

Optimizing reservoir characterization: insights from integrated data analysis

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Abstract

The Onshore Hydrocarbon prospectivity of the Niger Delta X-field is examined through the integration of 3D seismic and recorded information from well log data. Probable reservoirs of hydrocarbon-bearing were delineated to tackle the non-uniqueness in the identification of hydrocarbon quantity of concern. Three significant faulting patterns or systems were delineated and their architectural attributes depict a typical Niger Delta embedded anticlinal structural pattern. The study field exhibited both synthetic and antithetic structures, hence only fault on delineated reservoirs was used for structural modeling. All well locations were sited within the fault-supported synthetic and anticlinal structures and the static characteristics within the well coordinates were analyzed through petrophysical assessment. Depicted reservoir sands show low gamma ray readings, low volume of shale, considerate hydrocarbon saturation and low water saturation. The established petrophysical models showed a better net-to-gross (NTG) ratio, for the entire delineated reservoir units. This has contributed to the assessment of hydrocarbon-bearing reservoir units before employing the strategy for field development scenario, in order to eliminate dry hole drilling campaign. These will contribute to the reduction of operational costs, having delineated the accurate geometry and petrophysical model of hydrocarbon reservoir units.

Keywords Reservoir · Niger Delta · Hydrocarbon · Gamma-ray index · Prospectivity

1 Introduction

The depiction of reservoir architecture and characteristics can be achieved and detailed through the use of information from well-log data or records, seismic volume and local geological data. Actual position knowledge, quantity and hydrocarbon reservoir thickness can be improved and evaluated through numerous established techniques, such as the integration of well log and seismic data. This will contribute in improving the economic dynamics of the hydrocarbon reservoir for productivity efficiency and enhancement [15, 29, 32, 39]. The petrophysical parameters that tend to evaluate oil and gas quantity or oil in place in a given reservoir unit are hydrocarbon saturation and porosity. But the quantitative interpretation of a reservoir requires the knowledge of shale volume, net to gross, pore space, and reservoir thickness [13, 29, 30, 42]. Integrating well logs and seismic data provides the reservoir details or information for in situ measurement of the reservoir and wide coverage of variation away from well control [15, 17, 42]. The analysis of well-log data information and seismic volume signatures of an ideal reservoir characterization can be used to achieve an optimal hydrocarbon recovery scheme. Logs are frequently used in an exploration regime, in order to examine the association or correlation of reservoir sand bodies, isopach and isochron

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maps generation. It can also be applied in evaluating certain petrophysical properties of rocks, such as porosity, permeability, lithological unit identification and possible pore geometry [15, 17, 29, 42].

Dolomite, limestone and sandstone are consolidated reservoir rocks that have the accumulation tendency of hydrocarbon saturation in their pore spaces. In a recent study, Hussain et al. [25], developed Domain Transfer Analysis (DTA), a computation fluid dynamics novel approach for synthesizing multivariate petrophysical data types. Their findings attest to the robustness and versatility of DTA in petrophysical evaluation, covering key parameters like saturation, total organic carbon (TOC), mineral volumes, and brittleness [25]. Furthermore, the composition of clay minerals significantly impacts the petrophysical and hydraulic properties of clastic reservoirs. Numerous studies have demonstrated that the presence of these clay minerals in rock formations poses substantial challenges to accurately assessing reservoir permeability and porosity [26, 28, 58]. Also, it is worthy to note that the spectroscopy Gamma-ray (SGR) facilitates the estimation of thorium (Th), Potassium (K), and Uranium (U) concentration. However, the elemental ratios derived from these data can be employed infer sedimentary composition, provenance, and diagenetic processes [26].

Petrophysical parameter characterization of a reservoir unit, such as porosity, water saturation and permeability can be used to assess the pressure regime, in conjunction with seismic velocities, density logs, regional geology of the examined field, and the volume of hydrocarbon insitu as well as the reservoir depth. The use of resistivity log signatures and relative value of the permeability can separate oil, gas, and water-bearing reservoir units [14, 23, 51, 52, 55]. In a recent study, Hussain et al. [51], applied petrophysical analysis techniques to assess unconventional hydrocarbon reserves, providing valuable insights into their evaluation. The researcher further noted that rock physics models are governed by geological factors such as porosity, lithology, and fluid characteristics. Previous studies by several workers aimed at developing an acceptable technique for discerning and quantifying these geological parameters in sand reservoirs of the lower Goru Formation [27]. Accurate thickness and lithology determination is best achieved through the use of gamma rays and resistivity logs obtained from well data information [8, 16, 43]. Oil and gas are usually gathered into subsurface features and these features can be structural, stratigraphic or both structural and stratigraphic [34, 40, 41, 43, 48]. Subsurface structures such as faults are common in sub-terrain features that are related to a shift or displacement of the subsurface layer. A consistent structural interpretation can be carried out by classifying, discovering and also extracting each structure from 3D seismic sections or volumes. In the quest for oil and gas exploration, fault signatures play a vital role as they are closely tied to hydrocarbon accumulation and migration. However, identifying fault structures from seismic image requires meticulous human analysis, a task that demands careful consideration. This is particularly significant in the Niger Delta basin, where hydrocarbon bearing fields feature complex, stacked reservoirs exceeding 10,000 ft in depth, with diverse geological structures [29, 31, 41, 42, 46]. Differences on each scale of interest, from pore to primary reservoir sand index; lead to changes in reservoir properties. These properties contribute to the major issues associated with the production planning process [1, 41, 47]. The difficulty associated with oil and gas organization within the Niger Delta basin is the inability to delineate the complexity associated with reservoir units and accurate well placement. The evaluation of hydrocarbon productivity can only be attained through the characterization of reservoir units [20, 41].

The objective of oil and gas producers within Niger Delta basin is to improve their production rate at minimal computational cost. When a hydrocarbon reservoir is characterized poorly, it may contribute to low production rates and sometimes, leads to a dry hole during the drilling campaign [6, 19, 39, 42]. However, it is crucial to delineate reservoir heterogeneity to avoid overestimating reservoir performance, which may lead to either the over prediction or underestimation of hydrocarbon reserves within the study area [39]. Accurate porosity estimation is a crucial aspect in the oil and natural gas industries, as it significantly impacts the evaluation of reservoir characteristics. Consequently, developing an optimal approach for porosity prediction is essential to minimize the need for logging tests and enhance reservoir characterization [28]. These uncertainties can be resolved through reservoir characterization, which can utilize: (1) geologic (2) geophysical and (3) petrophysical assessment for field development procedures. Hence, better reservoir characterization describes the structural style, thickness and volume of hydrocarbon reservoir and also defines other prospect zones within the field. The study became necessary due to the probable incident of dry hole drilling scenario, such as no hydrocarbon shows, non-productive reservoir and reservoirs with low hydrocarbon saturation within the study location. This can be resolved through the assessment of hydrocarbon bearing units, thus the operational cost and field development plan will be optimized, having delineated the geometry and petrophysical hydrocarbon units. The study seeks to integrate onshore seismic data and wireline logs that are acquired from an onshore field, leveraging on robust techniques to delineate hydrocarbon bearing formations, elucidate the complex reservoir unit geometry, and also reveal the spatial distribution of reservoir properties.

2 Geology of the study area

The geology of the study area has been extensively discussed by many geoscientists, whose works tailored along structural features, stratigraphy, tectonic setting and hydrocarbon potentials [12, 18]. The study location falls within the latitude 3° and 6° N and longitude 5° and 8°E, with a maximum sediment thickness of about 12,000 m. The Niger Delta basin is composed of three geological units: Benin, Agbada, Akata formations, (Fig. 1) [17, 42, 45, 47, 57].

The Benin Formation is the shallowest, consisting of fresh water bearing continental sands and gravels that out crop in the coastal plain area, from Benin to Onitsha and beyond. It is primarily made up of non-marine sands deposited in an alluvial or upper coastal plain environment during the delta's progradation [11, 17]. The formation thins out towards the basin and ends near the shelf edge. The deposit is primarily continental in origin and contains high porous structure, fresh water bearing sandstones with localized clay of tiny shale layers and sediments that becomes more frequent and thicker at the bottom of the formation [4, 17, 18, 52]. Texturally, it consists of fine grained sand and grains are sub-rounded to well rounded, poorly sorted and partly unconsolidated. The thickness ranges from 0 to 2100 m [17, 49].

The Agbada Formation is the next in the sequence, underlying the Benin Formation; it consists of sand and shale intercalation. This forms a better representation of the actual deltaic sequence and it is the hydrocarbon reservoir unit of the sequence [4, 18, 32, 42]. Agbada formation occurs as a paralic sequence of alternating of shale and sand throughout the Niger Delta clastic wedge. The shale thickness increases with depth and its thickness ranges from 0 to 4500 m and its age is from Eocene to Pleistocene [2, 4, 11, 17, 18]. It crops out in southern Nigeria, where it is called the Ogwashi-Asaba and Ameki formations, respectively. The strata are generally interpreted to have formed in fluvial-deltaic environments [2, 4, 17, 43, 45, 57]. Texturally, the sandstone vary from coarse to fine grained; poorly to very well sorted, unconsolidated to slightly consolidated. The shales are medium to dark grey consolidated and silty with localized glauconities [3, 17, 18, 56]. The final of the sequence is Akata formation with upto 7000 m thickness; it is made up of shales, clays and silts. This formation is of a turbidite origin [17, 18].

The Akata formation is the source rock of the Niger Delta basin. Deformation in the Niger Delta is thin skinned and has resulted from slope instability of gravitational origin [2, 4, 9, 10, 17, 32]. The Akata shale has provided the necessary basal detachment; thin skinned structures are similar to those in other shale based deltas, such as Amazon cone; with the age from Paleocene to recent [9, 17, 32]. According to gravity modeling at the scale of the delta, the Akata Formation must have a low density, as in salt or poorly compacted shale [9, 17, 33]. One of the main structures due to slope instability in the Niger Delta are listric normal growth faults of extensional origin, on land, in shallow water folds and thrusts of compressional origin [9, 17].

Fig. 1 Stratigraphic column showing formations of the Niger Delta [after: 11, 53]

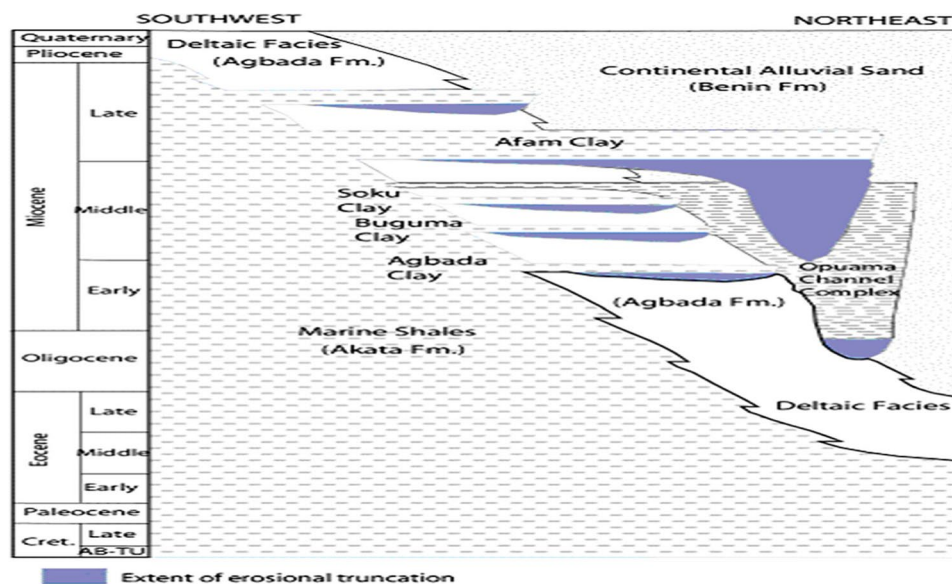


Fig. 2 Modeling workflow
(After Petrel [50])

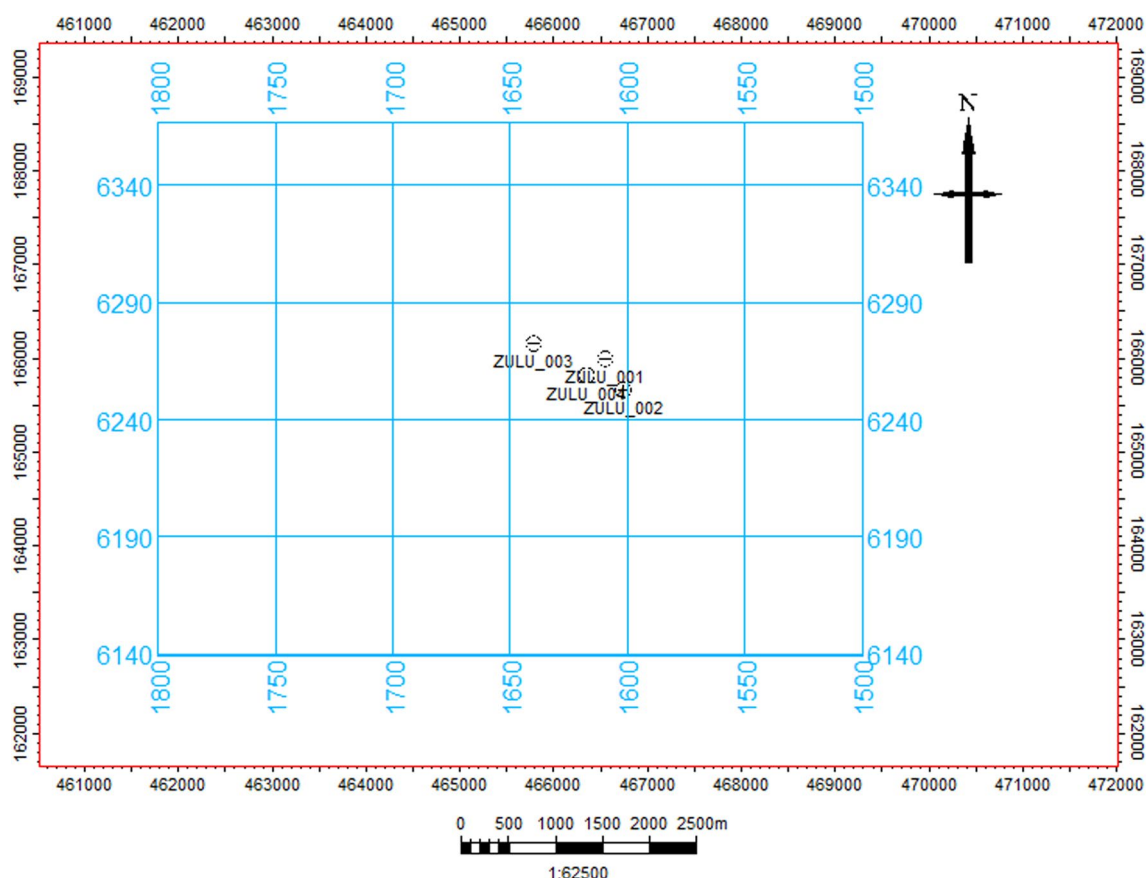
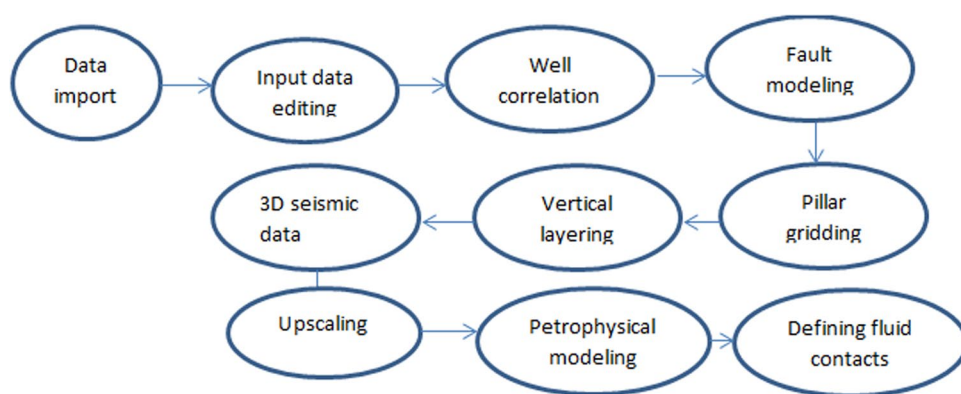


Fig. 3 Base map of the study location

3 Materials and methods

Some procedures of investigation were implemented to appraise the reservoir model. 3D geological static modeling of the petroleum reservoir was built using Petrel 2013 geophysical software, and the following workflow was adopted (Fig. 2) [50]. For the data analysis and model building, Petrel 2013.2 version of geophysical software was adopted.

Data used: For this study, we were provided with a comprehensive dataset comprising 3D seismic data in SEG-Y format, check shot data, a base map (Fig. 3), and well log data from four wells located within the same area. The well logs include a suite of logs for rapid interpretation, which were digitized and compiled into composite logs in LAS format.

Well log interpretation: The logs were employed to delineate hydrocarbon-bearing zones and the lithology of the formation. To determine the lithology of the formation, gamma ray logs were adopted. It measures or evaluates the natural gamma ray emissions from the radioactive formation. Its principle is based on distinguishing the difference in the energy level of the sediments, to discriminate in terms of sand/shale lithology sequence [8, 22, 24, 35, 36, 38]. This gamma ray log is measured in American Petroleum Institute (API), thus it shows high gamma ray log readings which correspond to shale (non-permeable bed) and low gamma ray log values that depict sand zones (permeable bed) within the study area. Fluid discrimination within the study location was identified using resistivity logs. Most minerals are very good insulators, which have significant conductivity properties. Most conduction takes place through the liquid phase, and the resistance therefore depends primarily on the pore liquid and its salt content. Sediments with oil and gas will greatly increase the resistivity. This is the characteristic feature that helps in identifying or discriminating fluids within a formation [8, 22, 24, 35, 36, 38]. High resistivity log values depict hydrocarbons, while low resistivity log value shows brine-saturated reservoirs.

To obtain an accurate interpretation, it became necessary to correct the well-logs used in this study for spike tendencies. This was achieved through well log correlation. Datum levels and well deviations were similarly corrected, to obtain the log true referenced and similar vertical datum. To develop the synthetic seismogram that will be used in correlating the seismic wavelet, acoustic impedance was initially derived before the evaluation of reflectivity through the impedance. Because the acoustic impedance is the product of density and compressional wave velocity and this compressional wave velocity was evaluated from the inverse of transit time of the sonic log. Hence, we then obtained the traces of acoustic impedance through the integration of the sonic log to check shot point conversion. This integrated sonic log was calibrated to tie with the check shot point, thus time to depth graph was obtained and the time-to-depth conversion was used to convert the data measurement from time to depth units [20, 48, 52].

Well to seismic tie: The 3D seismic data was then used to delineate the wide coverage of the study location in terms of structures and attributes. The synthetic seismograms generated from the well logs correspond with the events on seismic volume. This was achieved through the consideration of reflectivity as the differential value of acoustic impedance trace when it is moved down by a quarter wavelet. During the movement of the wavelets, hard and soft kicks were avoided [41]. The equivalent depth of variation in the lithology can be observed through the overlying of hard and soft kicks, with its correspondence with seismic events [21]. Static shift was applied to correct for the mismatch of synthetic events, due to possible seismic shift (Fig. 4).

Fault and horizon picking: For fault interpretation, the vertical discontinuities were traced on the inline seismic section. The interpretation of faults was done by digitizing the fault trends and the process uses fault sticks to pick the trends. The

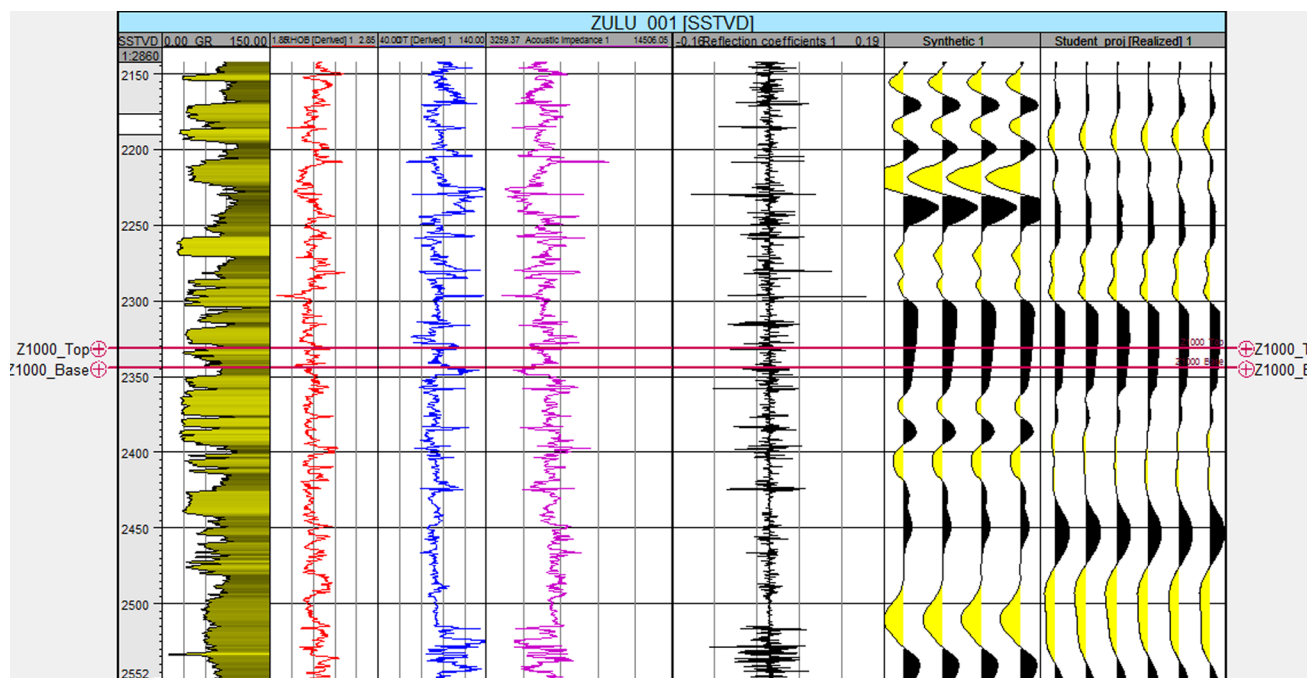


Fig. 4 Well to seismic tie using synthetic seismogram

process uses a fault stick to pick the trends of the faults, thereby giving room for fault skeleton generation. Lithological distortion is as a result of fault pattern, with an even known thickness of the reverse fault angles. The resemblance or difference between faulting systems is always connected with the fault model and depositional environment signatures [5, 41]. Because of its outstanding impact on reservoir unit partitioning, fault modeling is regarded as the most critical structural modeling technique. Fault modeling seeks to digitize and display all fault skeletons, and trends were built using key pillars or pillar systems. To be integrated in the reservoir modeling, the fault columns were installed along all the fault patterns [7, 41]. The horizon interpretation was done on the cross using the intersection of the inline and crossline [41].

Pillar gridding: The need to determine the shape and heterogeneity of the reservoir gave rise to the pillar gridding process. Pillar-gridding model faults are in the window where the modeled faults turn into loads along each fault plane. To determine the shape of the reservoir, there is a need to create an external grid boundary around the fault trends [41]. Grids were added to generate cells that can allow the establishment of a flow model and make it possible to delineate the top, middle, and base of the structural model [41].

Petrophysical evaluation: Petrophysical models and their variations throughout the reservoir were determined. The determined properties are porosity, water saturation, volume of shale and net-to-gross (NTG) ratio. These established properties were populated on the structural model, in order to show their variations. Because hydrocarbon saturation depends only on porosity and fluid saturation, thus a good hydrocarbon reservoir should have a minimum shale volume, water saturation and good porosity value. The shale volume was determined by applying the Larionov tertiary equation. It is given as [18, 45, 56]:

$$V_{sh} = 0.083 \times 2^{(3.7 \times IGR) - 1} \quad (1)$$

After [37]

where: V_{sh} —volume of shale, IGR—Gamma ray index

$$IGR = \frac{(GR_{log} - GR_{sand})}{(GR_{shale} - GR_{sand})} \quad (2)$$

where: GR_{log} —Gamma ray value in API.

GR_{sand} —Gamma ray value for sand bed.

GR_{shale} —Gamma ray value for shale.

Formation porosity along the well was determined using the density log. It was evaluated with the equation:

$$\varphi = \frac{(\rho_{max} - \rho_{log})}{(\rho_{max} - \rho_{min})} \quad (3)$$

where: ρ_{max} = maximum density log value.

ρ_{min} = minimum density log value.

φ = Formation porosity.

For the water saturation estimation, we adopted [54] expression. It is given as:

$$S_w = \frac{0.082}{\varphi} \quad (4)$$

After [54]

where: S_w = water saturation.

Net to gross was estimated along the well using the expression [37]:

$$NTG = \text{If } (GR < 65, 1, 0) \quad (5)$$

GR is the gamma ray reading; this means that for grids less than 65 API, NTG is one (1), otherwise it is zero (0).

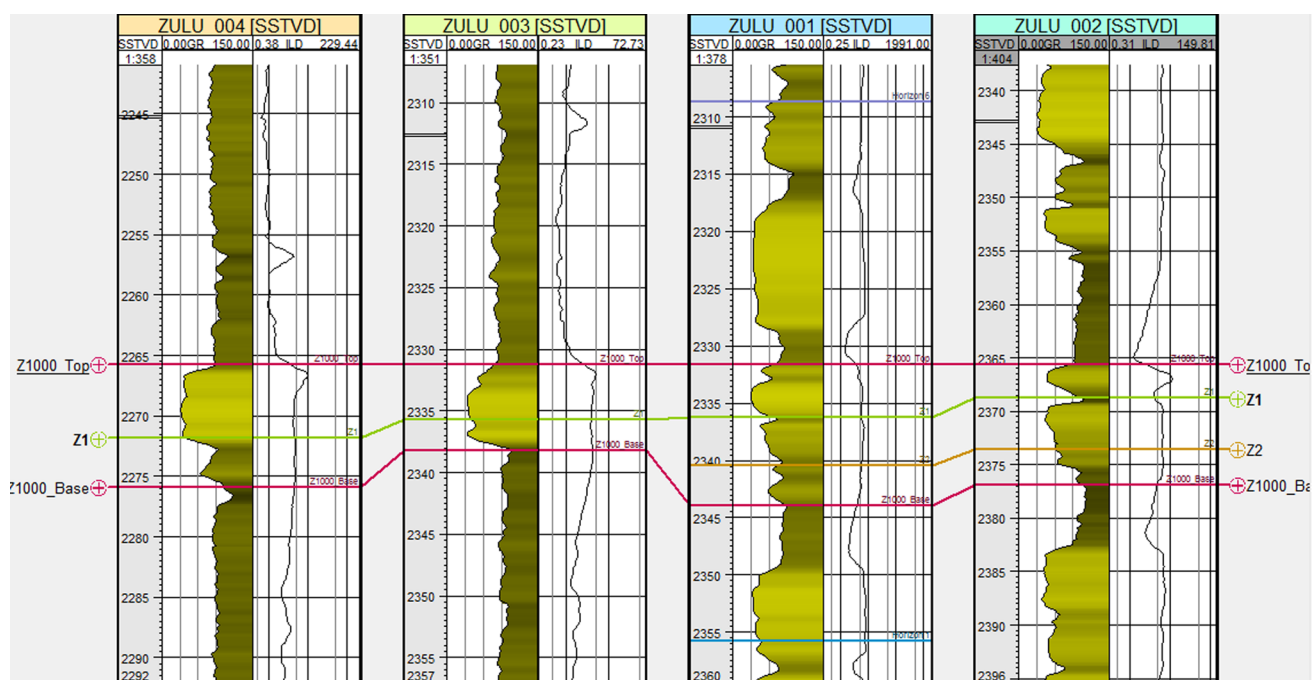


Fig. 5 Well log correlation

4 Result presentation and discussions

To identify the lithological variations, well correlations were done to map out and tie related reservoir beds across the position of wells within the study area (Fig. 5). Z100_top of the reservoir in Zulu 004 at 2265.5 m and was tied to other wells to correspond to Zulu 003 and Zulu001 at 23331 m. The top of Zulu 002 was correlated at 2365 m. At 2276 m, Z1000

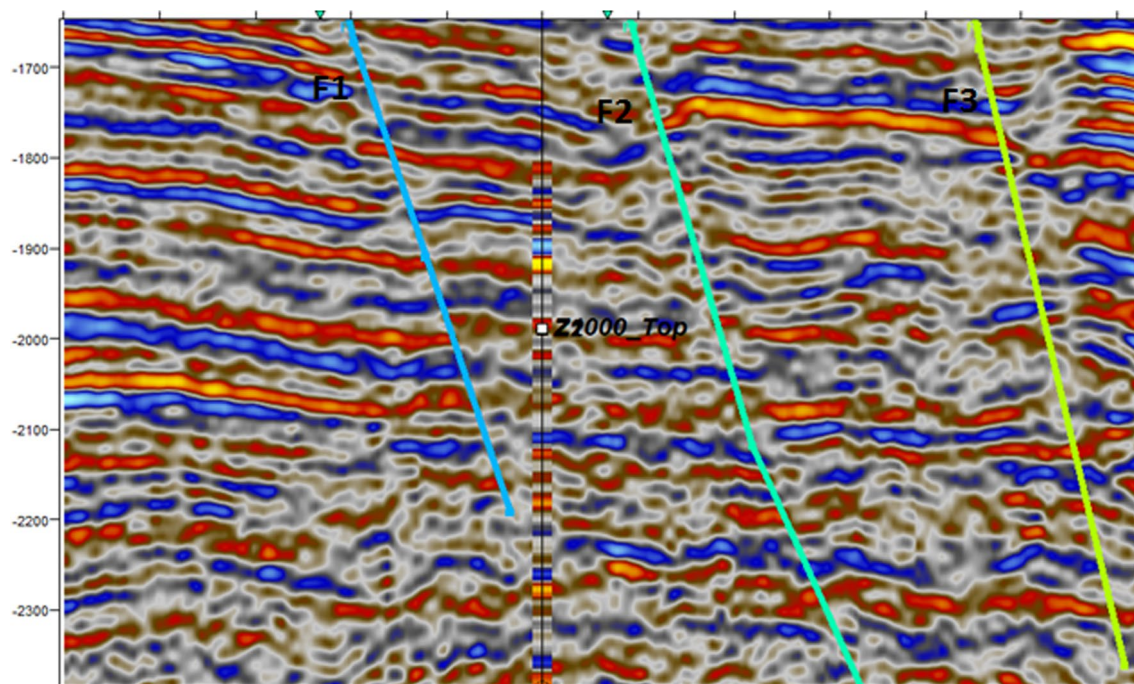


Fig. 6 Fault stick identification

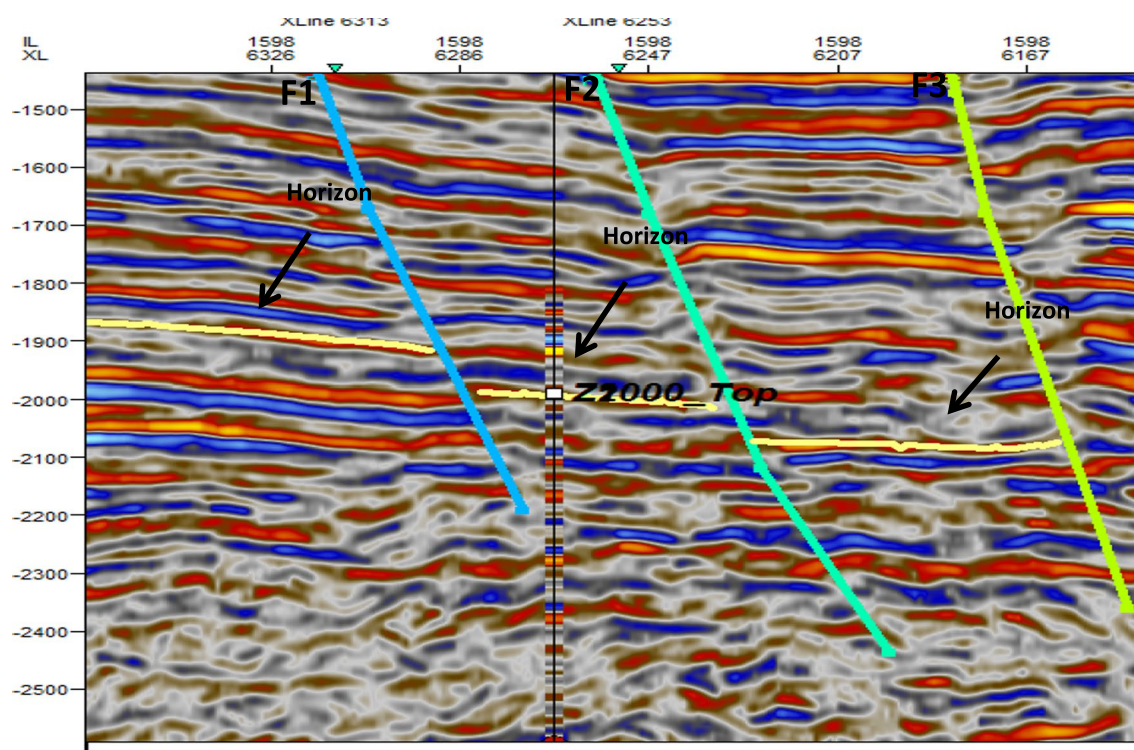
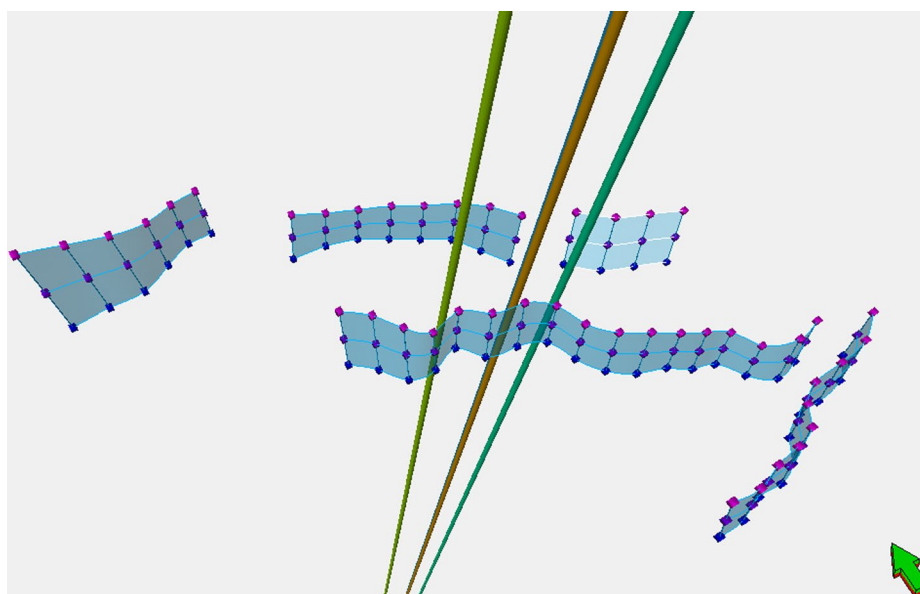


Fig. 7 Horizon interpretation

base of Zulu 004 was determined and correlated across other wells. Seismic gather reflectivity is clearer from the point source of the section ranging from 2100 to 2400 ms. The reflectivity range of the amplitude decreased from 2400 ms to the experimental limit point of the seismic volume. There is a discontinuity of the horizon at the fault boundaries, in the form of vertical discontinuity of the reflectivity (Figs. 6 and 7). For a better analysis to be achieved, the vertical discontinuities must be traced on the inline seismic volume. This inline ran from north to south and gave a better resolution of the structures. The three major faults were analyzed and the horizon was identified at 2000 ms on the seismic gather, after well-to-seismic correlation. The fault modeling tends to digitize and present all faults into skeletons, by constructing the fault sticks on the seismic volume using the pillar gridding method [41] (Fig. 8). This process made

Fig. 8 Pillar gridded model



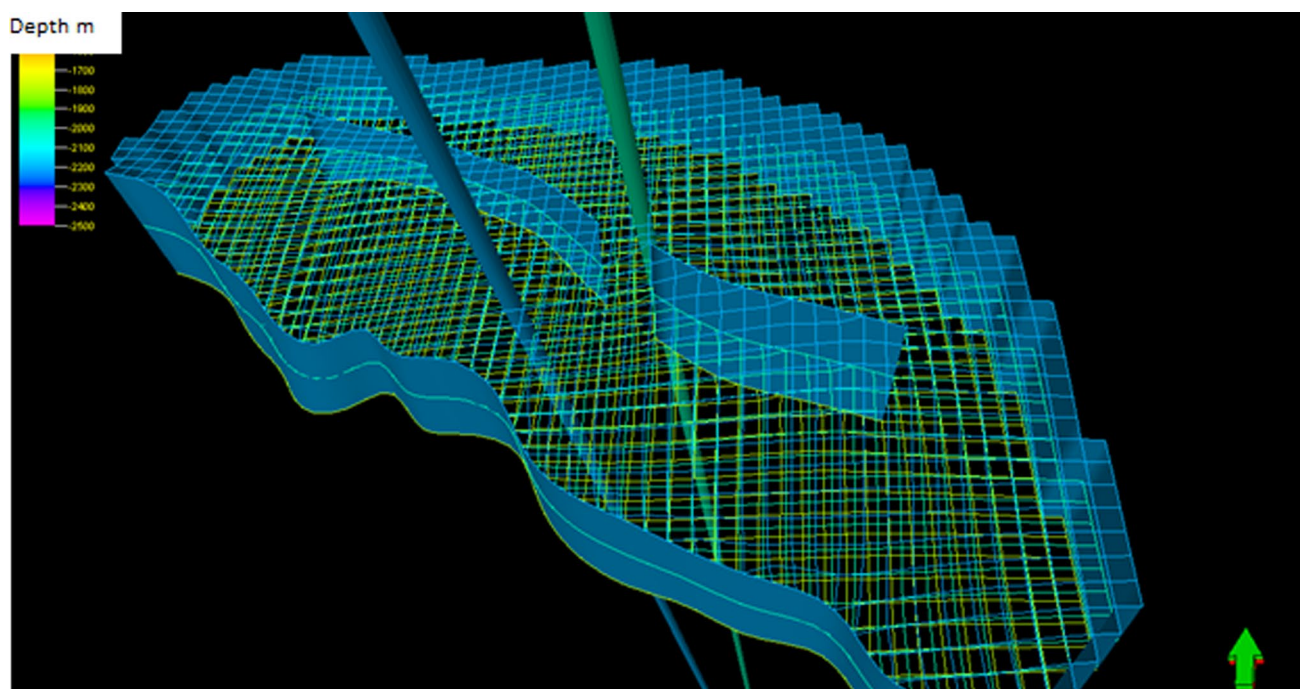


Fig. 9: 3D structural model

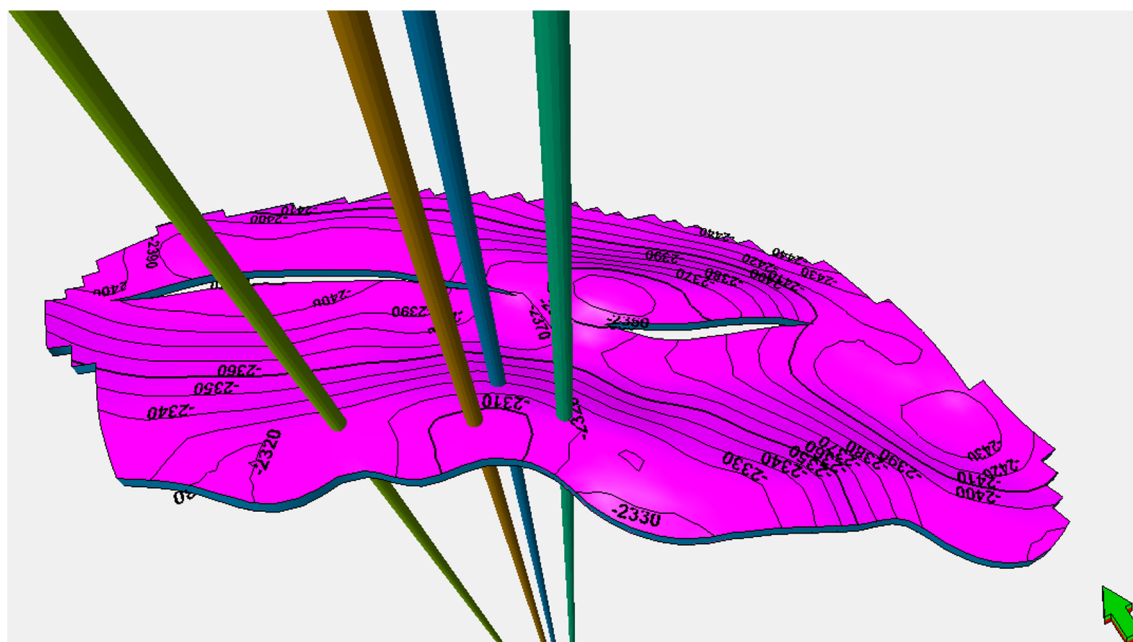


Fig. 10 Enclosed anticlinal structure

it possible to establish the top, middle and bottom of the structural model (Fig. 9). The structural model shows fault enclosed anticlinal structures which are the indication of the structural traps in Niger Delta (Fig. 10).

The contour map that shows the two-way time to a reflector, as picked on the seismic section, has been converted to the depth map using the average velocity information obtained from the sonic log and checkshot data [41, 44]. On the isochron map (Fig. 11) Z1000_top located at 2000 ms is equivalent to 7777 ft (2331.5 m) on the isopach map (Fig. 12), and all reservoirs were identified between 2250 and 2375 m. The well locations are sited within the fault-supported anticlinal closures and this demonstrates the major hydrocarbon traps in the Niger Delta basin [41]. Structural contour

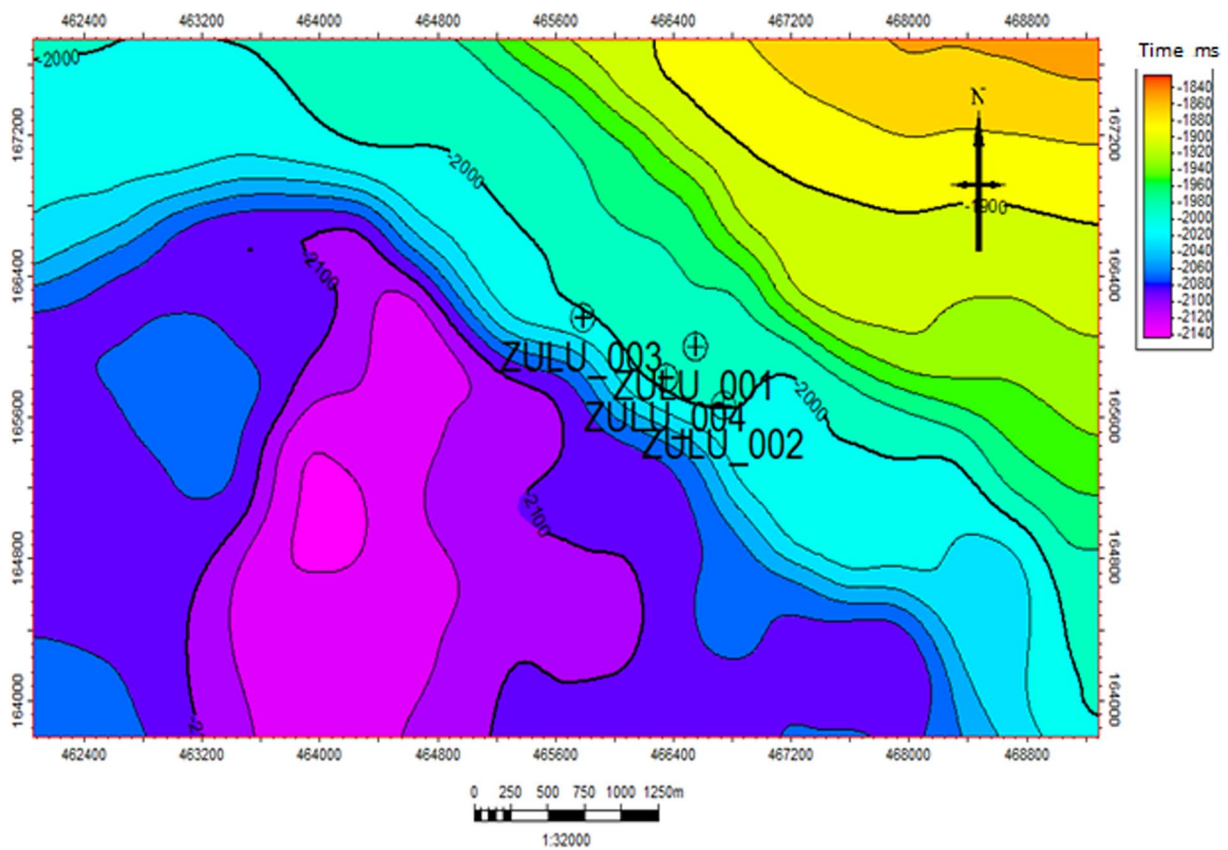


Fig. 11 Isochron map

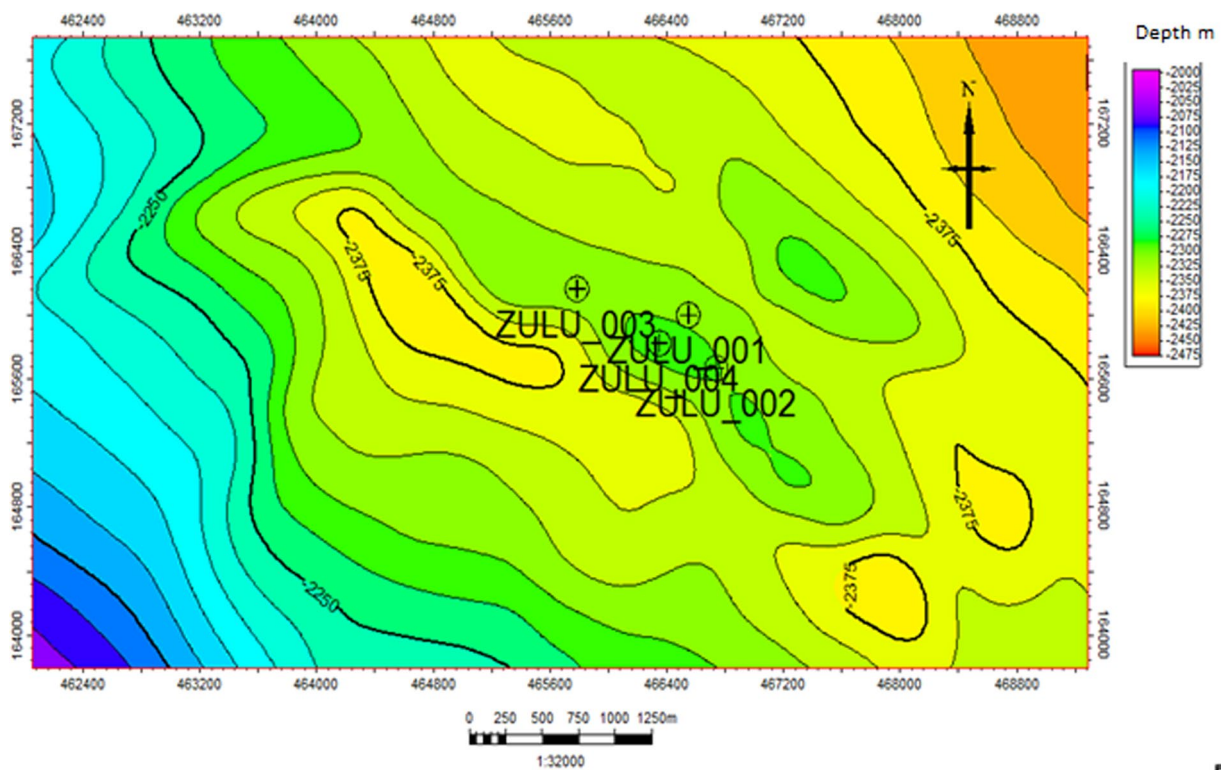


Fig. 12 Isopach map

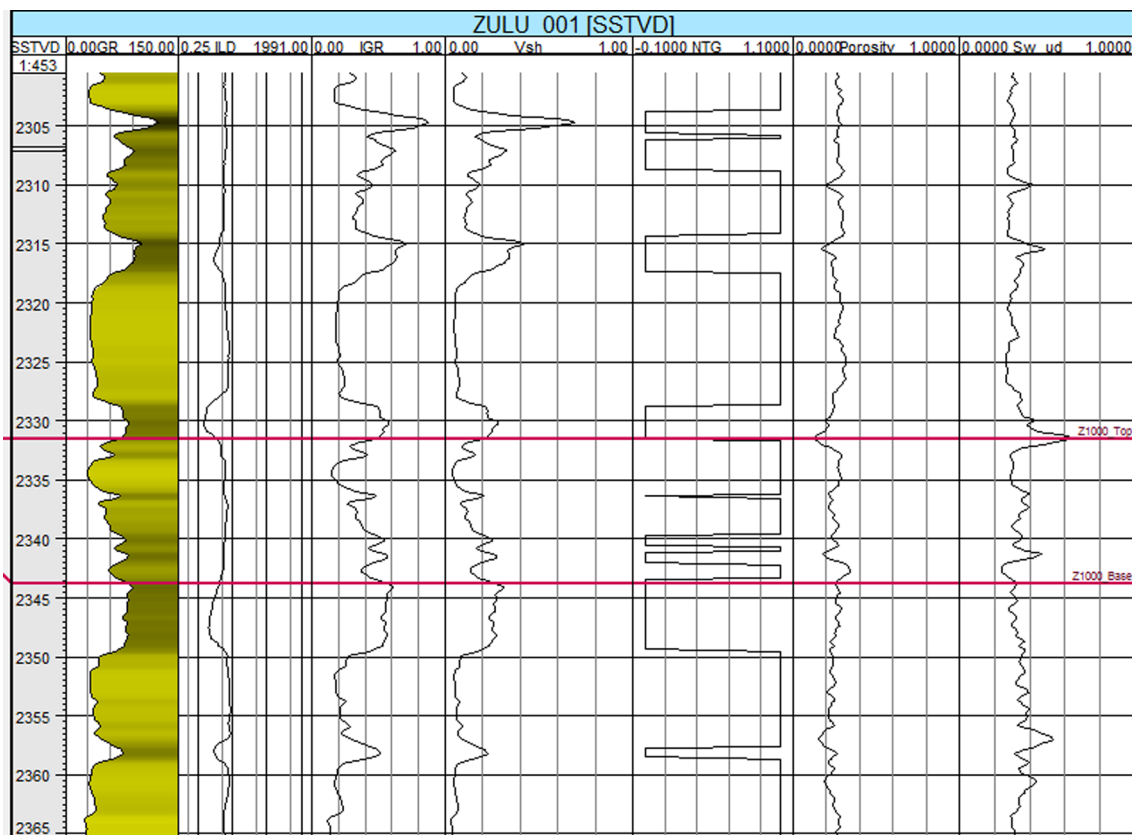


Fig. 13 Petrophysical parameters plot

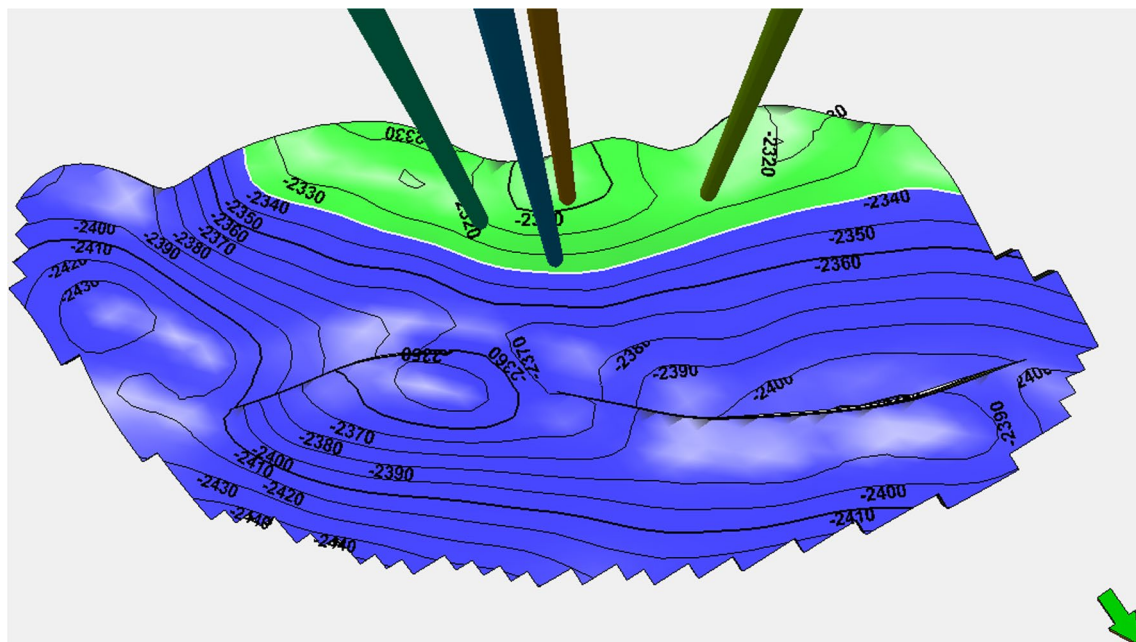


Fig. 14: 3D view of oil–water contact

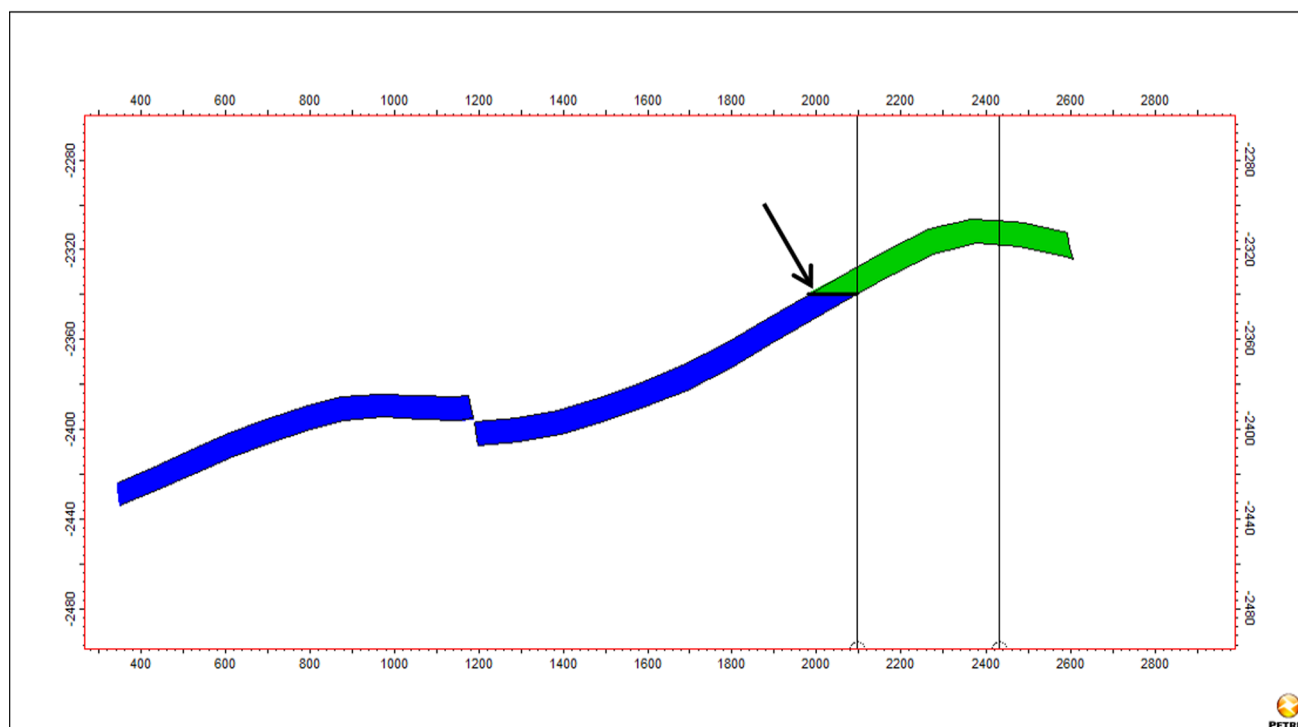


Fig. 15 Cross section view of oil–water contact

map development or creation on the pillar gridded framework model, improved the precise reservoir depth within the Niger Delta basin.

The petrophysical evaluation of the study area, Fig. 13, show that shale formation with high gamma ray reading values, while the reservoir sand units shows low gamma ray values. Zones of sand formation show good porosity, high hydrocarbon saturation and less water saturation. Density and neutron logs were used to discriminate the reservoir in terms of fluid contacts. The delineated oil–water contact was observed at 2340 ms (Figs. 14 and 15). The structural model depicts fault-enclosed anticlinal structural style of the Niger Delta basin [41]. A petrophysical model was used to evaluate the static properties along the wells and then on the structural model [18, 41]. The sensitivity of these properties was improved through upscaling the modeled grid cells. Water saturation is moderate, except in the middle where it tends to be high, hydrocarbon saturation and effective porosity are of good value within the delineated reservoirs. The estimated models proved a better net-to-gross (NTG) ratio, which is one of the qualities of a producing hydrocarbon reservoir [41].

5 Conclusion

This study has contributed to the identification, and delineation of reservoir parameters, thereby reducing the cost of production and placement of well location within the actual reservoir coordinates. The application of the established methodology will give rise to a robust definition of reservoir units within the Niger Delta basin and optimal production management. To establish the existence of the reservoir heterogeneity, a structural modeling technique was implemented. Reservoir geometry and in-situ measurement of the study location was achieved through the interpretation of 3D seismic data and well log records. Synthetic and antithetic faults were identified as the probable structural existence within the study field, also only identified structures with direct linkage with the reservoirs was used for structural modeling. This modeled structural signatures shows fault enclosed anticlinal structures. The structural grid that revealed the reservoir top and base can be used in modeling of the fluid flow dynamics of the reservoir. Due to lithostratigraphic heterogeneity of the delineated reservoir zones and thickness, there exist variations in hydrocarbon production capacity of the delineated reservoirs. This gave rise to hydrocarbon bearing reservoir assessment, in order to mitigate the reservoir the issues associated with dry hole drilling campaign.

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Data availability Data sets generated during the current study are available from the corresponding author on reasonable request. The well log and seismic data are available, but restrictions apply to the availability of these data, which were used under license for the current study, and so are not publicly available.

Code availability Not applicable.

Declarations

Competing interests The authors declare no competing interests.

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