

# Source, depositional environment and maturity levels of some crude oils in southwest Niger Delta, Nigeria

Mudiaga Chukunedum Onojake · L. C. Osuji ·  
S. Abrakasa

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**Abstract** A suite of crude oil samples, that had not been previously characterized geochemically, was collected from two oil fields in the southwest Niger Delta Nigeria. The saturate biomarkers were used to evaluate geochemical characteristics such as depositional environments, sources of organic matter and extent of biodegradation using gas chromatography–flame ionization detector and gas chromatography–mass spectrometry. Distribution of n-alkanes (Pr/Ph, and isoprenoide/n-alkanes ratios), the abundance of hopanes, oleanane skeleton and C<sub>27</sub>–C<sub>29</sub> steranes in the oils indicate that they were formed from mixed sources (marine and terrestrial kerogen) deposited in an oxic paleoenvironment with no particular maturity trend. These parameters also permit the source grouping of the oils into two families.

**Keywords** Biomarkers · Paleoenvironment · Biodegradation · Hopanes · Oleanane

## 1 Introduction

Crude oil study, which utilizes the detailed geochemical analysis of a representative suite of samples, is an excellent way of identifying and comparing samples sourced from a source rock located in a relatively close area (Doust and Noble 2008). Crude oil is a complex combination of hydrocarbons, ranging from C<sub>1</sub> to C<sub>60+</sub>, and it consists predominantly of aliphatic, alicyclic and aromatic hydrocarbons. It may also contain small amounts of nitrogen, oxygen and sulfur compounds, some organometallic complexes, notably of sulfur and vanadium, and dissolved gases, such as hydrogen sulfide.

The geochemical evaluation of source, depositional environment and maturity levels of crude oils help locate hydrocarbons in the explored areas and different stratigraphic units of the basin (Akinlua et al. 2007). This is also useful in petroleum exploration and production because it develops tools to describe, understand and predict the formation of oil and gas, their migration, the thermal history of the basins and the composition of the fluids that have passed through them. It can also serve for the characterization and production of the hydrocarbon fields, the identification of source rocks and the classification of crude oils into families (Karlsen et al. 1995; Larter and Aplin 1995; Huc 2003).

Geochemical methods of crude oil characterization include biomarker fingerprints, use of bulk parameters, stable isotope ratios, hydrocarbon contents, etc. (Barwise 1990; Udo et al. 1992; Oluwole et al. 1993). This mainly relies on gas chromatography–mass spectrometry (GC–MS) for the analysis of biomarkers. It is also responsible for the rapid development of petroleum geochemistry and its application in the oil and gas industry during exploration (Killops and Killops 1993).

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M. C. Onojake (✉) · L. C. Osuji  
Petroleum Chemistry Research Group, Department of Pure and Industrial Chemistry, University of Port Harcourt, Port Harcourt, Nigeria  
e-mail: mudiaga.onojake@uniport.edu.ng; ononed@yahoo.com

S. Abrakasa  
Centre for Petroleum Geosciences, Institute of Petroleum Studies, University of Port Harcourt, Port Harcourt, Nigeria

S. Abrakasa  
Department of Petroleum Engineering, Niger Delta University, Amassoma, Bayelsa, Nigeria

Biomarkers provide information on the organic source materials, environmental conditions during deposition, thermal maturity experienced by a rock or oil and the degree of biodegradation (El-gayer et al. 2002).

The hydrocarbons found within the basin in the Niger Delta occur at different productive horizons that are at very great depths apart (Sonibare et al. 2008). In the Niger Delta, a variety of studies have been carried out in order to determine the location and effectiveness of the region's source rocks (Knox and Omatsola 1978; Ekweozor and Daukoru 1994). But despite these in-depth studies, no consensus has yet emerged concerning the true identity of the petroleum system(s) that have contributed to the greater Niger Delta oil fields (Eneogwe and Ekundayo 2003).

This work is aimed at evaluating the geochemical relationship between the crude oils from two different fields in the southwest Niger Delta and to ascertain the source of organic matter, their depositional environment and their maturity levels.

## 2 Materials and methods

### 2.1 Province geology of Niger Delta

The study area lies within the Niger Delta; its geology is therefore typical of the Niger Delta Basin. The area forms part of a geological sequence of the Quaternary and Tertiary formations of the Niger Delta, consisting mainly of three main geologic formations: The Benin Formation, Agbada Formation and Akata Formation (Sundararaman et al. 2002). The Niger Delta province is the twelfth largest in the world with about 34.5 billion barrels of recoverable oil and 93.8 trillion cubic feet of recoverable gas. It is situated in the Gulf of Guinea and extends throughout the Niger Delta Province, as defined by Klett et al. (1997). From the Eocene to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola 1990). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km<sup>2</sup> (Kulke 1995), a sediment volume of 500,000 km<sup>3</sup> (Hospers 1965) and a sediment thickness of over 10 km in the basin depocenter (Kaplan et al. 1994). The petroleum system of the Niger Delta is referred to as the Tertiary Niger Delta (Akata–Agbada) Petroleum System (Fig. 1).

The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon (Fig. 1). The northern boundary is the Benin flank, an east-northeast trending hinge line south of the West Africa basement massif. The northeastern boundary is defined by outcrops of the Cretaceous on the

Abakaliki high and further east south east by the Calabar flank, a hinge line bordering the adjacent Precambrian. The offshore boundary of the province is defined by the Cameroon volcanic line to the east and the eastern boundary of the Dahomey basin (the eastern-most West African transform-fault passive margin) to the west. There are the 2-km sediment thickness contour or 4,000-m bathymetric contour, in areas where sediment thickness is greater than 2 km, to the south and southwest (Michele et al. 1999).

### 2.2 Sample collection

A suite of crude oil samples was collected from two different producing fields onshore, in the southwest Niger Delta. The crude oils were collected with glass vials with Teflon caps and, prior to laboratory analysis, stored in the refrigerator at a temperature of less 4 °C.

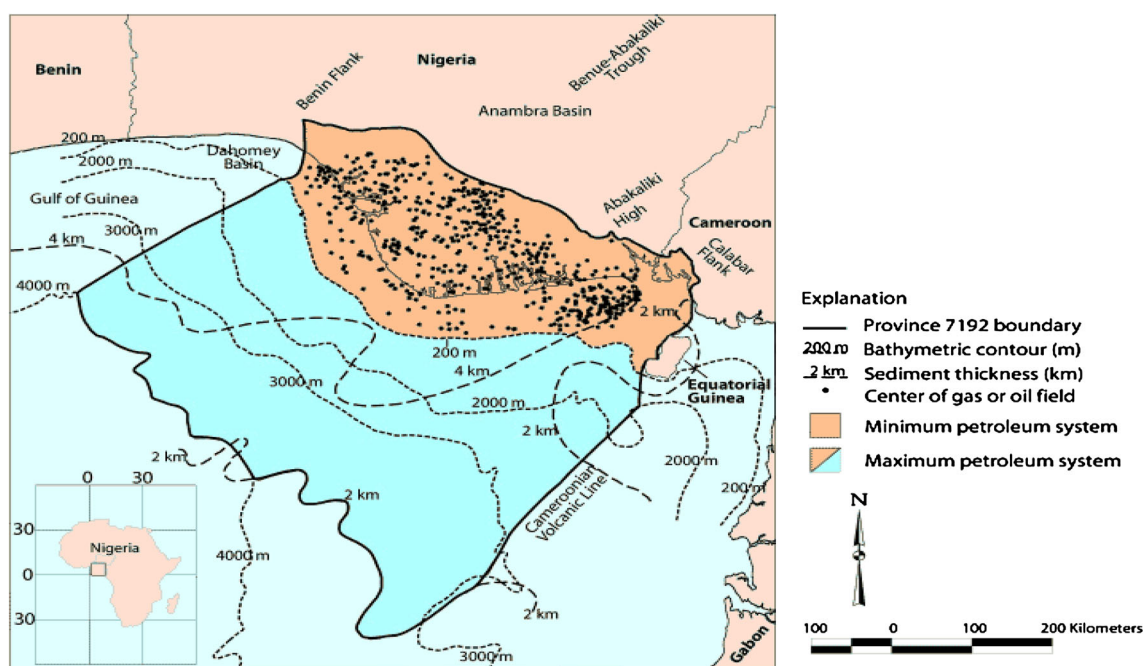
#### 2.2.1 Sample preparation for gas chromatographic mass spectroscopy analysis (GC–MS)

### 2.3 Fractionation of the oils

The crude oils were fractionated into saturates, aromatics hydrocarbons and polar compounds by column chromatography on a silica gel. The standard glass column, which is 50 cm in length and 0.5 cm in internal diameter, was rinsed first with dichloromethane (DCM) and later with light petroleum spirit (petroleum ether). The column was then plugged with cotton wool, to serve as a resting pad for the stationary phase silica gel (SiO<sub>2</sub>) and filled with petroleum ether. Then, the stationary phase (SiO<sub>2</sub>) was introduced. Two (2 g) of Alumina was added to keep the surface stable. An oil sample was introduced, followed by the eluents, gently. 70 ml of petroleum ether was added to elute the aliphatic fraction and 70 ml of DCM was used to elute the aromatic fractions, while 70 ml of methanol was used to elute the polar (resins). The aliphatic fractions were reduced with nitrogen stream to near dryness and then diluted with DCM for GC–MS analysis.

### 2.4 GC–MS analysis

The GC–MS analyses for the aliphatic hydrocarbons of the oils was performed using a Hewlett-Packard 5890II GC with a split/splitless injector (280 °C) linked to a Hewlett-Packard 5972 MSD with an electron voltage of 70 eV, filament current of 220 μA, source temperature of 160 °C, a multiplier voltage of 1600 V and interface of temperature 300 °C. The acquisition was controlled by an HP Vectra PC chemstation computer in both full scan mode and selected ion mode. The sample (1 μl) in DCM was injected by an HP7673 auto-sampler and the split opened after



**Fig. 1** Map of the Niger Delta showing province outline. Source U.S. Geological Survey Open File Report

1 min. Separation was performed on a fused silica capillary column (30 m  $\times$  0.25 mm i.d.) coated with 0–25  $\mu$ m, 5 % phenylmethylsilicone (HP-5). The GC was temperature programmed for 40–300  $^{\circ}$ C at 4  $^{\circ}$ C per minute and held at the final temperature for 20 min. The carrier gas was helium (flow 1 ml/min., pressure of 50 kPa, slit at 30 ml/min.). The acquired data was on a DAT tape for later processing. The data was processed using Chem Station G1701BA (version B.01.001989–1998) software and the integration of peaks was done with the RTE integrator. Figures 2, 3 and 4 show the GC–MS chromatograms of the crude oils samples.

### 3 Results and discussion

#### 3.1 Normal alkanes and isoprenoid distribution

In the geochemical evaluations of crude oils, the ratios of isoprenoids to *n*-paraffin are often used for oil-source correlation, maturation and biodegradation studies (Ekweozor et al. 1981). Various ratios of isoprenoids to *n*-alkanes were computed such as the Pr/Ph, Pr/*n*C<sub>17</sub>, Ph/*n*C<sub>18</sub>, *n*C<sub>25</sub>/*n*C<sub>18</sub>, (Pr + C<sub>17</sub>)/(Ph + C<sub>18</sub>) (Table 1). The gas chromatogram of the normal alkanes and the isoprenoids is shown in Fig. 2. The pristane/phytane (Pr/Ph) ratio is one of the most commonly used geochemical parameters and has been used as an indicator of depositional environment, though with low specificity due to the

interferences of thermal maturity and preliminary assessment of organic matter source inputs (Peters et al. 2005). It is also widely used as indicator of redox potential of the depositional environment. Ten Haven (1996) stressed that high Pr/Ph (>3.0) indicates terrigenous input under oxic conditions and low Pr/Ph (<0.8) indicates anoxic/hypersaline or carbonate environments. Low values of the Pr/Ph (<2) indicate aquatic depositional environments including marine, fresh and brackish water (reducing conditions), whereas high values (up to 10) are related to peat swamp depositional environments (oxidizing conditions) (Roushdy et al. 2010). The studied oil samples are characterized by pristane/phytane ratios, which ranged from 3.36 to 4.05 and 1.88 to 2.31, thus confirming that these oils originated from terrigenous organic matter deposited under an oxic paleo-environment. Sample U4L is slightly different from other samples; it has a Pr/Ph ratio of 1.88 (<2), indicating an aquatic environment. Pr/*n*C<sub>17</sub> ratios range from 0.44 to 1.35, while Ph/*n*C<sub>18</sub> ratios range from 0.16 to 0.65. The relatively high Pr/Ph ratios of some of the oils indicate their high maturation levels.

Several authors have used a plot of Pr/*n*C<sub>17</sub> versus Ph/*n*C<sub>18</sub> to classify oils and rock extracts into different groups (Fig. 5). Source, maturation, migration and biodegradation are the major factors responsible for the differences in crude oil composition. Values less than 1.0 are indicative of non-biodegraded oils. Both Pr/*n*C<sub>17</sub> and Ph/*n*C<sub>18</sub> decrease with maturation, due to the increasing prevalence of the *n*-paraffin. The values of Pr/Ph, Pr/*n*C<sub>17</sub>

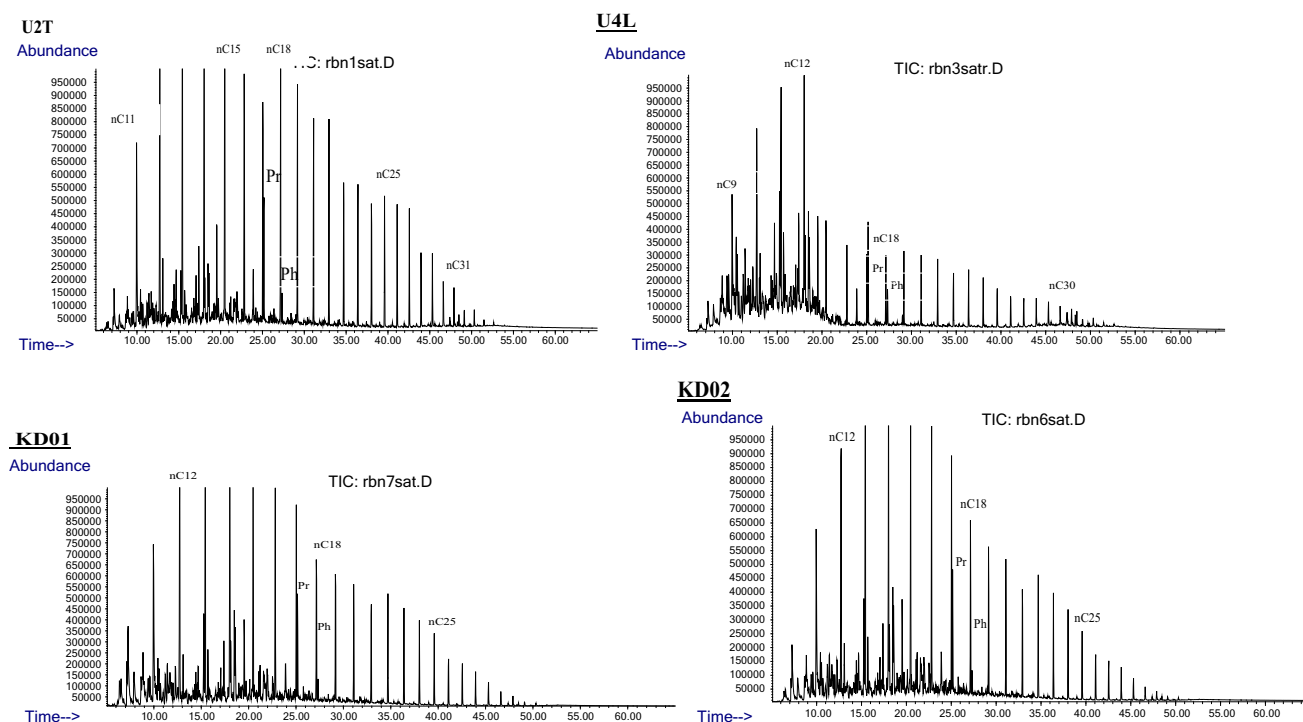


Fig. 2 Reconstructed chromatograms of crude oil samples

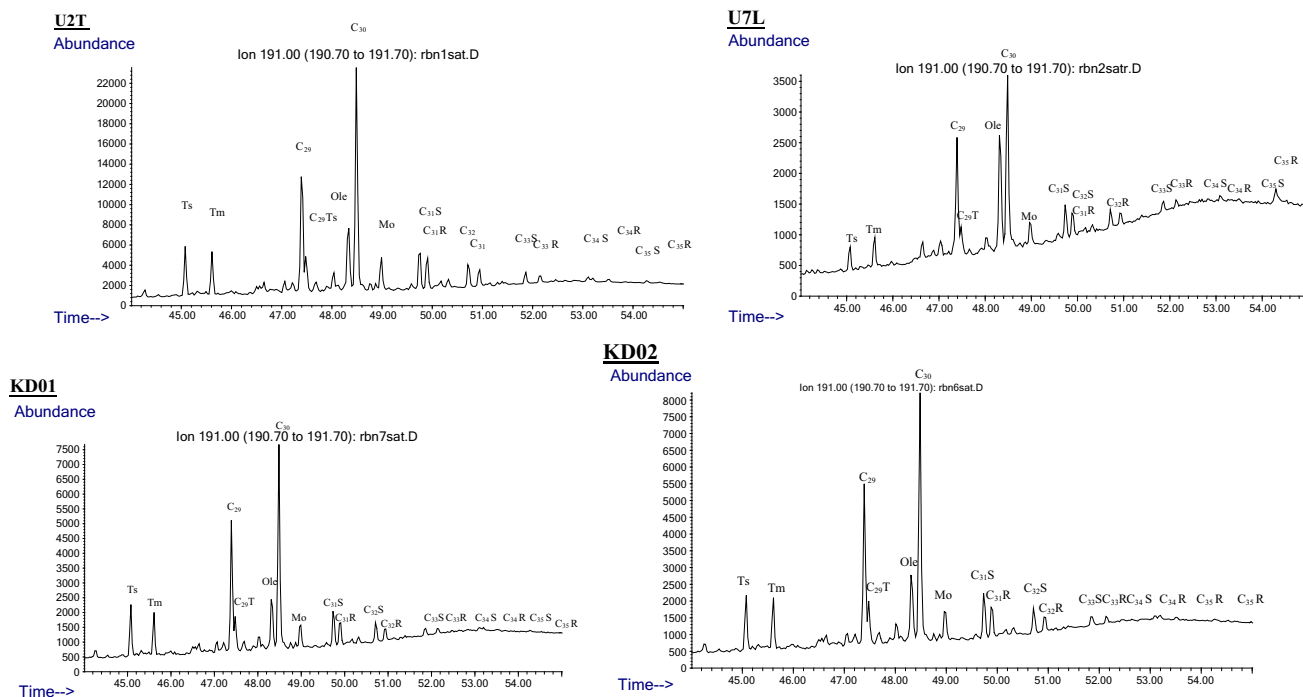
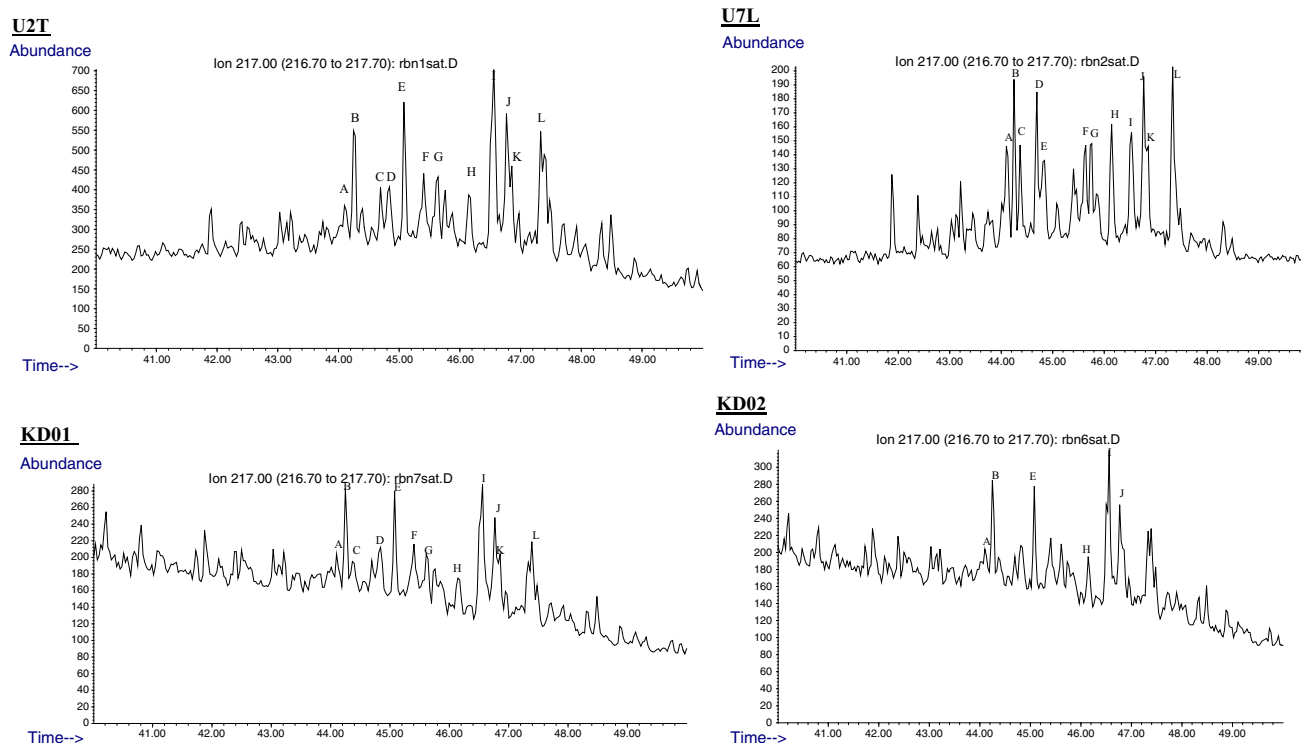


Fig. 3 GC-MS chromatograms of  $m/z$  191 for crude oil samples

and  $\text{Ph}/n\text{C}_{18}$  for the analyzed crude oils are given in Table 1. All samples have  $\text{Ph}/n\text{C}_{18}$  less than one ( $<1.0$ ), suggesting that these samples are non-biodegraded (Hunt; 1996).

### 3.2 Carbon preference index (CPI)

The CPI was the first maturity indicator applied to crude oils (Peters et al. 2005; Muhammad et al. 2010). Some



**Fig. 4** GC–MS chromatograms of  $m/z$  217 for crude oil samples

researchers observed that immature rocks often had high CPI values ( $>1.5$ ). The CPI values ranges between 0.72 and 1.09 for all crude oils (Table 1), so approximately 1.0, implying these are slightly or marginally mature oils. Figure 6 is a plot of pristane/phytane versus CPI that shows the depositional environment of the oils. Moldowan et al. (1985) concluded that an odd carbon preference is characteristic of oils derived from source rocks deposited in non-marine depositional environments. If the total even and odd numbers of paraffins are equally abundant, the value of the (CPI) will be equal to one, as is generally observed in high maturity samples (Tissot and Welte 1984).

In these studied oil samples, a slightly odd-over-even predominance of higher molecular weight n-alkanes ( $nC_{24}$ – $nC_{35}$ ) has been observed, producing CPI values of approximately 1.0 (Table 1). The observed CPI values in most of the study samples are believed to be influenced by the type of organic matter and the thermal maturity, as all samples are known to possess some level of maturity. Listed in Table 1 are the calculated values of the CPI of the crude oils samples. Sample U7L value is 0.76, indicating that the sample is more mature than other samples. None of the samples under study are above 1.5.

The plot of  $Ts/(Ts + Tm)$  versus  $20S/(20S + 20R)$  (Fig. 10) showed some correlation, indicating that  $Ts/(Ts + Tm)$  increases linearly with  $20S/(20S + 20R)$

(Hanson et al. 2000; Seifert and Moldwan 1986; Peters and Moldowan 1993). The plot also indicates that the KD 01–KD 03 oils samples show a fair cluster, implying very close maturity ranking. However, the U2T, U45, U4L and U7L oil samples show a slight variability in the maturity of the oils. These agree with the concept of lateral maturity gradient representing successive charging fronts with varying maturity ranks.

### 3.3 Saturated biomarker distribution

Peters and Moldowan (1993) showed that the Hopanes and Steranes include the biomarkers commonly used for maturity assessment. Figures 3 and 4 are the  $m/z$  191(hopanes) and 217(steranes) chromatograms for the saturated biomarkers distribution of studied crude oil samples. It shows that the pattern of all samples belongs mostly to the  $17\alpha$  (H),  $21\beta$  (H) hopanes series, with molecules ranging from  $C_{27}$  to  $C_{35}$ . The  $C_{30}$  regular hopane is the most predominant member series, followed by  $C_{29}$  norhopane. The ratio of  $C_{29}/C_{30}$  is in the range of 0.62–0.69 (Table 1). The ratio of  $18\alpha$  (H)-trisnorhopane (Ts) and  $17\alpha$  (H)-trisnorhopane (Tm) ranges from 0.79 to 1.47. The  $17\beta$  (H),  $21\alpha$  (H) series of molecules (mortetanes) and the compound are also present in varying abundance. The ratio of Ts to Tm increases by more than 0.5 times as the portion of shale in the calcareous facies increases (Hunt 1996). This

**Table 1** Source and thermal maturity parameters computed from the saturated biomarkers distributions in oil samples

	Samples						
	U2T	U7L	U4L	U45	KD01	KD02	KD03
Pr/Ph	4.05	2.31	2.31	1.88	3.36	3.44	3.40
Pr/n-C <sub>17</sub>	0.56	1.30	1.35	0.77	0.48	0.45	0.44
Ph/n-C <sub>18</sub>	0.16	0.16	0.65	0.42	0.16	0.16	0.16
nC <sub>25</sub> /nC <sub>18</sub>	0.53	0.49	0.67	0.64	0.40	0.38	0.37
CPI	1.01	0.72	1.08	1.02	1.09	1.02	1.04
(Pr + C <sub>17</sub> )/(Ph + C <sub>18</sub> )	1.52	1.52	1.58	1.26	1.40	1.53	1.50
Ts/Tm	1.19	0.82	0.79	0.86	1.25	1.15	1.47
Ts/(Ts + Tm)	0.54	0.45	0.44	0.46	0.56	0.53	0.59
C <sub>29</sub> /C <sub>30</sub> hop	0.62	0.65	0.69	0.67	0.64	0.65	0.60
Ol/C <sub>30</sub> hop	0.37	0.72	0.72	1.03	0.32	0.31	0.03
Ole index	0.37	0.72	0.72	1.03	0.32	0.31	0.03
Homo index	0.03	0.04	0.01	0.01	0.04	0.04	0.05
C <sub>30</sub> M/C <sub>30</sub> hop	0.15	0.14	0.17	0.17	0.17	0.14	0.15
Sterane/hopane	0.08	0.14	0.13	0.20	0.09	0.06	0.02
22S/(22S + 22R)	0.56	0.52	0.56	0.55	0.55	0.58	0.55
C <sub>30</sub> */C <sub>29</sub> Ts	6.57	8.35	6.86	7.39	7.03	7.20	6.36
C <sub>27</sub> steranes (%)	18.32	24.27	30.64	31.36	23.92	27.24	29.72
C <sub>28</sub> steranes (%)	43.16	48.39	30.01	31.57	25.92	29.96	30.68
C <sub>29</sub> steranes (%)	38.52	27.34	39.35	37.07	50.16	42.80	39.60
C <sub>29</sub> steranes: (20S)/(20S + 20R)							
ααα/ααα + αββ	0.60	0.50	0.51	0.50	0.63	0.55	0.46
αβ/αβ + βα	0.87	0.87	0.86	0.85	0.88	0.88	0.87
αββ/αββ + ααα	0.40	0.50	0.49	0.50	0.37	0.45	0.54

Pr/Ph pristane/phytane, Pr/nC<sub>17</sub> pristane/normal-C<sub>17</sub>, Ph/nC<sub>18</sub> phytane/normal-C<sub>18</sub>, CPI carbon preference index, Tm 17α (H), 22, 29, 30-trisnorhopane, Ts 18α(H), 22, 29, 30-trisnorhopane, Ol/C<sub>30</sub> oleanane/C<sub>30</sub> hopane, Homo Index homohopane index (C<sub>35</sub> homohopane S + R)/(C<sub>31</sub> + C<sub>32</sub> + C<sub>33</sub> + C<sub>34</sub> + C<sub>35</sub> homohopanes S + R); C<sub>30</sub>M/C<sub>30</sub>hop C<sub>30</sub> mortane/C<sub>30</sub> hopane, 22S/(22S + 22R) 17α (H), 21β (H)-bishomohopane (22S)/[17α (H), 21β (H)-bishomohopane (22S) + 17α (H), 21β (H)-bishomohopane (22R)] of C<sub>31–32–33</sub>, C<sub>30</sub>\*/C<sub>29</sub>Ts 17α (H) hopane/18α (H)-norhopane, C<sub>29</sub>, 20S/(20S + 20R) 5α (H), 14α (H), 17α (H)-20S/(5α (H), 14α (H), 17α (H)-20S + 5α (H), 14α (H), 17α (H)-20R) of C<sub>29</sub> sterane, αβ/αβ + βα αβC<sub>31+32+33+34+35</sub>(S + R)/αβC<sub>31+32+33+34+35</sub>(S + R) + C<sub>30</sub>Moretane (22S + 22R), αββ/αββ + ααα αββ C<sub>27+28+29</sub> (20S + R)/αββ C<sub>27+28+29</sub> (20S + R) + ααα C<sub>27+28+29</sub> (20S + R)

ratio proved to be useful, though not as decisive as a maturity parameter (Seifert and Moldwan 1986). Van Graas (1990) stated that the Ts/Tm ratios begin to decrease quite late during maturation, but Waples and Machihara (1991) reported that the Ts/Tm ratio does not appear to be appropriate for the quantitative estimation of maturity. There was no distinct variation in the observed values for the Tm/Ts ratios among the samples studied. This ratio may not be indicative of thermal maturity, but rather may be strongly influenced by the source differences among the oils (Palaces and Anders 1984).

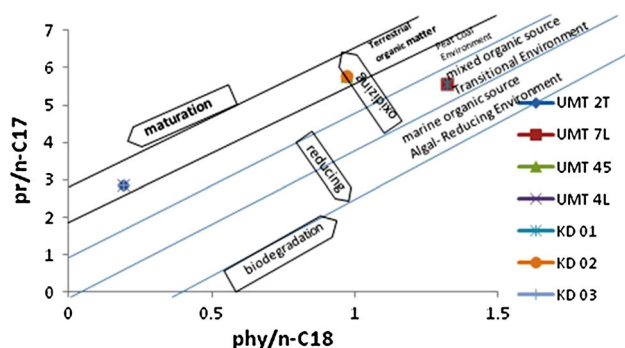
Oleanane is present in all the study samples and is identified as one peak representing 18α (H)-oleanane and 18β (H)-oleanane. The extended hopanes, which occur as stereoisomeric pairs from C<sub>31</sub> to C<sub>35</sub>, occur as either 22S or 22R epimers. The presence of the oleananes is a good indicator of a terrestrial input into the oil-prone source rocks deposited in a deltaic environment (Ekweozor et al.

1979., Philip and Gilbert 1986). Various studies show that oleananes may be considered reasonably reliable indicators of higher plant source material. Hopane (C<sub>30</sub>) αβ/αβ + βα and homohopane (C<sub>32</sub>) 22S/(22S + 22R) ratios for the oils range from 0.85 to 0.88 and 0.52 to 0.58, respectively (Table 1). These values are consistent with the oils generation from the early mature source rocks (Seifert and Moldwan 1986, Peters and Moldowan 1993).

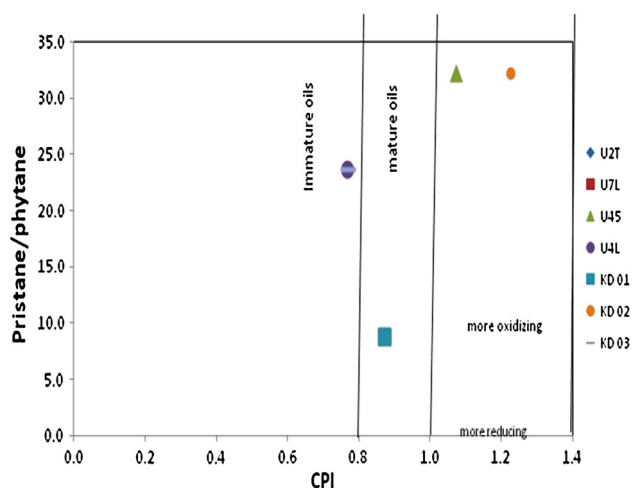
The ratios of C<sub>29</sub>/C<sub>30</sub> hopanes ranges from 0.60 to 0.69. Values greater than one indicate oil generated from organic rich carbonates and evaporates (Connan et al. 1986). All the studied oil samples have C<sub>29</sub>/C<sub>30</sub> hopane ratios of less than one (Table 1). This data illustrates that the oil samples are not sourced from source rocks rich in carbonaceous organic matters (Waples and Machihara 1991).

The distribution of 17α, 21β (H)—homohopanes 22R + 22S C<sub>35</sub>/(C<sub>31</sub>–C<sub>35</sub>), also known as the homohopane index in crude oils, can be used as an indicator of the redox





**Fig. 5** Plot of pristane/n-C<sub>17</sub> versus phytane/n-C<sub>18</sub> showing the sources the studied crude oils. A Terrestrial organic matter source, B peat coal environment, C mixed organic matter (source or transitional environment), D marine organic matter source (algal-reducing environment)



**Fig. 6** Pristane/phytane versus CPI to define depositional environments of the studied crude oils

potential to evaluate the oxic/anoxic conditions during and immediately after the deposition of the source sediments (Peters and Moldowan 1993). The studied crude oils have a low homohopanes index (0.01–0.05), which suggest an oxic deposition environment of the oil (Sonibare et al. 2008).

The  $m/z$  217 ions mass chromatogram shows the distribution of steranes for crude oil samples in Fig. 4. Steranes include the biomarkers most commonly used for maturity assessment (Peters and Moldowan 1993). Mackenzie (1984) stated that ratios involving different carbon numbers, in the range of C<sub>27</sub>–C<sub>29</sub> steranes, were used to detect source differences. The predominance of C<sub>29</sub> steranes is shown by the organic matter with higher plant inputs, while the marine organic matter shows higher C<sub>27</sub> steranes. Some of the studied crude oils are characterized by the predominance of C<sub>28</sub> and C<sub>29</sub> over C<sub>27</sub> steranes (Fig. 7), while the second group of oils show that the

dominance of C<sub>29</sub> over C<sub>27</sub> and C<sub>28</sub> steranes (Fig. 8). Figure 7 indicates that the crude oils are derived from mixed terrestrial and marine organic sources; while Fig. 8 has more of a higher terrestrial input. These assumptions are confirmed by the steranes ternary diagram (Fig. 9).

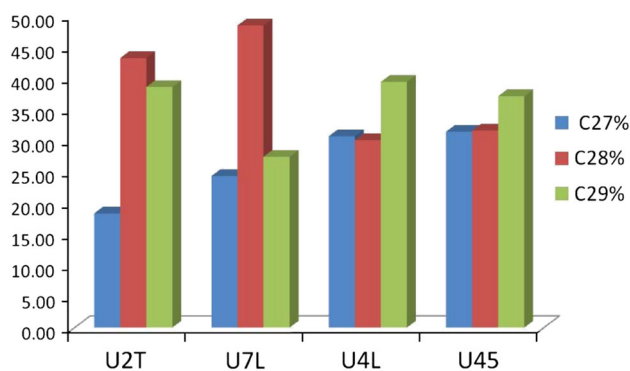
The regular steranes/17 $\alpha$  (H)-hopanes ratio (sterane/hopane ratio) is relatively high in marine organic matter, with values generally approaching unity or even higher. In contrast, low steranes and sterane/hopane ratios are more indicative of terrigenous organic matter (Noriyuki et al. 1996). The studied crude oils' steranes/hopanes ratio range from 0.02 to 0.20 (Table 1). This indicates that the majority of the studied crude oils are generated from terrigenous organic matter. These results are in agreement with the data obtained from the relationship between Pr/nC<sub>17</sub> and Ph/nC<sub>18</sub> (Fig. 5).

The steranes (C<sub>29</sub>) 20S/20S + 20R  $\alpha\beta\beta/\alpha\beta\beta + \alpha\alpha\alpha$  values range from 0.46 to 0.63 (Table 1). These low values support the low maturity status of the oils (Seifert and Moldwan 1986). The ratios of 22S/22S + 22R for the extended hopanes were also calculated and were found to have little variation with each other. The 22S/(22S + 22R) extended hopanes and 20S/(20S + 20R) C<sub>29</sub> steranes ( $\alpha\alpha\alpha/\alpha\alpha\alpha + \alpha\beta\beta$ ;  $\alpha\beta\beta/\alpha\beta\beta + \alpha\alpha\alpha$ ), which are used as maturity indicators, are close to the equilibrium value of 0.57–0.62 proposed by Peters and Moldowan (1993). The 22S/22S + 22R ratio has an equilibrium value of 0.55, which corresponds to the onset of hydrocarbon generation (Mackenzie 1984). There is no well-established maturity pattern observed between the indices used as the maturity parameters and the cross plots. The level of thermal maturity of the crude oils suggests either that the organic matter generating oils may have been buried at a considerable depth in the sediment or that these samples were severely affected by thermal metamorphism (Burgan and Ali 2009) (Fig. 10).

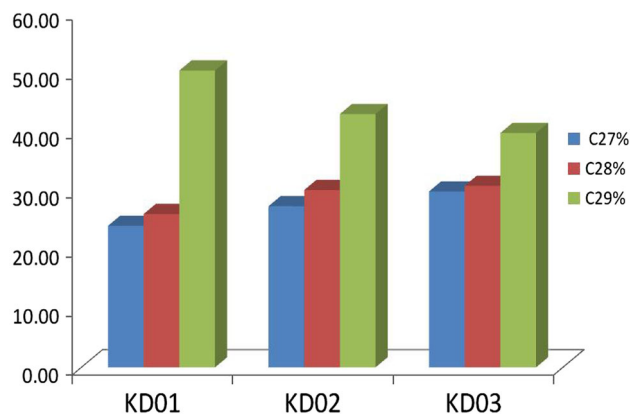
### 3.4 Depositional environment

Oleananes are specific biomarkers that originate from higher plant triterpenoid, not from a bacterial origin. They are specific to some angiosperms (flowering plants), a factor that also limits the source-rock age to the Tertiary or Upper Cretaceous and a proximal depositional environment. They occur in many terrestrial oils and shales, often in deltaic environment (Ekweozor et al. 1981). Moldowan et al. (1994) suggested that an oleanane index above 0.3 is an indication of crude oils derived from rocks of Tertiary age. From Table 1, it is apparent that most of the crude oils originated in the terrestrial environment of the Tertiary age.

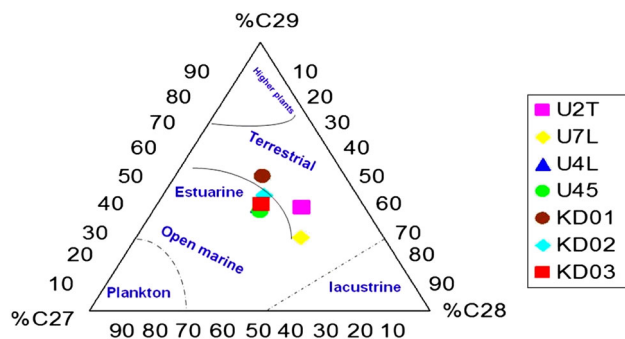
Alberdi and Lopez (2000) used the characterization of 18 $\alpha$  (H)-oleanane in oils to determine organic type and the age indicator for the assessment of the petroleum system.



**Fig. 7** Bar chart of %C<sub>27</sub>, %C<sub>28</sub> and %C<sub>29</sub> steranes showing dominance of %C<sub>28</sub> and %C<sub>29</sub>

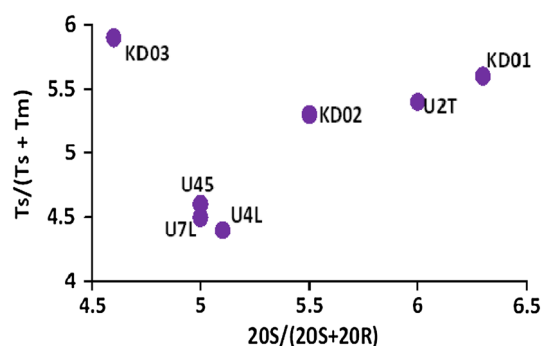


**Fig. 8** Bar chart of %C<sub>27</sub>, %C<sub>28</sub> and %C<sub>29</sub> steranes showing dominance of %C<sub>29</sub>



**Fig. 9** Ternary plot for relative proportions of the C<sub>27</sub>–C<sub>29</sub> steranes from both Umutu and Bomu

Type 1 oils show a high relative abundance of gammacerane, indicating a marine saline-source depositional environment. Furthermore, these oils have a predominance of C<sub>35</sub> to C<sub>34</sub> 17 $\alpha$  (H)-homohopanes and Type 2 oils have an oleanane content of more than 20 % of the concentration of C<sub>30</sub>  $\alpha\beta$  hopane, indicating that they originated from an angiosperm-rich, tertiary source rock (Moldowan et al. 1994).



**Fig. 10** Plot of Ts/(Ts + Tm) vs 20S/(20S + 20R)

## 4 Conclusion

This work presents a geochemical approach that enables accurate discrimination between oil samples from two different oil fields within the southwest of the Niger Delta. This study also reveals that the crude oils were derived from source rocks containing mixed kerogen (marine and terrestrial) that were deposited in an oxic environment. Gas chromatographic fingerprinting of the crude oils from the studied fields has provided an insight into the source signature of the hydrocarbon materials under investigation. Saturated hydrocarbon and molecular composition hydrocarbon composition of the crude, the distribution of n-alkanes/isoprenoids and the high Pr/Ph ratios suggest that the oils were derived from source rock with a significant terrestrial contribution and were deposited in an oxic paleoenvironment. The calculated CPI and steranes, which were used in determining the maturity level of the crude oils, could not ascertain their specific maturity pattern.

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