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Petrophysical Properties' Evaluation for Reservoir Characterization of AK Field, Onshore Eastern Niger Delta, Southern Nigeria

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Abstract

In this study, well log derived petrophysical parameters of four (4) delineated clastic reservoirs in AK field, located onshore eastern Niger Delta have been effectively employed to characterize and assess hydrocarbon prospect potential of the field. Wireline well log data, such as gamma ray, resistivity log suite, Compensated Neutron Log (CNL) and Formation Density Compensated (FDC) were studied and analyzed for qualitative and quantitative evaluation of the formation units in the field. Lithologic discrimination aided the identification of sandy units, while fluid identification and discrimination defined the hydrocarbon saturated reservoir units in the field. Other derived parameters such as porosity, permeability, water saturation, hydrocarbon saturation, Net To Gross (NTG), net hydrocarbon pay, Bulk Volume Water (BVW) among others were employed to quantitatively characterize the delineated reservoir units, especially to establish their hydrocarbon potential. Four (4) sandy reservoir units, A1, A2, A3 and A4 which ranged in thickness from about 60-350 ft were identified from four exploratory wells AK-01, AK-02, AK-03 and AK 04 to be hydrocarbon bearing. The clastic reservoirs presented medium to relatively high formation porosity (0.27-0.38), low to average permeability value (61.6-685.5 mD) and significant to high hydrocarbon saturation (0.42-0.97). A plot of true formation resistivity values (R_t) against water saturation (S_w) indicate that all reservoir units encountered in well AK-01 are oil saturated. However, only reservoir sands A1 and A2 are predominantly oil reservoirs in well AK02 while sands A3 and A4 plot in oil and water field. In well AK-03, reservoir A1 contains only oil while the remaining reservoirs contain oil and water. The reservoir units as encountered in well AK-04 show slightly different fluid saturation pattern as reservoir A1 contains only oil, A4 is gas saturated while the remaining two reservoir units (A3 and A4) plot in the field of both water and oil.

Key words: Petroleum prospect; Hydrocarbon saturation; Petrophysical parametlers; Reservoir characterisation; Niger Delta

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INTRODUCTION

The goal of oil and gas exploration is to identify and establish suitable reservoir formations with commercial accumulation and thereafter characterize the reservoir as accurate as possible in order to evaluate the hydrocarbon reserve as well as determine the most effective way of recovering as much of the resource as possible. Reservoir Characterization is a technique involving quantitative distribution of reservoir properties such as facies distribution, porosity, permeability and fluid saturations[1] and this knowledge is an important factor in quantifying producible hydrocarbon.[2] Well logs data provides reliable downhole geological information useful for evaluating the hydrocarbon potential of rock formations.[3] The generated information has been proven to reduce risk associated with hydrocarbon exploration.

This study seeks to determine the relevant reservoir petrophysical properties, evaluate and characterize AK field located onshore eastern Niger Delta, southern Nigeria in order to appraise its hydrocarbon potential. The study established vertical as well as lateral lithologic distribution across available wells in the field, delineate potential fluid bearing formations, discriminate formation fluids, determine the degree of saturation of the different fluids in the reservoirs.

1. GEOLOGY OF THE STUDY AREA

The AK field is situated in the eastern onshore block of the Niger Delta and has total area coverage of about 46 km^2. It is located northeast of Port Harcourt town in southern Nigeria (Figure 1). The Tertiary Niger Delta Basin, located in southern Nigeria at the inland margin of the Gulf of Guinea is situated at the southernmost extremity of the elongated intra-continental Benue Trough. It is situated between latitudes 3°N and 6°N and longitude 5°E and 8°E (Figure 2). The basin is bounded by the Calabar Flank in the east, Benin Flank in the west, Gulf of Guinea in the south and in the north by older (Cretaceous) tectonic elements such as the Anambra Basin and Afikpo Syncline.[4-6] The Niger Delta Basin is the most prolific deltaic hydrocarbon province in Nigeria and West African continental Margin, and among the major hydrocarbon provinces in the world. Oil and gas in the Niger Delta are principally produced from sandstones and unconsolidated sands predominantly in Agbada Formation.

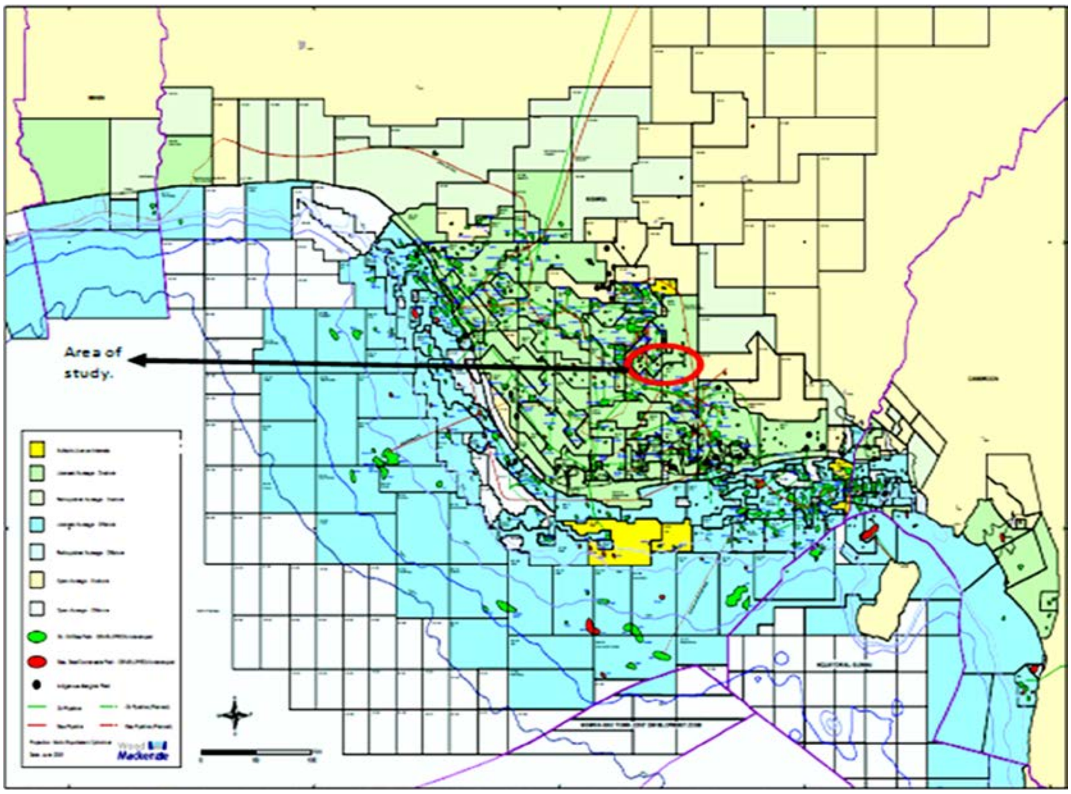

Figure 1
Map of Niger Delata Showing Area of Study

The entire Delta is composed of three major formations; Akata, Agbada and Benin Formations (Figure 3). The Benin Formation is the upper alluvial coastal plain deposit of the Niger Delta Complex. It extends from the west Niger Delta across the entire Niger Delta area and to the south beyond the present coastline. The Benin Formation deposited in a continental fluviatile environment and composed almost entirely of non-marine sandstone, consists of coarse-grained sandstones, lignite streaks and wood fragments with minor intercalation of shales. Benin Formation is of Miocene to younger age and has a variable thickness that exceeds 1,820 m.[8] In the subsurface, it is of Oligocene age in the north becoming progressively younger southwards but ranges from Miocene to Recent. Very little hydrocarbon accumulation has been associated with this formation.[9]

The Agbada Formation underlies the Benin Formation, and it is the major petroleum-bearing unit. It was laid down in paralic brackish to marine fluviatile, coastal environments. In the lower Agbada Formation, shale and sandstone beds were deposited in equal proportions, however, the upper portion is mostly sand with only minor shale interbeds. It is made up mainly of alternating sandstone, silt and shale. The sandstones are poorly sorted, rounded to sub-rounded, slightly consolidated but majority are unconsolidated. The sandstones grade into shale in the lower part of the formation. Agbada Formation ranges in age from Eocene in the north to Pliocene in the south. The sandy parts of the formation are known to constitute the main hydrocarbon reservoirs of the delta oil fields and

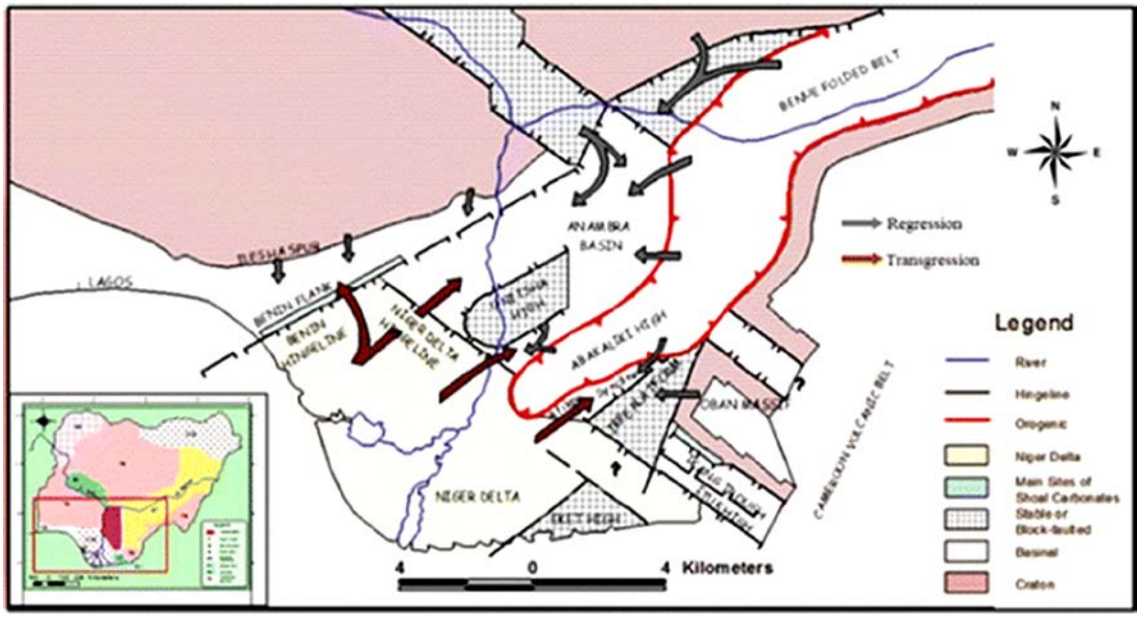

Figure 2
Tectonic Setting and Structural Elements of the Niger Delta Basin[7]

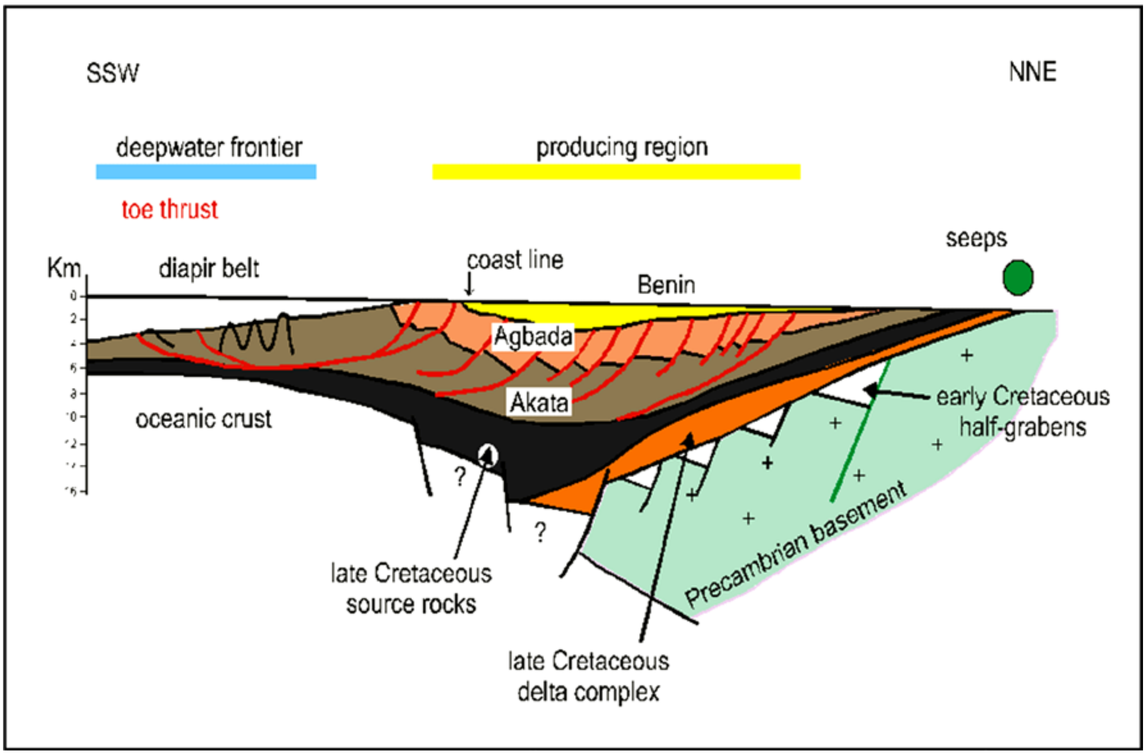

Figure 3
Structural Section of the Niger Delta Complex Showing Benin, Agbada and Akata Formations[9]

the shales serve as seals to constrain the generated oil and gas within the reservoir structures. The thickness of the formation reaches a maximum of about 4,500 m at the center of the basin.[9]

The Akata Formation is the lowermost unit of the Niger Delta Complex, it is of marine origin and it composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt. It is composed of mainly shale with sandstones and siltstones locally interbedded. It is estimated that the formation is up to 7,000 meters thick in the central part of the delta.[8] The formation underlies the entire delta, and it is typically overpressured. The Akata Formation outcrops offshore in diapirs along the continental slope, and onshore in the north east, where they are called Imo Shale. The age of the Akata Formation ranges from Eocene to Recent.[9]

2. MATERIALS AND METHODS

The data set used for the study include composite well logs data of four different widely spaced vertical wells (AK-01, AK-02, AK-03 and AK-04) from AK field onshore Niger Delta. The major logs used for characterizing reservoirs identified in the field include; gamma ray, resistivity, neutron and density porosity logs. The well log data were Quality Checked (QC), validated and edited as appropriate to reduce error. The reservoir characterization analysis of AK field was carried out qualitatively and quantitatively. The qualitative interpretation includes the lithologic identification, establishing stratigraphic relationship as well as lateral lithologic distribution through formation correlation of well log signatures from wells in the AK field. Quantitative interpretation on the other hand, includes the determination of formation thickness, Net to Gross (NTG), net oil / gas pay, effective porosity, formation permeability, hydrocarbon saturation, water saturation, shale volume, Bulk Volume Water (BVW). Figure 5 is the base map of the AK field showing the locations of the four exploratory wells used in this study. The field is located onshore Niger Delta and has an area coverage of about 46 km^2.

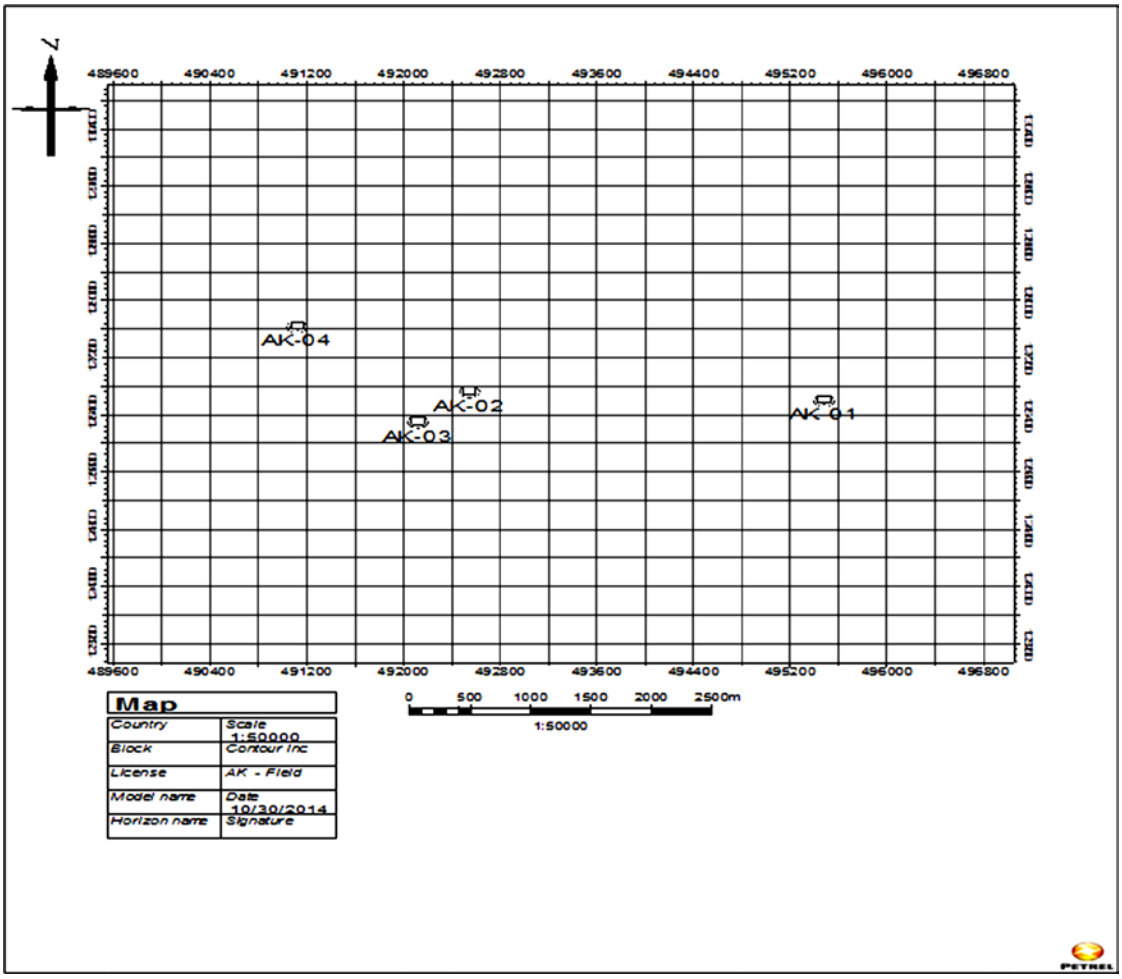

Figure 4
Base Map of AK Field Showing Wells Locations

Qualitative interpretation includes routine formation evaluation which involves discriminating between the permeable which could constitute the hydrocarbon reservoirs from the impermeable units which are likely hydrocarbon source rocks. The qualitative interpretation also discriminate different formation fluids, whether brine, oil or gas as well as establish the lateral distribution of litho units with constituent fluids from one well to another through well correlation. Lithologic discrimination was carried out using gamma ray log signatures, while true formation resistivity helped to discriminate hydrocarbon saturated from water bearing formations. A combination of Formation Density Compensated (FDC) and Compensated Neutron Log (CNL) was used to differentiate oil saturated sands from gas saturated reservoir. Contact information such as Gas-Oil Contact (GOC), Oil-Water Contact

(OWC) and Oil-Down-To (ODT) were also determined from the log signatures.

Quantitative Interpretation involves the determination of the reservoir hydrocarbon content which is a product of hydrocarbon saturation (S_{hc}) and formation porosity (Φ) (Equation 1).

$$\text{Hydrocarbon content} = \Phi * S_{hc}\ . \qquad (1)$$

Formation porosity was determined from the bulk density and neutron logs. For accuracy, the porosity values obtained from the two logs were compared and used to evaluate the degree of uncertainty associated with the estimated hydrocarbon reserve. The bulk density porosity (Equation 2), for example, is the overall gross or weight average density of a unit of the formation and it can be taken as total porosity for a monomineralic reservoir.

$$\Phi_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_{fl}}\ . \qquad (2)$$

Where ρ_{ma} = matrix (or grain) density, ρ_{fl} = fluid density and ρ_b = log derived bulk density which accounts for both the fluid and the grain density. The average rock density in clastic reservoir (sandstones) is 2.66 gcm^{-3}. In this study, the average of neutron and density logs derived porosities (Equation 3) presents most accurate porosity information used to characterize the reservoir.

$$\Phi_{\text{total}} = \frac{\Phi_N - \Phi_D}{2}\ . \qquad (3)$$

Where Φ_{total} = Porosity derived from the combination of neutron and density porosities

Φ_N = Porosity derived from neutron log

Φ_D = Porosity derived from density log

Accurate formation porosity known as the Effective porosity (Φ_e) is essential to obtain credible information for reservoir characterisation, especially to ensure correct reservoir volume estimate. Effective porosity accounts for the proportion of pore volumes occupied by shale grains within the shaly sandy formation. The volume of shale (V_{sh}) is usually determined from lithologic log reading such as gamma, SP or estimated from the cross plots of porosity logs reading. In this study the volume of shale within Niger Delta clastic reservoir was calculated from gamma ray, which first determine the Gamma Ray Index (I_{GR}) using the relation presented in Equation 4 and thereafter employed the Dresser Atlas formula (Equation 5) for Tertiary unconsolidated reservoir to determine V_{sh}.[2]

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

$GR_{\log}$ is the Gamma ray log reading of the formation, $GR_{\min}$ is the Minimum Gamma ray (clean sand) and $GR_{\max}$ is the Maximum Gamma Ray value (Shale).

$$V_{sh} = 0.083[2^{(3.7 \times IGR)} - 1.0]\ . \qquad (5)$$

Finally, Φ_e was calculated using the determined Volume of Shale (V_{sh}), which is a fraction of the total porosity (Equation 6) that is unoccupied by shale grains but available for formation fluid.

$$\Phi_e = \Phi_{\text{total}} * (1 - V_{sh})\ . \qquad (6)$$

Determining water and hydrocarbon saturation is key to estimating hydrocarbon reserve and was carried out using the Archie's mathematical relation (Equation 7) between water saturation (S_w) and formation water resistivity (R_w), true formation resistivity (R_t) determined from the deep resistivity measuring tool (LLd) and formation porosity (Φ).

$$S_w = \sqrt[n]{\frac{aR_w}{\Phi^2}}\ . \qquad (7)$$

Where "n" is the saturation exponent and "a" is the tortuosity factor.

Several methods exist for determining formation water resistivity (R_w), such as the ratio method, the Archie's method, estimating R_w from Spontaneous Potential (SP) data among others. This study adopted the simpler and less error prone Archie's method, by determining R_t at the water leg, below the Oil Water Contact. Here S_w is 1 and thus easy to rearrange the equation to determine R_w. True formation resistivity (R_t) was taken as the deep penetrating resistivity log (LLd) reading which measured the resistivity of the uninvaded zone at the oil leg, that is above OWC.

Since the pore volume not filled with water is filled with hydrocarbon, then hydrocarbon saturation (S_h) can be derived from water saturation (S_w) by using the simple relation presented in Equation 8.

$$S_h = 1 - S_w\ . \qquad (8)$$

In a water wet formation, there is always a certain amount of water held in the pores by capillary pressure. This water cannot be displaced by oil at pressure encountered in the formations, so the water saturation never reaches zero. This value of water saturation is called Irreducible Water Saturation (S_{wirr}) and was determined using the expression presented in Equation 9.

$$S_{\text{wirr}} = \sqrt{\frac{F}{2000}}\ . \qquad (9)$$

Formation resistivity factor (F) expresses the ratio between the bulk resistivity of water saturated formation (R_o) and the resistivity of the water saturating the formation. F can be computed ($\frac{a}{\Phi^2}$).

Permeability, a measure of the ease with which fluid flows through a rock formation often expressed in millidarcy was also determined for the delineated reservoir sands using a mathematical relationship (Equation 10) which expresses irreducible water saturation as a function of effective porosity (Φ_e) and permeability (K). Several mathematical equations exist for estimating permeability from measurements of porosity and irreducible water saturation, but that proposed by Timur and documented by Dresser (1982) was employed in this study.

$$K = 0.136 * \frac{\Phi_e^{4.4}}{S_{\text{wirr}}^2} \; . \tag{10}$$

Bulk Volume Water (BVW) bears a simple relationship with the irreducible water saturation, for example a formation is considered to be at irreducible water saturation where BVW values remain constant or nearly constant, but where the values vary widely, it is considered not to be at irreducible water saturation. The measured BVW value also directly relates to grain size, BVW value greater than or equal to 0.09 indicate fine-grained sand. A BVW value ≥ 0.06 will be recorded by medium-grained sand while greater than or equal 0.04 (≥ 0.04) indicate coarse-grained sand. For this study BVW was determined from the product of water saturation and effective porosity (Equation 11).

$$BVW = \Phi_e * S_w \; . \tag{11}$$

The estimated BVW value was employed to determine Bulk Volume of Hydrocarbon (BVH) by simply substituting the water saturation in the Equation 11 for hydrocarbon saturation (S_h).

$$BVH = \Phi_e * S_h \; . \tag{12}$$

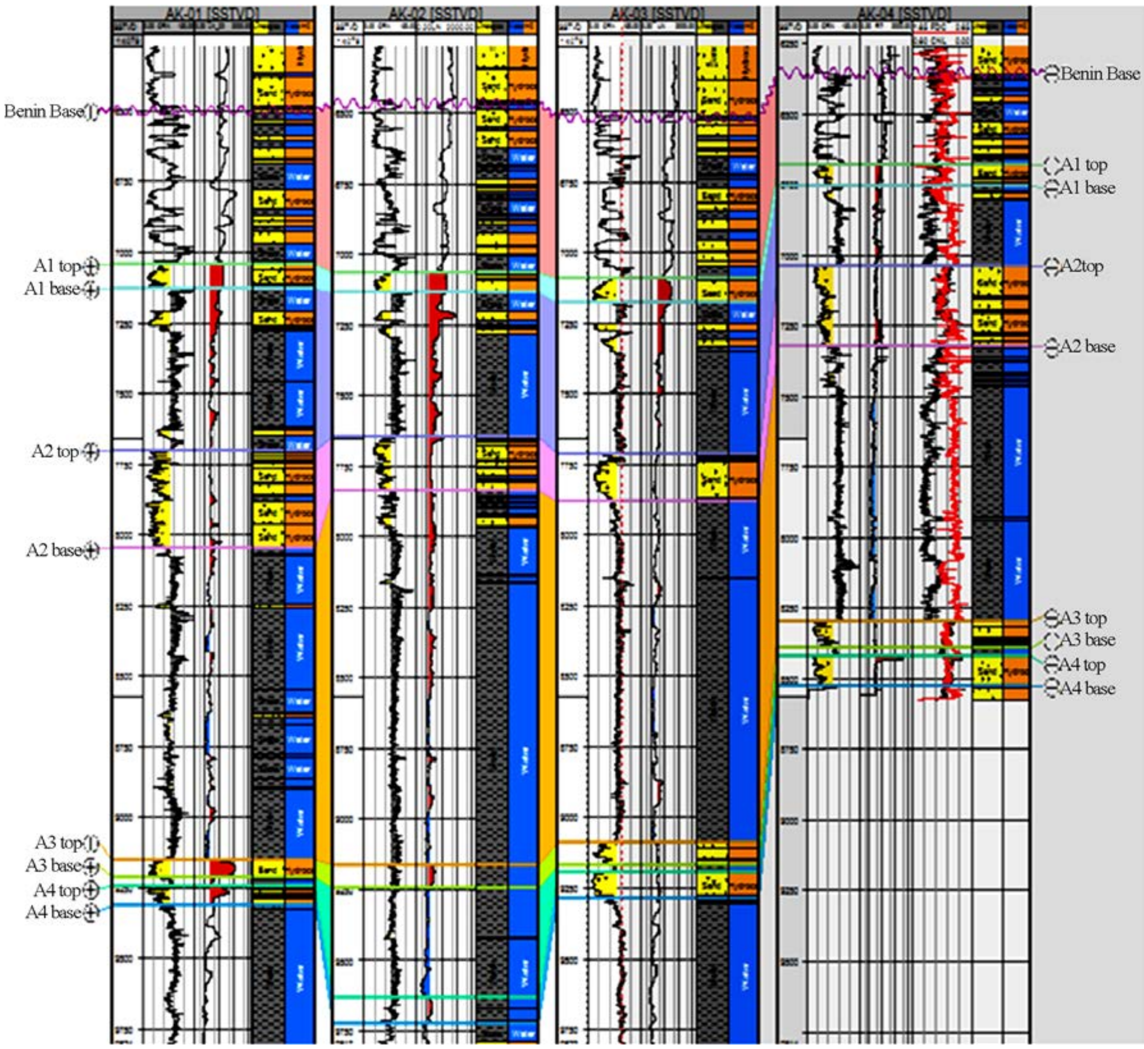

Figure 5
Correlation Panel of Wells AK-01, AK-02, AK-03 and AK-04

3. RESULTS AND DISCUSSIONS

This section presents the results obtained from qualitative and quantitative evaluation of the identified reservoir units in AK field located onshore Niger Delta. The results are presented as interpreted well log sections, correlation profiles across the field and different formation parameters employed to characterize and evaluate the petroleum potential of the field. Qualitative interpretation results which defined the formation type, formation fluid type in the permeable rock units as well as the vertical and lateral distribution of the formations across the field through the analyses of different wireline log signatures are presented in Figure 6. The figure is an E – W correlation panel of Wells AK-01, AK-02, AK-03 and AK-04 in that order. Several clastic permeable units were delineated from the wells through the relatively low permeable gamma ray deflection, but only four (4) of the permeable formations, designated A1, A2, A3 and A4, displayed significantly high formation resistivity to classify them as hydrocarbon bearing. The delineated hydrocarbon bearing reservoirs are all situated below the Benin Base within the Akata Formation of the Niger Delta. All the formations correlate fairly well, displaying very similar log signatures and maintaining almost equal thicknesses from well to well across the field. The thicknesses of the correlated units remain fairly uniform, except for minor variations, such as the thicknesses of reservoirs A1 and A2 which remain fairly constant in Wells AK-01 and AK-02 but increased and decreased respectively westward in wells AK-03 and AK-04.

Quantitative interpretation which defined petrophysical parameters of the delineated reservoir sands identified within the four wells were used to evaluate the hydrocarbon potential of the AK field. The summary of calculated petrophysical parameters through the analyses of available well log data are presented in Tables 1-4. Each of the tables presents the different petrophysical parameters obtained through the analyses of well logs from the four (4) hydrocarbon bearing clastic reservoir intercepted by the individual wells.

Table 1
Petrophysical Parameters of AK-01 Well

Reservoirs	Thickness (ft/m)	*Rt* (Ωm)	*Ro* (Ωm)	I_{GR}	*F*	Φ_e	V_{sh}	Φ_t	S_w	S_h	S_{wi}	*K*	BVW	Net sand	Net pay	N/G
Sand A1	83.13/ 25.34	21.63	0.71	0.04	5.92	0.37	0.009	0.37	0.14	0.86	0.054	587.27	0.068	82.99	79.85	0.98
Sand A2	349.5/ 105.9	13.53	0.95	0.03	7.91	0.38	0.007	0.38	0.17	0.83	0.053	685.54	0.065	68.67	60.08	0.90
Sand A3	56.99/ 17.27	133.15	0.67	0.63	5.61	0.26	0.016	0.26	0.08	0.92	0.077	61.16	0.021	87.77	78.22	0.94
Sand A4	66.29/ 20.08	50.00	0.79	0.35	6.61	0.26	0.039	0.27	0.12	0.88	0.075	64.46	0.031	68.33	56.77	0.87

Table 2
Petrophysical Parameters of AK-02 Well

Reservoirs	Thickness (ft/m)	*Rt* (Ωm)	*Ro* (Ωm)	I_{GR}	*F*	Φ_e	V_{sh}	Φ_t	*Sw*	S_h	S_{wi}	*K*	BVW	Net sand	Net pay	N/G
Sand A1	68.86/ 20.86	21.63	0.71	0.04	5.92	0.37	0.009	0.37	0.18	0.82	0.054	587.27	0.068	348	22.40	0.13
Sand A2	188.56/ 57.14	14.07	0.95	0.03	7.91	0.32	0.007	0.32	0.26	0.74	0.063	227.8	0.083	183.30	67.08	0.59
Sand A3	76.50/ 23.31	3.35	0.67	0.63	5.61	0.25	0.335	0.38	0.45	0.55	0.053	108.62	0.113	151.80	34.20	0.23
Sand A4	95.33 28.88	2.41	0.63	0.04	9.00	0.31	0.121	0.35	0.58	0.42	0.057	241.98	0.180	281.28	254.90	0.95

Table 3
Petrophysical Parameters of AK-03 Well

Reservoirs	Thickness (ft/m)	*Rt* (Ωm)	*Ro* (Ωm)	I_{GR}	*F*	Φ_e	V_{sh}	Φ_t	S_w	S_h	S_{wi}	*K*	BVW	Net sand	Net pay	N/G
Sand A1	87.78/ 26.60	32.99	0.46	0.08	6.61	0.34	0.019	0.35	0.12	0.88	0.057	363.33	0.041	54.86	46.23	0.91
Sand A2	167.13/ 50.64	2.23	0.46	0.09	6.61	0.34	0.0022	0.35	0.46	0.54	0.057	363.33	0.156	75.03	67.08	0.94
Sand A3	77.03/ 23.34	3.18	0.59	0.08	8.43	0.30	0.019	0.31	0.43	0.57	0.065	161.08	0.129	70.26	46.56	0.77
Sand A4	89.11/ 27.00	4.41	0.63	0.04	9.00	0.30	0.009	0.30	0.38	0.62	0.061	151.61	0.114	88.92	48.42	0.69

Table 4
Petrophysical Parameters of AK-04 Well

Reservoirs	Thickness (ft/m)	*Rt* (Ωm)	*Ro* (Ωm)	I_{GR}	*F*	Φ_e	V_{sh}	Φ_t	S_w	S_h	S_{wi}	*K*	BVW	Net sand	Net pay	N/G
Sand A1	71.44/ 21.65	9.62	0.25	0.04	9.00	0.30	0.009	0.30	0.16	0.84	0.067	151.61	0.048	65.49	38.31	0.61
Sand A2	286.35/ 86.76	3.48	0.18	0.10	6.25	0.35	0.024	0.36	0.22	0.78	0.056	427.62	0.077	86.27	75.04	0.93

To be continued

Continued

Reservoirs	Thickness (ft/m)	*Rt* (Ωm)	*Ro* (Ωm)	I_{GR}	*F*	Φ_e	V_{sh}	Φ_t	S_w	S_h	S_{wi}	*K*	BVW	Net sand	Net pay	N/G
Sand A3	91.21/ 27.64	2.54	0.25	0.03	9.00	0.30	0.007	0.30	0.31	0.69	0.067	151.61	0.093	84.47	19.56	0.24
Sand A4	101.75/ 27.00	406.34	0.31	0.02	11.11	0.27	0.004	0.27	0.03	0.97	0.075	76.11	0.008	99.14	65.12	0.74

Generally the tables indicate that the reservoir units were encountered around 6,500-9,850 ft. (TVDSS) in the wells. Four (4) pay units were delineated and they range in thickness from 68-84 ft. for sand A1, 167-350 ft. for sand A2, 56-92 ft for sand A3 and 66-102 ft. for sand units A4 as encountered in all the wells (Figure 6, Tables 1-4). Calculated effective porosities determined from well log data for reservoir units A1, A2, A3 and A4 ranges from 0.30-0.37, 0.32-0.38, 0.25-0.30 and 0.26-0.31, respectively across the field. Hydrocarbon saturation estimates of the pay zones encountered in all the four wells in the field indicate a range from 0.82-0.88 for A1, 0.54-0.83 for A2, 0.53-0.92 for A3 and 0.42-0.97 for A4 pay zones. Permeability determined from well log data range from 151.61-587.27 mD, 227.80-685.54 mD, 61.16-161.68 mD and 64.46-241.98 mD for reservoir units A1, A2, A3 and A4 respectively. The generated petrophysical parameters from the well log data analyses

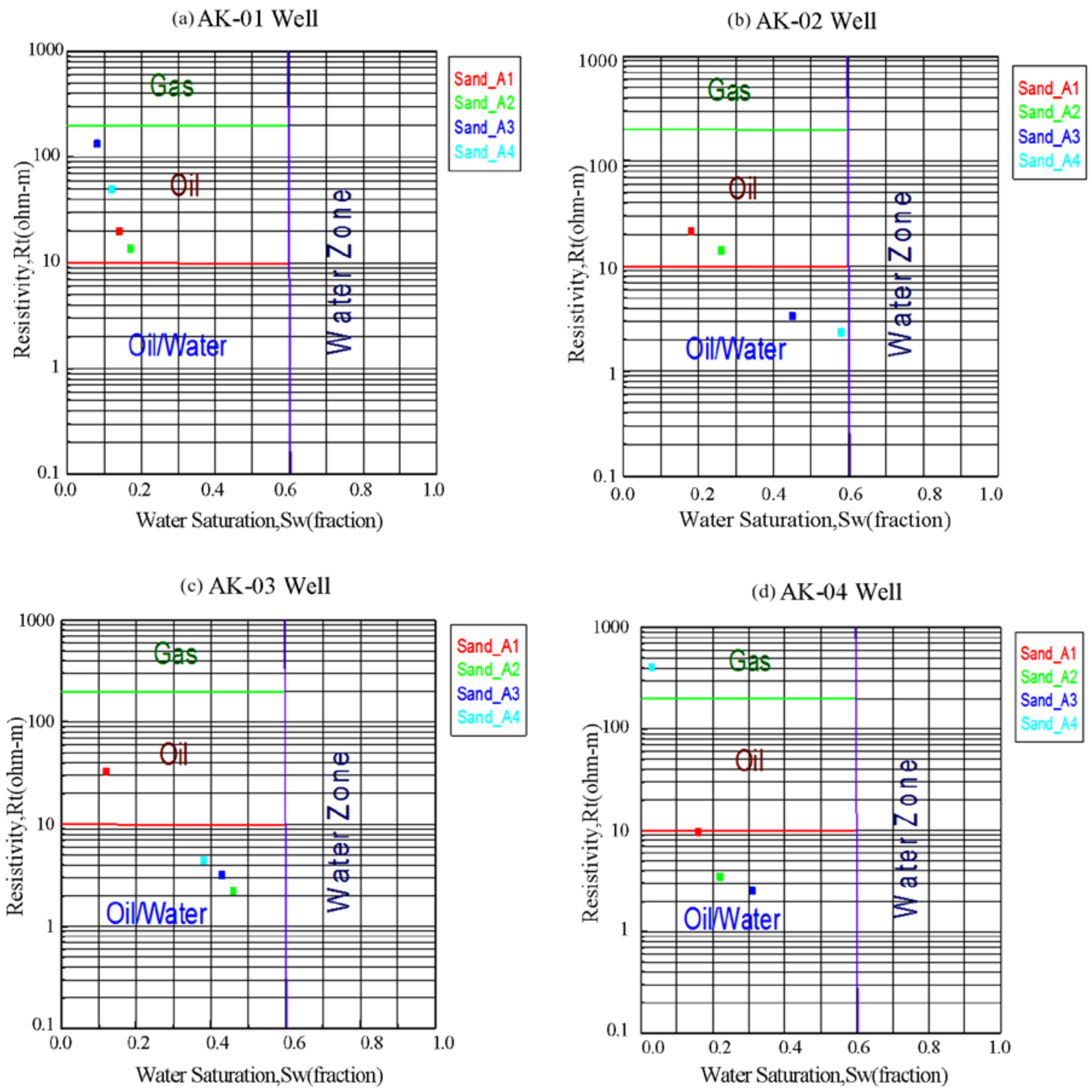

Figure 6
(a) Resistivity-Water Saturation Cross Plot of AK- 01, (b) Resistivity-Water Saturation Cross Plot of AK- 02, (c) Resistivity-Water Saturation Cross Plot of AK- 03, (d) Resistivity-Water Saturation Cross Plot of AK- 04

generally indicate reservoir unit A2 as the thickest, having the highest effective porosity and it is also the most permeable. However, reservoir unit A1 presented the highest hydrocarbon saturation.

A plot of formation resistivity (R_t) against water saturation (S_w) to determine the hydrocarbon fluid phase present in the different clastic reservoirs encountered in the four wells indicates only oil as the present hydrocarbon fluid present in all the reservoir units encountered in well AK-01 since all the sand units plot within the oil field of the graph (Figure 6a). In well AK-02 reservoir sands A1 and A2 plot in oil region while sands A3 and A4 plot in oil/water region of the graph (Figure 6b). Only sand A1 plots under the oil region in well AK-03 while sands A2, A3 and A4 plot under the oil/water zone (Figure 6c). In well AK-04, sand A4 plots under the gas region, sand A1 plots at the oil and oil/water boundary while reservoir sands A2 and A3 plot at the oil/water zone (Figure 6d).

The description of reservoir physical characteristics such grain size, sorting, level of cementation among others were determined from the plot of permeability (K) against Effective porosity which defines zone/field of coarsening, fining, sorting and cement clay within the plot. The permeability versus porosity plot of reservoir sands encountered by well AK-01 indicate that sands A1 and A2 are medium to coarse grained and averagely well sorted, while sands A3 and A4 plots at the region of fine grain size and poorly sorted field, respectively (Figure 7a). Almost all the reservoir sands encountered in well AK-02

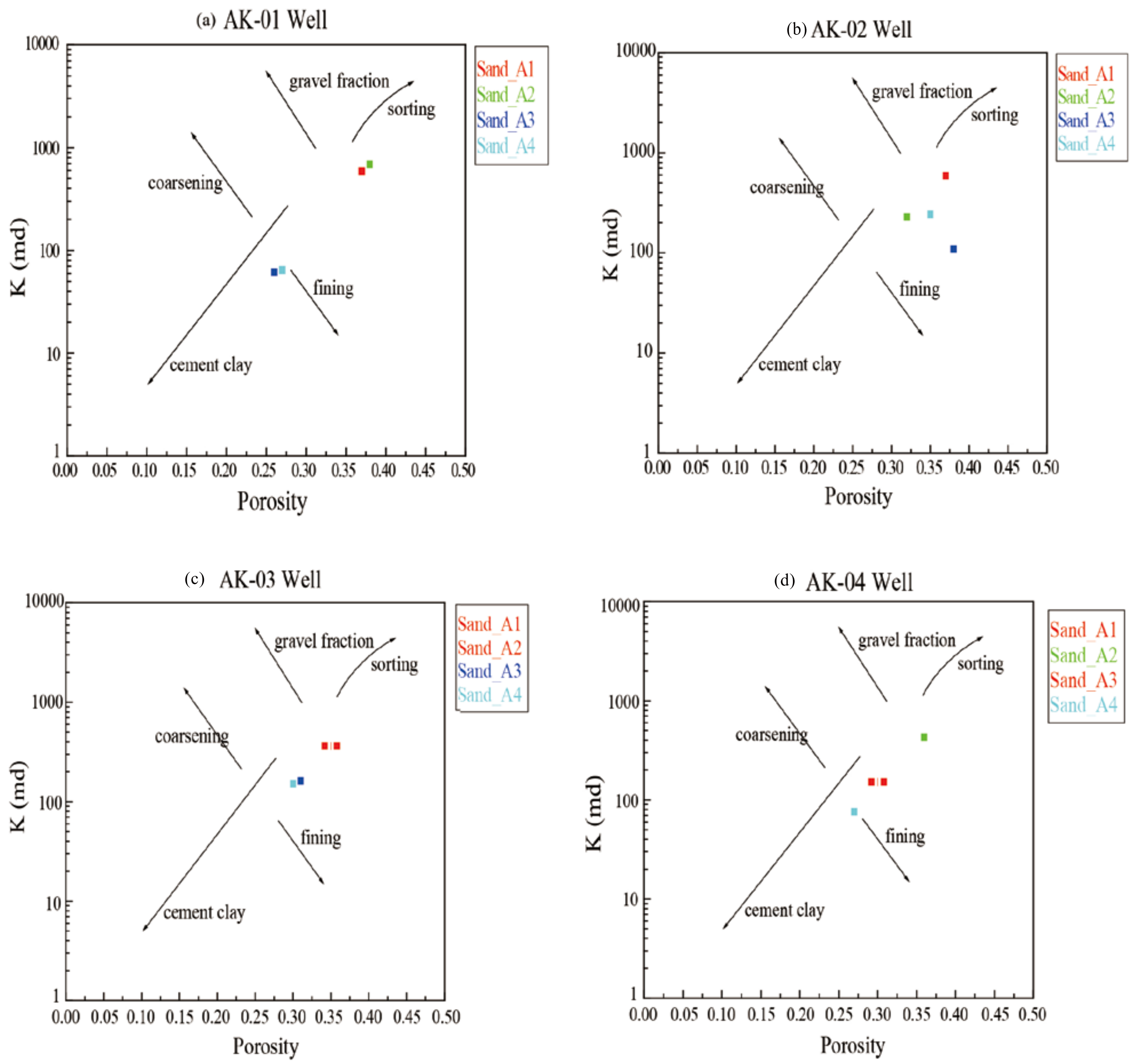

Figure 7
(a) Log *k* *Vs* Φ for Well AK-01, (b) Log *k* *Vs* Φ for Well AK-02, (c) Log *k* *Vs* Φ for Well AK-03, (d) Log *k* *Vs* Φ for Well AK-04

plot at medium grain size and averagely well sorted field of the plot (Figure 7b). The reservoir sands A1 and A2, encountered in well AK-03 plot within medium grain size field and they appeared to be better sorted than than sands A3 and A4 which also plot in medium grain size field (Figure 7c). The reservoir sands encountered in well AK-04 displayed unique physical properties as A1 plots under medium to coarse grain size but better sorted than A4 which plot in fine grain size field, Sands A2 and A3 plots in medium grain size and averagely well sorted field of the permeability – porosity cross plot (Figure 7d).

The summary of petrophysical information extracted from well log data analyses and cross plots for characterizing delineated reservoirs in AK field identified four (4) different reservoir units which present significant hydrocarbon potential. The first reservoir unit, reservoir A1 was intercepted by all the wells at slightly different depths, but presents similar well log responses, especially gamma and resistivity which enabled ease lithologic correlation between the wells. The sand unit ranges from about 79 to 90 ft. in thickness, with the maximum thickness (87.8ft) recorded in well AK-03 which is situated in the central part of the field. The reservoir sand is porous (0.30-0.37) and has medium to relatively high permeability (151.6-587.3 mD). The sand unit presented relatively high formation resistivity (R_t) above the Oil Water Contact (OWC), that is the oil/gas leg of the formation and the thickness of the hydrocarbon saturated zone ranges from 61-88 ft across the wells. The water saturation at the oil/gas leg of the reservoir sand ranges from 0.12-0.18, which indicate high hydrocarbon saturation (0.82-0.88). The second reservoir (reservoir sand A2) was also encountered by all the wells, it ranges in thickness from about 168-350 ft., the reservoir unit shows thickening towards the edges of the field as observed in wells AK-01 and Ak-04 where thickness of 350 and 287 ft. were recorded respectively while less thick sand units were identified in wells AK-03 and AK-02 (167 and 189 ft.) situated in the center of the field. Thin layer of shale was recorded to inter-bed the sand unit (Figure 6). Sand unit A2 presents formation porosity range from 0.32-0.38 with hydrocarbon saturation value ranging from 0.54-0.83 as relatively higher water saturation values were recorded for the reservoir in wells AK-02 and AK-04.

The A3 clastic reservoir unit was also identified in all the wells with its thickness ranges from 57-91 ft. This reservoir recorded the least thickness when compared to all other sand units encountered in the field. The unit presented medium to favorably high petrophysical parameters with relatively high formation porosity (0.25-0.30) and permeability values (61.16-161.08 mD). The unit also showed evidence of interlayering of shale unit within the reservoir sand, especially as observed in well AK-02. Hydrocarbon saturation ranges from 0.55-0.92 in the reservoir. Reservoir sand A4 was also encountered in all wells and it ranges in thickness from 66-102 ft. The unit presented lower formation porosity values when compared with other identified reservoir sands units in the field (0.26-0.31). It has low to medium formation permeability (64.5-241.9 mD). Oil is the most predominant fluid type in the reservoir occurring alone in well AK-01, together with water in well Ak02 and Ak03 while oil and gas occurred in well AK04 which is the only well that contains gas in the field.

CONCLUSION

This study has through the analyses of well log data evaluate the hydrocarbon potential of AK field located onshore eastern Niger Delta in southern Nigeria. Lithologic identifying well log data, hydrocarbon identifying and fluid discriminating information derived from well log data were employed to qualitatively access the hydrocarbon prospect of the field. Quantitative interpretation determined parameters useful to compute the volume of identified oil and gas within the reservoir as well as estimate reservoir properties required for ease of developing and producing the field. Four different hydrocarbon bearing reservoirs were identified in the field and the four of them were encountered by the four wells evaluated in this study. With the incorporation of seismic study, especially to determine the reservoir gross rock volume across the field, it will be easy to determine the volume of hydrocarbon originally in place in the field.

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