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Characterization of Depositional Environments and Hydrocarbon Potential in the AI Well Niger Delta Basin

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Abstract
Reservoir characterization is essential for understanding subsurface geology, supporting hydrocarbon exploration, and improving production strategies. This study investigates the AI Well within the Agbada Formation of the Niger Delta Basin through an integrated sedimentological, petrographic, and geochemical approach. A total of 100 ditch cutting samples were analyzed to evaluate lithofacies, mineralogical composition, and geochemical variations. The results indicate a depositional transition from high-energy fluvial to low-energy marine environments, with quartz-rich sandstones serving as primary reservoir units and clay-rich shales acting as effective seals. Petrographic and X-ray diffraction (XRD) analyses show that quartz is the dominant framework mineral, whereas kaolinite and chlorite are associated with reduced porosity and permeability. X-ray fluorescence (XRF) results reveal silica enrichment and ferruginization, indicating post-depositional diagenetic alterations that influence reservoir quality. The findings emphasize that both depositional facies and diagenetic processes play vital roles in controlling reservoir performance. This study underscores the significance of multidisciplinary integration in refining reservoir models and optimizing hydrocarbon recovery in the Niger Delta Basin.

Keywords
Agbada Formation, depositional environment, reservoir quality, petrography, Niger Delta Basin

1. Introduction

The study of sedimentary formations and their depositional environments remain a cornerstone of petroleum geoscience, forming the basis for hydrocarbon exploration, reservoir evaluation, and production optimization (Short and Stauble, 1967; Reijers, 2011; Fathy et al., 2023; Lee et al., 2025).

Effective reservoir characterization relies on the integration of sedimentological, petrographic, and geochemical data to interpret lithological heterogeneity, diagenetic pathways, and their effects on porosity and fluid flow (Weber and Daukoru, 1975; Boggs, 2009).

Early work in the Niger Delta emphasized the influence of depositional facies and lithofacies distribution on reservoir architecture (Short and Stauble, 1967), while subsequent studies utilized well-log interpretation to delineate reservoir zones (Asquith and Krygowski, 2004). Recent advances have focused on shale gas potential (Inyang et al., 2022), diagenetic influences on reservoir quality (Onyekuru et al., 2023), and depositional models for deep offshore settings (Olayiwola and Bamford, 2019). Despite these advances, uncertainties remain regarding how depositional transitions and post-depositional modifications interact to control reservoir effectiveness.

Multidisciplinary investigations in other regions have demonstrated that integrating sedimentological and geochemical datasets can unravel the interplay between facies changes, mineralogy, and reservoir behavior. For example, Fathy et al. (2023) used geochemical proxies to characterize Paleozoic source rocks in the Siwa Basin, Egypt, while Lee et al. (2025) showed that diagenetic processes in a syn-rift sequence in the Gulf of Suez play a crucial role in shaping reservoir quality. These findings underscore the need for similar integrated studies in the Niger Delta to improve reservoir predictability.

This study applies an integrated sedimentological, petrographic, and geochemical approach to investigate the AI Well located within the Agbada Formation of the Niger Delta Basin. The Agbada Formation is a prolific hydrocarbon-bearing unit with complex facies and diagenetic histories.

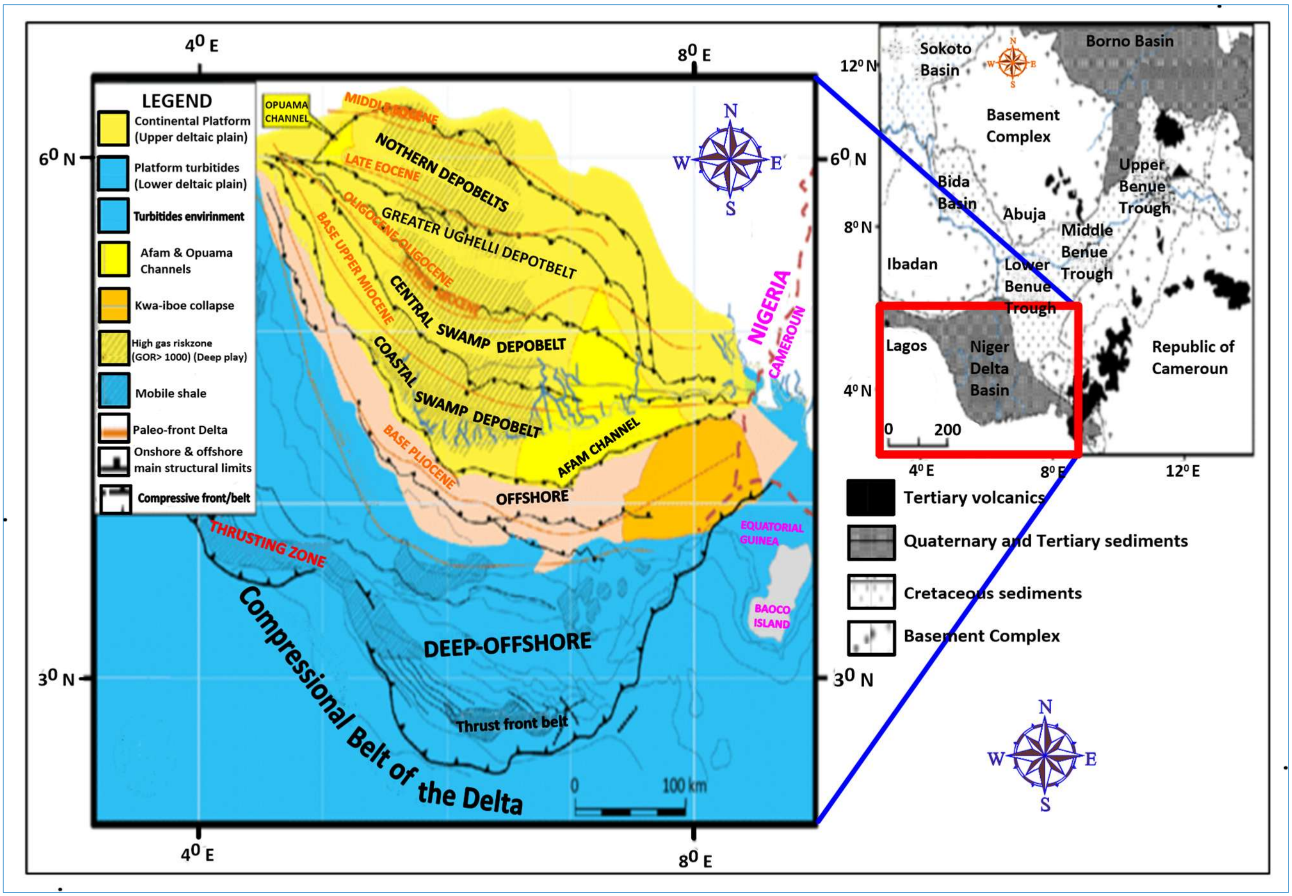

Fig. 1. Location of the AI well within the Coastal Swamp Depobelt of the Niger Delta Basin. Major depobelts and structural elements are indicated. Inset map shows tectonic setting of the Niger Delta relative to surrounding basins (modified after Doust and Omatsola, 1990)

By analyzing lithofacies, mineralogical composition, and geochemical signatures, this study seeks to enhance understanding of the depositional environments and post-depositional alterations that control reservoir performance in this section of the basin.

1.1. Background and Justification

The Niger Delta Basin, located along the Gulf of Guinea in West Africa, is among the world's most prolific hydrocarbon provinces and forms the backbone of Nigeria's oil and gas industry (Short and Stauble, 1967; Weber and Daukoru, 1975). The basin's structural and stratigraphic complexity, shaped by tectonic and depositional processes, has produced a diverse petroleum system with significant exploration and production potential (Reijers, 2011; Doust and Omatsola, 1990).

Previous studies have examined reservoir behavior, depositional models, and wellbore stability, particularly in offshore and deep formations (Onyekuru et al., 2023; Okoli et al., 2021). Facies-based reservoir studies in the Greater Ughelli Depobelt have demonstrated the value of core-derived interpretations in identifying depositional controls on reservoir quality (Maju-Oyovwikowhe and Lucas, 2019). With a surface area exceeding 75,000 km² and sedimentary fill greater than 12 km in thickness, the Niger Delta offers a wide range of reservoir types. Its lithostratigraphy, especially within the Agbada Formation, consists of interbedded sandstones and shales deposited in fluvial to shallow marine environments (Reijers, 2011; Weber and Daukoru, 1975).

The Agbada Formation serves as the primary reservoir unit, and its offshore extensions continue to attract interest due to their deepwater potential (Olayiwola and Bamford, 2019). While the sandstone-rich intervals generally exhibit good porosity and permeability, post-depositional diagenetic processes such as compaction and cementation can significantly reduce reservoir quality (Okoli et al., 2021; Overare et al., 2024; Overare et al., 2024). Studies on shale gas potential have also highlighted the influence of mineralogical composition and diagenetic alteration on reservoir performance (Inyang et al., 2022).

Despite decades of research, several uncertainties persist, including limited understanding of lateral facies heterogeneity, inconsistent correlations between mineralogy and permeability, and inadequate quantification of diagenetic impacts on hydrocarbon trapping. Previous authors have also noted spatial variations in reservoir quality and the difficulty of predicting these variations from well logs alone (Reijers, 2011; Onyekuru et al., 2023; Agbasi et al., 2020).

Traditional reservoir assessments in the Niger Delta have relied heavily on well-log and seismic interpretation (Asquith and Krygowski, 2004); however, these methods lack the mineralogical resolution needed to capture fine-scale heterogeneity. Recent research emphasizes the benefits of integrating X-ray diffraction (XRD), X-ray fluorescence (XRF), and petrographic analyses for more robust reservoir evaluation (Fathy et al., 2023; Lee et al., 2025).

To address these gaps, this study employs an integrated analytical approach using samples from the AI Well in the onshore portion of the Agbada Formation. By combining sedimentological, petrographic, and geochemical datasets, the study aims to improve predictive models of reservoir quality and support enhanced exploration strategies in the Niger Delta Basin.

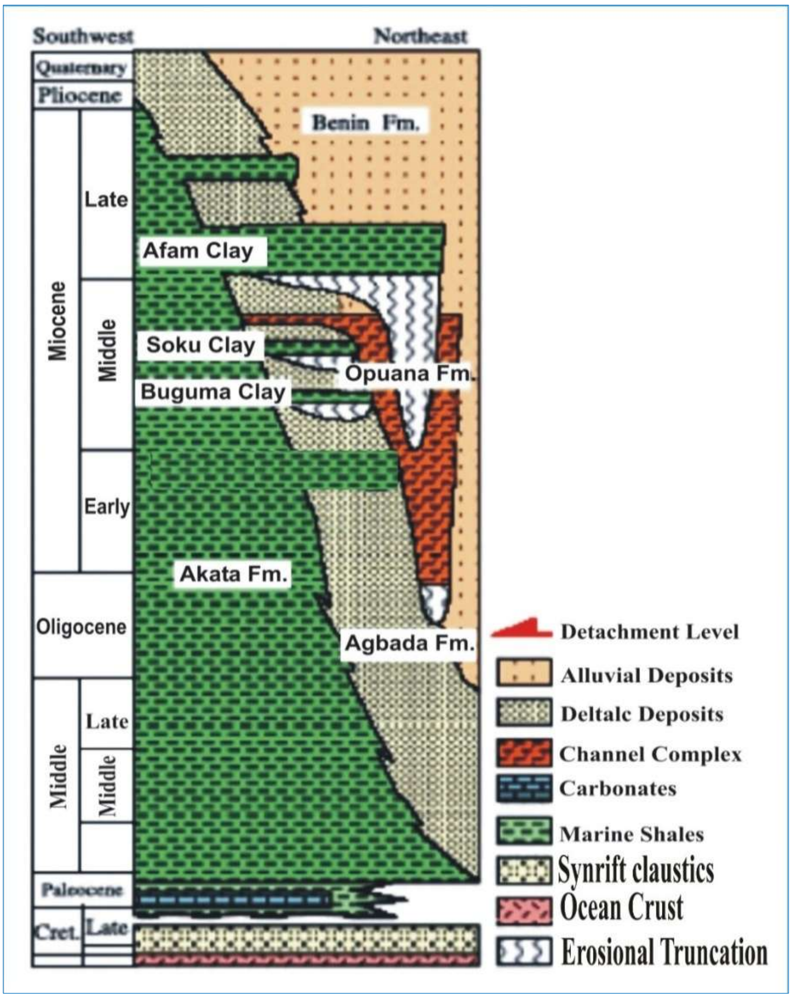

Fig. 2. Stratigraphic framework of the Niger Delta Basin showing the Akata, Agbada, and Benin Formations with their depositional settings, ages, and petroleum system roles (adapted from Corredor et al., 2005 and Whiteman, 1982)

1.2. Objectives of the Study

This research was designed with the following objectives: 1) To characterize the lithology and depositional facies of the AI Well using sedimentological and petrographic data, thereby inferring paleo-depositional environments in relation to established Niger Delta facies models (Olayiwola and Bamford, 2019; Aigbadon et al., 2017). 2) To evaluate the mineralogical composition of reservoir intervals using X-ray diffraction (XRD) and petrographic microscopy, focusing on how minerals such as quartz, feldspar, and clays influence porosity and permeability (Onyekuru et al., 2023; Nton and Rotimi, 2016). To determine the bulk geochemical composition of AI Well samples through X-ray fluorescence (XRF), identifying diagenetic trends and their implications for reservoir quality (Okoli et al., 2021; Overare et al., 2024). 4) To integrate sedimentological, mineralogical, and geochemical data for enhanced reservoir characterization, contributing to refined hydrocarbon exploration and development strategies in the Niger Delta Basin (Reijers, 2011; Fathy et al., 2023).

Through these objectives, the study provides a more predictive understanding of reservoir heterogeneity and performance, offering a high-resolution complement to conventional log-based analysis.

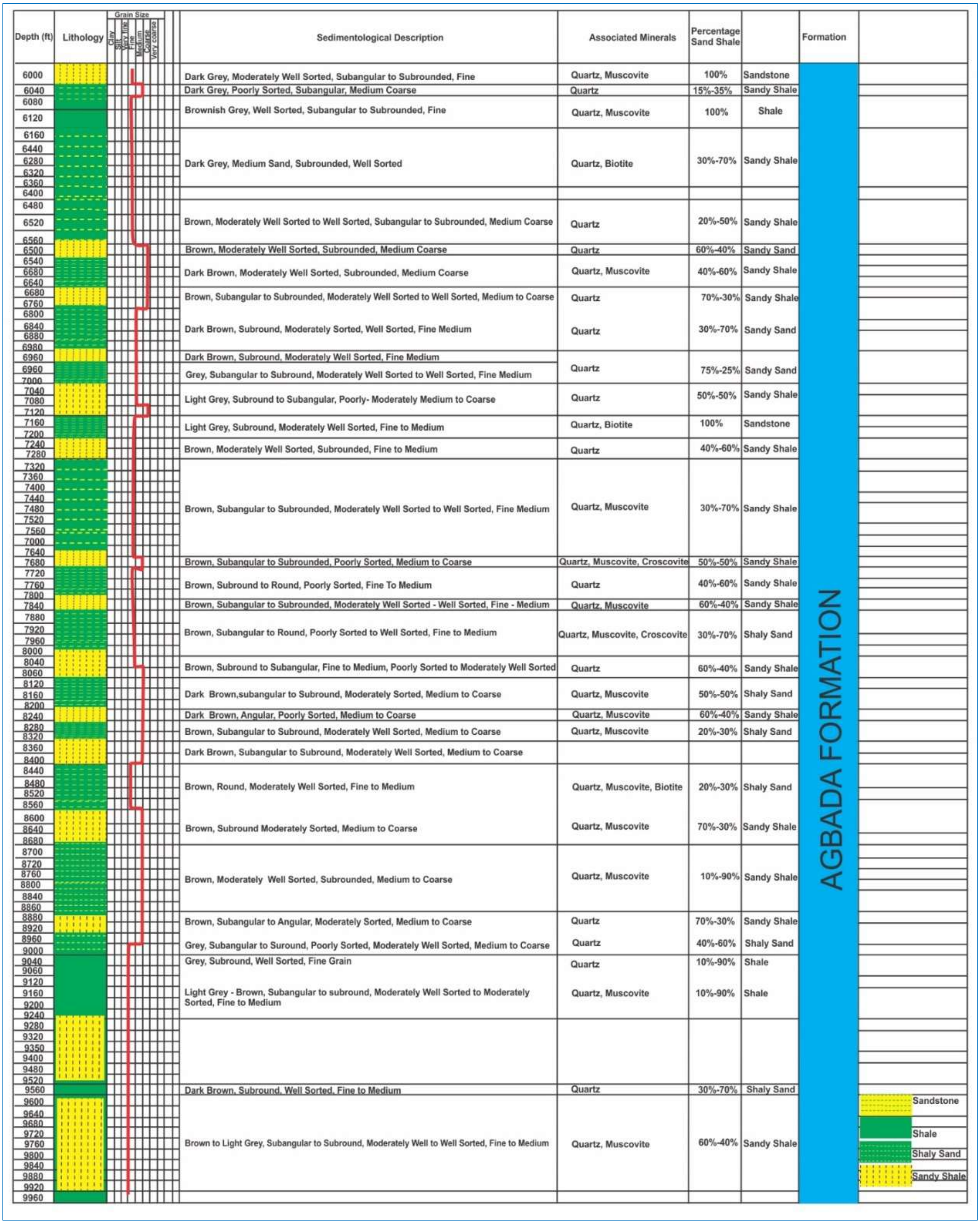

Fig. 3. Lithological log of the AI well showing the vertical distribution of key lithofacies, including sandstone, shale, and sandy shale. The succession reflects cyclic sedimentation characteristic of fluvial, delta-front, and prodelta depositional environments within the Agbada Formation of the Niger Delta Basin

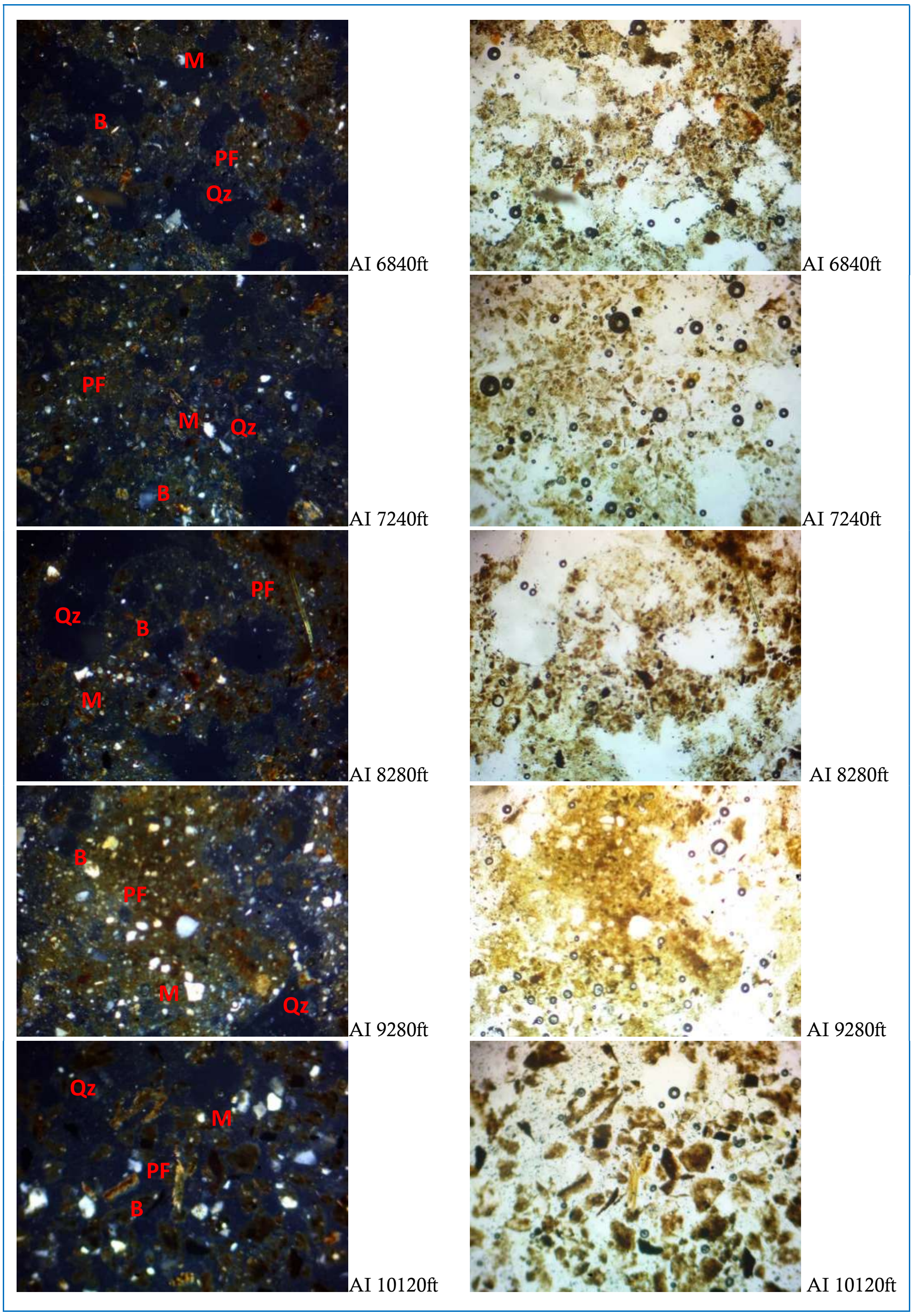

Fig. 4. Photomicrographs of thin-section samples from the AI well (depths 6,840–10,120 ft) viewed under plane-polarized light (PPL) and cross-polarized light (XPL), showing dominant quartz grains (QZ), plagioclase feldspar (PF), muscovite (M), and biotite (B), with variable clay matrix infill

1.3. Study Location and Geological Setting

The AI Well is situated in the Coastal Swamp Depobelt of the Niger Delta Basin (Fig. 1), which forms part of the West African passive continental margin. The basin is bounded by the Benue Trough to the north, the Anambra Basin to the east, and the Atlantic Ocean to the south (Doust and Omatsola, 1990). Its geological evolution is closely linked to the rifting of the South Atlantic and subsequent sedimentary infill from the Niger–Benue river system (Reijers, 2011).

The depositional framework of the delta has been shaped by fluvial–deltaic sedimentation, rapid subsidence, and syndepositional growth faulting, which have produced thick, hydrocarbon-bearing successions (Weber and Daukoru, 1975; Aigbadon et al., 2017).

Previous paleoenvironmental studies in the Coastal Swamp Sub-basin have documented both lateral and vertical facies variability, while offshore and onshore analyses have demonstrated how lithofacies distribution and diagenetic overprinting influence reservoir quality (Onyekuru et al., 2023; Overare et al., 2024).

1.3.1. Lithostratigraphy of the Niger Delta Basin
The stratigraphy of the Niger Delta comprises three diachronous formations (Fig. 2):

1.3.1.1. Akata Formation (Paleocene-Recent)
Predominantly marine shales and silts that serve as the principal hydrocarbon source rock (Evamy et al., 1978).

1.3.1.2. Agbada Formation (Eocene-Recent)
Alternating sandstones and shales are deposited in fluvial to shallow marine environments. This formation hosts the main reservoir intervals and is the focus of this study (Reijers, 2011).

1.3.1.3. Benin Formation (Miocene-Recent)
Composed mainly of fluvial sands and gravels that function as a regional aquifer rather than a reservoir (Obaje, 2009).

The AI Well samples were obtained from the Agbada Formation. Previous studies confirm that reservoir quality in this formation varies considerably, being controlled by clay content, facies architecture, and diagenetic cementation (Olayiwola and Bamford, 2019; Overare et al., 2024).

1.3.2. Tectonic Framework and Hydrocarbon Potential
The structural evolution of the Niger Delta Basin involves three key phases:

1. Cretaceous rifting**,** which initiated the opening of the South Atlantic Ocean and the deposition of marine source rocks (Doust and Omatsola, 1990).
2. Tertiary deltaic progradation**,** driven by high sediment input, leading to the development of rollover anticlines and growth faults that now serve as major hydrocarbon traps (Corredor et al., 2005).
3. Diapirism of Akata shales**,** which generated structural complexity, overpressure zones, and stratigraphic traps essential for petroleum accumulation (Whiteman, 1982).

These tectono-stratigraphic processes influence reservoir compartmentalization, pore pressure regimes, and fluid migration patterns—factors that are fundamental to effective reservoir development and field performance (Selley and Sonnenberg, 2014).

1.4. Significance of Study
This study enhances reservoir modeling, exploration planning, and production strategy in the Niger Delta Basin through the following contributions:

Facies-Scale Reservoir Interpretation: Detailed sedimentological and petrographic analyses improve understanding of lateral and vertical facies variability, supporting more accurate prospect evaluation (Aigbadon et al., 2017).

Mineralogical Control on Reservoir Quality: Through XRD, XRF, and thin-section petrography, the study identifies key mineralogical factors, especially clay and cement types, that govern porosity and permeability (Onyekuru et al., 2023; Overare et al., 2024).

Diagenetic and Geochemical Insights: The integration of geochemical data clarifies the influence of post-depositional processes on reservoir performance, extending previous work linking mineral diagenesis to pore pressure and production decline (Inyang et al., 2022; Nton and Rotimi, 2016).

The findings from this study provide a foundation for improved field development decisions, including well placement, stimulation design, and reservoir management. These insights support basin-wide predictive modeling and align with best practices in subsurface characterization.

2. Materials and Methods
2.1. Sample Collection and Preparation
A total of 100 ditch cutting samples were obtained from the AI Well operated by the Shell Petroleum Development Company (SPDC), covering depths between 6,000 and 10,120 feet. Sampling intervals were selected to capture key lithological transitions and support detailed reservoir evaluation. All samples were stored in airtight, labeled containers to preserve their integrity. Depths chosen for laboratory analyses were guided by well-log interpretation, following established protocols for facies-based reservoir assessment (Olayiwola and Bamford, 2019).

2.2. Lithological Analysis
, roundness, and sedimentary structures were examined using a hand lens and petrographic microscope. These features were used to infer depositional environments and to construct a lithological log (Figure 3), which allowed vertical facies correlation and delineation of reservoir zones (Reijers, 2011; Aigbadon et al., 2017). Depositional settings were interpreted within a sequence stratigraphic framework, such as fluvial, deltaic, or shallow marine systems, based on lithofacies associations and previously established paleoenvironmental models (Onyekuru et al., 2023).

2.3. Mineralogical Analysis
X-ray diffraction (XRD) analysis was conducted on five representative samples selected from intervals representing distinct lithofacies. The objective was to identify dominant crystalline minerals influencing reservoir quality, particularly quartz, feldspars, and clay minerals. Analyses were performed using a Rigaku Miniflex 600 diffractometer, and mineral phases were identified with reference to the ICDD database. The XRD results provided mineralogical confirmation of lithological variations observed during core logging and petrographic examination (Overare et al., 2024).

2.4. Geochemical Analysis
Major and trace element concentrations were determined by X-ray fluorescence (XRF) on the same five representative samples used for XRD analysis. Major oxides (SiO_2, Al_2O_3, Fe_2O_3, etc.) and trace elements (Zr, Sr, Ba, and Rb) were quantified to infer sediment provenance, depositional conditions, and diagenetic influences. Interpretation emphasized the reservoir implications of elevated SiO_2 (quartz enrichment), Fe_2O_3 (ferruginization), and Al_2O_3 (clay enrichment), following established geochemical–reservoir models from the Niger Delta Basin (Fathy et al., 2023; Agbasi et al., 2020).

2.5. Petrographic Analysis

Petrographic thin sections were prepared from five selected depths to evaluate framework mineralogy, textural maturity, and diagenetic features. Analyses were conducted using a Nikon polarizing microscope. Observations focused on quartz overgrowths, compaction textures, and pore-filling clays such as kaolinite and chlorite, which are known to influence reservoir quality (Nton and Rotimi, 2016; Overare et al., 2024). Thin-section studies followed procedures established in comparable facies-controlled reservoir investigations within the Niger Delta Basin (Maju-Oyovwikowhe and Okudibie, 2023).

2.5. Data Integration and Interpretation

Lithological, mineralogical, and geochemical data were integrated to construct a high-resolution reservoir characterization model. Quartz-rich intervals identified through XRD analysis were correlated with elevated SiO_2 concentrations from XRF data. Clay-rich zones indicated by high Al_2O_3 values corresponded to kaolinite and chlorite identified in petrographic observations.

Cementation and compaction features were further supported by Fe_2O_3 enrichment trends. This integrated analytical approach, consistent with regional workflows (Onyekuru et al., 2023), enabled a robust interpretation of reservoir heterogeneity and diagenetic evolution within the AI Well interval.

3. Results

3.1. Sedimentology

A total of 100 ditch cutting samples from the AI Well were analyzed using petrographic microscopy to evaluate lithological variation, infer depositional environments, and assess reservoir potential. Key sedimentological parameters such as grain size, sorting, texture, color, and mineral content were examined following established protocols for deltaic systems (Reijers, 2011; Aigbadon et al., 2017).

The lithological log (Figure 3) reveals cyclic alternations of sandstone, sandy shale, shaley sand, and shale facies, indicative of deposition within a fluvial-to-deltaic system. These transitions reflect fluctuating energy conditions typical of the Agbada Formation and are consistent with regional facies models of the Niger Delta Basin (Onyekuru et al., 2023; Olayiwola and Bamford, 2019).

Grain size varies from fine to coarse, with well-sorted, coarse sandstones corresponding to high-energy fluvial or distributary channel settings, and poorly sorted, finer sediments suggesting estuarine or delta-front deposition. Grain roundness ranges from subangular shales to well-rounded sandstones, reflecting progression from proximal to distal depositional environments (Selley and Sonnenberg, 2014). Color variations provide additional paleo-environmental insights:

- Light to dark grey sandstones with ferruginous staining indicate fluvial to nearshore marine deposition.
- Brown sandy shales represent transitional zones influenced by both fluvial and marine processes.
- Dark grey to black shales, dominant in deeper intervals, suggest anoxic marine settings conducive to organic matter preservation (Evamy et al., 1978).

Overall, the sedimentological profile depicts a vertically stacked succession of high- to low-energy facies that collectively form an effective reservoir–seal system. These findings align with previous reports from analogous wells in the Usani and OLI fields (Onyekuru et al., 2023; Aigbadon et al., 2017).

3.1.1 Grain Size and Sorting

Grain size within the AI Well samples ranges from fine to coarse sand, reflecting deposition under variable energy conditions. Fine-grained, well-sorted intervals, particularly within shale units, are typical of low-energy marine or prodelta environments. In contrast, coarser, moderately to well-sorted sandstones indicate deposition in high-energy settings such as fluvial channels and distributary mouth bars (Onyekuru et al., 2023).

Poorly sorted sand observed in some transitional facies suggests rapid sedimentation under fluctuating hydrodynamic conditions, typical of delta-front or storm-influenced zones. These sorting patterns correlate with sediment supply variability and flow energy, both of which strongly influence porosity and permeability distribution in deltaic reservoirs (Reijers, 2011; Olayiwola and Bamford, 2019).

3.1.2. Texture and Roundness

Grain textures across the AI Well samples vary from subangular to well-rounded, reflecting different degrees of transport and depositional energy. Subangular grains, dominant in fine-grained shales and muddy sands, indicate limited reworking and short transport distances typical of lagoonal or delta-front environments. These features correspond to low depositional energy and reduced textural maturity (Aigbadon et al., 2017).

Conversely, well-rounded grains are more abundant in sandstone intervals, particularly at shallower depths. These grains suggest sustained transport and mechanical abrasion in high-energy fluvial system conditions associated with improved sorting and efficient grain packing. Such textural attributes enhance primary porosity and contribute to favorable reservoir quality (Overare et al., 2024; Selley and Sonnenberg, 2014).

The observed variation in grain roundness supports a depositional model ranging from proximal fluvial to distal marine environments, consistent with the vertical facies stacking identified in the lithological log (Fig. 3).

3.1.3. Color and Mineral Composition

Color variations in the AI Well samples provide additional context for interpreting depositional environments and diagenetic processes. Light to dark grey sandstones, occasionally exhibiting ferruginous staining, are typical of fluvial to nearshore marine deposition and reflect oxidizing conditions with intermittent exposure common in high-energy regimes (Reijers, 2011).

Brown to dark brown sandy shales indicate transitional zones influenced by both fluvial and marine processes. Enhanced ferruginization within these intervals suggests diagenetic iron enrichment, likely linked to post-depositional fluid movement and redox fluctuations (Fathy et al., 2023).

Darker grey to black shales, particularly in deeper intervals, correspond to low-energy prodelta or offshore marine environments. These facies are associated with high organic matter preservation and anoxic conditions favorable for hydrocarbon source rock development (Inyang et al., 2022; Evamy et al., 1978).

These mineralogically driven color patterns help distinguish between reservoir-prone and sealing facies, reinforcing stratigraphic interpretations derived from facies and texture analyses.

3.2. Facies Analysis

Facies analysis of the AI Well interval identified four dominant lithofacies: sandstone, sandy shale, shaley sand, and shale. These facies represent deposition along a fluvial-to-marine energy gradient, consistent with established depositional models of the Agbada Formation (Onyekuru et al., 2023; Olayiwola and Bamford, 2019).

Table 1. Mineralogical composition of selected AI Well Depth Intervals (in weight %)

Mineral	AI 6840ft	AI 7240ft	AI 8280ft	AI 9280ft	AI 10120ft
Quartz	44	35	48.4	46.6	51
Albite	31.5	21	---	22.8	9.4
Orthoclase	3.7	37	23.7	24.2	8
Kaolinite	11.4	---	---	---	9.8
Muscovite	9.1	5	18.2	6.44	17
Clinochlore	---	1.3	---	---	---

Note: "-" indicates values below detection limits

Table 2. Major Oxide Composition of AI Well Samples (in wt%)

Major oxides in %	AI 6840ft	AI 7240ft	AI 8280ft	AI 9280ft	AI 10120ft
SiO_2	40.141	43.432	39.662	63.264	36.676
Al_20_3	16.147	14.542	1q4.765	7.574	10.462
Fe_2O_3	18.824	16.846	19.718	10.519	13.900
TiO_2	3.174	2.591	2.975	1.552	2.342
MgO	0.000	0.000	0.000	0.000	0.000
CaO	6.642	3.815	3.069	4.193	3.134
K_2O	2.042	1.934	2.006	2.466	1.915
MnO	0.204	0.242	0.185	0.197	0.078
P_2O_5	0.135	0.000	0.036	0.000	1.852
Na_2O	-	-	-	-	-

Note: "-" indicates values below detection limits

Table 3. Comparison of major oxide compositions between AI Well and other Niger Delta Reservoir samples

Oxide	AI Well (%)	Adebayo et al., 2016 (%)	Amiewalan et al., 2020 (%)
SiO_2	41.635	65.008	84.2
Al_2O_3	12.198	11.799	4.88
Fe_2O_3	15.961	5.6886	3.25
TiO_2	2.5268	0.6953	0.74
MgO	0.0	10.934	0.42
CaO	4.1706	10.542	3.1
K_2O	2.0726	1.3313	0.88
MnO	0.1812	0.034	0.04
P_2O_5	0.4046	0.1433	0.07

Note: Data compiled from AI well XRF analysis and comparative studies by Adebayo and Ojo (2014) and Amiewalan et al. (2020)

The sandstone facies, predominantly between 6,000 ft and 7,800 ft, comprises well-sorted, subrounded grains typical of high-energy fluvial or distributary channel deposits. These intervals exhibit favorable textural attributes and are interpreted as primary reservoir zones, consistent with findings from the Usani Field (Aigbadon et al., 2017).

Transitional facies, including sandy shale and shaley sand, occur between 7,800 ft and 8,500 ft and reflect deposition in estuarine or delta-front settings. These units are characterized by variable grain sizes and bedding styles indicative of fluctuating hydrodynamic energy. Their heterogeneity contributes to both lateral and vertical variation in reservoir quality (Reijers, 2011).

The shale facies, dominant below 8,500 ft, consists of dark grey, fine-grained sediments deposited in low-energy marine environments. These facies act as regional sealing units that promote hydrocarbon entrapment and pressure compartmentalization (Evamy et al., 1978).

The vertical stacking of these facies reflects a regressive depositional sequence typical of the Niger Delta Basin. This pattern highlights the importance of integrating facies interpretation with diagenetic and geochemical analyses to achieve robust reservoir modeling.

3.3. Petrography Analysis

Thin-section petrographic analysis was conducted on samples collected from depths between 6,240 ft and 10,120 ft to examine mineral composition, texture, and diagenetic characteristics. Observations under plane-polarized light (PPL) and cross-polarized light (XPL) revealed marked variations in grain fabric and cementation styles, each influencing overall reservoir performance (Overare et al., 2024).

Fig. 4 presents representative photomicrographs showing the predominance of quartz grains with varying degrees of overgrowth, along with feldspar (plagioclase and orthoclase), muscovite, biotite, and clay matrices. These mineral assemblages are consistent with previous petrographic studies of Agbada Formation Reservoirs (Reijers, 2011).

The occurrence of texturally mature quartz and moderate feldspar content suggests sediment derivation from a stable continental source. Kaolinite and chlorite appear as pore-filling clays and grain coatings, particularly in deeper intervals, where they are linked to reduced porosity and permeability (Inyang et al., 2022).

Petrographic features correspond closely with the sedimentological interpretations, confirming that higher-energy sandstone intervals retain better grain packing and primary porosity, while finer-grained, clay-rich units exhibit stronger diagenetic alteration and lower reservoir potential.

3.1.1. Mineralogical Composition

Quartz is the dominant mineral phase across all analyzed samples, with proportions ranging from approximately 35% to 51% (Table 1). This high quartz content reflects a mature sediment source and indicates derivation from a stable continental or cratonic provenance, consistent with interpretations from similar Niger Delta fields (Olayiwola and Bamford, 2019). Accessory minerals include albite and orthoclase feldspars, muscovite, and minor biotite, suggesting moderate compositional maturity and possible input from granitoid terranes.

Kaolinite and chlorite were identified as pore-filling and grain-coating clays, particularly in deeper intervals. These minerals are typically associated with reduced porosity and restricted fluid flow in deltaic reservoirs (Inyang et al., 2022; Overare et al., 2024). The observed mineral assemblage strongly supports the petrofacies interpretations derived from sedimentological and geochemical analyses, particularly the influence of mineral composition on reservoir quality.

3.3.2. Textural Characteristics

Grain sorting and roundness vary across the analyzed depth intervals, reflecting differences in depositional energy and transport distance. Well-sorted grains dominate the sandstone facies, especially in shallow to mid-depth sections, indicating deposition under high-energy fluvial or distributary channel conditions. Such settings promote efficient grain packing and minimal clay infiltration, thereby enhancing primary porosity (Selley and Sonnenberg, 2014; Overare et al., 2024).

Poorly sorted grains are more common in the mixed sandy facies, particularly those associated with delta-front and estuarine environments. These intervals are often characterized by rapid sedimentation under variable flow conditions, which limit sorting and reduce overall reservoir quality (Aigbado et al., 2017). Grain roundness ranges from subangular to well-rounded. Subangular grains indicate limited transport and short reworking typical of proximal depositional settings, whereas well-rounded grains in quartz-rich sandstones suggest longer transport distances, greater textural maturity, and potentially improved reservoir performance (Reijers, 2011).

These textural variations, when integrated with mineralogical and diagenetic observations, highlight the vertical and lateral heterogeneity of reservoir quality across the AI Well interval.

3.3.3. Diagenetic Features

Diagenetic modifications identified in the AI Well samples include quartz overgrowths, carbonate cementation, mechanical compaction, and pore-filling clays. These processes exert significant control on porosity and permeability, particularly at greater depths. Quartz overgrowths and calcite cementation are most pronounced below 9,000 ft, indicating advanced burial diagenesis. These features reduce primary porosity by clogging pore throats and reinforcing the grain framework (Overare et al., 2024).

Mechanical compaction, evidenced by grain deformation and tighter packing, is observed throughout the sampled interval and becomes more intense with depth. This trend is consistent with porosity reduction under increasing overburden pressure, a common feature of deltaic clastic reservoirs (Selley and Sonnenberg, 2014). Kaolinite and chlorite clays frequently occur as pore-filling and grain-coating phases. These minerals restrict permeability by obstructing pore throats and modifying wettability, leading to diminished reservoir efficiency (Inyang et al., 2022).

Overall, the combined effects of compaction, cementation, and clay mineral development contribute to pronounced vertical heterogeneity in reservoir quality and must be considered in predictive models for the Agbada Formation.

3.4. Geochemistry

Geochemical data obtained from X-ray fluorescence (XRF) and X-ray diffraction (XRD) analyses provide important insights into mineralogical variability, diagenetic alterations, and their effects on reservoir quality across the AI Well interval.

3.4.1. Major Oxide Composition

The chemical composition of major oxides is summarized in Table 2. The AI Well samples show high SiO_2 concentrations ranging from 40% to 63%, reflecting quartz dominance and confirming the petrographic interpretation of a silica-rich reservoir framework. This pattern is typical of high-energy fluvial deposits characterized by strong textural and compositional maturity (Reijers, 2011).

Elevated Al_2O_3 levels in shale-prone intervals correspond to higher clay mineral content, mainly kaolinite and chlorite. These minerals tend to reduce permeability by obstructing pore spaces and increasing reservoir heterogeneity (Selley and Sonnenberg, 2014; Overare et al., 2024). Fe_2O_3 concentrations between 10% and 19% indicate significant diagenetic ferruginization, particularly within transitional sandy shale facies. The presence of ferruginous cements limits pore connectivity and may promote lithification, which further reduces porosity in deeper intervals (Fathy et al., 2023).

Overall, these geochemical trends validate the mineralogical zonation observed in petrographic analysis and strengthen the interpretation of depth-dependent variations in reservoir quality.

3.4.2. Trace Element Analysis

Trace elements such as Zr, Rb, Sr, and Ba provide additional information on provenance and diagenetic history. Elevated Zr and Rb concentrations indicate derivation from felsic continental sources, whereas variations in Sr and Ba suggest fluctuations in sediment supply and marine influence (Okoli et al., 2021). Consistently high iron concentrations across multiple intervals point to continued diagenetic cementation processes, confirming observations from thin-section petrography and mineralogical analyses.

These trace element patterns help differentiate depositional settings and support interpretations of variable energy conditions and fluid chemistry during burial.

3.5. Integration with Lithological Log and Depositional History

The lithological log of the AI Well (Fig. 3) shows a vertically stacked succession of sandstone, sandy shale, and shale facies, reflecting a regressive depositional sequence that transitions from high-energy fluvial environments to low-energy marine settings (Reijers, 2011).

Sandstone-rich intervals, particularly those above 7,800 ft, display features characteristic of deposition under high-energy fluvial and distributary channel conditions. These zones are associated with well-sorted, texturally mature grains and high quartz content, supporting their interpretation as primary reservoir units (Aigbadon et al., 2017; Overare et al., 2024).

In contrast, the deeper shale intervals below 8,500 ft represent low-energy prodelta and shelf environments that function as regional sealing units. These facies are defined by fine grain size, high Al_2O_3 and Fe_2O_3 concentrations, and pervasive clay matrix and ferruginous cementation. Such features contribute to reduced porosity and limited fluid flow (Inyang et al., 2022).

Integration of sedimentological, petrographic, and geochemical data demonstrates a distinct facies-dependent variation in reservoir quality. High-energy, quartz-rich facies retain better primary porosity, while clay-rich and diagenetically modified intervals exhibit reduced reservoir potential as a result of compaction and cementation.

3.5.1. Reservoir Quality Implications

Quartz-rich sandstone intervals demonstrate favorable porosity and permeability characteristics, confirming their potential as productive reservoir zones [22]. These units correspond to high-energy depositional environments where efficient grain packing and limited clay infiltration promote the preservation of primary porosity.

Shale and sandy shale facies function as cap rocks or baffles that contribute to reservoir compartmentalization. Their fine grain size and high clay content create sealing barriers that trap hydrocarbons and maintain pressure integrity within the system.

Diagenetic processes such as quartz overgrowth, compaction, and iron oxide cementation become more pronounced with increasing depth and significantly impair reservoir quality. These alterations restrict pore connectivity and reduce effective permeability, emphasizing the role of burial diagenesis in vertical heterogeneity.

Overall, the integration of sedimentological, petrographic, and geochemical evidence indicates that reservoir performance within the AI Well is controlled by the interplay of depositional energy, mineral composition, and diagenetic modification. Recognizing these relationships is crucial for accurate prediction of reservoir behavior and for optimizing hydrocarbon recovery strategies in the Niger Delta Basin.

4. Discussion

The integrated sedimentological, petrographic, and geochemical assessment of the AI Well provides a comprehensive understanding of the subsurface reservoir architecture within the Coastal Swamp Depobelt of the Niger Delta Basin. The observed facies transitions from quartz-rich sandstones to clay-dominated shales represent a typical deltaic progradation pattern, capturing depositional shifts from high-energy fluvial systems to low-energy marine environments (Olayiwola and Bamford, 2019; Reijers, 2011).

The dominance of quartz, confirmed through XRD and XRF analyses, indicates a compositionally mature sediment source derived from a stable cratonic terrain. This mineralogical signature aligns with well-sorted sandstone facies that are interpreted as distributary channel and delta-front deposits. These facies exhibit high porosity and permeability, supporting their classification as the primary reservoir intervals (Overare et al., 2024).

Diagenetic features, including quartz overgrowth, carbonate cementation, and mechanical compaction, are more prevalent below 9,000 ft and contribute to the decline in reservoir quality with depth. These processes are not uniform throughout the section but are facies-dependent, with greater impact in the fine-grained sandy shale and shale units (Inyang et al., 2022). The presence of kaolinite and chlorite, as identified by petrography and supported by elevated Al_2O_3 levels, further contributes to porosity loss and permeability reduction through pore throat blockage and altered wettability.

The geochemical profiles strengthen this interpretation. High Fe_2O_3 concentrations indicate pervasive ferruginization, a diagenetic process that reduces pore connectivity and promotes rock stiffening. Elevated Zr and Rb contents suggest sediment derivation from felsic continental sources, while variations in Sr and Ba values reflect periodic marine influence and sediment recycling during deposition (Aigbadon et al., 2017; Fathy et al., 2023).

Integration of these datasets reveals that the AI Well exhibits a vertically heterogeneous reservoir system where high-quality sandstone facies alternate with low-permeability sealing units. This pattern highlights the combined effects of depositional facies variability and diagenetic overprinting on reservoir performance. The study demonstrates the importance of multidisciplinary approaches in characterizing complex deltaic systems, where accurate interpretation of facies transitions and diagenetic processes enhances predictive reservoir modeling.

4.1. Lithological Variations and Depositional Environments

The vertical succession of sandstone, shaley sand, sandy shale, and shale observed within the AI Well reflects a progradational depositional sequence typical of deltaic environments in the Niger Delta Basin. The predominance of quartz-rich, well-sorted sandstones indicates deposition under high-energy fluvial or distributary channel conditions. These facies, characterized by good textural maturity, are the most prospective for reservoir development because of their preserved primary porosity and permeability (Selley and Sonnenberg, 2014; Olayiwola and Bamford, 2019).

Intermediate units, composed of sandy shale and shaley sand, occur at transitional depths and display variable grain sizes, bedding styles, and degrees of ferruginization. These characteristics suggest deposition in estuarine to delta-front settings influenced by fluctuating hydrodynamic conditions. Such environments often produce stratigraphic heterogeneity and partial barriers to vertical and lateral fluid flow (Reijers, 2011; Aigbadon et al., 2017).

Deeper sections dominated by fine-grained, dark grey shales correspond to low-energy marine or prodelta environments. These facies are enriched in clay and organic matter, making them effective sealing units that support hydrocarbon entrapment. Variations in color from light grey to dark brown provide additional paleoenvironmental evidence, with lighter hues indicating oxidizing nearshore conditions and darker shades suggesting reducing anoxic environments conducive to hydrocarbon preservation (Evamy et al., 1978; Inyang et al., 2022).

Grain roundness also varies across the succession. Well-rounded grains in the shallower sandstone intervals indicate longer transport and reworking in high-energy systems, while subangular grains in deeper shales and muddy sands reflect proximal deposition and rapid burial. These variations in texture and color collectively reveal the environmental gradient from proximal fluvial to distal marine settings and their influence on reservoir geometry, heterogeneity, and seal integrity.

A detailed understanding of these lithological and textural transitions is critical for improving facies prediction and identifying productive zones within the Agbada Formation. The results reinforce the need to integrate sedimentological, mineralogical, and geochemical data for reliable reservoir modeling and field development planning.

4.2. Mineralogical Composition and Reservoir Quality

Petrographic and X-ray diffraction (XRD) analyses confirm that quartz is the dominant framework mineral throughout the AI Well interval, with concentrations ranging between 35% and 51%. This dominance reflects a compositionally mature sediment source derived from a stable cratonic terrain and is characteristic of fluvial to shallow marine depositional settings (Reijers, 2011; Overare et al., 2024). The quartz-rich sandstone intervals display better textural maturity and are associated with higher porosity and permeability, making them the most favorable zones for hydrocarbon accumulation.

Feldspar minerals, including albite and orthoclase, occur in moderate amounts within transitional facies. Their presence indicates mixed sediment input and intermediate compositional maturity. Although feldspar dissolution can enhance secondary porosity, these minerals are also susceptible to diagenetic alteration, especially at greater burial depths (Aigbadon et al., 2017). Alteration of feldspars to clay minerals often results in the reduction of pore connectivity and the formation of localized flow barriers.

Clay minerals such as kaolinite and chlorite play a crucial role in controlling reservoir quality. They are present as pore-filling and grain-coating materials, particularly in the sandy shale and deeper shaley sand intervals. These clays block pore throats, reduce permeability, and may alter rock wettability, leading to poorer reservoir performance even in zones with relatively good primary porosity (Olayiwola and Bamford, 2019; Inyang et al., 2022). The occurrence of muscovite and clinochlore further suggests the influence of burial diagenesis and compaction-induced alteration. These minerals are typically associated with reduced pore connectivity and increased capillary sealing.

Overall, the mineralogical variability observed across the AI Well demonstrates that quartz content, clay mineral distribution, and diagenetic transformations jointly control vertical heterogeneity in reservoir quality. Integrating mineralogical data with petrographic and geochemical observations provides a more accurate understanding of reservoir performance and assists in identifying productive intervals within the Agbada Formation.

4.3. Geochemical Insights into Reservoir Quality

Geochemical data from X-ray fluorescence (XRF) analysis provide additional insight into the compositional maturity, diagenetic imprint, and heterogeneity of the AI Well reservoir. Silica (SiO_2) dominates the major oxide composition, with values reaching up to 63.26 wt%. This high concentration confirms quartz enrichment and supports the interpretation of a mature, texturally stable reservoir deposited in high-energy environments (Olayiwola and Bamford, 2019).

A progressive decline in SiO_2 content in deeper samples, such as at 10,120 ft (36.68 wt%), coincides with increased Al_2O_3 and Fe_2O_3 concentrations. These trends indicate higher clay content and stronger iron cementation, both of which are indicative of diagenetic modification. Such alterations are typical of fine-grained, low-energy facies where compaction and cementation dominate, leading to reduced porosity and permeability (Evamy et al., 1978; Fathy et al., 2023).

Elevated Al_2O_3 levels correspond with the presence of kaolinite and chlorite, as confirmed by XRD and petrographic analyses. These clay minerals are known to obstruct pore throats, restrict fluid movement, and increase rock stiffness. Their occurrence, particularly in the lower sections of the well, highlights the relationship between mineralogical maturity and flow capacity. The strong alignment between Al_2O_3 enrichment and clay distribution underscores the importance of integrating geochemical and mineralogical data when assessing reservoir quality.

Fe_2O_3 concentrations ranging from 10% to 19% indicate pervasive ferruginization, particularly within transitional facies. This diagenetic process contributes to porosity occlusion, reduced connectivity, and enhanced lithification. High Fe_2O_3 values also suggest the influence of oxidizing fluids during burial, which can further complicate fluid–rock interactions and hydrocarbon migration (Overare et al., 2024)].

Trace element variations strengthen these interpretations. Elevated Zr and Rb contents point to a felsic continental provenance, while fluctuations in Sr and Ba values may reflect periodic marine influence and sediment recycling. These geochemical signatures collectively indicate alternating depositional regimes and the progressive modification of reservoir characteristics during burial.

Overall, the integration of XRF, XRD, and petrographic results demonstrates that compositional maturity and diagenetic alteration exert strong control on reservoir heterogeneity. Quartz-rich intervals correspond to high reservoir potential, whereas clay- and iron-enriched zones show significant quality deterioration. This geochemical framework enhances the predictability of productive horizons within the Agbada Formation and provides a reliable foundation for reservoir management and development planning.

4.3.1. Interpretation of Major Oxide Composition

The geochemical profile of the AI Well shows notable differences when compared with published major oxide data from other Niger Delta reservoirs (Table 3). The average SiO_2 concentration of 41.64% in the AI Well is significantly lower than those reported by Adebayo et al. (2016) and Amiewalan et al. (2020), which range from 65.0% to 84.2%. This reduced silica content suggests a more proximal sediment source and limited sediment reworking, both of which result in lower textural maturity and potentially reduced reservoir quality.

In contrast, the AI Well exhibits higher Al_2O_3 concentrations (average 12.20%) than those reported by Adebayo et al. (2016) at 11.80% and Amiewalan et al. (2020) at 4.88%. The elevated alumina levels indicate greater clay content and stronger diagenetic influence. This finding aligns with the petrographic evidence of pervasive kaolinite and chlorite, which contribute to diminished porosity and increased heterogeneity in the reservoir.

Fe_2O_3 concentrations in the AI Well (up to 15.96%) are considerably higher than those recorded in the comparison studies, reflecting intense ferruginization. This process results from diagenetic iron oxide precipitation, which promotes pore-filling cementation and contributes to lithification. Such ferruginous alteration is particularly evident in transitional facies and explains the lower permeability observed at greater depths.

Moderately high TiO_2 (2.53%) and K_2O (2.07%) concentrations point to contributions from heavy minerals and feldspar-rich lithologies. These components can influence the mechanical behavior of the reservoir and affect its diagenetic evolution. The near absence of MgO indicates a dominantly siliciclastic system with little carbonate input.

Overall, these compositional contrasts highlight the complexity of the AI Well reservoir and the necessity of localized geochemical evaluation. Even within the same formation, variations in oxide composition can produce substantial differences in reservoir quality. Understanding these geochemical patterns is therefore essential for accurate reservoir modeling and improved prediction of productive intervals within the Agbada Formation.

4.3.2 Implications for Reservoir Development

The geochemical and mineralogical framework established for AI Well provides a detailed understanding of the factors that control reservoir heterogeneity and flow behavior. Quartz-rich sandstone intervals, characterized by high SiO_2 and low clay content, represent the most promising zones for hydrocarbon production. These intervals exhibit good textural maturity, better grain packing, and preserved primary porosity, making them ideal targets for well placement and primary recovery (Olayiwola and Bamford, 2019).

Conversely, the deeper and transitional intervals that show elevated Al_2O_3 and Fe_2O_3 concentrations indicate higher clay content and strong ferruginous cementation. These features reduce effective porosity and permeability, resulting in poor flow characteristics. Such zones may require enhanced recovery techniques such as acidizing or hydraulic fracturing to improve fluid mobility and production efficiency (Fathy et al., 2023; Overare et al., 2024).

The occurrence of pore-blocking kaolinite and chlorite, as observed in petrographic and XRD analyses, further affects reservoir performance. These minerals alter rock wettability and restrict permeability, especially in mixed lithofacies where flow barriers are often subtle but significant (Inyang et al., 2022). Understanding their distribution is essential for planning zonal completions and stimulation programs.

From a field development perspective, the integrated data set highlights the importance of differentiating productive reservoir intervals from diagenetically altered or clay-rich units. Selective perforation of quartz-dominated zones will optimize production, while the presence of reactive minerals such as iron oxides and aluminosilicates should be carefully considered in stimulation design.

Overall, this study demonstrates that combining geochemical and mineralogical information provides a strong foundation for reservoir management. By identifying facies with favorable mineralogical and geochemical signatures, exploration and production strategies in the Niger Delta Basin can be better optimized to enhance recovery efficiency and minimize development risk.

5. Conclusion

This study employed an integrated sedimentological, petrographic, and geochemical approach to characterize the AI Well within the Agbada Formation of the Niger Delta Basin. The results demonstrate that lithological variation, mineral composition, and diagenetic overprinting collectively determine reservoir quality and heterogeneity.

Lithofacies analysis revealed a vertical succession of sandstone, sandy shale, shaley sand, and shale facies deposited across fluvial, estuarine, and marine environments. Quartz-rich, well-sorted sandstones were identified as the main reservoir units, while fine-grained, clay-rich shales act as effective sealing facies.

Petrographic and XRD analyses confirmed quartz dominance (35–51%) with subordinate albite, orthoclase, kaolinite, and chlorite. The presence of kaolinite and chlorite was linked to permeability reduction, while XRF results showed high SiO_2 concentrations consistent with reservoir maturity. Elevated Al_2O_3 and Fe_2O_3 levels reflected clay enrichment and ferruginization, indicating diagenetic processes that influence reservoir performance.

At depths greater than 9,000 ft, reservoir quality declines due to intensified diagenesis, including quartz overgrowth, carbonate cementation, and mechanical compaction. These processes significantly reduce effective porosity and permeability, emphasizing the vertical heterogeneity of the reservoir system.

The integration of sedimentological, mineralogical, and geochemical data highlights the necessity of a multidisciplinary approach for accurate reservoir evaluation. This methodology improves predictive modeling of reservoir behavior, enhances hydrocarbon recovery strategies, and provides valuable guidance for future exploration within the Niger Delta Basin.

Future research should incorporate seismic stratigraphy, core-plug analysis, and dynamic modeling to refine the understanding of reservoir performance. The application of hyperspectral remote sensing and machine learning techniques could also help in mapping mineralogical variations and iron oxide distribution across the basin (Qi et al., 2024).

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Consent to Publish

Not applicable.

Ethics and Consent to Participate

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