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PETROPHYSICAL ANALYSIS OF CHAD BASIN NIGERIA SANDSTONE FROM WELL LOGS

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Abstract

The study evaluates the petrophysical properties of the reservoir sands of the Chad basin Nigeria in an attempt to evaluate its prospect for hydrocarbon accumulation. The sand units within the Fika, Gongila and Bima Formations from 12 exploratory Wells drilled in the area were delineated in order to estimate the rock properties such as porosity, permeability, water saturation, hydrocarbon saturation and net-to-gross (NGR) values. The interpretation of the computed values suggests that the sandstone units in the basin have the potential to accumulate and transmit hydrocarbons. The thicknesses of the sand units vary from 10 to 360 m, with an average porosity of 26.62% for all the Wells. The permeability of the rocks ranges from 75 to 5600 mD, suggesting good to excellent while the hydrocarbon saturation of the interstitial spaces are between 3.64 and 83.78 %. Although the overall average porosity and permeability are within limits required for hydrocarbon generation and accumulation, the hydrocarbon saturation values suggest that some of the reservoir units in the basin might contain hydrocarbon in non-commercial quantities.

Keywords: petrophysical; reservoir; well logs; sandstone; Chad basin.

1. Introduction

The Nigerian Government decision to renew exploration work in the Nigerian sector of the Chad Basin has necessitated detailed and systematic analysis of available data from previously drilled wells. This is geared towards achieving successful hydrocarbon production from the basin. At present, about 23 exploration wells that have no hydrocarbon of commercial quantity have been drilled in the area. However, a recent commercial discovery of oil and gas in neighboring countries where the basin extends has aroused interests of researchers from different disciplines [1-6].

The optimal method of producing hydrocarbon from reservoirs is the interest of any producing company. One of the ways of achieving this is through good petrophysical analysis or hydrocarbon reservoir properties modeling. A good reservoir system is made up of the reservoir, the trap and an impervious caprock overlying the reservoir. In Bornu Basin, the reservoirs have been identified as the sandstone facies in the Gongila and Fika formations and Bima Sandstone while the source rocks are mainly in the Gongila formation and in the Fika shale [1, 7-9]. For a rock to be a potential reservoir, porosity and permeability must exist in sufficient magnitude. The entrapment conditions must also be right, and it should be able to release the hydrocarbon at a reasonable rate when it is penetrated by a well.

Well logs data is a key tool used in investigating the fluid quality of reservoir sandstone. It provides accurate reservoir properties by analyzing petrophysical properties taken from a reservoir and thus, is widely used as benchmark or validation data in reservoir characterization [10-11]. Interpreting these measured data helps in evaluating formation properties like porosity, permeability, water saturation, and hydrocarbon that are usually not measured directly. In this study, we have tried to examine the average petrophysical properties of the reservoirs at different stratigraphic zones from 12 exploratory wells with a view of ascertaining if the properties are good enough to support hydrocarbon generation, accumulation, and transmission. Knowledge of the distribution of these rock properties which occur at various scales [12] helps to determine the reservoir quality and in finding techniques that will give maximum fluid production.

In poorly explored regions like Bornu Basin, prediction of reservoir parameters (thickness, porosity, permeability, temperature when added to the knowledge of the geological development will be helpful to the explorationists in the area before the further commencement of drilling operations. Porosity is primarily related to depth, while the permeability also depends on porosity, mineralogy and grain size, which are controlled by the depositional environment.

2. Geologic Setting of Chad Basin

The Chad basin Nigeria is a broad sediment-filled depression stranding Borno, Bauchi, Plateau and Kano States of northern Nigeria. The area is located at longitude 11° 45` E and 14° 45` E and latitude 9° 30` N and 13° 40` N (Fig. 1). The origin of the Chad basin is attributed to the rift system that developed in the early Cretaceous when the African and South American lithospheric plates separated, and the Atlantic opened. The Basin developed at the intersection of many rifts, mainly in an extension of the Benue Trough. Obaje *et al.* [1] observed that Pre-Santonian Cretaceous sediments were deposited within the rift system.

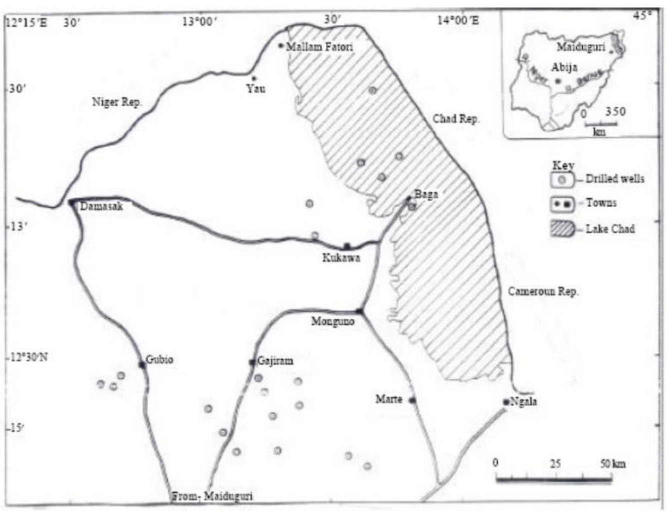


Fig. 1. Location map of the study area [13]

The lithostratigraphic units are the Chad, Fika, Gongila and Bima Formations. Bima Sand-stone is the oldest rock and is adjudged the main reservoir rock. It is of Albian to early Turonian age and lies unconformably on the basement complex [9]. The translational Gongila Formation overlies the Bima. It consists of a sequence of sandstones, clays, shales and limestone layers. Its sandstone texture varies from fine to coarse-grained with the base defined by the first appearance of marine limestone above the Bima Sandstone. The Fika Formation overlies the Gongila Formation, and it consists of shale and thin limestone. The reservoirs are provided by the sandstone facies of Fika and Gongila Formations and in the Bima Sandstone [9]. The Chad Formation is the youngest rock unit in the basin and is of Pleistocene age. The lithology consists of well developed fluvial sands, gravels, and grits with colour ranging from white, brown, yellow to grey.

3. Materials and methods

Wireline logs from twelve exploratory Wells drilled in Bornu Basin were analyzed for the purpose of evaluating the petrophysical parameters. The Wells considered, based on area spread and data completeness are Wadi-1, Krumta-1, Masu-1, Gaibu-1, Kanadi-1, Gubio-1, Herwa-1, Murshe-1, Mbeji-1, Kema-1, Tuma-1, and Ziye-1. The well logs were mainly in hard copy which made the use of any geophysical software for the analysis difficult. A simple, quick look approach was therefore employed in deriving the petrophysical parameters from the logs. The lithologies penetrated by the wells were delineated with the use of gamma ray log. The signature of the log deflecting to the left, below the cutoff point formed the sand bed while shale formation showed prominent high gamma ray signature to the right.

Having identified the bed boundaries, constant log values were assigned to the reservoir sand beds. The values digitized from the logs at 10 m intervals are gamma ray counts from the gamma ray log and interval transit time from the compensated sonic log. These values were then used to calculate the reservoir properties of each bed while the trends in the relationship between the parameters were achieved using the MS Excel. An inference of the potential and producibility of the formation as a suitable reservoir rock from various calculated parameters and cross plots was then made. The determined parameters in this study are porosity, permeability, and water saturation. The net to the gross sand ratio (NGR) was also considered for ease of analysis.

3.1. Determination of porosity

Evaluation of porosity was done using sonic log. For the sand porosity to be determined, the corresponding transit time Δt at any depth for each well was read and recorded from the sonic log. The percentage porosity for each well was calculated using the equation:

$$\emptyset = \left(\frac{\Delta t_{log} - \Delta t_m}{\Delta t_f - \Delta t_m}\right) x \ \frac{100}{1} \qquad (1)$$

where Δt_m is the transit time of the rock matrix; Δt_{log} is the transit time reading on the log and Δt_{fl} is the transit time of formation fluid. A value of 55.5 $\mu s/ft$ and 189$\mu s/ft$ for Δt_m and Δt_{fl} respectively have been used for the computation.

3.2. Determination of compressional wave (Vp) and shear wave (Vs) velocities

The Vp was estimated from the sonic log which measures the time, Δt taken for the sound wave to travel through one foot of a formation. Δt recorded in a well log in μs/ft is related to the Vp by

$$\Delta t = \frac{1}{Vp} \qquad (2)$$

or $$\frac{1}{Vp} = \frac{1}{\Delta t} \ x \ \frac{304800}{1} \ m/s \qquad (3)$$

The Vs was calculated from the compressional wave velocity by using the relation of [14] for sand and shale beds given respectively as

$$Vs_{sd} = (0.80416)Vp - 0.85588 \qquad (4)$$

$$Vs_{sh} = (0.76969)Vp - 0.86735 \qquad (5)$$

3.3. Determination of water saturation

Saturation of a formation defines the fraction of the rock's effective pore volume which is occupied by the particular fluid considered. Water saturation thus is the fraction of the volume occupied by Formation water. It is the fraction of the formation water in the undisturbed zone.

Water saturation was determined using [15] relation:

$$S_{W\ ud} = \frac{0.082}{\phi} \qquad (6)$$

where $S_{W\ ud}$ is the water saturation and Φ is the formation porosity.

It has been noted that for relatively small shale volumes, most shale models for estimating water saturation yield approximately similar results [16-17].

3.4. Determination of permeability

A number of methods for determining permeability from porosity are described in literature, including empirical approaches and various modelling techniques. In this study, permeability which measures the ease with which a formation allows fluid of certain viscosity to flow through it was estimated for the reservoir rock (sand bed) by employing the relation of [18] equation, which expresses permeability 'K' in terms of porosity and water saturation as:

$$K = 307 + 26552\phi^2 - 34540(\phi \times S_{W\,ud})^2 \qquad (7)$$

The net-to-gross sand ratio (NGR), which is the proportion of clean sand within a reservoir unit was computed as the ratio of the net sand to the gross sand [6].

4. Results

The reservoir sands with higher thickness have been used in estimating the petrophysical parameters used in this analysis. The computed values from representative Wells (from lower Fika to Bima Formations) in the basin are shown in Tables 1 – 6. Plots of the porosities against depth shown in Figure 2 are poor to excellent for hydrocarbon accumulation. Vp is greater than Vs and linear throughout (Fig. 3), and the Vp/Vs ratio for all the wells is nearly constant which is indicative of dry sandstone.

Table 1. Petrophysical parameters for Wadi-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	S_h %	K (mD)	NGR
1460 - 1610	50	4541.80	3651.48	8.70	94.29	5.71	275.57	83.81
2000 - 2060	60	2767.39	2224.57	40.93	20.03	79.97	4522.66	86.25
2265 - 2410	145	3403.31	2735.95	25.51	32.14	67.86	1803.07	84.92
2710 - 2750	40	4549.25	3657.47	8.61	95.19	4.81	271.78	87.29
2915 - 3210	295	4354.29	3500.69	10.36	75.50	24.50	387.99	90.70

Table 2. Petrophysical parameters for Masu-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	S_h %	K (mD)	NGR
2000 – 2290	290	3467.36	2787.46	24.42	34.12	65.88	1682.45	91.27
2390- 2450	60	4105.60	3300.71	58.42	41.58	79.97	597.96	93.71
2510 – 2590	80	4115.03	3308.28	58.95	41.05	67.86	588.51	92.13
2800 - 2845	45	4322.79	3475.36	72.93	27.07	4.81	410.41	91.71
2970 - 3085	115	3926.82	3156.94	49.49	50.51	24.50	803.72	91.28

Table 3. Petrophysical parameters for Kanadi-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	S_h %	K (mD)	NGR
1575 - 1620	45	2988.24	2402.16	34.83	23.54	76.46	3296.12	87.93
1740 - 1790	50	4549.25	3657.47	8.61	95.19	4.81	271.78	88.35
2185 - 2250	65	2796.33	2247.84	40.07	20.46	79.54	4338.99	86.14
2380 - 2500	120	4118.92	3311.41	13.86	59.17	40.83	584.65	90.88
2800 - 2890	90	4549.25	3657.47	8.61	95.19	4.81	271.78	92.78
2920 - 2980	60	4482.35	3603.67	9.36	87.58	12.42	307.54	92.38

Table 4. Petrophysical parameters for Gubio-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	S_h %	K (mD)	NGR
1785 - 1800	15	2848.60	2289.87	38.58	21.26	78.74	4026.14	98.37
2420 - 2470	50	2770.91	2227.40	40.82	20.09	79.91	4499.90	86.86
2765 - 2790	35	2745.95	2207.32	41.57	19.72	80.28	4663.78	90.84
2890 - 2945	55	2540.00	2041.71	48.31	16.97	83.03	6272.79	83.93
3165 - 3220	55	2605.13	2094.08	46.07	17.80	82.20	5709.64	89.44
3250 - 3280	50	2721.43	2187.61	42.32	19.38	80.62	4830.64	89.92

Table 5. Petrophysical parameters for Herwa-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	S_h %	K (mD)	NGR
1530 - 1560	30	2822.22	2268.66	39.33	20.85	79.15	4181.08	95.85
2100 - 2130	30	2673.68	2149.21	43.82	18.71	81.29	5173.30	88.95
3420 - 3690	270	4482.35	3603.67	9.36	87.58	12.42	307.54	92.46
3750 - 3810	60	4417.39	3551.43	10.11	81.09	18.91	346.27	87.93
4230 - 4260	30	4549.25	3657.47	8.61	95.19	4.81	271.78	88.45
4620 - 4700	80	4417.39	3551.43	10.11	81.09	18.91	346.27	83.93

Table 6. Petrophysical parameters for Ziye-1

Depth range (m)	Thickness (m)	Vp (m/s)	Vs (m/s)	Φ %	Sw %	Sh %	K (mD)	NGR
1630 - 1685	55	4233.33	3403.42	12.36	66.35	33.65	480.36	93.33
1910 - 1970	60	3810.00	3062.99	18.35	44.68	55.32	969.02	93.71
2330 - 2360	30	2770.91	2227.40	40.82	20.09	79.91	4499.90	93.71
2550 - 2660	110	2770.91	2227.40	40.82	20.09	79.91	4499.90	97.01
2720 - 2780	60	4292.96	3451.37	11.61	70.63	29.37	432.68	94.96
2840 - 2900	60	3958.44	3182.36	16.10	50.92	49.08	763.42	95.53
3110 - 3200	90	4762.50	3828.96	6.37	-	-	182.39	97.00

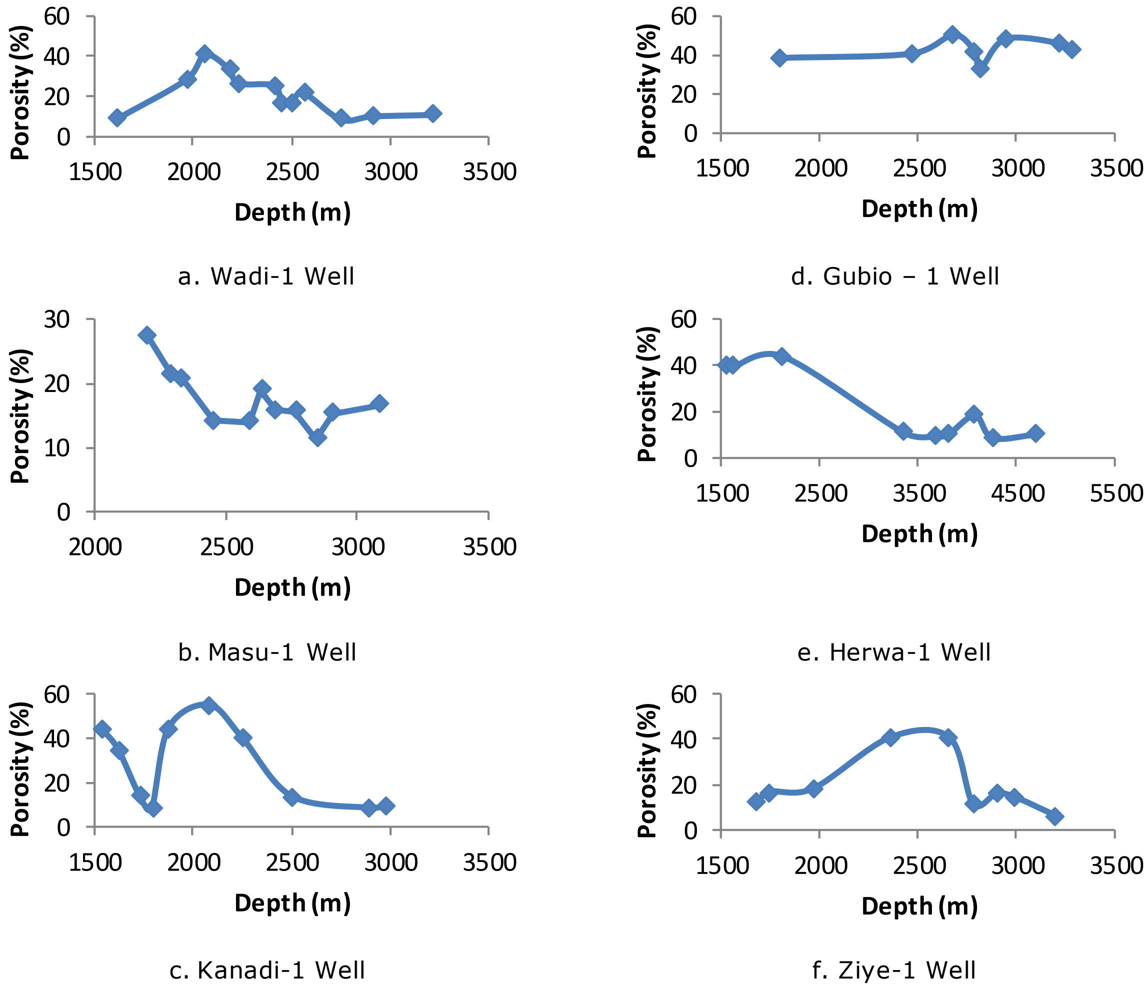
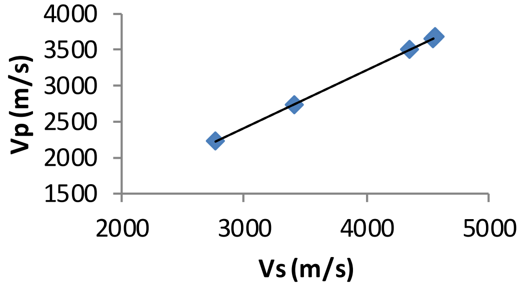


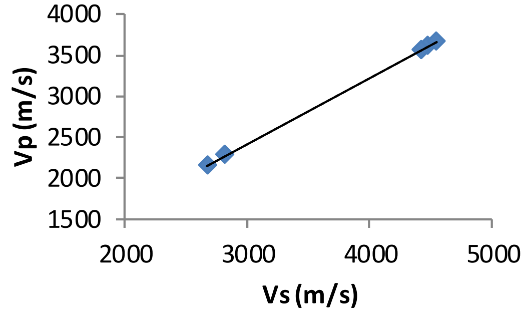
Fig. 2. Porosity - depth relationship between wells in Chad Basin

5. Discussion

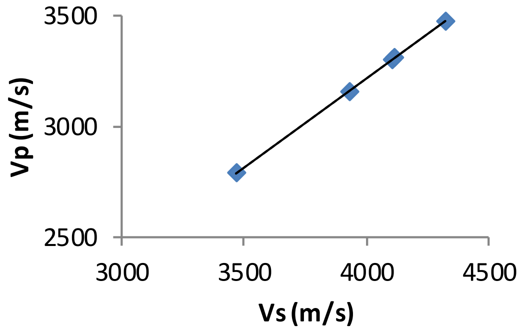
The sand units vary in thickness from 10 to 360 m, with the thickness increasing in deeper depths. The gamma ray log readings within the various sand units (11–118 API) are fairly low to moderate which is an indication that the sands are shaly. The porosity and permeability of the reservoir sandstone generally decrease with increasing burial depth, as a result of mechanical compaction and diagenetic alterations [19]. Generally, the permeability reduction with burial depth is more pronounced for fine grained sandstones than for coarse grained; however, the presence of detrital clay, sorting and other elements related to variations in the depositional environments affect permeability. The presence of diagenetic cement may also result in substantial permeability reduction, as the cement reduces the size of the pore throats.



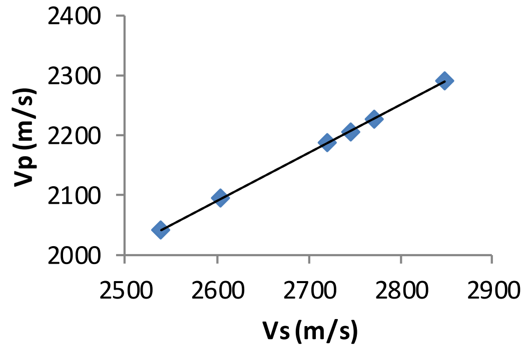
a. Wadi-1 Well



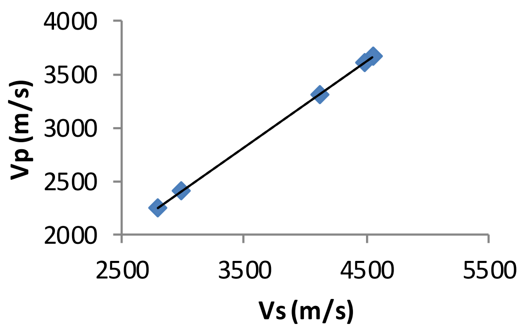
d. Gubio – 1 Well



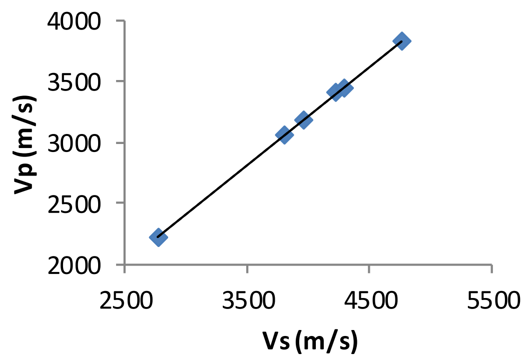
b. Masu-1 Well



e. Herwa-1 Well



c. Kanadi-1 Well



f. Ziye-1 Well

Fig. 3. Linear relationship between shear and compressional velocities

Porosity estimation and those of other parameters obtained in this study were based on sonic logs readings. A porosity range of 1.12 to 60.30% with a basin average of 26.62% was computed for the sand units. Permeability values range from 75 to 5600 mD are good to excellent for hydrocarbon production [20-21]. These computed values are an indication that fluids can flow through the rocks without causing structural changes. The average range of water saturation and hydrocarbon saturation are 16.22 and 96.36% and 3.64 and 83.78% respect-tively. The results show that some of the sand units are hydrocarbon bearing while some are water bearing. The hydrocarbon saturation values also suggest that many reservoir units in the basin might contain hydrocarbon in non-commercial quantities. However, the overall ave-rage porosity, permeability, and fluid saturations are within limits required for hydrocarbon generation and accumulation.

The sonic transit time log and the derived primary and shear velocities have proved to be a useful tool in predicting the rock properties of the study area. However, the [15] relation was ineffective in predicting reservoir fluids saturation when the transit time is less than 67 µs/ft. However, the general increases of both compressional and shear velocities with depth were not well pronounced in this study. This may be associated with heterogeneity nature of the lithology as seen from the calculated NGR values.

6. Conclusion

The overall computed porosities and permeabilities of the sand units are good enough to support the generation and accumulation of hydrocarbon. Depths with more likely water saturation in each of the wells are clearly delineated. A computed NGR value range of 78 to 99% for the basin is an indication of the presence of quality potential reservoir rocks. The hydrocarbon saturation obtained in some reservoir units suggests that the basin hydrocarbon potential might be of low to non-commercial quantities.

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