Pore Pressure Prediction in Shale Gas Field

by

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Jun 2013

Approved by

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Dr Sonny Irawan

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 reference and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MUNAWAR BIN AB HAMID

ABSTRACT

Natural gas resources are divided into two categories which are conventional and unconventional. They are classified conventional gas typically if it found in reservoirs with permeability greater than 1 millidarcy ("mD") and unconventional gas is found in reservoirs with relatively low permeability (less than 1 mD) and hence cannot be extracted via conventional methods. There are many types of unconventional gas resources but this paper focused on shale gas since it has a huge potential and it is known that shale make up over 75% of drilled formations and cause over 90% of wellbore stability problems.

This project is mainly about analyzing and studying about the pore pressure prediction method in shale gas reservoir. Pore pressures increase from slightly elevated levels to a surprisingly high geopressures over short intervals in shale gas due to the presence of gas in shale and the lack of permeability in shale formation. These pressures, if not correctly predicted, can lead to dangerous gas kicks and potentially blowouts. In shale gas, pore pressure prediction is of critical importance for drilling operations to improve drilling efficiency, reduce borehole trouble time, and avoid risks of well blowouts. However, unlike conventional reservoirs, mechanisms of abnormal pressure in shale gas formations are rarely reported, and pore pressure prediction in such formations can be problematic. The methodology that was used to study and analyze the pore pressure predictions are Eaton Method and Equivalent Depth Method. Barnett and Marcellus Shale were chosen as the base case for comparison with the predicted pore pressure.

The results obtained shows differences between predicted pore pressure and actual pore pressure in both Barnett and Marcellus shale field. This shows that the use of Eaton Method and Equivalent Depth Method to predict pore pressure is not suitable for Barnett and Marcellus shale gas field. It is also concluded that pore pressure prediction will deviate from actual pore pressure when failure on establish normal compaction trend and lithological variability and overpressure of shale creates difficulty in defining the appropriate normal compaction trends for pore pressure estimation.

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ABBREVIATION

EIA	Energy Information Administration
P	Formation Pressure
P_h	Hydrostatic Pressure
p_f	Fluid Density
g	Gravity Acceleration
z	Depth
P_g	Pressure Gradient
S	Overburden Stress
ϕ	Porosity
R_n	Resistivity normal
R_{ob}	Resistivity observed
T_n	Sonic transit time normal
T_{ob}	Sonic transit time actual
σ_{ob}	Overburden Stress Gradient
P_{ff}	Fracture Pressure
P_{pp}	Pore Pressure
TVD	True Vertical Depth
p_{ma}	Matrix Density
p_{log}	Measured Density
Pff,min	Minimum Fracture Pressure
Pff,max	Maximum Fracture Pressure

CHAPTER 1 INTRODUCTION

1.1 Background of Study

Natural gas is fossil fuel in its purest form. It contains just two elements – carbon and hydrogen, and is a gas in its raw state. This means it requires minimal processing and creates fewer emissions in its production and use than other fossil fuels. That makes natural gas an important fuel for reducing carbon dioxide and other atmospheric emissions [1].It has become very important energy source throughout the world due its environmental friendly characteristics.

Natural gas resources are usually separated into two categories which are conventional and unconventional. Conventional natural gas reservoirs are formed when these hydrocarbons are able to escape and move into larger group to much high porous rock becoming free gas. On the other hand, unconventional reservoirs are made up of the hydrocarbons that were not able to escape, remaining trapped within tight, ‘impermeable’ micro-pored rock, at much greater depths [2].There are several types of unconventional gas resources that are produced today but the three most common types are tight gas, coal bed methane and shale gas[3]. The diagram below shows how the gas-rich shale strata are typically the source rock for conventional oil and gas reservoirs.

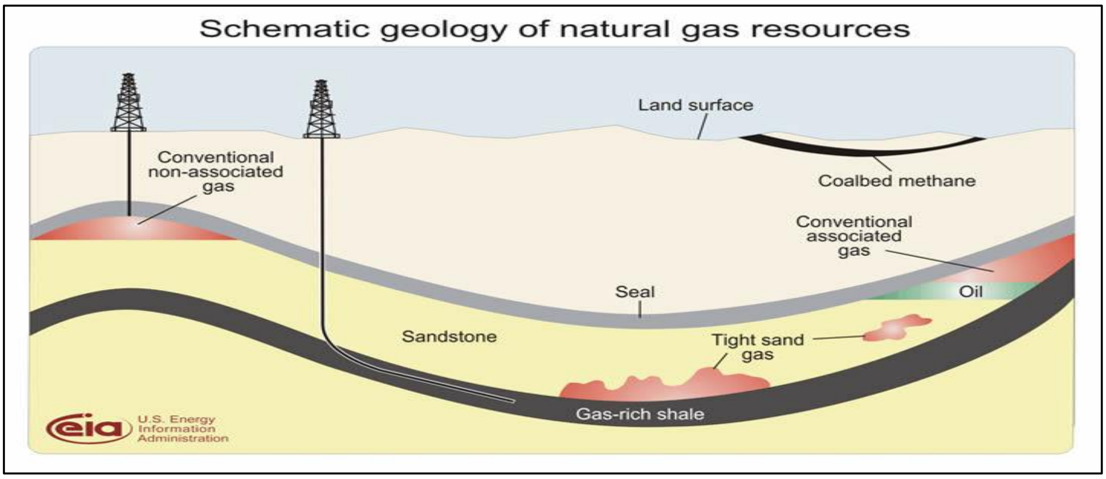

Figure 1 Geology of Natural Gas Resources [4]

Figure 2 below shows us two major differences between these two reservoirs. One: conventional reservoirs thousands of meters closer to the surface than unconventional reservoirs. Two: conventional reservoirs are typically a pool of free gas that have migrated, while the unconventional hydrocarbons are separately stuck in between the tight, micro-pores source rock [4]. With these two major points in mind, it can clearly be concluded that conventional reservoirs would be easier to drill, extract and produce, as can be seen in Figure 2. Because of the special techniques required for extraction, unconventional reservoir can be more expensive than conventional gas to extract

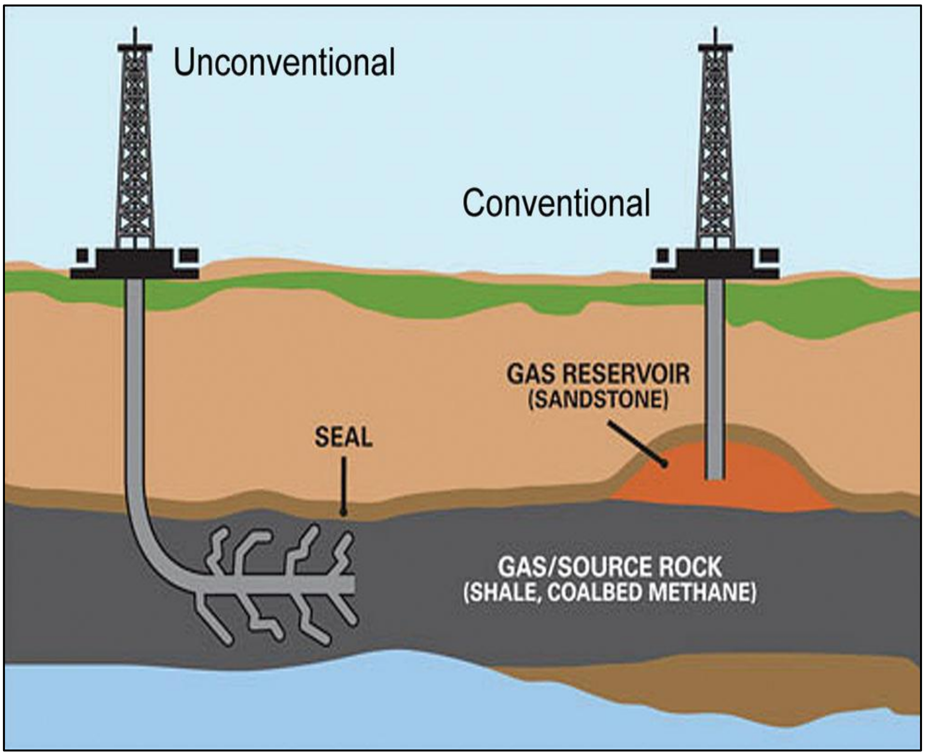

Figure 2 Conventional vs. Unconventional Gas Production [4]

As the energy demands worldwide increase at very fast rate due to the development across the globe, ideal fossil fuel reservoirs are becoming more scarce and harder to find, hence, the extraction of unconventional gas plays, such that of shale gas, suddenly becomes more lucrative and necessary. There is a huge potential in shale gas throughout the world it can be seen from the figure below which shows us the location all the shale gas basin around the world.

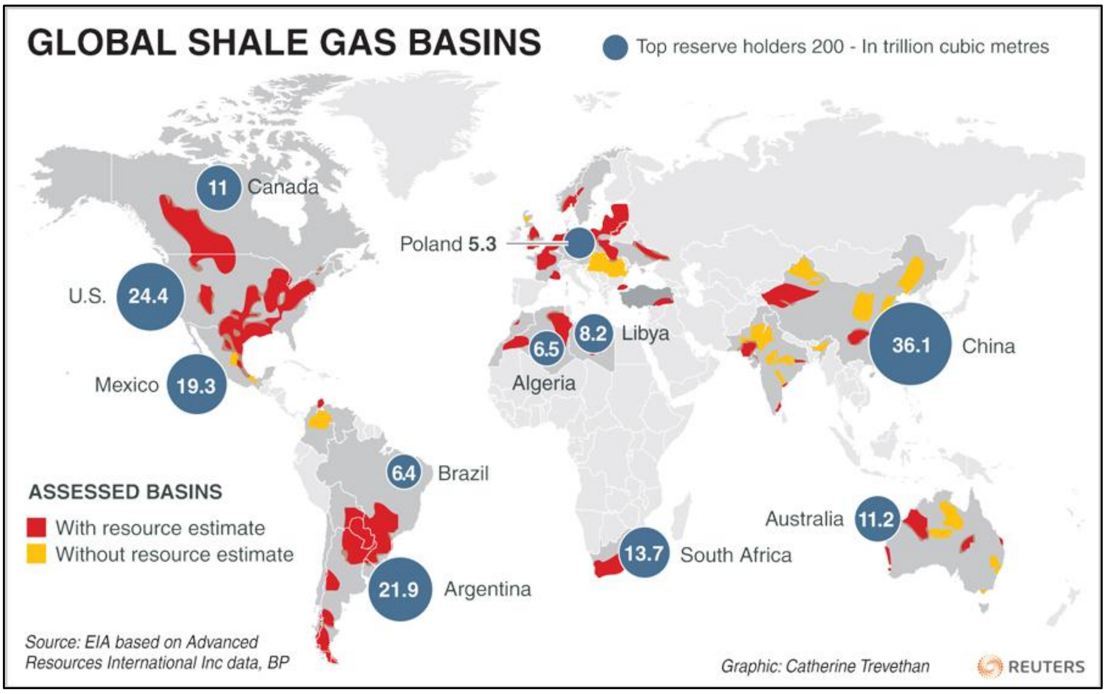

Figure 3 Global Shale Gas Basin [4]

Figure 3 above shows the global shale gas basin and resource estimate .It is noted that the potential for the shale gas is huge and with a proper research into the properties of these shale gas basins we can understand the complexity of these shale gas basins and exploit these hydrocarbons more efficiently.

It is clear that production of natural gas from conventional sources has been declining for over 15 years[5].Unconventional natural gas reservoirs have been making up the difference, and are expected to continue to do so in the future. Technology development, particularly the hydraulic fracturing of densely spaced directionally drilled wells, enable economic production from these unconventional reservoirs.

It is clearly seen that from the introduction that the prospect and the amount of gas that the international shale gas resource base is currently considered to be significant. The initial estimate of technically recoverable shale gas resources in the 32 countries examined in the EIA's "World Shale Gas Resources" study is 5,760 trillion cubic feet (see Figure 3). Adding the US estimate of the shale gas technically recoverable resources of 862 trillion cubic feet results in a total shale resource base estimate of

6,622 trillion cubic feet for the United States and the other 32 countries assessed. To put this shale gas resource estimate in context, the world's technically recoverable gas resources are roughly 16,000 trillion cubic feet, largely excluding shale gas [4]. Thus, adding the identified shale gas resources to other gas resources increases total world technically recoverable gas resources by more than 40 percent to 22,600 trillion cubic feet. It is also noted that annual natural gas consumption is expected to increase from 108 trillion cubic feet (TCF) in 2007 to 156 TCF in 2035[4].

1.2 Problem Statement

The major drawback of exploring these shale gas reservoirs has been the problem associated with pore pressure prediction and wellbore stability. It is known that shale has a high degree of variability. This variability further complicates the definition of shale normal compaction curves as shale compaction characteristics vary considerably. An important parameter for well planning is the knowledge about the formation pore pressure to avoid problems while drilling.

There many pore pressure predictions are used to predict pore pressure in oil and gas formation. The prediction of abnormal pore pressure is generally required for avoiding or mitigating drilling risks. However, pore pressure prediction becomes even more critical in shale gas formations where greater challenges exist versus conventional reservoirs. There are many reasons why drilling in shale gas formations presents additional challenges (e.g., formation anisotropy, gas-bearing shale, and gas effect on well logging data). Pore pressures increase from slightly elevated levels to a surprisingly high geopressures over short intervals. These pressures, if not correctly predicted, can lead to dangerous gas kicks and potentially blowouts. It is important to predict pore pressure because it used to estimate the mud weight required to prevent problem such as lost circulation and kick to occur. The main function of drilling mud is that it creates hydrostatic head to balance the formation pressure during drilling.

This project is relevant and is appropriate in the oil and gas industry because it is known that shale make up over 75% of drilled formations and cause over 90% of wellbore stability problems [5].It is also very important for us to study the pore pressure so that we can explore these unconventional gas reservoirs potential safely and further increase of our understanding of shale reservoir which will improve our drilling activity that will reduce the cost greatly.

1.3 Objectives and Scope of Study

1) To predict pore pressure for shale gas reservoir.
2) To investigate the accuracy of Equivalent Depth Method and Eaton Method in predicting pore pressure in shale gas reservoir.

The scope of study includes conducting research on

- Pore pressure prediction methods
- The impact of normal compaction trend line on pore pressure prediction.

The pore pressure prediction will be carried out using Eaton Method and Equivalent Depth Method. Barnett Shale and Marcellus shale will be chosen as basis for the comparison.

CHAPTER 2 LITERATURE REVIEW

2.1 Shale Characteristics

Shale is organic rich, fine grained sedimentary rock. It is the most common sedimentary rock worldwide and it can be found within all sedimentary basins. Shale is made of compacted silt and clay minerals that are collectively known as mud—consequently placing shale in a category known as 'mudstones'. What makes shale unlike from other mudstones is that it is made up of many thin layers of rock and that the rock easily splits along these laminations [6].

Figure 4 Physical Appearance of Shale [6]

There are four important characteristics in shale gas plays:

i. Organic maturity

   Organic maturity is usually in vitrinite reflectance (%R).It is an important method used to note the temperature history, which is proportional to the amount of organic maturity of the sediment. Typical values of 1.0-1.1% specify that the organic matter present in the shale is mature enough to produce natural gas, making it a possible source rock [6].

ii. Type of gas generated & stored in the reservoir

   There are two types of gas generated and stored which is thermogenic or biogenic gas. First type of gas which is the thermogenic gas is generated at deep depths by thermal cracking of hydrocarbon gas or secondary cracking of oil [7]. Usually this type of gas is a result of very high temperatures and pressures with higher organic maturity. Thermogenic gas can be dry (entirely methane) or wet (contains ethane, propane, etc.), depending on its composition. On the other hand, Biogenic gas is almost always dry. Biogenic gas is also formed at higher depths, at relatively lower pressures and temperatures and is not at all related to the oil forming process [6].

iii. Total organic content (TOC),

This is the most important properties of the shale gas [7]. It gives us the measure of the total organic content that is found in shale rock and is the present day measure of its organic richness.

iv. Permeability and porosity of the reservoir

Shale gas plays are known to have extremely low permeability, less than 1millidarcies (mD), and low porosity less than 10%, when compared to conventional plays at 1mD and porosity over 10% respectively [7].

2.2 Pore Pressure

The magnitude of the pressure in the pores of a formation, known as the formation pore pressure (or simply formation pressure), is an important consideration in many aspects of well planning and operations. Pore pressure is the pressure at which the fluid contained within the pore space of a rock is maintained at depth. In the absence of any other processes, the pore pressure is simply equal to the weight of the overlying fluid, in the same way that the total vertical stress is equal to the weight of the overlying fluid and rock. It is often referred as hydrostatic pressure.

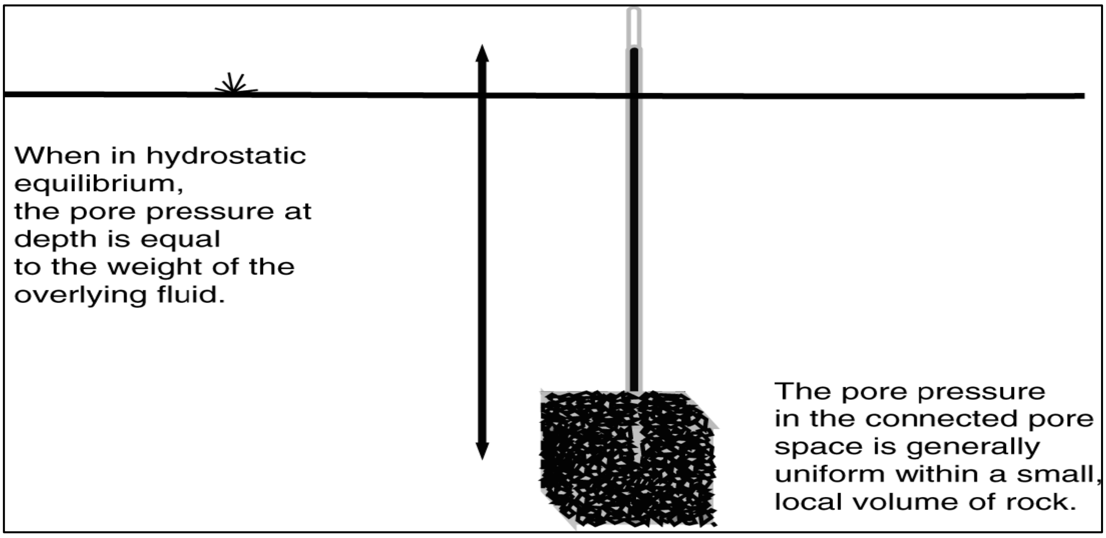

Figure 5 Illustration of pore pressure in permeable rock under hydrostatic pressure [7]

Hydrostatic pressure, P_h, is the pressure caused by the weight of a column of fluid [8].

$$P_h = \rho_f g z \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (1)$$

where z, ρ_f and g are the height of the column, the fluid density, and acceleration due to gravity, respectively. The size and shape of the cross-section of the fluid column have no effect on hydrostatic pressure. The fluid density depends on the fluid type, concentration of dissolved solids (i.e., salts and other minerals) and gasses in the fluid column, and the temperature and pressure. So it is clear that fluid density is depth dependent in any area [8].

The formation pressure gradient, expressed usually in pounds per square inch per foot (abbreviated by psi/ft) in the British system of units, is the ratio of the formation pressure, P (in psi) to the depth, z (in feet). It is not the true instantaneous gradient, dP/dz. In general, the hydrostatic pressure gradient, P_g (in psi/ft), can be defined by

$$P_g \equiv 0.433 \times \text{fluid density}(\text{in} \frac{g}{cm^3}) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(2)}$$

The pressure of the fluid in the pore space (the pore pressure) can be measured and plotted against depth as shown in Figure 5. This type of diagram is known as a P-Z diagram.

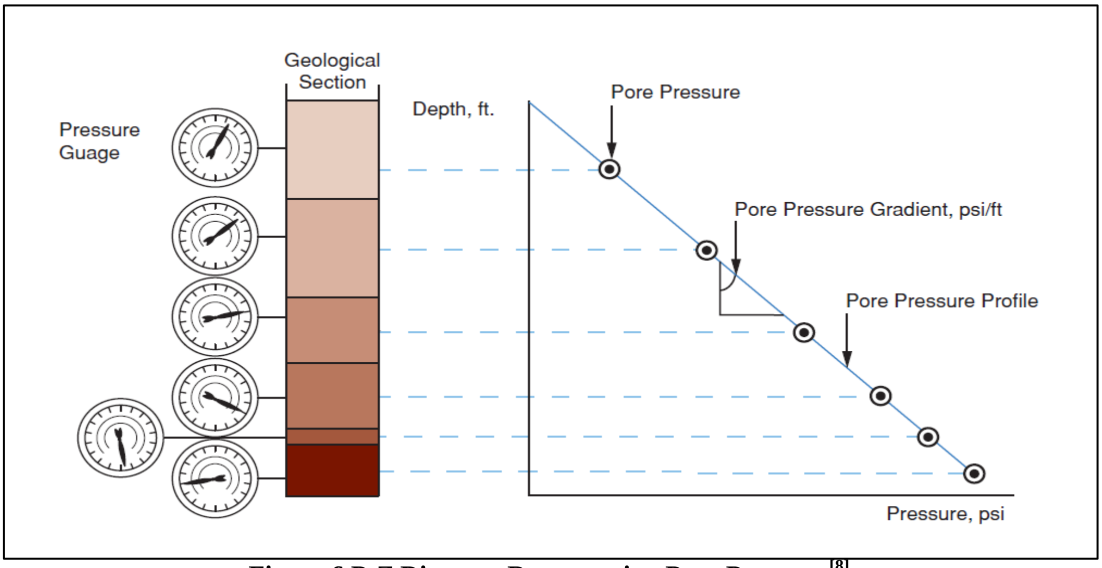

Figure 6 P-Z Diagram Representing Pore Pressure [8]

The overburden pressure, S (z), at any depth is the pressure which results from the combined weight of the rock matrix and the fluids in the pore space overlying the formation of interest. This is expressed as

$$S \equiv g \int_0^z p\, b(z) dz \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(3)}$$

Where ρ_b is the depth dependent bulk density given by

$$p_b \equiv \emptyset p_f + (1 - \emptyset) p_g \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(4)}$$

Where ϕ, ρ_f, and ρ_g are the fractional porosity, the pore fluid density, and the density of the matrix (grain density).The overburden pressure is depth dependent and increases with depth. In the literature, the overburden pressure has also been referred to as the geostatic or lithostatic pressure [8].

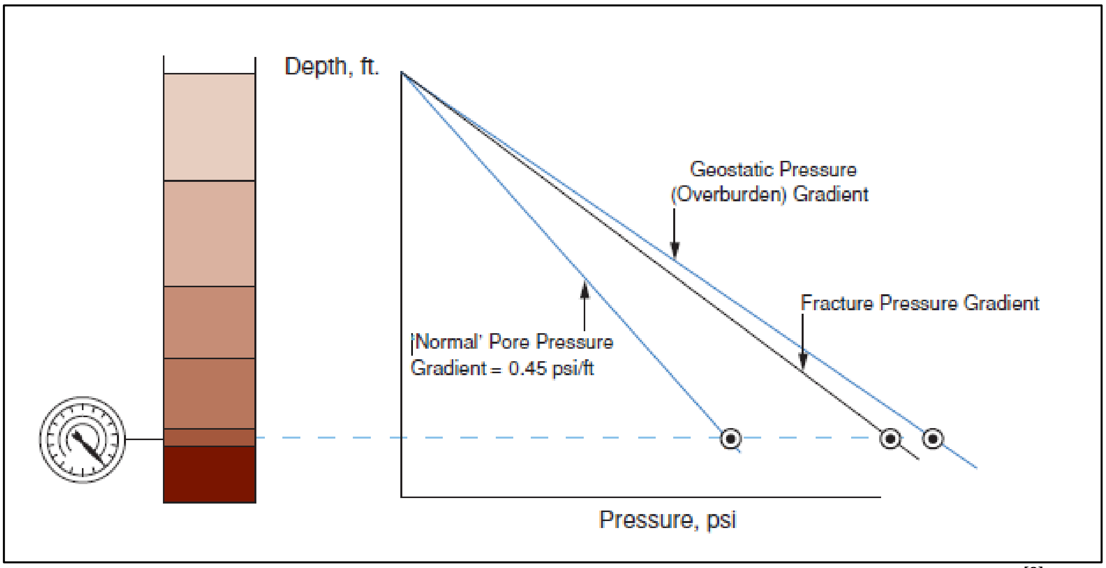

Figure 7 Pore Pressure, Fracture Pressure and Overburden Pressures and Gradients [8]

Processes that increase pore pressure are.

- Under compaction caused by rapid burial of low-permeability sediments
- Lateral compression
- Release of water from clay minerals caused by heating and compression
- Expansion of fluids because of heating
- Fluid density contrasts (centroid and buoyancy effects)
- Fluid injection (e.g., waterflooding)

2.2 Pore Pressure Prediction Method

The accurate prediction of pore pressure in shale gas reservoir is very important as we are drilling of shale reservoir which will have higher pore pressure mainly due to the presence of gas in the reservoir. This happen because gas will not be in equilibrium hydrostatic due to presence of shale which is a totally impermeable barrier. In such cases, pore pressures often are abnormally high and can exceed what otherwise are safe mud pressures. If the pore pressure is not accurately predicted, it can lead to drilling problems such as lost circulation, blowouts, hole instability, and excessive costs [9]. Thus drilling costs and problems can be reduced substantially by the early recognition of abnormally high pore pressures. There are few methods that are being used currently to predict pore pressure and in this project we will apply those methods to predict the pore pressure in shale gas formation. The methods are.

- Eaton Method
- Equivalent Depth Method

But the real constraint in the selection of prediction method is availability of data. In this research we will mainly focus on two method which is Eaton method and Equivalent Depth method to predict pore pressure in shale reservoir. Barnett Shale and Marcellus Shale have been chosen as our case study in this project due to the availability of the data.

2.2.1 Eaton Method

The Eaton Method is characteristically applied to seismic or acoustic velocity data, and resistivity data. The main objective is to examine the porosity vs. depth, establish a normal compaction trend and to make a ratio comparison between the value recorded and the expected value if the pore pressures where hydrostatic. In 1972 Eaton [10] published a technique for pore pressure prediction. Eaton recognized that Hottman and Johnson's basic relationship is correct, but can be improved. Hottman and Johnson's relationships, in the simplest terms, are as follows:

$$\frac{P_F}{D} = f\left[\frac{Ra_{sh}}{Rn_{sh}}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (5)$$

$$\frac{P_F}{D} = f\left(\frac{dTa_{sh}}{dTn_{sh}}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (6)$$

Rearranging the above equation will lead to

$$\frac{dTa_{sh}}{dTn_{sh}} = f\left(\frac{P_F}{D}\right) \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (7)$$

Eaton noted that the technique developed by Hottman and Johnson utilized just a single line drawn through the FPG versus the petrophysical parameter data and that data was considerably scattered. Eaton combined Terzaghi's and Hottman and Johnson's relationships by solving Terzaghi's relationship for pressure and dividing all of the variables by depth as follows:

$$\frac{P_F}{D} = \frac{\sigma_{OB}}{D} - \frac{\sigma_{EV}}{D} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (8)$$

Up to this point, it was argued that the overburden stress gradient is constant for a given area and of no significance. Eaton refutes this argument saying that overburden stress gradients are functions of burial depth in areas where compaction and abnormal pressures are caused by increasing overburden loads with deeper burial. The overburden stress is a function of burial depth and formation bulk density by the following relationship:

$$\sigma_{ob} = \int P_b \, dD \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(10)}$$

Based on the equation above Eaton developed the equation below. After conducting experiment and more study on pressure data, he decided that an exponent with a value of 1.5 should be used as constant in the equation.

$$\text{Ppore} = \text{Povb} - (\text{Pobv} - \text{Pp,n}) \left(\frac{R_{sh,a}}{R_{sh,n}}\right)^{1.5} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(11)}$$

With more experimental data and performing of his studies he published his result in 1975 as following formulas:

$$\text{Ppore} = \text{Povb} - (\text{Pobv} - \text{Pp,n}) \left(\frac{\Delta t_{,n}}{\Delta t_{,a}}\right)^{3} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(12)}$$

$$\text{Ppore} = \text{Povb} - (\text{Pobv} - \text{Pp,n}) \left(\frac{d_{c,a}}{d_{c,n}}\right)^{1.2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \text{(13)}$$

Ppore: Pore Pressure (psi)

Povb: Overburden Pressure (psi)

Pp,n: Normal Pore Pressure(psi)

Rsh,a: Resistivity (ohm) actual

dc,a: dc-exponents for actual

Δt,a: Sonic transit time(μsec/ft) for actual

Rsh,n: Resistivity (ohm) normal

dc,n: dc-exponents for normal

Δt, n: Sonic transit time (μsec/ft) for normal

$\frac{P_F}{D}$: Pressure gradient (psi/ft)

σ_{ob}: overburden stress

This method is empirically derived. It assumes that a normal trend can be defined and that the pore pressure at any point can be related to the ratio between actual and normal indicator value. Figure 8 below shows the plot of drilling exponent vs. depth.

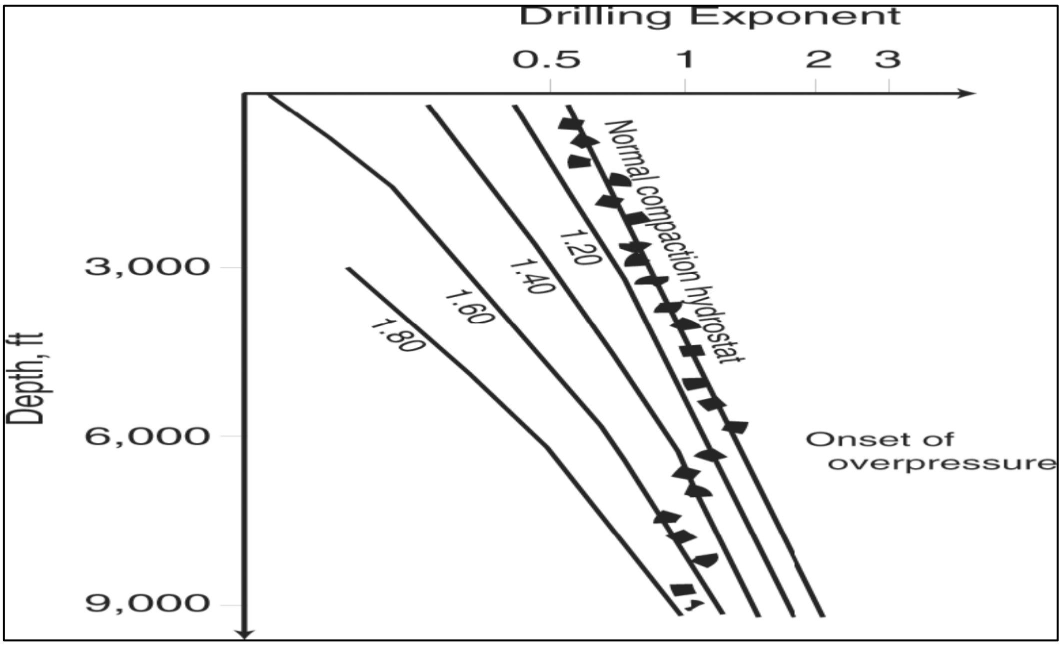

Figure 8 Drilling Exponent vs Depth [10]

2.2.2 Equivalent Depth Method

The method of equivalent depth is based on the assumption that the same shale with equal physical properties at different depths will have equal effective stress.

Principles:

One example of analysis using a trend line is the equivalent depth method illustrated in Fig.9. This method first assumes that there is a depth section over which the pore pressure is hydrostatic, and the sediments are normally compacted because of the systematic increase in effective stress with depth.

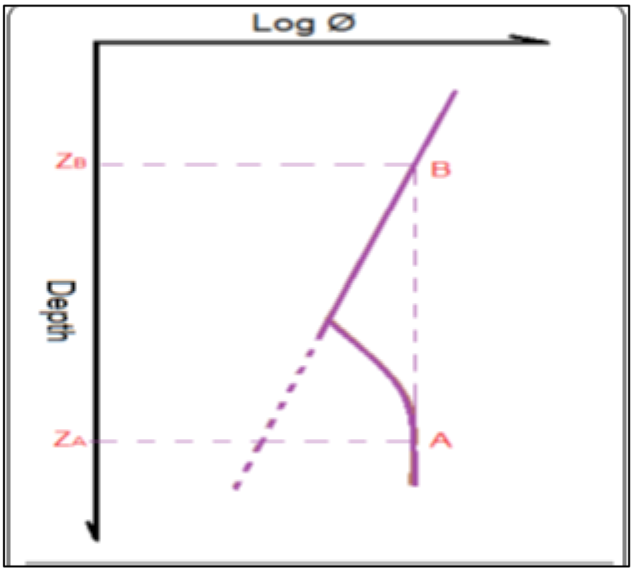

Figure 9 Porosity vs. Depth [11]

Every point A in an under compacted clay is associated with a normally compacted point B the compaction at point A is identical to that at point B .The depth of point B, Z_B is called the equivalent depth, or sometimes the isolation depth. The fluid contained within the pores of clay A has been subjected to all geostatic loads in the course of burial from Z_B to Z_A. It is known that

$$P_{ovb} = \sigma + P_{pore} \qquad (14)$$

$$\sigma_{\mathbf{B}} = P_{ovb,B} - P_{pore,B} \qquad (15)$$

$$\sigma_{\mathbf{B}} = \sigma_{\mathbf{A}} \qquad (16)$$

With knowing the overburden pressure at A ($P_{ovb,A}$), the pore pressure at A ($P_{pore,A}$) can be calculated.

$$P_{pore,A} = P_{ovb,A} - \sigma_{\mathbf{B}} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (17)$$

Then by eliminating σ_A and σ_B

$$P_{\mathbf{pore},\mathbf{A}} = P_{pore,B} + (P_{ovb,A} - P_{ovb,B)} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (18)$$

This equation is applied to predict pore pressure at point A.

2.3 Fracture Pressure

Fracture pressure is the pressure in the wellbore at which a formation will crack .The stress within a rock can be resolved into three principal stresses. A formation will fracture when the pressure in the borehole exceeds the least of the stresses within the rock structure. Normally, these fractures will propagate in a direction perpendicular to the least principal stress [16].

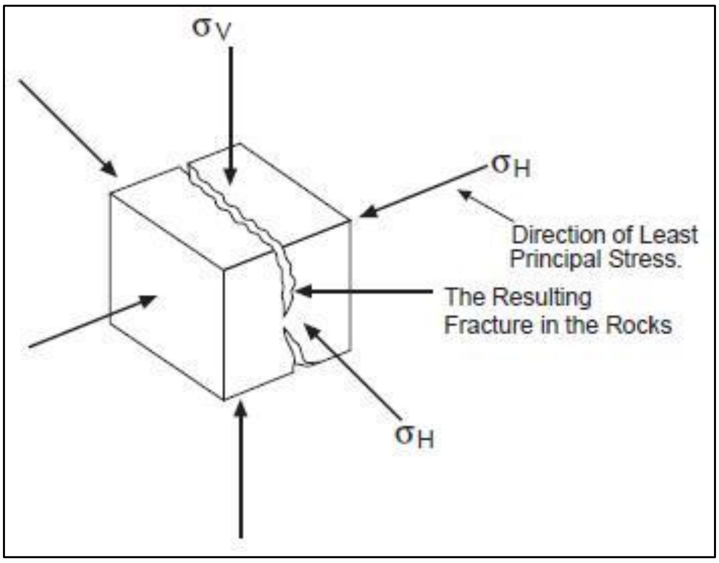

Figure 10 Fracture Pressure Stresses [18]

At sufficient depths (usually below 1000 m or 3000 ft) the minimum principal stress is horizontal; therefore, the fracture faces will be vertical. For shallow formations, where the minimum principal stress is vertical, horizontal (pancake) fractures will be created.

There are many method used currently to predict fracture pressure in the oil and gas industry. It is decided that Hubbert and Willis Equation is being used to predict the fracture pressure since this method introduced many fundamental principles that are still used widely today. The minimum wellbore pressure required to extend an existing fracture was given as the pressure needed to overcome the minimum principal stress [6]:

$$p_{ff} = \sigma_{min} + p_f \text{ ....} (19)$$

The minimum principle stress in the shallow sediments is approximately one-third the matrix stress resulting from weight of the overburden [6].

$$P_{ffmin} = \frac{\sigma_{ma}}{3} + P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (20)$$

Since the matrix stress $\boldsymbol{\sigma_{ma}}$ is given by

$$\sigma_{ma} = \sigma_{ob} - P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (21)$$

Substituting equation **21** into equation **20** will yield

$$P_{ffmin} = \frac{\sigma_{ob} - P_f}{3} + P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (22)$$

$$P_{ffmin} = \frac{\sigma_{ob} + 2P_f}{3} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (23)$$

The maximum principle stress in the shallow sediments is approximately half the matrix stress resulting from weight of the overburden [14].

$$P_{ffmax} = \frac{\sigma_{ma}}{2} + P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (24)$$

Since the matrix stress $\boldsymbol{\sigma_{ma}}$ is given by

$$\sigma_{ma} = \sigma_{ob} - P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (25)$$

Substituting Equation 25 into equation 24 will yield

$$P_{ffmax} = \frac{\sigma_{ob} - P_f}{2} + P_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (26)$$

$$P_{ffmax} = \frac{\sigma_{ob} + P_f}{2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ (27)$$

CHAPTER 3 METHODOLOGY

First step in the methodology is to find logs from shale gas reservoir. Two major shale plays was chosen which are the Barnett Shale and Marcellus Shale. Second part is to obtain details on the lithology of the reservoir.Final part is to compute the pore pressure using Equivalent Depth Method and Eaton Method. The- details on methodology is explained below.

3.1 Eaton Method Pore Pressure Prediction

1. Wirelines logs from the shale gas field are obtained and it is analyzed.
2. Data is studied and the lithology is identified from the logs provided.
3. Plot graph of sonic travel time vs. depth.
4. Establish the trend line from the sonic travel time vs. depth so a normal compaction trend line can be established
5. Establish the compaction trend line in the graph
6. Calculate the estimated pore pressure using Equation 12
7. Calculate the minimum and maximum fracture pressure using Equation 28 and Equation 29.
8. Based on the estimated pore pressure in step 7 calculate the mud weight based on Equation 31.
9. Plot graph of Pressure vs. Depth for pressure obtained in shale reservoir.
10. Plot graph of Equivalents Mud Density vs. Depth for shale reservoir.

3.2 Equivalent Depth Method Pore Pressure Prediction

1. Wirelines logs from the shale gas field are obtained and it is analyzed.
2. Data is studied and the lithology is identified from the logs provided.
3. Calculate the porosity of the formation using Equation 30.
4. Plot graph of porosity vs. depth.
5. Establish the trend line from the porosity vs. depth so a normal compaction trend line can be established
6. Establish the normal compaction trend line in the graph.
7. Calculate the estimated pore pressure using Equation 18.
8. Calculate the minimum and maximum fracture pressure using Equation 28 and Equation 29.
9. Based on the estimated pore pressure from step 7 calculate the mud weight based on Equation 31.
10. Plot graph of Pressure vs. Depth for shale gas reservoir.
11. Plot graph of Equivalents Mud Density vs. Depth for shale gas reservoir.

- Density Porosity Equation

$$\emptyset = \frac{p_{ma} - p_{log}}{p_{ma} - p_{fl}} \dots\dots\dots\dots\dots\dots \text{(30)}$$

- Mud Weight Equation

$$\text{Mud Weight} = \frac{P_{pp} + \text{Safety Factor}}{0.052 * \text{TVD(ft)}} \dots\dots\dots\dots\dots\dots \text{(31)}$$

CHAPTER 4 RESULTS AND DISCUSSION

This chapter will discuss the result obtained from pore pressure prediction method discussed. The expected results in this chapter include the plot of pressure vs. depth for Barnett shale and Marcellus shale. The plot of EMW vs. Depth for the Barnett shale and Marcellus shale is plotted to obtain the suitable mud weight for drilling operation. This chapter will contain the comparison of predicted pore pressure and actual pore pressure. It will contain a part of proposing a mud weight for these gas shale reservoirs Barnett shale and Marcellus shale based on the pore pressure prediction.

4.1 Barnett Shale

4.1.1 Well A

Based on Figure 15 and Figure 16**,** it can be observed that the pore pressure curve deviates around 5650 feet. This indicates the abnormal pressure zone. Thus, it can be deduced that gas might probably be at around 5650 feet (natural gas from Barnett Shale). The pore pressure prediction somewhat is consistent with the actual pore pressure but the biggest drawback is the pore pressure gradient is much lower than the expected gradient in Barnett Shale. We can see that the pore pressure gradient from the prediction is for both cases using Eaton and Equivalent Depth Method. The pressure gradient for Eaton method is 0.43-0.57 psi/ft. is higher than the expected pore pressure in the Barnett Shale which is around 0.43psi/ft-0.54psi/ft.[13].It is noted that the maximum predicted pressure using Eaton Method is higher than the actual maximum pressure gradient in this area. For the second method which is the equivalent depth method we can see that the predicted pore pressure is 0.43psi/ft-0.52psi/ft around which is lower than actual pressure gradient around the region which is 0.43psi/ft-0.54psi/ft. [13].It also noted that the maximum value for predicted pressure gradient using Equivalent Depth Method is lower than the maximum actual pressure gradient in this area.

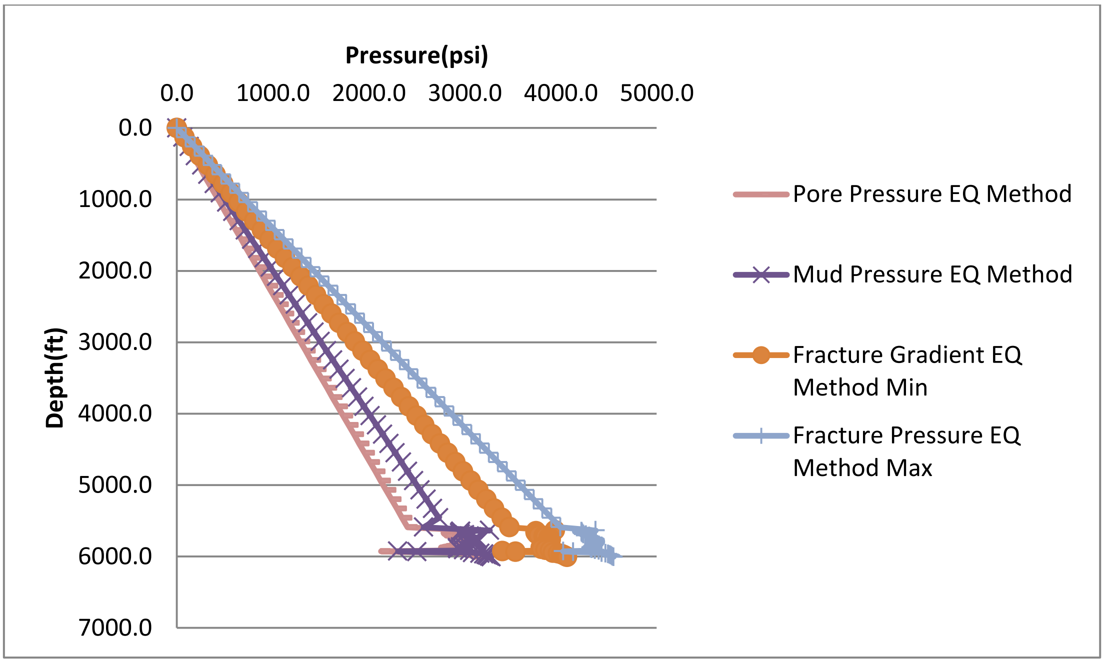

Figure 11 Pressure vs Depth Barnett Shale Well A (Equivalent Method)

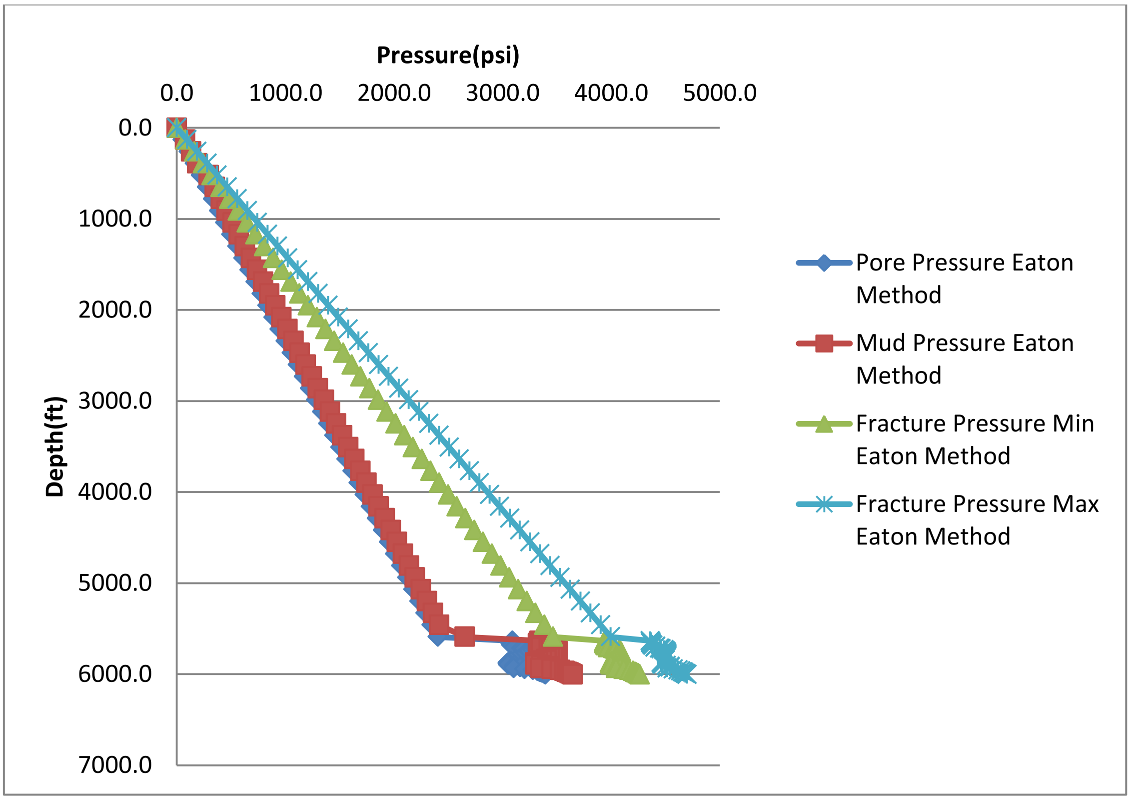

Figure 12 Pressure vs Depth Barnett Shale Well A (Eaton Method)

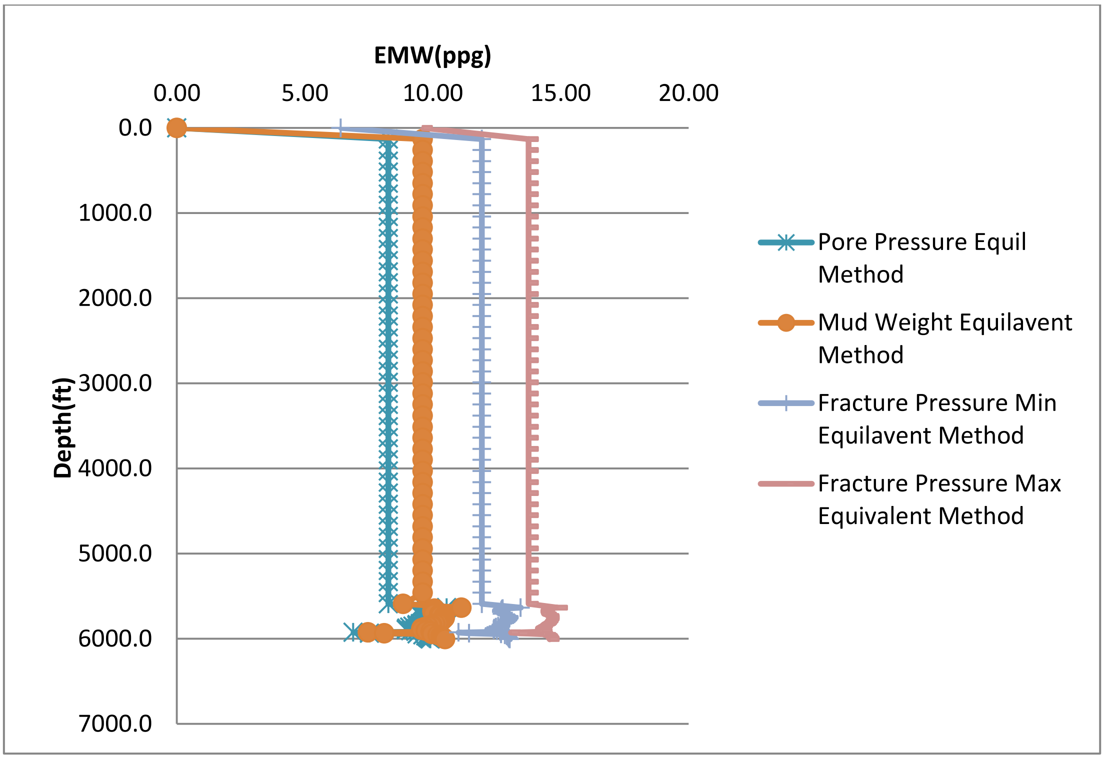

Figure 13 EMW vs Depth Barnett Shale Well A (Equivalent Method)

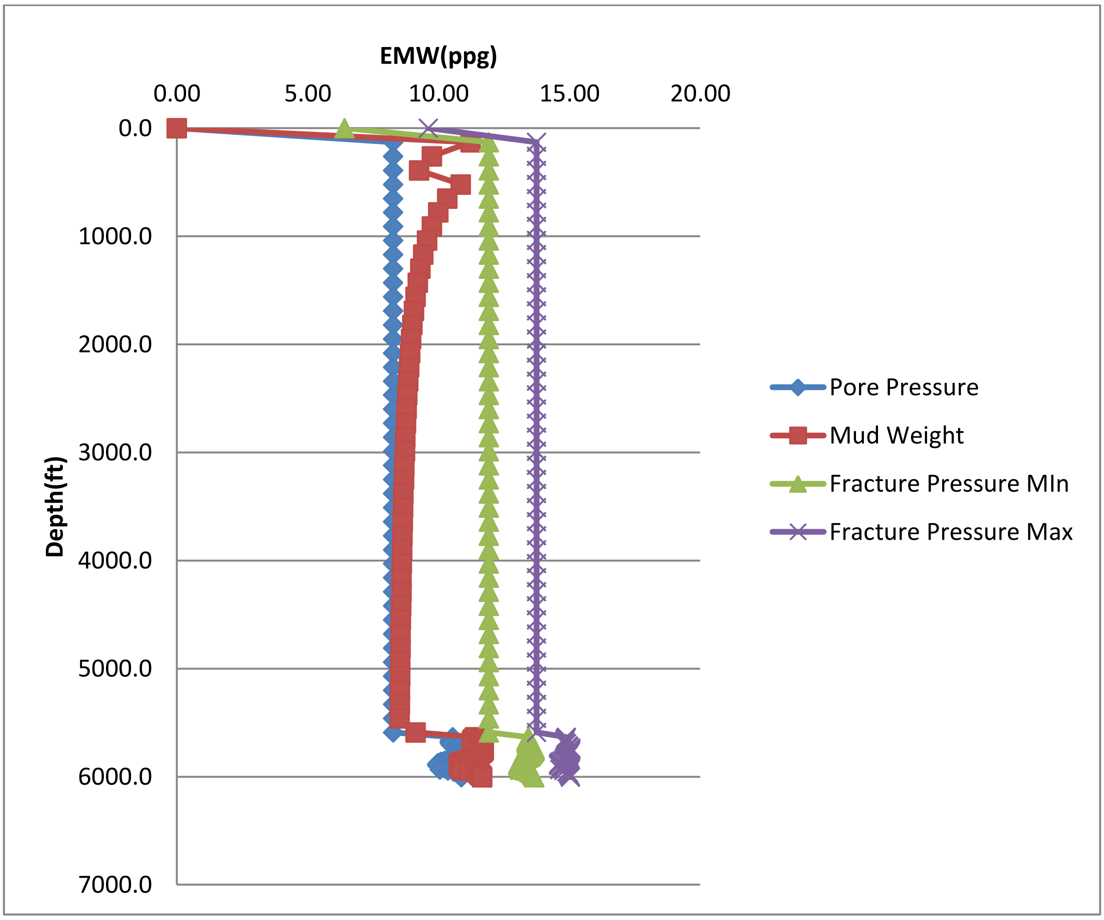

Figure 14 EMW vs Depth Barnett Shale Well A (Eaton Method)

Both graphs above shows that for well A the there is a huge difference in predicted pore pressure to the expected gradient in this region. The first case the proposed mud weight for Eaton Method is 8.5ppg-12ppg which is much higher than the actual mud weight in this area which is 8.4ppg-11.4ppg [13].The second case the proposed mud weight for Equivalent Depth method is 9.6ppg-11.1ppg which is lower than the actual mud weight in this area which is 9.3ppg-10.5ppg [13]. It is clear that the pore pressure prediction using Eaton Method and Equivalent Depth Method in this case this might lead to inconsistency in prediction of pore pressure where in the first case we overestimated the pore pressure and for second case we underestimated the pore pressure in this region which will cause a lot of problems while drilling such as loss of circulation, formation damage, plugged formation and many other problem related with inaccuracy of mud weight. The error is believed due to the failure to establish a suitable NCT trend line for both cases and lack of data form this particular region of Barnett Shale for both cases.

4.1.2 Well B Equivalent Method

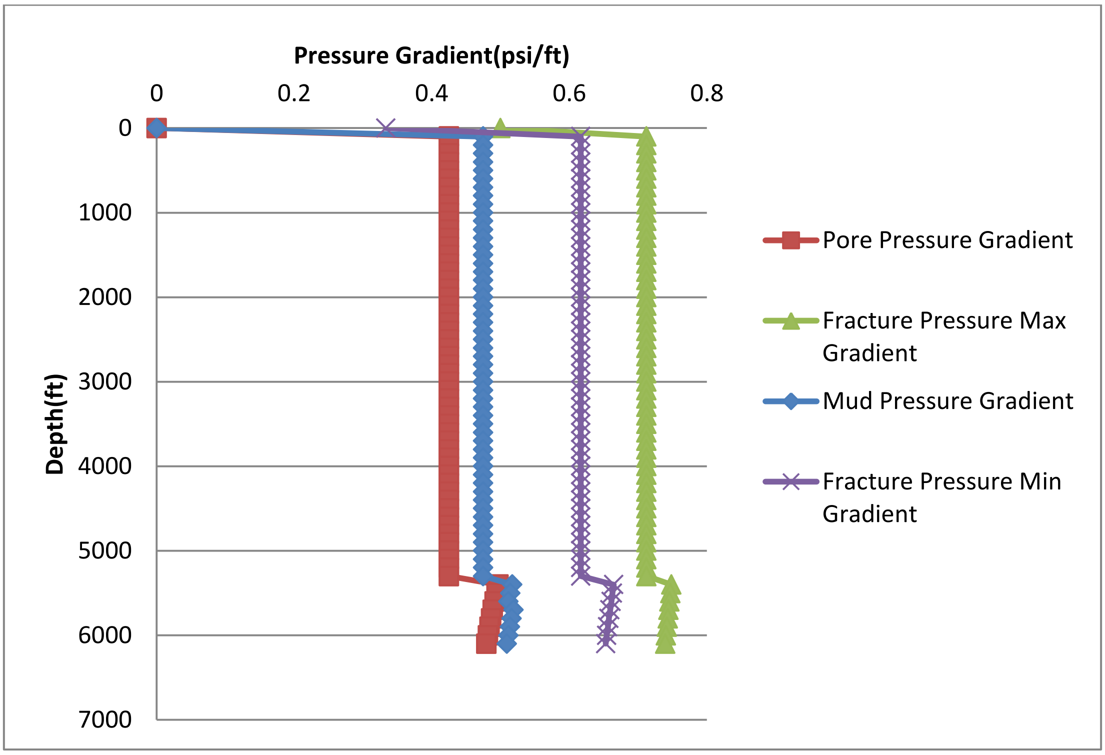

Figure 15 Pressure Gradient vs Depth Barnett Shale Well B

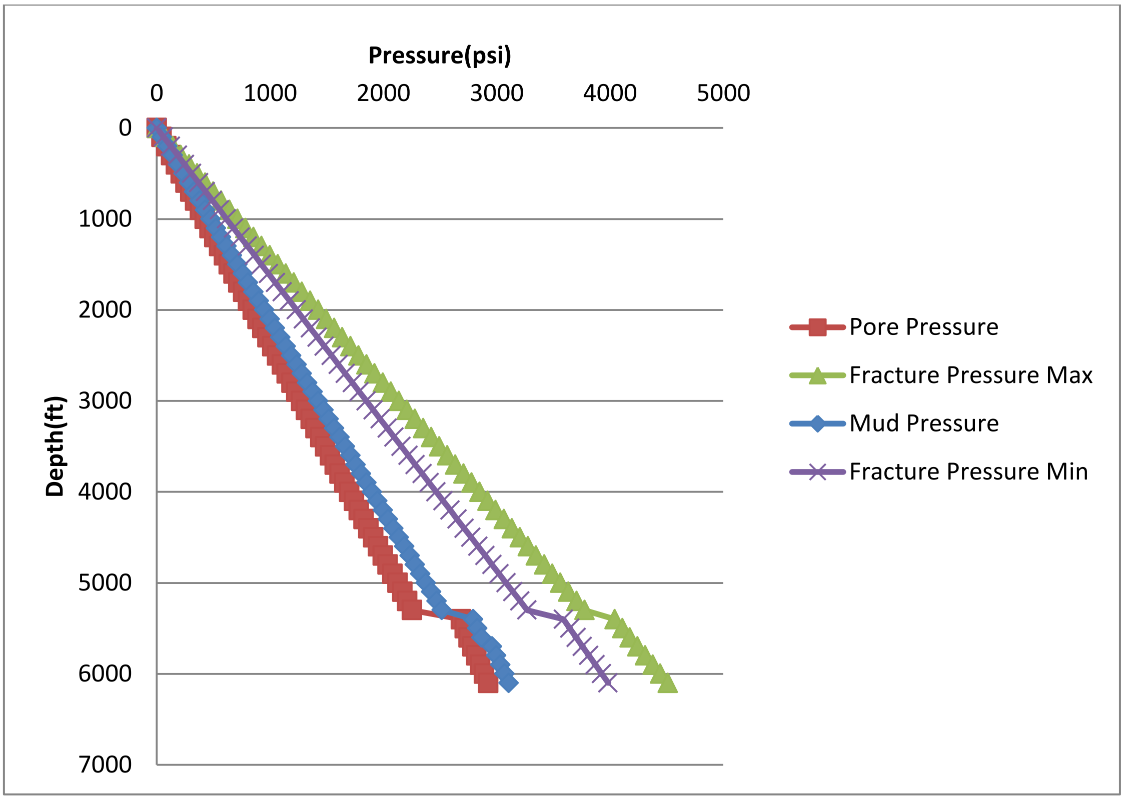

Figure 16 Pressure vs Depth Barnett Shale Well B

Based on Figure 21 and Figure 22, it can be observed that the pore pressure curve deviates around 5650 feet. This indicates the abnormal pressure zone. Thus, it can be deduced that gas might probably be at around 5650 feet (natural gas from Barnett Shale) which indicates the presence of gas. The pore pressure prediction for Well B in the Barnett Shale region only comprises of Equivalent Depth Method. This is due to the lack of data for prediction using other methods. Subsequently, a plot of equivalent mud weight (EMW) vs. depth was plotted in order to shed a light on what our mud weights ought to be.

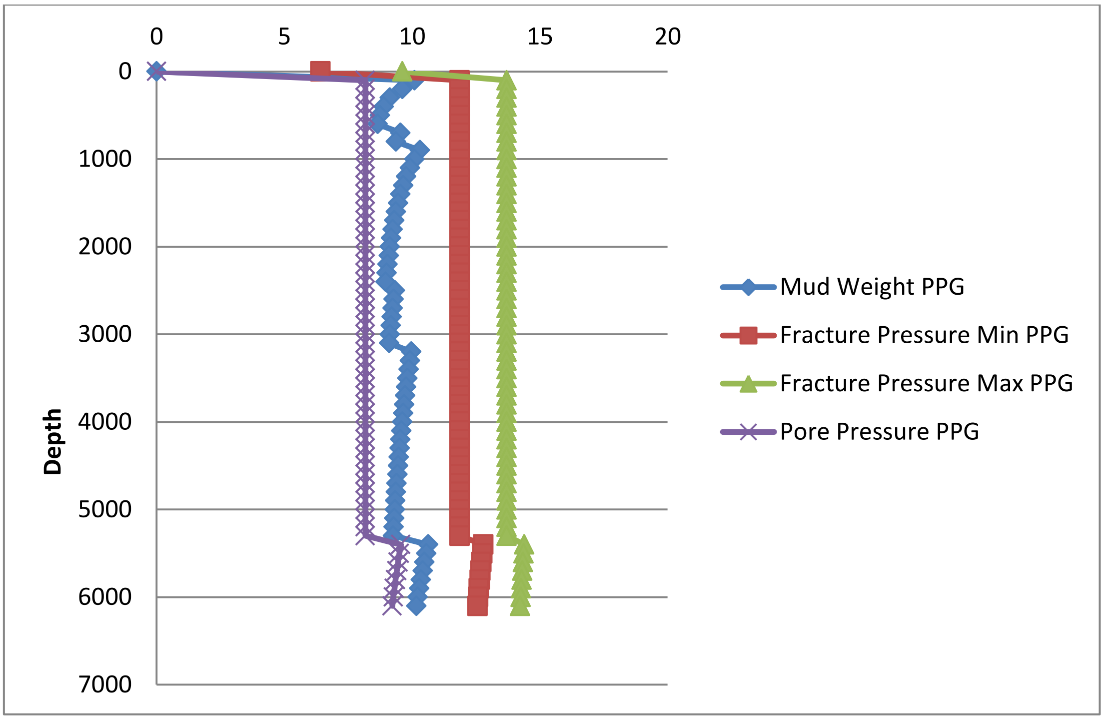

Figure 17 EMW vs Depth Barnett Shale Well B

According to the plot generated above Figure 23, mud weight needed at this well is 9.1ppg to 9.98ppg which is consistent the expected mud weight which is 9.1ppg to 10.1ppg in this area[13]. Safe and responsible drilling practice dictates that the mud weight that will be used has to stay within the range of pore pressure and fracture pressure gradients. The result in the second well which is Well B shows us that the pressure gradient which is 0.43psi/ft. to 0.53psi/ft. The predicted pore pressure is slightly lower than the actual pore pressure in this area which is 0.43psi/ft-0.54psi/ft. [13]. The result obtained is comparable to the expected gradient and are well within the range of expected pressure gradient in this area. In this case the proposed mud weight of will not cause any major issue during drilling such as loss of circulation, damage of formation and other major issues related to miscalculation of pore pressure and mud weight.

4.2 Marcellus Shale

4.2.1 Well A Equivalent Method

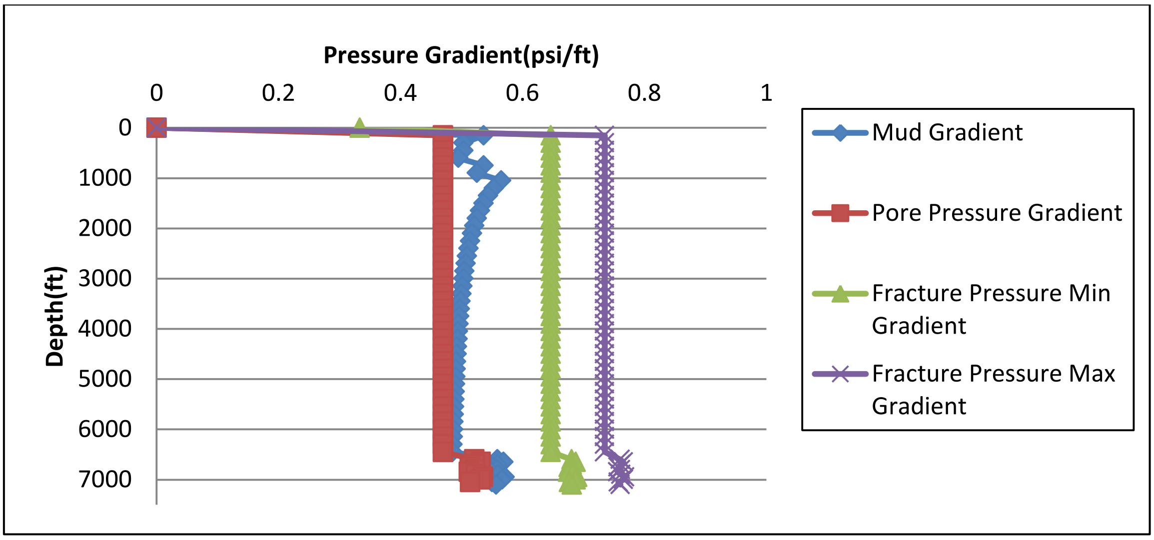

Figure 18 Pressure Gradient vs Depth Marcellus Shale Well A

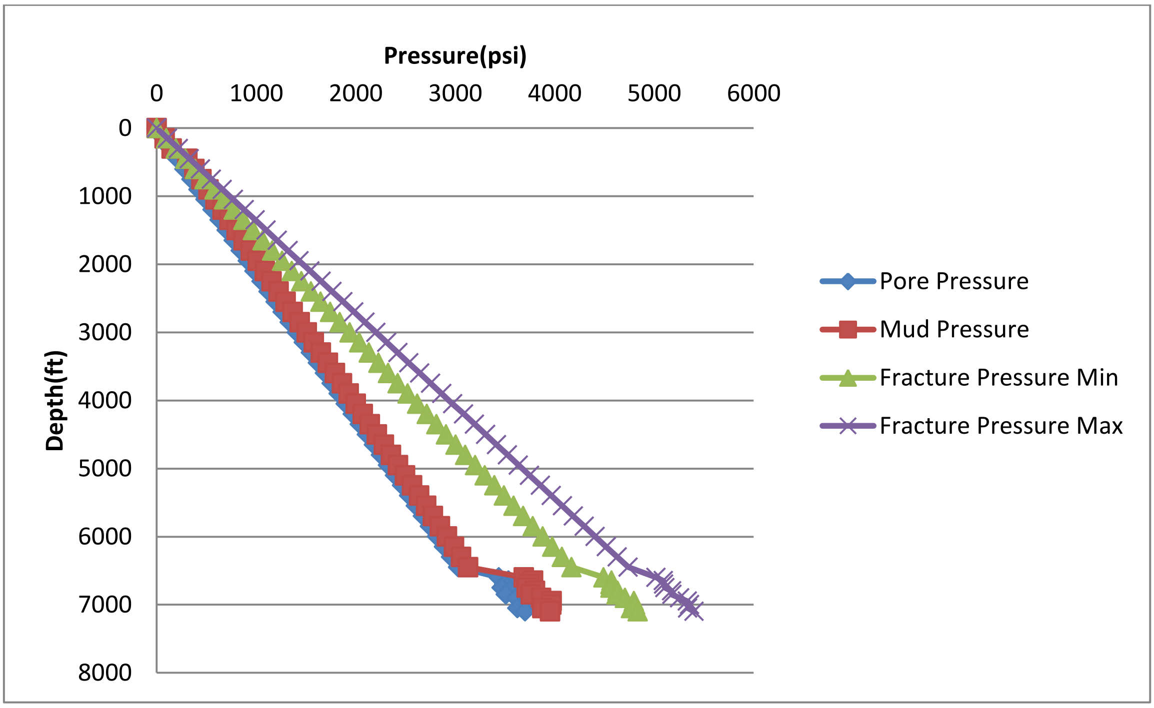

Figure 19 Pressure vs Depth Marcellus Shale Well A

Based on Figure 24 and Figure 25, it can be observed that the pore pressure curve deviates around 6500 feet. This indicates the abnormal pressure zone. Thus, it can be deduced that gas might probably be at around 6500 feet (natural gas from Marcellus Shale). It is noted that from the graphs and result obtained from the predicted pore pressure gradient is 0.47psi/ft-0.50psi/ft when it compared to actual pore pressure which is 0.46psi/ft-0.58psi/ft[11].It is clear that the prediction is lower than the actual pore pressure. It is noted that the maximum predicted pressure gradient is lower than the actual maximum pressure gradient in the field. Subsequently, a plot of equivalent mud weight (EMW) vs depth was plotted in order to shed a light on what our mud weights ought to be.

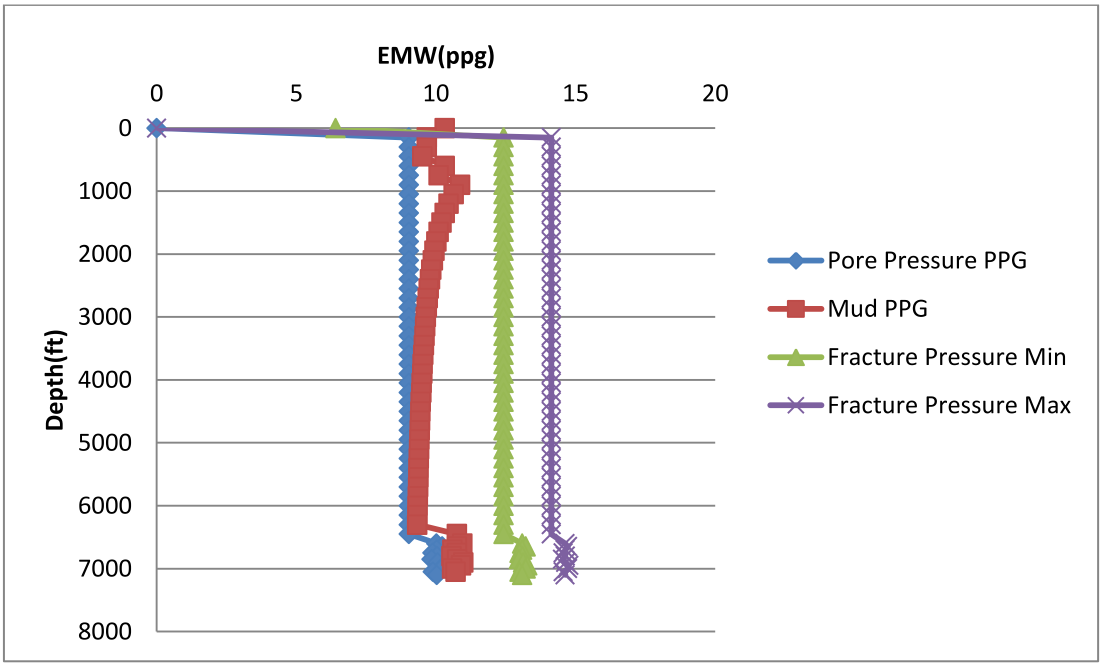

Figure 20 EMW vs Depth Marcellus Shale Well A

According to the plot generated above the predicted mud weight is 9.5ppg to 10.7ppg compared to actual mud weight in this area which is 9.4ppg-10.6ppg in this area [13]. The predicted result shows that for well in this Marcellus Shale is lower than the actual pressure gradient this will lead to miscalculation of mud weight which might lead to loss of circulation of fluid that might collapse the borehole of the wellbore. This also emphasize the importance to get a suitable trend line to have an accurate pore pressure prediction and the need for a lot of wireline data is need before this method can be carried out accurately.

CHAPTER 5 CONCLUSIONS&RECCOMENDATION

- Eaton Method and Equivalent Depth Method pore prediction techniques are not accurate in determining the pore pressure in Barnett Shale and Marcellus Shale.
- The pore pressure prediction will deviate from actual pore pressure when failure on establish normal compaction trend.
- Lithological variability and overpressure of shale creates difficulty in defining the appropriate normal compaction trends for pore pressure estimation.

RECCOMENDATION

- Employments of multiple techniques in pore pressure predication to help understand the uncertainty in each of the method used.
- Employing basin modeling, seismic and wireline–based predication techniques provide complementary results and valuable insights into the realistic range of uncertainty in predication.

APPENDIX

Appendix A: Barnett Shale

Well A

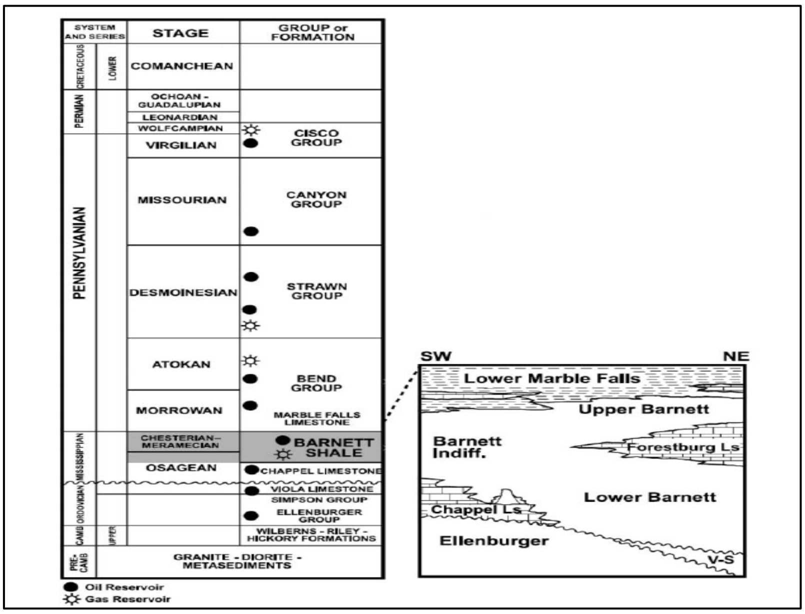

Figure 21 Generalized stratigraphy of the Barnett Shale [13]

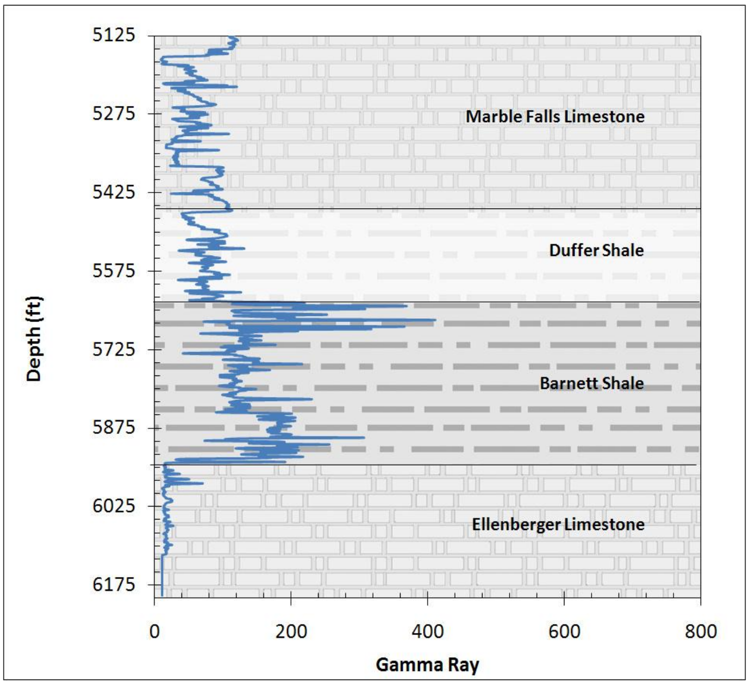

Figure 22 Gamma Ray Reading Barnett Shale [13]

Appendix A.1: Barnett Shale

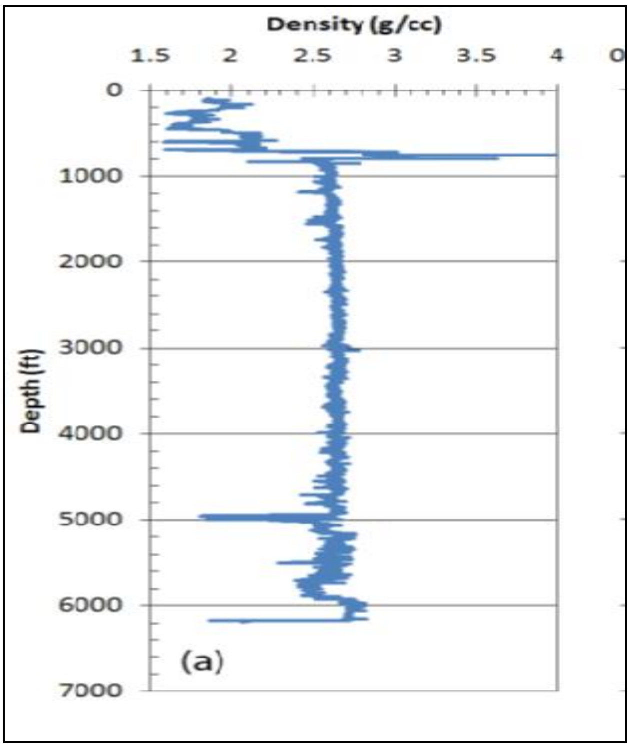

Figure 23 Density Log Barnett Shale [13]

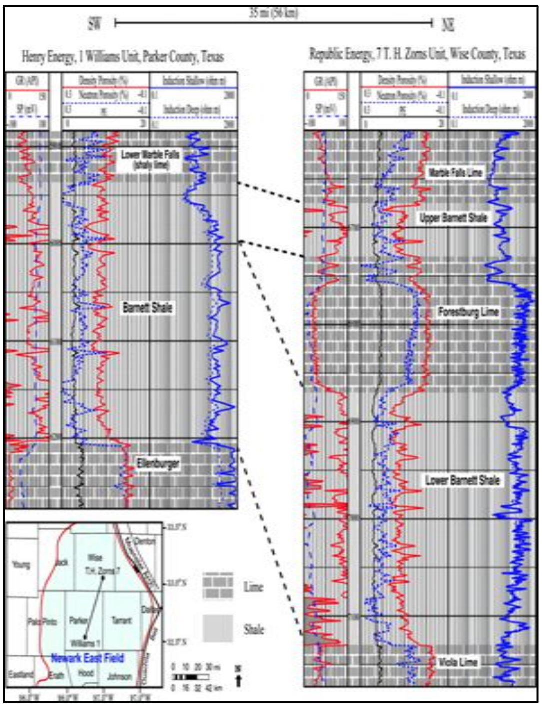

Figure 24 Barnett Shale Log [13]

Appendix A.2: Barnett Shale

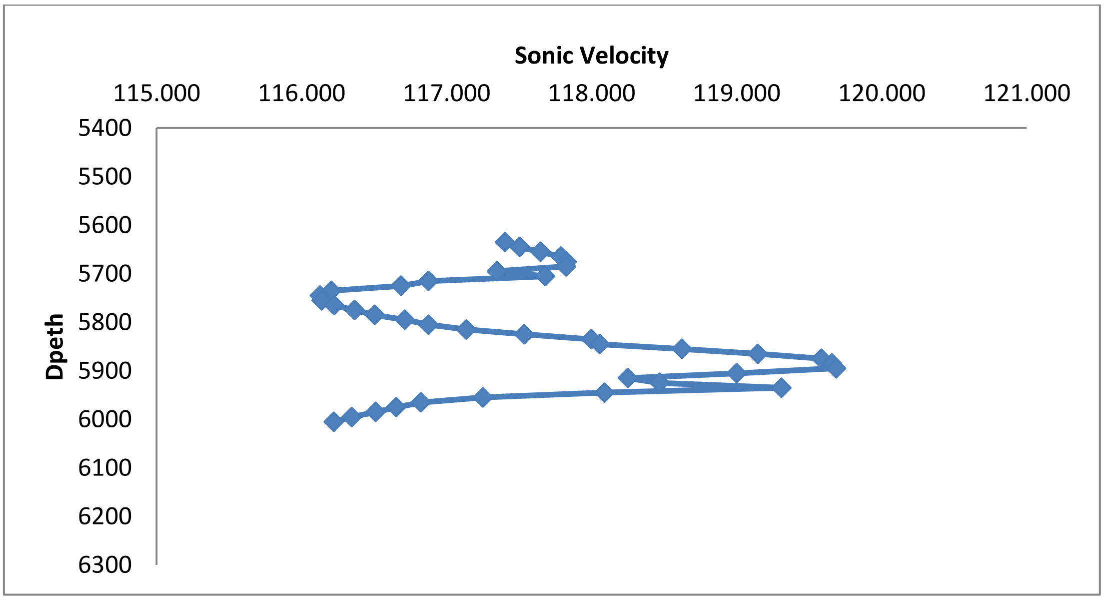

Figure 25 Sonic Velocity vs Depth Barnett Shale Well A

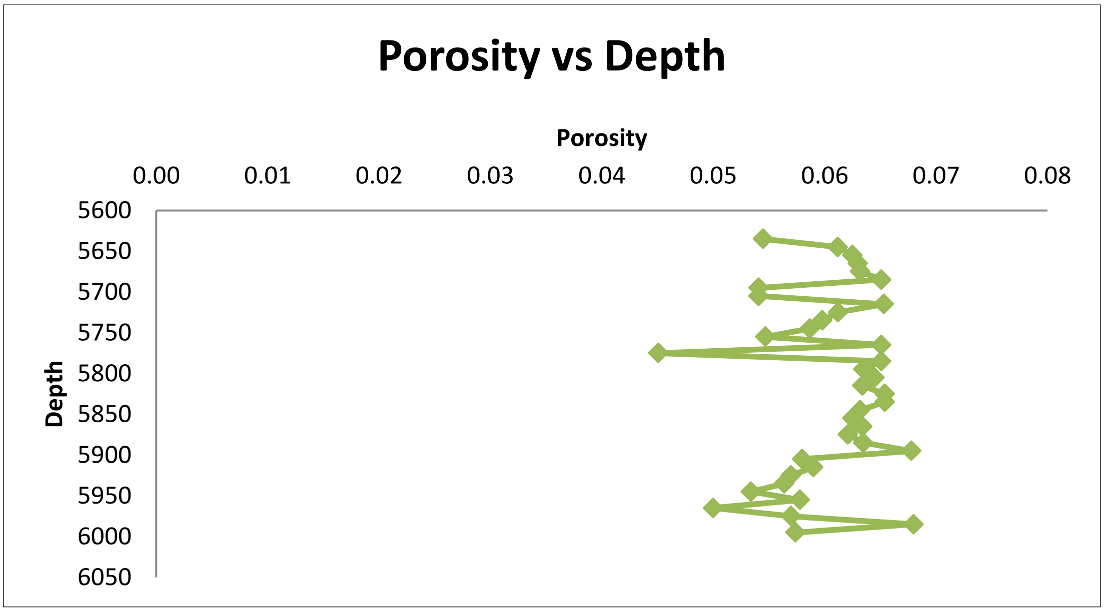

Figure 26 Porosity vs Depth Barnett Shale Well A

Appendix A.3: Barnett Shale

Well B

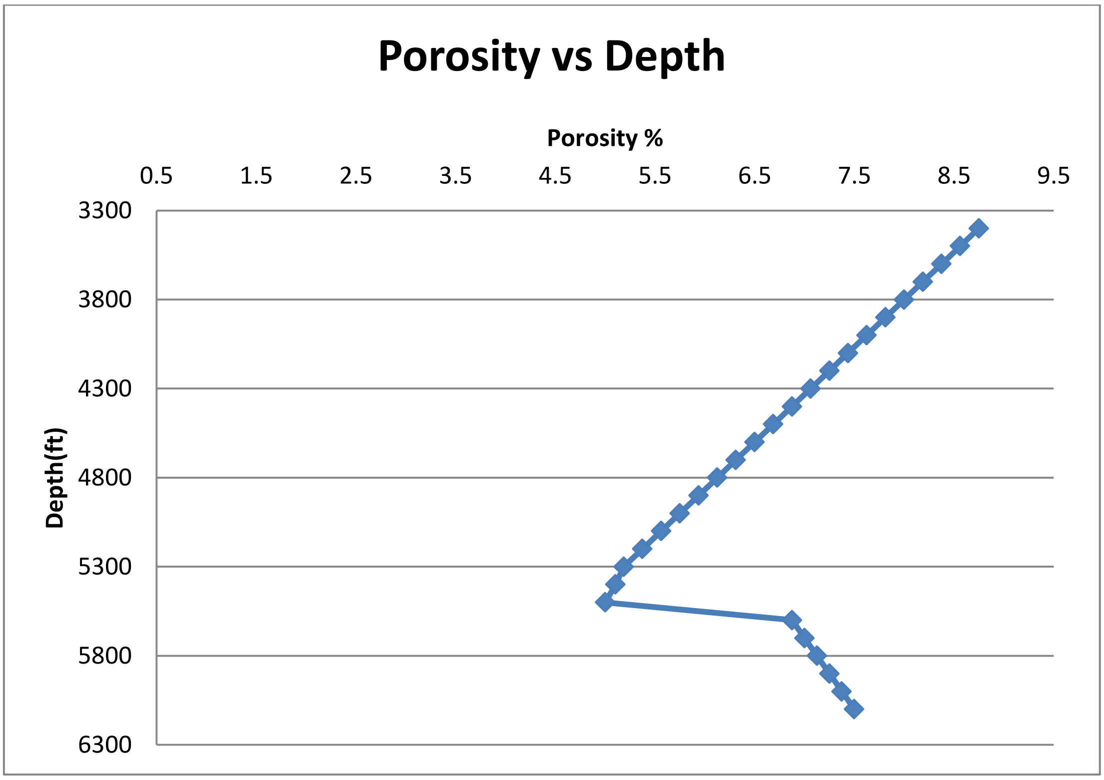

Figure 27 Porosity vs Depth Barnett Shale Well B

Appendix B Marcellus Shale

Well B

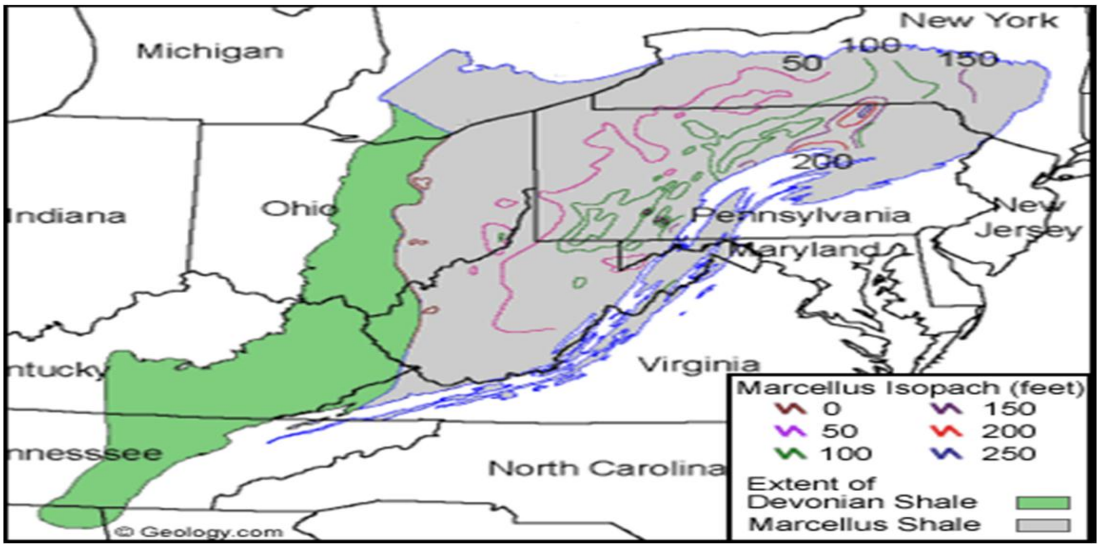

Figure 28 Marcellus Shale Area [14]

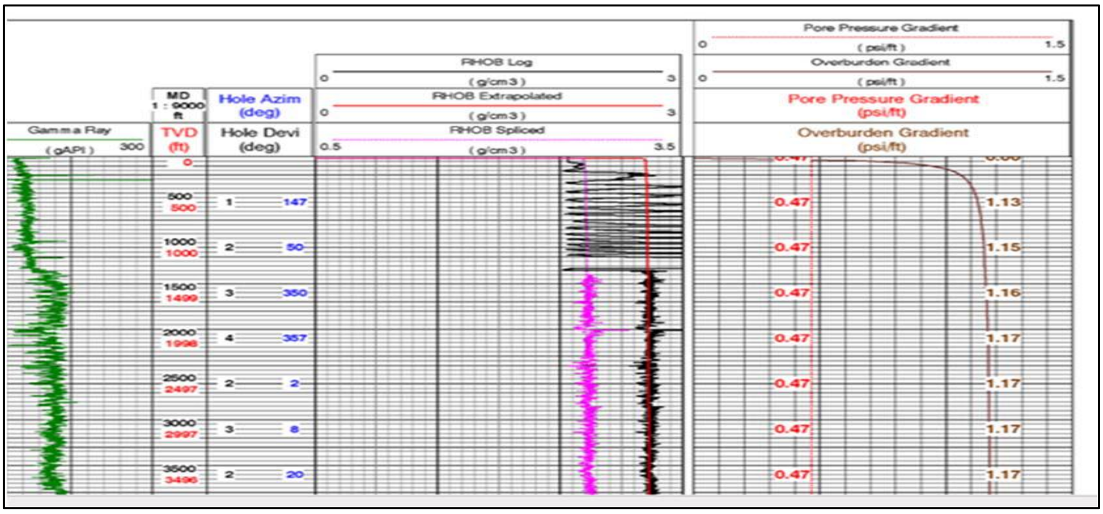

Figure 29 Well Log Marcellus Shale [14]

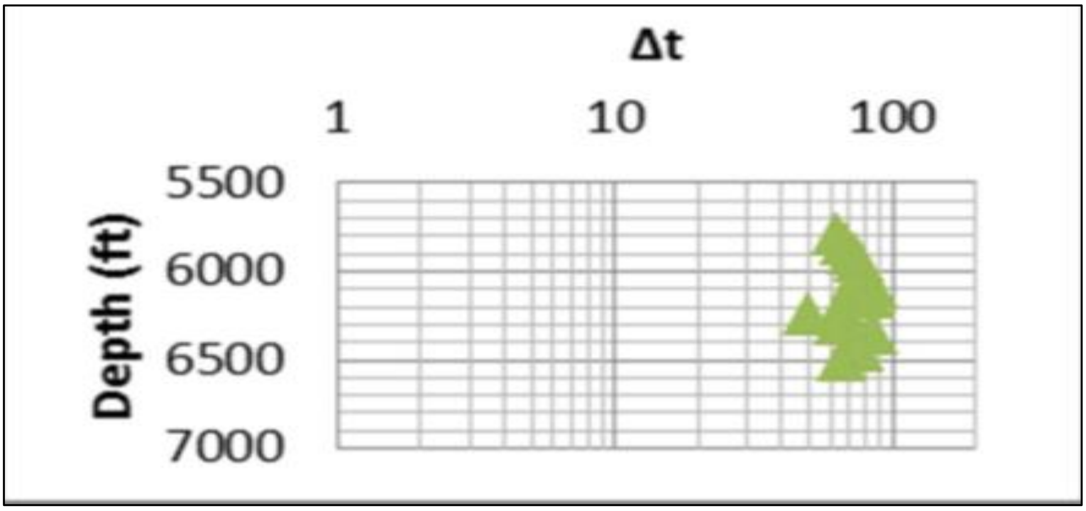

Figure 30 Sonic Velocity vs. Depth Marcellus Shale Well B

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