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Seismic data analysis and Petrophysical Studies for Hydrocarbon Evaluation of "FEM" Field, Niger Delta, Nigeria

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Abstract

A comprehensive 3D seismic interpretation and petrophysical analysis was performed on the 'FEM' Field in the Niger Delta. The objective was to integrate petrophysics and seismic data analysis for the assessment of the hydrocarbon potential of the field. Gamma-ray logs were used to delineate seven reservoirs, which were then correlated throughout the field to confirm the lateral continuity of these reservoirs. An in-depth petrophysical analysis of the 'FEM' well indicated that all the reservoirs contain oil and are all oil-down-to. The average petrophysical parameters of the reservoirs were estimated, revealing a porosity of 29%, water saturation of 27%, shale volume of 0.1, and a net-to-gross ratio of 0.034. The reservoirs delineated on the logs were transferred to the seismic record using the checkshot data from FEM- 3&4 wells and the synthetic seismograms. Six horizons were mapped across the entire study area, and time and depth maps were created to determine the structural architecture and the geometry of the reservoirs in the 'FEM' field. Two major faults were identified, trending in the NW-SE direction, with the structural traps located in the southeastern part forming a fault-assisted closure. All the wells were drilled targeting the crest of this closure. The Root Mean Square amplitudes generated for all the levels indicated the lateral extent of the reservoirs, but they did not conform to the structure and thus, are not direct indicators of hydrocarbons. The original oil in place in the 'FEM' field is estimated to be 2.35 billion barrels.
Keywords: Seismic data analysis, Shale volume, Niger Delta Basin, Petrophysics, Velocity model.

1. Introduction

The Niger Delta region, known for its mangrove forests and as a major source of Nigeria's oil wealth, is one of Africa’s leading oil provinces with extensive seismic data coverage and over 5,000 wells drilled (Owolabi *et al*., 2019). With growing hydrocarbon demand and maturing fields, reservoir characterization has become crucial, requiring precise seismic interpretation and petrophysical analysis to understand geological structures and lithology (Owolabi *et al*., 2019). This combined approach, including well log analysis, is essential for estimating hydrocarbon reserves and ensuring effective and profitable oil and gas production (Owolabi *et al*., 2019). Advances in exploration techniques have boosted the success rate from around 11% to over 60%, making it one of the highest globally, with 5,284 wells drilled within the basin, including 603 discovery wells. Currently, hydrocarbon extraction occurs from 323 developed fields in both onshore and offshore areas (Nigeria Upstream Petroleum Regulatory Commission, 2023).
To understand the petroleum systems in the Niger Delta and related basins, previous studies provide

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valuable insights. Tuttle *et al*. (1999) identified the Tertiary Niger Delta (Akata-Agbada) petroleum system, noting its origin from a rift triple junction and sediment accumulation over 10 km thick. Ugwu *et al*. (2020) used 3D seismic data to delineate subsurface structures in Ugwu-Field, while Paul *et al*. (2018) estimated hydrocarbon reserves in the Ovade area, revealing significant potential. Adewumi *et al*. (2016) mapped subsurface structures in the Tadelu field, identifying major faults and estimating substantial recoverable reserves. Benson (2018) highlighted the Akata Formation's superior hydrocarbon potential in Pologbene-1. Theophilus *et al*. (2022) characterized reservoirs in the J-P Field, demonstrating high hydrocarbon saturation. Diab *et al*. (2022) evaluated the Otumara field's source rock potential, and Alao *et al*. (2013) mapped hydrocarbon-bearing zones in the ALA field, identifying fault-assisted traps. Finally, Avbovbo (1978) detailed the lithostratigraphy of the Niger Delta, describing the Akata, Agbada, and Benin Formations.

This study aims to integrate 3D seismic records with well-log data to evaluate reservoir geometry, petrophysical parameters, and hydrocarbon volume in the 'FEM' field of the Niger Delta. The objectives include identifying hydrocarbon-bearing sands, evaluating petrophysical parameters, determining reservoir thickness and variation, producing subsurface maps, assessing hydrocarbon potential, and identifying leads within the study area.

2.0 Geology of the Study area, Materials and Methodology

2.1 Geology of the Study area

2.1.1 Geologic Settings of Niger Delta

The Niger Delta Basin is a highly complex and economically valuable extensional rift basin located on the passive continental margin of the Gulf of Guinea, near Nigeria's western coast, and extending to Cameroon, Equatorial Guinea, and São Tomé and Príncipe. It is one of Africa's largest subaerial basins, covering a subaerial area of 75,000 km² with a total area of 300,000 km² and a sediment fill of 500,000 km³ (Tuttle *et al*., 1999). The basin's sediment fill reaches depths of 9–12 km (Fatoke, 2010). The Tertiary section includes the Akata, Agbada, and Benin Formations, representing prograding depositional environments (Weber and Daukoru, 1975) (Figure 1).

2.1.2 Tectonic Settings of Niger Delta

The tectonic framework of the continental margin along the West Coast of equatorial Africa is influenced by Cretaceous fracture zones that form trenches and ridges in the Atlantic (Tuttle *et al*., 1999). These fracture zones segment the West African Shield into individual basins and create boundary faults in Nigeria, leading to the Cretaceous Benue Abakaliki Trough, a failed rift associated with the South Atlantic opening. Rifting began in the Late Jurassic and continued into the Middle Cretaceous (Lehner and De Ruiter, 1977). Gravity tectonism, driven by shale mobility, led to complex structures like shale diapirs, roll-over anticlines, and growth faults, which dominate the subsurface of the Niger Delta (Evamy *et al*., 1978; Doust and Omatsola, 1989).

2.1.3 Stratigraphy of Niger Delta

The Niger Delta basin contains Cretaceous to Holocene marine clastic strata overlying oceanic and continental crust fragments. While the Cretaceous section remains unpenetrated in the Niger Delta, similar lithologies from the nearby Anambra basin suggest Albian–Maastrichtian shallow-marine clastics (Nwachukwu, 1972; Reijers *et al*., 1997). From the Campanian to the Paleocene, deltaic sediments were deposited, shifting to wave-dominated sedimentation in the Eocene. The Tertiary section features the Akata, Agbada, and Benin Formations, representing prograding depositional environments (Short and Stäublee, 1967; Avbovbo, 1978; Evamy *et al*., 1978; Doust and Omatsola, 1990; Kulke, 1995) (Figure 2).

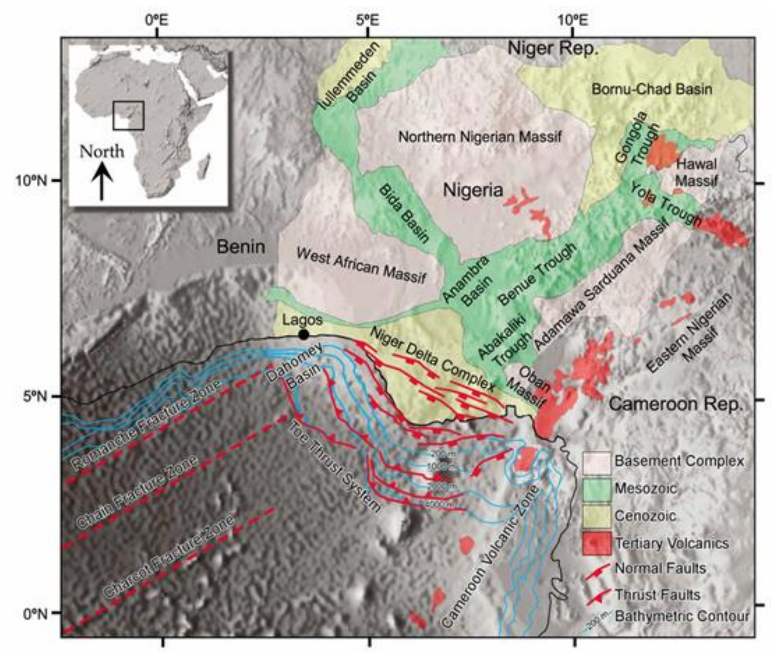


Figure 1: The location map of the Niger Delta region shows the main sedimentary basins and tectonic features (Corredor *et al*., 2005)

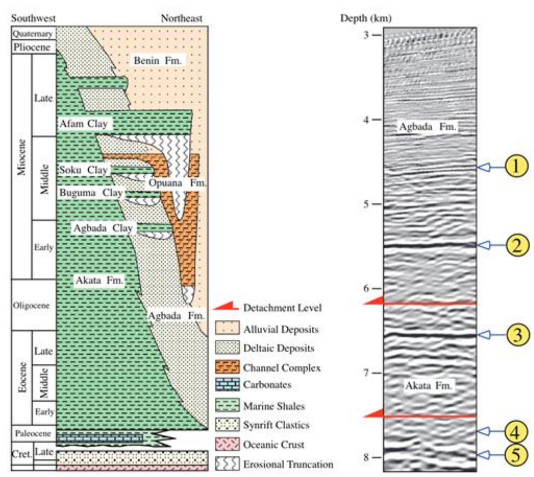


Figure 2: Schematic diagram of the regional stratigraphy of the Niger Delta and variable density seismic display of the main stratigraphic units in the outer fold and thrust belt and main reflectors, including. (1) Top of the Agbada Formation, (2) Top of the Akata Formation, (3) Mid-Akata reflection, (4) Speculated top of the syn-rift clastic deposits, and (5) Top of the oceanic crust. Main detachment levels are highlighted with red arrows (Corredor *et al*., 2005)

2.2 Materials and Methodology

2.2.1 Materials and Loading Platform

Geophysical and geological data, including 3D seismic data covering the entire field and nine well logs, were utilized for this analysis. Additional data used includes wellhead, deviation surveys, and checkshot data. The data quality was deemed satisfactory, with wells distributed across the study area. A Dell Precision workstation equipped with Petrel and Aspen Geolog software was used for the analysis, while Microsoft Office was utilized for computations and documentation. The workflow involved petrophysical evaluation on the Aspen Geolog platform while Petrel was used for the seismic interpretation. Figure 3 is the base map of the study area.

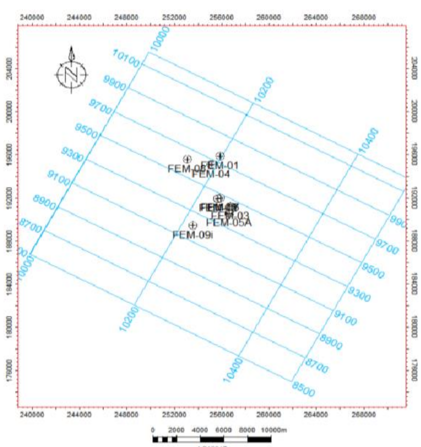


Figure 4: Basemap of study area showing the well location

2.2.2 Petrophysics

The qualitative analysis of well data involved visual observations of lithology, hydrocarbon-bearing zones, and fluid contacts while the quantitative analysis employed mathematical models to determine shale volume, porosity, water and hydrocarbon saturation, net pay, and original oil in place. The detailed analysis utilized key log curves including resistivity, bulk density, gamma ray, neutron porosity, and sonic. The theoretical basis of petrophysical analysis involves three key properties: porosity, volume of shale (Vsh), and water saturation. The gamma ray log was utilized to determine Vsh, employing the Larinov method based on its accuracy in Tertiary Niger Delta rocks. Porosity (∅) was estimated by the density-derived porosity equation, considering matrix density, formation bulk density, and fluid density. The Simandoux equation was adopted in the estimation of water saturation, though Archie expression is widely used but Simandoux equation offers advantages in the project area. These calculations aid in accurately assessing hydrocarbon reserves and optimizing reservoir development strategies in the FEM field.

2.2.3 Seismic Data Analysis

This involves several technical steps: data loading and quality control, well correlation, horizon mapping, fault pattern definition, time-depth conversion, and volumetric estimation of potential hydrocarbons. Time-domain seismic interpretation was utilized, but later converted to depth, this provides more accurate structural interpretations. 2nd Order Polynomial Time-Depth Analytical Function was employed in the depth conversion. It is worth noting that a robust velocity model aids in delineating concealed structures, reducing ambiguity in interpretation, and validating structural features.

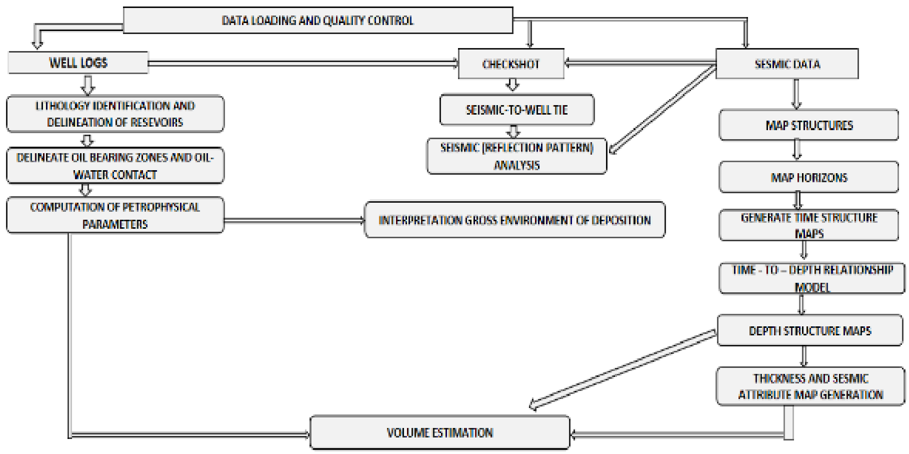


Figure 3: The workflow adopted for the study

3. Results and Discussion

3.1 Well Data Analysis and Interpretation

3.1.1 Well and Formation Correlation

Seven sand units were identified, and two sand sequences (A & A1) were correlated across all the wells while the other two sand bodies were correlated across three wells. Sands D, E, and F were identified in FEM 02. Correlation results from the study area revealed a variation in the reservoir thickness within the study area. Both stratigraphic and lithostratigraphic correlations were performed using the suite of wireline log signatures which provides general knowledge and a better understanding of the subsurface stratigraphic sequences in the field. The correlated top and base of the sandstone units for reservoirs A and A1 show the lateral continuity of the stratigraphic sequences in time and space. It establishes the stratigraphic principle of lateral continuity of strata and Walther's law of facies succession. Reservoir A shows a slightly uniform thickness across the whole field.

3.2 Petrophysical Analysis

Precise evaluation of petrophysical parameters from log data enhances reservoir understanding and lithology classification. Sand A is one of the reservoir units that contain hydrocarbon in the FEM field (Figure 5a), it is characterized by low gamma-ray and high resistivity readings. Key reservoir properties (volume of shale, porosity, and water saturation) were computed using the Larionov equation for shale volume, a Neutron Density cross plot for porosity (Bateman-Konen method), and the Pickett plot approach for formation-water resistivity (Simandoux method) (Figure 5b-d). The interpreted reservoir (RES_A) lies between 3502.5 to 3620.333 m with a thickness of over 117 ft. The average total porosity is 21.6%, shale volume is 1%, and water saturation is 27.5%, resulting in a hydrocarbon saturation of 72.5%. Petrophysical parameters for the hydrocarbon-bearing zone and net pay in FEM 01 are detailed in Table 1 and Figure 5.

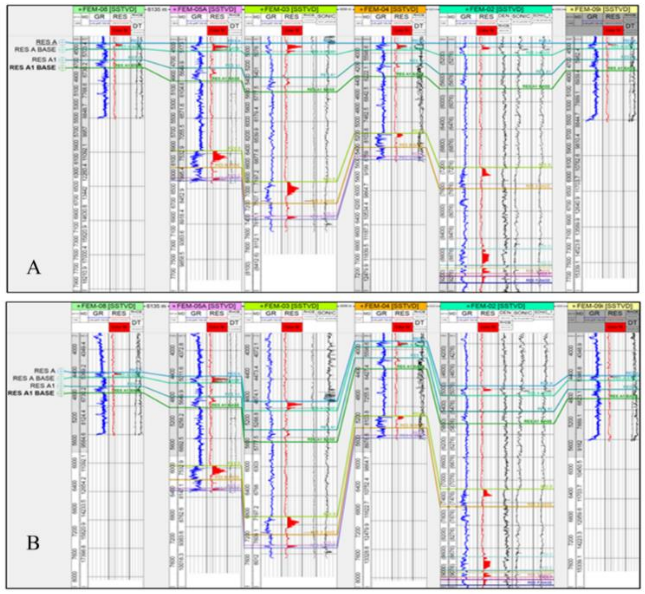
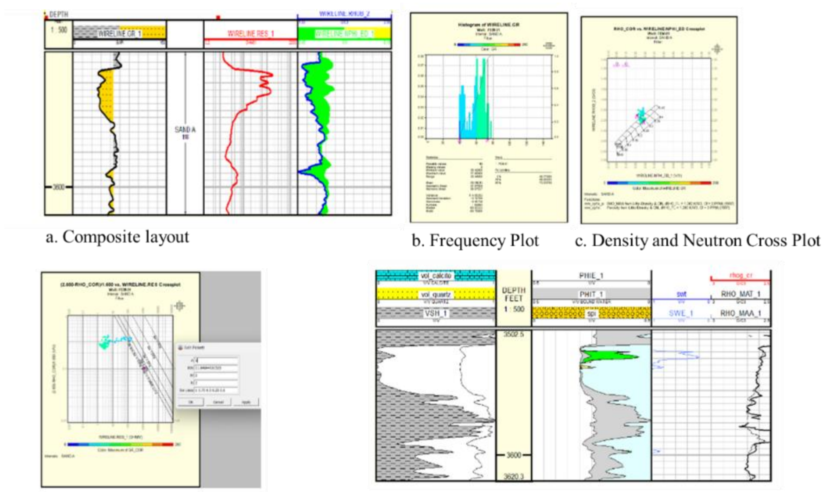


Figure 4: A. Structural well correlation flattens on reservoir 3500ftss, B. Stratigraphic well correlation flattens on reservoir "A" top



a. Composite layout

b. Frequency Plot

c. Density and Neutron Cross Plot

d. Picket Plot, Rw = 11.84644Ωm

e. Calculated petrophysical parameters

Figure 5: Reservoir A in FEM Field

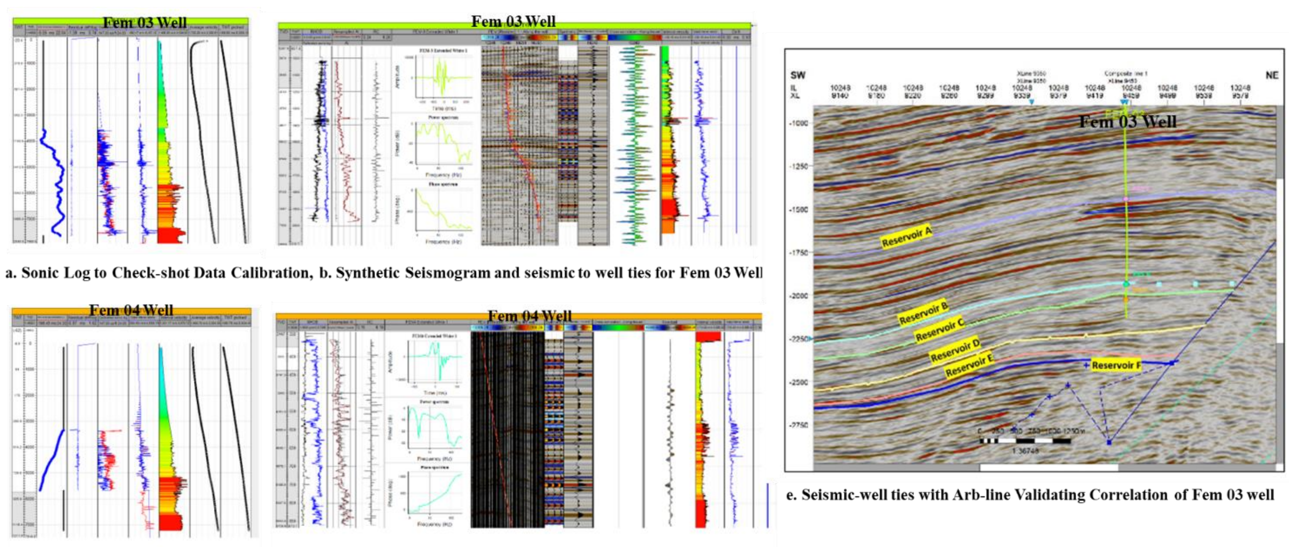
Table 1: Average Summary Results of Petrophysical Parameters of the FEM 1 well

Reservoir	Top(ft)	Base(ft)	Gross(ft)	Net(ft)	NTG(f/f)	ϕe(v/v)	Sw(v/v)	Vsh(v/v)
RES A	3502.5	3620.333	117.833	4	0.034	0.293	0.275	0.01

3.3 Seismic Data Analysis and Interpretation

3.3.1 Seismic to Well Tie

Check-shot data for FEM 03 & 04 wells were used to generate synthetic seismograms for seismic to well tie. Sonic data calibration was performed for quality control, ensuring velocity information was consistent. Reflectivity coefficient logs were generated and convolved with a synthetic wavelet to produce synthetic seismograms, which were then compared with traces around the wellbore to examine correlation (Figures 6a-d). No bulk time shift was applied to avoid distorting velocity data. For wells without check-shot data, information from nearby wells was used for time domain placement only. Consistency of well correlation and seismic-well tie processes was validated through arbitrary seismic-well tie lines in different directions (Figure 6).



a. Sonic Log to Check-shot Data Calibration, b. Synthetic Seismogram and seismic to well ties for Fem 03 Well

e. Seismic-well ties with Arb-line Validating Correlation of Fem 03 well

c. Sonic Log to Check-shot Data Calibration, d. Synthetic Seismogram and seismic to well ties for Fem 04 Well

Figure 6: FEM 03 and 04 Wells

3.3.2 Fault and Horizon Interpretation

For easy delineation of structural style and faults within the study area, a variance edge seismic cube was generated, capturing their distribution and orientation. The variance attribute algorithm enhances edge detection by emphasizing larger features (Figure 7a). Four major faults, trending NW-SE with structural traps in the southeast, were interpreted on every 5-line interval. Well information was extrapolated to seismic data using cross-sections from the seismic to well tie process. Six horizons (Reservoirs A-F) were consistently mapped and interpreted based on well-tie analysis, focusing on in-line and cross-line interpretations. Uncertain areas were excluded from the detailed interpretation and separated using distinct seismic grids. Manual fault picking and horizon mapping were performed using Petrel software, interpreting horizons on peak and tracking them throughout the seismic volume at 5 inline and crossline intervals to create a seismic seed grid (Figure 7b). Time structure maps for these interpreted levels were then generated (Figure 7c).

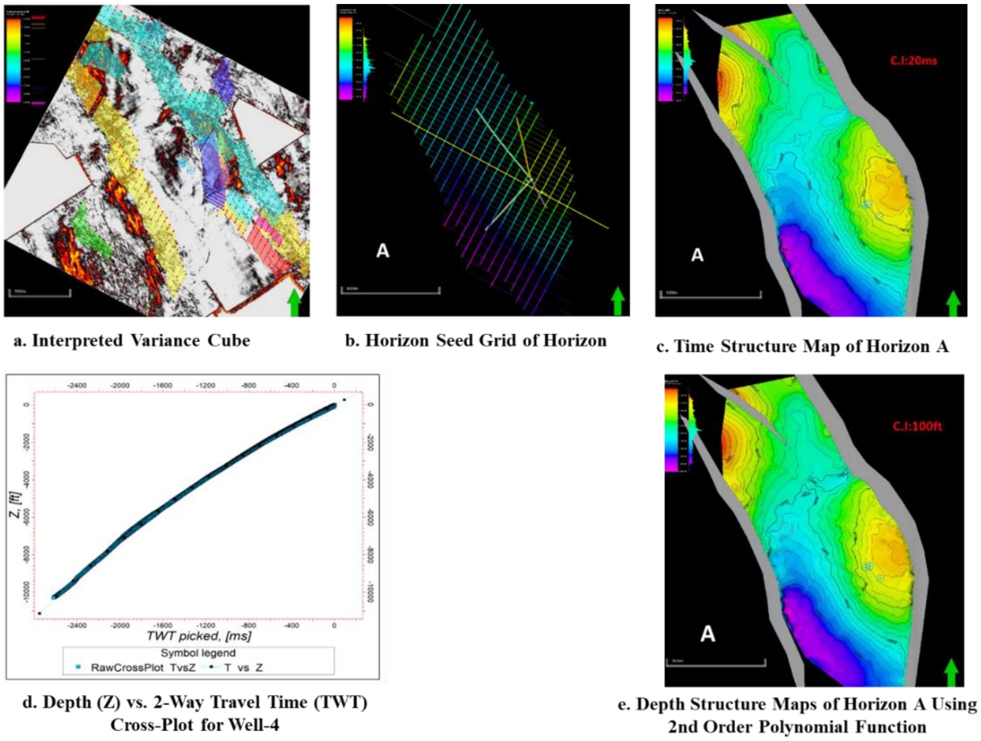


Figure 7: Subsurface maps and velocity model of FEM field

3.4 Discussion

3.4.1 Depth Conversion

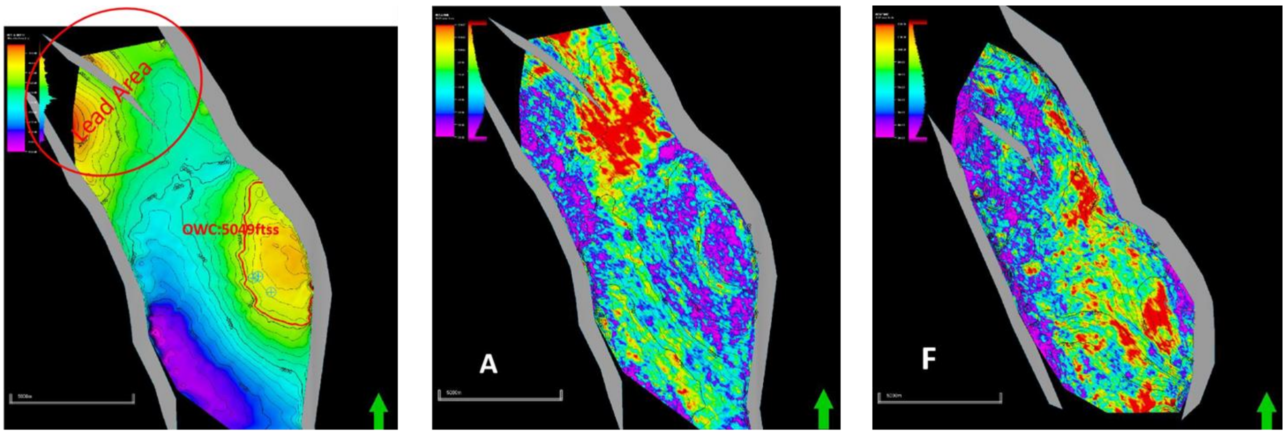
The velocity model adopted was the 2nd Order Polynomial Time-Depth Analytical Function from FEM 04 checkshot data. These points were considered subsets of the regional velocity distribution, grouped, and a polynomial line of best fit was generated (Figure 7d). This best-fit equation was used to convert time maps into depth maps (Figure 7e). The initial depth map was adjusted to well depths, and residual values at each well were recorded. The derived polynomial function for depth conversion had a covariance value of 1.8793E+6. Depth structure maps were produced using this model, shown in Figure 7e.

3.4.2 Delineation of Fluid Contacts

Fluid contacts were identified in the well sections. The oil-water contact (OWC) for Reservoir A was picked at approximately 5049 ft, and Reservoir B at about 7359 ft. Reservoirs C to F showed oil on rock (ODT) at various depths Table 2. The study also identified an additional lead in the northwestern part of the seismic data (Figure 8).

Table 2: Showing the contacts in feet and the wells

RES	Content Value	Contact	Picked from Well
A	5049	OWC	FEM 2
B	7359	OWC	FEM 2
C	7393	OWC	FEM 2
D	8992	OWC	FEM 2
E	9145	OWC	FEM 2
F	9313	OWC	FEM 2



a. Depth Map of Horizon A showing the fluid contact and the identified lead area **b. RMS Map of Horizon A** **c. RMS Map of Horizon F**

Figure 8: Delineation of Fluid Contact

3.4.3 Amplitude Extraction Maps

Seismic amplitude, a measure of reflection strength, is influenced by changes in lithology, porosity, gas, and oil fluids. Amplitude maps are commonly used to compare with structural features, where conformance might indicate hydrocarbons. This is crucial for reservoir characterization. Root mean square amplitude maps for six interpreted horizons showed no structural conformance, indicating reservoir presence. Figures 8b and 8c display the amplitude maps for reservoirs A and F.

3.4.4 Volume Estimation

Hydrocarbon volumes for six horizons were estimated using volumetric methods, focusing on stock tank oil initially-in-place (STOIIP) and hydrocarbon pore volume (HCPV). The calculations incorporated petrophysical parameters like porosity, water saturation, net-to-gross ratio, and reservoir thickness.

$$STOIIP = \frac{7758\ Ah\ \emptyset\ (1 - S_{wc})}{B_{Oi}}$$

Where: A= area, acre, h = reservoir thickness, ft, ϕ = rock porosity, %, Swc = connate water saturation, %, Boi = oil formation volume factor, rb/stb

The results are detailed in Table 3.

Table 3: Volumetric estimation results of FEM Field

Zones	GRV (*10^3 acre.ft)	NRV (*10^3 acre.ft)	STOIIP (MMSTB)	GIIP (TSCF)	Bo	Fluid
RA	491	125	402.08	0	1.74	OIL
RB	541	138	442.79	0	1.74	OIL
RC	125	320	102.78	0	1.74	OIL
RD	117	299	960.66	0	1.74	OIL
RE	283	721	231.56	0	1.74	OIL
RF	258	660	211.76	0	1.74	OIL
Total	**-**	**-**	**2351.63**	**0**	**-**	**-**

4. Conclusion

The hydrocarbon potential of FEM Field in the Niger Delta was assessed using 3D seismic and well-log data. This analysis provided a detailed structural framework and reservoir delineation, identifying fault-assisted and rollover anticline traps. The lithology correlation of six wells revealed sand-shale intercalation, with two sand reservoirs correlated across the field. Gamma and resistivity logs helped delineate these reservoirs, and synthetic seismograms tied their tops to seismic data. Structural interpretation showed two major listric faults trending NW-SE. the hydrocarbon-bearing sands were confirmed with an average porosity of 29% and water saturation of 27%. Six oil-bearing horizons were mapped, and time-depth conversion was achieved using a second-order polynomial function. Root Mean Square attribute extractions were utilized to identify potential reservoir facies and sediment flow direction, although amplitudes did not align with structures. We also estimated reserves for the hydrocarbon-bearing sands and a total proven recoverable oil estimate put at 2,351 MMbbl. Additionally, a lead was identified in the North-West, requiring further data for detailed evaluation. Integration of well log and seismic data is crucial for hydrocarbon evaluation and prospectivity analysis in both the study area and other geologically related basins.

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