The Crabs Eye-View of the Organic Sedimentological Evolution of the Anambra Basin Nigeria: Hydrocarbon Source Potential and Economic Implications

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GENERAL STATEMENT

The Vice Chancellor, Deputy Vice-Chancellor, The Registrar of the University of Ibadan, Dean of Science, Dean of Technology, Dean of the Postgraduate School, and other Deans present, Heads of Departments, learned colleagues and fellow students, distinguished ladies and gentlemen, to God be the honor and glory for granting us the grace, privilege and opportunity to witness toady's Faculty Lecture delivered by an earth scientist cum organic geochemist. I appreciate with thanks and deep appreciation the invitation extended to me by the Dean of Science to deliver this Faculty of Science lecture. To the best of my knowledge and since I joined the services of this great university, this is probably the first of such lecture delivered by someone from the Department of Geology.

The direct route is not always the swiftest or indeed the surest route to your destination. This is a fact many exploration geoscientists appreciate. Especially as oil/gas exploration is an expensive business that is played for the highest stakes. Each exploratory well will cost between US$8-10 million or maybe more depending on the area. We must bear in mind that on the average 6 out of 10 of these wells fail to find oil. Therefore, getting a precise hit on a structure that really contains hydrocarbon in a reservoir located ca. 4000 m beneath the earth's surface is geological challenge to rival any.

The unremitting quest for new oil and gas reserves is increasingly important especially as Nigeria's Vision 2010 targets at 50 billion barrels oil reserve base at year 2010. This is partly because we are dealing with finite resource and partly because our economic viability depends upon our success in the search for oil. In order to meet this target about 19 blocks in the Anambra basin has been allocated to various oil prospecting companies. Since the allocation of the concession blocks in the Anambra Basin, oil/gas exploration and prospecting activity has taken a new dimension. This involves locating geological structures in which hydrocarbons may be trapped with the help of satellite photo imagery, diverse geophysical surveys especially seismic and other geophysical techniques.

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Mr. Vice Chancellor, whether these structures if successfully located contain oil, gas, only water, a combination of hydrocarbons and water or absolutely nothing depends on the presence of hydrocarbon source rocks and fluid inventory in the subsurface. This is why I have chosen to speak on the topic: "Crab's eye view of the Organic Sedimentological Evolution of the Anambra Basin: its Hydrocarbon source potential and economic implications". I shall present the organic geochemical and petrographic aspects of my research findings in the Anambra basin and attempt to evaluate the hydrocarbon prospectivity of various stratigraphic horizons from the viewpoint of a crab housed deep inside its dwelling place in the subsurface.

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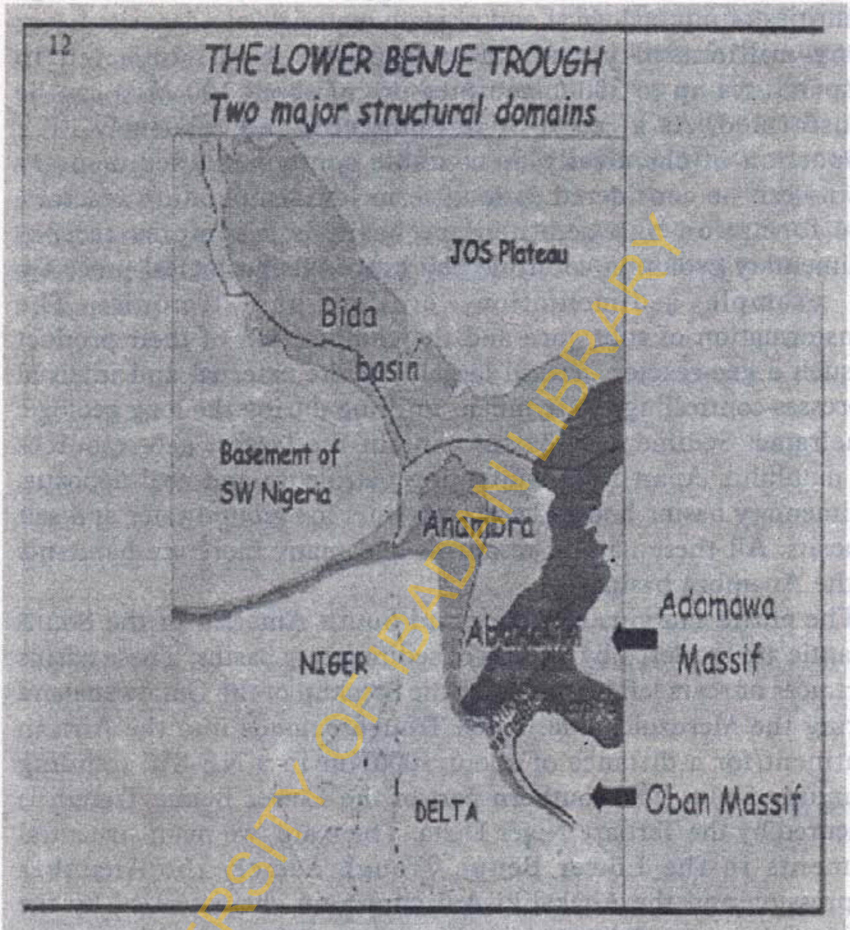

Fig. 1. Lower Benue Trough showing the major structural and geological domains and the location of Aanmbra Basin.

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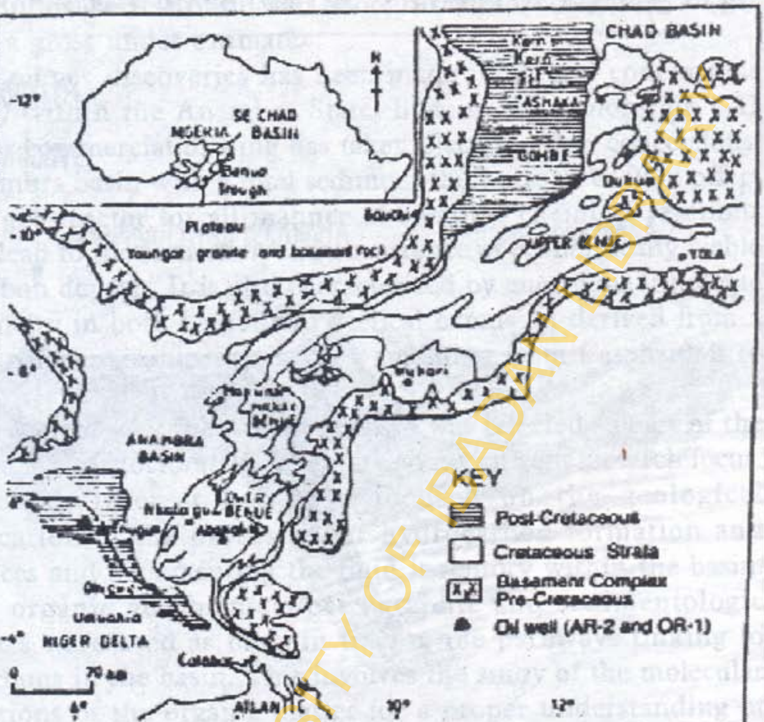

Fig. 1.(a)

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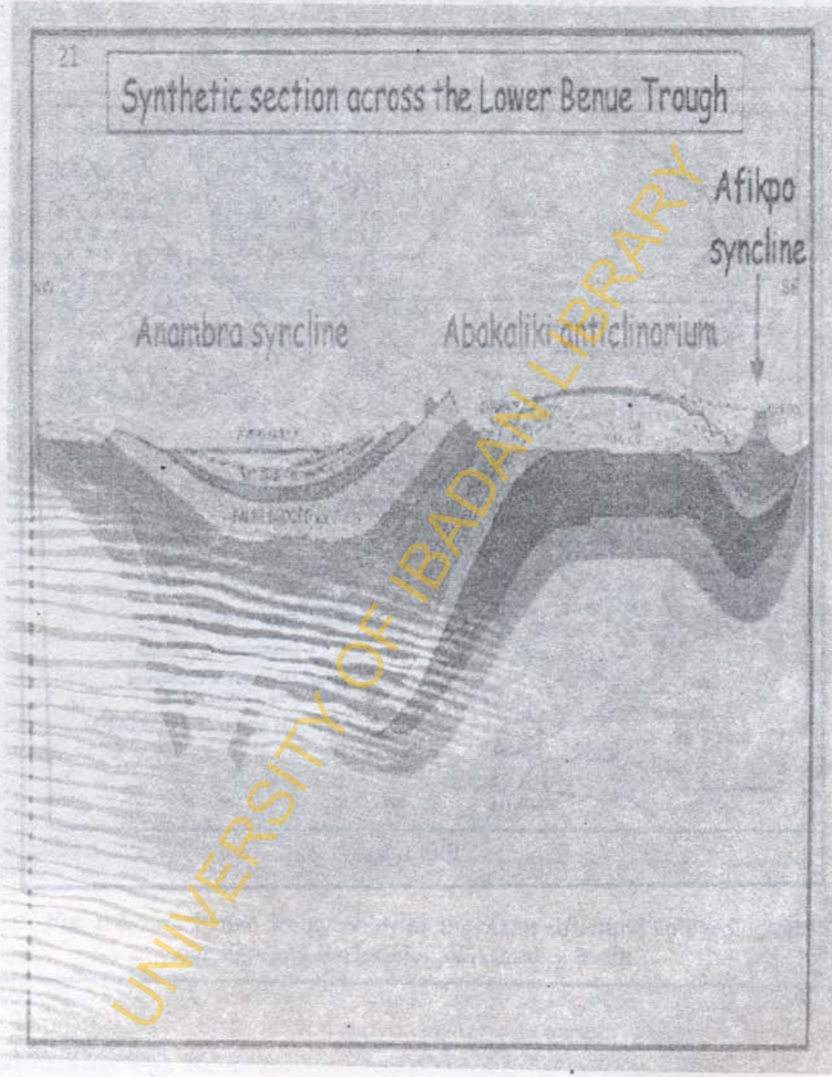

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HCs may be trapped with help of satellite photo imagery, diverse geophysical surveys especially seismic and other geophysical techniques. The Anambra basin is clearly under-explored with only 18 wells drilled in the entire basin to date (2 discoveries) and very scanty, old vintage 2-D seismic information. Based on these facts the hydrocarbon resources in the Anambra basin appraised to be about 1 billion barrels of oil and about 10 trillion cubic feet of gas could be a gross under estimate.

While oil/gas discoveries has been made in several concessions especially within the Anambra State, little or no exploration 3-D seismic or commercial drilling has taken place in other concessions. The Anambra basin with a total sediment thickness of ca 9km offers an ideal geo-reactor for all manner of complex chemical reactions that can lead to the formation and occurrence of economically viable hydrocarbon deposit. It is also characterized by enormous lithologic heterogeneity in both lateral and vertical extension derived from a range of paleoenvironmental setting spanning from Campanian to Recent.

These explain why the Anambra basin was selected as part of the study area for my doctoral dissertation and my current research focus. My research interest has been focused on the geological quantification of the processes for hydrocarbon formation and occurrences and documenting the fluid inventory within the basin. Applied organic geochemical/petrographic and sedimentologic techniques were used as tools in tracing the pathways linking to hydrocarbons in the basin. This involves the study of the molecular compositions of the organic matter for a proper understanding of the processes affecting its distribution and fate in the geosphere. Individual organic biomarkers i.e. compounds with a unique source are employed for the purpose of investigating the origins, and the transformational fairways of the organic matter in a variety of natural environments.

1.1 Geographical Location of the Anambra Basin

The Anambra basin is a structural depression located at the South-western end of the Benue Trough. The basin covers principally the present Anambra State partly extending eastwards into Enugu and Ebonyi States; partly westwards into the present Delta State and partly northwards into the present Benue and Kogi States. However, the most favored areas with respect to potential hydrocarbon prospectivity falls within the present Anambra, Kogi and some parts of Delta States as integrated results of comprehensive organic geochemical and petrographic investigation will reveal.

1.1.1 Geologic Setting

The sedimentation history in the Lower Benue Trough is related to the evolution of the Anambra depression and Abakaliki domain. This evolutionary trend is patterned by an East to West shifting of the depocenters. The initial area of important sedimentation and subsidence was located in the Abakaliki Trough active from Aptian to Santonian. The Anambra basin became an active depocenter after the Santonian tectonic event. Gravity studies reveal appreciable thickness of the pre-Santonian sediments overlying the basement and reconfirm the subdivision of the basin into two sub-basins by the so called "Nsukka High". The sequence of depositional events demonstrates a progressive deepening of the basin, from lower coastal plain and shoreline deltas to shoreline and shallow marine deposits. Coals and other organic rich pelitic materials occur within the Upper Campanian to Lowermost Maastrichtian facies, where they are associated with extensive swamp/flood plain and shoreline deposits. The main feature of the Anambra Basin succession is the lateral facies variations caused either by distance from the shoreline and/or by the rate of subsidence. Good quality reservoirs is expected to occur naturally in such a variable environmental settings e.g. the sheet like deposits of the Ajalli Sandstone which form a blanket over the entire basin.

1.1.2 Stratigraphy and Sedimentological Input

The sedimentary evolution of the Anambra basin can be outlined using subsurface data and correlations could be made along a traverse connecting several wells. The analysis of the Sedimentological characteristics of the deposits shows three main episodes in the basin evolution namely:

I. A pre-Santonian depositional history characterized by a strong subsidence in the Abakaliki domain while the Anambra do-

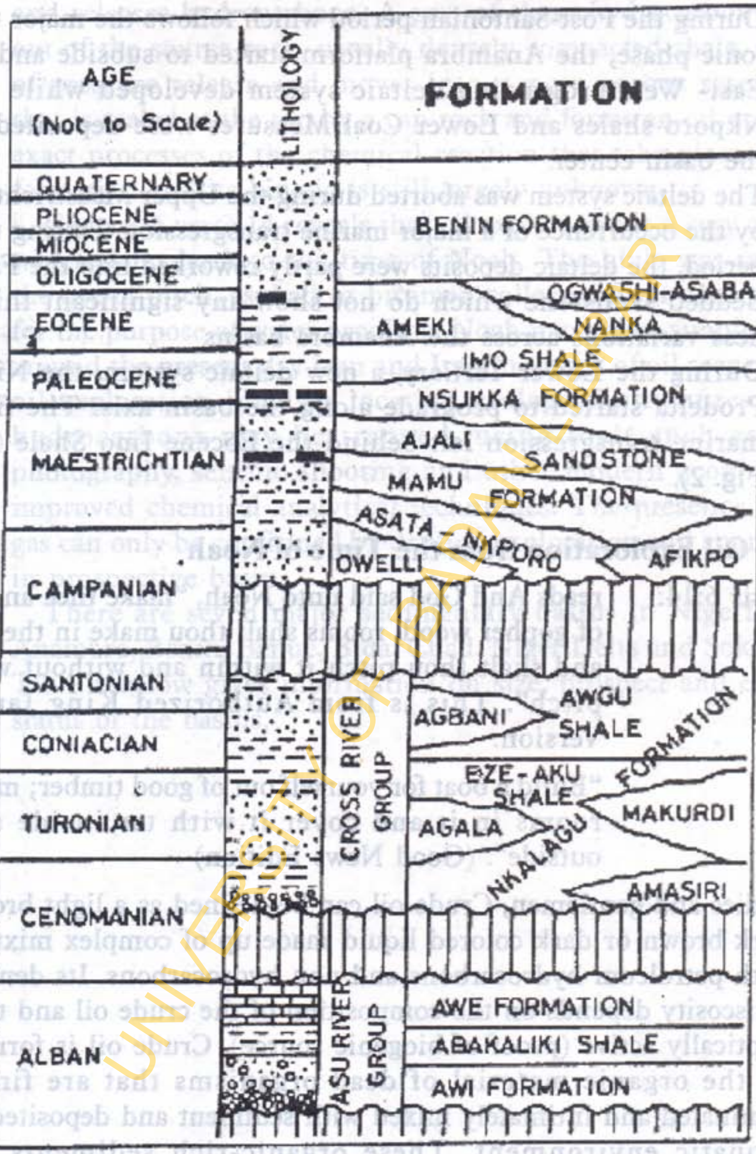

Fig. 2. Stratigraphic and Lithologic Section of Representative of the Anambra Basin.

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main remained a platform where mud was deposited in a shallow marine environment.

II. During the Post-Santonian period which follows the major tectonic phase, the Anambra platform started to subside and an East- West prograding deltaic system developed while the Nkporo shales and Lower Coal Measures were deposited in the basin center.

III. The deltaic system was aborted during the Upper Maastrichtian by the occurrence of a major marine transgression. During this period, the deltaic deposits were partly reworked into the False Bedded sandstone which do not show any significant thickness variations across the Anambra basins

IV. During the Lower Tertiary, a new deltaic system, the Niger Prodelta started to prograde along the basin axis. The final marine transgression left behind the Eocene Imo Shale (see Fig. 2).

1.2 Oil Exploration from the Time of Noah

Genesis 6:14: reads And God said unto Noah, "make thee an ark of gopher wood, rooms shalt thou make in the ark and shalt thou pitch it within and without with pitch". This is from Authorized King James Version.

"Build a boat for yourself out of good timber; make rooms in it and cover it with tar inside and outside". (Good News Edition)

Ladies and gentlemen, Crude oil can be defined as a light brown to dark brown or dark colored liquid made up of complex mixture of both petroleum hydrocarbons and non hydrocarbons. Its density and viscosity depends on the composition of the crude oil and they are optically active (proof of biogenic source). Crude oil is formed from the organic material of dead organisms that are finely disseminated and intimately mixed with sediment and deposited in an aquatic environment. These organic-rich sediments are subsequently covered by new and younger sediments during burial caused by subsidence. Consequently, the organic material gets to a greater depth, whereby it gradually comes under the influence of

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slowly increasing temperature in time frame ranging from a few tens to several hundreds of million years until it finally generates and releases hydrocarbons. A part of these hydrocarbons migrates out of the source rock, usually densely compacted shale, as a result of pressure release and moves into a more porous reservoir rock that is sealed at the top by a cap rock and forms an oil deposit. The exact processes of the chemical reaction that take place during oil formation and its kinetic is still largely unknown.

Genesis 6 verse 14 reveals that oil exploration is a very old pursuit which dates back to the time of Noah. The bible was referring to the use of pitch, asphalt or bitumen collected from natural seepages for the purpose of water proofing. Noah must have simply wandered around the present day Iran and Iraq in search of oil seepages. Today oil exploration involves locating geological structures in which hydrocarbons may be trapped, using tools such as satellite photography, seismic shooting and other modern geophysical and improved chemical analytical techniques. The presence of oil and gas can only be confirmed by drilling exploration and appraisal wells in prospective basin.

There are seven major sedimentary basins in Nigeria namely: Anambra, Benin, Benue, Bida, Chad, Niger Delta and Sokoto basins. Table 1 below gives information on size, prospect and exploration status of the basins.

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Table 1. Exploration status in Nigeria sedimentary Basins

S/No	Basin (Age)	Estimated Reserve and Size of Basin	Potential Reservoir and Trapping Style	Exploration Status	Operators	Remarks
1	Anambra (Cretaceous)	Oil and condensate: 1 billion STB; Gas: over 10 trillion cu.ft. (TCF)	Ajalli Sandstone	Proven oil and 705 billion cu. Ft. of gas from 2 discovery wells. 18 wells drilled to date.	TotalFinaElf	High geothermal gradient 19 blocks
2	Benin or (Dahomey E mbayment) (Cretaceous)	Proven hydrocarbon: 15 million bbls of oil and 1 trillion cu. Ft.of gas.	Mainly stratigraphic with minor structural/fault control.	Interest/scramble by many operators. 1 discovery well in 1996	Yinka Folawiyo (Indegenous operator) backed up by Abachan Resources of Canada	Extends across Nigeria-Benin border to Seme Field. 18 blocks
3.	Benue Trough (Cretaceous)	60,000 sq. km; estimated hydrocarbon volume: 500 million barrels)	Asu River Group	Relatively unexplored. Over 3,000 km of 2-D seismic. Well kolmani-1 spudded mid March by SPDC	ChevronTexaco, TotalFinaElf, and SPDC commenced exploration in 1994 in Gongola sub-basin	Ongoing exploration activity. 29 blocks

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S/No	Basin (Age)	Estimated Reserve and Size of Basin	Potential Reservoir and Trapping Style	Exploration Status	Operators	Remarks
4.	Bida (Cretaceous)	20,000 sq. km.		Relatively unexplored, with large acreage holding established.		18 blocks
5.	Chad (Cretaceous)	35,000 sq. km.	Tight reservoirs	Active exploration. Over 27,000 km of 2-D seismic and 24 wells with marginal shows in well Wadi-1.	NNPC's Frontier Exploration Services (FES)	Improved seismic techniques required for further basin evaluation. 49 blocks
6.	Niger Delta (including the relatively new concessions in Nigerian Deep Offshore)	75,000 sq. km. of basin fill with over 12 km thick sediment at the central part. Recoverable hydrocarbon: over 20 billion	The paralic Agbada formation lying between the base continental and source rock Akata formation.	Mature hydrocarbon province with vast potential still.	57 indigeneous and all major multinational companies including SPDC, ExxonMobil, Chevron	One of the most prolific hydrocarbon provinces in the world. Five major depobelts with afew

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S/No	Basin (Age)	Estimated Reserve and Size of Basin	Potential Reservoir and Trapping Style	Exploration Status	Operators	Remarks
		bbls of oil and 120 trillion			Texaco and TotalFinaElf cu.ft. of gas	major subdivisions. and Agip 164 blocks
7.	Sokoto (Cretaceous)	30,000 sq. km.	Shallow basin with sedimentary thickness between 500 and 1500 m.	Exploration activities by TotalFinaElf and ExxonMobil. Over 120 km of 2-D seismic acquired by TotalFinaElf		

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From the above table, it becomes clear that the Niger Delta is the only mature hydrocarbon province with modern 3-D seismic coverage and over 3,000 wells drilled to date whereas the Anambra basin is under-explored with only 18 wells drilled (2 discoveries) and few old vintage 2-D seismic data available. Based on this fact, the hydrocarbon resources in the Anambra basin listed in the table as 1 billion barrels of oil and 10 trillion cu. ft. of gas could be a gross under estimation.

Between 1952 and 1986 a total of 25 exploration wells, 2 appraisal wells and 8 core drill holes have been drilled in the whole basin by SPDC, TotalFinaElf and Agip Energy. Out of all these wells, oil/gas were proven and tested in one well (Anambra River-1), Gas and condensates were proven in five wells (Anambra River-2, Alo-1, Igbariam-1, Ihandiagu-1 and Amansiodo-1). One well Okpo-1 had substantial oil shows but was abandoned due to technical problems. Three other wells namely Ikpe-1, Nzam-1 and Akukwa-1) recorded some gas shows.

Most of the 2-D seismic data in the basin were acquired by the above mentioned operators. Also, the NNPC seismic crews shot 2-D seismic lines to cover the Benue Trough. During the same period, the Geological Survey Agency of Nigeria also carried out Aeromagnetic and Gravity surveys across the whole of Anambra, Benue and Chad basins. The results are made available to various prospecting companies.

2.0 HYDROCARBON POTENTIAL OF SEDIMENTARY BASIN

It has been generally accepted among petroleum explorationists that there are five principal criteria controlling the formation and occurrence of petroleum in any basin.

I. Presence of sedimentary basin
II. Presence of Source Rock
Maturation
Burial History
Thermal History (Heat Flow)
Hydrocarbon Generation
Migration

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Timing
Routes
Mechanism (Carrier beds)
Remigration

III. Presence of Reservoir Rocks
Lithology
Stratigraphic Position

IV. Presence of Seal (cap) Rocks
Lithology
Stratigraphic Position

V. Presence of Trap
Type
Timing
Deformation

Out of these criteria, my research interest in the Anambra basin covers the aspect that deals with the presence, localization and characterization of oil/gas source rocks. Since oil exploration involves mainly the use of seismic techniques in locating geological structures which may or may not contain hydrocarbons, organic geochemical study on rock samples determines whether or not hydrocarbons are generated and expelled for trapping in the structure.

2.1 Rock Samples and Methods

The rock samples used for most of the studies were ditch cuttings from exploration and appraisal wells located in the Anambra basin (Fig. 3). The samples are retrieved from various depth intervals and they cover all the lithologic units ranging from the Imo Shale through the coal measures to the Nkporo Shale. Other samples were derived from rock outcrops during my numerous field campaigns with the students. The samples are mostly shale, siltstone and coals, lignite, which under binocular microscope and as hand specimens contain dark substances with characteristic odor believed to be bitumen.

In order to characterize the organic matter finely and intimately disseminated in the sedimentary rock, the following organic-geochemical and organic petrologic methods were applied:

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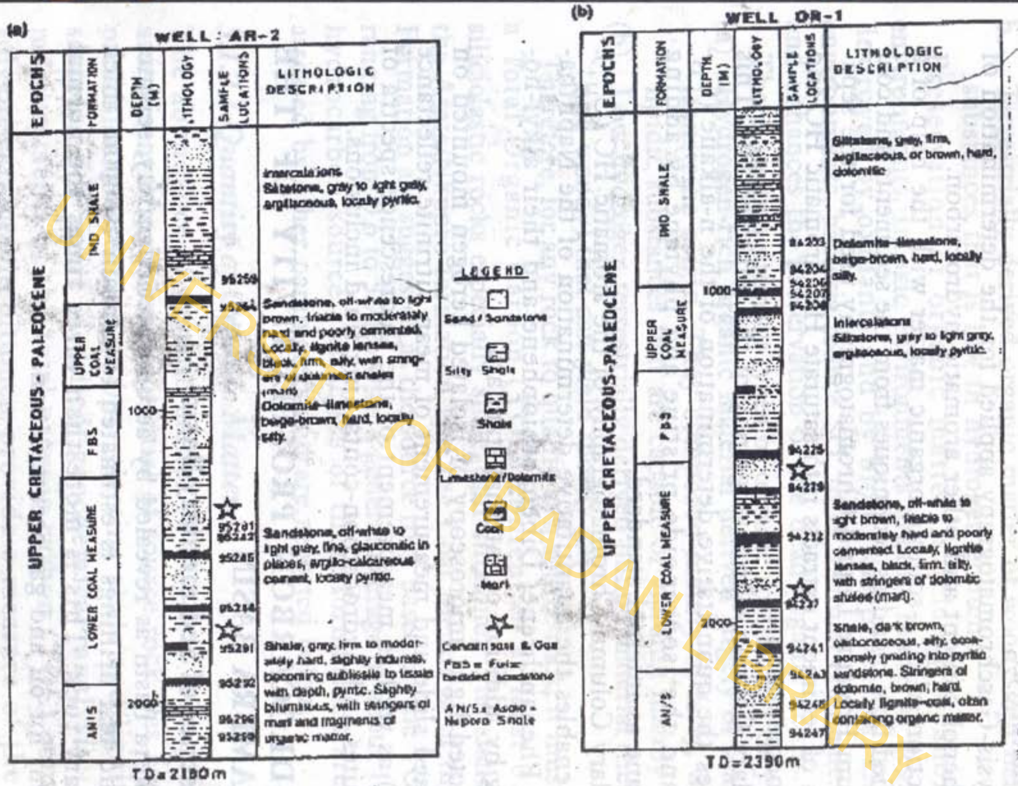

Fig.3. Lithologic Log of the Anambra River – 2 (AR-2) well and Oda River – 1 (OD-1) well.

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- Determination of Total Organic Carbon (TOC) with LECO C/S Analyzer
- Rock-Eval Pyrolysis for the determination of hydrocarbon potential as well as for the assessment of the kerogen type and their maturity.
- Pyrolysis-Gaschromatograpy applied for the determination of the phenol content and other aromatic hydrocarbon.
- Extraction of C_{11+}-soluble organic matter with the help of a modified flow blending techniques from the sediments and coal
- Medium Pressure Liquid Chromatography used for the separation of sediment extracts into saturate HC, aromatic HC and heterocomponents.
- Capillary Column Chromatography of the saturated HC. This enables the quantitative determination of the n-alkane (C_{15}-C_{36}) and the isoprenoide pristine and phytane by adding squalane as internal standard.
- Capillary Column Chromatography of the aromatic HC (C_{11+}). This enables the quantitative determination of the Naphthalene, Phenanthrene, Dibenzothiophene and their alkyl-homolog by addition of internal standard.
- Reflected light microscopy of isolated kerogen mounted on polished slide and measurement of mean vitrinite reflectance (%R_o) as well as measurement of the fluorescence spectra of liptinites and hydrocarbon-containing fluid inclusions.

3.0 HYDROCARBON PROSPECTIVITY OF THE ANAMBRA BASIN

3.1.1 Presence of Sedimentary Basin

The Anambra basin as revealed by aeromagnetic, gravity, seismic surveys and test drillings is estimated to contain >6000m thick sedimentary rock. This is more than three times the normal requirement for oil and gas accumulation.

3.1.2 Presence of Source Rock

The hydrocarbon generating potential of a fine grained source rock depends primarily on: (1) Quantity, (2) Quality or Type and 3) the Maturation state of the organic matter.

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The quantity of the organic matter is controlled by both productivity and preservation. The productivity is from two sources namely:

a. Marine derived organic matter mainly of phytoplanktonic (algae) origin with high hydrogen content.
b. Terrestrially derived organic matter of woody and herbaceous substances that is low in hydrogen content.

Preservation of organic matter is rèlated to anoxic-oxic environments. In oxic environments organic matter is degraded or destroyed by oxidants and by biological processes. In anoxic environments, bacteria reduce SO_4 to H_2S which eliminates oxygen and enhances the preservation of the dead organic debris.

There are two primary types of organic matter and they are:

(a) Hydrogen-rich organic material derived largely of marine and lacustrine origin. They composed mainly of fatty, waxy and lipidic substances that are capable of yielding mainly oil.
(b) Low hydrogen terrestrially derived humic material (herbaceous and woody) that can yield mostly gas.

Therefore, for any rock to qualify as a source rock, it must possess a Total Organic Carbon (TOC) content of at least 0.5% (for siliciclastic rocks especially shale, and siltstone). The shale beds of the Asata/Nkporo formation and the Coal Measures of the Mamu Formation are suggested as the source rock based on the TOC values ranging from 0.6 to 5.71% with a general average of about 1.8%. The hydrocarbon source characters of these formations are further assessed by other parameters and are reported below.

3.1.2.1 Quantity of Organic Matter

The abundance of organic matter (TOC) as a criterion for the assessment of petroleum potential of source rock was applied for preliminary screening and/or selecting shale and lignitic shale samples for more detailed geochemical analysis. Usually measurements of the total organic carbon (TOC) content and solvent-extractable bitumen provide a measure of the organic richness' of rocks and it is expressed in percent weight of the dry rock. The TOC content for the lithostratigraphic column for the well AR-2 generally varies between 0.8% and 4.2% (Table 2) and can be described as moderately to super rich in organic matter. The

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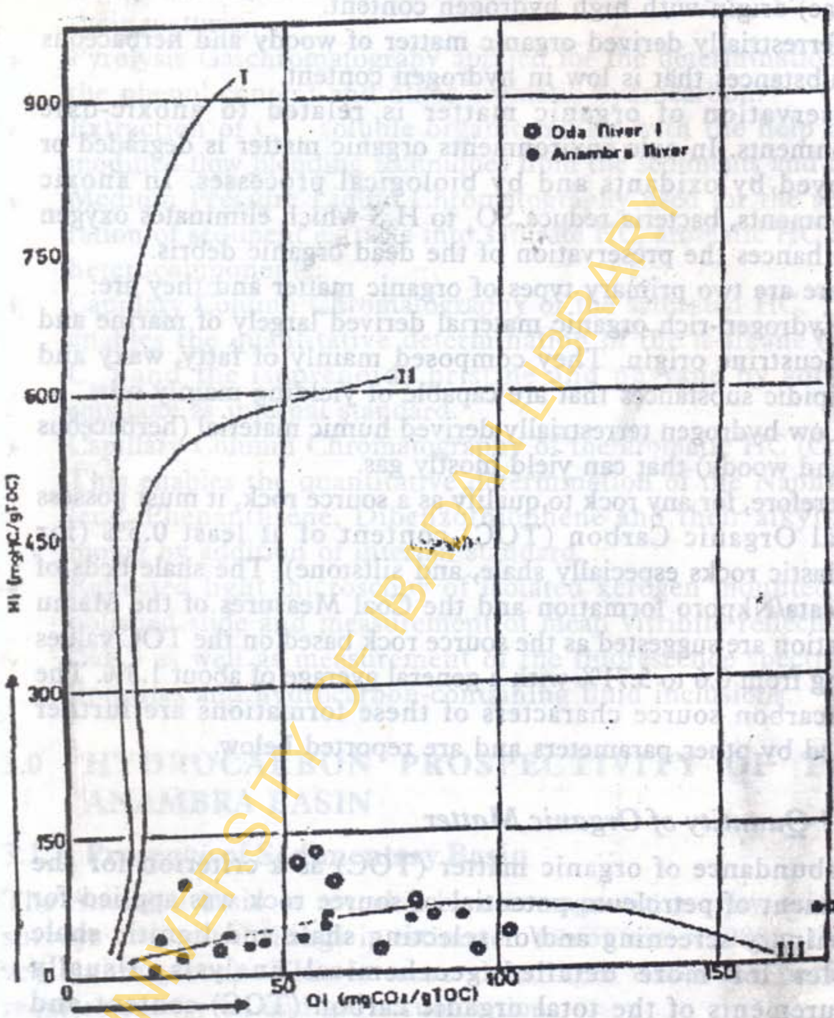

Fig. 4. HI vs. OI Plot showing a relatively higher HI values characterizing richer source rock units of type II/III Organic Matter.

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Nkporo Shale with the highest values of TOC ranging from 1.64 to 3.6% can be classified as very rich. The intercalated lignitic/silty shales and thin coal beds within the coal measures and Ajali Sands/ Sandstones show relatively high values of TOC ranging up to 5.71%. The Imo Shale exhibits the lowest TOC-values between 0.6-1.16% with a correspondingly low values of total sulphur contents (generally<1%) These cuttings samples also contain large abundance of solvent extract generally >500ppm except for a few samples from the Imo Shale and some shale interbeds within Mamu Formation. There is no clear depth trend with the TOC values.

The solvent extract (EOM) shows high values generally.>550ppm. The samples with extremely high values of solvent extract may be associated with migrated oil impregnation or from drilling additives from oil-base mud. This may sometimes lead to falsified over-estimation of the kerogen carbon.

3.1.2.2 Assessment of the Kerogen Character

The kerogen of the Campano-Maastrichtian silty shales, shales and carbonaceous shales within the study basin has been characterized by means of several standard organic geochemical tools including the newly developed infrared technique. The pyrolytic yield (S_1+S_2) of all the Nkporo Shale sample sets (Table 2) and other lignitic shales within the Upper and Lower Coal Measures for both study wells (AR-2 & OR-1) ranges from below detection limits to values <25mgHC/gTOC indicating a moderately good source potential (Peters 1986). The relationship between the hydrogen index (HI) and oxygen index (OI) (Fig.4) reveals Kerogen of type III and mixed type III/II organic matter which are predominantly gas-prone. This Kerogen type with hydrogen index values generally <100mgHC/ gTOC are restricted to the Nkporo shale facies and the overlying lignitic shale interbeds of the Ajali sandstone facies. This observation is common for the samples of the two study wells reflecting no obvious lateral facies variations. Visual. Kerogen analysis reveals that the deeper Nkporo shale are dominated by mainly vitrinitic material (>40%) intimately mixed with liptodetrinitic particles apparently derived from terrestrial plants. The vitrinitric proportions though unclassified are made up mainly of hydrogen-rich Desmocollinite? The mixed kerogen type contain

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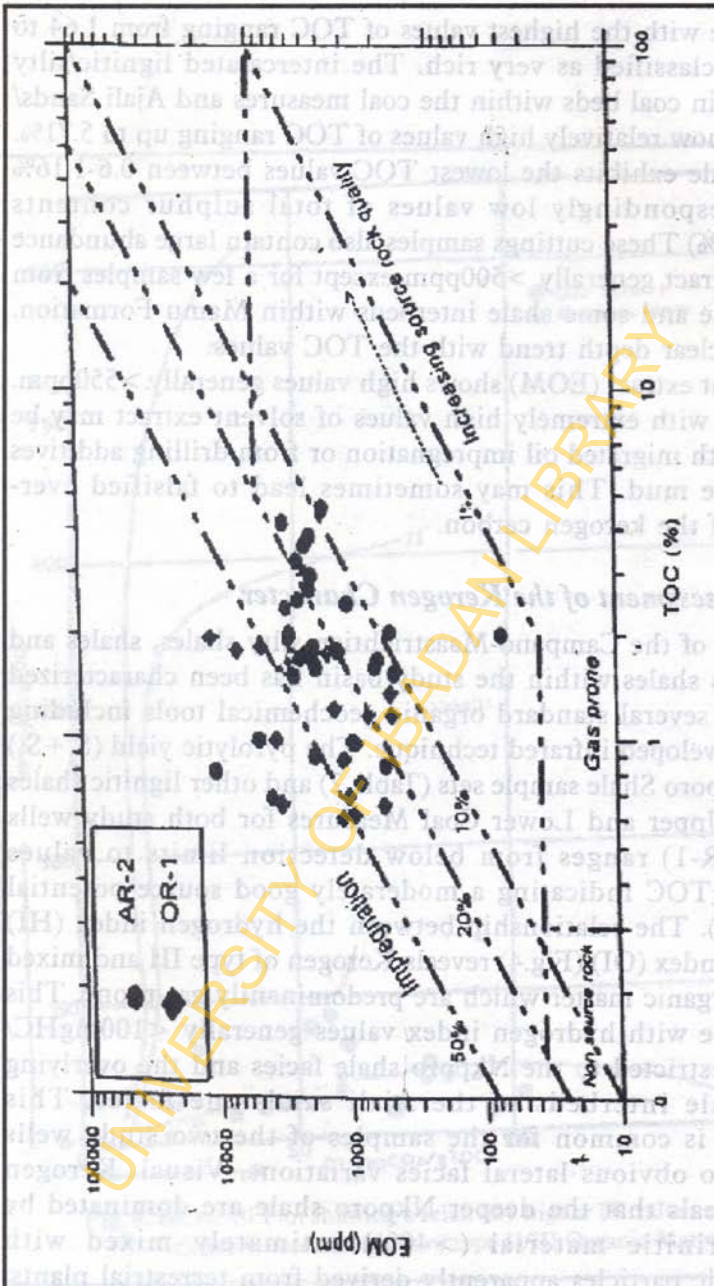

Fig. 5. Cross Plot of the EOM vs. TOC.

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also certain fraction of bacterially reworked terrestrial material which seem to dominate the liptinite fraction

3.1.2.3 Bitumen Content and Characterization

The total bitumen yield of all sample sets representative of the post-Santonian shales display not only a similar pattern but they are also identical with published data from same facies of organic richness and kerogen character. High average extract yield are recorded for the Nkporo shale facies and the respective Coal Measures and carbonaceous shales within the overlying formations. Maximum bitumen yield in excess of 5000ppm were noted for the deeper Nkporo Shale and for the overlying interbeds of coal measures and lignitic shale .Only one sample set from a depth of 2350m in the well OR-1 (Nkporo Shale) and a depth of 625m in the well AR-2 (Upper coal measures) show extremely high values of extract yield in excess of 10864ppm and 10184ppm respectively .The bitumen ratios expressed as mgExt/gTOC indicates that these sample sets are most likely impregnated with either migrating oil or perhaps that the samples were contaminated with oil-base mud. The later reasoning may be valid for the samples from the shallow depth (625m) of the well (AR-2) considering the low TOC value of the silty shale and the present of lower molecular weight n-alkane compounds as observed from the gas chromatogram. However, all the samples for both wells generally display acceptable extract yield that correspond to the TOC values though without a particular trend with depth. Cross plot of EOM against TOC for both study wells (Fig 5) as devised by Hunt (1979) and modified after Le Tran & Philippe (1993) show no significant trend. Most of the sample sets plot within the range of improved oil source rock i.e. between 1 and 50% EOM/TOC ratios. All other samples plotting outside this region with >1000ppm extract yield relative to low TOC-values (<1%) are indicative of oil stain or oil impregnation (Grabowski; 1984; 1994). A typical gas chromatogram of the saturate fraction from the solvent extract is shown in Fig. 6. The chromatogram displays a typical bimodal n-alkane distribution within the range of C_{15}-C_{34} and maximizing at C-17 and C-35 suggesting organic matter input from both marine and terrestrial sources .The of a relatively high concentration of high molecular weight alkanes implies organic matter contribution

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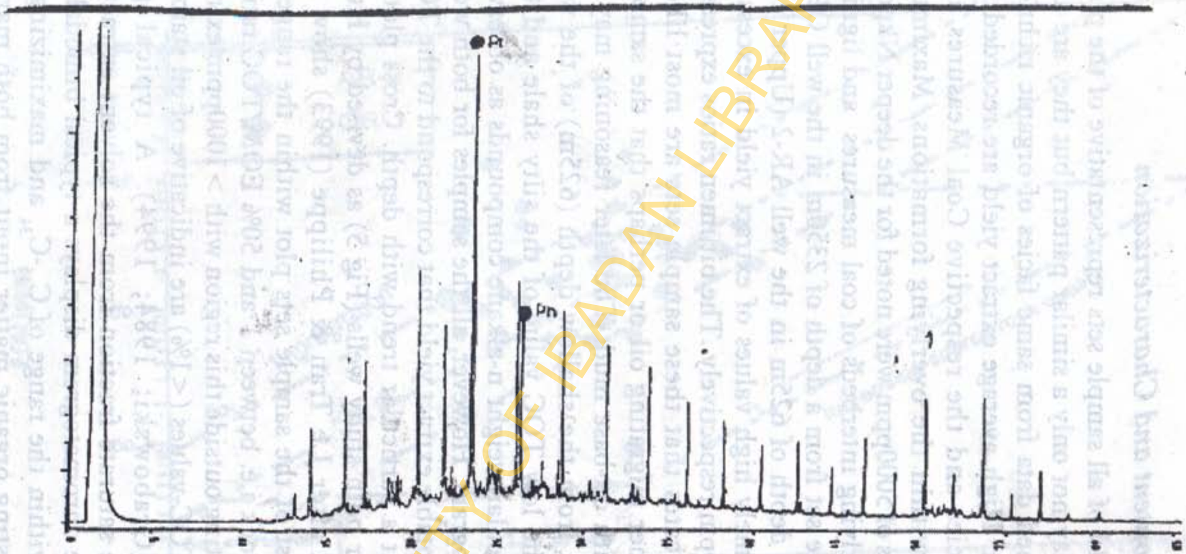

Fig. 6. Typical Gas Chromatogram of the Saturate showing bimodal n-alkane distribution with the range C15-C34.

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from predominantly terrestrial plants. The n-alkane in the higher range (C_{25}-C_{31}) show a significant odd to even carbon number preference expressed as CPI (value range from 0.99-3.16) for all sample and there is no trend with depth. The CPI data, Pr/Ph, Pr/n-C_{17} and Ph/n-C_{18} ratios correspond well with published geochemical data (Akaegbobi, 1995; Ekweozor & Gormly; 1983; Hagemann & Pickel 1991). Since there is no definite depth trend with these bulk geochemical parameters (especially Pr/Ph-ratios) for OR-1 and AR-2, it may be inferred that they are not related to different grades of maturity. The relatively high Pr/Ph ratio of >3.0, a Pr/n-C_{17} and Ph/n-C_{18} ratios of >1.2 and >1.0 respectively implies deposition in a less reducing environmental condition, where low pH, moderate oxygen content and the presence of complex mixtures of toxic humic substances and phenol is most likely to obscure active aerobic degradation of organic material.

Biomarker distribution for a selected sample sets, mainly from Nkporo Shale, based on the mass chromatogram (m/z 217) display higher relative concentration of C_{29} regular sterane (>50%) over their C_{27} and C_{28} counterparts (Fig. 7) confirming the predominance of terrestrial plants as organic source material. Only unusual trace amounts of the triterpanes that could not be correctly quantified from the mass chromatogram (m/z 191) were observed for the rock extract of the Nkporo Shales due to a very poor signal-to-noise ratio. It was, therefore not possible to determine the relative proportions of the sterane and hopane components which if corrected could have served as an additional maturity assessment tool.

3.1.2.4 C_{11+} Aromatic Hydrocarbons

The quantitative generation of polycyclic aromatic hydrocarbons was carried out for selected samples. This methodic approach was based on the fact that the concentration of aromatic hydrocarbons in sediment extracts increase with increasing maturity of the source rock in response to thermal effects. The quantification of the individual aromatic compounds was accomplished by using several internal standards; the results are summarized in the Tables 3 and 4. Data interpretation was limited to the temperature sensitive aromatic groups of naphthalene, phenanthrene and their alkyl homolog.

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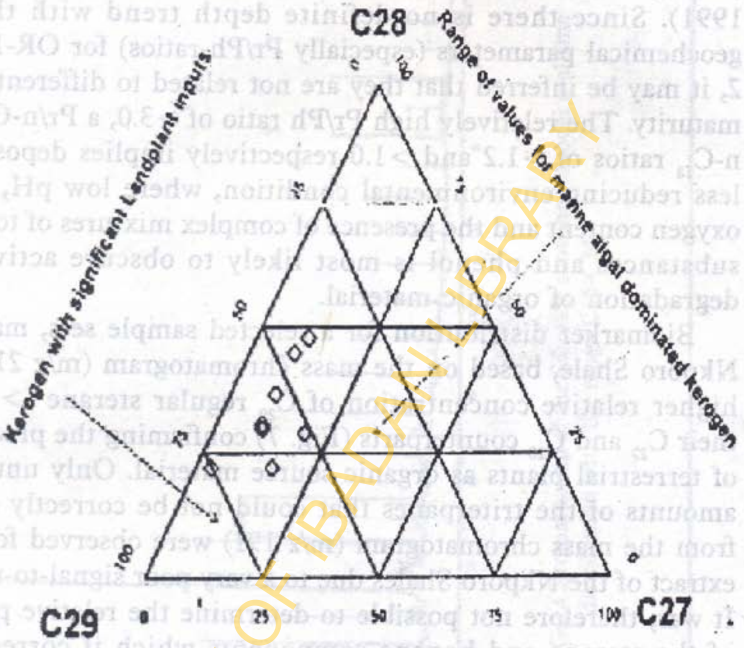

Fig. 7. C_{27}, C_{28}, C_{29} Ternary Diagram.

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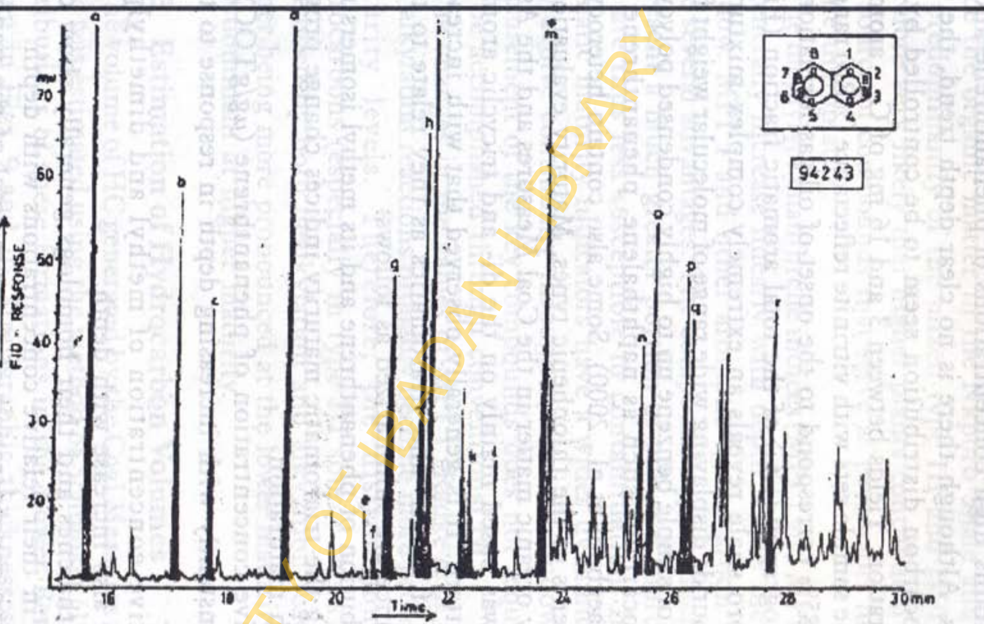

Identification of peaks:

a.	1-Phenylhexane	j.	1,4- + 2,3-Dimethylnaphthalene
b.	2-Methylnaphthalene	k.	1,5-Dimethylnaphthalene
c.	1-Methylnaphthalene	l.	1,2-Dimethylnaphthalene
d.	1-Phenylheptane	m.	1,8-Dimethylnaphthalene
e.	2-Ethylnaphthalene	n.	1,3,7-Trimethylnaphthalene
f.	1-Ethylnaphthalene	o.	1,3,6-Trimethylnaphthalene
g.	2,6- + 2,7-Dimethylnaphthalene	p.	1,3,5-Trimethylnaphthalene
h.	1,3- + 1,7-Dimethylnaphthalene	q.	2,3,6-Trimethylnaphthalene
i.	1,6-Dimethylnaphthalene	r.	1,2,5-Trimethylnaphthalene

Fig. 8. Gas chromatogram of the Aromatic fraction from a depth of 2300m in the ODA-1 well.

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The rock and coal extracts contain relatively high amounts of aromatic components Table 3. Naphthalene and its methylated homologs seem to be the largest individual component in the extracts which also contains high concentrations of phenanthrene and its methyl isomers. Although there is no clear depth trend, the C_{11+} aromatic hydrocarbon distribution seem to be controlled by the degree of maturation. Yields between 3 and 16 mg of C_{11+} aromatic HC/gTOC in the sample sets with vitrinite reflectance (%Ro) ranging from 0.51 to 0.85% correspond to the onset of oil/gas formation.

Gas chromatography (GC) of the total aromatic fraction (Fig.8) from the Nkporo shale reveals an extremely complex mixture of aromatic compounds displaying wide range of molecular weight from alkyl homologs of simple benzene up to highly condensed polycyclic aromatic hydrocarbons such as naphthalene, phenanthrene and anthracene (Akaegbobi et al., 2000). Some also contain heterocyclic structural elements of the thiophenic types. Maturity evaluation of the sedimentary organic matter in the Coal Measures and the Asata-Nkporo shale was based mainly on the di- and tricyclic aromatic distribution pattern. It is generally observed that with increasing depth features of the di- and triaromatics as they relate to their relative abundance are summarized as follows:

- The distribution of phenanthrene and its methyl isomers used in defining the triaromatic maturity indices change progressively with maturation.
- The relative concentration of phenanthrene (μg/gTOC) increases constantly with increasing depth in response to thermal stress.
- The relative concentration of methyl and dimethylphenanthrene also increase with depth.
- The naphthalenes and their homologs generally show clear variations in their relative concentrations with depth.
- The relative concentration of the sum total of the naphthalenes and its isomers is greater than that of the phenanthrenes.

The relative abundance of individual aromatic ring classes in the total aromatic fractions seems to be maturity/temperature controlled. The increase in the relative abundance of dimethylnaphthalene at higher rank can be attributed to thermal re-arrangement of 1-methylnaphthalene due to increasing thermal stress. Apparently

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the higher abundances of dimethyl and trimethylnaphthalene relative to phenanthrenes can be attributed to selective expulsion mechanism. A migration effect as a possible cause of the relatively low concentrations of phenanthrenes may not be generally accepted. Since the organic matter in the Nkporo Shale and Coal Measures are predominantly of the mixed type III and III/II kerogen, it is therefore very likely that higher plants contributed significantly to the source of compounds that serve as precursors for these isomers of the diaromatics.

The methylyphenanthrene indices (MPI 1 and MPI 2) are observed to generally increase linearly with depth within the zone of the oil window. MPI 1 and other aromatic hydrocarbon maturity ratios have several advantages. The compounds upon which they are based represent a much greater portion of oils and source rock extracts and are thus less susceptible to contamination. In addition, the aromatic maturity indicators have a wider dynamic range because they evolve continually throughout the oil window. Furthermore, measurement of the key compounds does not require GC-MS but can be accomplished through conventional GC.

The changes in the values of MPI 1 (Radke *et al.*, 1982a) suggest that alkylation reactions probably become more prominent at higher maturity levels. Therefore, the distribution of aromatic hydrocarbons (especially in type III source rocks) is most likely controlled by both dealkylation and alkylation reactions with the former being more pronounced at the lower maturity levels and the later dominant at higher maturity.

3.1.3 Estimation of Hydrocarbon Volumes

The volume of HC generated by the Coal Measures and the Nkporo shale was estimated using the method of Schmoker (1994). The aerial distributions of these formations in the Lower Benue Trough are shown in Figs. 9 and 10. Stratigraphic thicknesses were obtained from study wells and rock outcrops. An average measured TOC of 2.2 wt % and shale density of 2.6 g/cm^3 were assumed for the Nkporo shale. The net thickness of the mature Nkporo is 480 m over an area of 300 km^2. The effective source rock volume is 144 km^3. Therefore, the total mass (M) of organic carbon (in gTOC) is given by M (gTOC) = 2.2/100x2.6x144x10^{15} cm^3 which is equal to 8.24x10^{15} g.

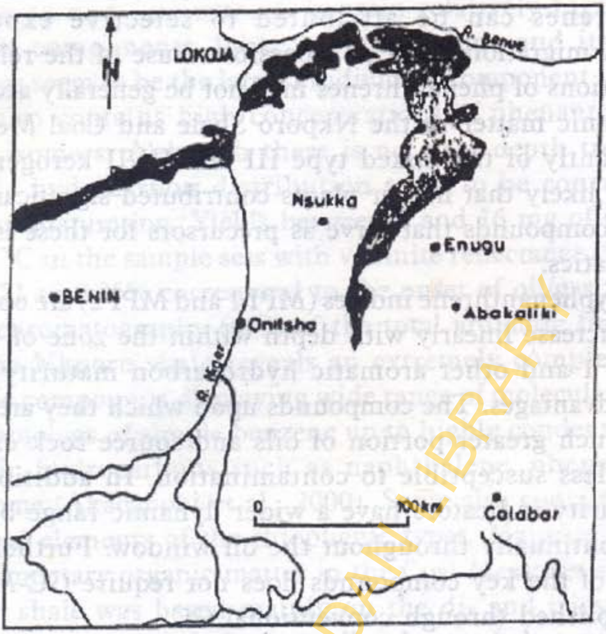

Fig. 9. Areal Distribution of the Asata-Nkporo Shale (Anambra Basin).

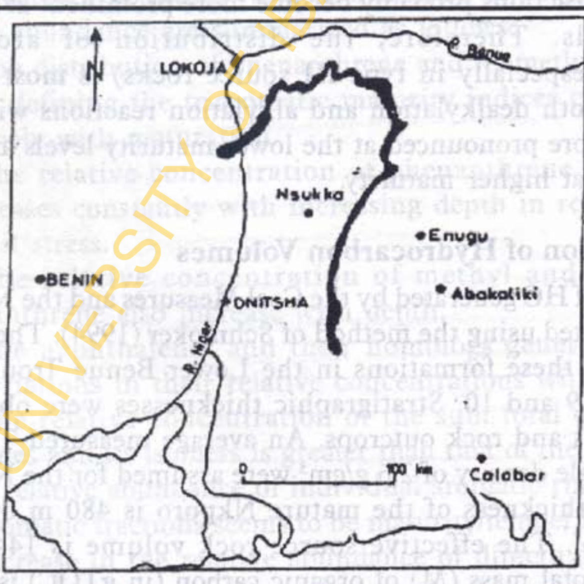

Fig. 10. Areal Distribution of the Lower Coal Measures (Mamu Formation) Anambra Basin.

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The average present hydrogen index (HIp) is 24 mgHC/gTOC at 0.81% Ro, whereas the initial hydrogen index (HIo) for the immature type III Nkporo Shale is 126 mgHC/gTOC (Unomah and Ekweozor, 1993). The difference between HIp and HIo approximates the mass of hydrocarbon (Q) generated per gram of TOC. Therefore, the total mass of hydrocarbon generated is the product of M and Q or 8.4×10^{11} kg HC. This is equivalent to 6300 million barrels of 30° API oil or 4.1×10^{13} cu ft of gas.

Similar calculation for the Lower Coal Measures (Mamu Formation) was carried out using the following data set: Net source rock thickness (including coals) = 581.25 m; Total Area of formation = 78 km^2; net source rock volume = 45.32 km^3; average TOC of shale and coal = 2.7 wt %; average Hip = 64 mgHC/gTOC; and average HIo = 126 mgHC/gTOC. Therefore, the total mass of HC generated is 1.98×10^{11} kg HC which gives a volume of 1490 million barrels of oil or 9.8×10^{12} cu. ft. of methane gas. Therefore, the total volume of oil generated by the Nkporo shale and Coal Measures is 7790 million barrels of oil or 5.08×10^{23} cu. ft. of gas.

This volume of oil by far exceeds the threshold value of 50 million barrels required for expulsion of oil (Macgregor, 1994). Expulsion efficiency is a function of source rock richness and varies greatly, being higher for gas prone than oil prone source rock. Assuming 10% expulsion efficiency for oil and 90% for gas, a total of 779 million bbl of 30° API oil or 4.75×10^{13} cu. ft. gas may have been expelled from the Nkporo shale and the Coal Measures (Mamu Formation) and probably entrapped in the basin. This may account for the hydrocarbon shows in early exploratory drilling in the basin.

3.1.4 Presence of Reservoir Rocks

A reservoir rock is one, which has enough pore spaces to accommodate fluids like water, oil gas or a combination of any two or all of them. The pore spaces should also be interconnected enough to allow some migration of the fluid for easy production. The quality of the reservoir rock is determined by the value of the porosity and permeability.

The Ajali sandstone and/or Owelli sandstone are the potential reservoirs in the Anambra basin. The porosity values of these

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sandstones range from 15 – 35%. These are also comparable to those of the reservoir sands of the neighboring Tertiary Niger delta.

3.1.5 Presence of Traps/Seal (Cap) Rocks

Oil seeps are associated with the Santonian unconformity exposed on the southeastern side of the Anambra basin. These may well be charged by accumulations down dip. Most of these seeps are found in younger rocks. It is not possible to say exactly how deep the Santonian unconformity may lie beneath the central part of the Anambra basin. Therefore, the play type is sub unconformity prolongation of the Benue-Abakaliki fold belts. Trapping styles may be anticlinal structure, fault related, unconformity and combination. There are positive surface and subsurface shows.

4.0 CONCLUSION

Petroleum Systems

From the foregoing discussion, a petroleum system can be defined as the "Oil and Gas machine" that generates and concentrates hydrocarbons within a basin over time. It is made up of two subsystems namely:

- Generative subsystem defined by source rock and oil characteristics
- Migration-entrapment subsystem defined by timing of generation, type of drainage (lateral or vertical) and trapping mechanism.

On the basis of available organic geochemical and organic petrographic data in the Anambra basin, only one petroleum system has been recognized. This is described as the Upper Cretaceous-Lower Paleocene Petroleum System. The inferred regional extent of the Upper Cretaceous-Lower Paleocene petroleum system is schematically illustrated in the diagram (Fig. 11). The system consists of type II and III/II oil prone kerogen and includes the post-Santonian Nkporo shale and all the carbonaceous shale and coal measures in the Mamu formation.

In conclusion the sedimentary rocks of the Anambra basin are quite similar in character to those of the Niger Delta. Although the Anambra Basin (Upper Cretaceous) is older than the Niger Delta

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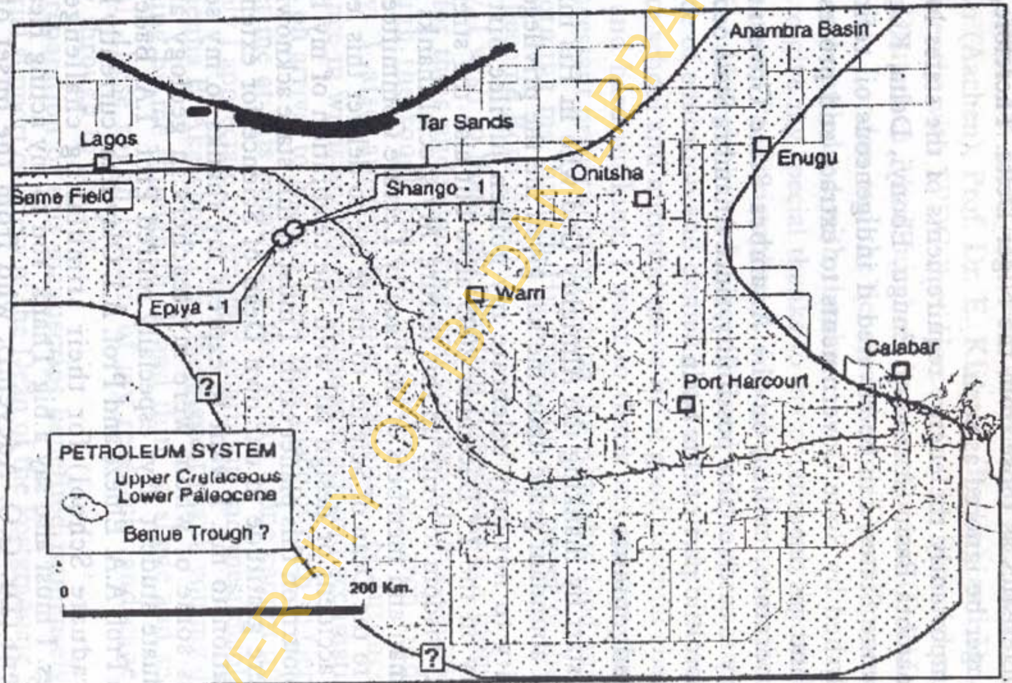

Fig. 11. Map showing Upper Cretaceous to Lower Paleocene Petroleum System.

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(Tertiary) their source rock quality are similar (Types II and III/II). Before now, the Anambra basin had not been attractive due to its distance from the coast and lack of other logistic infra-structures. The oil and gas pools in the Anambra basin have the same quality and characteristics as those from the Niger Delta. Therefore, they can no longer be ignored as such.

Most importantly the energy requirements of the states located on the Anambra Basin (Anambra, Enugu, Ebonyi, Delta, Kogi and part of Benue States) can be covered if indigeneous oil refineries are established by State Governments to extract and process the crude oil and gas deposits.

I am therefore, calling on the Anambra State Government particularly to catch on this possibility, since Anambra State occupies the most prolific part of this basin.

Acknowledgements

I want to start by thanking the Almighty God who in His infinite mercy and abundant grace upon me has given me the privilege and opportunity to not only celebrate my golden jubilee birthday anniversary on the 2nd December 2005 alive but also the strength, energy and wisdom to write up this lecture. My special thanks go to the Chairman and members of the Faculty Lecture Committee who suggested to the Dean of Science to invite me to deliver this lecture which by accident or design fall with the celebration of my half a century sojourn on this planet earth. I must at this stage acknowledge with sincere gratitude to our own Dean of Science for extending this invitation to me. I want to express my thanks to my senior colleagues some of whom were my teachers in geology at my undergraduate student days especially retired Prof. T.A. Badejoko, still active Prof. A.A. Elueze and Prof. A.I. Olayinka (currently Dean of Postgraduate School) for their stimulating challenges in geosciences. I must also say a big Thank You to my acting Head of Department (Dr. G.O. Adeyemi), who from the onset of the preparation for this lecture was a source of constructive advice and encouragement. I acknowledge all my other colleagues both academic and non teaching staff that has contributed to the advancement of knowledge.

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I wish to express my profound gratitude to my teachers at various universities in the Federal Republic of Germany for putting me through the rudiments of organic geochemistry and coal petrography especially Prof. Dr. D.H. Welte (Aachen), Prof. Dr. Roland Walter (Aachen), Prof. Dr. (Mrs.) M. Wolf (Aachen) Prof. Dr-Ing. H.W. Hagemann (Aachen), Prof. Dr. E. Klitzsch (Berlin), and Dr. H.H. Ganz (presently with SPDC Port Harcourt). The financial support from the Deutschen Akademischen Austauschdienst (DAAD), the Royal Society London and the Senate Research Grant University of Ibadan is acknowledged with thanks.

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Biography

Dr. Izuchukwu Mike Akaegbobi is a senior lecturer in Petroleum/ Coal Geology, Organic Geochemistry and Sedimentology at the University of Ibadan. He has taught courses in Petroleum Geology, Organic Geochemistry, Sedimentology and Stratigraphy at both postgraduate and undergraduate levels for more than ten years. His research interest focuses on applied Sedimentological and organic geochemical studies of organic matter in fine grained sediments and coals derived from a wide range of paleo-environment systems of the Lower Benue Trough and Niger Delta. His experiences include several years as consultant and training advisor to industry and government agencies.

Dr. Akaegbobi worked for Shell Petroleum Development Company Ltd. (SPDC) Port Harcourt as a Seismic Interpreter during his sabbatical year (2001-2002). He also successfully completed short research visits to University of Jena in Germany (DAAD Fellowship) and University of Aberdeen in Scotland (Royal Society Fellowship). Dr. Akaegbobi holds a B.Sc. degree with honors from the University of Ibadan (1979) and Diplom-Geologe (M.Sc) in Petroleum Sedimentology from the Technical University, Aachen, Germany (1989). He received doctorate degree in Petroleum Geochemistry from the Technical University Berlin, Federal Republic of Germany (1995). He is a member of several learned professional societies such as AAPG, NAPE etc where he has served on a number committee. Dr. Akaegbobi has published papers on petroleum geochemistry, sedimentology, and petrography in international journals. One of his papers on organic facies won the first prize of the 1996 NAPE/ TEXACO Best Paper Award.

Dr. Akaegbobi is married to Mrs. Uchenna B. Akaegbobi with three lovely daughters.

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Table 2. Rock-Eval Pyrolytic Data for study wells in Anambra Basin								
Sample No.	Depth (m)	Lithology	TOC (%)	HI	OI	PI	Tmax (°C)	Ro (%)
94203	850	Shale	1.61	9	22	0.07	430	0.56
94204	900	Shale	1.2	10	35	0.07	427	0.61
94206	960	Shale	1.16	12	45	0.06	425	0.51
94207	1000	Coal	2.68	22	58	0.06	424	0.65
94208	1020	Coal	3.28	51	78	0.09	430	0.75
94225	1500	Coal	0.98	54	91	0.1	430	
94229	1600	Coal	1.78	57	65	0.08	430	0.6
94232	1750	Coal	3.91	99	32	0.07	431	0.65
94237	2000	Coal	1.92	50	180	0.12	440	
94241	2200	Coaly Shale	1.74	29	25	0.17	447	0.73
94243	2300	Bit.Shale	2.17	23	45	0.1	434	0.81
94245	2385	Bit.Shale	1.78	27	63	0.12	442	
94247	2390	Bit.Shale	2.02	29	44	0.16	441	0.79
95259	560	Shale	1.51	35	107	0.07	426	0.5
95264	620	Coaly Shale	2.77	40	263	0.03	443	0.73
95281	1550	Coal	4.17	99	54	0.04	443	0.74
95282	1555	Coal	4.71	114	57	0.05	440	0.79
95285	1600	Coal	3.81	88	64	0.04	437	0.8
95288	1750	Coal	2.94	42	77	0.07	438	
95291	1890	Coal	1.67	19	89	0.03	450	0.75
95292	1900	Coal	2.5	50	72	0.08	437	0.82
95296	2055	Bit.Shale	1.83	24	78	0.08	471	0.85
95299	2130	Bit.Shale	3.6	18	34	0.17	442	
95300	2145	Bit.Shale	2.02	15	76	0.06	444	0.83

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Table 3. TOC and Bitumen Extract Yield							
Sample No.	Depth (m)	TOC (%)	Extract Yield (ppm)	Bit. Ratio (mgExt/gTOC) (%)	Saturates (%)	Aromatics (%)	NSO
94203	850	1.61	379	24	21.5	5.8	56.1
94204	900	1.2	337	27	22.8	2.3	39.8
94206	960	1.16	609	53	·18.6	4.7	32
94207	1000	2.68	1135	42	6.8	6.6	15.3
94208	1020	3.28	1513	46	40.6	13.7	33.8
94225	1500	0.98					
94229	1600	1.78	572	56	11.7	14.7	28.9
94232	1750	3.91					
94237	2000	1.92					
94241	2200	1.74	1161	66	37.5	11.6	24.5
94243	2300	2.17	1266	58	44.1	13.3	22.8
94245	2385	1.78	912	51	17.6	15.5	24.1
94247	2390	2.02	1602	79	18.4	14.3	22.6
95259	560	1.51	571	37	32.2	8.3	52.4
95264	620	2.77	564	20	26.5	15	38
95281	1550	4.17	1870	45	46.5	15.3	33.5
95282	1555	4.71	1849	39	49.2	13	32.4
95285	1600	3.81					
95288	1750	2.94	564	19	26.5	15	38
95291	1890	1.67	799	48	18.7	17.5	28.3
95292	1900	2.5	394	16	32.8	15.8	40.9
95296	2055	1.83	627	34	42.2	9.5	29
95299	2130	3.6	1974	55	15.1	13.4	26.5
95300	2145	2.02	1049	52	37.3	16.8	35.4

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Table 3 Continued

Sample No	Depth (m)	Strati-graphy	TOC (%)	TSC (%)	Extract Yield (ppm)	BR (mgExtr./g TOC)	Pr/Ph	Pr/n-C17	Ph/n-C18	CPI	A-Factor	C-Factor	HGP	VRE (%)
94196	550	IMS	0.6	0.79	1108	185	2.9	1.89	1.54	2.55				
94197	570	IMS	0.65	0.67	540	83								
94198	600	IMS	0.65	0.77	3200	492	1.01	1.95	0.95	1.5	0.64	0.39	4.16	0.6
94199	650	IMS	0.97	0.89										
94200	700	IMS	0.75	0.74	811	108	0.97	1.28	1.2	3.5				
94201	750	IMS	0.69	0.99	988	143	1.24	0.98	1.1	1.25				
94202	800	IMS	0.68	0.65	3841	565								
94203	850	IMS	1.16	0.86	700	60	1.3	2.13	1.49	2.49	0.41	0.29	4.75	0.75
94204	900	IMS	1.2	1										
94205	950	UCM	1.34	0.79	477	36	0.5	0.67	1.03	1.65				
94206	960	JCM	1.16	0.77	463	40	1.56	0.72	1.23	1.75	0.22	0.24	2.55	
94207	1000	UCM	2.68	1.98							0.48	0.34	12.86	0.65
94208	1020	FBS	3.27	1.56	2336	71	6.26	1.26	0.19	5.85	0.48	0.36	15.74	0.62
94224	1465	LCM	0.97	0.17	883	91								
94225	1500	LCM	0.98	0.22	943	96	2.89	0.92	0.95	1.48				
94226	1525	LCM	0.87	0.31	1100	126	3.91	0.92	1.93	1.48				

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Sample No	Depth (m)	Stratigraphy	TOC (%)	TSC (%)	Extract Yield (ppm)	BR (mgExtr./g TOC)	Pr/Ph	Pr/n-C17	Ph/n-C18	CPI	A-Factor	C-Factor	HGP	VRE (%)
94229	1600	LCM	1.01	0.48										
94230	1650	LCM	0.61	0.37	908	149								
94231	1700	LCM	1.21	0.57	1264	105	1.64	2.17	3.84	1.35				
94232	1750	LCM	3.09	0.46	2232	72	1.32	1.34	2.32	1.95	0.5	0.3	15.45	0.73
94236	1950	LCM	0.99	0.22	3518	355								
94237	2000	LCM	1.92	0.41	2770	144	1.69	1.27	0.7	1.75	0.55	0.22	10.56	0.88
94238	2050	LCM	1.75	1.54	1399	80	3.82	1.03	0.29	2.36				
94239	2100	LCM	1.73	0.76	2574	149								
94240	2150	LCM	1.59	0.56	2963	186	9.71	0.88	0.81	1.31				
94241	2200	LCM	1.74	1.04							0.53	0.28	9.22	0.78
94242	2250	ANS	1.82	0.51	4442	244	1.61	0.65	1.5	2.25	0.48	0.27	8.73	0.78
94243	2300	ANS	2.17	0.76							0.47	0.27	10.19	0.79
94244	2350	ANS	1.93	0.46	10864	563	6.45	0.99	0.17	1.24				
94245	2385	ANS	1.78	0.35	6787	381	1.68	1.6	1.01	2.75	0.49	0.26	8.72	0.81
94246	2389	ANS	1.72	0.33	2669	155	1.53	2.83	1.66	5.44				
94247	2390	ANS	2.02	0.49	2745	136	1.69	1.79	0.95	1.04	0.51	0.32	10.3	0.71

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Table 4. Kerogen Types and Aromatic Ratios

Sample No.	Depth (m)	Litho logy	Kerogen Type	Tmax (°C)	Ro (%)	Rc (%)	MPI	MPR	MNR	DNR	TNR
94203	850	Shale	III	430	0.56						
94204	900	Shale	III	427	0.61	0.6	0.42		1.6	3.84	0.46
94206	960	Shale	III	425	0.51						
94207	1000	Coal	III	424	0.65	0.64	0.44	0.86	1.59	3.33	0.58
94208	1020	Coal	III	430	0.75						
94225	1500	Coal	III	430							
94229	1600	Coal	III	430	0.6	0.67	0.51	0.85	1.56	4.2	0.72
94232	1750	Coal	III	431	0.65	0.7	0.53		1.45	3.8	0.71
94237	2000	Coal	III	440							
94241	2200	Coaly sh	III	447	0.73	0.82	0.78	0.97	1.46	3.85	0.73
94243	2300	Bit shale	III/II	434	0.81	0.83	0.8	1	1.39	4.07	0.75
94245	2385	Bit shale	III/II	442							
94247	2390	Bit shale	III/II	441	0.79	0.84	0.82	1,02	1.37	3.95	0.78
95259	560	Shale	III	426	0.5						
95264	620	Coaly sh	III	443	0.73	0.7	0.51	0.89	1.48	4.1	0.76
95281	1550	Coal	III	443	0.74						
95282	1555	Coal	III	440	0.79	0.79	0.72	0.94	1.46	4.22	0.63
95285	1600	Coal	III	437	0.8	0.8	0.76	0.98	1.45	4.31	0.75
95288	1750	Coal	III	438							
95291	1890	Coal	III	450	0.75	0.83	0.82	0.99	1.5	4.45	0.78
95292	1900	Coal	III	437	0.82						
95296	2055	Bit shale	III/II	471	0.85	0.88	0.86	1.1	1.66	4.84	0.83
95299	2130	Bit shale	III/II	442							
95300	2145	Bit shale	III/II	444	0.83	0.89	0.88	1.15	1.38	4.86	0.82

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