



Petrophysical Evaluation of Reservoir Properties Using Well Logs and 3D Seismic Data: A Case Study of the 'Northern' Field, Niger Delta

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Abstract

An integrated 3-D seismic data, check shot data and a suite of four well logs within the Northern field, Niger Delta were analyzed with Petrel software for reservoir characterization and petrophysical analysis of the field. The method adopted involves petrophysical analysis, structural analysis and reservoir classification. Detailed petrophysical analysis revealed two reservoirs. Average reservoir parameters such as porosity, gross thickness, hydrocarbon saturation, net-gross were derived from the petrophysical analysis. Structural analysis of the data showed fault assisted anticlinal structures which serve as structural traps that prevent the leakage of hydrocarbon from the reservoirs. The analysis of the all the well sections revealed that each of the sand units extends through the field and varies in thickness with some unit occurring at greater depth than their adjacent unit that is possibly evidence of faulting. The shale layers were observed to increase with depth along with a corresponding decrease in sand layers. From the analysis of the resistivity log, the two delineated reservoirs were identified as hydrocarbon bearing units across the four wells (North 10, North 5, North 7, and North 11). The area extent of the reservoir from the depth maps and the summary of the average results of the significant petrophysical parameters used as variables that determine reservoir quality in the Northern field and based on this, RES 1 was classified as the most prolific reservoir in the Northern field while RES 2 is less prolific.

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1.0 Background of Study

The Niger Delta is a major hydrocarbon-producing region located in southern Nigeria, renowned for its vast oil and gas reserves. This region has been a focal point for petroleum exploration and production activities since the mid-20th century. The Niger Delta complex geology is characterized by a combination of deltaic and shallow marine depositional environments and has resulted in the formation of numerous oil and gas fields, making it one of the most prolific hydrocarbon provinces globally (Doust & Omatsola, 1990; Avbovbo, 1978). Reservoir characterization and petrophysical evaluation are essential components of subsurface geological studies, critical for optimizing hydrocarbon recovery and reservoir management. These processes involve the detailed analysis of reservoir properties, including the study of rock porosity, permeability, fluid saturation, and the spatial distribution of these properties (Tiab & Donaldson, 2015; Lucia, 2007). Accurate characterization allows for the development of robust geological models, which are crucial for making informed decisions regarding drilling, production, and reservoir management (Selley, 1998). The Northern Field, located within the Niger Delta, represents one of the many marginal fields in this region. Marginal fields are typically smaller fields that were initially deemed uneconomical to develop but have gained renewed interest due to advancements in technology and changes in economic conditions (Nwankwoala & Warmate, 2014; Aigbedion & Iyayi, 2007). Despite the potential of the Northern Field, there has been limited detailed study and characterization of its reservoir properties. This lack of comprehensive data hampers the ability to fully exploit the field's

hydrocarbon resources (Ehirim & Ebeniro, 2013). Given the economic importance of the Niger Delta and the need to optimize resource recovery, it is imperative to conduct a thorough reservoir characterization and petrophysical evaluation of the Northern Field. Such a study will provide valuable insights into the subsurface properties of the field, enabling more efficient and effective development strategies. By integrating well logs and seismic data, this research aims to evaluate and characterize the reservoirs in the field and give a guide on future exploration and production activities in the Northern Field and similar marginal fields within the Niger Delta (Dandekar, 2013; Schlumberger, 1989). The findings from this study are expected to contribute significantly to the body of knowledge on reservoir characterization in the Niger Delta, offering practical implications for the oil and gas industry (Akpan *et al.*, 2020 a, b). Enhanced understanding of the Northern Field's subsurface properties will not only aid in maximizing hydrocarbon recovery but also in reducing operational risks and improving overall field management practices.

2.0 Location and Geology of Study Area

The “Northern” field as shown in figure 1 is located within the shallow offshore area of Niger delta in Nigeria. Geographically, the Niger Delta Basin lies between latitudes 3°N and 6°N and longitudes 5°E and 8°E. It is bounded to the north by the Anambra Basin, to the west by the Dahomey Basin, and to the east by the Calabar Flank and the Cameroon volcanic line (Weber & Daukoru, 1975). The basin extends southward into deep offshore areas, where it transitions into the Gulf of Guinea's continental slope and abyssal plain. The well locations are shown in figure 2.

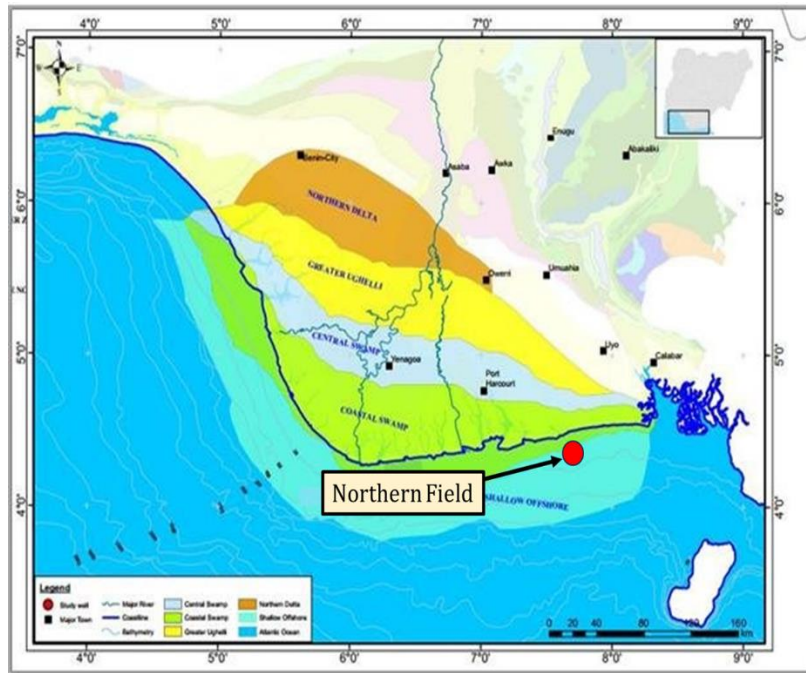


Figure 1. Map of the study area showing the location of Northern field

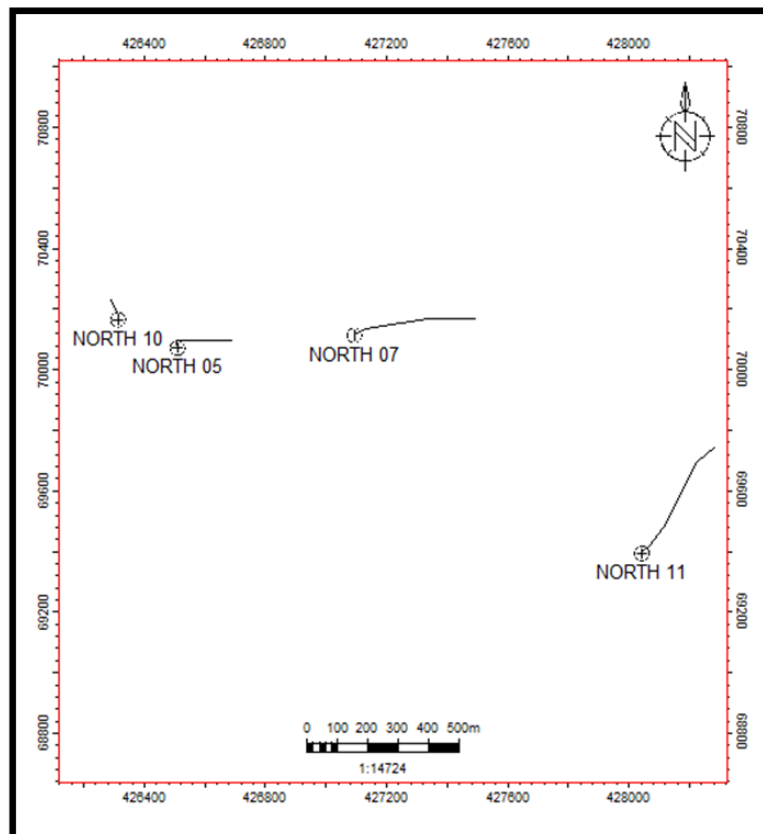


Figure 2: Base map of the study area showing the well locations.

2.1 Geology of the Study Area

The Niger Delta Basin, one of the world’s most prolific hydrocarbon provinces, is located on the Gulf of Guinea in West Africa. It spans an area

of about 300,000 km² and has a sedimentary thickness exceeding 12 km in some areas (Short & Stauble, 1967). The geological evolution of the basin has been largely controlled by

sedimentary processes, deltaic progradation, and tectonic activity linked to the opening of the South Atlantic Ocean.

The lithology of the Niger Delta Basin is dominated by three main lithostratigraphic units: the Akata, Agbada, and Benin Formations. The Akata Formation is the deepest unit, composed mainly of marine shales with minor sandstone and siltstone interbeds. This formation serves as the primary source rock for hydrocarbons in the basin and was deposited under anoxic conditions in deep marine settings, resulting in high organic matter content essential for petroleum generation (Weber & Daukoru, 1975). The Agbada Formation consists of alternating sandstones and shales, representing the transitional zone between deep marine and deltaic environments. The sandstone units form the major hydrocarbon reservoirs of the Niger Delta, while the shales act as seals (Doust & Omatsola, 1990). The Benin Formation is the youngest and most continental of the three formations, composed predominantly of massive, highly porous sands with minor clay intercalations. It was deposited in fluvial and upper deltaic environments (Short & Stauble, 1967). The stratigraphy of the Niger Delta Basin reflects a classic regressive sequence, with deep marine deposits at the base transitioning to shallow marine and then fluvial deposits at the top. The Akata Formation was deposited in the Paleocene-Eocene, forming marine shales in deepwater environments. By the Eocene-Oligocene, the Agbada Formation began to develop, marking a shift from deepwater to transitional deltaic conditions (Evamy *et al.*, 1978). The final stage of delta progradation occurred in the Miocene-Recent period with the deposition of the Benin Formation, characterized by fluvial sands and gravels. This phase resulted from an increasing sediment supply from the Niger River system, expanding the delta seaward (Doust & Omatsola, 1990). The depositional environment of the Niger Delta Basin developed through a complex interaction

of fluvial, deltaic, and marine processes. The delta evolved as a wave-dominated system in its early stages but later transitioned to a tide- and fluvial-dominated system due to increased sediment input (Doust & Omatsola, 1990). The Akata Formation represents deep marine deposits formed under low-energy conditions, while the Agbada Formation records high-energy delta front and distributary channel environments (Horsfall *et al.*, 2023). The Benin Formation, composed mainly of fluvial sands, marks the final phase of delta progradation. The tectonic evolution of the Niger Delta Basin is linked to the breakup of Gondwana and the opening of the South Atlantic Ocean during the Late Jurassic to Early Cretaceous. The rift phase initiated the formation of the basin as the African and South American plates separated, creating accommodation space for thick sedimentary sequences (Doust & Omatsola, 1990). The subsequent passive margin phase led to continuous sedimentation and subsidence, contributing to the basin's deltaic growth (Weber & Daukoru, 1975). The massive sediment load of the Niger Delta resulted in the development of large-scale listric growth faults and shale diapirs, which play a crucial role in hydrocarbon migration and accumulation (Evamy *et al.*, 1978). The interplay of lithology, stratigraphy, depositional processes, and tectonic forces has shaped the basin into a world-class petroleum system (Akpan *et al.*, 2022 a). Its well-defined lithostratigraphic units, deltaic sedimentation history, and structural framework make it one of the most significant hydrocarbon provinces globally.

3.0 Materials and Methods

3.1 Materials

Materials used in this study include a well header, suit of well logs, 3D seismic volume, check shot data, deviation data. The seismic data was used to map the areal extent of the reservoirs to aid in their characterization. The datasets were stored on the workstation and analyzed using Schlumberger Petrel 2014.

3.2 Methodology

The sequence in which the data interpretation was carried out is demonstrated in the workflow (Figure 3) below.

3.3 Well Data Import

The sequence of data import begins with the well heads and logs. The well heads file, contain the

well name, surface location of the wells (2D-XY coordinate system), Kelly bushing (Kb), the top depth and bottom depth. This will allow the display of well position on the base map. The logs (gamma ray, resistivity, density, porosity, water saturation and volume of shale) were then imported for all the wells.

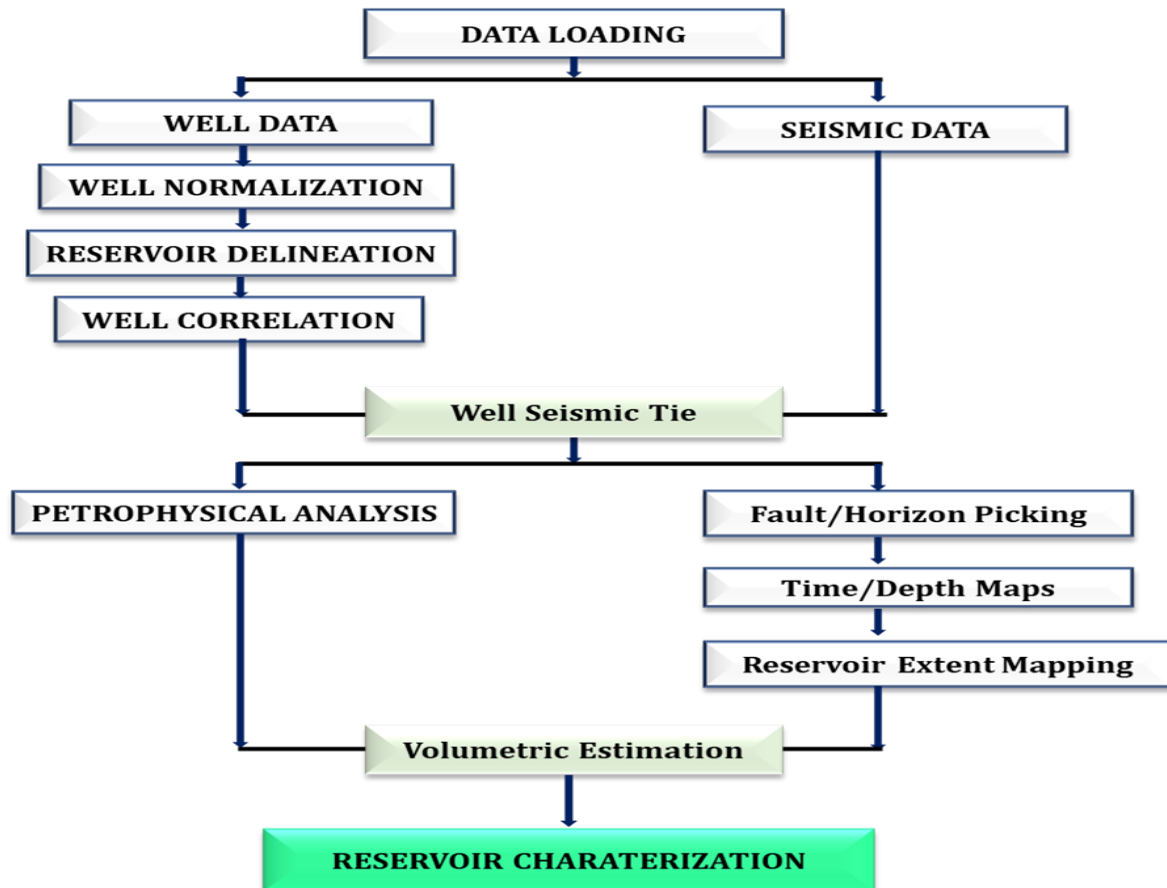


Figure 3: Workflow for reservoir characterization and petrophysical analysis of Northern Field

3.4 Delineation of Lithologies

Sand and shale bodies were delineated from the gamma ray log signatures. Sand bodies were identified by deflection to the left due to the low concentration of radioactive minerals in sand while deflection to the right signifies shale which is as a result of high concentration of radioactive minerals in it.

3.5 Identification of Reservoirs and Differentiation of Hydrocarbon and Non-hydrocarbon Bearing Zones

Reservoirs are subsurface formations that contain water and hydrocarbon. They were identified by using the log signatures of both gamma and resistivity logs. Intervals that have high resistivity are considered to be hydrocarbons while low resistivity zones are water bearing intervals. A combination of the gamma ray and resistivity logs were used to differentiate between the hydrocarbon and non-hydrocarbon bearing units. The scale increases from left to right, with a range of 0-150 for the gamma ray log and 0.2-2000-ohm meter for the resistivity. As the hydrocarbon saturation

increases, resistivity also increases; on the other hand, as water saturation increases, the resistivity decreases. This is indicated by the deflection on the resistivity log.

3.6 Well Correlation

The logs were activated and displayed on the well section window, on which correlation was carried out using the lithology log (Gamma ray log), the resistivity was used to check the fluid contents present within the sediments i.e. hydrocarbon or water. The top and base of the reservoir was picked.

3.7 Determination of Petrophysical Parameters

3.7.1 Determination of Gross and Net Sand Reservoir Thickness

Gross reservoir thickness interval is the interval covering shale and sand within a reservoir. Net thickness of sand is the interval covering only sand within a reservoir. It is called net productive sand. The gross reservoir thickness is determined by knowing interval covering both sand and shale within the reservoir studied using gamma ray log, the values was used as inputs in equation 1 below.

$$NTG = \frac{\text{Net Thickness}}{\text{Gross Thickness}} \quad 1$$

3.7.2 Volume of Shale (VSH)

The gamma ray log was used to calculate the volume of shale in a porous reservoir. The first step used to determine the volume of shale from a gamma ray log was the calculation of the gamma ray index using the equation 2 below:

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

where I_{GR} = Gamma ray index, GR_{log} = Gamma ray reading of the formation, GR_{min} = Minimum gamma ray (clean sand) and GR_{max} = Maximum gamma ray (shale). All these values were read off within a particular reservoir. Having obtained the gamma ray index, volume of shale was then calculated.

3.7.3 Porosity (\emptyset)

Porosity is defined as the percentage of voids to the total volume of rock. The formation density log was used to determine formation porosity. The porosity was determined by substituting the bulk density readings obtained from the density log within each reservoir into the equation 3 below;

$$\emptyset = \frac{P_{mat} - P_{bulk}}{P_{mat} - P_{fluid}} \quad 3$$

where P_{mat} = Density of Rock Matrix, P_{bulk} = Bulk Density and P_{fluid} = Fluid Density. The criteria for classifying porosity are given by Baker (1992) as: $\emptyset < 0.05$ = Negligible, $0.05 < \emptyset < 0.1$ = Poor, $0.1 < \emptyset < 0.15$ = Fair, $0.15 < \emptyset < 0.25$ = Good, $0.25 < \emptyset < 0.30$ = Very good, $\emptyset > 0.30$ = Excellent.

3.7.4 Permeability

Permeability refers to the amount of fluid (usually hydrocarbon) which, as a function of time and pressure, can flow through a rock and it is a function of the degree of interconnection between the pores (Akpan et al. 2022 b). So far, formation testing is the only instrument that can assess the permeability of a rock down a well in-situ. Permeability also can be empirically derived using the relationship between other well log measurements (porosity and sonic logs). Equation 4, known as Timur's Equation, provides an estimation:

$$k = 0.136 \times \emptyset^4 \times S_{wirr}^{-2} \quad 4$$

where S_{wirr} = Irreducible water saturation and \emptyset = Porosity

3.7.5 Estimation of Water Saturation

Water saturation relates to the water occupying porous space fraction and it is usually calculated using information from a tool that records the rock's resistivity and the symbol is S_w . Irreducible Water saturation, refers to water saturation in which all the water present within a formation adhere on the grains within the formation (Asquith & Gibson, 1982). At irreducible water saturation, water calculated in the uninvaded zone (S_w) will not move because

it is held on grains by capillary pressure. A formation at irreducible water saturation will produce water-free hydrocarbon.

Determination of the water saturation for the uninvaded zone was achieved using the Archie's (1942) formula shown in equation 5:

$$S_w^n = \frac{a}{\phi^m} \cdot \frac{R_w}{R_t} \quad 5$$

where S_w : Water saturation, R_w : Formation water resistivity, R_t : True formation resistivity, ϕ : Porosity, a : Tortuosity factor (1), m : Cementation exponent (typically 1.8–2.0 for sandstones) and n : Saturation exponent (typically 2.0 for water-wet rocks).

3.7.6 Formation Factor (F)

The formation factor was determined from the Archie's (1942) equation 6 below;

$$F = \left[\frac{a}{\phi^m} \right] \quad 6$$

where ϕ = Porosity, a = constant (0.62) and m = cementation exponent (2 for sands).

3.8 Seismic Interpretation

The seismic volume was imported into the user defined folder in SEG-Y format and then realized. From the realized volume, inline, crossline and time slice were inserted. A 3-D window and a new interpretation window was used to view and also to carryout fault mapping. The faults were mapped on the cross-lines and the continuity viewed on the in-lines.

3.8.1 Picking of Faults

A fault is a break in continuity of any geologic unit, which has involved either a lateral or vertical movement of any part of the rock unit, caused by varying geologic processes. The major difference between fault and fracture is that displacement of unit is associated with fault while no displacement whatsoever is associated with fracture. The conditions for fault mapping used are: (a) Abrupt termination of reflection events and (b) Displacement or distortion of reflection.

Most of the faults seen on the seismic section were not continuous across the seismic volume, but major and minor faults that were continuous were mapped. Fault planes and fault polygons using the variance attribute time slice were generated. The faults were posted on the surfaces using the fault polygons.

3.8.2 Seismic to Well Tie

In order to ensure the continuity of events both on the seismic section and wells, well to seismic tie was done. On an interpretation window, the wells with the reservoir tops and bases were displayed. This was superimposed on the seismic lines to ensure that there was accurate tie between the well and seismic events. To ensure the accuracy of the seismic to well tie, the bulk shift method was applied followed by the squeeze and stretch method.

3.8.3 Mapping of Horizons

A horizon is a surface separating two different rock layers. The surface is identified by distinctive reflection pattern that can be observed over a layer with relatively large extent. Identification of prospective sand is from the composite logs available. In area without well control, strong reflection on the seismic section can be selected for mapping. Time to depth conversion was done, and the corresponding depth structure map was produced.

3.8.4 Generation of Time Structural Maps

The horizons mapped on both cross line and inline were used to generate a 3-D grid that was auto tracked and used to generate time structure maps for the top and base of the reservoirs.

3.8.5 Time to Depth Conversion

Time to depth conversion was done using the polynomial function generated from the check shot data.

3.8.6 Generation of Depth Structure Maps

The time structural maps were converted into the corresponding depth maps using the check shot data provided.

3.8.7 Reservoir Area Extent Mapping

The area extent of each reservoir was determined from the depth structural maps. The last close contour was gridded in square and the length of the square was determined. Using $\text{Area} = L \times L$ the area of a single square was obtained. The total number of the square within the reservoir was multiplied by the unit area in order to get the total area of the reservoir.

4.0 Result and Discussion

4.1 Reservoir Identification and Well

Correlation

The well correlation results (Figure 4) reveal that the lithology of the study area consists primarily of interbedded sand and shale sequences, a common characteristic of the Agbada and Benin Formations in the Niger Delta Basin. The upper sections of the wells contain thick, freshwater-bearing sands, which are characteristic of the Benin Formation, while the lower sections are dominated by shale intercalated with hydrocarbon-bearing sands, representing the Agbada Formation. Based on the lithological analysis, it is evident that the wells penetrated the Benin, and Agbada Formation. The Benin Formation is predominantly fluvial to deltaic in origin, consisting of unconsolidated sands with minor shale interbeds, typically devoid of hydrocarbons (Akpan et al., 2023). In contrast, the Agbada Formation represents the main petroleum system of the Niger Delta, comprising alternating sands and shales deposited in a turbidite, deltaic, and paralic environment (Short & Stauble, 1967; Doust & Omatsola, 1990). The well correlation analysis identified two prominent reservoir units, designated RES 1 and RES 2, which are laterally extensive across the field but vary in thickness and depth. These variations suggest the presence of syndepositional growth faults, which influence reservoir geometry and hydrocarbon distribution. The neutron porosity and density log responses indicate the presence of gaseous hydrocarbons in the reservoirs, evidenced by low-density and low hydrogen index values

adjacent to the reservoir zones. Such characteristics are indicative of high-energy depositional environments where sand bodies form significant hydrocarbon reservoirs (Avbovbo, 1978). The identification of these reservoirs is consistent with previous studies that describe Niger Delta reservoirs as stacked, multi-layered sand bodies, deposited in a progradational sequence influenced by deltaic growth faults (Weber & Daukoru, 1975; Evamy et al., 1978). The presence of fault-induced compartmentalization within the field suggests the need for further analysis of fault seals and lateral continuity, as these factors can impact reservoir performance and connectivity.

4.2 Petrophysical Analysis

4.2.1 Petrophysical Properties of RES 1

The petrophysical evaluation of RES 1 (Table 1) reveals that the reservoir occurs at depths ranging from 3538.42 ft to 3934.82 ft across the four wells. The net-to-gross (NTG) ratio, which measures the proportion of sandstone relative to the total rock volume, varies between 0.57 and 0.77, indicating that RES 1 is predominantly composed of high-quality sand with minimal shale content. The porosity (Φ) values range from 0.22 to 0.25, averaging 0.24, which falls within the range for good-quality hydrocarbon reservoirs in the Niger Delta (Adeoye & Enikanselu, 2009). The permeability (K) values, which influence fluid flow and production potential, range from 1117 mD to 1407 mD, confirming excellent reservoir deliverability. The water saturation (S_w) values vary from 0.41 to 0.73, with an average of 0.52, suggesting that hydrocarbons are the dominant pore-filling fluid but with some water encroachment. Reservoirs within the Agbada Formation typically exhibit porosities between 0.20 and 0.35, permeabilities exceeding 1000 mD, and NTG values above 0.6 (Doust & Omatsola, 1990; Weber, 1987). The values obtained for RES 1 align well with these benchmarks, reinforcing its classification as a high-quality hydrocarbon-bearing interval. The comparative plot showing variation of

petrophysical parameters across RES 1 interval is shown in Figure 5.

4.2.2 Petrophysical Properties of RES 2

The RES 2 interval as shown in Table 2 is located at depths ranging from 3743.4 ft to 4182.77 ft across the four wells. The NTG ratio ranges from 0.54 to 0.81, indicating good reservoir quality but with slightly more shale content than RES 1. The porosity (Φ) values range from 0.16 to 0.24, with an average of 0.20, which is slightly lower than RES 1. This reduction in porosity can be attributed to greater burial depth, leading to increased compaction and diagenetic effects (Weber, 1987). The permeability (K) values range from 1078 mD to 1368 mD, indicating relatively high reservoir

connectivity. However, the water saturation (S_w) varies significantly, with an average of 0.64, indicating a higher risk of water encroachment and early water production. This suggests that RES 2 may require water control strategies to optimize hydrocarbon recovery (Evamy et al., 1978). Studies on Niger Delta reservoirs indicate that higher water saturations (>50%) can reduce hydrocarbon mobility and production efficiency (Doust & Omatsola, 1990; Adeoti et al., 2010). The lower porosity and higher water saturation of RES 2 suggest that it is more heterogeneous and may have compartmentalized zones with variable fluid distributions. The comparative plot showing variation of petrophysical parameters across RES 2 interval is shown in Figure 6.

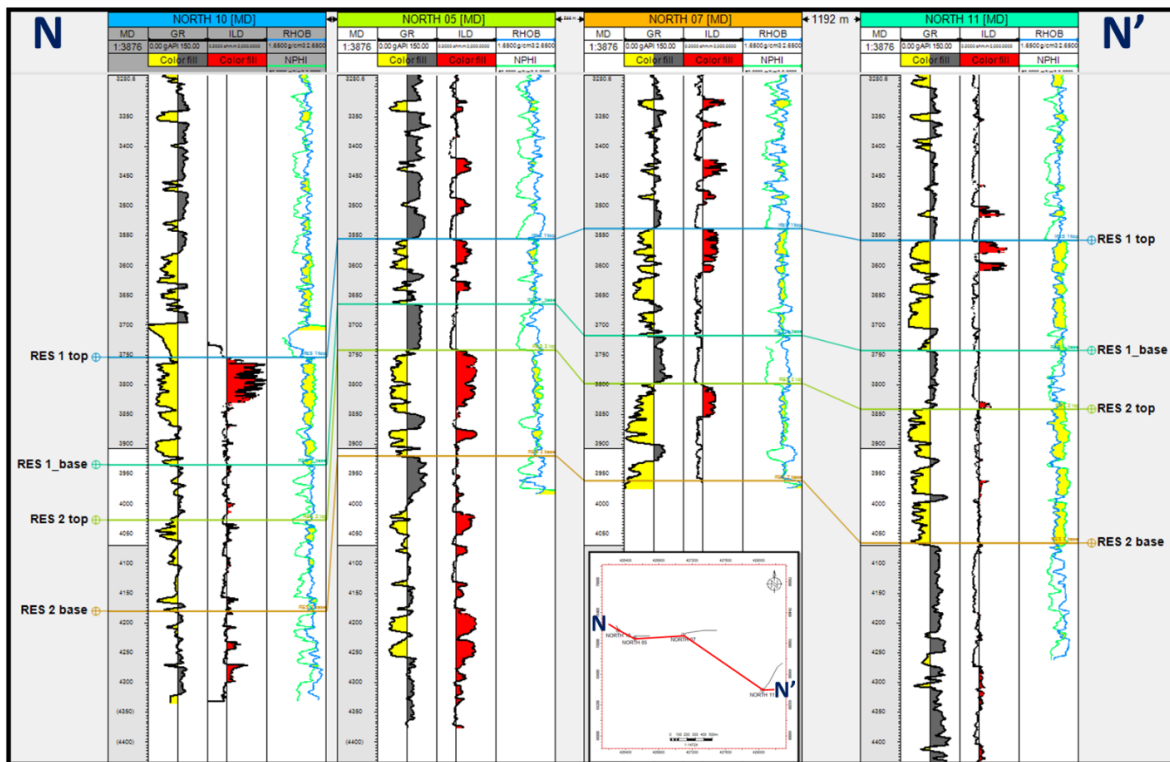


Figure 4: Well Correlation Panel across Northern Field showing The Top & Base of Reservoir 1 and 2 (values are in feet).

Table 1: Petrophysical Results for RES 1 Interval

RES 1							
WELL	Top	Base	Gross Sand Thickness	NTG	Porosity	Sw	Perm
	ft	ft	ft	frac	frac	frac	mD
NORTH 10	3762.3	3934.82	172.52	0.572	0.222	0.414	1117
NORTH 5	3551.53	3665.22	113.69	0.645	0.24	0.418	1265
NORTH 7	3538.42	3659.12	120.7	0.706	0.25	0.541	1407
NORTH 11	3557.78	3705.91	148.13	0.776	0.253	0.734	1301

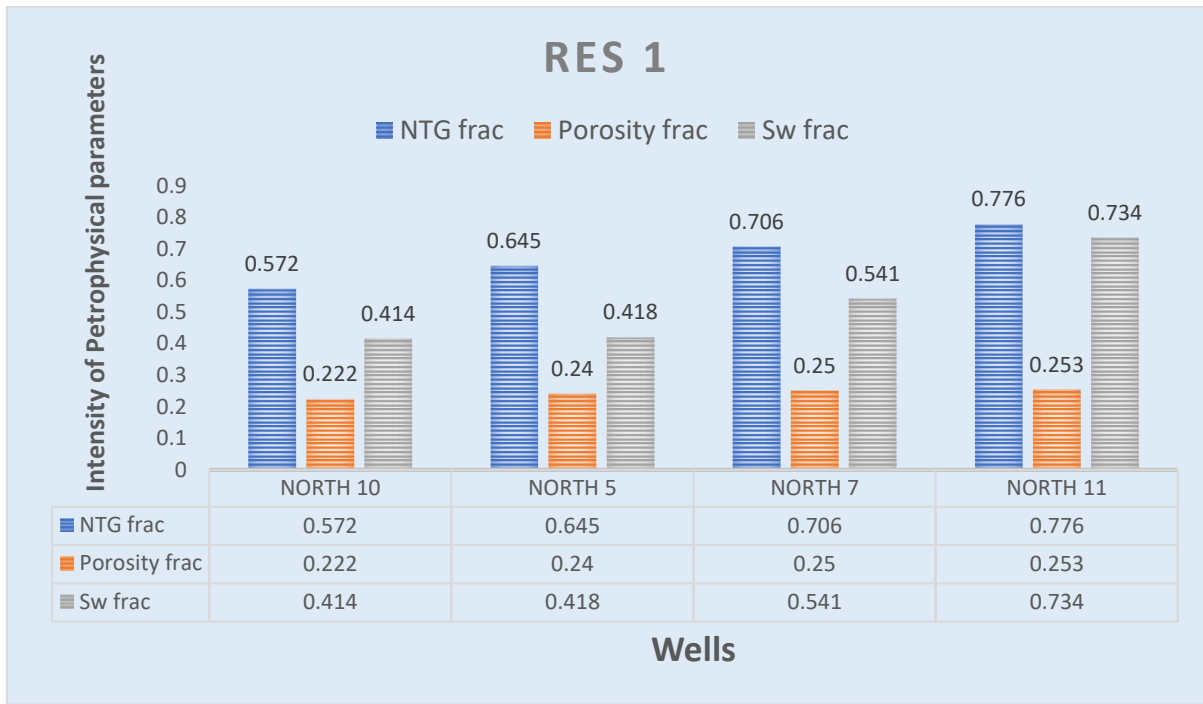


Figure 5: Petrophysical plot for RES 1 interval showing intensity of parameters

Table 2: Petrophysical Results for RES 2 Interval

RES 2							
WELL	Top	Base	Gross Sand Thickness	NTG	Porosity	Sw	Perm
	ft	ft	ft	frac	frac	frac	mD
NORTH 10	4026.26	4182.77	156.51	0.544	0.161	0.883	1078
NORTH 5	3743.4	3849.32	105.92	0.818	0.222	0.262	1254
NORTH 7	3815.79	3950.51	134.72	0.711	0.207	0.743	1187
NORTH 11	3837.43	4070.3	232.87	0.743	0.247	0.693	1368

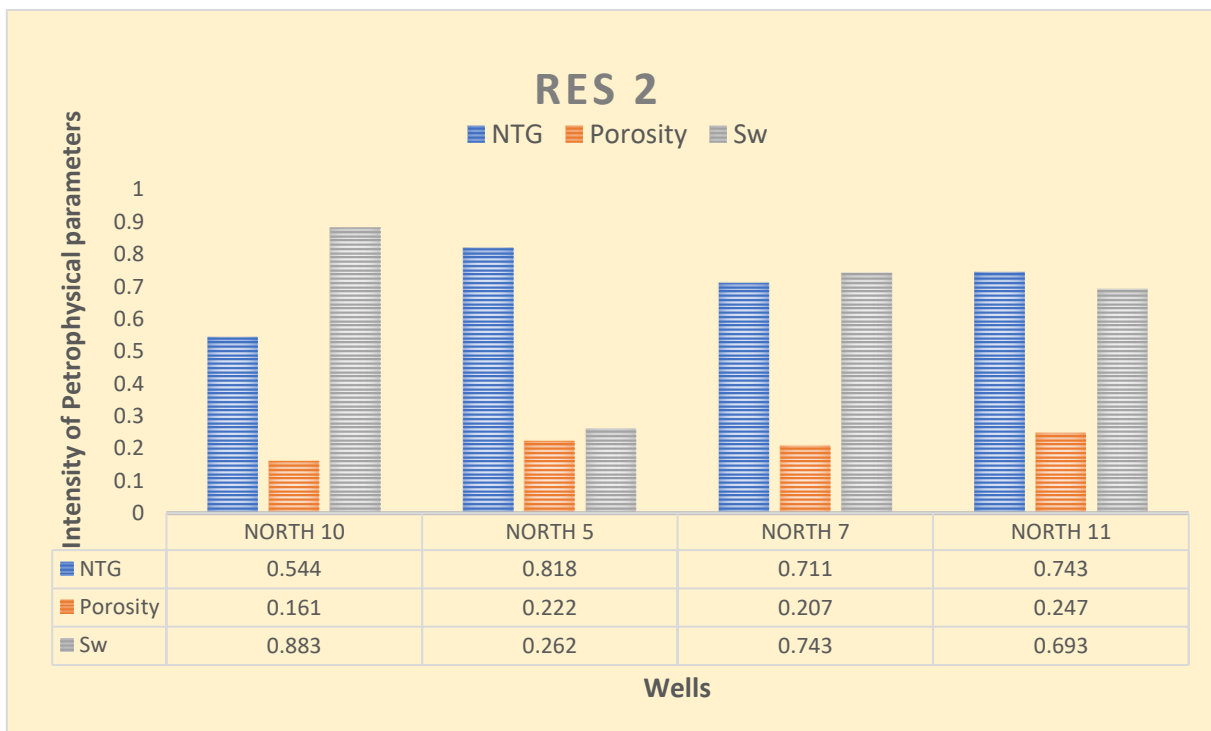


Figure 6: Petrophysical plot for RES 2 interval showing intensity of parameters

4.3 Synthetic Seismogram

The synthetic seismogram, generated using North 11 well data and a Ricker wavelet, serves as a crucial tool for correlating well log data with seismic reflections. The results indicate a strong match between the modeled and observed seismic responses, allowing for accurate reservoir top and fluid contact identification (Figure 7). Synthetic seismograms play an

essential role in reservoir characterization as they bridge the gap between well-based and seismic-based interpretations. This technique is widely applied in hydrocarbon exploration to validate seismic picks, enhance stratigraphic resolution, and improve structural mapping (Brown, 2004).

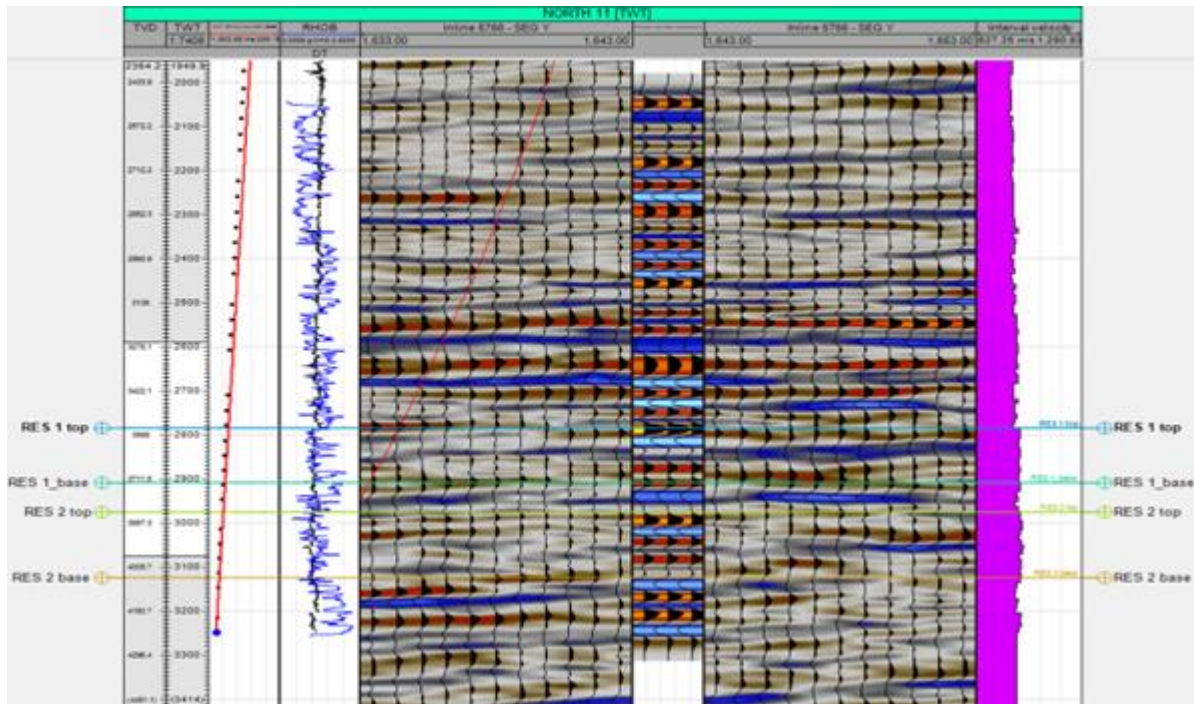


Figure 7: Synthetic seismogram showing the identified reservoirs from well North 11

4.4 Structural Interpretation

The fault mapping analysis revealed the presence of growth faults with rollover anticlines, which are characteristic of the extensional tectonic setting of the Niger Delta (Figure 8). A total of 19 faults were identified, with 11 showing significant continuity across the mapped area. These faults are listric in nature, exhibiting both synthetic and antithetic patterns common in gravity-driven fault systems (Weber & Daukoru, 1975). These growth faults act as both migration pathways and trapping mechanisms for hydrocarbons. The presence of faulted anticlines suggests that hydrocarbons are concentrated within structural highs, similar to fields described by Evamy *et al.* (1978) and Doust & Omatsola (1990).

4.4.1 Time Structural Map

The time structural maps for the two identified reservoirs (RES 1 and RES 2) were generated using interpreted seismic horizons and fault polygons. These maps, displayed in Figures 9 and 10, illustrate the dominant structural trapping mechanisms in the study area. The structural configuration of both reservoirs is characterized by a well-defined faulted anticlinal structure, forming a four-way dip closure in the central portion of the mapped horizons. This anticlinal feature, associated with crescentic growth faults, suggests a rollover structure, which is a primary trapping mechanism in the Niger Delta (Doust & Omatsola, 1990; Weber, 1987). The rollover anticlines trend in a northwest-southeast to

northeast-southwest direction, following the dominant extensional stress regime of the region. The presence of rollover anticlines is

significant because they provide structural closures that allow for the accumulation of hydrocarbons.

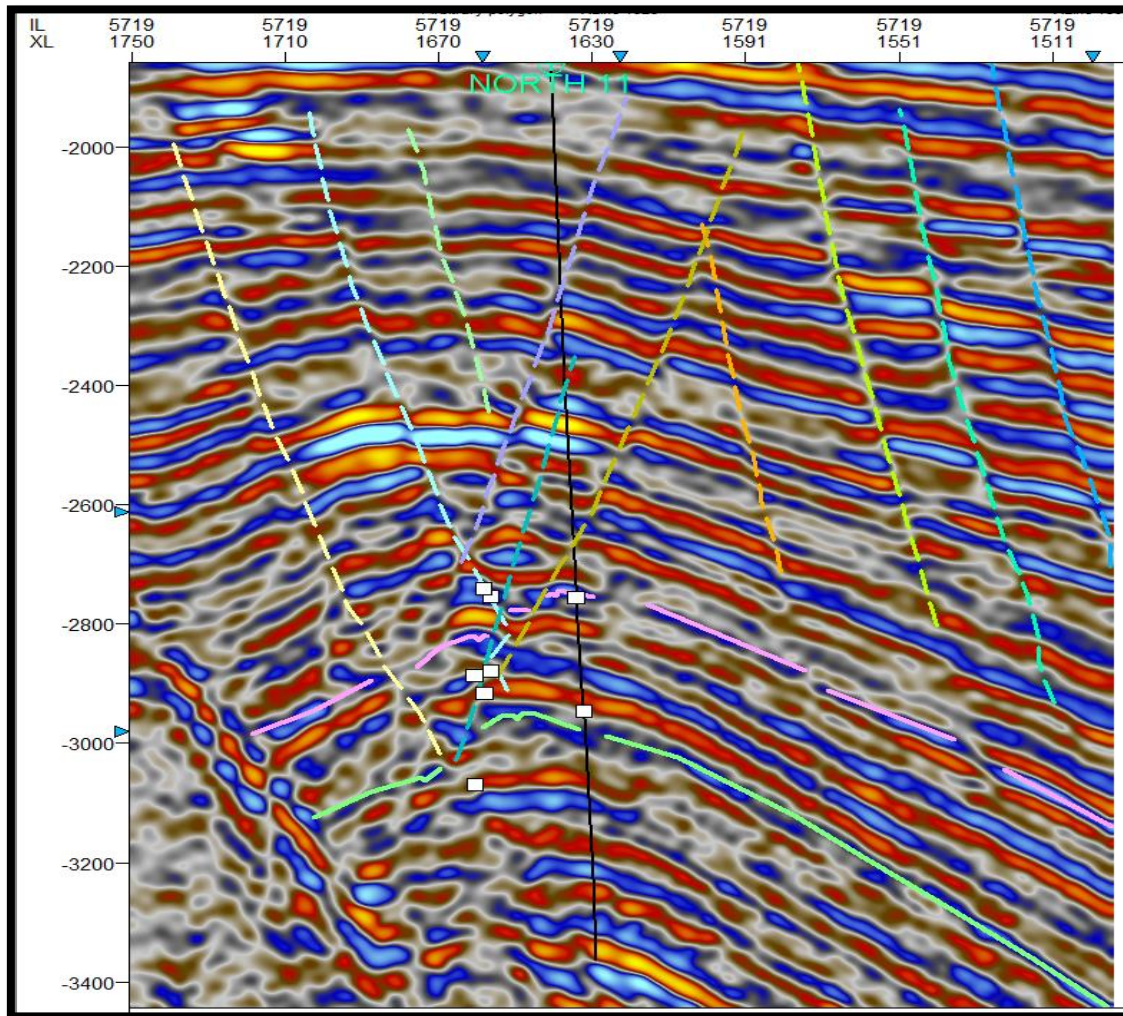


Figure 8: Seismic inline 5719 showing mapped faults and horizons

These structures develop due to syn-depositional faulting, where continuous sediment loading leads to differential compaction and fault block rotation, forming conducive traps for hydrocarbons (Weber & Daukoru, 1975; Evamy *et al.*, 1978). Previous studies in the Niger Delta have highlighted that growth fault-related rollovers account for more than 70% of hydrocarbon accumulations in the region (Doust & Omatsola, 1990; Adeoti *et al.*, 2010). The structural patterns observed in RES 1 and RES 2 are consistent with findings in similar deltaic settings, reinforcing the reliability of the interpreted trapping mechanism.

4.4.3 Depth Structural Map

To determine the true subsurface configuration, the time structural maps were converted into depth structural maps using the time-depth conversion polynomial function shown in Figure 11. The depth structural maps for RES 1 and RES 2, presented in Figures 12 and 13, confirm the presence of fault-bounded anticlinal structures and structural closures, reinforcing the viability of these reservoirs for hydrocarbon accumulation.

The depth maps provide crucial insights into the areal extent of each reservoir by delineating the hydrocarbon-filled portions within enclosing structural contours. The mapped reservoir extents were determined as follows:

- RES 1: 281.369 acres
- RES 2: 218.219 acres

These values indicate that RES 1 has a larger aerial extent than RES 2, which aligns with its higher hydrocarbon volumetrics and better petrophysical properties (Section 4.2). The difference in extent could be attributed to variations in depositional environment, fault

compartmentalization, and diagenetic influences (Doust & Omatsola, 1990). Hydrocarbon-bearing reservoirs in the Niger Delta generally have areal extents ranging between 200 and 500 acres, with rollover structures acting as primary trapping mechanisms (Doust & Omatsola, 1990; Avbovbo, 1978). The mapped extents of RES 1 and RES 2 fall within these typical ranges, further validating the structural interpretation.

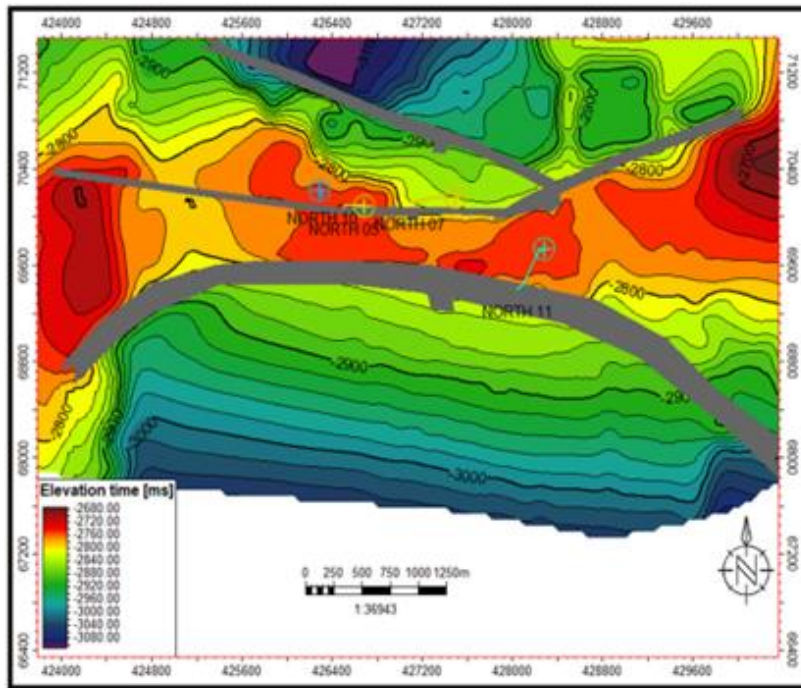


Figure 9: Res 1 Time structural map showing the faulted anticlinal structure

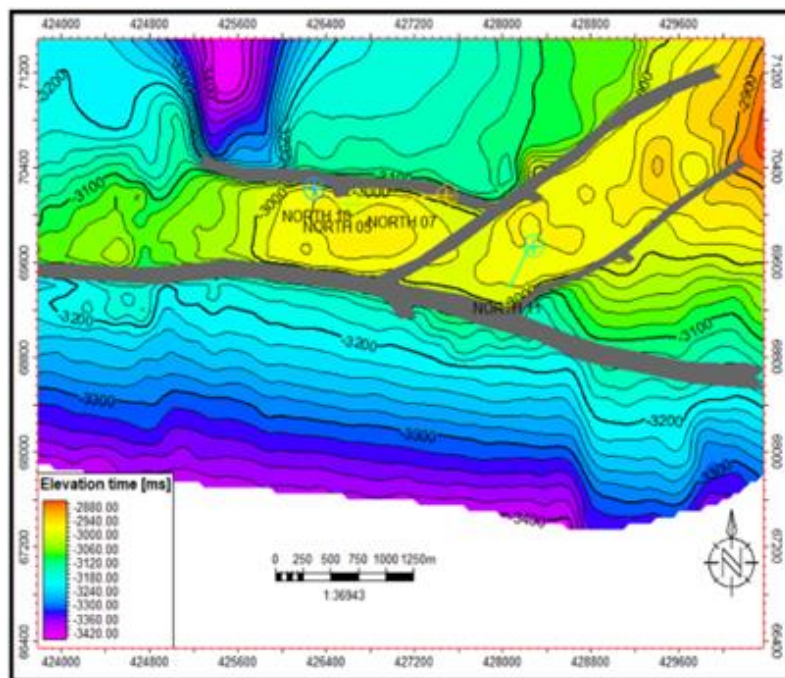


Figure 10: Res 2 Time structural map showing the faulted anticlinal structure

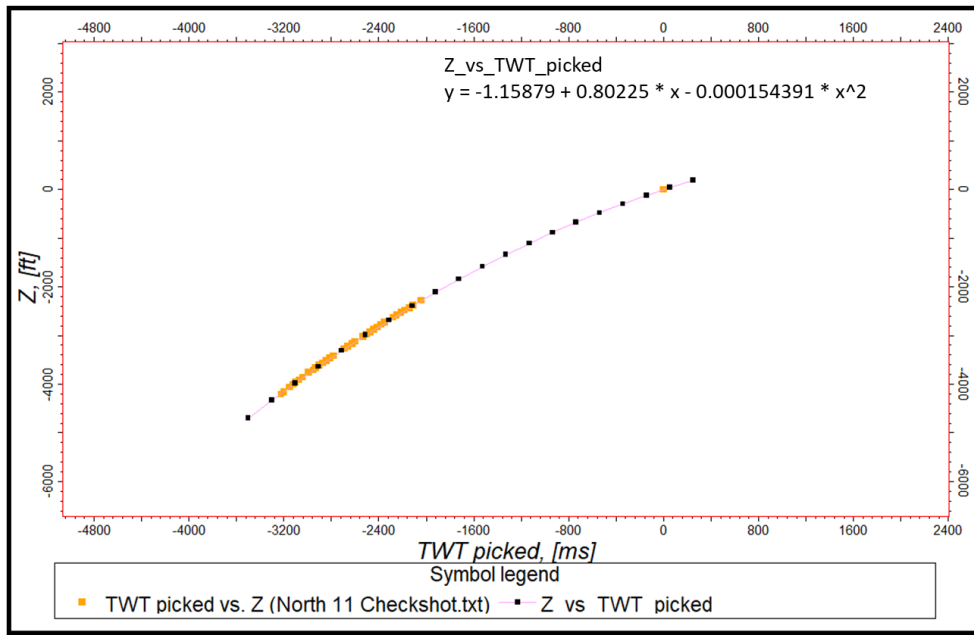


Figure 11: Polynomial function for time to depth conversion

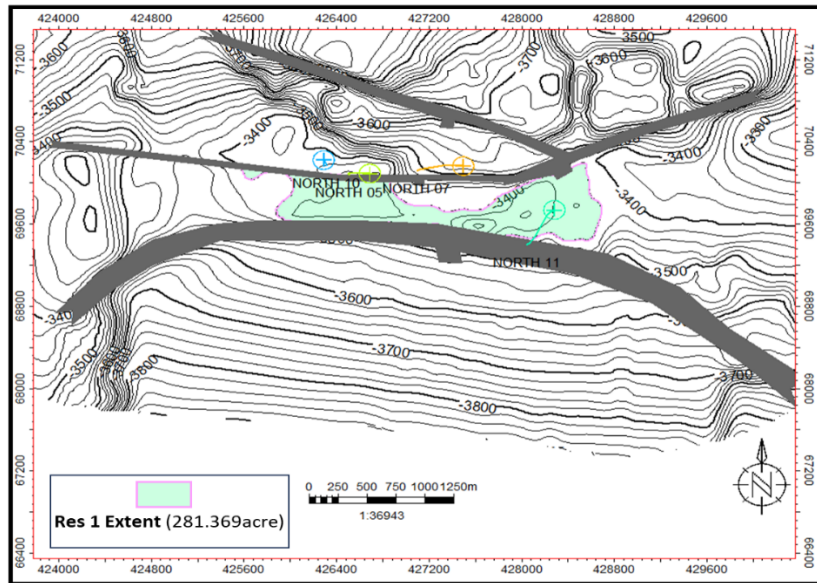


Figure 12: RES 1 Depth structural map Showing the Reservoir Extent

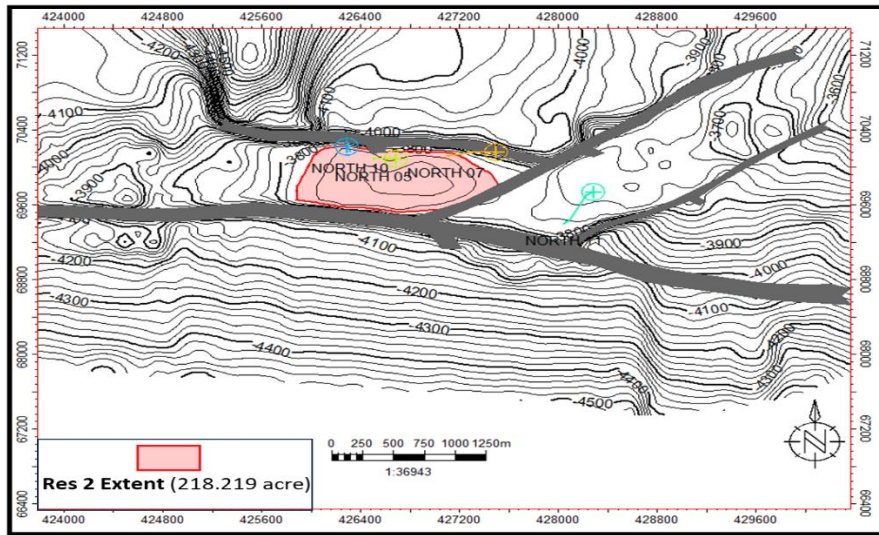


Figure 13: RES 2 Depth structural map Showing the Reservoir Extent

4.5 Volumetric Estimation

The volumetric estimation of the hydrocarbon potential within the evaluated reservoirs was carried out using the equation 7 below and the results are presented in Table 3.

STOIP- Stock Tank Oil in Place

$$STOIP = \frac{7758 \times GRV \times NTG \times \phi (1 - Sw)}{B_{oi}} \quad 7$$

where GRV= Gross rock volume, NTG = Net to Gross, ϕ = Rock porosity, %, Swc = Connate water saturation, %, B_{oi} = Oil formation volume

factor. The volumetric estimation results Table 3 indicate that RES 1 contains 18.7 million barrels of Oil Equivalent (MMBOE), while RES 2 holds 10.9 MMBOE. These findings align with production estimates from similar deltaic reservoirs in the Agbada Formation (Adeoti et al., 2010). The higher hydrocarbon volume in RES 1 supports its classification as the most prolific reservoir, whereas RES 2 requires careful reservoir management due to its higher water saturation.

Table 3: Volumetric results for Identified Prospects

RESERVOIR	Area (acre)	GRV (acre.ft)	N/G	PHI	Sw	Boi	STOIP (MMBOE)
RES 1	281,369	39,054.02	0.67	0.24	0.52	1.25	18.7
RES 2	218,219	34,369.49	0.70	0.21	0.65	1.25	10.9

4.5 Reservoir Characterization

Reservoir characterization is a critical aspect of hydrocarbon evaluation as it enumerates the quality, productivity, and storage capacity of the reservoir. The analysis of petrophysical parameters across four wells in the Northern Field reveals variations in reservoir properties that influence hydrocarbon potential.

RES 1 interval as shown in Table 4 has a gross thickness of 138.8 ft, with an average net-to-gross ratio (NTG) of 67%, indicating a

significant proportion of net reservoir rock suitable for hydrocarbon storage. The reservoir exhibits a porosity of 24%, which is considered good for a sandstone reservoir, facilitating effective fluid storage and migration. The water saturation (Sw) of 52% suggests that the remaining 48% of the pore space is occupied by hydrocarbons, making the reservoir a viable prospect. Additionally, RES 1 has a permeability of 1272.5 mD (Table 4), indicative of high fluid transmissibility, and a reservoir areal extent of

281.369 acres. The Stock Tank Oil Initially in Place (STOIP) is estimated at 18.7 MMBOE (million barrels of oil equivalent), affirming its commercial viability.

In contrast, RES 2 presents a greater gross thickness of 157.5 ft and a slightly higher NTG of 70%, implying a more substantial reservoir proportion compared to RES 1. However, its porosity (21%) is slightly lower, which may result in relatively reduced storage capacity. The permeability of 1221.75 mD, though high, is slightly lower than that of RES 1, potentially

affecting fluid flow efficiency. A water saturation of 65% indicates a higher volume of water within the pore spaces, which may reduce the effective hydrocarbon saturation. The reservoir areal extent is mapped at 218.219 acres, with an estimated STOIP of 10.9 MMBOE (Table 3), suggesting a moderate hydrocarbon potential compared to RES 1. The decline in porosity can be attributed to the depth of burial, which causes increased compaction and cementation, reducing primary porosity (Adeoti *et al.*, 2010; Avbovbo, 1978).

Table 4: Petrophysical Summary for Northern Field

RESERVOIR AVERAGE					
RES	Gross <i>ft</i>	NTG <i>frac</i>	PHI <i>frac</i>	Sw <i>frac</i>	Perm <i>mD</i>
RES 1	138.8	0.67	0.24	0.52	1272.5
RES 2	157.5	0.70	0.21	0.65	1221.75

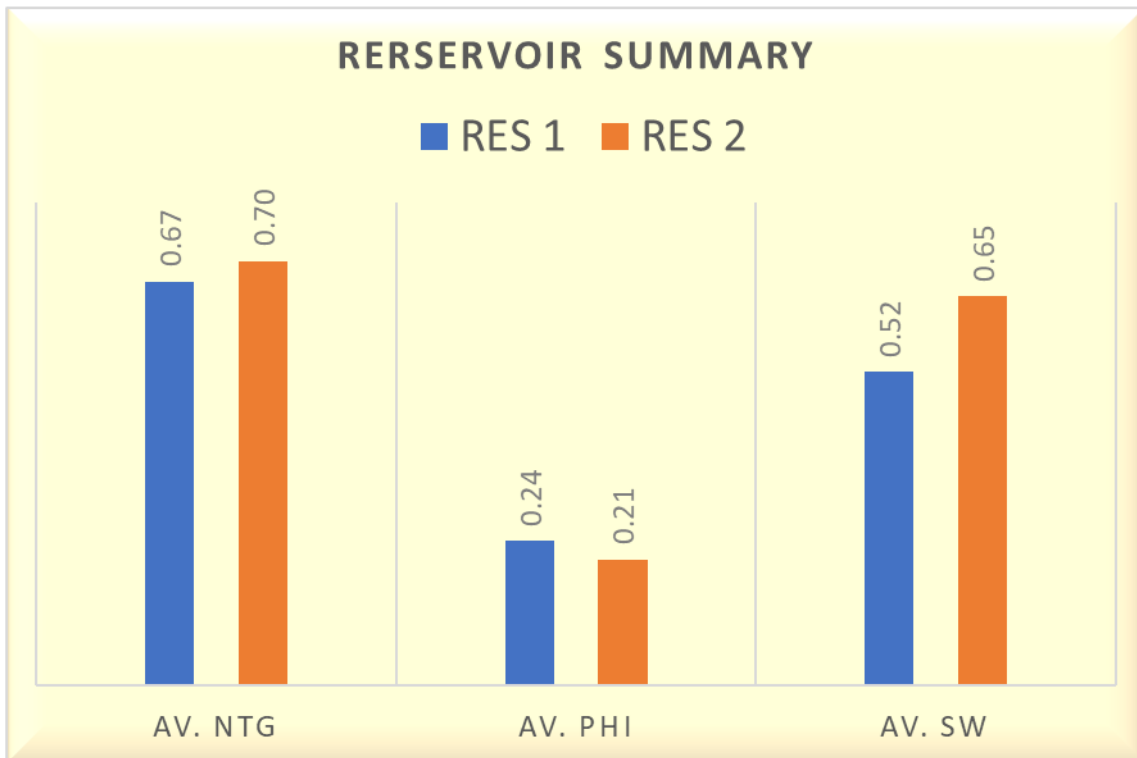


Figure 12: Statistical distribution of Petrophysical reservoir Properties across “Northern” field.

The petrophysical characteristics of the Northern Field reservoirs are consistent with those observed in other parts of the Niger Delta Basin. According to Doust and Omatsola (1990), Niger Delta reservoirs generally exhibit porosity

values ranging from 20% to 30%, permeability between 500 to 2000 mD, and NTG ratios of 50%–80%. The values for RES 1 and RES 2 fall within this expected range, reinforcing the reliability of the petrophysical evaluation. In

comparison with studies by Aigbedion & Iyayi (2007) and Adeoti *et al.* (2010) on Niger Delta reservoirs, RES 1 aligns more closely with highly productive reservoirs due to its combination of high porosity, low water saturation, and significant STOIP. Meanwhile, RES 2, despite having a slightly greater gross thickness, shows reduced porosity and higher water saturation, which could impact its hydrocarbon recovery efficiency.

The higher STOIP estimate in RES 1 suggests that it is more prolific and likely to yield higher recoverable reserves, whereas RES 2 may require enhanced recovery techniques to optimize production. Previous studies have indicated that reservoirs with intergranular porosity and high net-to-gross values typically exhibit better flow potential and hydrocarbon recovery (Weber, 1987; Avbovbo, 1978). Given these observations, RES 1 is characterized as the most prolific reservoir in the Northern Field, while RES 2, though still a viable target, may require careful reservoir management strategies to optimize production.

5.0 Conclusion and Recommendations

5.1 Conclusion

The petrophysical evaluation and reservoir characterization of the Northern field Niger Delta have been completed. Two hydrocarbon reservoirs have been identified, and two lithologies - sand and shale have been identified using the Gamma ray log. The analysis reveals that each sand unit extends through the field, varies in thickness, with some units occurring at greater depth than their adjacent units, which may be evidence of faulting. The shale layers were found to increase with depth, while the sand layers decreased in tandem.

Both identified reservoirs were hydrocarbon-bearing units across the four wells (North 10, North 5, North 7, and North 11), according to the resistivity log analysis. Petrophysical analysis was used to determine the average reservoir parameters, including porosity, gross thickness,

hydrocarbon saturation, permeability, and net-gross. Fault-assisted anticlinal structures, which act as structural traps to stop hydrocarbon leakage from reservoirs, are revealed by structure analysis.

The structural disposition of the two mapped horizons greatly favors the accumulation of hydrocarbon coupled with the good reservoir parameters obtained from the wells. The depth map's reservoir extent and the average results of petrophysical parameters were used to rank the two reservoirs. In the Northern field, RES 1 is the most prolific and RES 2 is the least.

5.2 Recommendations

Based on the results of this study, it is therefore recommended that exploitation for hydrocarbon can be carried out within the Northern field. However, I recommend the coring of the reservoir zones in these wells. These cores should therefore be subjected to further studies in the laboratory to measure and validate the various petrophysical parameters computed in this study. This will enhance the confidence of E&P companies in the values obtained.

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