Case Study

3D STRUCTURAL ANALYSIS OF OTU FIELD, NIGER DELTA, NIGERIA

ABSTRACT

3D structural analysis was carried out to evaluate the subsurface structures and hydrocarbon trapping potential of Otu Field, Niger Delta using 3D seismic and well log data. Lithologies and hydrocarbons were initially delineated on well logs with the aid of gamma ray, deep resistivity, neutron and density logs. The lithologies were correlated across the wells in the field. Network of faults were interpreted and this revealed growth faults which are listric in nature. Three horizons, C10, D10 and D31 were identified and mapped to produce the structure maps. The structure maps of the top of the reservoirs revealed that the hydrocarbon structures are fault assisted anticlinal structures and they correspond to the crest of the rollover anticlines on the seismic sections. The RMS amplitude attribute extracted on the surfaces revealed bright spots on the region of the anticlinal structures which indicates that the field has economic explorable hydrocarbons accumulations.

Keywords: Seismic, Horizons, listric, Structures, Reservoir, Niger delta

INTRODUCTION

The Niger Delta is ranked among the major prolific deltaic hydrocarbon provinces in the World and is the most significant in the West African continental margin (Aizebeokhai and Olayinka, 2011). Several workers have carried out structural interpretation in different fields of the Niger Delta using seismic and well log data (Opara et. al, 2011; Adewoye et. al, 2013; Ihianle et. al, 2013; Rotimi et. al, 2010). This is as a result of the high demand for hydrocarbon products since the 20th century.

The goal of oil and gas exploration is to identify and delineate structural and stratigraphic traps suitable for economically exploitable accumulations. This is because hydrocarbons are found in geologic traps, that is, any combination of rock structure that will keep oil and gas from escaping either vertically or laterally (Wan, 1995). These traps can either be structural, stratigraphic or a combination of both. Structural traps can serve to prevent both vertical and lateral migration of the connate fluid (Cofeen, 1984). Examples of these include rollover anticlines and flanks of salt domes (Adeoye and Enikanselu, 2009). Stratigraphic traps include sand channels, pinch outs, unconformities and other truncations (Folami et.al, 2008).

According to Doust and Omatsola (1990), majority of the traps in the Niger Delta are structural and to locate them, horizons are picked and faults mapped on the seismic inlines and crosslines to produce the time structure maps. This can reveal the structures that can serve as traps for the hydrocarbons (Adeoye and Enikanselu, 2009).

In this study, 3D seismic data were integrated with well logs to delineate the geologic structures and hydrocarbon trapping potential of the study area. In addition, amplitude attributes analysis that indicates bright spot which is a direct hydrocarbon indicator (DHI) was carried out. The bright spot is a valuable mapping tool because it suggests the presence of hydrocarbons directly on seismic data.

LOCATION AND GEOLOGY OF THE STUDY AREA

Otu field is an onshore field located in the Western part of the Niger Delta, Nigeria and lies between latitudes 5°N and 6°N and longitudes 5°E and 6°E (Figure 1). The field covers approximately 720km^2.

The Niger Delta is ranked among the major prolific deltaic hydrocarbon provinces in the world and is the most significant in the West Africa continental margin. The Niger delta basin is situated on the continental margin of the Gulf of Guinea between latitude 4°-9°N and longitude 4°-9°E. It is composed of overall regressive clastic sequence, which reaches a maximum thickness of about 12000m (Evamy et. al, 1978). The sedimentary sequence as formed in the subsurface of the Niger Delta has been modified by numerous transgressions which occurred from time to time breaking the continuity of the main overall regression and becoming stratigraphically superimpose (Hospers, 2005).

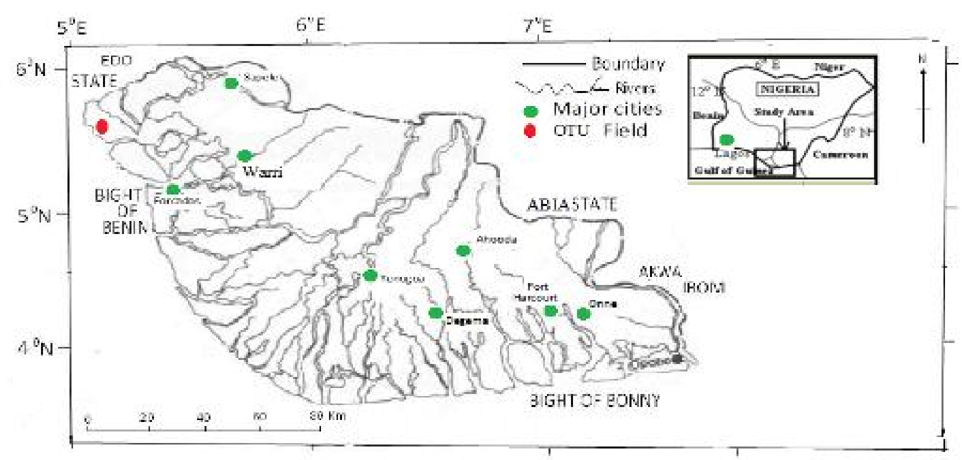

Fig. 1: Map of Niger Delta showing the location of the study area (Otu Field)

The Niger Delta consists of three broad formations (Fig. 2) representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratios (Tuttle et. al, 1999). These are: the basal paleocene to Recent pro-delta facies of the Akata Formation, the Eocene to Recent, paralic facies of the Agbada Formation, and the Oligocene to Recent, fluvial facies of the Benin Formation (Short and Stauble, 1967).

The Akata Formation at the base of the delta is of marine origin and is composed of thick shale sequence (potential source rock), turbidite sand (potential reservoir in deep water) and minor amounts of clay and silt (Opafunso, 2007). It was formed during lowstands when terrestrial organic matter and clays were transported to deep water areas characterized by low energy conditions and oxygen deficiency (Michelle et. al, 1999). It is estimated that the formation is up to 7000m in thickness in the central part of the delta (Doust and Omatsola, 1990). The formation underlines the entire delta and forms the base of the sequence in each depobelt. The marine shale is typically over pressured. The depositional environment is typically marine.

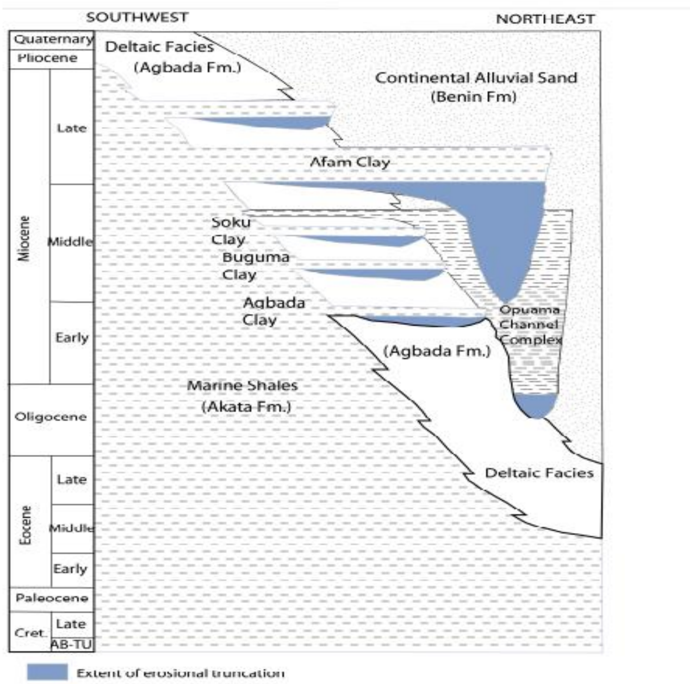

Fig. 2: *Stratigraphic column showing the three formations of the Niger Delta. (From, Doust and Omatsola, 1990).*

Overlying the marine shales is the paralic clastics facies of Agbada Formation. This forms the hydrocarbon prospective sequence in the Niger Delta. The formation consists of paralic siliclastics over 3700m thick and represents the actual detaic portion of the sequence. The clastics accumulated in delta-front, delta-topset, and fluvio-deltaic environments. In the lower Agbada Agbada Formation, shale and sandstones beds were deposited in equal proportions, however, the portion is mostly sand with only minor shale interbeds (Tuttle et. al, 1999).

The Agbada Formation is overlain by the third formation, the Benin Formation, a continental latest Eocene to Recent deposit of alluvial and upper coastal plain sands that are up to 2000m thick (Avbovbo, 1978; Tuttle et. al, 1999). It is deposited in upper coastal plain environments following a southward shift of deltaic deposition into new depobelt. It traps non-commercial quantities of hydrocarbon and has sand percentage of over 8% (Opafunso, 2007). Benin Formation occurs across the entire Niger Delta from Benin-Onitsha in the North to beyond the present coastline. It consists of massive, highly porous, fresh water bearing sandstone with local thin shale interbed, which is considered to be of braided stream origin (Opafunso, 2007). The sands and sandstone of the Formation are coarse to medium to fine grained in general and are poorly sorted.

There has been much discussion about the source rock for petroleum in the Niger Delta which has reflected in (Evamy et. al, 1978; Ekweozo et. al, 1979; Tuttle et. al, 1999). Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation and the marine Akata shale and a cretaceous shale (Tuttle et. al, 1999). The Agbada Formation has intervals that contain organic-carbon contents sufficient to be considered good source rocks. The intervals, however, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the delta (Evamy et. al, 1978; Stacher, 1995).

The Akata shale is present in large volumes beneath the Agbada Formation and is at least volumetrically sufficient to generate enough oil for a world class oil province such as the Niger Delta. Based on organic-matter content and type, Evamy et. al, (1978) proposed that both the marine shale (Akata Fm) and the shale interbedded with paralic sandstone (lower Agbada Fm) were the source rocks for the Niger Delta oils.

In the case of the cretaceous shale, it has never been drilled beneath the delta due to its great depth; therefore, no data exist on its source rock potential (Evamy et. al, 1978).

Petroleum in the Niger Delta is produced from the sandstone and unconsolidated sands predominantly in the Agbada Formation (Tuttle et. al, 1999). Characteristics of the reservoirs in the Agbada Formation are controlled by depositional environment and by depth of burial. Known reservoir rocks are Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15m to 10% having greater than 45m thickness (Evamy et. al, 1978). The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990).

Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. Edwards and Santogrossi (1990) describe the primary Niger Delta reservoirs as Miocene paralic sandstones with 40% porosity, 2 darcys permeability, and a thickness of 100m. The lateral variation in reservoir thickness is strongly controlled by growth faults; the reservoir thickness towards the fault within the down-thrown block (Weber and Daukoru, 1975). The grain size of the reservoir sandstone is highly variable with fluvial sandstones tending to be coarser than their delta front counterparts; point bars fine upward and the barrier bars tend to have best grain sorting. Most of this sandstone is nearly unconsolidated, some with minor component of argillo-silicic cement (Kulke, 1995).

Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon (Fig. 3). The structural traps developed during synsedimentary deformation of the Agbada paralic sequence (Evamy et. al, 1995). Structural complexity increases from the North (earlier formed depobelts) to the South (later formed depobelts) in response to increasing instability of the under-compacted, over-pressured shale. Doust and Omatsola (1990) describe a variety of structural trapping elements, including those associated with simple rollover structures; clay filled channels, structure with multiple growth faults, structures with antithetic faults, and collapsed crest structures (Fig. 3 & Fig. 4). Stratigraphic traps occur on the flanks of the delta (Tuttle et. al, 1999). Pockets of sandstone occur between diapiric structures in the region.

The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals – clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting, and vertical seals (Doust and Omatsola, 1990). On the flanks of the delta, major erosional events of early to middle Miocene age formed canyons that are now clay-filled (Fig. 2). These clays form the top seals for some important offshore fields (Doust and Omatsola, 1990).

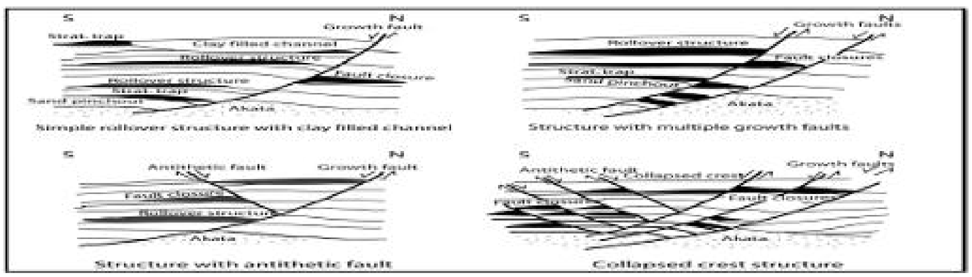

Fig. 3: Examples of Niger Delta oil field structures and associated trap types (Doust and Omatsola ,1990).

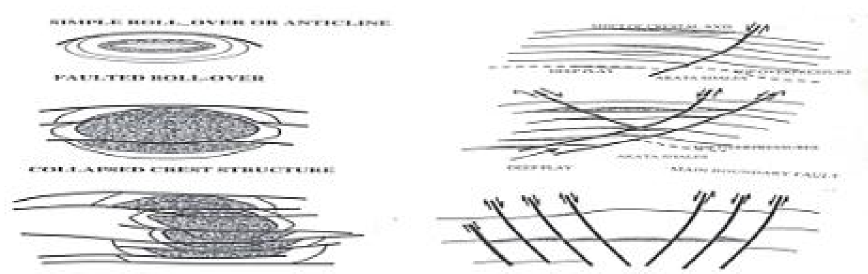

Fig. 4: Conventional trapping configuration in the Niger Delta (Modified from Weber and Daukoru, 1975).

METHODOLOGY

The data available for this study include 3D seismic volume in SEGY format, a composite well logs comprising of gamma ray (GR), resistivity deep (RES_D), Sonic (BHC), density (FDC) and neutron (NEU) logs, and checkshots data. Petrel software was used to interpret the seismic data and to generate maps as well as well log cross sections.

The gamma ray log (GR) was used to identify the lithology (sand and shale) because it is believed that in the Niger Delta, hydrocarbon reservoirs are found within sand units. The tops of the formation were correlated across the wells in the field and base of each formation was created to define vertical extent of the formation. Hydrocarbons were delineated on the formations with the aid of deep resistivity log. Synthetic seismogram was generated by convolving the reflectivity derived from sonic and density logs with the wavelet derived from seismic data (Fig. 5). The sonic log was calibrated (corrected) with checkshots before combining with the density log to produce reflection coefficient (Fig. 6).

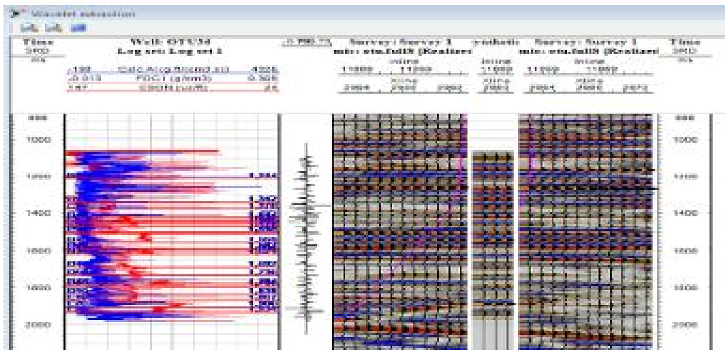

Fig. 5: Wavelet extraction for Otu36

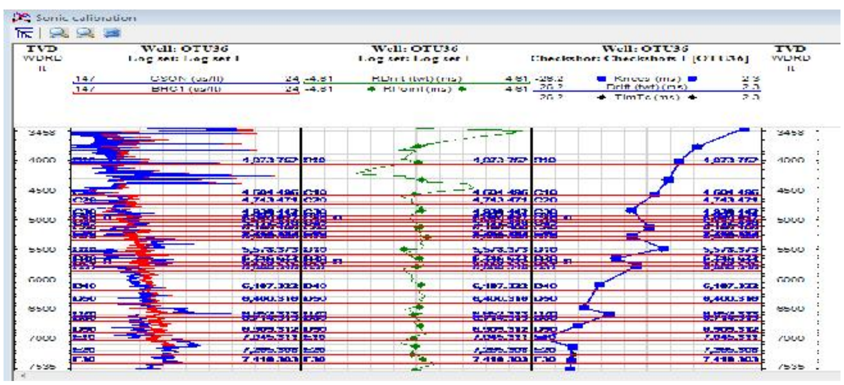

Fig. 6: Sonic calibration Otu36

The synthetic seismogram was used for tying the well data and seismic data. This tie formed the first step in picking events, which corresponded to the tops of the sands for interpretation. Picking of faults, mapping of horizons and loop tying were carried out manually.

Faults were recognized from the seismic section by distinct continuity or abrupt jump of seismic reflection events. The interpreted faults were quality checked on the variance time slice and corrected/assigned. Slices were moved up and down in time to confirm fault consistency. The variance attribute is an edge imaging detection method. By using the synthetic seismogram created previously, the tops of the sands identified on the logs were tied to the seismic reflection events on the seismic sections. Three horizons were interpreted based on the tops and were traced through the whole seismic volume. The horizons were interpreted on every 10 inlines and 10 crosslines and seismic seed grids were generated. The grids were infilled by interpolation.

The RMS amplitude attribute was extracted for each horizon. Time structure maps were produced using the interpolated seismic seed grids for each horizon. The time maps were then converted to depth maps using a simple velocity model.

DISCUSSION OF RESULTS

Well logs study revealed a few number of sand reservoirs of which three C10, D10, and D31 were mapped at depth of 4512ft, 5337ft and 5536ft respectively. The gross thickness of the C10 reservoir sandstone formation ranges from 45ft to 78.5ft. Since the reservoir was intercalated with shale, the net thickness varied between 11.5ft and 54.5ft. The gross thickness of the D10 reservoir varied between 55.5ft and 103ft; while the net thickness varied between 13ft and 51ft. The gross thickness of D31 reservoir varied between 127.5ft and 273ft and the net thickness varied between 11ft and 114ft. A log correlation connecting all the wells across the area is shown in Fig. 7.

The synthetic seismogram generated revealed that Otu wells have a good time depth tie with a trough to trough and peak to peak match. Well-to-seismic tie revealed that the mapped hydrocarbon bearing reservoirs lie on the trough of the rollover anticlines on seismic sections. Fig. 8 shows the synthetic seismogram of Otu36 and the mapped well tops. Several faults were identified and marked with different colours. This revealed three major growth faults (green, yellow and brown) which are listric in nature and concave basin-wards. Other faults mapped are synthetic and antithetic faults. Displacement of seismic facies across faults increases with depth in the seismic record. The three horizons mapped are characterized by low to high or variable amplitude reflections with moderate to good continuity. There are truncations in some places which are caused by faults. Fig. 9 shows the interpreted faults and horizons on the seismic sections. Fig. 10 shows the variance time slice used to QC'd the faults and corrected/assigned.

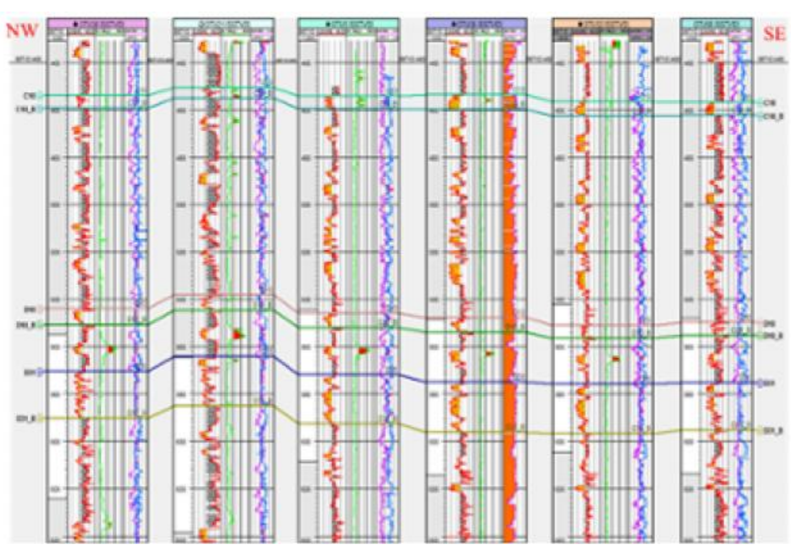

Fig. 7a: Well correlation panel of Otu Field

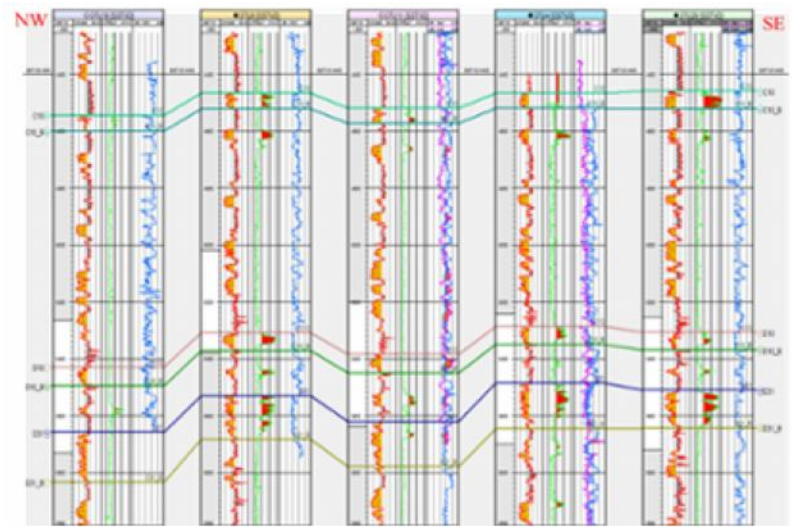

Fig. 7b: Well correlation panel of Otu Field contd.

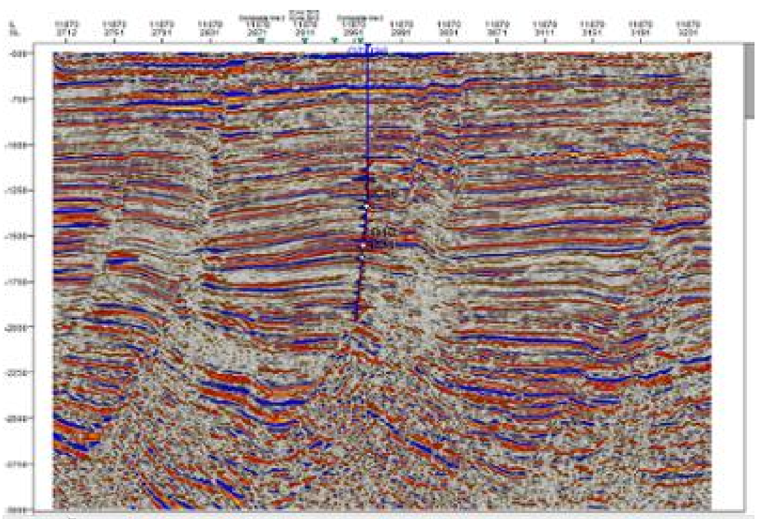

Fig. 8: Synthetic seismogram of Otu36 and the mapped well tops.

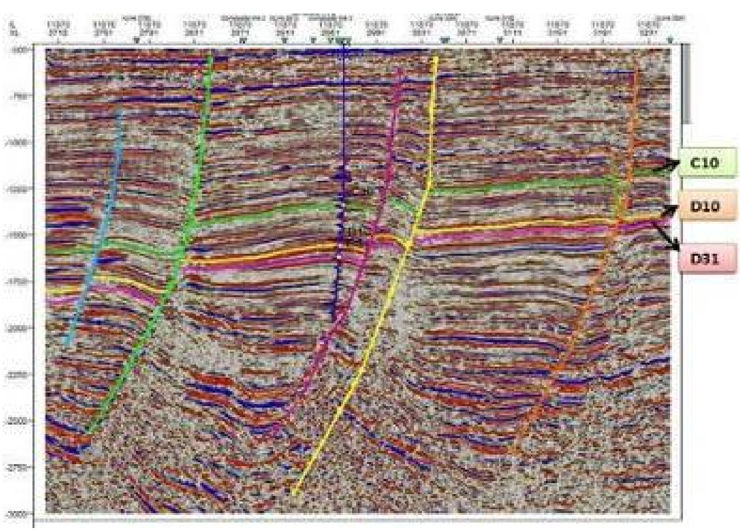

Fig. 9: Seismic Inline showing fault sticks, synthetic seismogram and horizons interpreted.

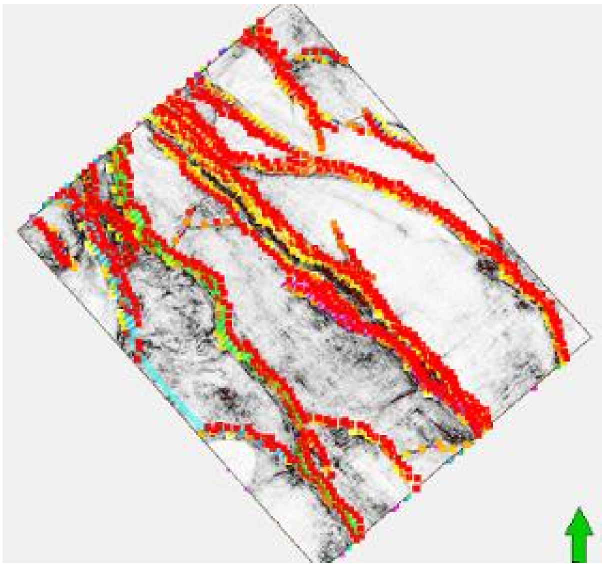

Figure 10: Variance time slice with fault sticks.

From the faults and the horizons interpreted, time structure maps were produced. The time structure maps were converted to depth structure maps using the velocity model. The contouring was actually done by joining points of equal depth going round the data with contour interval of 50ft for each surface. Points of equal depth are identified by having the same colour and the depth of each colour is shown in the colour bar in Fig.11 Fig.12 and Fig.13. Depth structural map of horizon C10 is shown on Fig.11. The contoured map has values ranging from 3400ft to 6100ft. Structural highs are observed at North-western and the central part of the field. This area forms a good trapping system thereby increasing retentive capacity for hydrocarbon. The hydrocarbon trapping system in the central part of the field where the wells are located is a faulted rollover anticlines. The low faults throw in the area is responsible for excellent retentive capacity of hydrocarbons. Structural lows are seen in the south-western region and the area is marked with no prospect. Fig.12 is the depth structural map for horizon D10. The contoured interval value ranges from 4250ft to 7200ft. Structural highs were observed in the North-Western part and the central part serve as good traps for the hydrocarbon accumulation. The hydrocarbon trapping system is still faulted rollover anticlines. In the South-Western and South-Eastern region of the field, structural lows are observed. The depth structure map of D31 horizon is presented in Fig.13. The D31 horizon is similar in characteristics to the horizon D10 but is located at a considerable deeper depth. They have the same structural style.

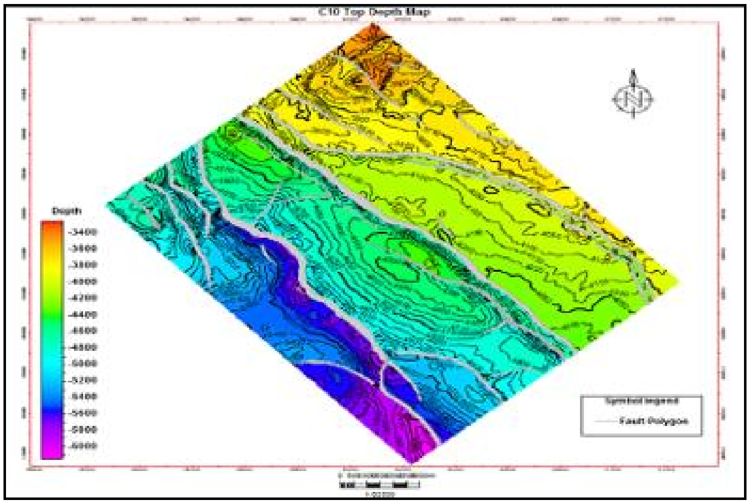

Fig. 11: Depth Structure Map of Horizon C10

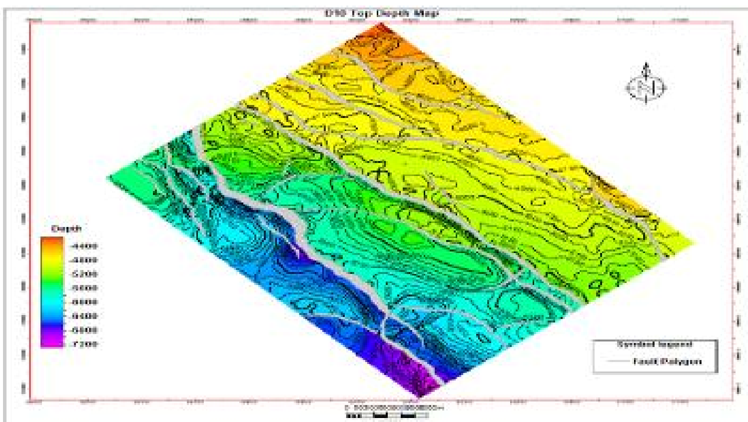

Fig. 12: Depth Structure Map of Horizon D10

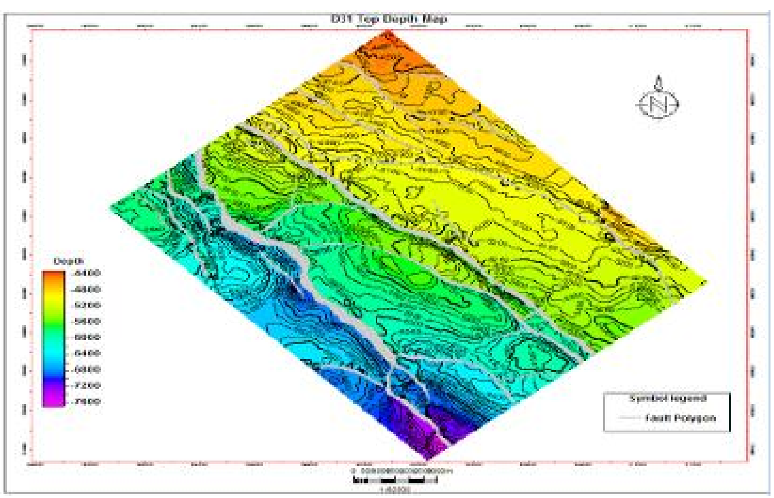

Fig. 13: Depth Structure Map of Horizon D31

Fig. 14 to 16 shows the RMS amplitude map of the interpreted horizons. The amplitude map was used to know the distribution of high and low amplitude across each horizon and try to find any special features in the study area, such as lithology and fluid content.

The high amplitude zones (red, yellow and green colour) at the E-W part of the map indicate the presence of hydrocarbon and correspond to the structural high of the map. The amplitude map for D31 sand didn't fully correspond to the lithology and this could be due to the search window used, or poor quality data at the deeper zone of the field. A greater part of the central part shows bright spot. Bright spots are seen as an indication of hydrocarbon presence (Obiekezie, 2014) the observed bright spots correspond to the rollover structure of the field.

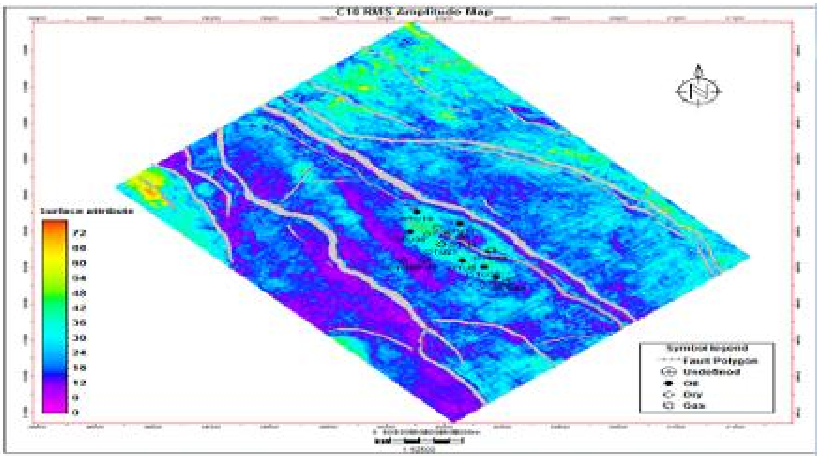

Fig. 14: RMS Amplitude for horizon C10

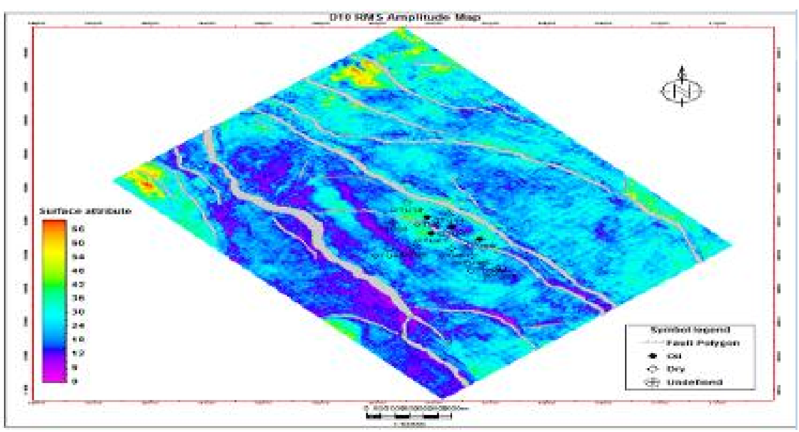

Fig. 15: RMS Amplitude for horizon D10

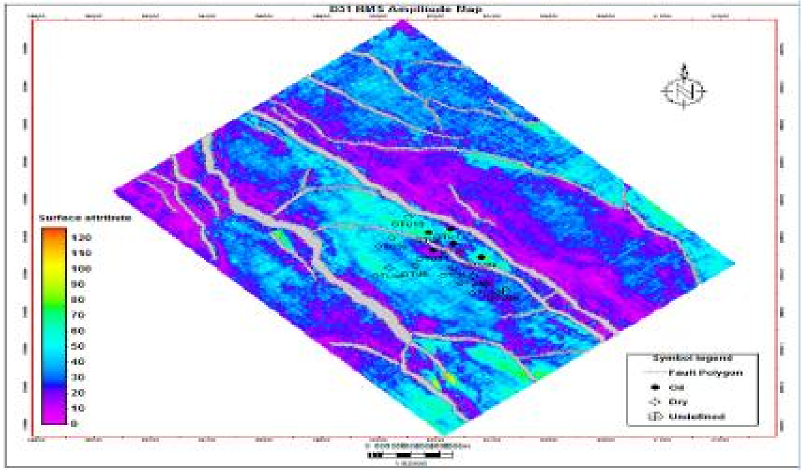

Fig. 16: RMS Amplitude for horizon D31

CONCLUSION

The 3D structural analysis of the Otu Field gave a better understanding of the structural styles and hydrocarbon trapping systems of the field. From the well logs analysis three hydrocarbon bearing reservoirs (C10, D10 and D31) were delineated. The net thickness of the reservoir varies between 45ft and 273ft. A network of faults and three horizons were interpreted to generate the structure maps. The main faults in the field are growth faults which are listric in nature. From the structure maps, it was discovered that hydrocarbon accumulations were basically due to structural highs and closures that are faults dependent. These structures correspond to the crest of rollover structure in the field. The amplitude maps revealed bright spots on these regions thereby suggesting economic explorable hydrocarbon accumulations.

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