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SOURCE ROCK POTENTIAL OF AGBADA FORMATION SHALES: CASE STUDY, DRM FIELD

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A B S T R A C T

This study investigates the source rock intervals within the Agbada Formation in the Niger Delta, utilizing biostratigraphic analysis, source rock assessment, and basin modeling. The study addresses the need to understand the geological history of the formation, focusing on wells DRM1 and DRM2. Biostratigraphic data, integrating foraminifera and palynological analyses, precisely determine the age and stratigraphy of the studied interval, identifying it as the Pliocene to late Miocene paralic Agbada formation. Notable peaks in foraminiferal abundance correspond to specific periods on the Global Sea Level Cycle Chart, geochemical analyses, including Rock-Eval Pyrolysis and vitrinite reflectance, reveal immature to early mature source rocks with a gas-prone nature in the Miocene Agbada Formation. Total organic content and hydrogen index indicate good to very good organic richness, while kerogen type analysis identifies type III kerogen. A one-dimensional basin model, using Petromod software, evaluates burial and thermal histories. The model indicates insufficient burial for thermal maturation and hydrocarbon generation in both wells, despite DRM-1 being within the early oil zone. Differential burial history explains DRM-2's immature source at present-day. This integrated approach offers valuable insights into the age, stratigraphy, and thermal history of the Agbada Formation. The findings contribute to source rock characterization and basin understanding in the Niger Delta, with implications for hydrocarbon exploration and resource assessment.

Keywords: one-dimensional modeling; biostratigraphy; Agbada shale; Niger Delta; source rock assessment, hydrocarbon exploration.

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1. Introduction

The Niger Delta basin, located in equatorial West Africa, is a significant region with respect to petroleum production. Occupying the Gulf of Guinea continental margin between latitudes 3° and 6° N and longitudes 5° and 8° E (fig.1), it ranks among the world's most prolific petroleum-producing Tertiary deltas. The Niger Delta basin is part of the larger and older tectonic feature known as the Benue trough, a NE-SW folded rift basin that stretches across Nigeria. Its formation coincided with the opening of the Gulf of Guinea and the equatorial Atlantic during Aptian-Albian times. The delta's structural evolution was influenced by basement tectonics and the movements along equatorial Atlantic oceanic fracture zones [1].

The Niger Delta, which has witnessed extensive progradation since the Eocene which has resulted in the formation of depobelts that represent the most active areas of the delta at different stages of its development. With an area of approximately 300000 km^2 and a sediment volume of 500000 km^3, the Niger Delta basin is one of the largest regressive deltas in the world [2].

The Niger Delta basin extends eastward offshore into the Rio del Rey basin in Cameroon, with the Cameroon-Annobon volcanic axis being its eastern limit. Volcanic activity took place during the Miocene along this axis which led to an uplift of the eastern part of the Niger Delta and created shale ridges which have induced later shale diapirism, this complex structural setting, in the southeast offshore Delta is slightly different from the rest of the onshore and offshore parts of the basin. Shale ridges, diapirism and toe thrusts present in this area increase the likelihood of stratigraphic traps.

Understanding the petroleum system elements and processes in sedimentary basins, such as the Niger Delta, presents significant opportunities for exploration and development. Well logging has played a crucial role in evaluating reservoir rocks, source rocks, sequence stratigraphy, and depositional environments. Petrophysical assessment using wireline logs aids in distinguishing productive zones from non-productive ones, while the integration of gamma-ray logs and other measurements helps analyze depositional environments and sequences. Source rock evaluation relies

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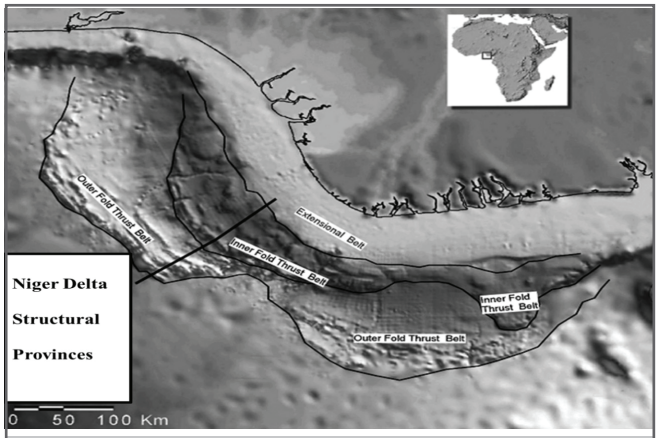

Fig. 1. Niger Delta location in the Gulf of Guinea continental margin [4]

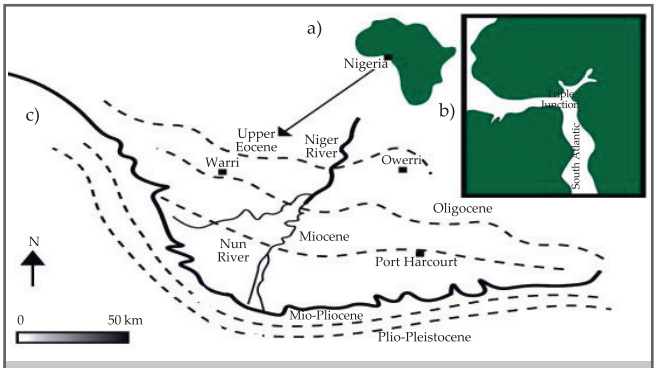

Fig. 2. a) Location of Niger Delta; b) Separation of Africa and South America showing the Triple Junction in the early Cretaceous [8]; c) Map of the Niger Delta showing the Current Coast (full line) and dated stages of Delta Growth (dashed lines) [9]

on determining the amount of generated hydrocarbons, the quality of organic matter, and the level of thermal maturity. However, the limited availability of core/well cutting and geochemical data sets in most of the Niger Delta poses challenges in evaluating the hydrocarbon source. To overcome these limitations, researchers have explored the relationship between source rocks and wireline logs, leveraging the physical properties that distinguish organic matter from the mineral components of the host rock.

The primary objective of this research is to assess the source rock potential in terms of organic matter quantity, quality, and thermal maturity in the DRM Field of the Niger Delta. The research focus on developing a 1D petroleum system model of the Niger Delta by integrating a high resolution biostratigraphical analysis and geochemical analysis to provide a comprehensive understanding of the hydrocarbon potential and aid in decision-making for future exploration and production activities in the region.

1.1. Geological setting

The Niger Delta is positioned between longitudes 4–9° East and latitudes 4 – 6° North in the southern part of Nigeria and is characterized by freshwater swamps and mangrove swamps, with the relief increasing towards the north.

The Niger Delta is situated in the Gulf of Guinea and the West African Continental Margin (fig. 2a,b,c), which formed the triple junction during the continents' breakup in the Cretaceous.

Doust and Omatsola stated that the Niger Delta has prograded southwestward, forming various depobelts that represent the most active portion of the delta at each stage of its development from the Eocene to the present. These depobelts make up one of the largest regressive deltas in the world today, with an aerial extent of about 300000 km^2 [5], a sediment volume of about 500000 km^3 [6] and a thickness of over 10 km in the basin depocenters [7]. As per Doust and Omatsola, the Niger Delta is characterized by tripartite regressive lithostratigraphic units referred to as the Akata, Agbada, and Benin formations.

Within the Niger Delta province, only one petroleum system has been identified i.e. the Tertiary Niger Delta (Agbada Formation) Petroleum System. Extensive research confirmed that this single petroleum system was formed at the triple junction tied to the creation of the Southern Atlantic beginning in the late Jurassic and until the Cretaceous [10]. The field hosts thousands of individual reservoirs, predominantly made up of sandstone strata, that are trapped in oil-rich shale strata. While the oil and gas fields are abundant, they are not exceptionally large.

2. Petroleum system

Akata Formation is the main source kitchen of the Niger Delta petroleum system [11]. Based on the evaluation of the organic contents and the kerogen type by Evamy the shales within the younger Agbada Formation have been inferred to contribute somewhat to the hydrocarbon generation in the delta. The Cretaceous formations below the Tertiary Niger Delta might have also contributed to the hydrocarbon charge. The speculation that a source of Cretaceous age might exist in the Niger Delta cannot be validated due to the lack of deep well data. The predominant kerogen in the Akata-Agbada petroleum system is the kerogen type III [12]. The TOC in the Niger Delta is considered low, with a range of 1.4% and 1.6% [13]. The Niger Delta is believed to provide a prolific oil province, notwithstanding the relatively low TOC, because of the synchronous occurrence of the reservoir rocks, traps, and seals.

2.1. Source rock

The Time-Transgressive Akata Formation is the established source rock of the Niger Delta petroleum system. It is comprised of mobile shales upon which growth faults detach and propagate basinward, thereby creating many accommodations in the basin of the Niger Delta.

2.2. Maturation and migration

Petroleum generation in the delta started during the Eocene and continues till date. Northwest oil window portion of Niger Delta, belongs to the upper Akata Formation and the lower Agbada Formation.[18] assumed that hydrocarbon migration occurred mainly through the fault gaps.

2.3. Reservoir seal

The Agbada Formation is the hydrocarbon reservoir interval in the Niger Delta. It is described as an intercalation of sandstones and shales. The growth faults that detach on the Akata Formation provide the effective pathways through which the porous and permeable sandstones of the Agbada Formation are connected. The intercalating shales of the Agbada Formation provide the local seal, in conjunction with

the appropriate fault framework (fig. 3). The three critical factors of the Source, Reservoir, and Seal in Niger Delta occurred during the Middle Eocene (fig. 3). Approximately 65% of the crude from the Niger Delta fall within the category of the sweet (Low-Sulphur-Content), 30 degrees to 40 degrees API gravity range.

3. Materials and methods

The materials employed in this research comprised high-resolution biostratigraphic data and geochemical data obtained from well reports, namely DRM1 and DRM2. The biostratigraphic data served the purpose of biozone and age controls, integrated into the standard chronostratigraphic analysis scheme specific to the Niger Delta region.

The high-resolution biostratigraphic data were instrumental in establishing biozones and age controls, thereby contributing to the overall chronostratigraphic analysis of the Niger Delta. The integration of these data allowed for a detailed assessment of the temporal framework within the studied wells.

The Rock-Eval Pyrolysis method was employed as a robust geochemical screening tool, providing comprehensive insights into the quality, quantity, and thermal maturity of organic matter within the sampled wells. The geochemical data derived from this analysis played a pivotal role in establishing the organic richness and source potential of wells DRM1 and DRM2. Furthermore, it facilitated an assessment of the thermal maturity of the respective well sections.

Vitrinite reflectance emerged as a highly effective method for determining the thermal alteration history of sediments. The obtained values of vitrinite served as a reliable calibration tool during the construction of a 1-D basin model in this study. This methodological approach enabled a thorough investigation into the thermal evolution of the sediments, contributing crucial information to the overall understanding of the geological history within the study area.

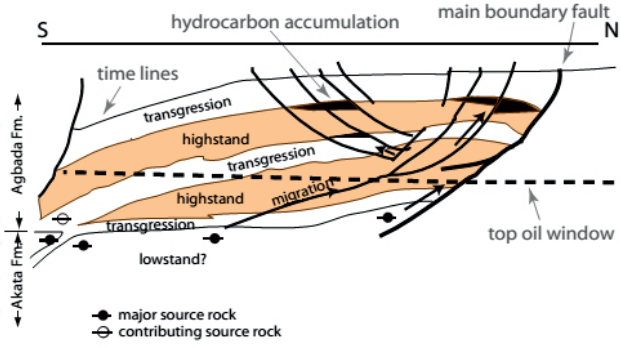

Fig. 3. Petroleum Province model of Niger Delta [14]

3.1. 1-D Basin modeling

The Burial and thermal histories of the two wells were evaluated using the Schlumberger petroleum system modeling software (Petromod). The input data used for the numerical modeling of the representative well are shown in table 1. The top depth and thickness of each stratigraphic sequence were acquired from lithological descriptions prepared from the biostratigraphical analysis scheme and well reports. To obtain reasonable results, Paleo-water depth (PWD), the temperature at the sediment-water interface (SWIT) and heat flow (HF) are the three important boundary conditions that were used in modeling. In this procedure, the Paleo-water depth was assigned based on Hardenbol [15] and varies from -35 to 188 meters. The present-day sediment-water interface temperature of 30° C was assumed suitable for the boundary

Table 1

Model input data used for present study

	Era	Period	Layer name	Age	Water depth	SWIT
DRM-1						
	Cenozoic	Quatenary	Present Day	0-3.40	0	30
		Tertiary	MFS-3.40	3.4-3.6	78	30
			MFS-3.60	3.6-4.98	58	30
			MFS-4.98	4.98-5.00	160	30
			SB2	5.00-5.50	155	30
			MFS-5.5	5.50-5.70	116	30
			SB1	5.70-5.86	100	30
			MFS-5.86	5.86-6.40	95	30
			MFS-6.40	6.40-6.50	119	30
DRM-2						
	Cenozoic	Quatenary	Present Day	0-3.9	0	30
		Tertiary	MFS-3.90	5-3.9	-35	30
			SB2	5.00-6.00	188	30
			MFS-6.00	6.00-7.40	21	30
			MFS-7.40	7.40-8.50	45	30
			SB1	8.50-9.50	91	30
			MFS-9.50	9.5	21	30

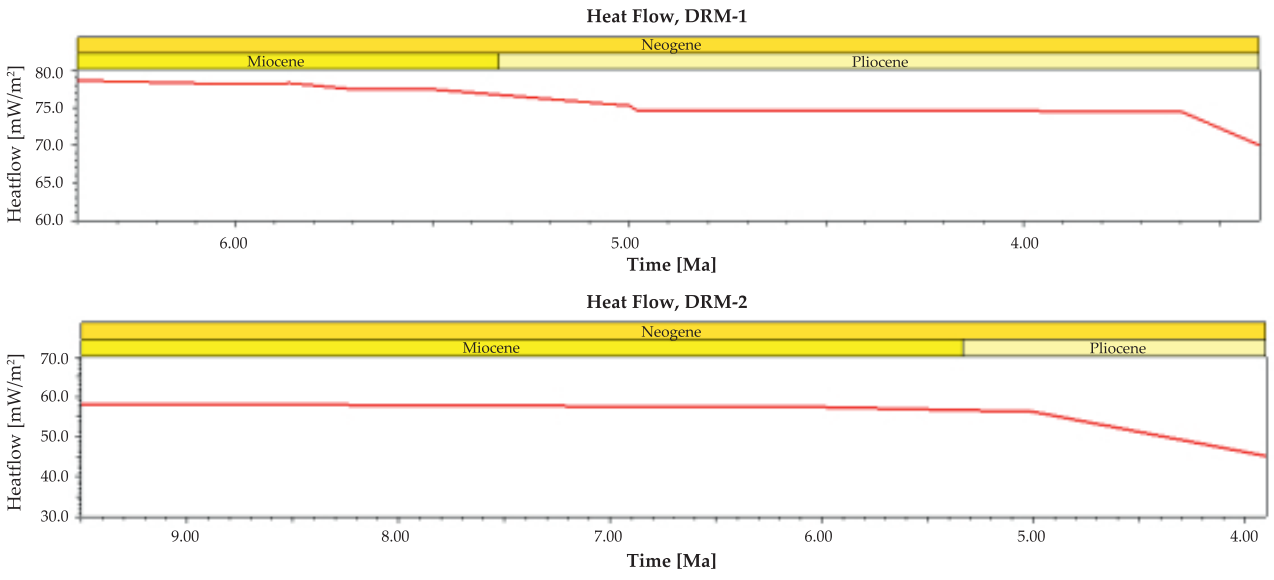

Fig. 4. Heat flow boundary condition plots calibrated from vitrinite reflectance for the two wells

condition for the model [16]. The heat flow history of the basin was derived using a modified simple shear model (fig. 4) and constrained using available vitrinite reflectance data from drilled wells to adjust the present heat flow in the study area. The kinetic model of Vandenbroucke et al. was used for the model simulation [17].

4. Results and discussion

4.1. Biostratigraphic zonation schemes

Foraminiferas and palynomorphs were utilized as biozones and age controls, which were then incorporated into the chronostratigraphic analysis. This integration allowed for the precise determination of ages for lithological units and their associated maximum flooding surface units, contributing to the establishment of a reliable stratigraphic framework. The identification of planktic foraminiferal zones was achieved by comparing the local Niger Delta benthic foraminiferal fauna zones in the wells with the standard planktic foraminifera zonal scheme proposed by Blow. Similarly, the palynological zones recognized through the work of Legoux and Morley further enhanced the accuracy of age assignments for the lithological units [18]. By combining the foraminifera and palynological data, the analyzed interval in the studied wells was determined to encompass a period ranging from approximately 3.4 to around 9.5 Ma. Based on this age information, the studied interval has been interpreted to belong to the Pliocene to late Miocene paralic Agbada formation.

Foraminiferal zonation

Planktic foraminiferal zones were determined by referencing age-diagnostic benthonic foraminifera that has known planktonic equivalents in the Niger Delta. The establishment of these inferred planktonic zones was based on the updated Cenozoic geochronologic and chronostratigraphic schemes developed by Berggren and Blow respectively. Within the intervals of 805–859m, 1097–1234m, and 1829–1948m, notable peaks in foraminiferal abundance and diversity were observed, indicating the presence of Maximum Flooding Surface Condensed Sections. These sections are believed to correspond to specific periods on the Global Sea Level Cycle Chart, specifically the 3.9 Ma, 5.0 Ma, and 6.0 Ma Maximum Flooding Surface Condensed Sections as indicated on the SPDC Niger Delta Cenozoic Chronostratigraphic chart. Furthermore, the occurrence of *Cyclammina cf minima* at 1207m, which is commonly associated with the 5.0 Ma Condensed Section in the onshore concessions of the eastern sector of the Niger Delta, supports this interpretation. These identified Condensed Sections are analogous to the Condensed Sections linked to the Za1 and Me2 Maximum Flooding Surfaces according to Hardenbol et al.

Palynological zonation

The palynological zonation scheme known as Zone P800 for the Tertiary Niger Delta, as commonly referred to as Evamy et al, was observed in the studied section. The presence of the diagnostic marker species, Nymphpheaepollis clarus and Peregrinipollis nigericus, which respectively indicate the upper and lower boundaries of the P850 subzone, was irregular, making it challenging to precisely delineate the subzone. Consequently, the identified zone was further divided into the P880, P870, P860, and P850 subzones. Additionally, based on the research conducted by Legoux , the presence of Zones J2 and J1 was established. Six Floral Zones, specifically P2 Upper, P2 Lower - P6, P7, M1, M2, and M3, were defined using the floral scheme developed by Morley.

4.2. Source rock assessment

Thermal maturation evaluation

The vitrinite reflectance (Ro) analysis from the two wells has Ro values of 0.46 to 0.52 Ro% which suggested that the studied well sections are immature to early mature source rock for hydrocarbon generation (table 2).

Source rock characterization

The results of the rock eval analysis indicated a varied hydrocarbon generative potential, ranging from poor to fair, as presented in table 2. The values of total organic carbon content (TOC) in the studied samples from both wells ranged between 0.74 to 3.08 TOC (wt.%), which suggests a good to

Table 2

Rock-Eval Pyrolysis, TOC, and Vitrinite Reflectance data for DRM-1 and DRM-2

Well	Depth	TOC	S1	S2	S3	Tmax	HI	OI	VR%
DRM-1	841	1.23	0.23	0.84	4.29	428	68	349	-
DRM-1	887	1	0.13	0.3	2.66	429	30	266	-
DRM-1	1061	1.1	0.34	1.1	2.65	433	100	241	-
DRM-1	1125	0.74	0.41	0.62	3.89	42	84	529	-
DRM-1	1375	3.08	0.41	1.91	7.74	415	62	251	0.46
DRM-1	1454	2.65	0.37	2.82	7.02	438	106	265	0.52
DRM-2	1515	1.79	0.14	1.96	4.22	436	109	236	-
DRM-2	1542	0.87	0.1	1.12	3.43	432	129	394	-
DRM-2	2237	1.94	0.11	2.2	4.18	430	114	216	-
DRM-2	2341	2.79	0.15	3.22	5.58	431	115	200	0.45
DRM-2	2472	2.12	0.13	2.89	4.73	438	136	223	-
DRM-2	2606	2.44	0.14	2.61	3.69	432	107	151	0.49
DRM-2	2688	1.86	0.12	2.58	4.58	430	139	247	-

very good organic richness of the source rock. Kerogen type is one of the critical indicators for distinguishing whether a certain source rock is oil-prone or gas-prone , the scattered plots of S2 versus TOC (fig. 5) were used to identify the type of organic matter (kerogen) in the samples and based on the results, all of the analyzed samples contained type III kerogen. The measured Tmax values ranged from 415 °C to 438 °C for the DRM-1 well and from 430 °C to 436 °C for the DRM-2 well. To determine the kerogen quality and maturity, the hydrogen indices (30-139 mg HC/g TOC) and the cross plot of HI versus Tmax / Ro% (fig. 6) were examined. The results from the pyrolyzed samples and the HI versus Tmax plots indicated that the Miocene source rocks within the Agbada Formation predominantly exhibited a gas-prone nature, with limited to no potential for oil generation.

5. Basin modeling

Burial and thermal history

A one-dimensional basin model was developed for two wells to assess the burial history of the studied basin. This model utilized age data obtained from the biostratigraphical results, along with boundary conditions such as paleogeometry, sediment-water interface temperature (SWIT), and heat flow. To calibrate the model, we used measured vitrinite reflectance (%Ro) data and applied the modified McKenzie simple shear model proposed by McKenzie [19]. This calibration process was used to determine appropriate heat flow values, which ranged from 45 to 75 mW/m². The heat flow values showed a progressive decrease over time, consistent with previous findings. In addition to assessing the burial history, a burial history plot diagram that incorporated deposition information and highlighted the relative impact of hydrocarbon generation in each well within the field was

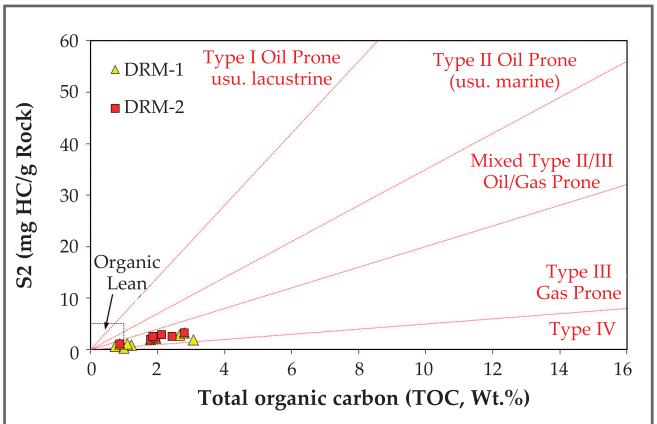

Fig. 5. Cross plot of S3 vs TOC(Wt%) showing kerogen type quality of DRM-1 and DRM-2 wells with samples indicating a gas prone type III kerogen

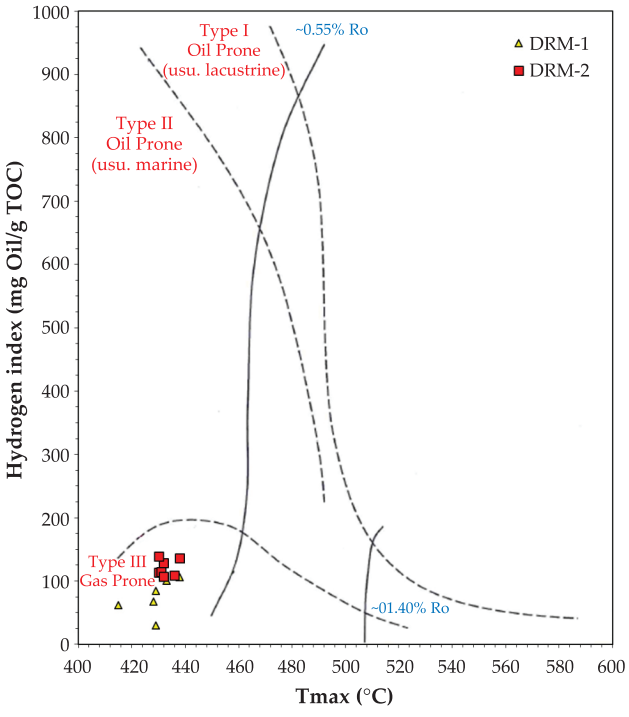

Fig. 6. Cross plot of Hydrogen Index and T_{max} showing Organic matter type and thermal maturity of DRM-1 and DRM-2 wells sample plots indicates a low thermal maturity of type III kerogen organic matter

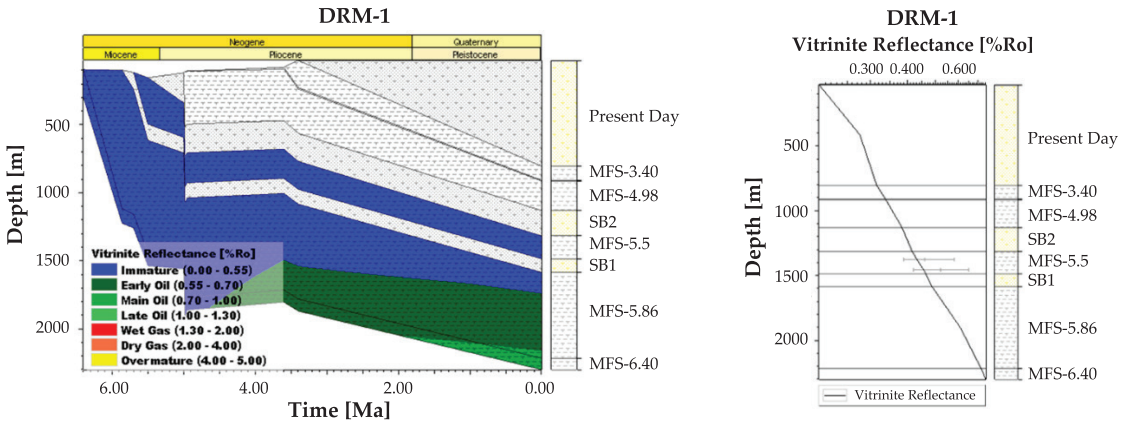

Fig. 7. Correlation of modeled and measured vitrinite reflectance data and burial history (with maturity overlay) for DRM-1 well, simulated model shows the source rock ranging from immature to main oil maturity window

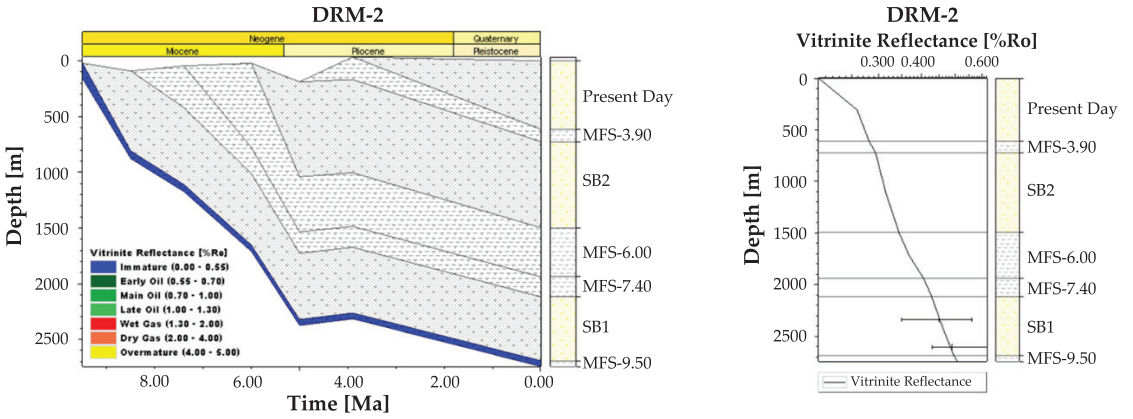

Fig. 8. Correlation of modeled and measured vitrinite reflectance data and burial history (with maturity overlay) for DRM-2 well, simulated model shows an immature source rock maturity window

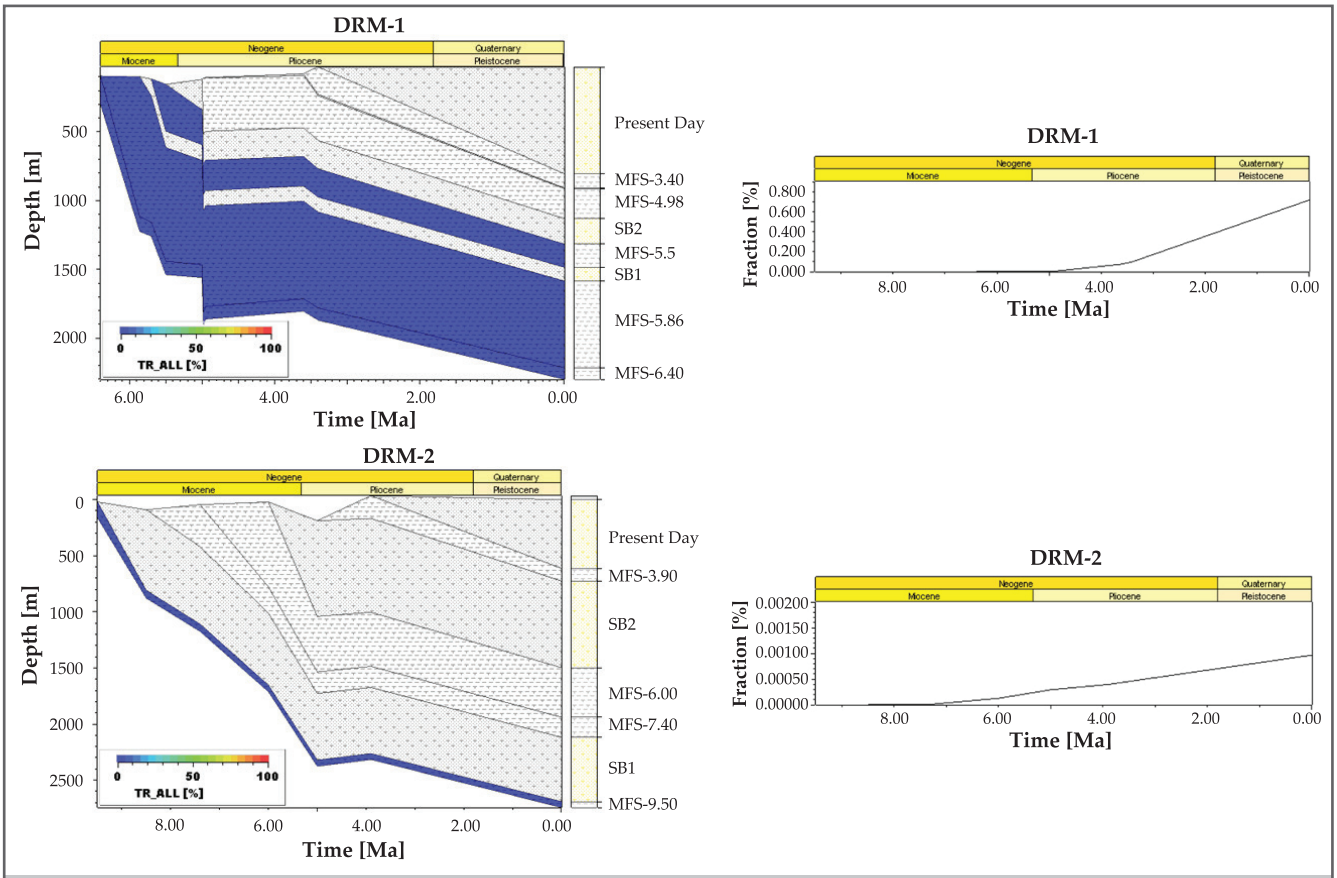

Fig. 9. Burial history with transformation ratio (TR) overlay showing insignificant TR values between 0-0.41% suggesting that the source rocks have not undergone sufficient burial for hydrocarbon generation

created. The total thickness of the studied interval was found to be 2688 m. However, the amount of overburden was insufficient for the thermal maturation of the source rock, specifically the Miocene Agbada formation. Determining the stage of source rock maturation and oil and gas generation is possible by examining vitrinite reflectance (%Ro). The simulation results from our model, depicting the modeled vitrinite reflectance (Easy %Ro) over time, indicated that the source rocks in the Agbada Formation reached the early oil zone in the DRM-1 well at 4.50 Ma and approach the main oil window at 6.40 Ma at present-day (fig. 7).

On the other hand, the DRM-2 well exhibited an immature source at present-day, likely due to differential burial history in the basin (fig. 8). To evaluate the potential for oil and gas generation, the transformation ratio (TR), which represents the ratio of the converted mass fraction of source rock that has undergone thermal maturation and generated hydrocarbons to the total generation potential of the source rock was utilized. Based on our modeling results, the TR values from both well ranges between 0–0.41 % which appears that the Miocene source rocks in the Agbada is unlikely to generate oil or gas (fig. 9), due to the insufficient burial history.

Conclusions

1. The integration of biostratigraphic analysis, source rock assessment, and basin modeling provided valuable insights into the source rock intervals within the Agbada Formation in the Niger Delta. The precise determination of ages and the establishment of a reliable stratigraphic framework contribute to the understanding of the formation's geological history.
2. The integration of foraminifera and palynological data revealed that the studied interval corresponds to the Pliocene to late Miocene paralic Agbada formation. Notable peaks in foraminiferal abundance and diversity were observed within specific intervals, indicating the presence of Maximum Flooding Surface Condensed Sections, aligning with specific periods on the Global Sea Level Cycle Chart. Additionally, the palynological analysis identified subzones within the P800 zone and identified additional floral zones which enabled the further division of the studied section into subzones. These findings contribute to a better understanding of the age and stratigraphy of the studied interval.
3. Furthermore, the evaluation of thermal maturation based on vitrinite reflectance indicated that the well sections studied are immature to early mature as source rocks for hydrocarbon generation. The Total Organic Content (TOC) of the analyzed samples exhibited good to very good organic richness with values ranging between 0.74 to 3.08 TOC (wt.%), while Hydrogen Index (30-139 mg HC/g TOC) indicated type III kerogen present in all samples. The Tmax values and HI versus Tmax plots suggested a gas-prone nature for the Miocene source rocks in the Agbada Formation, indicating limited potential for oil generation.
4. The one-dimensional basin model developed in this study allowed for an examination of the burial history of the basin considering the age data, paleogeometry (PWD), sediment-water interface (SWIT), and calibrated heat flow, using %Ro data to assess the burial history and thermal conditions in the basin. The modeling results indicated that there was insufficient burial history for the thermal maturation and hydrocarbon generation of the Miocene Agbada Formation in both wells. Despite DRM-1 being located within the early oil zone, the DRM-2 well still exhibited an immature source at present-day due to differential burial history in the basin.

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