Full Length Research Paper

Reservoir characterization and evaluation of depositional trend of the Gombe sandstone, southern Chad basin Nigeria

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This study attempts a reservoir characterization and evaluation of depositional trend of sands to assess the petrophysical qualities of Gombe sandstone as a potential reservoir unit for hydrocarbon accumulation in the Chad basin. The economic viability in parts of the Chad basin outside Nigeria and other structurally related contiguous basins such as Doba, Doseo, Bongor fields, and Termit-Agadem basin in the Niger Republic have been investigated. The investigations revealed commercial petroleum accumulations which necessitated the need to assess the petroleum potentials of the Nigerian portion of the Chad basin. Four sand units within Gombe formation penetrated by five wells (Ngammaeast 01, Ngornorth 01, Kinasar 01, Ziye 01 and Murshe 01) were delineated, correlated and their continuity estimated across the studied wells. Petrophysical parameters of these sand units such as porosity, permeability, water saturation, hydrocarbon saturation, bulk water volume, etc were computed and interpreted. Net-to-gross (NGR) values of these sand units were also calculated, and NGR maps were contoured for each sand unit. The direction of deposition of the sands was thus inferred to be east-west. The interpretation suggests that Gombe sandstone in Chad basin is a potential reservoir for hydrocarbon accumulation.

Key words: Petrophysical, sandstone, net-to-gross (NGR), well, Nigeria.

INTRODUCTION

Reservoir rocks are mainly sedimentary rocks which are products of recycling of rock debris from weathering of pre-existing rocks, for example, sandstone, limestone, dolomite, and shale. Essentially, the pore spaces of the reservoir rocks are interconnected such that petroleum is able to migrate and accumulate in a trap. This intercomnected nature of pore spaces is described as permeability which is a measure of the ease of flow of hydrocarbon in the reservoir. A good reservoir system comprises the reservoir, the trap and an impervious stratum overlying the reservoir usually referred to as caprock or seal for example, shale. Within the Chad basin, the source rocks could also provide suitable seals (Avbovbo et al., 1986).

In the Chad basin, source rocks are mainly in the Gongila formation (Olugbemiro et al., 1997; Obaje et al.,

2006; Adepelumi et al., 2010) and in the Fika shale (Petters and Ekweozor, 1982). Likely reservoirs are the sandstone facies in the Gongila and Fika formations and Gombe sandstone. Obaje et al. (2004) carried out geo-chemical studies to assess the qualities of source rocks penetrated by four wells (Kemar 01, Murshe 01, Tuma 01 and Ziye 01) in the Nigerian sector of the Chad basin. He concluded that fair to poor source quality entirely gas-prone source rocks are inherent in the sequences pene-trated by the studied wells. Also, from biomarker chromatograms and extract vs. TOC plots, the presence of oil shows in Ziye 01 well at a depth of 1210 m was indi-cated, he thus concluded that generated hydrocarbons would be overwhelmingly gaseous.

Gombe sandstone within the Chad basin directly overlies the Fika shale which is considered a potential source rock within the basin. Gombe sandstone is essen-tially a sequence of estuarine to deltaic sandstone. It is also discovered that the Gombe sandstone is restricted to the western part of the basin (Ali and Orazulike, 2010).

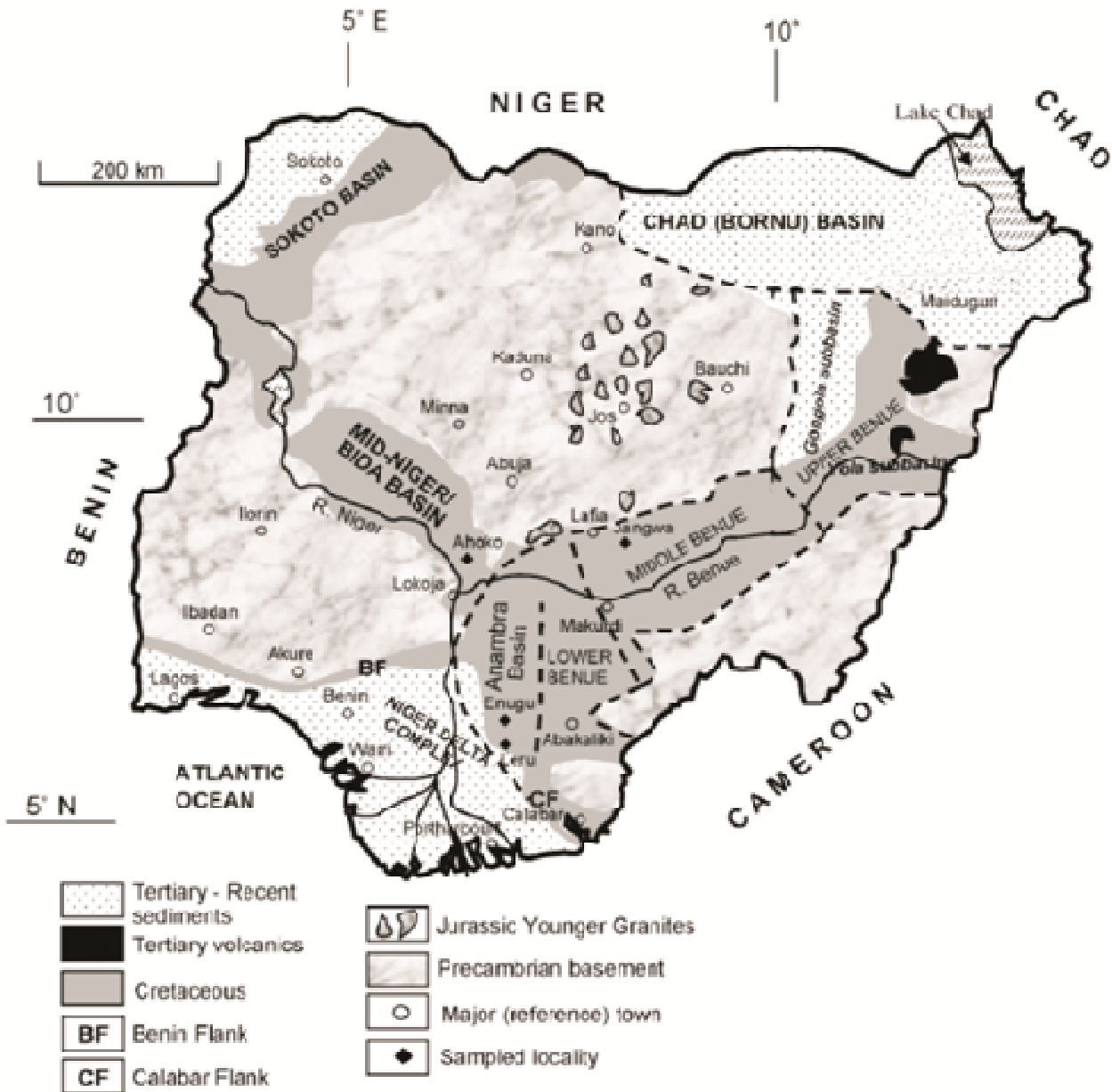*Corresponding author. E-mail: adepelumi@gmail.com.

Figure 1a. Geologic map of Nigeria showing the inland basins and the Nigerian sector of Chad basin (Obaje et al., 2006).

The economic viability of parts of the Chad basin outside Nigeria and other structurally related contiguous basins such as Doba, Doseo, Bongor fields, and Termit-Agadem basin in the Niger Republic have been investigated. The investigations revealed commercial petroleum accumulations and this necessitate the need to assess the petroleum potentials of the Nigerian portion of the Chad Basin. Thus, through this project, we aimed to carry out petrophysical evaluation of Gombe sandstone using lithologic, resistivity and porosity logs, and also to confirm the results of this evaluation from various cross-plots in order to ascertain the potential and producibility of the formation as a suitable reservoir rock.

GEOLOGY OF CHAD BASIN

The study area is the Chad basin (Figure 1). The Chad basin in Nigeria is a broad sediment-filled depression stranding Northeastern Nigeria and adjourning parts of Chad Republic. It is separated from the upper Benue basin by the Zambuk ridge (Adepelumi et al., 2010). By far the greater part of the Chad basin is located to the north outside Nigeria in the Republic of Chad. It occupies an area of about 2,500,000 km^2, extending over parts of Algeria, the Niger, Chad, and Sudan Republics as well as the northern parts of Cameroon and Nigeria. The study area is located within longitude 11°45`E and 14°45`E
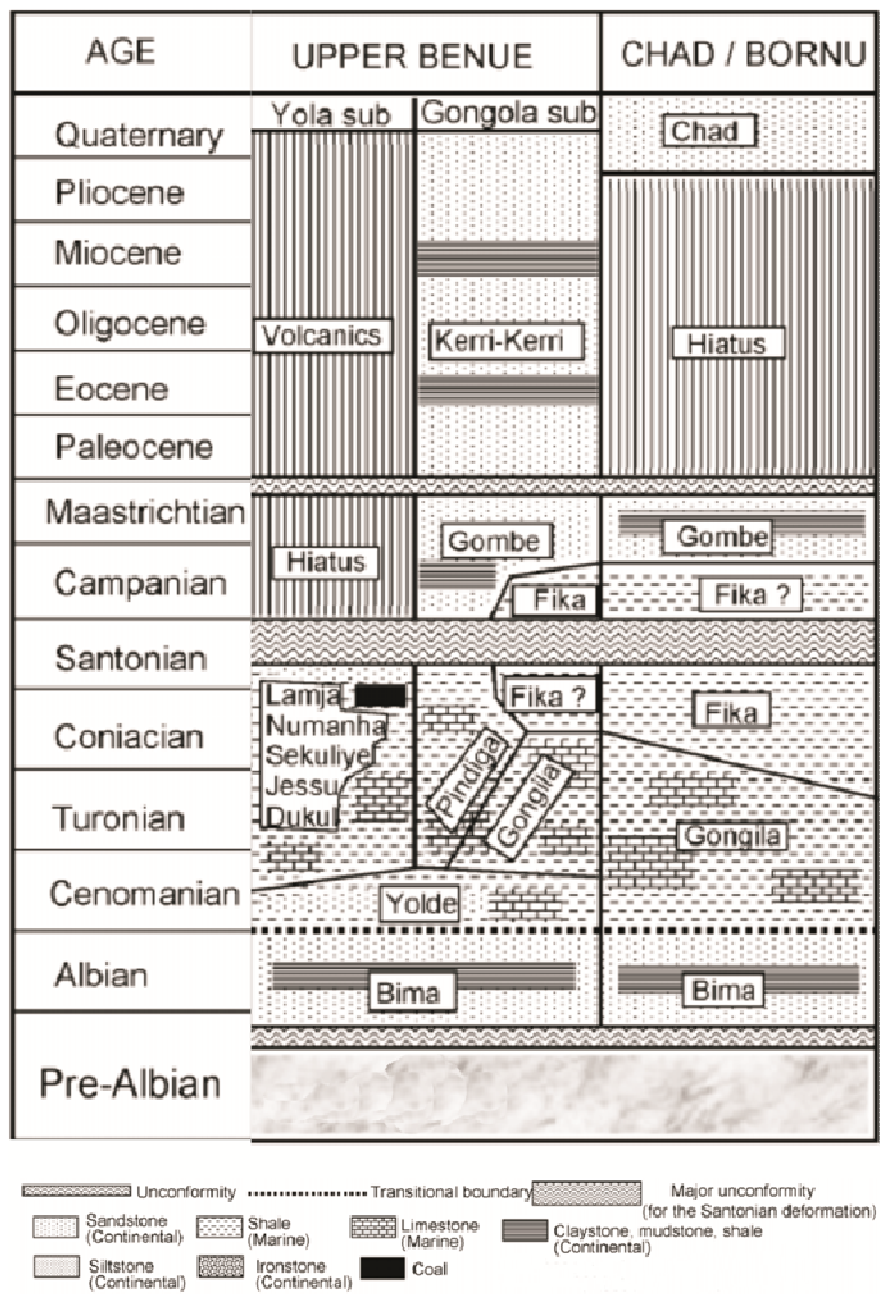
Figure 1b. Stratigraphic successions in the Nigerian sector of the Chad basin in relation to the Benue Trough (Obaje et al., 2006).

and latitude 9°30`N and 13°40`N.

The origin of the Chad basin has been generally attributed to the rift system that developed in the early Cretaceous when the African and South American lithospheric plates separated and the Atlantic opened. Pre-Santonian Cretaceous sediments were deposited within the rift system (Obaje et al., 2004, 2006). The Basin has been developed at the intersection of many rifts, mainly in an extension of the Benue Trough. Major grabens then developed and sedimentation started.

Sedimentary sequences were deposited from the Paleozoic to Recent, accompanied by a number of stratigraphic gaps. Sediments are mainly continental, sparsely fossiliferous, poorly sorted, and medium- to coarse-grained, feldspathic sandstones called the Bima Sandstone. A transitional calcareous deposit - Gongila formation - that accompanied the onset of marine incursions into the basin, overlies the Bima Sandstones. These are overlain by graptolitic shale (Okosun, 1995). The oldest rocks in the Chad basin belong to Bima Sandstone and the youngest to the Chad Formation as shown in the stratigraphic column of the study area (Figure 1b).

Bima sandstone

This formation has essentially the same lithology as in the upper Benue Basin. It is largely constituted of coarse feldspathic and cross-bedded sandstones. It is, however, thinner in the Chad Basin. It has been dated Albian.

Gongila formation

This unit consists of sequence of sandstones, clays, shales and limestone layers. It varies laterally into massive grey limestone overlain by sandstone, siltstones, thin limestone and shales with shally limestone. To the south at Kupto, however, a thick limestone is overlain by sandstones, mudstones, and shales with lime stones (Carter et al., 1963).

The limestone horizons are richly fossiliferous with abundant ammonites, pelecypods and echinoid remains, on the basis of these, Carter et al. (1963) assigned an Early Turonian age to the formation.

Fika shale

This formation consists of blue-grey shale, at times gypsiferous; with one or two non-persistent limestones horizons. A maximum thickness of 430 m has been penetrated in by boreholes near Maiduguri. Fossils of the Fika shale consist mainly of fish remains and fragments of reptiles suggesting a Cenomanian to Maastrichtian age (Dessauvagie, 1975). However, Dessauvagie (1975) suggests a pre-Santonian upper age limit for the formation based on stratigraphic evidence.

Gombe sandstone

This unit is a sequence of estuarine and deltaic sandstone, siltstone and subordinate shale. Thin coal seams are locally present. In outcrop many of the sandstones and siltstones are ferruginised forming low-grade ironstones. The macrofauna is limited and consists of a few indeterminate lamellibranchs (Carter et al., 1963). Shell-BP palynologists dated the coal late Senonian - Maastrichtian.

Kerri-Kerri formation

This consists of loosely cemented, coarse to fine-grained sandstone, massive claystone and siltstone; bands of ironstone and conglomerate occur locally. The sandstone is often cross bedded. The sediments are lacustrine and deltaic in origin and have a maximum thickness of over 200 m (Du Preez and Barber, 1965). The coal in the formation has yielded palynomorphs on the basis of which Shell-BP palynologists dated it Paleocene and later by Adegoke et al. (1986).

Chad formation

This formation is a succession of yellow and grey clay, fine- to coarse-grained sand with intercalations of sandy clay and diatomites. Its thickness considerably varies. It is estimated to be about 800 m thick on the western shore of Lake Chad. Vertebrate remains (*Hippopotamus imaguncula*) and diatoms collected from it indicate an Early Pleistocene (Villafranchian) age. However, its age is considered to range from Pliocene to Pleistocene. The Chad basin is capped by Tertiary volcanic rocks. The Biu Plateau Basalts underlie the Pleistocene diatomite deposits near Bulbaba but overly Cretaceous rocks (Carter et al., 1963). They are thus most probably of Tertiary age. The basalts consist of fine-grained, dense olivine-bearing varieties.

METHODOLOGY

The well log data used in this study were recorded as part of the Chad basin petroleum drilling program of the Nigerian National Petroleum Corporation (NNPC) database available in the Department of Geology, Obafemi Awolowo University, Ile-Ife, Nigeria. The data consist of a suite of well log readings from twenty-three (23) wells drilled in the Chad basin. Five (5) wells were selected for the purpose of this work. The analyses of the well log data began with arrangement of log data in a readable format using Excel Spreadsheet. Some parameters such as sonic-derived porosity and gamma ray index computed on the Excel Spreadsheet were converted into LAS file and imported along with the data already in LAS format into the RokDoc 5.4.4 Software (powered by Ikon Science). These imported data were then plotted as logs. These logs were used in the calculation of the petrophysical parameters which were consequently exported as Excel files and were finally tabulated.

The logs include lithologic logs (spontaneous potential and gamma ray), resistivity logs (induction log deep, short normal, micro-spherically focused log), porosity logs (bulk density, sonic) and caliper logs. The logs include useful information found on the header which includes the well name, depth of drilling, longitude and latitude, surface X and Y coordinate.

The wells used for this study were plotted as they appeared on the base map, that is, from west to east. The plot revealed that the sands reduced in thickness going from east to west. The direction of deposition of the sands was thus inferred to go from proximal (east) to distal (west).

The well logs were carefully studied. The caliper logs which measure the borehole size gives an indication of caving where the readings are inconsistent; the gamma ray logs were used to identify lithologies, that is, sand versus shale; the resistivity logs are also studied carefully in order to delineate hydrocarbon bearing zones in each well, these zones are indicated by high deep resistivity readings. However, high resistivity zones may indicate the presence of fresh water.

Sand units of interest were carefully picked and correlated across the wells to give an idea of the continuity of the reservoirs at different depths across the whole survey area. Petrophysical parameters obtained for reservoir evaluation in the course of this study includes:

1. Volume of shale: To derive V_{sh} from gamma ray, it is imperative that the gamma ray index, that is, I_{GR} is first determined. Using equation 3.1 of Schlumberger (1974):

$$I_{GR} = (GR_{log} - GR_{min}) / (GR_{max} - GR_{min}) \qquad (1)$$

Where I_{GR} = gamma ray index; GR_{log} = gamma ray reading of formation; GR_{min} = minimum gamma ray reading (clean sand or carbonate); GR_{max} = maximum Gamma ray reading (shale).

For the purpose of this work, formula of Larionov (1969) for older rocks was used. Larionov (1969) formula for Tertiary rocks:

$$V_{sh} = 0.083(2^{3.7*IGR} - 1) \tag{2}$$

On the basis of the following V_{sh} cut-offs, formations are regarded as clean, shaly, or shale zones:

i. V_{sh} < 10% implies a clean sand (Hilchie, 1978)
ii. V_{sh} 10-35% implies a shaly sand
iii. V_{sh} >35% implies a shale zone (Ghorab et al., 2008)

2. Porosity (sonic-derived porosity): Raymer-Hunt Gardner (RHG) equation (Raymer et al., 1980):

$$\Phi_S = 5/8*(\Delta t_{log} - \Delta t_{ma}) / \Delta t_{log} \tag{3}$$

Wyllie time-average equation (Wyllie et al., 1958):

$$\Phi_S = (\Delta t_{log} - \Delta t_{ma}) / (\Delta t_{fl} - \Delta t_{ma}) \tag{4}$$

Δt is increased due to the presence of hydrocarbon, to correct for hydrocarbon effect, Hilchie (1978) suggested the following empirical corrections:

$$\Phi = \Phi_S * 0.7 \text{ (gas)} \tag{5}$$

$$\Phi = \Phi_S * 0.9 \text{ (oil)} \tag{6}$$

In order to correct for the overestimation of sonic-derived porosity resulting from the effect of shale within formations, the following equation is used:

$$\Phi_{Scor} = \Phi_S - (V_{sh} - \Phi_{Sch}) \tag{7}$$

Where Φ_S = sonic derived porosity; Δt_{log} = Interval transit time in the formation; Δt_{ma} = Interval transit time in the matrix; Δt_{fl} = Interval transit time in the fluid in the formation; Φ_{Sch} = Apparent porosity of the shale point; Φ_{Scor} = corrected sonic porosity.

3. Effective porosity: This can be calculated from the combination of density and neutron logs but the entire well log data used for the purpose of this study lack neutron log. Hence, the effective porosity was simulated from the total porosity using the RokDoc 5.4.4 software.

4. Net-to-gross ratio (NGR): This is a measure of the proportion of clean sand within a reservoir unit. The gross sand is taken to be the whole thickness; the non-net sand refers to the shaly sequences within the gross sands that tend to divide it into flow units; the net sand is thus obtained by subtracting the non-net sand from the gross sand. The NGR reflects the quality of the sands as potential reservoirs. The higher the NGR value, the better the quality of the sand.

For predictive purposes, a NGR map is produced for the area of study. These maps can be used to estimate the viability of a test well in the exploration stage:

$$NGR = \text{Net sand / Gross sand} \tag{8}$$

Where Net sand = gross sand – non-net sand   (9)

5. Water and hydrocarbon saturation: For the uninvaded zone, according to Archie (1942):

$$S_w = [(a * R_w) / (R_t * \Phi^m)]^{1/n} \tag{10}$$

$$S_h = 1 - S_w \tag{11}$$

Where S_w = water saturation; R_o = resistivity of a water filled formation; R_t = true formation resistivity (that is, deep induction); R_w = resistivity of formation water at formation; Φ = porosity; n = saturation exponent usually taken as 2.0; m = cementation factor; a = tortousity factor

6. Irreducible water saturation: This describes the water saturation at which all the water is adsorbed on the grains in a rock or is held in capillaries by capillary pressure. Because production of water in a well can affect a prospect's economics, it is important to know the bulk volume water and whether the formation is at irreducible water saturation (S_{wirr}). At irreducible water saturation, water does not move and the relative permeability to water is zero. Hence, water saturation varies from 100% to a small value but never goes to zero because some water held in capillaries cannot be displaced:

$$S_{wirr} = (F/2000)^{1/2} \text{ (Asquith and Krygowski, 2004)} \tag{12}$$

Where F = formation factor

7. Bulk volume water (BVW): This is the product of water saturation and porosity corrected for shale:

$$BVW = S_w * \Phi_e \text{ (Asquith and Krygowski, 2004)} \tag{13}$$

Where BVW = bulk volume water; S_w = water saturation; Φ_e = effective porosity

If values for BVW calculated at several depths within a formation are consistent, then the zone is considered to be homogeneous and at irreducible water saturation. Therefore, hydrocarbon production from such zone should be water free (Morris and Biggs, 1967).

8. Determination of permeability: Permeability is a measure of the ease with which fluids are transmitted within a rock body. It is related to porosity but not always dependent upon it. From Timur (1968):

$$K = [(100 * \Phi^{2.25}) / S_{wirr}]^{0.5} \tag{14}$$

Where K = permeability (millidarcy; Φ = porosity; S_{wirr} = irreducible water saturation)

9. Identification of fluid type: Usually, a definite identification of fluid type contained within the pore spaces of formation is achieved by the observed relationship between the Neutron and Density logs. Presence of hydrocarbon is indicated by increased Density log reading which allows for a cross-over. Gas is present if the magnitude of cross-over, that is, the separation between the two curves is pronounced while oil is inferred where the magnitude of cross-over is low (Asquith and Krygowski, 2004).

However, the well log data used for this study lack Neutron compensated logs thereby making the identification of fluid type unfeasible. Hence, a general indication of fluid type, that is, the presence of hydrocarbon or water was inferred from the resistivity readings. High deep resistivity readings corresponding to sand units indicated hydrocarbon bearing or freshwater zones while low deep resistivity readings showed water bearing zones.

RESULTS AND DISCUSSION

Five wells were used for the purpose of this study namely Ngammaeast 01, Ngornorth 01, Kinasar 01, Ziye 01 and Murshe 01. These wells were selected on the basis of their surface elevations such that the resulting

Table 1. Average petrophysical parameters for Ngammaeast 01.

Sand unit	Thickness (m)	NGR (%)	Vshale (%)	S_w (%)	S_h (%)	K(mD)	BVW	S_{wirr} (%)	PHIE (%)
Sand 1	62.30	90.67	25.08	54.38	45.62	9986.74	0.12	6.59	22.05
Sand 2	131.63	86.88	15.29	40.44	59.56	18948.68	0.11	6.04	27.41
Sand 3	166.40	5.93	36.65	94.48	5.52	6669.82	0.16	7.06	17.53
Sand 4	32.01	85.70	20.61	97.00	3.00	5903.73	0.21	7.09	20.92

NGR (%) = net to gross ratio; Vshale = volume of shale (%); S_w= water saturation (%); S_h= hydrocarbon saturation (%); S_{wirr}= irreducible water saturation (%); BVW = bulk volume of water; PHIE= effective porosity (%); K = permeability (millidarcy).

Table 2. Average petrophysical parameters for Ngornorth 01.

Sand units	Thickness (m)	NGR (%)	Vshale (%)	S_w (%)	S_h (%)	K(mD)	BVW	S_{wirr} (%)	PHIE (%)
Sand 1	67.37	75.89	24.01	24.58	75.42	72881.72	0.08	4.73	33.10
Sand 2	126.75	90.60	18.05	24.37	75.63	43558.13	0.08	5.34	31.05
Sand 3	217.78	20.47	29.09	51.72	48.28	86860.75	0.17	4.61	32.84
Sand 4	34.17	89.34	23.50	62.89	37.11	90836.50	0.22	4.57	34.74

NGR (%) = net to gross ratio; Vshale = volume of shale (%); S_w= water saturation (%); S_h= hydrocarbon saturation (%); S_{wirr}= irreducible water saturation (%); BVW = bulk volume of water; PHIE= effective porosity (%); K = permeability (millidarcy).

Table 3. Average petrophysical parameters for Kinasar 01.

Sand units	Thickness (m)	NGR (%)	Vshale (%)	S_w (%)	S_h (%)	K(mD)	BVW	S_{wirr} (%)	PHIE (%)
Sand 1	57.71	92.19	20.68	36.13	63.87	36159.31	0.11	5.41	30.53
Sand 2	105.97	82.75	19.77	37.61	62.39	31615.35	0.11	5.48	30.23
Sand 3	225.18	92.30	14.33	27.22	72.78	26829.95	0.08	5.66	30.79
Sand 4	35.32	61.53	16.76	20.67	79.33	29596.23	0.06	5.51	30.89

NGR (%) = net to gross ratio; Vshale = volume of shale (%); S_w= water saturation (%); S_h= hydrocarbon saturation (%); S_{wirr}= irreducible water saturation (%); BVW = bulk volume of water; PHIE= effective porosity (%); K = permeability (millidarcy).

Table 4. Average petrophysical parameters for Ziye 01.

Sand units	Thickness (m)	NGR (%)	Vshale (%)	S_w (%)	S_h (%)	K(mD)	BVW	S_{wirr} (%)	PHIE (%)
Sand 1	51.09	75.01	12.98	4.66	95.34	25666.56	0.02	5.86	29.76
Sand 2	91.62	58.42	19.67	5.65	94.35	23960.88	0.02	5.82	28.37
Sand 3	144.60	94.34	14.30	3.83	96.17	23213.95	0.01	5.75	30.18
Sand 4	50.78	89.29	17.25	34.14	65.86	19625.23	0.01	6.00	28.28

NGR (%) = net to gross ratio; Vshale = volume of shale (%); S_w= water saturation (%); S_h= hydrocarbon saturation (%); S_{wirr}= irreducible water saturation (%); BVW = bulk volume of water; PHIE= effective porosity (%); K = permeability (millidarcy).

topography reflects the overall geomorphology of the Chad basin.

The average value of petrophysical parameters (Tables 1 to 5) such as volume of shale, net-to-gross ratio (NGR), porosity, permeability, water saturation, hydrocarbon saturation, bulk volume of water, etc. (Tables 1 to 5), were obtained for each reservoir unit of interest using appropriate equations as stated in methodology. As a predictive tool, NGR maps were produced for each sand unit across the study wells. The NGR maps help in the determination of the direction and energy of deposition

(that is, from proximal to distal).

Four sand units of interest namely Sands 1, 2, 3 and 4 were delineated and correlated across all the wells of study (Figures 2 and 3) .

Net -to-gross maps

The net-to-gross ratio (NGR) allows for the determination of the energy and direction of deposition of the sands. The higher the NGR value, the better the quality of the

Table 5. Average petrophysical parameters for Murshe 01.

Sand units	Thickness (m)	NGR (%)	Vshale (%)	S_w (%)	S_h (%)	K(mD)	BVW	S_{wirr} (%)	PHIE (%)
Sand 1	35.32	87.19	13.10	18.31	81.69	23881.16	0.05	8.99	25.05
Sand 2	110.38	93.38	12.11	17.66	82.34	25473.98	0.05	5.77	27.08
Sand 3	122.52	70.71	26.98	31.44	68.56	10057.01	0.05	6.49	14.88
Sand 4	67.33	67.26	24.75	57.39	42.61	15900.97	0.10	6.40	17.33

NGR (%) = net to gross ratio; Vshale = volume of shale (%); S_w= water saturation (%); S_h= hydrocarbon saturation (%); S_{wirr}= irreducible water saturation (%); BVW = bulk volume of water; PHIE= effective porosity (%); K = permeability (millidarcy).
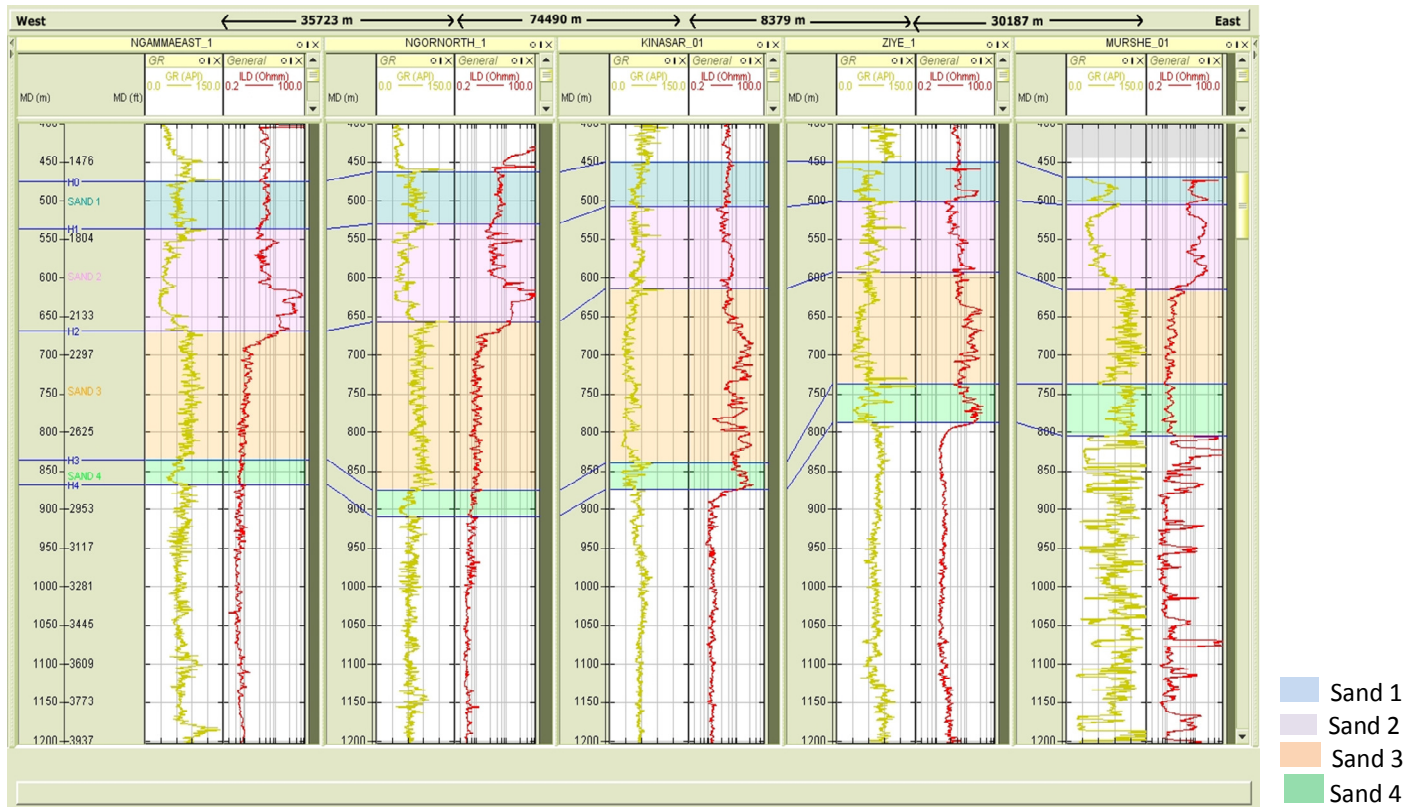
Figure 2. Attempted chronostratigraphic correlation of sands across study wells.

sands. Higher NGR indicates proximity to land that is, proximal source while lower NGR indicates distal source of sediments. Sands are lost on going from proximal to distal as the energy of deposition reduces and the hydro-dynamics of flow tends to zero resulting in the settling out of fine grained materials (Figures 4 to 7).

NGR values obtained for sands investigated in all the wells used for the purpose of this study were contoured using WinSurf® software (Figures 4 to 7). Thus a NGR map was produced for each sand unit. From the maps obtained, the NGR values are fairly consistent across the wells. The least NGR value (20.47%) was recorded in sand 3 in Ngornorth01 well while the highest NGR value (94.34%) was recorded in Sand 3 in Ziye01 well.

No particular trend was observed except in Sand 3 in which the NGR values decreased from about 94.34 % in Ziye 01 to about 5.93 % in Ngammaeast 01 well. On this basis, it can be suggested that deposition of sands with decreasing energy of flow goes from east to west, that is Murshe 01 well to Ngammaeast 01 well (Tables 1 to 5).

Cross-plots

In order to properly characterize the reservoir sands delineated and correlated across the studied wells, a plot of S_w vs. Φ (that is, Buckles plot) was made to determine the grain size range and also to show whether or not the sands are at irreducible water saturation.

To determine the grain size range of each sand unit in
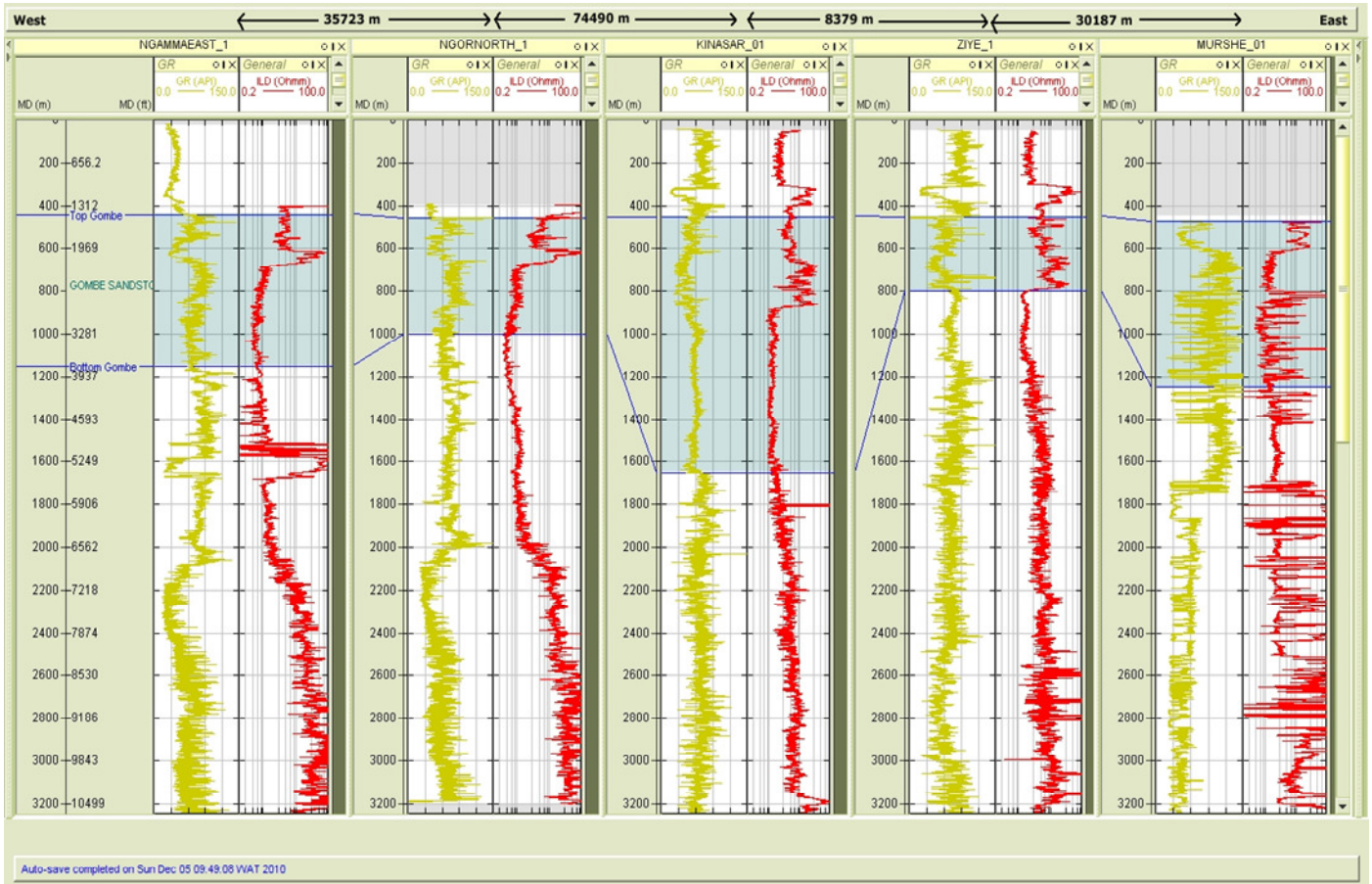
Gombe sandstone

Figure 3. Correlation showing the continuity of Gombe formation across the study well.
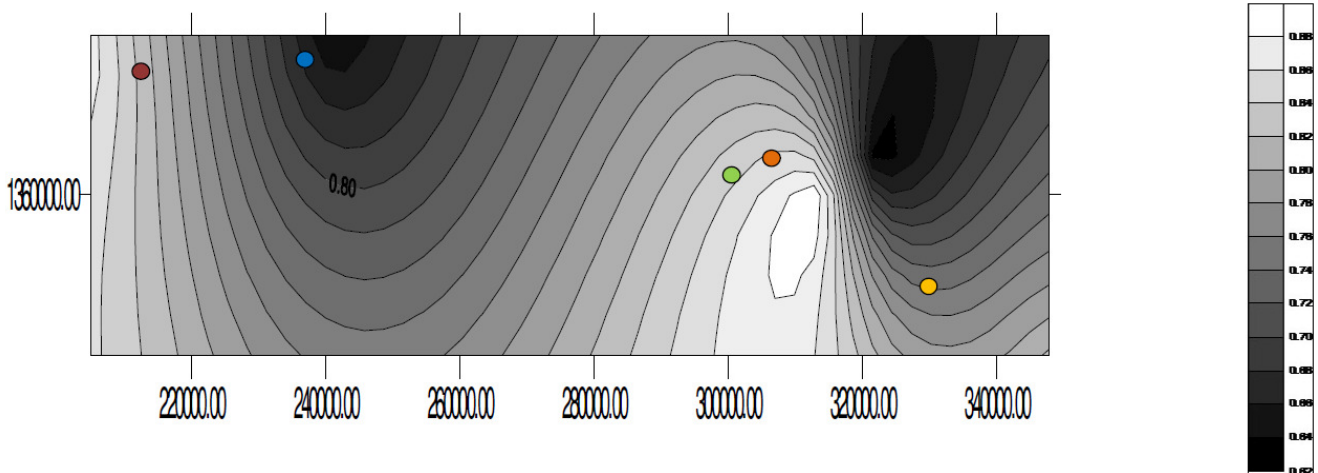

Figure 4. Net-to-gross map of Sand 1.

the studied wells, the average values of porosity are plotted against the average values of water saturation as data points. These points fall within specific fields that represent different ranges of grain size. Figure 8 shows that in Ngammaeast 01 well, the reservoir sands is observed to have very fine grains; sands in Ngornorth 01
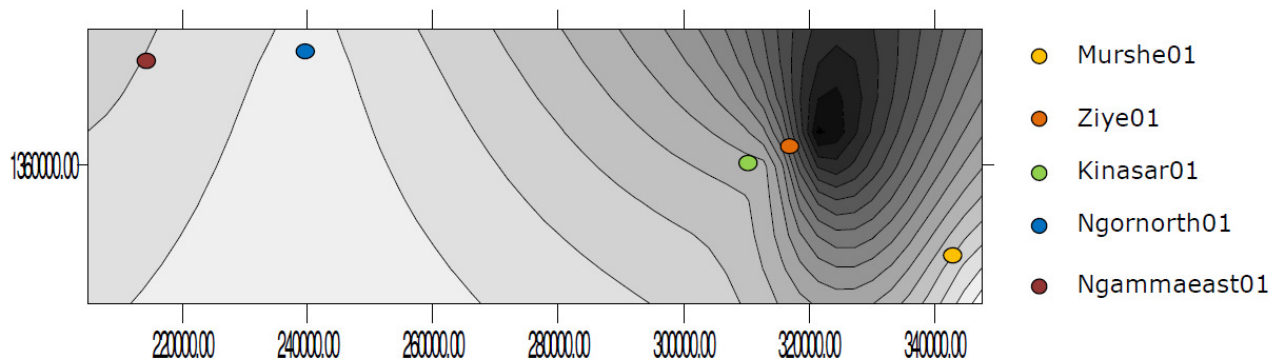
Figure 5. Net-to-Gross map of Sand 2
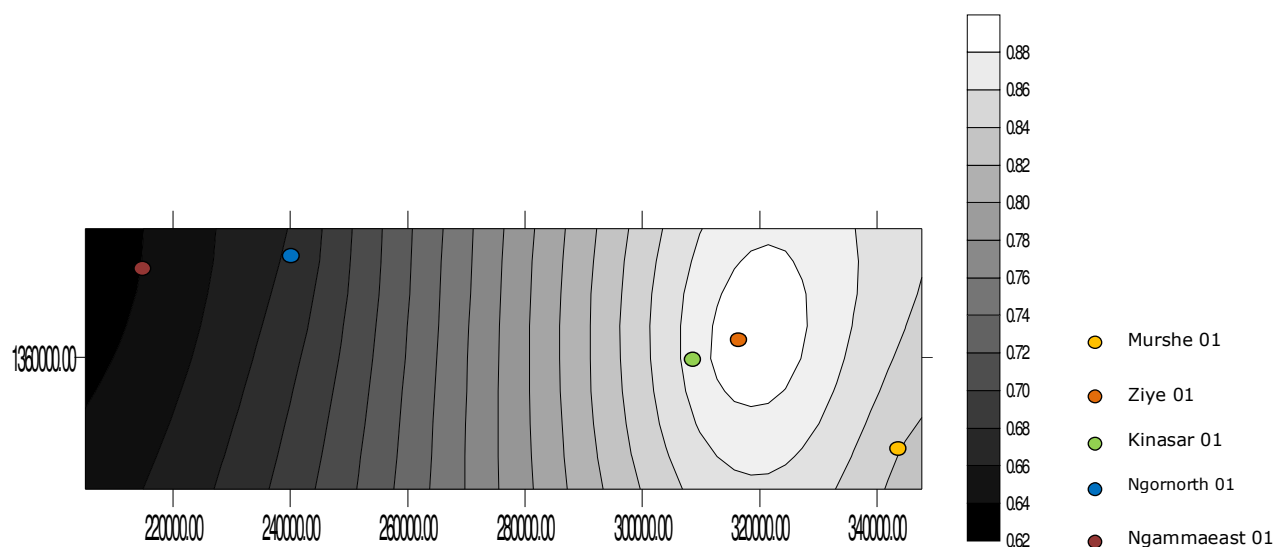
Figure 6. Net-to-Gross map of Sand 3.
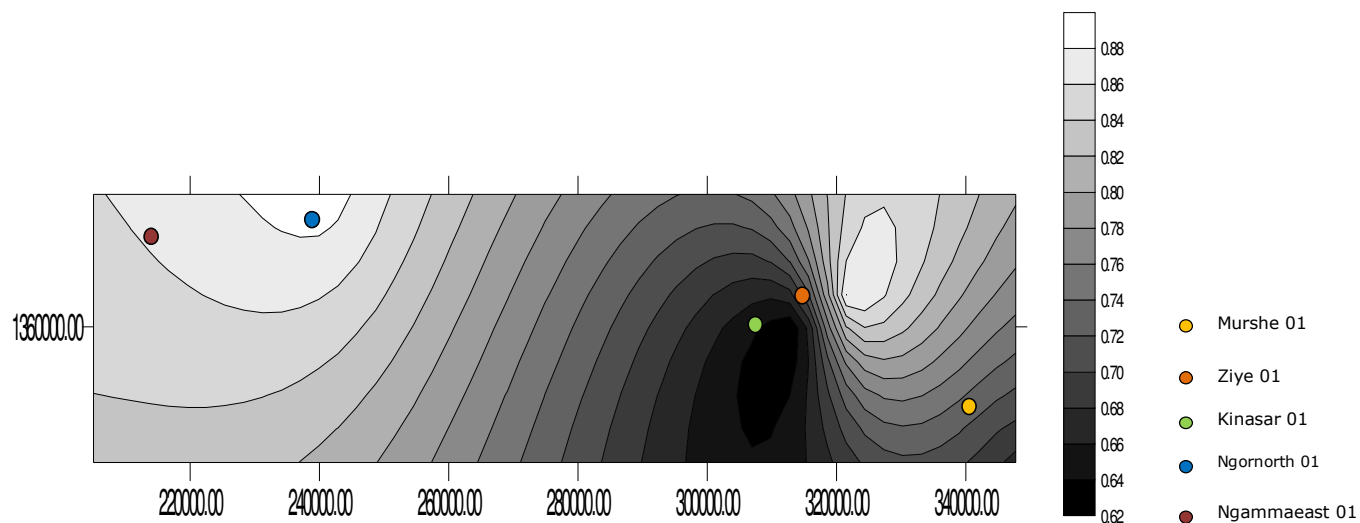
Figure 7. Net-to-gross map of Sand 4.
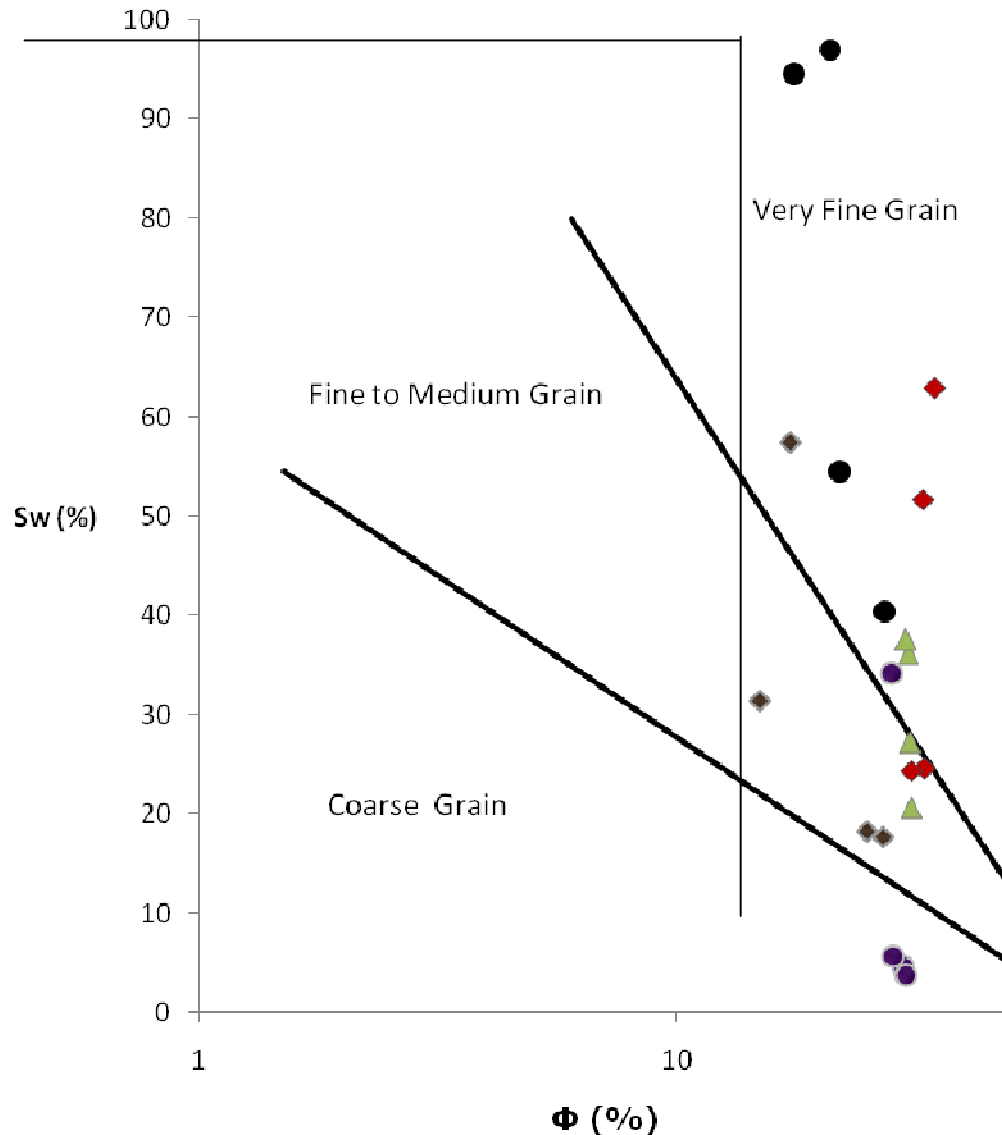
Figure 8. Grain size plot for the investigated sands in the studied wells (After Asquith and Gibson, 1982)

are also very fine grained; for Kinasar 01, well fine grained to very fine grained size reservoir sands are present; most of the reservoir sands in Ziye 1 well are mainly coarse grained; in Murshe 01, the range is from medium to very fine sands.

Using the plot of S_w versus Φ to determine if the sands are at irreducible water saturation, Asquith and Gibson (1982) suggests that if the data points plot along the hyperbolic curves of BVW (Figure 9a), the sands are at irreducible water saturation. However, if the data points are scattered, then the sands are no longer at irreducible water saturation.

From Figures 9b to 9f, it is obvious that with the exception of Ziye 01 well, the sands in each well are not at irreducible water saturation and thus are expected to flow

water along with hydrocarbon. The data points for Ziye 01 as shown on Figure 9e plot approximately along the hyperbolic curve of BVW = 0.02 indicating that the bulk volume of water is consistent and that the sand units are close irreducible water saturation. Hence it is expected that the hydrocarbon will be produced along with a minimal quantity of water. These observations conform to the deductions made from the values of BVW.
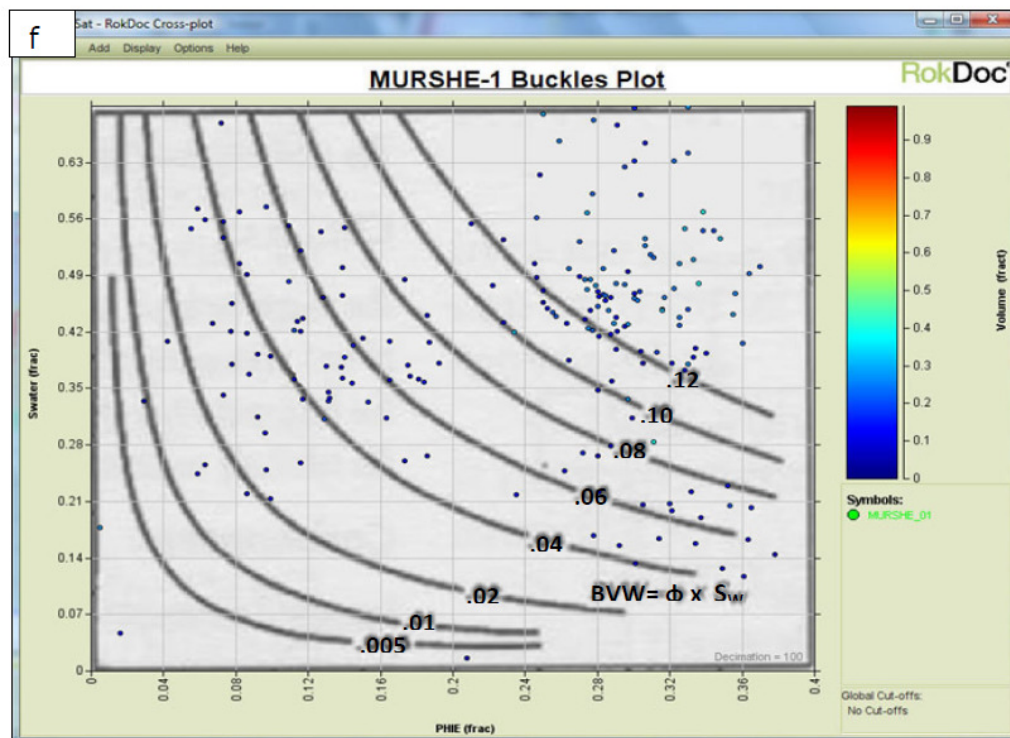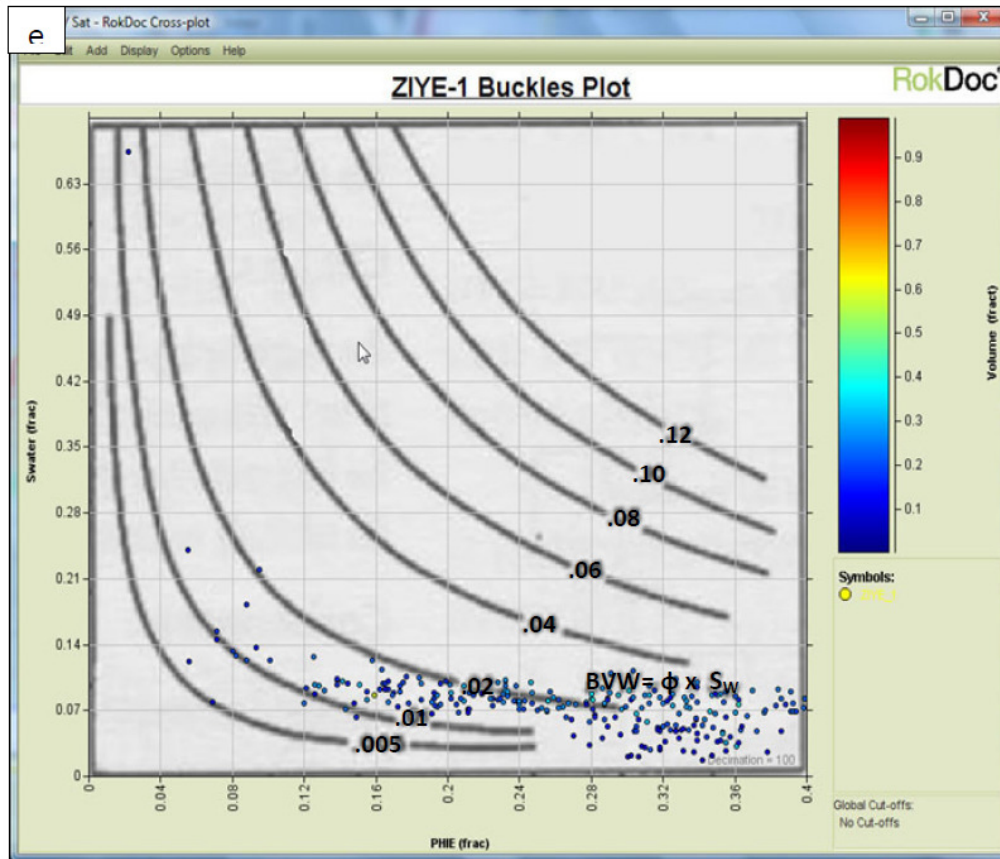
Conclusions

Reservoir characterization of the Gombe sandstone (Chad basin) was carried out using five petrophysical well logs. Four prospective reservoirs labeled Sands 1 to 4
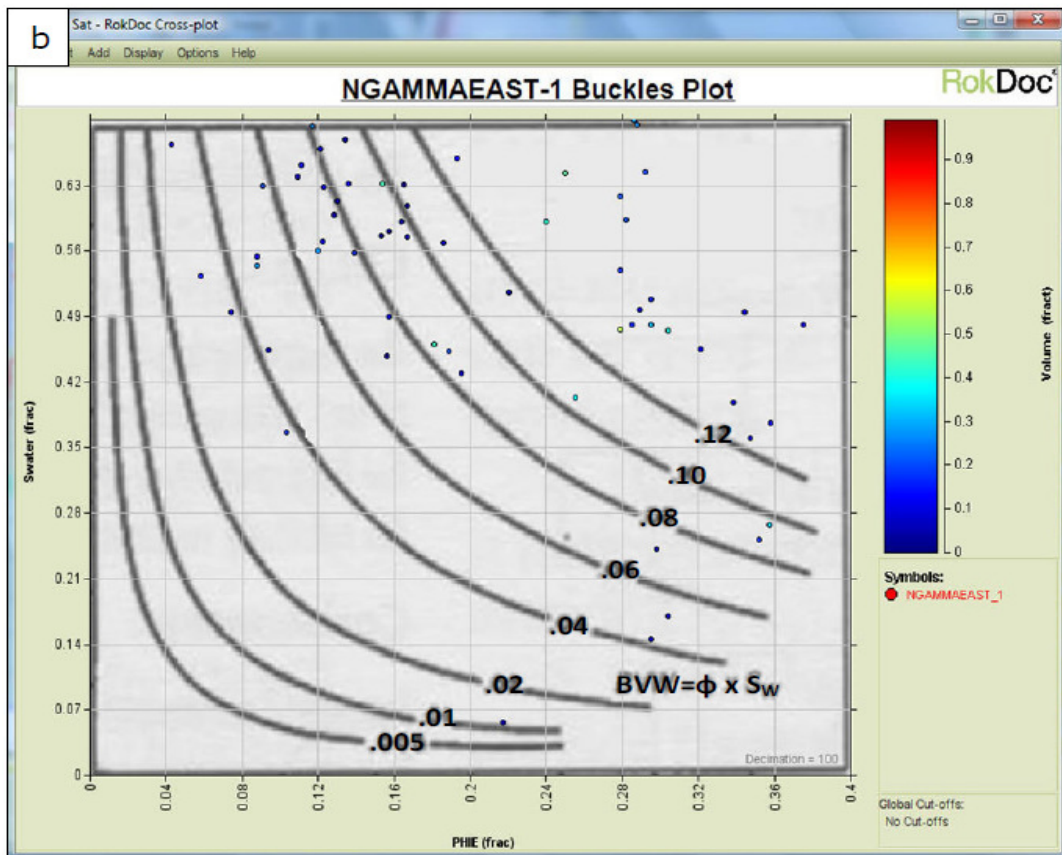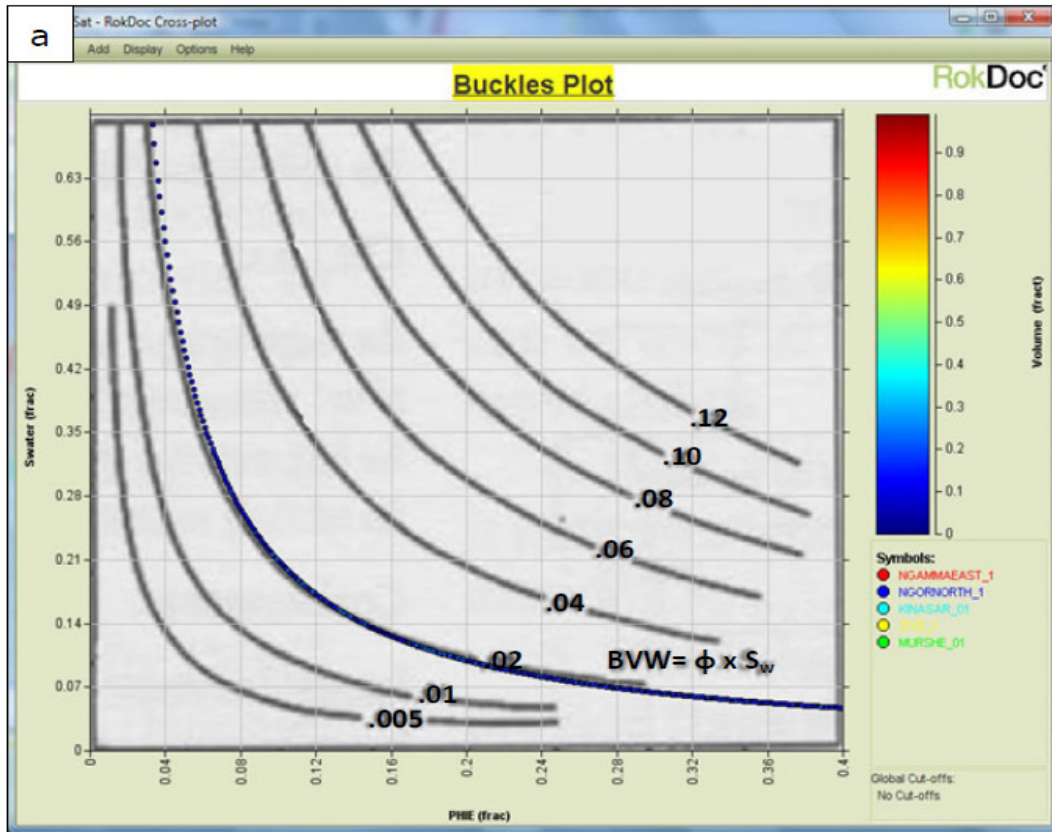
Figures 9a- b. Plot of S_w versus. Φ showing sands at irreducible water saturation.
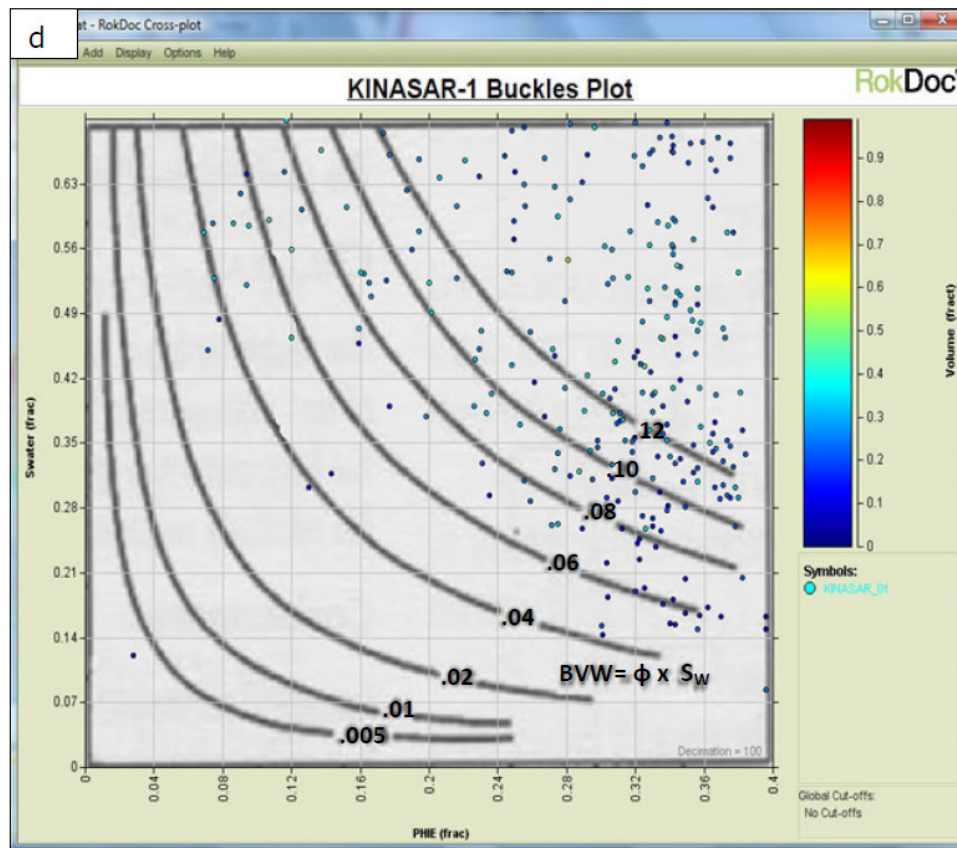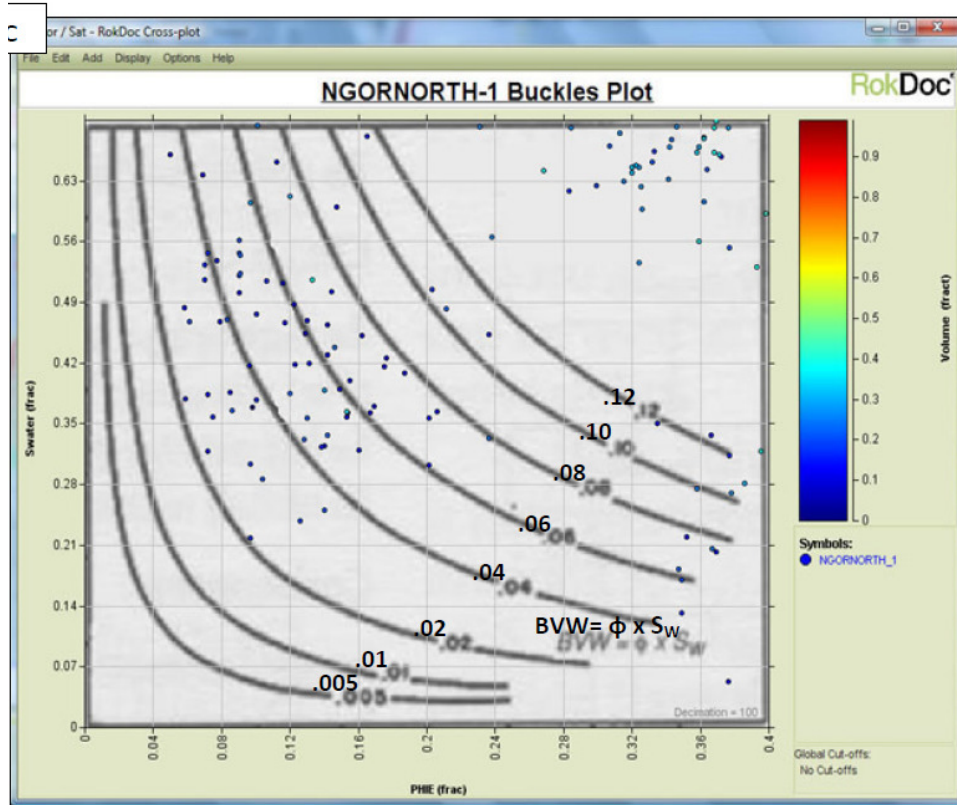
Figures 9c – d. Buckle plots for Ngornorth-1 and Kinasar 01

Figures 9e – f. Buckle plots for Ziye 01 and Murshe 01. The sands in all the wells are not at irreducible water saturation, except in Ziye 01 where the data points align along the BVW hyperbolic curve.

were delineated and correlated. The characterization of the four reservoirs of interest within wells Ngammaeast 01, Ngornorth 01, Kinasar 01 Ziye0 1, and Murshe 01 shows that the sand units have thicknesses varying from 32.01 to about 225.18 m; NGR values ranging between 5.93 and 94.34%; average effective porosity ranging between 14.88 and 34.74%; average volume of shale varying between 12.11 and 36.65%; average water saturation between 3.83 and 97.00%; average hydrocarbon saturation values going from 3.00 to about 96.17%; and average permeability varying between 5903 and 90836.5 mD.

The NGR values indicate the presence of quality potential reservoir rocks. The values also helped in suggesting the trend of deposition which is inferred to be going east-west, that is, proximal-distal. Also, from the NGR sand maps, NGR values can be interpolated and predicted for wells drilled at locations between studies wells. The porosity values obtained fall within the stipulated porosity range for sands and sandstone reservoirs (Schlumberger, 1989). These values indicate potential reservoir rocks of optimal porosity. The permeability values fall in the range of permeability values of producing formations which is extremely wide, and this is from 0.1 to over 10,000 mD (Schlumberger, 1989). Thus, it can be conclusively said that the porous sand beds are also permeable, thus enhancing effective fluid flow. The hydrocarbon saturation obtained suggests that the study area might contain hydrocarbon in non-commercial quantities. The petrophysical interpretation of the identified sand units in the study area thus suggests that Gombe formation of the Chad Basin is a prospective hydrocarbon reservoir. The lithology of the study area is essentially fine grained sand, siltstone and local occurrence of coal seams. The Gombe sandstone directly overlies the Fika shale so that the proportion of shale in the upper parts of the studied zone is low and increases as depth increases, that is, towards the bottom of the wells.

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