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Integrated Seismic Attribute-petrophysical Coupling for Reservoir Quality Prediction in the “MD” Field, Onshore Niger Delta, Nigeria

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INTEGRATED SEISMIC ATTRIBUTE-PETROPHYSICAL COUPLING FOR RESERVOIR QUALITY PREDICTION IN THE "MD" FIELD, ONSHORE NIGER DELTA, NIGERIA

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Abstract

This study presents an integrated seismic attribute petrophysical approach for reservoir quality prediction and hydrocarbon prospect delineation in the "MD" Field, onshore Niger Delta, Nigeria. The workflow integrates well log analysis, well-to-seismic tie, structural interpretation, and seismic attribute extraction using 3D seismic data and logs from five wells (MD_1 – MD_5). Two main reservoir intervals (MD1000 and MD2000) were delineated using gamma ray, resistivity, density, and neutron logs. Petrophysical evaluation indicates shale volume (Vsh) ranging from 0.07 to 0.52, suggesting predominantly clean to moderately shaly sands, while porosity values range from 0.10 to 0.27, indicating moderate to good reservoir quality. Water saturation (Sw) varies between 0.07 and 0.52, with corresponding high hydrocarbon saturation (Sh up to 0.93), confirming the presence of hydrocarbon bearing zones. Net-to-gross (N/G) values of 0.48 – 0.93 further indicate substantial net pay and reservoir continuity across the field. Well-to-seismic tie using synthetic seismograms established a reliable correlation between well data and seismic reflections, enabling accurate mapping of reservoir horizons. Structural interpretation reveals a fault controlled system dominated by listric growth faults and rollover anticlines, which serve as the primary trapping mechanisms. Seismic attributes, including RMS amplitude, envelope, and sweetness, highlight high amplitude anomalies associated with hydrocarbon accumulations, particularly within structurally favorable closures. The integration of seismic attributes with petrophysical results identified undrilled prospective zones with significant exploration potential. The study demonstrates that coupling seismic attributes with quantitative petrophysical analysis provides a robust framework for reservoir characterization and reduces uncertainty in hydrocarbon exploration within complex deltaic environments.

1 Introduction

All hydrocarbon exploration activities have the same goal: to uncover viable oil and gas reserves (Sansal, 2014). The production of hydrocarbons from the Niger Delta's oil and gas sources has been steadily declining in recent years. As a result of this difficulty, subsurface geoscientists (geologists and geophysicists) are currently using more advance computer software in interpretation methodologies. This is performed by using all available and appropriate techniques to enable a better knowledge of reservoir attributes and to maximize hydrocarbon exploration, develop both existing and undiscovered reservoir locations.

In reflection seismology, seismic attributes are measurements produced from seismic data that define the form or other properties of a seismic trace across time (or if the seismic data has been converted to depth, over a specified depth interval). Since seismic features allow interpreters to extract more information from seismic data, they are crucial in field survey. Horizon attributes, interval attributes, and surface attributes are the three sorts of attributes we typically use (Clemons *et al.,* 2017; Subrahmanyam & Rao, 2008; Taner, 1994). There are about 100 seismic attributes that may be estimated from seismic data and used to analyze geological structure, stratigraphy, and rock/pore fluid dynamics. The physical parameters of the reservoir, such as porosity, permeability, water saturation, and pore fluid, are defined by the reservoir description (Alabi and Enikanselu, 2019).

Furthermore, understanding the faults, horizon, and structural framework as well as generating seismic surfaces from the picked horizon is critical for determining the potential and actual volume of any seismic feature. Because these qualities serve as necessary and important inputs for reservoir volumetric/economic analysis, they are important elements in estimating a basin's hydrocarbon potential.

2 Location and Geology of the Study Area

The study region is located in the Niger Delta Basin (Fig. 1A), which is located on the west coast of Africa at the top of the Gulf of Guinea. The formation of the Niger Delta, one of the world's hydrocarbon producing basins, dates back to the Tertiary period (Olabode and Opeloye, 2013). It is confined on latitude 3°N to 6°N and on longitude 4°E to 8°E. “MD” Field is a shallow onshore field in the Niger Delta central swamp. Fig. 1B is the 2D well log view, which shows the strike and dip of the field. On Mars Field (Fig. 2), which comprises of five oil producing wells which have been drilled. While the early Niger Delta was thought to be dominated by rivers, the post-Oligocene delta is characterized by well-developed

shoreface sands, beach ridges, tidal channels, mangrove swamps, and freshwater swamps. It is one of the world's largest deltas, with an overall upward transition from marine shales 19685 ft (Akata Formation) to continental sands of the Benin Formation 6000 ft via a sand-shale paralic interval 9842.5 ft (Agbada Formation). The delta went through phases of regression and transgression depending on sea level changes, local subsidence, and sediment supply

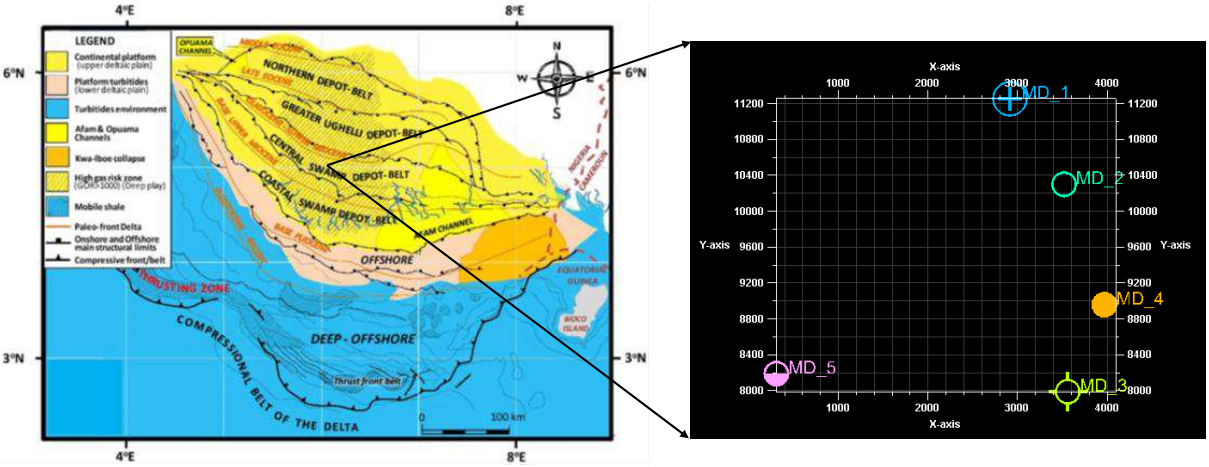


Fig. 1(A) Niger Delta basin map showing study location, depobelts, study area (Redrawn from Ebong *et al.,* 2020; Unukogbon and Emefurieta, 2008) and 1(B) 2D well log view of MD_1 – MD_5

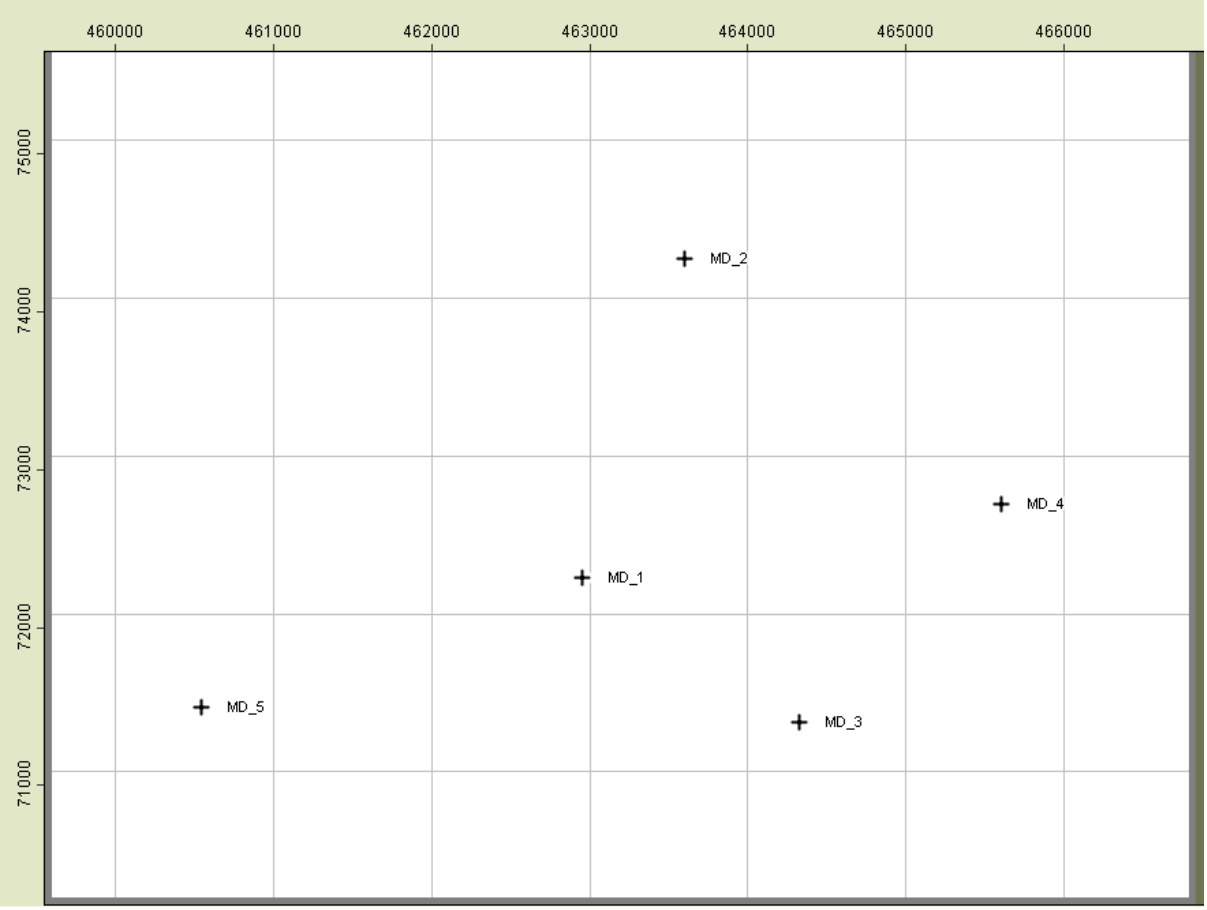


Fig. 2. Map window of five (5) wells selected in MD field

3 Source of data

To unravel the understanding of reservoir and hydrocarbon distributions in the study area (MD Field) of these wells (MD_1, MD_2, MD_3, MD_4, and MD_5) in Fig. 2 an approach that properly integrates seismic attributes was used to study the hydrocarbon distributions zones in the onshore Niger Delta, operated by Shell Petroleum Development Company of Nigeria (SPDC) and was renamed the "MD" Field for proprietary reasons.

The acquired data set given to us from Shell Petroleum Development Company of Nigeria for the purpose of this study are as follow; checkshot, wells (including well header, well logs and well deviation) and 3D seismic data. Five wells which include the following well features; Gamma ray composition (GR _Comp), Density composition (RHO _Comp), Porosity Composition, Sonic Composition and Resistivity (RES_DEEP) Logs from the 'MD' field. The 3D seismic is a post stack data. The software employed is a Schlumberger Petrel 2014 version, RokDoc, with Microsoft offices which includes; MS Excel, Notepad, Paint and Power Point.

4 Method of Data Analysis

An integrated workflow combining well log analysis, seismic interpretation, and seismic attribute extraction was employed to evaluate reservoir quality and identify hydrocarbon prospects in the “MD” Field. Well data, including headers, deviation surveys, and log suites (Gamma Ray, Density, Neutron, Sonic, Porosity, and Resistivity), were quality checked in RokDoc and imported into Schlumberger Petrel (2014) for visualization in 2D, 3D, and intersection windows. Checkshot data were used for time to depth conversion and well-to-seismic calibration. Reservoir intervals were delineated using Gamma Ray logs to distinguish clean sands from shale, while hydrocarbon bearing zones were identified based on high resistivity values and density to neutron log separation. Correlation of wells MD_1 to MD_5 along an east to west transect enabled evaluation of reservoir continuity, facies variation, and geometry across the field.

Petrophysical parameters, including shale volume (Vsh), porosity (ϕ), and water saturation (Sw), were computed from well logs using standard relationships, including Gamma Ray index and Archie’s equation. A well-to-seismic tie was performed using sonic logs and checkshot data to generate synthetic seismograms, allowing correlation of well log signatures with seismic reflections and mapping of key reservoir horizons (MD1000 and MD2000). Structural interpretation involved mapping faults and horizons using seismic data enhanced with relative acoustic impedance, revealing listric growth faults and rollover anticlines as the dominant trapping mechanisms. Seismic attributes such as RMS amplitude, relative acoustic impedance, envelope, and sweetness were extracted to highlight hydrocarbon indicators. These attribute responses were integrated with petrophysical results to establish relationships between seismic signatures and reservoir properties, enabling the identification of prospective zones where structural closures coincide with high amplitude anomalies and favorable reservoir characteristics which is accordance with Morris and Biggs, 1990; Emujakporue & Enyenihi, 2020.

RMS amplitude is used to map hydrocarbon indications in data as well as other geologic characteristics that are separated from background features by amplitude response. To generate a scaled approximation of seismic trace envelope, the root mean square (RMS) amplitude is utilized (Emujakporue & Enyenihi, 2020).

$$RMS\ Amplitude = \sqrt{\frac{(\sum_i^n amp^2)}{K}} \quad 1$$

Where amp is amplitude values and k are number of live samples

Determination of volume of Shale is intercalated in the Agbada Formation reservoirs, with depths rising from the north. Since a totally clean or shale-free formation is typically not possible, the presence of shale intercalations will have a significant impact on porosity value.

Due to its radioactive properties, shale is measured using a gamma ray log.

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

Where IGR is the gamma ray index, GRlog is gamma ray reading of function from the gamma ray log, GRmin is minimum gamma ray of relatively clean sand or carbon formation and GRmax is maximum gamma ray of an adjacent shale formation. The volume of shale (V_{SH}) utilized equation 3 and 4 which can be used to calculate older and tertiary rocks respectively

$$V_{SH} = 0.33[2^{(2\times I_{GR})} - 1.0] \quad 3$$

$$V_{SH} = 0.083[2^{(3.7\times I_{GR})} - 1.0] \quad 4$$

Determination of Porosity can be defined as the ratio of the volume of pores to the volume of bulk rock and is usually expressed as a percentage. Porosity can either be calculated from density log or neutron-density log using the respective equation;

$$\rho_b = \rho_f \emptyset_D + \rho_{ma}(1 - \emptyset_D) \quad 5$$

Rearranging, $\emptyset_D = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f}$ 6

Where $\emptyset_D$ is density derived porosity, ρ_{ma} is matrix density read from the density log (g/cm^3), ρ_b = bulk density read from the density log (g/cm^3) and ρ_f is the fluid density obtain from header of density log. We use equation 6 when there is no porosity log but for our research we porosity log as shown in fig. 3

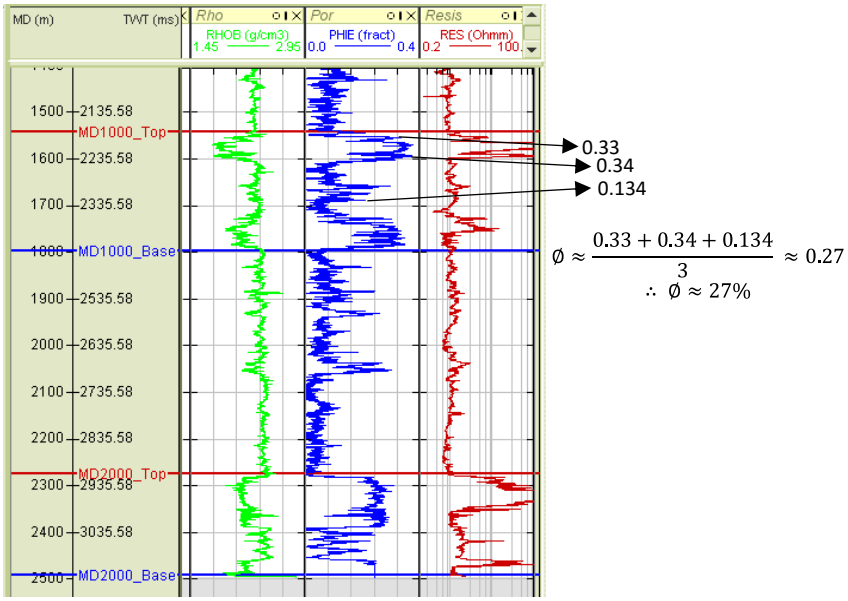


Fig.3 Calculation of MD1000's porosity from the log (PHIE)

Determination of Water or Hydrocarbon saturation can be defined as a degree to which formation of water/hydrocarbon fills the pore space. Ordinarily, it is stated in "fractions" or "percentages."

$$S_w = \left(F\ X\ \frac{R_w}{R_t}\right)^{\frac{1}{n}} \qquad 7$$

Where $R_t$is true formation resistivity (uninvaded zone from Resistivity log ;) R_w is water resistivity, n is saturation exponent usually taken as 2.0 and F is formation factor given by Humble's formula as:

$$\mathrm{F} = \frac{a}{\emptyset^m} \qquad 8$$

Humble proposed that $\emptyset$ is porosity value. 'a' is tortuosity factor which is 0.62 and 'm' is cementation factor which is 2.15 as modified by Archie (1942); therefore, one can modify Archie's equation for water saturation as:

$$\mathrm{S_w} = \left(\frac{0.62}{\emptyset^{2.15}} \times \frac{0.04}{R_t}\right)^{\frac{1}{2}} = \sqrt{\left(\frac{0.0248}{R_t \times \emptyset^{2.15}}\right)} \qquad 9$$

Hydrocarbon saturation can be calculated using: $S_h = 1 - S_w$ 10

Where Sw is the fractional part of the pore volume filled with water of resistivity Rw, n is the saturation exponent, Rt is true formation resistivity, F is the formation resistivity factor, $\emptyset$ is the fractional porosity (Pickett, 1966; Obimma *et al.,* 2017; Morris. and Biggs 1990)

5 Results and Interpretation

Fig. 4 displays correlated sands (yellow) and shale (gray) units in a study area using composite log data from the wells. Two hydrocarbon-bearing sand reservoirs (MD1000 and MD2000) were identified using gamma ray, resistivity, density, and neutron porosity logs. Petrophysical properties of the reservoir sand bodies are discussed in the next heading. Correlation aided in understanding the lateral distribution, continuity and geometry of reservoirs across the field. The sand tops coincided with the interpreted horizons from the 3D seismic data used in this study area. In Fig. 5 we can see variation in the logs where MD_1 has GR, PHIE (effective porosity), NEUT (neutron porosity), RHOB and RES; well MD_2 has GR, DEN, RES, SONIC; and well MD_3 has GR, RHOB, RES and SONIC, these are because of acquisition differences, tool availability, and operational decisions. The correlated well logs for MD_1 – MD_5 reveal significant lateral facies variation within the study area. The sands thin and pinch out laterally toward MD_2 (Fig. 5), highlighting reservoir discontinuity and suggesting a deltaic or channelized depositional system.

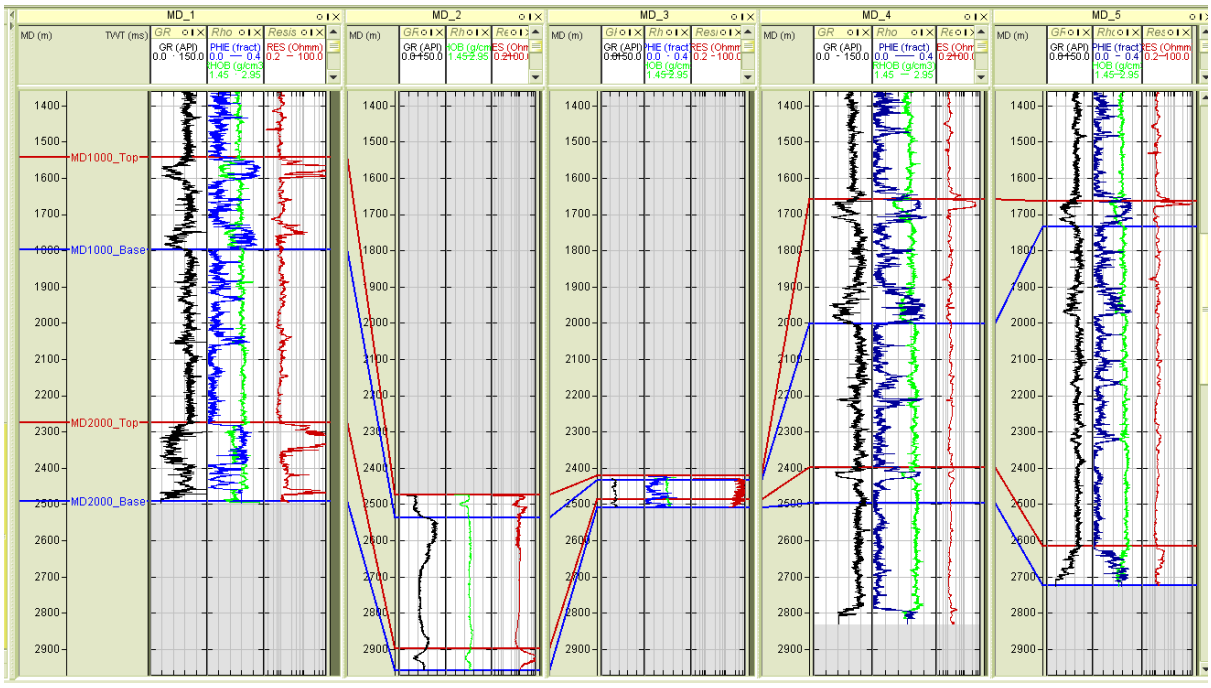


Fig. 4. Well log panel showing the correlated reservoir sand bodies. MD1000 and MD2000 are the two main reservoir sand units identified in the study area.

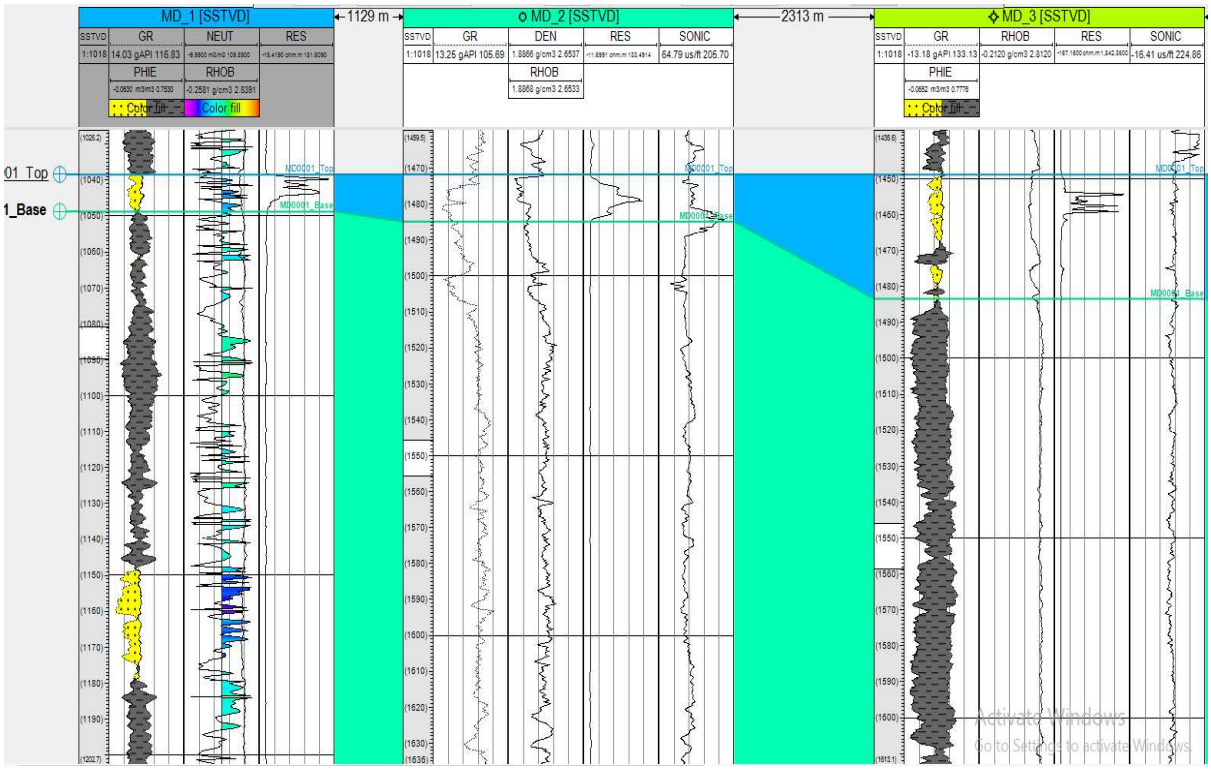


Fig. 5. Correlated well log panel of MD_1, MD_2 and MD_3 showing reservoir sand-shale facies distribution.

The study area shows a well correlation transect in neutron log signature, causing the gas effect or balloon structure. Oil in reservoirs increases density-neutron separation, but this is usually small. Water bearing zones have low resistivity readings and tramlining between density and resistivity logs. Hydrocarbon bearing zones have high resistivity and anti-correlation between density and resistivity logs. Petrophysical evaluations reveal reservoir properties variations in identified hydrocarbon zones (Ogbe *et al.,* 2021, Asquith and Krygowski, 2004).

5.1 Petrophysical Evaluation

Table 1 shows the petrophysical evaluation of the studied reservoirs which reveals significant variability in reservoir properties across wells MD_1 to MD_5, reflecting the heterogeneous nature of the depositional environment. Reservoir thickness varies widely, with the thickest interval observed in MD_4 and the thinnest in MD_3, indicating uneven sediment distribution typical of fluvio-deltaic systems. Shale volume (Vsh) values generally indicate moderately clean sand formations, although localized intervals of higher shale content suggest potential reductions in permeability and reservoir quality. Porosity values range from

moderate to good, suggesting adequate storage capacity within most reservoir units. The saturation analysis shows predominantly low water saturation and high hydrocarbon saturation in the majority of the wells, confirming the presence of commercially viable hydrocarbon accumulations. Additionally, the net-to-gross (N/G) ratios are generally high, indicating substantial net pay and good reservoir continuity across the field. Overall, the integration of petrophysical parameters including porosity, shale volume, fluid saturation, and net-to-gross ratio indicates that the reservoirs possess favorable characteristics for hydrocarbon production, particularly in wells MD_1, MD_2, and MD_3. However, variations in reservoir quality across the field highlight the importance of detailed characterization for effective reservoir management and optimal field development.

Table 1: Petrophysical Estimation from MD_1,2,3,4 and _5 wells

WELL	**MD_1**		**MD_2**		**MD_3**		**MD_4**		**MD_5**	
Reservoir	MD1000	MD200	MD1000	MD200	MD1000	MD200	MD1000	MD200	MD1000	MD200
Top (m)	1539.7	2471.69	2473.60	2897.66	2418.09	2483.71	1655.81	2397.89	1660.86	2614.97
Base (m)	1797.16	2488.76	2536.72	2955.72	2430.71	2506.43	2004.13	2493.81	1731.53	2720.93
Thickness	257.46	17.07	63.12	58.06	12.62	22.72	348.32	95.92	70.67	105.96
V_{sh}	0.23	0.07	0.15	0.32	0.09	0.13	0.32	0.31	0.52	0.29
S_h	0.77	0.93	0.85	0.68	0.91	0.87	0.68	0.69	0.48	0.71
N/G	0.77	0.93	0.85	0.68	0.91	0.87	0.68	0.69	0.48	0.71
∅	0.27	0.18	0.18	0.7	0.10	0.15	0.20	0.16	0.21	0.17
S_w	0.23	0.07	0.15	0.32	0.09	0.13	0.32	0.31	0.52	0.29

5.2 Well-to-Seismic Tie and Time to Depth Calibration

The sonic log calibration and well-to-seismic tie (Fig. 6) were used to determine a time-depth relationship between well sequences and seismic responses. The well-to-seismic tie was used to match and map horizons of interest corresponding to reservoir sand tops on seismic data. The well-to-seismic tie showed a fair to good match between well logs and 3D seismic data, enabling confident matching of geological events to their original reflector depth during seismic interpretation.

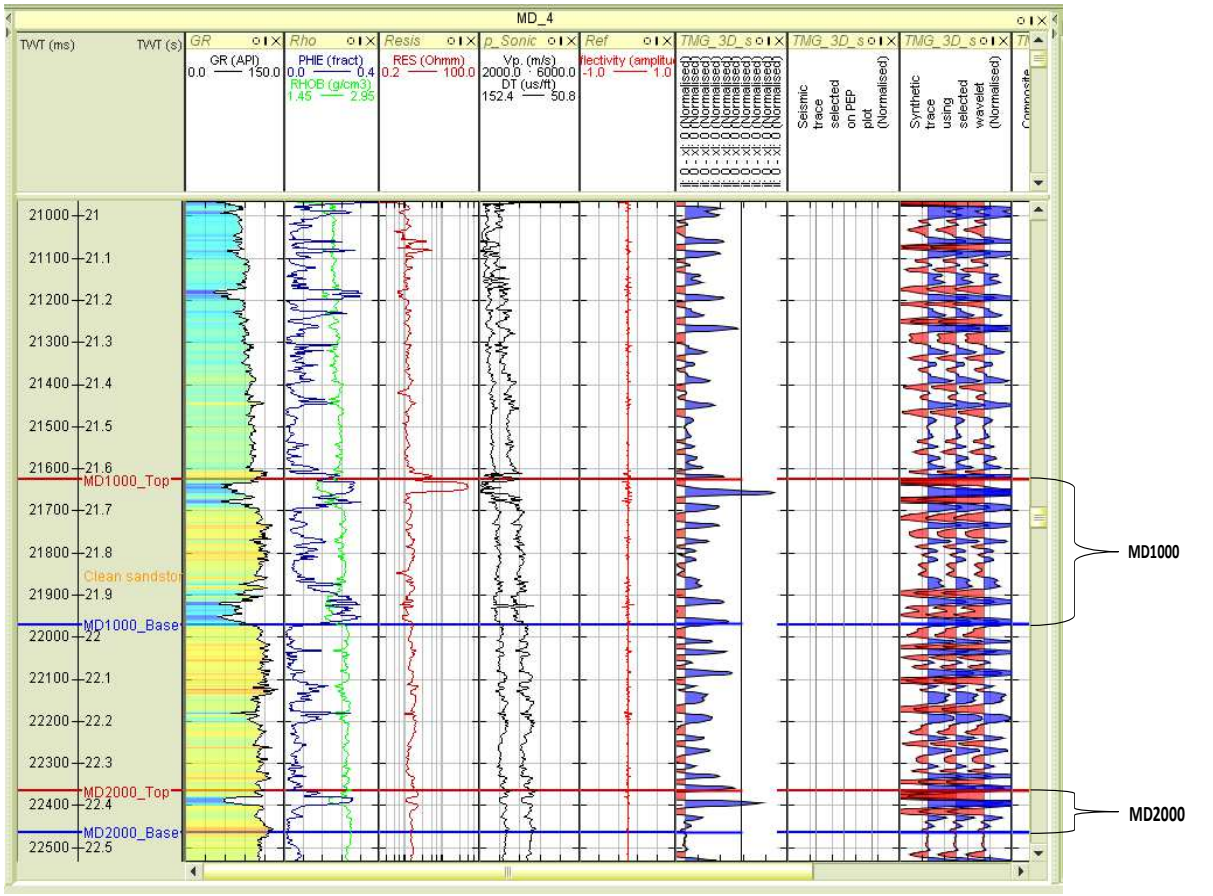


Fig. 6. Well section showing the well-to-seismic tie on MD_4 well.

5.3 Horizon Mapping

Fig. 7 shows an overlay of the generated synthetic seismogram from MD_4 well on seismic inline 9350. The synthetic seismogram aided the interpretation of horizons of interest in the study area. The interpreted horizons corresponded to the top of the identified hydrocarbon-bearing reservoir sands from well log analysis. The picked horizons were used to produce the time structural maps of the MD1000 and MD2000 reservoir sands, respectively. The mapped horizons combined with the interpreted faults to define the structural framework of the study area and variations in the seismic and reservoir properties across the field. The correlation between the synthetic trace and seismic reflections is generally good, providing confidence in the identification of key horizons (SH1 and SH2), which correspond to the tops of the hydrocarbon bearing reservoirs (MD1000 and MD2000). The interpreted faults observed on this section indicate structural deformation typical of the Niger Delta, with faulting playing a crucial role in reservoir compartmentalization and trapping mechanisms.

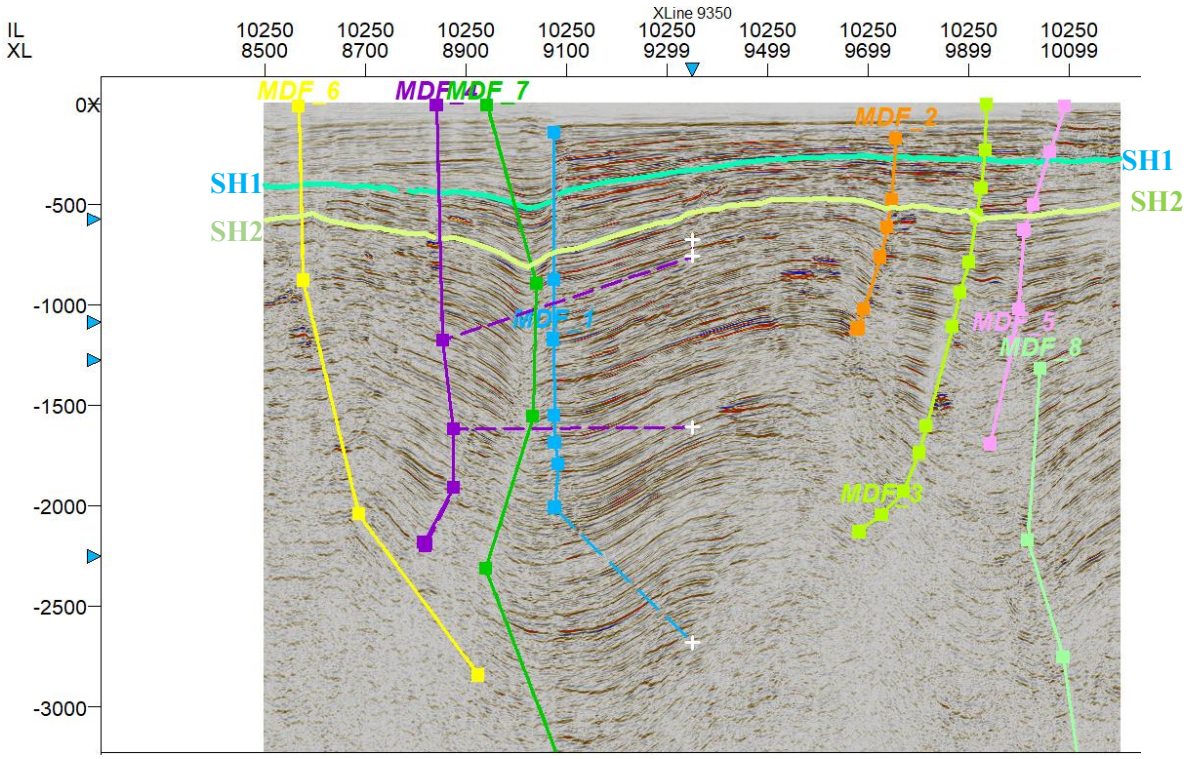


Fig. 7. Well-to-Seismic Tie on Inline 9350 Showing Synthetic Seismogram Overlay, Horizon Correlation (SH1 and SH2), and Fault Interpretation"

5.4 Fault Interpretation

Eight faults MDF1, MDF2, MDF3, MDF4, MDF5, MDF6, MDF7, and MDF8 were interpreted in the study area as shown in Fig. 7. The relative acoustic impedance Fig. 8 extracted from the seismic volume enhanced the imaging and picking of faults along the dip direction (inline), to understand the structural pattern of the field. The area is characterized by high-angle steeply dipping listric (growth) faults and their corresponding roll-over anticlines which form the main trapping geometry in the Niger Delta Basin. Doust and Omatsola (1990) interpreted these faults to be syn-sedimentary deformations that originated from rapid sediment loading and gravity tectonics. Growth faults controlled the deposition of thick sedimentary packages in several depo-axis within the Niger Delta Basin (Evamy *et al.,* 1978; Doust and Omatsola, 1990).

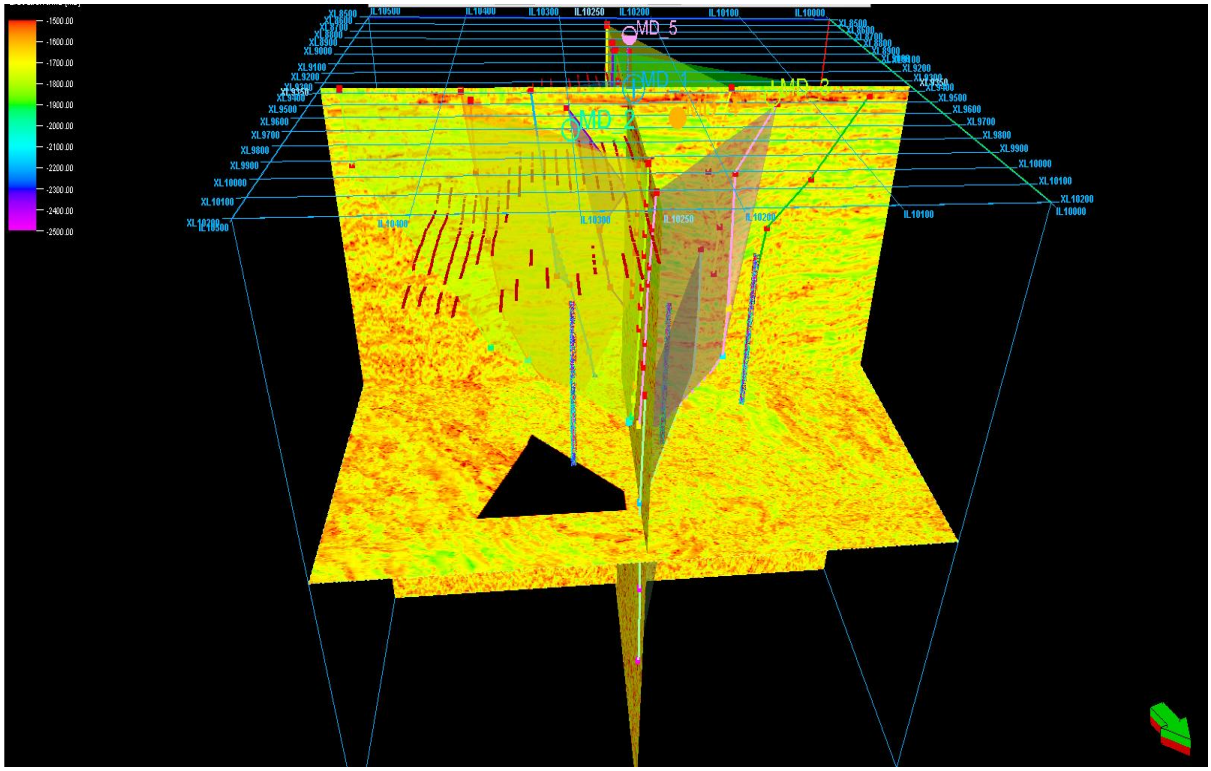


Fig. 8. Relative Acoustic Impedance time slide, Fault Mapping and Horizon Mapping in red

The structural geometry of the field gave insights on the impacts that both major and minor faults have on subsurface fluid flow and trap styles in the study area. The structures also played a key role in the identification of fault-dependent hydrocarbon leads and prospect prediction from seismic attributes interpretation in this study.

5.5 Seismic Attributes Interpretation and Prospect Definition

Figure 9 presents RMS amplitude time slices, which highlight zones of high amplitude anomalies interpreted as potential hydrocarbon accumulations. These anomalies are spatially associated with structural closures, particularly in the western part of the field, suggesting favorable conditions for hydrocarbon entrapment. The amplitude responses are indicative of fluid effects and lithological contrasts within the reservoir units.

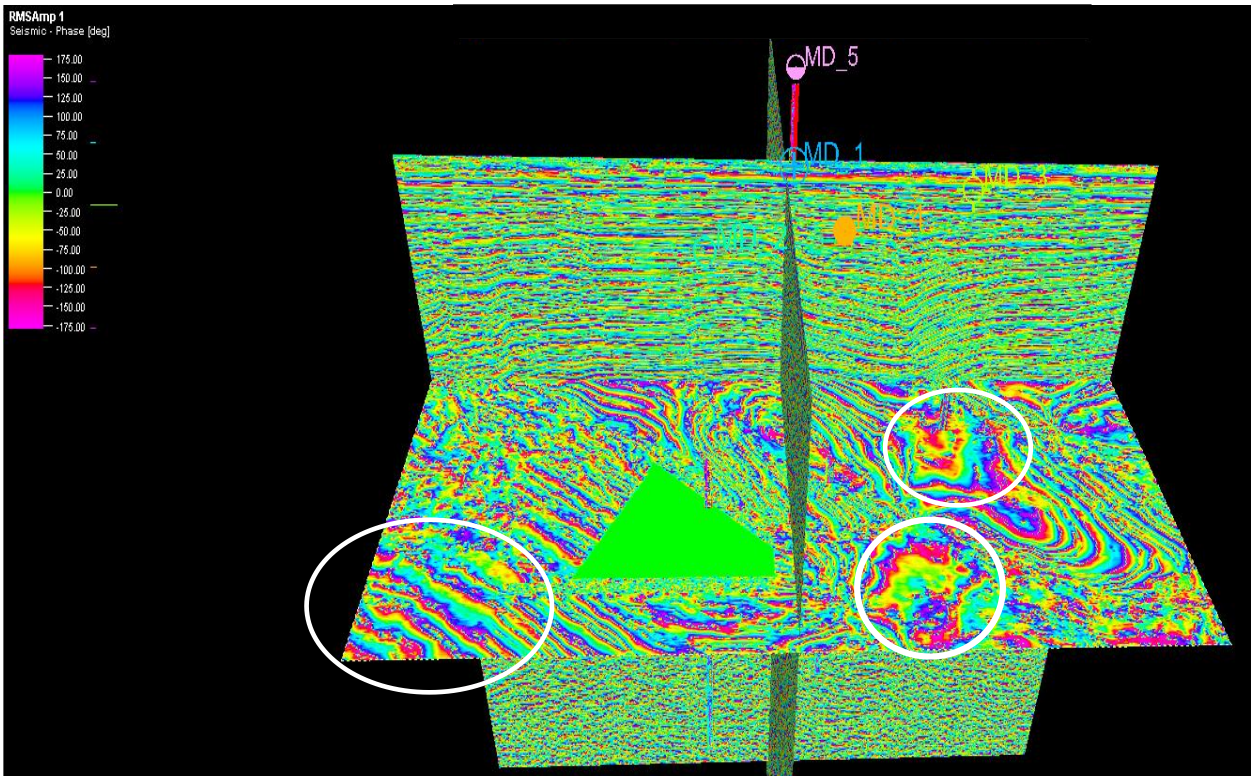


Fig. 9. Volume-based RMS Amplitude time slices at 9350 ms highlighting potential prospect in the study area

5.6 Surface Attributes Interpretation and Prospect Delineation

Surface attributes extracted from the two delineated reservoirs include RMS Amplitude, Sweetness and Average Envelope. The attributes serve as good measure for detecting hydrocarbon presence and were generated to understand the structural geometry in the subsurface and possibly identify new prospective zones in the study area.

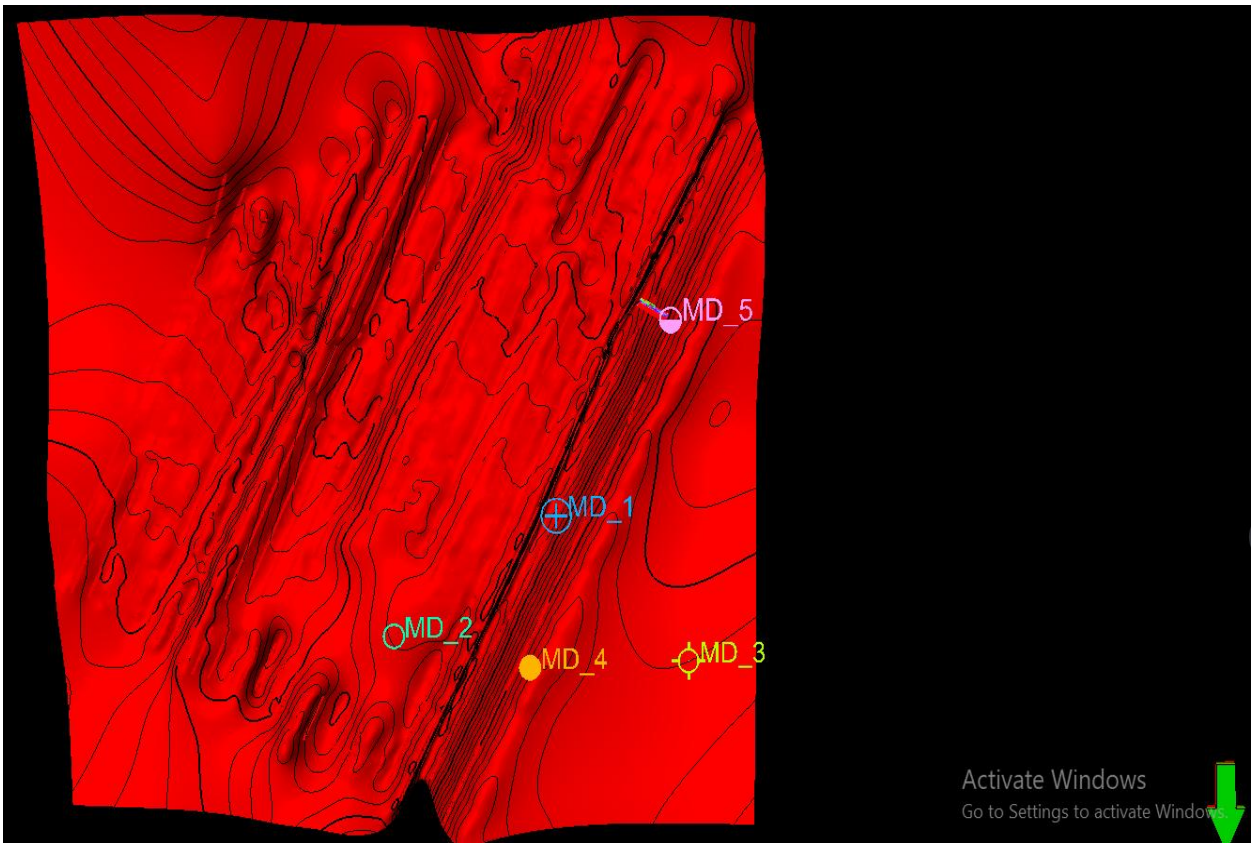


Fig. 10 Surface Attribute Expression of the MDF1 Horizon Highlighting Amplitude Anomalies Associated with Hydrocarbon Prospectivity

Surface attribute analysis further refines prospect identification, as shown in Fig. 10 to 12. The RMS amplitude map (Fig. 10) reveals distinct bright spots corresponding to possible hydrocarbon-bearing sands. The envelope attribute (Fig. 11) enhances reflection strength and continuity, clearly delineating stratigraphic features and amplitude anomalies associated with reservoir zones. Similarly, the sweetness attribute (Fig. 12), which combines amplitude and frequency information, enhances both structural and stratigraphic features, providing improved visualization of fault patterns and subtle hydrocarbon indicators. Fig. 13 presents a 3D visualization of the seismic attribute distribution, integrating inline, crossline, and depth slices. This combined view offers a comprehensive understanding of the spatial distribution of amplitude anomalies and structural features across the field. The 3D display highlights undrilled prospective zones that coincide with favorable structural closures and strong attribute responses, indicating high hydrocarbon potential.

The integrated interpretation of Fig. 7–13 demonstrates that hydrocarbon prospectivity in the "MD" Field is structurally controlled by growth faults and rollover anticlines, with seismic attributes such as RMS amplitude, envelope, and sweetness providing reliable indicators of fluid presence and reservoir quality. The identified amplitude anomalies, when combined with favorable petrophysical properties, define promising exploration targets within the study area.

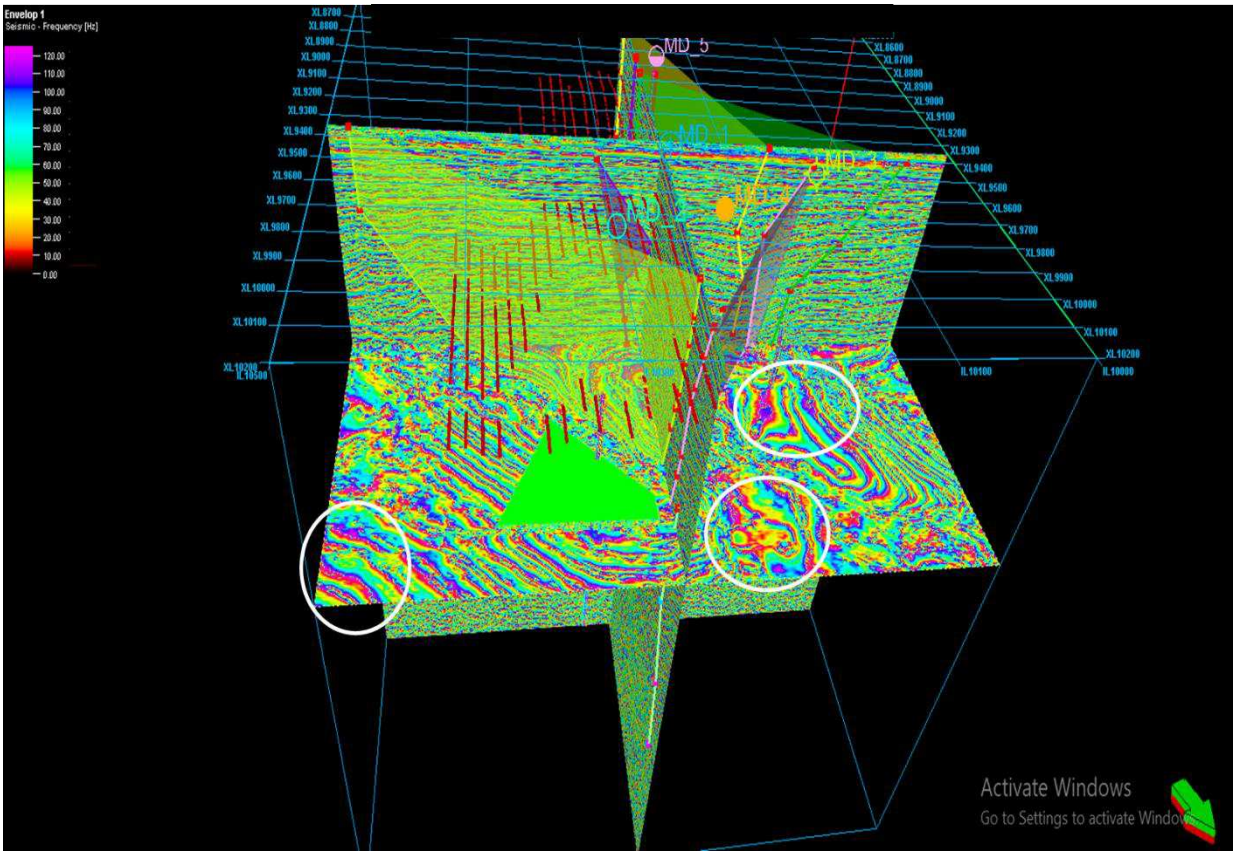


Figure 11. Seismic Envelope Attribute Time Slice Highlighting Reflection Strength and Stratigraphic Continuity Associated with Potential Hydrocarbon Zones in the MD Field

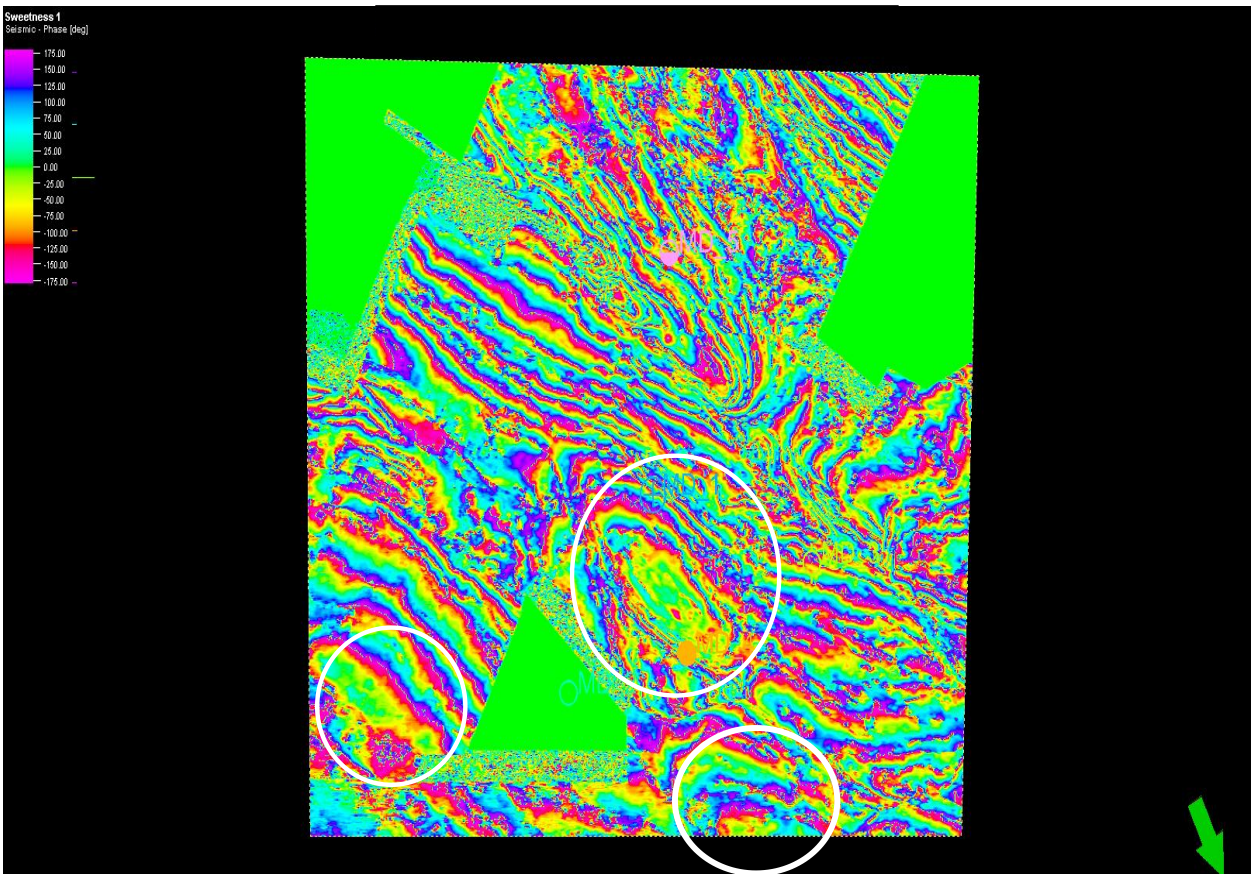


Figure 12. Sweetness Attribute Time Slice Enhancing Structural Features and Delineating Hydrocarbon Prospects within the MD Field

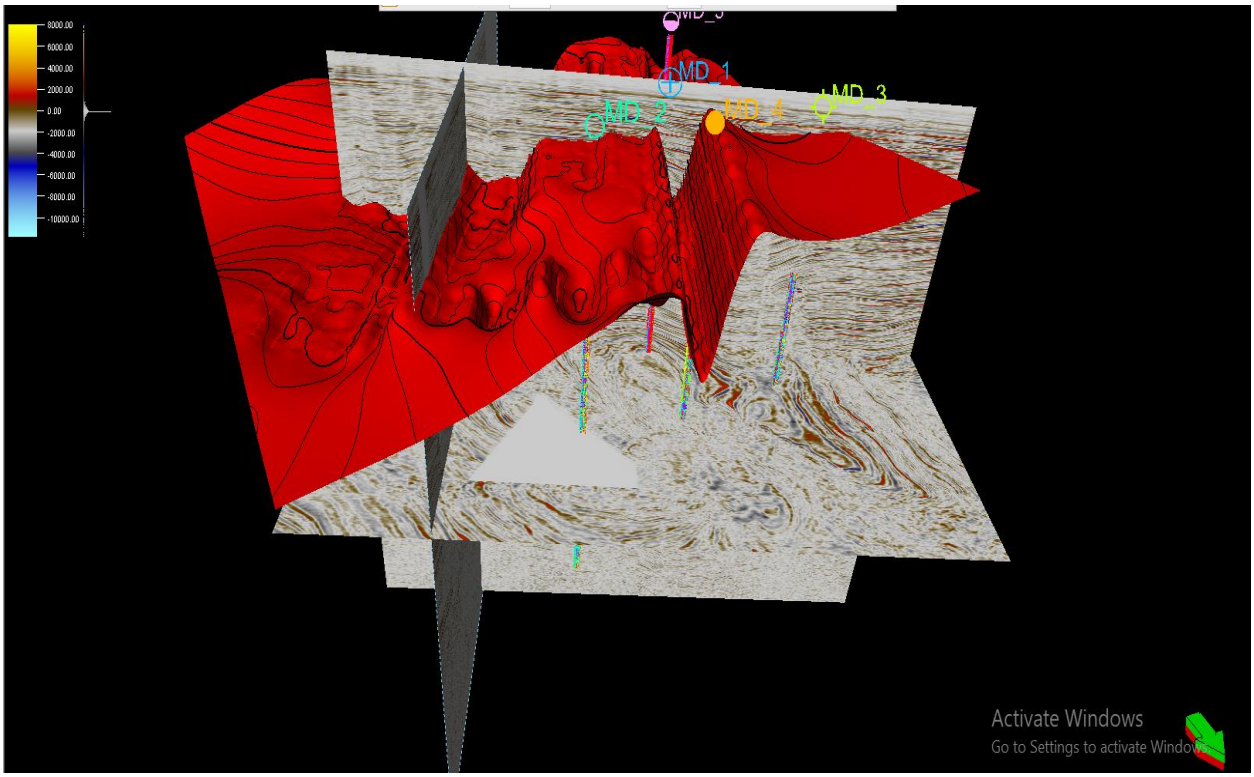


Fig. 13 3D display of Surface Attribute of Inline 10399, Xline 9350 and Z = - 1876.00

6 Conclusion

This study successfully applied an integrated workflow combining well log analysis, seismic interpretation, and seismic attribute evaluation to characterize reservoir quality and delineate hydrocarbon prospects within the “MD” Field, onshore Niger Delta. The well-to-seismic tie provided a reliable correlation between subsurface geology and seismic reflections, enabling accurate mapping of key reservoir horizons (MD1000 and MD2000). The consistency observed between synthetic seismograms and seismic data enhanced confidence in the structural and stratigraphic interpretation of the field. Structural analysis revealed that the field is dominated by listric growth faults and associated rollover anticlines, which serve as the primary trapping mechanisms for hydrocarbon accumulation. These fault systems not only controlled sediment deposition but also influenced reservoir compartmentalization and fluid migration pathways. The integration of relative acoustic impedance further improved fault delineation and structural mapping, highlighting the complex deformation typical of the Niger Delta Basin.

Seismic attribute analysis, including RMS amplitude, envelope, and sweetness, proved effective in identifying hydrocarbon indicators and delineating prospective zones. High-amplitude anomalies observed in both volume and surface attributes were closely associated with structural closures, particularly in the western part of the field, suggesting favorable conditions for hydrocarbon entrapment. The 3D visualization of seismic attributes provided a comprehensive spatial understanding of these anomalies and revealed undrilled prospects with significant exploration potential. When integrated with petrophysical evaluation, the results indicate that the reservoirs possess favorable characteristics, including moderate to good porosity, low to moderate shale volume, high hydrocarbon saturation, and appreciable net-to-gross ratios. These properties confirm the presence of commercially viable hydrocarbon accumulations within the study area.

The study demonstrates that the integration of seismic attributes with petrophysical data is a robust approach for reducing exploration uncertainty and improving reservoir characterization. The identified prospects, supported by both structural and attribute evidence, represent viable targets for future drilling and development. This approach is recommended for similar complex deltaic environments where reservoir heterogeneity and structural controls significantly influence hydrocarbon distribution.

Competing Interests: The authors declare that they have no competing interests.

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