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PETROPHYSICAL PROPERTIES DISTRIBUTION AND ASSESSMENT OF THE KOCR-FIELD USING WIRELINE LOGS AND CORE DATA, NIGER DELTA BASIN, NIGERIA.

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ABSTRACT

Petrophysical properties distribution and assessment was conducted on an onshore marginal field in Niger Delta with the aim of evaluating the rock and fluid properties to boost hydrocarbon production and exploration in the field. Eight well logs were used for the eight wells in each reservoirs A, B and C, the well log and core data obtained were utilized for this study. Petrophysical properties evaluated are porosity, net to gross, formation factor, irreducible water saturation, permeability, water saturation, hydrocarbon saturation and pay thickness. The well logs suite contained the following logs: Gamma ray log for lithology identification; Resistivity log for fluid type discrimination and determination of water saturation; Density log for porosity determination; and Neutron in combination with density log for hydrocarbon types. A total of three reservoir sands (Sand A, B and C) were identified and correlated across all the eight wells based on gamma ray, resistivity, neutron and density log profiles. The reservoir gross thicknesses ranged from 62.55 to 228.50 ft, shale volume from 7.0 to 24.60%, net to gross from 0.76 to 0.93%, effective porosity from 20.78 to 26.22%, water saturation from 35.80 to 62.30% and permeability ranged from 545.94 to 2821.97 mD. This shows that the reservoirs are of good quality for hydrocarbon production across the field. From the analysis the field indicated that the proportion of void spaces occupied by water is low, thus, indicating high hydrocarbon saturation. Quantitative porosity verification using Pearson Correlation Coefficient and Regression Equations revealed significant similarity in the porosity values obtained from petrophysical well log and core data. Plots on scatter diagrams using porosity values derived from petrophysical log and that from core analysis for the three reservoirs obtained correlation coefficient (r) values of 0.7165, 0.8094, and 0.5025, respectively for reservoirs A, B, and C indicating strong linear relationships. Plots of values of water saturation derived from core analysis and that from petrophysical log for the reservoirs also showed linear trends. Plots of porosity values against permeability values showed fairly strong linear relationships between the two variables in all the reservoirs indicating that the reservoirs are permeable and have pores that are in strong communication. The calculated volumetrics indicates that reservoir sand body A has the highest STOIIP of (3329MMSTB), followed by C with (220MMSTB), and B having the least of (29MMSTB). The petrophysical properties of the reservoirs are enough to permit hydrocarbon production. For optimal hydrocarbon recovery, static modeling report should be considered for best well placement positions in field development since wrong well positioning could easily compromise wells and cause production decline.

Key Words: Petrophysical, wireline logs, core data, porosity, permeability, Niger Delta.

INTRODUCTION

The Niger Delta basin is observed to be the major sedimentary basin for the production of hydrocarbon in sub-Saharan Africa (Nwankwo et al., 2014). The Delta is situated around the continental margin of the Gulf of Guinea and extends through the Niger Delta Provinces covering the borders of the Atlantic Ocean extending from about longitude 3^{o}E to 9^{0}E and latitude $4^{0}\ 3^{\ 1}$ N to $5^{0}2^{1}$ (Ekine and Ibe, 2013). It is made up of regressive clastic sequence, which reaches a maximum thickness of about 12km (Corredor et al., 2005), and covers an estimated area of 75,000 Km^2 extending from the Calabar flank and the Abakaliki trough of Eastern Nigeria to the Benin flank in the West, forming the prograding depositional complex of Cenozoic formation in the southern Nigeria, opening into the Atlantic Ocean and extending beyond the Gulf of Guinea, flowing from both Anambra Basin and Benue Trough provinces (Nwankwo et al., 2014).

Petrophysics is the study of the physical and chemical properties of rocks and their contained fluids. Despite the innovation in the exploration of petroleum in the Niger Delta using petrophysical principles, there are a lot of difficulties associated with well logging which has caused great damage to machines and personnel. In some cases, subsurface parameters have not been properly evaluated. This has led to some wells not producing optimally or experience dryness over a short period of time, which can be seen as a sharp contrast from the available data.

Properties like porosity, permeability, degree of fluid saturation, net-to-gross, are distributed across rock bodies and are known as petrophysical properties. The spontaneous growth in demand for hydrocarbon and subsequent intensity on oil/gas exploration to meet energy demands and the need to hasten the time needed for initial appraisal and reduction of uncertainties, risks and difficulty associated in exploring for the hydrocarbon, and also to cut down cost of exploration cannot be over emphasized and has resulted in the search for a comprehensive method to evaluate and characterize Petroleum Fields. One important method is the use of petrophysics in reservoir evaluation, characterization and modelling for optimal production rate and sweep (Emujakporue, 2017). The concepts of petrophysics are used to rank projects for investment decisions to be made on economically viable projects. Reservoir characterizations generate petrophysical models that allow for a more precise prediction of future performance and appraisal of reserves (Abraham-Adejumo et al., 2022). The Niger Delta Basin, which is our study location has heterogeneous reservoirs thus a critical petrophysical analysis and model development is required to ensure optimal enhancement of oil recovery using petrophysical model.

A reservoir is a subsurface rock that has effective porosity and permeability which usually contains commercially exploitable quantity of hydrocarbon. Reservoir characterization is undertaken to determine its capability to both store and transmit fluid. Hence, characterization deals with the determination of reservoir properties/parameters such as porosity (Φ), permeability (K), fluid saturation, and Net Pay thickness (Mehdipour et al., 2013).

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. 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. The fluid saturation is the proportion of the pore space that is occupied by a particular fluid. A reservoir can either be water saturated (S_w) or hydrocarbon saturated ($1-S_w$) depending on the type of fluid it contains. Saturation is a relative measurement and commonly expressed in decimal/fractional units or else as a percentage. Porosity can be obtained from sonic, neutron or bulk density log while resistivity logs are used for the calculation of water saturation. A good reservoir is one that is commercially productive. The improvement of reservoir characterization techniques is one of the most important existing and emerging challenges to geoscientists and engineers. Logging tool responses and core data are often used to draw inferences about lithology, depositional environments and fluid content. These inferences are based on empirical models utilizing correlations among tool responses, rock and fluid properties (Ezekwe and Filier, 2023).

A comprehensive petrophysical evaluation is necessary to optimize development and production, serve as reference information for petrophysical evaluation of oil wells, give further illustrations to the use of wire-line log to model, evaluate and characterise reservoir, and serve a baseline for the evaluation of petrophysical parameters such as porosity, permeability, fluid saturation etc. (Nwaezeapu et al., 2019).

However, this study is aimed at comprehensively combining petrophysical log data with core data to evaluate, qualify and quantify the reservoir potential of KOCR- Field, in the Niger Delta with the objectives to delineate hydrocarbon reservoir, estimate the petrophysical parameters within the reservoirs and model their lateral distribution.

The Study Area

The study area is located within the Niger Delta sedimentary basin (Fig. 1), within longitudes 05°41’27” E to 05°42’05” E and latitudes 05°51’55” N to 05°52’03” N. The Niger Delta is one of the most prolific hydrocarbon areas in the world (Oyedele et al., 2013; Stacher, 1995). Some geologists and geophysicists have work on the hydrocarbon potential and distribution pattern of the Niger Delta (Chukwueke, 1997; Doust and Omatsola, 1990; Weber, 1987). Three lithostratigraphies have been delineated in the basin: Benin, Agbada and Akata Formations. The Akata and Benin Formations form the base and top of the basin. Most hydrocarbon accumulation in the Niger Delta is confined to the Agbada Formation while the Akata Formation is the source rock (Nwankwo et al., 2014). The hydrocarbon reservoir in the Agbada Formation is due to the presence of growth faults and rollover anticlines which are critical trapping structures.

The Niger Delta is located on the West African continental margin where the east trending Equatorial coast turns south towards the Equator (Figure 1). It underlies the coastal plain, continental shelf and slope of Nigeria and western Cameroon, and the northern territorial waters of Equatorial Guinea, west of Bioko Island. The Tertiary delta covers approximately 211,000 sq km and developed south- westwards out of the Anambra basin and the Benue Trough. It lies south of the West African shield, and west of the Oban Massif and the Tertiary Cameroon Volcanic Trend. The delta is located east of the Benin Basin, and its southern margin is marked by seafloor escarpments that lie over oceanic crust. The fact that oceanic crust is believed to extend beneath this prolific oil province, even under parts of the onshore delta, makes it unique among major oil provinces (Ekweozor and Okoye, 1980). The Niger Delta is a coarsening upward regressive sequence of tertiary clastics that prograded over a passive continental margin sequence of mainly Cretaceous sediments. The site of Niger Delta was established at the initial rift separation of the African and the South American plates (Figure 1) from Jurassic to Neocomian times. (Ekweozor, and Okoye,1980).

The province covers 300,000 km and includes the geology extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum system (Ayanlade, 2015).

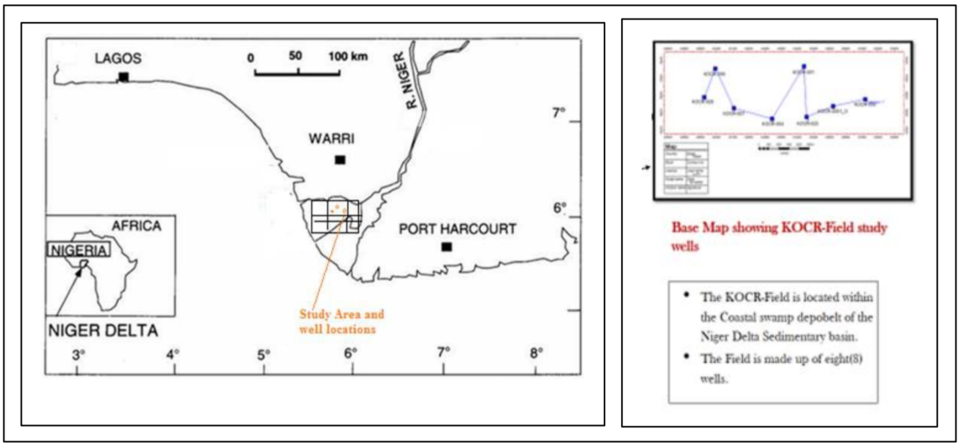


Figure 1: Map of the Niger Delta Showing the location of the study area (Google map of the Niger Delta province) and Base Map.

MATERIALS AND METHODS

The data set used for this research was provided by Shell Petroleum Development Company (SPDC) Nigeria Limited through the permission of the Department of Petroleum Resources (DPR). The data set includes, five composite well logs (Gamma Ray, Spontaneous Potential, Resistivity, Neutron and Density logs), core analysis data for the well that was cored and base map showing the positions of the wells.

The objective of coring is to obtain rock samples that are representative of the formation while minimizing physical and chemical alteration of the rock. Coring is therefore carried out on wells to recover rock samples that are representative of the reservoir rock in-situ condition. It offers first-hand information on the rock properties which can be observed both quantitatively and qualitatively. In this study, the core properties of the cored well depth is plotted with the log derived properties of the same well for qualitative comparison.

The Core Analysis data were entered into a spreadsheet database for processing and placed in each well file for depth plotting with the log data. Core data was depth- shifted to match well log depth. The methodology flow chart is as shown below.

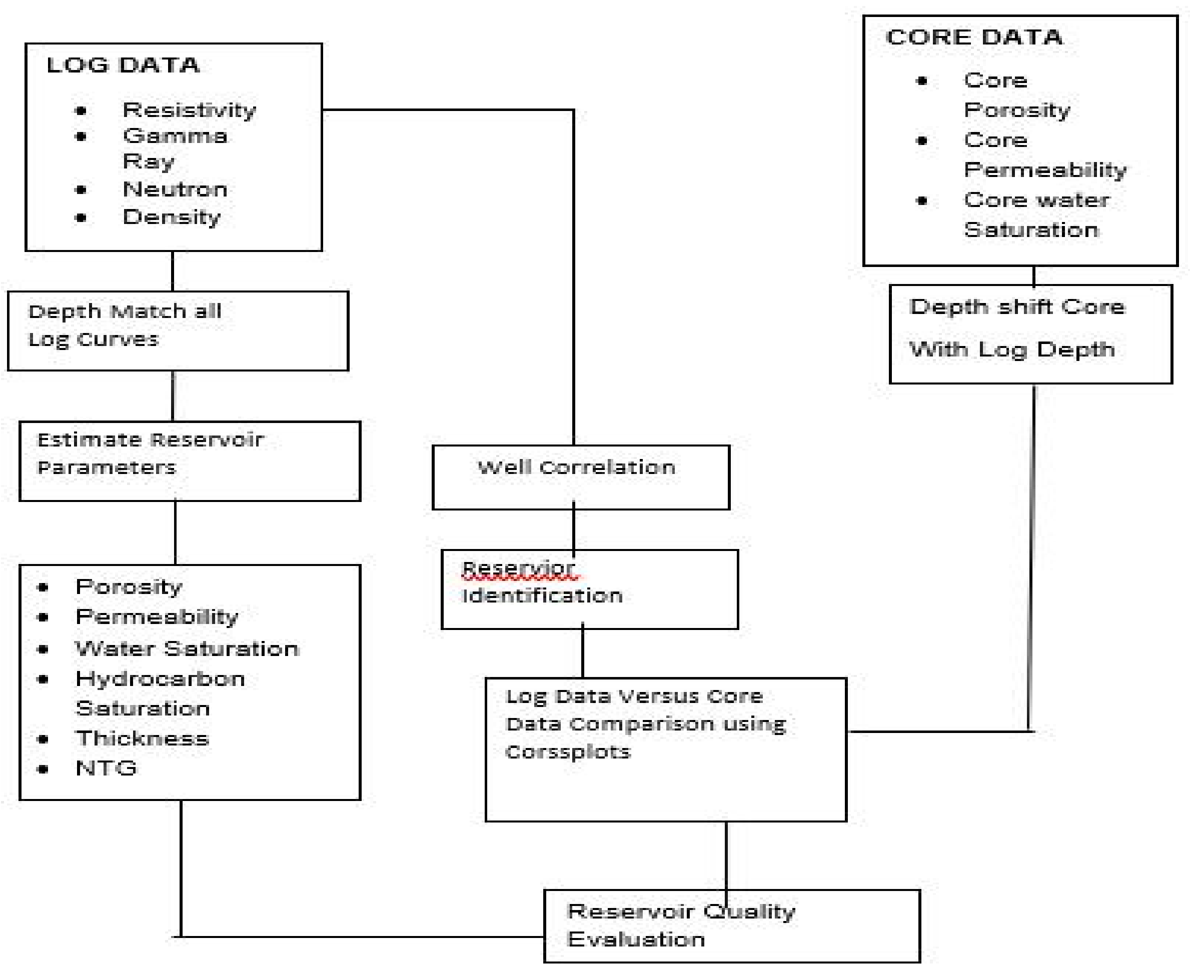


Figure 2: Methodology Flow Chart (after Emujakporue, 2017)

The following petrophysical analyses such as porosity (Ø), permeability (K), volume of shale (V_{Sh}), water saturation (S_w), hydrocarbon saturation (S_h), Net-to-Gross (N/G), and fractional total pore volume filled with hydrocarbon were carried out by using petrophysical calculation. These well logs were adequately digitized by reading the values from each of the respective tracks. The various measurements taken from the corresponding log zone of interest are the Gamma ray (GR) reading, the true resistivity reading (R_t), neutron porosity values and the density values (ρ_b). The log values obtained were substituted in appropriate petrophysical equations to obtain the various petrophysical parameters as indicated.

Porosity: Porosity, 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. The porosity of the various units was determined from the neutron and density logs. Density porosity was obtained from the log- derived bulk density using equation 1, after Rider (1986) while neutron porosity was read directly from the neutron log.

$$\emptyset = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fl})} \times 100 \qquad (1)$$

where,
Ø = Porosity (in %) derived from density log, ρ_{ma} = Density of Matrix, ρ_b = Bulk density value on Density Log, ρ_{fl} =Density of fluid.

Effective porosity was estimated as

$$\emptyset_e = \frac{(\rho_{ma} - \rho_h)}{(\rho_{ma} - \rho_{fl})} - \left\{\frac{(\rho_{ma} - \rho_{sh})}{(\rho_{ma} - \rho_{fl})} \times VCL\right\} \qquad (2)$$

where,
$Ø_e$ = Effective porosity, ρ_{sh} = Density of shale, VCL (ρ_{ma} - ρ_{sh})/(ρ_{ma} - ρ_{fl}) = Clay Bound Water, (ρ_{ma} = 2.65g/cc, ρ_{fl} = 1.0g/cc, ρ_{sh} = 2.6g/cc)

Permeability: Permeability is the capacity of a reservoir rock to permit fluid flow; a measure of the ease with which a formation permits fluid to flow through it. Permeability is a function of interconnectivity of the pore volume. A rock must therefore have interconnected pore spaces to be permeable. Permeability is measured in Darcy (D) or milli Darcy (mD) and is represented with the symbol K. It is critical to know the distribution of permeability in a reservoir. However, the distribution of permeability in a reservoir rock is affected by different controlling factors. These factors are distribution of grains and their shape, type of clay and their distribution, cementation, and grain size. Higher porosity will result in higher permeability and smaller gains will have smaller pores and pore throats which results in lower permeability (Glover, 2012). Reasonable determination of permeability is needed because it influences the decision in optimal placement of wells, the hydrocarbon production rate and the economy of the whole sector of development and operation of the oil and gas field (Omoja and Obiekezie, 2021). Permeability in the oil field is given as the Darcy's linear flow/radial equation that relates flow rate with permeability and the pressure difference in the flow. This is given in a formula for linear flow:

$$Q = \frac{K \times A \times \Delta P}{\mu \times L} \qquad (.3)$$

where:
K = Permeability, A = Cross-sectional area, μ = Viscosity of the fluid, Q = Flow rate, ΔP = change in pressure which is the pressure drop across the porous medium with length (L).

Table 1: Permeability Classification of Reservoir Rocks (modified after Glover, 2012)

Permeability Value (mD)	Classification
<10	Fair
10-100	High
100-1000	Very High
>1000	Exceptional

Water Saturation: Archie Equation was used to calculate the water saturation as shown in equation 3.4 due to its wide-scale applicability in the Niger Delta.

$$S_w^n = \frac{R_w}{\emptyset^m R_t} \text{ (Archie model)} \quad (4)$$

(a = 1.0, m = 1.6, n = 2)
where,
R_t = True formation resistivity, R_W = Resistivity of formation water, Ø = Porosity (fraction), S_w = Water saturation, m = Cementation exponent, n = Saturation exponent.

Hydrocarbon Saturation: Hydrocarbon saturation is the percentage or fraction of pore volume occupied by hydrocarbon. It is usually determined by the difference between unity and water saturation in fraction. It is given by:

$$S_h = 1 - S_w \quad (5)$$

where,
S_h = Hydrocarbon saturation, S_w = Water saturation, 1 = Unity.

Volume of Shale: The volume of shale is best determined from the gamma ray log. The presence of shale on reservoirs makes porosity logs to measure high porosity, lower water saturation values and causes low resistivity readings. This makes it difficult to determine the zone of productivity of a reservoir volume of shale in unconsolidated Tertiary rocks of the Niger Delta.
The minimum of gamma ray was used to compute shale volume as shown in equation 6.

$$V_{sh} = GR_{index} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}} \quad (6)$$

where:.
V_{sh}= Volume of shale, GR_{index} = Gamma ray index, GR_{Iog} = Gamma Ray log reading of the formation, GR_{min} = Minimum reading in a clean sand zone with 100% sand (0% shale), GR_{max} = Maximum reading in 100% shale bed (0% sand).

Stock Tank Oil Initially in Place (STOIIP): Stock tank oil-initially-in-place (STOIIP), refers to the oil in place before the commencement of production. Volumetric methods are used to estimate STOIIP. The oil in place is calculated using the following equation:

$$STOIIP = \frac{7758 * A * h * \emptyset * (1 - S_w)}{B_{oi}} \qquad (7)$$

where,

STOIIP = Stock tank oil-initially-in-place, 7758 = Conversion factor from acre-ft to bbl, A = Area of reservoir (acres) from map data, h = Reservoir thickness (ft), Ø = Formation Porosity (decimal), B_{oi} = Oil formation volume factor expressed in reservoir barrels (rb) and stock tank barrels (stb)., S_w = STOIIP * RF, 7758 = Conversion factor (acres feet to barrels).

Net-to-Gross: Measure of the potentially productive part of the reservoir expressed either as a percentage of the productive (net) reservoir within the overall (gross) reservoir packages or sometimes as a ratio. Net-to-Gross can vary from just a few percentages. Usually, a percentage cut-off is the criteria used in defining N/G. It is expressed as:

$$Net - to - Gross = \frac{Net\,Thickness}{Gross\,Thickness} \times 100 \qquad (8)$$

where

Net thickness = Gross thickness - Shale thickness.

Presentation of Results

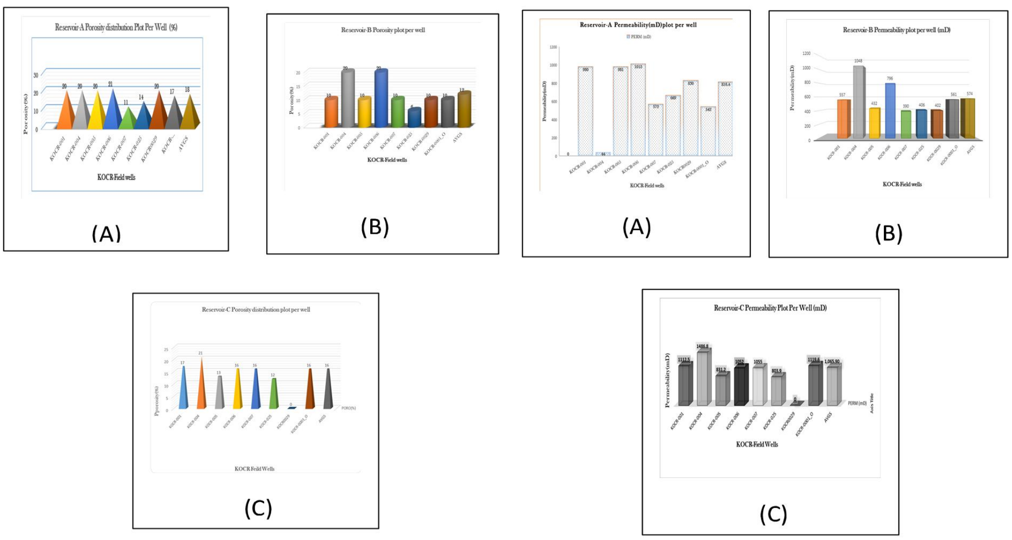


Figure 3: Porosity distribution plot per well in KOCR-Field Reservoir A, B, & C

Figure 4: Permeability distribution plot per well in KOCR-Field Reservoir A, B, & C

The permeability distribution plot per well for reservoir A bar chart presentation revealed W4 has the highest value of 1013 mD followed by W3 with 981 mD while the least value of 44 mD was recorded in W4 followed by 542 mD recorded in W8 (figure 4). The permeability distribution range for reservoir A from 44 mD – 1013 mD. Qualitatively, the rating for reservoir A is from moderate to excellent.

For reservoir B, W2 had the highest recorded value of 1048 mD followed by W4 with 796 mD while the least value of 390 mD was recorded in W5, followed by 402 mD in W7 appendix 2 table 2 (Figure 4.1b), therefore making the permeability distribution range for reservoir B to be from 390 mD – 1048 mD. Qualitatively, reservoir B is rated from very good to excellent.

For reservoir C, the highest value of 1486.8 mD was recorded in W2, followed by W8 with 1119.6 mD, while the least value of 803.9 mD was observed in W6 followed by 831.2 in W3, giving the reservoir C range from 803.90 mD -1486.80 mD. Qualitatively, reservoir C rating using Rider's scale is from very good to excellent. The grouped reservoir permeability pictorial representation shows W4 to have the highest values while the lowest values were seen in W5.

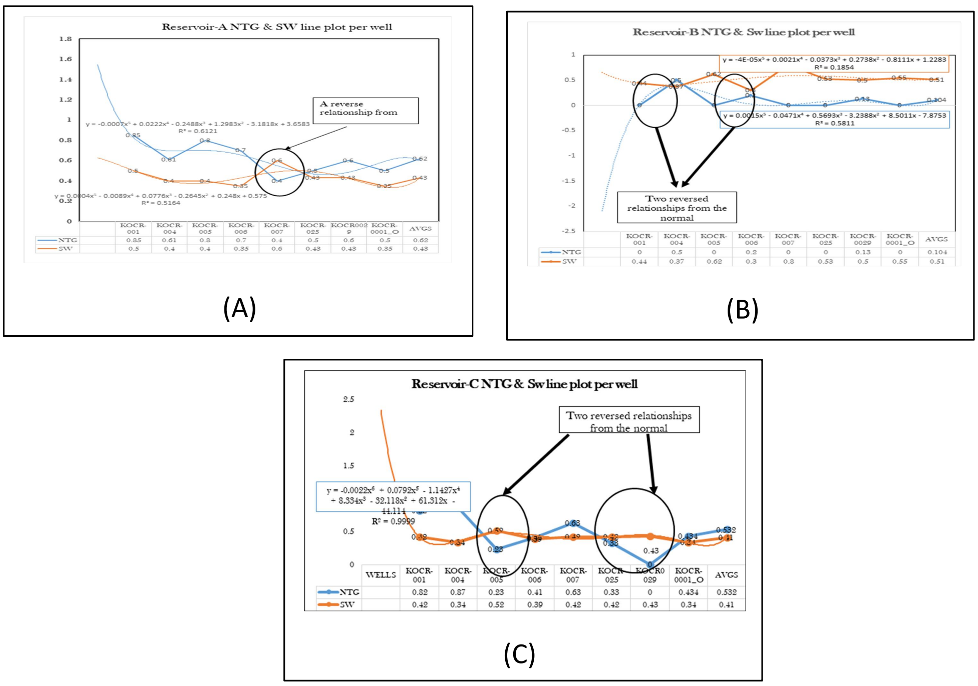


Figure 5: Net-to-Gross (NTG) and Saturation Water Line Plot Per Well in Reservoir A, B, & C

The Field Water saturation and Net-to-gross distribution graphical line plots per wells demonstrated polynomial relationships for all the Reservoirs under study with Reservoir-A displaying R^2 of 0.6 (NTG) and R^2 of 0.5 (S_W) (Figure 5a), Reservoir-B displayed R^2 of 0.6 (NTG) and R^2 of 0.2 (S_W) (Figure 5b) while Reservoir-C showed R^2 of 0.99 (NTG) and R^2 of 0.7 (S_W) (Figure 5c). Reservoir –C displayed the line of best fit generally.

For Reservoir-A, NTG increased with reducing Water saturation (S_w) except for well W5 which displayed a reverse relationship with water saturation increasing with reduction in

NTG AP (Figure 5a). However, Reservoir-B, displayed Net to gross (NTG) generally reducing with increasing water saturation (S_w) except for W2, and W4 which displayed reversed relationship where NTG increased with reduced water saturation (Figure 5b). With Reservoir-C, NTG generally increased with a reducing Water saturation except for wells W3 and W7 which demonstrated reversed relationship with NTG reducing with increasing S_w (Figure 5c). In all, Reservoir-A and Reservoir-C demonstrated the same trend of NTG increasing with corresponding reduction in water saturation while Reservoir B exhibited decreasing NTG with increasing water saturation.

Consequently, Reservoir-A is shown to demonstrate the highest and best average Net to gross (NTG) distribution compared to the other two reservoirs under study while Reservoir-C displays least average water saturation (S_w) compared to the other two study reservoirs. The general trend is that of high NTG producing low water saturation and low NTG producing high water saturation. And according to Onyekuru et al. (2022), zones with high water saturation are zones of dirty sand and poor reservoir quality, while zones with low water saturation are zones of clean sand and good reservoir quality. It therefore, follows from the findings that zones of high NTG are good quality reservoir zones while zones with low NTG are zones of poor quality reservoirs. Hence, reservoirs A and C are better quality reservoirs than reservoir B.

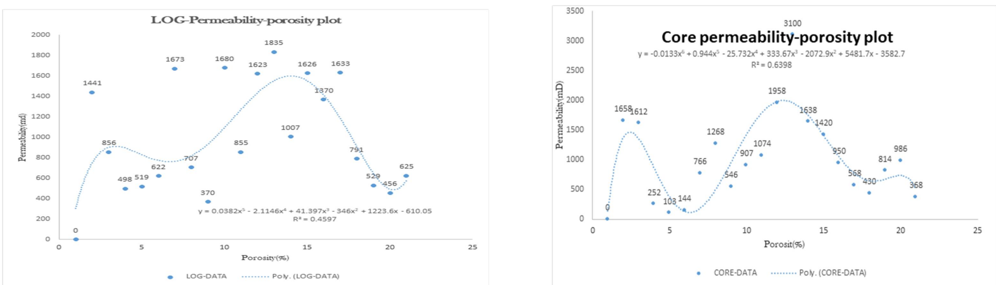
Figure 6: (a) Plot of Core and Log Porosity Against Average Reservoir Depth. (b). Plot Of Core and Log Permeability Against Average Reservoir Depth.

The Core report in line with the reviewed Cored interval (11824.0ft.-11993.6ft) of the Field (Core-A Top to Core-A Base) indicates that the logging depths interval of Reservoir A-Top to A-Base which is between 11810.5-11971.2 is about 11.5 ft. shallower than the core driller's depths. Hence the petrophysical evaluation will be based on Core-A Top and not Reservoir-A Top as shown in (figure 6a).

The plot of core porosity and log porosity against average reservoir depths (6a) and that of core permeability and log permeability against average reservoir depth (figure 6b) demonstrate both similarity and significant variation in shapes. The plot of core porosity and log porosity against average reservoir depth show similarity in shape (V-shape) at two points that is, within the average depth range of 11840ft-11870ft and 11955ft-11965ft, with the core porosity curve being above only except at depth of 11850ft where it started decreasing and came to its lowest 11855ft before going back again to 11870ft where it touched the peak of log porosity and continued rising to maintain a higher height than log porosity (figure 6a).

But in the plot of core permeability and log permeability against average reservoir depth (figure 6b), a greater similarity in shape is observed with a minor exception within the average depth range of 11890ft -11910ft where the shapes were a little not too similar. The plot also revealed that the core minima was lower than the log minima and they occurred at same average depth range of 11840ft-11855ft, and the core peak was also higher than the log maxima and both occurred at same average depth range of 11920ft – 11950ft.

Analysing the above, we see that similarity in shape at same position implies similarity in trend, hence, same shape at same positions implies that the two parameters are changing simultaneously in same direction i.e. increase in log porosity will also witness increase in core porosity and vice- versa. The same thing is applicable in the permeability plot. When a parameter is seen above the other, it means the values of that parameter are higher and when it is lower, it means the values are lower. Consequently, variation in shapes and amplitude of both plots indicate the existence of difference in Core values and log values, however, the amplitudes reveal that core results have higher values than log results in both porosity and permeability.



(a) (b)

Figure 7: (a) Reservoir Log Permeability – Porosity Plot (b) Reservoir Core Permeability – Porosity Plot.

The Log and core generated porosity and permeability graphical cross plots (figure 7) revealed that the core generated porosities are generally of higher values compared to the log generated porosity values while the permeability did not indicate any definite pattern. However, porosity and permeability cross plots of both log and core datasets showed that the two parameters demonstrated polynomial relationships with log poro-perm cross plot showing R^2 of 0.5 while cross plot for core showed R^2 of 0.6. Consequently, the poro-perm cross-plots regression coefficient (R^2) indicated that the two models demonstrated averagely good fit with the experimental relationship.

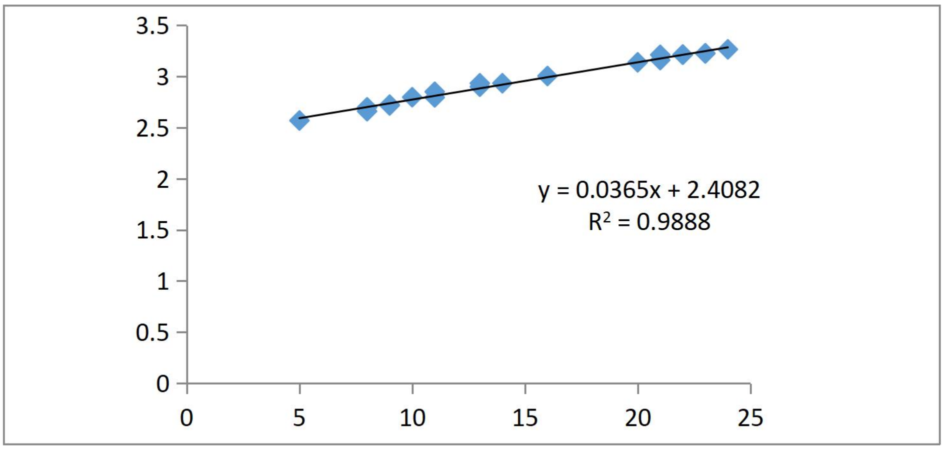


Figure 8: Cross plot of porosity against log of permeability

The graph of porosity against log of permeability (figure 8) is a straight line graph and is indicative of sandstone reservoir rocks (Elnaggar et al., 2018).

Reservoir Quality Evaluation

Reservoir quality as revealed by Osman et al., 2021, depends largely on porosity and permeability for fluid recovery. Onyekuru et al. (2022) revealed that reservoir quality in terms of hydrocarbon accumulation depends on thickness, porosity and fluid saturation while hydrocarbon recovery from reservoir depends on thickness and permeability. Considering the reservoirs in respect of the above, we see that on the whole, the petrophysical analysis result revealed that the average porosity values for Reservoir-A is 18% and that for Reservoir-B is 12% while that for Reservoir-C is 16%, which generally ranges from 12% to 18% and is qualitatively good. The average Permeability (k) for Reservoirs A, B and C are 816.38 mD, 574 mD and 1065.9 mD, and ranges from 574 mD to 10659 mD and is qualitatively from very good to excellent. Water saturation (S_w) average values for the three reservoirs are 43%, 51%, 41% respectively and ranged from 41% to 51%. The hydrocarbon saturation (S_h) for the three reservoirs are 57%, 49%, and 59% and ranges from 49% to 59%, while Net-to-Gross average values are 0.62, 0.104 and 0.532 respectively for the three reservoirs A, B, and C, ranged from 0.104 to 0.62.

The three studied reservoir sand bodies within the Field, the Porosity and Permeability from the petrophysics distribution revealed an average Porosity of 15.3% with average Permeability of 818.8mD which using Riders (2011) scale is indicative of a qualitatively good to very good reservoir quality. However, the intervals having values very much below the average values and quality of porosity and permeability corresponded to the mud-rich intervals, having low net to gross, implying higher shale volume, that is, dirty sand that retains more water and consequently, poor quality reservoir (Onyekuru et al., 2022), while the interval having average porosity represent zones of clean and porous sand good for hydrocarbon accumulation. Consequently, Reservoir-A is said to have a best NTG and Porosity values compared to Reservoir-B and Reservoir-C making Reservoir-A the best in terms of hydrocarbon accumulation considering average thickness (183ft = 54.9 m) and average porosity (18%) while Reservoir C is ranked best quality in respect of fluid recovery having best hydrocarbon saturation and permeability.

On the other hand, Reservoir-C has only one productive sand body with very clean sand Facies (W1) and still has porosity value of 17% and Permeability value of 1112.5 mD which are both above the general averages, irrespective of its small thickness (87.5ft = 25.3m) which is slightly less than two times the size of Reservoir-A. But reservoir A has a very high thickness, higher porosity and a relatively high hydrocarbon saturation and permeability so is consequently better compared to reservoirs B and C, while reservoir C is next best while reservoir B has the least quality.

Good values of porosity and permeability are critical to mobility of hydrocarbon from reservoir (Fagbemigun et al.2021; Onyekuru et al., 2022). Therefore, the good values of porosity and permeability make the reservoir viable and will make for easier and better hydrocarbon recovery from the reservoir.

The STOIIP for reservoirs A, B, C are 3329MMSTB, 29MMSTB, 220MMSTB respectively. The result indicates that reservoir A has the highest reserve followed by reservoir C, while reservoir B has the least reserve from the studied reservoirs. The serious variation in reserve estimates between reservoirs A and B, and A and C may be due to leakages arising from compromised seal integrity (Abiola, 2021), and the reservoir depths as shallower reservoirs tend to have more sand than shale and therefore, more pores for hydrocarbon accumulation (Abiola, 2021). Considering well by well petrophysical analysis, the summary indicates that reservoir A has better facies and thickness followed by reservoir B while reservoir C has the least thickness and sand quality which are factors that favour hydrocarbon accumulation (Abe et al., 2020; Onyekuru et al., 2022).

This significant variations in the maximum reserves of this work and those of others under review could be attributed to depth of the reservoirs which affects volume of accumulated hydrocarbon (Abiola, 2021), and possible leakages or seapage that may have occurred due to poor sealing of the reservoirs (Adadunogo et al., 2017), as well as difference in study locations and hydrocarbon saturation of the field (Oyedele et al., 2013; Sanuade et al., 2018).

CONCLUSION

Petrophysical properties distribution and assessment was conducted on an onshore marginal field in Niger Delta with the aim of evaluating the rock and fluid properties to boost hydrocarbon production and exploration in the field. Eight wells were examined with Gamma ray logs for reservoir sand bodies in the field, two major lithologies were revealed to be sand and shale. The petrophysical parameters considered for the three reservoir sand bodies were reservoir thickness, net to gross, porosity, permeability, water and hydrocarbon saturations. The average thickness of the three reservoirs recorded were 183.90ft (56.05m), 32.88ft (10.03m), and 87.46ft (26.67m) respectively and varies with reservoir location. Their respective ranges are 161.6ft -211.4ft (49.26m-64.43m), 8.9ft -90.5ft (2.71m-27.58m), and 47.1ft -151.1ft (14.36m-46.06m). The average net to gross (NTG) for the three reservoirs indicated that the reservoir A, B and C sand bodies has an average of 0.620, 0.104 and 0.532 respectively.

The average porosity for the three reservoir sand bodies as revealed by the study are A -18%, B- 12% and C-16%, and the range are 11%-21%, 6%-20%, and 12%-21%, respectively. The results also show that the average permeability for the three reservoirs in the field are in the order 816.4mD, 574mD and 1065.9mD for reservoir sand bodies A, B, C.

The average water saturation (S_w) for the various reservoir sand bodies are 43%, 51%, and 41% for A, B, C respectively. The computed hydrocarbon saturation (S_h) shows that the average hydrocarbon saturation for the reservoir A is 57%, B is 49%, and C 59%.

The plot of core porosity and log shows that the values of core porosity are higher than that of log porosity, while the variation in core and log permeability did not show any definite pattern though the highest values were obtained in core as well as the lowest value. The log poroperm plot is a linear graph indicative of sandstone reservoir rock environment. For reservoir quality, reservoir A is rated best in terms of accumulation while reservoir C is rated best in terms of fluid recovery. But overall, reservoir A is the best. The calculated volumetrics indicates that reservoir sand body A has the highest STOIIP of (3329MMSTB), followed by C with (220MMSTB), and B having the least of (29MMSTB).

The study reveals that KOCR-Field has good hydrocarbon potentials and a reservoir system considered good prospects for hydrocarbon production. For optical hydrocarbon recovery, static modelling report should be considered for best well placement positions in field development since wrong well positioning could easily compromise wells and cause production decline.

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Appendices

Table 1: Sand Analysis for KOCR-Field

	RESERVOUR A			**RESERVOUR B**			**RESERVOUR C**		
	Tops	Bases	Thickness	Tops	Bases	Thickness	Tops	Bases	Thickness
WELL	SSTVD (FT)								
W1	11741.9	11953.3	211.4	11366.8	11380.4	13.61	10710.69	10787.64	77.0
W2	11713.4	11900.6	187.2	11221.5	11266.4	44.95	10885.52	10968.36	82.3
W3	11922.4	12084.5	161.6	11449.7	11478.9	29.20	11139.63	11186.72	47.1
W4	11654.9	11841.9	187.0	11157.7	11175.6	17.90	10768.07	10919.14	151.1
W5	11614.0	11782.0	168.0	11163.0	11194.0	31.00	10932.46	11015.29	82.8
W6	11766.0	11945.0	179.0	11367.0	11396.0	27.00	11050.73	11123.32	72.6
W7	11807.5	11973.0	165.5	11374.5	11465.0	90.50	11101.38	11225.58	124.2
W8	11741.9	11953.3	211.4	11367.9	11376.8	8.90	11050.80	11112.99	62.2
Average Thickness			**183.9**			**32.9**			**87.5**

Table 2: Well Logs Petrophysical Evaluation Data

WELL	**WELL LOGS PETROPHYSICAL EVALUATION DATA**											
	RESERVOUR A				**RESERVOUR B**				**RESERVOUR C**			
	POR (%)	PERM (mD)	NTG	S_w	POR (%)	PERM (mD)	NTG	S_w	POR (%)	PERM (mD)	NTG	S_w
W1	20	980	0.85	0.50	10	557	0.0	0.44	17	1112.5	0.82	0.42
W2	20	044	0.61	0.40	20	1048	0.5	0.37	21	1486.7	0.87	0.34
W3	20	981	0.80	0.4	10	432	0.0	0.6	13	831.2	0.23	0.5

				0				2				2
W4	21	1013	0.70	0.35	20	796	0.2	0.30	16	1052.0	0.41	0.39
W5	11	572	0.40	0.60	10	390	0.0	0.80	16	1055.0	0.63	0.42
W6	14	669	0.50	0.43	06	406	0.0	0.53	12	803.9	0.33	0.42
W7	20	830	0.60	0.43	10	402	0.13	0.50	-	-	-	0.43
W8	17	542	0.50	0.35	10	561	0.00	0.55	16	1119.6	0.434	0.34
Average	**18**	**816.4**	**0.62**	**0.43**	**12**	**574**	**0.104**	**0.51**	**16**	**1,065.9**	**0.532**	**0.41**
STOIIP	**3329MMSTB**				**29MMSTB**				**220MMSTB**			

Table 3: KOCR-Field Core and log Petrophysical evaluations data table

DEPTH	LOG-DATA		CORE-DATA	
	Porosity (%)	Permeability (mD)	Porosity (%)	Permeability (mD)
11824-11830	21.0	1441	23.2	1658
11831-11886	14.0	856	26.6	1612
11837-11843	8.0	498	25.8	252
11846-11852	9.0	519	21.1	103
11853-11861	11.0	622	18.4	144
11865-11880	23.0	1673	23.0	766
11883-11885	11.0	707	25.0	1268
11886-11891	5.0	370	25.4	546
11898-11909	23.0	1680	25.2	907
11911-11915	13.0	855	26.8	1074
11921-11944	21.0	1623	26.9	1958
11945-11949	24.0	1835	27.1	3100
11951-11954	16.0	1007	26.7	1638

11955-11959	22.0	1626	25.6	1420
11960-11964	20.0	1370	24.2	950
11964-11969	22.0	1633	26.1	568
11970-11974	13.0	791	26.8	430
11975-11979	9.0	529	26.6	814
11980-11983	8.0	456	28.2	986
11984-11989	10.0	625	25.1	368

Table 4: Reservoir-A log permeability-porosity cross plot data

Porosity (%)	Permeability (mD)	Log of Permeability
21	1441	3.158663981
14	856	2.932473765
8	498	2.697229343
9	519	2.715167358
11	622	2.793790385
23	1673	3.223495941
11	707	2.849419414
5	370	2.568201724
23	1680	3.225309282
13	855	2.931966115
21	1623	3.210318520
24	1835	3.263636069
16	1007	3.003029471
22	1626	3.211120541
20	1370	3.136720567
22	1633	3.212986185
13	791	2.898176483
9	529	2.723455672
8	456	2.658964843
10	625	2.795880017