

Hydrocarbon Potential and Biomarker Studies of EE-1 Well, Offshore Eastern Dahomey Basin, SW Nigeria

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Abstract

The hydrocarbon potential, organic source input, and paleodepositional environment of subsurface sediments from EE-1 well, offshore Eastern Dahomey Basin, were assessed using Rock-Eval pyrolysis and biomarker geochemistry. The total organic carbon (TOC) and soluble organic matter (SOM) in the sediments ranged from 0.96wt% to 8.92wt% and 676.12 ppm to 2883.85 ppm, respectively, indicating adequate to excellent organic richness. The pseudo-Van Krevelen plot classified the sediments as types II and III kerogen, which have the potential to generate both oil and gas. The T_{max} and production index (PI) ranged from 422°C to 431°C (average, 426°C) and 0.03 to 0.24, respectively, suggesting low thermal maturity. The presence of C_{27} – C_{29} steranes, oleanane, and hopane/sterane ratio (1.53/16.11), indicated organic matter from mixed sources with more terrigenous input. Cross plots of Pr/nC_{17} against Ph/nC_{18} , C_{35}/C_{31} – C_{35} homohopane index (0.05 – 0.17) and other related biomarker ratios such as C_{21}/C_{23} tricyclic terpane ratio (0.33 – 0.82) signified that the sediments were deposited in mixed marine/terrigenous environment under oxic – suboxic conditions. This study has demonstrated that sediments had adequate organic matter with the potential to generate both oil and gas at appropriate thermal maturity.

Keywords: hydrocarbon potential, biomarker, Dahomey Basin

Introduction

The Dahomey Basin comprises a combination of inland, coastal, and offshore waters and stretches from Southeastern Ghana, through Togo and the Republic of Benin, to southwestern Nigeria [1] (Figure 1). The Eastern Dahomey Basin (Nigerian sector) has been of much geological interest as a result of the reported occurrences of bitumen, limestone, glass sands, and phosphates [2]. The initial motivation for oil exploration in the Eastern Dahomey Basin arose from the discovery of seepages and tar sand deposits as early as 1909. In the earlier days of exploration for oil in the basin, the wells drilled were classified as ‘dry’ and thus abandoned. Recent exploration and prospect re-evaluation efforts in the Nigerian segment of the basin have been encouraged following oil discovery and production in the neighbouring

Benin Republic sector, west of the basin and the social unrest in the prolific Niger Delta, east of the basin [3].

Numerous studies have been carried out on the Eastern Dahomey Basin by a host of earlier workers such as those listed in references [3–14], amongst others. These studies have increased our knowledge of stratigraphic resolution, established petroleum systems, and the hydrocarbon potential of the basin. However, in comparison with the contiguous Niger Delta, much is yet to be clearly understood in the Eastern Dahomey Basin. In the Dahomey Basin, for instance, there is no consensus of opinion on the stratigraphic nomenclatures in the offshore and onshore sectors and different names are assigned to the same units at different places by different authors [5, 13, 15]. This study therefore examines the sediments of EE-1 Well, for hydrocarbon potential,

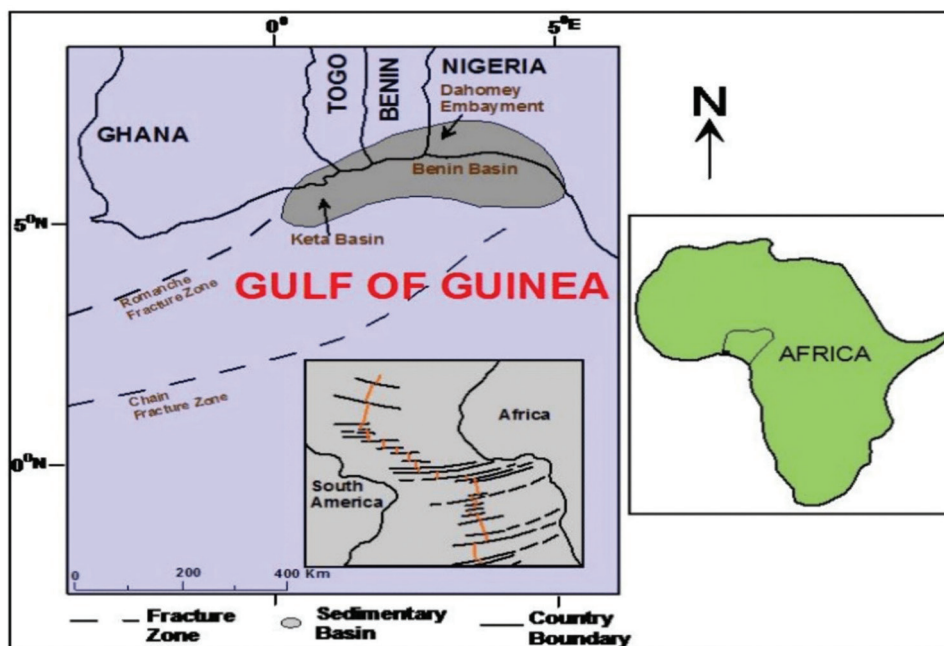


Figure 1: Regional map of four countries showing the location of the Benin (Dahomey) Basin in the Gulf of Guinea [11].

palaeodepositional environment using Rock-Eval and biomarker geochemistry in line with current understanding. The resulting information will be of great interest to explorationists and researchers.

Location of study area and geologic setting

The study area is located between latitudes 6°10'N and 6°20'N and longitudes 2°0'E and 2°30'E, offshore Eastern Dahomey Basin (Figure 2).

The Dahomey Basin is a coast-parallel basin, stretching from the western limit of the Niger Delta in Nigeria westwards, through Benin Republic and Togo, terminating in the Volta Delta in Ghana, with a total latitudinal stretch of about 500 km [16]. It is a marginal pull apart or marginal sag basin [17] which originated during the Early Cretaceous separation of African and South American plates [18]. The basin contains Late Cretaceous to recent sediments up to 3,000 m where they thicken markedly into the offshore and then thin beneath the deep water area. Onshore, the sediment-fill also thins both westward and eastward from the central area in Benin Republic. The maximum thickness of the sediments is around the Nigeria - Republic of Benin border. In the Nigerian sector, the sediments thin into the Basement Complex of the Okitipupa High, west

of the Niger Delta. Earlier stratigraphic study of the basin by Jones and Hockey [19] recognized both Cretaceous and Tertiary sediments. Other subsequent workers recognized three chronostratigraphic units: Pre-lower Cretaceous folded sequence, Cretaceous sequence and Tertiary sequence [6, 9]. The Cretaceous stratigraphy as compiled from outcrop and borehole records comprising the Abeokuta Group is further subdivided into three informal formational units, namely, Ise, Afowo, and Araromi Formations [5]. Ise Formation is the oldest Cretaceous unit and comprises predrift succession of conglomerates, sands, and mudrocks overlying the Basement Complex. The succession continues upwards with medium to coarse, loose sands interbedded with kaolinitic clays. Omatsola and Adegoke [5] assigned a Lower Cretaceous (Neocomian) age to this formation. The deposits are products of alluvial fan setting at the basin edge, following initial rifting [16]. The Afowo Formation comprises mostly medium to coarse sandstone, with thin to thick interbeds of shales, siltstones, and claystones. It has been described as tar-bearing and petroliferous. The formation has been assigned a Turonian age [8, 15]. The Araromi Formation is the youngest Cretaceous unit that conformably overlies Afowo Formation in the Eastern Dahomey Basin. The formation consists of fine to medium

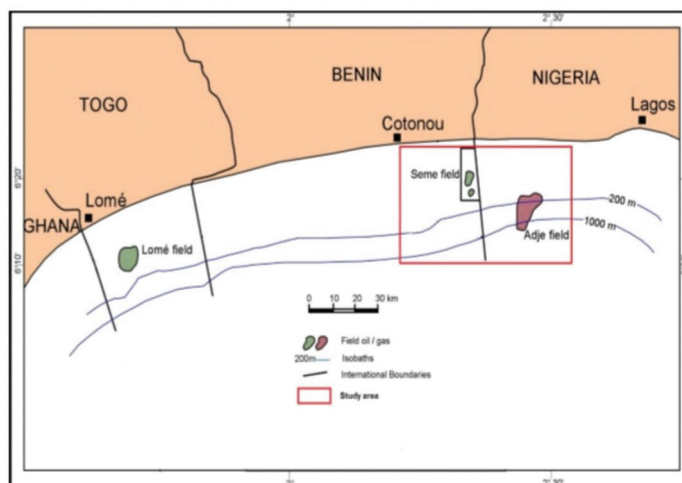


Figure 2: Dahomey embayment showing the study area (after d'Almeida et al. [14]).

sands at the base, overlain by a seaward thickening shale and siltstone with thin limestones and marls, as well as thin lignitic bands. The Araromi Formation has been assigned a Maastrichtian to Paleocene age [5]. Overlying the Cretaceous Abeokuta Group is the Ewekoro Formation. The Ewekoro Formation is predominantly limestone, but it is, however, not encountered offshore in coastal boreholes, where the shaley Imo Formation unconformably overlies the Afowo Formation [15]. Four microfacies, namely, bio-microsparite, shelly biomicrite, algal biosparite, and red phosphatic biomicrite, have been identified within this predominantly limestone body [4, 20]. The formation has been assigned Upper Paleocene by most authors [2, 21, 22]. The Akinbo Formation [23] overlies the Ewekoro Formation. The unit consists of fine-grained, dark micromicaceous shale, locally silty with glauconitic marl and conglomeratic at the base. The formation has been dated Upper Paleocene to Lower Eocene in age [12, 23]. The Oshosun Formation overlies the Akinbo Formation and consists of greenish grey or beige clay and shale, with interbeds of sandstones. The shale is thickly laminated and glauconitic [12]. According to Okosun [9], the basal beds consist of any of the following facies: sandstones, mudstones, claystones, clay-shale, or shale. This formation is phosphate-bearing [2, 19]. A Lower Eocene-Middle Eocene age is assigned to this formation. The Ilaro (Ijebu) Formation conformably overlies the Oshosun Formation in the Eastern Dahomey Basin.

This unit comprises massive, poorly consolidated, cross-bedded sandstones. Subrounded to rounded pure quartz grains dominate the base of the formation and it has been assigned an Eocene – Oligocene age. The Benin Formation, also called the Coastal Plain Sands [5] is the youngest sequence in the Eastern Dahomey Basin and comprises poorly sorted sands with lenses of clays. The sands are cross-bedded in part and show nearshore to continental distinctiveness. The formation age covers the Miocene to Recent periods.

There are lots of controversies concerning the stratigraphy of the Nigerian sector of the basin. This is due primarily to different stratigraphic names that have been proposed for the same formation in different localities in the basin [9, 24]. This situation can be fairly blamed on the lack of good borehole coverage and adequate outcrops for detailed stratigraphic studies [25].

Materials and methods

Samples

Subsurface samples of EE-1 Well from offshore Eastern Dahomey Basin were obtained for this study. Of a total depth of 315 m to 2257.5 m, the interval 1200–2260 m was used in this study. The detailed lithological description of the samples is shown in Figure 3. The lithologic sequence within the interval shows that the base to depth 2100 m is a thick sequence of silty

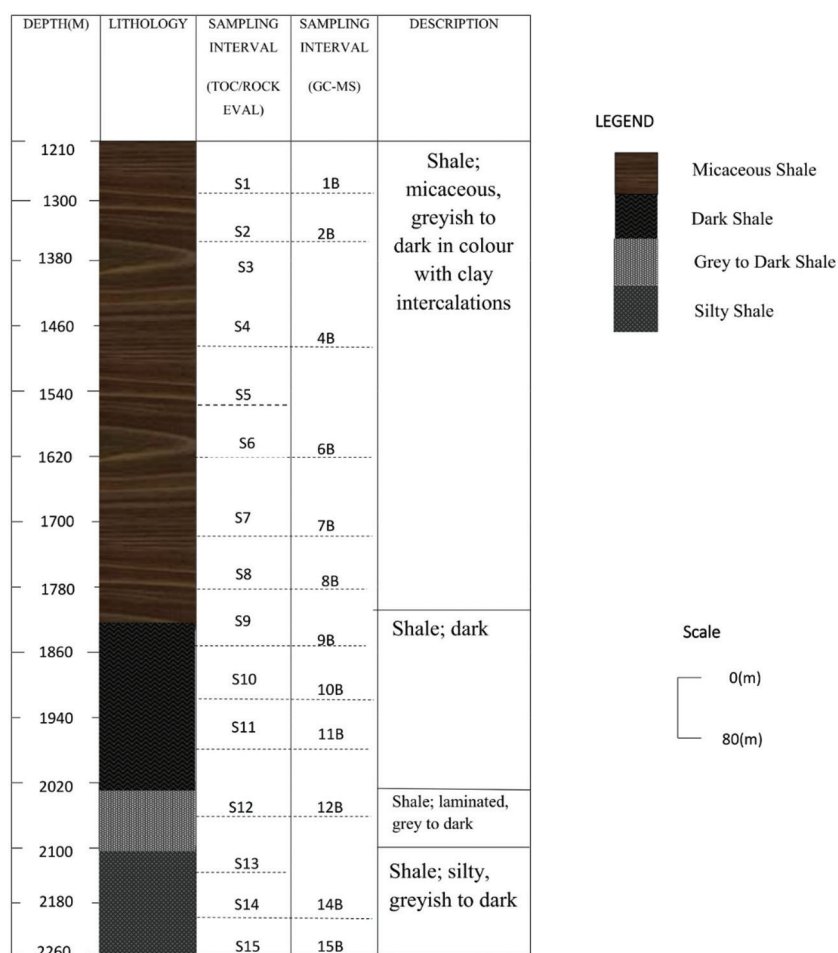


Figure 3: Lithological log of the studied section of EE-1 Well.

shale which is greyish to dark in colour. This is overlain by a greyish to dark shale sequence, a thick sequence of indurated, dark shale indicative of rich organic matter, which was encountered from 2020 m to 1810 m. From 1810 m to the top of the well (1210 m) is micaceous shale with clay intercalations, ranging in colour from grey to dark.

Analytical methods

Total Organic Carbon Determination

Approximately 10 g of each pulverized shale sample (15) was weighed out and decarbonated by treatment with concentrated hydrochloric acid (HCl) for two hours. After decarbonation, the samples were rinsed with distilled water and flushed through a filtration apparatus, fitted with a glass microfiber filter to remove the acid. The filtrate was then removed, placed into a LECO crucible and dried in a low temperature

oven (110°C) for four (4) hours. The samples were then analyzed in a LECO 600 carbon analyzer for the total organic carbon (TOC) content.

Rock-Eval pyrolysis

Based on the TOC adequacy, 100 mg of selected samples (15) were gradationally heated to 550°C at a 25°C/min heating rate using a HAWK Pyrolyzer from which the pyrograms were produced as calculated parameters. Both the TOC and Rock-Eval pyrolysis were undertaken at Geomark Research Ltd. Laboratory, Humble, Texas, USA.

Soluble organic matter extraction and fractionation

About 30–50 g of each pulverized shale sample was extracted using a mixture of methylene chloride/methanol in a Soxhlet extractor Tecator Soxtec System HT 2 1045 Extraction Unit. After the extraction, the solvent was

distilled and the soluble organic matter (SOM) was evaporated in a rotary evaporator, and the extracts were weighed. The extracts were later fractionated on silica gel column chromatography into saturate, aromatic, polar (NSO) fractions by successive additions of n-hexane, n-hexane/dichloromethane (4:1, v/v), and dichloromethane/methanol (1:1, v/v), respectively.

Gas chromatography—mass spectrometry

The saturate and aromatic fractions recovered from the liquid chromatography were analysed for their biomarkers by gas chromatography/mass spectrometry (GC/MS) using the selected ion monitoring mode (SIM). The fingerprints (fragmentograms) acquired from this analysis were identified by relative retention times from the GC/MS traces using 5b-Cholane and o-terphenyl standards for saturate and aromatic fractions, respectively, and quantifying of biomarkers was done by measuring peak heights. The chromatographic data were acquired using MS Chemstation software, version G1701BA, for

Microsoft NT. The bitumen extraction, fractionation and GC/MS analyses were carried out at Exxon Mobil Geochemical Laboratory, Qua Iboe Terminal (QIT), Eket. The detailed analytical procedures can be obtained from Emordi [26].

Results and discussion

Organic matter quantity

The quantity of organic matter present in a rock can be expressed as a percentage of total organic carbon (TOC), which is a measure of the organic richness of a sample expressed as the percentage weight of the dry rock sample [27]. The TOC values for the samples range between 0.96 and 8.92wt% (Table 1). These values are above the 0.5 wt% minimum for clastic source rocks to generate hydrocarbons [27]. The SOM content ranged from 676 ppm to 2883 ppm (average: 1893 ppm), which indicates good to very good organic richness while the genetic potential (GP) values range from 1.18 mg HC/g to

Table 1: Results of TOC and Rock-Eval Pyrolysis of the studied samples.

Sample ID	Depth (m)	SOM (ppm)	TOC	S1	S2	S3	Tmax	Calc. %Ro	GP (S1 + S2)	HI	OI	SOM/TOC	S1/TOC	PI
S1	1240	676.12	1.14	0.13	1.11	2.23	423	0.45	1.24	97	196	59.31	11	0.10
S2	1340	2004.31	1.01	0.16	1.02	2.36	422	0.44	1.18	101	234	198.45	16	0.14
S3	1410	ND	1.19	0.16	1.31	2.78	425	0.49	1.47	110	234	ND	13	0.11
S4	1480	1417.71	1.41	0.19	1.93	2.55	428	0.54	2.12	137	181	100.55	13	0.09
S5	1560	ND	0.96	0.15	1.15	2.51	429	0.56	1.3	120	262	ND	16	0.12
S6	1620	2456.23	0.97	0.15	1.26	1.96	429	0.56	1.41	131	203	43.03	16	0.11
S7	1700	2883.85	1.02	0.21	1.66	2.79	427	0.53	1.87	163	274	13.04	21	0.11
S8	1760	1835.19	1.47	0.25	2.60	2.39	430	0.58	2.85	177	163	15.28	17	0.09
S9	1830	1599.37	1.94	0.34	5.84	2.51	426	0.51	6.18	301	129	11.96	18	0.06
S10	1906	1205.55	2.63	0.93	8.24	2.53	427	0.53	9.17	313	96	6.13	35	0.10
S11	1965	2698.84	1.91	1.00	4.11	2.51	431	0.60	5.11	215	131	23.64	52	0.20
S12	2040	1826.01	2.03	0.95	2.99	3.29	425	0.49	3.94	147	162	6.28	47	0.24
S13	2118	ND	1.18	0.39	2.94	2.30	429	0.56	3.33	249	195	ND	33	0.12
S14	2180	2143.91	1.15	0.63	3.25	2.79	422	0.44	3.88	283	243	186.43	55	0.16
S15	2257.5	1978.45	8.92	1.35	43.18	3.15	426	0.51	44.53	484	35	22.18	15	0.03

TOC = weight percent organic carbon in rock, GP = petroleum genetic potential

T_{max} = °C, HI = hydrogen index

S₁+S₂ = mg HC/g of rock, OI = oxygen index

S₃ = mg CO₂/g of rock, PI = production index = S₁ / (S₁+S₂)

S₁/TOC = normalized oil content, Calc. % Ro = Calculated vitrinite reflectance

SOM = Soluble Organic Matter, ND = Not done

44.53 mg HC/g (average: 5.972 mg HC/g), indicating moderate to good source rock potential [27].

Organic matter type

The quality of organic matter content of a source rock determines the type of hydrocarbon generated [27]. Cross plots of hydrogen index

versus oxygen index (OI) (Figure 4) show that the samples consist of types II and III kerogen, which indicates that the organic matter can generate both oil and gas at appropriate thermal maturity [28]. The cross plot of the remaining hydrocarbon potential (S₂) against TOC (Figure 5) further supports type II/III (oil/gas prone) kerogen.

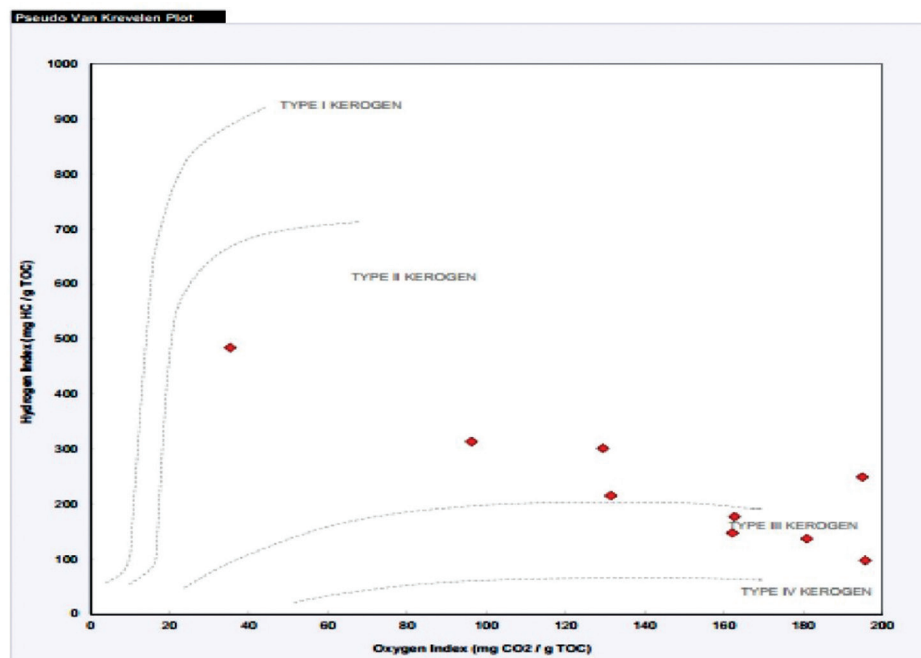


Figure 4: A cross plot of hydrogen index (HI) versus oxygen index (OI) showing that the organic matter of the studied well is of types II and type III kerogen (Modified after Van Krevelen [29]).

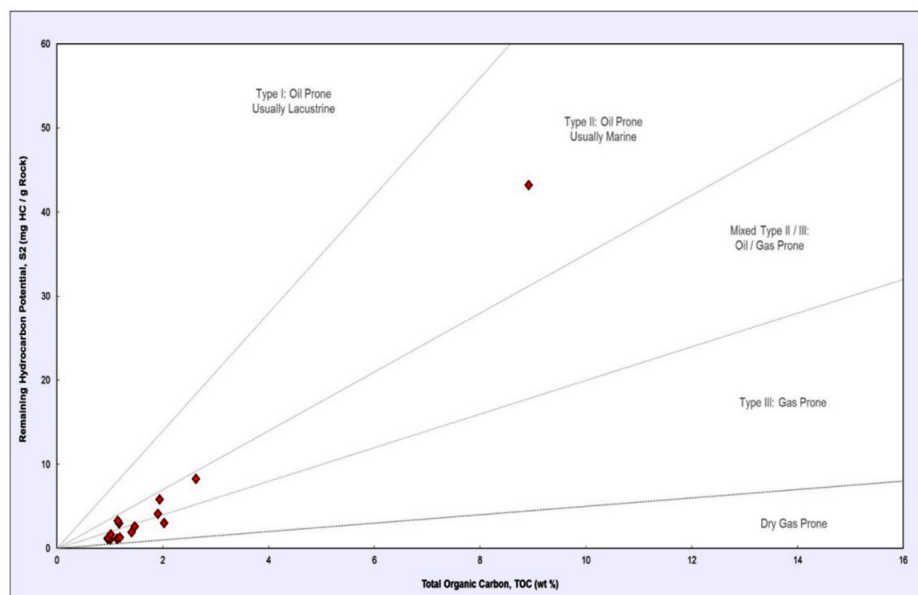


Figure 5: A cross plot of remaining hydrocarbon potential (S₂) against total organic content (TOC) showing the organic matter type and origin (after Jackson et al. [30]).

Maturity of organic matter

The generation of petroleum from organic matter during its burial history is a part of the overall processes of thermal maturation of organic matter [27]. Thermal maturity describes the extent of heat-driven reactions, which convert sedimentary organic matter into petroleum [31]. In this study, the values of T_{max} ranged from 422°C to 431°C (average 426.6°C), indicating immature status for the studied well [31]. Similar values have been reported by Nton et al. [12] in sediments of the Aje-1 well, Eastern Dahomey Basin where T_{max} values that ranged from 359°C to 465°C indicated the immature to marginal maturity status of the well. Cross plots of HI against T_{max} (Figure 6) further revealed that >95% of the samples are immature. The calculated vitrinite reflectance R_o for this study ranged from 0.44 to 0.60 and lie in the immature status defined by Peters and Cassa [32].

The production index (PI) is defined as the ratio $S1/(S1 + S2)$ and is an indicator of the degree of thermal maturity. It is also an indication of the amount of hydrocarbon which has been produced geologically relative to the total amount of hydrocarbon that the sample can produce PI values of 0.03 – 0.24, indicated immature status for the sediments [31]. The ratio of extractable bitumen to total organic carbon (bitumen/TOC), sometimes called the transformation ratio (TR), is often used as a

quantitative index to deduce the thermal maturity of sediments [31]. This ratio has been discovered to range from near zero in shallow sediments to about 250 mg/g TOC at the peak of oil generation. These values have also been observed to decrease at greater depths as a result of the conversion of bitumen to gas [31]. In the study well, the transformation ratio ranged from 22.18 to 282.73 mg/g TOC (average: 132.27) (Table 1), indicating immature to marginally mature status for the sediments. However, anomalous high figures observed in some of the samples may indicate contamination by migrated oil.

Normal alkanes and acyclic isoprenoids

The n-alkane data and biomarker maturity parameters were used to evaluate the level of thermal maturity of the sediments. Typical representative chromatograms showing distribution of n-alkanes and isoprenoids are shown in Figure 7. Using the chromatograms, parameters indicating source input, maturity, and depositional environment were generated as shown in Table 2.

The pristane/phytane (Pr/Ph) ratio, is one of the most commonly used geochemical parameters as an indicator of depositional environment, though with low specificity due to the interferences of thermal maturity and preliminary assessment of organic matter source

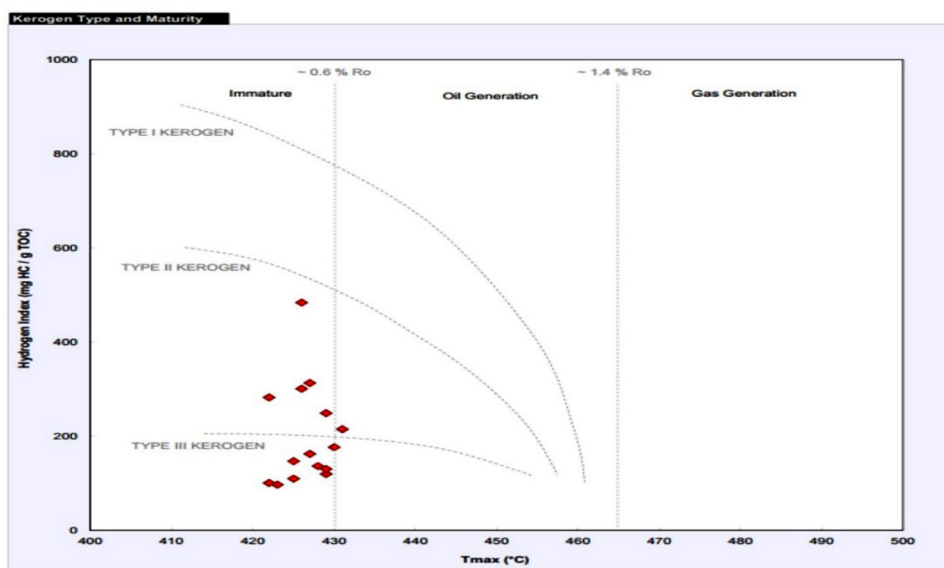


Figure 6: Plot of hydrogen index (HI) against T_{max} showing that the kerogen is in the immature window [33].

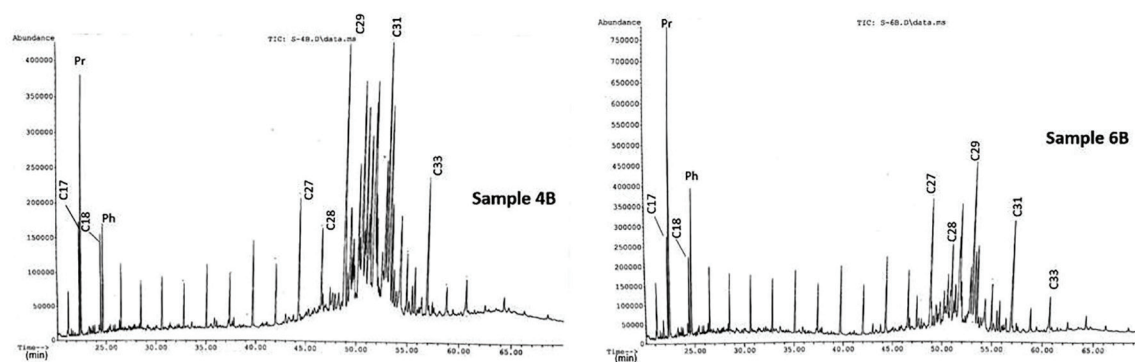


Figure 7: Total ion chromatograms showing the distribution of the saturated hydrocarbon fraction of representative Samples 4B and 6B from the study well.

Table 2: Data showing values of isoprenoids, isoprenoids/n-alkane ratios and other parameters for EE-1 well.

Sample ID	Pr/Ph	Pr/n-C ₁₇	Ph/n-C ₁₈	CPI	OEP-1	OEP-2
1B	1.47	0.98	0.62	1.93	0.51	0.83
2B	1.74	1.20	0.90	1.66	0.45	0.76
4B	2.38	2.41	1.08	1.70	0.51	0.8
6B	2.05	2.99	1.83	1.51	0.46	0.62
7B	3.20	2.42	1.40	1.67	0.53	0.7
8B	2.33	1.58	0.76	1.23	0.39	0.51
9B	1.49	2.31	1.55	1.27	0.47	0.49
10B	1.78	1.24	0.63	1.01	0.35	0.41
11B	2.20	0.99	0.51	1.12	0.39	0.44
12B	1.65	0.92	0.54	1.04	0.37	0.4
14B	1.94	0.60	0.46	0.37	0.4	0.08
15B	1.80	0.80	0.42	1.12	0.41	0.42

Abbreviations: Pr/Ph, pristane/phytane; Pr/nC₁₇, pristane/normal-C₁₇ alkane; Ph/nC₁₈, phytane/normal-C₁₈ alkane; CPI, carbon preference index, $2(C_{23} + C_{25} + C_{27} + C_{29}) / (C_{22} + 2C_{24} + C_{26} + C_{28} + C_{30})$; OEP-1, $(C_{21} + C_{23} + C_{25}) / (4C_{22} + 4C_{24})$; OEP-2, $(C_{25} + C_{27} + C_{29}) / (4C_{26} + 4C_{28})$; OEP, odd-to-even predominance.

inputs [34]. Ten Haven [35] 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. Values of Pr/Ph ranging from 1.47 to 3.20 (Table 2) indicate a mixed marine/terrigenous environment under suboxic to oxic conditions for the sediments. Cross plots of isoprenoids/n-alkanes (Figure 8) revealed that the samples are mainly in transitional environments with strong oxic influence and biodegraded.

The carbon preference index (CPI) and odd-even predominance (OEP) provide a crude estimate of source input, thermal maturity

of petroleum, and dispersed organic matter [31, 36]. According to Hunt [37], CPI considerably greater than 1.0 shows contribution from terrestrial continental plants and immaturity. Over 90% of the samples have CPI >1% and strongly indicate terrestrial contribution and marine influence. The OEP values are less than 1.0 for all samples (Table 2), which further indicate low thermal maturity status of the well [38].

Biomarker geochemistry

The composition and distribution of certain diagnostic chemical fossils (biomarkers) can indicate the maximum stress experienced by

the rocks or petroleum in which the compounds are found [40]. Typical representative chromatograms showing distribution of steranes (m/z 217) and terpanes (m/z 191) from this

study are shown in Figures 9 and 10. Using the chromatograms, an assessment of the thermal maturity levels was generated based on maturity parameters (Table 3).

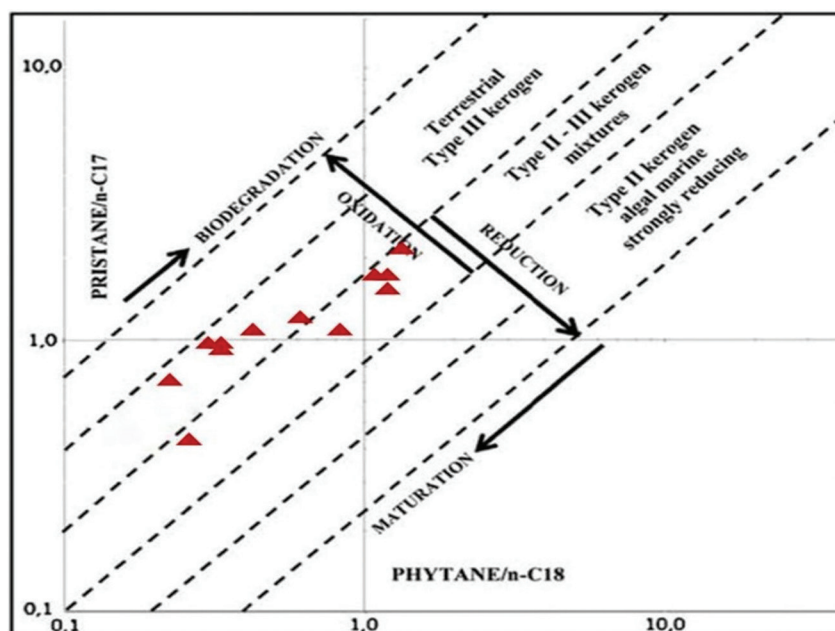


Figure 8: Cross plot of $Pr/n-C_{17}$ versus $Ph/n-C_{18}$ showing the sources of organic matter and the depositional environment (Modified after Cortes et al. [39]).

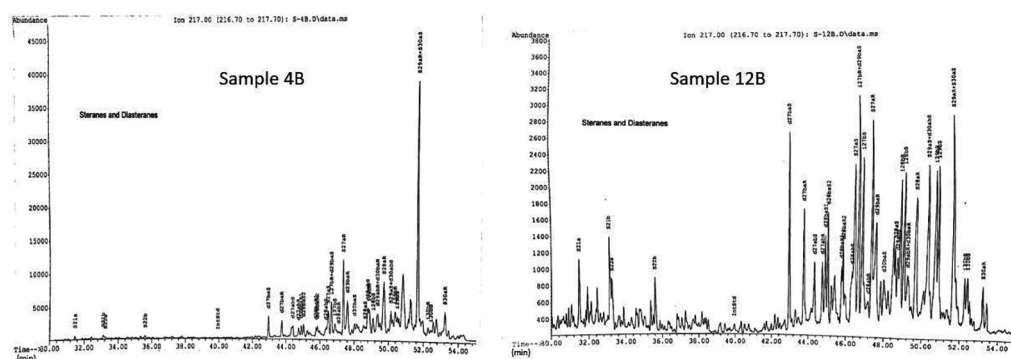


Figure 9: m/z 217 mass chromatograms showing the distribution of steranes and diasteranes in the selected samples 4B and 12B.

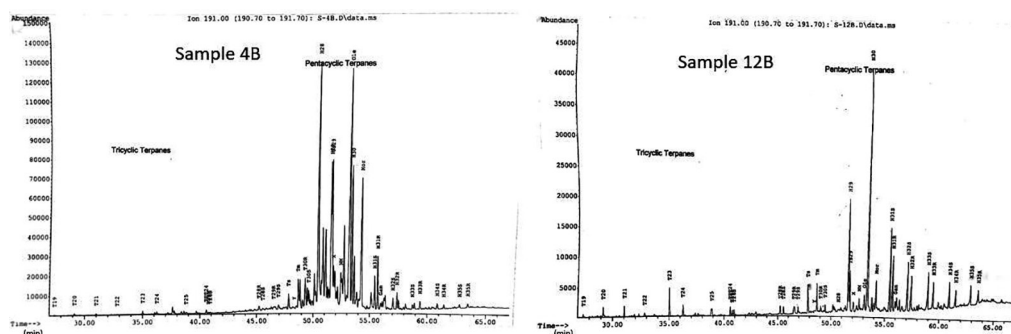


Figure 10: m/z 191 mass chromatograms showing the distribution of terpanes and hopanes in the EE-1 Well samples 4B and 12B.

Table 3: Biomarker maturity parameters computed for the studied well samples.

Sample ID	Ts /Tm	Mor / Hop	$\alpha\beta\beta/\alpha\beta\beta+\alpha\alpha\alpha$ C ₂₉ Sterane	22S/22S+22R	MPI-1	DMN	TMN-1	MDBT
1B	0.22	0.26	0.28	0.37	1.72	3.56	0.89	2.98
2B	0.25	0.26	0.25	0.34	1.46	2.96	0.73	3.35
4B	0.35	0.48	0.06	0.40	1.75	4.19	0.91	2.83
6B	0.32	0.29	0.21	0.38	1.37	4.04	1.13	3.11
7B	0.27	0.22	0.24	0.42	1.41	3.53	0.97	6.21
8B	0.34	0.18	0.23	0.46	1.35	2.25	1.06	1.81
9B	0.32	0.16	0.18	0.48	1.48	3.74	1.05	1.98
10B	0.35	0.14	0.30	0.57	1.12	3.01	1.17	0.82
11B	0.48	0.13	0.34	0.60	1.16	3.33	0.79	1.07
12B	0.50	0.11	0.44	0.58	1.01	3.25	0.67	1.51
14B	0.44	0.14	0.35	0.58	1.28	4.96	1.11	2.19
15B	0.45	0.10	0.42	0.59	1.32	4.36	0.79	1.47

Abbreviations: Ts/(Ts+Tm), trisnorneohopanes/trisnorhopanes ratio; Mor/Hop, 17 β , 21 α (H)Mortane/17 α , 21 β (H) hopane ratio; 22S/22S+22R, 22S/22S+22R extended hopanes ratio; MPI-1 - methyl - phenanthrene index, 1,5 (2MP + 3MP) / (P + 1MP + 9MP); DMN - dimethyl naphthalene ratio, 2, 6 DMN + 2,7 DMN/1,5 DMN; TMN-1 - trimethyl naphthalene ratio, (1,3,7 TMN)/(1,3,7 TMN + 1,2,5 TMN); MDBT - methyl-dibenzothiophene ratio, 4MDBT/1MDBT.

The Ts/Tm ratio is used as a maturity indicator, because C₂₇ 18 α -trisnorneohopane, or Ts, exhibits greater thermal stability than its regular hopane counterpart, C₂₇ 17 α -trisnorhopane, or Tm, although the ratio is also source dependent [34]. The Ts/Tm values for the study well ranged from 0.22 to 0.5 (Table 3), indicating the immaturity status of the samples. The moretane/hopane ratio ranged from 0.10 to 0.48 and point to an immature to marginally mature status of the study well. The 20S/(20S + 20R) C₂₉ steranes $\alpha\beta\beta/\alpha\beta\beta + \alpha\alpha\alpha$ and 22S/(22S + 22R) extended hopanes, which are used as maturity indicators, were computed for the study well. An equilibrium value of 0.55 for 22S/(22S + 22R) extended hopanes ratio corresponds to the onset of hydrocarbon generation, while > 0.5 20S/(20S + 20R) C₂₉ steranes $\alpha\beta\beta/\alpha\beta\beta + \alpha\alpha\alpha$ signifies thermal maturity [31]. The values of the 20S/(20S + 20R) C₂₉ steranes $\alpha\beta\beta/\alpha\beta\beta + \alpha\alpha\alpha$ and 22S/(22S + 22R) extended hopanes ratios ranged from 0.06 to 0.44 and 0.34 to 0.6 (Table 3), respectively, supporting the low maturity status of the study well. Calculated aromatic biomarker parameters such as MPI-1 (methyl phenanthrene index), DNR-1 (dimethyl naphthalene ratio), TMNR (trimethyl naphthalene ratio), and MDR (methyl dibenzothiophene ratio) ranged from

1.01 to 1.72, 2.96 to 4.96, 0.67 to 1.17, and 0.82 to 6.21, respectively (Table 3). These values indicate that the samples are immature to marginally mature [41].

Depositional environment

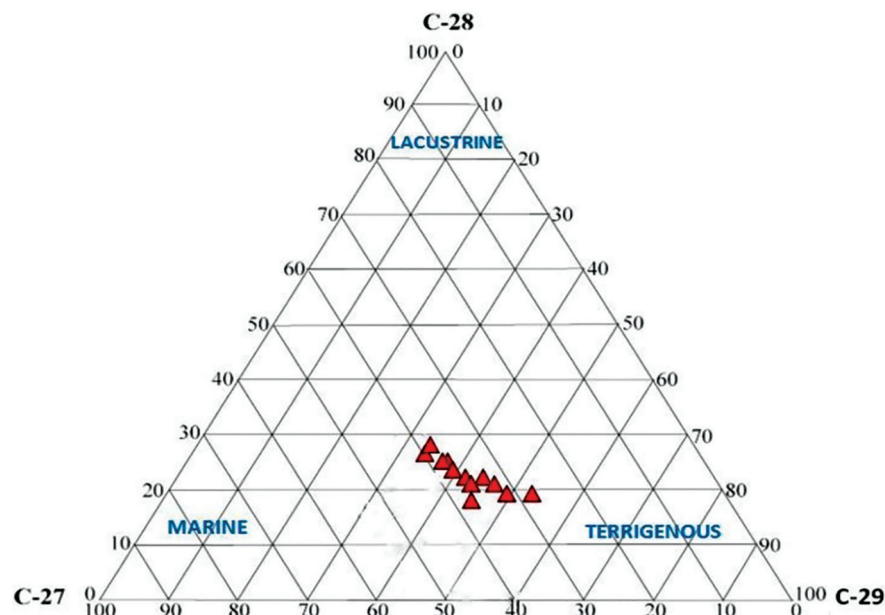
Biomarkers provide information about the depositional environment of organic matter, the conditions during deposition as well as the lithology in which the organic matter is present [31]. Source and depositional environment parameters computed from the saturate biomarkers of the studied well are shown in Table 4.

The samples were characterized by the presence of C₂₇ to C₂₉ steranes and disateranes, which indicate derivation from mixed sources (marine and terrestrial) with capacity to generate both oil and gas. A ternary plot (Figure 11) showing sterane distributions and relationship with source indicates dominance of C₂₉ over C₂₇ and C₂₈ and suggests a mixture of marine and terrigenous biomass to the study well, with stronger terrigenous input. The presence of oleananes, a biomarker for higher plants (angiosperms), strongly supports a terrestrial precursor for the studied well [42]. The distribution of 17 α , 21 β (H)—homohopanes 22R + 22S C₃₅/(C₃₁–C₃₅), also known as the homohopane index, can be used as an indicator of the redox potential

Table 4: Source and depositional environment parameters computed from the saturate biomarkers of the EE-1 well.

Sample ID	%C ₂₇ Sterane	%C ₂₈ Sterane	%C ₂₉ Sterane	C ₂₁ T/ C ₂₃ T	C ₂₃ T/ C ₂₄ T	Hop/ Ster	dia/ reg	Ole/ Hop	Gam/ Hop	C ₂₄ Tet / (C ₂₆ (S+R) + C ₂₄ Tet)	C ₂₅ / C ₂₆ (S+R)	C ₃₅ / C ₃₁ - C ₃₅ Hom
1B	33.50%	19.68%	46.82%	0.58	1.49	4.13	0.18	0.1	0.08	0.52	0.69	0.06
2B	34.79%	22.11%	43.10%	0.8	1.59	2.99	0.15	0.11	0.1	0.49	0.54	0.14
4B	27.36%	19.31%	53.33%	0.49	1.33	1.98	0.28	0.62	0.04	0.6	0.48	0.05
6B	33.10%	20.73%	46.18%	0.82	1.66	1.62	0.21	0.42	0.05	0.62	0.89	0.05
7B	33.35%	20.97%	45.68%	0.78	1.39	3.65	0.27	0.29	0.04	0.67	0.48	0.05
8B	36.81%	21.02%	42.17%	0.62	1.73	4.1	0.23	0.33	0.04	0.64	0.41	0.05
9B	36.85%	25.19%	37.96%	0.55	1.98	1.53	0.13	0.21	0.04	0.6	0.44	0.07
10B	40.18%	25.85%	33.97%	0.33	3.45	6.04	0.33	0.07	0.04	0.52	0.69	0.09
11B	38.09%	24.36%	37.55%	0.39	3.1	11.45	0.42	0.04	0.03	0.72	0.67	0.06
12B	38.86%	27.19%	33.95%	0.36	2.57	16.11	0.48	0.06	0.04	0.45	0.67	0.09
14B	36.49%	23.80%	39.71%	0.46	1.91	6.27	0.35	0.14	0.06	0.5	0.56	0.11
15B	37.53%	41.63%	45.42%	0.37	1.92	6.91	0.38	0.08	0.09	0.45	0.63	0.17

Abbreviations: Ole/Hop, oleanane index; Hop/Ster, hopane/sterane ratio; dia/reg, diasterane index; Gam/Hop, gammacerane index; C₃₅/C₃₁-C₃₅ Hom, homohopane index; C₂₅/C₂₆(S+R), C₂₅/C₂₆(S+R) tricyclic terpane ratio; C₂₄ Tet / (C₂₆ (S+R) + C₂₄ Tet), tetracyclic terpane ratio.

**Figure 11:** Ternary plot showing distribution of C₂₇, C₂₈, and C₂₉ steranes for EE-1 Well. (After Huang and Meinschein [49]).

during and immediately after the deposition of the source sediments [31]. The studied samples have a low homohopane index (0.05 – 0.17) (Table 4), which suggests a suboxic depositional environment [43].

The 17 α (H)-hopanes/regular steranes ratio reflects input of prokaryotic (bacteria) versus eukaryotic (mainly algae and higher plants) organisms to the source rock. The hopane/sterane ratio values for the well sediments

ranged from 1.53 to 16.11, indicating both terrigenous and marine organic matter input. It has been suggested by Qiu et al. [44] that C_{21}/C_{23} tricyclic terpane ratios < 0.5 are indicative of marine-sourced organic matter. In this study, this ratio ranged from 0.33 to 0.82, further indicating a mixed marine and terrigenous input to the sediments. The values of the gammacerane index ranged from 0.03 to 0.10 (Table 4), indicating a normal salinity environment of deposition of the initial organic matter [45]. The tetracyclic terpane ratio – C_{24} Tet / $(C_{26}(S+R) + C_{24} \text{ Tet})$ – ranged from 0.45 to 0.72 (average: 0.57), indicating a low salinity environment of deposition for the study well [31]. The abundance of 1, 2, 5-TMN (trimethyl naphthalene) observed in the samples has been reported to be indicative of significant land plant contribution to the organic matter [46, 47]. In addition, the occurrence of 1, 7-DMP (dimethyl phenanthrene) in the analyzed samples indicates a strong terrestrial organic matter input for the sediments [48].

Conclusions

Subsurface samples from EE-1 Well, offshore Eastern Dahomey Basin, have been analysed for their lithofacies distribution, hydrocarbon potentials, and paleodepositional environment based on Rock-Eval studies and biomarker evaluation. The sediments have adequate to excellent source rock potential. Organic matter type indicated the presence of mainly types II and III kerogen, implying a prospect to generate both oil and gas at appropriate thermal maturity. Evaluations of saturate and aromatic biomarker parameters indicate the thermal immaturity status, organic matter of mixed terrigenous and marine origin with higher terrigenous input, as well as deposition under oxic – suboxic conditions. It can be deduced that the sediments have adequate organic richness, deposited under mixed marine/terrigenous environment under oxic – suboxic conditions with significant terrestrial organic matter input and potential to generate both oil and gas at appropriate thermal maturity.

Acknowledgements

The authors thank the members and staff of Geomark Research Lab, Humble, Texas for their technical assistance in analyses. We are grateful to the management and staff of Exxon Mobil Geochemistry Lab, Qua Iboe Terminal, Eket for permission to use its laboratory facilities for some aspects of the work. Special thanks to Dr. Babatunde Alalade and Dr. Chidi Eneogwe, for all their assistance during different phases of this work.

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