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Reservoir Characterization and Fluid Analysis of the Majosa Field in the Niger Delta

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Abstract The aim of this study is to comprehensively characterize the reservoir and analyze the fluid behavior in the Majosa field located in the Niger Delta. The investigation involved the interpretation of well logs, fluid replacement modeling, and the generation of synthetic seismograms for well-to-seismic tie analysis. Interpretation of the well logs yielded valuable insights into the subsurface characteristics of the study interval. The gamma ray log successfully identified lithology, with leftward deflections indicating sand layers and rightward deflections indicating shales. The neutron-density overlay revealed a balloon structure in the reservoir, suggesting the presence of gas within the study interval. Moreover, the high resistivity kick and low water saturation further supported the existence of gas. Shale intercalations were observed within the reservoir sand, confirming the study interval to be within the Agbada Formation. The reservoir sand was located at an approximate depth of 3,392m, exhibiting 22% porosity and 18% water saturation. To assess log behavior and determine the real fluid composition indicated by the neutron-density overlay, fluid replacement modeling employing Biot-Gassmann's equations and the FRM function in Hampson-Russel Software was conducted. A two-phase fluid model (80% oil, 20% brine) accurately captured the S-wave behavior associated with gas sand observed in the logs. P-wave, S-wave, and density logs exhibited significant changes during the two-phase fluid replacement model. A synthetic seismogram was generated using a statistical wavelet derived from the fluid replacement model logs. The well-to-seismic tie achieved a correlation coefficient of 60.5%, improving subsurface interpretations. This study identified lithology, porosity, and the presence of gas, which impact exploration and production activities. It enhances reservoir management and development planning, emphasizing the potential for enhanced hydrocarbon recovery and the importance of gas monetization strategies. The comprehensive reservoir characterization and fluid analysis inform production optimization and maximize hydrocarbon recovery.

Keywords: *reservoir characterization, fluid analysis, well logs, fluid replacement modeling, synthetic seismogram, well-to-seismic tie, Niger Delta*

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1. Introduction

The Majosa field, located in the Niger Delta, has been a significant hydrocarbon producer for several decades. The Niger Delta province in Nigeria is a significant region for the production of oil and gas (Figure 1). The hydrocarbons are primarily found in the pore spaces of reservoir rocks, predominantly sandstone formations [1]. These reservoirs play a crucial role in storing and producing oil and gas resources. The reservoirs in the Niger Delta exhibit a distinctive geological characteristic, with alternating layers of sandstone and shale units. These formations vary in thickness, ranging from 100 feet to 1500 feet [2,3]. The sand in this formation is mainly hydrocarbon reservoir with shale providing lateral and vertical seal. Some 2 million barrels (320,000 m^3) per day are extracted in the Niger Delta, with an estimated 38 billion barrels of reserves [4]. However, the understanding of its reservoir characteristics and fluid behavior remains crucial for optimizing production and maximizing hydrocarbon recovery [2,5]. The first oil operations in the region began in the 1950s and were undertaken by multinational corporations, which provided Nigeria with necessary technological and financial resources to extract oil. [6]. Since 1975, the region has accounted for more than 75% of Nigeria's export earnings [7]. Together oil and natural gas extraction comprise" 97 per cent of Nigeria's foreign exchange revenues". [8].

The Niger Delta Basin is known for its complex structural deformation and faulting (Figure 2), which can introduce significant uncertainties in reservoir properties. This can have a profound impact on the exploration and development of oil and gas fields within the basin, including the "Majosa field." [2]. The presence of complex structural features and faults in the basin can pose challenges in accurately assessing and predicting reservoir characteristics such as porosity, permeability, and fluid distribution. These uncertainties can make it difficult to estimate the potential reserves, plan drilling operations, and optimize production strategies in the Majosa field and other fields within the Niger Delta Basin. The structural complexity and faulting can create variations in reservoir properties, leading to spatial heterogeneity and uneven distribution of hydrocarbons. This necessitates the use of advanced exploration and production techniques, including seismic imaging, reservoir modeling, and well testing, to mitigate uncertainties and improve reservoir characterization. Understanding the complexities of the structural deformation and faulting in the Niger Delta Basin is crucial for successful exploration and development activities. It requires a comprehensive geological and geophysical analysis, incorporating data from seismic surveys, well logs, and geological studies. By addressing the uncertainties associated with reservoir properties, operators can make informed decisions, optimize production strategies, and maximize the recovery of hydrocarbon resources in fields like the Majosa field.

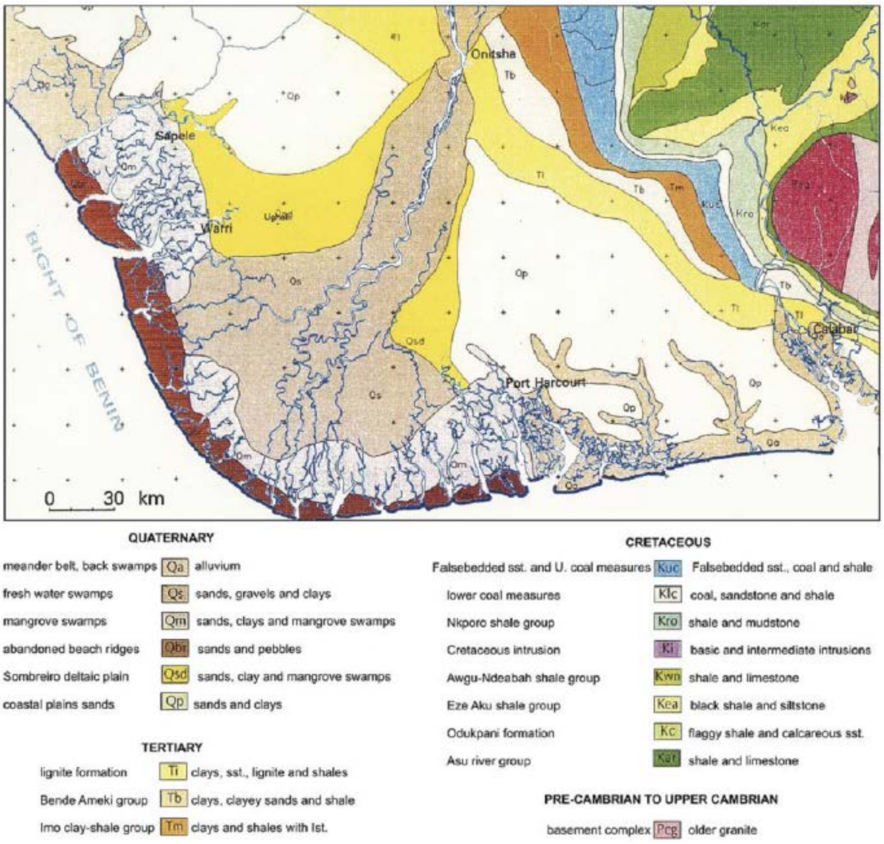

Figure 1. Geologic map of the Niger Delta [9]

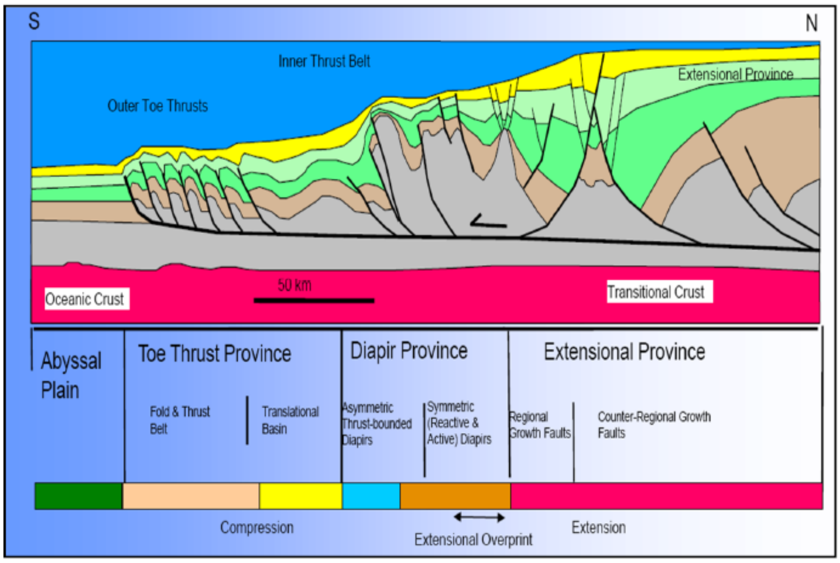

Figure 2. A cross section of the Niger Delta showing the structural styles and zones [10]

In this study, we aim to comprehensively characterize the reservoir and analyze the fluid behavior in the Majosa field, utilizing well log interpretation, fluid replacement modeling, and synthetic seismogram generation for well-to-seismic tie analysis. Previous studies in the Niger Delta region have highlighted the complex geological nature of the area, characterized by interbedded sands and shales, with significant variations in lithology, porosity, and fluid content [2,5,11]. However, many of these studies have focused on older literature, necessitating a reevaluation of the field using more recent data and advanced techniques. The hypothesis of this research is that a thorough analysis of well logs, coupled with fluid replacement modeling and well-to-seismic tie analysis will provide valuable insights into the reservoir characteristics and fluid behavior in the Majosa field. By integrating these techniques, we can enhance our understanding of the lithology, porosity, and fluid composition within the reservoir, enabling more accurate reservoir characterization and development planning.

The significance of this research lies in its potential to contribute to the optimization of hydrocarbon recovery and reservoir management in the Majosa field. By identifying the lithological variations, fluid content, and gas presence within the reservoir, operators can make informed decisions regarding well placement, production strategies, and reservoir stimulation techniques [12,13]. Furthermore, a robust well-to-seismic tie enhances the reliability of subsurface interpretations, enabling more accurate mapping of the reservoir and facilitating future exploration and production activities [14,15]. Overall, this study fills a critical knowledge gap by providing a comprehensive analysis of the reservoir characteristics and fluid behavior in the Majosa field. The findings have direct implications for reservoir management, development planning, and exploration strategies in the field. Moreover, the insights gained from this research can contribute to the broader understanding of reservoirs in the Niger Delta region and inform decision-making processes for similar hydrocarbon reservoirs worldwide.

1.1. Location and Geology of the Study Area

The study area of this research is the Majosa field located in the Niger Delta Basin (Figure 3). It is a ficticious name. The field encompasses both swamp and land environments, presenting unique geological characteristics. The Majosa Field is located within latitudes 4°N and 5°N and longitudes 5°E and 6°E. It covers an extensive area within the Niger Delta Basin [16], which is known for its complex and diverse geological features. The swamp environment within the Majosa Field is characterized by a network of rivers, creeks, and swamps, with extensive areas of waterlogged and vegetated terrain [16]. This environment is associated with the deposition of organic-rich sediments and is known to be a favorable setting for hydrocarbon accumulation. The land environment consists of relatively drier areas with less water saturation [16]. It may include terraces, floodplains, and higher elevated regions. The land environment is also important for hydrocarbon exploration, as it provides access to drilling and production operations. Geologically, the Majosa Field is composed of a variety of sedimentary rocks, including sands, shales, and mudstones [16]. These rocks act as reservoirs, trapping and storing hydrocarbons such as oil and gas. The presence of suitable reservoir rocks and the complex interplay of tectonic and depositional processes contribute to the formation and distribution of hydrocarbon accumulations within the field.

1.2. Regional Geology of the Niger Delta

The Niger Delta is a large actuate delta situated on the Gulf of Guinea on the west coast of central Africa between latitudes 3°N and 6°N and longitudes 5°E and 8°E [17]. It is known for its extensive sedimentary basin, covering an area of approximately 75,000 square kilometers and reaching depths of at least 11 kilometers [18]. The region has proven to be highly productive, with cumulative petroleum resources of 34.5 billion barrels of oil and 93.8 trillion cubic feet of gas [18]. The Niger Delta is characterized by three major lithostratigraphic units: the Akata Formation, the Agbada Formation, and the Benin Formation [19]. The Akata Formation, primarily composed of shale, is recognized as the principal source rock for oil and gas in the region. The Agbada Formation consists of sand and shale units, while the Benin Formation is predominantly composed of coastal plain sands [19]. Currently, oil exploration activities in the Niger Delta are shifting towards the deeper offshore waters, including areas with water depths exceeding 200 meters [18]. Notable discoveries such as the Bonga and Agbami Fields have contributed to the increasing focus on deepwater exploration, despite the higher costs associated with drilling and development in these challenging environments. The Palegeography showing the opening of the South Atlantic, and development of the region around the Niger Delta is given in Figure 4.

1.3. Stratigraphy of Niger Delta

The Niger Delta is characterized by a complex stratigraphy primarily consisting of a regressive off-lap sequence of clastic sediments. These sediments have accumulated over time, resulting in a total thickness ranging from 9,000 to 12,000 meters. The delta has evolved from separate depocenters to a unified system since the Miocene epoch. The Tertiary history of continuous progradation has facilitated the identification of three distinct depositional lithofacies, which are observed throughout the region despite some local facies variations. These lithofacies correspond to three formations: the Akata Formation, the Agbada Formation, and the Benin Formation. The formations span from the Eocene to the Recent age and are regionally and diachronously recognized. Sequence stratigraphic model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon traps related to growth faults is given in Figure 5. The main boundry fault separates mega structures which represent major breaks in the regional dip of the delta [20].

The Benin Formation, also known as "Coastal Plain Sands," consists mainly of sands and gravels with thicknesses ranging from 0 to 2100 meters. It is characterized by coarse to fine sandstones and thin shale layers, primarily found in Benin, Onitsha, Owerri Provinces, and other areas within the Niger Delta region. Although the Benin Formation has limited hydrocarbon potential, it serves as a significant source of portable groundwater in the Niger Delta [21]. The Agbada Formation is predominantly composed of sands, sandstones, and siltstones. It exhibits various off-lap rhythms and plays a crucial role as the primary hydrocarbon reservoir in the Niger Delta. Shale layers within the Agbada Formation act as reservoir seals and may contain hydrocarbon source rocks. The thickness of the Agbada Formation varies depending on location, ranging from approximately 10,000 to 15,000 feet [2]. The Akata Formation, the basal lithologic unit in the Niger Delta, is characterized by marine pro-delta megafacies. It consists mainly of shale, occasionally interbedded with turbidite sandstones and siltstones. The thickness of the Akata Formation ranges from 0 to 6000 meters. It has limited porosity and acts as a source rock for hydrocarbon generation in some parts of the Niger Delta. The hydrocarbons generated in the Akata Formation migrate into the overlying Agbada Formation, where they become trapped [2].

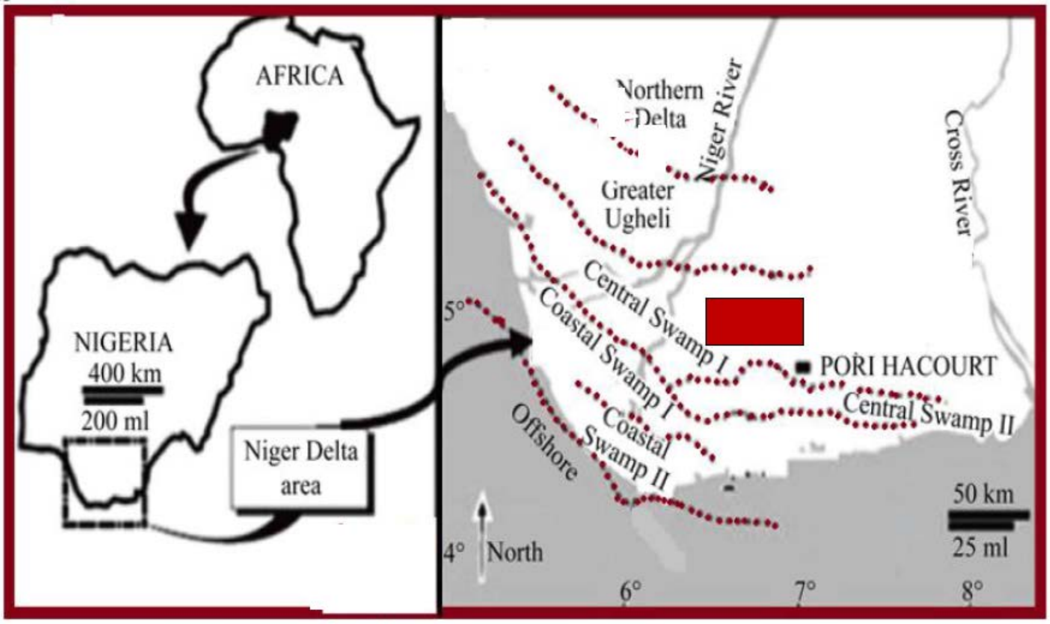

Figure 3. Map of the Niger Delta Showing the Depobelts and Location of the Field of Study (enclosed in red box)

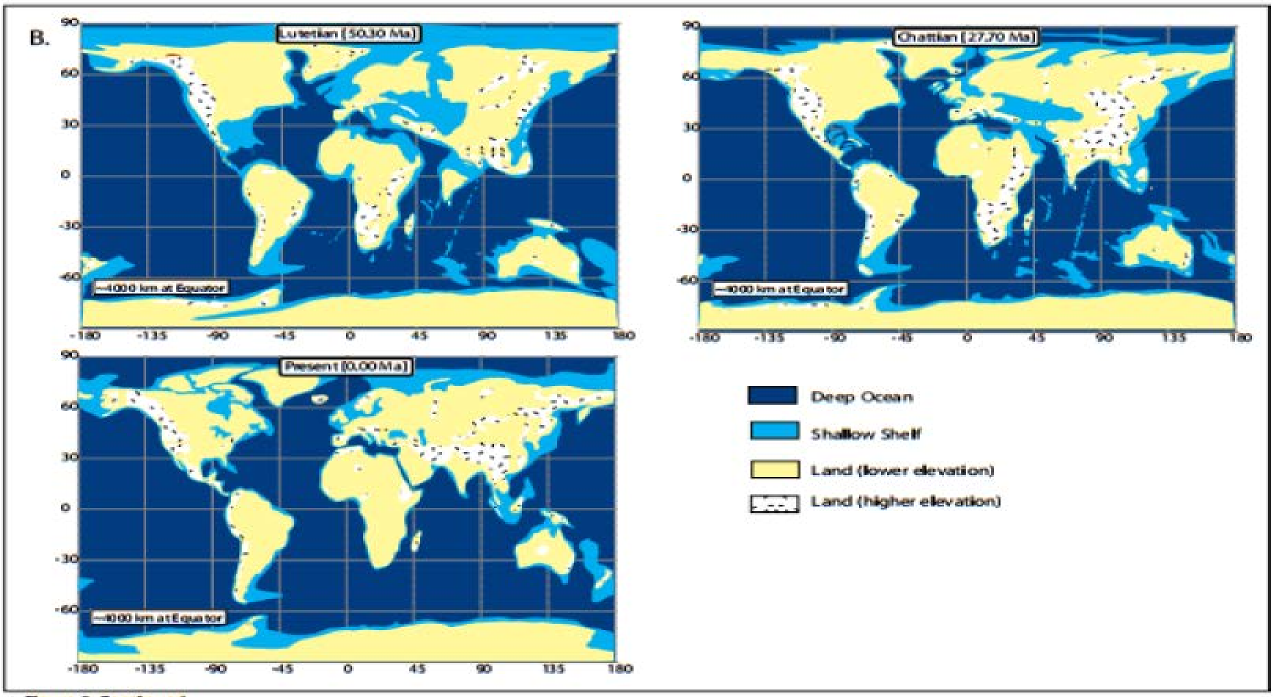

Figure 4. The South Atlantic opening, and development of the region around the Niger Delta. A. Cretaceous palegeography (130.0 to 69.4 ma). B. Cenozoic paleogeography (50.3ma to present). Plots generated with PGIS software

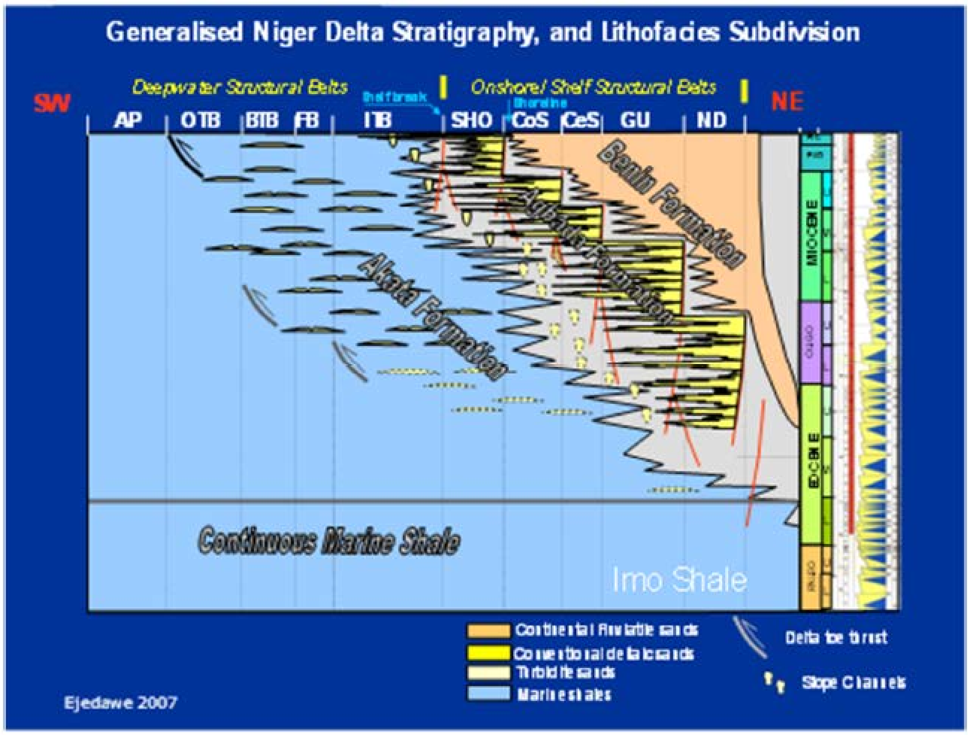

Figure 5. Generalised Niger Delta stratigraphy and Lithofacies subdivision [22]

1.4. Petroleum and Its Occurrence in the Niger Delta

The distribution of petroleum in the Niger Delta occurs within the Agbada Formation, forming an "oil-rich belt" that extends from the northwest offshore area to the southeast offshore and along north-south trends around Port Harcourt [2,20,22]. This belt corresponds to the transition between continental and oceanic crust and is within the axis of maximum sedimentary thickness. Initially, it was believed that the distribution of petroleum was linked to trap formation and petroleum migration. However, studies have shown that the growth of structures and the distribution of petroleum are not necessarily related [2]. Other factors come into play, such as the presence of delta lobes fed by different rivers and increased geothermal gradient relative to the delta center [23]. Additionally, the age of sediments within the belt and the heterogeneity of source rock type may contribute to the distribution of petroleum [2,23]. The oil-rich belt coincides with a concentration of rollover structures across depobelts, characterized by short southern flanks and little paralic sequence to the south [2,24]. Heterogeneity of source rock type, with a greater contribution from paralic sequences in the west, and remigration are also factors that may influence the distribution of petroleum [2]. The coastline of the Niger Delta has prograded since 35 Ma. The delta has advanced seaward over 200 km and has broadened from a width of less than 300 km to a width of about 500 km. The shorelines approximate the [2] (Figure 6).

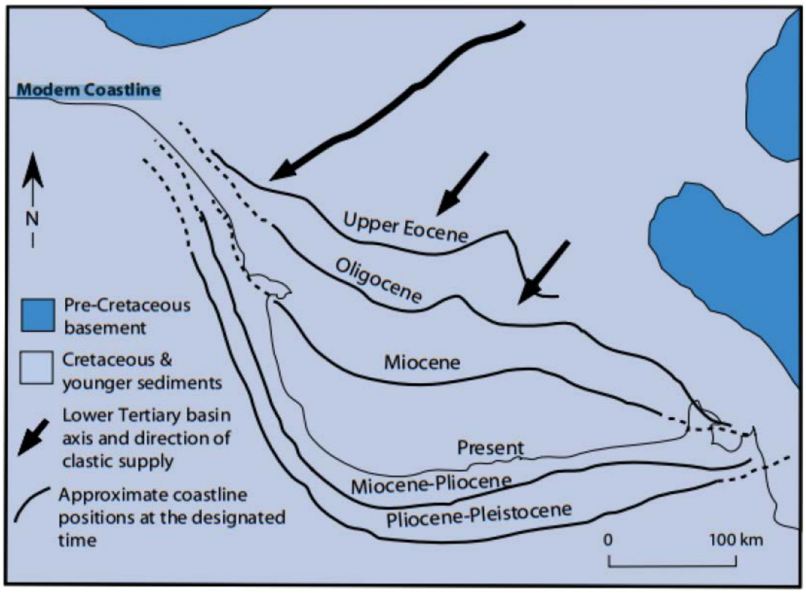

Figure 6. Prograding of the Niger Delta has prograded. Modified from [1]

A hydrocarbon habitat model for the Niger Delta suggests that faulting in the Agbada Formation provided pathways for petroleum migration and formed structural traps [25] (Figure 7). The model also highlights the significance of the shale in the transgressive system tract as an excellent seal above the sands and for enhancing clay smearing within faults [25]. The physical and chemical properties of petroleum in the Niger Delta vary widely. The oil has a gravity range of 16-50° API, with lighter oils being paraffin-based and waxy, while biodegraded oils from shallow reservoirs are naphthenic and non-waxy [1,26]. The concentration of sulfur in most oils is low, and there is a negative correlation between API gravity and sulfur content [27]. The associated gas in the Niger Delta is thermal in origin, with low CO and N concentrations, and high mercury concentrations have been observed [2].

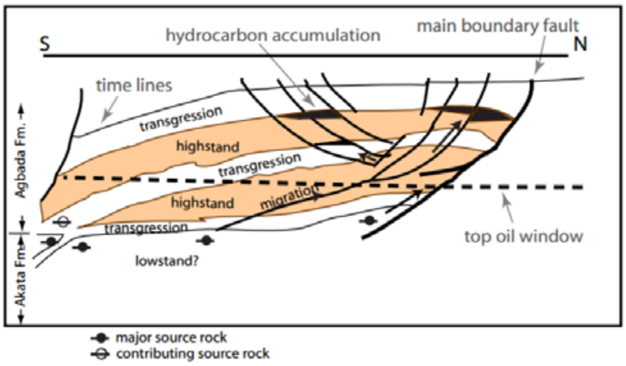

Figure 7. Sequence stratigraphic model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon traps related to growth faults. Modified from [25]

The central, easternmost, and northernmost parts of the Niger Delta have higher gas-to-oil ratios (GOR). GOR within each Depobelt increases seaward and along strike away from depositional centers (Figure 8). The causes for these GOR distributions are speculative and may include remigration induced by tilting, up-dip flushing of accumulations by gas generated at higher maturity, and heterogeneity of source rock type [2]

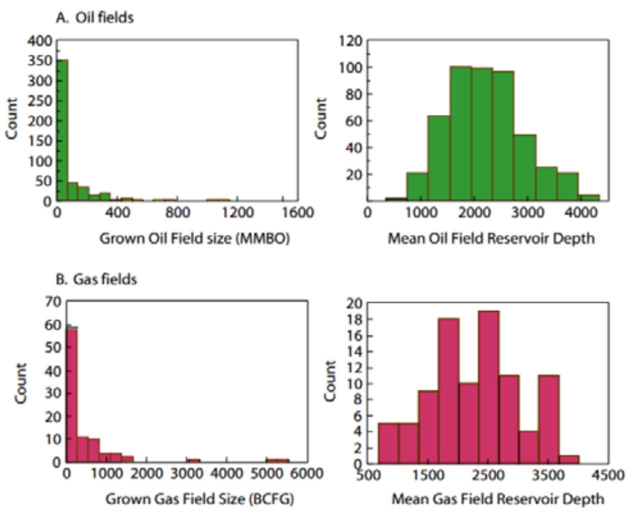

Figure 8. Histograms showing the distribution of size and average reservoir depth in (A) oil fields and (B) gas fields. Data from [18]

1.5. Rock Physics Basic Principles and Fluid Substitution Analysis

Rock physics provides the link between rock and fluid properties and the seismic response. Beyond structural imaging, it largely determines the information content in seismic data. It is concerned with parameters that are of critical importance, but which are often difficult to obtain. Figure 9 shows a schematic of the strain and stress acting on a siliciclastic rock deformation under normal stress and shear stress respectively based on the stress-strain relationship shown, quartz-rich wet sand, oil sand and gas sand and clay-rich sand will deform differently and therefore characterized by distinct rock physics constants.

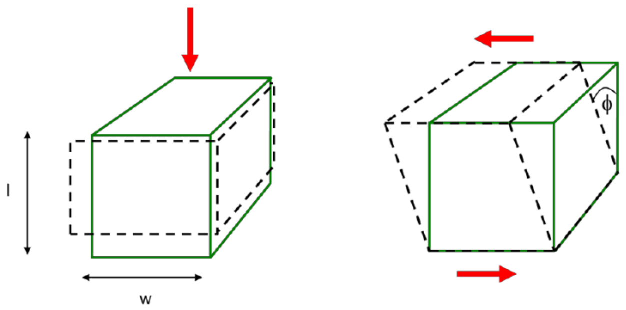

Figure 9. Schematic of the Strain and Stress Acting on a Siliciclastic Rock

The basic rock physics parameters and their derivative rock physics attributes can be expressed by the results of a three dimentional tensor relationship between stress and strain as shown in the equation

$$\frac{V_p}{V_s} = \sqrt{\frac{2(1-\sigma)}{(1-2\sigma)}} \tag{1.1}$$

$$V_s = \sqrt{\frac{V_p^2 2(1-\sigma)}{2(1-\sigma)}} \tag{1.2}$$

$$\sigma = \frac{0.5 - \left(\frac{V_s}{V_p}\right)^2}{1 - \left(\frac{V_s}{V_p}\right)^2} \tag{1.3}$$

Where ρ = density, Vp= compressional velocity, Vs = shear velocity, σ = poisons ratio

To extract fluid types or saturations from seismic, crosswell, or borehole sonic data, we need a procedure to model fluid effects on rock velocity and density. Numerous techniques have been developed. However, Gassmann's equations are by far the most widely used relations to calculate seismic velocity changes because of different fluid saturations in reservoirs. The importance of this grows as seismic data are increasingly used for reservoir monitoring. Compressional (P-wave) and shear (S-wave) velocities along with densities directly control the seismic response of reservoirs at any single location. Bulk modulus is more strongly sensitive to water saturation. The bulk volume deformation produced by a passing seismic wave results in a pore volume change, and causes a pressure increase of pore fluid (water). This has the effect of stiffening the rock and increasing the bulk modulus. Shear deformation usually does not produce pore volume change, and differing pore fluids often do not affect shear modulus. Gassmann's equations provide a simple model to estimate fluid saturation effect on bulk modulus. Eqs. 1a through 2 are convenient forms for Gassmann's relations that show the physical meaning:

$$K_s = K_d + \Delta K_d, \quad (1.4)$$

$$\Delta K_d = \frac{K_0\left(1 - \frac{K_d}{K_0}\right)}{1 - \phi - \frac{K_d}{K_0} + \phi\frac{K_d}{K_f}} \quad (1.5)$$

And

$$\mu_s = \mu_d, \quad (1.6)$$

where, K_0, K_f, K_d, and K_s, are the bulk moduli of the mineral, fluid, dry rock, and saturated rock frame, respectively Φ is porosity μ_s and μ_d are the saturated and dry rock shear moduli. ΔK_d is an increment of bulk modulus caused by fluid saturation. These equations indicate that fluid in pores will affect bulk modulus but not shear modulus, consistent with the earlier discussion. As pointed out by Berryman, a shear modulus independent of fluid saturation is a direct result of the assumptions used to derive Gassmann's equation.

2. Materials and Methods

In the current study, a quantitative approach was adopted, which involved a detailed description of a reservoir in the Majosa field in the Niger Delta. This description was achieved by integrating all the available data in the field. The dataset used in this study included 3D seismic data, well deviation survey data, and checkshot survey data.

2.1. Data Availability and Quality

The dataset available for this study includes:

i. 3D Seismic data
ii. Well deviation survey data
iii. Checkshot survey data (in one well)

2.1.1. 3D Seismic Data

The 3D seismic data covered the entire field and was of fair to good quality. However, the resolution of the data was found to be poor at deeper levels, beyond 2 seconds. Despite this limitation, the seismic data provided valuable insights into the subsurface structure and geological features of the reservoir.

2.1.2. Checkshot Data

Checkshot velocity data was obtained from one well in the field. This data was used to establish a seismic-to-well tie during horizon interpretation. The checkshot data helps in calibrating the seismic data to the actual velocities encountered in the well, improving the accuracy of the seismic interpretation.

2.1.3. Well log Data

Well log data, which included gamma ray, resistivity, density, and neutron logs, were also available for the wells in the field. The log data were generally of good quality and played a crucial role in the quantitative analysis conducted in this study. The gamma ray log provides information about the natural radioactivity of the formations, the resistivity log helps in evaluating the electrical properties of the subsurface, and the density and neutron logs assist in determining the porosity and lithology of the reservoir. Additionally, the SP log and caliper log were utilized for lithology identification and detecting hole washout, respectively. By integrating and analyzing these datasets, the study aimed to gain a comprehensive understanding of the reservoir characteristics in the Majosa field, including its geological structure, lithology, porosity, and fluid content.

2.2. Log Editing and Normalization

The following steps were carried out for log editing and normalization:

1. Dataset Harmonization:
   - The dataset names were standardized and assigned to their respective units using the appropriate Hampson Rusell process. This ensured consistency and compatibility across the dataset.
2. Depth Reference and Quantile Normalization:
   - The first Gamma Ray (GR) log run in each well was selected as the primary depth reference. This log was used to establish a consistent depth reference for all subsequent logs in the well.
   - The GR logs were then normalized using quantile normalization by linear transformation at the 5th and 95th percentiles. This normalization process helps to remove variations in the log responses caused by differences in logging tools and acquisition parameters.
3. Calibration of GR Logs:
   - After normalization, the minimum and maximum percentile values of the GR logs were calibrated to match typical sand and shale peak gamma ray readings of 20 API and 140 API, respectively.
   - This calibration step ensures that the gamma ray readings in the logs are consistent with the expected values for sand and shale formations.
4. Application of Cut-off Value:
   - A cut-off value of 80 was applied across the field to distinguish between different lithologies based on the gamma ray readings. This cut-off value helps to identify and differentiate sand and shale formations.
5. Spike Removal from Sonic Logs:
   - Sonic logs were examined for spikes, which can occur due to cycle skipping during logging. Spikes can introduce artifacts and inaccuracies in the log data.

- Where necessary, the sonic logs were de-spiked to remove the spikes and ensure the accuracy of the data.

6. Corrected and Processed Logs:
   - The edited and processed logs, including the normalized GR logs and de-spiked sonic logs, were used in subsequent geological and petrophysical analyses.
   - These corrected logs played a crucial role in the construction of the Reservoir X static model, which forms the basis for reservoir characterization and further analysis.

By performing log editing and normalization, the study ensured the consistency, reliability, and accuracy of the log data, which is essential for geological and petrophysical analyses and the construction of reservoir models.

2.3. Qualitative Interpretation of Logs

In the qualitative interpretation of logs for the study the following steps were taken:

1. Differentiation of Permeable Zones:
   - The permeable zones, which typically correspond to sand formations, were distinguished from non-permeable zones using a combination of Gamma Ray (GR), SP (Spontaneous Potential), and Neutron/Density logs.
   - These logs provide valuable information about lithology and can help identify zones with higher permeability, such as sand reservoirs.
2. Identification of Reservoir Tops and Bases:
   - Based on the interpretation of the GR, SP, and Neutron/Density logs, the tops (upper boundaries) and bases (lower boundaries) of the reservoir of interest were delineated in the available well.
   - This delineation is crucial for defining the extent and boundaries of the reservoir zone.
3. Identification of Fluid Types:
   - The Neutron/Density logs were used to identify the fluid types present in the reservoir.
   - By analyzing the response of these logs, it becomes possible to differentiate between oil, gas, and water.

2.4. Biot-Gasmann Fluid Replacement Modelling

Seismic signature analysis of the reservoir was conducted to evaluate the influence of fluid types on the observed seismic responses. Fluid substitution models were employed to predict changes in the elastic properties of the saturated reservoir rock under different fluid conditions. The Gassmann equations, formulated by [28], were utilized for fluid substitution, establishing a link between the bulk and shear moduli of the saturated rock, the elastic moduli of the rock matrix and dry rock, and the porosity and fluid bulk modulus. The Two Phase Fluid Replacement Model was utilized to examine the behavior of lithology properties in response to varying water saturation levels. Figure 10 illustrates the parameters of this model, providing insights into the changes in elastic properties of the reservoir rock when two different fluids are present. The key parameters involved in the model were depicted in the figure. To identify and characterize the fluid types present in the reservoir, the behavior of P-wave, S-wave, and Density logs for in-situ fluid conditions was analyzed. Figure 11 showcases the responses of these logs to the presence of specific fluids in the pore space. By analyzing these responses, the fluid types in the reservoir could be identified and characterized.

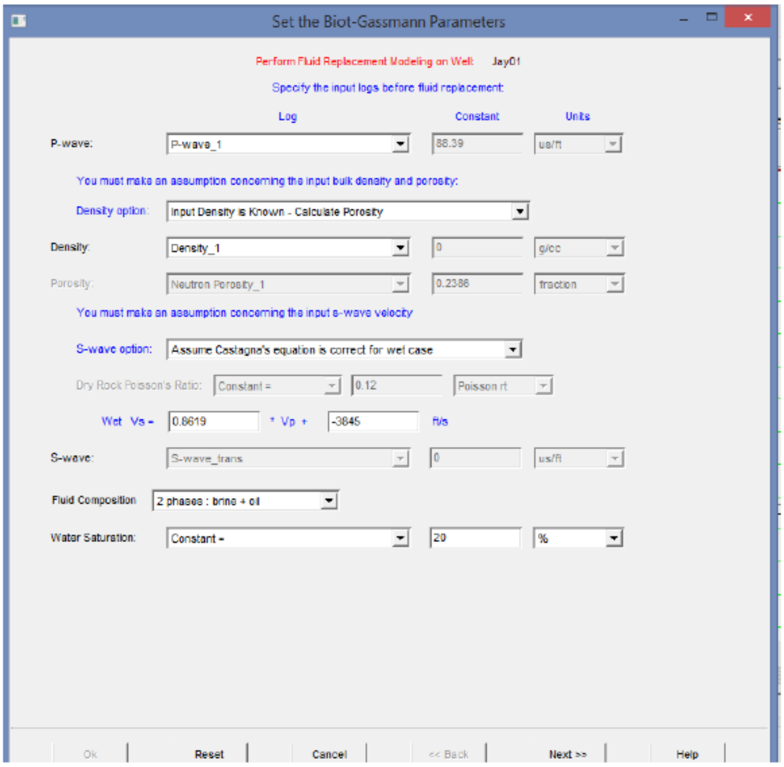

Figure 10. Two Phase Fluid Replacement Model Parameters

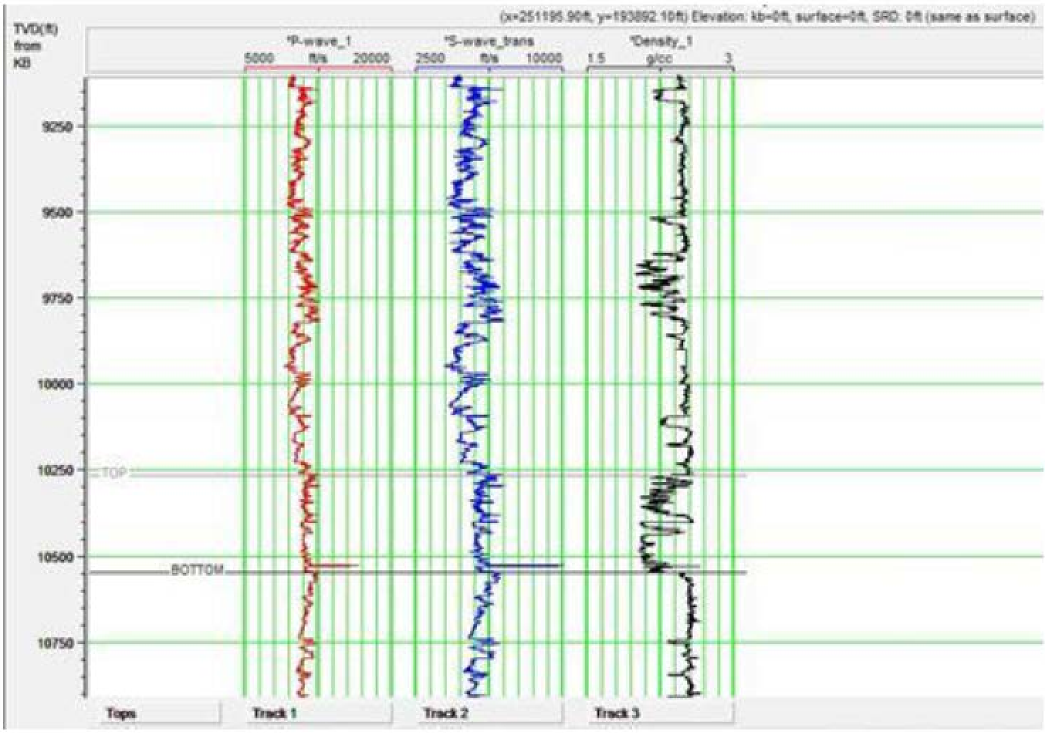

Figure 11. Behaviour of P-wave, S-wave and Density Logs for In-Situ Fluid Conditions

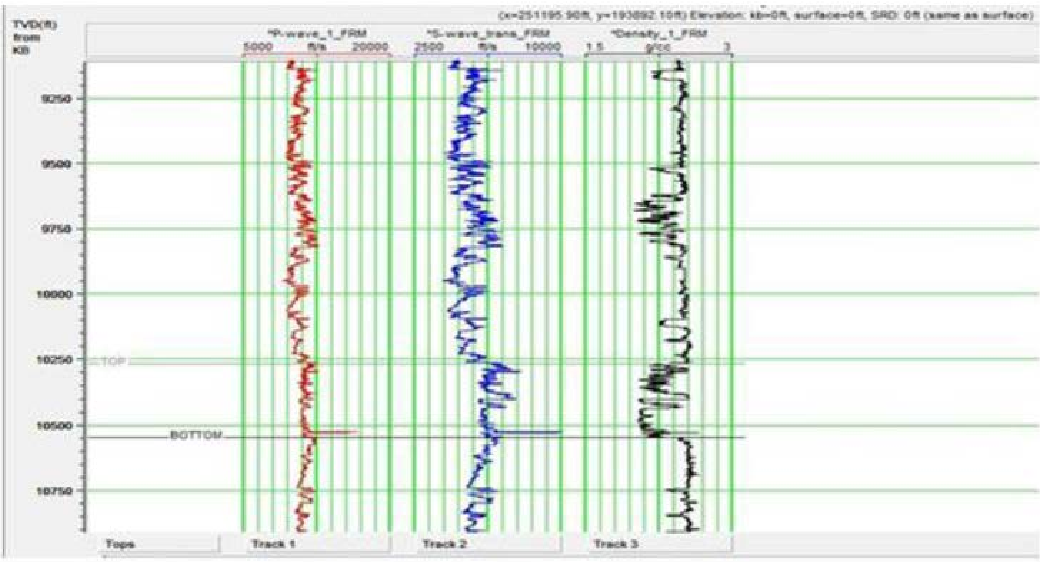

Figure 12. Increase in S-wave Signature during Two-Phase Fluid Replacement Model

Although the shear wave velocity log was not available, Castagna's Transform function on the Hampson Russell Software was used to generate an S-wave velocity log and the input parameters for the two and three phase fluid replacement models are shown in Figure 12.

Figure 12 illustrates the behavior of the S-wave signature during the two-phase fluid replacement model. It shows a gradual increase in the S-wave response as the fluid substitution takes place, indicating changes in the elastic properties of the saturated reservoir rock.

2.5. Seismic To Well Tie

The seismic-to-well tie process involved generating a synthetic seismogram for the well that had check-shot data. This synthetic seismogram was then used to establish a connection between the seismic data and the well data. To accomplish this, a statistical wavelet was created using the Near angle gather from the loaded seismic volume. The seismic data was then correlated with the well data by applying adjustments such as squeezing and stretching until a correlation coefficient of 60.5% was achieved (Figure 13). This correlation coefficient indicates the level of similarity and alignment between the seismic data and the well data. By achieving a good correlation, it becomes possible to accurately align and calibrate the seismic data with the well data, enhancing the accuracy of subsurface interpretations and analysis.

The amplitude response represents the strength or magnitude of the wavelet at different frequencies, providing insights into the distribution of energy across the frequency spectrum. The phase response indicates the time shift or delay of the wavelet at different frequencies, enabling the determination of the relative timing of different wavelet components. Analyzing the amplitude and phase responses can provide valuable information about the characteristics and behavior of the wavelet in the seismic data (Figure 14).

The Synthetic Seismogram panel (Figure 15) played a crucial role in the study as it provided a synthetic representation of the seismic response in the reservoir. This panel was generated based on the integration of well data and seismic information, allowing for a better understanding of the subsurface geological features and fluid content. The Synthetic Seismogram provided a simulated seismic response for the well location, taking into account the rock properties, fluid content, and other relevant parameters. It served as a valuable tool for tying the well data with the seismic data, enhancing the accuracy of interpretation and analysis. By comparing the Synthetic Seismogram with the actual seismic data, the seismic signature of the reservoir was accessed and the distribution of lithology and fluid content was known. This comparison helped in identifying potential hydrocarbon-bearing zones, distinguishing between different fluid types (oil, gas, water), and understanding the reservoir's overall seismic behavior.

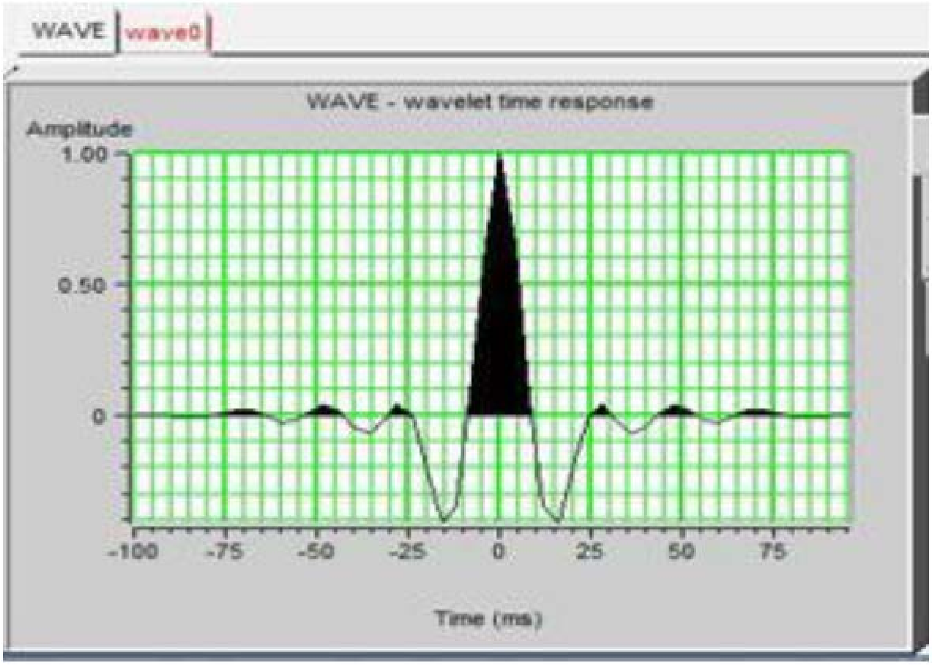

Figure 13. Extracted Wavelet from Seismic Data

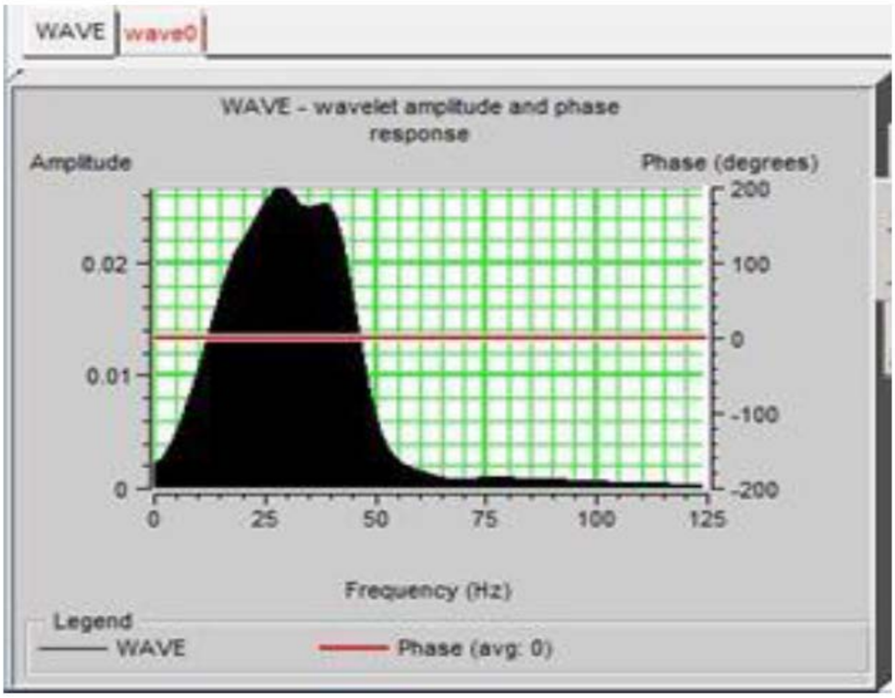

Figure 14. Amplitude and phase response of the extracted wavelet from the seismic data

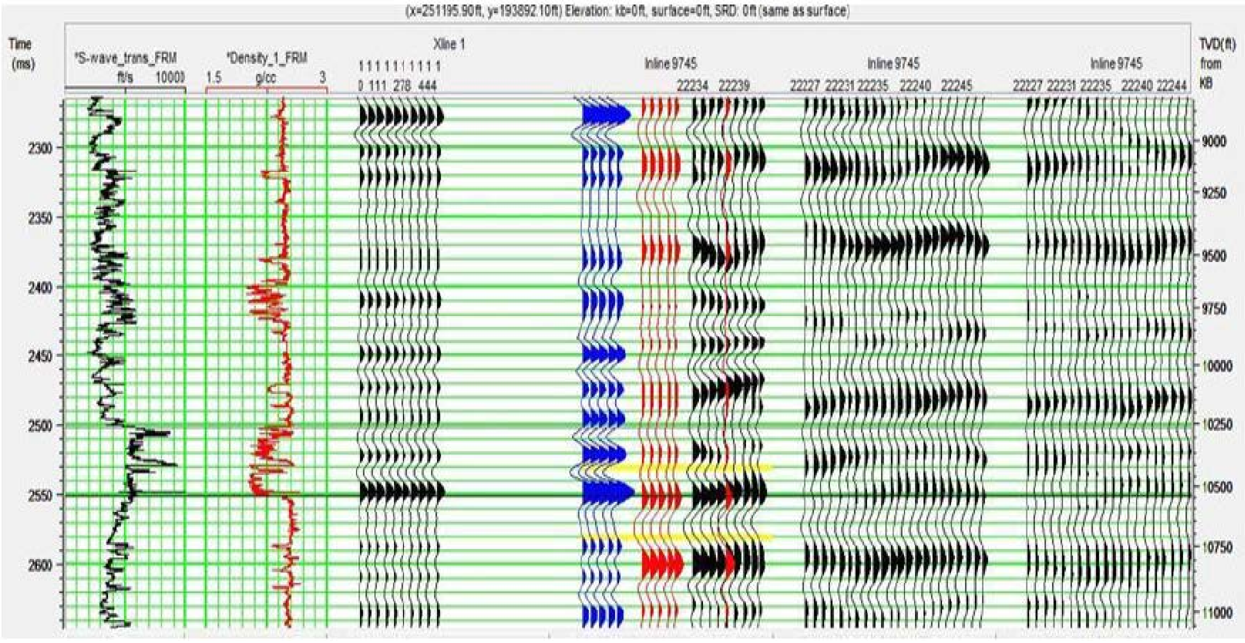

Figure 15. Synthetic Seismogram panel

3. Results and Discussion

3.1. Well Logs

The interpretation of the well logs plays a crucial role in understanding the subsurface geology and fluid content of the study interval. The gamma ray log was particularly useful in determining the lithology, with deflections to the left indicating the presence of sands and deflections to the right indicating the presence of shales. This information helps in identifying the different rock types and their distribution within the study area. In addition to lithology, the neutron-density overlay analysis provided significant findings regarding the fluid content within the reservoir. The presence of a balloon structure in the reservoir location suggested the existence of gas within the study interval. This observation is supported by the high resistivity kick and low water saturation values, which are characteristic of gas-bearing formations. The identification of gas is of great importance for resource assessment and future production planning. Furthermore, the well logs revealed the occurrence of shale intercalations within the reservoir sand. This indicates that the study interval is part of the Agbada Formation, which is known for its hydrocarbon-bearing potential. The presence of shale intercalations may have implications for reservoir quality, as the mechanical properties and permeability of the reservoir rock can be influenced by the presence of shale layers. The identification of the reservoir sand at a depth of approximately 3,392 meters is a significant finding. This information helps in determining the precise location of the target reservoir and provides valuable input for well planning and drilling operations. The porosity and water saturation values obtained from the well logs provide insights into the reservoir's fluid storage capacity and the proportion of water present within the pore spaces. A porosity of 22% indicates the potential for a substantial volume of hydrocarbons to be stored in the reservoir. The relatively low water saturation of 18% further supports the presence of gas, as gas reservoirs typically exhibit lower water saturations compared to oil reservoirs.

Overall, the interpretation of the well logs presented in Figure 16 enhances our understanding of the lithology and fluid content within the study interval. These findings contribute to the assessment of the reservoir's hydrocarbon potential and are essential for making informed decisions regarding exploration and production strategies.

3.2. Fluid Replacement Modelling (FRM)

Fluid replacement modelling using Biot-Gassmann's equations and the FRM function in Hampson-Russel Software was conducted to assess the behavior of the logs and determine the real fluid composition indicated by the neutron-density overlay. The purpose of this modelling was to simulate the response of the well logs under different fluid scenarios and understand the fluid behavior within the reservoir. A two-phase fluid model consisting of 80% oil and 20% brine was adopted to capture the S-wave behavior for gas sand, as suggested by the log signatures. This fluid composition was selected based on previous studies by [29] and [30] that indicated similar fluid characteristics in nearby gas-bearing reservoirs. The examination of P-wave, S-wave, and density logs under in-situ fluid conditions in the reservoir showed significant changes in the S-wave signature during the two-phase fluid replacement model. This analysis provides insights into the fluid composition's impact on the elastic properties of the reservoir rock and helps in understanding the seismic response in relation to the fluid content. Figure 17 displays the interpreted behavior of the P-wave, S-wave, and density logs for in-situ fluid conditions in the reservoir. It demonstrates the changes in seismic velocities and densities as a result of the fluid replacement modelling. The observed variations in the S-wave signature provide valuable information regarding the presence and distribution of gas within the reservoir interval.

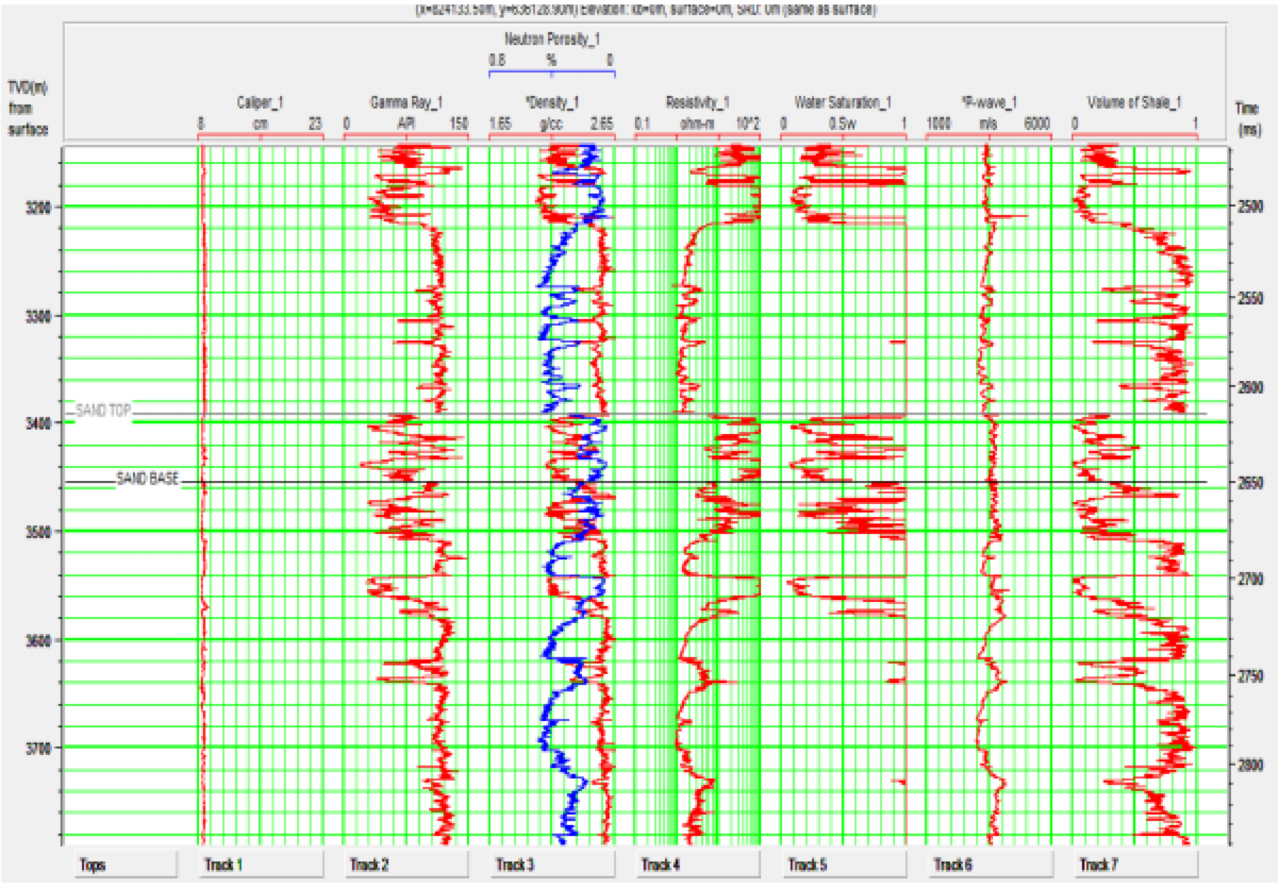

Figure 16. Well Log Interpretation of the Reservoir Lithology and Fluid Content

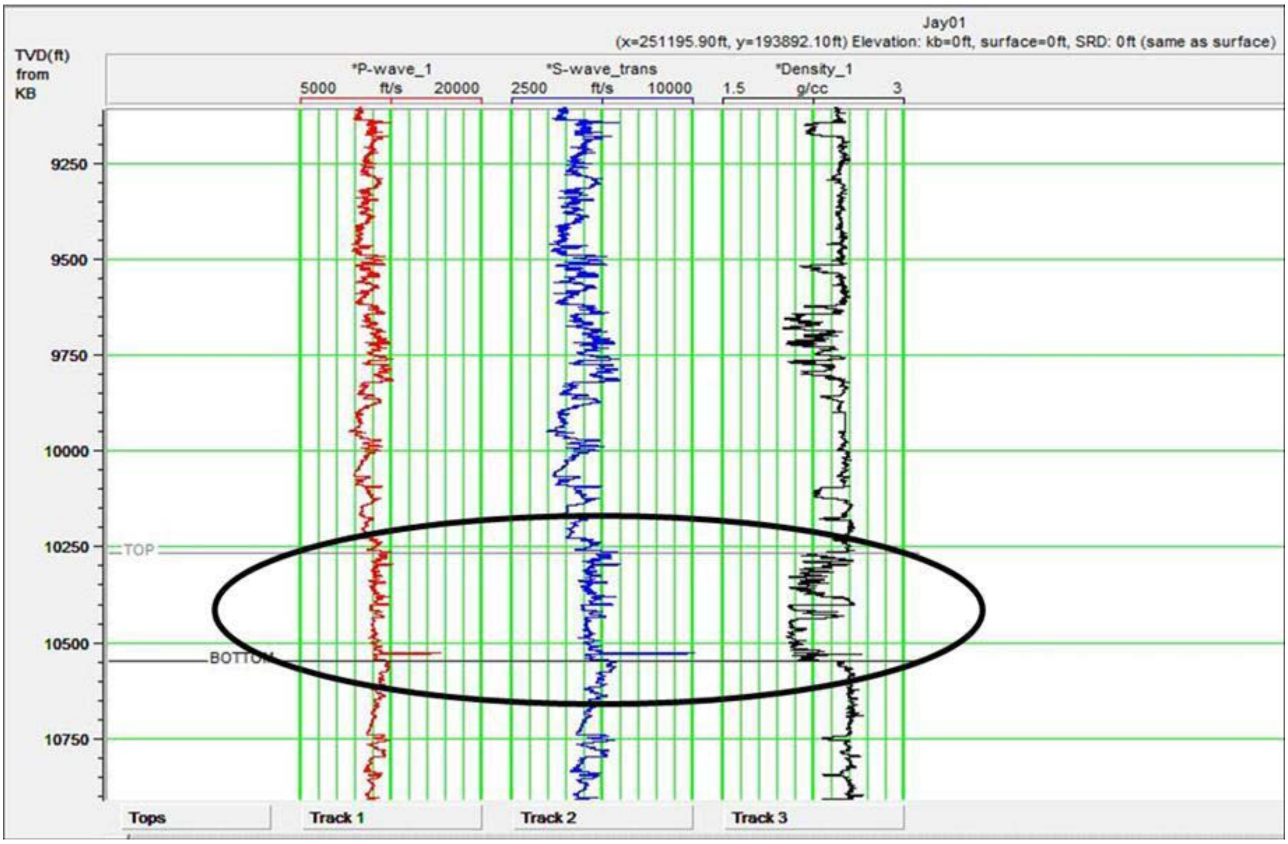

Figure 17. Interpreted Behavior of P-Wave, S-Wave, and Density Logs for In-Situ Fluid Conditions in the Reservoir

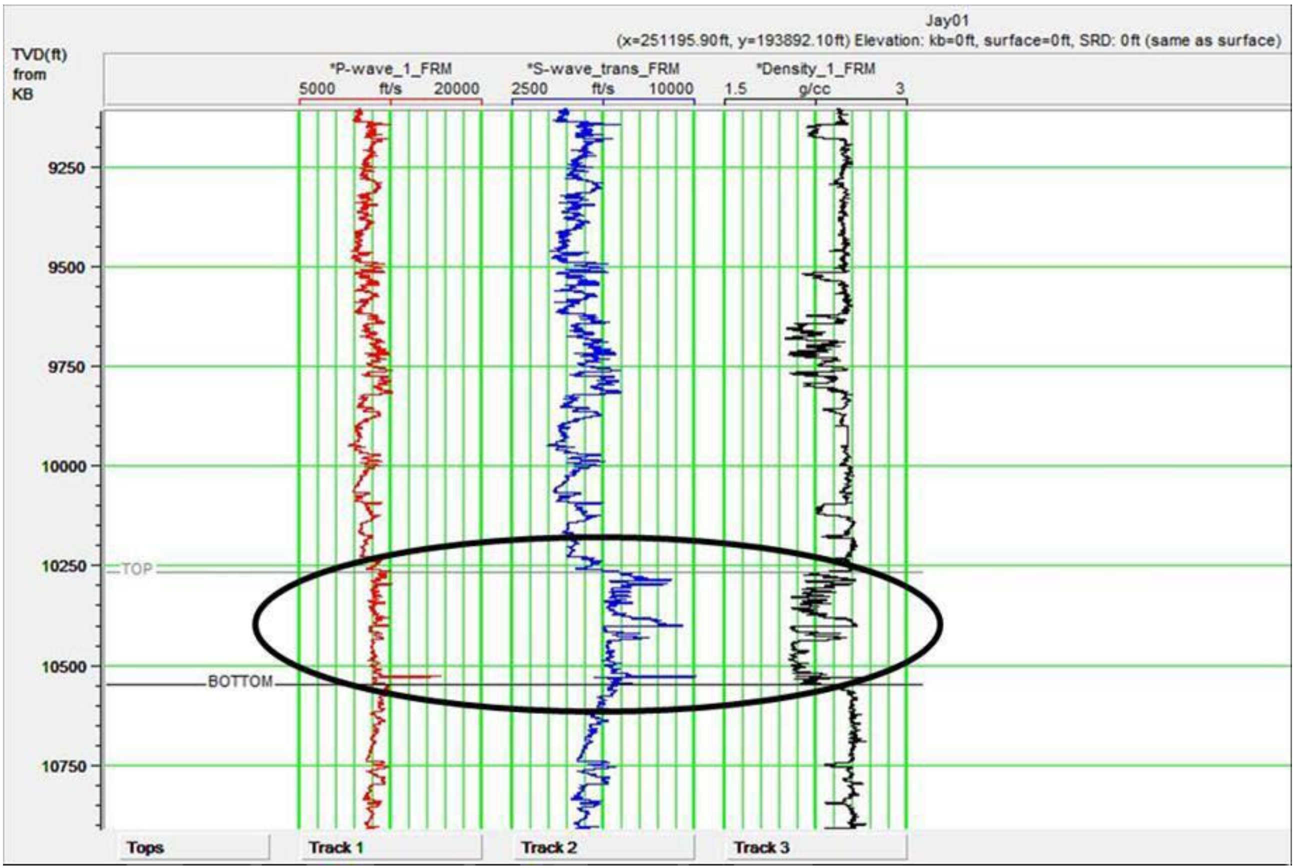

Figure 18. Shows interpreted behaviour of P wave, S wave and Density logs for the 3 phase fluid conditions in the reservoir

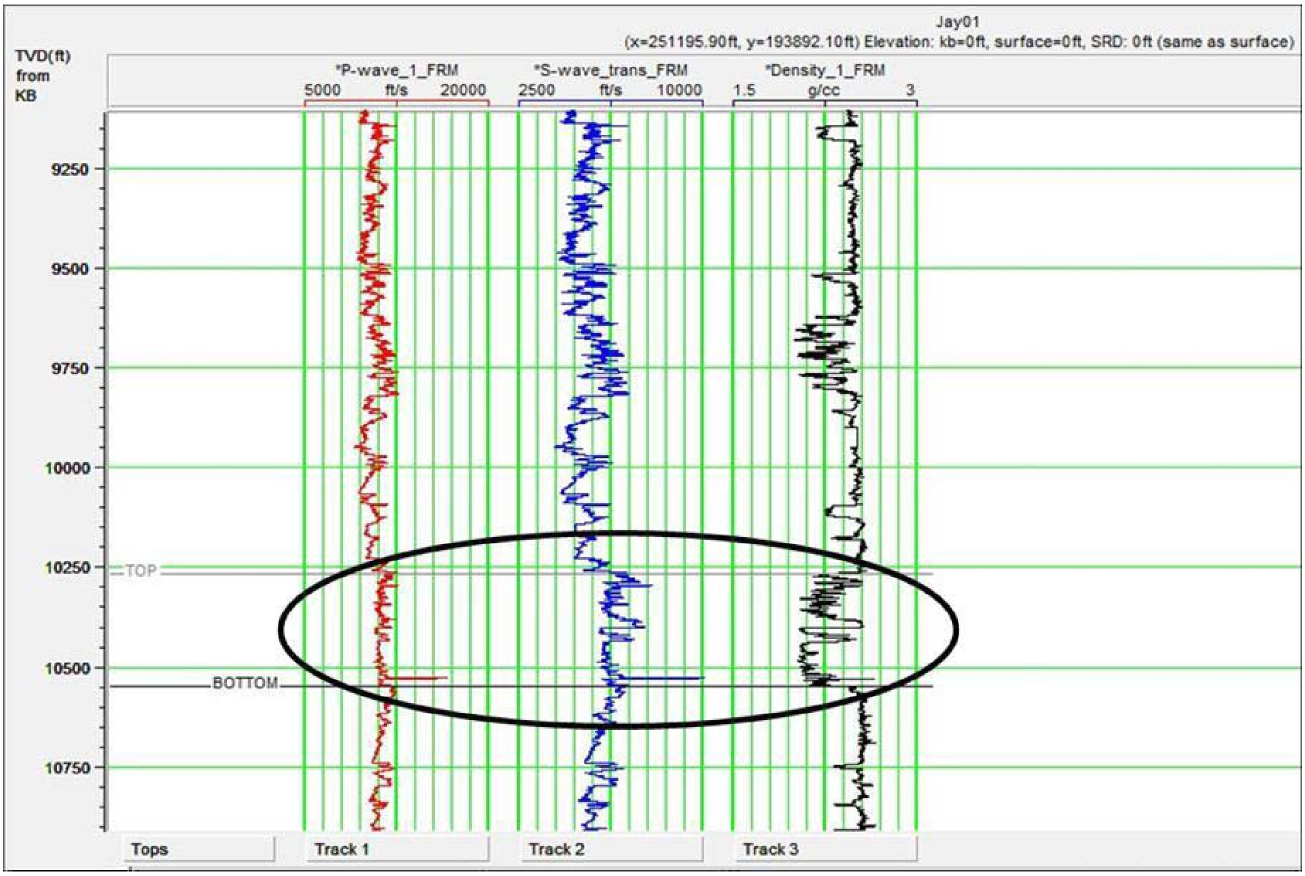

Figure 19. Shows interpreted behaviour of P wave, S wave and Density logs for the 2 phase fluid conditions in the reservoir

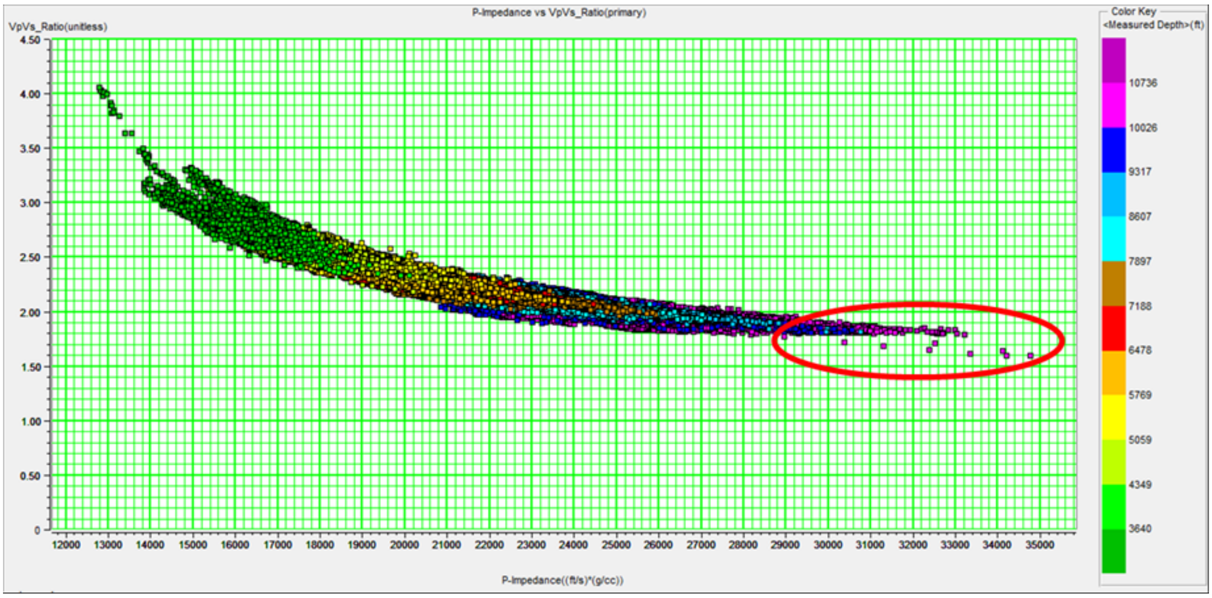

Figure 20. Interpreted crossplot of Vp-Vs Ratio against P-Impedance for the Insitu reservoir Fluid

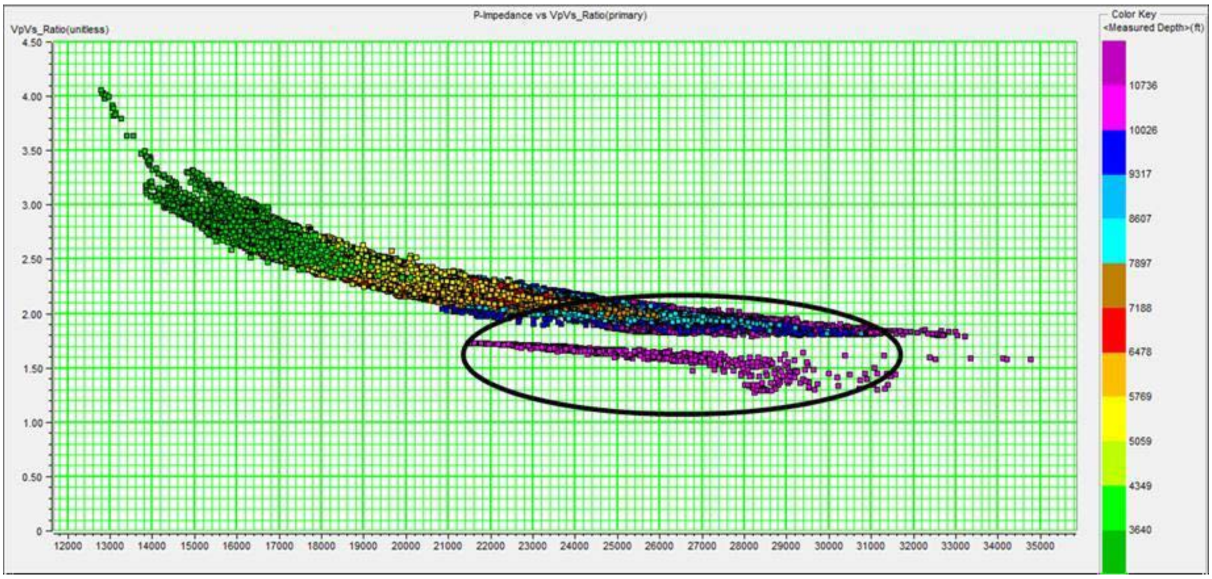

Figure 21. Interpreted crossplot of Vp-Vs Ratio against P-Impedance for the 3 phase reservoir Fluid

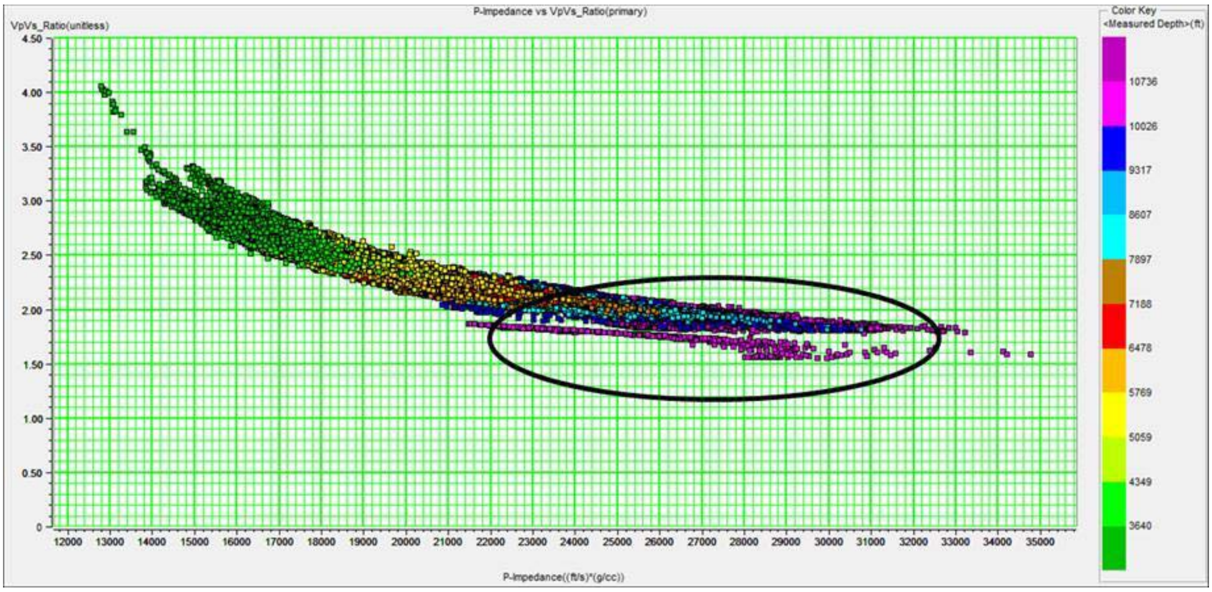

Figure 22. Interpreted crossplot of Vp-Vs Ratio against P-Impedance for the 2 phase reservoir Fluid

Further analysis was performed for three-phase and two-phase fluid conditions in the reservoir. Figure 18, Figure 19, and Figure 20 present the interpreted behavior of the P-wave, S-wave, and density logs for the three-phase and two-phase fluid conditions. These figures allow for a comprehensive assessment of the elastic properties of the reservoir rock and their variations under different fluid scenarios.

To better understand the fluid behavior within the reservoir, crossplots of Vp-Vs Ratio against P-Impedance were generated. Figure 21 and Figure 22 depict the interpreted crossplots for the three-phase and two-phase reservoir fluids. These crossplots provide valuable insights into the fluid type and saturation within the reservoir interval, aiding in reservoir characterization and fluid identification. The fluid replacement modelling results presented in this section enhances our understanding of the reservoir's fluid composition and behavior. By simulating the response of the well logs under different fluid scenarios, we can gain valuable insights into the reservoir's fluid dynamics and make informed decisions regarding reservoir management and production strategies.

3.3. Synthetic Seismogram and Well-to-Seismic Tie

A statistical wavelet (Figure 23) was generated using the near angle gather from the loaded seismic volume. This wavelet was then employed to generate a synthetic seismogram (Figure 24) based on the logs from the two-phase fluid replacement model. The synthetic seismogram was correlated with the well through squeezing and stretching adjustments until a correlation coefficient of 60.5% was achieved, establishing a well-to-seismic tie. To establish a correlation between the well logs and the seismic data, a synthetic seismogram was generated using a statistical wavelet derived from the near angle gather of the loaded seismic volume. The statistical wavelet, presented in Figure 23, provides a representation of the seismic wavelet characteristics that can be used to simulate seismic response.

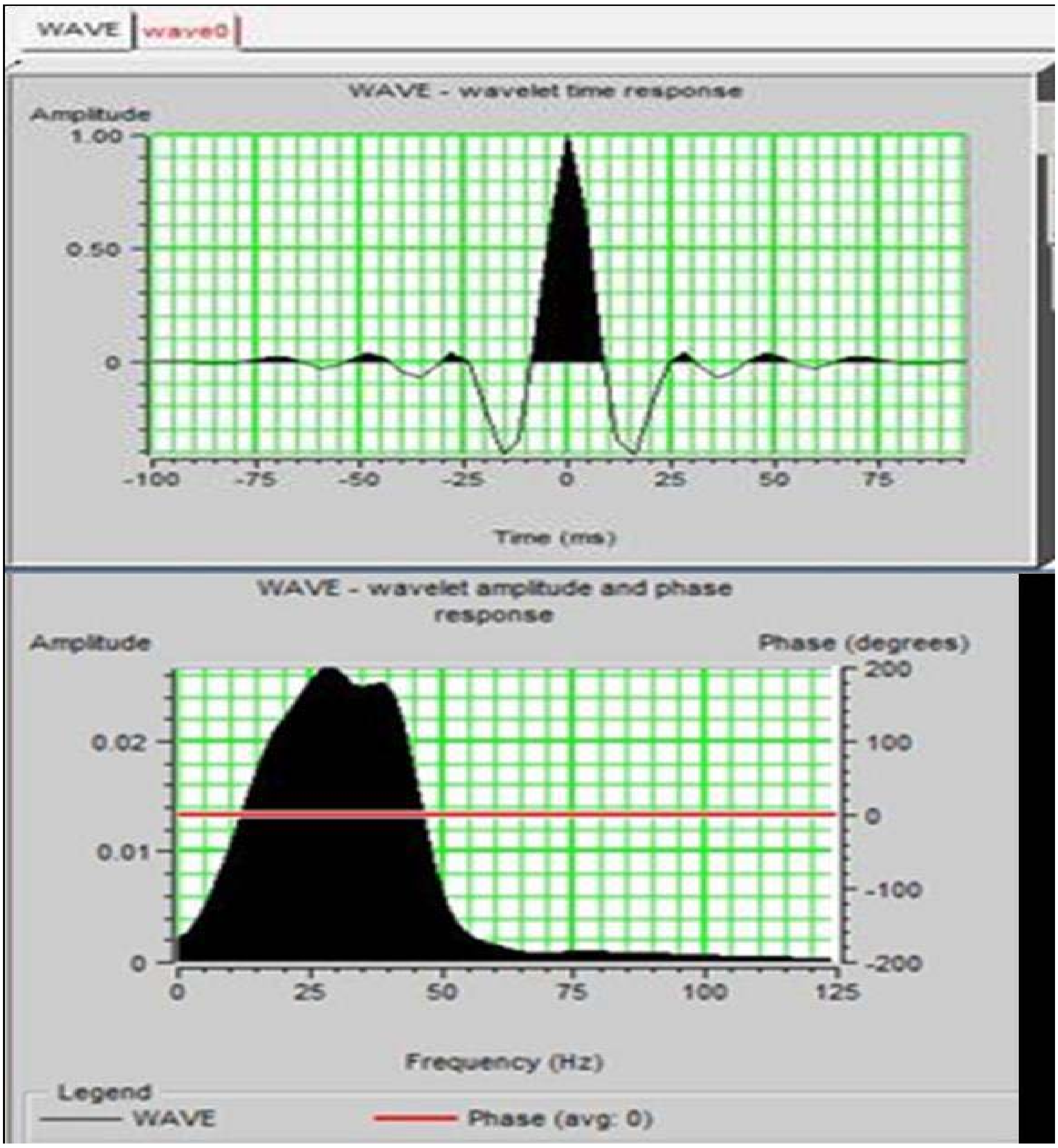

Figure 23. Statistical wavelet panel

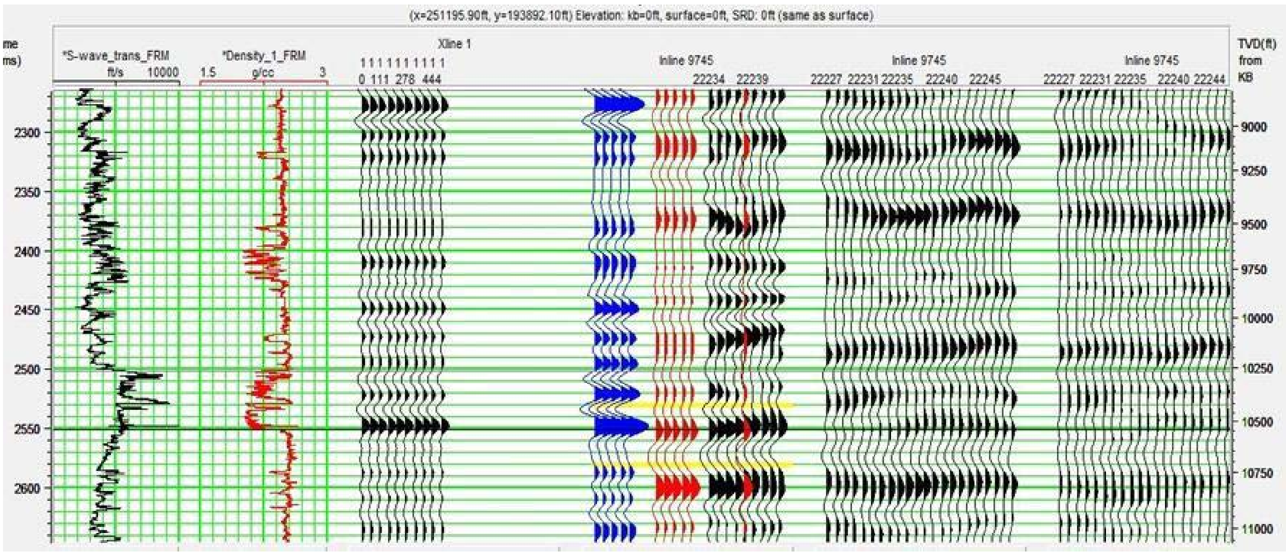

Figure 24. Synthetic wavelet generation and well to seismic match

Using the statistical wavelet, a synthetic seismogram was generated based on the logs obtained from the two-phase fluid replacement model. This synthetic seismogram, depicted in Figure 24, represents the expected seismic response given the subsurface properties and fluid composition determined from the well logs. The synthetic seismogram was then compared and correlated with the well data through squeezing and stretching adjustments. The goal of this process was to achieve a high correlation coefficient between the synthetic seismogram and the actual well data. After iterative adjustments, a correlation coefficient of 60.5% was achieved, indicating a reasonably good well-to-seismic tie. The establishment of a well-to-seismic tie is crucial for accurate subsurface interpretation and mapping. It allows for the integration of seismic data with well data, enabling a better understanding of the subsurface geology and the distribution of reservoir properties. The achieved correlation coefficient of 60.5% suggests a satisfactory alignment between the synthetic seismogram and the well data, providing confidence in the interpretation and mapping of seismic features within the study interval. The synthetic seismogram, generated using the statistical wavelet and calibrated with the well data, serves as a valuable tool for seismic interpretation and prospect evaluation. It helps in identifying seismic anomalies, mapping the extent of the reservoir, and making informed decisions regarding drilling targets and production strategies.

4. Conclusion

In conclusion, this research paper aimed to comprehensively characterize the reservoir and analyze the fluid behavior in the Majosa field located in the Niger Delta. The investigation involved the interpretation of well logs, fluid replacement modeling, and the generation of synthetic seismograms for well-to-seismic tie analysis. The findings of this study have significant implications for reservoir management, development planning, and hydrocarbon recovery optimization.

The interpretation of well logs provided valuable insights into the subsurface characteristics of the study interval. The gamma ray log successfully identified lithology, with leftward deflections indicating sand layers and rightward deflections indicating shales. The neutron-density overlay revealed a balloon structure in the reservoir, suggesting the presence of gas within the study interval. Shale intercalations were observed within the reservoir sand, confirming the study interval to be within the Agbada Formation. The porosity and water saturation values indicated the potential for hydrocarbon storage in the reservoir.

Fluid replacement modeling using Biot-Gassmann's equations and the FRM function provided a deeper understanding of the fluid behavior within the reservoir. The two-phase fluid model accurately captured the S-wave behavior associated with gas sand observed in the logs. The analysis of P-wave, S-wave, and density logs under different fluid scenarios revealed significant changes, providing insights into the fluid composition's impact on the elastic properties of the reservoir rock.

A synthetic seismogram was generated based on the two-phase fluid replacement model, and a well-to-seismic tie was established. The achieved correlation coefficient of 60.5% improved subsurface interpretations and enhanced the accuracy of seismic data calibration with well data.

The significance of this research lies in its contribution to reservoir characterization, exploration, and production activities. The identification of lithology, porosity, and the presence of gas helps in assessing hydrocarbon potential and designing effective production strategies. The comprehensive reservoir characterization and fluid analysis provide valuable information for reservoir management, development planning, and the optimization of hydrocarbon recovery.

Despite the significant contributions of this study, there are still gaps in knowledge that warrant further research. Future studies could focus on: Expanding the fluid replacement modeling to include additional fluid scenarios and variations, Incorporating additional well data and seismic data from neighboring fields to enhance the accuracy and reliability of the results., Investigating the potential for enhanced hydrocarbon recovery and optimizing gas monetization strategies in the field. By addressing these research gaps, future studies can continue to advance our understanding of the reservoir and contribute to the development of effective exploration and production strategies in the Niger Delta.

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