



Structural characterization and water saturation evaluation of a shaly-sand reservoir rocks in an onshore, Niger Delta, Nigeria

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Abstract

Evaluation of shaly-sand reservoir units in an onshore field Niger Delta was undertaken. The study aim is to optimize recoverable hydrocarbon volumes/water saturation and structural style characterization using 3D seismic and composite well log data. The two delineated reservoirs were correlated with oil–water contacts estimated at 2628.02 m (8622 ft) and 2750.8 m (9025ft), respectively. The Larinov tertiary equation was applied in estimating the shale volume of the identified reservoirs. However, water saturation was estimated using Udegbumam, modified Simandoux, and Dual water models. The Formation water saturation value derived from the Pickett plots was inputted into the modified Simandoux, and Dual water models for each well. Furthermore, the reservoir pay thicknesses were 32 ft and 50 ft, respectively, with projected average net-to-gross (NTG) ratios of 78% and 76%. From structural characterization, a total of four (4) fault features were identified with F1, F2, F3, and F4 focusing on the designated reservoir units. The identified synthetic faults are F1 and F2, whereas the antithetic faults are F3 and F4 based on the style. Using the time map layout of the picked horizons on the seismic volume, the reservoir peaks were deduced. The evaluation of the reservoir properties proved that the Dual water model is more robust owing to the values obtained from water saturation, NTG, and STOIP of the identified reservoirs.

Keywords Shaly sand · Reservoir · Udegbumam model · Simandoux model · Pickett

Introduction

The process of distinguishing distinct reservoir features using all available subsurface data or information for the construction of a reliable subsurface reservoir model and properly predict reservoir performance is known as reservoir characterization (Jong 2005). This method could be a quantitative or qualitative in nature (Fajana et al. 2019). The quality of work measured in a qualitative reservoir description is to determine the hydrocarbon reservoir dynamics. Hence, the quantitative reservoir characterization entails the numerical statement of some characteristics that reservoir displays, such as permeability, porosity, water saturation, pressure,

hydrocarbon saturation, etc. (Jong 2005; Fajana et al. 2019). Exploration and production organizations emphasize on hydrocarbon saturation, as most reservoirs contain at least two liquid phases: (1) gas–water and (2) water–oil. Majority of the reservoirs contain all the three phases of gas, oil, and water sequence (Dandekar 2006; Fajana et al. 2019). Description of the reservoir characteristics expected performance is one of the critical skills in reservoir Engineering or studies. Many substantial flaws in reservoir performance can be attributed due to lack of proper and accurate characterization. These discrepancies may lead to a significant loss of hydrocarbon capacity during the extraction process (Alimoradi et al. 2011). In geological delineation activity, water saturation evaluation is essential for reservoir characterization studies, as an inappropriate or erroneous value can potentially contribute to reservoir estimation pitfalls (Alimoradi et al. 2011; Latome 2016). In recent times, the focus on new hydrocarbon asset in Niger Delta has centered on convenient reservoirs at shallower depths that are frequently linked with reduced exploration risks (Opara et al. 2020). However, considerable efforts have been developed in the energy industry to contribute to the realistic visualization

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of reservoir parameters for hydrocarbon volume identification and description (Inyang et al. 2021). Additionally, even during the management of an oil field, the subsurface information obtained is integrated into hydrocarbon evaluation variables that are being used as an indicator in the scenario model for well design, well completion, and production phases (Abriel 2008; Inyang et al. 2021).

Several petrophysical evaluation investigations have led to the identification of new hydrocarbon volume in the Onshore Niger Delta. Since most of the technique studied by other researchers did not provide model base enhanced petrophysical evaluation method, they were ineffective to provide pertinent data on the shaly-sand unit. Some of the early workers employed a traditional Petrophysical methodology that focused more on the effects of Archie's formulae on water saturation. Assessment of shaly-sand reservoir units has long been a key concern. The basic challenge is to identify the degrees to which clay minerals affect reservoir quality using core or log signatures. This quality is an important factor in determining the reservoir pay zones. The possibilities of establishing water saturation via the porosity and electrical resistivity characteristics of a clean (non-shaly) Formation seem encouraging (Archie 1942; McCarter 1984; Sahimi 2010; Sam-Marcus et al. 2018). However, the values of porosity for consolidated and unconsolidated sandstones are 0.8 and 0.6, respectively, and 0.1 for carbonates (Kamel and Mabrouk 2002). The cementation exponent for Archie's formula can assume values between 1.6 and 2.4, but generally, it is equal to 2 and the value of saturation exponent is different from 1.7 to 2.2 (Moradzadeh and Ghavami 2001). For its likely reliability and simplicity, most interpreters employ Archie's formula to delineate a clean sand reservoir. This approach contributes to the leading tool of a reservoir's reliable evaluation (Adeoti et al. 2015a, b). According to Latome (2016), obtaining the resistivity of water and porosity values of an unknown rock matrix using Archie's formula is limited, since water saturation can only be estimated with resistivity log from given well logs (Ghorab et al. 2012).

Ellis and Singer (2007), Holstein (2007), and Amiri et al. (2012) stated that water saturation can be obtained by correlating the density log with hydrocarbon index obtained from Nuclear magnetic resonance (NMR) log. However, this procedure is only sensitive to the gas saturations and can be applied only in the regions close to the wells (Holstein 2007). Hingle (1959) and Pickett (1963), presented a graphical method using two different plots that were essentially obtained from the Archie's formula. Although these plots predicted an improved water saturation, but also not reliable in shaly (unclean) and heterogeneous formations. Hence, the presence of clay contributes to an increased conductivity. This conductivity introduces error in the estimation of water saturation (Dandekar 2006; Amiri et al. 2012). To resolve the issues associated with the increase in shaly sands due to

clay mineral presence, Schwartz and Sen (1988), Cremers et al. (2013), and Amiri et al. (2012) introduced empirical models which consider the effect of shale in sands, to estimate the value of water saturation. Kamel and Mohamed (2006) examined how Acoustic logs used to determine porosity in clean/shaly Formations. Using the Archie and Simandoux models, a direct comparison of hydrocarbon potential in shale sand reservoirs was conducted by Adeoti et al. (2015a, b). Amiri et al. (2015), and they employed Artificial Neural Network (ANN) to optimized water saturation estimation in a shaly sandstone reservoir (Amiri et al. 2012).

To estimate the hydrocarbon possibilities of the location, structural or geological evaluation of seismic data, petrology, and depositional environment of repository sandstone from multiple aspects of the Niger Delta basin have been carried out (Ajakaiye and Bally 2002; Morgan 2003; Ibe and Anyawu 2014). However, to adequately describe the features that seem to be optimal for hydrocarbon accumulation, geological patterns must be thoroughly understood. This is due to the fact that hydrocarbons are accumulated in geological features, which could be structural or stratigraphic in style (Coffen 1984; Ibe and Anyanwu 2014). Structural features are prevalent in Niger Delta basin, but stratigraphic traps are equally prominent (Michele et al. 2012). When 3D seismic data are combined with well-log data, a useful strategy for establishing the structural style and predicting location assets can be achieved (Futalan et al. 2012; Oyedele et al. 2013; Ihianle et al. 2013; Amigun et al. 2014; Onayemi and Oladele 2014; Sanuade et al. 2018). According to Sanuade et al. (2018), rollover anticlinal closures at the three sand levels evaluated by the workers are hydrocarbon entrapment that is commonly capped by a significant listric fault that divides the field into northwest and southeast. The model base and structural characterization of an enhance methodology was considered in this research to determine water saturation, structural style of the study location. These were achieved through the integration of 3D seismic and well-log data (Sharaf 2016; Fajana et al. 2019).

The significance of this study is to establish the empirical techniques and models that can be applied in the prediction or estimation of the water saturation and probable recoverable hydrocarbon volumes in shaly-sand formation.

Geology of Niger Delta Basin

The basic development of the Niger Delta can be described chronologically in six stages. The initial stage was the pre-cretaceous basement complex prior to the separation of South America and Africa. The second stage took place in the early Cretaceous when the continents pulled apart and the first marine incursion (mid Albian) occurred. This transgression is represented by the Asu River group of

sediments having Abakaliki shales as a prominent member (Etu-Efeotor 1998). By late Cretaceous, the third stage of the delta development was underway with deposition of sediments and the growth of the proto Niger Delta following the companion-Maastrichtian regression. The fourth stage began in the early Tertiary when the dominant process was regressive and this mark the beginning of the modern Niger Delta (Sharaf 2016). By the fifth stage in the Tertiary, the Delta was well developed as regression has persisted till present (Etu-Efeotor 1998). The Niger Delta has thus prograded into the Gulf of Guinea at a steadily increasing rate in response to involving drainage area, basement subsidence and eustatic sea-level changes (Sanuade et al. 2018). Initially, the delta prograded over extensionally thinned continental crust of the West African margins as far as the triple junction, filling in the basement graben and horst topography (Fajana et al. 2019; Etu-Efeotor 1998; Doust et al. 1990; Olowokere et al. 2011; Wali et al. 2019; Whiteman 1982; Chiadikobi et al. 2011).

Cretaceous rift patterns manifested as dips and slopes in the deep Atlantic controlled tectonic frame work of the continental edge, along the west coast of equatorial Africa (Tuttle 1999). The trough is a collapsed sleeve of a rift triple junction related with the Niger Delta creation, when rifting ceased entirely in the late Cretaceous. Gravity erosion became the major geodynamic mechanism when rifting stopped, and shale mobility caused internal deformation in relation to various cycle (Kulke 1995). Shale diapirs formed as greater density poorly compacted Delta front sands, over pressured pro-delta and delta shape clays from Akata to Agbada Formations. The under compacted clays delta slope experienced shape instability due to lack of lateral basin ward support. Shale has been over pressured and squeezed farther seaward, forming large ridges and diapirs due to the rather rapid deposition of sediments in the Niger Delta Eocene stage (Ajakaiye et al. 2002). The Tertiary Niger Delta has been discovered to be a sedimentary structure generated by a complicated regressive offlap series of clastic deposits with thicknesses ranging from 9,000 m to 12,000 m (Magbagbeola and Willis, 2007). Since the Miocene age, Niger Delta has converged to form a single integrated system, starting as discrete depocentres. By the late Miocene, diapiric shale structures were forming as a result of lateral shale withdrawal from beneath the advancing deltaic load, as well as compressional uplift and folding of pro-delta strata (Owoyemi et al. 2006). These structures were buried by the prograding delta during the Pliocene and Pleistocene periods, and extensional development shear failure occurred. Sedimentation within the depobelts ended on a sporadic basis, at which point alluvial sands advanced fast across the delta top, coinciding with a basin ward shift in deposition, resulting in seaward stepping depocentres (Owoyemi et al. 2006). During periods of low sea-level

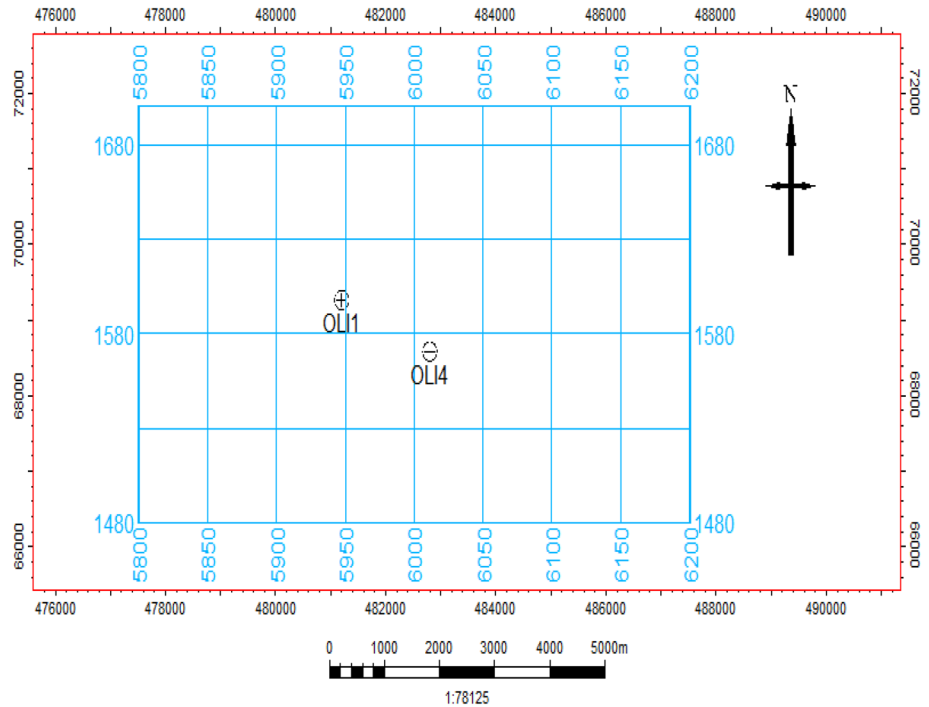
deltas migrated seaward to the shelf edge, while turbidity currents and accompanying mass flows delivered huge volumes of sediment to the slope rise and deep sea fans via under water canyons (Magbagbeola and Willis, 2007).

Materials and methods

The data used in this work were well-log data and 3D post-stack seismic data from an offshore area in Niger Delta oil field. The data consist of suites of well logs, a base map (Fig. 1), and 3D seismic data. The field area covered 145 sq km with a seismic inline range of 5800–6200, X-line interval of 25 ms. The time range signal was between 1000 and 6400 ms, with zero-phase wavelength type and polarity of SEG reverse. The data used was then transferred into Geophysical software, where it was interpreted. The seismic portion in the interpretation window shows the inline and xline, once the seismic data were being simulated. Well logs, on the other hand, were loaded in conformity with their format, thereby indicating the signatures of the required logs for an optimal interpretation. To assure the consistency of the well-log data, the logs were edited to limit the number of negative sample points (Artun, 2005). This will confirm the validity of the signatures in correlation with seismic events. This became necessary in modifying and adjusting the logs employed for this work for wash out tendencies, to achieve an accurate interpretation. Furthermore, all invasion that could compromise the data's integrity were addressed. The logs were then corrected for well and datum level variation, to ensure accurate vertical and referenced datum with the seismic survey. To establish a better well to seismic correlation, acoustic impedance was reduced to a third of the total wavelet toward becoming low in comparison to reflectivity. The seismic event linked the matched synthetic.

To obtain reliable information during reservoir characterization, the Petrophysical properties and their variation throughout the reservoir was evaluated and determined. The well-log data were edited to limit the number of bad data points, to ensure the reliability of the results obtained. The necessity of well-log correction aids in correlation accuracy of seismic to well-log data, and also wash out tendency of the data (Shalabyi et al. 2020). Well-log correlation procedure was equally employed to delineate the reservoir laterally, through uniform sand beds mapping. Well logs signatures are utilized to recognize and describe geological lithology and fluid discrimination (Etu-Efeotor 1997; Kurah et al. 2021). The phases of the lithology are identified through the use of gamma ray and spontaneous potential (SP) logs. These became necessary due to the natural radioactive content associated with rocks. To account for the poorly consolidated quality of the reservoir rock, caliper log was used. It suggested the presence of caves within the identified reservoirs. Fluid discrimination into hydrocarbon

Fig. 1 Base map of the study location



and water were obtained with resistivity, neutron, and density logs (Kurah et al. 2021). The tendency of rock units to oppose the flow of electric current can be measured by its resistivity. The conduction is due to salinity presence in water; hence, hydrocarbon presence on pore spaces increases the resistivity values (Bridge and Demicco 2008; Kurah et al. 2021).

Furthermore, reservoir tops and base of similar Sand beds were used as the correlation precursor. The gamma ray index is the ratio of the difference between the interval gamma ray reading, and the gamma ray reading at the Sand baseline to the difference between the gamma ray reading at the shale baseline and gamma ray reading at the sand baseline was obtained using the expression (Larionov 1969)

$$\text{IGR} = \frac{\text{GR} - \text{GR}_{\min}}{\text{GR}_{\max} - \text{GR}_{\min}} \quad (1)$$

The shale volume V_{sh} which is the volume of wetted shale per unit volume of reservoir rock was calculated using (Larionov 1969)

$$V_{\text{sh}} = 0.083(23.7 \text{ IGR} - 1), \quad (2)$$

where V_{sh} Shale volume and IGR-Gamma ray index.

Also, porosity of the formation was obtained using the expression (Wyllie 1958)

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

Net-to-gross (NTG) is the ratio of the thickness of the sand bearing hydrocarbons to the total thickness of the sand formation. It was calculated along the well by the use of the relation (Larionov 1969)

$$\text{NTG} = \text{If } (\text{GR} < 68, 1, 0). \quad (4)$$

Based on the above relation, the condition is that if the gamma ray log reading is less than 68 API net-to-gross, NTG is equal to 1; otherwise, it is zero (Jingling et al. 2017).

To obtain the water saturation of the formation, three empirical models or calculations were employed: Udegbum model: According to Udegbum et al. (1988), water saturation can be estimated by applying the relationship

$$S_w - u_d = \frac{0.082}{\varphi}, \quad (5)$$

where $S_w - u_d$ - water saturation by Udegbum et al. (1988)

Modified Simandoux model: Simandoux (1963) proposed an empirical model that employed in the estimation of water saturation in shaly-sand formation as

$$\frac{1}{Rt} = \frac{S_w^2}{F.Rw} + \frac{\epsilon S_w}{Rsh}. \quad (6)$$

However, the Simandoux equation recently adopted is usually the modified version, which is like a quadratic equation of water saturation Bardon et al. (1969) and Worthington (2011):

Fig. 2 **a** Picket plot for Reservoir A Well I. **b** Picket plot for Reservoir A in well II

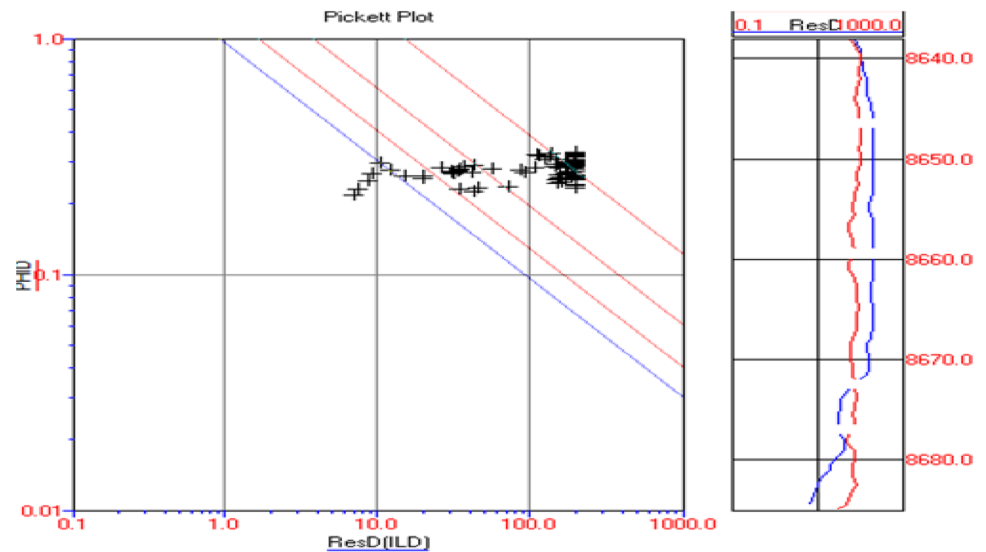


Fig. 2a Picket plot for Reservoir A Well I

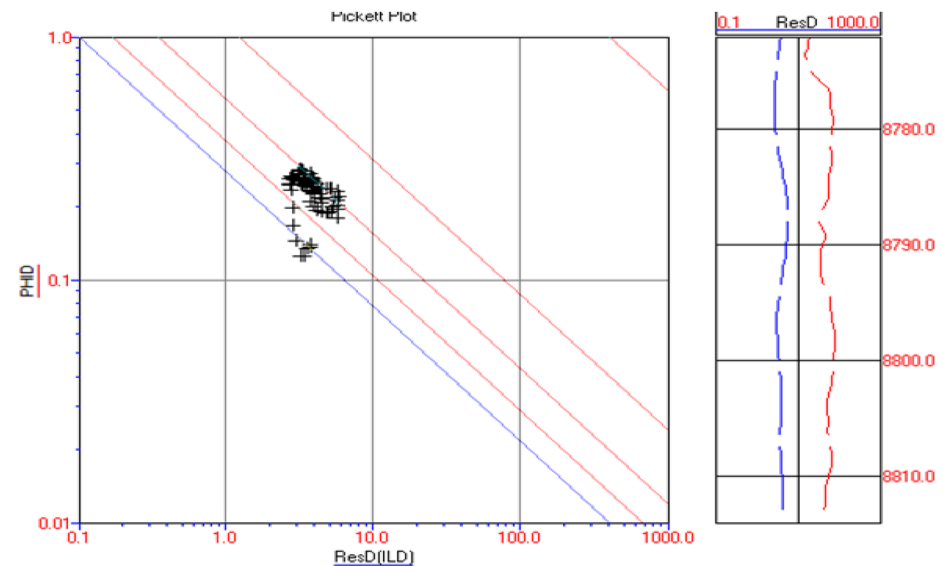


Fig. 2b Picket plot for Reservoir A in well II

$$\frac{1}{R_t} = \frac{S_w^2}{F \cdot R_w} + \frac{V_{sh} S_w}{R_{sh}} \quad (7)$$

$$S_{wt}^n = \frac{F R_w}{R_t} + S_{wb} * S_w \epsilon^{n-1} * \left(1 - \frac{R_w}{R_d}\right). \quad (8)$$

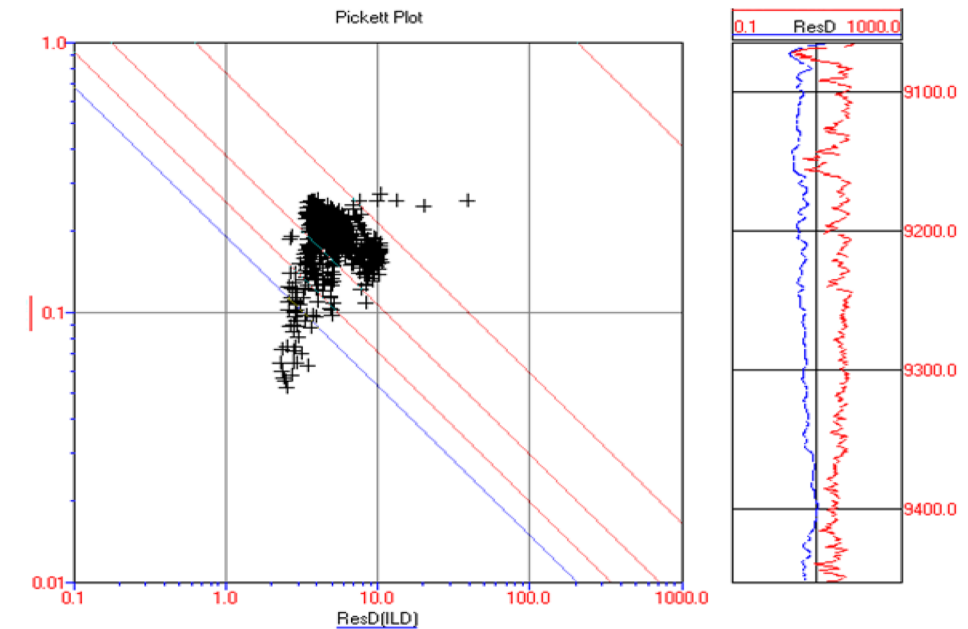
Dual water model

The dual water model is commonly used to calculate water saturation (Clavier et al. 1984; Worthington 2005). “It predicts the presence of two electrically different waters in the clay structure, irreducible water closer to the clay grain surface and mobile water that can be displaced by hydrocarbons” (Sam-Marcus et al. 2018). The dual water model used in calculating the water saturation is given as

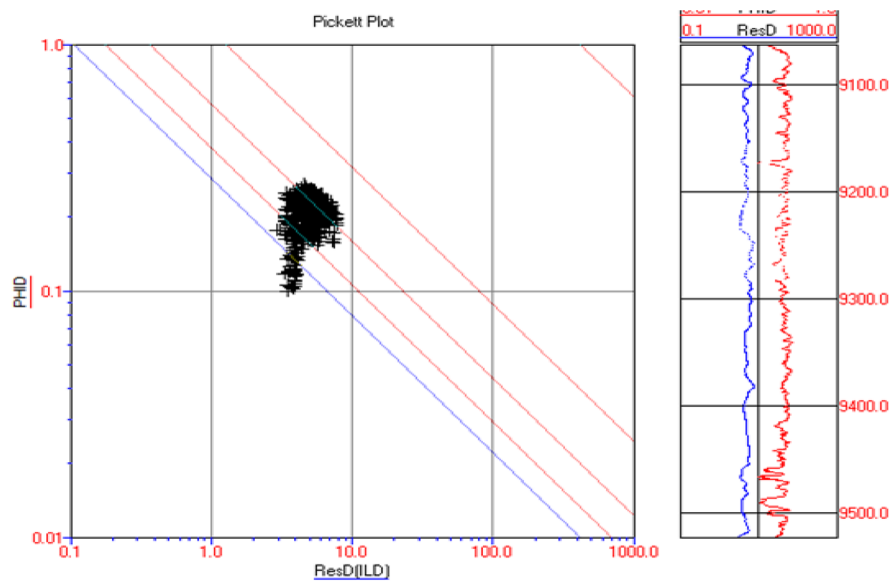
The influence of clay mineral occurrence on the resistivity of reservoir rocks can be activated due to free water existence in the pore space of reservoir rocks and also the bound water within the clay matrix (Clavier et al. 1977; Sam-Marcus et al. 2018). The aim of Dual water model establishment was due to conduction processes in clay mineral. This became necessary as a result of conductivity that occurs near the double and free clay effect layers (Sam-Marcus et al. 2018).

The evaluation of water saturation for Well I and II of the two identified reservoirs sand (A and B) was established

Fig. 3 **a** Picket plot for Reservoir B in Well I. **b** Picket plot for Reservoir B in Well II



a Picket plot for Reservoir B in Well I



b Picket plot for Reservoir B in Well II

using Simandoux and Dual water models. These models are porosity determinant of the formation.

Pickett plots was also adopted to calculate the petrophysical exponents m , n , and a , for the clean formation. The plots have been greatly employed in log interpretation, and a resistivity index and water saturation were calculated from log–log plots (Pickett 1966, 1973; Ghorab et al. 2012) (Figs. 2, 3). Aguilera (1990) demonstrated that laminas, dispersed, and total shale volume can be analyzed using log–log

cross plots of porosity against true resistivity. The advantage of the cross plot is that all shaly intervals can be displayed in a single plot together with porosity and water saturation (Aguilera 1990; Ghorab et al. 2012).

Hydrocarbon volume estimate was obtained using the relation

$$STOIIP = \frac{77758XAXHX\phi XNTG(1 - SW)}{B0} \quad (9)$$

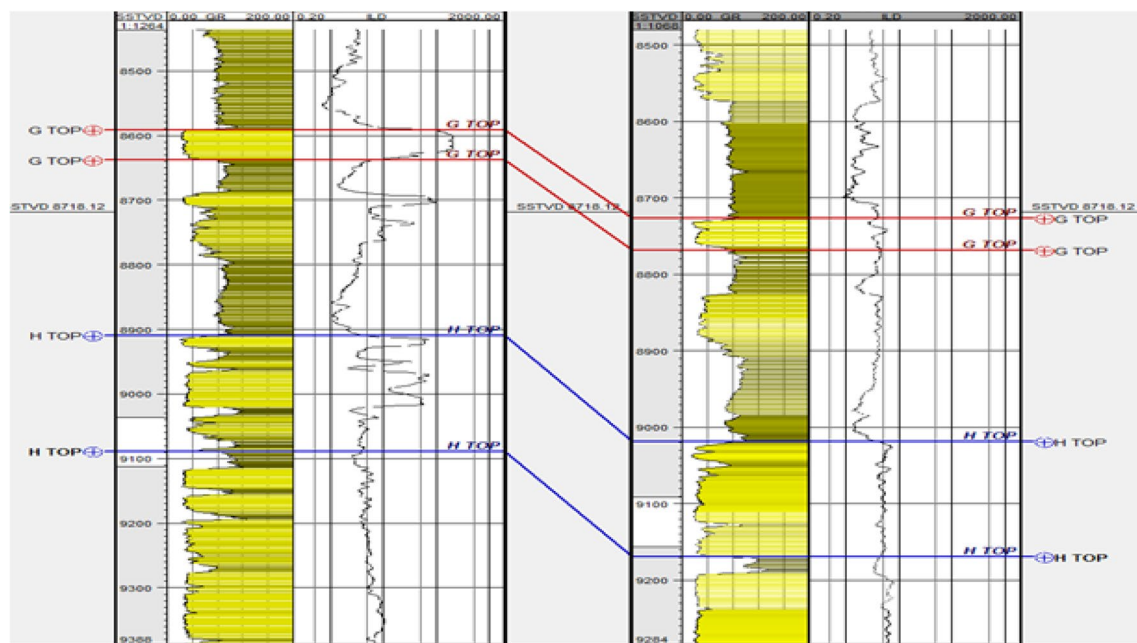


Fig. 4 Well-to-well correlation

Table 1 Identified Reservoir parameters

Well	Reservoir A			Reservoir B		
	Top (ft)	Base (ft)	Thickness (ft)	Top (ft)	Base (ft)	Thickness (ft)
I	8591.46	8638.30	46.84	8909.53	9089.08	179.55
II	8726.79	8768.92	42.13	9018.07	9169.80	151.7

Table 2 Average reservoir properties of Reservoir A

Well	Porosity	Net/Gross	Sw_ud	Sw_d	Sw_ms
I	0.2	0.75	0.29	0.19	0.2
II	0.19	0.82	0.37	0.23	0.3
Average	0.195	0.78	0.33	0.21	0.25

Table 3 Average reservoir properties of Reservoir B

Well	Porosity	Net/Gross	Sw_ud	Sw_d	Sw_ms
I	0.18	0.79	0.35	0.20	0.28
II	0.21	0.73	0.29	0.18	0.22
Average	0.195	0.76	0.32	0.19	0.25

Results presentation and discussion

The study evaluated the water saturation of the identified reservoirs A and B using empirical models. The lateral extent and depths of the reservoirs was obtained using well logs and 3D seismic data respectively. The lithological

interpretation depicted sand/shale sequence that represents a typical Niger Delta system, also the top, base and thickness of the corrected wells of the reservoirs were identified (Fig. 4). The average thickness of the reservoir A is 44.49 ft, while for reservoir B is 165.64 ft (Table 1). Petrophysical analysis shows oil–water contacts (OWC) were delineated in the both identified reservoirs. The low resistivity log value identified oil–water contact at 8622 ftss and 9025 ftss for reservoirs A and B respectively.

In Tables 2 and 3, Udegbunam's model from the estimated Petrophysical properties gave rise to high water saturation in both reservoirs A and B in comparison with Model Simandoux and Dual water models. Furthermore, modified Simandoux water Saturation value is equally higher than the values obtained from Dual water model. This signifies the robustness and sensitivity of the models with respect to water saturation. However, the identified areas of shale intercalation in Reservoir B experience high water saturation values for the entire adopted models, in comparative with clean sand zones in Reservoir A. This was attributed as a result of probable intercalation of shale formation within the field (Fig. 5).

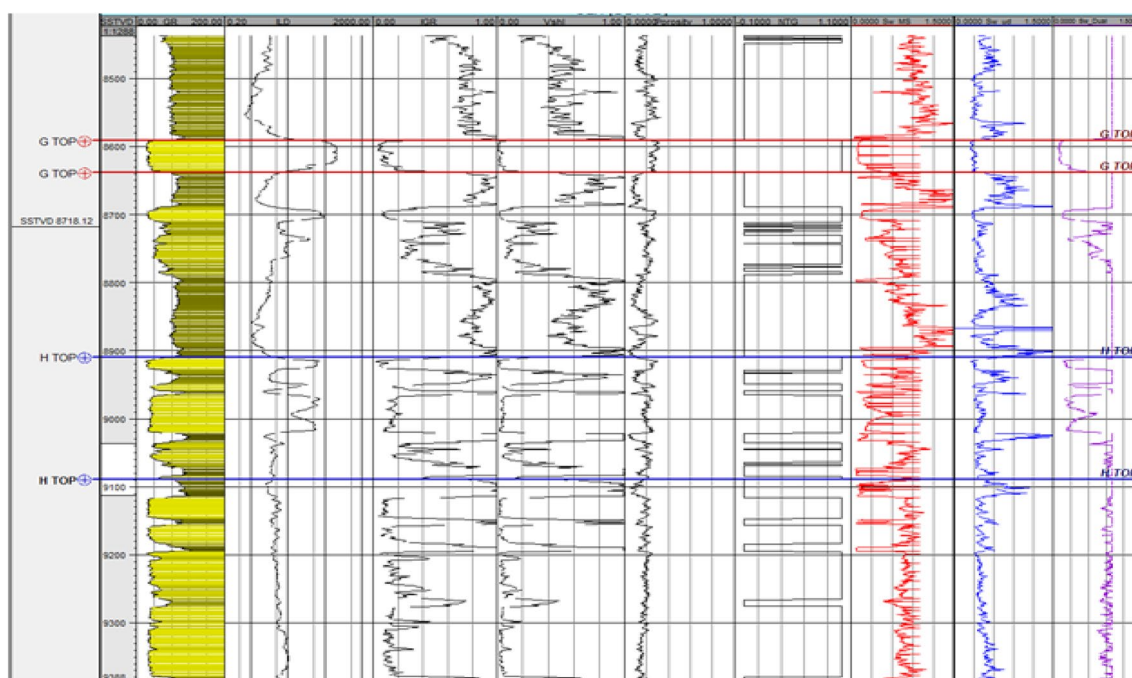


Fig. 5 Petrophysical properties log for Reservoir A and B

Table 4 Volume calculation for Reservoir A using the three water saturation correlation models

Model	Area	Pay thickness	Porosity	NTG	Sw	STOIIP
Udegbumam	1350	32	0.195	0.78	0.33	23.7
M. Simandoux	1350	32	0.195	0.78	0.25	22.5
Dual water	1350	32 0.195	0.78	0.19	28.7	

Table 5 Volume calculation for Reservoir A using the three water saturation correlation models

Model	Area	Pay thickness	Porosity	NTG	Sw	STOIIP
Udegbumam	1360	50	0.195	0.76	0.32	33.2
M. Simandoux	1360	50	0.195	0.76	0.25	36.6
Dual water	1360	50	0.195	0.76	0.19	39.5

Comparable to Reservoir A, the water saturation derived by utilizing the Udegbumam, Dual water, and modified Simandoux models are lower in Reservoir B. This demonstrates that Reservoir B seems to have an improved chance of securing significant hydrocarbon prospects in the research area. The pay thickness and identified area of the reservoirs were 35 ft and 1350 acre for Reservoir A, and 35 ft and 1350 acre for reservoir B respectively, to ascertain the feasibility of in situ hydrocarbon. The stock tank initial oil in place (STOIIP) obtained using the identified models for reservoir A are 23.7 MMSTB for Udegbumam model, 22.5 MMSTB for modified Simandoux model, and 28.7 MMSTB for Dual water model. Also, for reservoir B, we obtained 33.3 MMSTB for Udegbumam, 36.6 MMSTB

for modified Simandoux, and 39.5 MMSTB for Dual water model (Tables 4, 5).

The main goal of structural understanding is to use seismic sections to distinguish subsurface features, since it gives wide coverage of the study location and ultimately is the critical position for hydrocarbon exploration (Emujakporue and Ngwueke, 2013). This can be achieved along the dip and strike segment, by considering the impact of faulting system on the sedimentary architecture of the subsurface (Opara et al. 2020). The study locations' structural features were obtained by utilizing seismic volume images from xline (1480–1680 ms) and inline (5800–6200 ms) respectively. Features were identified using fault markers on the inline section of the seismic volume which

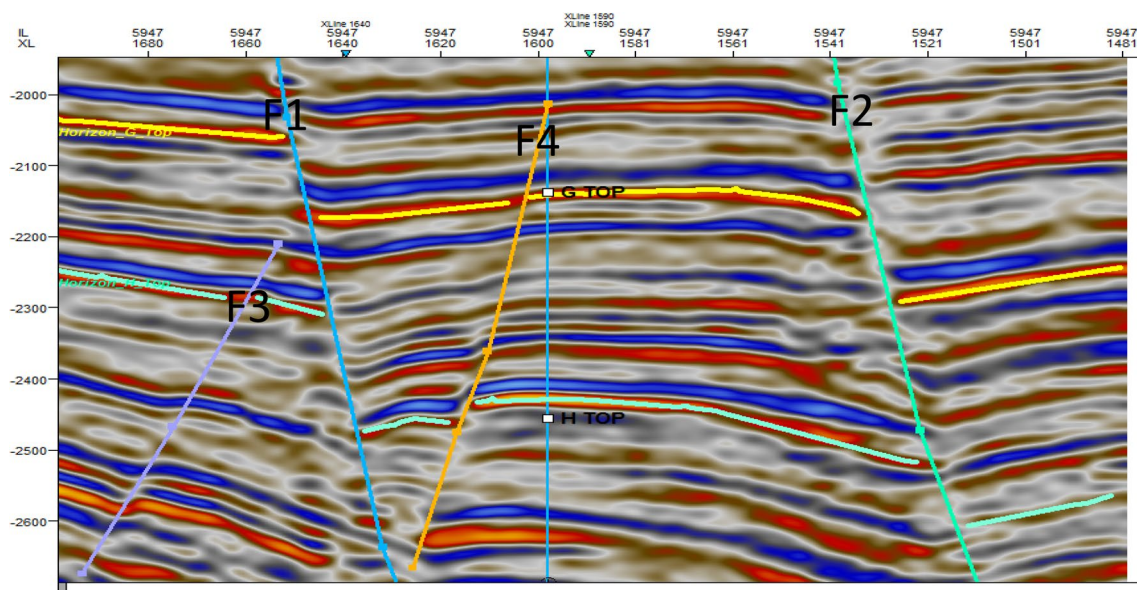


Fig. 6 Fault identification and interpretation

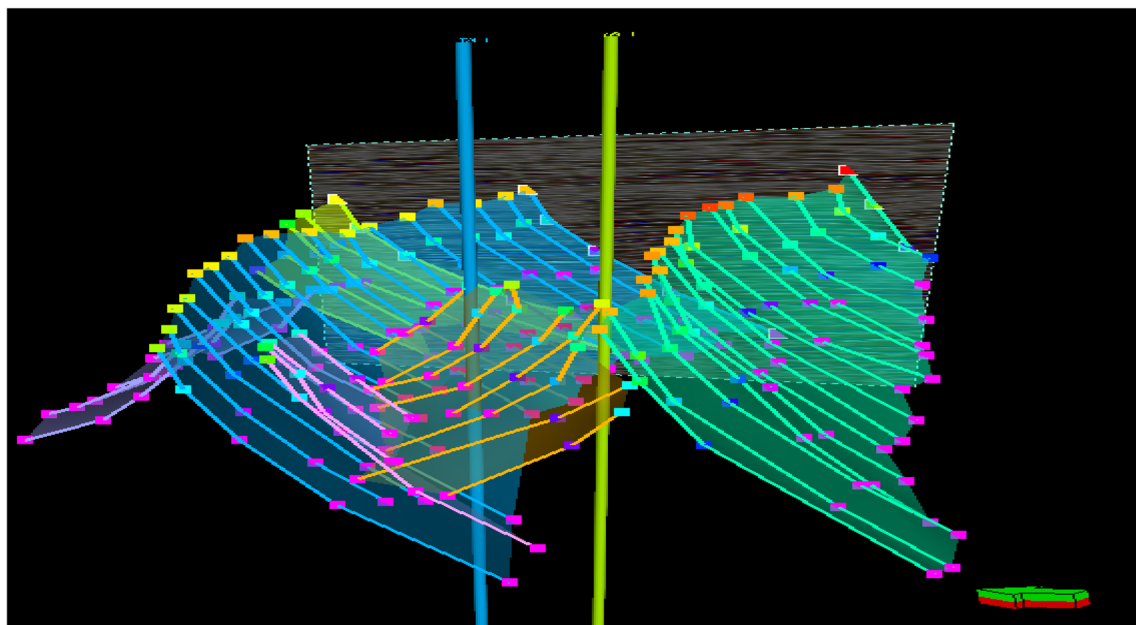


Fig. 7 3D view of the analyzed faults

showed zones along the deformation. A combination of four (4) faults features was identified with F1, F2, F3, and F4 focusing on the designated reservoir units. The identified synthetic faults are F1 and F2, whereas the antithetic faults are F3 and F4 based on the style (Fig. 6). Using the time map layout of the picked horizons on the seismic volume, the reservoir peaks were deduced. This framework was produced by overlaying both the seismic signal and location grid (Fig. 7). Childs et al. (2003) discovered that

the downthrown subsurface blocks are quite high in thickness than the corresponding upthrown block (Kurah et al. 2021). This suggests that the stratigraphic Formations of Niger Delta basin were generated instantaneously and steadily as sedimentation advanced (Kurah et al. 2021). These faults are possibly characterized as syn-depositional extensional faulting system (Lin et al. 2004; Kurah et al. 2021). The extension fault is generated by a geological gravitational disequilibrium of finite amplitude of birth,

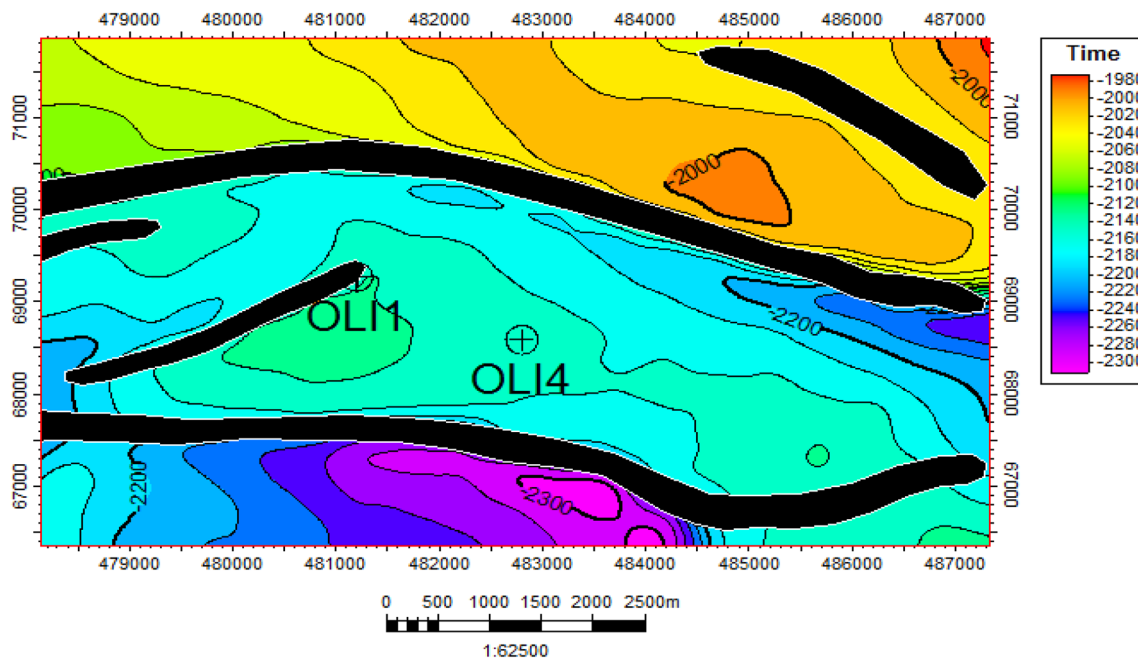


Fig. 8 Depth map of the delineated reservoir

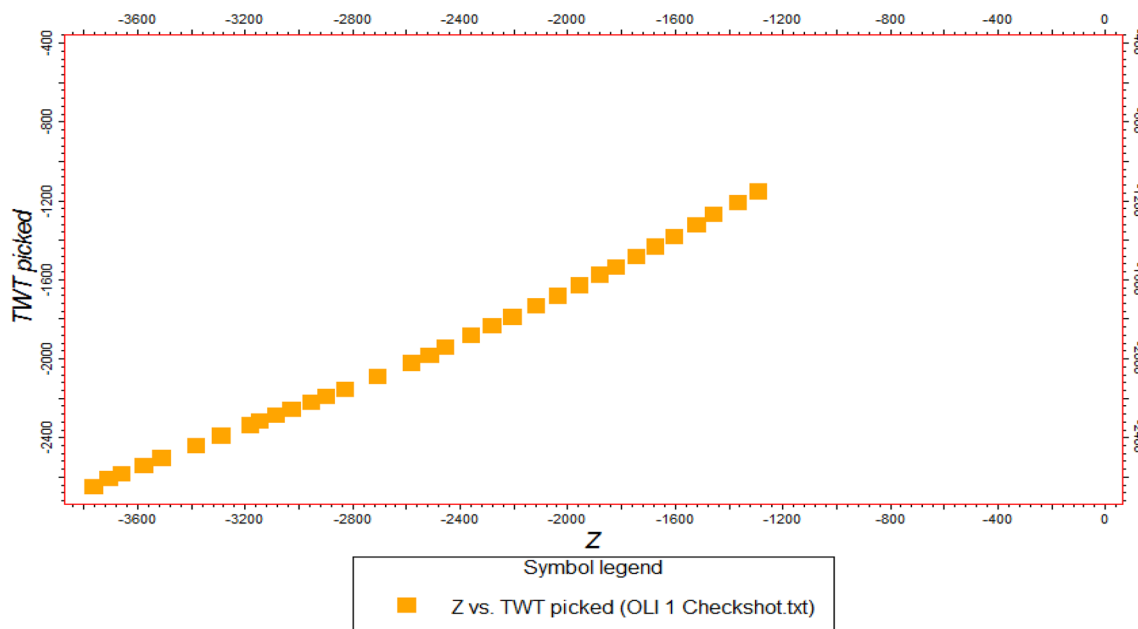


Fig. 9 Time-to-depth conversion of the delineated reservoir

growth, and decay Formation phases (Mauduit and Brun 1998; Kurah et al. 2021).

On the time map of the identified reservoirs by the grid provisions, contour lines spanning intervals of 20 ms were equally used to characterize the reservoir peaks. The two drilled hydrocarbon wells were positioned at approximately

2140 ms and 2160 ms, respectively (Fig. 8). They were positioned on an anticline structural feature of the subsurface. Most significantly, the subsurface thickness was defined using the depth map for appropriate understanding, and the time-to-depth (T–Z) trajectory was used for this purpose (Figs. 9 and 10), the corresponding time values on the time map

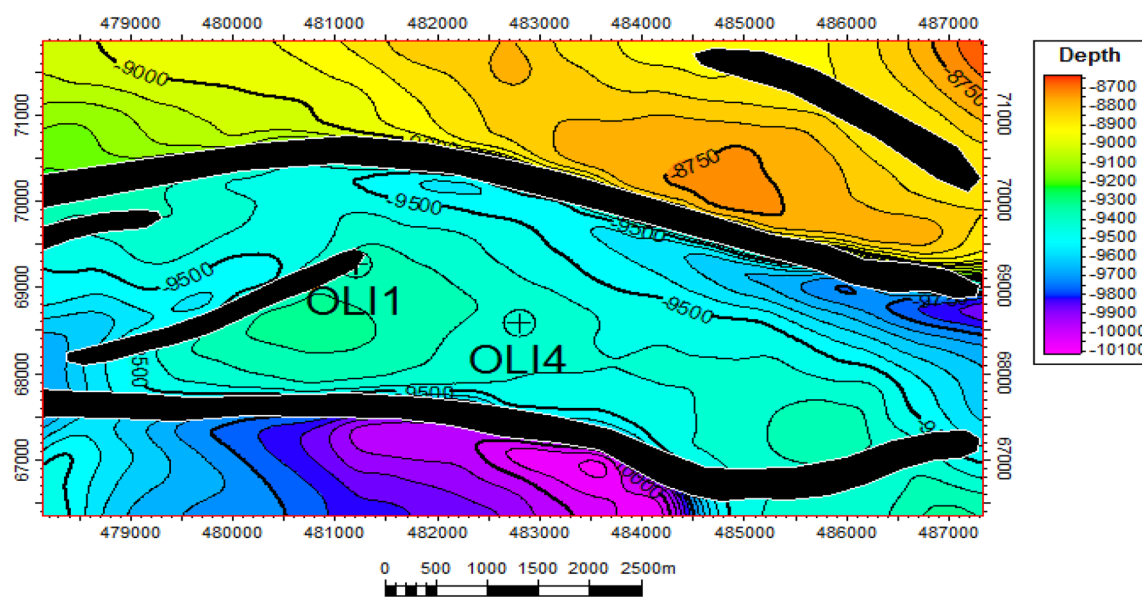


Fig. 10 Depth map of the delineated reservoir

collaborated with its thickness on the depth map. This gave the clear understanding of the established reservoir depth.

Conclusion

The study adopted 3D seismic data and well-log from a specified location in an onshore Niger Delta in the characterization of the identified reservoir lateral extent, depths, and Petrophysics. Shale and sand formation sequence was portrayed in the lithologic assessment. Three models, namely, Udegbumam, modified Simandoux, and Dual water models, for water saturation evaluation have been employed to evaluate water saturation and recoverable hydrocarbon volumes in the study area. The adopted approach aid in evaluating the viability of the identified prospects. Two reservoir units were identified from the well logs used, and these gave rise to high resistivity and low gamma ray values. Also, both gamma ray index and shale volume values show similar signatures. Pay zones with shale intercalation experience high water saturation than the clean sand formations. From the empirical models employed for water saturation evaluations, it was identified that Dual water model shows a robust water saturation and stock tank oil initial in place (STOIIP) in both delineated reservoirs. The study signifies that reservoir B is found to be more productive due to the hydrocarbon saturation obtained using the Dual water model compared to other models.

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