ORIGINAL PAPER-EXPLORATION GEOPHYSICS

An integrated source rock potential, sequence stratigraphy, and petroleum geology of (Agbada-Akata) sediment succession, Niger delta: application of well logs aided by 3D seismic and basin modeling

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Abstract

We investigated the source rock potential, sequence stratigraphy, and characterized hydrocarbon reservoirs at Otumara field, Niger delta, using integrated 3D seismic, wireline log analysis, and basin modeling. The burial history and thermal maturity were modeled, the reservoirs were delineated, and the petrophysical parameters were also estimated from the wireline logs. The Passey "ΔLog R" method for estimating the preliminary evaluations of the total organic carbon (TOC) from integrating sonic, neutron, and density with resistivity has been used. The results indicate that the primary source rock of hydrocarbons is the Upper Akata Formation, despite a higher TOC percentage in the Agbada Formation. Based on sequence stratigraphy analysis, TA4, TB1, TB2, and TB3 second-order supercycles were obtained in the studied well TD46. The results also revealed that the field has two large net pays with high-quality reservoir facies: a deltaic slope fan at the upper shoreface and a river mouth sandbar at the lower shoreface. Furthermore, the reservoirs were faulted by a series of growing faults that faulted the basin slope. The reservoir facies are characterized by an average of 18% porosity, 1200 mD permeability, 16% volume of shale, and high hydrocarbon saturation of about 85%. Finally, the petroleum system elements have been defined for improved hydrocarbon exploration. In the absence of complete or partial core samples, this case study emphasizes the importance of using wireline logs to estimate organic richness and investigate sequence stratigraphy in clastic sediments.

Keywords Niger delta · Petroleum system · Log-derived TOC · Shoreface facies · Sequence stratigraphy · Source rock

Introduction

Identification of petroleum system elements and processes in sedimentary basins can lead to massive exploration and development opportunities (Magoon and Dow 1994;

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Radwan et al. 2021). The use of well logging in the evaluation of reservoir rocks, source rocks, sequence stratigraphic, and depositional environments has attracted the interest of hydrocarbon researchers worldwide (e.g., Peters and Cassa 1994; Oraby 2020; Catuneanu 2006; Ellis and Singer 2007; Diab and Khalil 2021; El-Dakak et al. 2021; Radwan 2021). In reservoir evaluation, petrophysical assessment using wireline logs plays an integral role in discriminating among productive and nonproductive bearing zones (e.g., Ellis and Singer 2007; Cannon 2015; Abdel-Fattah et al. 2019). Furthermore, the gamma-ray log pattern can be used to analyse depositional environments and sequences (e.g., Catuneanu 2006; Kadkhodaie and Rezaee 2017; Radwan, 2021). In source rock evaluation, the estimation of the amount of generated hydrocarbons in a basin or prospect requires the determination of the source rock, its yield, as well as the level of thermal maturity of the total organic matter (Meyer and Nederlof 1984). Also, the nature of the generated hydrocarbons depends on the type of organic matter in the source rocks. Therefore, measuring the quality and quantity of the

organic matter in sedimentary source rocks is vital as this would provide insight into the paleoenvironment and basin evolution.

The quality and quantity of organic matter in source rocks and their maturity are usually determined in the laboratory by chemical and microscopic analysis of rock samples (Zhao et al. 2016, 2017). However, in most of the Niger delta, the researchers face problems in evaluating the hydrocarbon source due to the limited availability of core/well cutting and geochemical data sets. This data shortage results from the high burial depth of the source rock. Therefore, it is possible to investigate the relationship between source rocks and wireline logs. The possibility of relating the organic matter in source rocks to the measurements from wireline logs is due to the physical properties of organic matter that are considerably different from those of the mineral components of its host rock. For instance, organic matter is expected to have a lower density, higher sonic transit time, higher uranium amount, high hydrogen and carbon concentrations, and higher resistivity (Kamali and Mirshady 2004). More so, the results from previous studies have demonstrated how well logs are related to source rocks. For example, Kamali and Mirshady (2004) quantified the correlation between wireline logs (sonic, density, neutron, and resistivity logs) and total organic carbon using an approach called "ΔLogR" and Neuro Fuzzy. They employed the integration of sonic/resistivity, neutron/resistivity, and density/resistivity logs. The total organic carbon (TOC) results were calibrated using geochemical analysis data.

Zhao et al. (2016) integrate the clay indicator curve with the GR log to estimate TOC contents in source rocks in two shale gas plays with high-maturation kerogen in China. They calibrated their results with core data. Aziz et al. (2020) estimated TOC from well logs using four methods, including density log, spectral GR log, multivariate fitting, and ΔlogR methods. They concluded that the ΔlogR estimated the TOC with the highest accuracy. Shalaby et al. (2019) successfully demonstrated TOC estimation from well logs in the Jurassic source rocks of the Northwestern Desert, Egypt. Their study used well log mathematical models and machine learning approaches. Zheng et al. (2021) employed resistivity, density, sonic and GR logs to predict TOC values from four basins in Canada and China. They used deep learning models for the estimation of TOC from well logs.

The primary goal of this research is to assess the source rock potential in terms of organic matter quantity, quality, and thermal maturity in Otumara Field as a case study from the Niger delta. This field lies within the onshore division of a matured oil block in the Niger delta, situated a few kilometres north of Warri city, Niger delta (Fig. 1). The Otumara Field belongs to the Otumara-Saghara-Escravos area and produces oil and gas from the Tertiary petroleum system units. The study area is linked to the Niger delta basin

structure and petroleum system published by Obiekezie and Bassey (2015). Despite oil and gas discoveries in various parts of the Otumara Field zone, little is documented about the comprehensive model for the petroleum geology characteristics of the Tertiary deposits, which encouraged us to research more existing petroleum systems. Because core sample measurements were not available in the Otumara Field, we relied on the log response as an effective tool for evaluating the studied succession. This work will show the relationship between the potentiality of source rocks and the response of wireline logs by providing preliminary evaluations for the TOC in source rocks. We investigated the burial history and the thermal maturity of the source rock and characterize the hydrocarbon potential of the Otumara Field. Furthermore, we have studied the sequence stratigraphy and the total petroleum system of the field, which is very important for further field development.

Regional geology of Niger delta

Stratigraphy

During the Late Jurassic, the Niger delta basin started to open and ended in the Middle Cretaceous. The Niger delta stratigraphic column contains sediments from the Cretaceous to the Holocene with a total depositional sequence that reaches an optimum thickness of 9–12 km at the approximate depocenter in the central part of the delta (Fig. 2). The Tertiary deposits contain a thick wedge of clastic deposits covering an approximate 105,000 km² with a high hydrocarbon reserve (Avbovbo 1978). The primary petroleum system in the Niger delta is found in the Tertiary clastic sequence, which was deposited from the combined depositional packages of progradation offlap cycles (Ekweozor and Daukoru 1984). This clastic wedge is divided into three main formations in ascending order, including the Paleocene Akata Formation, Eocene Agbada Formation, and Oligocene Benin Formation (Doust and Omatsola 1989) (Fig. 2).

The Akata Formation comprises marine pro-delta shales and turbidite sands with minor amounts of silt. There is no drilled well that reaches the base of the Akata Formation, while the most bottomless well penetrated about 3658 ft of the Akata Formation (Sanuade et al. 2017). The Cretaceous shale lies uncomfortably on the basement with a thickness of up to 2000 ft in the onshore area and could reach up to 6550 ft in the offshore area of the Niger delta (Bellingham et al. 2014). The Akata Formation was developed during a prograding lowstand with a thickness of about 21,000 ft in the central part of the clastic wedge, characterized by low oxygen supply and reduced energy conditions (Stacher 1995). This loading made the underlying shale of the Akata Formation to be compressed into shale diapirs. The Agbada
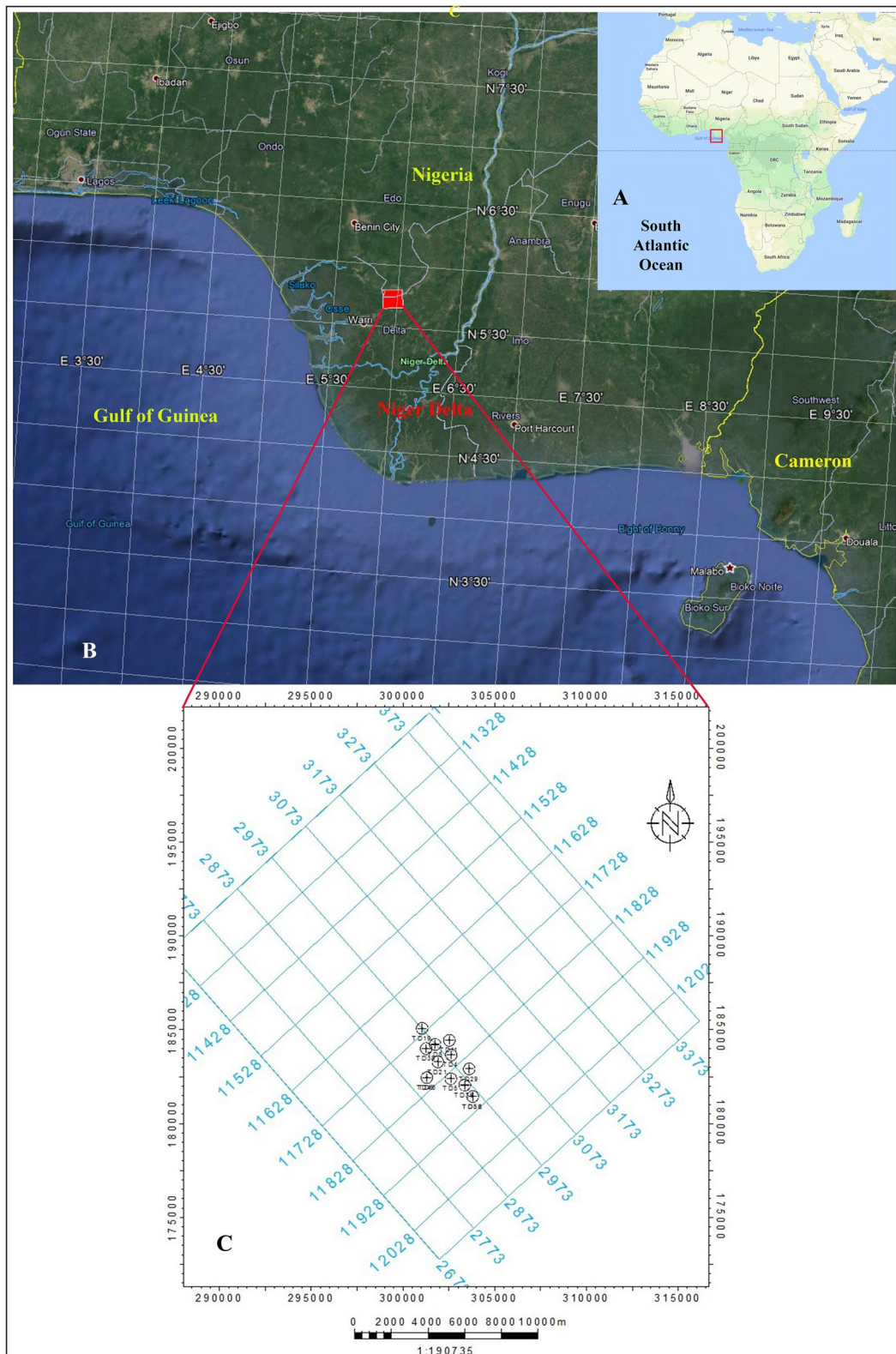
Fig. 1 **A** Location of Niger delta on the western coast of Africa, **B** Location of onshore Otumara mara field in the Niger delta area, **C** Base map shows the data used in this study either seismic data cube or/and wells
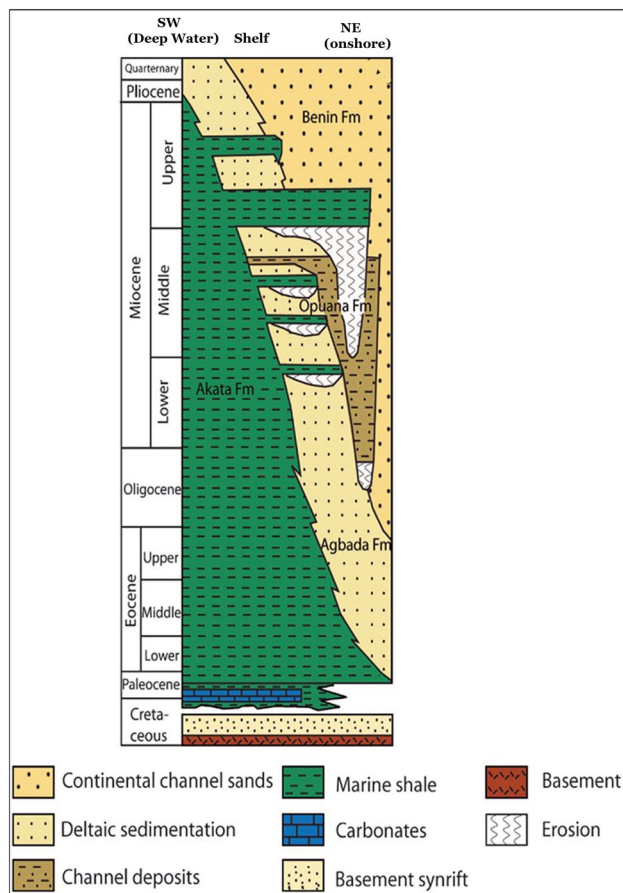
Fig. 2 The regional stratigraphic column of the Niger delta Basin shows the three major units in the delta (Akata, Agbada, and Benin formations) (Doust and Omatsola 1990)

Formation overlies the Akata Formation, and it was deposited during the Eocene and is still depositing due to the diachronous deposition in the Niger delta Basin (Short and Stäuble 1967). The Agbada Formation is a transition zone and represents the deltaic part of the Niger delta. The formation is composed of sequences of sands and shales (paralic siliciclastics) with a thickness of up to 13,000 ft. It constitutes the main hydrocarbon reservoir in the Niger delta (Tuttle et al. 1999). The Benin Formation comprises the youngest sediments in the delta, deposited from the Eocene to the Holocene. This formation comprises mainly alluvial sands with a thickness of about 4600 ft (Avbovbo 1978; Obaje 2009). The Benin Formation serves as an overburdened rock in the Niger delta (Sanuade et al. 2017).

Structural setting

The Niger delta is an extensional basin rifted from the Late Jurassic to the Late Cretaceous and is considered one of the basins formed due to the failing arm of the triple junction. The extensional force created a system of trenches and

ridges in the Atlantic Ocean and troughs on the western margin of Africa (Tuttle et al. 1999; Whiteman 2012; Anomneze et al. 2020). The Niger delta is situated between the Benue trough and the Atlantic Ocean (Corredor et al., 2005). The Niger delta Basin is surrounded by a mega tectonic frame such as the Benin and Calabar flanks, which represent the northwestern and eastern boundaries of the delta, respectively. The Anambra Basin and the Abakaliki High represent the northern boundary (Fig. 3A; (Tuttle et al. 1999)). The delta started to spread out over the continental–lithospheric transition zone during the Eocene and has since started to prograde the sediments over the oceanic crust of the Gulf of Guinea, reaching a total progradation of 250 km with a sediments thickness of about 12 km (Obaje 2009; Reijers 2011). The dominant subsurface structures in the Niger delta are the syn- and post- sedimentary listric and growing faults, which affect the main delta sequence (Fig. 3B). The growing fault system is a series of major growing faults that increase in space and become younger as the delta progrades southwards (Doust and Omatsola 1989). Some structural features are associated with the growth fault systems, such as rollover anticlines, shale ridges, and shale diapirs (Hosper 1971; Merki 1972). The syn-sedimentary structures produced from the gravity sliding during sedimentation cause structural complexity in the Niger delta (Basile et al. 2005).

Petroleum system

The Niger delta is one of the largest regressive deltas globally and covers about 300,000 km^2 (Ekweozor and Daukoru 1994; Samuel et al. 2009; Sonibare et al. 2008). It consists of three petroleum systems: Tertiary (deltaic), Upper Cretaceous–Paleocene (marine), and Lower Cretaceous (lacustrine) petroleum systems. The Tertiary petroleum system is the only system that contributes to hydrocarbon production, while the other two petroleum systems have not been proven to contribute to the hydrocarbon production in the basin (Haack et al. 2000). The charging of matured hydrocarbons is believed to be coming from the thick Akata Formation deposited during the rapid prograding sedimentation in the Niger delta. However, the base of the Agbada Formation may also contribute as a source rock (Esegbue et al. 2020). Unfortunately, there is not enough knowledge about the regional distribution of source rocks all over the basin because of the lack of deep wells that penetrated the source rock (Samuel 2008).

The thicker paralic sandstones represent good reservoir facies within the Agbada Formation, with a porosity value of 40% and a permeability of 2000 mD (Edwards and Santagrossi 1990; Adelu et al. 2016). The growth faults led to the lateral variations in reservoir thickness (Tuttle et al. 1999). Sand is found in stacked channels and point bars, distributary channels, and coastal barrier bars, while the main trap
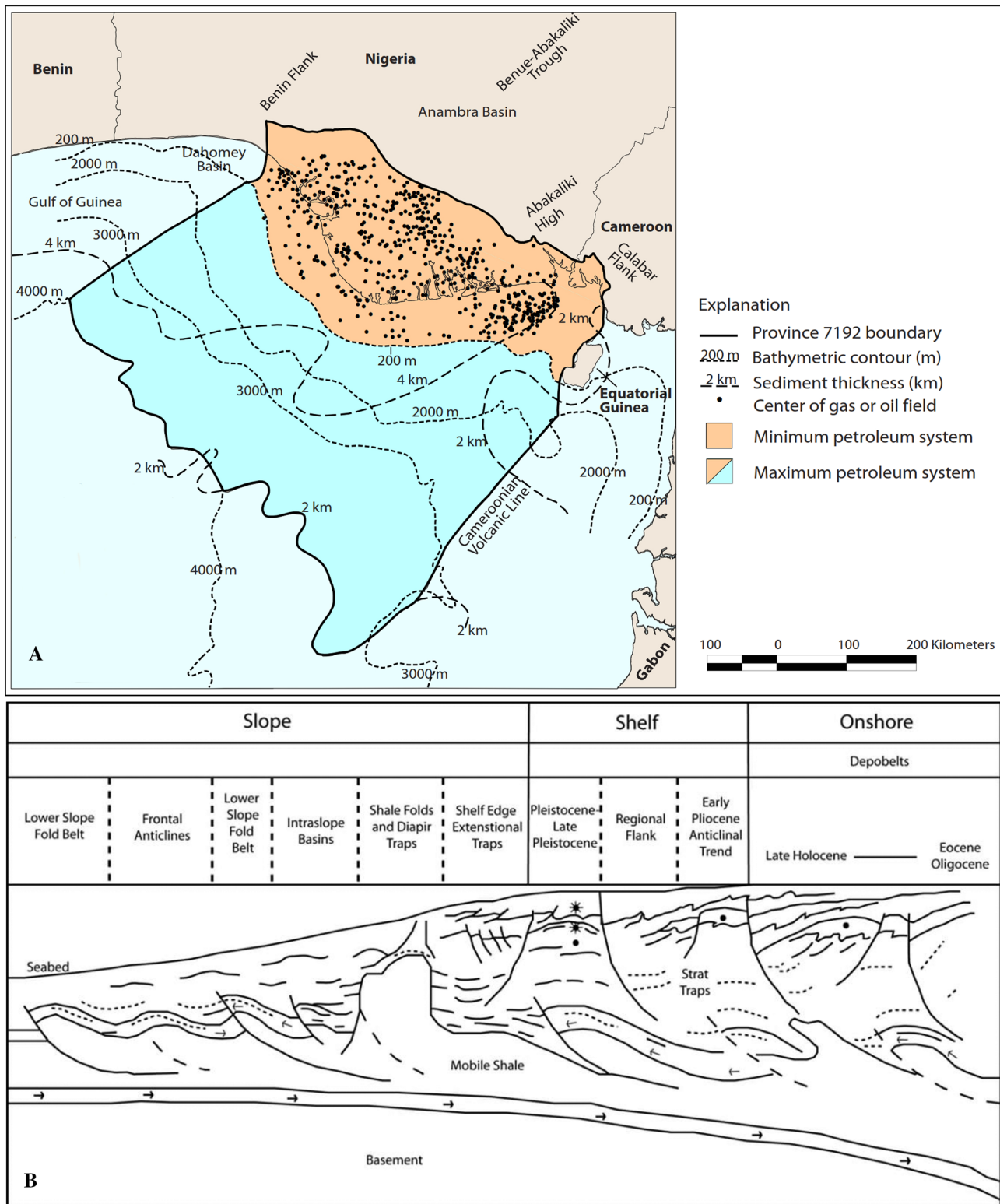
Fig. 3 **A**) Map of the Niger delta showing Province outline, indicating by colors to the maximum and minimum petroleum system as defined by oil and gas field center points, with major structure elements in the delta (Tuttle et al. 1999), **B** Schematic structural profile of the Niger delta perpendicular on shoreline, shows the listric and growth faults with gentle rollover anticline (Ojo, 1996)

type in the Niger delta is structural traps such as rollover anticlines (Owoyemi and Willis 2006). The interbedded shale smear along the faults acts as a horizontal seal, while the shale also represents the vertical seal for the sand reservoirs in the Agbada Formation (Doust and Omatsola 1990; Abdel-Fattah et al. 2019). In the Niger delta, the growth faults represent the pathways for hydrocarbons from the Akata Formation to the Agbada Formation (Tuttle et al. 1999).

Materials and methods

This study used wireline logs from 13 wells to estimate TOC generation zones and evaluate hydrocarbon reservoirs at the Otumara Field, Niger delta. The wireline logs used include resistivity (Rt), gamma-ray (GR), density (ρb), neutron (ΦN), sonic (ΔT), caliper, and composite logs. The wireline logs were analyzed using TechLog® software to identify reservoir zones and estimate matrix density, porosity, permeability, water saturation, clay percentage, and hydrocarbon saturation. In addition, we employed PetroMod® software to estimate TOC and thermal maturity (Maleki et al. 2021). 3D seismic data, which covers an area of 165 km², was also available for this study. The 3D seismic data delineated the reservoir zones and determined the structural effect on the area. In addition, the wireline data were employed for sequence stratigraphic analysis following the standard techniques by (Catuneanu 2006).

Source rock evaluation

We employed the $\Delta LogR$ technique to estimate the TOC as Passey et al. (1990) proposed. In this technique, the sonic/resistivity, neutron/resistivity, and density/resistivity integration were used to provide information about the presence of organic matter in the rocks. The separation between sonic/neutron/density and resistivity logs was used to estimate the $\Delta LogR$ according to Eqs. 1, 2 and 3. It is believed that the offset produced by rocks rich in the organic matter would be due to low density and low velocity of kerogen on the neutron and density logs and the response of the resistivity logs to the formation fluids.

$$\Delta Log\, R_{sonic} = Log_{10}\left(R/R_{baseline}\right) + 0.02\, x\left(\Delta t - \Delta t_{baseline}\right) \quad (1)$$

$$\Delta Log\, R_{neutron} = Log_{10}\left(R/R_{baseline}\right) + 4.00\, x\left(\Phi N - \Phi N_{baseline}\right) \quad (2)$$

$$\Delta Log\, R_{density} = log_{10}\left(R/R_{baseline}\right) - 2.50\, x\left(\rho b - \rho b_{baseline}\right) \quad (3)$$

where $\Delta Log\, R$ is the curve separation measured in the logarithmic resistivity cycle; R is the resistivity (ohm-m)

measured by the logging tool; $R_{baseline}$ is the value of resistivity corresponding to the $\Delta t_{baseline}$, $\Phi N_{baseline}$, and $\rho b_{baseline}$ which represents the curved values for non-source rock lithology. Δt is the measured transit-time in msec/ft; ΦN is the measured neutron porosity scaled in the fraction unit, and ρb is the measured bulk density in g/cm³.

Since the $\Delta Log\, R$ separation is linearly related to the TOC and is a function of maturity (Kamali and Mirshady 2004; Mahmoud et al. 2017; Wang et al. 2019), the empirical equation for calculating TOC in organic-rich rocks from $\Delta Log\, R$ is given by Eq. 4 (Passey et al. 1990):

$$TOC = (\Delta Log\, R)\, x\, 10^{(2.297 - 0.1688\, x\, LOM)} \quad (4)$$

The TOC is measured in wt%, and LOM (level of organic metamorphism) is the maturity.

In this study, we applied the above technique of $\Delta Log\, R$ to well TD46 which reaches 11,500 ft and penetrates the Akata Formation by 3300 ft. Prior to the application of the technique to the well, we estimated the amount of LOM from the burial and thermal history and the relationship between the maximum temperature (T_{max}) and effective heating time (T_{eff}) (Mohamed et al. 2016; Hood et al. 1975; Passey et al. 1990).

Reservoir sand bodies evaluation

Petrophysical interpretation is typically implemented to process the geophysical log data into physical parameters such as shale content, permeability, porosity, water, and H/CS saturation. Practical evaluation of these reservoir properties would considerably boost the competence to discriminate among hydrocarbon and nonhydrocarbon bearing zones (Radwan et al. 2020). From the GR log, we calculated the volume of shale (Vsh) for the reservoir sand bodies using Eq. 5, and the results were confirmed using Neutron-Density logs.

$$V_{sh} = 0.33 * [2(2 * IGR) - 1] \quad (5)$$

where IGR is the index of gamma-ray, which is calculated by using Eq. 6 (Schlumberger 1974):

$$IGR = \left(GR_{log} - GR_{min}\right) / \left(GR_{max} - GR_{min}\right) \quad (6)$$

where:

GR_{Log} is the reading of the GR log in the reservoir formation, GR_{min} is the minimum reading of the GR log in front of clean sand, and GR_{max} is the maximum reading of the GR log at shale lithology.

The porosity was calculated from the neutron and bulk density log (ρ_b) using the Eq. 7 of Tiab and Donaldson (1996) and Eq. 8 of Wyllie et al. (1958), respectively.

$$\Phi_{Ncorr} = \Phi_N - (V_{sh} * \Phi_{Nsh}) \tag{7}$$

where Φ_{Ncorr} is corrected porosity for clean rock from shale and Φ_{Nsh} is the neutron porosity value for shale.

$$\Phi_D = (\rho_{ma} - \rho_b) / (\rho_{ma} - \rho_f) \tag{8}$$

where ρ_{ma} is the density of the matrix, ρ_b is the bulk density measured from the log, and ρ_f is the fluid density.

Then, the effective porosity (Φ_e) was calculated by using Eq. 9 (Schlumberger 1998) after correcting the total porosity (Φ_t) from the shale effect.

$$\Phi_e = \Phi_t * (1 - V_{sh}) \tag{9}$$

The water saturation was calculated from Archie's equation (Archie 1952), using Eq. 10.

$$S_w = [(a / Fm) * (R_w / R_t)](1/n) \tag{10}$$

where S_w is water saturation, Fm is the formation factor ($= 1/\Phi^m$), R_w is derived from the value of deep resistivity log in front of the pure water-saturated zone around the reservoir, R_t is the observed deep resistivity, and the constants a, m and n are Archie's coefficients were determined from Pickett plot.

We used the empirical Eq. 11 proposed by Wyllie and Rose (1950) to calculate the permeability of the reservoirs.

$$K = (250 \text{ x } (\Phi^3 / S_{wir}))^2 \tag{11}$$

where K is permeability in millidarcies (mD), Φ is porosity, and S_{wir} is irreducible water saturation. The irreducible water saturation is the amount of water in the oil zone and calculated from Eq. 12.

$$S_{wir} = [C/(\Phi/(1 - V_{cl}))] \tag{12}$$

where V_{cl} is the volume of shale and C is Buckles's constant.

Burial history

The burial history of the basin is estimated based on the thickness, depth, and temperature of each rock unit (Table 1). Typically, the thermal model of the lithologies shows the deposition history and the temperature versus depth calibrated by vitrinite reflectance (Ro). Doust and Omatsola (1990) estimated the thickness of the Akata Formation, which is up to 7000 m (~ 23,000 ft) in the central part of the basin, while the Agbada Formation reaches up to 3700 m (~ 12,000 ft) in the central part of the basin. Avbovbo (1978) estimated the thickness of the Benin Formation at 2000 m (~ 6500 ft). By estimating the total thickness of the sedimentary section in the delta, Tuttle et al. (1999) created depth and thickness maps of the three Tertiary formations. Consequently, we designed the burial history and thermal models (Fig. 4). The thermal information was correlated and calibrated by Emujakporue et al. (2009)'s thermal model for the Niger delta.

Results

Sequence stratigraphy

We carried out the sequence stratigraphy analysis using the wireline data. The stratigraphic section response to E-logs provides evidence for long- and short-term sea-level change. The sequence comprises an alternation of clastic lithologies that occur in combined depositional packages of progradation offlap cycles. The shale of the Akata Formation collapsed under the load of prograding deltaic Agbada and fluvial Benin Formation deposits (Owoyemi and Willis 2006; Magbagbeoloa and Willis 2007; Durand 1995). The formation of the Niger delta clastic started in the Eocene age and continued until the Holocene, which lasted for 54.6 Ma, and a thick succession of 12 km prograded over the continental basement into the Gulf of Guinea. A long regression occurred in the Eocene and extended through the last 40 Ma (Fig. 5), resulting in offlapping sediments delta-wide. The deepest well in this study penetrates the

Table 1 Burial history and thermal model parameters

Formation	Top (m)	Base (m)	Thick-ness(m)	Depo. From [Ma]	Depo. To [Ma]	Lithology	PSE	Temp. °C at 36 Ma	Vitrinite reflectance % (R_o) at 36 Ma
Benin	0	1300	1300	11.5	0	Sandstone	overburden rock		
Agbada	1300	2750	1450	32	11.5	Sand & Shale	reservoir rock	74–115	0.6–1.5
Akata	2750	11,000	7250	60	32	Shale (organic rich)	source rock	167–382	1.5–4
Basement	11,000	–	–	–	60	Basement	Base		

Fig. 4 The thermal model of the lithologies shows the deposition history and the temperature versus depth for well TD-46, calibrated by vitrinite reflectance (R_o)
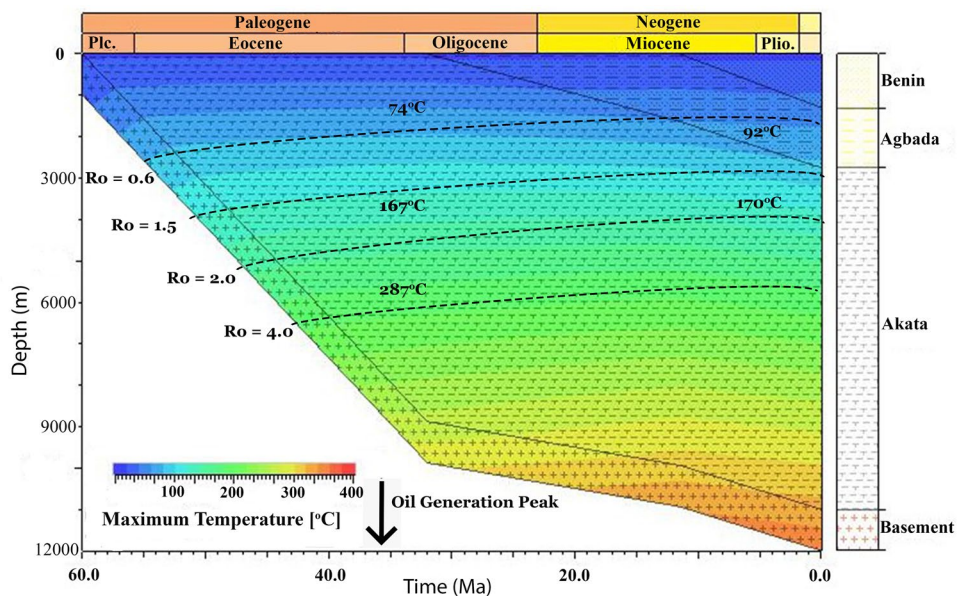
top of the Akata Formation, at 9500 ft (~ 30 Ma), which is deposited at the highest point of the eustatic sea-level curve. During the mega-sequence regression of the sea level, TA4, TB1, TB2, and TB3 second-order supercycles that occurred through the Cenozoic were obtained in well TD46. These supercycles are heterogeneous in time duration and sediment packages due to differences in eustatic sea-level above the Niger delta through the mega-regression first order cycle. The Upper Akata Formation deposited during the TA4 cycle, which lasted for 13.4 Ma, is characterized by basinal and slope marine shale facies with sporadic lowstand turbidite sands that are often overpressured. Regional shale markers (Uvigerinella-8, Orogho shale, and Uvigerinella-5) were deposited in this cycle as part of the lithotype of the Akata Formation (Fig. 5). The Agbada Formation, formed during the supercycles TB1, TB2, and TB3, was characterized by facies of regular sand shale alternations and transitional marine to shoreface deltaic facies throughout a 27.82 Ma period (Reijers 2011; Doust and Omatsola 1990). Seven regional shale markers were deposited during the deposition of the Agbada Formation. These include Alabamina-1, Ogara shale, Chilogembelina-3, Cassidulina-7, Dodo shale, Uvigerina-8, and Bolivina-46, which acted as a vertical seal for the sand reservoirs of the Agbada Formation (Fig. 5). At the top of the succession, the Benin Formation is composed of non-marine sand deposited in alluvial or upper coastal plain environments during the progradation of the delta (Oluwajana et al. 2017; Doust and Omatsola 1989). During the second-order long-term fall of the eustatic curve, between the supercycles TA4 and TB1, the Opuama Channel started in the western delta and underwent, in its lifetime, several phases of incision and filling, resulting in a set of nested channels (Knox and Omatsola 1989). This complex

channel reflects high periodicity in sea-level change, with alternating erosion and fill. As the sea level rise, the adjacent shore-face sands destabilized and triggered slumping and gravity transport, resulting in chaotic sand deposits on the shoreface and the basin slope.

Source rock potential

The thermal model (Fig. 4) derived from 1D modeling of well TD46 shows that the Upper Akata Formation and the Lower Agbada Formation temperatures were 287 °C and 167 °C, respectively, before the oil generation peak (36 Ma). These temperatures appear to be sufficient to mature the organic matter. The cross-plot of the effective heating time (T_{eff}) versus the maximum temperature (T_{max}) shows that the LOM value of the Upper Akata Formation ranges between 12 and 16, which are equivalent to 27 and 33 kcal, while the vitrinite reflectance (R_o) value ranges between 1.5 and 4%. The LOM and R_o values obtained in this study indicate that the organic material in the Upper Akata Formation was found in the oil generation window. On the other hand, the Lower Agbada Formation at Miocene-Pliocene age reached the maturity zone with a temperature of 170 °C, R_o between 1.5 and 2%, and a LOM range from 9 to 11. These conditions show that the organic matter also falls within the oil generation window. However, the Lower Agbada Formation reached the maturity condition in the Neogene age after the oil generation peak (36 Ma), which is likely to be the present oil generation from the Akata Formation.

We calculated LOM to derive the TOC values from the E-logs, as shown in Eq. 4. The log-derived TOC values (Fig. 6) range between 0.6 and 3.4 wt% at the depth range of 4459 ft (Agbada Formation) to 11,545 ft (Upper Akata

Fig. 5 Sequence stratigraphy analysis of well TD46, the deepest well drilled in the Otumara oil field
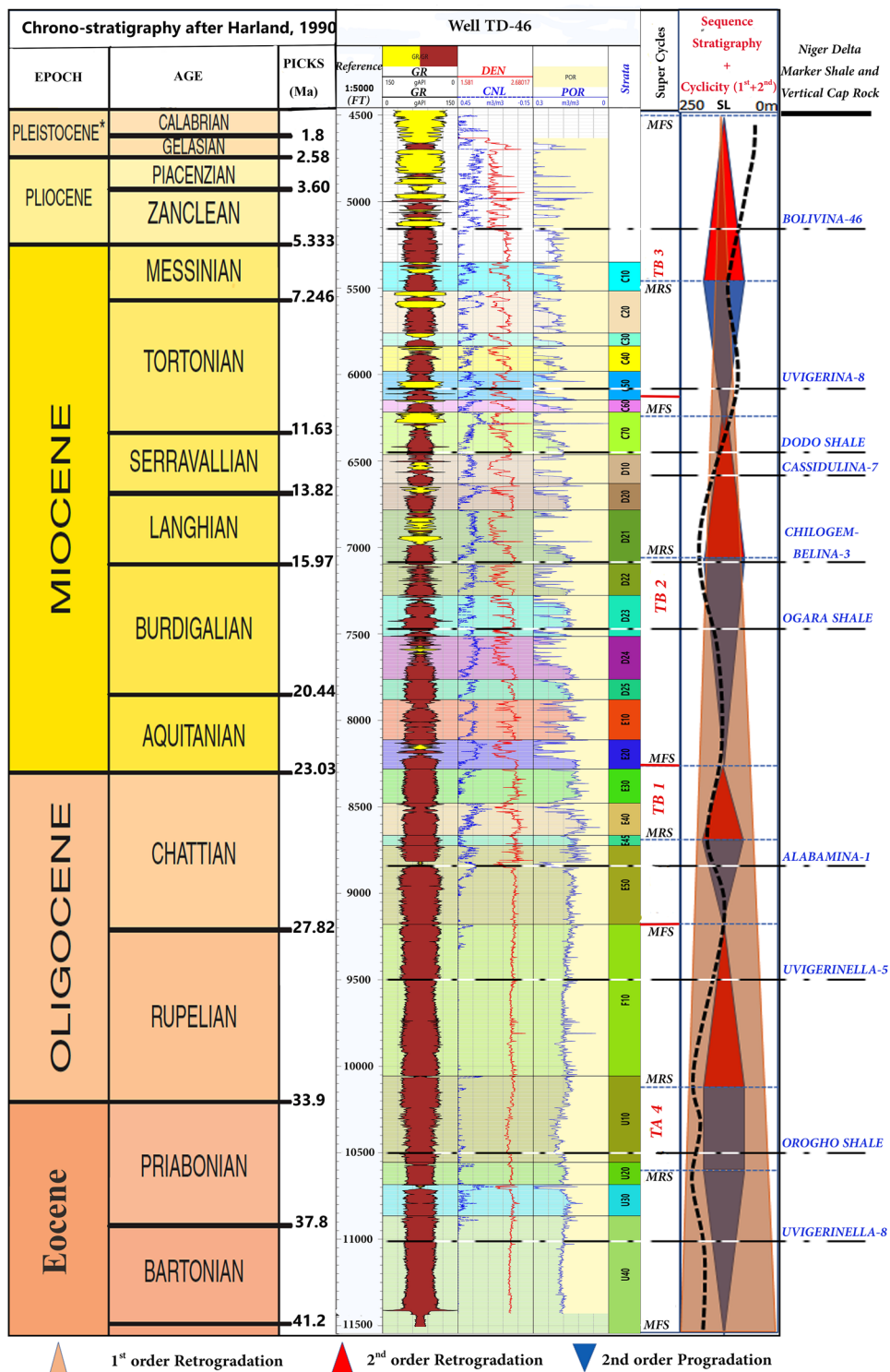
Formation). The highest TOC values (1.5–3.4 wt%) are concentrated in the Agbada Formation at depths of 4700 to 5200 ft (Fig. 7). The TOC values between 0.6 and 1.5 wt% were found in the Lower Agbada Formation and the Upper Akata Formation at depths between 5,500 and 11,000 ft. However, only the Upper Akata Formation entered the oil generation window before the expulsion time (36 Ma), and a large amount of reserved hydrocarbons in the Niger delta may be due to the extensive thickness of the source rock facies that contains organic carbon. Therefore, the high TOC values that characterized the Agbada Formation are
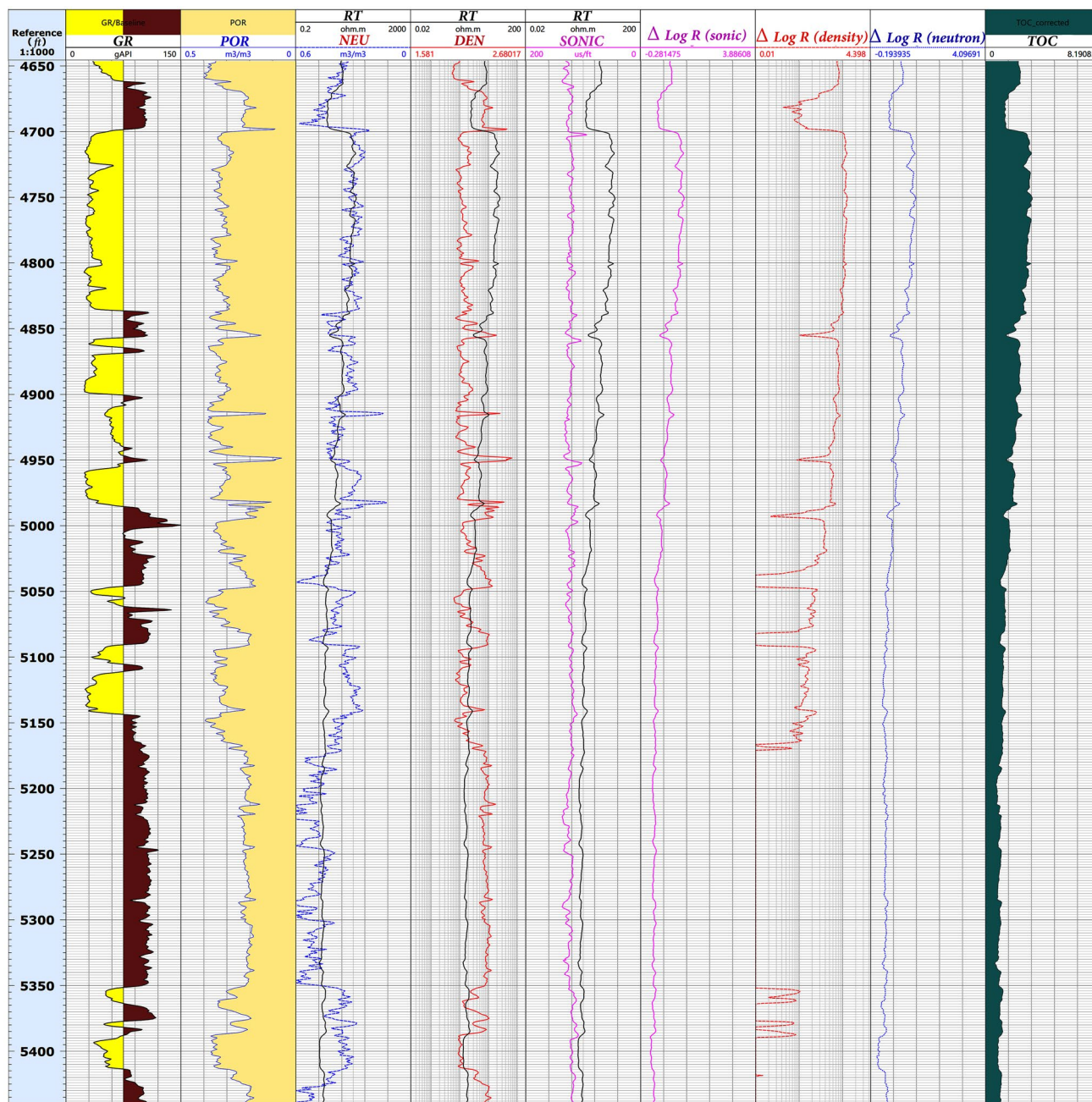
Fig. 6 Layout showing log-derived TOC using Passey et al. (1990) method of sonic/resistivity, neutron/resistivity, and density/resistivity overlays and the calculated Δ log R. The yellow color in GR-log for sand zone and the brown color for shale zone

likely to result from fluvial-deltaic processes as estimated from the gamma-ray log.

Spatial distribution and reservoir characteristics of the Agbada formation

The Niger delta is characterized by a complexity of structural, stratigraphic, and faulted stratigraphic traps that developed during the deformation of the Agbada Formation (Stacher 1995). Most of the reservoirs are sandstone and the sands of the paralic Agbada Formation with facies characteristics that depend on the depositional environment (Tuttle et al. 1999). In this study, the Otumara Field was observed to have many reservoir facies in the sedimentary column of the Agbada Formation, but the most significant sand bodies in this area are the sand bodies of slope fan and river mouth sandbar, as obtained from the seismic data and correlation of the wireline logs.

Fig. 7 **A** TOC vs depth cross plot shows the concentrations of TOC at different depths, **B** The histogram and associated statics show the cumulative TOC values through the well TD-46
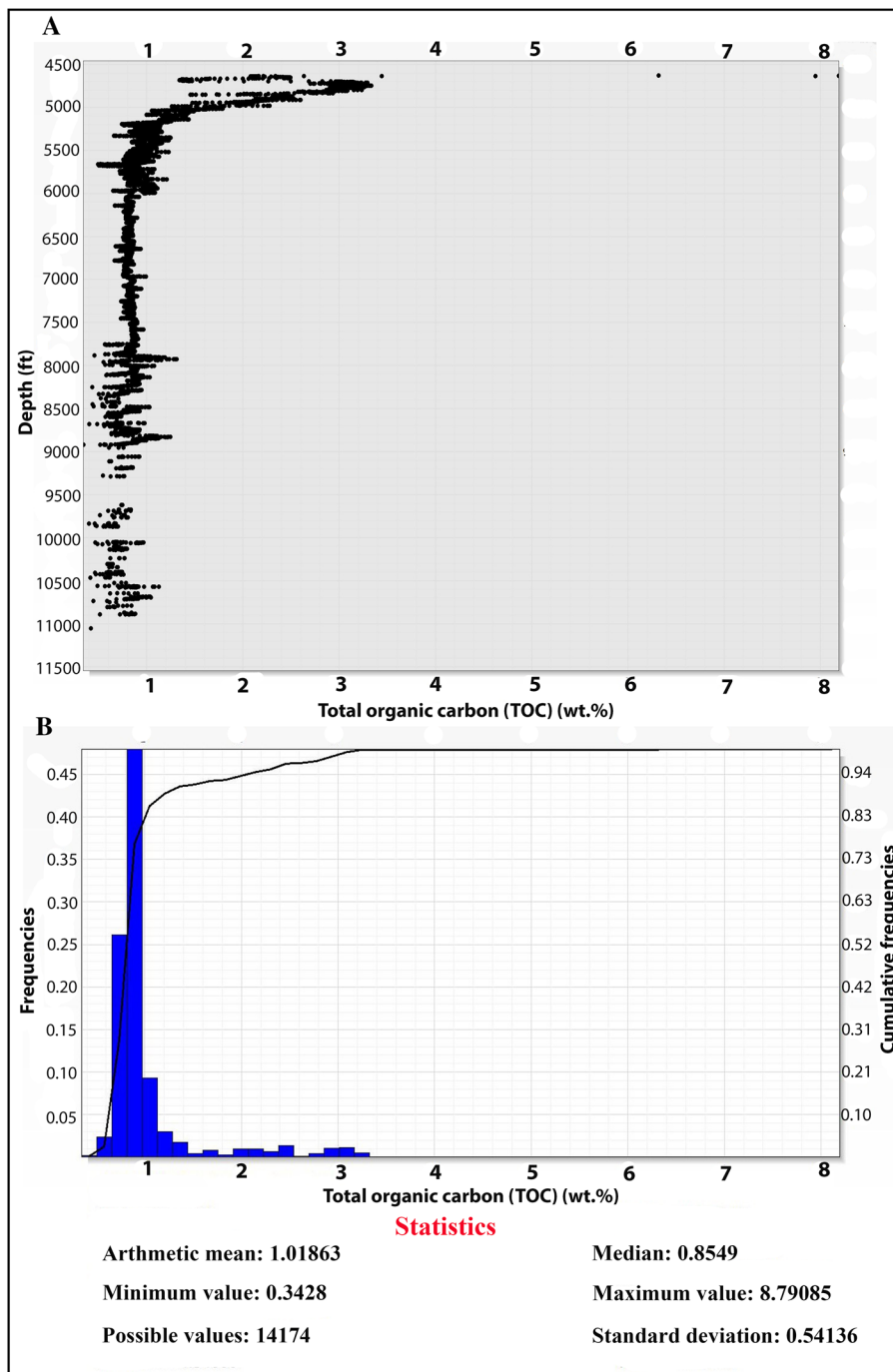
The depositional environments of these reservoirs are deltaic distributary channels and coastal barrier bars. However, most of the channels, coastal barrier bars, and other basin slope sand bodies appear to be faulted by listric and growth faults (Fig. 8). The throw and displacement of the growing faults strongly control the lateral variation in reservoir facies and thickness.
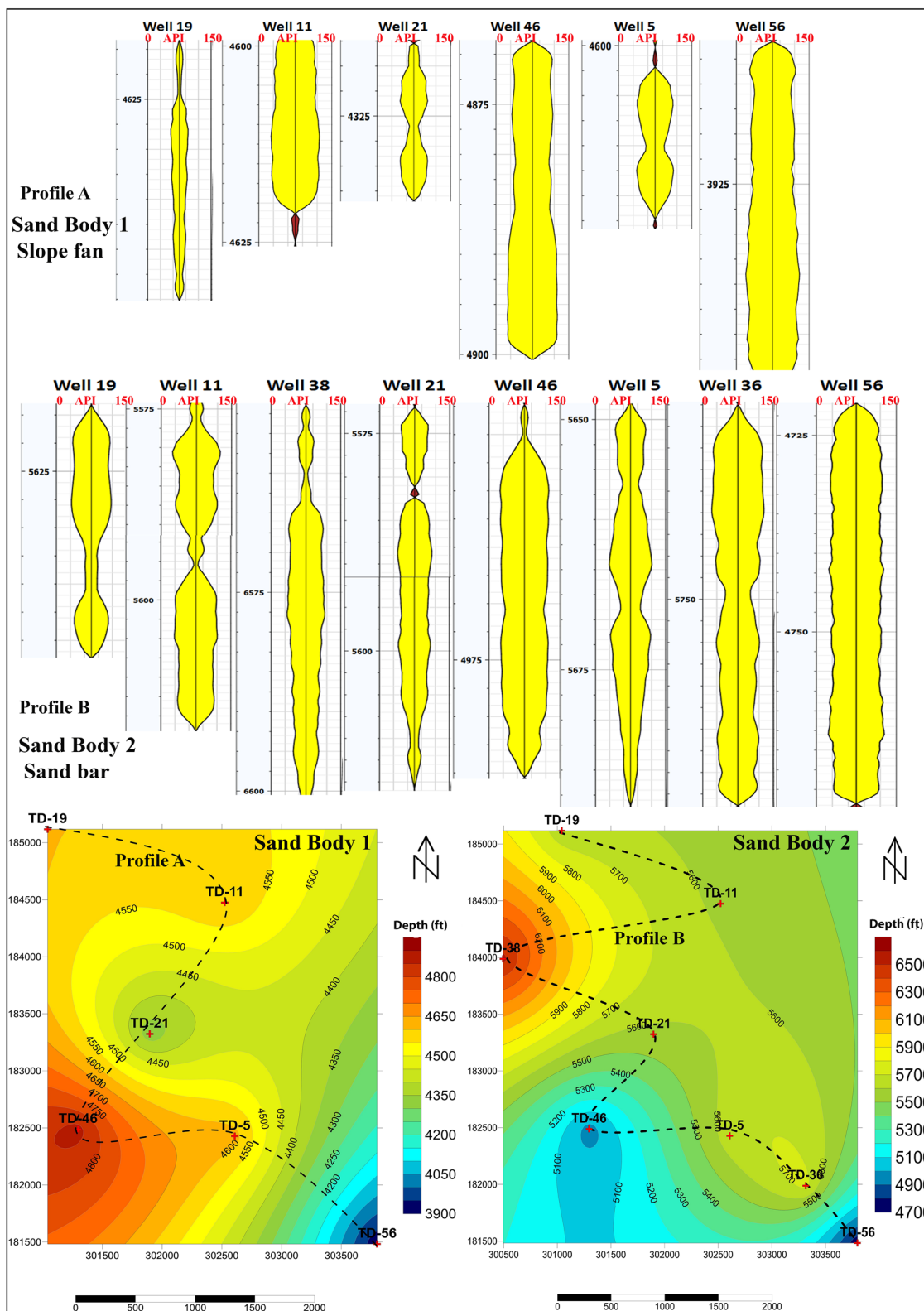
Sand body 1 (slope fan)

The interpretation of wireline logs in 13 wells shows that this sand unit was formed on the upper shoreface due to the progradation of sediments' fluid from the river. The depth of the sand body ranges between 3900 ft at the southeast corner and 4900 ft at the southwest of the fan
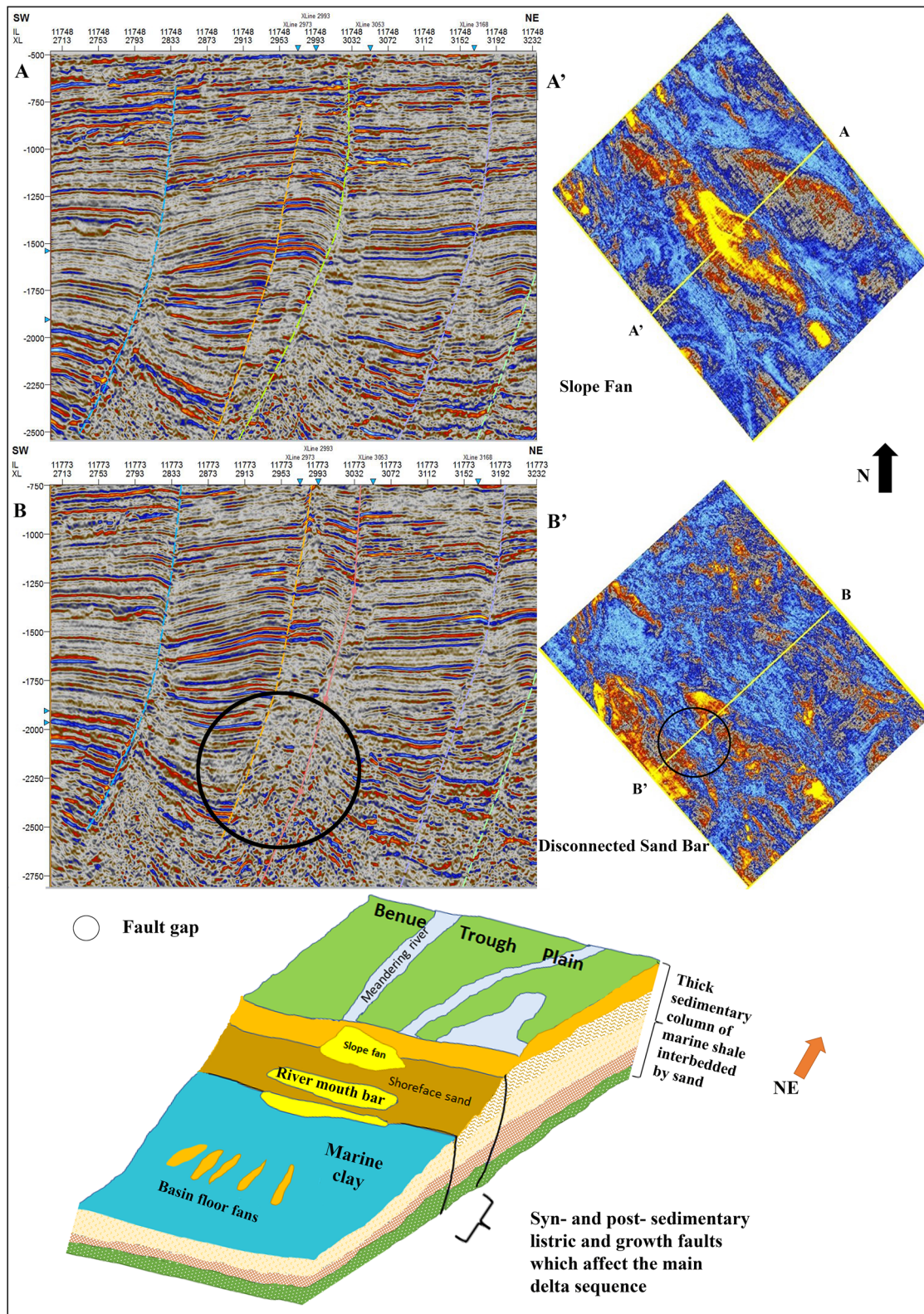
Fig. 8 The sand body 1 (slope fan) and sand body 2 (sandbar) on time slices cute by profiles (A-A') and (B-B'), respectively, to show the faulting of the sand bodies on the shoreface by a series of listric and growth faults. Below, the sketch obtain the depositional environment of the shoreface sand bodies

Fig. 9 The depth maps of the slope fan (sand body 1) and the sandbar (sand body 2) with two well-correlation sections passing through the wells in which the facies appear and show the sand bodies shape by mirror image of gamma ray log. The GR log is scaled from 0 to 150 API in both directions

(Fig. 9). The thickness ranges from 5 ft in the northwest to 35 ft in the southeast and southwest of the fan. The net pay and the petrophysical parameters of sand body one are mapped in Fig. 10 The average volume of shale is 14% and reaches 26% in the central part of the southeast and northwest, and less than 1% in the northeast and southwest. The average effective porosity is 21% and reaches a maximum of 35% in the southwest, where the permeability reaches 3000 mD and decreases towards the northwest to 100 mD. The highest percentage of hydrocarbon saturation lies in the southern half of the sand body, which is the thickest part of the sand body. The variation in petrophysical parameters is controlled by the slope and depth, which

could cause a change in the cementation and compaction of the reservoir facies.

Sand body 2 (coastal sandbar)

Sand body 2 is a deltaic front barrier sandbar deposited on the upper shoreface due to the progradation of the sediments. It lies below the sand body (1) by 1000 ft at a depth range between 4700 and 6700 ft, and the reservoir thickness varies from 16 ft in the southeast to 50 ft in the east, center, and western parts. The high range of depth of the sandbar, which is about 2000 ft, can be related to the faulting of the sandbar body by growth faults that separated the bar into two blocks:

Fig. 10 Layers illustrating the petrophysical parameters of sand body (1), the slope fan, showing the distribution of; the volume of shale (Vsh), effective porosity, permeability (K), hydrocarbon saturation (Sh), and net pay thickness
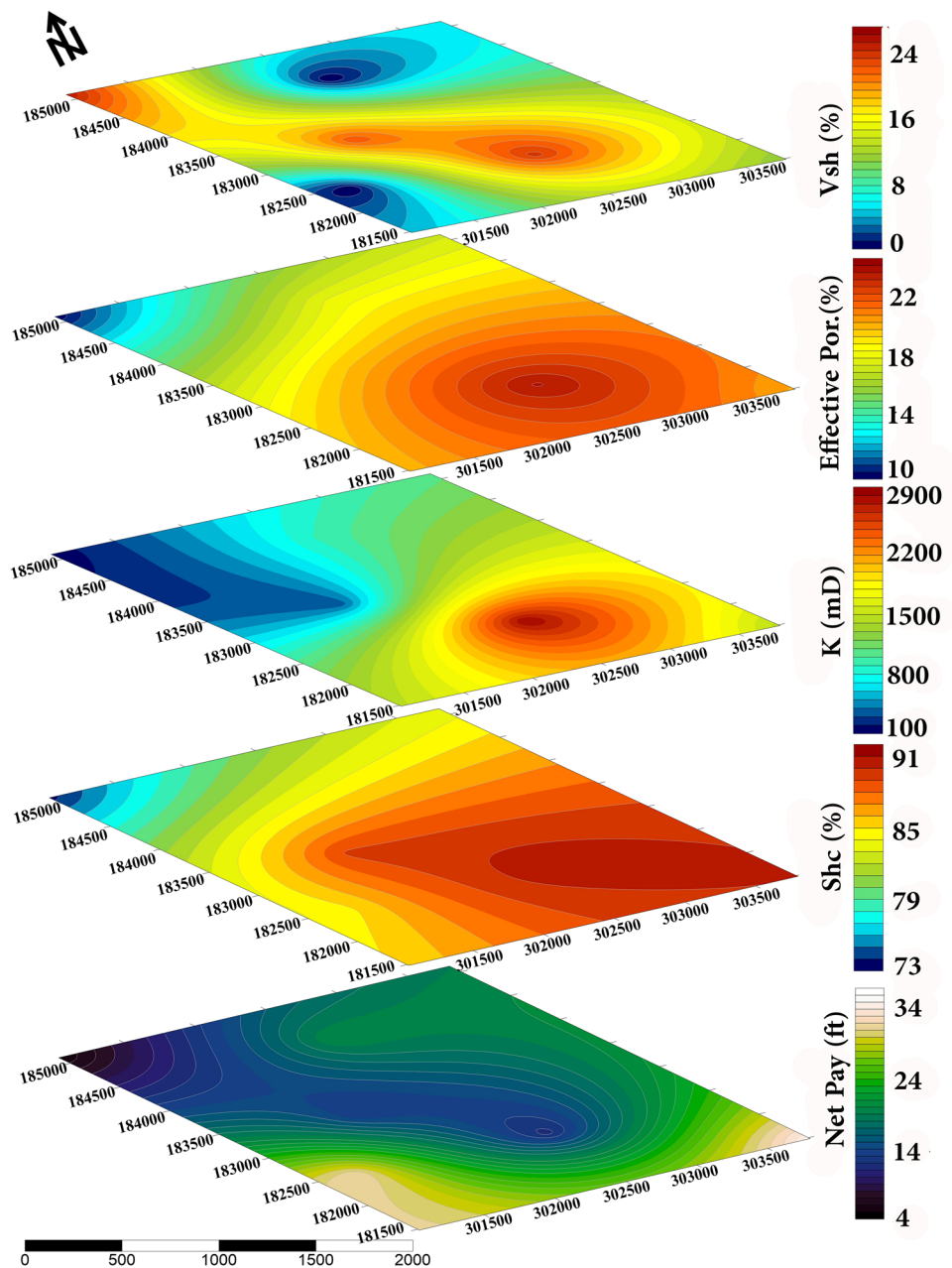
northern and southern blocks. The petrophysical parameters of the southern block of the sandbar showed more potential than the northern part, where the shale volume is about 20% while it reaches 40% in the north (Fig. 11). The average effective porosity is 18% but increases to 26% in the south, and the average value of permeability is about 1310 mD, increasing to 3800 mD in the south. The hydrocarbon saturation reached 94% in the southern half of the body, while it decreased northwards to 60% in the northeastern part of the sandbar body.

Distributary sand channels

We also delineated other hydrocarbon pay zones, which are dispersed as the channel fills at varied depths, reaching 8300 ft (Fig. 12). However, the lithology at this depth is thick shale, which can be related to marine sediments of the Akata Formation. These dispersed pay zones may not contribute to hydrocarbon production because they are thin pay zones with large internal spacing, making them difficult targets.

Fig. 11 Layers illustrating the petrophysical parameters of sand body (2), showing the distribution of; the volume of shale (Vsh), effective porosity, permeability (*K*), hydrocarbon saturation (Sh), and net pay thickness
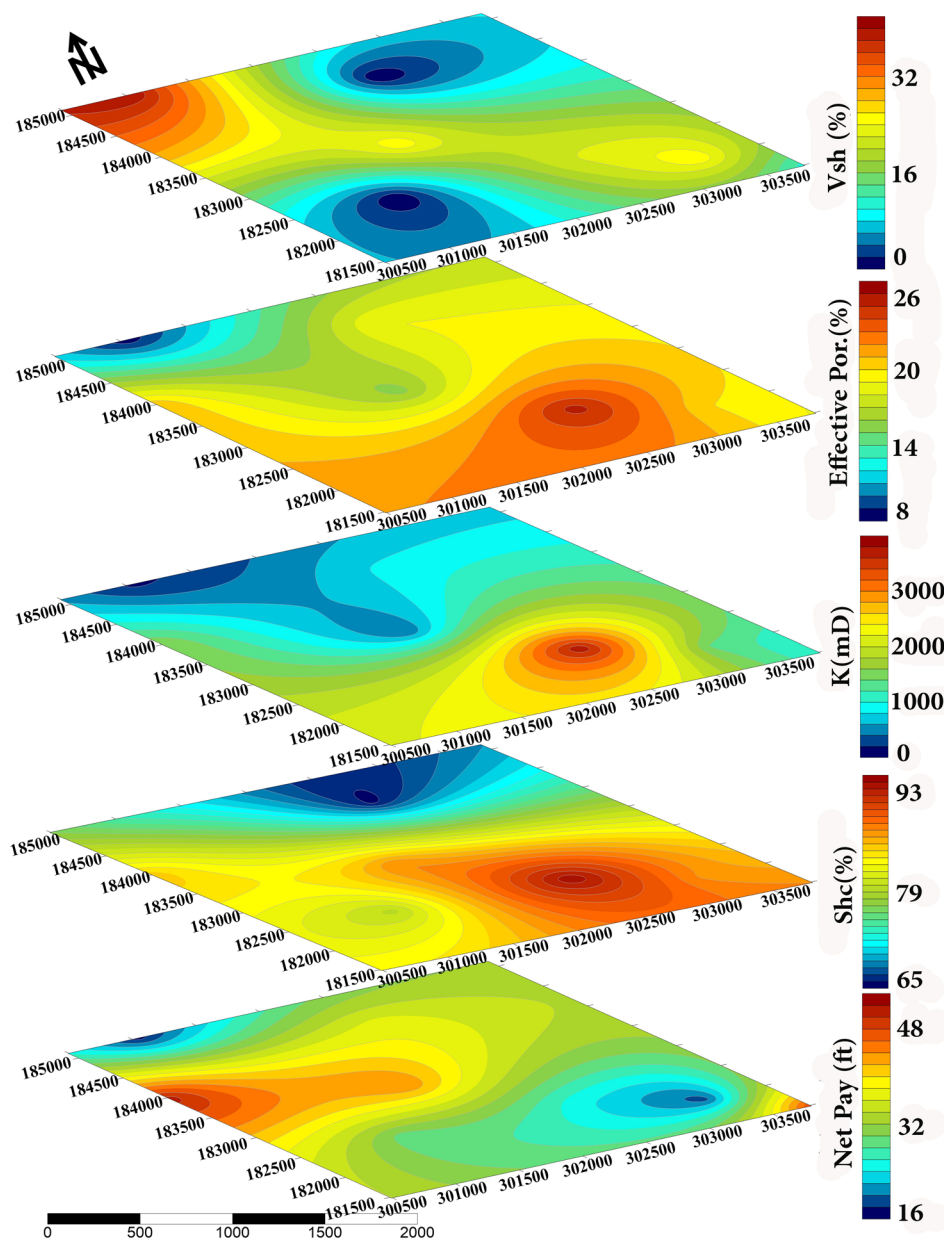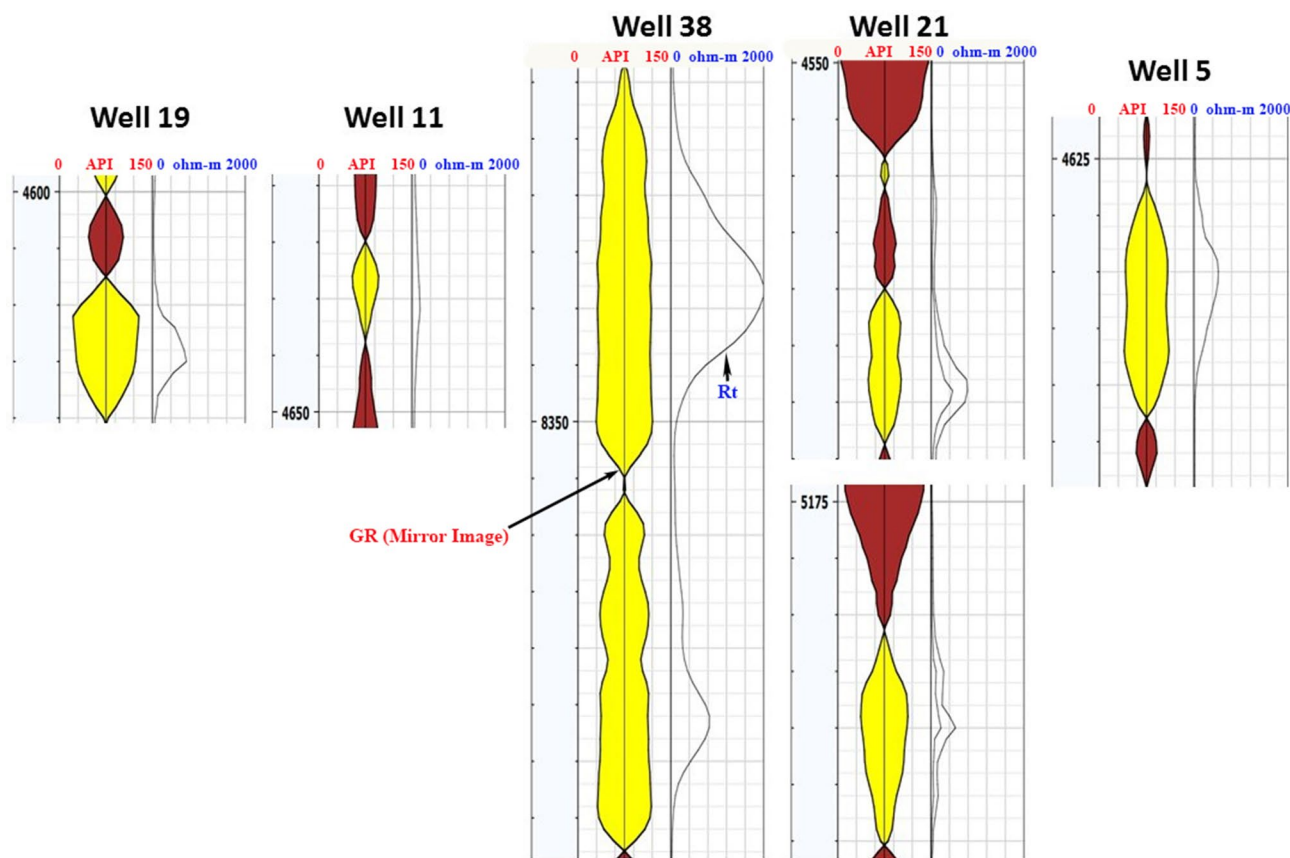
Fig. 12 Scattered signatures of channels filled with reservoir facies at different depths, using mirror image of gamma ray log. The GR log is scaled from 0 to 150 API in both directions

Discussion

We will discuss the existing petroleum system elements in the Otumara Field based on previous petrophysical, sequence stratigraphy and source rock analysis:

I.   *Source rocks*

Our study used the "ΔlogR" separation technique for calculating the TOC values from the wireline data (sonic, density, neutron, and deep resistivity). The shale sequences of the Akata and Agbada Formations are of marine and deltaic origin, in an arrangement that provided favorable conditions for preserving organic matter. The TOC ranges estimated for the Akata, and Agbada Formations lie between 0.6 and 3.4 wt%, qualifying them as a fair to excellent source rocks (Peter 1986). The log-derived TOC values are significantly correlated to those reported in the literature for the Niger delta. The values vary widely from 0.9 to 2.2 wt% (Bustin 1988), 2.3–2.5 wt% (Ekweazor and Udo 1988), and 0.21–4.22 wt% (Akinlua and Torto 2011). Therefore, the published

laboratory measurements from nearby fields verified the results from our study. The advantage of the log-derived TOC values deduced from the wireline is that they cover all the logged sedimentary succession, which ranges between 4500 and 11,500 ft.

Petroleum system modeling (PSM) applied to the studied succession shows that prolific shales lie in the temperature window suitable for hydrocarbon generation. The preliminary evaluation in this study shows the high TOC values within the Agbada Formation and the high maturity of the kerogen within the same formation, which make it an excellent potential unconventional resource. However, only the most profound part of the formation can be considered a source rock that is currently expelling the hydrocarbon and does not contribute to the produced oil trap because this part of the formation reached the source rock condition after the oil peak generation. The Akata Formation is found in extensive volumes beneath the Agbada Formation and generates enough oil to fill the traps in the Niger delta. This finding agrees with Ekweazor and Okoye's (1980) and Weber

and Daukoru (1975). Based on the organic-matter type and content, Evamy et al. (1978) proposed that the source rocks of the Niger delta are both the marine shale of the Akata Formation and the shale interbedded with paralic sandstone of the Lower Agbada Formation, at a depth range between 9500 and 11,100 ft. The paleo-geographic location of the Akata Formation at the time of deposition played a crucial role in contributing to these high TOC values, as the Eocene era witnessed warmer climates that might have influenced the TOC concertation of these sediments (Sexton et al. 2011). High organic production rates of both Akata and Agbada deposits led to enhanced TOC concentration owing to the suitable paleo-environment at the time of deposition.

Furthermore, the maximum flooding surfaces across the depositional sequences of both the Akata and Agbada Formations are usually associated with high levels of organic enrichment. Slow decomposition and high production rates for the organic matter subsequently led to good organic matter preservation, as shown by the thermal maturity modeling for the studied formations in Fig. 4. According to our data, the Akata and Agbada deposits in the Otumara Field have an economical depth starting at about 4700 ft below the surface (Fig. 6), with a significant thickness (Figs. 5, 6, 7) and good to excellent TOC values (Figs. 6, 7). The results from this study and others have demonstrated how well logs are related to source rocks.

II. *Migration pathways and seal rocks*

The migration pathways of the hydrocarbons from the underlying Cretaceous Akata Formation are not proven in this study. However, Tuttle et al. (1999) suggested that the migration pathways are similar to the migration model of the Gulf of Mexico, where the hydrocarbons migrate from matured, over-pressured shales to fractured and sealed top intervals. In addition, Bellingham et al. (2014) used a deep depth-migrated seismic section of 18 s two-way travel time to confirm a severe brittle deformation in the Upper Akata Formation, which may be a good route for the hydrocarbon migration pathway to the top Agbada sealed sands. In this study, the two sand bodies (slope fan and coastal sandbar) are overlain by a thick clay that reaches a thickness of up to 1000 ft in some wells, which could be the vertical seal of the reservoir with the shales of the Benin Formation. Based on sequence stratigraphy analysis, seven regional shale markers (Alabamina-1, Ogara shale, Chilogembelina-3, Cassidulina-7, Dodo shale, Uvigerina-8, and Bolivina-46) are deposited through the deposition of the Agbada Formation and act as a seal for the sand bodies of the Agbada Formation.

III. *Reservoir*

During the Late Oligocene to Middle Miocene (34–15 Ma), which corresponds to supercycles TA4, TB1, and TB2, the incision of the Opuama Channel into the ocean divides the delta coastline into eastern and western sectors. During the Middle-Late Miocene, a large amount of sediment accumulated in the active Central Swamp and began to prograde on the basin floor in the Gulf of Guinea (Knox and Omatsola 1989). Along with this 19 Ma, the rate of sediment transportation from the Central Swamp to the ocean was changed by eustatic sea-level change, creating different forms of sand bodies such as slope fans, sandbars, channel fill, and basin floor fans. The delta progradation growth is affected by the weight of the ensuing sand accumulation and increases the delta's faulting during the Eocene. The main reservoirs in Otumara Field are slope fans and coastal sandbars on the shoreface, which faulted and threw. In our study, we have integrated the seismic work (Fig. 8), well correlation along with the sandstone bodies (Fig. 9, 12), petrophysical parameter maps (Fig. 10, 11), depositional environment (Fig. 8) to characterize the reservoirs of the Otuomara Field. The sandstone bodies' correlations of the Agbada Formation seem to have potential and good reservoir characteristics. Several sandstone bodies are deltaic deposits that formed a potential reservoir for migrated hydrocarbon from the source rocks of Akata and Agbada productive shale sequences. The sand bodies of slope fan and river mouth sandbar have the best reservoir characteristics. However, they display substantial lateral variation in reservoir facies and thickness that influences their continuity as revealed by seismic, well correlation, and petrophysical analysis.

The slope fan sandstone body is distinguished by thicknesses ranging from 5 to 36 ft, low shale volume (Avg. 14%), effective porosity (Avg. 21%), and high hydrocarbon saturation (Avg. 85%), demonstrating the sandstone body's ability to store hydrocarbons. The petrophysical maps of slope fan sand body (Fig. 10) show an excellent reservoir potential toward the southern area of the Otumara Field. The second sand body, coastal bar sandstone, is relatively thicker than the slope fan body, with thicknesses ranging from 16 to 50 ft. Because of the separation into southern and northern fault blocks due to faults, the petrophysical parameters of this coastal sand body vary. The southern block of the sandbar is distinguished by shale volume (Avg. 20%), effective porosity (Avg. 26%), estimated permeability (3800

mD), and high hydrocarbon saturation (94%). On the other hand, the northern sandbar block is characterized by shale volume (Avg. 40%), effective porosity (Avg. 18%), estimated permeability (1310 mD), and high hydrocarbon saturation (60%). According to the aforementioned petrophysical analysis, the southern sandbar block of the coastal sandstone body has a higher reservoir quality than the northern sandbar block. The petrophysical maps of the coastal bar sandstone body (Fig. 11) show excellent reservoir potential toward the southern area of the Otumara Field. Therefore, the best reservoir facies quality lies in the south; its quality decreases in all directions, whereas the clay percent increases and porosity decreases. On the contrary, the thin sandstone bodies of deeper channel fill in the Akata Formation could be hydrocarbon pay zones, however, their exploration pose drilling challenges and exploration risk due to their low thickness and discontinuity.

IV. *Entrapment style*

The entrapment style is typically controlled by structural, stratigraphic, and combined stratigraphic-structural styles (e.g., Walker 1978; Biddle and Wielchowsky 1994; Radwan et al. 2021). When the seismic and structural map of the Otumara Field was compared to the Niger delta's historical tectonic events, it was noticed that the NE-SW growth faults controlled the structural configuration of the Niger delta deposits and formed associated rollover anticlines in the studied field, which matched the general setting of the Niger delta (Fig. 13). At the Eocene age, the delta spread out over the continental–lithospheric transition zone (Obaje 2009; Reijers 2011) and prograded the sediments over the oceanic crust of the Gulf of Guinea. Hence, the Akata and Agbada Formations were influenced by combined syn- and post- sedimentary listric and growth faults (Owoyemi and Willis 2006; Magbagbeoloa and Willis 2007). The lateral variation in reservoir facies and thickness across the studied field is controlled by the throw and displacement
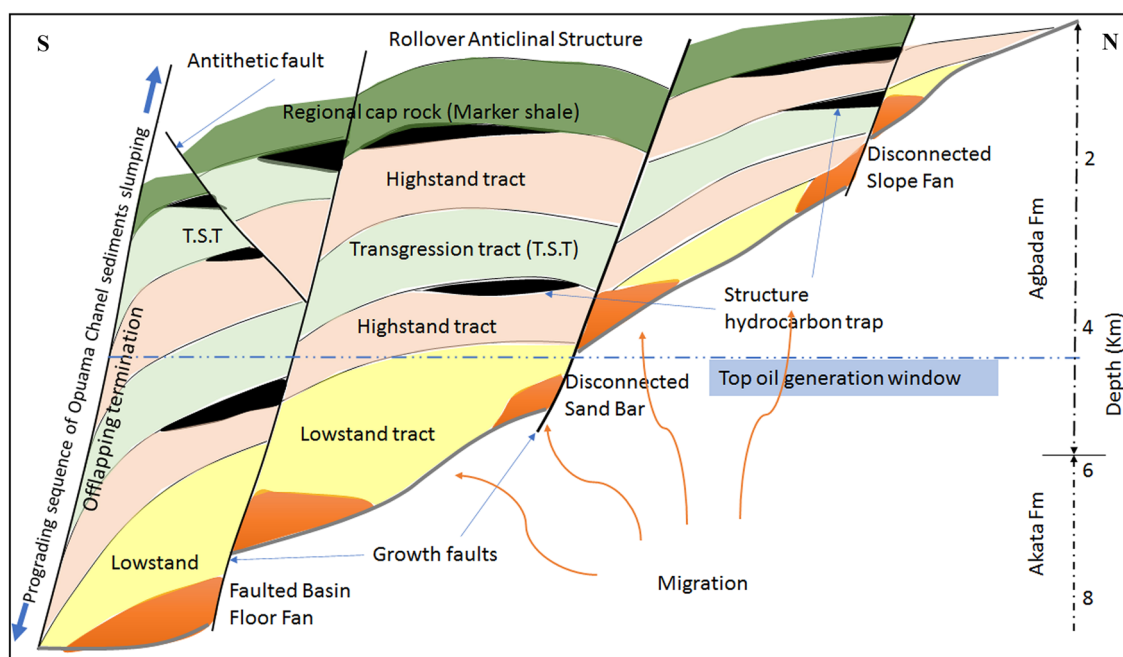
Fig. 13 Entrapping styles of the hydrocarbon in the Niger delta, including stratigraphic traps and structural traps because of the fault system. The hydrocarbon traps sealed vertically by regional marker shale

of the syn- and post-sedimentary listric and growth faults. In terms of stratigraphic traps, sandstone pinch-out is common in such deltaic depositional environments, and it can be traced across the field using seismic data. The listric and growth faults are the main controlling factors of deposition and trapping across the Niger delta and the Otumara Field in structural traps. According to seismic and well correlation, the combined effect of stratigraphic and structural trapping mechanisms may exist in the Otumara Field (Fig. 13).

Conclusion

The stratigraphic section response to E-logs provides evidence for long- and short-term sea-level change and comprises an alternation of clastic lithologies that occur in combined depositional packages of progradation offlap cycles. Four second-order supercycles, namely TA4, TB1, TB2, and TB3, were obtained. The ΔLog R technique was used to estimate the preliminary total organic carbon (TOC) at Otumara Field, onshore Niger delta. The TOC values were derived using the sonic/resistivity, neutron/resistivity, and density/resistivity integrations. Based on previous studies, the log-derived TOC values (0.6–3.4 wt%) were close to the measured and published TOC values (0.9–4.2 wt%). The highest values of TOC lie in the Agbada Formation at a depth range of 4700 to 5200 ft, but this zone did not reach the oil generation window before the expulsion time at 36 Ma, while the TOC values that ranged from 1.5 to 2 wt% was found in the thick shale of the Upper Akata Formation, which is considered the primary contributing source rock in the Niger delta. The oil generation started in the Eocene to recent times and migrated to the deltaic sand bodies of the Agbada Formation. In terms of petroleum geology, the Akata marine and deltaic sediments and the deepest part of the Agbada Formations are the dominant source rocks that have reached maturity and can expel oil and gas. According to migration models in many basins worldwide, the most likely migration paths could be through the fractures and faults associated with the area. The reservoirs in the Niger delta are slope fans, barrier sandbars, and channel fill. In the Otumara Field, the main reservoir sand bodies are slope fans on the upper shoreface and deltaic front barrier bar, but they are disconnected due to the growth faults that hit the basin slope. The reservoir sands are characterized by high-quality facies with an average porosity of 20%, permeability that reaches more than 3000 mD, and hydrocarbon saturation of up to 94% in some reservoirs. Regional shale markers from the Agbada Formation and the Benin Formation may be vertical seals for Agbada sandstone reservoirs. According to seismic and well correlation, the combined effect of stratigraphic and structural trapping

mechanisms may exist in the Otumara Field. This study shows the importance of using integrated well logs, seismic, and basin modeling to identify the petroleum system elements in the Otumara Field. In particular, well logs can characterize source rocks in the absence of geochemistry data. It can also be considered a practical approach to analyzing and identifying potential hydrocarbon sources in other parts of the Niger delta and the world.

Declarations

Conflict of interest The authors imply that there is no conflict of interest with any of the authors or others. Also, this manuscript has not been published and is not under consideration for publication elsewhere.

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