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Scrutiny of Porosity information from Well-log in the South Eastern Niger Delta Region

Joseph Gordian Atat[1*], Idara Okon Akpabio[2], Sunday Samuel Ekpo, Oscar Michael[4]

Abstract

Raw well data from oil wells J and K in some parts of the Niger Delta were used for estimating porosity in sandstone and shale units. Porosity is seen as an important parameter for estimating the appreciable volume of hydrocarbons and other fluid content that may be accessible in the reservoir. Gamma ray log and sonic log with respect to depth were generated using Microsoft Excel for analysis. The results of these suites of log were used to estimate porosity. The major outcomes resulting from the porosity estimates revealed that the average porosity values are about 35% for well J and 30% for well K. This study shows that the increase in sonic transit time gives rise to an increase in porosity irrespective of the lithology. However, sonic transit time decreases with increase in depth; depth having a strong coefficient of determination of about 0.9 with temperature, implies an increase in temperature also leads to a decrease in porosity. The Depth-Temperature relation shows T = 0.0228D + 16.671. The porosity which has been obtained in the study is appreciable as it is in the excellent class. Also, a Porosity-Transit Time Equation ($\emptyset = 0.3806\Delta t - 6.8104$) has been obtained. This model satisfies and improves porosity estimates irrespective of the value of sonic in microsecond per foot for the South Eastern part of Niger Delta Basin.

Keywords:

Gamma Ray, Model, Porosity, Reservoir, Sand, Sonic, Temperature

1. Introduction

Porosity is the void available in the rock which is significant for the accumulation of fluids like oil, gas and water. Porosity also aids the movement of those fluids to a location with lesser pressure if the rocks are permeable. Procedure to calculate porosity may be either by density log, sonic log, neutron log or a combination between them. Porosity is seen as an important parameter for estimating the appreciable volume of hydrocarbons that may be accessible in the reservoir [1]. Porosity of a formation can also enable the evaluation of fluid content and possibility of fluids flow in a reservoir. It is one of the vital attributes of hydrocarbon reservoir.

Almost all reservoirs have porosity in a range of 5 to 45% with the majority falling between 10 and 20% [2]. Porosity field could as well be used to predict abnormal pressure areas during oil-well drilling [3-4]. The surface porosity can be used to study geohistory analysis of a sedimentary basin [5]. Characterization of hydraulic properties of rocks, such as the porosity, is essential for dynamic basin analysis since porosity and permeability account for the flow of subsurface fluids [6]. However, according to [7], the criteria for classifying porosity include: porosity values less than 0.05 is negligible, between 0.05 to 0.10 is poor, greater than 0.10 but less than 0.15 is fair, about 0.15 to 0.25 is good, from 0.25 to less than 0.30 is very good and porosity values greater than 0.30 is excellent.

The aim of this research is to obtain a suitable model for sonic porosity estimates from investigation of the porous nature of Wells J and K in the South Eastern part of Niger Delta from Wyllie time porosity equation using well data for this region. Gamma ray log and sonic curves with respect to depth are necessary data which were generated including temperature curve; identify the possible API index of lithologies from gamma ray log, identify the sandstone and shale lithologies to achieve the target. This research evaluates the pore spaces for the appreciable amount of hydrocarbons that may be available and also relates depth with temperature. With only Sonic Transit Time information, this research contributes massively to knowledge as porosity estimates in the South Eastern Niger Delta may be obtained directly from the Sonic-Porosity relation. Sonic log enables the determination of compressional wave velocity. It is the most accurate log; not affected by the magnitude of the hole, production temperature and salt content. Sonic log also measures the transit time of the formation.

Corresponding author: Joseph Gordian Atat
Email: josephatat@uniuyo.edu.ng
Phone Number: +2347069500697
1,3,4Department of Physics, University of Uyo, Uyo, Nigeria.
2Department of Geoscience/Physics, University of Uyo, Uyo, Nigeria

1.1 Location and geology of the study area

Location

Wells J and K are situated in the South Eastern part of Niger Delta, Rivers State, Nigeria. According to [8], the latitude of the region is within 3^0N and 6^0N; the longitude is between 5^0E and 8^0E [9-10]. The location is captured in Figure (1).

Geology of the Study Area

The deposit volume is about 5.0 x 10^5 km^3 [11-12], with thickness not less than 10 km in the basin [13]. The particles of the available rocks are known by their shapes, sizes, mineral structures, the age and time of deposition [14-16]. The Niger Delta Province comprises the petroleum system called the Tertiary Niger Delta (Akata –Agbada) Petroleum System, which is the twelfth richest in petroleum resources, with 2.2% of the world's discovered oil and 1.4% of the gas [17-20]. Niger Delta experiences both wet and dry seasons; average rain in a month during wet season is about 1.35 x 10^{-1} m and this falls to 6.50 x 10^{-2} m during dry season [21-24].

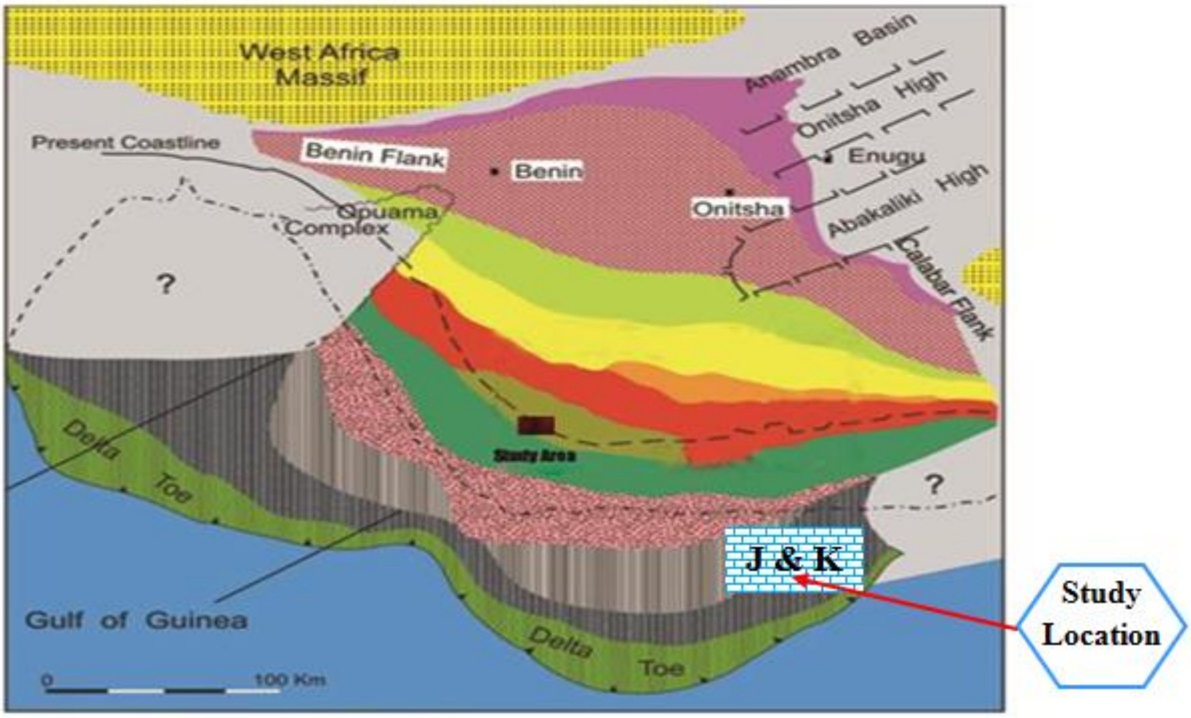

Figure 1: Location and Geology map of Niger Delta [25]

1.2 Basic theory

Porosity and sonic Log

Porosity of a formation is important in the evaluation of fluid content, potentiality of fluids flow and recaptures amounts in a pool [26]. The volumetric concentration of pore space or assessment of porosity can be determined using Equations 1 and 2. Porosity measurements obtained from high-resolution records and low-resolution data can enhance the knowledge of porosity heterogeneity for reservoir modelling [27]. The major problem, when developing these relationships consists of correlating the high-resolution sections, Computerized Tomography (CT) data, to the low-resolution information, well log data [28]. Sandstones porosity is about 1.0 x 10^1 to 4.0 x 10^1%. It may approach 80 percent in deposited unconsolidated sediments.

Sonic log enables the determination of compressional wave velocity. It is the most accurate log; not affected by the magnitude of the hole, production temperature and salt content. Sonic log (Figure 2) also measures the transit time of formation. Gas may be present within the pore spaces at high porosity if the first arrival cannot be picked from the head waves of the energy refracted along the borehole wall; these are cases of severe borehole damage or fractures. Caving and rugosity can induce spikes on the sonic response [18 and 29].

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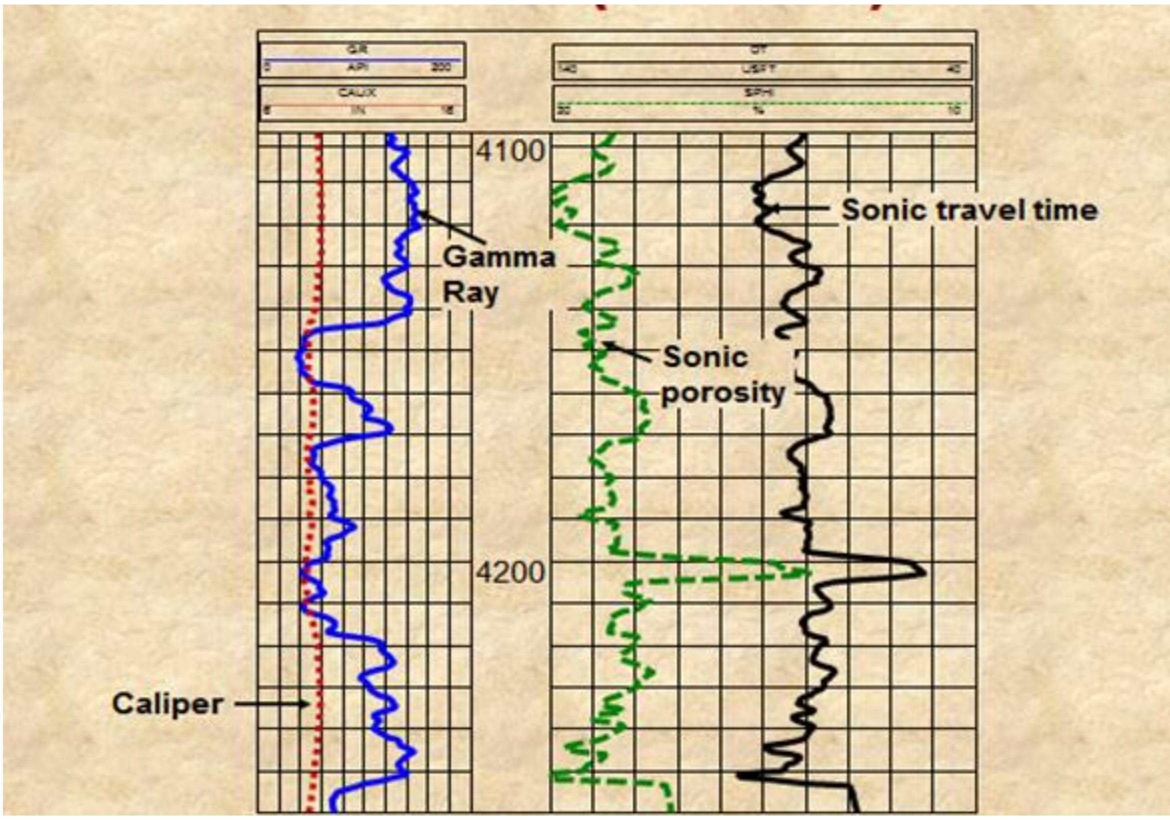

Figure 2: Sonic log and some other logs [30].

When the velocity (or transit time (Δt) or travel time (t)) of the rock matrix and borehole fluids are known, porosity can be computed using Equations 1 and 2.

$$\emptyset = \frac{t_{log} - t_{ma}}{t_f - t_{ma}} \tag{1}$$

t_{log} is log reading in μsec/ft

t_{ma} is the matrix travel time in μsec/ft

t_f is the fluid travel time in μsec/ft

$\emptyset$ is the porosity

In terms of velocity

$$\frac{1}{V} = \frac{\emptyset}{V_f} + \frac{(1 - \emptyset)}{V_{ma}} \tag{2}$$

$\emptyset$ is the porosity of the rock

V is velocity of the formation in ft/sec

V_f is velocity of fluid in ft/sec

V_{ma} is the velocity of rock matrix in ft/sec

The velocity of most borehole and reservoir fluids (except gas) does not vary greatly. A fluid velocity (Δt_f of 189 µsec/ft) of 5,300 ft/sec is generally assumed for fresh drilling fluids. A slightly lower value, 185 µsec/ft, is used for salt muds. Fluid type becomes more of a concern when Oil-Based Mud (OBM) is used if the formation of interest is not invaded or if invasion is very shallow. The lithology must be known or estimated in order to select the appropriate matrix velocity. The Wyllie equation represents consolidated and compacted formations. In poorly consolidated or unconsolidated rocks, a correction factor is necessary (Equation 3). Also, the presence of shale or clay within the sand matrix will increase Δt by an amount proportional to the bulk-volume fraction of the clay. An empirical equation (Equation 3) is used for calculating porosity in sandstones in which adjacent shale values (Δt_{sh}) exceed 100 µsec/ft. The compaction correction factor can be evaluated using Equation 4.

$$\emptyset = \frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \times \frac{1}{C_p} \tag{3}$$

where C_p is the compaction correction factor, defined mathematically as

$$C_p = \frac{\Delta t_{sh} C}{100} \tag{4}$$

Where Δt_{sh} = specific acoustic transit time in adjacent shales (µsec/ft), 100 = acoustic transit time in compacted shales (µsec/ft). The shale compaction coefficient (C) usually ranges from 1.0 to 1.3, depending on the regional geology. The highest velocities detected in sandstones approach about 20,000 ft/sec (50 µsec/ft), but most sandstones have a lower matrix velocity. Velocities in adjacent shales are used to adjust the matrix velocity for sands with velocities lower than 18,000 ft/sec.

Also, according to Standard - AAPG Wiki [31], porosity estimates from sonic may be obtained from the Wyllie time average equation (Equation 5).

$$\emptyset = \left(\frac{\Delta t - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}}\right) \frac{H_y}{C_{pa}} \tag{5}$$

$$C_{pa} = \frac{\Delta t_{sh}}{100} \tag{6}$$

In order to avoid overestimation of porosity in uncompacted sandstones and hydrocarbon bearing reservoirs, Equation 6 became necessary to reduce this error. C_{pa} (the compaction factor), defines the impact of pore pressure on the sonic porosity equation. H_y is the hydrocarbon term and it is set as 0.9 for oil and 0.7 for gas. Table (1) recommends the suitable value of Δt_{ma}. If the lithology of carbonate rocks can be reasonably estimated and the porosity distribution is fairly uniform, the Wyllie time-average formula can offer reliable determination of porosity for this assemblage. Table (2) accounts for the Velocity and Acoustic slowness (Transit Time) for common reservoir lithologies. In fast formations, the shear velocity is also useful for porosity calculation in an approach which is almost like the one for compressional velocity. Acoustic travel time in gas and oil is higher than in water. The presence of unflushed hydrocarbons in an interval may result in high values of apparent formation porosity. Commonly used correction factors are 0.9 in oil zones and 0.7 in gas zones [32].

Table 1: Recommendations for appropriate matrix transit time [33].

Δt_{sh} (μsec/ft)	V_{ma} (ft/sec)	Δt_{ma} (μsec/ft)
70 - 80	20,000	50.0
80 to 90	19,000	52.5
90 to 100	18,000	55.5
Greater than 100	Use compaction correction (C_p) adjustments	

Table 2: Velocity and Acoustic slowness (Transit Time) for common reservoir lithologies [34].

Lithology (matrix)	V_{ma} (ft/sec)	Compressional Δt_{ma} (μsec/ft)	Shear Δt_{ma} (μsec/ft)
Sandstone (unconsolidated)	17,000 or less	58.8 or more	93
Sandstone (semiconsolidated)	18,000	55.6	92.9
Sandstone (consolidated)	19,000	52.6	92.9
Shale	6000 to 16,000	62.5 to 167.0	

2. Materials and Method

2.1 Materials

Data acquired from the onshore Niger Delta oilfield include well history, well location, raw well data and geology. Microsoft Excel was used for data loading, processing, plots/curves, diagrams and other computations.

2.2 Method

Two wells (J and K) were available for this study. This data enabled the analysis leading to suites of log such as depth, gamma ray and sonic. These data were analysed using Microsoft Excel. The workflow is highlighted in Figure 5. The dominant lithology at the top of each reservoir is seen as shale with API value greater than 75; the dominant lithology in the reservoir is sandstones with API value less than 75. The depths with shale-sand-shale lithology were noticeable and considered for porosity estimates.

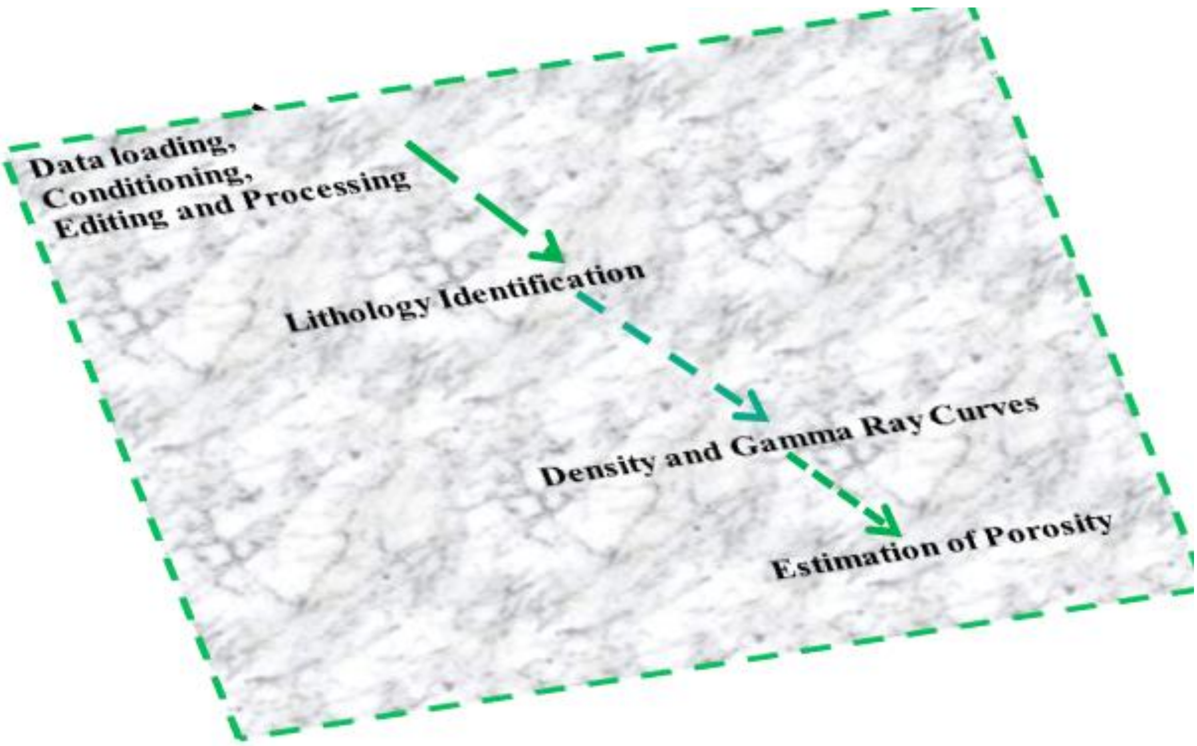

Figure 5: Workflow of the study.

3. Results and Discussion

3.1 Results

Two wells were analyzed in this study and the results are presented in Figures (4 to 6). Logs generated in this study are part of the log suite of Figures (4 and 6). The results of discrimination are in Figures (4 and 6). For the modelling of Depth-Temperature relationship, the relationship shows an increase in depth leads to an increase in Temperature (Figure 9). Porosity estimates result as a function of time, temperature and depth. Figures (5 and 6) present these results for wells J and K respectively. The Porosity-Time (sonic) relationship achieved is Equation (15) which was obtained from the curves of Figures (10 and 11).

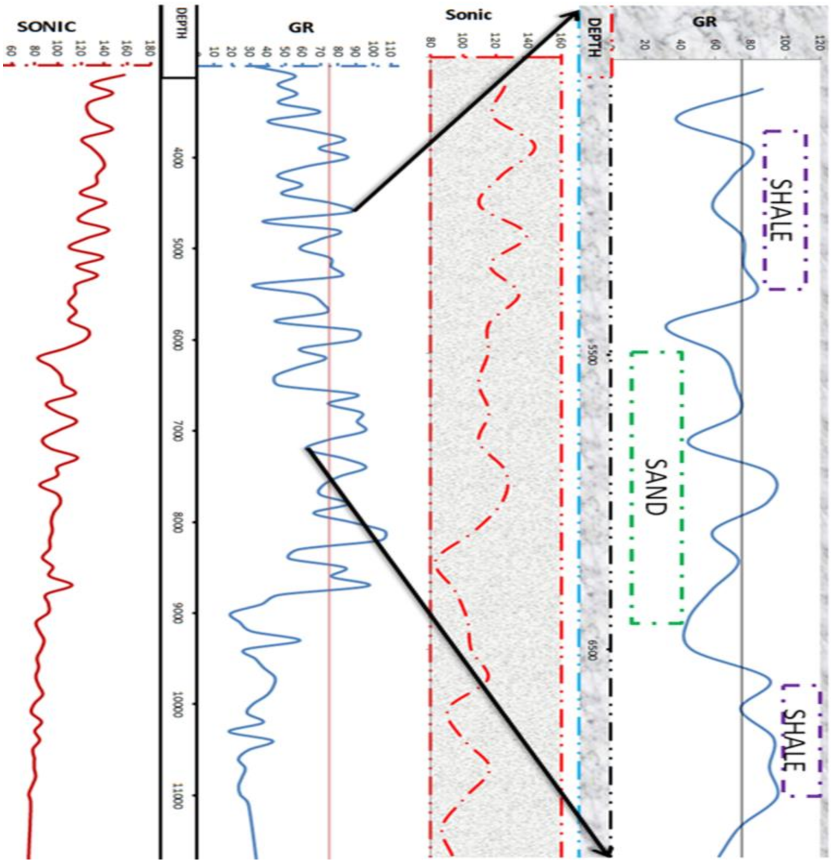

Figure 6: Sonic (in red) and Gamma Ray (in blue) Curves with respect to Depth indicating the Sandstones and Shales Lithologies of Well J.

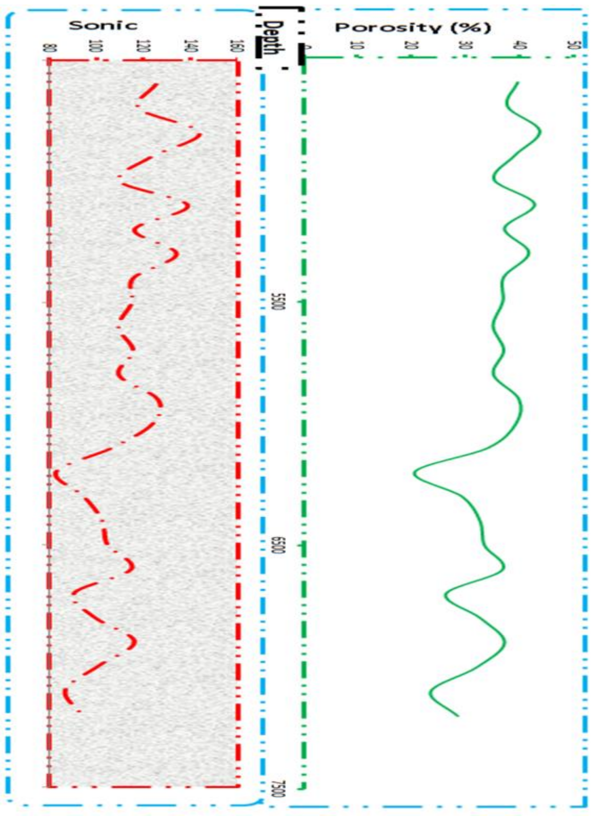

Figure 7: Porosity (in green) information estimated from Well J.

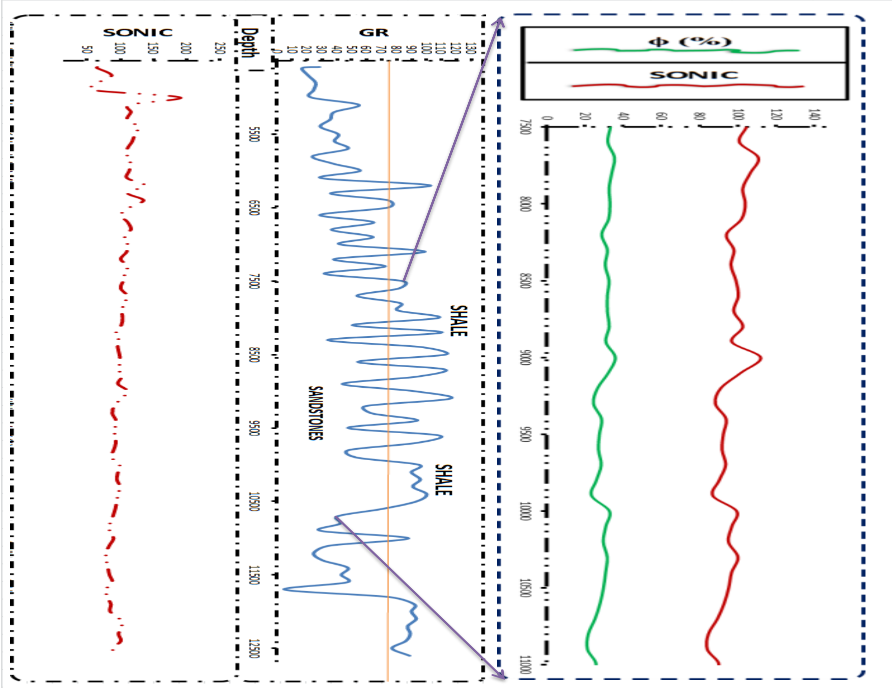

Figure 8: The result of Porosity (in green) Estimates from Sonic (in red) and Gamma Ray (in blue) Curves with respect to Depth from Sandstones and Shales Lithologies of Well K.

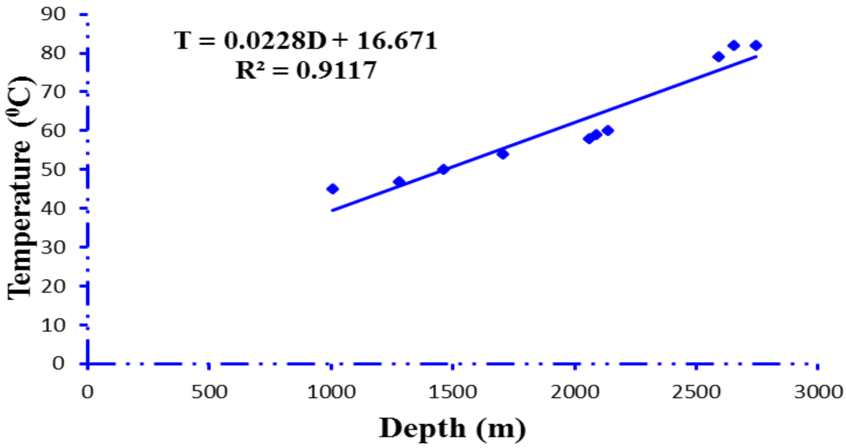

Figure 9: Depth-Temperature relationship..

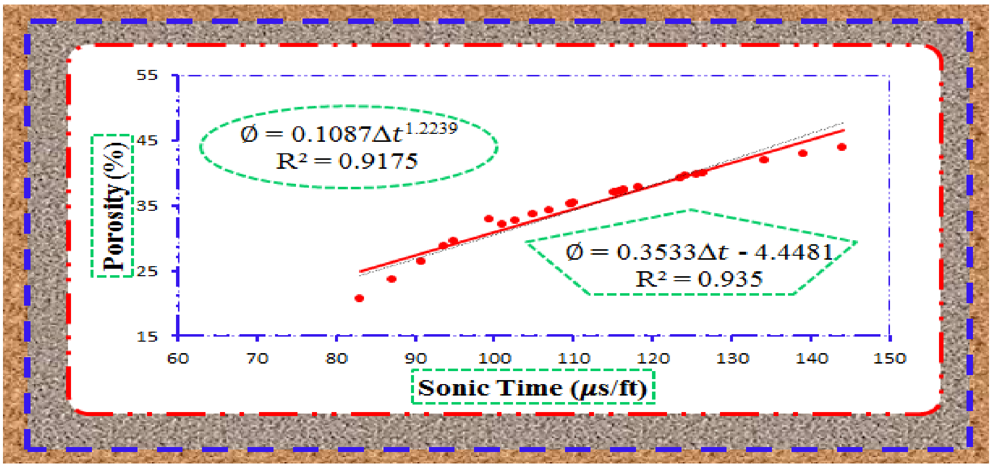

Figure 10: Porosity-Time curve for Well J

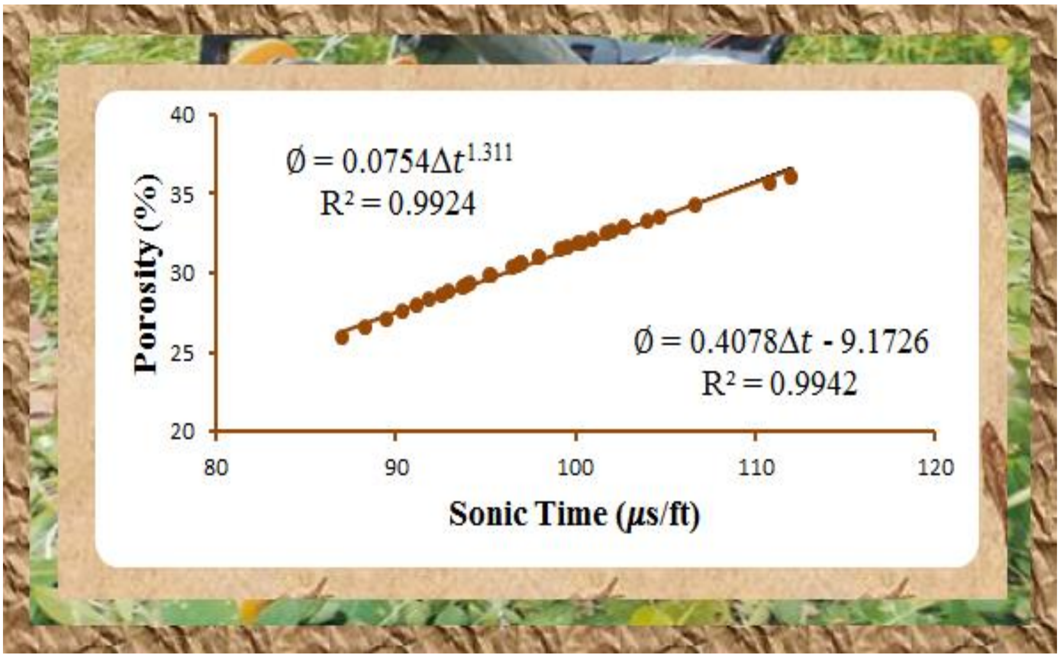

Figure 11: Porosity-Time curve for Well K.

3.2 Discussion

Porosity estimates in sandstones lithology and shales lithology as a function of time, temperature and depth have been achieved for the Southeastern part of Niger Delta. Microsoft Excel was used to obtain the results as presented in Figures (6 to 8).

The raw data were analyzed to create suites of logs (Figures 6 and 8) which include sonic log (red) and gamma ray log (blue) with respect to depth. Gamma ray log was used to identify the lithologies (sandstone and shale) since our focus is on these two formations (Figures 6 and 8). The dominant lithology at the top of the reservoir is shale with API value greater than 75; the dominant lithology in the reservoir is sandstones with API value less than 75. The corresponding depth and sonic log obtained were adequate for the porosity estimates (green) (Figures 7 and 8).

Equations (3 and 4) are supposed to be equal to Equations (5 and 6) respectively but seem different as presented by different Authors. Shale compaction coefficient C ranges from 1.0 to 1.3 [29]. [32] recommended C as 0.9 for oil zones which is our target. The difference between corresponding Equation 3 and 4 with 5 and 6 is on the compaction coefficient introduction. In order to agree with this discrepancy, the reciprocal of compaction factor gives rise to 0.9, meaning that the reciprocal of 0.9 is the compaction factor which results in 1.1. The mean of 1.0 and 1.1 (that is, 1.05) was used for C in the computation.

Equation (1) was employed in Microsoft Excel for mathematical analysis. Since some values of time are in excess of 100 µsec/ft, Equation 3 was used to account for these excesses and Equation 4 enabled the determination of the compaction correction factor.

The results show that the porosity ranges from 21.0% to 44.0% and 20.0% to 39.0% for wells J and K respectively. According to [7], the criteria for classifying porosity (fractional) include porosity less than 0.05 is negligible, 0.05 less than porosity less than 0.10 is poor, 0.10 less than porosity less than 0.15 is fair, 0.15 less than porosity less than 0.25 is good, 0.25 less than porosity less than 0.30 is very good, porosity greater than 0.30 is excellent. Therefore, the porosity obtained is in the excellent class. This results in the average values of about; resulting in the average values of about 35% for well J and 30% for well K. (this means that the average porosity obtained ranges within 30% to 35% in the Field).

Therefore, increase in sonic leads to an increase in porosity irrespective of the lithology. In order to relate porosity estimates to temperature having known how it relates to sonic, a plot of depth against temperature was considered (Figure 9). However, since sonic decreases with an increase in depth, and depth shows a strong coefficient of determination about 0.9 with temperature implies an increase in temperature also leads to a decrease in porosity.

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The Wylie's model is in the form of Equation 1. If it is solved with appropriate constants for sandstone lithology in terms of porosity (fractional), it results in Equation 7.

$$\Delta t = 133.5\emptyset + 55.5 \tag{7}$$

But if it is percentage porosity, implies

$$\Delta t = 1.335\emptyset + 55.500 \tag{8}$$

Solving Equations 7 and 8 completely yields porosity (percentage)-time relation (Equation 9).

$$\emptyset = 0.7491\Delta t + 41.5730 \tag{9}$$

Equation 9 is the linear relationship between porosity and sonic log without the effect of rock reservoir contents in the Niger Delta Basin.

The correlation coefficient between these two parameters (porosity and sonic information) results as 0.935 which is better. This leads to a linear and non-linear relationships presented in Equations 10 and 11 respectively for well J.

$$\emptyset = 0.3533\Delta t - 4.4481 \tag{10}$$

$$\emptyset = 0.1087\Delta t^{1.2239} \tag{11}$$

Also, for well K, the coefficient of determination between these two parameters (porosity and sonic information) results as 0.994 which is better. This leads to a linear and non-linear relationships presented in Equations 12 and 13 respectively for well J.

$$\emptyset = 0.4078\Delta t - 9.1726 \tag{12}$$

$$\emptyset = 0.075\Delta t^{1.311} \tag{13}$$

However, Equation 9 is not adequate or suitable if values of sonic are greater than 100µsec/ft; Equation (14) is the appropriate relation after solving it completely.

$$\emptyset = (71.3267\Delta t - 3958.6305)/\Delta t_{sh} \tag{14}$$

Equation 14 is also the linear relationship between porosity (percentage) and sonic log without the effect of rock reservoir contents in the Niger Delta Basin.

In order to obtain a relation for percentage porosity estimates from sonic log for Niger Delta Basin, the average value of Equations 10 and 12 is adequate, which results in Equation (15).

$$\emptyset = 0.3806\Delta t - 6.8104 \tag{15}$$

Therefore, Equation 15 may be used to obtain better and improve porosity estimates in the Basin of Niger Delta (mostly in the south eastern region).

4. CONCLUSION

Porosity estimates is essential for assessing the potential volume of hydrocarbons it may contain as it evaluates the voids in a geologic unit. The outcomes show that the porosity ranges from 21.0% to 44.0% and 20.0% to 39.0% for wells J and K respectively. This results in the average values of about 35% for well J and 30% for well K. The results of necessary curves show that increase in sonic gives rise to an increase in porosity irrespective of the lithology. Equally, since sonic decreases with increase in depth having a strong coefficient of determination of 0.9 suggests an increase in temperature also leads to a decrease in porosity. Also, a Porosity-Time model has been obtained. This model satisfies and improves porosity estimates irrespective of the value of sonic in microsecond per foot for the South Eastern part of Niger Delta Basin.

Conflict of interests

There are non-conflicts of interest.

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