

HYDROCARBON GENERATIVE POTENTIAL OF CRETACEOUS SEDIMENTS OF KANADI-1 WELL, BORNU BASIN, NIGERIA

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ABSTRACT

The hydrocarbon potential and paleodepositional environment of Cretaceous sediments from the Bornu Basin, Nigeria, were assessed by Rock-eval pyrolysis and biomarker geochemistry. The Total Organic Carbon (TOC), soluble organic matter (SOM) and genetic potential (GP) values ranged from 0.52 – 0.82wt%, 455.64 – 1003.04 ppm and 0.23 – 0.63 mg/g, respectively. These values suggested that the sediments were moderately rich in organic matter. The Hydrogen Index (HI) values (19 – 85 mgHC/gTOC) and cross plots of Hydrogen Index (HI) versus Oxygen Index (OI), classified the sediments as types 111 and IV organic matter which had potential to generate mainly gas. The T_{max} and Production Index (PI) values ranged from 339 – 436°C and 0.08 – 0.32 while the Production Index (PI) ranged from 0.08 – 0.32, respectively, suggesting low maturity. Biomarker data revealed the presence of C_{27} to C_{29} steranes and *oleanane* which indicated organic matter from mixed sources with more terrigenous contribution. The dominance of C_{29} over C_{28} and C_{27} , also supported higher terrigenous input. Various thermal maturity parameters computed from the terpanes and steranes distributions in the sediments indicated low thermal maturity. The $C_{35}/C_{31} - C_{35}$ Homohopane index and Pr/Ph values ranged from 0.06-0.24 and 0.23 – 2.52 respectively. These values suggested organic matter deposited under anoxic to suboxic conditions. The results of this study showed that the sediments had potential to generate mainly gas at appropriate thermal maturity.

Keywords: Bornu Basin, Biomarkers, Hydrocarbon Potential, Paleodepositional Environment

INTRODUCTION

The Bornu Basin, which represents the Chad Basin in Nigeria, is one-tenth of the total area extent of the Chad Basin and extends to Niger Republic, Chad and Cameroon (Okosun, 1995). The Bornu Basin corresponds to the south-western arm of the Chad Basin and lies between longitudes 8°21'49"E and 14° 40'22"E and latitudes 11° N and 13° 43'38"N in north-eastern Nigeria (Fig.1). Occurrences of oil and gas "shows" in the eastern and western parts of the Chad Basin in the neighbouring Chad and Niger Republics (Bignell, 1977.; Whiteman, 1982.;

Schlumberger, 1985.; Genik, 1992; 1993) have led to intensive exploration activities in the Bornu Basin. In addition, the similarities in tectonic evolution between Libya's petroleum producing Sirte Basin (ASGA – UNESCO, 1963), Benue Trough (Frankl and Cordry, 1967; Whiteman, 1971) and Chad Basin, attest to a possible petroleum potential in the Bornu Basin. Whiteman (1982) reported on the likely prospect for hydrocarbons especially for the Turonian rocks which were laid down when the southern end of Bornu Basin was connected via Gongola arm with the Benue Trough.

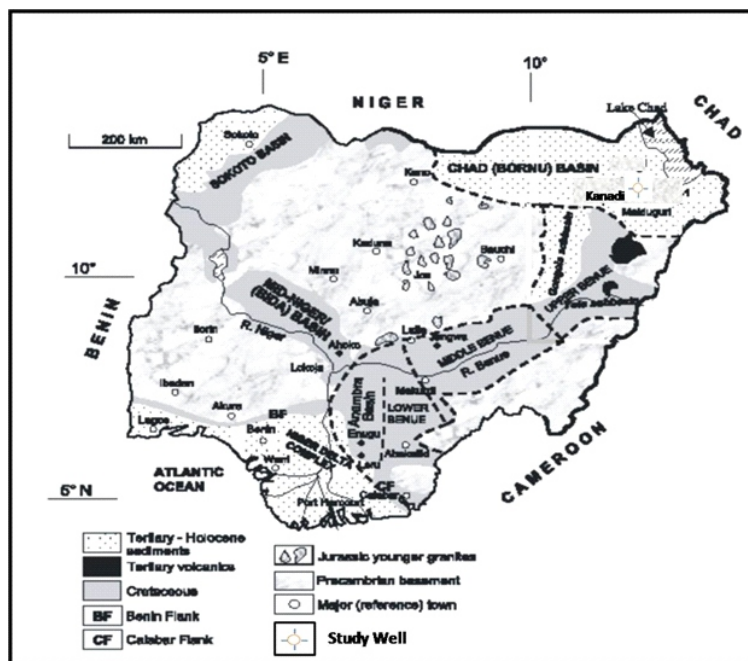


Figure 1: Geological Map of Nigeria Showing the Inland Basins, Location of Bornu Basin and Kanadi Well (After Obaje *et al.*, 2004)

Olugbemiro *et al.* (1997) have investigated the petroleum potential of the Bornu Basin and deduced that the Fika shale has good source rock potential but of low thermal maturity. They also deduced that the Gongila Formation is organically lean while the argillaceous member of the Bima Formation could be a good source rock but situated in a rather high thermal regime that is likely to vaporize such generated hydrocarbon. They proposed the continental Bima sandstone as the possible reservoir rock. Nton and Arowosegbe (2012) have examined the sedimentological characteristics and hydrocarbon potential of subsurface sediments of Kinasar-1 Well within the Bornu Basin. Their study revealed that the siliciclastics are products of continental block provenance from the Zambuk Ridge and/or the north central basement and deposited in fluvial environment while the organic matter is immature to slightly mature and of terrestrial precursor with prospects to generate gas.

At present, Nigeria's current national reserve asset (proven) put at 38 billion barrels of oil and about 190 trillion standard cubic feet of gas, is derived solely from the Niger Delta (Obaje *et al.*, 2011). In recent times, efforts have been geared towards the development of other sedimentary

basins outside the Niger Delta. This study therefore examines the sediments of Kanadi-1 Well for biomarker distribution in order to deduce the hydrocarbon potential and palaeodepositional environment of the Cretaceous sediments of the Bornu Basin, northeast Nigeria, in line with current understanding. Findings from this study no doubt, will provide additional information that will be useful to explorationists and researchers.

Description of the Study Area and Geology

The Kanadi-1 well, which was drilled in 1980's by the Nigerian National Petroleum Cooperation (NNPC), is located in the Bornu Basin, northeastern Nigeria and lies within longitude 12°25'E and latitude 13°25'N (Fig. 2). Various hypothesis have been put forward for the evolution of the Bornu Basin (Carter *et al.*, 1963; Ajakaiye and Burke, 1973; Avbovbo *et al.*, 1986) among others. The Bornu Basin, which represents the Chad Basin in Nigeria, is a part of the Western Central African Rift System (WCAS) that was formed in response to the separation of the African crustal blocks in the Cretaceous (Genik, 1992). The basin belongs to the West African Rift Subsystem (WAS) component of WCAS. The tectonic model and the different phases of evolution of the basin have been reported by Genik (1992).

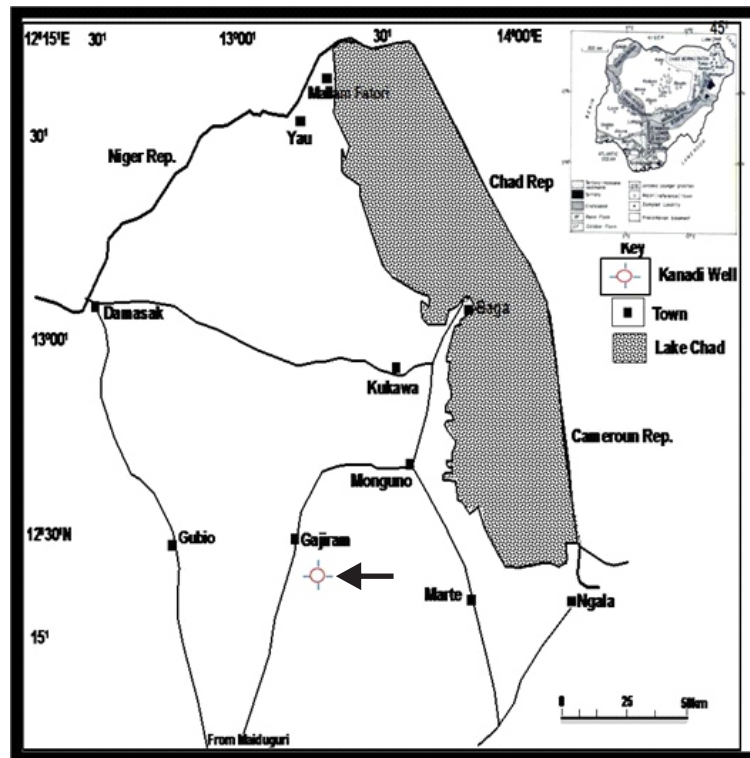


Fig. 2: Location Map of Northeastern Bornu, Showing Kanadi-1 Well

The stratigraphic units represented in the Nigerian sector of the Chad Basin ranges from Albian to Recent, where deposition took place under varying conditions. The stratigraphy of the Bornu Basin from oldest to youngest is as shown below:

The Bima Sandstone is the oldest stratigraphic unit in the Bornu Basin which lies unconformably on the basement complex (Okosun, 1995). It is made up of continental, poorly sorted, sparsely fossiliferous, thickly bedded, cross-stratified fine to coarse grained feldspathic sandstones and conglomerates. Thin bands of claystone and siltstone, varying in colour from red to grey or brown, occur as intercalations within the sandstone. Odusina *et al* (1983) reported that the Bima Sandstone is wholly continental in the northern part of the basin, while in the south, shale occurs in the lower part. This formation is diachronous and is from Albian –Turonian age (Carter *et al*, 1963).

Overlying the Bima Sandstone is the Gongila Formation. It is a transitional sequence between the underlying continental Bima Sandstone and the overlying Fika Shale (Carter *et al.*, 1963; Avbovbo *et al.*, 1986). Okosun (1995) described

the Gongila Formation as consisting thin to moderately thick intervals of shale, silty sandstone and sandstone. The shale is grey to dark-grey while the sandstone is of variable colours; ranging from brown through white, yellow to purple and grey. Volcanic intrusives, occurring as diorite sills, are present at several horizons within the formation (Okosun, 1995; Olugbemiro, 1997). Carter *et al.* (1963) reported the presence of numerous Cenomanian-Lower Turonian ammonites from the basal shaly facies in outcrops of the formation. The Gongila Formation marks the onset of marine incursion into the Chad Basin in the Turonian (Obaje *et al.*, 2004).

The Fika Formation overlies the Gongila Formation and was deposited during the marine transgression in the Turonian-Coniacian (Carter *et al.*, 1963). It comprised blue-black gypsiferous shale with thin intercalations of limestone. There are reported occurrences of volcanic intrusions at numerous horizons of the formation which affects the thermal alteration of the adjacent shale. The formation varies in thickness from the southwest part of the basin to the northwest part. It may be suggested that the older Cretaceous beds thicken towards the centre of the basin

(Avbovbo *et al.*, 1986).

Overlying the Fika Shale is the Gombe Sandstone and is made up of sequences of estuarine and deltaic sandstone, siltstone, shale, claystone, thin coal beds and intercalating limestone. The formation is best developed in the southwestern portion of the basin, where a thickness of 350 m has been reported and gets thinner towards the Lake Chad in the northeast (Matheis, 1976). The sandstone and siltstone are cross-bedded. The formation has been assigned a Maastrichian-Paleocene age.

Successively overlying the Gombe Formation is the Kerri-kerri Formation, which consists of thin to thick beds of sandstone siltstones and claystone. This formation appears similar in lithology to the Bima Sandstone, except for the lower proportion of feldspar (Carter *et al.*, 1963). The sandstones are cross-bedded and lignite bands occur at the base of the formation. The Kerri Kerri Formation is of Paleocene age (Adegoke *et al.*, 1973).

The Chad Formation is the youngest stratigraphic unit in the Bornu Basin and overlies the Kerri-Kerri Formation. It is made up of Quaternary lacustrine and fluvial thick bodies of claystone, separating three major sand bodies with lenses of diatomite, up to a few meters thick (Wright *et al.*, 1985). Feldspathic sandstone dominates the lower portion, which is overlain by gravels and a thick stratum of greenish-grey claystone with fine grained sandstone. The Chad Formation is a product of erosion from the watershed into the Chad Basin accompanied by episodic and sporadic uplift and volcanism (Burke, 1976). The formation was dated Pliocene-Pleistocene by Carter *et al.* (1963).

MATERIALS AND METHODS OF STUDY

Samples

The ditch cuttings from Kanadi -1 well were obtained from the Nigerian Geological Survey Agency (NGSA), Kaduna. The samples covered a depth range of 850 m – 3047 m. The detailed lithological description of the samples is shown in Figure 3. The lithologic description sequence is made up of a lower fine to medium grained,

poorly sorted brown sandstone. This is overlain by dark to black shale sequence and overlain by dark gray sandy shale in the middle part. A thick dark shale unit caps the sequence in the upper part.

Analytical Techniques

Total Organic Carbon

The samples were pulverized and approximately 0.10 g of each was treated with dilute Hydrochloric acid (HCl) to remove carbonates for Total Organic Carbon (TOC) determination. The samples were left in the acid for a minimum of two hours and later drained off with a filtration apparatus fitted with a glass microfibre filter. The filter was placed in a LECO crucible and dried at 110°C for a minimum of one hour. After drying, the samples were analyzed in a LECO 600 Carbon Analyzer for the Total Organic Carbon content.

Rock Eval Pyrolysis

100 mg of each sample was progressively heated to 600°C at 25°C/min heating rate. This computerized system output the pyrograms as well as the calculated parameters. Both the Total organic carbon and Rock eval pyrolysis were carried out at the Weatherford Laboratories, Texas, U.S.A with the same instrumentation.

Soluble Organic Matter (SOM) extraction and fractionation

About 30-50 g of each pulverized shale sample was Soxhlet extracted for 24 hrs using methylene chloride/methanol mixture for Soluble Organic Matter (SOM) extraction. After the extraction, the solvent was distilled and the soluble organic matter was then weighed. The extracts were fractionated on silica gel column chromatography into saturate, aromatic, polar (NSO) fractions by successive elution with 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 were analyzed for their biomarkers by gas chromatography/mass spectrometry (GC/MS) using the selected ion monitoring mode (SIM) with an Hp 6890 gas chromatograph fitted with

DB-5 silica capillary column (30 m x 0.25 mmID, 0.25 um film thickness) coupled with Hp 5973 MSD. The oven temperature was held at 60°C for 5 min and programmed from 60°C to 300°C at 40°C/min (held for 10 min). Helium was used as the carrier gas at constant flow rate of 1.0 ml/min. The mass spectrometer was operated at electron energy of 70Ev, an ion source temperature of

250°C and separation temperature of 250°C. The chromatographic data were acquired using Ms Chemstation software, version G1701BA for Microsoft NT®. Detailed analytical techniques can be found in Ekom (2011). This analysis was carried out at the Exxon Mobil Geochemical Laboratory, (QIT) Ibeno, Eket, Nigeria.

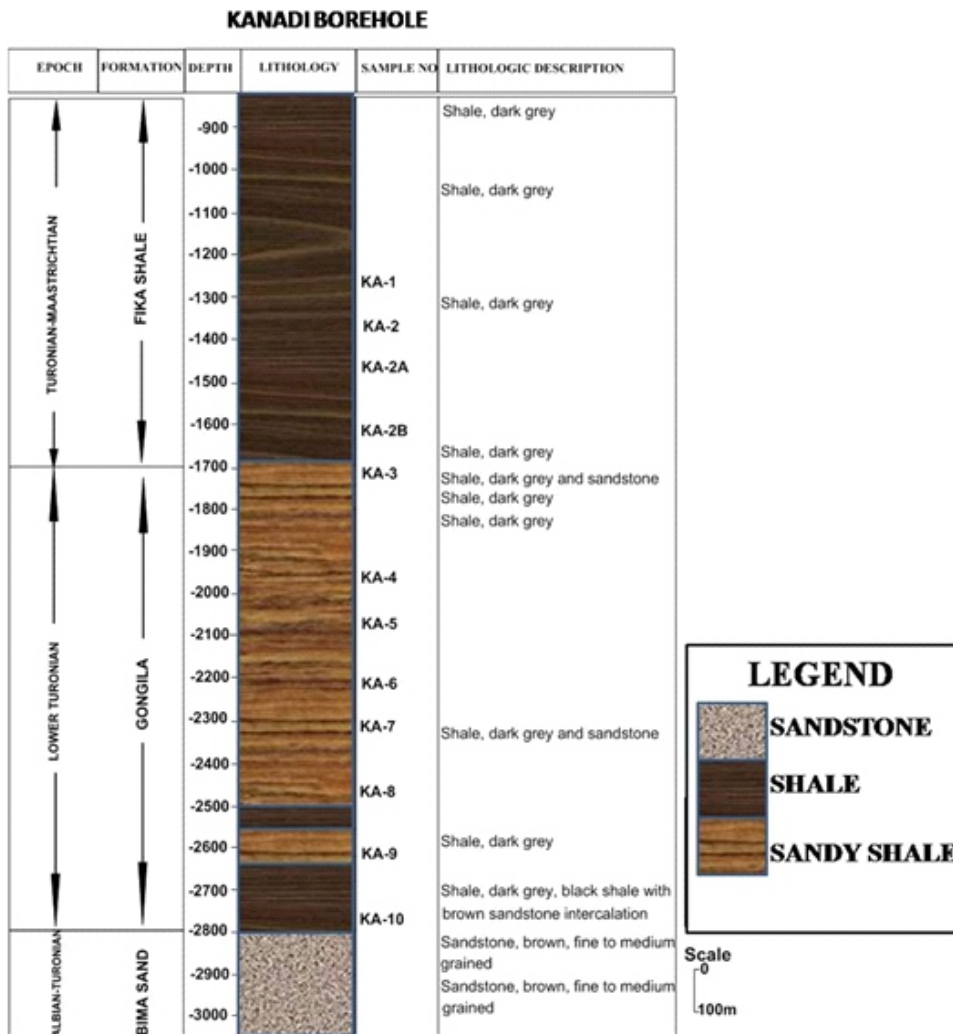


Fig. 3: Lithological Profile of Kanadi -1 Well

DISCUSSION OF RESULTS

Organic Matter Quantity

The Total organic carbon (TOC) contents for the samples range from 0.52-0.82 wt. % (Table 1). These values are slightly higher than the minimal 0.5 wt. % required for clastic source rock (Hunt, 1995; Tissot and Welte, 1984). The soluble organic matter (SOM) values range from 455.64 – 1003.04 ppm (av. 669.94 ppm, Table 2) and imply

that the organic matter is adequate. The saturated hydrocarbons (SHC), total hydrocarbon (THC) and genetic potential (GP) values range from 16 – 237 ppm (av.158 ppm), 35 – 405 ppm (av. 271 ppm) and 0.23 – 0.63 mg/g (av. 0.41mg/g), respectively. These values are lower than the expected values to generate oil except for gas (Tissot and Welte, 1984).

TABLE 1: Results of the TOC and Rock-Eval Pyrolysis of Kanadi -1 Well Sediments

Sample No.	Depth (M)	TOC (wt. %)	S ₁ (mg/g)	S ₂ (mg/g)	S ₃ (mg/g)	S ₁ + S ₂ (mg/g)	S ₂ /S ₃	S ₁ /TOC *100	HI	OI	PI	PC	T _{Max} (°C)	SOM /TOC (mg/g)
KA-1	1240	0.69	0.05	0.58	0.54	0.63	1.07	7	85	79	0.08	0.05	434	103
KA-2	1340	0.57	0.05	0.33	0.65	0.38	0.51	9	58	114	0.13	0.03	436	90
KA-2A	1440	0.54	0.05	0.34	0.57	0.39	0.59	9	63	106	0.13	0.03	436	111
KA-2B	1590	0.65	0.06	0.30	0.43	0.36	0.70	9	46	66	0.17	0.03	432	70
KA-3	1690	0.68	0.08	0.30	0.77	0.38	0.39	12	44	113	0.21	0.03	435	75
KA-4	1940	0.68	0.07	0.16	0.50	0.23	0.32	10	24	74	0.30	0.02	342	107
KA-5	2040	0.66	0.10	0.21	1.00	0.31	0.21	15	32	151	0.32	0.03	339	91
KA-6	2190	0.82	0.07	0.16	1.00	0.23	0.16	9	19	122	0.30	0.02	454	95
KA-7	2290	0.72	0.15	0.45	0.88	0.60	0.51	21	62	122	0.25	0.05	359	139
KA-8	2440	0.79	0.11	0.29	0.79	0.40	0.37	14	37	100	0.28	0.03	356	91
KA-9	2590	0.52	0.06	0.20	0.62	0.26	0.32	12	39	119	0.23	0.02	358	114
KA-10	2740	0.64	0.06	0.36	0.65	0.42	0.55	9	56	102	0.14	0.04	354	124
Average		0.66	0.08	0.29	0.70	0.38	0.48	11.33	47	106	0.21	0.03	395	101

Table 2: Data of Fractionated Parameters and Geochemical Ratios for Studied Well

Sample No.	Depth (m)	TOC (wt.%)	SOM (ppm)	SHC (ppm)	AHC (ppm)	THC (ppm)	NSO (ppm)	ASPHA (ppm)	UNREC (ppm)	SOM/TOC (mg/g)	SHC/TOC (mg/g)	THC/TOC (mg/g)
KA-1	1240	0.69	711.21	198	66	264	287	153	7	103	29	38
KA-2	1340	0.57	512.48	120	157	277	62	171	3	90	21	49
KA-2A	1440	0.54	599.97	151	136	287	207	101	5	111	28	53
KA-2B	1590	0.65	455.64	146	60	206	165	82	3	70	23	32
KA-3	1690	0.68	512.12	152	78	230	192	88	2	75	22	34
KA-4	1940	0.66	706.77	206	101	307	269	129	2	107	31	46
KA-5	2040	0.82	747.49	207	171	378	191	158	20	91	25	46
KA-6	2190	0.72	684.04	160	141	301	199	178	6	95	22	42
KA-7	2290	0.72	1003.0	16	19	35	50	788	127	139	2	5
KA-8	2440	0.79	718.02	150	255	405	173	136	4	91	19	51
KA-9	2590	0.52	592.24	158	87	245	196	145	6	114	30	47
KA-10	2740	0.64	796.20	237	82	319	282	193	2	124	37	50
Average		0.66	669.94	158	113	271	189	194	16	101	24	41

TOC = Total Organic Carbon, SOM = Soluble Organic Matter, SHC = Saturated Hydrocarbon, AHC = Aromatic Hydrocarbon, THC = Total Hydrocarbon, NSO = Heterocompounds, ASPHA = Asphathenes, UREC = Unrecovery.

Organic matter type

The plot of remaining hydrocarbon potential (S₂) versus total organic carbon (Fig. 4) shows that the majority of the sediments fall within types III and IV kerogen. The cross plot of hydrogen index against oxygen index (Fig. 5) also indicates types III and IV kerogen, suggesting greater input of terrestrial organic matter and gas prone. The

presence of *oleananes* (Table 3a) which is a marker for higher plants, (angiosperms) strongly supports a terrestrial precursor for the samples in this study (Ekweozor and Udo, 1987). A ternary plot of steranes C₂₇, C₂₈ and C₂₉ (Fig.6), shows a dominance of C₂₉ over C₂₇ and C₂₈ (C₂₇ < C₂₈ < C₂₉), which is an indication of high terrigenous input (Huang and Meischein, 1979).

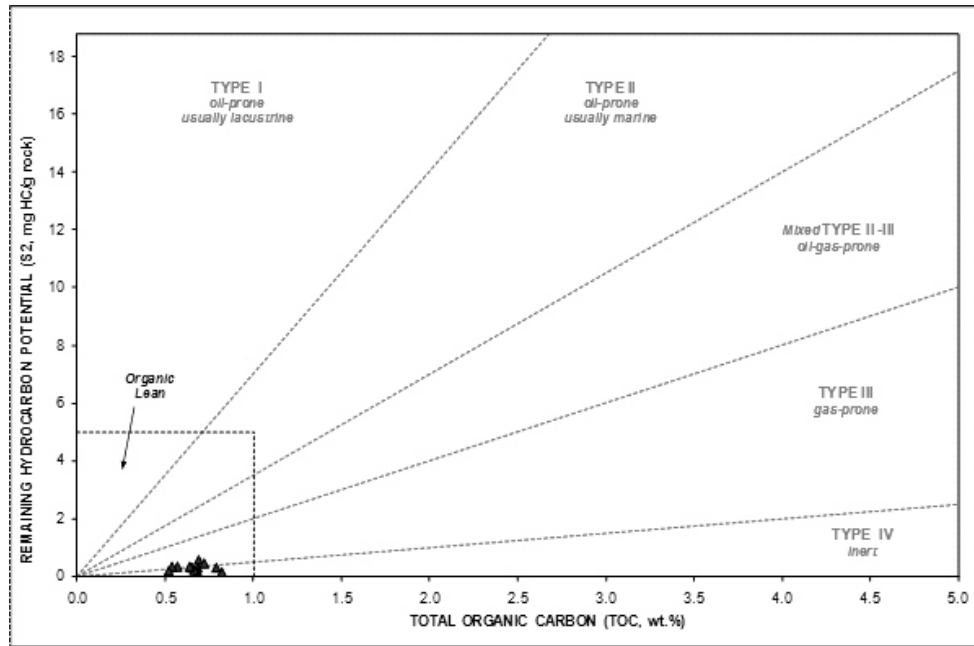


Fig. 4: Plots of Hydrocarbon Potential vs TOC for Studied Well (Modified After Jackson *et al.*, 1985)

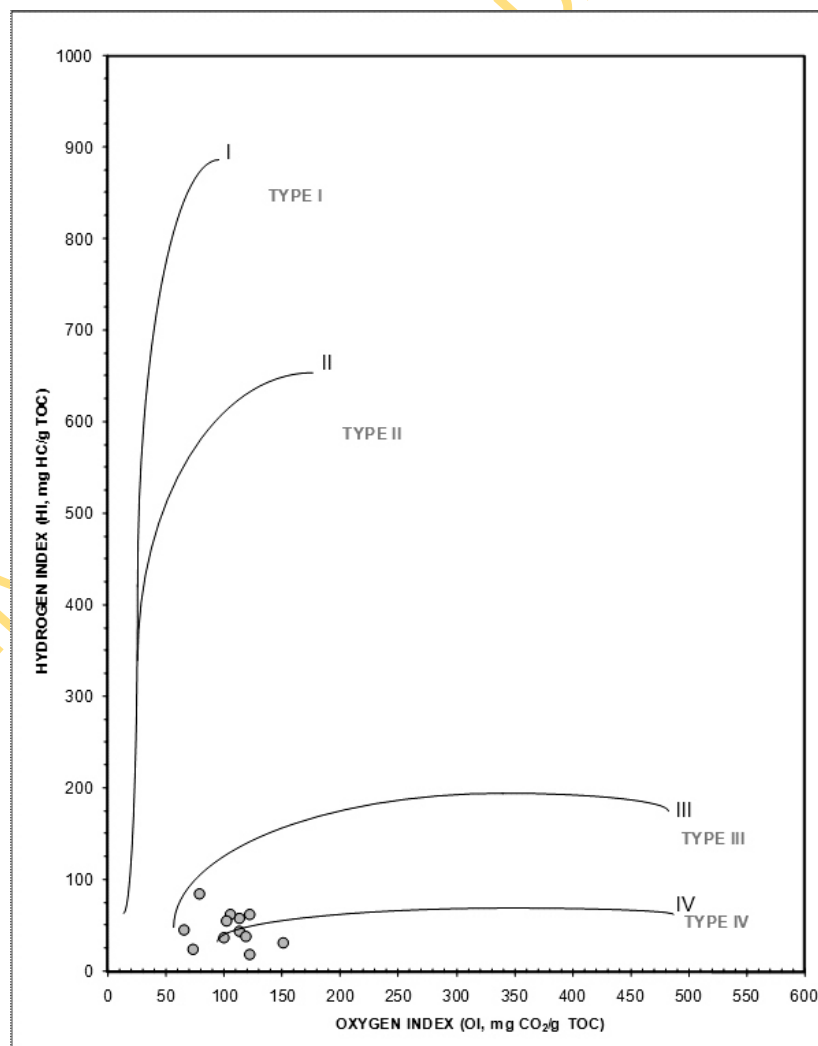


Fig. 5. Plots of Hydrogen Index against Oxygen Index for the Studied Well (Modified After Van Krevelen, 1961)

Table 3a: Triterpanes and Steranes Parameters Computed from the Saturate Biomarkers for Studied Well

Sample No	Depth (m)	Tet24/T26(S+R) + Tet24	Ts/Ts+Tm Trisnor-	Ol/Hop Oleanane	X/Hop+X Diahopane	$\beta\alpha/\beta\alpha+\alpha\beta$ C30Moretane	Gam/Hop+Gam Gammacerane	22S/22S+22R C32Homohop	Dia/regular C27
KA-1	1240	0.35	0.21	0.01	0.01	0.17	0.30	0.55	0.12
KA-2	1340	0.56	0.33	0.02	0.03	0.17	0.24	0.56	0.34
KA-2A	1440	0.44	0.34	0.03	0.03	0.15	0.23	0.54	0.20
KA-2B	1590	0.42	0.41	0.05	0.04	0.15	0.16	0.56	0.53
KA-3	1690	0.46	0.39	0.04	0.03	0.14	0.19	0.57	0.32
KA-4	1940	0.44	0.46	0.12	0.04	0.13	0.07	0.58	0.49
KA-5	2040	0.42	0.46	0.09	0.04	0.14	0.08	0.56	0.50
KA-6	2190	0.45	0.43	0.08	0.04	0.13	0.07	0.60	0.46
KA-7	2290	0.35	0.43	0.10	0.08	0.15	0.07	0.54	0.48
KA-8	2440	0.40	0.47	0.13	0.04	0.14	0.06	0.59	0.50
KA-9	2590	0.43	0.48	0.08	0.04	0.15	0.06	0.57	0.54
KA-10	2740	0.36	0.45	0.08	0.04	0.14	0.05	0.58	0.49

Ol/Hop – Oleanane/hopane ratio which is equivalent to the Oleanane index (OI)

Ts/Ts + Tm – 22, 29, 30-trisnor-18 α (H)hopane/(22,29,30-trisnor-17 α (H)hopane)

Tet24 – Tetracyclic 24, T26 – Tricyclic 26

X (C30)/Hop+X(C30) – Diahopane ratio

Gam/Hop+Gam - Gammacerane index.

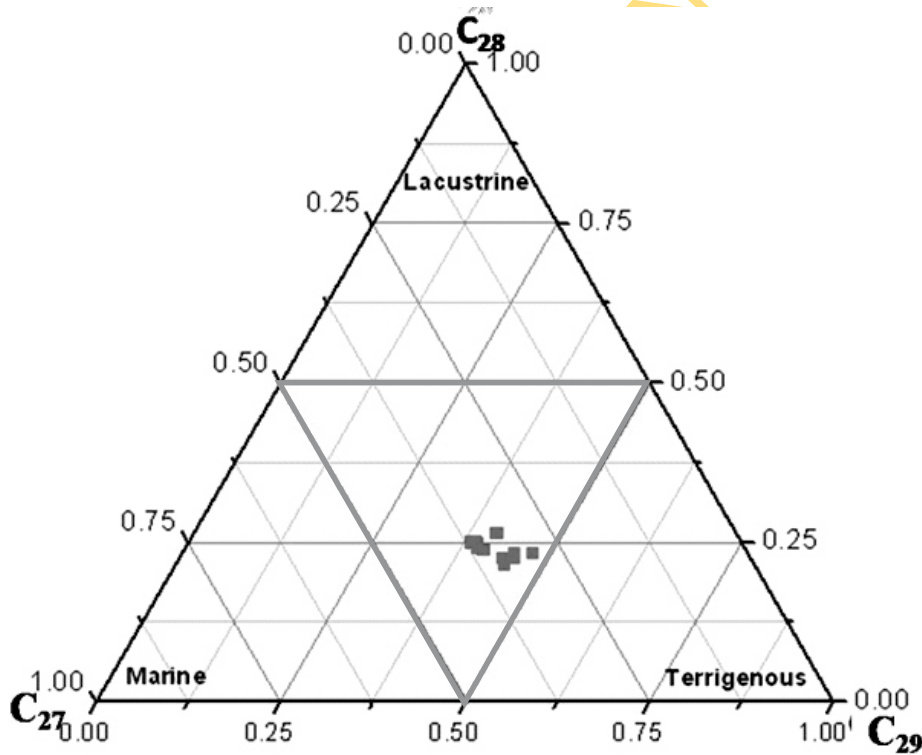


Fig.6. Ternary Plots of C_{27} , C_{28} and C_{29} Steranes for Studied Well (After Huang and Meischein, 1979)

Maturity of Organic Matter

The T_{max} values calculated for the shales range from 339°C to 454 °C (av. 395°C) indicating that the shales are immature. The cross plot of hydrogen index versus T_{max} (Fig. 7) indicates that the majority of the samples are immature with a few (30%) lying within the oil window. The ratio of extractable bitumen to total organic carbon (Bitumen/TOC), sometimes called Transformation Ratio (TR) can be used in

determining sediment maturity (Peters and Moldowan, 1993). It has been pointed out that such values range from near zero in shallow sediments to about 250mg/g TOC at the peak of oil generation. It has been demonstrated that these values decrease at greater depths as a result of conversion of bitumen to gas (Peters and Moldowan, 1993). In this study, the bitumen ratio ranges from 70.0 to 139 mg/g TOC (Table 2). This range indicates immature sediments.

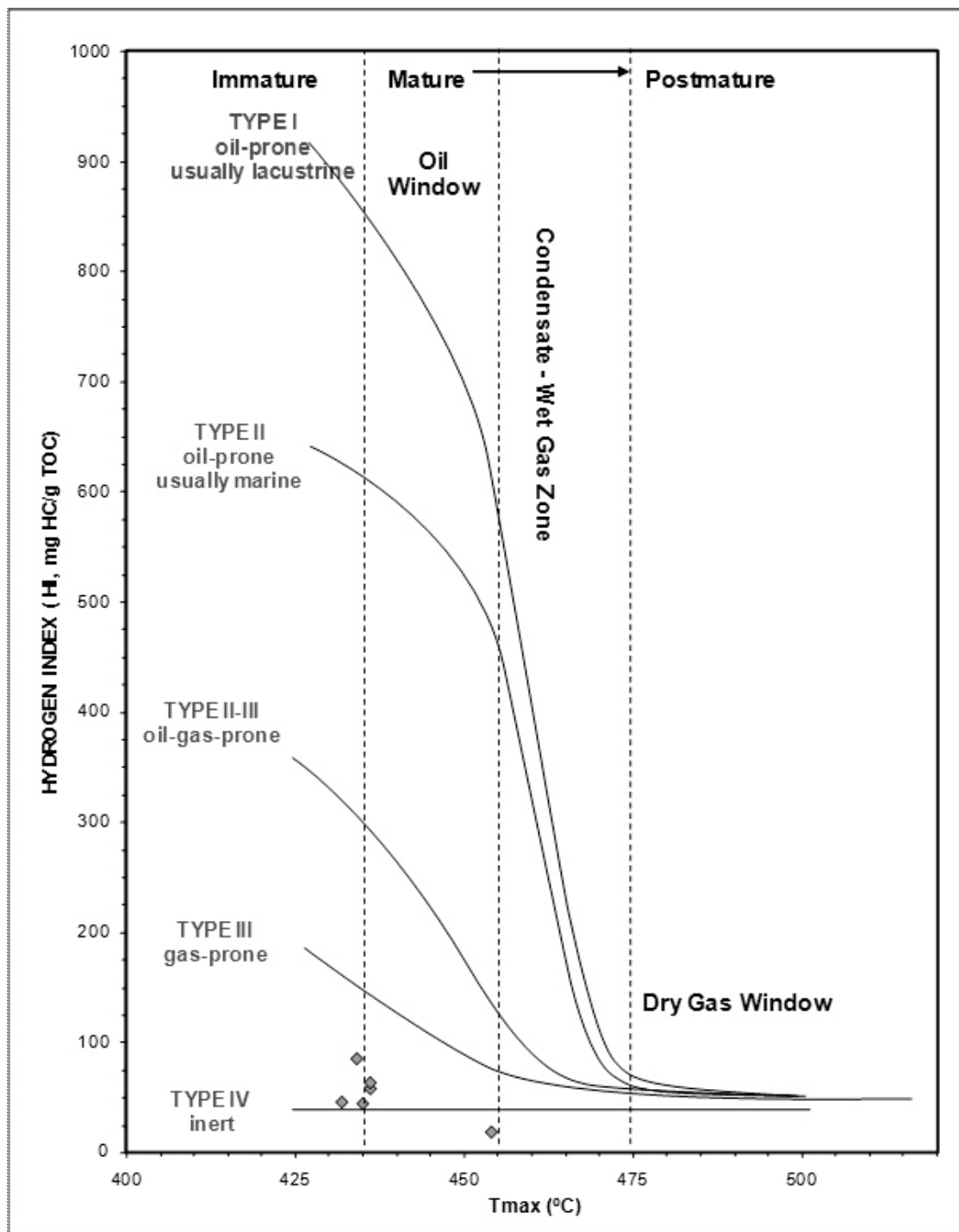


Fig.7. Cross Plots of Hydrogen Index versus T_{max} for Kanadi -1 Well (Modified After Jackson *et al.*, 1985)

Biomarkers are used to describe the maturity of the organic matter present in source rock depending on its relation to the oil generation window (Peters and Moldown, 1993). Typical representative gas chromatograms (GC-MS) of triterpane (m/z 191) and sterane (m/z 217) are shown in Figs. 8 and 9. The various maturity

parameters calculated from the terpanes and steranes distributions in the sediments are given in Tables 3a and 3b. The homohopane, $20S/(20S+20R)$ sterane, C_{29} $\alpha\beta\beta/(\alpha\beta\beta+\alpha\alpha\alpha)$ sterane ratios range from 0.54 – 0.60 (Table 3a); 0.15 – 0.37 and 0.39 – 0.65 (Table 3b), respectively.

Table 3b: Triterpanes and Steranes Parameters Computed from the Saturate Biomarker for Studied Well

Sample No	Depth (m)	C19/C20 Tricyclic	Tet24/T24 Tetracyclic	C35/C31-C35 Homohopane Index	C24/C26(S+R)	$\alpha\beta$ /H30+ $\alpha\beta$ Norhopane Index	% C27	% C28	% C29	$\alpha\alpha\alpha$ 20S/20S+20R C29 Sterane	$\alpha\beta\beta$ / $\alpha\beta\beta$ + $\alpha\alpha\alpha$ C29 Sterane
KA-1	1240	0.30	0.48	0.07	0.57	0.33	36.21	24.10	39.69	0.20	0.39
KA-2	1340	0.34	0.71	0.06	0.60	0.40	35.57	23.66	40.77	0.21	0.44
KA-2A	1440	0.30	0.45	0.08	0.64	0.32	32.41	26.41	41.18	0.15	0.41
KA-2B	1590	0.42	0.48	0.08	0.64	0.36	35.87	25.10	39.03	0.24	0.50
KA-3	1690	0.70	0.55	0.07	0.63	0.36	36.71	24.93	38.37	0.21	0.47
KA-4	1940	0.50	0.28	0.10	0.76	0.39	35.84	24.86	39.47	0.37	0.59
KA-5	2040	0.35	0.22	0.09	0.84	0.41	33.57	22.50	43.93	0.32	0.60
KA-6	2190	0.52	0.25	0.08	0.77	0.40	31.79	22.86	45.35	0.33	0.60
KA-7	2290	0.48	0.28	0.24	0.74	0.40	29.17	23.23	47.60	0.33	0.65
KA-8	2440	0.47	0.25	0.08	0.77	0.41	31.69	23.23	45.08	0.36	0.62
KA-9	2590	0.36	0.22	0.10	0.80	0.42	33.53	21.16	44.32	0.37	0.61
KA-10	2740	0.44	0.21	0.09	0.78	0.39	32.07	22.50	45.43	0.36	0.62

All the analysed samples have low $T_s/(T_s+T_m)$ ratio ranging from 0.21 to 0.48 and the moretane/hopane ratio exceeding 0.15 (Table 3a). These values reflect the thermal immaturity status of all the shales (Seifert and Moldowan, 1986; Waples, 1985; Waples and Machihara, 1991; Mackenzie *et al.*, 1980; Spiro, 1984; Seifert and Moldowan, 1980; Grantham, 1986).

Depositional Environment

The Pr/Ph ratio reflects the redox potential of the

depositional environment with values <1.0 , indicating anoxic environment while values >1.0 indicate oxic environment (Didyk *et al.*, 1978; Peters and Moldowan, 1993). The Pr/Ph ratio for Kanadi -1 well ranges from 0.23-2.52, indicating that the sediments were deposited in anoxic to oxic environment but with stronger oxic influence (Table 4). Cross plots of isoprenoids/n-alkanes (Fig. 10) revealed that the samples are mainly in oxidizing environment and biodegraded.

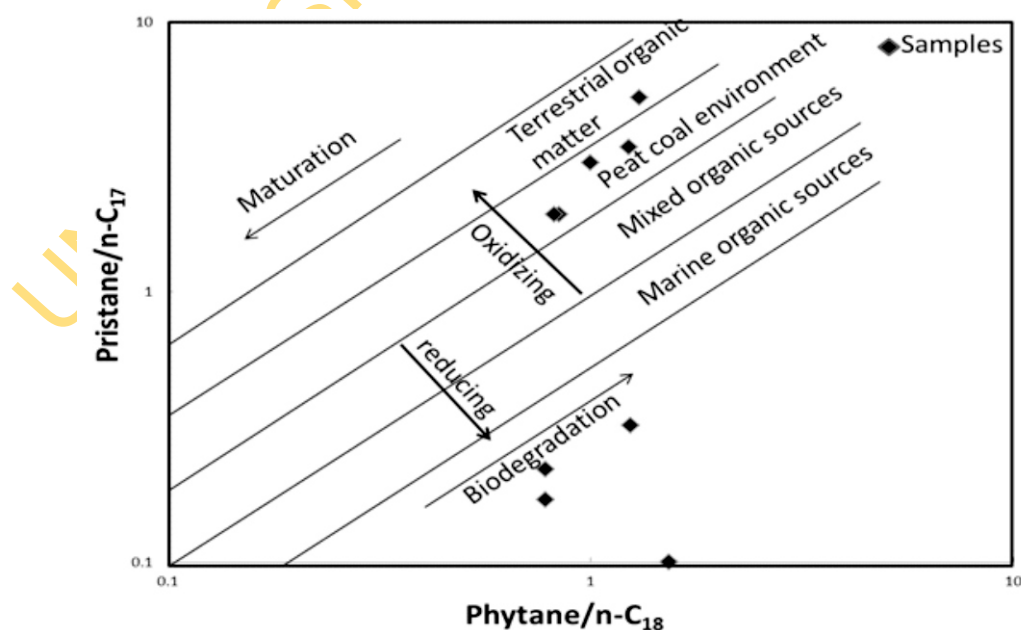


Fig. 10. Plots of Pristane/ n -C₁₇ versus Phytane/ n -C₁₈ for the Kanadi -1 Well (Modified after Datta *et al.*, 2008)

Table 4: Gas Chromatographic Data Showing values of Isoprenoids, Isoprenoids/n-alkane Ratios and other Parameters for Kanadi-1 Well

Sample No.	Depth (m)	Pr/Ph	Pr/nC17	Ph/nC18	Odd/Even Ratio	Long/Short Chain
KA-1	1240	0.23	0.10	1.53	1.19	0.12
KA-2	1340	0.45	0.22	0.78	0.95	0.51
KA-2A	1440	0.57	0.17	0.79	1.06	0.35
KA-2B	1590	-	-	1.30	1.01	-
KA-3	1690	0.54	0.32	1.24	0.96	0.13
KA-4	1940	1.63	1.93	0.82	1.01	0.10
KA-5	2040	1.81	3	1	1.04	-
KA-6	2190	1.74	2.24	0.84	1	0.03
KA-7	-	-	-	-	-	-
KA-8	2440	2.52	5.23	1.30	1.02	-
KA-9	2590	-	-	-	-	-
KA-10	2740	1.37	3.43	1.23	1.03	-
Average		1.20	1.85	1.10	1.03	0.21

Pr – Pristane, Ph – Phytane

Long/short – ratio of long chain n-alkanes/short chain n-alkanes

$$= (nC_{27} + nC_{29} + nC_{31}) / (nC_{15} + nC_{17} + nC_{19}), \text{Odd/even} = (nC_{21} + 6nC_{23} + nC_{25}) / (4nC_{22} + 4nC_{24})$$

Biomarkers provide information about the type of depositional environment of organic matter, the conditions during deposition and the lithology in which the organic matter is present (Peters and Moldowan, 1993). The 17 α (H)-homohopane distributions can provide information about the palaeoenvironment (Waples and Machihara, 1991). Homohopane index (C35) is very low for all the shale samples, ranging from 0.06 to 0.24 (av.0.10) (Table 3b). The low homohopane index values is an indications of suboxic depositional environment (Moldowan *et al.*, 1986; Hunt, 1995). Gammacerane is a typical biomarker in lake and sea sediments of high salinity (Waples and Machihara, 1991; Hunt, 1995; Peters and Moldowan, 1993). The values of gammacerane index in the studied samples range from 0.05 – 0.30 (Table 3a). Furthermore, the tetracyclic terpane -Tet24/(T26(S+R)+Tet24, another indicator of salinity (Connan *et al.*,1986), is present in the Kanadi Shale samples with values ranging from 0.35 to 0.56 (Table 3a). Peters and Moldowan (1993) assigned tetracyclic terpane values > 1 to be hyper salinity while < 1, indicate

low salinity. The average value of 0.42 (Table 3a) in this study however indicates low salinity.

The C25/C26(S+R) tricyclic terpane ratio has been reported as a valuable tool in distinguishing marine from non-marine environments (Burwood *et al.*, 1992; Hanson *et al.*, 2000). Values higher than 1.0, indicate a marine environment, while values lower than 1.0, reflect non-marine environment. The C25/C26(S+R) ratios in the samples range from 0.57 – 0.84 (Table 3b) and indicate that the samples were deposited in non-marine environment or terrestrial environment.

SUMMARY AND CONCLUSIONS

Hydrocarbon generative potential and paleodepositional environment of subsurface sediments of the Kanadi-1 well, Bornu Basin, Nigeria were carried out. The source rocks are moderately rich in organic matter and are mainly types 111 and 1V organic matter . The dominance of C₂₉ over C₂₈ and C₂₇, indicates organic matter of mainly terrigenous input and were deposited in environment ranging from anoxic to oxic

conditions with greater oxic influence. The various thermal maturity parameters computed from terpanes and steranes distributions in the sediments indicate low thermal status. The study shows that the sediments have potential to generate mainly gas at appropriate thermal maturity.

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