	YES	YES	YES
GR log	YES	YES	YES
Density log	NO	YES	NO
Neutron log	YES	YES	YES
Sonic log	NO	YES	NO
Bit size log	YES	YES	YES
Caliper log	YES	YES	YES
Pef log	YES	YES	YES
Spontaneous log	YES	YES	YES
Deep resistivity	YES	YES	YES
Medium resistivity	YES	YES	YES
Shallow resistivity	NO	NO	YES

An essential component of the well data information was the well header data. This data included specifics regarding the wells' elevation depth (KB, DF, RT), total depth (TD), and individual position (surface X, Y). Before a quantitative interpretation was carried out, the individual logs were merged and used for a quick look interpretation (lithology identification, reservoir zones, and fluid discrimination) of the distinct log traces. GR in GAPI, LLS, Rxo, Rt in ohm, RHOB IN g/cm3, NPHI in V/V, caliper and bitsize in inches, photoelectric log in B/E, spontaneous log in mV, and sonic in us/ft were all given along with the log depth in meters. Microsoft Excel was used to plot log curves, while Schlumberger software *Petrel 2014™* was used for data processing, analysis, and computations. The Petrel exploration and production software was used to perform petrophysical analysis while the Microsoft excel was used primarily for graphing.

5.2 Methods (Research Workflow)

Every aspect of the workflow shown in Figure 3 is discussed below and these steps were carefully followed through for a successful completion of the focal aim of the study.

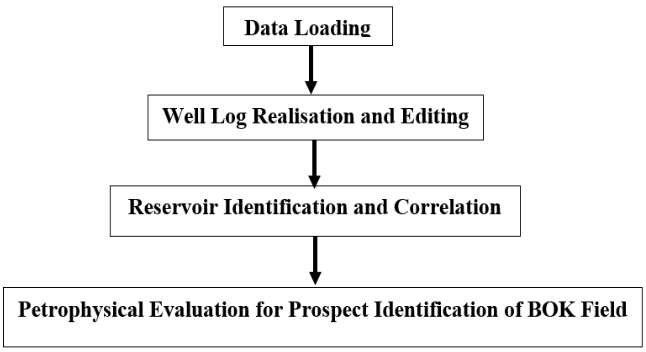

Figure 3: Workflow for petrophysical analysis of BOK field for prospectivity appraisal.

5.2.1 Data Import

The first step in performing data analysis properly is data importing. A new file is made, and the units and coordinate reference system are adjusted to correspond with the data. The proper file type was used to import the log data, well header, and well deviation.

5.2.2 Petrophysical Analysis

The study of rock characteristics and how they interact with fluids is known as petrophysics. Electrical resistivity, electron density, sound velocity, and other physics-type parameters are used in almost all logging measurements to describe formations. Understanding the amount and distribution of water and hydrocarbons in a subsurface reservoir is the primary objective of petrophysical investigation. Petrophysical models are estimated using a set of empirical formulas that connect the formation properties to log measurement. Interpreting well logs provides a solution in two aspects:

- Qualitative
- Quantitative

Qualitative interpretation—also known as quick-look interpretation—identifies permeable and porous beds and their borders, as well as the pore fluids, subsurface strata correlation, and facies that are indicative of depositional conditions. In contrast, a thorough quantitative interpretation can fairly accurately predict the fractional volume of shale, water saturation, hydrocarbon saturation and its bearing zones, permeability, porosity, and other log-derived parameters. The basic background resources required for an accurate and perceptive log interpretation are listed below;

- Understanding of typical log responses.
- Empirically derived equations for quantitative interpretation.
- Applying all of the knowledge (geology, cuts, cores)

5.2.3 Qualitative Interpretation

5.2.3.1 Lithology Delineation

Examining the many lithology logs that were made available helped identify the lithological units. In addition to the spontaneous potential, caliper, bit size, and neutron density cross plot, a combination of the gamma ray log and photoelectric (Pef) log were taken into consideration. Sand-shale intercalation predominates in the formation of Niger Delta clastic sedimentary rocks, which are the consequence of weathering or fragmentation of pre-existing rocks and minerals. Because of the presence of radioactive isotopes like potassium, uranium, and thorium in this formation, the gamma ray log in this area shows low values (0-75 API) for sand formation and very high values (> 65-200) for shale formation. Sand is shown by a yellow gamma ray log, while shale is indicated by a brown one. The photoelectric log value is a sensitive indication of mineralogy since it directly correlates with the total atomic number of the constituent elements in a formation. According to the photoelectric log, the typical reference values for reservoir minerals at zero porosity are calcite 5.08, dolomite 3.14, and quartz 1.81. Figure 4 shows a typical example of lithology delineation slightly below 1500m on the depth track. The gamma ray value on the first track was 21.4395 GAPI, while the Pef log value on the third track was 1.4675 B/E.

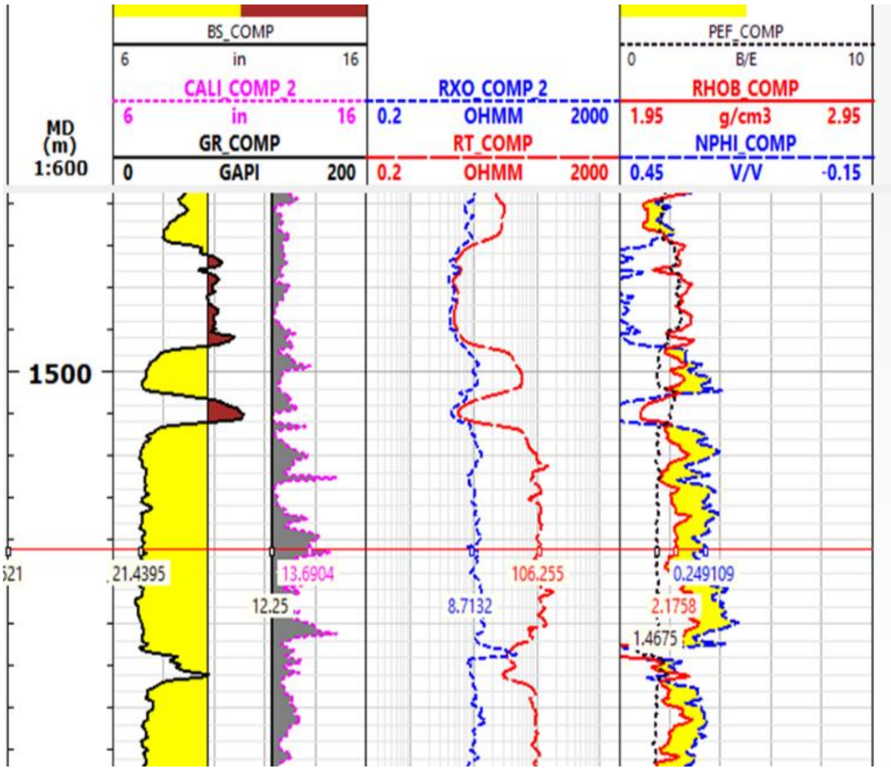

Figure 4: Lithology identification using gamma ray log and photoelectric log.

5.2.3.2 Reservoir/Fluid Discrimination

Three fluids are often found in hydrocarbon reservoirs: gas, oil, and water. A mix of lithology logs, resistivity logs, and neutron density logs cross plotted on the same track are used to determine reservoirs and their fluid volume. High resistivity values suggest zones saturated with hydrocarbons, whilst low resistivity readings indicate zones bearing water. According to Figure 4 above, the yellow sand interval on the gamma ray log indicates a good separation between the flushed zone's resistivity (Rxo) and the uninvaded zone's real resistivity (R_T), which is a sign of permeability. If the neutron value on the neutron density cross plot is not very low, it leads to tight formation and can also affect resistivity log values, and therefore high actual resistivity is most likely a zone of interest. They can also be used as a lithology discriminator if the density and neutron logs are put on the same track, operated on a compatible scale, and have one track inverted. On track three, the neutron log (blue) is on the right and the density log (red) is on the left for sand. With a big region between both logs indicating gas saturation (also known as the balloon effect) and limited separation indicating oil saturation, this cross plot can also be used to deduce the kind of hydrocarbon present in the formation.

5.2.3.3 Well correlation

Using gamma ray logs to help with the lithostratigraphic correlation of the relevant log pattern, three wells are shown on the well section window based on how close they are to one another. Determining the continuity and equivalency of lithological units, especially reservoir sands or marker sealing shale, throughout a subsurface formation is known as correlation.

5.2.4 Quantitative Interpretation

Finding porosity, water saturation, hydrocarbon saturation, shale volume, net to gross (NTG), and permeability of prospects from well log data is an intriguing field of petrophysics known as practical quantitative interpretation. It may be necessary to determine an intermediary property (such as shale volume) before determining any or all of these petrophysical properties.

5.3 Shale Volume

This is the portion of the reservoir rock that is made up of shale (clay) (Cannon, 2016). The volume of shale in a shaly formation can be calculated in a variety of methods. The most rapid and popular method is by the use of the gamma ray log. Equations (9) and (10) in section 4.0 above have already described the empirical relations needed for its computation.

5.4 Water saturation (S_w)

Water saturation is defined as the proportion of the pore space occupied by water and expressed in percentage. Equations (5), (6), (7), and (8) in section 4.0 already introduce Archie's equation for its computation.

5.5 Porosity (ø)

Equations (1), (2), (3), and (4) in section 4.0 provide a clear definition of the methodology for calculating porosity from log data. There was no discussion of the formula for effective porosity, which is of major interest for petrophysicists. Below is a basic introduction to it.

5.6 Effective porosity

This is the proportion of a material's bulk volume to its interconnected pore volume. The porosity that causes flow in a reservoir is known as the effective porosity.

$$\emptyset_E = (1 - V_{sh})^*\emptyset \quad (14)$$

5.7 Permeability (K)

The ease with which a fluid can pass through a formation is measured by its permeability. The millidarcy (mD) is the unit of permeability. In section 4.0, equations (11), (12), and (13), clearly define the methodology for calculating permeability (K) from log data.

5.8 Hydrocarbon pay

The overall reservoir thickness in a well is referred to as the gross reservoir thickness. Hence, it reflects all of the rock in a reservoir between two levels; non-shale layers are subtracted from the total to leave a net reservoir thickness, or the interval of high-quality rock. Therefore, the net-to-gross (NTG) ratio is the ratio. The intervals in a well containing movable hydrocarbons defined and computed from user-set petrophysical cut-offs are represented by hydrocarbon-bearing levels, or net pay.

6. Results and Discussions

In this study, four hydrocarbon bearing sands A, B, C and D was delineated across three (3) wells to ensure proper characterization of the reservoirs. The three wells were correlated as shown in Figure 5.

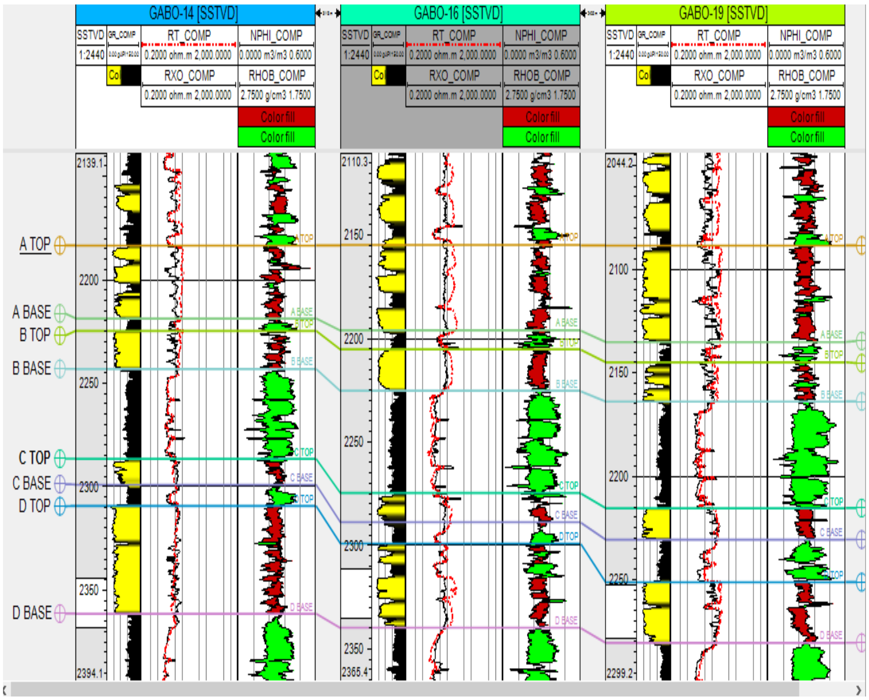

Figure 5: Vertical well display showing correlation of reservoir sand A-D

Using suites of logs provided for the three (3) wells, six (6) petrophysical parameters were evaluated for reservoir A, B, C and D in Tables 2 - 5. These parameters are volume of shale, total porosity, effective porosity, permeability, water saturation and hydrocarbon saturation. Figure 6 and 7 shows the graphical plot of the various petrophysical parameters for each well.

Table 2: Petrophysical parameters for reservoir A

WELLS	Thickness	Vsh (%)	NTG (%)	$\emptyset_T(\%)$	$\emptyset_E(\%)$	$S_w(\%)$	K (mD)	$S_h(\%)$
BOK - 14	36.04	18.00	51.64	25.89	21.79	63.63	171.874	36.37
BOK - 16	41.72	17.09	62.22	27.56	23.20	36.68	183.945	63.32
BOK - 19	45.84	21.91	50.83	26.85	21.52	35.14	168.025	64.86
AVERAGE		**19**	**54.90**	**26.77**	**22.17**	**45.15**	**174.61**	**54.85**

Table 3: Petrophysical parameters for reservoir B

WELLS	Thickness	Vsh (%)	NTG (%)	$\emptyset_T(\%)$	$\emptyset_E(\%)$	$S_w(\%)$	K (mD)	$S_h(\%)$
BOK – 14	18.63	18.00	18.46	25.89	21.79	20	96.600	80
BOK – 16	19.44	16.73	56.10	23.81	20.37	39.36	154.783	60.64
BOK – 19	19.37	33.82	41.41	22.37	15.57	37.31	114.322	62.69
AVERAGE		**22.85**	**38.66**	**24.02**	**19.24**	**32.22**	**121.90**	**67.78**

Table 4: Petrophysical parameters for reservoir C

WELLS	Thickness	Vsh (%)	NTG (%)	$\emptyset_T(\%)$	$\emptyset_E(\%)$	$S_w(\%)$	K (mD)	$S_h(\%)$
BOK - 14	12.96	18.00	58.49	25.89	21.79	63.63	171.874	36.37
BOK - 16	41.72	17.09	75.47	27.56	23.20	36.68	183.945	63.32
BOK - 19	45.84	21.91	92.22	26.85	21.52	35.14	168.025	64.86
AVERAGE		**13.09**	**75.40**	**27.49**	**24.23**	**39.41**	**199.073**	**60.59**

Table 5: Petrophysical parameters for reservoir D

WELLS	Thickness	Vsh (%)	NTG (%)	$\emptyset_T(\%)$	$\emptyset_E(\%)$	$S_w(\%)$	K (mD)	$S_h(\%)$
BOK - 14	51.83	15.93	62.59	23.38	20.28	55.70	155.038	44.4
BOK - 16	40.9	15.12	64.07	23.62	20.57	46.20	155.283	53.80
BOK - 19	45.84	19.71	63.52	24.51	21.19	35.56	162.24	64.44
AVERAGE		**16.92**	**63.40**	**23.85**	**20.68**	**27.47**	**157.520**	**72.53**

The average petrophysical parameters for reservoir A, according to the results of the petrophysical analysis, are 45.15% for water saturation, 174.61mD for permeability, 54.90% for net-to-gross, and 22.17% for effective porosity. The average petrophysical parameters for Reservoir B are as follows: 121.90mD for permeability, 38.66% for net-to-gross, 19.24% for effective porosity, and 32.22% for water saturation. The average petrophysical parameters for Reservoir C are as follows: 199.073mD for permeability, 39.41% for water saturation, 75.40% for net-to-gross, and 24.23% for effective porosity. Lastly, the calculated average petrophysical characteristics for reservoir D are water saturation at 27.47%, permeability at 157.520mD, net-to-gross at 63.40%, and effective porosity at 20.68%. The standard values in Table 6 were compared with the calculated porosity and permeability for reservoirs A, B, C, and D. The results showed that the four reservoirs have very good porosity and good permeability. Generally these four reservoirs exhibits good petrophysical properties and therefore holds great prospect for BOK field.

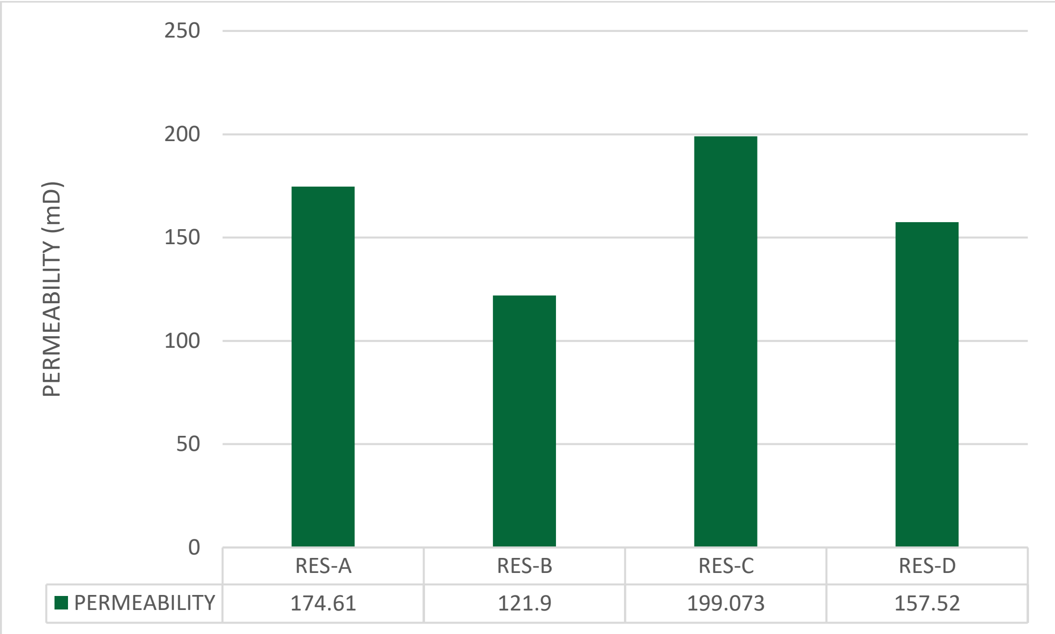

Figure 6: Histogram plot of average permeability in reservoir A, B, C and D.

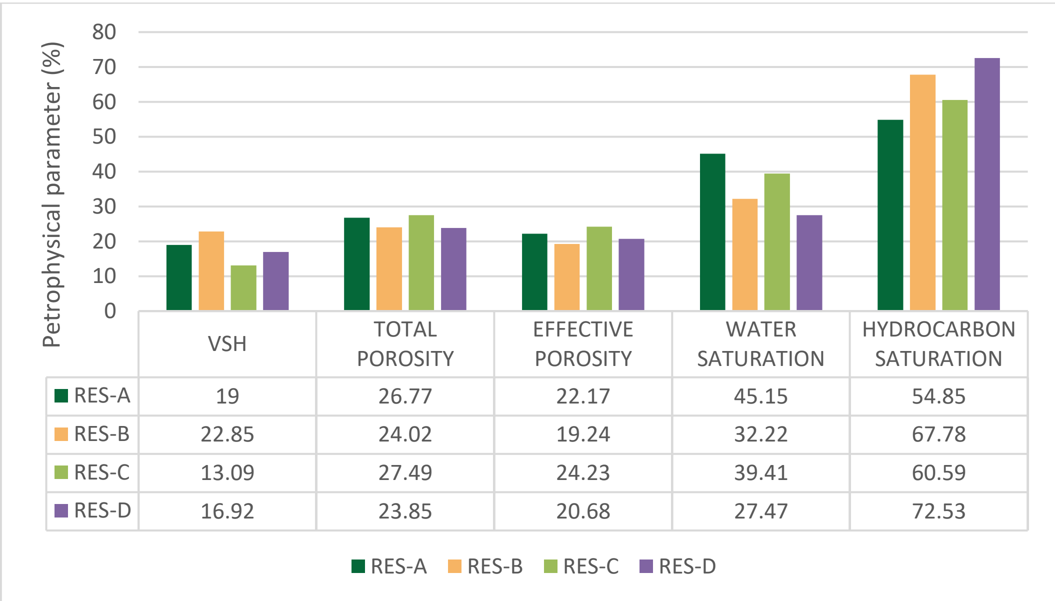

Figure 7: Histogram plot of average petrophysical parameter in reservoir A, B, C and D.

Table 6: Qualitative evaluation of porosity and permeability (Adopted from Riders, 1996).

Percentage porosity (%)	Qualitative Description
0-5	Negligible
5-10	Poor
15-20	Good
20-30	Very good
>30	Excellent
Average permeability value	**Qualitative Description**
<10.5	Poor to fair
15-50	Moderate
50-250	Good
250-1000	Very Good
>1000	Excellent

The two primary lithologies identified by the qualitative and quantitative analysis of the available suite of logs, as depicted in Figure 5, are interpreted as sandstone and shale, respectively, and are completely consistent with the geology of the Niger Delta basin. With a high sand/shale ratio and an increasing trend of shale thickness, the chosen sandstone lithologies exhibit a similar gamma ray log theme throughout the area, which is suggestive of the dominant Agbada formation of the Niger Delta basin, where oil exploration and drilling are now being conducted. According to a study, the intercalations are essentially the result of movements in the delta depositional axes and differential subsidence fluctuation in the sediment supply, which leads to local transgressions and regressions (Short and Stauble, 1967). We leveraged on the two resistivity values; the medium resistivity value R_{XO} and the deep resistivity value R_T to aid in the fluid discrimination. The petrophysical analysis of the sandstone facies was interpreted as good quality reservoir with NTG values between 38.66% - 75.40%, porosity value between 19.24% - 24.23%, permeability values between 121.90mD - 199.073mD. The reservoir quality is consistent and similar to other reservoir systems reported by Ihianle *et al.,* (2013) in "X-Y" field of Niger Delta basin and Salami *et al*., (2018) in Baze field, Onshore Niger Delta.

7. Conclusion

The BOK field has been evaluated for its prospectivity and hydrocarbon potentials in this study. From the detailed petrophysical analysis undertaken in the course of the study, four hydrocarbon bearing reservoir sand formations with volume of shale ranging from 13.09% to 22.95%, effective porosity ranging from 19.24% to 24.23, 13% to 22.85%, net to gross ranging 38.66% to 75.40% and hydrocarbon saturation of 54.85% to 72.53%. From the petrophysical properties computed after the thorough petrophysical analysis and computations from the well log data, it was evident that the identified reservoirs in BOK field had good to very good petrophysical properties ranges and were therefore prolific, holding great prospects for hydrocarbon fluid saturation which could be exploited for profitable use. The authors wish to advance the quantitative interpretation objectives of the BOK field by means of initiating a complementary study that will integrate 3D seismic data acquired from the field to carry out a detailed volumetric assessment of the prospectivity of BOK to guide in the field economics assessment of the field that would help steer the course for drilling and exploitations programs in the BOK field.

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Conflict of Interest

The authors declare no conflict of interest.

Authors Contributions

The authors conceived and designed the work, performed the data processing, analysis and interpretation with the first author as team lead. The second author and third author wrote the first draft and second drafts of the paper respectively, while the first author vetted, corrected and edited the manuscript to its current form and now serves as lead/corresponding author. All the authors approved the manuscript in its current form.

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