PETROPHYSICAL ANALYSIS OF THE KACHAN FIELD RESERVOIR SANDS FROM WIRE-LINE LOGS, NIGER DELTA, NIGERIA

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Abstract: Reservoir characterization of Kachan field, Niger Delta was evaluated using petrophysical analysis. This was done with the aim of determining petrophysical properties so as to know the reservoir quality and potential of the study area for a well planning program. The dataset employed in this study include one deviated well and another two wells. These well log suites include gamma ray log, resistivity logs, bulk density and sonic logs. Schlumberger's *Petrel* software was used for the interpretation of the well data. Three reservoir sands were mapped. They include Dede, Deeds and Habeeb, each from the three wells respectively. The results of the three reservoir sands showed that Dede sand had effective porosity estimated at 0.24 with water saturation 0.22. Deeds sand with the following results effective porosity 0.23 and water saturation 0.32 while the Habeeb reservoir sand has an estimate effective porosity of 0.20 and water saturation 0.20.Volume of shale and Net to gross for the three reservoirs ranged between 0.2 to 0.7 and 0.63 to 0.88, respectively. These have been deemed to be appreciable for commercial hydrocarbon production.The purpose of this paper is to illustrate why petrophysics is so important to reservoir evaluation.

Keywords: Hydrocarbons, lithology,petrophysical properties,reservoir quality, well logs

Introduction

A reservoir is a subsurface rock that has effective porosity and permeability which usually contains commercially exploitable quantity of hydrocarbon. Petrophysical logs interpretations used for the characterization of reservoir sands are very useful and important tools for selecting, planning and implementing operationally sound supplementary recovery schemes (Ekine and Iyabe, 2009). Furthermore, the pores and fractures have to be interconnected if the hydrocarbons will eventually be produced as such hydrocarbons are needed to flow towards production wells. Porosity and permeability are thus key reservoir parameters in this regard and as such parts of the Niger Delta opportunities have been captured at the shallow, intermediate and deep levels (Olowokere, 2009b).

Reservoir characterization is the art and science of integrating different data types. It attempts to integrate geologic and geophysical data on different scales to form a picture of the reservoir and to integrate the knowledge of the reservoir engineer, geophysicist and geologist. It is undertaken to determine the capability of the reservoir to both store and transmit fluid. Storage is essential else such hydrocarbons will not be found in the first place. Therefore, in the search for hydrocarbons, lithology units that will serve as the reservoir must be delineated and searched out. But, essentially, characterization deals with the determination of reservoir petrophysical properties/parameters such as porosity (Φ), permeability (K), fluid saturation, and Net Pay thickness.

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 the particular fluid. A reservoir can either be water saturated (Sw) or hydrocarbon saturated (1-Sw) 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. The formation evaluation and reservoir characterization of some parts of Niger Delta revealed the two major lithological units in the area to be sand and shale (Abe and Olowokere, 2013; Ologe, 2016); a good reservoir is one that is commercially productive if it produces enough oil or gas to pay back its investors for the cost of drilling and leaves a profit.

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. It is possible to build on the research; thereby allowing for the extraction of more information from the field and the making of new discoveries especially which can lead to increase in lifespan of the field and in unraveling the geology of the area.

The justification of this study relates back to the fact that in this field (Kanchan field), oil and gas production has recorded relative successes and in some cases the production wells discover only water. The enhanced understanding of reservoir characteristics is needed and improved integrated methods must be adopted to maximize future hydrocarbon production. There is therefore the need to determine petrophysical properties in order to evaluate the reservoir quality and production potential of this field.

Materials and Methods

Location and description of the study area

The field location is not known but it was stated as occurring in the offshore southwestern Niger delta. The field has three well log data that include 2 deviated wells and 1 straight well drilled to an average depth of 3,660 m. Fig. 1 is the base map of the study area, showing the three wells in the field and some of the seismic lines.

Geological setting of the study area

The Niger-Delta forms one of the world's major Hydrocarbon provinces, and it is situated on the Gulf of Guinea on the west coast of central Africa (Southern part of Nigeria). It covers an area between longitude 4 – 9ºE and Latitude 4-9º N (Fig. 2). It is composed of an overall regressive clastic sequence, which reaches a maximum thickness of about 12 km (Evamy*et al.*, 1978).

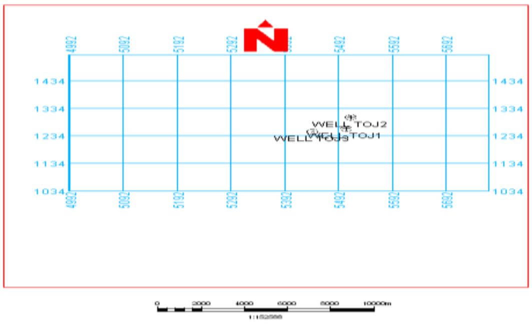


Fig. 1: Base Map of Kachan field showing well locations

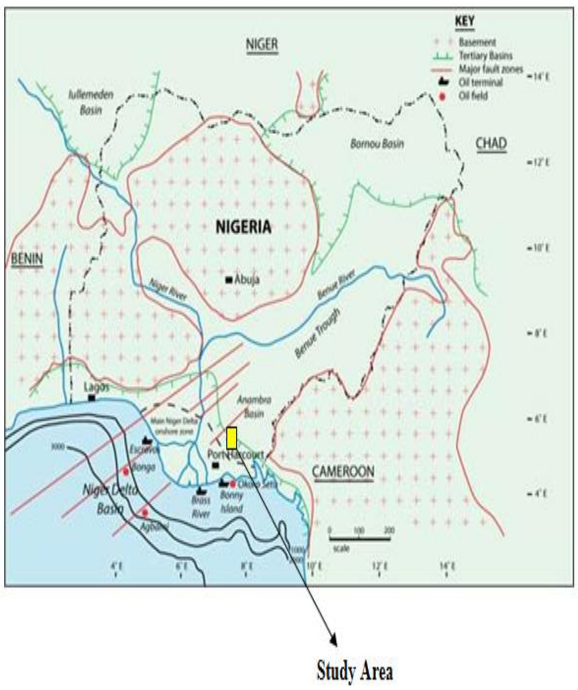


Fig. 2: Map of Niger Delta showing the study area (Jane, 2008)

Lithostratigraphy

The Niger-Delta consists of three broad formations (Short and Stauble, 1967). These are the continental top facies (Benin formation) which is the shallowest part of the sequence and consists predominantly of fresh water bearing continental sands and gravels, Agbada formation which underlies the Benin Formation and consists primarily of sand and shale and it is of fluviomarine origin (it is also the hydrocarbon window) and the Akata formation. The lithofacies of the Akata formation is composed of shales, clays and silts at the base of the known Delta sequence. They contain a few streaks of sand, possibly of turbidite origin.

Hydrocarbon source rock

There has been much discussion about the source rock for petroleum in the Niger Delta which has reflected in Ekweozor*et al*. (1979), Ekweozor and Okoye (1980), Lambert-Aikhionbare*et al*. (1984), Ryan (2007) and Doust&Omatsola (1990). Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation, the marine Akata shale and the Cretaceous shale (Weber and Daukoru, 1975;Ejedawe, 1979; Ekweozor and Okoye, 1980;Lambert-Aikhionbare*et al*., 1984; Doust&Omatsola, 1990; Stacher, 1995; Frost, 1979; Haack*et al.*, 1997). The Agbada Formation has intervals that contain organic-carbon contents sufficient to be considered good source rocks. The intervals, however, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the Delta (Evamy*et al.*, 1978; Stacher, 1995). The Akata shale is present in large volumes beneath the Agbada Formation and is at least volumetrically sufficient to generate enough oil for a world class oil province such as the Niger Delta. In the case of the cretaceous shale, it has never been drilled beneath the delta due to its great depth; therefore, no data exist on its source-rock potential (Evamy*et al.*, 1978).

Reservoir rock

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial. Known reservoir rocks are Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than 45 meters thickness (Evamy*et al.*, 1978*)*. The thicker reservoir represents composite bodies of stacked channels (Ekweozor and Okoye, 1980). Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. The primary Niger Delta reservoir was described in (Evamy*et al.*, 1978)as Mioceneparalic sandstones with 40% porosity, 2 darcys permeability, and a thickness of 100 meters. The lateral variation in reservoir thickness is strongly controlled by growth faults; the reservoir thickens towards the fault within the down-thrown block (Lambert-Aikhionbare*et al.*, 1984).

The area of study is located in the southwestern part of Niger Delta (Fig. 1). The datasets employed were provided by the Shell Producing Development Company, Nigeria. These includes soft copy data of composite well logs comprising mainly gamma ray, resistivity, volume of shale, density and neutron logs from three wells. *Petrel* software was used to interpret the data. A Base map showing well locations in the field was also provided. The 3 wells of “KACHAN” field are all located around the centre of the field (Fig. 1).

A typical gamma ray well log through the Agbada Formation in field has values that are very high near the base of the Formation. In the upper part of the successions, within the Benin.

Formation gamma ray values are generally low. Gamma-ray logs measure natural radioactivity in formations, therefore enabling qualitative identification of zones of shale (high gamma readings) from sand (low gamma readings). High gamma ray values between 80-150 API units were classified as shaly intervals. On the other hand intervals with low gamma ray values in the range of 0-70 API units were considered sand units (Schlumberger, 1989). In Niger-Delta, the sand units are regarded as the reservoir units because shales are not porous enough to retain and release fluid. Therefore in the sand units delineated, differentiation between reservoir fluids (hydrocarbon and water) was done using the resistivity log. Since the resistivity of hydrocarbon is higher than that of the formation water (Schlumberger, 1989) hydrocarbon sand units were inferred from high resistivity values observed from the deep resistivity reading tool provided namely: Rt_0 which measures the resistivity of the uninvaded zone (true formation resistivity).

Geophysical logs are not direct measures of the petrophysical properties of the formation. The logs measure different formation parameters that are then translated to properties of geological significance during log interpretations. In this research work, the following petrophysical properties were evaluated;volume of shale, effective porosity, water saturation, net to gross and net pay and hydrocarbon pore volume.

Petrophysics is regarded as the process of characterising the physical and chemical properties of the rock-pore-fluid system through the integration of the interpretation of the geological environment, well logs, rock and fluid sample analyses and their production histories. In the case of this project, only wireline logs were used. Since the hydrocarbon resides in the open spaces in the rock. It is of utmost importance that the parameters that determine the behaviour of pore system are known. In this study, these included the assessment of properties such as percentage of shale volume, effective porosity and an estimate of water saturation. The successful evaluations of these properties are necessary for determining the hydrocarbon potential of a reservoir system performance and also help predict the behaviour of complex reservoir situations. After targeting hydrocarbon indications with obvious water zones and hydrocarbon zones differentiated from resistivity logs, computed petrophysical parameters was obtained from the hydrocarbon bearing reservoirs. These include determination of porosity and effective porosity.

Porosity values for the hydrocarbon reservoirs were estimated. Density log supplied the bulk density of the formation and the density porosity log was generated from this using (Asquith, 2004) see equation 1. This was corrected for the volume of shale using (Dewan, 1983) (equation 2):

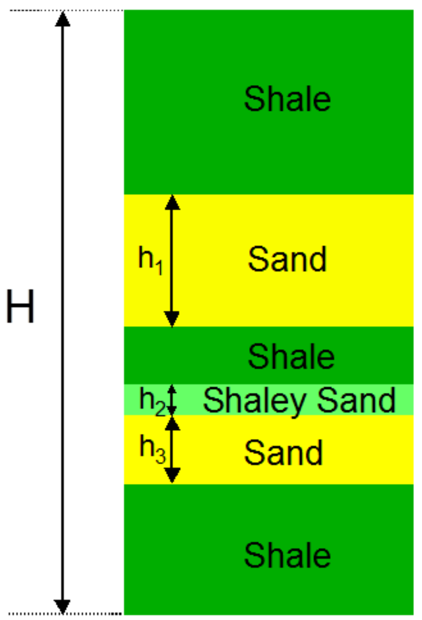
$$\varphi = (\delta_{ma} - \partial_b)/(\, \delta_{ma} - \partial_{bfl} \qquad (1)$$

Where: φ =porosity derived from density log; δ_{ma}=matrix (or grain) density; ∂_b = bulk density (as measured by the tool and hence includes porosity and grain density); ∂_{bfl}= fluid density

$$\varphi corr = \varphi d - Vsh * \varphi Dsh \qquad (2)$$

Where: φcorr =shale corrected density porosity; φd =Density porosity; φd =Shale volume; φDsh =density porosity of nearby shale

Net thickness of hydrocarbon zones was determined by subtracting shale units from the gross reservoir thickness (Fig. 3). The net to gross of such zones were determined by adding up net sand units (h_1, $h_2$and h_3) and dividing the gross thickness (H) of the zones. These reservoirs properties were used in the assessment of the reservoir quality.



$$N/G = \frac{\sum_{i=1}^{n} h_i}{H} = \frac{\text{Net reservoir}}{\text{Gross interval}}$$

Net thickness=H- ($shale_1$+$shale_2$+$shale_3$)

Fig. 3: Illustration showing how net thickness of sand and net sand thickness-gross thickness ratio was obtained.

Water and hydrocarbon saturations were determined from logs and using equations 3 and 4 (Asquith, 2004):

$$S_w = \frac{(aR_w)}{(\emptyset^m R_t)} \times \frac{1}{n} \qquad (3)$$

$$S_h = 1 - (S_w) \qquad (4)$$

S_w is the water saturation of the uninvaded zone (Archie method), R_w is the resistivity of formation water at formation temperature, R_t is the true resistivity of formation, Φ is the porosity, a is the tortuosity factor, m is the cementation exponent, n is the saturation exponent which varies from 1.8 to 2.5 and S_h is the hydrocarbon saturation.

Results and Discussion

Identification and correlation of shale and reservoir sands

Low gamma ray readings and high resistivity usually means hydrocarbon sand, as observed in some of the sand units in the log (Fig. 4). However low resistivity and high gamma ray readings which are indicative of shaly reservoirs are also observed. In all, three hydrocarbon bearing sands at different depth interval were mapped within the study area and they include deeds, dede and habeeb.

Log correlation profiles correlating lithogy passing through Wells TOJ 1, TOJ 2, and TOJ 3is shown in Fig.5. The correlation when narrowed down to individual reservoirs gives an overview and visual information about the lithology and thickness of important (reservoir) formations, and also the lateral continuity of the reservoirs across the wells.

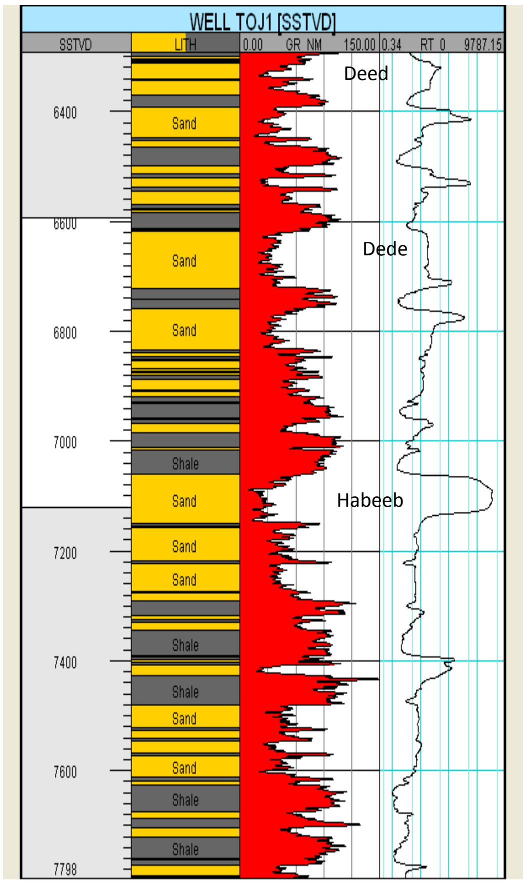


Fig. 4: Reservoir sand Identification from interpretation of Gamma ray and resistivity logs

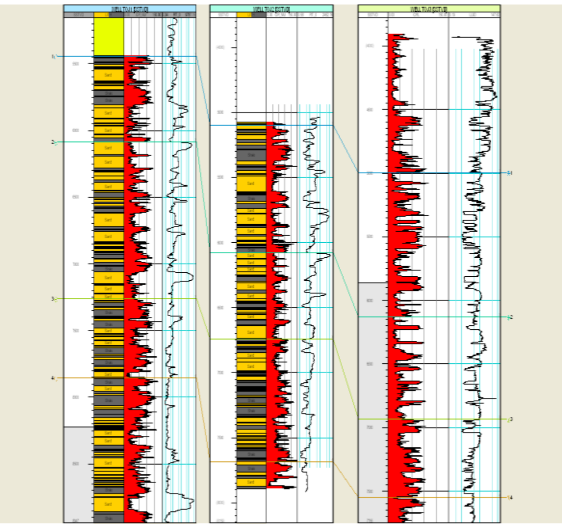


Fig. 5: Lithologic correlation along the three wells

Petrophysical interpretation

Reservoir deed (Fig. 4) is a shaly sand and has medium porosity with values ranging from 0.20- 027. Reservoirs dede and habeeb are clean sands and have high porosity ranging from 0.25-0.30. All other units within the zone shown on the well logs contain intercalated shale with no useful porosity. Obvious water zones with high porosity and low resistivity were also observed but not discussed as they portend little value for hydrocarbon exploitation in the field. Fresh water may look like hydrocarbons, particularly in shallow zones. The porosity was computed from density logs but needed to be corrected for shale.

The volume of shale

The volume of shale (Vsh) quantity is defined as the volume of wetted shale per unit volume of reservoir rock. Wetted shale is the space occupied by water confined to the shale known as bound water. The reservoir zones of the field under study predominantly consist of sand intercalated in shale sequences. Shale can be distributed in sandstone reservoirs in threepossible ways as shown in Fig. 6. They are: laminar shale, where shale can exist in the form of laminae between layers of clean sand, structural shale, where shale can exist as grains or nodules within the formation matrix and dispersed shale, where shale can be dispersed throughout the sand, partially filling the intergranular interstices, or can be coating the sand grains (Worthington *et al.,* 2009). All this form can occur simultaneously in the same formation. They affect the amount of rock porosity by creating a layer of closely bound surface water on the shale particle.

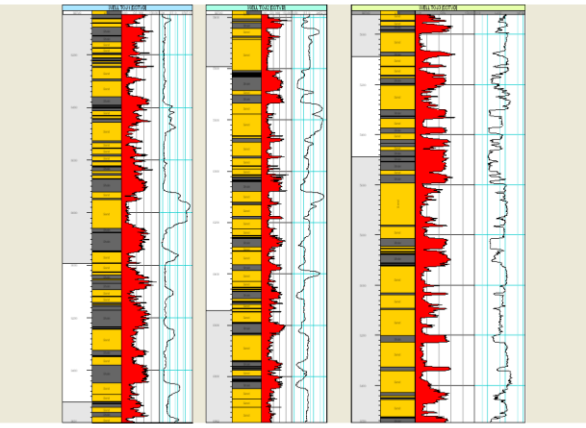


Fig. 6: Lithology identification showing gamma ray log and the lithologies (sand and shale), respectively

Volume of shale interpretation

The volume of shale can be obtained from Larinov (1967) equation using the Gamma Ray log. However in this study, the volume of shale log was provided. Table 1 is a summary forthe values of the volume of shale obtained for the different reservoirs. The reservoir zones of the field predominantly consist of sand intercalated with shale in the sequence (Fig. 7). The implication is that reservoir quality may be computed or interpreted in error if volume of shale is not taken into consideration. In this project, the volume of shale was calculated in petrophysical evaluation in order to correct porosity and water saturation results for the biased effects of shale, in which the lower shale content usually indicates a better reservoir.Reservoir dede and deed show most viable reservoir quality in the field as their shale volumes were significantly low and therefore porosity and hydrocarbon estimates in such hydrocarbon zones were high.

Table 1: Petrophysical analysis

Reservoir	Top MD (m)	Bottom MD (m)	VSH
Dede	2901	2927	0.2
Deeds	3208	3227	0.5
Habeeb	3201	3220	0.7

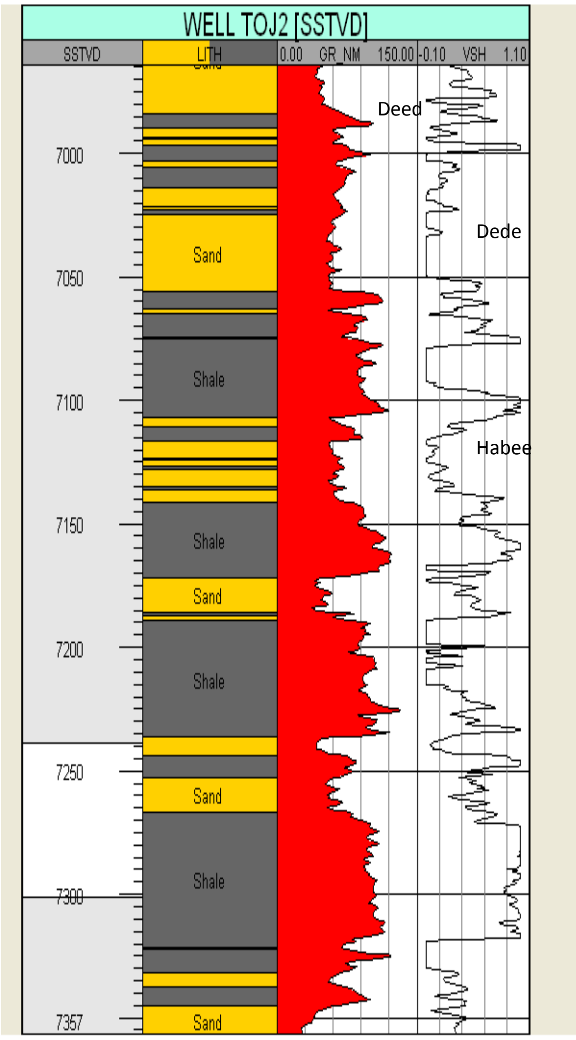


Fig. 7: Volume of shale computed from the volume of shale log in TOJ 2

Effective porosity and water saturation

Effective porosity and water saturation also varies within the reservoir as shown on the Table 2. Effective porosity values varied between 0.23 in reservoir deeds and 0.24 in reservoir Dede and Habeeb. Computed water saturation recorded for the three reservoirs varied from 0.20 to 0.32. This is to demonstrate the fact that lateral changes in porosity are also noticed. Table 2 shows the summary of the results obtained. A general observation is that the reservoirs have a moderately high effective porosity and the implication is that the presences of physically interconnected pores will mean that fluids can actually move between the pores during production. This is favorable for hydrocarbon production.

Table 2: Petrophysical analysis

Reservoir	Top MD (m)	Bottom MD (m)	Effective Porosity	Computed Water Saturation
Dede	2901	2927	0.24	0.22
Deeds	3208	3227	0.23	0.32
Habeeb	3399	3432	0.24	0.20

Table 3: Petrophysical analysis

Reservoir	Top MD (m)	Bottom MD (m)	Thickness (Gross) m	Thickness (Net) m	Net/ Gross
Deeds	2901	2927	26	21	0.81
Dede	3208	3227	19	12	0.63
Habeeb	3399	3432	33	29	0.88

Net–to–gross values of the hydrocarbon sands

Net pay (NP) and net-to-gross ratio (NGR) are often crucial quantities to characterize a reservoir. Generally, net pay is a parameter in reservoir evaluation, because it identifies those penetrated geological sections that have sufficient reservoir quality and interstitial hydrocarbon volume to function as significant producing interval (Aigbedion and Iyayi, 2007). Net pay cannot be really determined as it involves computer modeling with seismic data which was not provided for the study. Net to gross is the ratio of the porous and permeable interval to the nonporous and/or non-permeable interval of a reservoir.

In Table 3,the net-to-gross of individual reservoir units are displayed. Reservoir Dede has the highest net-to-gross and as such the best reservoir in the area. This is followed by reservoir deeds with a net-to-gross value of 0.81. Table 3 summarizes the result obtained. Net Pay cannot be successful determined as it takes into consideration the lateral modeling of shale units which was not done as at the time of the study.

In this research work, the volume of shale was calculated in petrophysical evaluation in order to correct porosity and water saturation results for the biased effects of shale. The volume of shale is considered as an indicator for reservoir quality, in which the lower shale content usually indicates a better reservoir. The shale content is determined using different shale indicators. The gamma ray method was adopted to define the shale volumes in this work.

Conclusion

The study was carried out in the southwestern Niger Delta. The field has three (3) wells log data that include two (2) deviated wells and one (1) straight well drilled to an average depth of 3,660 m. The objective of the research is to determine the hosting lithology in the field serving as the hydrocarbon reservoir, also determination of such reservoir depth, interval and thickness in the well. For the purpose of this project, the following petrophysical properties were evaluated; Volume of shale, effective porosity, Water saturation and Net to gross. Three hydrocarbon-producing reservoirs were identified namely: reservoirs Dede, Deeds and Habeeb. Porosity estimates in these reservoirs vary from 0.20 to 0.32 and the net/gross thicknesses of the reservoir sand ranges from 0.61 to 0.88 m. These have been deemed to be appreciable for commercial hydrocarbon production.

Conflict of Interest

Author declares that there are no conflicts of interest.

Acknowledgement

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