International Journal of Earth Sciences Knowledge and Applications (2024) 6 (1) 12-22

IJESKA contribution to science

International Journal of Earth Sciences Knowledge and Applications
journal homepage: http://www.ijeska.com/index.php/ijeska

Research Article
e-ISSN: 2687-5993

Petrophysical Characteristics of Reservoir Sands in Sam-Bis Field, Greater Ughelli Depobelt, Niger Delta Basin, Nigeria

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INFORMATION

Article history
Received 16 March 2024
Revised 07 April 2024
Accepted 08 April 2024

Keywords
Niger Delta Basin
Reservoir sands
Petrophysical properties
Fluid saturation
Depositional environments

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ABSTRACT

To understand the variations of petrophysical properties with paleoenvironments of deposition of reservoir sands, mathematical models were applied to a suit of wire line logs data to calculate thickness, volume of shale, porosity, permeability and fluid saturations. Twenty-one sand units were identified. The average sand thickness ranged from 2.6m in the fluvial distributary channel to 14.93m in the tidal channel. The average volume of shale ranged from 0% in some sand units of the mouth bar to 26.3% in a sand unit of the tidal channel. Effective porosity values ranged from 12.12% in a sand unit of distributary channel to 30.8% in a sand unit of mouth bar, while permeability values ranged from 96.3Md in a sand unit of distributary channel to 903.2Md in a sand unit of mouth bar. The cross-plot of porosity values against depth and permeability gave regression coefficients of 67.9 and 64.5, respectively. Therefore, there is a strong relationship between porosity and permeability, and with depth, it decreases gradually. Generally, the porosity values are fair to very good, while the permeability values are good to very good for hydrocarbon production. The order of increase in porosity with depositional environments is given as follows: fluvial distributary channel, lower/middle shoreface, point bar, tidal channel, and mouth bar. The tidal channel formed a thicker reservoir than the mouth bar, but the mouth bar formed a higher-quality reservoir due to the energy of the depositional environment. Rocks deposited in the same depositional environment have similar porosity values. Therefore, petrophysical properties are controlled by depositional processes, thickness, and depth. Only 14.3% of the identified reservoir sand units have hydrocarbon in commercial quantity with hydrocarbon saturations that ranged from 47.8 to 81.5%.

1. Introduction

A reservoir is a major element of a petroleum system that ensures petroleum accumulates in a pool and releases it when penetrated by a well (Magoon and Dow, 1999). These functions of the petroleum reservoir, be it sandstone or carbonate, depend on the physical rock properties that include the ability to store fluid and the ability or capacity to flow or transmit the stored fluid (Dewan, 1983; Berg, 1986; Bjørlykke, 2015). For sandstone reservoirs, these physical rock properties, according to Berg (1986), classified as dependent or secondary rock properties, are controlled by the rock properties classified as definitive or primary rock properties that include reservoir shape and thickness, texture, sedimentary structures, and mineral composition. These definitive or primary properties reflect depositional processes and environments (Reading, 2009; Nichols, 2009). The relationship of these definitive or primary rock properties with fluid types and saturation is here described as petrophysical characteristics that include volume of shale fraction, porosity, permeability, net/gross reservoir, fluid saturation, and net/gross pay (Worthington, 2011). The quality of a reservoir is therefore defined by the petrophysical parameters that quantify the properties of the reservoir.

Sandstone forms petroleum reservoirs in the Niger Delta basin, and its petrophysical properties at different oil fields or depobelts have been studied over the years for the purpose of optimizing petroleum production (Weber and Daukoru, 1975; Edward and Santogrossi, 1990; Stacher, 1995). The petrophysical parameters or characteristics that define the quality of sandstone vary with the depositional processes or environment of deposition, depth of burial, thickness, diagenetic, and temperature history (Lien et al., 2006; Gier et al., 2008). The paleo-depositional processes or environment of deposition are interpreted from lithofacies (identified in cores or outcrops) or well log motifs (Serra, 1989).

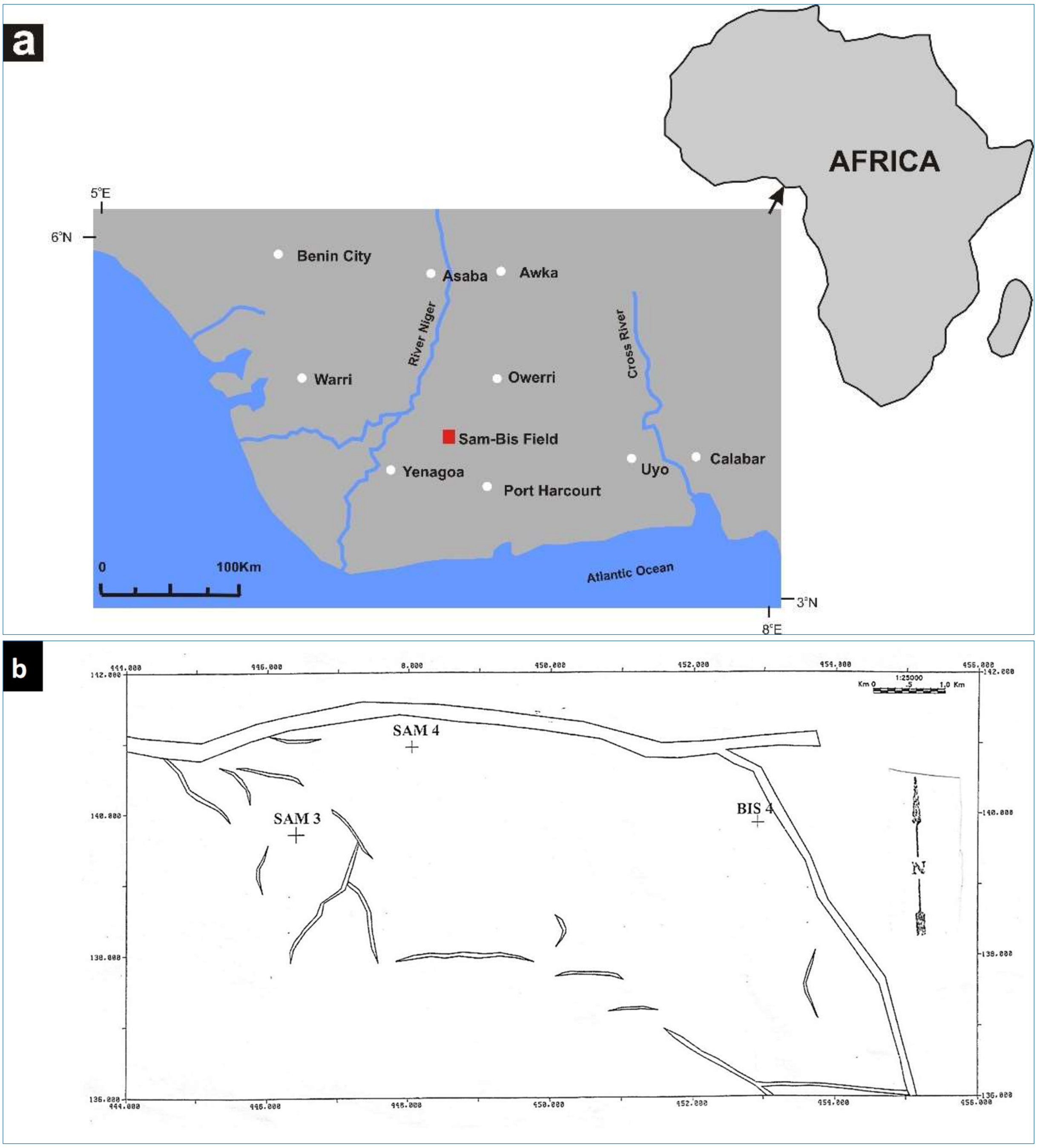

Fig. 1. (a) shows the location of Sam-Bis Field in the Niger Delta basin, situated at the Gulf of Guinea in West Africa. (b) Base map of Sam-Bis Field showing well locations and distributions of growth faults (after Oyanyan et al., 2012)

Oyanyan et al. (2012) studied the paleo-depositional environments of reservoir sands in Sam-Bis Field using wireline logs and some cores obtained from some sections of the studied well. The objective of this study is therefore to evaluate the petrophysical properties of the reservoir sands that have been identified, with the aim of determining the variations of these properties with the different environments of deposition. The aim also includes identifying the hydrocarbon-bearing reservoir sand units and estimating their fluid saturation, pore volume, hydrocarbon range, and contacts.

1.1. Location and Geological Setting

Sam-Bis Field is part of Oil Mining Lease (OML) 61 and is in the north-eastern part of Bayelsa State, within the Greater Ughelli depobelt of the Niger Delta basin, Nigeria (Fig. 1a).

It lies between latitudes 5° and 5° 3' north of the equator and longitudes 6° and 6° 45' east of the Greenwich Meridian. The oil wells on the field are situated on an extended rollover anticline that is bordered to the north and east by large east-west and north-west-south trending growth faults, respectively (Fig. 1b).

The Niger Delta Basin is situated in equatorial West Africa, between latitudes 3° and 6° N and longitudes 5° and 8° E, on the continental margin of the Gulf of Guinea, precisely at the intersection of Benue Trough and South Atlantic Ocean where a rifting triple junction developed when Africa separated from South America (Knox and Omatsola, 1987; Reijers et al., 1997; Tuttle et al., 1999) (Fig. 1a). It is one of the most prolific deltas in the world for producing petroleum, making up roughly 5% of global oil and gas reserves and 2.5% of Earth's basin areas (Reijers et al., 1997). With a total size of roughly 75,000 km2, the basin is made up of a regressive clastic sequence with a thickness that ranges from 9,000 to 12,000 m (29,500 to 39,400 ft) (Short and Stauble 1967; Weber and Daukoru, 1971; Reijers et al., 1997).

The Niger Delta basin dates from the Cenozoic era. Synsedimentary tectonics normal to the progradation coincided with the Cenozoic sediment build-up, producing a sequence of parallel fault-bounded depositional belts (depobelts) that grew younger from north to south as the delta prograded southward (Doust and Omatsola, 1989; Stacher, 1995). The depobelts are offshore, central swamps I and II, coastal swamps I and II, Greater Ughelli, and the Northern Delta. Three regional diacchronous formations, which span the Eocene to the present, are overprinted with the same stratigraphic sequence from top to bottom on the depobelt architecture. From base to top, they are referred to as the Agbada Formation, the Benin Formation, and the Akata Formation (Short and Stauble 1967).

At the base of the delta is the Akata Formation, which is marine-derived, with a typical age range of Paleocene to Recent and an estimated thickness of up to 7,000 metres (Doust and Omatsola, 1989). It is composed of thick or uniform over-pressured shale sequence (possible source rock), turbidite sand (possible reservoir in deep water), and a minor amount of clay and silt.

Aged between the Eocene and the Recent, the Agbada Formation, which sits on top of the Akata Formation, is made up of paralic siliciclastic sediments of interbedded sand and shale. Its overall thickness is approximately 3700m, and it represents the actual deltaic portion of the Niger delta sequence (Doust and Omatsola, 1989). The sandstone components of the formation form the petroleum reservoir, while the shale components form a lateral seal against further vertical petroleum migration, resulting in the formation of a petroleum pool.

The Benin Formation, the topmost formation found throughout the entire Niger Delta, is a continental deposit of alluvial and coastal plain sands that range in age from the Eocene to the Recent. Its thickness is up to 2000 m (Avbovbo, 1978).

2. Data Set and Method of Study

As of the time of this study, Sam-Bis Field has only three wells, viz., Sam 3, Sam 4, and Bis 4 (Fig. 1b). The Sam 4 well, by virtue of its location, was taken as a "type or marker well" for study. A suit of logs for the Sam 4 well and the base map were therefore provided for this study by the licensed operator of the field with the permission of the then-Department of Petroleum Resources (DPR), now the Nigerian Upstream Petroleum Regulatory Commission (NUPRC). The logs are gamma ray, calliper, high-resolution photoelectric factor (PEF), 10 inches (shallow) to 60 inches (deep) investigation resistivity, high-resolution formation density, and neutron (Fig. 2). The methods of study were divided into the following steps.

2.1. Reservoirs Identification and Thickness Determination

Gamma ray log was used to segregate reservoir sandstone from shale, with gamma ray values of 0 to 30 API taken as clean sand, 35 to 75 API as shaly sand to sand shale, and greater than 75 API as shale (Dewan, 1983; Crain, 1986; Bjørlykke, 2015). The identified reservoir units were labelled alphabetically from top to bottom after Oyanyan et al. (2012) (Fig. 2).

The sandstone reservoirs and boundaries with shale were validated with photoelectric factor (PEF) values. PEF values that ranged from 1.6 to 2.7 indicated a sandstone reservoir consisting mainly of quartz, while values greater than 2.7 to 3.42 indicated shaly sand to shale (Rider, 2004; Bjørlykke, 2015). The gross thicknesses of reservoir units were then determined by subtracting the depth value of the top from that of the bottom (Egbele et al., 2005).

2.2. Volume of Shale in Reservoirs Determination

To calculate the volume of shale or shale volume in the reservoirs, gamma ray index (I_{GR}) was first calculated from gamma ray log data using equation 1 adopted from Schlumberger (1974) and Bjørlykke (2015).

$$I_{GR} = [GR\ Value_{(log)} - GR_{(Min.)}] / [GR_{(Max.)} - GR_{(Min.)}] \quad (1)$$

where GR Value$_{(log)}$ is the gamma ray log value of the reservoir, GR_{min} is the minimum gamma ray value for clean sand sandstone, and GR_{max} is the maximum gamma ray reading for shale zone.

The I_{GR} was then substituted into the Dresser Atlas (1982) empirical correlation model, equation 2, for the determination of the volume of shale for the Tertiary unconsolidated rocks.

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

2.3. Identification of Hydrocarbon Bearing Reservoirs

A 60-inch investigation (deep) resistivity log (laterolog) was used to identify petroleum bearing reservoirs and the contact between water and hydrocarbons because resistivity is high in porous rocks containing oil and gas but low in marine water (Dewan, 1983). Crossover and balloon-like deflections of high-resolution density and neutron logs motifs were used to identify gas zone and gas-oil contact in the reservoir.

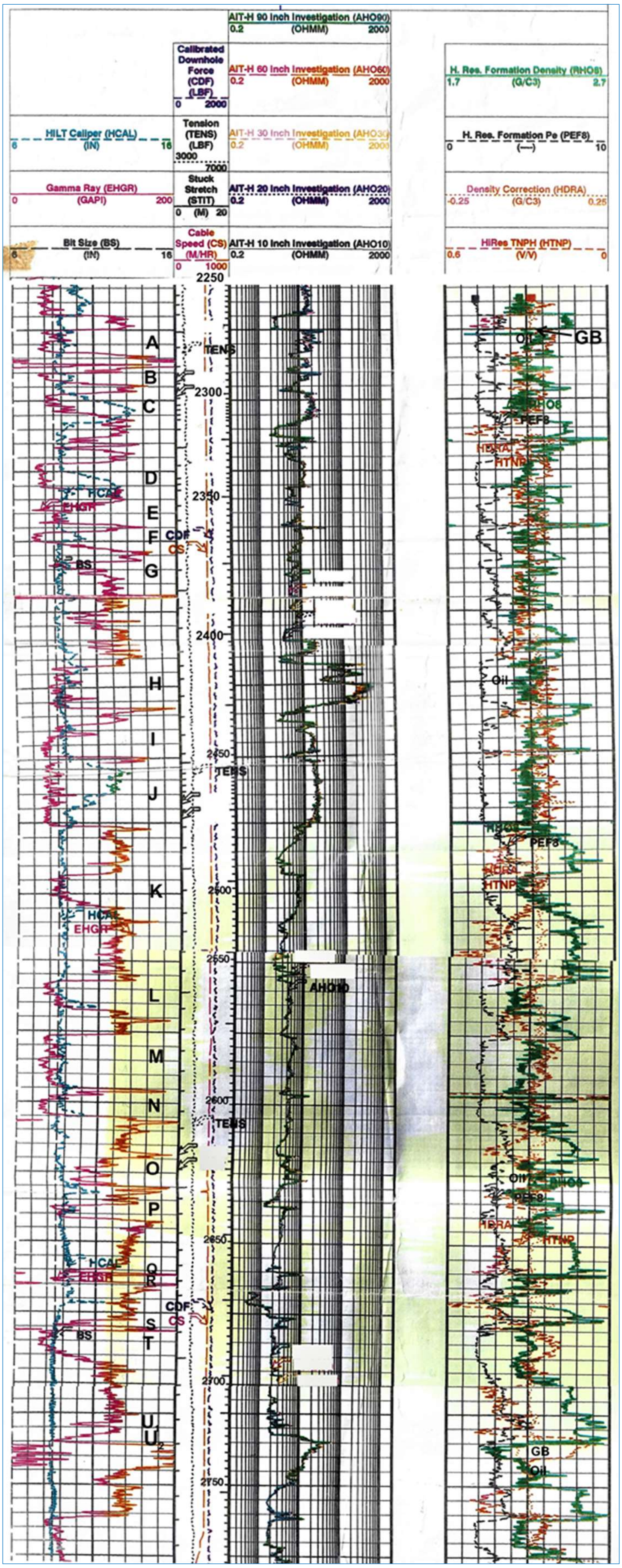

Fig. 2. A suit of well logs showing identified reservoir sand units and some hydrocarbon-bearing zones

Table 1. Log data, volume of shale in percentage and porosity values of the sand units in Sam 4 Well

Sand Units	Log Data				Results			
Units/Depth(m)	**Gr (API)**	**R_t (ohm)**	**ϕ_N (Fr.)**	**P_b (g/cm^3)**	**Vshale (%)**	**ϕ_d (%)**	**ϕ_N (%)**	**ϕ_e (%)**
A: 2275-2280	48	40	0.24	2.25	6.0	28.0	24.0	26.0
2280-2287	40	20	0.22	2.20	1.5	30.0	22.0	26.1
B: 2292-2296	40	30	0.20	2.14	1.5	3.0	20.0	27.5
C: 2300-2310	40	21	0.24	2.10	2.7	37.6	24.0	30.8
D: 2337-2348	30	12	0.24	2.2	0	31.0	24.0	27.5
E: 2350-2360	44.5	10	0.3	2.30	9.0	24.0	30.0	27.0
F: 2362-2370	30	40	0.24	2.15	0	34.5	24.0	29.3
G: 2372-2377	43	10	0.28	2.20	5.7	30.0	28.0	29.0
2377-2380	60	6	0.30	2.30	2.4	19.0	30.0	25.1
H: 2410-2425	45	350	0.24	2.22	4.1	29.0	24.0	26.5
I: 2427-2435	46	12	0.24	2.23	7.4	25.1	24	24.6
2435-2437	39.4	18	0.24	2.18	1.0	28.9	24.0	26.5
J: 2453-2482	39.4	20	0.24	2.25	1.0	27.2	24.0	25.8
K: 2495-2501	50	6.5	0.18	2.10	13.3	36.7	24.0	29.8
2501-2505	55	6.0	0.24	2.20	18.7	29.0	28.0	28.5
L: 2558-2570	40	4.2	0.30	2.2	3.7	30.8	30.0	30.4
M: 2578-2582	40	6.5	0.18	2.25	0.7	27.5	18.0	22.9
2587-2597	40	4.5	0.30	2.15	0.7	34.4	30.0	32.4
N: 2598-2601.5	55	8.5	0.21	2.35	1.0	19.0	21.0	20.1
2601.5-2606.5	39.4	4.5	0.24	2.2	0.3	31.0	24.0	27.5
O: 2621.5-2622	75	6.5	0.18	2.18	29.0	21.4	18.0	10.7
2622.5-2626	70	11.0	0.18	2.20	24.9	21.6	18.0	19.8
2627-2632	70	3.5	0.24	2.15	25.0	25	24.0	24.5
P: 2640-2647	48	8.0	0.18	2.20	6.6	29.4	25.6	24.8
Q: 2662.5-2657	62	9.0	0.06	2.12	17.3	22.3	6.0	14.15
R: 2666-2680	42	2.9	0.24	2.25	0.3	24.6	24.0	12.12
S: 2681.5-2685	55	4.8	0.15	2.4	9.7	15.8	15.0	15.4
T: 2686-2698	40	2.0	0.18	2.2	0.7	31.0	22.0	27.4
U_1:2727.5-2730	65	5.0	0.24	2.5	29.5	10.0	24.0	17.0
U_2: 2732-2738	50	50.0	0.08	2.20	6.1	0.4	8.0	22.2

GR (API) = Average Gamma ray values; ϕ_d (%) = effective density porosity; R_t (ohm) =True resistivity values; ϕ_N (%) =Neutron Total porosity; ϕ_N(Fr.) = Neutron Total porosity in fractions; ϕ_e (%) = average effective or true porosity; P_b (g/cm^3) = Formation bulk density and Vshale (%) = Volume of shale in percentage

2.4. Total, Effective, and Average Porosity of Reservoirs Determinations

The total porosity, which is the ratio of the volume of all pore spaces to the bulk volume of the reservoir (Hook 2003), was first of all calculated by substituting the reading of the formation density log into equation 3 adopted from Schlumberger (1974 and 1985) and Dewan (1983). The effective or true porosity, which is the ratio of interconnected pore volume to the bulk volume of the reservoir, was then calculated by subtracting the product of the volume of shale and shale density total porosity from the total porosity, as indicated in *Equation* 4 after Asquith and Gibson (1982).

$$\textit{Total Porosity } (\phi_T) = (\rho_{ma} - \rho_b)/(\rho_{ma} - \rho_f) \quad (3)$$

$$\textit{Effective Porosity } (\phi_{eff}) = \phi_T - [V_{sh}(\rho_{ma} - \rho_{sh})/(\rho_{ma} - \rho_f)] \quad (4)$$

where, ρ_{ma} = Matrix density (2.65g/cm^3), ρ_b = Bulk density of sand measured by the tool, ρ_f = Fluid density and ρ_{sh} =bulk density of shale adjacent to reservoir measured by tool. According to Dewan (1983), liquid bearing formation density is typically that of mud and filtrate. Therefore, for salt mud, ρ_f = 1.07g/cm^3).

The average effective porosity values of various sand bodies were obtained by cross-plotting the effective porosity values, now also called density porosity values, with those of neutron porosity values using the appropriate cross-plot chart (Schlumberger, 1991). Averaging the porosity values cancels the effect of lithology (Bjørlykke, 2015). The values obtained were confirmed with approximation formulas, equations 5 and 6 (Dewan 1983).

$$\textit{For-Liquid filled formations: } \phi = (\phi_d + \phi_n)/2 \quad (5)$$

$$\textit{For Gas–Bearing Formations: } \phi = \sqrt{\left(\phi_d^{\,2} + \phi_n^{\,2}\right)/2} \quad (6)$$

2.5. Determination of Fluid Saturation

To determine the reservoir fluid saturations, water saturations for the various reservoir sand units identified on the wireline logs were first estimated using the appropriate Archie (1942) *Equations* 7 to 12.

Where oil – water contact identified:

$$\textit{Water saturation } (S_w) = \sqrt{\frac{R_o}{R_t}} \quad (7)$$

where, R_0 = Resistivity of water bearing formation and R_t = True resistivity oil bearing formation.

Where no obvious oil water contact:

$$R_o = FR_w, \quad (8)$$

where, F = Formation factor and R_w = Resistivity of water.

$$Water\ saturation\ (S_w) = c\sqrt{R_W/R_t}\ /\ \phi \quad (9)$$

where, C = 0.9 for sands and ϕ = Porosity.

To calculate the fractional water saturation (Sw) under this condition, F and R_w were first calculated. The R_w was then calculated using the Archie formula, Equation 8 above.

The F was calculated using Archie's equation.

$$F = a/\phi^m \quad (10)$$

where "m" is the cementation exponent taken as 2 and "a" as constant taken as 0.81 (Dewan, 1983).

The fractional hydrocarbon saturations were estimated from the relations:

$$Hydrocarbon\ saturation\ (S_H = 1 - S_W) \quad (11)$$

The fractional pore volumes filled by hydrocarbon were then estimated using the relation.

$$\phi \times (1 - S_W) \quad (12)$$

where ϕ= Average effective porosity.

The saturation values in different reservoir sand were then calculated in percentages. Also evaluated is the Bulk volume water (BVW), which shows whether a formation is at irreducible water saturation or not using the equation:

$$BVW = S_W X\ \phi \quad (13)$$

The formation is at irreducible water saturation if the bulk volume water values are constant or nearly constant, but if the values are widely varied, then it is not at irreducible water saturation.

2.6. Permeability of Reservoir Estimation

Equation 7 proposed by Timur for the estimation of permeability of reservoir sands from wireline logs and documented by Dresser Atlas (1982) was used to estimate the permeabilities of the different reservoir sands.

$$K\ (MD) = 0.136\ \frac{\phi\ 4.4}{Swirr\ ^2} \quad (14)$$

where, Swirr = irreducible water saturation, and K= Permeability (in millidarcies).

2.7. Gross and Net Pay Thickness

Pay thickness is the thickness of the reservoir that has petroleum. Gross pay thickness was determined by subtracting the depth of the top of the reservoir from the depth of hydrocarbon-water contact, while net pay thickness was determined by subtracting the sum of the thickness of shales within the pay interval from the gross pay thickness (Egbele et al., 2005).

3. Results and Interpretations

3.1. Reservoir Units, Thickness, Volumes of Shale and Depositional Environments

Twenty-one (21) reservoir sand units labelled alphabetically from "A" to "U" were identified within the zone of interest in the Agbada Formation (Table 1). The depositional environments of the sand units, as interpreted by Oyanyan et al. (2012) using a combination of gamma-ray log motifs and cores, are the tidal channel, mouth bar, point bar, lower/middle shoreface, and fluvial distributary channel. Out of the 21 sand units, there are 9 mouth bars, 7 tidal channels, 4 fluvial distributary channels, 1 point bar, and 1 lower/middle shoreface sand deposit (Table 2).

According to Oyanyan et al. (2012), the lower/middle shoreface depositions at 2732–2738 m depth (U_2) consists of successions of shale-to-sand-dominated heterolithic lithofacies that were truncated by the fluvial distributary channel at 2727.5–2730 m depth (U_1) (Fig. 2 and Table 1).

The range of sand thickness deposited by the different environments of deposition is as follows: Mouth bar, 4–10 m with an average thickness of 9.33m; tidal channel, 9–29 m with an average thickness of 14.93m; fluvial distributary channel, 2–4 m with an average thickness of 2.6m; point bar, 10m; and lower/middle shoreface, 3m. These show that the tidal channel deposited the thickest reservoir sand, followed by the mouth bar, while the thinnest sand unit was deposited by the fluvial distributary channel (Fig. 3).

The volume of shale also varies in the different depositional environments (Table 1 and Fig. 3). Mouth bar sands have the least volume of shale that ranged 0 to 5.7% with an average value of 3.62%, followed by that of the Point bar sands with an average value of 4.2%. The highest volume of shale was given by fluvial distributary sand and followed by that of tidal channel sand and then the lower/middle shoreface sand.

3.2 Porosity Values and Variations with Volumes of Shale, Thicknesses, Depth and Depositional Environments

The effective porosity and volume of shale values of all the reservoir sands in the Sam 4 well were determined using wireline log values. These values are presented in Table 1. The average porosity values of each reservoir sand in the Sam 4 well were plotted against depth as shown in Fig. 4. The regression coefficient of 67.9 indicates a good relationship between porosity and depth. The plot shows a general, gradual decrease in porosity values with depth. The decrease in porosity with depth is possibly a function of the degree of compaction of the sediment by the overburden weight.

Effective porosity values ranged from 12.12% in sand unit "R" of fluvial distributary channel deposition to 30.8% in sand unit "C" of mouth bar deposition. The average effective porosity varied with the different depositional environments with values for sands deposited in mouth bar, tidal channel, point bar, lower/middle shoreface and fluvial distributary channels as 27.84, 25.65, 25.6, 22 and 13.87% respectively (Fig. 5).

Using changes in the shape of resistivity log patterns, variations in porosity within reservoir sands were determined. Porosity values were found to be fairly constant within some reservoirs, such as in B, C, D, E, H, J, L, and Q, while porosity varies within some reservoirs (Table 1).

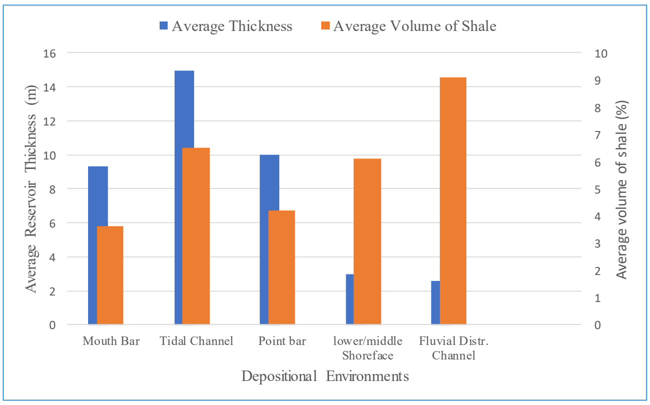

Fig. 3: Variations of Average reservoir sand thicknesses and volumes of shale with different depositional environments

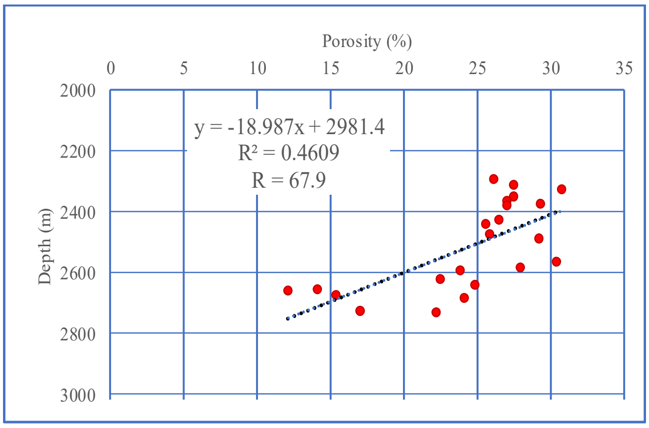

Fig. 4: The plot of average effective porosity values against depth

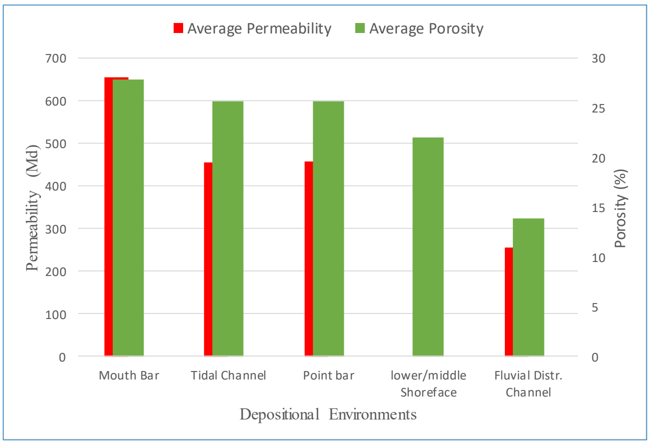

Fig. 5. The variations of Permeability and porosity values with the environments of deposition

For example, the porosity values of G, K, and T, all of mouth bar deposition, increase upward while the porosity values decrease upward in sand units A, I, M, O, and U_1, of tidal and fluvial distributary channel deposition. This characteristic attest to sandstone texture control on reservoir quality. The texture of sandstone is a function of rock type, distance of travel and the energy of the depositional environment (Selly, 2000).

Results show that the volume of shale affects the porosity values. The higher the sand/shale ratio or the lower the volume, the higher the porosity, and the lower the sand/shale ratio or the higher the volume of shale, the lower the porosity. Most of the reservoir sands have a low volume of shale and are hence characterized by high porosity values (Table 1).

The variations in porosity values were found to correspond with variations in volume of shale or the degree of shaliness in the reservoir sands deposited in the different environment of deposition (Table 1). The volume of shale increases with an increase in GR values and decreases with an increase in porosity. The average volume of shale in sands ranged from 0% in sand units D and F of mouth bar deposition to 26.3% in sand unit O of tidal channel deposition. Therefore, though tidal channel-deposited sands are generally thicker than those of mouth bars, they are of lesser quality compared to mouth bar deposition that gives the highest average effective porosity values.

Fluvial distributary channels have the lowest porosity values because of their small thickness (2–4 m). This can be attributed to the fact that thin reservoirs are more easily compressed by adjacent shale bodies than thicker reservoir sands. For example, sand unit T is more porous than adjacent sand units R and S. It is also documented that fluvial distributary channel sands have low porosity values because of poor sorting of grains (Selly, 2000).

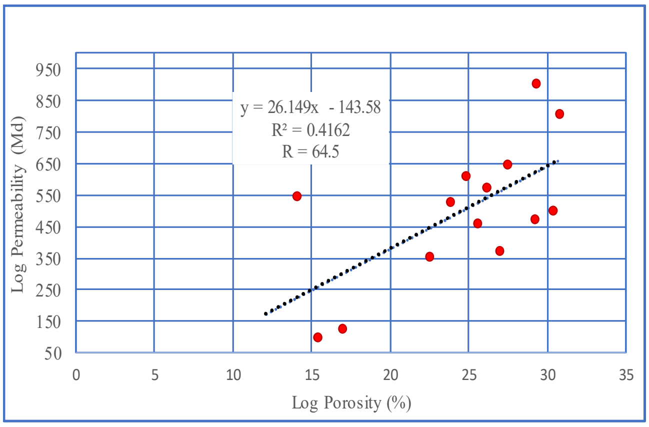

Fig. 6. The plot of log porosity against log permeability

3.3. Permeability Values and Variations with Depositional Environments

The permeabilities of reservoir sands were only calculated for those units that are assumed to be at irreducible water saturation using bulk water volume. The permeability value ranged from 96.3 Md in the sand unit "S" of the fluvial distributary channel to 903.2 Md in the sand unit "F" of the mouth bar (Table 2). The permeability distribution across the sand units shows that, just like porosity, permeability varies with the environment of deposition (Fig. 5). Permeability in mouth bar sands ranged from 469.4 to 903.2 Md, with an average value of 654.97 Md. The permeability of point bar sands is 458 Md, while that of tidal channel sands ranged from 353.8 to 570 Md, with an average value of 454.63 Md. The permeability of fluvial distributary channel ranged from 93.6 to 545.7Md with an average permeability of 255.67Md.

Table 2: Sand Units Thickness, Water Saturation, Bulk Volume Water and Permeability Values in Sam 4 Well

Sand Unit and Thickness in Metres		Average ϕ (%)	Formation Factor (F)	Resistivity Values (Ohmm)	Formation Water Resistivity	Water Saturation (S_W in %)	Bulk Volume Water (BVW)	Permeability (Md)	Depositional Environment After Oyanyan et al. (2012)
A	12	26.05	11.94	30	1.5	77.3	20.12	570.0	Tidal channel
B	4	27.5	10.70	30	1.68	77.5	21.3	645.4	Mouth bar
C	10	30.8	8.54	21	1.68	82.6	24.4	807.2	Mouth bar
D	11	27.5	10.71	12	1.5	99.99	27.5	-	Mouth bar
E	10	27.0	11.10	10.1	1.07	99.99	23.88	370.0	Tidal channel
F	8	29.3	9.44	20	1.06	70.7	20.7	903.2	Mouth bar
G	8	27.0	9.60	10	1.04	100.00	29.0	-	Mouth bar
H	15	26.5	11.53	350	1.04	18.5	4.91	-	Tidal channel
I	10	25.6	12.40	14.5	1.04	94.2	24.1	458	Point bar
J	29	25.8	12.20	20	1.04	79.55	20.5	-	Tidal channel
K	10	29.2	9.50	6.0	0.60	97.50	28.5	469.4	Mouth bar
L	12	30.4	8.80	4.2	0.40	99.99	30.24	497.8	Mouth bar
M	19	27.9	10.40	5.0	0.40	91.20	25.40		Tidal channel
N	9	23.8	14.50	8.5	0.31	72.20	17.19	524.7	Tidal channel
O	10.5	22.5	16.0	11.0	0.18	52.20	18.50	353.8	Tidal channel
P	7	24.8	13.2	8.0	0.30	70.70	17.50	606.8	Mouth bar
Q	2	14.1	35.50	10.0	0.28	38.10	5.37	545.7	Distr. Channel
R	4	12.12	55.14	2.9	0.28	99.99	12.11	-	Distr. Channel
S	3	15.4	34.20	4.82	014	99.80	15.40	96.3	Distr. Channel
T	14	24.1	13.90	2.0	0.14	100.00	24.10	-	Mouth bar
U_1	2	17.0	28.03	4.0	0.14	99.0	16.80	125.0	Distr. Channel
U_2	5	22.2	16.4	50.0	0.14	21.64	4.80	-	Shoreface and Distr. Channel

Table 3: Hydrocarbon Characteristics (Average hydrocarbon saturation, fluid contacts and average total pore volume fill by hydrocarbon)

Sand Unit	Depth (m) Top Bottom	Thickness (m)	Hydrocarbon Contacts	Hydrocarbon Saturation (S_h) in %	Av. Total Pore volume fill by H.C. in %	Gross pay thickness (m)	Net pay thickness (m)
A	2275 2287	12	OGC 2279.5	22.7	6.0	4.5	2
B	2292 2296	4	OGC 2293 OWC 2295	22.5	6.2	3	2
C	2300 2310	10		17.4	5.0	2	2
F	2362 2370	8	OWC 2367.5	29.3	8.0	5.5	4
H	2410 2425	15	-	81.5	21.6	16	10
J	2453 2482	29		20.45	5.0	27	
N	2593 2662	9	OWC 2594.5	27.2	6.0	1.5	1
O	2621.5 2632	10.5	OWC 2630	47.8	11.0	8.5	5
P	2640 2647	7	OWC 2647.5	29.3	7.0	3.5	2.5
Q	2655 2657	2	-	25.1	8.7	2	2
U_2	2727 2732	5	OGC 2738	78.6	17.0	15	6

3.4. Relation between Permeability and Porosity

The cross plot of log porosity against log permeability, resulting in a regression coefficient of 64.5, shows a good relationship (Fig. 6). The direct relationships between porosity and permeability can also be inferred by comparing the values of two close adjacent reservoir sand units with the same or similar thickness and with almost the same effect of depth. For example, sand unit F has a higher average porosity (29.3%) and permeability (903.2 Md) than that of an adjacent overlying sand unit E, with an average porosity of 27% and permeability of 370 Md.

Therefore, the higher porosity, the higher the permeability of reservoir sands and vice versa in the Sam-Bis field.

3.5. Fluid Saturations and Characteristics

3.5.1. Formation Water Resistivity

The formation water resistivity values decrease gradually with depth, from an average of 1.68 ohmm in reservoirs of shallower depth to 0.14 ohmm at the bottom of the well (Table 2). This can be attributed to an increase in salinity corresponding to changes from a brackish water environment to a pure marine water environment.

3.5.2. The Water Saturation

The water saturation of all the reservoir sands ranges from 18.5% in sand unit H to 100% in sand units G and T (Table 2). The water saturation values show that the reservoir sands in Sam 4 well are predominantly made up of water, with an average water saturation of 73.95%.

3.5.3. Hydrocarbon Characteristics

The hydrocarbon characteristics of reservoir sands include hydrocarbon saturation, fluid contacts, the average total pore filled by hydrocarbon, the gross pay thickness or height of the hydrocarbon column, and the net pay thickness. These parameters, derived from composite wireline logs of Sam 4 Well (Fig. 2) using the method explained in Section 2.0, are presented in Table 3.

Hydrocarbons were identified in eleven out of the twenty-one reservoir sand units (Table 3). Hydrocarbon saturation ranged from 17.4% in sand unit "B" to 81.5% in sand unit "H.". However, only sand units O, U_2, and H sand units, representing 14.3% of the total reservoir sand units, have hydrocarbon in commercial quantity with hydrocarbon saturations of 47.8, 78.6, and 81.5%, respectively. The sand units O, U2, and H also have an average total pore volume filled by hydrocarbons of 11.17 and 21.6% and a net pay thickness of 5, 6, and 10 m, respectively.

Hydrocarbon contacts include oil-water contact (OWC), which is the depth at which the boundary between oil in place and water was encountered, and gas-oil contact (GOC), which is the contact between gas and oil. The identification of hydrocarbon contacts is a further validation of the presence of hydrocarbons in reservoirs. OWCs were identified in sand units B, F, N, O and P, while GOCs were identified in sand units A, B, and U (Table 3).

4. Discussion

4.1. Reservoir Quality

The quality of a reservoir is indicated by porosity (ability to store fluid) and permeability (ability to flow fluid). The results of the study show that reservoir quality parameters vary with depositional processes or facies, thickness, and burial depth, conforming to the general characteristics of sandstone reservoirs in other basins like those in the Niger Delta (Lien et al., 2006).

Average porosity ranges from 12.12% to 30.8%, while permeability ranges from 96.3Md to 903.2Md, depending on depth, thickness, and depositional environment. These values are quite lower than those described by Edward and Santogrossi (1990) for Niger Delta reservoir sands. The differences can possibly be attributed to differences in thickness, depth, and depositional processes. However, the log porosity and permeability values obtained for mouth bar reservoir sands are quite like the core porosity and permeability values obtained by Oyanyan and Oti (2016) for mouth bar sands in another oil field also located in the same depobelt.

Nonetheless, comparing these values to those of Dresser Atlass (1982), it is observed that the porosity values of reservoir sands in Sam-Bis Field range between fair and very good, while permeability ranges from good to very good. Both reservoir property estimations are good for hydrocarbon production.

4.2. Petrophysical Properties and Depositional Environments

It has been established that porosity varies with the depositional environment, as typified by grain size trends (Berg, 1986). Coarsening upward reservoir sand, such as that of the mouth bar, has porosity higher at the top than at the bottom, and the reverse is true for fining upward reservoir sands, such as that of the point bar, tidal channel, and fluvial distributary channel. For example, reservoir sand T (a mouth bar) has porosity of 20.8% at the bottom and 27.8% at the top, while "O" (a tidal channel) has porosity of 24.5% at the bottom and 10.7% at the top. This observation of petrophysical parameter distribution controlled by depositional facies is typical of reservoir sands in the Niger Delta basin and others (Gier et al., 2008; Oyanyan and Oti, 2015).

Results showed that mouth-bar reservoir sands have the highest quality and always have a porosity higher than that of adjacent reservoirs deposited in a different environment. For example, reservoir 'T', a mouth bar sand, has an average porosity (24.1%) higher than that of the adjacent fluvial channel reservoir sands, 'S' and 'U2', which are 15.4% and 22.2%, respectively. Permeability is also higher in mouth bar sand (F) than adjacent tidal channel sand (E).

Also, all reservoir sands deposited under the same energy conditions in the same environment have been found to have similar or close porosity values. For example, all the tidal channel deposits encountered within the close-depth range have porosity values around 27%. These observations show the energy of the depositional environment as a determinant factor in the quality of reservoirs. The higher the energy of the environment of deposition, the higher the sorting of grains, as fine particles that block pore-throats in sandstone reservoirs are winnowed out, resulting in high-quality reservoir formation (Selly, 2000).

Generally, with the effect of depth taken into consideration, the complete petrophysical analysis of all the sand bodies gives the order of increase in porosity with depositional environments as: fluvial distributary channel, lower shoreface, point bar, tidal channel, and mouth bar.

5. Conclusion

The following conclusions can be drawn from this study.

1. Permeability is strongly related to porosity in the studied reservoir sands. Generally, the reservoir sands exhibit porosity values that range from 12.12% to 30.8%, which can be considered to be fair to very good, while

permeability ranges from 96.3Md to 903.2Md which is good to very good for hydrocarbon production in the studied depobelt.

2. Petrophysical parameters (porosity, permeability, and volume of shale) of reservoir sands in the Sam-Bis field are controlled by depositional processes, thickness, and depth. Porosity and permeability values therefore vary with depositional facies and depth. With the effect of depth taken into consideration, the order of increase in porosity with depositional environments is given as: fluvial distributary channel, lower shoreface, point bar, tidal channel, and mouth bar.

3. Reservoir quality varies with the energy of paleo-depositional environments. The tidal channel formed a thicker reservoir than the mouth bar, but the mouth bar formed a higher-quality reservoir due to the energy of the depositional environment.

4. Out of the twenty-one reservoir sands identified, only eleven have hydrocarbon accumulations. All the hydrocarbon-bearing reservoir sands show a wide range of hydrocarbon saturation, from 17.4% to 79.9%, with a total pore space filled by hydrocarbons ranging from 5.0% to 17.3%. However, only three reservoir sand units have commercial accumulations of hydrocarbon, with saturation ranging from 47.8 to 81.5%.

Acknowledgment
Special thanks to the Agip Oil Company, Port Harcourt, Nigeria and the Nigerian Upstream Regulatory Commission (NURC), formerly known as the Department of Petroleum Resources (DPR) of the Federal Ministry of Petroleum, Nigeria, for providing the data used for this study.

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