

**RESERVOIR QUALITY EVALUATION AND DEPOSITIONAL  
ENVIRONMENTS OF SAND BODIES OF VAL-FIELD,  
OFFSHORE, WESTERN NIGER DELTA, NIGERIA.**

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**B.Sc GEOLOGY, UNIBEN**

**A PROJECT REPORT SUBMITTED TO THE DEPARTMENT**

**OF**

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**IN PARTIAL FULFILMENT OF THE REQUIREMENT FOR  
THE AWARD OF DEGREE OF MASTER OF SCIENCE (M.Sc.)  
IN GEOLOGY (PETROLEUM GEOSCIENCES)**

**JULY, 2021.**

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**JULY, 2021.**

## **CERTIFICATION**

This is to certify that the project work herein is the genuine work of Valentine OLUBAYO of the department of Geology, Faculty of Physical Sciences, University of Benin, Benin City.

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**Dr. S. A. SALAMI**  
(Project Supervisor)

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**DATE**

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**Prof. O. I. IMASUEN**  
(Head of Department)

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**DATE**

## **DEDICATION**

This piece of work is dedicated to God Almighty for His divine mercies, grace and favors.

## **ACKNOWLEDGEMENT**

I am most grateful to my Mother Mrs. Olubayo and my siblings for their support and their unalloyed prayers and assistance. My profound gratitude goes to my supervisor Dr. S. A. Salami for his support, guidance and the role he played to that this work was adequately supervised. My special thanks go to the Head of Department, Prof. C. N. Akujieze, Prof. F. A. Lucas, the post graduate studies coordinator of the department, Prof. O. I. Imasuen and other members of staff of the Department of Geology, University of Benin, for the knowledge acquired from them. My unreserved appreciation goes to Dr. F. Balogun, Mr. M. Anucha and my colleagues for their assistance and encouragement.

# TABLE OF CONTENTS

<b>Title page</b> -----	<b>I</b>
<b>Certification</b> -----	<b>II</b>
<b>Dedication</b> -----	<b>III</b>
<b>Acknowledgement</b> -----	<b>IV</b>
<b>Table of contents</b> -----	<b>V</b>
<b>List of figures</b> -----	<b>VI</b>
<b>List of tables</b> -----	<b>VII</b>
<b>Abstract</b> -----	<b>VIII</b>

## CHAPTER ONE

<b>1.1 Introduction</b> -----	
<b>1.2 Aim and objectives</b> -----	
<b>1.3 Location of the study area</b> -----	
<b>1.4 Scope of the study</b> -----	
<b>1.5 Limitation of the study</b> -----	

## CHAPTER TWO

<b>2.0 Literature review</b> - -----	
<b>2.1 Geology of Niger Delta Basin</b> -----	
<b>2.2 Tectonics</b> -----	
<b>2.3 Lithology</b> -----	
<b>2.4 Depobelts</b> -----	
<b>2.4.1 Petroleum and its occurrence</b> -----	
<b>2.4.2 Properties of petroleum fields</b> -----	
<b>2.4.3 Properties of oil and gas</b> -----	
<b>2.4.4 Source rock</b> -----	
<b>2.4.5 Agbada Formation</b> -----	
<b>2.4.5 Akata Formation</b> -----	

2.5 Source rock potential -----  
2.5.1 Reservoir rock -----  
2.5.2 Traps and seal -----

**CHAPTER THREE**

**MATERIALS AND METHODS**

3.1 Heavy mineral separation analysis-----  
3.2 Grain size analysis -----

**CHAPTER FOUR**

**RESULTS AND DISCUSSION**

4.1 Discussion of petrographic analysis -----  
4.2 Discussion of reservoir properties -----  
4.3 Textural characterization of reservoir sand bodies -----  
4.4 Grain sorting of the reservoir sand bodies -----  
4.5 Carbonate cementation of the reservoir sand bodies -----  
4.6 Quartz cementation of the sand bodies -----  
4.7 Mechanical compaction -----  
4.9 Effects of clay minerals, maturity of sandstone bodies and granular texture on porosity and permeability -----  
4.9.1 Provenance -----  
4.9.2 Environment of deposition -----

**CHAPTER FIVE**

**CONCLUSION AND RECOMMENDATION(S)**

6.1 Findings -----  
6.2 Contribution to knowledge -----  
6.3 Conclusion -----  
6.4 Suggestion for further studies -----

**REFERENCES -----**

**LIST OF FIGURES**

- Fig 2.0 Location map of study area - - - - -
- Fig 2.1 Map of Niger Delta showing province outline - - - - -
- Fig 2.2 Early cretaceous separation of Africa and South America - - -
- Fig 2.3 Structural unit of Niger Delta Basin - - - - -
- Fig 2.4 Schematic of a seismic section from Niger Delta continental slope showing result of internal gravity tectonics- - - - -
- Fig 2.5 Schematic of a seismic from the Niger Delta continental slope showing result of internal gravity tectonics on sediments - - - - -
- Fig 2.6 Stratigraphy of Anambra Basin from Late Cretaceous through Eocene and time equivalent formation in Niger Delta - - - - -
- Fig 2.7 Stratigraphic chart of the Niger Delta - - - - -
- Fig 2.8 Generalized Niger Delta stratigraphy and lithofacies subdivision - - - - -  
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- Fig 2.9 : Schematic showing the location of lobes of the early Niger Delta, prolific oil centers, and shales prone areas - - - - -
- Fig 2.10 Sequence stratigraphic model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon - - - - -  
-----
- Fig 2.11 Stratigraphic Column Showing the Three Formations of the Niger Delta -  
-----
- Fig 3.1 Showing a mechanical sieve machine - - - - -
- Fig 4.1 Crossplot of intergranular volume against matrix - - - - -
- Fig 4.2 Crossplot of porosity against quartz cementation - - - - -
- Fig 4.3 Classification of samples - - - - -
- Fig 4.4 Diagrammatic processes, mainly quartz cementation as a function of temperature and time - - - - -
- Fig 4.5 porosity variation with percentage cement - - - - -
- Fig 4.6 Showing how porosity varies with sorting - - - - -
- Fig 4.7 Lithologic al model of the penetrated Toms-well - - - - -

## **LIST OF TABLES**

Table 4.1 Results of Petrographic Analysis - - - - -

Table 4.2 Textural Properties - - - - -

Table 4.3 Index of chemical maturity - - - - -

Table 4.4 result of heavy mineral analysis and provenance inference - -

## **ABSTRACT**

One hundred and seventy seven ditch cutting samples were collected from Toms-well, Vals-Field, Niger Delta, at interval of 5715-5730ft to 8680-8695ft which marks the total depth of the well. The samples were subjected to sedimentological, mechanical and heavy mineral separation analysis. Ten (10) depths of interest were selected for proper analysis using a mechanical sieve machine. Pickett crossplots were integrated in evaluating the reservoir quality and depositional environment of sand bodies of the Toms-well in the Val's Field, Offshore Niger Delta. Evaluated parameters include; storage properties (porosity, saturation), flow property (permeability) as well as reservoir heterogeneities. Results show that the sand are texturally and compositionally matured. The porosity is fine to medium. The presence of cementing materials act as barriers to vertical flow of fluids but porosity is however preserved and permeability is enhanced by other processes such as coating of the grains by micro-quartz which slows down cementation. The sandstones are sourced from mainly felsic igneous rocks and from low to high grade metamorphic rocks. The depositional system is fluvial while the depositional environment is coastal plain. On the whole, the reservoir quality of the Toms-well, Val's field is good and will yield optimal output on production.

## CHAPTER ONE

### 1.0 INTRODUCTION

Grain size studies of beach sediments provide a wealth of information on the intrinsic properties of sediments and their depositional environment. Further, they help to delve into the nature and energy flux of the multifarious agents transporting the sediments. The complex coastal processes operated in the past and operating today have left their imprints in the sediments. In this regard, the sedimentology of sediments plays a vital role in documenting the depositional history of a region (Angusamy and Rajamanickam, 2007). Sedimentologists are particularly concerned with three aspects of particle size: (a) techniques for measuring grain size and expressing it in terms a grade scale, (b) methods for quantifying grain size data and presenting them in a graphical or statistical form and (c) the genetic significance of these data (Boggs, 1995).

The siliciclastic sedimentary unit of the the western Niger Delta Basin, which is part of the Maastrichtian lithostratigraphic units, is an important sedimentary Basin in Nigeria. Textural characteristics of sedimentary units result from complex sedimentary processes and products, including weathering, erosion, and transportation. (Bhatia and Crook, 1986; Roser and Korsch, 1986). In addition, grain size, mineralogy, and shape of siliciclastic rocks is a function of syn-depositional and post-depositional conditions: this involves processes such as diagenetic dissolution, lithification, and compaction of sediments, which are critical to effective reservoir geometry (Makowitz *et al.*, 2016).

The existing correlation between sediment textural parameter (grain size and their frequency distribution) and morphometric analysis, including relationship between skewness and sorting, bivariate-plots for Skewness Vs. Median, Standard deviation Vs. Median, visual estimation of pebble roundness and pebble indices (flatness ratio, coefficient of flatness, elongation ratio, oblate-prolate index and maximum projection sphericity index) are usually good in delineating paleoenvironment and depositional process of sediment (Folk and Ward, 1957; Friedman, 1961; Folk, 1965; and Sames, 1966). The sedimentary units of the Western Niger Delta Basin are important for this study because they occur in a large area and result from a complex history.

The onshore and continental shelf Niger Delta is being explored for more than half a century now. However, exploration activities are gradually being shifted to the deep offshore to unveil its hydrocarbon potential. The deep sea channel sandstone bodies are the main exploration target in this section of the Niger Delta (Whiteman, 1982). A lot of information about the sediments and sedimentary processes is contained in the basin. Sediments in different paleoenvironments display characteristic log motifs. As a result, borehole logs are widely used to interpret sedimentary facies (Weber, 1971).

Information about the sediments and sedimentary processes may not be sufficient alone, due to some lithologies having similar natural radioactivity and electrical properties. Information from cuttings and cores is therefore often an

essential component of any lithologic analysis. The Formations in the Tertiary Niger Delta include the Agbada and Benin Formations to the North with a transition to the Akata Formation in the deep water portion of the Basin where the Agbada and Benin Formations thin and disappear seaward. The Akata Formation at the base of the delta is of marine origin and is composed of thick shale sequences (potential source rock), turbidite sand (potential reservoirs in deep water), and minor amounts of clay and silt. The formation underlies the entire delta, and is typically over-pressured. Turbidity currents likely deposited deep sea fan sands within the upper Akata Formation during development of the delta (Burke, 1972).

The Agbada Formation which overlies the Akata Formation consists of unconsolidated to slightly consolidated paralic siliciclastic sequence of sandy unit with minor shale intercalations. Reservoir quality and depositional environment of sand bodies can be evaluated using data from ditch cuttings obtained from Val-Field, offshore western Niger Delta. The palaeodepositional environments in the field will be inferred from the lithologic model of the penetrated sedimentary succession within the Val-Field.

## **1.2 AIM**

The aim of the research is to ascertain the reservoir quality and environment of deposition of sandstones in the Toms-well, Val-Field.

## **1.3 OBJECTIVES**

1. Build a lithologic model of the penetrated sedimentary successions.
2. To present new analytical data (textural and pebble morphometric) of the sediments.
3. To infer possible ancient deposition environment, mechanism of deposition, and textural attributes based on the pebble morphometric studies of sediments at the source area.
4. Produce concrete information on the reservoir quality by integrating data textural analysis, diagenetic processes and compaction.

## **1.4. SCOPE OF THE STUDY**

The study focuses on reservoir quality and paleo environmental re-construction from one hundred and seventy seven ditch cutting samples at ten (10) depths of interest in the TOMS-WELL, VAL'S FIELD, Offshore, Western Niger Delta.

### **1.5. LIMITATION OF THE STUDY**

In the course of this study there were a number of limitations the researcher faced which includes: obtaining well logs and bio-data of the location and unwillingness of the industrialists to release data in the studied location for this research work.

### **1.6. LOCATION OF THE STUDY AREA**

The well under study is pseudo-named Toms-well in Val-Field, Niger Delta Basin, in accordance with the Company's confidentiality agreement. The field is located within the offshore compressional features of the Niger Delta Basin, south-south, Nigeria (fig. 1.1). The field belongs to an active oil producing company in Nigeria. It covers an area of about 51.187km<sup>2</sup> and it is within longitude 8.0°E to 8.3°E and Latitude 4.0°N to 4.3°N.

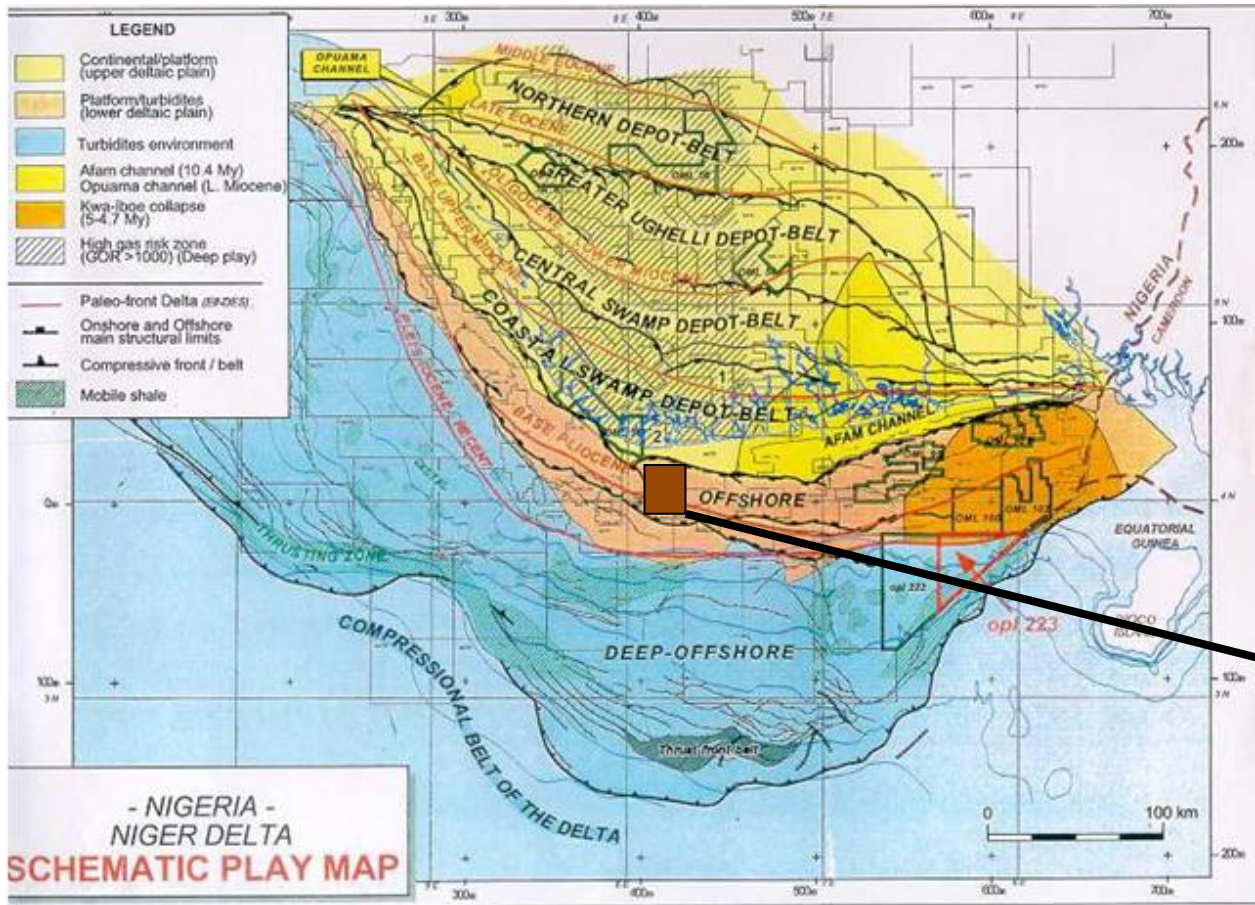


Figure 2: Location Map of Study Area (Nwozor et al., 2013)

## CHAPTER TWO

### 2.0 LITERATURE REVIEW

The Niger Delta Sedimentary Basin is classified as an extremely prolific hydrocarbon province and one of the largest Tertiary Deltaic Systems in the world (Doust and Omatsola, 1990). The Basin which has an age range from the Cretaceous to present (Short and Stauble, 1997) is located in the Southern part of Nigeria. The Basin is situated at the zone where the Benue Trough intersects the South Atlantic Ocean, a point where a triple junction developed during the Late Jurassic separation of South America and Africa plate (Whiteman, 1982) and is located within Longitudes 3°-9°E and Latitudes 4° -6°N. The subsurface Niger Delta sedimentary basin is sub-divided into three stratigraphic units, the Benin Formation, Agbada Formation and Akata Formation (Short and Stauble, 1967; Doust and Omatsola, 1990). Contains only one identified petroleum system known as the Tertiary Niger Delta (Akata –Agbada) Petroleum System (Kulke, 1995; Ekweozor and Daukoru (1994). The Benin Formation comprises entirely of non-marine sand deposited in coastal plain environments (Doust and Omatsola, 1989). The Agbada Formation which is the major hydrocarbon–prospective sequence, deposited in a transitional to marine paralic environment (Lambert-Aikhionbare and Ibe, 1980). The Akata Formation is of marine origin and composed of thick shale sequence (potential source rock within the basin (Ekweozor, and Okoye, 1980).

The Niger Delta Sedimentary Basin is situated in the Gulf of Guinea (Figure 2.1) and extends throughout the Niger Delta province as defined by Klett *et al.*, (1997), it is located in the southern part of Nigeria between the Longitudes 3°-9° East and Latitudes 4° -6° North. From the Eocene to the present, the delta has prograded southwestward, forming deposits that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). These deposits form one of the largest regressive deltas in the world with an area of some 300,000km<sup>2</sup> (Kulke, 1995), a sediment volume of 500,000km<sup>2</sup> (Hospers, 1965), and a sediment thickness of over 10km in the basin depocenter (Kaplan *et al.*, 1994).

The Niger Delta province contains only one identified petroleum system (Kulke, 1995; Ekweozor and Daukoru, 1994). This system is referred to as the Tertiary Niger Delta (Akata-Agbada) Petroleum system. The maximum extent of the system is defined by the areal extent of fields and contains known resources (cumulative producing plus proved reserves) of 3.4 billion barrels of oil equivalent. BBOE) (Petroconsultants, 1996a). Currently, most of this petroleum is in fields that are onshore or on the continental shelf in waters less than 200 meters deep (Figure 2.1), and occurs primarily in large, relatively simple structures. A few giant fields do occur in the delta, the largest contains just over 1.0 BBO (Petroconsultants, Inc., 1996a). Among the province ranked in the U.S. Geological Survey's World Energy Assessment (Klett *et al.*, 1997),

the Niger Delta province is the twelfth richest in petroleum resource, with 22% of the world's discovered oil and 1.4% of the world's discovered gas (Petroconsultants, Inc. 1996a).

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The Niger Delta Basin which is the largest sedimentary basins of the southern Nigeria developed along the West Coast of Africa continent during the Tertiary times. It is positioned at the intersection of the triple ridge junction in the eastern corner of the Gulf of Guinea from which the rifting and separation of the South America and Africa continents was initiated (Figure 2.2). The failure of the third arm (Benue Trough complex) to spread into an oceanic stage set the stage for the subsequent development of the Niger Delta Basin.

The modern Niger Delta covers an area of some 140,000km<sup>2</sup> and lies on top of a thick prism of regressive clastic sequence, which reaches a maximum thickness of 12,000m at the basin centre (Knox and Omatsola, 1989). This prism of clastic

sediments forms the prominent seaward bulge on the continental margin off southern Niger (Figure 2.3).

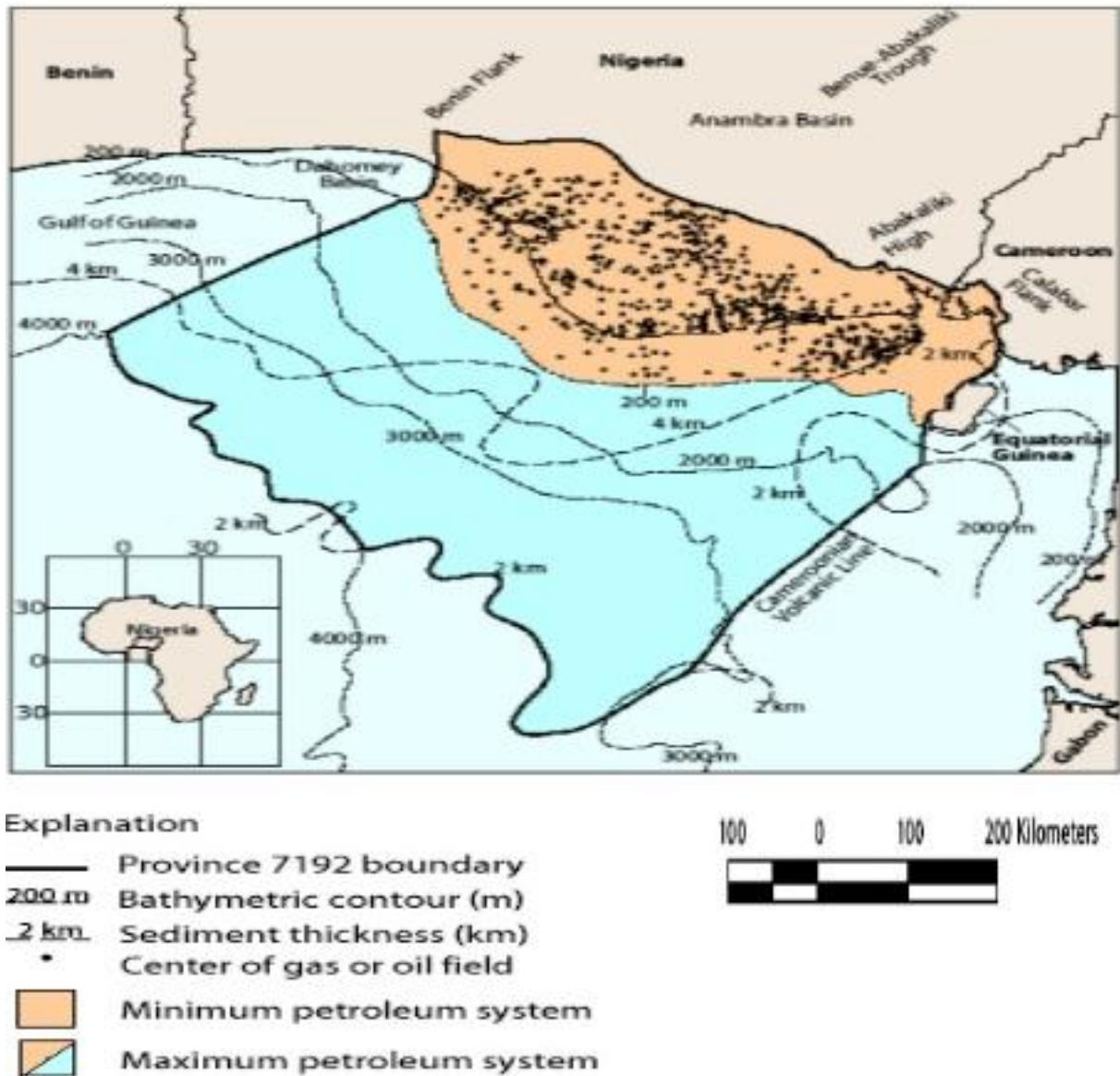


Figure 2.1: Map of the Niger Delta showing the province outline (maximum petroleum system bounding structure features; minimum petroleum system as defined by oil and gas field center points (data from Petroconsultants, 1996a); 200, 2000, 3000 and 4000m bathymetry contours; and 2 and 4Km sediment thickness.

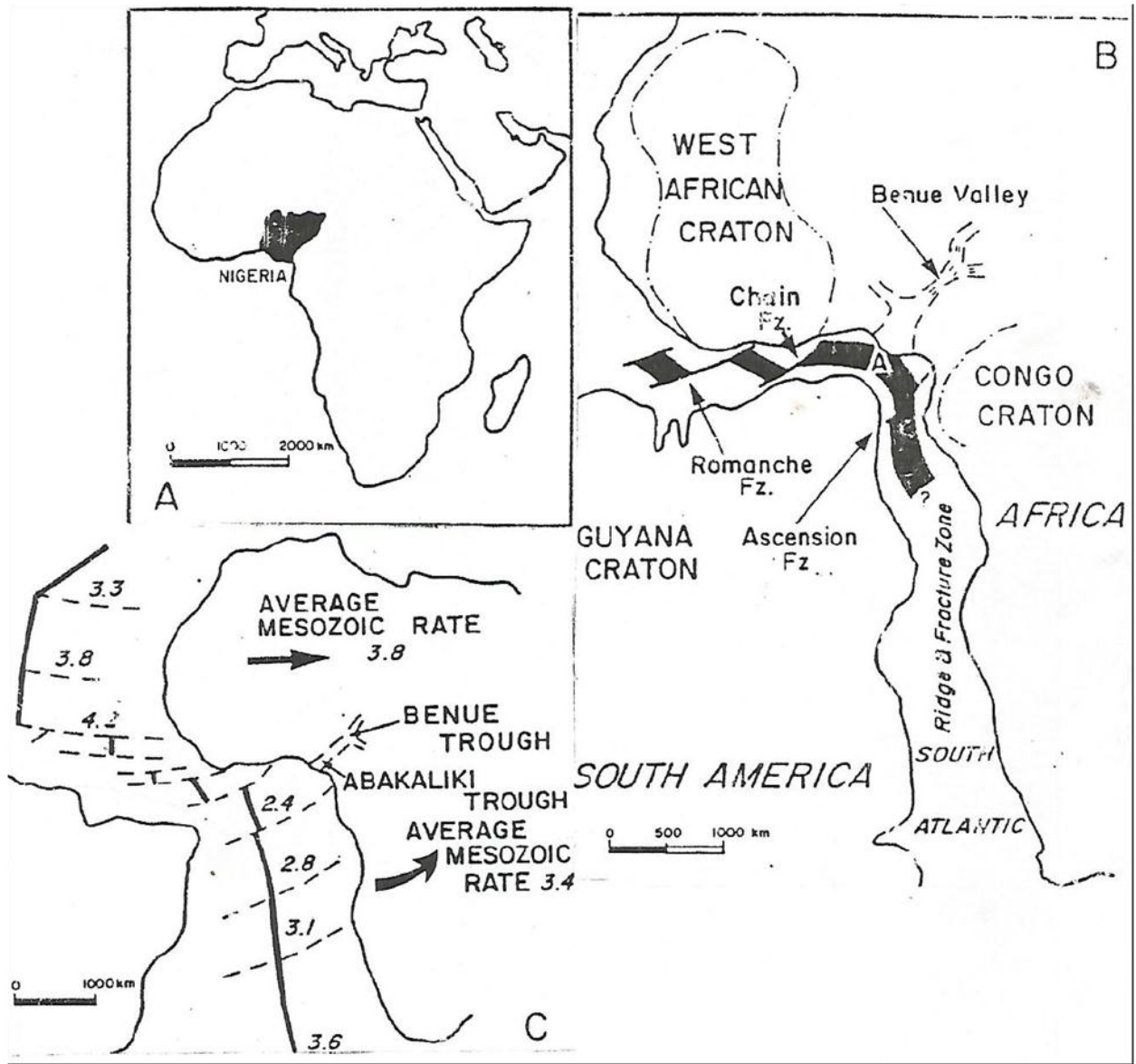


Figure 2.2: Early Cretaceous separation of Africa and South America showing proposed Niger Delta Triple Junction (Whiteman, 1982).

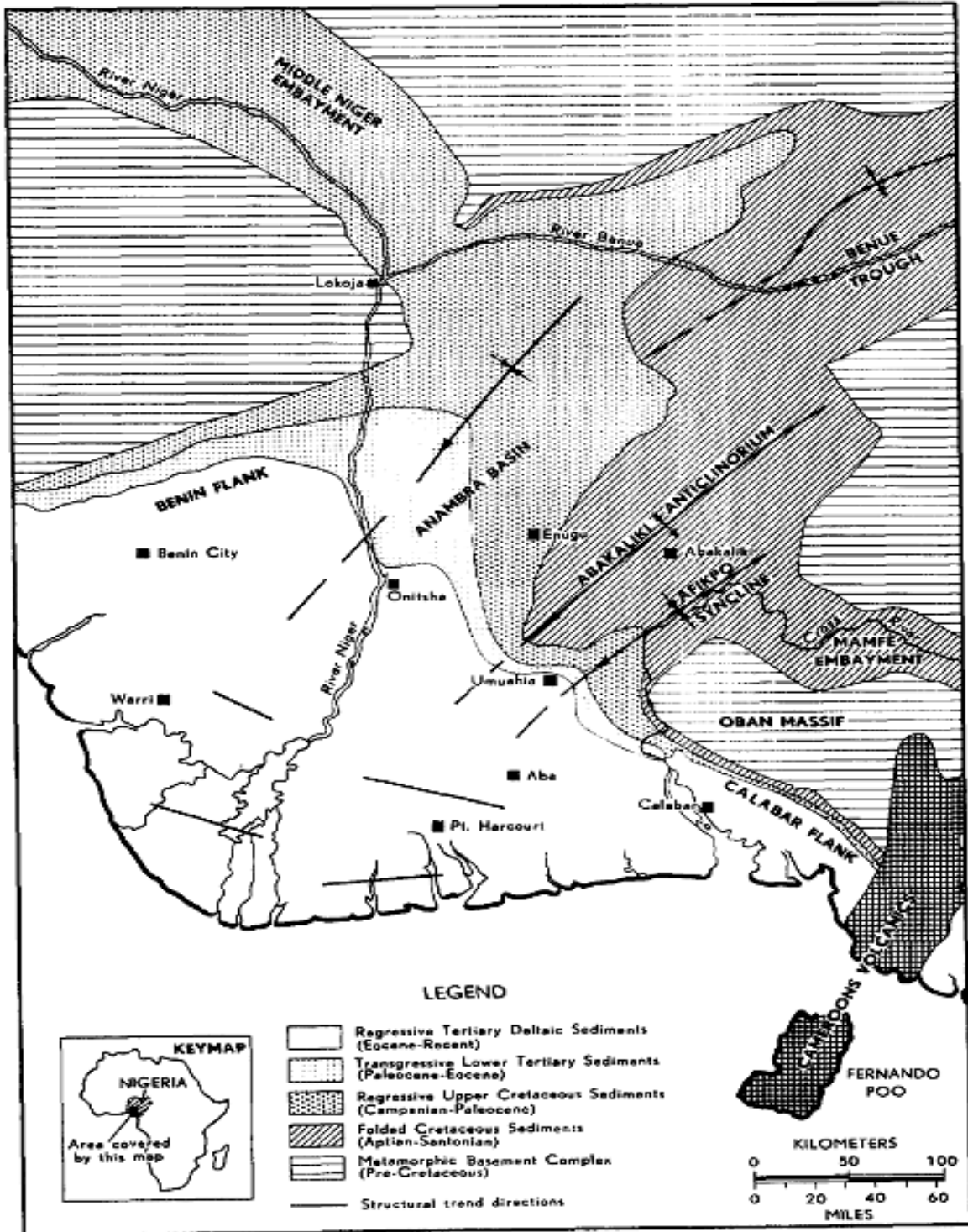


Figure 2.3: Structural units of the Niger Delta Basin (Short and Stauble, 1967).

## **2.1 GEOLOGY OF THE NIGER DELTA BASIN**

The onshore portion of the Niger Delta Basin is delineated by the geology of southern Nigeria and southwestern Cameroon (Figure 2.1). The northern boundary is the Benin flank—an east-northeast hinge south of the West Africa basement massif (Evamy *et al*, 1978). The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further east-south-east by the Calabar flank—a hinge line bordering the adjacent Precambrian (Doust and Omatsola, 1990).

The offshore boundary of the province is defined by the Cameroon volcanic line to the east, the eastern boundary of the Dahomey Basin (the eastern-most West African transform-fault passive margin) to the west, and the two kilometer sediment thickness contour or the 4000meter bathymetric contouring areas where sediment thickness is greater than two kilometers to the south and southwest (Whiteman, 1982). The province covers 300,000 km<sup>2</sup> and includes the geologic extent of the Tertiary Niger Delta (Akata-Agbada) Petroleum System (Short and Stauble, 1997).

## **2.2 TECTONICS**

The tectonic framework of the continental margin along the West Coast of equatorial Africa is controlled by Cretaceous feature zones expressed as trenches and ridges in deep Atlantic. The fractures zone ridge 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). In the region of Niger Delta, rifting diminished altogether in Late Cretaceous. Shale mobility induced internal deformation and occurred in response to two processes (Kulke, 1995). First, shale diapirs formed from loading of poorly compacted, over-pressured pro-delta and delta-slope clays (Akata Formation). For any given depobelt, gravity tectonics were completed before deposition of the Benin Formation and expressed in complex structures, including shale diapirs, roll-over anticlines, collapsed growth fault crests, back-to-back features, and steeply dipping, closely spaced flank faults (Evamy *et al.*, 1978; Xiao and Suppe, 1992). These faults mostly offset different parts of the Agbada Formation and flatten into detachment planes near the top of the Akata Formation.

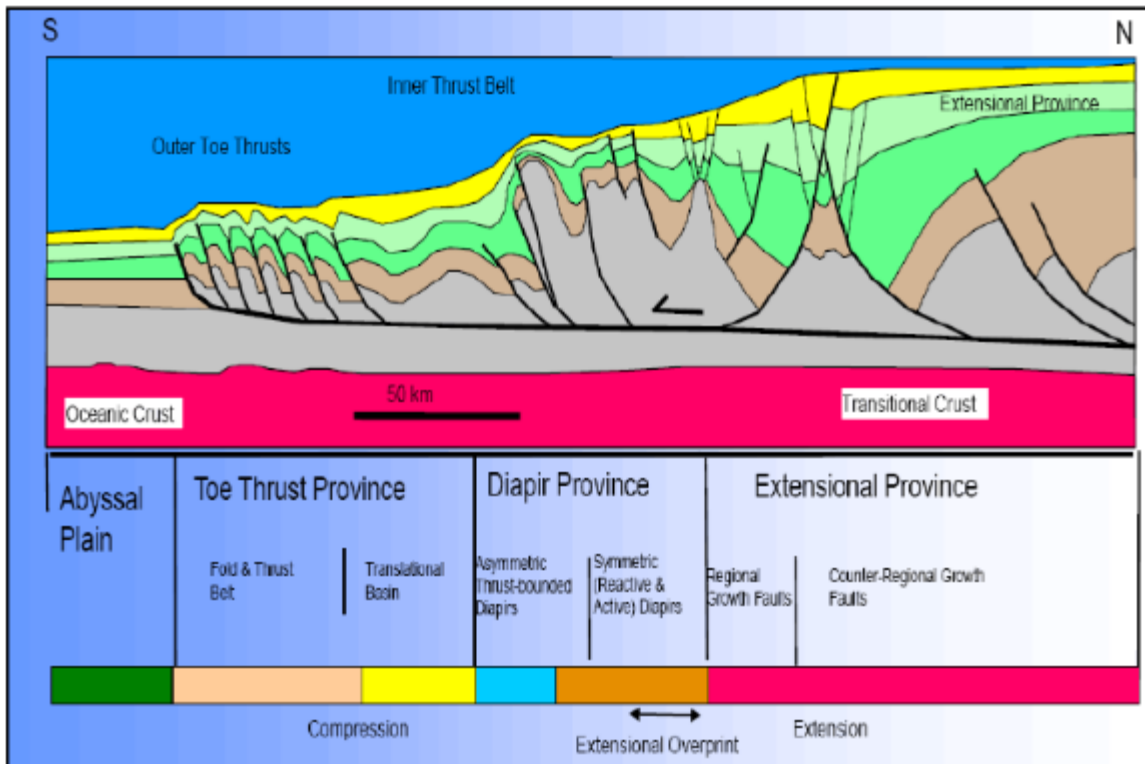


Figure 2.4: Schematic of a seismic section from the Niger Delta continental slope/rise showing the results of internal gravity tectonics on sediments at the distal portion of the depobelt (Reijers *et al*, 1997).

### 2.3 LITHOLOGY

The Cretaceous section has not been penetrated beneath the Niger Delta Basin, the youngest and southernmost sub-basin in the Benue-Abakaliki trough (Reijers *et al*, 1997). Lithologies of Cretaceous rocks deposited in what is now the Niger Delta Basin can only be extrapolated from the exposed Cretaceous section in the next basin to the northeast-the Anambra basin. From the Cambrian through the Paleocene, the shoreline was concave into the Anambra Basin (Hospers, 1965), resulting in convergent longshore drift cells that produced tide-dominated deltaic sedimentation during transgression and river-

dominated sedimentation during regression (Reijerset *al*, 1997). Shallow marine clastics were deposited farther offshore and, in the Anambra Basin, are represented by the Albian-Cenomanian Asu River shale, Cenomanian-Santonian Eze-Uku and Agwu shales, and Campanian/Maastrichtian Nkporo shale, among others (Nwachukwu, 1972; Reijerset *al*, 1997). The distribution of Late Cretaceous shale beneath the Niger Delta is unknown.

In the Paleocene, a major transgression (referred to as the Sokoto transgression by Reijerset *al*, 1997) began with the Imo shale being deposited in the Anambra Basin to the northeast and the Akata shale in the Niger Delta Basin area to the southwest. In the Eocene, the coastline shape became convexly curvilinear, the longshore drift cells switched to divergent, and sedimentation changed to being wave-dominated (Reijerset *al*, 1997). At this time, deposition of paralic sediment began in the Niger Delta Basin proper and, as the sediments prograded south, the coastline became progressively more convex seaward. Today, delta sedimentation is still wave-dominated and longshore drift divergent (Burke, 1972).

The Tertiary section of the Nigeria Delta is divided into three formations, representing prograding deposition facies that distinguished mostly on the basis of sand-shale ratios. The type section of these formations are described in Short and Stauble (1997) and summarized in a variety of papers (e.g. Avbobvo, 1978; Doust and Omatsola, 1990; Kulke, 1995). The Akata Formation at the base is of

marine origin and is composed of thick shale sequence (potential source rock), turbidites sand (potential reservoirs in deep water), and minor amounts of clay and silt (Figure 2.4, 2.5 and 2.6). Beginning in the Paleocene and through to the Recent. The Akata Formation formed during lowstand when terrestrial organic matter and clays were transported to deep water areas characterized by low energy conditions and oxygen deficiency (Stacher, 1995). Little of the formation has been drilled; therefore, only a structural map of the top of the formation is available. It is estimated that the formation is up to 7,000 meters thick (Doust and Omatsola, 1990). The formation underlies the entire delta, and is typically overpressured. Turbidity currents likely deposited deep sea fan sands within the upper Akata Formation during development of the delta (Burke, 1972). Deposition of the overlying Agbada Formation, the major petroleum-bearing unit, begins in the Eocene and continues into the Recent (Figure 2.4, 2.5 and 2.6). The formation consists of paralic siliciclastics over 3700 meters thick and represents the actual portion of the sequence. The clastics accumulated in delta-front, delta-topset, and fluviodeltaic environments. In the lower Agbada Formation, shale and sandstone beds were deposited in equal proportion, however, the upper portion is mostly sand with only minor shale interbeds or intercalations.

The Agbada Formation is overlain by the third formation, the Benin Formation, a continental latest Eocene to Recent deposit of alluvial and upper coastal plain sands that are up to 2000 m thick (Avbovbo, 1978).

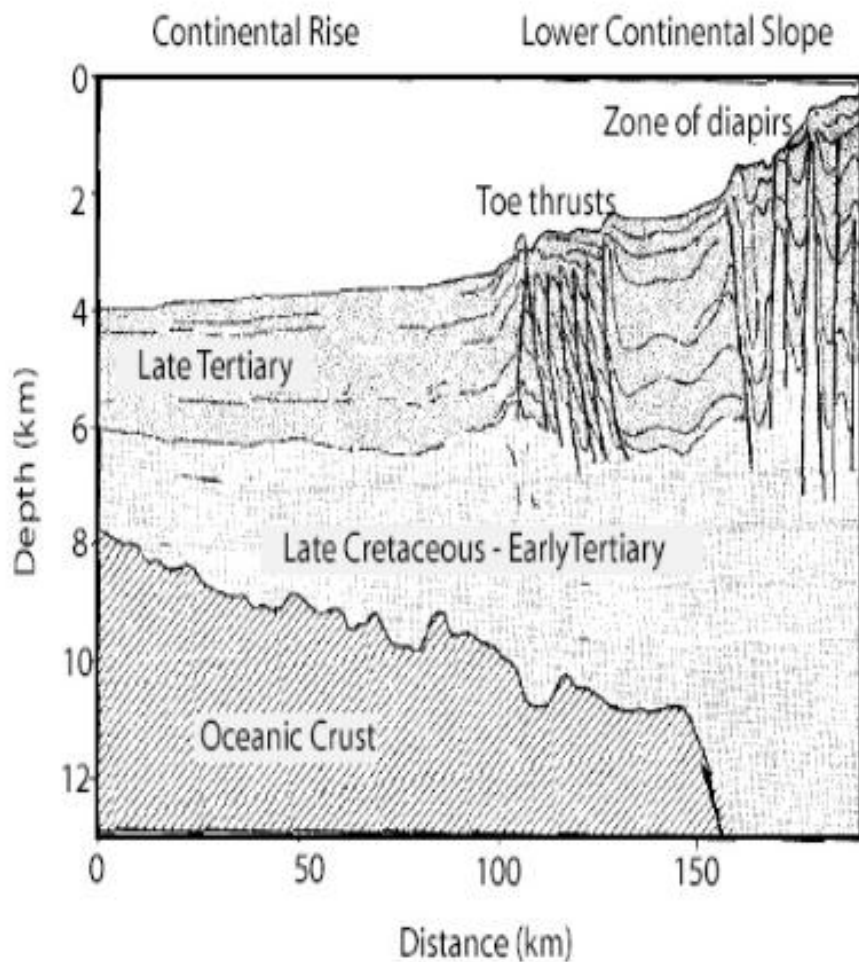


Figure 2.5: Schematic of a seismic section from the Niger Delta continental slope/rise showing the result of internal gravity tectonics on sediments at the distal portion of the depobelt (Modified from Reijers *et al*, 1997).

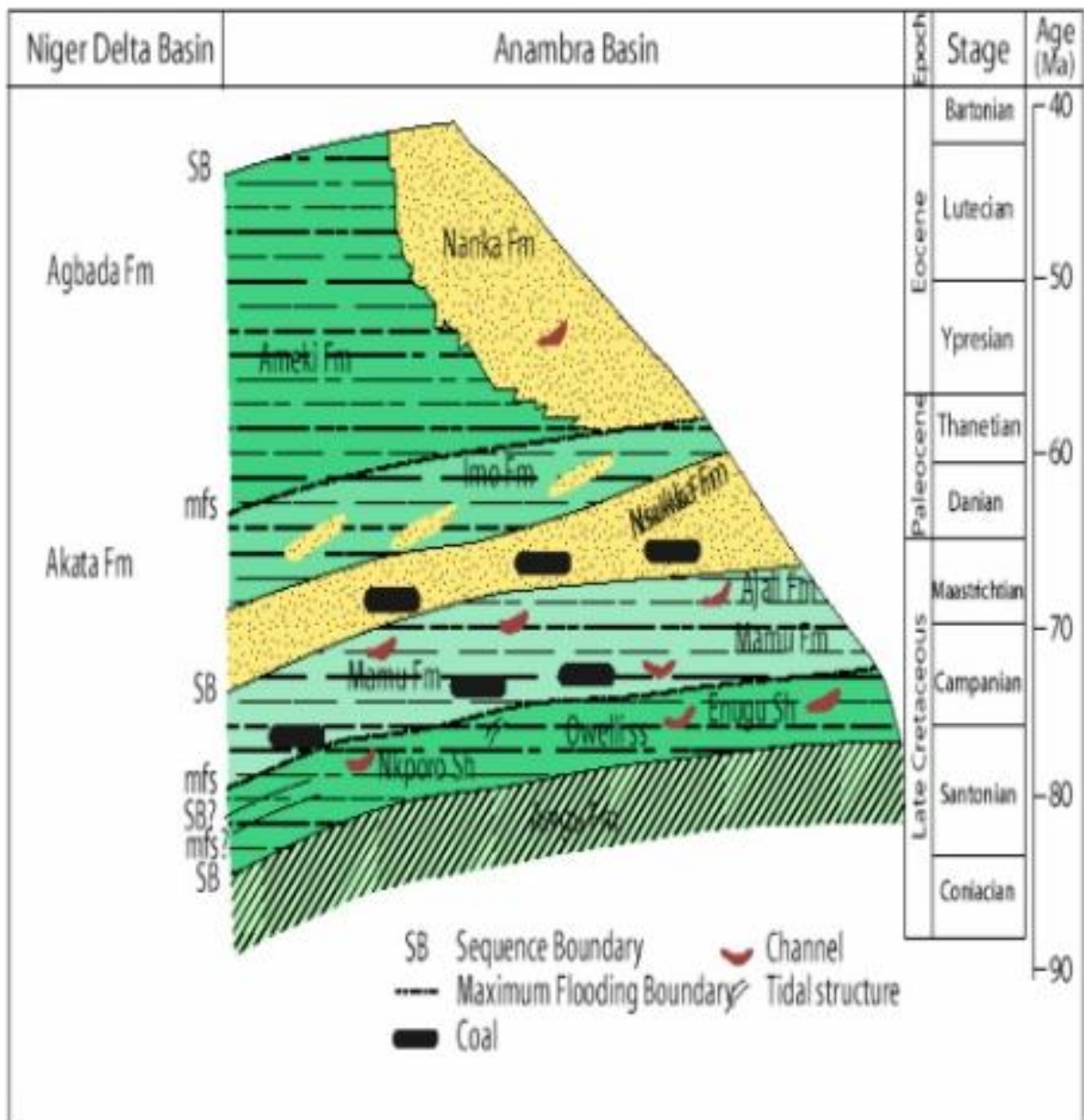


Figure 2.6: Stratigraphic of Anambra Basin from the Late Cretaceous through the Eocene and time equivalent formation in the Niger Delta. (Modified from Reijers *et al.*, 1997).

## 2.4 DEPOBELTS

Deposition of the three formation occurred in each of the five offlapping siliciclastic sedimentation cycles that comprise the Niger Delta. These cycles (depobelts) are 30-60 kilometers wide, prograde southwestward 250 kilometers over oceanic crust into the Gulf of Guinea (Stacher, 1995), and are defined by synsedimentary faulting that occurred in response to variable rates of subsidence and sediment supply (Doust and Omatsola, 1990). The interplay of subsidence and supply rates resulted in deposition of discrete depobelts when further crustal subsidence of the basin could no longer be accommodated, the focus of sediment deposition shifted seaward, forming a new depobelt (Doust and Omatsola, 1990). Each depobelt is a separate unit that corresponds to a break in regional dip of the delta and is bounded landward by growth faults and seaward by large counter-regional faults or the growth fault of the next seaward belt (Evamy *et al*, 1978); Doust and Omatsola, 1990).

Five major depobelts are generally recognized, each with its own sedimentation, deformation, and petroleum history. Doust and Omatsola (1990), describes three depobelt provinces based on structure. The northern delta province, which overlies relatively shallow basement, has the oldest growth faults that are generally rotational, evenly spaced, and increases their steepness seaward.

The central delta province has depobelts with well- defined structures such as successively deeper rollover crest that shift seaward for any given growth fault. Lastly, the distal province is the most structurally complex due to internal gravity tectonics on the modern continent slope.

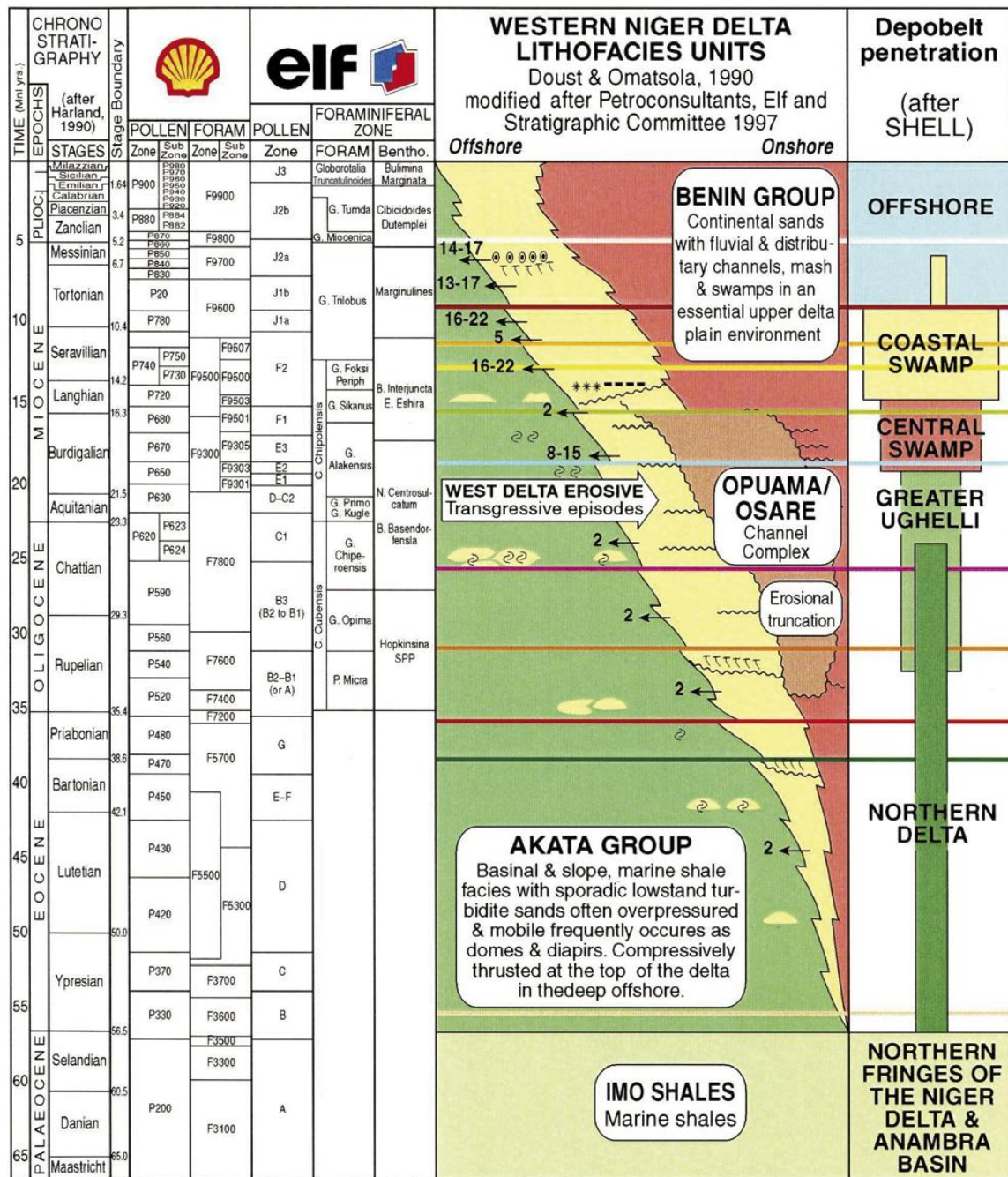


Figure 2.7: Stratigraphic chart (west and east halves combined) of the Niger Delta. Modified from Reijers (2011).

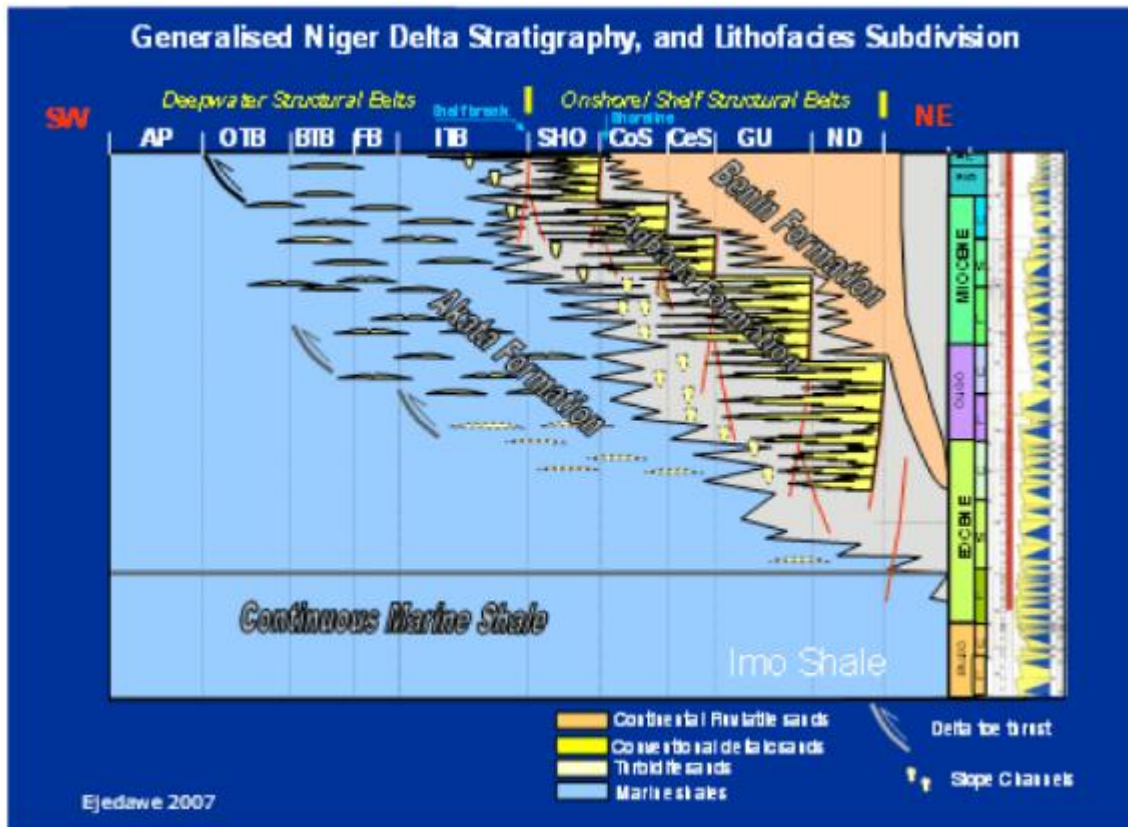


Figure 2.8: Generalized Niger Delta stratigraphy and Lithofacies subdivision (after Ejedawe, 2007).

### 2.4.1 PETROLEUM AND ITS OCCURRENCE

Petroleum occurs throughout the Agbada Formation of the Niger Delta Basin; however several directional trends form an “oil-rich belt” having the largest field and lowest gas-oil ratio (Evamy *et al.*, 1978; Doust and Omatsola, 1990). The belt extends from the northwest offshore area to the southeast offshore and along a number of north-south trends in the area of Port Harcourt (Figure 2.8). It roughly corresponds to the transition between continental and oceanic crust, and is within the axis of maximum sedimentary thickness.

This hydrocarbon distribution was originally attributed to timing of trap formation relative to petroleum migration (earlier landward structures trapped earlier migrating oil). Evamy (2007), however, showed that in many rollovers, movement on the structure building fault and resulting growth continued and was relayed progressively southward into the younger part of the section by successive crestal faults, concluding that there was no relation between growth along a fault and distribution of petroleum. Ejadawe (1981) relates the position of the oil-rich areas within the belt to five delta lobes fed by four different rivers. He states that the two controlling factors are an increase in geothermal gradient relative to the minimum gradient in the delta center and the generally greater age of sediments within the belt relative to those further seaward. Together these factors gave the sediments within the belt the highest “maturity per unit depth” Weber (1987) indicates that the oil-rich belt (“golden lane”) coincides with a concentration of roll-over structures across depobelts having short southern flanks and little paralic sequence to the south. Doust and Omatsola (1990) suggest that the distribution of petroleum is likely related to heterogeneity of source rock type (greater contribution from paralic sources in the west) and/or segregation due to re-migration. Haack *et al.*, (1997) relate the position of the oil-rich belt to oil-prone marine source rocks deposited adjacent to the delta lobes (Figure 2.8), and suggest that the accumulation of these source rocks was controlled by pre-Tertiary structural sub-basins related to basement structures.

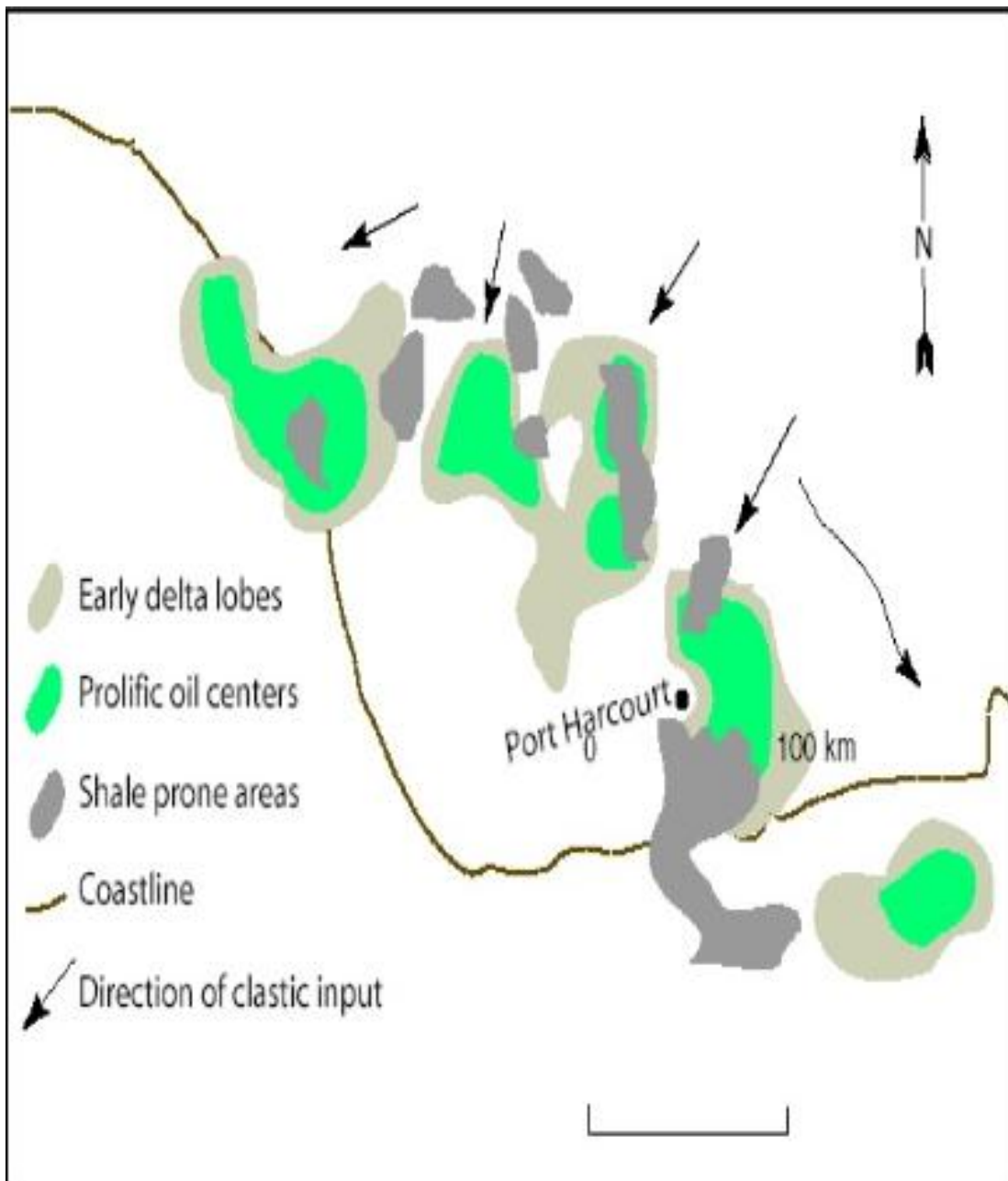


Figure 2.9: Schematic showing the location of lobes of the early Niger Delta, prolific oil centers, and shales prone areas. Modified from Ejadawe (2007) and Reijers *et al.*, (1997).

Outside of the “oil-rich belt” (central, easternmost, and northernmost parts of the delta), the gas: oil ratios (GOR) are high. The GOR within each depobelt increase seaward and along strike away from deposition centers. Causes for the distribution of GOR are speculative and include remigration induced by tilting during the later history of deposition within the downdip portion of the depobelt, updip flushing of accumulations by gas generated at higher maturity, and /or heterogeneity of source rock type (Doust and Omatsola, 1990).

Stacher (1995), using sequence stratigraphy, developed a hydrocarbon habitat model for the Niger Delta. The model was constructed for the central portion of the delta, including some of the oil-rich, and relates deposition of the Akata Formation (the assumed source rock) and the sand/shale units in the Agbada Formation (the reservoir and seals) to sea level. Pre-Miocene Akata shale was deposited in deep water during lowstands and is overlain by Miocene Agbada sequence system tracts. The Agbada Formation in the central portion of the delta fits a shallow ramp model with mainly highstand (hydrocarbon-bearing sands) and transgressive (sealing shale) system tracts third order lowstand system tracts were not formed.

Faulting in the Agbada Formation provides pathways for migration and formed structural traps together with stratigraphic traps for accumulation of petroleum. The shale in the transgressive system tract provided an excellent seal above the sands as well as enhancing clay smearing within faults.

## **2.4.2 PROPERTIES OF PETROLEUM FIELDS**

Most fields consist of a number of individual reservoirs that contain oil of varying composition with different gas/oil ratios. Gas caps are common. Many reservoirs are overpressured and primary production is majorly from gas expansion (Kulke, 1995). Common oil production problems include water coning, unconsolidated sands, wax deposition and high gas/oil ratios, leading to ultimate recovery rates up to 30% (Kulke, 1995).

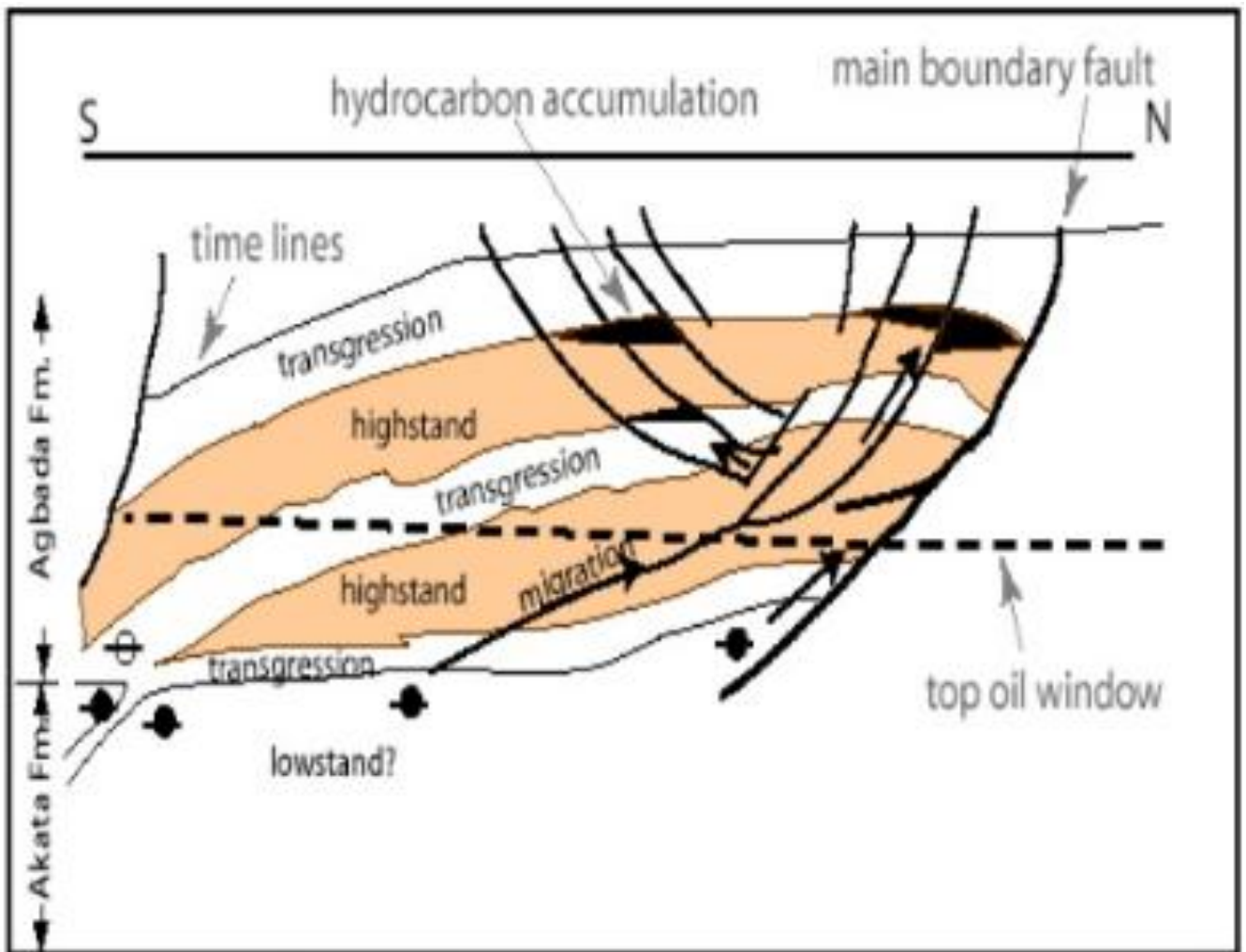


Figure 2.10: Sequence stratigraphic model for the central portion of the Niger Delta showing the relation of source rock, migration pathways and hydrocarbon traps related to growth faults separates megastructures which represent major breaks in the regional dip of the delta (Evamy et al., 1978). Modified from Stacher (1995).

### 2.4.3 PROPERTIES OF OIL AND GAS

The physical and chemical properties of the oil in Niger Delta are highly variable, even down to the reservoir level. The oil within the delta has a gravity range of 16.50° API, with the lighter oil having a greenish brown color (White man 1982). Fifty-six percent of Niger Delta oils have API gravity 30° and 40° (Thomas, 1995). Most oils fall within one of two groups. The first group are light paraffin based, waxy oils from deeper reservoir (wax content up to 20%, but commonly around 5%; Kulke, 1995; Doust and Omatsola, 1990; high n-paraffin/naphthene of 0.86). The second group of oils are biodegraded and from shallow reservoirs. They have lower API gravity (average API of 26%; Kulke, 1995) and are naphthenic non-waxy oils (n-paraffin/naphthene =0.37). Oils with less than 250 API account for only 15% of the Niger Delta reserves (Thomas, 1995).

The concentration of Sulphur in most oil is low, between 0.1% and 0.3% (Beka and Oti, 1995), with a few samples having concentrations as high as 0.6% (Etu-Efeotor, 2007). The associated gas in the Niger Delta is thermal in origin (Doust and Omatsola, 1990), with low CO<sub>2</sub> and N<sub>2</sub> concentrations. Hydrogen sulphides are not a problem associated with Niger Delta gas; however, relatively high mercury concentrations have been observed. Currently, 75% of the gas produced from the Niger Delta is flared, 5-10% is refined is reinjected to maintain reservoir pressure and only 15% marketed.

#### 2.4.4 SOURCE ROCK

There has been much discussion about the source rock for petroleum in the Niger Delta (e.g. Evamy *et al.*, 1978; Ekweozor *et al.*; Ekweozor and Okoye, 1980; Lambert-Aikhionbare and Ibe, 1984; Bustin, 1988; Doust and Omatsola, 1990). Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation and the marine Akata shale, and Cretaceous shale (Amajor, 1987; Evamy *et al.*, 1978; Ejedawe *et al.*, 1979; Ekweozor and Okoye, 1980; Ekweozor and Daukoru, 1984; Lambert-Aikhionbare and Ibe, 1984; Doust and Omatsola, 1990; Stacher, 1995; Haack *et al.*, 1997).

#### 2.4.5 AGBADA-AKATA

The Agbada Formation has intervals that contain organic carbon sufficient to be considered good source rocks. The intervals, however, rarely reach thickness sufficient to produce a world-class oil province and are immature in various parts of the delta (Evamy *et al.*, 1978; Stacher, 1995). The Akata shale is present in large volumes beneath the Agbada Formation and is at least volumetrically sufficient to generate enough oil for a world class oil province such as the Niger Delta.

Based on organic-matter content and type, Evamy *et al.*, (1978) proposed that both the marine shale (Akata Formation) and the shale interbedded with paralic sandstone (lower Agbada Formation) were the source for the Niger Delta oils.

Lambert-Aikhionbare and Ibe (1984) argued that the migration efficiency from the over pressured Akata shale would be less than 12%, including that little fluid would have been released from the formation. They derived a different thermal maturity profile, showing that the shale within the Agbada Formation is mature enough to generate hydrocarbons. Ejedawe *et al.*, (1984) use maturation models to conclude that in the central part of the delta, the Agbada shale source the oil while the Akata shale source the gas. In other parts of the delta, they believe that both shales source the oil. Doust and Omatsola (1990) conclude that the source organic matter is in the deltaic offlap sequence and in the sediments of the lower coastal plain. Their hypothesis implies that both the Agbada Formation likely has disseminated source rock levels, but the bulk will be in the Agbada Formation. In deep water, they favour delta slope and deep turbidite fans of the Akata Formation as source rocks. The organic matter in these environments still maintains signature; however, it may be enriched in amorphous, hydrogen-rich matter from bacterial degradation. Stacher (1995) proposes that the Akata Formation is the only source rock volumetrically significant and whose depth of burial is consistent with the depth of the oil window.

## **2.5 SOURCE ROCK POTENTIAL**

Edegbai *et al.*, (2019), have estimated the average source potential index (SPI) for the Niger Delta at  $14\text{HC}/\text{m}^2$ . One hundred to 300 meters mature source rock could be easily accommodated in the mature, lower portion of the Agbada

Formation and the uppermost Akata Formation. We agree with researchers (Evamy *et al.*, 1978) who believe that both formations are source rocks for the Niger Delta oil. The two formations are just different facies within the same depositional system and likely contain similar organic matter. Each formation contributes variably to the hydrocarbon generated, depending on the location within the delta and the depth of burial.

### **2.5.1 RESERVOIR ROCK**

Petroleum in the Niger Delta is produced from sandstone and unconsolidated sands predominantly in the Agbada Formation. Characteristics of the reservoirs in the Agbada Formation are controlled by deposition environment and by depth of burial. Known reservoir rocks are Eocene to Pliocene in age, and are often stacked, ranging in thickness from less than 15 meters to 10% having greater than meters thickness (Evamy *et al.*, 1978). The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990). Based on reservoir geometry and quality, Kulke (1995) describe the most important reservoir as Miocene paralic sandstones with about 40% porosity, 2 Darcy's permeability, and a thickness of 100 meters.

The lateral variation in reservoir thickness is strongly, controlled by growth faults; the reservoir thickens towards the fault within the down-throw block (Akpofure and Etu-Efeotor, 2013). The grain size of the reservoir sandstone is highly variable with fluvial sandstones tending to be coarser than their delta

front counterparts; point bars fines upward, and barrier bars tend to have the best grain sorting. Much of this sandstone is nearly unconsolidated, some with a minor component of argillo-silicic cement (Kulke, 1995). Porosity only slowly decreases with depth because of the young age of the sediment and the coolness of the delta complex.

In the outer portion of the delta complex, deep-sea channel sands, low-stand sand bodies, and proximal turbidites create potential reservoirs (Beka and Oti, 1995). Burke (1972) describes three deep-water fans that have likely been active through much of the delta's history. The fans are smaller than those associated with other large deltas because much of the sand of the Niger-Benue system is deposited on top of the delta, and burial along with the proximal parts of the fans as the position of the successive depobelts moves seaward (Burke, 1972). The distribution, thickness, shaliness, and porosity/permeability characteristics of these fans poorly understood (Kulke, 1995).

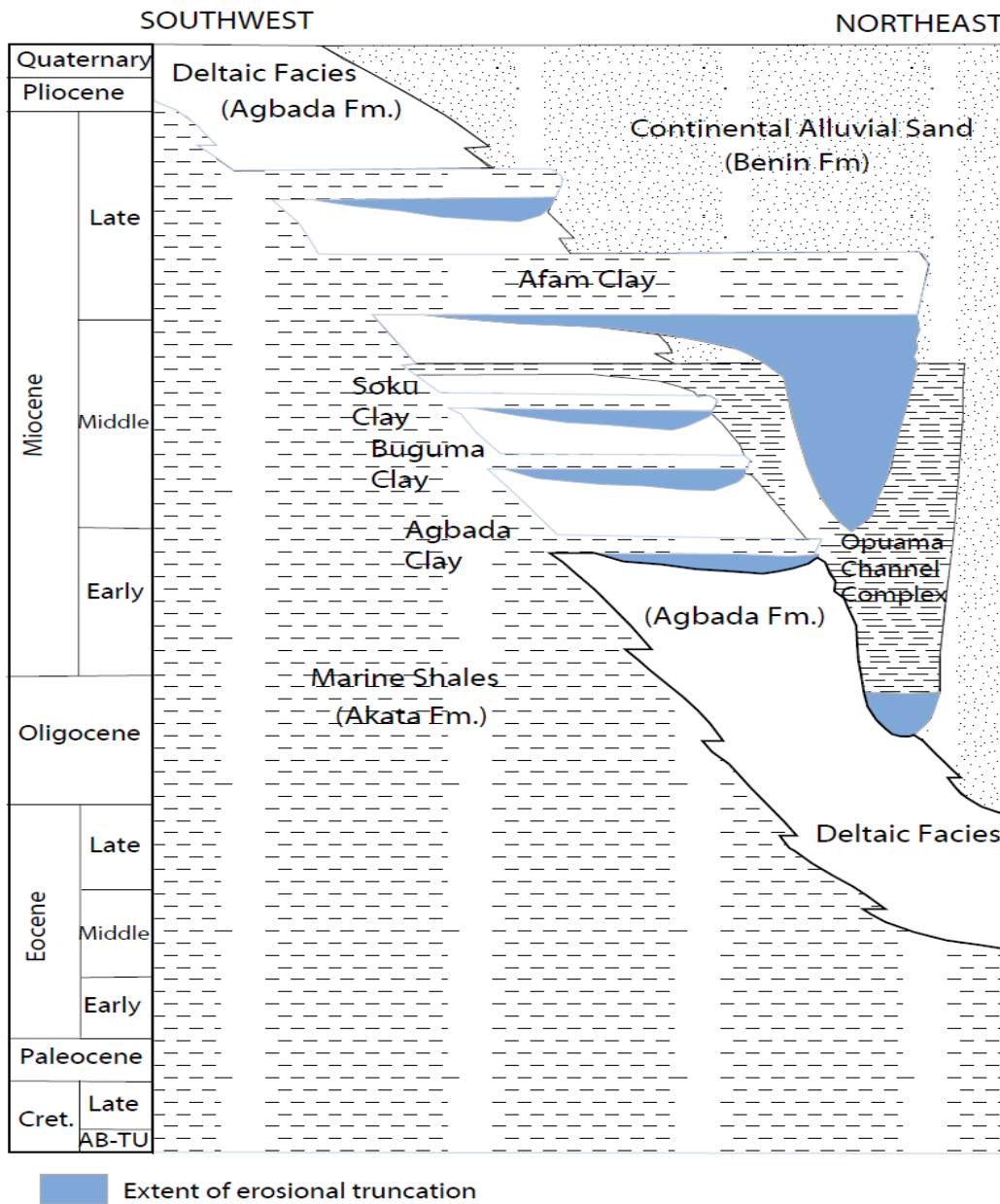


Figure 2.11: Stratigraphic Column Showing the Three Formations of the Niger Delta. Modified from Doust and Omatsola (1990).

### 2.5.2 TRAPS AND SEALS

Most known traps in Niger Delta fields are structural although stratigraphic traps are not uncommon. The structural traps developed during synsedimentary deformation of the Agbada paralic sequence (Evamy *et al*, 1978; Stacher, 1995). As discussed earlier, structural complexity increases from the north (earlier formed depobelts) to the south (later formed depobelts) in response to increasing instability of the under-compacted, over pressured shale. Doust and Omatsola (1990), describe a variety of structure trapping elements, including those associated with simple rollover structure; clay filled channels structure with multiple growth faults, structures with antithetic faults, and collapsed crest structures.

On the flanks of the delta, stratigraphic traps are likely as important as structural traps (Beka and Oti, 1995). In this region, pockets of sandstone occur between diapiric structures. Towards the delta toe (base of distal slope), this alternating sequence of sandstone and shale gradually grades to essentially sandstone. The primary seal rock in the Niger Delta is the interbedded shale within the Agbada Formation. The shale provides three types of seals-clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting, and vertical seals (Doust and Omatsola, 1990).

On the flanks of the delta, major erosional events of early to middle Miocene age formed canyons that are now clay-filled. These clays form the top seals for some important offshore fields (Doust and Omatsola, 1990).

## **CHAPTER THREE**

### **METHODS AND MATERIALS**

One hundred and seventy seven (177) ditch cutting samples within the interval of 5715-5730ft to 8680-8695 ft from Toms-Well, Val-Field, Greater Ughelli Depobelt, Niger Delta Basin were subjected to sedimentological analysis. The well was code named Toms-well for confidential reasons. These samples were dried and kept in sample bags which were labeled accurately. The samples and the location map of the selected well were provided by Nigerian Petroleum Development Company (NPDC), Benin City, Nigeria. The samples were then subjected to sedimentological analysis at the sedimentology laboratory, University of Benin, Benin City. This research involves the collection of ditch cutting samples, sedimentological analysis of ditch cutting samples, erection of lithologic model of the penetrated sedimentary succession and interpretation of results. The collection of the ditch cutting samples was achieved during the drilling operation of the well. Samples were collected and stored in polythene bags, properly labeled for easy identification during laboratory analysis. Laboratory analysis comprises detailed analytical studies of samples collected. This includes; sedimentological characteristics.

Ten ditch cutting samples were selected at different interval after the sedimentological analysis and subjected to different analytical methods and the subsequent results were carefully integrated. It involved the following methods;

1. Mechanical analysis: This was carried out using the mechanical sieve shaker for grain size analysis. The mineral assemblages were studied petrographically to see the percentage composition of constituent minerals which were used to determine the mineralogical maturity of the sediments
2. Pickett crossplots were plotted to see the variations and relationships between porosity, permeability, matrix and intergranular volume
3. Review of diagenetic processes at depth and compaction
4. Use of well log signatures to determine environment of deposition
5. Heavy mineral analysis was carried out to determine the heavy minerals components of the sediments which were then used to infer the provenance. This was done using the samples, separating funnel, conical flash, bromoform with specific gravity of 2.85, water, oven, acetate, Bunsen burner and a set of sieves. The resultant litmus paper was left to dry and mounted on a glass slide and viewed under the microscope.

### **3.1 HEAVY MINERAL SEPARATION ANALYSIS**

The apparatus include separating funnel, flask (Conical flask), litmus paper; bromoform (Specific gravity of 2.85, water, oven, acetate, Bunsen burner, set of sieves.

## **1. Procedures**

2. Disaggregate the samples
3. Measure about 200g of disintegrated samples.
4. Boil the sample with dilute HCl to dryness
5. Pour samples into the set of sieves
6. Shake the set of sieves
7. Pour out what is retained in the sieve mesh below 63  $\mu\text{m}$ .
8. Pour the bromoform into the separating funnel and close the tap beneath it.
9. Pour the sieved samples of sizes below 63 $\mu\text{m}$  and below into the separating funnel containing the bromoform
10. Stir the mixture vigorously
11. Allow the mixture to settle down
12. Open the tap of the separating funnel to allow the heavy minerals that might have settled to the bottom of the funnel to pass through onto a litmus paper placed on top of the flask.
13. Close the tap once all the heavy minerals have been flushed out
14. Add some drops of acetone in order to remove the effect of the bromoform
15. Allow the heavy mineral in the litmus paper to dry
16. Mount the heavy minerals on a glass slide using a mounting medium known as Canada balsam.

17. Identify the heavy minerals under a petrographic microscope on the basis of their optical properties.

### 3.2 GRAIN SIZE ANALYSIS

The apparatus/equipment include a set of sieves with a pan, weigh balance, mortar and pestle, brushes for cleaning the sieves, a sieve shaker (mechanical)

#### *Procedures*

- 1) Dry the samples
- 2) Disaggregate the samples: During disaggregation, ensure that the particles/grain is not broken down.
- 3) Clean the sieves thoroughly
- 4) Arrange the sieve in order of decreasing size with the pan at the base of the smaller size
- 5) Weigh out the desired weight using the weighing balance. This is done by coning
- 6) Pour the measured sample into the set of sieves and cover the topmost sieve the cover
- 7) Sieve the sample, sieving can be done mechanically or manually and should be timed, usually 15 minutes is required for a sieving operation
- 8) Allow the sediments/samples to settle in the sieve before opening for measurement; the time required maybe about 5 minutes



Figure 3.1: Showing a mechanical sieve machine (Casagrande, 1931).

## CHAPTER FOUR

### RESULTS AND DISCUSSION

The results obtained from the sedimentology and morphometric analyses were systematically presented. These results have been presented in the order in which the analysis were done and represented using tables, charts, logs, bivariant plots, ternary and coarsest particles – median (CM) diagrams all geared towards easy and comprehensive data interpretation.

Table 4.1. Grain size parameters of ten (10) sample depths, of mean, sorting skewness, kurtosis, minimum, maximum and average values.

Depth (ft)	Mean	Sorting	Skewness	Kurtosis
Maximum	1.7	1.5	0.464	3.28
Minimum	0.3	0.3	0.0625	0.801
Average	1	0.9	0.263	2.041
Maximum	2	0.8	0.193	1.5
Minimum	0.7	0.5	-0.083	0.81
Average	1.35	0.65	0.055	1.155
Maximum	1.5	1.2	0.253	1.23
Minimum	0.4	0.8	-0.0717	0.934
Average	0.95	1	0.0907	1.082
Maximum	2.3	1.5	0.14	1.639
Minimum	1.7	0.3	-0.06	1.03
Average	2	0.9	0.04	1.335
Maximum	2.3	1.1	0.216	1.27
Minimum	1.2	0.7	0.071	0.94
Average	1.75	0.9	0.0725	1.105

## 4.2. Textural characteristics of Toms-Well, Vals-Field

The mean, sorting, skewness and kurtosis of the sampled depths are: 1.4, 0.87, 0.104 and 1.344)φ respectively from Table 1, indicates moderately sorted medium sand, near symmetry with Leptokurtic grain. Folk, classified sorting values as; (1–3) φ for sand class; (0.25–0.5) φ for beach sand and (0.35-1.0) φ for fluvial/shallow marine sand. Therefore, Toms-Well, Vals-Field is of fluvial origin, after Folk' environmental discrimination scheme. This corroborates with the result from the environmental discrimination plots (Fig. 2), which also confirm the river/fluvial paleo-environment of deposition. Extremely high or low kurtosis values is an indication of different sources for the sediment and most likely from a high-energy environment. The differences in the values for kurtosis reflect the flow characteristics of the deposition medium. The dominance of the mesokurtic and leptokurtic nature of sediments reflects compositionally and mineralogically mature sand. The summary of grain size parameters as a percentage of the total number in each sector (Table 2) clearly shows that Toms-Well, Vals-Field is predominantly medium grained sands that are moderately sorted. This is a pointer to a depositional process with an intermediate energy source during sediment transport. The skewness is mainly near symmetry and coarse skewed of both positive and negative skewness, representing a predominant population and a subordinate population. Most sands are leptokurtic and are either positively or negatively skewed. This can be explained by the fact that most sand consist of two populations: one predominant population and one very subordinate coarse (leading to negative skewness) to fine (leading to positive skewness). The plot between mean and standard deviation shows the clustering of points in a narrow range of mean value on left limb of inverted V-shape trend (Fig. 4a).

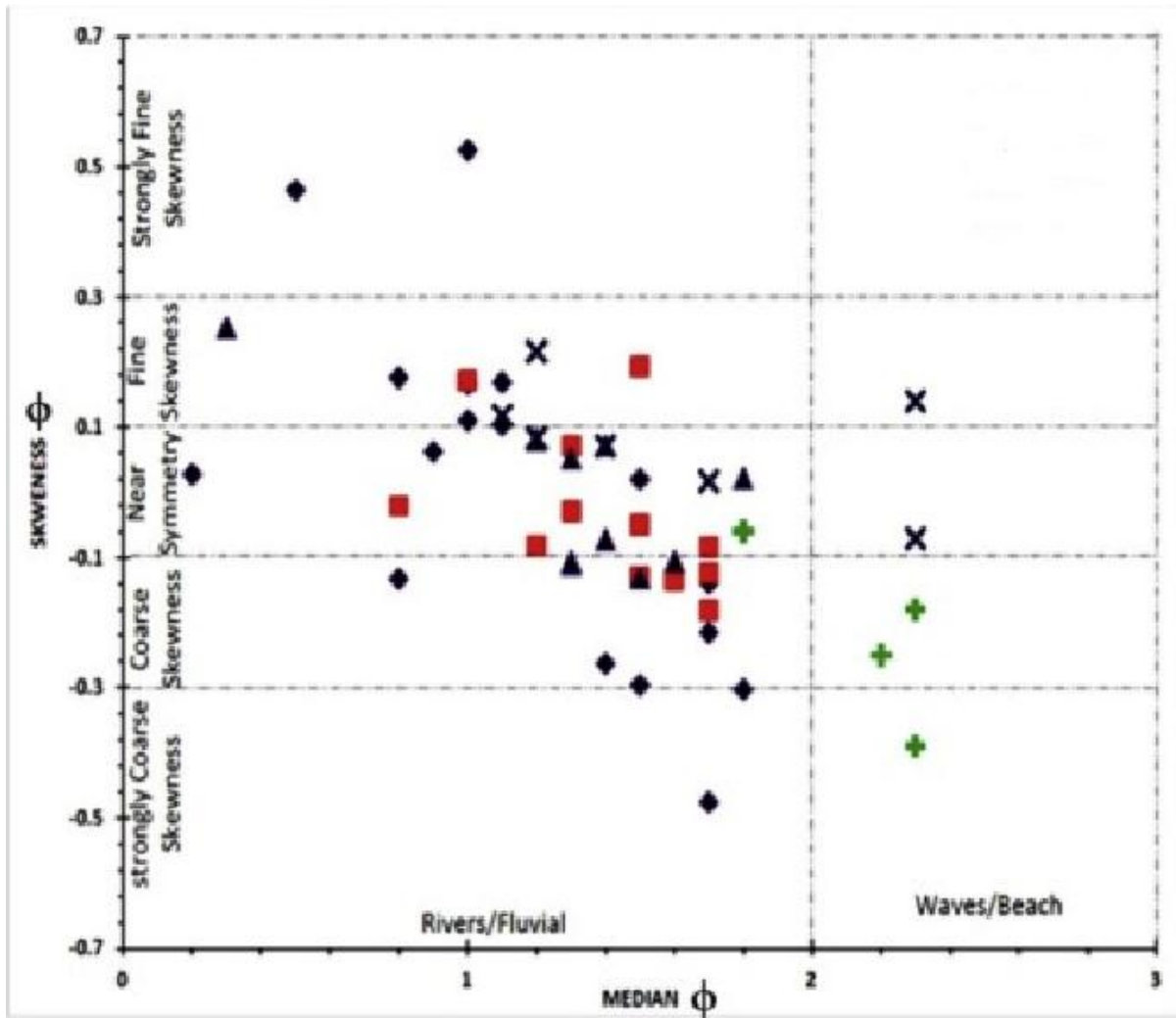


Figure 4.1(a). Environmental discrimination plot for Skewness vs. Media.

The mean vs. skewness curve for the studied samples, denote proportionate admixture of two size classes of the sediments i.e. medium to fine sand which form the sinusoidal curve, falling in negatively to positively skewed area showing medium grained, moderate to moderately well sorted nature indicating river environment (Fig. 4b). The Mean vs. Kurtosis plot also indicate the same result (Fig. 4a). The Skewness vs. Standard deviation indicates all the samples are coarse for near symmetry, falling within the circle (Fig. 4).

The Standard deviation vs. Kurtosis and Skewness vs. Kurtosis plot show that the sediments are restricted to a narrow range of kurtosis mostly from mesokurtic to leptokurtic and are near symmetry, which is matching with statistical measurements. These plots support the conclusion already drawn on the bases of previous bivariate plot. The positive skewness indicates dominance of non-beach, mostly a fluvial system of deposition in all studied samples.

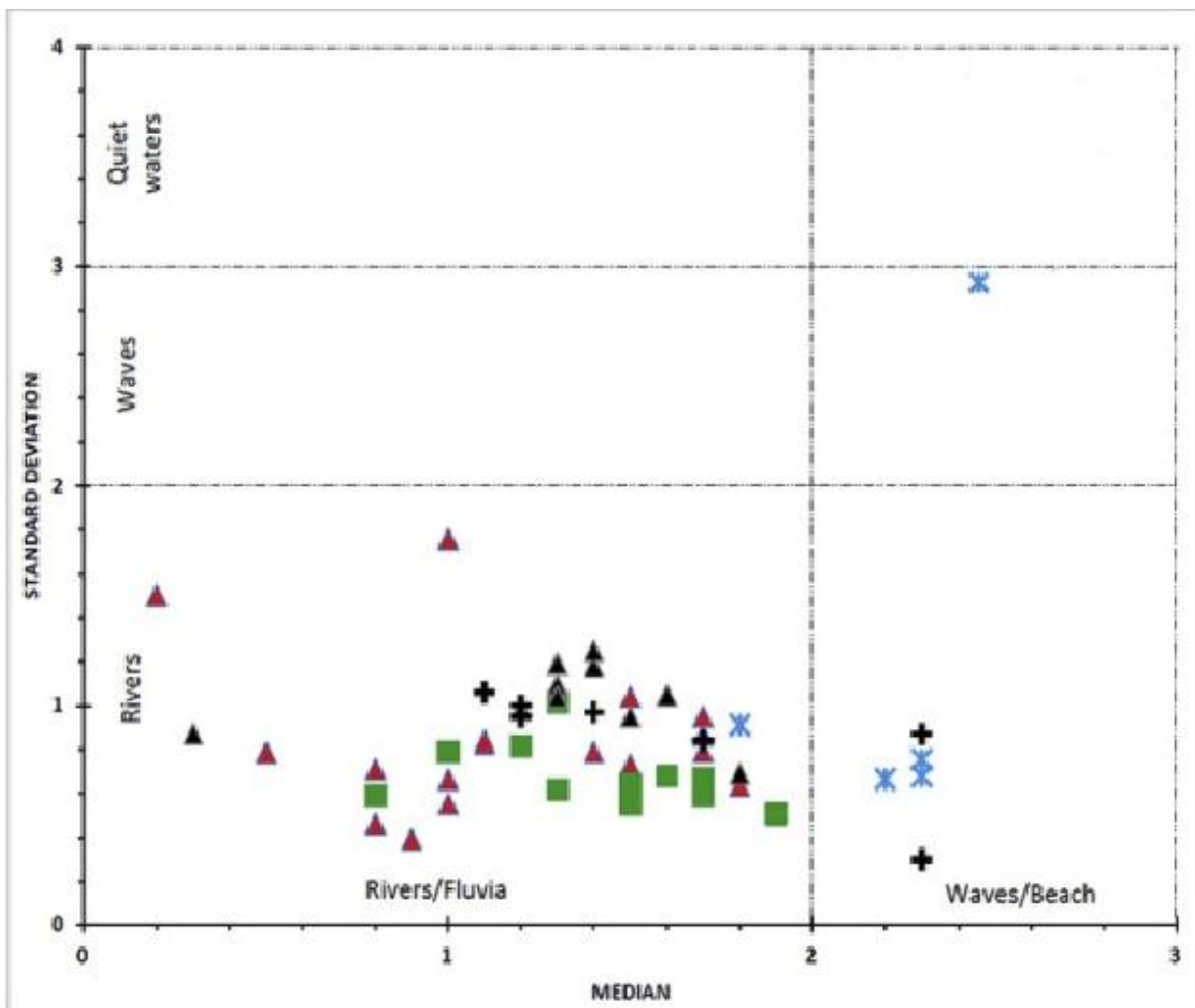


Figure 4.2 (b). Environmental discrimination plot for Standard deviation Vs. Median

Table 4.2. Summary of grain size parameters in percentage of the total number of each depth.

Mean	2466 ft	2470 ft	2479 ft	2502 ft	2524 ft	2538 ft	2551 ft	2565 ft	2574 ft	2586 ft
CS	22.99	9.47	3.175	0	0	22.99	11.47	33.175	0	2.31
MS	77.02	78.69	96.83	16.1	78.94	78.02	78.69	96.83	19.1	78.94
FS	0	11.84	0	88.9	21.06	2.34	11.84	1.13	88.9	21.06
Sorting										
WS	6.41	0	0	0	0	5.41	0	3.34	2.31	6.16
MWS	13.93	78.93	0	40.66	11.17	14.93	77.61	4.51	44.66	17.11
MS	68.36	21.07	36.22	50.38	71.68	66.36	21.07	36.22	61.38	77.28
PS	11.31	0	63.78	0	17.16	13.31	0	63.78	0	21.16
VWS	0	0	0	8.96	0	0	1.31	0	8.96	1.03
Skewness										
SFS	13.1	0	16.98	0	47.37	13.1	0	16.98	0	46.37
FS	39.3	0	0	0	25.87	29.3	0	0	0	25.87
NS	7.89	25.69	0	13.73	0	7.89	25.69	0	13.73	0
CS	37.1	52.68	30.39	17.65	26.75	53.1	52.68	30.99	17.65	26.75
SCS	2.49	21.61	52.62	68.63		2.49	21.61	52.62	78.63	
Kurtosis										
PK	7.43	5.83	0	0	0	7.43	5.83	0	0	0
MK	39.24	48.3	76.47	15.26	51.04	39.24	48.3	76.47	15.26	53.14
LK	22.5	45.87	23.54	60.45	48.96	22.5	45.87	23.54	70.45	48.96
VLK	15.78	0	0	24.29	0	15.78	5.17	0	24.29	0
ELK	15.04	0	0	0	0	16.04	0	5.71	0	2.61

### 4.3. Pebble morphometry and its paleoenvironment significance

The data on (Table 3) was employed in the plot the result on Fig. 4 (a and b) from which the paleoenvironment of deposition was inferred. From the result of the plot of roundness versus elongation shows that 99% of data points plot in the fluvatile: This indicates a fluvatile paleoenvironment of deposition for the sediments. The sphericity versus oblate - probate index, shows that 97% of data points plot in the fluvatile environment: This again, confirms the environment of deposition as fluvial paleoenvironment.

The unimodal dominated population as well as enhance saltation-suspension segments of the accumulative curve strongly indicate tidal influenced sediments. However, the environmental discrimination models and analytical techniques employed in this work, present clear evidences that the ancient environment of deposition is continental fluvial in origin (Fig. 4.2 & 4.4). The mechanism of transportation, from the CM diagram of the studied depths indicates that the deposition of sediment was by rolling, bottom suspension, and graded suspension this denotes sediments transported by fluvial processes and deposition.

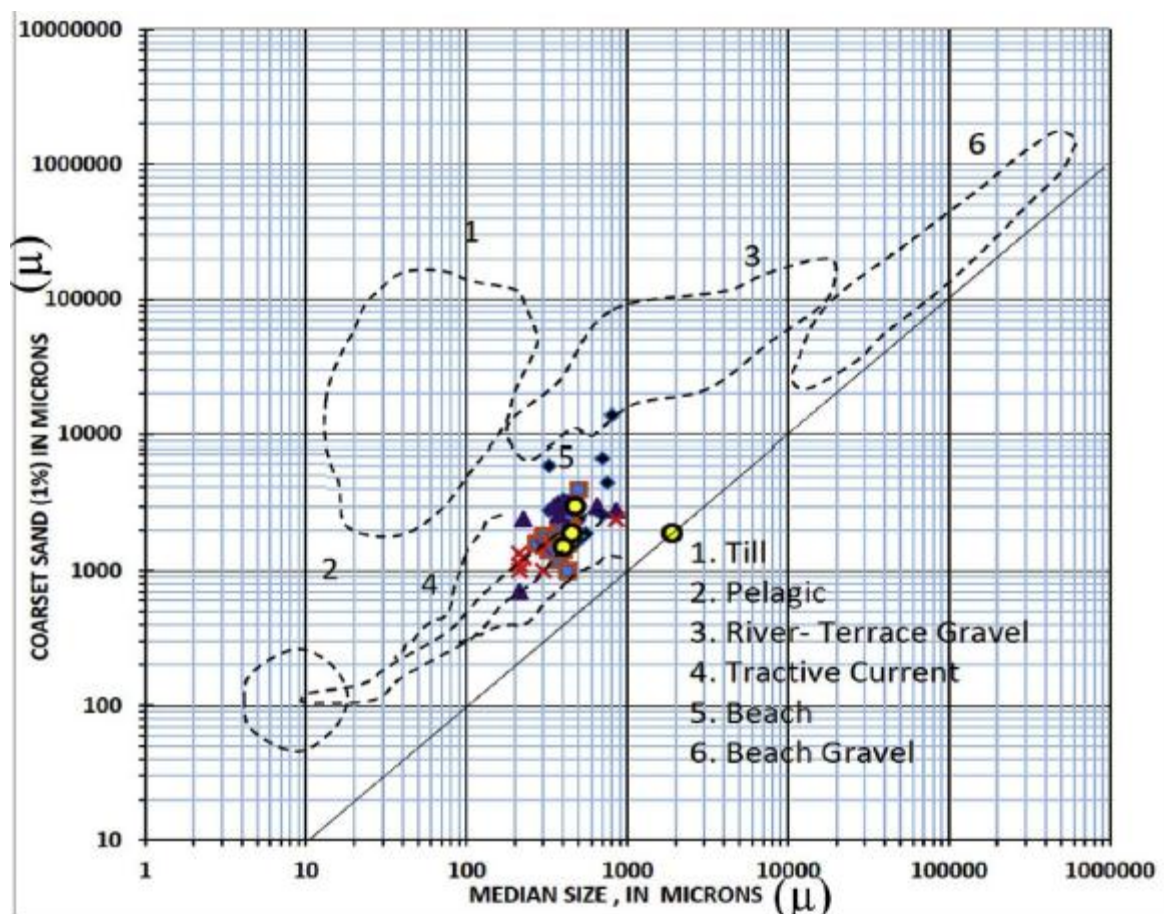


Fig. 4.3(a): Coarsest Sand-Median (CM) diagram.

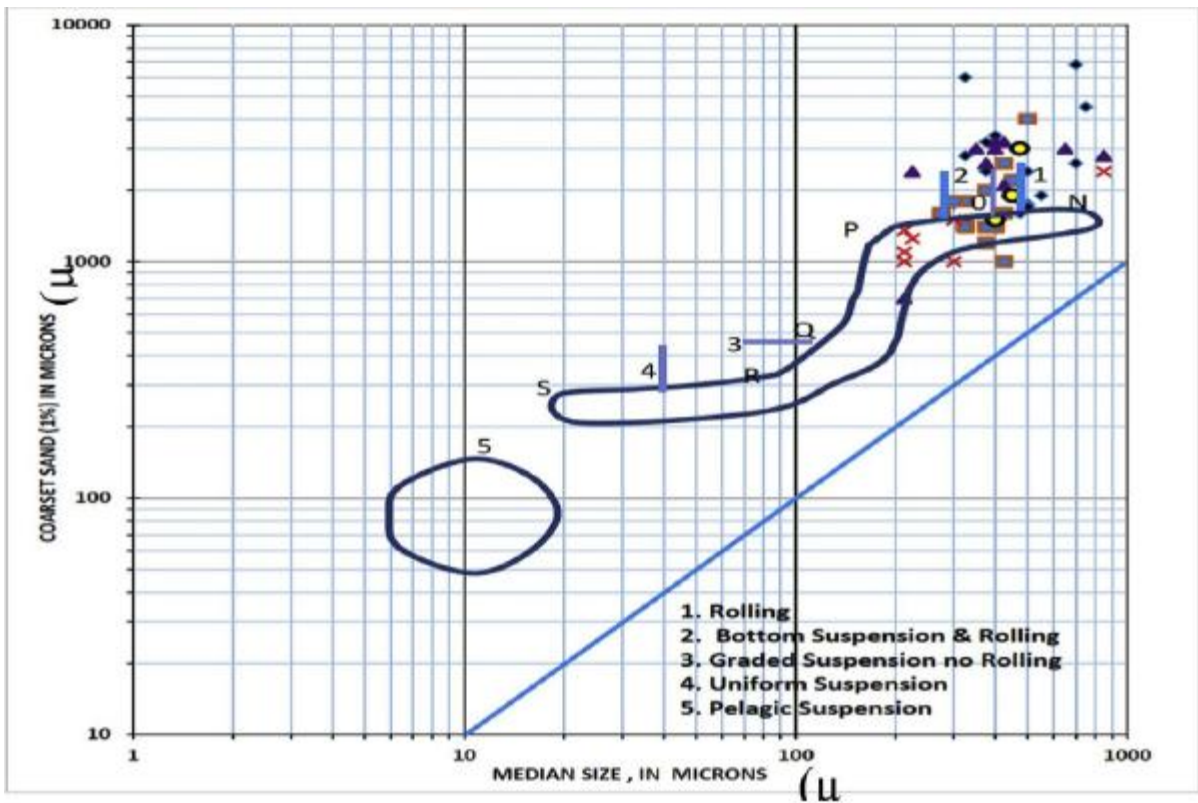


Fig. 4.3(b): Tractive current deposit for the western flank of Toms-Well, Vals-Field.

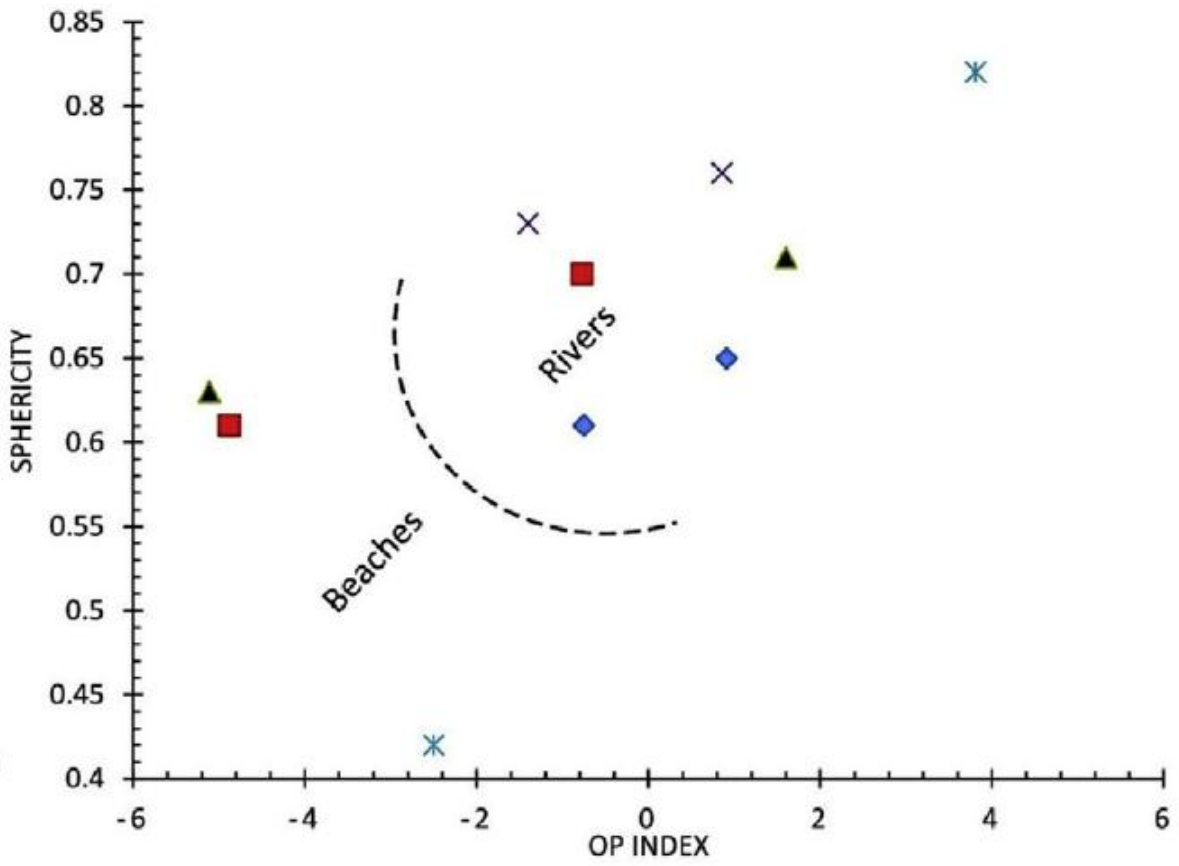


Fig. 4.4(a): Pebble roundness plotted against the Elongation ratio

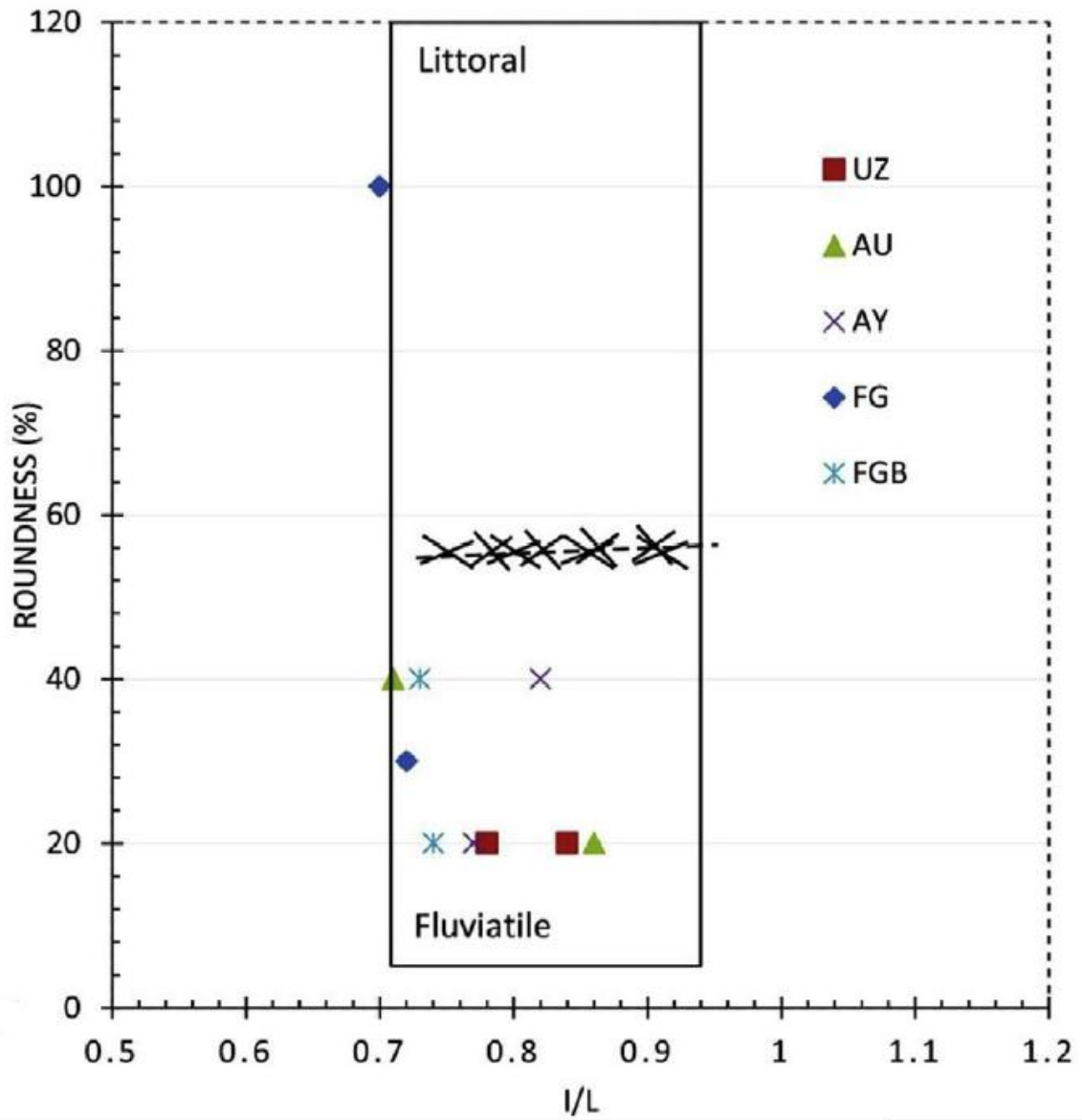


Fig. 4.5(b): Sphericity versus Oblate-probate index

Table 4.3: Average values of pebble morphometric data. Where L, I and S are long, intermediate and short axes respectively. Compact Bladed (CB) ¼ 50%; Platy (P) ¼ 20%; Bladed (B) ¼ 20%; Compact Elongate (CE) ¼ 10%.

Sample Depths (ft)	L (cm)	I (cm)	S (cm)	S/L	I/L	OP Index	Form Name	Roundness %	Bladed form (L-1)/(L-5)	Maximum Projection Sphericity
2466	1.29	0.95	0.48	0.37	0.74	-2.5	B	20	0.57	0.42
2470	1.27	0.99	0.66	0.52	0.78	-0.77	B	20	0.46	0.7
2479	1.31	0.87	0.66	0.58	0.77	0.86	CB	20	0.55	0.76
2502	1.52	1.27	0.66	0.43	0.84	14.88	P	20	0.29	0.61
2524	1.36	1.11	0.77	0.57	0.82	11.40	B	20	0.42	0.73
2538	1.22	1.05	0.57	0.47	0.86	15.11	P	40	0.26	0.63
2551	1.63	1.17	0.65	0.4	0.72	10.75	B	20	0.46	0.61
2565	1.49	0.04	0.65	0.44	0.7	0.91	B	30	0.54	0.65
2574	1.13	0.82	0.71	0.53	0.73	3.81	CE	100	0.74	0.82
2586	1.69	1.2	0.85	0.5	0.77	1.6	CB	40	0.58	0.71

Table 4.4: Results of Petrographic Analysis

<b>SampleDepth(m)</b>	<b>Average Size Grain (mm)</b>	<b>Quartz Composition</b>	<b>Feldspar Composition</b>	<b>Rock Fragments</b>
2466	0.02	85.23	8.49	-
2470	0.013	87.04	6.10	0.21
2479	0.2	93.10	6.72	0.48
2502	0.018	91.25	13.21	-
2524	0.02	88.69	10.04	-
2538	0.015	91.02	13.88	-
2551	0.013	88.06	8.87	-
2565	0.25	85.33	9.48	-
2574	0.015	95.25	10.33	-
2586	0.02	93.25	15.06	-

Table 4.5: Textural Properties of the samples

<b>Sample Depth(m)</b>	<b>Sorting</b>	<b>Grain Size</b>	<b>Grain Shape</b>
2466	Poorly sorted to moderately sorted	Medium to Fine grained	Sub-angular to sub-rounded
2470	Moderately sorted	Medium grained	Angular
2479	Moderately sorted	Medium grained	Sub-rounded
2502	Well sorted	Fine grained	Angular
2524	Poorly sorted to moderately sorted	Medium to Fine grained	Sub-rounded to rounded
2538	Well sorted	Fine grained	Angular
2551	Well sorted	Fine grained	Rounded
2565	Moderately sorted to well sorted	Medium to fine grained	Sub-rounded to rounded
2574	Moderately sorted	Fine to very fine	Rounded
2586	Well sorted	Fine to very fine	Rounded

Except for depths 2466m, 2524m and 2565, which are poorly sorted, other samples were moderately to well sorted. This is the result of the volume of spaces between the grains higher or finer grains. It also shows that the well sorted the grains, the better the porosity and the degree of uniformity of the grains size.

Table 4.6: Mineralogical composition and index of chemical maturity of the samples.

<b>SAMPLE DEPTH(m)</b>	<b>QUARTZ COMPOSITION</b>	<b>FELDSPAR COMPOSITION</b>	<b>INDEX OF CHEMICAL MATURITY (TO NEAREST NUMBER)</b>
2466	85.23	14.77	6
2470	87.04	12.75	7
2479	93.01	6.42	14
2502	91.25	8.75	10
2524	88.6	11.31	8
2538	91.02	8.98	10
2551	88.06	11.94	7
2565	85.33	14.67	6
2574	95.48	4.52	21
2586	93.25	6.75	14

Most of the samples fell within the quartz arenite region and few on the sub-feldspathic arenite region. This is an indication of a high quartz composition and minimal feldspar content of the samples. The high quartz arenite content is also an indication that the samples are texturally and compositionally matured. The highest quartz arenite content was observed in sample 9 with 95.48% quartz content. This is followed by sample 10 with 93.25% quartz content and sample 3 with 93.10% quartz content. In general, the quartz composition ranges from 85.23-95.48%, thereby, conforming to the maturity of the sandstones that make up the reservoirs of the Vals-Field.

Table 4.7: Result of heavy mineral analysis and provenance inference

HEAVY MINERALS	PROVENANCE INFERENCE			
	IGNEOUS ROCK		METAMORPHIC ROCK	
	MAFIC	FELSIC	HIGH GRADE	LOW GRADE
Zircon		YES		
Hornblende		YES	YES	YES
Glauconite		YES		YES

Heavy minerals are characteristic minerals found in metamorphic and igneous rock, some are also diagnostic of sedimentary rock; these minerals are usually resistant to chemical weathering and occur in accessory order in sedimentary rocks. They are usually less than 1% of the rock composition. These heavy minerals have specific gravity greater than 2.65 which is the specific gravity of bromoform. For the sandstone analyzed, the major heavy minerals are zircon, hornblende and tourmaline (Table 4.4). From the table, it is shown that zircon is sourced mainly from felsic igneous rocks; hornblende is sourced from felsic igneous rocks and high grade metamorphic rocks. On the other hand, tourmaline is sourced from high grade metamorphic rock and felsic igneous rocks.

#### **4.4. Environment of deposition (EOD) from log motif**

The environment of deposition was delineated using mainly the log signature as shown in (Figure 4.7). The litho log displays mostly a fining upward sequence; a bell shape pattern indicative of a non-marine environment. The depositional system could be interpreted as fluvial. The coarse grained basal sandstone facies consists of amalgamated and isolated sharp-based fining upward sand bodies characterized by blocky to bell-shaped Log motif. The sand units are locally separated by thin bands of shale/mudstone and lack marine fauna. The lithologic facies is interpreted as fluvial channel deposits based on these characteristics. These channel deposits represent deposition in a coastal plain setting landward of the tidal zone. The blocky log pattern is common in incised valley fills. The lack of serration in the lithology suggests minimal or complete absence of tidal influence.

Lithofacies Unit	sh-sand%	(m)	Litho-type	sand%-shale	Mineral Assemblages	Sedimentological Description
5715 - 5730		1714m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5730 - 5745		1719m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5745 - 5760		1723m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5760 - 5775		1728m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5775 - 5790		1732m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5790 - 5805		1737m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5805 - 5820		1741m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5820 - 5835		1746m		100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5865 - 5880		1759m	sand	100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5880 - 5895		1764m	sandyshl	15%sand-85%shal	qtz and coal	shalysand, dark
5895 - 5910		1768m	shly/sand	100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5910 - 5925		1773m	shale	60%sand-40%shale	qtz and coal	sandy shale, grey in colouration, c/m grain and ps/ms
5925 - 5940		1777m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
5940 - 5955		1782m	sandyshl	15%sand-85%shal	qtz	shalysand, dark
5955-5970		1786m	sandyshale	45%sand-55%shale	qtz	shalysand, dark
5970 - 5985		1791m	sand	100%sand	qtz and coal	sand,mlky,brown,c/m,sa./sr,ps/ms.
5985 - 6000		1795m	shalysand	15%shale-85%sand	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6000 - 6015		1800m	sandyshl	20%sand/80%shl	qtz	shalysand, dark
6015 - 6030		1804m	sandyshl	15%sand/85%shl	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6030 - 6045		1809m	sand	100%sand	qtz/ limonite	sand,mlky,brown,c/m,sa./sr,ps/ms.
6045 - 6060		1813m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6060 - 6075		1818m	sand	100%sand	qtz/limonite	sand,mlky,brown,c/m,sa./sr,ps/ms.
6075 - 6090		1822m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6105 - 6120		1831m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6120 - 6135		1836m	sandyshale	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6135 - 6150		1840m	sandyshale	85%sand- 15%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6150 - 6165		1845m	sandyshale	85%sand-15%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6165 - 6180		1849m	shalysand	80%sand-20%shl	qtz	sandy shale, grey in colouration and platy in nature
6180 - 6195		1854m	sand	100%sand	qtz/ limonite	sand,mlky,brown,c/m,sa./sr and ps/ms.
6210 - 6225		1863m	shalysand	50%shale-50%sand	qtz	shalysand, dark grey in colouration and platy in nature
6225-6240		1867m		100%sand	qtz/ limonite	sand,mlky,brown,m/f,sa./sr,ms/ws.
6240 - 6255		1872m	shale	100%shale	qtz	sandy shale, dark grey in colouration and platy in nature

6270 - 6285		1881m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6285 - 6300		1885m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6300 - 6315		1890m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6315 - 6330		1894m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6330 - 6345		1899m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6345 - 6360		1903m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6360 - 6375		1908m	sand	100%sand	qtz/ limonite	sand,mlky,brown,c/m,sa./sr,ps/ms.
6375 - 6390		1912m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6390 - 6405		1917m	sand	100%sand	qtz	sand,mlky,brown,c/m,sa./sr,ps/ms.
6405 - 6420		1921m	sand	100%sand	qtz/ limonite	sand,mlky,brown,c/m,sa./sr,ps/ms.
6420 - 6435		1926m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6435 - 6450		1930m	shale	100%shale	qtz	shale, dark grey in colouration and platy in nature
6450 - 6465		1935m	shalysand	70%shale-30%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6465 - 6480		1939m	shly/sand	60%shale-40%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6480 - 6495		1944m	sandyshale	sand55%- 45%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6495 - 6510		1948m	sandyshale	60%sand-40%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6510 - 6525		1953m	sandyshale	80%sand-20%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6525 - 6540		1957m	sandyshale	85%sand-15%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6540 - 6555		1962m	sandyshale	90%sand-10%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6555 - 6570		1966m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6570 - 6585		1971m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6585 - 6600		1975m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6600 - 6615		1980m	sandyshale	70%sand-30%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6660 - 6675		1998m	sandyshale	55%sand-45%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6675 - 6690		2002m	sandyshale	85%sand-15%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6690 - 6705		2007m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6690 - 6705		2007m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
6705 - 6720		2011m	sandyshale		qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6720 - 6735		2016m			qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6735 - 6750		2020m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6750 - 6765		2025m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6765 - 6780		2029m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6780 - 6795		2034m	sandyshale	95%sand-5%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms

6795 – 6810		2038m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6810 – 6825		2043m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
6825 – 6840		2047m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6840 – 6855		2052m	sandy/shl	90%sand-10%shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
6855 – 6870		2056m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6865 – 6900		2059m	shly/sand	80%sand-20%shl	qtz	shalysand, dark grey in colouration and platy in nature
6870 – 6885		2061m	shly/sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6900 – 6915		2070m	shalysand	50%sand-50%shale	qtz	shalysand, dark grey in colouration and platy in nature
6930 – 6945		2073m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
6945 – 6960		2083m	shlale	100%shale	qtz	shale, dark grey in colouration and platy in nature
6960 – 6975		2088m	shalysand	80%shale-20%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6975 – 6990		2092m	shalysand	70%shale-30%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
6990 – 7005		2097m	shalysand	sand40%- 60%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7005 – 7020		2101m	shalysand	60%sand-40%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7020 – 7035		2106m	shalysand	80%sand-20%shl	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7035 – 7050		2110m	sandyshale	85%sand-15%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7050 – 7065		2115m	sandyshale	90%sand-10%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7065 – 7080		2119m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7080 – 7095		2124m	sandyshale	95sand-5%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7095 – 7110		2128m	sand		qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7110 – 7125		2133m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7125 – 7140		2231m	sandy/shale	95%sand-5%shl	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7140 – 7155		2142m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7155 – 7170		2146m	sandyshale	90%sand-10%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7170 – 7185		2151m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7200 – 7215		2160m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7215 – 7230		2164m	sandyshale	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7230-7245		2169m	shalysand	95%sand-5%shl	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7245 – 7260		2173m			qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7260 – 7275		2178m			qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7290 – 7305		2187m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,ms/ws.
7300 – 7320		2190m	sandy/shl	90%sand-10%shl	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7300 – 7350		2190m	sandy/shl	80%sand-20%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms

7300 – 7365		2190m	shale	shale100%	qtz	shale, dark grey in colouration and platy in nature
7320 – 7335		2196m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7335 – 7350		2200m	sandy/shl	90%sand-10%shl	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7365 – 7380		2209m	sandyshale	85%sand-15%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7380 – 7395		2214m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7395 – 7410		2218m	shale	shale100%	qtz	shale, dark grey in colouration and platy in nature
7410 – 7425		2223m	shalysand	70%shale-30%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7425 – 7440		2227m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7440 – 7455		2232m	shly/sand	60%shale-40%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7455 – 7470		2236m	shly/sand	50%shale-50%sand	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7470 – 7485		2241m	shly/sand	70%sand-30%shale	qtz	sandy shale, dark grey in colouration, c/m grain and ps/ms
7485 – 7500		2245m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7500 – 7515		2250m	sandyshale	85%sand-20%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7515 – 7530		2254m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7530 – 7545		2259m	shale	100%shale	qtz	shale, dark grey in colouration and platy in nature
7545 – 7560		2263m	shale	100%shale	qtz	shale, dark grey in colouration and platy in nature
7560 – 7575		2268m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7575 – 7590		2272m	shly/sand	85%shale-15%sand	qtz	sandy shale, dark grey in colouration, m/f grain and ps/ms
7590 – 7605		2277m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7605 – 7620		2281m	shly/sand	90%sand-10%shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7620 – 7635		2286m	sand	100%sand	clay/qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7635 – 7650		2290m	shly/sand	85%sand-15%shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7650 – 7665		2295m	shly/sand	95%sand-5%shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7665 – 7680		2299m	shly/sand	95%sand-5%shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
7680 – 7695		2304m	sand	100%sand	clay/qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7710 – 7725		2313m	sandyshale	85%sand-20%shale	qtz	sandy shale, grey in colouration, c/m grain and ps/ms
7755 – 7770		2326m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7770 – 7785		2331m	shale	80%sand-20%shale	qtz	shalysand, dark grey in colouration, m/f grain and ps/ms, platy in nature
7785 – 7800		2335m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7800 – 7815		2340m	sandyshale		qtz	sandy shale, grey in colouration, c/m grain and ms/ws
7815 – 7830		2344m	sandyshale	95%sand-5%shale	qtz	sandy shale, grey in colouration, c/m grain and ms/ws
7830 – 7845		2349m	sand	100%sand	qtz	sand,mlky,brown,m/f,sr,r,s/ws.
7835 – 7950		2350m	sandyshale	90%sand-10%shale	qtz	sandy shale, grey in colouration, c/m grain and ms/ws

7845 - 7860		2353m	sandyshale	95% sand-5% shale	qtz	sandy shale, grey in colouration, c/m grain and ms/ws
7869 - 7875		2360m	sand	100% sand	qtz	sand, mlky, brown, m/f, sr, r, s/ws.
7875 - 7890		2362m	shale	100% shale	qtz	shalysand, dark grey in colouration and platy in nature
7890 - 7905		2367m	sand	100% sand	qtz	sand, mlky, brown, m/f, sr, r, s/ws.
7905 - 7920		2371m	sandyshale	95% sand-5% shale	qtz	sandy shale, grey in colouration, c/m grain and ms/ws
7920 - 7935		2376m	sandyshale	95% sand-5% shale	qtz	sandy shale, grey in colouration, c/m grain and ms/ws
8100 - 8115		2430m		100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8115 - 8130		2434m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8130 - 8145		2439m	shale	85% shale-15% sand	qtz	shalysand, dark grey in colouration and platy in nature
8145 - 8160		2443m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8160 - 8175		2448m	sandyshale	90% sand-10% shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
8175 - 8190		2452m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8190 - 8205		2457m	sandyshale	90% sand-10% shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
8205 - 8220		2461m	shale	100% shale	qtz	shale, dark grey colour shale, platy in nature
8220 - 8235		2466m	sandyshl	90% sand-10% shale	qtz	sandy shale, grey in colouration, m/f grain and ps/ms
8225 - 8310		2467m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8235 - 8250		2470m	sand	100% sand	qtz	sand, mlky, brown, m/f, sr, r, s/ws.
8250 - 8265		2475m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8265 - 8280		2479m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8280 - 8295		2484m	sand	100% sand	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8310 - 8325		2493m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8325 - 8340		2497m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8340 - 8355		2502m			glauconite/qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8355 - 8370		2506m	sand	100%	qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8370 - 8385		2511m	shale	100% shale	qtz	shale, dark grey colour shale, platy in nature
8400 - 8415		2520m	sandyshale	70% sand-30% shale	qtz	sandy shale, grey in colouration, f/m grain and ms/ws
8415 - 8430		2524m	sand	100% sand	clay/qtz	sand, mlky, brown, F/V, F, sr, r, ps/ms.
8425-8440		2527m		100% shale	qtz	shale, dark grey in colouration and platy in nature
8440 - 8445		2532m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8445 - 8460		2533m	sandyshale	95% sand-5% shale	qtz	sandy shale, grey in colouration, f/m grain and ps/ms
8460 - 8475		2538m	sand	100% sand	glauconite/qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8490 - 8505		2547m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8505 - 8520		2551m	sand	100% sand	clayqtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8520 - 8535		2556m	shale	100% shale	qtz	shale, dark grey colour shale, platy in nature
8535 - 8550		2560m	shalysand	60% shale-40% sand	qtz	shalysand, dark grey in colouration, m/c grain and ms/ws
8550 - 8565		2565m	sand	100% sand	glauconite/qtz	sand, mlky, brown, F/V, F, sr, r, ms/ws.
8565 - 8580		2569m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8580 - 8590		2574m		100% sand	glauconite/qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8590 - 8605		2577m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8605 - 8620		2581m	shale	100% shale	clayqtz	dark grey colour shale, platy in nature
8620 - 8635		2586m	sand	100% sand	glauconite/qtz	sand, mlky, brown, F/V, F, sr, r, s/ws.
8635 - 8650		2590m		100% shale	qtz	shale, dark grey in colouration and platy in nature
8650 - 8665		2595m	shale	100% shale	qtz	shale, dark grey in colouration and platy in nature
8665 - 8680		2599m	shalysand	shale 80%-20% sand	qtz	sandy shale, dark grey in colouration and platy in nature
8680 - 8695		2604m	shalysand	shale 70%- 30% sand	qtz	shaly sand, dark grey in colouration and platy in nature

Figure 4.7: A Lithologic al model of the penetrated Toms-well

## **TEXTURAL PROPERTIES OF THE RESERVOIR SAND BODIES**

The highest value was recorded in sample three (3) while the least was observed in sample one (1). There is no particular order in the distribution of the grain sizes in the sand bodies of Toms-well in the Vals-Field with depth as it fluctuates within the ten samples. The grains were medium to fine-grained. There were no records of coarse-grained sandstone in the sampled depths, indicating that the sediments must have been transported from the source and were not studied in-situ. When viewed under the microscope, the intergranular space or volumes between the samples were higher on the finer grains.

## CHAPTER FIVE

### CONCLUSION AND RECOMMENDATION(S)

#### 5.1 CONCLUSION

The studied depths in Toms-Well, Vals-Field of the Niger Delta Basin are dominated by medium-grained, moderately sorted sandstone, which is characteristic of the Agbada Formation. The textural studies revealed intermediate energy for the transporting medium, mesokurtic to leptokurtic grains that are near-symmetrical, which indicates environments where the effect of erosion and deposition are almost balanced. The evidence from the paleoenvironmental studies suggests a marine paleoenvironment. The sandstones bodies in the study area are texturally and compositionally matured. The sandstones are sourced from mainly felsic igneous rocks as well as from low to high grade metamorphic rocks. The main accessory minerals are zircon, hornblende and tourmaline. The reservoir quality is good and sands are both texturally and mineralogically matured. The porosity of the reservoir sand bodies is fine to medium. Finally, we can conclude that the reservoir sand bodies of the Toms-well, Vals-Field is good and will yield maximum output on production. The environment of deposition is marine environment as indicated by the discriminant plots for environment of deposition interpretation scheme proposed by Folk's, (1964).

## **5.2. RECOMMENDATION(S)**

The core samples were not matched with well logs correlation to determine the lateral extent of the textural, petrophysical and diagenetic properties. Further studies on the Val-Field should therefore consider creating a correlation panel tied with core data.

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