# QUANTIFYING FINE GRAINED ROCKS FROM LOGS AND THEIR RELATION SHIP WITH PORE PRESSURE AND STRATIGRAPHY

**SAMUEL GETNET TSEGAYE**

**MSc. PETROLEUM ENGINEERING, UNIVERSITY TEKNOLOGI PETRONAS**

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**PREPAIRED BY - SAMUEL GETNET TSEGAYE**
**ACADAMIC SUPERVISOR- WAN ISMAIL WAN YUSOFF (A.P.)**

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**University Teknologi PETRONAS**
**Bandar Seri Iskanadar**
**31750 Tronoh**
**Perak Darul Ridzuan**

CERTIFICATION OF APPROVAL

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**BY**

**SAMUEL GETNET TSEGAYE**

**A project dissertation submitted to the**
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**Approved by,**

**……**

**UNIVERSITY TEKNOLOGI PETRONAS**

**TRONOH, PERAK**
**JULY 2008**

# CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

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SAMUEL GETNET TSEGAYE

# ABSTRACT

On this project work on the title "Quantifying fine grained rocks from logs and there relation ship with pore pressure and stratigraphy" there are two main parts. The first part in literature review on shaly sands and shale which are normally used for the entire class of fine-grained sedimentary rocks that contain substantial amount of clay minerals. Since the presence of low density overpressure is derived for the porosity within the unit in the fine grained rocks in the subsurface which includes shales or mudstone in a sedimentary sequence which influences the operations of petroleum exploration, drilling and production, their relation ship with the pore pressure has also been conducted in this part. During the exploration phase such low density fine grained rocks also influence the interpretation of seismic and gravity surveys. In addition to the immediate influence of high pressures and compaction phenomenon on the petroleum industry, fine grained rocks including shales are thought to have been the source of petroleum found in permeable reservoir rocks. There fore a better understanding of these fine grained rocks in the subsurface is very important. A common method for evaluating the fine grained rocks in the subsurface using the known interpretation techniques which includes the different logging tools measurements is also studied on this part of the report.

The second part presents a study conducted on the real data from GELAMA MERAH field to evaluate the effect of the fine grained rocks on the hydrocarbon occurance, pore pressure, and stratigraphy.How the presence of clays in the formation affects resistivity reading by lowering it which will lead for miss – interpretation of the oil – bearing zone as a water – bearing zone because of the excess conductivity due to the presence of clay minerals is also evaluated.

Proper pore pressure prediction and determination is important and crucial for the purpose of optimizing casing and drilling fluid programs, to improve well control and to increase drilling efficiencies, to reduce drill time/costs per well. There fore, it is important to understand the fine grained rock which usually is the shale that will lead to abnormal pressure and cause well bore instability and since the shale effect depends on shale content, the estimation of $\mathbf{V_{sh}}$ is of prime importance.

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My gratitude also goes to ELIAS B ABLLAH for coordinating the individual research project effectively by devoting his time through out the duration of the project work till the end.

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| | |
|---|---|
| **API** | American Petroleum Institute |
| **D** | Depth of calculation point (ft); |
| **DS** | Depositional Sequence (after Exxon) |
| **FDP** | Field Development Project |
| **GM** | Gelama Merah |
| **GM1** | Gelama Merah 1 |
| **GMST1** | Gelama Merah Side Trucked 1 |
| **GR** | Gamma ray |
| **GRV** | Gross Rock Volume |
| **GSS** | Genetic Stratigraphic Sequence (after Galloway) |
| **HCPV** | Hydrocarbon Pore Volume. |
| **HWU** | Herriot Watt University |
| **LAS** | Log Analysis Software |
| **LWD** | Logging While Drilling |
| **MDT** | Modular Formation Dynamics Tester |
| **MSL** | Mean Sea Level |
| **MWD** | Measurement While Drilling |
| **NMR** | Nuclear Magnetic Resonance |
| **OBM** | Oil Based Mud |
| **OBP** | over Burden Pressure |
| **P** | Pressure |
| **PPG** | Pore Pressure Gradient |
| **PPP** | Pore Pressure Prediction |
| **RF** | Radio Frequency |
| **SB** | Sabah Basin |
| **SPE** | Society of Petroleum Engineers |
| **SW** | Saturation of Water |

| | |
|---|---|
| **TVD** | True Vertical Depth |
| **TVDKB** | True Vertical Depth from Kelly Bushing |
| **Vcl** | Volume of Clay |
| **Vsh** | Volume of Shale |
| **WBM** | Water Based Mud |

# SUBSCRIPTS

| | |
|---|---|
| $\mathbf{D_e}$ | Equivalent depth (ft) with same sonic transit time. |
| **δw** | Formation – water gradient (psi / ft), |
| **δr** | Litho static gradient (psi / ft); |
| γc | average gamma ray response in the cleanest formation |
| $\mathbf{Ø_D}$ | porosity reading from density log |
| $\mathbf{Ø_N}$ | porosity reading from neutron log |
| $\mathbf{Ø_S}$ | porosity reading from sonic log |
| $\mathbf{V_{Lam}}$ | the percent volume of laminated shale. |
| ***Pc*** | capillary Pressure |
| $\mathbf{R_{mf}}$ | Resistivity of Mud Filtrate |
| $\mathbf{R_{sd}}$ | clean sand resisitivity |
| $\mathbf{R_{sh}}$ | shale resisitivity. |
| $\mathbf{R_w}$ | Resistivity of water |

# GREEK SYMBOLS

| | |
|---|---|
| $\Theta$ | Contact angle between the drilling fluid and native pore fluid interface |
| $\acute{\emptyset}$ | Porosity |
| $\gamma$ | gamma ray |
| **K** | Permeability |
| ***SP*** | Spontaneous Potential |
| $\delta$ | Stress in the spring |

# CHAPTER 1

# INTRODUCTION

## 1.1 Introduction to Formation Evaluation

Formation Evaluation is a sub discipline of petroleum engineering, specializes in the gathering of data and the quantification of parameters needed for the practice of the other three major sub disciplines: drilling, production, and reservoir engineering. Formation evaluation method includes rock and fluid-sample analyisis, well logging, and pressure and production testing. A Combination of these methods is usually required for a complete and thorough evaluation.

The continuous recording of a geophysical parameter along a bore hole produces a geophysical well log .The value of the measurement is plotted continuously against depth in the well. The most appropriate name for the continuous depth recorded is wire line geophysical well log conveniently shortened to well log or log. It has often been called an "electrical log" because historically the first logs were electrical measurements of electrical properties.

## 1.2. Problem Statement

Frequently petroleum engineers analyze well logs to extract information necessary for exploration, drilling and production and reservoir management activities. However, because the interpretation process is highly affected by measurement quality and the limitations of Petrophysical models, the petroleum engineer must be well versed in all three aspects.

On the first section of my literature review part, I will address the electric, radioactive and acoustic properties of sedimentary rock and especially fine grained sedimentary rocks. And the relation ship among these properties and other formation properties, such as porosity, and fluid saturations.

The exact theoretical treatment of rock properties to measurement is quite involved and complex. The complexity arises from the relatively involved geometry and the porous nature of the formation of interest. Nowadays, different modern geophysical well logs exist. They are records of sophisticated geophysical measurements along a bore hole. These may be measurements of spontaneous phenomena, such as natural radioactivity (the gamma ray log), which requires a tool

consisting simply of a very sensitive radiation detector: or they maybe induce, as for the formation velocity log (sonic log), in which a tool emits sound in to formation and measures the time taken for the sound to reach a receiver at a set distance along the tool.

Geophysical well logging is necessary because geological sampling during drilling ("cutting sampling") leaves a very imprecise record of the formation encountered. Entire formation samples can be brought to the surface by mechanical coring, but this is both slow and expensive.

**1.3. Objective and Scope of study**

Basic logging measurements may contain large amounts of information. In the past, some of this data was not recorded because of the luck of high data-rare sensors and electronics down hole, the inability to transmit the data up the cable, and inability to record in the logging unit. Similarly, those limitations have prevented or delayed the introduction of some new logging measurements and tools. Digital recording techniques within the logging unit provide a substantial increase in recording capability.

The first step in the interpretation of the logging data is to determine the type of rock which is being logged. The nest step is to determine the porosity, saturation and permeability of the rocks. The classification system uses a pseudo-rock chemistry classification. The method is very useful since many of the responses from well logging tool reflect physical and chemical properties of the rocks. This classification is used extensively in the evaluation of logs and in particular in the charts used for interpretation. This classification system is based on the following categories of rocks.

- Sandstone- $SiO_2$
- Limestone- $CaCo_3$
- Dolomite- $CaCo_3MgCo_3$
- NaCl, Anhydrite, Gypsum, Clay.

Although considerable research has been devoted to studying shaly formations **(fine grained rocks)**, most of these effects are not fully understood, and perfect and universal models describing them remains illusive. For example, models that express shaly sands resistively are deficient or require knowledge of parameters that can not be determined practically.
Some of the objectives of the study will be then:

- By gathering data and by quantifying the fine grained rocks from formation evaluation, to do a good practice for the other sub-disciplines - drilling, production and reservoir engineering.
- To analysis and interpret the fine grained rocks basic relation ship with pore pressure
- By improving well control/drilling efficiencies, to reduce drill time/cost per well.

**1.4. Relevance and feasibility of the study**

By looking for the changing lithologies (correct determination of clay content ,shale content and shaly formations ),to interpret the connectivity within the pore spaces, and to determine the irreducible water saturation and with that to be able to quantify the effects of the fine grained rocks for the interconnectedness of the reservoir. In general the over all relevance of the study is to improve the characterization of reservoirs in the ***Gelama - Merah*** field found in the ***Sabah Basin*** which is one of the areas of the petroleum resources of *Malaysia*. Most of the reading materials that I used for my literature review part are from books, papers published by organizations like society of petroleum engineers **(*SPE*)**, and Geological societies from online magazines and journals, from the formation evaluation module and drilling engineering module of *HERRIOT WATT UNIVERSITY*.

For the data analysis part and discussion of the results, the study is done based on the preliminary log analysis data that is useful during the initial phase of projects during Field Development Project (*FDP)* of the *GELEMA MERAH FIELD.*

Pore pressure prediction is possible by utilizing different data types in different situations like seismic interval velocities, offset well logs, and well histories. We improve the reliability of the predictions by cross referencing analysis from these different data types or other supporting

indicators whenever possible. By which, I will interpret the pore pressure relation ship with the fine grained rocks in the subsurface in my paper using interactive pertopysics software for the GM1 and GMST1 of *Gelama Merah*( GM) field.

The duration of the project longs for three months. on the first one month and a half I finished my literature review part of the project by looking on different *SPE* papers published, from different reference books and by reviewing my reading materials and modules of *HERRIOT WATT UNIVERSITY,* by which after I discussed on my progress report with my supervisor, I analyzed the real data from GM field of the Sabah Basin to come up with results. Even if there were difficulties to find the data's, I requested the data from our previous *FDP* coordinator and I finally collected the *LAS* data for the wells of the field. In general the main objective of my paper is to be able to quantify the fine grained rocks from logs and then to interpret in practice their relation ship with pore pressure and stratigraphy using real datas.

# CHAPTER 2

# LITRATURE REVIEW

## 2.1. LITHOLOGY RECONSTRUCTION FROM LOGS

There are two independent sources of litho logy data available from oil wells. One set of data coming directly from the drilling and one set from the wire line logging. The drilling data consist of cuttings, cores and all recorded drilling parameters (and, of course, MWD/LWD logs).The logging data consists of the wire line, geophysical log suite and side wall cores. For a reliable litho logical reconstruction, both sets of data are essential. As a result the great sophistication of wire line logs, the drilling data are often forgotten. This should never be the case since continuous sample of formation litho logy comes from drill cuttings.

### 2.1.1. lithology from drill data - the mud log

The mud log and the way in which it is made is described briefly so that the data it represents can be used properly in log interpretation. Drill-derived data and Log-derived data often appear to be in conflict mud log (misnometer that has some how stuck) is the geologist's record of the drilling of the well. Before wire line logging was invented, it was the only record that exists. On this recorded the lithology, the drilling rate, bit changes gas record,calcimery, dates and events. The lithology is based on an examination of cuttings-small chips broken off the formation as the drill advances.

When interpreting the cuttings logs, it is the arrival of a new lithology which is significant. During drilling from a thick shale in to a thick sand stone, when the bed is actually penetrated only a small percentage of the cuttings will be sand stone .The drilling rate how ever will correlate with major litho logical changes – the so called 'drilling break'. Gas levels are also likely to change.

### 2.1.2. Lithology from cores - direct physical sampling

Cores may be cut during drilling, when a continuous, cylindrical sample of the information is recovered, or they may be taken after drilling, when small punctual samples may be taken from the borehole wall.

During drilling and before logging, when a complete record of lithology is required (for example in a reservoir), a continuous sample is taken by coring. The drill bit is placed by a core barrel. The retrieved core, depending on the preceding hole size, will have a cylinder of rock 2-15 centimeters in diameter and up to 60 meters long ( Blackbourn,1990).Cores do in fact need interpretation and processing before they can be compared in to logs. The principal problem is one of depth. Cores are cut during drillings so that their depth limits are calculated by adding all the lengths of the drill string together. Mistakes often occur, and frequently these depths do not agree with the depths shown on the well logs. The logs are taken as a reference: For detail the reference may be just one log, frequently the sonic or the density log.

Several methods are available for core sampling once a hole has been drilled and logged. All of them involve cutting in to a bore hole wall. The most frequent method is side wall coring. A side wall 'gun' is lowered in to the hole on the logging cable: it consists of a series of hollow cylindrical 'bullets' 1.8 cm in diameter and 2.0 to 3.0 cm long. Side wall coring as a method of lithology sampling should be used essentially for verification. As the sample is so small, interpretation problems can arise, and side wall core results should be used with care. In sands with shale laminae for example, a side wall may fall in a shale laminae and it will not be representative of the zone as a whole. For this reason in reservoirs, a closely-set serious of samples is taken. The obvious advantage of a side wall core is that its depth is known and it can be used in a specific chosen lithology.

### 2.1.3. Lithology interpretation from wire line logs - manual method

The manual interpretation of lithology from well logs should be undertaken only using all the logs registered. Using digital well records, all the runs from a well can be re-plotted by computer to give one composite plot which includes all the gamma ray, spontaneous potential, the porosity logs (density, sonic, and neutron logs) and the resititivity which run over the same interval. The final litholgical interpretation may appear on this composite plot or, to avoid over clustering, may be transferred to a document with only the logs usually used for correlation. This is often the gamma-ray (or SP) and a resisitiviy log, or the gamma ray and a sonic log. The original litho logical

interpretation, how ever, must be made on the composite document showing all logs. Lithological interpretation from logs should take the following basic things into consideration:

- Horizontal routine
- Vertical routine
- Absolute values and lithology
- Bed boundaries
- Presentation

There are no simple rules for the quick manual interpretation of lithology from logs. A schematic approach is best, thus the gross lithology is suggested by the mud log, and this can then be corroborated and compared at the same depth horizontally, to a simple log such as Gamma ray or the SP. The interpretation is then continued again horizontally through the other logs – resisitivity, sonic, and density – neutron. If all corroborate the same interpretation, the lithology can be noted and then compared side wall cores or other samples. If the lithology is not corroborated, then there must be a 'feed back' from one log to the next. The first aspect to check is that of log quality. The hole may be very caved, one or more of the logs may be badly recorded, and hence the readings are anomalous.

For example in a sand – shale sequence, there may be 40% sand and 60% shale marked on the mud log. The gamma ray log may read persistently high, so that only shale is suspected. The resisitiviy log and the sonic log are not diagnostic, but the density – neutron combination shows that it is either sand stone, lime stone or dolomite: sand stone is indicated from the mud log. The sand stones are then marked on lithology log and compared to the mud log or side wall samples. A check with the SP log shows that the neutron – density indicated sand intervals correspond to permeable zones, and that in turn these have mud – cake indicated by the caliper. The anomalous log, there fore is the gamma – ray. From the interpretation it can be concluded that the sand stones have a high gamma ray count because included feldspars, micas, or other non – shale radioactive elements. The manual interpretation should find a compatible explanation for the reaction of all logs. Although the horizontal routine is the basis for any lithological interpretation, individual logs

should also be examined vertically for trends, base lines, or absolute values. For the gamma ray log, for instance and also for the SP, a shale base line can be drawn but also minimum clean sand, lime stone, etc. For some of the more difficult, uncommon lithologies and for beds with a very high or very low reading, absolute value tables can be very useful. For example evaporates are generally pure enough in the subsurface to have distinct densities and velocities – this is certainly the case with salt .Abrupt peaks, which may be important in stratigraphical interpretations or diagnostic of a particular interval, are often best interpreted using absolute – value table. Coals for example will be distinct on logs, as will be pyrite and other mineralization.

Bed boundaries should be drawn concisely. More over the correct log should be chosen to position a limit. The best geophysical logs for bed boundary definition are those with a moderate depth of investigation, in general the SFL and density logs. The shoulder where a log is responding to two different lithologies simultaneously is generally broader in logs with greater depth of investigation but thinner in shallow investigating logs. When mud cake is present, an accurate limit may be taken from the caliper because it gives a mechanical response and has no shoulder effects.

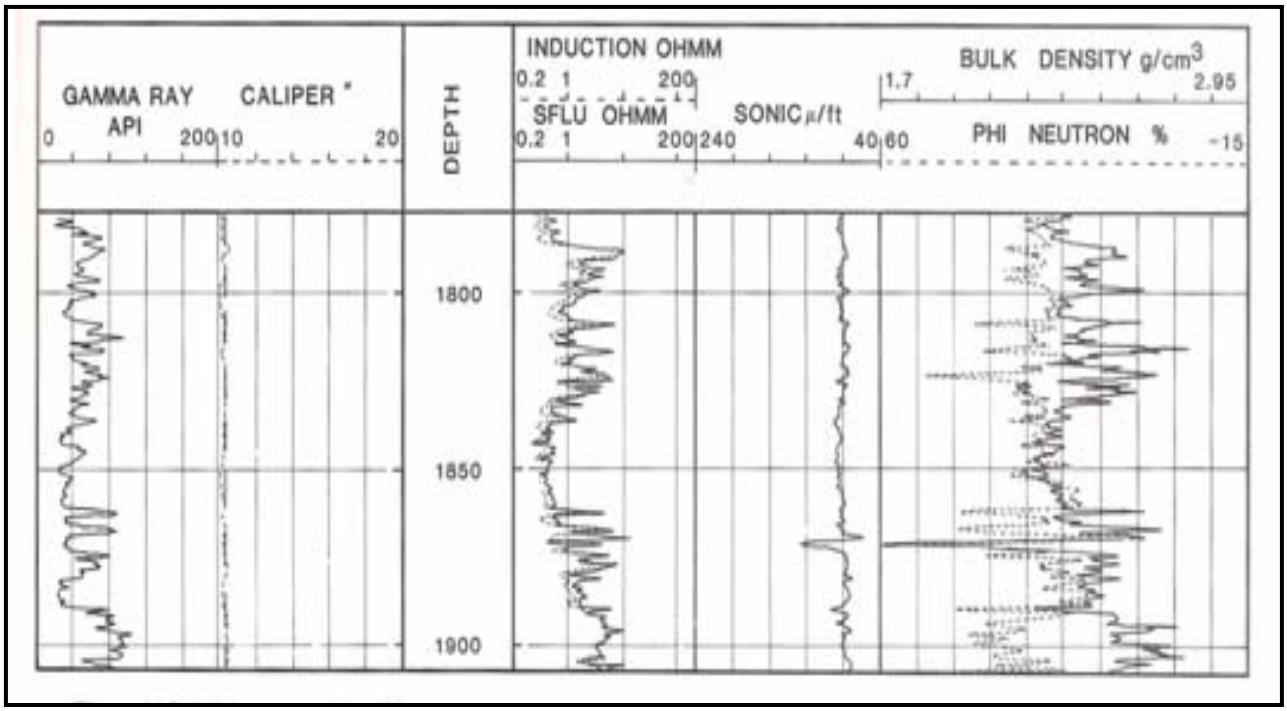


**Figure .2.1. Well log composite, all logs run over the same interval and replotted together**

The final lithological interpretation should be clear and concise. Accepted and stylized symbols for lithology and bed boundaries should be used. The resultant lithology should not be over – clustered. It is this interpretation which will be used for the well completion logs, the document used to summarize drilling and geological data when a well is completed (variously called Final Log, Completion Log, and Composite Log etc). The interpretation will also be used as a database for stratigraphy, correlation and for making small scale, résumé logs.

| **Tools** | **Designation** | | **Measurement** | **Qualitative use** | **Quantitative use** |
|---|---|---|---|---|---|
| | **Schlum** | **WA** | | | |
| **Gamma ray** | **GR.** | | -Gamma radiation from formation | -Correlation<br>-Shale Vs. non-shale<br>-Detection of radioactive minerals<br>-Estimate shale in 'dirty' sands | -depth control<br>-shale content |
| **Spontaneous potential** | **SP** | | -Electrical potential across sand/shale interfaces | - detection of permeable zones<br>-correlation | -formation water salinity<br>-bed thickness determination |
| **Sonic**<br>**-borehole compensated**<br>**-long spaced sonic**<br>**-array sonic** | **BHC**<br>**LSS** | | -Propagation of sound through rock | -Lithology<br>-Correlation<br>-Detection of fractures<br>-Lateral prediction | -Porosity<br>-Seismic Velocity |
| **Density**<br>**-Compensated formation density**<br>**-Litho density tool** | **FDC**<br>**LDT** | | -impact of Gamma-rays on Electrons in formations | -identification of minerals in complex lithologies<br>-nature of fluid in pores<br>-Gas detection<br>-Lateral prediction | -porosity<br>-density<br>-seismic velocity |
| **Neutron** | **CNL** | | -Impact of | -correlation | - Porosity |

| | | | | | |
|---|---|---|---|---|---|
| **-compensated neutron log** | | | Neutrons on **H** atoms | -lithology<br>-gas detection | |
| **Normal res.logs**<br>**-Short normal**<br>**-long normal**<br>**-lateral** | **SN**<br>**LN**<br>**LAT** | | Resistivity | | -determine Saturation Of water<br>-non focused<br>-sever invasion effect<br>-non-conductive muds |
| **-laterolog 3**<br>**-laterolog 7**<br>**-laterolog 9**<br>**-dual laterolog** | **LL3**<br>**LL7**<br>**LL9**<br>**DLL** | | Deepresistivity In salty mud's | | -determine Saturation of water –focused |
| **Induction logs**<br>**-Induction Electrical Survey**<br>**-induction tool**<br>**-Induction Spherically Focused**<br>**-Dual induction** | **IES**<br>**6FF40**<br>**ISF**<br><br>**DIL** | | -Deep resistivity in resistive mud's | | -Determine Sw focused<br>-oil based or freshwater mud |
| **Micro log** | **ML** | | | -Mud cake indicator | |
| **Microresistivity logs:**<br>**-micro laterolog**<br>**-proximity log**<br>**-micro spherically** | **MLL**<br>**PL**<br>**MSFL** | | -Resistivity ( invaded zone ) | | -Determine Sw<br>-poor if thick mud cake<br>-poor if shallow invasion |

**Table .2.1. Summary table for logging tools and measurements**

## 2.2. SHALY FORMATIONS

Shale is a sedimentary rock composed of clay minerals, precipitates, and fine clastic particles. The chemical composition and physical nature of shale can not uniquely defined. In various proportions, hales are composed of clay minerals, silt, carbonates, and other non-clay minerals. Silt is mostly fine grained mineral that is predominantly quartz, possibly containing (in small quantities) feldspars and calcite. The clay minerals are kaolinite, illite, and montmorillonite.

If shale is composed of clay and silt is predominantly quartz, then our porosity tool should see the silt portion of the shale as sand matrix (assuming a sand matrix) and clay volume. That is to say, what we are really concerned with is clay not shale. Log analysis has a tendency to place emphasis on litho logical terms, rather than in terms of mineral involved. Logging tools see the mineral rather than the lithology.
We frequently use limestone rather than calcite and sandstone in place of quartz. Shale, being no exception, should be called clay. Not to be confusing, the term shale will be used throughout but it should be taken as clay.

### 2.2.1 Understanding Subsurface Shale

The term shale is normally used for the entire class of ***fine-grained sedimentary rocks that contain substantial amount of clay minerals***. Sedimentologists find shale hard to work with since shale is fine grained, lacks well-known sedimentary structure (so useful in sandstones), and readily applicable tools and models are not available to study shale. The distinguishing features of shale (of interest to oil industry) are its clay content, low permeability (independent of porosity) due to poor pore connectivity through narrow pore throats (typical pore diameters range 3 nm-100 nm with largest number of pores having 10 nm diameter), and large difference in the coefficient of thermal expansion between water and the shale matrix constituents. To understand drilling fluid interaction with shale, one must start from basic properties of *in situ* shale (e.g. pre-existing water in shale, mineralogy, porosity), and then analyze the impact of changes in stress environment on the properties of shale.

Several factors affect the properties of shale buried at various depths. The amount and type of minerals, particularly clay, in shale decide the affinity of shale for water. For example, shale with more smectite (surface area - 750 $m^2$/gm) has more affinity for water (adsorbs more water) than illite (surface area -80 $m^2$/gm) or kaolinite (25 $m^2$/gm). Three different types of water are found associated with clays, although each clay will not contain all of the types. Inter-crystalline water is found in associated with the cations neutralizing the charge caused by elemental substitution. Osmotic water is present as an adsorbed surface layer associated with the charges on the clay. The swelling associated with this type of mechanism occur when Sedimentary rocks are unloaded as occurs in drilling. Bound water is present in the clay molecule itself as structurally bonded hydrogen and hydroxyl groups which under extreme conditions, temperatures of 600-700$^0$ C, separate from the clay to form water

The free water exists only within the pore space between the grains. The porosity of shale is normally defined as the percent of its total volume with that of water. This value is normally measured by drying a known volume of shale at elevated temperature. Porosity then is a measure of free water, osmotic water and to a lesser extent inter-crystalline water. Chemically bound water is not measured in this procedure. Properties of shale and drilling fluid/shale interaction are strongly influenced by the bound water and to a lesser extent by the free water.

Some of water associated with clay can also be removed using pressure. The majority of the loosely held osmotic water can be removed with an overburden pressure of about 290 psi. In the inner-crystalline case, up to four layers of water may be found. The third and fourth layer can be removed with about 3900 psi. Approximately, 24,000 psi is required for second mono-layer and according to various estimates; pressure over 50,000 psi is required to squeeze water in single monolayer of clay platelets. It requires temperatures in excess of 200$^o$ C to remove all bound water from clay. It is, therefore, doubtful that shale is ever completely void of water in typical drilling environment. Prior to drilling, the exact amount of bound and free water in shale's buried at depth, however, depends on the past compaction history.

Compaction of clay proceeds in three main stages. the clays are removed from land by water and deposited in quiescent locations. Clays, at their initial state of deposition and compaction, have both high porosity and permeability; pore fluids are in communication with the seawater above; sediments consisting of hydratable clay with absorbed water layers prevent direct physical grain-to-grain contact. At the time of deposition, mud water contents may be 70-90%.In the normal compaction process as clay/shale sediments are buried with pore water being expelled, porosity (sonic travel time) decreases. However, any disruption of this normal compaction and water expulsion process can lead to increase in both porosity (sonic travel time) and pore pressure.

In fractured stressed – shale formations, it is particularly important to control water movement because the in – situ stresses are in critical state. Any disturbance of the formation by chemical and / or mechanical means could result in shale breaking and sliding in to the hole. Once the well bore instability is initiated, it becomes difficult to stop.

On of the fundamental driving forces for the movement of water into and out of the shale formations is the chemical potential difference between shale formations and drilling fluids. Water activity of shale formations is an excellent indicator of the shale's state of hydration and its potential to absorb or desorbs water. It is affected by changes in pressure, temperature, mineralogy, c – spacing, pore fluid composition, etc.

Osmotic water and water inter-layers beyond two layers are squeezed out by the action of overburden. After a few thousand feet of burial, the shale retains only about 30% water by volume, of which 20-25% is bound interlayer water and 5-10% residual pore water. In the early stages compaction strongly depends on depth of burial, grain size (fine-grain clays have more porosity but compact easily), deposition rate (high rate results in excessive pore pressures and under-consolidation), clay mineralogy (montmorillonitic shale contain more water than illitic or kaolinitic shale), organic matter content, and geological content. In the second stage of compaction, pressure is relatively ineffective for dehydration that is now achieved by heating, removing another 10 to 15% of the water. The second stage begins at temperatures close to $100^{o}C$ and digenetic changes in clay mineralogy may also occur.

The third and final stage of compaction and dehydration is also controlled by temperature but is very slow, requiring hundreds of years to reach completion and leaving only a few percent of water.

In the second stage of compaction, pressure is relatively ineffective for dehydration that is now achieved by heating, removing another 10 to 15% of the water. The second stage begins at temperatures close to $100^{o}C$ and digenetic changes in clay mineralogy may also occur. The third and final stage of compaction and dehydration is also controlled by temperature but is very slow, requiring hundreds of years to reach completion and leaving only a few percent of water.

To sum up, the properties of drilled shale formation, which are important for shale/fluid interaction and shale stability, are dictated by the past compaction history and the current in situ stresses and temperature. For example, affinity (thirst) for water of the shale at any depth depends on compaction/ loading history, in situ stresses, clay composition, and temperature. These factors also determine shale porosity, permeability and the amount of water squeezed out.

NMR log uses a permanent magnet, a radio frequency (RF) transmit, and an RF receiver. The tool responds to the fluids in the pore space is used to measure lithology - independent effective porosity, pore size distribution, bound and movable fluid saturation, and permeability of a foot-by-foot basis. Mathematical models, which include pore size distribution, predict permeability more accurately than those that include effective porosity, since permeability is controlled by a pore throat size.

A small relaxation time for an NMR tool corresponds to small pores and large relaxation time reflects the large pores. The distribution of the time constant $T^{2}$ in clastic rocks tends to be approximately log – normal. A good single representation of the $T^2$ is there fore obtained from the geometric or logarithmic mean value. Shlemberger – Doll research (SDR) developed the following model for permeability.

- $K = 4T^{2}ml\acute{O}^{2}$

Where

K = permeability. MD

$T^2$ ml = log mean of relaxation time .$T^2$, milliseconds

Ǿ = NMR porosity, fraction

The SDR model is sensitive to the presence of a hydrocarbon phase in the pores.T2 response appears to be bimodal in water – wet rocks due to the partial presence of hydrocarbons .

**2.2.2. Shale/Fluid Interaction Mechanisms**

Analysis of the available experimental data (O'Brien-Goins-Simpson Associates and University of Texas, Austin, Shell and Amoco sponsored Projects); clearly shows that the shale strength and the pore pressure near the bore-hole are indeed affected by fluid/shale interaction. Basic results confirmed by this analysis can be summarized as follows:

- Activity imbalance causes fluid flow into/or out of shale
- Different drilling fluids and additives affect the amount of fluid flow in or out of Shale.
- Differential pressure or overbalance causes fluid flow into shale
- Fluid flow into shale results in swelling pressure
- The moisture content affects shale strength. Moisture content relates to sonic velocity.

The instability and shale/fluid interaction mechanisms, coming into play as drilling fluid contacts the shale formation, can be summarized as follows.

1 Mechanical stress changes as the drilling fluid of certain density replaces shale in the hole. Mechanical stability problem caused by various factors is fairly well understood, and stability analysis tools are available.
2 Fractured shale- Fluid penetration into fissures and fractures & weak bedding planes
3 Capillary pressure, Pc, as drilling fluid contacts native pore fluid at narrow pore throat interface.
4 Osmosis (and ionic diffusion) occurring between drilling fluid and shale native pore fluid (with different water activities/ ion concentrations) across a semi-permeable membrane (with certain membrane efficiency) due to osmotic pressure (or chemical potential), PM.

5 Hydraulic (Advection), ph, causing fluid transport under net hydraulic pressure gradient because of the hydraulic gradient.
6 Swelling/Hydration pressure, ps, caused by interaction of moisture with clay-size charged particles.
7 Pressure diffusion and pressure changes near the well bore (with time) as drilling fluid compresses the pore fluid and diffuse pressure mechanism.
8 Fluid penetration in fractured shale and weak bedding planes can play a dominant role in shale instability, as large block of fractured shale fall into the hole.

Capillary phenomenon also is now fairly well understood, and an interesting exposition is given in a recent paper. Increasing the capillary pressure for water-wet shale has been successfully exploited to prevent invasion of drilling fluid into shale through use of oil base and synthetic mud using esters, poly-alpha-olefin and other organic low-polar fluids for drilling shale. The capillary pressure is given by

- $\mathbf{Pc = 2\gamma \cos\theta / r}$

Where, $\gamma$ is interfacial tension, $\theta$ is contact angle between the drilling fluid and native pore fluid interface, and r is the pore radius. When drilling water-wet shale with oil base mud, the capillary pressure developed at oil/pore-water contact is large because of the large interfacial tension and extremely small shale pore radius.

In addition to the shale – fluid interaction mechanisms in the well bore a more fundamental look at shale physics can be taken to gain better insight into which factors need to be included in strength correlation. Some of the factors for that can be

· Clay mineralogy
· Clay content
· Compaction.

The main conclusion from the shale – fluid interaction mechanisms discussed above is; under in situ stress and native pore fluid salinity conditions; clay mineralogy and contents are of secondary importance regarding their effect on shale strength. The degree of compaction (characterized by

water content, porosity, sonic Velocity, etc.) appears to be the dominant factor. Thus, strength can be tied to any of the following related parameters:

- Water content
- Porosity
- Sonic velocity
- Density

The impact of clay mineralogy and contents on strength (and stability) of shale can become quite significant while drilling, in cases like, when a foreign drilling fluid contacts in situ smectitic shale and alters the salinity of native pore fluid through shale/fluid interaction. Smectitic shales have a lower tolerance to drilling fluid invasion, and will tend to fail easier than formations in which kaolinite and/or illite are the only clay types present. The effect of clay mineralogy on strength can be important if the drilling process severely disturbs a formation from its natural state. In those cases, smectitic formations will be more susceptible to failure.

## 2.3. LOG INTERPRETATION OF SHALY FORMATIONS

Shales are one of the more important common constituents of rocks in the log analysis. Aside form their effects on porosity and permeability, this importance stems from their electrical properties, which have a great influence on the determination of fluid saturations.

The evaluation of shaly formations (i.e., formations containing clay minerals) has long been a difficult task. Clay minerals affect all well-logging measurements to some degree. The shale effects have to be considered during evaluation of such reservoir parameters as porosity and water saturations.

From tools like self potential (SP), and the three porosity logs in a hypothetical clean sand, on their responses on clean sands if shale is added, the tools response will be displaced to ward the normal shale response. The degree of displacement increases as shale content, ***Vsh,*** increases. The presence of shale in the sand tends to reduce the true resisitivity, ***R****t*, of hydrocarbon-bearing zones and to increase the value of Ro. This can affect both quantitative and qualitative interpretation and

quantification. Quantitatively a non representative high ***Sw***, value is calculated if clean formation models are used. The potential of the zone is then underestimated or completely masked. A high ***V****sh* might even encumber visual detection of Hydrocarbon zones. The presence of shale also affects the responses of the three porosity tools. Using clean formation models in the quantitative interpretation results in over estimation of porosity values. The interpretation problem in shaly formations is in calculating porosity and saturation values free from the shale effect. Because the shale effect depends on the shale content, the estimation of ***V****sh* is of prime importance.

### 2.3.1. Shale content from the SP log

***V****sh* from the SP log can be estimated with the following linear relation ship:

- ***Vsh=1-Epsp/Essp……equation based on linear relation ship***

Where ***Epsp*** is the shale response in the shaly zone of interest and ***Essp*** is the shale response in an adjacent clean, thick zone that contains the same water salinity as the zone of interest.

Use of this method should be restricted to cases where the SP is of good quality and other shale indicators are absent. Several factors, such as salinity changes, Rw/Rmf contrast, and hydrocarbon content, affect the estimation of Vsh from the SP log. The presence of hydrocarbon in a formation reduces the reading of the SP log.

### 2.3.2. Shale content from the gamma ray response

The shale volume is related to the shale index, ***Ish***:

- ***I*sh = (γlog - γc)/ (γsh - γc)**

Where γlog = gamma ray response in the zone of interest, γc = average gamma ray response in the cleanest formation, and γsh = average gamma ray response in shale's. It is customary to assume that Vsh=Ish. This assumption, how ever, tends to exaggerate the shale volume .Empirical relationships were found to be more reliable. Several empirical relation ships were developed for different geologic ages and area. The most notable correlations were developed by Larionov, Stieber, and Clavier *et al.*

*For tertiary rocks, the Larionov equation is*

$Vsh = 0.083( 2^{3.7Ish} - 1)$

*The stieber equation is*

$Vsh = Ish / (3 - 2Ish)$

*And the clavier et al, equation is*

$Vsh = 1.7 - (3.38 - (Ish + 0.7)^2 )^{1/2}$

*For older rocks, the Larionov equation is*

$Vsh = 0.33(2^{2Ish} - 1)$

An empirical equation can be also developed specifically for formation or geologic unit of interest

### 2.3.3. Porocity logs in shaly formations

Porosity log response can be expressed in general by Log-derived porosity values

**ØD, ØN**, and **ØS** as

- **ØD** or **ØN** = f (matrix, total porocity, shale type and amount, type and amount of fluids in pore space)

And **Øs** = f (matrix, primary porosity only, degree of formation compaction, shale type and amount, type and amount of fluids in pore space)

The above two equations reduce to tool response = f (matrix, porosity, shale content)

The presence of shale complicates the interpretation of the tool response because of the diverse characteristics of shale's and the different responses of each porosity tool to the shale content. On the density porosity log, shales display low to moderate porosity value. On the sonic neutron logs, shale display moderate to relatively high porosity values.

## 2.4. SHALY SANDS

The way the shalinnes affects a log reading depends on the amount of shale and is physical properties. It may also depend on the way the shale distributed in the formation. Shale can be distributed in a sand in one of the three ways. Laminated shale, dispersed shale, and structural shale. Shales are one of the more important common constitutes of rocks in log analysis. Aside form their effect s on porosity and permeability, this importance stems from their electrical prorpeties, which have a great influence on the determination of fluid saturations.

Shale's are loose, plastic, fine grained mixtures of clay sized particles or colloidal particles and often contain a high proportion of clay minerals. Most clay minerals are structured in sheets of alumina – octahedron and silica tetrahedron lattices. There is usually an excess of negative electrical charges within the clay sheets

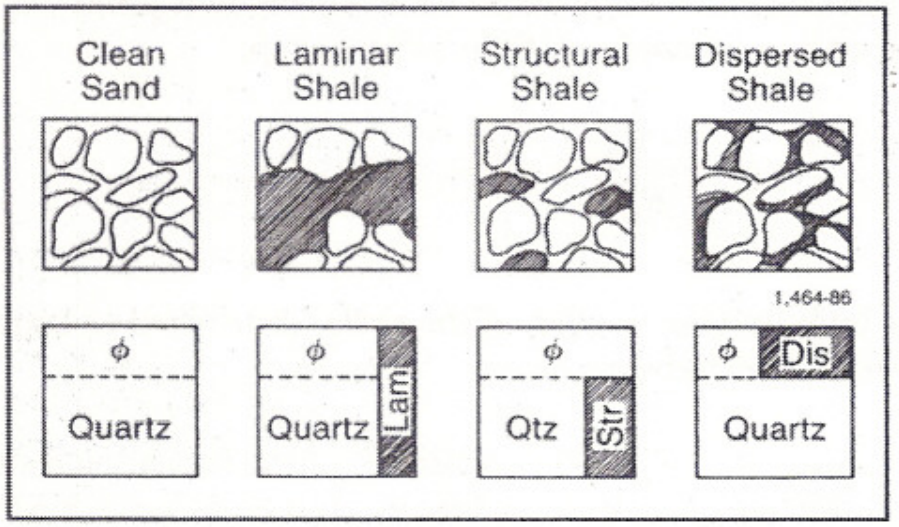


**Figure 2.2 - Forms of shale classified by manner of their distribution in formations.**

### 2.4.1. Laminated shale

Laminated shale exists as layers of shale (thin shale beds or streaks) between sand beds. The shale can exist in the form of laminae between which is layers of sand. This type of shale has no effect on the intermatrix porosity or permeability of each individual sand bed. Note that while each sand bed is not affected by the shale laminae, the zone as a whole has less porosity.

### 2.4.2. Dispersed Shale

Dispersed shale is shale that either accumulates or adheres to the grains of the sand, or acts as a cementing factor between two grains. The shaly material can be dispersed throughout the sand. Dispersed shale porosity and permeability to a great degree. Effective porosity is reduced

proportionately by the amount shale present. An 18% porosity is thus reduced to 8% from a shale volume of 10%.

### 2.4.3. Structural Shale

Shale can exist as grains or nodules in the formation. Structural shale, unlike to the above two models, has no effect on porosity or permeability. Structural shale occurs in small granules just as the sand grains, and is considered part of the matrix. The shale replaces matrix rather than adds to it.

## 2.5. RESISITIVIY RESPONSES OF SHALY FORMATIONS

Resistivity logs can not be used for a first recognition of the common lithologies. There are no characteristics resisivity limits for shale, or limestone or sand. The value depends on many variables such as compaction, composition, fluid content and so on. How ever in any restricted zone, gross characteristics tend to constant and the resistivity log may be used as a discriminator. For example, in a sand – shale sequence, shale characteristics may be constant and sands may be similar and with constant fluid salinities. The resistivity then becomes an excellent log for lithological distinction.Indeed, this is especially the case in younger, unconsolidated sediments and in the top sections of off shore boreholes where the quality of most logs is poor, but the deep resistivity can be still used. In certain specific cases, how ever, the resisitivity log can be used to indicate a lithology. These cases are clearly where certain minerals have distinctive resistivity values. Salt, anhydrite, gypsum and coal all have usually high, diagnostic resistivities. High resisitivities will also be associated with tight limestones and dolomites.

Over the years, large numbers of models relating receptivity and fluid saturations have been proposed. Many have been developed assuming the shale exists in a specific geometric form. (I.e. laminar, structural, dispersed) in the shaly sand. All these models are composed of a clean sand term, described by the Archie water saturation equation, plus shale term.

The term porosity can be confusing in terms of shale. While the previously mentioned porosities are actual porosities, it is not to say that log porosity will be unaffected. Tool responses will be

affected because the mineral make up of the matrix has changed. Thus in the case of structural shale, the responses of particular porosity tool will represent a different porosity than what is actual. The sonic porosity, for instance, will not exhibit the true porosity even if the relation ship for this model states that **Óe=Ó.** The sonic porosity is affected by the type of shale present .Neutron and Density porosity are affected by and the shale type (or model).Shale resisitivity is one of the parameters up on which the approach to shaly sand can be found. Normal practice would be to take the ***Rsh*** of adjacent shale

### 2.5.1. Laminated sand – shale simplified model

In the case of laminated shale, the resisitivity of the sand is affected by the resisitivity of the shale by a parallel conductivity. Rt the resisitvity in the direction of the bedding planes, is related to Rsh (the resisitivity of the shale laminae) and to Rsd (the resisitivity of the clean sand laminae) by a parallel resistivity relation ship.

- **1/Rt = ((1 – V1am)/Rsd) + V1am/Rsh**

Where

V1am = the percent volume of laminated shale.

Rsd = the clean sand resisitivity

Rsh = the shale resisitivity.

For clean sand laminae, Rsd + FsdRw/$Sw^{2,}$ where Fsd is the formation resistivity factor of clean sand. Since Fsd= a/$Ósd^2$, (where Qsd is the sand – streak porosity) and Ó = (1 – V lam) Ósd (where Ó is the bulk formation porosity), then

- **1/Rt = (( $Sw^2Ó^2$)/( 1 – V lam) aRw ) + Vlam / Rsh**

To evaluate Sw by the laminated model Rt, Rw, Ó, Vlam, and Rsh must be determined.

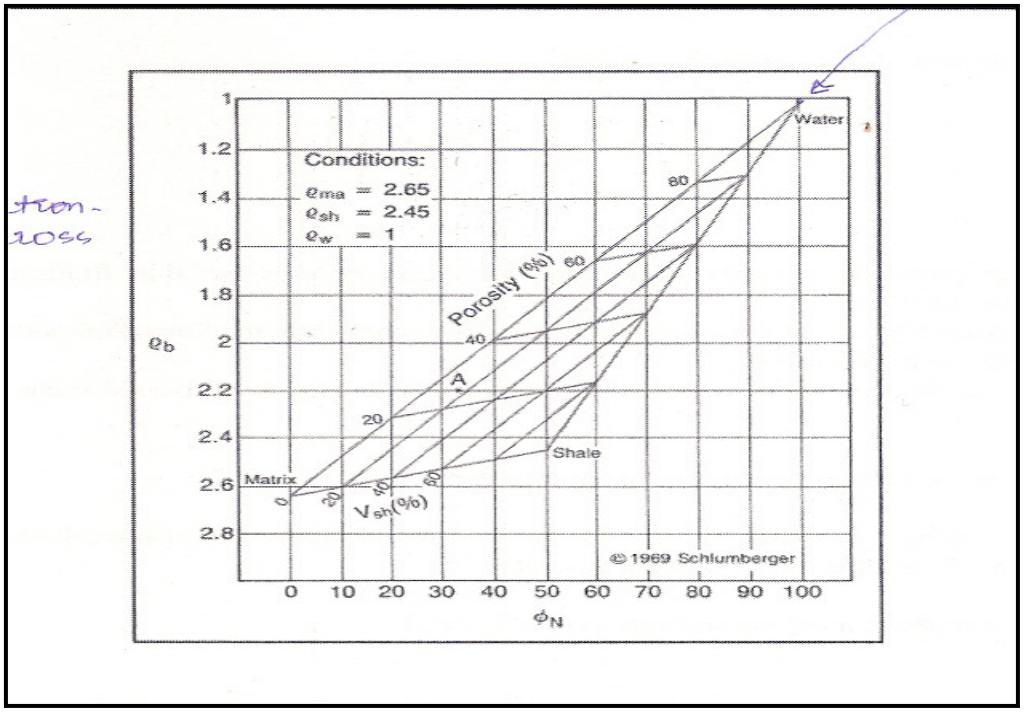


**Figure.2.3- Neutron-density cross plot showing matrix, water and shale points**

### 2.5.2. Water saturation in Dispersed shale's

Water saturation in dispersed shales within the sands can be interpreted in one of the three models mentioned below

- The Simandoux model
- Waxman - Smits and Thomas model
- The Dual - water model

The dual water model is relatively young system of shaly sand analysis. It is based on the theory that there are two types of water in the shaly formation. The first type of water is said to be "bound" water. Bound water is the water which adheres or is contained by the clay. A certain amount of water is directly absorbed by the clay crystal, followed by a layer of water at its surface surrounding a sodium cation. This thin sheet of salt- free water is quite significant. Clays have upto 6,300 acres of surface per cubic foot (900 $km^2/m^3$) as compared to one tenth of an acre per cubic foot (0.014 $km^2/m^3$) for an average sand. One can easily see that clay water contributes a significant amount water, as compared to the total pore spaces.

The second type of water is termed “free” water. This by no means implies that the water is producable.It simply states that it is water not bound to clay. It includes irreducible water as well as water that can move.

## 2.6. GAS EFFECT ON FINE GRAINED LITHOLOGIES/ POROSITY CROSS PLOTS

On the litho logy /porosity cross plots, gas bearing zones assume non – representative portions. On a density / neutron cross plot, for example ,a liquid filled lime stone porosity will assume portion A on **figure .2.4**,below..The presence of gas in a zone of the same lithology and porosity results in a shift upward and to the left. This shift from portions A to portion B is almost parallel to the iso porosity lines. The porosity of gas zones can then be approximated by a direct reading from the chart. How ever the lithology indications from the cross plot can be in error. For example the porosity of a gas zone that assumes position C in the cross plot is about 13%.Its lithology could be a lime stone/dolomite mixture, depending on the shift caused by the gas effect. A gas correction is needed to deduce the correct lithology. The gas correction consists of shifting a point that represents a gas zone in to a position that represents a liquid – filled point of the same porosity.

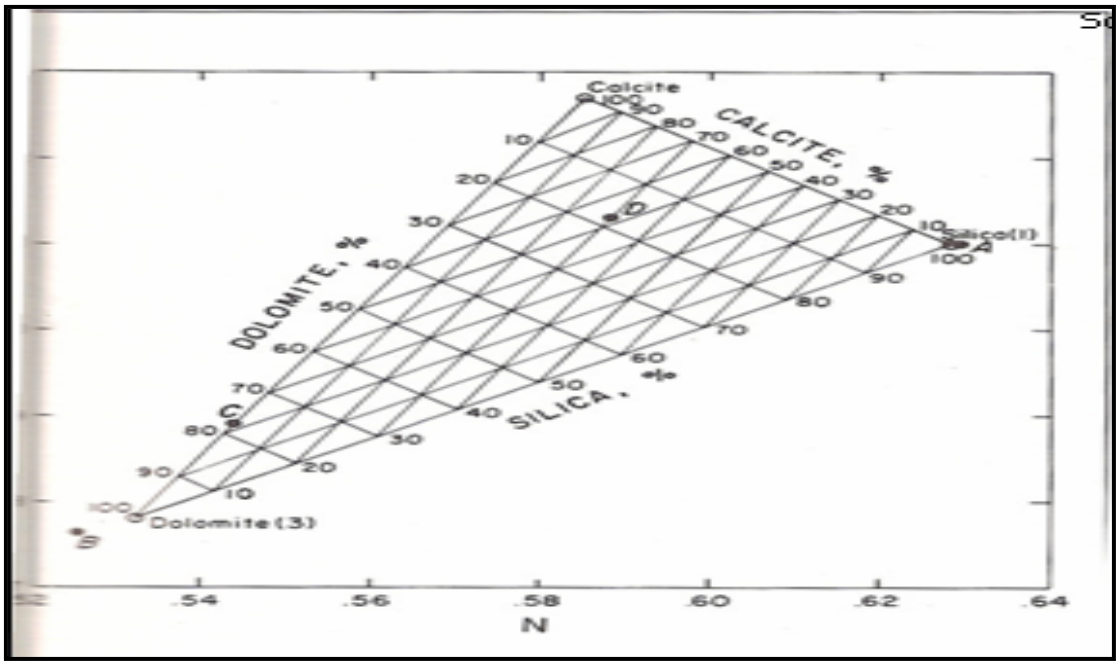


**Figure.2.4. M/N lithology identification plot**

### 2.6.1. Shaly gas bearing formations

The difference of porosity values recorded by the neutron and density logs where **$Ø_D > Ø_N$** is used as a direct method of gas detection .Where the formation investigated is shaly, the separation between the two curves decreases because shale effects on both logs are opposite that of gas. When the shale content is large enough, the separation will disappear completely or even reverse **(i.e. $Ø_D < Ø_N$).**Gas may be detected in shaly formations by use of one of several techniques as:

- With a Neutron/Density porosity overlay.
- With a **($Ø_D - Ø_N$) vs.** Gamma Ray cross plot.
- With a fluid identification plot
- With the Density/ Neutron cross plot

## 2.7. PORE PRESSURE

During a period of erosion and sedimentation, grains of sediments are continuously building up on top of each other, generally in a water filled environment. As the thickness of the layer of sediment increases, the grains of the sediment are packed closer together, and some of the water is expelled from the pore space. How ever, if the pore throats through the sediment are interconnecting all the way to surface the pressure of the fluid at any depth in the sediment will be the same as that which would be found in a simple column of fluid.

The magnitude of the pressure in the pores of the formation is known as formation pore pressure (formation pressure) and is an important consideration in many aspects of well planning and operations. It will influence the casing design and mud weight selection and will increase the chances of stuck pipe and well control problems. It is particularly important to be able to predict and detect high pressure zones, where there is a risk of a blow – out.

In addition to predicting the pore pressure in a formation it is also very important to be able to predict the pressure at which the rocks will fracture. These fractures can result in losses of large

volumes of drilling fluids and, in the case of an influx from a shallow formation, fluids flowing along the fractures all the way to surface, potentially causing a blow out.

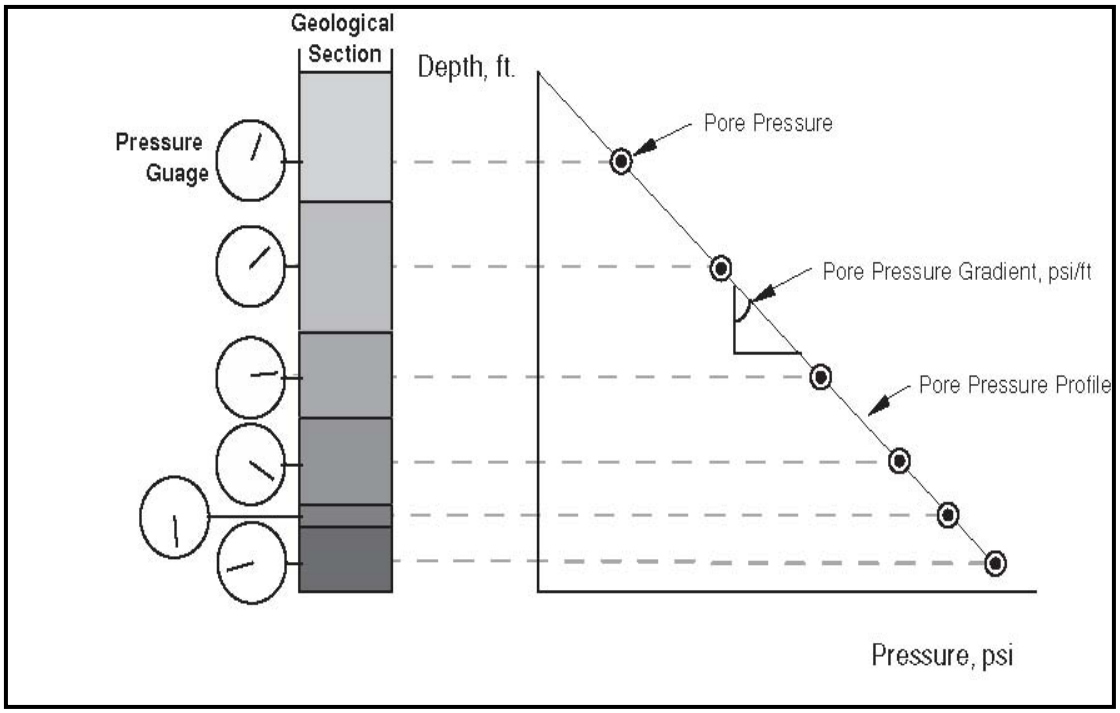


**Figure.2. 5. P-Z Diagram representing pore pressures**

### 2.7.1. Representation of pore pressure in the formations

The pressure in the formation to be drilled is often expressed in terms of a pressure gradient. The gradient is derived from a line passing through a particular formation pore pressure and a datum point at surface and is known as the Pore pressure gradient.

The datum which is generally used during drilling operations is the drill floor elevation but a more general datum level used almost universally, is mean sea level, MSL When the pore throats through a sediment are interconnecting, the pressure of the fluid at any depth in the sediment will be the same as that which would be found a simple column of fluid and there fore the pore pressure gradient is a straight line as shown in ***Figure.2.6*** The gradient of the line is **a** representation of the density of the fluid. Hence the density of the fluid in the pore space is often expressed in units of psi/ft.

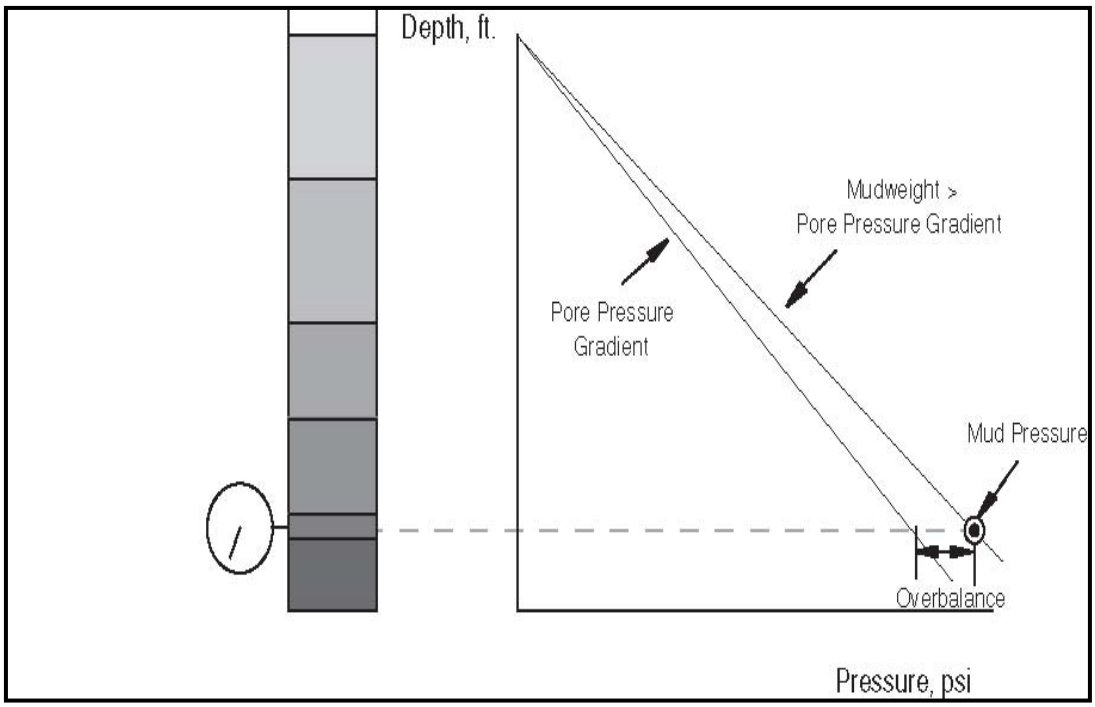


**Figure .2.6 - Mud density compared to pore pressure gradient**

Representing the pore pressures in the formation in terms of pore pressure gradients is also convenient when computing the density of the drilling fluid that will be required to drill through the formations in question .If the density of the drilling fluid in the well bore is also expressed in units of psi/ft then the pressure at all points in the well bore can be compared with the pore pressure to insure that the pressure in the well bore exceeds the pore pressure.

The differential between the mud pressure and the pore pressure at any given depth is known as the **overbalance pressure** at that depth. It will be seen below that the fracture pressure gradient of the formations is also expressed in units of psi/ft. Any formation pressure above or below the points defined by the normal pressure gradient is then **abnormal pressure**.

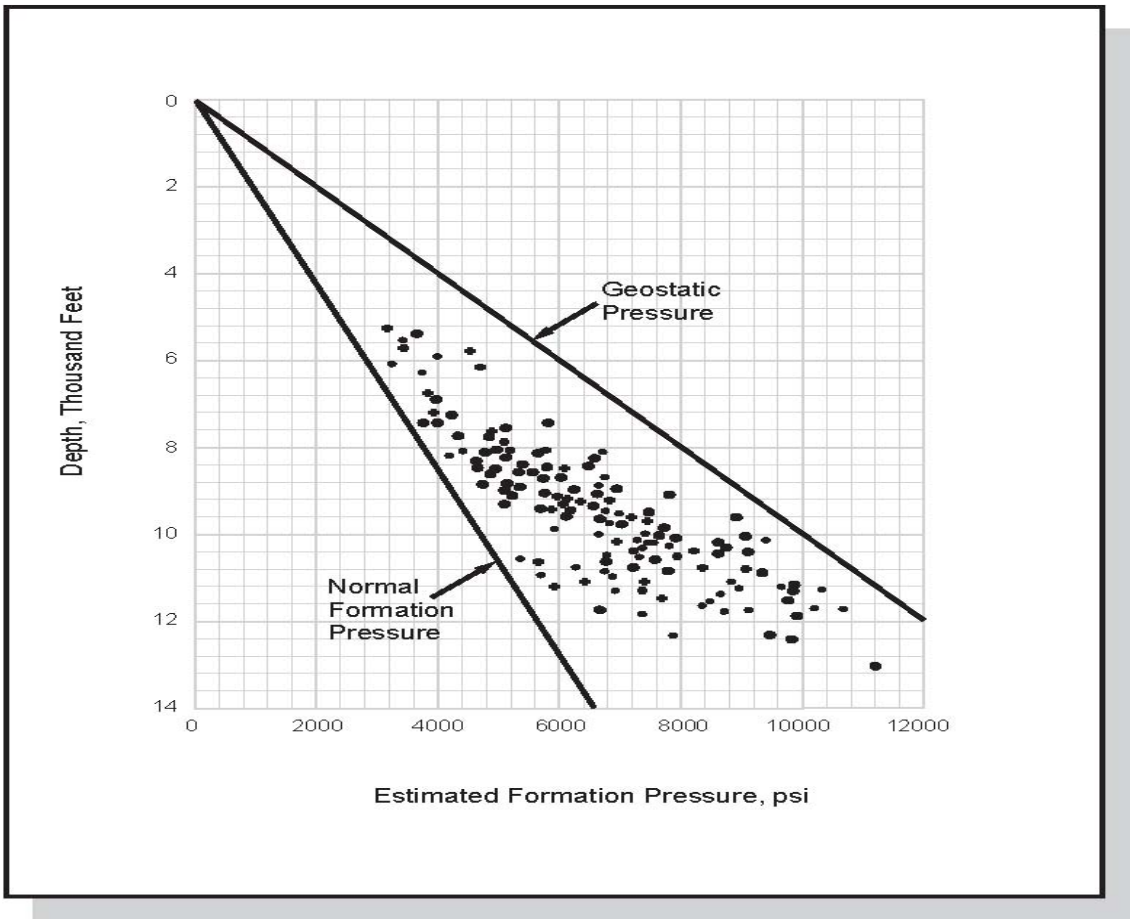


**Figure .2.7 - Abnormal formation pressures plotted against depth for 100 US wells**

### 2.7.2. Overburden pressures.

The pressure discussed above in **section 2.7** and **section 2.7.1** relate exclusively to the pressure in the pore space of the formations. It is how ever also important to be able to quantify the vertical stress at any depth since the pressure will have a significant impact on the pressure at which the borehole will fracture when exposed to high pressures. The vertical pressure at any point in the earth is known as the overburden pressure or geostatic pressure. The overburden pressure at any point is a function of the mass of the rock and fluid above the point of interest. In order to calculate the overburden pressure at any point, the average density of the material (rock and fluids) above the point of interest must be determined. The average density of the rock and fluid in the pore space is known as the bulk density of the rock.

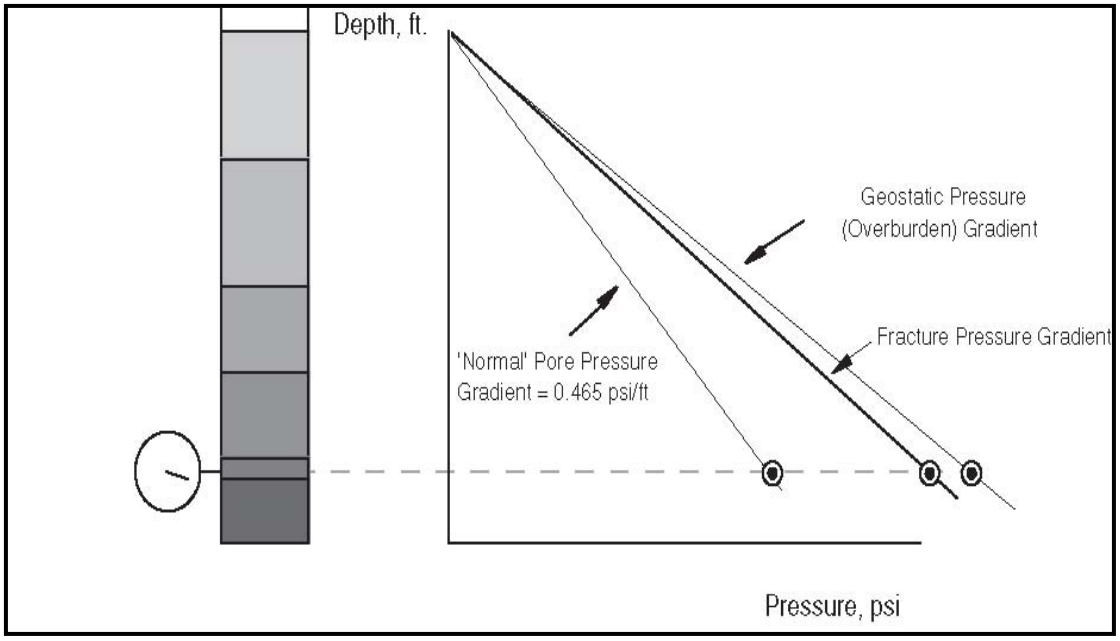


**Figure .2.8 - Pore Pressure, Fracture Pressure and Overburden Pressures and Gradients for a Particular Formation**

**2.7.3. Abnormal pressures.**

In the worldwide search for oil and gas, abnormally high pressure zones (geopressured) have been encountered in numerous countries on several continents. Such geopressured, or abnormally high sub - surface pressures, are defined as any pressure which exceeds the hydrostatic pressure of a column of water.

A number of methods are used in industries to detect and evaluate abnormally pressured formations. The ability to detect and recognize abnormally pressured formation is critical in conducting efficient end safe drilling operations. Observed changes in the properties of rocks, especially shales, can be used to evaluate the overpressure zones. Variations of rock properties can be detected by geophysical methods, wire-line logging techniques, surface measurements on the drilling mud and shale cuttings, and monitoring of several drilling parameters. The best approach for the detection and evaluation of abnormally pressured formations is the study of a combination of several measured parameters since relying on one type of data can result in misinterpretations.

However, for the oil industry, occurrences of abnormal pressures (Geopressures) are important in many respects. For instance much of the extra cost in the search for and development of hydrocarbon reserves is for drilling fluid and casing programs. An additional, quite expensive item is the properly selected completion method which must be effective, safe and allow for killing of the well. Here, too, reliable pore pressure and fracture gradient data are a prerequisite.

Pore pressures which are found to lie above or below the "normal" pore pressure gradient line are called abnormal pore pressure. These formation pressures may be either subnormal (i.e. les than 0.465 psi/ft) or Overpressured (i.e. greater than 0.465psi/ft).

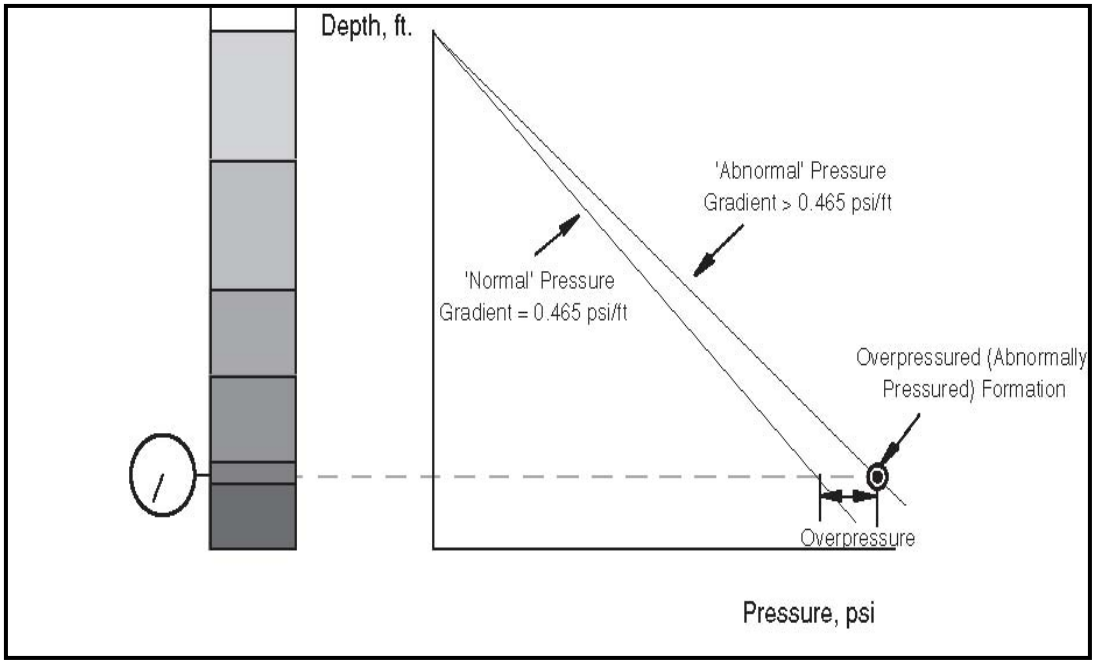


**Figure.2. 9 – *A* schematic that shows Over Pressured (Abnormally Pressured) Formation**

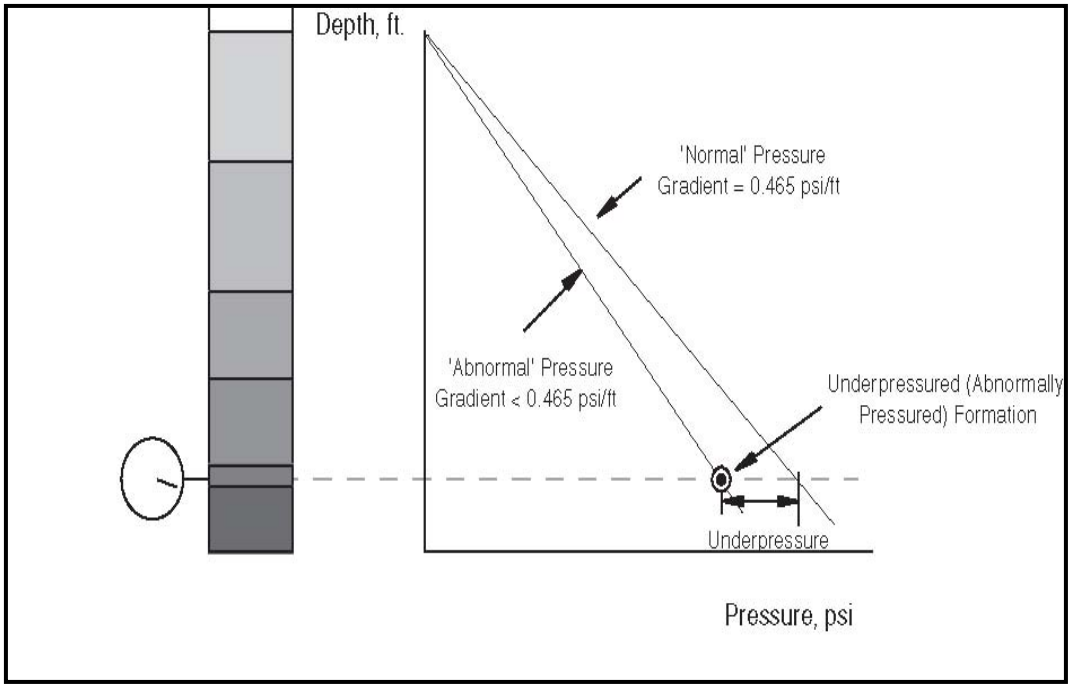


**Figure .2 .10 – A schematic that shows under pressured (Subnormal Pressured) formation.**

The mechanism which generates these abnormal pore pressures can be quite complex and vary from region to region .However the most common mechanism for generating overpressures is called under compaction and can be best described by the under compaction model.

The compaction process can be described by a simplified model on ***Figure 2.11,*** below, consisting of a vessel containing a fluid (representing the pore fluid) and a spring (representing the rock matrix).The overburden stress can be simulated by a piston being forced down to the vessel. The overburden (S) is supported by the stress in the spring (δ) and the fluid pressure (P).Thus:

$$\mathbf{S = \delta + P}$$

If the overburden is increased (e.g. due to more sediments being laid down) the extra load must be borne by the matrix and the pore fluid. If the fluid is prevented from leaving the pore space (drainage path closed) the fluid pressure must increase above the hydrostatic value.

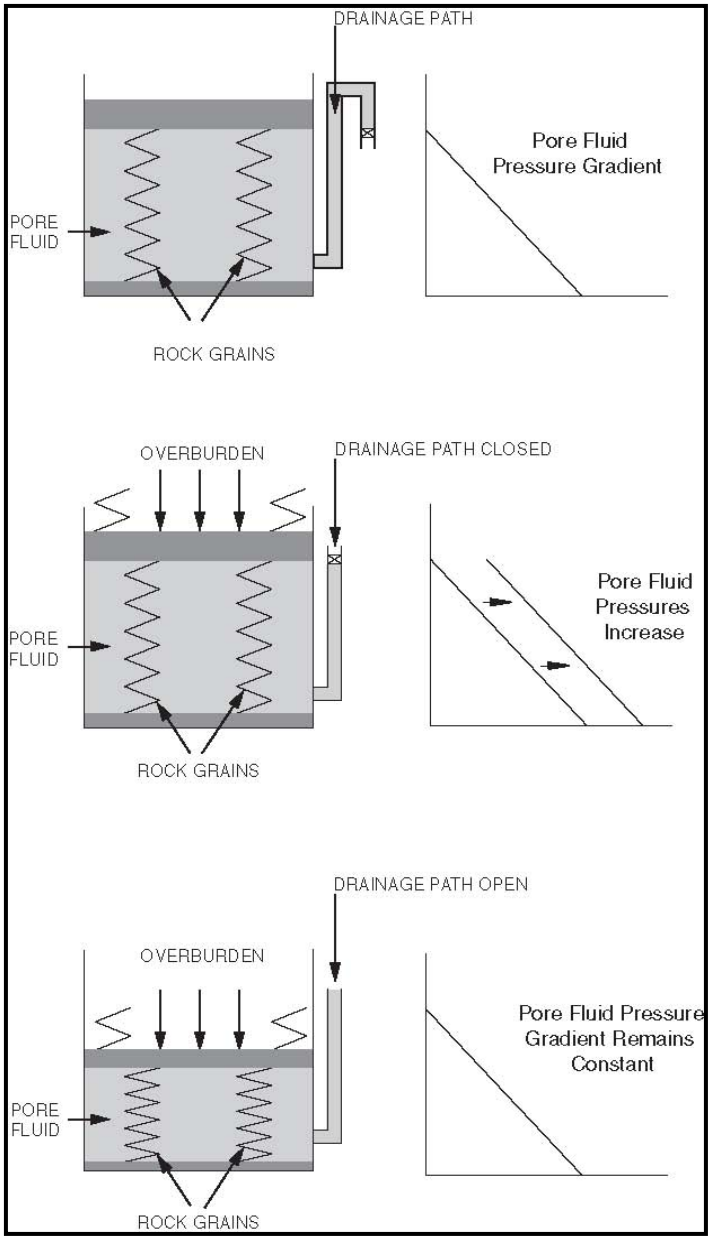


**Figure.2. 11- Overpressure Generation Mechanisms**

Such a formation can be described as over pressured (i.e. part of the over burden stress being supported by the pore fluid and the grain to grain contact stress is not increased.

In a formation where the fluids are free to move (drainage path open),the increased load must be taken by the matrix, while the fluid pressure remains constant .Under such circumstances the pore pressure can be described as Normal ,and is proportional to depth and fluid density.

| **Origin of sub-normal Formation pressures** | **Remarks** | **Origin of over-pressured formations** | **Remarks** |
|---|---|---|---|
| **Thermal expansion** | As sediments and pore fluids are buried the temperature rises. | **Incomplete sediment compaction** | In a rapid burial of low permeable clays or shale's there is little time for fluids to escape then if burial is rapid then will Lead to overpressure. |
| **Formation foreshortening** | During a compression process the intermediate beds will be subnormaly pressured zones | **Faulting** | Faults may redistribute sediments ,and place permeable zones opposite impermeable zones, thus creating briers to fluid movement |
| **Depletion** | When HC or water are produced from a competent formation in w/c no subsidence occurs then a subnormaly pressured zones may result. | **Phase changes during compaction** | Minerals may change phase under increasing pressure. Thus the phase change will result release of water then if the water can not be escaped then Overpressures will be generated. |
| **Precipitation** | In arid areas (e.g. Middle East) the water table may be located hundreds of feet below surface, thereby reducing the hydrostatic pressure. | **Massive rock salt deposition** | On the depositions of salt, since salt is impermeable to fluids the underlying formation become over pressured. |
| | The structural relief of a | | The upward movement of low |

| | | | |
|---|---|---|---|
| **Potentiometer surface** | formation. can be thousands of feet above or below ground levels | **Salt diaperism** | density salt dome due to buoyancy will disturb the normal layering of the sediments and will produce pressure Anomalies. |
| | | **Tectonic compression** | The lateral compression of sediments may result either in uplifting weathered sediments or fracturing / faulting of stronger sediments. |
| | | **Generation of hydrocarbons** | Shale's which are deposited with a large content of organic material will produce gas as the organic material degrades under compaction. If it is not allowed to escape, the gas will cause overpressures to develop. |

**Table .2.2. Origins of Abnormal Formation (pore) Pressures**

## 2.8. DRILLING PROBLEM ASSOCIATED WITH ABNORMAL FORMATION PRESSURES

When drilling through a formation sufficient hydrostatic mud pressure must be maintained to be able to:

- Prevent the bore hole collapsing and
- Prevent the influx of formation fluids.

To meet these two requirements the mud pressure is kept slightly higher than formation pressure. This is known as **overbalance**. If how ever, the overbalance is too great this may lead to:

- Reduced penetration rate( due to chip hold down effect)
- Breakdown of formation (exceeding the fracture gradient) and subsequent lost circulation (flow of mud in to formation).
- Excessive differential pressure causing stuck pipe.

The formation pressure will also influence the design of casing strings. If there is a zone of high pressure above a low pressure zone the same mud weight cannot be used to drill through both formations otherwise the lower zone may be fractured. The upper zone must be "cased off", allowing the mud weight to be reduced for drilling the lower zone. A common problem is where the surface casing is set too high, so that when over pressured zone is encountered and an influx is experienced, the influx can not be circulated out with heavier mud with out breaking down the upper zone.

### 2.8.1 Transition zones

It can be seen from figure 2.12, that the pore pressures in the shallower formations are "normal". That is that they correspond to a hydrostatic fluid gradient. There is then an increase in pressure with depth until the "over pressured" formation is entered. The zone between the normally pressured zone and the over pressured zone is known as the **transition zone.** The pressure in both the transition and over pressured zone is quite clearly above hydrostatic pressure gradient line. The transition zone is there fore the seal or **caprock** on the over pressured formation. It is important to note that the transition zone shown in ***Figure 2.12***, below is representative of **a thick shale sequence** (fine grained rock).

The shale will have some low level of porosity and the fluids in the pore space can there fore be over pressured. However, the permeability of the fine grained rock (the shale) is so low that the fluid in the shale and is there fore effectively trapped. Hence the cap rock of a reservoir is not necessarily a totally impermeable formation but is generally simply a very low permeable fine grained rocks which usually is shale rich of clay minerals.

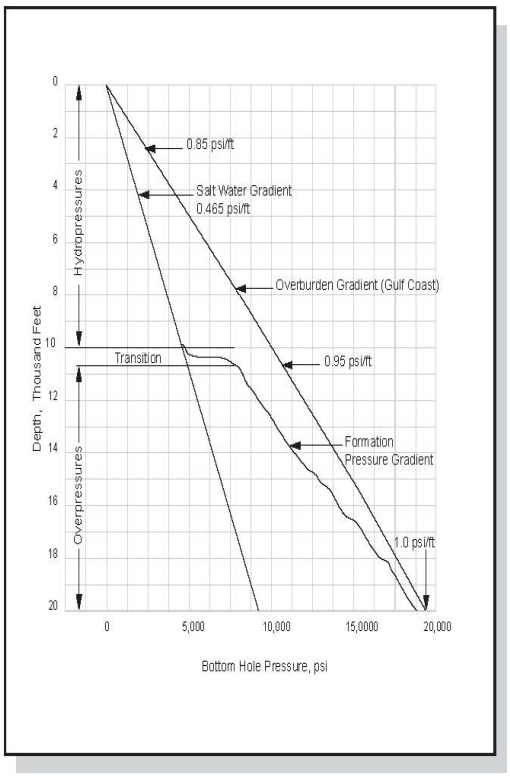


**Figure.2. 12 - Transition from normal pressures to overpressures**

If the seal is a thick shale, the increase in pressure will be gradual and there are techniques for detecting the increasing pore pressure. How ever, if the seal is a hard, crystalline rock (with no Permeability at all) the transition will be abrupt and it will not be possible to detect the increase in pore pressure across the seal.

## 2.9. WHY WE PREDICT PORE PRESSURE?

Some of the main reasons for the prediction of pore pressure are for well planning, material and cost estimates for construction of a safe, modern well including logistics, operations planning and procedural guide lines. Because of the uncertainties that encounter in the subsurface, recording pore pressure measurements for future use is advisable. The other reason behind predicting pore pressure is, after identifying trouble some shaly formations, to choice non-aqueous drilling fluids so as to reduce well bore instability problems.

Usually before a well is drilled, by which the pore pressure is going to be predicted, the only reliable data that can be used is the seismic data. From the seismic velocity to pressure relation ship it is possible predict pore pressure assuming it is known that the velocity directly is related with the pressure.

But predicting the pore pressure from the seismic velocity versus pressure relation ship is not sufficient, and so we require supporting information to strengthen the prognosis. So that we need to predict pore pressure by analyzing fine grained rocks, stratigraphy and history of the area, drilling engineering experience of past drilling history. Additional geological and petrophysical details about the offsetting wells, if there are any would greatly improve the accuracy of the prediction. This is where measurement while drilling and post drilling information are very important.

## 2.10. STRESSED SHALE AND DRILLING FLUIDS.

It is generally accepted that non-aqueous drilling fluids are superior to water-based muds in improving well bore stability in shaly formations. How ever, some field cases have demonstrated that well bore instability problems still occur even when oil- or synthetic-based fluids are used, especially in fractured formations.

It is well known that water fluxes it to or out of shale formations during drilling is a key factor in controlling well bore stability. Studies showed that water absorption by shale formation altered the stress distribution, reduce the strength and at the same time, changed the young's modules of the near well bore formation, which may potentially destabilize the well bore. On the other hand, dehydration causing pore pressure decrease and strength increase is beneficial to well bore stability. However, over-dehydration results in fractures in the near well bore formation and may also disturb well bore stability. Water adsorption in fractured shale's may widen the fractures and destabilize the wellbore.Slight water adsorption may, infact, soften the fracture surface and is necessary to stabilize well bore.

In fractured stressed shale formations, it is particularly important to control water movement because the in-situ stresses are in a critical state. Any disturbance of the formation by chemical and /or mechanical means could result in shale breaking and sliding into the hole. Once the well bore instability is initiated, it becomes difficult to stop. But the better option is to improve the well bore instability in the fractures shale formations by keeping mechanical balance, and more over maintaining the chemical balance between shale formations and non- aqueous drilling fluids to minimize well bore instability problems. How ever, it is very challenging to determine the chemical potential balance between shale formations and drilling fluids due to the difficulty in directly measuring the chemical potential.Generaly, the maintaining will be done as, by balancing the water activity of the non- aqueous fluids with the water activity of the formation to control water movement so as to improve well bore stability. Although it is difficult to balance water activity of shale formations with drilling fluids exactly everywhere in a well, because shale- water activity varies with depth and mineralogy, so that is will be better to balance the water activities of shale formations and drilling fluids at the problematic locations or depths.

## 2.11. HIGH PRESSURE IDENTIFICATION USING SONIC LOG

As a sediment becomes compact, so its velocity increases. The effect is most obvious on reduced-scale sonic logs where, over thick shale intervals, there is a regular increase in velocity down wards due to compaction.

Acoustic velocity can be used to identify overpressure. Other things remaining constant, an increase in pore pressure or overpressure is indicated by a drop in sonic velocity. A plot of shale interval transit times through an over pressure zone shows a distinct break in the average compaction line. The principal reason for this drop is probably the increase in shale porocity, although several factors are probably compounded. It is considered possible to calculate the amount of over pressure form the extent of deviation of the sonic velocity from the normal compaction trend (Hottman and Johnson, 1965).Overpressures may also be calculated by an equivalent depth method, which can be expressed by the formula;

$$\mathbf{P = (\delta w * D_e) + \delta r\ (D - D_e)}$$

Where P = formation fluid pressure at depth D (psi); **δw** = formation – water gradient (psi / ft), *and* δr = litho static gradient (psi / ft); D = depth of calculation point (ft); $\mathbf{D_e}$ = equivalent depth (ft) with same sonic transit time.$\boldsymbol{D_e}$ is the point in the section at normal pressure which has the same interval transit time as the point being measured. An example of ***D*** and $\boldsymbol{D_e}$ equivalence is marked on the sonic log depth plot. The above calculation suggests that the pressure at ***D*** is the sum of the hydrostatic pressure to ***De*** and the lithostatic pressure from ***De*** to ***D***. Although the sonic log can be used to identify over pressure in the sub surface, it can only do once drilling and logging are completed, by which time it may be too late.

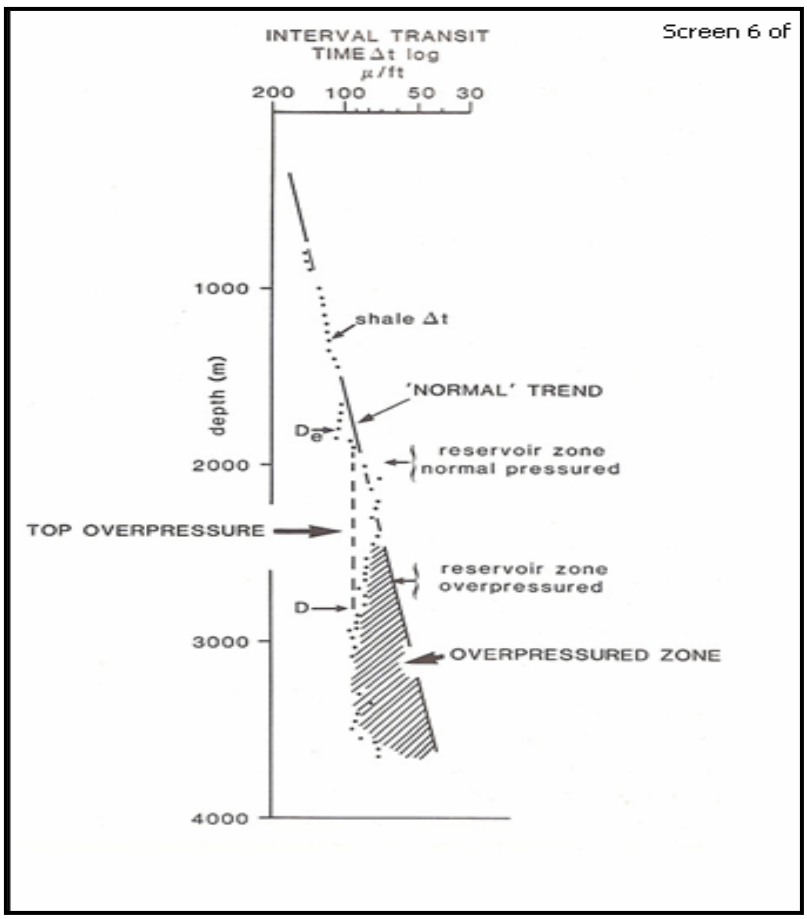


**Figure .2.13. Over pressures indicated by a plot of shale interval transmit times against depth. A decrease from the normal compaction trends indicates overpressures.**

## 2.12. SEQUENCE STRATIGRAPHY AND FINE GRAINED ROCKS

### 2.12.1. Rock Types Definition

A rock type is defined as an interval of rock within which the geological and petrophysical properties that effect fluid flow are consistent and predictable. A rock type will have a certain effective pore throat size distribution that produces a particular family of capillary pressure curves and controls porosity, permeability and water saturation. The reservoir rocks that correspond to a particular rock type should have identical rock fabric (i.e. Dunham classification), pore types (e.g. proportion of primary to secondary porosity) and pore throat size distribution. Each rock type is defined as having a distinct set of pore types, pore sizes and degree of connectivity. The distribution of pore size is controlled by:

- The size and sorting of the particles (grains of several 100's micron across or micrite particles of 3 micron across).
- The volume of the various pore spaces.

The connectivity of the various parts of the pore system depends on the size and type of pore spaces, which are linked to the primary depositional texture, and to the digenetic overprint. Accordingly, the type of pores preserved within a rock type is a function of the interplay between depositional environment and digenesis, although it is the texture of the rock, which ultimately controls reservoir quality in most cases.

### 12.2.2. Well logs and siliclastic sequence stratigraphy

As a means of correlation, the use of wire line logs is obvious. As an aid to sequence stratigraphy analysis, logs are invaluable .But as a tool in sequence stratigraphy; their use so far, is seriously undeveloped. Sequence stratigraphy is the study of genetically related facies within a framework of chrono-stratigraphicaly significant surfaces. It is a concept that explains the vertical and lateral variations of sedimentary successions in terms of relative sea level changes.

A condensed sequence represents a long period of time during which land derived detrital input is small and most of the sediments deposited comes from a hemipealgic or pelagic source and represents deeper water conditions. Such a sequences is typically rich in pelagic fauna and micro fauna, is a finely laminated, has low quartz content and is enriched in marine organic mater.The log identification of condensed sedimentation depends mostly on its high organic matter content.Marrine organic matter is associated with uranium so that condensed sediments have a high gamma ray value.Oragnic richness is also registered by high neutron values and a low density.

The fine laminations, a frequent feature of these slowly accumulating shales, amplify the high interval transit times (low velocity) and generally low resistivity already caused by organic content. In fact, most of the log responses will be such that in the electro sequence analysis, condensed sections will be picked out as 'anomalous'. An organic rich condensed sequence there fore, has a whole suite of log responses which are generally more diagnostic and reliable than the simple gamma ray 'spike' although not all condensed sequences are maximum flooding surfaces.

The identification of condensed sections is fundamental in any sequence stratigraphic analysis and in planning of drilling a well bore. In the deeper marine environment and even in the shallow, near coastal environments, the increased organic content and laminated texture of the sections, gives a distinctive set of log responses which will generally be identified in an electro sequence analysis as anomalous. They can be also used to correlate from the deeper to shallower depositional environments and can also be used to divide the sections up in to sediment logically distinct electro sequences (facies secessions) More over their nature as condensed can be confirmed by microbiological investigation as they contain increased numbers of pelagic fauna: this may also lead to a dated event. The more important condensed sequences are chronostratigraphic markers. However, not all condensed sequences are enriched in organic matter and not all intervals enriched in organic matter should be assumed to be condensed sequences.

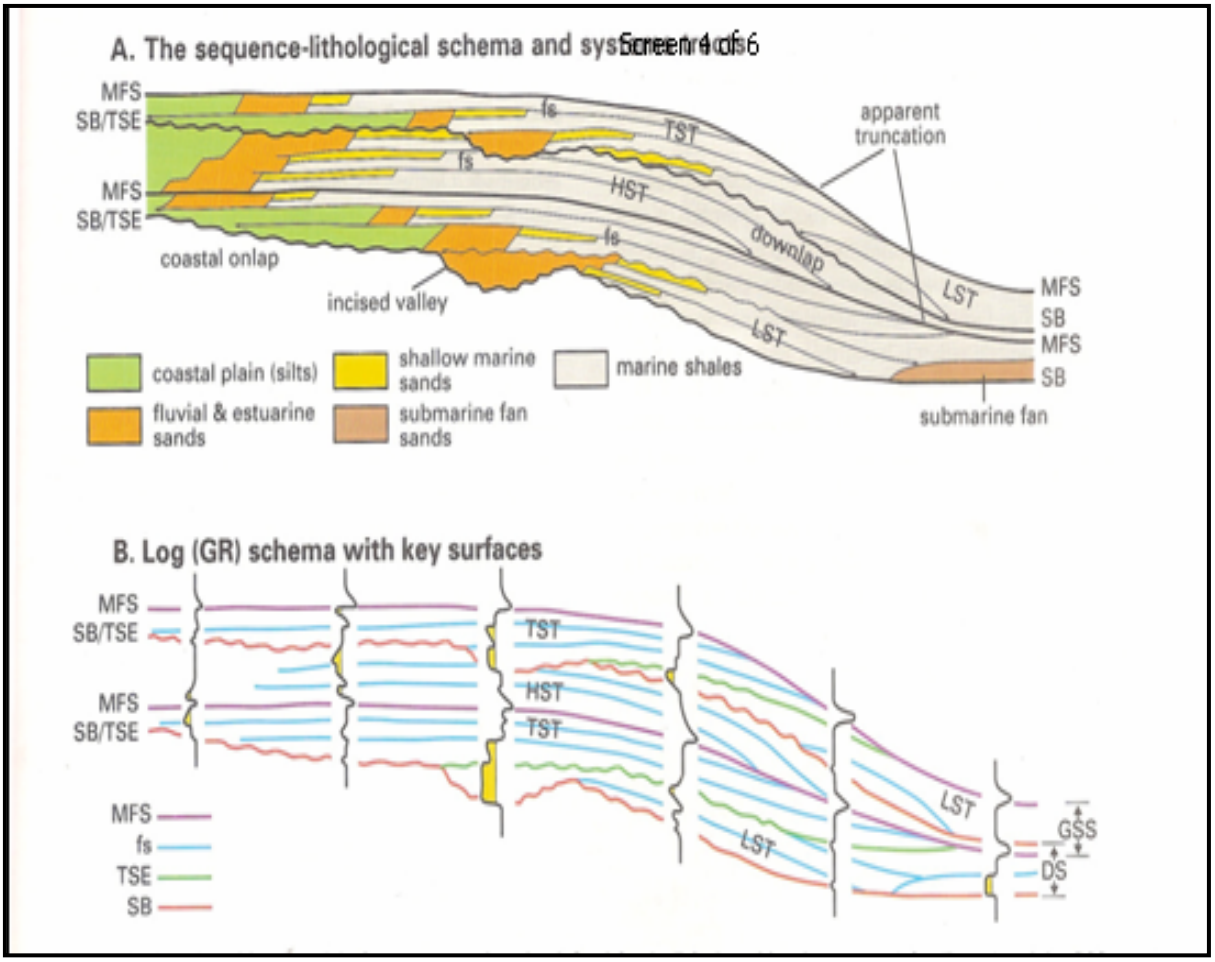


**Figure.2.14. The depositional model of sequence stratigraphy, defined for the DS, depositional sequence (after Exxon) and the GSS genetic stratigraphic sequence (after Galloway)**

## 2.13. ESTIMATING PETROPHYSICAL UNCERTAINTY

Petrophyical uncertainty can be classified as one of the three main sources of uncertainty, which is the container uncertainty related to seismic picks and depth conversion, fluid contacts and field segmentation.

The second is from property mapping uncertainty which is the uncertainty in the mapping of rock properties away from the wells. This could equally well be named as “Geological Uncertainty”. It includes issues such as zone isochore variations, sand body distribution and pinch out, and trends and variability in net reservoirs properties.

To choose an approach on estimating Petrophysical uncertainty, it is useful to summarize the basic observations on sources of Petrophsical uncertainty. Systematic errors in the basic input measurements and parameters them selves, or introduced by the methods applied to derive results from these data, are the main sources of Petrophsical uncertainty.

# CHAPTER 3

# DATA ANALYSIS

## 3.1. REVIEW OF METHODOLOGIES AND EXISTING DATA

For this study well data is taken from the *Gelama Merah field* found in the ***Sabah Basin*** which is one of the areas of the petroleum resources of *Malaysia*. The field is located at 114° 59' E, 5° 33' N which is in offshore North West Sabah basin. It is a middle Miocene Sedimentary basin. Province wise the Gelama Merah field is part of the Southern Inboard region.

The petroleum resources of Sabah are described with reference to the intensity of exploration activities and the most significant play types in the 3 Tertiary Neogene's basins, namely Sabah, the Northeast Sabah and Southeast Sabah basins. The Gelama Merah field was discovered in the Sabah Basin respectively.

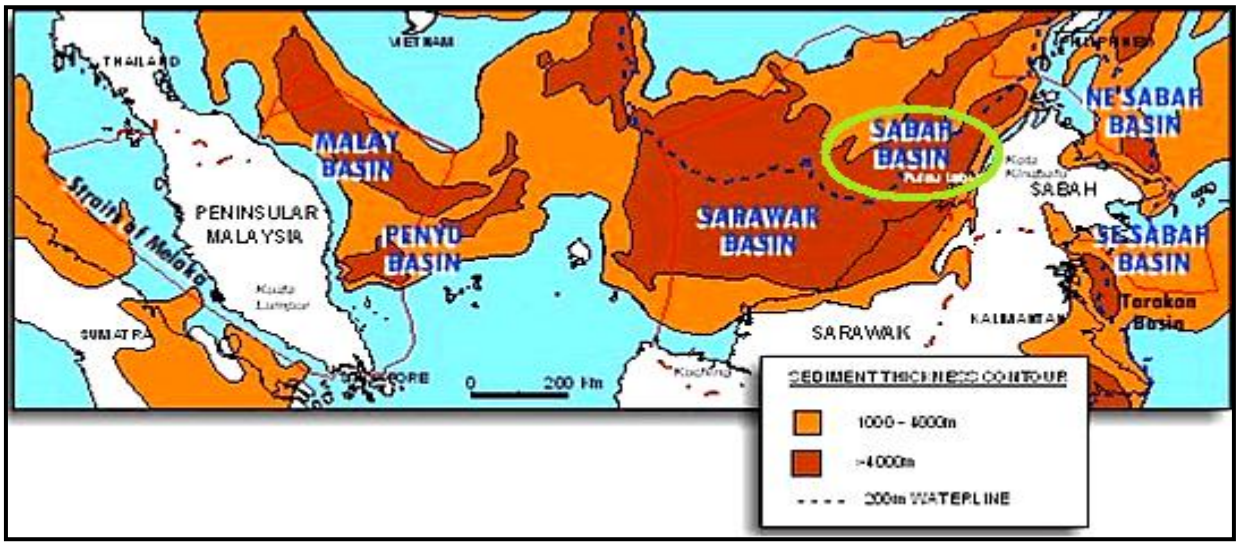


**Figure 3.1: The Sedimentary Basins of Malaysia**

The Sabah Basin (also known as the NW Sabah Basin) is a predominantly offshore Middle Miocene sedimentary basin that underlies the continental margin off western Sabah. It contains approximately 12-km thick Neogene sediments that were deposited within the deep marine and progradational shelf slope environment. Reservoirs consist of channel bodies, shallow marine clastics and deepwater turbidite.

The Sabah Basin is a structurally complex basin that was formed on the southern margin of a foreland basin that resulted from the collision between the NW Sabah platform western Sabah during the early Middle Miocene. Its complex syn-tectonic sedimentary history resulted in the recognition major unconformity bounded sedimentary packages. Major hydrocarbon accumulations have been formed and produced from siliclastic reservoirs.

The Sabah Basin is made up of several tectonostratigraphic provinces. These are the Inboard Belt, the Outboard Belt, Kudat Platform, the East Baram Delta and the Lower Tertiary Thrust Sheet, bounded to the NW and W by the Sabah Trough and NW Sabah Platform. Commercial oil fields in the Sabah Basin occur in the Inboard and Outboard Belts and in the East Baram Delta. Significant oil and gas discoveries have been made from deepwater channel and fans and promise to be the trend in the future.

The methodology adopted for the data analysis is, the LAS data at hand is taken from the Gelama Merah field by which two exploration wells "***the gelama merah 1 (GM1)*** and the ***gelama merah side trucked (GMST1)***" are drilled on the gelama merah field of the Sabah basin, and I used the *LAS SOFTWARE* and the *INTERACTIVE PETROPHYSICS SOFTWARE* to interpret the different lithologies and to come up with cross plots. Once the fine grained rocks are quantified from the LAS data I plotted the pore pressures and there relationship with trouble making rocks in the well bore which are usually the less permeable transition zone rocks.

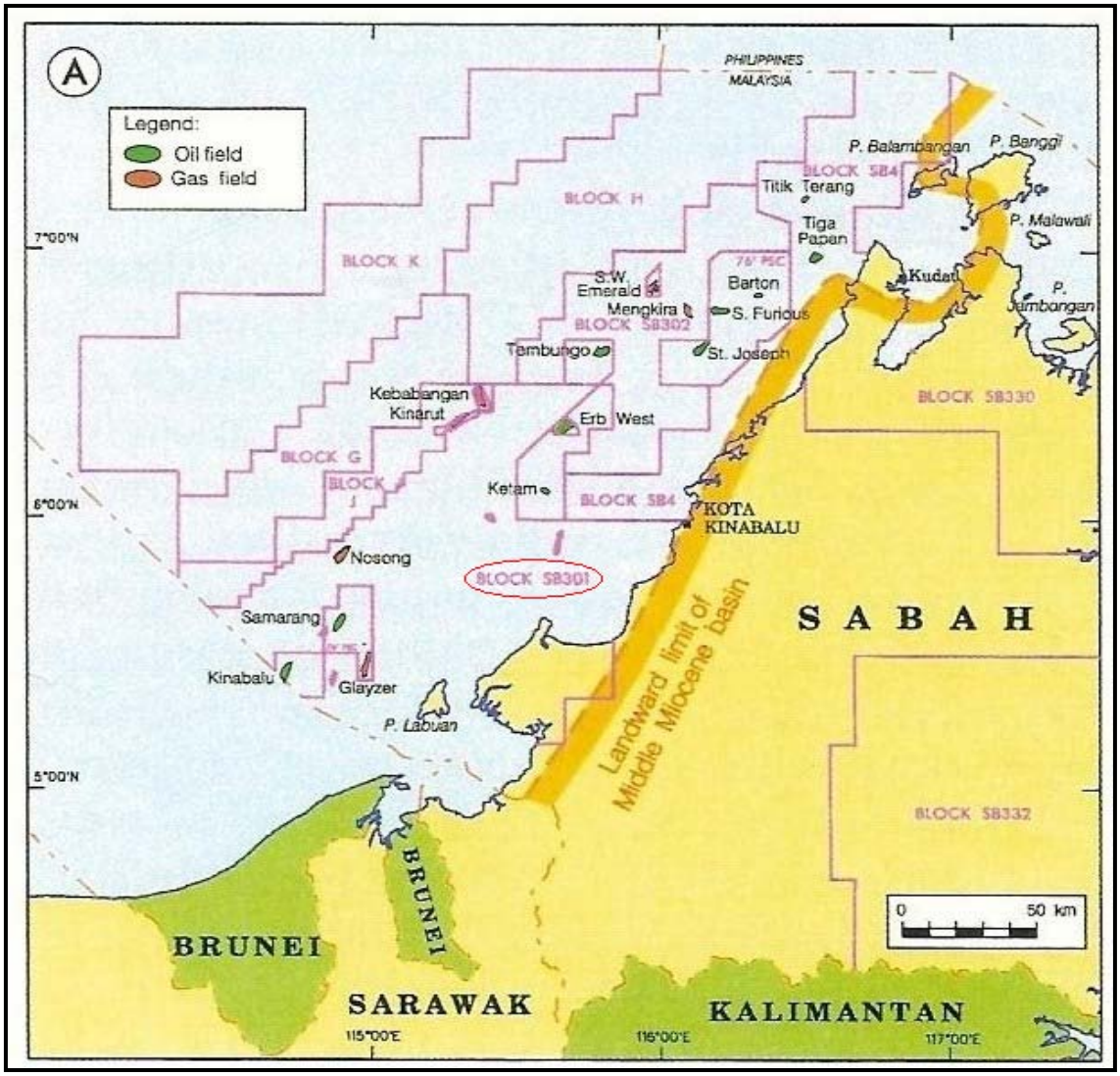


**Figure 3.1.2: Map of West Sabah basin showing the location of the Sabah basin**

## 3.2. PROJECT WORK

### 3.2.1. Identification of lithologies by cross plotting compatible logs

Typical and illustrative of this kind of cross plotting is the neutron – density cross – plot: the plot of neutron porosity values against density porosity values. By them selves, the neutron and the density logs are difficult to use for gross lithology identification. However, once

combined, they become probably the best available indicator. Both the neutron log and the density log should be showing the same formation parameter – porosity.

Interpretation of the density log cab be affected by shale or clay in the formations. Although the properties of shale vary with the formation and locality, typical densities of shale beds and laminar shale streaks re of the order of 2.2 to 2.65g/cm$^{3.}$Where as the neutron tools see all hydrogen in the formation even if some is not associated with the water saturating the formation porosity. For example, it sees bound water associated with the shale's since shales in general have an appreciable hydrogen index; in shaly formations the apparent porosity derived from the neutron response will be greater than the actual effective porosity of the reservoir rock.

The neutron – density combination is the best lithology indicator for most formations. Shale and shaliness and evaporates can be identified. Clean formations and even matrix type can be suggested, and unusual minerals located with the possibility of identification. Neutron and density values can also be used quantitatively for lithology identification.

Form the two neutron – density cross plots below for the *GM1* and *GMST1* we can clearly identify pure matrix and / or related porosity, since this is impossible using only the value from one of the logs. On the *GM1* it can be inferred that the well bore is clan porous sand with gas by which some of the readings have bulk density of 1 g/cm$^3$ and neutron porosity reading close to 50%.How ever this effect is more clear on the *GMST1* well by which most of the readings for the neutron porosity is close to 50%.When we see the GR readings, on the GM1 most of the points have higher GR readings which shows that even if there is clean sand in the well bore, there is also matrix related with the clean sand which could be calcareous shale which can usually create troubles in the well bore while drilling because of its instability.

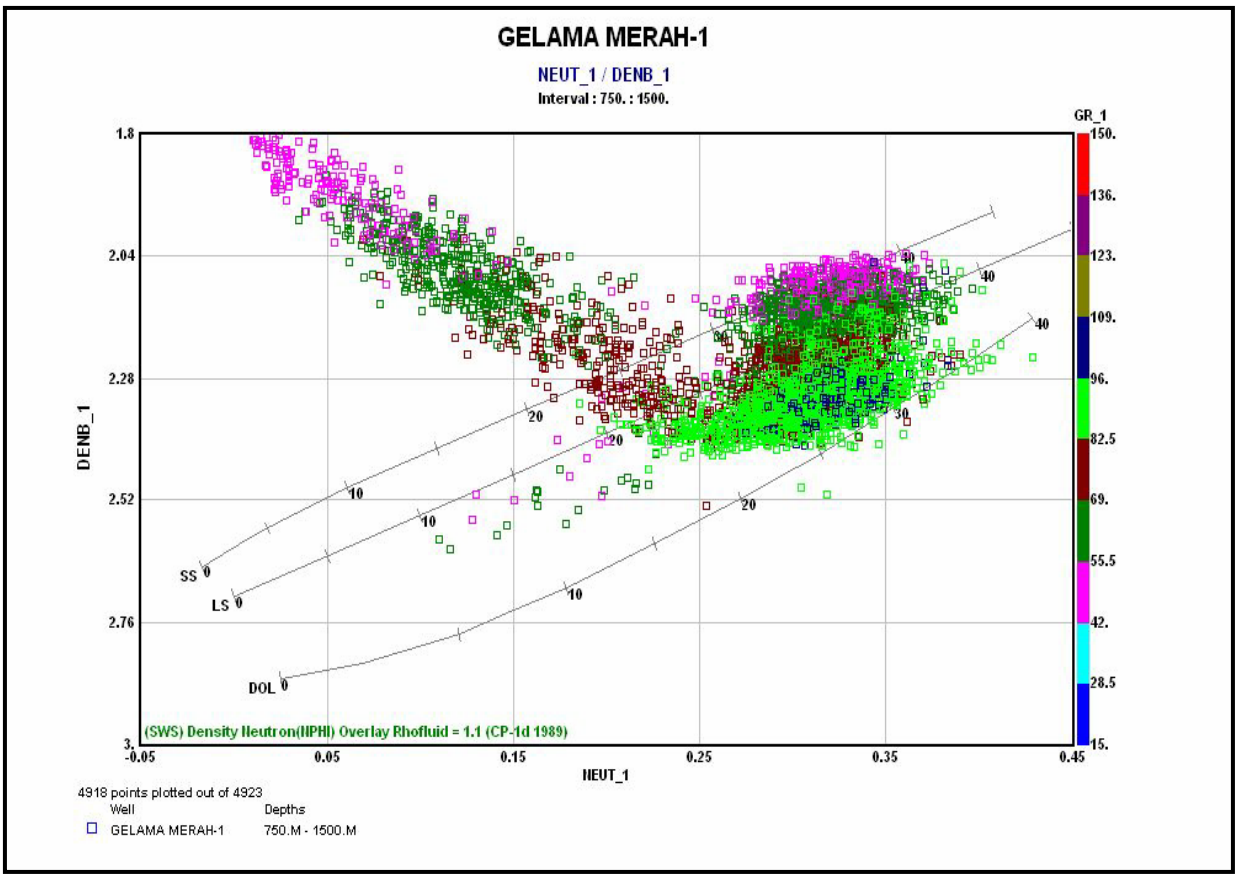


**Figure 3.2.1. Neutron – density cross plot for GM1 used to determine lithology empirically and quantitatively**

From the density vs. neutron cross plots of *GM1* and *GMST1* we can see that there is gradational sand to shale changes defined and anomalous log responses highlighted. For the GM1 the nature of the shale within the sand is of laminated whereas for the *GMST1* the nature of the shale is of dispersed as can be seen from the two cross plots.

In Gelama Merah field, it can be seen from the cross plots that the shale zone was identified by lower neutron porosity reading and a bit higher density porosity reading due to the presence of the gas present in the shale zone.

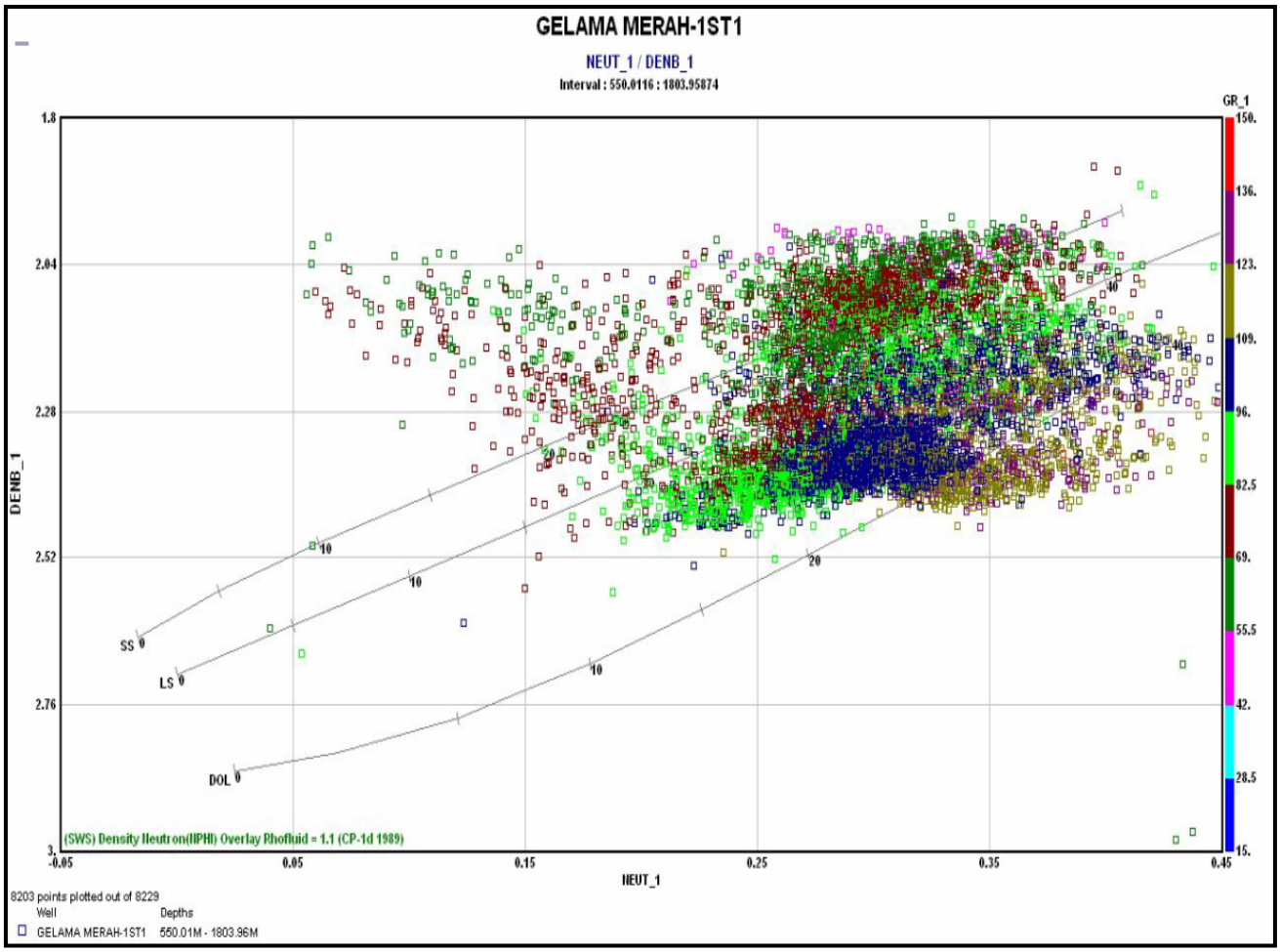


**Figure3.2.2. Neutron – density cross plot for GMST1 used to determine lithology empirically and quantitatively**

### 3.2.2. Identification of lithologies by cross plotting incompatible logs

The cross – plotting of incompatible logs is usually done to quantify lithology. Incompatible logs are those which do not in the instance, measure or indicate the same parameter. Resisitivity and gamma ray logs are incompatible; one gives the resisitivity, the other natural radioactivity, by inference shale volume. However on cross plotting, compatibility will become evident (there usually is compatibility). The resisitivity logs, for instance will show a consistent set of values in shale, as will the gamma ray log; this will become evident on cross plotting.

Plotting the gamma ray log values against the neutron log values, for example bring out several relation ships. There is a consistent, straight line relation ship between the two where both the gamma ray and the neutron logs are reacting to shale – sandstone mixture. Each log is showing the volume of shale on its own way. A neutron – gamma ray plot, infact, is very useful for analyzing shale changes in general. It is also very important to note down that plotting incompatible logs bring out relation ships which are often geologically significant.

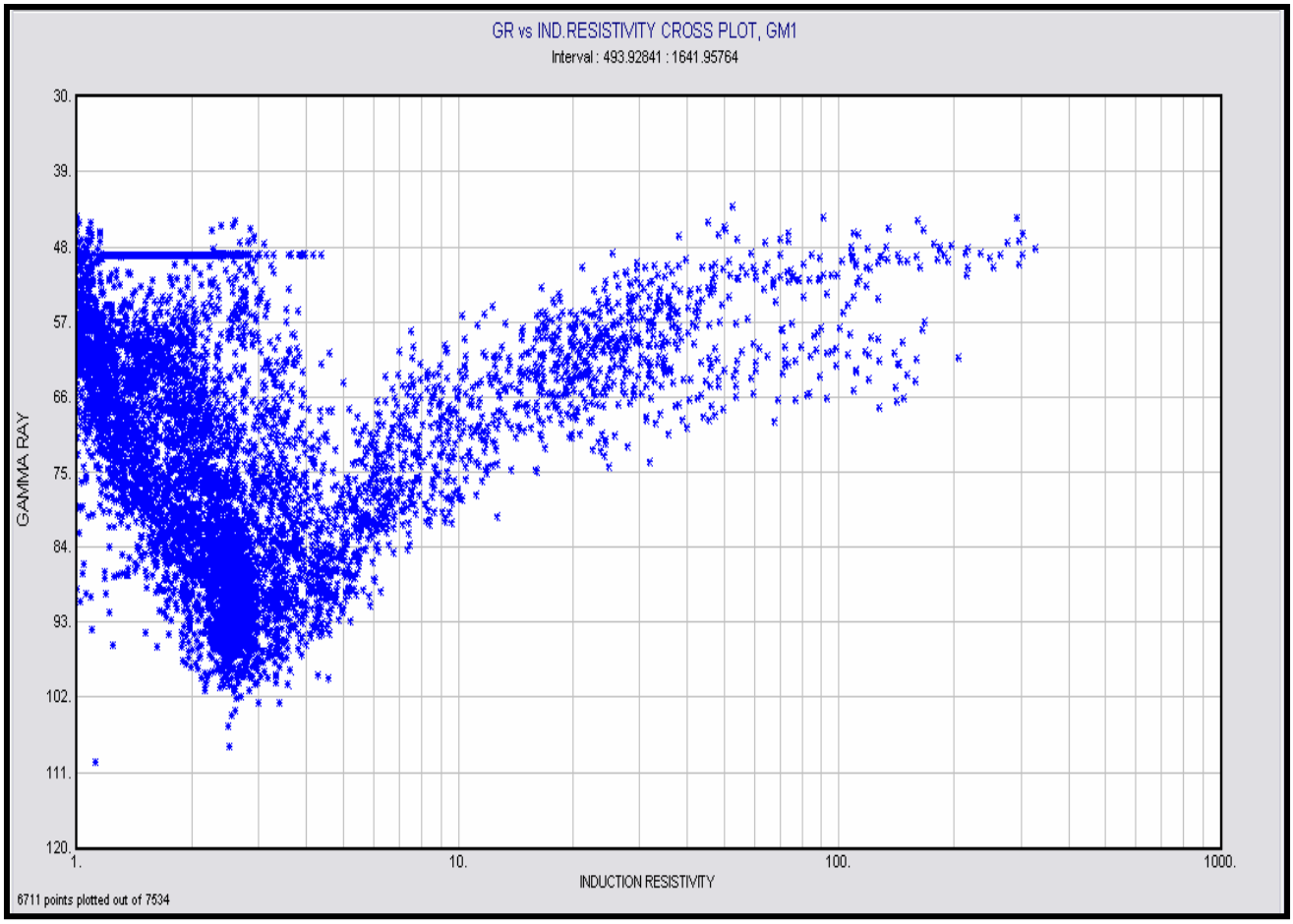


**Figure 3.2.3. Cross plot of incompatible logs, gamma ray and resistivity values for GM1**

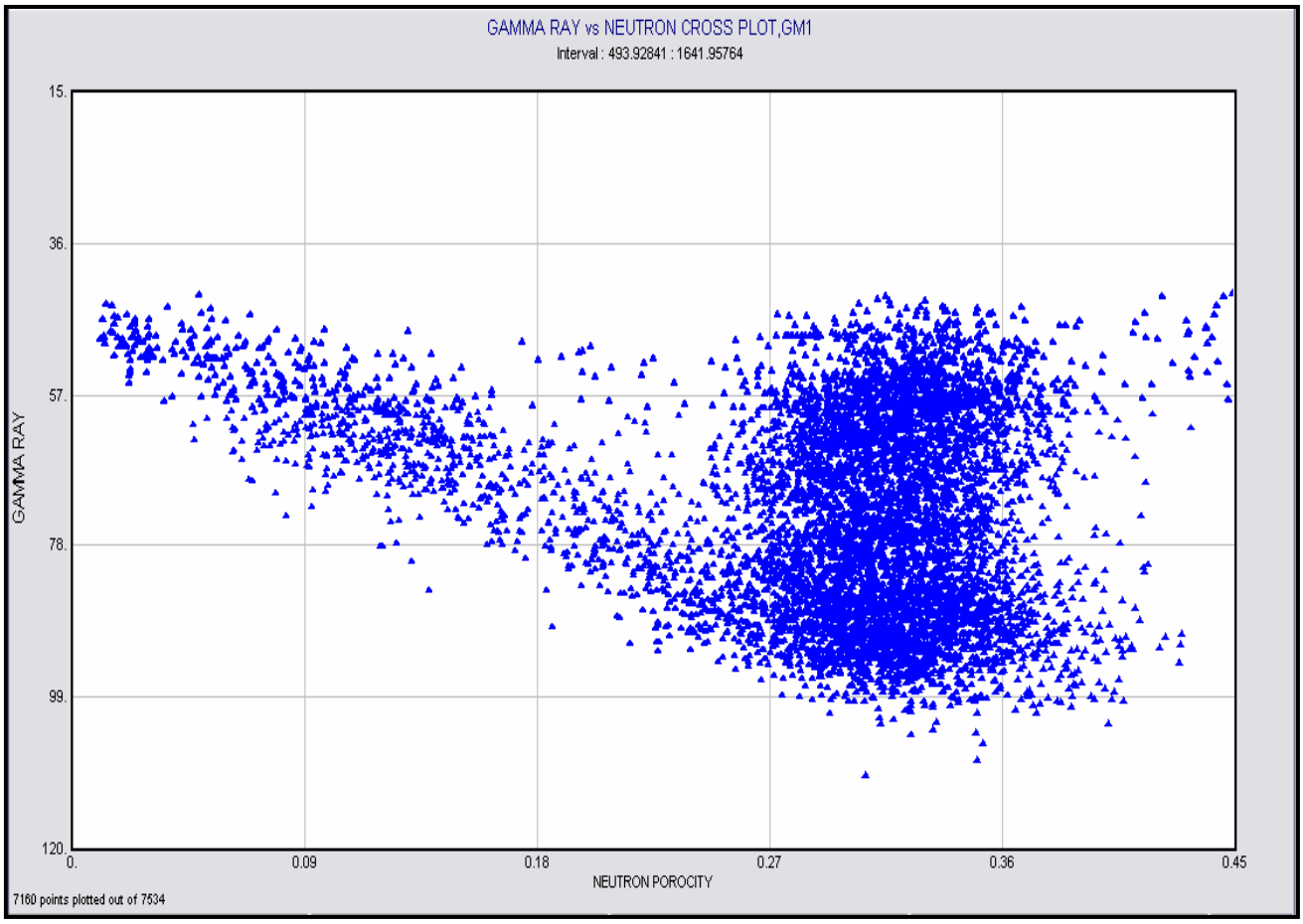


**Figure 3.2.4. Cross plot of gamma ray against neutron porosity for GM1**

From the **Figures 3.2.3 & 3.2.4,** above we can see that there is condensed section which have higher gamma ray value with low resistivity and high gamma ray value with high neutron response.

### 3.2.3. Identification of Sand - Shale Sequence

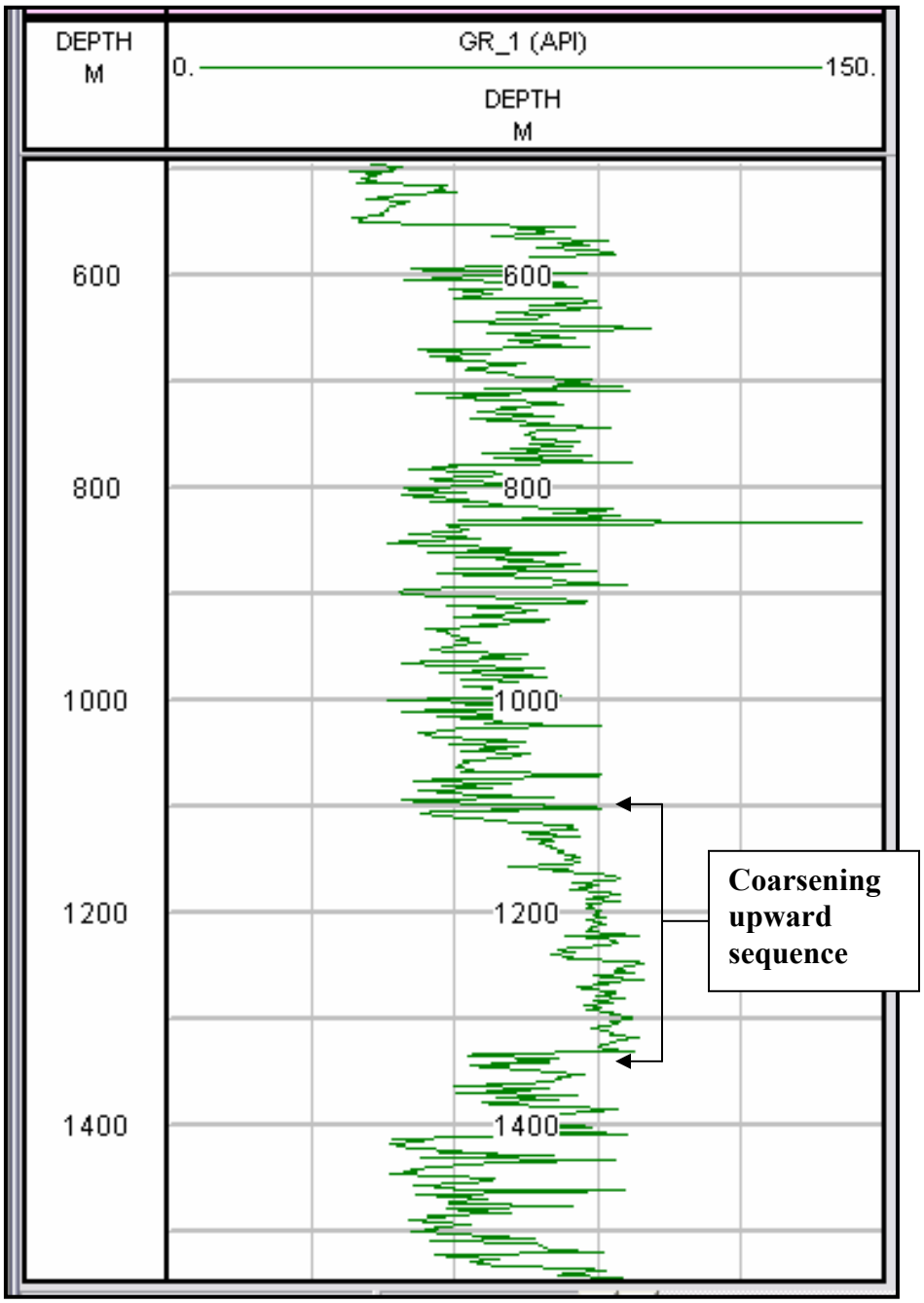


**Figure .3.2.5. Identification of sand shale and silt stone sequence for the data taken from GM1 using the GR plot.**

To identify and interpret the sand – shale sequences, the gamma ray log is a very important tool. For the *GM1* plot on ***Figure 3.2.5***..above I used the API reading to come up with the sequence identifications.***API*** reading between ***15*** to ***60*** is considered as sandstones, ***60 – 75*** as siltstone and all values above ***75*** are taken as shales.

**3.2 4. Evaluation of volume of shale**

On the literature review part on **section 2.3** of my paper, I stated that Shales are one of the more important common constituents of rocks in the log analysis. Aside form their effects on porosity and permeability, this importance stems from their electrical properties, which have a great influence on the determination of fluid saturations they are also troublesome formations in the well bore and it is very important to identify shaly zones in the subsurface before planning for drilling and doing pore pressure estimations.

To study and analysis their effects on log interpretation, it is important to estimate volume of shale. The volume of shale (Vsh) can be estimated through different mechanisms as I explained on my literature review part. Some of the methods are

- Estimation of Vsh from gamma ray log
- Estimation of Vsh from SP log
- Estimation of Vsh from porosity logs

Among the above techniques stated on the literature review at ***Section 2.3,*** I did estimation of shale volume based on gamma ray log response for the depth interval of ***750 m - 1250 m*** of *GM1*. Since the gamma – ray log provides a measure of the total natural radioactivity of a formation, regardless of its energy level or energy spectrum. The spectral gamma – ray log, or gamma ray log spectrometry tool, also detects the naturally occurring gamma ray and defines the energy spectrum of the radiations.Becouse potassium,thorium,and uranium are responsible for the energy observed by the tool ,there respective elemental concentrations can be calculated. The result is indicated on ***Figure 3.2.6***.below.

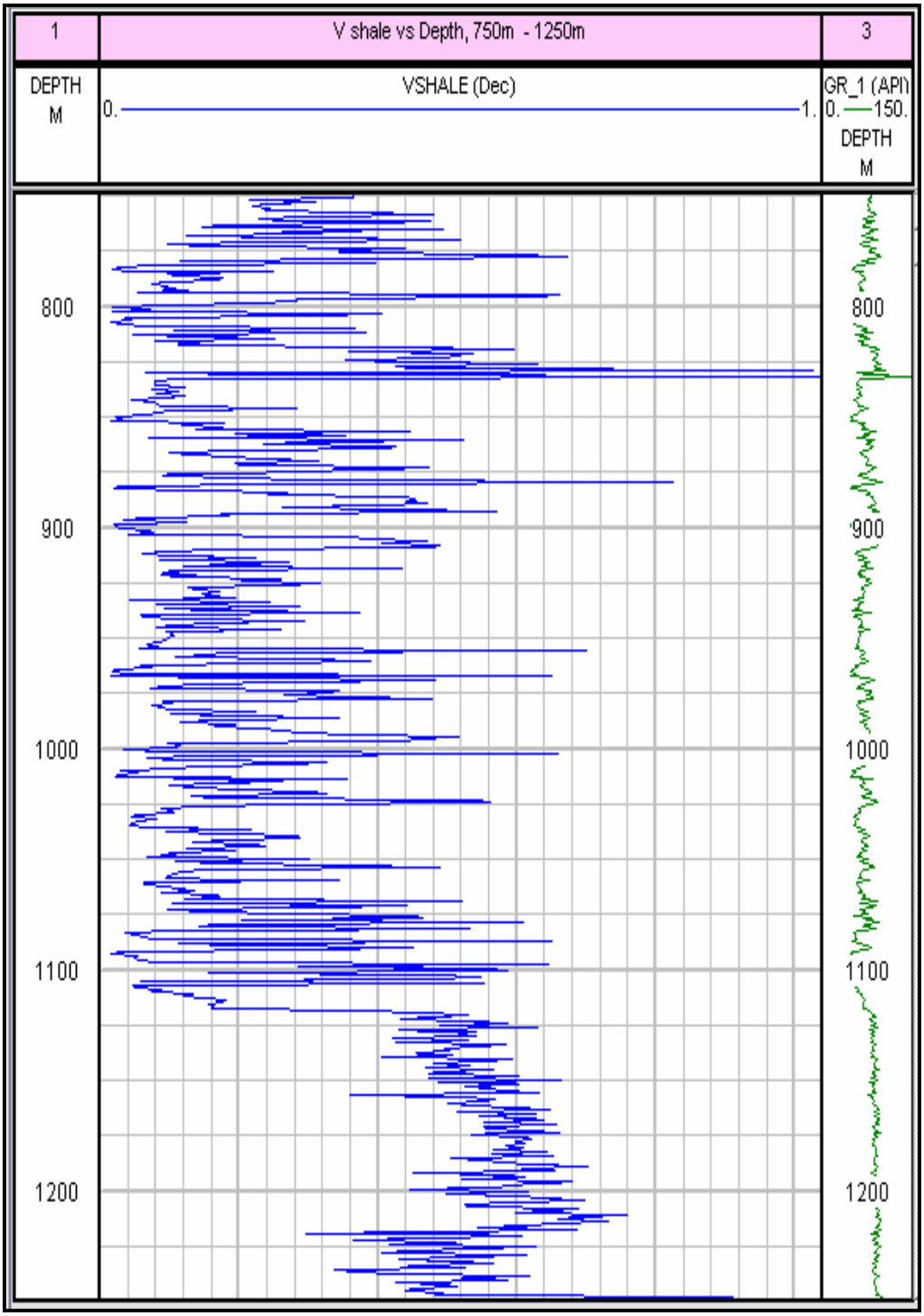


**Figure .3.2.6.Volume of shale vs. depth as estimated from gamma ray log.**

### 3.2.5. Log interpretations

The Manual interpretation of lithology from well logs should be undertaken only using all the logs registered. For the GM field, using digital logs registered, I run for the well GM1 and I plotted it sing interactive petophysics software to come up with one composite plot which can be seen on ***Figure 3.2.7,*** below. The final lithological interpretation appears on the composite plot, or it is also possible to come up with only logs that usually used for correlation which is often the gamma- ray log (or SP) and the resistivity log, or the gamma-ray and the sonic log. The original lithological interpretation, how ever, must be made on the composite document showing all the logs.

As can be seen on ***Figure 3.2.7,*** below, the log interpretation for the *GM1* was done using interactive petrophysics software. The first track shows gamma-ray from which the lithologies like sand, shale and also clay content can be calculated. From the plot ,on the intervals ***1100 to 1400m*** it can be interpreted that the lithology is of shale, by which till ***1100m*** it becomes sand and then shaly sand. In the second track the porosity logging tools (the density and neutron logs) were plotted. The reading for the density log increases from left to right of ***1.95 to 2.95*** and the neutron porosity reading increases to the right from a reading of ***-0.15 to 0.45*** whose primary use is for delineation of porous formations and determination of porosity by which it primarily responses to the amount of hydrogen in the subsurface..

On the third track the resistivity readings were plotted which are the deep resistivity, the shallow resistivity and the micro resistivity tools, by which all of them are on logarithmic scale of ***0.2 to 20***.They are used to infer the presence of hydrocarbon ***(HC).*** Within the interval ***1350 to 1520m*** the resistivity readings are high which shows presence of hydrocarbon on the interval mentioned for the GM1.This result is expected because on the hydrocarbon bearing zones the resistivity reading is higher than non – hydrocarbon ,water bearing zones.

This result can also be clearly seen from the porosity logs '***crossing'*** on the mentioned interval by which the density reading becomes lower as the neutron porosity reading becomes lower as well for the specified interval which is gas bearing zone in the Gelama Merah1 well. Since from MDT plot the oil bearing zone for GM1 is within the depth interval of 1494m to 1534m of TVDKB.

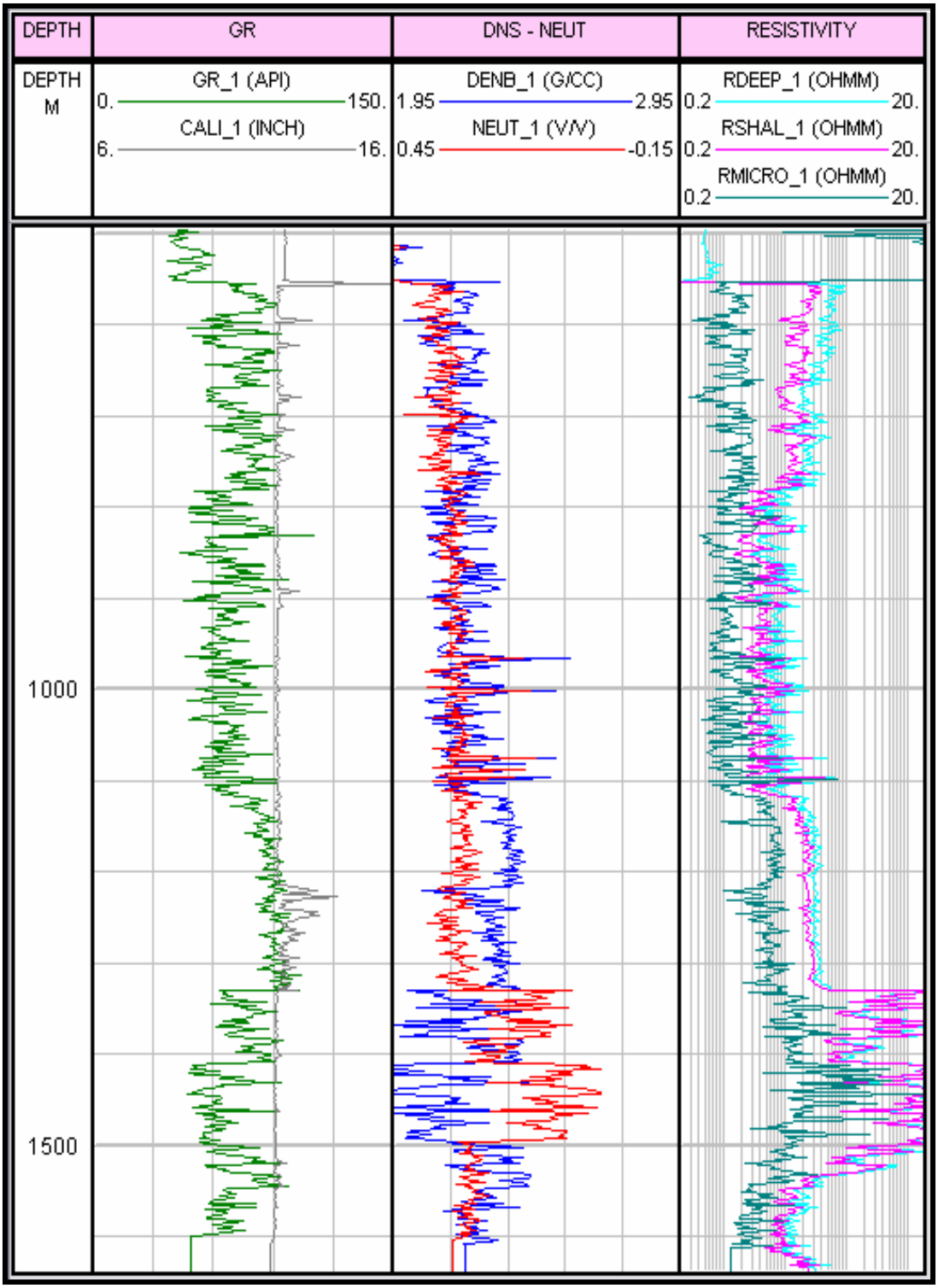


**Figure .3.2.7.Log interpretation for GM1 using interactive petrophysics software**

### 3.2.6. Effect of shale on resisitivity

From Neutron – Density cross plot an estimated lithology and porosity have a real value as a Vshale indicator. It can not discriminate whether the shale is effective or not (i.e., has an active effect on the resistivity response). The shale effectiveness depends on its type and locations in the formation.Dessiminated shale (clays) have the strongest effect, followed by laminated shale.

From MDT plots the gas oil contact and the oil water contact for the GM1 is delineated to be 1468 and 1507 m TVD respectively and TVDKB of 1494m and 1534m respectively based on these corresponding contacts the cross plot of volume of shale vs. resistivity for the oil bearing zones and water bearing zones of the *GM* field is plotted as can be seen on the ***Figures .3.2.8***.and ***3.2.9.*** below using the Interactive Petrophsics software.

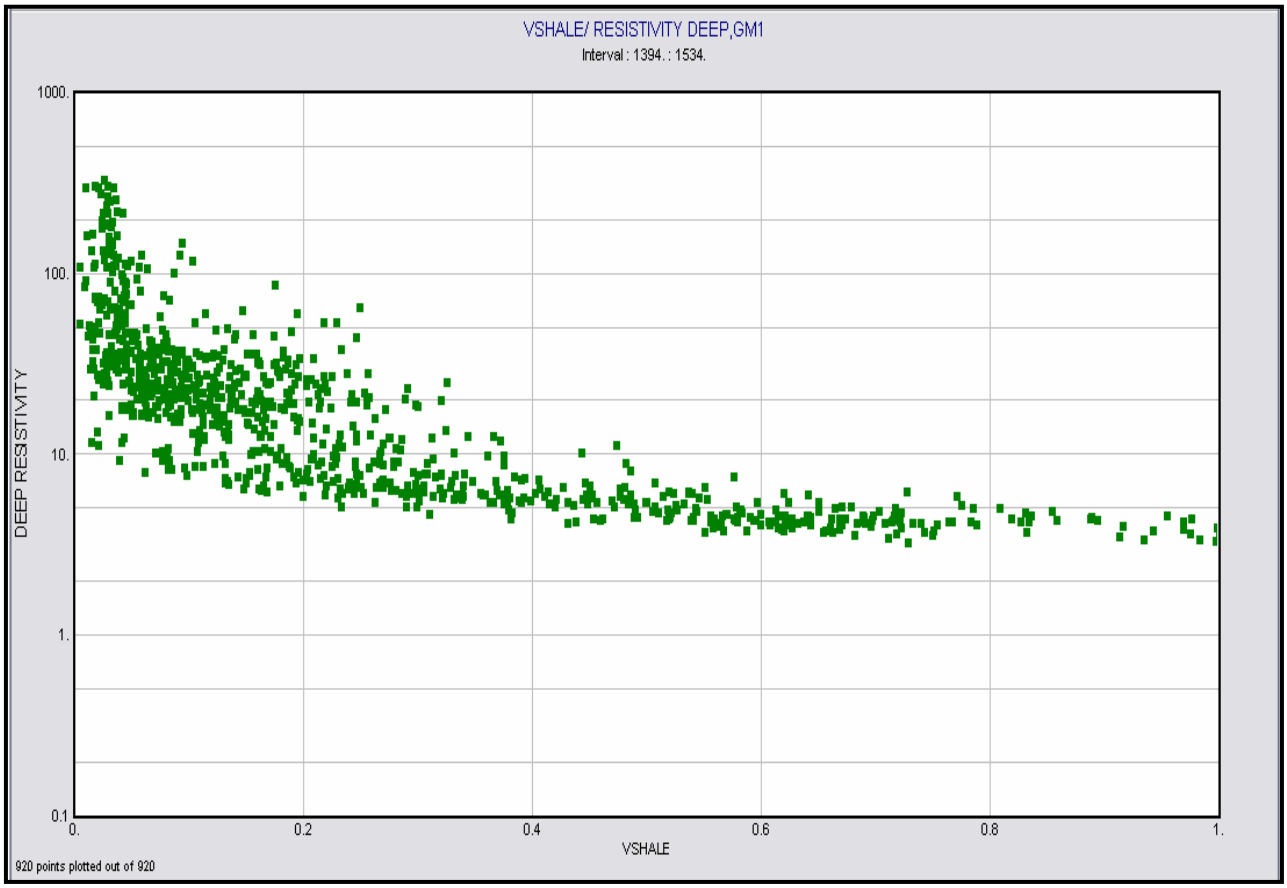


**Figure .3.2.8.Vsh vs. Resistivity plot for the HC bearing zone of GM1, 1334m- 1534m**

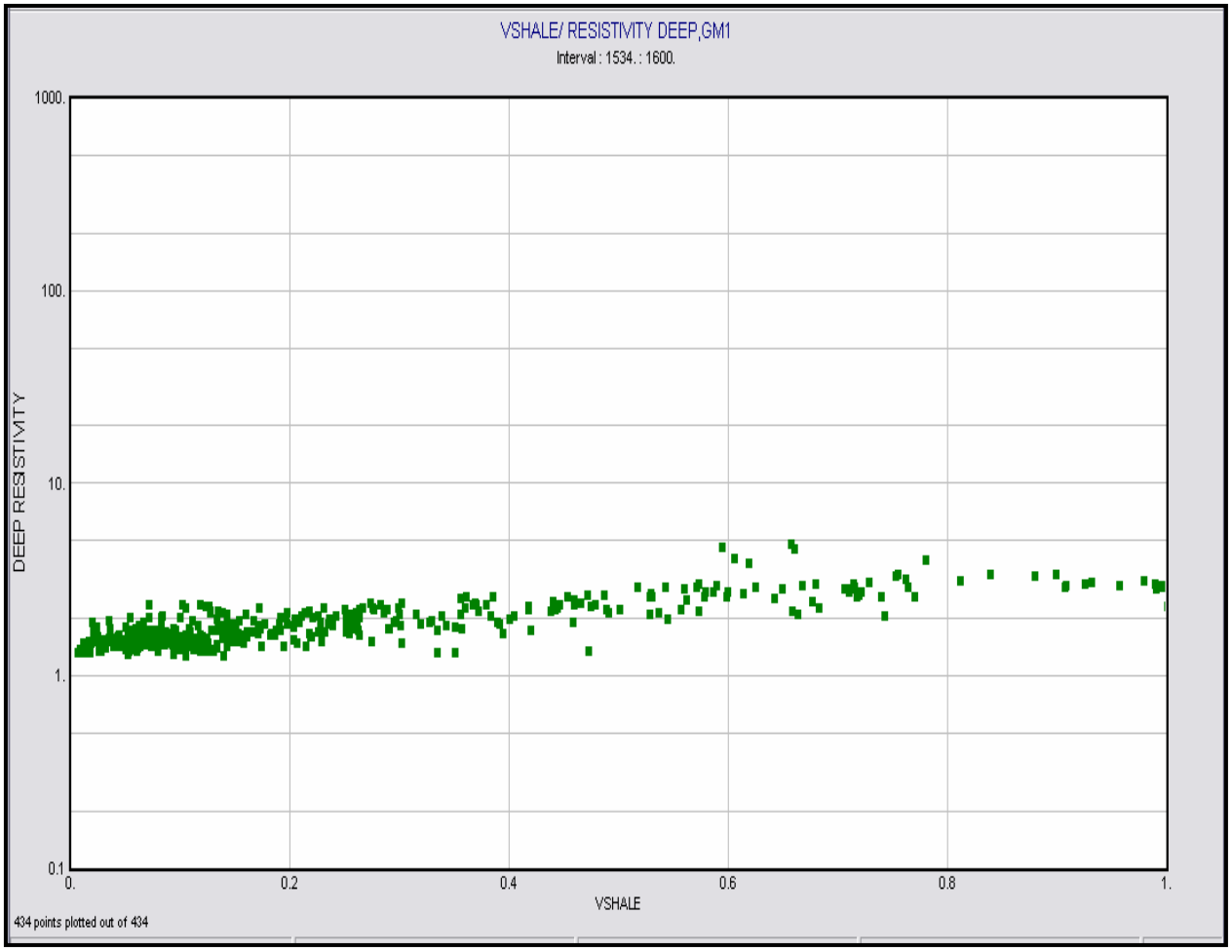


**Figure .3.2.9.Vsh vs. Resistivity plot for water bearing zone of GM1**

We can see from the two cross plots above that, for the oil bearing zones of the *GM*, the resisitivity is declining as the volume of shale increases and as I stated this in my literature review part on ***Section 12.2.2***, a condensed sequence represents a long period of time during which land derived detrital input is small and most of the sediments deposited comes from a hemipealgic or pelagic source and represents deeper water conditions and the condensed sequences which are usually the shales are rich in organic content which leads them to have low resisitiviy values as can be seen in the cross plot on *Figure 3.2.8.*

But when we look on the resisitivity vs. volume of shale plot for the water bearing zone on Figure 3.2.9 above, the above effect stated was not observed and the resistivity values are fairly constant with the increase of the volume of shale. This is because of the fairly constant salinity and the water bearing zone, since more importantly resisitivity depends on the pore fluid content, the nature of the plot is as expected.

### 3.2.7. Saturation of water vs. Resistivity cross plot

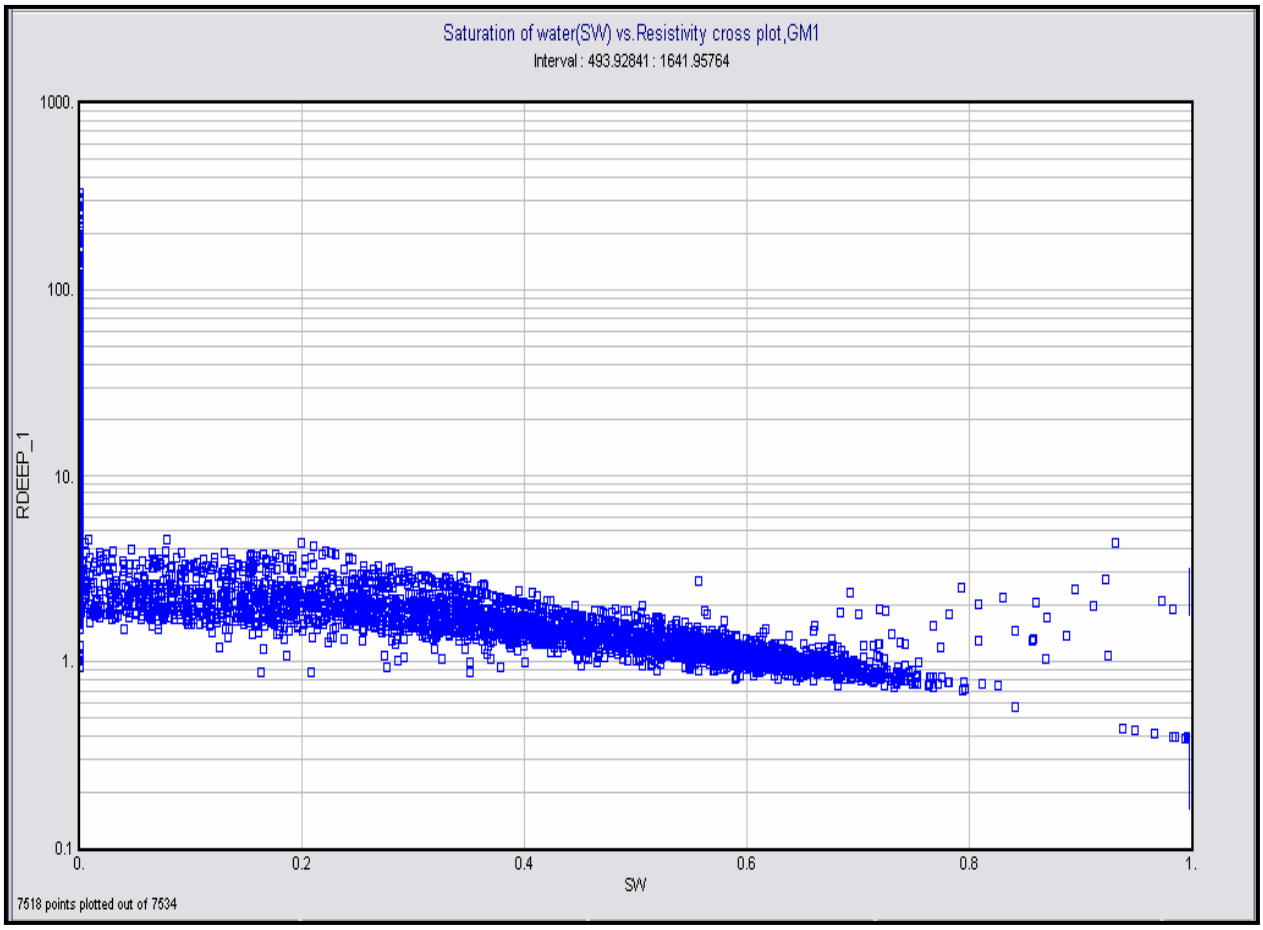


**Figure 3.2.10. Saturation of Water (SW) vs. resistivity cross plot**

There are a number of techniques available to determine the water saturation of a formation and there fore the hydrocarbon saturation. How ever the most commonly used techniques are; direct application of the humble formula, resistivity vs. porosity cross plotting (hinge Plot), ***Raw*** comparison, and Flushed zone resistivity ratio method.

Form ***Figure 3.2.10*** of saturation of water vs. resistivity plot above for the *GM1,* we can see that the resistivity values fairly decreases as the saturation of water increases because of the fairly constant salinity in the water bearing zone.

### 3.2.8. Effect of volume of shale on Sw (oil zone)

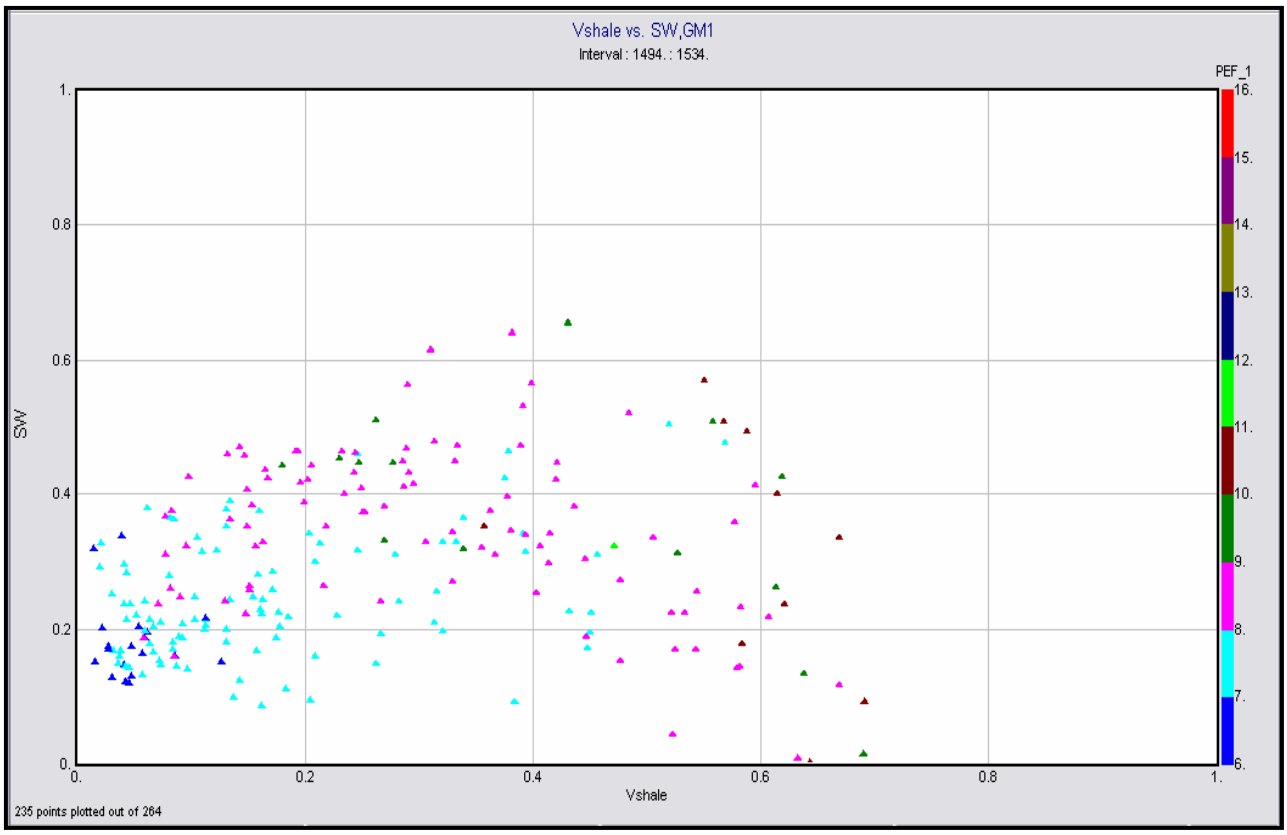


**Figure 3.2.11. Saturation of Water vs. Vshale cross plot for oil bearing zone of GM1 (1494m – 1534m)**

The effect of shale is to reduce the actual resistivity reading and finally results in an over estimation of water saturation and consequently leads to an interpretation of the oil bearing zone as a water zone. This effect can be seen from ***Figure 3.2.11*,** above on the cross plot of Vshale vs,Sw for oil bearing zone of *GM1*,which indicates the increase of water saturation as Vshale increases.

### 3.2.9. Effect of porosity on resisitivity

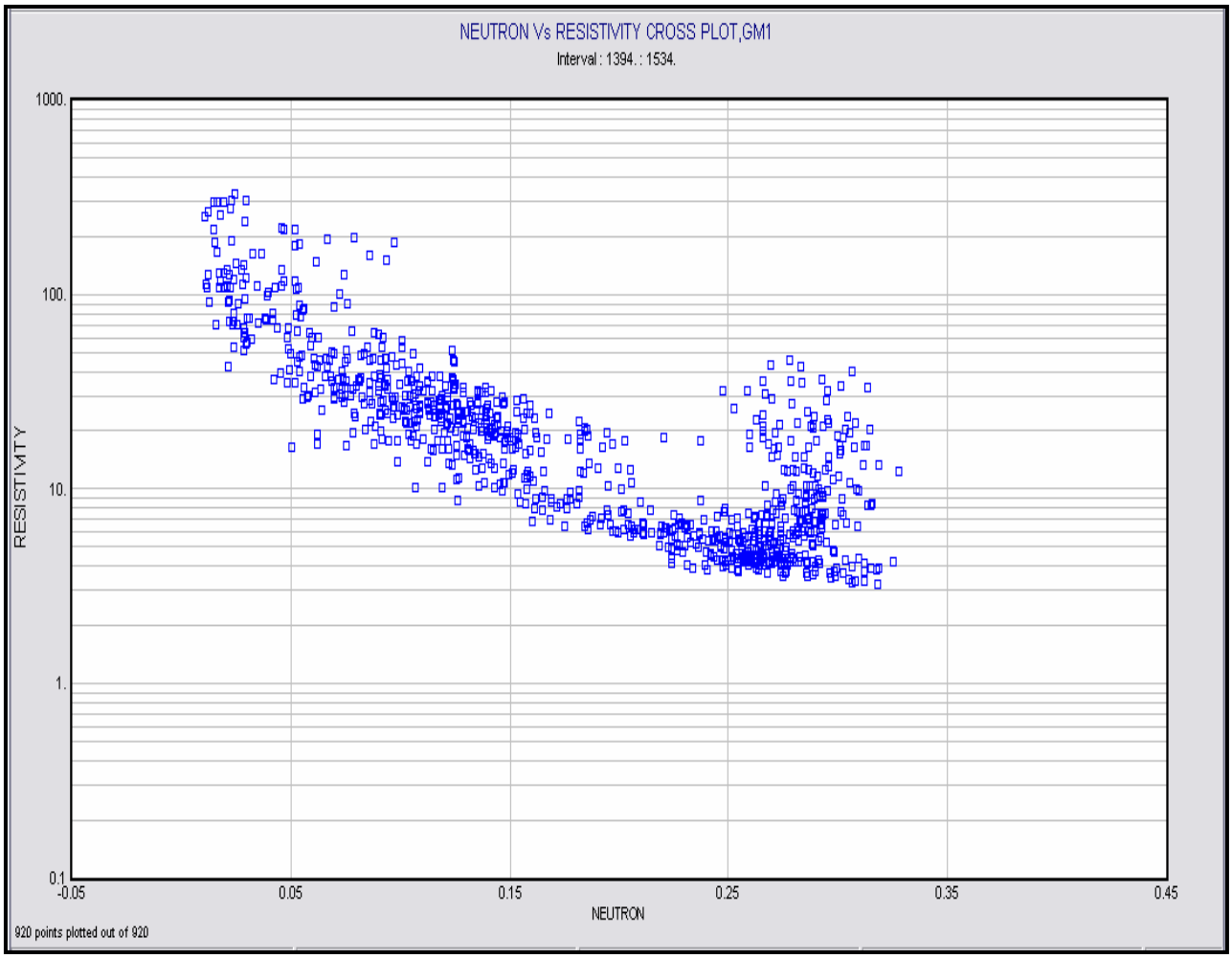


**Figure.3.2.12. Resivtivity deep vs. neutron porosity for the oil bearing zone of GM1 (1494m- 1534m)**

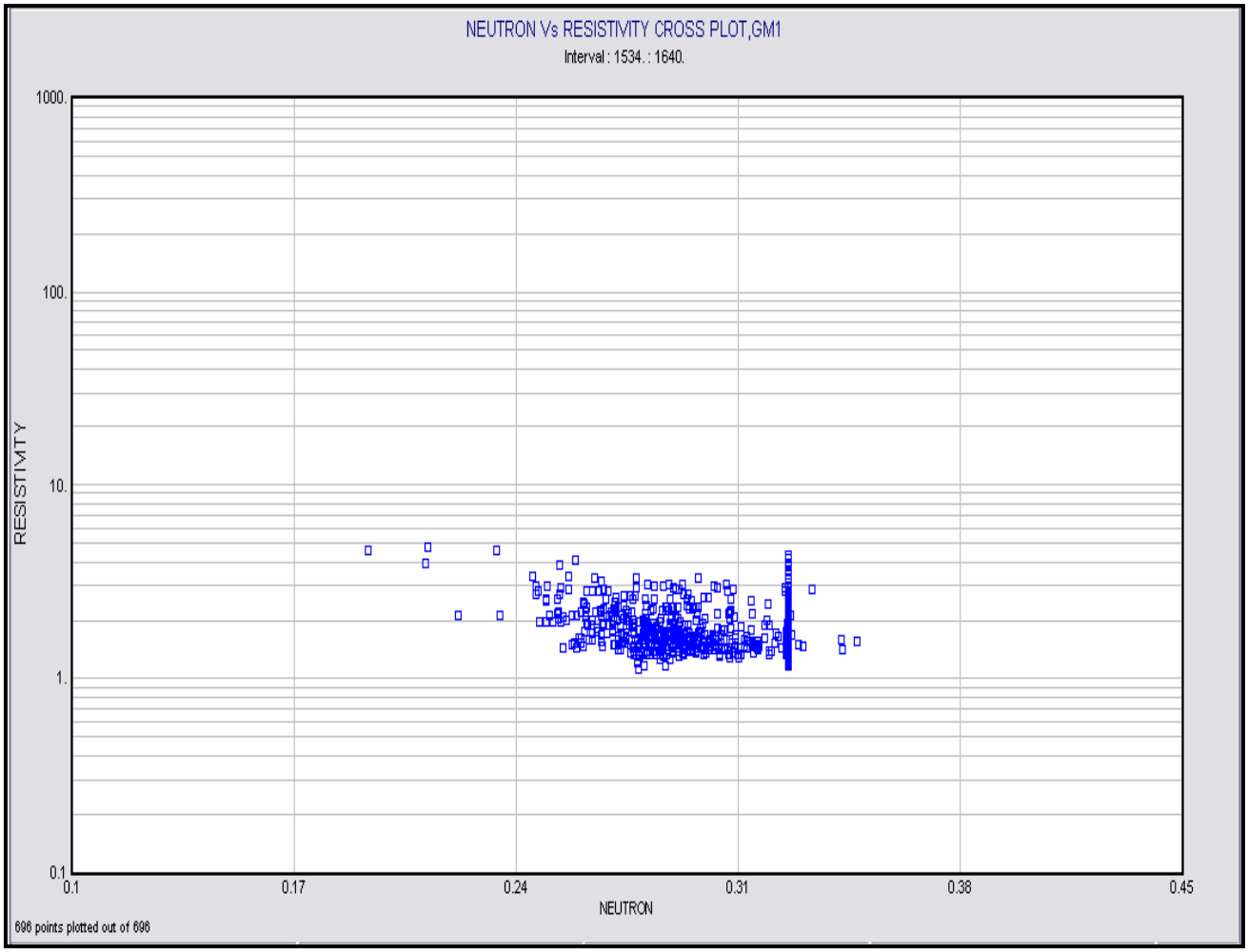


**Figure.3.2.13. Resistivity Deep vs. Neutron Porosity for the water bearing zone of GM1 (1534m-1640m)**

The proportion of water and there fore hydrocarbons in the pore space of formations is generally determined from the levels of resistivity of the formations in question. The resistivity of the formation is however also a function of a number of other variables such as porosity and the salinity of the water in the pore space. From ***Figure 3.2.11***, which is the oil bearing zone of GM1, the high resistivity values and the low neutron porosity values can be seen, where as for the water

bearing zone of GM1 the resistivity value is lower and because of the salinity of the water this result is expected as can be seen from ***Figure 3.2.12.***

### 3.2.10. Over pressure identification using sonic log

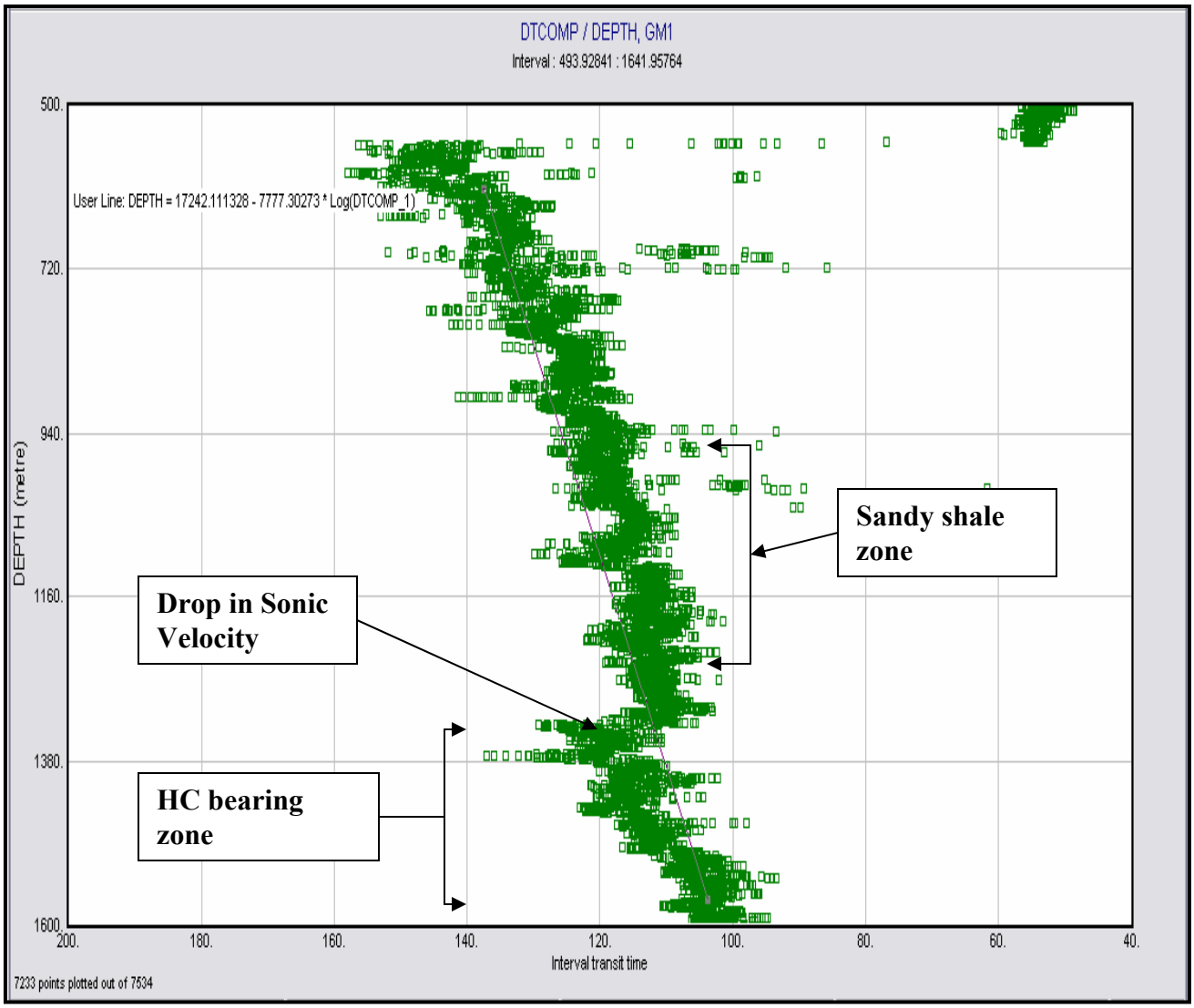


**Figure .3.2.14. Sonic transit time vs. depth plot for GM1**

Abnormal pore pressures can be deduced from deviations of sonic velocities from known trends and acoustic velocity can be used to identify over pressured zones. Other things remaining constant, an increase in pore pressure or overpressure can still be indicated by a drop in sonic velocity. As discussed on literature review of ***Section 2.11*** of the report, a plot of shale interval

transit times through an over pressured zone shows a distinct break in the average compaction line. This effect can be seen on the sonic transit time versus depth plot for *GM1* on ***Figure 3.2.13*** above at an approximate depth of 1334 m by which there is a deviation of the sonic velocity from the normal compaction trend. The principal reason for this drop is probably the increase in shale porocity, although several factors are probably compounded.

### 3.2.11. Pore pressure plot

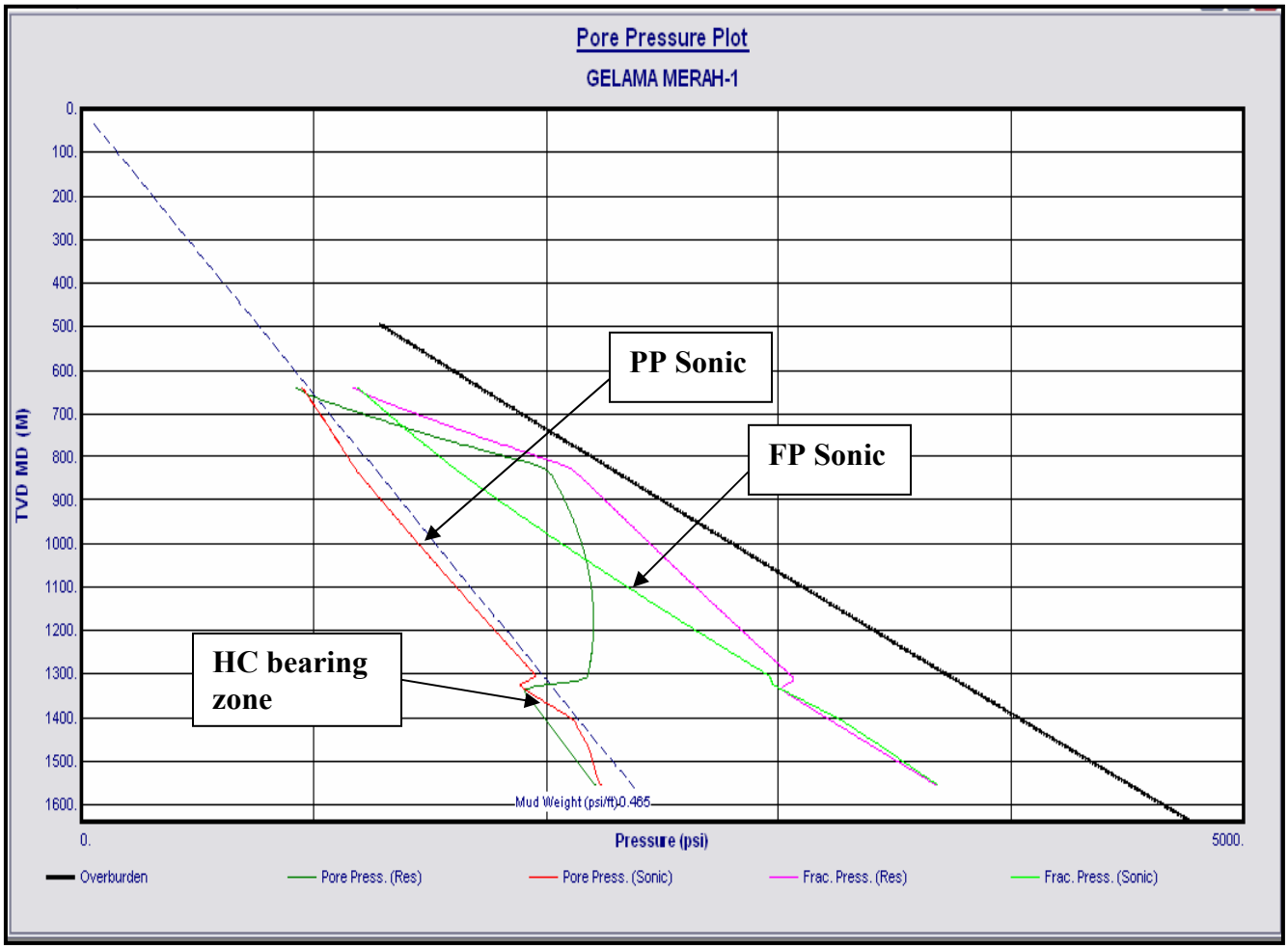


**Figure .3.2.15. Pore pressure plot for GM1 using pore pressure (sonic), pore pressure ( resistivity), fracture pressure (sonic) and fracture pressure (resistivity)**

The pore pressure plot above is done using interactive petropysics software. It shows the pressure vs. depth plot by which the pore pressures and fracture pressures from the sonic and resistivity logs are indicated. As can be seen from the plot, starting from the depth of 1334m the pore pressure readings from both sonic and resistivity logs becomes lower which the pressure becomes 1900 psi., which is because the gas zone for the *GM1* starts at the stated depth. The fracture pressure gradient from sonic log also starts lowering and the pressure becomes 3000 psi.

### 3.2.12. Stratigraphy Identification Plots

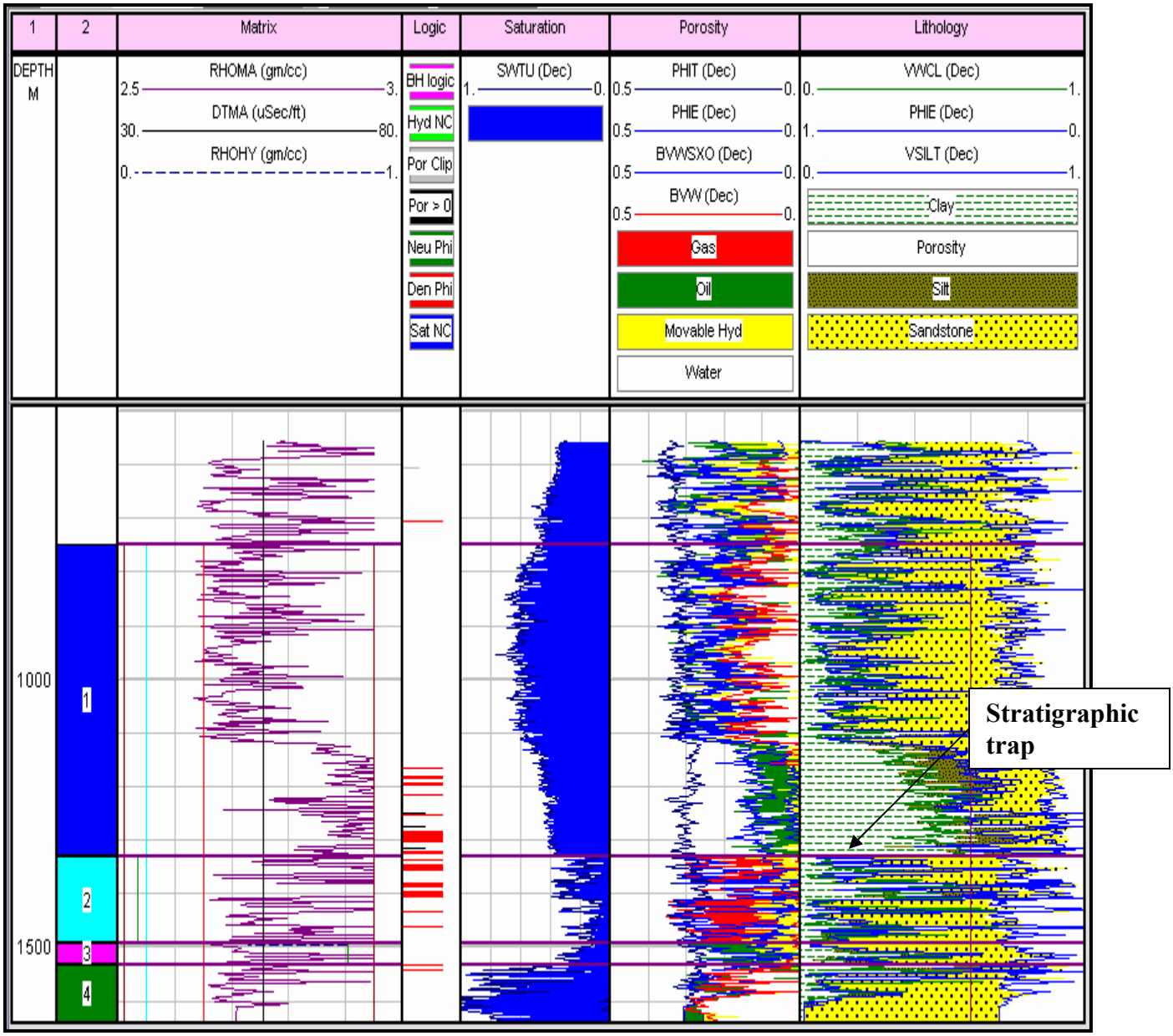


**Figure .3.2.16. A schematic that shows Stratigraphic sections with water saturation and HC saturation for GM1**

Understanding a province's depositional environment, burial histories, and structural setting, are paramount in the prediction of the potential of abnormal pressures and stresses in any formation. In general, the prediction of abnormally pressured zones in the subsurface the integration of well logs

and seismic velocities of the geological basin or "field". Stratigraphic features that may indicate geopressured formations are thick shale intervals, growth-faulting and tectonic folds and traps.

From the stratigraphic identification plot above there are seven trucks by which the first two trucks shows the depth and the legend for the gas, oil and water respectively. The stratigraphy identification which is based on lithologies is plotted on the last truck of the plot.

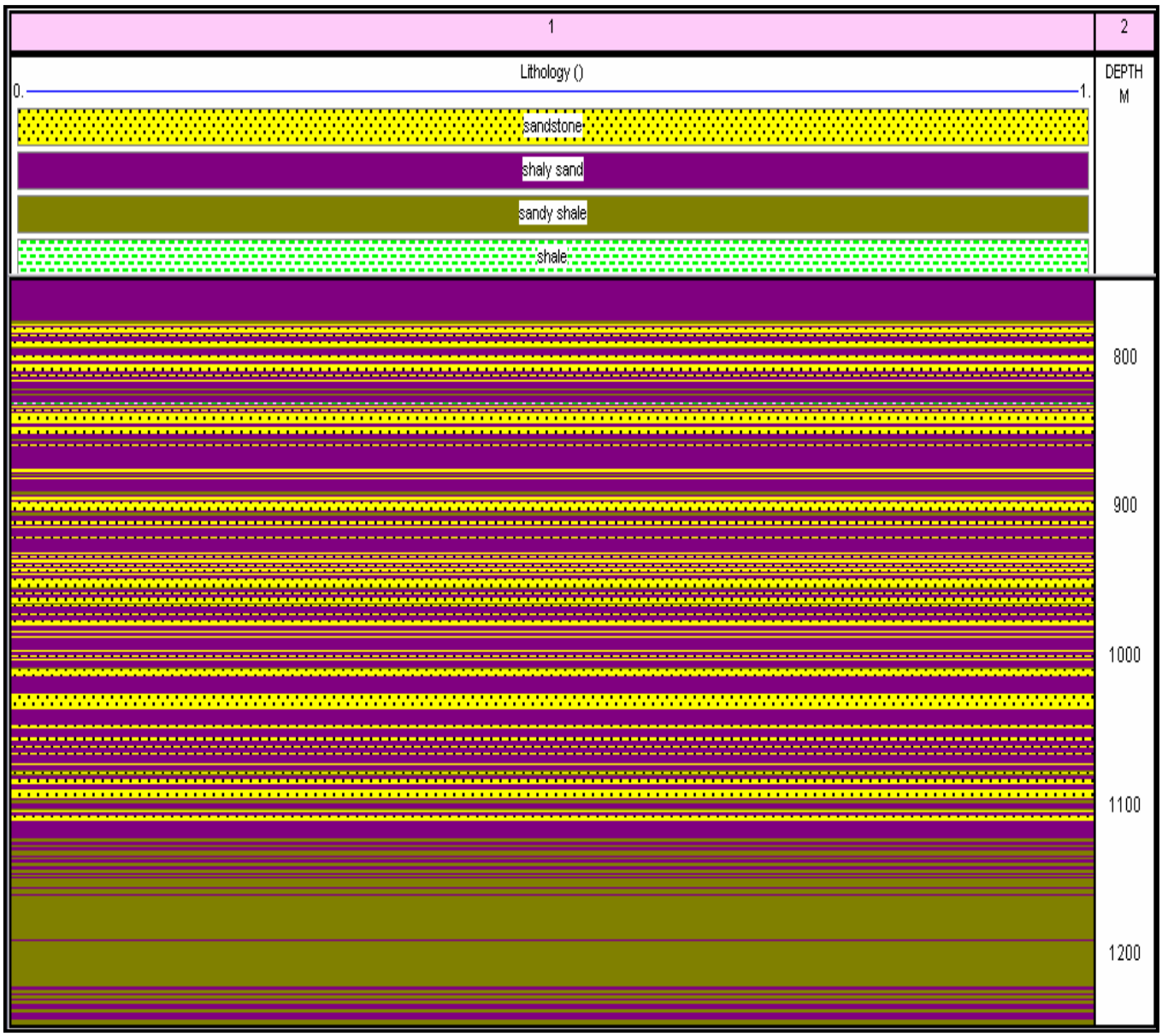


**Figure 3.2.17. Lithology identification based on Vshale for GM1 of depth interval 750m – 1250 m**

The plot on ***Figure 3.2.16*** shows the sand and silt and the clay lithologies in the subsurface of GM1.At depth of 1334m there is a trap by which below that the lithology is dominantly sand and the zone is a hydrocarbon bearing zone as can be seen from truck two. This can also be seen from truck 5 that the SW becomes lower at the specified depth interval.

For *GM1* the stratigraphic sequences identification plot is done for depth interval of 750m to 1250 m to identify subsurface lithologies in the well bore using volume of shale contained within the lithologies. As can be seen from ***Figure 3.2.17*** above, the lithologies are considered to be sand if the Vshale contained is less than 0.1, and with a Vshale content of 0.1 to 0.5 is considered to be shaly sand, and with a Vshale content of 0.5 to 0.9 is sandy shale and for Vshale greater than 0.9 is interpreted as shale. It can be seen from the Figure above that at approximate depth interval of 1150 m to 1240 m of GM1 the lithology is dominantly sandy shale by which at shallow depths the lithology is sand intercalated with shaly sand.

# CHAPTER 4

# DISSCUSION OF RESULTS

It has been shown that the Sonic–Density–Neutron logging suite can be used to determine rock characteristics which, in turn, provide information concerning potential reservoir qualities and lithology.A common practice in log interpretation is to cross-plot various porosity log readings in order to determine formation lithology and compute porosity accurately. Cross plots of Sonic versus Density logs are widely used in the interpretation of shaly sands. For carbonates, Density versus Neutron cross-plots are commonly employed. These plots and the calculations based on them are extremely important plots and the calculations based on them are extremely useful, but, when the lithology is a complex mixture of minerals, interpretation of the data often becomes ambiguous.

The "Litho-Porosity" cross-plots introduced on ***Section 3.2*** of my report above are for interpretation in formations of the subsurface lithology of the Gelama Merah field. The cross plots presents simultaneously the data from the two exploration wells *GM1* and *GMST1* of the standard porosity tools: the Sidewall Neutron Porosity log or the porosity tools: the Sidewall Neutron Porosity log, or the GNT; the Formation Density Compensated log, and the Borehole Compensated Sonic log

It is well known that the effect of shale is to reduce the actual resistivity readings and finally result in an over estimation of water saturation and consequently in the interpretation of the oil bearing zones as a water bearing zone. This can be seen from ***Figure.3.2.11*** which is a cross plot of Vshale vs. Sw for the oil bearing zone of the *GM1* which indicates an increase in water saturation as shale volume increases.

The interpretation problem in shaly formations is in calculating porosity and saturation values free from the shale effect.Becouse the shale effect depends on shale content, the estimation of Vsh is of

prime importance. Qualitatively volume of shale calculation indicates whether the formation can be considered clean or shaly. Quantitatively; Vsh is used to estimate the shale effect on log responses and, if needed, to correct them to the clean formation responses. Like the SP log, the gamma ray log can be used to delineate shale beds and to correlate between logs. The gamma ray log substitutes for the SP log when the SP is flat as a result of low contrast between $\mathbf{R_{mf}}$ and $\mathbf{R_w}$ and when the SP log cannot be recorded, as in the case of oil-based mud, empty holes, and cased holes. When potassium is the only or the major contributor to shale radioactivity, the gamma ray log response is used to estimate the shale content. A shale index, $\mathbf{I_{sh}}$ is calculated from

$$\boldsymbol{I}\mathbf{sh} = (\gamma\mathbf{log} - \gamma\mathbf{c})/ (\gamma\mathbf{sh} - \gamma\mathbf{c})$$

Where, $\gamma\mathbf{log}$ is the log response in the zone analysed, and $\gamma\mathbf{sh}$ and $\gamma\mathbf{c}$ are the log responses in shales and in zones of minimum radioactivity, respectively. Then the $\boldsymbol{I}\mathbf{sh}$ is converted to the $\mathbf{V_{sh}}$, with the methods detailed in ***Section.2.3***

The presence of low density overpressure is derived for the porosity within the unit in shales or mudstone in a sedimentary sequence influences the operations of petroleum exploration, drilling and production. During the exploration phase such low density fine grained rocks influence the interpretation of seismic and gravity surveys. During the drilling of prospects the mud casing and log programs and safety are affected by abnormal pressures in the subsurface.

During production, the possible influx of shale water requires investigation. In addition to the immediate influence of high pressures and compaction phenomenon on the petroleum industry, fine grained rocks including shales are thought to have been the source of petroleum found in permeable reservoir rocks. There fore a better understanding of these fine grained rocks in the subsurface is very important.

Pore pressure is the pressure and fluids contained in reservoirs. Proper pore pressure prediction and determination is important and crucial for the purpose of optimizing casing and drilling fluid programs, to improve well control and to increase drilling efficiencies, to reduce drill time/costs per well. More over the pore pressure prediction can be widely used for prospect definition, financial risk assessment, overall project viability and ranking before drilling.

There fore, to come up with the above benefits mentioned, it is very important to locate the abnormal pressure region and also magnitude of the abnormality. Towards the end of my paper I mentioned the important methods to predict the pore pressure by using data from well *GM1* of *GELAMA MERAH* field. Even if field is a normally pressured zone there are still some abnormalities at around depth 1334m as can be seen on ***Figure 3.2.13*** form pore pressure plots using sonic and resistivity logs which is a contact of the water and gas zones by which the pore pressure response from both the sonic and resistivity logs becomes lower. At the specified depth interval of 1334m to 1494m the zone is delineated to be gas zone.

# CHAPTER 5

# RECOMMENDATIONS AND CONCLUDING REMARKS

Formation evaluation in thin sand-shale lamination seeks first to determine sand resistivity, volume fraction, and porosity. Afterwards, saturation and volume are simple Archie applications. Resistivity anisotropy techniques can provide estimates of sand resistivity and volume fraction, but good results depend on the choice of the anisotropic shale point. The same shale point should be used in the determination of sand porosity. Difficulties will arise when anisotropy is not caused by sand-shale laminations, when no sand-shale point exists, or when the nearby thick sand-shale is not representative of the sand-shale in the laminations.

In view of the shale instability costs, it is imperative to understand shale behavior and its interaction with different fluids. Completely satisfactory answers to questions such as: Which drilling fluid to use for drilling a particular shale, or how long can we keep the hole exposed to a particular fluid without causing shale instability, can be given only after such an understanding. The quantification of the impact of fluid invasion on effective stresses and shale strength near the well bore is critical for shale stability analysis models. Simple and realistic shale testing procedures and shale/ fluid interaction testing procedures are required in order to achieve practical assessments of well bore instability risks. Efforts to develop predictive models and to develop more effective fluids for drilling shales, based on improved understanding of shale/fluid interaction mechanisms must continue.

In normal situations, pore fluids are assumed to be in hydrostatic equilibrium all the way from the surface to the depth attained. Apart from some uncertainty in pore – fluid dencity, this provides a simple prediction of the pore pressure (i.e., for a water density of 9 lbm/gal.the gradient will be 0.47psi/f) that will always lie below a realistic mud pressure gradient, because the mud will be denser than water.

In normal situations, how ever, pore fluids will not be in equilibrium hydrostatic contact with surface, such as when a cap rock provides totally impermeable barrier isolating fluids beneath it or when relatively impermeable sedimentary rocks not reached pore – pressure equilibrium. In such cases, pore pressure often are abnormally high and can exceed what other wise are safe mud pressures. Drillers need warning of this situation. On what they base their estimate of pore pressure? Clearly ,periodic direct measurement are desirable, even if on my paper the pore pressures are estimated by/after quantifying fine grained rocks from logs for *GM* field from the exploration well *GM1*.

In recent times, every drilling operation will take in to consideration the effects of pore pressure before planning drilling. Therefore, to be able to accurately predict the existence of abnormal pore pressure at a certain depth prior to drilling can improve the decisions made for the planning and execution of a particular drilling or well development program. By predicting pore pressure and by identifying problem making zones in the well bore before planning to drill a well, one can benefit: safety by being able to drill through a high pressure areas safely by deploying proper countermeasures or totally avoiding the risky areas, can also save cost and time by eliminating multiple trials and errors as in being able to decide prior to the actual drilling the proper drill rig set up, suitable sizes, optimum rate of penetration and selection of type of drilling mud ( whether OBM or WBM),and the mud weight to be used.

The log identification of condensed sedimentation depends mostly on its high organic matter content. Marine organic matter is associated with uranium so that condensed sediments have a high gamma ray value. Organic richness is also registered by high neutron values and a low density. The fine laminations, a frequent feature of these slowly accumulating shales, amplify the high interval transit times (low velocity) and generally low resistivity already caused by organic content. In fact, most of the log responses will be such that in the electro sequence analysis, condensed sections will be picked out as 'anomalous'. From the cross plots done in ***Section 3*** the stratigraphic sequence that lead to the deposition of the lithologies is deep marine. The HC source which is the shale is of rich in organic contents and deposited slowly forming laminations with the sand reservoirs.

# CHAPTER 6

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# APPENDIX CHAPTER 3

## Appendix 1 – Volume of shale with total frequency distribution (FD) for GM1

HISTOGRAM STATISTICS

Date: 6/6/2008 3:44:13 PM

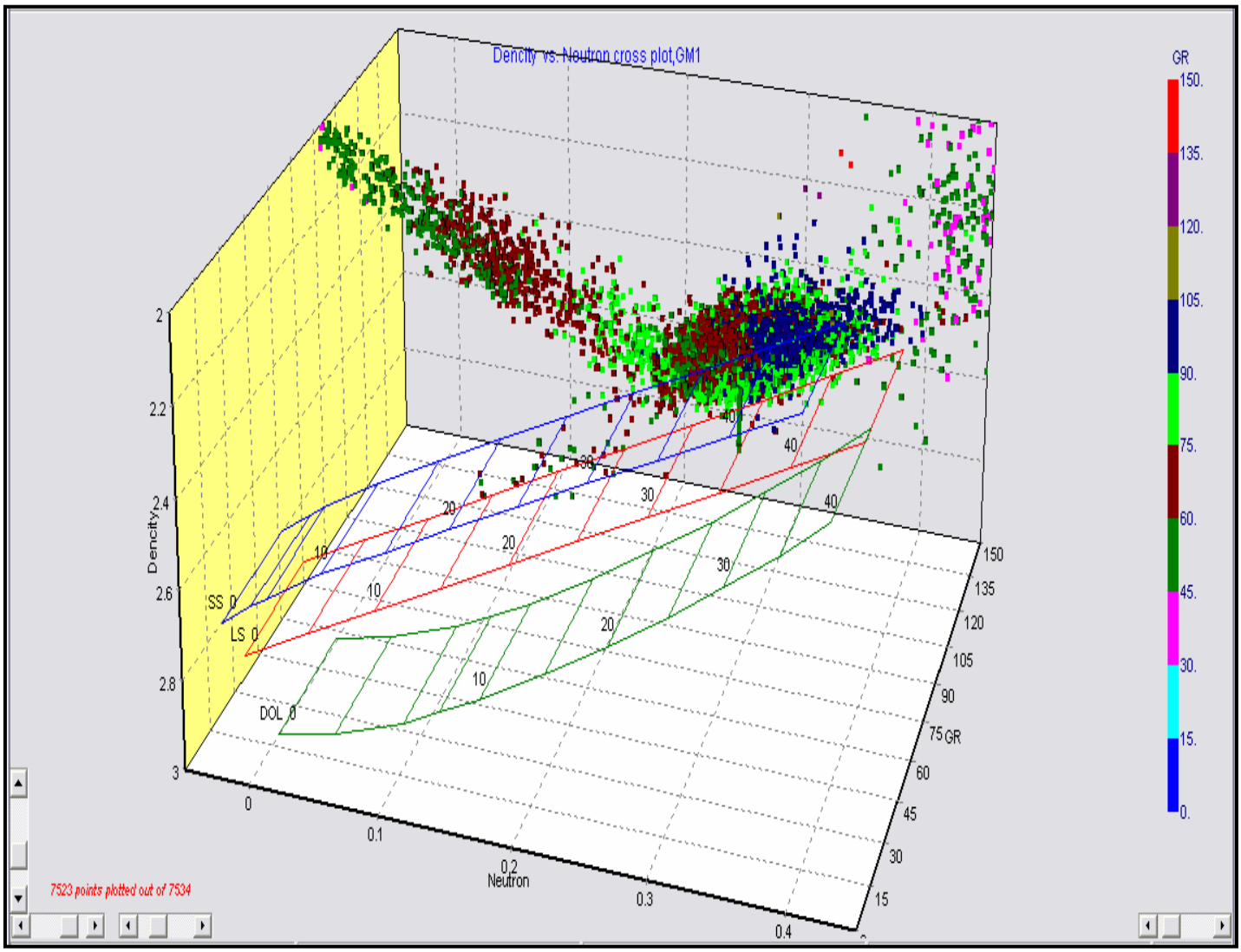
Well: GELAMA MERAH-1
VSHALE (Dec)

| | | | Mean | STD Dev |
|---|---|---|---|---|
| Well (1): GELAMA MERAH-1 | - 493.9284M | - 1641.957M | 0.23865 | 0.1586 |
| All Zones | | | 0.23865 | 0.1586 |

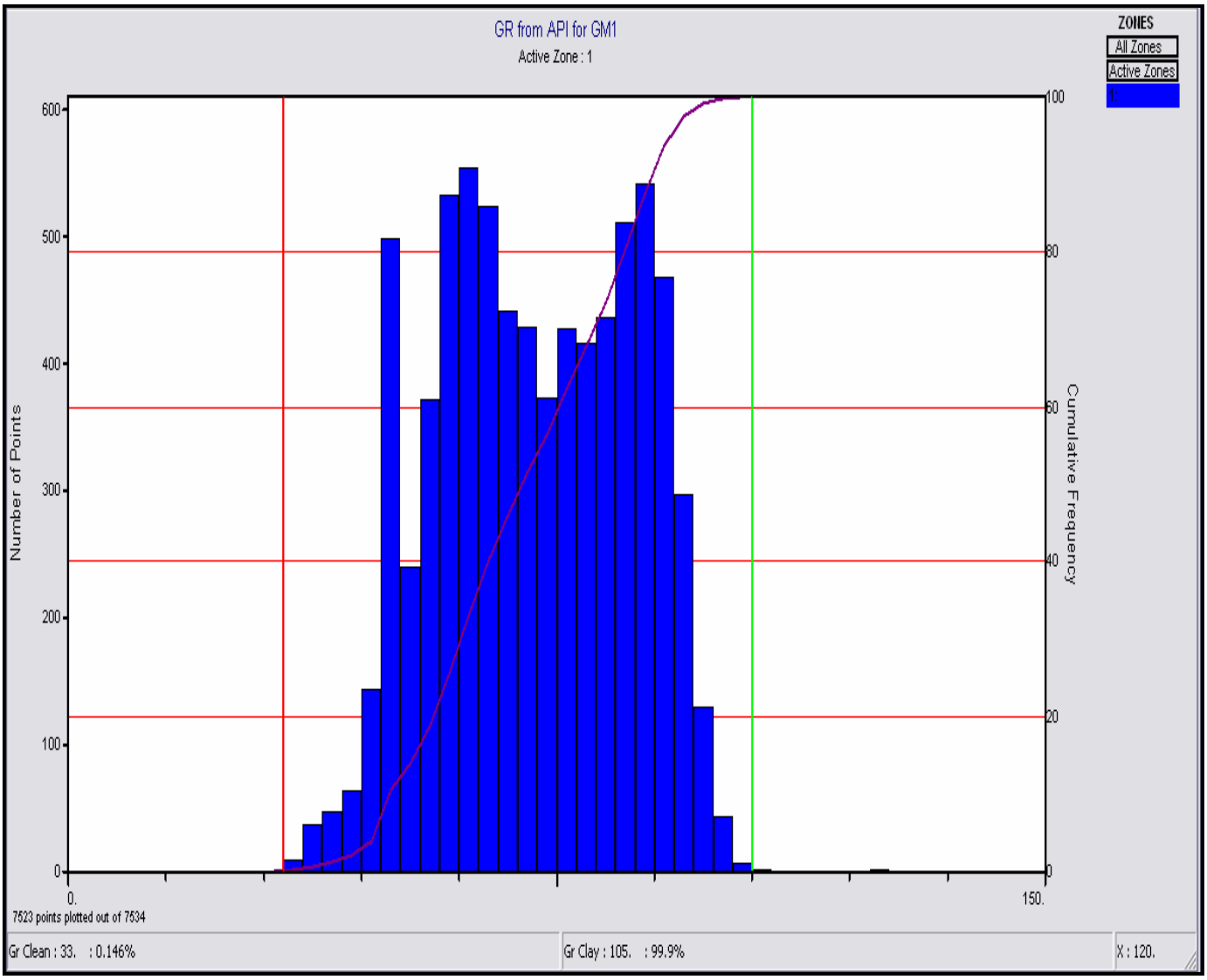
| Value VSHALE | Total cum % |
|---|---|
| 0.01 | 1.183 |
| 0.03 | 7.311 |
| 0.05 | 13.13 |
| 0.07 | 22.08 |
| 0.09 | 29.4 |
| 0.11 | 34.02 |
| 0.13 | 37.19 |
| 0.15 | 40.14 |
| 0.17 | 42.87 |
| 0.19 | 45.75 |
| 0.21 | 48.89 |
| 0.23 | 52.47 |
| 0.25 | 56.3 |
| 0.27 | 59.93 |
| 0.29 | 63.36 |
| 0.31 | 66.77 |
| 0.33 | 70.26 |
| 0.35 | 73.54 |
| 0.37 | 76.68 |
| 0.39 | 80.19 |
| 0.41 | 84.06 |
| 0.43 | 87.49 |
| 0.45 | 90.9 |
| 0.47 | 93.18 |
| 0.49 | 94.85 |
| 0.51 | 96.14 |

| | |
|---|---|
| 0.53 | 97.06 |
| 0.55 | 97.94 |
| 0.57 | 98.59 |
| 0.59 | 99.04 |
| 0.61 | 99.36 |
| 0.63 | 99.6 |
| 0.65 | 99.78 |
| 0.67 | 99.84 |
| 0.69 | 99.86 |
| 0.71 | 99.88 |
| 0.73 | 99.89 |
| 0.75 | 99.9 |
| 0.77 | 99.9 |
| 0.79 | 99.93 |
| 0.81 | 99.94 |
| 0.83 | 99.94 |
| 0.85 | 99.94 |
| 0.87 | 99.94 |
| 0.89 | 99.94 |
| 0.91 | 99.94 |
| 0.93 | 99.94 |
| 0.95 | 99.96 |
| 0.97 | 99.96 |
| 0.9**9** | 100. |

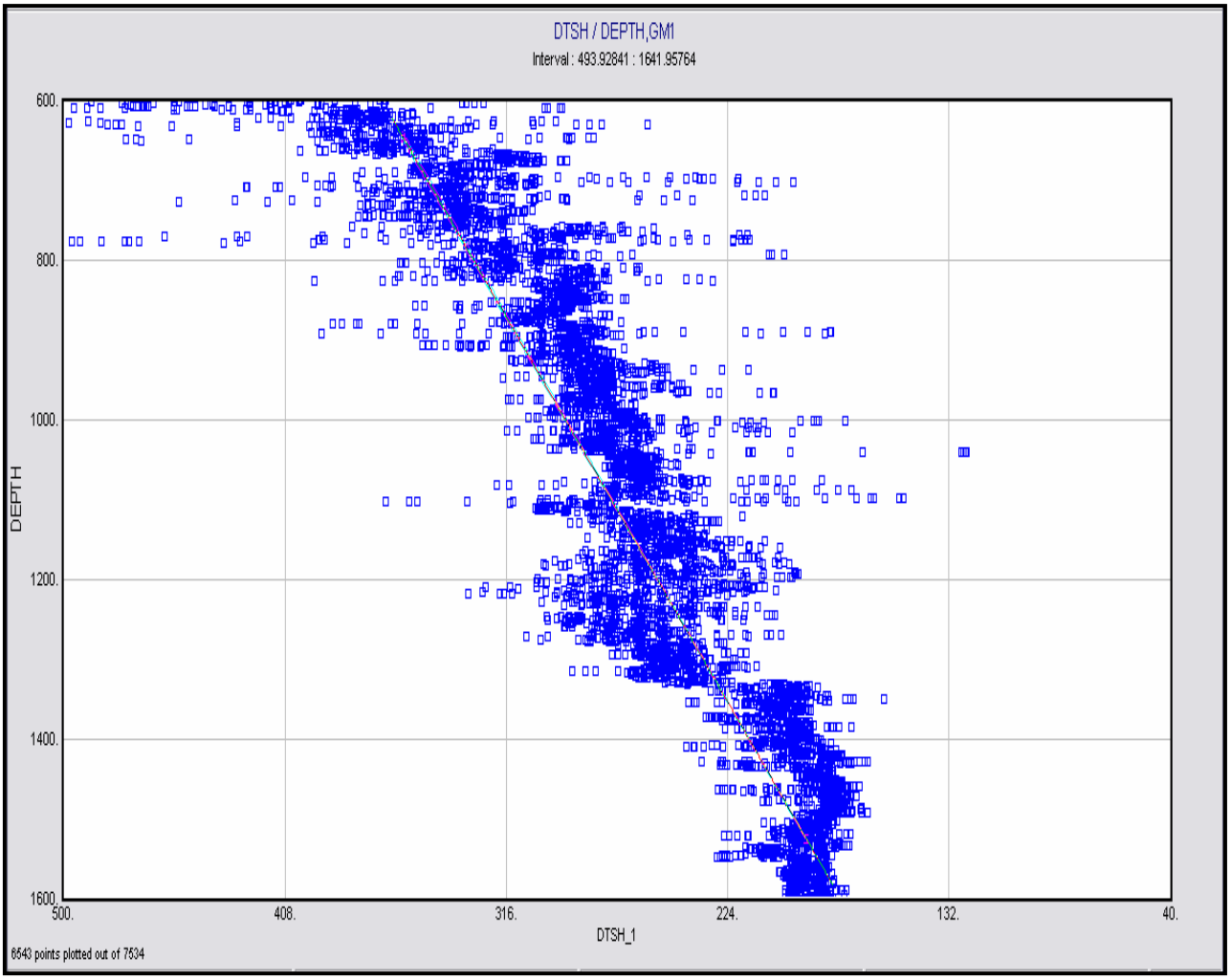
**Appendix 2. 3D view of the Density vs. Neutron Cross plot of GM1**



**Appendix 3 - Volume of shale estimation via CF for GM1 based on GR response**



## Appendix 4 – Depth vs. sonic transit time plot from DTSH for GM1



## Appendix 5: MDT pressure vs. Depth plot for GM1 to delineate fluid contacts