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Petroleum Source Rock Potential Assessment of the Oligocene - Miocene Ogwashi Asaba Formation, Southern Anambra Basin, Nigeria

By

Samuel O. Akande*, M. O. Adeoye*, and Bernd D. Erdtmann**

Abstract
The Oligocene - Miocene Ogwashi Asaba Formation of the Anambra Basin is the outcropping equivalent of the Agbada Formation in the Niger Delta, subsurface. Exposed rocks of this formation consist of interbedded successions of lignite, shale, claystone, siltstone, sandstone, and conglomerate facies of a paralic environment. The present study has investigated the petroleum potentials of the outcrop samples exposed at Azagba Ogwashi, Oba and Ihioma areas from the organic petrologic and geochemical viewpoints.

Maceral analysis revealed that the Azagba Ogwashi lignites have an average composition of huminite : liptinite : inertinite (H: L : I) ratio of 60:31:9, 79:18:3 for the Oba lignites, and 71:21:8 for the Ihioma lignites. Maceral constituent ratio in the shales range from 72:22:6 in Azagba Ogwashi, 83:7:10 for Oba, and 69:30:1 in the Ihioma area.

Total Organic Carbon (TOC) of the lignite samples range from 13.28 to 68.04wt% (mean = 46.56 wt%) for twenty samples whereas those of the shales range from 4.98 to 12.38wt% (mean = 8.52wt%) for thirteen samples. Petroleum source potential (S1 + S2) for the lignites range from 13.05 – 460.63 kg HC/t (mean = 133.59 kg HC/t) and HI range from 53 to 639 mgHC/gTOC (mean = 234.85 mgHC/gTOC). In the shale samples, S1 + S2 range from 1.25 – 35.19 kg HC/t (mean = 14.59 kg HC/t) and HI range from 17 to 260 mgHC/gTOC (mean = 129.52 mgHC/gTOC). The Tmax values range from 394°C - 421°C (mean = 411°C) in the lignites while those of the shales range from 384 to 426°C (mean = 411°C).

The relatively high proportion of liptinite (Type II kerogen) in the lignite especially in Azagba Ogwashi suggests its potential for oil generation, while the predominance of huminite (Type III kerogen) in Oba and Ihioma suggest their potential for gas generation in the deeper section of the basin where the appropriate thermal maturity would have been attained. The source rock facies investigated have good to excellent organic matter content and can therefore be considered as potential petroleum source rocks which upon thermal maturity will generate oil and gas. This conclusion suggests that equivalent lithologic units in the Agbada formation are candidate petroleum source rocks in the subsurface Niger Delta.

Introduction
The increasing demand and decreasing reserves of hydrocarbons in Nigeria require increased activities in petroleum exploration and an improvement in the exploration success ratio. New oil and gas fields must be found and explored areas should be reassessed for additional oil and/or gas pools. At the core of petroleum exploration is the evaluation of the petroleum-generative potentials of prospective source rocks. The main objective of this study is to geochemically characterize the Ogwashi Asaba Formation in terms of organic richness, organic matter type, thermal maturity and the hydrocarbon generation potential.

The study area falls within the southern part of the Anambra Basin (Fig. 1)[1] where the lithologic successions of the Ogwashi Asaba Formation are exposed (Fig. 2)[2]. Three locations

*Department of Geology and Mineral Sciences, University of Ilorin, Ilorin Nigeria
**Institut fur Geologie, Technische Universitat Berlin, Ackerstrasse 71 – 76, D-13355 Berlin, Germany.

were studied. These include: the Azagba Ogwashi area (between Latitude 06° 14' 622" – 06° 14' 080" and Longitude 006° 36' 259" – 006° 37' 738"); the Oba area (on Latitude 06° 03' 067 – 06° 02' 864" and Longitude 006° 51' 232" – 006° 48' 598"); and the Ihioma area (between Latitude 05° 48' 718" – 05° 49' 073" and Longitude 007° 00' 804" – 007° 00' 332"). Lignites in the study area represent part of the lignite belt of the southern Nigeria that are confined to a narrow belt of about 16km wide, trending NW – SE, and extending for a distance of about 240km from Nigeria in the west to the Cameroun frontier, east of Calabar, to the east.

Tectonic and Stratigraphic Geological Setting

The Anambra Basin forms a part of the Benue Trough comprising several rift related basins in Nigeria. The trough is about 80 – 90km wide fault-bounded depression containing up to 5000m of deformed Cretaceous – Tertiary sedimentary and volcanic rocks. It is subdivided geographically into the Northern, Central and Southern Benue Basins with the southern consisting of the Abakaliki and the Anambra Basin. The importance of the Benue rift in the evolution of Atlantic mega-tectonic region led to the proposal of numerous tectonics models for it origin and evolution.

The tectonic evolution of the basin was reported by several authors[3,4,5,6]. The author[7] considered the trough as analogous to the Red Sea being a part of the unstable RRR triple plate junction as a result of plate dilation and opening of Gulf of Guinea in the Early Cretaceous[8]. Wrenching was suggested as a dominant tectonic process in Benue Trough evolution[9,10].

The first stage of evolution of the Benue Trough was controlled by opening of the Gulf of Guinea during the Early Cretaceous. This stage was marked by the reactivation of inherited fault zones which played a major role in the distribution and geometry of the numerous sub-basins. These fault zones probably existed throughout the Benue Trough during Aptian times, although there is no direct evidence of their existence[11]. During first Albian transgression, there was deposition of up to 2000m of immature sediments of the Asu River Group[12], this

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2 Akande, S. O., Ogunmoyero, I. B. Petersen, H. I. and Nytoft, H. P., 2007. Source rock evaluation of coals from the Lower Maastrichtian Mamu Formation, SE Nigeria: Journal of Petroleum Geology, v. 30, p. 303-324.

3 King, P. B., 1962. Leonard and Wolfcamp Series of Sierra Diablo, Texas, in Leonardian Fades of the Sierra Diablo Region, West Texas: Society of Economic Paleontologists and Mineralogists (Permian Basin Section), Publication v. 62-7, p. 42-65.

4 Grant, N. K., 1971. The South Atlantic Benue Trough and Gulf of Guinea Cretaceous triple junction: Geol. Soc. Amer. Bull., v.82, p.2295-2298.

5 Ofoegbu, C. O., 1984. A model for the tectonic evolution of the Benue Trough of Nigeria: Geol. Rundsch., v. 73, p. 1009-1020.

6 Benkhelil, J., 1989. The Origin and evolution of the Cretaceous Benue Trough, Nigeria: Journal. Afri. Earth Sci., v. 8, p. 251-282.

7 Op.cit

8 Olade, M. A., 1975. Evolution of Nigeria’s Benue Trough, a tectonic model: Geological Magazine, v.112, p.575-583.

9 Bissada, K. K., 1982. Geochemical constraints on the petroleum generation and migration – a Review. Proceed. Vol. Asian Council on Petroleum (ASCOPE ‘ 81) p. 69 – 87.

10 Benkhelil, J., 1986. Carateristiques structurales et evolution geodynamique du basin intra – continental de la Benoue’ Nigeria : These d’etat, Nice, p. 275.

11 Op.cit

12 Nwachukwu, J. I. 1972. The tectonic evolution of the southern portion of the Benue Trough, Nigeria. Geology Magazine, v. 109, p. 511-419

was succeeded by the regressive phase during the Cenomanian period restricting sediments to the Calabar flank, leading to the deposition of the Odukpani sequence. The beginning of the second marine transgressive cycle in the Southern and Central Benue Basins led to the deposition of laminated shales and calcareous siltstone of the Eze-Aku Formation which is succeeded by thick black shales and limestone of the Awgu Formation deposited during the transgressive maxima from the Turonian to Coniacian times[13]. Also, the third cycle involving the Upper Turonian-Lower Santonian have been largely removed by erosion as a result of the late Santonian deformation and uplift of the Benue depression. During the Pre-Santonian period, sediments of the first and second depositional cycle were compressionally folded, faulted and uplifted in the Southern Benue and clearly marked by deformational structures at the Abakaliki anticline, the Anambra Basin and Afikpo syncline[14].

The Post-Santonian collapse of the Anambra platform led to the emergence of several parts of the Southern and Central Benue Basins during the Campanian-Maastrichtian and shift in the depositional axis of sediments for the third transgressive cycle to the Anambra Basin.

Sediment derived from erosion of the anticlinorium and ancestral Niger River filled the Anambra Basin. The various lithostratigraphic units resulting from these depositional cycles are here presented.

Enugu Formation

The Campanian Enugu Formation consists of coarsening upward sequences with thick, dark grey shale at the base, grading upward through siltstones into thin, texturally mature sandstone (Fig. 3)[15]. The lithologic assemblage suggests deltaic progadation during active delta growth. The carbonaceous shale at the base is interpreted as full marine pro-delta subfacies while the upper part of the section represents shallow water shoreface subfacies[16].

Mamu Formation

The Maastrichtian Mamu Formation consists of rhythmic sequences of sandstones, shales, siltstones, mudstones, sandy shales with interbedded coal seams suggesting deposition under paludal to possibly marginal marine[17,18] (Fig. 3). The coal beds and carbonaceous shales are more concentrated in the basal section of the formation and rare towards the top.

Ajali Sandstone

Ajali Sandstone consists entirely of crossbedded sandstones with drapes of claystones extending as stacks of sheetlike bodies from the Calabar flank northwards towards Enugu. It

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[13] Akande, S. O., Egenhoff, S. O., Obaje, N. G., Ojo, O. J., Adekeye, O. A. and Erdtmann B. D., 2012. Hydrocarbon potential of Cretaceous sediments in the Lower and Middle Benue Tough, Nigeria: Insights from new source rock facies evaluation: Journal of African Earth Sciences, v. 64, p. 34-47.

[14] Op.cit

[15] Akaegbobi, I. M., Nwachukwu, J. I., and Schmitt, M., 2000. Aromatic hydrocarbon distribution and calculation of oil and gas volumes in post-Santonian shale and coal, Anambra Basin, Nigeria: In M. R. Bello and B. J. Katz, eds., Petroleum systems of South Atlantic margins: Amer. Assoc. Petrol. Geol. Memoir 73, p. 233-245

[16] Ojo, O. J., Kolawole, A. U. and Akande, S. O., 2009. Depositional environments, organic richness, and petroleum generating potential of the Campanian to Maastrichtian Enugu Formation, Anambra Basin, Nigeria. The Pacific Journal of Science and Technology, v. 10, no. 1, p. 614 – 628.

[17] Nwajide, C. S, Reijers T. J. A., 1996. Sequence architecture in outcrops: examples from the Anambra Basin, Nigeria. Nigerian Association of Petroleum Explorationists Bulletin, v. 11: p. 23–33.

[18] Akande, S. O., Ogunmoyero, I. B. Petersen, H. I. and Nytoft, H. P., 2007. Source rock evaluation of coals from the Lower Maastrichtian Mamu Formation, SE Nigeria: Journal of Petroleum Geology, v. 30, p. 303-324.

is a regressive phase conformably overlying the Mamu Formation. The lithology of this formation consists of white, friable, coarse-grained, moderately to poorly sorted, with thin beds of whitish claystone as well as numerous bands of variegated rarely carbonaceous shale[19,20]. Depositional environment of the Maastritchtian sediments was interpreted to be tidal due to several occurrences of herringbone cross-bedding and bioturbations[21].

Nsukka Formation

The Danian Nsukka Formation marks the onset of the transgression and a return to paludal conditions. The fluvio-deltaic formation overlies the Ajali Sandstone and consists of variety of sandstones that passes upward into well-bedded blue clays, fine-grained sandstones, and carbonaceous shales with thin bands of limestone[22, 23].

Imo Shale

The marine Imo Shale is the outcropping equivalent of the Akata Formation in the subsurface Niger Delta. The shales contain a significant amount of organic matter and may be a potential source for hydrocarbons in the northern part of the Niger delta. The authors [24,25] assigned a Paleocene age to the Imo Formation and its depositional environment is mainly marine with littoral to neritic environments.

Ameki Group

The Ameki Group consists of the Nanka Sand, Nsugbe Formation, and Ameki Formation[26]. These formations mark the return to transgressive conditions. The outcropping deposits of the Eocene regression, which marked the beginning of the Niger delta progradation, constitute the "Ameki Group" which includes tidal facies and backshore as well as pro-deltaic facies. The Ameki Formation is predominantly alternating shale, sandy shale, clayey sandstone, and fine-grained fossiliferous sandstone with thin limestone bands[27, 28, 29].

Ogwashi Asaba Formation

The Oligocene – Miocene Ogwashi Asaba Formation consist of interbedded successions of lignite, shale, sandstone, siltstone, and claystone facies. It is the outcropping equivalent of the Agbada Formation in the subsurface Niger Delta. Depositional environment has been interpreted to be continental[30].

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[19] Reyment, R. A., 1965. In: Aspects of the Geology of Nigeria. University of Ibadan Press, Nigeria, Pp. 145.

[20] Op.cit

[21] Agagu, O. K., Fayose, E. A., Petters, S. W., 1985. Stratigraphy and sedimentation in the Senonian Anambra Basin of Eastern Nigeria: Journal of Mining and Geology v. 22, p. 25–36.

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[27] Op.cit

[28] Arua, I., 1986. Paleoenvironment of Eocene deposits in the Afikpo Syncline, Southern Nigeria. Journal of African Earth Sciences v. 5, p. 279–284.

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Considerable interests were shown on the aspects of sedimentology, paleontology, paleothermometry and geochemistry of the southern Benue Basins by[31,32,33,34,35,36,37,38,39,40,41,42,43,44] especially in relation to petroleum prospectivity. Based on integrated sedimentologic, macrofossil, and palynofacies data from Paleocene-Middle Eocene outcrops in the Anambra Basin/Afikpo syncline,[45] interpreted four lithofacies associations which include; lithofacies Association I that is characterised by fluvial channel and/or tidally influenced fluvial channel sediments; lithofacies Association II (Glossifungites and Skolithos ichnofacies) of estuarine and/ or proximal lagoonal in origin; lithofacies Association III (Skolithos and Cruziana ichnofacies) considered to be of distal lagoon to shallow shelf; shoreface and the foreshore sediments (Skolithos ichnofacies) comprises lithofacies Association IV.

More recently, the overall source rock potentials of the Cretaceous sequences in the Southern and Central Benue Basins of the large Benue Trough in relation to stratigraphic evolution of the successions were outlined[46]. The author[47] also examined and evaluated organic rich sediments using organic petrology, chemical and mineralogical analysis to determine the paleoenvironmental conditions and the factors controlling their formation. The maceral analysis revealed the dominance of humodetrinite and sporinite that accumulated in a reed marsh depositional environment during an anoxic condition.

Methodology

The current study investigated three sections of the Oligocene – Miocene Ogwashi Asaba Formation exposed at Azagba Ogwashi, Oba, and Ihioma. Comprehensive logging of the sections, descriptions, and collection of representative samples were carried out and selected samples were subjected to organic petrological and geochemical studies.

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[31] Nwachukwu, J. I., 1985. Petroleum prospects of Benue Trough, Nigeria: Amer. Assoc. Petrol. Geol. Bull., Vol. 69, No 4, p.601-609.

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[33] Akande, S. O., Hoffknecht, A. and Erdtman, B. D., 1992a. Rank and petrographic composition of selected Upper Cretaceous and Tertiary coals of Southern Nigeria. International Journal of Coal Geology, v. 20, p. 209 – 224.

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[36] Op.cit

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[38] Op.cit

[39] Op.cit

[40] Op.cit

[41] Op.cit

[42] Obaje, N. G., 2005. Fairways and reservoir potential of Pliocene – Recent sands in the shallow offshore Niger Delta. J. Mining Geol. v. 40 p. 25–38

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[44] Ogala, J. E., Siavalas, G., and Christanis, K., 2012. Coal petrography, mineralogy and geochemistry of lignite samples from Ogwashi Asaba Formation, Nigeria. Journal of African Earth Sciences, v. 66-67, p. 35-45.

[45] Op.cit

[46] Akande, S. O., Egenhoff, S. O., Obaje, N. G., Ojo, O. J., Adekeye, O. A. and Erdtmann B. D., 2012. Hydrocarbon potential of Cretaceous sediments in the Lower and Middle Benue Tough, Nigeria: Insights from new source rock facies evaluation: Journal of African Earth Sciences, v. 64, p. 34-47.

[47] Op.cit

Organic Petrology

Maceral analysis on polished samples was carried out to determine the composition of the different coal and shale macerals. The samples were crushed to less than 2mm, impregnated in epoxy resins, ground and polished. Organic petrologic studies were carried out using Reichert Jung Polyvar photomicroscope equipped with stabilized halogen and high pressure vapour mercury lamps, a photomultilier and a computer unit. Random reflectance (R_om) was measured using monochromatic (546nm) non-polarised light in conjunction with a x40 oil immersion objective. The photomultiplier was calibrated with standards of know reflectance (1.23% and 3.1%). Data collection and evaluation were carried out using the coal programme by Reichert Jung. ASTM rank classes were obtained from reflectance data by using the correlation chart of physical and chemical parameters[48]. Maceral composition was determined by means of a Swift automatic point counter and a mechanical stage after identification using white and blue light excitation. Each composition is based on at least 30 counts. In the samples studied, macerals of huminite group were counted as telohuminites (textinite and eu-ulminite), detrohuminite (attrinite and densinite) and gelohuminite (gelinite and corpohuminite). Results on a mineral matter free basis are expressed in volume percentage of each component (vol. %) for H (huminite), L (Liptinite), and I (Inertinite), where H + L + I = 100%

Organic Geochemistry

Total Organic Carbon

A total of 33 samples of shale and lignite were collected, washed, pulverized and analyzed for Total Organic Carbon (TOC) by means of LECO – CS analyser. Approximately 100mg of each sample was used and standard method of pulverisation and hydrochloric acid (HCl) treatment for carbonate removal was utilized prior to measurement.

Rock-Eval Pyrolysis

The hydrocarbon generation potential, maturity, type of kerogen and Hydrogen Index (HI) values were determined using a Rock – Eval II instrument up to an elevated temperature of ca. 600°C[49]. Pyrolysis of 30 – 40 mg of each sample at 300°C for 4 min was followed by programmed pyrolysis at 25°C/min to 550°C in an atmosphere of helium.

Rock-Eval pyrolysis provides evidence by direct estimation of the free already generated hydrocarbons in the rock (S1) and the hydrocarbons that can be generated from the Kerogen by thermal cracking (S2), S1+S2 represent the rocks total hydrocarbon generation potentials[50]. The authors[51] suggest that a hydrocarbon yield (S1+S2) less than 2 kg HC/t corresponds to little or no oil potential and some potential for gas, S1+S2 from 2 to 6 kg HC/t indicate moderate to fair source rock potential, and hydrocarbon yield above 6 kg HC/t indicate good to excellent source rock potential. The threshold of S1+S2 greater than 2 kg

48 Stach E., Mackowsky, M. Th., Teichmuller, M., Taylor, G. H., Chandra, D. and R., Teichmuller, 1982, Stach's Textbook of Coal.

49 Espitalie, J., Madoc, M., Tissot B. P. Menning, J. J., Leplat, P.. 1977. Source rock characterisation method for exploration. In: Offshore Technology Conference Paper 2935. 11th Annual OTC, Houston, vol. 3, pp.439-444.

50 Dymann, T. S., Palacos, J. G., Tysdal, R. G., Perry, W. J. and Pawlewicz, M. J., 1996. Source Rock Potential of Middle Cretaceous Rocks in Southwestern Montana: Amer. Assoc. Petrol. Geol Bull., v. 80, p. 1177-1184.

51 Tissot, B. P. and Welte, D. H., 1984. Petroleum Formation and Occurrence, 2nd ed. Springer-Verlag, Berlin p. 699.

HC/t can be considered as prerequisite for classification as a possible oil source rock[52] and provides the minimum oil content necessary for the main stage of hydrocarbon generation to saturate the pore network and permit expulsion.

Kerogen type could be identified from the HI values[53]. Type I kerogen is hydrogen rich (HI greater than 600mg HC/g TOC) and this is considered to be predominantly oil prone. Type II Kerogen is characterized by HI between 350 and 600mg HC/g TOC and this can generate both oil and gas at appropriate level of maturity. Type III Kerogen is characterized by low to moderate HI of between 75 and 200mgHC/g TOC and could generate gas at the appropriate level of thermal maturity. However, humic coals (with Type III kerogen) may have HI up to 300mgHC/g TOC and possess the capacity to generate oil[54,55]. Type IV Kerogen normally exhibits very low HI, less than 50 mgHC/g TOC and is formed under oxic (wild fire) conditions[56]. Peters[57] suggested that at a thermal maturity corresponding to a vitrinite reflectance of 0.6% (Tmax 435°C) rocks with HI above 300mg HC/g TOC will produce oil; those with HI between 300 and 150 will produce oil and gas; and those with HI between 150 and 50 will produce gas and those with HI less than 50 are Inert.

RESULTS

Organic Petrology

Azagba Ogwashi Section

Result of the seven lignite and five shale samples of the Azagba Ogwashi area shows a moderately high amount of huminite ranges between 45.5% - 69.2% (mean = 60.3%) for the lignites and between 68.2% - 75.9% (mean = 72.1%) for the shales (Table 1). The huminites consist of detrohuminite (attrinite and densinite) and telohuminite (ulminite). Liptinite macerals are mostly resinite, sporinite, cutinite, liptodetrinite and rare occurrence of bituminite and exudatinite in a decreasing order of abundance (Figs 4a-4d). The relative proportion of the liptinite maceral varied widely with a value ranging between 21.6 to 45.5% (mean = 31%) for the lignites and between 13.8 to 27.3% (mean = 22%) for the shales. Inertinite contents occur with semi-fusinite as the dominant subgroup and it occurs in small amount ranging from 5.1 to 14.6% (mean = 8.8%) for the lignites and between 3.9 to 10.3% (mean = 5.94%) for the shales (Table 1).

Oba Section

Maceral constituents and distribution in the Oba area are quite high in huminite with values ranging between 71.5 to 88.4% (mean value of 78.45%) for the lignites, and between 81.1 to 84.5% (mean = 82.8%) for the shales. Liptinite contents range from 6.5 to 28.5% (mean = 18.4%) for the lignites and between 6.5 to 8.3% (mean = 7.4%) for the shales with sporinite,

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52 Bissada, K. K., 1982. Geochemical constraints on the petroleum generation and migration – a Review. Proceed. Vol. Asian Council on Petroleum (ASCOPE ‘ 81) p. 69 – 87.53.
53 Tissot and Welte, (1984).
54 Petersen, H. I., 2006. The petroleum generation potential and effective oil window of humic coals related to coal composition and age. Int. J. Coal Geol., v. 67, p. 221–248.55.
55 Petersen, H. I. and Nytoft, H. P., 2006. Oil generation capacity of coals as a function of coal age and aliphatic structure: Org. Geochem., v. 37, p. 558–583.
56 56. Op. Cit
57 Peters, K.E. 1986. Guidelines for evaluating petroleum source rock using programmed pyrolysis: Amer. Assoc. Petrol.Geol. Bull. v.70, p. 318-329.

resinite, cutinite and liptodetrinite as the dominant sub macerals (Figs 5a-5d). Inertinite in the samples ranges from 0 to 6.8% (mean = 3.13%) for the lignites and between 9.0 to 10.6% for the shales with the dominant occurrence of fusinite, semifusinite and a trace amount of micrinite.

Ihioma Section

Maceral constituents in the Ihioma area show high percentage of huminites group between 55.4 to 86.6% (mean = 71.4%) for the lignites. and between 50 to 83.5% (mean = 69.2%) for the shales. Humodetrinite and humotelinite maceral subgroup constitute the dominant type in this area (Figs 6a-6d). Inertinite macerals range from 0.5 to 22.3% (mean = 8.0%) for the lignites and between 0 to 6.2% (mean = 1.0%) for the shales with dominant occurrence of semi-fusinite, whereas, resinite and sporinite constitute the liptinite maceral group with value ranging between 11.2 to 33.3% (mean = 20.6%) for the lignites and between 16.5 to 50% (mean = 29.8%) for the shales.

Vitrinite Reflectance

Thirty three random vitrinite reflectance ($R_o m$ %) measurements were taken. Result of the measurement showed that the reflectance of Azagba Ogwashi samples ranges between 0.36 to 0.42% $R_o m$ (mean of 0.40% $R_o m$), and slightly higher than the Oba and Ihioma samples that ranges between 0.36 to 0.42% $R_o m$ (mean of 0.39% $R_o m$) and 0.31 to 0.37% $R_o m$ (mean of 0.34% $R_o m$) respectively (Table 1). These suggest that the samples investigated in the Azagba Ogwashi, Oba, and Ihioma seams are within the lignite rank of the ASTM classification.

Mineral Matter

The highest content of mineral matter is only 2 vol. %. Most common are pyrite and clay minerals (up to 1.8 vol. %) which are dispersed throughout the coals (Fig 5a).

Elemental Composition

The Elemental analysis data on five coal samples (Table 2) indicate that the coals contain relatively high proportions of carbon (ranging from 49.49 – 68.21%), with low concentrations of sulphur (0.60 – 2.49%), nitrogen (0.79 - 0.84%), oxygen (21.04 – 31.40%) and hydrogen (4.64 – 7.66%). The calculated atomic H/C and O/C ratios vary from 1.06 – 1.35 and 0.23 – 0.48 respectively (Table 2). The low sulfur content of the studied coals (< 2.49%) clearly indicates that during deposition there was no total marine influence; instead peat growth occurred in a fresh water environment[58, 59.]

Classification and Depositional Environment of the coal

Petrographic composition of the coals permits facies classification and deductions of the paleoenvironments of the peat deposition. The percentages of the three maceral groups, huminite, inertinite, and liptinite have been plotted in ternary diagrams (mmf) in order to provide some information of the coal paleomires. The coals from Azagba Ogwashi, Oba and Ihioma areas generally consist of high abundance of huminites with lesser amounts of liptinite and inertinite. Hence, they are therefore of duroclaritic nature (Fig. 7). The

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[58] Price, F. T. and Casagrande, D. J., 1991. Sulfur distribution and isotopic composition in peats from the Okefenokee Swamp, Georgia and the Everglades, Florida. International Journal of Coal Geology v. 17, p. 1-20.59.

[59] Demchuck and Moore, 1993;

classification of the coal based on H/C and O/C atomic ratios[60] distinguishes two types of coals which are the sapropelic and the humic coal.

Humic coal is defined as kerogen Type III, which has the relatively low initial H/C ratio (usually less than 1.0) due to a higher relative abundance of condensed aromatic and oxygen-containing structures[61]. In contrast, the Type I and II sapropelic coals contain little oxygen but relatively large amounts of hydrogen in the dominant lipid-rich macerals. Figure 6 shows that the analysed coal samples plotted between the sapropelic and humic coal ring. Although, the high level of hydrogen content in the Azagba – Ogwashi coal suggest the tendency towards sapropelic affinity, the high level of oxygen and low hydrogen content in the Ihioma and Oba coals indicate their humic origin.

As the liptinite content of organic matter increases so does the hydrogen content and the potential to generate oil[62]. This is in consonance with other author's reports[63,64]. Inertinite content are generally low in the study area and with semi-fusinite and fusinite as the dominating sub-maceral associated with traces of sclerotinite and micrinite.

Humotelinite and liptinite are facies-critical macerals in lignites. It has been shown[65] that coals rich in well preserved humotelinite are related to an accumulation in a forest type swamp whereas coals rich in humodetrinite and sporinite are thought to accumulate in a reed marsh depositional environment. Based on this, the lignites of the study areas are probably formed and deposited in a reed marsh depositional environment. This is in line with other report[66,67] that the Tertiary lignite of Azagba-Ogwashi and Ihioma formed in a reed marsh depositional environment.

The ABC ternary plot[68] lend credence to the paleovegetation characteristics and nature of the peat forming plants, as well as the oxic/ anoxic conditions prevailing during peat accumulation. The thirty-three samples plotted have indicated relatively anoxic to oxic conditions during peat accumulation and dominant reed-mire vegetation for all the samples (Fig. 9).

ROCK-EVAL DATA

Samples of the lignites and shales were evaluated by Rock Eval Pyrolysis to determine the organic richness and quality of the organic matter in the rocks. In all, a total number of thirty three (33) samples were analysed. The Rock Eval data are presented on a Table 3 with the geochemical parameters e.g. TOC, Tmax, V R_om, and their derivatives i.e. S1, S2, and HI.

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60 Van Krevelen, D. W., 1993. Coal, Typology-Physics-chemistry-Constitution, 3rd Ed., Elsevier, Amsterdam, p. 979.

61 Op.cit

62 Hunt, J. M., 1991, Generation of gas and oil from coal and other terrestrial organic matter. Organic Geochemistry, v. 17, p. 673-680.

63 Lewan, M. D., 1985. Evaluation of petroleum generation by hydrous pyrolysis experimentation. Philosophical Transactions Royal Society, London A v. 315, p. 124-134.

64 Op.cit

65 Teichmuller, M., 1962. Die Genese der kohle. C. R. 4 ieme Congr. Int.Stra. Geol. Carbonifere Heerlen, 1958, v. 3, p. 699-722.

66 Op.cit

67 Op.cit

68 Mukhopadhyay, P., 1989. Organic petrography and organic geochemistry of Tertiary coals from Texas in relation to depositional environment and hydrocarbon generation. Report of investigations. Bureau of Economic Geology, Texas, Pp. 118.

Total Organic Carbon

TOC of twenty (20) lignites in the study areas (Azagba Ogwashi, Oba, and Ihioma) range from 13.28 to 68.04wt% with an average TOC value of 46.56wt% (Table 3), while those of the thirteen (13) shale samples range from 4.98 to 12.38wt% with an average TOC value of 8.52wt%. The highest concentrations of organic carbon are present in the Azagba Ogwashi lignites with an average TOC of 58.46wt%. The lignites with TOC less than 40wt% were classified as impure lignite (Table 3). Most of the samples have TOC values in excess of 2.0wt% and such levels of organic enrichment are considered as very good to excellent source rocks for hydrocarbon generation (Fig. 10).

Hydrogen Index (HI)

Although organic matter content in sediments is usually estimated by a determination of organic carbon, the limiting element in the petroleum forming reaction is not carbon but hydrogen[69]. The reason for analysing carbon, however, is that only the hydrogen bonded in organic molecules is active in the petroleum forming processes. In the Azagba Ogwashi samples, the HI values all exceed 200 mgHC/gTOC ranging from 268.23 to 639 mgHC/gTOC with an average value of 426.31 mgHC/gTOC indicating an assemblage Type II kerogen for the lignite whereas HI in the shale range from 191 to 240 mgHC/gTOC with an average of 220.36 mgHC/gTOC indicating an assemblage Type II/III Kerogen[69].

In the Oba area, HI values less than 200 mgHC/gTOC ranging from 53 to 130.7 mgHC/gTOC with an average of 107.95 mgHC/gTOC indicating an assemblage Type III kerogen for the lignite, and are between 34 to 83.12 mgHC/gTOC with an average of 58.56 mgHC/gTOC indicating an assemblage Type III Kerogen for the shales. The Ihioma samples have values less than 200 mgHC/gTOC ranging from 123 to 178.38 mgHC/gTOC with an average of 152.17 mgHC/gTOC for the lignite, and between 17 to 105.06 mgHC/gTOC with an average of 77.47 mgHC/gTOC for the shales.

Both the lignites and shales of Ihioma indicate that they have dominance of Type III organic matter assemblage.

He[70] has indicated that as the hydrogen content increases, organic matter is transformed from solid to liquid and consequently to gas. The reflectance of all macerals decreases as the hydrogen content increases suggesting that the higher the hydrogen contents of coal, the greater the ability of coal to generate oil and gas. There is a considerable scatter in individual values in the plot of diagram (Fig. 9)[71], however, the general trend indicated by the increasing liptinite constituents suggests enhanced hydrogen content and the potential to generate oil.

Azagba Ogwashi lignites and shales can be considered as potential source rock for oil and gas generation because of the high value of HI with a mean value of 426.31 mgHC/gTOC for lignite and 220.36 mgHC/gTOC for the shale. This is supported by the presence of high liptinite (especially resinite and sporinite) in both the lignites and shales. The Oba and Ihioma

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[69] Petters, K. E. and Cassa, M. R., 1994. Applied source rock geochemistry. In Magoon, L. B., and Dow, W. G. eds. The petroleum system from source to trap; AAPG Memoir 60 Pp. 93-117.
[70] Op.cit
[71] Mukhopadhyay, P. K., Hagemann, H. W. and Gormly, J. R., 1985. Characterization of kerogens as seen under the aspect of maturation and hydrocarbon generation: Erdbl und Kohle, Erdgas. Petrochemie. V. 38, p. 7-18.

lignites and shales have the tendency of generating gas because of the relatively lower hydrogen content.

Petroleum Source Potential (S1+S2)

Since organic carbon content alone cannot be used to establish the potential and or the effectiveness of petroleum source rocks as different organic matter types have different hydrocarbon yields for similar quantities of organic carbon[72], a more direct measure of source rock capability to generate hydrocarbons is required for detailed assessment. The Rock-Eval parameter S1 + S2 is an accepted measure of genetic potential[73] or the total amount of petroleum that might be generated from a rock. The threshold of S1+S2 greater than 2 kg HC/t can be considered as prerequisite for classification as a possible oil source rock[74]. Result of the Rock Eval analysis in Table 3 shows that the Azagba Ogwashi lignites have S1+ S2 value ranging between 123.47 – 460.63 kg HC/t (mean = 274.60 kg HC/t) while the shales also have S1 + S2 value ranging between 20.43 – 35.19 kg HC/t (mean = 28.56 kg HC/t). These suggest that the source rocks have excellent potential to generate oil. The Oba lignites have S1 + S2 value ranging from 13.05 – 60.37 kg HC/t (mean = 33.96 kg HC/t) and between 2.49 - 4.92 kg HC/t (mean of 3.71kg HC/t) for the shales. These suggest that the lignites have very good potential for hydrocarbon generation, while the shales are moderately fair for hydrocarbon generation.

The source potentials of the Ihioma samples range between 66.76 – 98.49 kg HC/t (mean of 77.97 kg HC/t) for the lignites, and between 1.25 – 9.91 kg HC/t (6.57 kg HC/t) for the shale. These suggest that the source rock potentials of the lignite are very good, while the shale have moderate source potentials for hydrocarbon generation.

Kerogen Type

Kerogen typing classifies organic matter according to the maceral from which it was derived and is useful for determining whether oil or gas will to be generated. The average maceral composition based on the average percentages of huminite-liptinite-inertinite (H:L:I) ratios are 60:31:9 for the Azagba Ogwashi lignites, 79:18:3 for the Oba lignites, and 71:21:8 for the Ihioma lignites. The percentage of huminite : liptinite : inertinite (H:L:I) ratios of the shales are: 72:22:6 for Azagba Ogwashi, 83:7:10 for Oba, and 69:30:1 for the Ihioma samples. This indicates a predominance of huminite (Type III kerogen) with contributions of liptinite (Type II kerogen) in the organic matter. Type III Kerogen is highly gas prone and is dominated by aromatic structures, heteroatomic ketones, and carboxylic acid groups. The dominance of hydrogen rich sporinite and resinite with the high HI values support the presence of Type II oil prone Kerogen especially for Azagba Ogwashi lignites and this is capable of generating oil.

Cross plot of the Hydrogen Index (HI) versus Tmax, (Fig. 11) shows that majority of the studied samples plot within Types III gas prone kerogen (with the exception of Azagba Ogwashi lignites and shales, which lies within the Type II oil prone field). This is supported by the high occurrence of Type III Kerogen organic constituent. Type III organic matter is usually derived from terrestrial plants, and is dominated by huminite with lesser amounts of inertinite.

[72] Katz, B. J. 2006. Significance of ODP results on deepwater hydrocarbon exploration – eastern equatorial Atlantic region. J. Afr. Earth Sci. 46, 331-345.
[73] Op. Cit
[74] Op. Cit

In the light of the rock criteria[75], the best oil prone source rocks in the Ogwashi Asaba Formation appears to be restricted to the Azagba Ogwashi lignites with Type II oil prone Kerogen, while the Azagba Ogwashi shales together with lignites and shales of both Oba and Ihioma plot in the Type II/III and Type III gas prone Kerogen field respectively which could be considered as oil and gas, and gas prone at the appropriate maturation level.

Thermal maturity

Tmax value represents the temperature at which the largest amount of hydrocarbons is produced in the laboratory during pyrolysis. The production of these hydrocarbons by pyrolysis is linked to the amount of hydrogen the rock contains and, therefore, to its level of maturation since the more mature the rock is, the lower the amount of hydrogen it contains and the highest amount of energy it needs to liberate hydrocarbons. The thermal maturation level can be estimated from the Tmax values.

Tmax of the Azagba Ogwashi lignites ranges from 406°C - 421°C (mean = 417°C) and between 415 - 426°C for the shale (mean = 421°C). This indicates that the lignites of Azagba Ogwashi are thermally immature while the shales are marginally mature. Within the Oba lignites, Tmax values ranges from 408°C - 425°C (mean = 415°C) and between 395°C - 418°C (mean = 407°C) for the shales. This indicates that both the Oba lignites and shales are thermally immature. Also in the Ihioma section, the lignites have Tmax values ranging from 394°C to 412°C (mean = 403°C) while the shales Tmax ranges from 384°C - 420°C (mean = 404°C) suggesting the they are thermally immature. The plot of Tmax against HI reveals~~ed~~ Azagba Ogwashi lignite and shale to be potential source rock for oil & gas, while both lignite and shale of Oba and Ihioma areas are potential source rock for gas at maturity (Fig. 12)

The standard measurement for maturity i.e. vitrinite reflectance (Ro), extends over a wider maturity range than any other indicator[76]. Thermally mature sediments are thought to display VR_om values between 0.6 and 1.3%[77]. In contrast, the vitrinite reflectance (VR_om) measurement carried out on thirty three (33) samples of both lignite and shales of Ogwashi Asaba Formation range from 0.31 to 0.42% with a mean value of 0.38%. Azagba Ogwashi samples display the highest VR_om with a mean value of 0.4%. These results show that the lignite and shale samples of the study area are thermally immature.

CONCLUSIONS

The Oligocene – Miocene Ogwashi Asaba Formation exposed at the Azagba Ogwashi, Oba and Ihioma areas in the Anambra Basin consists of shales, sandstone, siltstone with interbedded lignite and claystone facies of a paralic environment.

The coal seams are lignitic in rank and dominated by humodetrinites and sporinites that are thought to have accumulated in a reed marsh anoxic to oxic depositional environment.

The relatively large proportion of liptinites (Type II oil prone Kerogen) in the lignite especially in Azagba Ogwashi suggests the potential for oil generation, while the predominance of huminites (Type III gas prone kerogen) in Oba and Ihioma suggest the potential for gas generation. Source rock facies including the shales and coals investigated have good to excellent organic matter content and can therefore be considered as potential petroleum source rocks which upon maturity will generate oil and gas. Equivalent facies of

[75] Op. Cit
[76] Op. Cit
[77] Op. Cit

the Ogwashi Asaba Formation in the subsurface Niger Delta (i.e the Agbada Formation) therefore have the capabilities to source oil and gas at the thermally matured stratigraphic levels of greater than10km thick successions of the gas rich hydrocarbon province.

Acknowledgements

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CAPTIONS FOR FIGURES

Fig. 1: Generalized geological map of Nigeria showing Anambra Basin (modified from Obaje, 2004).

Fig. 2: Generalised geological map of southeastern Nigeria (boxed area of inset) Showing transverses within Ogwashi Asaba Formation. Numbers of the formations represent: 1. Asu River Group, 2. Odukpani Formation, 3. Eze-Aku Shale, 4. Awgu Shale, 5. Enugu/Nkporo Shale, 6. Mamu Formation, 7. Ajali Sandstone, 8. Nsukka Formation, 9. Imo Shale, 10. Ameki Formation, 11. Ogwashi Asaba Formation (after Akande *et al*. 2007).

Fig. 3: Stratigraphic and Lithologic section of Southern Benue Trough and Anambra Basin from (modified from Akaegbobi *et al*., 2000).

Fig. 4a. Photomicrograph of sample Az-01b2 from the Azagba – Ogwashi seam in reflected light showing the cloud outline of cutinite in the matrix of light grey huminite fragments on the lower left side of photo. H – huminite, C – cutinite.

Fig. 4b. Same view in ultraviolet light showing the grains of resinite showing yellow fluorescing colours in a liptodetrinite (particles with yellow fluoresce) matrix. The cutinite fragment in the lower left side of photo show yellowish brown colours. C – cutinite.

Fig. 4c. Photomicrograph of sample Az-01b from the Azagba – Ogwashi seam in reflected light showing the huminite matrix and the liptodetrinite particles in the lower portion of photo. Fragments of resinites are distinguishable with their morphology and dark grey to brown colour. H – huminite, R – resinite.

Fig. 4d. Same field of view in ultraviolet light with yellow fluorescing resinites and sporinite aggregates in the lower part of photo. R – resinite, S – sporinite.

Fig. 5a. Photomicrograph of sample OB-03m from the Oba seam in reflected light showing the aggregate of cutinite maceral (folded) diagonally aligned in the coal matrix. C – cutinite, M – mineral matrix.

Fig. 5b. Same field of view in ultraviolet light showing the serrated outline of the folded cutinite. Note the yellow fluorescing structures diagonally arranged in the matrix. C – cutinite.

Fig. 5c. Photomicrograph of sample OB-03m2 from Oba seam in reflected light showing the centrally placed resinite grain (glowing brownish) at the centre of humodetrinite. HD – humodetrinite, R – resinite.

Fig. 5d. Same field of view in ultra violet light. The yellowish fluorescing resinite sits at the centre of the non – fluorescing humodetrinite.

Fig. 6a. Photomicrograph of sample IH-03b from Ihioma seam in reflected light showing clouds of attrinite, densinite and gelinite (homodetrinite) with rims of sporinite. HD – humodetrinite, M – mineral matrix.

Fig. 6b. Same field of view in the ultraviolet light showing the rims of sporinite on the right side of the photo. Dispersed sporinite are visible on the upper left side of photo. HD – humodetrinite, S – sporinite.

Fig. 6c. Photomicrograph of sample Ih-03T from Ihioma seam in reflected light showing a centrally located outline of a liptinite maceral (revealed in violet light) with a rim of humodetrinite. HD – humodertinite, C – cutinite.

Fig. 6d. Same field of view in ultra violet light. The whole leaf structure is preserved as shown by the yellow fluorescing leaf with palisade tissues preserved confirming its constitution and derivation from higher land plants. C – cutinite.

Fig. 7: Maceral composition of the source rock facies showing the abundant of huminites in the seams and the interbedded shales. Notice the significant enrichment of liptinite with low abundance of inertinite in the sketch.

Fig. 8: The van Krevelen diagram for Ogwashi Asaba Formation lignite samples: Notice the tendency of the Azagba – Ogwashi seam towards sapropelic characteristic.

Fig. 9: ABC Ternary Plot provides evidence for the paleovegetation characteristics and Anoxic/ Oxic conditions of the paleomires, A – C values for each sample was calculated for the relationship outlined on the diagram (after Mukhopadhyay, 1989).

Fig. 10: Summary of source rock quality on the basis of Rock-Eval parameters, Hydrocarbon yield (S_2KgHC/t of rock) vs Total Organic Carbon (TOC wt%) of the studied coals. Notice the classification of the investigated coal as primary hydrocarbon source with lesser contributions from secondary source.

Fig. 11: HI against Tmax (^oC) diagram for the interpretation of kerogen types and maturity of the Ogwashi Asaba Formation.

Fig. 12: Tmax versus HI plots of Ogwashi Asaba Formation showing their relative hydrocarbon potentials level.

CAPTIONS FOR TABLES:

Table 1: Maceral analysis of lignites and coaly shales from the Ogwashi – Asaba Formation, Anambra Basin.

Table 2: Elemental Composition of the Azagba - Ogwashi, Oba and Ihioma lignite

Table 3: Rock-Eval data of the lignite and shale samples from the Ogwashi - Asaba Formation, Anambra Basin. AO, AZ and AZG series are samples from Azagba Ogwashi; BA and OB series are samples from Oba, while IM, IH and IHM series are samples from Ihioma Section.

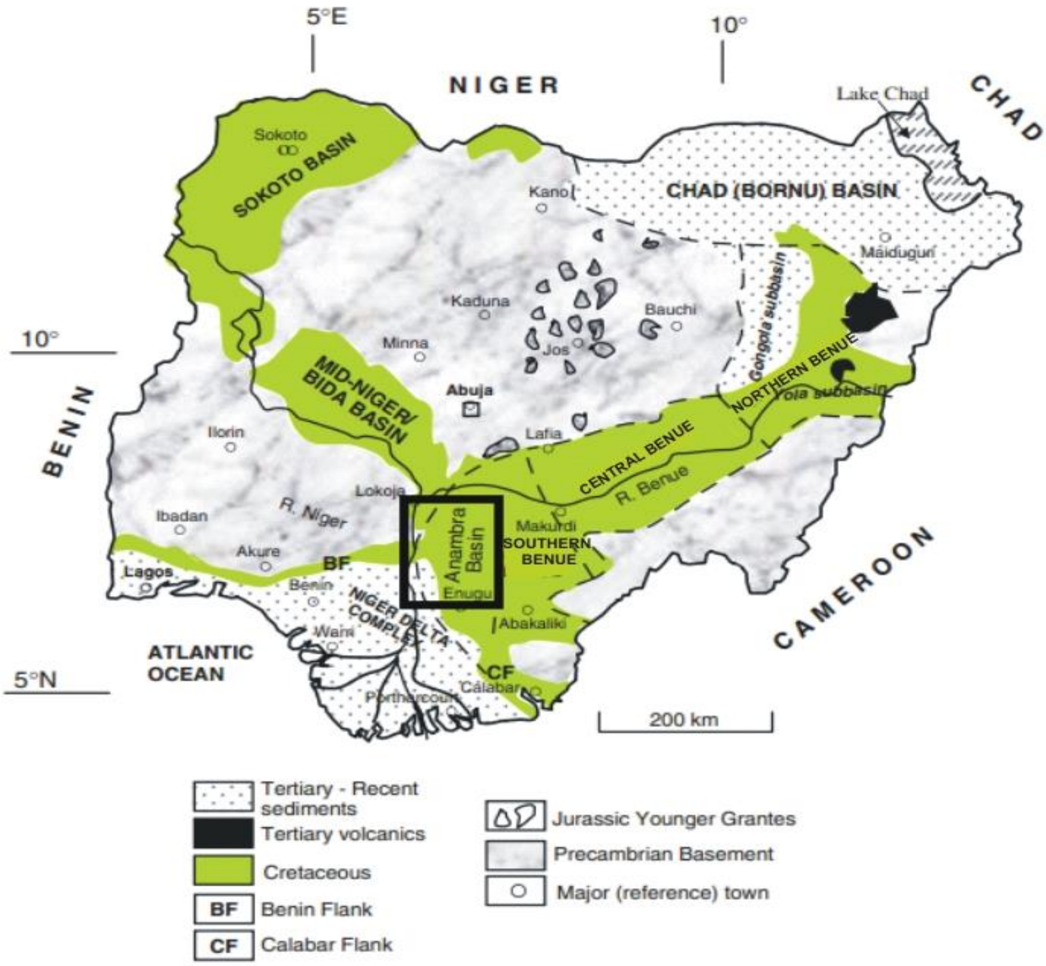

5°E
10°
NIGER
Lake Chad
CHAD
Sokoto
SOKOTO BASIN
Kano
CHAD (BORNU) BASIN
Maiduguri
Kaduna
Bauchi
Gongola subbasin
NORTHERN BENUE
Yola subbasin
10°
Minna
Jos
MID-NIGER/ BIDA BASIN
Abuja
BENIN
Ilorin
Lafia
CENTRAL BENUE
R. Benue
Lokoja
R. Niger
Ibadan
Anambra Basin
Makurdi
SOUTHERN BENUE
Akure
BF
Lagos
Benin
Enugu
NIGER DELTA COMPLEX
Abakaliki
CAMEROON
Warri
ATLANTIC OCEAN
5°N
CF
Calabar
Portharcourt
200 km
Tertiary - Recent sediments
Tertiary volcanics
Cretaceous
BF Benin Flank
CF Calabar Flank
Jurassic Younger Grantes
Precambrian Basement
Major (reference) town

Fig. 1:

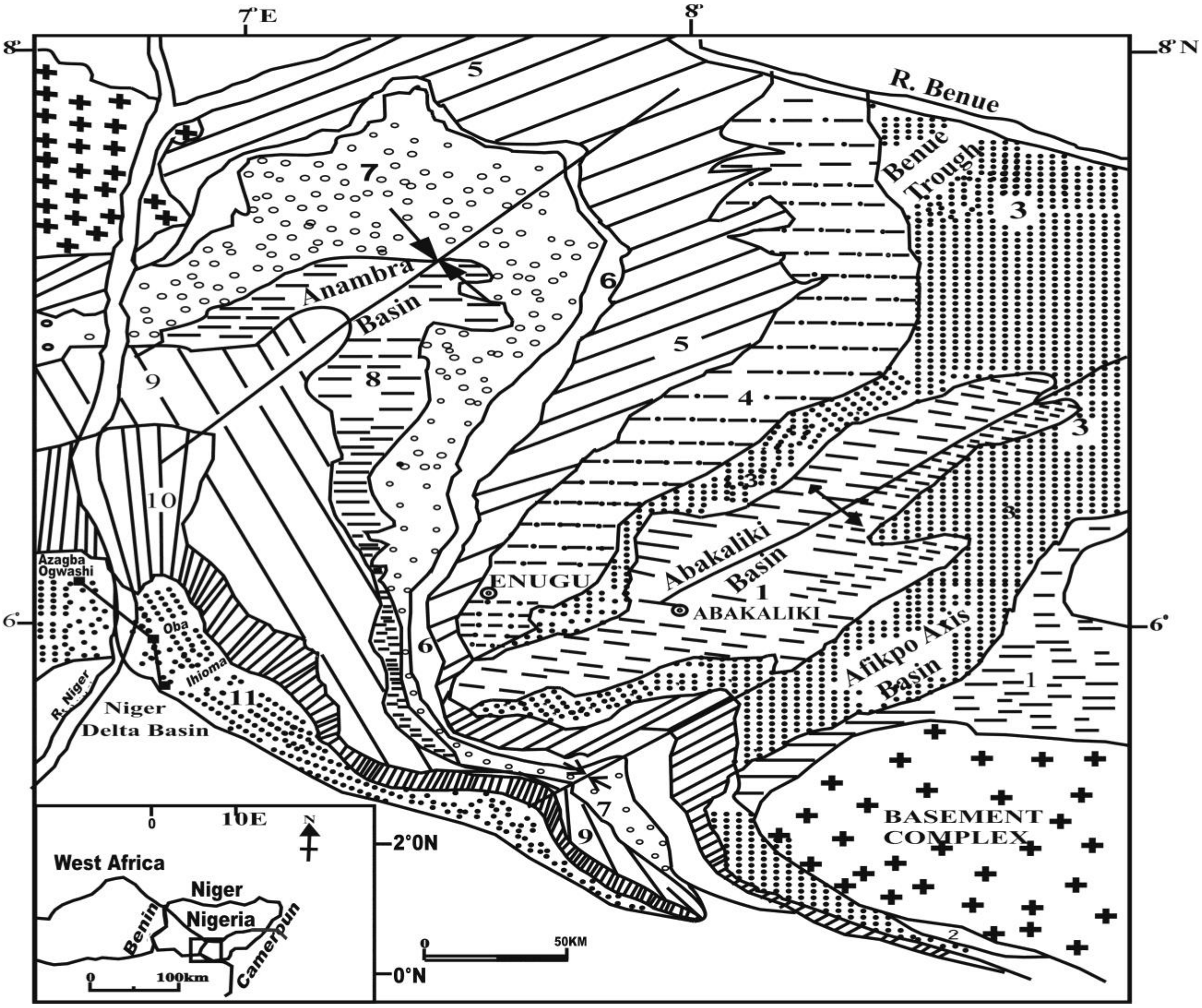

7°E
8°
8°
8°N
R. Benue
Benue Trough
5
7
Anambra Basin
6
5
4
3
8
9
10
Abakaliki Basin
1
ENUGU
ABAKALIKI
Afikpo Axis Basin
1
Azagba Ogwashi
Oba
Ihioma
11
R. Niger
Niger Delta Basin
6°
6°
7
9
BASEMENT COMPLEX
2
0
50KM
10E
2°0N
0°N
West Africa
Niger
Nigeria
Benin
Cameroun
100km

Fig. 2:

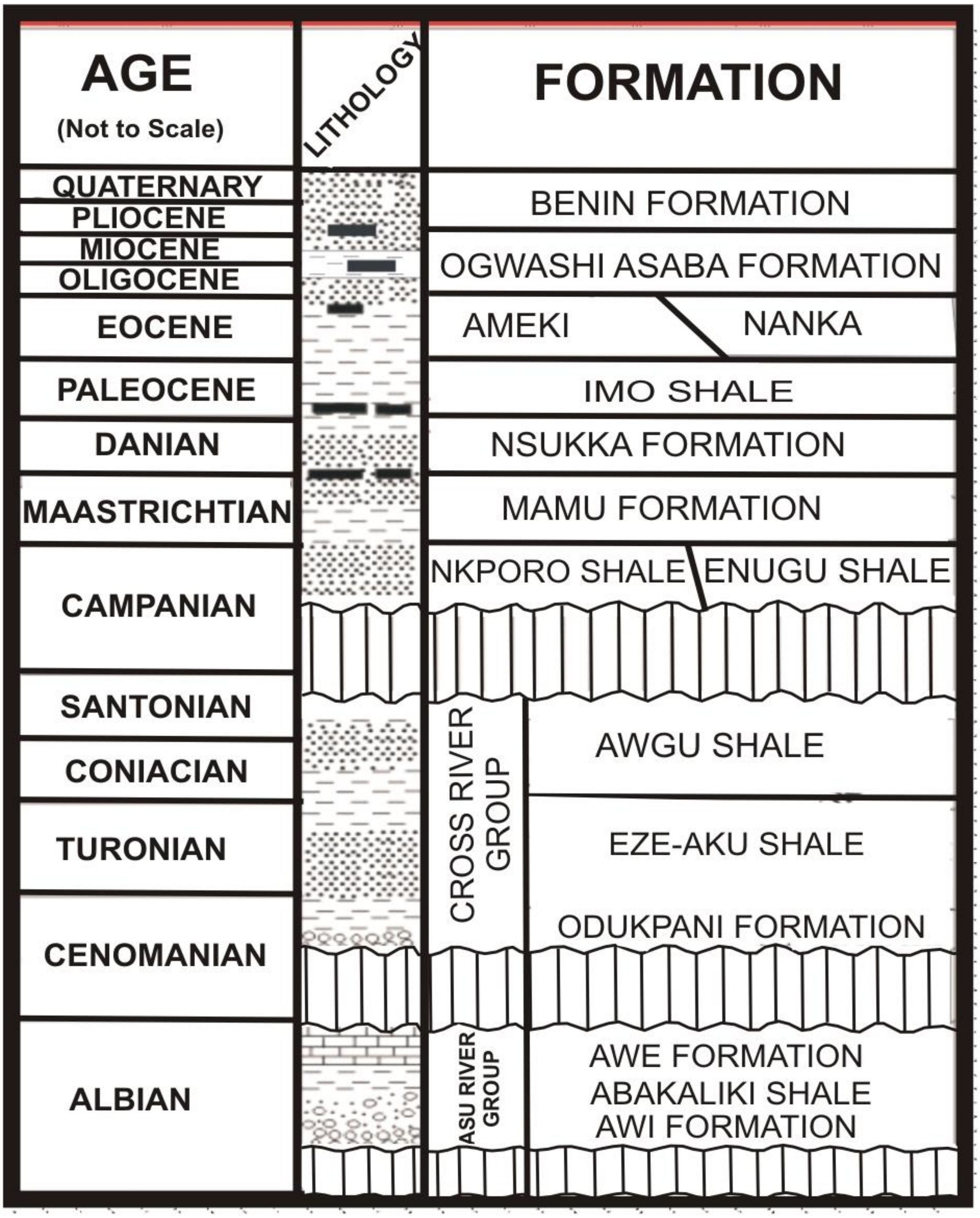
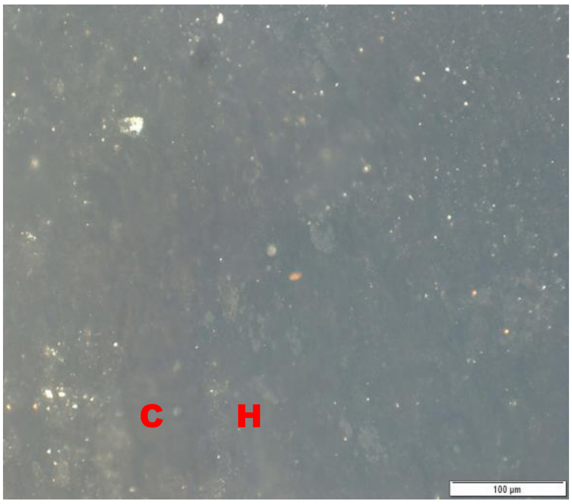

AGE
(Not to Scale)
LITHOLOGY
FORMATION
QUATERNARY
PLIOCENE
MIOCENE
OLIGOCENE
EOCENE
PALEOCENE
DANIAN
MAASTRICHTIAN
CAMPANIAN
SANTONIAN
CONIACIAN
TURONIAN
CENOMANIAN
ALBIAN
BENIN FORMATION
OGWASHI ASABA FORMATION
AMEKI
NANKA
IMO SHALE
NSUKKA FORMATION
MAMU FORMATION
NKPORO SHALE
ENUGU SHALE
CROSS RIVER GROUP
AWGU SHALE
EZE-AKU SHALE
ODUKPANI FORMATION
ASU RIVER GROUP
AWE FORMATION
ABAKALIKI SHALE
AWI FORMATION

Fig. 3:

4a



4b

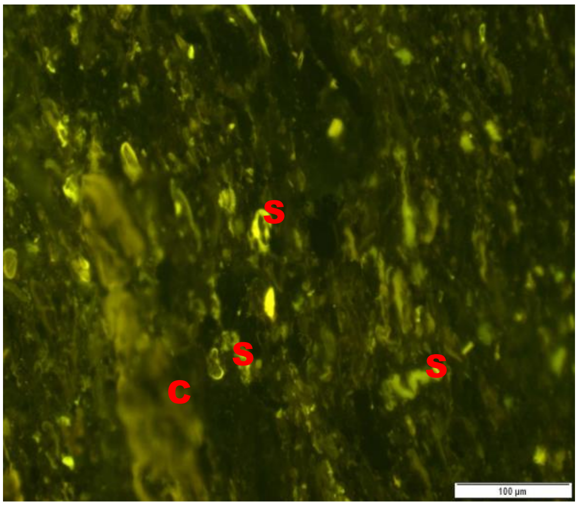
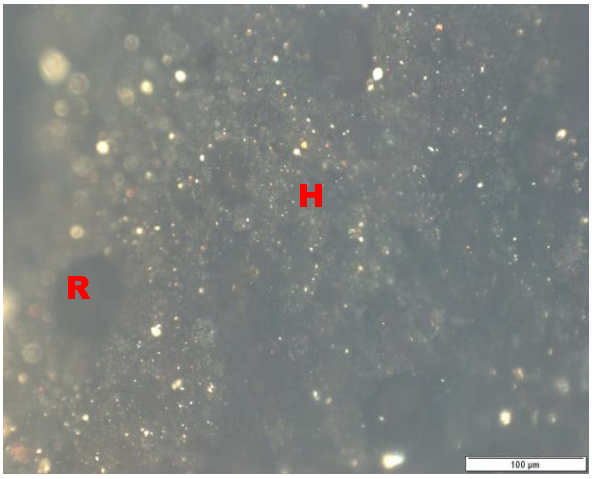


Fig. 4a.

Fig. 4b.

4c



4d

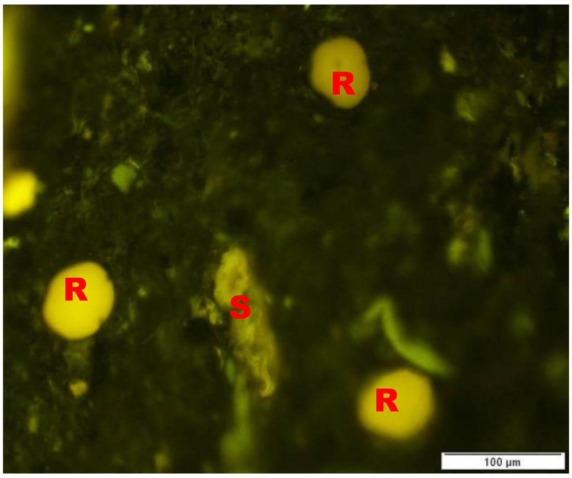


Fig. 4c.

Fig. 4d.

5a

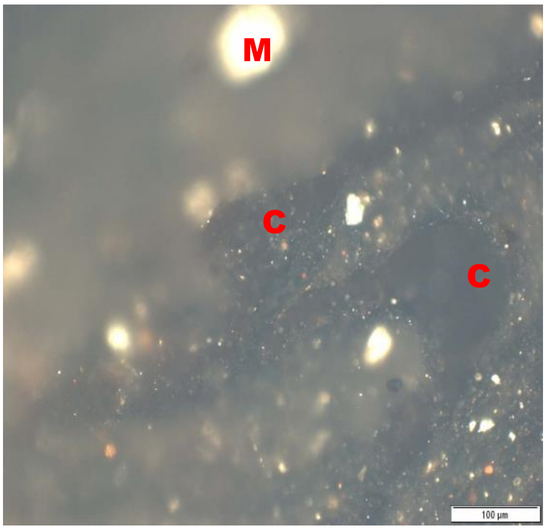


Fig. 5a.

5b

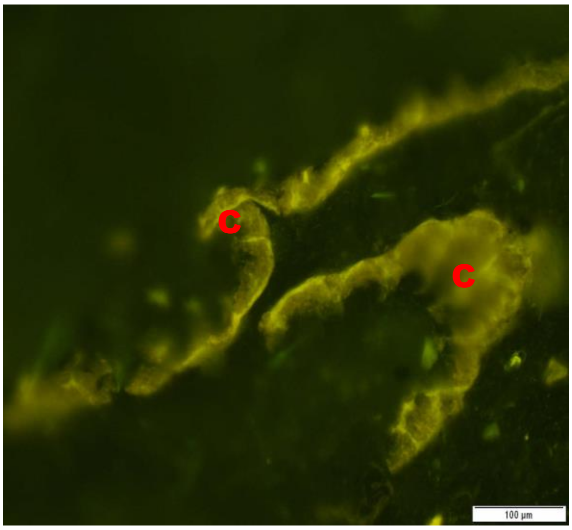


Fig. 5b.

5c

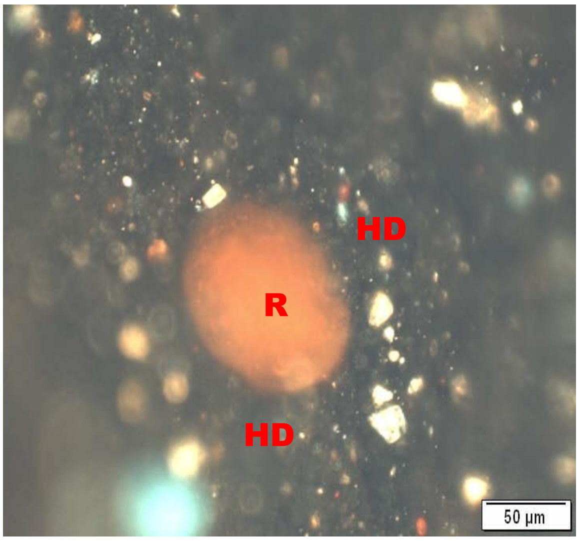


Fig. 5c.

5d

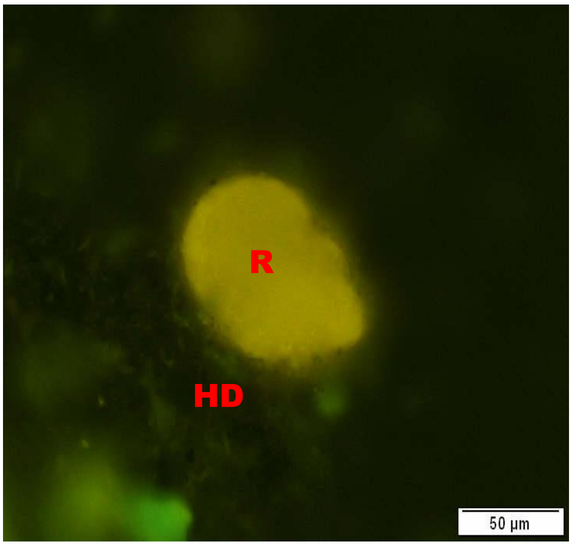


Fig. 5d.

6a

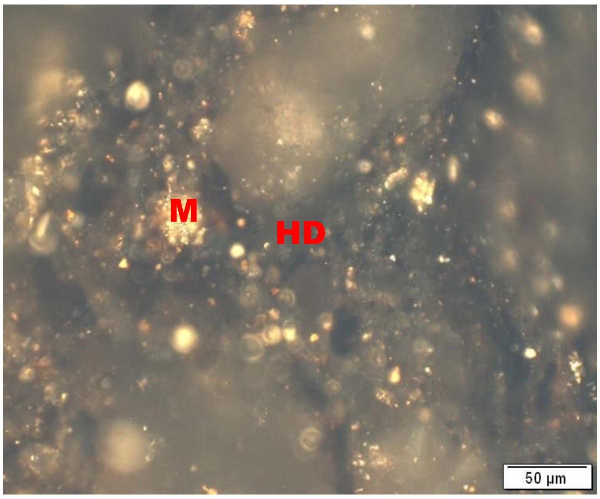


Fig. 6a.

6b

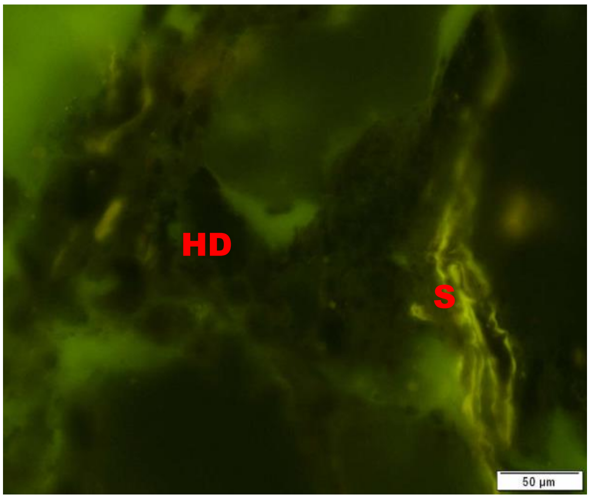


Fig. 6b.

6c

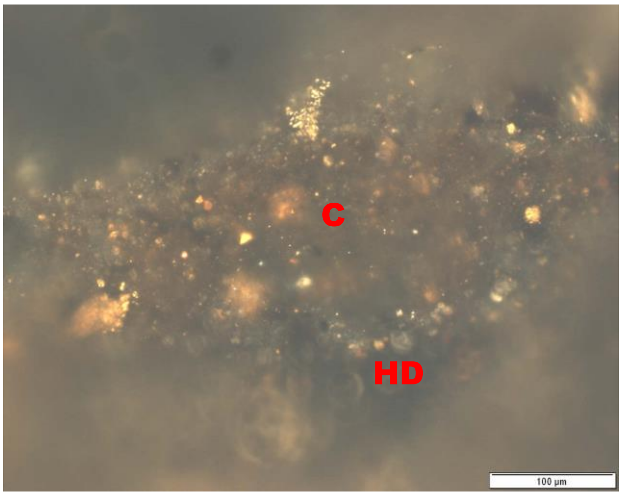


Fig. 6c.

6d

Fig. 6d.

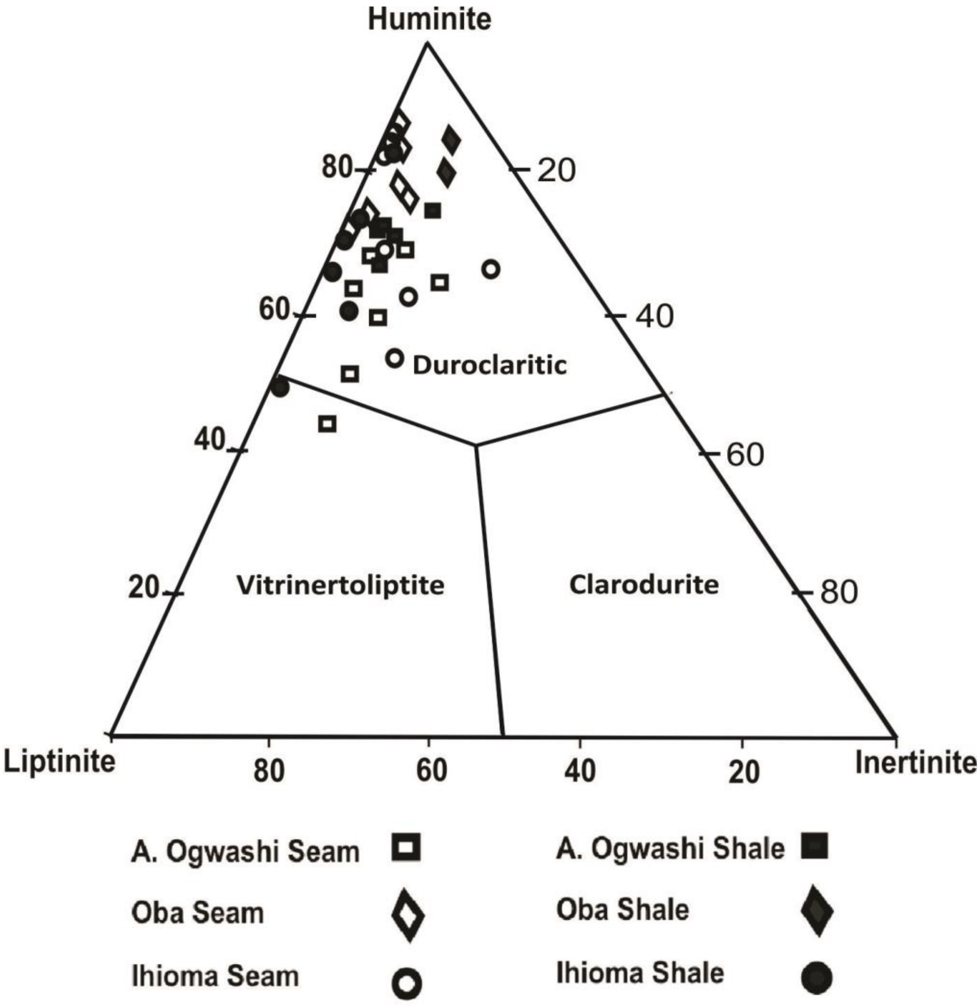

Huminite
80
60
40
20
20
40
60
80
Duroclaritic
Vitrinertoliptite
Clarodurite
Liptinite
80
60
40
20
Inertinite
A. Ogwashi Seam
A. Ogwashi Shale
Oba Seam
Oba Shale
Ihioma Seam
Ihioma Shale

Fig. 7:

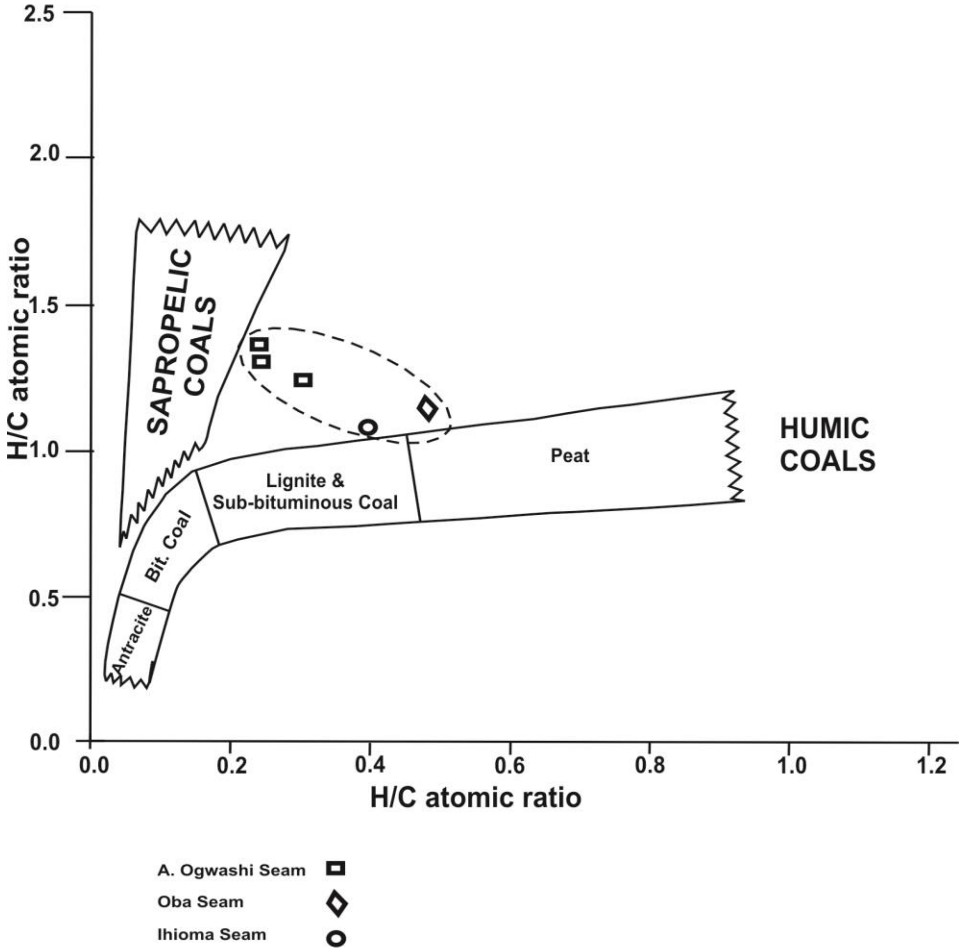

2.5
2.0
1.5
1.0
0.5
0.0
H/C atomic ratio
SAPROPELIC COALS
HUMIC COALS
Peat
Lignite &
Sub-bituminous Coal
Bit. Coal
Antracite
0.0
0.2
0.4
0.6
0.8
1.0
1.2
H/C atomic ratio
A. Ogwashi Seam
Oba Seam
Ihioma Seam

Fig. 8:

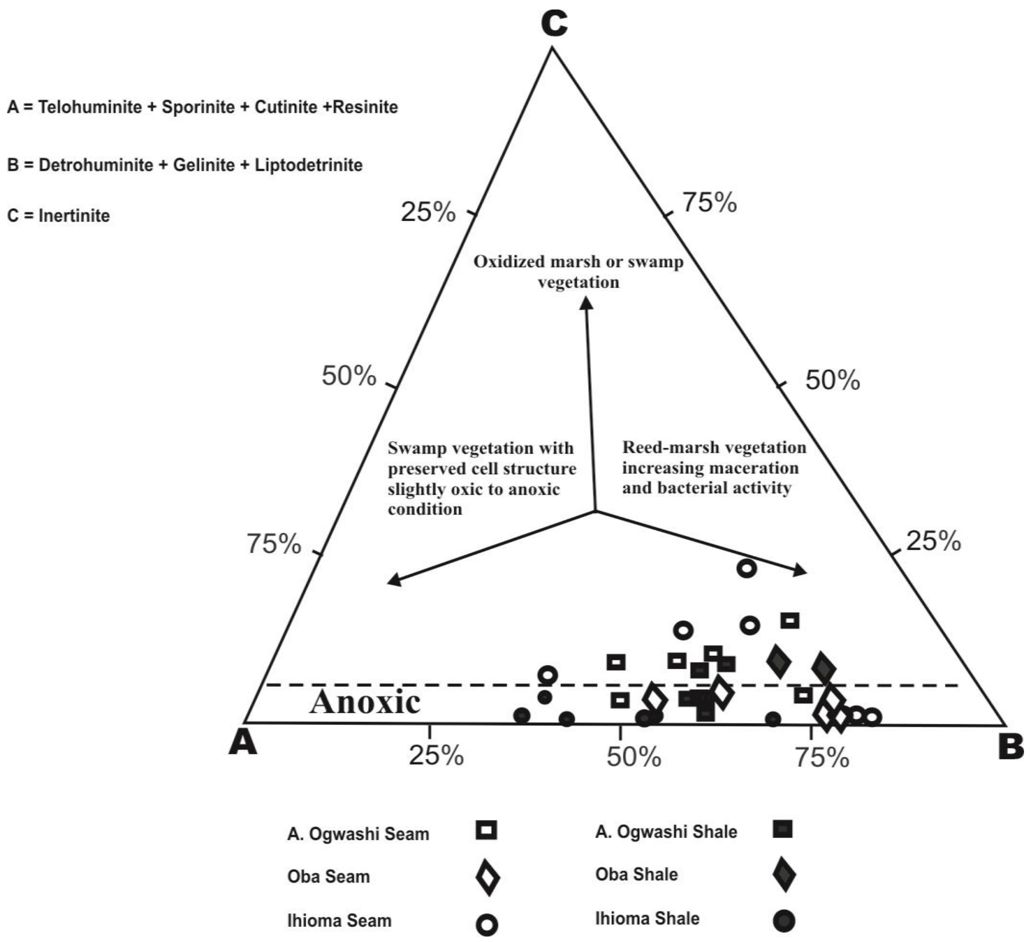

A = Telohuminite + Sporinite + Cutinite +Resinite
B = Detrohuminite + Gelinite + Liptodetrinite
C = Inertinite
C
A
B
25%
50%
75%
75%
50%
25%
25%
50%
75%
Oxidized marsh or swamp vegetation
Swamp vegetation with preserved cell structure slightly oxic to anoxic condition
Reed-marsh vegetation increasing maceration and bacterial activity
Anoxic
A. Ogwashi Seam
A. Ogwashi Shale
Oba Seam
Oba Shale
Ihioma Seam
Ihioma Shale

Fig. 9:

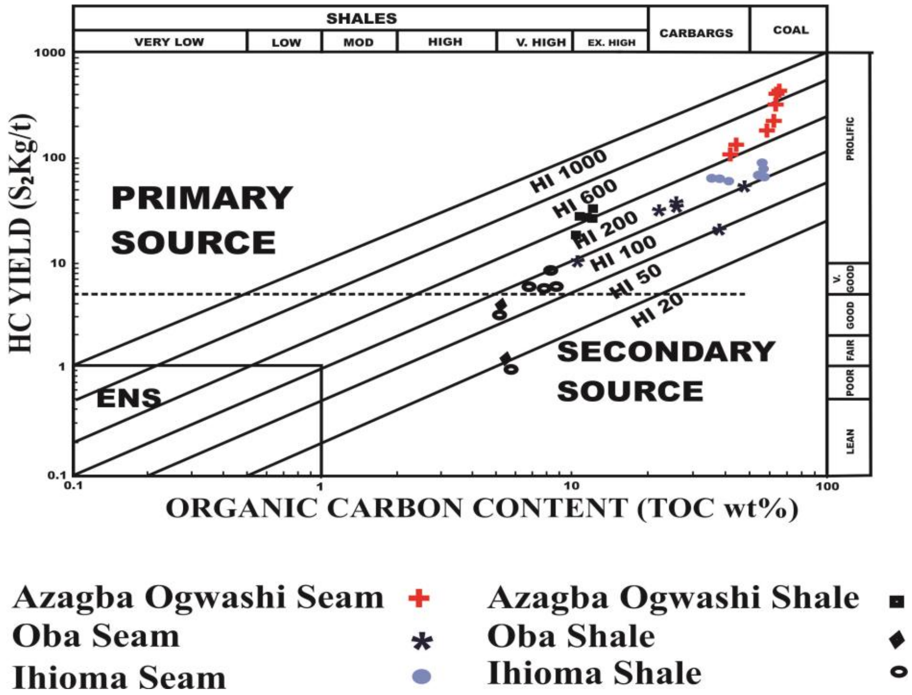

SHALES
VERY LOW
LOW
MOD
HIGH
V. HIGH
EX. HIGH
CARBARGS
COAL
PROLIFIC
V. GOOD
GOOD
FAIR
POOR
LEAN
PRIMARY SOURCE
SECONDARY SOURCE
ENS
HI 1000
HI 600
HI 200
HI 100
HI 50
HI 20
HC YIELD (S2Kg/t)
ORGANIC CARBON CONTENT (TOC wt%)
1000
100
10
1
0.1
0.1
1
10
100
Azagba Ogwashi Seam
Oba Seam
Ihioma Seam
Azagba Ogwashi Shale
Oba Shale
Ihioma Shale

Fig. 10:

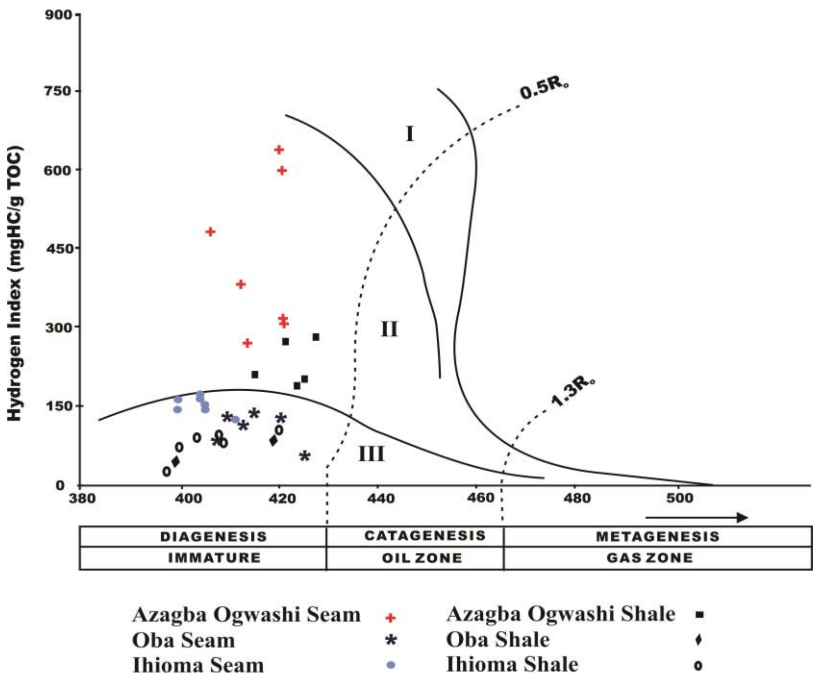

900
750
600
450
300
150
0
Hydrogen Index (mgHC/g TOC)
380
400
420
440
460
480
500
I
II
III
0.5Ro
1.3Ro
DIAGENESIS
CATAGENESIS
METAGENESIS
IMMATURE
OIL ZONE
GAS ZONE
Azagba Ogwashi Seam
Oba Seam
Ihioma Seam
Azagba Ogwashi Shale
Oba Shale
Ihioma Shale

Fig. 11:

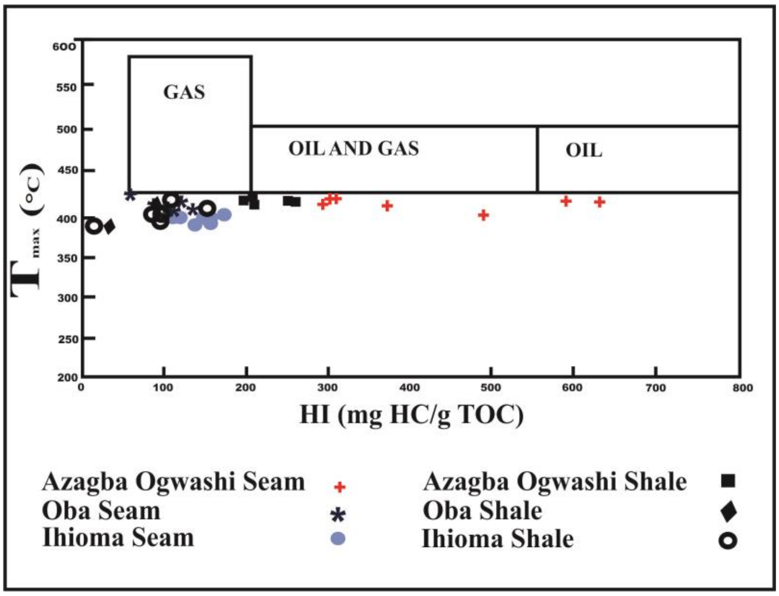

600
550
500
450
400
350
300
250
200
GAS
OIL AND GAS
OIL
Tmax (°C)
0
100
200
300
400
500
600
700
800
HI (mg HC/g TOC)
Azagba Ogwashi Seam
Oba Seam
Ihioma Seam
Azagba Ogwashi Shale
Oba Shale
Ihioma Shale

Fig. 12:

Table 1:

Serial No.	Sample No.	Location	Lithology	Rom %	**Huminites**	Telo-huminite	Gelo-huminite	Detro-huminite	**Liptinites**	Sporinite	Cutinite	Resinite	Bituminite	Exudatinite	Liptodetrinite	**Inertinites**	Fusinite	Semi-fusinite	Sclerotinite	Micrinite	Sum (vol%mmf)
1	AZG-1	Azagba Ogwashi	Lignite	0.40	**67.5**	-	17.7	49.8	**26.6**	12.5	4.7	8.2	1.2	-	-	**5.9**	-	3.4	2.5	-	100
2	AZG-2	Azagba Ogwashi	Lignite	0.40	**69.2**	2.4	23.7	43.1	**21.6**	7.7	0.4	12.1	0.9	-	0.5	**9.2**	-	6.3	2.9	-	100
3	AZG-3	Azagba Ogwashi	Lignite	0.42	**62.5**	2.9	28.4	31.2	**32.4**	9.9	4.5	15.6	-	-	2.4	**5.1**	-	2.0	3.1	-	100
4	AZG-4	Azagba Ogwashi	Shale	0.41	**70.5**	6.1	17.9	46.5	**22.5**	4.8	4.7	7.6	3.0	2.4	-	**7.0**	4.9	2.1	-	-	100
5	AZ-01B	Azagba Ogwashi	Lignite	0.42	**45.5**	-	3.0	42.5	**45.5**	9.1	12.1	18.2	-	6.1	-	**9.0**	2.0	2.0	-	5.0	100
6	AZ-01M	Azagba Ogwashi	Lignite	0.40	**63.3**	4.9	26.9	31.5	**22.1**	2.4	2.4	4.9	2.8	-	9.6	**14.6**	-	7.3	-	7.3	100
7	AZ-01T	Azagba Ogwashi	Lignite	0.40	**60.9**	8.7	10.9	41.3	**30.4**	6.6	2.2	8.6	-	8.6	4.4	**8.7**	-	2.2	-	6.5	100
8	AZ-01	Azagba Ogwashi	Lignite	0.36	**53.0**	-	5.5	47.5	**38.0**	12.1	3.0	15.7	-	5.2	2.0	**9.0**	3.0	3.0	-	3.0	100
9	AZ-02	Azagba Ogwashi	Shale	0.40	**73.0**	14.8	17.7	40.5	**23.0**	3.8	3.8	7.7	3.9	3.8	-	**4.0**	-	4.0	-	-	100
10	AZ-02B	Azagba Ogwashi	Shale	0.38	**72.9**	7.6	15.3	50.0	**23.2**	3.9	3.9	7.6	3.9	3.9	-	**3.9**	-	3.9	-	-	100
11	AZ-02M	Azagba Ogwashi	Shale	0.40	**68.2**	4.5	9.1	54.6	**27.3**	9.1	4.5	13.7	-	-	-	**4.5**	-	4.5	-	-	100
12	AZ-02T	Azagba Ogwashi	Shale	0.42	**75.9**	13.8	20.7	41.4	**13.8**	6.9	-	6.9	-	-	-	**10.3**	6.9	3.4	-	-	100
13	OBA-1	Oba	Shale	0.38	**81.1**	7.9	8.4	64.8	**8.3**	5.4	-	2.9	-	-	-	**10.6**	-	5.7	4.9	-	100
14	OBA-2	Oba	Impure Lignite	0.40	**76.0**	12.1	22.5	41.4	**17.2**	1.7	1.7	13.8	-	-	-	**6.8**	3.4	3.4	-	-	100
15	OBA-3	Oba	Impure Lignite	0.40	**78.2**	13.2	25.3	39.7	**17.1**	12.4	-	4.7	-	-	-	**4.7**	2.3	2.4	-	-	100
16	OBA-4	Oba	Impure Lignite	0.37	**73.5**	17.5	24.6	31.4	**22.3**	14.0	-	8.3	-	-	-	**4.2**	2.2	2.0	-	-	100
17	OB-02B	Oba	Shale	0.36	**84.5**	18.1	29.8	36.6	**6.5**	4.9	-	1.2	-	-	0.4	**9.0**	3.0	6.0	-	-	100
18	OB-03B	Oba	Impure Lignite	0.40	**83.1**	10.9	15.6	56.6	**13.8**	6.3	2.8	1.9	-	-	2.8	**3.1**	-	-	-	3.1	100
19	OB-03M	Oba	Impure Lignite	0.42	**88.4**	9.6	26.9	51.9	**11.6**	3.9	5.8	1.9	-	-	-	**0.0**	-	-	-	-	100
20	OB-03T	Oba	Lignite	0.39	**71.5**	4.8	23.8	42.9	**28.5**	7.1	7.1	4.8	-	-	9.5	**0.0**	-	-	-	-	100
21	IHM-1	Ihioma	Impure Lignite	0.35	**84.5**	-	24.5	60.0	**14.8**	4.4	1.6	8.8	-	-	-	**0.7**	-	0.7	-	-	100
22	IHM-2	Ihioma	Impure Lignite	0.31	**83.3**	2.3	7.0	74.0	**16.2**	5.6	3.3	7.0	-	-	0.3	**0.5**	-	0.5	-	-	100
23	IHM-3	Ihioma	Lignite	0.33	**86.6**	1.0	15.6	70.0	**12.9**	11.6	0.3	1.0	-	-	-	**0.5**	-	0.5	-	-	100
24	IHM-4	Ihioma	Shale	0.37	**74.6**	14.0	14.7	45.9	**25.4**	3.2	-	22.2	-	-	-	**0.0**	-	-	-	-	100
25	IHM-5	Ihioma	Shale	0.32	**83.5**	12.6	3.1	67.8	**16.5**	3.3	-	11.1	-	-	2.1	**0.0**	-	-	-	-	100
26	IH-01B	Ihioma	Lignite	0.35	**63.6**	6.1	6.1	51.4	**24.2**	6.1	-	12.0	-	-	6.1	**12.2**	-	6.1	-	6.1	100
27	IH-01M	Ihioma	Lignite	0.33	**55.4**	7.4	5.5	42.5	**31.6**	1.9	-	26.0	-	-	3.7	**13.0**	-	3.7	-	9.3	100
28	IH-01T	Ihioma	Lignite	0.35	**66.5**	8.3	13.8	44.4	**11.2**	-	-	5.6	-	-	5.6	**22.3**	-	5.6	5.6	11.1	100
29	IH-03B	Ihioma	Shale	0.32	**66.6**	30.3	12.1	24.2	**33.4**	6.1	-	27.3	-	-	-	**0.0**	-	-	-	-	100
30	IH-03M	Ihioma	Shale	0.37	**50.0**	20.0	5.0	25.0	**50.0**	15.0	5.0	20.0	-	-	10.0	**0.0**	-	-	-	-	100
31	IH-03T	Ihioma	Shale	0.34	**71.4**	14.3	14.2	42.9	**28.6**	-	-	28.6	-	-	-	**0.0**	-	-	-	-	100
32	IH-04	Ihioma	Lignite	0.33	**60.0**	21.7	13.3	25.0	**33.3**	3.3	8.3	21.7	-	-	-	**6.7**	-	6.7	-	-	100
33	IH-05	Ihioma	Shale	0.35	**68.8**	31.3	15.6	21.9	**25.0**	-	6.2	18.8	-	-	-	**6.2**	-	6.2	-	-	100

Table 2:

Sample	C	H	N	O	S	H/C	O/C
	Wt%					Atomic ratio	
AZ – 01B	62.77	6.42	0.82	26.16	0.90	1.23	0.31
AZ – 01M	67.37	7.32	0.80	21.45	0.60	1.30	0.24
AZ – 01T	68.21	7.66	0.80	21.04	0.80	1.35	0.23
OB – 03T	49.49	4.64	0.79	31.40	2.49	1.13	0.48
IH – 01B	58.60	5.16	0.84	31.24	1.09	1.06	0.40

Table 3:

S/N	Sample No.	Lithology	TOC (Wt %)	Tmax (°C)	Vrom (%)	S1 (mgHC/g rock)	S2 (mgHC/g rock)	S1+S2 (kg HC/t rock)	HI mgHC/g TOC	PI
1	AZG - 1	Lignite	46.7	421	0.4	11.97	147.45	159.42	317.85	0.08
2	AZG -2	Lignite	42.27	414	0.4	10.09	113.38	123.47	268.23	0.08
3	AZG - 3	Lignite	59.46	421	0.42	21.26	180.83	202.09	304.12	0.11
4	AZG - 4	Shale	12.1	426	0.41	2.61	24.41	27.02	201.8	0.04
5	AZ - 01B	Lignite	61.47	413	0.42	11.35	232.56	243.91	378	0.05
6	AZ - 01M	Lignite	67.78	421	0.4	16.52	403.74	420.26	596	0.04
7	AZ - 01T	Lignite	68.04	420	0.4	25.91	434.72	460.63	639	0.06
8	AZ - 01	Lignite	63.49	406	0.36	6.93	305.52	312.45	481	0.02
9	AZ - 02	Shale	10.34	423	0.4	0.66	19.77	20.43	191	0.03
10	AZ - 02B	Shale	12.38	419	0.38	2.99	32.2	35.19	260	0.08
11	AZ - 02M	Shale	12.37	415	0.4	2.56	25.91	28.47	209	0.08
12	AZ - 02T	Shale	11.4	421	0.42	3.2	28.48	31.68	240	0.1
13	OBA - 1	Shale	4.98	418	0.38	0.78	4.14	4.92	83.12	0.16
14	OBA - 2	Impure lignite	25.96	414	0.4	3.54	34.54	38.08	133.05	0.09
15	OBA - 3	Impure lignite	25.79	409	0.4	3.33	33.25	36.58	128.92	0.09
16	OBA - 4	Impure lignite	23.77	420	0.37	3.21	31.06	34.27	130.7	0.09
17	OB - 2B	Shale	5.61	395	0.36	0.6	1.89	2.49	34	0.2
18	OB - 03B	Impure lignite	13.28	408	0.4	1.77	11.28	13.05	85	0.14
19	0B - 3M	Impure lignite	38.1	425	0.42	1.02	20.38	21.4	53	0.05
20	OB - 03T	Lignite	48.27	413	0.39	3.69	56.68	60.37	117	0.06
21	IHM - 1	Impure lignite	38.25	400	0.35	3.12	64.4	67.52	168.37	0.05
22	IHM - 2	Impure lignite	37.74	404	0.31	3.85	67.32	71.17	178.38	0.05
23	IHM - 3	Lignite	42.98	394	0.33	4.67	62.09	66.76	144.46	0.07
24	IHM - 4	Shale	8.11	420	0.37	1.39	8.52	9.91	105.06	0.14
25	IHM - 5	Shale	5.2	408	0.32	0.93	4.98	5.91	95.77	0.16
26	IH - 01B	Lignite	57.3	404	0.35	4.96	93.53	98.49	163	0.05
27	IH - 01M	Lignite	57.56	405	0.33	3.55	86.16	89.71	150	0.04
28	IH - 01T	Lignite	57.7	412	0.35	1.98	70.69	72.67	123	0.03

29	IH - 03B	Shale	6.88	404	0.32	1.11	6.26	7.37	91	0.15
30	IH - 03M	Shale	7.61	409	0.37	1.3	6.19	7.49	81	0.17
31	IH - 03 T	Shale	8.38	396	0.34	1.23	6.24	7.47	75	0.16
32	IH - 04	Lignite	55.21	405	0.33	3.19	76.26	79.45	138	0.04
33	IH - 05	Shale	5.46	384	0.35	0.32	0.93	1.25	17	0.26