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Petrophysical Analysis and Palynological Study of Tiko - Field, Coastal Swamp Depobelt, Niger Delta.

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ABSTRACT
This petrophysical analysis and palynological study of Tiko - Field, Coastal Swamp Depobelt, Niger Delta was undertaken to determine the petrophysical properties and the sequence stratigraphic framework of the Tiko-Field, Coastal Swamp, Niger Delta based on well logs and biostratigraphy data. The cored interval was correlated across the field / well using gamma ray log motif pattern. The motif revealed a progradational stacking pattern for this interval mapped as A1 reservoir. The reservoir thickness decreases from the East (106ft) to the West (8.0ft) in the study area. Petrophysical evaluation confirms that A1 reservoir has a good to excellent storage and flow characteristics. On the average, petrophysical evaluation revealed shale volume is <30%, effective porosity is 21.8%, Permeability is 1235.05 mD and hydrocarbon saturation > 50%. The palynological analysis of the cored section shows the presence of diagnostic fossil assemblages such as Hanzawaia strattoni, Nonionella auris, Florilus atlanticus, Bolivina scalprata miocenica, Quinqueloculina seminula, Eponides berthelotianus and Altistoma tenuis. The result suggest a Coastal Deltaic environment with minor influences from the Inner to Middle Neritic environment. Biomarkers such as Eponides berthelotianus, Cyclicargolithus floridanus and Helicospharea ampliaperta suggests that these environments were probably deposited during the Middle to Early Miocene.
Key words: Petrophysical, Palynological, Progradational, Permeability.

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I. INTRODUCTION

Hydrocarbons are deposited within the subsurface reservoir rocks, and they are brought to the surface when penetrated by a well. In the Reservoir, hydrocarbons reside in the microscopic pore spaces or open fractures of sedimentary rocks like sandstones and carbonates. To produce them, detailed geological, petrophysical knowledge and data are needed to guide the placement of production platforms and well paths (Stat Oil Research Group, 2003). This can consequently help to optimize hydrocarbon recovery, and to improve predictions of reservoir performance. In addition, studying the spatial uniformity of the saturating reservoir fluids can be crucial to oil and gas production (Schlumberger, 1989). Petrophysics can, thus be used to study the lateral change in content of fluids as it helps presume the lateral continuity or extent of the reservoir when seismic data is not available (Adeoye and Enikanoselu, 2009). This thus mitigates failure in hydrocarbon exploration. Therefore estimates of lithology, fluid content and porosity are indispensable. Also in the evaluation of clastic reservoirs such as obtained in the Niger Delta, shaliness (which is a measure of the cleanliness of the reservoir) is a parameter to be considered as it can give a wrong impression of estimated petrophysical values like porosity and hydrocarbon saturation when they are not corrected for (Aigbedion and Iyayi, 2007).

Well-log sequence stratigraphy on the other hand, being an integral part of well-log seismic sequence stratigraphy allows the geoscientists to divide a rock section into series of genetic units bounded by condensed section and their associated maximum flooding surface using wire line log signatures (Nton and Esan, 2010, Rotimi, 2010, Vail, 1977). Each sequence can be sub-divided into smaller sediment packages called systems tracts on the basis of characteristic well-log patterns (Ola-Buraimo et al., 2010). Sequence analysis and system tract study allows the prediction of the environment of deposition and this can be related to the petrophysical property values obtained. This study aim at determination of petrophysical parameters such as porosity, shale volume, permeability, and water saturation and the palynological analysis for the cored interval.

The study field, lies within one of the six depobelts of the onshore region of the Niger Delta basin (Fig1), and is located between latitudes $5^0 00^i 00^{ii}$N and $8^0 00^i 00^{ii}$N and longitudes $4^0 00^i 00^{ii}$E and $6^0 00^i 00^{ii}$E of the Greenwich meridian.

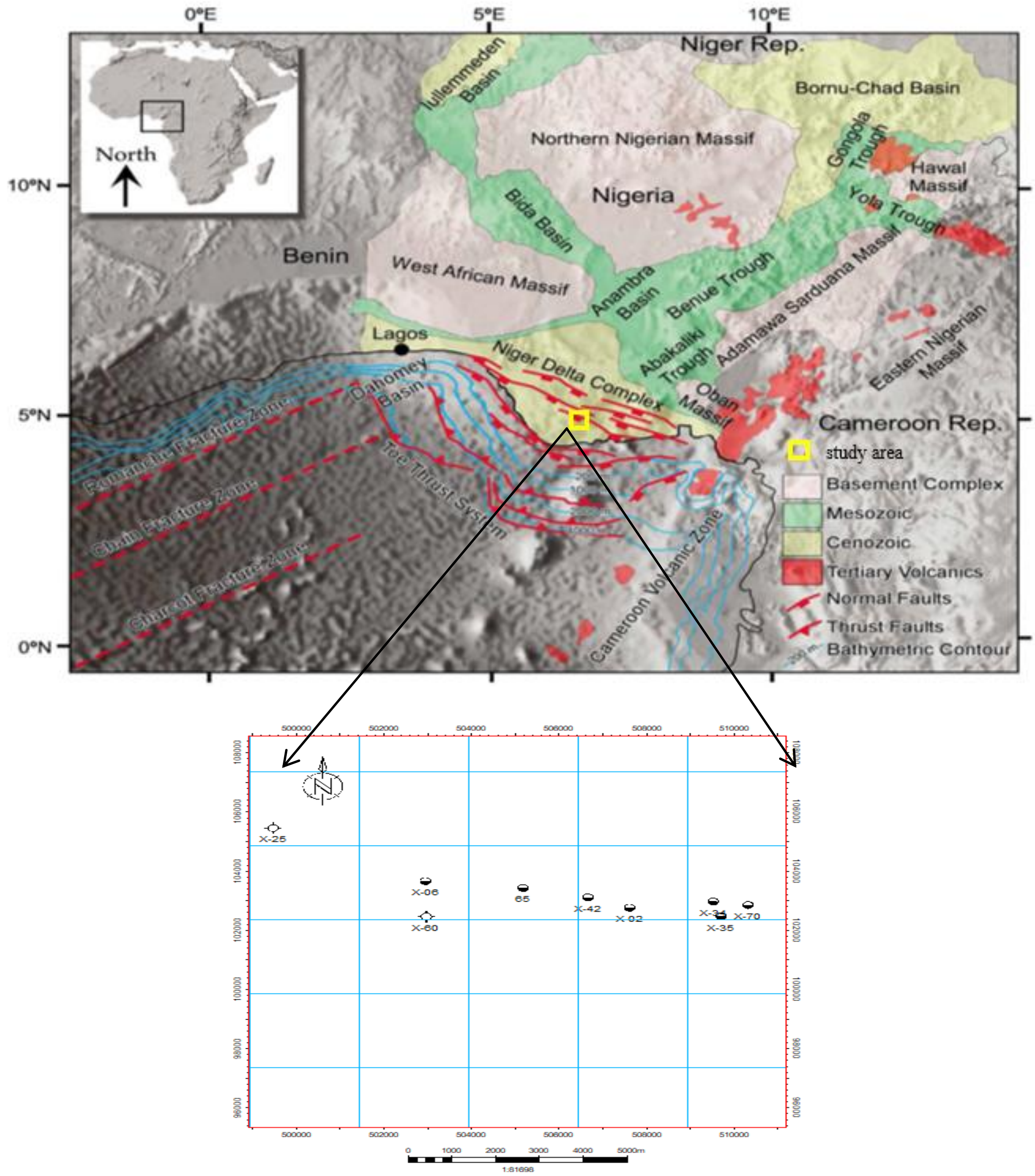

Figure 1: Location of the study area, onshore Niger Delta region (Corredor et al., 2005)

REGIONAL AND STRATIGRAPHIC SETTING

Three formations according to Short and Stauble (1967) make the Niger Delta basin. From the oldest to the youngest, are; Akata Formation, Agbada Formation and Benin Formation (Fig 2).

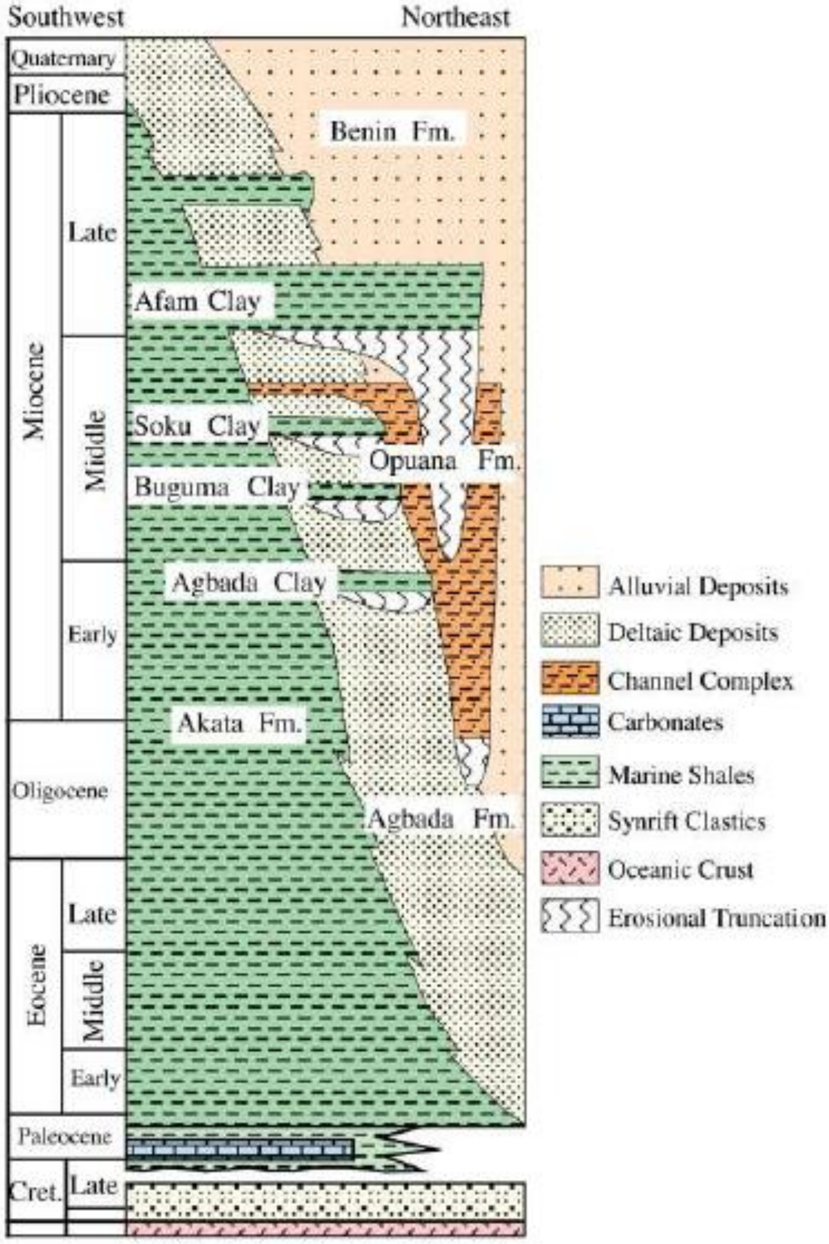

Figure 2: Stratigraphic units of the Niger Delta basin (Doust and Omatsola, 1990)

AKATA FORMATION

This formation is the oldest amongst the others. According to (Whiteman, 1982), it is of Eocene to Holocene in age and comprises of over 6500m of marine clays composed of silty and sandy interbeds. The overburden weight of the other formations above it makes this formation to be over-pressured. This formation according to Beka and Oti (1995), serve as good reservoir rocks within the offshore part of the basin. Also, (Whiteman, 1982) indicated the presence of planktonic forams within this formation suggesting its deposition to be within the shallow marine depositional setting and many other authors are of the view that this formation is the main source in the basin.

AGBADA FORMATION

Directly above the Akata is the Agbada Formation and according to Weber, 1971, it is composed of paralic to marine coastal and fluvio-marine deposits that are coarser towards its top. The sands within this formation are unconsolidated to slightly consolidated and sorting poorly to very well sorted while its grain sizes varies from coarse at the top through medium to fine towards its base. Moving from this formation to the underlying formation shows an increase in sand-shale ratio. The study of Short and Stauble, (1967). According to Whiteman, (1982) and the depositional environment of Agbada Formation include; tidal coastal plain, barrier foot, lower deltaic flood plain, barrier bar and holomarine.

BENIN FORMATION

This is the youngest and the top most formation of the Niger Delta. Reijers, (2011), is of the opinion that its thickness is approximately 2500m with fluviatile sands, gravel and backswamp deposits being its main constituent.

Adiela and Ofuyah (2017) carried out paleoenviromental studies of aka wells, Offshore Niger Delta, using wireline logs (GR and resistivity), 3D seismic and biostratigraphy data. Their results indicate that the stratigraphic development in the Aka Field, took place in delta plain to pro-delta environments within non-marine to middle neritic paleo-water depths.

II. METHODOLOGY

Petrophysical Evaluation

The petrophysical parameters utilized in this study includes shale volume, total porosity, effective porosity, water saturation, hydrocarbon saturation and permeability.

Shale Volume (V_{SH})

The volume of shale is the part of the reservoir that cannot easily be produced. Shale volume is the amount of shale that is found in a reservoir rock. The higher the shale content, the higher the shale volume and the poorer the quality of the reservoir. The gamma ray index (I_{GR}) is the first calculation performed in determining shale volume. In clean sandy reservoirs, I_{GR} is equal to the shale volume. In Niger Delta, where reservoirs are shaly, shale volume is estimated by first calculating I_{GR} using Asquith and Gibson, (1982) equation:

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (3.1)$$

Where;

$I_{GR} = Gamma\ ray\ index\ which\ describes\ a\ linear\ response\ to\ shale\ content.$

$GRlog = \log reading\ at\ the\ depth\ of\ interest.$

$GRmin = Gamma\ Ray\ value\ in\ a\ nearby\ clean\ sand\ zone.$

$GRmax = Gamma\ Ray\ value\ in\ a\ nearby\ shale.$

Shale volume is calculated using the Larionov (1969) non-linear relationship for Tertiary rocks as follows;

$$\mathbf{V_{SH} = 0.083 * \left(2^{(3.7 * GR_{index})} - 1\right)} \quad (3.2)$$

Where;

$V_{SH} = is\ the\ volume\ of\ shale$

$I_{GR} = Gamma\ ray\ index$

Porosity determination

Porosity is the spaces found between two grains in a rock. These spaces could either be in connection or isolated from each other. The open spaces between the grains are referred as the pore throat. Either gas, oil or water are always found occupying the pore throat of any porous media. The pores accounts for the amount of fluids in storage in any given rock. Some of the factors that can affect the size of the pores in a rock include; cementation, sorting, grain size, diagenesis, dissolution, weathering etc. Two types of porosity are often distinguished; Total porosity and effective porosity. Total porosity accounts for both the isolated pores and the connected pores. Meanwhile, effective porosity accounts for only the pore throats that are in connection with each other to allow for free passage of fluids. In all cases, the total porosity always exceeds or is equal to the effective porosity. Total porosity was calculated in this study as follows;

$$\emptyset_T = \frac{\rho_{ma} - \rho_{bulk}}{\rho_{ma} - \rho_{fl}} \quad (3.3)$$

Where

$\emptyset_T = Total\ porosity$

$\rho_{ma} = matrix\ density = 2.65$

$\rho_{bulk} = bulk\ density\ reading\ read\ from\ density\ log$

$\rho_{fl} = fluid\ density\ (o.74\ for\ gas, 0.9\ for\ oil\ and\ 1.0\ for\ water)$

The effective porosity which is responsible for flow within a reservoir is calculated using total porosity and shale volume as follows

$$\emptyset_e = \emptyset_T \times (1 - V_{SH}) \quad (3.4)$$

Where;

$\emptyset e_e = Effective\ porosity$

$\emptyset_T = Total\ porosity$

$V_{SH} = Shale\ volume$

Permeability determination

The permeability of a reservoir is its ability to allow fluids to flow from one point to another. The permeability of a reservoir in clastic sedimentary rocks is directly linked to porosity. The higher the porosity, the higher the permeability. Some of the factors which affect permeability of a reservoir are; size of the pores, grains sorting, size of the pore throat, grain roundness, packing and cement. Owolabi *et al. (1994)* empirical model was used to calculate permeability in this study. The Owolabi's model was preferred due to its widespread acceptability in the Niger Delta. The Owolabi's equation is as follows;

$$K(mD) = 307 + 26552(\emptyset_e^2) - 34540\ (\emptyset_e \times S_w)^2 \qquad (3.5)$$

Where;

$K(mD) = permeability\ in\ milliDarcy$

$\emptyset_e = effective\ porosity$

$S_w = water\ saturation$

Water Saturation

The fluids that occupy the pores of any given rock can either be water or hydrocarbons. Water saturation is the volume of water that is found within the pore throat of a rock. To determine the amount of water saturation in the reservoirs, Archie's empirical model was utilized in this study as follows;

$$S_w = \sqrt{\frac{R_o}{R_t}} \qquad (3.6)$$

Where;

$S_w = water\ saturation$

$R_o = Resistivity\ of\ the\ oil\ leg$

$R_t = True\ resistivity\ reading$

The reservoir hydrocarbon saturation was determined by the difference between unity and water saturation. It is given as follows;

$$S_H = 1 - S_w \qquad (3.7)$$

Where;

$S_H = hydrocarbon\ saturation$

$S_w = water\ saturation$

Identification of fluid type

The presence of hydrocarbons in the reservoir can be seen from the behavior of the resistivity log. Hydrocarbons are poor conductors; hence they tend to have very high resistivity values compared to water which is conductive. This behavior can easily be recognized on the resistivity log. A sharp increase in the resistivity measurement signals the presence of an oil water contact. The resistivity tool is not a good indicator for discriminating between the types of hydrocarbons in a reservoir. The Neutron and density logs used in combination are the best logs used for differentiating oil from gas. To use the neutron and density tool to discriminate the type of hydrocarbons in a reservoir, the two logs must be placed in the same tract and the scale of any of the two logs is reversed. Gas can be identified based on a large separation between the neutron and density log while in the oil-bearing leg, the neutron and density tool tend to tract together. With this in mind, oil, gas and water can then be discriminated.

III. RESULTS AND DISCUSSION

Well log-core calibration

Core gamma revealed that there was no significant difference between the wireline logger's depth and the driller's depth. Depth error ranged from -0.10 to +0.05 ft (Table 4.1). The cored interval was identified on well X-70 as A1 reservoir and correlated across to all other available wells in the Field (Fig. 4.5).

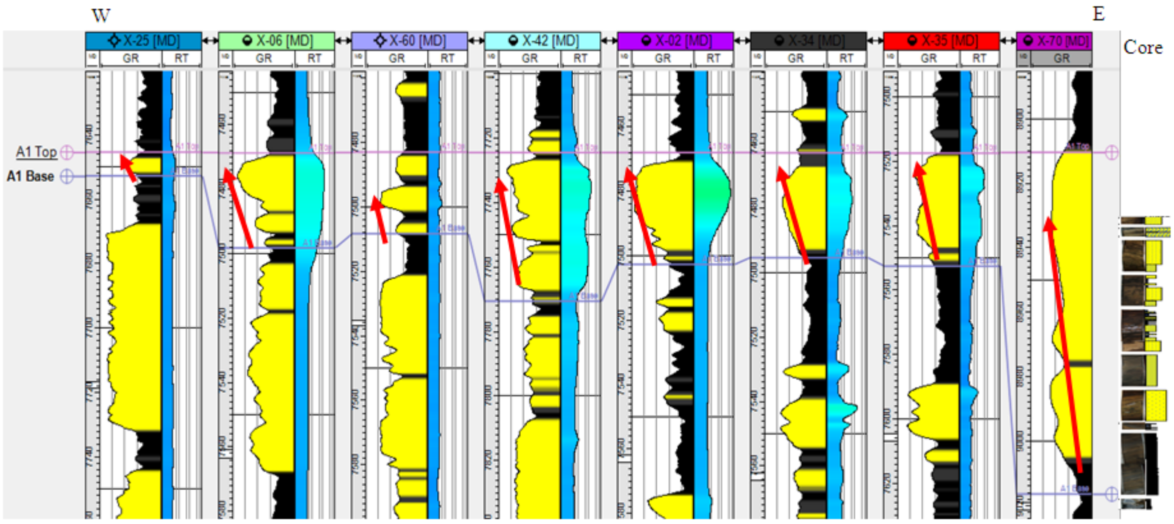

Figure 3: Results of well log reservoir identification and correlation for the cored reservoir interval. Red arrow shows a progradational pattern

Results of Petrophysical Evaluation

Petrophysical logs generated from this study for the cored section of well X-70 and correlated across to other wells are presented in Figures 4.6, 4.7, 4.8 and 4.9. The results of the petrophysical analysis along with the statistical averages are presented in Table 4.2. Shale volume ranges from 15% in well X-02 to 47.20% in well X-25 with mean and S.D values of 28.22±10.08%. The average shale volume is < 30%, indicative that the sands are predominantly clean reservoir sands.

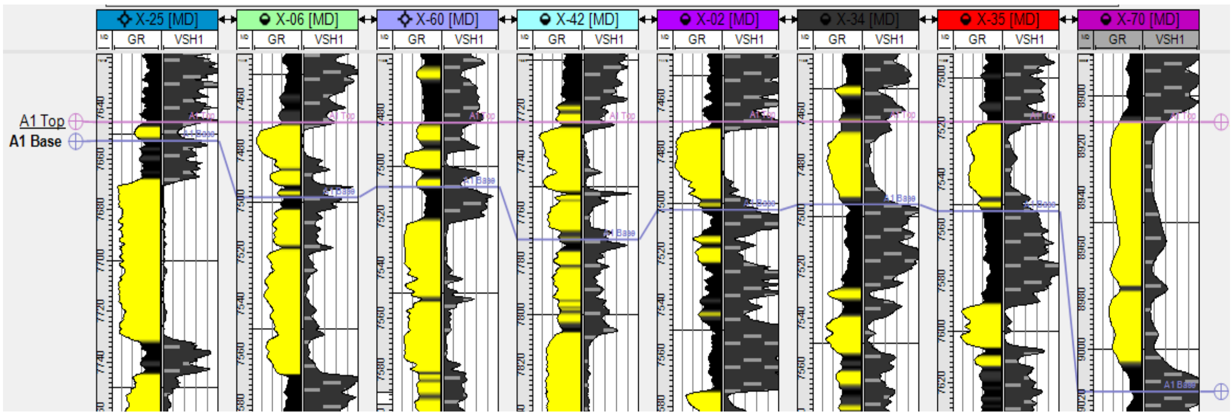

Figure 4: Well section window showing shale volume estimated from gamma ray log

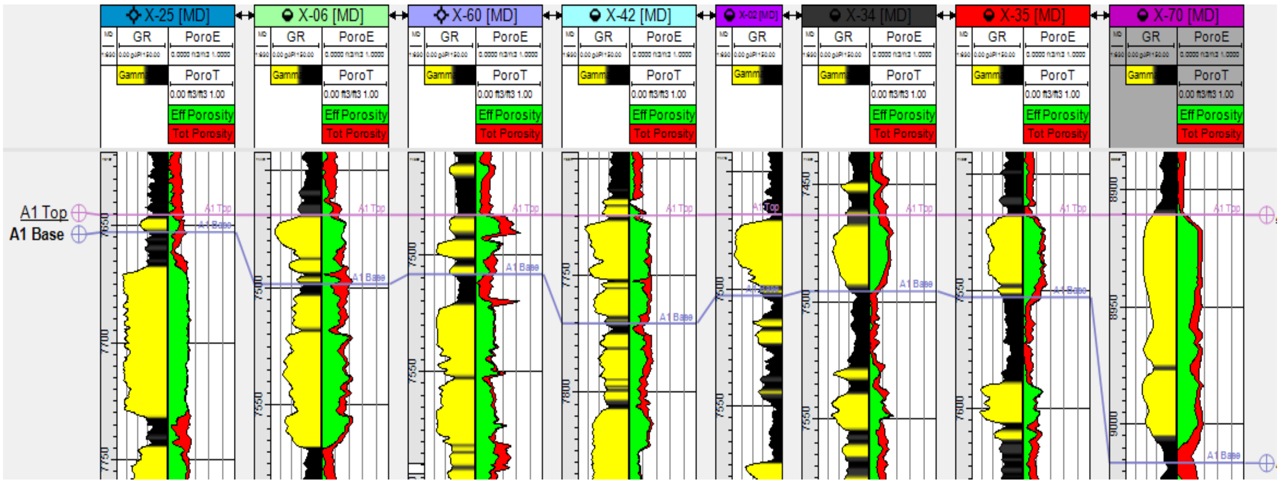

Figure 5: Well section window showing total and effective porosity determination using density logs

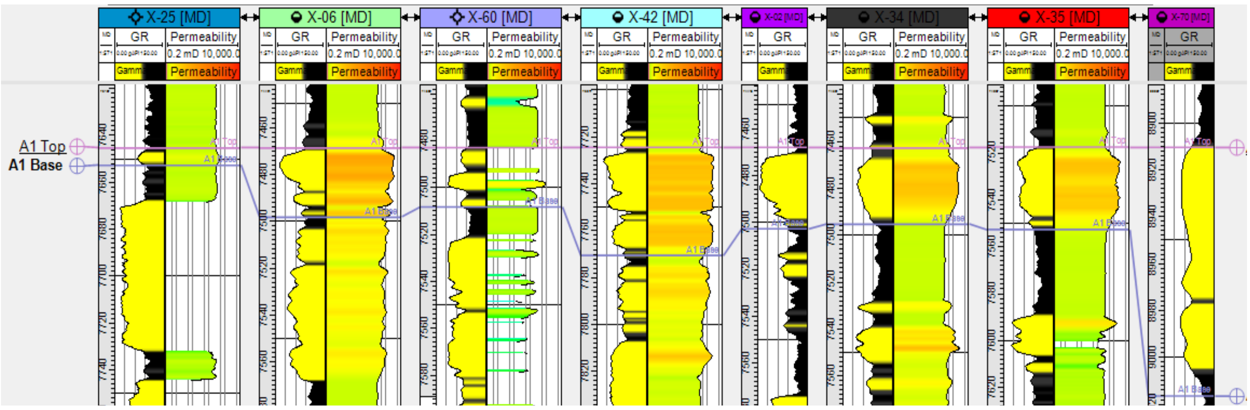

Figure 6: Well section window showing Permeability estimated using porosity and water saturation log

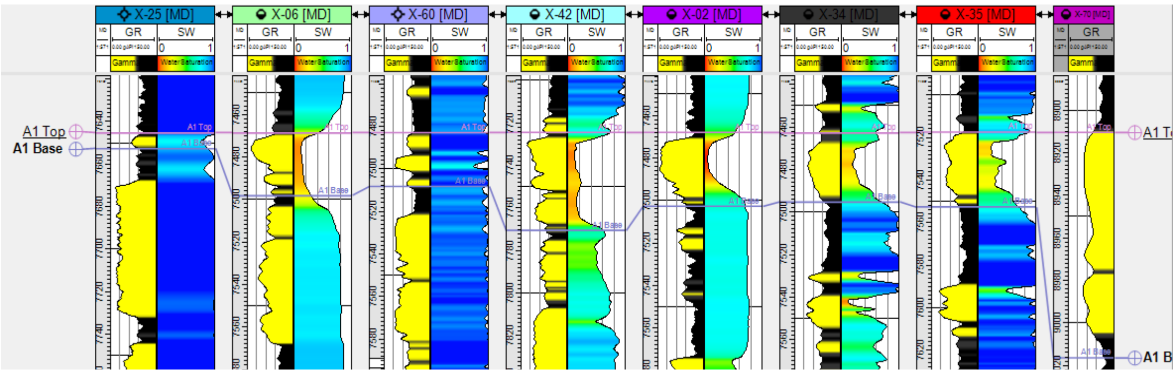

Figure 7: Well section window showing water saturation estimated using resistivity log

Table 1: Results of petrophysical evaluation using well logs

Wells	Shale Volume	Total Porosity	Effective Porosity	Water Saturation	Hydrocarbon Saturation	Effective Permeability
X-02	15.00	-	-	22.80	77.20	-
X-06	23.19	33.88	25.74	16.98	83.02	2125.11
X-25	47.20	22.40	11.90	82.58	17.42	373.21
X-34	25.10	28.37	21.65	35.88	64.12	1468.33
X-35	25.87	28.68	21.76	43.10	56.90	1406.79
X-42	21.45	29.35	23.24	24.19	75.81	1742.23
X-60	37.44	36.99	23.31	94.28	5.72	294.61
X-70	30.49	33.53	25.18	-	-	-
Minimum	15.00	22.40	11.90	16.98	5.72	294.61
Maximum	47.20	36.99	25.74	94.28	83.02	2125.11
Mean	28.22	30.46	21.83	45.69	54.31	1235.05
S.D.	10.08	4.79	4.64	30.65	30.65	743.04

Total porosity ranges from 22.40 in X-25 well to 36.99% in X-60 well whereas effective permeability ranged from 11.90 in X-25 well to 25.74% in X-06 well (Table 2). The average total and effective porosity values are 30.46% and 21.83% respectively. Rider (1986) classification of reservoir quality based on porosity shows that the measured average total and effective porosities are very good, having porosity values >20%. Again, permeability ranged from 294.61mD in X-60 to 2125.11mD in X-06 with an average value of 1235.05±743.04 mD. The high average permeability value (>1000 mD) is classified by Rider (1986) as excellent permeability. Both porosity and permeability values recorded in this study suggests that the A1 reservoir has very good storage and flow potentials.

Water saturation ranged from 16.98% in well X-06 to 94.28% in well X-60 (Table 1). The high-water saturation recorded from wells X-60 and X-25 is due to the absence of hydrocarbons in these wells. Meanwhile all other wells had low water saturation values and high hydrocarbon saturation values. Hydrocarbon saturation in wells containing hydrocarbons ranged from 56.90% in well X-35 to 83.02% in well X-06. This shows that the A1 reservoir is of good hydrocarbon prospect.

Environment of Deposition (EOD)

Table 2-.5 shows the interpreted dominant fauna and flora identified from the cored section of well X-70 (from 8938.45ft to 9022 ft). Fossil fauna were scarce throughout the cored sections. They were only found at 8956ft and 9014ft. All other cored sections were barren of fossil fauna, meanwhile, fossil floras were found throughout the entire thickness of the cored interval.

Table 2: Paleoenvironmental synthesis of the cored interval (8938.45-9022.25 ft) for the x-70 well

INTERVAL (feet)	*DOMINANT FAUNA*	*DOMINANT FLORA*	*PALEOENVIRONMENT*
8938.45	Barren	*Psilatricolporites crassus, Psilatricolporitesspp.*	Coastal Deltaic
8941.30	Barren	*Psilatricolporites crassus, Laevigatosporitesspp.*	Coastal Deltaic
8944.00	Barren	*Acrostichum aureum, Laevigatosporitesspp.*	Coastal Deltaic
8947.20	Barren	*Helicosphaera ampliaperta Laevigatosporitesspp.*	Coastal Deltaic
8950.20	Barren	*Acrostichum aureum, Laevigatosporitesspp.*	Coastal Deltaic
8953.00	Barren	*Acrostichumaureum*	Coastal Deltaic
8956.00	Commonrecord of *Eponides berthelotianus, Bolivina scalprata miocenica, Altistoma tenuis, Florilus atlanticus, Hanzawaia strattoni, Nonionella auris, Quinqueloculina seminula,* andspecies of *Nodosaria* and *Lagena*	*Helicosphaera ampliaperta Gemmamonoporitesspp., Inaperturopollenitesspp., Psilatricolporites crassus, Retibrevitricolporites obodoensis, Retitricolporites irregularis, Sapotaceoidaepollenitesspp., Acrostichum aureum, Laevigatosporitesspp.*	Inner to Middle Neritic

Table 3: Paleoenvironmental synthesis of the cored interval (8938.45-9022.25 ft) for the x-70 well (cont.)

INTERVAL (feet)	*DOMINANT FAUNA*	*DOMINANT FLORA*	*PALEOENVIRONMENT*
8960.50	Barren	*Helicosphaera ampliaperta Gemmamonoporitesspp., Psilatricolporites crassus, Acrostichum aureum, Laevigatosporitesspp.*	Coastal Deltaic
8963.00	Barren	*Leoisphaeridiaspp., Laevigatosporitesspp.*	Coastal Deltaic
8967.20	Barren	*Laevigatosporitesspp.*	Coastal Deltaic
8970.00	Barren	*Helicosphaera ampliaperta Cyclicargolithus floridanus Tricolpitesspp., Laevigatosporitesspp., Zonocostites ramonae*	Coastal Deltaic
8973.00	Barren	*Laevigatosporitesspp.*	Coastal Deltaic
8976.00	Barren	*Psilatricolporitesspp.*	Coastal Deltaic

8979.00	Barren	Fungal spore	Coastal Deltaic
8982..00	Barren	Fungal spore	Coastal Deltaic
8985.00	Barren	Fungal spore	Coastal Deltaic

Table 4: Paleoenvironmental synthesis of the cored interval (8938.45-9022.25 ft) for the x-70 well (cont.)

INTERVAL (feet)	***DOMINANT FAUNA***	***DOMINANT FLORA***	***PALEOENVIRONMENT***
8989.00	Barren	*Acrostichum aureum*, Fungal spore, *Verrucatosporitesspp*.	Coastal Deltaic
8992.60	Barren	*Verrucatosporitesspp*.	Coastal Deltaic
8995.00	Barren	Fungal spore	Coastal Deltaic
8998.00	Barren	Fungal spore	Coastal Deltaic
9001.00	Barren	Charred Graminae Cuticle	Coastal Deltaic
9005.30	Barren	*Psilatricolporites crassus, Acrostichum aureum, Retibrevitricolporites obodoensis, Magnastriatites howardi, Polypodiaceoisporitesspp*.	Coastal Deltaic
9008.00	Barren	Fungal spore	Coastal Deltaic
9010.00	Barren	*Psilatricolporites crassus, Acrostichum aureum, Laevigatosporitesspp., Verrucatosporitesspp., Retitricolporites irregularis*	Coastal Deltaic

Table 5: Paleoenvironmental synthesis of the cored interval (8938.45-9022.25 ft) for the x-70 well (cont.)

INTERVAL (feet)	***DOMINANT FAUNA***	***DOMINANT FLORA***	***PALEOENVIRONMENT***
9012.00	Barren	*Acrostichum aureum, Leoisphaeridiaspp., Laevigatosporitesspp*.	Coastal Deltaic
9014.00	*Ammobaculitesspp*.	*Laevigatosporitesspp., Verrucatosporitesspp., Polyadopollenites vancampoi*	Coastal Deltaic
9016.00	Barren	*Laevigatosporitesspp., Verrucatosporitesspp*.	Coastal Deltaic
9017.00	Barren	*Acrostichum aureum, Laevigatosporitesspp., Verrucatosporites spp*.	Coastal Deltaic
9019.00	Barren	*Acrostichum aureum, Laevigatosporitesspp., Magnastriatites howardi*	Coastal Deltaic
9022.00	Barren	Foraminifera Test Linings, *Laevigatosporitesspp*.	Coastal Deltaic

The microfloralassemblage of the cored section is characterised by common records of *Acrostichum aureum*, *Laevigatosporites* spp., *Verrucatosporitesspp*., *Zonocostites ramonae* and spot records of *Leiosphaeridia* spp. Other microfloral assemblages identified included; *Helicosphaera ampliaperta, Gemmamonoporites* spp., *Inaperturopollenites* spp., *Psilatricolporites crassus, Retibrevitricolporites obodoensis, Retitricolporites irregularis, Sapotaceoidaepollenites spp., Retibrevitricolporites obodoensis, Magnastriatites howardi, and Polypodiaceoisporites* spp. The foraminifera assemblage of the sample contains common *Hanzawaia strattoni, Nonionella auris, Florilus atlanticus, Bolivina scalprata miocenica, Quinqueloculina seminula, Eponides berthelotianus* and *Altistoma tenuis* suggesting an environment of deposition that is predominantly Coastal Deltaic with Inner to Middle Neritic influence at a depth of 8956 ft **(**Adegoke *et al*. 1976; Murray 1991, Adegole *et al.,* 2017).

Age

Diagnostic fossils recorded from the cored intervals were used to infer the age for the cored intervals. The presence of age diagnostic fossil like *Eponides berthelotianus* at a depth of 8956 ft (Table 4) suggests an Early Miocene age (Gradstein et al., 2012) for the cored section of the X-70 Well. The calcareous nannofossils within the cored interval are long vertical ranging species. However, the occurrences of *Cyclicargolithus floridanus* at 8970.00 ft and *Helicospharea ampliaperta* at 8947.20 ft, 8956.00 ft, 8960.50 ft, and 8970.00 ft are also suggestive of an age ranging across Middle to Early Miocene (Adegoke *et al.,* 2017). This study therefore concludes that the cored section of the X-70 well was deposited in the Early Miocene.

IV. CONCLUSION

These facies and facies associations showed a general progradational stacking parasequences pattern on the gamma ray log. The GR log revealed that the cored interval (A1 reservoir) is predominantly sands and ranges in thickness from 8.0 ft in well X-25 to 106.00ft in well X-70. Generally, the thickness of the A1 reservoir decreases from East to West in the Tiko-field. The GR log also revealed that the sands are predominantly hydrocarbon bearing, with very good effective porosity values (21.83% on average), excellent permeability values (1235.05 mD on average), low water saturation and shale volume < 30% of the entire gross thickness. Hence, in order of decreasing reservoir quality, the fluvial channel sandstones facies association are of better quality than the tidal channel sandstones facies. The coastal Plain heteroliths have the poorest reservoir quality because of the high juxtaposition of sands and thin clayey and coal layers. Correlation of the cored section of X-70 well across the field (A1 reservoir) revealed high hydrocarbon saturations, and petrophysical evaluation confirms that these coastal deltaic deposits have good to excellent storage and flow characteristics.

Analysis of fossil fauna and flora from the cored section of the X-70 well revealed the presence of diagnostic fossil assemblages such as *Hanzawaia strattoni, Nonionella auris, Florilus atlanticus, Bolivina scalprata miocenica, Quinqueloculina seminula, Eponides berthelotianus* and *Altistoma tenuis* which suggested a Coastal Deltaic environment with minor influences from the Inner to Middle Neritic environment. The presence of ichnofossils of *Ophiomorpha* and *Skolithos* traces found on the cored photographs suggests a Coastal Deltaic environment of deposition.

The age for the cored section of the X-70 well was inferred using diagnostic biomarkers such as *Eponides berthelotianus, Cyclicargolithus floridanus* and *Helicospharea ampliaperta* suggests that these environments were formed during the Middle to Early Miocene time.

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