Fountain Journal of Natural and Applied Sciences 2026; 15(01): 106-117

FOUNTAIN JOURNAL OF NATURAL & APPLIED SCIENCES

A Publication of the College of Natural & Applied Sciences

Fountain University, Osogbo, Nigeria

Petrophysical and reservoir characterisation of MAR field onshore of Niger Delta, Nigeria

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ABSTRACT

The Niger Delta Basin is a prolific hydrocarbon province with complex depositional environments influenced by alternating transgressive and regressive phases. This work focuses on the MAR Field, onshore Niger Delta, analysing reservoirs M1, M2, and M7 to evaluate the petrophysical properties and depositional environments critical for hydrocarbon exploration. We used gamma ray, resistivity, neutron, and density logs from four wells to assess key parameters such as porosity, permeability, water saturation, and hydrocarbon saturation. The analysis indicated favourable petrophysical properties across the reservoirs, with net-to-gross ratios greater than 60%. Reservoir M1 presented excellent porosity (23.8%) and permeability (1,358.5 mD), reflecting strong hydrocarbon storage and flow capacity. In general, Reservoir M2 showed a balanced set of attributes, with a high hydrocarbon saturation of 40.1% and contributions from lower shoreface and channel sands. Reservoir M7 also showed robust permeability of 1,242.2 mD and hydrocarbon saturation of 44.0%, although with a slightly lower porosity of 19.9%. Gamma ray log motifs identified the shoreface and channel sands as dominant depositional environments, related to progradational and retrogradational stacking patterns. This study provides important insights into the hydrocarbon potential of the MAR Field, supporting optimisation of exploration and sustainable resource development within the Niger Delta. The findings highlight the role of detailed petrophysical analysis in reducing uncertainty and enhancing decision-making in hydrocarbon exploration.

ARTICLE INFO

Article history:
Received November 2025
Revised May 2026
Accepted June 2026

Keywords:
Gamma ray log, Niger Delta, Paleoenvironment, Porosity, Shale volume

Introduction

The Niger Delta Basin, located in southern Nigeria, is one of the most prolific hydrocarbon provinces in the world (1). It has played a major role in supplying oil and gas to the world market. According to Esegbue (1) Niger Delta Basin petroleum prospectivity is inextricably linked to the various depositional environments, which are strongly influenced by its complex history of alternating transgressive and regressive phases. Several depositional frameworks, including lowstand, transgressive, and highstand systems tracts, have been unravelled in studies conducted both onshore and offshore. (2-5). These studies show that while depositional environments offer great potential for hydrocarbon exploration and development, they are equally challenging because of inherent geological heterogeneity. Characterising and understanding such environments is crucial for deciphering subsurface properties and optimising the production potential of onshore fields.

For reservoir characterisation of onshore fields, petrophysical analysis is necessary; therefore, it provides key information concerning rock properties and hydrocarbon potential. The Niger Delta Basin has been studied, and an effective approach has been deduced for assessing subsurface features and quality (6,7). Key parameters analysed in this study include porosity, permeability, water saturation, and lithology, determined from well log data comprising gamma ray, resistivity, and density/neutron logs (8).

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

These properties help identify hydrocarbon-bearing zones and determine economic viability. Integrating rock physics and petrophysics can further enhance litho-fluid discrimination and reservoir compartmentalisation, reducing exploration uncertainty (9). Some previous studies in the Niger Delta have shown that the reservoirs generally exhibited favourable characteristics for hydrocarbon accumulation and production, with good porosity and permeability values, low shale volumes, and high hydrocarbon saturation in the identified reservoirs (7,8,10).

Despite extensive exploration and production activities in the Niger Delta, detailed knowledge of petrophysical and reservoir characteristics in individual onshore fields remains incomplete. Past work has usually targeted regional-scale analyses, overlooking the complexity of each field, including changes in connectivity, spatial variation in petrophysical properties, and the impact of structural geology on performance.

The present work presents a detailed petrophysical and reservoir characterisation study of the MAR onshore field in the Niger Delta using an integrated approach based on well log data interpretation. Well logging provides highly accurate measurements of important petrophysical
The study will determine reservoir boundaries, locate hydrocarbon-rich zones, and analyse the effect of the depositional environment on reservoir performance, providing clues for efficient management and sustainable development.

Geological setting and stratigraphy of the study Area

The onshore MAR Field is located in the Tertiary Niger Delta Basin, southern Nigeria, within the Coastal Swamp Depobelt at 6°17'55.0023" E and 4°37'54.7679" N (Figure 1). This depobelt is an important structural unit of the Niger Delta well known for its complicated geology and rich hydrocarbon stock (11,12).

The Niger Delta Basin is regarded as a prolific hydrocarbon province comprising three major formations: Akata, Agbada, and Benin (13). These consist dominantly of marine shales within the Akata Formation, dominantly paralic sands and shales within the Agbada Formation, and continental alluvial sands within the Benin Formation (13,14). Recent studies in the region indicate huge hydrocarbon potential. Organic matter in both Akata and Agbada represents mainly a mixture of gas- and oil-prone kerogen with fairly sufficient conditions for hydrocarbon generation in rocks (14). In addition to that, gravity gliding tectonics influenced the geological framework of the Niger Delta, determining its structural features (13).

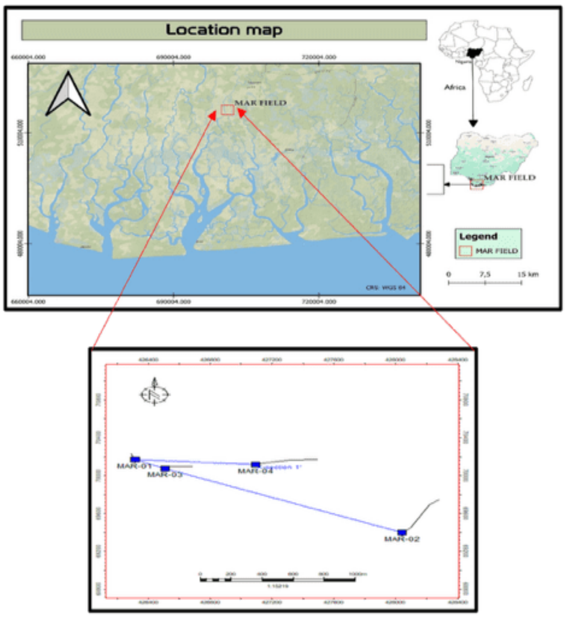

Figure 1: Location and base map of the study area parameters including porosity, permeability, and fluid saturation

The depositional environment evolves from fluvio-deltaic to marine; the lithology involves alternating sand and shale units. Highstand sands form excellent reservoirs, while transgressive shales constitute effective seals (15,16). While the Coastal Swamp Depobelt is diapirically deformed and involves fault systems such as growth and normal faults, hydrocarbon migration and trapping have occurred. Studies by Oyeyemi *et al.* (17) and Lawson and Balogun (7) have shown porosities ranging from 17 to 30.62%, permeability up to 1678 mD, and hydrocarbon saturation as high as 96.90% in the Niger Delta. Furthermore, Okwaraojimadu *et al.*(18) estimated the ultimate recoverable volumes for the CZ field as 1.2 billion barrels of oil equivalent and 8.0 trillion cubic feet of gas.

Materiel and methods

Wireline logs were obtained across four wells in the MAR field to determine petrophysical parameters. These include Neutron Porosity, Bulk Density, Gamma Ray, and Deep Resistivity logs. The logs provide crucial data on depth (meters), gamma ray (gAPI), resistivity (ohm.m), neutron porosity (m^3/m^3), and bulk density (g/cm^3) (Table 1). Lithology was then defined using

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

gamma-ray logs. Resistivity and neutron-density cross-plots were conducted to identify fluid contacts and hydrocarbon-bearing zones using Schlumberger PETREL™ (2018 version) software. Petrophysical properties, such as porosity and hydrocarbon saturation, were estimated from these logs using Excel. This integrated study provided a more detailed review of reservoir characteristics, petrophysical estimation, and hydrocarbon prospects in the MAR Field.

Table 1: Description of data available in four wells (Y=Yes, N=No)

Well name	Well logs								Well header	Well deviation	Check shot
	GR	RES		CAL	NEU	SON	SP	DES			
		LLS	LLD								
MAR-01	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N
MAR-02	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	Y
MAR-03	Y	Y	Y	Y	Y	Y	Y	Y	Y	Y	N
MAR-04	Y	N	Y	Y	Y	Y	Y	Y	Y	Y	N

The workflow adopted in this study was designed to systematically approach well log interpretation for reservoir characterisation by integrating both qualitative and quantitative methods. Figure 2 illustrates the detailed process.

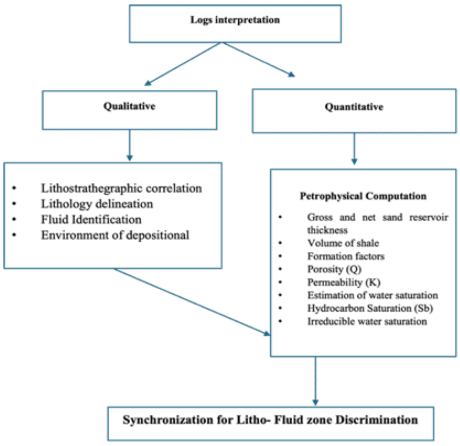

Figure 2: Systematic workflow adopted for the MAR Field reservoir and petrophysical characterisation

Log interpretation

Quality assurance

Well log data interpretation involved rigorous quality control to ensure reliable estimates of petrophysical properties, reservoir identification, and geological reconstruction.

Qualitative logs interpretation

The lithostratigraphic reservoir correlation of the four wells in MAR Field used gamma ray (GR), spontaneous potential (SP), resistivity (LLD and LLS), and neutron-density cross plots (NPHI/RHOB). This study included three lithologies: sandstone, shale, and sandy-shale. From the gamma ray log histogram, the sand baseline was defined by the lowest gamma ray value (gAPI), the shale baseline was set at approximately 150 gAPI, and a cutoff of 75 gAPI was adopted for reservoir delineation. The spontaneous potential log, when corrected by the gamma ray log, indicated a positive value for shale at 150 mV and a negative value for clean sand at -150mV. The resistivity log was used to distinguish lithologies, as sandstone exhibited high resistivity. The density log was used to differentiate between tight and loose formations, with shale having high density and sand having low density. Reservoir zones were identified using GR and resistivity logs, with hydrocarbons distinguished by high resistivity, validated by neutron and density logs. Resistivity and neutron-density cross plots were also used to complement the definition. These techniques allowed the identification of fluid contacts and hydrocarbon-bearing zones, as resistivity and density variations highlight the presence of hydrocarbons or water within the reservoir (19,20).

The depositional environment was determined by analysing gamma logs (GR). By examining the patterns and shapes of GR curves, which reflect changes in grain size and lithology, the adopted approach followed Cant (21) guidelines. Funnel-shaped curves (upward coarsening) indicate progradation environments like deltas or nearshore areas. Bell-shaped patterns (upward refinement, fining up) suggest fluvial deposits or tidal channels.

Cylindrical (blocky) patterns represent uniform sedimentation, often observed in littoral bars or shallow marine environments. Symmetrical patterns indicate cyclic sedimentation, typical of tidal mudflats or certain lacustrine environments. Finally, irregular patterns indicate complex depositional environments with varied energetic conditions, such as estuaries or deltaic environments.

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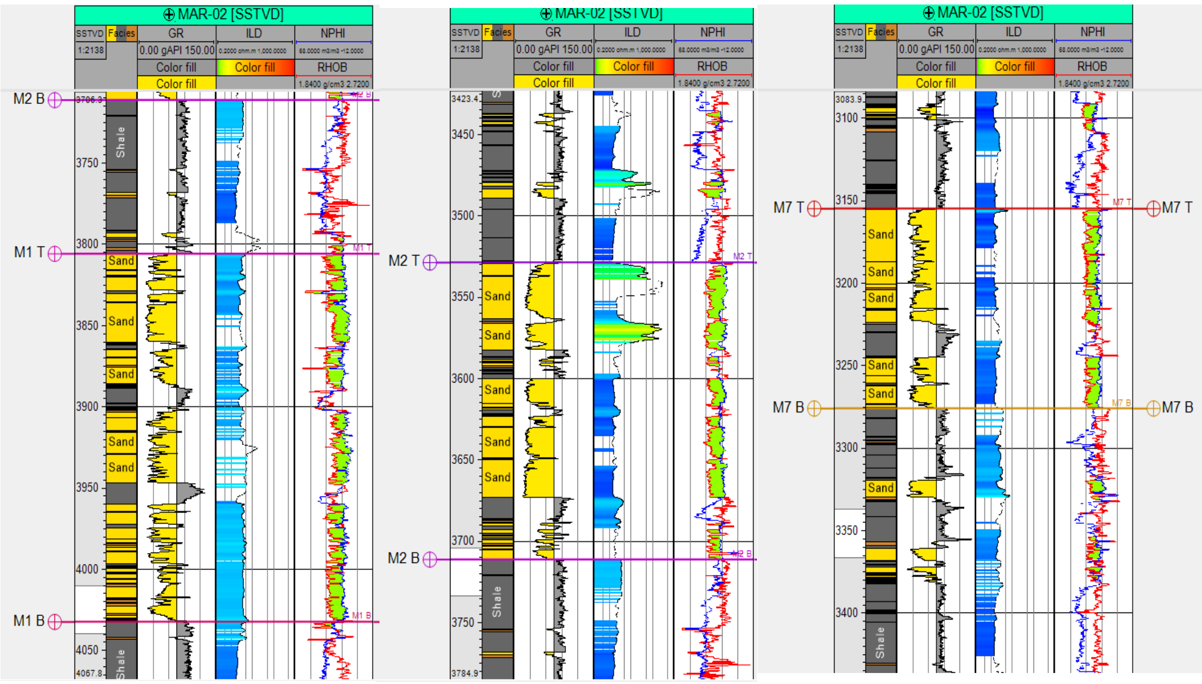

Figure 3: Neutron–density (NPHI–RHOB) log analysis for lithology, fluid characterisation, and hydrocarbon identification in reservoir m1, m2, and m7 (well mar-02, Mar field); the porosity track displays the neutron porosity (NPHI, blue line) & bulk density (RHOB, red line). Cross-over of neutron-density occurs whenever the RHOB log moves toward the left, & the NPHI log moves toward the right; this is a definitive hydrocarbon indicator

Quantitative logs interpretation

The available wireline logs were processed to derive various physical properties of the reservoir rocks, including porosity, permeability, hydrocarbon and water saturations, volume of shale, and net-to-gross thickness. These computations were performed using the software's log calculator feature. The quantitative petrophysical evaluation involved analysing wireline logs to calculate key reservoir properties using standard petrophysical equations. Table 2 summarises the parameters determined in this study, along with the corresponding equations.

Equation 1: Net-to-gross is a measure of a reservoir's productive capability, defined as the percentage of producible net reservoir volume relative to total gross reservoir volume. NTG was calculated using the standard thickness ratio method of Asquith and Gibson (22).

Equation 2: Estimation of gamma ray index is a normalised measurement used to determine the volume of the shaly fraction in the reservoir rock. IGR

was determined using the linear gamma ray model by Asquith and Gibson (22).

Equation 3: Estimation of volume of shale. Because Niger Delta reservoirs are made of unconsolidated sandstones, the equation for unconsolidated rocks was applied to compute the volume of shale. Vsh was calculated using a formula developed by Larionov (23).

Equation 4: The estimation of the water saturation value is read out at the interval and averaged from the available water saturation log at the point of minimum deflection adjacent to the reservoir of interest. The model applied an empirical quick-look correlation based on an Archie-derived simplification (24).

Equation 5: Estimation of permeability. Permeability measures a reservoir's ability to conduct fluids or enable flow between the reservoir and the wellbore. Permeability was estimated using the empirical permeability equation adopted in this study. This is based on the work of Owolabi et al.(25). This permeability equation was developed especially for the unconsolidated sands in the Niger Delta, which is where the field of study is located

Results and discussion

The results of this study were structured as follows: well log interpretation across four wells, including well correlation, reservoir determination, petrophysical properties analysis, and depositional environment interpretation to reconstruct the paleoenvironment of the MAR field's reservoir sands

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Table 2: petrophysical equations

Parameter	Equation
Net -To-Gross	Net-to-gross = $\frac{NT}{GT} \times 100$ where, NT = Net thickness, GT = Gross Thickness
Estimation of Gamma Ray Index	$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$ where: GR_{log} = Observe day reading of the formation; GR_{min} = Observed minimum Gamma ray reading (clean sand or carbonate) GR_{max} = Observed maximum Gamma ray reading (Shale).
Estimation of Volume of Shale	$V_{SH} = 0.832 \times (2^{(3.7-I_{GR})} - 1.0)$
Estimation of Water Saturation	$Sw = \frac{0.082}{\emptyset eff}$ where, Ø = effective porosity
Hydrocarbon saturation (SHc)	$SHc = 1 - Sw$
Estimation of Permeability	$k = 307 + (26552^{(\emptyset^2)}) - (\emptyset \times Sw)^2$ Where, Ø = porosity and Sw = water saturation

Well log interpretation

The well log interpretation in this study involved analysing data from four wells, MAR-01, MAR-02, MAR-03, and MAR-04, to assess the geological and petrophysical properties of the reservoirs.

The findings reveal that gamma ray logs effectively distinguish between sand and shale, with low readings indicating sand and high readings indicating shale, consistent with methods used in similar studies in the Niger Delta (26,27). Resistivity logs also confirmed higher values in sand zones, indicating brine sands, which aligns with the identification of hydrocarbon-bearing zones in the Alpha Oilfield (27). Using density logs to differentiate oil and water zones in sand layers supports findings from the Niger Delta, where density and neutron porosity logs were used to correct for shale effects and estimate fluid content (26,27). Additionally, the impact of shale content on permeability and saturation was evident, with high shale volumes reducing permeability and skewing saturation calculations; this was addressed through shale correction models such as Simandoux and Indonesian (26,27). These results highlight the importance of accurate shale corrections in refining petrophysical evaluations of shaly sand reservoirs. The similarity with other research by Fozao et al. (26) and Coker et al. (27) is based primarily on the geological setting of the Agbada Formation, where fluvio-deltaic deposits dominate and govern the log response with respect to gamma ray, resistivity, and density-neutron properties. However, the MAR Field shows higher reservoir heterogeneity due to vertical and lateral variation within fluvio-deltaic sequences. Log analysis from MAR-01, MAR-02, and MAR-07 shows facies changes within the interval and reservoir compartmentalisation due to the depositional history. In contrast to other research, this information helps explain reservoir discontinuities.

Well log correlation and reservoir delineation

This study, conducted on the MAR field in the Niger Delta, utilised well logs to comprehensively characterise the MAR field reservoir properties, lithology, and environment affecting hydrocarbon potential. Analysis across four wells (MAR-01, MAR-02, MAR-03, and MAR-04) enabled identification of key reservoir sands and assessment of their hydrocarbon storage and flow characteristics. Seven reservoirs, designated M1, M2, M3, M4, M5, M6, and M7, were delineated, and this study focused on three (3) principal reservoirs: M1, M2, and M7 (Figure 4).

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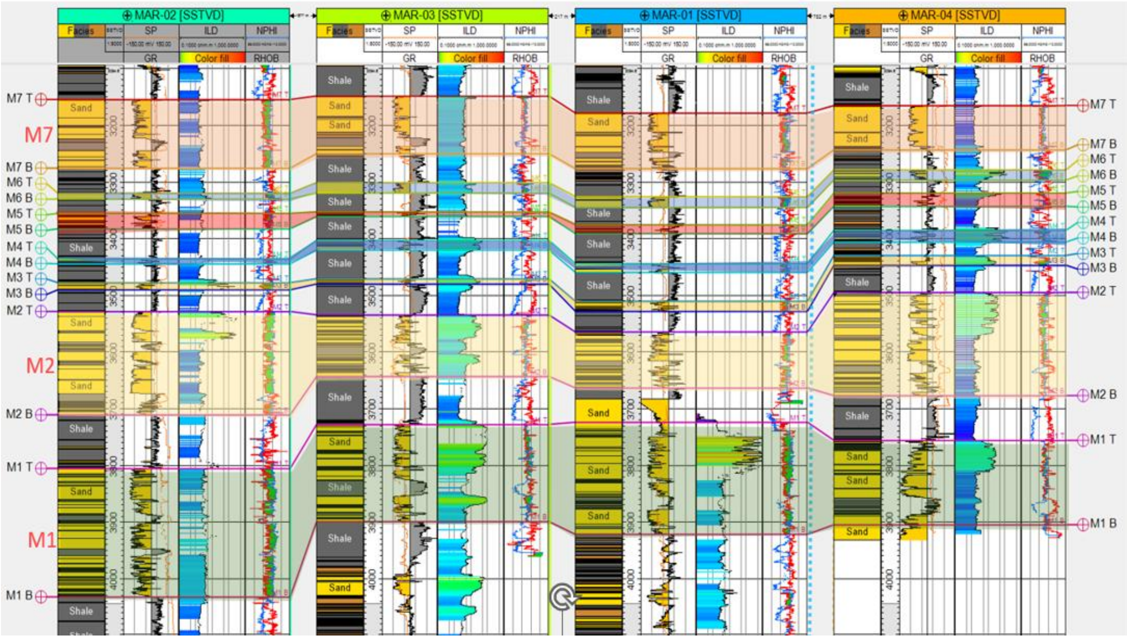

Figure 4: Lithostratigraphic correlation for seven reservoirs across four wells

Petrophysical properties evaluation

Results of Petrophysical analysis carried out for seven reservoir sand units M1, M2, M3, M4, M5, M6, and M7 across MAR field were estimated (Table 3), and the Average petrophysical properties were estimated for all reservoirs (M1, M2, M3, M4, M5, M6 and M7) (Table 4; Figures 5.,6, 7 and 8).

The petrophysical analysis of reservoirs M1, M2, and M7 was conducted to evaluate reservoir quality by determining key properties, including thickness, net-to-gross ratio, porosity, permeability, and fluid saturations.

The petrophysical analysis of Reservoir M1 reveals promising characteristics for hydrocarbon production. With an average sand thickness of 166.3 m and a net-to-gross ratio of 67.0%, M1 contains a significant proportion of productive sand relative to the entire formation. The moderate shale volume of 33.0% further suggests minimal obstruction to fluid flow (26,28). These attributes align with those observed in the Niger Delta region, where reservoirs with lower shale content have demonstrated increased hydrocarbon production potential (29).

Based on Rider's (1986) classification, the total porosity of 23.8% and effective porosity of 15.8% are classified as "very good" to "good," reflecting a substantial storage capacity for hydrocarbons. These values align with those of the Fuba Field, Niger Delta, where similar total porosity values (23.5%) were recorded in productive reservoirs (28). The high permeability of 1358.5 mD indicates efficient fluid flow, which is crucial for optimising hydrocarbon extraction. Similar studies in the Niger Delta have classified permeability values as excellent and linked to strong production potential (27,29). The water saturation of 58.2% and hydrocarbon saturation of 41.8% further validate the reservoir's potential to store and release hydrocarbons, aligning with observations from Fozao et al. (26), who recorded similar saturation levels in productive Niger Delta reservoirs.

Reservoir M2 exhibits similarly favourable petrophysical characteristics. With a sand thickness of 134.0 m and a net-to-gross ratio of 68.88%, M2 is also expected to perform well for hydrocarbon production. The total porosity of 23.8% and effective porosity of 17.9% are consistent with values observed in the Fuba Field, where porosities in the range of 20-30% were found in productive reservoirs (28). The permeability of 1091.9 mD in M2 supports efficient fluid flow, akin to other Niger Delta reservoirs with permeability values within this range, which have demonstrated good flow potential and high production rates (29). The water saturation of 59.9% and hydrocarbon saturation of 40.1% in M2 align with findings from the UPX field, where water saturations of 50-60% indicate a favourable balance between water and hydrocarbons, further enhancing the reservoir’s viability for extraction (29).

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

Table 3: Results of petrophysical evaluation of seven reservoirs for four wells

Wells	Reservoir Sand	Top (m)	Base (m)	Gross (m) Thickness	Shale Volume (%)	Shale Volume (m)	Net Sand (m)	Net to Gross (%)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Permeability (mD)	Hydrocarbon Saturation (%)
MAR-01	M1	3758.81	3921.28	162.47	18.89	30.68	131.79	81.12	24.8	17.68	58.36	1221.12	41.64
	M2	3578.99	3677.81	98.82	37.96	37.51	61.31	62.05	21.3	14.86	59.93	1062.95	40.07
	M3	3524.83	3542.48	17.65	22.65	4.00	13.65	77.35	18.4	17.27	54.09	960.71	45.91
	M4	3458.23	3473.67	15.44	43.12	6.66	8.78	56.88	22.6	14.70	42.27	1607.30	57.73
	M5	3389.66	3405.3	15.64	32.03	5.01	10.63	67.98	20.5	14.31	67.05	1206.70	32.95
	M6	3340.02	3358.98	18.96	12.46	2.36	16.60	87.55	29.0	15.55	34.53	1810.92	65.47
	M7	3192.69	3290.69	98	33.35	32.68	65.32	66.66	17.0	13.85	50.69	1312.66	49.31
MAR-02	M1	3840.26	4070.85	230.59	51.35	118.41	112.18	48.65	35.1	14.00	57.48	1999.39	42.52
	M2	3558.11	3704.41	146.3	15.96	23.34	122.96	84.05	21.7	14.27	62.24	1130.82	37.76
	M3	3506.66	3519.2	12.54	16.48	2.07	10.47	83.53	24.5	18.73	95.40	842.63	4.60
	M4	3464.1	3472.61	8.51	16.73	1.42	7.09	83.27	21.9	17.81	92.13	893.44	7.87
	M5	3382.15	3409.92	27.77	25.63	7.12	20.65	74.38	19.8	12.57	72.23	1363.71	27.77
	M6	3346.36	3356.66	10.3	5.72	0.59	9.71	94.29	22.8	22.16	39.53	1092.79	60.47
	M7	3178.72	3301.47	122.75	38.24	46.93	75.82	61.77	19.9	11.30	60.45	1380.68	39.55
MAR-03	M1	3749.77	3921.23	171.46	43.86	75.19	96.27	56.15	19.0	17.14	67.19	1094.77	32.81
	M2	3556.55	3665	108.45	41.91	45.45	63.00	58.10	25.0	16.10	57.46	725.79	42.54
	M3	3492.7	3501.96	9.26	15.18	1.41	7.85	84.83	28.3	15.26	64.90	1077.37	35.10
	M4	3424.78	3441.98	17.2	28.04	4.82	12.38	71.97	24.9	12.39	90.09	1384.68	9.91
	M5	3374.91	3382.73	7.82	38.37	3.00	4.82	61.63	23.5	15.13	62.21	989.40	37.79
	M6	3322.91	3341.43	18.52	10.15	1.88	16.64	89.85	27.0	15.60	62.28	2157.96	37.72
	M7	3170.32	3271.86	101.54	54.66	55.50	46.04	45.34	22.5	14.83	50.93	1215.90	49.07
MAR-04	M1	3799.56	3900.2	100.64	18.02	18.14	82.50	81.98	16.4	14.23	49.84	1118.88	50.16
	M2	3537.2	3719.58	182.38	28.68	52.31	130.07	71.32	27.1	26.47	60.08	1448.06	39.92
	M3	3471.7	3489.14	17.44	16.71	2.91	14.53	83.30	25.4	23.69	41.28	1543.69	58.72
	M4	3427.27	3448.04	20.77	22.69	4.71	16.06	77.31	24.1	20.00	58.70	1667.06	41.30
	M5	3361.34	3384.87	23.53	40.59	9.55	13.98	59.42	26.2	14.56	61.14	685.97	38.86
	M6	3320.19	3338.35	18.16	11.64	2.11	16.05	88.36	32.5	21.91	81.29	1819.43	18.71
	M7	3206.15	3282.52	76.37	19.28	14.72	61.65	80.72	20.5	18.84	62.03	1059.52	37.97

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

Table 4: Average petrophysical values for the seven reservoirs across four wells

Reservoirs	Gross Thickness (m)	Shale Volume (m)	Net Sand (m)	Shale Volume (%)	Net to Gross (%)	Total Porosity (%)	Effective Porosity (%)	Water Saturation (%)	Permeability (mD)	Hydrocarbon Saturation (%)	Fluids
M1	166.3	60.6	105.7	33.0	66.97	23.8	15.8	58.2	1,358.5	41.8	Oil+water
M2	134.0	39.7	94.3	31.1	68.88	23.8	17.9	59.9	1,091.9	40.1	Oil+ wayer
M3	14.2	2.6	11.6	17.8	82.25	24.1	18.7	63.9	1,106.1	36.1	Oil+ wayer
M4	15.5	4.4	11.1	27.6	72.36	23.4	16.2	70.8	1,388.1	29.2	Oil+ wayer
M5	18.7	6.2	12.5	12.5	65.85	22.5	14.1	65.7	1,061.4	34.3	Oil+ wayer
M6	16.5	1.7	14.7	10.0	90.01	27.8	18.8	54.4	1,720.3	45.6	Oil+ wayer
M7	99.7	37.5	62.2	36.4	63.62	19.9	14.7	56.0	1,242.2	44.0	Oil+water

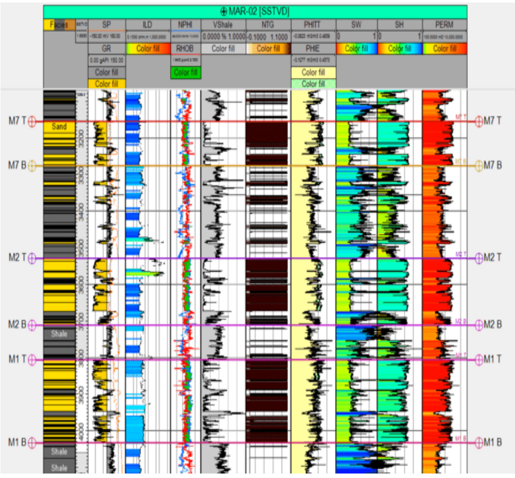

Figure 5: Log interpretation and Petrophysics properties for three reservoirs for well MAR-01

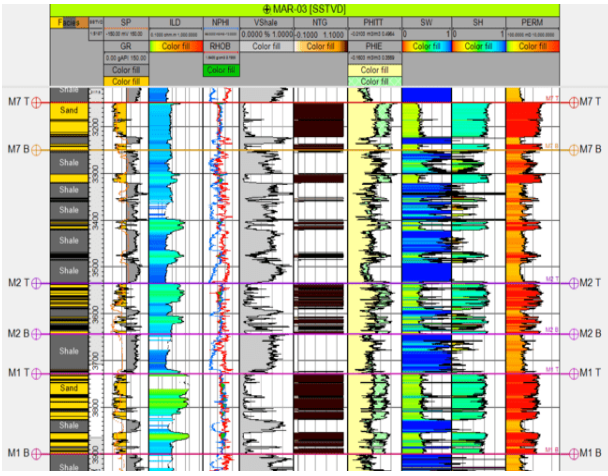

Figure 7: Log interpretation and Petrophysics properties for three reservoirs for well MAR-03

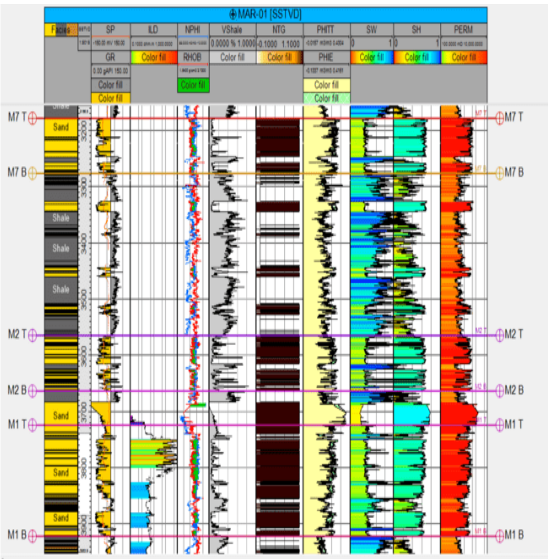

Figure 6: Log interpretation and Petrophysics properties for three reservoirs for well MAR-02

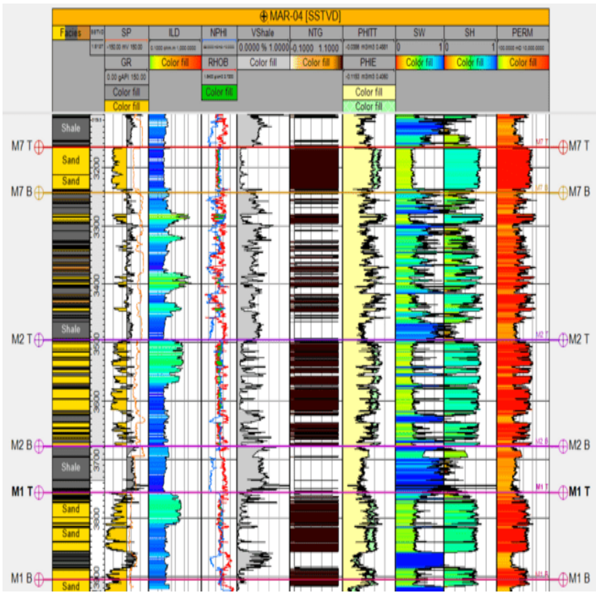

Figure 8: Log interpretation and Petrophysics properties for three reservoirs for well MAR-04

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

Although Reservoir M7 has a slightly lower total porosity of 19.9%, it still shows strong potential due to its effective porosity of 14.7% and a high permeability of 1242.2 mD. These properties ensure robust fluid flow, consistent with results from the UPX field, where similar reservoirs with lower porosity but high permeability exhibited excellent production characteristics (29). The water saturation of 56.0% and hydrocarbon saturation of 44.0% indicate a significant amount of hydrocarbons available for production, which are comparable to those from other fields in the Niger Delta (e.g., Fuba field - Ochoma, 2024). Similarities may be explained by the similar geological background of the Agbada Formation, where sand-shale alternations consistently control reservoir characteristics. According to Fozao et al. (26), shale content significantly influences permeability and fluid saturation. Similarly, the high porosity and permeability of reservoirs M1, M2, and M7 align with previous studies (26-28) suggesting that connected sands provide efficient hydrocarbon storage and flow. Nevertheless, the relationship between shale content and reservoir quality is much more apparent in the MAR Field case. Shale content influences effective porosity, permeability, and saturation, suggesting that reservoir characteristics depend not only on sand but also on shale distribution. The difference between the two studies' results may mean that deposition controls reservoir characteristics in the MAR Field.

Environment of deposition

The depositional environments of reservoirs M1, M2, and M7 were interpreted through gamma ray log analysis, focusing on stacking patterns derived from lithological interpretations. These patterns were classified based on gamma ray log motifs, as defined by Cant (1992), to identify key depositional environments. The observed stacking patterns aggradation, progradation, and retrogradation revealed characteristic gamma ray log shapes corresponding to specific depositional settings: funnel-shaped, cylinder-shaped, and bell-shaped patterns. These patterns provided insights into the stratigraphic architecture and sedimentary processes governing each reservoir.

Reservoir M1

Four distinct stacking patterns were identified in Reservoir M1, reflecting a combination of depositional environments. In the upper section, a cylinder-shaped gamma-ray motif with sharp tops and bases indicated deposition in a channel-sand environment. The middle section showed a bell-shaped motif, representing a fining-upward sequence typical of lower shoreface sands, followed by a funnel-shaped motif indicative of coarsening-upward shoreface sand deposition. The lower section again displayed a cylinder-shaped motif, suggesting channel sands (Figure 9 and Table 5). These findings are similar to those observed by Uhuo et al. (30) in the UK Field, Niger Delta, where the bell-shaped motifs in both the upper and lower sections were interpreted as lower shoreface deposits. They also identified tidal channels and distributary point bars as significant features in their study of deltaic systems, further supporting these observations. Additionally, the funnel-shaped motif in Reservoir M1 suggests a coarsening-upward sequence, in line with earlier interpretations of deltaic systems, where increasing marine influence with depth is evident. Shale volume in M1 plays a key role in determining reservoir quality. Studies have shown that higher shale volumes can negatively impact permeability and hydrocarbon recovery (e.g., Ugwu et al. (29)). In contrast, the lower shale content in Reservoir M1 enhances the quality of the sand units, ensuring their productivity. The permeability values observed in M1 further support this, indicating a good potential for fluid flow. This is similar to the reports of Edohor and Balogun (31) on reservoirs with low shale content and high permeability, which are more favourable for hydrocarbon production.

Reservoir M2

Reservoir M2 displays a clear stratigraphic progression influenced by alternating marine and fluvial environments, characterised by three primary stacking patterns. The upper and lower sections feature bell-shaped gamma ray motifs, indicating fining-upward sequences typical of lower shoreface sands. In contrast, the middle section exhibits a cylinder-shaped motif, representing blocky sand deposition characteristic of channel sands (Figure 10 and Table 5). This arrangement emphasises a depositional system dominated by lower shoreface and channel environments, reflecting periodic shifts in sediment supply and energy conditions. These patterns align with the depositional model established by Durogbitan (32) for the Agbada Formation, where similar transitions between fluvial and marine depositional systems were observed.

DOI: https://doi.org/10.53704/fujnas.v15i1.1878

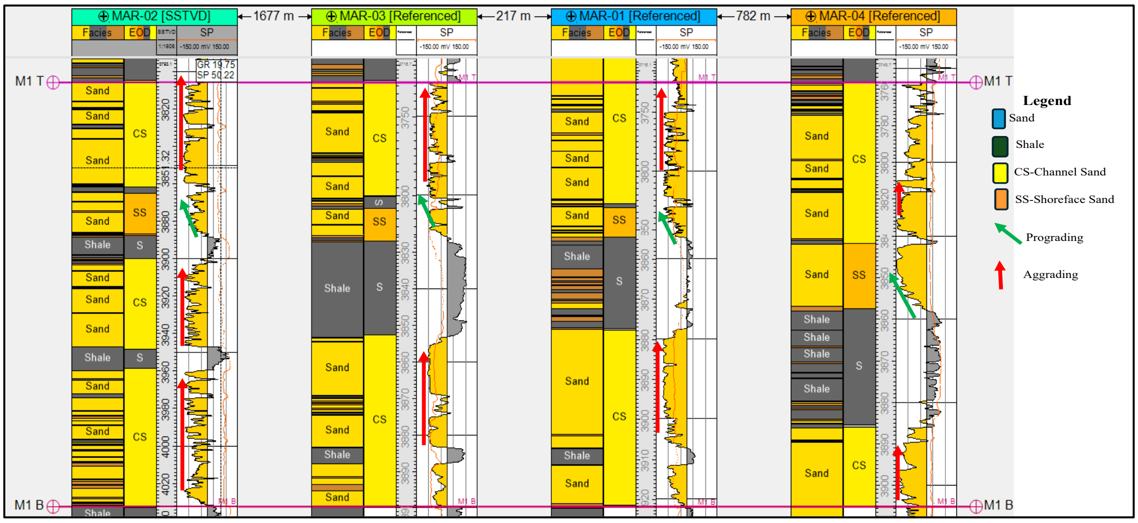

Figure 9: Environment Of Deposition of reservoir M1

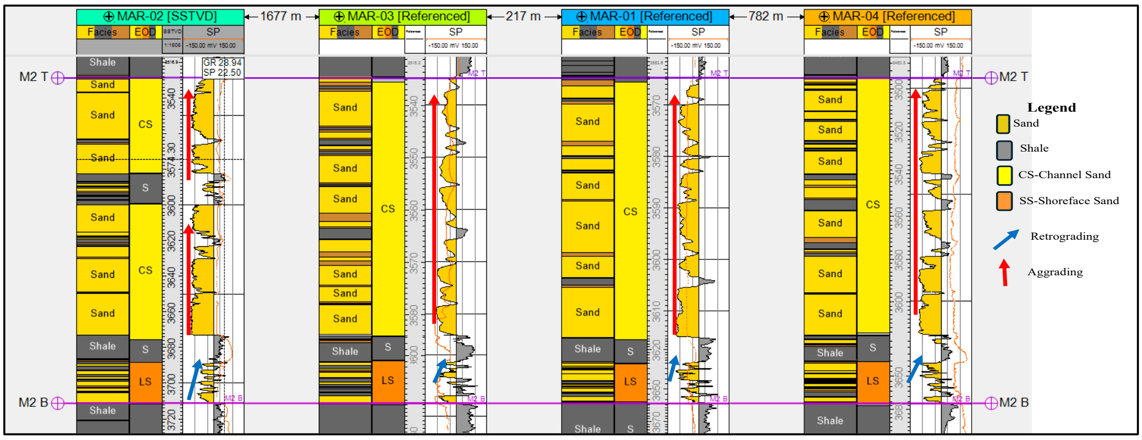

Figure 10: Environment of deposition of reservoir M2

Table 5: Environment of deposition of each reservoir.

Gamma-ray motifs	Reservoirs	Depositional-environment
Cylinder	1a	channel-sand
Bell	1b	lower shoreface
funnel	1c	shoreface sand
Cylinder	1d	channel-sand
Bell	2a	lower shoreface
Cylinder	2b	channel-sand
Bell	2c	lower shoreface
Funnel	7a	shoreface sand
Cylinder	7b	channel-sand

In this study, lower shale volumes positively correlated with higher net sand thickness and good porosity, suggesting that Reservoir M2 benefits from high-quality reservoir conditions. The alternating bell-shaped and blocky motifs in M2 mirror the distributary channels and lower shoreface sands observed by Durogbitan (32) in the Agbada Formation, while the funnel-shaped motif suggests a transition to coarser sands in the lower sections, consistent with coastal barrier systems. These characteristics, along with minimal shale intercalation, ensure favorable conditions for hydrocarbon accumulation and permeability, making Reservoir M2 well-suited for hydrocarbon production.

Reservoir M7

In Reservoir M7, two primary stacking patterns were identified, reflecting a relatively straightforward depositional architecture. The upper section displays a funnel-shaped gamma ray motif, indicative of coarsening-upward shoreface sands, while the lower section shows a cylinder-shaped motif, characteristic of blocky channel sands with sharp tops and bases (Figure 11 and Table 5). This combination suggests a depositional environment transitioning from marine-dominated shoreface processes to fluvial channel sand deposition, highlighting the influence of proximal sediment sources on the reservoir's stratigraphy. This similarity to other cases (30-32) is a consequence of regional control over the development of the fluvio-

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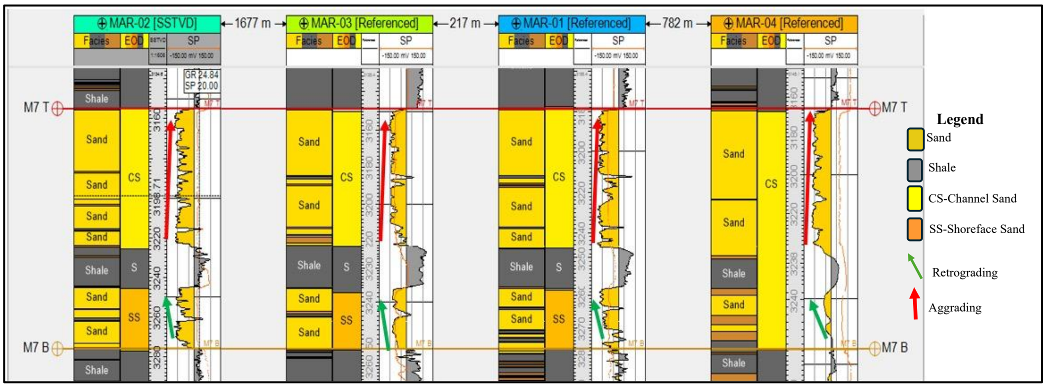

Figure 11: Environment of deposition of reservoir M7

deltaic system within the Niger Delta, during which the Agbada Formation displays organised sand-shale cyclicity caused by changes in the water level and sedimentation energy. These settings result in specific gamma ray log signatures in the form of funnels, bells, and cylinders, suggesting prograding, regressive, and channel-filling environments. In general, this response demonstrates significant basin-scale stratigraphic control over sedimentary processes. By contrast, the MAR Field displays more complex sedimentological features characterised by regular alternations between shoreface and channel settings, implying increased heterogeneity of the internal reservoir architecture. Therefore, the reservoir in the field under discussion is highly sensitive to changes in depositional conditions.

Conclusion

This study focused on the petrophysical analysis of reservoirs M1, M2, and M7 in the MAR Field, onshore Niger Delta, revealing favourable characteristics for hydrocarbon exploration. The reservoirs exhibited high porosity, permeability, and hydrocarbon saturation, with net-to-gross ratios exceeding 60% in all cases. Reservoir M1 demonstrated excellent reservoir quality, supported by strong effective porosity and permeability. Reservoir M2 showed balanced petrophysical properties with high hydrocarbon saturation, while Reservoir M7 displayed robust permeability despite slightly lower porosity. These results highlight the potential of the MAR Field's reservoirs for efficient hydrocarbon storage and flow, emphasising the importance of petrophysical evaluation in understanding and optimising reservoir performance.

The findings from this study, which are field-specific data from the MAR Field in relation to the Coastal Swamp Depobelt, provide an additional layer of information that sheds more light on the current understanding of reservoir structure in this depobelt through one key observation, contrary to prevailing assumptions regarding their composition. The findings show that each reservoir unit in the MAR Field exhibits distinct internal compartmentalisation associated with stacked depositional sequences of fluvial-marine contacts, an attribute not highlighted in the current regional models of the depobelt. This makes the reservoirs heterogeneous, characterised by varying sand bodies in quality and connectivity within the same reservoir unit. The channel deposits are always made up of good flow units, while those of the shoreface vary because they are influenced by shale, meaning sand alone cannot determine reservoir quality. This is because reservoirs do not have the homogeneous characteristics assumed in most current models and thus require a more specific approach to understand their behaviour and predict performance effectively.

Acknowledgements

This research publication is part of the MSc thesis of the first author. Funding for the research is provided by the African Union through the Pan African University Life and Earth Sciences Institute (including health and agriculture), PAULESI.

Conflict of interest

The authors declare no conflict of interest.

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DOI: https://doi.org/10.53704/fujnas.v15i1.1878