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Estimation of Reservoir Potentials of Two Wells in Niger Delta Region, Nigeria

A. O. Ebuka[1], A. O. Akankpo[1,*], U. E. Essien[2]

[1]Department of Physics, Faculty of Science, University of Uyo, P. O. Box 1017, Uyo, Akwa Ibom State, Nigeria
[2]Department of Science Technology, Akwa Ibom State Polytechnic, Ikot Osurua, Akwa Ibom State, Nigeria
*Corresponding author: akankpo@yahoo.com

Abstract This study provides accurate behaviour of petrophysical properties with depth for this formation by using Interactive Petrophysics software. The results of the analysis revealed the presence of different sand and shale units. From the analysis of the geological logs comprising gamma-ray and electrical resistivity, the Sonic, Density, Gamma, Neutron, Resistivity and Net Pay Zone value for the reservoirs of the two wells are 110.604 µs/ft., 341.659 µs/ft.; 2.180 g/cc, 2.195 g/cc; 52.782 API, 97.50API; 0.343, 0.52; 8.148 ohmm, 41.651 ohmm and 3295.5 ft, 2301.0 ft, the total porosity in the hydrocarbon bearing zone was found to range from 0.006 to 0.514, the water saturation range from 0.166 to 0.836 and the hydrocarbon saturation 0.164 to 0.834. Good well-to-well lithology correlation was established across the fields studied. The researcher found that the bulk of the hydrocarbon encountered in the Niger Delta basin was found to be within a depth range of 5,473 – 13,381 ft (1,668.17 – 4,078.53 m). The hydrocarbon reservoirs in this study were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta, Nigeria.

Keywords: *Niger Delta, Nigeria, petrophysics, hydrocarbon saturation, water saturation*

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1. Introduction

The porosity of a sedimentary layer is an important consideration when attempting to evaluate the potential volume of hydrocarbons, water and gas it may contain. Almost all reservoirs have porosity in a range of 5 to 45 % with the majority falling between 10 to 20% [1,4,6,8,9,22]. Applied porosity analysis in the geodynamic processes influences the evolution of sedimentary basins including the Niger Delta basin and continental margin of Nigeria, and hydrocarbon potentials of the basins.

Porosity can be determined by using different logging devices. If a density logging tool is to be used, the rock matrix density must be known in order to determine the porosity. Likewise, using sonic log for porosity determination, the known parameter must be the matrix travel time and for neutron log, the parameter that must correspond to the rock type is the matrix setting for the neutron logging tool. If the encountered lithologies are simple or if the detailed information about the geology of the formation is shown, many problems should not arise in the determination of these parameters. Reservoirs characterization is a process of describing various reservoir properties using all the available data to provide reliable reservoir models for accurate reservoir performance prediction [17]. In order to calculate the hydrocarbon reserve in a formation, the water saturation amount must be known [2].

According to Islam, *et al.,* [16] petrophysical parameter studies are very important for the development and production of the well and estimation of the hydrocarbon reserves in any gas field. The geological model of gas reservoir is based on the estimates of reservoir properties such as lithology, porosity, permeability and fluid type [7]. Petrophysical evaluation has a unique opportunity to observe the relationship between porosity and saturation [19]. According to Islam *et al.,* [15] well log data are used to give erroneous values for water saturation and porosity in the presence of shale effect. The determinations of reservoir quality and formation evaluation processes are largely depend on quantitative evaluation of petrophysical analysis. Islam *et al.,* [14] describes Reservoir characterization as the process of mapping a reservoir's thickness, net to gross ratio, pore fluid, porosity, permeability and water saturation.

The formations in the Niger Delta, Nigeria consist of sands and shale's with the former ranging from fluvial (channel) to fluvial-marine (Barrier Bar), while the later are generally fluvial-marine or lagoon. These Formations are mostly unconsolidated and it is often not feasible to take core samples or make drill stem tests [3]. Formation evaluation is consequently based mostly on logs, with the help of mud logger and geological information as in this study. Petrophysical parameters like the lithology, fluid content, porosity, water saturation, hydrocarbon saturation and permeability were derived from the well log data. The main petrophysical parameters needed to evaluate a reservoir are its porosity, hydrocarbon saturation, thickness, area, and permeability [10].

In the evaluation of a clastic reservoir, the presence of clay particles or shale within the sand is a parameter which must be considered. Shaliness is known to affect both formation characteristic and logging tool response. Carbonates, non-clastic reservoirs, are characteristically limestone and dolomite. Their importance as reservoirs rocks should not be under estimated. Approximately, 50% of hydrocarbon reservoirs are carbonate rocks [20]. Well logging tools respond primarily to the chemical nature of matrix and pore fluids. The lithology of a reservoir impacts the petrophysical calculations in numerous ways. The depositional environment and sediments being deposited will define the grain size, its sorting, and its distribution within the reservoir interval. In most sandstone reservoirs, the depositional environment controls the porosity/permeability relationship.

2. Methodology

Well logs data was used for this research. These well logs specifically sonic, resistivity, neutron, density and gamma ray log were used to compute porosity, lithology, and volume of shale. Determination of porosity values was achieved by digitizing the sonic logs. The well analysis from Interactive Petrophysics (IP) and data were used for well logging interpretation directly. Accurate estimates of porosity values in certain stratigraphic intervals can be derived from several well log types, i.e. the sonic, neutron or bulk density log. The sonic tool measures the time it takes sound pulses to travel through the formation (Δt_{log}). This time is referred to as the interval transit time, or slowness and it is the reciprocal of velocity of the sound wave. The interval transit time of a given formation is dependent on the Lithology elastic properties of the rock matrix, the property of the fluid in the rock, and porosity.

The sonic tool is selected to calculate the porosity in a good borehole condition. The Sonic log is used as porosity method;

$$\varphi_w = \frac{\Delta t_{\log} - \Delta t_{\max}}{\Delta t_{ft} - \Delta t_{\max}}. \quad (1)$$

Equation (1) is known as Wyllie Time Average Porosity equation [23].

$\Delta t_{\log}$ is the reading on the sonic log in µs/ft.

$\Delta t_{\max}$ is the transit time of the matrix material (about 55.5 µs/ft.)

Δt_{ft} is the transit time of the saturating fluid (about 189 µs/ft. for fresh water)

Theoretically, the volume fraction of shale can be derived from the gamma ray log as the shale volume is linearly proportional to the gamma ray log value (*GR*). Note that this is valid only under the assumption that radioactive potassium elements of the shale minerals are the sole contributors to the gamma ray log signal:

$$I_{GR} = \frac{GR_{\log} - GR_{\min}}{GR_{\max} - GR_{\min}} \quad (2)$$

$GR_{\log}$ is the gamma reading from the log, $GR_{\max}$ maximum gamma reading of the well

$GR_{\min}$ minimum gamma reading of the well [21].

The volume of shale can be calculated from the equation below:

$$V_{sh} = 0.08\left(2^{3.7 I_{GR}} - 1\right). \quad (3)$$

Equation three is Larinor equation for calculating volume of shale [11].

When a given zone is water bearing that R_t reverts to the water bearing resistivity (R_o). Therefore, a number of water zones can be plotted as depth versus Rw from calculation [5].

$$F = \frac{R_o}{R_w} \quad (4)$$

F = formation resistivity factor or simply formation factor
R_o = resistivity of rock when water saturation is 1 (100% saturated)
R_w = resistivity of saturating water

$$F = \frac{a}{\varphi^m} \quad (5)$$

Φ = porosity
a = empirical constant (default = 1)
m = cementation exponent (default = 2).

For determination of water saturation of a clean sand formation we use the following equations [5].

$$S_w{}^n = \frac{R_o}{R_t} \quad (6)$$

S_w = water saturation
R_t = resistivity of rock when $S_w < 1$
R_o = resistivity of rock when water saturation is 1 (100% saturated).

Combining the above equations gives Archie's equation, the most fundamental equation in well logging.

$$S_w{}^n = \frac{aR_w}{R_t \varphi^m} = \frac{FR_w}{R_t}. \quad (7)$$

Practical average Archie's Equation which is the general equation for finding water saturation is

$$S_w = \left[\frac{0.62 \times R_w}{\varphi^{2.15} \times R_t}\right]^{1/2}. \quad (8)$$

3. Results and Discussion

The two wells, each of which is divided into hydrocarbon bearing zone were analyzed. In each zones of the wells, the formation was determined using the plot of Depth versus Gamma log. High gamma reading indicates shale formation while low gamma reading indicates sand formations. Porosities within the field were observed generally to decrease with depth. The petrophysical properties of well 1 are shown in Table 1. The Table shows the average and range of the petrophysical properties of Well 1. Well 1 was further divided into hydrocarbon bearing zones of high pay zones.

Table 2 – Table 4 shows the average and range of the petrophysical properties of the four identified Reservoirs. Figure 1 is the complete log plot of the petrophysical properties of well 1, Figure 2 – Figure 4 show the log plot of the Reservoirs in well 1. Table 5 shows the average and range of the petrophysical properties of Well 2. Well 2 was further divided into hydrocarbon bearing zones of high pay zones. Table 6 – Table 9 show the average and range of the petrophysical properties of the four identified Reservoirs. Figure 5 is the complete log plot of the petrophysical properties of well 2 while Figure 6 – Figure 9, show the log plot of the Reservoirs in well 2. The two wells, each of which is divided into hydrocarbon bearing zone were analyzed. In each zones of the wells, the formation was determined using the plot of Depth versus Gamma log. High gamma reading indicates shale formation while low gamma reading indicates sand formations.

Porosities within the field were observed generally to decrease with depth. The porosity values for well 1 range from 0.006 to 0.568, with an average value of 0.26. For well 2 the porosity values range from 0.154 to 0.514 with an average value of 0.323, decreasing with depth. From the analysis of the geological logs comprising gamma-ray and electrical resistivity, the total porosity in the hydrocarbon bearing zone was found to range from 0.006 to 0.514. These low porosity values may be attributed to mainly grain size and sorting effects within the reservoir sands [5,18]. The sand units investigated in both wells are all confined within the Agbada Formation. The varying shale contents and the depths of burial may have contributed, though to a minor extent, to the decrease in porosity. The porosity values are however considered to be fairly good for hydrocarbon accumulation.

The water saturation range from 0.166 to 0.836, while the hydrocarbon saturation range from 0.164 to 0.834.

Hydrocarbon saturation was calculated using;

$$S_h = 1 - S_w. \tag{9}$$

Good well-to-well lithology correlation was established across the fields studied .The bulk of the hydrocarbon encountered in the Niger Delta basin was found to be within a depth range of 5,473 – 13,381ft (1,668.17 – 4,078.53m) as compared to the values gotten by Falebita, 2003 (about 1,200 – 3,650m) and Aigbedion, [3] (about 2,510 – 3,887m). The hydrocarbon reservoirs were found to be in the Agbada formation, which is in conformity with the geology of the Niger Delta, Nigeria.

The resulting distribution of these estimated parameters from the log interpretation shows that: the Niger Delta Region has a potential field for hydrocarbon; the two wells studied encountered oil and gas in their formations; hydrocarbon-bearing zones were between 1668.17 m and 4078.53 m. The low porosity of hydrocarbon-bearing zones suggests tight reservoir section. Hydrocarbon pay zones were 0.5m, while hydrocarbon potential of the wells was sufficient for economic viability. Higher average hydrocarbon saturation values suggest that gas reservoir is built up by very high hydrocarbon accumulation [13].

Table 1. Petrophysical Properties of well 1

Complete Well 1				
		Top	Bottom	Net
		5954.5	13381.0	7427.0
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.563	0.211
CALI	IN	6.730	22.250	9.640
DEN_QI_EDIT	g/cc	1.785	2.684	2.251
DT_QI_EDIT	us/ft.	67.600	194.300	97.132
GRN	API	10.074	165.630	59.103
NEU	Dec	0.049	0.612	0.300
PHI	Dec	0.006	0.568	0.260
RES_DEP	ohmm	0.800	160.240	4.436
RWapp	ohmm	0.000	19.703	0.341
SW	Dec	0.112	1.000	0.837
SWu	Dec	0.112	1.300	1.037
VCL	Dec	0.000	1.000	0.199
VSH	v/v	0.000	1.000	0.178

Table 2. Petrophysical Properties of well 1, Reservoir 1

Well 1: Reservoir 1				
		Top	Bottom	Net
		5954.5	8255	2301.0
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.266	0.145
CALI	IN	N/A	N/A	N/A
DEN_QI_EDIT	g/cc	2.011	2.684	2.180
DT_QI_EDIT	us/ft.	82.758	194.300	110.604
GRN	API	13.139	133.824	52.782
NEU	Dec	0.049	0.612	0.343
PHI	Dec	0.006	0.443	0.298
RES_DEP	ohmm	1.440	70.020	8.148
RWapp	ohmm	0.000	8.170	0.707
SW	Dec	0.112	1.000	0.495
SWu	Dec	0.112	1.300	0.496
VCL	Dec	0.000	0.853	0.146
VSH	v/v	0.000	1.000	0.240

Table 3. Petrophysical Properties of well 1, Reservoir 2

Well 1: Reservoir 2				
		Top	Bottom	Net
		8340	8371.5	32.000
Curve	Units	Min	Max	Mean
BVW	Dec	0.063	0.308	0.131
CALI	IN	N/A	N/A	N/A
DEN_QI_EDIT	g/cc	2.078	2.300	2.146
DT_QI_EDIT	us/ft.	93.100	108.000	102.632
GRN	API	28.130	67.639	44.015
NEU	Dec	0.222	0.388	0.316
PHI	Dec	0.212	0.353	0.310
RES_DEP	ohmm	4.810	160.240	57.534
RWapp	ohmm	0.387	19.703	6.174
SW	Dec	0.180	1.000	0.442
SWu	Dec	0.180	1.286	0.447
VCL	Dec	0.000	0.251	0.046
VSH	v/v	0.000	0.317	0.076

Table 4. Petrophysical Properties of well 1, Reservoir 3

Well 1: Reservoir 3				
		Top	Bottom	Net
		13273.5	13381	108.000
Curve	Units	Min	Max	Mean
BVW	Dec	0.083	0.302	0.184
CALI	IN	6.730	7.980	7.803
DEN_QI_EDIT	g/cc	2.168	2.360	2.284
DT_QI_EDIT	us/ft.	74.400	86.500	78.360
GRN	API	16.880	98.102	32.321
NEU	Dec	0.150	0.320	0.184
PHI	Dec	0.176	0.338	0.223
RES_DEP	ohmm	2.140	93.190	20.579
RWapp	ohmm	0.081	6.652	1.090
SW	Dec	0.310	1.000	0.836
SWu	Dec	0.310	1.300	0.915
VCL	Dec	0.000	0.528	0.016
VSH	v/v	0.000	0.128	0.002

Table 5. Petrophysical Properties of well 2

Complete Well 2				
		Top	Bottom	Net
		5470.5	10532.5	5062.500
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.423	0.249
CALI	IN	0.705	22.275	13.616
DEN_QI_EDIT	g/cc	1.838	2.453	2.195
DT_QI_EDIT	us/ft.	204.880	759.071	341.659
GRN	API	44.879	155.398	97.500
NEU	Dec	0.144	0.882	0.520
PHI	Dec	0.154	0.514	0.323
RES_DEP	ohmm	0.094	2000.000	41.651
RWapp	ohmm	0.011	368.687	3.736
SW	Dec	0.013	1.000	0.796
SWu	Dec	0.013	1.300	0.811
VCL	Dec	0.044	1.000	0.523
VSH	v/v	0.071	1.000	0.939

Table 6. Petrophysical Properties of well 2, Reservoir 1

Well 2: Reservoir 1				
		Top	Bottom	Net
		5473	8766	3293.500
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.423	0.263
CALI	IN	11.314	22.275	14.421
DEN_QI_EDIT	g/cc	1.838	2.449	2.128
DT_QI_EDIT	us/ft.	211.150	759.071	396.352
GRN	API	44.879	137.851	92.132
NEU	Dec	0.144	0.882	0.560
PHI	Dec	0.165	0.514	0.359
RES_DEP	ohmm	0.094	2000.000	25.108
RWapp	ohmm	0.011	368.687	4.077
SW	Dec	0.013	1.000	0.745
SWu	Dec	0.013	1.300	0.749
VCL	Dec	0.044	0.890	0.474
VSH	v/v	0.115	1.000	0.947

Table 7. Petrophysical Properties of well 2, Reservoir 2

Well 2: Reservoir 2				
		Top	Bottom	Net
		9038.5	9097	59.000
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.231	0.053
CALI	IN	11.972	12.652	12.292
DEN_QI_EDIT	g/cc	2.008	2.344	2.094
DT_QI_EDIT	us/ft.	228.085	273.202	247.932
GRN	API	52.313	102.076	65.154
NEU	Dec	0.314	0.439	0.351
PHI	Dec	0.231	0.404	0.358
RES_DEP	ohmm	1.068	2000.000	503.086
RWapp	ohmm	0.057	308.102	71.943
SW	Dec	0.014	1.000	0.166
SWu	Dec	0.014	1.064	0.167
VCL	Dec	0.112	0.564	0.229
VSH	v/v	0.080	1.000	0.290

Table 8. Petrophysical Properties of well 2, Reservoir 3

Well 2: Reservoir 3				
		Top	Bottom	Net
		9656	9715.5	60.000
Curve	Units	Min	Max	Mean
BVW	Dec	0.012	0.230	0.100
CALI	IN	11.930	12.827	12.249
DEN_QI_EDIT	g/cc	1.978	2.402	2.214
DT_QI_EDIT	us/ft.	220.126	253.032	239.207
GRN	API	59.896	114.021	87.551
NEU	Dec	0.288	0.473	0.373
PHI	Dec	0.208	0.427	0.303
RES_DEP	ohmm	1.137	454.487	25.314
RWapp	ohmm	0.060	48.761	3.166
SW	Dec	0.036	1.000	0.374
SWu	Dec	0.036	1.037	0.375
VCL	Dec	0.181	0.673	0.432
VSH	v/v	0.071	0.992	0.545

Table 9. Petrophysical Properties of well 2, Reservoir 4

Well 2: Reservoir 4				
		Top	Bottom	Net
		10440.5	10463	23.000
Curve	Units	Min	Max	Mean
BVW	Dec	0.006	0.246	0.141
CALI	IN	1.844	1.844	1.844
DEN_QI_EDIT	g/cc	1.985	2.407	2.222
DT_QI_EDIT	us/ft.	222.812	222.812	222.812
GRN	API	68.234	151.267	112.935
NEU	Dec	0.192	0.363	0.277
PHI	Dec	0.230	0.440	0.319
RES_DEP	ohmm	1.039	1956.540	91.791
RWapp	ohmm	0.063	261.064	12.353
SW	Dec	0.016	1.000	0.473
SWu	Dec	0.016	1.015	0.473
VCL	Dec	0.257	1.000	0.663
VSH	v/v	0.226	0.974	0.680

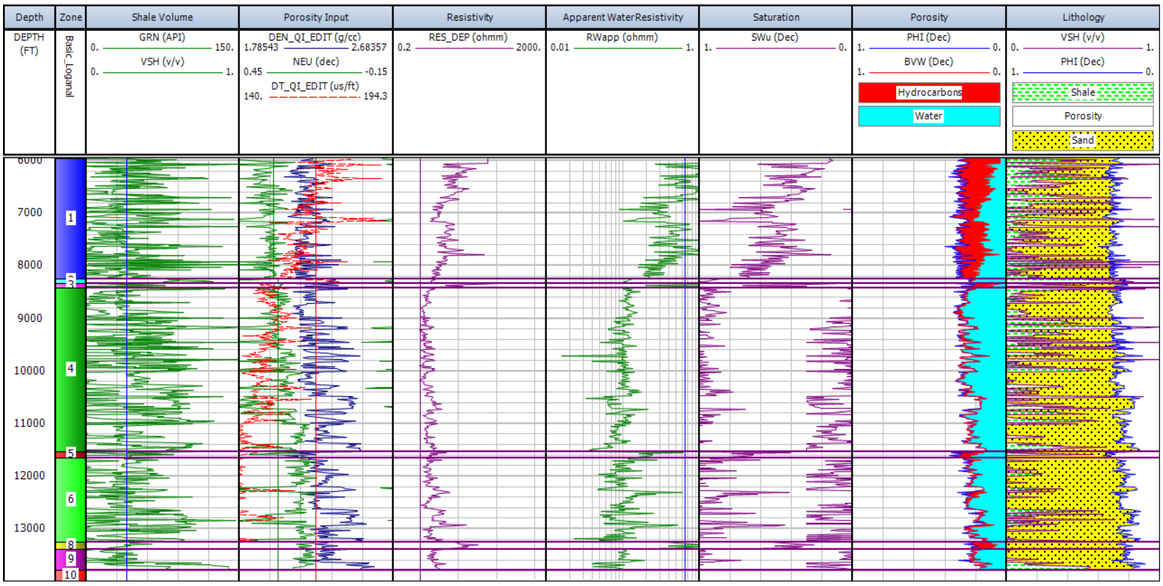

Figure 1. Log Plots of Well 1

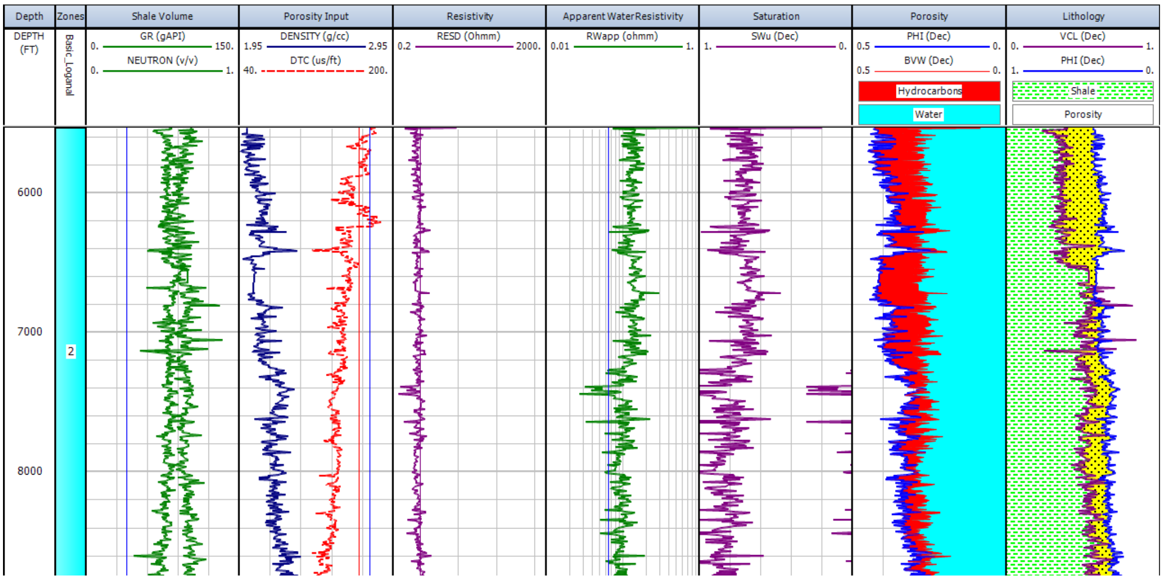

Figure 2. Log Plots of Well 1, Reservoir 1

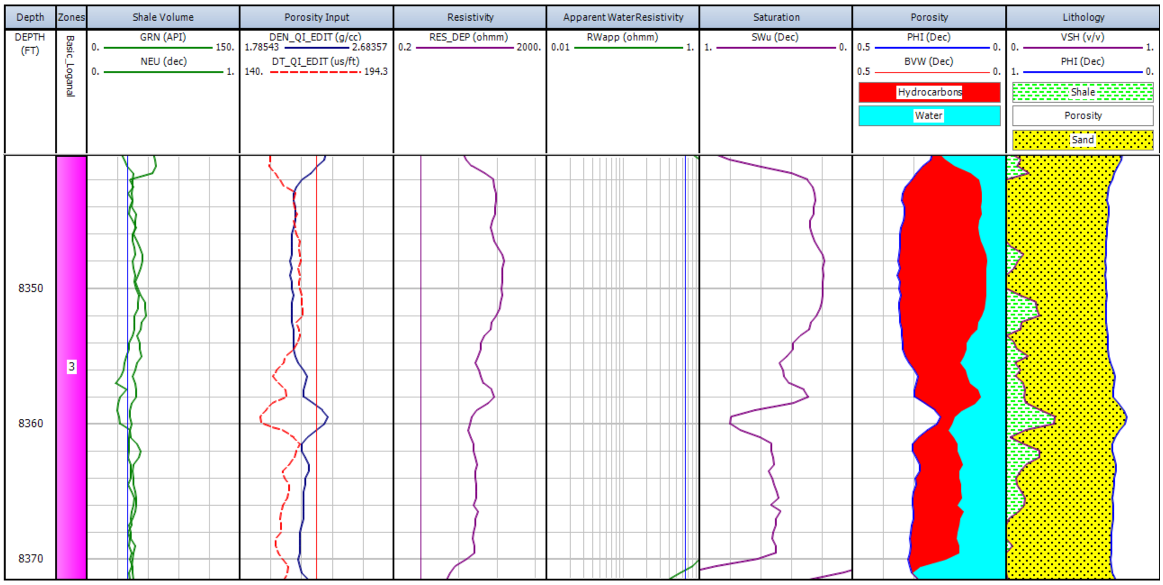

Figure 3. Log Plots of Well 1, Reservoir 2

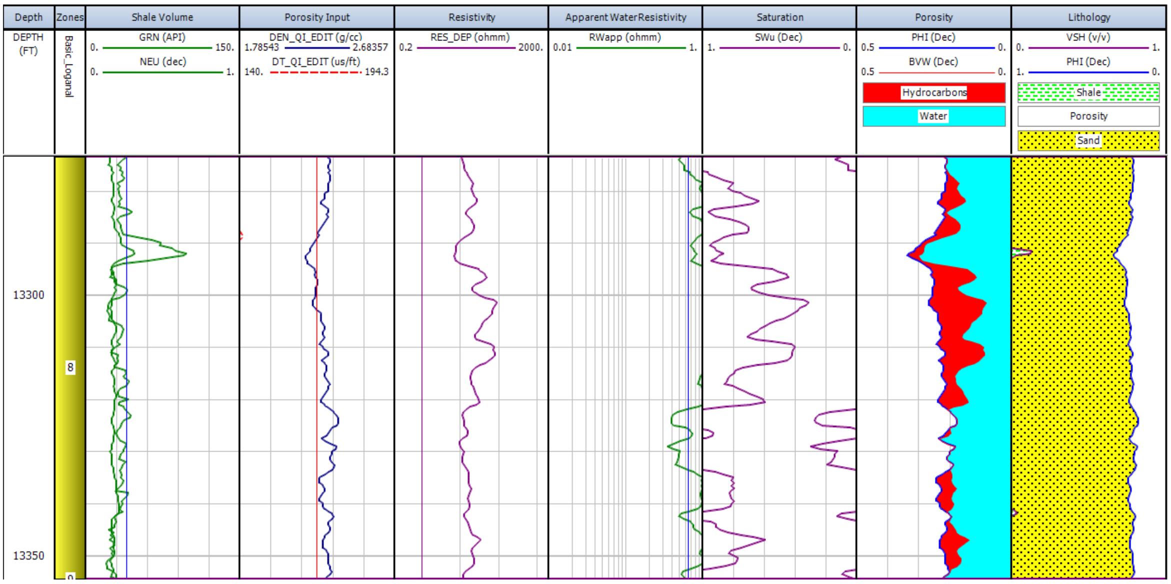

Figure 4. Log Plots of Well 1, Reservoir 3

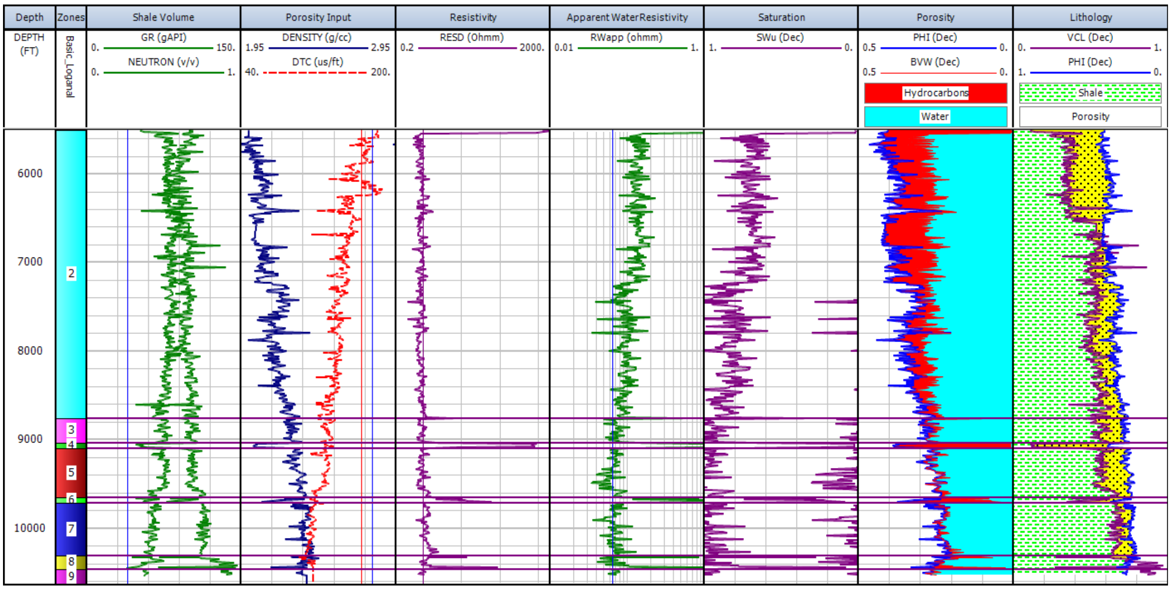

Figure 5. Log Plots of Well 2

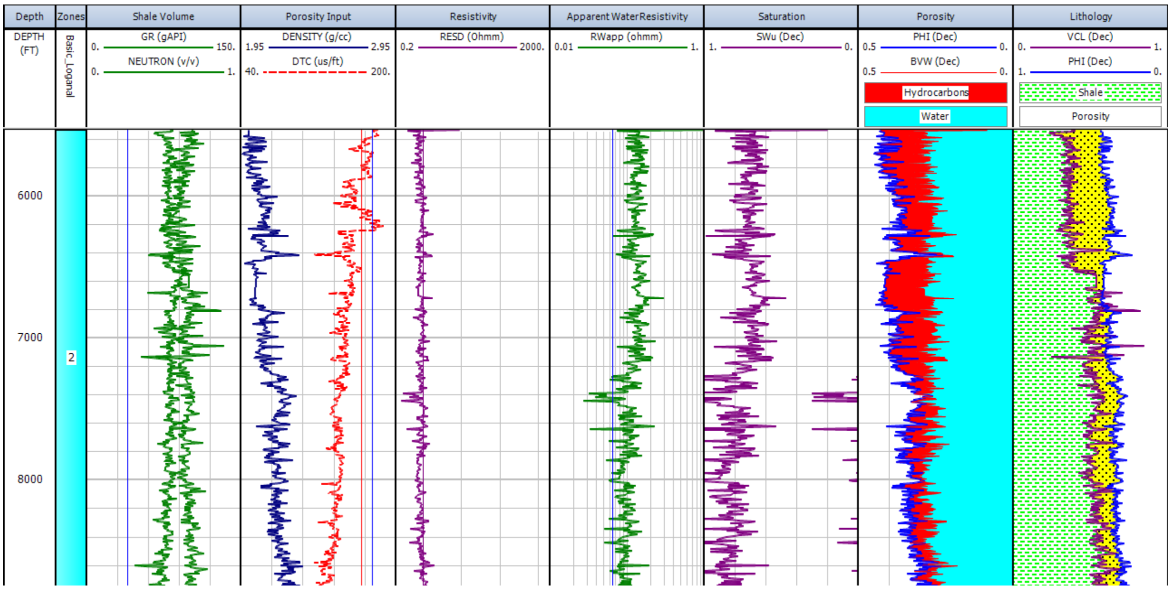

Figure 6. Log Plots of Well 2, Reservoir 1

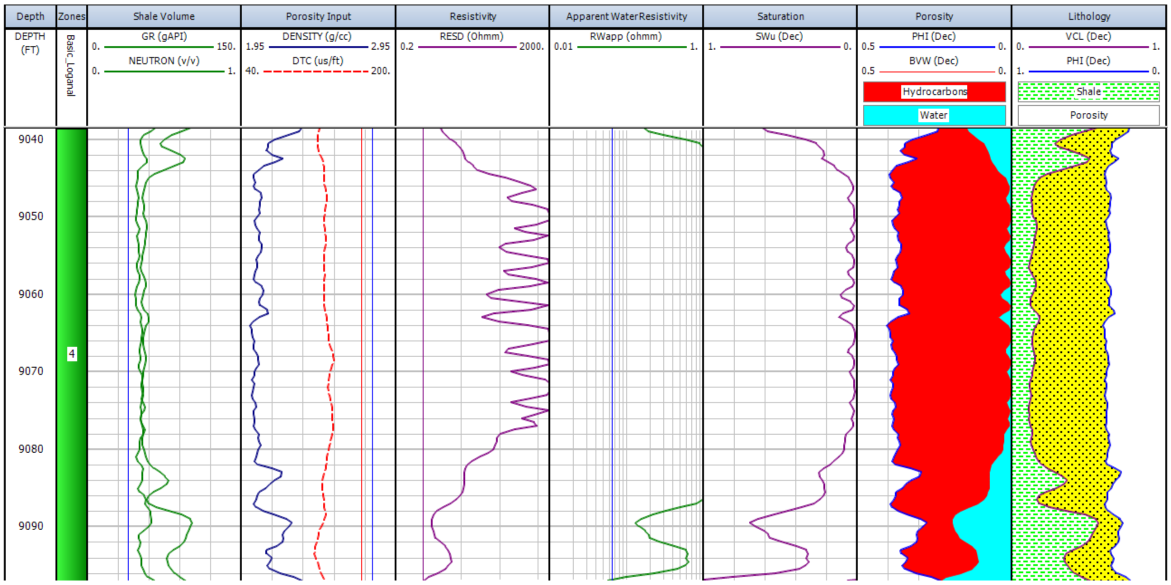

Figure 7. Log Plots of Well 2, Reservoir 2

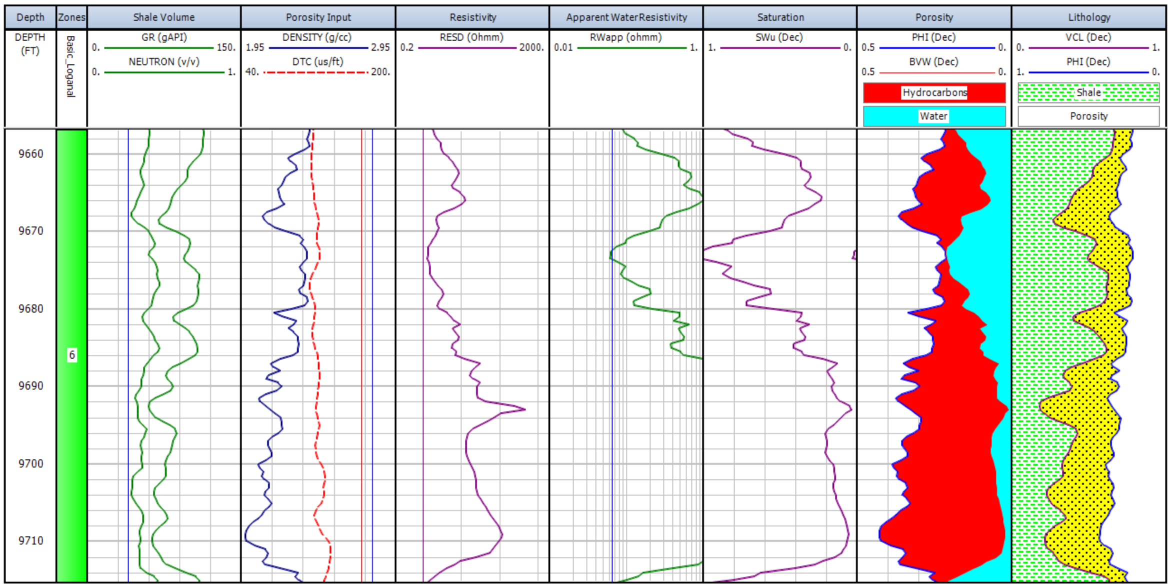

Figure 8. Log Plots of Well 2, Reservoir 3

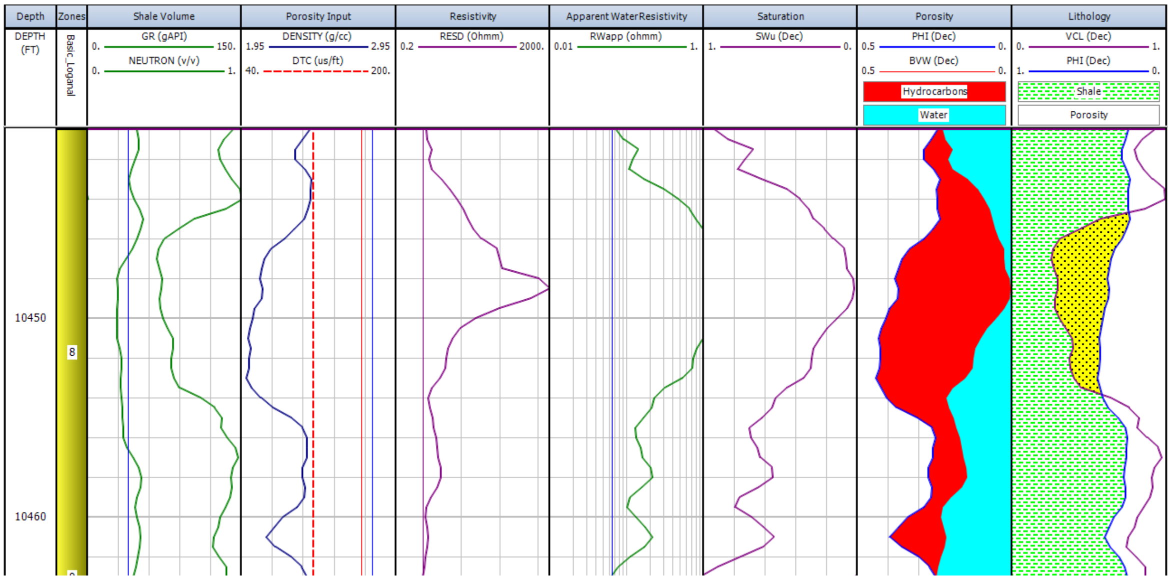

Figure 9. Log Plots of Well 2, Reservoir 4

Figure 10. Cross plot of neutron and density for well 1 reservoir zones showing high porosity for the clean sand unit.

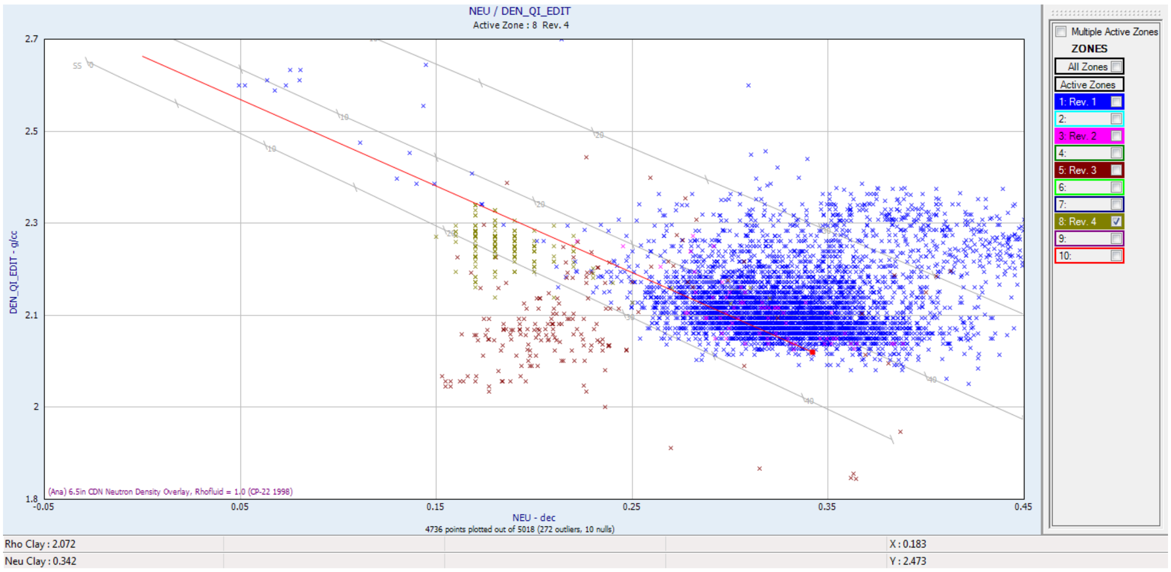

Figure 11. Cross plot of neutron and density for well 2 reservoir zones showing high porosity for the clean sand unit

Table 10. Hydrocarbon Saturation for Well 1 and Well 2 Reservoirs

Zones	Top (ft.)	Bottom (ft.)	Net (ft.)	Sh (dec.)
Well 1, Reservoir 1	5954.5	8255.0	2301.0	0.505
Well 1, Reservoir 2	8340.0	8371.5	32.0	0.558
Well 1, Reservoir 3	13273.5	13381.0	108.0	0.164
Well 2, Reservoir 1	5473.0	8766.0	3293.5	0.255
Well 2, Reservoir 2	9038.5	9097.0	59.0	0.834
Well 2, Reservoir 3	9656.0	9715.5	60.0	0.626
Well 2, Reservoir 4	10440.5	10463.0	23.0	0.527

4. Conclusion

Petrophysical analysis was carried out for all the identified hydrocarbon intervals, from eight wells studied in the Niger Delta Fields using suites of geophysical well logs. One of the most important tasks in reservoir engineering is characterizing different parameters of the reservoir, which have been done in this work. Water saturation is a parameter which helps evaluating the volume of hydrocarbon in reservoirs.

The well log analysis methods employed is efficient and less expensive in prospecting for hydrocarbons and can be relied upon when combined with other geophysical methods such as seismic and core analysis, for further exploratory work and development of the basin. A reservoir simulation based on this new reservoir description will have greater predictive power because reservoir flow capacity is better defined in this study.

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