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Petrophysical Characterization and Formation Evaluation of Sandstone Reservoir: Case Study from Osa Creek Oilfield, Niger Delta

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Abstract: This article provides a comprehensive reservoir assessment of five wells in the OSA oilfield, Niger Delta, utilizing well log data. The distributions and thicknesses of sand bodies were ascertained within each well in the field utilizing interactive Petrel subsurface software. The quantitative analysis was conducted for the five exploratory wells, with depth ranges of 9476- 11234ft for the OSA-11, 10585-11952ft for the OSA-22, 10242-12145ft for the OSA-33, 10282-11656ft for OSA-44 and 9905-11358ft for OSA-55. Five separate porous sand formations were detected in the field (Sand_A1, Sand_B2, Sand_C3 and Sand_D4 and Sand_E5). A petrophysical examination was conducted using a set of wire-line logs, including gamma ray, resistivity, neutron, and density logs from the wells. The average gross thickness of the five reservoirs defined was 3316.76ft, while the average net reservoir thickness was 2660.17ft and the average net pay thickness was 1047.96ft. The calculated shale volume varies from 21 to 32%, with average porosity ranging from 14 to 19% and average water saturation ranging from 35 to 54%. The research provided a foundation for identifying and evaluating hydrocarbon-bearing formations. Furthermore, the research will give adequate background for petroleum engineers to evaluate hydrocarbon reservoirs, plan well completion, and optimize production operations throughout the reservoir's lifespan.

Keywords: Petrophysical characterization, formation evaluation, Net-to-Gros, Niger delta, Well logs, Porosity, Water Saturation.

1. Introduction

To find hydrocarbon, a geologist must first understand the geology of the area where sedimentary sand deposition occurs. After the geophysicist has completed seismic surveys and data processing, more susceptible wildcat exploration wells can be drilled to evaluate the most appropriate geological and seismic structural model. Data collection is necessary to determine the extent, quality, and volume of hydrocarbon deposits. The decision to move an exploratory well to completion is based on its economic viability. To determine this feasibility, a qualitative and quantitative study of all available well data is required. This analysis, conducted at the midpoint of a significant financial investment in the field development study, will ultimately decide whether to continue with well completion and pay the associated costs or not. Petrophysics, without a doubt, is an important factor in determining well and field potential.

Resistivity and porosity are the most critical measurements made by convectional logging tools and serve as the foundation of the hydrocarbon industry. Petrophysics is responsible for the conversion of resistivity, gamma ray, and porosity tool measurements into reservoir properties. The purpose of petrophysics evaluation is to analyze, predict, and establish formation lithology and porosity, hydrocarbon saturation, permeability, producibility, and estimate the economic viability of a well by combining well log, core, mud log, and other distinct data sources.

Well logs are used to identify productive zones, correlate zones that are ideal for hydrocarbon accumulation, calculate the depth and thickness of zones, differentiate between gas, oil, and water in a reservoir, and estimate hydrocarbon reserves, according to [2].

The qualitative assessment of petrophysical properties focuses on interpreting geophysical responses to various geological properties, such as the meaning of natural radioactivity in relation to shale content, the interpretation of sonic velocity in relation to shale compaction, the meaning of bulk density in relation to mineral composition, etc [17,20]. This independent study focuses on utilizing geophysical well log data to determine the lithology and fluid type of prospect zones, as well as to predict average water saturation and productive capabilities. Even if log parameter is important, before drilling, additional relevant information such as the drill stem test, mud log assessment, sample shows, surrounding production, etc., should be consulted.

In this study therefore, the goal is to characterize the petrophysical parameter and formation evaluation of sandstone reservoir in the Osa creek oilfield, Niger Delta. The primary objectives of this study are to identify the net to gross thickness of reservoir units, estimate porosity across wells, estimate permeability across wells, estimate water saturation, and estimate reservoir performance.

2. Geology of the Study Area

The research area is the OSA oilfield, situated in the central region of the Coastal Swamp Depobelt within the Niger Delta oil and gas province. The region is situated in the Coastal Swamp Depobelt of the Niger Delta, bounded by longitudes 7° to 8° E and latitudes 4° to 4.5° N (Fig 1). The Niger Delta is located in the Gulf of Guinea and covers the Niger Delta Province as identified by [11]. Since the Eocene epoch, the delta has advanced southwestward, creating Depobelts that signify the most dynamic segment of the delta at each developmental phase [5]. The Depobelts constitute one of the biggest regressive deltas globally, including an area of about 300,000 km², a sediment volume of 500,000 km³, and a sediment thickness of 10 km at the basin depocenter [12]

The onshore segment of the Niger Delta Province is defined by the geological characteristics of southern Nigeria and southwestern Cameroon. The northern limit is the Benin flank, an east-northeast oriented hinge line situated south of the West Africa basement massif. The northeastern limit is delineated by Cretaceous outcrops on the Abakaliki High and extends farther southeast by the Calabar flank, which serves as a hinge line close to the Precambrian [9].

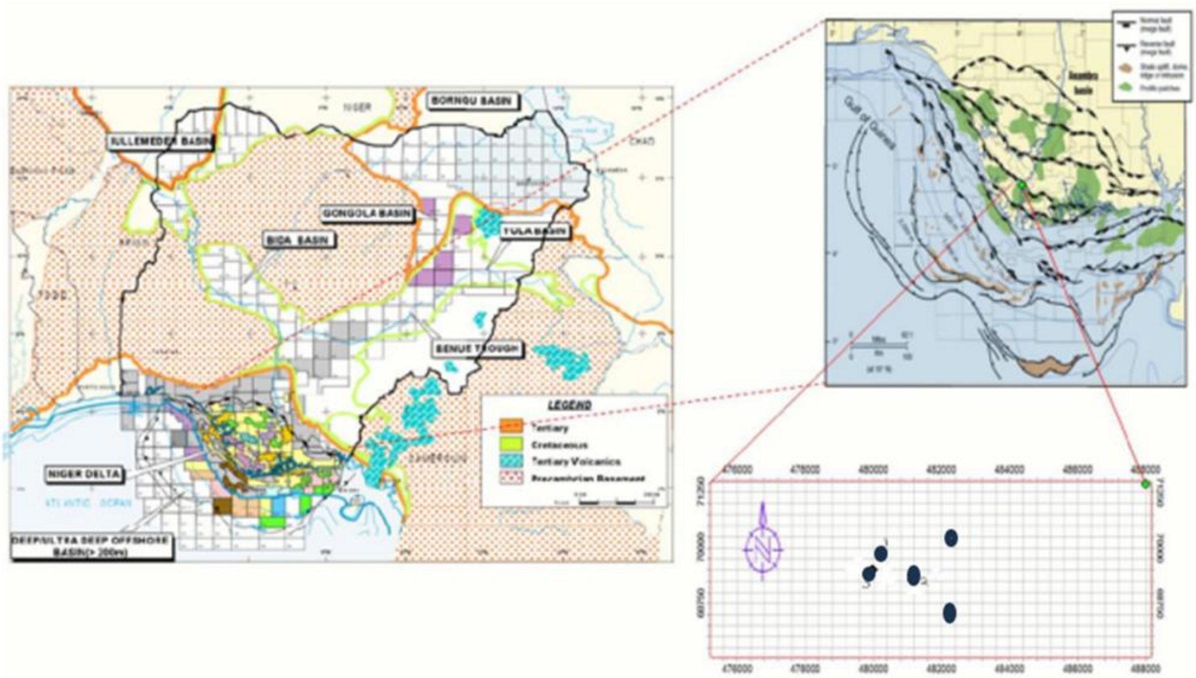

Figure 1: Map of Nigeria Showing the Location of the Niger Delta and the Base map of OSA oilfield with well locations representing OSA_A1, OSA_B2, OSA_C3, OSA_C4 and OSA_E5 (Modified from Whiteman)

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 kilometers 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 [10,12]. This system is referred to here as the Tertiary Niger Delta (Akata-Agbada) Petroleum System. [19,22] in their research stated that Tertiary Niger Delta is divided into three main formations, which represent the prograding depositional 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 classics 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

Five (5) well logs, comprising gamma ray, resistivity, neutron, density, and acoustic logs, were utilized in conducting the investigation. The software utilized was Schlumberger Techlog64, version 2015.3. The well logs were meticulously refined before their use in a modeling workflow on Techlog Workstation. The conditioning of well logs encompasses de-spiking and filtering to eliminate or rectify abnormal data points, as well as normalizing the logs to establish suitable ranges and thresholds for porosity, clay content, water resistivity, and saturation [18].

Determination of Petrophysical Properties

The petrophysical characteristics utilized in this investigation are delineated below. Empirical equations were employed to compute some petrophysical paraft, as they cannot be directly measured from well log data during data collecting.

Determination of Shale Volume (Vsh)

This study used the empirical equation given by [14] for the volume of shale in tertiary rocks.

$$V_{sh} = 0.083[2^{(3.7 \times IGR)} - 1.0] \qquad 1$$

where Vsh is the percentage of shale in the formation and IGR is the Gamma ray index. Gamma ray index was computed using the GR log response IGR [21],

$$I_{GR} = (GR_{LOG} - GR_{MIN})/(GR_{MAX} - GR_{MIN}) \qquad 2$$

Where,

I_{GR} = gamma ray index

GR_{LOG} = gamma ray reading of formation from log

GR_{MIN} =minimum gamma ray (clean sand)

GR_{MAX} = maximum gamma ray (shale)

Determination of Total Porosity (ϕ_D)

Geoscientists widely acknowledge that porosity calculations derived from bulk density logs are more precise [3, 17]. Porosity was calculated using the method referenced in [18]. This was derived from the density porosity log utilizing the equation:

$$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid}) \qquad 3$$

where:

ℓ_{max} =density of rock matrix which is assumed to be 2.65g/cc for sandstones [6];

ℓ_b = Bulk density read directly from the log

ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil and 1.1 g/cc for water).

Determination of Effective Porosity, Φeff

Typically, this is predicated on adjusting total porosity using estimated shale volume (content). [6] states that the following formula provides effective porosity:

$$\Phi eff = \Phi T - [\Phi sh \times Vsh] \quad 4$$

where Φeff = effective porosity; ΦT = total porosity; Φsh = log reading in a shale zone and
Vsh = 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

Determination of Water Saturation

Equation 5 for water saturation was calculated using the Indonesia formula. The [1] parameter, which are as follows: m = 2; n = 2; a = 1, are the primary parameter used.

Determination of the water saturation for the uninvaded zone was achieved using the [1] equation given below.

$$S_w^2 = (F \times R_w)/R_T \quad 5$$

$$\text{But, } F = R_o/R_w \quad 6$$

Thus,

$$S_w^2 = R_o/R_T \quad 7$$

Where:

S_w = water saturation of the uninvaded zone

R_o= resistivity of formation at 100% water saturation

R_T= true formation resistivity

Determination of Hydrocarbon Saturation

This was obtained directly by subtracting the percentage of water saturation from 100.

Thus $S_{hy} = 1 - S_w$

$$\text{Or } S_{hy}\% = 100 - S_w\% \quad 8$$

Where, S_{hy} is the hydrocarbon saturation (expressed as a fraction or as percentage).

Determination of Net-to-Gross Thickness

The net/gross ratio aids in understanding the formation by defining the percentage of intervals that are reservoirs. Since it is represented as a ratio of two values with the same unit, it lacks a unit. The total quality of a zone, regardless of its thickness, is reflected in the net/gross ratio. The zones that include reservoir beds—both productive and non-productive zones—are referred to as reservoir gross thickness. The following is the Net/Gross Reservoir thickness:

$$h = H - hshale \quad 9$$

Net/Gross = h/H, where H = Gross reservoir thickness; h = Net reservoir thickness and hshale = Shale thickness.

Determination of Formation Factor

The 100% water line in dotted red was chosen using the traditional Archie parameter in the saturation equation with the help of the Pickett Plot. The Archie equation

$$F = a/Ø^m \quad 10$$

Where,

F	=	formation factor
a	=	tortuosity factor = 0.62
Ø	=	porosity
m	=	cementation factor = 2.15

Determination of Formation Water Resistivity (R_w)

Using the Archie's equation that related the formation factor (F) to the resistivity of a formation at 100% water saturation (R_o) and the resistivity of formation water (R_w), the resistivity of the formation water was estimated as:

$$R_w = R_o/F \quad 11$$

Cutoffs Sensitivity Analysis

To achieve and accurately model the calculated petrophysical parameter, a sensitivity analysis was performed on the volume of shale (Vsh), porosity, and water saturation to ascertain the final values of the associated variables. A 30% cut-off was applied to the volume of shale (Vsh) sensitivity analysis in order to enhance reservoir quality. A 10% cut-off was used to the porosity sensitivity study in order to get accurate porosity estimations and enhance reservoir net pay values. And to increase the production of the hydrocarbon resources already found in the area, a 60% cut-off was applied to water saturation.

A shale volume (Vsh) value of 30% was utilized to account for hydrocarbon saturation in the silt components of the reservoir rock inside the transition zone.

A porosity cut-off of 10% retains 99% of the residual Hydrocarbon Column (HCOL) subsequent to the application of a volume of shale (Vsh) cut-off of 30%. For the sensitivity analysis of water saturation, 60% was chosen for accurate reservoir description

4. Results and Discussions

The defined reservoirs and geological correlation of the wells in Field OSA are illustrated in Fig. 2, whilst the petrophysical parameter assessed for wells OSA-11 to OSA-55 are detailed in Tables 1, 2, 3, 4, and 5, respectively. Table 6 presents the cumulative overview of all wells.

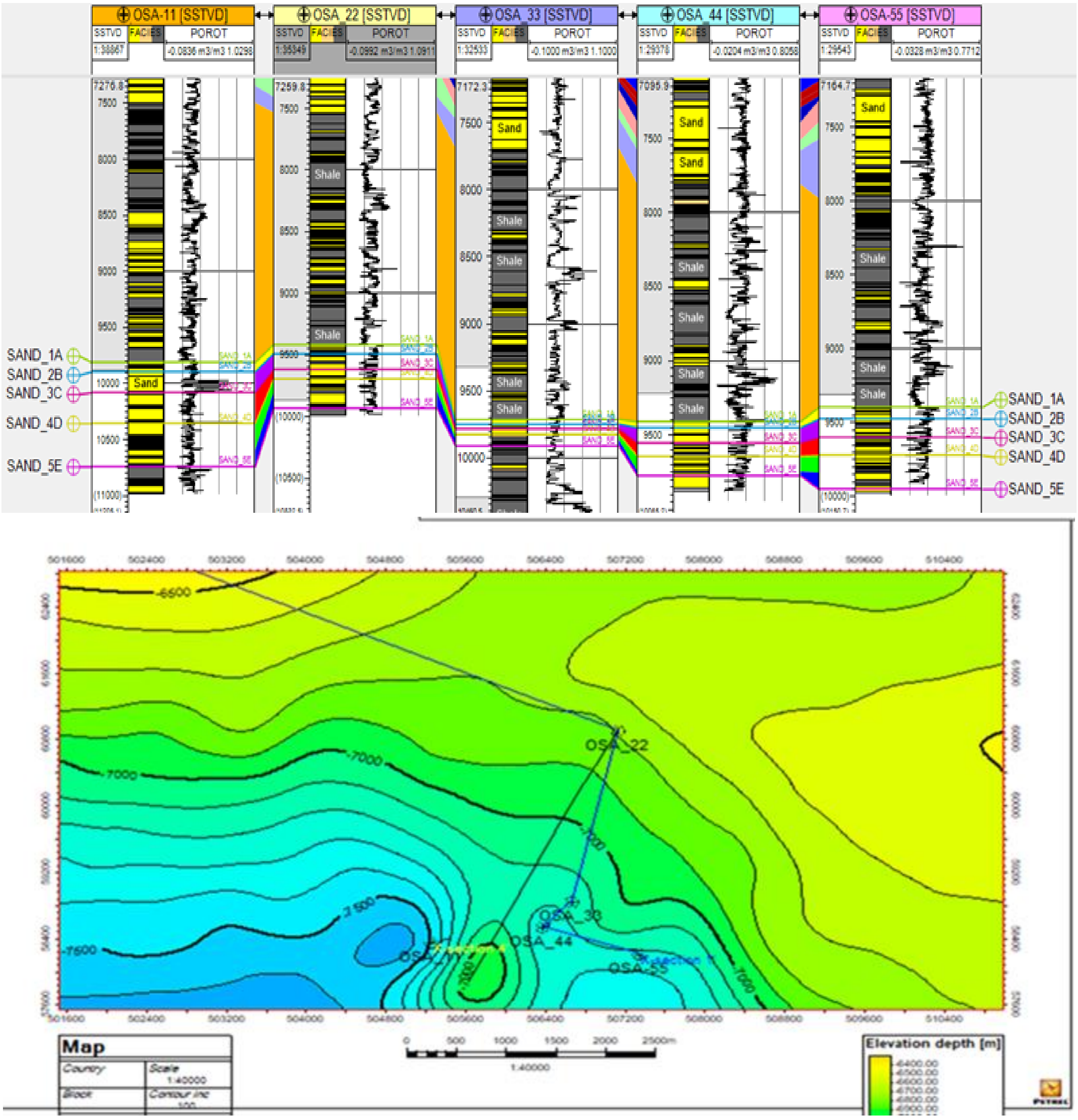

Figure 2: Reservoirs in Wells OSA_A1, OSA_B2, OSA_C3, OSA_C4 and OSA_E5 in Oilfield OSA, (a) Correlation and Delineation of Reservoirs (b) Structural Map of Field OSA oilfield

Findings of Petrophysical Characterization for OSA-11

With a gross thickness of 444.16ft, a net reservoir thickness of 417.42ft, a net pay thickness of 121.32ft, and a net to gross ratio of 0.89, four reservoirs were identified. 8 % is the average shale volume. Average water saturation varies from 74 to 94 %, while average porosity ranges from 0.14 to 0.18 %. Table 1 displays these findings.

Findings of Petrophysical Characterization for OSA-22

With a gross thickness of 781.39ft, a net reservoir thickness of 515.41ft, a net pay thickness of 85.00ft, and a net to gross ratio of 0.71, five reservoirs were identified, 34% is the average shale volume. The average water saturation is between 42 and 62 %, and the average porosity is between 21 and 23 %. Table 2 displays these findings.

Findings of Petrophysical Characterization for OSA-33

With a gross thickness of 684.97ft, a net reservoir thickness of 551.08ft, a net pay thickness of 246.94ft, and a net to gross ratio of 0.82, five reservoirs were identified, 23% is the average shale volume. The average water saturation is between 38 and 48 %, and the average porosity is between 12 and 17 %. Table 3 displays these findings.

Findings of Petrophysical Characterization for OSA-44

With a gross thickness of 820.83ft, a net reservoir thickness of 712.43ft, a net pay thickness of 237.59ft, and a net to gross ratio of 0.90, four reservoirs were identified, 0.18 % is the average shale volume. The average water saturation is between 35 and 52%, and the average porosity is between 14 and 18%. Table 4 displays these findings.

Findings of Petrophysical Characterization for OSA-55

With a gross thickness of 585.40ft, a net reservoir thickness of 463.81ft, a net pay thickness of 357.08ft, and a net to gross ratio of 0.80, four reservoirs were identified, 29% is the average shale volume. The average water saturation is between 45 and 54%, while the average porosity is between 12 and 18 %. Table 5 displays these findings.

Table 1: Result of well OSA-11 showing the Petrophysical Characterization

Well Names	Zones Name	Lithology Flag	Top ft	Bottom ft	Gross Thickness ft	Net Thickness ft	NTG	Avg. Shale Volume %	Avg. porosity %	Avg. Water saturation %
OSA-11	Sand_A1	Sst	9476.41	9545.60	101.7	101.7	3.28	01	18	91
		Reservoir	9476.41	9545.60	101.7	101.7	3.28	01	18	91
		Pay zone	9476.41	9545.60	101.7	1.64	0.06	16	21	91
	Sand_B2	Sst	9646.11	9741.20	94.50	94.50	3.28	01	17	02
		Reservoir	9646.11	9741.20	94.50	94.50	3.28	01	17	02
		Pay zone	9646.11	9741.20	94.50	0.00	0.00	-	-	-
	Sand_C3	Sst	10122.82	10152.54	29.81	29.81	3.28	01	19	02
		Reservoir	10122.82	10152.54	29.81	29.81	3.28	01	19	02
		Pay zone	10122.82	10152.54	29.81	0.00	0.00	-	-	-
	Sand_D4	Sst	11025.31	11234.76	218.70	211.50	3.18	04	08	68
		Reservoir	11025.31	11234.76	218.70	191.80	2.68	04	08	67
		Pay zone	11025.31	11234.76	218.70	119.60	1.80	02	08	54

Table 2: Result of well OSA-22 showing the Petrophysical Characterization

Well Names	Zones Name	Lithology Flag	Top ft	Bottom ft	Gross Thickness ft	Net Thickness ft	NTG	Avg. Shale Volume %	Avg. porosity %	Avg. Water saturation %
		Sst	10585	10663	77.26	69.06	0.87	03	19	86
	Sand_A1	Reservoir	10585	10663	77.26	69.06	0.87	03	19	86
		Pay zone	10585	10663	77.26	0.00	0.00	-	-	-
		Sst	10833	10918	85.30	82.02	0.91	01	24	80
	Sand_B2	Reservoir	10833	10918	85.30	82.02	0.91	01	24	80
		Pay zone	10833	10918	85.30	19.68	0.24	01	24	44
		Sst	10953	11128	175.95	162.23	0.94	02	24	88
	Sand_C3	Reservoir	10953	11128	175.95	162.23	0.94	02	24	88
OSA-22		Pay zone	10953	11128	175.95	0.00	0.00	-	-	-
		Sst	11571	11683	109.31	89.33	0.83	03	19	58
	Sand_D4	Reservoir	11571	11683	109.31	87.69	0.82	04	19	57
		Pay zone	11571	11683	109.31	47.57	0.41	01	24	44

Table 3: Result of well OSA-33 showing the Petrophysical Characterization

Well Names	Zones Name	Lithology Flag	Top ft	Bottom ft	Gross Thickness ft	Net Thickness ft	NTG	Avg. Shale Volume %	Avg. porosity %	Avg. Water saturation %
		Sst	10242	10298	55.11	49.0	0.87	11	17	57
	Sand_A1	Reservoir	10242	10298	55.11	49.0	0.85	08	17	57
		Pay zone	10242	10298	55.11	34.35	0.64	08	18	48
		Sst	10564	10695	129.26	106.36	0.80	13	13	69
	Sand_B2	Reservoir	10564	10695	129.26	96.55	0.79	12	13	63
		Pay zone	10564	10695	129.26	50.68	0.36	07	17	48
		Sst	10744	10777	30.21	24.54	0.71	17	12	77

	Sand_C3	Reservoir	10744	10777	30.21	13.09	0.40	13	14	68
OSA-33		Pay zone	10744	10777	30.21	6.52	0.24	13	13	58
		Sst	11062	11318	258.56	254.98	0.97	07	14	67
	Sand_D4	Reservoir	11062	11318	258.56	238.64	0.90	03	14	64
		Pay zone	11062	11318	258.56	112.82	0.40	04	13	37
		Sst	11709	11840	127.59	96.48	0.79	12	14	69
	Sand_E5	Reservoir	11062	11840	127.59	78.51	0.64	09	13	67
		Pay zone	11062	11840	127.59	42.51	0.34	09	17	49

Table 4: Result of well OSA-44 showing the Petrophysical Characterization

Well Names	Zones Name	Lithology Flag	Top ft	Bottom ft	Gross Thickness ft	Net Thickness ft	NTG	Avg. Shale Volume %	Avg. porosity %	Avg. Water saturation %
		Sst	10282	10410	124.67	93.11	0.78	08	18	77
	Sand_A1	Reservoir	10282	10410	124.67	93.11	0.78	08	18	77
		Pay zone	10282	10410	124.67	29.52	0.22	03	18	44
		Sst	10600	10885	282.61	250.62	0.87	09	18	83
	Sand_B2	Reservoir	10600	10885	282.61	248.98	0.89	09	18	83
		Pay zone	10600	10885	282.61	80.38	0.26	13	17	54
		Sst	10912	11062	151.01	126.31	0.83	08	17	48
	Sand_C3	Reservoir	10912	11062	151.01	126.31	0.83	08	17	48
OSA-44		Pay zone	10912	11062	151.01	116.46	0.79	03	17	43
		Sst	11394	11656	262.02	249.08	0.98	04	16	93
	Sand_D4	Reservoir	11394	11656	262.02	244.02	0.91	04	16	93
	Pay zone	11394	11656	262.02	11.22	0.02	04	16	38	Pay zone

Table 5: Result of well OSA-55 showing the Petrophysical Characterization

Well Name	Zones Name	Lithology Flag	Top ft	Bottom	Gross Thickne	Net Thickne	NTG	Avg. Shale	Avg. porosit	Avg. Water

s				**ft**	**ss ft**	**ss ft**		**Volume %**	**y %**	**saturation %**
		Sst	9905	10000	96.39	69.06	0.74	13	19	87
	Sand_A 1	Reservoir	9905	10000	96.39	65.81	0.67	12	19	87
		Pay zone	9905	10000	96.39	0.00	0.00	-	-	-
		Sst	10252	10298	46.31	35.99	0.79	15	17	56
	Sand_B 2	Reservoir	10252	10298	46.31	35.99	0.72	15	17	58
		Pay zone	10252	10298	46.31	29.46	0.64	14	18	54
		Sst	10524	10738	211.45	166.96	0.77	14	18	54
	Sand_C 3	Reservoir	10524	10738	211.45	160.43	0.77	13	13	53
OSA-55		Pay zone	10524	10738	211.45	134.21	0.65	12	17	48
		Sst	11128	11358	230.61	220.80	0.98	07	14	53
	Sand_D 4	Reservoir	11128	11358	230.61	203.24	0.89	06	14	54
		Pay zone	11128	11358	230.61	193.40	0.74	03	14	48

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

	Well Names	**No. of Reservoirs**	**Gross Thickness ft**	**Net Thickness ft**	**Net Pay Thickness ft**	**Net to Gross**	**Avg. Shale volume %**	**Avg. porosity %**	**Avg. Water saturation %**
	OSA - A1	04	444.16	417.42	121.32	0.89	8	14 - 18	74 - 94
	OSA - B2	05	781.39	515.41	85.00	0.71	34	21 - 23	42 - 62
OSA	OSA - C3	06	684.97	551.08	246.94	0.82	23	12 - 17	38 - 48
	OSA - D4	04	820.83	712.43	237.59	0.90	20	14 - 18	35 - 52
	OSA - E5	04	585.40	463.81	357.08	0.80	29	12 - 18	45 - 54

5. Conclusion

This study used well-log data to provide a reliable petrophysical characterization of reservoirs. A crucial step in this investigation was the comprehensive petrophysical characterization, which produced reliable petrophysical data for reservoir management and volumetric calculation. To get a better understanding of the underlying rock formations in the research region, a thorough examination of a variety of petrophysical paraft is required, including gross thickness, net pay thickness, net to gross, average shale volume, average porosity, and average water saturation data. Every piece of information obtained for this study from Nigerian Agip Oil Company was trustworthy and enhanced the final product. With the use of the Microsoft Excel spreadsheet and Schlumberger Techlog 2015.3 software, efficient data quality checks and quality control were carried out. To guarantee the accuracy and dependability of the data utilized for evaluation, data quality checks and controls were crucial. Data validation and verification at the start of the project reduced the possibility of misunderstandings by producing more accurate findings and useful insights.

The reservoir zones were discovered and delimited utilizing the accessible and requisite well log suite. The importance of reservoir delineation and correlation in this study is in its function in comprehending the nature, structure, extent, and attributes of subsurface reservoirs. This information underpinned good reservoir management, resource assessment, well location, and production methods, all crucial for successful and economically feasible hydrocarbon extraction activities in the studied region. The findings from the petrophysical assessment in Table 6 indicate that the discovered and defined reservoirs possess high quality and are economically feasible for hydrocarbon extraction.

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