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Research Article

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Petrophysical Evaluation of Reservoir Rocks, using Well-Logs Data in Field 'DL' of the Onshore Northern Depobelt Niger Delta, Nigeria

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Abstract The science dealing with the fundamental chemical and physical properties of porous media, and in particular of reservoir rocks and their contained fluids, is regarded as Petrophysics. Petrophysical evaluation is the study of the relationships among the physical properties of rocks. Petrophysical analysis of five wells in Field "DL", onshore Northern Depobelt, Niger Delta, has been conducted in this study. Composite wireline logs have been employed in this research to provide a robust reservoir characterization in the study area. The petrophysical results indicated that, the six (6) reservoirs delineated had an average gross thickness of 1010.95m, average net reservoir thickness of 810.82m and average net pay thickness of 319.42m. The shale volume computed ranges from 0.20 to 0.30 v/v, average porosity ranges from 0.15 to 0.19 v/v and average water saturation ranges from 0.36 to 0.53 v/v. The study has established a basis for the identification and assessment of hydrocarbon bearing formations. Furthermore, the study will provide sufficient backdrops for petroleum engineers, in the evaluation of hydrocarbon reserves, and in planning well completion as well as optimization of production operations during the lifetime of a reservoir.

Keywords Petrophysical evaluation, reservoir rocks

1. Introduction

Petrophysics is the science dealing with the fundamental chemical and physical properties of porous media, and in particular of reservoir rocks and their contained fluids. These include storage and flow properties (porosity, permeability and fractional flow), fluid identification, fluid phase distribution within gross void space (saturation), interactions of surface forces existing between the rock and the contained fluids (capillary pressure), measurements of pressure, stress conditions, electrical conductivity of fluid-saturated rocks, etc. These properties and their relationships are used to recognize and assess hydrocarbon reservoirs, source rocks, cap rocks, and aquifers. Petrophysical properties form a set of essential engineering parameters and still remain the basic tools to obtain reliable information by which reservoir rocks may be described quantitatively, in order to assist petroleum engineers in the evaluation of hydrocarbon reserves and for planning well completion and optimize production operations during the reservoir life [1].

Petrophysical evaluation of reservoir rocks has always been a crucial factor for the identification and assessment of hydrocarbon bearing formations. It has provided the estimation of fluid and mineral types, rock/pore fabric type, fluid and mineral volumes for invaded and virgin zones [2].

It is the determination of reservoir properties from logs, and cores data. These properties include porosity, permeability, and fluid saturation amongst others. It is one of the first set of tasks carried out during exploration for petroleum. Petrophysical evaluation can be said to be as old as exploration of petroleum itself, but the various techniques applied have been modified and improved overtime. A good reservoir is characterized by sufficient porosity to contain the hydrocarbon and permeability to permit their movement [3]. According to [4] Petrophysical evaluation is the study of the relationships among the physical properties of rocks.

The aim of this study is to evaluate the distribution of petrophysical properties of reservoirs in the study area. The main objectives of this work is to define the net to gross thickness of the reservoir units, estimate porosity for each reservoir across wells, estimate permeability of each reservoir across well, estimate water saturation, and predict reservoir performance.

2. Geology of The Study Area

The study area is the '*DL*' Field, located within the central parts of the Northern Depobelt in the Niger Delta oil and gas province. The area lies within Northern Depobelt region of the Niger Delta, between longitudes 7° to 8° E and latitudes 4° to 4.5° N (Fig 1). The Niger Delta is situated in the Gulf of Guinea (Fig 1) and extends throughout the Niger Delta Province as defined by [5]. 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 [6] (D. These Depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km^2 [7] a sediment volume of 500,000 km^2 [8], and a sediment thickness of over 10 km in the basin depocenter [9].

The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and south-western Cameroon. The northern boundary is the Benin flank--an east-northeast trending hinge line south of the West Africa basement massif. The north-eastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further east- South-East by the Calabar flank - a hinge line bordering the adjacent Precambrian.

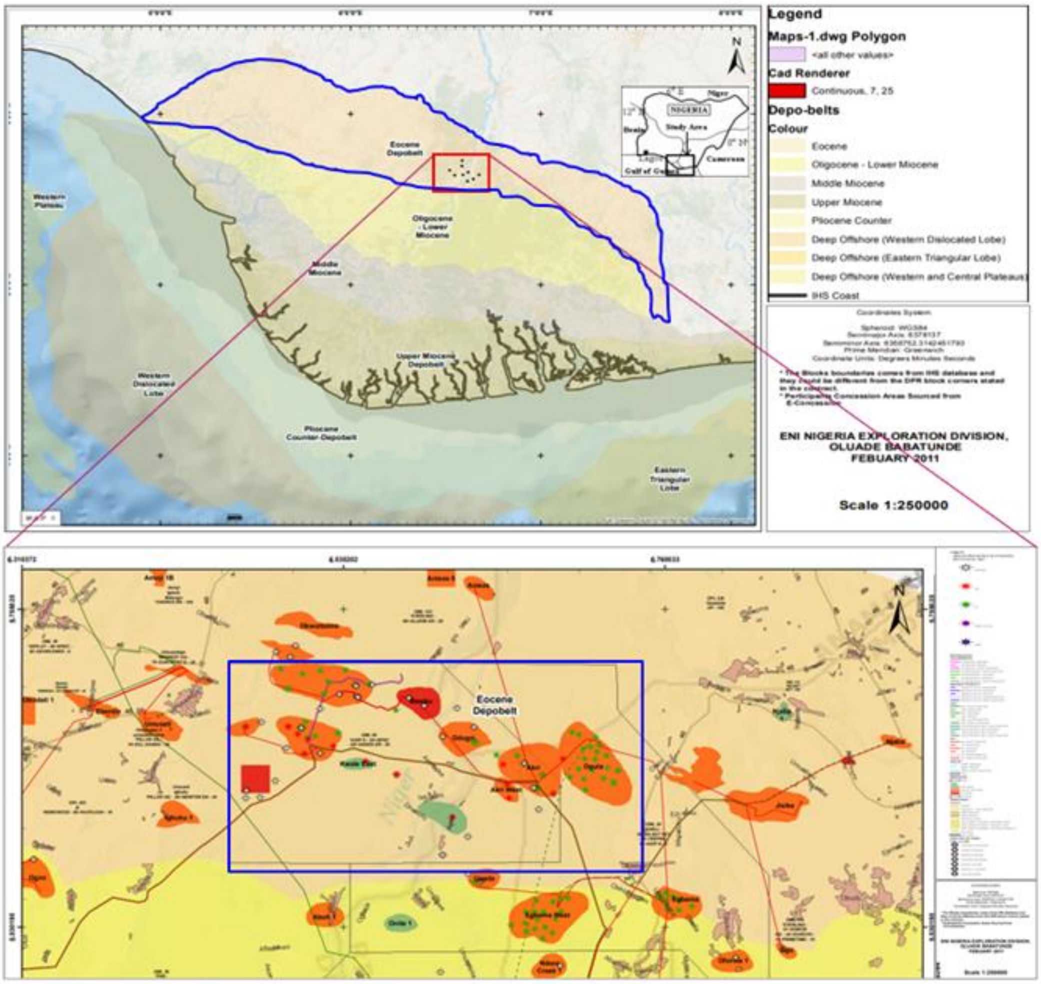

Figure. 1: Map of Niger Delta showing Study Area (GIS ENI Nigeria 2011)

The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin) to the west, and the two-kilometre sediment thickness contour or the 4000m bathymetric contour in areas where sediment thickness is greater than two kilometres to the south and southwest. The province covers 300,000km^2 and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum System. The Niger Delta Province contains only one identified petroleum system [7,10]. This system is referred to here as the Tertiary Niger Delta (Akata-Agbada) Petroleum System. [11,12] in their research stated that Tertiary Niger Delta is divided into three main formations, which represent the prograding depositinal facies of sand and shale. The Akata Formation at the base of the delta is of marine origin and is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt. The second is the Agbada Formation which is the major petroleum-bearing unit. Its formation consists of paralic siliciclastics over 3700 m thick and represents the actual deltaic portion of the sequence. The clastics accumulated in delta-front, delta-topset, and fluvio-deltaic environment. In the lower Agbada Formation, shale and sandstone beds were deposited in equal proportions, however, the upper portion is mostly sand with only minor shale interbeds. The Agbada Formation is overlain by the third formation, the Benin Formation, a continental latest Eocene to Recent deposit of alluvial and upper coastal plain sands that are up to 2000 m thick.

3. Materials and Method

In executing the study, five (5) well logs with suits of logs, gamma ray, resistivity, neutron, density and sonic were employed. The software used was the Schlumberger Techlog64, 2015.3. The well logs were carefully conditioned or edited prior to their use in a modelling workflow on Techlog Workstation. The well logs conditioning includes, De-spike and filter to remove or correct anomalous data points, normalization of the logs to determine the appropriate ranges and cut-offs for porosity, clay content, water resistivity and Saturation [13].

3.1 Determination of Petrophysical Properties

The petrophysical properties used in this study are discussed below., Empirical equations where used to calculate some of these petrophysical properties, since they cannot be directly recorded on well log data, during data acquisition.

3.1.1 Determination of Shale Volume (V_{sh})

In this work, the empirical equation derived by [14] for volume of shale equation for tertiary rocks is used.

$$V_{sh} = 0.083(23.7 * I_{GR} - 1) \quad (1)$$

where V_{sh} is the percentage of shale in the formation and I_{GR} is the Gamma ray index.
Gamma ray index was computed using the GR log response I_{GR} [15],

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

where I_{GR} = gamma ray index; GR_{log} = Gamma ray reading from log; GR_{min} = Minimum value of the gamma ray reading; GR_{max} = Maximum value of the Gamma ray reading.

3.1.2 Determination of Total Porosity (Φ_T)

It is generally accepted among geoscientists that porosity calculation from bulk density logs is more accurate [16, 17]. Porosity was determined from the formula according to [18]. This was calculated from density porosity log using the equation:

$$\Phi_T = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} \quad (3)$$

and I_{GR} is the Gamma ray index
Gamma ray index was computed using the GR log response I_{GR} [15];
where I_{GR} = gamma ray index; GR_{log} = Gamma ray reading from log; GR_{min} = Minimum value of the gamma ray reading; GR_{max} = Maximum value of the Gamma ray reading.

where ρ_{ma} = matrix (or grain) density which is assumed to be 2.65g/cc for sandstones [19]; ρ_b = Bulk density read directly from the log; ρ_f = the fluid density which is approximated to be 1 for gas and 0.87 for oil; Φ_T = total porosity.

3.1.3 Determination of Effective Porosity, Φ_{eff}

This is usually based on an adjustment of total porosity by means of estimated shale volume (content). According to [19], effective porosity is given by the formula:

$$\Phi_{eff} = \Phi_T - [\Phi_{sh} \times V_{sh}] \quad (4)$$

where Φ_{eff} = effective porosity; Φ_T = total porosity; Φ_{sh} = log reading in a shale zone and V_{sh} = shale volume. According to [20], the criteria for classifying porosity are as follows: $\Phi < 5$ = Very insignificant; $5 < \Phi < 10$ = Insignificant; $10 < \Phi < 15$ = Fairly Significant; $15 < \Phi < 25$ = Significant; $25 < \Phi < 30$ = Good; $\Phi > 5$ = Excellent

3.1.4 Determination of Water /Hydrocarbon Saturation

The Indonesia formula was used to compute water saturation equation 5. The main parameters applied are the [21] Archie (1942) parameters stated as follows: m = 2; n = 2; a = 1.

$$S_{wind} = \frac{\sqrt{\frac{1}{R_t}}}{\frac{V_{sh}}{\sqrt{R_{sh}}}\left(1-\frac{V_{sh}}{2}\right)+\sqrt{\frac{\varphi^m}{aR_w}}} \quad (5)$$

where ϕ_e = Effective porosity; R_w = Formation water resistivity; R_{sh} = shale resistivity; V_{sh} = volume of shale; m = Cementation Exponent; n = Saturation Exponent; a = Tortuosity factor.

Hydrocarbon saturation S_h is given as:

$$S_h = (100 - S_w)\% \quad (6)$$

$$S_h = 1 - S_w \quad (7)$$

3.1.5 Determination of Net-to-Gross Thickness

Net/gross ratio is used to define the proportion of the intervals that are reservoirs and it help in the understanding of the formation. It has no unit because it is expressed as ratio of two quantities with same unit. The net/gross ratio reflects the overall quality of a zone not minding its thickness. Reservoir gross thickness is defined as the zones where reservoir beds occur these beds includes both productive and non-productive zones. The Net/Gross Reservoir thickness is given as:

$$h = H - h_{shale} \quad (8)$$

Net/Gross = h/H, where H = Gross reservoir thickness; h = Net reservoir thickness and h_{shale} = Shale thickness.

3.1.6 Determination of Formation Water Resistivity of Formation Water (R_w)

The conventional Archie parameters were used in the saturation equation with the aid of Pickett Plot to select 100% water line in dotted red. Archie equation:

$$R_w = R_o\left(\frac{\varphi^m}{a}\right) \quad (9)$$

where ϕ = Porosity; m = Cementation exponent; a = Tortuosity.

3.1.7 Cutoffs Sensitivity Analysis

In order to achieve and model the calculated petrophysical parameter accurately, a sensitivity analysis was performed on the volume of shale (V_{sh}), Porosity and Water saturation to obtain the final values of the respective variables

- 30% cut-off was applied to the volume of shale (Vsh) sensitivity analysis with aim of achieve a better reservoir quality.
- 10% cut-off was applied to the porosity sensitivity analysis to achieve good porosity values and enhance reservoir net pay values.
- 60% cut-off was applied to water saturation to enhance the production of the hydrocarbon resources already discovered in the field.

Volume of shale (V_{sh}) value of 30% was applied to achieved considering the hydrocarbon saturation in the silt components within the reservoir rock at the transition zone.

A porosity cut-off 10% captures 99% of the remaining Hydrocarbon Column (HCOL) after a volume of shale (V_{sh}) cut-off of 30% was applied. For the water saturation sensitivity analysis, 60% was selected for proper reservoir characterization.

4. Results and Discussions

The delineated reservoirs and geological correlation of the wells in Field 'DL' is presented in Fig. 2, while the petrophysical parameters evaluated for wells DL-1 to DL-5 are presented in Tables 1, 2, 3, 4 and 5 respectively. The cumulative summary of all wells is presented in Table 6.

4.1 Well DL-1 Results of Petrophysical Characterization

Four reservoirs were delineated with gross thickness of 135.38m, net reservoir thickness of 127.23m, net pay thickness of 36.98m and net to gross ratio of 0.94. Average shale volume of 0.06 v/v. Average porosity ranges from 0.15 to 0.19 v/v and average water saturation ranges from 0.50 to 0.63 v/v in hydrocarbon level and 0.93 to 1.00 v/v in water bearing level. These results are shown in Table 1

4.2 Well DL-2 Results of Petrophysical Characterization

Six reservoirs were delineated with gross thickness of 238.17m, net reservoir thickness of 157.10m, net pay thickness of 25.91m and net to gross ratio of 0.66. Average shale volume of 0.30 v/v. Average porosity ranges from 0.20 to 0.22 v/v and average water saturation ranges from 0.40 to 0.61 v/v. These results are shown in Table 2

4.3 Well DL-3 Results of Petrophysical Characterization

Six reservoirs were delineated with gross thickness of 208.78m, net reservoir thickness of 167.97m, net pay thickness of 75.27m and net to gross ratio of 0.80. Average shale volume of 0.20 v/v. Average porosity ranges from 0.13 to 0.16 v/v and average water saturation ranges from 0.39 to 0.49 v/v. These results are shown in Table 3.

4.4 Well DL-4 Results of Petrophysical Characterization

Four reservoirs were delineated with gross thickness of 250.19m, net reservoir thickness of 217.15m, net pay thickness of 72.42 and net to gross ratio of 0.86. Average shale volume of 0.18 v/v. Average porosity ranges from 0.15 to 0.19 v/v and average water saturation ranges from 0.36 to 0.51 v/v. These results are shown in Table 4.

4.5 Well DL-5 Results of Petrophysical Characterization

Four reservoirs were delineated with gross thickness of 178.43m, net reservoir thickness of 141.37m, net pay thickness of 108.84m and net to gross ratio of 0.79. Average shale volume of 0.26 v/v. Average porosity ranges from 0.13 to 0.17 v/v and average water saturation ranges from 0.46 to 0.53 v/v. These results are shown in Table 5

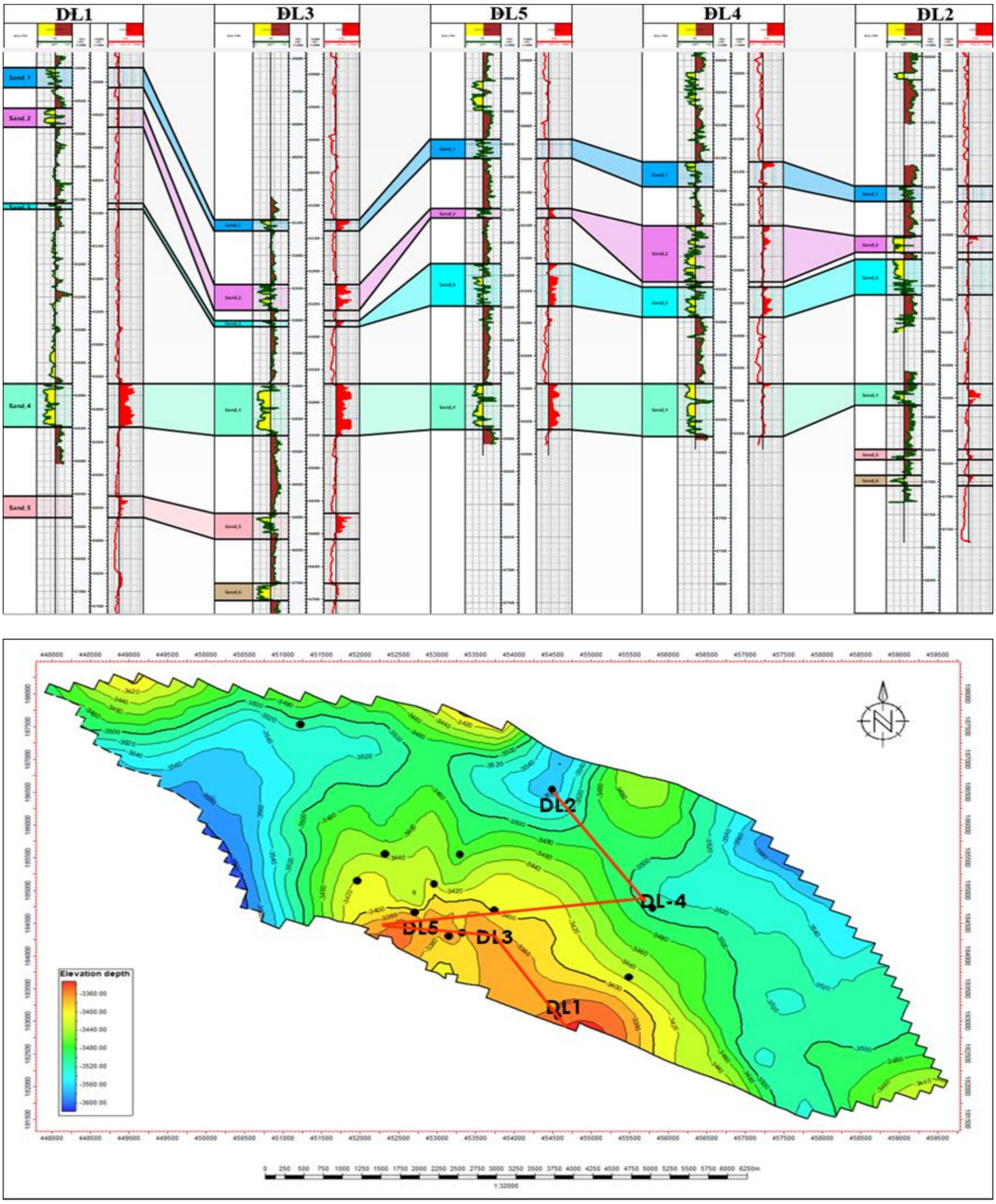

Figure. 2: Reservoirs in Wells DL1, DL2, DL3 and DL4 in Field DL, (a) Correlation and Delineation of Reservoirs (b) Structural Map of Field 'DL'

Table 1: Result of Petrophysical Characterization of Well DL-1

Well	Zones	Flag Name	Top	Bottom	Gross	Net	NTG	Avg. Shale Volume	Avg.Phi	Avg. Sw
			m	m	m	m		v/v	v/v	v/v
DL-1	Sand_1	ROCK	2877.60	2908.52	30.91	30.91	1.00	0.00	0.19	0.93
		RES	2877.60	2908.52	30.91	30.91	1.00	0.00	0.19	0.93
		PAY	2877.60	2908.52	30.91	0.50	0.02	0.15	0.20	0.93

		ROCK	2940.50	2969.28	28.78	28.78	1.00	0.00	0.15	1.00
	Sand_2	RES	2940.50	2969.28	28.78	28.78	1.00	0.00	0.15	1.00
		PAY	2940.50	2969.28	28.78	0.00	0.00	-	-	-
		ROCK	3085.47	3094.53	9.06	9.06	1.00	0.00	0.18	1.00
	Sand_3	RES	3085.47	3094.53	9.06	9.06	1.00	0.00	0.18	1.00
		PAY	3085.47	3094.53	9.06	0.00	0.00	-	-	-
		ROCK	3360.50	3427.13	66.63	64.47	0.97	0.02	0.08	0.64
	Sand_4	RES	3360.50	3427.13	66.63	58.47	0.88	0.02	0.08	0.63
		PAY	3360.50	3427.13	66.63	36.48	0.55	0.01	0.08	0.50

Table 2: Result of Petrophysical Characterization of well DL-2

Well	Zones	Flag Name	Top	Bottom	Gross	Net	NTG	Avg. Shale Volume	Avg.Phi	Avg. Sw
			m	m	m	m		v/v	v/v	v/v
		ROCK	3226.54	3250.09	23.55	21.05	0.89	0.04	0.21	0.97
	Sand_1	RES	3226.54	3250.09	23.55	21.05	0.89	0.04	0.21	0.97
		PAY	3226.54	3250.09	23.55	0.00	0.00	-	-	-
		ROCK	3302.08	3328.08	26.00	25.00	0.96	0.02	0.22	0.82
	Sand_2	RES	3302.08	3328.08	26.00	25.00	0.96	0.02	0.22	0.82
		PAY	3302.08	3328.08	26.00	6.00	0.23	0.00	0.25	0.40
		ROCK	3338.64	3392.27	53.63	49.45	0.92	0.01	0.22	0.98
	Sand_3	RES	3338.64	3392.27	53.63	49.45	0.92	0.01	0.22	0.98
DL-2		PAY	3338.64	3392.27	53.63	0.00	0.00	-	-	-
		ROCK	3527.98	3561.29	33.32	27.23	0.82	0.04	0.21	0.58
	Sand_4	RES	3527.98	3561.29	33.32	26.73	0.80	0.03	0.21	0.57
		PAY	3527.98	3561.29	33.32	14.50	0.44	0.00	0.24	0.41
		ROCK	3628.75	3644.19	15.44	12.13	0.79	0.05	0.20	0.79
	Sand_5	RES	3628.75	3644.19	15.44	12.13	0.79	0.05	0.20	0.79
		PAY	3628.75	3644.19	15.44	4.00	0.26	0.01	0.22	0.61
		ROCK	3683.81	3770.04	86.23	21.74	0.25	0.05	0.22	1.00
	Shale_6	RES	3683.81	3770.04	86.23	21.74	0.25	0.05	0.22	1.00
		PAY	3683.81	3770.04	86.23	0.00	0.00	-	-	-

Table 3: Result of Petrophysical Characterization of Well DL-3

Well	Zones	Flag Name	Top	Bottom	Gross	Net	NTG	Avg. Shale Volume	Avg.Phi	Avg. Sw
			m	m	m	m		v/v	v/v	v/v
		ROCK	3122.38	3139.27	16.89	14.95	0.89	0.10	0.16	0.55
	Sand_1	RES	3122.38	3139.27	16.89	14.46	0.86	0.09	0.16	0.55
		PAY	3122.38	3139.27	16.89	10.47	0.62	0.07	0.17	0.46
		ROCK	3220.64	3260.04	39.40	32.42	0.82	0.11	0.14	0.66
	Sand_2	RES	3220.64	3260.04	39.40	29.43	0.75	0.10	0.14	0.64
		PAY	3220.64	3260.04	39.40	15.45	0.39	0.05	0.16	0.49
DL-3		ROCK	3275.90	3285.11	9.21	7.48	0.81	0.18	0.10	0.78
	Sand_3	RES	3275.90	3285.11	9.21	3.99	0.43	0.14	0.13	0.69
		PAY	3275.90	3285.11	9.21	1.99	0.22	0.14	0.14	0.56
		ROCK	3372.11	3450.91	78.81	77.72	0.99	0.06	0.13	0.65
	Sand_4	RES	3372.11	3450.91	78.81	71.74	0.91	0.04	0.13	0.63
		PAY	3372.11	3450.91	78.81	34.39	0.44	0.03	0.14	0.39
	Sand_5	ROCK	3569.63	3608.52	38.89	29.41	0.76	0.10	0.13	0.68
		RES	3569.63	3608.52	38.89	23.93	0.62	0.08	0.14	0.65

		PAY	3569.63	3608.52	38.89	12.96	0.33	0.08	0.15	0.47
		ROCK	3676.58	3702.17	25.59	24.92	0.97	0.11	0.15	0.96
	Sand_6	RES	3676.58	3702.17	25.59	24.42	0.95	0.11	0.15	0.96
		PAY	3676.58	3702.17	25.59	0.00	0.00	-	-	-

Table 4: Result of Petrophysical Characterization of Well D-4

Well	Zones	Flag Name	Top	Bottom	Gross	Net	NTG	Avg. Shale Volume	Avg.Phi	Avg. Sw
			m	m	m	m		v/v	v/v	v/v
		ROCK	3134.90	3173.01	38.11	28.38	0.75	0.07	0.19	0.76
	Sand_1	RES	3134.90	3173.01	38.11	28.38	0.75	0.07	0.19	0.76
		PAY	3134.90	3173.01	38.11	9.00	0.24	0.01	0.19	0.42
		ROCK	3231.88	3318.02	86.14	76.39	0.89	0.08	0.19	0.81
	Sand_2	RES	3231.88	3318.02	86.14	75.89	0.88	0.08	0.19	0.81
DL-4		PAY	3231.88	3318.02	86.14	24.50	0.28	0.11	0.18	0.51
		ROCK	3326.40	3372.43	46.03	38.50	0.84	0.06	0.18	0.46
	Sand_3	RES	3326.40	3372.43	46.03	38.50	0.84	0.06	0.18	0.46
		PAY	3326.40	3372.43	46.03	35.50	0.77	0.04	0.18	0.44
		ROCK	3473.65	3553.56	79.92	75.92	0.95	0.02	0.15	0.90
	Sand_4	RES	3473.65	3553.56	79.92	74.38	0.93	0.02	0.15	0.90
		PAY	3473.65	3553.56	79.92	3.42	0.04	0.02	0.15	0.36

Table 5: Result of Petrophysical Characterization of Well D-5

Well	Zones	Flag Name	Top	Bottom	Gross	Net	NTG	Avg. Shale Volume	Avg.Phi	Avg. Sw
			m	m	m	m		v/v	v/v	v/v
		ROCK	3019.21	3048.59	29.38	21.05	0.72	0.11	0.17	0.88
	Sand_1	RES	3019.21	3048.59	29.38	20.06	0.68	0.10	0.17	0.88
		PAY	3019.21	3048.59	29.38	0.00	0.00	-	-	-
		ROCK	3125.59	3139.91	14.31	10.97	0.77	0.14	0.15	0.57
	Sand_2	RES	3125.59	3139.91	14.31	10.47	0.73	0.14	0.15	0.56
DL-5		PAY	3125.59	3139.91	14.31	8.98	0.63	0.12	0.16	0.53
		ROCK	3208.88	3273.33	64.45	50.89	0.79	0.12	0.14	0.53
	Sand_3	RES	3208.88	3273.33	64.45	48.90	0.76	0.12	0.14	0.52
		PAY	3208.88	3273.33	64.45	40.91	0.64	0.11	0.15	0.47
		ROCK	3392.16	3462.45	70.29	67.30	0.96	0.06	0.13	0.52
	Sand_4	RES	3392.16	3462.45	70.29	61.95	0.88	0.05	0.13	0.50
		PAY	3392.16	3462.45	70.29	58.95	0.84	0.04	0.13	0.49

Table 6: Summary of Average Petrophysical Characterization Results of all the wells

Field	Well Names	No. of Reservoirs	Gross Thickness	Net Thickness	Net Pay Thickness	Net to Gross	Avg. Shale volume	Avg. porosity	Avg. Water saturation
			m	m	m		v/v	v/v	v/v
	DL-1	4	135.38	127.23	36.98	0.94	0.06	0.15 - 0.19	0.93 - 1.00
	DL-2	6	238.17	157.10	25.91	0.66	0.30	0.20 - 0.22	0.40 - 0.61
DL	DL-3	6	208.78	167.97	75.27	0.80	0.20	0.13 - 0.16	0.39 - 0.49
	DL-4	4	250.19	217.15	72.42	0.86	0.18	0.15 - 0.19	0.36 - 0.51
	DL-5	4	178.43	141.37	108.84	0.79	0.26	0.13 - 0.17	0.46 - 0.53

5. Conclusion

A robust petrophysical characterization of reservoirs using well-logs data was achieved in this research. The integrated petrophysical characterization was a critical process in this study to provide a robust petrophysical results for volumetric computation and reservoir management. This involves a comprehensive analysis of various petrophysical properties such as gross thickness, net pay thickness, net to gross, average shale volume, average porosity and average water saturation data to better understand the subsurface rock formations in the study area. All data received from Nigerian Agip Oil Company for this research were reliable and contributed positively to the final output. Effective data quality checks and quality control were performed with the aid Techlog 2015.3 Schlumberger software and Microsoft excel spreadsheet. The data quality checks and control were essential to ensure the integrity and reliability of data used in evaluation. Validating and verifying data at the outset of this project, provided more accurate results and actionable insights thereby reducing the potential misinterpretations in the results of the research.

The reservoir zones were identified and delineated using the available and required well logs suite. The significance of reservoir delineation and correlation in this research, lies in their role in understanding the nature, structure, extent, and characteristics of subsurface reservoirs. This knowledge formed the basis for effective reservoir management, resource estimation, well placement, and production strategies, all of which are essential for successful and economically viable hydrocarbon extraction operations in the study area.

The results obtained from the petrophysical evaluation in Table 6 suggest that the reservoirs identified and delineated are of good quality and economically viable for hydrocarbon extraction.

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