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WELL LOG CORRELATION AND PETROPHYSICAL INTERPRETATION OF "OS"-FIELD, NIGER DELTA

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ABSTRACT

This study presents correlation analysis of four wells in 'OS'-field in the Niger Delta. The sand and shale were first differentiated by the GR based on the relative occurrence of radioactivity in sand and shale. SP log differentiates permeable and impermeable beds based on differences in mud filtrate in the borehole and formation water. Three major sands (A, B and C) were correlated at the depth intervals (1736.95 - 1809.06 m), (1931.79 - 2052.82 m) and (2180 - 2285.89 m) respectively across the wells. In Well 2, radioactive sand was identified at 2013.83 m measured depth. It has a low GR curve but positive SP deflection. It is suspected that sand B in this well is radioactive (red) and therefore fake sand. It is treated as shale and it is part of shale resistivity marker. The shale correlation was done using Deep Induction Log (ILD). Three Shale Resistivity markers (SRM), SRM1, SRM 2 and SRM 3 were identified. Petrophysical analysis of the three mapped reservoir was also carried out. It revealed average porosity of 1.55, water saturation of 9.0%, hydrocarbon saturation of 91.0% and hydrocarbon pore volume of 91.16%. The porosity and hydrocarbon pore volume values of the reservoir within the field proved them to be quite prolific.

Key words: Petrophysics, Radioactive sands, Reservoir, Spontaneous potential, Deep Induction.

INTRODUCTION

Reservoir characterization has evolved through several generations such as the originally petrophysics, geologic analogs, and more recently on multidisciplinary integration. The petrophysical approach began in the 1950s, where reservoir attributes were determined using logs, cores, and well tests. Multidisciplinary approach, attempts to integrate all available geologic, engineering, and geophysical data along with modern probabilistic and risk analysis techniques to produce a better reservoir model. The geophysical (well log) data of this multidisciplinary approach was used in this research work. The use of exploratory wells that are drilled through prospective geological structures have been of greater assistance in evaluating the hydrocarbon potential of so many locations (Illo, 2015). Radioactive sands have often been mistaken for pay sands during an initial review of well logs. This means we might miss potential pay zones unless we integrate all the available log, core, sample, and laboratory data (Crain, 2016). In order to estimate the quantity of hydrocarbon accumulation in reservoir rocks (sandstone, limestone or dolomite), some basic petrophysical parameters must be evaluated.

The proper knowledge of the petrophysical properties of a reservoir depends on the investment in coring or well logging. Tiab and Donaldson (2004) defined Petrophysics as "the study of rock properties and their interactions with fluids (gases, liquid hydrocarbons, and aqueous solutions)". In petroleum studies, petrophysical properties are those properties of the reservoir which enable the reservoir rocks to store and transmit reservoir fluids thus also enabling quantitative determination of the constituent hydrocarbon as well as the appropriate method of extraction of the fluids (Samuels, 2013). These parameters include Gamma Ray Index, Porosity, Thickness, Formation Factor, Hydrocarbon Saturation, Permeability, Water Saturation, Volume of Shale, Effective Porosity, Formation Water Resistivity, Resistivity, Index, Bulk Volume Water, Hydrocarbon Pore Volume, Irreducible Water Saturation and Net to Gross Ratio.

This work is aimed at taking a step further to delineate pay zone by differentiating it from radioactive sand in order not to miss it for pay zones while drilling and further determine the prolific nature of the wells in the chosen oil field. The objectives include:

- Delineate the sand and shale units in the study area.
- Defining the reservoir geometry and then,
- Identify and correlate the sand units in the study area,
- Identify the radioactive sands within the wells with comparison of gamma ray and spontaneous potential logs,
- Identify and correlate the shale units in the study,
- Carry out petrophysical analysis of the reservoir units.

The outcomes of this research study include: reduction of uncertainties in determination of pay zones and precise interpretation of the petrophysical properties associated with the identified reservoirs.

Study Area

The "OS" field is located onshore Niger Delta, some 55 km south of Onitsha in the southeastern area of Nigeria as depicted in Figure 1 while Figure 2 shows the distribution of wells on the base map. It straddles at deeper levels to the west into the concession border with Shell. The Niger Delta basin is situated on the continental margin of the Gulf of Guinea between latitude 3^0 and 6^0 N and longitude 5^0 and 8^0 E (Opara, *et al.*, 2011). The Niger Delta started to evolve in early Tertiary times when clastic river input increased (Doust and Omatsola, 1990). The Cenozoic Niger Delta is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of the continents of South America and Africa in the late Jurassic (Whiteman, 1982). Generally the delta prograded over the subsidizing continental-oceanic lithospheric transition zone, and during the Oligocene spread on to oceanic crust of the Gulf of Guinea (Adesida, *et al.*, 1997). The weathering flanks of out-cropping continental basement sourced sediments through the Benue-Niger drainage basin. Thickness of sediments in the Niger Delta averages 12 km covering a total area of about 140,000 km^2.

According to Short and Stauble (1967), the Niger Delta comprises of a regressive sequence of deltaic and marine clastics, defined by three major lithofacies. From the base, predominantly marine shale, made up of Akata Formation, followed by paralic sequence of Agbada Formation and topmost non-marine alluvial (continental) sands of the Benin Formation (Figure 3).

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Figure 1: Map showing study area.

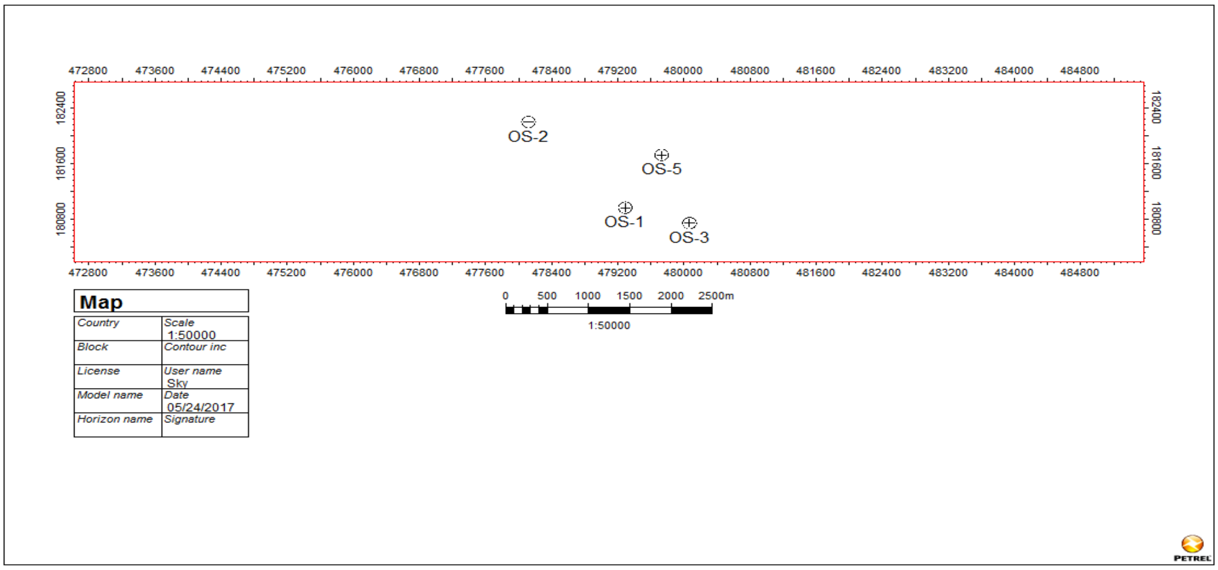

Figure 2: Base map of the study area showing the distribution of wells.

The Akata is made up of thick shale sequences and it serves as the potential source rock. It is assumed to have been formed as a result of the transportation of terrestrial organic matter and clays to deep waters at the beginning of Paleocene (Tuttle et al., 1990). Doust and Omatsola (1990), estimated the thickness of this formation to be about 7,000 m thick, and it lies under the entire delta with high overpressure. Agbada Formation is the major oil and gas reservoir of the delta, it is the transition zone and consist of intercalation of sand and shale (paralic siliciclastics) with over 3,700 m thick and represent the deltaic portion of the Niger Delta sequence (Doust, 1990; Tuttle et al., 1990).

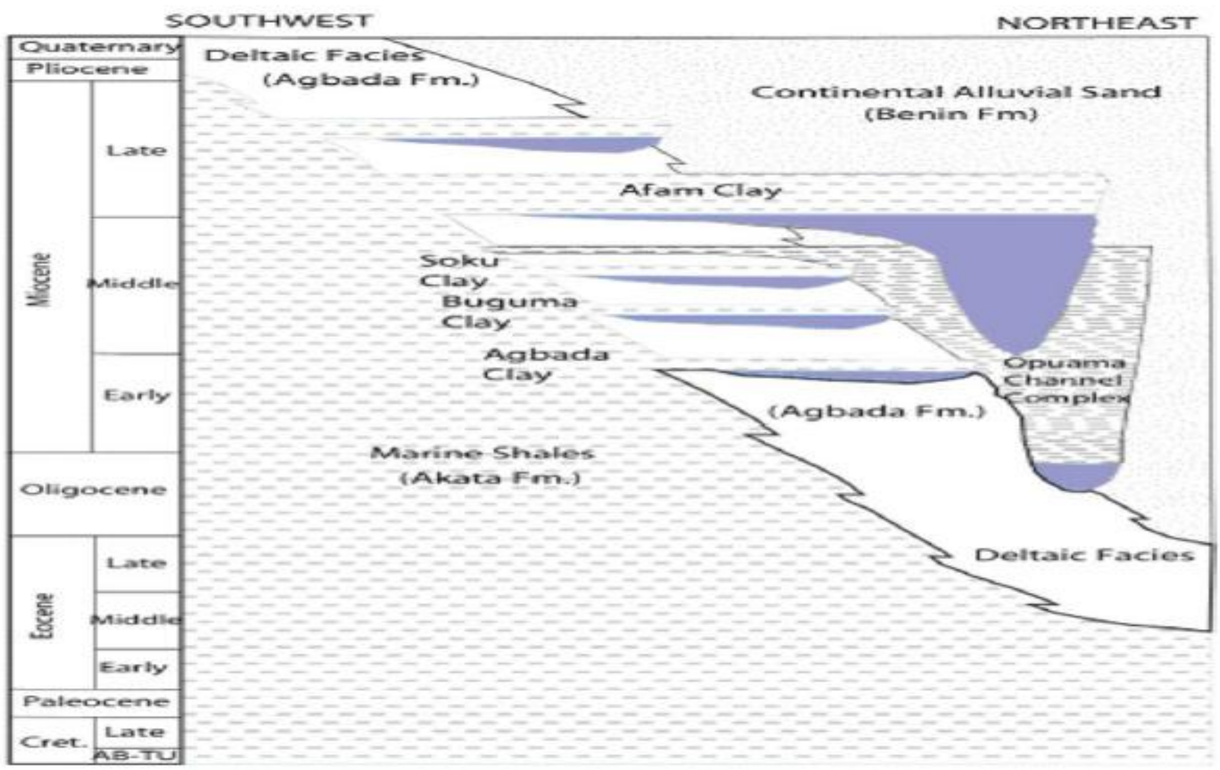

Figure 3: Stratigraphic column showing the three formations of the Niger Delta (Modified from Doust and Omatsola (1990).

The last 40 million years have been important in shaping the geology of the Niger Delta. The petroleum potentials associated with this area have attracted so many geological and geophysical studies which range from petroleum geology, sedimentology and stratigraphy, bio-stratigraphic and paleontology and to amplitude variation with offset/amplitude variation with angle, AVO/AVA (Illo, 2015). A good number of researchers have done their work using petrophysical techniques to quantify the amount of hydrocarbon in place but a few have done their work to detect radioactive (fake) sands in the area.

Nwankwo and Nwosu (2016) carried out an investigation on the shale content in sand reservoirs in parts of Chad Basin, Nigeria. It was successfully delineated by estimating the Gamma ray index in a given stratigraphic unit and utilizing the computed value to evaluate the shale volume and porosities of the area. The sand units within the four stratigraphic zones of the basin were evaluated. The depths of high gamma ray counts correspond to high gamma ray index and shale volume. The evaluated shale volumes in the reservoirs were moderate to low and do not vary linearly with depth or well location. The differences in value could have resulted from different depositional processes and faulted areas, which is capable of causing pinch out in the reservoir. The reservoirs in the northeastern wells were observed to be relatively thicker than those in the west and hence it can be inferred that the direction of deposition of sands is east west. However, the reservoirs

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in the south central contain more shale and will therefore have poor petrophysical properties than the reservoirs in the north east with lower shale volume. The estimated shale volumes, reservoir thickness and porosities in all the wells, however, support hydrocarbon potential in the basin. The net-to-gross sand thickness shows similar consistency in the thickness trend for all the wells.

Ologe (2016), made use of neutron, density, gamma ray and resistivity logs to analyze eighteen (18) reservoirs. The correlation of the reservoirs depicted that the subsurface stratigraphy is that of sand shale interbreeding. The delineated zones of interest (eighteen in number) have an average net sand thickness of between 12 m – 209 m, average effective porosity in the range of 0.068 to 0.28 and hydrocarbon saturation ranging from 0 to 85% which are favorable indicators for commercial hydrocarbon accumulation. The quality of the reservoirs is determined by the average permeability values of 1 to 6206 md, and the porosity value was also between 6.83 to 28 percent. Consequently, petrophysical evaluation of the reservoirs showed that the porosity ranges from very poor to excellent while the permeability varies from poor to excellent. The water saturation value ranges from 15 to 100%, while the hydrocarbon saturation of the well ranges from 0 to 85%. From the value of the bulk volume of water, the reservoirs are at irreducible water saturation, implying that the reservoirs can produce water-free hydrocarbon. The result of the formation evaluation shows that reservoir zones AR1, AR3, AR5, AR7, AR9 and AR15 contain oil, reservoirs AR2, AR4, AR6, AR8, AR11 and AR12 contain gas while reservoirs AR10, AR13, AR14, AR16, AR17 and AR18 are water filled. The contact between the oil and water (Oil water contact- OWC/Free Water Level) is at a depth of 6670 ft.

Olisa and Oke (2014) in their study presented correlation analysis of three wells in X-field in the Niger Delta, using three well logs namely Spontaneous Potential (SP), gamma ray (GR) and deep induction log (ILD). Three major sands were correlated. These sands are sand 1, sand 2 and sand 3 at 1463 m, 1509 m and 1570 m respectively at measured depths in all the wells. Sand 1, 4800 sand is in the same position in all the Wells. In Well A-2, radioactive sand was identified at 5000 ft measured depth. This is equivalent to 4950 ft sand in Wells A-1 and A-3. The shale correlation was done using Deep Induction Log (ILD). Three Shale Resistivity markers (SRM) were identified in the wells. These are SRM1, SRM 2 and SRM 3.

Akpabio *et al*., (2014) correlated and did petrophysical analysis of well log data from eight wells located in the X-fields of the Niger Delta Basin. Well log data were obtained from sonic, gamma-ray, matrix density and resistivity logs. The Petrophysical characteristics investigated were porosity, water saturation, tortuosity and permeability. The results of the analysis revealed the presence of different sand and shale units. The thickness of each sand unit was highly variable, ranging between 6.1 and 21.5 m. Average porosities vary between 25.0 and 72.0 percent and generally decreasing with depth. A modeled water saturation showed a better value for water saturation (calculation) for non-Archie media. The average water saturation of these units varied between 5.0 and 64.0 percent. These values are generally high for the sand units in varying wells. Similarly, the average permeability values varied between

22.0 and 70.0. Their study was carried out to find out if the petrophysical parameters computed in the field will encourage deeper drilling in the area of study and it did proved to be.

Amigun and Odole (2013), in their petrophysical properties evaluation for reservoir characterization of Niger Delta using a field they called SEYI oil field said that reservoir with porosity ranging from 0.22 to 0.31 indicates a suitable reservoir quality, permeability values from 881.58 md to 14425.01 md attributed to the well sorted nature of the sands and hydrocarbon saturation range from 20.29% to 91.97% implying high hydrocarbon production.

In the work of Abraham-Adejumo (2013), Neutron, density, gamma ray, resistivity/conductivity logs were employed in the analyses and examination of an oil field in western Niger Delta. Four wells, R1, R2, R3 and R4 were considered. Three hydrocarbon bearing reservoirs (L, P and S) of varying thicknesses were identified and mapped at the depths of 2,943 m, 3,248 m and 3935 m respectively. Across the wells, reservoir L shows an averaged porosity of 30.5 % and Volume of shale of 14%. In R1, R3 and R4, it has an averaged hydrocarbon saturation of 80.7%. R2 is 100% water saturated. Reservoir P shows averaged porosity and volume of shale of 30.5% and 23% respectively. R1 and R3 shows averaged hydrocarbon saturation of 79.5% the reservoir was found not to be economically viable in R2 and R4 at all. Reservoir S shows an averaged porosity of 29.5% and Volume of shale of 10.5%. In R1, R2 and R3, it has an average hydrocarbon saturation of 81.3%. The reservoir is not yielding well in R4.

According to the work Adewoye *et al*., (2013) on Maiti field, the hydrocarbon reservoir sand delineation, the petrophysical analysis, reservoir ranking and structural analysis revealed that Maiti field is a prolific hydrocarbon zone. Three hydrocarbon reservoirs were delineated. Petrophysical parameters for the reservoir sands have porosity, φ range of 0.28 – 0.35, permeability k (mD) range of 68-168, hydrocarbon saturation, Sh range of 0.65 to 0.68 and volume of shale Vsh range of 0.02 – 0.15. The average values of these petrophysical parameters were used to rank the three reservoirs R1, R2, R3.
It was deduced that reservoir R1 is the most oil prolific reservoir while R2 is the least within Maiti field. The time structure maps of the top the three reservoirs showed a fault assisted anticlinal structure known as structural trap within Maiti field, Niger delta, Nigeria.

The work of Amigun *et al*., (2012) presented the log analysis results of a suite of geophysical logs comprising gamma ray (GR), resistivity (LLD), neutron (PHIN) and density (PHID) logs from six wells in 'Laja' Field located in the Niger delta. The analysis was carried out to evaluate the field's hydrocarbon prospect i.e. identify hydrocarbon bearing reservoir(s) and study reservoir properties based on log data from the six wells. Eleven zones of interest (sand bodies) were delineated and correlated across this field. Six of these sands were further identified as potential hydrocarbon reservoirs. The computed petrophysical parameters for the reservoir layers have porosity range of 13% – 38% and hydrocarbon saturation range of 0.16% to 22.2%. The analysis indicates that reservoirs (sands) are encountered at depth range of 4350 m to 7650 m with relative

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permeability to oil ranging from 314.0 to 18521.8 md. These results on the whole suggest that the reservoir sand units of 'Laja' Field contain significant accumulations of hydrocarbon.

According to Egbai and Aigbogun, (2012), eleven sand reservoirs (or zones) were observed in the well of which eight wells of the reservoirs are hydrocarbon bearing while the remaining three are water bearing zones. The porosity value of the well is between (23.36 – 33.03) % while hydrocarbon bearing sand, ø ranges between (9-40) %. This shows from the porosity value obtained from the data, we can conclude that the reservoirs are productive except R8, R10 and R11. Most of the reservoirs in the well are gas bearing. The hydrocarbon saturation Sh of all the hydrocarbon bearing zones ranges from (74.18 – 94.64) % in the well with water saturation while water bearing zones have the value of Sw= 100%. High resistivity, Rt values in all the hydrocarbon bearing zones were observed from the data. Thus, from the petrophysical analysis results, high quality reservoir characteristics, porosity and permeable sand were highly observed in the well.

Ulasi *et al.*, (2012) reported that the characterization of the Uzek Well reservoir sand bodies was made possible by the careful integration of well log responses and core information. The study examined the vertical sequence of lithologies of the sand bodies, trend of data, and log interpretation. A detailed petrophysical parameter estimation of their work showed that: Reservoir quality was found to be strongly influenced by grain size, the high values of porosities and permeabilities are attributed to the well sorted nature of the sands. Also porosity and permeability increased with increasing reservoir quality. Average water saturation values range from 12 to 54, while the average hydrocarbon saturation values range from 35 to 94. And that quantitative porosity verification shows good correlation between log and core porosities. The discrepancies existing in cross plots obtained are due to the heterogeneities of the formation and to the fact that the core data are from spot sample measurements, while log represent an average and continuous measurement.

In a study by Opafunso *et al*., (2008), eleven wells were correlated in an oil field belonging to Chevron Nigeria Limited using Petrel software workflow. The work was done to determine the structural styles favourable for hydrocarbon accumulation. Result from their study suggests that one of the well code named B2 was a hydrocarbon water formation with a tendency of very little exploitable hydrocarbon present. They reported however that three other wells were prolific in hydrocarbon accumulation.

MATERIALS AND METHODS

In the petroleum industry, the principal areas from which data can be generated are: Well Logs (Wire line or Logging-While-Drilling), Seismic survey, Laboratory analysis of core and others. While the significance of other data sources cannot be under-rated, it is however important to state that for the purpose of this research task, emphasis would be placed on well log data. The method of study includes lithology analysis, well log correlation and petrophysical analysis using Schlumberger's Petrel Software. The first step was lithology analysis to differentiate sand and shale beds using Gamma Ray log. The second step is sand correlation and shale correlation by combining the Gamma Ray (GR), Spontaneous Potential (SP) and Deep

Induction (ILD) logs. Finally, the petrophysical interpretation was carried out.

PETREL Software

The PETREL software contains INPUT Section, called PETREL Explorer; into which data can be imported. Except for well data, all the other principal data categories are imported obeying similar procedure. It is important to mention that data to be imported must be compatible with the PETREL Format. Data type imported into PETREL for correlation and petrophysical analysis is contingent on the intended purpose of the work to be done by the software.

Well Logs

In petroleum industry, well logs play a vital role in oil and gas exploration and reservoir evaluation. When a well drilling is finished, a decision must be made as to whether to complete the well or abandon it. Well logs often provide the data that help make the correct decision. A well log is a graph of depth in well versus some characteristics or properties of the rock. The rock properties are derived from measurements made when instruments are lowered into the well on an electrical wireline or cable. A single well log cannot exclusively extract all relevant data from a reservoir. Data obtained from well logs fitted for specific activities are assimilated and utilized for the evaluation of the reservoir. Four wells, namely OS-01, OS-02, OS-03 and OS-05 that penetrated reservoirs of interest were used for this study and only data for the Agbada formation were acquired.

Well log correlation

Three steps were used in the correlation analysis. The first step was lithology analysis to differentiate sand and shale using gamma ray log. The lithology delineation of the study area was done using the gamma ray (GR) log. GR value criteria of 70 API on a scale of 0-150 API for high GR sandstone reservoir was used. The second step is sand correlation and the third step is shale correlation. The logs used are Gamma Ray (GR), Spontaneous Potential (SP) and Deep Induction (ILD) logs.

Petrophysical Analysis

Petrophysical analysis involves the use of empirical formulae to estimate the petrophysical properties of the mapped reservoir units delineated on the well logs. The reservoir units which were identified through the use of the electrofacies signatures were further characterized quantitatively to arrive at these petrophysical parameters.

Gamma Ray Index

The gamma ray log was used to determining the gamma ray index using the formula according to Asquith and Gibson, (1982):

$$I_{GR} = (GR_{LOG} - GR_{MIN}) / (GR_{MAX} - GR_{MIN}) \quad 1$$

Where,

I_{GR} = gamma ray index

GR_{LOG} = gamma ray reading of formation from log

GR_{MIN} = minimum gamma ray (clean sand)

GR_{MAX} = maximum gamma ray (shale)

Volume of Shale

The volume of shale was calculated by applying the gamma ray index in the appropriate volume of shale equation according to Larionov (1969) for tertiary rocks:

$$V_{sh} = 0.083[2^{(3.7 I_{GR})} - 1.0] \quad 2$$

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Where,
V_{sh} = volume of shale

Net to Gross Ratio
This is the ratio between the net reservoir thickness and the gross reservoir thickness.
NTG = $Net\ thickness\ /\ Gross\ Thickness$ 3

Porosity
The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity ($\emptyset_D$), and then the neutron-density porosity ($\emptyset_{N-D}$), was estimated using the neutron ($\emptyset_N$) porosity coupled with the density derived porosity.

The Wyllie equation for density derived porosity is given as:

$$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid}) \quad 4a$$

Where:
ℓ_{max} = density of rock matrix = 2.65 g/cc
ℓ_b = bulk density from log
ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water).

The Neutron – Density porosity could be calculated according to Shell/Schlumberger (1999) as:

$\phi_{N-D}, = (\emptyset_N + \emptyset_D)/2$ (For oil and water column) 4b

Effective Porosity
This is the porosity of the interconnected pore spaces. It assumes the absence of shale from the reservoir. It can be calculated using the following relationship:

$$\emptyset_{effective} = \left(1 - V_{SHALE}\right) \times \emptyset_{N-D} \quad 5$$

Water Saturation
Determination of the water saturation for the uninvaded zone was achieved using the Archie (1942) equation given below.

$$S_w{}^2 = (F \times R_w)/ \quad 6a$$

But, $F = R_0/R_w$

Thus,

$$S_w{}^2 = R_0/R_T \quad 6b$$

Where,

S_w = water saturation of the uninvaded zone
R_0 = resistivity of formation at 100% water saturation
R_T = true formation resistivity
R_w= water resistivity
F= Formation factor

Bulk Volume Water
Bulk volume of water (BVW) was estimated as the product of water saturation (S_w) of the uninvaded zone and porosity ϕ_{N-D}
Thus,
$BVW = S_w \text{x} \emptyset_{N-D}$ 7

Hydrocarbon Saturation
This was obtained directly by subtracting the percentage water saturation from 100.
Thus:
$$S_{hc} = 1 - S_w \quad 8a$$

Or

$$S_{hc}\% = 100 - S_w\% \quad 8b$$

Where,

S_{hc} is the hydrocarbon saturation (expressed as a fraction or as percentage).

Formation Factor

This was achieved using the Humble equation:

$F = a/\emptyset^m$

9

Where,

F = formation factor

a = tortuosity factor = 0.62

Ø = porosity

m = cementation factor = 2.15

Irreducible Water Saturation

The irreducible water saturation was calculated using the following relationship:

$$S_{wirr} = (F/2000)^{\frac{1}{2}} \quad 10$$

Where,

S_{wirr} = irreducible water saturation

F = formation factor.

However, this theoretical estimate of irreducible water is majorly useful in the estimation of relative permeability.

Hydrocarbon Pore Volume

The hydrocarbon pore volume (HCPV) is the fraction of the reservoir volume occupied by hydrocarbon. This was calculated as the product of neutron-density porosity and hydrocarbon saturation as shown below:

$$HCPV = \phi_{N-D} \times (1 - S_w) \quad 11a$$

$$HCPV = \phi_{N-D} \times (S_{hc}) \quad 11b$$

RESULTS

Lithology Analysis

GR value criteria of 70 API on a scale of 0-150 API for high GR sandstone reservoir was used. Sands with API value above 70 are considered as shale. Sandstone is on the whole, less radioactive than shale. This caused the GR readings to be lower in sand than in shale. The GR curve separates the sandstone (yellow colour) from the shale (mud red colour) in track the four tracks shown in Figure 4.

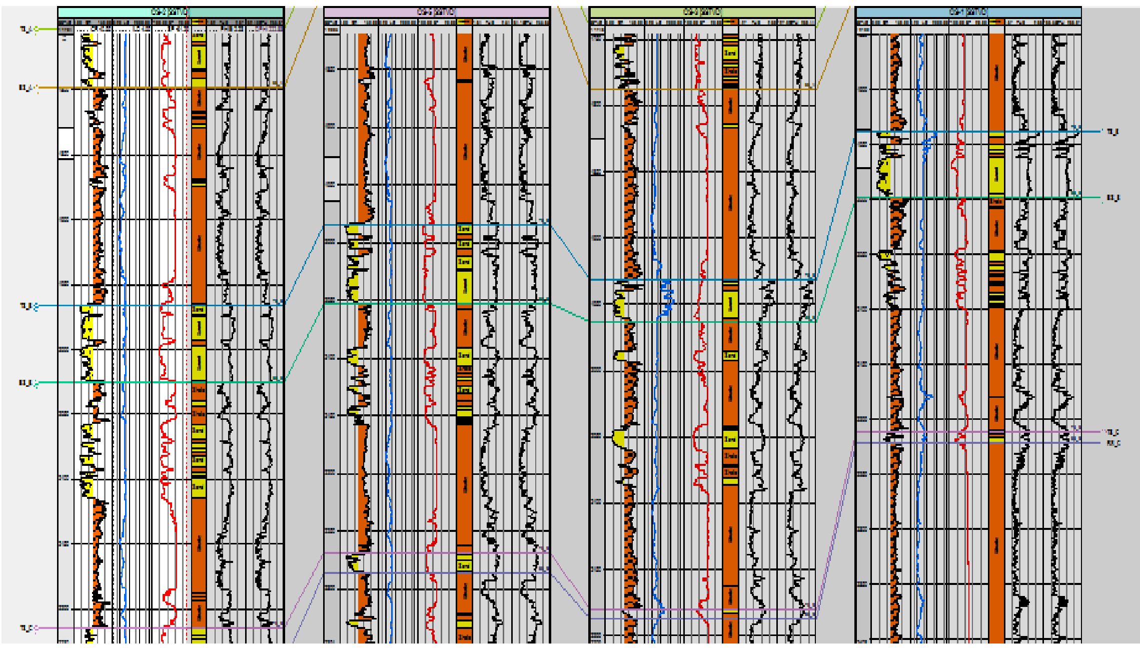

Figure 4: Lithology Analysis and Sand Correlation of wells

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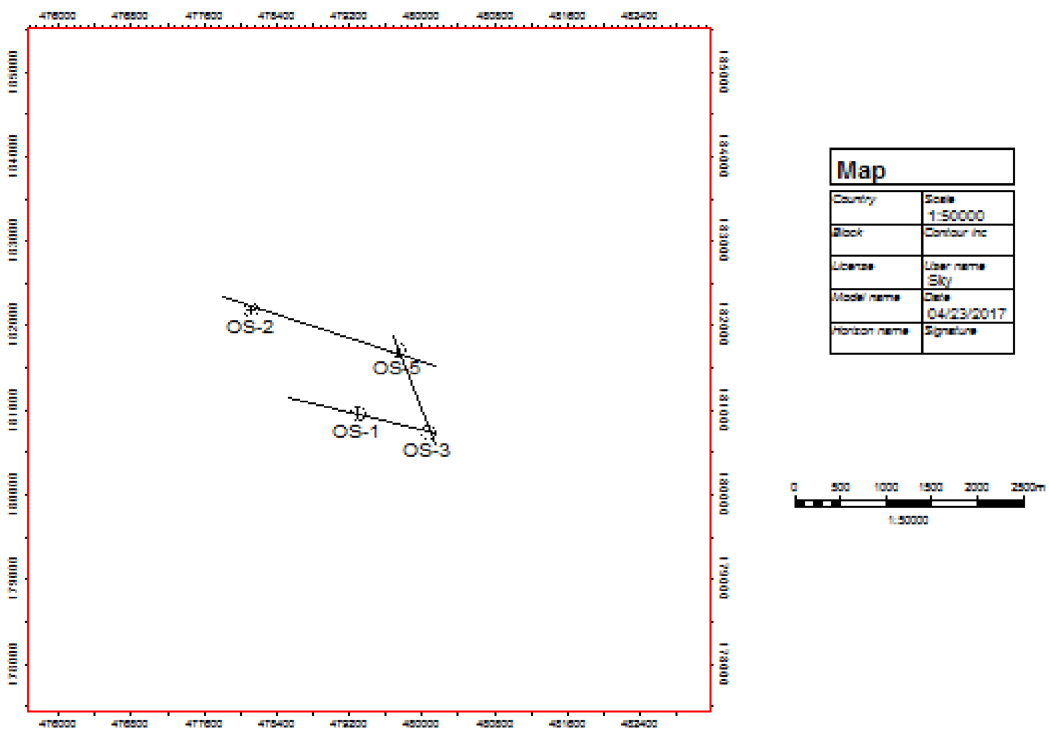

Figure 5: Well geometry

Well Correlation

This is the second step in lithology analysis to differentiate sandstone and shale using gamma ray log, deep induction log and spontaneous potential. The well geometry is as shown in Figure 5 to be from Well 2 to Well 5 to Well 3 and to Well 1.

Table 1: Sand Depth Analysis of Wells.

		SAND A	SAND B	SAND C
WELL-2	TOP (m)	1753.04	1966.10	2214.17
	BASE (m)	1798.40	2025.24	2241.53
	THICKNESS (m)	45.36	59.14	27.36
WELL-5	TOP (m)	1736.95	1984.54	2263.57
	BASE (m)	1778.84	2025.82	2285.89
	THICKNESS (m)	41.89	41.28	22.32
WELL-3	TOP (m)	1740.73	1931.79	2180.22
	BASE (m)	1785.91	1963.53	2187.13
	THICKNESS (m)	45.18	31.74	6.91
WELL-1	TOP (m)	1758.32	1937.33	2211.12
	BASE (m)	1809.06	1998.60	2220.67
	THICKNESS (m)	50.74	61.27	9.55

Sand Correlation

The results in Table 1 show the respective depths and thickness of sand correlated for the four wells.

Radioactive sand

Figure 6 shows fake sand sections in Well 2 and Well 3 between (2011.43 m – 2019.53 m) and (1011.11 m - 1025.22 m and 1169.10 m - 1178.59 m) measured depth respectively. These sand sections have low GR curve but positive SP deflection. It is suspected that these sands in these well are fake sand.

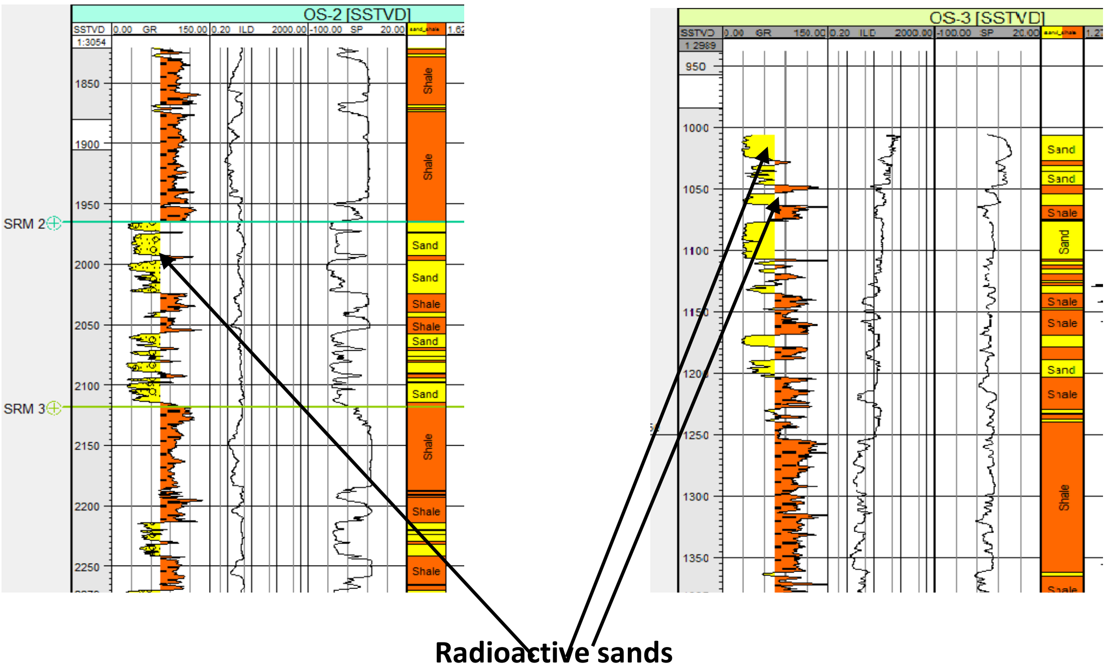

Figure 6: Radioactive Sand Sections in well 2 and well 3

Shale Correlation

The analysis was carried out using Deep Induction Log (ILD). There are three shale resistivity markers as shown in Figure 7. Table 2 shows the depth and thickness shale correlated across the reservoir.

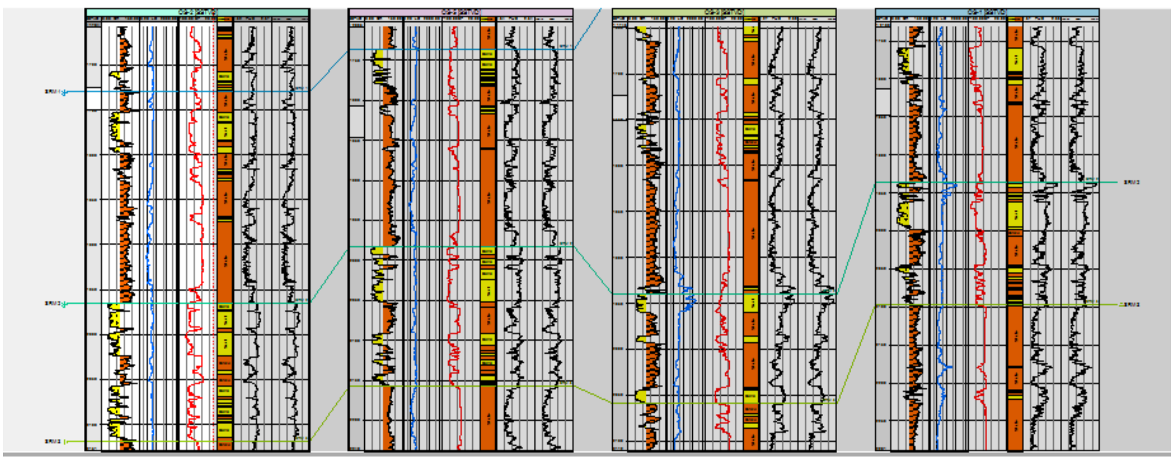

Figure 7: Shale Correlation showing Shale Resistivity Markers 1, 2, 3

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Table 2: Shale analysis in Wells 2, 5, 3 and 1

		SRM (1-2)	SRM (2-3)
WELL-2	TOP (m)	1729	1964
	BASE (m)	1964	2118
	THICKNESS (m)	235	154
WELL-5	TOP (m)	1735	1983
	BASE (m)	1983	2156
	THICKNESS (m)	248	173
WELL-3	TOP (m)	1613	1939
	BASE (m)	1939	2088
	THICKNESS (m)	326	149
WELL-1	TOP (m)	1567	1935
	BASE (m)	1935	2097
	THICKNESS (m)	368	162

Petrophysical Interpretation of Sands A, B & C.

For quantitative interpretation, the methodology as previously described was applied to the three (3) zones of interest i.e. sands defined in each well. Table 3 presents the results of the log analysis.

Table 3: Calculated Petrophysical Parameters of Wells 2, 5, 3 and 1.

SAND A											
THICKNESS (M)	**IGR**	**VSH**	**N/G**	**POR**	**EFF POR**	**SW**	**BVW**	**SHC %**	**SWIRR**	**F**	**HCPV**
								OS-2			
43.36	0.27	0.11	0.89	1.56	1.4	9.9	0.14	90	0.01	0.33	0.9
								OS-5			
41.89	0.14	0.04	0.958	1.5	1.43	9.88	0.14	90	0.01	0.36	0.9
								OS-3			
45.18	0.32	0.13	0.8687	1.42	1.24	10.82	0.13	89	0.01	0.4	0.89
								OS-1			
50.74	0.29	0.11	0.8916	1.54	1.37	11	0.15	89	0.01	0.34	0.89
SAND B											
THICKNESS (M)	**IGR**	**VSH**	**N/G**	**POR**	**EFF POR**	**SW**	**BVW**	**SHC %**	**SWIRR**	**F**	**HCPV**
								OS-2			
59.14	0.21	0.08	0.9216	1.6	1.48	10.03	0.15	89	0.01	0.32	0.9
								OS-5			
68.28	0.16	0.05	0.9457	1.53	1.45	10.9	0.16	89	0.01	0.35	0.89
								OS-3			
31.74	0.24	0.1	0.9019	1.6	1.45	4.18	0.06	96	0.01	0.32	0.96
								OS-1			

61.27	0.27	0.12	0.8795	1.61	1.42	7.93	0.11	92	0.01	0.31	0.92
SAND C											
THICKNESS (M)	**IGR**	**VSH**	**N/G**	**POR**	**EFF POR**	**SW**	**BVW**	**SHC %**	**SWIRR**	**F**	**HCPV**
								OS-2			
27.36	0.29	0.1	0.9009	1.61	1.45	9.45	0.14	91	0.01	0.31	0.91
								OS-5			
22.32	0.16	0.05	0.9546	1.56	1.49	9.26	0.14	91	0.01	0.33	0.91
								OS-3			
7.11	0.39	0.15	0.8462	1.51	1.28	6.21	0.08	94	0.01	0.38	0.9486
								OS-1			
9.55	0.46	0.22	0.7844	1.57	1.24	8.42	0.1	92	0.01	0.33	0.92

DISCUSSION

Reservoir Quality

Petroleum reservoirs are dominantly clastic or carbonate rocks. Shale or clay beds are not good reservoir rocks because they lack both effective porosity and permeability and can act as barriers to the lateral and vertical flow of fluids, thus, the inclusion of shale particles and clay minerals within a sandstone or carbonate matrix will tend to reduce the quality of the formation as a reservoir.

Therefore, the grain size of "OS" Well was inferred from the gamma ray log by its response to clay minerals/contents. "OS" Well log revealed that gamma ray values increased to the right of the track with high clay contents and fine-grain size, and decreased to the left indicating coarse-grained sands and low clay gamma ray values.

Analysis of Petrophysical Parameter Estimation

The geometry of the well formed the basis for the picking of reservoirs which is our area of concern and analysis. These reservoirs are of various depths across the wells and of varying thickness. Sand A is the thickest in Well-1, Sand B is thickest in Well-1 and Sand C is thickest in Well-2. The reservoir was found to have very good porosity values. Porosity which is a measure of reservoir storage capacity is defined as the proportion of the total rock volume that is void and filled with fluids. Porosity is a relative measurement and commonly expressed in decimal/fractional units or else as a percentage. Gamma ray, neutron, and density logs were used as indirect indicators of permeability of the "OS" Well reservoirs. Low gamma ray reading indicated low clay content and higher permeability, while high neutron density porosity indicated high permeability. Permeability is the capacity of a reservoir rock to permit fluid flow. It is a function of interconnectivity of the pore volume; therefore, a rock is permeable if it has an effective porosity.

Net/gross ratio was used to define the proportion of the intervals that were considered to be reservoirs and it aided in the understanding of the formation. This ratio is dimensionless and reflects the overall quality of a zone not minding its thickness. These intervals indicated areas/units where sand deposition is concentrated, and where better reservoir quality is to be found with variations in the quality of sand.

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The average water saturation revealed the proportion of void space occupied by water in "OS" Well reservoirs based on the calculations made, and it showed that water saturation of the reservoirs is low, thus, high hydrocarbon saturation and high hydrocarbon production. The values of hydrocarbon saturation and hydrocarbon pore volume (formation available to hydrocarbon intrusion) which indicate movability of hydrocarbons in each reservoir were determined and considered satisfactory for the production of hydrocarbon. Figure 8 shows the bar chart of selected reservoir properties considered in the study.

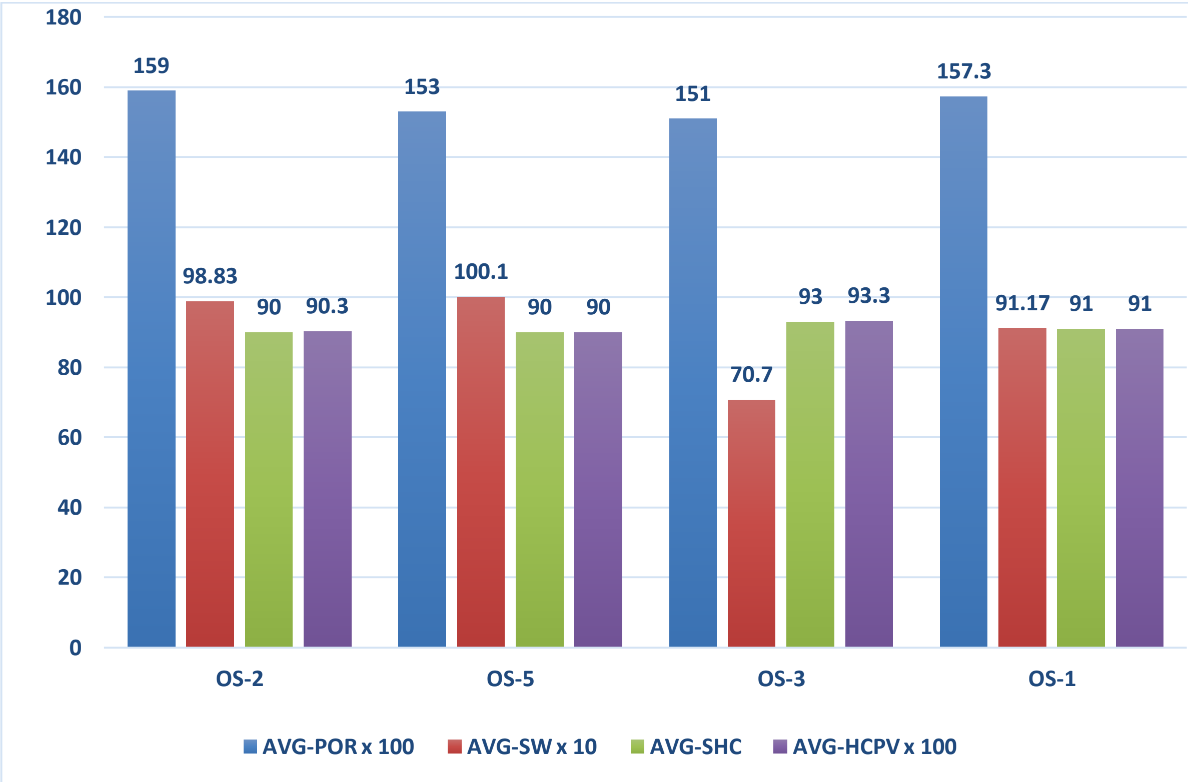

Figure 8: Bar Chart showing relationship among the average values of porosity, water saturation, hydrocarbon saturation and hydrocarbon pore volume of the reservoirs.

Petrophysical analysis of the three mapped reservoir within the field proved them to be prolific. The mapped reservoirs have low water saturation between 4.18 - 10.90%, high hydrocarbon saturation of 89 - 96%, porosity ranging from 1.42 - 1.61 and hydrocarbon pore volume range of 89 - 96%. Hence, it was found that well 3 is highly favourable among the wells because of its relatively high porosity values, low water saturation, high hydrocarbon saturation and hydrocarbon pore volume. This oil field is suspected to contain radioactive sands. Hence, the need for the integration of all the available log, core sample, and laboratory data in order not to miss these sands for pay zones.

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