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RESEARCH ARTICLE

Hydraulic Flow Unit Characterization in Sandstone Reservoirs, Niger Delta, Nigeria

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ABSTRACT

The key factor in a successful oil field development plan is understanding the reservoir. The effectiveness of oil extraction is determined by variations in the reservoir, specifically the distribution of porosity and permeability. To create an accurate model of the reservoir, the vertical distribution of its qualities must be determined and separated into flow units, each with its own unique characteristics that affect fluid flow. By identifying these flow units, the preferred flow zones can be discovered. The aim of this study is to identify the number and distribution of hydraulic units, their important characteristics, and the flow performance in two specific wells in the Niger Delta, Nigeria, using the Modified Lorenz Plot (MLP) method. In the hydrocarbon-rich intervals of the wells, a total of 18 flow units were found, with 12 in Well 1 and 6 in Well 2. The number of flow units indicates the level of heterogeneity in the reservoir. This study showed that the Modified Lorenz Plot (MLP) is an efficient and low-cost method for defining petrophysical flow units. This research study aims to transform the conventional approach to reservoir characterization by conducting a thorough analysis of hydraulic flow units in sandstone reservoirs located in the complex geological setting of the Niger Delta, Nigeria. By examining the hydraulic properties of reservoir rocks, the study seeks to gain a better understanding of subsurface fluid flow behavior and the potential for hydrocarbon accumulation.

1. Introduction

The Niger Delta region in Nigeria is known for its abundant oil and gas reserves contained in sandstone reservoirs. To optimize production and maximize recovery, it is crucial to understand the flow behavior of fluids within these reservoirs. Hydraulic flow unit characterization is a key tool used in this evaluation, which involves the analysis of the flow properties of subsurface rock formations. This approach helps identify the most permeable zones within a reservoir, which can inform well placement and production strategies [1]. By combining data from various sources, such as well logs, core samples, and seismic sur-

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veys, geologists can gain a comprehensive understanding of the hydraulic flow units within sandstone reservoirs in the Niger Delta. This information is crucial for effective reservoir management and, ultimately, the success of oil and gas operations in the region [2].

The upstream petroleum industry relies on reservoir characterization to gain a comprehensive understanding of the reservoir. The current priority is to enhance these characterization techniques. These advancements are beneficial as they give a more accurate representation of the storage and flow abilities of the petroleum reservoir and significantly decrease the number of residual hydrocarbons [2]. By comprehending essential reservoir features such as pore geometry, tortuosity, and permeability, geologists and engineers can improve reservoir characterization and achieve better reservoir performance and development over time.

Historically, permeability has been evaluated through a linear regression model that assumes a linear relationship between core porosity and permeability [3]. This method fails to account for data dispersion and assumes it's due to measurement errors, ignoring the possibility of high and low permeability zones with similar porosities existing in the same reservoir [4]. Limestone formations with low porosity and high permeability further challenge this assumption [5].

Recognizing these limitations, researchers have shifted their focus to the interdependence of permeability and various depositional characteristics such as grain size, pore geometry, and tortuosity, which are influenced by diagenetic factors like cementation, fracturing, and solution [6]. This calls for a new approach to reservoir characterization that considers geological principles and the physics of fluid flow in porous media [7-9]. The hydraulic flow unit (HFU) approach is proposed as this solution.

An HFU is a rock volume unit with similar fluid flow properties, differentiating it from other units. Unlike lithofacies, which focus on the distribution of lithologies, HFU clusters comparable fluid pathways in the reservoir in [2]. The study on Hydraulic Flow Unit Characterization in Sandstone Reservoirs, Niger Delta, Nigeria, addresses the scientific problem of understanding the distribution of reservoir properties and heterogeneity in sandstone reservoirs, which can impact hydrocarbon production. By accurately characterizing hydraulic flow units, the study seeks to improve field development strategies for the oil and gas industry. This research study aims to examine the impact of various HFUs and RQIs (Reservoir Quality Indicators) on the pressure behavior, flow regimes, and productivity index of horizontal wells in limited reservoirs.

2. Regional Geology and General Stratigraphy of the Niger Delta

The research area is within the Niger Delta Basin, which has been extensively studied [10]. The basin is a large delta on the continent's margin that was built out into the Central South Atlantic Ocean during the Eocene near the mouths of the Niger-Benue and Cross River systems [11]. The delta is affected by tides and waves and has sand bodies whose thickness can be altered by growth faulting [12]. It is the world's second-largest delta, with a shoreline that spans over 450 km and ends at the Imo River's mouth [13]. The region spans approximately 20,000 km^2 and is known as Africa's largest wetland, including freshwater swamps, mangrove swamps, beaches, bars, and estuaries.

Short and Stauble [10] identified the Benin, Agbada, and Akata formations as three subsurface offshore units in the southern Nigerian sedimentary basin, which includes the Niger Delta (as shown in Figure 1). The surface outcrops of these units are referred to as the Benin Formation, Ogwashi-Asaba Formation, and Ameki Formation.

The geology of the Niger Delta is characterized by thick sedimentary sequences that have been deposited over a long period of time. The deposition of these sediments has been influenced by a variety of factors, including sea-level changes, tectonic activity, and climate change, and most reservoirs in the Niger Delta region are sandstone reservoirs. The sedimentary deposits in the Niger Delta have given rise to a vast amount of hydrocarbon resources, making it an important region for oil and gas exploration and production.

3. Methodology

3.1 Materials

This study makes use of wireline log data from three wells in an X field in Nigeria's Niger Delta region. The wireline log data from a field in Nigeria's Niger Delta Region, which included Sonic, Neutron, Density Gamma Ray, and Resistivity logs, was utilized to evaluate hydraulic flow units (HFU) in reservoirs in the Niger Delta Region. Because of existing restrictions inside Nigerian oil companies, the precise site of the wells would not be revealed and is referred to as an X-field for secret or security reasons.

The Interactive Petrophysics (IP v. 4.5) advanced interpretation approach is used for data analysis (2018). Shell Petroleum Development Company would provide the data for this project (SPDC).

3.2 Porosity

Porosity in good logs refers to the measurement of the

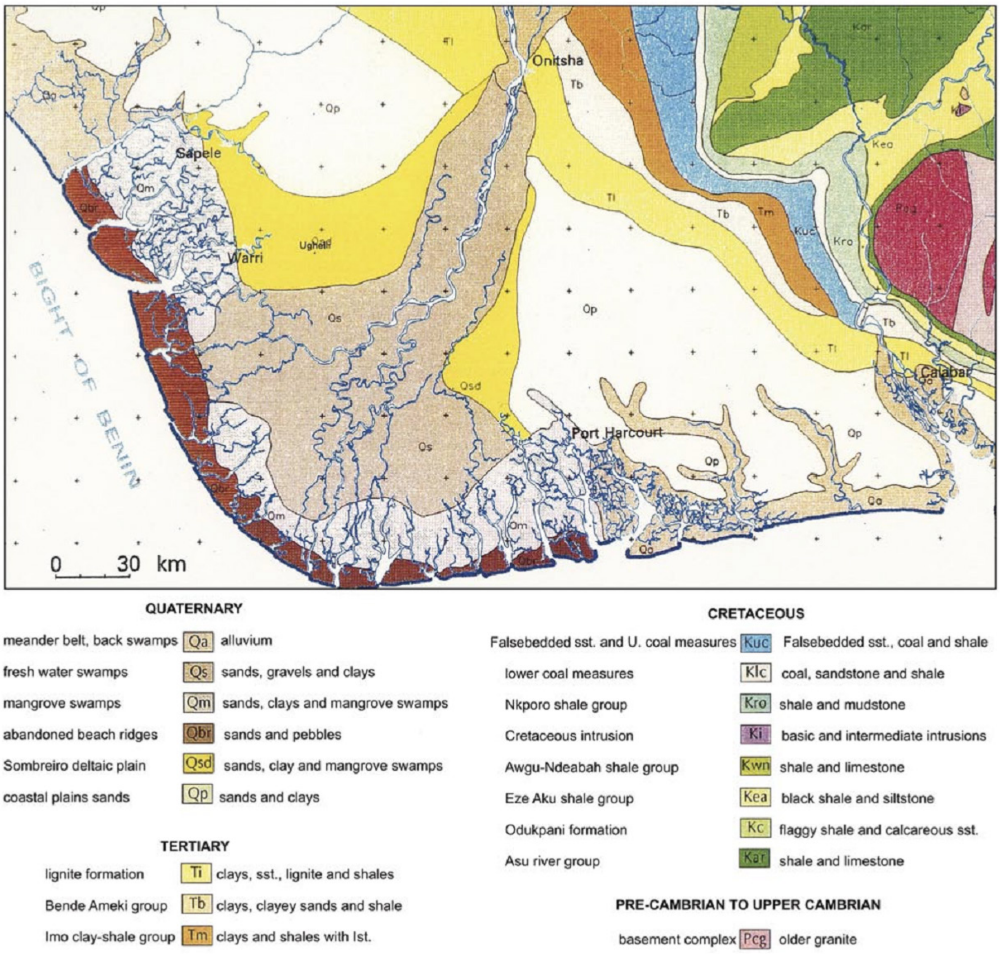

Figure 1. Geological map of Niger Delta and its surroundings.

volume of void space or the pore space within subsurface rock formations [14]. It is commonly used in the oil and gas industry to evaluate the potential for hydrocarbon production from a well [2]. Porosity can be measured using various well-logging tools such as neutron, density, and sonic logs [14]. The results of these logs provide a representation of the rock's porosity as a function of depth, allowing geologists to identify permeable formations and make predictions about fluid flow within the subsurface.

Porosity in sands and sandstones is essentially determined by the degree of connectivity of pores, grain size and shape, packing distribution and arrangement, cementation, and clay concentration [14]. To determine porosity, we must simulate a rock sample and calculate the bulk volume and matrix volume.

$$\phi_{sonic} = \frac{\Delta t_{log} - \Delta t_{ma}}{\Delta t_f - \Delta t_{ma}} \quad (1)$$ [2]

ϕ_{sonic} = sonic derived porosity in clean formation
Δt_{ma} = interval transit time of the matrix
Δt_{log} = interval transit time of formation
Δt_f = interval transit time of the fluid in the well bore

3.3 Permeability

To put it simply, the ease at which fluid can flow through a rock (permeability) is determined by the presence of channels for fluid flow, which is impacted by the rock's qualities such as grain shape and size, pore distribution, and fluid-rock friction. Also, pore spaces can contain more than one fluid, such as gas, oil, and water, and the permeability of each fluid depends on its saturation and properties at varying rates. If there is only one fluid present, the permeability of the rock is at its maximum [2]. When multiple fluids are present in the pore spaces, the permeability of each fluid is called the "effective permeability", and it can differ from each other and not be the same as the permeability of the rock with a single fluid.

Timur equation is given as:

$$K = \frac{0.136\phi^{4.4}}{S_{wi}^2} \quad (2)$$ [2]

where K = permeability
ϕ = porosity
S_{wi} = irreducible water saturation

3.4 RQI (Reservoir Quality Index)

The Reservoir Quality Index (RQI) is a well-log-based index used to quantify the reservoir quality of a subsurface rock formation. It is calculated using multiple well-log measurements, such as resistivity, porosity, and sonic velocity, which are used to estimate key parameters that affect fluid flow in a reservoir, such as permeability and fluid saturations [1]. The RQI provides a single value that summarizes the reservoir quality of a formation, making it easier to compare different formations and rank them in terms of their potential for hydrocarbon production. The RQI is commonly used in exploration and development efforts to help identify the most prospective areas for further investigation and drilling [2,15].

A method called the reservoir quality indicator (RQI) was introduced by Amaefule et al. [16] to categorize reservoir data into different hydraulic flow units (HFUs) with distinct characteristics. This methodology provides a reliable and efficient way to describe the reservoir.

$$\text{Permeability K} = 1014\,\frac{\phi e^3}{(1-\phi e)^2}\left(\frac{1}{F_S\tau^2 S_{gv}^2}\right) \quad (3)\ [15]$$

They expressed the permeability (k) in terms of effective porosity (ϕ_e), shape factor (T_s) for turosity (t) and surface area per unit grain volume (S_{gr}).

The parameters F_s and τ were grouped into a term called Kozeny constant.

The Kozeny constant is related to the permeability of the rock, which is a measure of how easily fluids can flow through it [15]. The higher the Kozeny constant, the higher the permeability of the rock. In sandstone reservoirs, the Kozeny constant can be used to classify the rocks into different hydraulic flow units (HFUs) based on their permeability and porosity properties.

$$K = 1014\frac{\phi e^3}{\phi_e(1-\phi_e)}\text{ x }\left(\frac{1}{F_S\tau^2 S_N^2}\right) \quad (4)\ [15]$$

$$\sqrt{\frac{K}{\phi e}} = \sqrt{\frac{\sqrt{\phi e^2}}{\sqrt{(1-\phi_e)^2}}}\text{ x }\left(\frac{\sqrt{1}}{\sqrt{F_S\tau^2 S_{gv}^2}}\right) \quad (5)\ [15]$$

$$\sqrt{\frac{K}{\phi_e}} = \frac{\phi e}{(1-\phi e)}\text{ x }\left(\frac{1}{\sqrt{F_S\tau^2 S_{gv}^2}}\right) \quad (6)\ [15]$$

The Reservoir Quality Index (RQI), Pore Volume to Grain Ratio (ϕe), and Flow Zone Indicator (FZI) are metrics used in oil and gas exploration and production to evaluate the productivity of hydrocarbon reservoirs. The RQI measures the quality of a reservoir rock based on its permeability and porosity, while the ϕe measures the storage capacity of the rock relative to its grain size [15]. The FZI is a measure of fluid flow properties in the reservoir. These metrics are used together to identify and evaluate potential reservoirs, with a high RQI, high ϕe, and high FZI indicating a high-quality reservoir rock with good storage and flow properties, making it a prime target for oil and gas exploration and production [15].

$$RQI = 0.0314\sqrt{\frac{K}{\phi e}} \quad (7)\ [2]$$

$$\phi_e = \frac{\phi_e}{1-\phi_e} \quad (8)\ [2]$$

$$\phi_e = \frac{\phi_e}{1-\phi_e} \quad (9)\ [2]$$

Substituting Equations (7), (8) and (9) into related parameters as shape factor, tortuosity and surface area per unit grain volume to the ratio of permeability and effective porosity.

3.5 FZI (Flow Zone Indicator)

The Flow Zone Indicator (FZI) is a tool used in well-log analysis to locate permeable zones or flow units within a subsurface formation. It is a computer-generated tool that builds a graphical picture of the rock's permeability using data from many well logs, including resistivity and sonic [2]. The FZI shows places in a hydrocarbon reservoir where fluid flow is expected to happen, which is helpful for identifying probable production zones [17]. The efficiency of hydrocarbon recovery can be increased by optimizing drilling and completion techniques using this information.

The flow zone indicator (FZI) is a valuable tool that connects the flow characteristics of a reservoir between small-scale petroleum physical parameters, such as core plugs, and large-scale measurements, like well bore level. It provides a mathematical representation of flow zones based on surface area and tortuosity [18].

$$FZI = \frac{0.314\sqrt{K/Q}}{\frac{\phi}{1-\phi}} \quad (10)\ [18]$$

where FZI = flow zone indicator, μm

ϕ = porosity

K = permeability, mD

3.6 Stratigraphic Modified Lorenz Plot (SMLP)

A Stratigraphic Modified Lorenz Plot (SMLP) is a type of well log plot used to visualize and interpret subsurface stratigraphic information from well logs [19]. It is a modified version of the Lorenz plot, a plot that displays the cumulative frequency of values on one axis and the cumulative proportion of values on the other axis [19]. In an SMLP, the cumulative frequency is replaced with the stratigraphic position of the log values, and the cumulative proportion is replaced with the deviation from the mean or median value of the log data. The plot allows geologists to identify patterns, trends, and anomalies in the subsurface stratigraphic data, which can be used to help inform interpretations of the subsurface geology.

The Lorenz plot is a diagram used in petrophysics to evaluate the heterogeneous nature of a reservoir. The Lorenz coefficient, provides a single metric to gauge the level of heterogeneity based on the reservoir's porosity and permeability [20,21]. The Lorenz coefficient ranges from 0 to 1. The diagram shows the relationship between flow capacity (KH) and storage capacity (H) in a simple manner but does not indicate the spatial distribution of either flow or storage capacity.

4. Results

Interactive petrophysics was used for the analysis of petrophysical parameters and the hydraulic flow unit. Microsoft Excel was also used for data analysis and graph plotting.

Water saturation (S_w), Volume of Shale (V_{sh}), Bulk Volume of Water (BVW), Permeability (k) and Porosity (ϕ) where the petrophysical parameters estimated in the two wells. The results of the petrophysical and hydraulic parameters are presented in Log panels, graphs and tables. Fractional permeability, fractional porosity, cumulative storage capacity and cumulative flow capacity were the hydraulic flow unit characteristics that were calculated. Alongside RQI and FZI for each flow unit.

Two reservoirs were identified in each of the two wells, based on the sand unit and water saturation values. The hydrocarbon saturation value was inferred from the value of water saturation, where:

$$S_w + S_h = 1 \quad (11)$$ [2]

$$S_h = 1 - S_w \quad (12)$$ [2]

where S_w is water saturation and S_h is hydrocarbon saturation.

Figure 2 shows the correlation based on the sand units and saturation properties. The identified reservoirs in the two wells are between 9976 ft to 12123 ft and net pay zone is between 33 ft to 63.4 ft.

The reservoirs in Well 1, have a net pay zone between 37–63.5 ft as seen in Figure 3 and Table 1. The mean gamma ray values (57.342–57.540 gAPI) correspond to the values of the Volume of Shale (0.394–0.396) indicative of sand units. The resistivity values of the reservoir for Well 1 are between 4.106–45.552 Ohmm. This shows a low value of resistivity corresponding to high hydrocarbon saturation and low water saturation. The mean Bulk Volume of Water in the reservoirs in Well 1 is between 0.082–0.137. The porosity is seen to decrease with depth in Well 1. The porosity values for the reservoirs in Well 1 are between 0.154–0.274, which fall within the range of a good porosity reservoir. The reservoirs are highly permeable, having permeability values ranging from 6.987 mD to 1180.531 mD. In Well 1, the reservoirs are between 9976–10012.5 ft.

The modified Lorenz plot for reservoir 1 is shown in Figure 4. Seven (7) flow units were identified in reservoir 1.

The reservoirs in Well 2, have a net pay zone between

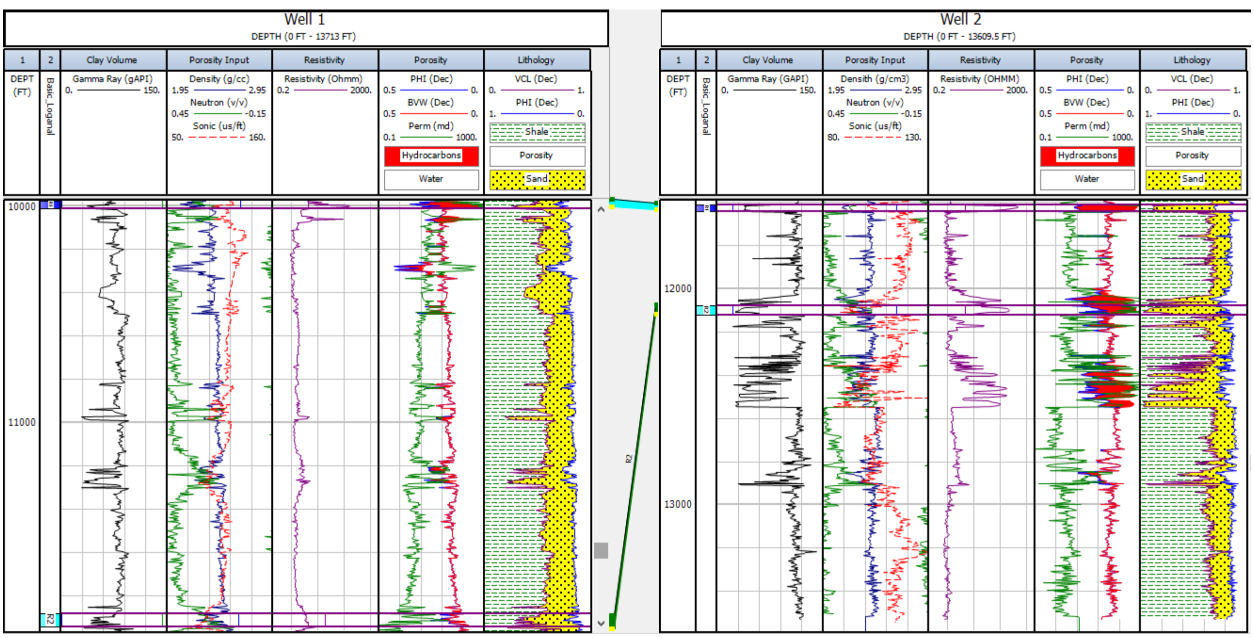

Figure 2. Composite well for well tie for the two wells.

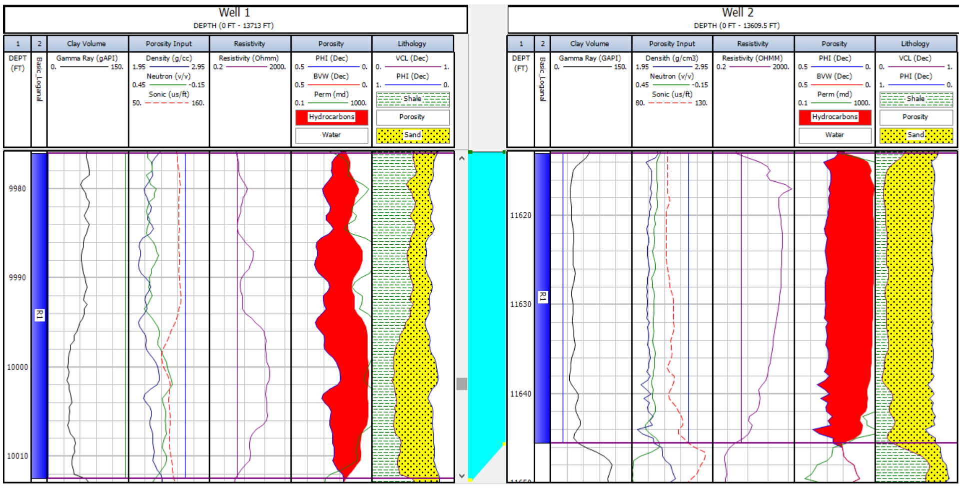

Figure 3. Composite well for (a) Well 1 reservoir 1 (b) Well 2 reservoir 1.

Table 1. Petrophysical properties of the two reservoirs in Well 1.

Well/Reservoir		**Top:9976 ft, Bottom: 10012.5 ft, Net: 37 ft**			**Top: 11882 ft, Bottom: 11944.5 ft, Net: 63.5 ft**		
Curve	Units	Min	Max	Mean	Min	Max	Mean
Bulk Volume of Water	Dec	0.024	0.167	0.082	0.062	0.198	0.137
Density	g/cc	2.062	2.358	2.198	2.221	2.54	2.387
Gamma Ray	gAPI	35.74	77.278	57.54	31.118	88.169	57.342
Neutron	v/v	0.129	0.337	0.242	0.062	0.356	0.211
Permeability	md	4.753	5989.262	1180.531	0.043	46.567	6.987
Porosity	Dec	0.177	0.356	0.274	0.062	0.255	0.154
Resistivity	Ohmm	3.605	171.457	45.553	2.55	8.499	4.106
Sonic	us/ft	93.894	120.684	111.352	67.07	100	88.262
Water Saturation	Dec	0.094	0.941	0.311	0.662	1	0.92
Volume of Shale	Dec	0.241	0.536	0.396	0.208	0.613	0.394

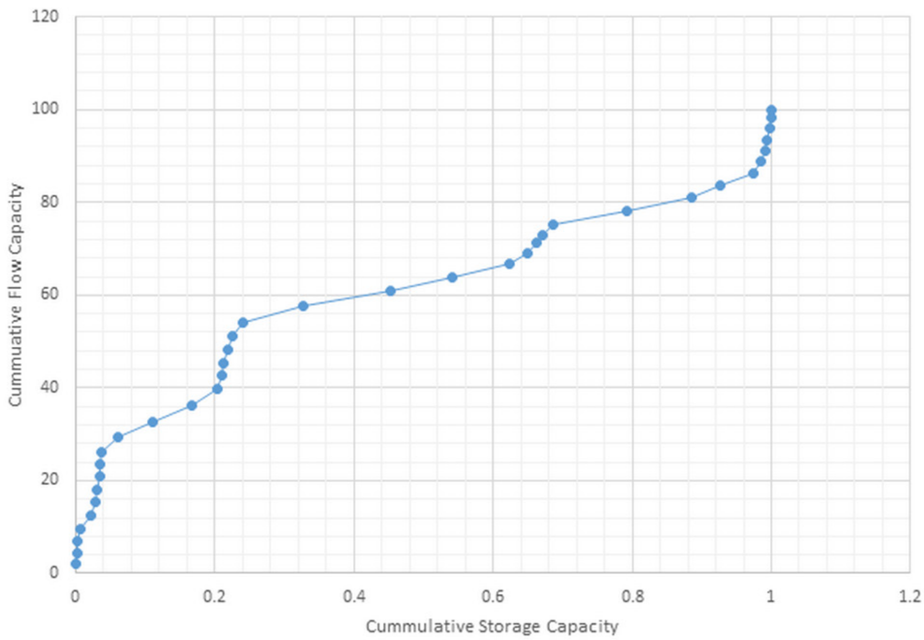

Figure 4. Modified Lorenz plot for reservoir 1, Well 1.

33–44 ft as seen in Figure 5 and Table 2. The mean gamma ray values (42.774–45.683 gAPI) correspond to the values of the Volume of Shale (0.148–0.170) indicative of sand units. The resistivity values of the reservoir for Well 1 are between 106.605–259.063 Ohmm. This shows a low value of resistivity corresponding to high hydrocarbon saturation and low water saturation. The mean Bulk Volume of Water in the reservoirs in Well 1 is between 0.038–0.049. The porosity is seen to decrease with depth in the Well 1. The porosity values for the reservoirs in the Well 1 are between 0.201–0.301, which fall within the range of a good porosity reservoir. The reservoirs are highly permeable, having permeability values ranging from 661.540 mD to 10541.705 mD. In Well 1, the reservoirs are between 11613–12123 ft.

The modified Lorenz plot for reservior 1 is shown in Figure 6, while Table 3, shows hdraulic flow units paprameters for well 1 reservior 1. Figure 7 shows the modified Lorenz plot for reservoir 2. Four (4) flow units were identified in reservoirs 2.

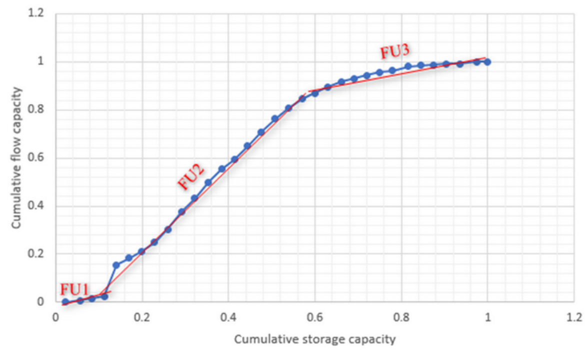

Figure 6. Modified Lorenz plot for reservoir 1, Well 2.

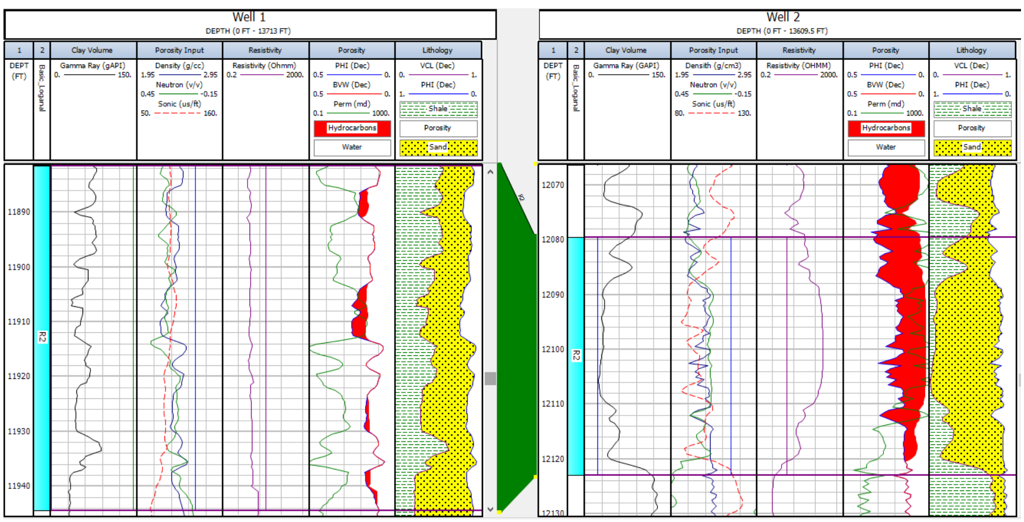

Figure 5. Composite well for (a) Well 1 reservoir 2 (b) Well 2 reservoir 2.

Table 2. Petrophysical properties of the two reservoirs in Well 2.

Well/Reservoir		**Top: 11613 ft, Bottom: 11645.5 ft, Net: 33 ft**			**Top: 12080 ft, Bottom: 12123 ft, Net: 44 ft**		
Curve	Units	Min	Max	Mean	Min	Max	Mean
Bulk Volume of Water	Dec	0.008	0.209	0.038	0.021	0.208	0.049
Density	g/cm^3	2.010	2.268	2.154	2.111	2.49	2.318
Gamma Ray	GAPI	33.885	70.51	42.774	24.38	116.69	45.683
Neutron	v/v	0.243	0.356	0.287	0.153	0.440	0.227
Permeability	mD	20.010	46269.836	10541.705	0.299	8097.911	661.546
Porosity	Dec	0.231	0.388	0.301	0.097	0.327	0.201
Resistivity	OHMM	2.283	1495.330	259.063	1.268	224.667	106.605
Sonic	us/ft	100.939	114.659	103.968	85.943	115.888	96.844
Water Saturation	Dec	0.028	0.826	0.13	0.072	1.000	0.277
Volume of Shale	Dec	0.082	0.354	0.148	0.012	0.697	0.170

Table 3. Hydraulic flow unit for reservoir 1, Well 1.

Depth	K	Porosity	Fractional Permeability	Fractional Porosity	Cumulative Storage Capacity	Cumulative Flow Capacity	Cumulative Storage Capacity	Cumulative Flow Capacity	RQI	FZI
9976	13.1262	0.2042	0.0003	0.0202	0.0202	0.0003	2.0157	0.0300	2.5175	9.8111
9977	62.4081	0.2491	0.0014	0.0246	0.0447	0.0017	4.4746	0.1726	4.9701	14.9821
9978	65.0172	0.2527	0.0015	0.0249	0.0697	0.0032	6.9690	0.3213	5.0366	14.8947
9979	141.3055	0.2667	0.0032	0.0263	0.0960	0.0064	9.6016	0.6442	7.2277	19.8727
9980	666.4240	0.3085	0.0152	0.0305	0.1265	0.0217	12.6468	2.1675	14.5941	32.7125
9985	95.0038	0.2667	0.0022	0.0263	0.2605	0.0377	26.0537	3.7702	5.9264	16.2947
9986	1002.5278	0.3448	0.0229	0.0340	0.2946	0.0606	29.4573	6.0616	16.9315	32.1737
9987	2175.3958	0.3382	0.0497	0.0334	0.3280	0.1103	32.7957	11.0340	25.1833	49.2794
9988	2523.7854	0.3509	0.0577	0.0346	0.3626	0.1680	36.2595	16.8026	26.6296	49.2598
9989	1577.9307	0.3467	0.0361	0.0342	0.3968	0.2041	39.6818	20.4092	21.1834	39.9168
9990	271.3282	0.2988	0.0062	0.0295	0.4263	0.2103	42.6312	21.0294	9.4621	22.2049
9997	3862.6177	0.2939	0.0883	0.0290	0.6381	0.5417	63.8136	54.1654	35.9974	86.4843
9998	3548.2642	0.2927	0.0811	0.0289	0.6670	0.6228	66.7029	62.2757	34.5721	83.5424
9999	1137.1512	0.2430	0.0260	0.0240	0.6910	0.6487	69.1015	64.8749	21.4801	66.9153
10000	612.5842	0.2085	0.0140	0.0206	0.7116	0.6628	71.1597	66.2751	17.0200	64.6107
10001	413.8050	0.1952	0.0095	0.0193	0.7309	0.6722	73.0865	67.2209	14.4573	59.6068
10002	571.0463	0.2139	0.0131	0.0211	0.7520	0.6853	75.1979	68.5261	16.2241	59.6248
10003	4651.8062	0.3048	0.1063	0.0301	0.7821	0.7916	78.2066	79.1588	38.7912	88.4765
10004	4125.7285	0.2939	0.0943	0.0290	0.8111	0.8859	81.1077	88.5890	37.2032	89.3813
10005	1797.7697	0.2564	0.0411	0.0253	0.8364	0.9270	83.6387	92.6981	26.2929	76.2534
10006	2065.7144	0.2648	0.0472	0.0261	0.8625	0.9742	86.2525	97.4197	27.7336	77.0005
10007	498.2383	0.2539	0.0114	0.0251	0.8876	0.9856	88.7588	98.5586	13.9097	40.8744
10008	211.0224	0.2467	0.0048	0.0244	0.9119	0.9904	91.1940	99.0409	9.1835	28.0419
10009	162.0880	0.2388	0.0037	0.0236	0.9355	0.9941	93.5512	99.4114	8.1807	26.0767
10010	170.8218	0.2376	0.0039	0.0235	0.9590	0.9980	95.8966	99.8018	8.4193	27.0156
10011	78.2902	0.2309	0.0018	0.0228	0.9818	0.9998	98.1758	99.9808	5.7819	19.2588

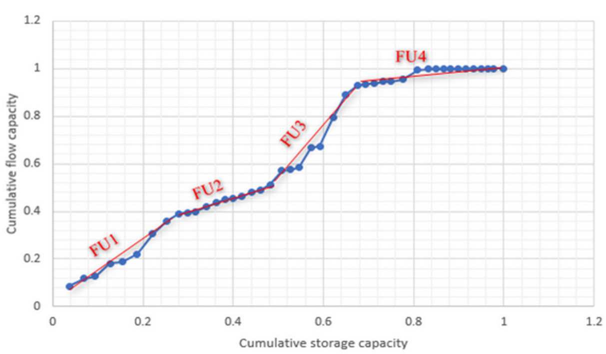

Figure 7. Modified Lorenz plot for reservoir 2, Well 2.

5. Discussion

In this study, two wells (Well 1 and Well 2) were investigated to evaluate their respective hydrocarbon reservoirs. The results indicate that Well 1 has a net pay zone ranging from 37 feet to 63.5 feet, while Well 2 has a net pay zone ranging from 33 feet to 44 feet. The net pay zone refers to the thickness of the rock formation that contains hydrocarbons and can be economically produced.

The gamma-ray values for both wells show values that correspond to sand units, as indicated by the volume of shale values ranging from 0.394 to 0.396 for Well 1 and from 0.148 to 0.170 for Well 2. These results suggest that both wells contain sandstone reservoirs, which are known to be good reservoirs for hydrocarbons due to their high porosity and permeability. The resistivity values for Well 1 range from 4.106 Ohmm to 45.552 Ohmm, indicating high hydrocarbon saturation and low water saturation. A similar trend is observed in Well 2, with resistivity values ranging from 106.605 Ohmm to 259.063 Ohmm. These results suggest that both wells have a high potential for producing hydrocarbons.

The bulk volume of water in both wells ranges from 0.038 to 0.137 for Well 1 and from 0.038 to 0.049 for Well 2. This indicates that the water saturation in both wells is relatively low, further supporting the potential for hydrocarbon production. The porosity values for both wells decrease with depth, with values ranging from 0.154 to 0.274 for Well 1 and from 0.201 to 0.301 for Well 2. Despite the decrease in porosity with depth, the values fall within the range of a good porosity reservoir. The permeability values for both wells are high, ranging from 6.987 mD to 1180.531 mD for Well 1 and from 661.540 mD to 10541.705 mD for Well 2. This suggests that both wells have good flow properties, further supporting the potential for hydrocarbon production.

The modified Lorenz plot was used to identify flow units within the reservoirs. Three flow units were identified in reservoir 1, and four flow units were identified in reservoir 2, as shown in Figures 6 and 7, respectively. These flow units are important for characterizing the reservoirs and understanding the fluid flow properties within them. Overall, the results suggest that both wells have good potential for producing hydrocarbons.

6. Conclusions

In summary, this study aimed to characterize hydraulic flow units in sandstone reservoirs located in the Niger Delta region of Nigeria using well-log data and the Modified Lorenz Plot (MLP) method. Four hydrocarbon-rich intervals from two wells were evaluated, and the analysis revealed variations in reservoir properties, including thickness, porosity, and permeability. The number of flow units determined the level of heterogeneity in the reservoir, with a greater number indicating more challenges in hydrocarbon production. The ultimate goal of identifying flow units is to enhance our understanding of reservoir behavior and minimize uncertainties in field development economics.

Two wells were evaluated using well log data that had four hydrocarbon-rich intervals. The analysis showed the thickness of the reservoirs varied from 33 ft to 63.5 ft, with porosity ranging from 15.4% to 35.6% and permeability from 6.987 mD to 1054.17 mD. The Modified Lorenz Plots (MLP) were used to define flow units based on the slope inflection of flow capacity. Well 1 had 12 flow unit intervals with a thickness of 37 ft to 63.5 ft, while Well 2 had 6 flow units with a thickness of 33 ft to 44 ft. More flow unit intervals indicate greater heterogeneity in the reservoir, leading to poor hydrocarbon production.

The MLP method proved to be a reliable and cost-effective approach for defining petrophysical flow units. Well 1 had 12 flow unit intervals, while Well 2 had 6, suggesting a higher level of heterogeneity in Well 1. Overall, the study contributes valuable insights into the hydraulic flow unit characterization of sandstone reservoirs in the Niger Delta region of Nigeria and can potentially aid in the optimization of field development strategies for the oil and gas industry.

Author Contributions

The research was a collaborative effort, with Boniface I. Ijeh responsible for drafting the protocol and Esomchi U. Nwokoma designing the study. The initial draft of the manuscript was written by Chukwunenyoke Amos-Uhegbu and Esomchi U. Nwokoma. Esomchi U. Nwokoma supervised the field investigation, while Boniface I. Ijeh and Chukwunenyoke Amos-Uhegbu carried out the analysis of the geophysical data. Chukwunenyoke Amos-Uhegbu also oversaw the literature searches. All authors read and approved the final manuscript.

Conflict of Interest

There is no conflict of interest.

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