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EVALUATION OF 3D SEISMIC DATA AND INTERPRETATION OF MARS FIELD OFFSHORE DAHOMEY BASIN NIGERIA

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Abstract: 3D seismic interpretation of the Mars Field in the Dahomey Basin, Nigeria was done to delineate the lithostratigraphy, structures, seismic stratigraphy and mapping of potential reservoirs within the basin. This was achieved by the use of 4 wells and 3D seismic data. This study determines the structural style, stratigraphic units, unconformities, channels, clinoform, structural framework, time, and depth maps of the potential reservoirs. The fault within the field is normal fault, and the hydrocarbon trapping styles are four-way closures and fault assisted closures. The local stratigraphy reveals that presences of the basement, erosional surfaces, topset and bottom set of the prograding clinoform. The faulting within the basin affected mainly the pre-rift sediments which are the Albian Carbonates, while the Cretaceous sediments are syn-rift sediments. The hydrocarbon bearing reservoir units are the Turonian reservoirs, which were correlated and mapped across the 3D seismic section. The hydrocarbon contact was used on the depth map to delineate the fluid contact on the map. The seismic interpretation was carried out to delineate the structural style of the basin. The fault was mapped as normal fault using inline and variance time slice. The structural framework was generated to understand the geomorphology of the Late Cretaceous sediments which reveals the degree and the effect of the unconformity on these sediments showing that some part has been completely eroded. The trapping style in the field is faulted anticlinal closure. The fault has therefore offset the continuity of the reservoirs thereby juxtaposing the reservoir beds (sands) with non-reservoir beds (shales) essentially trapping hydrocarbons. The Cretaceous sediments are the major hydrocarbon reservoir within the basin and four hydrocarbon bearing reservoir maps were generated to show the hydrocarbon distribution within the basin.

Keywords: Dahomey/Benin basin, depth map, time map, local stratigraphy, fluid distribution map, clinoform, Turonian.

Introduction

The Mars Field, located approximately 24 kilometers offshore western Nigeria along the West African Transform Margin, provides a critical window into the geological history of the Dahomey Basin (Billman, 1992) (Fig. 1). This study reviews the biostratigraphy of the Mars Field using data from three wells Mars-01, Mars-03, and Mars-05, drilled in this offshore region. Biostratigraphy, a fundamental tool in subsurface analysis, leverages the distribution of fossil assemblages to establish the relative ages of sedimentary strata and correlate them across regions (Berggren et al., 1995). In this investigation, selected samples from the tops of the wells to various depths were examined to reconstruct the temporal and environmental evolution of the basin. The analysis integrates lithostratigraphy, micropaleontology, and palynology to provide a comprehensive stratigraphic framework.

The Dahomey Basin, also referred to as the Benin Basin, is a significant sedimentary depocenter along the West African margin, characterized by a complex tectonic history influenced by the opening of the Atlantic Ocean (Omatsola & Adegoke, 1981). The basin's sedimentary fill spans the Cretaceous to the Paleogene, recording a range of depositional environments from fluvial to marine settings (Kaki *et al*., 2012). Understanding its biostratigraphy is essential not only for academic purpose, but also for hydrocarbon exploration, as fossil markers help delineate reservoir-bearing formations and unconformities (Asquith & Krygowski, 2004). In this study, ditch cutting samples were analyzed to describe the lithostratigraphy, offering insights into rock types and depositional conditions. Micropaleontology, focusing on foraminifera, was employed to identify key biozones, while palynology—examining pollen, spores, and dinoflagellate cysts—provided additional age constraints and paleoenvironmental clues.

The Mars Field wells penetrate a succession of strata that reveal a rich microfossil record, with varying abundance and diversity at different depths. Foraminifera, such as Globotruncana and Morozovella species, serve as reliable indicators of Cretaceous and Paleocene ages, respectively (Bralower *et al*., 1995). Palynomorphs, including dinoflagellates and pollen, further refine the zonation, particularly in the deeper Cretaceous intervals where microfossils may be sparse or absent (Adeigbe *et al*., 2013). This multi-proxy approach enhances the resolution of the stratigraphic column, allowing for a detailed correlation with regional geological frameworks. The study area's proximity to the Okitipupa Ridge, a faulted basement high separating the Benin Basin from the Niger Delta Basin, adds structural complexity that influences fossil preservation and

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distribution (Coker & Ejedawe, 1987). By synthesizing these datasets, this paper aims to elucidate the biostratigraphic succession of the Mars Field, contributing to a broader understanding of the Dahomey Basin's geological evolution.

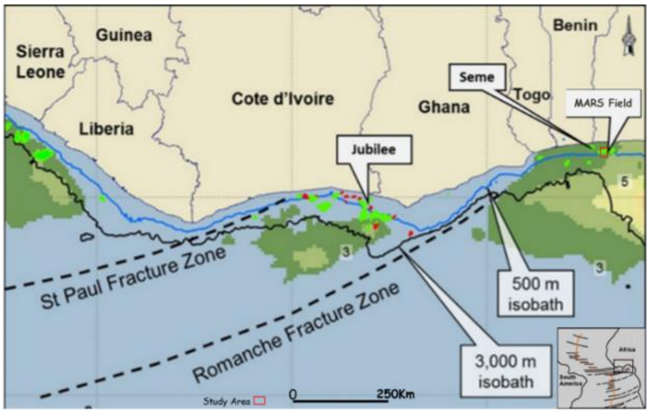

Fig. 1 Map showing location of Mars Field.

This characterizes the potential reservoir of the offshore Dahomey basin using 3D seismic and well logs. This study involves integration of wells and 3D seismic data to delineate and map the potential reservoir of the Mars Field Dahomey Basin, Nigeria. The mapped reservoirs intervals comprises the Turonian reservoirs which predominately consist of oil, gas and condensate. The seismic interpretation shows that the structural style within the field are normal fault and fault assisted closures. The time and depth maps were generated for all the identified Turonian reservoirs. The Mars Field is a shallow offshore block with water depth ranging from 0.1km to 1km, and it covers an area of about 70km^2.

Geological Setting

The Dahomey Basin, also known regionally as the Benin Embayment, is a marginal sedimentary basin located along the Gulf of Guinea, stretching from southeastern Ghana through Togo and Benin into southwestern Nigeria. As part of the West African passive continental margin, the Dahomey Basin developed during the Early Cretaceous as a result of the rifting and subsequent drift that accompanied the opening of the South Atlantic Ocean. This rift–drift transition gave rise to a complex geological framework, influenced by both tectonic and eustatic processes, and characterized by a diverse stratigraphic succession and promising, though underexplored, hydrocarbon potential.

The stratigraphy of the Dahomey Basin records a full sedimentary history from rift initiation through post-rift marine transgression to modern deltaic sedimentation. The Abeokuta Group (Albian–Cenomanian) forms the basal unit and represents the syn-rift deposits. It comprises the Ijebu Formation (continental clastics, including conglomerates and sandstones), the Afowo Formation (transitional to marginal marine sandstones and shales), and the Araromi Formation**,** which includes thick marine shales and siltstones with occasional limestone intercalations (Omoboriowo *et al*., 2019; Adepoju *et al*., 2021).

Overlying the Abeokuta Group is the Ewekoro Formation (Paleocene), a highly fossiliferous limestone deposited during a regional marine transgression. This unit is widely exposed in southwestern Nigeria and is considered a key marker horizon across the basin. It is succeeded by the Akinbo Formation (Paleocene–Eocene), composed mainly of dark grey to black shales, phosphatic beds, and glauconitic sandstones, deposited under deeper marine, low-oxygen conditions (Oyedele & Akande, 2020).

The Oshosun Formation (Eocene) follows, with sandy clays, siltstones, and glauconitic sandstones indicating a regression to shallower marine environments. The Ilaro Formation, deposited during the Late Eocene, consists of thick cross-bedded continental sandstones, interpreted as fluviodeltaic channel and point-bar deposits. The youngest unit is the Benin Formation (Miocene–Recent), which consists of unconsolidated sands and gravels, laid down in a fluvial to coastal plain setting and forms the uppermost sequence of the Niger Delta in the Dahomey area (Adebayo *et al*., 2020; Ojo *et al*., 2022).

The tectonic evolution of the basin is closely linked to the opening of the South Atlantic. Initial extensional tectonics in the Early Cretaceous produced a network of normal faults, half-grabens, and tilted fault blocks, which controlled the distribution of early sediments. Subsequent thermal subsidence in the post-rift stage led to widespread marine transgression and sediment accumulation (Ogunbanjo *et al*., 2022). Structural interpretation of seismic data reveals rollover anticlines, listric faults, and subtle compressional features, particularly in the offshore segment of the basin (Ekwueme *et al*., 2023). Evidence of salt tectonics is absent in this basin, unlike the Niger Delta, though differential compaction and growth faulting remain important structural controls.

In terms of petroleum geology, the Dahomey Basin remains underexplored compared to neighboring basins, but several studies have confirmed the presence of a working petroleum system. The Afowo and Araromi formations contain organic-rich shales that serve as potential source rocks, with Total Organic Carbon (TOC) values ranging from 1.2% to 4.5% and kerogen types II and III (Adepoju *et al*., 2021; Olabode & Obaje, 2020). Vitrinite reflectance data suggest that maturity increases offshore, where some parts of the basin reach the oil window (Olatinsu *et al*., 2021).

The reservoir rocks are primarily found within the sandstones of the Afowo and Ilaro formations. These units exhibit moderate to good porosity (15–25%) and permeability, especially where they are clean and well sorted. Petrographic analysis by Adebayo *et al*. (2020) indicates that the Ilaro Formation sandstones are compositionally mature and texturally submature, with quartz content exceeding 90%. These characteristics make them suitable reservoir targets, particularly in the offshore and deeper subsurface, where they are less cemented.

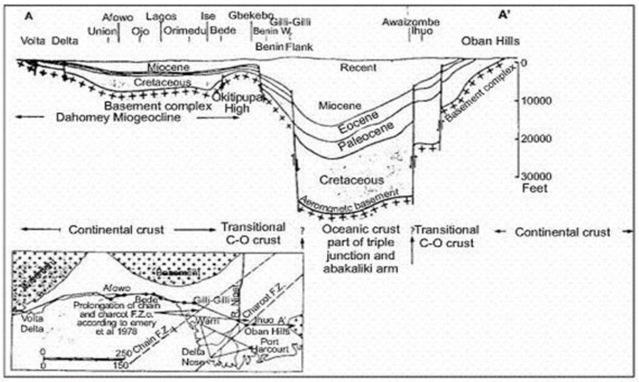

Fig. 2 East-West section showing the Tectono-stratigraphic frame work of the Benin Basin and upper part of Niger-Delta Basin (Whiteman, 1982).

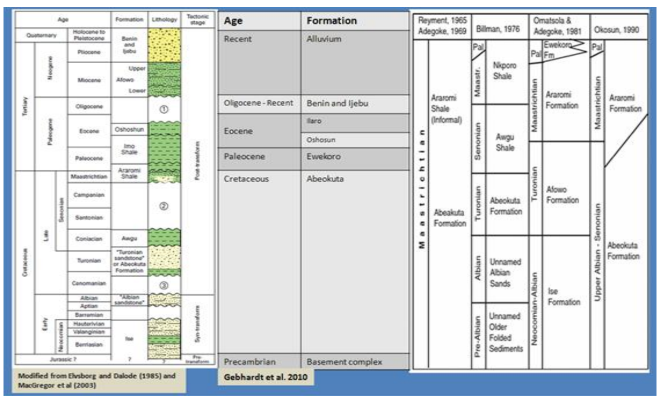

Fig. 3 Stratigraphic column of the Benin Basin (Omatsola & Adegoke, 1981).

Seals in the basin are provided by the marine shales of the Araromi and Akinbo formations, which are laterally continuous and low in permeability. The combination of interbedded sand-shale sequences allows for effective trap formation. Trapping mechanisms include fault-bounded closures, rollover anticlines, and stratigraphic pinch-outs. Recent seismic and structural modeling by Ekwueme *et al.* (2023) identified several potential traps, including buried hills and channel fills in the deep offshore Benin region.

Despite a relatively low level of commercial success, there have been hydrocarbon showing in wells such as the Seme Field (offshore Benin), which produced oil from the Cretaceous Afowo sands (Agagu, 1985; Ekwueme *et al.*, 2023). More recent offshore drilling campaigns are focusing on deep turbiditic plays and basin floor fans, believed to hold untapped reserves. Geophysical advances, including full waveform inversion (FWI) and spectral decomposition, have enabled better delineation of deep stratigraphic traps and channel complexes (Ojo *et al.*, 2022; Adebanjo & Ogunbanjo, 2024).

The geology of the Dahomey Basin is shaped by a complex interplay of rift-related tectonics, eustatic sea-level fluctuations, and long-term thermal subsidence. Its sedimentary fill spans from continental clastics to open marine carbonates and deltaic sandstones, offering a complete rift-to-drift stratigraphic record. Although historically overlooked in favor of the Niger Delta, the Dahomey Basin is gaining renewed interest due to improved geological understanding and advances in exploration technology. With its diverse stratigraphy, organic-rich source rocks, and promising structural traps, the basin remains a frontier area with significant hydrocarbon potential.

Materials and Methods

The available dataset available for the evaluation are 3D seismic cube, well logs from four wells Mars-01, Mars-02, Mars-04 and Mars-05, well headers, coordinate, deviation data, and check-shot data from all the wells. The quality of the 3D seismic data provided is relatively fair to good at the shallow depth, but the quality of the data deteriorates considerably with depth. There is a reasonable seismic data coverage across the farm-out area (Fig. 4). The methodology adopted for the seismic interpretation are data gathering, Data QC, well correlation, fault interpretation, well to seismic tie, time and depth map generation.

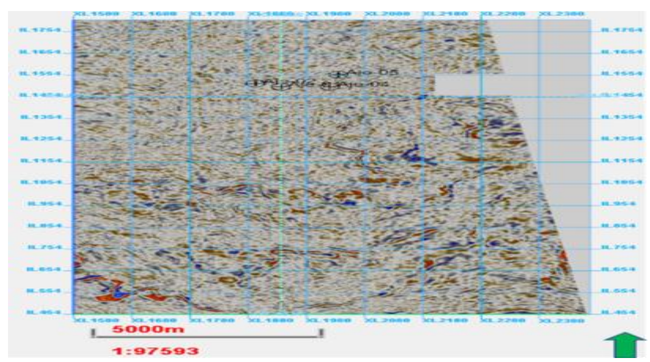

Fig. 4 Time slice showing 3D seismic data coverage.

Data Loading

The seismic and well log data were quality checked to ensure that the wells and the 3D seismic are loaded into the software with the correct reference coordinate together with the check-shot and deviated data using Petrel® (A Schlumberger software).

Well Correlation

The wells were correlated in the basinward direction and the stratigraphic tops provided from the well information and petrophysics analysis was used to correlate the reservoir tops across the wells (Fig. 6).

Seismic to Well Tie

Prior to the interpretation of any seismic data, it is important to establish a relationship between seismic reflections and geological horizons in the well. Synthetic seismograms are the bridges between geological information derived from well data in depth and geophysical information (seismic in time) (Fig. 7). This helps us to recalibrate our seismic data from time domain to depth domain using the check-shot data and sonic logs, and establishing time-depth relationships for the wells. Acoustic impedance and reflection coefficients were calculated and the reflection coefficients were then convolved with a zero-phased wavelet to obtain the seismic "Wiggle" trace and this was compared with the seismic trace.

Fault Picking

Faults were interpreted on inline sections (dip sections) where there have been relative displacement or discontinuity of horizons. Linear features related to seismic reflection truncations were taken to be faults, especially for significant horizons. These criteria were used to interpret the faults (Fig. 8).

Horizon Picking

Horizons were picked on both inline and crossline on the seismic sections as the continuous and strong seismic reflections which represent the top of the reservoirs mapped (Fig. 10). The synthetic seismogram gave indication of events that correspond to the reservoir tops.

Generation of Time and Depth Maps

Time maps were generated by tracking well-tied seismic horizons throughout the seismic cube and subsequently converted to depth maps using check-shot velocities.

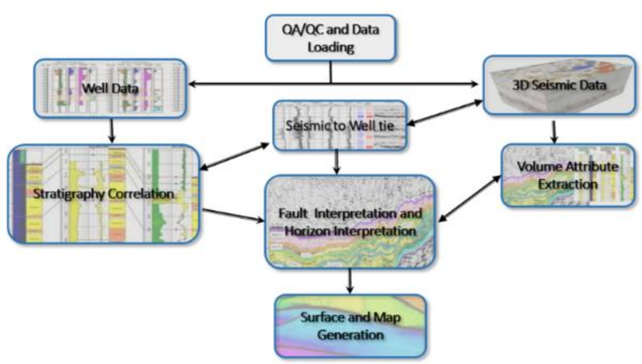

Fig. 5 Diagrammatic representation of seismic interpretation workflow.

Results and Discussion

Well Log Correlation and Sand Picks

A lithostratigraphic approach was adopted for the correlation of the available well logs. Significant flooding surfaces were identified from log motifs and correlated across wells within individual fields, and subsequently across the basin. Thereafter, sand-to-sand correlations were carried out, yielding reliable results within the fields. The log correlation shows an extensive distribution of sandstone sequence and extensive shale provide seals for each reservoir (Fig. 6).

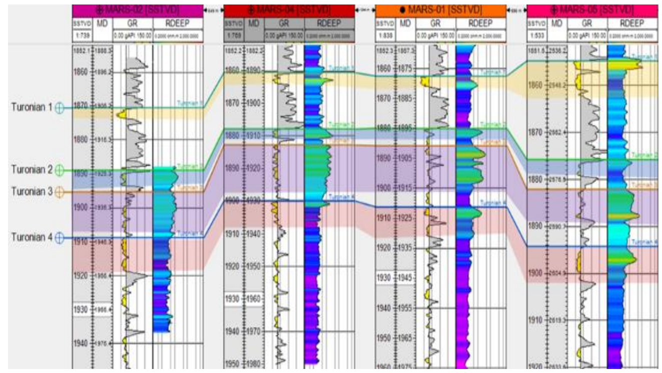

Fig. 6 Reservoir sand well correlation section, Mars Field.

Seismic to Well Tie

Existing well picks corresponding to the reservoir tops in the hydrocarbon bearing wells were reconciled with the picks resulting from the correlation exercise and the quick look petrophysical evaluation exercise. The provided check-shot surveys (T/D chart) were used in posting the respective formation picks on seismic sections. The quality control exercise showed reliably consistent picks. Sonic calibration and seismic to well tie was carried out using Mars-01 because the well has check-shot data, sonic and density logs. The sonic log was calibrated using the check-shot data. The synthetic seismogram was generated using extended white deterministic wavelet method (Fig. 7). Stretching and squeezing were done where necessary.

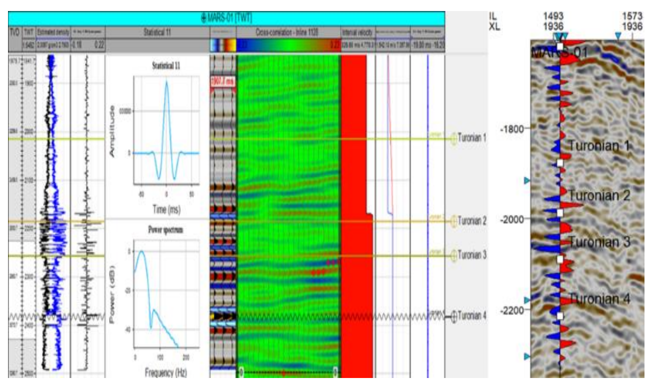

Fig. 7 Synthetic seismogram using Mars-01 well.

Fault Interpretation

In order to properly delineate the trend of the faults, variance attribute was generated. The main faults were identified on time slices at the representative levels (Fig. 8). This initial interpretation formed the backbone for the detailed inline and crossline interpretation of the main faults. The interpreted faults were then correlated to delineate structural trends and ultimately construct the regional structural framework (Fig. 9). The fault was interpreted on every fourth inline and fifth crossline within the cropped seismic volume, validated with the variance cube.

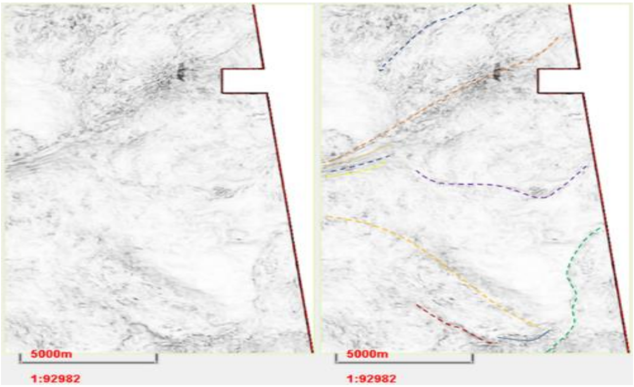

Fig. 8 Variance attribute for fault delineation interpreted Time-Slice @ -2300m.

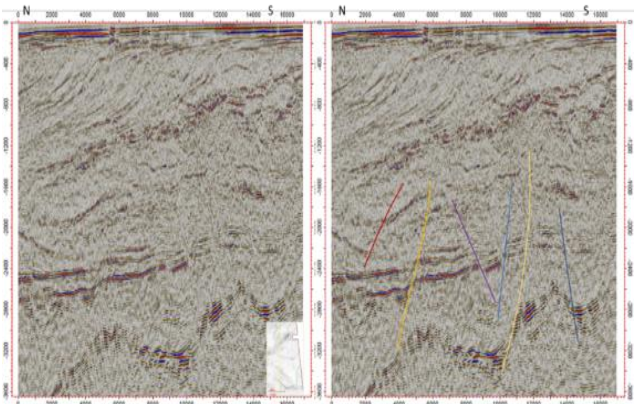

Fig. 9 Seismic sections showing fault interpretation.

Horizon Interpretation

Horizon interpretation was carried out after tying the seismic data to the well tops, and the interpreted horizons were tracked throughout the seismic cube to generate time maps, which were subsequently converted to depth maps using check-shot velocities. Then the reservoir tops were mapped to define the structural extent of the reservoirs. This was coarsely mapped and was intended to establish consistent event identification across the area of interest then horizons were then refined to a denser grid on both inline and crossline (Fig. 10).

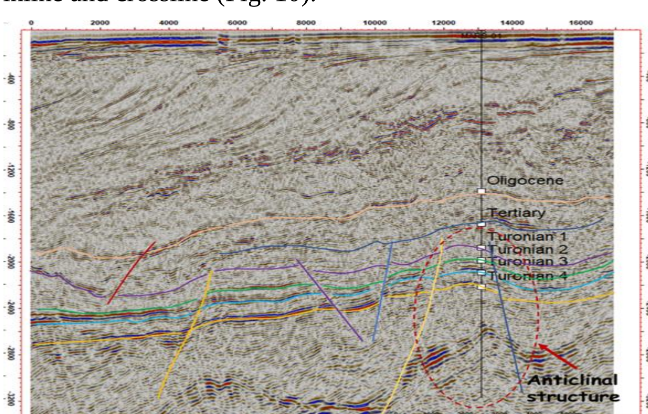

Fig. 10 Seismic sections showing fault and horizon interpretation.

Structural Style and Traps

The faults within the study area are normal faults which occur during the basin evolution as a result of rifting. The reservoir is also affected by the faulting because it was deposited during the Cretaceous period as syn-rift sediments. The faulting within the reservoir could act as a trapping mechanism for hydrocarbon accumulation, but the major trapping style within the study area is a four-way anticlinal closure with presence of faulting that could result in reservoir compartmentalization (Fig. 11). The closure could be as a result of sediment deposition within the basin in which the sediment follows the topography of the underlying structure.

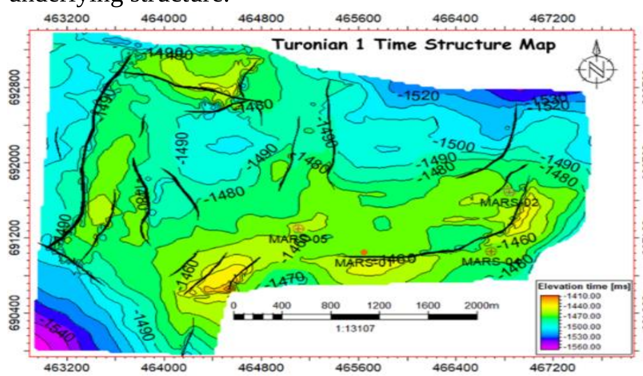

Fig. 11 Seismic sections showing the Turonian sediment having similar anticlinal structure with the underlying Albian sediment and Basement.

Time Structure Maps

The horizon interpretation around the Mars Field was completed, fault polygons were drawn, and time structure maps were generated (Figs. 12-15).

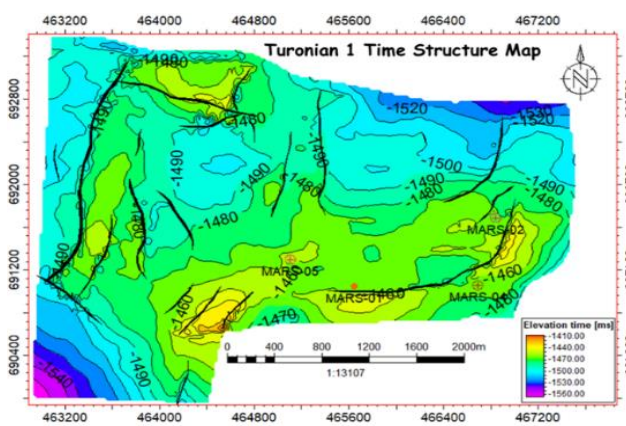

Fig. 12 Turonian 1 time structure map.

Depth Conversion

Available check-shots from Mars-01 was used to generate TDR curve used in the velocity modelling for depth conversion using polynomial functions *(*Figs. 10).

A good TZ trend was established for the fields and a trend line was fitted, from which a polynomial function was derived from this curve (Figs. 16-19).

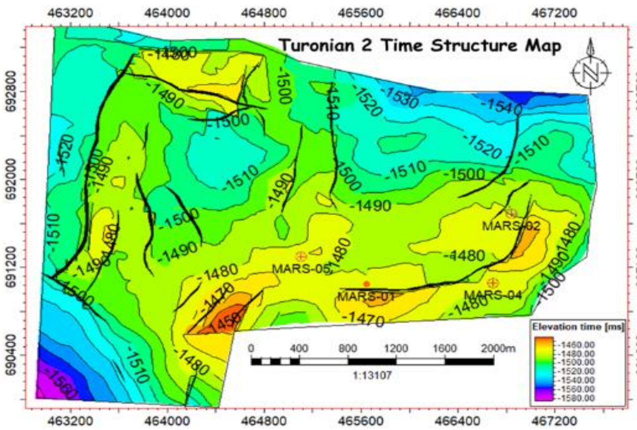

Fig. 13 Turonian 2 time structure map.

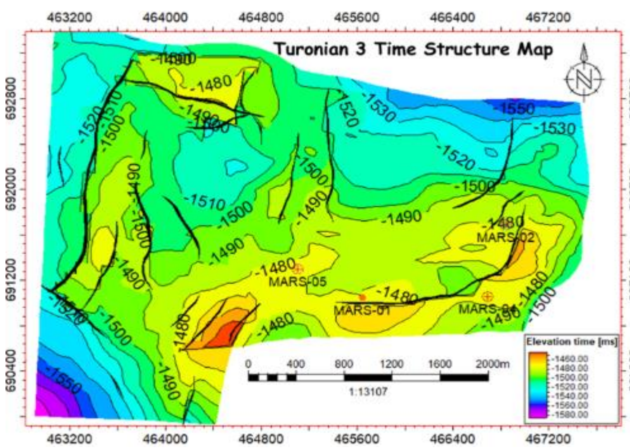

Fig. 14 Turonian 3 time structure map.

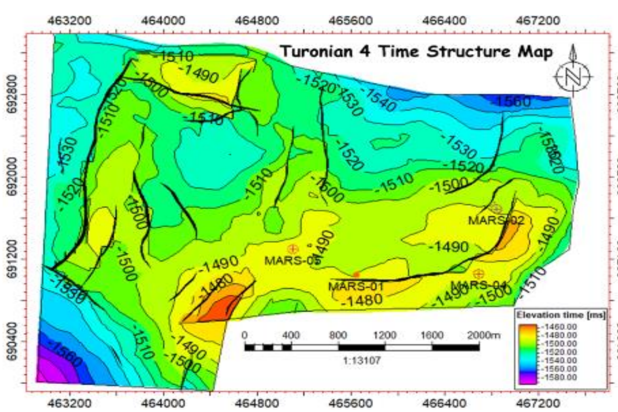

Fig. 15 Turonian 4 time structure map.

Hydrocarbon Distribution Maps

The hydrocarbon contacts derived from petrophysical evaluation (Table 1) were used to create hydrocarbon contacts in the depth maps (Fig. 21-24) to view the fluid distributions across the prolific reservoir.

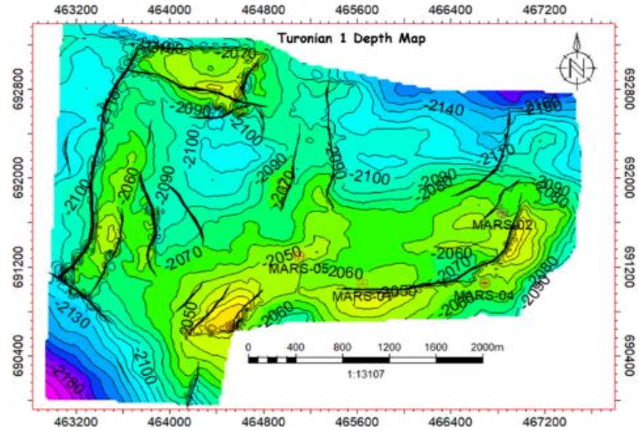

Fig. 16 Turonian 1 depth structure map.

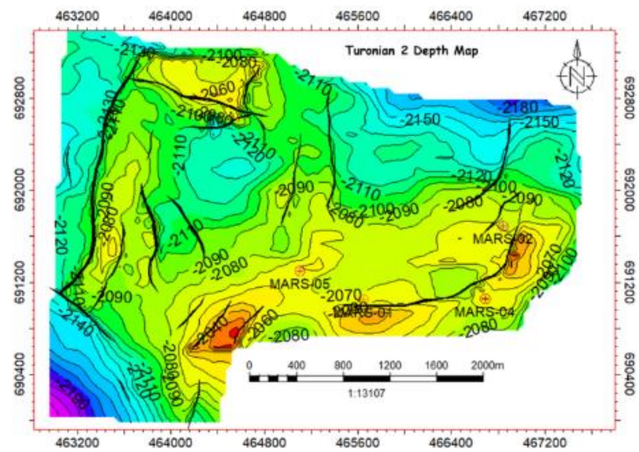

Fig. 17 Turonian 2 depth structure map.

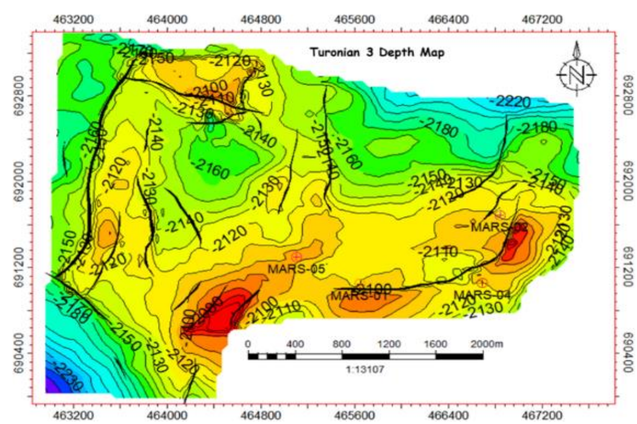

Fig. 18 Turonian 3 depth structure map.

Local stratigraphy: The stratigraphy of the field is underlain by basement followed by the possible presence of carbonate facies deposited during the Albian, this was later followed by deposition of sand and shales form the Turonian to Cretaceous. During the Cretaceous period there appears to be an unconformity due to the presence of erosional surface such as channels and canyon. This was followed by succession of Tertiary, Eocene and Oligocene sediments. During Recent period we have the prograding clinoform with top set, fore set and bottom set as the sediment are depositing into the basin (Fig. 25).

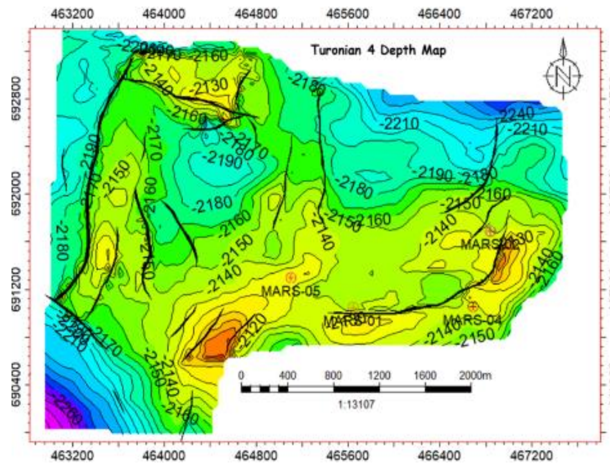

Fig. 19 Turonian 4 depth structure map.

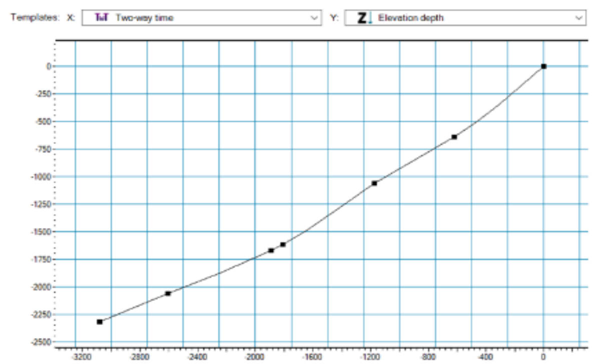

Fig 20 Diagram showing the polynomial function for depth conversion.

Table 1. Fluid distribution contact derived from petrophysical analysis.

Reservoirs	Hydrocarbon Contact (Tvdss m)	Fluid Type
Turonian 1	-2061.43m	GAS
Turonian 2	-2075.12m	GAS
Turonian 3	-2115.45m	GAS or Condensate
Turonian 4	-2140.23	GAS/OIL

The faulting in the basin affected majorly the pre-rift sediment which are the Albian carbonates while the Cretaceous sediment are syn-rift sediments. The Tertiary sediments are not affected by faulting because they are post-rift sediments.

Structural framework: The structural framework was generated using the horizon surface and fault model to show the stratigraphic variation and distribution of sediment within the subsurface. The structural framework was carried out on the Cretaceous sediments and this reveals the effect of erosional activity on the Late Cretaceous sediments (Fig. 26). Towards the south it shows that the part of the Late Cretaceous sediments were completely eroded. This further shows the presence of uniformity around the Late Cretaceous when the basin was exposed. This gives rise to the presence of canyon and channels within the Late Cretaceous sediments.

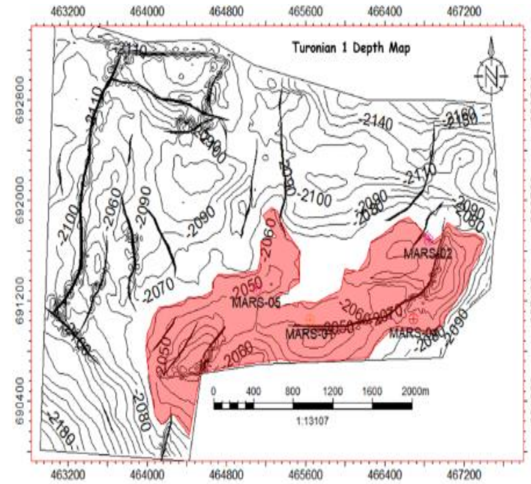

Fig. 21 Turonian 1 hydrocarbon distribution map.

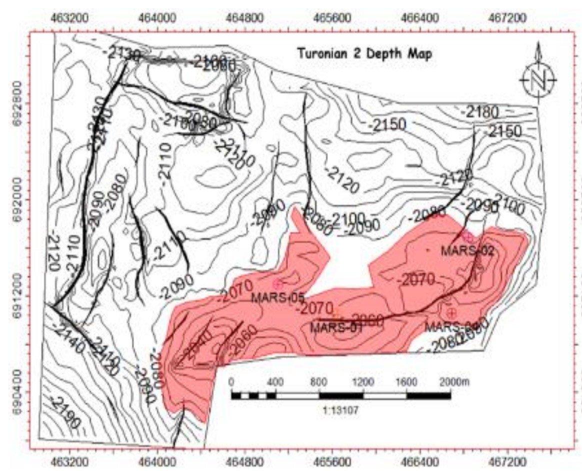

Fig. 22 Turonian 2 hydrocarbon distribution map.

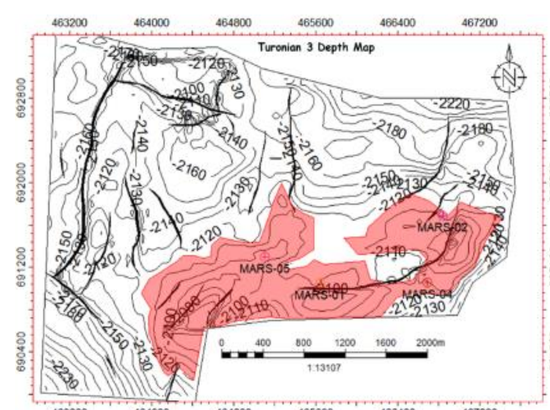

Fig. 23 Turonian 3 hydrocarbon distribution map.

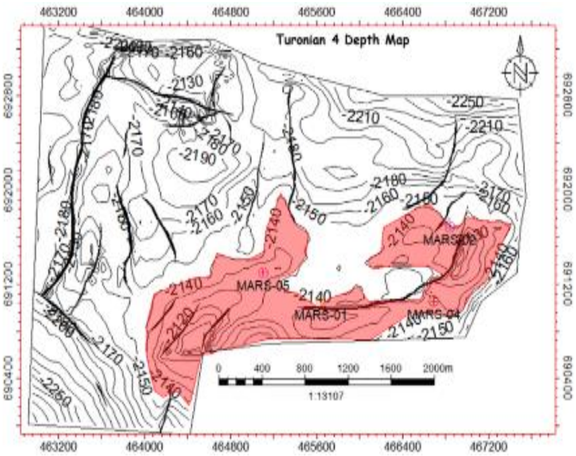

Fig. 24 Turonian 4 hydrocarbon distribution map.

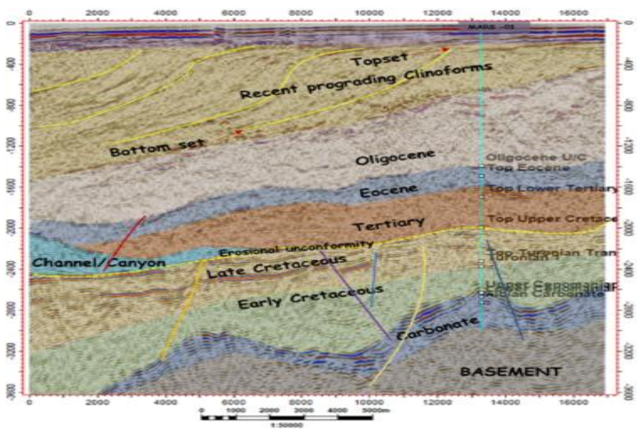

Fig. 25 Local stratigraphy of the field from seismic facies and stratigraphic tops.

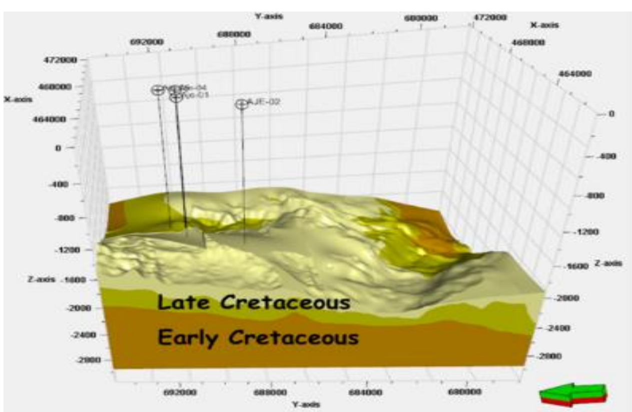

Fig. 26 Geobody showing how the stratigraphy are related to each other in 3D plane.

Conclusion

The seismic interpretation was carried out to delineate the structural style of the basin. The fault was mapped as normal fault using inline and variance time slice. The stratigraphy of the basin was interpreted horizon in which time map and depth map of potential hydrocarbon bearing reservoir were generated. The local stratigraphy reveals the presence of clinoform, channels, unconformity, stratigraphic successions and basement within the Benin Basin. The structural framework was generated to understand the geomorphology of the Late Cretaceous sediments which reveals the degree and the effect of the unconformity on these sediments showing that some part has been completely eroded. The trapping style in the field are faulted anticlinal closures. The fault has therefore offset the continuity of the reservoirs thereby juxtaposing the reservoir beds (sands) with non-reservoir beds (shales) essentially trapping hydrocarbons. The Cretaceous sediments are the major hydrocarbon reservoir within the basin and four hydrocarbon bearing reservoir maps of were generated to show the hydrocarbon distribution within the basin.

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Conflicts of Interest

The authors declare no conflict of interest.

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