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Integrated Core Analysis and Wireline Logging for Characterizing Rock Properties in Selected Reservoirs of X Field, Niger Delta

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Abstract

The present study characterises the reservoir properties of selected hydrocarbon-bearing intervals in the X Field, Niger Delta Basin, through the integration of conventional core analysis and wireline log interpretation. Wireline logs in LAS format, comprising gamma-ray, resistivity, density, neutron, acoustic, and calliper logs, were integrated with conventional core data to identify lithofacies, interpret depositional environments, and calibrate petrophysical responses. Reservoir delineation and well-to-well correlation identified ten reservoir units (R1–R10) across the field. Petrophysical evaluation employed industry-standard techniques, including the Larionov gamma-ray method for shale-volume estimation, density-derived porosity calculation, and Archie's equation for water-saturation determination. Results reveal considerable reservoir heterogeneity, with porosity ranging from 0.076 to 0.321, representing poor to excellent storage capacity. Shale volume varies from 0.055 to 0.855, whereas water saturation ranges from 0.018 to 0.894, reflecting substantial variations in clay content, fluid saturation, and overall reservoir quality. Intervals characterised by high porosity (>0.300), low shale volume (<0.220), and low water saturation (<0.090), particularly Well 3 R4 and Well 4 R3–R4, demonstrate significant hydrocarbon potential. Conversely, Well 4 R1 and Well 5 R1–R3 exhibit poor reservoir quality associated with high shale content and water saturation. Core analysis identified laminated shale, bioturbated shale, tidal sandstone, distributary-mouth-bar sandstone, and shoreface deposits, representing offshore-to-delta-plain depositional environments. The integrated core-log approach significantly improves reservoir characterisation and demonstrates that depositional facies exert fundamental controls on reservoir quality, heterogeneity, and distribution within the Niger Delta Basin.

Keywords

Niger Delta Basin;
Reservoir Characterization;
Wireline Logs;
Core Analysis;
Petrophysical Evaluation;
Facies Analysis

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Introduction

Accurate characterization of reservoir rocks remains crucial for hydrocarbon exploration, field development, and production optimization within complicated sedimentary basins. Reservoir quality is largely controlled by lithofacies distribution, depositional environment, diagenetic alteration, and petrophysical heterogeneity, all of which affect fluid storage and flow behavior within subterranean formations (Gluyas & Swarbrick, 2021). In clastic petroleum systems, particularly deltaic settings, fast lateral and vertical facies fluctuations can result in heterogeneous reservoirs, complicating reservoir appraisal, reserve calculation, and production forecasting. As a result, integrated techniques that combine direct laboratory measurements with continuous subsurface logging data are becoming critical for enhancing reservoir characterisation and minimizing subsurface uncertainty (Miall, 2016; Tiab & Donaldson, 2015).

The Niger Delta Basin is one of Africa's most productive hydrocarbon regions, having considerable oil and gas accumulations in paralic and shallow marine depositional systems (Doust and Omatsola, 1990; Uhuo et al., 2022). Reservoirs in the Agbada Formation are mostly made up of intercalated sandstones and shales deposited in fluvio-deltaic circumstances, where depositional processes have a considerable influence on reservoir design and quality (Short & Stauble, 1967). Due to differences in grain size, sorting, shale distribution, sedimentary structures, and post-depositional diagenetic activities, these reservoirs often show significant variability.

To precisely identify reservoir units and assess their storage and flow capacity, such complexity requires thorough sedimentological and petrophysical research (Aigbadon et al., 2022; Nduaguibe et al., 2020). These reservoirs frequently exhibit substantial heterogeneity arising from variations in grain size, sorting, shale distribution, sedimentary structures, and post-depositional diagenetic processes. Such complexities necessitate detailed sedimentological and petrophysical investigations to accurately delineate reservoir units and evaluate their storage and flow capacities (Aigbadon et al., 2022; Nduaguibe et al., 2020).

Wireline logging, which offers continuous real-time measurements of subsurface formations, remains one of the most commonly employed technologies in reservoir investigation. Conventional wireline logs, such as gamma ray, resistivity, density, neutron, and sonic logs, are widely utilized to estimate lithology, shale volume, porosity, permeability, and fluid saturation (Rider & Kennedy, 2011; Tiab & Donaldson, 2015). Gamma-ray logs help differentiate shale from clean sandstone intervals, whereas resistivity logs are critical for detecting hydrocarbon-bearing zones and determining water saturation. Porosity is generally determined using density-neutron combinations, but sonic logs are useful for estimating elastic properties and characterizing geomechanical structures. Although wireline logs provide continuous vertical coverage of formation parameters, their interpretation is frequently indirect, influenced by borehole circumstances, invasion effects, and lithological complexity (Ellis & Singer, 2007).

Core analysis can provide the most accurate direct measurements of reservoir rock parameters and serves as the basis for calibrating and validating petrophysical interpretations based on well logs. Laboratory core measurements yield quantitative data on porosity, permeability, grain density, capillary pressure behavior, fluid saturation, and rock mechanical characteristics (Andersen et al., 2013). Furthermore, core descriptions enable for extensive sedimentological study by identifying lithofacies, sedimentary structures, bioturbation intensity, grain size changes, and diagenetic characteristics (Selley & Sonnenberg, 2015). Core photography under white and ultraviolet illumination enhances facies interpretation and hydrocarbon characterization. Core data improves reservoir model dependability and reduces uncertainty in characterisation studies by providing ground-truth findings (Maíra & Maria, 2017).

The amalgamation of core analysis with wireline logging has therefore become a fundamental procedure in current reservoir investigations. Integrated core-log analysis allows for the discovery of empirical and physics-based correlations between laboratory-measured rock parameters and continuous log responses, allowing reservoir variables to be anticipated beyond cored intervals (Gharavi et al., 2023). This integration increases the accuracy of porosity and permeability estimation, improves lithofacies discrimination, and gives a more reliable assessment of reservoir heterogeneity and continuity. Furthermore, the combined interpretation of core data and wireline logs enables sequence stratigraphic analysis, depositional environment reconstruction, reservoir zonation, and flow unit characterisation (Miall, 2016; Tiab & Donaldson, 2015).

Existing research in the Niger Delta has frequently relied on sedimentological core investigations or petrophysical log analysis separately, which has limited our understanding of reservoir architecture and the distribution of rock properties. The intricate connections between depositional facies, petrophysical characteristics, and reservoir performance may not be sufficiently captured by stand-alone methods. Therefore, to enhance reservoir prediction and maximize hydrocarbon extraction within diverse deltaic systems, combined studies that integrate sedimentological observations with petrophysical and geophysical datasets are required (Obidike & Chiazor, 2023).

This study focuses on the combined use of core analysis and wireline logging to characterize rock attributes in selected reservoirs of the X Field, Niger Delta. The aim of the research is to assess lithofacies distribution, depositional environments, reservoir continuity, and petrophysical parameters using thorough analyses of core samples and well log data. By combining laboratory-derived core measurements with continuous wireline data, the project hopes to create accurate correlations for forecasting reservoir quality and enhancing subsurface characterisation. The findings of this work are likely to improve reservoir evaluation, reduce uncertainty in petrophysical interpretation, and give useful insights for reservoir modeling, well design, and production optimization in the Niger Delta Basin (Aigbadon et al., 2022; Gharavi et al., 2023).

Study Area and Geological Setting

The X Field is located in southern Nigeria's renowned hydrocarbon-rich Niger Delta Basin, between latitudes 4° 19′ 00″ N and 5° 50′ 00″ N, and longitudes 5° 30′ 30″ E and 6° 10′ 00″ E. Fig. 1(a) represent the Niger Delta Basin and the study region (modified from Agbasi et al., 2021), whereas Fig. 1(b) depicts the distribution of wells in the field. The Niger Delta Basin is divided into three primary lithostratigraphic units: the Akata, Agbada, and Benin Formations, which are placed in ascending stratigraphic order (Short and Stauble, 1967). Knox and Omatsola (1989) describe these formations as a complicated clastic wedge deposited in a prograding deltaic environment throughout the Tertiary period. Sedimentation within the basin was strongly influenced by fault-controlled depobelts, which controlled sediment dispersal, accommodation space, and structural development.

The Akata Formation is the basin's oldest lithostratigraphic unit, consisting primarily of dark grey shales and silts, with rare sandy intercalations indicating turbiditic deposition. The formation was formed in shallow marine conditions from the Paleocene to the present, and its thickness is estimated to be over 6400 m in the delta's core region. The Akata Formation is the primary source rock for hydrocarbons in the Niger Delta Basin.

The Agbada Formation, which lies above the Akata Formation, is the basin's primary hydrocarbon-bearing unit. The Agbada Formation is mostly composed of alternating sandstones, siltstones, and shales formed in fluvio-deltaic to shallow marine depositional settings. The formation was deposited between the Eocene and Pleistocene epochs and has an estimated thickness of 3900 m (Doust & Omatsola, 1990). The Agbada Formation's reservoir intervals display high lateral and vertical variety as a result of fast facies fluctuations, shale interbeds, and complicated depositional processes associated with deltaic sedimentation.

The Benin Formation is the Niger Delta Basin's youngest lithostratigraphic formation, consisting primarily of continental to non-marine sands with small shale intercalations. The formation is mostly composed of sands deposited in upper coastal plain and alluvial settings. The Benin Formation, with a thickness of up to 1400 m, is the topmost portion of the clastic wedge and crowns the stratigraphic sequence of the basin. The formation ranges from the Oligocene to recent periods and has good porosity and permeability properties because to its high sand content and freshwater depositional effect (Tuttle et al., 1999).

The Niger Delta Basin formed as a result of tectonic events related to the rifting and subsequent separation of the African and South American continental plates during the Early Cretaceous epoch (Burke 1972). Major regressive periods, which began with the elevation of the Benin and Calabar flanks throughout the Paleocene to Early Eocene, also affected basin evolution.

By the Late Miocene, rapid deltaic progradation had altered the basin's topography from a concave shoreline to a vast concave delta. Sedimentation within the basin was strongly controlled by growth faults and counter-regional faults, which defined the boundaries of the various depobelts and influenced sediment distribution patterns. According to Evamy et al. (1978), a number of these structural characteristics aided the upward and basinward movement of underlying marine shales, resulting in complex deformation patterns that influenced sediment deposition and reservoir architecture. Hydrocarbon buildup in the Niger Delta is mostly related with roll-over anticline structures created by the combination of sediment loading and synsedimentary growth faulting. This tectonic and stratigraphic framework creates favourable circumstances for hydrocarbon formation, movement, trapping, and accumulation in the onshore X field.

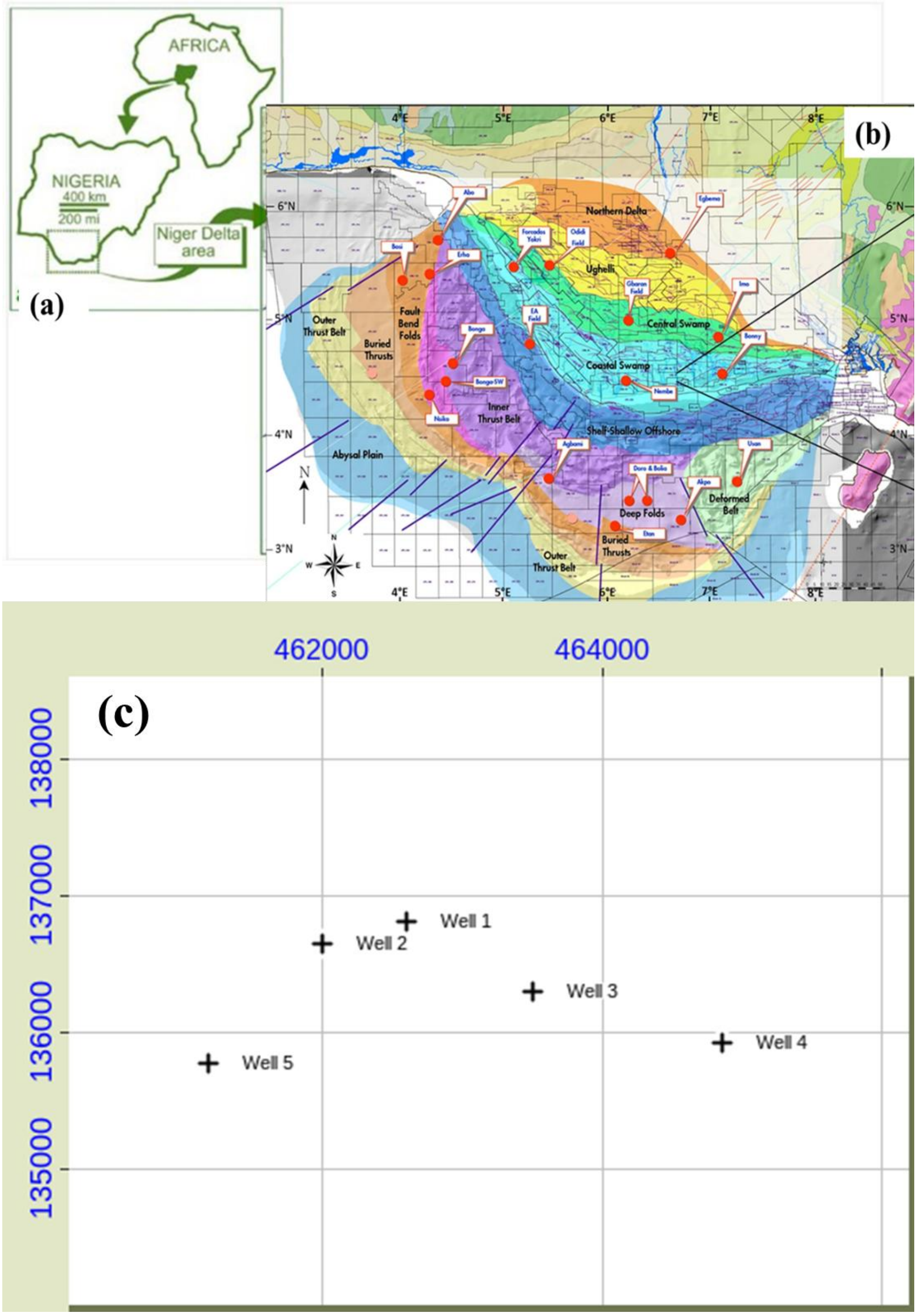

Figure 1 (a) Map of Africa, Nigeria and Niger Delta (b) Map of the Niger Delta and its depositional belts (c) Base Map of showing wells in the Study area (after Adojoh et al., 2017)

Materials and Methods

This study combines wireline well logs and standard core data from X Field in the Niger Delta Basin to determine reservoir parameters and depositional conditions. The data, which included gamma ray, resistivity, density, neutron, sonic, and calliper logs in LAS format, as well as conventional core samples, were received from an International Oil Company (IOC) following regulatory authorisation. The core data gave raw lithological and sedimentological information that may be used to calibrate log-based interpretations and better comprehend subsurface reservoirs.

To minimise noise and enhance clarity, data quality control comprised log editing, despiking, filtering, and unit standardisation. Such preprocessing is required in petrophysical research to provide accurate reservoir parameter estimate from wireline logs (Onuoha et al., 2018; McDonald, 2021).

To define reservoir intervals and demonstrate stratigraphic continuity throughout the field, well-to-well correlation was performed using gamma ray and resistivity logs backed by petrophysical trends (Rider, 1986). Shale volume was estimated using the gamma ray index (Larionov, 1969; Schlumberger, 1974), total porosity was determined using density logs, and water saturation was calculated from five wells using Archie's equation for clean sand formations (Archie, 1942). Reservoir quality, fluid distribution, and hydrocarbon potential were evaluated using these metrics over the designated intervals.

With an emphasis on lithology, grain size, sedimentary structures, bioturbation, and facies features, a thorough sedimentological description at a 1:40 scale was used to perform core analysis. To identify depositional settings and reservoir genetic units, lithofacies were categorised using conventional sedimentological methods and combined with wireline log responses (Miall, 2014; Maju-Oyovwikowhe & Ukpebor, 2019). The workflow combined literature review, data acquisition, log analysis, petrophysical computation, and facies interpretation to achieve a robust integrated reservoir characterization framework applicable to complex paralic settings of the Niger Delta Basin (Doust & Omatsola, 1990; Reijers, 2011).

Results and Discussions

Reservoir Correlation and Stratigraphic Interpretation

Figure 2 illustrates reservoir correlation across five wells (Wells 1-5), revealing a laterally continuous and vertically layered reservoir architecture typical of the paralic Agbada Formation in the Niger Delta Basin (Doust and Omatsola, 1990; Reijers, 2011). The characterised reservoirs (R1-R10) are located within alternating layers of sandstone and shale strata, suggesting multiple cycles of delta progradation, marine flooding, and coastal regression (Stacher, 1995; Tuttle et al., 1999). Variations in reservoir depth, thickness, and continuity reflect a combination of depositional processes and structural deformation, notably syndepositional growth faulting (Doust & Omatsola, 1990; Okiotor et al., 2023).

Reservoir depth gradually increases from Well 4 to Well 5, indicating basinward thickening and differential subsidence within the field. Well 4 has the shallowest reservoirs, whereas Well 5 records the deepest intervals, indicating a structurally downthrown location. Similar depth patterns have been seen in Niger Delta depobelts where growth faults regulate sediment formation (Reijers, 2011; Nton & Adesina, 2022). The more elevated reservoirs (R1-R3) are relatively uniform among wells, while local thickness differences are apparent. Reservoir R1 in Well 4 is much thicker than in surrounding wells, indicating increased sand deposition or channel amalgamation. These shallow reservoirs are thought to be distributary channel and mouth-bar deposits created during vigorous delta progradation (Stacher, 1995; Adegoke et al., 2021). Their very shallow burial depths may have helped to preserve basic porosity and permeability.

The intermediate reservoir units (R4-R7) exhibit significant thickness variations, particularly in Well 4, where R4, R6, and R7 are much thicker than corresponding intervals in other wells. The pattern supports confined depocenters connected with syndepositional growth faults, which offered more accommodation area for sediment accumulation (Doust & Omatsola, 1990; Okiotor et al., 2023). These reservoirs are thought to be stacked channelised and shoreface sands accumulated during shifting deltaic conditions. Intervening shale intervals most likely serve as vertical seals, improving reservoir compartmentalisation and hydrocarbon trapping effectiveness.

Deeper reservoirs (R8-R10) have increased thickness and enhanced vertical development across the field. Reservoir R10 is particularly widespread and thick in Wells 2 and 5, indicating deposition in a significant fluvial or delta-front channel system with consistent sediment supply (Tuttle et al., 1999; Eyinla et al., 2024). Although deeper burial in Well 5 may have resulted in compaction and diagenetic change, the significant sand formation may support favourable net-to-gross ratios and hydrocarbon storage capability.

The reservoir architecture and depth distribution of Wells 1-3 are similar, indicating strong lateral continuity and deposition within the same sedimentary fairway. Localised channel migration, differential compaction, and minute structural changes during sedimentation may all be reflected in small thickness differences (Reijers, 2011). The reservoir succession is an example of a conventional stacked deltaic reservoir system found in the Niger Delta petroleum province's Agbada Formation. Sandstones make up reservoir intervals, whereas marine shales serve as efficient seals and potential source rocks. These alternating sandstone and shale strata are indicative of cyclic transgressive-regressive depositional processes (Doust & Omatsola, 1990; Tuttle et al., 1999).

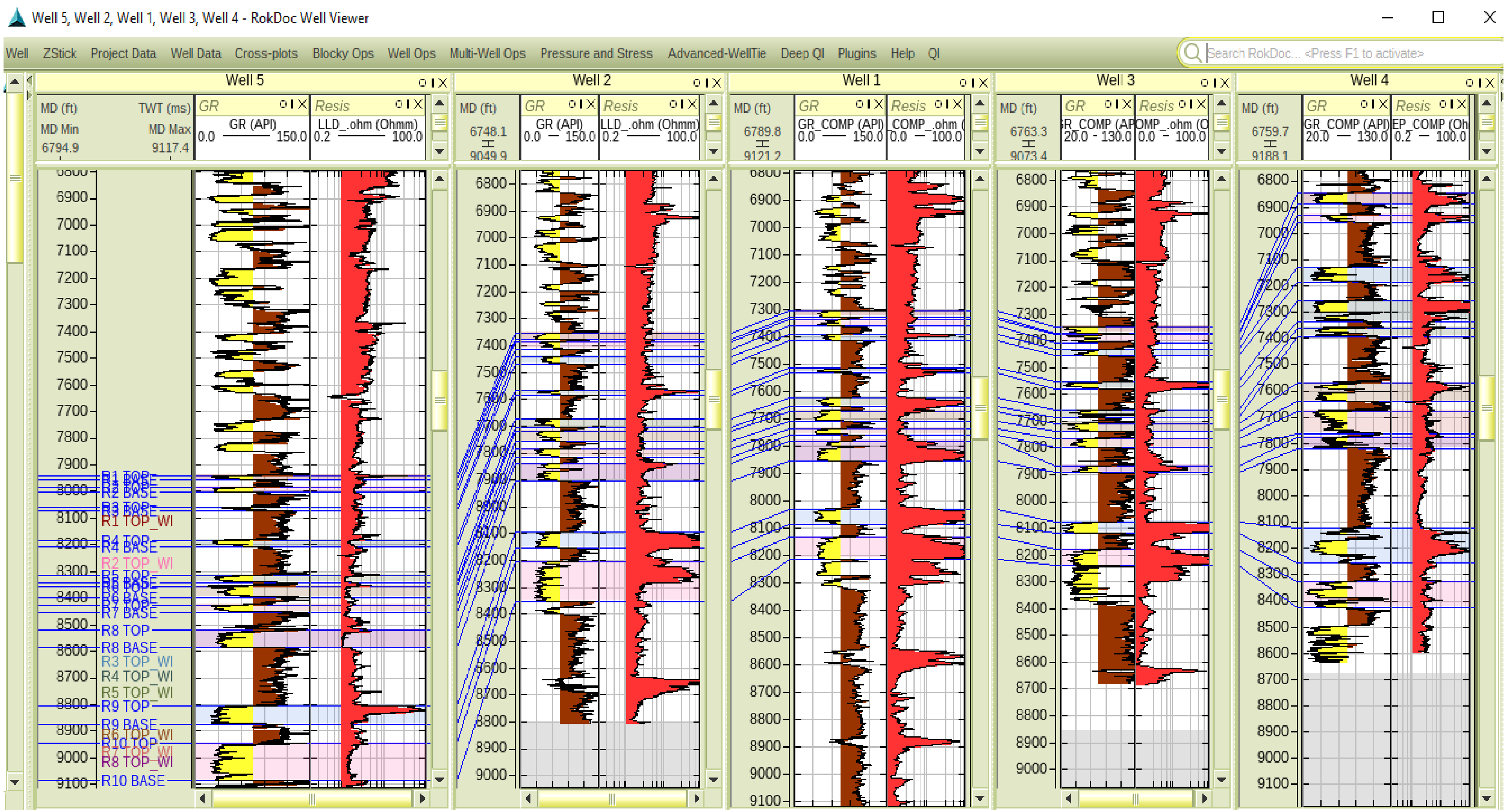

Figure 2: Well section window showing the correlation panel sand bodies across the wells

Petrophysical Evaluation

Significant vertical and lateral variation in reservoir quality within the field is revealed by the petrophysical assessment of the indicated reservoir intervals throughout the five wells (Table 1). The wireline log responses shown in Figures 3–7 show alternating successions of shaly and clean sandstone units, which are typical of the Niger Delta Basin's paralic depositional processes. Variations in depositional energy, grain sorting, clay distribution, and post-depositional diagenetic processes that affect reservoir performance and hydrocarbon production are reflected in variations in porosity, shale volume, and water saturation (Aigbedion and Iyayi, 2022; Nton and Adesina, 2021). The reservoirs have moderate-to-excellent petrophysical characteristics overall, indicating significant hydrocarbon potential across a number of periods.

Well 1 (Figure 3) possesses generally favourable reservoir characteristics, most notably in reservoirs R1, R2, R5, and R6, which are distinguished by very high porosity (0.261-0.278), low shale volume, and low water saturation. Reservoir R5 is the most prospective interval, with a porosity of 0.278 and a water saturation of just 0.070, suggesting good pore connection and high hydrocarbon saturation. Reservoirs R4 and R8 have poor reservoir quality due to increased shale volume and reduced porosity, indicating a strong clay effect and restricted permeability. These alternating clean and shaly periods most likely represent changes in depositional energy during sediment buildup in distributary channels and deltaic environments (Obaje et al., 2023; Emujakporue and Ekine, 2020).

Well 2 (Figure 4) has reasonably steady and laterally continuous reservoir quality when compared to the other wells. Reservoirs R3, R4, R6, and R7 have consistently high porosity but low water saturation, indicating well-developed sandstone reservoirs with favourable hydrocarbon saturation. The relatively homogeneous petrophysical parameters discovered in this well might imply stable depositional circumstances with negligible diagenetic change. However, reservoir R9 has a relatively large shale volume, which may drastically reduce permeability despite the presence of moderate porosity. Similar findings have been reported in Niger Delta reservoirs, where clay mineral distribution has a significant impact on reservoir effectiveness and fluid transmissibility (Ehirim and Nwankwo, 2021; Oyeyemi et al., 2024).

Well 3 (Figure 5) has some of the most promising reservoirs in the study region. With very high porosity (0.321), very low water saturation (0.018), and relatively low shale content, Reservoir R4 has remarkable reservoir quality, indicating a clean and highly hydrocarbon-saturated sandstone body. Additionally, reservoirs R2, R3, and R9 have excellent reservoir characteristics, including modest shale content and strong pore preservation. On the other hand, shale intercalations that decrease effective pore space and fluid flow capacity predominate in intervals like R1, R5, and R10. These petrophysical patterns point to alternating depositional regimes, which are typical of deltaic reservoir systems and are marked by recurring shifts between low-energy shale accumulation and high-energy sandstone deposition (Akinlua et al., 2022; Oloruntobi and Adeyemi, 2023). There is significant reservoir variability in Wells 4 and 5 (Figures 6 and 7). In Well 4, reservoirs R3 and R4 display excellent reservoir quality with high porosity and low water saturation, whereas R1 represents the poorest interval due to extremely high shale volume and water saturation.

Similarly, well 5 has generally poor shallow reservoir quality, but deeper intervals, notably R9, have improved petrophysical features, including high porosity and significant hydrocarbon saturation. The observed downward improvement in reservoir quality is most likely due to a gradual shift to cleaner sandstone facies before resuming shale enrichment at higher depths. Overall, the integrated petrophysical analysis confirms that reservoir quality in the field is primarily determined by shale distribution, depositional facies variability, and diagenetic modification, which is consistent with previous research on Niger Delta hydrocarbon reservoirs (Short and Stauble, 1967; Reijers, 2011; Adebayo et al., 2024).

Table 1 : Estimated petrophysical characteristics from the reservoir intervals.

Wells	Formation	Top (ft)	Bottom (ft)	Gross Thickness (ft)	Avg. Water Saturation (Sw)	Avg. Porosity (POR)	Avg. Vshale
Well 1	R1	7304.223	7325.679	21.46	0.192	0.267	0.193
Well 1	R2	7335.977	7358.291	22.31	0.193	0.262	0.277
Well 1	R3	7390.044	7413.645	23.60	0.260	0.225	0.644
Well 1	R4	7514.467	7529.128	14.66	0.338	0.176	0.767
Well 1	R5	7620.547	7652.458	31.91	0.070	0.278	0.158
Well 1	R6	7670.569	7706.792	36.22	0.169	0.261	0.181
Well 1	R7	7734.390	7755.951	21.56	0.324	0.202	0.562
Well 1	R8	7780.099	7853.407	73.31	0.344	0.182	0.661
Well 1	R9	8028.475	8086.179	57.70	0.138	0.250	0.481
Well 1	R10	8132.625	8210.923	78.30	0.094	0.252	0.439
Well 2	R1	7352.652	7378.378	25.73	0.190	0.262	0.179
Well 2	R2	7385.542	7413.222	27.68	0.185	0.256	0.389
Well 2	R3	7439.937	7468.095	28.16	0.179	0.284	0.281
Well 2	R4	7567.985	7584.256	16.27	0.096	0.277	0.431
Well 2	R5	7674.653	7705.388	30.73	0.217	0.251	0.484
Well 2	R6	7718.043	7757.215	39.17	0.233	0.275	0.256
Well 2	R7	7784.334	7815.069	30.74	0.241	0.274	0.274
Well 2	R8	7840.255	7902.378	62.12	0.226	0.259	0.377
Well 2	R9	8093.679	8151.892	58.21	0.179	0.260	0.739
Well 2	R10	8204.714	8350.245	145.53	0.161	0.260	0.438
Well 3	R1	7346.042	7369.737	23.69	0.291	0.225	0.688
Well 3	R2	7377.276	7406.356	29.08	0.217	0.276	0.371
Well 3	R3	7433.282	7455.959	22.68	0.210	0.282	0.362
Well 3	R4	7554.048	7578.570	24.52	0.018	0.321	0.055
Well 3	R5	7660.175	7687.460	27.28	0.280	0.236	0.571
Well 3	R6	7707.565	7738.549	30.98	0.269	0.242	0.453
Well 3	R7	7765.407	7799.271	33.86	0.262	0.254	0.543
Well 3	R8	7867.324	7891.522	24.20	0.185	0.260	0.421
Well 3	R9	8076.023	8116.894	40.87	0.098	0.286	0.257
Well 3	R10	8179.993	8239.257	59.26	0.149	0.230	0.719
Well 4	R1	6849.136	6889.136	40.00	0.894	0.076	0.855
Well 4	R2	6929.168	6958.028	28.86	0.139	0.236	0.153
Well 4	R3	7129.325	7186.114	56.79	0.088	0.306	0.119
Well 4	R4	7257.213	7335.502	78.29	0.072	0.308	0.215
Well 4	R5	7359.246	7392.616	33.37	0.205	0.237	0.564
Well 4	R6	7569.730	7640.961	71.23	0.139	0.268	0.551
Well 4	R7	7676.256	7760.963	84.71	0.201	0.229	0.673
Well 4	R8	7776.364	7819.359	43.00	0.295	0.179	0.822
Well 4	R9	8124.176	8256.371	132.19	0.177	0.199	0.516
Well 4	R10	8327.381	8425.333	97.95	0.278	0.184	0.535
Well 5	R1	7941.397	7956.408	15.01	0.456	0.103	0.854
Well 5	R2	7983.366	8004.198	20.83	0.310	0.152	0.804
Well 5	R3	8059.034	8071.900	12.87	0.205	0.199	0.718
Well 5	R4	8183.706	8208.558	24.85	0.160	0.234	0.463
Well 5	R5	8313.103	8343.096	29.99	0.180	0.219	0.538
Well 5	R6	8356.807	8397.083	40.28	0.267	0.178	0.666
Well 5	R7	8426.218	8454.664	28.45	0.183	0.218	0.619
Well 5	R8	8522.468	8587.665	65.20	0.228	0.199	0.768
Well 5	R9	8802.929	8872.998	70.07	0.120	0.293	0.374
Well 5	R10	8946.755	9085.200	138.45	0.224	0.228	0.699

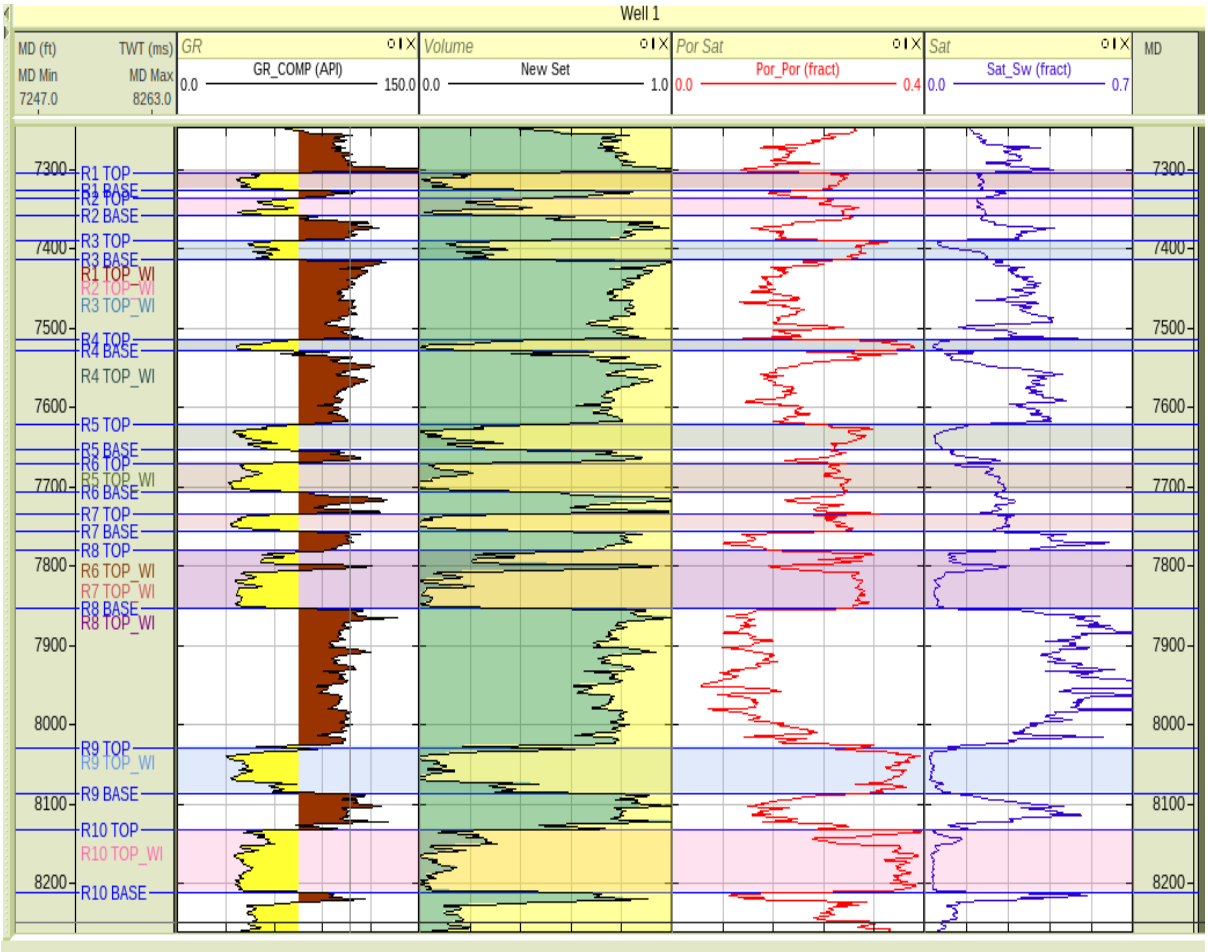

Figure 3: Display of Well 1 Curves for Reservoirs R1 to R10

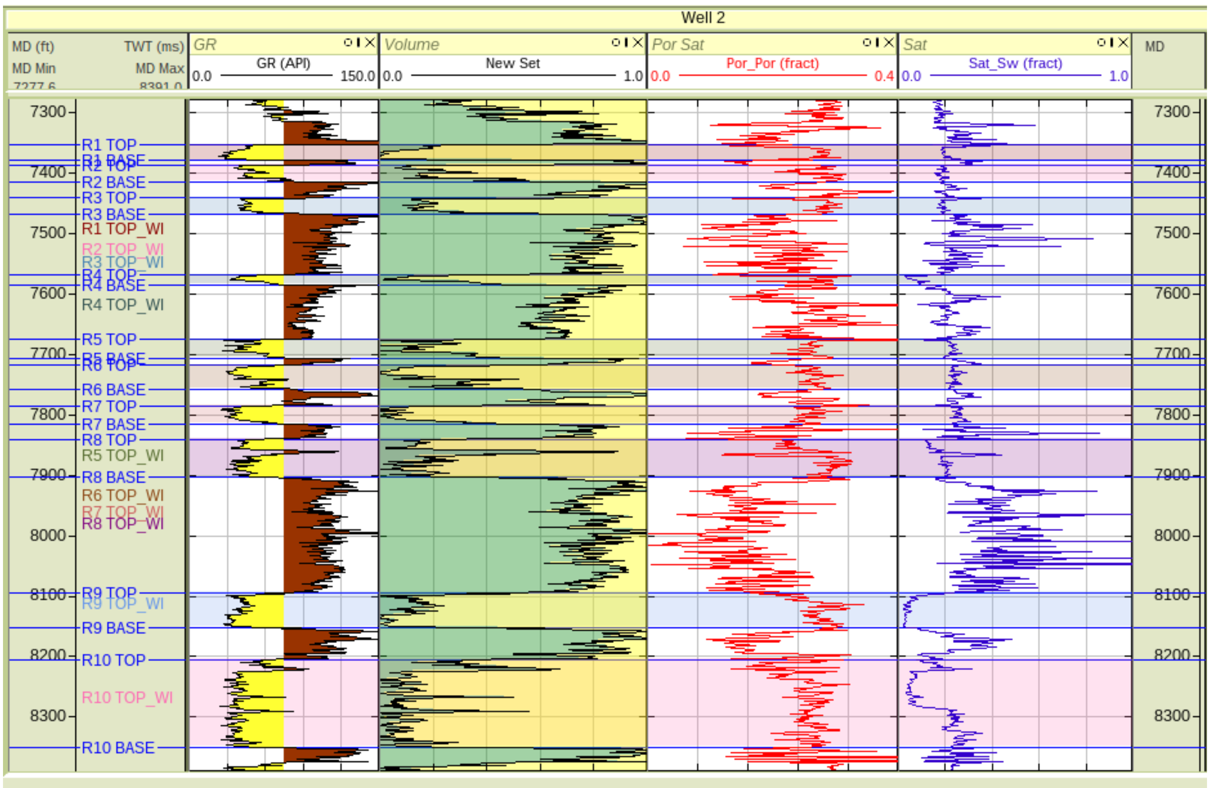

Figure 4: Display of Well 2 Curves for Reservoirs R1 to R10

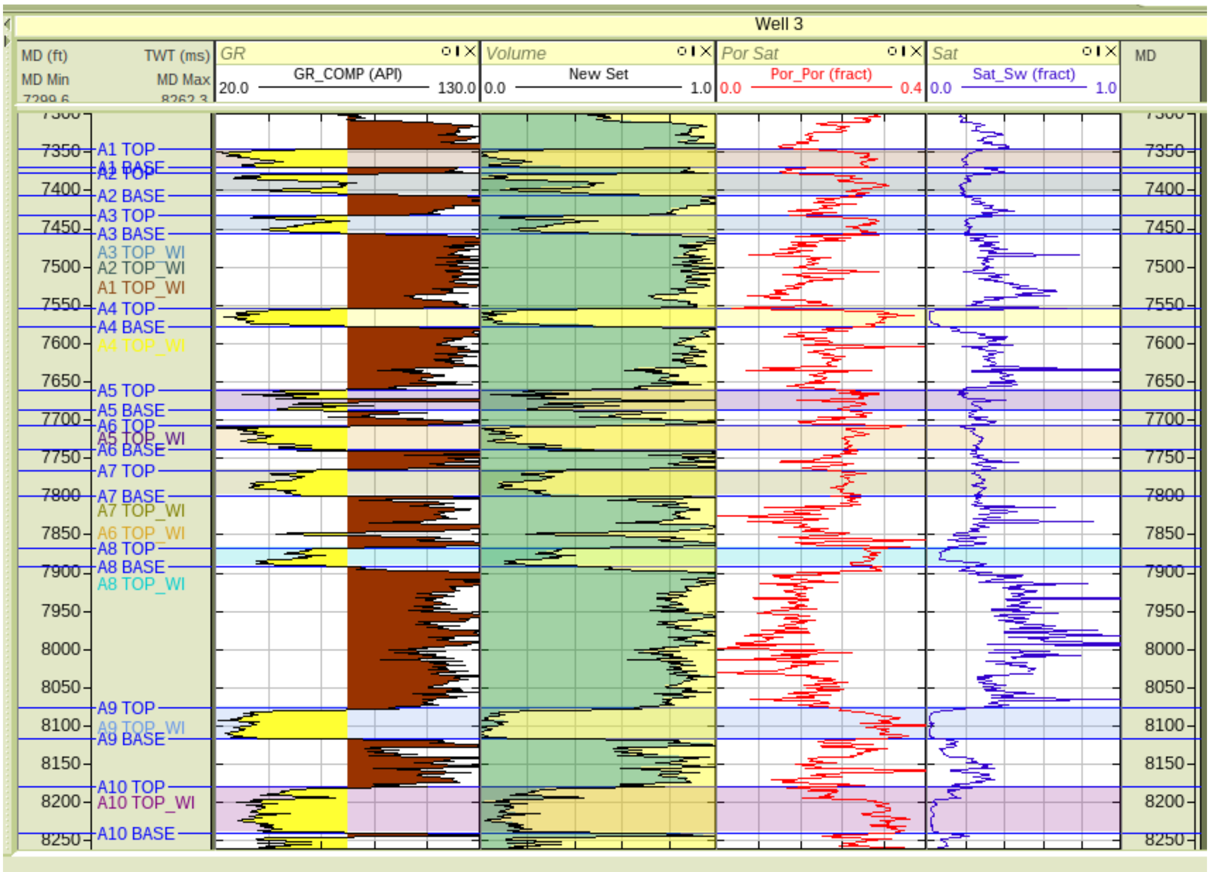

Figure 5: Display of Well 3 Curves for Reservoirs R1 to R10

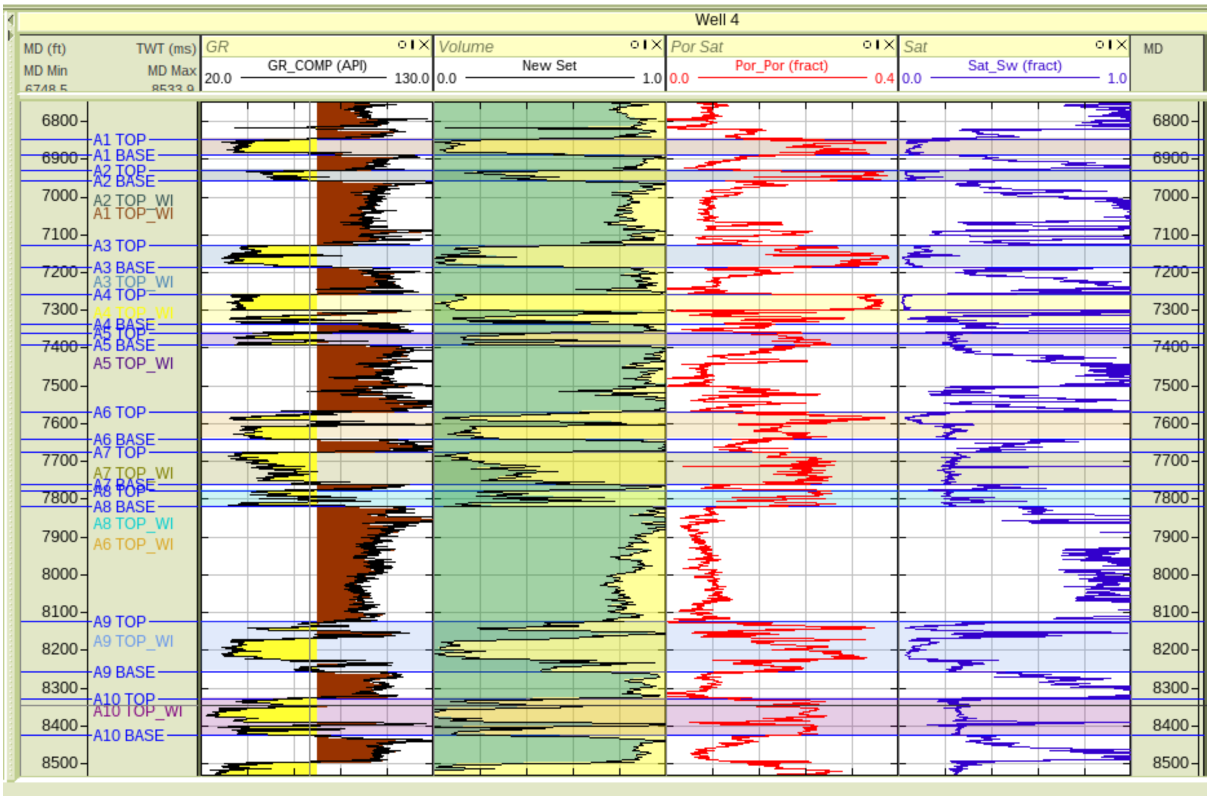

Figure 6: Display of Well 4 Curves for Reservoirs R1 to R10

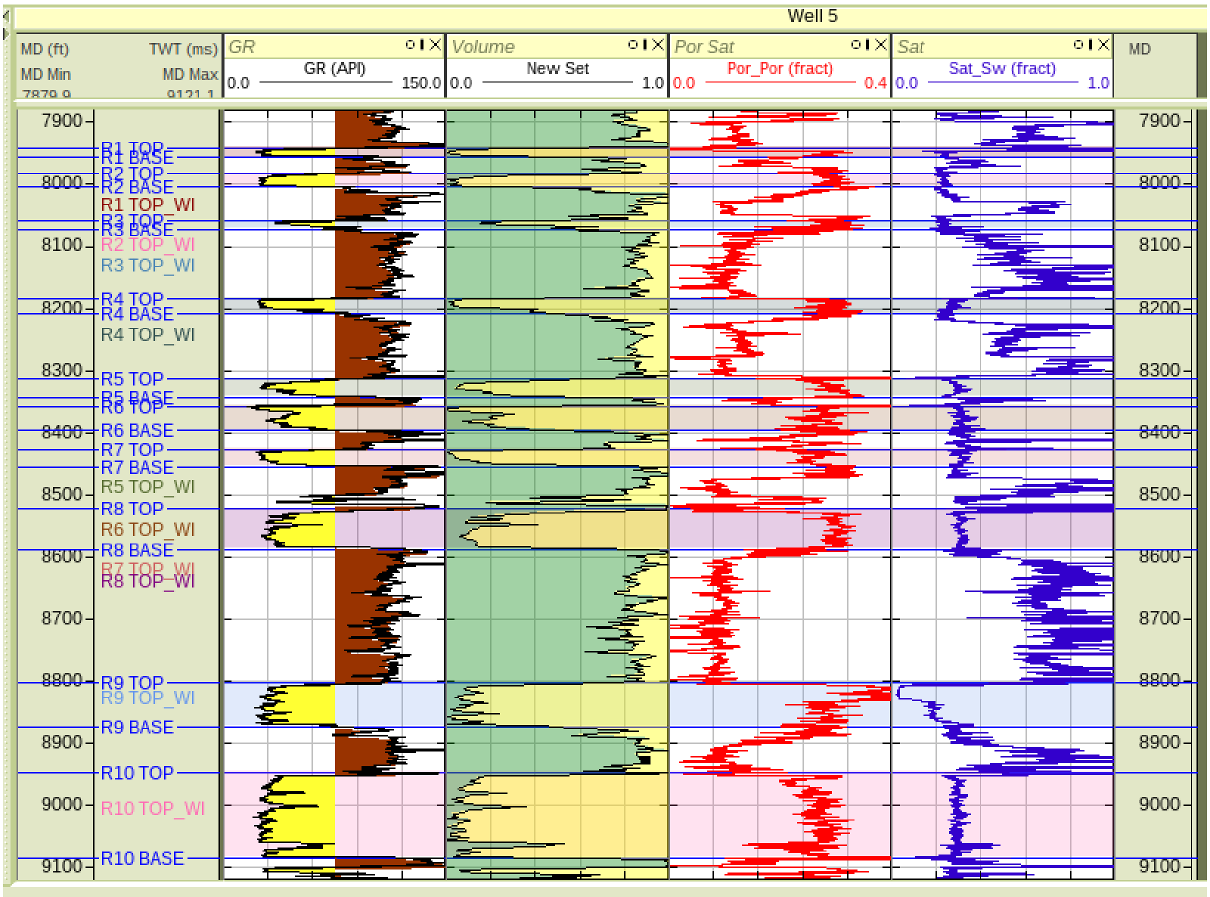

Figure 7: Display of Well 5 Curves for Reservoirs R1 to R10

Facies Analysis, Description and Distribution

The facies architecture revealed by core descriptions in Wells 1 and 2 shows a vertically layered deltaic succession that ranges from continental swamp deposits to shallow-marine and prodelta settings. Tables 2 and 3 summarise the facies distribution and sedimentological properties, while Figures 8 and 9 show typical core images of the discovered lithofacies. The integrated facies study shows deposition in a wave-, storm-, and tide-influenced deltaic environment with high lateral and vertical heterogeneity, as is characteristic of the Niger Delta Basin's paralic successions (Doust & Omatsola, 1990; Reijers, 2011).

The dominant facies in Well 1 consist of laminated shale to silty shale (F1), lenticular-bedded shale and siltstone (F2), extremely bioturbated sandstone (F5), tidal sandstone with mud-like coverings (F7), bioturbated shale and siltstone (F13), coal to coaly shale (F14), and massive shale with root traces (F15) (Table 2; Figure 8a-g). Facies F1, F2, and F13 are considered as prodelta to offshore deposits generated under low-energy marine conditions characterised by suspension settling and periodic storm reworking (Walker & James, 1992; Nichols, 2009). These facies are distinguished by high clay concentration, extensive bioturbation, and retained lamination, resulting in poor reservoir quality and a high sealing capacity. Facies F5 and F7, on the other hand, are tidally influenced lower shoreface to distributary-channel deposits that exhibit flaser bedding, mud drapes, sandy lithologies, and widespread biogenic reworking. These features suggest varying hydrodynamic conditions in tide-dominated environments (Dalrymple, 1992; Boggs, 2014). The presence of Facies F14 and F15 further illustrates floodplain and upper delta-plain swamp conditions linked to pedogenesis, peat buildup, and subaerial exposure—all of which are typical in deltaic floodplain habitats (Allen, 1965; Selley, 1998).

Wavy-bedded shale to very fine-grained sandstone (F3), siltstone to fine-grained sandstone (F4), laminated shale to silty shale (F1), and laminated very fine-grained sandstone (F8) make up the majority of the facies assemblage in Well 2 (Table 3; Figure 9a–d). These facies show deposition in distributary mouth-bar, lower shoreface, and delta-front habitats affected by storms.

Facies F3 and F4 are characterized by wave ripples, undulatory cross-stratification, and sporadic bioturbation, pointing to fluctuations between low- and high-energy sedimentary conditions linked to storm-wave reworking (Reading & Collinson, 1996; Boggs, 2014). Facies F8 show steady upper delta-front to shoreface conditions with consistent sediment supply and layered sandy deposition. These sandy facies have better reservoir qualities than shale-dominated facies because of decreased clay concentration and increased pore connectivity (Slatt, 2006).

The vertical facies stacking pattern seen in both wells indicates a clear proximal-to-distal depositional transition from upper delta-plain swamp habitats to tidally impacted distributary systems to shallow-marine delta-front and offshore prodelta settings. This depositional development is characterised by periodic coastline movement and changes in accommodation space within the Niger Delta paralic succession (Stacher, 1995; Reijers, 2011).

Integrated petrophysical and facies characterisation reveals that reservoir quality is heavily influenced by depositional environment and lithofacies distribution. Sandstone-bearing facies associated with tidal channels, distributary mouth bars, and delta-front settings have moderate to good reservoir quality, as evidenced by relatively high porosity and low shale concentration (Weber and Daukoru, 1975). Conversely, shale-rich facies deposited in prodelta, offshore, and delta-plain swamp environments have poor reservoir characteristics due to high clay concentration and compaction. As a result, the most promising hydrocarbon-bearing intervals are associated with cleaner sandstone facies such as F4, F5, F7, and F8, whereas Facies F1, F2, F13, F14, and F15 primarily serve as seals, barriers, or non-reservoir intervals within the stratigraphic framework (Evamy et al., 1978; Selley, 1998).

Table 2: Facies Distribution and Core Description for Well 1 (Base to Top)

Well	Interval (m)	Facies Code	Facies Name	Description
Well 1	**2386.0–2386.6**	F1	Laminated Shale to Silty Shale	Light grey, very fine-grained laminated shale deposited under quiet, low-energy suspension fallout conditions (prodelta/offshore).
Well 1	**2295.4–2296.0**	F13	Bioturbated Shale and Siltstone	Intensely bioturbated black shale and siltstone, reflecting prolonged sedimentary stasis in a low-energy offshore to prodelta environment.
Well 1	**2157.0–2157.6**	F14	Coal to Coaly Shale	Very dark to black, organic-rich shale indicating swampy to marshy delta-plain conditions.
Well 1	**2133.2–2133.85**	F7	Tidal Sandstone with Mud Drapes	Very fine- to fine-grained sandstone with alternating sand–mud couplets, thin mud drapes, wavy/flaser bedding, and current ripples, indicative of persistent tidal influence.
Well 1	**2113.35–2114.0**	F15	Massive Shale with Root Traces	Massive, fine-grained shale with vertical root traces, reflecting pedogenic overprint and subaerial exposure on the delta plain.
Well 1	**2111.2–2111.85**	F5	Intensely Bioturbated Sandstone	Fine- to very fine-grained sandstone with pervasive bioturbation, deposited in a reworked lower shoreface to tidal-flat setting.
Well 1	**2103.4–2103.85**	F2	Lenticular-Bedded Shale and Siltstone	Lenticular shale–siltstone with wave ripples and episodic storm influence in a prodelta setting.

Table 3: Facies Distribution and Core Description for Well 2 (Base to Top)

Well	Interval (m)	Facies Code	Facies Name	Description
Well 2	**2412.25–2412.8**	F3	Wavy-Bedded Shale to Very Fine-Grained Sandstone	Wavy-bedded shale and very fine sand with wave ripples and local HCS, deposited under storm-influenced delta-front conditions.
Well 2	**2411.25–2411.9**	F4	Siltstone to Fine-Grained Sandstone	Siltstone to fine-grained sandstone with swaley/hummocky cross-stratification and local bioturbation, indicating higher-energy storm deposition.
Well 2	**2404.35–2405.0**	F1	Laminated Shale to Silty Shale	Laminated black, dark grey, green or purplish-red shale to silty shale, locally containing diagenetic siderite nodules or beds, organic matter, and millimetric plant debris. This facies is very tight and exhibits no reservoir potential.
Well 2	**2084.0–2084.5**	F8	Laminated Very Fine-Grained Sandstone	Laminated very fine-grained sandstone representing upper delta-front to shoreface or distributary mouth-bar conditions.

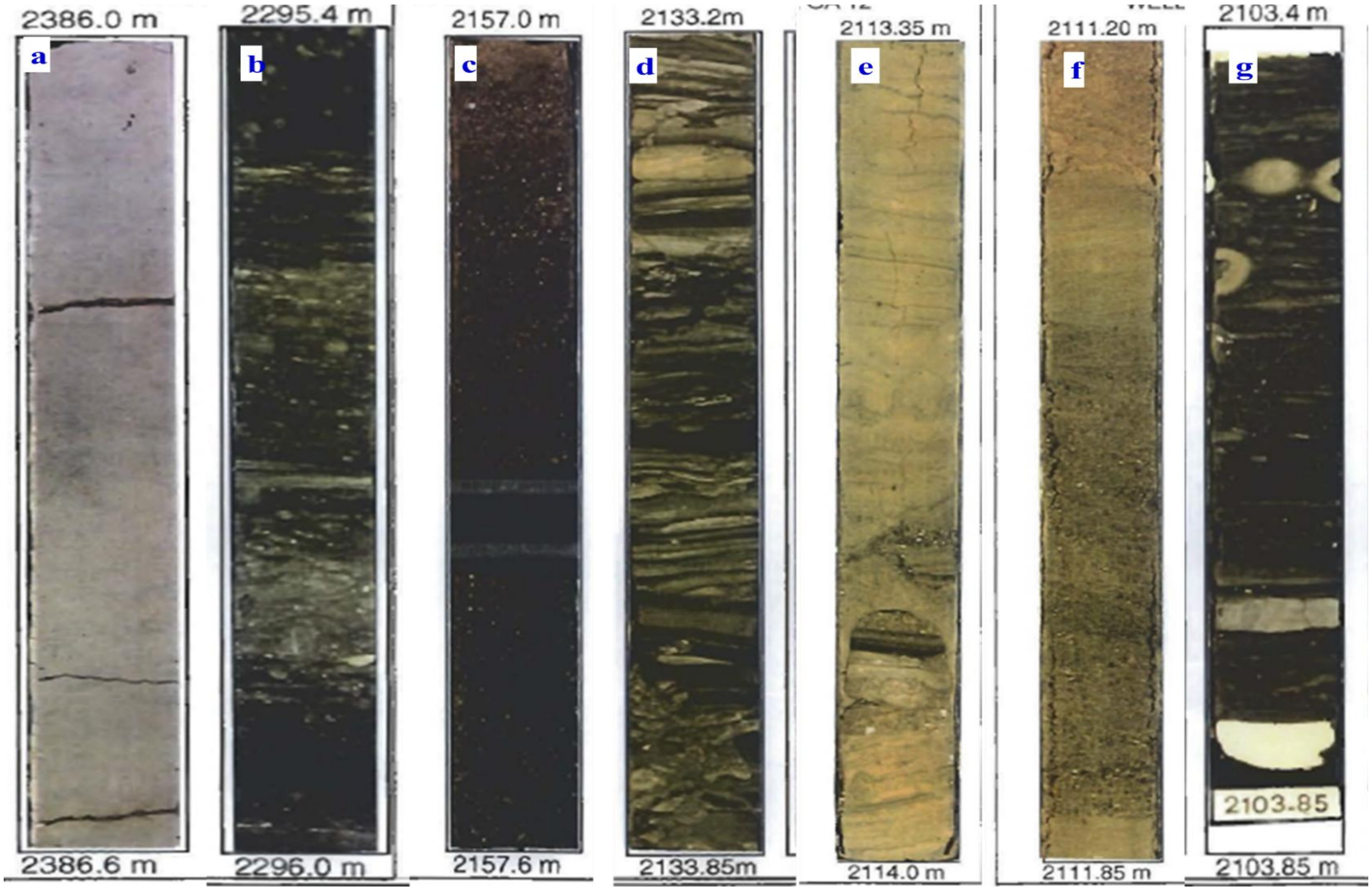

Figure 8. Core photograph showing identified lithologic units and lithofacies in Well 1. (a) Laminated Shale to Silty Shale (F1); (b) Bioturbated Shale and Siltstone (F13); (c) Coal to Coaly Shale (F14); (d) Tidal Sandstone with Mud Drapes (F7); (e) Massive Shale with Root Traces (F15); (f) Intensely Bioturbated Sandstone (F5); (g) Lenticular-Bedded Shale and Siltstone (F2)..

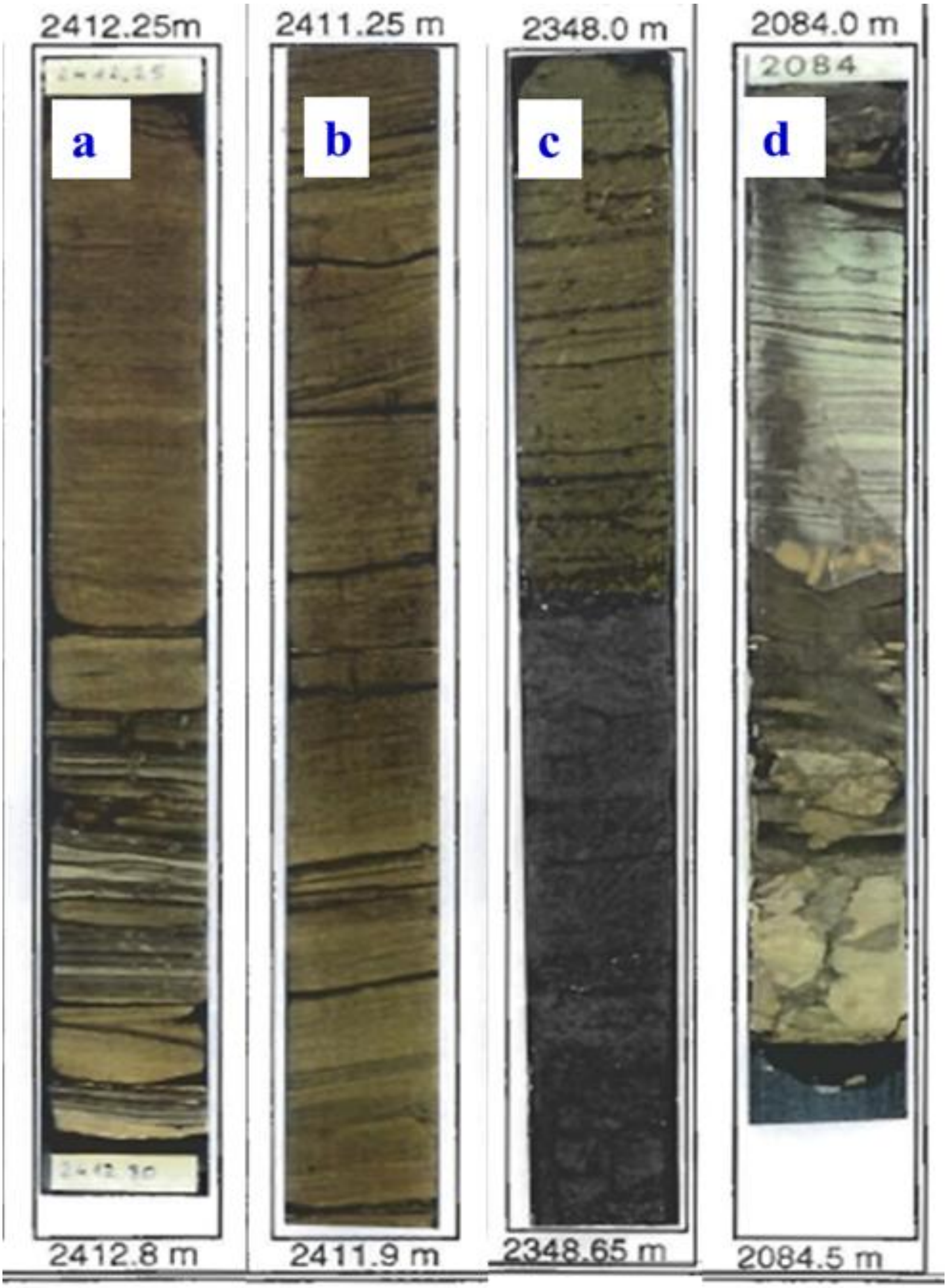

Figure 9: Core photograph of identified lithologic units and lithofacies in Well 2. (a) Wavy-Bedded Shale to Very Fine-Grained Sandstone (F3); (b) Siltstone to Fine-Grained Sandstone (F4); (c) Laminated Shale to Silty Shale (F1); (d) Laminated Very Fine-Grained Sandstone (F8).

Conclusion

This study confirmed the efficacy of integrating conventional core analysis with wireline log interpretation for reservoir characterisation in the X Field, Niger Delta Basin. The combined disciplinary method enhanced our knowledge of reservoir distribution, heterogeneity, and depositional controls over the study periods. A total of ten reservoir units (R1-R10) were discovered, with considerable differences in shale volume, porosity, and water saturation, indicating high lateral and vertical heterogeneity in the field. Facies research indicated that the reservoirs were deposited in a complex paralic system that ranged from offshore-prodelta to delta-plain settings. Reservoir quality is largely determined by depositional energy and facies type, with cleaner sandstone facies (tidal channels, distributary mouth bars, and shoreface deposits) exhibiting the highest reservoir qualities, whereas shale-rich and bioturbated facies function as seals or non-reservoirs. Thus, the study demonstrates that combined core and log analysis greatly lowers subsurface uncertainty and offers a more dependable framework for field development planning, hydrocarbon forecast, and reservoir appraisal in the Niger Delta Basin.

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