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Petrophysical Interpretation and Source Rock Assessments of the Pearl Field, Niger Delta

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Abstract: *This study presents an interpretation of well log data from five wells in the Pearl field, Niger Delta, Nigeria. Log analysis combining gamma ray (GR), resistivity (LLD), neutron (PHIN), and density (RHOD) logs effectively defined the depth and thickness of hydrocarbon- bearing zones. Depth correlation and permeable zone identification utilized gamma ray and caliper logs, characterizing two reservoirs across the studied wells. Well log analysis enabled the characterization of lithological descriptions and calculation of petrophysical parameters such as porosity, net-to gross, water saturation, and hydrocarbon saturation. Results show average porosity values of 0.29 and 0.27 for Reservoir 1 and 2, respectively. Water saturation values of 0.35 and 0.33, average net-to gross value of 0.88 and 0.81, and hydrocarbon saturation value of 0.65 and 0.67 were obtained for Reservoir 1 and 2 respectively. These results findings indicate a potential hydrocarbon source and a satisfactory reservoir system for hydrocarbon production. Further testing is recommended to quantify production capacity.*
Keywords: Petrophysical interpretation, well log data, pearl field, hydrocarbon, reservoir.

INTRODUCTION

The integration of subsurface data for petrophysical characterization of reservoirs is a major aspect in formation evaluation in the oil and gas industries (Bate et al., 2023). This is because well log data provide useful information about the reservoir quality, quantity and recoverability of hydrocarbon (Asquith and Krygowski, 2004). Qualitative evaluation of hydrocarbon resources involves the integration of seismic and well data interpretations (Aizebeokhai and Olayinka 2011). Porosity, permeability and water saturation are the main petrophysical properties of a reservoir rock and have a vital impact on hydrocarbon reservoir evaluation and characterization (Emujakporue, 2017). To evaluate hydrocarbon reserves, there is a need for accurate determination of porosity, water saturation and pore volume and recovery factor as seen in the works of Chopra and Michelena (2011); Yu et al. (2011); Rotimi et al. (2013). Petrophysical properties have a reasonable contribution to reservoir estimation, therefore it needs a serious attention (Emujakporue, 2017). Reservoir characterization is the integration of different data in order to describe the reservoir properties of interest in inter-welllocations (Mehdipour et al., 2013; Ezekwe and Filler, 2005).

This study evaluated the integrated basin of the pearl field through the use of pre-conditioned attributes, fault delineating seismic attributes and quantitative definition of the reservoir units of petrophysical model distributions, through the use of 3D seismic and well log data. In this research, the lithology of the area and gross depositional setting was determined, the petroleum system elements were evaluated, the delineating play from structural map and the risk associated with key petroleum elements were investigated.

Geological framework

The studied area is located in the offshore Niger Delta basin, Gulf of Guinea, Southern Nigeria, within latitude 5.06°N – 5.08°N and Longitude 0.1^0E - 0.14°E. It is bounded on the east, west, respectively as shown in Figure 1. Niger Delta is bounded in the north by older (Cretaceous) tectonic elements among which are the Anambra Basin, Abakaliki uplift and Afikpo syncline.

The Niger Delta basin was formed as a result of separation of South America and Africa caused by rifting. The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins, and, in Nigeria, form the boundary faults of the Cretaceous Benue-Abakaliki trough, which cuts far into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous (Lehner and De Ruiter., 1977). In the region of the Niger Delta, rifting diminished altogether in the Late Cretaceous. After rifting ceased, gravity tectonism became the primary deformational process. According to Kulke, (1995), Shale mobility induced internal deformation and occurred in response to two processes. First, shale diapirs formed from loading of poorly compacted, over-pressured, prodelta and delta-slope clays (Akata Fm.) by the higher density delta-front sands (Agbada Fm.).

Figure 1.1 Map of Nigeria showing the location of the Pearl field (study area). Source: Wikipedia

Second, slope instability occurred due to a lack of lateral, basinward, support for the under-compacted delta-slope clays (Akata Fm.). For any given depobelt, gravity tectonics were completed before deposition of the Benin Formation and are expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults (Evamy et al., 1978; Xiao and Suppe., 1992). These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation. Figure 2 and figure 3 are the paleogeography showing the opening of the South Atlantic, and development of the region around Niger Delta.

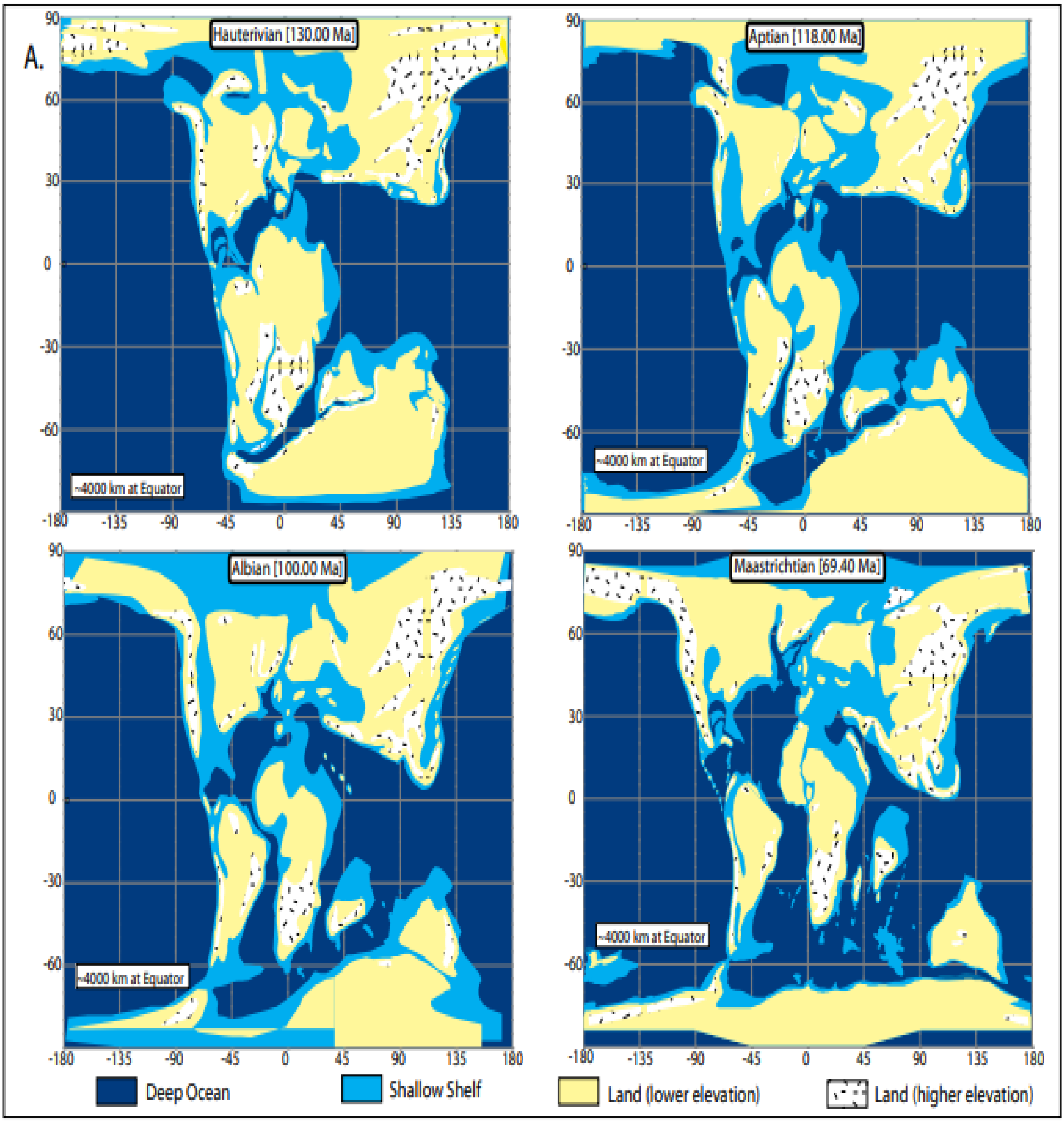

Figure 2 Cretaceous paleogeography (130.0 to 69.4 ma).

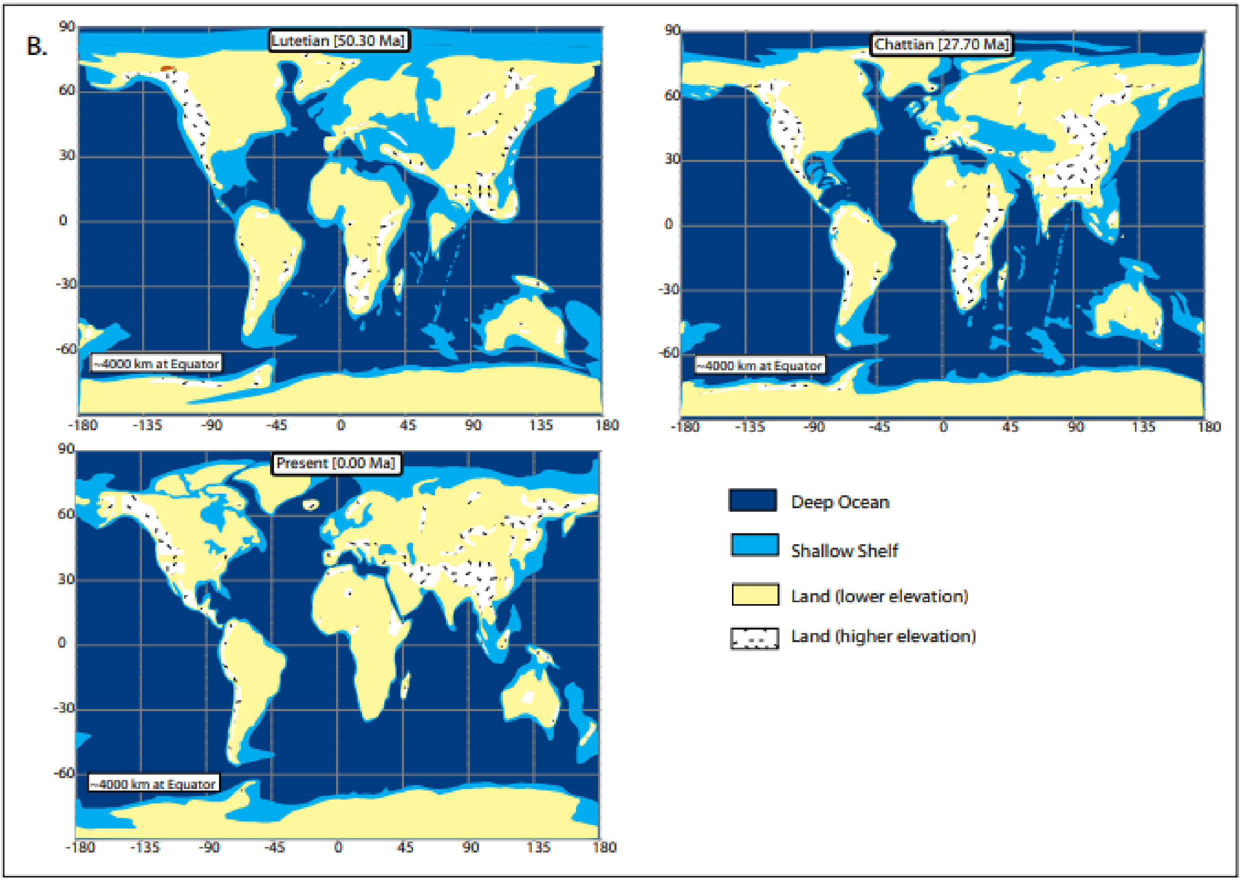

Figure 3. Cenozoic paleogeography (50.3ma to present).

As shown in figure 4 and 5, Niger Delta is divided into three broad lithostratigraphic units which are; Akata formation from Paleocene to Pleistocene, Agbada formation from Eocene to recent, and Benin formation from Miocene to recent. This stratigraphic classification is based on the interpretation of foraminifera, fossil, spores and calcareous Nano plankton. Niger Delta has an average thickness of 12km. During the Paleocene, the Akata formation was deposited, followed by the Agbada formation during the Eocene. This loading caused the underlying shale Akata formation to be squeezed into shale diapirs. Then in the Oligocene the Benin formation was deposited, which is still being deposited today.

In the Niger Delta, three depositional settings indicate that deposition occurred during several regressive/transgressive episodes in overall progradational setting. These depositional settings can be subdivided into the lower over pressured marine Akata Formation which underlies the delta, and it is composed of thick shale successions (potential source rock), turbidite sands (potential reservoirs in deep water) and minor amounts of clay and silt. Turbidity currents likely deposited the deep sea fan sands within the upper Akata Formation during development of the delta (Burke., 1972). Most structural traps observed in the Niger Delta developed during syn-sedimentary deformation of the Agbada paralic sequence (Evamy *et al.*, 1978). The primary seals are interbedded shales within the Agbada Formation. The paralic successions also grade into an upper series of massive sands and gravels (Benin Formation), deposited under continental conditions (Evamy *et al.*, 1978; Weber., 1986). It is a transitional series composed mainly of sand but with some shale.

As shown in figure 6, Petroleum occurs throughout the Agbada Formation in the Niger Delta clastic wedge. Although the distribution of hydrocarbons is complex, there is a general tendency for the ratio of gas to oil to increase southward within individual depo belts (Doust *et al.*, 1989). Stacher., (1995) developed a hydrocarbon habitat model based on sequence stratigraphy of some petroleum-rich belts within the Niger Delta area, and provides a short summary of basin, trap, reservoir, source rock and hydrocarbon character (Table 2). Gas to oil ratios within reservoirs were reported by (Evamy *et al.*, 1978, Ejedawe., 1981 and Doust and Omatsola., 1990). Reservoirs occur along northwest-southeast "oil rich belts" and along a number of north-south trends in the Port Harcourt area. Tuttle *et al*. (1999) suggest t belts roughly correspond to the transition between continental and oceanic crust within the axis of maximum sediment thickness. Other authors have related oil-rich belts to structural or depositional controls, to an increase in the geothermal gradient, and shifts in deposition basin ward within subsequent depo-belts (Ejedawe., 1981; Weber., 1986; Doust and Omatsola., 1990; *Haack et al.*, 1997). The Niger Delta has been the focus of hydrocarbon exploration since 1937. Now it is Africa's leading oil province. The Niger Delta is situated in the Gulf of Guinea, and it is located in the southern part of Nigeria. In the Niger Delta basin, the Akata-Agbada petroleum system has been identified as the only petroleum system.

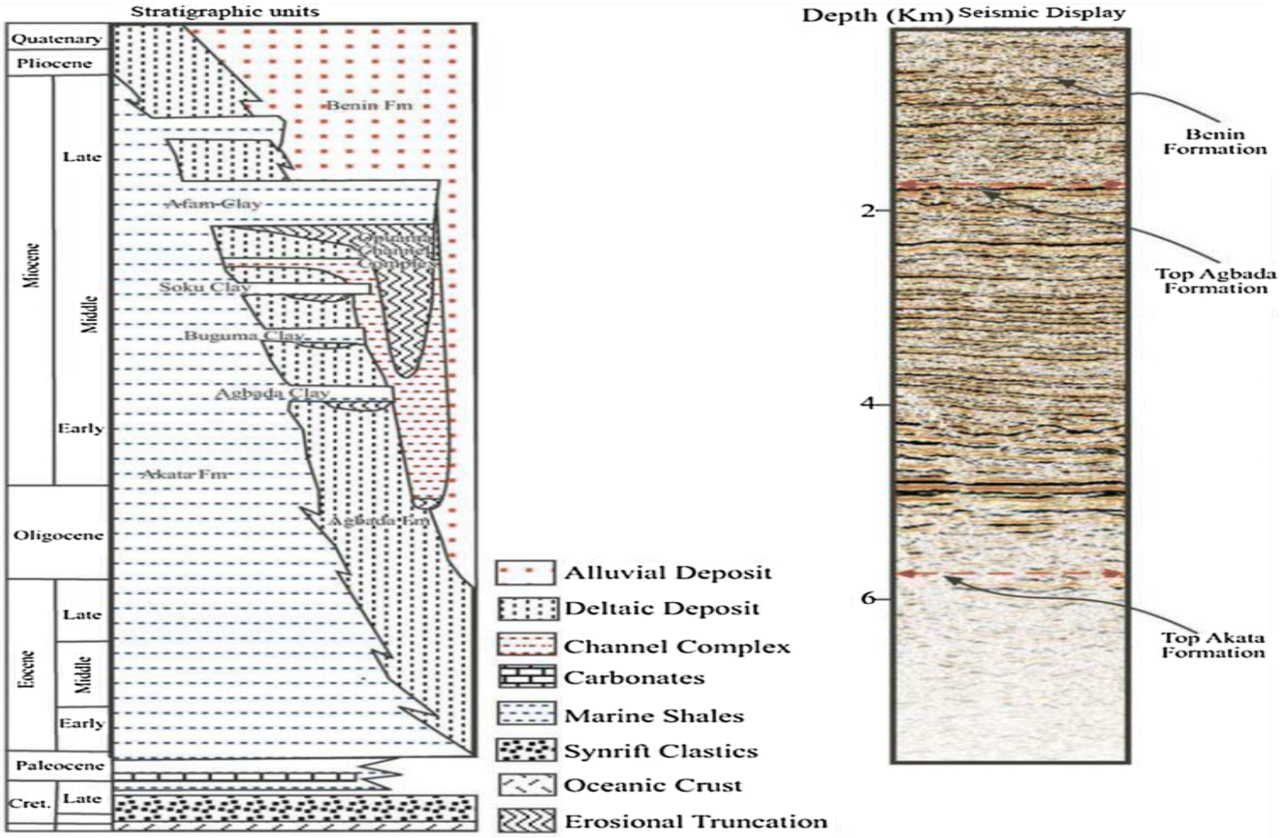

Figure 4. Stratigraphy of the Niger Delta and variable density seismic display of the main stratigraphic units in the outer and thrust belt and the main reflectors.

Source: Lawrence et al. 2002

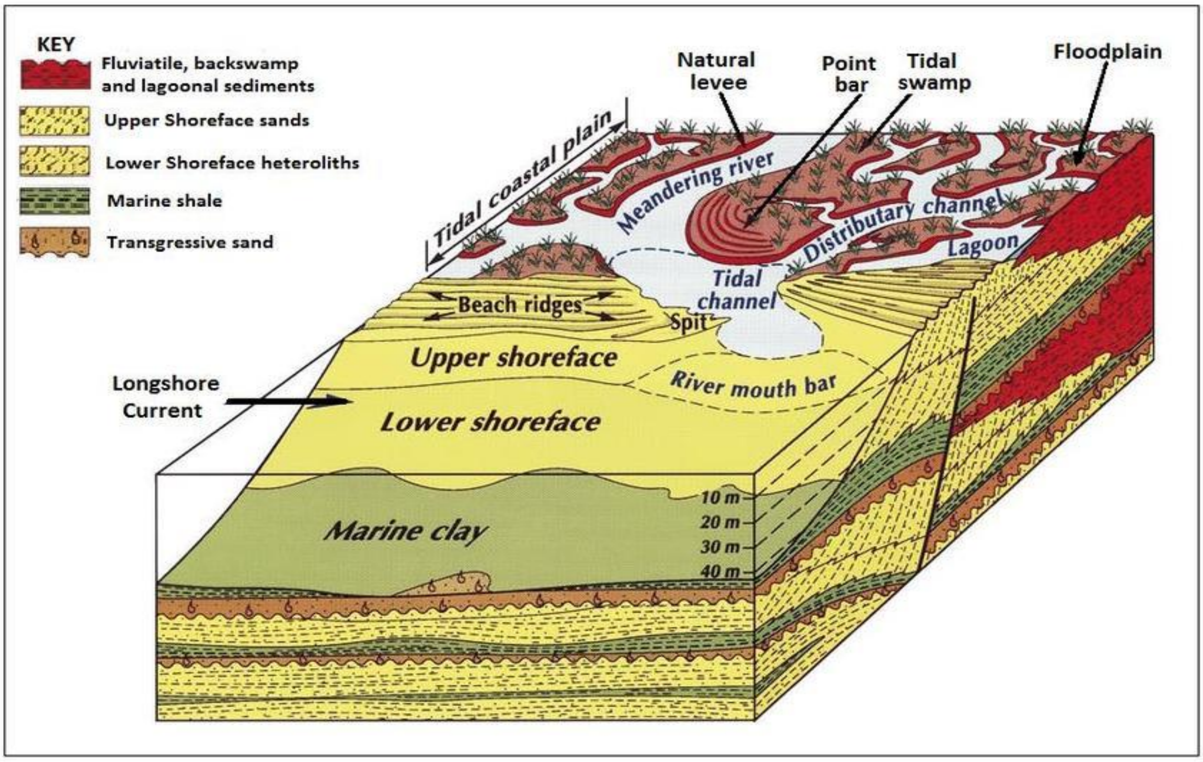

Figure 5 Depositional environments of the Niger Delta

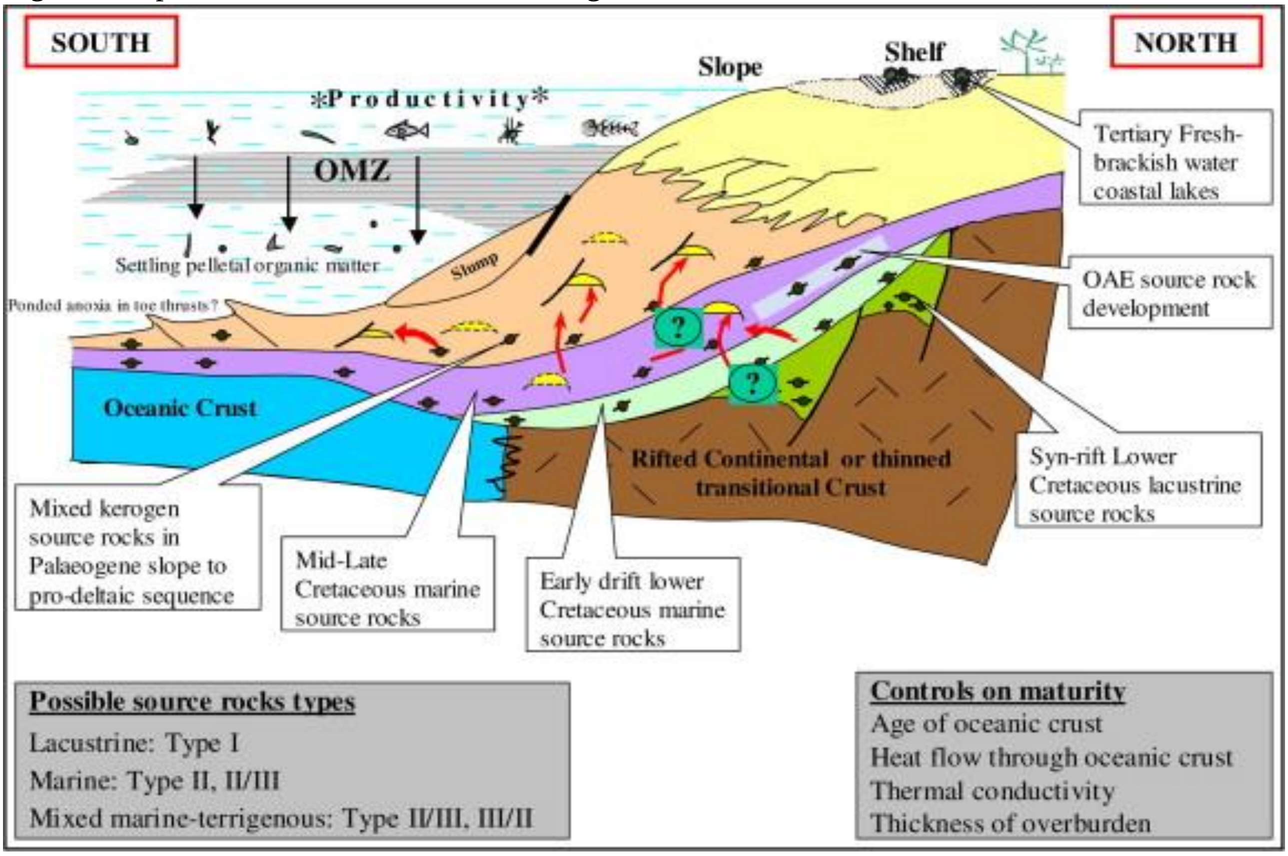

Figure 6 Petroleum system in the Niger delta showing flow and patterns.

Materials and methods

In the Pearl field, a comprehensive dataset from five wells (PEARL01 - 05) provided invaluable insights. Key logs- gamma ray, caliper, density, neutron, sonic and resistivity- enabled precise calculation of critical petrophysical parameters. Wireline logging was used for data acquisition. Well logs or wireline logs are recordings against depth, the characteristics of a formation which are extracted by means of traversing a measuring equipment in the well bore. The well log suites of gamma and deep resistivity logs aided the delineation and correlation of the reservoir. Petrophysical analysis of wireline logs was interpreted in order to evaluate parameters such as; lithological units, volume of shale, Porosity, water saturation, hydrocarbon saturation and net-pay thickness. Schlumberger's Petrel v.2016 software was instrumental in well log analysis, enabling accurate interpretations.

Well log interpretation

Well log interpretation is a powerful tool to understand lithology, petrophysical analysis, fluid saturation and reserve estimation. Well log interpretation is the use of well log data to estimate various reservoir properties. Interpretation of well logs will reveal both the mineralogical and proportion of solid constituents of the rock (i.e. grains, matrix and cement), and the nature and proportions (porosity, saturations) of the interstitial fluids. These logs are also key instruments in well productivity assessment.

In this study, we gamma ray logs (GR), and caliper logs were used for the correlation of depth and identification of permeable zones. Porosity logs (density logs, neutron logs, sonic logs) were used to calculate porosity at each point. Then, the matrix identification (MID) method was used to correct porosity to get more accurate results. To identify gas zones, density and neutron logs crossovers were used. Porosity and water saturation were used to identify permeable zones. Resistivity logs were used to obtain water saturation. After obtaining water saturation, both oil and gas saturation were calculated.

Wireline logs are tools that are attached to a "wireline" or steel cable, lowered to the bottom of a well after each major stage of drilling and the hauled back. As the tools pass by the various rock layers on the way back to the drilling rig, they record both intrinsic and induced properties of the rock and their fluids. The table 1 shows a structured arrangement of the wells analyzed, with the available information listed.

Table 1. Various wells analyzed and available information for petrophysical and well-log interpretation.

WELLS					
INFORMATION	PEARL01	PEARL02	PEARL03	PEARL04	PEARLX01
DEVIATION SURVEY	X	X	X	X	X
CALIPER	-	X	X	X	X
GAMMA RAY	X	X	X	X	X
DENSITY	X	X	X	X	X
NEUTRON	X	X	X	X	X
SONIC	X	X	X	X	X
DEEP RES	X	X	X	X	X
VSP	X	-	X	X	X

KEY	
X	AVAILABLE
-	NOT AVAILABLE

RESULTS AND DISCUSSION

All the data is interpreted through Petrel software. Petrophysical analysis was done to estimate the shale value for reservoir that how much clean is our reservoir and also the facies were analyzed by studying the Sequence stratigraphy through Gamma ray Log. LLD (laterolog deep) was used to identify maximum hydrocarbons against the water Saturation. Sonic Log used for porosity to calculate the total and effective porosity of reservoir. After interpreting all these reservoir properties, we came to conclude the Hydrocarbon Saturation, Water saturation of the wells Pearl-01, 02, 03,04 and 05 with the upper and lower reservoirs.

Lithologic and reservoir description

The gamma-ray and resistivity logs were used for the identification of lithology and the reservoir intervals. Deflection pattern of the lithology was identified as shale or sandstone.

Deflection of gamma in response to shale shows more concentration of radioactive substance and sand shows less concentration of radioactive substance. The deflection of the gamma-ray to the left associated with increase in resistivity was suggested to indicate reservoir intervals, whereas the deflection of the gamma-ray to the right associated with decrease in resistivity was assumed to indicate non-reservoir (mudrock) lithology. Pearl01 well consists of intercalation (alternation) of layers or lithology (sand and shale). The total depth of this well is 2655m and the first layer of shale occur from 1860m to 1960m, and sand is at 1960m to 2050m. At 1850m, there is a minor intercalation of sand and shale. There is also another shale deposit at 1680m to 1850m and sand deposit from 1610 to1680m. A major intercalation is occurring at a depth between 1460m to 1610m. As shown in figure 7, the yellow colour represents sand and the gray represent shale while black represents the poorly resolved interval.

Well log correlation

All the five wells (pearl01, pearl02, pearl03,pearl04 and pearl05) were correlated to know the similarities across the wells using gamma ray log as shown in Figure 8. This correlation is strictly on the lithological distribution of the particular wells. As shown in figure 8, all five wells were correlated with distinct regions color coded as maroon (horizon 1-2), green (horizon 2-3), blue (horizon 3-4), and red (horizon 4-5) with increasing depth. The maroon region consists of mainly sandstone and can be found at depths of 500 to 900 m, 1000 to 1300m, 1050 to 1380m, 1000 to 1300m, and 1100 to 1400m for pearl01, pearl02, pearl03,pearl04 and pearl05, respectively. It can also be observed that the green and red regions consist of intercalation (alternation) of layers or lithology (sand and shale). This can be observed at depths 900-1700m/1950-2300m , 1000 to 1300m/2170 to 2300m, 1390 to 1900m/2250 to 2310 m, 1300 to 1810m/2190 to 2250m and 1400 – 1760 m/2000 to 2450m for pearl01, pearl02, pearl03,pearl04 and pearl05, respectively. Finally, the blue section consists mainly of shale with very little proportion of sandstone for all the wells observed, and this can be found in depths of 1700 to 1950m, 1650 to 2170 m, 1900 to 2250m, 1810 to 2190, and 1760 to 2000m for pearl01, pearl02, pearl03,pearl04 and pearl05, respectively. This continuity in formation shown by the well log correlation across the five wells is based on the similarities in the signature of the gamma ray. No missing formation or thinning out laterally across the wells was observed.

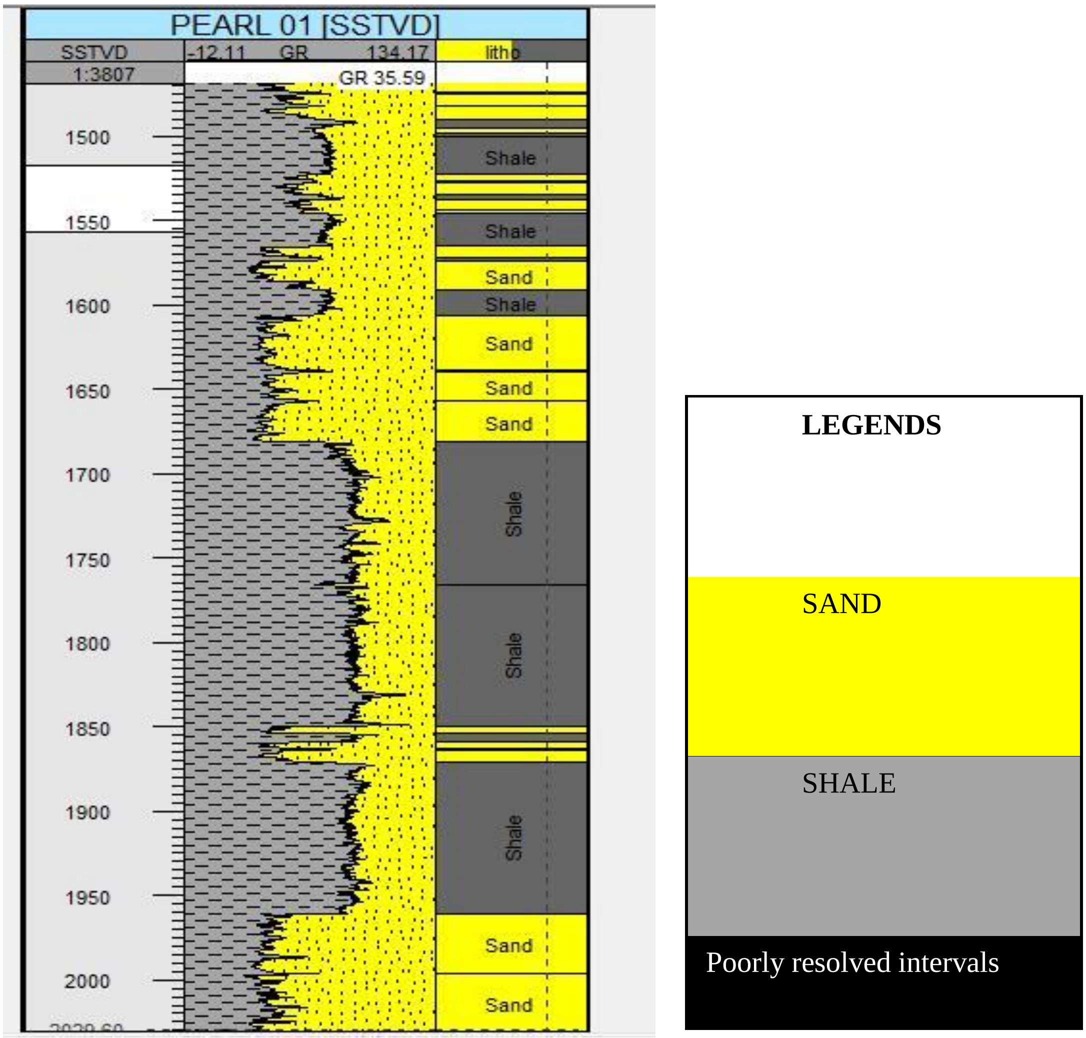

Figure 7 Gamma ray log of pearl01 well

Reservoir identification

After the wells were correlated, appropriate reservoirs bodies were characterized in terms of their parameters. With the aid of the resistivity log, all the reservoirs were marked out. The reservoir (Pearl01) has a thickness of about 139.21m **,** reservoir (Pearl03) has a thickness of about 102.71m and the reservoir (Pearl04) has a thickness of about 88.09m**.** All three wells have an average thickness of 110m. as shown in figure 9, the log trend is in red and the areas where you have a spike are the probable reservoirs. High spikes across pearl01 gives you the idea of the reservoir at this particular interval and the depth of occurrence for the reservoir in pearl01 well is at 1845.53m at the top to 1871.40 at the bottom. The gross thickness is 21.87m. While the net thickness is 16.35m, net to gross is 0.75. Porosity, water saturation and hydrocarbon saturation is 0.35, 0.27 and 0.73 respectively. High spikes across Pearl02 gives you the idea of the reservoir at this particular interval and the depth of occurrence for this well is at 2035.15m at the top.

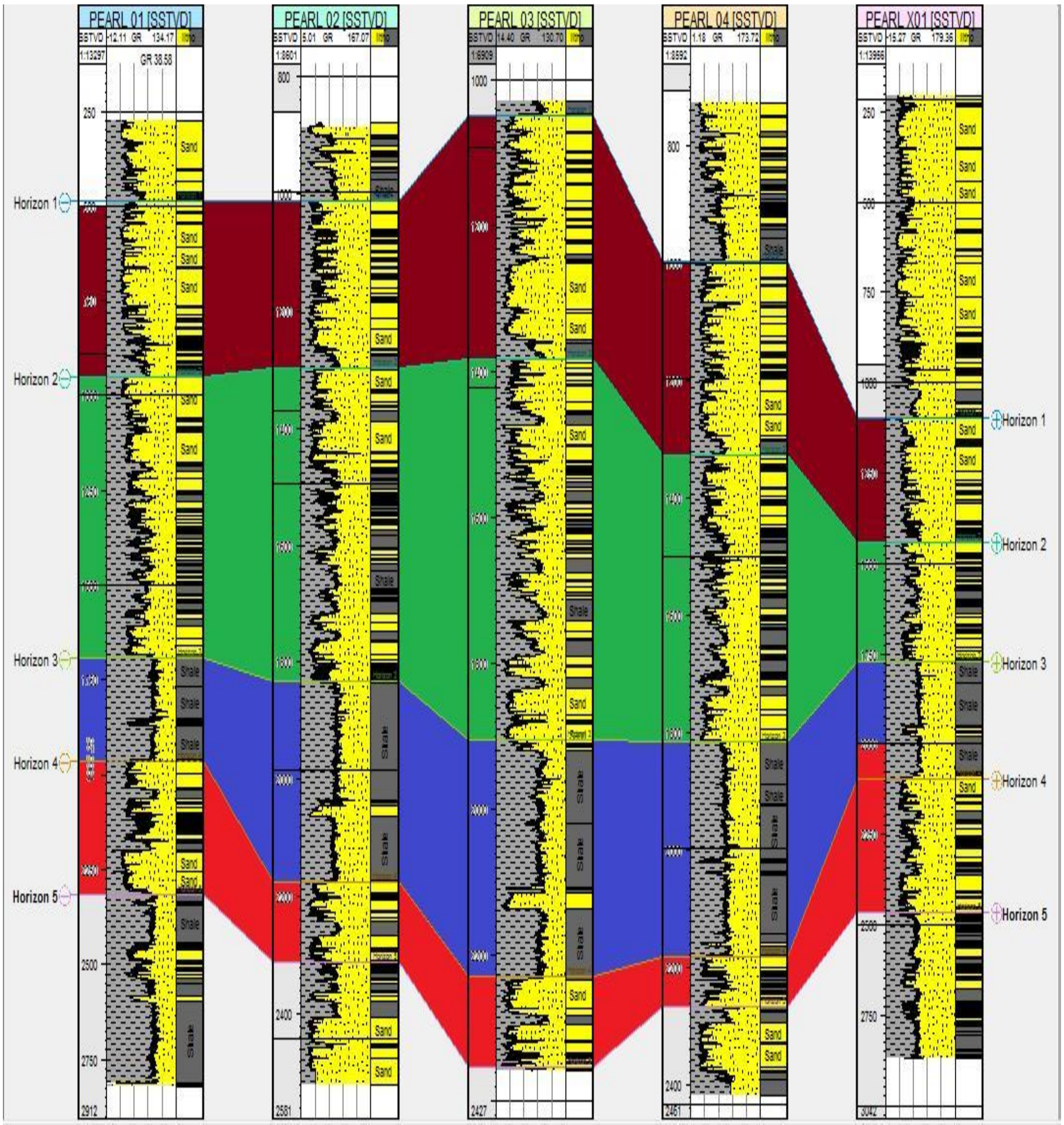

Figure 8 Well Log Correlations

The petrophysical analysis

The petrophysical parameters such as porosity, water saturation and hydrocarbon saturation in the identification of reservoir1 and reservoir2 in the whole sequence using the well log data that were available from five wells. In table 2, the reservoir top and bottom in meters are shown. The gross thickness, net thickness is also in meters while the net to gross, porosity, water saturation and hydrocarbon saturation are dimensionless.

Source rock evaluation

As shown in figure 10, the source rock evaluation was done using the sonic and resistivity logs. In pearl01, matured source rock from sonic log and resistivity log cross-plot ($\Delta logR$ separation) TOC value =10.5wt% In pealr03 matured source rock from sonic log and resistivity log cross-plot ($\Delta logR$ separation).

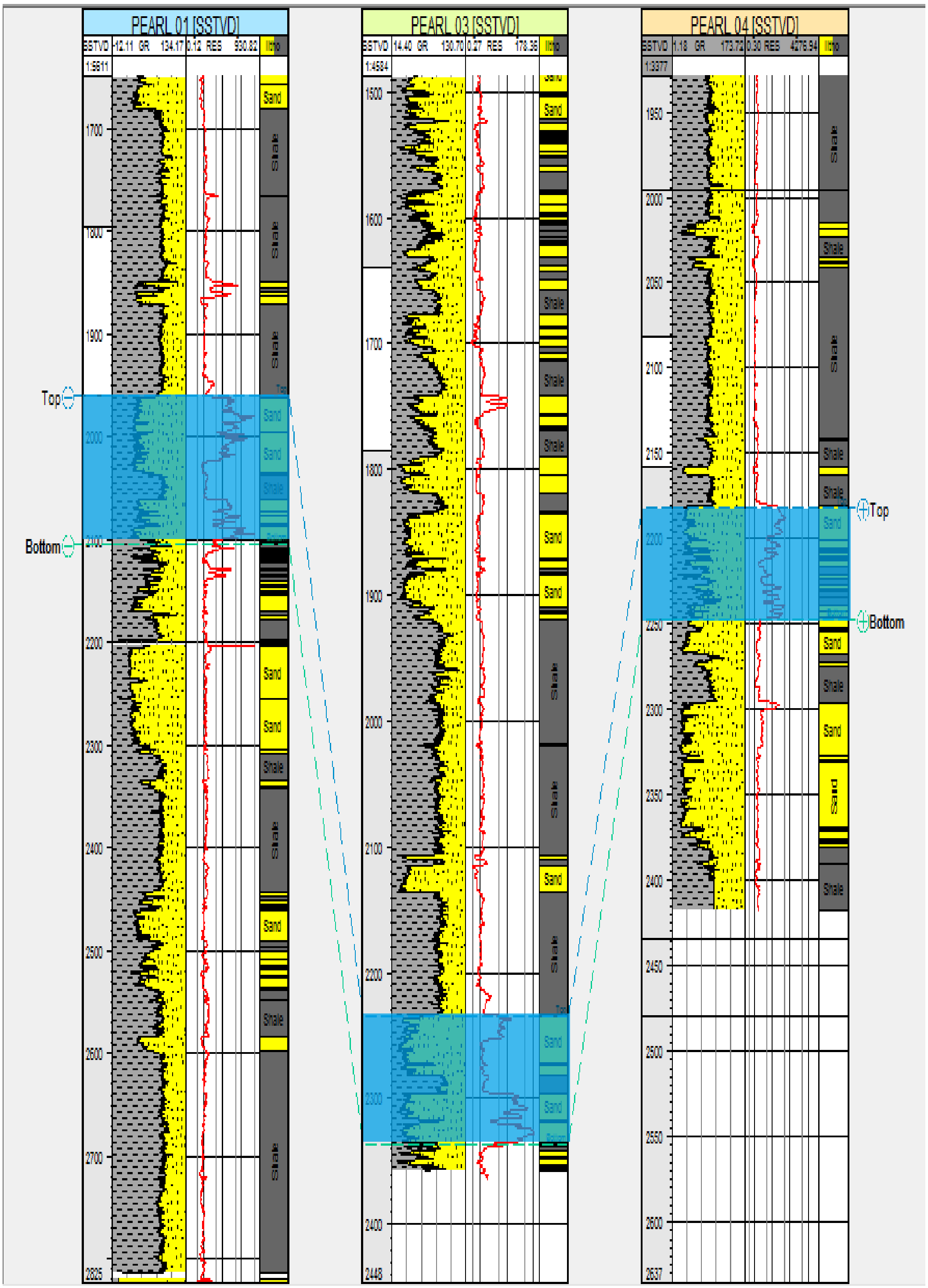

Figure 9. More Log Correlation for PEARL 01(SSTVD), PEARL 03(SSTVD) and PEARL 04(SSTVD)

Table 2 Petro-Physical analysis results

	RESERVOIR 1			RESERVOIR 2			
	PEARL 02	PEARL 05	AVERAGE	PEARL 01	PEARL 03	PEARL 04	AVERAGE
TOP (m)	1849.53	2035.15		1961.12	2232.01	2179.82	
BOTTOM (m)	1871.40	2068.82		2100.33	2334.72	2267.91	
GROSS THICKNESS (m)	21.87	13.69	17.78	139.21	102.71	88.09	110.03
NET THICKNESS (m)	16.35	13.69	15.02	112.35	83.63	60.09	85.36
NET TO GROSS	0.75	1	0.88	0.81	0.81	0.68	0.81
POROSITY	0.35	0.24	0.29	0.30	0.23	0.27	0.27
WATER SAT.	0.27	0.43	0.35	0.17	0.52	0.31	0.33
HYDROCARBON SAT.	0.73	0.57	0.65	0.83	0.48	0.69	0.67

Seal presence evaluation

As shown in figure 11, shale is serving as the seal here because it has low permeability, and its pores are small and disconnected. In pearl01subsea time vertical depth (SSTVD), the occurrence of shale is at about 1700m at the top to 1910m at the bottom and the seal thickness is about 272.87m and there is a minor intercalation of sand between 183m5 to 1845m. In pearl03 subsea time vertical depth (SSTVD), the occurrence of shale is at about 2130m at the top to 2230m at the bottom and the seal thickness is about 98.54m. In pearl04 subsea time vertical depth (SSTVD), the occurrence of shale is at about 1805m at the top to 2080m at the bottom and the seal thickness is about 364.47m.

Seal integrity

The depth of pearl01 well was plotted against density and also against pressure. The shale happens to fall under brittle, and this indicates that the seal integrity is not guaranteed as high density shales are observed in most parts to fall under brittle. The best shale for seal that can be relied upon to stop the vertical migration of hydrocarbon is the ductile type because the brittle type can cause escape of the hydrocarbon. This was done using the Skerlec model

(1982). During the seal integrity interpretation, the shale that we encountered shows it is more brittle than ductile. This can be visualized in Figure 12-14 below. It can be observed that our depth vs density is concentrated at around 2.3 which corresponds to more brittle using Skerlec model in Figure 14.

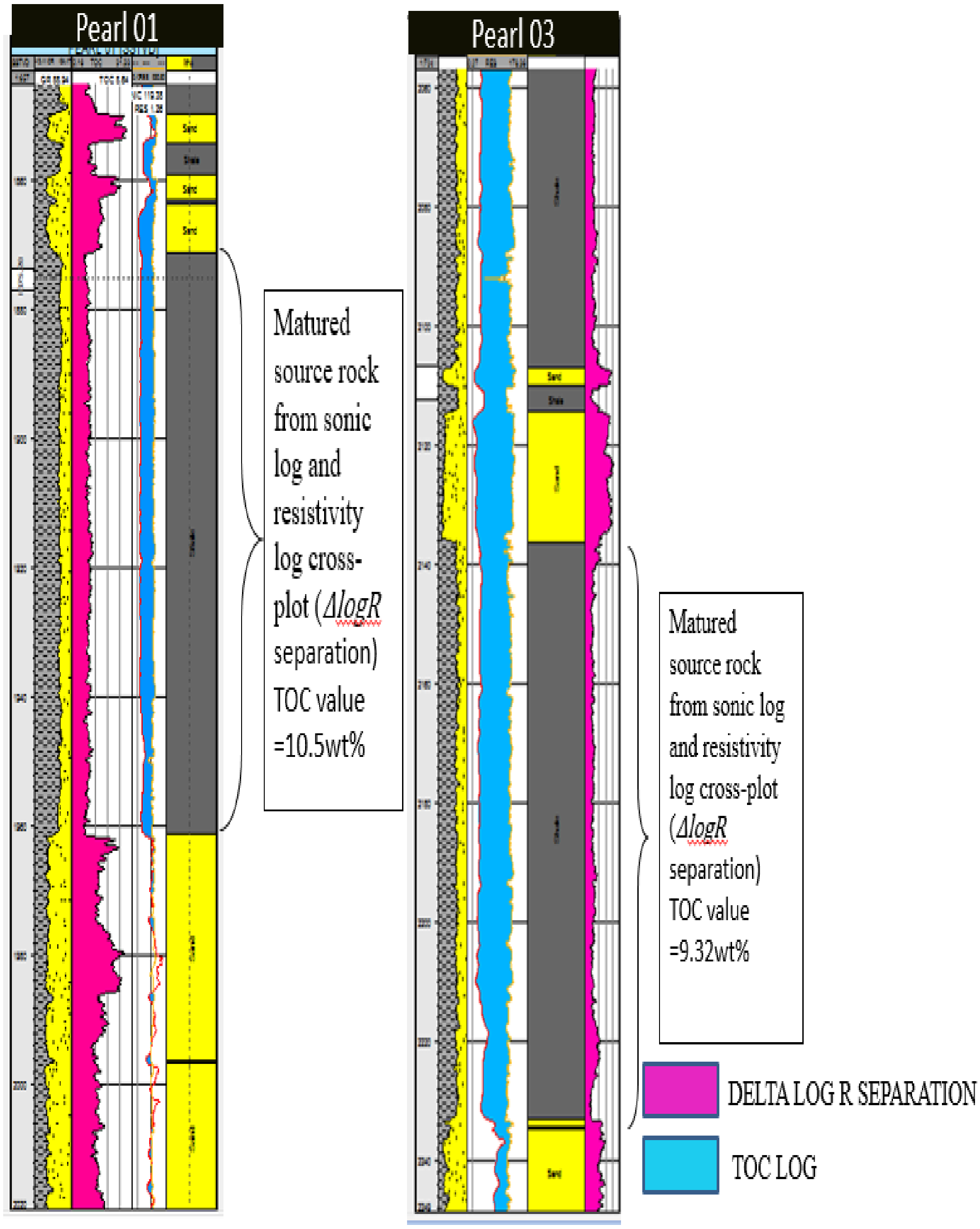

Figure 10 Source Rock Evaluation
TOC value =9.32wt%. TOC content was calculated using Schmoker's equation

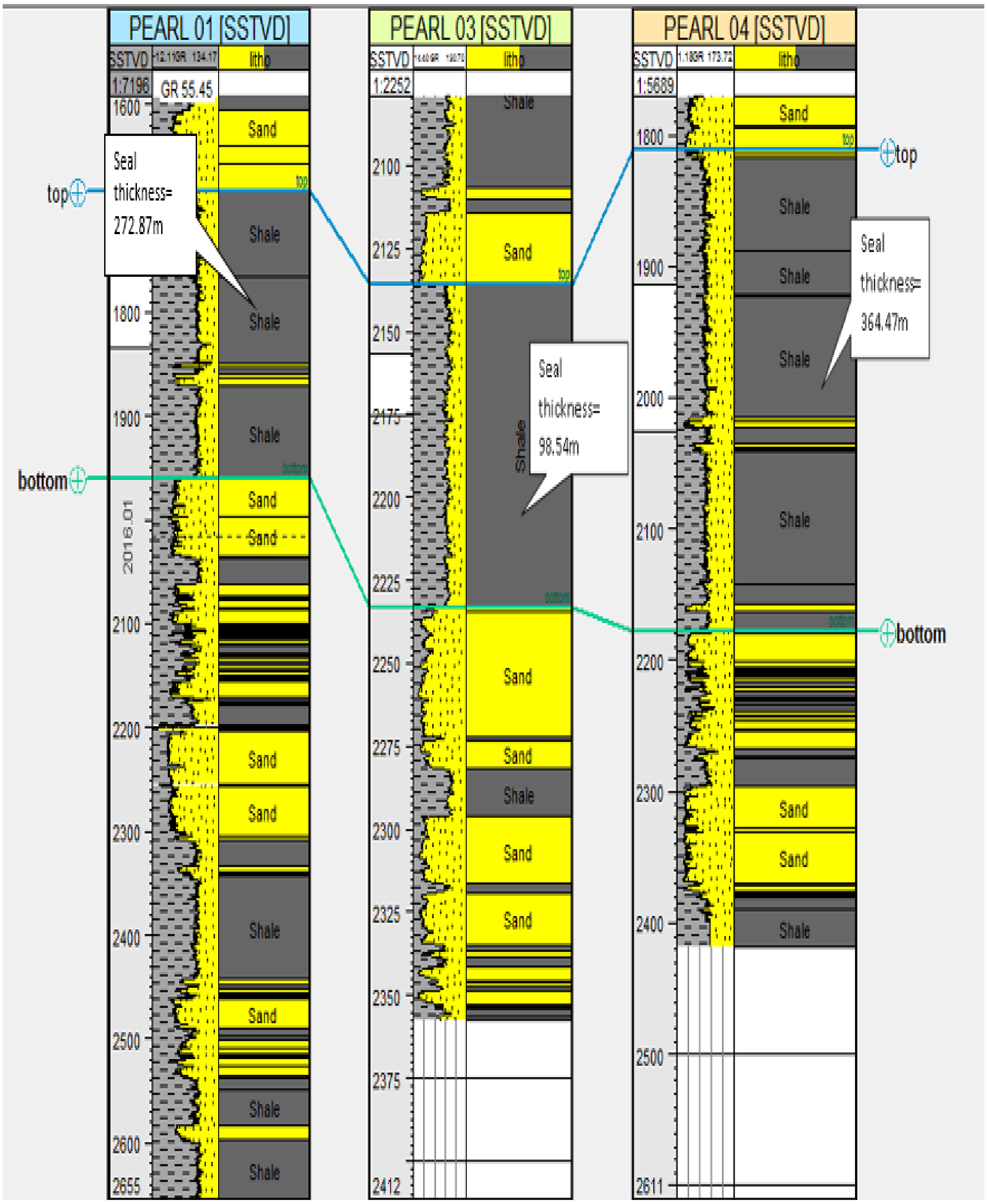
PEARL 01 [SSTVD]
PEARL 03 [SSTVD]
PEARL 04 [SSTVD]
Seal thickness= 272.87m
Seal thickness= 98.54m
Seal thickness= 364.47m
top
bottom
Sand
Shale

Figure 11 Seal Presence Evaluation

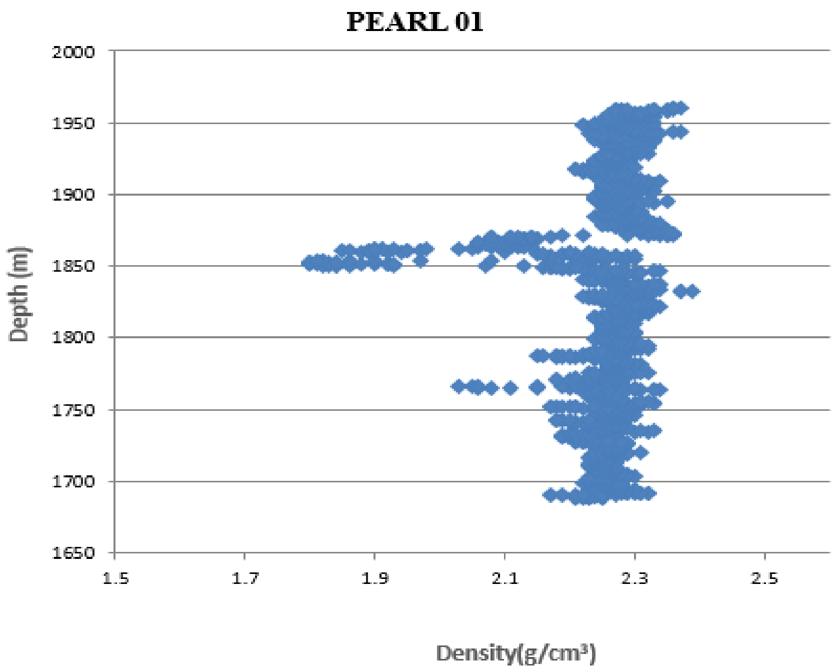

Figure 12 Seal Integrity (Depth vs Density)

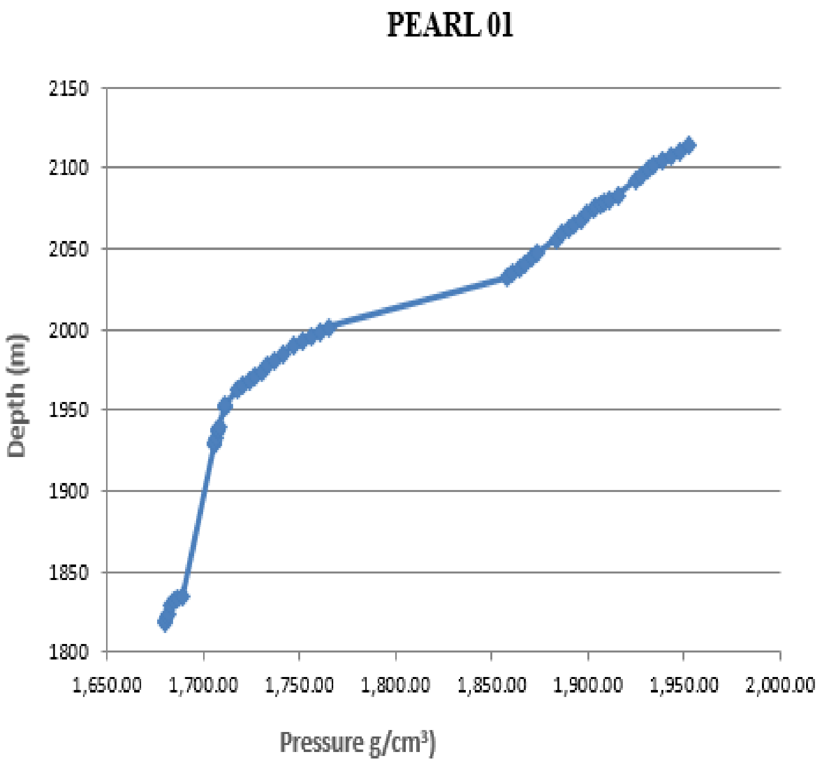

Figure 13 Seal Integrity (Depth vs Pressure)

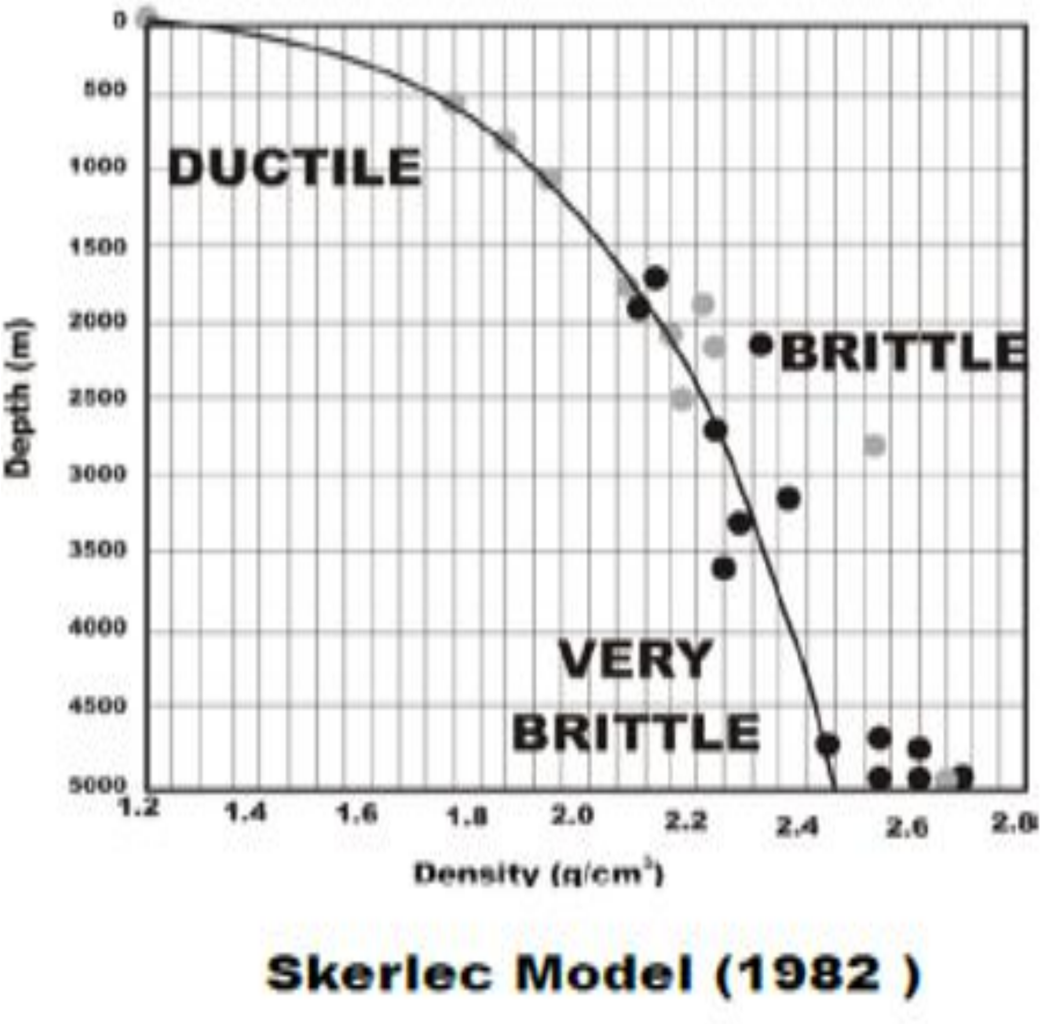

Figure 14. Model for Seal integrity interpretation

CONCLUSION

Integration of the available dataset has enabled the interpretation of lithology and depositional environment of the pearl field. The wells in the study area penetrated the following lithologies: sandstones, sandy shale, and shale with varying thickness. Most of the sandstones are not clean and reservoir continuity laterally across the wells was observed and pearl01, pearl02 and pearl03 have an average thickness of 110m. Results from petrophysical analysis showed that the average porosity for reservoir1 and reservoir2 was 0.29 and 0.27 respectively. Also, water saturation value of 0.35 in reservoir1 and 0.33 in reservoir2, an average net-to gross value of 0.88 in reservoir1 and 0.81 in reservoir2, and hydrocarbon saturation value of 0.65 in reservoir1 and 0.67 in reservoir2 were obtained.

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