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Source Rock Maturity and Petroleum Generation in the Dahomey Basin SW Nigeria: Insights from Geologic and Geochemical Modelling

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ABSTRACT

Sedimentology, foraminifera paleoecology, geochemical and petroleum system modelling studies were performed on Cretaceous shales from onshore Orimedu-1 and offshore X (at a water depth of 914 m) wells in the Dahomey Basin, southwestern Nigeria to evaluate their maturity, hydrocarbon generation potentials, and regional significance for petroleum prospectivity. Foraminifera biofacies analysis of the studied shales suggests deposition in dominantly marine environments. The average total organic carbon content (TOC, wt%) and hydrogen index (HI, mgHC/gTOC) for Cenomanian, Turonian, and Coniacian shales in X-well are 1.3, 0.9, 1.3 and 406, 560, 214 respectively. While the Cenomanian and Turonian shales in Orimedu-1 have TOC (wt%) of 1.3 and 1.9, and HI (mgHC/gTOC) of 179 and 357 respectively. Well X source rocks contain predominantly marine-derived Type II kerogen, while Orimedu-1 well contain terrigenous-derived gas prone kerogen. The integration of recently acquired kinetic data from immature source rocks further constrains the prediction of petroleum generation in the study area.

1D basin modelling of X well reveals that the Cenomanian Source Rock (CSR) is the most mature bed in the basin having attained the initial 10 % transformation ratio (TR) at 87 Ma, got to peak TR (~50 %) at 86 Ma, and reached 83 % at 53.6 Ma. with a present-day thermal maturity of 0.95 % VRo. The Turonian source in well X also attained the initial 10 % TR at 87 Ma, got to peak (~50 % TR) at 86 Ma and 69 % TR at 50 Ma. These modelled source beds are deeper than the source with 0.62 %VRo used for kinetic study. The observed maturity trend is mostly controlled by the regional erosive events associated with the West African rift system during Santonian and Eocene times. The source rocks in Orimedu-1 are immature. The timing of the generated and expelled hydrocarbons into the Cretaceous petroleum

systems of Dahomey Basin is of regional significance with the entire Gulf of Guinea basins because of the similar evolution and sedimentation history along with recent discoveries and production of hydrocarbon.

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1. INTRODUCTION

Dahomey Basin is one of the West African basins in the Gulf of Guinea province covering the western border of the Niger Delta to the eastern part of Ghana (Fig. 1). Its structural configuration is characterized by numerous horst and graben structures that form regional tectonic structures from the onshore flank into the offshore of Benin Republic (Adegoke et al., 1980). The Nigeria segment, southwestern part of the country has some series of significant hydrocarbon discoveries in the past decades and recent time.

Exploration activities started as far back as 1905 by the Mineral Survey of southern Nigeria and 16 shallow boreholes drilled to basement encountered bituminous sands that constitute the 42 bbl in-place bitumen belt extending about 120km by 6km inland from the coastline (Adegoke et al., 1981) (Fig. 1). Despite the discovery of tar sands on the Nigeria onshore side of Dahomey Basin (Fig. 1), it has received little attention because of initial difficulties encountered in conventional methods of recovering the bitumen and heavy crude on a commercial scale. Nigerian Bitumen Corporation also encountered heavy oil in the 15 wells drilled penetrating about 500 – 950 m of sediment in different locations. This project was abandoned at the beginning of the First World War. Shell D’Arcy Petroleum Development Company of Nigeria in 1937 again carried out geological and geophysical studies in the basin and drilled a few wells to basement but the interest was short lived after their first commercial oil and gas discovery at Oloibiri in the Niger Delta in 1955.

Nevertheless, there is a renewed interest in Dahomey Basin, motivated by yet unknown source of tar sand deposit and recent discovery of about 774 mmboe hydrocarbon accumulations in Albian to Turonian reservoirs by independent local oil and gas companies. Haack et al. 2000 also posited the idea of the deepest and oldest Cretaceous petroleum systems beneath the entire Tertiary Niger Delta which could also be a potential target for exploration in the Dahomey Basin. Pre-Santonian source potential has also been associated with oil seeps or tar sand outcropping in the Dahomey Basin, neighbouring West of Cape Three Points, Tano and onshore Ivory Coast Basins (Brownfield and Charpentier, 2006). In order to evaluate the hydrocarbon potential of the Cretaceous source rock in Dahomey Basin, this study investigates the organic richness, maturity and generation potentials of the Pre-Santonian successions from one offshore and coastal wells (Fig. 2) through geological and geochemical integrated with 1D basin modelling.

2. GEOLOGICAL BACKGROUND

The rifting event that parted South American and African continental plates in the Early Cretaceous was accompanied with uplift, and subsidence leading to formation of many horst and graben structures in the Dahomey Basin (Omatsola and Adegoke, 1981, De Matos, 2000). This tectonic event initiated the first marine transgression of South Atlantic Ocean succeeded by regressions which deposited sediments of varied thicknesses within the Cretaceous to Neogene stratigraphic units of the basin and other West African Rift Systems (WARS) (De Matos, 2000, Brownfield and Charpentier, 2006) (Fig. 1 and 2). Stratigraphic sequences in the basin are the Neocomian to Albian Ise Formation overlain by Cenomanian-Coniacian Afowo Formation and further succeeded by Campanian to Maastrichtian Araromi Formation. Araromi Formation passes on into the Paleocene Ewekoro Formation, followed by the Late Paleocene to Early Eocene Akinbo Formation, the Eocene Oshosun Formation, the Oligocene to Miocene Ilaro Formation, and capped by the youngest Pleistocene Benin Formation (Fig. 3). Rock types in the basin comprises of siliciclastic and carbonate sedimentary succession that exceeded 6000m thickness in the depocentre. The geological evolution of the basin is subdivided into pre, syn and post transform stages.

2.1 Pre-Transform Stage (Late Jurassic – Barremian)

The present-day position of the Dahomey Basin was a closed platform before the initial faulting of the basement in the Late Jurassic essentially controlled by the Romanche, Chain and Charcot fracture zones (Fig. 1) and led to the splitting of the former continent into the landmasses we recognize today as Africa and South America (Adediran and Adegoke, 1987; De Matos, 2000; Arthur et al., 2003). Plate tectonic events at this stage is characterized by rifting, block faulting, subsidence and pulling apart of the crystalline basement which created series of depositional environments on the horsts and grabens in the Gulf of Guinea area. The structural depressions accommodated sets of fluvio-deltaic, lacustrine and deep water basinal deposits in the late Jurassic–Barremian which include conglomerates, sandstones, shales, evaporites and mudstones, representing the oldest part of Ise Formation (Fig. 3) (Dumestre, 1985; Adediran and Adegoke, 1987; Haack et al., 2000; De Matos, 2000; Arthur et al., 2003; MacGregor et al., 2003).

2.2 Syn-Transform Stage (Aptian – Late Cenomanian)

In the Aptian-Late Cenomanian, strong extensional rifting and block faulting in the Gulf of Guinea province continued creating more accommodation for sediments. This led to the initial breakup of the continents at this time causing the first marine transgression into Dahomey Basin during the Albian and extends into the neighbouring Abakaliki Basin. Marine black shales of Ise Formation were deposited at this time and more depositional environments ranging from fluvio-deltaic to marine develops favouring the sedimentation of claystone, mudstone, shale, and sandstone (Omatsola and Adegoke, 1981). This was succeeded by major unconformity separating the Albian marine post-rift sequences from the marine shales of Late Cenomanian. Albian-Cenomanian unconformity had been reported in the marginal basins of Brazil, and Abakaliki Basin in Nigeria, which give credence to their similar geologic histories suggesting that the two continents were in proximity during the Late Jurassic to Early Cretaceous, (Dumestre, 1985; Kjemperud et al., 1992; MacGregor et al., 2003; Brownfield and Charpentier, 2006).

2.3 Post-Transform Stage (Late Cenomanian – Holocene)

The post-transform period corresponds to the global transgression of the Atlantic Ocean during which the North and South Atlantic waters united. The full marine transgression extends through the Gulf of Guinea areas up to the northern part of Benue Trough in northeastern Nigeria

(Petters, 1978). It is interesting to note that the Cretaceous planktonic foraminifera assemblages in the Upper Cretaceous Afowo Formation in the Dahomey Basin are similar to those reported from the Eze-Aku Shale in the Abakaliki Basin, southwestern Nigeria, (Ehinola, et al., 2003; Adeoye et al., 2013). The foraminifera assemblages support the significant contributions of the Cenomanian transgression in the sedimentation of predominantly thick Cenomanian and Turonian marine shales, across the Dahomey Basin and contiguous southern Benue Trough (Adeoye et al., 2013). These organic rich black shales with well-preserved planktonic foraminifera are also observed in the present study, suggesting that restricted water circulation and low oxygen conditions continued during the Turonian marine transgression. The late Cenomanian marine shales from the X-well analysed in the present study show characteristics of high organic constituents and abundant marine foraminifera and therefore are considered as potential Pre-Santonian petroleum source rocks.

Post Santonian Araromi Formation consisting of shales and shallow marine carbonates conformably overlays the Cenomanian - Coniacian Afowo Formation (Omatsola and Adegoke, 1981). Shallow marine and lagoonal environments favoured the deposition of fossiliferous carbonates of the Ewekoro Formation on top of Araromi Formation (Omatsola and Adegoke, 1981; Okosun, 1990). Ewekoro Formation is unconformably succeeded by Palaeocene to Eocene Akinbo and Oshosun formations comprising grey shales, glauconites, and phosphorites, deposited during sea level (Adegoke, 1969). Ensuing sea regression continues in the Late Eocene favouring sedimentation of continental sandstones of Ilaro Formation.

3. ANALYTICAL METHODS

Eighty (80) ditch cuttings of shale were sampled from the offshore X well, and onshore Orimedu-1 wells in the southernmost part of the Dahomey Basin (Fig. 2) for sedimentological, foraminifera paleoecology, and organic geochemical analyses.

3.1 Foraminifera Paleoecology

Foraminifera paleoecology study was carried out on the 80 shale samples from the two wells to estimate paleowater depths and depositional environments. They were treated with 10% hydrogen peroxide solution to loosen the clay and washed in water, sieved with 0.063μm mesh to retain the foraminifera. Identification, picking, and description of the foraminifera were carried out and selected specimens were photographed with a scanning electron microscope.

3.2 Leco TOC and Rock Eval Pyrolysis

Total Organic Carbon (TOC) was measured on 54 shale samples from X and Orimedu-1 wells with a Leco Analyser. 100mg of the shale samples were crushed into powder form and treated with hydrochloric acid (HCl) in oven-sterilized crucibles to remove their carbonates constituents. The HCl was drained off after about 6 hours before transferring the crucibles to an oven set to 60 ˚C and left overnight to completely remove the acid. The treated sample residues were subjected to Leco Analyser for combustion and TOC measurements. A Rock-Eval II (Espitalie et al., 1984) was used to perform the organic geochemical assessment and determine the hydrocarbon generative potential, S_1, S_2, and thermal maturity (Tmax) on the same selected 58 shale samples from X and Orimedu-1 wells.

3.3 Source Rock Kinetics

Source rock kinetics is a laboratory experiments on immature source rocks that describes how the constituents of kerogen break down to form hydrocarbons upon maturation (Yang et al., 2016). Kerogen conversion to hydrocarbon varies based on their composition and structure and controls the activation energies (Ea) and frequency factor (A) in thermal degradation reactions (Peters et al., 2006). This provides primary reaction kinetics data to estimate hydrocarbon generation to geological heating rates in basin modelling. Generation are equivalent to transformation ratio of 10 %, 50 % and 90 % (Horsfield et al. 2015). Two immature shales source rock from the two wells in this study were subjected to open system bulk kinetic analysis as described in Yang et al. (2016). The source rock analyser® (SRA) with heating rates of 0.7, 2.0, 5.0 and 15.0 °C/min were used to determine the bulk kinetics parameters (activation energy (Ea) and frequency factor (A)) (Braun & Burnham, 1987 and Yang et al., 2016).

3.4 Vitrinite Reflectance Measurements

Vitrinite reflectance measurements were carried out specifically on six samples from X-well at the Zentraleinrichtung für Elektronenmikroskopie (ZELMI) at the Technical University of

Berlin. The average vitrinite reflectances in oil (VRo) were measured from the reflectance of at least 30 grains of vitrinite following the procedure described in Akande and Erdtmann (1998).

4. RESULTS AND DISCUSSIONS

4.1 Sedimentology and Lithofacies Definition

Well X was drilled in 914 m of water depth offshore Nigeria and ditch cuttings were recovered along the entire drilled depth to 2585 m below sea level. The principal lithologies are Cenomanian to Campanian shales, sandstones, and very thin carbonate beds which constitute the Afowo and Araromi formations. The basal section, from 2585 m depth consists of fossiliferous, parallel laminated, carbonaceous and calcareous grey to black shale units of Cenomanian Afowo Formation. Overlying this unit within the Afowo Formation are interbedding medium to coarse-grained sandstones and sandy shales. The intercalations of these sandy shales and sandstones form a heterolithic deposit characterized by alternating short period of fine and coarse sediment deposition in fairly disturbed environments. An example of such associations is a shoreface to foreshore setting with intermittent influx of coarse sediments into the basin probably due to significant sea level changes (Oboh-Ikuenobe et al., 2005; Walker and Plint, 1992). The 177 m thick calcareous shale (2182 to 2005 m) overlying the heterolithic bed represents the boundary between Afowo and Maastrichtian Araromi Formation (Adekeye et al 2019). The calcareous shale passes onto a 1.7 m thick fossiliferous carbonate unit, typical of shallow marine environments. Overlying the carbonate unit is the fossiliferous, calcareous Araromi grey shale at a depth of 1995 to 1914 m before transitioning into a Paleocene to Recent (?) non-calcareous, carbonaceous grey to black shale (Fig. 4).

Orimedu-1 reached a total depth of 1612 m with dominance of shales and sandstones. The base is Afowo Formation and it consists of 27 m thick shaly sandstone overlain by 244 m thick grey silty and sandy shale. This evolves up-section into approximately 610m thick medium to coarse grained Afowo sandstones subsequently capped by thick laminated grey Araromi shales (Adekeye et al., 2019) (Fig. 4). The sediment stack indicates a fining upward sequence commonly in fluvial environments. The sandy shale unit at the base suggests shallow marine shoreface environments where intermittent input of coarser particles by wave or tide is common whereas the topmost shale bed is characteristic for deposition in an undisturbed deep-water environment.

4.1.2 Foraminifera Paleoecology

Foraminifera are one-celled animal-like organisms that secret shells normally less than 1mm in diameter which can remain intact in drill cuttings and are generally well preserved in cores. Benthic species are adapted to a relatively narrow water depth whose distribution is influenced largely by water temperatures. They are particularly abundant in shallow-marine waters but are less common in the deeper, more hostile environments. Planktonic foraminifera are stenohaline and typically marine organisms (Phleger, 1960; Bandy, 1967). They are independent of sea bottom conditions and their distributions are influenced primarily by the temperature of the surface waters. Therefore, foraminifera habitats serve as a good indicator for assessing paleowater depth, paleoclimate, and other paleoenvironmental conditions of the host rocks.

The rocks of offshore well X and onshore Orimedu-1 wells yielded abundant planktonic and benthic foraminifera species at different intervals. Their abundance varies from location and biostratigraphic levels in the wells. Some of the planktonic species include *Rotalipora sp., Dicarinella sp., Praeglobotruncana sp., Marginotruncana sp. Heldbergella sp., Whitenella sp., Heterohelix sp.,* and *Abathomphalus sp.* (Fig. 5A) (Adekeye et al., 2019). The benthic species are *Orthokarstenina sp., Ammobaculites sp.,* and *Bolivina sp*. (Fig. 5B). An assemblage of *Rotalipora, Hedbergella, Praeglobotruncana, Whiteinella sp.* planktonic species (Fig. 5A) are the most abundant at the base of offshore X-well within the depth of 2167-2585 m assigned to the Cenomanian–Turonian intervals. These laminated grey shales are mostly populated by the planktonic foraminifera species with very little arenaceous benthic species supporting water stratification characteristic for outer neritic to upper bathyal deep marine environments. Planktonic foraminifera population changes with latitude, water depth, and salinity from one type of water to another and is abundant in many open ocean areas of the world where the surface salinity values fall generally within the range of 34-37 ‰ (parts per thousand). The principles of paleobathymetric interpretations are based on their different habitat conditions (Phleger, 1960; Boltovskoy and Wright, 1976). The planktonic species are less abundant at the same biostratigraphic level in Orimedu-1within the depth of 670 – 1612 m. There are more shallow water dweller benthic species in the Cenomanian to Turonian in Orimedu-1, probably due to the fact that depositional environments in the basin were characterized by shallow water with favourable nutrients and oxygen supply. The organic constituents are notably reduced compared with the X well.

The sandy nature of the Cenomanian to Turonian sediments in the Orimedu-1 coupled with the increase in benthic foraminifera ratio suggest a prevailing inner neritic environment. The abundance of planktonic foraminifera and less sandy facies in the Cenomanian–Turonian period in the offshore area where well X is located contrast with the sparse planktonic species and sandy nature of the shale onshore where Orimedu-1 wells are located. This illustrates a possible down dip geometry of the basin at this time favourable for organic matter deposition and preservation in the present offshore areas. Therefore, during the Cenomanian to Turonian paleowater depths possibly ranged within 150-250 m in X well, and 50-150 m in Orimedu-1 well. The Coniacian to Maastrichtian possibly had a paleowater depth ranging from 50 to 100 m. The temporal evolution of water depth is illustrated in the paleowater depth boundary condition curve (Fig. 10) for subsequent basin modelling.

4.2 Organic Matter of the Source Rock

Pyrolysis of organic matter provides different screening methods like Rock Eval to determine the quantity and quality of organic matter in a source rock (Peters and Cassa, 1994). The Total Organic Carbon (TOC) and hydrogen index (HI, the ratio of hydrocarbons cracked from kerogen represented by S_2 vs. TOC) are preliminary quick measures of the quantity and quality of organic matter present in a source rock (Peters and Cassa, 1994). The type of hydrocarbons a source rock generates depends on maturity and kerogen type. Kerogens can be classified into four types based on their biological constituents, depositional environment, and resulting hydrogen content, determined by the hydrogen index (HI). Type I kerogen contains more algal material commonly found in lacustrine environments. It has HI greater than 600 mgHC/gTOC producing mainly waxy oils. Type II kerogens are developed from autochothonous organic matter under low oxygen or reducing marine conditions having moderate high HI of 300–600 mgHC/gTOC with potential to generate mainly oil. Type III is sourced from terrestrial plant material or organic matter deposited in oxidizing environment and are composed of low HI ranging from 50–200 mgHC/gTOC and generates mainly gas. Type IV kerogen is produced by oxidized organic matter resulting HI less than 50 mgHC/gTOC with no potential for hydrocarbon (Tissot and Welte, 1984, and Peters and Cassa, 1994).

4.2.1 X-Well

In the X-well, TOC (wt%) and hydrogen index (HI mgHC/gTOC) of Cenomanian shales range from 0.8 – 1.9 (mean 1.3 wt %) and 331 – 484 (mean 406 mgHC/gTOC), Turonian shales range from 0.6 – 2.3 (0.9 wt%) and 454 – 707 (mean 560 mgHC/gTOC) and Coniacian shales range from 0.8 – 2.2 (mean 1.3 wt%) and 180 – 241 (mean 214 mgHC/gTOC) respectively (Table 1, Fig. 4). The Cenomanian and Turonian source rocks consist predominantly of Type II marine oil and gas prone kerogen while Type III gas prone kerogen dominates the Coniacian facies (Fig. 6, 7 and 8). Shales with high hydrogen index form X well (X-8470 (2582 m), X-8140 (2481 m), X-7810 (2380 m) and X-7480 (2280 m)) were further assessed for their maceral constituents. The maceral compositions are better studied in coal because of its high concentration that makes up the organic matter which are sparse in shale but can still be estimated through organic petrological studies. The dominant maceral group is the vitrinite which range from 43.9 - 50.0 %. Liptinite ranges from 22.2 - 46.3 % with an average value of 37.0 %. The liptinite content is high and dominated by lamalginite and liptodetrinite microlithotypes and may be responsible for the hydrogen concentration in those source rocks. Inertinite content range from 3.3 - 11.1 % averaging 7.9 % suggesting low amount of reworked organic matters.

4.2.2 Orimedu-1

The potential Cenomanian source rock in the onshore Orimedu-1 well has a TOC and HI ranging between 0.8 - 1.9 (mean 1.3 wt%) and 99 – 285 (179 mgHC/gTOC), and the Turonian facies range from 0.9 – 2.6 (1.9 wt%) and 188 – 472 (mean 356 mgHC/gTOC) respectively (Table 2 and Fig. 4). The kerogens are essentially mixed Type II and III oil and gas prone (Fig. 6, 7 and 8). The marine organic matter content was probably diluted by terrigenous organic matter influx into the basin. The shales are sandy and contain abundant amounts of shallow-water marine dwellers (benthic foraminifera) that habituate environments prone to wave and tide activity.

The investigated Cenomanian, Turonian and Coniacian source rocks from the two exploratory wells have TOC values of at least 0.9 wt% which is above the minimum threshold of 0.5 wt% TOC for clastic rocks and are thereby classified as very good source rocks for hydrocarbon generation. The apparently best source rocks are the Cenomanian and Turonian shales in the offshore area with primarily marine Type II kerogen. These shales contain the most abundant planktonic foraminifera species (Fig. 5) peculiar to the outer neritic to upper bathyal deep marine environments.

4.3 Source Rock Maturity

The thermal maturity of a source rock is an important parameter due to the correlation between temperature and hydrocarbon generation. Determination of Tmax, vitrinite reflectance, production index, and burial history are very significant in the assessments of the source rock maturity.

4.3.1 Tmax and Vitrinite Reflectance Measurement

The Tmax values of Cenomanian to Turonian (CT) source rocks in X well range between 350–424 ^{o}C (mean 368 ^{o}C) while Coniacian range between 414 – 431 ^{o}C (423 ^{o}C). The Tmax values of the older CT source rocks are lower compared with higher values recorded in the overlying Coniacian beds (Fig. 7). The best explanation for the observed depression of Tmax is impregnation by oil as indicated by oil stains observed on the rock samples. An accumulation of oil or heavy bitumen in the sample can result in a decrease of the Tmax, due to the contribution of resins and asphaltenes to the S_2 peak which is normally related to pyrolysis of the insoluble kerogen as described in Tissot et al. (1987). The Tmax from the pyrolysis were therefore ignored and were not used for the calibration of the 1D thermal and burial history modelling. Instead, the vitrinite reflectance measured on these samples which ranges from 0.68–0.9 % VRo with a mean value of 0.8%, were used for the model. This initial preview of the source rock from the VRo suggests that the Cenomanian and Turonian source rocks are mature early in X well and within the oil window while the Coniacian rocks are immature (Fig. 8).

Orimedu-1 well have Tmax values in the range of 418–439 $^{\circ}$C with a mean value of 432 $^{\circ}$C showing that the Cenomanian–Turonian are immature to marginally mature. Vitrinite reflectance (%Ro) was calculated from Tmax for Orimedu-1 well (Fig. 8) using equation Ro = 0.018 x Tmax - 7.16 (Jarvie et al., 2001). The limitation of this equation is that it is not suitable where there is dominance of Type I organic matter because Tmax also functions of reaction rate as vitrinite reflectance (Jarvie et al., 2001).

4.3.2 Production Index

Production indices (Fig. 8) can supplement maturity determination as postulated by Nuccio and Condon (1996). The minimum threshold of production index of is 0.08 for hydrocaron generation, and the thermal maturity range is 0.08 to 0.50. The production indices of the source rocks in Orimedu-1 indicate that they are immature, while the Cenomanian and Turonian source rocks are mature in wells X (Fig. 8).

5. BASIN MODELLING

Basin modelling technique is useful in assessing thermal and maturation histories of source rocks and resulting timing of hydrocarbon generation from past to present (Hantschel and Kauerauf, 2009; Welte et al., 1997; Waples et al., 1992). Model simulations require a conceptual model which puts the geological evolution of the studied area in an uninterrupted sequence of events in time and space integrating all available geological, paleontological, geophysical, and geochemical data (Peters et al., 2012; Poelchau et al., 1997). The modelling study was carried out using PetroMod 2016 (© Schlumberger) to assess the burial and thermal history, and the resulting timing of hydrocarbon generation of the Cenomanian, Turonian and Coniacian source rocks in the two exploratory wells in the offshore and onshore area of the basin, including previous knowledge to provide new information on the Cretaceous petroleum systems in the Dahomey Basin.

5.1 Input Data

The input data for the 1D modelling are the age of the formations, respective lithology and thickness, source rock properties (TOC and Hydrogen Index) and bulk kinetics determined on samples from each of the wells. Activation energies (Ea) and frequency factors (A) of the bulk kinetic data derived from immature source rock from X well is 51 Kcal/mol and 2.28 x 10^{13} s^{-1} while in Orimedu-1 is 53 Kcal/mol and 4.2 x 10^{13} s^{-1} (Fig. 9a). The nearly symmetrical distributions centred within 51 and 53 Kcal/mol activation energy mimic the typical marine type II kerogen of Jurassic Kimmeridge Clay (North Sea) and the Cretaceous La Luna Formation (Venezuela) source rocks (Peters, et al., 2006). The 50 % transformation ratio based on heating rate of 3 °CMa^{-1} of Type II kerogen in the two immature shales occurred within the temperature range of 136–147 °C (Fig. 9b).

The two exploratory wells did not penetrate the Neocomian–Albian rock units which unconformably overlay the crystalline basement (Omatsola and Adegoke, 1981). The unpenetrated segments to basement are essential for modelling in confining the reconstruction of the entire basin evolution (Al-Hajeri et al. 2009) and better constrain the crustal heating effect through time. The stratigraphy beyond the total depth of the wells to the basement was extrapolated from depth to magnetic basement map of Oladele and Ayolabi, 2014 to reduce the geological uncertainties in the model (Natasha D. and Christine Y., 2019). Their study and other regional work from Brownfield and Charpentier, 2006, show that the study area or well locations have about 4000 to 6500 m depth to basement. The X well was projected to 6800 m from total depth (TD) of 2600 m and Orimedu-1 to 2200 m from 1412 m (TD) and stratigraphy assigned after Omatsola and Adegoke, 1981.

5.2 Boundary Conditions

The Paleowater Depth (PWD) in the basin from Cenomanian to Recent in the two exploratory wells was estimated from foraminifera paleoecology reconstruction of the biofacies recovered in the sediment (Figs.11). Marine habitat of benthic and planktonic foraminifera commonly ranges from the nearshore to as deep as bathyal environments depending on the species. This habitat makes them an important tool for the assessment of paleowater depths of the Early Cretaceous successions in this study as it reflects the tectonic evolution and eustatic sea levels in the basin (Brownfield and Charpentier, 2006). Sediment water interface temperature (SWIT) boundary values were estimated from paleosurface temperatures of the latitudes of the two wells in PetroMod modelling software (Wygrala, 1989).

5.3 Calibration Data

Measured and calculated vitrinite reflectances (VRo) were the only available data in this study for calibrating the burial history (Fig. 11b, 12b and 13b). The observed vitrinite data scatter with a fairly defined trend. The scattering of the VRo data could be due to the presence of different vitrinite precursor materials or reworked vitrinites which is the more likely explanation than local heating by fault-controlled circulation of hydrothermal fluids, because of the absence of magmatic intrusions within the basin area (Scheidt and Littke, 1989, Behar et al., 2007).

Borehole temperature data of the two studied wells were not available. Nevertheless, the average geothermal gradient 39.6 °C/km^{-1} of the neighbouring Afowo-1 well located on coast north of the X well (Avbovbo, 1978, Onuoha and Ofoegbu, 1987), the heat flow of 59.5 $\pm$ 10.9 mW/m^2 in the Gulf of Guinea area (Herman et al., 1997), the heat flow of 50mW/m^2 reported along the margin of Cote d'Ivoire, Togo and Nigeria, (Macgregor et al., 2003) and the average heat flow of 42.5 mW/m^2 in the contiguous Niger Delta (Odumodu and Mode, 2016) were used as control for the initial modelling based on their proximities and similar tectonic history with the Dahomey Basin. The geothermal gradient in the Afowo-1 (Dahomey Basin) and average heat of Gulf of Guinea basins was described to be higher than some part of the contiguous Niger Delta Basin. Herman et al. (1997) and MacGregor et al. (2003) suggested that the high heat flow in the Gulf of Guinea province may imply that the lithosphere in the region is probably thin and being heated up by the underlining asthenosphere. The present-day heat flow of 65mW/m^2 and 45mW/m^2, in the offshore X well and onshore Orimedu-1 respectively in this study is in agreement with the suggested heat flow increase towards the offshore, where the continental crust is thinner, giving shallower onset of hydrocarbon generation depth (Herman et al., 1997; MacGregor et al., 2003) (Fig. 11c, 12c and 13c)

5.4 Burial History Modelling

The burial history plots of X, and Orimedu-1 wells (Fig. 11a, and 12a) illustrate the burial and thermal events controlled by the tectonic activities in the basin. Uplift and erosion in the basin are defined by four unconformities namely; Albian-Cenomanian, Santonian, Eocene–Oligocene and Miocene (Elvsborg and Dalode, 1985; MacGregor et al., 2003; Brownfield and Charpentier, 2006) were important uncertainties for the reconstruction of the burial and thermal histories. Different past and present heat flow scenarios and eroded thickness were calibrated and tested to attain the best fit of measured and modelled vitrinite reflectance. The first rapid subsidence in the early Cretaceous caused by initial breakage, sagging and block faulting marked the beginning of sedimentation of the continental conglomeratic sandstones, claystones and shales with varied thicknesses across the basin. During the Berriasian to Aptian, close to 3000m sediment accumulated in the X well and 700m in Orimedu-1 at the present coastline area. Sediments thicknesses at the coast area are thinner, probably due to the lack of sediment supply and/or accommodation in comparison to the offshore X well (Fig 12a, and 13a). The variation in sediment thickness indicates a deepening of the basin configuration towards the south. The rifting was fully active in Albian times with strong wrenching of the basement and sudden subsidence, creating a large accommodation taking up siliciclastic sediments deposited with the incursion of the first marine transgression. The early sediments were then buried to about 4200m in the X well and 2600m in Orimedu-1 well towards the Late Albian. After initial opening of the South Atlantic the Albian – Cenomanian erosion follows the erosion of up to 1200m of Cenomanian sediments in well X, and 50m in Orimedu-1 (Fig 12a, and 13a). Burial continues with gentle subsidence of the basement as the drifting episode began in the Cenomanian after complete separation of the South American and African plates. The complete separation of the plates connected the North and South Atlantic Oceans leading to a full marine transgression in the Dahomey Basin as well as the adjacent Benue Trough. The maximum flooding event was responsible for the formation of thick Cenomanian and Turonian organic rich shale across Dahomey Basin and Southern Benue Trough (Adeoye et al., 2013). Other erosion events were recorded in the Santonian, Eocene and Miocene with approximate eroded thicknesses of: 1400m, and 950m; 1200m, and 400m; and 600m, and 400m in X, and Orimedu-1 well, respectively. The rock types in the two wells varies significantly in facies associations as seen in the X well having more of fine-grained sediments, which are essentially clays and shales with abundant planktonic foraminifera, while the sand ratio in the Orimedu-1 is very high with abundant benthic species.

5.5 Petroleum Generation Modelling

5.5.1 Offshore X well

The burial rates of Cenomanian, Turonian and Coniacian source rocks appear rapid as shown on the burial history plot (Fig. 11a). The source rocks were all exposed to temperature peak causing the early stage of maturity estimated at a vitrinite reflectance of 0.62%VRo reaching about 10% of their generation potential at 87Ma (Coniacian). This marked the early oil generation window (Fig. 11a and Fig. 13). Onset and amount of organic matter transformation in a source rock depends on kerogen type, time and the burial controlled temperature increase. The Cenomanian and Turonian source rocks were further buried in the Santonian and reached their maximum temperature and realized 50% of their transformation potential at 87 and 86Ma (Santonian) respectively. The Coniacian source rock facies has not reached sufficient maturity to generate hydrocarbons, whereas the Cenomanian and Turonian source rocks reach transformation ratios of

83% and 69% at 54Ma (Early Eocene) and 50Ma (Late Eocene) respectively (Fig. 13). Their transformation ratios reveal that the Cenomanian and Turonian source rocks have been subjected to temperatures almost sufficient for total kerogen conversion whereas the Coniacian source rocks are early mature still having significant generation potential if subjected to higher temperatures.

5.5.2 Onshore Orimedu-1 well

The Santonian rapid burial and subsequent uplift was the most significant tectonic event although the Cenomanian and Turonian source rocks in Orimedu-1 have not been buried to reach a maturity level sufficient for hydrocarbon generation (Fig. 12a and Fig. 14) probably due to poor sedimentation in the northern part of the Dahomey Basin.

5.6 Petroleum System Events

The Cretaceous petroleum systems elements source rock, reservoir, and seal were favourably formed at different time and preserved in the two exploration wells. The potential petroleum source rocks of the producing systems in the Ivory Coast (Belier Field), Tano (Jubilee) field, Ogooue Delta (Anguille Field) range in age from Albian to Coniacian, average TOC (3.0, 2.0 and 2.0 wt%) and HI (300, 350, 400 mgHC/gTOC). The interval of importance in this discussion is the viability of the Cenomanian to Coniacian facies distributed across these basins during the post transform period of the basin evolution which make them significant in the West Africa sub region. They are comparable in age, environments type, organic matter type and potential with the intervals delineated for the Dahomey Basin in this study. These similarities can be attributed to the worldwide Cretaceous oceanic anoxic event that affects the Gulf of Guinea and the other West Africa coastal basins, responsible for the deposition of Albian to Coniacian black shales. Therefore, this study has established for the first time that the Cenomanian to Turonian petroleum source rocks are of high quality, mature and have potential for oil generation (Kjemperud et al., 1992, Tucker, 1992, Katz and Mello, 2000, MacGregor et al., 2003, Brownfield and Charpentier, 2006, and Atta-Peters and Garrey, 2014).

The fine-grained Turonian sandstone~~s~~ in the X well are thinly interbedded with the shales. In Orimedu-1 well, 14 m thick Early Turonian sandstones (1436–1450 m), 134 m thick Late Turonian sand (1207–1341 m) and 438 m thick Middle Coniacian sandstones (744–1182 m) are more conspicuous and well preserved. The sandstones are coarse grained, moderately to well sorted and have been classified as fluvio-deltaic sands in the two wells (Adeoye, 2017 unpublished thesis). The sandstones could be described as quartz-arenites which suggest their mineralogical and textural maturity. Two main potential reservoir sections exist in the Gulf of Guinea province and include Albian sandstones and the Cenomanian-Maastrichtian marginal marine to turbiditic sands common in the Espoir and Belier fields of Cote d'Ivoire, Seme Field of Benin, and the Nigerian Aje Field (Tucker, 1992 and Macgregor et al., 2003). On the basis of available data from the investigated wells and published data, the Cenomanian to Coniacian sandstones may serve as potential reservoir rocks.

Rocks with seal potential in the study area include the thick and non-sandy shale deposit overlying the Turonian to Coniacian sandstones. These shales occur in the Coniacian and Maastrichtian with varying thicknesses ranging from 94-152m in the two studied exploration wells in the basin. Their occurrence in the two wells suggests a possible lateral continuity in the basin, but will be better traced and understood on seismic profiles. The Campanian shales are grey and non-sandy. They have thicknesses ranging from 89 to 130m and could probably serve as a good seal rock.

The traps proven to date in the Gulf of Guinea province include the stratigraphic traps of Maastrichtian age in the Ivorian and Tano Basin, Ghana, channel-erosion trapping system in Benin Basin, fault-block, and anticlinal traps of Espoir and Belier Basin of Cote D'voire (Grillot et al. 1991, Craven, 2000 and MacGregor et al., 2003). Rift related trap configuration should be expected in the region of investigation and would be better delineated through seismic imaging which is not currently available for this study.

The modelled transformation ratio suggests that hydrocarbons may have been expelled and trapped in the reservoirs and seals that are present within the system (Fig. 15). The volume of hydrocarbon generated and their preservation cannot be estimated, and the implications of the magnitude of erosion induced by tectonic subsidence in the Albian-Cenomanian, Santonian, Eocene and Miocene unconformities in the basin on the trapping system cannot be confirmed through 1D modelling. Seismic data is essential for 2D modelling of the basin in order to understand the structures that control the hydrocarbon traps, migration, accumulation, and preservation of the generated hydrocarbons in relation to the large bitumen deposits and present ongoing oil and gas exploration particularly in the offshore areas.

6. CONCLUSIONS

This study integrated geology, organic geochemistry, paleoecology and 1D petroleum system modelling to predict the paleoenvironments, quality, maturity and generation potentials of the Upper Cretaceous source rocks in the onshore and offshore areas of the Dahomey Basin. The basin fill consists dominantly of siliciclastic rocks (shale, sandstone, and siltstone) with varying thicknesses from the onshore area to the offshore. The Cenomanian and Turonian shales have abundant microfossils which are essentially planktonic foraminifera with very few benthic species. Paleo water depth varies during the Cenomanian to Coniacian across the basin from marine upper bathyal (<250 m) to neritic (<100 m) as suggested by the preserved foraminifera species in the shales. The Cenomanian and Turonian source rocks in the offshore region (X well) consist predominantly of Type II marine oil and gas prone kerogen while Type III gas prone kerogen characterizes the Coniacian facies. In the onshore region (Orimedu-1 well), Cenomanian and Turonian source rocks contain essentially mixed Type II and III oil and gas prone kerogen. The influx of terrigenous organic matter into the basin at the time of deposition probably diluted the marine organic matter. Evidently, the burial, thermal and maturity history modelling of the two exploration wells revealed that the most mature intervals are the Cenomanian and Turonian source rocks in the offshore region. They have probably generated substantial amounts of hydrocarbons as shown by their modelled transformation ratios of 83 and 69 respectively. Cenomanian and Turonian source rocks in the onshore area have not attained their maximum generating potential. Thus, the Cenomanian and Turonian source rocks in the offshore region are identified as the potential source for the Cretaceous petroleum system in the Dahomey Basin.

Regional 2D or 3D petroleum system modelling considering timing of expulsion, migration and accumulation can provide robust insights into the timing and volumes of generated hydrocarbon in the study area, particularly as more data such as seismic data become available. The generated and expelled hydrocarbons may have significant contributions to the current discovered petroleum accumulation and tar sand resource being produced in the basin. This integrated study therefore represents a first approach to the identification of a working Cretaceous petroleum system in the Dahomey Basin.

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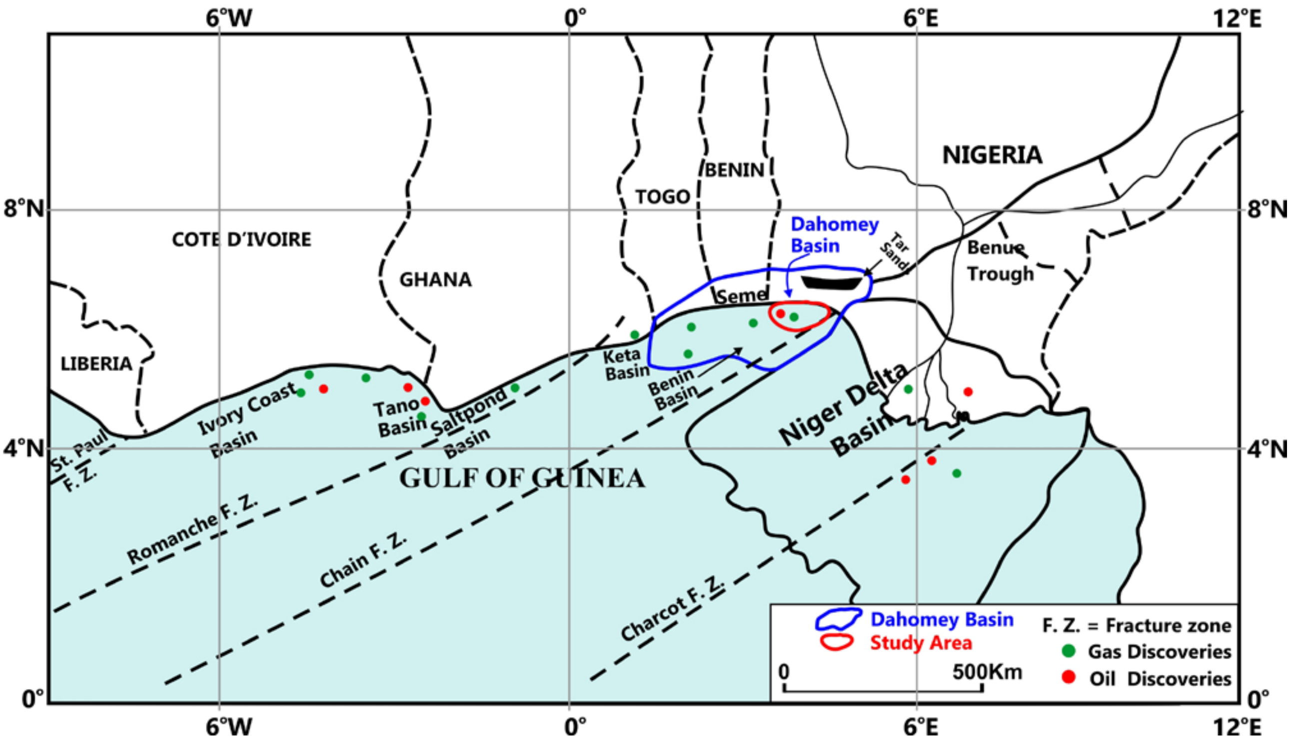


Fig. 1 Map of the Gulf of Guinea Province, West Africa showing Benin / Dahomey, Keta, Saltpond, Tano, and Ivory Coast Basins and some structural features (After Brownfield and Chapentier, 2006).

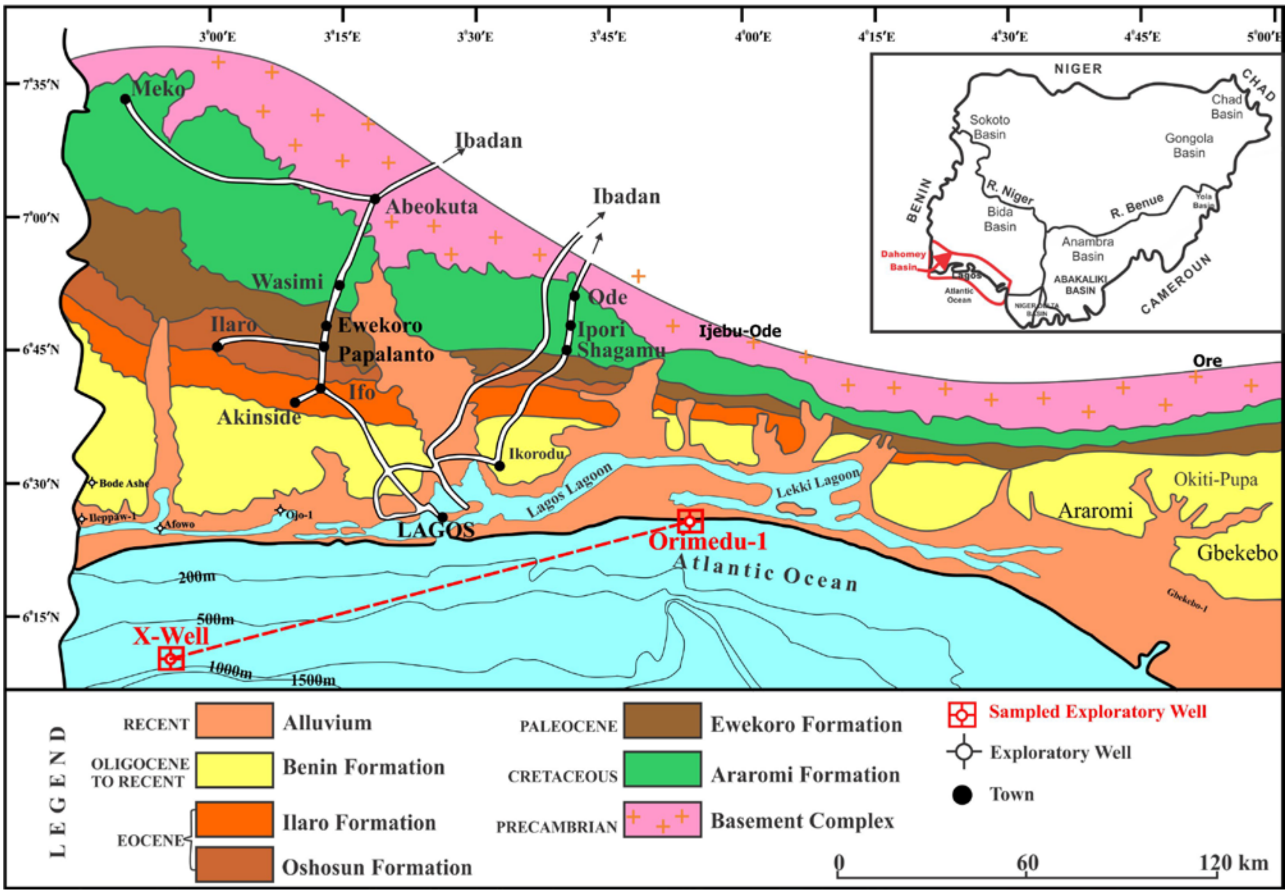


Fig. 2 Geological map of the Dahomey Basin indicating the position of the sampled exploratory wells (Modified after Gebhardt et al., 2010)

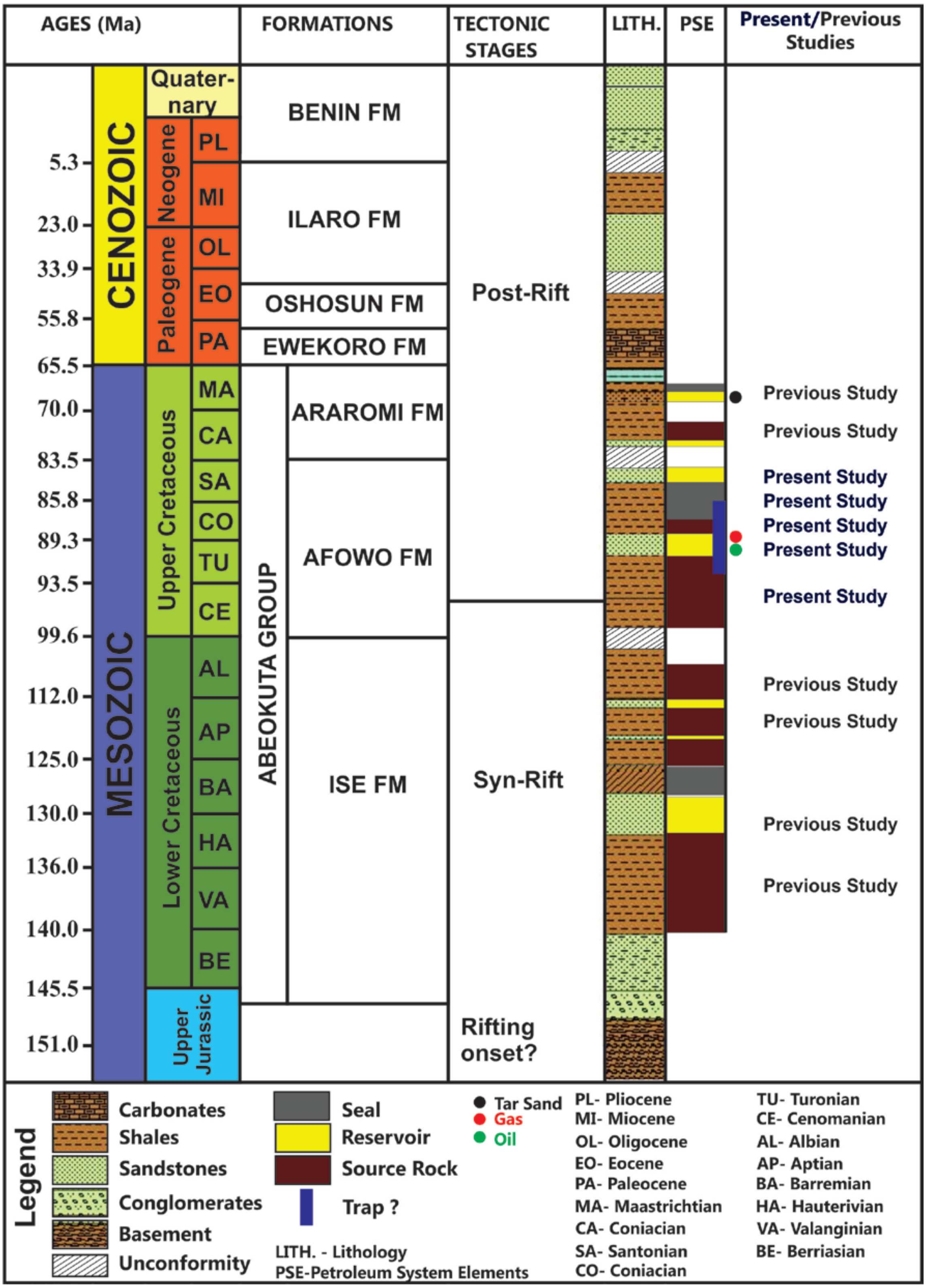


Fig. 3 Chronostratigraphic chart of the Dahomey Basin showing key tectonic stages in relation to the geologic formations and lithologies (Modified after Adeoye et al., 2020).

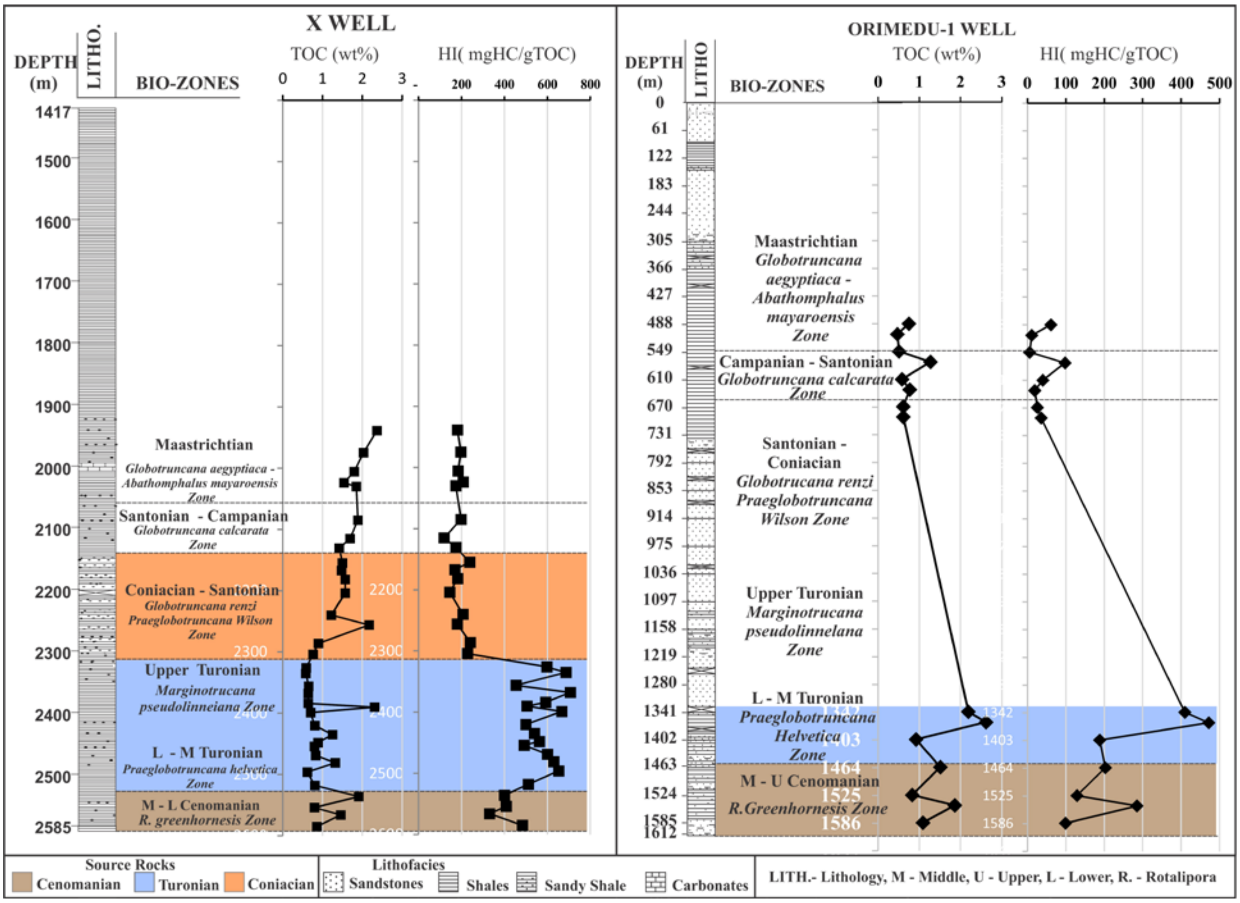


Fig. 4 The lithologies, biostratigraphic, Total Organic Carbon (TOC) and Hydrogen Index (HI) plots showing organic matter variations in the Cenomanian, Coniacian and Turonian source rocks in the two exploration wells.

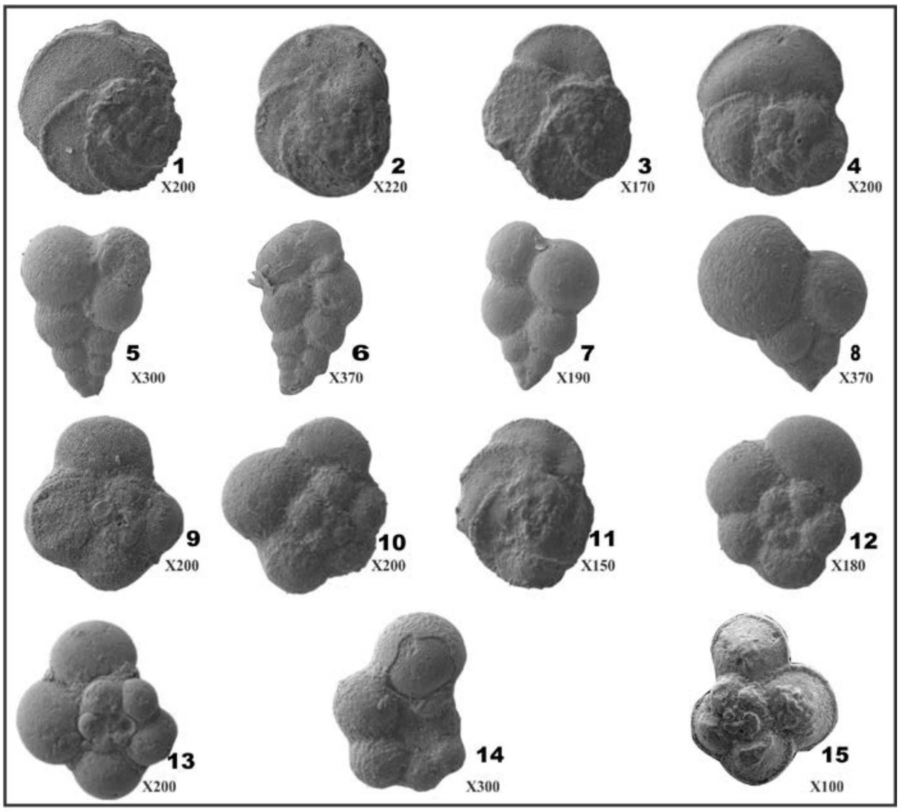
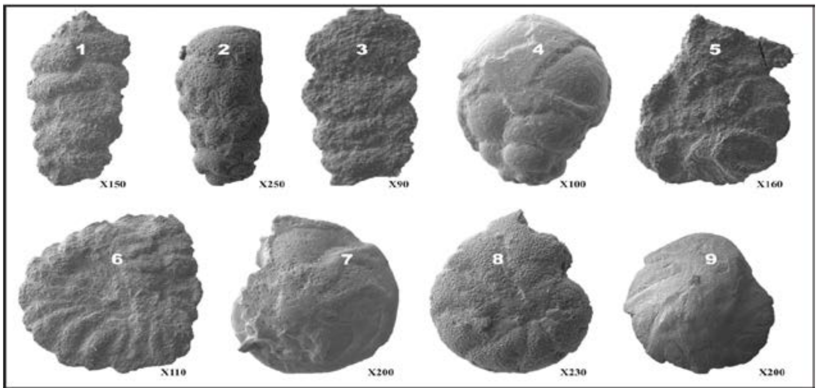


Fig. 5b SEM photograph of representative planktoniuc foraminifera species recovered from selected Cenomanian-Turonian source rocks for paleoenvironmental study. (*1. Rotalipora greenhenoensis, 2. Marginotruncana cf., pseudolinneiana 3. Dicarinella primitiva, 4. Whiteinella inornata, 5. Heterohelix moremani, 6. Heterohelix pulchra, 7. Heterohelix globulosa, 8. Heterohelix reussi, 9. Praeglobotruncana stephani, 10. Whiteinella archaeocretacea, 11. Marginotruncana cf. renzi, 12. Whiteinella baltica, 13 Hedbergella delrioensis, 14. Hedbergella simplex, 15. Rotalipora cushmani)* (After Adekeye et al., 2019)



1. Textularia, 2. Afrobolivina, 3. Reophax, 4. Gabotina, 5. Ammobaculites, 6. Haplophragmoides, 7. Planulina, 8. Gavelina, 9. Lenticulina

Fig. 5b SEM photograph of representative Benthic Foraminifera species recovered from selected Cenomanian-Turonian source rocks for paleoenvironmental study.

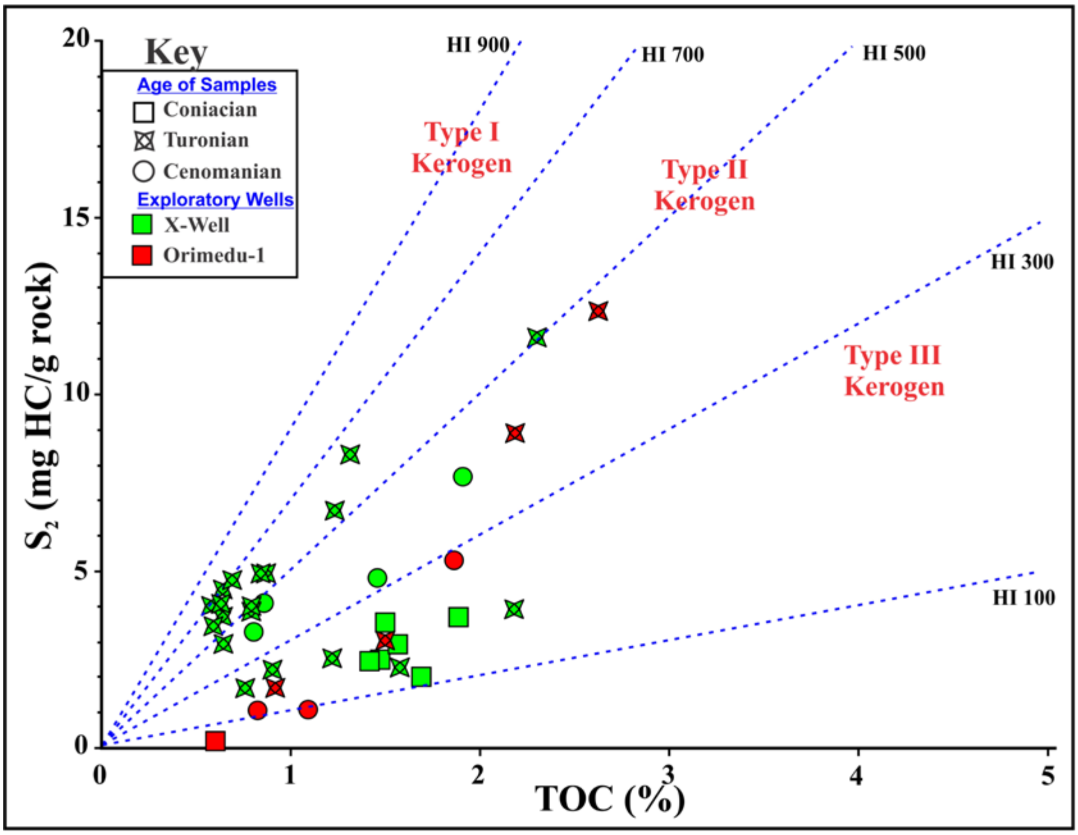


Fig. 6 Kerogen typing from Hydrogen Index (HI) variations derived from S_2 and TOC of the Cenomanian to Coniacian source rocks from the two exploration wells.

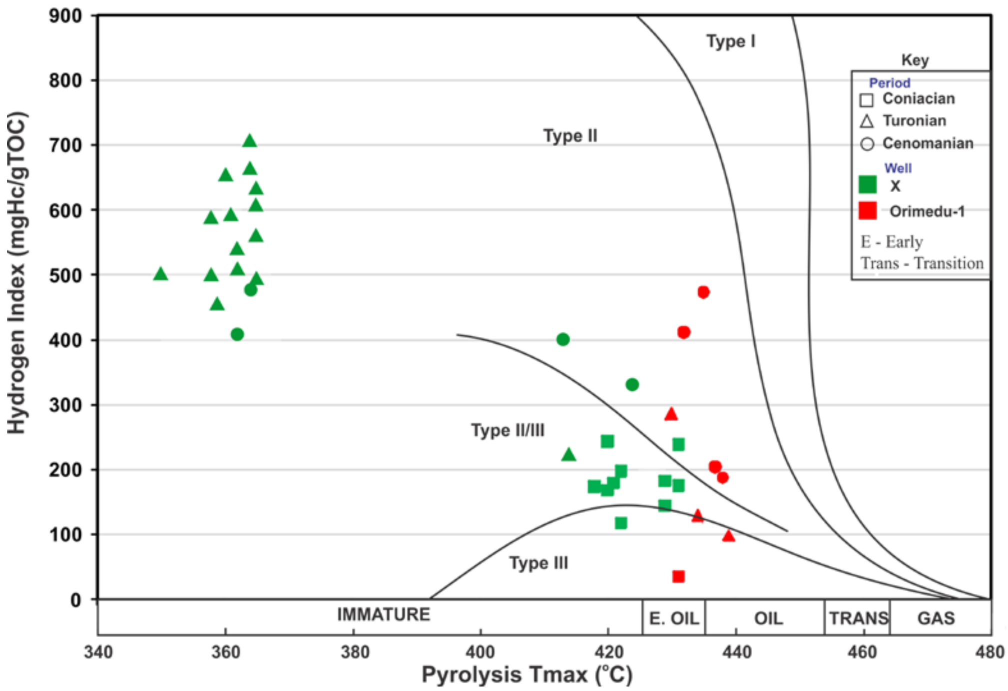


Fig. 7 Tmax vs Hydrogen Index plot for rapid characterization of the organic matter types and maturity of the source rock. The very low Tmax values measured in well X are interpreted as effect of hydrocarbon stained samples.

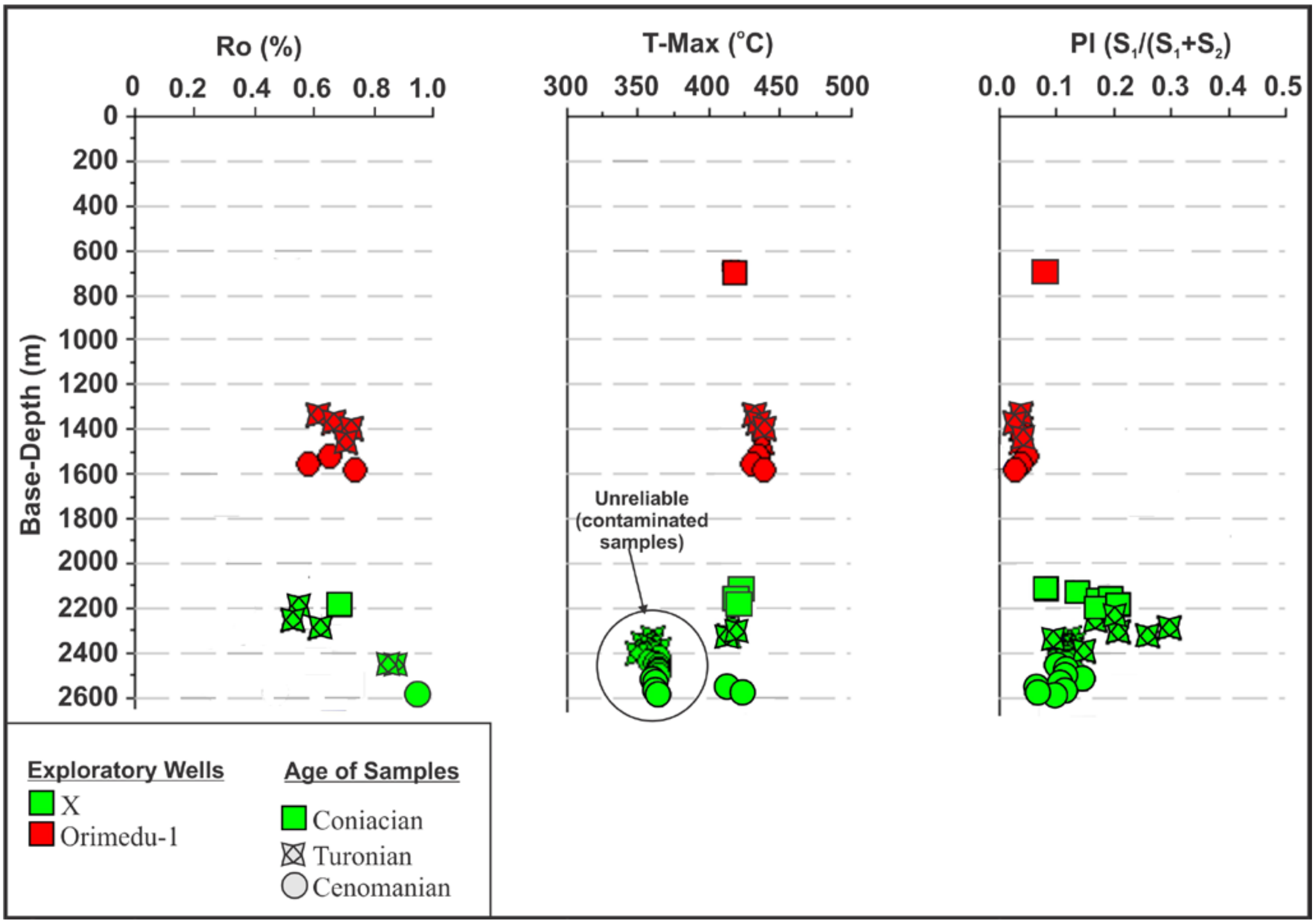


Fig. 8 Vitrinite reflectance (%Ro), Tmax and Production Index (PI) of the Cretaceous source rocks in X, and Orimedu-1 wells showing their maturity patterns and the oil stained zones with low Tmax in X well.

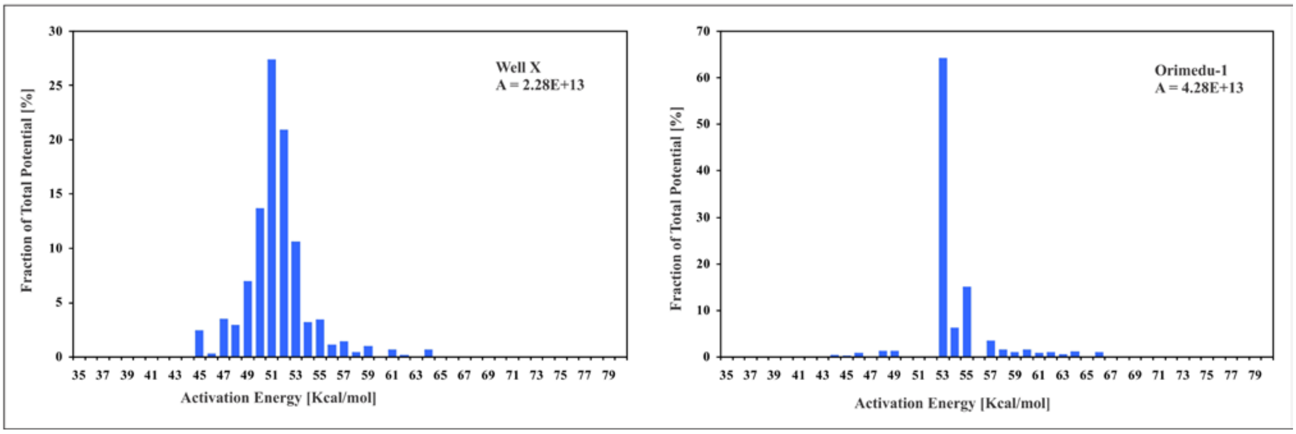


Fig.9a. Bulk kinetics models of whole-rock samples from the two exploratory wells.

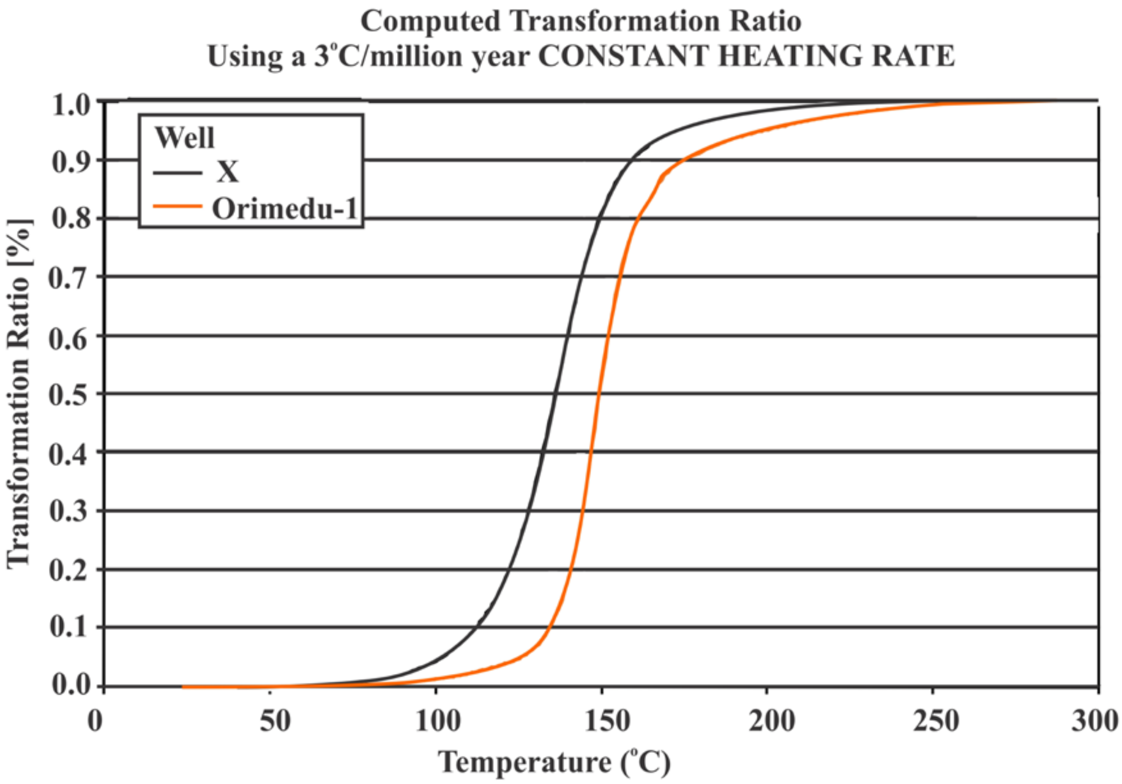


Fig. 9b. Transformation ratios of wells X, and Orimedu-1 calculated for geological heating rate of 3°C Ma^{-1}.

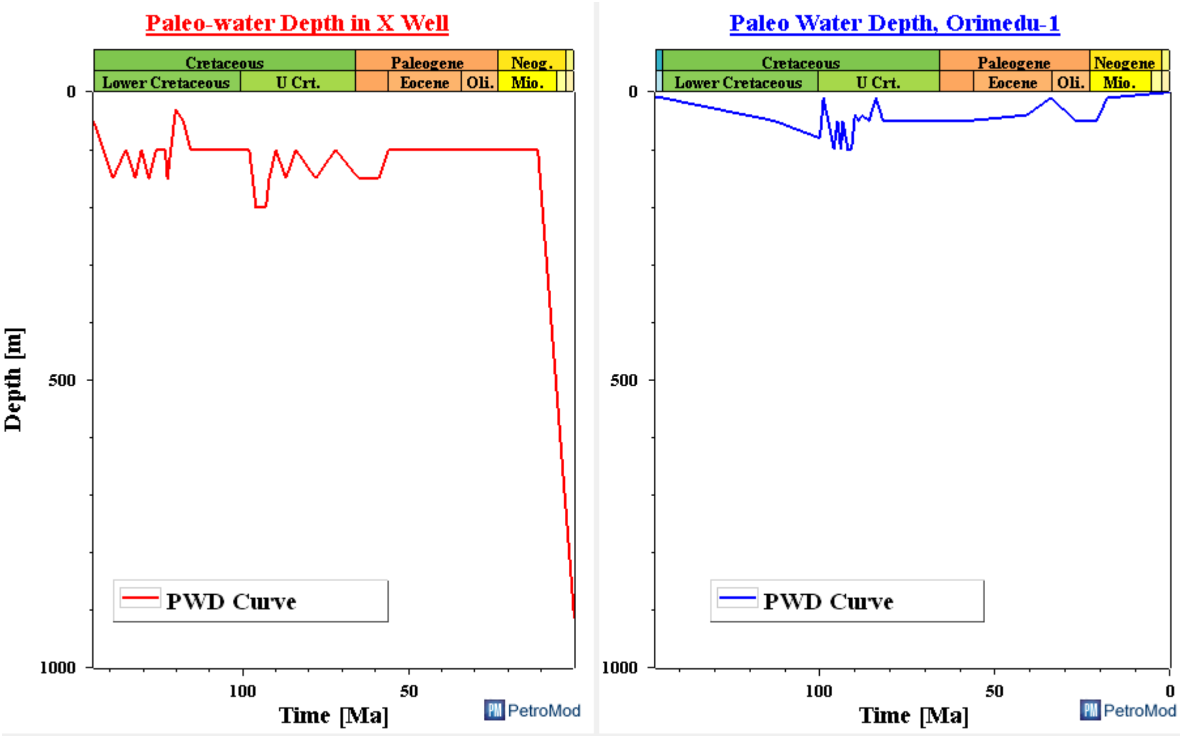


Fig.10 PaleoWater Depth (PWD) estimated from foraminifera paleoecology reconstruction of the biofacies recovered from the Cenomanian to Recent sediment in X and Orimedu-1 wells.

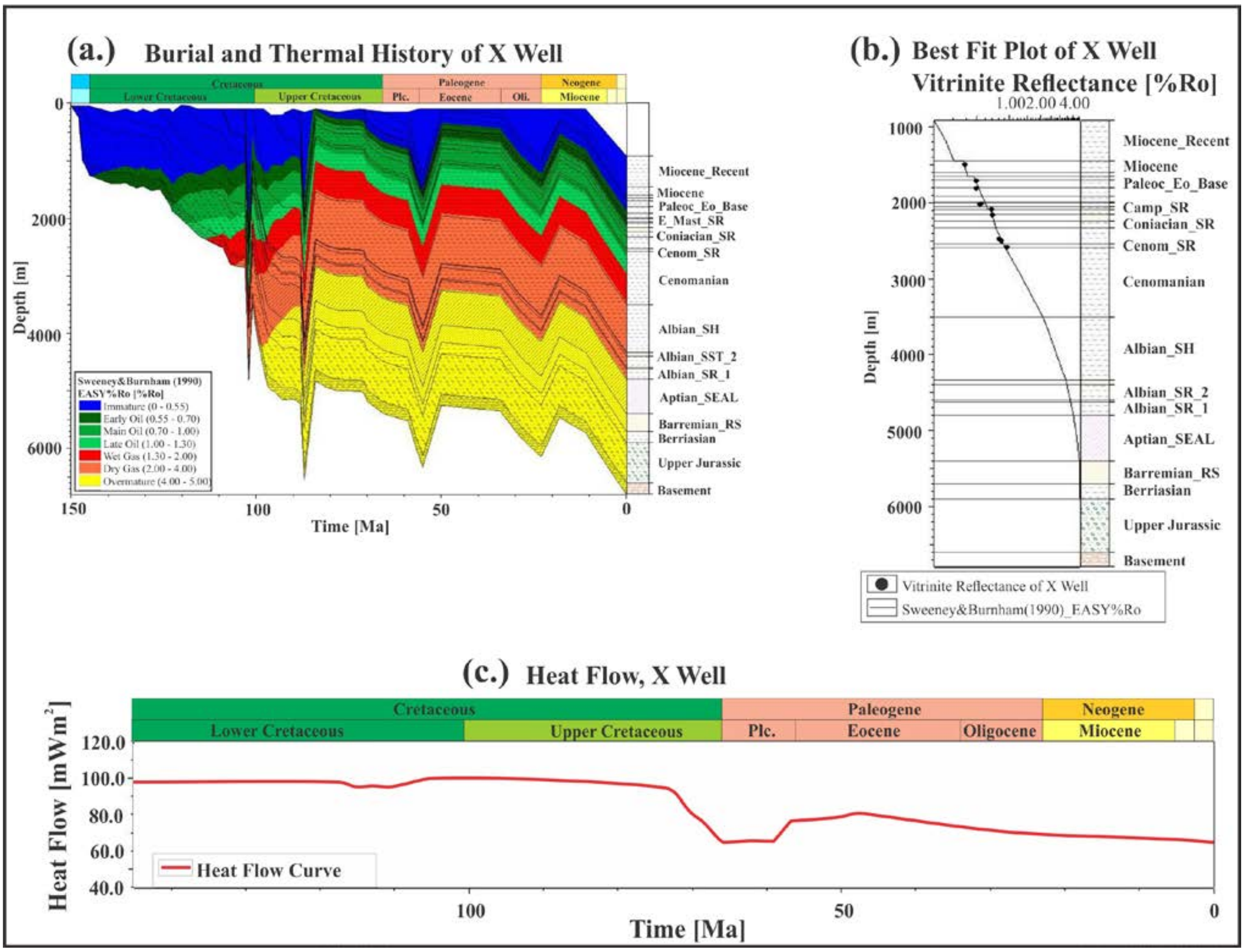


Fig. 11 a. Modelled burial history of offshore X well with resulting vitrinite reflectance overlay. (The two oldest rapid burial and erosion events were the most significant periods of the source rock transformation) **b.** A best fit between calculated (black line) and measured vitrinite reflectance (black dots) is observed in the well. **c.** Paleo heat flow used for modeling. (SH-Shales, SST-Sandstones, SR-Source Rock, RS-Reservoir Rock)

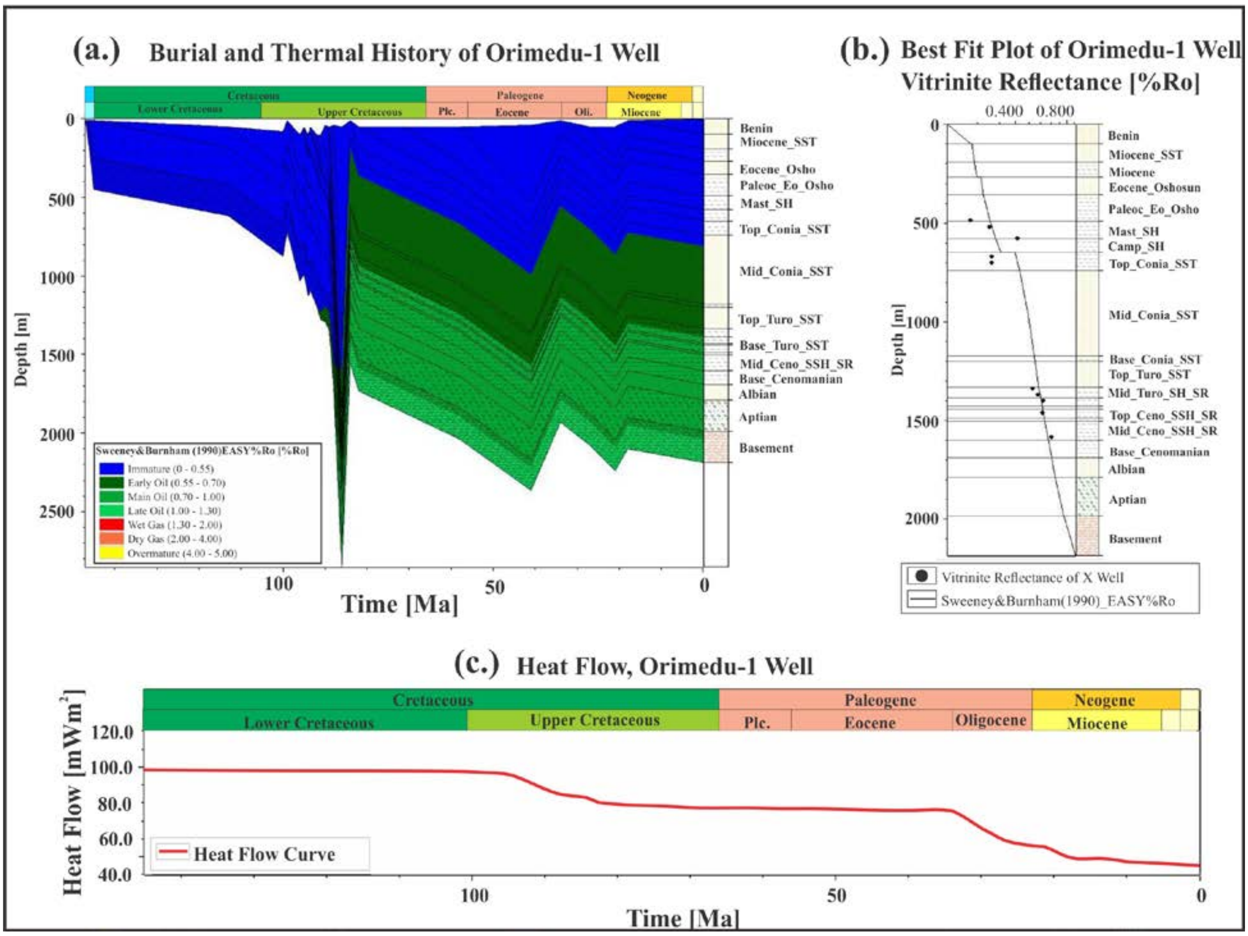


Fig. 12 a. 1-D burial history of onshore Orimedu-1 well with Vitrinite reflectance overlay. **b.** A best fit between calculated and measured vitrinite reflectance is observed in the well. **c.** heat flow evolution used for the modeling.

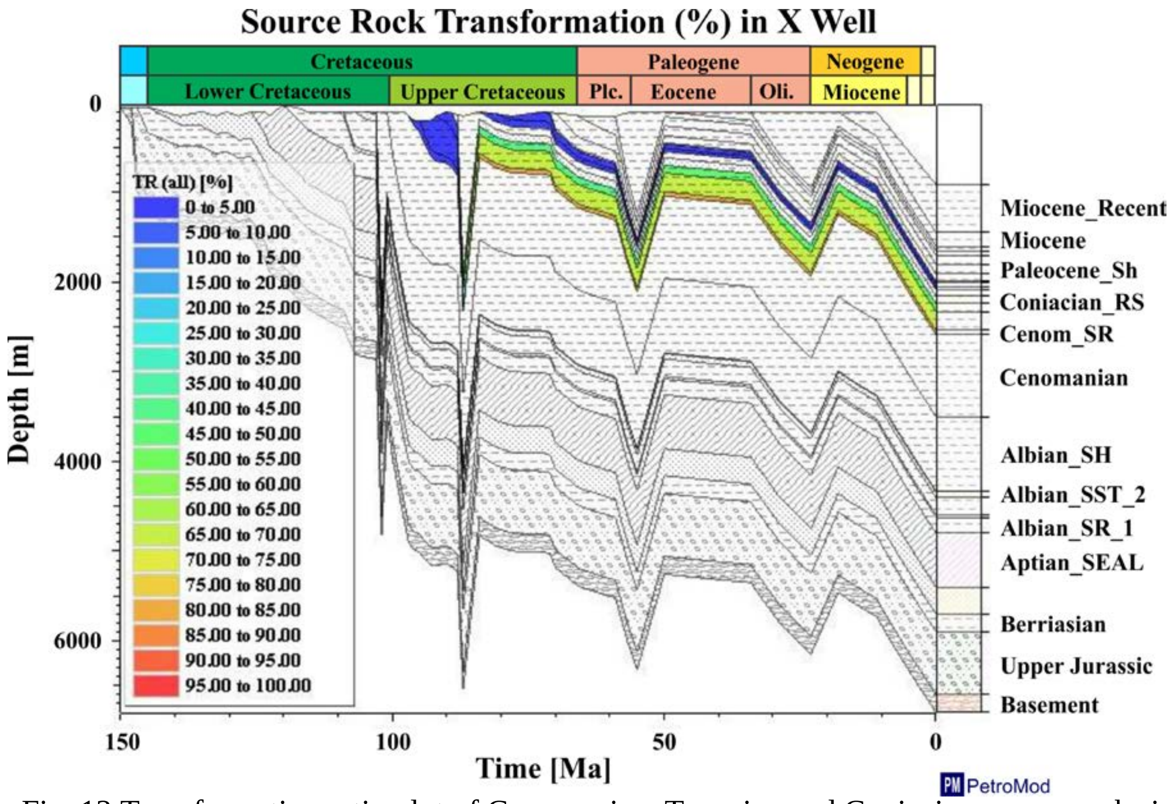


Fig. 13 Transformation ratio plot of Cenomanian, Turonian and Coniacian source rocks in X well showing generation of hydrocarbon above 80 % in the older Cenomanian source beds after Upper Cretaceous burial and erosion event.

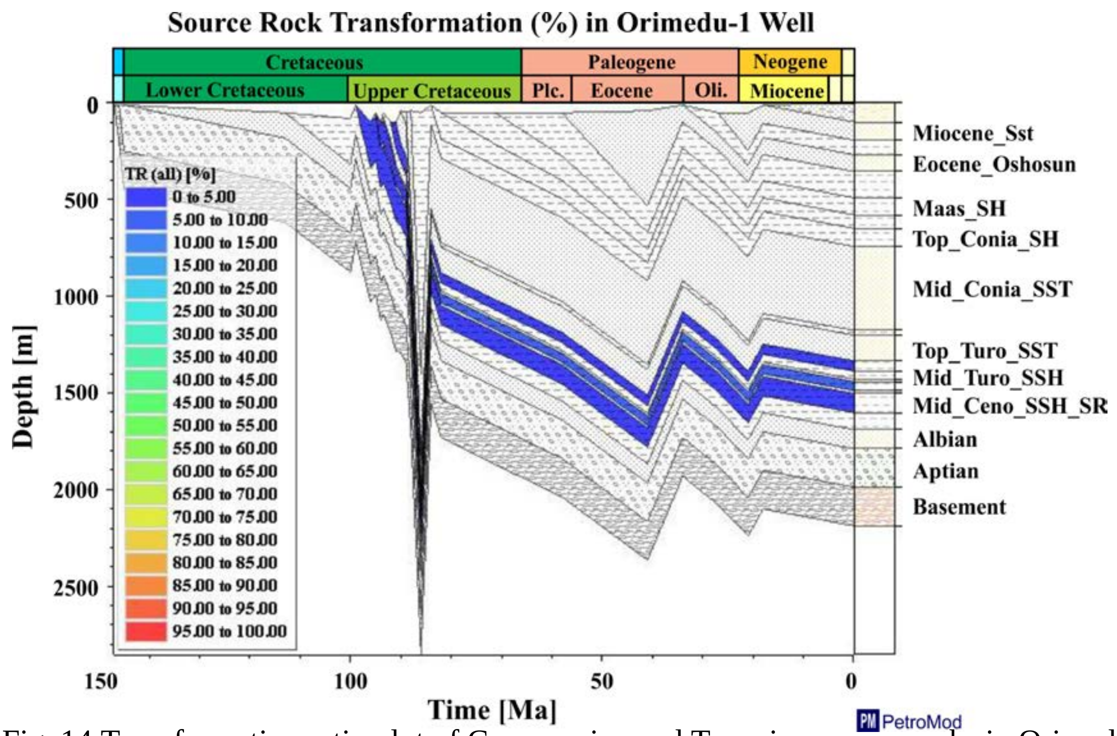
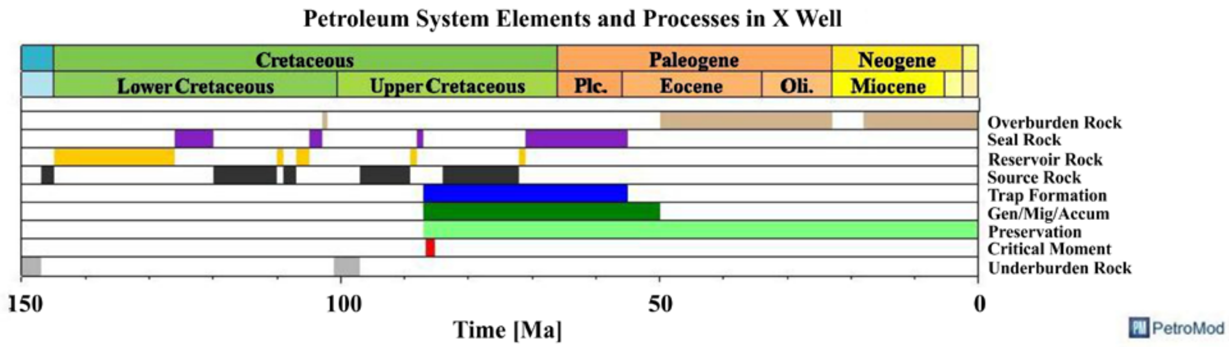


Fig. 14 Transformation ratio plot of Cenomanian and Turonian source rocks in Orimedu-1 well showing only very low amount of generated hydrocarbons.

(a)



(b)

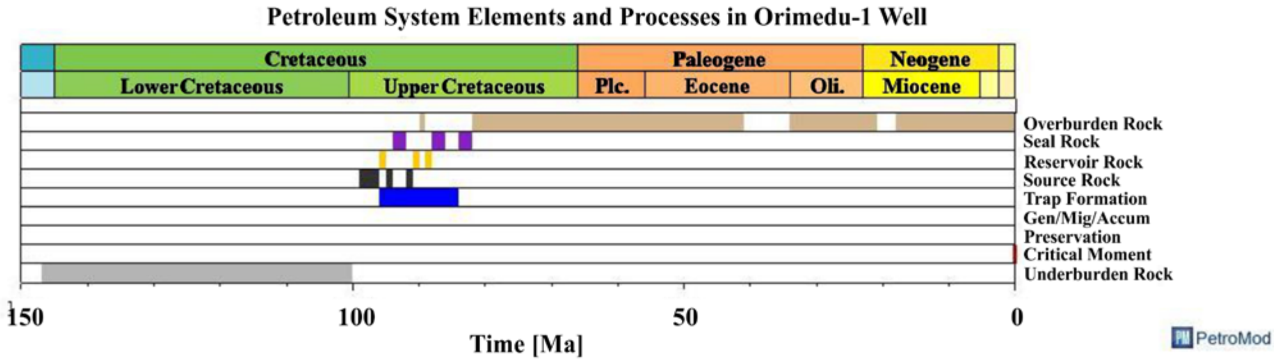


Fig. 15 Events charts representing timing of the petroleum system elements and processes in the Dahomey Basin. There is a potential trapping system before the onset of hydrocarbon generation from the upper Cretaceous source rocks, but their integrity under the various tectonic stages needs further investigation. The events in the offshore area of the basin are represented by (a) while (b) is onshore.

Table 1. Rock Eval Data of the studied shales in X Well.

S/N	**Depth (m)**	**Period**	**Lithology**	**TOC**	**S_1**	**S_2**	**$S_1 + S_2$**	**T-max**	**HI**	**VRo**
1	1807	Maastrichtian	Shale	2.2	0.4	3.2	3.6	429	143	0.6
2	1856	Maastrichtian	Shale	2.3	0.3	2.8	3.1	425	122	n.d
3	1893	Maastrichtian	Shale	2.4	0.4	4.3	4.7	415	177	n.d
4	1914	Maastrichtian	Shale	2.4	0.4	5	5.4	418	208	n.d
5	1939	Maastrichtian	Shale	2.4	0.5	4.3	4.8	425	181	0.5
6	1975	Maastrichtian	Shale	2	0.4	4	4.4	428	198	n.d
7	2006	Campanian	Shale	1.8	0.4	3.3	3.7	427	184	0.5
8	2024	Campanian	Shale	1.5	0.5	3.2	3.7	425	208	0.5
9	2030	Campanian	Shale	1.9	0.3	3.2	3.5	431	174	0.68
10	2085	Campanian	Shale	1.9	0.4	3.7	4.1	422	197	n.d
11	2115	Coniacian	Shale	1.7	0.4	2	2.4	422	118	n.d
12	2131	Coniacian	Shale	1.4	0.8	2.5	3.3	418	173	n.d
13	**2155	Coniacian	Shale	1.5	0.8	3.6	4.4	431	238	0.69
14	2167	Coniacian	Shale	1.5	0.9	2.5	3.4	420	169	n.d
15	2182	Coniacian	Sandy Shale	1.6	0.7	2.9	3.6	429	183	0.6
16	2204	Coniacian	Sandy Shale	1.6	0.8	2.3	3.1	429	145	n.d
17	2240	Coniacian	Sandy Shale	1.2	0.6	2.5	3.1	427	207	0.5
18	2256	Coniacian	Sandy Shale	2.2	2.8	3.9	6.7	421	180	0.62
19	2286	Coniacian	Sandy Shale	0.9	0.8	2.2	3	420	242	n.d
20	2304	Turonian	Sandy Shale	0.8	0.9	1.7	2.6	414	226	n.d
21	2326	Turonian	Shale	0.6	0.6	3.5	4.1	361	595	n.d
22	2335	Turonian	Shale	0.6	0.7	4	4.7	353	686	n.d
23	2356	Turonian	Shale	0.7	0.4	3	3.4	359	455	n.d
24	2368	Turonian	Shale	0.6	0.8	4.5	5.3	364	706	n.d
25	2384	Turonian	Shale	0.6	0.8	3.8	4.6	358	588	n.d
26	2390	Turonian	Shale	2.3	1.5	11.6	13.1	350	503	n.d
27	2399	Turonian	Shale	0.7	0.7	4.7	5.4	364	666	n.d
28	2420	Turonian	Shale	0.8	0.6	4	4.6	358	499	n.d
29	2435	Turonian	Shale	1.3	1	6.8	7.8	362	541	n.d
30	2448	Turonian	Shale	0.9	0.7	5	5.7	365	563	n.d
31	2454	Turonian	Shale	0.8	0.6	3.9	4.5	365	490	n.d
32	2469	Turonian	Shale	0.8	0.9	5	5.9	365	604	0.8
33	2481	Turonian	Shale	1.3	1.2	8.3	9.5	365	629	0.84
34	2496	Turonian	Shale	0.6	0.9	4.1	5	360	655	n.d
35	2518	Turonian	Shale	0.8	0.6	4.1	4.7	362	509	n.d
36	2536	Cenomanian	Shale	1.9	0.6	7.7	8.3	413	401	n.d
37	2554	Cenomanian	Shale	0.8	0.5	3.3	3.8	362	409	n.d
38	2566	Cenomanian	Shale	1.5	0.4	4.8	5.2	424	332	n.d
39	2576	Cenomanian	Shale	0.9	0.5	4.1	4.6	364	481	0.95

***: Sample used for kinetic analysis*

Table 2. Rock Eval Data of the studied shales in Orimedu-1 well

Depth (m)	Period	Lithology	TOC	S_1	S_2	$S_1 + S_2$	T-max	HI
488	Maastrichtian	Shale	0.75	0.06	0.46	0.52	413	61
511	Maastrichtian	Shale	0.47	0.02	0.05	0.07	417	11
549	Maastrichtian	Shale	0.51	0.02	0.03	0.05	346	6
572	Maastrichtian	Shale	1.27	0.04	1.24	1.28	426	98
610	Campanian	Shale	0.58	0.14	0.23	0.37	334	40
633	Campanian	Shale	0.77	0.02	0.15	0.17	407	19
670	Campanian	Shale	0.61	0.03	0.16	0.19	418	26
693	Coniacian	Shale	0.61	0.02	0.22	0.24	418	36
1341	Turonian	Shale	2.19	0.34	8.96	9.30	432	410
1364	Turonian	Shale	2.62	0.44	12.36	12.80	435	472
1402	Turonian	Shale	0.92	0.07	1.72	1.79	438	188
1463	Turonian	Shale	1.51	0.11	3.07	3.18	437	203
1524	Cenomanian	Shale	0.83	0.06	1.07	1.13	434	129
**1547	Cenomanian	Shale	1.86	0.21	5.31	5.52	430	285
1585	Cenomanian	Shale	1.09	0.03	1.08	1.11	439	99

***: Sample used for kinetic analysis*