Petroleum geology of outcropping sediments along Imiegba road, in Etsako east local government area of Edo state, Southern Anambra Basin flank, Nigeria: Inference from sedimentology and organic geochemistry.

ABSTRACT

The outcropping sediments along Imiegba road have been studied using their sedimentological and organic geochemical (TOC and SOM) parameters. A total of sixteen (16) samples were collected and analyzed for the study. Based on sedimentological and field evidences, the main lithofacies identified from the study area are sandstone, shale and claystone. The sandstones are fine to medium-grained and friable. Also the result of the textural analyses show that the sandstones are sub-rounded, moderately to poorly sorted, strongly coarsely skewed and mesokurtic. The calculated permeability values ranging from 307.18-724.85 Md showed that they possess good permeability. Based on the high permeability values of the sands, the sandstones were inferred as good to excellent potentials for fluid transmission making them good reservoir for hydrocarbon.

The TOC values range from 0.17-1.42 wt.%(%) with most of the samples above the threshold of 0.5 wt.% while the SOM, greater than 500ppm indicates that the shales have poor to good organic matter quantity and in adequate concentration for petroleum generation if other factors are suitable.

Key words: geochemistry, permeability, porosity, sedimentology, sandstone, shale, reservoir

1. Introduction

The studied area “Imiegba” is located in Etsako East local Government area of Edo state, Benin flank of the southern Anambra Basin, Nigeria and falls within the coordinates N 07°11'57.0 and E006°26'48.1 (Figure, 1). This study was aimed at the determination of the hydrocarbon potentials as well as the reservoir quality of the outcropping sediments along Imiegba road using Sedimentological, and Organic Geochemical analysis. The objectives of the study were to determine the lithofacies characteristics of the sediments of the study area, the hydrocarbon potential from geochemical parameters such as TOC and SOM, and characterize the reservoir properties (porosity and permeability) from the textural analysis.
2.1 Geologic Setting and Stratigraphy

The Anambra Basin is one of the Cretaceous sedimentary basins of Nigeria, bounded on the southwestern flank by the Niger Delta hinge line, northwest by the Benue flank and southeast by the Abakaliki fold belt. The basin is roughly triangular in shape and covers an area of about 40,000 square kilometres with sediment thickness increasing southwards to a maximum thickness of 12,000m in the central part of Niger Delta. The basin lies between latitudes 5.00N and 8.00N and longitudes 6.30E and 8.00E. Anambra Basin is one of the intracratonic basins in Nigeria and its origin is linked to the tectonic processes that accompanied the separation of the African and South American plates in the Early Cretaceous during the opening of the Atlantic[2,3], (Figure, 2).

Anambra Basin is a post Santonian depo-centre in Southern Nigeria. Before the Santonian tectonism, Anambra Basin and Afikpo syncline were platforms bordering the Benue trough to the west and east respectively. The compressional stress regime that dominated during the Santonian period according to[4], led to the folding and uplift of the Abakaliki sector of the Benue Trough. Consequently the bordering platforms were downwarped to form Anambra Basin and Afikpo syncline, [5] and [2].

Sediments were sourced from the Abakaliki anticlinorium to these basins with subsequent accumulation of thick sedimentary pile ranging from late Cretaceous – Tertiary in age. The earliest sedimentation episode in Anambra Basin was the Campano – Maastrichtian sedimentation cycle that led to the deposition of Nkporo Shale with Enugu Shale as its lateral equivalent. This unit is overlain by the Mamu Formation (Lower Coal Measures), which is conformably overlain by Ajali sandstone . The Nsukka Formation overlies the Ajali sandstone. it is characterized by alternating succession of sandstones, mudstones, dark shales and sandy shales with thin coal seams at some horizons (the upper Coal Measures) [6, 7]. This Formation ranges from late Maastrichtian to Danian in age, [9].
The Tertiary succession consists of the Paleocene Imo Shale which conformably overlies the Nsukka Formation. This formation is composed predominantly of thick fossiliferous clayey shales. It is overlain by the Ameki Formation of Eocene age characterized by greys-green sandy clays, sandstones and claystones with calcareous concretions, clayey sandstones with occasional shelly limestones and lignites at some horizons. The Stratigraphic summary is given in Table 1.

Table 1: Stratigraphic Sequences in the Anambra basin (Modified after [6])

| Age     | Basin            | Stratigraphic Units          |
|---------|------------------|------------------------------|
| Thanetian | Niger Delta       | Imo Formation                |
| Danian  | Anambra Basin    | Nsukka Formation             |
| Maastrichtian |             | Ajali Formation              |
| Campanian |                  | Mams Formation               |
| Santonian | Southern House Trough | Awgu Formation |
|          |                  | Nkpere Form | Nkpere Shale | Nkpere Shale | Okpita | Afikpo | Otukp | Lafia |

3: Method of study: this research involved the Field Mapping (logging of outcrop) and sample collection of outcropping sediments in the study area, laboratory studies involving sedimentological, Total Organic Carbon (TOC and SOM) analyses of collected samples, quantitative determination of permeability of the sediments, and subsequent interpretation of the results.

3.1: Sample Collection

A total of sixteen (16) fresh samples were collected from the outcrop section for this study. Samples were taken from fresh, unweathered surfaces to be able to reveal the original, unaltered structural and mineralogical (chemical) properties of the rocks. The samples were kept in sample bags (polythene bags) and later taken to laboratory for analyses (Figure 3).
Figure, 3: point of sample collection on outcrop

3:2: Textural Analysis:
The samples were subjected to sieve analysis to determine the grain size distribution, sorting, kurtosis and skewness. Quantitative determination of permeability was also done using the data set from sieve analysis. Values obtained were used to plot a graph of Cumulative Weight Percent (%) versus Phi (Ø) from where statistical moments were determined. The statistical moments (parameters) of Folk and Ward (1957) were used for the Granulometric analysis as follows.

\[
\text{Mean (Mz)} = \frac{\phi_{16} + \phi_{50} + \phi_{84}}{3}
\]

\[
\text{Sorting/Standard Deviation (δI)} = \frac{\phi_{84} - \phi_{16} + \phi_{95} - \phi_{5}}{3}
\]

\[
\text{Graphic Skewness (SKI)} = \frac{2(\phi_{84} - \phi_{16})}{2(\phi_{95} - \phi_{5})} - 2 \phi_{50}
\]

\[
\text{Graphic Kurtosis (KG)} = \frac{\phi_{95} - \phi_{5}}{2.44 (\phi_{75} - \phi_{25})}
\]

The foregoing parameters of [9] were then used to determine the paleodepositional environment for the sediments using the plot models of [10].

3:2: Quantitative Determination of Permeability:
Quantitative determination of permeability was done using the empirical formula propounded by Krumbrien and Monk (1942) as follows.

\[
K = \frac{C_0 \cdot D_m^2 \cdot e^{-1.31 \delta}}{10^6}
\]

Where; 
\( K \) = permeability in millidarcies (mD)
\( C_0 \) = empirical constant (769 Darcies/mm²)
\( D_m \) = median diameter (mm)
\( \delta \) = sorting (Phi standard deviation)

3.3: Total Organic Matter Analysis Procedure.
2.0g of the Samples were weighed into 250ml conical flask [Erlenmeyer]. 1.0g should be used if the organic content is between 1&3%, 2.0g if it is less than 1%. 10ml of 1N K₂Cr₂O₇ solution was accurately Pipette into each flask and swirled gently to dispense the sediment.

20ml conc. H₂SO₄ was Added rapidly and swirled; allowed to stand for 30 minutes after which 100ml of distilled water added. 10ml of O-phosphoric acid was added with 3-4 drops of indicator and titrated with 0.5N Ferrous Ammonium sulphate or Ferrous Sulphate till the colour changed from green to blue and finally to red [maroon colour] which is the end point. The blank titration was also set up in the same manner but without the sediment [3, 4, 5 and 6], to standardize the dichromate.

The TOC was Calculated according to the following formula.

\[
\%\text{TOC} = \frac{\text{ml Fe}^{2+} \text{ for blank} - \text{ml Fe}^{2+} \text{ for ?X Normality of Fe}^{2+} \cdot 0.390 \text{ sample}}{\text{Wt of sediment in gram (g)}}
\]
3:4: Soluble Organic Matter Analysis Procedure

30g of the sieved outcrop sample was placed inside a thimble and placed inside the soxhlet extractor. The thimble was pre-extracted with hexane-acetone (1:1v/v) before placing the sample in it. The sample was then extracted with same solvent mixture for 10 hours. The extracts were cleaned by passing them through a column of anhydrous sodium Tetraoxosulphate (vi).

4: Results and Discussions

4.1: Sedimentology:

Based on field study, four (4) lithofacies- sandstone, siltstone, claystone and shales were encountered in the studied location (Figure 4). The Particle Size Distribution of the sandstone from the sieve analysis is presented in appendix1; the Percentile Values for the Granulometric Analysis are presented in table 2, and the Graphical Representation of the percentiles is shown in figure 5 while the summary of the textural attributes of the sediments interpreted from the sieve analysis results are given in Table, 3.

Table 2: Percentile Values from the Granulometric Analysis

| S/N | SAMPLE INTERVALS | 5%   | 16%  | 25%  | 50%  | 75%  | 84%  | 95%  |
|-----|------------------|------|------|------|------|------|------|------|
| 1   | BED 3            | 1.55 | 0.8  | 1.74 | 2.0  | 2.9  | 3.17 | 3.8  |
| 2   | BED 5            | 0.15 | 1    | 1.3  | 1.9  | 2.18 | 3.18 | 3.7  |
| 3   | BED 6            | 0.03 | 0.51 | 0.78 | 1.34 | 1.73 | 1.94 | 3.6  |
| 4   | BED 7            | -1.1 | -0.2 | 0.5  | 2.24 | 3.18 | 3.3  | 3.7  |
| 5   | BED 13           | -1.4 | -0.6 | -0.1 | 1.6  | 2.9  | 3.34 | 4.2  |
| 6   | BED 15           | 1.24 | 1.6  | 1.8  | 2.14 | 2.54 | 2.9  | 4.0  |

4.2: Petrophysical analysis

Porosity is highly dependent on sediment sorting and grain packing [11]. Poorly sorted sediments usually have low porosity. The finer sediments in poorly sorted sediments typically fill the pore spaces thereby impeding porosity. Similarly, permeability is a secondary property of rocks and depends on its primary properties such as texture, composition and structure. In particular, permeability depends on parameters such as grain size, shape and size of pores (porosity), sorting, packing and/or compaction.

From the calculated sorting values (Table 3) which generally indicate moderate to poor sorting, a moderate to poor porosity was inferred for the sediments. However, the sandstones as observed from the outcrops were mainly friable to moderately-consolidated. It is therefore, inferred that porosity-loss in the sediments for this study due to compaction has been minimal. This inference is based on the fact that porosity reduces with compaction. Empirical determination of permeability using [12] formular for the sand facies of the study area shows that the sediments have good permeability (Table 4). The application of the empirical formular of [12] is premised on the fact that there is a valid relationship between porosity and permeability in sandstones. The high permeability values are due to the poor to moderate consolidation of the sediments as well as the sub-rounded morphology of most of the grains.
**Figure 4: Litholog of the studied area**

| DEPTH (FT) | LITHOLOGY | LITHOLOGIC DESCRIPTION |
|------------|------------|------------------------|
|            |            | Light grey mudstone.    |
|            |            | Fine - medium grained,  |
|            |            | moderately sorted, pink |
|            |            | to reddish brown        |
|            |            | sandstone               |
|            |            | Black mudstone.         |
|            |            | Fine grain, poorly      |
|            |            | sorted sandstone. Pink  |
|            |            | in colour, indicating  |
|            |            | high quantity of K-      |
|            |            | Feldspar.               |
|            |            | Lateralised black        |
|            |            | Mudstone.               |
|            |            | Dark fissile shales      |
|            |            | interbedded sandstone,   |
|            |            | which contain megafossils|
|            |            | (pelecepods, mollusks and|
|            |            | trilobites).             |
|            |            | Dark colour siltstone   |
|            |            | with patches of brown   |
|            |            | colouration.             |
|            |            | Fine- grained, dark      |
|            |            | coloured (organic rich  |
|            |            | sandstone).              |
|            |            | Medium grained, poorly   |
|            |            | sorted sandstone.        |
|            |            | Black shale interbeded   |
|            |            | with reddish brown       |
|            |            | sandstone, highly        |
|            |            | fossilized (contain     |
|            |            | pelecepods, mollusks and|
|            |            | trilobites).             |
|            |            | Black shale, fissile and |
|            |            | contain pelecepods,      |
|            |            | mollusks and trilobites,|
|            |            | brachiopods etc.         |
### Table 3: Textural Interpretation of the Sediments

| BED | MEDIAN | MEAN | SORTING | SKEWNESS | KURTOSIS | INTERPRETATION |
|-----|--------|------|---------|----------|----------|----------------|
| 1   | 2.0    | 1.99 | 0.955   | 0.290    | 0.77     | Medium grained, moderately well sorted, strongly fine-skewed, and platykurtic. |
| 3   | 1.9    | 2.03 | 1.14    | 0.094    | 0.92     | Fine grained, poorly sorted, strongly fine skewed, mesokurtic. |
| 5   | 2.24   | 1.78 | 1.675   | -0.393   | 0.73     | Medium grained, poorly sorted, strongly fine skewed, platykurtic. |
| 6   | 1.6    | 1.45 | 1.915   | -0.094   | 1.03     | Medium grained, poorly sorted, strongly coarse-skewed, platykurtic |
| 7   | 2.14   | 2.21 | 0.785   | 0.418    | 0.95     | Fine grained, moderately sorted, strongly fine-skewed, mesokurtic. |
| 13  | 1.66   | 1.66 | 0.45    | 0.02     | 0.9      | Medium grained, moderately sorted, strongly coarse skewed, platykurtic. |
| 15  | 2.59   | 2.6  | 0.683   | 0.08     | 0.94     | Fine grained, poorly sorted, strongly fine skewed, mesokurtic. |

From the above interpretations (Table 3), the sandstone facies are fine to medium-grained, sub-angular to sub-rounded, moderately to poorly sorted sands with the sorting values ranging from 0.67 – 1.92. The sediments are strongly coarse, skewed and ranges from mesokurtic to leptokurtic. It also shows that the porosity and permeability of the sandstone facies of the study outcrop is high, which indicates a good reservoir quality.
Table 4: Calculated Permeability for the Outcropping Sandstone Facies at Imiegba

| SAMPLE INTERVALS | MEDIAN(DM) | SORTING(Δ) | PERMEABILITY(MD) | REMARK   |
|------------------|------------|------------|------------------|----------|
| BED 1            | 2.0        | 0.29       | 393.72           | VERY GOOD|
| BED 3            | 1.9        | 1.14       | 444.17           | VERY GOOD|
| BED 5            | 2.24       | 1.67       | 724.85           | VERY GOOD|
| BED 6            | 1.6        | 1.91       | 623.40           | VERY GOOD|
| BED 7            | 2.14       | 0.78       | 307.18           | VERY GOOD|
| BED 13           | 1.66       | 0.97       | 554.61           | VERY GOOD|
| BED 15           | 2.59       | 0.26       | 361.89           | VERY GOOD|

4:3: Total Organic Carbon (TOC) and Soluble Organic Matter (SOM).

4:3:1: The Organic Matter Richness of the Shales

The organic matter richness of source rock is usually determined using the total organic carbon content, which is the total amount of organic material (kerogen) present in the rock, expressed as a percentage by weight (TOC wt.%).

The higher the TOC value the better the chance and potential for hydrocarbon generation. According to [13], the TOC values between 0.5 and 1.0% indicate a fair source generative potential, TOC values varying from 1.0 to 2.0% reflect a good generative potential whilst values between 2.0 and 4.0 refer to a very good generative potential, and rocks with TOC greater than 4.0% are considered to have excellent generative potential. The TOC values range from 0.17-1.42 wt (%), with a mean of 0.7wt. (%), indicating that the shale samples have non to good hydrocarbon generative potential (figure 5).

4:3:2: Hydrocarbon generative potential: The SOM of the samples ranges from 150 to 1350ppm with the average hydrocarbon generative potential of 500ppm. [13], showed that source rock with SOM in the range of 0-500ppm has a poor potential for petroleum generation; between 500-1000ppm is fair; 1000-2000ppm is good; 2000-4000ppm is very good while those with values above 4000ppm have excellent petroleum potential. Therefore the shales have poor to excellent generative potential for oil and gas (figure 6).
| S/N | SAMPLE ID       | TOC (%) | SOM (PPM) | SOM (WT %) | SOM/TOC |
|-----|----------------|---------|-----------|------------|---------|
| 1   | IMIEGBA BED 1  | 1.42    | 11500     | 1.15       | 0.80    |
| 2   | IMIEGBA BED 2  | 1.07    | 9500      | 0.95       | 0.88    |
| 3   | IMIEGBA BED 3  | 0.52    | 4500      | 0.45       | 0.86    |
| 4   | IMIEGBA BED 4  | 0.17    | 1500      | 0.15       | 0.88    |
| 5   | IMIEGBA BED 5  | 0.39    | 2300      | 0.23       | 0.58    |
| 6   | IMIEGBA BED 8  | 0.76    | 5900      | 0.59       | 0.77    |
| 7   | IMIEGBA BED 10 | 0.89    | 7500      | 0.75       | 0.84    |
| 8   | IMIEGBA BED 12 | 0.70    | 5900      | 0.59       | 0.84    |
| 9   | IMIEGBA BED 14 | 0.42    | 2900      | 0.29       | 0.69    |

4.2.4 TRANSFORMATION RATIO (TR)

The transformation ratio (TR) defined by SOM/TOC was used as a maturity index. It is a measure of the transformation of kerogen into hydrocarbon. [14], stated that TR values between 0.002-0.016 indicate no hydrocarbon generation. The mean transformation ratio of 0.74 was far above the threshold value required for hydrocarbon source generation, implying that the organic matter in the shales is mature and in adequate concentration for hydrocarbon generation (figure 7).
Summary /Conclusion

Based on sedimentological and field evidences, the main lithofacies identified from the study area are sandstone, shale and mudstone. The sandstones are fine to medium-grained and friable. The result of the textural analyses showed that the sandstones are sub-rounded, moderately to poorly sorted, strongly coarsely skewed and mesokurtic. The calculated permeability values ranging from 307.18-724.85 Md showed that they possess good permeability. Based on the high permeability values of the sands, the sandstones were inferred as good to excellent potentials for fluid transmission making them good reservoir for hydrocarbon.

The TOC values ranges from 0.17-1.42 wt (%) with most of the samples above the threshold of 0.5 wt% with SOM greater than 500ppm indicating that the shales have poor to good organic matter quantity and in adequate concentration for petroleum generation.

In Conclusion, the result of the various analyses carried out show the sandstones are moderately to poorly sorted with high permeability, indicating a good reservoir quality for the sandstone, while the geochemical parameters showed that hydrocarbon generation potential of the shale samples is fair, therefore can source hydrocarbon.

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