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Integration of 3-D Seismic and Well Log Data for Structural Interpretation and Hydrocarbon Reserve Estimation in the "Becky" Field, Onshore Niger Delta Basin, Nigeria

Ndip Edwin Ayuk*[1], Teghen Nelson Bah[2] and Anatole Eugene Djieto Lordon[1]

1. Department of Geology, Faculty of science, University of Buea, Cameroon

2. Skolkovo Institute of Science and Technology, Moscow, Russia

Abstract

Accurately, estimating hydrocarbon reserves in a field is essential to determine its economic potential. Therefore, it is crucial to conduct structural interpretation of 3-D seismic data to understand subsurface faults and reservoir geometry comprehensively. In this study, structural interpretation of 3-D seismic data and petrophysical characterization of reservoirs in the "Becky" field onshore Niger Delta Basin was done. The zones of hydrocarbon-bearing reservoirs in the field are located at depths of around 10 to 12 km and are found beneath the Benin Formation, with good petrophysical properties. The main structures seen on the 3D seismic sections were growth faults that have deformed the anticlines hosting the hydrocarbons, resulting in a fault-assisted anticline (3-way closure) trapping system at depths of around 9 to 12 km. Appropriate equations were used to calculate the GIIP and STOOIP, and the total volume of oil in the field is 386,255,807 barrels, and the total gas volume is 1,810,308,838 standard cubic feet. The application of qualitative well log analysis and 3D seismic structural interpretation has proven effective in delineating the architectural characteristics of reservoir units as well as estimating the hydrocarbon reserves in the field. These findings can be valuable in further exploration and development activities in the Niger Delta Basin, Nigeria.

Keywords: STOIP, GIIP, Reservoir Geometry, Growth Fault, Petrophysical Characterization.

Introduction

It is crucial to conduct structural interpretation of 3-D seismic data in the onshore Niger Delta Basin's "Becky" field to gain a comprehensive understanding of subsurface faults and reservoir geometry. The interpretation of 3-D seismic data has proven to be a valuable tool in field appraisal, development, production, and hydrocarbon exploration. Due to the rapid sedimentation load and gravitational instability of the Agbada sediment pile and continental Benin sands accumulating on the mobile under compacted Akata prodelta shales, the Niger Delta structural setting predominantly comprises growth faults with associated rollover anticlines [1]. Accurately, estimating the available hydrocarbons in a field is essential in determining whether it will yield an economic profit if exploited [2]. However, estimating reserves remains a challenge in exploration due to the uncertainty involved in the process. As available data (geologic and engineering) increases, the degree of uncertainty decreases [3,-5]. Reserve estimation involves interpreting geologic and/or quantitatively calculating the petrophysical data, PVT (pressure, volume, and temperature), and production histories to estimate the reserve. Researchers such as [5-9] have utilized volumetric methods, material balance, decline curve analysis, and reservoir simulation in estimating the hydrocarbon reserves in a particular field.. The most accurate reserve estimation can only be determined at the end of field production (reservoir depletion). The selection of a particular method for reserve estimation depends on the availability of data and the stage of exploration or production [5].Some research scientists, such as [10-12] have estimated reserves in some fields in the Niger Delta Basin using both volumetric and material balance methods, while 13utilized only the volumetric method for reserve estimation in an exploration field in the shallow offshore depobelt of the Western Niger Delta, where they combined seismic and well log data. In this study, we aim to conduct structural interpretation of 3-D seismic data and petrophysical characterization

**Corresponding author:* Ndip Edwin Ayuk, Department of Geology, Faculty of science, University of Buea, Cameroon
E-mail addresses: ndip.ayuk@ubuea.cm
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of reservoirs in the “Becky” field onshore Niger Delta Basin. This will enable us to estimate the amount of hydrocarbons present and map the subsurface structures of this field.

Geological Setting.

The formation of the Nigerian peri-cratonic basin can be attributed to the rift faulting of the pre-Cambrian, as shown in Fig. 1. The outlines of the Niger Delta are shaped by deep-seated faults along the “Benin” and “Calabar” hinge lines. The basin has experienced at least three major sedimentary cycles since the early Cretaceous, according to [14]. The delta began to grow during the second cycle, between the Campanian and Paleocene transgressions. The main part of the delta’s growth, however, occurred during the third sedimentary cycle, which began in the Paleocene.

The deltaic sequence comprises mainly clayey marine sediments, overlain by paralic sediments - mixed continental, brackish water, and marine deposits - and covered by continental sands and gravels, as depicted in Fig. 1.

A time stratigraphic unit of such deltaic sediments typically exhibits an S-shaped cross-section, according to [15].

The stratigraphy of the Niger Delta is primarily influenced by the various depositional processes that occur in the area. The Delta exhibits a concentric arrangement of terrestrial and transitional depositional environments, as described by [16]. These environments can be broadly classified into three distinct facies belts: (a) the Continental Delta top facies, (b) the paralic Delta front facies, and (c) the Pro-Delta facies, according to [17]. The depositional environments resulting from fluvial, coastal, and marine processes, including turbidity currents, in conjunction with the rise and fall of sea-level, have all contributed to the stratigraphic fill of the Niger Delta. The Niger Delta basin is comprised of a series of depocenters or belts, with each depo-belt’s location determined by major structure building growth faults, as noted by [18]. The entire sedimentary wedge was deposited sequentially in five major depo-belts, each 30-60 km wide, with the oldest belt lying further inland and the youngest situated offshore, according to [19]. Due to the continuous deltaic progradation that began in the Early Tertiary, the stratigraphic unit in the Niger Delta is highly diachronous and challenging to subdivide and correlate using marine biostratigraphic criteria. Sequence stratigraphy is a valuable tool in the Niger Delta because the fundamental building block of the Niger Delta succession is a well-defined cyclic offlapping parasequence set. Each parasequence set comprises a marine clay that represents the marine flooding surface, which transitions upward into proximal fluvio-marine interlaminated silt, sand, and clay. This is usually followed by various types of lower and upper shoreface sand and coastal plain continental deposits, as noted by [16]. The subsurface of the Niger Delta complex is tectonically made of listric faults and collapsed clastic wedge due to deep-seated marine shale that was overpressured and ductile, giving rise to what is known as a normal fault [20]. These faults formed during delta syndeposition and progradation, resulting in sediment dispersion. The density pattern of the fault system is determined by the structural complexity of the local area. Folds and flanks can be seen along individual faults, and anticlines were developed due to listric-fault geometry and deltaic sediment loading [21]

With regards to its stratigraphy, the Niger Delta basin has been divided into three main subdivisions; Benin, Agbada, and Akata, which represent prograding depositional facies primarily distinguished by the sand-shale ratio. These subdivisions are further subdivided into depobelts as progradation proceeds into deeper waters, according to [22-25] .The Akata Formation is primarily composed of marine Prodelta mega-facies within the Niger Delta basin, as indicated in Fig. 2.

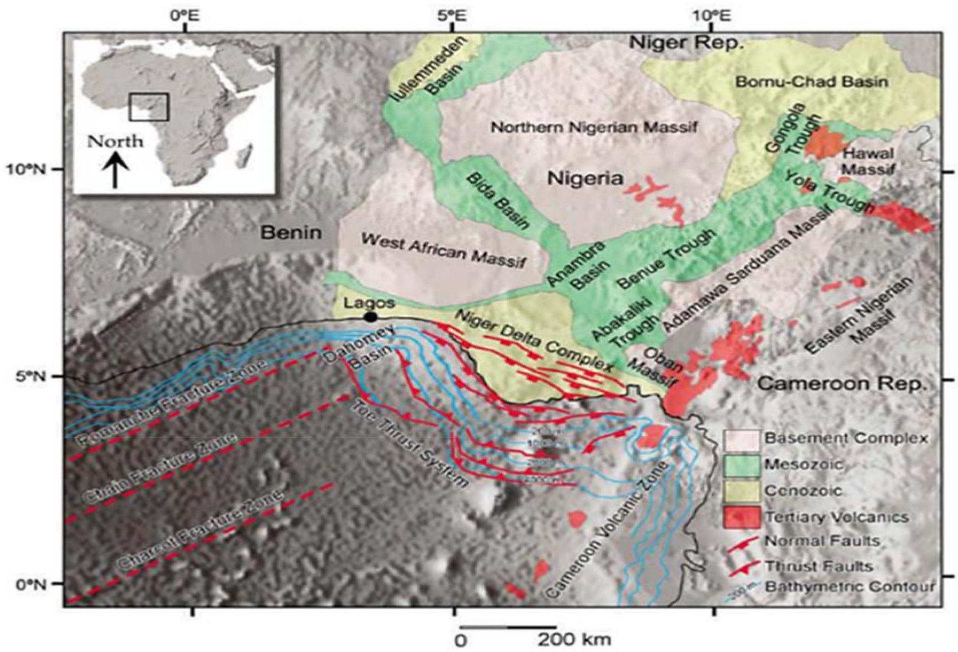

Fig. 1 Location map of Niger Delta region showing the main sedimentary basins and tectonic features (adapted from Onuoha, 1999).

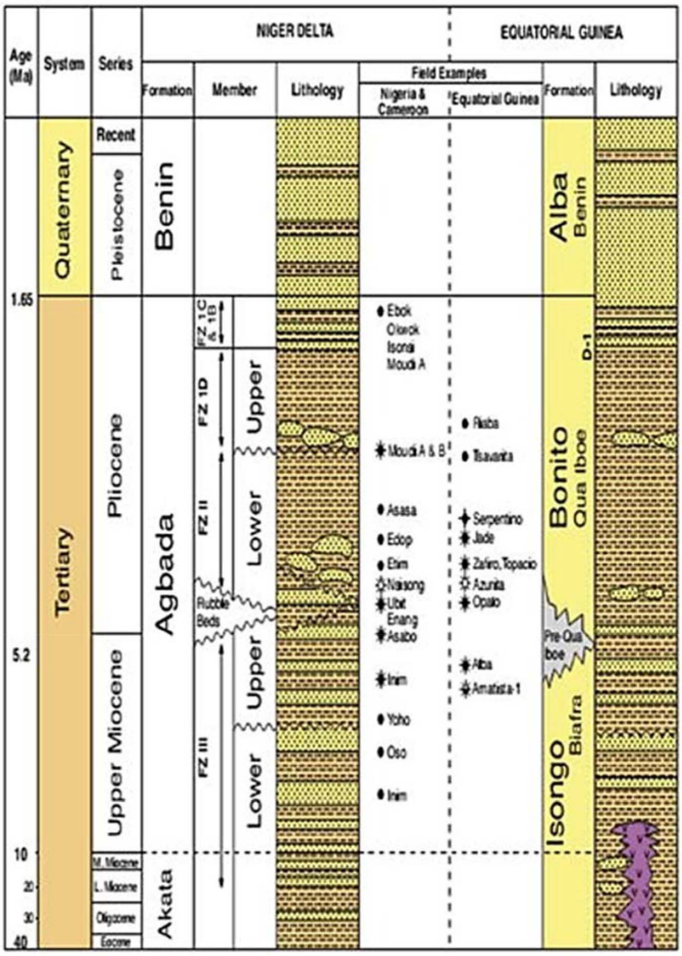

Fig. 2 Stratigraphic column showing the three formations of the Niger Delta (modified from Doust and Omatsola, 1990).

It is predominantly comprised of marine shale with occasional turbidite sandstone and siltstone, according to [23] .The Akata Formation serves as the source rock complex, with an abundance of planktonic foraminifera assemblage suggesting deposition in a shallow marine environment, according to [26]. The Akata Formation's age ranges from Palaeocene to Holocene, according to [24].The Agbada Formation is a paralic succession of alternating sandstones and shales, with its sandstone reservoirs accounting for the oil and gas production in the Niger Delta, as noted by [27]. The strata are generally interpreted to have formed in fluvial-deltaic environments. The Formation's age ranges from Eocene to Pleistocene, as reported by [23].

The Benin Formation is the upper section of the Niger Delta clastic wedge, extending from the Benin-Onitsha area in the north to beyond the present coastline, according to 23. Shallow portions of the Benin Formation consist entirely of non-marine sand deposited in an alluvial or upper coastal plain environment during delta progradation, as noted by [28]. Although the lack of preserved fauna inhibits accurate age dating, the Formation's age is estimated to range from Oligocene to Recent, according to [23]..

Materials and Methods

This study utilized wireline log data in LAS format (Which included natural gamma-ray data, Deep Laterolog, Formation density, and Neutron porosity), check shots, and 3D seismic data in SEG-Y format, obtained from Field "Becky" in the onshore portion of the Niger Delta Basin. The wireline logs of three wells (T1, T2, and T3) and the 3D seismic data were analyzed and interpreted using Senergy Interactive Petrophysics and PETREL 2018, respectively. The workflow used in this study is presented in Fig. 3. Prior to performing petrophysical and structural interpretation data quality control was done. It involves checking the quality of the wireline logs and 3D seismic data for any inconsistencies or errors were and missing data were interpolated.

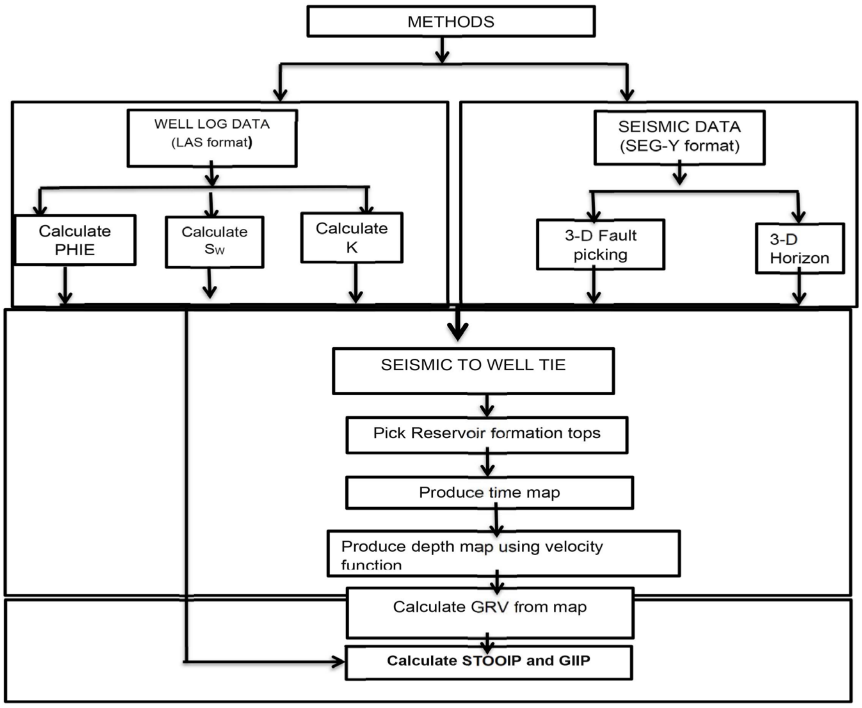

Fig. 3 Summary of the workflow plan used in this study.

Petrophysical Analysis

The wireline log data were analyzed using Senergy Interactive Petrophysics software to obtain petrophysical parameters such as porosity, water saturation, and permeability. In this study, several petrophysical parameters were calculated using different equations. The shale volume (Vsh) was calculated using the [29] Equation 2 with values obtained from the gamma ray index Equation 1 [30].The porosity log utilized was the bulk density log, and density porosity was estimated using Equation 3 for the intervals of interest. Average porosity was calculated using Equations 4 and 5 for liquid and gas saturations, respectively. To determine the water saturation, the Indonesian model [31] was employed, as [32] used in Equation 6. This model takes into account the contribution of shale volume to the formation resistivity, and as opposed to the regular Archies equation which gives an overestimation of water saturation since it does not consider the contribution of shale conductivity. Finally, the permeability values were estimated using [33] Equation 7 for medium-gravity oils and Equation 8 for dry gas which are reflective of fluids present in the reservoirs of this basin. These equations involve porosity (Ø), irreducible water saturation (Swirr), and constants (such as c). Overall, the following equations were used to calculate essential petrophysical parameters to understand the hydrocarbon potential of the study area.

$$I_{GR} = \frac{(GR_{\log} - GR_{\log})}{(GR_{\max} - GR_{\min})} \tag{1}$$

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

$$\phi_D = \frac{\rho ma - \rho b}{\rho ma - \rho fl} \tag{3}$$

$$\phi = \sqrt{\phi_N + \phi_D} \quad \text{-For liquid saturation} \tag{4}$$

$$\phi = \sqrt{\frac{\phi_N^2 + \phi_D^2}{2}} \quad \text{-For gas saturation} \tag{5}$$

$$S_w = \left\{\left[\left(\frac{V_{sh}^{\frac{2-V_{sh}}{2}}}{R_{sh}}\right)^{\frac{1}{2}} + \left(\frac{\phi_e^m}{R_w}\right)^{\frac{1}{2}}\right]^2 R_t\right\}^{-\frac{1}{2}} \tag{6}$$

$$K = (250 * \frac{\phi^3}{S_{wir}})^2, \quad \text{(Medium- Gravity oils)} \tag{7}$$

$$K = (79 * \frac{\phi^3}{S_{wir}})^2, \quad \text{(dry gas)} \tag{8}$$

where;

I_{GR} = gamma ray index

$GR_{\log}$ = gamma ray log reading of formation

$GR_{\min}$ = gamma ray sand (sand zone)

$GR_{\max}$ = gamma ray shale (100% shale zone)

$Ø_N$ = neutron porosity obtained from the neutron log

$Ø_D$ = density porosity, determined from Wyllie's equation

V_{sh} = lowest of the various shale indicators

R_t = deep resistivity (corrected for invasion)

R_{sh} = deep resistivity reading in adjacent shale

Φ_e = effective porosity

ϕ = porosity,

S_{wirr} = irreducible water saturation = $c\phi$, where, c = constant (for sandstone, c = 0.02 to 1.0)

Seismic to Well Tie and Subsurface Mapping

Seismic-to-well tie is a critical step in connecting well log information in depth to seismic events in time to achieve a reliable and accurate interpretation, as noted by [34]. This process allows for the correlation of formation tops and seismic reflectors, which is essential for understanding the subsurface geology and hydrocarbon potential. The seismic to well calibration was achieved in this study using the following 8 step approaches as modified from [35]:

1)The seismic volume was, first of all, imported.

2) Secondly, wavelets were extracted.

3) Followed by importing the wells, each of which has a check shot data.

4) 3D horizons, well markers, and time-depth curves were also imported.

5) The log database was edited by filling the missing sonic sections in the log database and, if available, building a density log from the sonic (using the constant value or Gardner's equation).

6) The density and sonic logs were merged into impedance and reflectivity, depth-time converted (including an upscaling), and convolved with the wavelet-based on the available data. The end result is a simulated seismic trace for the well. On the nearest trace, this trace will be compared to a composite seismic trace collected in the volume along the well path. Both synthetic and composite seismic traces are cross-correlated, and the output value indicates the quality of alignment and matching.

7) The alignment was then performed by shifting the synthetic trace up or down, selecting various sites in both seismic traces, and specifying and applying a shift function that varies with transit time. The applied changes must be confirmed before being turned into a new time-depth function that replaces the prior one. There are no updates to the well logs.

8) A deterministic wavelet may be computed at each tying step using the time-converted reflectivity log and the composite seismic trace. This deterministic wavelet should vary each well and is known to link well data to seismic data more accurately.

Time surface maps were generated from the derived horizon grids with the aid of the make surface tool provided by Petrel interpretation software. These time surface maps were then used to produce depth maps using Petrel interpretation software. Overall, this workflow allowed for a reliable and accurate correlation between the well-log and seismic data, providing a better understanding of the study area's subsurface geology and hydrocarbon potential.

Reserves Estimation

This study used the volumetric method to estimate the hydrocarbon reserves in the field. Equations 9 and 10 were employed to calculate the stock tank oil originally in place (STOOIP) and gas initially in place (GIIP), respectively. Equation 9 is given as:

$$STOOIP = \frac{7758 \times GVR \times PHIE\,(1 - S_W)}{B_{oi}} \tag{9}$$

where:

• GRV is the gross rock volume of the reservoir

• PHIE is the effective porosity of the reservoir

• S_w is the water saturation of the zone of interest

• B_{oi} is the oil formation volume factor (1.2 for Niger Delta)

Equation 10 is given as:

$$GIIP = \frac{43560 \times GVR \times PHIE\,(1 - S_W)}{B_{gi}} \tag{10}$$

where:

• GRV is the gross rock volume of the reservoir

• PHIE is the effective porosity of the reservoir

• S_w is the water saturation of the zone of interest

• B_{gi} is the gas formation volume factor (0.75 for Niger Delta)

Overall, these equations provide a means to estimate the hydrocarbon reserves in the field based on the gross rock volume, effective porosity, water saturation, and formation volume factors for oil and gas in the Niger Delta Basin.

Results and Discussion

Results

Well Correlation

The orientation of the well correlation across the four wells in the field was from the northwest to the east. Additionally, the lithostratigraphic correlation of the sand and shales encountered in the field is shown in Fig. 4. This correlation illustrates the different lithological units encountered in the wells and how they relate to each other in terms of depth and lithology. By correlating the lithological units across the wells in the field, it is possible to understand better the distribution and geometry of the reservoirs and their hydrocarbon potential.

Petrophysical Evaluation

Three reservoir zones (R1, R2, and R3) were delineated from the well data. These reservoir zones have good petrophysical parameters, which are significant in estimating the hydrocarbon reserves of the study wells. Reservoir zone R1 has a net/gross ratio of 0.052 with an average porosity of 19%, an average water saturation of 30.4%, and an average shale volume of 31.8%. Reservoir zone R2 has a net/gross ratio of 0.322 with an average porosity of 22.5%, an average water saturation of 29.4% (Using Equation 6), and an average shale volume of 4.2% (Using Equation 2). This reservoir zone has a layer of gas at the very top, underlined by a layer of oil, and a layer of water at the bottom. Reservoir zone R3 has the highest net thickness with a net/gross ratio of 0.397, an average porosity of 18.0%, an average water saturation of 21.8%, and an average shale volume of 17.4%. The lithology and fluid saturation analysis were conducted using gamma ray and resistivity logs, indicating three hydrocarbon-bearing reservoirs (as shown in Fig. 5). Cut-off values of 0.1 for porosity, 0.5 for water saturation, and 0.5 for shale volume were used to distinguish the gross reservoir zone from the net reservoir thickness. The results of this cut-off application are represented in Fig.s 6a, b, and c, and the resulting net reservoir thickness for each reservoir is presented in Table 1. Reservoir R3 is seen to have the highest net-to-gross ratio, while R1 has the least. The net reservoir thickness is an essential parameter for assessing the potential hydrocarbon volume in the reservoir. It represents the thickness of the reservoir rock that contains hydrocarbons and is therefore available for production. The net-to-gross ratio is an indicator of the quality of the reservoir, with higher values indicating a greater proportion of the reservoir rock that is available for production. The information provided in Table 1 can be used to estimate each reservoir's hydrocarbon volumes and plan for optimal production strategies.

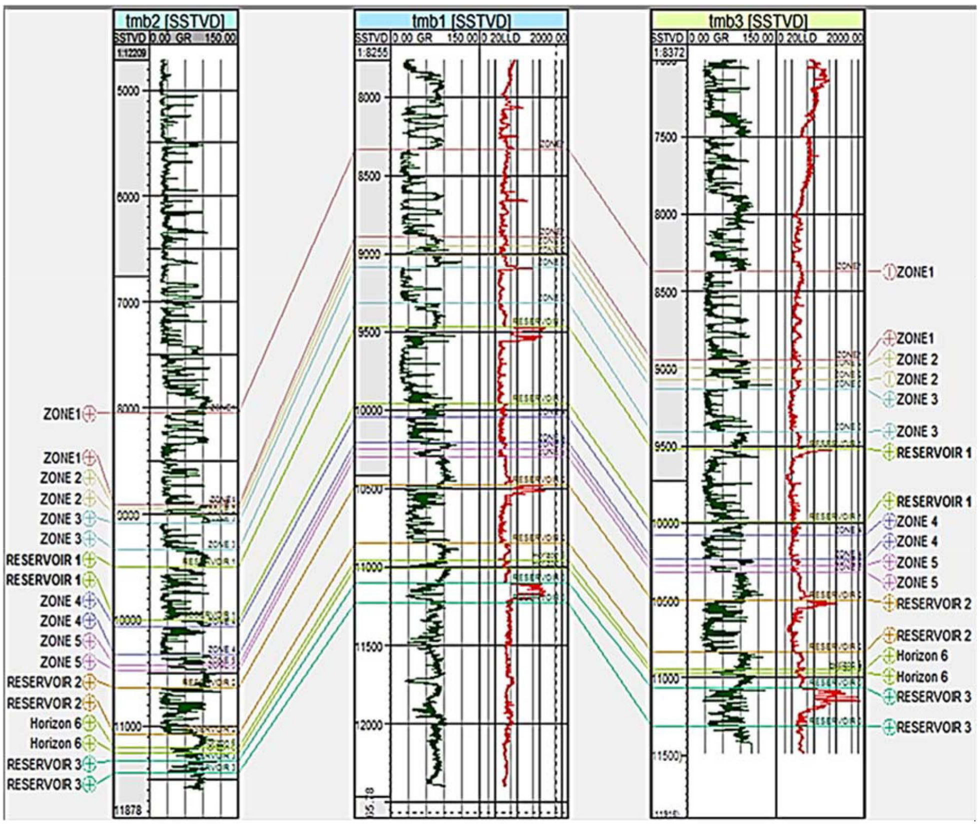

Fig. 4 Well correlation of wells T1, T2 and T3.

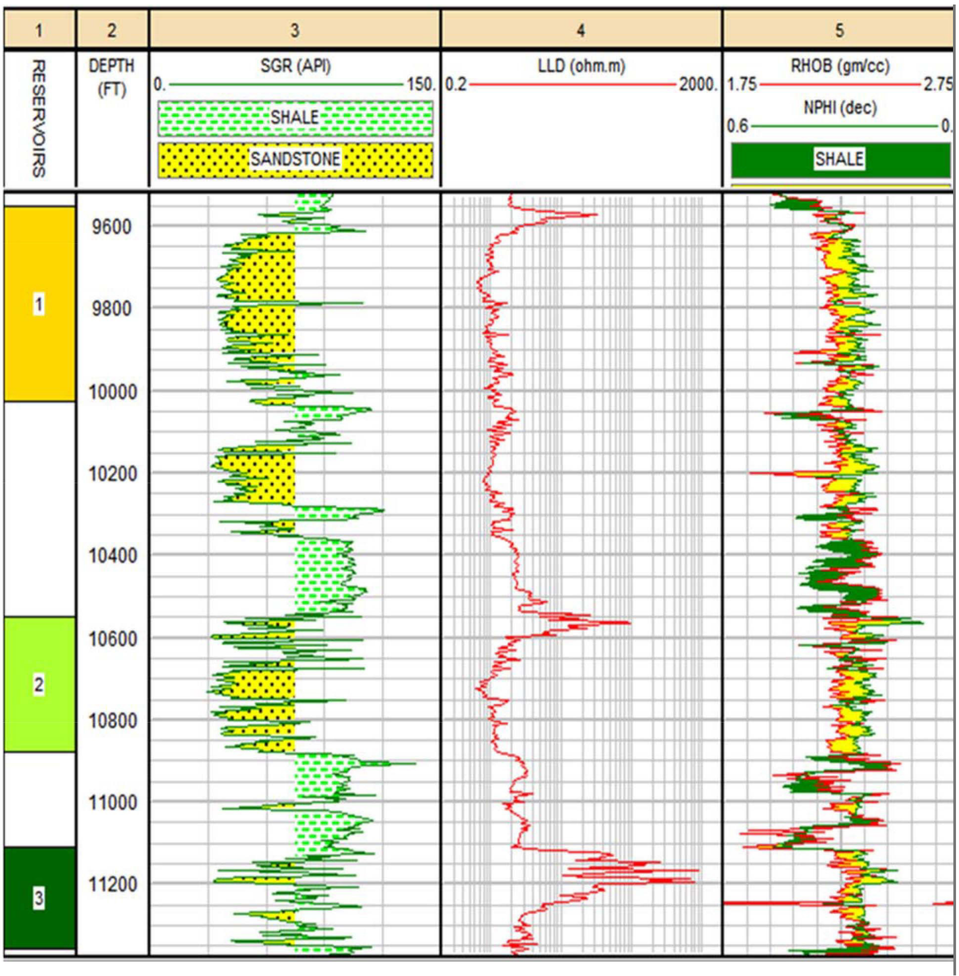

Fig. 5 Lithological interpretations of well T-3 using Gamma ray curve, and RHOB/NPHI curve indicating various reservoirs zones.

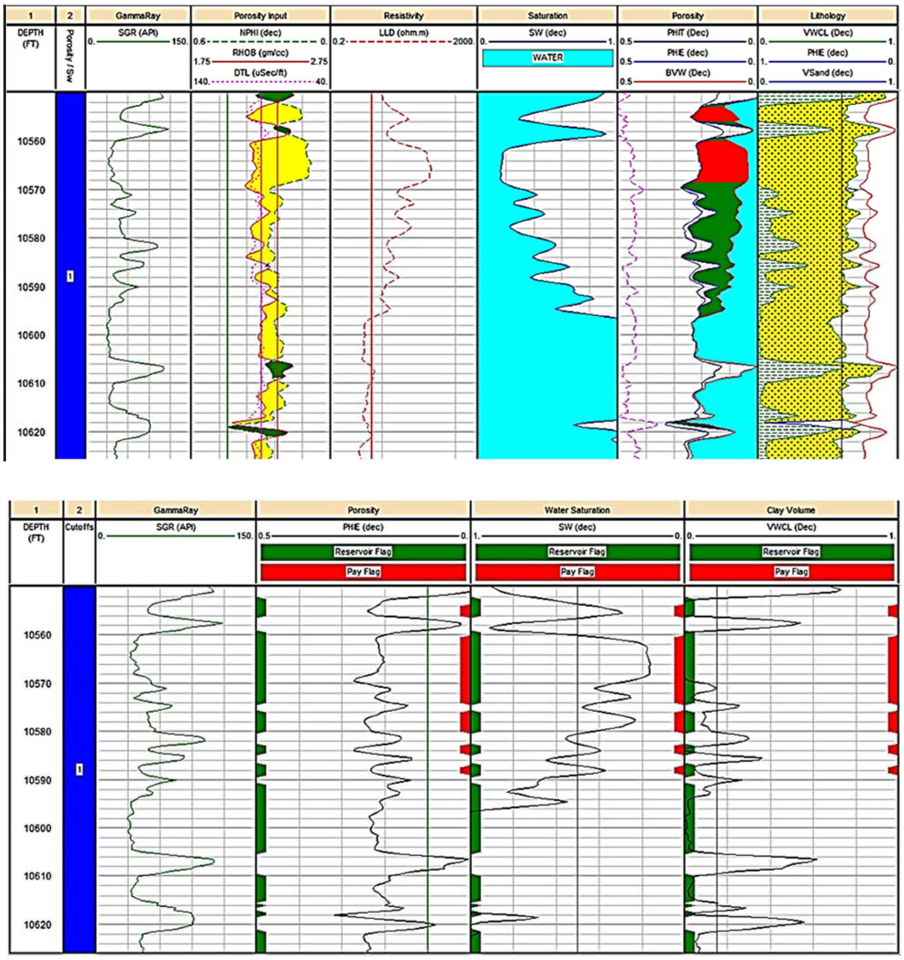

Fig.6a) Petrophysical results for reservoir zone 1 a) Graphical illustration of petrophysical results and b) illustration of gross thickness (green) and net pay (red).

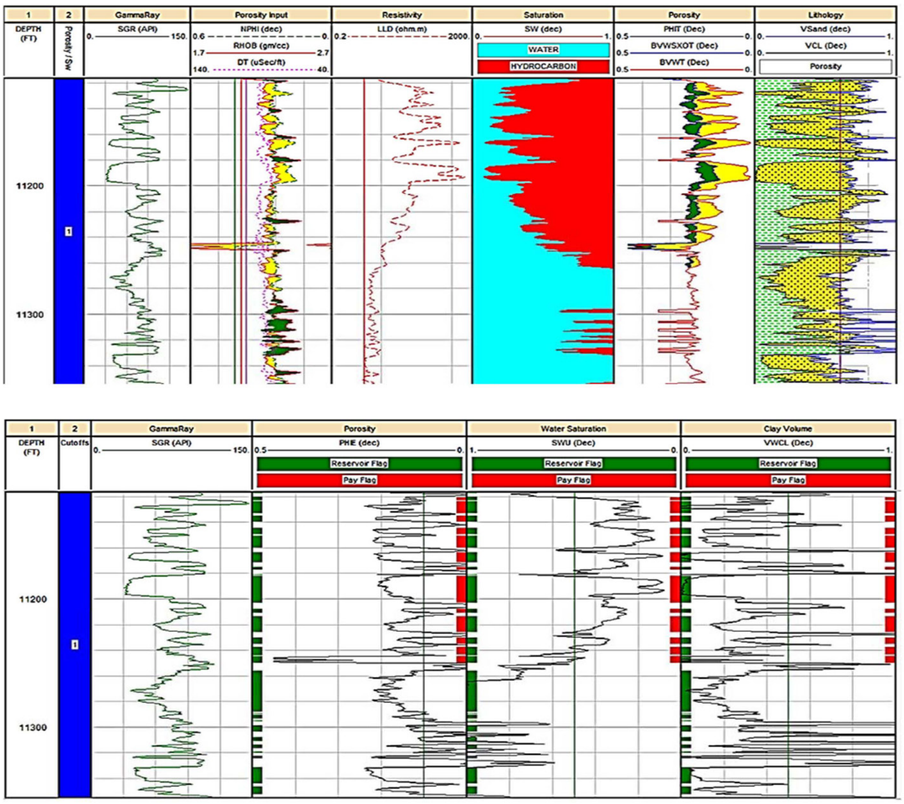

Fig.6b: Petrophysical results for reservoir zone R2 a) Graphical illustration of petrophysical results and b) illustration of gross thickness (green) and net pay (red).

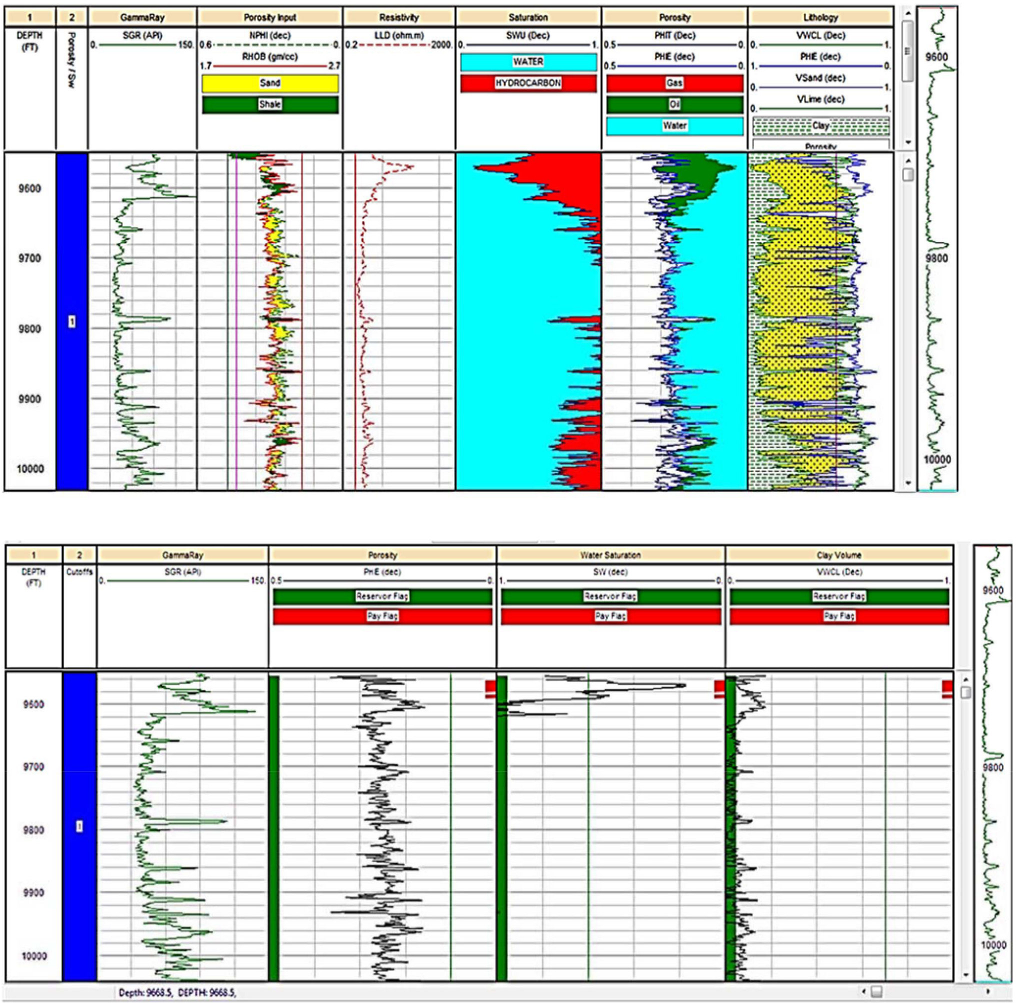

Fig. 6c: Petrophysical results for reservoir zone R3 a) Graphical illustration of petrophysical results and b) illustration of gross thickness (green) and net pay (red).

Table 1 Petrophysical evaluation results.

Reservoir zones	Top	Bottom	Gross (ft)	Net (ft)	Net/Gross ratio	Av Phi	Av Sw	Av Vcl
R1	9555	10042	487	25.5	0.052	0.190	0.304	0.313
R2	10550	10626	76	24	0.322	0.225	0.294	0.042
R3	1111.7	11355	238	94	0.397	0.180	0.218	0.174

Seismic Structural Interpretations

The geological structures of interest to hydrocarbon reserve estimation in this field include an antithetic and three synthetic faults, shown in Fig.s 7 and 8. Three horizons corresponding to reservoir zones R1, R2, and R3 were identified and mapped through seismic-to-well tie (Fig. 9). Time structure maps of these reservoir zones were generated and are shown in Figs. 10a, b, and c. The depth structure maps obtained from converting the time maps are shown in Figs. 11a, b, and c.

The peripheries of the reservoirs were delineated and used to calculate the area and hydrocarbon volume, shown in Fig.s 12a, b, and c. The reservoir zone R1 contour depth values range from about -11200 ft to about -8500 ft. The red-circled area in Fig. 12a has been identified as the oil-bearing zone of the reservoir. The resistivity curve characteristics indicate a hydrocarbon zone around this depth, and the red color curve has been identified as the oil-water contact (OWC) at a depth of -9620 ft.

The reservoir zone R2 contour depth values range from about -9400 to -12000 ft. The white-circled area in Fig. 12b has been identified as the oil-bearing zone of the reservoir, while the red-circled area accommodates the oil. The resistivity curve characteristics indicate a hydrocarbon zone around this depth, and the red color has been identified as the gas-oil contact (GOC) at a depth of -10570 ft., with the oil-water contact seen at a depth of -10596 ft. The reservoir zone R3 contour depth values range from about -10000 to over -13000 ft. The yellow circled area in Fig. 12c has been identified as the oil-bearing zone of the reservoir, which is the periphery of the oil-water contact that exists at a depth of -11250 ft. The resistivity curve characteristics indicate a hydrocarbon zone around this depth.

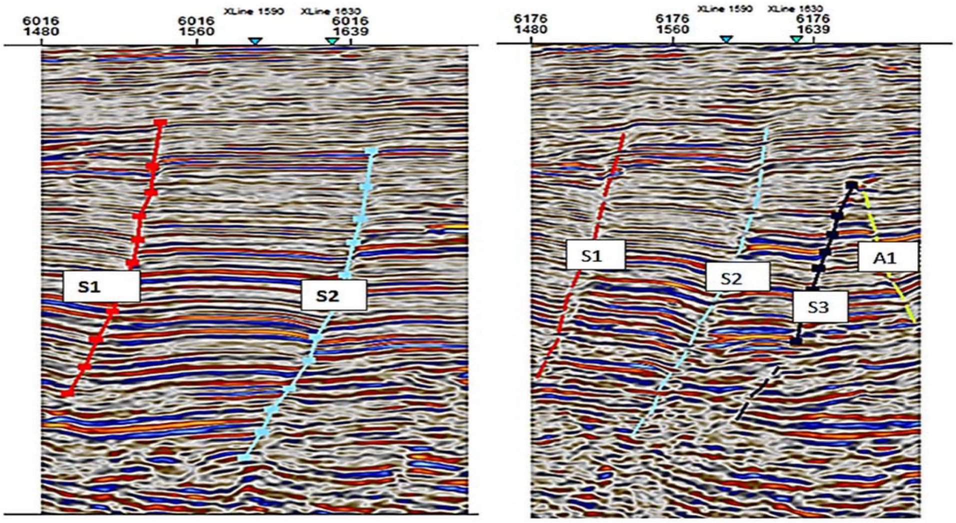

Fig.7 Seismic cross section showing the antithetic (A1) and synthetic (S1, S2 and S3) faults running through the Becky field.

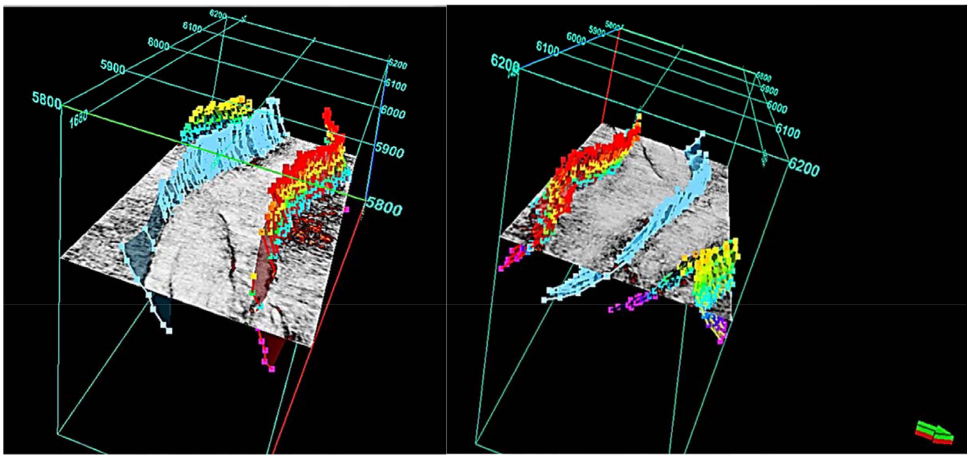

Fig. 8 3-Dimensional representation of the faults running through the Becky field

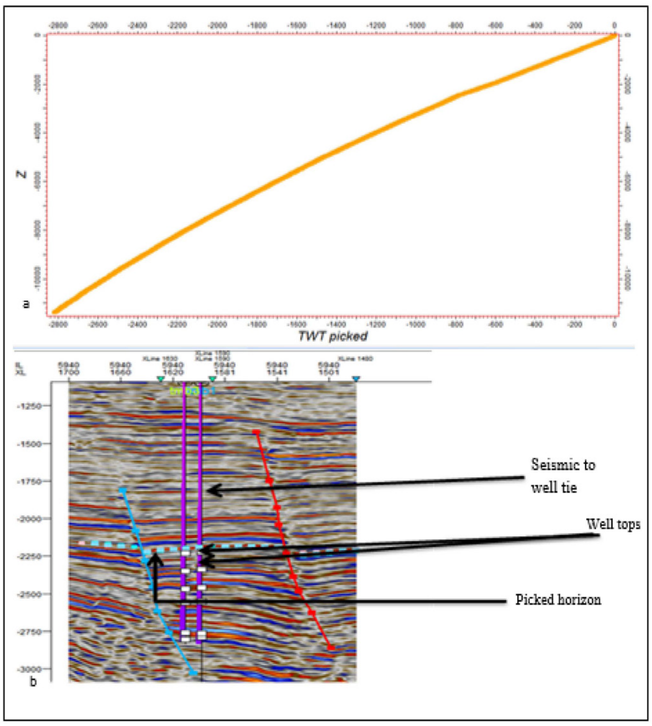

Fig. 9 The lookup function used for depth conversion of the time surfaces (a) and (b) seismic to well tie.

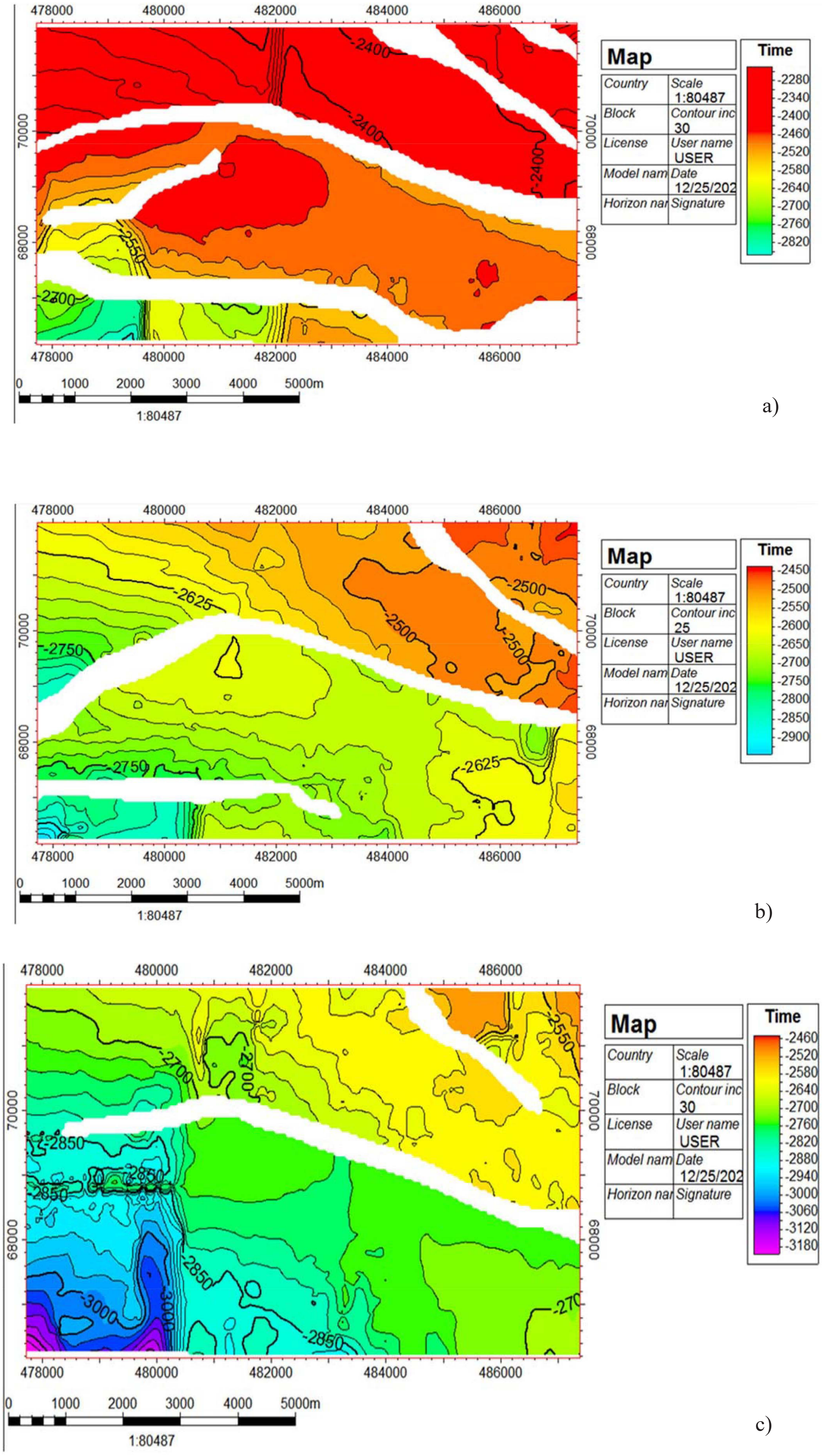

Fig. 10 a, b, & c: Time surface map for reservoir R1, R2 and R3 respectively showing all major faults.

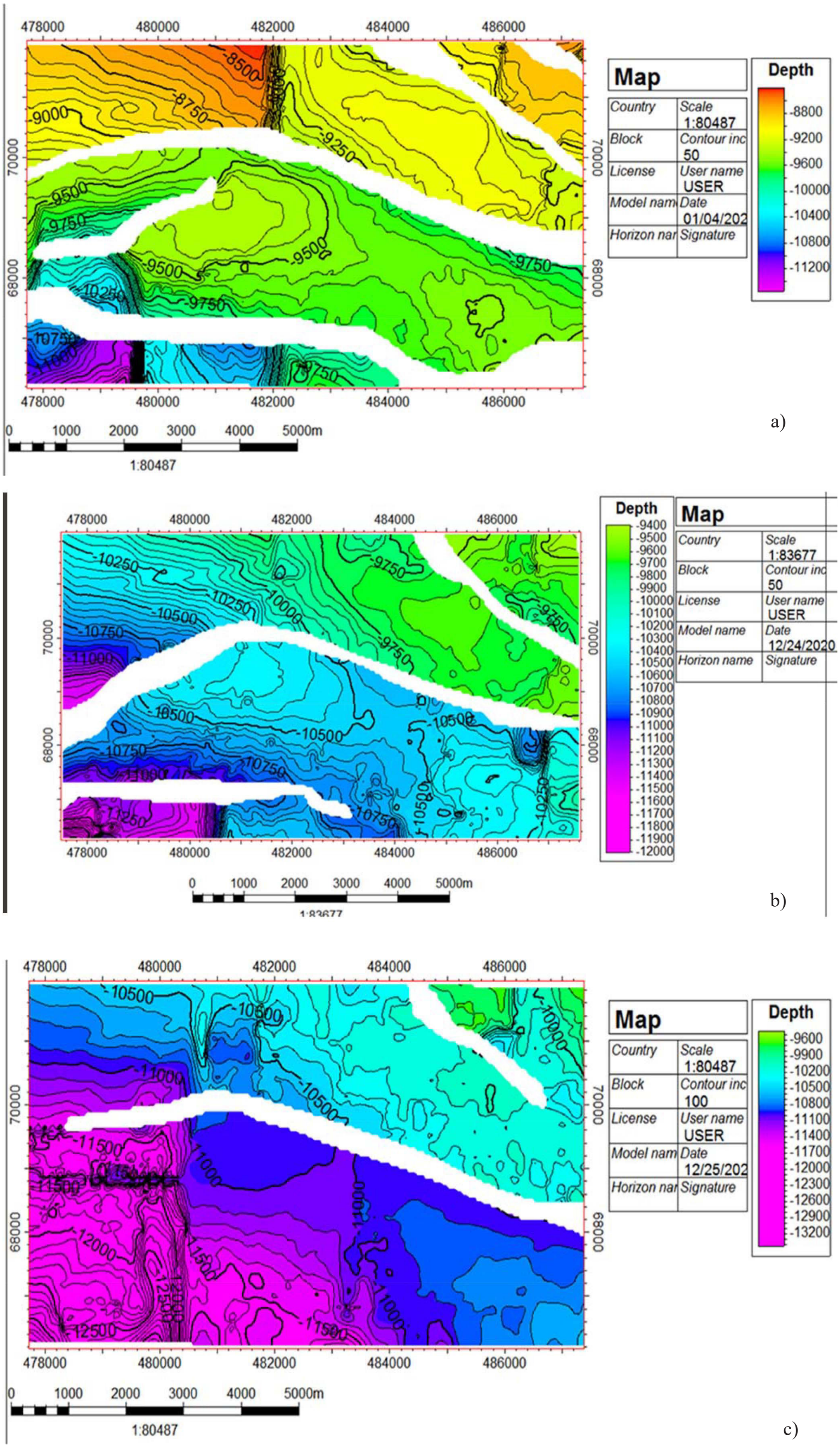

Fig. 11 a, b, and c: The depth converted surface map of reservoirs R1, R2, &R3 respectively.

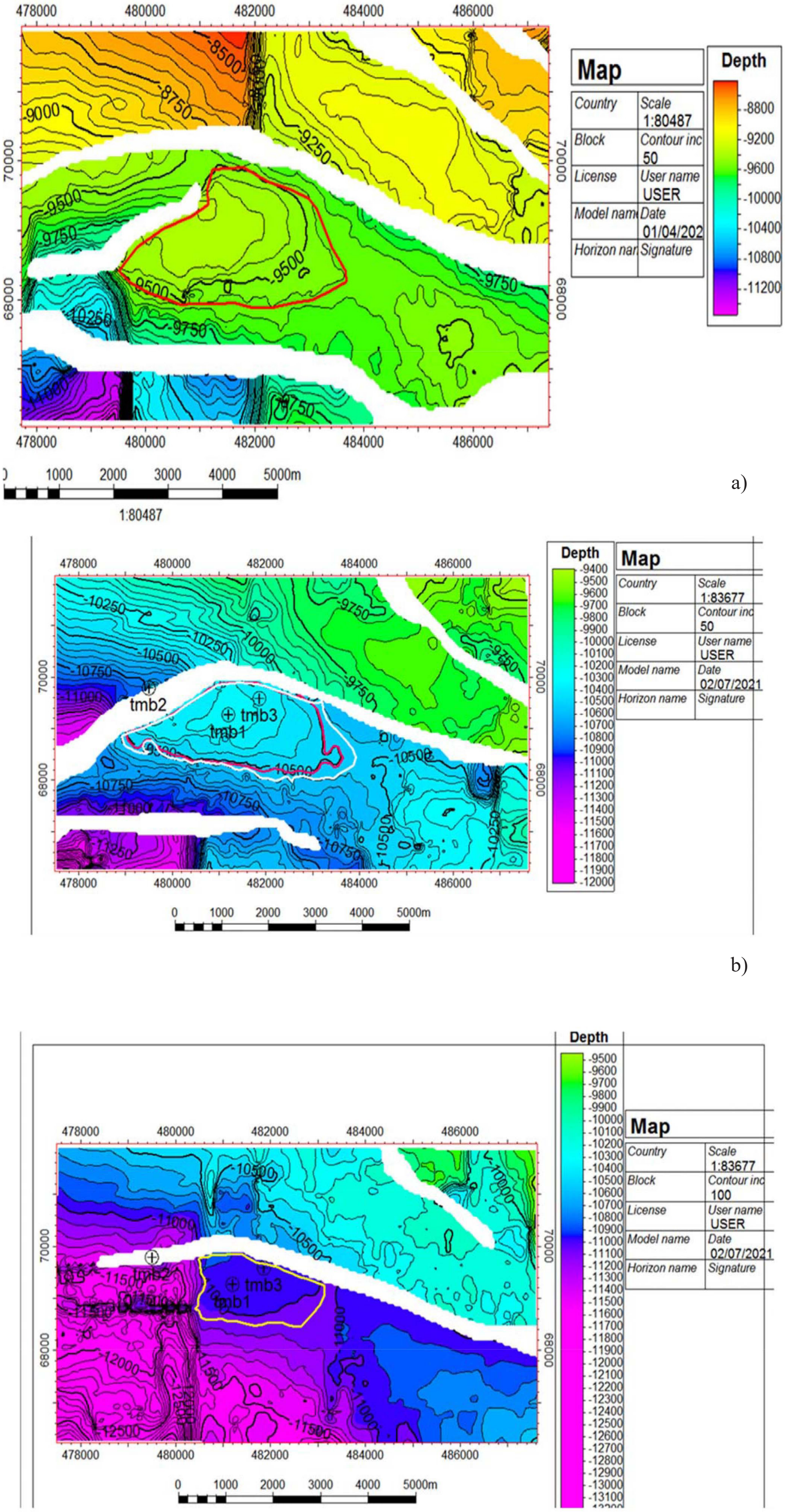

Fig.12 a, b, & c: Hydrocarbon area polygon for reservoir zone R1, R2 & R3 respectively.

Hydrocarbon Reserve Estimate

The hydrocarbon area polygon was calculated to indicate the area occupied by hydrocarbons in the field. The calculation results, the gross rock volumes, and the estimated volumetric reserves of oil and gas are presented in Table 2.

Discussion

Lithostratigraphy

After applying the cut-off values, the lithologic sequence identified in the study wells is of a massive sand unit with a top-to-bottom depth of 8000 ft. in well T1, 8300 ft. in well T2, and 8400 ft. in well T3. Beneath this massive sand unit is an alternation of sands and shale where all the hydrocarbon-bearing reservoir zones are hosted (Fig. 5).

This lithologic sequence of alternating sand and shale in the study wells is similar to the geology of the Agbada Formation of the Niger Delta Basin, as reported by [36]. According to [36]. These shale units are marked by significant high pore pressure, as compared to the sandstones indicating that the sands are mostly unconsolidated, while shales are highly compacted. The massive sand unit sections of the study wells are in conformity with reports from [37] and are interpreted to be part of the Benin Formation of the Niger Delta clastic sequence. Understanding the lithologic sequence is important for identifying formations capable of containing hydrocarbons based on the presence of a cap rock formation overlaying a reservoir rock [38].This information can be used for petroleum system analysis and geomodelling, and ultimately, it provides the basis for further exploration and development activities in the area, providing valuable insights into the subsurface geology and hydrocarbon potential of the study area [39].

Petrophysical Property of Reservoirs Zones

For well T3, the most prominent oil-bearing reservoirs are shown to contain a top layer of gas, followed by oil. Then, water at the bottom of this alternation is typical of Niger Delta reservoirs, as seen in other studies by [40-42] The top gas reservoir will prove to be important for oil recovery by providing a gas cap drive, while the bottom water reservoir will be vital during water flooding in later stages of the field development [43] The porosity and permeability values permit the containment and flow of hydrocarbons, and will also be vital for enhanced oil production and recovery [44] These petrophysical parameters are important in estimating the hydrocarbon reserves of the study wells. Overall, the petrophysical evaluation of the reservoir zones in the study wells suggest that the reservoirs can qualitatively be described as good to very good based on their porosity when inferred on the descriptive table proposed by 45.

Structural Style

Four major faults have been identified in the study. These faults consist of three synthetic (growth) faults that dip in the basinward direction and an antithetic fault that dips in the landward direction (Fig. 7). The growth faults in this study are triggered by pre-contemporaneous deformation of deltaic sediments in the Niger Delta Basin, which is consistent with previous research by 46The trapping mechanism in this field is fault-assisted anticline closure, rather than stratigraphic closure as interpreted from the seismic sections. Similar trapping mechanisms have been reported by [47, 48] in the Emi Field of the Niger Delta Basin.

Hydrocarbon Volume and Economic Evaluation

The hydrocarbon volumes in this study indicate the presence of significant amounts of oil in millions of barrels and several billion standard cubic feet of gas, as reported in similar studies by [49]. The net to gross ratio higher than 70%, significant oil saturation, and effective porosity values also indicate great economic potential of the reservoirs in this study similar to results of 50The total volume of oil in the “BECKY” field is 386,255,807 barrels, and the total gas volume is 1,810,308,838 standard cubic feet (scf). At the current oil price of $62.85 per barrel, the oil in the field is worth over $24 billion. The gas reserve in the field is valued at about $4.8 million as at the time of 2021.

Considering that Nigeria’s current oil consumption stands at about 428,000 barrels per day, as reported by www.worldometers.info, the “BECKY” field alone can sustain Nigeria’s oil needs for over 900 days. Additionally, the field accounts for about 1% of Nigeria’s total oil reserves, about 37 billion barrels. These estimates underscore the significant value and potential of the “BECKY” field, not only for Nigeria’s energy needs but also for its economic development. However, it is important to note that these estimates are based on current economic conditions and may fluctuate depending on global oil and gas prices and other factors.

Table 2 Estimated volumetric hydrocarbon reserves of reservoir zones in the Becky field.

Reservoir	GRV	PHIE	1-SW	BOI/BOG	STOOIP/GIIP	
1	184405	0.19	0.696	1.2	157,653,662	158 MMBbl
2 GAS	196218	0.225	0.706	0.75	1,810,308,838	1.8 MMMScf
2 OIL	48363	0.225	0.706	1.2	49,667,120.4	50 MMBbl
3	196629	0.18	0.782	1.2	178,935,025	179 MMBbl
					Total oil	387 MMBbl
					Total gas	1.8 MMMScf

Conclusions

The hydrocarbon-bearing reservoirs' zones in the "BECKY" field are located at deeper depths and found beneath the Benin Formation, where the lithology is composed of an alternation of sands and shale (Agbada Formation). Three sandstone units that meet the minimum cut-off petrophysical parameters to be called a reservoirs were identified. The petrophysical properties of importance in reserve estimation, such as porosity, water and hydrocarbon saturation, and shale volumes, were calculated. It was found that the reservoirs have good petrophysical properties, with porosity values ranging from 18% to 22.5%, water saturation ranging from 21.8% to 30%, and shale volume from 4.2% to 31.3%, considering their Net/Gross ratios. The main structures seen on the 3D seismic sections were growth faults that have deformed the anticlines hosting the hydrocarbons, resulting in a fault-assisted anticline (3-way closure) trapping system. Appropriate equations were used to calculate the GIIP (gas initially in place) and STOOIP (stock tank original oil in place), and it was found that the total volume of oil in the "BECKY" field is 386,255,807 barrels, and the total gas volume is 1,810,308,838 standard cubic feet (scf). The application of qualitative well-log analysis and 3D seismic structural interpretation has proven effective in delineating the architectural characteristics of reservoir units and estimating the hydrocarbon reserves in the field. These methods can provide valuable insights into the subsurface geology and hydrocarbon potential of the area, which can inform further exploration and development activities and contribute to the economic development of the region.

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