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NIGERIAN CRETACEOUS COAL DEPOSITS AND THEIR PETROLEUM SOURCE ROCK CHARACTERISTICS

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ABSTRACT: *Some Nigerian Cretaceous coal deposits have been mapped and characterized for their petroleum source rock potential based on Rock Eval pyrolysis. These coal deposits which occur entirely within the Anambra Basin/Benue Trough have been mapped at Owukpa, Okaba, Ogboyaga, Omelehu, Lafia-Obi and at Gombe-Kumo. Some of these coal deposits lie deep down at great depths in the Anambra Basin and Benue Trough where they constitute active source rocks. Stratigraphically, the coals in the Anambra Basin and Upper Benue Trough are deposited within fluvio-deltaic Maastrichtian succession of the Mamu and Gombe Formations, respectively, while those in the Middle Benue Trough are embedded in Turonian-Coniacian paralic-shallow marine facies of the Awgu Formation. Although not studied here, Turonian-Coniacian coal deposits also occur in the Lower Benue Trough at Amansiodo and in the Upper Benue Trough at Lamza. Rock Eval pyrolysis results on the coal deposits show Hydrogen Index values of between 206-283mgHC/gTOC for the Anambra Basin coals with Tmax in the immature to sub-mature zone (419-428^{o}C) while the coals in the Middle Benue Trough gave HI values of 54-58mgHC/gTOC and Tmax values that show maturity within the main oil window. Results obtained on the Gombe-Kumo coals are similar to those of the Anambra Basin. Interpretation of the results using the Van Krevelen and HI-Tmax diagrams indicate that the coals as source rocks are characterized by Type II/III kerogens for the Maastrichtian deposits, oil and gas prone and generally sub-mature with respect to hydrocarbon generation at the present depth of study. The coals in the Middle Benue Trough are characterized by Type III/Type IV kerogens, gas prone and mature with respect to hydrocarbon generation. At greater depths, the Middle Benue Trough coals would have completed generation and reached over-cooked facies while the Maastrichtian coals would have entered the main oil window except the Gombe coals which are stratigraphy too shallow.*
KEYWORDS: Nigerian, cretaceous coal deposits, petroleum source, rock characteristics

INTRODUCTION

The Nigerian government through the Nigerian National Petroleum Corporation and other investors are currently acquiring exploration data to enable a comprehensive assessment of the oil and gas prospects in the frontier hinterland basins of Nigeria. These hinterland basins comprise the Anambra Basin, Benue Trough, Bida Basin, Chad Basin (Nigerian sector), Dahomey Basin and Sokoto Basins (Fig. 1). The oil and gas potentials in the basins will depend on the fate of the elements that make up the petroleum system, namely, mature source rocks and their volumes, good quality reservoir rocks and seal lithologies, effective generation, expulsion and migration into reservoirs, availability of trapping structures and timing of generation, expulsion and migration in relation to other events. While most exploration projects are heavily biased toward seismic studies of structures and possible traps, such exercises are usually futile if the availability of deep-seated source rocks and their characteristics had not been evaluated and tested. At the centre of the petroleum system is the availability of good quality source rocks. Source rocks for petroleum generation are usually shales, carbonates and coals. Coal deposits of Cretaceous ages are widely distributed within the sedimentary basins of Nigeria. Apart from scantily reported thin coaly beds in the Bida and Sokoto Basins (Braide, 1992; Kogbe, 1981), all the Cretaceous coal deposits in Nigeria occur within sedimentary strata in the Benue Trough of which the Anambra Basin is a southeast portion.

The subject of coal as a major source of oil and gas in many parts of the world has been extensively reviewed and succinctly discussed by many authors (e.g. Hunt, 1991; Hendrix et al., 1995; Obaje et al., 2004). Coal has long been recognized as a source of gas, primarily methane and carbon dioxide but its importance as a source of economic accumulations of oil has been difficult to prove as coals are often interbedded with shales which are always assumed to be the source beds. Increasing evidence, however, suggests that coals and associated type III kerogens can yield not only gas or condensate (e.g. Tissot and Welte, 1984), but also significant quantities of oil (Hendrix et al., 1995).

The aim of this short paper is to identify surface locations of Cretaceous coal deposits in up-dip sections along the Benue Trough stratigraphic sequences in Nigeria and to carry out Rock Eval pyrolysis on the collected samples as a basis for extrapolating their potentials to generate or to have generated hydrocarbons or otherwise at greater depths in this SW-NE rifted structure which presently constitutes a major centre for hydrocarbon exploration in Nigeria.

Geological Setting / Background Literature

The discussion on the geological setting will focus on the Anambra Basin being part of the Lower Benue Trough and the Middle and Upper Benue Trough. This geological setting hosts the investigated coal deposits (Fig. 1)

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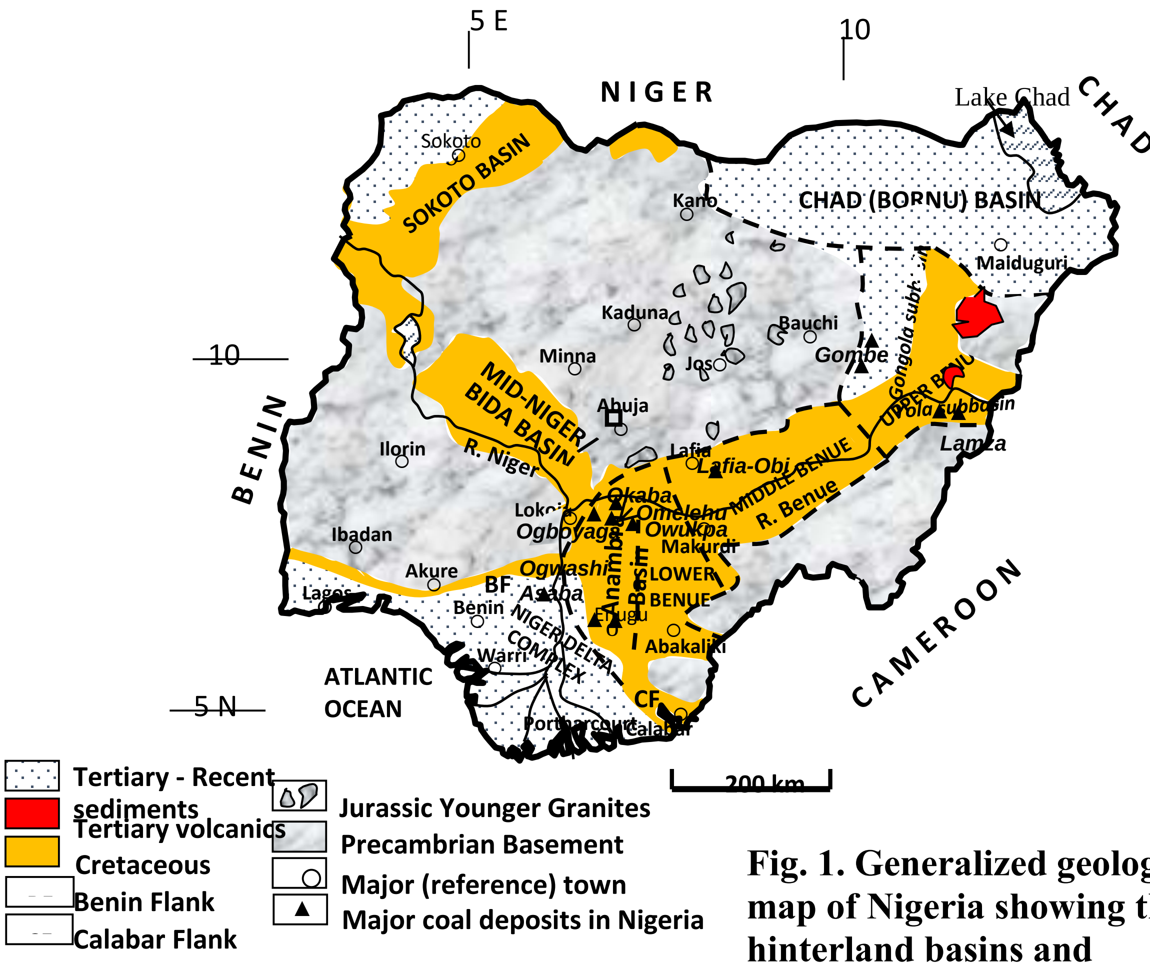

Fig. 1. Generalized geological map of Nigeria showing the hinterland basins and locations of major coal deposits

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Anambra Basin / Lower Benue Trough

The Anambra Basin is believed to be an integral unit of the Lower Benue Trough (Figs. 1, 2). Sedimentation in the Lower Benue Trough commenced with the marine Albian Asu River Group (Fig. 2). The Asu River Group is made up of the shales, limestones and sandstone lenses of the Abakaliki Formation in the Abakaliki area and the Mfamosing Limestone in the Calabar Flank (Petters, 1982). The marine Cenomanian-Turonian Nkalagu Formation (black shales, limestones and siltsones) and the interfingering regressive sandstones of the Agala and Agbani Formations rest on the Asu River Group. Mid-Santonian deformation in the Benue Trough displaced the major depositional axis westward which led to the formation of the Anambra Basin. Post-deformational sedimentation in the Lower Benue Trough, therefore, constitutes the Anambra Basin. Sedimentation in the Anambra Basin thus commenced with the Campanian-Maastrichtian marine and paralic shales of the Enugu and Nkporo Formations, overlain by the coal measures of the Mamu Formation. The fluviodeltaic sandstones of the Ajali and Owelli Formations lie on the Mamu Formation and constitute its lateral equivalents in most places. In the Paleocene, the marine shales of the Imo and Nsukka Formations were deposited, overlain by the tidal Nanka Sandstone of Eocene age. Down-dip, towards the Niger Delta, the Akata Shale and the Agbada Formation constitute the Paleogene equivalents of the Anambra Basin

The Enugu and the Nkporo Shales represent the brackish marsh and fossiliferous pro–delta facies of the Late Campanian–Early Maastrichtian depositional cycle (Reijers and Nwajide, 1998; Obaje, 2009). Deposition of the sediments of the Nkporo/Enugu Formations reflects a funnel-shaped shallow marine setting that graded into channeled low-energy marshes. The coal-bearing Mamu Formation and the Ajali Sandstone accumulated during this epoch of overall regression of the Nkporo cycle. The Mamu Formation occurs as a narrow strip trending north-south from the Calabar Flank, swinging west around the Ankpa plateau and terminating at Idah near the River Niger (Nwajide, 2013). The Ajali Sandstone marks the height of the regression at a time when the coastline was still concave. The converging littoral drift cells governed the sedimentation and are reflected in the tidal sand waves which are characteristic for the Ajali Sandstone. The Mamu Formation and its interbedded coals are best exposed at the Miliken Hills in Enugu, with well-preserved sections along the road cuts from the King Petrol Station up the Miliken Hills and at the left bank of River Ekulu near the bridge to Onyeama mine (Obaje et al., 1999; Nwajide, 2013).

The works of Nwajide and Reijers (1996) and Obaje et al. (1999a) discussed some occurrences of coal deposits in the Anambra Basin. Apart from the large deposits of coal within the Maastrichtian succession, some high volatile bituminous coals (of higher grade than the Maastrichtian coals) occurrences within Coniacian Awgu Formation at Amansiodo have been reported by same authors.

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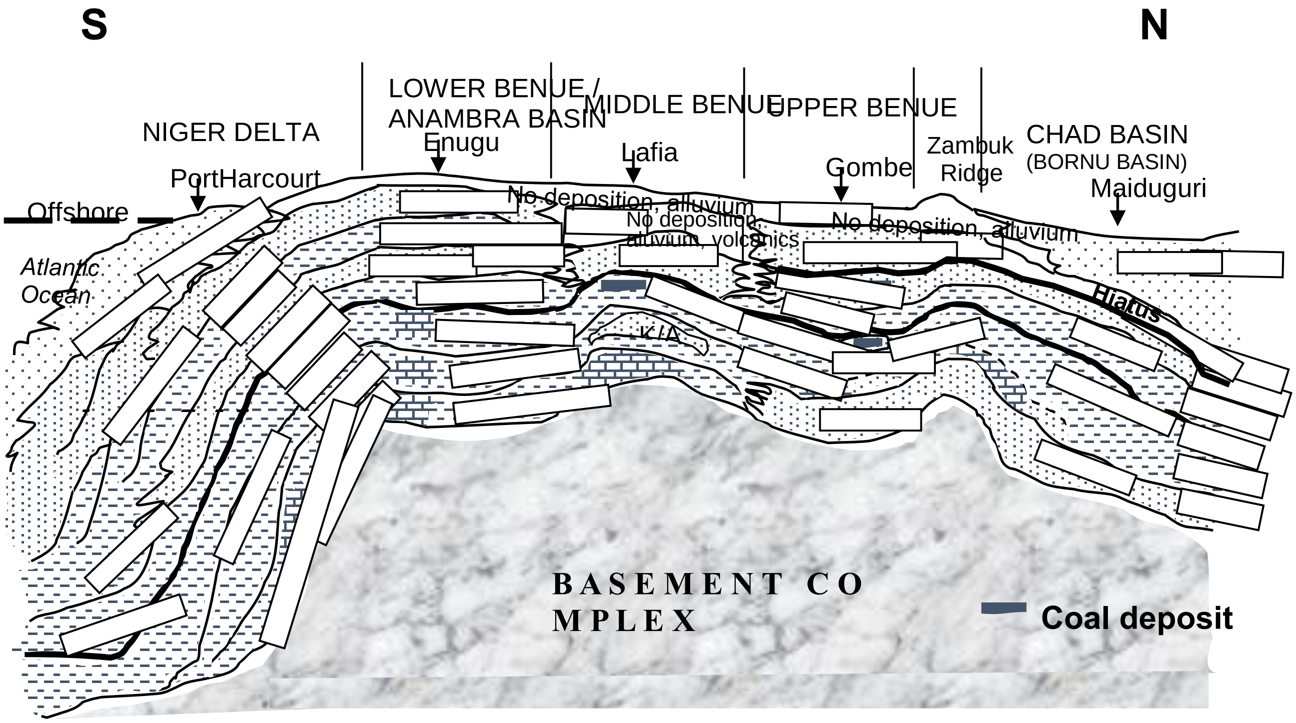

Fig. 2. Stratigraphical cross-section from the Niger Delta through the Anambra Basin-Benue Trough onto the Chad Basin showing coal depositions within respective geological formations (after Obaje et al., 2004)

The Middle Benue Trough

According to Obaje et al. (2004) and Abubakar et al. (2006), stratigraphic succession in the Middle Benue Trough is made up of Albian Arufu, Uomba and Gboko Formations, generally referred to as the Asu River Group (Offodile, 1976; Nwajide, 1990). These are overlain by the Cenomanian – Turonian Keana and Awe Formations and the Cenomanian – Turonian Ezeaku Formation. The Ezeaku Formation is coterminous with the Konshisha River Group and the Wadata Limestone in the Makurdi area. The Late Turonian – Early Santonian coal-bearing Awgu Formation lies conformably on the Ezeaku Formation. In the Makurdi area, the Makurdi Sandstone interfingers with the Awgu Formation. The mid-Santonian was a period of folding throughout the Benue Trough. The post-folding Campano-Maastrichtian Lafia Formation ended the sedimentation in the Middle Benue Trough (Fig. 2), after which widespread volcanic activities took over in the Tertiary.

The Asu River Group outcrops mainly in the Keana anticline east of Keana town and south of Azara and in the area around Gboko. The lithologic composition of the Asu River Group comprises limestones, shales, micaceous siltstones, mudstones and clays (Offodile, 1976; Obaje, 1994). The Awe Formation was deposited as passage (transitional) beds during the Late Albian to Early Cenomanism regression. Its typical sections occur around the town of Awe, where Offodile (1976) estimated the thickness to be about 100m. The Keana Formation resulted from the Cenomanian regression which deposited fluviodeltaic sediments. The deposition of the Ezeaku Formation is attributed to the beginning of marine transgression in the Late Cenomanian (Petters, 1982). The sediments are made up mainly of calcareous shales, micaceous fine to medium friable sandstones and beds of limestones which are in places shelly. The deposition took place in a presumably shallow marine coastal environment (Offodile, 1976).

Based on the works Offodile (1976) and Ofoegbu (1990), the Awgu Formation marks the end of marine sedimentation in the Middle Benue Trough. The formation is made up of bluish-grey to dark-black carbonaceous shales, calcareous shales, shaley limestones, limestones, sandstones, siltstones, and coal beds. The major outcrop of the coal-bearing Awgu Formation is at the bank of River Dep in Shankodi, 7km to the west of the village of Jangwa (Obaje, 1994). The Lafia Formation is the youngest formation in this area. The formation was deposited under continental condition (fluviatile) in the Maastrichtian and lies unconformably on the Awgu Formation.

The works of Obaje et al. (1994), Obaje and Abaa (1996), Obaje and Hamza (1999), Obaje et al. (1999b, c, d) have succinctly discussed the occurrences of coal deposits in the Middle Benue Trough and presented their petrographic characteristics.

The Upper Benue Trough

Abubakar et al. (2006) described the Upper Benue Trough as being made up of two arms, the Gongola Arm and the Yola Arm (although some authors have sub-divided the Upper Benue Trough to include a third central Lau-Gombe sub-basin, eg. Akande et al., 1998). The Albian Bima Sandstone lies unconformably on the Precambrian Basement. This formation was deposited under continental conditions (fluvial, deltaic, lacustrine) and is made up of coarse to medium grained sandstones, intercalated with carbonaceous clays, shales, and mudstones. The Bima Sandstone was subdivided by Carter et al. (1963) into a Lower, Middle and Upper Bima. The Yolde Formation lies conformably on the Bima Sandstone. This formation of Cenomanian age represents the beginning of marine incursion into this part of the Benue Trough. The Yolde Formation was deposited under a transitional/coastal marine environment and is made up of sandstones, limestones, shales, clays and claystones. In the Gongola Arm, the laterally equivalents Gongila and Pindiga Formations and the possibly younger Fika Shale lie conformably on the Yolde Formation. These formations represent full marine incursion into the Upper Benue during the Turonian – Santonian times. In the Yola Arm, the Dukul, Jessu and Sekuliye Formations, the Numanha Shale, and the Lamja Sandstone are the Turonian – Santonian equivalents of the Gongila and Pindiga Formations. The Turonian - Santonian deposits in the Yola Arm are lithologically and palaeoenvironmentally similar to those in the Gongola Arm, except the Lamja Sandstone which has a dominating marine sandstone lithology and contains coal beds which were studied by Jauro et al. (2006). The Santonian was a period of folding and deformation in the whole of the Benue Trough (Abubakar and Obaje, 2001). Post-folding sediments are represented by the continental Gombe Sandstone of Maastrichtian age and the Kerri-Kerri Formation of Tertiary age. The Gombe Sandstone is lithologically similar to the Bima Sandstone, attesting to the re-establishment of the

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Albian palaeoenvironmental condition. The Gombe Sandstone, however, contains coal, lignite, and coaly shale intercalations which in places are very thick.

Petroleum Source Rock Characteristics of Coals

Pyrolysis data have revealed that the hydrocarbon richness of sedimentary rocks is dependent on the amount and nature of liptinite and some vitrinite macerals (Hunt, 1991; Hendrix et al., 1995). The abundance of liptinite macerals is therefore the major criterion when considering any sedimentary rock (including coal) as a potential source for liquid hydrocarbons. A minimum of 15-20% liptinite content (by volume) of total macerals in shales, carbonates, or coals is considered an important criterion for a rock to be characterized as a potential oil source rock (Hunt, 1991). Although the concentration of long-chain aliphatic constituents has also been considered as a primary determinant of the oil generation potential of coals (Curry et al., 1994), the factors which govern their occurrence in different coals are poorly understood. Permian coals from the Cooper Basin in Australia, which have sourced commercial accumulations of oil (Curry et al., 1994), were deposited in high latitude bogs and contain 40-70% inertinite. Pristane/phytane ratios range from 2.15 to 6.00 and HIs are moderate (up to 243mgHC/gTOC). The extracts and pyrolysates both contain high relative concentration of aliphatic groups. These aliphatic groups were found to be derived from microbial biomass (bacterial and algal degradation products). The Taranaki coals of New Zealand, which also are the source of commercial oil accumulations, were deposited in temperate fluvial-deltaic environments (Collier and Johnson, 1991). HI values range from 236-365. Extracts have high pristane/phytane ratios and variable abundances of hopanoid and other non-hopanoid terpanes. The extracts and pyrolysates both contain high relative concentrations of aliphatic groups $>nC_{20}$ which were interpreted to be derived directly from higher plant materials. The geochemical results from the studies of Cooper Basin and Taranaki Nasin coals show that long-chain aliphatic groups in coals can be derived directly from higher plant materials, from microbial activity in the depositional environment, or from a combination of both..

Coals and related continental strata with type III kerogen provide the source for commercial oil accumulations in many other sedimentary basins around the world: e.g. in the Mahakam Delta of Indonesia (Huc et al., 1986), the Karoo Basin in Tanzania (Mpanju et al., 1991), the Junggar and Tarim Basins in northwestern China (Hendrix et al., 1995) and in the Harald and Lulita fields in the Danish Central Graben of the North Sea (Petersen et al., 2000). And in the Niger Delta of Nigeria, source rocks of dominantly type III kerogen produce the vast amounts of hydrocarbons that have accumulated in that part of the West African continental margin. The major problem with hydrocarbons generated from coaly source rocks is the fact that most of such hydrocarbons are adsorbed in the interstices of the coal matrix which has made effective expulsion, migration, accumulation and producibility very difficult (Barker et al., 1989). This is probably the case with the envisaged coaly-sourced hydrocarbons in the Nigerian Benue Trough. Exploration for hydrocarbons in these coals, therefore, must target deep coal seams that have been subjected to local and regional tectonics.

Charcoal is one of the most widely used adsorbent for taking bitumens and other organic matter contaminants out of a flowing water system. Laboratory experiments have shown that as you go from high volatile bituminous coal to anthracite, the adsorption of hydrocarbons increases. Increasing pressure also increases the adsorption. Wyman (1984) slowly desorbed coal samples obtained at a depth of 2835 m in the deep Western Canadian basin and found that after 15 days only the hydrocarbons, methane, ethane and propane were desorbed. By 34 days he was able to obtain isobutane, n-butane and isopentane. Extraction of these coals released up to 30mgHC/gTOC which apparently was strongly adsorbed on the coal surface. Landais and Monthioux (1988) carried out open and closed pyrolysis of coals. The same coal samples followed different maturation pathways using open, confined and closed system pyrolysis. Comparing these results with extraction data, they concluded that natural coals keep free hydrocarbons trapped in the pores of their structures and that these hydrocarbons are in turn released when these coals have been fractured.

METHODS OF STUDY

The methodological approach adopted involved field survey of already known coal deposit locations and investigation of new ones, hitherto undocumented. The known coal deposit locations covered comprise Okaba, Ogboyaga, Owukpa, Lafia-Obi and Gombe. The only newly investigated coal deposit is at Omelehu (see Fig. 3). The survey was conducted attempting to evaluate the aerial and stratigraphic extents (volumetry) of the respective deposits. Samples were collected for Leco TOC determination and Rock Eval pyrolysis as a basis for evaluating the hydrogen indices and Tmax which in turn were used for assessing the kerogen types and the overall source rock characteristics of the coal beds. Such characteristics where appropriate for oil and gas generation are only applicable where the coal beds are deeply buried, possibly below 3,000m depth in the Anambra Basin-Benue Trough successions.

RESULTS AND DISCUSSION

Field Study

Aspects of the field mapping and surveys on the respective coal deposits are shown in Figure 3. Field mapping and core drilling to 50m depth at Okaba and Owukpa show that the Okaba coal field has a surface area exposure of 5,408 sq m measuring 52m x 104m. Drilling shows that there are 9 seams of average 3m thick from the present surface into the subsurface. It has an operating mine. Omelehu coals are exposured sparingly only along a stream channel but geophysical surveys indicate 6 seams of average 5m thick in the subsurface. Omelehu does not have an operating mine at present but some companies have acquired licenses for exploration works. The Owukpa field with exposed coals measures 50m x 20m (1,000 sq m). Core drilling to 50m depth proved 9 coal seams of average 3.5m in the subsurface. The Ogboyaga coal deposits are also exposed along a stream channel in the village of Odu Okpakili in Kogi State with1.7m thick coal seam. No core drilling was undertaken and subsurface information is not available. There are also no operating mines. Coal deposits of the Lafia-Obi are also sparingly exposed along the bank of River Dep in the village of Shankodi near Jangwa in Nasarawa State. The thickest seam is ca 0.5m. Core drillings by the National Steel Raw Materials Exploration Agency indicate several subsurface seams with thicknesses of

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up to 5m for a seam. The Gombe coal deposits at Maiganga overlain by a very thick overburden and some layers of Maastrichtian clays and sandstones of the Gombe Formation. The topmost seam, presently being mined is about 6m thick covering an area of ca 60m x 60m. There are reportedly another 6 layers (seams) of coal in the subsurface beneath the presently mined layer. The Gombe coal mine is presently being operated by the Ashaka Cement Company. The coal provides the source of energy for the operations of the Ashaka cement production.

The studied coal deposits have been exposed and studied at geologically up-dip locations. For their source rock application, the coal deposits are presumed to have stratigraphical equivalents deposited at depth ranges of 3,000m and deeper and only those that have attained such depths could serve as hydrocarbon source rocks. Many of the source rock parameters evaluated in this study may not change at greater depth except the Tmax which may vary depending on the time of exhumation and/or uplift that led to their present near-surface exposure.

Fig. 3. Exposures of coal deposits at up-dip sections in the Northern Anambra Basin at Okaba (Kogi State) and Owukpa (Benue State)

Rock Eval Pyrolysis

The result of the Rock Eval pyrolysis of the selected samples of the Nigerian coal deposits is shown in Table 1. A plot of the result on the Van Krevelen diagram of Espitale (1977) (Fig. 4) shows that Nigerian coal deposits are composed majorly of Type II/Type III kerogens and consequently have more gas generating potential than oil, however with some oil and gas generating potential. This is further buttressed by the HI-Tmax diagram (Fig. 5) which shows that the Anambra Basin and Upper Benue Trough coals

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(Maastrichtian) are immature to submature (marginally mature) with respect to the commencement of oil and gas generation from source rocks. However, the studied samples are from outcrops and near surface. The scenario with respect to maturation may be different, in favor of a higher maturity in deeper sections and consequently could have contributed to the oil and gas resources in the Anambra Basin and possibly still generating. The results on the Middle Benue Trough show that the coals have lean hydrogen indices but well mature into the oil and gas window, whereby the potential is overwhelmingly gas generation.

Table 1. Rock Eval pyrolysis results obtained on some Nigeria coal deposits

Sample ID	Location, Basin	S2	S3	Tmax	TOC	S	HI	OI
		mg/g	mg/g	°C	wt%	mg	*	**
LBI-001	Lafia-Obi, Middle-Benue Trough	20.72	11.36	451	36.08	0.54	57	32
LBI-002	Lafia-Obi, Middle-Benue Trough	19.54	10.85	451	36.05	0.49	54	30
LBI-003	Lafia-Obi, Middle-Benue Trough	19.76	11.04	452	36.20	0.51	55	31
LBI-004	Lafia-Obi, Middle-Benue Trough	20.56	10.71	451	34.90	0.50	59	31
LBI-005	Lafia-Obi, Middle-Benue Trough	20.16	10.99	450	36.30	0.54	56	30
OGB-001	Ogboyaga, Anambra Basin	150.06	23.8	425	63.40	0.62	237	38
OGB-002	Ogboyaga, Anambra Basin	133.89	25.65	423	62.10	0.71	216	41
OGB-003	Ogboyaga, Anambra Basin	153.36	24.12	424	63.70	0.64	241	38
OGB-004	Ogboyaga, Anambra Basin	154.59	24.05	424	64.00	0.66	242	38
OGB-005	Ogboyaga, Anambra Basin	153.44	24.28	424	63.80	0.64	241	38
OKB-001	Okaba, Anambra Basin	170.92	12.14	421	62.90	1.28	272	19
OKB-002	Okaba, Anambra Basin	174.84	12.11	420	62.80	1.08	278	19
OKB-003	Okaba, Anambra Basin	178.08	12.05	423	62.90	1.18	283	19
OKB-004	Okaba, Anambra Basin	177.36	12.14	419	63.10	1.08	281	19
OKB-005	Okaba, Anambra Basin	174.95	12.22	419	63.20	1.10	277	19
OML-001	Omolehu, Anambra Basin	92.73	13.47	421	54.00	0.64	206	30
OML-002	Omolehu, Anambra Basin	123.78	14.11	420	52.50	0.79	236	27
OML-003	Omolehu, Anambra Basin	111.62	13.49	423	48.90	0.75	228	28
OML-004	Omolehu, Anambra Basin	103.76	13.71	423	46.60	0.71	223	29
OML-005	Omolehu, Anambra Basin	112.42	13.63	422	48.70	0.74	231	28
OWU-001	Owukpa, Anambra Basin	93.23	8.03	426	39.55	0.37	236	20
OWU-002	Owukpa, Anambra Basin	92.12	8.13	427	38.85	0.36	237	21
OWU-003	Owukpa, Anambra Basin	90.01	7.77	427	39.10	0.38	230	20
OWU-004	Owukpa, Anambra Basin	91.32	8.14	427	39.00	0.35	234	21
OWU-005	Owukpa, Anambra Basin	89.76	8.01	428	38.40	0.36	234	21
GMB-001	Gombe, Gongola Basin	90.53	9.24	416	49.6	ND	183	19
GMB-002	Gombe, Gongola Basin	92.66	8.37	414	49.3	ND	188	17
GMB-003	Gombe, Gongola Basin	91.79	8.08	416	48.7	ND	188	17
GMB-004	Gombe, Gongola Basin	95.82	9.14	418	47.6	ND	201	19

***HI = mgCO2/gTOC; **OI = mgCO2/gTOC**

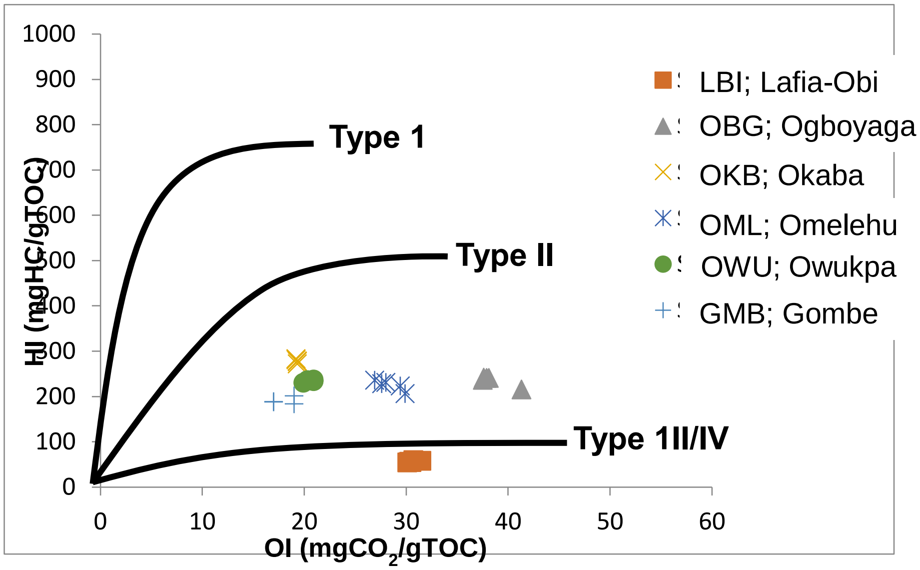

Fig. 4. Plots of Nigerian coal deposits on the Van Krevelen diagram showing that the deposits are overwhelmingly of Type II/Type III with potential to generate oil and gas except the Lafia-Obi coals that may have generated non-associated gas at deeper sections

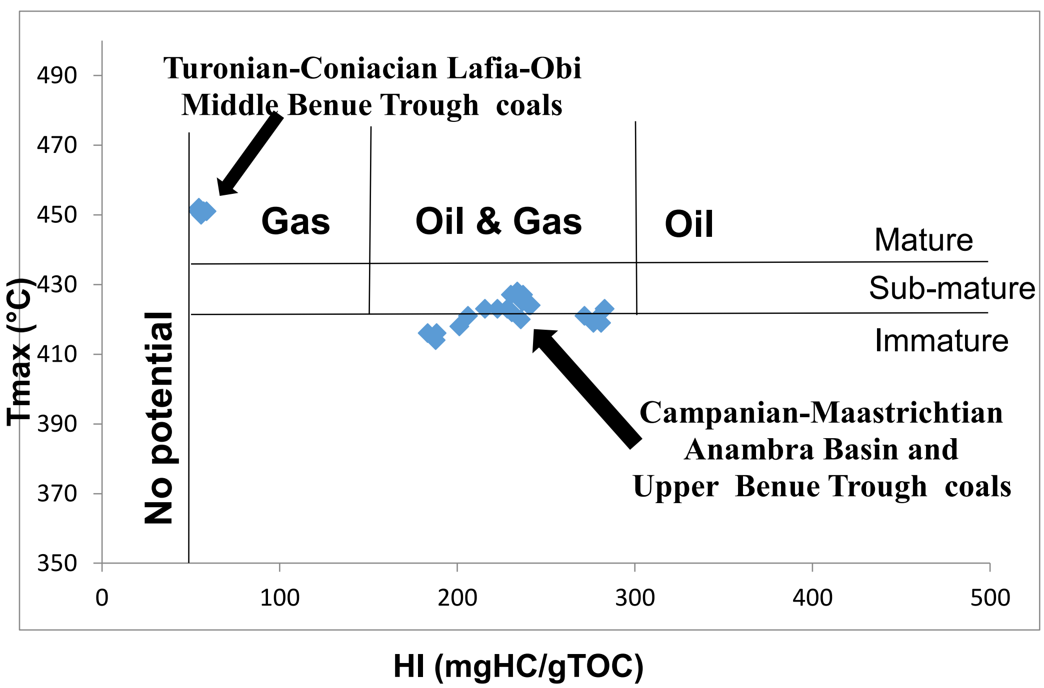

Fig. 5. HI-Tmax diagram for evaluating hydrocarbon proneness (after Obaje et al., 2004) shows that the organic matter are immature to sub-mature and overwhelmingly oil and gas-prone at deep-seated levels where appropriate maturities have been attained. Lafia-Obi deposits are entirely gas-prone.

CONCLUSIONS

Coal deposits are widespread within Turonian-Coniacian and Campanian-Maastrichtian successions in the rifted Benue Trough structure from north to south. These coal deposits have been mapped in the Anambra Basin in southeast/central Nigeria at Okaba, Owukwa, Ogboyaga and Omelehu, in addition to the already well known deposits at Enugu; in the Middle Benue Trough at Lafia-Obi and in the Upper Benue Trough at Gombe (Kumo). Rock Eval pyrolysis analysis on the coal deposits show that the deposits in the Anambra Basin are characterized of Type II/Type III kerogens and capable of generating oil and gas in the deeper subsurface where the maturities would have been attenuated. The deposits in the Middle Benue Trough are entirely gas-prone. Coal beds and related continental strata with type III kerogens provide the source for commercial oil accumulations in many other sedimentary basins around the world: e.g. in the Mahakam Delta of Indonesia, the Karoo Basin in Tanzania, the Junggar and Tarim Basins in northwestern China and in the Harald and Lulita fields in the Danish Central Graben of the North Sea. The knowledge of the existence of these coal deposits with the evaluated petroleum source rock characteristics in the deep sub-surface of the Benue Trough and the Anambra Basin is expected to boost investors' confidence in the reduction of the high risk associated with petroleum exploration in such high-risk basins.

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