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AN EVALUATION OF MAASTRICHTIAN-PALEOCENE SOURCE ROCK INTERVAL ON THE WESTERN FLANK OF NIGER DELTA BASIN, NIGERIA: IMPLICATIONS FOR HYDROCARBON PROSPECTIVITY

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ABSTRACT

Maastrichtian and Paleocene shales recovered from a vertical exploratory well on the western flank of Niger Delta Basin, close to the boundary of the Dahomey (Benin) Basin, were studied for their possible contribution to the hydrocarbon potential of the basin. The organic matter richness, kerogen types, and thermal maturity of the studied shale samples and implications of hydrocarbon generation potential were determined based on results of TOC/Rock-Eval analysis. The Maastrichtian and Paleocene shale samples are characterized by total organic carbon (TOC) values of up to 4.70 wt. % and S_2 (hydrocarbon-generating potential) values range from 0.68 to 2.69 mgHC/g rock, indicating poor to fair source potential. The presence of type III and type IV kerogen is indicative of poor-quality organic matter that has the potential to generate gaseous hydrocarbon. This study suggests that the Maastrichtian and Paleocene source rocks on the western flank of the Niger Delta Basin are immature to early mature stage, and could not have generated a commercial amount of hydrocarbon.

Keywords: Source rocks, Hydrocarbon generation, Maastrichtian, Paleocene, Niger Delta Basin.

INTRODUCTION

Petroleum exploration in the Niger Delta Basin has resulted in the discovery of over 250 oil and gas fields, with total proven reserves of about 22 billion barrels (Ejedawe *et al*., 1983). The vast hydrocarbon potentials in the Niger Delta Basin have attracted petroleum explorationists that have continually examined the oil and gas occurrences in Cretaceous to Neogene sequences in different depobelts (sub-basins).

There have been a lot of speculations in the literature about the origin of hydrocarbon in the Niger Delta Basin (Frost, 1997; Ekweozor, 2005; Samuel *et al*., 2008). The recent discovery of hydrocarbon accumulation in the Cretaceous sequence of Toju Ejanla-1 well, drilled on the western flank of the Niger Delta Basin, has confirmed the possibility of Cretaceous play in the Niger Delta Basin. This necessitates the source re-evaluation/assessment of the Cretaceous to Paleogene rocks in the Niger Delta basin.

The present work aims at providing valuable information on the source rock attributes of the Maastrichtian to Paleocene strata, especially the source rock quantity, quality, and maturity phases, and implications on hydrocarbon generation potentials. The TOC/Rock-Eval results of seven (7) ditch cutting samples obtained from an exploration well (named Bini-1 well for proprietary reasons) are presented and discussed.

The studied well is located on the western flank of the Niger Delta Basin, close to the boundary of the Benin Basin (Figure 1). This current study focuses on the hydrocarbon potential of the Maastrichtian to Paleocene Shales on the western flank of the Niger Delta Basin, Nigeria, and it is expected that this study would provide information on the source rock potential of Cretaceous shales on the Niger Delta Basin.

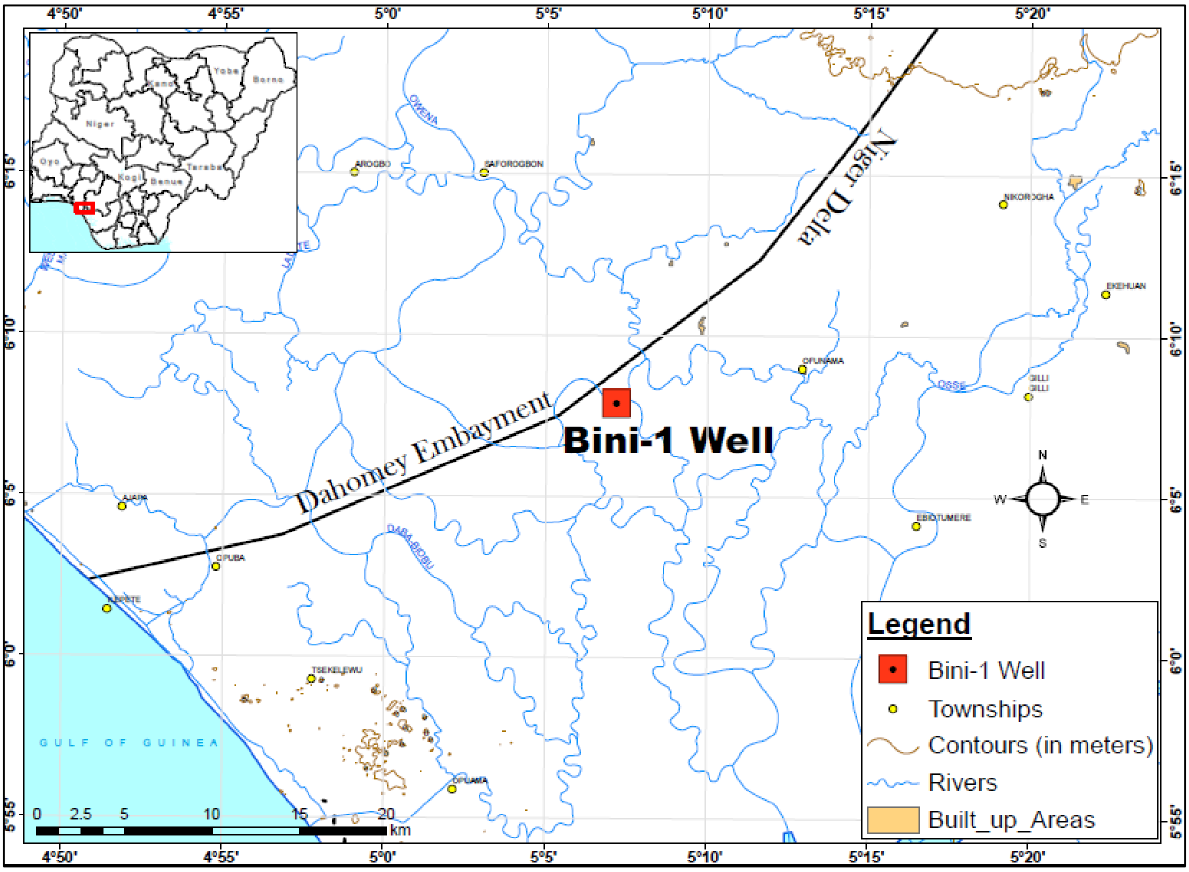

Figure 1. The topographical map of the western flank of the Niger Delta Basin, showing the location of Bini-1 well. The black line on the map represents the boundary between Niger Delta and Dahomey (Benin) Embayment.

Geologic setting

The Niger Delta continental margin (Figure 2) is one of the largest deltaic systems in the world (Doust and Omatsola, 1990). The sub-aerial part of the delta covers about 75,000 km^2 and extends more than 300 kilometers from apex to mouth (Adeogba *et al*., 2005). The total sedimentary sequence was deposited in a series of mega-sedimentary belts in a succession temporally and spatially with southward progradation of the Delta (Doust and Omatsola, 1990).

Two arms of a triple junction comprising collapsed margin of south Atlantic gave rise to the Niger Delta evolution following the early Cretaceous subsidence of the African continental margins and deposition of clastic materials (Ehinola and Ejeh, 2009). The growth of the Niger Delta Basin started during Paleocene (Azeez, 1989). Subsidence and minor tilting southward,

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along the delta front, occurred after a mild Early Paleogene uplift (Azeez, 1989). The building of the Niger Delta over the edge of the African continent began in Middle-Late Eocene (Hosper, 1965). During the Middle and Late Eocene times, regional deltaic deposition has been established with sediments largely derived from the weathering flanks of the Niger-Benue drainage system (Stacher, 1994). Oligocene and younger sediments thicken progressively towards the continental shelf (Figure 2). These sediments accumulated rather fast and hence gravitational movements resulted in growth faults (Azeez, 1989).

The sedimentary fill is usually divided into three diachronous formations (Eocene-Recent); namely; the undercompacted, marine Akata Formation, paralic Agbada Formation, and continental fluviatile Benin Formation (Figure 2). The Akata Formation is typically overpressured and made up of prodeltaic shales with occasional turbidite sands (Adeogba *et al*., 2005). In the lowermost part of the Akata Formation is a uniform shale development consisting of dark grey silty shale with plant remains at the top (Azeez, 1989). It is believed to have been deposited in a front of the advancing delta and ranges from Eocene to Recent.

Agbada Formation consists of paralic, mainly shelf deposits of alternating sands, shales, and mudstone (Oluwajana *et al.*, 2017; Oluwajana, 2018). The sediments of the Agbada Formation comprise brackish-water lower deltaic plain (mangrove, swamps, flood-plain basin, marsh) and the coastal area with its beaches, barrier bars, and lagoons (Short and Stauble, 1967). A fluviatile origin is indicated by the coarseness of the grains and the poor sorting (Azeez, 1989).

The Benin Formation consists of predominantly massive, highly porous, freshwater-bearing sandstones, with local thin shale interbeds considered to be of braided-stream origin (Oluwajana, 2018). It is coarse-grained to locally fine-grained, gravelly, poorly sorted, sub-angular to well-rounded, and bears lignite streaks and wood fragments, it is a continental deposit of probable upper deltaic depositional environment (Azeez, 1989).

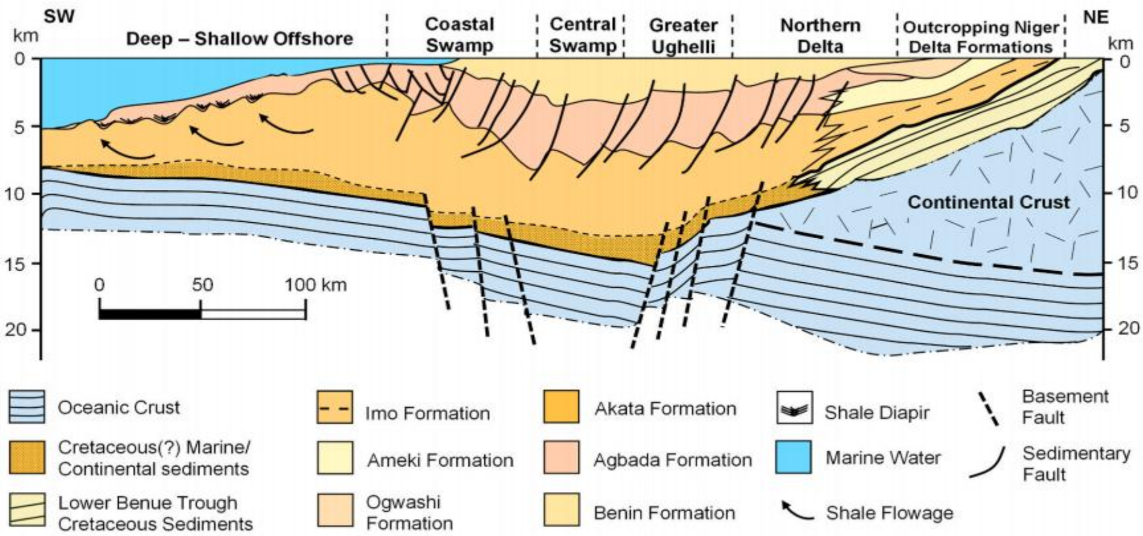

Figure 2. The schematic stratigraphic dip section of the Cenozoic Niger Delta Basin shows the position of the various depobelts with the three diachronous lithostratigraphic formations and associated depositional structures (Ovie *et al*., 2021).

MATERIALS AND METHODS

The studied well is located on the western flank of the Niger Delta Basin. It was drilled to a depth of 10,782ft (3,286m) by Shell Petroleum Development Company of Nigeria, as a vertical exploration well (Figure 3) that targeted conventional reservoirs in Upper Cretaceous strata. The exploration well for proprietary reasons was named “Bini-1” well.

Seven (7) ditch-cutting samples retrieved at depths 2,440m, 2,593m, 2,745m, 2,882m, 3,050m, 3,142m, and 3,270m TVD of the Bini-1 well were subjected to standard analytical procedures. The shale samples were dried, crushed to fine particles, and subsequently analyzed the TOC content using a LECO analyzer. Rock-Eval pyrolysis analyses were subsequently performed on the powdered samples using a Rock-Eval II instrument. S_1 (free hydrocarbon), S_2 (liquid hydrocarbon), S_3 (carbon dioxide), and T_{max} (maximum temperature) values were recorded by the Rock-Eval II analyzer. Hydrogen Index, Oxygen Index, and Production Index were determined from measured Rock-Eval pyrolysis parameters.

1. The Hydrogen Index (HI) = $(S_2/TOC)*100$; measured in mgHC/g TOC
2. Oxygen Index (OI) = $(S_3/TOC)*100$, measured in mg CO_2/g TOC
3. Production index (PI) = $S_1/(S_1+S_2)$

The results of the TOC/Rock-Eval Pyrolysis analyses were provided by the exploration department of Shell Petroleum Development Company, Port Harcourt, Nigeria.

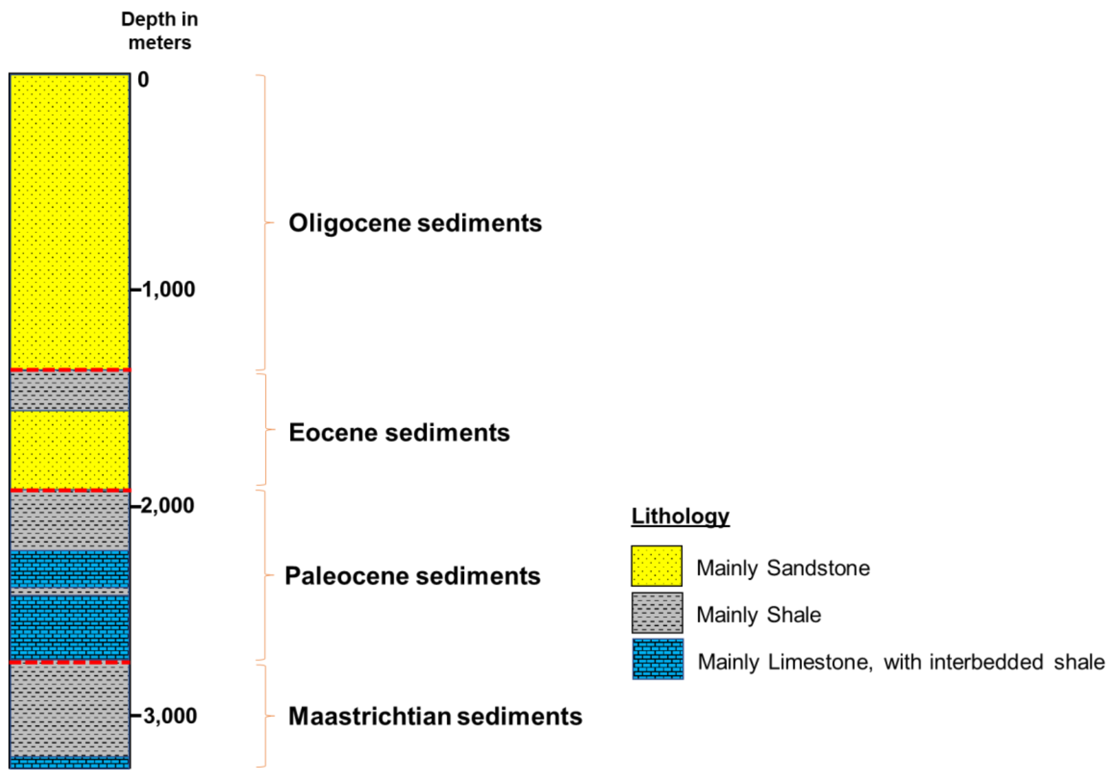

Figure 3. A simplified stratigraphic chart of the exploration well (Bini-1). The vertical axis is the measured depth in meters. The ages (relative) of each Formation are illustrated on the right-hand side.

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RESULTS AND DISCUSSIONS

Organic Matter Richness

The Maastrichtian and Paleocene shale samples in the Bini-1 well have total organic carbon (TOC) content varying from 1.4 to 1.6 wt. % (av. 1.50 wt.%) and 1.0 to 4.7 wt.% respectively (Table 1). The TOC values of all the shale samples exceed the minimum thresholds (≥ 0.5 wt. %) required for potential source rock (Tissot and Welte, 1978) hence the Maastrichtian and Paleocene source rocks from Bini-1 well are rich in organic matter concentration (Figure 4).

Table 1. The results of Rock-Eval pyrolysis and TOC content analyses of Maastrichtian and Paleocene source rocks in well Bini-1, Niger Delta Basin.

Sample no	Age	Depth (m)	TOC (wt.%)	T_{max} (°C)	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	HI mgHC/ gTOC	OI $mgCO_2$/ gTOC	PI
Bini-S1	Paleocene	2,440	1.4	439	4.42	1.11	0.74	79	53	0.8
Bini-S2	Paleocene	2,593	1.6	426	4.29	0.68	1.04	43	65	0.86
Bini-S3	Maastrichtian	2,745	1	433	7.78	1.67	2.72	167	272	0.82
Bini-S4	Maastrichtian	2,882	4.7	414	10.57	2.69	3.59	57	76	0.8
Bini-S5	Maastrichtian	3,050	3.2	426	5.2	1.46	1.91	46	60	0.78
Bini-S6	Maastrichtian	3,142	2.4	381	5.42	1.15	1.73	48	72	0.82
Bini-S7	Maastrichtian	3,270	2	385	4.27	0.82	1.84	41	92	0.84

Abbreviations:
TOC = total organic carbon (wt. %); S_1 = Free hydrocarbon content, mg/g; S_2 = pyrolysable hydrocarbon, mg/g; S_3 = carbon dioxide released during pyrolysis, mg/g; T_{max} = temperature at which the maximum generation of the hydrocarbons occurs (°C); HI = hydrogen index, measured in mgHC/gTOC; OI = oxygen index, measured in $mgCO_2$/gTOC; PI = Production index.

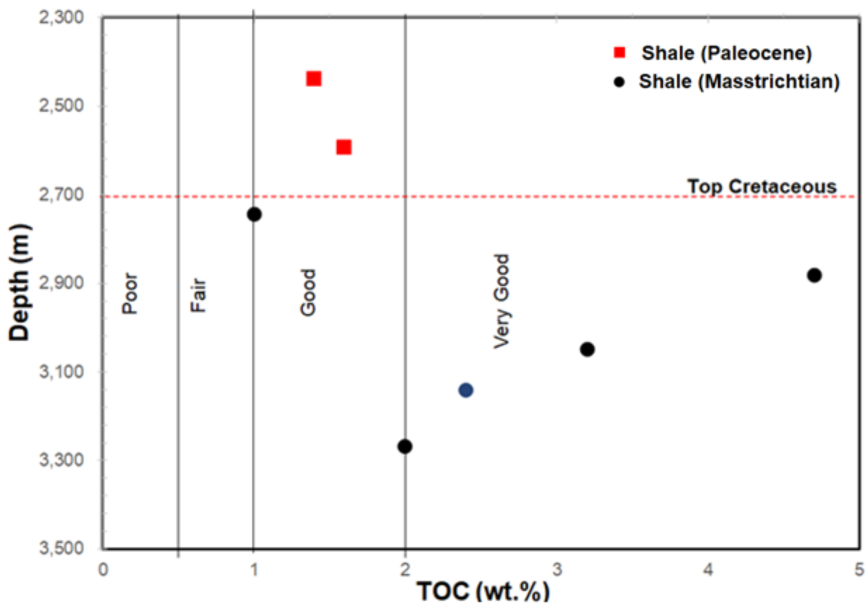

Figure 4. The plot of TOC versus depth showing the organic carbon richness and variation with depth

Hydrocarbon generative potential

The TOC content alone is not sufficient to determine the generative potential of source rocks (Hakimi *et al*., 2021). Rock-Eval S_2 yield must be considered alongside the TOC content for reliable evaluation of hydrocarbon generative potential (Peters and Cassa 1994; Dembicki 2009; Hakimi *et al*., 2021). The plot of TOC content against S_2-generative hydrocarbons of the samples indicates that the Paleocene samples have poor generative potential, while Maastrichtian shale samples have poor to fair generative potential (Figure 5; Çiftçi *et al*., 2010).

The Hydrogen Index (HI) values range from 41 to 167mgHC/gTOC. The relationship between HI and TOC shows that all the Paleocene shales and most of the Maastrichtian shale samples are capable of generating gas (Figure 6). The generally low hydrogen index (HI) values of the studied shale samples, despite being good-very good source rocks, could be attributed to high organic productivity, poor preservation condition, and scarcity of lipid-rich marine zooplanktons (Ojo *et al*., 2020). Hydrogen depletion is believed to be the consequence of pervasive oxidation and extensive grazing under oxic conditions in organic matter (Ojo *et al*., 2020).

Type of Organic matter

The type of organic matter contained in shales was deduced from the Rock-Eval parameters. The classification of kerogen type of the Maastrichtian and Paleocene shale samples in the Bini-1 well is done by a cross plot of OI and HI (Figure 7a). The samples classify mainly as Type III to Type IV (Figure 7a), suggesting residual carbon that has the potential to generate gaseous hydrocarbon (Ehinola *et al*., 2006). Also, a plot of S_2 versus TOC corroborates the Type III to Type IV organic matter (Figure 7b) predicted by the OI versus HI plot. Mineral matrix effect on the kerogen cannot be ruled out as the reason for the poor quality observed (Ehinola *et al*., 2006)

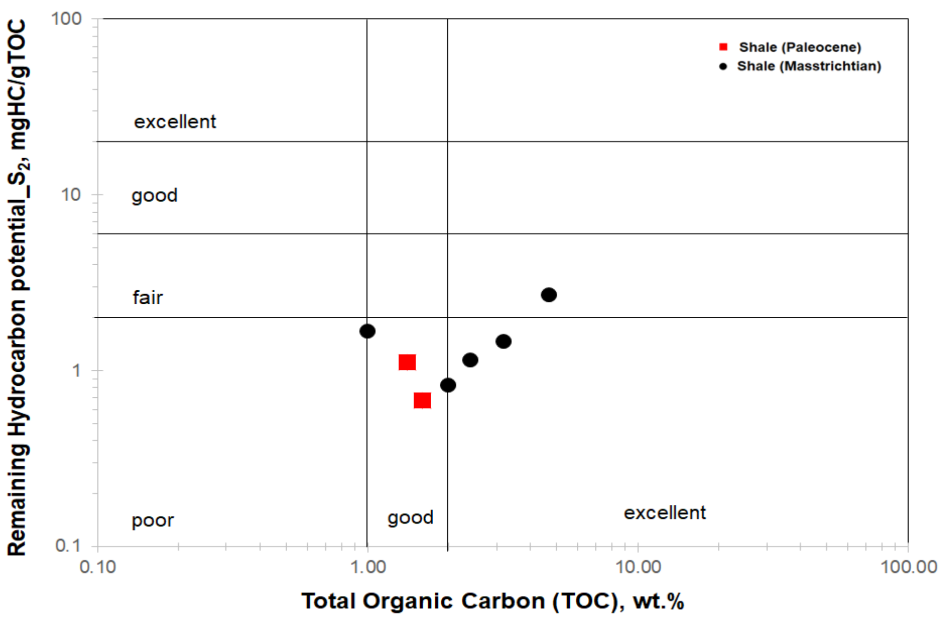

Figure 5: Plot of S_2 and TOC for shale samples from Bini-1 well, Niger Delta Basin indicating good to excellent source rock

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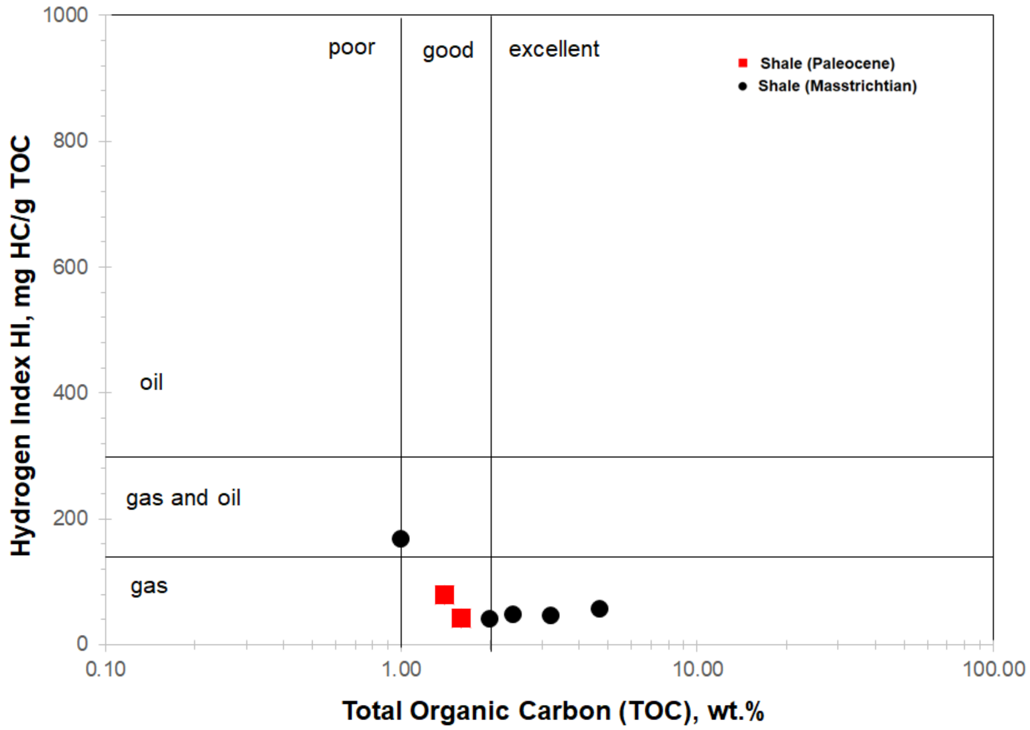

Figure 6: Plot of HI and TOC for shale samples from Bini-1 well, Niger Delta Basin showing good to excellent source rock

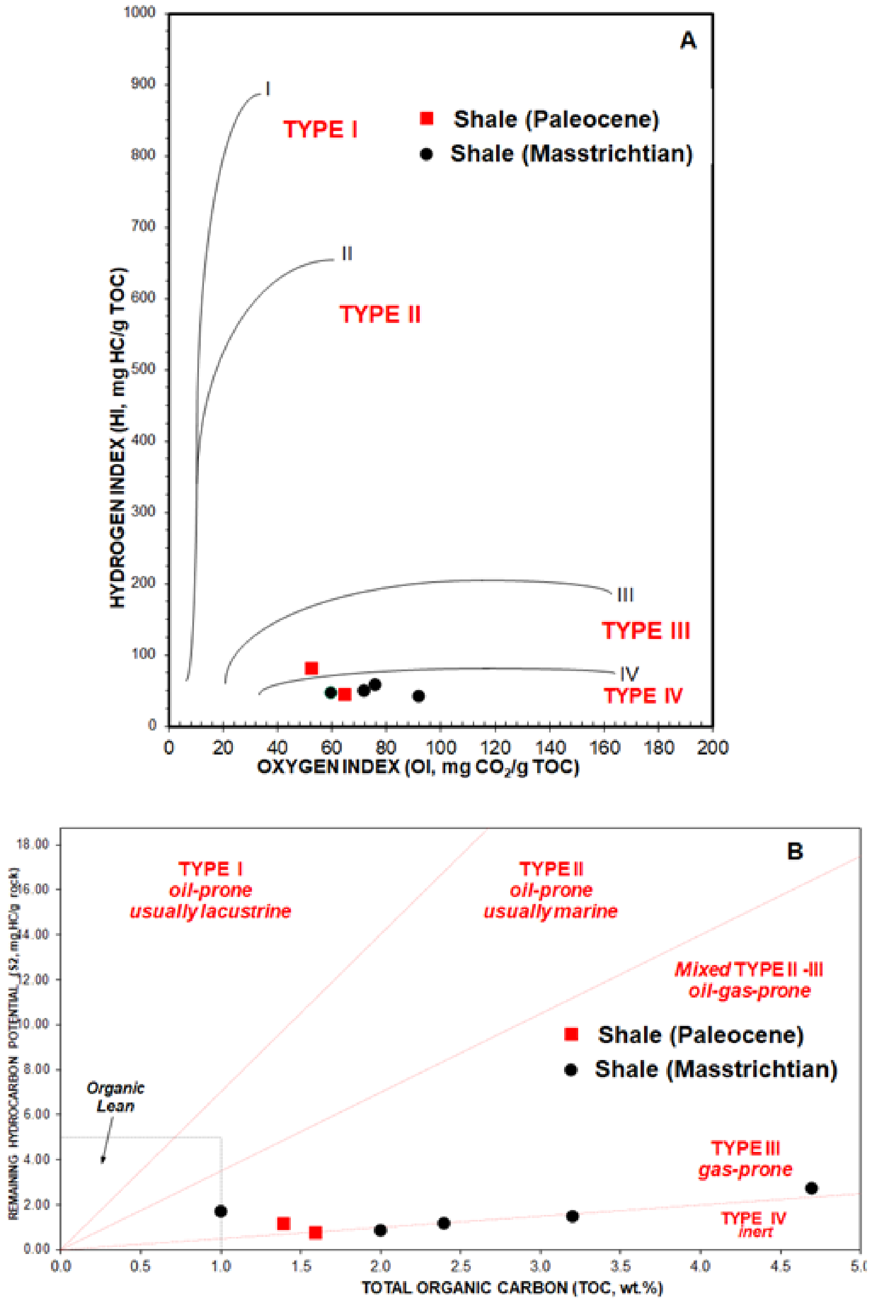

Figure 7. Kerogen/organic matter type discrimination plots of the Bini-1 well; (A) relationships between OI and HI, (B) relationship between TOC and S_2. Type III and IV organic matter types are present in the samples.

Thermal maturation of the organic matter

Pyrolysis temperature at the maximum yield of hydrocarbons (T_{max}) was used to estimate the maturation of organic matter in source rocks (Peters and Cassa 1994; Hakimi *et al*., 2021). The plot showed that the studied samples are generally immature to mature for hydrocarbon generation (Figure 8). The maturity of the shale samples decreased with depth, with all Maastrichtian shales being immature while the Paleocene samples are immature to mature (Figure 8).

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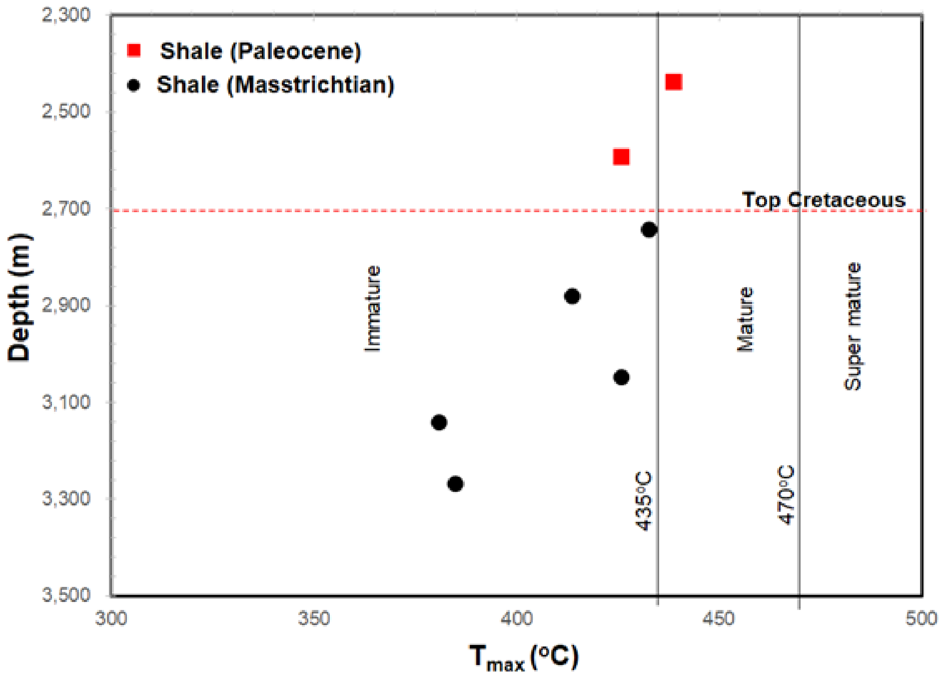

Figure 8. The plot of T_{max} versus depth overlaid with maturity fields. The organic matter in the Maastrichtian and Paleocene source rocks are largely immature

Implications for Cretaceous play

The TOC values of Paleocene samples vary from 1.4 to 1.6 wt.% indicating good source rock while Maastrichtian shale samples have TOC values ranging from 1.00 to 4.7 wt.%. However, Maastrichtian and Paleocene samples have poor to fair hydrocarbon potential based on genetic potential.

The plots showing the relationships between OI and HI, and TOC and S_2 indicate that the shale samples contain type III and type IV organic matter. However, the effect of oxidation or mineral matrix effect on the kerogen cannot be ruled out as reasons for its poor quality (Ehinola *et al.*, 2006). The generally low HI values (< 100 mgHC/gTOC) of the Maastrichtian and Paleocene shale samples may have occurred as a result of sediment dilution, selective transport, and oxidation of the organic matter (Bustin, 1988). In addition, high organic productivity and poor preservation condition, and scarcity of lipid-rich marine zooplanktons are believed to be major influence on the low HI values recorded in the Bini-1 well (Ojo *et al.*, 2020).

The geochemical indices indicate that the Maastrichtian and Paleocene shale samples retrieved from Bini-1 well generally represent organic-rich source rocks presently within the immature to the early mature phase of oil generation, and may not have generated commercial amount of hydrocarbon, even a production report on the exploration well indicates that there is no evidence of hydrocarbon in Cretaceous-Neogene strata. A viable amount of hydrocarbon should be expected from deeply buried Cretaceous source beds. Recent studies have shown that Paleogene-Neogene reservoired hydrocarbons in the Niger Delta basin are derived from multiple source rocks namely deeply buried Cretaceous (sub-delta) source rock, thick shale of Akata Formation, and source rocks at the base of the Agbada Formation, this assertion has been proven in the nearby Dahomey (Benin) Basin and Anambra Basin (Frost, 1997; Haack *et al*., 2000; Samuel *et al*., 2008; Esegbue *et al*., 2020; Egbo *et al*., 2020).

CONCLUSIONS

The geochemical investigation on the seven (7) shale samples retrieved from Maastrichtian to Paleocene intervals of an exploratory well (Bini-1) on the western flank of the Niger Delta indicates that the Maastrichtian and Paleocene shale samples are good to very good source rocks based on the TOC content. The kerogen content of the studied shales is mainly of type III and type IV, suggesting a poor-quality organic matter that has the potential to generate gaseous hydrocarbon. The range of maturity parameter, T_{max}, indicates that the shale samples are currently within the immature to an early-mature phase of oil generation. The organic-rich Maastrichtian to Paleocene shale samples obtained from exploration well “Bini-1” show low source rock potential and may not have generated a commercial amount of hydrocarbon at present, even a production report on the exploration well indicates that there is no evidence of hydrocarbon in the Cretaceous-Neogene strata. A viable amount of hydrocarbon should be expected from deeply buried Cretaceous source beds on the western flank of the Niger Delta Basin.

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