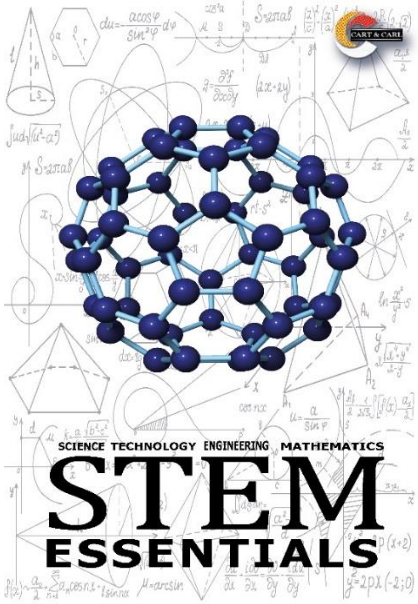
Original Research

STEM ESSENTIALS
https://cartcarl.com/journal/stem-essentials

E-ISSN: 3121-956X



Impact of Biomarker Distribution on Reservoir Classification: Insights from Niger Delta Reservoirs

Authors
[a] Anyanwu, N. [a]Ikiensikimama, S. [a] Elechi, W.

[a] Department of Petroleum Engineering, University of Port Harcourt, Nigeria

Corresponding Author
Anyanwu, N.
(emekaranyanwu@gmail.com)

Received: 07 January 2026
Accepted: 20 January 2026
Published: 23 January 2026

Citation
Anyanwu, N. Ikiensikimama, S. Elechi, W. (2026). Impact of Biomarker Distribution on Reservoir Classification: Insights from Niger Delta Reservoirs. *STEM Essentials, 2* (1), 01 - 05. *https://doi.org/10.70726/STEM-E.2026.956X001*

Abstract

Reservoir classification remains a fundamental aspect of petroleum geoscience and production optimization, serving as a key determinant of a nation's ability to manage, audit, and allocate hydrocarbon resources accurately. In Nigeria, where the Niger Delta represents the epicenter of petroleum production, understanding the subtle geochemical variations that differentiate oil and gas reservoirs is vital for both technical and policy purposes, particularly under OPEC audit and classification criteria. This study investigates the impact of biomarker distribution on the characterization and classification of reservoir fluids within the Niger Delta Basin using gas chromatography–flame ionization detection (GC-FID) and compositional fingerprinting techniques. Fifty (50) reservoir fluid samples were analyzed across representative stratigraphic intervals and depositional settings. The distribution of n-alkanes (n-C7–n-C35), isoprenoids (pristane and phytane), and diagnostic biomarker ratios such as Pr/Ph, C17/C18, Carbon Preference Index (CPI), and sterane–terpane distributions were evaluated. Results demonstrate that biomarker assemblages provide clear, reproducible discrimination between oil, gas-condensate, and borderline systems. Gas-dominant fluids are characterized by lighter hydrocarbon dominance (n-C7–n-C15), Pr/Ph < 1.0, CPI ≈ 1.0, and higher maturity indicators, while oil-prone systems exhibit heavier n-alkane envelopes (n-C20–n-C35), Pr/Ph > 1.5, and elevated CPI values. Transitional fluids display intermediate signatures reflective of mixed organic inputs and moderate maturity. The findings confirm that GC-FID-based biomarker fingerprinting offers a robust, auditable, and cost-effective framework for reservoir classification, with significant implications for reservoir management, production forecasting, and Nigeria's compliance with OPEC audit requirements.

Keywords : Biomarkers, Reservoir Classification, GC-FID, Niger Delta, OPEC Audit, Geochemical Fingerprinting

Introduction

Accurate classification of reservoir fluids is central to petroleum exploration, development planning, reserve estimation, and production optimization. At the national level, reservoir classification directly influences reserve booking, fiscal frameworks, infrastructure planning, and compliance with international regulatory and auditing bodies such as the Organization of the Petroleum Exporting Countries (OPEC). For producing countries like Nigeria, inconsistencies in reservoir fluid classification can have far-reaching technical and economic consequences, particularly in the context of production quota negotiations and reserve audits.

Reservoir classification is a fundamental aspect of petroleum geology and reservoir engineering, as it provides the basis for understanding reservoir heterogeneity, fluid distribution, and hydrocarbon recovery potential. Accurate classification of reservoirs enhances exploration success, supports effective field development planning, and improves reservoir management strategies. In complex sedimentary basins such as the Niger Delta, reliance on conventional classification methods based solely on petrophysical and seismic data often proves insufficient due to pronounced lithological variability, structural complexity, and multiple hydrocarbon charge events. Consequently, the integration of geochemical techniques, particularly biomarker analysis, has become increasingly important in refining reservoir classification frameworks (Speight, 2014).

Biomarkers are molecular fossils derived from the lipid components of once-living organisms and preserved in crude oils and sedimentary organic matter through geological time. These compounds retain diagnostic structural characteristics that reflect their biological origin, depositional environment, and thermal maturity history. Commonly studied biomarkers include n-alkanes, isoprenoids, steranes, and terpanes, which are routinely analyzed using gas chromatography–mass spectrometry (GC-MS). The distribution and relative abundance of these biomarkers provide valuable information on organic matter input, redox conditions during deposition, levels of thermal maturity, and post-depositional alteration processes such as biodegradation and water washing.

In the Niger Delta Basin, one of the most prolific hydrocarbon provinces in the world, biomarker studies have played a significant role in unraveling petroleum system characteristics. Numerous geochemical investigations have demonstrated that crude oils in the basin are largely derived from mixed terrigenous and marine organic matter deposited in deltaic to shallow marine environments under oxic to sub-oxic conditions. Variations in biomarker parameters, such as pristane/phytane ratios, sterane distributions, and hopane indices, have been used to establish oil-oil and oil-source rock correlations across different depobelts, thereby enhancing the understanding of hydrocarbon generation and migration patterns.

Beyond source rock characterization, biomarker distribution has important implications for reservoir classification. Variations in biomarker signatures within and between reservoirs can indicate differences in migration pathways, timing of hydrocarbon charge, reservoir compartmentalization, and in-reservoir alteration processes. Oils with similar biomarker fingerprints may suggest a common source and shared migration history, whereas distinct biomarker patterns within adjacent reservoirs or wells may reflect separate charging events or the presence of sealing barriers. These geochemical distinctions provide insights into reservoir connectivity and heterogeneity that may not be readily apparent from conventional geological or petrophysical data alone. The integration of biomarker distribution into reservoir classification therefore offers a more comprehensive approach to reservoir evaluation in the Niger Delta. By complementing seismic interpretation and petrophysical analysis, biomarker-based classification enhances the discrimination of reservoir units, improves understanding of reservoir continuity, and supports more accurate prediction of fluid behavior. Given the structural complexity and stratigraphic variability characteristic of Niger Delta reservoirs, incorporating biomarker insights is essential for developing robust reservoir models and optimizing hydrocarbon exploration and production strategies.

The Niger Delta Basin is one of the most prolific hydrocarbon provinces globally, characterized by complex stratigraphy, multiple petroleum systems, and significant lateral and vertical fluid heterogeneity. Traditional reservoir classification methods in the basin have largely relied on bulk physical and thermodynamic properties such as gas–oil ratio (GOR), API gravity, condensate yield, and ASTM D86 distillation characteristics. While effective in many cases, these parameters can be ambiguous in reservoirs hosting volatile oils, gas condensates, and near-critical fluids, which are common within the Niger Delta.

Geochemical biomarkers provide an alternative and complementary approach to reservoir classification by offering molecular-level insights into fluid origin, depositional environment, and thermal evolution. Biomarkers are resistant to post-accumulation alteration and are therefore well suited for forensic evaluation and auditing purposes. This study builds on the growing recognition that biomarker distributions, when systematically analyzed, can significantly improve the reliability of reservoir classification frameworks, particularly under OPEC audit scrutiny.

The objective of this paper is to evaluate the impact of biomarker distribution on reservoir fluid classification in the Niger Delta and to demonstrate how GC-FID-based fingerprinting can enhance classification accuracy, reduce ambiguity in borderline systems, and support auditable, science-based decision-making.

Conceptual Review

Concept of Biomarkers

Biomarkers, also referred to as molecular fossils, are complex organic compounds derived from the biochemical constituents of once-living organisms and preserved in sedimentary rocks, crude oils, and natural gases. These compounds retain characteristic molecular structures that reflect their biological origins and the environmental conditions under which the organic matter was deposited. Due to their resistance to thermal and biological degradation, biomarkers serve as reliable indicators of source rock characteristics, depositional environments, and thermal maturity (Peters, Walters, & Moldowan, 2005). Common biomarker groups used in petroleum geochemistry include n-alkanes, isoprenoids (pristane and phytane), steranes, and terpanes (hopanes). These compounds are typically analyzed using gas chromatography–mass spectrometry (GC-MS), which enables detailed molecular identification and quantification. The distribution of biomarkers provides insights into organic matter input, redox conditions during deposition, and post-depositional processes such as biodegradation and water washing (Tissot & Welte, 1984).

Concept of Biomarker Distribution

Biomarker distribution refers to the relative abundance, compositional patterns, and spatial variability of biomarker compounds within and between petroleum samples. Differences in biomarker distributions may arise from variations in source rock facies, depositional environment, thermal maturity, migration history, or in-reservoir alteration processes (Peters et al., 2005). In petroleum systems, similar biomarker distributions across reservoirs typically indicate a common source rock and shared migration pathway. Conversely, variations in biomarker signatures can suggest multiple source rocks, different charging events, or reservoir compartmentalization. As a result, biomarker distribution serves as a geochemical fingerprint for distinguishing genetically related and unrelated hydrocarbons (Hunt, 1996).

Concept of Reservoir Classification

Reservoir classification involves the systematic grouping of reservoir rocks based on their geological, petrophysical, and fluid characteristics. Traditional reservoir classification relies primarily on lithology, porosity, permeability, fluid properties, and structural setting derived from well logs, core analysis, and seismic data. While effective, these approaches may not fully capture subsurface complexity in highly heterogeneous reservoirs (Tiab & Donaldson, 2015). Modern reservoir classification increasingly incorporates geochemical data to complement geological and petrophysical interpretations. This integrated approach improves reservoir characterization, enhances understanding of reservoir continuity, and reduces uncertainty in field development planning (Lake et al., 2014).

Biomarkers and Reservoir Classification

The incorporation of biomarker analysis into reservoir classification provides a geochemical dimension that enhances conventional classification methods. Biomarker distributions can be used to identify reservoir compartmentalization, determine fluid communication between wells, and distinguish between reservoirs with similar petrophysical properties but different hydrocarbon charge histories (Peters & Fowler, 2002). Reservoirs exhibiting similar biomarker fingerprints are often interpreted as being hydraulically connected or charged from the same source rock, while contrasting biomarker signatures may indicate sealing faults, stratigraphic barriers, or multiple charging episodes. These geochemical insights are particularly valuable in complex reservoirs where structural and stratigraphic heterogeneities obscure fluid flow patterns (England & Mackenzie, 1989).

Niger Delta Reservoir Context

The Niger Delta Basin is characterized by thick sequences of deltaic sands and shales, growth faults, rollover anticlines, and multiple depobelts. These geological features result in highly heterogeneous and compartmentalized reservoirs. Biomarker studies conducted in the Niger Delta indicate that most crude oils are derived from mixed terrigenous and marine organic matter deposited in deltaic to shallow marine environments under varying redox conditions (Ekweozor & Okoye, 1980; Doust & Omatsola, 1990). Variations in biomarker parameters such as pristane/phytane ratios, sterane distributions, and hopane compositions across different fields and stratigraphic intervals reflect differences in source input, depositional environment, and migration pathways. These variations have been widely used to classify reservoirs, establish oil-oil correlations, and infer reservoir connectivity in the Niger Delta (Abdulkareem et al., 2017).

Link between Biomarker Distribution and Reservoir Classification

Conceptually, biomarker distribution influences reservoir classification by revealing genetic relationships among hydrocarbons, identifying compartmentalization, and providing insights into migration and accumulation processes. When integrated with geological and petrophysical data, biomarker analysis strengthens reservoir classification by improving discrimination between reservoir units and reducing interpretational uncertainty (Peters et al., 2005). In geologically complex basins such as the Niger Delta, where reservoirs are affected by faulting, stratigraphic variability, and multiple charge events, biomarker-based classification is essential for developing robust reservoir models and optimizing hydrocarbon exploration and production strategies.

Biomarkers and Reservoir Classification Theory

Biomarkers in Petroleum Systems

Biomarkers are complex organic compounds derived from biological precursors such as algae, bacteria, and higher plants. Common biomarker groups include n-alkanes, isoprenoids, steranes, and terpanes. Their molecular distributions reflect source rock type, depositional environment, redox conditions, and thermal maturity.

Diagnostic Biomarker Ratios

Key biomarker ratios employed in this study include pristane/phytane (Pr/Ph), C17/C18, CPI, and sterane distributions (C27–C29). Pr/Ph ratios provide insight into depositional redox conditions, while CPI values reflect organic matter maturity. Sterane and terpane distributions offer additional information on organic input and depositional facies.

Relevance to Reservoir Fluid Classification

Although biomarkers occur in trace concentrations, their distributions correlate strongly with bulk compositional characteristics and phase behavior. As such, they provide indirect yet powerful indicators for distinguishing oil, gas, and transitional systems, particularly where conventional PVT-based criteria overlap.

Materials and Methods

Sample Collection and Handling

Fifty (50) reservoir fluid samples were collected from producing fields across the Niger Delta, representing a range of stratigraphic levels, depths, and production histories. Strict chain-of-custody procedures were followed to ensure data integrity and consistency with OPEC audit requirements.

GC-FID Analytical Procedure

Whole-oil samples were analyzed using GC-FID under standardized conditions. Chromatograms were interpreted to quantify n-alkane distributions from n-C7 to n-C35, isoprenoid abundances, and paraffinic–naphthenic–aromatic (PNA) fractions.

Data Analysis and Classification Workflow

Biomarker ratios were calculated and statistically analyzed to identify clustering patterns corresponding to reservoir fluid types. These results were compared with existing field classifications and production data to validate interpretations.

Results and Discussion

n-Alkane Distribution Patterns: Gas-condensate systems exhibited unimodal distributions skewed toward low molecular weight hydrocarbons (n-C7–n-C15). Oil systems displayed broader, bimodal envelopes extending toward heavier fractions (n-C20–n-C35), while borderline systems showed intermediate profiles.

Isoprenoid Ratios and CPI: Pr/Ph ratios below 1.0 were characteristic of gas and condensate systems, whereas oil systems commonly exhibited Pr/Ph values exceeding 1.5. CPI values ranged from 0.95–1.20 in gas systems and 1.20–1.60 in oil systems, reflecting maturity differences.

Sterane and Terpane Distributions: C29 sterane dominance was associated with terrigenous organic input typical of oil-prone deltaic systems, while C27-enriched patterns were more prevalent in gas-condensate reservoirs. Tricyclic terpane ratios further delineated depositional variations across the basin.

The results confirm that biomarker distributions provide a coherent and reproducible basis for reservoir classification in the Niger Delta. Biomarkers are particularly effective in resolving borderline cases where bulk properties alone are inconclusive. Their resistance to operational and surface effects makes them suitable for audit and verification purposes. Incorporating biomarker fingerprinting into reservoir classification workflows enhances Nigeria's ability to defend reservoir categorizations during OPEC audits. The approach provides a transparent, science-based framework that complements conventional PVT and production data.

Conclusions

This study demonstrates that biomarker distribution significantly influences reservoir classification outcomes in the Niger Delta. GC-FID-based fingerprinting using Pr/Ph ratios, CPI values, and sterane–terpane distributions offers a robust and auditable framework for distinguishing oil, gas, and transitional systems. The findings support the formal integration of biomarker analysis into national reservoir classification and reporting practices.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

References

Abdulkareem, A. S., Adekola, S. A., & Akinlua, A. (2017). Biomarker characteristics and oil-oil correlation of crude oils from the Niger Delta Basin, Nigeria. Journal of African Earth Sciences, 129, 283–295.

Doust, H., & Omatsola, E. (1990). Niger Delta. In J. D. Edwards & P. A. Santogrossi (Eds.), Divergent/passive margin basins (AAPG Memoir 48, pp. 201–238). American Association of Petroleum Geologists.

Ekweozor, C. M., & Daukoru, E. M. (1994). Petroleum source bed evaluation of Tertiary Niger Delta using organic geochemical data. AAPG Bulletin, 78(2), 234–254.

Ekweozor, C. M., & Okoye, N. V. (1980). Petroleum source bed evaluation of Tertiary Niger Delta. American Association of Petroleum Geologists Bulletin, 64(8), 1251–1259.

England, W. A., & Mackenzie, A. S. (1989). Some aspects of the organic geochemistry of petroleum fluids. Organic Geochemistry, 16(1–3), 353–362.

Evamy, B. D., Haremboure, J., Kamerling, P., Knaap, W. A.,

Hunt, J. M. (1996). Petroleum Geochemistry and Geology. W.H. Freeman and Company.

Lake, L. W., Johns, R. T., Rossen, W. R., & Pope, G. A. (2014). Fundamentals of enhanced oil recovery. Society of Petroleum Engineers.

Moldowan, J. M., Seifert, W. K., & Gallegos, E. J. (1985). Relationship between petroleum composition and depositional environment of petroleum source rocks. AAPG Bulletin, 69(8), 1255–1268.

Peters, K. E., & Fowler, M. G. (2002). Applications of petroleum geochemistry to exploration and reservoir management. Organic Geochemistry, 33(1), 5–36.

Peters, K. E., Walters, C. C., & Moldowan, J. M. (2005). The Biomarker Guide: Biomarkers and Isotopes in Petroleum Exploration and Earth History. Cambridge University Press.

Speight, J. G. (2014). The Chemistry and Technology of Petroleum. CRC Press.

Tiab, D., & Donaldson, E. C. (2015). Petrophysics: Theory and practice of measuring reservoir rock and fluid transport properties (4th ed.). Gulf Professional Publishing.

Tissot, B. P., & Welte, D. H. (1984). Petroleum formation and occurrence (2nd ed.). Springer.