UNIOSUN JOURNAL OF BASIC AND APPLIED SCIENCES
OSUN STATE UNIVERSITY, OSOGBO
UJBAS

ISSN: 3121-9837
www.ujws.uniosun.edu.ng/ujbas
ujbas@uniosun.edu.ng

CHARACTERISATION AND SOURCE EVALUATION OF N-ALKANES IN CRUDE OILS FROM OFFSHORE EASTERN OFFSHORE NIGER DELTA

Kehinde O. Akinterinwa[1], Olubunmi C. Adeigbe[2], Olugbenga T. Fajemila[1], Modupe A. Egbeola[2].

Email: kehinde.adeosun@uniosun.edu.ng

Authors Affiliation:

[1]Department of Geological Sciences, Osun State University, Osogbo, Nigeria

[2]Department of Geology, University of Ibadan, Ibadan, Nigeria.

History:

Volume 1, Number 1
Published: 30/05/2026

Keywords:

Biomarkers, Thermal maturity, Paleoenvironment, Biodegradation, Organic matter

ABSTRACT

Hydrocarbon source rocks and crude oils contain biomarkers that provide geochemical information on organic matter source, thermal maturity and paleoenvironment among others. Hence, this study was designed to characterize crude oil samples. Two samples from Kitamarine field (KTM-10H, KTM-117) and one from Okwok field (OK-24), offshore eastern Niger Delta were subjected to Gas Chromatography (GC) in order to evaluate their paleo-depositional environment, source input, thermal maturity as well as to determine their extent of biodegradation. The *n*-alkanes of KTM-10H, KTM-117 and OK-24 saturate fractions peaked at *n*C2316, *n*C157 and *n*C136, respectively, signifying that the three oil samples have been slightly biodegraded. The pristane/phytane (Pr/Ph) ratios of the three samples were 2.24, 2.03 and 2.42, respectively indicating derivation from sub-oxic environmental conditions. The Pr/*n*C17 (1.89, 4.32, 0.89) and Phy/*n*C18 (0.99, 2.20, 0.45) values and their cross plot revealed that the three oil samples were sourced from mixed organic matter (Type II/III kerogen). Carbon Preference Index (CP1) values were 0.34, 0.40 and 0.43 respectively. Terrigenous/Aquatic Ratios (TAR) are 0.04, 0.71 and 0.31, respectively, supported sub-oxic depositional setting in a mixed marine and terrigenous environment of deposition.

1. INTRODUCTION

The Niger Delta is the twelfth richest in petroleum resources, with 2.2% of the world's discovered oil and 1.4% of the world's discovered gas (Petroconsultants1996a, Klett et al., 1997). There are constraints on oil and gas reserves in Nigeria, it is therefore important to revisit abandoned fields and perform basin wide geochemistry of all the sedimentary basins in Nigeria. These geochemical analyses will in turn give rise to the understanding the organic source materials of the oils within the basins, environment of deposition and to establish their thermal history (maturity) as well as to determine document their degree of possible microbial degeneration. Oils within a field usually have a similar geologic history (for example, corresponding source and maturation), the disparity may not be identified from bulk characteristics like viscosity, gravity, sulfur and isotopic structure (Ekpo et al, 2018). Therefore, n-alkanes are needed because they are major indicators in petroleum geochemistry, that serve as basic molecular fingerprints for determining the origin, maturity, and alteration of crude oils and sedimentary organic matter. While they represent only a percentage of total hydrocarbons, their arrangements obtained through gas chromatography (GC) give rise to detailed data for oil-oil and oil-source rock correlations.

According to Phillip and Lewis (1987), biomarkers are organic compounds in a geological sample that can be structurally related to its precursor molecule which occurs as a natural product in plant, animal, bacteria, spore, fungi or any other potential source materials. These biomarkers are the parameters used in oil fingerprinting technology and the comprise diagnostic ratios such as isoprenoids/n-alkanes, Pristane/Phytane ratios, Terrigenous Aquatic Ratios (TAR) and other parameter like Carbon Preference Index (CPI) and Odd Even Predominance (OEP). This oil technology regionally has helped to decipher the size or the degree (reservoir continuity) and extent of a field and has also been useful in designing the progress of a field and particularly the quantity and position of wells needed to exhaust the field. Oil geochemistry (oil fingerprinting) has to do with reservoir continuity evaluation in various geological settings comprise a comprehensive range of field sizes, fundamental environments, reservoir lithologies, and oil categories. (Slentz, 1981; Kaufman et al., 1990; Hwang and Baskin, 1994; Hwang et al., 1994; Sundararaman et al., 1995).In this present study, gas chromatographic analyses were carried out on oil samples from wells located at offshore eastern Niger delta to determine the degree of biodegradation, organic matter types and source, thermal maturation and paleodepositional environment.

Location of study

The study area is located in the western offshore eastern Niger Delta as shown in Figure 1.

The Niger Delta Basin is a unique sedimentary basin situated on the continental margin of the Gulf of Guinea in equatorial West Africa and lies between latitudes 4° and 7°N and longitudes 3° and 9°E (Whiteman, 1982). It extends to the southern part of Nigeria and covers an area of about 75,000km^2, with a 12km thick clastic wedge overlying the lower part of the Benue trough which has greatly influenced its formation. It is enclosed in the southern part by the Gulf of Guinea (or the 4000m bathymetric contour) and in the northern part by older (Cretaceous) tectonic elements which include the Anambra Basin, Abakaliki uplift and the Afikpo syncline. The Cameroon volcanic line and the Dahomey Basin mark the bounds of the Delta in the east and west respectively. This sedimentary basin is reported as one of the most productive hydrocarbon provinces in the world, and current colossal oil findings in the deep-water areas propose that this region will continue to be a spotlight of exploration activities (Corredor et al., 2005). The Niger Delta has prograded into the Gulf of Guinea at a progressively rising rate in reaction to the sprouting drainage area, basement subsidence and eustatic sea level changes.

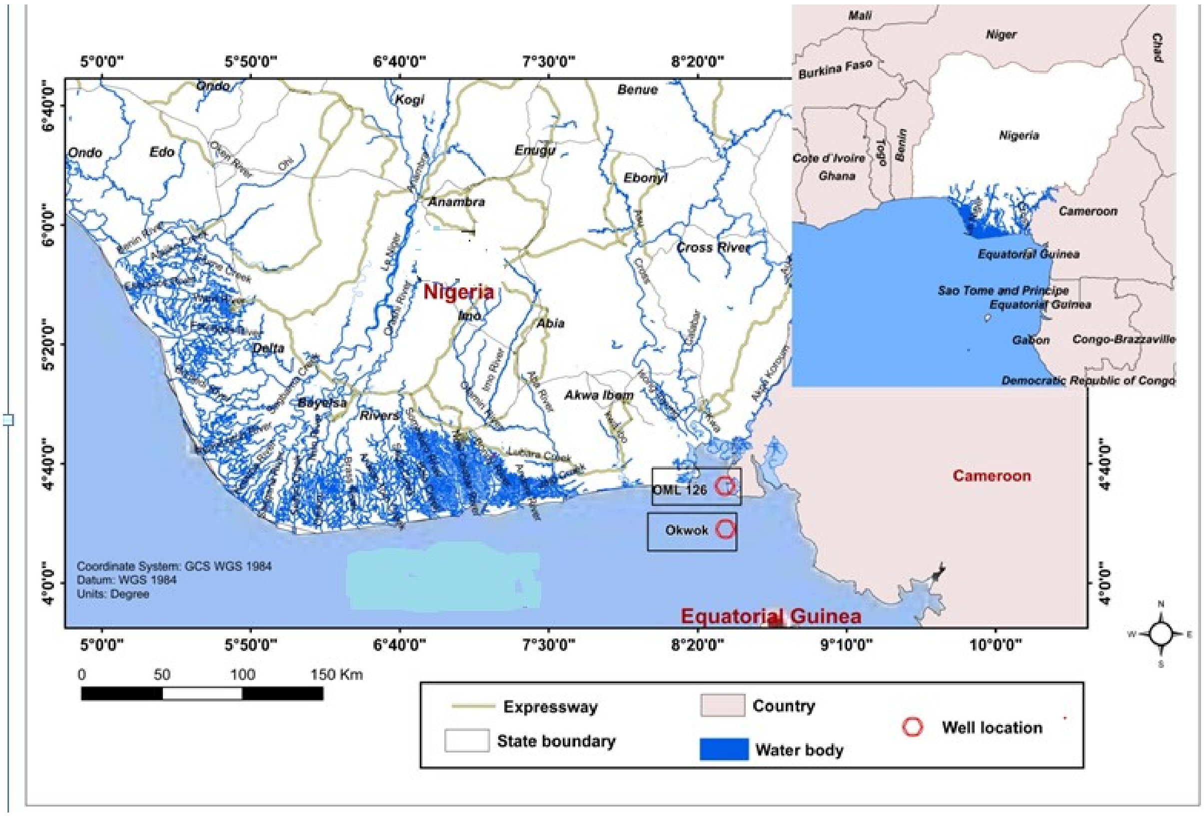

Figure 1: Location Map of Study Area

Results and Discussions

Gas Chromatography

The fingerprints of gas chromatography can be used to decipher the organic matter source. N-alkane concentrations gotten from asphaltene fractions of studied oils, pristane/phytane ratios, Carbon Preference Index (CPI), isoprenoid/n-alkane ratios are the main parameters geochemical characterization in this study.

N-alkane distributions

With the distributions of nC_9-nC_{32}, as presented in Figure 2, KTM 10H reflects a steady rise from nC_9 and having its peak at nC_{16} and declining to nC_{34}. Figure 3, presents KTM 117 n-alkane distributions rising steadily from nC_9 maximizing at nC_{17} followed by a decline to nC_{33} and OK 24 followed the same trend rising from nC_9 to peak at nC_{13} and declining to nC_{33} as shown in Figure 4. This is an implication that organic matter was derived from a mixture of both marine and terrestrial environments. With these similar trends in the n-alkane distributions, there is an indication of slight evidence of degradation in the three (3) analyzed oil samples. (Peters et al., 2005a; Hunt *et al.,*, 2012; Waples, 1994).

Pristane/Phytane ratios

Pristane and phytane are essential tools used to identify the source of organic matter as well as the conditions of the environment of deposition of crude oils (Powell and Mckirdy, 1973; Didyk et al., 1978; Peters and Moldowan, 1993; Chandra et al., 1994; Peters et al., 2005). The three oil samples revealed the existence of pristane (Pr) and phytane (Pphy). Their ratios have been widely used to assess the redox conditions during sedimentation and diagenesis

(Chandra et al., 1994; Didyk et al., 1978). These two fingerprints that are called acyclic isoprenoids are present in noteworthy values with pristane in the main thereby exceeding that of phytane (Table 1). KTM 10H has a Ppr/Pphy ratio of 2.02, that of KTM 117 is 2.02 and OK 24 taking up a value of 2.42 as shown in Table 1. These ratios indicate that the three oil samples were formed under a suboxic condition hence, mixed marine and terrigenous environment of deposition.

Carbon Preference Index (CPI)

This tool is a mathematical depiction of odd-over-even predominance (OEP) in n-alkanes in a specified carbon number series and often used as a maturity pointer. They have been found very useful in paleoenvironmental and maturation assessments (Radke et al., 1986; Chakhmakhchev et al. and Suzuki, 1996a, b, 1997; Hughes et al., 1995). The CPI values for the three (3) oil samples KTM 10H, KTM 117 and OK 24 are 0.30,0.40 and 0.40 respectively and their corresponding OEP values are 0.04,0.71and 0.31 as shown in Table 1.

Peters et al,. (2005) stated that CPI was the maturity indicator applied to crude oils and established that values greater than 1.0 signify immature samples. Therefore, the values for KTM 10H, KTM 117 and OK 24 imply that the said oil samples are thermally mature. Moreover, a plot of Pr/Ph against CPI is to determine the redox condition of the environments of deposition of the crude oils. Figure 6 shows that all the three oil samples were deposited within suboxic environments of deposition.

Isoprenoids/n-alkanes ratios

The connection between isoprenoids/n-alkanes is dependent on pristane/nC17 and phytane/nC18. These are tools considered in oil correlation studies. According to Lijmbach (1975), crude oils that are from rocks formed within open water setting exhibit Pr/nC17<0.5 as against others from inland peat swamps with ratios >1.0. Here in this study, care was taken in the elucidation of these isoprenoid/n-alkanes ratios because they both decline as thermal maturity of petroleum decreases. Also, n-alkanes preceding the isoprenoids in the ratios, are by and large removed during further biodegradation.

The values of Pr/nC17and Phy/nC18 for the three oil samples are presented in Table 1. The former has 1.89, 4.32 and 0.89 while the latter takes up 0.99, 2.19 and 0.45. Figure 5 is a plot of isoprenoids/n-alkanes. Its purpose is to describe the maturity of the source rock at the time of discharge of the oils, their organic matter type and the redox conditions of the depositional environments. These fingerprints are also used to decipher the extent of degeneration of oils. (Connan and Cassou, 1980).

KTM -10H, KTM-117 and OK-24 all plotted within Mixed Type II/III kerogen. This implies that oils which are definitely from offshore eastern Niger Delta are constant with terrestrial organic and mixed terrestrial/ marine organic input. This agrees with the findings of Egbo et al. (2025) that oils from Niger Delta are composed of organic matter from mixed marine and terrestrial origin.

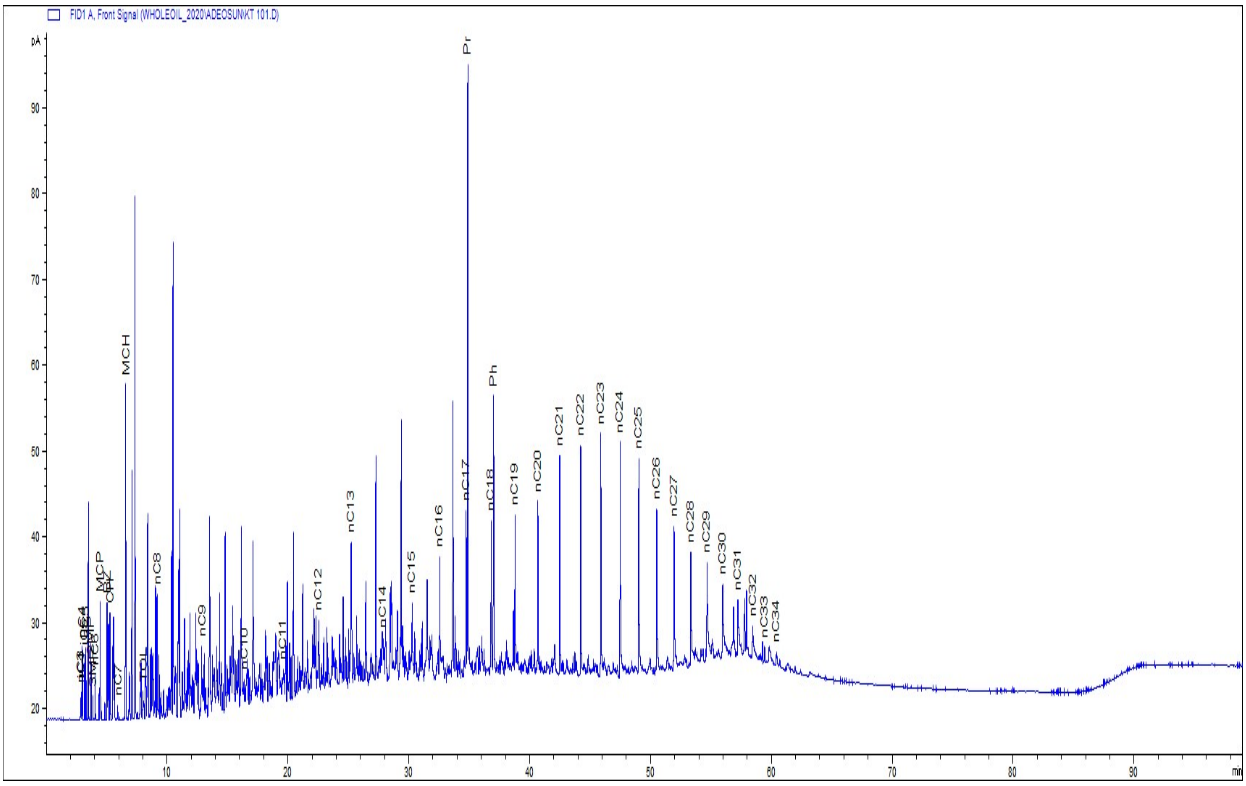

Figure 2: Whole oil chromatogram of KTM-10H

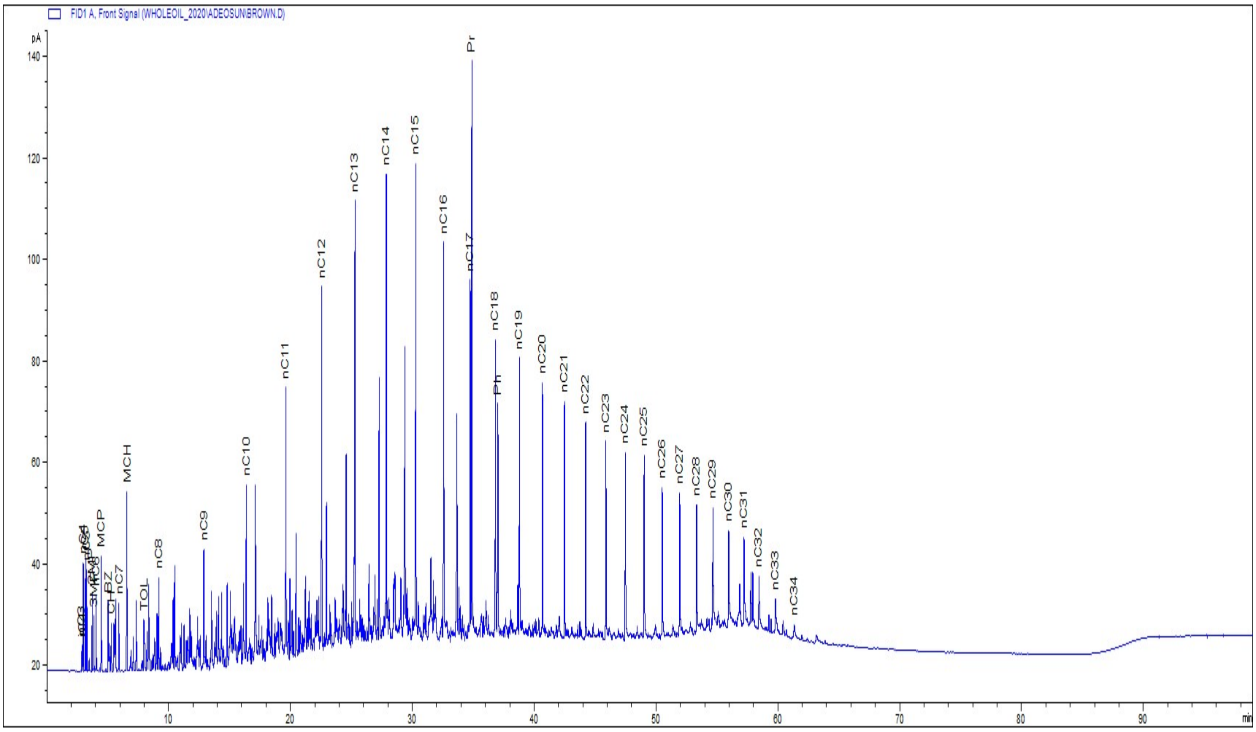

Figure 3: Whole oil chromatogram of KTM-117

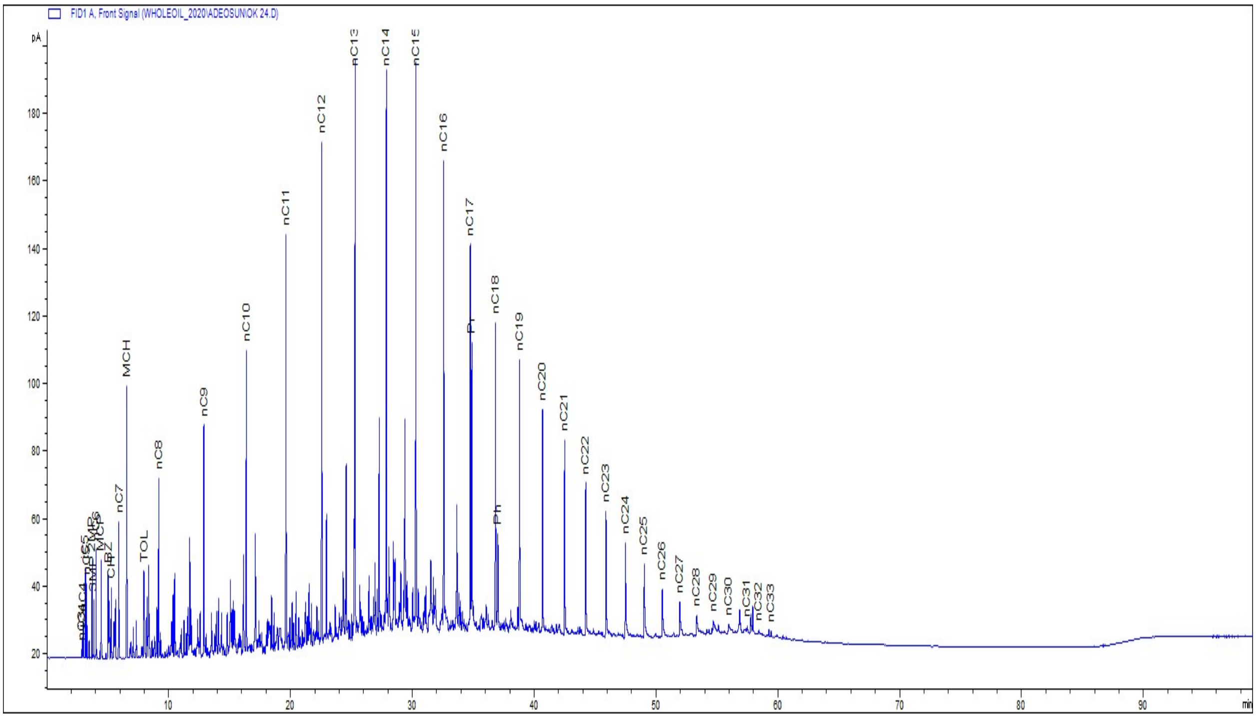

Figure 4: Whole oil chromatogram of OK-24

The concentration of regular steranes C_{27}-C_{29} in the oils implies that the studied oils are generated from mixed kerogen Types I/II origin. Hence, they are of mixed marine and terrestrial environments. The Ternary plot of the regular steranes (C_{27}, C_{28} and C_{29}), further supports that the oils are from mixed marine and terrestrial environments with the dominance of algae. Hence, oils that have marine and terrigenous sources organic of matter will either reflect combined gathering or discharge from source rocks deposited in distal deltaic setting that obtained great marine algae and terrigenous organic matter contributions (Volkaman et al., 1998).

The three studied oils, KTM-10H, KTM-117 and OK-24 are characterized mainly by C_{27}, C_{28} and C_{29} steranes (Figure 7) which are implying oils generated from on a large extent mixed terrestrial and marine organic matter.

Table 1: n-Alkane and isoprenoid parameters

Sample	KTM-10H	KTM-117	OK-24
Field	Kitamarine	Kitamarine	Okwok
Pr/Ph	2.24	2.02	2.42
Pr/nC17	1.89	4.32	0.89
Ph/*n*C18	0.99	2.19	0.45
***n*C17/*n*C18**	1.17	1.03	1.21
Pr+Ph/*n*C17+*n*C18	1.47	3.28	0.69
Degree of waxiness	0.91	2.10	0.41
CPI	0.30	0.40	0.40
OEP	1.09	1.04	1.01
TAR	0.04	0.71	0.31

(Pr : Pristane, Ph : Phytane, Pr/Ph : Pristane/Phytane, Pr/nC17 : Pristane/nC17, Pr/nC18 : Pristane/nC18, CPI : Carbon Preference Index=[(C25+C27+C29+C31+C33) / (C24+C26+C28+C30+C32) + (C25+C27+C29+C31+C33) / (C26+C28+C30+C32+C34)] /2, TAR : Terrigenous/Aquatic Ratio = (C27+C29+C31) / (C15+C17+C19), Waxiness : Σ (nC21-nC31) /Σ (nC15-nC20)

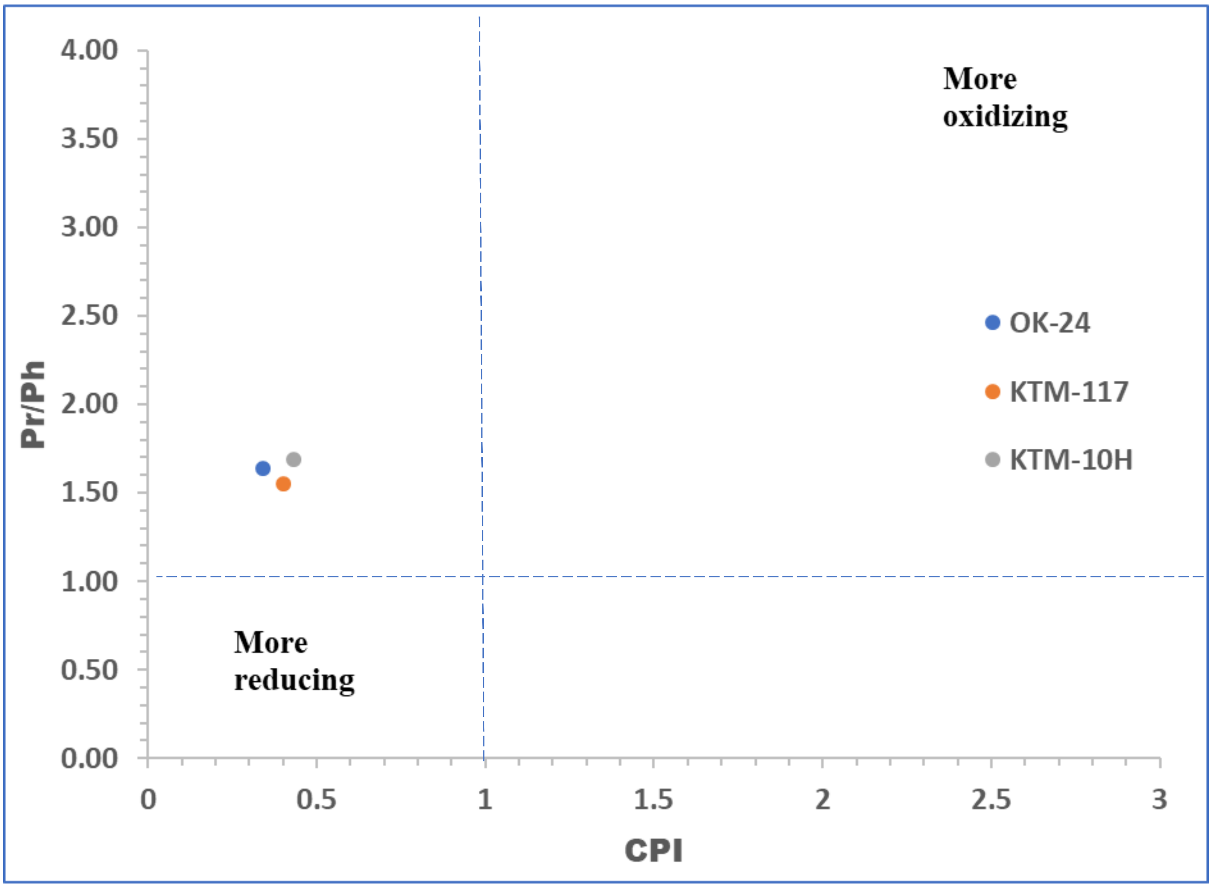

Figure 5: Plot of Pr/Ph against CPI (modified after Collister et al., 1992)

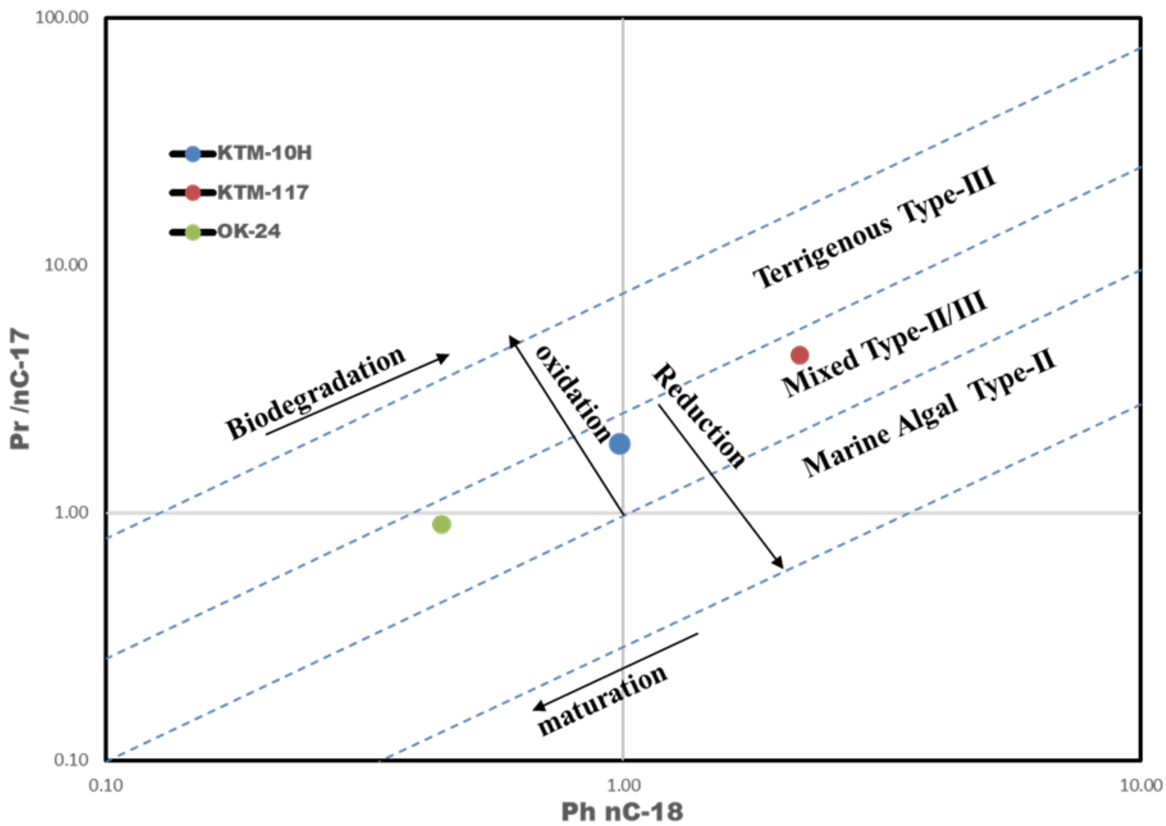

Figure 6: Plot of Pr/nC17 against Ph/nC18 (modified after Collister et al., 1992)

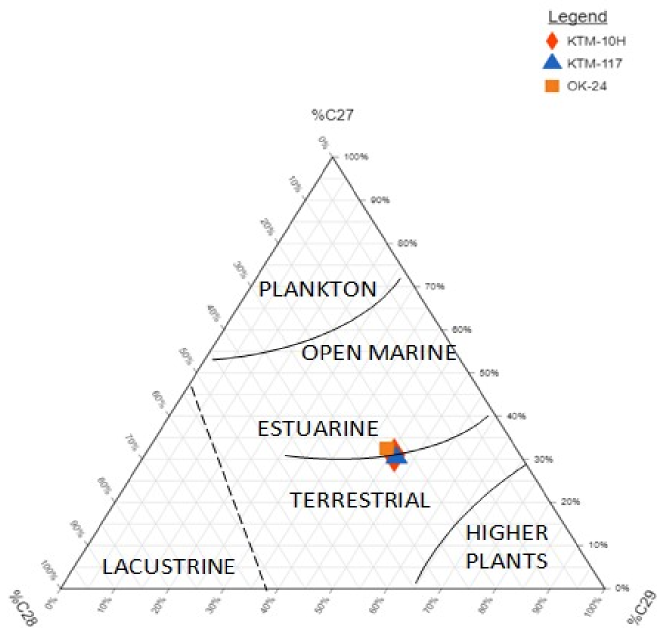

Figure 7: Ternary diagram of the oil samples (modified after Seybold *et al.*, 2009)

Conclusion

The studied oil samples have been classified to have their organic matter generated from Type II/III origin with high terrestrial (algae) input. From their Gas Chromatography (GC) biomarker compositions, there is an indication that the aforementioned organic matter was deposited in sub-oxic mixed marine and terrigenous environments. They are all thermally mature with evidence of slight depletion (biodegradation) which was inferred from the unresolved complex mixtures (UCM) humps in the GC chromatographic fingerprints. The oils are considered to be thermally mature because of their Carbon Preference Index (CPI) values which are less than 1.0. The paleo-depositional environment of the oils is therefore concluded to be a significant terrestrial condition deposited in a suboxic paleoenvironment.

Acknowledgement

The authors are grateful to Exxon-Mobil Laboratories in Eket, and its staff for the opportunity given to Kehinde O. Akinterinwa to carry out the Gas Chromatography analyses.

References

Chakhmakhchev, A., Suzuki, N., Suzuki, M. and Takayama, K., 1996. Biomarker Distributions in Oils from the Akita and Niigata Basins, Japan. *Chemical geology*, *133*(1-4), pp.1-14.

Chandra, K., Mishra, C.S., Samanta,U., Anita Gupta. K, and Mehotra, I. 1994. Correlation of Different Maturity Parameters in the Ahmedabad-Mehsana Block of the Cambay Basin. Organic Geochemistry,Volume 21, Issues 3–4,Pages 313-321.

Collister, J. W., Summons, R. E., Lichtfouse, E. L., and Hayes. 1992. "An Isotopic Biogeochemical Study of the Green River Oil Shale." Organic Geochemistry 19: 265-76

Corredor, F., Shaw, J.H, and Bilotti, F. 2005.Structural stylesin the deep-water fold and thrust belts of the Niger Delta AAPG Bulletin, V. 89, No. 6 pp. 753-780.

Connan, J. and Cassou, A.M., 1980. Properties of Gases and Petroleum Liquids Derived from Terrestrial Kerogen at Various Maturation Levels. Geochimica et Cosmochimica Acta, 44(1), pp.1-23.

Didyk, B. M., Simoneit, B.R.T., Brassell, S. C., & Eglinton, G. 1978. Organic Geochemical Indicators of Palaeoenvironmental Conditions of Sedimentation. Nature, 272(5650), 216–222.

Egbo, O.K., Adeigbe, O.C.and Esegbue, O., 2025. Biomarker Fingerprinting of crude oils from Niger Delta depobelts, Nigeria. Journal of African Earth Sciences 231 (2025) 105768

Ekpo, B.O.,Essien,N., Neji,P.A. and Etsenake, R.O., 2018. Geochemical Fingerprinting of Western offshore Niger Delta Oils. Journal of Petroleum Science and Engineering 160 (2018) 452–464

Hughes, W.B., Holba, A.G. and Dzou, L.I., 1995. The ratios of Dibenzothiophene to Phenanthrene and Pristane to Phytane as Indicators of Depositional Environment and Lithology of Petroleum Source Rocks. Geochimica et Cosmochimica Acta, 59(17), pp.3581-3598.

Hunt, A.G., Darrah, T.H. and Poreda, R.J., 2012. Determining the Source and Genetic Fingerprint of Natural Gases Using Noble Gas Geochemistry: A northern Appalachian Basin Case Study. AAPG bulletin, 96(10), pp.1785-1811.

Hwang, R.J., Baskin, D.K., 1994. Reservoir connectivity and oil homogeneity in a largescale reservoir. Middle East Pet. Geosci. Geo'94 2, 529–541.

Hwang, R.J., Ahmed, A.S., Moldowan, J.M., 1994. Oil Compos. Var. Reserv. Continuity Unity Field, Sudan Org. Geochem 21, 171–188.

Kaufman, R.L., Ahmed, A.S., Elsinger, R.J., 1990. Gas Chromatography as a development and production tool for fingerprinting oils from individual reservoirs: applications in the Gulf of Mexico. In: Schumaker, D., Perkins, B.F. (Eds.), Proceedings of the 9th Annual Research Conference of the Society of

Economic Paleontologists andMineralogists, pp. 263–282. October 1, 1990: New Orleans.

Klett, T. R., Ahlbrandt, T. S., Schmoker, J. W.and Dolton, G. L. 1997. Ranking of the World's Oil and Gas Provinces by Known Petroleum volumes (No. 97-463). US Dept. of the Interior, Geological Survey.

Lijmbach, W.M., 1975, May. SP (1) on the Origin of Petroleum. In World Petroleum Congress (pp. WPC-16134). WPC.

Peters, K.E, and Moldowan, J.M .1993. The Biomarker Guide: Interpreting Molecular Fossils in Petroleum and Ancient Sediments. Prentice-Hall, Inc, Englewood Cliffs, New Jersey.

Peters, K.E., Walters, C.C. and Moldowan, J.M. 2005. The Biomarker Guide, Biomarkers and Isotopes in Petroleum Exploration and Earth History, Volume 2. Cambridge University Press, Cambridge.

Peters, K.E, and Moldowan, J.M .1993. The Biomarker Guide: Interpreting Molecular Fossils in Petroleum and Ancient Sediments. Prentice-Hall, Inc, Englewood Cliffs, New Jersey.

Petroconsultants, 1996a, Petroleum Exploration and Production Database: Houston, Texas, Petroconsultants, Inc., [database available from Petroconsultants, Inc., P.O. Box 740619, Houston, TX 77274-0619].

Phillip, R. P. and Lewis, C. A. 1987. Organic Geochemistry of Biomarkers. Annual Review of Earth and Planetary Sciences, *15*(1), 363-395.

Powell, T. G. and McKirdy, D. M. 1973. Relationship Between Ratio of Pristane to Phytane, Crude Oil Composition and Geological Environment in Australia. Nature Physical Science, 243(124), 37-39.

Radke, M., Welte, D.H. and Willsch, H., 1986. Maturity Parameters Based on Aromatic Hydrocarbons: Influence of the Organic Matter type. Organic Geochemistry, 10(1-3), pp.51-63.

Seybold, H. J., P.Molnar, H. M.Singer, J. S.AndradeJr., H. J.Herrmann, and W.Kinzelbach (2009), Simulation of birdfoot delta formation with application to the Mississippi Delta, J. Geophys. Res., 114, F03012, doi:10.1029/2009JF001248.

Slentz, L.W., 1981. Geochemistry of reservoir fluids as unique approach to optimum reservoir. SPE #9582. In: Presented at Middle East Oil Technical Conference (Manama, Bahrain).

Sundararaman, P., Patterson, B.A., Udo, O.T., 1995. Reservoir geochemistry: applications and case studies in Nigeria. In: Grimalt, J.O., Dorronsoro, C. (Eds.), Organic Geochemistry: Developments and Applications to Energy, Climate, Environment and Human History. Selected Papers from the 17th International Meeting on Organic Geochemistry. AIGOA, Donostia-SanSebasti_an, The Basque Country, Spain: San Sebastian, pp. 369–371.

Waples, D.W., 1994. Maturity Modeling: Thermal Indicators, Hydrocarbon Generation, and Oil Cracking: Chapter 17: Part IV. Identification and Characterization.

Whiteman, C.D. and McKee, T.B., 1982. Breakup of Temperature Inversions in Deep Mountain Valleys: Part II. Thermodynamic Model. Journal of Applied Meteorology and Climatology, 21(3), pp.290-302.