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Full Length Research Paper

Statistical analysis and evaluation of lithofacies from wireline logs over 'Beleema' field, Niger Delta, Nigeria

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A statistical analysis of well-log data for the purpose of estimating and evaluating lithofacies with depth, around 'Beleema' field, Niger Delta, was carried out. The principal component analysis (PCA) technique and the bulk volume water and the grain size relationships formed the main principles of analysis. The PCA was applied to selected lithology-sensitive logs, each serving as a variable within the trivariate statistical system. It involved determining the first principal component (PC1) in each well, plotting them against depth and segmenting into intervals with similar statistical characteristics. The gamma ray log was used as control for the segmentation. A total of forty-three (43) electrofacie-blocked units, grouped into two major facies - sand and shale (major) - as well as two shaly-sand and sandy-shale (minor), were identified within the wells studied. Also, the bulk volume water (BVW) was observed to vary from 0.0224 in coarse grained sand facies to 0.0892 in silt grained sand facies. The grain size values obtained varied from about 0.0625 mm in silt grained facies to a range of 0.5 to 1.0 mm in coarse grained facies. The computed BVW curves closely mimic the field gamma ray traces; such that the former could be confidently employed where the latter is unavailable.

Key words: Lithofacies, principal component analysis (PCA), bulk volume water (BVW), irreducible water saturation and producibility.

INTRODUCTION

Lithofacies identification is important for many geological and engineering disciplines. Lithofacies, rock or sediment units, characterized by texture or other features can be used to correlate and predict important reservoir characteristics such as permeability and porosity (Chikhi et al., 2005). Identifying various lithofacies of the reservoir rocks is a primary task for petroleum reservoir characterization.

Traditionally, lithofacies are identified from cores. However, while core data provide direct observations of lithofacies, they are costly to acquire and recovery is often less than 100% as they seldom encompass the entire stratigraphic interval of interest (Chang et al., 2000). Also, core description can be time consuming and dependent on geologists' extensive wealth of experience. Therefore, an alternative lower-cost method yet providing similar or improved accuracy and resolution is desirable.

A number of approaches have been applied in the estimation and evaluation of lithofacies from well log data; all of which involve intense computer analysis and programming. Some of these methods include the hybrid neural networks which combine probabilistic neural method with radial-bias function (Chikhi et al., 2005), clustering method, litho quick- look approach and the multidimensional histogram approach (Frew, 2004) and cluster analysis technique (Saggaf and Nebrija, 2000). Others include Doveton (1986) who provided a clue to mathematical analysis of log trends and patterns and Elek (1988) who showed how principal-component analysis could be applied to zonation and well-log correlation. Asquith (2004) related the bulk volume water (BVW) with the grain sizes of facies with depth.

In this paper, we have subjected a suite of well-logs obtained from the "Beleema field" of the Niger Delta to the principal component analysis (PCA). The PCA technique is a procedure that transforms a number of

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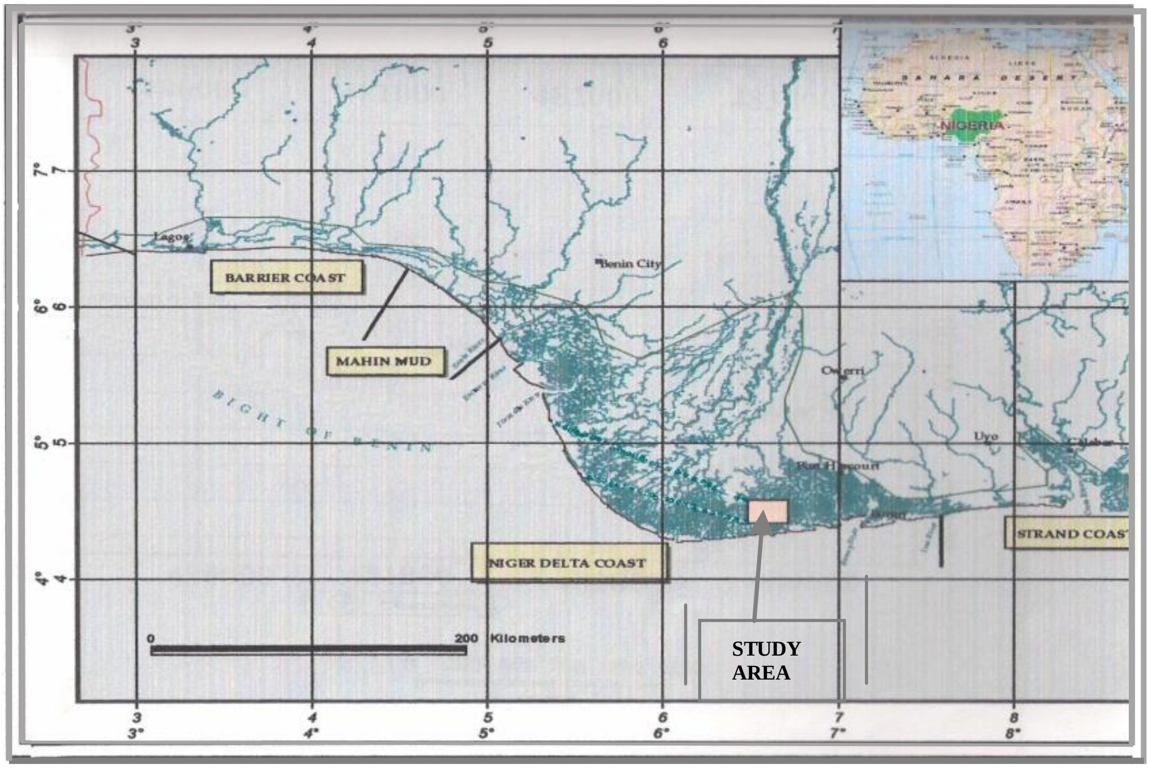

Figure 1. Map of the Nigerian Coastline (Awosika and Folorunso, 2002) showing the study area.

possibly correlated variables into a smaller number of uncorrelated variables called principal components. The first principal component accounts for the variability in the data while the succeeding components account for as much of the remaining variability. In doing this, the mean, standard deviation, variance and covariance were computed. The covariance matrix obtained is resolved to obtain the eigenvectors and the eigenvalues of the data set. The variable that accounts for the most variability is usually depicted by the possession of the highest eigenvalues and hence represents the first principal component.

In the study, the PCA method and the grain size technique were integrated to proffer a statistical approach to the estimation of the facies and evaluate their producibility. Not only does the PCA assist in the estimation of lithofacies, it is useful in the reduction of the error thus ensuring accuracy of prediction. The method is amenable to direct digitized numerical well log data values. The results can then be used to predict lithofacies in non-cored wells (or un-cored intervals in cored wells) or more especially in wells that do not have useful lithofacies identification logs (Chang et al., 2000).

The use of the gamma ray log as control in the estimation is to provide information on the subsurface geology which is useful in bridging the gap between the geologists and the engineers. It also helps to integrate the statistical analysis with the geology of the environment with a view to maximize the accuracy of the estimation.

Location and geology of the study area

The Niger Delta province is situated in the Southern part of Nigeria between latitudes 4 and 6°N and Longitudes 3 and 9°E (Nwachukwu and Chukwura, 1986). The location of 'Beleema' Field (Figure 1) is situated in the Gulf of Guinea which is part of the Niger Delta Province. From the Eocene to the present, the delta has prograded south-westward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990).

These depobelts form one of the largest regressive deltas in the world with an area of about 300,000 km^2 (Kulke, 1995), a sediment volume of 500,000 km^3 and a sediment thickness of over 10 km in the basin depocenter. The Niger Delta Province contains only one identified petroleum system (Kulke, 1995; Ekweozor and Daukoru, 1994). This system is referred to as the Tertiary Niger Delta (Akata–Agbada) Petroleum System

Lithostratigraphy

The regional lithostratigraphy of the Niger Delta reveals that it consists of three broad facies units or formation.

These are the continental top facies (Benin Formation), the paralic delta front facies (Agbada Formation) and the Akata Formation which is the pro-delta facies (Short and Stäuble, 1967). The Benin Formation is the shallowest unit and occurs throughout the entire onshore and part of the offshore Niger delta and very little hydrocarbon accumulation has been associated with its highly porous and generally fresh water-bearing sand (Short and Stauble, 1967). It consists predominantly of fresh water-bearing continental sands and gravels deposited in an upper deltaic plain environment. The overall thickness of the Formation varies from 1000 feet(305 m) in the off-shore to 10,000 feet (3050 m) onshore. Various structural units are identifiable within the formation: point bars, channel fills, and natural levees. The oldest known age of the Benin Formation at the surface is Miocene while at the subsurface, Oligocene.

The Agbada Formation underlies the Benin Formation and consists of alternation of coastal fluviomarine sand, siltstone and shale. The formation occurs in the subsurface throughout the entire Niger Delta area with thickness ranging from 300 to 4500 m. Most structural traps observed in the Niger delta developed during syn-sedimentary deformation of the Agbada paralic sequence (Evamy et al., 1978). The primary seal rock is the interbedded shale within the Formation.

The Akata Formation is the basal sedimentary unit and it is characterized by uniform dark grey marine shale, deposited as the high speed delta advance into deep water. It consists of sandstone, siltstone and plant remains in the upper parts - rich in fauna of both planktonic and benthonic type. The Akata shales are typically under-compacted and over-pressured and form diapiric structures including shale swells and ridges which often intrude into overlying Agbada Formation. The Akata Formation is thought to be the main source rock of liquid hydrocarbon in the Niger Delta complex.

MATERIALS AND METHODS

The materials used for this study include: bulk density (RHOB), gamma ray (GR), neutron porosity (NPHI), sonic (Δt), deep resistivity (RES), and water saturation (S_w) logs and the base map of the study area. These lithology-sensitive logs were selected from four of the six wells in the field; the two others were used for bulk volume water estimation and grain size analysis. In each well, digitized log data from three lithology identification well-logs were imported from their '*Excel*' or '*ASCI*' formats unto the '*MATLAB*' scientific package. The three selected logs were turned into a population of numerical data sets having zero mean and unit variance. They were then subjected to principal component analysis. The well-log in each well whose eigenvector has the highest eigenvalues becomes the first principal component (PC1) that is, it contains the highest degree of variability of the log data which are representative of lithofacies.

These first principal component logs were selected and segmented (blocked) into intervals of similar statistical behavior. The bulk volume water (BVW), that is, the product of the average water saturation of each facies and the corresponding effective porosity, as computed from either the density or neutron logs, was estimated for the interval under consideration. The BVW values were subsequently used to classify the facies into grain size ranges (Asquith, 2004).

Both the bulk volume water and the grain sizes were used to predict the producibility of the entire interval; since at irreducible water saturation, it is expected that the facies would produce water–free hydrocarbon. The producible reservoir facies identified in the selected wells were correlated with their respective grain sizes using the gamma ray (GR) log. Correlations of the first principal components were also carried out with the predicted facies.

Theoretical background

The principal component analysis is a classical statistical method of analyzing, discriminating and reducing high dimension data. It involves the conversion of a multivariate set of closely correlated variables into a set of values of uncorrelated variables called principal components, via the eigenvector-eigenvalue based statistical approach. The number of the principal components may be less than or equal to the number of the original variables.

The procedure involves calculating the variance of the entire multivariable system; comparing the variances to obtain a covariance matrix, from where the eigenvalues as well as the eigenvector are deduced. The variance and eigenvalue of the variables are a function of the degree of variability in the data. Hence, the first principal component (PC1) is significant and important in that it not only accounts for as much of the variability in the data set compared to all other principal components, but also reveals the variable having the strongest pattern of distribution among the variables.

The major advantage of the PCA is that it helps in identifying patterns in data, thus expressing the data in such a way as to highlight their similarities and differences. Since patterns in data can be hard to find in data of high dimension, where the luxury of graphical representation is not available, PCA is a powerful tool for analyzing data. The other advantage of PCA is that, once these patterns are found in the data, it is possible to compress or reduce the number of dimensions, without much loss of information.

RESULTS AND DISCUSSION

In all, wireline logs from four of the six wells procured from the study area were used for the estimation and evaluation of the lithofacies. Wells 2, 4, 5 and 6 had gamma ray, neutron, density, resistivity logs (the dual laterolog) and sonic logs, for the PC analysis. Wells 1 and 3 had effective porosity (E-PHI), $V_{shale,}$ and caliper logs, for BVW estimation and grain size analysis. Where these logs were unavailable, the S_w and Φ_e were computed using the Archie (1942) formulation. The gamma ray log (being a primary lithology log) was used as control log in the blocking (or segmentation) of the first principal component traces. The generated bulk volume water (BVW) traces were used to predict the grain sizes of the respective facies which were in turn related to the irreducible water saturation (S_{wir}) from which the producibility of such facies was deduced. The details are presented in the following.

Principal component analysis (PCA)

Table 1 shows the results of the PCA obtained from wells

Table 1. Results of principal component analysis in wells 2, 4, 5 and 6.

Wells	Well 2			Well 4			Well 5			Well 6		
Variable	**ΔT**	**GR**	**RES**	**NPHI**	**LLD**	**RHOB**	**LLD**	**RHOB**	**NPHI**	**RES**	**RHOB**	**NPHI**
Mean	124.9	28.9	147.7	0.345	5.49	2.085	106.2	2.18	0.345	32.6	2.1340	0.340
Standard deviation	2.85	14.9	83.73	0.082	2.25	0.239	56.6	0.096	0.065	43.4	0.0574	0.073
Variance	8.14	222.5	7011.1	0.007	5.068	0.057	3206	0.008	0.004	188	0.0033	0.005
	8.14	13.44	-81.8	0.006	-0.08	-0.01	-0.08	-0.004	0.004	188	-0.143	-0.67
Covariance	13.4	222.5	-858	-0.11	0.245	0.057	1.61	0.009	-.004	-0.1	0.0033	-0.00
	-81.8	-858	7011	-0.08	5.096	0.245	3205.	1.6147	-0.09	-0.7	-0.001	0.005
	0.99	0.03	-0.011	0.973	-0.02	-0.231	-0.00	0.5047	0.863	0.000	0.000	0.999
Eigenvectors	-0.03	0.99	-0.123	0.232	0.04	0.972	0.00	-0.863	0.504	0.896	-0.45	8.461
	0.01	0.12	0.992	0.004	0.99	-0.051	0.99	0.0006	-2.76	0.444	0.896	0.001
	7.08	0.00	0.00	0.003	0.00	0.00	0.00	0.0000	0.002	0.01	0.000	0.000
Eigenvalues	0.00	116	0.00	0.000	5.11	0.00	0.00	0.0097	0.000	0.00	0.006	0.000
	0.00	0.00	7119	0.000	0.00	0.05	3206	0.0000	0.000	0.00	0.000	188.1
Percentage	0.009	1.59	98.30	0.012	99.0	0.93	99.9	0.0003	0.001	0.01	0.003	99.95

2, 4, 5 and 6. In well 2, the selected logs were the sonic, gamma ray and resistivity logs and the computed means respectively. The process revealed the highest value of standard deviation in the resistivity log with a value of 83.73 Ω-m. while the lowest value of 2.85 μs/feet was recorded for the sonic log. The variances of each data set also showed the highest value in the resistivity log while the lowest was in the sonic log.

An estimation of the covariance revealed a three by three matrix; resolved to produce the eigenvalues for the trivariate system, a diagonal matrix having values of 7.08 μs/feet, 116 API and 7119 Ω-m in sonic, gamma ray and resistivity logs respectively. This result showed that most of the variability was contained in the resistivity log; thus constituting the first principal component (PC1) in the well. The first principal component was selected and transformed into its principal component trace and segmented into eleven (11) electrofacies zones while the gamma ray log served as control. Similarly, wells 4, 5 and 6 had 11, 11, and 10 electrofacies zones respectively (Figure 2), totaling forty three (43). were 124.9 μs/feet, 28.9 API and 147.73 Ω-m

Figure 2 shows the observed inverse relationship between resistivity and the gamma ray response for the wells studied. The 'highs' on the gamma ray log coincide with the 'lows' on the resistivity logs and vice versa. Such areas are C2, C4, C6, C8 etc. This is characteristic of a facies unit dominated and influenced by quartz (Barrash et al., 1997). We adduce the fairly low gamma ray log response observed to the presence of scanty radioactive materials in sand while the relatively high resistivity values are a reflection of the low conductivity of the sandy materials. Facies recognized with these characteristics therefore reflect that of a shaly-sand. The sand-bearing facies are characterized by very low gamma ray responses and high resistivity; for depth intervals of 4,650 to 4,900 feet (1417.32 to 1493.52 m) and 4,910 to 5,090 feet (1496.57 to 1551.43 m); notwithstanding observed occasional thin shale lenses.

In all, a total of 11 electrofacies zones were delineated into shaly-sand, sandy-shale, sand and shale. These are identified as C1 through C11 (Figure 2).

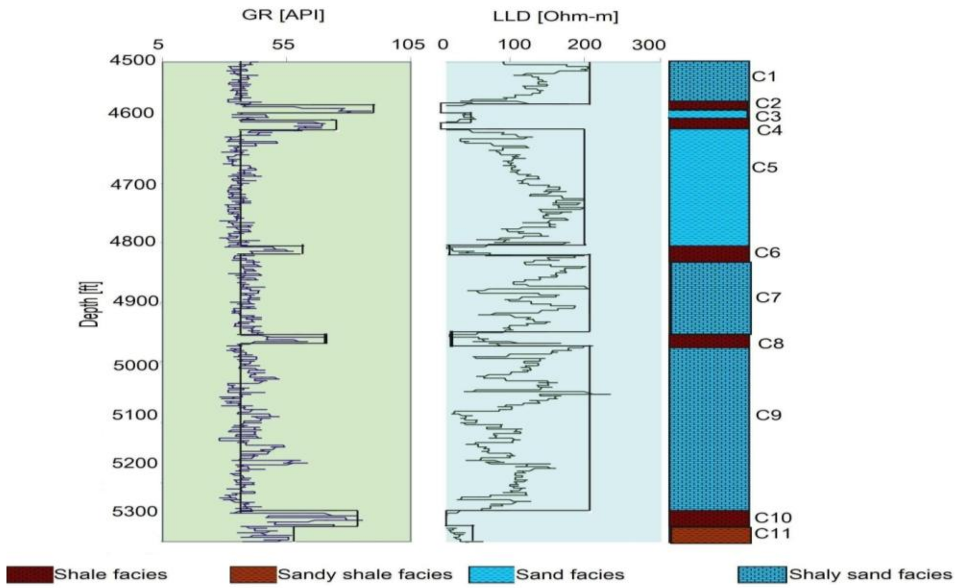

Figure 2. The segmented gamma ray (blue), PC1 (black) and the interpreted facies in well 4.

Similarly, in well 4, the neutron, deep laterolog and the density logs were analysed and the estimated mean for the three logs were found to be 0.345, 5.49 Ω -m and 2.085 g/cc respectively (Table 1). The standard deviation and the variance showed the highest value in the deep resistivity (laterolog) with values of 2.25 and 3.0956 Ω-m respectively. This is in contrast to the low values recorded for the bulk density and the neutron logs observed to be 0.239 and 0.057 g/cc in the density log and 0.082 and 0.007 in the neutron log.

The covariance matrix obtained for the three well logs, when resolved statistically, produced a group of eigenvectors whose eigenvalues were computed to be 0.003, 5.11 Ω-m and 0.05 g/cc for the neutron, deep laterolog and the density logs respectively. From the analysis, most of the variability, therefore resided in the deep laterolog; hence the first principal component.

Transformation of the principal component and segmentation produced eleven (11) blocked electrofacies zones (Figure 2) grouped into shaly-sand, sandy-shale, sand and shale. The shaly sand facies occur at a depth of 4,500 to 4,570 feet (1371.6 to 1392.94 m) and 4,800 to 4,820 feet (1463.04 to 1469.13 m) and are designated C1 and C6. The sand bearing facies occurs at depths of 4,610 to 4,800 feet (1405.13 to 1463.04 m), 4.810 to 4,940 feet (1466.09 to 1505.71 m) and 4,970 to 5,250 feet (1514.86 to 1600.20 m) and has been designated C5, C7 and C9.

In well 5, mean values were 106.2 Ω-m, 2.18 g/cc and 0.345 for the deep laterolog, density and the neutron logs respectively, and standard deviation values were 56.6 Ω-m, 0.096 g/cc and 0.065 respectively. The variance is highest in the deep laterolog with values of 3206 Ω-m, and lowest in the neutron log with values of 0.004; density values being 0.008 g/cc. The first principal component was the deep laterolog and the gamma ray served as control for the transformation and segmention to produce eleven (11) electrofacies-blocked zones (not shown) grouped into four facies viz: sand, shaly sand, sandy shale and shale bodies.

The sand bearing facies at depths of 4,675 to 5,075 feet (1424.94 to 1546.86 m) shows a characteristic increase in the resistivity response but a lower gamma ray response due to low radioactive materials present in them. However, a shaly-sand facies, characterized by a sharp increase in the resistivity response and a sudden drop in the resistivity response, interrupted the sequence at a depth of 4,800 feet. This suggests the possible presence of a gaseous hydrocarbon. Shaly sand facies occurs at a depth interval of 4,500 to 4,570 feet (1371.6 to 1392.94 m) while a sandy shale occurs at a depth interval of 5,080 to 5,120 feet (1548.38 to 1560.58 m).

In well 6, the mean values of 32.6 Ω-m, 2.1340g/cc and 0.341 were recorded for the resistivity, density and the neutron logs respectively. The standard deviation also increased in that order with resistivity log having the highest value of 43.4 Ω-m and the density and neutron logs with values of 0.0574g/cc and 0.073 respectively. However, the variance was highest in the resistivity log (1883 Ω-m) but lowest in the neutron log (0.0033). It was found to be moderate in the density log, (0.005 g/cc). A resolution of the covariance matrix obtained from the analysis revealed eigenvectors having eigenvalues of0.002 Ω-m, 0.0056g/cc and 188.1 in the resistivity, density and neutron logs respectively. The neutron log was therefore identified as the PC1.

The first principal component in the well, Neutron log and the gamma ray log, when transformed and segmented

Table 2. Computed bulk volume water and grain size analysis of delineated facies.

Well 4					Well 5				
DI [m]	**FU**	**BVW**	**GSR[mm]**	**DF**	**DI [m]**	**FU**	**BVW**	**GSR [mm]**	**DF**
1372-1389	C1	0.0347	0.025 - 0.035	Medium grain shaly sand	1372-1389	C1	0.0263	0.025-0.035	Medium grain shaly sand
1389.8-1395.5	C2	0.0693	0.05- 0.07	Very fine grain shale	1389.6-1402.0	C2	0.0681	0.05-0.07	Very fine grain shale
1396.0-1402.1	C3	0.0752	0.07 - 0.09	Silty sand	1402.1- 1414.3	C3	0.0439	0.035-0.05	Fine grain sand
1402.1-1408.2	C4	0.0653	0.05- 0.07	Very fine grain slide	1414.3-1456.9	C4	0.0519	0.05-0.07	Very fine grain shale
1408.2-1463.0	C5	0.0403	0.035-0.05	Fine grain sand	1426.5-1456.9	C5	0.0416	0.035-0.05	Fine grain sand
1463.0-1471.0	C6	0.0520	0.05-0.07	Very fine grain shaly sand	1456.9-1463.0	C6	0.0573	0..05-0.07	Very fine grain shaly sand
1470.9-1508.8	C7	0.0249	0.02- 0.025	Coarse grain sand	1463.0-1553.9	C7	0.0224	0.02-0.025	Coarse grain sand
1509.1-1514.9	C8	0.0555	0.05-0.070	Very fine grained shale	1553.9-1562.1	C8	0.0531	0.05-0.07	Very fine grain shale
1515.2-1600.0	C9	0.0340	0.025-0.035	Medium grained sand	1562.1-1571.2	C9	0.0872	0.07-0.09	Silty grain sand
1600.2-1607.8	C10	0.0576	0.05-0.070	Very fine grained shale	1571.2-1581.9	C10	0.0536	0.05-0.07	Very fine grain shale
1607.8-1615.0	C11	0.0892	0.07- 0.09	Silty sand	1581.9-1615.4	C11	0.04201	0.035-0.05	Fine grain sand
			Well 6						
1372 -4630	C1	0.0333	0.025-0.035	Medium grain shaly sand					
1411.2-1414.3	C2	0.0503	0.05 - 0.07	Very fine grain shale					
1414.3- 1417.3	C3	0.0467	0.035 - 0.05	Fine grain sand					
1417.3-1420.4	C4	0.0564	0.05 - 0.07	Very fine-grain shale					
1420.4-1447.8	C5	0.0341	0.025 - 0.035	Medium grained sand					
1447.8-1450.8	C6	0.0512	0.05 - 0.07	Very fine grain shaly sand					
1450.8-1478.3	C7	0.0243	0.02 - 0.025	Coarse grain sand					
1478.3-1505.7	C8	0.0625	0.05 - 0.07	Fine grain shaly sand					
1505.7-1600.2	C9	0.0302	0.025 - 0.035	Medium grain sand					
1600.2-1615.4	C10	0.0848	0.07 - 0.09	Silty shale					
-	-	-	-	-					

DI: delineated interval; FU: facies unit; BVW: bulk volume water; GSR [mm]: grain size ranges; DF: delineated facies.

produced ten (10) electrofacie- blocked zones comprising shaly-sand, sand and the shale bodies.

The shaly-sand occurs between the depths of4, 500 to 4,600 feet (1371.6 to 1402.08 m), 4,850 to 4,950 feet (1478.28 to 1508.76 m) and 4,730 to 4,760 feet (1441.7 0 to 1450.85 m). They are characterized by a generally low density response but having intermittent increase in dense shale material in them. Sand bearing facies, however occurs at depths of 4,660 to 4,720 feet (1420.37 to 1438.66 m), 4,760 to 4,850 feet (1450.848 to 1478.28 m) and 4,940 to 5,260 feet (1505.71 to 1603.25 m). They are generally characterized by low bulk density responses.

Bulk volume water estimation and grain size analysis

The bulk volume water was estimated for the

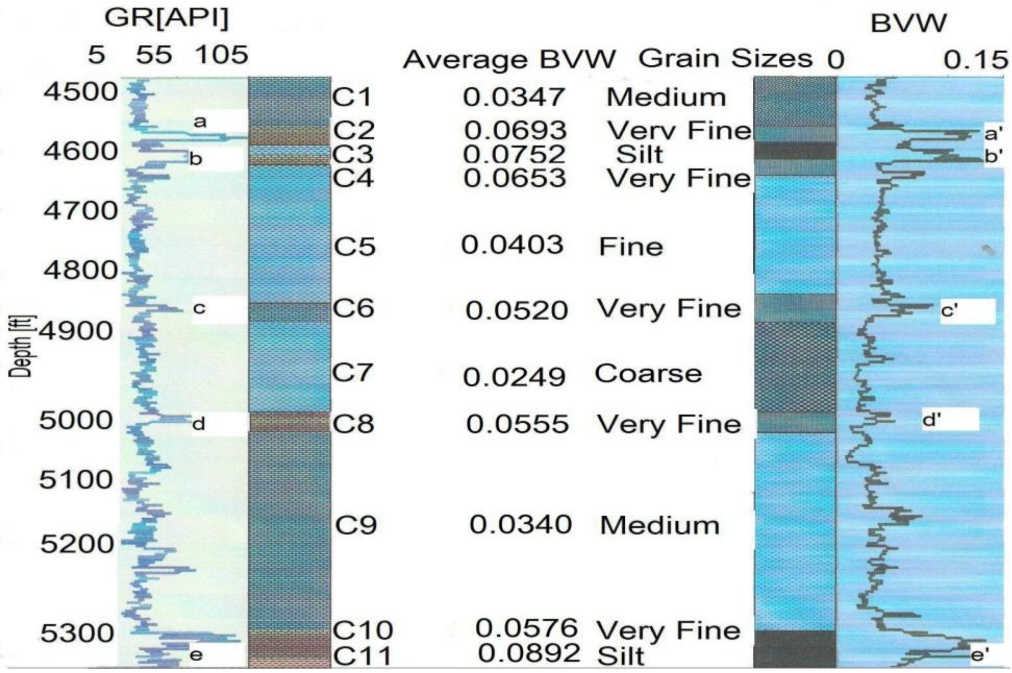

Figure 3. Bulk volume water at Irreducible water saturation correlated with gamma ray log in well 4.

entire depth interval that is, 4500 to 5300 feet (1371.6 to 1615.4 m). Table 2 shows the results as computed in wells 4, 5, and 6. The grain sizes (Asquith, 2004) were also deduced. Usually, the lower the values of the bulk volume water, the lower the irreducible water saturation, hence the higher the hydrocarbon saturation. At this point, the facies materials usually possess coarser grain texture. Conversely, the finer the facies material, the higher the bulk volume water value; and so the higher the irreducible water saturation (S_{wir}). At this point, the reservoir facies becomes less productive; producing a great deal of water with little or no hydrocarbon.

Well 4

Table 2 shows the results of the BVW and the grain sizes of the delineated facies in well 4 for the depth interval of interest. Further, Figure 3 shows the correlation of the computed bulk volume water at irreducible water saturation with the field gamma ray log in the well. The BVW values ranged from as low as 0.00249 in medium grained sand facies to as high as 0.0892 in fine grained silt. The low values were encountered in facies C1, C5, C7 and C9, the lowest being at C7, C1 and C9. Hence these facies would be at relatively low irreducible water saturation, hence their producibility increases from C9 to C1 and finally to C7 (Figure 3).

In Figure 3, a strong correlation was observed to occur between the gamma ray trace and the bulk volume water trace in the well. Increase in the bulk volume water value showed a corresponding increase in the gamma ray values (points a/a´, b/b´ to……….. e/e´ etc., Figure 3). This can be explained by the fact that very fine grained materials in shale contain more pore spaces that hold back more amount of water in its matrix, hence leading to higher bulk volume water values.

The bulk volume water estimate increases from as low as 0.0263 in a medium grained shaly sand facies to as high as 0.0872 in the silt in the well. From the grain size analysis, a coarse grained sand facies was encountered at a depth of 4,820 to 5,080 feet (1469.14 to 1548.38 m) while a medium grained shaly-sand facies exists at a depth of 4,500 to 4,550 feet (1371.6 to 1386.84 m). Fine grained sand facies are encountered at depths of 4,680 to 4,795 feet (1426.46 to 1461.52 m), 5,250 to 5,300 feet (1600.2 to 1615.44 m) and 4,600 to 4, 640 feet (1402.08 to 1414.27 m) (Table 2).

From the analysis, the bulk volume water (BVW) estimate showed that there exist low values at facies C7, C1. These derived values possibly implied that these two facies are at irreducible water saturation and the grain sizes are larger, with C7 having a coarser grain size while C1 has a medium grained size. Hence they are more producible than any other facies in the well (Figure 3).

Well 6

In well 6, the bulk volume water increases from as low as 0.0243 in the sand facies in C7 to as high as 0.0848 in silt. Grain size analysis revealed a medium grained shaly-sand at depths of 4,500 to 4,620 feet (1371.6 to 1408.18 m) and medium grained sand at 4,940 to 5,500 feet

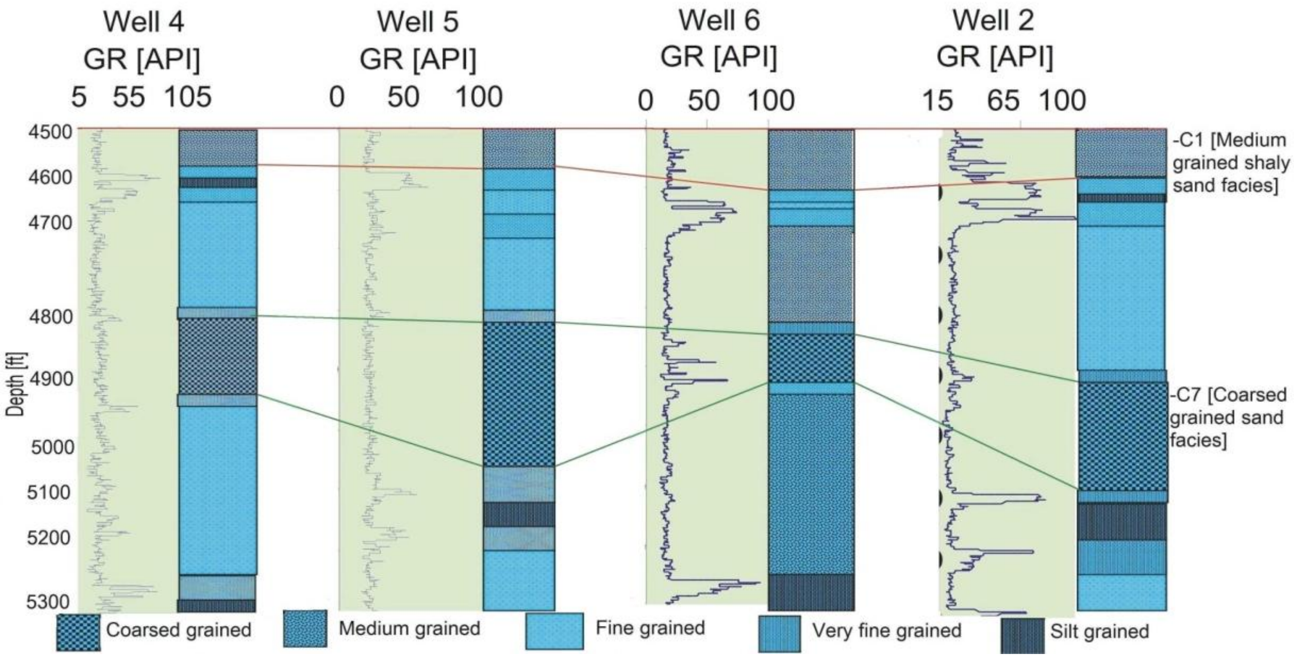

Figure 4. Reservoir facies correlation of gamma ray log with grain sizes in wells 4, 5, 6 and 2.

(1505.71 to 1676.4 m). Coarse grained sand was encountered at a depth of 4,760 to 4,850 feet (1450.85 to 1478.28 m).

The decrease in the bulk volume water in facies C1, C5, C7 and C9 possibly indicate that these facies are at irreducible water saturation, and hence a larger grain sizes than the others in the well. They all have higher porosity and permeability and hence higher producibility.

Reservoir facies correlation

Having identified the producible facies units in each well using the bulk volume water and the grain sizes, a relationship between the grain sizes of the entire interval under consideration is established with that of the gamma ray response by correlation in order to predict the reservoir facies in the entire interval. The result is as shown in Figure 4.

The reservoir facies correlation indicates that producible facies that may be of interest are those of facies C1 and C7 due to their low bulk volume water (0.0347 and 0.0249) respectively (Figure 3). Thus, this indicates low irreducible water saturation. Also, their large grain sizes are indicative of high porosity and permeability

Conclusion

The principal component analysis technique has been effectively applied to well-log data obtained from the Beleema field in Niger Delta to evaluate lithofacies of similar statistical characteristics and their behavior. The variables have been selected in four wells and segmented into depth intervals of similar statistical behavior using gamma ray log as control. A resultant forty-three (43) electrofacie-blocked units (Figure 4) were delineated in the four of the six wells studied and were grouped into major and minor facies.

The result of the BVW analysis revealed varied bulk volume water values from as low as 0.0224 in coarse grained sand to 0.0892 in silt grained sand facies. From these, the grain sizes of the facies units as well as their respective producibility were deduced. The facie grain sizes varied from as high as 1.0 to 0.5 mm and 0.5 to 0.25 mm in coarse sand facies and medium grained shaly-sand facies respectively. Grain size values less than 0.0625 mm were associated with silt in the shale body. The producible coarse grained sand facies were found to possess very low bulk volume water of 0.0249, 0.0224 and 0.0243 in wells 4, 5 and 6 respectively. Also, the producible medium-grained sand facies were found to have bulk volume water of 0.0347, 0.0263 and 0.03333 in wells 4, 5, and 6 respectively. These two producible facies were at low irreducible water saturation and of higher grain sizes. Increase in the bulk volume water value showed a corresponding increase in the gamma ray values. This could be due to the fact that very fine-grained materials in shale contained more pore spaces that hold back much water in its matrix, hence leading to higher bulk volume water.

From the analysis, a strong visual correlation between the gamma ray and the bulk volume water traces was observed in the wells; indicating the possibility of employing the bulk volume water trace as a surrogate for facies estimation in the absence of gamma ray log.

Based on the results, coupled with the grain sizes and information from predicted irreducible water saturation, two viable and producible reservoir facies were mapped and correlated within the depth interval of study. These were the medium grained shaly-sand facies at a depth of 4500 to 4580 feet (1371.6 to 1395.98 m) and the coarse grained sand facies at a depth of 4900 to 4980 feet (1493.52 to 1517.90 m). The observed good correlation between the gamma ray and the bulk volume water (BVW) traces suggests that the latter could be employed in areas where the former is unavailable.

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