

**HIGH RESOLUTION OVERPRESSURE PREDICTION FROM SEISMIC VELOCITY  
AND FIELD DERIVED FORMATION PARAMETER IN THE ONSHORE NIGER  
DELTA.**

**CERTIFICATION**

UNIVERSITY OF NIGERIA, NSUKKA

SCHOOL OF GRADUATE STUDIES

HIGH RESOLUTION OVERPRESSURE PREDICTION FROM SEISMIC VELOCITY AND  
FIELD DERIVED FORMATION PARAMETER IN THE ONSHORE NIGER DELTA.

BY

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**APPROVAL PAGE**

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FIELD DERIVED FORMATION PARAMETER IN THE ONSHORE NIGER DELTA

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## **DEDICATION**

This research work is dedicated to God almighty and to the memory of my late father Elder V.O Odofin, who instill courage in me to always take bold step even when I have hidden fears.

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## ABSTRACT

Occurrence of overpressured formation is common in Tertiary basins (e.g. Niger Delta), which can result in geomechanical problems, such as “kicks”, loss of expensive drilling mud, blowout, stuck pipe, reservoir quality damage, wellbore instability etc. if it is not accurately predicted prior to drilling. This study did a critically re-evaluation of the two commonly utilized methods and practices involve in pore pressure work in the industry. The main aim was to accurately predict pore pressure ahead of drilling using seismic velocity. This involve analyzing ten offset wells to probing the overpressure origin, deriving a site specific Bower’s parameter, establishing a relationship between velocity and pressure using well data, and accurate velocity analysis for pore pressure prediction. The velocity – density crossplot for all the wells analyzed showed a compaction disequilibrium as the origin of the overpressure. The lithology log derived from GR showed a typical sand dominated Benin Formation to a depth of about 9,200ft (TVD) and beyond that depth a shale dominated Agbada Formation. The overburden gradient ranges from 0.78 psi/ft. to 0.96 psi/ft. contrary to 1.0 psi/ft. fixed gradient sometimes used. Bower’s parameter ( $A = 7.5$ ,  $B = 0.68$ ) were derived specifically for the field, instead of the regional parameters ( $A = 8$ ,  $B = 0.57$ ) in use. The velocity pressure relationship established using the offset well data gave a good match with the measured pressure data where it’s available, which affirms the reliability of using acoustic velocity for pore pressure prediction. The onset of overpressure (at 10,200ft) corresponds with the 15.0 maximum flooding surface (which hinders fluid expulsion), further confirms compaction disequilibrium as the origin of the overpressure. Bower’s method at the shallow section (for Kappa 39 ST 1) gave a pressure ranging from 0.54 psi/ft. to 0.66 psi/ft. which is far greater than the mud pressure of 0.52 psi/ft. to 0.53 psi/ft. that was used in drilling the well (i.e. overestimate pore pressure). Whereas Eaton’s method gave a range of 0.44 psi/ft. to 0.46 psi/ft. for the same depth interval, which evidence that the offset well was drilled overbalanced, and not underbalanced as suggested by Bower’s prediction at that shallow depth. Seismic velocity analysis for pore pressure prediction and calibration with well data results in a good match of predicted pressure from seismic data with measured pressure for the offset well, which strengthens the assurance that seismic velocity can be relied upon to give an accurate pore pressure estimate where log data are not available. A safe drilling mud window interval between predicted pressure and fracture pressure was established also. It is therefore important to suggest based on the result of this work that Eaton’s and Bowers’ methods should be integrated for any deep exploration well, such that, the result of Eaton’s method can be relied upon at shallow section, where Bowers method tend to overestimate pore pressure. The origin of overpressures at the deeper section of the Onshore Niger Delta is an unresolved question, which should be given a priority as more deep exploration wells are been drilled.

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## CHAPTER ONE

### 1.0 Introduction

Occurrence of formation fluid pressure above the pressure of a static column of water extending to the surface (termed overpressure) is a major concern in exploration and production of oil and gas. Pore pressure prediction has been a vital concern to the oil and gas industry for many decades. Most sedimentary basins exhibit overpressures (Fertl, 1976; Hunt, 1990), and as the industry explores for deeper targets, encountering high overpressures becomes more common. As deeper and more complex geology is drilled, the technical difficulties in predicting and safely drilling through overpressures have become more prominent and challenging as such, the need for accurate pre-drill geopressures prediction cannot be underestimated. Overpressure poses a major threat to the success of exploration and production of hydrocarbon in Niger Delta oil field since the discovery of the oil field. Rapid processes of deposition and sedimentation that builds up Tertiary basins have resulted into under-compaction at depths (Osborne and Swarbrick, 1998). It is commonly accepted that compaction results majorly due to vertical stress induced by deposition or tectonic activities (Burst, 1969; Danes 1982; Tissot 1984; Luo and Vansseur, 1996; Osborne and Swarbrick 1998; Hansom and Lee, 2005). Rapid burial rate gives sediments less time to dewater. Lithologically, fine grained sediments reduce the permeability thus impeding dewatering (Nwozor et.al, 2013). This fluid retention is most favoured by the presence of low permeability rocks such as shales, evaporites, and well cemented carbonates often referred to as seals. These seals prevent the escape of pore fluids at rates sufficient enough to compensate for the rate of increase in vertical stress induced by the overlying beds, and thus the pore fluid pressure begins to carry a large part of the load, and thereby increase the pore fluid pressure.

Pressure compartments are characterized by their distinct pressure regimes which affect the maturation, migration and trapping history of hydrocarbons (Hunt, 1990). An understanding of the rock/fluid characteristics of the subsurface formation is of critical importance in the evolution of oil and gas fields. During the exploration phase, pore pressure prediction for example helps in studying the hydrocarbon trap seals, mapping of hydrocarbon migration pathways, analyzing trap configurations and basin geometry and providing calibrations for basin modeling. While during production, pressure information is essential in planning field depletion, especially in compartmentalized fields. Pre-drill pore pressure prediction allows for appropriate mud weight to be selected and drill casing to be optimized, thereby enabling safe and economic subsurface drilling. Drilling success, safety and reservoir depletion history are all affected by the presence of overpressure strata. A good estimate of pore pressure can help to prevent “kicks” loss of drilling mud (hydraulic fracturing), blowouts (e.g. Macondo blowout 2010), wellbore instability problems due to shear failure, as well as, save lives and money.

Knowledge of pore pressure implies knowledge of the effective stress, which is a key input for several geomechanics application, such as fault slip and fault seal analysis and reservoir compaction studies. It is also a required input for 3D and 4D seismic reservoir characterization. Because, the seismic response of shales and sand depends on their compaction history, the effective stress in turn controls the sedimentary seismic response. This is in contrast to normally pressured regimes, where the depth below mudline (or overburden stress) is typically used to characterize the compaction effect. Moreover, with advances in technology, emphasis is put on a better prediction of overpressure in order for exploration and production work to be carried out in wells that have been termed no go area at a time because of unforeseen pressure encountered there. Abnormal pore pressures, particularly overpressures, can greatly increase drilling non-

productive time (NPT) and cause serious drilling incidents if the abnormal pressures are not accurately predicted before drilling and while drilling. The result of a recent operator study shown in figure 1 cited 44% of their non-productive time was associated with formation pressure related issues leading to geopressures and wellbore instability related delays in well construction (Halliburton Drillworks Geomechanics). This unscheduled events result when annular pressures stray from inside the safe operating envelope defined by shear failure pressure, pore pressure and fracture pressure. The annular pressure must be constrained inside this “safe” envelope if this time consuming events are to be minimized or avoided.

Abnormally high pore pressures not only caused the kicks and blowouts, but also induced geologic disasters, such as mud volcano eruptions (Tingay et al., 2009) and weakness in faults (Tobin and Saffer, 2009).

The Nigerian oil and gas industry is presently faced with the challenged of achieving the national crude oil reserves target of 40 billion barrels and production of increased volumes of Liquefied Natural Gas (LNG) in order to meet export and domestic needs. The strategic growth plan therefore requires finding and producing from new reserves. And, finding and producing new hydrocarbon reserves involves contending with increasingly harsh downhole conditions i.e. drilling more exploratory wells in deeper and more challenging geologic settings.

There are numbers of methods which are available for pore pressure prediction ahead of drill bit using seismic data, but the focus of this work will be on methods commonly used in the oil industry. Eaton (1968) relates formation pressure to effective stress and total vertical stress. This requires establishing a porosity compaction trend and compare the observe measurement with what is expected if the formation have been compacted normally. Bower’s uses the sonic

velocity and empirically determined parameters to determine the vertical effective stress, which is subtracted from the total vertical stress to determine the pore pressure. He derived also, an empirical relationship that can be applied at intervals where disequilibrium compaction is not the only mechanism responsible for overpressures. However, despite all the advances in pore pressure prediction, non-productive drilling time associated with pore pressure have not been resolved. This calls for a critical re-evaluation of the current methods. It is also important to note that better understanding of the relationship between geological processes and overpressure development is essential for accurate pore fluid prediction, therefore, a quick prognosis into the origin of overpressure will be undertaken.

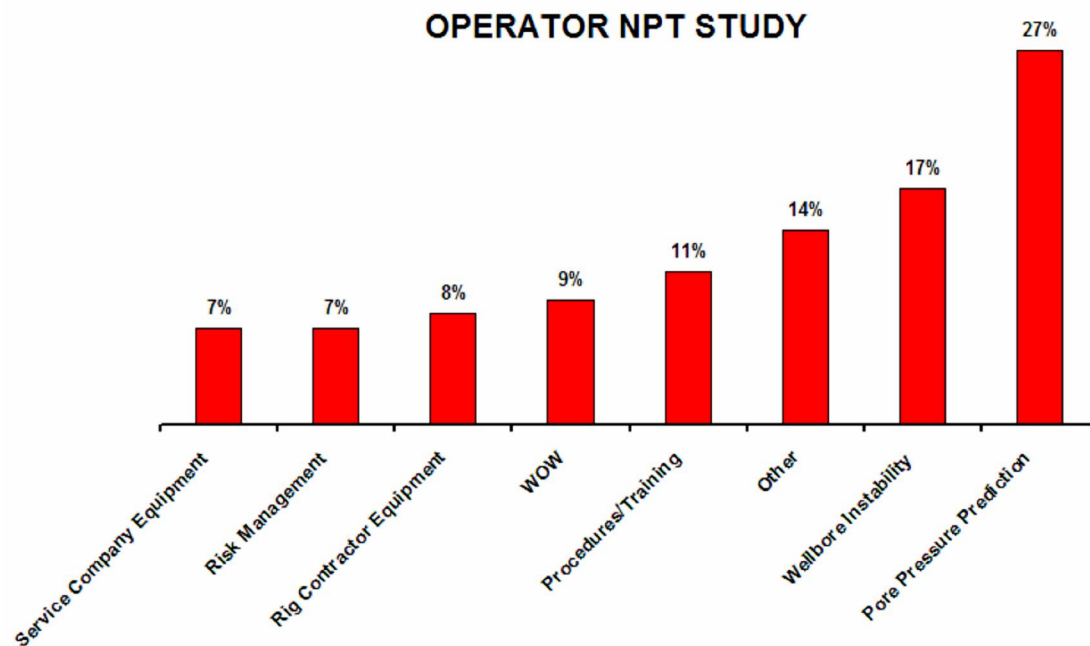


Fig. 1: Showing the result of operator non i productive time study (William and Gemma, 2013).

## **1.1 Problem Statement**

Despite the advances and widespread campaign for accurate pore pressure prediction, 44% of drilling non-productive time have been attributed to annular pressures leading to geopressure incidents (kicks, stuck pipe, hydraulic fracturing, loss of expensive drilling mud etc.). This high drilling nonproductive time calls for a critical re-evaluation of the methods and practices involved in predicting geopressures.

## **1.2 Justification**

The success of this work will ensure efficient service delivery by maximizing drilling time, allowing appropriate mud weight to be selected, thereby ensuring safe and cost effective drilling, and as well reduce the risk of drilling fail wells.

Availability of data and work station for this study is also another justification for embarking on this research work.

## **1.3 Project Aim and Objectives**

This is to do a critical re-evaluation of the two current methods (Eatons and Bowers), commonly use in the oil and gas industry for accurate pore pressure prediction ahead of drilling bit using seismic data. The objectives shall include:

- 1) To probe the mechanism resulting into the high overpressures.
- 2) Derive a relationship between velocities and pore pressure applying Eaton's and Bowers's method, using offset well data, calibrating it with measured pressure.
- 3) Derive site specific velocity - pressure transform parameters for Bowers method.

- 4) Seismic velocity analysis for pore pressure prediction (Picking of VACKS)
- 5) Seismic velocity calibration with well data
- 6) Pore pressure/Fracture pressure prediction
- 7) Estimate safe mud weight window/casing point selection.

## **1.4 Scope of Work**

This shall include probing the origin of overpressures and establishing a relationship between velocity and pressure (applying Eaton and Bower's) using offset well data, and applying it over a seismically derived velocity to predict formation pressure for a proposed high pressure/high temperature (HPHT) deep exploration well.

### **1.5.1 Impact of overpressure on drilling**

The presence of overpressured formation fluids in sediments affects the drilling of wells in three significant ways (as shown in fig. 2):

1. When a borehole is drilled into a permeable formation that is overpressured, the pressure exerted by the mud in the borehole must be increased to at least balance the pressure in the aquifer and prevent influx of formation fluid into the borehole (kicks). If the pore pressure increases unexpectedly and at a fast rate or too high to be shut in at the well head, a "blowout" will result as formation fluid escapes uncontrollably to the surface.
2. Drilling into a permeable aquifer at greater depth, with a greater formation pressure than the pressure required to fracture sediments shallower in the borehole can result in losses of drilling mud. If not quickly controlled, this situation can result in the rapid movement of considerable volumes of formation fluid into the shallower formation, referred to as an "internal

blowout. To avoid this situation, the weaker, shallow sediments have to be isolated from the higher pressure sediments by the setting of casing.

3. When a well is drilled through low permeability sediments that are overpressured, the mudweight in the borehole will generally have to be increased to prevent influx of sediment and gas held in solution into the borehole.

It is not possible however, to simply increase the mudweight in the borehole unguided, in order to cover for the possibility that overpressured sediments will be encountered. Drilling through sediments with mudweights that are in excess of the formation pressures (drilling overbalanced) has its own consequences:

1. Drilling overbalanced is, in general, slower and therefore more costly than using the correct mudweight.

2. Drilling permeable units with mudweights that are too high will fracture the formation, and invariably result in the loss of costly drilling fluid into the formation. The injection of drilling mud into the formation can significantly reduce the permeability of the aquifer units, extremely important if they happen to be the productive reservoirs of a hydrocarbon accumulation.

3. Drilling with mudweights that are too high can fracture the formation and result in fluid losses. Setting casing shallower than expected to control the losses may prevent the well from reaching its target depth, knowing the pressure and planning the casing settings is critical to the success of the operation. All of the consequences of drilling wells with pressures that are too high or too low have significant safety and cost implications. Any study, therefore, that aids the detection of the origin, distribution and magnitude of overpressure will aid the planning and drilling of wells.

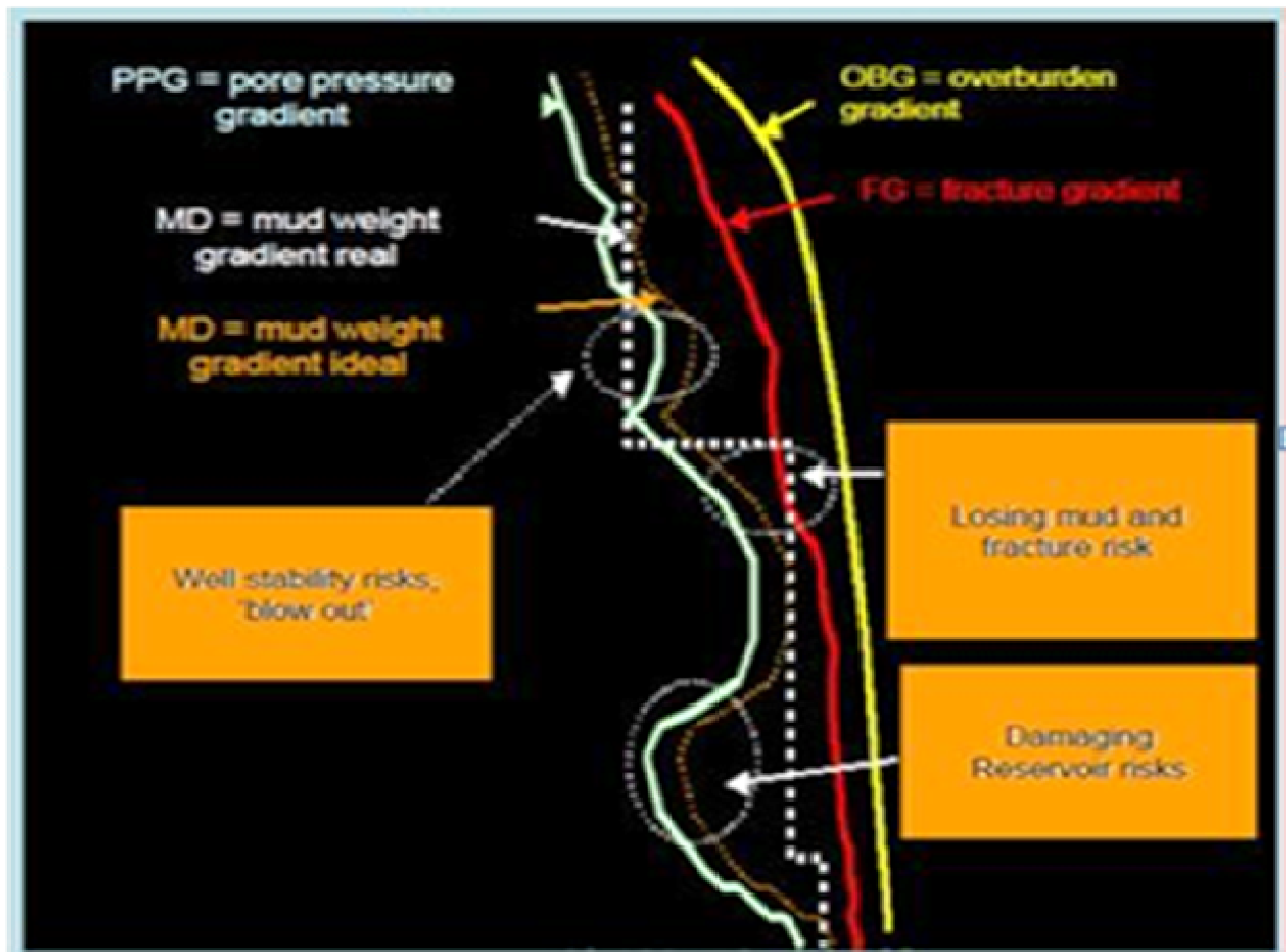


Fig. 2: Showing the danger of drilling with inappropriate mud weight pressure (Source: Bowers 1995).

### **1.5.2 Impact of overpressure on petroleum systems.**

When a hydrocarbon accumulation is proposed, the prospective accumulation has to be assessed in terms of hydrocarbon migration and the sealing potential of the formations that surround the hydrocarbon reservoir.

Understanding the origin, magnitude and distribution of overpressure will indicate the potential directions of fluid flow in the subsurface and allow the validity of possible migration pathways to be tested.

The amount of overpressure present in the subsurface will strongly influence the sealing capacity of the formations/faults that trap the hydrocarbons. If the pore pressures exceed the fracture pressure of the sealing lithology or to open the fault then hydrocarbons may be able to escape from the structure (Harrold et. al. 1999). It is important, therefore, to assess the origin and magnitude of the overpressures relative to the strength of the sealing units prior to drilling. This is the reason for absence of hydrocarbons in high overpressure reservoirs (Law and Spencer, 1998).

## **1.6 Regional Geology of Niger Delta.**

The Niger Delta, situated at the northeastern margin (apex) of the Gulf of Guinea on the west coast of Africa, is one of the most prolific hydrocarbon provinces in the world. The sedimentary basin fill occupies a total area of about 75 000 km<sup>2</sup> and is composed of an overall of upward-coarsening regressive clastic sequence which reaches a maximum thickness of 30,000 to 40,000ft (9,000 to 12, 000km). Estimate of ultimately recoverable hydrocarbon for the entire Niger delta are about 22.5 billion bbl of oil, 770 million of condensate, and 124 TCFG. The Niger delta provinces ranked the twelfth richest in petroleum resources, with 2.2% of the world's discovered

oil and 1.4% of the world's discovered gas. (Petroconsultants, Inc.1996a). The geology of the tertiary Niger Delta province has been described by several workers (Short and Stauble, 1967; Weber, 1971; Weber and Daukoru, 1975; Evamy et al., 1978). The onshore portion of the Niger Delta Province is delineated by the geology of southern Nigeria and southwestern Cameroon. The northern boundary is the Benin flank – an east-northeast trending hinge line south of the West Africa basement massif. The northeastern boundary is defined by outcrops of the Cretaceous on the Abakaliki High and further East-south-east by the Calabar flank- a hinge line bordering the adjacent Precambrian. The offshore boundary of the Dahomey basin (the easternmost West African transform-fault passive margin) to the west, and the two-kilometer sediment thickness contour or the 4000-meter bathymetric contour in areas where sediment thickness is greater than two kilometers to the south and southwest. Basement tectonics related to crucial divergence and translation during the late Jurassic and Cretaceous continental rifting probably determined the original site of the main rivers that controlled the early development of the Delta. The Cenozoic development of the delta is also believed to have taken place under approximate isostatic equilibrium. The main depocenter is thought to have been at the triple junction between the continental and oceanic crust where the delta reached a main zone of crustal instability.

Following a major marine transgression in the Paleocene, the paleo-Niger delta started to prograde the southwest into the equatorial Atlantic Ocean. This sediment build-up was accompanied by growth fault tectonics normal to direction of progradation which resulted in a series of seven parallel fault-bounded depositional belts (depobelts). These depobelts form one of the largest regressive deltas in the world with an area of some 300,000 km<sup>2</sup> (Kulke, 1995) and a sediment volume of 500, 000 km<sup>3</sup> (Hospers, 1965). The depobelts show the same stratigraphic sequences that consist of three thick rock units, which from the shallowest to the deepest are:

- a) Northern Delta depobelt
- b) Greater Ugheli depo belt
- c) Central Swamp depobelt
- d) Costal Swamp depobelt
- e) Offshore depobelt

Deposition of three formations occurred in each of the five offlapping siliciclastic sedimentation cycles that comprise the Niger Delta. Benin, Agbada, and Akata formations are time-equivalent, prograding facies unit of the sequence and ranges in age from early tertiary to recent. A separate member, the Afam clay member, of the Benin formation is recognized in the eastern part of the delta and is considered as an ancient valley fill formed in Miocene sediments. The formations are strongly diachronous and cut across the time stratigraphic units which are characteristically S-shaped in cross-section. Most economically exploitable hydrocarbon in the delta is believed to be trapped within the Agbada formation.

Structurally, the Niger Delta shelf developed as a prograding extensional complex overlying a ductile substrate which probably composed largely of over pressure marine shales. The onshore growth fault systems have been described by Doust and Omatsola (1990) as a series of major growth fault bounded depobelts or mega-structures thought to be transient basinal areas succeeding one another in space and time as the delta progrades southward. The extensional system is dominated by a stepped structure in which landward-dipping growth faults intersect seaward-dipping in complex interlocking fault networks. The most striking structural features of the Cenozoic Niger Delta complex are the syn-sedimentary structures which deform the delta largely beneath the Benin sand facies. These structures, regarded as the product of gravity sliding

during the course of deltaic sedimentation, are polygenic in origin and their complexity increases generally in down delta direction (Merki, 1972). The syn-sedimentary structures, called growth faults, are predominantly trending northeast to southwest and northwest to southeast (Hosper, 1971). Associated with these growth faults are rollover anticlines, shale ridges and shale diapirs which are caused by shale upheaval ridges. Mud diapirs are the most common and occur on the landward side of the growth faults restricting sedimentation on the up-thrown side of the faults and enhancing sedimentation on the down-thrown side. Most of the faults are listric normal; others include structure-building growth faults, crestal faults, flank faults, counter regional faults and antithetic faults.

In general, the offshore Niger Delta has the characteristic shelf slope break of growth fault modified ramp margins. Trap configuration in the offshore Niger Delta is controlled by gravity driven systems of linked extensional growth faults and compressional toe thrusts initiated during the Paleocene when the modern Niger Delta was formed (Ejedawe, 1981). The present day shelf is dominated by long counter regional faults. Further offshore, there exist a back-to-back fault trend along the shelf edge and upper slope. Down the slope, there are examples gentle folds, with thrust and diapirs sometimes cutting the sea bed.

Oil and gas are predominantly trapped by roll over anticlines and fault closures. Stratigraphic traps of palaeo-channel fills, regional sand pinch-outs and truncations, crustal accumulations below unconformity surfaces, cayon-fill accumulations above unconformity surfaces, incised valley and low-stand fans have been recognized (Avbovbo, 1978; Kruise and Idiagbor, 1994). Petroleum occurs throughout the Agbada Formation of the Niger Delta, however, several directional trends forms an oil-rich belt having the largest field and lowest gas:oil ratio (Ejedawe, 1981; Evamy and other; 1978; Doust and Omatsola, 1990). The belt extends from the

northwest offshore area to the southeast offshore and along a number of north-south trends in the area of Port Harcourt. It roughly corresponds to the transition between continental and oceanic crust, and is within the axis of maximum sedimentary thickness. This hydrocarbon distribution was originally attributed to timing of trap formation relative to petroleum migration. Trap configuration in the deep water Nigeria is controlled by gravity driven system of linked extensional growth faults and compressional toe thrusts initiated during the Paleogene, when the modern Niger delta was formed (Haack et al., 2000). Evamy and others (1978), however, showed that in many rollovers, movement on the structure-building fault and resulting growth continued and was relayed progressively southward into the younger part of the section by successive crestal faults, concluding that there was no relation between growth along a fault and distribution of petroleum. Ejedawe (1981) relates the position of the oil-rich areas within the belt to five delta lobes fed by four different rivers. He states that the two controlling factors are an increase in geothermal gradient relative to the minimum gradient in the delta center and the generally greater age of the sediments within the belt the highest maturity per unit depth. Weber (1987) indicates that the oil oil-rich belt coincides with a concentration of rollover structures across depobelts having short southern flanks and little paralic sequences to the south. Doust and Omatsola (1990) suggest the distribution of petroleum is likely related to heterogeneity of source rock type and/or segregation due to remigration.

Most of the reservoir facies in the offshore Niger Delta are related to an aggrading lowstand complex where a slow relative rise in the sea levels allows sediment input to keep pace with the creation of accommodation space over a long period of time. A thick expanding edge of coarse clastics is trapped on the shelf behind the counter regional faults and most of the sediments are therefore, deposited on the shelf, indicating that the sand content and gross sediment input

reduces dramatically with increasing distance from provenance. Much of the section of the delta shelf consists of alternating stacked cycles of low-stands slope fan and low-stand prograding wedge deposits. Good reservoir sand units may occur in either of the two main low-stand system tracts.

Hosper (1971) suggested that the Niger Delta area in Nigeria has a clay/shale base of considerable thickness. It is well known that overpressures are encountered in the delta area and have been attributed to the high rate of sedimentation responsible for the building of the basin as well as hydrocarbon. The organic rich marine shale Akata Formation and the shale interbedded with paralic sandstones lower Agbada formation (source rocks for the Niger Delta oils) have been termed high risk zone due to overpressures.

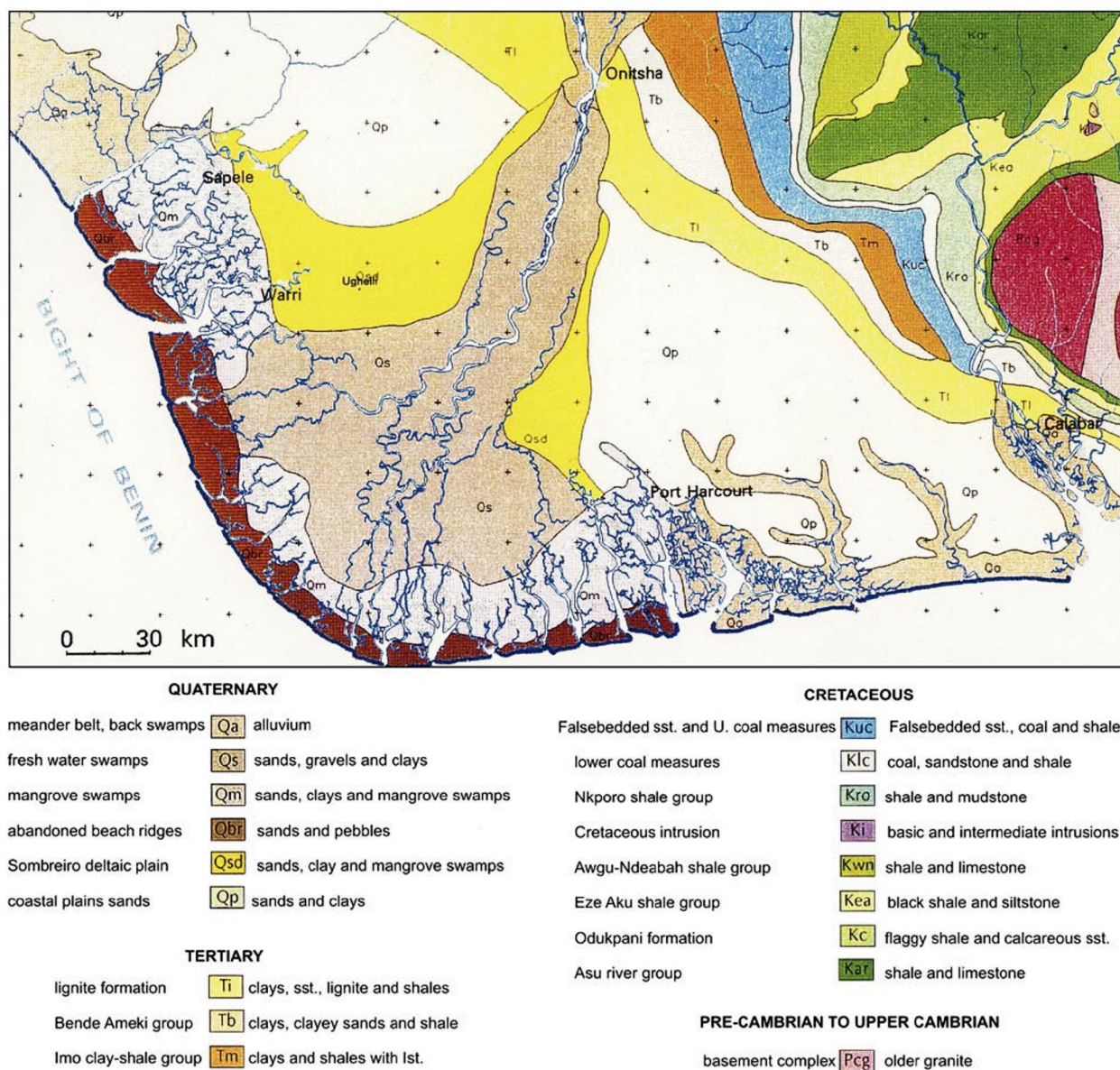


Fig. 3: Geological map of the Niger Delta and surroundings. Source: Avbovbo (1978).

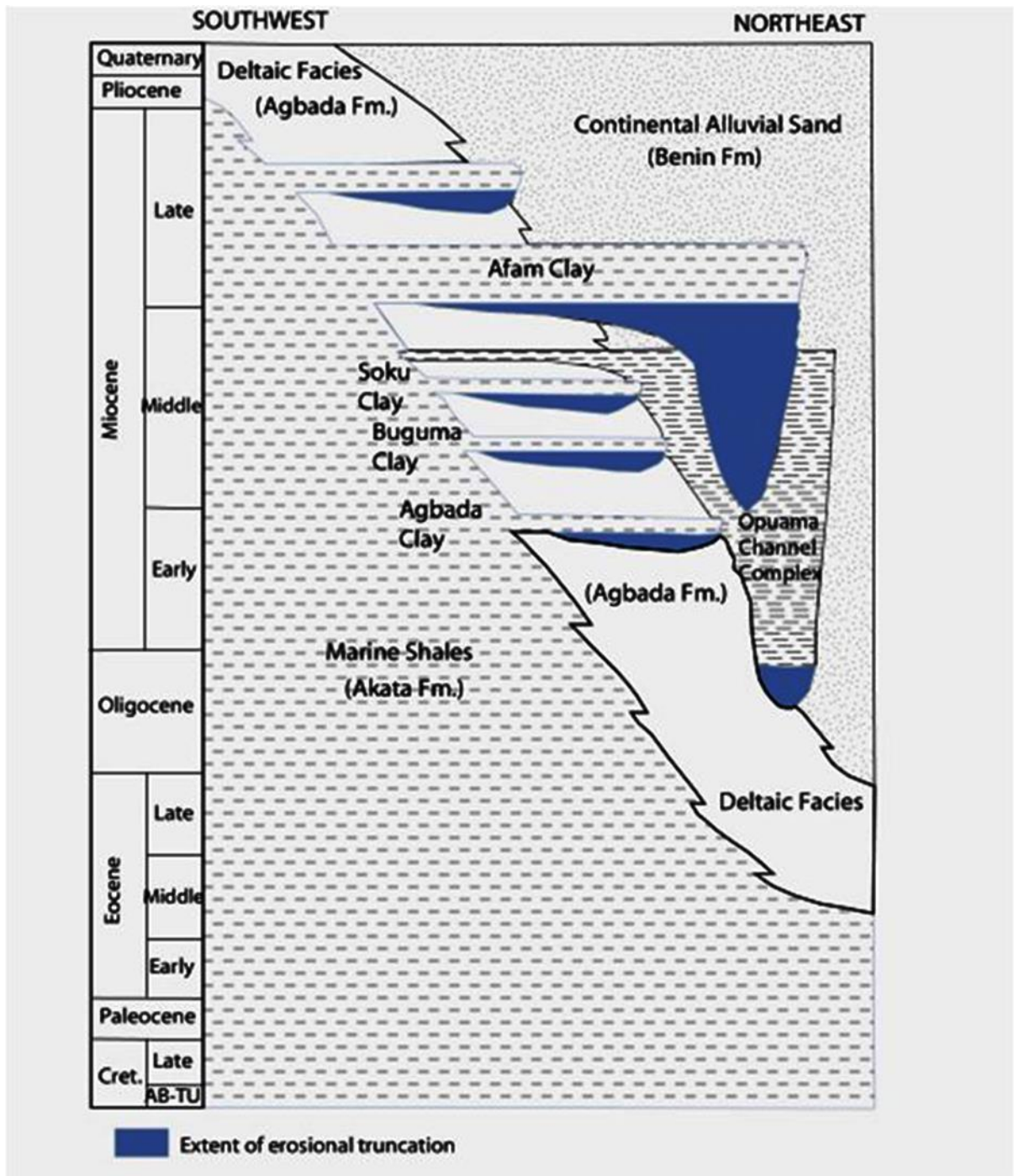


Fig. 4: Stratigraphic column showing the three Formations of the Niger Delta, the continental Benin Sandstone, the paralic Agbada Formation and the Marine Akata shale. Source: Doust and Omatsola (1990).

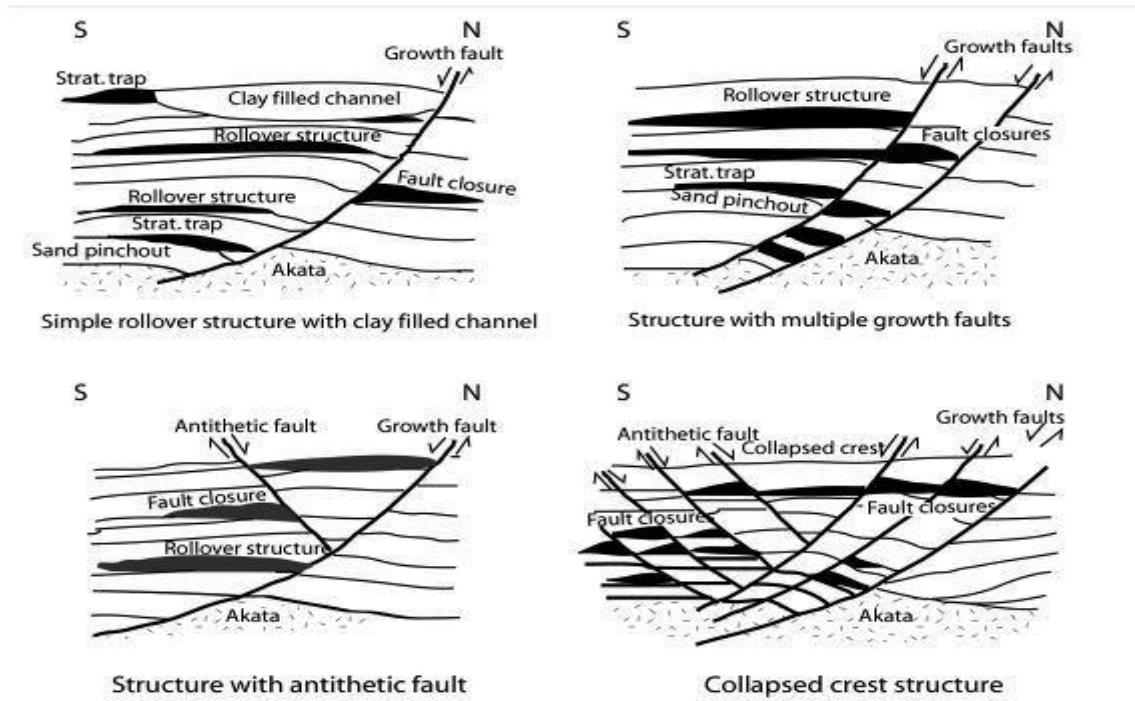


Fig. 5: Example of Niger Delta oil field structures and associated trap types. Modified from Dust and Omatsola (1990) and Stacher (1995).

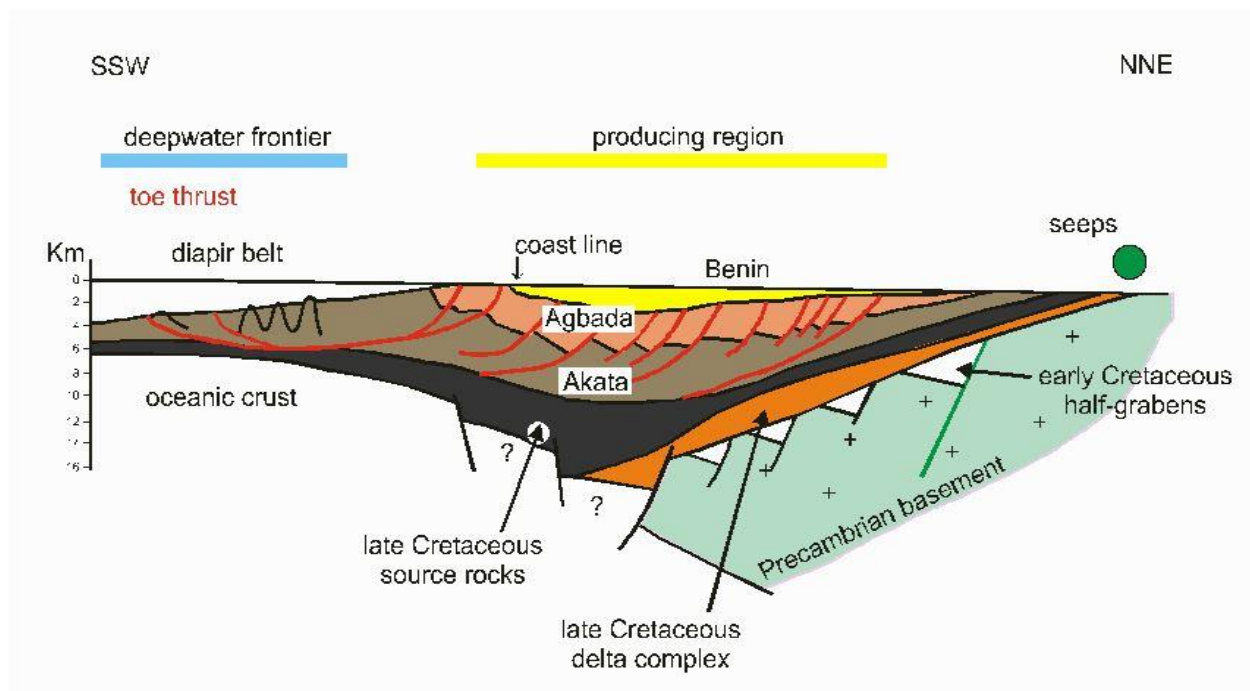


Fig. 6: Averaged cross-section through the Niger Delta (derived from Thomas, 1995).

## 1.7 Study Area/Data Set

Kappa field is part OML 28 (110 Km off Port Harcourt), located in Central Swamp Onshore Niger Delta basin with high net-to-gross ratio. Kappa field was discovered in 1961. A total of forty six (46) wells have been drilled to date, cutting across eleven (11) reservoir of interest. Hydrocarbon type is oil and gas as well as non-associate gas (NAG). Kappa deep IX well was aimed at investigating 1000ft of untested stratigraphic section containing three objective intervals, making it a better choice for this kind of research.

The data for this work were obtained from Shell Petroleum Development Company (SPDC) during my one year of research internship.

For this study, a total of eleven wells were used for this pressure analysis, (which is located in the immediate environment of the proposed HPHT deep IX well). Data for each of the wells comprises:

1. Wireline log (.las Format). For all the wells, caliper, gamma ray, sonic, density, neutron and resistivity logs were available.
2. Measured pressure data from the permeable aquifers (RCI), Leak off test (LOT), and mudweights available for the work.
3. Directional survey of the wells.
4. Maps and literatures on pore pressure prediction.

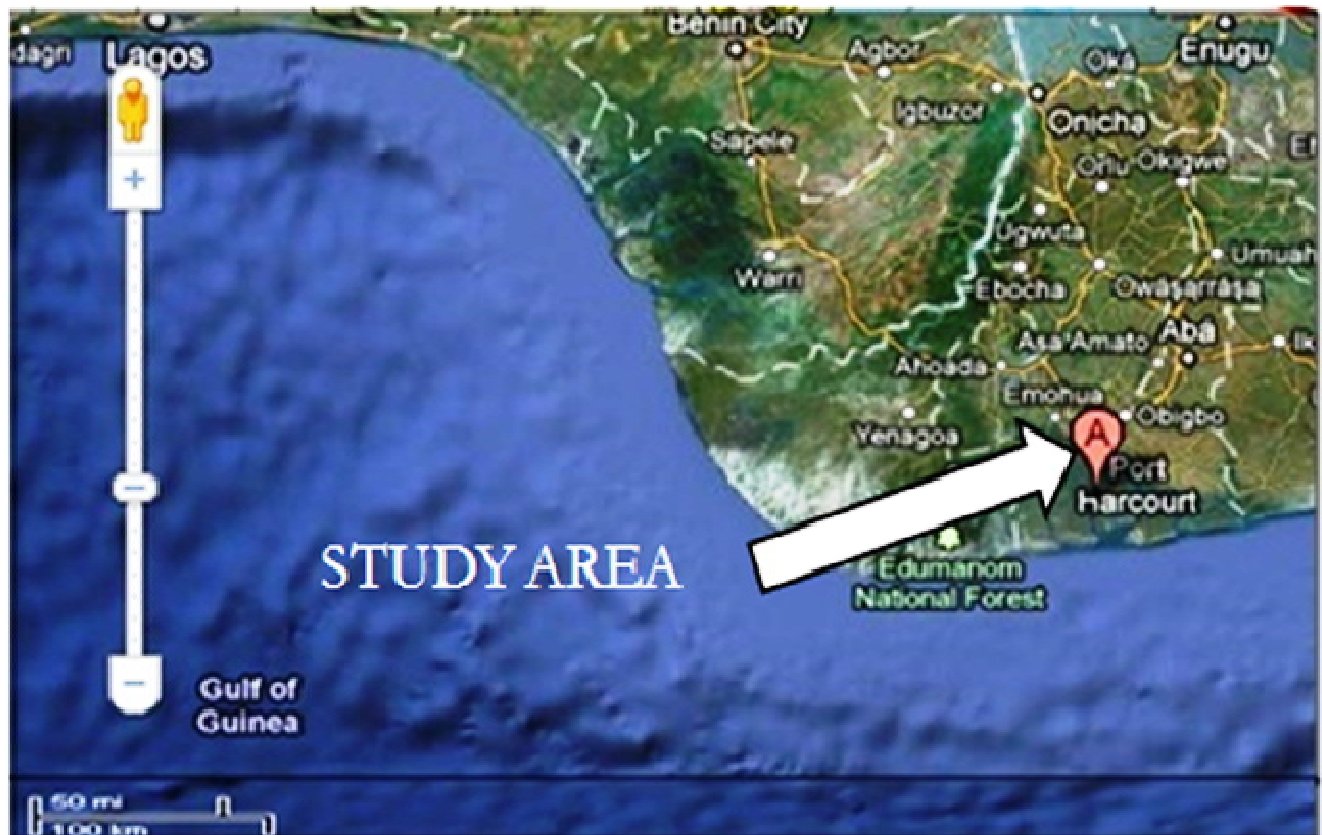


Fig. 7: Outline Map of the Study Area (Modified from Google Earth 2011).

Table 1: Showing the list of wireline logs used for the research ( Well names coloured green have complete log set required for pore pressure prediction, while those coloured amber have incomplete log set).

| Well         | GR | SONIC | RESIS | DEN | NEU | CAL | MPP | CHECKSHOT |
|--------------|----|-------|-------|-----|-----|-----|-----|-----------|
| Kappa 28     | Y  | N     | Y     | N   | N   | Y   | Y   | Y         |
| Kappa 29     | Y  | N     | Y     | Y   | Y   | Y   | Y   | N         |
| Kappa 30     | Y  | N     | Y     | Y   | N   | Y   | Y   | N         |
| Kappa 31     | Y  | N     | Y     | Y   | Y   | Y   | Y   | Y         |
| Kappa 33     | Y  | N     | Y     | Y   | N   | Y   | Y   | N         |
| Kappa 34     | Y  | Y     | Y     | Y   | Y   | Y   | Y   | Y         |
| Kappa 35     | Y  | N     | Y     | Y   | Y   | Y   | N   | Y         |
| Kappa 36     | Y  | N     | Y     | Y   | Y   | Y   | Y   | N         |
| Kappa 39 ST1 | Y  | Y     | Y     | Y   | Y   | Y   | Y   | Y         |
| Kappa 39 ST2 | Y  | Y     | Y     | Y   | Y   | Y   | Y   | Y         |
| Kappa 42     | Y  | Y     | Y     | Y   | Y   | Y   | Y   | Y         |

## **1.8 Worldwide Example of Overpressure**

Many of the world basins contain overpressured reservoirs; Hunt (1990) cites a total of 180 basins, including basins from Americas, Africa, Europe, Middle East, Far East, and Australia, where overpressure has been recognized (fig 14 and 15). Overpressured sediments are found in the subsurface of both young basins from about 1.0 to 2.0 km downwards, and in older basins, in thick sections of fine-grained sediments. The age of rocks in which overpressures has been recognized varies from Pliocene to Cambrian. Overpressure is found in carbonate and clastic reservoirs, and in rocks deposited in the full range of sedimentary environments. Hydrocarbons are often associated with overpressures, because the same process responsible for the generation, expulsion, migration, and entrapment of hydrocarbon have been found to be responsible for overpressure generation, but there does not seem to be a universal relationship between overpressure and hydrocarbon traps (Swarbrick and Osborne 1998, Law and Spencer 1998). Disequilibrium compaction has been generally accepted as the primary mechanism of overpressure generation in Tertiary basins, with unloading mechanism adding to it at greater depth.

## **1.9 Overpressures in Niger Delta**

Overpressure have been discovered early in the history of exploration in Niger Delta, where the depth of exploration wells were determined more or less by the occurrence of first kicks in such wells. It was believed that, the occurrence of first kicks marks the onset of overpressure and hence the termination of drilling. This practice lasted for a long period before the adoption of controlled drilling approach, in which with precautionary increases in mud weight, target depths were often achieved with many of such wells erroneously classified as non-overpressure on the

basis that no kicks were experienced (Nwozor et al. 2013). Based on kick data and reversal in logs, early studies in the basin develop a series of pressure graphs and rudimentary maps aimed at delineating the onset of overpressure and their distribution in the basin as they believed that, undercompaction was the cause of overpressure in Niger Delta.

It has been observed that the onset of overpressures varied widely between 4494 ft (1370m) tvdss to 14006 ft (4270m) tvdss with a very diffuse trend in spatial distribution, thus making isobar maps irrelevant in pore pressure prediction (Nwozor et al. 2013). Anowai et al. postulated that the top of overpressure is relatively shallower in the Northern and Greater Ugheli Depobelts when compared with the Central Swamp Depobelt and other near-to-offshore fault-bounded megastructures. This follows from recommendations in Krusi which took a more quantitative approach by investigating the relationship between the top of overpressures with both shaliness and rate of subsidence and noted a pattern of pressure increases where net-to-gross ratio drops below 35% -20% in proximity with discontinuous or detached reservoirs such as beach and channel sands. This was perceived as resulting from restriction to normal dewatering/expulsion of fluid of the compacting sediments that result in pore fluid being trapped and thus bearing part of the overburden weight.

Until recent time, undercompaction has been taken as the mechanism responsible for overpressure generation in Niger Delta. Nwozor et al. in their work suggest an evidence of secondary mechanism of overpressure generation following Bowers velocity ÷ effective stress crossplot. This approach does not give detailed account about the mechanism resulting into the overpressures. But this current study applies Hoesni's method which uses velocity ÷ density crossplot as a basis for determining the mechanism that results to the overpressures.

## CHAPTER TWO

### 2.0 REVIEW OF PREVIOUS WORKS

The fundamental theory for pore pressure prediction is based on Karl Terzaghi's and Biot's effective stress law (Biot, 1941; Terzaghi 1943; Terzaghi et al. 1996). This theory indicates that pore pressure in the formation is a function of total stress (or overburden stress) and effective stress. The effective stress and pore pressure in vertical direction in one dimensional condition can be expressed as following (Biot, 1941):

$$\sigma_e = S_v - \alpha p$$

Where:

**P** = pore pressure

$\sigma_e$  = the vertical effective stress

$S_v$  = the overburden or vertical stress

$\alpha$  is the Biot's effective stress coefficient (conventionally assumed to be equal to 1 in geopressure community). Therefore the equation is commonly expressed as:

$$\sigma_e = S_v - p$$

Pore pressure study dated as far back as 1965; when **Hottmann and Johnson** used shale properties derived from well log data from Upper Texas and southern Louisiana Gulf Coast (i.e. acoustic travel time/velocity and resistivity) to establish that, porosity decreases with depth. This trend represents the normal compaction trend, and a deviation from this trend is due to abnormal

pressure at that depth. Based on the Hottmann and Johnson (1965), Gardner et al. (1974) came up with an equation for pore pressure prediction.

$$P = S_v - (\alpha_v - \beta)(A_1 - B_1 \ln \Delta t)^3 / Z^2$$

Where P is the formation fluid pressure;  $S_v$  is the overburden stress;  $\check{U}_v$  is the normal overburden stress gradient;  $b$  is the normal fluid pressure gradient; Z is the depth;  $q_t$  is the compressional sonic transit time;  $A_1$  and  $B_1$  are the constants,  $A_1 = 82776$  and  $B_1 = 15695$ .

The compressional transit time is the inverse of the compressional interval velocity and can be expressed in the following form:

$$V_p = \frac{10^5}{\Delta t}$$

Where  $v_p$  is the compressional interval velocity in ft/s;  $q_t$  is the compressional transit time in  $\epsilon$ s/ft.

### 2.1.1 Eaton (1972, 1975)

Eaton estimates pore pressure by relating effective stress with the effective stress of a normally compacted formation, velocity of a normally compacted formation and the measured velocity.

$$\bar{\sigma}_v = \sigma_{vn} \left( \frac{V}{V_n} \right)^3$$

Where:

$\bar{\sigma}$  = Effective stress,  $\sigma_n$  = effective stress of a normally compacted formation,  $V_n$  = velocity of a normally compacted formation and  $V$  = observed velocity. From this equation, he derived an expression for pore pressure gradient in young Sedimentary basins (where under-compaction is the major cause of overpressure e.g. the Gulf of Mexico, the Gulf of Guinea etc.) from sonic compressional transit time as well as resistivity log using Terzaghi's equation.

$$P_p = P_{ovb} - (P_{ovb} - P_n) \left( \frac{R}{R_n} \right)^n$$

$$P_p = S_v - (S_v - P_n) * \left( \frac{\Delta t_{norm}}{\Delta t_{obs}} \right)^3$$

$$P_p = S_v - (S_v - P_n) * \left( \frac{V_{p_{obs}}}{V_{p_{norm}}} \right)^3$$

Where  $P_p$  is the formation pore pressure gradient;  $P_{ovb}$  is the overburden stress gradient;  $P_n$  is the hydrostatic pore pressure gradient (normally 0.45 psi/ft or 1.03 MPa/km, dependent on water gradient salinity);  $R$  is the resistivity shale resistivity obtained from well logging;  $R_n$  is the shale resistivity at the normal (hydrostatic) pressure;  $n$  is the exponential ( resistivity = 1.2, sonic = 3);  $\Delta t_{norm}$  is the sonic transit time or slowness in shales at the normal pressure;  $\Delta t_{obs}$  is the sonic transit time in shales obtained from well logging, and it can be derived from seismic interval velocity;  $V_{p_{obs}}$  is velocity observed; and  $V_{p_{norm}}$  is velocity on normal trend.

This method is based on the assumption that:

- 1) Rocks are mechanically compacted
- 2) Sediments are at maximum effective stress
- 3) Lithology is thick shale
- 4) Normal compaction trend can be defined (based on the assumption that, only mechanical compaction has operated and rocks are presently at their maximum effective stress).

Different lithologies compact at different rates, and from contrasting starting porosity. The compaction trend should be established within the cleanest possible shale. Lithological variability is accounted for by 'best fit' of the shallow data, assumed to be normally compacted if porosity is decreasing with increasing depth.

- 5) Porosity can be imaged determined with reference to a well constrained overburden (lithostatic stress).

It is applicable in some petroleum basins but it does not consider unloading effects. This limits its application in geologically complicated area, such as carbonates formation and formation with uplifts.

Lang et al (2011) argue that the Eaton's method is effective for young sedimentary basins where under-compaction is the major cause of overpressure. But it does not consider unloading effects, and that limits its application in geologically complicated areas.

### **2.1.2 Zhang (2010)**

He modified Eaton's method using depth-dependent normal compaction trend to come up with an empirical equation in which the normal compaction trend decreases exponentially with depth.

### **2.1.3 Bowers (1995)**

Bowers pointed out the significant error associated with relating pore pressure with a deviation in velocity from an observed compaction trend in carbonate rock. The observed reversal according to him could be as a result of change in lithology e.g. salt dome could result in a significant change in velocity, not necessarily associated with pore pressure. He therefore proposed a

relationship that relates pore pressure with measured velocity and the velocity at the mudline. This method also account for the shortcomings related to predicting pore pressure when unloading is involved in overpressure generation and proposed a method which account for excess pressure generated by both under compaction and fluid expansion mechanism. The method compute effective stress from velocity (without having to establish a compaction trend, because of the geology of some basins that makes it impossible to define a normal compaction trend) and the result is subtracted from overburden stress to obtain pore pressure.

$$V_p = V_{ml} + A\sigma_s^B$$

Where:

$V_p$  = the compressional velocity at a given depth;

$V_{ml}$  = the compressional velocity in the mudline (i.e. the sea floor or the ground surface, normally  $V_{ml}$ ) Zhang (2010) noted that this method overestimate pore pressure when shallow formation is poorly or un-consolidated, because of the very slow velocity of such formation.

Bowers and Katsube in their work proposed that a rock's pore space consist of a combination of relatively large, high aspect ratio storage pores linked together by a network of lower ratio connecting pores. They further stressed that Storage pores undergo primarily inelastic volume losses, while the more flexible connecting pores are capable of elastic rebound. Consequently, effective stress reductions cause connecting pores to elastically widen without significantly changing storage pore sizes. Thereby evidencing why sonic and resistivity logs respond to transport properties, whereas neutron and density logs reflect bulk properties. Thus proposed cross plotting velocity-vs-effective stress/density-vs-effective stress as a quick tool for probing into the origin of overpressure (fig 8).

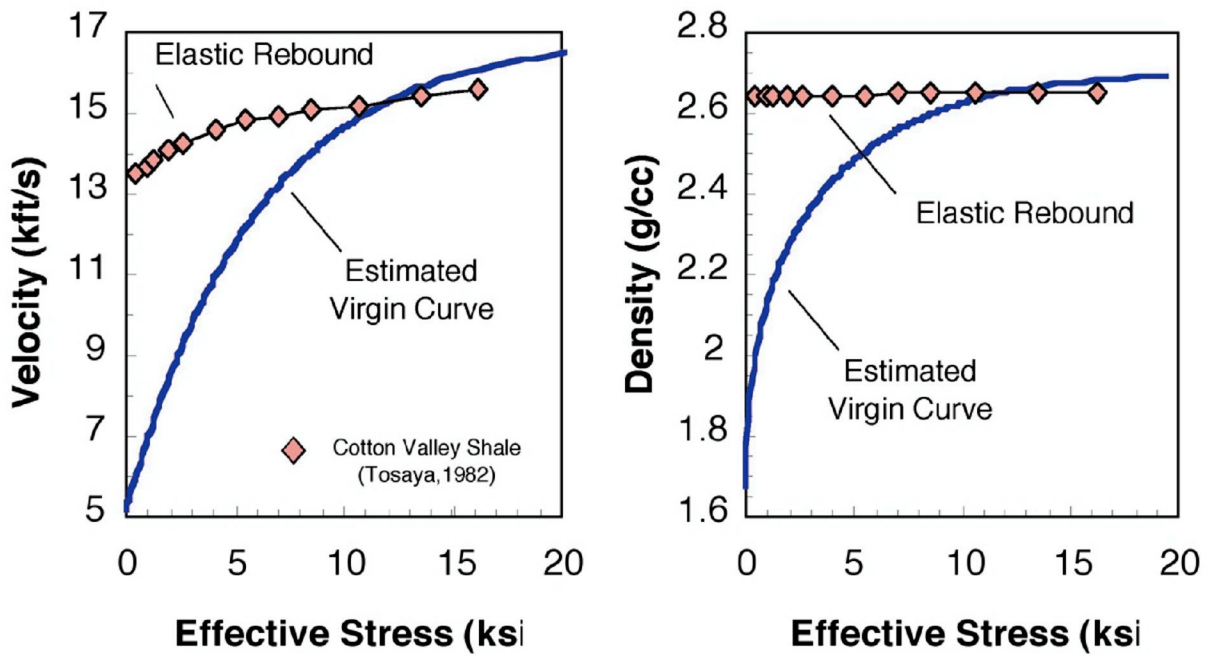


Fig. 8: Showing shale compaction/rebound behaviour (Tosaya, 1982).

#### 2.1.4 Miller (2002)

He derived a relationship between velocity and effective stress which put into consideration the effect of unloading. An input parameter  $\tilde{d}_{\max}$  in the Miller's equation controls whether unloading has occurred or not; depending on if  $d_{\max}$  is less than depth ( $Z$ ) or not.

#### 2.1.5 Lopez et al (2004)

Gutierrez et al (2006) introduce a  $\tilde{\tau}$  variable into the effective stress equation which put into consideration the effect of the matrix transit time and mudline velocities.

#### 2.1.6 Hoesni (2004)

He notes that sonic and density signatures associated with pore pressure gradient increase cause by different over-pressure generation mechanisms. He proposed that, overpressures generated by disequilibrium compaction are expected to plot on top of the normally pressured sonic-density loading curve (fig 9). Overpressures associated with clay diagenesis or load transfer are predicted to undergo an increase in density and little change in sonic velocity with increasing overpressure. Sequences that are overpressured through gas generation are predicted to undergo a sharp reduction in velocity, with little or no change in density. Lahann and Swarbrick 2011 further hypothesize that, if pore pressure gradient reduces with depth, sonic density value will return to the original loading curve if overpressures were caused by gas generation, whereas sequences affected by clay diagenesis or load transfer will plot along a new loading curve, possibly sub parallel to the original loading curve.

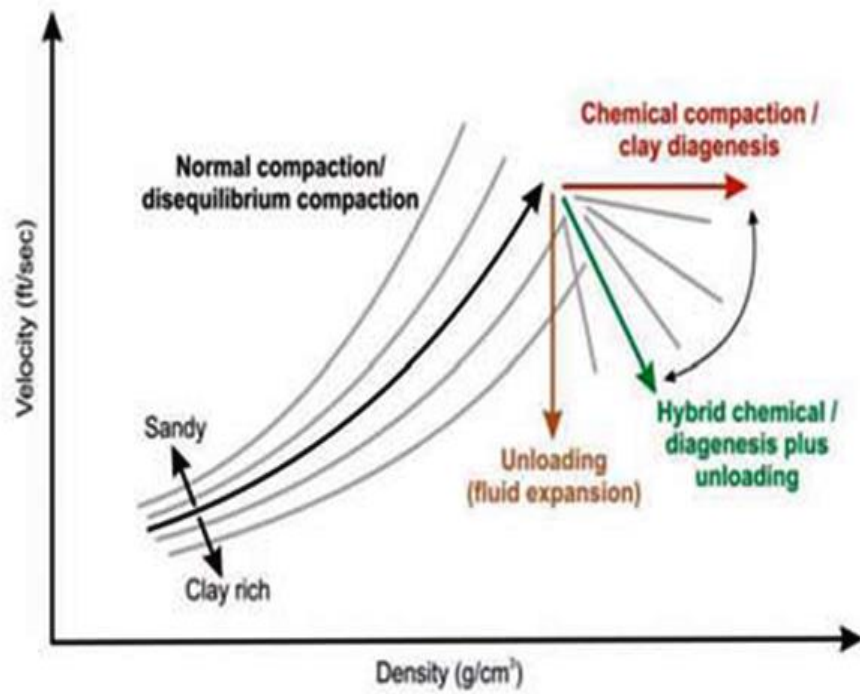


Fig. 9: Velocity-vs-density curve type (Source: Hoesni 2004; O'Connor et al., 2011).

## **2.2.0 Introduction to the Pore Pressure System**

All formations penetrated during the drilling of a well contain pressure which may vary in magnitude depending on depth, location and proximity to other structures. In order to understand the nature, extent and origin of formation pressures, it is necessary to define and explain basic wellbore pressure concepts.

### **2.2.1.0 Pressure**

This is defined as force per unit area that is equal in all directions. In the geoscience field, we measure the pressure of fluids within the rock volume or borehole with gauges and downhole tools. Pressure can be reported as absolute pressure, which is relative to the atmosphere or gauge pressure, which is the value measured directly from a gauge. Typically the geoscientist is concerned with several pressures in the subsurface. It includes:

#### **2.2.1.1 Pore or formation pressure**

This is the pressure acting upon the fluids (formation water, oil, gas) in the pore space of the formation. Pore pressure can only be measured in porous and permeable rocks with the aid of wireline formation testing (WFT) and sampling tools, e.g., RFT, MDT, RCI, and FIT. This is because, the tool requires fluid influx. While direct pressure reading in impermeable beds, such as mudrocks, can only be inferred through pressure measurements within adjacent permeable beds or from indirect indications such as mud weight, cuttings, gas, or rate of penetration (ROP) during the drilling operation. Pore pressure prediction is only possible by comparing expected (normal) and actual porosity or proxy to porosity (density, resistivity, or sonic) responses from wireline logs. Normal formation pressures in any geologic setting will equal the hydrostatic pressure. Abnormal formation pressures, by definition, are then characterized by any departure from the normal trend line. Formation pressures exceeding hydrostatic pressures in a specific

geologic environment are defined as abnormally high formation pressures i.e. **overpressure** (i.e. it is the inability of formation fluid to escape at a rate which allows equilibrium with hydrostatic pressure.), whereas formation pressures less than hydrostatic are called **underpressure**. Global exploration for hydrocarbon resources, both on- and offshore, has shown that abnormal formation pressures occurs worldwide, with overpressures occurring more frequent. In overpressure condition, fluids are trapped in the pores and bear part of the weight of the overlying solids. And one of the primary controls on the presence and distribution of overpressure is permeability; an attribute which controls seal behavior.

### 2.2.1.2 Normal or hydrostatic pressure

Pressure exerted by the weight of a static column of formation fluid extending to the surface is known as hydrostatic pressure. In this case, the pore fluid only supports the weight of the overlying pore fluids (primarily brine) that is present in a porous formation, with pore spaces continuously connected to the surface. It is caused by the unit weight and the vertical height of the fluid column (i.e. it is a function of average fluid density and vertical height or depth of the fluid in the column).  $HP = \gamma \cdot D = C \cdot MW \cdot D$

Where HP = hydrostatic pressure,  $\gamma$  = average density, D = vertical height of the column, C = conversion constant, MW = mud weight or fluid density. The reference datum for the hydrostatic curve is sea level, where atmospheric pressure is at 1 Atm, or 14.7 psia (pounds per square inch absolute). The hydrostatic pressure increases with depth at a rate dependent on the density of the pore fluid. If the pore fluid is fresh water (1.00 g/cc), then, the hydrostatic pressure will increase by 0.433 psi/ft. This is also known as the pressure gradient. If the formation fluid is brackish, with a NaCl content of 20,300 ppm, then the hydrostatic pressure gradient is 0.4338 psi/ft. Typically, in a basin where salt is not part of the sedimentary succession, a pressure gradient of 0.45 psi/ft is sufficient to use in a pore pressure study. It is often more convenient to refer to hydrostatic pressures in terms of a pressure gradient.

A **pressure gradient** is the rate of increase in pressure per unit vertical depth i.e., psi per foot (psi/ft) or equivalent mud weight units in pounds per gallon (ppg). The hydrostatic pressure gradient is affected by the concentration of dissolved solids (i.e. salts) and gases in the fluid column and different or varying temperature gradients. Hydrostatic pressures can easily be converted to equivalent mud weights and pressure gradients. Hydrostatic pressure gradient is given by:

$$HG = HP / D \text{ é (psi/ft)}$$

It is usual to convert wellbore pressures to gradients relative to a fixed datum, such as seabed, mean sea level or ground level. The resulting figure (pressure gradient) allows direct comparison of pore pressures, fracture pressures, overburden pressures, mud weights and Equivalent Circulating Density (ECD) on the same basis. In addition the use of pressure gradients accentuates variations in pressure regimes in a given area when values are plotted or tabulated.

### 2.2.2 Porosity and permeability

Porosity is the total pore (void) space in a rock

Permeability is the ease with which fluids can flow through the rock.

### 2.2.3 Compaction

The mechanical response of sediments experiencing an increase in effective stress is to undergo a reduction in volume by means of reorganization and deformation of the matrix material and the loss of porosity. Chemical processes may also occur and contribute to the loss of porosity. This process of porosity reduction is referred to as compaction. Shale has a lot of porosity to lose and fluid to expel. If the fluid cannot escape to balance the stress, a higher porosity is retained and the rock is overpressured. During normal compaction, sediments undergo a monotonic increase in effective stress which causes an elasto-plastic reduction in porosity (and void ratio) as illustrated by fig 10. The resultant relationship between effective stress and void ratio is known as the normal compaction curve. Hence the use of seismic velocity for pore pressure prediction is

focused on an interpretation of velocity as a proxy for porosity, with comparison between the actual and expected interval velocity on the normal compaction curve. Pressure in the shales can be quantified exploiting the relationship between total stress (normally vertical stress tied to the estimation of the overburden) and vertical effective stress based on the interval velocity (porosity) comparison.

Quantitative methods of pressure estimation from wireline logs require the establishment of a normal compaction trend (NCT) for each log type as an input in the workflow. The NCT should be established in the cleanest possible shale intervals. Shale pressure prediction is based on the assumption that shale pressure is at equilibrium with pressure in the adjoining sand interval, an assumption that is not always true.

#### 2.2.4 Normal compaction trend (NCT) from porosity logs

The NCT can be established using the linear or exponential form of Athy's (1930) equation:

$$\epsilon = \epsilon_o - cz \quad \text{Athy's linear equation}$$

$$\epsilon = \epsilon_o \exp(-cz) \quad \text{Athy's exponential form}$$

Where  $\epsilon$  = porosity (%),  $\epsilon_o$  initial surface porosity (%),  $c$  = compaction constant and  $z$  = depth.

#### 2.2.5 Normal compaction trend (NCT) from sonic log

The NCT can be derived from sonic transit log using Ramdhan & Goult (2011) equation:

$$\Delta t = (\Delta t_o - \Delta t_m) \exp(-bz) + \Delta t_m$$

Where:

$\Delta t$  = transit time,  $\Delta t_o$  = initial surface transit time,  $\Delta t_m$  = matrix transit time,  $b$  = compaction constant and  $z$  = depth.

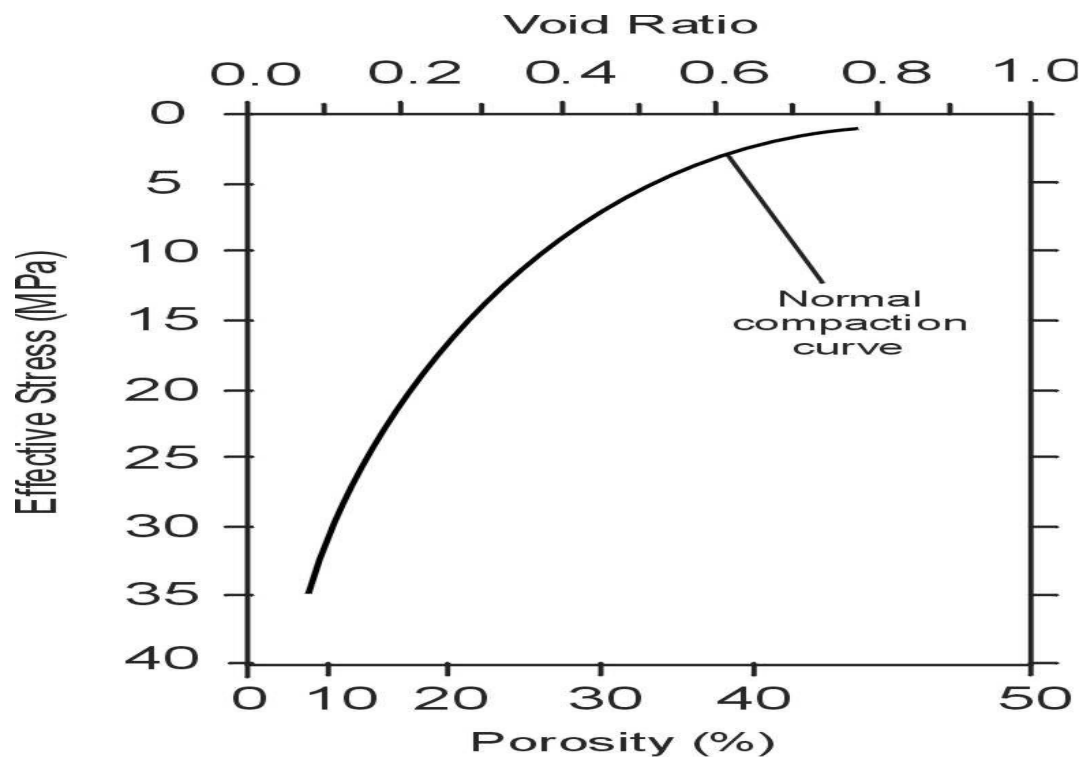


Figure 10: Showing the relationship between effective stress and porosity defined by the shale normal compaction curve (Source Toby et al., 1999).

### 2.3.0 Overburden pressure (OVB)

Overburden pressure, also commonly called overburden, lithostatic or vertical stress, is the pressure that results from the combine weight of the rock matrix and the fluids in the pore space overlying the formation of interest (fig 11). In such cases, the pore fluids of the sediments support all the weight of the overlying sediments. Overburden pressure increases with depth and is also called vertical stress. The lithostatic pressure is dependent on depth and the density of the overburden. In a given area, the overburden gradient is not constant with depth due to variations in formation density. This results from variations in lithology and pore fluid densities. In addition the degree of compaction and thus formation density increases with depth due to increasing overburden.

In general, when density data are unavailable or unreliable, an overburden gradient of 1psi/ft is often used as the default. But when the data are available, a more realistic evaluation based on lithology and density coupled with knowledge of local geology is preferable.

The overburden stress,  $S_v$ , is estimated by the relationship:

$$S_v = \rho_b * Z$$

Where:

$\rho_b$  = formation average bulk density.

$Z$  = vertical thickness of the overlying sediments.

The bulk density is a function of the rock matrix, fluid density and the porosity:

$$\rho_b = \rho_m (1 - \Lambda) + \rho_f (\Lambda).$$

Where:

$\rho_m$  = density of the rock matrix,

$\rho_f$  = density of the fluid, and

$\Lambda$  = porosity.

Because sedimentary basins contain a mixture of lithologies that have undergone various degrees of compaction, an average bulk density of  $2.31 \text{ g/cm}^3$  is commonly used for a thick sedimentary section.

### 2.3.1 Kick

Kick occurs where formation pore fluid enters the wellbore. This is the result of drilling into a formation where the pore pressure exceeds mud hydrostatic pressure. Wells are planned and drilling operations are controlled with the intention that primary well control is always maintained i.e. hydrostatic mud pressure is greater than formation fluid pressure. Fluid pressures are fundamental to many aspect of oil well drilling. If downhole pressures are not kept under control, an uncontrolled release of oil and gas to the surface (called **blow out**) can result, which might lead to loss of life, massive environmental damage to underground reservoir, and damage to rig and other facilities.

### 2.3.2 Effective stress

Effective stress is defined as the pressure acting on the solid rock framework i.e. the grain-to-grain contact stress. Terzaghi defined it as the difference between overburden stress and the pore-pressure. Effective stress thus controls the compaction that takes place in porous granular media including sedimentary rocks and this has been confirmed by laboratory studies (Tosaya, 1982; Dvorkin, 1999). In normally compacted rock, porosity is reduced with increasing effective stress. Any process causing a reduction of effective stress in a seal formation will results in overpressure, because that will result in the overburden stress been transferred to the pore fluid rather than the rock matrix. The relationship between effective stress and overburden stress is given by Terzaghi's equation:

$$P = (S_v - \sigma) / \alpha$$

Where:

$\sigma$  = effective stress,

$\alpha$  = Biot effective stress coefficient. It is conventionally assumed  $\alpha = 1$  in geopressure community

$S_v$  = overburden stress, and

$P$  = pore pressure.

### 2.3.3 Fracture pressure

This is the fluid pressure required to initiate a fracture in the surrounding sediments or rocks at a specific depth.

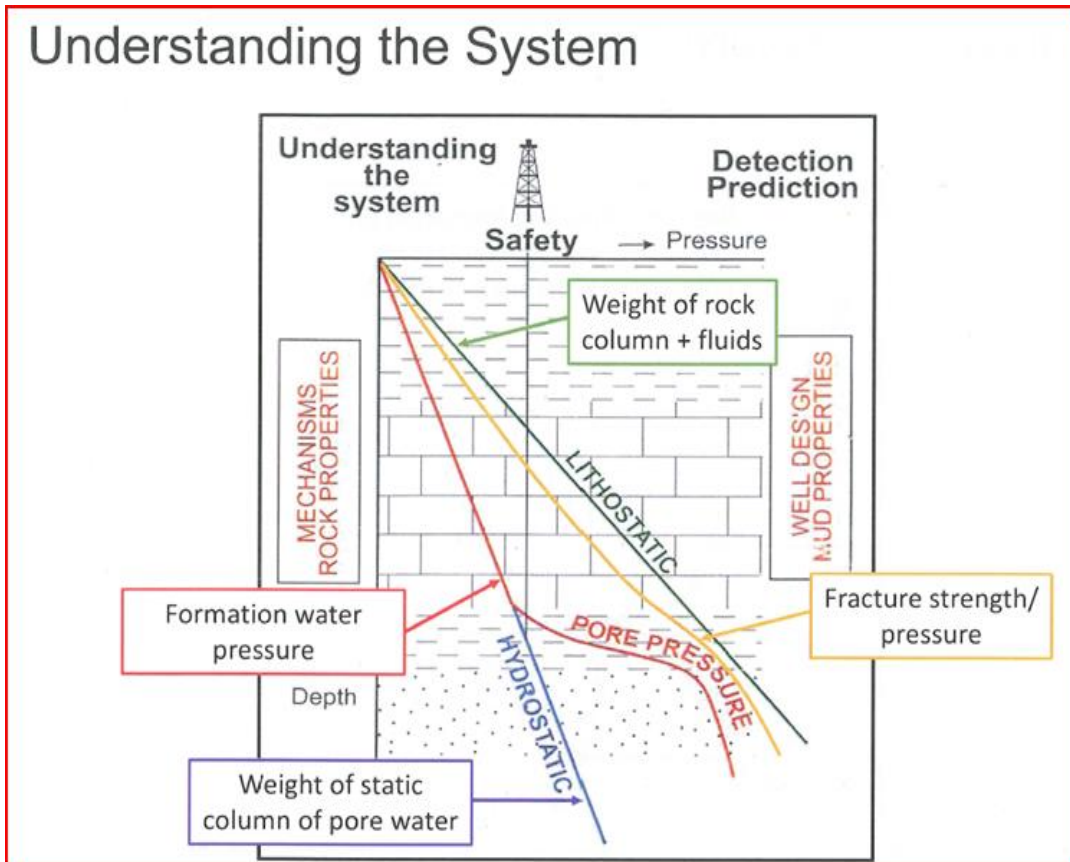


Fig. 11: A schematic diagram showing the basic terms in pore pressure work.

(Source: Lahann and Swarbricks 2011).

## 2.4 Mechanisms of Overpressure Generation

The amount of overpressure and the rate at which it can build up depends largely on the mechanism which is generating the excess fluid. Several mechanisms have been proposed as the cause of overpressure in subsurface rock in the past. In one of the first studies of abnormal pressures using data from the Gulf of Mexico, Dickson (1953) suggested that the high pressures in the clastic sequences there could be explained by incomplete dewatering of the sediments. Other explanations were later suggested for the high pressures in the rock, including thermal effects (Baker, 1972), clay mineral changes (Burst, 1969, Bruce, 1984) and osmosis (Marine and Fritz, 1981). In other basins, the influence of hydrocarbon generation/maturation has been proposed to explain overpressured reservoir (Spencer, 1987), and gas generation as a mechanism has been invoked for the Gulf of Mexico situation (Hunt et al., 1991). Some authors suggest one dominant mechanism, e.g., disequilibrium compaction (Bredehoft and Hanshaw, 1968; Summa et al., 1993), or hydrocarbon generation (Meissner, 1978a, b), whilst others have attempted to ascribe the relative proportion of each mechanism (Hart et al., 1995). Most papers dealing with abnormal pressure provide a brief overview of the range of possible mechanisms, but only few deals explicitly with each, and the conditions required for them to create abnormal pressures. A review of the mechanisms, especially as applied to drilling overpressured reservoirs, is provided in Fertl (1976), Mouchet and Mitchell (1989) and Fertl et al. (1994). Swarbrick and Osborne (1998) grouped the mechanisms considered responsible for overpressure conditions into three broad categories which are:

1. Stress related, (i.e. compression leading to pore volume reduction.

Mechanisms:

Disequilibrium compaction (vertical loading stress)

Tectonic stress (lateral compressive stress)

2. Fluid volume increase

Mechanisms:

Temperature increase (aquathermal expansion)

Clay diagenesis

Hydrocarbon maturation/generation

Cracking of oil to gas

3. Fluid movement and buoyancy

Mechanisms:

Osmosis

Buoyancy due to density contrasts.

#### **2.4.1 Stress related mechanism:**

##### **2.4.1.1 Disequilibrium compaction**

Most overpressure observed in sedimentary basins is caused by disequilibrium compaction, which results from continuous loading of effectively sealed sediments (Mouchet and Mitchell, 1989; Osborne and Swarbrick, 1997). During deposition of sediments, fluids within the pore spaces try to escape as the pores compact with the increase in vertical stress. If the sedimentation rate is slow, normal compaction occurs, i.e. equilibrium is attained between increasing overburden and the reduction of pore fluid volume due to compaction (Mouchet and Mitchell, 1989). This normal compaction generates hydrostatic pore pressure in the formation. Rapid burial results into faster expulsion of formation fluid in response to rapidly increasing overburden stress. When a formation with low permeability is encountered with a high rate of sedimentation, fluid in the sediments can only be partially expelled, while the remaining fluid

trapped in the formation will have to carry a large part of the load and pore-fluid pressure will increase (fig 12). The rate of porosity loss varies with rock-type. Each rock-type will have a lower limit beyond which no further mechanical compaction is possible and porosity loss is thereafter due to chemical compaction. Sandstones compact at a relatively slow rate from a starting point of about 40% to 45% porosity to about 20% to 30% porosity due to rearrangement of the sand grains and some dissolution at grain contacts (McBride et al., 1991). At depths of only 1.5 to 2.5 km there is little potential for significant further reduction in primary porosity due to mechanical compaction involving bed thickness reduction, and further porosity reduction is primarily a function of diagenetic cementation (McBride et al., 1991). By contrast, clays have a typical porosity at the time of deposition of 65% to 80% and compact more quickly than sands. Clays will continue to compact, by grain rearrangement and ductility, to great depths (typically 4 to 6 km) where the porosity can be reduced to 5% to 10% of the rock volume (Katsube and Williamson, 1994; Hunt et al., 1994). However, not all clays behave in the same way, which explains some of the variability in porosity vs. depth curves for clay-rich rocks. In this case porosity decreases less rapidly than it should be with depth, and formation are said to be under-compacted or in compaction disequilibrium. Examples of where disequilibrium compaction is cited as the primary reason of abnormal pressure include the U.S. Gulf coast, Niger Delta, Mahakam Delta, MacKenzie Delta, North Sea, Adriatic Sea, the Nile Delta, Alaska Cook Inlet; Beaufort Sea, Malay Basin, Eastern Venezuelan Basin (Trinidad) and the Potwar Plateau of Pakistan (Powley, 1990; Burrus, 1998; Heppard et al., 1998; Law and Spencer, 1998; Yassir and Addis, 2002; Nelson and Bird, 2005).

### **2.4.1.2 Tectonics stress**

Overpressure generation through tectonic stress follows the same principle as disequilibrium compaction, but with the incomplete expulsion of the fluid as a result of horizontal tectonic compression. Overpressuring due to lateral stress is reported along major fault zones, both within the fault and in the adjacent porous wall-rock (Byerlee, 1993). Episodic release of overpressured fluids is associated with earthquakes and fault rupture (Byerlee, 1990). In addition, overpressure is a characteristic of accretionary sedimentary prisms, where horizontal compression coupled with loading and under plating is caused by subduction (Davis et al., 1983). The amounts of horizontal compression are most likely small in passive continental margin and intracratonic areas, but may contribute to overpressure in undeformed sedimentary sequences where the rock neither buckles nor faults. High fluid pressures encountered in deep boreholes in the California Coast Ranges are attributed to lateral tectonic compressive forces (Berry, 1973). Some notable occurrences of over pressuring and present day compressional tectonics includes the Barbados Accretionary Prism (Trinidad), the Andes, Papua New Guinea, California and Gulf of Alaska.

### **2.4.2.0 Secondary pressure mechanism**

These have been grouped together under as secondary pressure mechanism because they occurred after primary compaction and undercompaction processes have taken place. These include;

#### **2.4.2.1 Fluid expansion unloading mechanism**

Over pressure in the pore spaces of a formation can results by fluid expansion mechanism as the rock matrix constrains the increased volume of pore fluid (fig 13). The process include; clay diagenesis, hydrocarbon maturation/generation, aquathermal expansion, cracking of oil to gas etc.

#### 2.4.2.2 Aquathermal expansion

Temperature increase that occurs within geopressured zone is another major factor that contributes to fluid pressure. The overlying, normally pressured sediments, that are compacted possess a lower thermal conductivity and act as a "blanket" decreasing the transfer of heat from the deep mantle. A leak-proof permeability seal is required in order to have a closed system, and the heat trapped by the blanket effect above the geopressured zone produces an abnormally high temperature in the formation. This contributes to fluid pressure within the zone. The principle which governs aquathermal expansion as an overpressure mechanism is the thermal expansion of water when heated above 4°C (this is what causes water in a tin heated to certain temperature to pop its lid open). If the body of water is contained in a sealed vessel the pressure rises rapidly. For example, Barker (1972) shows a pressure rise of 8,000 psi in water heated from 54.4°C to 93.3°C caused by a volume increase of only 1.65%. This pressure increase over about 1.0-1.5 KM would lead to a sharp transition zone at the top of overpressure section. This is only possible if the environment is completely isolated, with no change in pore volume. Several authors (e.g., Daines, 1982; Luo and Vasseur, 1992) have shown that the conditions for aquathermal pressuring will rarely be met. In particular when water is heated its viscosity reduces and facilitates more rapid expulsion, even at low permeabilities. An additional objection to aquathermal expansion is that in many overpressured rocks there is a gradual transition zone to high amounts of overpressure. This implies permeability and hence the section is not fully sealed and cannot fulfill the requirements for aquathermal pressuring. Aquathermal pressuring is only feasible if a seal with permeability close to zero can be proven to exist. Hunt (1990) suggested that there are diagenetic seals with highly effective sealing properties, typically at depth of about 3.0 km, which are laterally extensive. Although banded cements have been described where the

top of overpressure is observed (Tigert and Alshaieb, 1990), the origin of these diagenetic seals and their ability to form regional impermeable barriers is subject to further questioning (Swarbrick and Osborne, 1998).

#### **2.4.2.3 Clay diagenesis**

Several common mineral transformations in sediments involve the release of clay bound water. The most common of these involves smectite to illite transformation, gypsum to anhydrite in evaporitic sediments and coalification (Law et al., 1983). Surficial, young argillaceous sediments are often rich in smectite mineral called montmorillonite. Smectite absorb water due to their imbalance ionic charge (Van der Waals bond). During burial, smectite alters chemically by addition of Al and K ions and the release of Na, Ca, Mg, Fe, and Si ions plus water, to produce illite, which does not have the same capacity to absorb water. The reaction is kinetically controlled and is dependent on the combined effects of time and temperature, as well as the influence of mineral fabric and permeability (Hall, 2004). In several mud-dominated basins a gradual and systematic change from smectite to illite downwards in the stratigraphic section is observed, broadly coincident with the transition to high amount of overpressure (Bruce, 1984). The overall volume change involve with smectite transformation is not well known, because the exact chemistry of the reaction is not known. Conversion of one volume of smectite to illite would release 0.36 volumes of water according to the reaction proposed by Hower et al. (1979), leading to an overall volume decrease of about 23% if all the reaction occurs in a closed system. Boles and Franks (1979) claim a release of 0.56 volumes of water, which would create a volume increase of about 25%. Hence the origin of overpressure by this mechanism is far from conclusive. However, the coincidence of overpressure at the same stratigraphic levels as smectite

to illite transformation may be related to the resulting changes in the rock fabric, trapping excess fluids generated by another mechanism, e.g. disequilibrium compaction.

The transformation of smectite to illite clay is accompanied by changes in the physical characteristics of the sediments. Firstly, the collapse of the smectite clay framework and release of bound water influences the compressibility of the sediment. If the compressibility factor is increased, the overburden induces additional compaction requiring expulsion of newly released water from the rock to achieve equilibrium. If the low permeability of the rock acts to retain the fluid, then overpressure will result, i.e. disequilibrium compaction induced by mineral dehydration. Smectite transformation is also accompanied by the release of silica, which tends to reduce the permeability of shales to produce a hydraulic seal and hence potentially a transition into the overpressured section below. Freed and Peacor (1989), however, have argued that normal pressure stops when the transformation smectite to illite began and continued to rise through the zone of increasing illite. This coincidence of overpressure near the depth of the smectite-illite transformation results from a reduction in the permeability of shales, not due to silica cementation promoted by the reaction, but by reordering of the illite into packets. Reduction of permeability by mineral reordering would help to retain fluids and hence contribute to the preservation of overpressure, but would not be responsible for its initiation. Silica cementation could involve some volume change but the rate is likely to be too slow to create overpressure (Swarbrick et al. 1998)

#### **2.4.2.4 Hydrocarbon maturation/generation**

The two main reactions involved with the generation of oil and gas from petroleum source rocks are: (1) kerogen maturation to produce oil and/or gas, and (2) oil and bitumen cracking to gas.

These reactions typically occur at depths of 2.0 to 4.0 km and at temperatures in the range 70°i 120°C for kerogen maturation (Tissot et al., 1987), and 3.0i 5.5 km and 90°i 150°C for oil cracking to gas (Barker, 1990). The increased volume of hydrocarbons and residue relative to unaltered organic material, and the inhibited structural collapse of the rock framework as overburden-supporting solid organic matter are converted to hydrocarbon pore fluid result into overpressure. If the kerogen sustains part of the overburden stress before maturation, that stress will be transferred to the liquid hydrocarbon, and if the liquid cannot escape, there will be an increase in pore pressure. Meissner (1987) suggested that the catagenesis of solid kerogen is accompanied by 25% volume expansion. Whereas, maturation of kerogen to gas can results in a large volume increase as much as 50% (Ungerer et al 1983). It is this high pressure resulting from increase in pore fluid and creation of additional pore spaces during maturation of source rocks to oil, that aid the expulsion of petroleum from low permeability source rock into carrier beds (England et al 1987). It is important to note that, regardless of any volume change, the presence of oil and gas as separate phases (from water), especially within fine-grained rocks including source rocks, will severely reduce the effective permeability of the rocks. This phenomenon will be very important to the retention capacity of these rocks and their ability to seal excess fluids created by any of the overpressure mechanisms.

#### **2.4.2.5 Oil to gas cracking**

Amidst all the unloading overpressure generation mechanism, only the generation of gas are consider being able to produce high magnitude overpressures (Swarbrick et al 2002; Tingay et al 2007; Lahann and Swarbrick 2011). Ungerer et al (1990) examined hydrocarbon generation for type-2 Toarcian black shales in the Paris Basin in France and observed that, generation of oil is associated with a 3 to 6% decrease in fluid volume; maturation of kerogen into gas can result in a

large fluid volume increase of potentially as much as 50%. Primary migration of hydrocarbon is the principal evidence for gas generation as a mechanism of overpressure generation (England et al 1987).

Neuzil (1995) and Osborne and Swarbrick (1997) predicted that overpressures generated by fluid expansion are unlikely to occur in isolation and will also include some component of overpressure generation by disequilibrium compaction. This is because, once a seal of sufficient quality has been developed to allow the formation of overpressures by fluid expansion, any increase in stress applied to the sealed sequences will also generate overpressure by disequilibrium compaction.

#### **2.4.3.0 Fluid movement and buoyancy mechanisms**

##### **2.4.3.1 Osmosis**

Occurs when two solutions of different ionic concentrations are separated by a semi permeable membrane that allow solvent to pass through by diffusion from the more dilute side to the other side of the membrane with high concentration. The osmotic flow will continue until the chemical potential of diffusion is equal on both sides of the membrane. Pressure increase thereby occurs if the solvent moving into the more concentrated solution enters a closed compartment. Large contrasts in the brine concentrations of formation fluids, from dilute to saltier water, across a semi-permeable membrane can induce transfer of fluids across the membrane. Marine and Fritz (1981) suggested that osmotic pressure could be an explanation for some overpressured sections. Swarbrick and Osborne (1998) argued that this mechanism have only local effect. As it is required to have recharge of the more saline, and discharge of the originally less saline waters to maintain the pressure, which they believe is unlikely to happen during normal compaction processes. In addition, it has been observed that brines in overpressured zones tend to be of a

lower salinity than adjacent normally pressured brine, which would act to reduce the pressure in the overpressured zones.

#### **2.4.3.2 Hydrocarbon buoyancy (density contrasts)**

Gases and most oils have a lower density than the associated formation waters and hence have a lower pressure gradient. Since overpressure is the excess pressure above hydrostatic for a given depth, there is always some amounts of overpressure wherever a column of oil or gas is present. This mechanism is restricted to structural and stratigraphic traps of hydrocarbons, and cannot cause regional overpressure. The amount of overpressure within the hydrocarbon accumulation is a function of the pressure gradients of oil, gas and water and the height of the hydrocarbon column.

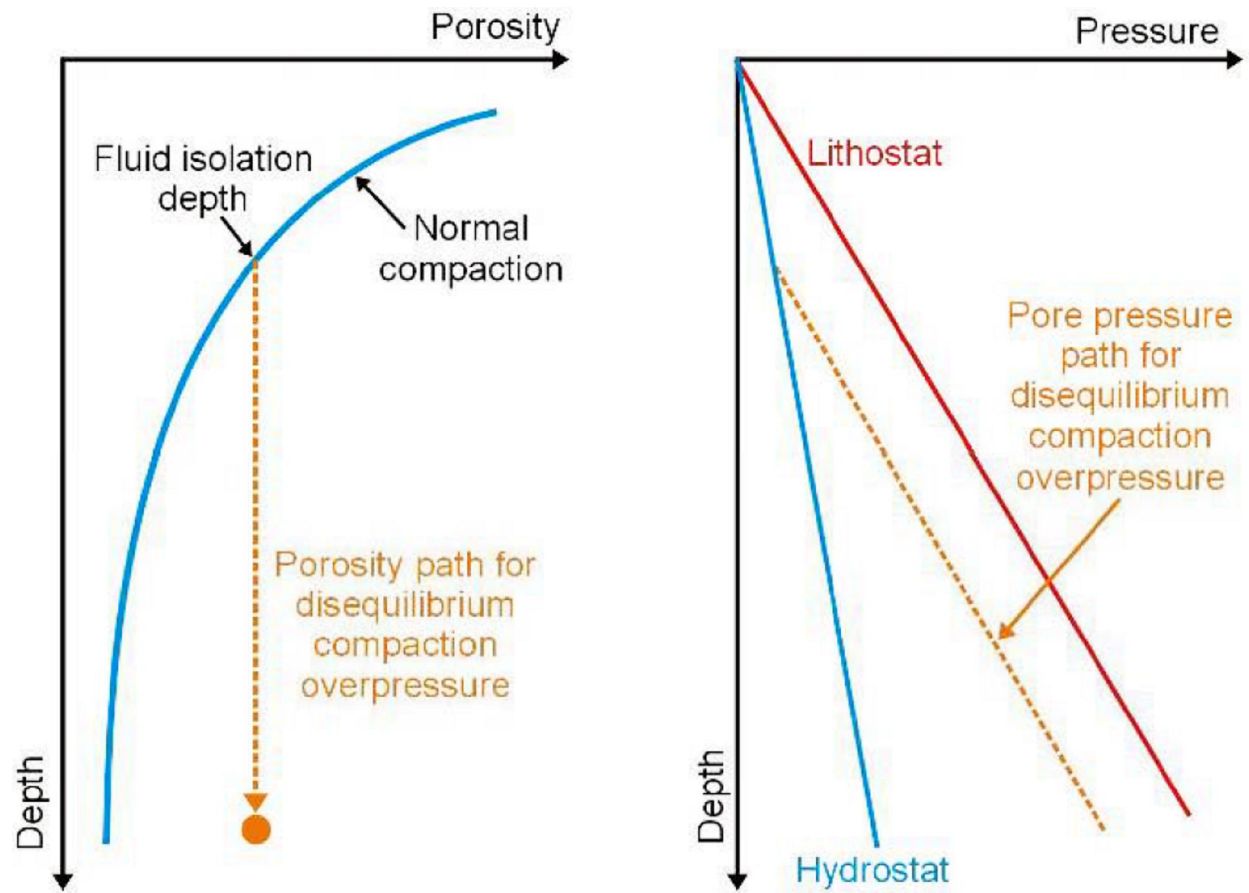


Figure 12: Porosity vs Depth and Pressure vs Depth path for overpressure generated by disequilibrium compaction. (Bowers 1995; Tingay et al 2007).

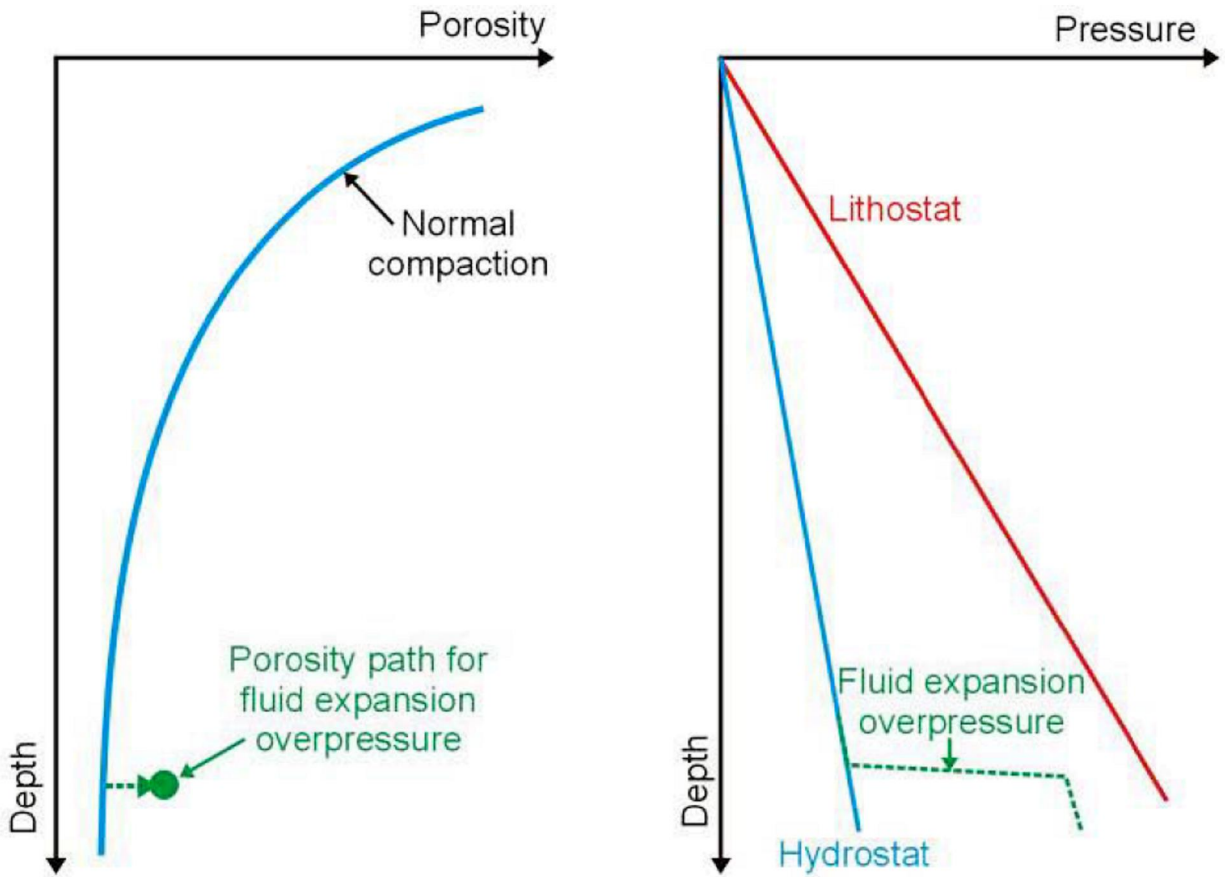


Figure 13: Porosity vs Depth and Pressure vs Depth path for overpressure generated by fluid expansion. (Bowers 1994; Tingay et al 2007).



Fig. 14: Map showing the global distribution of abnormal pressures (Law et al 1998)

| Region                                            | Index No. | Age of Abnormally Pressured Rocks | Depositional System                     | Structural Setting       | Depth to Top of Abnormal Pressure (ft) | Maximum or Minimum Pressure (psi) | Seal                      | Temperature Top of Abnormal Pressure (°F) | Thermal Maturity Top of Abnormal Pressure (%R <sub>o</sub> ) | Fluid Phase      | Hydrocarbon Source & Age             | Associated Accumulation Type | Cause(s)  | References                                                      | Remarks                                                                                                       |
|---------------------------------------------------|-----------|-----------------------------------|-----------------------------------------|--------------------------|----------------------------------------|-----------------------------------|---------------------------|-------------------------------------------|--------------------------------------------------------------|------------------|--------------------------------------|------------------------------|-----------|-----------------------------------------------------------------|---------------------------------------------------------------------------------------------------------------|
| Alaska National Wildlife Refuge<br>Alaska, U.S.A. | 1         | Cretaceous                        | marine nonmarine                        | foreland deltaic/fluvial | 10,000 (3,000)                         | 0.84 (19.4)                       | -                         | 150°-183° (66°-73°)                       | 0.55                                                         | -                | -                                    | -                            | uncertain | Gaulier et al. (1987)                                           | Conclusion based on 2 wells.                                                                                  |
| Beaufort-Mackenzie<br>Canada                      | 2         | Paleozoic & Miocene               | deltaic                                 | passive margin           | 6,550-16,400 (2,000-5,000)             | 0.85 (19.4)                       | faults                    | highly variable                           | 0.75                                                         | water/gas        | -                                    | structure                    | -         | Hitchon et al. (1990)                                           |                                                                                                               |
| Alberta Deep Basin<br>Canada                      | 3         | Triassic, Jurassic Cretaceous     | deltaic marginal marine                 | foreland                 | >3,000 (>1,000)                        | -                                 | water block*              | -                                         | 0.7-1.0                                                      | gas              | Cretaceous Type III OM               | basin-center gas             | HC        | Masters (1979, 1984) Wette et al. (1984)                        | Under & overpressured. See Masters (1984) Fig. 18. Very little pressure data, largely interpretive.           |
| Jeanne d'Arc Basin<br>Canada                      | 4         | Jurassic                          | marine                                  | failed rift              | 9,500-15,100 (2,900-4,600)             | 0.99 (21.3)                       | shale                     | -                                         | -                                                            | water/gas*       | Jurassic                             | structure                    | uncertain | Rogers & Yassir (1993)                                          |                                                                                                               |
| Scottian Shelf<br>Canada                          | 5         | Jurassic                          | deltaic                                 | rift                     | >14,750 (>4,500)                       | 0.87 (20.1)                       | -                         | >248° (>120°)                             | 0.8                                                          | -                | Jurassic-Cretaceous                  | structure                    | CDHC      | Mudford & Best (1989) Rogers & Yassir (1993)                    |                                                                                                               |
| Columbia Basin<br>U.S.A.                          | 6         | Tertiary                          | fluvial                                 | foreland                 | 9,000-10,000 (2,700-3,000)             | >0.80 (>18.5)                     | water block*              | 200° (93°)                                | 0.8                                                          | gas              | Tertiary                             | basin-center gas             | HC        | Law et al. (1994)                                               | Overpressured sequence covered with thick basalts.                                                            |
| Williston Basin<br>U.S.A.                         | 7         | Mississippian Devonian            | marine                                  | cratonic basin           | 9,000 (2,740)                          | 0.73 (16.9)                       | -                         | 190° (88°)                                | 0.4-0.5                                                      | oil              | Mississippian Devonian               | basin-center oil             | HC        | Meisner (1978)                                                  | Type I organic material.                                                                                      |
| Powder River<br>U.S.A.                            | 8         | Cretaceous                        | dominantly marine                       | foreland                 | 10,000 (3,000)                         | 0.8 (18.5)                        | unconformity water block* | 200° (96°)                                | 0.5                                                          | gas & condensate | Cretaceous                           | stratigraphic                | HC        | Spencer (1987) Surdam et al. (1994)                             |                                                                                                               |
| Big Horn Basin<br>U.S.A.                          | 9         | Cretaceous                        | fluvial & marine                        | foreland                 | 11,000 (3,350)                         | >0.6 ? (13.6 ?)                   | water block*              | 200° (96°)                                | >1.2                                                         | gas              | Cretaceous                           | -                            | -         | Spencer (1987)                                                  | Experienced cooling associated with uplift and erosion.                                                       |
| Wind River Basin<br>U.S.A.                        | 10        | Mississippian Cretaceous Tertiary | marine fluvial                          | foreland                 | variable                               | 0.8 ? (18.5 ?)                    | water block* shale        | -                                         | 1.1                                                          | gas              | Cretaceous                           | basin-center gas             | HC        | Biyeu (1978) Johnson et al. (1996)                              |                                                                                                               |
| Greater Green River Basin, U.S.A.                 | 11        | Tertiary Cretaceous               | marine-nonmarine deltaic/fluvial        | foreland                 | 8,000 (2,440)                          | 0.9 (20.6)                        | water block               | 180°-200° (82°-96°)                       | 0.75-0.85                                                    | gas              | Cretaceous                           | basin-center gas             | HC        | McPeck (1981) Law (1984) Spencer (1987)                         | Underpressured gas accumulation at shallow depths above deeper, overpressured rocks.                          |
| Piceance Basin<br>U.S.A.                          | 12        | Mississippian Cretaceous          | fluvial to marine                       | foreland                 | 6,000-8,000 (1,830-2,440)              | 0.82 (18.9)                       | water block               | 165°-200° (74°-96°)                       | >0.8                                                         | gas              | Cretaceous                           | basin-center gas             | HC        | Spencer (1987) Johnson et al. (1987)                            | Locally overpressured CO <sub>2</sub> in Mississippian carbonates, see Wilson et al. (this volume).           |
| Uinta Basin<br>U.S.A.                             | 13        | Tertiary                          | lacustrine fluvial                      | foreland                 | 10,000 (3,000)                         | 0.83 (19.2)                       | water block               | 210° (98°)                                | -                                                            | oil              | Tertiary Type I OM                   | basin-center oil             | HC        | Lucas & Drexler (1976) Spencer (1987)                           |                                                                                                               |
| Sacramento Basin<br>U.S.A.                        | 14        | Cretaceous Tertiary               | fluvial-deltaic                         | forearc                  | 3,900-10,000 (1,190-3,060)             | 0.85 (19.7)                       | -                         | -                                         | -                                                            | gas*             | -                                    | -                            | TC/AE     | Berry (1973) Lico & Kharaka (1983)                              | Diminished shale gas production when pressure gradient >0.7 psi/ft (>16.3 kPa/m).                             |
| Anadarko Basin<br>U.S.A.                          | 15        | Mississippian Pennsylvanian       | fluvial fluvial deltaic marine, deltaic | foreland                 | 9,000-10,000 (2,740-3,050)             | 0.9 (20.8)                        | diagenetic                | 140°-155° (60°-66°)                       | 0.81-0.89                                                    | gas              | Devonian Mississippian Pennsylvanian | stratigraphic basin-center*  | HC/OCD    | Breeze (1970) Al-Shaleb et al. (1994)                           | Types II & III kerogen, Burns & Hatch (1989).                                                                 |
| Apalachian Basin<br>U.S.A.                        | 16        | Slurian                           | fluvial deltaic marine                  | foreland                 | >2,500 (>760)                          | 0.36* (8.37*)                     | water block*              | -                                         | -                                                            | gas              | Ordovician ?                         | basin-center                 | HC        | Russell (1972) Davis (1984) Zagorsk (1988) Law & Spencer (1993) | Underpressured, locally overpressured at depths >10,000 ft (>3,000 m).                                        |
| Gulf Coast<br>U.S.A.                              | 17        | Jurassic Cretaceous Tertiary      | marine deltaic                          | passive margin           | 6,000-16,000 (1,800-4,875)             | near lithostatic                  | shale                     | -                                         | -                                                            | oil/gas/water    | -                                    | structure                    | CDHC      | Dickinson (1983) Bradley (1975)                                 | Numerous overpressured stratigraphic units. The world's most extensively studied abnormally pressured region. |

## 2 F 2

| Region                              | Index No. | Age of Anomally Pressured Rocks        | Depositional System                                    | Structural Setting | Depth to Top of Anomalous Pressure ft (m)  | Maximum or Minimum Pressure Gradients psi/ft (kPa/m)    | Seal                               | Temperature Top of Anomalous Pressure °F (°C)     | Thermal Maturity Top of Anomalous Pressure %Ro | Fluid Phase                                        | Hydrocarbon Source & Age   | Associated Hydrocarbon Accumulation Type | Cause(s)                              | References                                                          | Remarks                                                                                                                           |
|-------------------------------------|-----------|----------------------------------------|--------------------------------------------------------|--------------------|--------------------------------------------|---------------------------------------------------------|------------------------------------|---------------------------------------------------|------------------------------------------------|----------------------------------------------------|----------------------------|------------------------------------------|---------------------------------------|---------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------------------------------|
| Trinidad West Indies                | 18        | Cretaceous to Tertiary                 | marine to deltaic                                      | active margin      | 1,500-12,000 (460-3,650)                   | 0.95 (21.9)                                             | faults shale                       | -                                                 | -                                              | water/gas/oil                                      | Upper Cretaceous           | structure                                | CD/HC? AE?/TC?                        | Heppard et al. (this volume)                                        | Mud diapirs and mud volcanoes. Max. pressure gradient in productive fields is 0.73 psi/ft (16.9 kPa/m).                           |
| North Sea                           | 19        | Triassic Jurassic Cretaceous Paleocene | fluvial paralic marine                                 | failed rift        | >5,900 (>1,800)                            | 0.87 (20.1)                                             | marls shale faults claystone       | -                                                 | -                                              | oil/gas/water                                      | Jurassic                   | structure                                | CD/HC/TC/AE                           | Buhrig (1989) Leonard (1983) Gaarenstroom (1993) Holm (this volume) | Examples of pore pressure compartment.                                                                                            |
| Bakex Basin Hungary                 | 20        | Neogene                                | fluvial deltaic lacustrine                             | back-arc rift      | >5,900 (>1,800)                            | 0.86 (20.0)                                             | -                                  | 257° (125°)                                       | 0.45                                           | gas/water/ condensate                              | Neogene Cretaceous ?       | structure                                | CD/HC/CO <sub>2</sub>                 | Spencer et al. (1994)                                               | High heat flow. Rapid deposition.                                                                                                 |
| Adriatic Basin Italy                | 21        | Pliocene                               | turbidite                                              | foreland           | variable, hard pressure at >7,500 (>2,300) | near lithostatic                                        | faults/ shale                      | -                                                 | -                                              | water/gas/oil                                      | Lower Tertiary for oil     | structure                                | CD                                    | Carlin & Darnelli (this volume)                                     | Biogenic gas to 13,100 ft (4,000 m). Also thermogenic gas.                                                                        |
| Nile Delta/North Sinai Basins Egypt | 22        | Jurassic-Pliocene                      | pre-Tertiary-marine, fluvial Tertiary - deltaic marine | passive margin     | 1,700-12,140 (520-3,700)                   | 0.89 (20.6)                                             | evaporites shales faults           | 185° (85°)                                        | -                                              | gas/water/ condensate/ oil                         | Jurassic Oligocene-Miocene | structure                                | CD/AE/HC                              | Nashaat (this volume)                                               | Temperature & pressure limits of oil & gas production indicated in Nashaat (this volume).                                         |
| Niger Delta Nigeria                 | 23        | Tertiary                               | deltaic                                                | passive margin     | >9,000* (>2,740*)                          | -                                                       | shale                              | 200° (95°)                                        | 0.6*                                           | water plus dissolved gas*                          | Eocene                     | structure                                | CD                                    | Evamy et al. (1978) Chukwu (1991) Ejedawe et al. (1986)             | Nearly all productive fields at or near top of overpressure.                                                                      |
| Timan-Pechora Basin Russia          | 24        | Devonian Carboniferous Permian         | marine deltaic fluvial                                 | foreland           | highly variable >1,000 (>300)              | 0.38 Permian (8.8)                                      | shale/ evaporites water block      | -                                                 | 0.8-0.9                                        | oil/gas/water                                      | Permian for basin-center   | structure reefs, basin-center in Permian | HC in Permian                         | Law et al. (1996)                                                   | Overpressured in Devonian & Carboniferous. Underpressured in Permian.                                                             |
| Dnieper-Donets Donbas Ukraine       | 25        | Carboniferous                          | marine to paludal                                      | rift               | 1,500-14,750 (450-4,500)                   | 0.79 (18.3)                                             | water block* diagenetic evaporites | 212°-230° (100°-110°)                             | 0.9                                            | gas                                                | Carboniferous              | basin-center*                            | HC                                    | Poltiranko (this volume) Law et al. (1997)                          | Overpressured in Dnieper-Donetsk & underpressured in Donbas region.                                                               |
| South Caspian Basin Kazakhstan      | 26        | Tertiary                               | flysch & molasse                                       | foreland           | >3,000 (>1,000)                            | 0.85 (19.6)                                             | shale*                             | -                                                 | -                                              | water & dissolved gas                              | -                          | structure*                               | CD                                    | Bredelhoff et al. (1988) Gurevich & Chilingar (1995)                | Contains numerous mud volcanoes see Dumsh'yan (1972) for discussion of origin & relationship of mud volcanoes to HC accumulation. |
| Potwar Plateau Pakistan             | 27        | Paleozoic to Neogene                   | marine fluvial deltaic                                 | foreland           | extremely variable >1,000 (60-300)         | near lithostatic in Neogene & 0.7 (15.8) in pre-Neogene | uncertain                          | 110° (43°) in Neogene & 180° (82°) in older rocks | 0.8-0.9 in pre-Neogene                         | water in Neogene & oil/gas in water in pre-Neogene | Eocene ? Eocambrian ?      | structure                                | CD in Neogene HC/AE/TC in pre-Neogene | Law et al. (this volume)                                            | Two pressure regimes - Neogene & pre-Neogene.                                                                                     |
| Sichuan Basin China                 | 28        | Permian Triassic                       | marine                                                 | foreland           | -                                          | 0.93 (21.4)                                             | carbonates                         | -                                                 | -                                              | gas                                                | Permian                    | structure                                | TC/O/TC                               | Da-Jun & Yun-ho (1994)                                              | Over- and underpressured carbonates.                                                                                              |
| Nagasaki Plain Japan                | 29        | Miocene                                | volcanics                                              | active margin      | >4,600 (>1,400)                            | 0.69 (16.0)                                             | mudstone                           | -                                                 | -                                              | oil/gas/water                                      | Miocene                    | structure                                | CD                                    | Magara (1968)                                                       | Overpressured rock are composed of lava, tuff breccia & agglomerates.                                                             |
| Mahakam Delta Indonesia             | 30        | Miocene                                | marine deltaic                                         | active margin      | 11,500-13,100 (3,500-4,000)                | 0.87 (20.1)                                             | shale                              | 200°-248° (100°-120°)                             | 0.6                                            | water/gas                                          | Miocene                    | structure                                | CD                                    | Burns et al. (1992) Oudin & Plard (1982) Burtus (this volume)       | Coal is hydrocarbon source rock.                                                                                                  |
| Dampier sub-Basin Australia         | 31        | Jurassic Cretaceous                    | -                                                      | passive margin     | >2,970 (>875)                              | 0.85 (19.7)                                             | -                                  | -                                                 | -                                              | -                                                  | -                          | -                                        | CD/MT                                 | Nyein et al. (1977)                                                 | Only one well used in study.                                                                                                      |

Cause(s) codes used: CD = Compaction Disequilibrium, HC = Hydrocarbon Generation, AE = Aquathermal Expansion, O = Osmosis, MT = Mineral Transformations, CO<sub>2</sub> = Carbon Dioxide Generation  
 \* = Authors interpretation

### **2.5.0 Methods of Pore Pressure Prediction**

Pore pressure prediction (all through exploration and production life span of a well) can be undertaken using several approaches requiring input from multiple technical disciplines. The approach depends heavily on the situation, the geologic setting, the data available and the required application of the results. Some of the methods are as follows:

#### **2.5.1 Seismic method**

Apart from drilling a well, the only way to predict potential hazards like overpressured zones is through the use of seismic surveys. Seismic methods detect changes of interval velocities with depth from velocity analysis of CMP data. This is based on the fact that, elastic wave velocities in rocks increase during loading due to a reduction in porosity and increases contact at grain boundaries for sediments that compacted normally (i.e. normal compaction trend). A deviation from the normal compaction trend causes velocity of sound waves to reduce and is interpreted in seismic data as indicator of overpressure. To be accurate, precise sound velocity data are needed and this may determine the successful application of this method. Previous works reveal that, accurate prediction of pore pressure from velocity requires two sets of information. One is an accurate velocity trend. The other is sufficient data to calculate the effective pressure at enough points to establish and calibrate a relationship between velocity and effective pressure. That in turn requires density and pore pressure measurements in a similar setting.

The basic assumptions in predicting pore pressure from seismic data include:

- 1) It is assumed that, vertical effective stress controls sediment porosity during burial and compaction.

- 2) Sediment porosity is related to acoustic velocity.
- 3) Seismic velocity predominantly reflects the mudrock velocity and hence mudrock porosity.

### **2.5.2 Drilling rate**

Drilling rate is a useful tool in detection of changes in pore pressure. Formations with high shale pressures are easier to drill, as high porosity results into increasing rate of penetration and taking less weight on bit. This is why ROP is a decent indicator of approaching abnormally high pressures; the ROP will increase with little or no change in wob, rpm, etc. However, it should be noted that, other factors like bit weight, rotary speed, fluid properties, lithology changes, bit type e.t.c. also affect drilling rate. Therefore, this method is only applicable when all the other factors that affect drilling rate are held constant (and since changes in lithology cannot be controlled, the integrity of using this method is at stake). The common procedure for doing this is to establish a normal drilling rate trend and then establish the pore pressure from drilling rate increases above the normal trend line.

### **2.5.3 Shale density**

Sediments density increases with depth as it compacts, as such, a deviation from this trend is assumed to results from pore pressure which prevents further compaction at that depth. Theoretically, this method is an excellent overpressure indicator, but because of the difficulty involved in making precise measurements and selecting the shale that represents drill cuttings, it is not commonly practice.

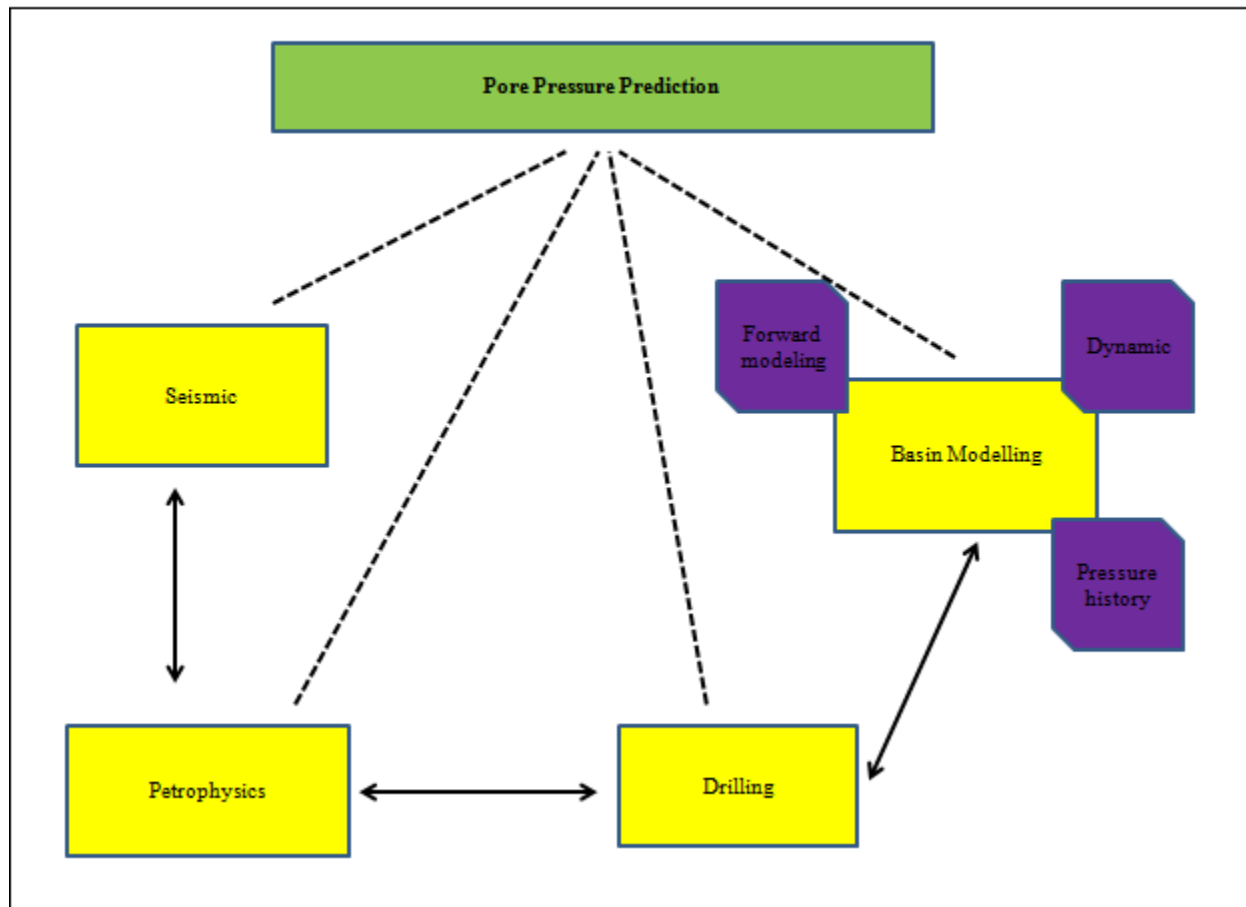


Fig. 15: A schematic diagram showing the methods of predicting pore pressure.

#### **2.5.4 Temperature measurements**

Continuous recording of flow line temperature measurements may serve as overpressure indicator in zones with abnormal increase above the trend line. But because of circulation rate, changes in solid content in the mud, increase bit torque e.t.c. that also affect flow line temperature, the use of flow line temperature should be apply as a secondary indicator of overpressure.

#### **2.5.5 Wireline logs (Petrophysics)**

Direct pressure measurement in porous and permeable formation has been made for decades. But direct measurement in shale (by RFT< MDT< FIT, e.t.c.) seems to be impossible due to their low permeability. And as such, log based prediction is still one of the major method employed to estimate pore pressure in shale formation. It is based on several assumptions about the rock properties and so, unless copious amount of calibration data has been produced, accurate estimation of porosity from wire line logs will be difficult.

Overpressured shale's contain pressured fluid, with lower density and higher than normal porosity. Shale comprises a large portion of most sedimentary basins and forms the seal and source rock for many hydrocarbon reservoirs. It is commonly assumed that overpressured shale is under compacted relative to its depth of burial. And such, exhibit several of the following properties when compared with the normally pressured section at the same depth (illustrated in fig 16):

- 1) Higher porosities
- 2) Lower bulk densities
- 3) Lower effective stresses

- 4) Higher temperatures
- 5) Lower interval velocities and impedances
- 6) Higher Poisson's ratios
- 7) Lower resistivity
- 8) Lower bulk modulus and shear modulus

Wireline methods of pore pressure prediction involves establishment of a base line from normal pressure shale reading, which is been extrapolated into the abnormal pressured region. And in the abnormal pressure region, the observe values are related to the extrapolated values. This is a post drilling method which serves to help in planning for future exploration wells in the area and to better understand the origin of the overpressures. Wireline pore pressure prediction work well in low temperature, young, fine grained sediments particularly where the lithology remains similar throughout the section drilled, and where an upper shallow section exhibit a recognizable normal compaction curve.

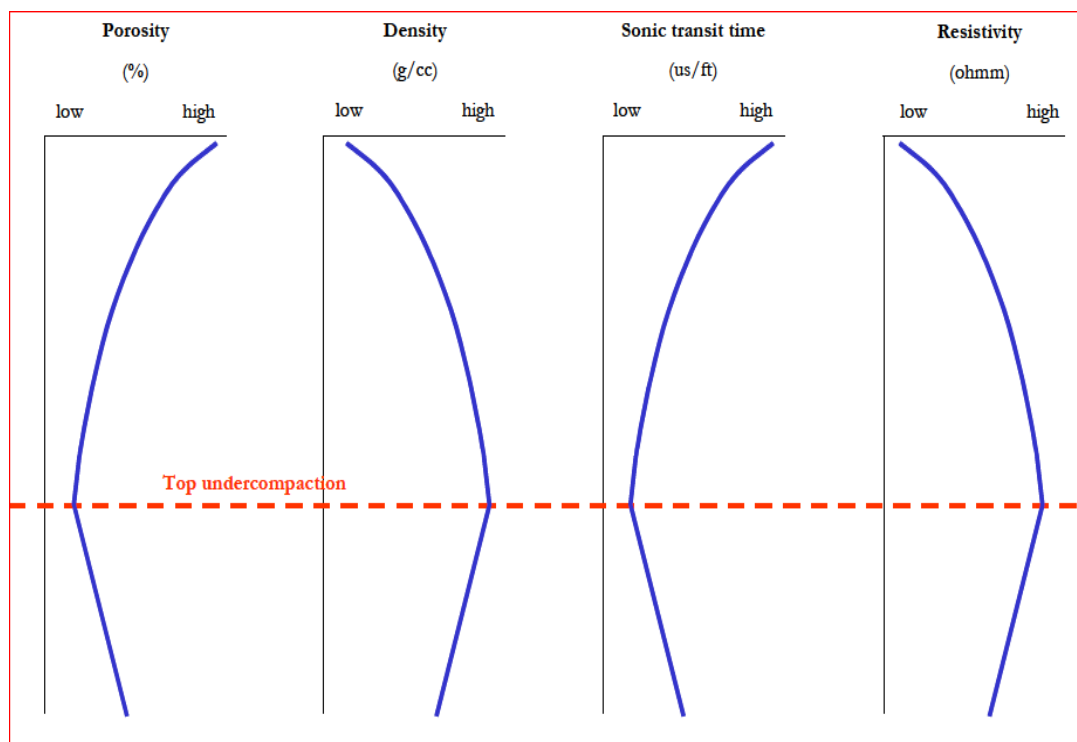


Fig. 16: Showing log responses to compaction disequilibrium

### **2.5.6 While drilling method**

Pore pressure can be monitored while drilling using LWD (logging while drilling), MWD (measurement while drilling), as well

### **2.5.7 Direct pressure measurement**

Direct pressure measurement can be made using wireline pressure tools such as the RFT (repeat formation tester), MDT (modular dynamics test) or by a DST (drill stem test). The formation pressure can only be measured using these tools in permeable formations, and not impermeable layers such as muds, silts, shales, marls and chalk. A permeable layer is needed because the measurements require a flow of pore fluid from the formation. It is often assumed that mudrocks in the section have pore pressures equal or similar to the reservoir section directly above or below the mudrock interval.

### **2.5.8 Basin modelling**

Data derived from drilling logs, core and cutting samples, company literature, published reports and seismic profiles, and grids are used in the construction of pore pressure model.

Other methods include; sloughing rate, gas units in mud, chloride content, change in mud properties, bentonite content in shale, and paleo information.

## **2.6.0 Data Description**

A brief description of the data set used in this work is as below:

### **2.6.1 Wireline logs**

The majority of the data used in this study are from the open-hole wireline logs.

### **2.6.2 Caliper log**

The caliper log was supplied for all wells in this study and proved important when picking data points. The tool makes measurements of the well bore diameter as it is pulled up the borehole by means of one or more spring mounted arms.

The caliper log is very important in overpressure study as pressure tends to cause a number of problems during drilling. These problems often resulted in damage to the borehole and influenced the response of the other wireline tools, such as the density tool, which rely on direct contact with the borehole wall to take measurements. In standard petrophysical analysis of wireline logs, borehole corrections are applied to the different tool responses to compensate for the effects of the changing borehole diameter.

### **2.6.3 Natural gamma ray tool**

All rocks emit natural gamma radioactivity as a function of their mineralogy where radioactive elements, chiefly potassium uranium and thorium, are present. As the radioactive elements decay, they emit alpha particles, beta particles or, of prime importance for this tool, gamma rays. A scintillation detector in the tool detects gamma rays, and the number of detected gamma rays is recorded in standard API (American Petroleum Institute) units.

The radioactive isotopes of potassium, uranium and thorium are found in a number of minerals such as illite (potassium), organic matter (uranium) and heavy minerals such as zircon and sphene (thorium). All of these minerals are normally far more abundant in shales than sandstones (the dominant lithologies encountered in the wells in this study) so shales have higher gamma ray API responses than sand bodies.

The importance of the gamma ray tool to this study comes from the fact that it was supplied for all the wells and is the main data source used to subdivide the lithology.

#### **2.6.4 Sonic log**

Along with the gamma ray, caliper and resistivity tools, the acoustic logging tool is used as standard for logging wells. For this study the sonic log is considered to be the most accurate as it is largely unaffected by borehole size, formation temperature and pore fluid salinity.

The tool measures the interval transit time (ITT) of the formation being investigated. A compressional wave signal is emitted at one end of the tool and travels through the mud into the formation, is refracted along the borehole wall, and generates head waves which are refracted back into the borehole to be detected by the two receivers at the other end of the tool. Since the spacing between the two receivers is constant, the difference in signal arrival time corresponds to the speed of sound in the formation between the two receivers. And the measured interval transit time is taken to represent the velocity at the midpoint between the two.

Special circumstances where the first arrival is not the head wave from energy refracted along the borehole wall include cases of severe borehole damage/fractures, the presence of gas in the pore spaces and very high porosity.

The key factors that do affect the acoustic log are formation type, and compaction related effects such as porosity/density and are therefore directly applicable to pore pressure evaluation.

The sonic log is not as strongly influenced by borehole conditions as some of the other logging tools such as the density log. However, caving and rugosity can induce spikes on the sonic response.

In normal compaction profile, the transit time should decrease with depth due to decreased porosity and increasing density. Abnormally pressured shale tends to have higher porosity and lower density than normally pressured shale, and hence are easily depicted by acoustic log signature.

### **2.6.5 Resistivity and conductivity log**

The resistivity and induction tools are used in almost all wells drilled to measure the electrical current carrying capacities of the formations. The resistivity tools measure the formation's resistance to the flow of electrical current (the resistivity), whilst the induction tools measure the formation's ability to conduct current (the conductivity). The measurements are equivalent since the conductivity is the reciprocal of the resistivity.

The flow of current in the formation is controlled by a number of factors: the resistivity of the pore fluid, the resistivity of the matrix material, the resistivity of the mud-filtrate, porosity, salinity of the pore fluid and the temperature.

The resistivity effect of the mud-filtrate is overcome by using deep resistivity reading which are taken outside the mud zone. And since salinity does not normally vary greatly with depth, its effects are often discounted. Temperature on its own normally increases uniformly with depth and hence, resistivity value can be corrected for the temperature increase. Therefore, only porosity affects resistivity majorly, thereby making it effective as a viable porosity determinant tool to complement acoustic log.

### **2.6.6 Density log**

The importance of the density log to this study is for the calculation of shale porosity and vertical stress in the wells. Density increases with depth due to the increased compaction resulting from

the weight of the overlying sediments as new sediments were been deposited. In abnormally pressured shale, compaction is often retarded, resulting in an increased porosity and thus lower density than normally pressured shale at an equivalent depth. Such a decrease in shale bulk density value from normal compaction value is observed when entering a zone of abnormal pressure. Where it has been supplied for analysis, density-derived porosity is used for comparison with porosity computed from the sonic log. Such a comparison has been proposed for use in determining whether unloading had contributed to observed overpressures (Bowers, 1998). The theory here is that unloading induces a change in the fabric of the shales which affects the sonic waves more than the density log, causing a separation in the two tool responses over the interval i.e. unloaded.

The density tool works by bombarding the formation with medium energy, focused gamma rays and measuring the back scattered flux of gamma rays at near and far detectors. As the density of the formation increases, so the count per second of gamma rays decreases.

To accurately measure the formation density, the source and detector are kept as close to the formation as possible. This is achieved by mounting the source and detectors on a sensor pad that is pressed hard against the borehole wall by a spring mounted caliper arm. Problems arise with the measurements when the sensor pad is not in contact with the borehole wall due to caving or increased rugosity (a measure of the roughness of the borehole wall). As the separation between the sensor and the borehole wall increases, the density values become representative of the mud, which results in "spiking" of the log response or intervals of anomalously low values when large caves are encountered.

### **2.6.7 Seismic data**

Seismic data (the two way transit time of a controlled acoustic energy within the earth that is reflected back from the boundaries in the subsurface) remain the major source of information ahead of the drill bit. The conventional processing of seismic data produces a good synthetic image of the Earth's subsurface geologic structure. But, the process involves smoothening of the velocity to give a good stack section, which tends to overlook zones of small reversal which is of interest to pore pressure prediction. As such, it is important that special seismic processing should be carried out for pressure prediction.

### **2.6.8 Formation pressure measurement**

Formation pressure can be measured only where the formation is sufficiently permeable for fluid to reach equilibrium with the pressure gauge in a reasonable period of time (i.e., measured in minutes rather than hours or days).

Several wireline tools have been developed for fluid sampling and pressure measurement in order to provide detailed fluid properties. The close repeatability of the mud pressure measurement gives confidence that the tool is working properly.

Common results from a wireline pressure test are:

A good test

- (1) A tight test occurs when the permeability of the formation is low enough that pressure build-up time is longer than 10-15 minutes. Operators are generally reluctant to leave the tool in place down hole for much longer than this for fear of tool sticking in the borehole. If the pressure build up has not achieved a stable value, then an accurate formation pressure cannot be assessed and the result is logged as "tight".

(2) A seal failure occurs when the probe is not isolated by the packers from the drilling mud.

In this case, the pressure measurement is often close to the initial and final "hydrostatic" mud pressure measurements.

(3) Supercharging occurs when invasions of borehole fluids at pressures higher than the formation pressure "charge" the zone around the wellbore. As a result, measured pressures will be too high, but generally less than the "hydrostatic" mud pressure. Supercharged zones are often recognized by plotting the measured pressure data to establish a gradient against which the higher-pressure tests will plot as anomalies.

A brief description of the pressure tools used for measuring the data in this work is as follows:

#### **2.6.9 Reservoir characterization instrument (RCI)**

Barker Atlas's RCI wireline formation pressure testing and fluid sampling tool allows numerous repeat pressure tests without having to reset the tool and packer against the borehole wall and without forcing fluid back into the formation. A sensor measuring the electrical properties of the fluid helps to distinguish mud filtrate from formation fluid.

#### **2.7.0 Repeat formation tester (RFT)**

This tool succeeded the formation interval tester in about 1978. Repeat formation test tool (fig 17) has been designed to:

- 1) Measure Formation Test
- 2) Collect Reservoir Fluid Samples.

The tool can make an unlimited number of pressure measurements and can normally collect two samples of the borehole fluid on a single "run". The tool operates by isolating a small area of the formation from the well bore fluids and allowing formation fluids to flow into two chambers. A

pressure gauge records the inflow into and the subsequent pressure build-up, the rate of which is a function primarily of formation permeability.

The pressure is continuously monitored throughout the test which comprises

- An initial flow period,
- An initial pressure builds up period, which yields the Initial Shut in Pressure (ISIP), the best estimate of true formation pressure.
- A second period of flow. And a final pressure build up which yields the final shut in pressure (FSIP).

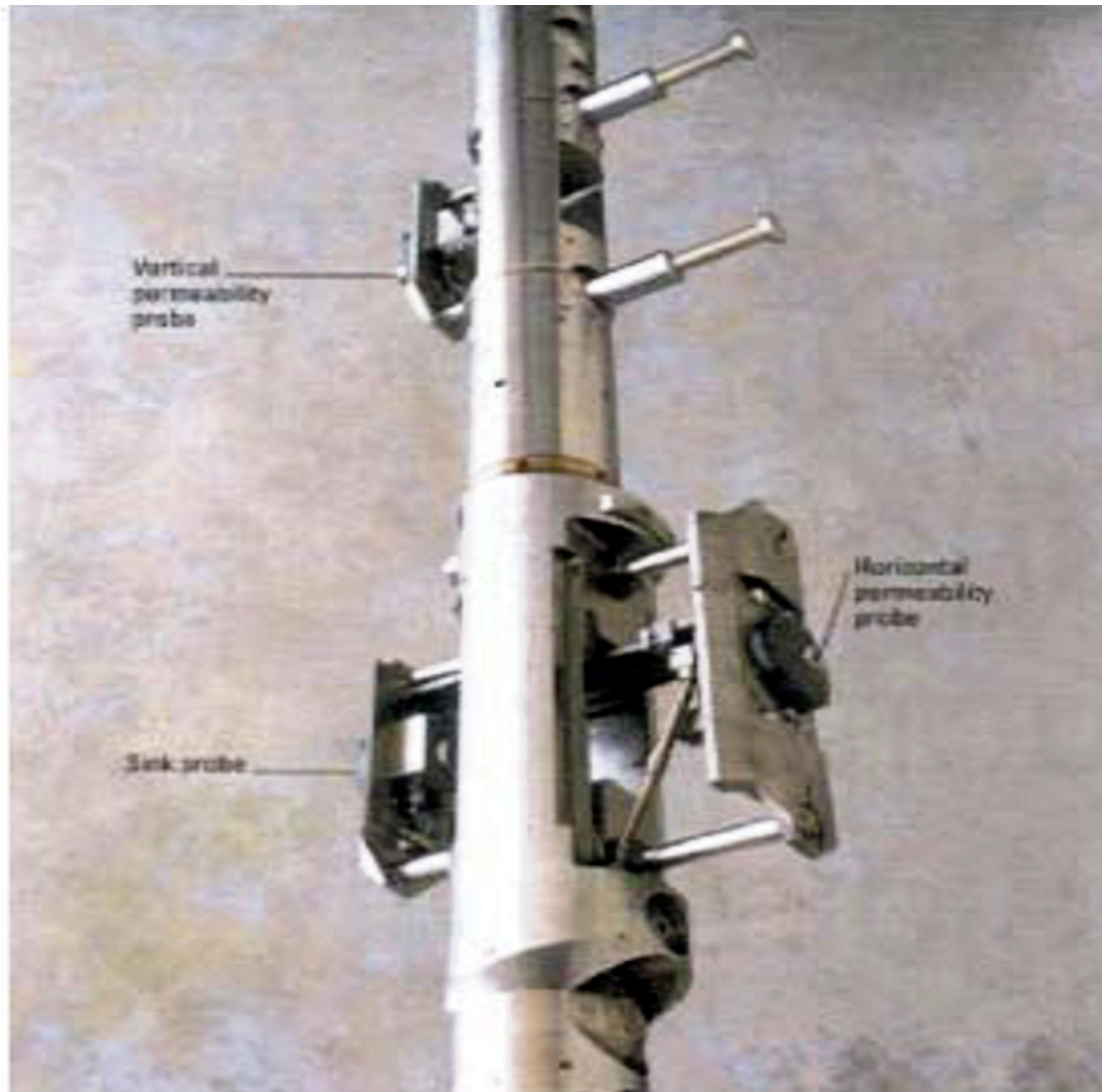


Fig. 17: Modern multi tester tool (RFT, DST é ) from Schlumberger.

### **2.7.1 Modular formation dynamics tester (MDT)**

Schlumberger's MDT tool is their latest generation fluid sampling tool. It has multiple probes (up to three), which allows measurement of in-situ vertical and horizontal rock permeability. In addition, the tool is able to collect more fluid samples during a single run by adding additional sample chambers.

### **2.7.2 Leak off test**

Estimates of minimum stress from leak off tests (LOTs)

LOTs are performed to assess the minimum stress values in the section cut by the wellbore. The LOT is generally conducted after casing has been set in the well and cement has been applied to isolate the shallower sections from any higher pressure fluids that may be encountered deeper in the section.

Firstly, a short section (typically 20 feet) is drilled below the base of the cement before increasing the pressure in the borehole until mud is lost into the formation. The pressure in the mud is continuously monitored and recorded throughout the test. As long as the cement is sound, mud loss is a consequence of failure of the rock usually by the propagation of fractures in the direction of minimum stress. The LOT pressure value represents the magnitude of the minimum stress plus the tensile strength of the formation, which has to be exceeded before fractures will form (Swarbrick, 1999; Mouchet and Mitchell, 1989).

In many cases "leak off" is not reached, but a defined maximum pressure is reached without mud loss, and considered high enough to continue drilling ahead safely. This is often referred to as a formation integrity test (Swarbrick, 1999).

## **CHAPTER THREE**

### **3.0 Methodology**

The following are the methodology adopted:

#### **3.1 Data Loading and Quality Checking**

To ensure that the available data is in the right format, appropriate quality steps were taken. The coordinate system and the reference elevations were checked and accurately set in ROKDOC to map the project in a correct geographic location in space. Correct log units and scales were set in the ROKDOC project before loading the data set. A systematic order was followed in loading the data set, to ensure accuracy. Well deviation data were loaded before conversion is done from measured depth to true vertical depth. This is to ensure a correct depth conversion. Caliper logs were used to check for washout and expansion zones to ascertain integrity and uncertainty level.

##### **3.2.1 Overburden Stress**

Overburden stress is an important parameter for pore pressure prediction. It is an estimate of the combined weight of the fluid and the matrix rock above the depth of interest. The estimate is used in the determination of overburden gradient which is fixed in Terzaghi's equation as a proxy for maximum principal stress for relating effective stress and pore pressure.

Overburden pressure is calculated from bulk density using cumulative summation of the sediment weight for each depth interval. The greatest challenge with overburden pressure evaluation is any large gaps in the density data and extrapolation of density data from the shallow section where the density was not logged. The common methods for overburden pressure estimation include fixed gradients (e.g. 1.0 psi/ft. which assumes a constant mudrock porosity of 24% and tends to overestimate overburden pressure at the shallow section and

underestimate overburden pressure at the deep end), local density log integration (which is the method used for this work), and regional relationships.

To generate a robust overburden pressure, a model fit is calculated from the input Rho log (called Rho fit) in ROKDOC software.

The exponential equation was used to calculate the Rho fit:

$$\text{Rho}(zml) = (\text{RhoMatrix} - \text{RhoTop}) * \exp(-b * zml)$$

Where: Rho (zml) = density at depth z below mudline; RhoMatrix = matrix density, RhoTop = density at mudline (seabed) and b is the compaction coefficient.

This Rho fit gives a good estimate of the gradient above the first density reading.

The model derived density is now integrated to generate an overburden profile (Pob) for each well. For Pob (from Rho log), the gaps in the input Rho log is filled using the value derived from the model Rho fit.

### 3.2.2 Shale Volume

As a way of picking the clean shale formation interval, in order to be able to use it for establishing the compaction trend, the volume fraction of shale Vsh is usually measured along well bore. It represents the volume fraction of shale as measured or inferred from formation properties. It is missing in the entire well analyzed for this work; as such it was generated from GR log with Ikon Science Rokdoc software using the standard equation:

$$V_{sh} = (GR_{log} - GR_{sd}) / (GR_{sh} - GR_{sd})$$

Where:

$GR_{log}$  = log response

$GR_{sd}$  = log value in clean sand

$GR_{sh}$  = log value in clean shale

The  $V_{sh}$  output is also used as additional filter in picking clean shale during NCT generation.

### 3.3 WORKFLOW

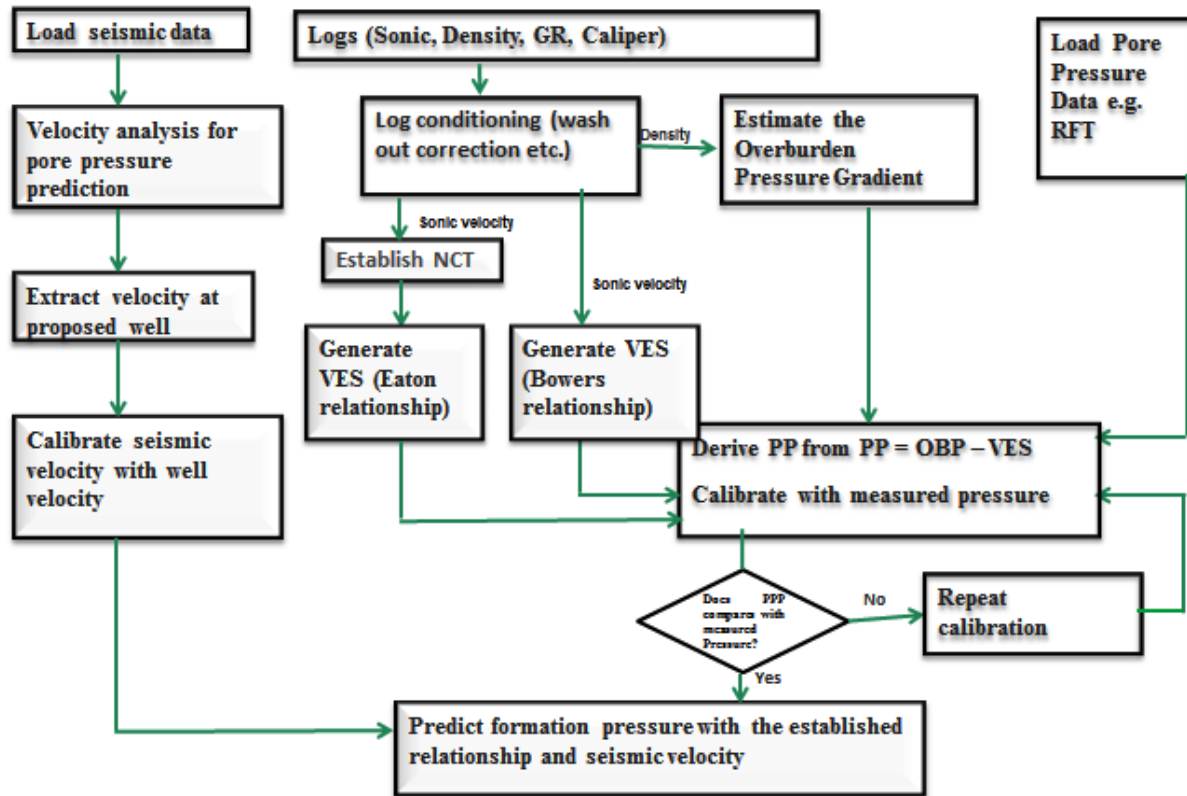


Fig. 18: Showing the workflow of calibrating well data with seismic velocity for pore pressure prediction

### 3.4.1 Log filtering

As part of achieving an accurate result, petro-physical quality control combined with frequency filtering to 30Hz was applied on gamma ray, density and sonic velocity logs. This results in a less spiky log set. Shell filtering tool was applied for this purpose.

### 3.4.2 Transferring shale intervals to porosity indicating datasets (vp shale filtered trend).

In pore pressure prediction work, emphases are placed within the shale (low permeability) interval, because those are the zones where pressure cannot be measured real time.

Velocity values were picked within the clean shale interval selected based on the volume of shale calculated from the lithology log (GR) i.e. velocity values were picked at point where the volume of shale is above a specified cut-off usually 0.5 out of 1. The log values in shale are passed into a chimera filter, which applies a kalman filter and then fit a spline to the filtered values. The filtered and smoothed output log is a shale trend.

### 3.4.3 Normal compaction trend

This step is necessary because on a velocity i depth plot, velocity should increase symmetrically with depth as a result of compaction (termed normal compaction trend). A deviation from this is related to overpressure.

This is an estimate of porosity (proxy to porosity) if the formation was compacted normally.

A normal compaction trend model is calculated from input log data (NCT fit). This trend is estimated using the reciprocal input log transform given below.

$$\frac{1}{V_{p(mi)}} = \frac{1}{V_{pMatrix}} + \left( \frac{1}{V_{pMatrix}} - \frac{1}{V_{pTop}} \right) * \exp(-b * Z_{ml}).$$

This was generated using velocity within clean shale in each well with Rokdoc. Shale cut off of Vsh > 60% was applied and the data points removed are greyed out.

### **3.4.4 Vp – Rho cross plot**

Cross plotting velocity with density log, in order to understand the mechanism of over pressuring of the field is an important part of geopressure prediction. As showned by Hermanrud et al (1998), overpressures resulting from compaction disequilibrium, is usually showed with a marked decrease on all porosity indices logs. While secondary mechanism overpressuring is noticeable with a reversal in velocity and resistivity log without any significant change in the density and neutron log response at such depth. This is the justification for crossplotting velocity against density to probe the origin of the overpressures.

This was done colouring it with gamma ray as well as depth to enable us understand the behavior of velocity and density with change in depth/with change in lithology.

Hoesni's Vp – density crossplot was chosen instead of Bowers Vp – effective stress crossplot approach because, effective stress cannot be measured directly in the field, and a certain percentage of error could have been introduce by the calculation process, which may be further amplified when applied in further work.

### **3.4.5 Deriving a relationship between velocity and pore pressure using Eaton's and Bowers' method**

It is crucial to establish a relationship between velocities and pore pressure using offset well data. This is because, it enable us to test how reliably well, the acoustic parameter can be used to determine the formation pressure and to as well derive the calibration parameters required in the methods used. The established relationship will be applied on seismic velocity to predict formation pressure ahead of drilling. The accuracy of the relationship is based on the availability of measured pressure data to logged depth, which serves as a calibrating standard. Acoustic sonic velocity is inputted into the equation of the two methods using ROKDOC to establish the relationship.

### **3.5.0 Seismic velocity analysis for pore pressure prediction (picking of vacks)**

There are many different types of seismic velocities, but only those velocities that are accurate and are close to the propagation velocity of the formation under consideration are suitable for pore pressure prediction. Processing of seismic velocity is to account for the moveout in reflection time with offset. Common processing procedure sort data into common midpoint gathers and determines the best-fit normal moveout velocity ( $V_{nmo}$ ) as a function of vertical two way time for each major reflector i.e. velocity that flattens the reflector at zero-offset time. Generally, stacking velocities are in adequate for detailed pressure prediction work this is because of migration velocity that is applied to seismic volumes during processing to improve image quality. Migration velocity is usually a smoothed version of the stacking velocity field that has been adjusted a few percent. This usually results in a highly smoothed velocity field that is designed to operate with migration algorithms that are not designed to handle abrupt changes in the velocity across features like faults, salt bodies and other geological features. Velocity analysis for geopressure prediction is designed to detect such abrupt velocity changes and record them for use in the prediction process. This is the reason why this tedious process of picking the best velocity that flattens the reflector at zero offset must be embarked upon, to ensure the accuracy of the prediction. Shell 123DI software was used for this process.

#### **3.5.1 Seismic velocity calibration with well data**

There is need to do a comparison between well velocity and seismic velocity in order to determine whether a calibration shift of the seismic velocity to match the well velocity is necessary. Calibration shift is a vital stage since if the well and seismic velocities do not match, a prediction using normal compaction trend from the well on seismic velocities will produce a spurious pore pressure prediction. This was done by crossplotting the two velocity sets and fit a

polynomial curve to derive a relationship between the two velocities. The polynomial equation is applied to the seismic data to get a calibrated seismic velocity.

### **3.5.2 Pore pressure/ fracture pressure prediction**

The formation pressure prediction was carried out applying both Eaton's and Bowers's method. The parameters in the equation have been derived one after the other as stated above in the methodology. This last stage is to combine all parameters in one equation to derive the formation pressure. Ikon science ROKDOC software was used for this process.

The predicted pore pressure was applied in Mathew and Kelly equation of fracture pressure prediction to determine the minimum stress at which a formation will fracture.

## **CHAPTER FOUR**

### **4.0 Results and Discussion**

This chapter is aimed at presenting the result of the pore pressure prediction.

#### **4.1.0 Overburden Pressure**

The offset well data was used to derive the overburden pressure. The deepest well closed to the proposed deep exploration well was used because of its depth of penetration and the quality of the log.

The overburden gradient derived from density log (shown in fig. 19) plotted parallel to the gradient generated assuming a fixed gradient of 1.03 psi/ft. Based on the calculations carried out using the density log, the overburden gradient ranges from 0.78 to 0.96 psi/ft. The gradient was extrapolated over intervals where we do not have density log reading.

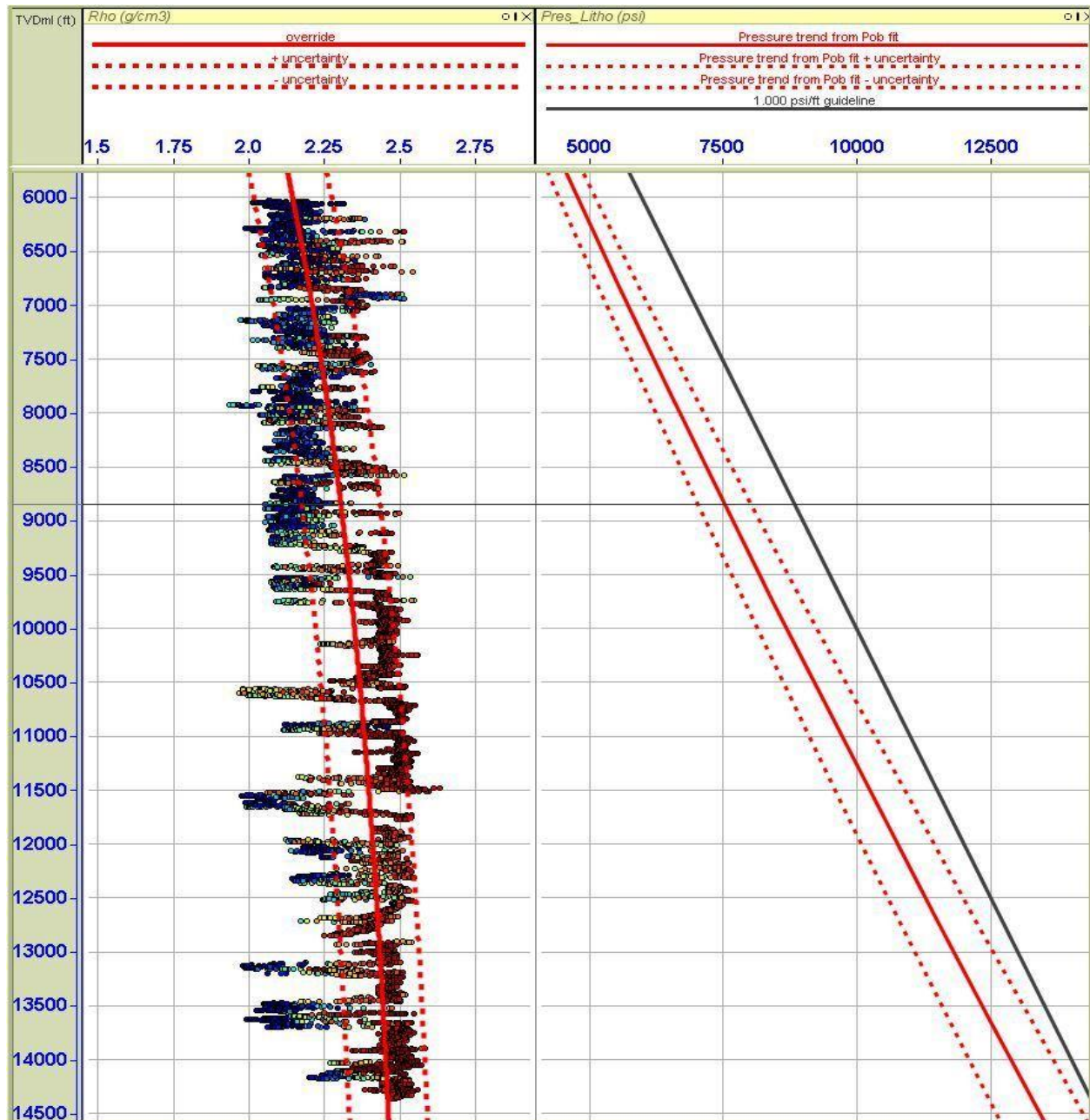


Fig. 19: A sample of OVB generated from the density log.

The black line on the left represent overburden pressure of a fixed gradient, while the red line is the estimated overburden gradient from density log with the error margin in dotted line. On the left hand is the density log (Rho) and the Rho fit.

#### **4.1.2 Shale volume**

An example of a plot of volume fraction of shale is shown in fig. 20. The first log column to left shows volume of shale and clay calculated from GR log. The middle log is GR log bound with crosshair line indicating the calculation extent. While the last log to the right is a volume fraction set, showing the major lithology in Niger Delta (sand coloured yellow and shale coloured green).

#### **4.1.3 Log filtering**

The de-spiking process result in clean log in which the noise effect as well as measurement errors sometimes referred to as "cycle skips" on the log have been removed. Fig. 21-23 shows the various log types before and after de-spiking.

#### **4.1.4 Vp shale filtered trend**

Applying a shale cut off of 0.5, helps to remove the velocity within the sand intervals as shown in Fig. 24. This is to allow us fit a compression trend within the cleanest shale.

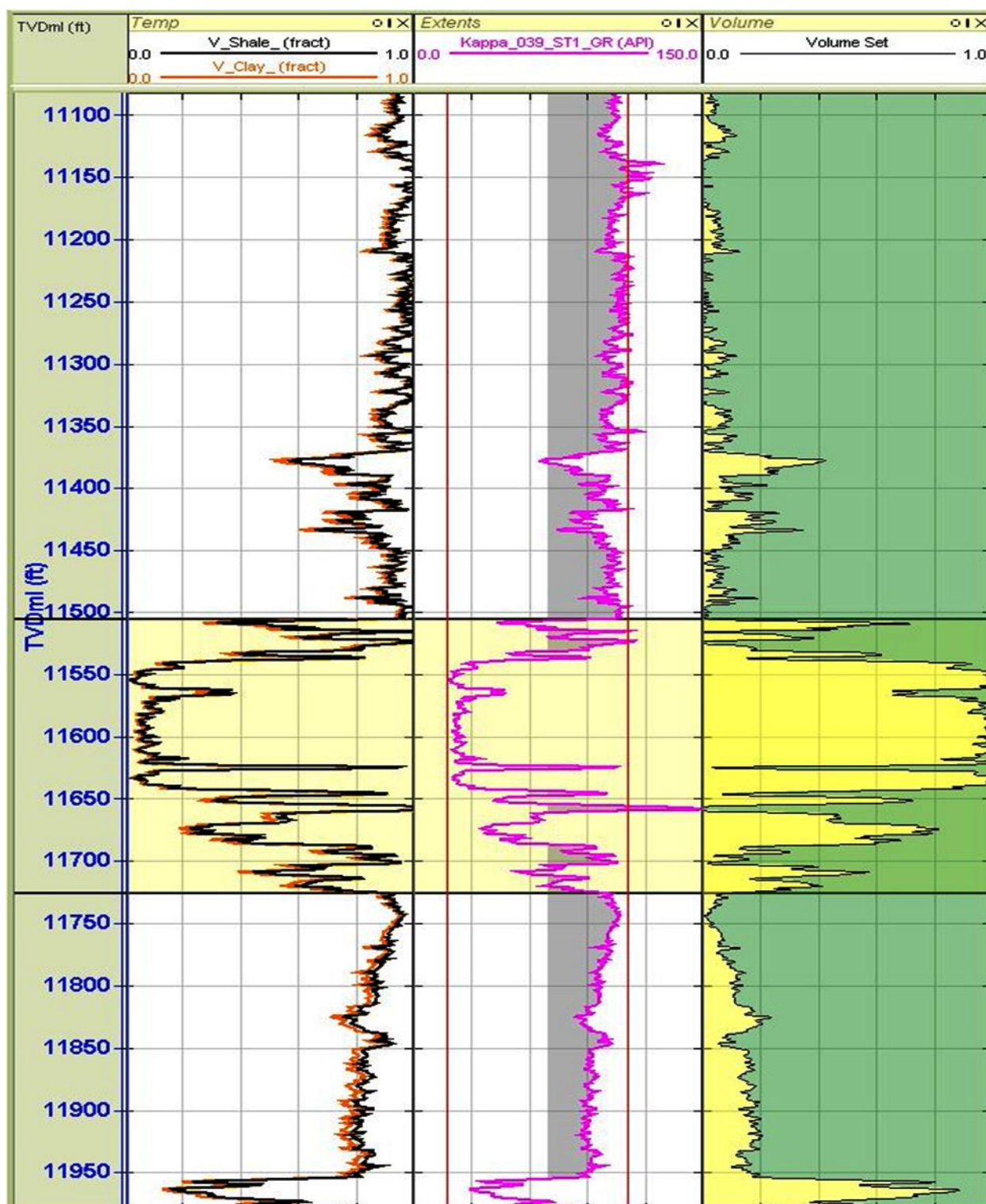


Fig. 20: Showing the Vshale log generation where Vshale tracks the Vclay.

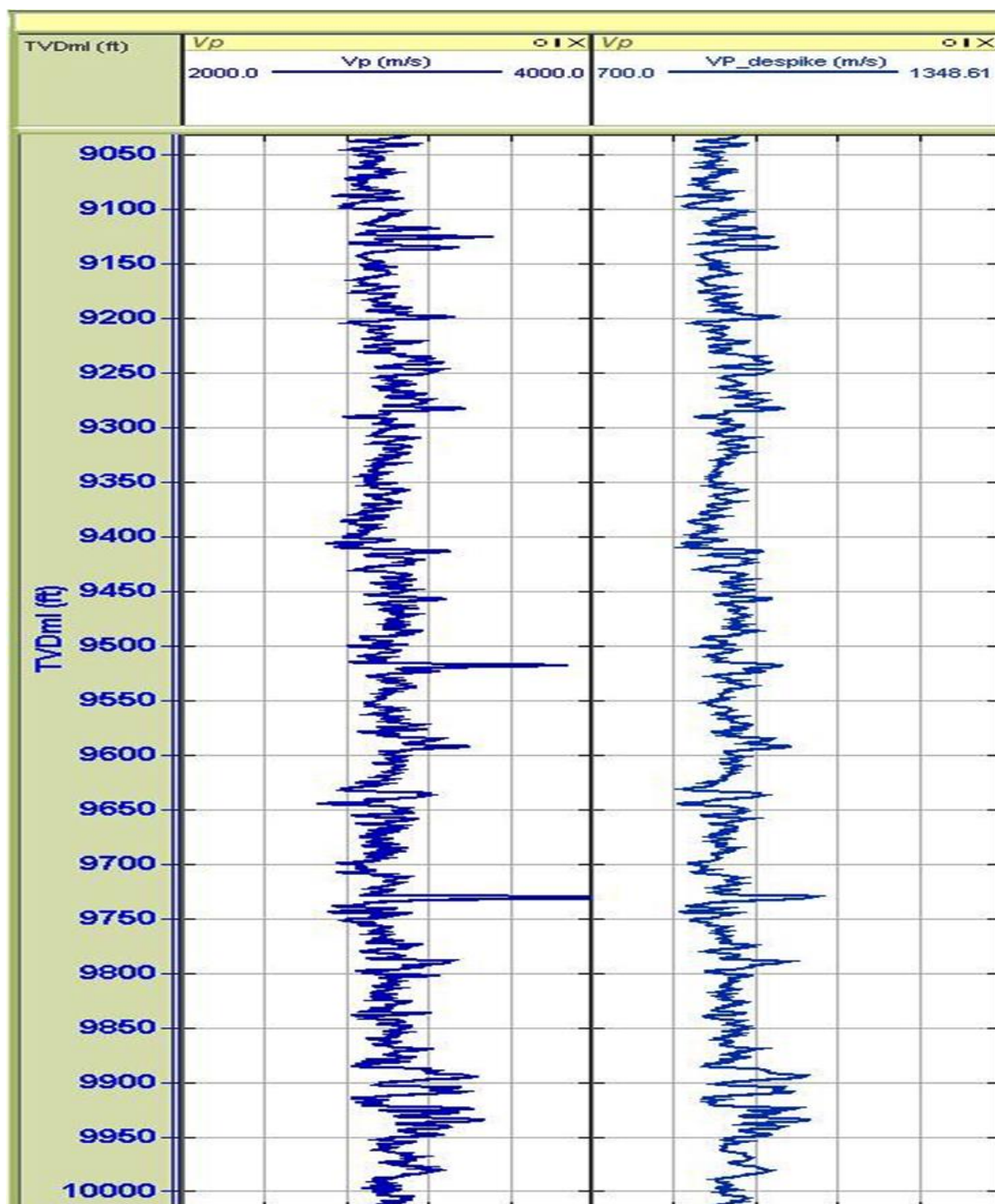


Fig. 21: Showing Vp log before and after filtering.

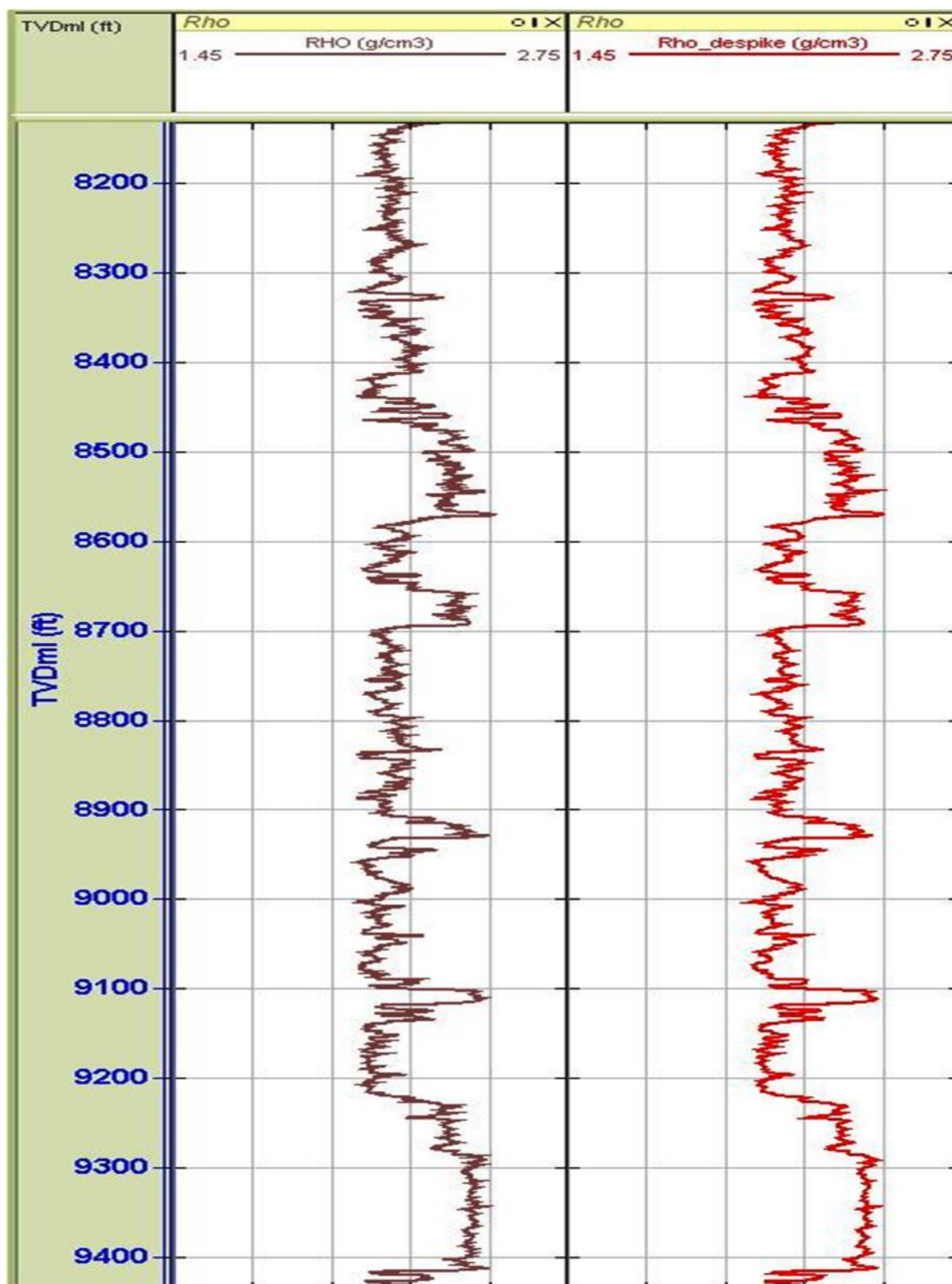


Fig. 22: Showing density log before and after filtering.

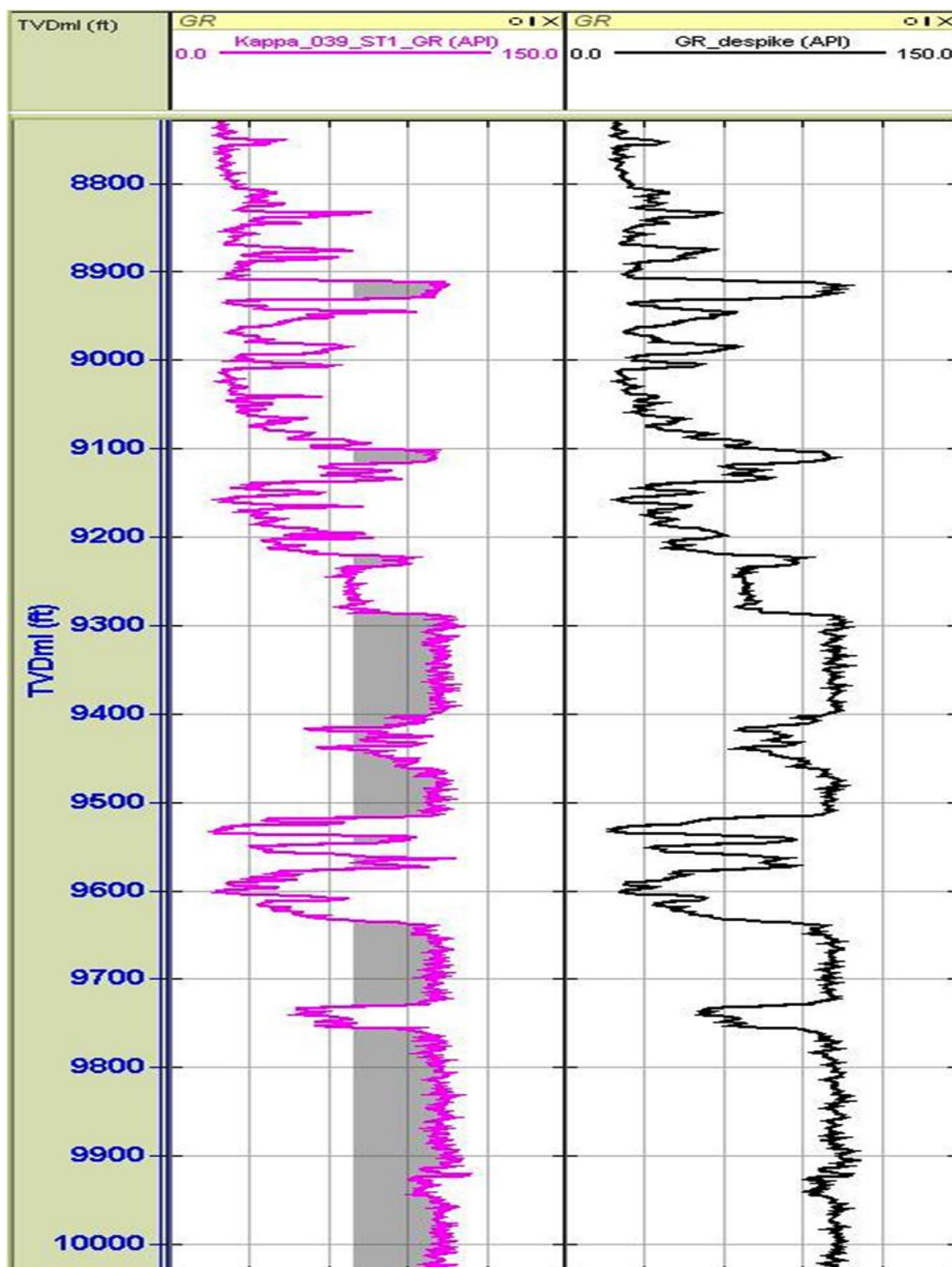


Fig. 23: Showing GR log before and after filtering.

#### 4.1.4 Vp shale filtered trend

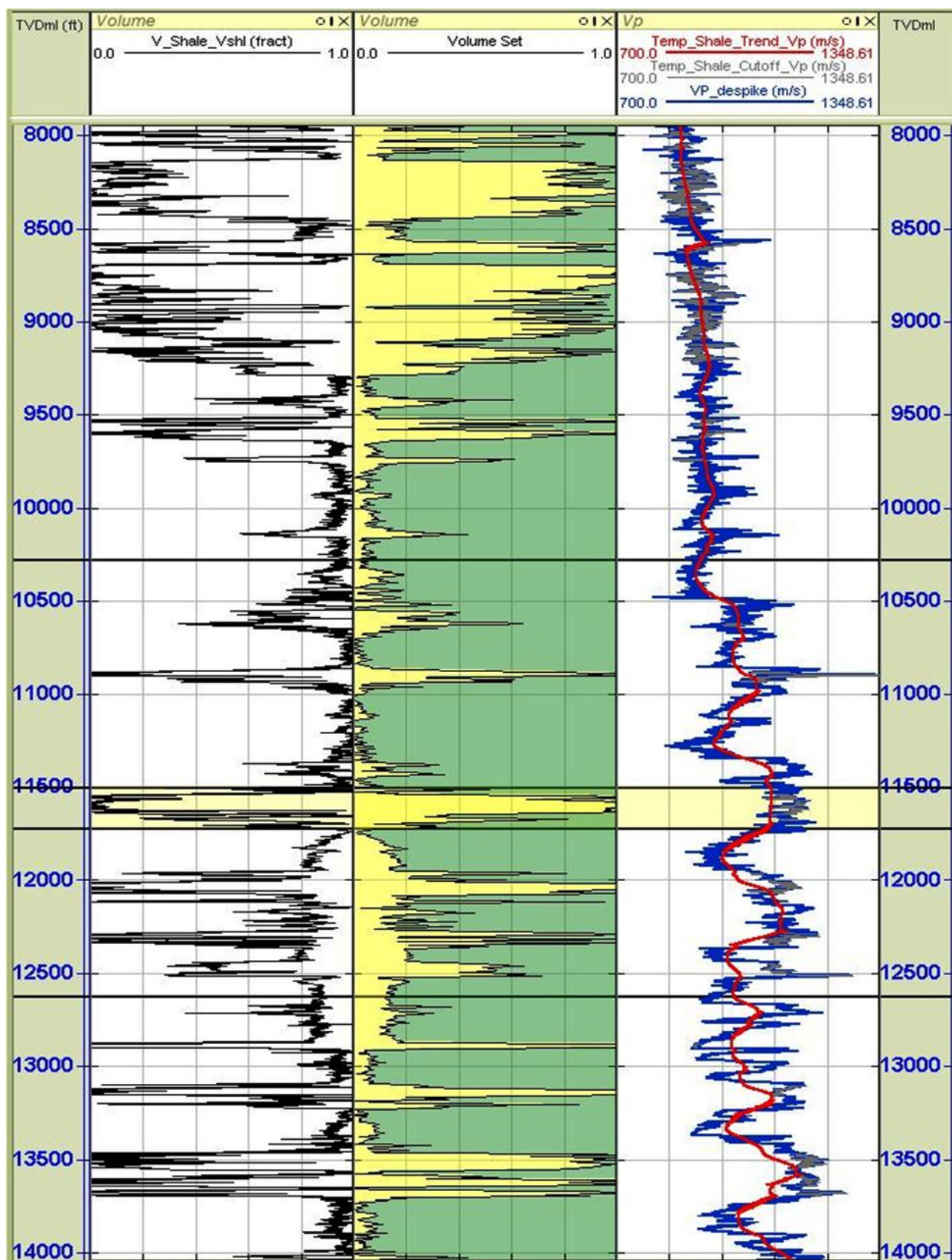


Fig. 24: Showing Vp shale filtered trend.

Fig. 25 is a display of all the logs ( starting with GR overlaid with caliper log to the left, lithology log, volume fraction set, Vp (Vp, Vp shaletrend, and Vp NCT), Vs, density (Rho), porosity, resistivity, p\_sonic (interval transit time) and s\_sonic. The caliper log shows there is no so much wash out, thereby establishing the data quality, which is essential for this kind of special work. The NCT showed a marked deviation from the observed compaction trend at the shallow depth which is an indication of porosity preservation as a result of disequilibrium in compaction of the sediments. At a depth of about 10,600ft, there is a marked increase in resistivity reading corresponding with a sharp decrease in density and velocity data which also indicate overpressure.

#### **4.1.5 Normal compaction trend**

A trend fit to the sonic velocity in fig. 26, shows a pronounced compaction gradient that increases at a fast rate at the shallow depth and a slow rate at greater depth. The sediments compact normally until a depth of about 10300 ft. (TVDml) where we have the onset of overpressure. Shale cut off of 0.5 was applied to remove sand intervals which are the greyed out points on the plot. Overpressure onset depth falls within the 15.0 MFS (maximum flooding surface), which suggest the 15.0 MFS as the sealing boundary that acts as a blanket preventing the total expulsion of pore fluid, which in porosity being retained at depth.

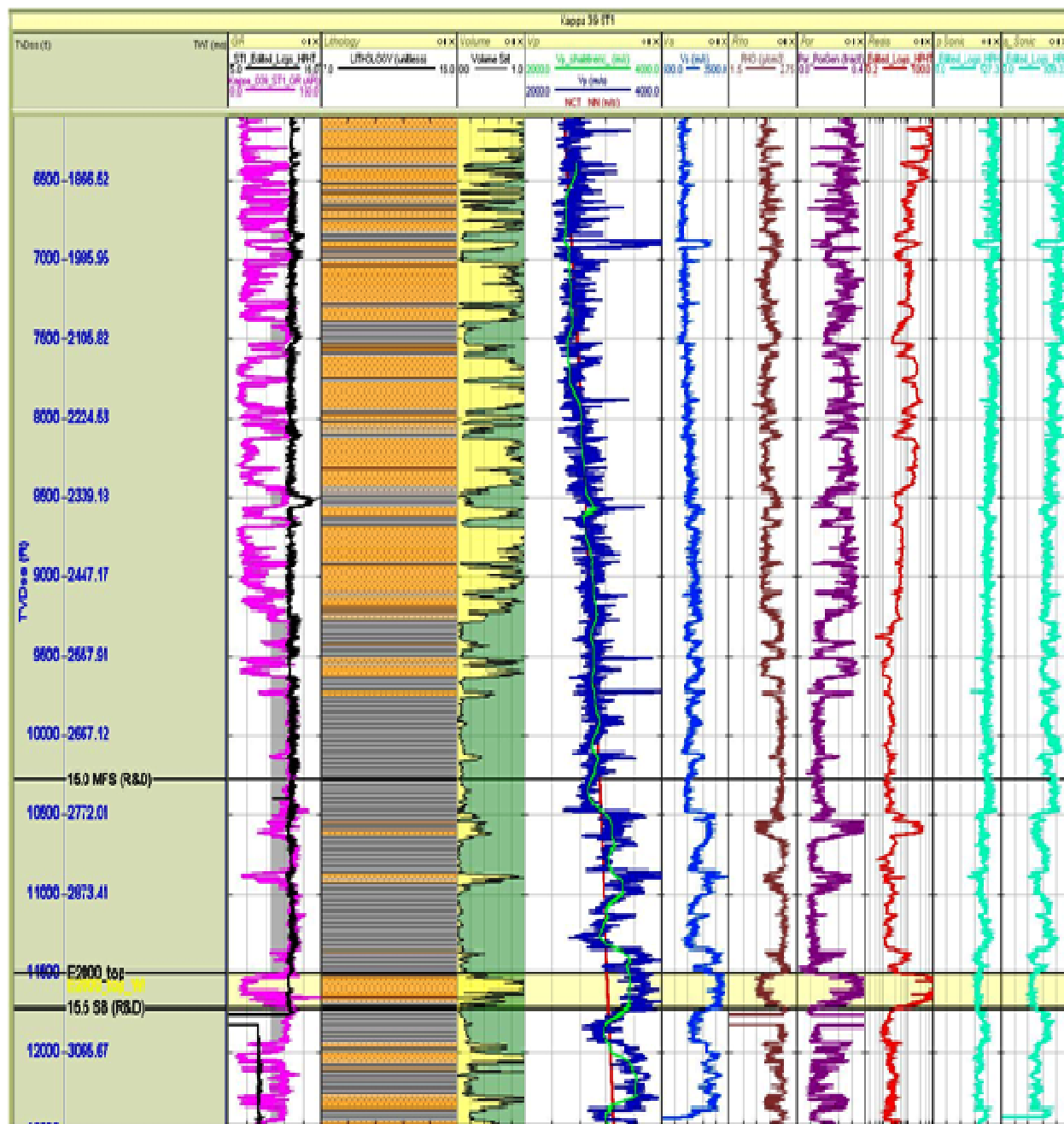


Fig. 25: A view of Kappa 39 ST 1 logs use for this work.

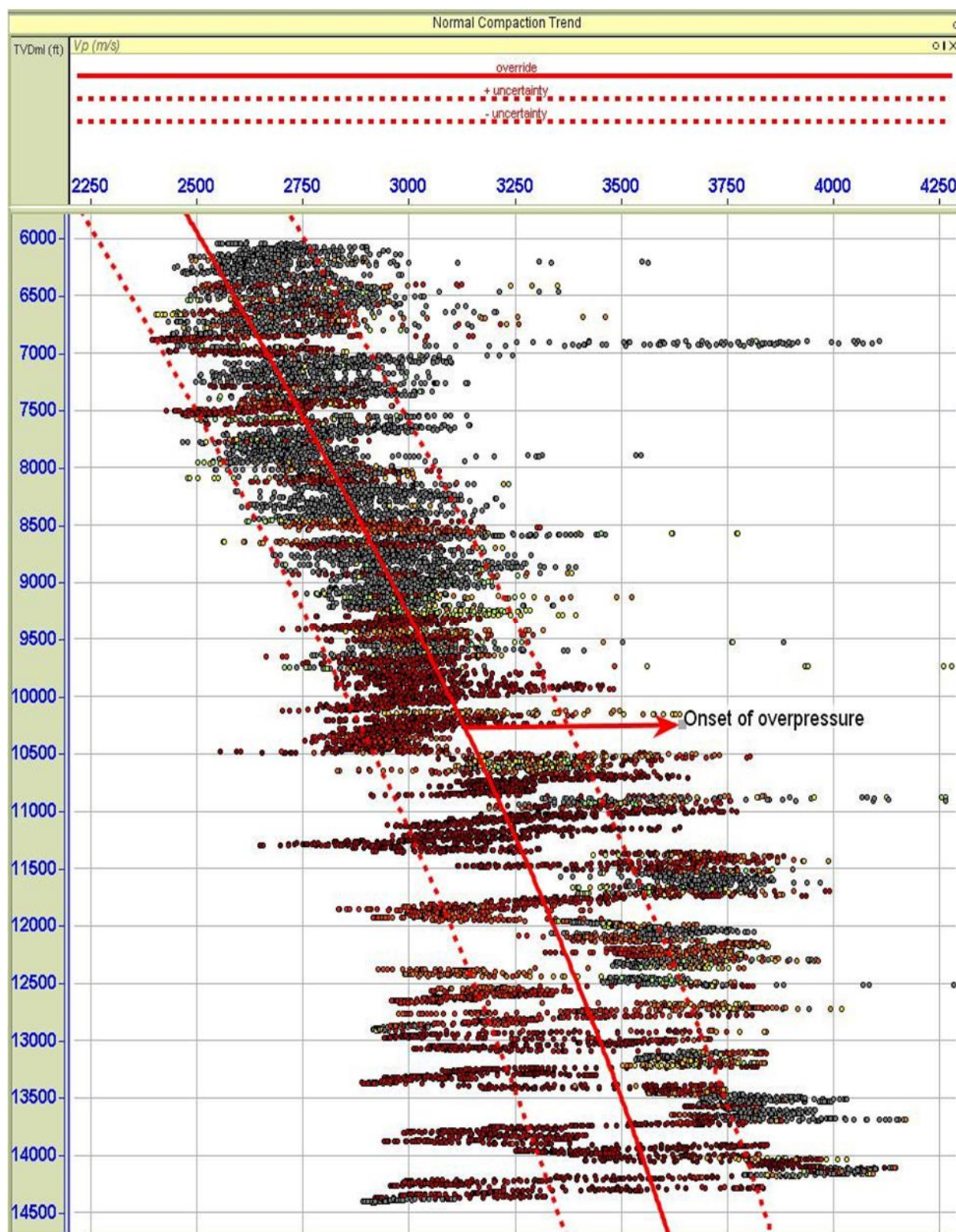


Fig. 26: Showing sonic velocity generated NCT.

#### 4.1.6 Vp – Rho cross plot

A plot of Vp vs Rho as shown in fig. 27 and 28 suggests compaction disequilibrium as the mechanism responsible for the overpressures (as illustrated by Hoesni curve) i.e. a typified increase in density with a corresponding increase in velocity. The plot was coloured by depth to show the behaviour of density and sonic velocity with depth. There is a sharp increase in density gradient at shallow depth to a depth of 10,200ft which correspond with the maximum flooding surface as well as the top of overpressure. The velocity/density gradient changed from that depth onward, as well a pronounced reversal in velocity and density readings.

Colouring the crossplot with GR log (with a shale cut off of 0.5), showed that the onset of overpressure which is inferred from change in velocity/density gradient falls within the shale interval. This further confirms that the fluid retention at that depth is as a result of rapid influx of low permeability sediments during within the 15.0 maximum flooding surface.

The same crossplot for other wells in the same field showed increase in velocity with corresponding increase in density. As all the plots could not be shown in this print out considering the number of plot involve and since all of them have the same pattern, some sample plots are as shown in fig. 29 ÷ 31.

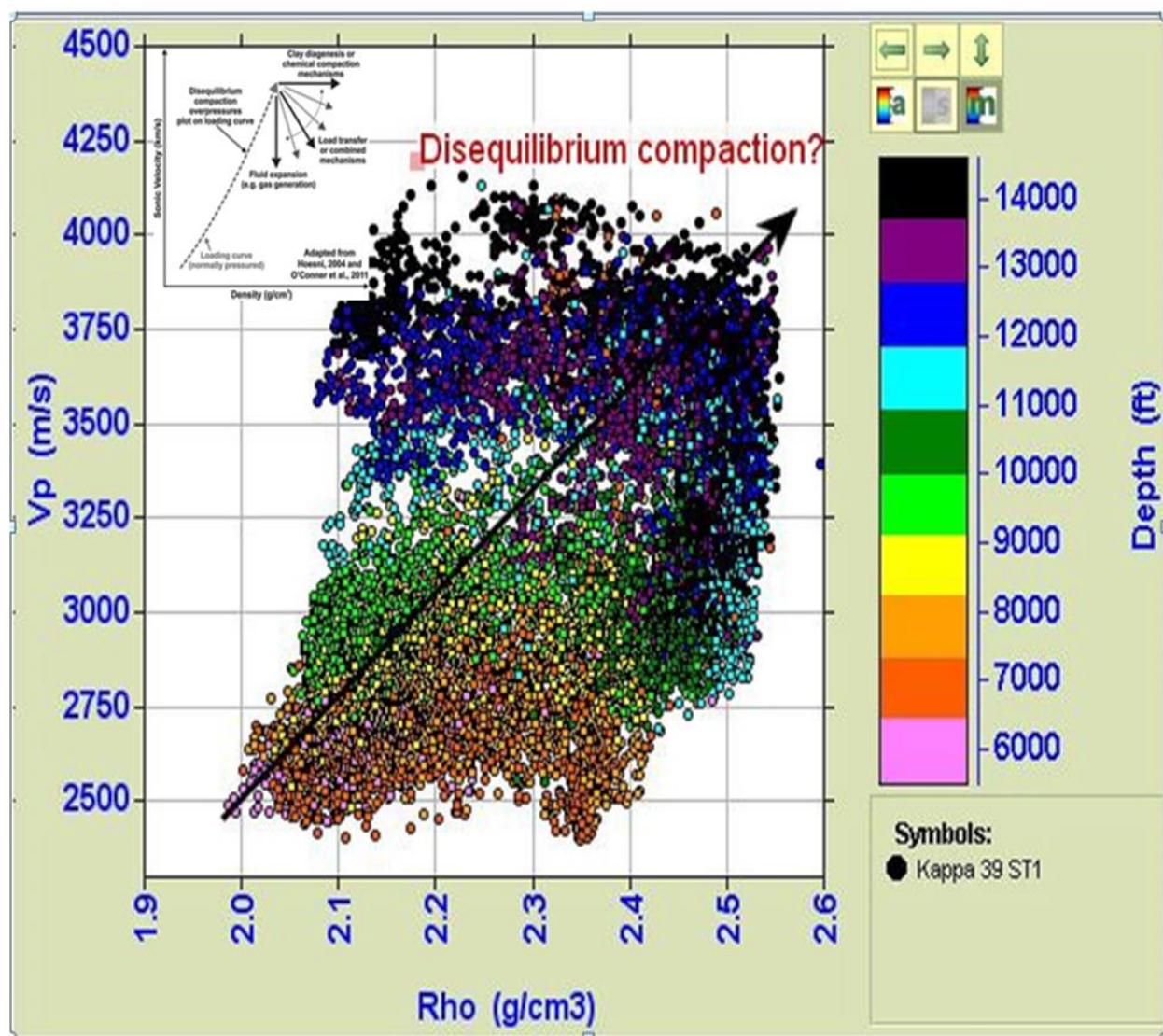


Fig. 27 Showing Vp vs Rho crossplot for Kappa 39 ST1 (Coloured by depth).

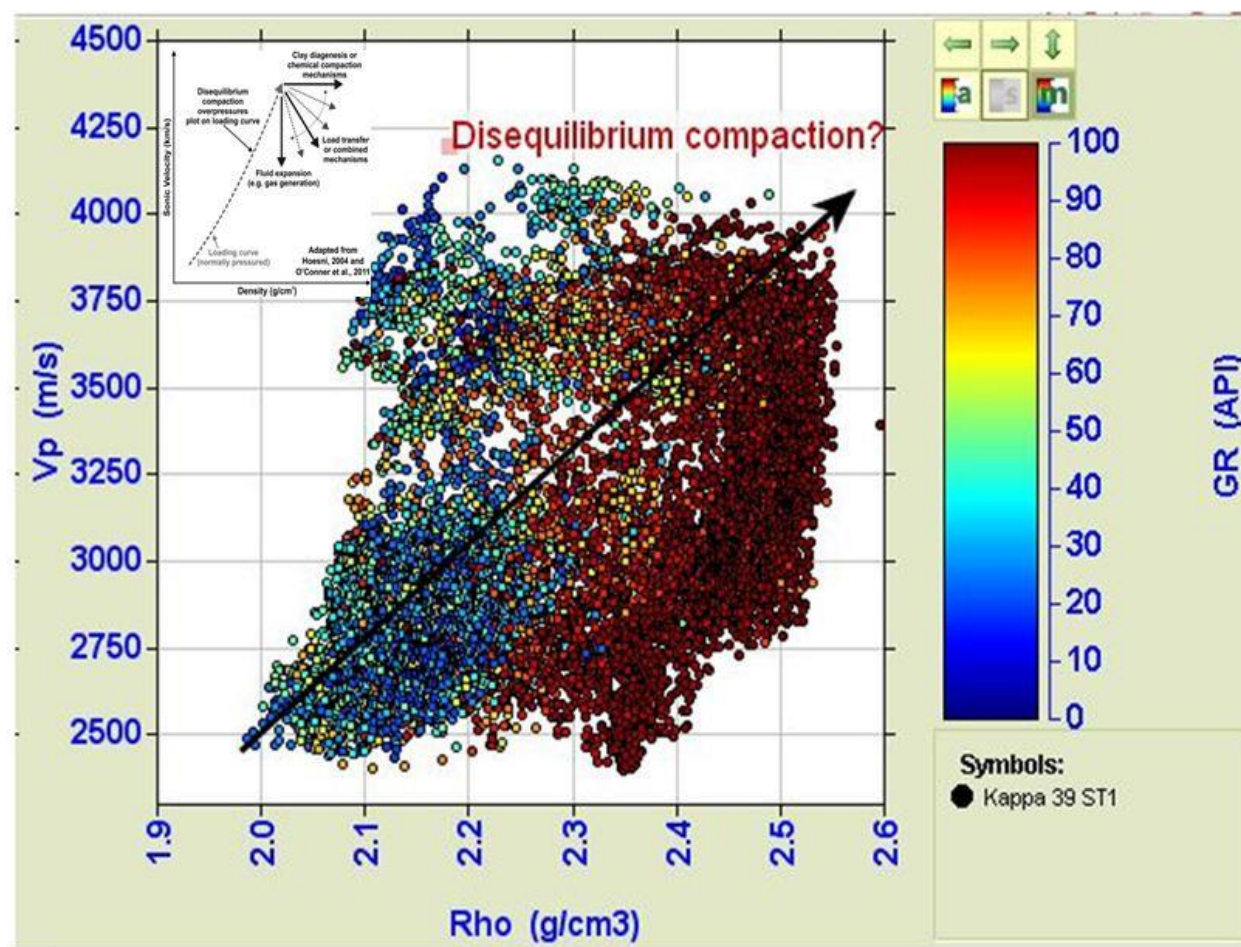


Fig. 28:  $V_p$  vs  $Rho$  (coloured by GR).

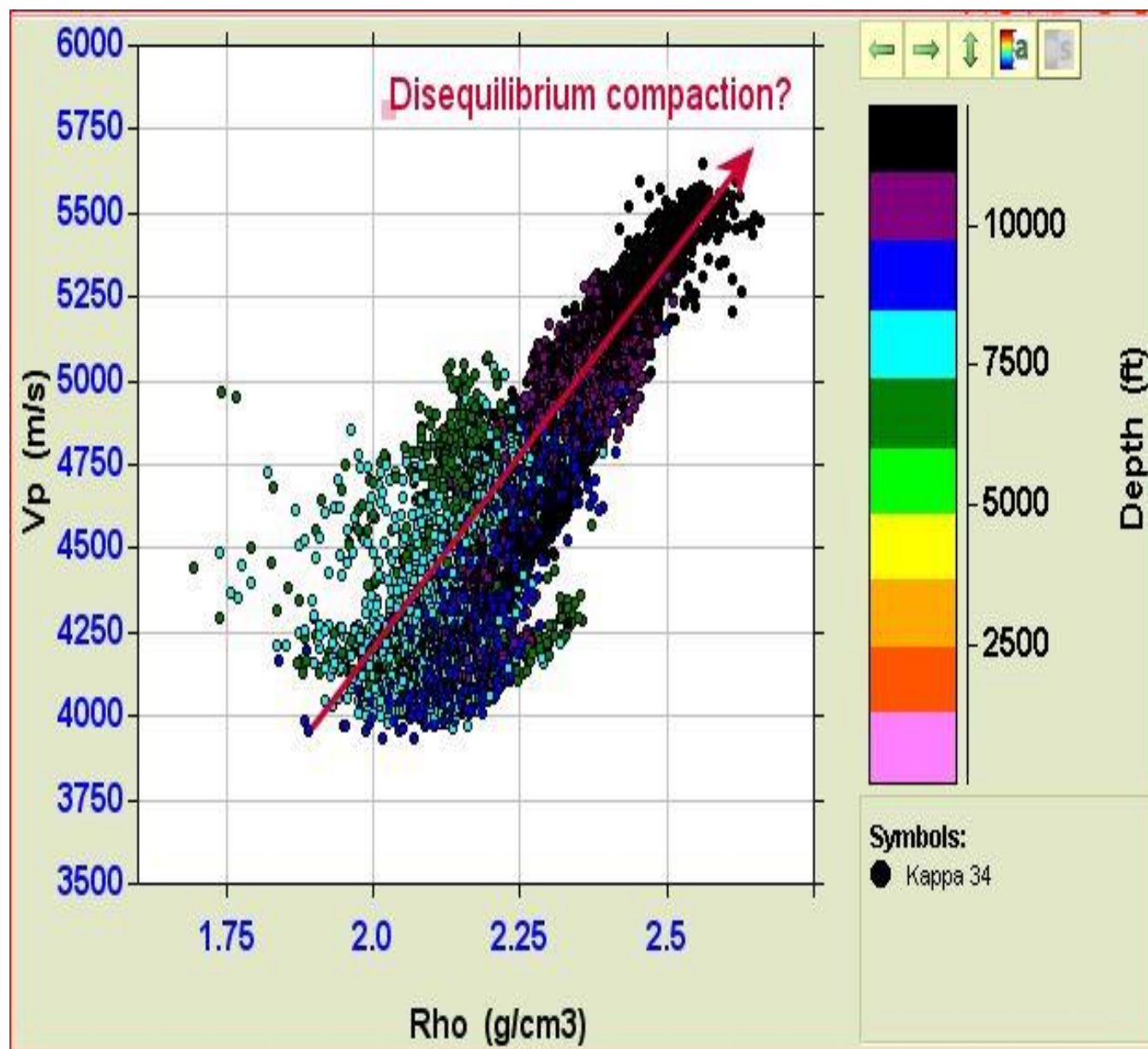


Fig. 29 Showing  $V_p$  vs  $\rho$  for Kappa 34 (coloured by depth).

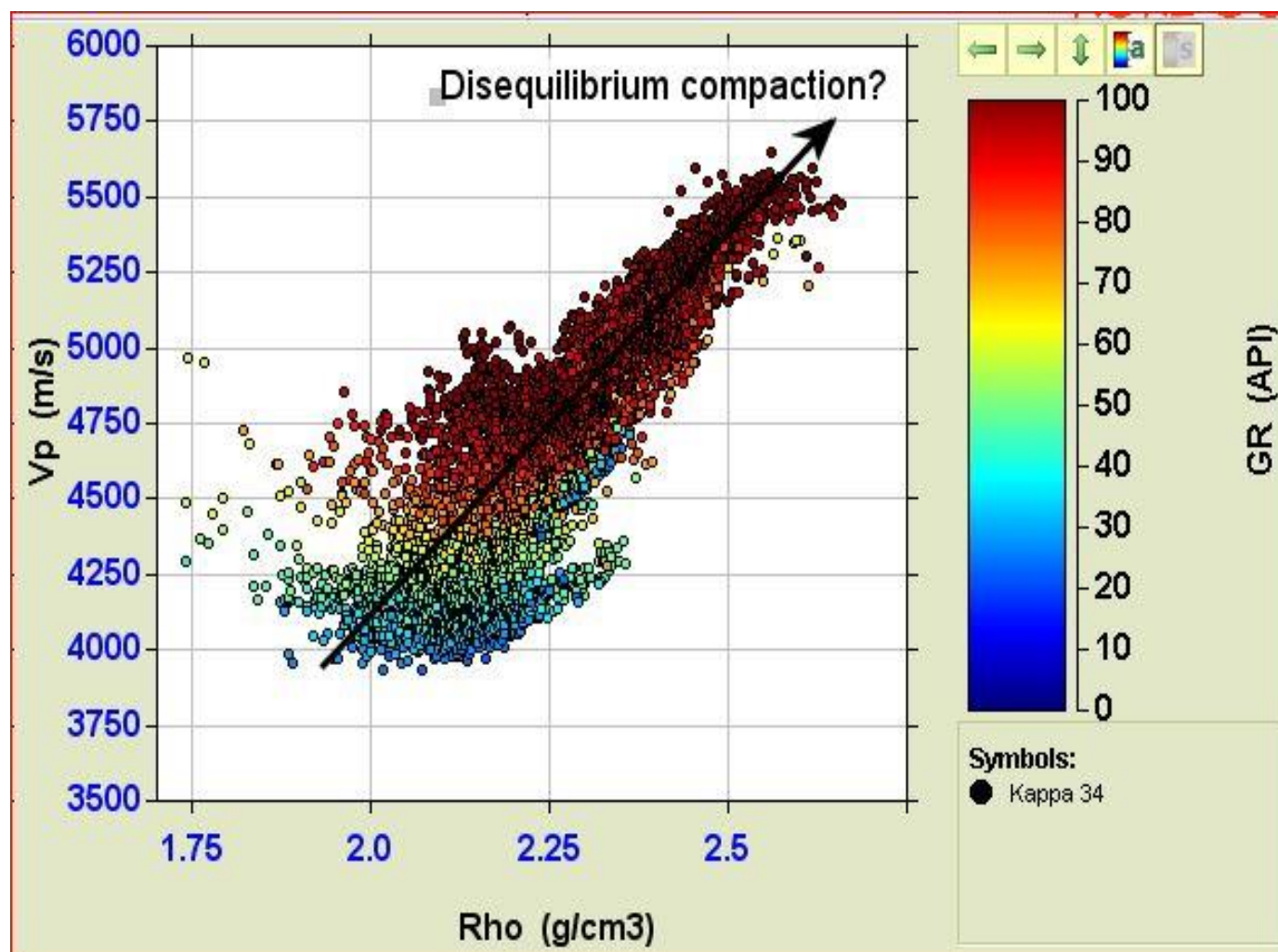


Fig. 30 Showing  $V_p$  vs  $Rho$  for Kappa 34 (coloured by GR)

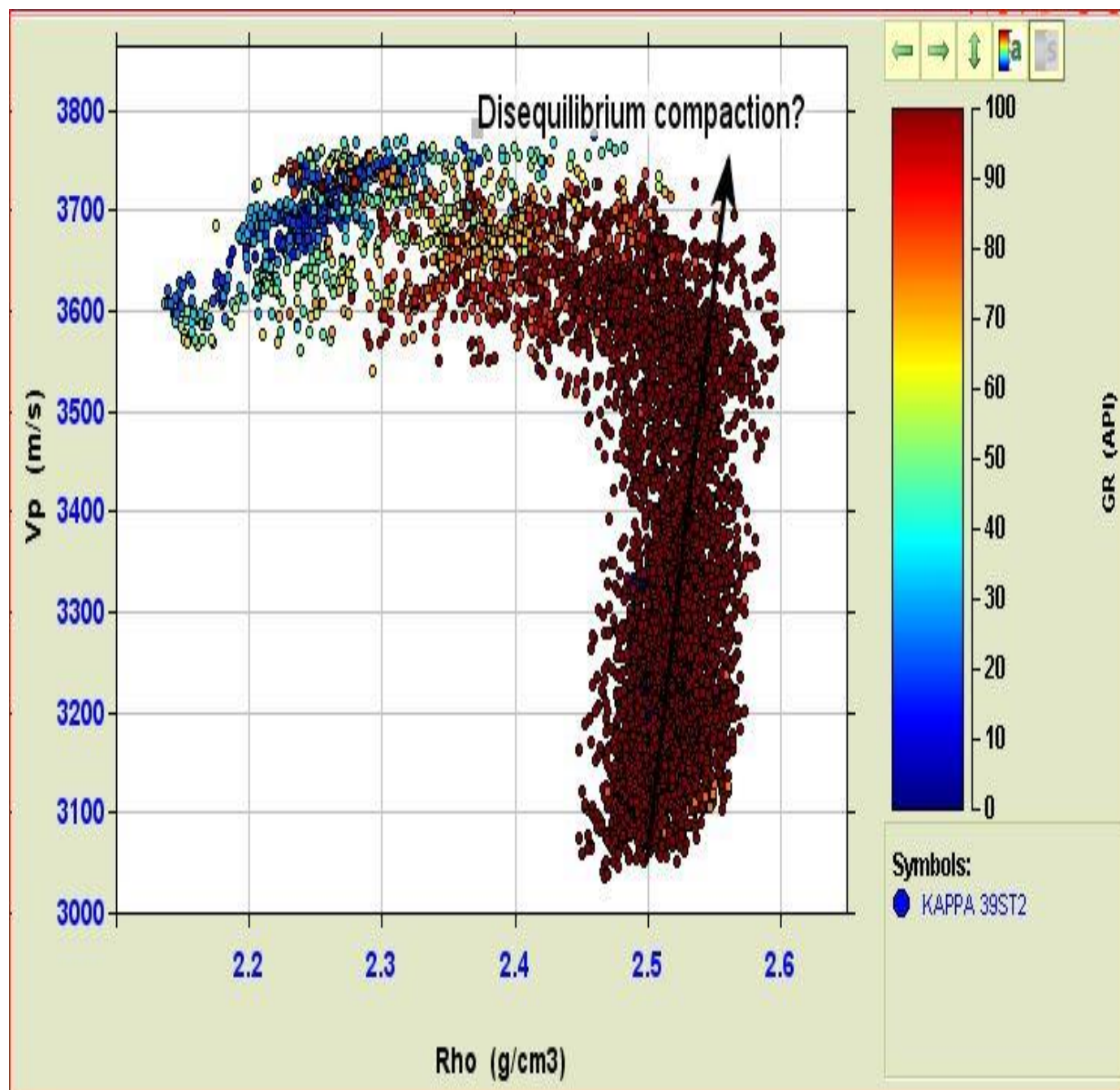


Fig. 31 Showing  $V_p$  vs  $Rho$  for Kappa 39 ST 2 (coloured by GR)

#### 4.1.7 Offset well prediction

The nearby offset wells were used to derive a relationship between velocity and effective stress (which was transform to pore pressure using Tezhagi's equation).

Eaton exponential of 3 gave a pressure profile that aligned closely well with the measured pressure. The measured pressure and Eaton's prediction in fig 32 (Coloured red), between the depth of 11,500ft and 12,000ft falls below hydrostatic gradient. This according to the end of the well report is as a result of depletion due to production at the shallow depth to about 12,000ft. This was confirm with this work as there is no evidence of overpressuring due to lateral drainage in any of the well within that same fault block. And previous works showed that the major fault bounding the fault block is a sealing fault.

It is noteworthy also that, Bowers method (coloured blue) at the shallow depth gave an estimate of pressure greater than the required mudweight used while drilling the well i.e. overestimate pore pressure at shallow depth. With a personal communication with Bowers, he suggested that I should vary the mudline velocity, but without given a geologic condition that must be met before the option of changing mudline velocity could be necessary. At the end of that process, i observed that the mudline velocity which will give a good match with mudweight at shallow depth, do not calibrate with measured pressure at greater depth. Such was the reason why Bowers method was not considered for shallow depth for the proposed well.

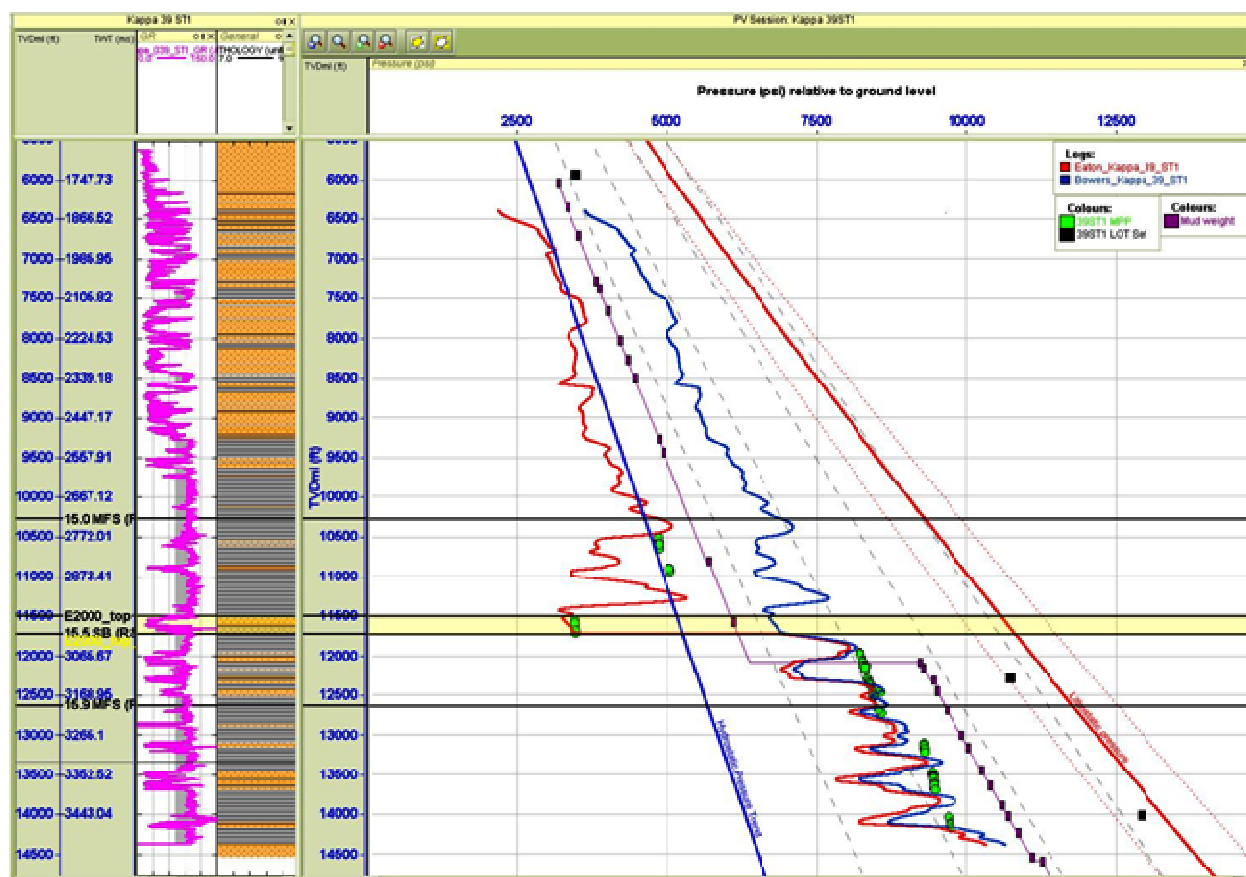


Fig. 32: Showing the result of the offset well prediction.

#### **4.2.0 Velocity Analysis for Pore Pressure Prediction**

A typical example of what a seismic section looks like before and after processing is as shown in fig 33 and 34. Each common mid-point gathers have to be processed one after the other in order to get the true formation velocity which will help achieve an accurate formation pressure prediction.

#### **4.2.1 Seismic to well calibration**

Fig. 35 is a plot of seismic velocity before (black line) and after calibration (red line). And it justifies the need for calibrating seismic velocity, as the calibrated seismic aligned with the sonic log (blue wiggle).

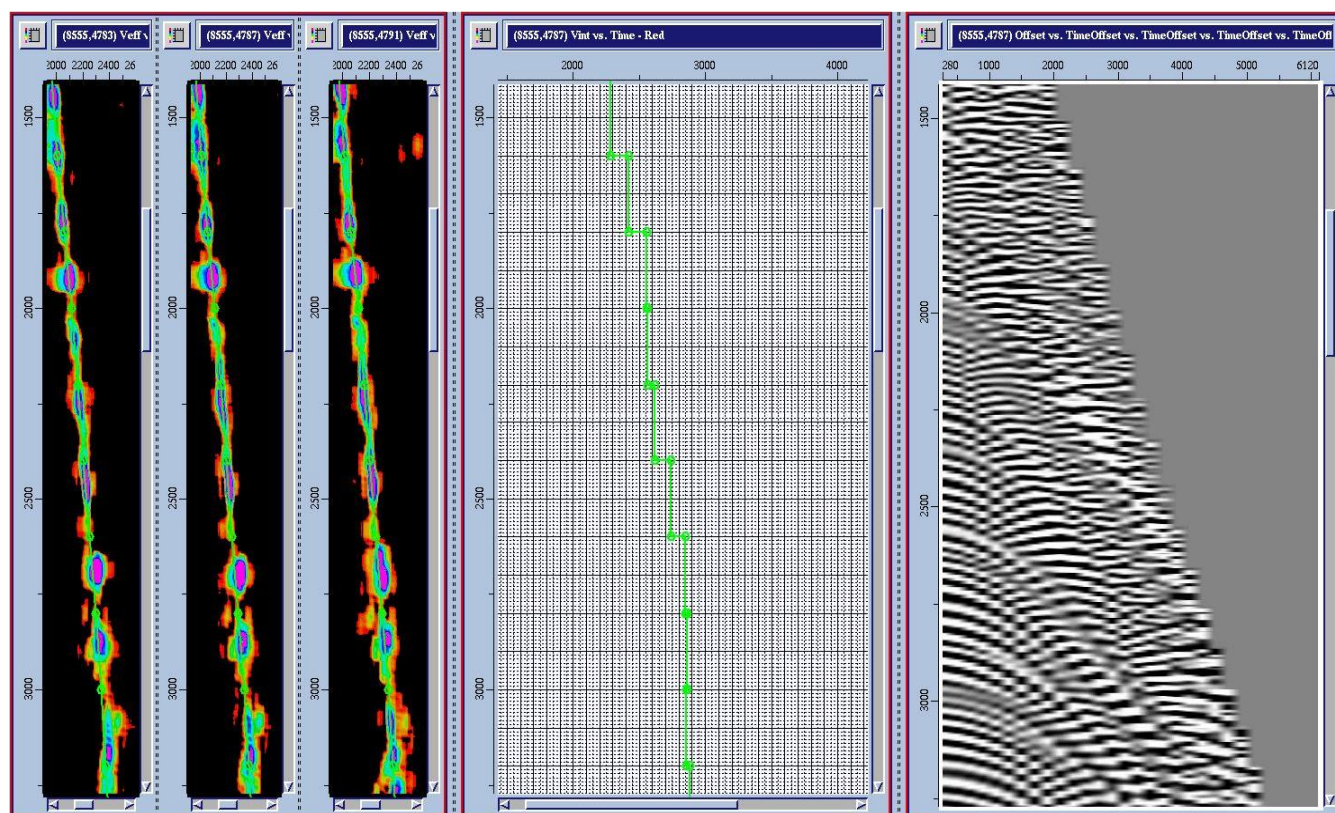


Fig. 33: Showing common mid-point gathers before processing.

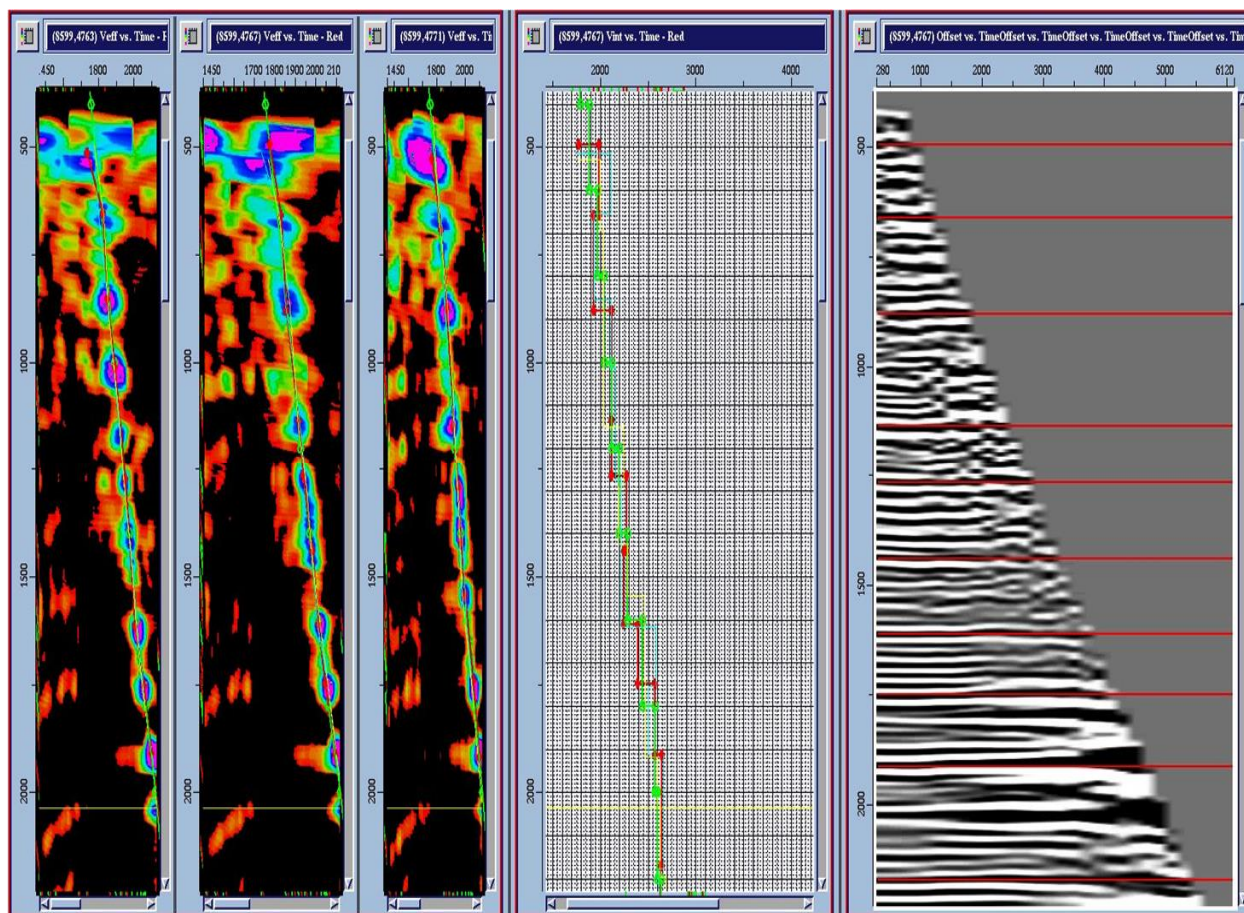


Fig. 34: Showing flattened reflectors after processing.

#### **4.2.2 Seismic pore pressure prediction for the offset well (kappa 39 ST 1)**

Applying the established velocity to pore pressure transformed generated from offset sonic velocity, gave a pressure profile which calibrated well with the measured data as shown in fig 36. This increase my level of confidence in the transform and as such, it could be reliably applied to the proposed deep exploratory well that has no log data. The velocity was also scale on a factor of +/- 5% of the raw seismic velocity to account for local variation effect in seismic data, and the result used in predicting formation pressure as shown in fig. 37.

The predicted pressure was also used as an input into Mathew and Kelly equation for calculating the minimum stress at which the formation will fracture (fracture pressure). That gave a fracture gradient that is less than the insitu measured minimum stress (Leak off test data). This further strengthens the reliability of the result of this prediction and gives an assurance that, if the same procedure is followed for a proposed well without log data and measured pressure, the result could be relied upon for a successful drilling.

#### **4.2.4 Seismic pore pressure prediction for the exploration deep well (kappa deep ix)**

With the reliability of the transform been justified by the result of Kappa 39 ST 1 pressure prediction, the transform was confidently applied to the proposed exploration well. It indicate the onset of overpressure at a depth, a little bit deeper than what was observed in the offset well (Kappa 39 ST 1).

The velocity was also scaled by a factor of +/- 5%, and the result of the predicted pressure show that, a higher mud weight will be required for drilling the proposed deep exploration well, in order not to experience kick at greater depth. The result of Kappa deep IX pressure prediction exercise (fig 38 and 39) gave an estimate of what the expected pressure over the untested stratigraphic section should be.

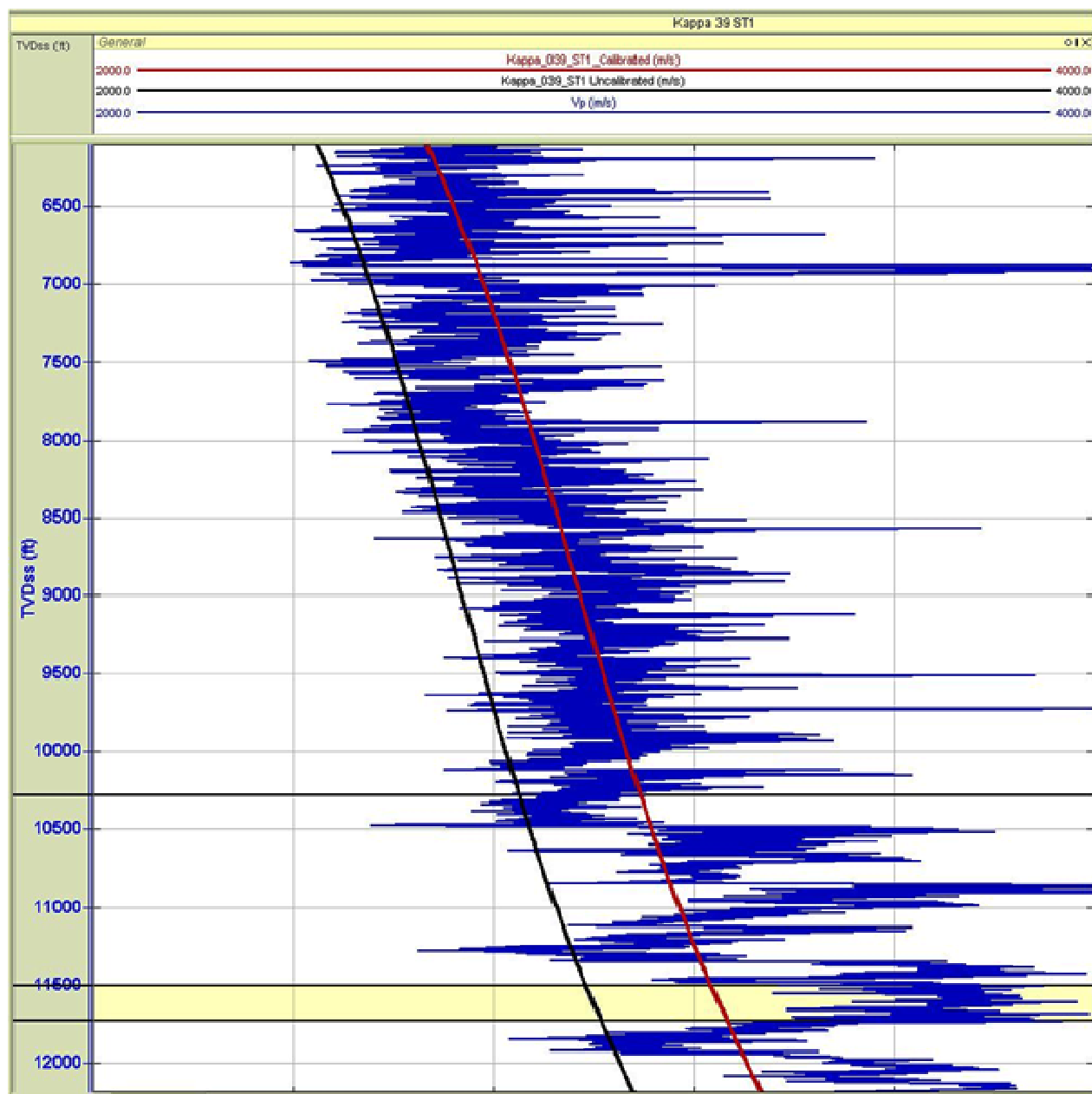


Fig. 35: Showing seismic to well calibration. Black line is the un-calibrated seismic velocity, while red line is the calibrated velocity.

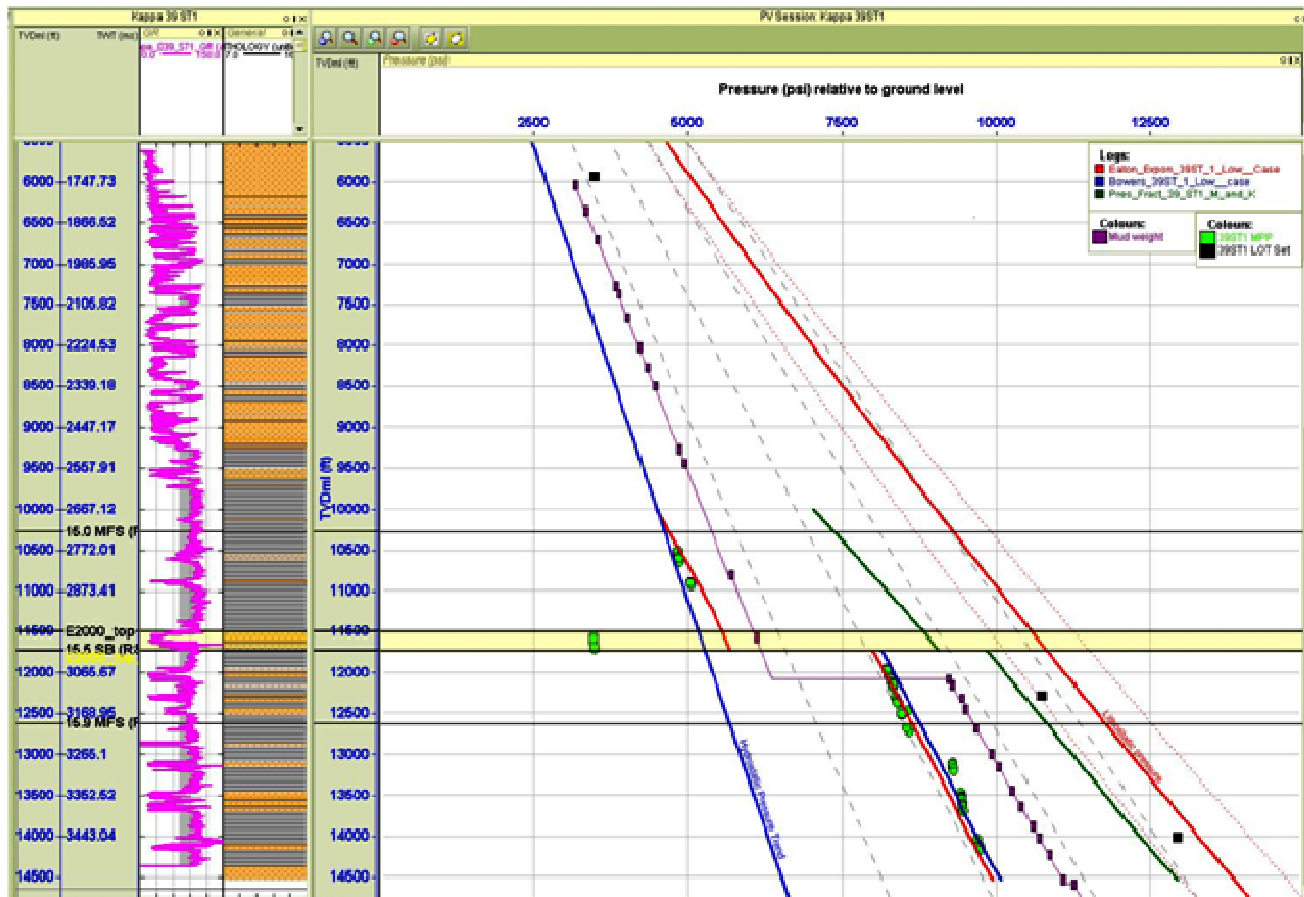


Fig. 36: Showing seismic pore pressure prediction for Kappa 39 ST1.

The blue line with label is the hydrostatic gradient line, while the red line with label is the lithostatic gradient line and the lines between the two is the prediction result. The red unlabeled line is the predicted pressure using Eaton's method, while the blue line is the predicted pressure using Bowers's method and the green line is the predicted fracture pressure (all shown in the legend).

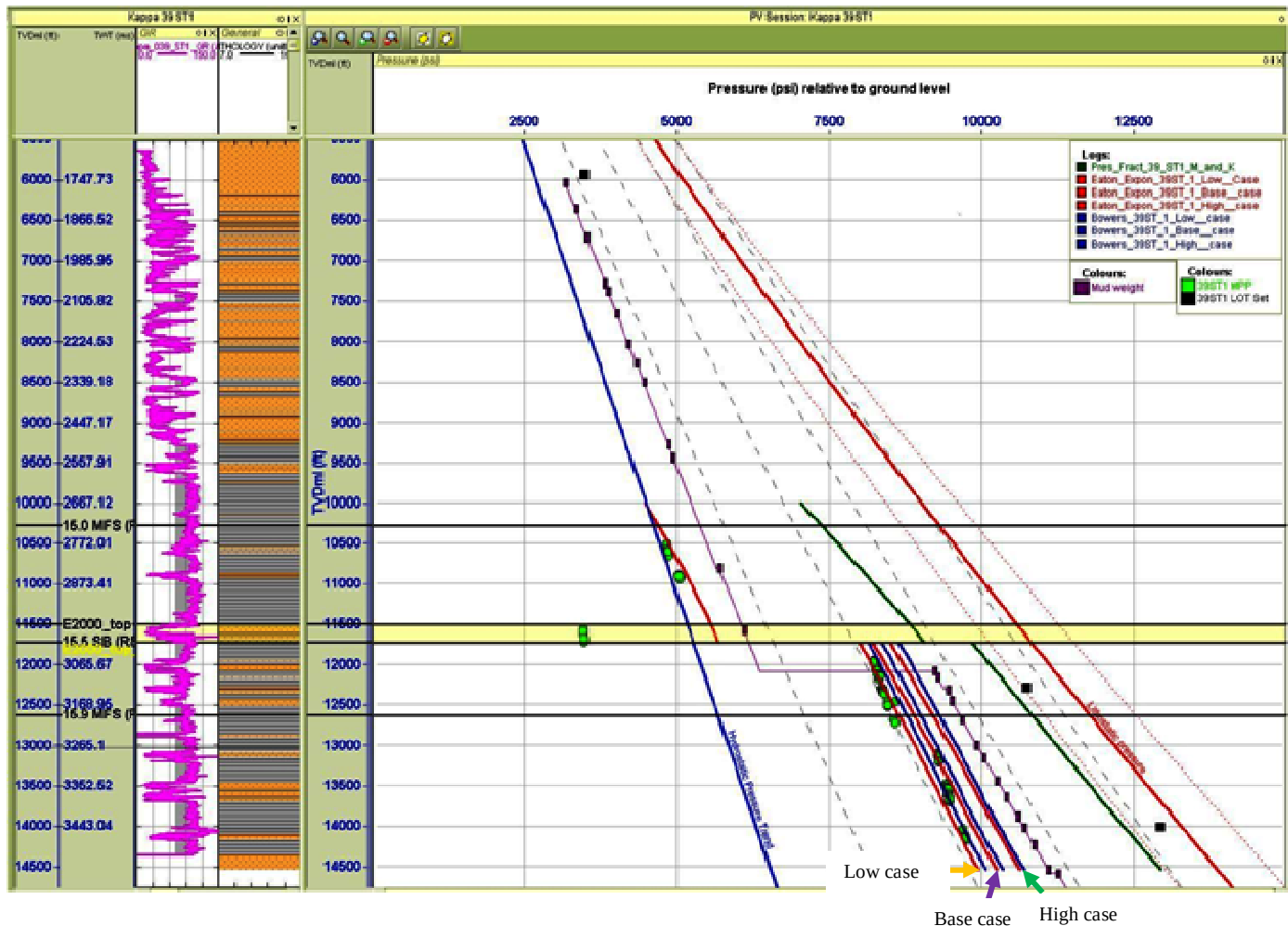


Fig. 37: Seismic pore pressure prediction for Kappa 39 ST1 (low case, base case and high case). The interval between the high case predicted pressure and the fracture pressure is what the drillers refers to as the safe mud window.

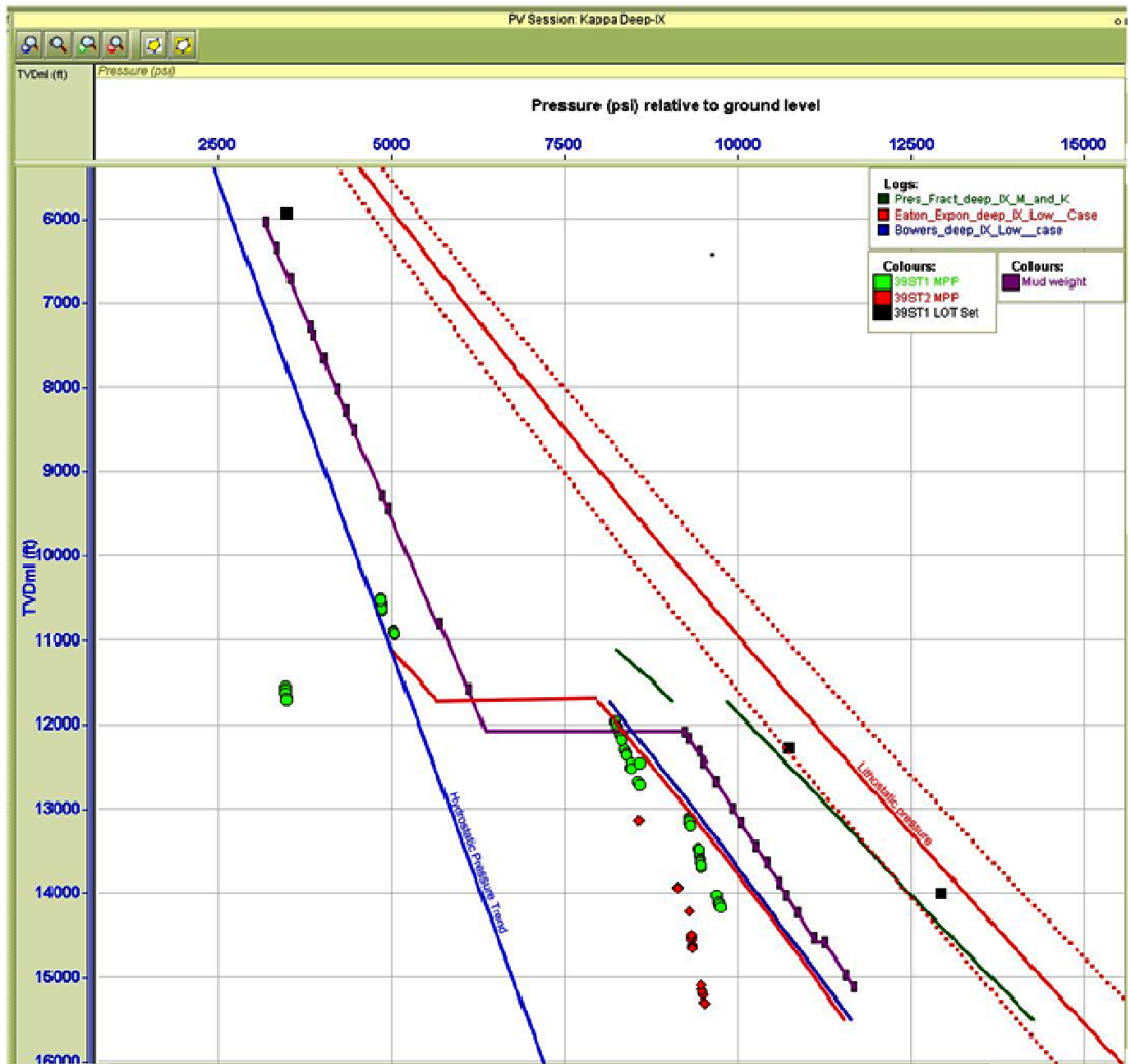


Fig. 38: Showing seismic pore pressure prediction for Kappa deep IX

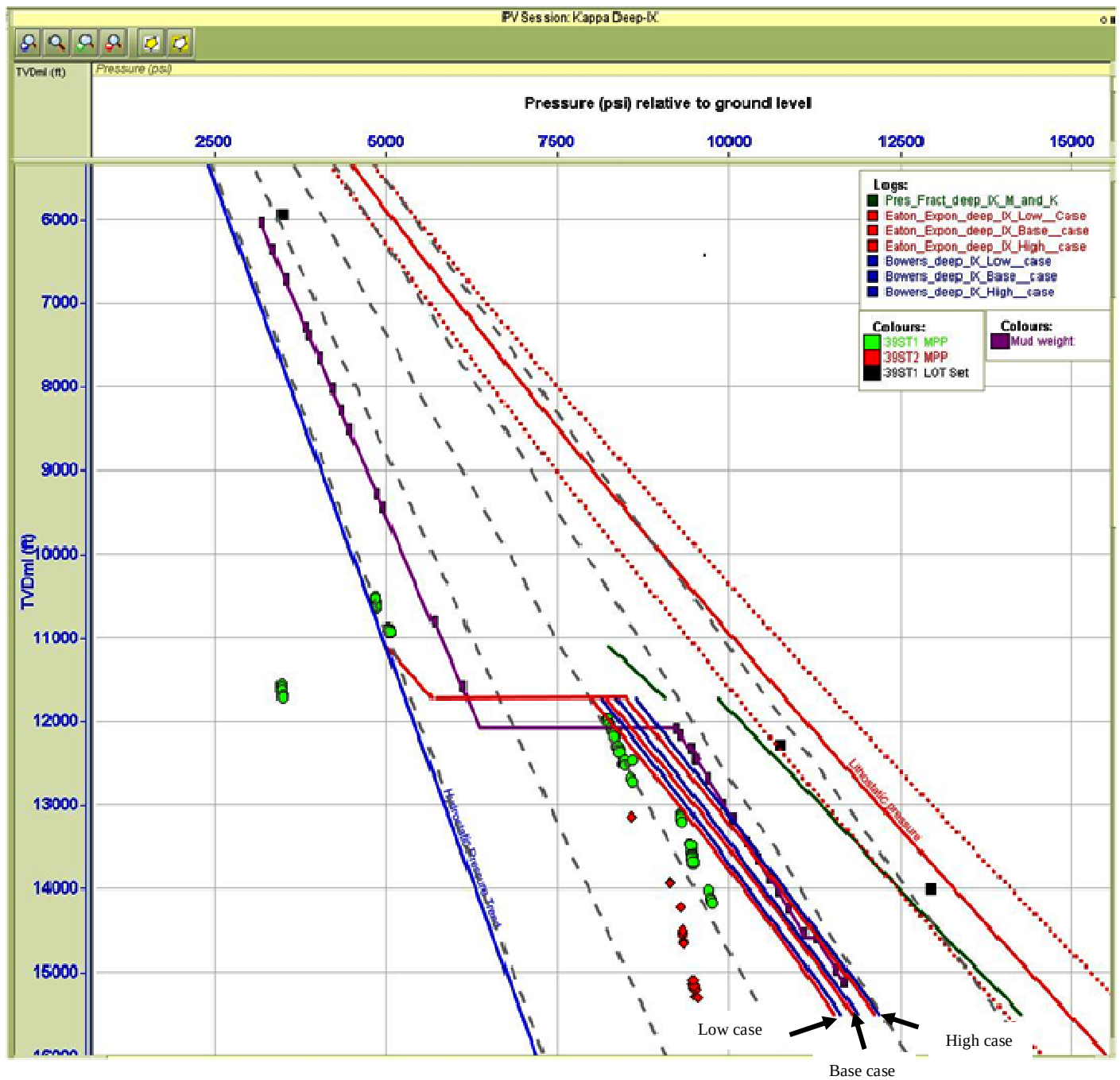


Fig. 39: Seismic pore pressure prediction for Kappa deep IX (low case, base case and high case).

## CHAPTER FIVE

### 5.0 SUMMARY AND CONCLUSION

#### 5.1 Summary

- a) Velocity ÷ density crossplot for all the wells analyzed plot along a typical compaction disequilibrium curve.
- b) The lithology log derived from GR log showed a typical sand dominated Benin Formation to a depth of about 9,200ft (TVD) and beyond that depth to the total depth, a shale dominated (with intercalated sand) Agbada Formation.
- c) The overburden gradient derived from the density log plotted parallel to the line of a fixed gradient of 1.0 psi/ft. And it ranges from 0.78 psi/ft. (at shallow depth) to 0.96 psi/ft. (at greater depth).
- d) The offset well data was used to establish a relationship between velocities and pore pressure, and the result gave a good match with the measured pressure.
- e) The onset of overpressure (at 10,200ft) corresponds with the 15.0 maximum flooding surface. Which further confirm compaction disequilibrium as the origin of the overpressures.
- f) Bower's parameters ( $A = 7.5$ ,  $B = 0.68$ ) were determined specifically for the field, instead of the regional parameters ( $A = 8$ ,  $B = 0.57$ ) in use.
- g) Bowers method at the shallow section (for Kappa 39 ST 1) gave a pressure prediction ranging from 0.54 psi/ft. to 0.66 psi/ft. which is far greater than the mud pressure of 0.52 psi/ft. to 0.53 psi/ft. that was used in drilling the well (i.e. overestimate pore pressure).

Whereas Eaton's method gave a range of 0.44 psi/ft. to 0.46 psi/ft. for the same depth interval, which shows that the well was drilled overbalanced.

- h) Seismic velocity analysis for pore pressure prediction and calibration with well data results in a good match of predicted pressure from seismic data with the measured pressure for the offset well. This strengthens the assurance that seismic can be relied upon to give an accurate estimate where log data is missing.
- i) A safe drilling mud window interval between predicted pressure and fracture pressure was established also.

## 5.2 Conclusion

Based on the results summarized above, the following conclusions were made:

- 1) The overpressure is as a result of compaction disequilibrium.
- 2) Accurate relationship should be establish between velocity and pore pressure using well data, before proceeding with seismic velocity.
- 3) Seismic method can be relied upon to give an accurate pore pressure prediction, when appropriate velocity analysis, velocity calibration with well data, as well as deriving well specific empirical parameters for the model used have been keenly carried out.
- 4) Both Eaton's and Bowers method should be integrated for any HPHT pore pressure prediction work. This is because of the result of this work which shows that Bowers method overestimate formation pressure at shallow depth. And also putting to consideration of the fact that, Eaton method will under predict pressure where ever unloading (secondary mechanism) has taking place.

- 5) Accurate safe mud weight window/casing point selection could be attained with an accurate pore pressure in place.

### **5.3 Recommendation**

The origin of overpressure at the deeper section of the Onshore Niger Delta is yet an unresolved question, which should be given a priority as more deep exploration wells are been drilled.

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