EVALUATION OF DEPOSITIONAL ENVIRONMENTS AND RESERVOIR QUALITY OF SEDIMENTS IN THE “OLI FIELD”, OFFSHORE, NIGER DELTA, NIGERIA.

BY

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CERTIFICATION

This is to certify that this thesis "Evaluation of Depositional Environments and Reservoir Quality of Sediments in "OLI Field" was carried out by NNAGHA, OLUCHI JOAN (PGS/M.Sc./20114773708) in partial fulfillment of the requirements for the award of the degree of Master of Science (M.Sc.) in Sedimentary/Petroleum Geology in the Department of Geology, Federal University of Technology, Owerri.

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DEDICATION

This work is dedicated to the Almighty God, the giver of every good and perfect gift, for His provision, wisdom and strength to carry out this project and my parents Mr. and Mrs. B.I. Nnagha for their immeasurable support all through my life, financial, spiritual and otherwise, I am extremely grateful to them.

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ABSTRACT

The evaluation of environments of deposition and reservoir quality of sediments in the “OLI Field”, Offshore Niger Delta, Nigeria, was done using a suite of wire line logs from five (5) wells, one analogue well and core data. Lithofacies were determined by systematic description of petrographic features from core data and inferred lithology and depositional environments from characteristic log motifs. Reservoir quality of different sand bodies was determined from interpretation of petrophysical parameters obtained from both log and core data. The results revealed that the rock properties are variable and were controlled by successive depositional environments during Oligocene – late Miocene. Three lithofacies (sand, silt and shale) and five sub lithofacies (ranging from coarse grained sand to silty shale) were delineated based on the relationship between grain size and bulk volume water. The results of gamma ray log motif and core analyses revealed the sandstones to have been deposited in a broad environment of fluvio-deltaic plain, deltaic front and open-shelf margin / slope. Five reservoir sand units were identified. Reservoir sands were found from 1800 m to 4000 m. The porosity of reservoir sands, which ranged from 14.29 % to 22.5 %, was interpreted as fair to very good. Their permeability, with average field range from 43.95 mD to 121.68 mD, was interpreted as moderate to good. Hydrocarbon saturation was high in all the reservoir sands, ranging from 70.65 % to 80.28 %, with corresponding water saturation from 19.72 % to 29.35 %. Water saturations were irreducible for reservoir sands C, D and E. The field is predominantly an oil field because, gas only occurs in sand E. The reservoir quality of “OLI Field was found to be good to very good.

Keywords: Depositional environment, Reservoir quality, porosity, permeability, Niger Delta

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CHAPTER ONE

INTRODUCTION

1.1 Background Statement

The Niger Delta province has commercial quantities of hydrocarbon which almost constitutes Nigeria's sole revenue base. The hydrocarbons in the Niger Delta is accumulated in the microscopic pore spaces or open fractures of the reservoir rocks. Reservoirs in the Niger delta are basically sandstone.

A reservoir rock may be defined as a formation that has the capacity to store fluid and have the ability to release the fluid when tapped as a resource (Etu – Efeotor, 1997). Such fluid can be oil, gas or water. Therefore, the exploration for oil and gas in the Niger Delta is actually the search for hydrocarbon bearing reservoir. Various studies by geologists such as Short and Stauble (1967), Weber and Daukoru (1975), Doust and Omatsola (1990), Reijer (2011), and others, reveal that the reservoir rocks in Niger Delta are sandstone.

Identifying depositional setting of a field is fundamentally important in the determination of reserves and in the design of optimum reservoir management procedures. Sands deposited in different depositional environments are characterized by different sand body trend, shape, size, and heterogeneity.

This tends to show that the physical characteristics of clastic reservoir rocks reflect the response of a complex interplay of processes operating in depositional environments. Hence, the reconstruction of depositional environments in clastic successions provides optimum framework for describing and predicting reservoir quality distribution. Knowledge of depositional environment of reservoirs through accurate description, interpretation of wire line logs and core data allows for a better understanding of reservoir characteristics and hence its quality for optimal utilization of the embedded resources.

Reservoir quality is a measure of the viability of a reservoir. This can be obtained from petrophysical parameters distribution and trends observed from formation evaluation. Basically, Reservoir quality is a function of its porosity and permeability.

Ascertaining the reservoir quality of an oil field is very important to geoscientists and engineers. It gives information which helps in making crucial decisions for exploitation and investment opportunities. Logging tool responses and core data are often used to draw inferences about lithology, depositional environments and fluid content. These inferences are based on empirical models utilizing correlations among tool responses, rock and fluid properties.

Weber and Daukoru (1975), Evamy (1978), Ekweozor and Okoye (1980) have reported in their works on Niger Delta reservoir rocks, that the quality of the sandstones as initially deposited is a function of the source area, the depositional processes and the environment in which the deposition takes place. Well data provided a variety of information about the mineralogy, porosity and sometimes the morphology of the pore spaces and fluid content and detailed depth constraints on geologic horizons (Weber and Daukoru, 1975).

A lot of information about the sediments is contained in well logs. Sediments in different paleoenvironments display characteristic log motifs. As a result, well logs are commonly used to interpret sedimentary facies (Weber, 1971).

This study attempts to identify reservoirs in the “OLI field” offshore western Niger Delta. It also tries to identify lithofacies, their succession, distribution and impact on the petrophysical properties (such as porosity and permeability) based on evidence obtained from analysis of well log response and core data obtained from and relevant to the “OLI field”. To advance this knowledge, the depositional environment and reservoir quality evaluation of “OLI field”, Niger delta were studied using core data and well log data available and relevant to the study area.

1.2 Statement of the Problem and Justification of the Study

In an oil prone area like the Niger Delta, even though hydrocarbon is within the subsurface, it cannot impulsively gush to the surface when penetrated by a production well (Aigbedion and Iyayi, 2007). Detailed geological, Petrophysical knowledge and data are therefore needed to guide the placement of production platforms and well paths to consequently help optimize hydrocarbon recovery, and improve predictions of reservoir performance (Stat Oil Research Group, 2003). To ensure a reduced risk and economically successful exploitation of this hydrocarbon it is important to characterize and describe the reservoirs so as not only to quantify hydrocarbon in place but to identify the controls of the reservoir properties.

1.3 Aim and Objectives

The aim of this work is to evaluate the environment of deposition and reservoir quality of sediments in the “OLI field”, Niger delta, in order to establish their relationships.

To achieve this aim, the following objectives had to be met;

- Determination of lithology and lithofacies in order to establish the dominant environment(s) of deposition/reservoirs of the field.
- Delineation of the top and base of the reservoirs in the field, in order to deduce thickness of the reservoir units.

- Determination of petrophysical properties of the reservoir in order to comparatively establish their distribution and qualities.

- Flow unit characterization using simple cross-plotting technique in order to establish permeability and inhibitions to flow of fluid

1.4 Location of the Study Area

The "OLI field" is located in OML-X, Offshore, Niger Delta of Nigeria, Gulf of Guinea belonging to Nigerian Agip Exploration Ltd. Fig 1.1 shows the locations of the wells in the "OLI field".

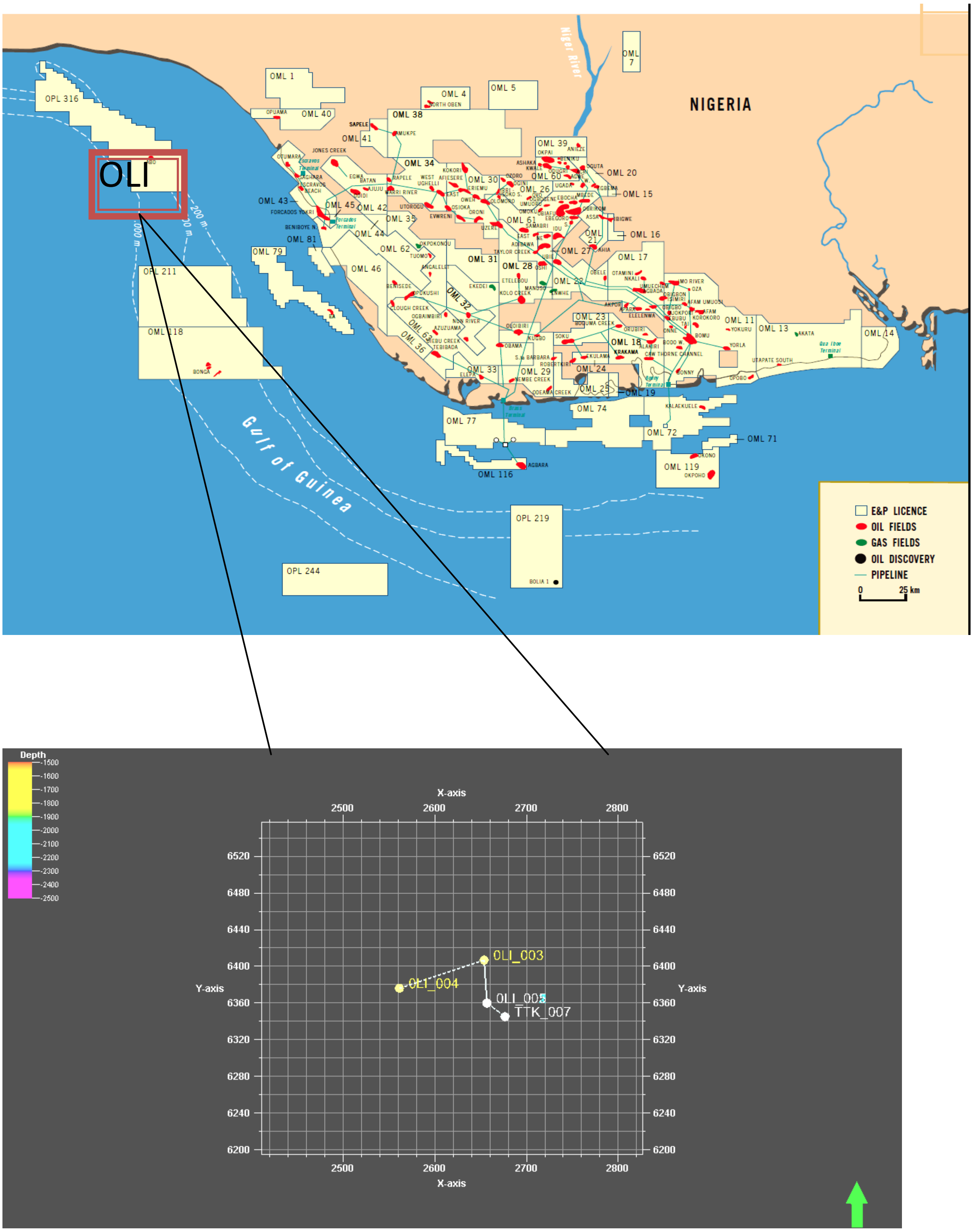


Fig.1.1. Location of the wells in the "OLI Field" and the location of the field in the Niger Delta.

1.5 Previous Studies on the Niger Delta

Detailed studies on tectonics, stratigraphy, depositional Environment, petrophysics, sedimentology and hydrocarbon potential of the Niger Delta have been well documented in several works.The mega tectonic setting of the Niger Delta was analyzed and discussed by Stoneley (1966) and Burke et al., (1970, 1972). Merki (1972) and Evamy et al., (1978) described extensively the syn-sedimentary tectonics of the Tertiary delta.

Short and Stauble (1967), Weber and Daukoro (1975) outlined the three major depositional cycles in the coastal sedimentary basins of Nigeria. The first began with an Albian marine incursion and terminated during the Santonian time; the proto-Niger Delta started during the second cycle, the growth of the Niger Delta continued from Eocene to Recent time. At several stages during the late Quaternary, sedimentation was interrupted by uplift and erosion, during which several cycles of channels were cut and filled which resulted to submarine canyons (Evamy et al., 1978).

Burke et al., (1972) correlated these late quaternary canyons to the drowning of river and the mouths, which were incised on the continental shelf during the Wisconsin fall in sea level, which probably resulted in the formation of the Afam canyon and the Qua Iboe clay fill, during the Miocene, in the south-east delta. Short and Stauble (1967) and Doust and Omatsola (1990) found that the Niger delta comprises a regressive sequence of deltaic and marine clastics, defined by three major lithofacies. Directly overlying the basement are the marine shales of the Akata Formation, overlain by paralic sequence (intercalation of sand and shale) of Agbada Formation and which is overlain by the Continental sand of the Benin Formation. Oomkens (1974) examined the sediments in the terrestrial and submarine parts of the modern delta and grouped them into five major lithofacies, using lithological characteristics and other sedimentary features. These lithofacies are grouped into sandstone, heterolith and mudstone.

Doust and Omatsola (1990) recognized six depobelts in the Niger Delta, which are distinguished primarily by age. They are: Northern Delta (late Eocene – Early Miocene), Great Ughelli (Oligocene – early Miocene), Central Swamp I (Early-Middle Miocene), Central Swamp II (Middle Miocene), Coastal Swamp I and II (Middle Miocene) and Offshore Mega structures (Late Miocene).

Poston et al., 1981 suggested combining well log interpretation and core data to aid the spatial variation of porosity and permeability within particular reservoir intervals.

Asquith (2004) and Enikanselu et al. (2012) relationship between grain size and Bulk volume water which helps to classify sediments into five lithofacies, which are; coarse grained sand, medium grained sand, fine grained sand, very fine grained shale and silty shale.

Sneider et al., 1978 discussed the integration of core data and log data in formation evaluation. This according to him will help ensure the reliability of the result of analysis of the sediments.

Keelan (1982) discussed a variety of measurement protocols, characterized certain rock properties such as porosity, permeability, grain density, and capillary pressure, and showed how these properties varied with the geological factors such as the environment of deposition. Amaefule et al. (1993) noted that for enhanced reservoir characterization, core data must be integrated with log data to account for the uncertainties that exist at both levels of measurement which must be recognized and incorporated in sensitivity studies. They also noted that the key to enhanced reserves determination and improved productivity is not based on the use of empirical correlations but it is based on the establishment of casual relationships among core-derived parameters and log-derived attributes. These theoretically correct relationships can then be used as input variables to calibrate logs for improved reservoir characterization.

CHAPTER TWO

LITERATURE REVIEW

2.1 Basin Evolution

The study area lies within the Niger Delta. The geologic evolution of the Niger Delta basin transcends and predates the Paleocene regressive clastic wedge that is conventionally ascribed to the delta (Frankl and Cordry, 1967; Short and Stauble 1967; Weber and Daukoru, 1975). It is connected to the tectonic setting of the southern Benue Trough, which is the mega structure whose coastal and oceanward part lies with the Niger Delta. Benue Trough is a NE – SW folded rift basin that runs diagonally across Nigeria. It represents a failed arm of a triple junction associated with the opening of the Gulf of Guinea and the equatorial Atlantic in Aptian-Albian times when the equatorial part of Africa and South America began to separate. (Benkhelil et al., 1989).

The formation of the Niger delta basin began after second depositional cycle (Campanian-Maastrichtian) of Benue trough that formed the proto-Niger Delta. The third and last depositional cycle of the southern Nigerian basin formed the Niger delta formations.

According to Reijers (2011), the evolution of this basin was and is controlled by allocyclic and autocyclic processes. Autocyclic cycles result from natural redistribution of energy within a depositional system such as channel meandering or switching and delta avulsion. While allocyclic cycles results from changes in sedimentary system as a result of an external cause such as eustatic sea level change, tectonic basin subsidence and climate change. The Combined effect of the two processes resulted in delta-wide sediment distribution and progradation of siliciclastic system over the pre-existing continental slope into the deep sea during the late Eocene and is still active today (Burke, 1972).

2.2 Geology of Niger Delta

The Niger Delta is located at the southern end of Nigeria bordering the Atlantic Ocean and extends for about longitude 3^o-9^o E and latitude 4^o30^1-$5^o20^,$ N. It is bounded by fault flexures to the Northwest (Benin Hinge line), which coincides with the up dip limit of the delta tectonics. It is bounded in the south by the Gulf of Guinea and to the north by older (Cretaceous) tectonic sediment such as the Anambra basin, Abakaliki uplift and Afikpo syncline. The evolution of the Niger Delta is described by the third phase of megatectonic events that occurred in the southern Nigeria (Murat, 1972).The event which occurred towards the end of Eocene, was characterized by uplift and subsidence of Benin and Calabar flanks that are bounded by NE-SW and NW-SE trending faults respectively to form the Niger Delta basin. The delta since Eocene has witnessed series of progressive out building, which resulted in a progressive shift to the coastline from about 16 km^2 seaward in the Late Miocene to about 40 km^2 seaward by the Pleistocene times (Bustin, 1988).

The Tertiary Niger Delta basin thus, recorded regressive and transgressive units that were related to sea level fluctuation during the last glaciations (Allen, 1965; Oomkens, 1974). The Niger which is the major source of sediments supply to the present delta system is about 4,100 km long from the source (Futon Jallon in Cameroun) to the sea and has a total drainage area greater than 1,000,000 km^2. It is one of the world’s largest deltas covering an area of about 75,000 km^2.

The Niger Delta is characterized by synsedimentary growth faults and associated structures. Due to the progradative nature of the delta, since regressive sequence modified by the numerous intervening transgression which have tended to break the continuity sequences, their transgressive members form three (3) lithostratigraphic units within the basin namely the Akata, Agbada and Benin Formations. The Niger Delta is one of the World's largest Tertiary delta systems and an extremely prolific hydrocarbon province. Hydrocarbons have been located in all of the depobelts of the Niger Delta, in good quality sandstone reservoirs belonging to the main deltaic sequence (the 'paralic sequence' of common usage). Most of the larger accumulations occur in roll-over anticlines in the hanging-walls of growth faults, where they may be trapped in either dip or fault closures.

2.3 Sedimentary Cycles

A sedimentary cycle consists of series of stacked coarsening or fining-upwards sequences which are generated from sea level transgression and regression phases within a basin. There are three main sedimentary cycles in Niger Delta.

a. The oldest which extends from Albian to Santonian time
b. The next one which lasted from the Campanian to the Paleocene
c. The youngest which started in the lower Eocene and is still active today.

2.3.1 Albian to Santonian Cycle

This is the oldest dated sedimentary cycle in the Niger Delta. They are micaceous, sandy shales and fine grained sandstones of the Asu River Group. Cenomanian sediments sandstones and fossiliferous limestones have been found only in the eastern part of the delta (Oban Massif). During the Turonian and Cenomanian time a thick marine sequence of grey calcareous, fossilliferous shale was deposited. The shale is called the Eze Aku Shales, have been observed to grade laterally into sandy shale and calcareous sandstones, the Amaseri Sandstone. During Cenomanian time, the beds of rapidly changing lithofacies, were deposited including shales, limestones and increasing amount of sandstones. It was interpreted as the onset of the active tectonic phase of folding, faulting, and uplifting which terminated this first depositional cycle (Short and Stauble, 1967).

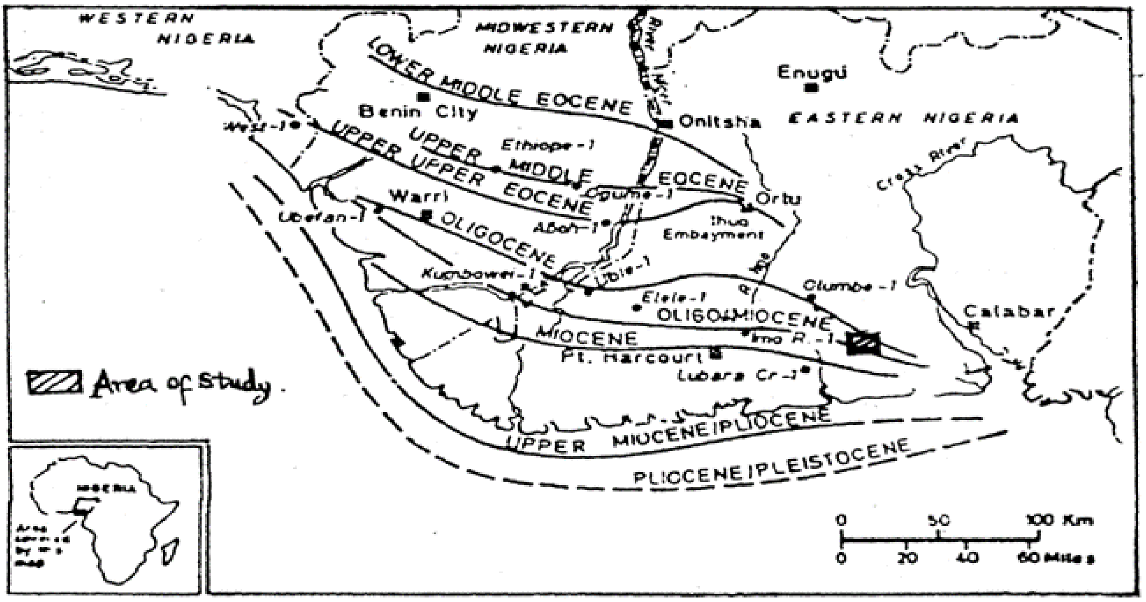


Fig.2.1. Paleogeography of Tertiary Niger Delta – Stages of Delta Growth (After Short and Stauble, 1967)

2.3.2 Campanian –Paleocene Cycle

After a short marine transgression manifested by the Santonian/Campanian Nkporo shales, the history of this cycle is first one of a strong regression during which sandy deposit (Mamu, Ajali, Nsukka Formation) of a proto- Niger Delta advanced rapidly in the Anambra basin and the Afikpo syncline. The regression lasted into the uppermost Cretaceous possibly locally into Paleocence. The second part of the cycle is marked by a rather sudden transgression during which the blue-grey, fossiliferous Paleocene to Lower Eocene Imo shale was deposited. The onset of a new regression initiates the cycle during which the sediments of the Tertiary Niger Delta were deposited.

2.3.3 Recent Delta Cycle

The Niger Delta constitutes an advance of terrestrial deposits into high energy marine environment. Biostratigraphical dating is possible only in the more marine sequence such as the Paleocene-Eocene Imo shale and the Eocene Ameki Formation. Towards the south we have poorer and younger Ogwashi-Asaba and Benin formation which are marked by thick, partly weathered layers of the Recent Niger Delta.

The history of the Niger Delta since its inception in the Lower Eocene is one of the major regression with a gradual southward offlap of such mega lenses. As a result of this, this Recent Delta sequence starting with coarse sandy deposits and ending with marine clays is observed in the entire Niger Delta.

2.4 Stratigraphy

Stratigraphically, the Niger Delta comprises a lower marine unit, the Akata Group; a middle paralic, the Agada Group, and an upper continental sequence, the Benin Group. These units are strongly diachronous because of deltaic progradation (Short and Stauble, 1967). Abundant and diverse planktonic and benthic foraminifera were obtained from Akata Shale and the marine shale intercalations in the Agbada Formation. Foraminifera were also recovered from large clay fills of ancient submarine canyons in the eastern and western Niger Delta. Benthic foraminiferals paleobathymetric analysis has revealed an ancient canyon system in the western delta. This is the Opuama shale Formation in the Agbada Group. Other submarine canyon shales in the Agbada Group are the Orogho Shale, the Elelenwa Clay, Buguma Clay, Soku Clay, Afam Clay and Qua Iboe Clay.

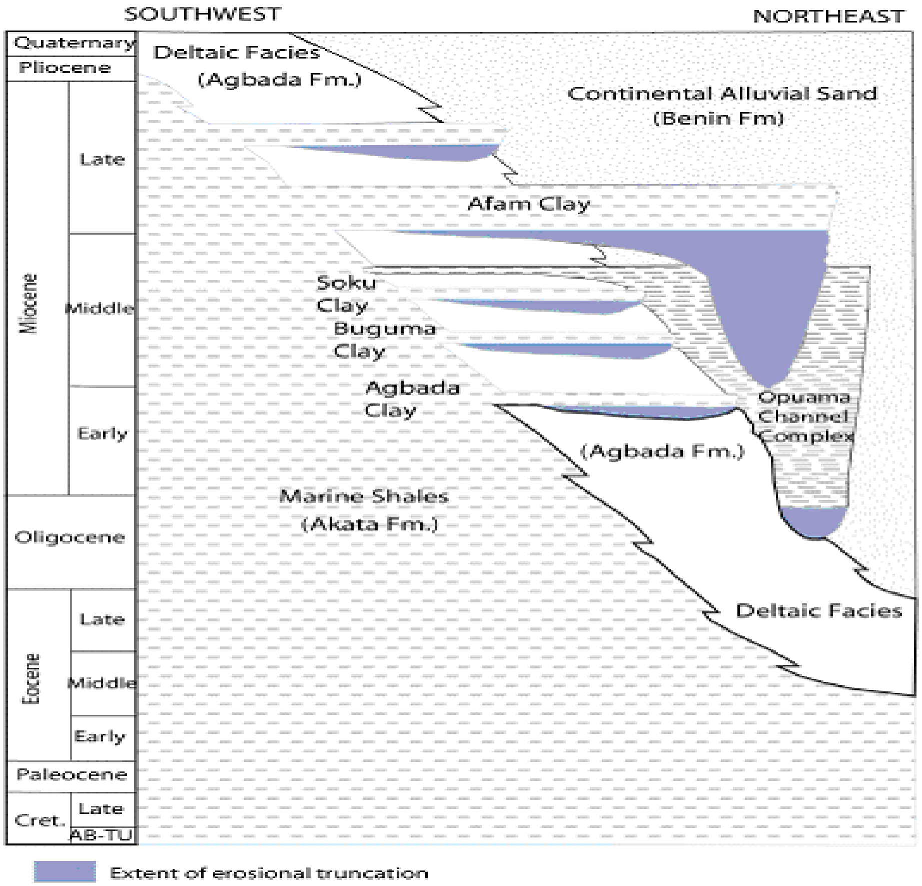


Fig.2.2. Stratigraphic column showing the three formations of the Niger Delta. Modified from Shannon and Naylor (1989) and Doust and Omatsola (1990).

2.4.1 Akata Formation

The Akata Formation (Eocene – Recent) is a marine sedimentary succession that is laid in front of the advancing delta and ranges from 1,968 ft to 19,680 ft (600 m- 6,000 m) in thickness. It consists of mainly uniform under-compacted shales with lenses of sandstone of abnormally high pressure at the top (Avbovbo, 1978). The shales are rich in both planktonic and benthonic foraminifera and were deposited in shallow to deep marine environment (Short and Stauble, 1967).

Akata Formation is characterized by a uniform shale development. There are, however, prominent sand lenses which represent deep-sea submarine fans intercalated within the Akata Formation. The Akata shale is dark grey, in some places sandy or silty, and contains especially in the upper part of the group plant remains and some mica. Towards the top of the Akata Formation where it grades into overlying Agbada Formation, some thin sandstone lenses may occur. Paleontologically the Akata Formation is very rich in planktonic foraminifera, which may make up over 50% of the microfauna. The benthonic assemblage suggests deposition in shallow to deep marine environments.

The Akata Formation is a marine sedimentary sequence deposited in front of the advancing delta. From the margins of the delta where the entire succession of the Akata has been penetrated in oil wells, the base of the Formation has been defined as the top of the highest sandstone body of Early Tertiary age or the first major unconformity below the Akata shale. The Akata Formation is the subsurface equivalent of the Imo Shale.

2.4.2 Agbada Formation

The Agbada Formation (Eocene-Recent) is characterized by paralic interbedded sandstone and shale with a thickness of over 3,049 m (Reijers, 1996). The top of Agbada Formation is defined as the first occurrence of shale with marine fauna that coincides with the base of the continental-transitional lithofacies (Adesida and Ehirim, 1988). The base is a significant sandstone body that coincides with the top of the Akata Formation (Short and Stauble, 1967). Some shales of the Agbada Formation were thought to be the source rocks; however, Ejedawe et al. (1984) deduced that the main source rocks of the Niger Delta are the shales of the Akata Formation**.**

The Agbada Formation extends throughout the whole Niger Delta, south of the exposure of the Anambra basin of the Ogwashi-Asaba Formation. It is characterized by the alternation of sandstone and sand bodies with shale layers. The Formation is divisible into two major units: an upper succession in which sandstone-shale alternations are abundant and the shale intercalations relatively lower; and a lower unit in which the shale units become more prominent and in some places are thicker than the intercalated sandstone or sand bodies. The sandstone percentage ranges from 75 % in the upper unit to 50 % in the lower unit. The sandstone and sand are very coarse to very fine-grained, predominantly unconsolidated or slightly consolidated with a calcareous matrix. Sorting generally is poor except where the sand or sandstone grades into shale. The shale beds are gray and dense at the base; they become markedly sandy and silty upward and grade into the overlying sand and sandstone bodies. Commonly they contain a micro fauna which is best developed at the base of the shale units and becomes sparse or absent in the upper part. This indicates an increase in the rate of deposition in front of the prograding delta.

The occurrence of some larger foraminifera at the base of the more prominent shale units suggest that in a few places, non-deltaic conditions were present at the beginning of a marine transgression. Coarse and poorly sorted sand bodies in the Agbada Group suggest fluviatile origin. The well sorted; generally finer-grained, sand and sandstone beds with glauconite grains and shell fragments represent beach or coastal barrier sand deposits. It is over 10,000 ft thick.

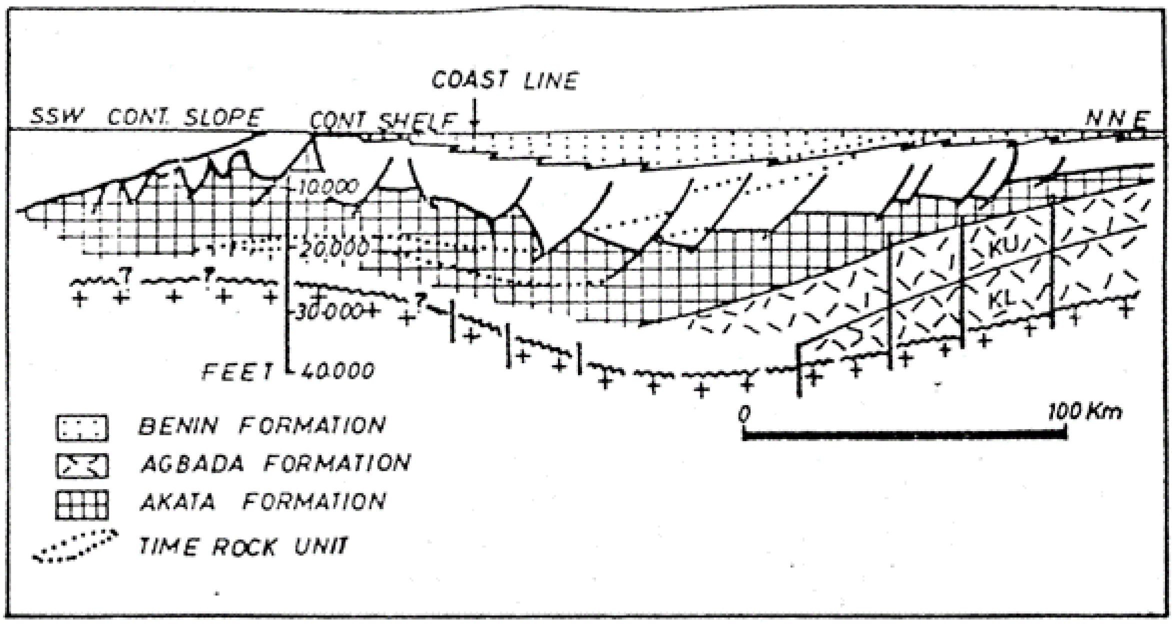


Fig.2.3. Niger Delta Dip Section (After Murat, 1972).

2.4.3 Benin Formation

The Benin Formation is the youngest lithostratigraphic unit in the Niger Delta. It is Miocene –Recent in age with a minimum thickness of more than 6,000 ft. (1,829 m) and made up of continental sands and sandstones (>90 %) with few shale intercalations. The sands and sandstones are coarse-grained, sub-angular to well-rounded and are very poorly sorted.

The top of the Benin Formation is the recent coastal plain deposits in the southern Nigeria, especially the Niger Delta. The base of the group is the top of the highest shale bearing a marine fauna. The sand and sandstones are coarse-grained, quartzitic, very granular and pebbly to very fine-grained. They are poorly sorted with the grains sub-angular to well-rounded and bears lignite streaks and wood fragments. Various structural units (point bars, channel fills, natural levees and back swamp deposits) are identifiable within the formation, indicating the variability of the shallow water depositional medium. In the subsurface, it is of Oligocene age in the north becoming progressively younger southwards. In general, it ranges in age from Miocene to Recent. The thickness is variable but generally exceeds 6,000ft. Very little hydrocarbon accumulation has been associated with it.

Table.1.1. Formations in Niger Delta (Short and Stauble, 1967)

<table>
<tr><th colspan="3">Subsurface</th><th colspan="3">Surface Outcrops</th></tr>
<tr><th>Youngest known Age</th><th></th><th>Oldest known Age</th><th>Youngest Known Age</th><th></th><th>Oldest Known Age</th></tr>
<tr><td>Recent</td><td>Benin Fm
Afam Clay Member</td><td>Oligocene</td><td>Plio/ Pleistocene</td><td>Benin Fm</td><td>Miocene</td></tr>
<tr><td>Recent</td><td>Agbada Fm</td><td>Eocene</td><td>Miocene
Eocene</td><td>Ogwashi-Asaba Fm
Ameki Fm</td><td>Oligocene
Eocene</td></tr>
<tr><td>Recent</td><td>Akata Fm</td><td>Eocene</td><td>Lower Eocene</td><td>Imo shale Fm</td><td>Paleocene</td></tr>
<tr><td colspan="3" rowspan="7">Equivalent Not Known</td><td>Paleocene</td><td>Nsukka Fm</td><td>Maestrichtian</td></tr>
<tr><td>Maestrichtian</td><td>Ajalli Fm</td><td>Maestrichtian</td></tr>
<tr><td>Campanian</td><td>Mamu Fm</td><td>Campanian</td></tr>
<tr><td>Camp./Maest.</td><td>Nkporo Shale</td><td>Santonian</td></tr>
<tr><td>Coniacian/Santonian</td><td>Awgu Shale</td><td>Turonian</td></tr>
<tr><td>Turonian</td><td>Eze Aku Shale</td><td>Turonian</td></tr>
<tr><td>Albian</td><td>Asu River Group</td><td>Albian</td></tr>
</table>

2.5Structural and Depositional History of Niger Delta

The tectonic framework of the continental margin along the west coast of equatorial Africa is controlled by Cretaceous fracture zones expressed as trenches and ridges in the deep Atlantic. The fracture zone ridges subdivide the margin into individual basins and in Nigeria, form boundary faults of the cretaceous Benue- Abakaliki trough, which cuts far into the West Africa Shield.

The trough represents failed arm of a rift triple junction associated with the opening of the South Atlantic. In the region of the Niger delta rifting diminished altogether in the late Cretaceous. A rifting ceased, gravity tectonism became the primary deformational process. Shale mobility induced internal deformation and occurred in response to two processes.

Firstly, shale diapirs formed from loading of poorly compacted, over pressured, prodelta and delta-slope clays (Akata Formation) by the higher density delta front sands (Agbada Formation). Secondly, slope instability occurred due to a lack of lateral, basinward, support for the under compacted delta slope clays (Akata Formation). For any given depobelt, gravity tectonics were completed before deposition of the Benin formation and are expressed in complex structures, including shale diapirs, rollover anticlines, collapsed growth crests, back-to-back features, and steeply dipping, closely spaced flank faults. These faults mostly offset different parts of the Agbada Formation and flattened into detachment planes near the top of Akata Formation.

Diapric shale structures began forming by late Miocene time in response to lateral shale withdrawal from beneath the advancing deltaic load, combined with compressional uplift and folding of prodelta strata. During Pliocene and Pleistocene time, these structures were buried by prograding delta and extensional growth faulting commenced subsidence within the depobelts ceased episodically, at which time alluvial sands advanced rapidly across the delta top concurrent with a basinward shift in deposition and thereby seaward stepping depocenters. Extensive gravity has deformed sediments over the continental slope and the resulting folding, faulting and diaprism have created intraslope basin 10 to 25 km wide, filled with thick sequences of ponded sediments that represent a wide range of depositional processes.

2.6 Tectonic Structure

The most striking structural features of the area are the large synsedimentary faults, which have deformed the delta largely beneath the Benin Formation. These synsedimentary faults are called growth faults and the anticline associated with them is the rollover anticlines. Large oil fields around the Agbada wells are related to rollover anticlines associated with multiple growth faults and anticline faults. Some are associated with collapsed anticlinal structures complex fault and associated pseudo diapric shale structures.

Growth faults are so called because they are initiated around local depocenters and grow during sedimentation. A growth fault is one which offsets an active surface of deposition. They are crescent shaped with the concave side fairing the downthrown block usually seawards. If sufficient movement takes place along these concave sides, an elongated anticline forms in front of the fault. This is called rollover anticline. Growth faults act as migratory faults for hydrocarbon generated in the Akata shales thus enabling them to migrate and accumulate in the Agbada reservoir sands. The hydrocarbon produced in the Akata Formation, migrates in the upward direction and accumulates in the Agbada Formation sand reservoir.

2.7 Petroleum Potential of the Niger Delta

Petroleum in the Niger delta is produced from sandstone and unconsolidated sand predominantly in the Agbada Formation. Characteristics of the reservoir in the Agbada Formation are controlled by depositional 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 m to 10 % having greater than 45 m thickness. The primary source rock is the upper Akata Formation, the marine-shale facies of the delta, with possible contribution from interbedded marine shale of the lowermost Agbada Formation. Oil is produced from sandstone facies within the Agbada Formation. The turbidite sand in the upper Akata Formation however, is a potential target in deep water offshore and possibly beneath currently producing interval onshore. The Agbada groups of plays are the main contributors of reserves. The most significant play is the stratigraphic structural play which account for 58 % of the basin recoverable oil reserves and 55 % of the basin recoverable gas reserves. The Agbada structural plays account for another 40 % of hydrocarbon reserve.

2.8 Source Rock

There has been much discussion about the source rock for petroleum in the Niger Delta which has reflected in Ekweozor et al. (1979, 1980) Possibilities include variable contributions from the marine interbedded shale in the Agbada Formation, the marine Akata shale and the Cretaceous shale.

The Agbada Formation has intervals that contain organic-carbon contents sufficient to be considered as good source rocks. The intervals, however, rarely reach thicknessess sufficient to produce a world-class oil province and are immature in various parts of the delta 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. In the case of the Cretaceous shale, it has never been drilled beneath the delta due to its great depth; therefore, no data exist on its source-rock potential.

2.9 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 depositional 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 45 meters thickness . The thicker reservoir represents composite bodies of stacked channels. Based on reservoir geometry and quality, describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. The primary Niger Delta reservoirs were described as Miocene paralic sandstones with 40 % porosity, 2 darcys 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-thrown block.

2.10 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.

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) describes a variety of structural trapping elements, including those associated with simple structures 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.

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.

CHAPTER THREE

MATERIALS AND METHODS

3.1 Materials

The dataset used for this study were obtained from Nigeria AGIP Exploration Limited, Portharcort, Rivers State. They include wireline well logs which includes; gamma ray log, spontaneous potential, resistivity log, neutron density log, for five wells. The data also includes core data which comprises of petrophysical parameters like porosity, permeability and plug description of core which includes details like colour, lithology type, roundness, lamination and more. The dataset also contained a base map (Fig 1.1.) showing the location of "OLI FIELD" in the Niger Delta and the positions of the well in the field in relation to each other were also provided. These data were integrated and interpreted to evaluate the depositional environments and petrophysical properties of the field.

This combination is necessary as the interpretation of a cored section can be correlated to the response of the same section on well logs. Therefore, the use of core in this study, giving direct knowledge of the rock, increases the reliability of estimates with wireline logs.

3.1.1 Well logs

Well logs are graphical measurements acquired by instruments lowered down a borehole on a wireline cable or drill pipe during or after drilling operation. During acquisition most measurements are made continuously whilst the instruments are moving. The resulting log of the measurements comprises a uniformly sampled set of data that is plotted against depth. Logs are an objective dataset that show how specific measurements vary within and between formation units. Well logs for petrophysical analysis could be obtained from LWD (logging while drilling) data or from wireline logging data that could be cable conveyed or pipe conveyed.

A lot of information about the sediments and sedimentary processes are contained in well logs. Sediments in different environments display characteristic log motifs. Consequently, borehole logs are widely used to interpret sedimentary facies (Weber, 1971).

The Well log data consists of Gamma ray log, Spontaneous Potential, Resistivity log, Neutron density log obtained from five wells OLI 1, OLI 2, OLI 3, OLI 4, OLI 5 and one analogue well TTK 7.

The gamma ray logs of wells were first placed at equal depth in order to facilitate correlation. The depth measurement was considered in True Vertical Depth Subsea (TVDSS) value. Matching of similar lithologies was then carried out from well to well using the top and bottom datum as controls. Similar features in terms of gamma ray signatures and resistivity were marked. The resistivity log was used in conjunction with the gamma ray to determine whether the sand bodies are reservoirs or not. Deflection of the resistivity log to the left indicates low resistivity-highly conductive shale or water-bearing formations. Sandstones with high resistivities or low conductivities were inferred as reservoirs with the prospect of being hydrocarbon bearing.

3.1.1(a) Gamma ray log

The gamma-ray logging device consists of an electrically operated, downhole counter that detects naturally occurring gamma rays. The gamma rays are detected as pulses that are transmitted to the surface where they are converted to electrical voltages and recorded continuously on film as the sonde is pulled up the hole. The rays are emitted by the unstable elements uranium, thorium, and potassium, which are found in measurable amounts in all rocks. Shale generally contains the greatest concentrations of these elements, and typically is more radioactive than sandstone, limestone, dolomite, salt, or anhydrite. Gamma-ray logging is thus highly useful in distinguishing shale from other rock types. Gamma-ray recording equipment is usually designed so that the curve deflects toward the right as radioactivity increases. On the gamma ray log, the deflection to the extreme right indicates shale. The parts of the curve with less deflection indicate non-shale lithologies such as sandstone and limestone. The gamma-ray log is used principally for bed definition, correlation, and determination of lithofacies because of its shale-distinguishing characteristic. The high penetrating power of gamma rays permits logging in cased or uncased holes, regardless of the nature of the fluid, if any, in the hole. The log is commonly calibrated from 0 to 150 API on a linear scale.

The gamma ray log used in this study has a shale reference line of 75 API, chosen from the range of 0-150 API values, which respond to the natural radioactivity of the formation.

The gamma ray log was used to determine the gamma ray index using the formula according to (Asquith and Gibson, 1982)

3.1.1(b) Spontaneous Potential log

The spontaneous potential (SP) log, measured in milivolts (mv), records the electrical potential (voltage) produced by the formation which result from differences in salinities between resistivity of mud filtrate (Rmf) and that of the formation water (Rw). At positions where shales are encountered, the SP curve usually defines a more or less straight line on the log known as the shale baseline. Opposite sandstone or any other permeable formation, the curve shows deflection from the shale baseline. If Rw > Rmf, deflection is to the left and vice versa (Schlumberger, 1989).

3.1.1(c) Compensated Neutron log

The neutron log consists of an americium-beryllium or plutonium-beryllium source that emits fast neutrons, and a radiation detector placed close to the source. The emitted neutrons are electrically neutral particles that proceed outward from the source and penetrate into the adjacent rocks until they are captured by the atomic nuclei of certain elements after several collisions. When the neutron is captured, it is absorbed and one or more high-energy gamma rays are emitted. The induced gamma rays are of greater intensity and quantity than the naturally occurring gamma rays, thus permitting the measurements of the induced radiation without interference from the relatively weak, natural radiation. The atomic nucleus most successful in slowing down the emitted neutron is the hydrogen nucleus which has a mass almost identical to the neutron. When the hydrogen concentration is large, most of the neutrons are slowed down and captured within a short distance. Due to the source-detector spacing commonly used, a high concentration of hydrogen allows only a few gamma rays to reach the detector. Because hydrogen is a common component of formation fluids, and rocks must be porous to contain these fluids, the intensity of the induced gamma rays indicates the amount of fluid and porosity. High intensity generally signifies non porous rock, whereas low intensity signifies porous, fluid-bearing beds. Neutron is used to bombard the formation and the induced gamma ray from the bombardment is measured. The presence of hydrogen atoms tends to absorb the neutrons giving less room for gamma ray induction thus leading to low count rate. Shale generally shows a high porosity on a neutron log because of the hydrogen chemically combined in its molecules or present in water in its pores. The porosity, however, is not "effective porosity", as the voids are not interconnected, and shale is usually impervious. Natural gas, which contains less hydrogen than oil or water, gives a higher counting rate and the neutron curve records low, inaccurate porosity. The primary use of the neutron log is for porosity determination. It is also useful for delineation and correlation of formations. The log, like the gamma-ray log, can be made in either cased or uncased holes and requires no fluid. When used with the gamma ray, the neutron log may provide a quantitative record of shale and indicate porous and non-porous rock. Thus, it is particularly helpful in cased wells, for surveying old wells, and doing "workover" jobs. Gas containing rocks may also be indicated. It is of interest to know here that neutron log only resolve the liquid filled pore spaces and give abnormally low porosity value for gas filled spaces. The neutron porosity could be calibrated in fractional porosity or in terms of percentage porosity. This work puts the fractional porosity calibration into consideration. It is calibrated from 0.7 on the left to 0 porosity units on the right i.e. it decreases to the right.

3.1.1(d) Litho density Log

The density log is acquired with a radioactivity tool based on the response of the rock to induced, medium-energy gamma rays. The result is an approximate measurement of the bulk density of the rock. The bulk density, as used in well logging, is the number of grams or mass weight of a substance divided by its volume. The tool consists of a gamma-ray source and a detector mounted on a skid that is in contact with the borehole wall. Gamma rays, which are emitted by the source, are transmitted through the formation. The number that reaches the detector depends on the abundance of electrons within the rock material. If many electrons are present, the gamma rays are quickly absorbed and only a few are counted. Conversely, if the electrons are few, many gamma rays are counted. An increase in counting rate therefore indicates a decrease in bulk density. Gamma ray from radioactive source is used to bombard rock and the reflected and diffused gamma ray is counted. Electrons tend to absorb the gamma ray and thus giving less count in the reflected gamma ray. The density log actually responds to electron density, but because the two densities are so closely related, the log is scaled in bulk density. Shales have a higher electron density than sand and thus its presence yields fewer counts than sand. The important relationship between the electron density as recorded by the density log and the porosity of a formation is simple and direct. A formation with a considerable amount of open space offers little resistance to the progression of medium-energy gamma rays. Therefore, rock with good porosity has a low electron and bulk density, as indicated by a high count of diffused gamma rays. The density log provides another method of direct porosity measurement. Oil and gas are less dense than water, which results in a lower density reading, and therefore, unlike a neutron log, their presence causes an indication of favorable porosity. When used to estimate effective porosity, the density log is not influenced as strongly by shale as the neutron log. The density log is calibrated from left to right and increases towards the right. The calibration used for the course of this project is from 1.65 to 2.65 g/cc.

3.1.1(e) Resistivity Log

The resistivity log records the resistivities of subsurface formations and any fluids they may contain. Its design is based on electrical theory and instrumentation. The resistivity of the rock formation must be measured in the uncased portion of the borehole. Current and measuring electrodes are mounted on a mandrel or sonde and lowered down the hole. Different spacing between electrodes allows resistivity measurements at different distances from the borehole into the rock formation. A short spacing between electrodes gives a radius of investigation of only a few inches into the formation; longer spacing measures a larger radius. Three simultaneous resistivity measurements (micro, shallow and deep), using different electrode spacing, are usually recorded. The resistivities at different radii of penetration are compared to indicate the true resistivity, which is modified to varying degrees near the borehole by the invasion of the drilling mud into the rock and the influence of the borehole itself. The resistivity logs are calibrated on a logarithmic scale in ohm meters. High resistivity values are a direct indication of hydrocarbon bearing intervals. Gas and condensate resistivity values are relatively higher than those of oil. However resolution of fluid contact based on resistivity alone could be quite erroneous.

Resistivity logs measure the resistance of rock unit to electric current, which is determined by voltages across the electrodes. Porous and permeable sands contain fluids, which increase the resistivity while shales are compacted low resistivity rocks.

Log shapes are interpreted to predict lithology, lithofacies, depositional environment and most importantly, the depositional sequence.

Some Uses of resistivity logs includes;

- Establish permeable zones.
- Discriminate hydrocarbon versus water saturated zones.
- Estimate water/moveable hydrocarbon saturations.
- Estimate porosity (based on resistivity).
- Correlate strata areally

3.1.2 Core Data

Information about the sediments and sedimentary processes from the above logs 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. From the combined core description and wireline log data, it is commonly possible to generate a series of (wireline) log facies. Such log facies may be used to describe the reservoir section in uncored, but logged, wells (Gluyas and Swarbrick, 2004).

Archer et al. (1986) defined a core as a sample of rock from a well section generally obtained by drilling into the formation with a hollow section drill pipe or bit.

Core Data contains petrophysical parameters values such as porosity, permeability, grain density and lithologic description of core samples. This information was very valuable because, it helped to check the reliability of the petrophysical parameter values calculated from wireline logs readings during formation evaluation.

3.1.3 Software Used

Schlumberger Petrel 2010 package, MS Excel and Notepad were used to upload and process the well log and core data.

3.2 Methods

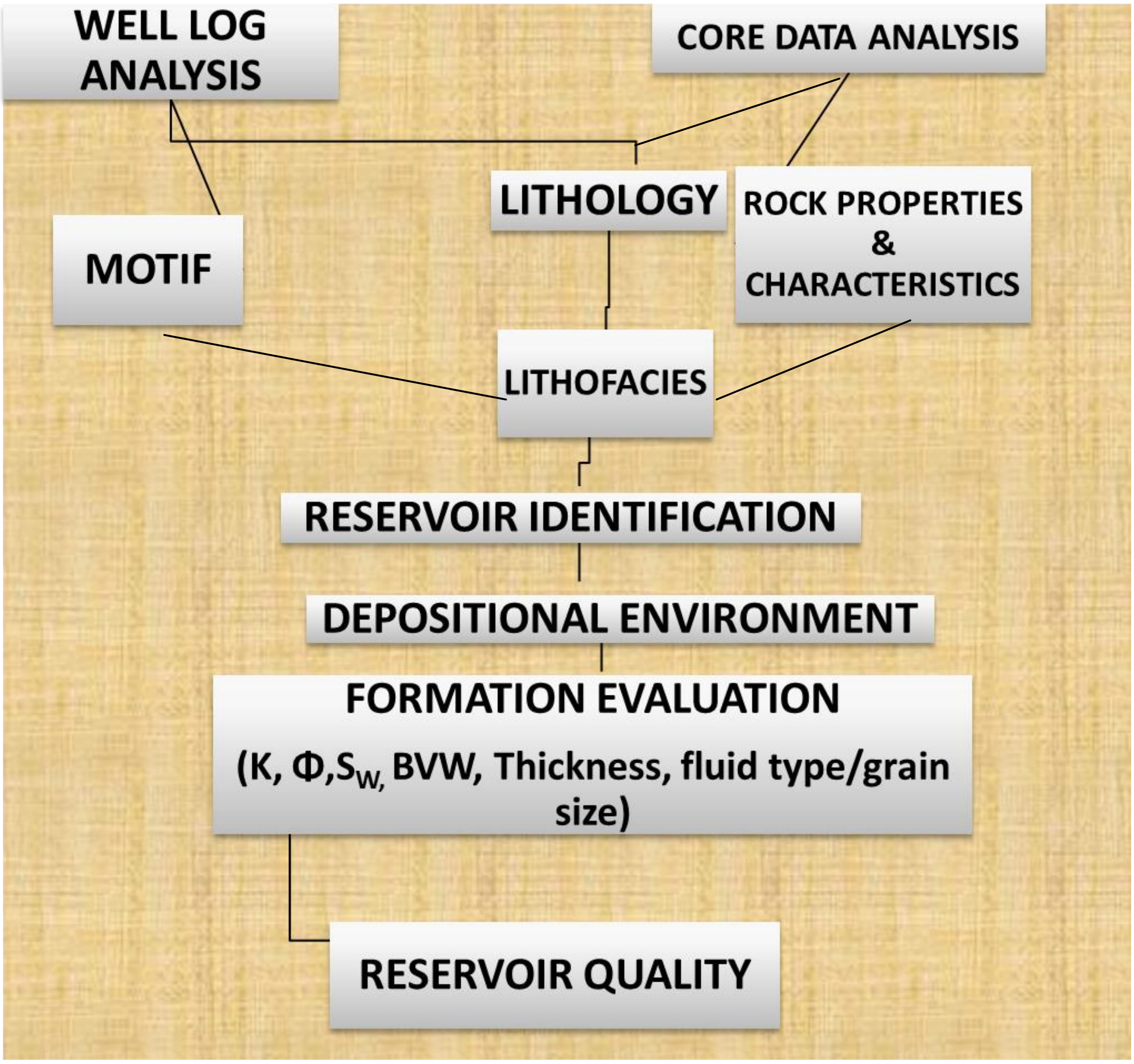


Fig.3.1. Work flow chart showing different stages and Methodology used in the Evaluation of the Depositional Environments and Reservoir Quality of the "OLI Field".

As shown in the diagram above, well log data (gamma ray log and resistivity log) was integrated with core plug description (lithology type and other rock properties) were integrated to delineate the lithology in the “OLI Field”. The gamma ray log motif and core plug description helped in identifying some lithofacies. The resistivity log in conjunction with the gamma ray log and guided by core data was used in delineating reservoirs and environment(s) of deposition. Formation evaluation was then carried out to determine the reservoir quality of the field.

3.2.1 Petrophysical Analysis

This involves the use of empirical formulae to estimate the reservoir properties. The reservoir was characterized quantitatively to arrive at these petrophysical parameters, which include: volume of shale, Bulk volume water, porosity, water saturation, permeability. These parameters are discussed below:

3.2.1(a) Gamma Ray Index

$I_{GR} = (GR_{LOG} - GR_{MIN})/(GR_{MAX} - GR_{MIN})$ (Asquith and Gibson, 1982).

Where, I_{GR} = gamma ray index

GR_{LOG} = gamma ray reading of formation from log

GR_{MIN} = minimum gamma ray (clean sand)

GR_{MAX} = maximum gamma ray (shale)

3.2.1(b) Net to Gross Ratio

This refers to the proportion of clean sand to shale within a reservoir unit. The gross sand is the whole thickness of the reservoir; the non-net sand is the shaly sequences within the whole reservoir thickness; the net sand is thus obtained by subtracting the non-net sand from the gross sand.

This is the ratio between the net reservoir thickness and the gross reservoir thickness. However in terms of hydrocarbon pay, it could be calculated as the ratio between the net pay thickness and the gross pay thickness.

The Net-to-gross ratio reflects the quality of the sands as potential reservoirs. The higher the NTG value, the better the quality of the sand.

Net to gross = Net thickness ÷ Gross Thickness

Net sand = gross sand – shaly intervals

3.2.1(c) Shale and Clay Volume

This was derived from the gamma ray log first by determining the gamma ray index I_{GR} (Asquith and Gibson, 1982).

$I_{GR} = (GR_{log} – GR_{min}) / (GR_{max} - GR_{min})$

Where I_{GR} = gamma ray index;

GR_{log} = gamma ray reading of the formation;

GR_{min} = minimum gamma ray reading (sand baseline);

GR_{max} = maximum Gamma ray reading (shale baseline).

For the purpose of this project work, Larionov's (1969) volume of shale formula for Tertiary rocks was used.

$Vsh= 0.083[2^{(3.7 \text{ x } IGR)} – 1.0]$

Where,

V_{SH} = volume of shale

3.2.1(d) Porosity

The computation of porosity was done in stages, the first involved the use of the Wyllie equation to estimate the density derived porosity (ϕ_D), and then the neutron-density porosity (ϕ_{N-D}), was estimated using the neutron (ϕ_N) porosity coupled with the density derived porosity.

The Wyllie equation for density derived porosity is given as:

$\phi_D = (\ell_{max} - \ell_b)/(\ell_{max} - \ell_{fluid})$

Where:

$\ell_{max} =$ density of rock matrix = 2.65 g/cc for oil and 1.1 g/cc for water)

The Neutron – Density porosity was be calculated according to Shell/Schlumberger (1999) as:

$\phi_{N-D} = (\phi_N + \phi_D)/2$ for oil and water column

$\phi_{N-D} = (2\ \phi_D + \phi_N)/3$ for gas bearing zones

ℓ_b = bulk density from log

ℓ_{fluid} = density of fluid occupying pore spaces (0.74g/cc for gas, 0.9g/cc for oil).

3.2.1(e) Permeability

Permeability: measure of the ease with which a fluid (gas, oil or water) flows through connecting pore spaces of reservoir rock. It is very important in predicting the rate of production from a reservoir.

k = 0.136 (4.4 / Swirr2) – Timur, 1968

Where K = permeability (millidarcy)

Φ = porosity;

Swirr = irreducible water saturation

3.2.1(f) Formation Factor

This was achieved using the humble equation:

$F = a/Ø^m$

Where,

F = Formation Factor

a = tortuosity factor = 0.62

Ø = porosity

m = cementation factor = 2.15

3.2.1(g) Water and Hydrocarbon Saturation:

The water and hydrocarbon saturation are much related. Using the Archie's equation that related the Formation Factor (F) to the resistivity of a formation at 100% water saturation (R_O) and the resistivity of formation water (R_W), the resistivity of the formation water was estimated as:

$R_W = R_O/F$

Determination of the water saturation for the uninvaded zone was achieved using the Archie (1942) equation given bellow:

$S_W^2 = (F \text{ X } R_W)/R_T$

BUT $F = R_O/R_W$

Thus,

$S_W^2 = R_O/ R_T$

Where,

S_W = water saturation of the uninvaded zone

R_O = resistivity of formation at 100% water saturation

R_T = true formation resistivity

$S_W = [(a * R_W)/ (R_T * \Phi_M) 1/n$

Where

S_W = water saturation;

R_W = resistivity in the water leg (that is resistivity of formation water);

R_T = true formation resistivity derived from the deep induction resistivity log;

Φ = porosity;

N = saturation exponent usually taken as 2.0;

m = cementation factor;

a = tortuosity

Hydrocarbon saturation was obtained directly by subtracting the percentage water saturation from 100.

Thus:

$H_S = 1 - S_W$ Or

$H_S\% = 100 - S_W\%$

Where,

H_S = hydrocarbon saturation (expressed as a fraction or as percentage).

3.2.1(h) Resistivity Index

This was estimated using the ratio of formation true resistivity (R_T) to resistivity of formation at 100% saturation (Ro):

$I = R_T/R_O$

Where,

I = resistivity index.

When I is equal to unity, it implies that the reservoir is at one hundred percent (100%) water saturation, the higher the value of I, the greater the percentage of hydrocarbon saturation.

3.2.1(i) Total Volume of Shale.

This is the total volume of shale represented as a depth factor within a well. It is calculated by:

Average V_{SH} x Gross thickness

Where

V_{SH} = volume of shale

3.2.1(j) Net Thickness

This is the column of the reservoir that is occupied by reservoir formation (e.g. sand) only and exclusive of non-reservoir formations (e.g. shale). It is calculated by:

Gross Thickness – V_{sh} Total

Where

V_{SH} Total = Total volume of shale

3.2.1(k) Effective Porosity

This is the porosity of the interconnected pore spaces. It assumes the absence of shale from the reservoir. This is usually based on an adjustment of total porosity by means of an estimated shale volume.

$\Phi eff = \Phi total - (\Phi sh * Vsh)$

Where

Φeff = effective porosity,

$\Phi total$ = total porosity,

Φsh = log reading in a shale zone,

Vsh = volume of shale

It can also be calculated using the following relationship:

$\Phi_{effective} = (1 - V_{SH}) * \phi_{N\text{-}D}$

Where $\phi_{N\text{-}D} =$ Neutron-Density porosity.

3.2.1(l) Storage Volume

This is the capacity to store hydrocarbon in the reservoir. The storage volume is always higher than the hydrocarbon pore volume within a well because the net pay zone is inclusive of the grain matrix whereas, the grain matrix is absent in the hydrocarbon pore volume computation as only the hydrocarbon in the pore spaces is calculated for.

Storage Volume = $\phi_{N\text{-}D}$ * Net Pay Thickness

$\Phi_{effective} = (1 - V_{SHALE}) * \phi_{N\text{-}D}$

3.2.1(m) Bulk Volume Water

Bulk volume of water (BVW): This is the product of water saturation and porosity corrected for shale (Adepelumi et al., 2011):

If values for BVW calculated at several depths within a formation are coherent, then the zone is considered to be homogeneous and at irreducible water saturation. Therefore, hydrocarbon production from such zone should be water free (Morris and Biggs, 1967).

Bulk volume of water (BVW) was estimated as the product of water saturation (S_w) of the uninvaded zone and porosity ($Ø_{N-D}$).

Thus,

$$BVW = S_w \times Ø_{N-D}$$

Where,

$Ø_{N-D}$ = neutron-density porosity.

Or

BVW = Sw * Φe (Asquith and Krygowski, 2004)

Where

BVW = bulk volume of water;

Sw = water saturation;

Φe = effective porosity

3.2.1(n) Irreducible Water Saturation

It is sometimes called critical water saturation. It defines the maximum water saturation that a formation with a given permeability and porosity can retain without producing water.

$$Sw_{IRR} = (F/2000)^{1/2}$$

$$F = 0.81/\Phi^2 \text{ (in most sandstone reservoirs)}$$

Where

F = Formation factor

3.2.1(o) Fluid Type

Delineation of fluid type contained within the pore spaces of formation is achieved by the observed relationship between the Neutron and Density logs. Presence of hydrocarbon is indicated by increased Density log reading which allows for a cross-over. Gas is present if the magnitude of cross-over, that is, the separation between the two curves is pronounced, while oil is inferred where the magnitude of cross-over is low (Asquith and Krygowski, 2004).

3.2.2 Formation Evaluation

Lithology Delineation from Well Logs: The gamma ray log was used in identifying the lithology penetrated by the wells. A shale base line was first established. Maximum deflection of the log signature to the right of the shale base line was interpreted as shale while maximum deflection to the left of the shale base line was interpreted as sandstone. Intermediate values were interpreted as sandy shale or shaly sands. For the resistivity log, deflections to the left were interpreted as low resistivity or high conductivity. Saline water formations are highly conductive while hydrocarbon prone areas have high resistivity.

Lithofacies were determined by systematic description of petrographic features from core data and inferred lithology and Depositional environment from characteristic log motifs. Reservoir qualities of different lithologies were determined from interpretation of Petrophysical parameters obtained from log and core data.

Reservoir sand candidate formations (i.e. hydrocarbon containing sands) were identified using Gamma ray log, Spontaneous Potential log, Resistivity log, Neutron density log.

The gamma ray and resistivity logs were used to delineate lithofacies.

Determination of porosity/permeability of the reservoir sands from the wireline logs using petrophysical calculations (Archie, 1942; Asquith and Krygowski, 2004)

Petrophysical parameters gotten from the core data were compared to the petrophysical parameters gotten from the well log using cross plots data to establish the reliability of the parameters

3.4 Limitation of the Study

There was no seismic Seg Y and Biostratigraphy data, which would have been used in seismic/sequence stratigraphic studies to enhance the identification of environment of deposition.

CHAPTER FOUR

RESULTS, INTERPRETATION AND DISCUSSION.

4.1 Lithological Units in the "OLI Field".

The various lithologies were identified using Gamma ray responses and Core plug description. Two major Lithologies, sand and shale, were identified. Those with high API (that is, right deflections of Gamma ray) were classified as shale while those with low API (that is, left deflections of Gamma ray) were classified as sands. These lithologies were confirmed using core Plug Description data for the sampled depth.

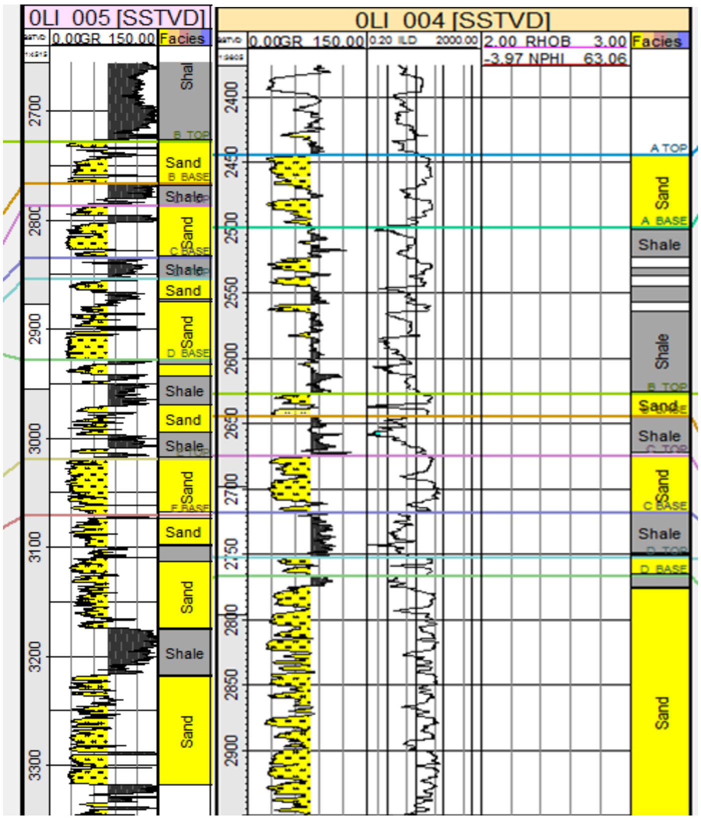


Fig.4.1. Representative well Sections showing the lithological units (sand and shale) in the "OLI Field".

4.2 Lithofacies

One of the first steps in the facies analysis of a clastic reservoir is the description and interpretation of available conventional core. An important result of core description is the subdivision of cores into lithofacies, defined as subdivisions of a sedimentary sequence based on lithology, grain size, physical and biogenic sedimentary structures, and stratification that bear a direct relationship to the depositional processes that produced them. Lithofacies and lithofacies associations (groups of related lithofacies) are the basic units for the interpretation of depositional environments

Four lithofacies were identified using log signatures and core plug description.

- Sand: this was identified in areas with high Resistivity readings and low Gamma Ray readings, confirmed by core plug descriptions.

- Shaly sand: this was identified in areas with sharp increase, then drop in Resistivity readings, confirmed by core plug descriptions.

- Sandy Shale: this was identified in areas with sharp decrease, then increase in resistivity, confirmed by core plug descriptions.

- Shale: this was identified in areas with low Resistivity, High Gamma Ray readings, confirmed by core plug descriptions.

From Core data which followed Asquith (2004) and Enikanselu et al., 2012 relationship between grain size and Bulk Volume Water five Lithofacies were identified:

- Coarse grain sand: with bulk volume water volume values of (0.02 – 0.025) which coincides with the range of its grain size.

- Medium grain sand: with bulk volume water volume values of (0.025 – 0.035) which coincides with the range of its grain size.

- Fine grain sand: with bulk volume water volume values of (0.035-0.05) which coincides with the range of its grain size

- Very fine grain shale: with bulk volume water volume values of (0.05-0.07) which coincides with the range of its grain size.

- Silty shale: with bulk volume water volume values of (0.07-0.09) which coincides with the range of its grain size.

4.3 Inferred Environment of Deposition

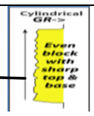
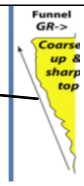
GR LOG	LOG MOTIF MODEL	LOG SHAPE TYPE	INFERRED GRAIN SIZE VARIATION/STACKING/FACIES TYPE	INFERRED DEPOSITIONAL ENVIRONMENT
			SHALE	MARINE
		funnel shape	Prograding stacking (Beach sands, alluvial fans and barrier bars)	Mouth bars, deltaic front and shoreface.
		Cylindrical/blocky shape	Aggrading stacking (Massive thickly bedded sandstone)	Fluvial/Tidal flood plain, fluvial channels,deltaic distributary and tidal channel.
			SHALE	MARINE
		Irregular blocky shape	Aggrading stacking (Massive thickly bedded sandstone)	Fluvial/Tidal flood plain, fluvial channels,deltaic distributary and tidal channel.
			SHALE	MARINE
		Hour glass/ symmetrical	Prograding , aggrading,retrograding stacking (barrier channel, bars, tidal channels sandstone and siltstone)	Tidal flat-tidal channel fill, shore face proximal offshore.
			SHALE	MARINE
		Bell shaped	Retrograding stacking	fluvial point bar, tidal point bar, deep tidal channel fill, tidal flat, regressive shelf
			SHALE	MARINE
			Aggrading stacking (thick sandstone interbedded with siltstone, silts and clays)	Fluvio deltaic plain, deltaic front prodelta, reworked offshore bars.
			SHALE	MARINE
		funnel shape	Prograding stacking (Beach sands, alluvial fans and barrier bars)	Mouth bars, deltaic front and shoreface.

Fig.4.2. Well section and inferred Depositional Environment using log motif model

Prediction of depositional environment can be made based on sandstone composition, grain size characteristics, spontaneous potential, and gamma ray log shapes (Morris and Biggs, 1990). Vail and Wornardt (1991) used the log shapes, resulting from a combination of spontaneous potential or gamma ray and resistivity to interpret the lithofacies and depositional systems in the Gulf of Mexico. In this study, prediction of depositional environment was made from the usage of gamma ray log shapes (Fig.4.2).

Based on reservoir geometry and quality, Kulke (1995) describes the most important reservoir types as point bars of distributary channels and coastal barrier bars intermittently cut by sand-filled channels. However, 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). Edwards and Santogrossi (1990) described the primary Niger Delta reservoirs as Miocene paralic sandstones with 40% porosity, 2 Darcy's permeability, and a thickness of 100 meters.

Deductions from the log motif and Core plug description culminated in interpretation that the inferred environment ranges from fluvio-deltaic to deltaic front to prodeltaic to shelf margin and marine for the Shales.

The gamma ray logs reveal a cylindrical / blocky shape base for sand A and base of sand B funnel shaped top for reservoir sand A indicating deposition in a fluvial / tidal flood plain, channel, deltaic distributary, deltaic front and shoreface. Sand C showed a symmetrical hour glass shape implying deposition in a tidal flat – tidal channel and shoreface – proximal offshores. Fig 4.2 shows types of gamma ray log shape and their stacking patterns along with interpreted depositional environment.

Sands D and E showed serrated, funnel and bell log shapes correspondingly indicating coarsening and fining upward stacking patterns, implying deposition in deltaic environment of tidal flats, fluvial channels and/or deltaic distributaries.

With the knowledge of depositional environment from the cored section, differences in well log patterns can generally be attributed to lateral changes in rock character, which in turn, can be identified in relation to the section interpreted.

The information from gamma ray log motifs and confirmed by core plug description revealed reservoir sands were deposited from fluvio-deltaic plain – deltaic front environments to prodeltaic to shelf margin/slope. This wide depositional environments account for variation observed in the porosity and permeability of the rock units. It is established that porosity and permeability of sandstones depend on grain size, sorting, cementation and compaction (Schlumberger, 1991; Etu-Efeotor, 1997; Rider, 1986, 1996). These variables undoubtedly are functions of the sedimentary environment and depositional processes.

As explained by Tyler (1988), fluvial (channel) and fluvio-marine (barrier bar) processes would generate better quality reservoirs as against marine processes which tend to decrease reservoir quality by producing less sorted heterolithic lithologies. Hence, the difference in quality of reservoir sand units in terms of porosity and permeability is, to a greater extent, related to the degree of sorting of sandstone which is fundamentally controlled by depositional environments and processes, as well as the volume of shale in each unit.

4.4 Well Correlation

Correct interpretation of log is critical to any reservoir evaluation and characterization. Log correlation provides the basis for the determination of reservoir geometry and architecture. (David K Davies, 2002). Well Log correlations were made on “OLI field” based on lithology and knowledge of the geology of the formation.

4.4.1 Delineated Top and Base of the Reservoirs in the Study Area.

The top and bases of five reservoirs A, B, C, D and E were delineated across the wells; results showed that the reservoirs were laterally continuous.

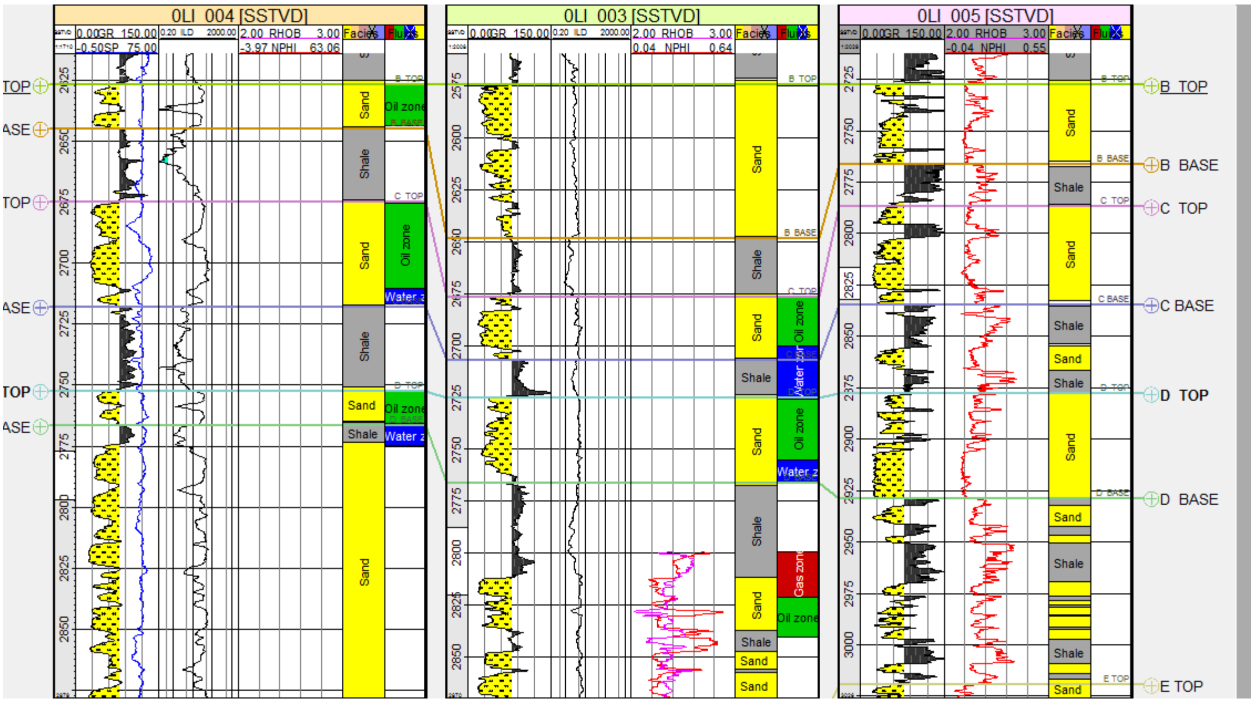


Fig.4.3. Log correlation profile through OLI00_4, OLI_003, and OLI_005 showing some reservoirs.

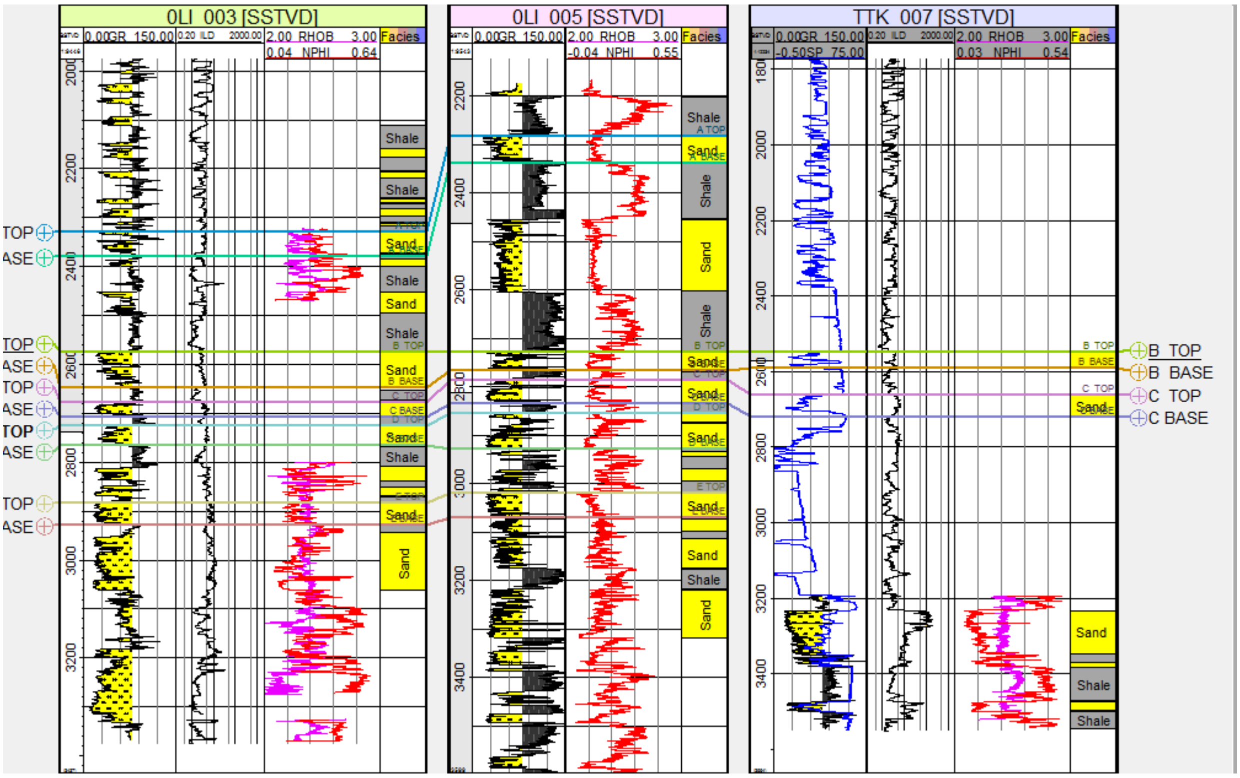


Fig.4.4. Log correlation profile through OLI00_3, OLI_004, OLI_005 and OLI_007 showing some reservoirs.

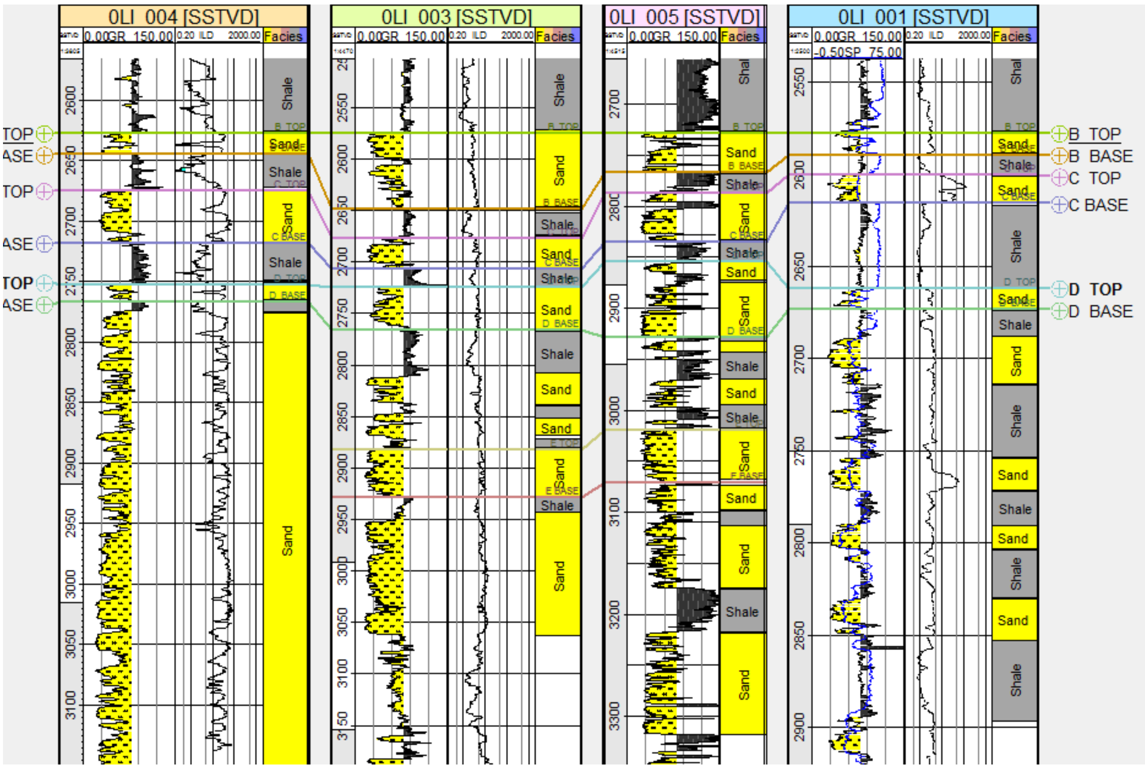


Fig.4.5. Log correlation profile through OLI_001, OLI 00_3, OLI_004 AND OLI_005 showing the geometry of the field.

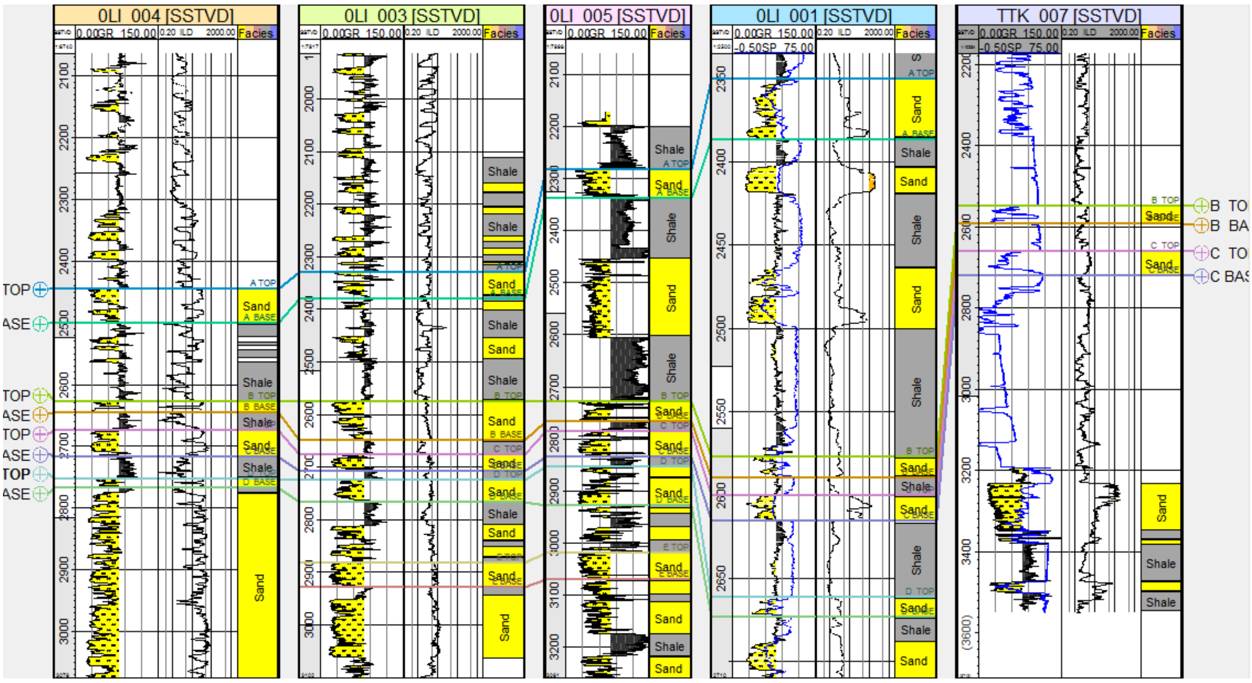


Fig.4.6. Log correlation profile through OLI_001, OLI00_3, OLI_004, OLI_005, OLI_007

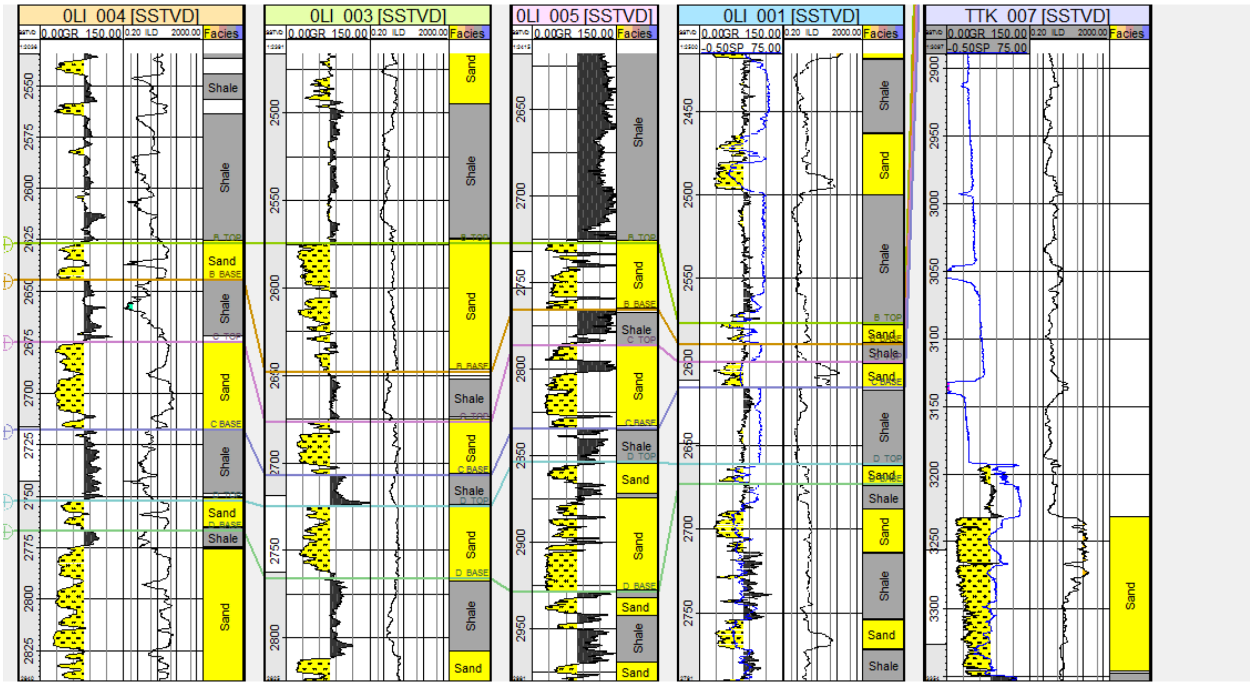


Fig.4.7. Log correlation profile through OLI_001, OLI00_3, OLI_004, OLI_005, OLI_007

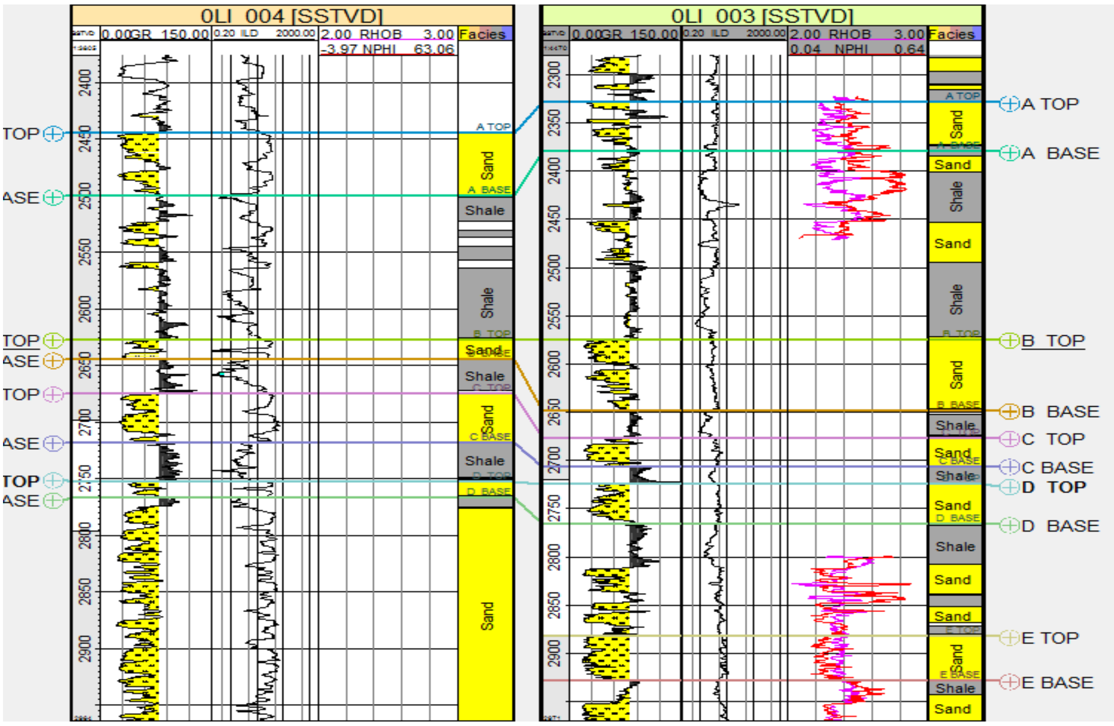


Fig.4.8. Log correlation across OLI 004 and OLI 003 showing the five reservoirs with their respective tops and bases.

Fig 4.3, Fig 4.4, Fig4.5, Fig 4.6, Fig 4.7 and Fig 4.8 shows Litho-stratigraphic correlation of Reservoir intervals across the wells. Correlation was based on Gamma Ray signatures guided by the geology of the formation.

From the Litho-stratigraph correlation, reservoirs are continuous as seen across the wells. Reservoirs B, C, D are seen across all the wells. All the Reservoirs A-E can be seen across wells 003 and 004. This correlation shows lateral continuity of the reservoirs in the "OLI Field".

Fig 4.5 shows the geometry of the field, it shows a decrease in sand from left to right, probably indicating a shift from deltaic environment to marine environment.

4.5 Petrophysical Properties of the Rock Units.

4.5.1 Thickness of rock units

Reservoir thickness ranges from less than 15 meters to 10% having greater than 45 meters thickness (Evamy et al., 1978). The lateral variation in reservoir thickness is strongly controlled by growth faults.

The thicker reservoirs likely represent composite bodies of stacked channels (Doust and Omatsola, 1990).

For the "OLI Field", the thickness of the Reservoir ranges from 15 m to 440 m.

Table.4.1. Depth and thickness of Lithologic units across “OLI Field” as observed across Wells (All depth and thickness are in meters.)

Litho Units	OLI 001			OLI 003			OLI 004			OLI 005			TTK 007		
	Top	Base	Thickness	Top	Base	Thickness	Top	Base	Thickness	Top	Base	Thick Ness	Top	Base	Thick ness
SAND A	2350	2380	30	2330	2380	50	2430	2500	70	2370	2610	240	2180	2380	200
SAND B	2575	2590	15	2575	2650	75	2620	2648	28	2725	2775	50	2560	2595	35
SAND C	2600	2620	20	2675	2710	35	2675	2720	45	2780	2842	62	2650	2700	50
SAND D	2660	2675	15	2720	2770	50	2752	2773	21	2850	2930	80	2720	3100	290
SAND E	2690	2775	85	2810	3250	440	2780	2975	195	3010	3250	240	3200	3370	170

The table above shows the top, base and thickness of the rock units (in meters) across the “OLI Field”

4.5.2 Porosity

The porosity of different units of reservoir sands shows variation laterally, due to changing environmental condition. Sand body A, with average porosity of 14.8 % across the field, had average porosities of 16.29 % at Well 003, 15.09 % at Well 004; Sand B, with average value of 15.42 % had the value of 15.14 % at Well 001, 18.11 % at Well 003, 14.40 % at Well 004 and 28.77 % at Well 005; Sand C with average field value of 22.5 % was found to have the porosity values of 18.33 %, 21.70 % , 20 % and 26.05 % at Well 001, Well 003, well 004 and Well 05, respectively (Table 2).

Table.4.2. Porosity (Φ) values of reservoir sand units across “OLI Field”

Litho Units	**OLI 001**		**OLI 003**		**OLI 004**		**OLI 005**		**CORE**	**CORE**	**Quality Evaluation**
	Φ (%) Range	Φ (%) Aver.	Φ (%) Range	Φ (%) Aver.	Φ (%) Range	Φ (%) Aver.	Φ (%) Range	Φ (%) Aver.	**Ave. Φ Range (%)**	**Ave. Φ (%)**	
SAND A			15-20	16.29	15 – 18	15.09			10 – 17	14.89	Fair to good
SAND B	13-17	15.14	22-31.90	22.5	13 – 15	14.40	22 - 34	28.77		15.42	Good to excellent
SAND C	10-23	18.33	20-24	21.70	19-24	20	19 - 32	26.05		22.5	Good to v.good
SAND D			12.22-25.04	19. 52	14-22	16	21- 26	23.14		19.93	Good to v.good
SAND E			13-17	13.32			19 -37	29.59	7 – 16.4	14.29	Fair to good

The Table above shows the result of porosity evaluation of the sand units of the Field.

The evaluated sands showed little reduction in porosity with increase in depth. This, according to Schlumberger (1985), is due to the unconsolidated nature of the Niger Delta. Compaction and diagenetic processes therefore, seemed to have very little or no effect on the porosity of the field in contrast to the depositional processes and environments of deposition.

The lateral variation in porosity might have been caused by changes in the depositional environment and the gradual deepening of the depth of deposition due to the progradation of the coastline and the shift in depobelts southerly and seaward. This finding is consistent with the reports of Evamy et al. (1978) and Bouvier et al. (1989).

This is evident on the gamma ray log motifs where sands deposited in low energy of this environment had very little or no influence on the reworking of the sands (due to the shales, silts and clays associated with this environment), hence the decrease in porosity. This contrasts with Sands deposited in high energy environment of tidal plain and the deltaic front where strong waves influence reworked the sands, this processes associated with this environment enhances sorting and reduces heterolithic nature of sediment.

4.5.3 Permeability

Although highly variable, the average permeability of Sand C which is the most permeable unit within the field ranged from 9.71 mD to 253.49 mD with overall average value of 106.63 mD -130.25 mD. This was closely followed by Sand D with average field value of 83.93 mD, and with average permeability values of 150.53 mD, 18.06 mD, 21.50 mD and 68.89 mD at Wells 001, 003, 004 and 005, respectively. These two reservoir sandstones (Sands C and D) are the most porous and permeable units within the field. However, the other three sand bodies, reservoir sand A, B and E have moderate permeability values compared to sand bodies C and D. While sand E showed a slightly higher permeability values than sands A and B, the later nevertheless has almost the same permeability values across the field.

The permeability values of the five (5) reservoir sands encountered in the study area are presented in Table 3.

Table.4.3. Permeability (K) values of reservoir sands across "OLI Field".

Litho Units	**OLI 001**		**OLI 003**		**OLI 004**		**OLI 005**		**CORE**	**CORE**	**Quality Evaluation**
	K (mD) Range	**K(mD) Aver.**	**K (mD) Range**	**K(mD) Aver.**	**K (mD) Range**	**K(mD) Aver.**	**K (mD) Range**	**K(mD) Aver.**	**Ave. K Range (mD)**	**Ave. K (mD)**	
SAND A	**1.06 - 540.58**	**53.24**	**38 - 49.90**	**43.95**	**22.15 – 185.68**	**85.6**				**50.21**	**Good**
SAND B	**6.18-279.92**	**89. 0**	**87.7-221.1**	**103.97**		**105.1**		**54.64**		**80.02**	**Good**
SAND C	**36.98-355.85**	**170.4**		**172.0**		**68.1**		**53.99**	**9.71 - 253.49**	**121.68**	**Good**
SAND D	**6.80 – 127.17**	**61.5**	**0.62-24.96**	**6.80**		**73.7**		**53.72**		**43.95**	**Moderate**
SAND E	**12.56 – 180.25**	**71.13**		**75.7**		**90.8**		**30.19**			**Good**

Permeability values though highly varied both laterally and vertically, were moderate to good. The high permeability of the reservoir sandstones in the field would result in rapid water and hydrocarbon flow.

4.5.4 Reservoir fluids

Sands B, C, D and E were found to contain hydrocarbon. The fluid type and their column in each reservoir vary across Wells. Reservoir sand A was found to contain oil and water at Wells 003 and 004. For reservoir sand B, oil and water accumulate at location of Well 04 whereas gas, oil and water were widespread in other locations. Reservoir sand C, was also rich in oil and water at Wells 003 and 004. Reservoir sand E contained gas, oil and water at all Wells 3 and 4. Tables 4.5 and 4.6, show the reservoir fluid type and column across four (4) Wells in the studied field. The fluid type and column could not be computed for Well 001, 002 and 005 due to insufficient Well data.

4.5.5 Hydrocarbon and Water Saturation

In Well 003 (Table 4), reservoir sand C was found to contain 72.50 % hydrocarbon saturation and 27.50 % saturation water at depth 2675 -2715 m.The oil was up to (OUT) 2675 m, Water contact (OWC) at 2700 m. This reservoir sand B, with an average Volume of Shale (Vsh) of 8.9 %, average porosity of 22.5 and average permeability of 54.24 mD was found to not be irreducible at approximately 4.4 % Bulk Volume Water (BVW), an indication that more water will be produced than oil. Reservoir sands D and E encountered at Well 003 location were irreducible; an indication that more oil will be produced than water. Sand D has 73.15 % hydrocarbon saturation and 26.85 % water saturation; oil up to (OUT) 2725m and oil-water contact (OWC) at 2758m. Sand E contained 76.96 % hydrocarbon saturation and 23.04 % water saturation. The oil was up to (OUT) 2818 m, with OWC at 2860 m. Its gas content was up to (GUT) 2800 m with Gas-Oil contact (GOC) at 2818 m.

At Well 004 (Table 4), only reservoir sands B, C and D which contained only oil and water were irreducible. Sand C contained 70.65 % hydrocarbon saturation and 29.35 % water saturation; sand B contained 71.72 % hydrocarbon saturation and 28.28 % water saturation; while sand D contained 80.28 % hydrocarbon saturation and 19.72 % water saturation.

The fluid content of the reservoirs could not be ascertained for wells 001, 002 and 005 because of incomplete data. Some had only one of neutron or density logs, some had both, but, it did not extend to the areas of interest while others did not have neutron or density logs at all.

4.5.6 Bulk Volume Water

There was wide variation in bulk water volume values in the field, the wide variations in the bulk volume water (BVW) indicate that some zones were not at irreducible water saturation. These zones would produce wet hydrocarbons (that is, wet gas and oil) whereas the zones where the BVW were at irreducible water saturation would produce water-free hydrocarbons. The water-free hydrocarbon production zones vary laterally along the reservoir sand units and also across the different reservoir units in the field. Of all the sand units, Sand B was not irreducible in well 003. Thus, any well screened within these units would produce wet hydrocarbon. The reservoir sands C, D and E within the field would produce high amount of water-free hydrocarbons.

Table.4.4. Summary of reservoir sand properties at OLI Well 003

Sand	Depth	Thickness	%vsh		% φ	K(md)	Sw (%)	Swirr	HS (%)	Bvw (%)	Fluid type	Fluid contact/ Column	Nature of formation water
			Range	Aver.									
	2575-2650	75	7.5-28.9	8.9	22.5	103.97	19.88	12.91	80.12	4.4	Oil and water	OUT: OWC:	Not Irreducible
C	2675-2710	35	8.5-38.6	8.9	21.70	172.0	27.50	24.01	72.50	2.44	Oil and water	OUT:2675 OWC:2700	Irreducible at ≈ 2% BVW
D	2720-2770	50	0.8 – 11.6	5.6	19.52	16.80	26.85	21.93	73.15	2.93	Oil and water	OUT;2725 OWC;2758	Irreducible at ≈ 2% BVW
E	2810-3250	440	0.8 – 34.9	5.3	13.2	75.7	23.04		76.96	0.33	Gas, Oil and water	GUT;2800 GOC;2860 OUT;2818 OWC;2860	Irreducible at ≈ 0.3% BVW

Table.4.5. Summary of reservoir sand properties at OLI Well 004.

Sand	Depth	Thickness	%vsh		% φ	K(md)	Sw (%)	Swirr	HS(%)	Bvw (%)	Fluid type	Fluid contact/ Column	Nature of formation water
			Range	Aver.									
B	**2620-2648**	**28**	**1.5-38.9**	**4.9**	**14.40**	**105.1**	**28.28**	**21.40**	**71.72**	**3.39**	**Oil and water**	**OUT OWC**	**Irreducible at ≈ 3 BVW**
C	**2675-2720**	**45**	**0.8 – 21.6**	**5.6**	**20**	**68.1**	**29.35**	**22.01**	**70.65**	**3.25**	**Oil and water**	**OUT OWC**	**Irreducible at ≈ 3**
D	**2752-2773**	**21**	**0.8 – 34.9**	**5.3**	**16**	**73.7**	**19.22**	**12.11**	**80.28**	**0.28**	**Oil and water**	**OUT OWC**	**Irreducible at ≈ 0.2% BVW**

4.5.7 Cross Plots Depicting the Flow Unit Characterization

Fluid flow takes place largely along the stratigraphic unit of the geological formation, thus a correct description of the geometry of the sedimentological rock bodies that make up a reservoir as well as their interrelations in an essential requisite for simulation of the production/injection performance of a field.

Gunter et al. (1997) described a technique for combining porosity, permeability and bed thickness data for flow unit identification. This he did by utilizing the Stratigraphic Modified Lorenz (SML) plot for characterization. This method of flow-unit determination is quite useful, because it requires only routine porosity and permeability data (from log and/or cores) and also it is independent of facies identification, and uses simple cross-plotting techniques.

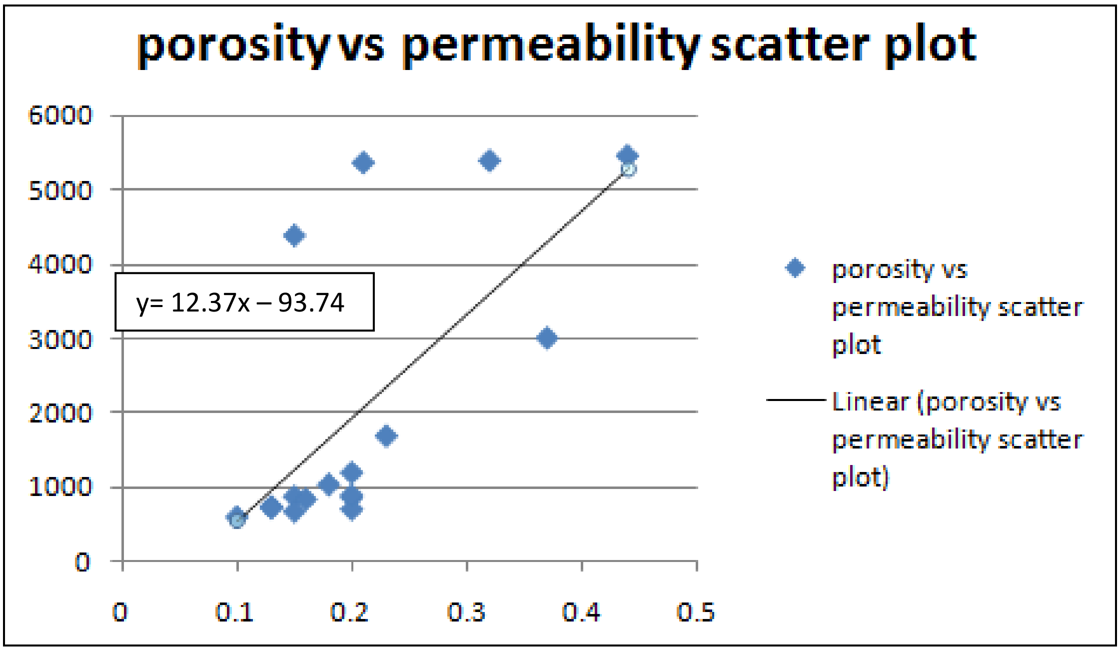


Fig.4.9. Log porosity Versus Permeability cross plot for OLI_003

From Fig 4.9, the relationship between porosity and permeability for well 3 appears to be linear. Porosity generally increases with increase in permeability and vice versa. There are very few variations to this relationship.

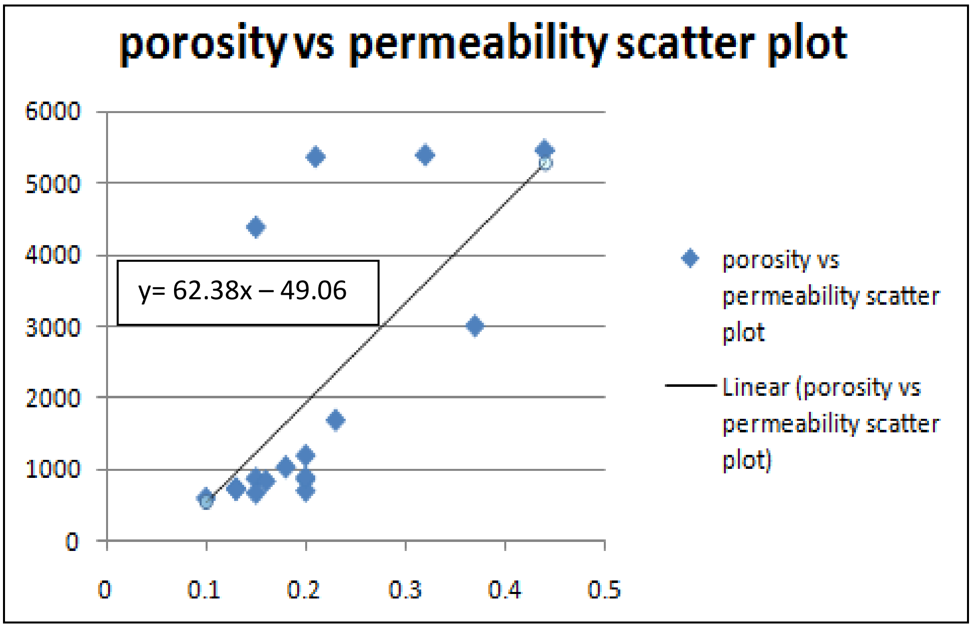


Fig.4.10. Log porosity Versus Permeability cross plot for OLI_004

The trend observed in well 4 (fig 4.10) is almost the same as that observed in fig 4.9. porosity generally increases with permeability and vice versa.

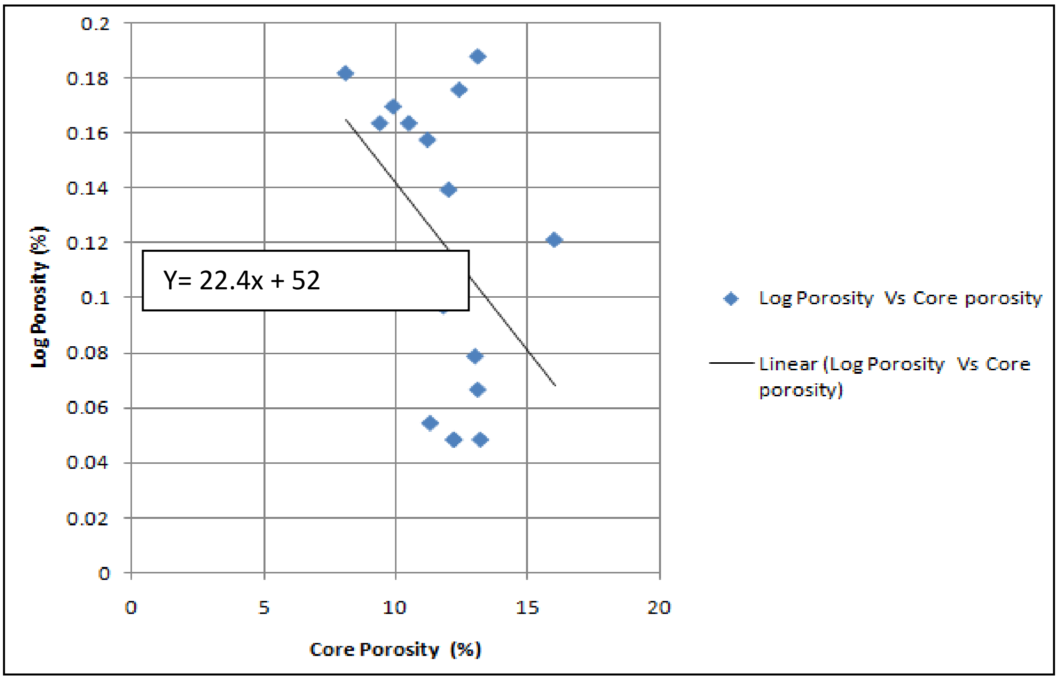


Fig.4.11. log Porosity versus core porosity cross plot for OLI 003

The trend for fig 4.11 is that most of the time log porosity is slightly higher than core porosity (shown as the plotted points above the line), while a few times the core porosity is slightly higher than the log porosity (shown as the plotted points below the line).

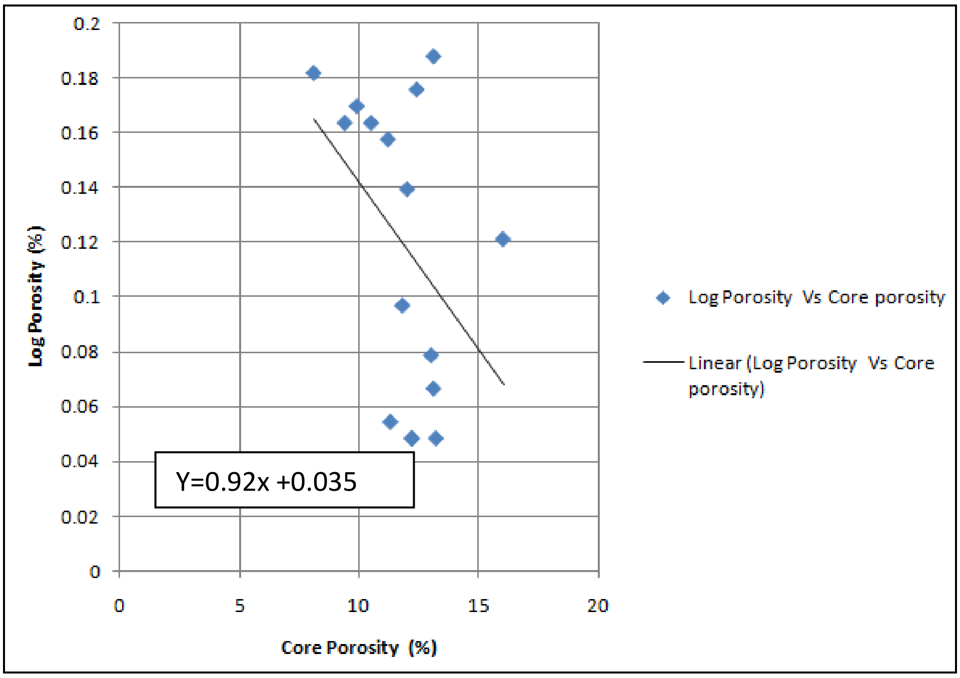


Fig.4.12. log Porosity versus core porosity cross plot for OLI 004

The trend for fig 4.12 is the almost the same as 4.11, most of the time log porosity is slightly higher than core porosity (shown as the plotted points above the line), while a few times the core porosity is slightly higher than the log porosity (shown as the plotted points below the line. This shows the reliability level of core derived porosity versus log derived porosity. The level of reliability is 0.85.

It is the same trend for TTK_007 in fig 4.13 below.

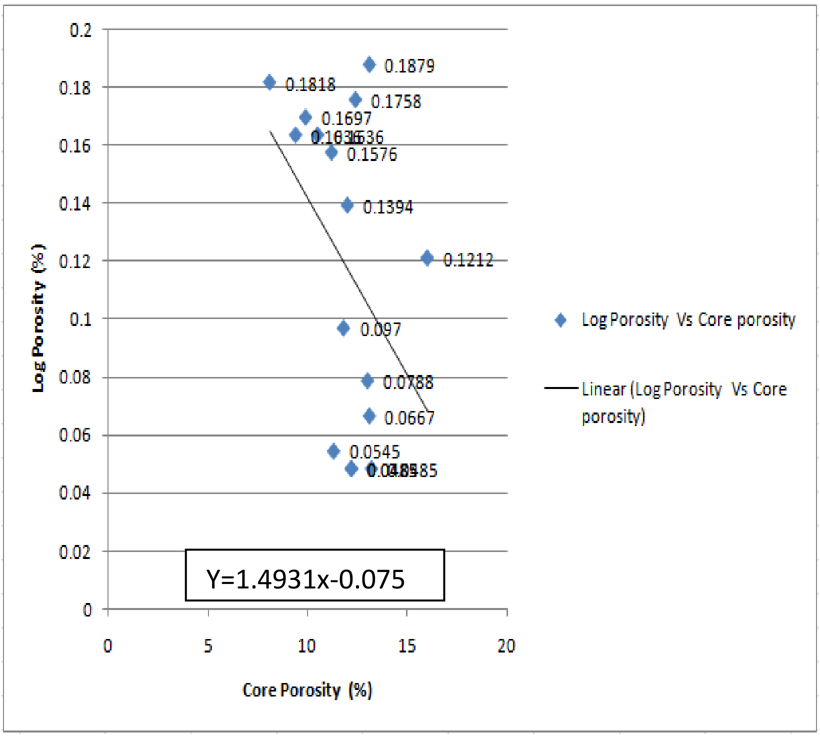


Fig.4.13. log Porosity versus core porosity cross plot for TTK_007.

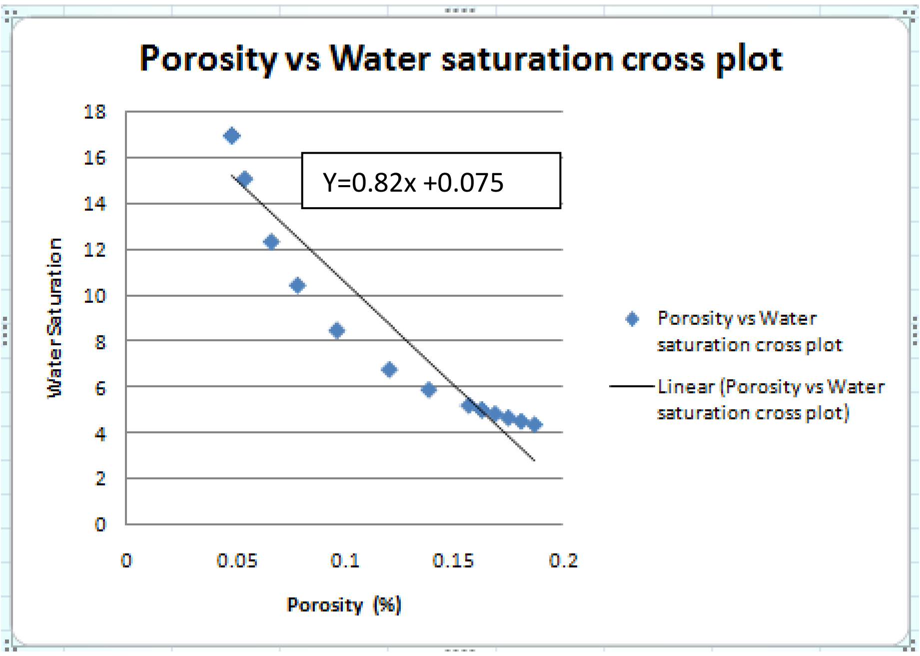


Fig.4.14. Log porosity Vs Water saturation cross plot.

Figure 4.14 shows that with increasing porosity, the water saturation for the reservoir also decreases. We would expect to have other fluids available in reservoir sections with higher porosity and smaller water saturation. Thus reservoir quality is improving with increasing porosity values coupled with decreasing water saturation.

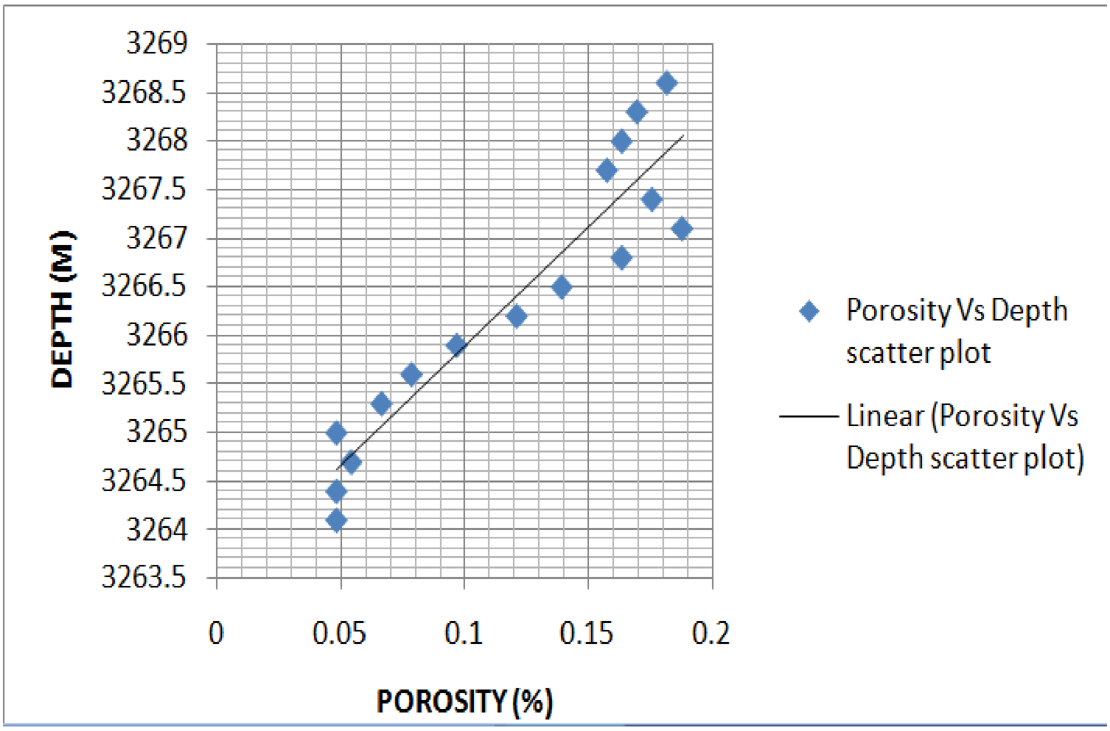


Fig.4.15. Depth versus Porosity cross plot in well TTK_007

Porosity is generally increasing with depth in this reservoir section between 3263.5 m to 3269 m.

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CHAPTER FIVE

SUMMARY, CONCLUSION AND RECOMMENDATION

5.1 Summary

From the evaluation of the "OLI Field", four lithofacies (Sand, Sandy Shale, Shaly Sand and Shale) and five sub lithofacies (Coarse grain sand, Medium grain sand, Fine grain sand, Very fine grain shale, Silty shale) were identified.

In the "OLI field" sand is the major reservoir while Shale acts as lateral and vertical seal.

The results of gamma ray log motif and core analyses revealed the sandstones to have been deposited in a broad environment of fluvio-deltaic plain, deltaic front and open-shelf margin / slope. The fluvio-deltaic and deltaic front facies were deposited as point bar and tidal channel sands of the lower – upper shoreface. Conversely, the shale units were deposited at the shelf margin / slope in association with changes in sea level.

The rock properties of the field were found to be variable due to the influence of the environment of deposition and depth of burial of the sediments.

Some sand units were found to have good qualities/properties that will qualify them to act as reservoir rocks while the shale units functions both as source rocks and seals.

The porosities of the reservoir sands across the field are generally good to very good while their permeabilities were generally moderate to good.

Oil accumulation is high and widespread throughout the field while gas was found only in sand E. Sand B which was found not to be irreducible will produce wet hydrocarbons, while other sands which were found to be irreducible will produce water free hydrocarbons.

From the analysis of the trends of the Petrophysical properties of the “OLI Field”, the reservoir quality was found to be generally good to very good (on a scale of poor to excellent).

The observed range in the reservoir quality of the “OLI field” reflects the observed primary variations in provenance (grain composition, depositional environment and texture).

5.2 Conclusion

The evaluation of depositional environment and reservoir quality of sediments in the “OLI Field” offshore, Niger Delta, Nigeria was successful and detailed geological, petrophysical knowledge and data about the field obtained. This information will help to guide the placement of production platforms and well paths to consequently help optimize hydrocarbon recovery and improve predictions of reservoir performance of the “OLI Field”.

Geological and petrophysical Information obtained from this study will also guide and help in evaluating properties of fields similar to the “OLI Field”.

5.3 Recommendation

It will be a good idea to obtain seismic data and biostratigraphy data of the field to confirm these findings from the integration of well log and Core data. Even though the reservoir quality of the field has been found to be generally good to very good, it should be noted that not all sands or parts of the field have this quality. Therefore further exploitation on the field should be guided by the trends of the Petrophysical parameters to ensure proper placement of production platforms and well paths, which will consequently lead to optimal hydrocarbon recovery.

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