RESERVOIR ROCK CHARACTERIZATION OF LAMU BASIN IN SOUTHEAST KENYA

KAMAU S. MAINA

REG. NO: I13/2364/2007

A RESEARCH PROJECT SUBMITTED IN PARTIAL FULFILLMENT FOR THE AWARD OF BACHELOR OF SCIENCE DEGREE IN GEOLOGY,

DEPARTMENT OF GEOLOGY,

UNIVERSITY OF NAIROBI

JUNE 3RD, 2011

DECLARATION

Student Declaration

I hereby certify this project as my original work and has never been presented for examination by any other person. No publication or reproduction of this document should be done without my permission or liars with the Department of Geology at the University of Nairobi.

SIGN…………………………………… **DATE……………………………………..**

KAMAU SAMUEL MAINA

REG. NO: I13/2364/2007

Declaration by the Supervisor

This project has been submitted for examination with my approval as the supervisor

SIGN…………………………………… **DATE……………………………………..**

DR. D. W. ICHANG'I

Declaration by the Project Coordinator

This project has been submitted for examination with my approval as the coordinator

SIGN…………………………………… **DATE……………………………………..**

DR. D. O. OLAGO

ABSTRACT

Lamu Basin formed as a result of failed arm of a tri-radial rift system (Reeves et al., 1986) that developed passively in Mesozoic after the subsequent drift of Madagascar from the East Africa coast. It is the largest sedimentary basin in Kenya encompassing 170,000 km^2 both onshore and offshore. Lamu Basin is characterized by distinct sandstone facies which formed from Permo-Carboniferous through Tertiary in four Megasequences that show variation in grain sizes, porosity, permeability, compaction, shaliness and cementation. This is largely determined by the forces involved in the formation and their environmental setting. This categorizes the facies into; continental rift basin sandstones, fluvial-deltaic sandstones, and the sandstones due to marine deposition.

The study objectives were developed in line with the need to investigate on the sedimentological (grain size, texture, thickness and sorting) and petrophysical (porosity, permeability and the seismic velocity contrasts) parameters of mainly the sandstones as reservoir rocks. This was achieved by adopting information from the well logs (porosity, resistivity, gamma ray and seismic data) studied from the drilled wells in Lamu Basin. The relationships between these properties were determined in order to evaluate the quality of the sandstone as reservoir rocks.

The results showed that the petrophysical properties of the characteristic sandstones are directly related to their sedimentological characteristics (primary factor) but are either improved or reduced by diagenesis (secondary factors) for instance cementation, dissolution or compaction. The sands grade from siltstones to coarse grained (0. 0039-1.0 mm) sizes whereby the higher and low grades are related to fluvial and deltaic origin respectively. Their porosity values range from fair to excellent with the highs of >20% and lows of <15%. The sandstones with higher values of effective porosity were considered permeable but <10% porous ones implied negligible permeability. The seismic velocity contrasts were used to determine the degree of compaction of the sandstones in relation to other rocks in the basin. High compaction depict high seismic velocity, relatively low porosity and permeability whereas the vice versa is true.

The study was considered successful by having achieved the objectives that were set for investigations. From the sedimentological and petrophysical point of view, most of the sandstones in Lamu Basin have relatively good reservoir characteristics.

ACKNOWLEDGEMENT

My gratitude goes the almighty Lord for giving us life and health to enable us to go through the whole process of preparing this project. I really appreciate the great work by Dr. Ichang'i in the corrections of this document. Thanks to the leader of the exploration team and the whole Library staff in the National Oil Corporation of Kenya (NOCK) and the Ministry of Energy for their indispensable support in my research work. The pieces of advice given by Mr. Muia and Mr. Anthony were of great help into my research. I thank my parents too for their continued support in my studies throughout the course. May the Lord bless them in abundantly.

DEDICATIONS

I dedicate this project to my parents (Jane and Wilson), my sisters (Bilhah and Elizabeth) and my friends.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

CHARACTERIZATION OF RESERVOIR ROCK IN LAMU BASIN

CHAPTER ONE: INTRODUCTION

1.1 Introduction

Reservoir characterization involves studies on various parameters that support occurrence of fluids in a rock. This study is an attempt to understand how the reservoir properties are related to the stratigraphic sequences and depositional processes that were involved during the formation of the rock. This is the basis of determining the overall quality and productivity of the reservoir rock. This chapter will give an introduction of the study that will entail the major objective and knowledge gap, and a review of the previous work on the Lamu Basin.

1.2 Lamu Basin

Lamu Basin is located in Southeast Kenya, east of the 39th meridian, and includes the adjacent continental shelf and slope areas of the Indian Ocean (Figure 1.1). It is the largest sedimentary basin in Kenya encompassing 170,000 km^2 both onshore and offshore has sediment thickness ranging from 3250 m in the northern boundary to 10,000 m in the coastal area (Nyagah, 1995). The basin consists of sediments of Permo-Carboniferous through Tertiary continental rift basin sandstones, fluvial-deltaic sandstones, marine shales and carbonates. The offshore depo-centre has a sedimentary column which is 12,000 m to 13,000 m thick (Nyagah, 1995).

According to Nyagah (1995) Lamu Basin is the failed arm of a tri-radial rift system (Reeves *et. al.*, 1986) that developed passively in Mesozoic after the subsequent drift of Madagascar from the east coast of Africa (Bosellini, 1986). Development of the southern part of the basin as a passive margin is closely related to considerations of the pre-drift position of Madagascar and formation of the Indian Ocean basin during Mesozoic. Cretaceous and Tertiary strata in the basin comprise an eastward-thickening gross succession of sediments on which eustatic sea-level fluctuations and a sequence of unconformities related to pulses of transgressive and regressive depositional trends are superimposed.

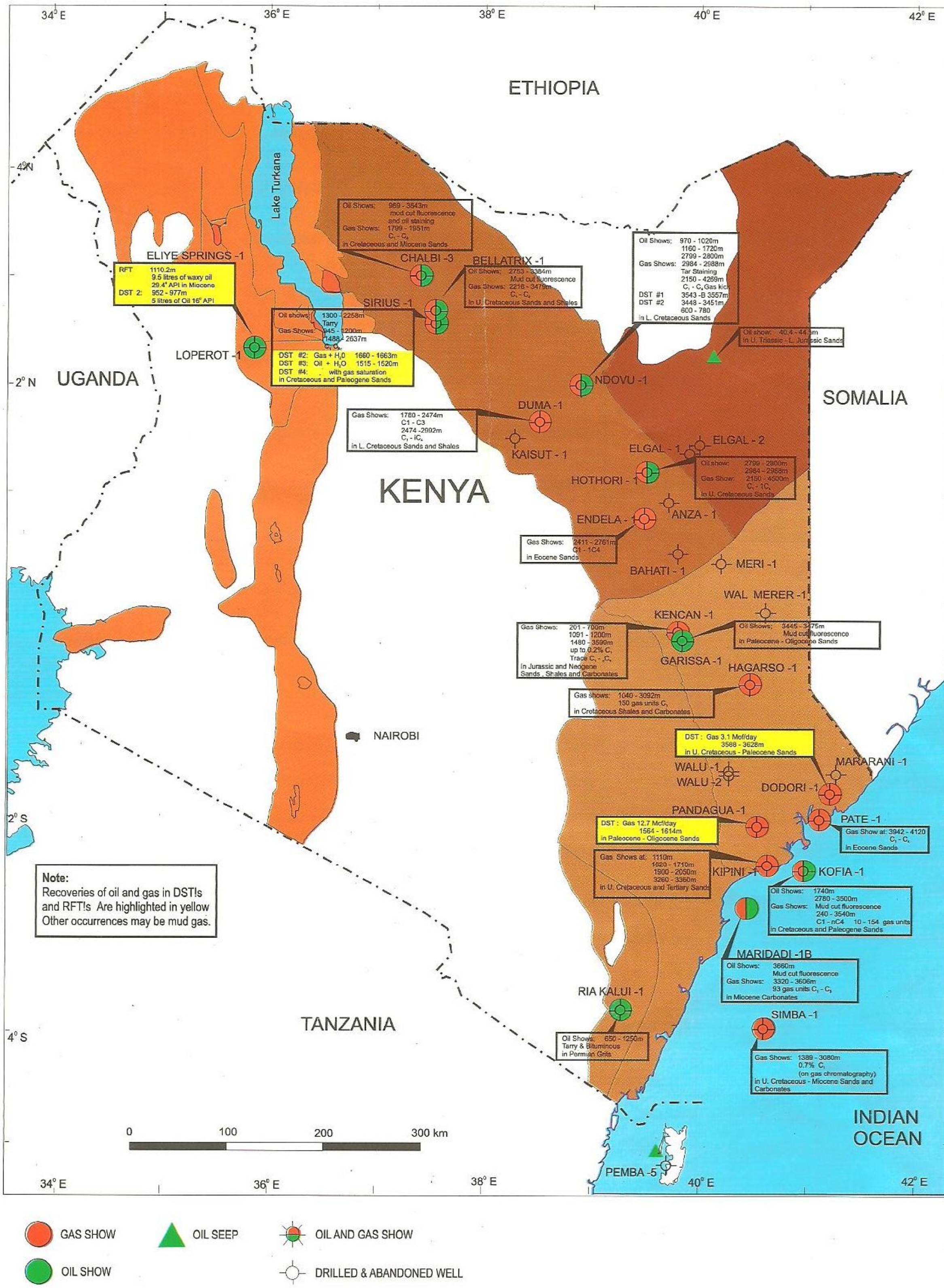

Figure 1. 1: The Map Showing Wells Drilled in Kenya.

Map available at the National Oil Corporation of Kenya Library

1.2.1 Lamu Basin Mega-Sequences

The Permo-Carboniferous through Tertiary sediments of the Lamu Basin can be divided into four mega-sequences (NOCK, 1995) each bounded by regional unconformities recording interruptions in the basin depositional history (Figure 1.2).

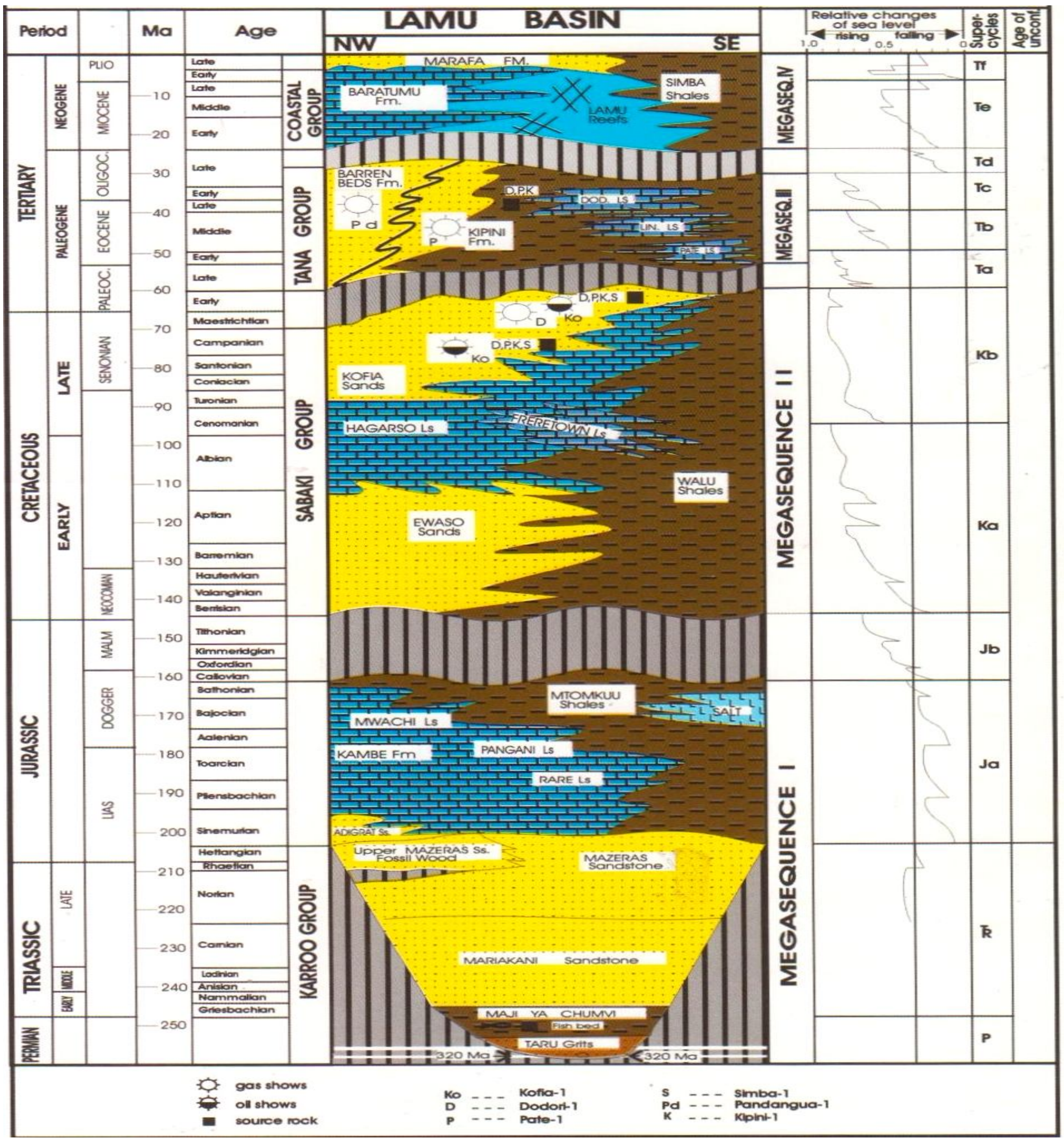

Figure 1. 2: Lithostratigraphic column of Lamu Basin

Figure adopted from the Integrated Report by National Oil Corporation of Kenya (1995)

Megasequence I show the Karoo Group of Permo-Carboniferous to Early Jurassic rocks which occur on Precambrian basement rocks. The Megasequences are stratigraphic units with regional continuity within the basin and commonly encompass several related depositional systems, both vertically and laterally, with each system recording a common palaeogeographic event (Nyagah, 1988).

1.3 Previous Work

The area of post-Karoo sedimentary cover was geologically mapped by various workers of the Geological Survey of Kenya (Caswell, 1953, 1956; Karanja, 1982). Waiters and Linton (1973) studied the development of the Karoo and post-Karoo basins. The first attempt at establishing a complete stratigraphic correlation for the Phanerozoic rocks in the Lamu Basin was made by Waiters and Linton (1973). Most of the units could not be readily related to a time framework, largely on account of limited availability of subsurface information from deep wells. Cannon *et. al,*. (1981) provided a more comprehensive stratigraphic analysis that also examined the development of the basin through rifting in the Carboniferous and later detachment of Madagascar from the coast of east Africa.

Regional studies covering the geology of East Africa have been compiled by Kent (1965, 1972), Kamen-Kaye (1978), Kamen- Kaye and Barnes (1978, 1979), Karanja (1988) and Nyagah (1988). Kenting Earth Science (1982) initiated the studies of Aeromagnetic Survey. Considerable work in the investigations on potential petroleum in Eastern Kenya was done by BEICIP (1982) which included studies of seismic surveys, Aeromagnetic, Gravity, Geophysical and Geochemistry Anomalies. The most controversial concerns investigations related to the palaeoposition of Madagascar in relation to Africa. A synthesis of data gathered from past results and new information gathered by Lamont-Doherty Earth Observatory of Colombia University was integrated with the stratigraphy of the East African and Madagascan basins and documented by Coffin and Rabinowitz (1988). Mutunguti (1988) carried out a study to analyze Kerogen in sediments in Lamu Basin. A detailed geological, geophysical and geochemical study of the basin by the National Oil Corporation of Kenya was conducted in 1993 and documented in NOCK (1995).

1.4 Foreword

Sandstones are very important as reservoirs for oil and gas; more than 50% of the world's petroleum reserve is estimated to occur in sandstones (Begg, 1989). Depositional environments, and thus facies characteristics, determine the overall reservoir properties of sandstones. Reservoir characterization comprises determining reservoir architecture, history and depositional environment during its formation, establishing fluid-flow trends, and identifying reserve growth potential to detect its productivity. Lamu basin is characterized with Permo-Carboniferous through Tertiary rocks which are mainly sandstones, limestone and shale (Nyagah, 1988).

Most of the past studies which have been carried out on Lamu Basin and other sedimentary basins in Kenya have exhausted in the formation history, lithology, stratigraphy and geology of the basins. Proper analyses and correlations on the reservoir rock characteristics have not been done. The quality of potential oil reservoir rocks in Kenya has not been intensively examined in the past studies. There is need therefore, to evaluate the subsurface geologic structures and the parameters that control oil flow pattern in the reservoir rocks. This study will attempt to describe the sandstones that have been identified in the four mega-sequences of the Lamu Basin by analyzing and determining the significance relationships between their sedimentological and the petrophysical properties. The knowledge from this study will make it easier for petroleum geologist in modeling, studying changes of various reservoir attributes and prospecting for oil or other fluids.

1.5 Objectives of the Study

i) To investigate the sedimentological characteristics (texture, grain size, thickness) of the reservoir rock in Lamu Basin.
ii) To establish the petrophysical properties (porosity, permeability, and seismic velocity contrasts in relation to other rocks in the basin).
iii) To establish relationships between the sedimentological, petrophysical properties and diagenesis of sandstones in Lamu Basin.
iv) To recommend the sandstones facies showing relatively good properties of a quality reservoir rock.

1.6 Justification of the Study

This study brings out the understanding of various reservoir rock parameters that favor the occurrence of hydrocarbon in Lamu Basin. The information acquired from this study will be essential in correlating and prospecting for other areas of similar characteristics. The knowledge will minimize the uncertainty of high exploration costs incurred in hostile and inaccessible potential areas.

1.7 Importance of the Study

The global oil consumption is projected to increase by about 36% by 2030 (www.worldeconomicforcast). In Africa, oil consumption could nearly double in that time. As more countries scramble for an increasingly limited supply of oil, the price and availability of fuel will become ever more challenging issues. Correlation of the reservoir rock characteristics is a guide in prospecting potential reservoir rocks in different area which will in turn attract foreign investors. This will ensure new discovery, recovery, and sustenance of hydrocarbon reserves toward vision 2030 in Kenya.

1.8 Methodology

The research combined the data on the geological, geophysical and stratigraphycal studies of the Lamu Basin in the selected wells. Seismic Petrophysics Method (Geophysical Well Log Analysis) is applied to give the well logs and core data. Four wells were critically selected for this study. Dodori-1, Pate-1, Kipini-1 and Kofia-1 well showed quite adequate data for the study. Correlations on varied attributes that is, permeability, porosity, and seismic velocity contrasts, compaction, grain sizes and texture are established to determine how they influence the quality of the overall reservoir rock.

CHAPTER TWO: SEDIMENTOLOGICAL PROPERTIES OF THE RESERVOIR ROCK

2.1 Introduction

Sedimentary rocks are the result of weathering and sedimentation processes, originating from older igneous, metamorphic and previously deposited sediments that have been broken down physically and chemically (Gregor, 1998). One of the most important groups of sedimentary rocks is the sandstones. Sandstones frequently form major aquifers and petroleum reservoirs, with predictable geometry and reservoir performance compared to carbonates. Integrated sedimentological and petrophysical methods in characterizing sandstone reservoirs have been carried out by several authors (Friedman, 1979; Gueguen, and Palciauskas, 1994; Gregor, 1998).

2.2 Sedimentology and Characteristic Facies

The term facies refers to all of the characteristics of a rock unit which come from the depositional environment. Thus, a facies is a distinct kind of rock for that area or environment. Its individuality is a combination of all or some of the following characteristics such as sedimentary structures, fossil content, lithology, geometry and paleo-current pattern (Pettijohn *et. al.*, 1987). Lamu Basin mega-sequences are bounded by regional unconformities which are seismically defined as Permo-Carboniferous, Jurassic, Paleocene, Oligocene, and Pliocene with varied sandstone facies. They bear a close relationship to the major episodes of rifting and subsidence distinguished for the depositional history of the basin.

2.2.1 Sandstone Facies in Lamu Basin and their Depositional Environments

Megasequence II (Sabaki Group)

The sandstones which dominate the Sabaki Group are Ewaso and Kofia sands. The two are products of marine regressions and an intervening transgression.

Ewaso Sands

Ewaso Sands- Early Cretaceous, lie on the Late Jurassic erosion surface that occurs between Karoo and Sabaki Groups. The total thickness of the unit is about 1697 m as observed in the Walmerer-1 well formed by deltaic effect.

Kofia Sands

Kofia sands- lie on the limestone units; Hagarso and Freretown Limestone. They are deltaic sediments which represent reversion to a regressive depositional phase during the Turonian through Early Paleocene period in a deltaic effect. Its thickness ranges from 398-1152 m.

Megasequence III (Tana Group)

Tana Group (Eocene to Oligocene) contains a lithostratigraphic assemblage that resulted from a deposition which took place in the course of three pulses of sea-level rise and a single regressive phase of deposition. The characteristic sands are the Barren beds and the Kipini Formations.

Barren Beds formation

This unit seen in Late Paleocene to Oligocene formed by fluvial effect and is laterally equivalent to the Kipini sands.

Megasequence IV (Coastal Group)

Marafa Sands

Marafa formation has siliciclastic fine to very fine grained Pliocene sands. The sands were formed in the course of three cycles of sea- level changes that occurred in the Pliocene that also led to the deposition of marine shales, Lamu Reefs, the Simba Shale and Baratumu Formation.

2.2.2 Lithology and Texture

Lithology is a function of transportation processes and the macroscopic nature of the mineral content, grain size, texture and color of rocks (Doveton, 1994). The characters of reservoir rocks vary based on their sedimentary textures that are produced by depositional and digenetic processes. The term texture has a broad meaning and refers to the interrelationships among the population (Pettijohn *et. al.,* 1987). Texture is also considered as a main factor controlling some petrophysical properties, such as porosity and permeability. The principal and commonly measured elements of texture are grain size and sorting.

2.2.2.1 Grain size

Grain size is the most fundamental physical property of sediment because grains are the particles which support the framework of sediment. Sedimentary particles come in all sizes; it is convenient to be able to describe sediments as gravels, sands (of several grades), silt and clay.

Table 2. 1: The Wentworth Grade Scale for the Clastic Sediments

φ values	Particle diameter (mm diam.)	Wentworth grades	Rock name
		Cobbles	
−6	64		Conglomerate
		Pebbles	
−2	4		
		Granules	Granulestone
−1	2		
		Very coarse	
0	1		
		Coarse	
1	0·5		
		Medium sand	Sandstone
2	0·25		
		Fine	
3	0·125		
		Very fine	
4	0·0625		
		Silt	Siltstone
8	0·0039		
		Clay	Claystone

The Wentworth grade scale for the sediments; after (Wentworth, 1922)

2.2.2.2 Sorting

Sorting gives an indication of the depositional mechanism. Sediments deposited with high energy (strong current or waves) are generally poorly sorted; sediments which have been worked and reworked are much better sorted (Fuchtbauer, 1974). Increasing sorting correlates with increasing permeability whereas well-sorted sand grains are about the same size and shape but poorly sorted sands contain grains with different size and shape (Fuchtbauer, 1974).

2.2.3 Mineralogy and Textural Characteristics

Ewaso Sands

The total thickness of the Ewaso sands is 1697 m in the Walmerer-1 well. It comprises a deltaic succession of alternating fine- to coarse-grained (0.125-1.0 mm) (Figure 2.1), orthoquartzites, siltstones, shales and subordinate calcareous sandstones, arenaceous limestones, thin layers of anthracite and abundance of flora. The presence of orthoquartzites is attributed to secondary silicification associated with uplift of the Garissa-Walmerer High and the Early Tertiary unconformity.

Kofia Sands

Kofia sands are located offshore about 300 km southeast of the coast of Somalia. The Sands have a thickness that ranges from 398-1152 m at the Simba-1 well. The sands are well-cemented, and white to pale grey, fine to medium-grained (0.125-0.5 mm) (Figure 2.1) at the Kofia-1 well in about 928 m thickness. The sands are intercalated with olive grey, calcareous claystones and medium to light grey calcareous silty claystones that grade in places into siltstone. In the onshore at the Kipini-1well the unit is 398 m thick and consists of interbedded calcite-cemented sandstones with poor to fair porosity and calcareous shales with an abundance of carbonaceous plant remains.

Sandstone in the Barren Beds Formation

Sandstone in Barren Beds Formation occur as fluvial "red beds" which are lateral equivalents of the Kipini unconsolidated sands (0.0039-0.0625 mm) (Figure 2.1), seen in the Middle Eocene through Late Oligocene intervals of the Pandangua-1 (925 m), Walu-2 (1003 m), Hagarso-1 (286 m), Walmerer-1 (655 m), Garissa-1 (614 m) Kencan-1 (688 m) and the equivalent sequences in Dodori-1 and Pate-1 wells. The sandstones are characterized with carbonate facies (*Pate, Linderina* and *Dodori Limestones*) that built up between periods of their deposition which are related to a tectonically influenced depositional pattern involving episodic uplift and subsidence in marine setting which prevailed during the Palaeogene.

Kipini Sands

Kipini sands occur in the Kipini Formation which is fairly extensive, covering the southern part of the Lamu Basin on both flanks of the Walu-Kipini High. It spans the Early Eocene through part of the Late Oligocene period. Kipini Sands which show a total thickness of 1953 m in Kipini-1; form the major distinguishable clastic lithology in Kipini formation that often grade into siltstones (0.0039-0.0625 mm) (Figure 2.1). They are composed of calcareous sandstones interbedded with shale and mudstones on the higher levels, and siltstone, shale, pyritic, and micaceous at the lower levels. These sands are also observed in Pate-1 well.

Marafa Sands

Marafa Sands form the Pliocene sequence in Lamu Basin apart from Simba-1 and Walu-2 wells. They consist of very pale orange to greyish orange, medium- to coarse-grained (0.25-1.0 mm) poorly consolidated quartz sands with sandstones and kaolinitic clays (Nyagah, 1988). Their depositional phase was synchronous with the deformation in central Kenya related to the rift valley tectonism and was contemporaneous with north-south faulting in the Tana River valley (Wright and Pix, 1967).

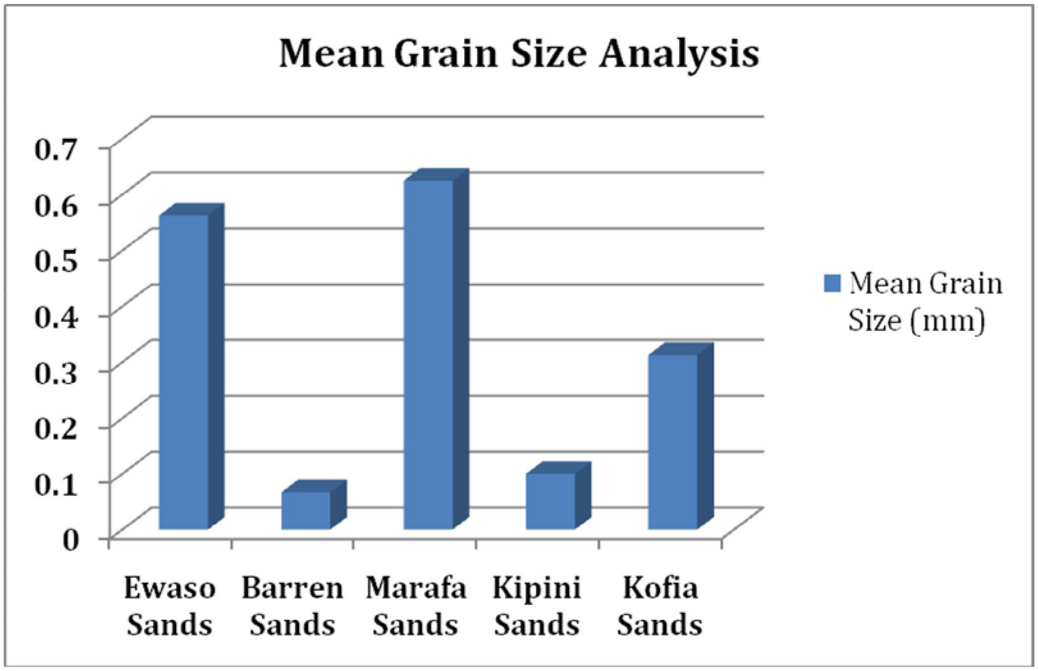

Figure 2. 1: Grain Size Analysis

CHAPTER THREE: RESERVOIR AND PETROPHYSICAL PROPERTIES OF SANDSTONES

3.1 Introduction

Sandstone reservoirs are deposited in fluvial, eolian and lacustrine environments in non-marine settings, whereas in marine settings, these rocks may be deposited in deltaic, shallow marine and deep marine settings (Martin *et. al.,* 1997). Petrophysical properties of sedimentary rocks are influenced by porosity, permeability, velocity and density; these properties are partly controlled by facies characteristics which in turn are related to depositional processes (Cant and Walker, 1976).

3.2 Porosity of the Sandstone Facies

The major parameters bearing the porosity of sandstones in Lamu Basin include shaliness, late or early cementation, dissolution, recrystallization and fracturing (BEICIP, 1982). Low energy conditions resulted to deposition and inclusions of Shale thus low porosity. During burial, compaction of the sediments causes intergranular constraints, followed by dissolution where the grains come into contact with the cement deposition in the neutral zones (Cant and Walker, 1976). Dissolution results from the percolation of under-saturated water which enhances the porosity especially in Calcareous cemented sandstones.

Thick intervals of poorly sorted and unconsolidated sands assigned to the Kipini sands occur in Kipini-1 well. The sands are 26 % porous at about 300 m in the Oligocene-Middle Eocene section that is water saturated. The Kofia sands are observed at Kofia-1 (3558-3570 m), Dodori-1 and Kipini-1 wells 4311 m that lie on the Mararani-Dodori- Pate anticlinal trend that is dominated by Tertiary faults. The effective porosity of the Kofia sands is about 12%. They are characterized with approximately 122 m Campanian section of 23% absolutely porous section of 100% water saturated. Barren Beds sands at Pate-1 well occur in four intervals of the Late Eocene from 3989-4186 m with estimated porosity of 20%. The effective porosity of the Ewaso sands is relatively as low as 15% probably due to higher compactions and their occurrence at low depth of more than 3630 m though their abundance composition of flora.

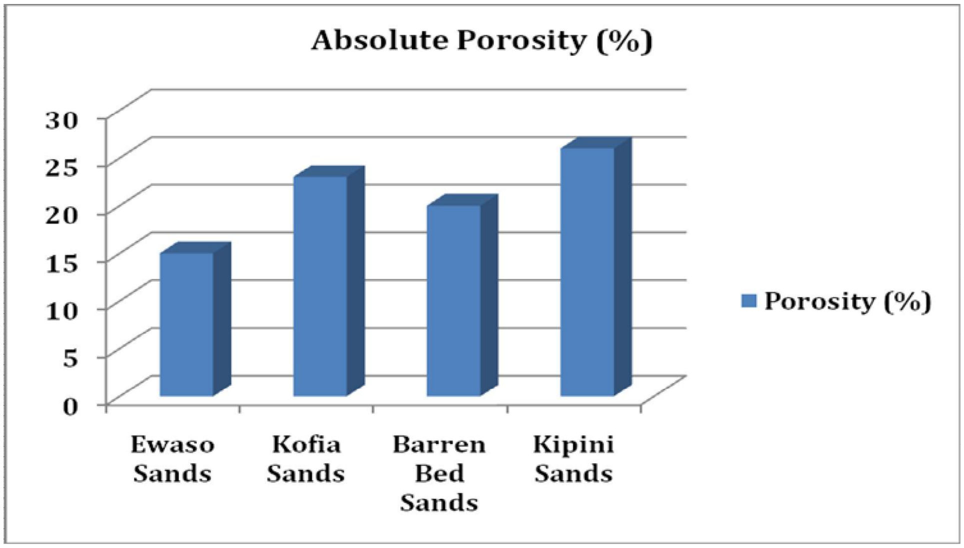

Figure 3. 1: Absolute Porosity of some of the Major Sandstones in Lamu Basin

3.3 Permeability

The ability of a rock to allow fluids to circulate is called permeability, in the other words; permeability is the ability of the sediment to transmit fluid (Cant and Walker, 1976). Pore throats are the smaller connecting spaces linking pores and providing the more significant restrictions to fluid flow. In 1856, the French engineer Henry Darcy found the main relationship to define the laminar flow of a viscous fluid through a porous rock.

$$\boldsymbol{Q = KA/_{\mu} \times \frac{dp}{dx}}$$

Where-

Q= volume per unit time (volume flux) in cm/sec in horizontal flow;

K= permeability constant;

A= cross-sectional area in cm^2;

μ= viscosity of the fluid in Centipoises;

$\frac{dp}{dx}$= hydraulic gradient i.e. difference in pressure, p in direction of flow, x (in Atmospheres per centimeter)

q≤ 5 probably implies tight sandstone or a dense limestone. The permeability of average reservoir rocks generally range between 5-1000 millidarcys (Pittman, 1992).

Permeability is related in a variable and complex way to porosity, pore size, arrangement of pores and pore throats, and grain size. Fine sediments such as clay exhibit low permeability compared to sand and gravel, due to the lack of connection between the pore space and the small size of the pore throat. Open grain packing shows high porosity and therefore high permeability than closed packing. Reservoir rock whose permeability is 5 md or less is called tight sand or a dense limestone, according to its composition (Levorsen, 1965). A rough field appraisal of reservoir permeability is:

Fair	1.0-10 md
Good	10-100 md
Very good	100-1000 md

Effective permeability is described as the ability of a rock to conduct an under-saturated fluid in presence of other fluids in that rock (Levorsen, 1965). Begg, *et. al.* (1989) proposed a general estimator for effective vertical permeability, $k_{ve,}$ for a sandstone medium containing thin, discontinuous, impermeable mudstones, based on effective medium theory and geometry of ideal streamline:

$$K_{ve} = K_e(1 - V_m) \Big/ (a_z + fd)^2$$

Where: V_m is the volume fraction of mudstone, a_z is given by $(k_{sv}/k_{sh})^{1/2}$, k_{sh} and k_{sv} are the horizontal and vertical permeability of the sandstone, f is the barrier frequency, and d is a mudstone dimension $(d=L_m/2$ for a 2D system with mean mudstone length, $L_m)$. This method is valid for low mudstone volume fractions and assumes thin, uncorrelated, impermeable, discontinuous mudstone layers.

3.3.1 Grain Size Model

A large amount of different theoretical models have been developed to account for the ecological as well as economical importance of the ability of permeability prediction. Berg (1970) published one of the first models which links directly grain size with permeability. From consideration of only rectilicular pores (those pores which penetrate the porous medium without change in shape or direction) of various packing of spheres, he developed an equation, which relates permeability to the square of the grain diameter:

$$K = 80.8p^{5.1}d^2m^{-1.385s}$$

Where

K = permeability [md]

m = cementation factor (= 1.8)

p = fractional porosity

d = median grain diameter [μm]

s = sorting term

The sorting term also called the percentile derivation (s= S90 – S10), incorporates any spread in grain size into the formula and is expressed in phi units, where phi = -log2d (mm). For example a sample with a median diameter of 0.177 mm, a value of 1 for s implies that 10 percent of the grains are larger than 0.25 mm and 10 percent are smaller than 0.125 mm.

A Combination of theoretical, empirical, and heuristic models can be applied to attempt to repair the bad or missing data. A common example is the problem of mud filtrate invasion (Walls, *et al*., 2001; Vasquez, *et al*., 2004). Mud filtrate invasion occurs during drilling with over-balanced mud weight conditions. The positive pressure gradient between the wellbore and the formation causes some of the mud liquids to penetrate into the permeable zones, displacing original fluids near the borehole wall. The severity of this condition varies greatly depending on permeability, mud weight, mud type, and original fluid saturation. The relationship is expressed as;

$$\mathbf{V_s=0.73V_p-767\ (m/sec)}$$

3.4 Seismic Velocity

One of the key factors needed for the successful use of seismic wave velocities in reservoir development, characterization, and recovery is a fuller understanding of what seismic waves can tell about the state of reservoir rocks and the fluids contained in their pore space (Gueguen and Palciauskas, 1994).

The porous sedimentary rocks generally show lower velocities and a broader range for an individual rock type compared to igneous and metamorphic rocks. Both features are mainly due to the influence of the pore contents with their low elastic parameters. Petrophysical analysis shows a general decrease in rock velocity with increasing porosity (Gueguen and Palciauskas, 1994).

3.4.1 Velocity Contrasts

The seismic velocity contrasts between different sandstones facies and the major rocks in the Lamu Basin; shales and limestones, have been examined from different wells. The reliable wells are Pate-1, Kipini-1, Kofia-1, and Simba-1 wells. These wells show distinct velocities of the same lithology for instance Kipini sands show varied velocities as observed at the Kipini-1 and Pate-1 wells. The other examinable facies include the Ewaso, Kofia, Barren Beds sandstones. These velocity contrasts can be applied in estimating the compaction, depth, and density of the rock in thought.

Ewaso sands

These sands are observed in Kipini-1 well at about 6300-8300 m depth. This sedimentological facies is intercalated with equivalent Walu shales, Hagarso and Freretown limestone sequences and coal. The velocity contrasts between Ewaso sands and coal, Walu shales-Ewaso sands, Hagarso and Freretown limestones zones are 87%, 50% and 33% respectively.

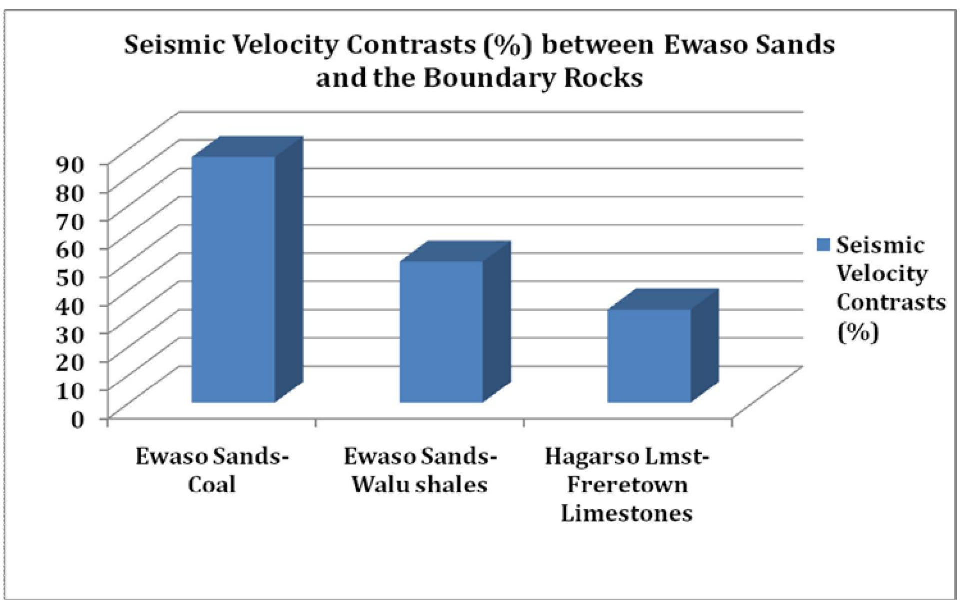

Figure 3. 2: Seismic Velocity Contrasts between the Ewaso Sands and the Boundary Rocks

Kofia sands

Kofia sands are observed in Kipini-1 well at 4800-5800 m depth. They are also interbedded with Walu shales, Hagarso and Freretown limestone sequences. The velocity contrasts at this well between Kipini sands-Walu shales, Kipini sands-Hagarso limestones and Walu shales-Hagarso Limestones zones are 43%, 14% and 53% respectively. This case is also observed at Kofia-1 well where the velocity contrast between Kofia sands and Walu shale is 40%. The Values at the Simba-1 well are lower as 31% between Walu shale-Kofia sands and 45% between Hagarso limestone-Kofia sands. These velocity contrasts are equivalent to the values for the Kipini sands observed in Kipini-1 well at the same depth interval.

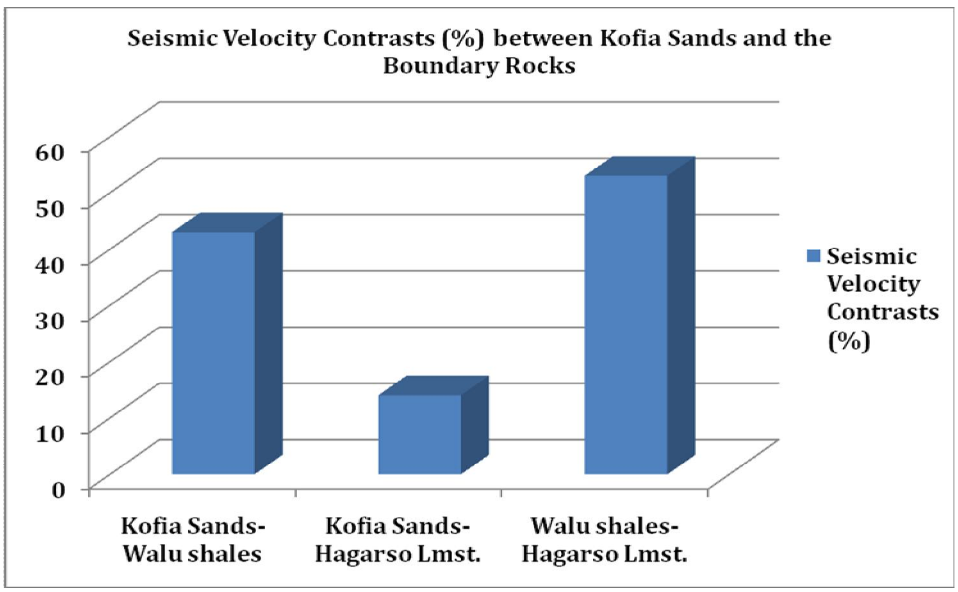

Figure 3. 3: Seismic Velocity Contrasts between the Kofia Sands and the Boundary Rocks

Sandstone in the Barren Beds Formation

The sands are identified in Pate-1 well at the depth between 4000-9000 m in about 300 m thickness. They are interbedded with Early Tertiary Pate and Dodori limestones and Simba Shales. Velocity contrasts are 23% Simba shales-sands, 80% Simba shales-Pate limestone, and 46% in sands-Dodori limestone. These velocity contrasts are equivalent to the values for the Kipini sands observed in Pate-1 well at the same depth interval.

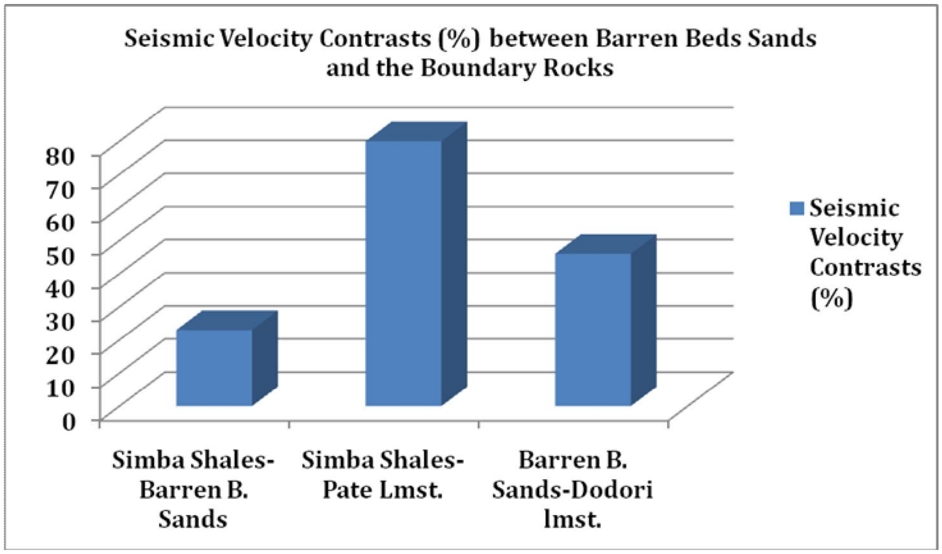

Figure 3. 4: Seismic Velocity Contrasts between the Barren Beds Sands and the Boundary Rocks

CHAPTER FOUR: RELATIONSHIPS BETWEEN THE SEDIMENTOLOGY AND PETROPHYSICAL PROPERTIES OF THE RESERVOIR ROCK

4.1 Introduction

The petrophysical properties of the sandstone facies are related to their deposition history in regard to the conditions that prevailed during the processes of accumulation and diagenesis (Cant and Walker, 1976). This chapter attempts to link these properties with their possible influencing factors in order to evaluate the quality of sandstone as a reservoir rock.

4.2 Porosity

The porosity of a given sedimentological facies would be determined by the factors involved in the process of their deposition (primary controls) and the factors that come about in the diagenetic processes that take place after or immediately after deposition.

4.2.1 Primary Controls

In general the most important textural parameters in controlling porosity are grain size, sorting, shape, roundness and packing. Sands with high sphericity and high roundness pack with minimum pore space. Therefore, it is expected that as sphericity and roundness decrease, porosity increases as a result of the bridging of pores and looser packing (Burley, and Kantorowicz, 1986). The occurrence of shales, claystones and siltstones interbedded in the sandstones implies low energy involved in the deposition of the sand sediments.

4.2.2 Secondary controls

Diagenetic processes are the main causes of the modification of porosity in the sandstones, and compaction and cementation are the main controlling factors (Burley, and Kantorowicz, 1986), other factors are dissolution and recrystallization. The variability in the porosity of the highly porous sandstones in Lamu Basin could be caused by the variation in compaction due their occurrence in different levels for instance Ewaso Sands. Von Engelhart (1967) suggested that grain rearrangement could reduce the porosity of sand from 40% to 28%. In additional, the presence of orthoquartzites in the sands due to silicification could be taken into account for the decrease in porosity in the Ewaso sands. Kipini and Kofia sands are interbedded with calcareous silty claystones and calcite cement thus lower porosity.

4.2.3 Grain Size –Porosity Relationship

The graph below shows the relationship between the grain size and porosity of the sandstone facies. Low grain size sands show relatively lower porosity due to reduced pores spaces and invasion by siltstone and mudstone. When dissolution occurs in calcareous or silicified sandstone for example in Kipini sands, porosity is improved. Low porosity in larger grain sizes is caused by high degree of interbedded shales, claystones and siltstones which are associated with marine, low energy and deltaic effect during the deposition of the sands (Gregor, 1998).

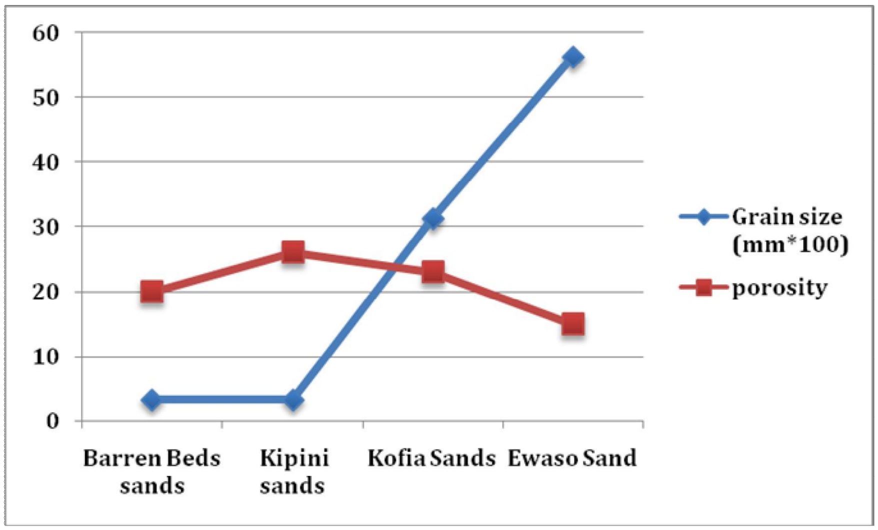

Figure 4. 1: Grain Size- Porosity Relationship

4.3 Permeability

In order to analyze and identify the Poro-Perma relationship on the sandstones in Lamu Basin, the major characteristic sands are divided into high and low porous groups. Highly porous group involves sands with porosity values >20% and the low porosity group with </=15%. The permeability prediction for the group of sands with the high porosity values is estimated to be relatively higher as compared to the group with the low porosity values. An increase in permeability can also be related to the same factors that cause increase in the porosity of the sands as explained above. Permeability could also be reduced by mechanical compaction and grain fracturing (could block pore-throats), for example in Ewaso sands.

4.3.1 Poro-Perma Relationship

Knowing the stratigraphic and well-to-well distribution of permeability is a key to predicting reservoir performance (Denicol & Jing, 1996). The major difficulty in predicting permeability in mature reservoirs is lack of sufficient data, particularly core analyses. In case the reservoir rock is homogeneous, the values for porosity of the respective sands in this study could be used to predict their correspondence permeability values. According to Gregor (1998) a homogeneous reservoir rock which would have samples showing porosity percentages of 0-5%, 5-10%, 10-15%, and 15-20% would be related with the permeability as shown in the graph below.

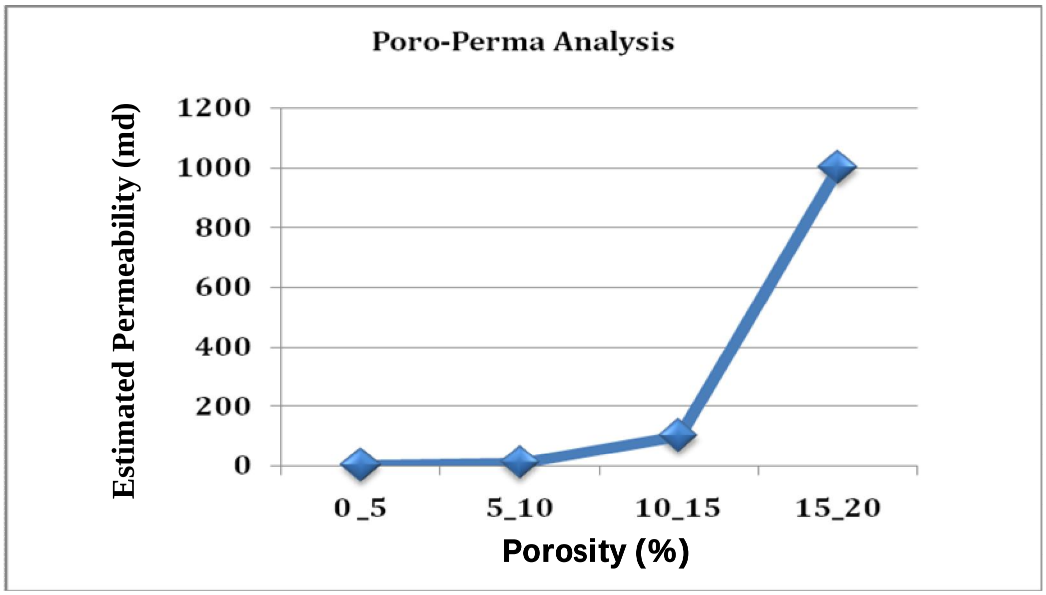

Figure 4. 2: Poro-Perma Analysis

Figure: Modified after Gregor (1998)

4.4 Velocity Contrast -Compaction Relationship

Compaction in sandstones is a post-cementation effect that is high in sediments that were filled with high amount of cementing material after deposition (Tissot and Welte, 1984, Gregor, 1998). More compacted sands are denser and therefore would show relatively low velocity contrast of about 50% as in Ewaso sands-Walu Shale zone (Figure 3.3). Ewaso sands are slight more compact in relation to their stratigraphic occurrence as compared to the rest of the sands under investigation.

CHAPTER FIVE: DISCUSSION, CONCLUSION AND RECOMMENDATIONS

5.1 Discussion

The result of the grain size analyses show that the sandstones facies in Lamu Basin are generally poorly sorted, medium to coarse grained indicating abrasion and rapid deposition (Friedman, 1979) in short distances. Kipini sand and Barren Beds resulted from fluvial deposition. They both have desirable porosity of 26% and 20% respectively. The absolute porosity of the Kofia sands is 23% higher than Ewaso sands with 15% probably due to increased overburden. There exists an excellent correlation between porosity and grain size because sandstones have distinct characteristics related to their respective depositional sequence, mode of formation and alteration of the original porosity. Siltation and shaliness have a great effect in decreasing the porosity and permeability. Compaction effects are negligible since it affects the whole formation to approximately the same degree. In well sorted sandstones both compaction and overgrowth have virtually the same effect on permeability as a function of porosity (Bryant and Blunt, 1992). Calcareous sandstones are massively affected by dissolution which in turn widens up the pore spaces thus higher porosity and permeability. High velocity contrasts between the sands and other related facies imply varied degree of compaction and densities of the rocks.

5.3 Conclusion

Sandstones in Lamu Basin show excellent characteristics of a potential reservoir rock for the hydrocarbon and other fluids. The objectives of the study were met since the investigation of the reservoir sedimentological characteristics (texture, grain size, and thickness), petrophysical properties (porosity, permeability, and velocity contrasts in relation to other rocks in the basin) and their relationships to the current performance of the sands have been done.

5.4 Recommendations and Further Study

However lack of adequate information on permeability has caused uncertainty in analysis. Permeability is an essential property to be considered in determination of yield of a potential reservoir rock. There is need re-examine and carry out a clear and intensive study on petrophysical properties and their sedimentological interpretations. This would help to evaluate and correlate the performance and productivity of the reservoir rocks in Lamu Basin and other sedimentary basins occurring in Kenya. More exploration into different well log classification methods for instance, reservoir quality index is required.

REFERENCES

BEGG, S. H., CARTER, R. R. & DRANFIELD, P., 1989 Assigning Effective Values to simulator gridblock parameters for heterogeneous reservoirs. *Reservoir Engineering*, 4, 455-463.

BEICIP, 1982. Petroleum Potential of Eastern Kenya: Seismic, *Aeromagnetic, Gravity, Geophysical and Geochemistry Surveys,* Integrated Report available at National Oil Corporation of Kenya, pp 104-165.

BERG, R., 1970. Method of Determinating Permeability from Reservoir Rock Properties. Transactions, *Gulf Coast Association of Geological Societies*, 20, p.303-317

BOSELLINI, A., 1986. East African Continental Margins. *Geology,* 19: pp. 76-78.

BRYANT, S and BLUNT, M., 1992. Prediction of relative permeability in simple porous media. *Physical Review*, 46, p. 2004-2007

BURLEY, S. D. and KANTOROWICZ, J. D., 1986. Clastic Diagenesis. *Sedimentology*, 33, p. 587-604

CANNON, R. T., SIAMBI, W.M.N.S. and KARANJA, F.M., 1981. The Proto-Indian Ocean as a probable Paleozoic/ Mesozoic tri-radial rift system in East Africa. *Earth Planet. Sci. Lett.*, 52: 419-426.

CANT, D. J. and WALKER, R. G. 1976. Development of a Braided-Fluvial Facies Model for the Devonian Battery Point Sandstone, *Earth Science,* 13, pp. 102-119. Quebec: Canada.

CASWELL, P.V., 1953. The Geology of Mombasa-Kwale Area. *Geological Survey of Kenya*, Pb. 24, pp. 54.

CASWELL, P.V., 1956. Geology of the Kilifi-Mazeras Area. *Geological Survey of Kenya*, Republished. 34, pp. 34

COFFIN, M. F. and RABINOWITZ, P.D., 1988. Evolution of the conjugate East African-Madagascan margins and the Western Somali Basin. Pap. 226, p. 78

DENICOL, P. S. and JING, X. D., 1996. Estimating permeability of reservoir rocks from complex resistivity data. *SPWLA,* 37th Annual Logging Symposium, 1996

DOVETON, J. H., 1994. Geologic Log Interpretation, *Tulsa,* Pb. 169 pp. 22- 35

EBINGER, C. J. and YOUNG, C.J., 1993. *Subsidence and Gravity Analyses of the Lamu Embayment.* University of Leeds, Report submitted to the National Oil Corporation of Kenya, pp. 35-40.

FRIEDMAN, G. M., 1979: *Sedimentology*, Springer-Verlag, New York. vol. 26, pp. 13 – 32.

FUCHTBAUER, H., 1974. Sediments and Sedimentary Rocks. *Sedimentary Petrology Part II*. Stuttgart.

GREGOR, B., 1998. *Sedimentological and Petrophysical Characterization of the Lochaline Sandstone, Upper Cretaceous.* Published M.sc. Thesis. NW Scotland, University of Tübingen. pp. 36-58.

GUEGUEN, Y. and PALCIAUSKAS, V., 1994. *Introduction to the Physics of Rocks*. Princeton University Press, West Sussex.

HOLLAND, M., 2004. *Global Oil Status.* Available online at: http//www.worldeconomicforcast/html

INTERNATIONAL COMMISSION ON STRATIGRAPHY (ICS) 2009 "Chronostratigraphic Units" *International Stratigraphic Guide*; (2009) Paper. Available online at *http//www.ics/isg/html.,* Accessed on 14-MAR-2011.

KAMEN-KAYE, M. and BARNES, S. U., 1978. Exploration outlook for Somalia, coastal Kenya and Tanzania, International Oil Gas Journal, vol. 76: pp. 80-84.

KAMEN-KAYE, M. and BARNES, S.U., 1979. Exploration Geology of Northeastern Africa-Seychelles Basin. *Journal of Petroleum Geology*, 2(1): pp. 23-45.

KAMEN-KAYE, M., 1978. Permian to Tertiary Faunas and Paleogeography: Somalia, Kenya, Tanzania, Mozambique, Madagascar, South Africa. *Journal of Petroleum Geology*, 1(1): pp. 79-

101.

KARANJA, F. M., 1982. *Report on the geology of the Kilifi, Gede and Sokoke area*. Published M.Sc. Thesis. p. 32. Geological Survey of Kenya, Nairobi: Kenya.

KARANJA, S.W., 1988. A Sedimentologic and Stratigraphic Study of Carboniferous through Jurassic Strata of East Kenya. Unpublished M.Sc. Thesis, University of Windsor, Ont., 207 pp.

KENT, P. E., 1965. An Evaporite Basin in Southern Tanzania. In: *Salt Basins Around Africa, Proceedings of the Joint Meeting of the Petroleum and Geological Societies*, London, 3 March 1965, pp. 41-65.

KENT, P. E., 1972. Mesozoic History of the East Coast of Africa. *Nature*, 238: pp. 147-148.

KENTING EARTH SCIENCE 1982. Regional Stratigraphic and structural Framework of Karoo Rocks and their Equivalents in East Africa and Madagascar. Published Report. pp. 40-62 National Oil Corporation of Kenya.

LEVORSEN, A. I., 1965 *Geology of Petroleum: Reservoir Pore Space*, 2nd Edition, CBS Publishers & Distributors Pvt. Ltd, New Delhi

MARTIN, A. J., SOLOMON, S. T. and HARTMANN, D. J., 1997. Characterization of petrophysical flow units in carbonate reservoirs. *American Association of Petroleum Geologists Bulletin*, v. 81, No.5, pp. 734- 759.

MUTUNGUTI, F., 1988. *Kerogen Analysis of Sediments in Lamu Embayment of Kenya.* Unpublished M.sc. Thesis. pp. 7-10. National Oil Corporation of Kenya.

NATIONAL OIL CORPORATION OF KENYA (NOCK) 1995. Integrated Report: *Hydrocarbon Potential of Kenya.* National Oil Corporation of Kenya.

NYAGAH, K., 1988. A Sedimentologic and Stratigraphic Study of Cretaceous through Tertiary Strata of East Kenya. Unpublished MSc. Thesis, University of Windsor, Ont., 207 pp.

NYAGAH, K., 1995. "Stratigraphy, depositional history and environments of deposition of Cretaceous through Tertiary strata in the Lamu Basin, southeast Kenya and implications for reservoirs for hydrocarbon exploration". *Sedimentary Geology*. National Oil Corporation of Kenya, Nairobi, Kenya, pp. 43-71

PATTERSON, M. S., 1983. The equivalent channel model for permeability and resistivity in fluid-saturated rock - a reappraisal. *Mechanics of Materials*, 2, pp. 345-352.

PETTIJOHN, F. P., POTTER, P.E. and SIEVER, R., 1987. *Sands and Sandstones.* Springer-Verlag, New York.

PITTMAN, E. D., 1992. Relationship of porosity and permeability to various parameters derived from mercury injection capillary pressure curves for sandstone. *The American Association of Petroleum Geologists Bulletin (AAPG)*, 76, p.191-198

REEVES, C.V., KARANJA, F. M. and MACLEOD, I. N., 1986. Geophysical evidence for a Jurassic Triple-Junction in Kenya. *Earth Planet.* Science. pb. 81: 299-311.

REVIL, A. and GLOVER, P.W.J., 1997. Theory of ionic-surface electrical conduction in porous media. *Physical Review Bulletin*, 55, pp.1757-1773.

TISSOT, B. P., and WELTE, D. H., 1984. *Petroleum Formation and Occurrence*. 2nd Edition, Springer-Verlag, Berlin Heidelberg, N.Y.

VAN BAAREN, J. P., 1979. Quick-look permeability estimates using sidewall samples and porosity logs. *6th Annual European Logging Symposium of the Society of Professional Well Log Analysists.* Available online at: *http://www.elsspwla/permeability.html*. Accessed on 13th April, 2011.

VASQUEZ, G. F., L. DILLON, C. VARELA, G. NETO, R. VELLOSO, and C. NUNES, 2004. Elastic log editing and alternative invasion correction methods, *The Leading Edge*, Vol. 23, No. 1, pp. 20-25.

VON ENGELHART, W., 1967. Interstitial solutions and diagenesis in sediments. In: *Diagenesis in Sediments.* (Eds.: Larsen, G and Chilingar, G.W.). Elsevier, Amsterdam.

WAITERS, L. and LINTON, E. R., 1973. The sedimentary basin of coastal Kenya. In: G. Blant

(Editor), *Sedimentary Basins of the African Coasts,* Part 2. *South and East Coast.* Association of African Geological Surveys, Paris, pp. 133- 158.

WALLS JOEL D, and CARR M. B., 2001. The Use of Fluid Substitution Modeling for Correction of Mud Filtrate Invasion in Sandstone Reservoirs, *71st Annual Meeting of Society of Exploration Geophysicists,* San Antonio, TX.

WASHBURN, E.W., 1921. Note on a method of determining the distribution of pore sizes in a porous material. *Proceedings of the National Academy of Science*, 7, p.115-116.

WENTWORTH, C. K., 1922. *Journal of Geology*. Vol. 30, pp. 377 – 392.

WESTERN ATLAS INTERNATIONAL (W.A.I) 1990. *The Hydrocarbon potential of Kenya, Seismic Investigation, petrophysical analysis and synthetic seismograms.* Unpublished Geological Report. Available at National Oil Corporation of Kenya.

WILSON, J. C. and MCBRIDGE, E. F., 1988. Compaction and porosity evolution of Pliocene sandstones, Ventura Basin, California. *AAPG Bulletin*, 72, pp.664-681.

WRIGHT, J. B. and PIX, P., 1967. *Evidence of trough faulting in Eastern Central Kenya*. Institute of Geological Science. Overseas Geological Miner. Resource, 10: 30-41.

APPENDICES

Appendix I: A List of Wells Drilled In Kenyan Sedimentary Basins

BLOCK	WELL	OPERATOR	LOCATION LAT (S/N)	LOCATION LONG (E)	TOTAL DEPTH (M)	STRATIGRAPHIC LEVEL AT TOTAL DEPTH		YEAR COMPL-ETED	STATUS
L-3	WALU - 1	BP/SHELL	01°38'04"S	40°15'09"E	1,768	LATE CRET.	SENONIAN	1960	P & A
L-4	PANDANGUA - 1	BP/SHELL	02°05'51"S	40°25'15"E	1,982	EARLY TERT.	PALEOGENE	1960	P & A with gas show in tertiary
3	MERI	BP/SHELL	0°20'36"N	40°11'00"E	1,941	EARLY TERT.	PALEOGENE	1961	P & A
L-3	MARARANI	BP/SHELL	01°34'57"S	41°14'10"E	1,991	EARLY TERT.	PALEOGENE	1962	P & A with fluorescence in tertiary
7	RIA KALUI	MEHTA & CO.			1,538	PERMO-TRIAS	KAROO	1962	P & A with oil stain in Permo-Trias Karroo?
L-3	WALU - 2	BP/SHELL	01°38'02"S	40°15'10"E	3,729	EARLY CRET.	APTIAN	1963	P & A with fluorescence in cret.
L-5	DODORI	BP/SHELL	01°48'53.7"S	41°11'04"E	4,311	LATE CRET.	CAMPANIAN	1964	P & A with oil-gas shows in Tertiary/Cret.
L-3	WAL MERER	BP/SHELL	0°06'35"S	40°35'05"E	3,794	EARLY CRET.	NEOCOMIAN	1967	P & A with gas shows in Cret.
L-1	GARISSA	BP/SHELL	0°22'04"S	39°48'43"E	1,240	MID JURRASIC	BATHONIAN	1968	P & A
L-5	PATE	BP/SHELL	02°03'53.98"S	41°04'52"E	4,188	EARLY TERT	EOCENE	1971	P & A with gas shows in Eocene
L-6	KIPINI	BP/SHELL	02°29'23.57"S	40°35'51"E	3,663	LATE CRET.	CAMPANIAN	1971	P & A with fluor. & gas shows in Tert./Cret.
L-1	HAGARSO	TEAS PACIFIC	0°47'43.5"S	40°26'40.5"E	3,092	EARLY CRET.	ALBIAN	1975	P & A with gas shows in Cret.
3	ANZA	CHEVRON	0°55'10.864"N	39°41'42.761"E	3,662	LATE CRET.	CENOMANIAN?	1976	P & A with oil stain in Cretaceous
3	BAHATI	CHEVRON	0°26'32.913"N	39°47'5.077"E	3,421	LATE CRET.	CENOMANIAN?	1976	P & A with oil stain in Cretaceous
L-9	SIMBA (off shore)	TOTAL	04°00'06.60"S	40°34'03.68"E	3,604	LATE CRET.	CAMPANIAN	1978	P & A with gas shows in Tert./Cret
L-6	MARIDADI - 1B (off shore	CITIES	2°53'8.795"S	40°24'7.856"E	4,198	MID TERT.	OLIGOCENE	1982	P & A with gas shows in Tertiary
L-7	KOFIA (off shore)	UNION	02°32'31.90"S	40°56'18.30"E	3,629	LATE CRET.	MAASTRI-CHTIAN	1985	P & A with flour. and gas shows in Tert./Cret.
L-1	KENCAN	PETRO-CANADA	0°18'57.384"S	39°46'16.572"E	3,863	PERMO-TRIAS	KARROO	1986	P & A
2	ELGAL - 1	AMOCO	01°22'47"N	39°53'09"E	1,280	PERMIAN	KARROO	1987	P & A (Stratigraphic Well)
2	ELGAL - 2	AMOCO	01°27'32.708N	39°58'40.063"E	1,908	TRIASSIC	KARROO	1987	P & A (Stratigraphic Well)
9	NDOVU	TOTAL	01°59'58"N	38°52'57"E	4,269	EARLY CRET.	HAUTERIVIAN	1988	P & A with fluor. & gas shows in Cret
10	SIRIUS	AMOCO	2°35'00.14"N	37°32'48.98E	2,638			1988	P & A
10	BELLATRIX	AMOCO	2°42'12.98"N	37°32'22.34"E	3,480			1988	P & A
9	DUMA	TOTAL	1°39'35.66"N	39°30'19.77"E	3,333	EARLY CRET.	APTIAN?	1989	P & A with gas shows in Cret.
2	HOTHORI	AMOCO	01°11'16.8"N	39°29'37.8"E	4,392	LATE CRET.		1989	P & A with flour. & gas shows in Tert./Cret.
10	CHALBI - 1	AMOCO	3°01'50.81"N	37°24'43.09"E	3,644			1989	P & A
3	ENDELA	WALTER	0°45'20"N	39°28'52"E	2,779	EARLY TERT.	PALEOGENE	1989	P & A with gas shows in Paleogene
9	KAISUT	TOTAL	1°31'03.82"N	38°16"28.89"E	1,450	EARLY TERT.	EOCENE?	1990	P & A
10B	LOPEROT	SHELL	02°21'46.229"N	35°52'24.132"E	2,950	PALEOCENCE?.		1992	P & A with oil shows
10B	ELIYE SPRINGS - 1	SHELL	03°13'50.62"N	35°54'40.19"E	2,964	UPPER MIOCENE?		1992	P &A

Source: NOCK Library