PRINT ISSN 1119-8362
Electronic ISSN 2659-1499

Full-text Available Online at
https://www.ajol.info/index.php/jasem
https://www.bioline.org.br/ja

J. Appl. Sci. Environ. Manage.
Vol. 28 (3) 633-641 March 2024

# Geochemical and Biostratigraphical Evaluation of Lokpanta Shale in Abakaliki Anticlinorium, Anambra Basin Province, Southeast Nigeria

***[1]UZOEGBU, MU; [2]AMOKE, AI**

**[1]Department of Geology, Michael Okpara University of Agriculture, Umudike, Nigeria*
*[2]Department of Geology/Geophysics, Alex Ekwueme Federal University, Ndufu-Alike, Nigeria.*

**Corresponding Author: mu.uzoegbu@mouau.edu.ng*
**ORCID ID: http://orcid.org/0009-0007-5831-3703*
**Tel: 08030715958*

*Co-Author: amoke.ignatius@funai.edu.ng*

**ABSTRACT:** A geochemical and biostratigraphic method has been applied to explore the quality of organic matter, thermal evolution, potential hydrocarbon source and type of fossils of Lokpanta Shale from the Abakaliki Anticlinorium, Anambra Basin Province, Southeast Nigeria. Data obtained reveal that the total organic carbon (TOC) (2.18wt%) of the shale constitutes that of good to excellent source rock with gas-prone kerogen indicated by Rock-Eval $S_2/S_3$ (2.32). The low oxygen index (OI) (27.20 $mgCO_2g^{-1}$TOC) suggest deposition under low energy environments. The plots of HI against $T_{max}$ classified the organic matter as Type III kerogen. The poor concentration of OM is thought to account for its current hydrogen index (31.47 $mgHCg^{-1}$TOC). The predominance of Type III kerogen in the Lokpanta shale suggests their potential to generate gas in the deeply buried sections. The $T_{max}$ values from the pyrolysis of the shales of the Lokpanta ranges from 428 to 442ºC corresponding to maturity levels within the oil formation. The lamination of the sediments of the Lokpanta area with no burrows and the occurrence of dominantly planktonic foraminiferal assemblages also indicate a quiet water anoxic marine condition.

**DOI: https://dx.doi.org/10.4314/jasem.v28i3.2**



**Cite this Article as**: UZOEGBU, M. U; AMOKE, A. I. (2024). Geochemical and Biostratigraphical Evaluation of Lokpanta Shale in Abakaliki Anticlinorium, Anambra Basin Province, Southeast Nigeria. *J. Appl. Sci. Environ. Manage.* 28 (3) 633-641

**Dates:** Received: 18 January 2024; Revised: 24 February 2024; Accepted: 12 March 2024 Published: 29 March 2024

**Keywords:** Anambra basin; Source rock; Kerogen type; Pyrolysis; Maturity; Foraminifera

Details on the geology and stratigraphy of the Benue trough have been comprehensively discussed, reviewed and presented by Carter et al.(1963), Whiteman (1982), Dike (1993), Akande et al. (1998), Obaje et al. (1999), Obaje and Hamza (2000), Pearson and Obaje (2000), Obaje et al. (2004), Akande et al. (2007) and Uzoegbu et al. (2013) amongst others.

However, there is paucity of information on the geochemical and biostratigraphical evaluation of Lokpanta Shale in Abakaliki Anticlinorium; hence the objective of this investigation is to explore the quality of organic matter, thermal evolution, potential hydrocarbon source and type of fossils of the Lokpanta Shale in Abakaliki Anticlinorium, Anambra Basin Province, Southeast Nigeria.

## MATERIALS AND METHODS

*Description of Study area and basin history:* The Lokpanta area is located in the Abakaliki Anticlinorium and it is bounded by Ndeaboh in the East, Umuchieze in the South and Awgu in the North on latitude $6^0$ 01"N and longitude $7^0$ 30"E within the Anambra Basin. Anambra Basin comprises an almost

**Corresponding Author: mu.uzoegbu@mouau.edu.ng*
**ORCID ID: http://orcid.org/0009-0007-5831-3703*
**Tel: +2348030715958*

triangular shaped embayment covering an area of about 30,000sq km. It stretches from the area just south of the confluence of the Rivers Niger and Benue across to areas around Auchi, Okene, Agbo, and Asaba, west of the Niger, and Ayangba, Idah, Nsukka, Onitsha and Awka areas, east of the River Niger. The surface area of the basin is marked by the Udi, Idah and Kabba escarpments, to the east, north and northwest respectively.

The Anambra Basin joins the southeastern-most sector of a NNE-SSW stretch of the Benue Trough (Fig. 1). The Anambra Basin, the Benue Trough, the Mid-Niger (Bida) Basin, and the Sokoto Basin constitute Nigeria's set of inland basins.

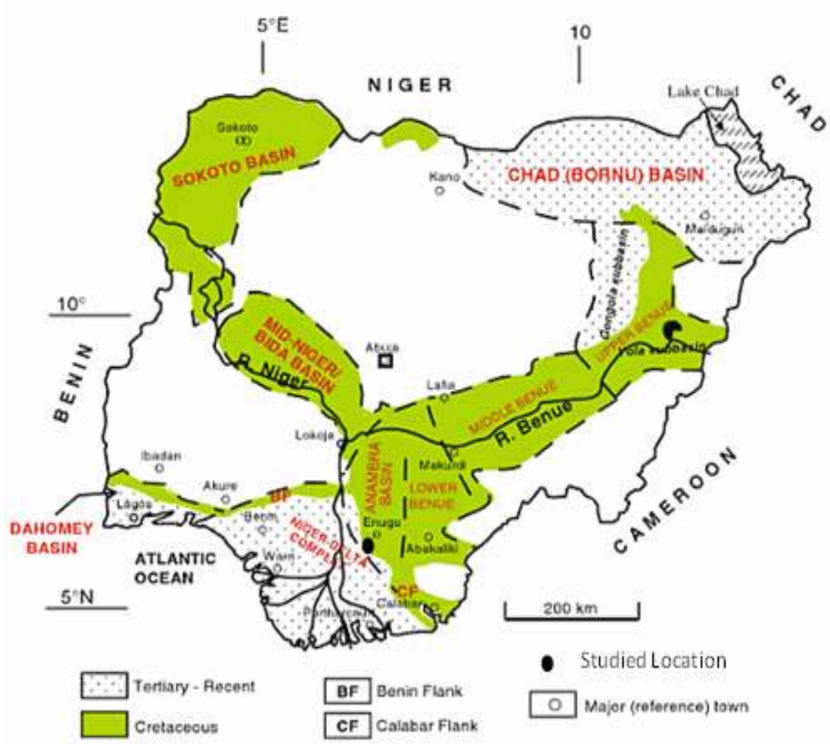


**Fig. 1:** Sketch geological map of Nigeria showing the location of the Anambra Basin and the relationship to other inland basins (After Obaje, 2009).

The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins, and, in Nigeria, form the boundary faults of the Cretaceous Benue-Abakaliki trough, which cuts far into the West African shield. The trough represents a failed arm of a rift triple junction associated with the opening of the South Atlantic. In this region, rifting started in the Late Jurassic and persisted into the Middle Cretaceous (Lehner and De Ruiter, 1977).These inland basins make up another set of a series of Cretaceous and younger rift basins in Central and West Africa whose origin is related to the opening of the South Atlantic.

*Stratigraphic Framework***:** The Benue trough of Nigeria is a rift basin in central West Africa that extends NNE-SSW for about 800 km in length and 150 km in width (Fig. 1). The trough contains up to 6000 m Cretaceous – Tertiary sediments of which those pre-dating the mid-Santonian have been compressionally deformed, faulted, and uplifted in several places. Compressional folding during the mid-Santonian tectonic episode affected the whole of the Benue trough and was quite intense, producing over 100 anticlines and synclines (Benkhelil, 1989). Following mid-Santonian tectonism and magmatism, depositional axis in the Benue trough was displaced westward resulting subsidence of the Anambra basin. The Anambra basin, therefore, is a part of the lower Benue trough containing post-deformational sediments of Campano-Maastrichtian to Eocene ages. It is logical to include the Anambra basin in the Benue trough, being a related structure that developed after the compressional stage (Akande and Erdtmann, 1998). The Benue trough is subdivided into a lower, middle and an upper portion (Figs. 1 and 2). A generalized stratigraphic succession in the Benue trough and the relationship to the Chad basin and Niger delta is given on Figs. 2. *Sample Collection:* The outcrop samples were obtained from Lokpanta shales south of Enugu along Enugu–Port Harcourt express road and the Enugu shale at Enugu near the Onitsha-Road Flyover. Care was taking to avoid weathered portions of the outcrop and to obtain material sufficient for various geochemical analyses. The samples were hard, thickly laminated but not fissile, with texture indicative of low permeability. This macro-structure suggests minimum risk of organic matter oxidation. The samples are attributed to the Cenomanian-Maastrichtian marine and paralic siliciclastics strata which are overlain by the coal measures of the Mamu Formation (Fig. 2). The fluviodeltaic sandstones of the Ajali and Owelli Formations lie on the Mamu Formation. In the Paleocene, the marine shales of the Imo, and the continental/delta plain shale, mudstone, siltstones and sandstones of the Nsukka Formations were deposited, overlain by the tidal Nanka Sandstone of Eocene age which followed by lignitic Miocene-Oligocene Ogwashi-Asaba Formation.

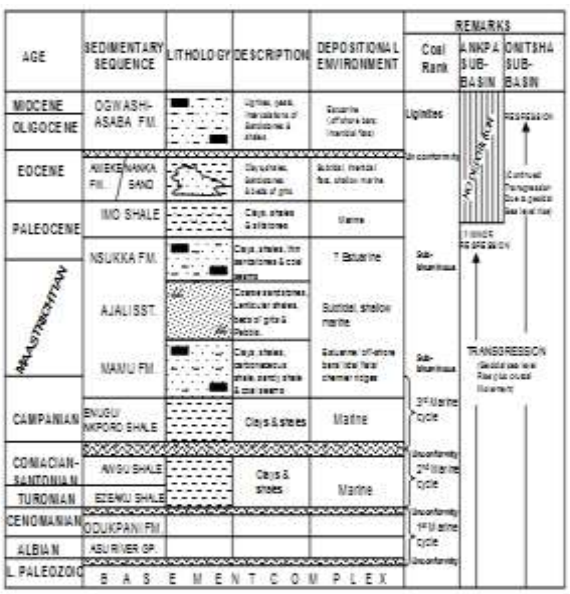


**Fig. 2:** The stratigraphy and environment of deposition of sediments in the Anambra Basin southeastern Nigeria.

*Geochemical Laboratory Analyses:* In the laboratory, a total of six shale samples were subjected to geochemical laboratory analyses, the samples were reshaped using a rotating steel cutter to eliminate surface that could be affected by alteration. Chips were cut from the samples and dried in an oven at 105ºC for 24 hours. Chips cut perpendicular to bedding were embedded in epoxy and polished following the procedures of Taylor *et al*. (1998) to yield polished blocks for reflectance and fluorescence studies using scan electronic microscope. Another portion of the dried sample was pulverized in a rotating disc mill to yield about 50 g of sample for analytical geochemistry. The total organic carbon (TOC) and inorganic carbon (TIC) contents were determined using Leco CS 200 carbon analyzer by combustion of 100 mg of sample up to 1600ºC, with a thermal gradient of 160ºC $min^{-1}$; the resulting $CO_2$ was quantified by an Infrared detector. The sample with known TOC was analyzed using a Rock-Eval 6, yielding parameters commonly used in source rock characterization, flame ionization detection (FID) for hydrocarbons thermal conductivity detection (TCD) for $CO_2$. A total of eight outcrop shale samples were subjected to palaeontological analyses. About 20 to 25g of each sample was analyzed for microfossil content. The samples were washed and treated with hydrogen peroxide ($H_2O_2$) and sodium bicarbonate ($Na_2CO_3$). The treated samples were dried in an oven. The dried samples were further sieved through a 212 µm mesh for easy picking. The picking, counting and identification of microfossils were done using reflected light under a binocular paleontological microscope. The identified microfossils were studied and classified.

## RESULTS AND DISCUSSION

*Geochemical Variation:* The amount of organic carbon (TOC) is a measure of the quantity of organic matter (OM) in the source rocks (Tissot and Welte, 1984). As shown in Table 1, the Total Organic Carbon (TOC %) for the Lokpanta shales varies from 1.30 to 3.59%. The average TOC value 2.18wt% for the Lokpanta shales indicates a good to excellent organic matter concentration (Hunt, 1979; Tissot and Welte, 1984). The quality of organic matter (OM) in the source rock facies of the Lokpanta shale was done by using Rock-Eval generated data (HI and $T_{max}$). The shale samples of the Lokpanta plot mainly along the gas prone kerogen evolutionary pathway as indicated by the plot of HI against $T_{max}$ (Fig. 3). This confirms that a substantial proportion of the organic matter is of terrestrial origin with gas potential despite their marine environment of deposition (Uzoegbu and Ikwuagwu, 2016a). This view is further supported by the ratios of A-factor and C-factor (1.3), which shows predominance of gaseous prone type III organic matter in the shales of the Lokpanta. They contain relatively high carbonyl/carboxyl groups and moderate aliphatic groups (Ojo and Akande, 2002). This is also further supported based on the Mukhopadyay and Hatcher (1993) classification of kerogens relative to HI and OI, all of the samples plots within Type III field, where desmocollinite (collodetrinite) is dominance macerals as a good potential for the generation of gas (Fig. 4). The gas-prone nature of this rock rules out Type II kerogen, which usually shows $S_2/S_3$ greater than 5, the average S2/S3 value of Lokpanta shale is 2.32. While the maturity from $T_{max}$ suggest that the current HI results from thermal evolution of a Type III kerogen, with initial HI between 600 mgHC $g^{-1}$TOC and 850 mgHC $g^{-1}$TOC (Lafargue *et al*., 1998).

**Table 1**: Rock – Eval pyrolysis data for samples from Campanian Lokpanta Shales in the Anambra Basin.

| Sample Name | Locality | Lithology | Tmax (°C) | S1 (mg/g) | S2 (mg/g) | S3 (mg/g) | PI | S2/S3 | S1/TOC | TOC (%) | HI (S2mg/ gTOC) | OI (S3mg/ gTOC) | S1 + S2 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SAM-1 | Lokpanta | Shale | 428.00 | 0.03 | 0.72 | 0.40 | 0.04 | 1.80 | 0.02 | 1.30 | 34.30 | 47.70 | 0.75 |
| SAM-2 | Lokpanta | Shale | 431.00 | 0.06 | 0.70 | 0.20 | 0.08 | 3.50 | 0.02 | 2.16 | 28.00 | 9.00 | 0.76 |
| SAM-3 | Lokpanta | Shale | 428.00 | 0.02 | 0.74 | 1.24 | 0.03 | 0.60 | 0.01 | 2.94 | 24.80 | 41.80 | 0.76 |
| SAM-4 | Lokpanta | Shale | 439.00 | 0.07 | 2.53 | 0.42 | 0.03 | 6.02 | 0.02 | 3.59 | 70.00 | 11.00 | 2.60 |
| SAM-5 | Lokpanta | Shale | 433.00 | 0.05 | 0.33 | 0.20 | 0.13 | 1.65 | 0.02 | 1.78 | 18.00 | 11.00 | 0.38 |
| SAM-6 | Lokpanta | Shale | 442.00 | 0.02 | 0.19 | 0.57 | 0.10 | 0.33 | 0.02 | 1.31 | 13.70 | 42.70 | 0.21 |

*Note: Tmax =Temperature at which maximum decomposition of kerogen occurs (°C); S1=Free bitumen determined by thermovarpourization at 300°C (mgHCg$^{-1}$ rock); S2 =Amount of kerogen that may be converted to petroleum (mgHCg$^{-1}$ rock); S3 =Amount of carbon dioxide from carboxyl and carbonyl groups in kerogen (mgCO$_2$/g rock); PI =Production Index ($S_1/(S_1+S_2)$; TOC = Total Organic Carbon (wt%); HI = Hydrogen Index; OI = Oxygen Index.*

High TOC contents (as low as 2.18 wt %) and HI between 13.70 and 70.00 mg HC/g TOC characterize the shale beds of the Lokpanta. The regression equation based on the $S_2$ vs. TOC diagram gave an average HI value of 66.5 mg HC/g TOC for the Lokpanta shales (Fig. 5). A plot of $S_2$ vs. TOC and determining the regression equation has been used by Langford and Blanc-Valleron (1990) as the best method for determining the true average HI and measuring the adsorption of hydrocarbons by rock matrix. Peters (1986) has suggested that at a thermal maturity equivalent to vitrinite reflectance of 0.6% ($T_{max}$ 435ºC), rocks with HI above 300 mg HC/g TOC produce oil, those with HI between 300 and 150 produce oil and gas, those with HI less than 50 are inert.

The TOC is a primary parameter in source rock appraisal, with a threshold of 0.5-1 wt% at the immature stage for potential source rocks (Tissot and Welte, 1984; Bordenave *et al*., 1993; Hunt, 1996). The value of 2.18 wt% of the shale studied falls above this threshold. High TOC of 4.45 wt% was obtained in Mamfe basin and this value exceeds the threshold for oil generation (Eseme *et al*., 2006). However, high TOC is not a sufficient condition for oil generation. Coals usually have high TOCs that exceed 50 wt% but do not generate oil except when rich in liptinite, indicating the relevance of maceral composition.

In contrast, deltaic sediments may have TOCs 1 wt% but generate commercial accumulations of petroleum due to deposition of large volumes of sediments, as seen in the Niger Delta. High TOC content in shales indicates favorable conditions for preservation of organic matter produced during deposition. This may related to the redox condition, with high oxygen favoring organic matter oxidation, but also amount of organic matter produced. Shale samples of the Lokpanta in the studied area have $T_{max}$ values in the range of 428 to 442ºC (Table 1). These values correspond to maturity levels within the oil formation zone (Espitalié *et al*., 1984; Ramanampisoa and Radke, 1992; Plumer, 1994; Gries *et al*., 1997). Average $T_{max}$ of 433.5$^{O}$C for the Lokpanta indicates maturity status at the threshold stage.

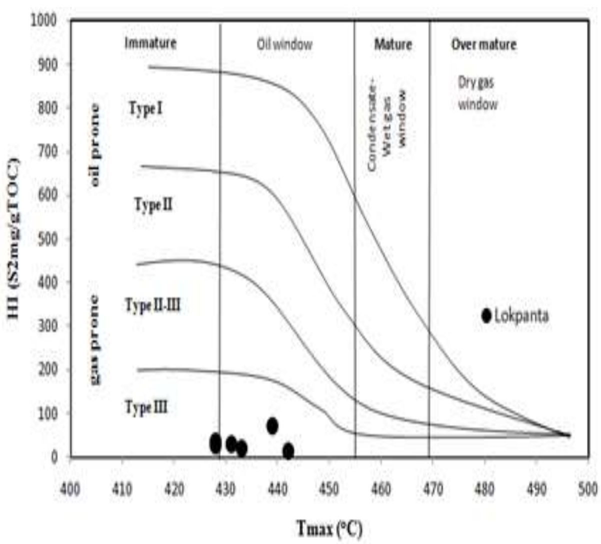


**Fig. 3**: Classification of kerogens of the Lokpanta shales on the HI – Tmax.

The production index (PI) is used to assess the generation status of source rocks but is often useful when homogeneous source rocks of different rank are compared, in which case it is characterized as the transformation ratio (Bordenave *et al*., 1993). Hunt (1996) suggested that a PI from 0.08 to 0.4 is characteristic of source rocks in the oil window. The average value of PI (0.07) of this shale is consistent with its $T_{max}$ (433.5$^{O}$C). This maturity is also consistent with the fairly well fluorescing organic matter as well as Rock Eval $T_{max}$ of 433.5$^{o}$C, reaching the 431-442$^{o}$C for high sulphur mature source rocks containing Type III (Bordenave *et al*., 1993; Hunt, 1996).

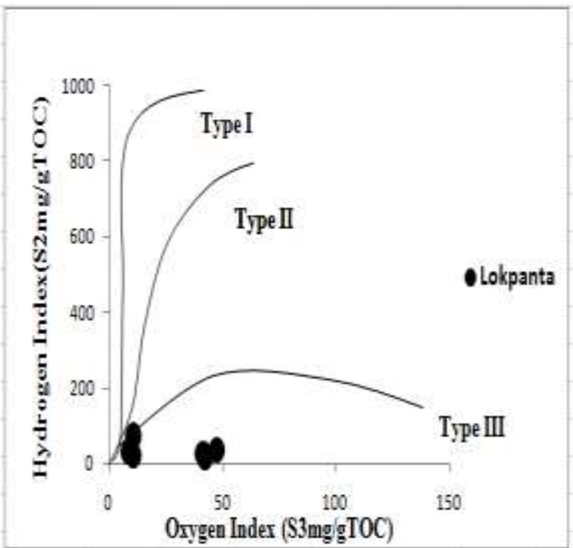


**Fig. 4**: Composite HI – OI classification of kerogen types of source rocks in the Lokpanta shales.

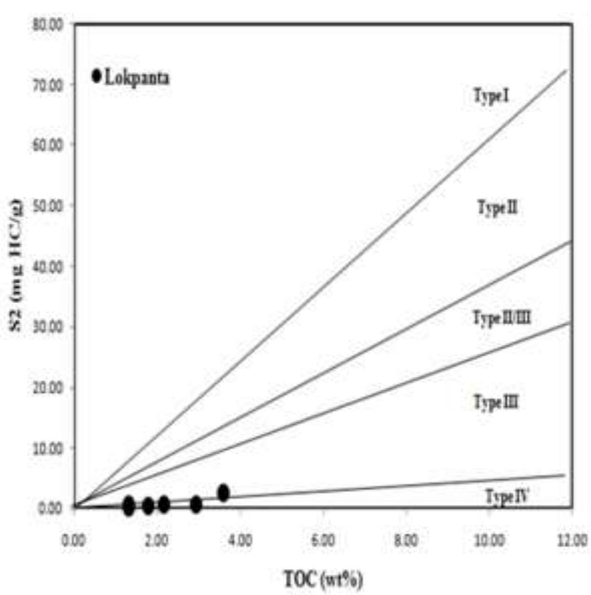


**Fig. 5**: Classification of kerogens of the Lokpanta shales based on the S2 – TOC.

The PI is not affected by expulsion (Rullkötter *et al*., 1988) and this will not limits its use as an indicator of the organic matter transformation because generation may start for rocks with Type II at 0.55%$R_o$ (Leythaeuser *et al*., 1980). Rullkötter *et al*. (1988) used a mass balance scheme to show that, at 0.68% $R_o$, the transformation ratio in the Posidonia shale from northern Germany had reached 30%.

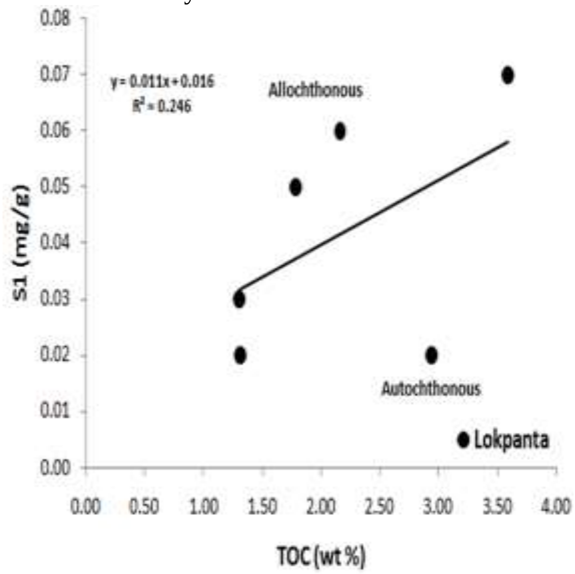


Fig. 6: Diagram of S1/TOC using Lokpanta shales for discriminating betweenm non indigenous and indigenous organic matter.

In Table 1, $S_1$/TOC values are between 0.01 and 0.02 with an average of 0.2. The plot of S1 versus TOC (Fig. 6) can be used to discriminate between non-indigenous organic matter (allochthonous) and indigenous organic matter (autochthonous). The plot shows that the organic matters in the samples were characterized equally by both the allochthonous and autochthonous organic matters. This indicates that some of the organic matters were transported from another location (Uzoegbu and Ikwuagwu, 2016b).

*Biostratigraphy:* Field examination of various lithological type shows that the Nmavu river section of the Lokpanta Shale (type locality) consists of dark-grey to black calcareous alternation of shales and marls which occurs rhythmically. Impressions of *Inoceramus* mould, presence of dwarfed ammonites and concretions which are concordant to the bedding plane characterize the Lokpanta shale. The *Inoceramus* impressions and dwarfed ammonites are the only macrofossils present.

There are eight outcrops along the Nmavu river channel and they consist of a total of fifty three (53) units (25 light-grey marlstones and 28 dark-grey to black calcareous shales) making up to 48m thickness

(Fig. 7). The calcareous shales are generally thicker than the marlstones. The marlstones are 10 -50cm thick units of millimetre scale laminated or platy beds while the shale units with 0.5 – 1.0mm fissile fissility ranged from 0.3 -5.0m thick. The shale units contain calcareous concretions of varying sizes and shapes with diameters ranging from 1.5- 20cm (Fig. 8).

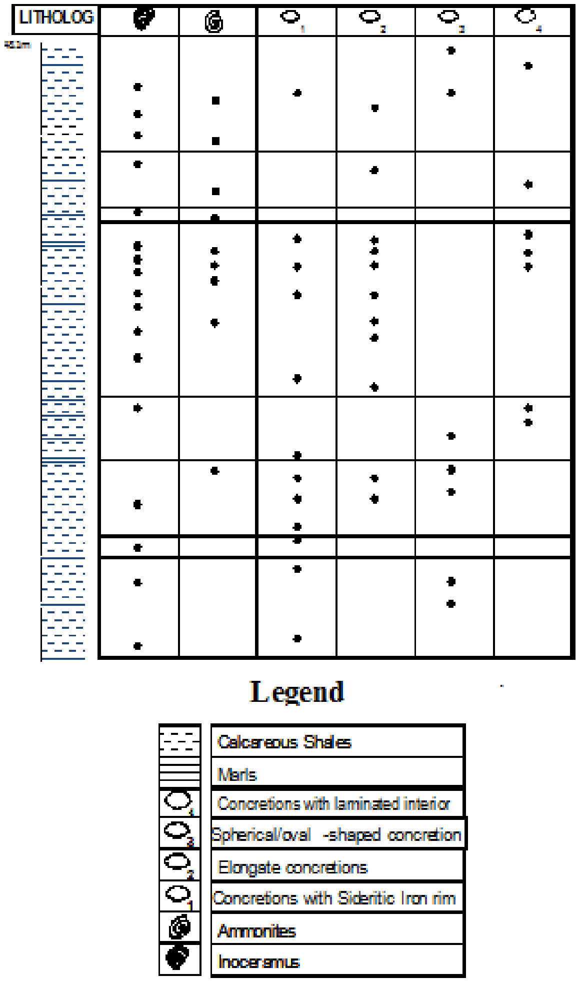


Fig. 7: Composite log of the Lokpanta section

Fig. 8: Concretions embedded in shale unit at Lokpanta.

*Foraminifera:* Samples analysed yielded Foraminiferal assemblages of both benthonic and planktonic forms. The foraminiferal fauna recovered yielded a rich planktonic assemblage with rare benthonics. Planktonic species recovered include *Heterohelix moremani*, *Heterohelix globulosa*, *Hedbergella delrioensis*, *Hedbergella gorbachikae*, *Rugoglobigerina rugosa*, *Globigerinelloids caseyi* etc while the benthonics include *Haplophragmoides sp.*,*Eponides morani*, *Bolivina anambra*, *Gavelinella sp.*,*Bolivina sp* etc (Fig. 9).

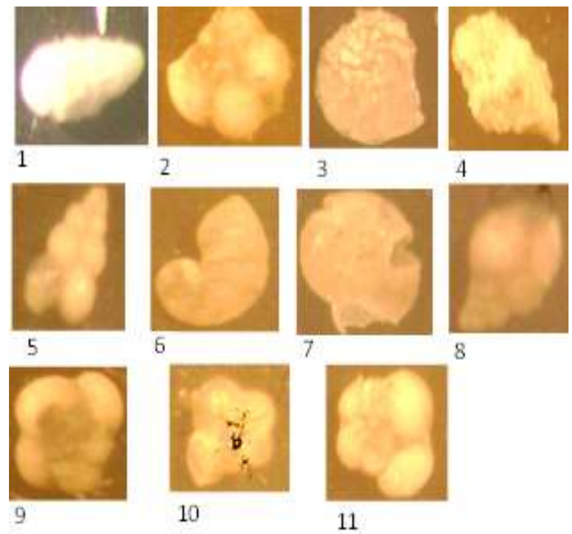


**Fig 9:** Foraminiferal photomicroram of Lokpanta shales as indicated

Key: *1= Bolivia sp; 2 = Hedbergella delreoensis; 3 = avelinella sp; 4 = Bolivina anambra; 5 = Heteroheli globulosa; = Haplophragmoides so; 7= Eporides morani; 8 = Heterohelix moremani; 9 = Rugoglobigerina rugosa, 10 = Globigerinelloides caseyi; 11 = Hedberella gorbachikae*

*Age and Environmental Interpretation:* The Lokpanta shale facies of the Eze-Aku Formation rests unconformably on the Albian sediments of the Asu River Group. Reyment (1965) dated the Eze-Aku shale as Turonian based on diagnostic ammonite fauna, although Petters (1995) has dated parts of the formation as late Cenomanian. Ehinola et al. (2003) recorded that in the Lokpanta shale, there is oil smell in addition to other characteristics of the Lokpanta shale which includes occurrence of *Inoceramus* impressions, dwarfed ammonites etc and also suggested that these characteristics indicate that the Lokpanta shale deposit is a facies of the Eze-Aku Shale. The fact that the Lokpanta shales exhibit high lamination with absence of bioturbation suggests prevalence of anoxic condition in the water column and sediment- water layer (Ehinola et al., 2003). The sediments of the Lokpanta shale (Eze-Aku Group) were deposited during the extensive Cenomanian – Turonian marine transgression. Iwobi (1991) established the Cenomanian stage in the lower parts of the Nkalagu formation based on the co-occurrence of *Rotalipora balernaensis* and *Globigerinelloids caseyi.* Association of *Heterohelix moremani* and *Eouvigerina gracilis* have also been used to date rocks of Cenomanian age in the gulf coast of the United States and Brazil (Darmonian 1975). Foraminiferal index fauna for Cenomanian age such as *Globigerinelloids caseyi* and *Heterohelix moremani* were also recovered from the study area. Ehinola et al., (2003) recorded the recovery of *Heterohelix moremani* and *Eouvigerina gracilis* while dating the mid- Cretaceous shales in the Abakaliki Anticlinorium. Adegbie and Bassey (2007) recorded that species belonging to suborder *Heterohelix* are mainly restricted to Turonian age while Iwobi (1989) recorded that *Whiteinella areheaocretacea* found in association with the bivalve *Inoceramus labiatus* is considered a good maker for early Turonian. The above described planktonic Foraminiferal assemblages suggest a Cenomanian – Turonian age. Samples analyzed contain majority of the foraminiferal fauna assigned sediments as late Cenomanian – early Turonian age.

*Depositional Environment Implication:* The rhythmically interbedding nature of the shale and marlstone units, stratigraphically suggest variation in sediment flux within the basin. The occurrence of dwarfed ammonites and *Inoceramus* impressions suggests low energy marine shelf anoxic depositional setting. In the Lokpanta area, the occurrence of *Heterohelix* and *Hedbergella* indicates a shallow water regime probably between 0 – 50m depth (Wonders 1980). Also, the occurrence of *Inoceramus labiatus* and some ammonites indicate true marine conditions during the deposition of the Lokpanta shale. The lamination of the sediments of the Lokpanta area with no burrows and the occurrence of dominantly planktonic foraminiferal assemblages also indicate a quiet water anoxic marine condition. Petters (1982) among others are of the opinion that *Inoceramus* thrives under low oxygen conditions.

*Conclusion:* In summary, the predominance of terrestrially derived organic matter (Type III kerogen) within the source rock horizons suggests that the Lokpanta region is gas prone. Thermal maturity indicator such as measured $T_{max}$ indicates that the source rocks are thermally mature. There is an equal dominance of allochtonous and autochtonous type III organic matter and high concentration of organic matter in the Cretaceous Lokpanta shales which suggest prevalence of anoxic condition corresponding to the earlier proposed Cretaceous anoxic model in the lower Benue Trough based mainly on foraminiferal content. The finely laminated dark-grey to black shales and marls of the Lokpanta area with the absence of bioturbation and dominance of planktonic Foraminifera with rare benthonics except dwarfed ammonites suggests that these rocks were deposited in anoxic marine environments.

*Acknowledgements:* Gratitude is expressed to all the Staff in the Department of Geology, Michael Okpara University of Agriculture for their advice. Institute for Geosciences and Natural Resources, Geochemistry of Energy Resources and Gas Monitoring, Hannover, Germany is gratefully acknowledged for the analyses of these samples.

## REFERENCE

Adegbie, TA, Bassey, CE (2007). Cretaceous foraminiferal biostratigraphy of Ikono-1 well, Calabar Flank,southeastern Nigeria. *J. Min. Geol.* 43(1): 31-41.

Akande, SO, Hoffnecht, A, Erdtmann, BD (1992). Rank and petrographic composition of selected Upper Cretaceous and Tertiary coals of Southern Nigeria. *Int. J. Coal Geol*. 20: 209-224.

Akande, SO, Erdtmann, BD (1998). Burial metamorphism (thermal maturation) in Cretaceous sediments of the Southern Benue Trough and Anambra Basin, Nigeria. *Ame. Assoc. Petrol. Geol. Bull*. 82(6): 1191-1206.

Akande, SO, Ojo, OJ, Erdtmann, BD, Hetenyi, M (1998). Paleoenvironments, source rock potential and thermal maturity of the Upper Benue rift basins, Nigeria: implications for hydrocarbon exploration. *Org. Geochem*. 29: 531-542.

Akande, SO, Ogunmoyero, IB, Petersen, HI, Nytoft, HP (2007). Source rock evaluation of coals from the Lower Maastrichtian Mamu Formation, SE Nigeria. *J. Petrol. Geol*. 30(4) : 303-324.

Benkhelil, J (1989). The evolution of the Cretaceous Benue Trough, Nigeria. *J. Afr. Earth Sci*. 8: 251-282.

Bordenave, ML, Espitalie, J, Leplat, P, Oudin, JL, Vandenbroucke, M (1993). Screening techniques for source rock evaluation. In: Bordenave, M. L. (Eds.) – Applied Petroleum Geochemistry, Editions Technip, Paris, 217-278.

Carter, JD, Barbar, W, Tait, EA, Jones, GP (1963). The geology of parts of Adamawa, Bauchi and Borno Provinces in northeastern Nigeria. *Geol. Sur. Nig. Bull*. 30: 1-108.

Darmonian, S. A. 1975. Planktonic foraminiferal from the upper Cretaceous of southeastern Iraq: biostratigraphy and systematic of the *Heterohelicidae.* Micropaleontology, 21(22), 185-214.

Dike, EFC (1993). Stratigraphy and structure of the Kerri-Kerri Basin, north-eastern Nigeria. *J. Min. Geol.* 29(2): 77-93.

Ehinola, OA, Bassey, CE, Ekweozor, CM (2003). Preliminary studies on the Lithostratigraphy and depositional environment of the Oil shale deposits of Abakaliki Anticlinorium, southeastern Nigeria. *J. Min. Geol.* 39(2): 85 -94.

Eseme, E, Littke, R, Agyingi, CM (2006). Geochemical characterization of a Cretaceous black shale from Mamfe Basin, Cameroon. *Petrol. Geosci*. 12: 69 – 74.

Espitalié, J, Marquis, F, Barsony, I (1984). Geochemical logging. In: Analytical Pyrolysis – Techniques and Applications, K. J. Voorhees (Ed.) Boston, Butterworth, 276-304.

Gries, RR, Clayton, JL, Leonard, C (1997). Geology, thermal maturation and source rock geochemistry in a volcanic covered basin: San Juan Sag, South Central Colorado. *Amer. Assoc. Petrol. Geol. Bull*. 81: 1133-1160.

Hunt, JM (1979). Petroleum geochemistry and geology. Freeman, San Francisco.

Hunt, JM (1996). Petroleum geochemistry and geology. 2nd Edition, Freeman and Co., New York.

Iwobi, OC (1989). Cretaceous foraminiferal biostratigraphy of the Southern Benue Trough, Unpublished Ph.D dissertation. University of Calabar, Nigeria. 256p.

Iwobi, OC (1991). foraminiferal ages in the Southern Benue Trough, Nigeria. *Nig. Assoc. Petrol. Expl. Bull.* 6: 39-47.

Lafargue, E, Marquis, F, Pillot, D (1998). Rock- Eval 6 applications in hydrocarbon exploration, production, and soil contamination studies. *Renue de L' Inst. Fr. Petrole*, 53(4): 421-437.

Langford, FF, Blanc- Valleron, MM (1990). Interpreting Rock-Eval pyrolysis data using graphs of pyrolyzable hydrocarbons vs Total Organic Carbon. *Ame. Assoc. Petrol. Geol. Bull*. 74(6): 799-804.

Lehner, P, De Ruiter, PAC (1977). Structural history of Atlantic Margin of Africa: *Ame. Assoc. Petrol. Geol. Bull*. 61, p. 961-981

Leythaeuser, D, Hagemann, HW, Hollerbach, A, Schaefer, RG (1980). Hydrocarbon generation in source beds as a function of type and maturation of their organic matter: a mass balance approach. Proc. World Petrol. Congr., 2, Heyden, 31-41.

Mukhopadhyay, PG, Hatcher, PG (1993). Composition of coal. pp. 93-118. In: Law, BE, Rice, DD (Ed.): Hydrocarbons from Coal. *Ame. Assoc. Petrol. Geol.* Stud. Geol. 38.

Obaje, NG (2009). Geology and Mineral Resources of Nigeria. Lecture Notes in Earth Sciences 120, Springer-Verlag Berlin Heidelberg, 57-63

Obaje, NG, Ulu, OK, Petters, SW (1999). Biostratigraphic and geochemical controls of hydrocarbon prospects in the Benue Trough and Anambra Basin, Nigeria. *Nig. Assoc. Petrol. Expl. Bull.* 14(1): 18-54.

Obaje, NG, Hamza, H (2000). Liquid hydrocarbom source-rock potential of mid Cretaceous coals and coal measures in the middle Benue trough of Nigeria. *Int. J. Earth Sci*. 89: 130-139.

Obaje, NG, Wehner, H, Scheeder, G, Abubakar, MB, Jauro, A (2004). Hydrocarbon prospectivity of Nigeria's inland basins: From the viewpoint of organic geochemistry and organic petrology. *Ame. Assoc. Petrol. Geol. Bull*. 87: 325-353.

Ojo, JO, Akande, SO (2002). Petroleum geochemical evolution of the Mid Cretaceous sequence in the Dadiya Syncline, Yola Basin, north eastern, Nigeria. *J. Min. Geol*. 38(1): 35-42.

Pearson, MJ, Obaje, NG (2000). Onocerane and other triterpenoids in Late Cretaceous sediments from the upper Benue trough of Nigeria: tectonic and paleoenvironmental implications. *Org. Geochem.* 30: 582-593.

Peters, KE (1986). Guidelines for evaluating petroleum source rocks using programmed pyrolysis. *Ame. Assoc. Petrol. Geol. Bull* .70: 318-329.

Petters, SW (1982) Central West African Cretaceous-Tertiary Benthic foraminifera and stratigraphy. *Palaeont*. 179A: 1-104.

Petters, SW (1978). Mid-Cretaceous Palaeoenvironments and Biostratigraphy of the Benue trough, Nigeria. *Bull. Geol. Soc. Ame*. 89: 151-155.

Plumer, PhS (1994). Mesozoic source rocks and hydrocarbon potential of the Seychelles offshore. *J. Petrol. Geol*. 17(2): 157-176.

Ramanampisoa, L, Radke, M (1992). Thermal maturity and hydrocarbon generation in rocks from the sedimentary Basins of Madagascars. *J. Petrol. Geol*. 15(4): 379-396.

Reyment, RA (1965). Aspects of the Geology of Nigeria. Ibadan Univ. Press, Ibadan, Nigeria, 145pp.

Rullkötter, J, Leythaeuser, D, Horsfield, B, Littke, R, Mann, U, Müller, PJ, Radke, M, Schaefer, RG, Schenk, HJ, Schwochau, K, Witte, EG, Welte, DH (1988). Organic matter maturation under the influence of a deep intrusive heat source: A natural experiment for quantitation of hydrocarbon generation and expulsion from a petroleum source rock (Toarcia Shale, northern Germany. In: Mattsvelli, L, Novelli, E (Eds.): Advances in Organic Geochemistry, 1987. *Org. Geochem*. 13: 847-856.

Schull, TJ (1998). Rift basins of interior Sudan: petroleum exploration and discovery. *Ame. Assoc. Petrol. Geol. Bull.* 72: 1128-1142.

Taylor, GH, Teichmuller, M, Davis, A, Diessel, CFK, Littke, R, Robert, P (1998). Organic Petrology. Gebruder Borntraeger, 25-502.

Tissot, BP, Welte, DH (1984). Petroleum Formation and Occurrence, 2nd Ed. Springer- Verlag, Berlin, Heidelberg, New York, Tokyo, 699pp.

Uzoegbu, UM, Dike, EFC, Obaje, NG, Uchebo, UA **(**2013). The Unusual microscopic features in coal and characterization of coals from the Anambra basin, Nigeria. *Afr. J. Phy. Sci*. 6(1): 127-142.

Uzoegbu, MU, Ikwuagwu, CS (2016a). Hydrocarbon Generative Potential of Campanian Source Rock from Ihube, Anambra Basin, Nigeria. *Int. J. Geol. Min*. 2(1): 053-063.

Uzoegbu, MU, Ikwuagwu, CS (2016b). Characterization of Organic Matter and Hydrocarbon Potential of Shale from Uturu, Isigwuato, SE Nigeria. *Int. J. Sci. Res. Publ*. 6(9): 754 – 759.

Whiteman, A (1982). Nigeria: Its Petroleum Geology, Resources and Potential. Graham and Trotman, London, 381p.

Wonders, AAH (1980). Middle and late Cretaceous planktonic foraminifera of the Western Mediterranean area, Utrch. *Micropalaeo. Bull*. 24: 1-157.