KWAME NKRUMAH UNIVERSITY OF SCIENCE AND TECHNOLOGY

COLLEGE OF SCIENCE

DEPARTMENT OF PHYSICS

USING SEISMIC ATTRIBUTES AND PETROPHYSICAL ANALYSIS FOR RESERVOIR CHARACTERIZATION – A CASE STUDY OF THE OFFSHORE CAPE THREE-POINTS (OCTP) BLOCK IN THE TANO BASIN, GHANA.

By

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Bsc. (Geomatic Engineering)

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AUGUST, 2015

CERTIFICATION

We certify that this thesis is the candidate‟s own research.

Signature ………………………………..	Signature……………………………
Prof. S.K. Danour	Joshua Kpan
(Supervisor)	(Student)

Signature……………………………

Head of Department

DEDICATION

This work is dedicated to my late grandfather, Mr Leo Aabo-iibo Kpan for being my inspiration in life and the architect of my education.

ACKNOWLEDGEMENTS

I would first of all thank my family for their immense support throughout this period of studies for this degree.

I would like to thank Professor S. K. Danuor for being a fantastic supervisor; he has guided me along the path that motivated me to where I am today, completing five chapters of this thesis, and one chapter of my life. With his open mind, he embraced the ideas of reservoir characterization that is regarded as a specialized field in the oil and gas industry. His enthusiasm encouraged me, his constructive comments inspired me, and his approachable demeanour made me regard him not only as a professor, but also a father.

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The ultimate gratitude goes to God almighty for the knowledge, wisdom and understanding granted me throughout this period.

ABSTRACT

Seismic amplitudes and petrophysical analysis of well logs for reservoir characterization have been undertaken in this project. The seismic attribute that was considered in this research was the Root Mean Square (RMS) amplitude which is good discriminator of reservoir sands. A total of three wells were considered in the study and three reservoirs were successfully characterized. 3D seismic data and data from three wells were obtained from the Ghana National Petroleum Corporation (GNPC). The study was carried out in two discovery areas; the Gye Nyame and Sankofa discovery area located in the Offshore Cape Three-Points (OCTP) Basin, Ghana. For each well studied, resistivity log, formation density log, compensated neutron-porosity log and gamma ray logs were collected and analysed. The seismic data was subjected to RMS amplitude extraction that helped to delineate the reservoir sands zones. A detailed petrophysical property model was constructed for each well and the following petrophysical parameters were computed; reservoir thickness, net pay, net-to-gross ratio, porosity and water saturation. The reservoir thickness values ranged from 16.5 to 22.1 m, net pay ranged from 1.7 to 15.3 m, net-to-gross ratio ranged from 10 to 75 %, porosity ranged from 10 to 24 % and water saturation values ranged from 24 to 34 %. The depositional environment for each reservoir was determined from the shape of the gamma ray log. The depositional environment for the reservoir in the Leo 1 well was a fan whiles that of the reservoir in the Capitol well was fine grained sandstone at the upper part of a tidal channel grading into laminated tidal flat mudstone at the base and that of the reservoir in the Silicon well was probably a tidal channel.

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CHAPTER ONE (1): INTRODUCTION

1.1 INTRODUCTION

Reservoir characterization is the practice of calculate the thickness of a reservoir, its net-togross ratio, pore fluid, porosity, permeability and water saturation. As a requirement for Reservoir characterization, a comprehensive 3D petrophysical property models enclosed within a geological framework needs to be constructed. Structural interpretation of seismic data is also important in the generation of the framework of the reservoir model (Ajisafe and Ako, 2013).

In the reservoir characterization process, 3D seismic amplitudes were calibrated against real and computer-generated well data to identify hydrocarbon accumulations and reservoir compartmentalization. The integration of various disciplines such as complex structural interpretation, seismic/sequence stratigraphy, core/log data, basic geological knowledge and depositional/facies environment modelling which are all critical parts in the building of reservoir geological model are the dependent variables for a success of the characterization process. Reservoir characterization comprises the determination of structure reservoir limits, volume, and reservoir properties such as porosity, net pay thickness, permeability, and heterogeneity. To qualitatively deduce rock and fluid properties from seismic data, seismic attributes have been utilized previously to achieve that. (Ajisafe and Ako, 2013).

Seismic Reservoir Characterization which is also known as reservoir geophysics has advanced into a multi-disciplinary, business-critical function in the Exploration and Production (E&P) industry. Sheriff (1973) defines reservoir geophysics as "The use of geophysical methods to assist in delineating or describing a reservoir or monitoring the changes in a reservoir as it is produced". In the oilfield life cycle ranging from discovery, early development to tertiary recovery, reservoir geophysics is applied across. A thorough analysis and understanding of the petrophysical properties for the well logs and core data is one important part of this process.

To identify reservoirs, demarcate them and define the distribution of their important properties, such as lithology and porosity, which will help in the determination of the economic potential of the reservoir is the overall aim of seismic reservoir characterization process. A reservoir characterization project using seismic data and well data is subjected to several processes such as transformation, calibration and interpretation and continuous iteration contributes to refine it. The accurate determination of the physical properties of the subsurface and also the overall success of the project depends on the appropriate selection and application of these processes (Dopkin and Wang, 2008).

Seismic data contains information about the reservoir properties. The signature of the seismic response changes as a result of the varying physical and chemical properites of the rock through which the waves propagates. The observed acoustic and elastic behaviour of seismic data is affected by the rock properties as seen by differences in the travel time and dynamic responses (Dopkin and Wang, 2008).

All the measured or computed quantities acquired from the seismic data are termed as seismic attributes and they provide a link between rock properties and seismic data. They are directly or indirectly related to rock properties, and are directly measured from the seismic data (Thapar, 2004). The advantage of using well and seismic data rather than well data only, is that the seismic data can be used to give a near-accurate interpretation between two extreme ends, using the well as control (Cooke and Muryanto, 1999). Reservoir models constructed from log data alone display an excellent vertical resolution but a poor horizontal resolution (Haas and Dubrule, 1994). The well log and seismic data possess opposite resolution characteristics in that, the log data has high vertical resolution and limited depth of investigation whiles the seismic data has high horizontal resolution (depth of investigation) and poor vertical resolution.

1.2 PROBLEM STATEMENT

Defining a reservoir in adequate detail is a basic necessity in the appraisal phase of the development cycle of every hydrocarbon field. This stage precedes the development of a field for commercial production and it helps determine the field‟s economic potential. The absence of reservoir characterization study has therefore affected the reservoir development planning process that will help to obtain higher recoveries with fewer wells in better positions at minimum cost through optimization and also minimize uncertainty in the production forecasts.

Hence this research will go to help E&P companies operating in this area to make appropriate decisions on development, production and completion.

1.3 RESEARCH OBJECTIVES

The objective of this research is to characterise the Sankofa and Gye Nyame reservoirs which are located within the Offshore Cape Three Points Block (OCTP) in the Tano Basin of Ghana.

The specific objectives that the research seeks to achieve are:

1. To delineate the occurrence of reservoir sands with Root Mean Square (RMS) amplitude extraction from seismic section.
2. To determine the reservoir thickness.
3. To determine the reservoir Net-to-Gross (N/G) ratio.
4. To determine the reservoir porosity and Permeability.
5. To determine the water saturation (S_w) and Hydrocarbon Saturation of the reservoir.
6. A detailed 3-D petrophysical property models enclosed in a geological framework will be constructed and structural interpretation of the seismic data will be carried out to show the structural features that contain the reservoir.
7. To describe the depositional environment of each reservoir

1.4 SCOPE OF THE RESEARCH

The research shall cover the two hydrocarbon discovery areas both in the Offshore Cape Three Points (OCTP) Basin namely; the Sankofa discovery and Gye Nyame discovery. The Gye Nyame discovery area is covered by a polygon of 352.79 km^2 volume of 3D seismic data and the Sankofa discovery area is covered by a polygon of 254 km^2 volume of 3D seismic data. A total of three (3) wells were used in the research in the study area; Silicon and Capitol wells were used in the Sankofa discovery and Leo wells were used in the Gye Nyame discovery area. The study is concentrated in reservoirs discovered in the Upper Cretaceous geological time, specifically the Campanian formation.

1.5 THE STUDY SITE AND GEOLOGICAL SETTING

The Tano-Cape Three Points Basin is a Cretaceous wrench modified pull-apart basin. It has its boundaries to the East by the Saltpond Basin and to the West by the St. Paul Fracture Zone. The basin was formed as a result of trans-tensional movement during the separation of Africa and South America and opening of the Atlantic in the Albian and it is the eastern extension of the Cote D‟Ivoire-Ghana Basin. Active rifting and subsidence during this period caused the development of a deep basin. Conditions at the time were ideal for the deposition of shales, thus thick organic rich shale was deposited in the Cenomanian and Turonian. Several river systems contributed significant clastics into the deep basin and led to deposition of large turbidite fan or channel complexes.

The basin is made up of a thick Upper Cretaceous drift section which is predominantly stratigraphic traps, basin floor fans and channel systems. The rift section involves continental deposits to shallow marine. The working play type is the Cretaceous Play, which consists of Cenomanian-Turonian and Albian shales as source rocks with Turonian slope fan turbidite sandstones and Albian sandstones in tilted fault blocks as reservoirs. Trapping is both stratigraphic and structural (Adda, 2013).

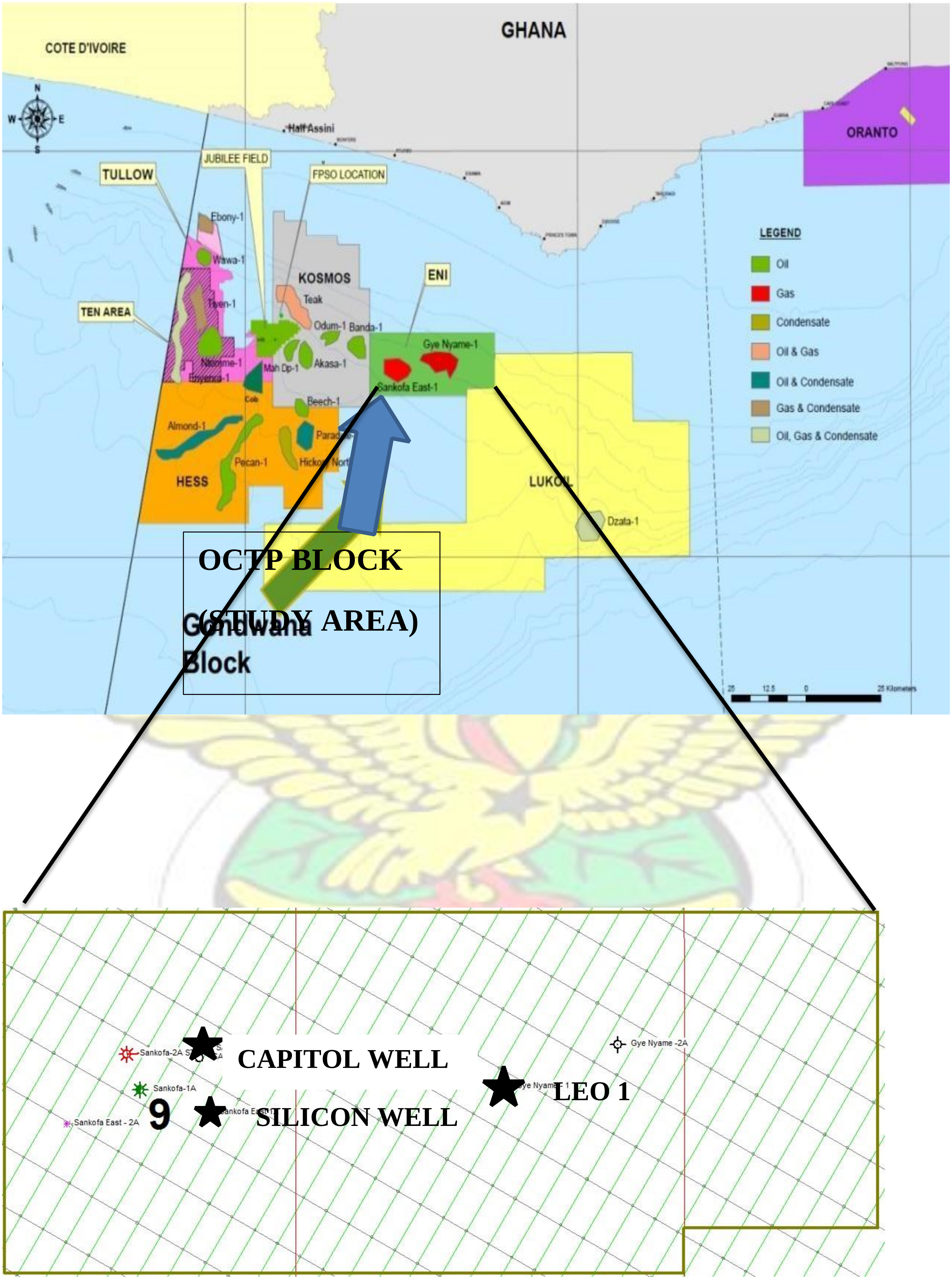

Figure 1.1: Map of study

The study site is the Offshore Cape-Three Points (OCTP) Block offshore of the coast of Ghana, West Africa. A total of three wells are under consideration in this research. The Leo 1 well is the second exploration well drilled in the OCTP concession. It is located east of the Silicon and Capitol wells. It has a vertical profile drilled to a total depth of about 3700 m in a water depth of 546 m. The well penetrated the reservoir at about 2460 m in the Campanian formation. The hydrocarbon discovered in this reservoir is gas condensate.

The Silicon well is located in the south-west part of OCTP Block Offshore Ghana and about 100 km from Takoradi shore base. The well location lies west of Leo 1well and 3 km North of Capitol well. The water depth at the well location is approximately 825 m. The hydrocarbon type is gas condensate.

The Capitol well is located in the central part of OCTP Block Offshore Ghana, about 110 km from Takoradi shore base. The well is located in a water depth of 805 m. It encountered the Campanian target resting at about 2550 m. The hydrocarbon discovered in this reservoir is non-associated gas.

CHAPTER TWO (2): LITERATURE REVIEW

2.1 HISTORY OF SEISMIC EXPLORATION

Much of seismic theory was developed prior to the availability of instruments that were capable of sufficient sensitivity to permit significant measurements. Earthquake seismology preceded exploration applications. In 1845, Mallet experimented with "artificial earthquakes" in an attempt to measure seismic velocities. Knott developed the theory of reflection and refraction at interfaces in a paper in 1899 and Zoeppritz and Wiechert published on wave theory in 1907. During World War I, both the Allies and Germany carried out research directed toward locating heavy guns by recording the arrival of seismic waves generated by the recoil. Although this work was not very successful, it was fundamental in the development of exploration seismology, and several workers engaged in this research later pioneered the development of seismic prospecting techniques and instruments. Among these researchers, Mintrop in Germany and Karcher, McCollum, and Echhardt in the United States were outstanding.

In 1919, Mintrop applied for a patent on the refraction method and, in 1922, Mintrop"s Seismos Company furnished two crews to do refraction seismic prospecting in Mexico and the Gulf Coast area of the United States using a mechanical seismograph of rather low sensitivity. The discovery, in 1924, of the Orchard salt dome in Texas led to an extensive campaign of refraction shooting during the next six years, the emphasis being principally on the location of salt dome. By 1930 most of the shallow domes had been discovered and the refraction method began to give way to the reflection method. Whereas refraction techniques were ideal for locating salt domes, reflection techniques are more suitable for mapping other types of geologic structures commonly encountered (Telford et al., 1990).

Reflection seismic prospecting stemmed principally from the pioneering work of Reginald Fessenden about 1913. This work was directed toward the measuring of water depth and detecting icebergs using sound waves. In the early 1920"s, Karcher developed a reflection seismograph that saw field use in Oklahoma. It was not until 1927, however, that commercial utilization of the reflection method began with a survey by the Geophysical Research Corporation of the Maud field in Oklahoma, which used a vacuum tube amplifier. Oklahoma proved to be particularly suitable for the application of reflection methods, just as the Gulf Coast had been suitable for refraction technique, and the reflection method rapidly grew in popularity until it virtually displaced the refraction method. Although reflection has continued to be the principal seismic method, there are certain areas and types of problems where refraction techniques enjoy advantages over reflection shooting, and so they continue to be used to a modest degree (Telford et al., 1990).

A distinctive reflection was characteristic of the first reflection application in Oklahoma. Hence the first reflection work utilized the *correlation method* whereby a map was constructed by recognizing the same event on isolated individual records. However, most areas are not characterized by such a distinctive reflector and so, in general, the correlation method has little application.

In 1929, the calculation of dip from the time difference across several traces of a seismic record permitted the successful application of reflection exploration in the Gulf Coast area where reflections were not distinctive of a particular lithologic break and could not be followed for long distances. This method proved to be much more widely applicable than correlation shooting and so led to rapid expansion of seismic exploration.

As the capability of recording the data from more geophones grew, recording became spaced so closely that reflection could be followed continuously along lines of profile, and the continuous coverage became the standard seismic reflection method. Reflections from interface were interpreted on photographic recordings to map structural features.

In 1936, Rieber published the idea of processing seismic data using variable-density records and photocells for reproduction; however, widespread use of playback processing did not begin until magnetic tape became commercially available in 1953. Magnetic tape recording spread rapidly in the next few years, especially after digital recording and processing were introduced in the 1960s. Magnetic tape recording made it possible to combine the data from several recordings made at different times and this made the use of weaker energy sources feasible. Introduction, in 1953, of a dropped weight as a source of seismic energy was the forerunner of a series of different kinds of seismic sources.

Radar was one of the outstanding technological advances of World War II and it was widely used in the detection of aircraft. However, noise frequently interfered with the application of radar and considerable theoretical effort was devoted to the detection of signals in the presence of noise. The result was the birth of a new field mathematics-information theory. Early in the 1950s a research group at the Massachusetts Institute of Technology studied its application to seismic exploration problems. Simultaneously with this development, rapid advances in digital computer technology made extensive calculations feasible for the first time. These two developments had great impact on seismic exploration in the early 1960s and before the end of the decade, data processing (as the application is called) had changed seismic exploration dramatically, so much so that it came to be referred to as the "digital revolution". Most seismic recording is now done in digital form and most data are subjected to data processing before being intercepted.

The common-midpoint method (also called common-depth-point and common-reflectionpoint) was patented in 1956. This method involves recording data from the same subsurface a number of times with varied source and geophone locations and then combining the data in processing. The redundancy of data achieved with this method has made it practically possible for a number scheme for the attenuation of noise (including multiple reflections) and improved data quality so much that most areas were remapped with the new techniques.   Most seismic sources are impulsive, that is, they develop a short, sharp wavefront. In contrast, the Vibroseis method, developed in 1953 but not applied extensively until much later, generates a wavetrain that is so long that reflections overlap extensively. Processing effectively collapses the wavetrain back to that achieved with an impulsive source. About half of the land data is now acquired with the Vibroseis method.

Because of continual improvements in instrumentation and processing, many areas have been resurveyed and a lot of data have been reprocessed repeatedly; each time better quality of data is achieved. New acquisition techniques, such as vertical profiling and the use of Swaves, have been developed. In areas of special interest, three-dimensional acquisition techniques are employed that cover an area rather than merely along occasional profile lines. Interpretation techniques also have been improved continually. Rather than being limited merely to mapping structural features, interpretation now involves studies of velocity, amplitude, frequency, and waveform variations so that information can be determined about the lithology, stratigraphic features and hydrocarbon accumulations. Applications are extending beyond locating hydrocarbons to helping guide oil-field development and monitoring production (Telford et al., 1990).

2.2 STRATIGRAPHY COMPONENT OF THE WESTERN BASIN (TANO-CAPE THREE POINTS BASIN)

Sedimentary infill of the initial rift phase of the Western Basin consist of more than 4000 m of Lower Cretaceous (Aptian to Lower Albian) sandstone and shale, mainly non-marine in the lower section but increasing marine-influence in the upper part, where thick sandstone units form oil and gas reservoirs. This thick rift-fill unit, the Kobnaswaso formation, surrounds and buries a large tilted block, the Central Tano structure, which may be cored either by early Cretaceous or Palaeozoic (including Devonian) rocks.

Middle and Upper Albian Sedimentation in the Western Basin was characterized by shallow marine shelf to shore face sandstones and shale in several depositional units, including newlynamed Bonyere, Voltano, and Domini and Tano formations. The North Tano faultbounded tilted structural block is a result of Early Albian tectonics.

Final separation of West African and Northern Brazil continental plate and opening of equatorial Atlantic Ocean south of Ghana occurred at the Early Cretaceous (Albian) or Early Cenomanian time, and resulted in faulting, uplift and erosion along the outer margin of the Tano basin and creation of South Tano structural trend. Subsequent Upper Cretaceous sedimentation was dominantly open marine in character, with porous sandstones in the near shore and onshore settings. The end of Cretaceous time was marked by widespread deposition of very porous shelf and shoreline sands. A series of marine tertiary sediment wedges completed the sedimentary fill of the Western Basin.

Earlier, the oldest drilled section in the Western Basin was found to be Aptian to Lower Albian Kobnaswaso formation, penetrated for more than 2 km by some wells. The oldest drilled rocks are Early Cretaceous (Aptian) in age, but older Cretaceous and possibly Triassic to Late Palaeozoic rocks may be present in the basal Western Basin. In the onshore section, the Kobnaswaso consist of mainly thinly interbedded lithic and feldspathic sandstones and shales, and is interpreted to be dominantly fluvial plain and braided stream in origin. The formation is thick sequence of sandstones, shales and other intermixed lithologies that has been partly penetrated three or four of the deep Gulf onshore wells, and seven of the nine offshore Western Basin wells. The sandstones are fine grained to conglomeratic poorly sorted and sub-angular to sub-rounded.

This information is a summarized version of larger results of the study conducted by PetroCanada International Assistance Corporation on behalf of Ghana National Petroleum Corporation (1988-89), (GNPC, unpublished)

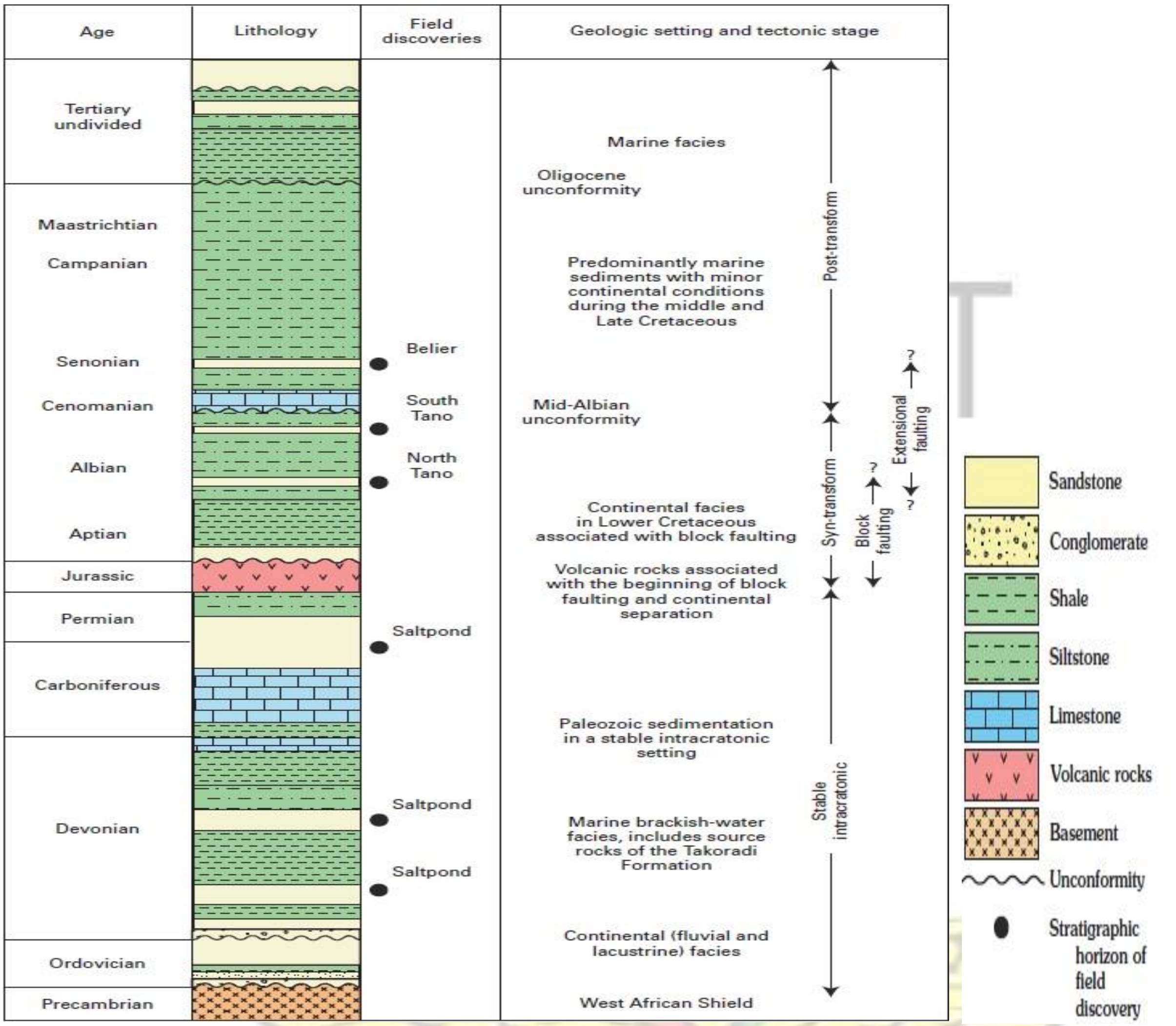

Figure 2.1: Stratigraphy of area (from GNPC, unpublished report).

2.3 THE RESERVOIR THEORY

2.3.1 RESERVOIR GEOLOGY

A petroleum reservoir is a porous subsurface formation containing hydrocarbons and water in different proportions. These fluids are contained in the pore spaces of rock formations, among the grains of sandstones or in cavities of carbonates. The pore spaces are interconnected so the fluids can move through the reservoir. There must exist a seal that will serve as barrier to the porous formations in such a way that hydrocarbons can only move out through the wellbore (Mahmoud, 2010).

2.3.2 THE PETROLEUM RESERVOIR

Oil and gas fields are geological features that result from the occurrence of five types of geologic features as indicated in figure 2.2 below:

- Hydrocarbon source rocks,
- Reservoir rocks,
- Migration,
- Traps Seals.

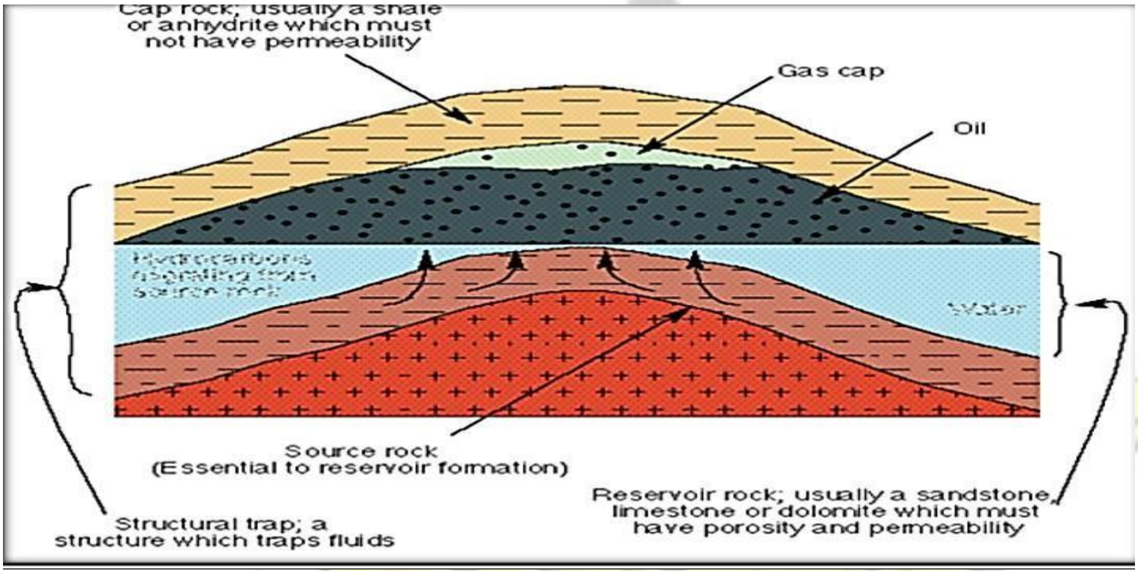

Figure 2.2: The petroleum reservoir (Mahmoud, 2010).

2.3.3 SOURCE ROCK

Source rocks are an important part of a petroleum system. They are rocks formed from organic-rich sediments deposited over a long period of time in a variety of environments and hence are capable of generating hydrocarbons. Most source rocks in the Offshore Cape Three Points block are made of organic-rich sandstones, even though other rocks has the capabilities of generating hydrocarbons such as carbonates and shales.

2.3.4 TYPES OF SOURCE ROCKS

Source rocks are classified according to the types of kerogen that they are formed from:

- Type 1 kerogen are formed from algal remains deposited under anoxic conditions in deep lakes and they tend to generate waxy crude oils when subjected to thermal stress during deep burial
- Type 2 kerogen is formed from marine planktonic remains preserved under anoxic conditions in marine environments and they produce both oil and gas when thermally cracked during deep burial.
- Type 3 kerogen is formed from terrestrial plant material that has been decomposed by bacteria and fungi under anoxic or sub-oxic conditions and they tend to generate mostly gas with associated light oils when thermally cracked during deep burial.

  (Mahmoud, 2010)

2.3.5 RESERVOIR ROCK

A reservoir rock is a rock that has connected pore spaces which has the capacity to contain hydrocarbons. To be commercially productive, it must be of sufficient thickness, areal extent, and pore space and these pores must be interconnected (Permeable).

There is relatively free movement of hydrocarbons once they migrate into the reservoir rock. Most reservoir rocks are initially saturated with saline groundwater which has a density of more than 1.0 g/cm^3. Due to the lower densities of the hydrocarbons from the ground water (density oil = 0.82-0.93 g/cm^3 and density gas = 0.12 g/cm^3), they rise upward through the water-saturated pore spaces until they encounter the barrier of impermeable cap rock (Mahmoud, 2010). Figure 2.4 shows the configuration of a typical reservoir rock.

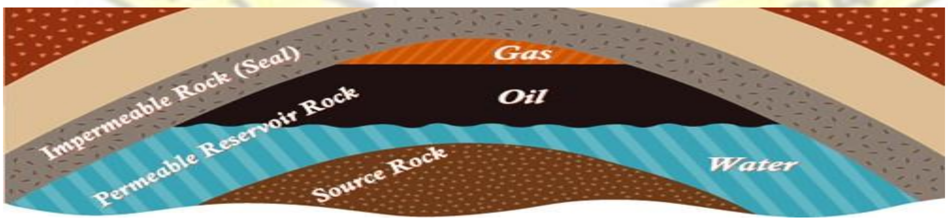

Figure 2.4: The Reservoir Rock (Mahmoud, 2010).

2.3.6 THE SEAL (CAP ROCK)

The seal or cap rock as indicated by figure 2.5 below is a relatively impermeable rock that forms a barrier above and around reservoir rock so that fluids cannot migrate beyond the reservoir entrapment. The permeability of a cap rock must therefore be equal to zero. Some examples of cap rock are shales, evaporites and salt.

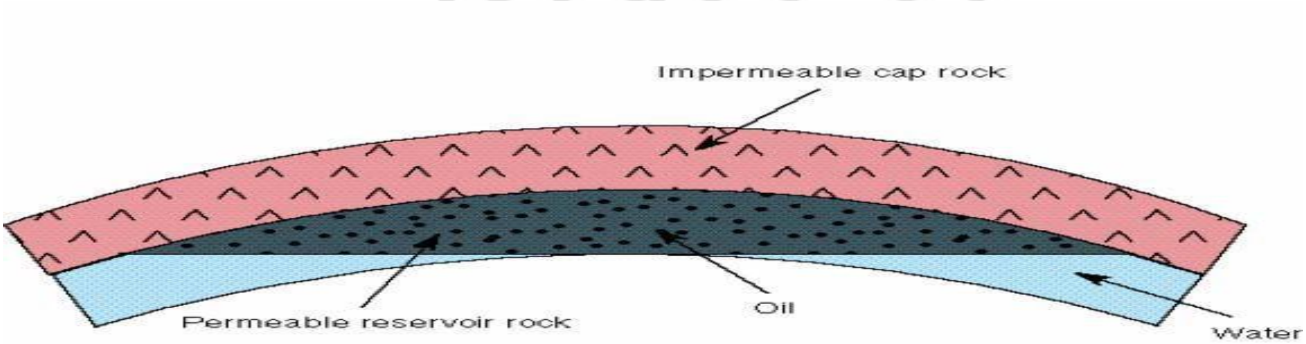

Figure 2.5: The Hydrocarbon seal (Mahmoud, 2010).

2.3.7 THE TRAP

A trap is an arrangement of relatively impermeable formation rocks suitable for containing hydrocarbons and has the capacity to hold hydrocarbons in place to curtail migration. Traps can either be structural; when the space of petroleum is limited by a structural feature or stratigraphic; where the space is created by the limits of reservoir rock itself. Other traps are form by the combination of two or more trapping mechanisms and these are classified as combination traps. Figure 2.6 below shows different trapping mechanism that can host hydrocarbon in place.

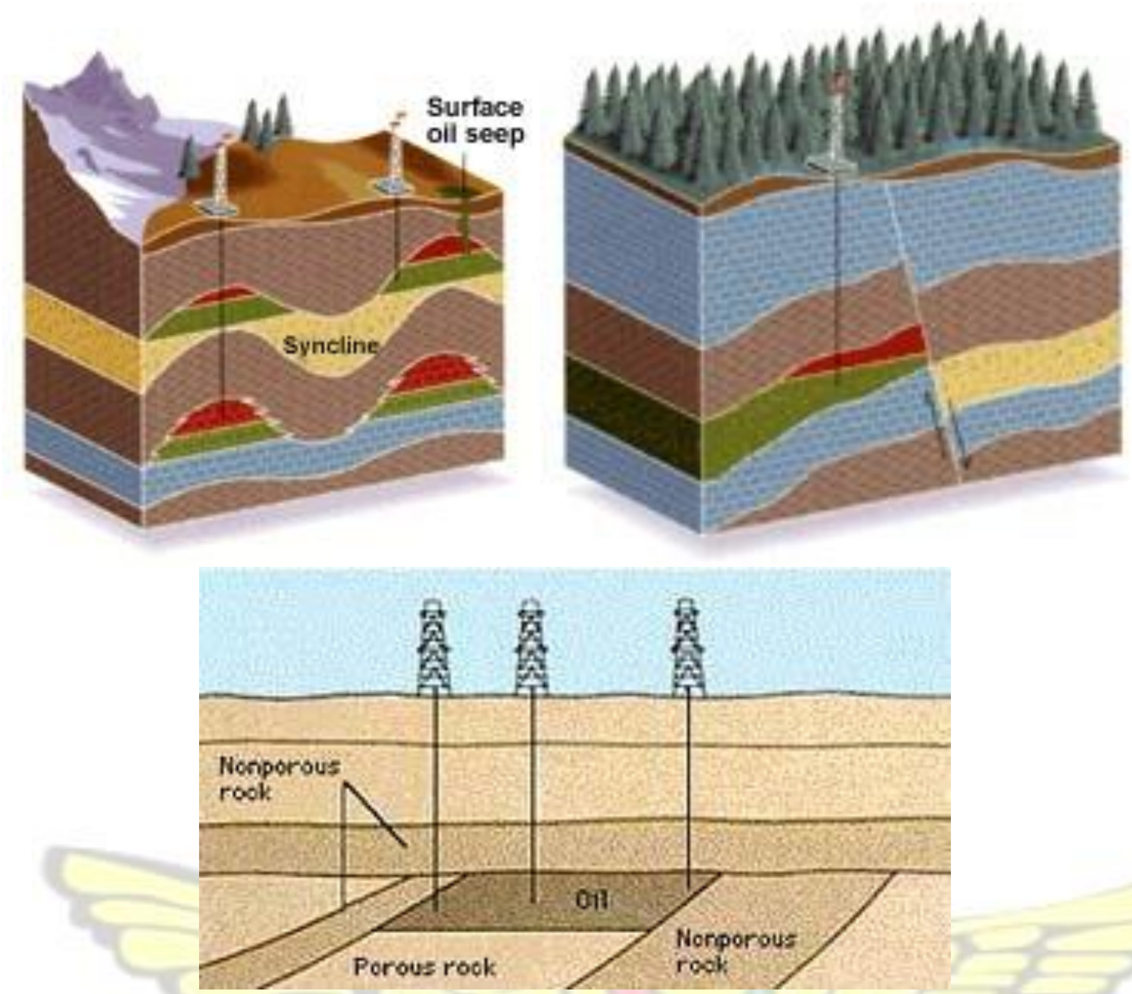

Figure 2.6: Hydrocarbon Traps (Mahmoud, 2010)

2.3.8 MIGRATION

Migration is the process by which hydrocarbons moves into traps from source rocks through permeable carrier bed. Migration is caused by burial, compaction, and increase in volume and separation of the source rock constituents. Enough porosity must exist in the reservoir rock to contain the hydrocarbon and the rock must also be permeable to allow the free movement of the hydrocarbons into the welllbore for production to take place. The migration paths of hydrocarbons is mostly upwards until it is curtailed by an impermeable seal. (Mahmoud, 2010).

2.3.9 TYPES OF MIGRATION

- Primary migration is the movement of hydrocarbons directly from source rock. As the sediments build up to greater thickness in sedimentary basins, fluids are expelled from the source rock by the weight of the overlying sediments and these fluids tend to move toward the lowest potential energy. The movement of hydrocarbons is initially upwards, but as compaction progresses, there is lateral as well as vertical movement.

- Secondary migration is the movement of hydrocarbons to or within the reservoir entrapment. Hydrocarbons are separated according to their density once they migrate into the trap. Gas being the lightest, goes to the top of the trap to form the free gas cap whiles water goes to bottom of the reservoir since it is heaviest and it is always present in every reservoir. Oil with the intermediary density goes to the middle.

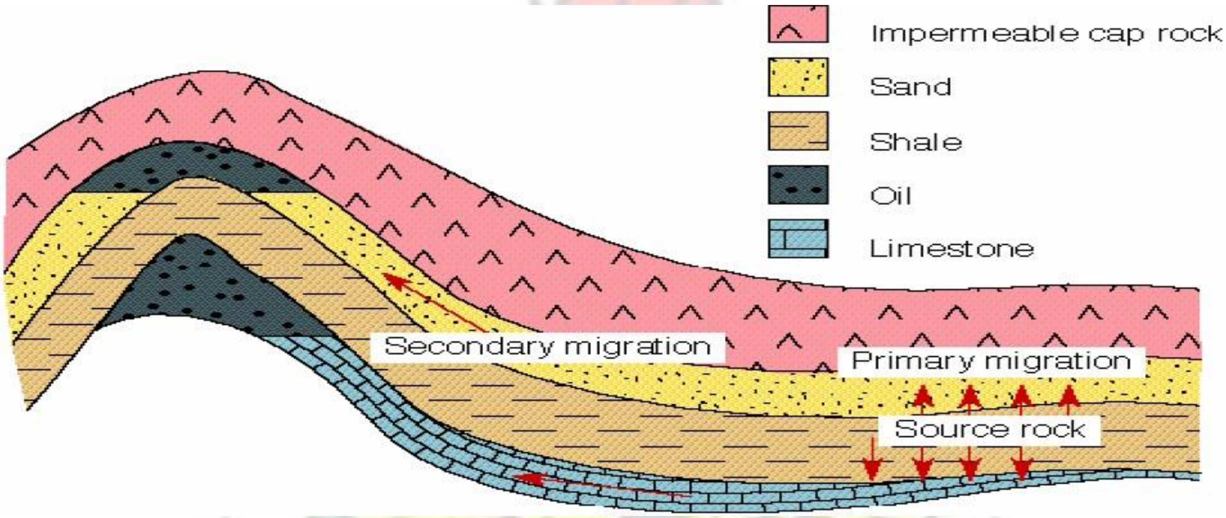

Figure 2.3: Hydrocarbon migration mechanism (Mahmoud, 2010).

2.4 SEISMIC ATTRIBUTES

All of the measured or computed quantities acquired from the seismic data are termed as Seismic attributes and they tend to provide a link between rock properties and the seismic data. They are directly or indirectly related to rock properties, and are directly measured from the seismic data (Thapar, 2004).

Seismic data attributes provide the seismic interpreter with new images that enhance the physical and geometric descriptions of the subsurface. Geometric attributes facilitate the definition of both the structural and stratigraphic framework of the seismic interpretation, while physical attributes may be used as direct hydrocarbon or lithologic indicators. From the time of their introduction in early 1970‟s, seismic attributes have gone a long way and they became an aid for geoscientists for reservoir characterization and also as a tool for quality control. Numerous different seismic attributes have been developed from varied computational methods since the introduction of Complex Trace Attributes in the 19th century. Some attributes are sensitive to only one quality and therefore termed as “Primitive” attributes. Through some statistical computation or mathematical manipulation, a number of these primitive attribute may be combined to form “Hybrid” attributes. The drive behind the computation of these amalgamated attributes is to use them as analytical variables in reservoir characterization projects. Most characteristic studies use attributes qualitatively, for example, in seismic stratigraphic interpretations showing internal bedding geometries and terminations, or to reveal spatial patterns related to depositional environments, faults or factures. The trend however is towards the quantitative use of single or combined attributes to predict petrophysical features, fluid type, lithology, or facies (Barnes, 2001).

Chambers and Yarus (2002) noted that the quality of the seismic data must as a necessity be checked as a first step before it is used for the computation of various attributes. The problem that needs to be solved in the computation process should be the determining factor for the outlined processing workflow. The quality of the data will determine the extent to which it can be used for purposes of interpretation. When the data has poor signal quality, low frequency content at the reservoir level, and improper processing, it often cannot be used beyond the purposed of basic interpretation. For a data to be suitable for structural interpretation, a data processing method using a minimum phase wavelet and a gain to enhance structural surfaces is required. However, the quantitative use of seismic attributes requires a different processing methodology termed “stratigraphic” processing. For stratigraphic and rock and fluid properties interpretation, seismic data must be processed using zero-phase, true amplitude, and migrated data, which is more costly and intense, but a necessity if most attribute studies are to be successful. However, geometrical attributes for the purposes of spatial and temporal continuity description do not require such arduous processing methodology. The data must be zero-phase, with true-amplitude recovery if it is supposed to be used for the purposes of acoustic impedance inversion; otherwise the resulting impedance cube is pointless for quantitative interpretation. AVO analysis studies the fundamentals of amplitude variations with offset which result from impedance contrasts of rock properties. AVO analysis starts with unstacked data, producing huge volumes of data, but may be combined with post-stack inversion techniques to determine rock properties. Again, the success the AVO analysis depends on zero-phase, true-amplitude seismic data (Chamber and Yarus, 2002).

2.5 REQUIREMENT FOR RESERVOIR CHARACTERIZATION FROM SEISMIC DATA

The following parameters can be measured from the seismic data

1. Travel time
2. Amplitude
3. The patterns of events
4. The character of events.

From these measured parameters, we can then compute the following information (Sheriff, 1992):

1. Depth maps of horizons can be generate from the traveltimes
2. Impedance can be generated from measurement of reflection amplitude;
3. Locations of faults and trapping mechanism information can be generated from discontinuities in reflection patterns;
4. Dip and discontinuities can be generated from the information obtained from differences in traveltimes.

After obtaining the above information, it is often then possible to infer the following:

1. Fluid content, lithology, temperature, or abnormal pressure information can be obtained from Velocity data;
2. Hydrocarbon locations and other petrophysical information can be derived from lateral amplitude changes.
3. Depositional environments can be derived from seismic data patterns;
4. Velocity anisotropy information can be derived from changes in measurement direction;
5. Locations of changes can be derived from time-lapse measurements (4D seismic) ─ (Chambers and Yarus, 2002).

2.6 RELATIONSHIP BETWEEN ELASTIC PROPERTIES OF ROCK AND SEISMIC WAVE PROPAGATION

Before a seismic data can be used quantitatively for reservoir characterization, it is imperative to know what information is contained in the seismic wavelet and how to extract it. The propagation of the seismic wave through the rocks is affected by the rock‟s physical properties, such as shear modulus, bulk modulus, lithology, pore fluid, gas saturation, clay content and porosity.

The elasticity theory represent the elastic properties of rocks and also provides the expression for the velocity of seismic P-wave and S-wave in terms of elastic rock constant for simple cases. Elasticity deals with deformation that disappears totally upon removal of the stress which caused the deformation (Sheriff, 1973). The elastic media is inferred from the velocity and density (ρ) measurements. For isotropic media (Sheriff, 1992; Hilterman, 2001),

$$\text{P-wave velocity} = V^{\rho} = \sqrt{[\lambda + \frac{2\mu}{\rho}]} \qquad 2.1$$

$$\text{Shear wave velocity} = V_S = \sqrt{(\frac{\mu}{\rho})} \qquad 2.2$$

$$V^{\rho}/V_s = \left[\frac{1-\sigma}{0.5-\sigma}\right]^{0.5} \qquad 2.3$$

Where:

σ - Poisson ratio, λ - Lame‟s constant and this elastic parameter is sensitive to fluid content, is related to μ and κ by

$$\lambda = \kappa - 2\mu/3 \qquad 2.4$$

These physical properties are related to the capability of rocks to transmit seismic waves. Our interest in P-wave and S-wave is that they travel through rocks differently depending on the fluid content and physical rock properties.

Further theory leads to the equation of Gassmann (1951) and Biot (1956) which relates seismic velocity to porosity and the rock and fluid properties.

Seismic velocity is dependent on porosity of the transmitting medium and a decrease in velocity and a corresponding increase in porosity is the principal controlling element of velocity. We often use the time-average equation (Wyllie et al., 1956) to calculate porosity from velocity from the equation below:

2.5

Where:

ϕ - Porosity,

V_f - Velocity of the interstitial fluid

V_m - Velocity of the rock matrix.

The equation 2.5 above represent the physical relationship between the seismic attribute and rock and fluid properties and this equation must be considered when using attributes for the quantitative prediction of rock properties.

2.7 APPLICATION OF WELL LOGS IN RESERVOIR CHARACTERIZATION:

Electrical well logging has been an integral part of the oil and gas industry since its introduction almost a century ago. Several other additional and improved logging devices have been developed and are in use since that period. As the science of well logging and it‟s the interpretation of the data have both advanced considerably over the years. This advancement has led to the possibility of inferring accurate values of various petrophysical parameters such as hydrocarbon and water saturations, porosity, permeability, and the lithology of the reservoir rock from a detailed analysis of a chosen suite of wireline logs.

Different logs are used to give an indication of different reservoir properties of interest.

The Gamma Ray (GR) log is a measure of the natural radioactivity of the formations. Because radioactive elements tend to concentrate in clay and shales, gamma ray log usually reflects the shale content of the formations in sedimentary environment. Unless radioactive contaminant such as volcanic ash or granite wash is existing or the formation water contains dissolved radioactive salts, clean formations usually exhibit a very low level of radioactivity. The GR log is principally suitable for discriminating shale beds. The GR log reflects the proportion of shale and, in many regions, can be quantitatively used as a shale indicator.

The electrical resistivity of a substance is its capability to inhibit the flow of electrical current through the substance. Most formations logged for potential oil and gas saturation are made up of rocks which, when dry, will not conduct electric current, i.e., the rock matrix has zero conductivity or infinitely high resistivity. An electrical current will flow only through the interstitial water saturating the pore structure of the formation, and then only if the interstitial water contains dissolved salts. These salts dissociate into positively charged cations (Na^+, Ca^{++},….) and negatively charged anions (Cl^-, SO_4^-, ….). Under the influence of an electrical field these ions move, carrying an electrical current through the solution. Other things being equal, the greater the salt concentration, the lower the resistivity of the formation water and, therefore, of the formation. The greater the porosity of the formation and, hence, the greater the amount of formation water, the lower the resistivity (Schlumberger, 1989).

Resistivity measurements are essential for saturation determinations, particularly saturation determinations in the virgin, noninvaded portion of the reservoir (Schlumberger, 1989). These are also used to determine the resistivity close to the borehole (called flushed-zone resistivity, Rxo), where mud filtrate has largely replaced the original pore fluids. Resistivity measurements, along with porosity and water resistivity, are used to obtain values of water saturation. Saturation values from both shallow and deep resistivity measurements can be compared to evaluate the producibility of the formation. Neutron-Density logs are primarily used as porosity logs (Schlumberger, 1989).

2.8 DEPOSTIONAL ENVIRONMENT

Sedimentary depositional environment describes the combination of physical, chemical and biological process associated with the deposition of a particular type of sediment and, therefore, the rock types that will be formed after lithification, if the sediments are preserved in the rock record. In most cases the environments associated with a particular rock type or associations of rock types can be matched to existing analogues (Mahmoud, 2010).

Depositional environments can be broadly divided into three major categories:

1. Continental deposits
2. Transitional deposits
3. Marine deposits 1. Continental deposits:

a) Terrestrial deposits

- Desert deposits

  These are sediments accumulated by the action of wind, wash from upland slopes and ephermal streams.

• Glacial deposits

A glacier is a perennial mass of ice that moves over land. A glacier forms in locations where the mass accumulation of snow and ice spans over many years. Glacial deposits are composed of different amount and shape of till. Till is a general term used to describe all the unsorted rock debris deposited by glacier. Till is composed of rock fragments ranging from clay to boulder size (Mahmoud, 2010). b) Fluvial deposits: Alluvial fan

An alluvial fan is a fan-shaped deposit formed where a fast flowing stream flattens, slows and spreads typically at the exit of a canyon onto the flatter plan.

• River and stream.

It comprises the motion of sediment and erosion of deposition on the river bed. c) Lacoustrine

Lakes are well-suited to the development of deltas. Deltas are built up by sedimentsladen streams that drop their load of sediments as they lose velocity (Mahmoud, 2010).

2. Transitional deposits

a) Lagoons:

A lagoon is a body of comparatively shallow salts or brackish water separated from the deeper sea by a shallow or exposed barrier beach or coral reef. The water salinity ranges from fresh water to water with salinity greater than that of sea. b) Deltas:

A delta is a landform that is created at the mouth of a river which flows into an ocean, sea, estuary, lake. They are formed from the deposition of the sediment carried by the river as the flow leaves the mouth of the river. Deltas are divided into delta front, which include sand bars at the mouth of the distributary and delta plain which include channels, bays and flood plains (Mahmoud, 2010).

3. Marine deposits

In the marine environment, sediments can be deposited in different part of the marine body. Much siliclastic sediments can be deposited in the marine shore. Such deposits are referred to as marine shoreline environment (Mahmoud, 2010).

Shallow marine (Neritic zone) environment also has coarser materials deposited near shore and grade into finer deposits upwards. Shallow marine sediments are made of sediments derived from land by way of stream, glacier or Aeolian. Sediments may consist of remains of organisms and chemical precipitates.

Bathyal deposits are found at the continental slope and covered by fine sediments of land origin which is called blue muds (Mahmoud, 2010).

Deep marine (Abyssal deposits) are mostly of volcanic, pelagic and meteoric origin. They are usually very poorly sorted, set in motion by storms and quakes, calcareous and siliceous oozes. In the deepest part of the ocean, the bottom is covered by fine red clay which is composed of calcareous to siliceous to terrestrial clay, shells and other organic matters (Mahmoud, 2010).

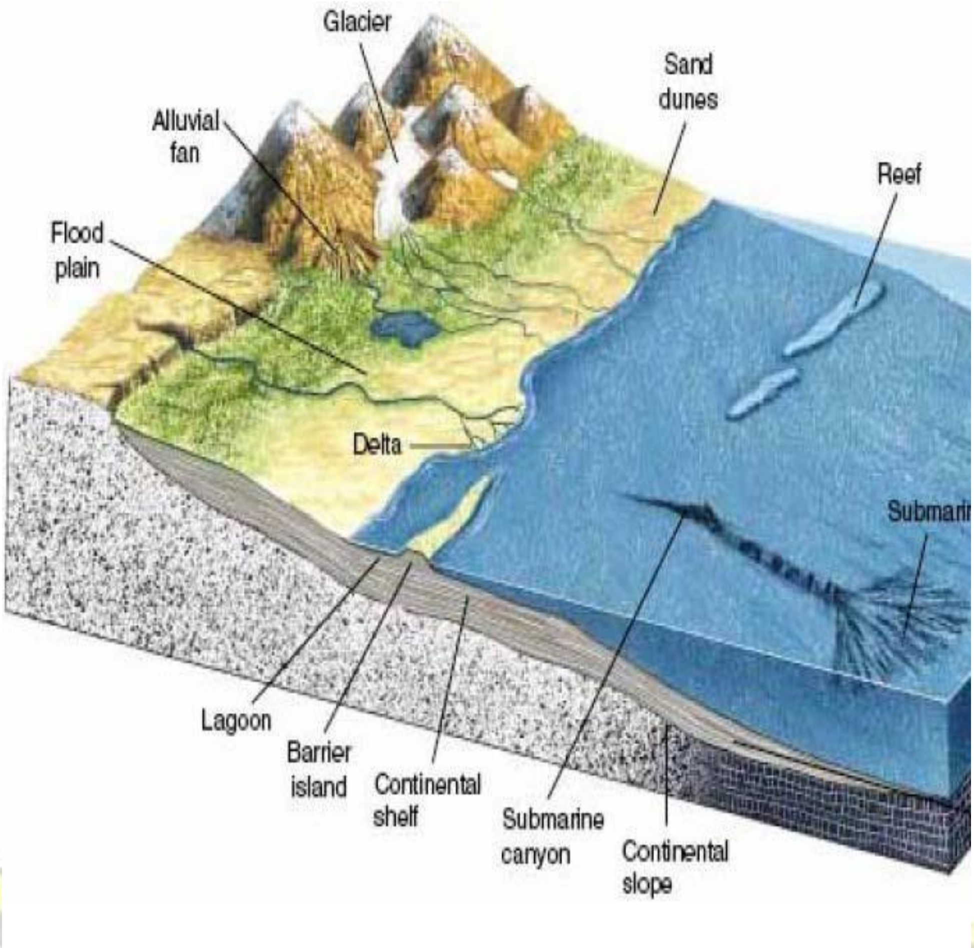

Figure 2.7: Types of depositional environments (Mahmoud, 2010).

2.9 DEPOSITIONAL ENVIRONMENT DETERMINATION USING WELL LOGS

In recent times, the shape of gamma ray log is becoming more important as these been found to be very variable, show greater detail and are related to the sediments character and depositional environment. The gamma ray log is frequently an indicator of shale content. This is related to the clay content. A bell shaped log with gamma ray values increasing upwards to a lower value indicated increasing clay content. A funnel shape with the values decreasing regularly upwards shows a decrease in clay content. The decrease in clay content is correlated to an increase in sand content and grain size. Shapes on the gamma ray log can be interpreted as grain size trends and by sedimentological association as cycle. A decrease in gamma ray value will indicate an increase in grain size. Small grain size will correspond to higher gamma ray values. The sedimentological implication of this relationship leads to a direct correlation between facies and log shape (Omoboriowo et al., 2012).

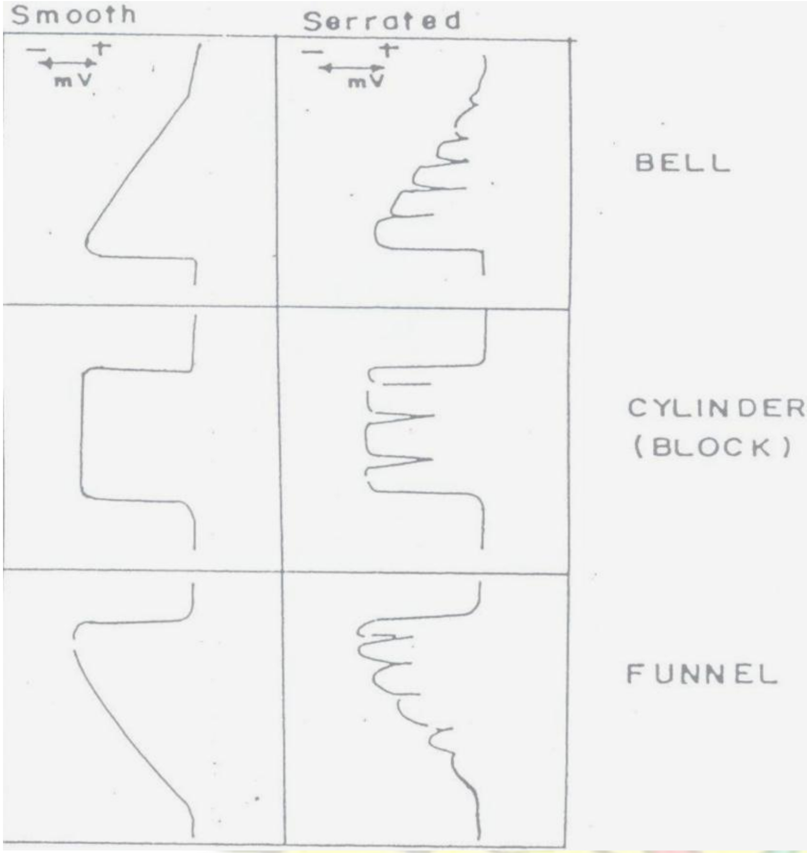

Figure 2.8: Log shape classification. The basic geometrical shapes and description used to analyze GR log shape (from Rider, 2002)

A blocky or cylindrical shape indicates massive or thickly bedded sandstone which is lithologically uniform or with very little thin non-sandy interbedded. This type of sands is characteristic of tidal channel, barrier bars and fluvial channel sand in the delta plain (Omoboriowo et al., 2012).

A funnel shape curve indicates a coarsening upwards trend. This is typical of beach sand, barrier bar sand and stream bars, which are characteristic of shore line deposits and deltaic environment (Omoboriowo et al., 2012).

2.10 RESERVOIR CHARACTERIZATION

Reservoir characterization is the process of mapping a reservoir's thickness, net-to-gross ratio, pore fluid, porosity, permeability and water saturation. Reservoir characterization requires the construction of detailed 3D petrophysical property models contained within a geological framework. Structural interpretation of seismic data has been and continues to be important in the generation of the framework of the reservoir model.

The knowledge of the character and extent of a hydrocarbon reservoir are important factors in quantifying the hydrocarbon in place (Schlumberger 1989):

The prior information required are the thickness, pore space and areal extent of the reservoir. Other intrinsic parameters are the shale volume/content, net to gross ratio and saturation values. These parameters are important because they serve as veritable inputs for reservoir volumetric analysis and consequently estimation of the volume of hydrocarbon in place (Edwards and Santogrossi, 1990).

Determination of the reservoir thickness is best obtained from cut-offs which are visible on well logs, especially with the gamma ray and resistivity logs (Asquith, 2004).
The density-neutron log also provides a means to estimate reservoir thicknesses in addition to revealing the type of hydrocarbon present in the reservoir. A higher percentage of oil and gas is produced from lithologies like sandstones, limestone and dolomites which are first identified with the aid of the gamma ray log (Asquith, 2004).

The resistivity log is a valuable tool used to obtain the true formation resistivity as well as identify the oil – water contact as it differentiates between water and hydrocarbon in the pore space of the reservoir rocks.

Several researchers have used different approaches in the reservoir characterization depending on the type of reservoir. Reservoirs can broadly be distinguished into two (2) types; conventional and unconventional reservoirs. The approach used by these researchers was dictated by the availability of data, the type of reservoir being characterized and software package.

2.11 APPROACH TO RESERVOIR CHARACTERIZATION BY OTHER RESEARCHERS

1. Passey et al. (1990) proposed a technique for measuring total organic content (TOC) in shale gas formations. Fundamentally, this technique is based on the porosityresistivity overlay to locate hydrocarbon bearing shale pockets. Usually, the sonic log is used as the porosity indicator. In this technique, the transit time curve and the resistivity curves are scaled in such a way that the sonic curve lies on top of the resistivity curve over a large depth range, except for organic-rich intervals where they would show crossover between themselves. P-wave velocity (V_p), S-wave velocity (V_s), density and anisotropy are influenced by TOC changes in shale formation and thus should be detected on the seismic response.
2. Rickman et al. (2008) showed that brittleness of a rock formation can be assessed from the computed Young‟s modulus and Poisson‟s ratio well log curves. This suggests a workflow for estimating brittleness from 3D seismic data, by way of simultaneous pre-stack inversion that yields P reflectivity (I_p), S reflectivity (I_s),

   V_p/V_s, Poisson‟s ratio, and in some cases meaningful estimates of density. Better reservoir quality as well as brittle zones is found in areas with high Young‟s modulus and low Poisson‟s ratio (higher TOC, higher porosity). Such workflow works well for good quality data.
3. Koesoemadinata et al. (2011) in their article "Seismic reservoir characterization for Marcellus shale" employed the Prestack inversion methodology in the

   characterization process. In their research, a well-log data set was available for carrying out the prestack inversion. The well curves included gamma ray, sonic and shear, and bulk density measurements. Because the well was situated quite far away from the line, they depended on visual pattern-matching to tie well synthetic to seismic data at the point of intersection of the two lines. No additional stretching and squeezing were needed to make the excellent well tie.

Prestack inversion with angle stacks covering up to 42^0 angles of incidence enabled them to obtain inversion of density along with acoustic and shear impedances. Poststack inversion with the nearest angle stack ($0\text{-}10^0$) was also carried out. This enabled them to compare the Young‟s modulus attribute calculated from poststack inversion (Banik et al., 2010) with that from the Prestack inversion. A low-frequency model for inversion was created using an up-scaled version of the log data propagated in the layers bounded by picked horizons. The final wavelets for simultaneous inversion of multiple angle stack.

4. Sharma and Chopra (2013) proposed an integrated workflow in which well data as well as seismic data are used to characterize the hydrocarbon bearing shale. They begin with the generation of different attributes from the well-log curves. Then, using the cross-plots of these attributes, hydrocarbon bearing shales zones are identified. Once the analysis is done at the well locations, seismic data analysis is picked up for computing appropriate attributes. Seismically, prestack data is essentially the starting point. After generating angle gathers from the conditioned offset gathers, Fatti‟s equation (Fatti et al., 1994) can be used to compute reflectivity, S-reflectivity, and density which depend on the quality of input data as well as the presence of long offsets. Due to the band-limited nature of acquired seismic data, any attribute extracted from it will also be band-limited, and so will have a limited resolution. While shale formations may be thick, some high TOC shale units may be thin. So, it is desirable to enhance the resolution of the seismic data. An appropriate way of doing it is the thin-bed reflectivity inversion (Chopra et al., 2006; Puryear and Castagna, 2008). Following this process, the wavelet effect is removed from the data and the output of the inversion process can be viewed as spectrally broadened seismic data, retrieved in the form of broadband reflectivity

data that can be filtered back to any bandwidth. This usually represents useful information for interpretation purposes. Thin-bed reflectivity serves to provide the reflection character that can be studied, by convolving the reflectivity with a wavelet of a known frequency band-pass. This does not only provide an opportunity to study reflection character associated with features of interest, but also serves to confirm its close match with the original data. Further, the output of thin-bed inversion is considered as input for the model based inversion to compute P-impedance, S-impedance and density. Once impedances are obtained, we can compute other relevant attributes. These are used to measure the pore space properties and get information about the rock skeleton. Young‟s modulus can be treated as brittleness indicators and Poisson‟s ratio as TOC indicator.

5. Sena et al. (2011) in their article "Seismic reservoir characterization in resource shale plays: "sweet spot" discrimination and optimization of horizontal well placement", they chose to use the stress analysis methodology in the characterization of a shale gas reservoir.

   To provide a quantitative understanding of the geomechanical properties of the reservoir rock using isotopic prestack seismic data, a detailed reservoir-oriented gather conditioning, followed by prestack seismic inversion and multi-attribute analysis can be used.

   As a requirement for understanding fracture behaviour in shale, azimuthal anisotropic analysis and interpretation has to be used. The preservation of azimuths from the processed seismic gathers through azimuthal velocity and AVO analysis, in combination with geomechanical properties derived from isotropic methods, can be used to predict in-situ stresses acting on shale reservoirs. Such stresses, when oriented, would yield oriented fracture patterns during well completion. Optimal completion fracture patterns would be non-oriented, so that a maximum volume of reservoir can be accessed from the fracture origin.

Stress and strain relationship is controlled by the elastic properties of the rock and is given by Hooke‟s law. The idea of Hydraulic fracturing which is applied to tight reservoirs to induce porosity into these regimes originates from the application of Hooke‟s law. This is done by deforming and fracturing the rock by stressing it with hydraulic pressure in the borehole. The Linear Slip Theory was used by Gray et al. (2010) to estimate the stress and strain relationship from seismic data. The combination of elastic rock properties obtained from the seismic inversion with azimuthal velocity and AVO analysis of 3D seismic data provide estimation of the principal stresses. An important parameter for prediction of hydraulic fractures, the Differential Horizontal Stress Ratio (DHSR), can be estimated solely from the seismic parameters, without any knowledge of the stress state of the reservoir. These estimated stresses should be calibrated to the reservoir derived from drilling and completion data, microseismic analysis and regional information.

In their study area, optimal targets exhibit relatively high values of isotropic Young‟s modulus (more brittle) and low differential horizontal stress ratio (no preferential orientation). Such zones are more prone to fracturing in a complex pattern leading to a greater stimulated volume and production.

6. Carcione (2001) showed that for a given layer thickness and kerogen content, the PP reflection coefficient decreases with increasing angle. This implies that if the near and far stack are examined for a given seismic data volume, at the top of the reservoir rock, the negative amplitudes on the near stack will be seen as dimmed on the far stack, exhibiting a class-IV AVO response. Similarly, the base of the reservoir zone will exhibit a distinct positive reflection that will also dim with offset, giving rise to a class-I AVO response. This is expected since the acoustic impedance for shale reservoir rocks

with TOC > 4% is lower than the same rocks without TOC. Such a simple exercise allows separation of reservoir facies from the non-reservoir ones.

7. Impedance curves from wells that penetrate the shale strata, when put together on the same plot exhibit reservoir quality variations (Treadgold et al., 2011; Loseth et al., 2011). Zones associated with higher organic content are associated with lower acoustic impedance values and could be picked up from such a display.

CHAPTER THREE (3): METHODOLOGY

3.1 OVERVIEW OF METHODOLOGY

This chapter deals with a variety of concepts necessary for handling the quantitative aspect of this research. It will outline the various steps employed in carrying out the computation of the various petrophysical parameters as well as the seismic attribute analysis for this study

Seismic attributes analysis and petrophysical analysis are the two major methods used in this research. RMS amplitudes were calculated for both the top and base of each reservoir zone for each horizon. The RMS amplitudes are calculated as the square root of the average of the square of the amplitudes found within each analysis window.

For the petrophysical analysis, a Computer Processed Image (CPI) was generated to show the various petrophysical parameters set out in the objectives of this research. The input data for the petrophysical computations were the Gamma ray log, Resistivity log, Neutron-porosity log and Density log.

A 3D volume of seismic data was used for the seismic attribute analysis, whiles well logs were used for the petrophysical analysis. Volume of Shale (V_{sh}), Reservoir thickness, Net pay, porosity, Net-to-Gross (N/G) and water saturation (S_w) were the petrophysical parameters computed from the well logs.

A successfully characterized reservoir will help in an early determination of the reservoir‟s economic potential and also can offer an opportunity for the geophysicist to determine the productivity of the reservoir ahead of the commencement of production.

3.2 DATA.

The data available for this research is a 3D volume of seismic data and well logs. Well logs used for this study include; Resistivity logs, Gamma Ray logs (GR), Total Neutron-porosity logs (TNPH), compensated Density logs (DTCO).

The Well logs were carefully checked for quality and completeness by deleting abnormal breakage in the log tracks and subsequently edited to suit the study area before they were used in the analysis. Splicing was applied to join the logs together.

3.3 SOFTWARE PACKAGE:

IHS Kingdom software (2D/3DPak, EarthPak) was used to analyse the seismic data. 3D seismic data was loaded onto the software platform and the horizons defined in each reservoir zones was subsequently mapped.

Schlumberger Techlog and Interactive Petrophysics (IP) were the software packages used for the petrophysical analysis aspect of the study. The Schlumberger Techlog software was used for the petrophysical analysis for the Gye Nyame reservoir whiles Interactive Petrophysics (IP) software was used for Sankofa reservoir.

3.3 LOADING OF FORMATION TOPS

Formation tops were loaded onto the software package using their Time-Depth (TD) charts. The TD charts give an indication of the depth and their corresponding two-way traveltime. The accuracy of the TD chart plays a major role in the analysis since a wrong chart will place formation tops in different geological times.

Therefore to ensure the accuracy of the TD chart used, Vertical Seismic Profile (VSP) data acquired in the various wells were used. VSP was acquired in the boreholes to record reflected seismic energy originating from the seismic source at the surface. VSP data therefore improves the accuracy of the travel time.

3.4 HORIZON CREATION AND PICKING

A horizon is the surface separating two different rock layers; also, the reflection from this surface. A horizon can either be picked as a peak or a trough. Horizons which were created and loaded for the various formation tops for the study are: Gye Nyameh top and base, Sankofa Silicon top and base, and Sankofa Capitol top and base. Figure 3.1 below shows a picked horizon for the Gye Nyame.

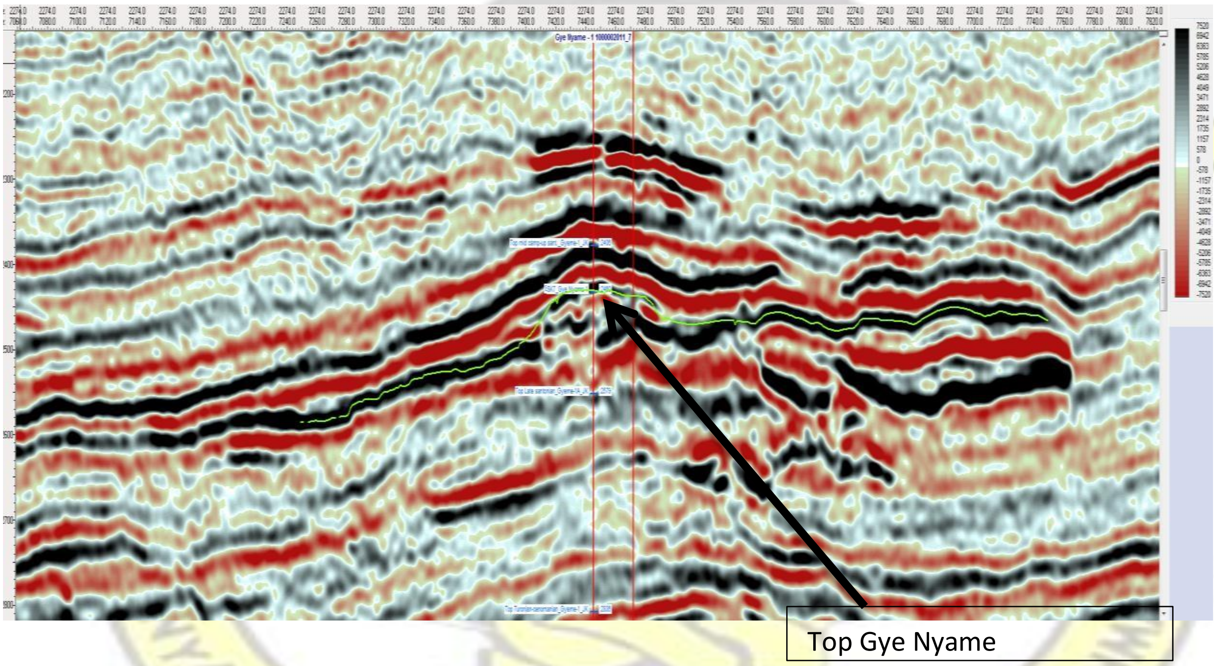

Figure 3.1: Top of Gye Nyame horizon picked in the study area (shown in green)

- A total of nine horizons were mapped for the reservoirs used in this study.
- The top and base of each reservoir zone was mapped as a horizon
- Different colours were assigned to each mapped horizon
- For consistency, the peaks were picked for all horizons
- Horizon picking was done at every single seismic trace for each of the horizons

3.5 GENERATION OF ISOCHORE MAPS

An isochore map represents contours connecting points of equal true vertical thickness of strata, formation, reservoirs or other rock units. Isochores that were created between the top and base of each mapped horizon represent the thickness of the reservoir under consideration. This was done by subtracting the shallower horizon from the deeper horizon; in this case, the top horizon was subtracted from the base horizon.

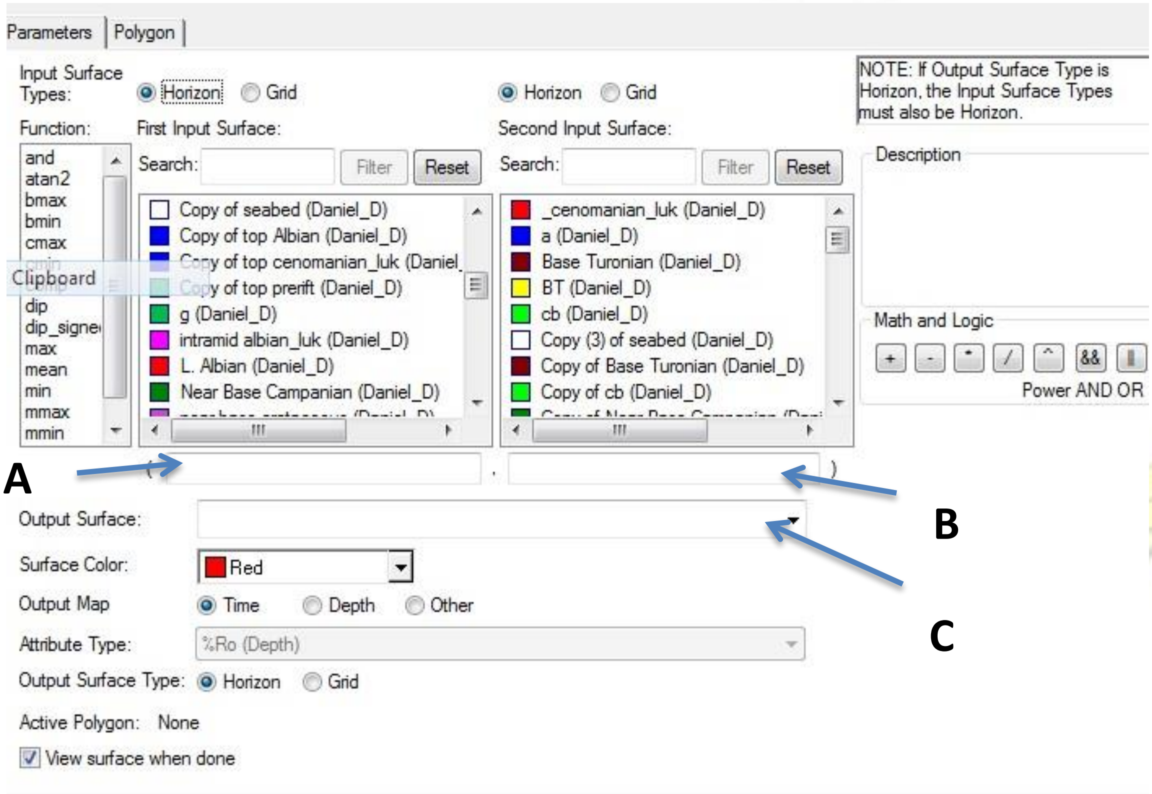

Figure 3.2: Software window for computing isochore maps

The above window in figure 3.2 was used to compute the isochore maps in the research. In the above window in the Kingdom software package, you define the parameters to be used in computing the Isochore maps for each reservoir zone.

In the workspace labelled A, you define the deeper horizon (in this case, the base horizon), in the workspace labelled B, you define the shallower horizon (in this case, the top horizon) and thereafter give the name for the output isochore map in the workspace labelled C.

In the polygon window, you define which window you want the computation to be performed on. Failure to define the polygon will lead to the isochore map being computed for the whole survey area.

3.6 GENERATION OF CONTOUR MAPS

Contours are lines that connect points of equal elevations. Contour maps were created for all mapped horizons by using the IHS Kingdom software suite. The following information was defined in the contour parameters window:

- Contour interval: 1 m
- Method: Krigging
- Horizon name Survey area.

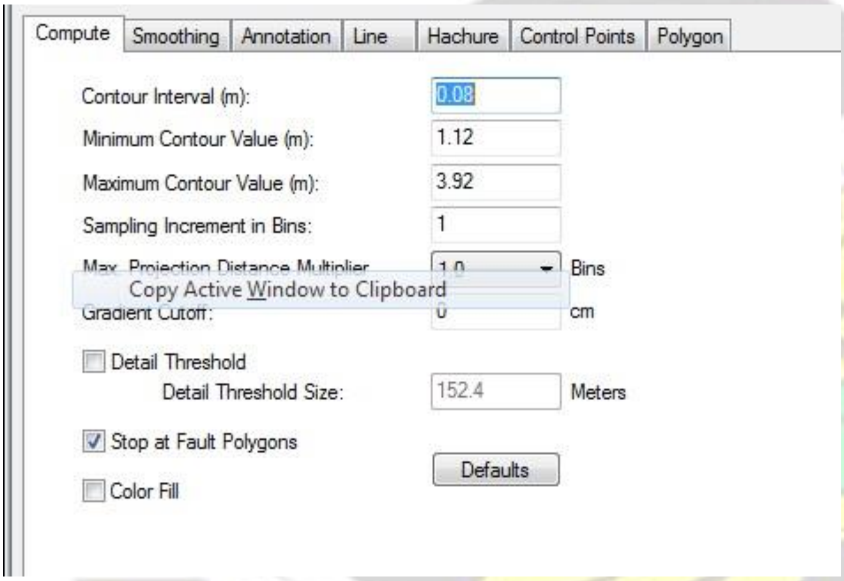

Figure 3.3: Software window for generating contour maps

In the above window in figure 3.3, the various parameters for the computation of the contours were defined including the contour interval, minimum contour value, maximum contour value and sampling increment. In the smoothing, you define the smoothing parameters for the contour lines and finally define the polygon in which you want to constrain the contour computation to. The contour interval of 1m was chosen to be close enough to show the maximum structural feature in the study area. Some structures could be missed if a wider contour interval is chosen.

3.7 RMS AMPLITUDE EXTRACTION

The RMS amplitudes are calculated as the square root of the average of the squares of the amplitudes found within an analysis window and they are sensitive to sandstone-bearing depositional systems tracts within the reservoir-bearing successions. The equation below was used in computing the RMS amplitudes for each analysis window.

$$P_x = \sqrt{\frac{1}{N}\sum_{i=1}^{N} {X_i}^2}$$

The RMS amplitudes were calculated between two bounding surfaces (i.e. the top and base of the reservoir) to generate a map revealing several depositional elements associated with the reservoir.

RMS amplitudes were therefore extracted between the Top and Base of each mapped reservoir as well as the reservoir level respectively. These amplitudes give an indication of the presence of reservoir sands at each of the mapped horizons as well as an indication of the geometry of the area and the structural elements in the reservoir zones.

2.8 PETROPHYSICAL ANALYSIS

The petrophysical analysis for the research was done using two industry software packages provided by the Ghana National Petroleum Cooperation (GNPC); Schlumberger Techlog and the Interactive Petrophysics (IP). The input data for the petrophysical analysis were the borehole logs; Gamma ray log, Density log, Resistivity log and Neutron-porosity log. These logs were loaded onto the software platform and used as the input data for the various computations.

3.9 VOLUME OF SHALE (Vsh)

The volume of shale (Vsh) was computed using the Gamma ray log dataset as the input data. The linear method was used in the computation since the geology of the study area is predominantly sandstone and the reservoir zone is within the Campanian and hence fairly younger rock. The volume fraction of shale was derived from the gamma ray log as the shale volume is linearly proportional to the gamma ray log value (GR).

$$GR_{index} = \frac{GR - GR_{matrix}}{GR_{shale} - GR_{matrix}}$$

$$GR_{sh} = GR_{index}$$

During the computation performed on the zones of interest, the Vsh was automatically calculated using the above stated formula with the Schlumberger Techlog software.

Volume of shale values gives an indication of the lithology of the formation in the reservoir zone.

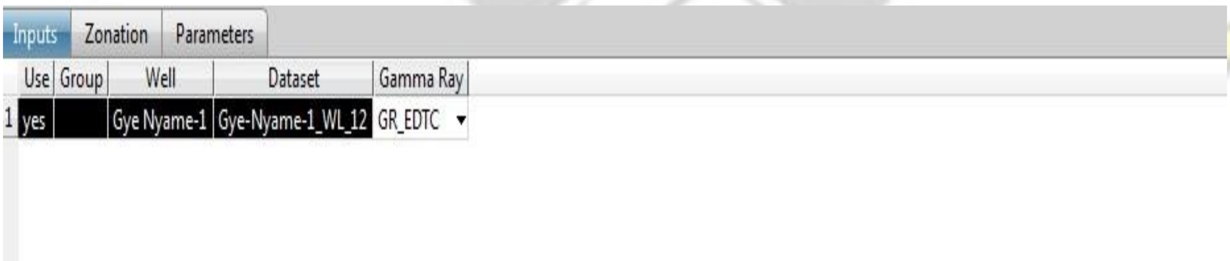

Figure 3.4: Input file for Vsh in Schlumberger Techlog

Figures 3.4 above is the Techlog software window indicating the input dataset used in the volume of shale (V_{sh}) computation for the reservoir zone. The edited gamma ray log (GR_EDTC) is the input dataset file for the V_{sh} computation

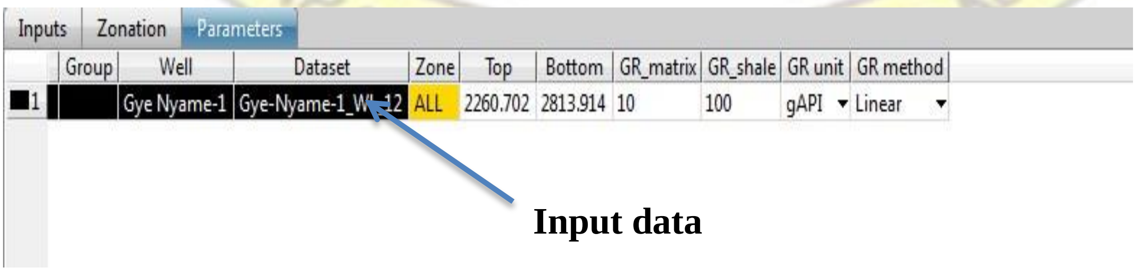

Figure 3.5: Input parameters for Vsh using Schlumberger Techlog

Figure 3.5 above shows the Techlog software window indicating the parameters for calculating the V_{sh}. It specifies the computational method used (i.e. Linear method) and also the top and base of the reservoir. Knowledge of the volume of shale is used in the porosity calculation.

3.10 POROSITY

The effective porosity was computed for each of the reservoirs. The effective porosity was calculated with the Schlumberger Techlog using the equation below:

$$PHIE = PHIA * (1 - V_{sh})$$

Where:

PHIE: Effective porosity

PHIA: Average porosity

V_{sh}: Volume of Shale

The knowledge of porosity is paramount because it determines the ultimate volume of a rock type that can contain hydrocarbons. Thus, porosity represents the volume of the total rock that is occupied by pores.

The porosity for the reservoirs were calculated using the following input log parameters;

1. Neutron-Density log
2. Bulk density log

3. Resistivity.

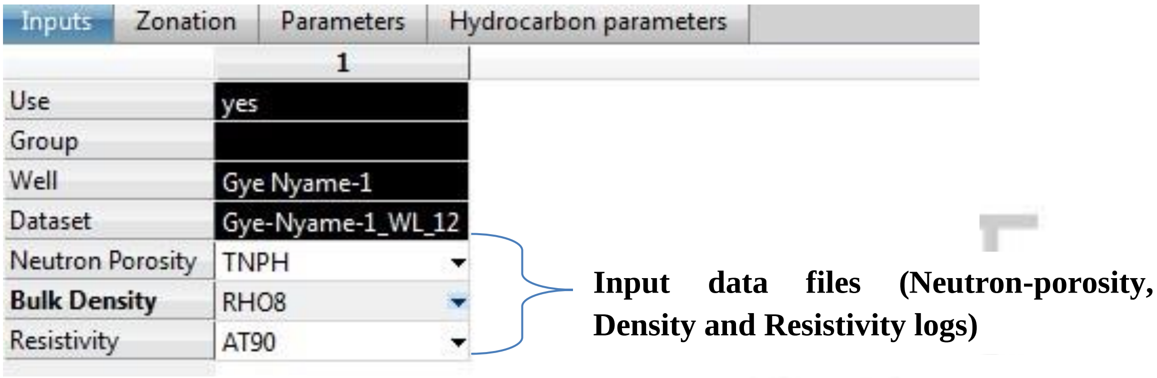

Figure 3.6: Input file for porosity computation in Schlumberger Techlog

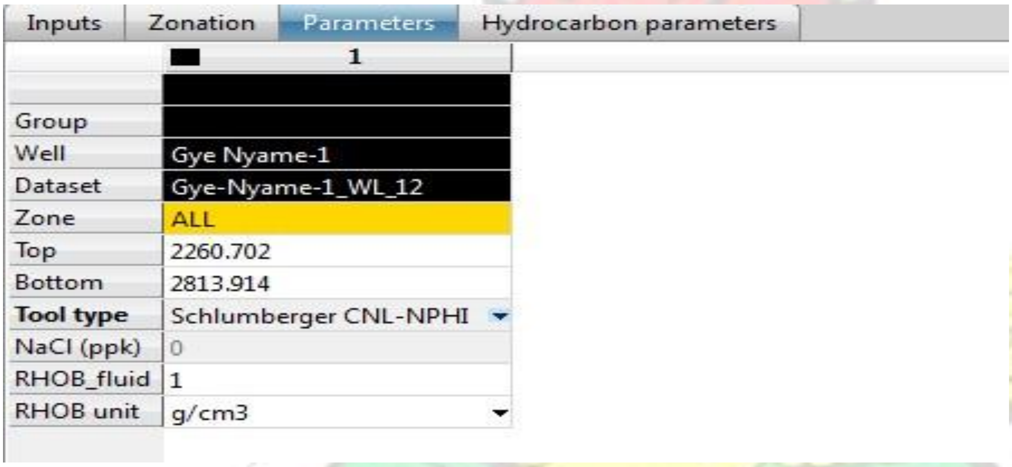

Figure 3.7: Input parameters for porosity computation

Figure 3.6 above shows input dataset used in the porosity computation using the Schlumberger Techlog software. The neutron-porosity log, the bulk density and the resistivity logs were used as the input data for calculating the porosity. In the case of the resistivity, the deep resistivity value (AT90) was used. The deep resistivity curve shows the uninvaded zone and hence represents the true resistivity.

Figure 3.7 shows the parameters used in the computation. It indicated the limiting zonation (i.e. the top and base of the reservoir).

3.11 WATER SATURATION

Determination of water saturation (S_w) values is the most challenging but important of all the petrophysical calculations. This is so because, water saturation values are used to quantify the hydrocarbon saturation ($1 – S_w$).

The Archie‟s method was used to compute the water saturation of the reservoir zone of interest.

$$S_w = \left(a * \frac{R_w}{R_T * PHIA^m}\right)^{\frac{1}{n}}$$

where:

Sw: Water Saturation

Rw: Resistivity of water

R_T: Total resistivity

Where a, n & m are constants; a=1, n=2, m=2.

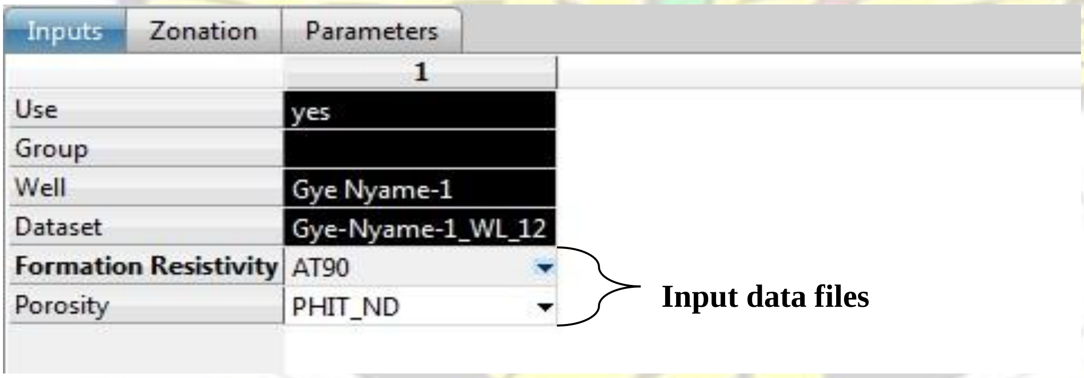

Figure 3.8: Input files for Water Saturation (Sw) calculation using Schlumberger Techlog

Figure 3.8 above indicates the input curves used in calculating for the water saturation values for the reservoir. The porosity was used as an input curve in the water saturation computation and also the formation resistivity was also considered. The deep resistivity (AT90) value was used to represent the formation resistivity.

Inputs	Zonation	Parameters
	1	
Group		
Well	Gye Nyame-1	
Dataset	Gye-Nyame-1_WL_12	
Zone	ALL	
Top	2260.702	
Bottom	2813.914	
a	1	
m	2	
n	2	
Rw (ohm.m)	0.03	

Figure 3.9: Input Parameter for various constants and water resistivity for water saturation

Figure 3.9 shows the input parameters for the water saturation computation. The corresponding values for the constants expressed in the formula for water saturation were defined in this window as well as indicating the top and base of the reservoir zone.

3.12 NET PAY DETERMINATION

Net pay is a thickness with unit of length. It is a subinterval within the gross rock thickness that contains reservoir sands. It includes net reservoir rock comprising a significant volume of hydrocarbons in place. The aim of the net-pay calculations was to exclude non-productive rock intervals. Reservoir description and quantitative hydrocarbons-in-place interpretation can thereafter be obtained from the net pay calculations. Therefore, the computation was simply the identification and summation of those subdivisions of the reservoir that will contribute to the accumulation of hydrocarbons and hence exclude the rest of the bulk rock that is regarded as non-productive.

This computation was done using the Gamma ray log as the input data since the gamma ray log is a good indicator of lithology and hence was able to discriminate the reservoir sands from the non-reservoir sands and therefore automatically summed up the reservoir sand packages from the entire gross rock using the gamma ray log as a guide.

3.13 NET TO GROSS RATIO (N/G)

Net-to-gross (N/G) is the fraction of reservoir volume occupied by hydrocarbon-bearing rocks. The significance of the N/G ratio is ultimately to define productive zones in the reservoir for hydrocarbon exploitation.

The net-to-gross is the total amount of pay divided by the total thickness of the reservoir interval. N/G of 1.0 means that the whole of the reservoir interval is pay and N/G of 0 means that the whole of the rock interval has no pay associated with the bulk rock volume.

The N/G ratio for the study was computed using the software package. This was done by summing the total sand zones present in the total rock package. Hence it is a ratio of the reservoir sand package (net pay) to the total block rock volume. The gamma ray log was used as the input data for this computation.

This is given by the relationship below:

$$N/G = \frac{NET\ PAY}{TOTAL\ RESERVOIR\ THICKNESS} \text{ X } 100\%$$

3.14 CUT-OFFS

Cut-offs are basically limiting values and their importance is to exclude those rock volumes that do not contribute significantly to the storage and production of hydrocarbons. The major use of cut-offs is to demarcate net pay, which can be described mainly as the summation of those depth intervals through which hydrocarbons are economically producible.

The porosity, water saturation and shale clay volume cut-offs values below were used in the research. The choice of cut-off values were influenced by data and reservoir quality that was inferred from the RMS amplitude extraction. Therefore, any formation porosity below 10% was considered tight and hence ignored, water saturation below 65% was considered not economically viable and subsequently cut off from the computation and shale volume of 45% was also cut off from the computation.

CHAPTER FOUR (4): RESULTS AND DISCUSSION

4.1 GYE NYAME DISCOVERY AREA**.**

- The **LEO 1** and **LEO 2** wells were used in the research in this discovery area

- The reservoir was found at the Campanian formation

  The reservoir is termed as SK9 in this research.

4.1.1 SEISMIC SECTION OF GYE NYAME

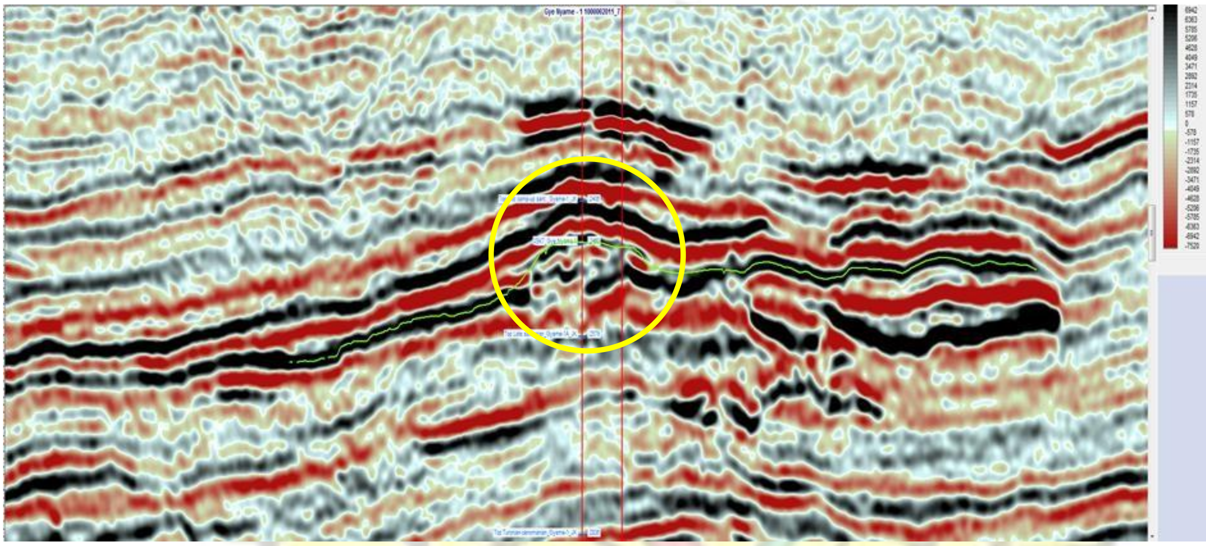

Figure 4.1: Seismic section of Gye Nyame discovery area

Figure 4.1 shows the seismic section for the Gye Nyame discovery area from which the structural interpretation was carried out. It shows the presence of an anticlinal structure as indicated by the yellow circle. The green line shows a sample pick of the base of the reservoir.

4.1.1 ISOCHORE OF GYE NYAME

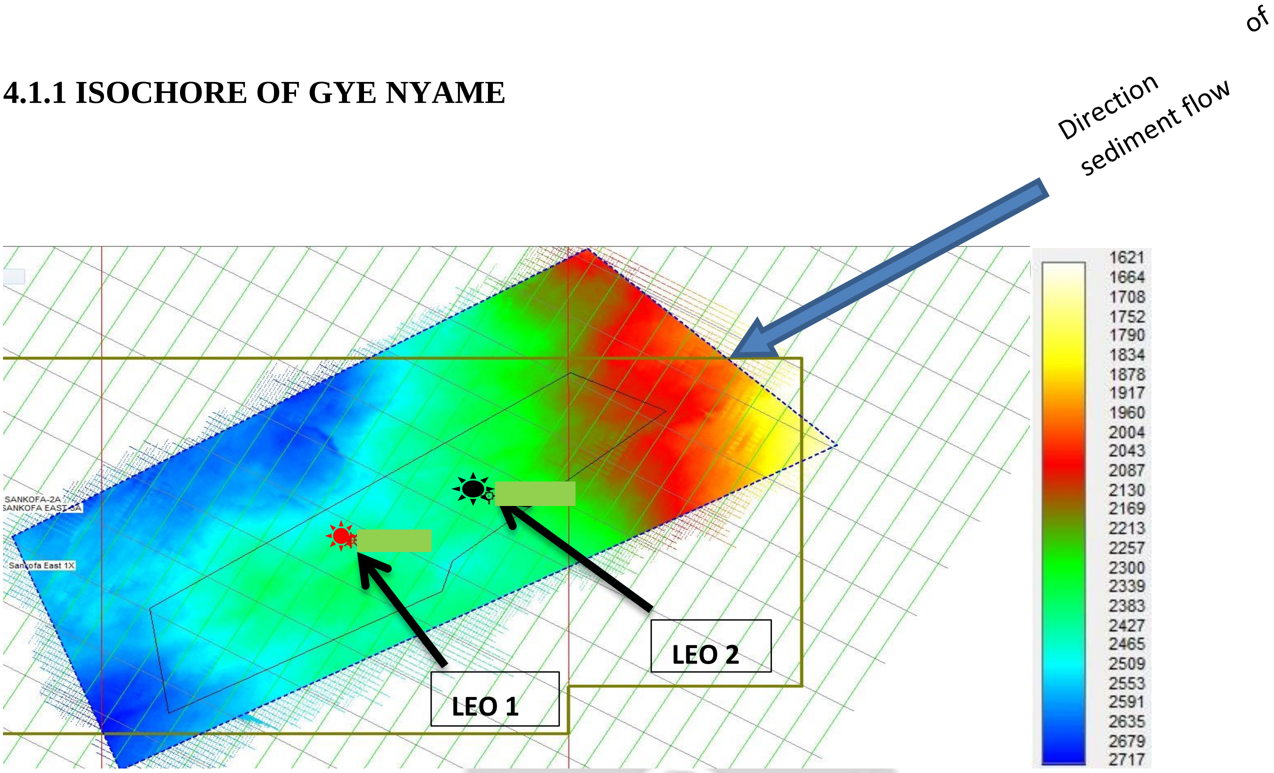

Figure 4.2: Isochore map of Gye Nyame

- The isochore map in figure 4.2 shows the terrain is sloping downwards from yellow to blue, as indicated by the highest and lowest point in the map. The highest point on the map is 2717 m and the lowest point is 1621 m.
- Sediments may therefore be trending down-slop as indicated by the arrow

4.1.2 CONTOUR MAP OF GYE NYAME

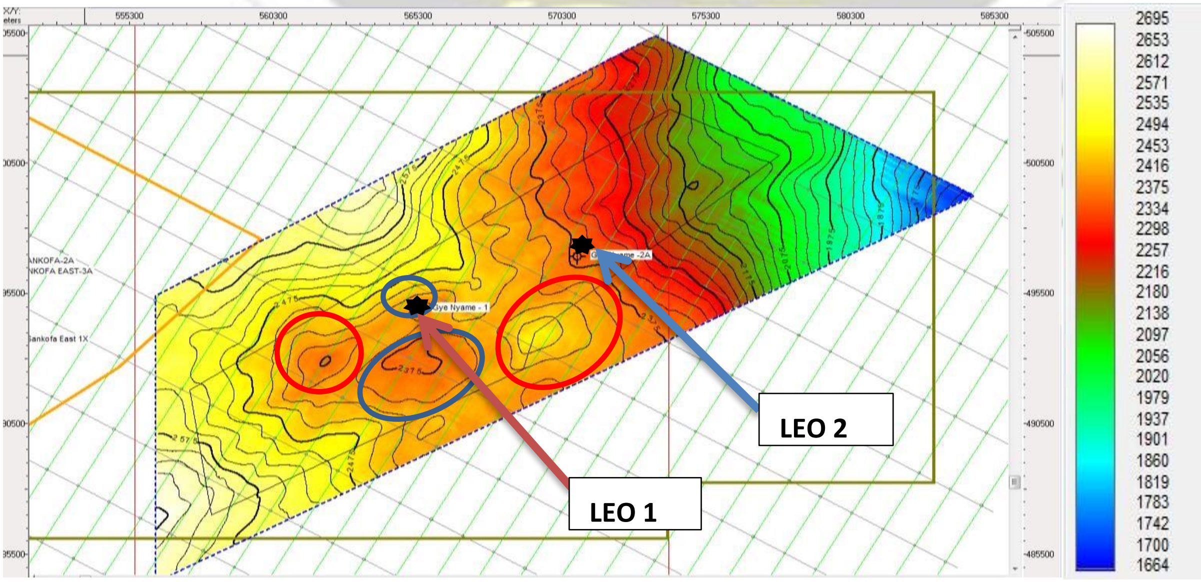

Figure 4.3: Contour map of top of reservoir for Leo wells

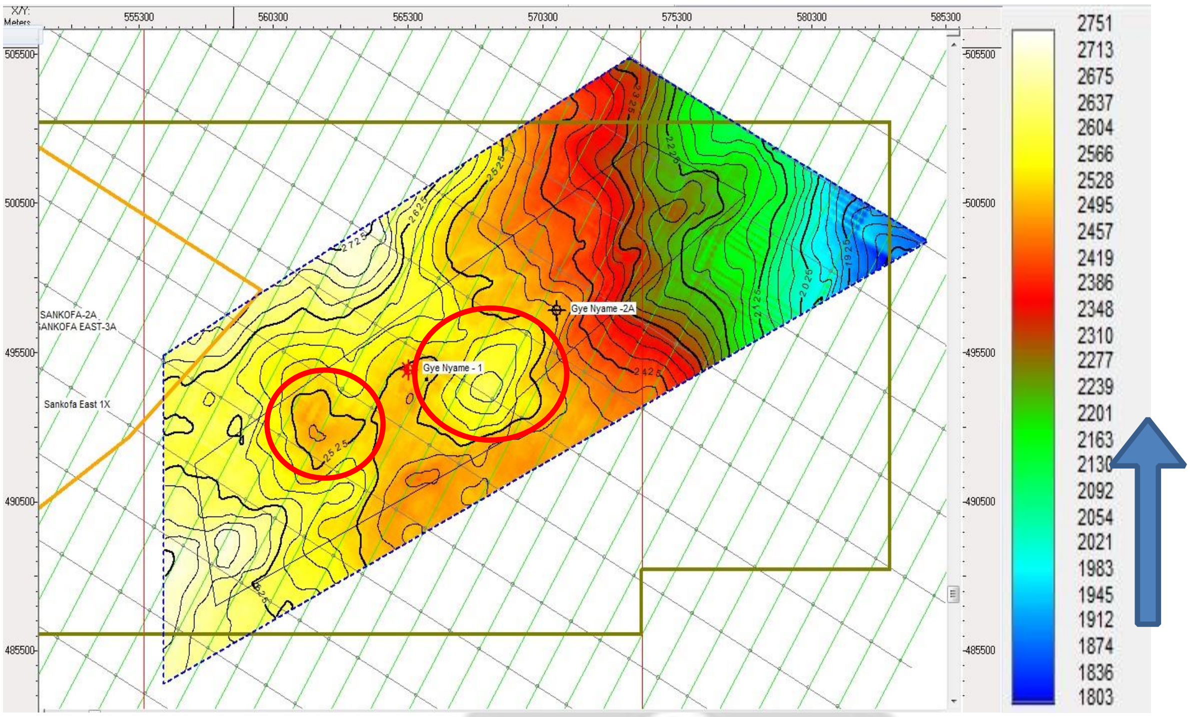

Figure 4.4: Contour map of base of reservoir in Leo wells.

4.1.3 INTERPRETATION OF CONTOUR MAPS:

The contours of the top of the reservoir as shown in figure 4.3 above reveal the presence of several four-way closures (indicated by blue and red circles), that could be an indication of the presence of combined stratigraphic-structural trap. The **LEO 1** well falls within a fourway closure as indicated by the contour map, whiles **LEO 2** well does not fall within any four-way closure.

The contours of the base of the reservoir as indicated in figure 4.4 indicate the occurrence of four-way closures as indicated by red circles. These four-way closures indicated by the red circles are seen occurring in both the top and base of the reservoir. This could indicate the presence of a huge structure.

The contours also show that the terrain is slopping from North-East to South-West, and hence the trend of sediment deposition is in a similar direction.

4.1.4 RMS AMPLITUDE MAP

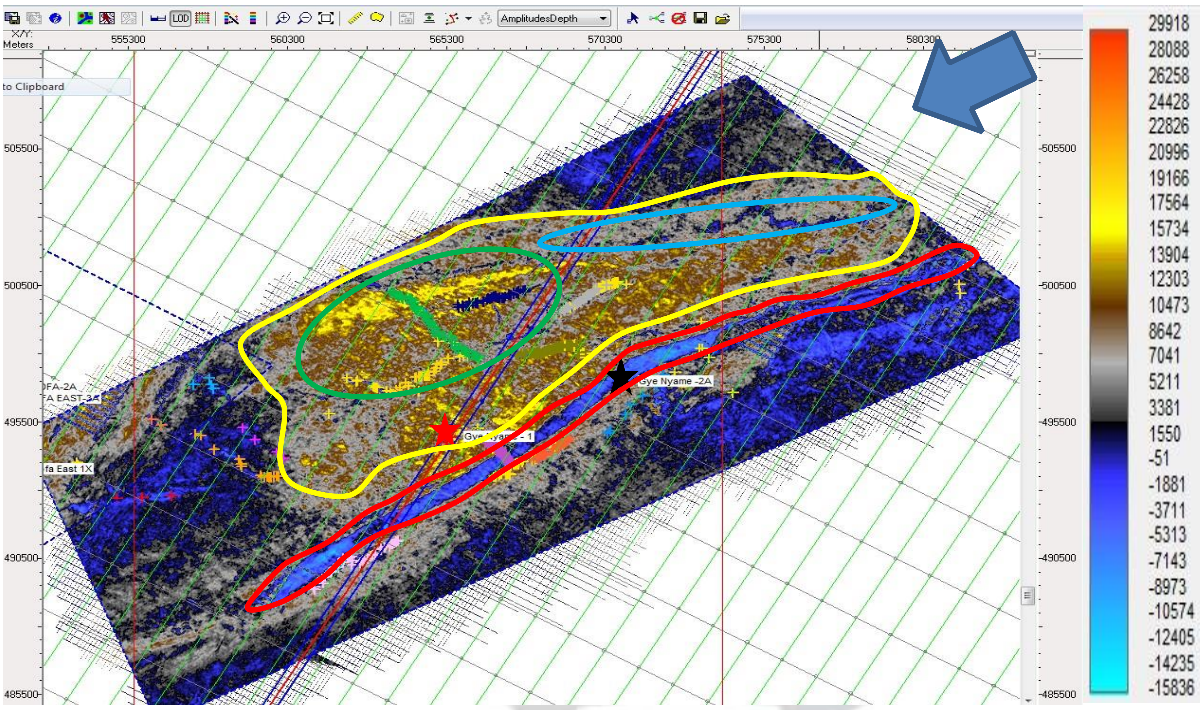

Figure 4.5: RMS amplitude extraction for top of reservoir.

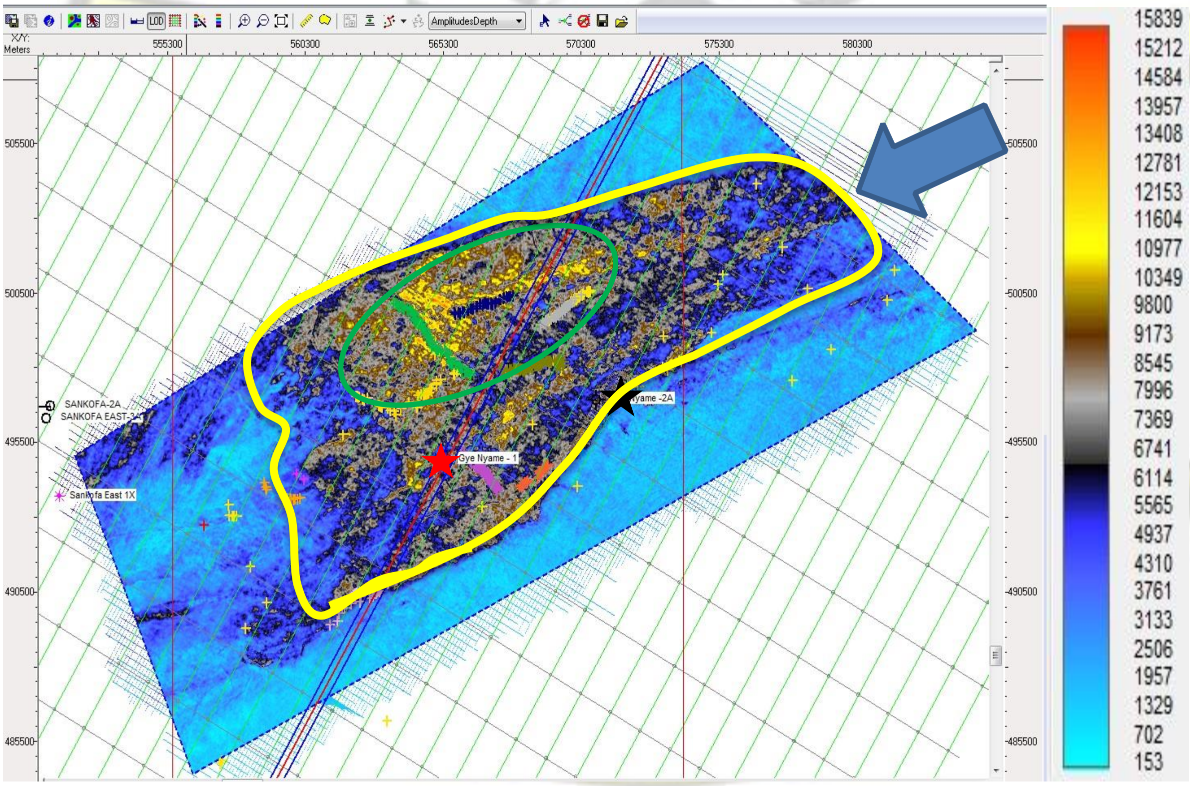

Figure 4.6: RMS amplitude extraction between top and base of the reservoir.

4.1.5 INTERPRETATION OF RMS AMPLITUDE MAPS

4.1.6 TOP RESERVOIR MAP

- The map for the top of the reservoir is shown is figure 4.5 above
- The amplitude extraction from the top of the reservoir reveals the presence of turbidite reservoir sands deposited in a coeval but distinct fairway trending north-east. The direction of sediment flow is indicated by blue arrow. This is proven by the presence of high RMS amplitude regime in the reservoir zone. High RMS amplitude indicates the presence of reservoir sands whiles low RMS indicates non-sands.
- The sand body is deposited in a fan system as depicted in the yellow layout in the diagram in the figure 4.6 above.
- It also reveals the presence of an old channel system which is interpreted as mud filled, hence the show of mainly low amplitudes.
- **LEO 2** well, as indicated by the red star, was drilled in the mud filled old channel system and hence it was a dry hole. This was because of the lack of presence of reservoir sands in the fairway.
- It also reveals sediments of low amplitudes, which show non-reservoir sands and it might be an indication of mud or shale
- It further reveals high concentration of reservoir sands in the middle portion of the map and a good zone for further drilling campaign. This is indicated by a green circle in both figure 4.5 and 4.6.

4.1.7 RMS AMPLITUDE MAP FOR EXTRACTION BETWEEN TOP AND BASE OF RESERVOIR

- This map reveals a distinct fairway of a sand body deposited in a fan system, as indicated by the yellow layout and it is trending from north-east to south-west as indicated by the blue arrow

- It also reveals the presence of high concentration of quality reservoir sands in the middle of the map. This could prove to be a prospective drill zone in the event of further drilling campaign in the future.

4.2 RESULTS OF PETROPHYSICS FOR LEO 1 RESERVOIR

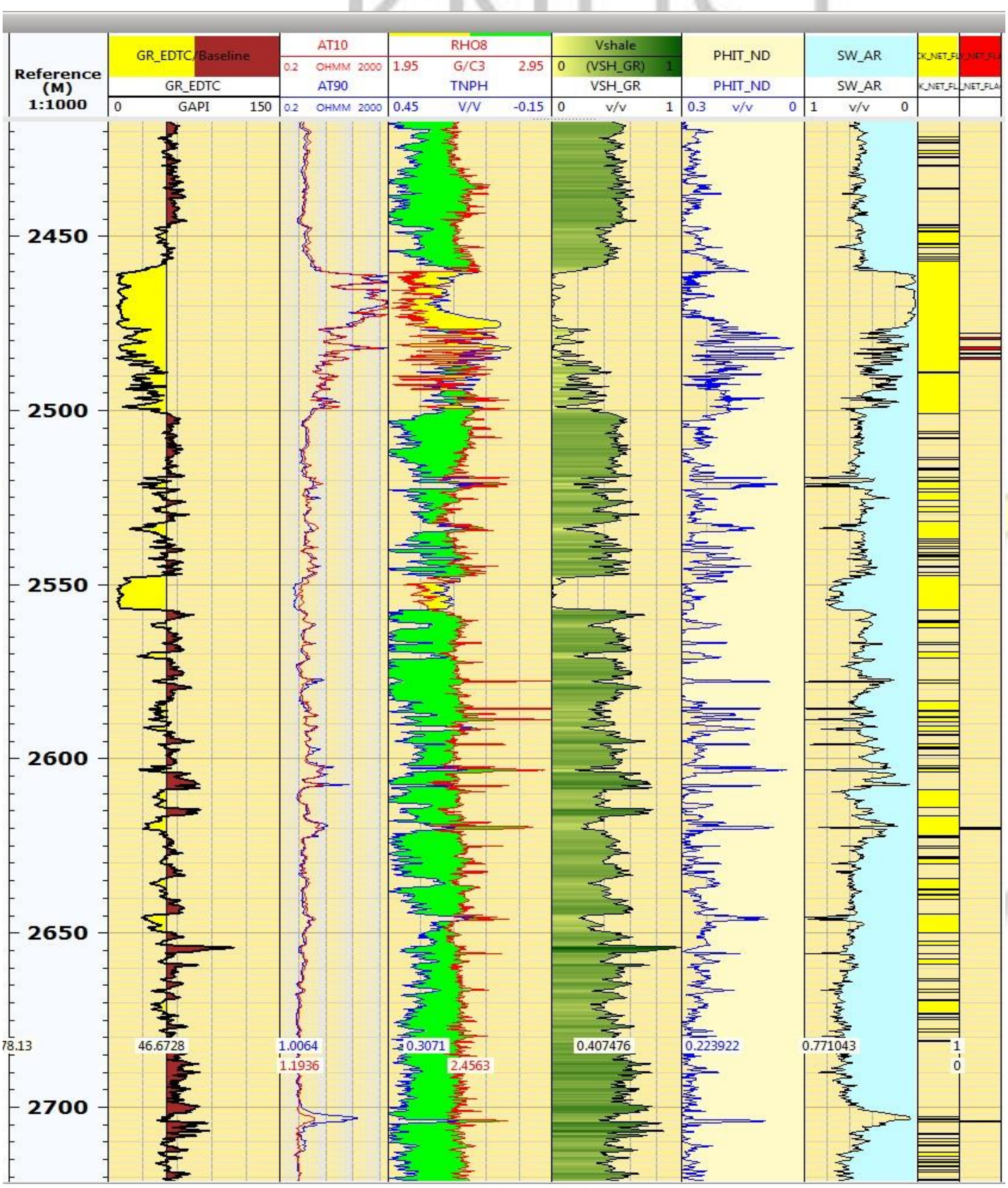

Figure 4.7: Computer Processed Image (CPI) for entire LEO 1 well indicating resistivity, Gamma ray, Density and Neutron-porosity logs.

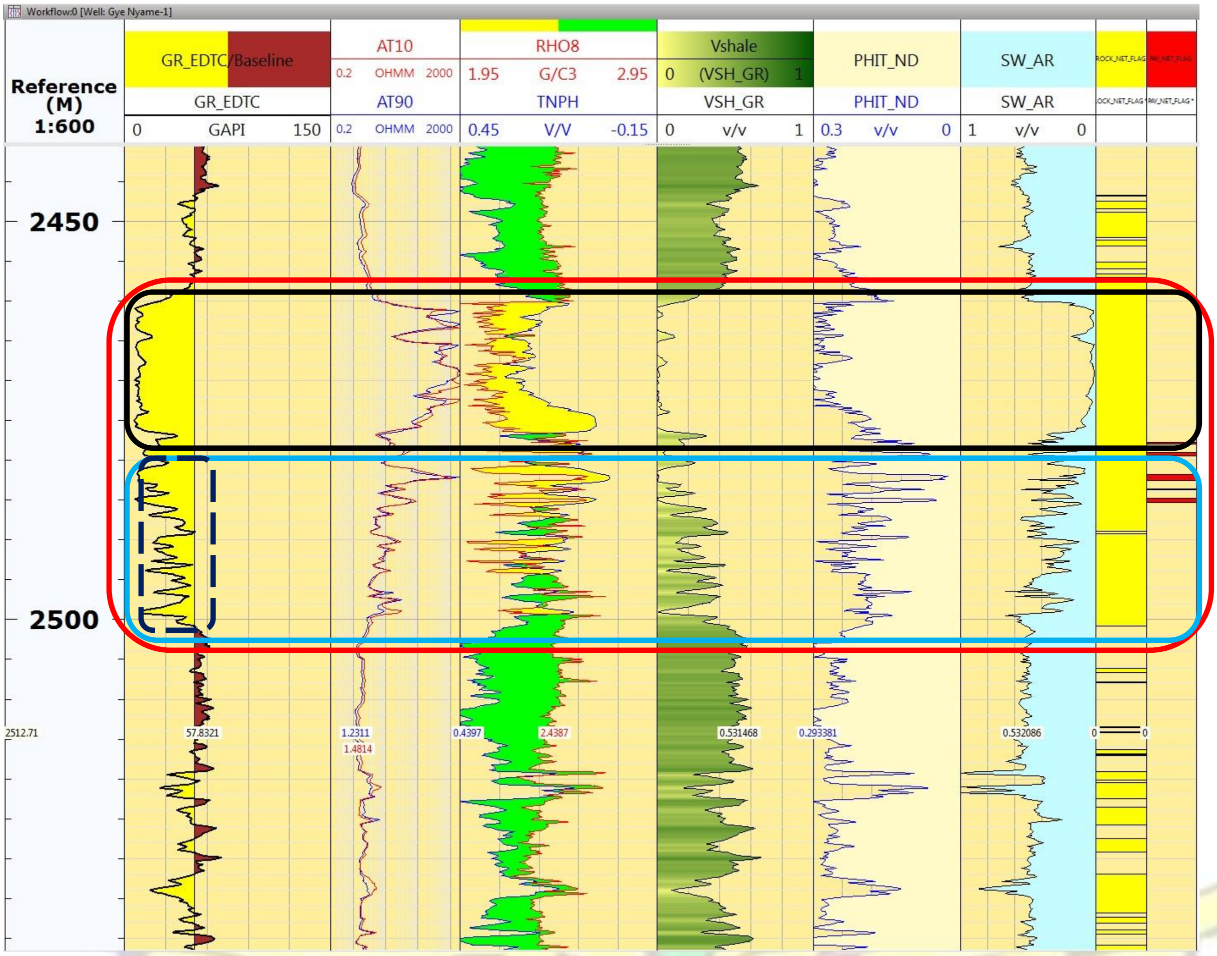

Figure 4.8: CPI for reservoir zone in LEO 1 well.

4.2.1 INTERPRETATION OF PETEROPHYSICS FOR TOP LEO 1 (2459 m - 2476 m)

- The entire reservoir zone under consideration is between 2459 m to 2500 m as shown in the Computer Processed Image (CPI) above in figure 4.8 and is indicated by the red rectangle.
- The reservoir is subdivided into two zones, the most productive top part from 2459 m to 2476 m, indicated by a black rectangle, as shown in figure 4.8.
- The upper part of the reservoir section comprised of more clean reservoir sands as indicated by the gamma ray log.
- It shows excellent petrophysical features as shown in Table 4.1 below.

Table 4.1: Petrophysical analysis for top of reservoir zone (2459 m – 2476 m)

Reservoir thickness (m)	16.5

Net pay (m)	16.1
Net/Gross (%)	97.57
Porosity (%)	25.1
Water Saturation (Sw) (%)	8

4.2.2 IMPLICATION OF PETROPHYSICAL PARAMETERS TO PRODUCTION

Porosities determine void space that can contain fluid and hence the greater the porosity, the greater the quantity of fluid that can be contained in the reservoir and vice versa. Permeability determines the flow of fluid; therefore if permeability is poor, fluid movement into the well bore is curtailed and limits production and also if permeability is high and much fluid is contained in the reservoir, then much production can take place. Sw is water saturation. The higher the Sw, the lower the volume of oil/gas in the reservoir and lower Sw means higher quantity of oil/gas in the reservoir.

From the above petrophysical parameters of the reservoir in Leo 1 well in Table 4.1, it can be deduced that the reservoir has high porosity (25.1%) and hence the potential to contain greater quantity of hydrocarbons. The Water Saturation, Sw is significantly low (8%) and that indicates that its most important compliment, hydrocarbon saturation is high (92%). A 97.57% N/G gives an indication that, the reservoir is a vast total of the total rock volume is represented by reservoir sands with a few interfering of other non-reservoir materials

4.2.3 INTERPRETATION OF PETEROPHYSICS FOR LOWER LEO 1 (2476 m - 2500 m)

- The lower part of the reservoir is characterized by less clean reservoir sands interfingering with muddy/clay sediments as indicated by the gamma ray log. This can be seen as turbidites in the log within that part of the reservoir under consideration
- The formation in this part of the reservoir records lower porosity readings, which may be an indication of a tight reservoir rock.

- Volume of shale computation in the zone is slightly high which could indicate a low sandstone
- The reservoir region records good petrophysical features as indicated in Table 4.2 below

Table 4.2: Petrophysical analysis for lower Leo 1 (2476 m – 2500 m)

Reservoir thickness (m)	22.1
Net pay (m)	14.2
Net/Gross (%)	64.3
Porosity (%)	17.0
Water Saturation (Sw) (%)	30

4.2.4 IMPLICATION OF PETROPHYSICAL PARAMETERS TO PRODUCTION

From the results in Table 4.2 above for petrophysical parameters of the reservoir in Leo well, it can be deduced that porosity is low and hence the potential to contain smaller quantity of hydrocarbons. The Water Saturation, Sw, is slightly high and that indicates that its most important compliment, hydrocarbon saturation is low lower than the section above.

4.2.5 DEPOSITIONAL ENVIRONMENT

The interpretation of the depositional environment was based on the signature of the gamma ray log. The gamma ray log of the upper section of the reservoir (2459 m -2476 m) shows a blocky serrated shape which could suggests probably a Tidal Channel. The gamma ray log of the lower section of the reservoir (2476 m - 2500 m) shows a serrated funnel shape which may be indicating laminated upper shoreface.

4.3 SANKOFA DISCOVERY.

The Sankofa discovery is part of the larger Offshore Cape Three Points (OCTP) discovery.

Two wells are under consideration in the research for this area; the Capitol and Silicon well.

4.4 CAPITOL WELL

The Capitol well was drilled in the OCTP as commitment well of the second extension exploration period to investigate the eastern of the gas filed outlined by the Silicon and Diamond wells. The Sankofa non-associated gas accumulation was discovered in a Lower Campanian reservoir by the Diamond exploration in well in the OCTP Block, offshore Tano Basin, in 860 m of water depth. The Capitol well delineated the size of the discovery encountering gas and condensate in the main targets, resting between 2500-2600 mssl. **4.4.1 ISOCHORE MAP**

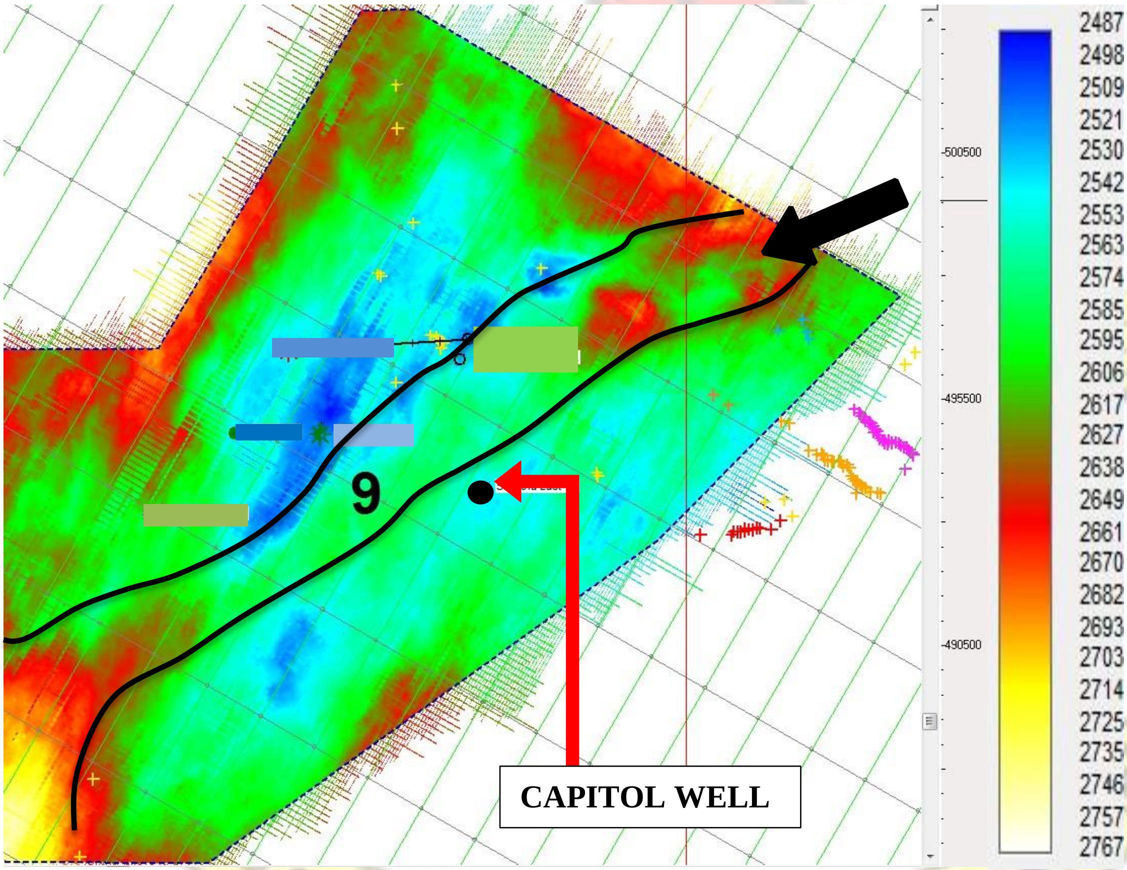

Figure 4.9: Isochore for top of Capitol reservoir

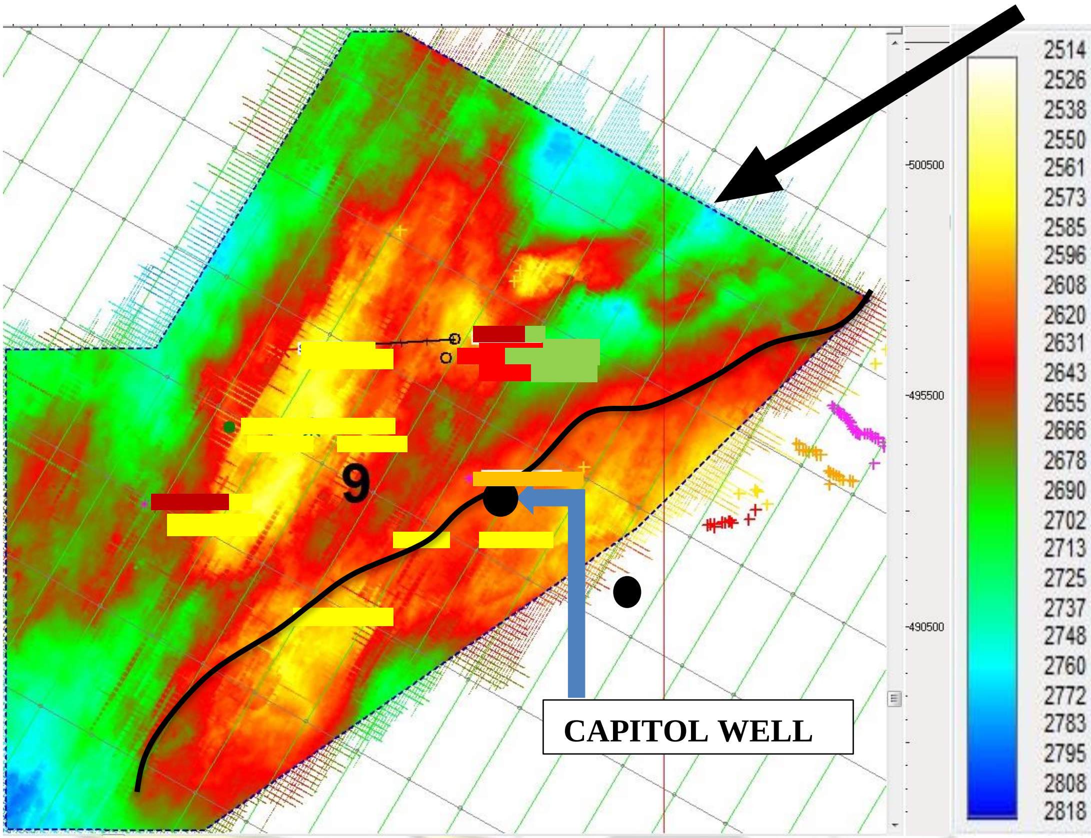

Figure 4.10: Isochore for base of Capitol reservoir

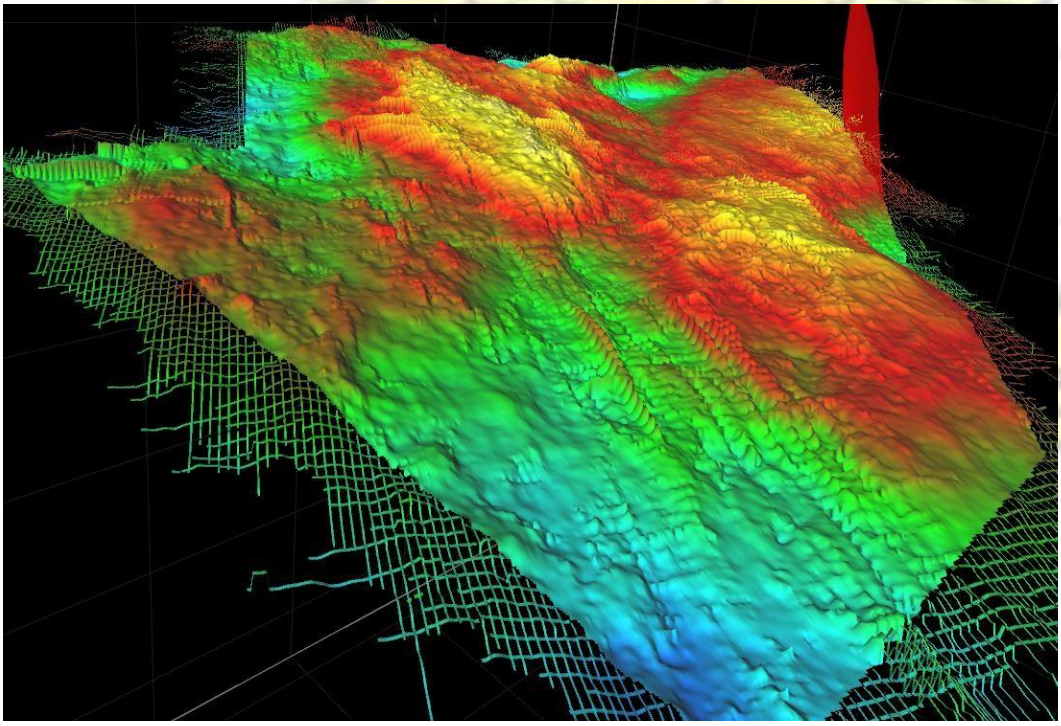

Figure 4.11: 3D view of Capitol reservoir

4.4.2 INTERPRETATION FOR ISOCHORE MAPS

Isochore maps depict the thickness of the area. The thickest portion of the reservoir is at 2818 m and the thinnest portion is 2514 m

The isochore maps for both the top and base of the reservoir reveals the presence of a channel formed between two high lying areas as indicated by the 3D view in figure 4.11.

The flow of sediments is interpreted as down-dip as indicated by the arrow in the map in figure 4.10 above. Thicker sand bodies are shown by the red colour whiles the thinner sand bodies are indicated by blue colour.

4.4.3 CONTOUR MAP FOR CAPITOL RESERVOIR (TOP AND BASE)

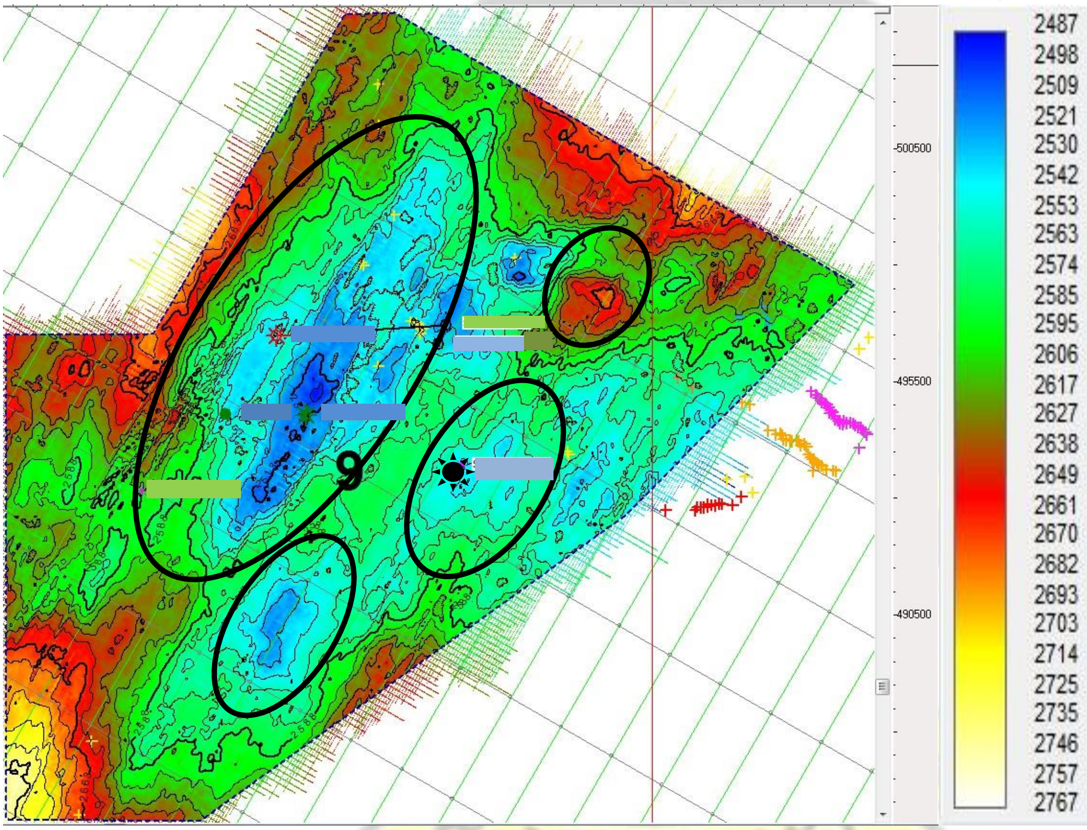

Figure 4.12: Contour map of top of Capitol reservoir

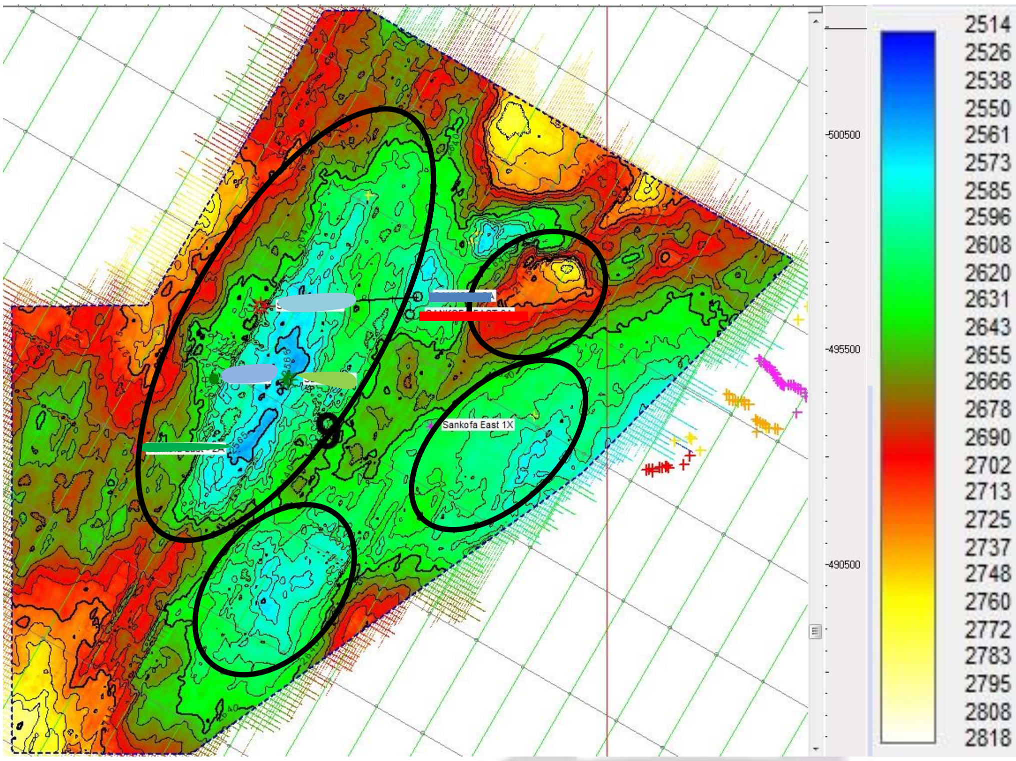

Figure 4.13: Contour map for base of Capitol reservoir

4.4.4 INTERPRETATION OF CONTOUR MAPS FOR SK7 RESERVOIR LEVEL FOR CAPITOL WELL The contour map as shown in figure 4.12 reveals the presence of several four-way closures (indicated by black circles), which could be an indication of the presence of structural traps and the Capitol well was drilled in a contour closure.

The reservoir is an elongated confined turbidite system, fed from N-E to S-W and composed of stacked turbidite channels. The sequence is comprised of unconformity surfaces, with clear erosive behaviour at the base.

4.4.5 AMPLITUDE MAP FOR RESERVOIR ZONE

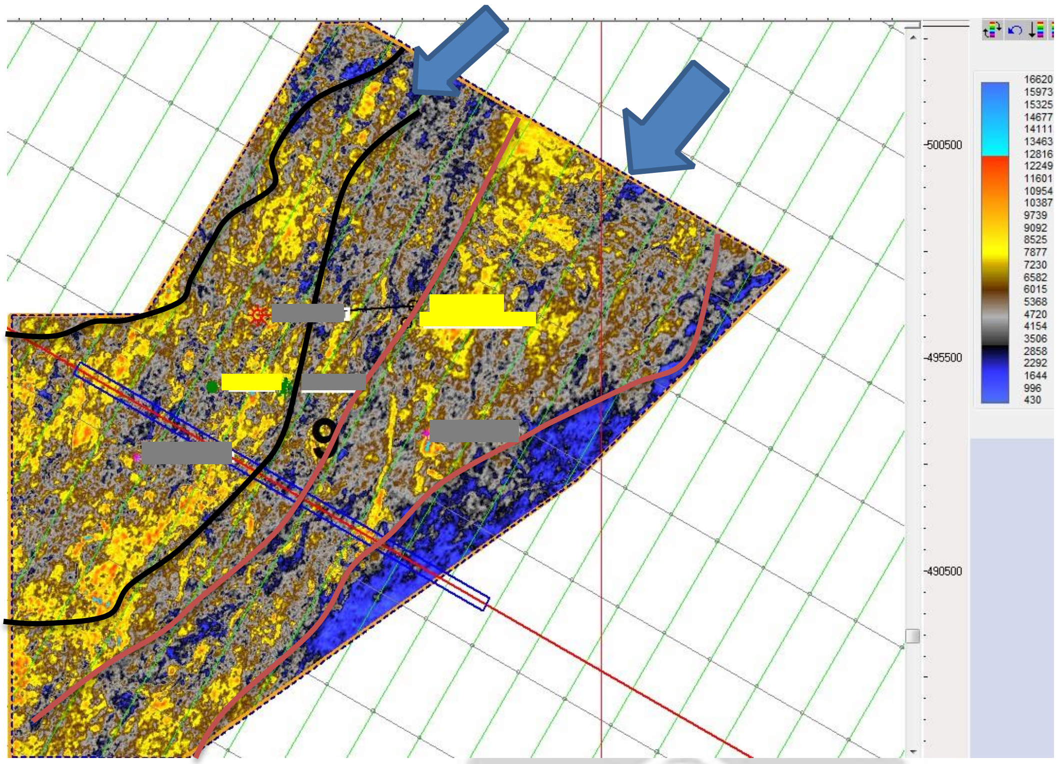

Figure 4.14: Amplitude map of reservoir for capitol well

4.4.6 INTERPRETATION OF AMPLITUDE MAP

- The amplitude map in figure 4.14 shows some high concentration of reservoir sands as indicated by the yellow bright spots.
- Sediments seem to be flowing in the fairly distinct channels as indicated by the arrows on the map in figure 4.14 above and these zones could give clues as to possible drill targets for future drilling campaigns.
- It is interpreted as a confined turbidite system and likely composed of stacked turbidite channels. The sequence is comprised between unconformity surfaces, with clear erosive behaviour at the base.
- The amplitude map shows the occurrence of sand bodies and hence, in comparison to the depth map; the occurrence of sands as indicated by the yellow colour in the amplitude map coincides with the deeper areas on the Isochore maps. This indicates that, the thickest sand bodies are located in the deeper portions of the reservoir.

4.4.7 PETROPHYSICAL ANALYSIS FOR CAPITOL WELL

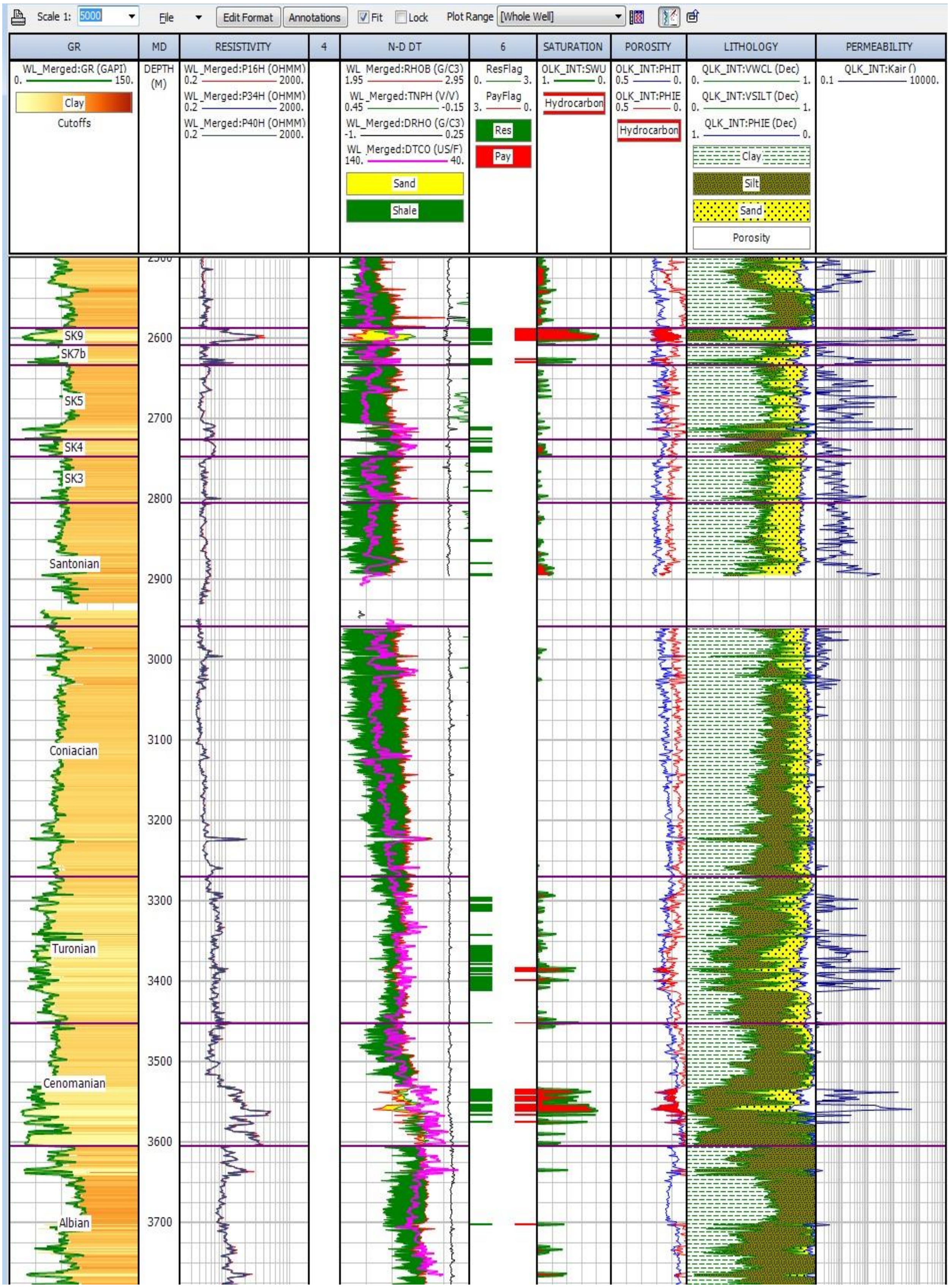

Figure 4.15: CPI for Capitol well showing various reservoir zones

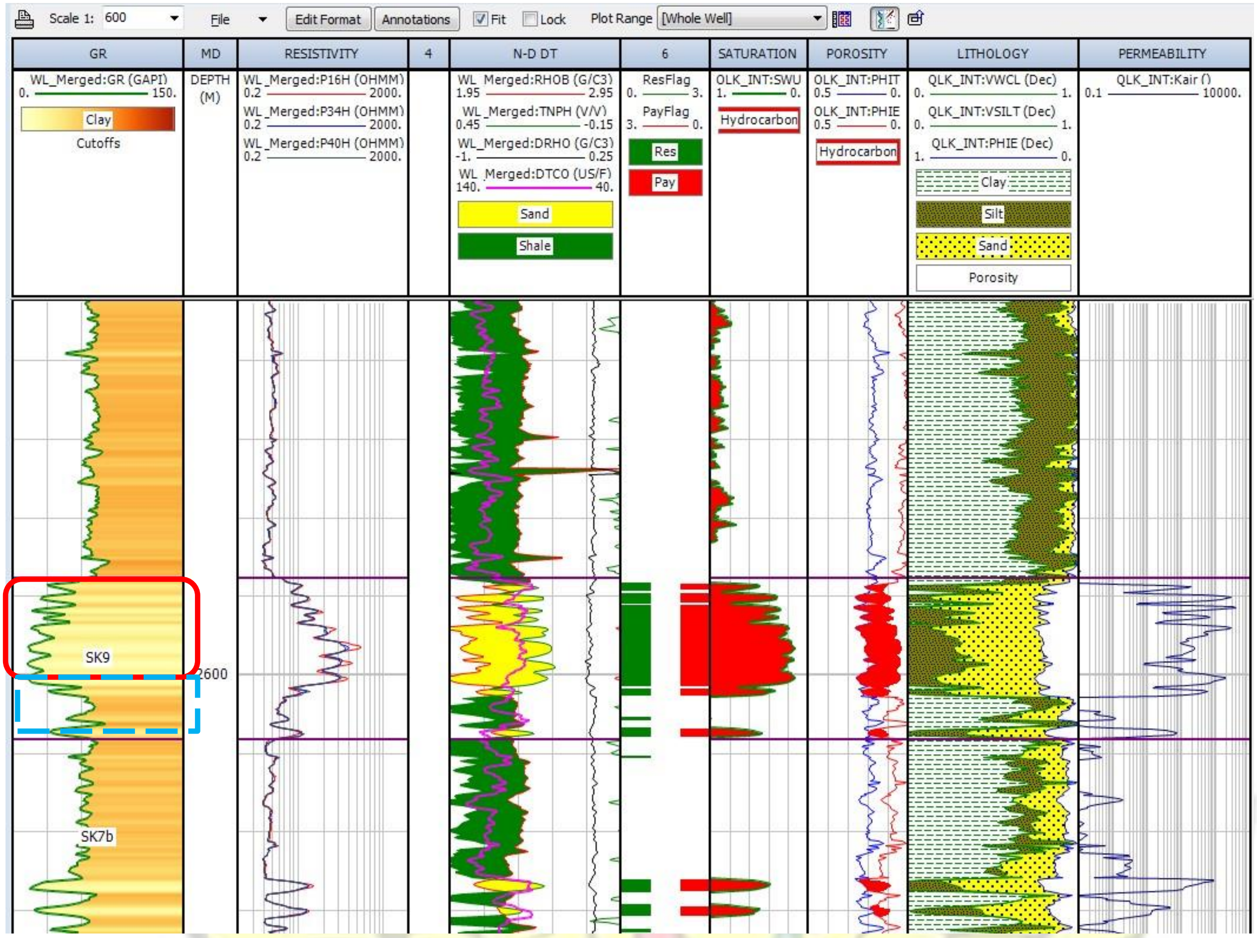

Figure 4.16: CPI for SK9 reservoir for Capitol well

4.4.8 INTERPRETATION OF PETROPHYSICAL FEATURES FOR RESERVOIR

- The gamma ray log in track one as show in the CPI in the figure 4.16 above indicates the occurrence of clean sands in the reservoir zone as indicated by the gamma ray log. This is shown by the red rectangle.
- There is a surge in the resistivity values in the reservoir zone which could be an indication of the presence of hydrocarbons, since hydrocarbon exhibit high resistivity. This is further confirmed in the hydrocarbon saturation track, which indicates the presence of hydrocarbons in the reservoir.
- The top of the channelized target sandstone prone sequence is overlaid by transgressive shale sequence constituting the vertical seal.

- The reservoir zone shows excellent petrophysical features as indicated in table 4.3 below

Table 4.3: Petrophysics for reservoir for capitol well

Reservoir thickness (m)	20.5
Net pay (m)	15.3
Net/Gross (%)	75
Porosity (%)	24
Water Saturation (Sw)	24

4.4.9 IMPLICATION OF PETROPHYSICAL PARAMETERS ON PRODUCTION

From the above petrophysical parameters of the reservoir in capitol well as shown in Table 4.3, it can be deduced that the high porosity indicates that a greater quantity of hydrocarbons will be contained in the reservoir, a low Sw indicates high hydrocarbon saturation, since hydrocarbon saturation is determined by 1-Sw.

4.4.10 DEPOSITONAL ENVIRONMENT

The Gamma ray log in Figure 4.15 shows serrated symmetrical to bell shape, which could indicate fine grained sandstone at the upper part of tidal channel, grading into laminated tidal flat mudstone at the base.

4.5 SILICON WELL

The silicon well was drilled in the OCTP Block, offshore Tano Basin, as a second appraisal well of the Sankofa discovery to investigate a possible upside, laterally developed with respect to the previous canyon outline.

4.5.1 ISOCHORE MAP OF RESERVOIR FOR SILICON WELL

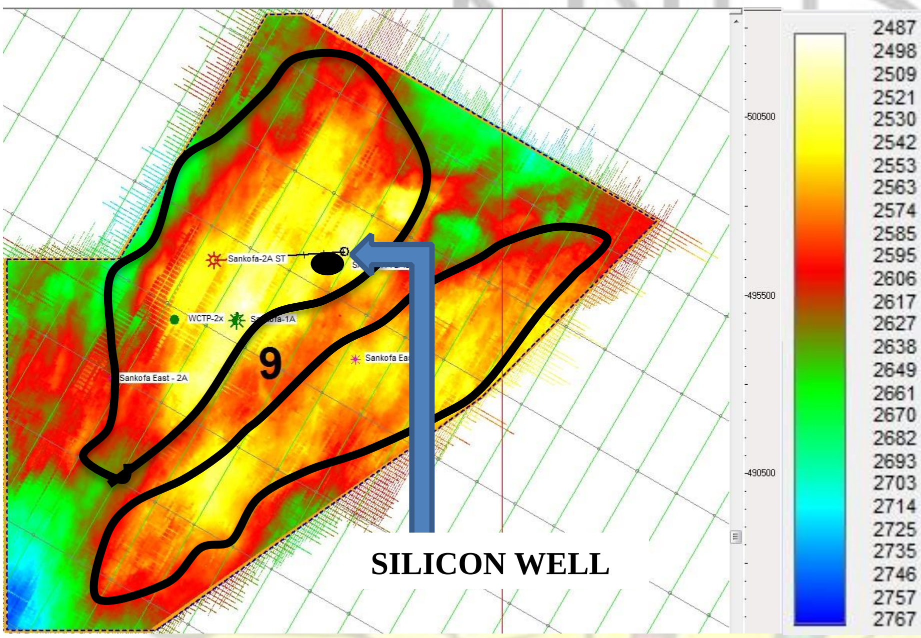

Figure 4.17: Top of reservoir for Silicon well

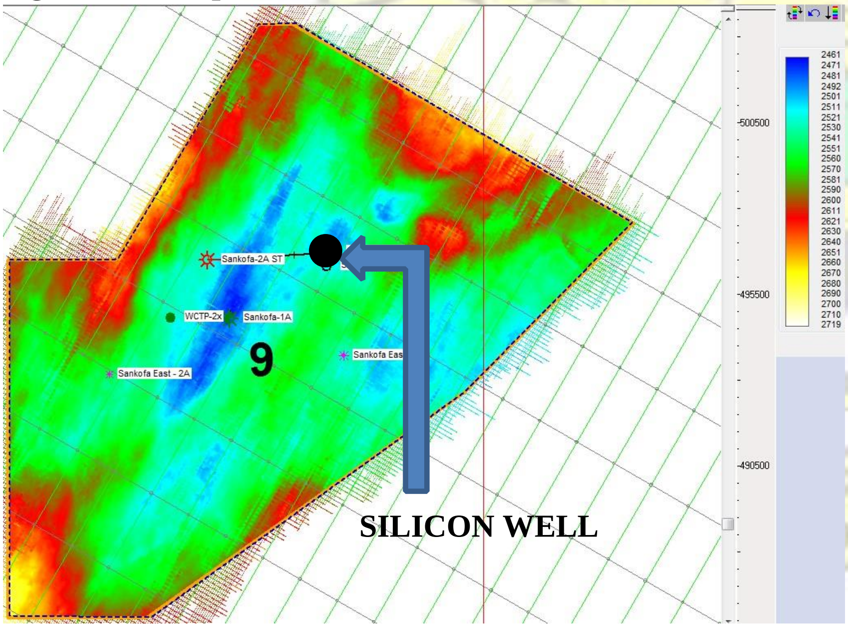

Figure 4.18: Base of reservoir for Silicon well

4.5.2 INTERPRETATION OF ISOCHORE MAPS

- The isochore map shows the presence of a channel sandwiched by two relatively thicker sediments as indicated by the circled portion. This is shown in Figure 4.17 and figure 4.18.
- The Silicon well is located in one of the thickest portions**.** The reservoir thickens in the middle and flattens out as you get to the edges.
- The thinnest portion is 2487 m and the thickest portion is 2747 m.

4.5.3 CONTOUR MAP OF RESERVOIR FOR SILICON WELL

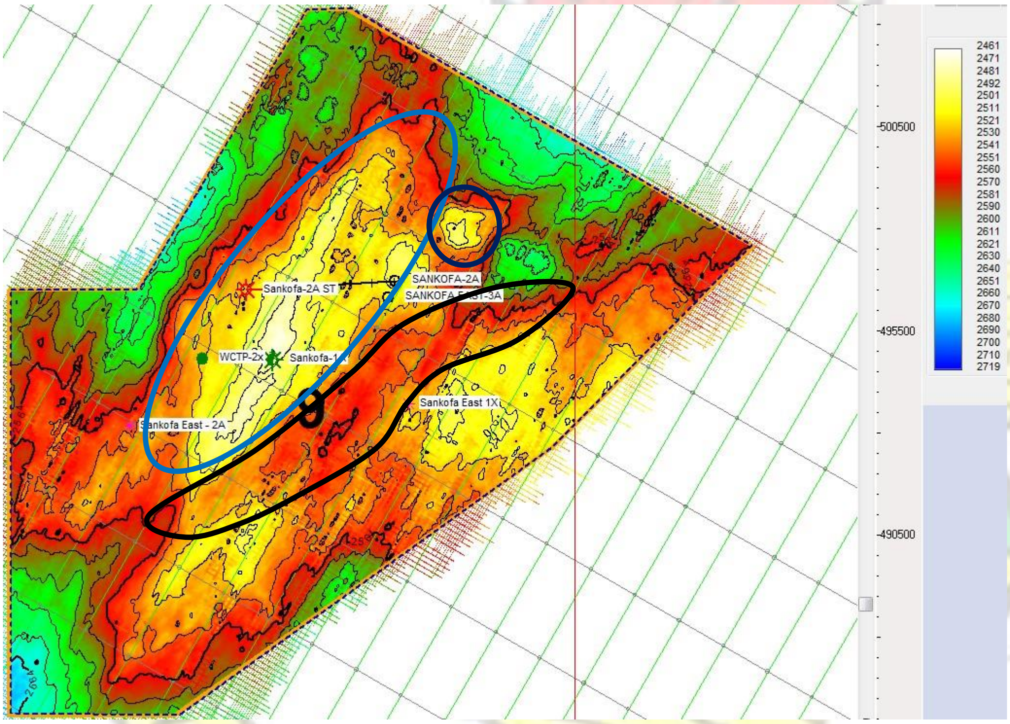

Figure 4.19: Contour map of Silicon reservoir

4.5.4 INTERPRETATION OF CONTOUR MAP

The contour map of the area as shown in figure 4.19 reveals the presence of four-way closures that could indicate the presence of a stratigraphic trap within the reservoir zone. It also reveals a canyon fill depositional body. A possible explanation for the presence of an isolated reservoir is the separation through an erosional surface that is identifying two different depositional events with the canyon fill.

The silicon well was drilled in within a four-way closure. Sediments are trending north-east to south-west.

4.5.5 AMPLITUDE MAP OF RESERVOIR OF SILICON WELL

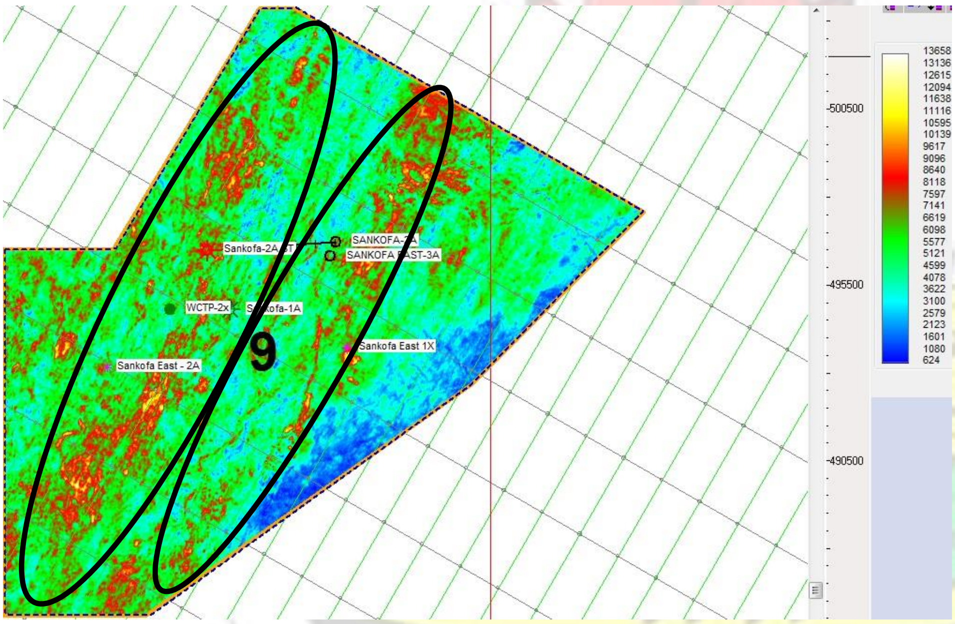

Figure 4.20: Amplitude map of reservoir for Silicon well.

4.5.6 INTERPRETATION OF AMPLITUDE MAP

- The reservoir zone as shown in figure 4.20 above is characterized generally by low amplitude response regime with isolated high amplitudes responses trending in welldefined canyon/channel axis as indicated by the black ovals in the map.
- These high amplitude responses could be an indication of the presence of reservoir sands.

4.5.7 PETROPHYSICAL ANALYSIS FOR SILICON WELL

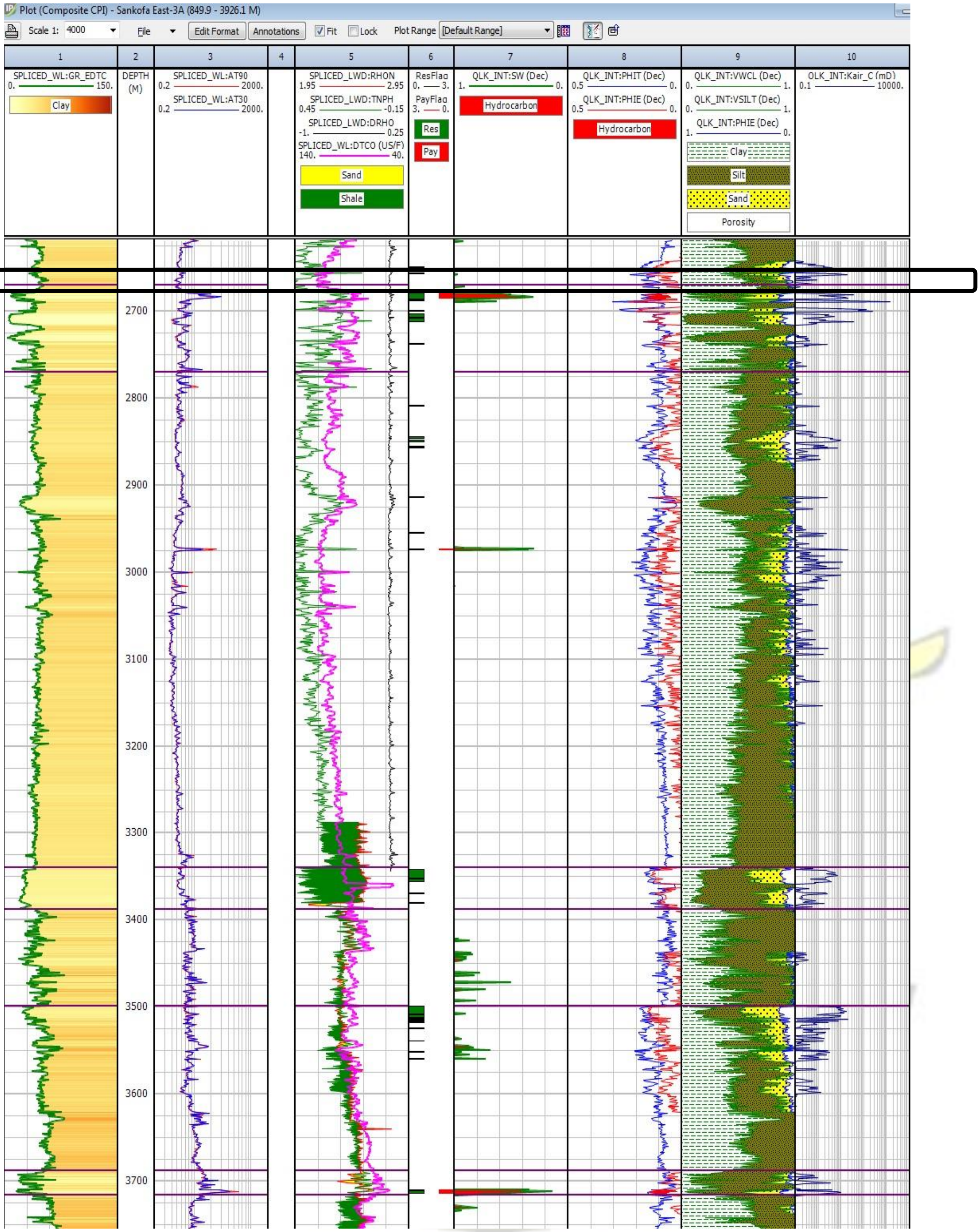

Figure 4.21: CPI of Silicon well showing SK9 reservoir

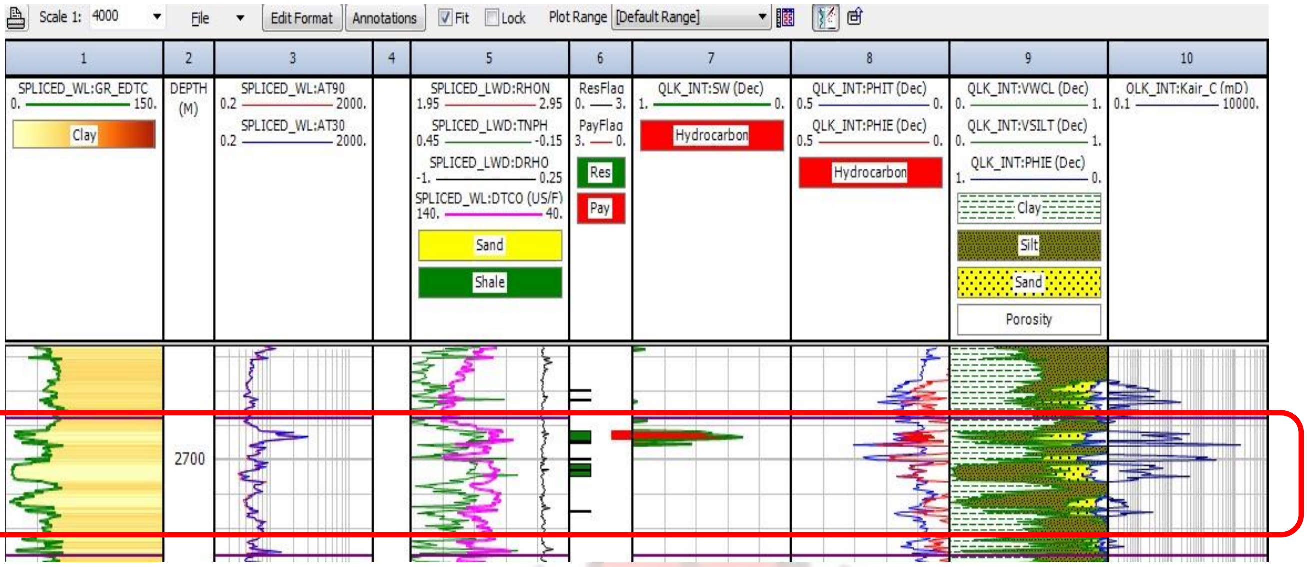

Figure 4.22: CPI for Reservoir zone of interest 4.5.8 INTERPRETATION OF PETROPHYSICAL FEATURES WITHIN THE

RESERVOIR

- The reservoir is characterized by a thin layer and poor petrophysical characteristics as indicated by the CPI in figure 4.22.
- The gamma ray log shows that the reservoir might be sandstone with interfingering of local shale. There could exist traces of hydrocarbon in the reservoir as the resistivity log has a sharp increase in the zone of interest. The reservoir has relatively low porosity and hence contains limited hydrocarbons.

Table 4.4: Petrophysical parameters of reservoir.

Reservoir thickness (m)	16.5
Net Pay (m)	1.7
Net/Gross ratio (%)	10
Porosity (%)	10
Water Saturation (%)	34

4.5.9 IMPLICATION OF PETROPHYSICAL PARAMETERS TO HYDROCARBON PRODUCTION

The reservoir exhibits low porosity but as well shows a relatively low water saturation and therefore may be an indication of a greater percentage of hydrocarbon saturation. Therefore interpreting from the porosity value, the reservoir is tight. Hydraulic fracturing may be employed to induce greater porosity into the reservoir to enable production to take place.

4.5.10 DEPOSITIONAL ENVIRONMENT

The gamma ray log as shown in figure 4.21 shows a serrated blocky shape and could suggest probably a tidal channel.

CHAPTER FIVE (5): CONCLUSIONS AND RECOMMENDATIONS

5.1 CONCLUSIONS

Reservoir characterization is the process of mapping a reservoir's thickness, net-to-gross ratio, pore fluid, porosity, permeability and water saturation. It also involves the construction of detailed 3D petrophysical property models contained within a geological framework.

Three wells were considered in this research; Leo, Silicon and Capitol wells, and three reservoirs successfully characterized.

As set out in the objectives of this research, the research is to measure the thickness of the various reservoirs under consideration, their net-to-gross ratio, porosity and water saturation using well logs and 3D seismic data.

The data available for this research include 3D seismic data and well log data comprising of resistivity log, sonic log, Gamma ray log, Neutron-Porosity log and Density logs.

In the attribute analysis, RMS amplitude was used in this research. RMS amplitude was extracted from the various horizons mapped in this research. The RMS amplitude extraction aided in discriminating the sand zones in the reservoir and delineating their depositional setting.

5.2 GYE NYAME DISCOVERY

The RMS amplitude extraction for the Gye Nyame revealed that the reservoir is lying in a fan system depositional setting with other minor channels running through it. The amplitude extraction further revealed in the research that the Leo 2 well drilled in the Gye Nyame discovery area was drilled into a mud filled old channel system and hence a dry hole since there were no charged reservoir sands present in the area. This was inferred from the high RMS amplitude values obtained in the reservoir zone.

The petrophysical features to be determined as set out in the objectives of the research were successfully achieved. The reservoir exhibited excellent petrophysical features which confirm the high amplitude exhibited in the RMS amplitude extraction for the area. The high amplitude shows the presence of sands in the reservoir.

The reservoir has a total thickness of 16.5 m and16.1 m of this total thickness is occupied by reservoir sands and that represents the net pay for the reservoir. The N/G ratio of 97.57% indicates that a greater proportion of the bulk volume of the rock is occupied by reservoir sands. The reservoir exhibits a low S_w value of 8%, which means it has a higher hydrocarbon saturation of 92%, since hydrocarbon saturation is represented by ($1-S_w$). The reservoir also shows an excellent porosity regime of 25.1%.

5.3 SANKOFA DISCOVERY

5.3.1 CAPITOL WELL

The RMS amplitude extraction for the reservoir in the capitol well reveals the reservoir is located in a channelized depositional setting with the occurrence of high amplitudes along these channels indicating the presence of sands.

The reservoir exhibited good petrophysical features which confirm the reservoir sands delineated through the RMS amplitude extraction.

The total reservoir thickness is 20.5 m and a net pay of 15.3 m, which represents the volume of rock which is occupied by reservoir sands. The N/G ratio for the reservoir is 75% which is a representation of the percentage of the bulk rock volume that is occupied by reservoir sands. The water saturation for the reservoir is 24% which represents the percentage of the void space occupied by water and therefore its hydrocarbon saturation is 76%, a representation of the void space occupied by hydrocarbons. The porosity for the reservoir is 24%.

5.3.2 SILICON WELL

The RMS amplitude extraction for the reservoir in the silicon well reveals the reservoir is located in an erosional surface located behind two thick lying areas, which forms the channel for the reservoir. There is the occurrence of relatively low amplitude in the reservoir zones.

The reservoir does not exhibit good petrophysical features which is in conformity with the low amplitude regime exhibited in the RMS amplitude map.

The total reservoir thickness is 16.5 m and only 1.7 m of that total thickness is occupied by reservoir sands, therefore the net pay for the reservoir is low. The N/G ratio of the reservoir is low due to the low net pay in the reservoir. The S_w of the reservoir is 34% and is relatively high and hence the hydrocarbon saturation of the reservoir would be low. The porosity of the reservoir is 10% which is relatively low and is therefore interpreted as being tight. Therefore, to produce from such a reservoir, hydraulic fracturing would need to be utilized to introduce greater porosity into the reservoir.

The combination of the seismic amplitude analysis and the petrophysical analysis leads me to make the following conclusions:

- The Offshore Cape Three Points (OCTP) block has a potential for hydrocarbon production
- The porosity for both the reservoir in the Leo 1 and Capitol wells are excellent for hydrocarbon production whiles that for silicon well exhibit a tight regime and may require special production techniques such as hydraulic fracturing to induced porosity into the reservoir
- The hydrocarbon net pay for the reservoirs in the Leo 1 and Capitol wells were between 14 m and 16 m, which is considered economically viable, whiles the net pay for the

reservoir in silicon well is 1.7 m which is considered to be not economically viable for production.

- RMS amplitude is an excellent attribute analytic tool for the indication of reservoir sands
- Hydrocarbon potential of the silicon well was not sufficient for economic viability.
- The objectives as set out in this research were achieved to a very large extend

5.4 RECOMMENDATIONS

The various petrophysical parameters computed for the reservoirs under consideration in this study were done by relying on only the well logs data, which can imposed various computational errors in the final results

Furthermore, interpretation for the depositional environment of the various reservoirs was done based solely on using the shape of the Gamma ray log signature, which can sometime lead to misleading results.

To therefore enhance the level of confidence in these results, I recommend the coring of the reservoir zones in these wells. These cores should therefore be subjected to further studies in the laboratory to measure the various petrophysical parameters computed in this study. This will enhance the confidence of E&P companies in the values obtained.

Furthermore, volumetric computation should be carried out on all the reservoirs to quantify the actual volume of hydrocarbon in place to ascertain the economic viability of each reservoir.

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