Petroleum and Coal

Article **Open Access**

Assessing the Reservoir Quality and Prospectivity of the "MUH" Field, Onshore Niger Delta Basin

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Received February 22, 2025; Accepted May 27, 2025

Abstract

Integrated interpretation of 3D seismic and well log data was carried out in this study to assess the reservoir quality and prospectivity of the "MUH" Field onshore Niger Delta Basin, Nigeria. The study revealed two reservoir units designated as "Sand A" and "Sand B", representing probable hydrocarbon possibilities that were penetrated by wells evaluated in this study. The reservoir units exhibited effective porosity (Øe) values greater than 20 %, net-to-gross ratio (N/G) values of over 70 %, water saturation (Sw) values lesser than 50 %. Lithofacies identified from well logs include Heterolithic Facies, Shaly Sand Facies, Mudrock Facies, and Massive Sandstone Facies, reflecting the variable interplay of the sub-environments in which the sediments were deposited. The petrophysical evaluation results showed that the sand units are characterized by high N/G and Øe values, suggesting that they are high quality reservoirs.

Keywords: *Reservoir quality; Prospectivity; 3D seismic; Well logs; Niger Delta Basin.*

1. Introduction

The petroliferous Niger Delta is one of the world's most productive basins, with more promising reserves still to be discovered as exploration moves deeper into the ocean. The urgent need for our country, Nigeria, to increase its national reserve base necessitates a vigorous search for new hydrocarbon deposits as well as a re-examination of mature fields in the region. In order to meet national and global energy demand, it is now critical to employ newly developed exploration and production methods and expertise to effectively harness these resources for increased oil recovery [1–3].

The increasing demand for energy and subsequent decline in supply of hydrocarbons globally, requires increased activities in petroleum exploration and an improvement in the ratio of exploration success. Nigeria is responding to these new challenges by adding new oil and gas prospects in deep offshore plays and frontier areas as well as reassessing areas already explored and exploited in the past with better exploration techniques.

Long-term oil and gas production in the Niger Delta province have depleted hydrocarbon reserves in over 150 onshore and offshore fields, producing from shallow (2000 m) to middle (4000 m) depth ranges associated with growth fault systems and rollover anticlines [4-5]. This is evidenced in the fast disappearance of giant fields from the onshore areas, thereby shifting exploration activities towards the more challenging and cost intensive shallow and deep offshore as well as frontier areas.

Although there are still unknown oil and gas pools in the Niger Delta province's onshore areas, discovering these modest but potentially rich hydrocarbon zones will necessitate the use of innovative geological and geophysical techniques. As a result, applying rock physics principles and seismic stratigraphic techniques to current fields in the Niger Delta province will be particularly valuable in identifying prospective structural and stratigraphic plays for higher productivity. The main goal of this study was to predict potential petroleum play elements and prospects by combining well logs and seismic data in order to determine the parameters that control reservoir quality.

2. Location and geology of the study area

The study area is located within the Greater Ughelli Depobelt of the Niger Delta Basin (Fig. 1), geographically covered between latitudes 4° 00' N to 6° 03' N, and longitudes 4° 30' E to 8° 30' E. The Cenozoic Niger Delta is situated at the intersection between the Benue Trough and the South Atlantic Ocean, establishing a threefold junction between South America's and Africa's Late Jurassic split. During the Tertiary, the delta extended out into the Atlantic Ocean near the mouth of the Niger-Benue system, with a drainage area of more than one million square kilometers of largely savanna-covered plains. From the Eocene to the present, the delta has prograded southwestward, generating depobelts that represent the most active parts of the delta at each stage of its history. With a volume of approximately 500,000 km^3, these depobelts comprise one of the world's biggest regressive deltas [6–8]. The Greater Ughelli Depobelt, nevertheless, encases a fairly shallow basement with enhanced steepness seawards.

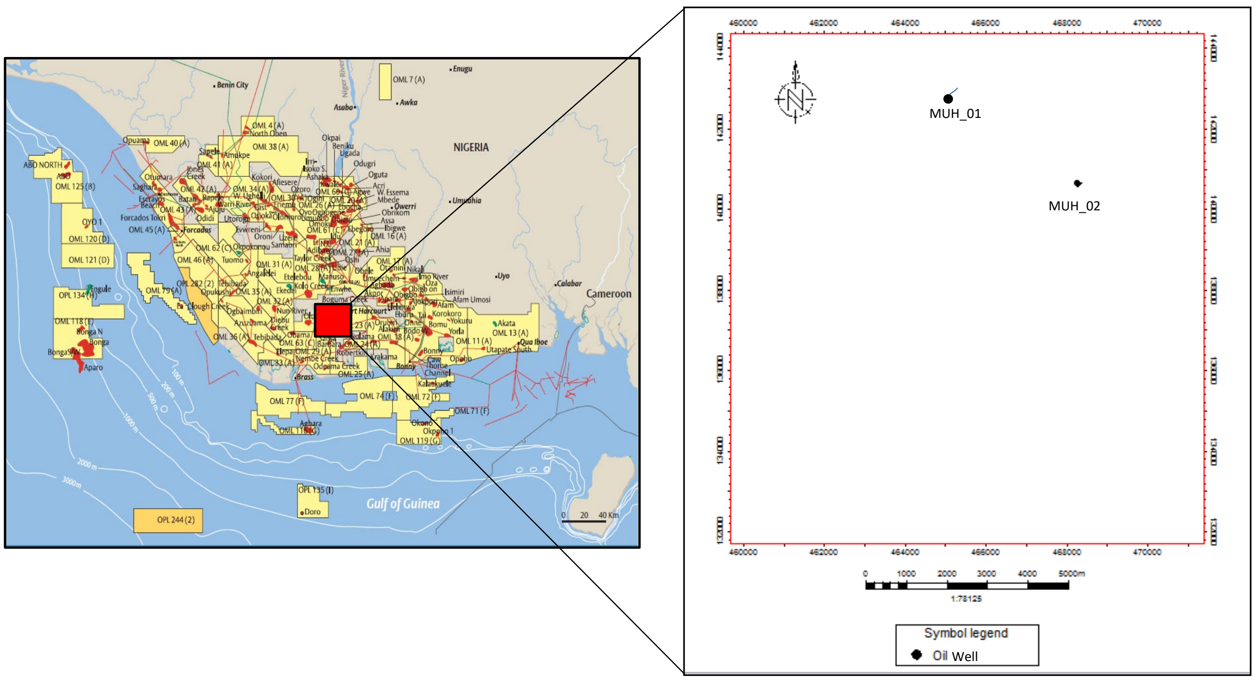

Fig. 1. Concession map of the Niger Delta Basin showing the location of the “MUH” Field.

The Niger Delta Province's onshore section is defined by the geology of southern Nigeria and southwestern Cameroon. The northern boundary is formed by the Benin flank, a pivot line running east-northeast south of the West African Basement Massif. Cretaceous sedimentation exposures on the Abakaliki High establish the northeastern border, whereas the east-south-east border is defined by the Calabar flank, a pivot line bordering adjoining Precambrian rocks [6]. The offshore demarcation of the region is described to the east by the Cameroon volcanic line, to the west by the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin), and to the south and southwest by the 2 km sediment layer curvatures or the 4000 m bathymetric curvatures [8].

Short *et al*identified three lithostratigraphic units in the Niger Delta Basin [9]. These include the Akata, Agbada, and Benin Formations (Fig. 2). Knox *et al.* [10] opined that these geological units constitute the complex prograding deltaic wedge of clastic sediments that developed in the Cenozoic times. Sediment deposition in the delta was controlled by regional fault-bounded depo-centers (depobelts) which exerted a major influence on the various deposition settings [11] (Fig. 3).

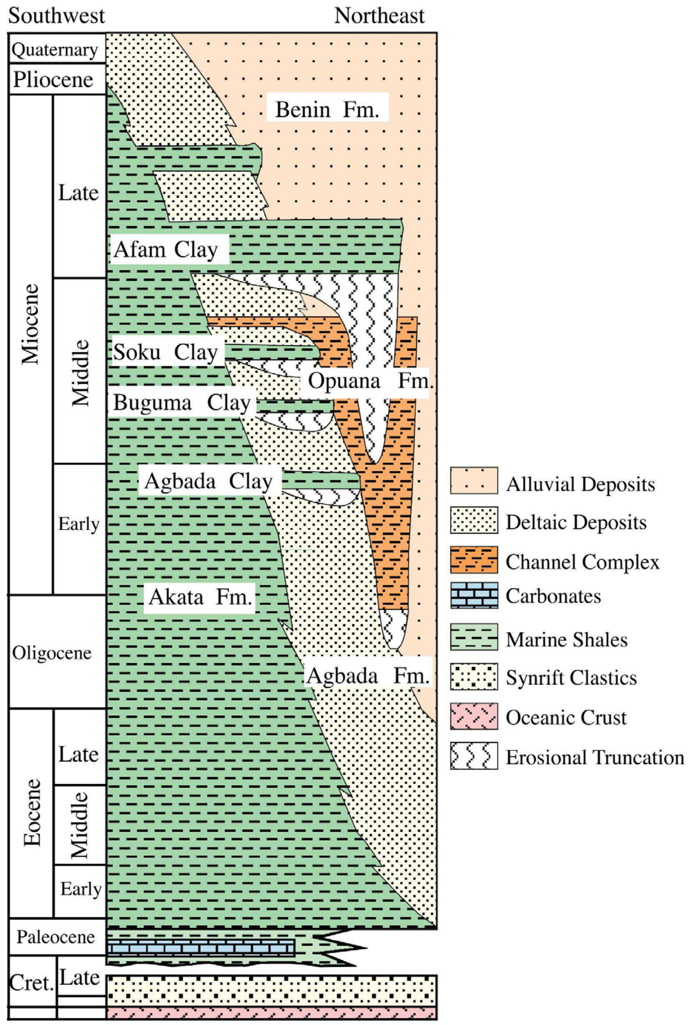

Fig. 2. Regional stratigraphy of the Niger Delta Basin showing the clay-filled gullies in Agbada and Benin Formations (after [11,23]).

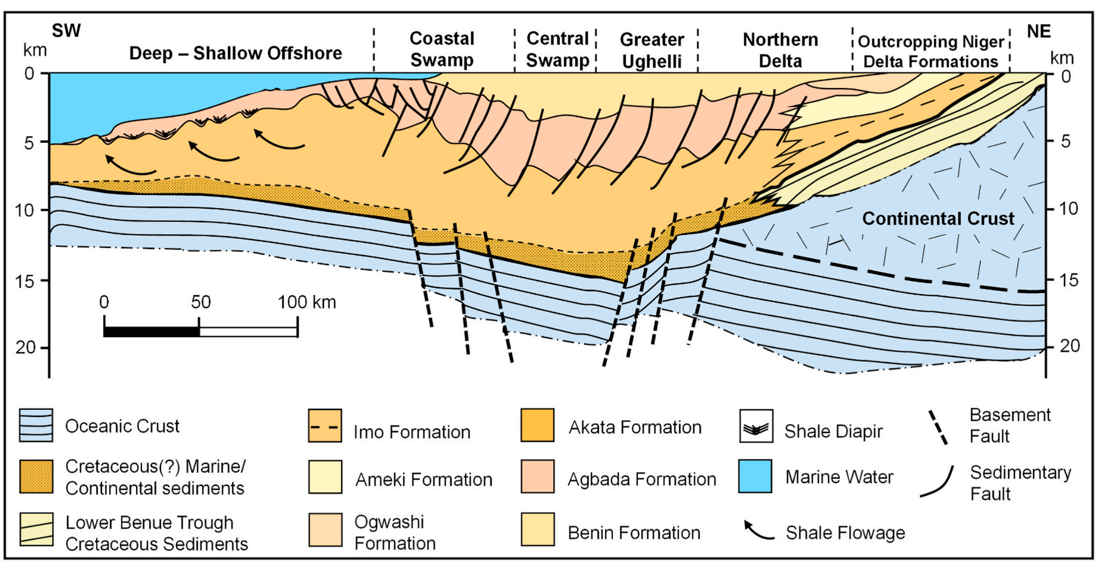

Fig. 3. Schematic diagram of the Cenozoic Niger Delta Basin showing the various depobelts, with the three diachronous lithostratigraphic formations and associated depositional structures (modified from [2,24]).

The Akata Formation which is the oldest lithostratigraphic unit in the basin is comprised mainly of dark gray shales and silts with occasional streak of sands (turbidite deposits). The sediments reflect deposition in an open marine setting, and is estimated to have a thickness of up to 6.4 km at the center of the delta [12]. The Akata Formation serves as the source rock for petroleum generation in the Niger Delta Basin. The paralic Agbada Formation overlies the Akata Formation, and consists mainly of intercalation sandstones, shales, and silts. This units reflects sediment deposition in a riverine or deltaic setting. [11] have shown that the Agbada Formation attained a thickness of about 3.9 km between the Eocene and Pleistocene times. The youngest geologic unit in the Niger Delta Basin is the Benin Formation, and is made up of terrestrial sands deposited in the upper coastal plain and alluvial settings. This lithostratigraphic unit is about 1.4 km in thickness and forms the uppermost part of the Niger Delta clastic wedge [11,13].

3. Dataset and methodology

The dataset used for this study is comprised of well header/deviation files, composite log suites from two (2) wells (including gamma ray, neutron, sonic, density and resistivity logs), biostratigraphic markers, 3D seismic volume, and checkshot data. These datasets were combined in an integrated workflow to uncover the structural and stratigraphic complexities in the study area. The steps adopted in this study are further explained in the following paragraphs, under the following headings: lithofacies analysis, lithological correlation of logs, petrophysical properties estimation, and faults and horizon mapping.

3.1. Lithofacies analysis

Analysis of the various lithofacies penetrated by the wells was carried out using the gamma ray log motif to understand the interplay of the environmental settings in which the sediments were deposits. The depositional environments leave their imprints on the facies, making them distinct in appearance and character which usually reflects the conditions responsible for their origin, and also differentiates them from other associated rock units or adjacent units [14–15]. Hence, the gamma ray signatures were utilized in this study to infer sediment grainsize variations and depositional energy, which in turn provided clue on the environments of deposition of the sediments. The depositional environments interpretation was based on the model propounded by [16].

3.2. Lithological correlation of logs

Lithological correlation between the wells was established using the biomarker information provided in well MUH_01. This was carried across to the other well MUH_02 for appropriate mapping of sand units and easy identification reservoirs of interest. The gamma ray and resistivity logs were used for this purpose, while the density and neutron logs were utilized in delineating hydrocarbon-bearing sand units in the field.

3.3. Petrophysical parameters estimation

Petrophysical properties including volume of shale (V_{sh}), effective porosity ($Ø_e$), net-to-gross ratio (NTG), and water saturation (S_w) were determined from well logs in order to understand the variation of these parameters in the reservoirs of interest. The following equations were used for the petrophysical calculations:

$$Ø_{den} = \frac{(\rho_m - \rho_b)}{(\rho_m - \rho_b)} \qquad (1)$$

where ρ_b = bulk density; ρ_f = fluid density; ρ_m = matrix density; $Ø_{den}$ = density-derived porosity. This algorithm was used to calculate the total porosity of each reservoir of interest.

The following algorithm was used to compute the volume of shale (V_{sh}), which is the proportion of shale present in a sandstone or heterolithic reservoir:

$$V_{sh} = 0.083 * (2^{3.7*I_{GR}} - 1) \qquad (2)$$

where I_{GR} is the gamma ray index and is given by:

$$I_{GR} = \frac{(GR_{log} - GR_{min})}{(GR_{max} - GR_{min})} \quad (3)$$

This approach is based on the gamma ray log, which determines the maximum and minimum gamma ray values.

To compute the saturation of the reservoir sands' fluid content, the formation water saturation was first estimated using Archie's equation for water saturation, which is provided as:

$$S_w = \left(\frac{FR_w}{R_t}\right)^{\frac{1}{n}} \quad (4)$$

where F = formation factor; n = saturation exponent; R_t = rock resistivity;, R_w = formation water resistivity

The formation factor was calculated using Humble's formula for unconsolidated sands, which is as follows:

$$F = \frac{0.62}{\emptyset^{2.15}} \quad (5)$$

where 0.62 is a constant value for the tortuosity factor utilized in this approach for unconsolidated Tertiary rocks of the Niger Delta.

The net-to-gross (N/G) which is the ratio of the thickness of the clean, porous and permeable, productive (Net) reservoir sand to the overall (Gross) reservoir thickness was determined using the equation:

$$N/G = IF(V_{sh} \leq 0.40, (1 - V_{sh}), 0) \quad (6)$$

It is generally not consistent across a reservoir and can range from 1.0 (clean reservoir) to 0.0 over a short lateral distance (non-reservoir). The fraction of the net reservoir containing petroleum and from which petroleum will flow is referred to as net pay. Reservoirs with low or erratic NTG ratios frequently need a large number of wells to maximize recovery.

Lastly, the effective porosity (Øe) was estimated using the following equation:

$$\emptyset_e = (1 - V_{sh}) * Por_{den} \quad (7)$$

3.4. Faults and horizon mapping

Mapping of faults and horizons in the study area was preceded by well-to-seismic calibration process to tie the seismic which is time, with the well data which is given in depth. This involved generating a synthetic seismogram by convolving the reflectivity derived from digitized sonic and density logs with the wavelet derived from seismic data. This was then compared to stratigraphic markers and correlation points in the well logs that coincides with major seismic events, for improved horizon mapping.

Interpretation of faults was carried out along the dip lines, while horizon picking was done in the inline and crossline strike sections of the 3D seismic cube to understand the structural styles and depositional geometry of the field. The mapped horizons indicate the laterally extent and continuity of the gross reservoir units identified in the study area.

4. Results and discussion

4.1. Lithofacies and depositional environments

Facies is the aspect of appearance and characteristics of a rock unit usually reflecting the condition of its origin especially in differentiating it from other associated rock units or adjacent units. It is an interpretation or inference of the depositional environment based on observable features. The gamma ray (GR) log can be used to indicate grain size vertical profile in sand - shale sequences. The lithofacies profiles were derived from the GR log signatures which gave insights into the depositional environments of the sediments penetrated by the wells. Bell shaped log patterns on GR logs indicate increasing shale content up section or fining upward trends, typical of fluvial channel deposits (Fig. 4). Funnel shaped log patterns indicate decreasing shale content up section or a coarsening upward trend associated with deltaic progradation, while cylindrical (blocky) log motif indicate a thick uniformly graded coarse grained sandstone unit, perhaps deposits of braided channel, tidal channel or subaqueous slump deposits. Serrated log motif suggests intercalation of shales and sandstone layers, typically of fluvial, tidal or marine processes.

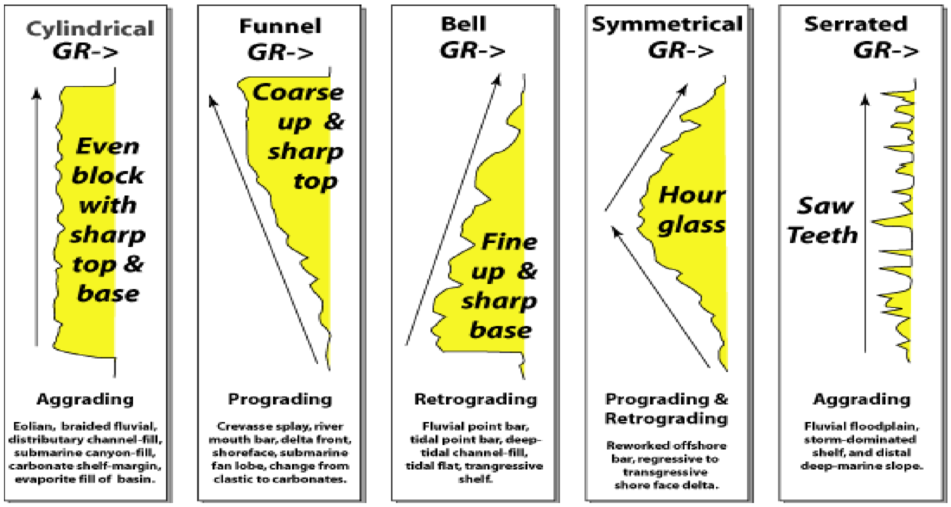

Fig. 4. Gamma ray response to grain size variation model (after [16]).

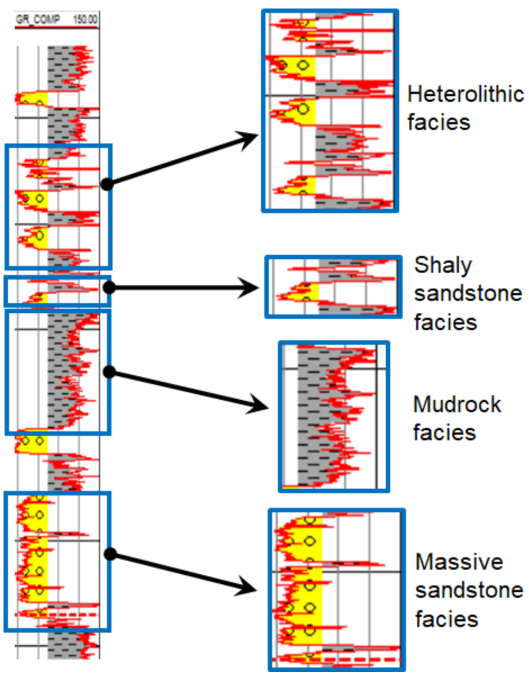

Fig. 5. Delineated lithofacies units in the study area.

Based on the above-described log patterns, four (4) lithofacies were identified in the study area. These include the Heterolithic Facies, Shaly Sandstone Facies, Mudrock Facies, and Massive Sandstones Facies (Fig. 5). These lithofacies depicted the interplay between different sub-environments ranging from foreshore to upper shoreface, lower shoreface, tidal channels, fluvio-marine and open marine settings.

4.2. Well log correlation

The log panel showing the correlation of the two wells used in this study is presented in Figure 6. Correlation of the wells enabled the delineation of reservoirs (sands) from non-reservoirs (shales), as well as the identification of hydrocarbon-bearing sand units of interest. The mapped hydrocarbon sand zones were designated as “Sand A” and “Sand B” for proper evaluation of the petrophysical properties. The gamma ray and resistivity logs were integrated in the lithological delineation. The combination of density and neutron logs enabled the identification of hydrocarbon-bearing units penetrated by the wells (Fig. 7).

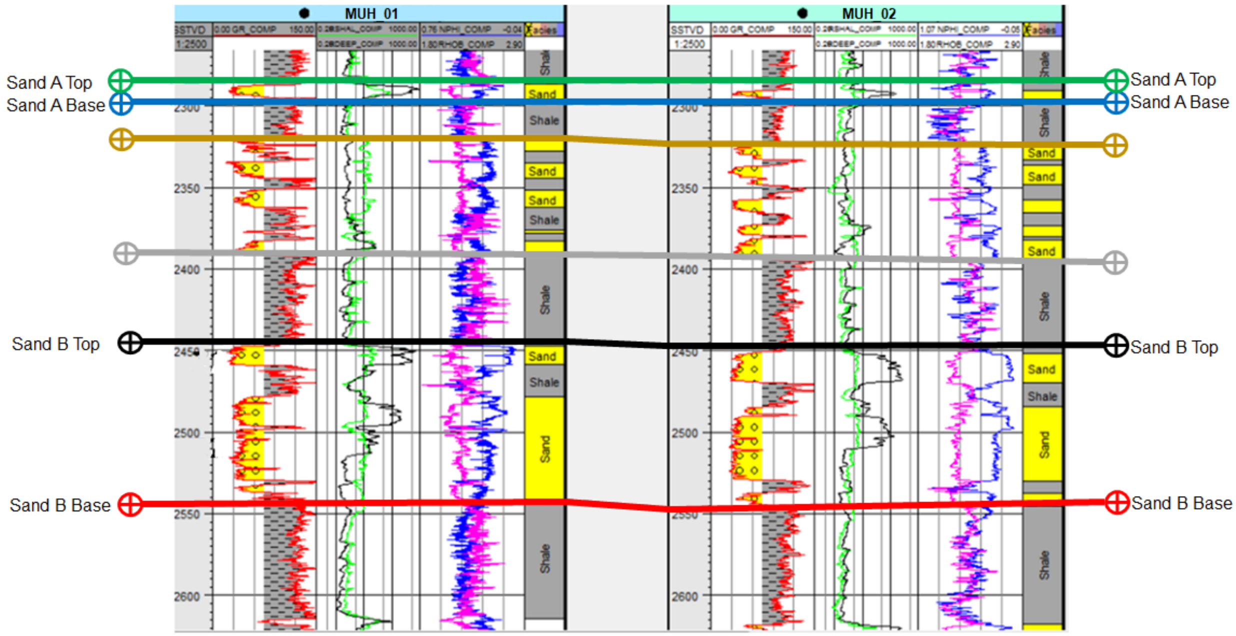

Fig. 6. Well log panel showing the correlated sands and shale units in the study area.

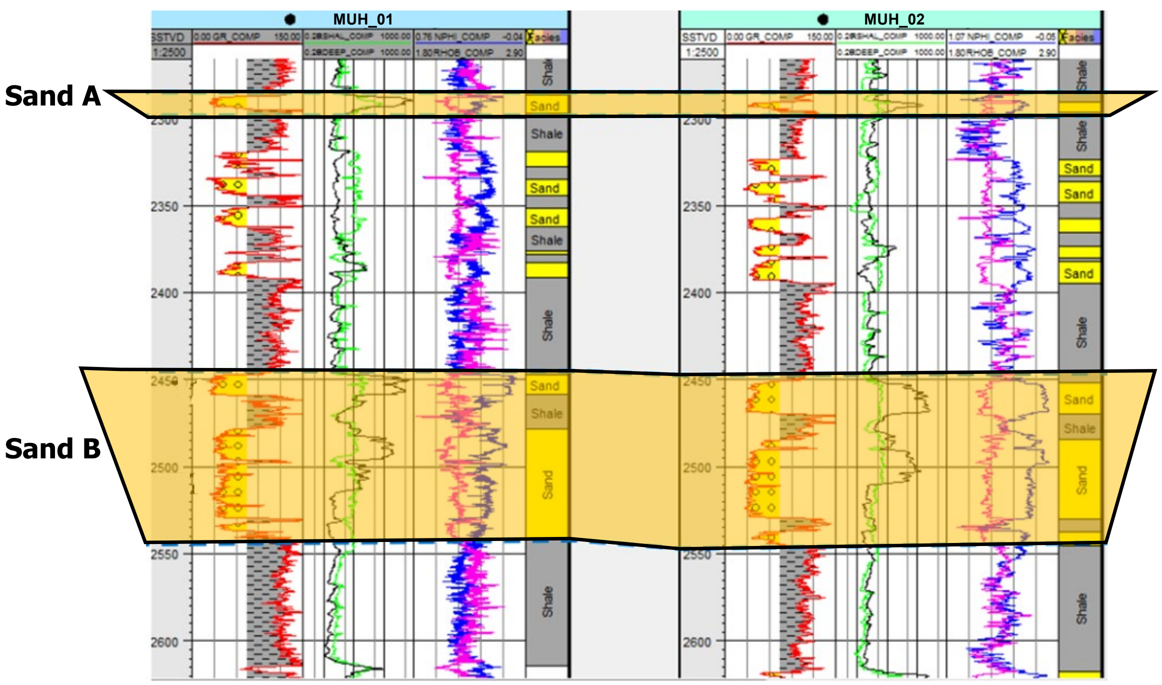

Fig. 7. Well log panel showing the delineated hydrocarbon-bearing sand units in the study area.

4.3. Petrophysical properties and reservoir quality of the hydrocarbon-bearing sand units

Tables 1 and 2 are a summary of the estimated petrophysical properties for the delineated reservoir units in the study area. These two potential prospective zones were identified based on the distinctive petrophysical parameters, including volume of shale, effective porosity, net-to-gross, and water saturation. The reservoir zones were penetrated by the two (2) wells, and showed varying stratigraphic thicknesses. Sand A is about 6 m in thickness, with average N/G of 0.79, average $Ø_e$ of 0.23, and average S_w of 0.12. This indicates that the reservoir is saturated with more than 50% hydrocarbon. The Sand B reservoir is about 91.68 m in thickness, and is divided into two zones (Fig. 8). Zone 1 is characterized by average N/G of 0.86, average Øe of 0.28, and average S_w of 0.11, while Zone 2 showed average N/G of 0.79, average Øe of 0.21, and average S_w of 0.39. The estimated high N/G and Øe values in the two zones shows that the reservoir is of good quality. This may be attributed to the fact that the reservoir units belong to the Massive Sandstone Facies that depicts shoreface sands or channel fill deposits. Sediments deposited in such environments have been characterized as fair to excellent reservoirs in the Niger Delta Basin [11]. However, the reservoir quality can vary substantially at the pore scale.

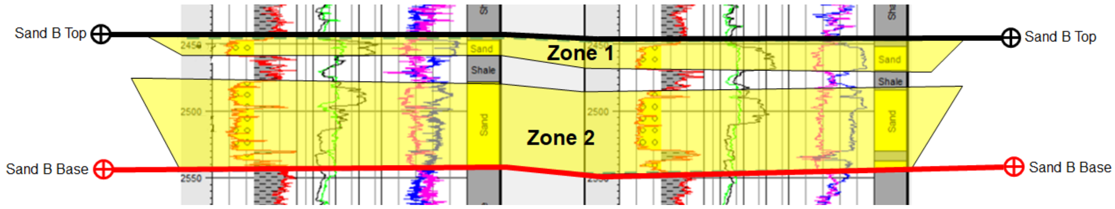

Fig. 8. Well log panel showing the two zones of Sand B reservoir.

Table 1. Petrophysical result for Sand A reservoir.

Gross (m)	Net (m)	N/G	V_{sh}	$Ø_e$	S_w	S_h
6.00	4.74	0.79	0.21	0.23	0.12	0.88

Table 2. Petrophysical result for Sand B reservoir.

Zone	Gross (m)	Net (m)	N/G	V_{sh}	$Ø_e$	S_w	S_h
1	13.16	11.32	0.86	0.13	0.28	0.11	0.89
2	57.46	45.39	0.79	0.21	0.21	0.39	0.61

4.4. Seismic interpretation and structural framework of the study area

Figure 9 is a display of generated synthetic trace overlayed on seismic inline 11458. The synthetic seismogram was used to establish a proper time-depth relationship between the seismic events and the corresponding stratigraphic intervals responsible for them, thereby fostering accurate horizon mapping both in the time and depth domain [17-18]. A good well-to-seismic match was obtained at the vicinity of MUH_01 well. This also guided the picking of horizons that corresponded to the tops of reservoir sands of interest.

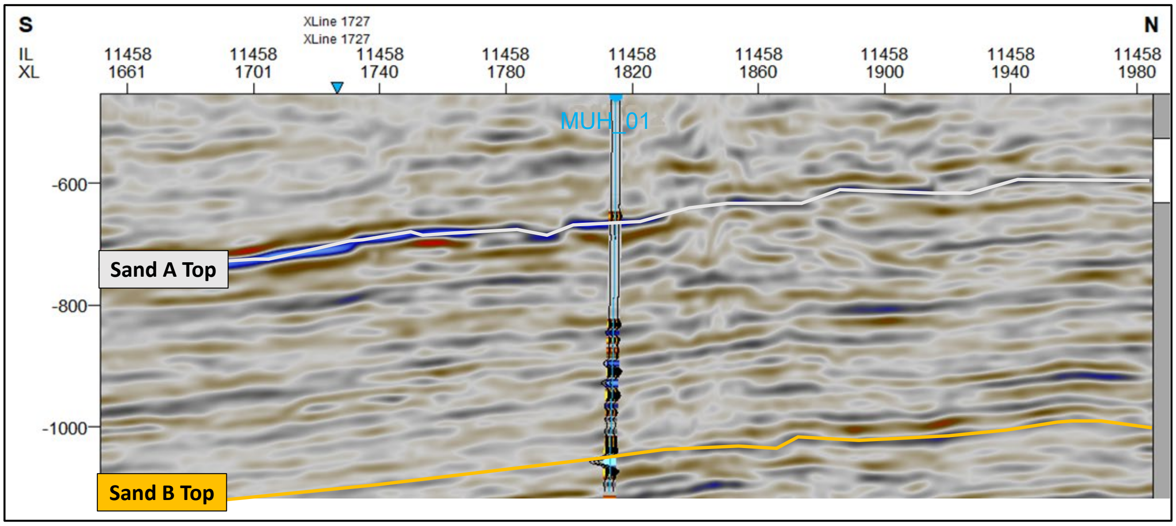

Fig. 9. An overlay of the generated synthetic seismogram on seismic inline 11458 showing a good tie with the seismic at the vicinity of MUH_01 well.

Horizons and faults interpreted in the field are presented in Figure 10. The fault mapping process was guided using the variance attributes time slice to ensure accuracy in the interpretation (Fig. 11). The mapped faults were listric (curvilinear) in nature, and are oriented in the east to west direction, with a general dip to the south (ocean basin). These faults were typical of the syn-depositional growth fault systems and roll-over anticlinal structures that formed as a result of rapid sediment loading and gravity tectonics, and constitute the main trapping mechanisms in the Niger Delta Basin [11,19]. The faults created accommodation spaces for sediment infilling, and formed the boundaries of several depocenters (depobelts) in which the time transgressive lithostratigraphic units of the Niger Delta were deposited [11,20–21].

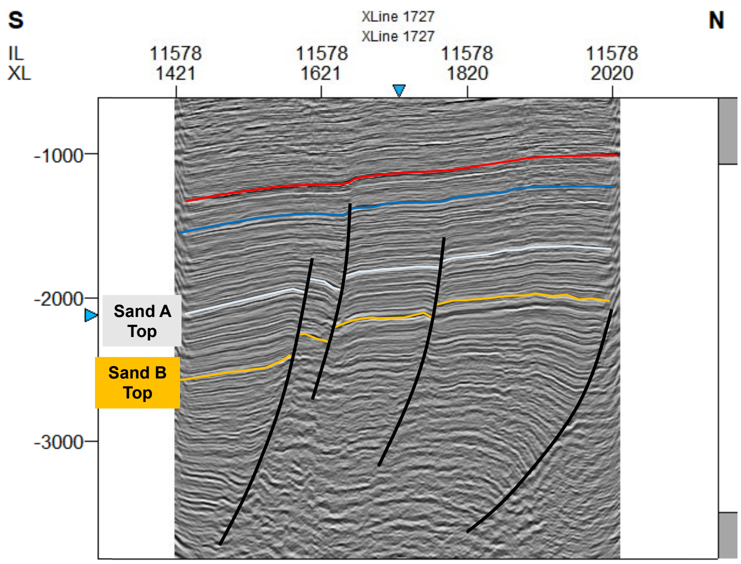

Fig. 10. Interpreted seismic section showing mapped horizons and faults in the study area.

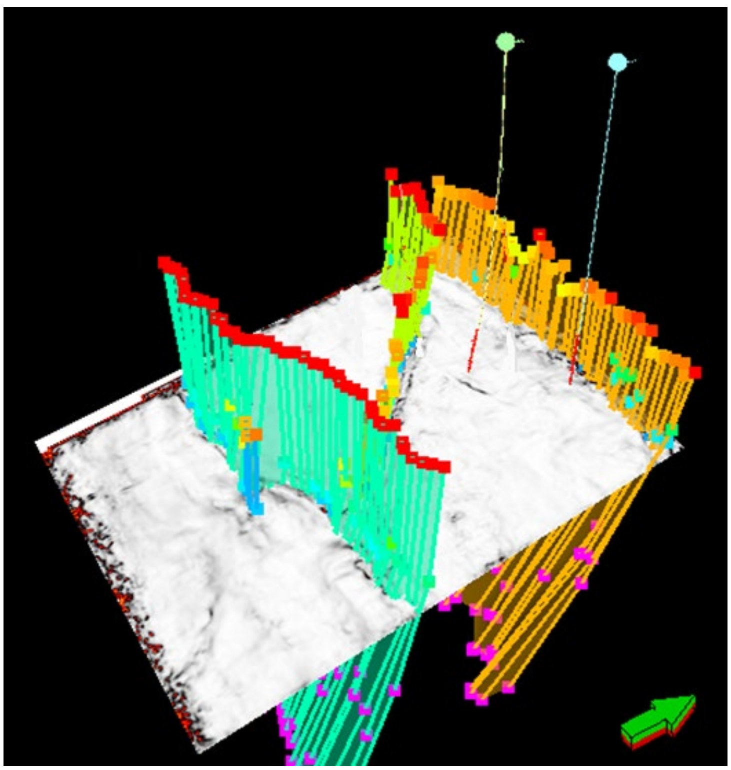

Fig. 11. 3D display of interpreted faults constrained by variance attributes time slice.

The time and depth structure maps generated from the mapped reservoir sand tops are presented in Figure 12 and Figure 13. The maps shaded light the geometry and structural disposition of the sands of interest, including the various reservoir compartments. The combination of horizons and faults gave insights into the structural framework and geometry of the reservoirs in field (Fig. 14). The identified trap styles in the field are fault-dependent closures with roll-over anticlinal traps. However, the MUH_01 and MUH_02 wells intersected the reservoirs at the by roll-over anticlinal structure towards the northeastern part of the field. The reservoir tops are within the hanging wall side of the faults, which poses a major risk in terms of hydrocarbon development, particularly if the fault is not sealing or maybe the sealing integrity is breached which will result in leakage [18–19].

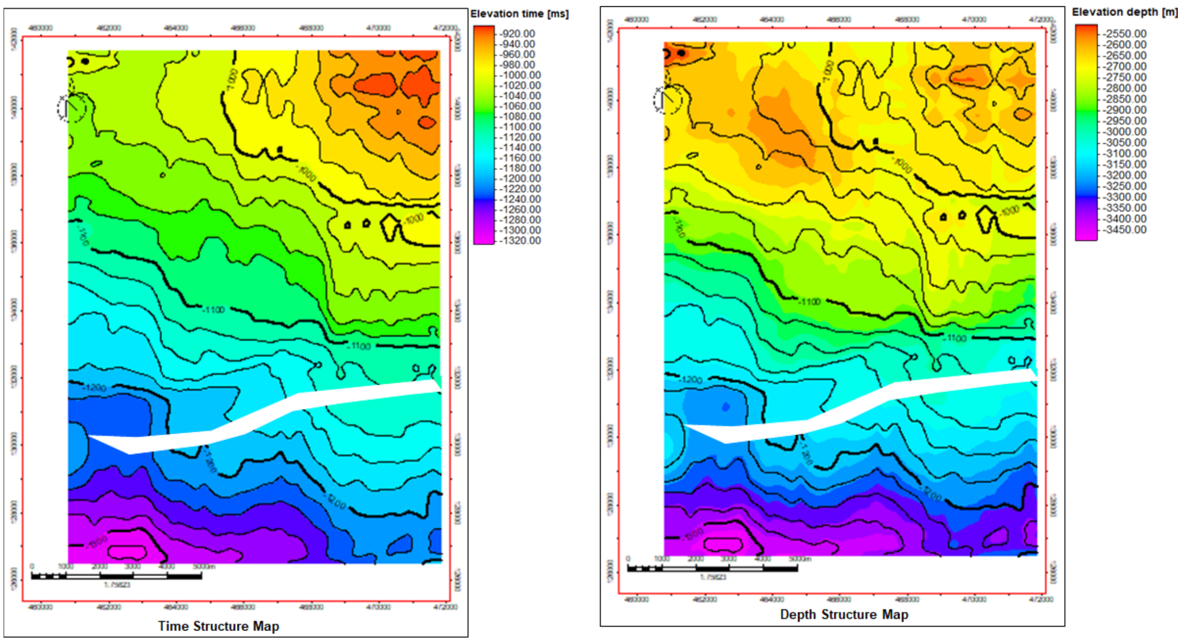

Fig. 12. Time and depth structure maps for Sand A reservoir top.

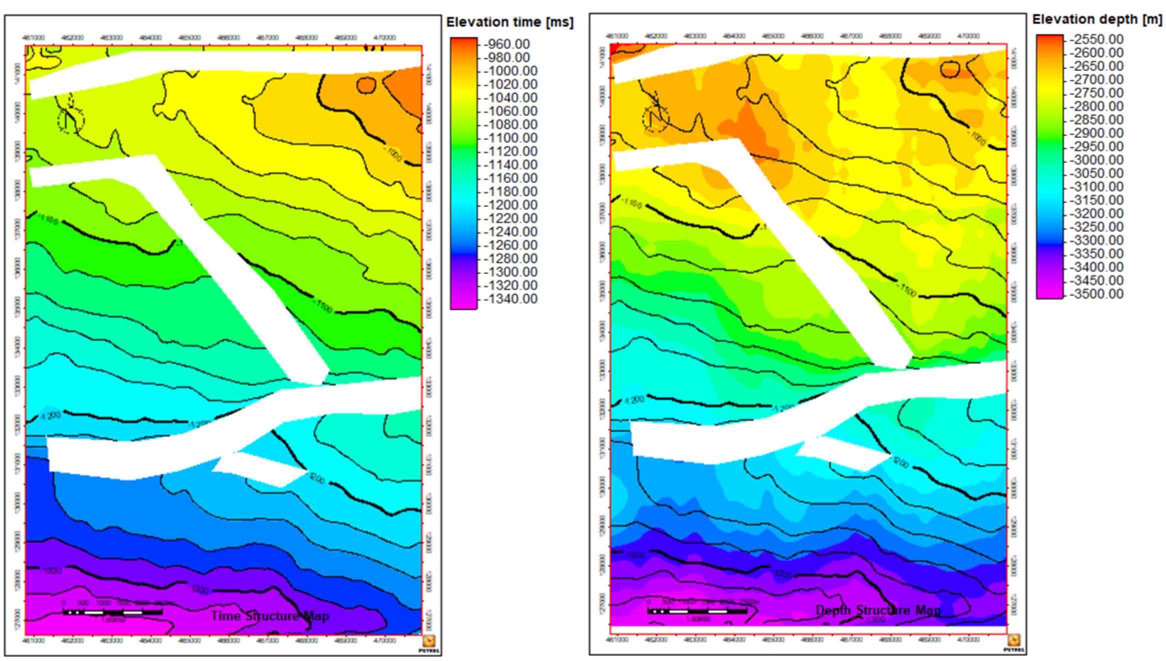

Fig. 13. Time and depth structure maps for Sand B reservoir top.

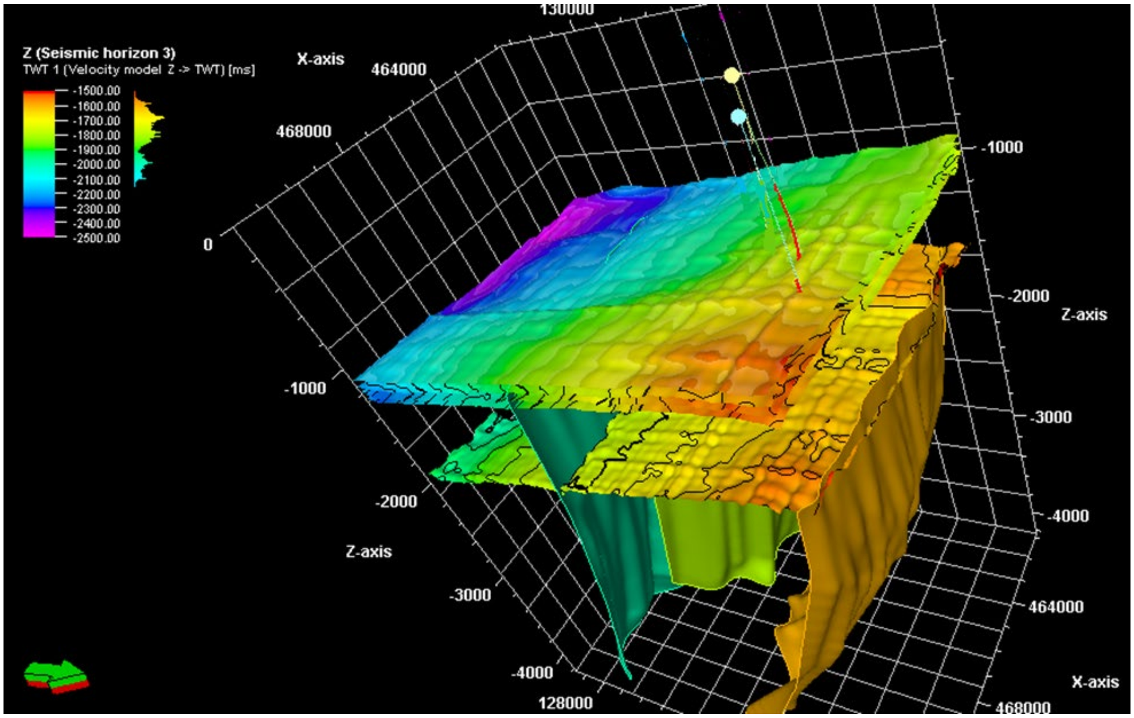

Fig. 14. Combination of fault framework model and interpreted horizons showing the structural disposition of the study area.

5. Conclusion

The integration of well logs and 3D seismic data aimed at assessing the reservoir quality and prospectivity of the MUH Field onshore Niger Delta Basin have been attempted in this study. Well log facies analysis revealed four distinct lithofacies units including Heterolithic Facies, Mudrock Facies, Shaly Sandstone Facies, and Massive Sandstone Facies. These facies reflected the interactions between sub-environments from fluvio-deltaic to deep marine settings. Lithological correlation of the logs revealed two reservoir units (Sand A and Sand B) envisaged to be potential viable hydrocarbon prospects owing to their unique petrophysical properties. Structural characteristics of the field were indicated by major growth faults and roll-over anticlines mapped from seismic data. Petrophysical evaluation revealed that the sand reservoir units are characterized by high effective porosities and high net-to-gross ratio values, indicating that the sands are of high reservoir quality. It is recommended that further studies involving sedimentological and core data interpretations be integrated for detailed reservoir description of the study area.

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