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Biomarker-Based Classification of Crude Oils from Niger Delta Depobelts: Implications for Source Rock Discrimination (Akata vs. Agbada).

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Abstract*—This study investigates the molecular geochemistry of crude oils from different depobelts within the Niger Delta Basin using biomarker parameters derived from gas chromatography–mass spectrometry (GC–MS). The aim is to classify oil families and discriminate between source rocks, particularly the Akata and Agbada Formations. Key biomarker indices, including pristane/phytane (Pr/Ph) ratios, hopane distributions, Ts/Tm ratios, and sterane compositions, were analyzed to evaluate depositional environments, organic matter input, and thermal maturity. Results indicate that the oils are predominantly of marine origin, with a minor terrigenous component, as evidenced by low Pr/Ph ratios and the dominance of C_{30} hopanes and extended homohopanes (C_{31}–C_{35}). Thermal maturity parameters suggest that the oils fall within the peak to late oil generation window. Variations in biomarker distributions across depobelts reflect differences in source input and depositional settings. The study successfully distinguishes oils derived from the Akata Formation, characterized by strong marine signatures and high maturity, from those of the Agbada Formation, which show variable terrestrial–marine input and variable maturity levels. These findings demonstrate the effectiveness of biomarker geochemistry in oil–source correlation and provide valuable insights for hydrocarbon exploration in the Niger Delta Basin.

***Keywords*—Biomarkers, Hopanes, Steranes, Niger Delta, Thermal maturity, GC–MS**

I. INTRODUCTION

The Niger Delta Basin is one of the most prolific hydrocarbon provinces globally, characterized by complex depositional environments and diverse mini-petroleum systems. Understanding the origin, evolution, and classification of crude oils within this basin is critical for improving hydrocarbon exploration and production strategies. Molecular geochemistry, particularly biomarker analysis, has become a fundamental tool in petroleum studies due to its ability to preserve information about source rock characteristics, depositional environments, and thermal maturity (Peters et al., 2005).

Biomarkers are organic compounds derived from biological precursors that retain their structural integrity during diagenesis and catagenesis. These compounds serve as molecular fingerprints, allowing geoscientists to correlate oils with their source rocks and reconstruct paleoenvironmental conditions (Moldowan et al., 1994). Key biomarker groups include hopanes, steranes, and isoprenoids such as pristane and phytane, which provide insights into redox conditions, organic matter input, and maturity levels.

The Niger Delta Basin comprises three major lithostratigraphic units: the Akata, Agbada, and Benin Formations. The Akata Formation, consisting of deep marine shales, is widely regarded as the primary source rock, while the Agbada Formation contains both source and reservoir units deposited in deltaic to shallow marine environments (Evamy et al., 1978). The variability in depositional environments across depobelts leads to significant differences in oil composition, posing challenges for oil–source correlation.

Previous studies have highlighted the importance of biomarker parameters such as Pr/Ph ratios, Ts/Tm ratios, and sterane ternary and isomerization ratios in distinguishing marine versus terrestrial inputs and assessing thermal maturity (Peters et al., 2005; Nwachukwu et al., 1995). However, comprehensive biomarker-based classification of oils across multiple depobelts remains limited.

This study aims to:

i. Analyze biomarker distributions in crude oils from different depobelts
ii. Evaluate depositional environments and organic matter sources
iii. Assess thermal maturity using biomarker indices
iv. Differentiate oils derived from Akata and Agbada Formations

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The study provides new insights into petroleum system characterization and supports improved exploration strategies in the Niger Delta Basin.

II. GEOLOGICAL SETTING

The Niger Delta Basin is located in southern Nigeria and formed during the separation of the African and South American plates in the Mesozoic. It covers approximately 75,000 km² and consists of a thick sedimentary sequence exceeding 12 km in some areas (Doust & Omatsola, 1990).

The basin is subdivided into several depobelts, each representing distinct depositional cycles and structural features. These depobelts are associated with growth faults and rollover anticlines that control hydrocarbon migration and accumulation.

Stratigraphically, the basin comprises three main formations (Figure 1):

i. Akata Formation: Deep marine shales, primary source rock
ii. Agbada Formation: Interbedded sandstones and shales, reservoir and secondary source
iii. Benin Formation: Continental sands, mainly overburden

The variation in depositional environments across these formations significantly influences the geochemical characteristics of crude oils.

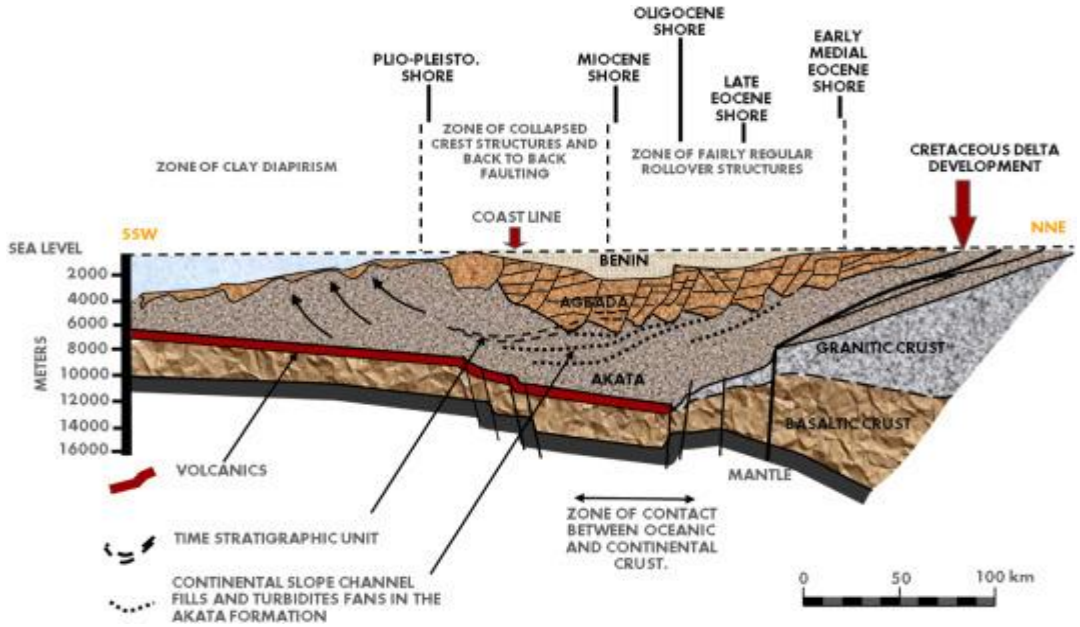

Figure 1: Lithostratigraphy of Niger Delta Basin (modified after Weber and Daukoru, 1975)

III. MATERIALS AND METHODS

3.1 Sample Description

Crude oil three (3) samples were collected namely ADEBAWA.D, AGBADA.D, ad Sample C from different depobelts within the Niger Delta Basin, representing different stratigraphic intervals and depositional settings.

3.2 Analytical Techniques

Biomarker analysis was conducted using gas chromatography–mass spectrometry (GC–MS). The saturated hydrocarbon fractions were analyzed to obtain mass chromatograms at specific m/z values (e.g., m/z 191 for hopanes, m/z 217 for steranes).

3.3 Biomarker Parameters

Key parameters used include:

i. Pristane/Phytane (Pr/Ph) ratio
ii. Ts/Tm ratio
iii. C_{31} homohopanes isomerization
iv. Sterane ternary and isomerization ratios (C_{27}, C_{28}, C_{29})

These parameters have been used to infer depositional environment, organic matter input, and thermal maturity.

IV. RESULTS

4.1 Hopane Distribution (m/z 191 Chromatograms)

The m/z 191 mass chromatograms of the analyzed crude oil samples reveal a well-defined distribution of pentacyclic triterpanes, dominated by C_{30} 17α(H),21β(H)-hopane and a homologous series of extended homohopanes (C_{31}–C_{35}). The relative abundance of C_{30} hopane across all samples indicates

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a significant contribution from bacterial organic matter, which is typically associated with marine depositional environments (Peters et al., 2005).

The extended homohopanes exhibit a decreasing trend in concentration from C_{31} to C_{35}, with C_{31} and C_{32} being more prominent than the higher homologues. This distribution pattern is characteristic of oils generated from marine shales deposited under reducing conditions. In several samples, the presence of relatively high concentrations of C_{35} homohopane suggests deposition under strongly anoxic conditions, likely within stratified water columns where oxygen depletion facilitated the preservation of organic matter.

The Ts/Tm ratio, derived from the relative abundance of 18α(H)-22,29,30-trisnorneohopane (Ts) to 17α(H)-22,29,30-trisnorhopane (Tm), varies moderately across the dataset. Most samples exhibit Ts/Tm values indicative of thermally mature oils. Higher Ts/Tm ratios observed in certain depobelts suggest increased thermal maturity and/or clay-rich source rock facies, as Ts is known to be more stable in clay-dominated environments.

Gammacerane is either absent or present in very low concentrations in most samples, indicating limited stratification in the depositional environment or minimal hypersaline influence. However, trace occurrences in a few samples may suggest localized water column stratification during deposition.

The hopane stereochemistry, particularly the C_{31} homohopane 22S/(22S+22R) ratio, approaches equilibrium values (~0.6), confirming that the oils have reached at least peak oil window maturity. This observation is consistent across multiple depobelts, indicating a relatively uniform thermal evolution despite differences in depositional settings.

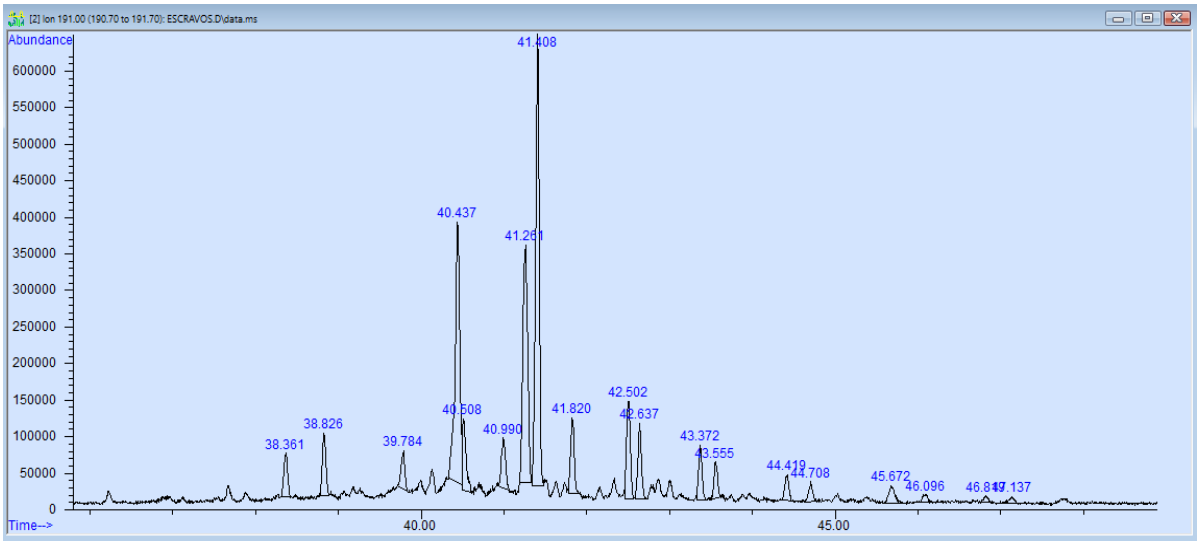

Figure 2: GC–MS m/z 191 mass chromatogram showing the distribution of hopanes in representative Niger Delta crude oil samples. The chromatogram is characterized by dominant C_{30} 17α(H),21β(H)-hopane and extended homohopanes (C_{31}–C_{35}), indicating marine source input and deposition under reducing conditions.

Overall, the hopane distributions strongly support a marine source rock origin, with variations in homohopane abundance reflecting subtle differences in redox conditions and depositional environments across the basin.

4.2 Sterane Distribution (m/z 217 Chromatograms)

The m/z 217 chromatograms show a clear predominance of regular steranes, particularly C_{27}, C_{28}, and C_{29} homologues, which provide critical insights into the source of organic matter. The analyzed samples are characterized by a dominance of C_{27} steranes, indicating a strong contribution from marine algal organic matter (Moldowan et al., 1994). C_{28} steranes are present in moderate proportions, while C_{29} steranes occur in relatively lower concentrations, suggesting limited input from higher terrestrial plants. This distribution pattern is typical of oils derived primarily from marine source rocks, such as the Akata Formation, with minor terrestrial influence.

The sterane isomerization ratios, particularly the C_{29} 20S/(20S+20R) and ββ/(ββ+αα) ratios, approach equilibrium values, further confirming that the oils

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are thermally mature. These maturity indicators are consistent with the hopane-based maturity parameters, reinforcing the interpretation of peak to late oil window generation.

Diasteranes are present in varying amounts across the samples. Elevated diasterane concentrations in some oils suggest a higher clay content in the source rock, as diasteranes are typically formed through clay-catalyzed rearrangement reactions during early diagenesis. This observation may indicate that certain oils were derived from more siliciclastic-rich facies within the Agbada Formation.

The relative distribution of steranes varies slightly between depobelts, reflecting differences in organic matter input and depositional conditions. Oils from deeper depobelts tend to show stronger marine signatures, while those from shallower or more proximal settings exhibit minor terrestrial influence.

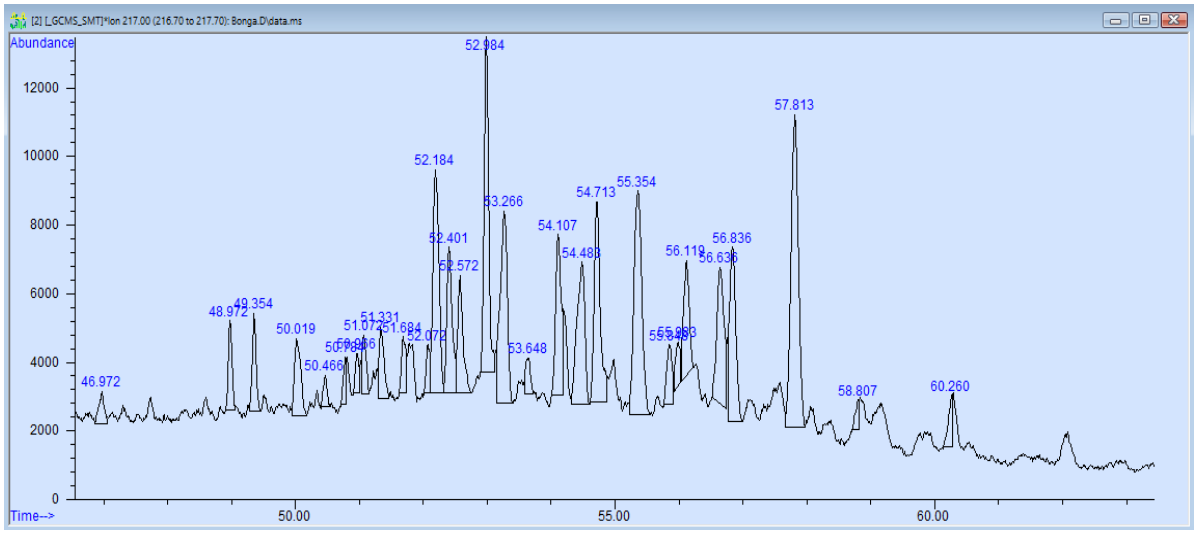

Figure 3: GC–MS m/z 217 mass chromatogram illustrating sterane distribution in crude oil samples. The dominance of C_{27} steranes relative to C_{28} and C_{29} homologues indicates a predominantly marine algal source with minor terrestrial input.

4.3 Pristane/Phytane Ratios and Isoprenoid Distribution

The distribution of acyclic isoprenoids, particularly pristane (Pr) and phytane (Ph), provides important information about the redox conditions during deposition. The Pr/Ph ratios for the analyzed samples generally range from less than 1 to slightly above 1, indicating predominantly anoxic to suboxic depositional environments.

Low Pr/Ph ratios (<1) observed in several samples are indicative of strongly reducing conditions, typically associated with marine shale deposition in oxygen-deficient environments. These conditions favor the preservation of phytane relative to pristane, resulting in low ratios.

In contrast, samples with slightly higher Pr/Ph ratios (≈1–2) suggest more oxic or transitional depositional conditions, possibly reflecting deltaic influences or fluctuating oxygen levels. These variations may be linked to the depositional environments of the Agbada Formation, where alternating marine and deltaic conditions prevail.

The relative abundance of n-alkanes compared to isoprenoids further supports these interpretations. Most samples exhibit smooth n-alkane distributions with no significant odd–even predominance, indicating mature oils that have undergone substantial thermal alteration.

Additionally, the absence of pronounced biodegradation signatures, such as preferential removal of n-alkanes, suggests that the oils are relatively fresh and have not been significantly altered post-generation.

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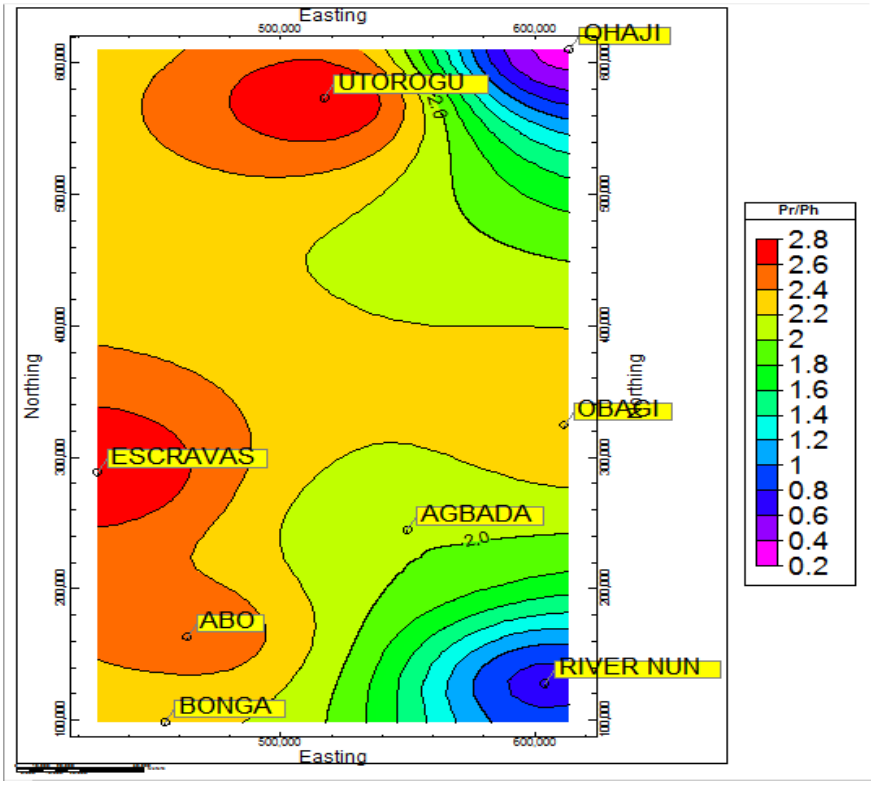

Figure 4: Cross-plot of pristane/phytane (Pr/Ph) ratios used to infer depositional redox conditions. Values <1 indicate anoxic conditions, while values between 1–2 suggest suboxic to transitional environments.

Overall, the isoprenoid data corroborates the biomarker evidence for predominantly marine, reducing depositional environments, with localized variations reflecting environmental heterogeneity across depobelts.

4.4 Thermal Maturity Indicators

Thermal maturity assessment based on biomarker parameters indicates that the analyzed oils have reached the peak to late stages of oil generation. Multiple maturity indicators were evaluated, including Ts/Tm ratios, homohopane isomerization ratios, and sterane isomerization parameters.

The Ts/Tm ratios show moderate to high values across the samples, consistent with mature oils. Higher values observed in certain samples may reflect either increased thermal maturity or lithological effects related to clay-rich source rocks. The C_{31} homohopane 22S/(22S+22R) ratios approach equilibrium values (~0.57–0.62), indicating that the oils have undergone sufficient thermal maturation. Similarly, sterane isomerization ratios (20S/(20S+20R)) are close to equilibrium, further confirming advanced maturity levels.

The consistency of these maturity parameters across different depobelts suggests that the oils have experienced comparable burial histories and thermal regimes, despite variations in depositional environments.

However, slight variations in maturity indicators between samples may reflect differences in burial depth, geothermal gradient, or timing of hydrocarbon generation. Oils from deeper depobelts tend to exhibit slightly higher maturity levels, consistent with greater burial depths and higher temperatures.

These findings indicate that the oils are well within the oil window, with some samples approaching the late oil to early gas generation stage.

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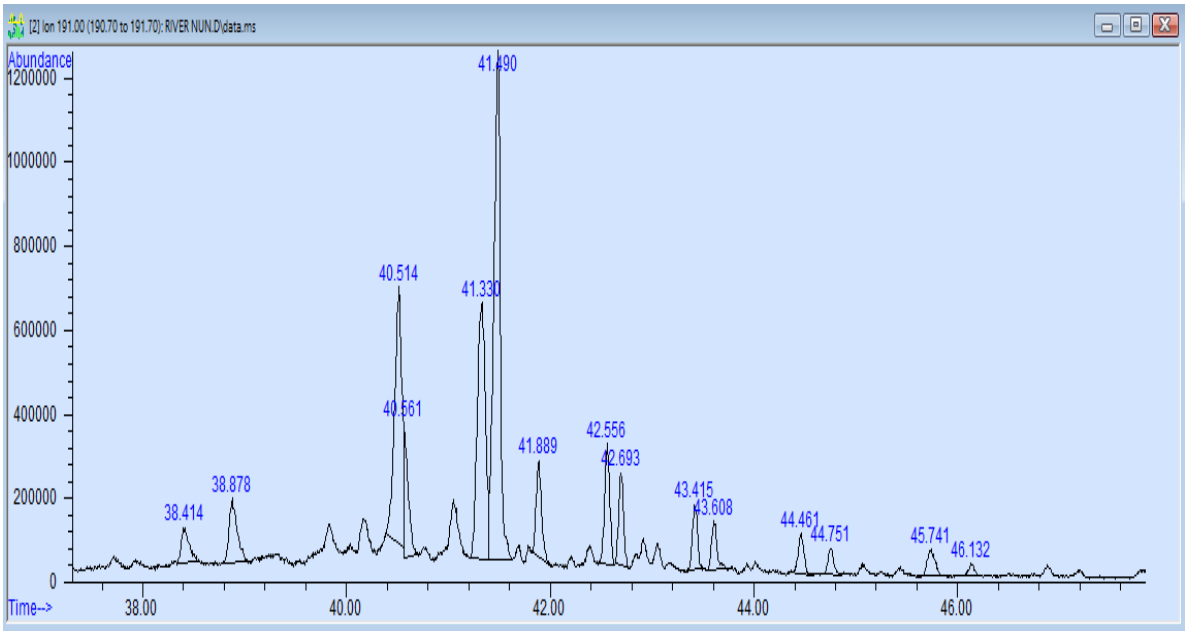

Figure 5: Cross-plot of Ts/Tm versus C_{29} sterane 20S/(20S+20R) ratios showing that the oils fall within the peak to late oil generation window.

4.5 Summary of Biomarker Characteristics Across Depobelts

The combined biomarker data reveal both similarities and variations among oils from different depobelts. All samples share key characteristics, including dominance of C_{30} hopane, prevalence of C_{27} steranes, low Pr/Ph ratios, and maturity parameters indicative of peak oil window generation.

Despite these similarities, subtle differences are observed:

Oils from deeper depobelts exhibit stronger marine signatures and higher maturity

Oils from shallower depobelts show minor terrestrial input and slightly variable redox conditions

Variations in diasterane abundance suggest differences in source rock lithology

These variations reflect the complex depositional and geological history of the Niger Delta Basin, where multiple source rocks and depositional environments contribute to the observed geochemical signatures.

Overall, the results provide a robust dataset for subsequent interpretation of source rock characteristics, depositional environments, and oil–source correlations.

Table 1: Summary of Biomarker Parameters

Sample ID	Pr/Ph	Ts/Tm	C31 22S/ (22S + 22R)	C29 20S/ (20S + 20R)	Interpretation
ADEBAWA.D	<1	High	~0.60	~0.52	Marine, Anoxic, Mature
AGBADA.D	~1–1.5	Moderate	~0.58	~0.50	Mixed input, suboxic
Sample C	<1	High	~0.61	~0.53	Marine, anoxic, late mature

Table 2: Hopane Distribution Characteristics

Parameter	Observation	Interpretation
C30 Hopane dominance	High	Marine organic input
C31–C35 Homohopanes	Present	Reducing conditions
C35 abundance	Moderate–High	Strong anoxia
Ts/Tm ratio	Moderate–High	Thermal maturity
Gammacerane	Low	Weak stratification

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Table 3: Sterane Composition

Sterane Type	Relative Abundance	Interpretation
C27	High	Marine algal input
C28	Moderate	Mixed origin
C29	Low–Moderate	Minor terrestrial input

Table 4: Depositional Environment Indicators

Parameter	Range	Environment
Pr/Ph < 1	Low	Anoxic marine
Pr/Ph 1–2	Moderate	Suboxic/transitional
High C35 hopane	Present	Strongly reducing
Diasteranes	Variable	Clay-rich facies

Table 5: Thermal Maturity Indicators

Parameter	Value Range	Maturity Interpretation
Ts/Tm	Moderate–High	Mature
C31 22S/(22S+22R)	~0.57–0.62	Equilibrium (peak oil)
C29 20S/(20S+20R)	~0.50–0.55	Mature
Sterane ββ/(ββ+αα)	High	Late maturity

V. DISCUSSION

The biomarker data obtained from the analyzed crude oil samples provide a coherent framework for interpreting source rock characteristics, depositional environments, and thermal maturity across the Niger Delta depobelts, thereby directly addressing the objectives of oil classification and source discrimination. The dominance of C_{30} 17α(H),21β(H)-hopane and the well-developed series of extended homohopanes (C_{31}–C_{35}) observed in the m/z 191 chromatograms (Figure 2) strongly indicate that the oils are derived predominantly from marine organic matter with significant bacterial input. This interpretation is consistent with established geochemical models that associate high hopane abundance with microbial reworking of organic matter in marine shale environments (Peters et al., 2005). The relative enrichment of higher homohopanes, particularly C_{33}-C_{35}, further supports deposition under reducing to strongly anoxic conditions, where enhanced preservation of organic matter occurs due to limited oxygen availability. These findings align closely with the characteristics of source rocks within the Akata Formation, which is known to consist of organic-rich marine shales deposited in deep, anoxic environments.

Variations in hopane distributions across the samples, as summarized in Table 2, reflect subtle differences in depositional conditions and source facies. While all samples exhibit marine signatures, slight differences in homohopane abundance and Ts/Tm ratios suggest variability in redox conditions and lithological controls. The moderate to high Ts/Tm ratios indicate thermally mature oils but also point to clay-rich source rock contributions, as Ts is preferentially formed in argillaceous environments. This observation is particularly relevant for distinguishing between Akata-derived oils, which are typically associated with deeper marine shales, and Agbada-derived oils, which may originate from more siliciclastic, deltaic sequences. The low occurrence of gammacerane in most samples suggests that hypersaline or strongly stratified water column conditions were not dominant during deposition, although minor occurrences indicate localized environmental heterogeneity.

The sterane distributions derived from m/z 217 chromatograms (Figure 3) further reinforce the interpretation of a predominantly marine source. The clear predominance of C_{27} steranes over C_{28} and C_{29} homologues indicates that algal and planktonic organic matter contributed significantly to the source

material. This pattern is characteristic of marine depositional systems and contrasts with terrestrial-dominated systems, where C_{29} steranes are typically more abundant (Moldowan et al., 1994). However, the presence of moderate amounts of C_{28} and C_{29} steranes suggests that some terrestrial input was incorporated into the depositional system, likely through fluvial processes associated with deltaic environments. This mixed signature is particularly evident in samples attributed to the Agbada Formation, which represents transitional settings between marine and continental environments.

The occurrence of diasteranes in varying concentrations provides additional insight into source rock lithology and depositional conditions. Elevated diasterane levels in certain samples suggest a higher clay content in the source rock, supporting the interpretation of siliciclastic influence. This is consistent with the known characteristics of the Agbada Formation, where interbedded sandstones and shales create a more heterogeneous depositional environment. Consequently, the sterane and diasterane distributions together provide a robust basis for differentiating between oils derived from the Akata and Agbada Formations, fulfilling one of the primary objectives of the study.

The analysis of pristane and phytane ratios offers further constraints on depositional redox conditions. The generally low Pr/Ph ratios observed across the dataset (Table 1; Figure 4) indicate that the oils were generated from organic matter deposited under anoxic to suboxic conditions. Ratios below unity are particularly indicative of strongly reducing environments, which favor the preservation of phytane relative to pristane. Such conditions are typical of deep marine settings with limited oxygen penetration, further supporting the interpretation of an Akata source for many of the samples. Conversely, samples with slightly elevated Pr/Ph ratios suggest more oxygenated or fluctuating redox conditions, likely reflecting the influence of deltaic processes and episodic oxygenation in the Agbada depositional system. These variations highlight the environmental heterogeneity within the Niger Delta Basin and demonstrate the sensitivity of isoprenoid ratios to depositional conditions.

Thermal maturity assessment based on multiple biomarker parameters indicates that the oils have reached peak to late stages of hydrocarbon generation. The Ts/Tm ratios, homohopane isomerization values, and sterane isomerization parameters all converge on a consistent maturity interpretation (Table 5; Figure 4). The C_{31} homohopane 22S/(22S+22R) ratios approaching equilibrium values (~0.6) and the C_{29} sterane 20S/(20S+20R) ratios near equilibrium confirm that the oils have undergone significant thermal evolution. This level of maturity is typical of deeply buried source rocks within the Niger Delta Basin and is consistent with previous studies that place Akata-derived oils within the peak oil window (Peters et al., 2005). The relatively uniform maturity levels observed across the samples suggest that the oils have experienced similar burial and thermal histories, although minor variations indicate localized differences in geothermal gradients or burial depths.

The integration of biomarker data across all parameters allows for a comprehensive classification of oil families within the study area. Oils characterized by strong marine signatures, low Pr/Ph ratios, high C_{27} sterane abundance, and elevated maturity indicators can be confidently attributed to the Akata Formation. In contrast, oils exhibiting mixed sterane distributions, moderate Pr/Ph ratios, and variable diasterane content are more consistent with derivation from the Agbada Formation. This classification is supported by the combined evidence presented in Figures 2–5 and Tables 1–5, demonstrating the effectiveness of biomarker geochemistry in resolving source rock contributions in complex petroleum systems.

From an exploration perspective, these findings have significant implications. The ability to distinguish between Akata and Agbada-derived oils provides valuable insights into hydrocarbon migration pathways and reservoir charging mechanisms. Akata-sourced oils, generated in deeper marine settings, are likely to migrate vertically along fault systems into overlying reservoirs, whereas Agbada-sourced oils may be generated and trapped within more proximal deltaic sequences. Understanding these relationships is critical for predicting the distribution of hydrocarbon accumulations and optimizing exploration strategies.

Furthermore, the observed variations in depositional environment and organic matter input across depobelts underscore the importance of integrating geochemical data with geological and structural

information. The Niger Delta Basin is characterized by complex fault systems and depositional heterogeneity, which influence both source rock development and hydrocarbon migration. Biomarker data, when combined with stratigraphic and structural analysis, can significantly enhance the accuracy of petroleum system models and reduce exploration risk.

In summary, the biomarker results provide strong evidence for predominantly marine, anoxic source rocks with high thermal maturity, while also revealing subtle variations that reflect the complex depositional history of the Niger Delta Basin. The integration of hopane, sterane, and isoprenoid data successfully achieves the study's objectives by enabling oil classification, source discrimination, and environmental reconstruction. These findings not only advance the understanding of the Niger Delta petroleum system but also demonstrate the critical role of molecular geochemistry in modern hydrocarbon exploration.

5.1 Limitations of the Study

These interpretations should be read alongside several limitations. The dataset presented here is small relative to the number of depobelts discussed, and broader statements about basin-wide trends will need a larger, more systematically documented sample set — with named wells, depths, and depobelt locations — before they can be generalized with confidence. The biomarker evidence would also be strengthened by an independent line of corroborating data, such as bulk or compound-specific carbon isotope ratios, which are increasingly used alongside hopane and sterane distributions in Niger Delta oil–source correlation studies (Ogbesejana et al., 2020). Finally, reporting the full analytical dataset (individual sample ratios, replicate measurements, and instrumental parameters) rather than qualitative ranges would allow the classification scheme proposed here to be tested and reproduced by other workers.

VI. CONCLUSION

This study demonstrates that biomarker geochemistry is a powerful tool for classifying crude oils and identifying their source rocks in the Niger Delta Basin. The oils analyzed are predominantly marine in origin from deeper series and were deposited under anoxic conditions. Thermal maturity indicators place the oils within the peak to late oil window. Distinct biomarker signatures enable the differentiation of Akata and Agbada-derived oils. These findings provide valuable insights for petroleum system analysis and exploration strategies.

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