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# Formation Fracture Gradient Correlation for Niger Delta Basin Natural Gas Wells

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## Abstract

Offshore drilling of gas wells in the Niger Delta is becoming very expensive and requires high skilled manpower. Therefore, it is essential to accurately update the fracture pressure data, maintain adequate measurement while drilling and ensure acceptable prediction with the conventional empirical correlations as drilling operations is going on to avoid any Non-Productive Time (NPT) event. To effectively drill an offshore well and deliver it safely without endangering the safety of personnel, safeguard the environment and equipment, the drillers must ensure that the wellbore pressure is enough to balance the pore pressure without exceeding the fracture pressure anywhere along the open section of the well. In order to drastically reduce offshore drilling nonproductive time and take control the safety of men and materials on site, the need to calculate and predict fracture pressure is important. There are many correlations for predicting fracture pressure. However, they are mostly limited to onshore and shallow water fields, but as wells are being drilled deeper in Offshore Niger Delta field, there is the need to develop a correlation (equation) using offshore Leak-Off Test (LOT) report data that can reliably predict fracture pressure. Thus, this research adopts the concept of mathematical modelling technique to develop an improved offshore fracture gradient equation from Leak-Off test data to suit offshore Niger Delta needs was obtain to literature. The developed correlation (equation) was statistically analysed and it gave a reliable coefficient of determination. It was further tested with field cases and the results were comparable to Leak-Off Test results.

**Keyword:** Natural Gas Well, Formation Fracture Gradient Correlation, Niger Delta

## 1. Introduction

As the drilling of an offshore well is going on and the drillers drill deeper as shown in Figure 1, the pore pressure and fracture pressure increase, but not always precisely in tandem. When this happens, the drilling mud weight is increased to maintain the overbalance and prevent possible drilling flow of fluid from the wellbore into the formation (Altun, et al, 2001). The mud weight (wellbore pressure) required to balance the pore pressure is increased until it approaches the fracture pressure. At this point, the drillers install and cement a casing to protect the exposed formation from the wellbore pressure. After doing so, the drillers can drill deeper increasing the wellbore pressure as necessary without fracturing the formation. The accurate determination of formation fracture gradient is of utmost important to the drilling engineer to drill a well safely, efficiently and economically. A clear determination and interpretation of formation pressure is needed during well planning phase to choose correct casing setting depth, mitigate lost circulation events, mud weight selection and wellbore stability determination. There are a number of correlations developed by researchers for determining (predicting) formation fracture gradients.

The above widely used correlations for determining formation fracture gradient relates the fracture to the minimum in-situ stress without considering conditions to create or initiate fracture (`Oil Field Geomehanics). Considering fracture creation or initiation invokes the consideration of well geometry. Well geometry is important during fracture initiation because to initiate fracture, ressure is applied to the formation which as well generates compressive stress. But because of differences in the variation of formation around the world, there is often a disagreement between the fracture pressures of a section of a wellbore (Bourgoyne, 2010). Hence, the best available method is to intentionally create a small fracture at the top of the section and measure the pressure required to do so. This operation is called LEAK-OFF TEST

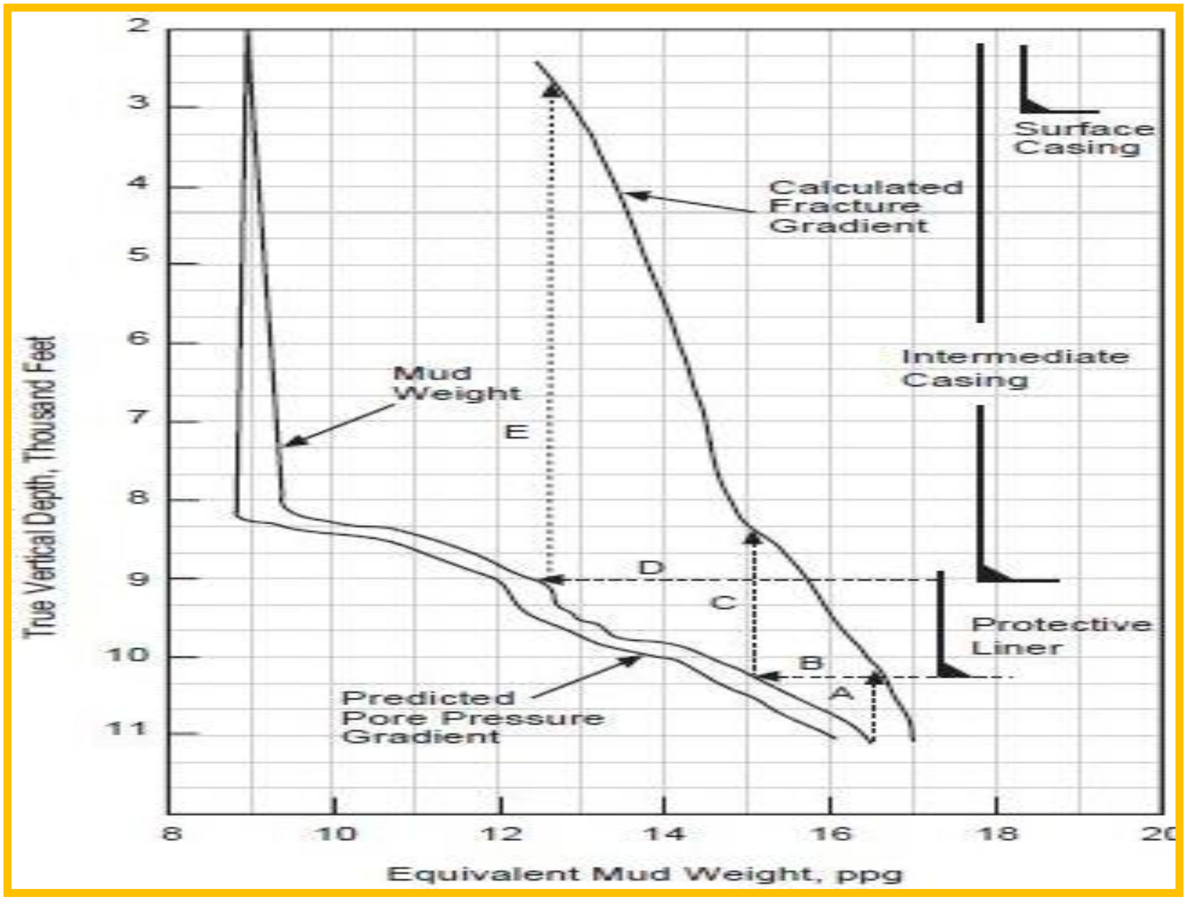


Fig. 1 : Pore pressure, Mud Weight and Fracture Pressure along (Lin, et al 2008)

LOT is used to determine the pressure at which the rock in the open hole section of the well just starts to break down (or "leak off"). In this type of test, the operation is terminated when the pressure no longer continues to increase linearly as the mud is pumped into the well. During a LOT, the blowout preventer is closed and the fracturing fluid is slowly pumped into the well. A linear response between the volume pumped and pressure is then observed. The LOT data as collated fall on a straight line due to constant pressure increase for incremental drilling fluid pumped. The straight line trend continues until Point A where the formation grains begin to loss integrity and allow mud to enter the formation. This pressure, departure point from the straight line at Point A, is the leak-off pressure (LOP) and used to calculate the formation fracture gradient. However, in some cases pumping is continued until a maximum test pressure is observed. Then, pumping is stopped at Point B, and the well is shut-in to observe the rate of pressure decline due to mud or mud filtrate loss to formations. The deviation from nonlinear behavior show a fracture initiation similar to a small volume hydraulic fracturing. The LOP is viewed as the pressure that initiate such fracture. But, this LOP represents a poor estimate of the minimum total horizontal stress. Hence, as much as it is often the practices to take LOP – depth trends as the minimum total horizontal stress as a function of depth. However, the advent of small powerful personal computers has led to the development of many inexpensive and comprehensive data modeling (correlations) and application procedures which allow for the manipulation and display of various types of well data. The three most commonly used correlations (Hubbert and Willis, 1957; Matthew and Kelly, 1967; and Eaton, 1969) in the oil and gas industry to determine fracture gradient have some short comings in that they do not consider the following: Condition to create or propagate fracture in the well, Geometry of the well and Differences in formation variations. Hence this study is carried out in order to proffer solution to the following problems: Nigerian oil industry needs to use fracture gradient correlation developed with data gotten from offshore delta formation. Nigerian oil industry needs fracture gradient correlation developed with data gotten by actually creating fracture in a well. The goal of this study is to develop an improve formation fracture gradient correlation with LOT data obtained from offshore Niger Delta. The developed correlation will help in the following: 1. Determine Fracture Pressure (FP). 2. Determine Leak-Off Pressure (LOP). 3. Determine Safe drilling margin

## 2. Review of Literature

### 2.1: General Principle of Leak-off Test (LOT)

Before a well is drilled, the pore pressure and facture pressure are predicted based on geologic and geophysical data. These predictions constitute the indirect method accessing information on formation stresses and it requires emperical correlations such as (Hubbert and Willis 1957) equation, (Matthew and Kelly 1967) correlation, (Eaton 1968) correlation, and (Christman 1973) equation. During a LOT, the blowout preventer is closed and the fracturing fluid is slowly pumped into the well. A linear response between the volume pumped and pressure is observed. The deviation from nonlinear behaviour during fracture initiation similar to a small volume hydraulic fracturing. The LOP is viewed as the pressure that initiate such fracture. But, this LOP represents a poor estimate of the minimuim total horizontal stress. Hence, as much as it is often the practice to take LOP – depth trends as the minimuim total horizontal stress as a function of depth, it is not recommended Modification of the conventional LOT by repeated pressurization known as extended leak-off test (XLOT) is more accurate way to determine the absolute mangnitude of the minimuim total horizontal stress (Altun et al, 2001). An XLOT is an extended version of a LOT, but it is also similar to the hydraulic fracturing test used for stress measurement. During an XLOT, pumping continues beyond the LOP point until the pressure peaks at formation breakdown pressure (FBP) as shown in Figure 2. This creates a new fracture in the borehole wall. Pumping is then continued for a few more minutes, or until several hundred liters of fluid have been injected, to ensure stable fracture propagation into the undisturbed rock formation.

The pumping pressure then stabilizes to an approximately constant level, which is called the fracture propagation pressure (FPP). Pumping then ceases (known as “shut-in”). The instantaneous shut-in pressure (ISIP) is defined as the point where the steep pressure decrease after shut-in deviates from a straight line. From the perspective of (Lin et al 2008), the most important pressure parameter is the fracture closure pressure (FCP), which occurs when the newly created fractures closes again. FCP is determined by the intersection of two tangents to the pressure versus mud volume curve (see Figure 2.2). The value of FCP represents the minimum principal stress, because the stress in the formation and the pressure of fluid that remains in the fractures has reached a state of mechanical equilibrium. Lin et al (2008) collected high-quality XLOT data and showed that both FCP and ISIP provide better estimates of minimum principal stress than LOP, although the difference in the values of LOP and ISIP was small. The point is that the simple LOT is quite adequate to determine fracture pressure of the formation, in lieu of the complex XLOT. In addition, ISIP is visually easier to determine than FCP. To end the test, the valve in rig floor is opened and some of the fluid in the borehole flows back into the fluid tank (known as “bleed-off”). To confirm the pressure values obtained from the initial XLOT, a second pressurization cycle is warranted. Because a fracture has been created by the first execution of XLOT, in the second cycle the pressure at the time of re-opening of the fracture corresponds approximately to the FPP of the first cycle. In general, it is advisable to conduct additional pressurization cycles beyond the second cycle in order to confirm that stable values of FCP and ISIP have been obtained.

### 2.1.1: Factors that Cause the nonlinear Deviation of LOT

LOT is a confirmatory test and as such its prediction is based on the pressure measurement while drilling. It follows that the anticipation that the next section of the reservoir formation to be drilled would follow previous trend of presure behaviour could be misleading. So, the potential deviation of LOT from straight-line behaviour need to be understood in order to arrive at an accurate analysis of the test.There are situation where LOT deviates from the ideal straight-line before fracture is common in offshore wells where leaks and interferences are frequent. In the nonlinear behaviour mode, the straight line behavour of the pump pressure and pump volumes is often masked therefore, conventional analysis is not suitable for this type of LOT. (Udai et al 2014) summarized the factors that cause the deviation to include: Heterogenity of the reservoir, Non-elastic behaviour of the rocks, Presence of Pre-existing Fractures, Bad Cementing Job, However, they showed that LOT is not influenced by pore pressure in any specifed direction as shown in Figure 2.

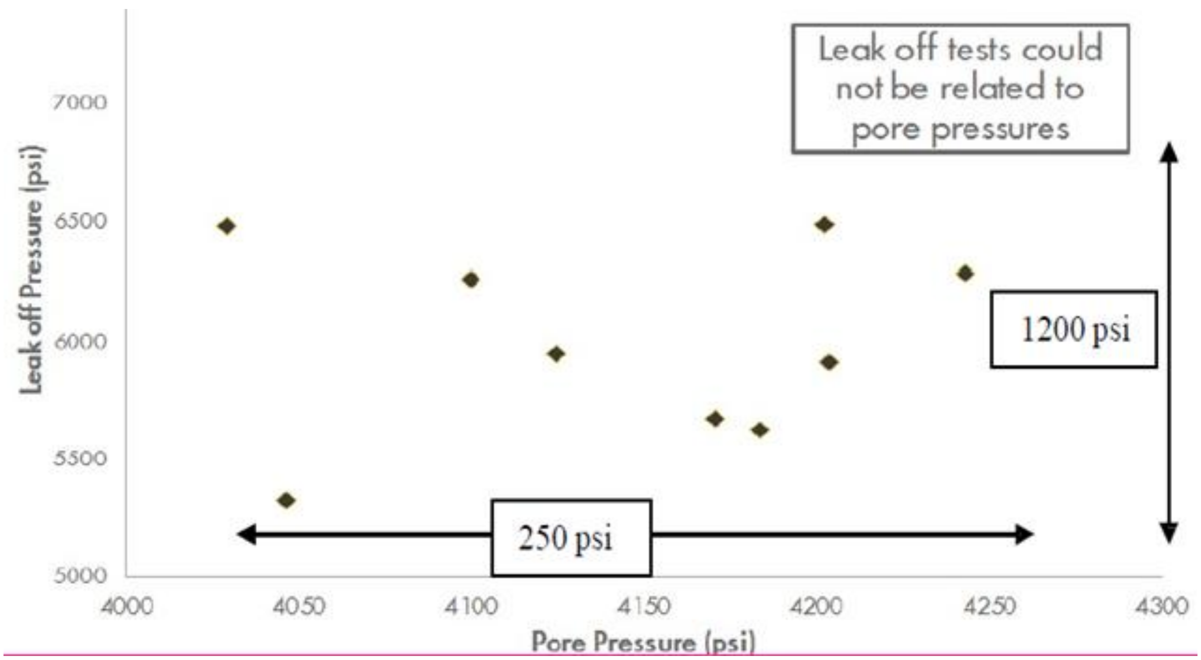


**Fig. 2.:** Leakoff pressure as a function of Pore Pressure (Udai et al., 2014)

### Heterogenity of the Reservoir

The anticipating that the LOT behaviour of a drilled section should apply to yet to be drilled section constitute a danger because the reservoir formation is heterogenous in nature. The question of reservoir heterogenity can be resolved by delinating the fornation into flow units. The idea of the flow units will give an insight into the anticipated varying behaviour of the well pressure along the borehole. Defining reservoir flow units means to assign a number, denoted by uniformity coefficient, which indicates the degree of departure of a homogeneity reservoir from uniformity of that particular measured property through the thickness of reservoir. A homogeneous reservoir has a uniformity coefficient of zero whereas a completely heterogeneous reservoir has a uniformity coefficient of unity. Between the two extremes, reservoir has uniformity coefficients comprised between zero and one. The uniformity coefficients can be modeled on the basis of hydraulic flow units. A novel model to represent reservoir heterogeneity is the development of Hydraulic Flow Units (HFU). The hydraulic unit is defined as the representative elementary volume of total reservoir rock within which geological and petrophysical properties that affect fluid flow are internally consistent and predictably different from properties of other rock volumes (Amaefule, et al, 1993).

### 2.1.3: Non-Elastic Behaviour of the Rocks

Rocks do not deform in a perfectly elastic-brittle way. One often observe a non-linear pressure – voilme response that makes the indentification of true leakoff point difficult. In addition to non- elastic rock behaviour, the compressibilty of the drilling fluids used for the test contributes to the non-linearity of the pressure – volume response. A non-linear response in the pressure-volume curve much below the expected LOP may not represent a true leakoff caused by fracture initiation. The pressure-volume response of the LOT must be carefully scrutinized to identify correct LOP indicating a true initiation.

### 2.1.4: Presence of Pre-existing Fractures

The formation exposed along the borehole during a LOT is typically a few meters, and thus much larger han during a mini-fracture test or macro-fracture test. The larger the exposed formation, the greater the chance of encouraging such natural fractures. A pre-existing fracture with zero tensile strength would have a lower fracture initiation pressure. However, as the tensile strength of sedimentary rock is generally low, it is not expected that a significant reduction in LOP due to this effect. Problems arise when the fracture dimensions are large, possibly twice more than the borehole diameter. In such case, the fracture initiation pressure can be significantly less than expected. For an intact borehole, failure in shear mode is generally preceded by failure in tensile mode.

### Bad ementing Job

An improper cement job can leave permeable channels through which drilling fluid can flow to shallower depth. In such a case, a leakoff may be created at a shallower depth that is not representative of the true LOP at the casing shoe. Typically, the LOP in such a situation is lower than expected, and a cement squeeze is recommended as a means to try to close such pathways.

**Indirect Methods of Estimating Formation stresses**

(Rocha 2004) identified that the methods of determining formation fracture pressure are the indirect and direct methods. Before drilling a well, engineers predict pore pressure and facture pressure based on geologic and geophysical data. These predictions are the indiect methods and requires emperical correlations such as (Hubbert and Willis 1957) equation, (Matthew and Kelly 1967) correlation, (Eaton 1968) correlation, and (Christman 1973) equation. After the well is drilled, the predicted pressures are continually upadated with actual measuments. The direct method therefore rely on actual measurement of the pressure required to fracture the formation and the pressure required to propagate the resulting fracture. The leakoff test (LOT), commonly known as the pressure integrity test (PIT), is a direct method which uses drilling mud to pressurize the well until formation fracture is initiated.

## 2.2: Fracture Pressure Models

### 2.2.1: Hubbert and Willis Fracture Pressure Model

Hubbert and Willis (1957) Fracture pressure model e.g., provided the foundation for the development of fracture pressure. They described fracture pressure gradient $g_f$ as a function of pore pressure gradient $g_p$, overburden pressure gradient $g_o$, and the effective stress ratio $K$ as follows:

$$g_f = g_p + K(g_o - g_p) \qquad 2.1$$

The overburden pressure has been either assumed to be 1.0 psi/ft or more correctly, evaluated from measured formation properties such as velocity data from seismic surveys, sonic logs, or integration of the bulk density log (Brannan and Annis, 1984). Pore pressure, necessary to convert total stresses to effective stresses has either been assumed as normal pressure gradient of 0.44psi/ft or in the case of abnormal pressure, evaluated from resistivity logs, actual formation test results, and sonic measurement. The conclusion is that overburden pressure and pore pressure can be accurately determined from measured formation properties. This leaves the effective stress ratio to be evaluated. Hubbert and Willis (1957) assumed a constant effective stress ratio of 1/3 in the regions of normal faulting, such as the US Gulf Coast area. Usually, effective stress ratio is developed as depth dependent from empirical correlations (Zhou and Wojtanowicz, 1999)

### 2.2.2: Mathew and Kelly Fracture Pressure Model

The (Hubbert and Willis (1957) model is not valid for deeper formation Matthews and Kelley (1967) presented a similar model to Hubbert and Willis but replaced the assumption that the minimum stress was one-third the matrix stress by a variable parameter. This is a Matthews and Kelley curves showing the variable stress ratio as a function of depth for two areas. For simplicity, Matthews and Kelley assumed that the average overburden stress is 1 psi/ft and an average pore pressure gradient is 0.465 psi/ft. The following procedure is adopted to calculate a fracture gradient by the method of Matthews and Kelley.

1. Obtain the formation pore pressure at the given depth as

$$p = g_p D = 0.465D \qquad 2.2$$

2. Determine the effective stress

$$\sigma = g_o D - p = 1.0D - p \qquad 2.3$$

3. Determine the depth at which the abnormal pressure occur by

$$D_i = \frac{\sigma}{0.535} \qquad 2.4$$

4. Use the value of $D_i$ from the preceding step to determine the effective stress ratio $K$, 5. With the resulting data, calculate the fracture gradient from the Hubbert and Willis model (see Equation 2.1), there are however two inherent weaknesses in the Matthews and Kelley model. One is the assumption that the overburden stress is equal to 1.0 psi/ft of depth. The other weakness is that the stress ratio used in calculating the fracture gradient in abnormally pressured formations is that of the deepest normally pressured formation. The Matthews and Kelly (1967) approach represents a significant advancement in fracture gradient technology, and the variable stress ratio concept is quite valid when compared with field data analysis (Eaton, 1969).

### 2.2.3: Eton Fracture Pressure Model

To improve the Hubbert and Willis model, Eaton (1969) developed the functional relationship of the effective stress ratio to the Poisson ratio *v* by

$$K = \frac{v}{1-v} \qquad 2.5$$

He therefore used the data of Costley (1967) to back-calculate the middle Poisson ratio curve of Figure 3.

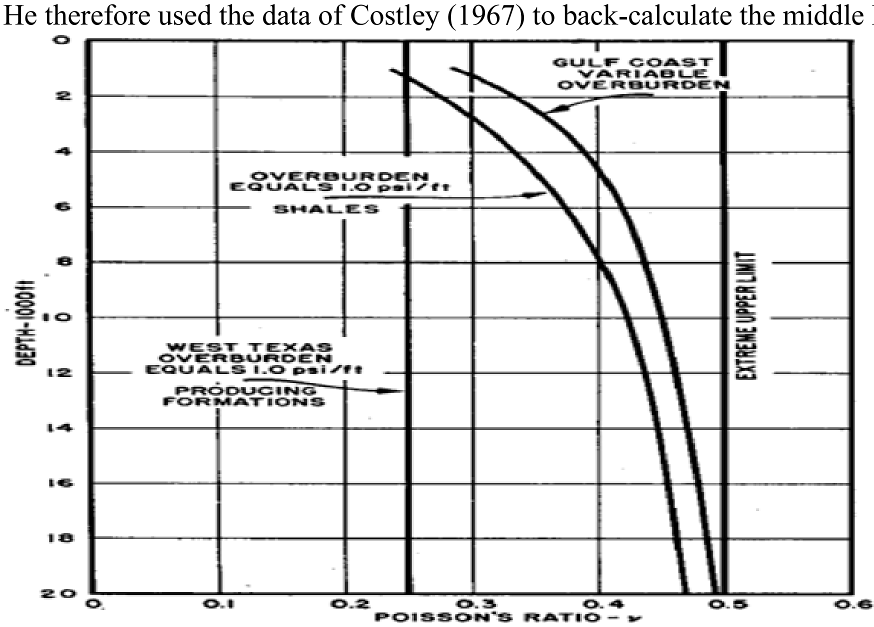


**Fig.3 :** Variation of Poisson's ratio with Depth

The curvature of the trend of Poisson ratio versus depth is observed to approach 0.5 as an upper limit. This limit is the Poisson ratio of an incompressible material in the plastic failure environment. Constant and Bourgoyne Jr. 1988) proposed that the effective stress ratio can be modeled as a function of sediment depth by

$$K = 1 - a e^{bD_s} \qquad 2.6$$

The sediment depth was used instead of the total depth because matrix stress starts at the mud line. Thus, changes in matrix stress caused by changing pore pressure are not accounted for in the calculation of effective stress ratio (Constant and Bourgoyne Jr., 1988). The coefficients *a* and *b in e*quation 2.6 can be chosen to fit local conditions. (Constant and Bourgoyne Jr. 1988) therefore, converted the Eaton's data for Poisson's ratio were converted to effective stress ration with Equation 2.5 and after least-squares analysis for the coefficients *a* and *b,* the working equation was obtained as

$$K = 1 - 0.629 e^{-1.28\times 10^{-4} D_s} \qquad 2.7$$

## 2.3: Analysis of LOT Based on Compressibility Equation

Altun et al (2001) provided a mathematical formulation to analyze nonlinear LOT was based on the compressibility equation and the material balance equation. The compressiblity equation was developed for three systems which include compresion of the drilling fluid, expansion of casing string and fluid leakage. If the compressibility equations are integrated to volume, then the material balance is that the total volume pumped is equal to volume contributed to drilling fluid compression plus volume contributed to casing expansion plus volume contributed to leak. That is

$$\begin{pmatrix} \text{Volume} \\ \text{Pumped} \end{pmatrix} = \begin{pmatrix} \text{Volume} \\ \text{to Mud} \end{pmatrix} + \begin{pmatrix} \text{Volume} \\ \text{to Casing} \end{pmatrix} + \begin{pmatrix} \text{Volume} \\ \text{to Leaks} \end{pmatrix} \qquad 2.8$$

The typical assumption for the ‘’appliocation” of the model are: isotropic formation, compressible and isothermal fluid. Again, the application of the formulation is restricted by extensive data requirement

## 2.4: Volume Contribution to Drilling Fluid Compression

The pressure change was derived from pumping drilling fluid into the well at a steady rate resulting to compression of well fluid. Such fluid compressibility was computed from the fluid compressiblity equation given by

$$c_f = -\frac{1}{V_o}\left(\frac{\mathrm{d}V}{\mathrm{d}p}\right) \qquad 2.9$$

The basic assumption is that the borehole was totally closed or isolated, ensuring that during the LOT the pressure boundary is essentially rigid and fixed. It can be seen from the Equation 2.9 that the negative sign signified an inverse relationship between the pump pressure and the pump volume. That is, the volume of the drilling fluid in the wellbore is decreased due to injection. Consequently, the pressure of the drilling fluid is increased. The fact is that decrease in fluid volume due to compression is a measure of pumped volume. On seperating variables and integrating Equation 2.9, the following relationship of pump pressure with pump volume is obtained

$$c\,p = \ln\left(1 + \frac{V}{V_o}\right) \qquad 2.10$$

This solution can be solved in terms of pumped volume as

$$V = V_o\left(e^{c\,p} - 1\right) \qquad 2.11$$

In essence, the drilling fluid is known to be slightly compressible and as such Equation 2.10 can be written for a slightly compressible fluid using Taylor series approximation of the exponetial function. That is

$$\ln(1 + x) = x - \frac{x^2}{2} + \frac{x^3}{3} - \frac{x^4}{4!} + \cdots \qquad 2.12$$

where $x$ is the argument $1+\dfrac{V}{V_o}$ in Equation 2.10. So, using Equation 2.12 into 2.10 gives:

$$c\,p = \frac{V}{V_o} - \left(\frac{V}{V_o}\right)^2 + \left(\frac{V}{V_o}\right)^3 - \left(\frac{V}{V_o}\right)^4 + \cdots \qquad 2.13$$

If it assumed that the volume pumped is far less than the intial volume in the wellbore, the powers higher than 1 are neglected. In that case, the approximate solution is given by

$$V = V_o c\,p \qquad 2.14$$

### 2.4.1: Volume Contribution to Casing Expansion

Consider the different principal stresses: radial stress $\sigma_r$, tagential or hoop stress $\sigma_\theta$, and vertical or longitudinal stress $\sigma_z$ acting on the casing string. The combined effects of these stresses will cause strain and therefore result in volume change.

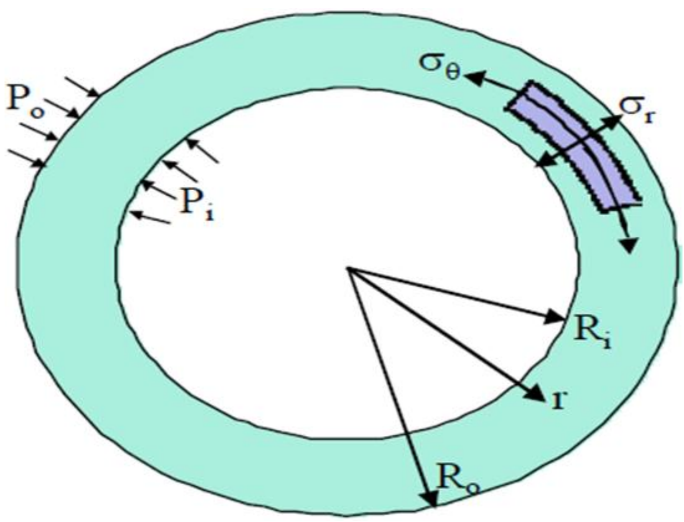


**Fig. 4. :** Different Stresses acting on a Casing String

However, it is assumed that there is no strain in the vertical irection and so there is only plain stress. The change in the vertical stress is then derived from the Hook's law which relates the principal stress and strain using linear elasticity concept. Thus, the equation predicting change in vertical stress with plain strain is given by

$$\sigma_z = v\left(\Delta\sigma_r + \Delta\sigma_\theta\right) \qquad 2.15$$

Where $v$ is the Poisson ratio. The strain caused by the change of the inside pressure is given from Hook's law as

$$\varepsilon_\theta == \frac{1}{E}\left(\Delta\sigma_\theta - \Delta\sigma_z\right) \qquad 2.16$$

Having found the vertical stress, Jaeger and Cook (1976) expressed the radial and tangential stresses as with the sign convention that compression and contraction are possitive while tension and elongation are negative.

$$\Delta\sigma_r = \frac{R_i^{\,2} R_o^{\,2}(\Delta p_i - \Delta p_o)}{R_o^{\,2} - R_i^{\,2}}\left(\frac{1}{r^2}\right) - \frac{R_i^{\,2}\Delta p_i - R_o^{\,2}\Delta p_o}{R_o^{\,2} - R_i^{\,2}} \qquad 2.17$$

$$\Delta\sigma_\theta = -\frac{R_i^{\,2} R_o^{\,2}(\Delta p_i - \Delta p_o)}{R_o^{\,2} - R_i^{\,2}}\left(\frac{1}{r^2}\right) - \frac{R_i^{\,2}\Delta p_i - R_o^{\,2}\Delta p_o}{R_o^{\,2} - R_i^{\,2}} \qquad 2.18$$

The radial and tagential stresses vary with radial location in the casing wall. The radial and tagential stresses on the inner-casing wall can be computed from Equation 2.17 and 2.18 y replacing the inner wall radius by any radius *r*. That is

$$\Delta\sigma_r = \Delta p \qquad 2.19$$

$$\Delta\sigma_\theta = \frac{R_i^{\,2} + R_o^{\,2}}{R_i^{\,2} - R_o^{\,2}}\Delta p \qquad 2.20$$

Using Equations 2.19 and 2.20 into 2.15 gives the vertical stress:

$$\sigma_z = v\Delta p\left(1 + \frac{R_i^{\,2} + R_o^{\,2}}{R_i^{\,2} - R_o^{\,2}}\right) \qquad 2.21$$

Equations 2.20 and 2.21 are used to compute the strain caused by pressure change inside the casing from Equation 2.16. Once the strain is obtained, the casing expansion volume is estimated using

$$V_c = \pi h R_i^{\,2}\left(2\varepsilon_\theta + \varepsilon_\theta^{\,2}\right) \qquad 2.22$$

Equation 2.22 is computed using Equations 2.16, 2.20 and 2.21 to have

$$V_c = 2\pi h_c R_i^{\,2}\,\frac{p}{E}\left[\frac{R_i^{\,2} + R_o^{\,2}}{R_i^{\,2} - R_o^{\,2}}\left(1 - v^2\right) + \left(v - v^2\right)\right] \qquad 2.23$$

This equation expressed the casing expansion volume as a function of pump pressure. The volume required to compress the drilling fluid created by attributed to casing expansion is given as

$$V = V_c c\, p \qquad 2.24$$

That is, the wellbore volume in Equation 2.14 is replaced with casing expansion volume to obtain Equation 2.24.

### 2.4.2: Volume Contribution to Leak

Leak is a condition in which the well well allows fluid losses. It was assumed that the is closed with constant volume and fixed boundary. In general, the leak volume is directly related to the pressure drop at any time of pumping. That is

$$V_L = Dt\,\Delta p \qquad 2.25$$

The pump time is defined as the ratio of pumped volume to flow rate given by

$$t = \frac{V}{q} \qquad 2.26$$

The leak constant *D* is modeled by the Poiseuille's law, which is used to model flow through a channel of fracture width *W*. supposing that the channel is in the form of a rectangle, then the leak constant was defined by Craft et al (1991) in field units as

$$D = 8.7 \times 10^{9} \frac{W^{2} A}{\mu L} \qquad 2.27$$

The cross sectional area of the fracture $A$ is equal to the product of the fracture width and the lateral extent of the fracture. Let's assume that the LOT allowes only volume pumping to cause fluid compression and leak, then the pumped volume becomes

$$V = V_{o} c\, p + V_{L} \qquad 2.28$$

Using Equations 2.25 and 2.26 into Equation 2.28 gives

$$V = V_{o} c\, p + D\, p \frac{V}{q} \qquad 2.29$$

The pumped volume occurred on both sides of the equation and so it is reaaranged to make the pumped volume the subject of the formula as

$$V = \frac{V_{o} c\, p}{1 - \frac{D}{q} p} \qquad 2.30$$

The term $Dp/q$ is always less than one and so the donominator of Equation 2.30 can be approximated usin the binomial expansion given by

$$\frac{1}{1 - \frac{D}{q} p} = \sum_{n=0}^{\infty} \left( \frac{Dp}{q} \right)^{n} = 1 + \frac{Dp}{q} + \left( \frac{Dp}{q} \right)^{2} + \left( \frac{Dp}{q} \right)^{3} + \left( \frac{Dp}{q} \right)^{4} + \cdots \qquad 2.31$$

So, using Equation 2.31 into 2.30 results to

$$V = V_{o} c\, p \left[ 1 + \frac{D}{q} p + \left( \frac{Dp}{q} \right)^{2} + \left( \frac{Dp}{q} \right)^{3} + \left( \frac{Dp}{q} \right)^{4} + \cdots \right] \qquad 2.32$$

The exact solution can be gotton by using Equation 2.12 for the first term in Equation 2.29 to have

$$V = \frac{V_{o} \left( e^{c\, p} - 1 \right)}{1 - \frac{D}{q} p} \qquad 2.33$$

### 2.4.3: Volume Contribution to Wellbore Expansion

In some rare cases there could be wellbore expansion due to loading. This leads to the assumption that the well is closed but the boundary is not constant. In reality, the wellbore expands due to loading from the original volume $V_{o}$ increased with pumping time to a new volume $V_{o} + V_{w}$. The term $V_{w}$ is the volume increment of the wellbore due to expansion caused by pumping pressure. The strain relationship is given from Young's Modulus expression as

$$\mathrm{d}p = E \mathrm{d}\varepsilon \quad \text{or} \quad \int_{0}^{p} \mathrm{d}p = E \int_{r_{o}}^{r_{o} + \Delta r} \mathrm{d}\varepsilon \qquad 2.34$$

But $\mathrm{d}\varepsilon = \frac{\mathrm{d}r}{r}$ such that

$$\int_0^p \mathrm{d}p = E \int_{r_o}^{r_o+\Delta r} \frac{\mathrm{d}r}{r} \qquad 2.35$$

Integrating Equation 2.34 and solving for the wellbore expansion with pump pressure gives

$$\Delta r = r_o\left(e^{p/E} - 1\right) \qquad 2.36$$

It followed that the volume increment due to expansion can be expressed by the simple geometric formula

$$V_w = \pi h\left[\left(r_o + \Delta r\right)^2 - r_o{}^2\right] \qquad 2.37$$

Substituting for radius expansion from Equation 2.35 into 2.36 gives

$$V_w = \pi h_w r_o{}^2\left(e^{2p/E} - 1\right) \qquad 2.38$$

The approximate solution for the expansion of the wellbore can be obtained using the first power approximation of the Taylor's series expansion of the exponential function to have

$$V_w = 2\pi h r_o{}^2\left[\frac{p}{E} + \left(\frac{p}{E}\right)^2\right] \qquad 2.39$$

Finally, the volume required to compress the volume created by the borehole expansion is given by

$$V = V_w c\, p \qquad 2.40$$

### 2.4.4: Overall Volume Contribution in LOT

The overall volume contribution in LOT equivalent to the pumped volume is the summation of all the sub-volumes contributed by fluid compression, casing expansion, leak and wellbore expansion. That is, if the wellbore radius is equal to the outer radius of the casing string then

$$V = V_o c\, p + 2\pi h R_i{}^2 \frac{p}{E}\left[\frac{R_i{}^2 + R_o{}^2}{R_i{}^2 - R_o{}^2}\left(1 - v^2\right) + \left(v - v^2\right)\right] + \frac{V_o c\, p}{1 - \frac{D}{q} p} \qquad 2.41$$

$$+ \pi h R_o{}^2\left(e^{2p/E} - 1\right)$$

Technically, the above equation demands the calculation of each component contributed by fluid compression, casing expansion and wellbore expansion from drilling fluid, casing and geometric data. The pumped volume is recored with the pumped pressure and therefore they are known. This leaves the leak term to be determined by difference. Thus, the summary of the method is outlined as:

1. Compute the volume contribution by fluid compression $V_f$ , casing expansion $V_c$ and wellbore expansion $V_w$ from Equations 2.11, 2.23 and 2.37 respectively at all the specified pumped pressure.
2. Using the pumped volume corresponding to a pumped pressure evalaute the volume contributed by leak as

$$V_L = V - \left(V_m + V_c + V_w\right) \qquad 2.42$$

3. From Equation 2.30, evalute the leak constant *D* at a given pumped pressure and volume. Plot the generated functions
4. Consequntly compute the channel width *W* from Equation 2.27 at all calculated *D*. Plot the generated functions.
5. The values of *D* and *W* corresponds to the region where the plots converged
6. Using the leak constant value and all other relavant information, generate Equation 2.40 such that the pumped volume is a function of pumped pressure.
7. Tune the generate function to match LOT history

## 2.5: Review of the Geology of the Niger Delta Basin

The Niger delta is located in the Gulf of Guinea in a rift triple junction related to the opening of the southern Atlantic started in the Late Jurassic to the Cretaceous see Figure 4. It is situated between latitudes 4$^o$ and 6$^o$ N and longitudes 4$^o$30’ and 8$^o$00’E. The Niger Delta is one of the world’s most prolific petroleum producing Tertiary deltas (Ojo and Tse, 2016).


**Fig. 4.:** General Map of the Niger Delta

The internal structure of Niger Delta basin is divided into three lithostratigraphic formations, namely: the upper sandy Benin Formation, a lower shaly Akata Formation, sandwiched by an alternating sandstone and shale called the Agbada Formation. A clay unit of the sandy Benin Formation called Afam is found in the Port Harcourt area. The shaley Akata Formation is a source rock which is estimated to be up to 7,000 metres thick and is composed mainly of marine shales, with sandy and silty beds which are thought to have been laid down as turbidites and continental slope channel fills (Ojo and Tse, 2016). It is overlain by the Agbada Formation and consists mostly of shore face and channel sands with minor shales in the upper part, and alternation of sands and shales in the lower part. The Agbada Formation has structural and stratigraphic traps resulting from movement under the influence of gravity. Generally, structural traps are predominant over stratigraphic traps. These include traps associated with simple rollover structures such as clay filled channels, structures with multiple growth faults, structures with antithetic faults, and collapsed crest structures. The primary seal rock in which are the interbedded shale within the Agbada Formation provide three types of seals namely: clay smears along faults, interbedded sealing units against which reservoir sands are juxtaposed due to faulting, and vertical seals (Doust and Omatsola, 1990). The rollover anticlines which occur in front of growth faults are the target of oil exploration. The Agbada Formation is the major reservoir from which oil is produced primarily from gas expansion. These reservoirs have average porosity of 40% and permeability of 200mD. Reservoir thickness ranges from less than 15m to 10% having greater than 45m thickness although thicknesses of 100 meters may be encountered (Edwards and Santogrossi 1990). The sandy Benin Formation consists of coarse grained, gravelly, poorly sorted, sub-angular to well-rounded sand. It is the most prolific aquifer in the region and comprises over 90% massive, porous sands with localized clay/shale inter-beds. Niger Delta aquifers range from localized, shallow unconfined aquifers up to 400m in the subsurface to deeper, laterally more extensive ones. The deeper aquifers may contain several clay layers which subdivide them into series of aquifers/sub-aquifers which are essentially independent units without hydraulic interconnection. These intermediate and regional-scale flow characteristics are desirable for sequestration.

## 3. Materials and Method

### 3.1: Leak-off Test (LOT) Procedure and Calculations

The LOT represents an experimental approach to determine the fracture pressure of an open formation. The sequence of LOT is outlined thus as shown in Tablie 1 in Run and cement casing, 2. Drill out about 10ft below the casing shoe, 3. Close the BOPs, pump fluid into the wellbore to slowly increase the wellbore pressure.

1. Monitor, measure and record the leak-off pressure (LOP) in terms of equivalent mud weight at which a leak into the open formation occur (see Table 3.1: The depth at which such leaks occur is measured and recorded in true vertical depth (TVD)
2. The minimum horizontal stress ($H_{min}$) is measured and recorded in terms of its equivalent mud weight.
3. For offshore wells, the water depths (WD) are also measured and recorded, such that the depth below mud-line ($D_{BML}$) is computed as:

$$D_{BML} = TVD - WD \qquad 3.1$$

**Table 1: LOT Data from Niger Delta Fields**

| Well Name | TVDss [ft] | WD [ft] | LOP [Psi] | Hmin [Psi] |
|---|---|---|---|---|
| NDW 1 | 3145 | 1089 | 2214 | 1995 |
| NDW 2 | 3850 | 1722 | 2444 | 2202 |
| NDW 3 | 2764 | 499 | 2050 | 1847 |
| NDW 4 | 2764 | 270 | 2042 | 1840 |
| NDW 5 | 4603 | 1942 | 3179 | 2863 |
| NDW 6 | 3054 | 1786 | 1798 | 1620 |
| NDW 7 | 5048 | 1812 | 3559 | 3208 |
| NDW 8 | 4963 | 806 | 3925 | 3536 |
| NDW 9 | 6538 | 270 | 5661 | 5100 |
| NDW 10 | 3550 | 1942 | 2182 | 1966 |
| NDW 11 | 3792 | 1812 | 2500 | 2252 |
| NDW 12 | 3212 | 1204 | 2225 | 2004 |
| NDW 13 | 1995 | 345 | 1534 | 1385 |
| NDW 14 | 1530 | 420 | 1111 | 1002 |
| NDW 15 | 4463 | 2365 | 2834 | 2553 |
| NDW 16 | 3856 | 1689 | 2448 | 2206 |
| NDW 17 | 4040 | 1552 | 2859 | 2576 |
| NDW 18 | 3008 | 420 | 2291 | 2065 |
| NDW 19 | 3208 | 420 | 2462 | 2219 |
| NDW 20 | 5087 | 2225 | 3444 | 3103 |
| NDW 21 | 4501 | 1204 | 3473 | 3129 |
| NDW 22 | 5741 | 1362 | 4224 | 3806 |
| NDW 23 | 1792 | 461 | 1324 | 1193 |

| | | | | |
|---|---|---|---|---|
| NDW 24 | 3026 | 1362 | 1928 | 1737 |
| NDW 25 | 2810 | 806 | 1946 | 1753 |
| NDW 26 | 3186 | 1132 | 2280 | 2054 |

### 3.2: Development of Fracture Pressure Correlation

Keaney et al (2010) summed-up 4 different methods for estimating fracture gradient as: minimum stress method, hoop stress method, fracture mechanics method, and direct method. Minimum stress method presupposes that considerable mud losses will occur when the wellbore pressure equals the minimum in-situ stress. Minimum stress methods are applicable for cases where near wellbore effects are negligible, including cases when the wellbore contains a large crack and rock tensile strength is negligible. Hoop stress methods are based upon analytical solutions for stresses around a wellbore, predicting massive loss when the mud pressure causes the minimum hoop stress to equal the rock's tensile strength. Hoop stress fracture gradient methods assume that leakoff is highly sensitive to near-wellbore effects (i.e., in the case where the wellbore is intact or contains only very short cracks). The fracture mechanics approach determines the conditions under which a fracture will begin and end propagating. Direct methods relate fracture gradient to some other parameter, such as depth. For the purpose of developing an improved offshore fracture gradient prediction correlation for the offshore Niger Delta region, the study focused on minimum stress method. The fundamental theory to the development of the correlation was hinged on matching LOT report data with a nonlinear power function that depends on some depth parameters as shown in Figures 5.

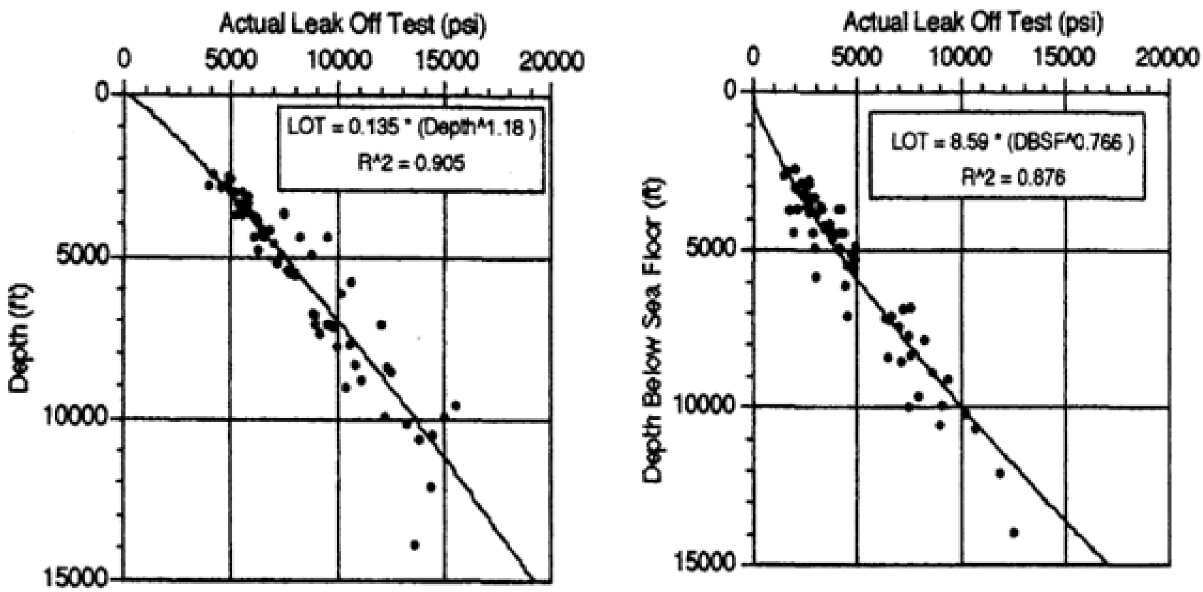


**Fig. 5**: LOP vs. Depth and Depth below seafloor for the Gulf Coast (Rocha and Bourgoyne, 1996)

Rocha and Bourgoyne (1996) observed that a correlation coefficient as high as 0.905 and that such high coefficient can be seen as a good indication that depth is one of the most important factors affecting fracture pressure. The pressure-depth relationship assumed by this study is therefore in the form given by

$$p(D,c) = a_o D_{BML}{}^{a_1} \tag{3.2}$$

Where

$$p(D) = LOP - 0.447WD \tag{3.3}$$

Here $p(D,c)$ and $p(D)$ are LOP computed and measured respectively below mud-level. The constant 0.447 represents the adopted pressure gradient of sea water in the Niger Delta region. It could vary slightly from other regions depending on the water salinity.

To find the unknown regression constants $a_0$ and $a_1$, initial guesses are required to tune the nonlinear equation to match measured LOP for a particular water depth. The fact is that all methods for nonlinear optimization are iterative. From a starting guess, the method produced series of solutions to the unknown constants which converged to a local minimum after some iteration counts. So, wrong guess of initial values of the unknown could either not converge at all or converge toward a saddle-point in lieu of a minimum. There is no guarantee that the use of any optimization method will necessarily give reliable match results. In particular, statistical optimization methods may suffer from several problems which limit the accuracy of prediction. However, it is always up to the judgment of the engineer to decide what effects may detract from a prediction.

The basic assumption in the application of statistical optimization model to a proposed mathematical model is that the data and the model are both correct. In some cases this assumption may not be guaranteed. When there are systematic errors in the data, then it is quite possible that an apparently good match to the model is obtained, yet the estimates from regression may be substantially in error. In general, there is no statistical method for detecting bias in the data. Instead, it is up to the judgment of the engineer to understand the quality of the data. However, recognition of the problem may allow for the determination of whether the regression estimates are high or low. Although statistical tests can sometimes show a modeling inadequacy, there is no substitute for engineering judgment. Only by fully understanding the physical properties and geological setting of the reservoir, can such modeling errors normally be identified.

Once the optimal regression constants are determined, statistical parameters are computed for the converged solution using the weight values. The weight value equals the mean square measurement of error. That is

$$w = \sqrt{\frac{\sum_{i=1}^{n}\left[p(D) - p(D, c)\right]^2}{n}} \qquad 3.4$$

The covariance matrix is then computed from

$$COV = \left[J^T wJ\right]^{-1} \qquad 3.5$$

and the asymptotic standard parameter error is given by

$$\sigma_p = \sqrt{\text{diag}\left[J^T wJ\right]^{-1}} \qquad 3.6$$

The asymptotic standard parameter error is a measure of how unexplained variability in the data propagates to variability in the parameters, and is essentially an error measure for the parameters. The standard error of the fit is given by

$$\sigma_V = \sqrt{\text{diag}\left[J^T wJ\right]^{-1} J^T} \qquad 3.7$$

### 3.3: Fracture Pressure Update Procedure

The least-square minimization problem is employed to develop an improved offshore fracture gradient correlation by calibrating LOT to a defined power function. If the LOT produced a fracture pressure -depth relationship $p(D)$, then the power function to which it was matched is defined by $p(D,c)$,$c$ being a solution vector whose elements is defined by the coefficient and exponent of the power function. The least-square minimization problem can be formulated as follows. An objective function $F(c)$ is defined as

$$F(c) = \sum_{i=1}^{n} r_i^{\,2} \qquad 3.8$$

where$n$ is the number of measured points. The elements of $r$ are dependent variables called residues. The residue expresses the relative difference between the LOT's pressure-depth relationship, $p(D)$, and the corresponding predicted fracture pressure, $p(D,c)$.

$$r_i = p(D) - p(D, c) \tag{3.9}$$

It can be observed that the predicted fracture pressure and the objective function are non-linear function of depth and some undefined constants (coefficient and exponent of the power function), and as such an iterative process is required. At iteration $k$, the location of the base point in the parameter space is defined by $c^k$, that is the value of $c$ at the $k$th iteration. The iteration procedure is continued until convergence is achieved, whenever, $\left[F\left(c^{k+1}\right) - F\left(c^k\right)\right] / F\left(c^k\right) < \varepsilon$, where for example $\varepsilon = 10^{-8}$. The procedure may also be terminated for other reasons, for instance, when the perturbation $\Delta c^k = c^{k+1} - c^k$ are very small. If it is assumed that $F\left(c^k\right)$ is continuous, and that its first and second derivatives exist, a minimum of $F\left(c^k\right)$ can only be found at a stationary point. That is a point where

$$\frac{\mathrm{d}F\left(c^k\right)}{d\,c} = 0 \tag{3.10}$$

$F\left(c^k\right)$is expanded in a Taylor series around the $k$th iteration $c^k$, such that ignoring third and higher order terms, the first and second derivatives of $F$ are described as follow:

$$\nabla F\left(c^k\right) = 2J\left(c^k\right)^T r\left(c^k\right) \tag{3.11}$$

$$\nabla^2 F\left(c^k\right) = 2\left[J\left(c^k\right)^T J\left(c^k\right) + Q\left(c^k\right)\right] \tag{3.12}$$

where the elements of the Jacobian matrix $\boldsymbol{J}$ are

$$J\left(c^k\right)_i = \frac{\mathrm{d}r\left(c^k\right)_i}{\mathrm{d}c} \tag{3.13}$$

### 3.3.1: Update Using Gauss-Newton Model

The Gauss-Newton model formulates the least-squares problem in the form

$$\left(J^T J\right)\Delta c^k = J^T r \tag{3.14}$$

Since the Hessian matrix is approximated by first derivatives of the residuals $\boldsymbol{r}$ and simplifies to $H = J^T J$, the solution to Equation 3.14 can be written as:

$$\Delta c^k = -H^{-1} J^T r \tag{3.15}$$

A necessary condition for a minimum to exist is that $\boldsymbol{H}$ is positive definite, that is, all eigenvalues of $\boldsymbol{H}$ are positive. When some or all eigenvalues of $\boldsymbol{H}$ are less than zero, the parameter space is a saddle point or a maximum. When Hessian matrix is singular or nearly so, its inverse does not exist, and Equation 3.15 has no solution. In this case, the Hessian matrix may have one or more eigenvalues equal to zero. Even when the eigenvalues are close to zero, the Hessian matrix approaches singularity. This leads to round-off errors in the inversion of Hessian matrix, and results in unrealistically large values of the perturbation at the iteration count $\Delta c^k$. Typically, this occurs when a regression parameter with a negligible effect on the sum of squares is defined, that is, a "null-effect" parameters. When the Hessian matrix is positive definite, the Gauss-Newton model results in a solution vector $\Delta c^k$ with a direction which always leads to a lower sum of squares in the neighbourhood of $c^k$. This is known as the property of truncation convergence. The solution obtained by the Gauss-Newton does not necessarily yield the global minimum. The algorithm called the LU decomposition yields a numerically stable solution to the linear systems of Equation 3.15. L is the lower triangular matrix of the Hessian and U is the non-singular upper triangular matrix. The QR decomposition process is about twice as expensive as Gauss elimination process and LU decomposition with or without pivoting.

### 3.3.2: Update Using Steepest Descent Model

A steepest descent model with solution vector given by

$$\Delta c^k = -J^T r \qquad 3.16$$

always guarantees the property of the truncation convergence, that is, reduction of the sum of squares of the residuals. But this model may not converge as fast as the Gauss-Newton model when the parameters are close to their optimal values. The Gauss-Newton model may fail to converge when the solution at the current iteration point is far from the solution and $F(c)$ is large. In this situation, the steepest descent model may be optimal. So, when the solution is far from the actual solution, the steepest model is employed but switches to Gauss-Newton model at close point. The switch parameter is defined by the error of prediction.

### 3.4: Procedure for Comparing Fracture Gradient Correlations

It is not all fracture gradient correlations are suitable for predicting fracture pressure of the offshore Niger Delta region for a number of technical and regional reasons. Preliminarily, the correlations are first screened for their predictive suitability based on some properties of the region in which they are to be applied. Then Suitable correlations are then ranked in accordance with performance. There are many complicated and intricate numerical models to assess the suitability of correlations to their application in different regions. Even analytical models require a momentousamount of data preparation and input, and considerable amount of computerresources for running each suitability check. To eliminate all these constraints in the evaluation of predictive suitability of fracture gradient predictions, the study developed an analytical screening model and a ranking procedure.

The raking algorithm employed by this study was adopted from the procedure developed by Rivas et al (1994). It is based on determining for each property (j) of the correlation (i), $P_{i,j}$, a corresponding normalized parameter $X_{i,j}$, defined by the following equation:

$$X_{i,j} = \frac{\left|P_{i,j} - P_{o,j}\right|}{\left|P_{w,j} - P_{o,j}\right|} \qquad 3.17$$

Where $P_{i,j}$ is the magnitude of property (j) in the correlation (i) being ranked. $P_{o,j}$ is the magnitude of property (j) in a fictitious correlation, called the optimum correlation, in which the magnitudes of the characteristic parameters have been defined such as to give the best prediction among the correlation to be ranked. On the other hand $P_{W,j}$, is the value of the property in another fictitious correlation, called the worst correlation, which is defined such as to give the worst prediction among the correlation to be ranked. The variable $X_{i,j}$, changes linearly between0 and 1. In the extremes, it will be zero if the magnitude of a property in a given correlation exactly coincides with the value of that property in the optimum correlation, while it will be one if it coincides with the worst correlation. The normalized linear parameters, $X_{i,j}$ are transformed to exponential varying parameters, $A_{i,j}$, using the following heuristic equation:

$$A_{i,j} = 100\exp\left(-4.6X_{i,j}{}^2\right) \qquad 3.18$$

The actual grading of correlation (i) is done using the elements of matrix $A_{i,j}$, instead of $X_{i,j}$, since it is considered that an exponential function is more adequate that a linear function, for comparing different elements within a set. The relative importance of each correlation parameter is taken into account using assigned weighting factors $w_j$ for each property (j), such that a final score $S_i$ is obtained for each correlation (i), according to

$$S_i = \sum_j A_{i,j} w_j \qquad 3.19$$

## 4. Results And Discussion

### 4.1: Newly Developed Offshore Fracture Pressure Correlation

LOP is the pressure at which the pressure-volume curve starts to deviate from a straight line. That is to say that LOP is the pressure at which a fracture is initiated at the casing shoe. During drilling, LOP can exceed the minimum horizontal stress due to the hoop (compressive) stress effect. So, LOP measured during a LOT in a well not intersected by geological faults is generally a good approximation for the upper bound of fracture pressure. On the other hand, LOP measured during a LOT in a well intersected by geological faults is generally a good approximation for the lower bound of fracture pressure. The offshore fracture gradient correlation was developed with 26 LOT data (see Table 3.1) measured from wells in different offshore Niger delta fields. The LOT data was used to update Equation 3.2 to give the fracqture pressure correlation for the Niger Delta as:

$$p_f = 0.591196 D_{BML}^{1.043856} + 0.447WD \qquad 4.1$$

Where

$$D_{BML} = TVD - WD \qquad 4.2$$

The newly developed correlation is dependent on depth below mud-level and water depth, such that whenever water-depth (WD) is zero, the true vertical depth (TVD) equals the depth below mud level ($D_{BML}$) and the computed LOP approximates onshore fracture pressure. Table 2: shows the statistical parameters associated with the nwely developed fracture pressure correlation.

**Table 2:** Statistical parameters of developed fracture pressure correlation

| **Statistical Analysis** | |
|---|---|
| **average percent relative error** | **-0.06559** |
| **percent standard deviation of the relative error** | **0.041768** |
| **standard deviation** | **0.867%** |
| **percent coefficient of determination ($R^2$)** | **0.994** |

These statistical parameters indicated that the newly developed accurately modelled fracture pressure correlation with coefficient of determination of 0.994 as shown by the performance plot in Figure 6. The correlation was further tested with an offshore Niger Delta well code named NDW 27 whose casing shoe is set at the depth 3911 ft and water depth of 558 ft to give fracture pressure of 3079.36 Psi as against 3082 Psi obtained from LOT. This amounted to average percent relative error of 0.0856%. The computation is readily compared to entire regression data as shown in Figure 7 It can be seen from the Figure 4.2 that NDW 27 data (shown by the blue point) lies almost on the regression line. The observation from Figure 4.2 is that a plot of fracture pressure less water pressure versus depth below the mud-level is a straight line. Conversely, a plot of fracture pressure versus true-vertical depth is not a straight line as shown in Figure 8 This nonlinearity is caused by the effect of water level, that is, if the effect of water is removed, then the plot of fracture pressure versus depth will result to a straight line.

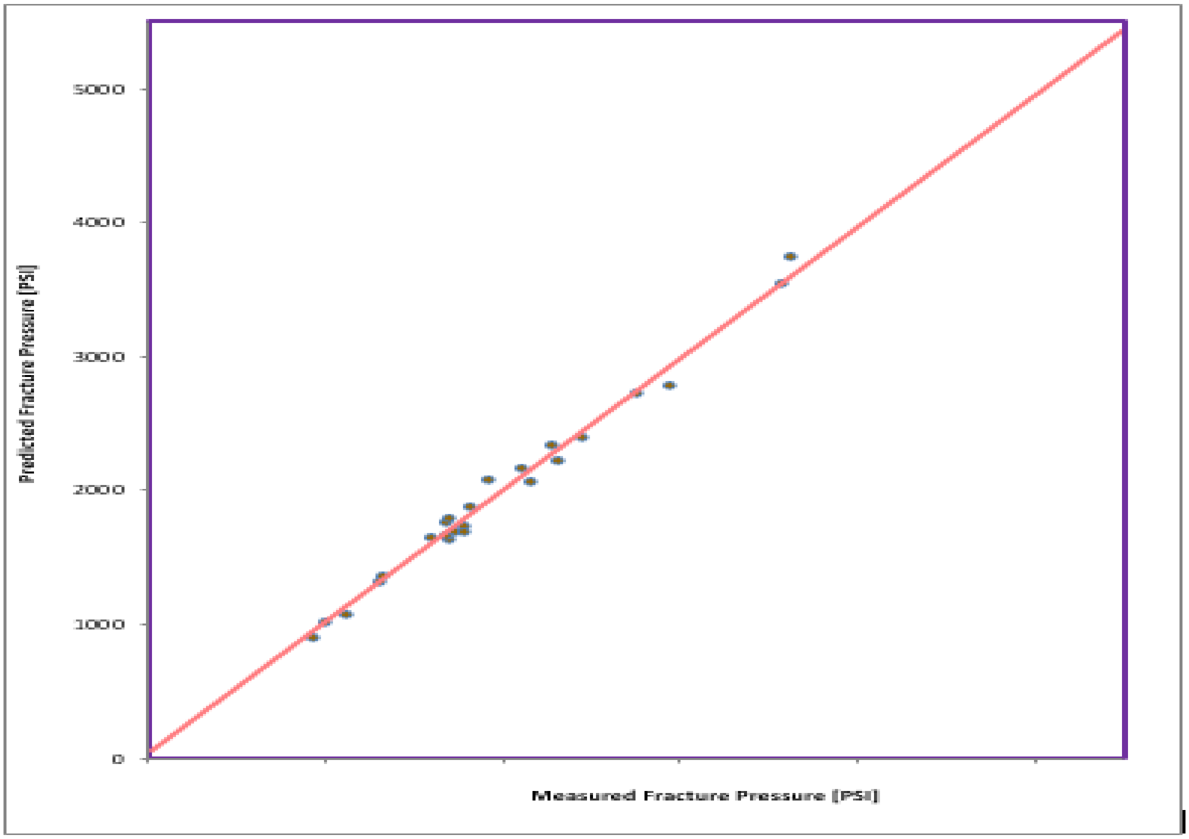


**Fig. 6.** : Fracture Pressure Performance-Plot

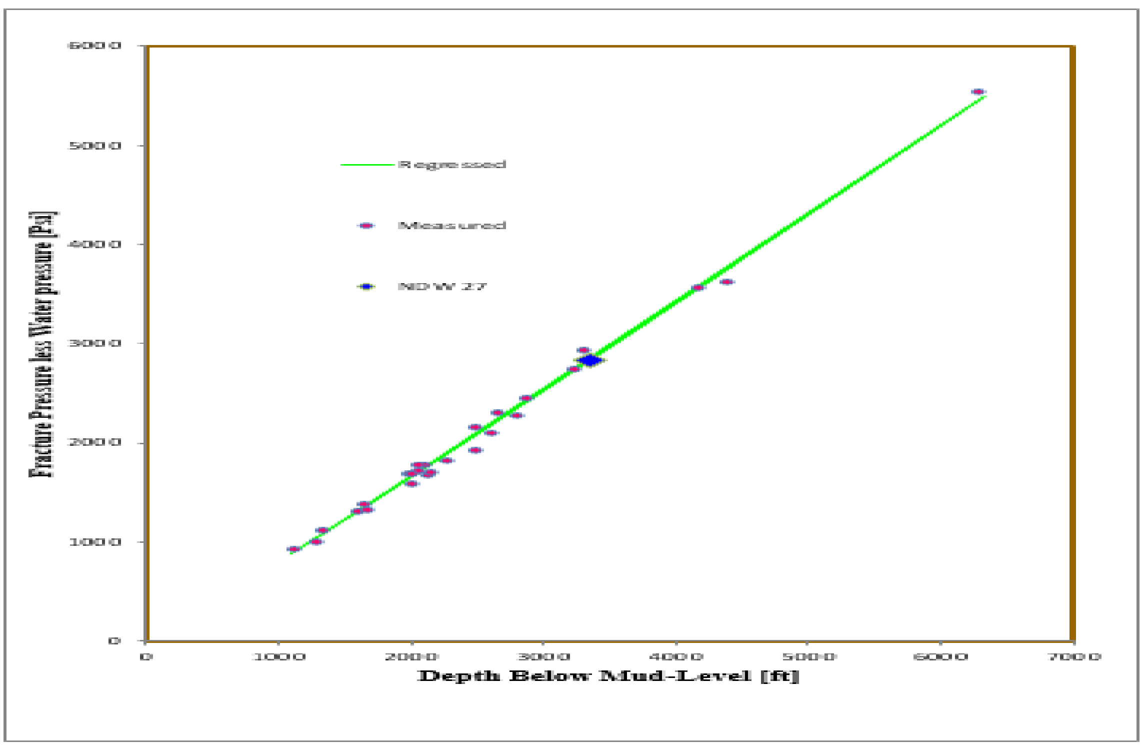


**Fig. 7.** : Fracture Pressure versus Depth below Mud-level

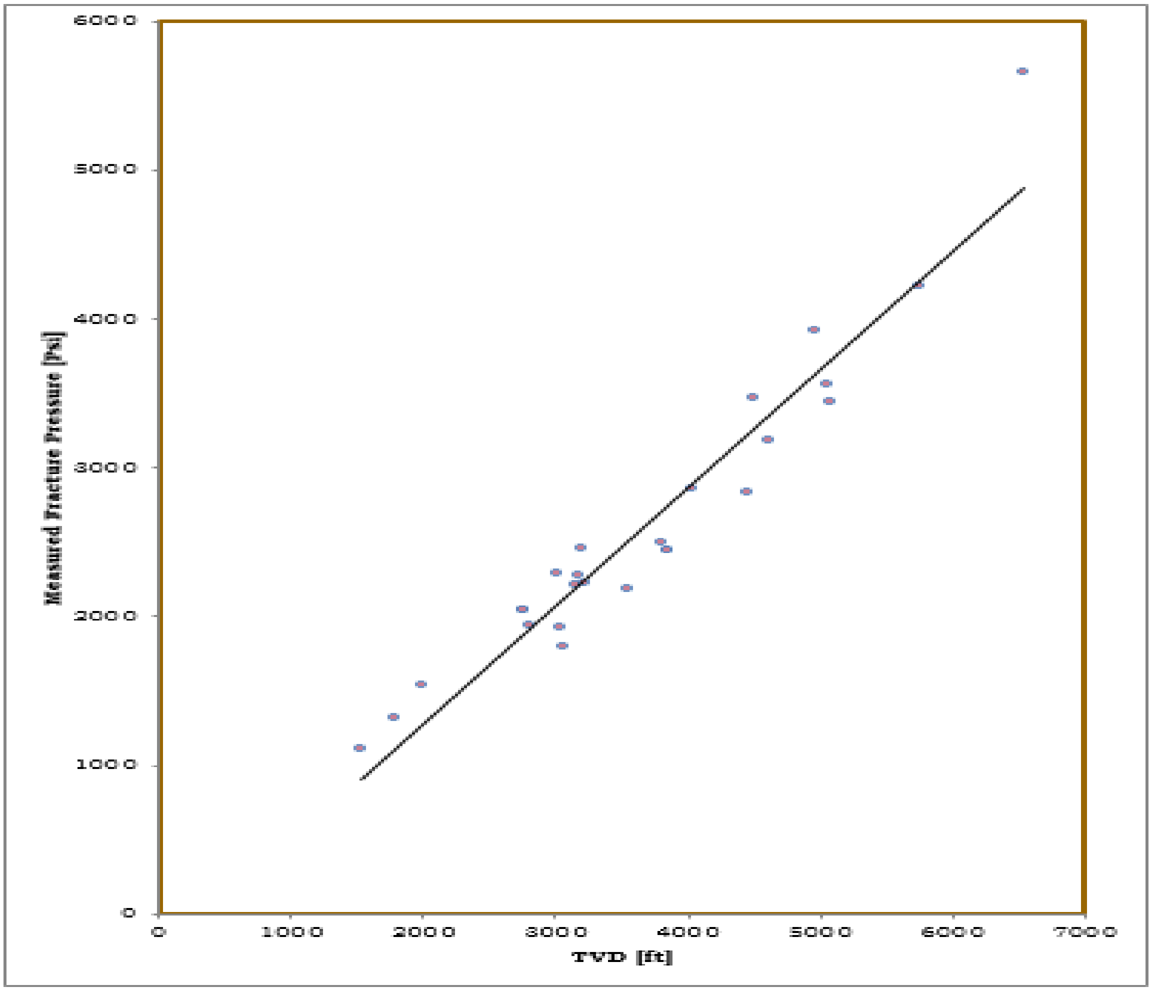


**Fig. 8:** Measured Fracture Pressure versus True Vertical Depth

### 4.2: Determination of Safe Drilling Margin

Aside the expected pore pressure, the fracture pressure helps to determine the safe drilling mud weight (SMw) for drilling operations. The maximum allowable pressure on the formation just lower than the casing shoe is usually expressed as an equivalent mud so that it can be compared with the mud weight to be used in the subsequent hole section. Given the fracture pressure, the safe drilling mud weight is given by:

$$SMw = \frac{P_f + 0.447WD}{0.052\,TVD} \qquad 4.3$$

This safe drilling margin tells the drillers that a static mud having the weight as computed by Equation 4.3 or higher could fracture the formation and therefore unsafe. So, using the LOT data collected from an offshore Niger Delta field, the safe drilling mud weight for each well is computed from Equation 4.3 as shown in Table 3

Usually a safety factor of 0.5 ppg equivalent to fracture gradient of 0.026 psi/ft is subtracted from the safe drilling mud weight. The justification for the safety factor is due to the fact that the next hole section to be drilled is usually a weaker formation than the drilled section on which LOT was conducted.

**Table 3.:** Equivalent Safe Drilling Mud Weight

| Well Name | TVDss [ft] | WD [ft] | LOP [Psi] | Safe Mud Weight, [ppg] |
|---|---|---|---|---|
| NDW 1 | **3145** | **1089** | **2214** | **13.54** |
| NDW 2 | **3850** | **1722** | **2444** | **12.21** |
| NDW 3 | **2764** | **499** | **2050** | **14.26** |
| NDW 4 | **2764** | **270** | **2042** | **14.21** |
| NDW 5 | **4603** | **1942** | **3179** | **13.28** |
| NDW 6 | **3054** | **1786** | **1798** | **11.32** |
| NDW 7 | **5048** | **1812** | **3559** | **13.56** |
| NDW 8 | **4963** | **806** | **3925** | **15.21** |
| NDW 9 | **6538** | **270** | **5661** | **16.65** |
| NDW 10 | **3550** | **1942** | **2182** | **11.82** |
| NDW 11 | **3792** | **1812** | **2500** | **12.68** |
| NDW 12 | **3212** | **1204** | **2225** | **13.32** |
| NDW 13 | **1995** | **345** | **1534** | **14.79** |
| NDW 14 | **1530** | **420** | **1111** | **13.97** |
| NDW 15 | **4463** | **2365** | **2834** | **12.21** |
| NDW 16 | **3856** | **1689** | **2448** | **12.21** |
| NDW 17 | **4040** | **1552** | **2859** | **13.61** |
| NDW 18 | **3008** | **420** | **2291** | **14.65** |
| NDW 19 | **3208** | **420** | **2462** | **14.76** |
| NDW 20 | **5087** | **2225** | **3444** | **13.02** |
| NDW 21 | **4501** | **1204** | **3473** | **14.84** |
| NDW 22 | **5741** | **1362** | **4224** | **14.15** |
| NDW 23 | **1792** | **461** | **1324** | **14.21** |
| NDW 24 | **3026** | **1362** | **1928** | **12.25** |
| NDW 25 | **2810** | **806** | **1946** | **13.32** |
| NDW 26 | **3186** | **1132** | **2280** | **13.76** |

## 4.3: Effect of Water Depth on Offshore fracture gradient

In a conventional offshore drilling, there is always a fine margin between the mud weight required to manage pore pressure and the mud weight that would cause an exposed formation to fracture. Figure 9 is a diagrammatic representation of the influence of various water depths on the fracture gradients (expressed in equivalent mud weight) on a casing set at 3500ft below mudline. It can be seen that there is a drastic decrease in fracture gradient as water depths increase: a decrease from 12.6ppg for a water depth of 500ft to 9.8ppg for a water depth of 13000ft. This effect occurs because the open hole formation in all necessity should support a column of mud that is heavier than seawater and the mud that extends far above the sea floor to the floating drilling vessel at the surface. Figure 9 Effect of Water Depth on offshore fracture weight. Figure 9 shows the effect of water depth of 499ft on NDW 3 at different drilling depths. It showed a normal offshore pressure trend in which the pore pressure is close to the fracture pressure. Indeed, every offshore driller is bound to encounter narrow drilling margins. However, the best way to manage narrow drilling margins is to carefully monitor and analysis the pressure trends and draw conclusion set more casing strings if desired.

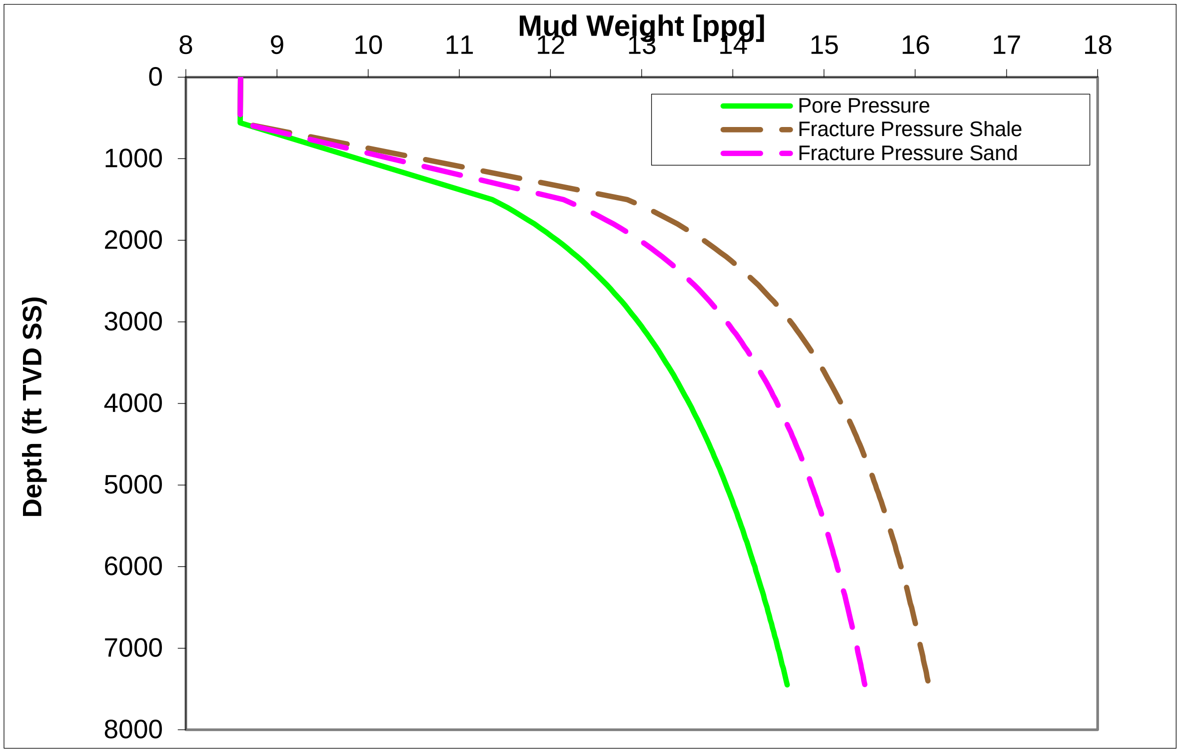


**Fig. 9:** NDW 3 showing pressure trends with depth for 499ft water depth

## 5.0 Conclusion

### 5.1 Conclusion

An improved fracture pressure correlation was developed using Leak-Off Test data from Offshore Niger Delta. The newly developed correlation depends on depth below mud level and water depth. The correlation was statistically analysed and it gave a 99.4 coefficient of determination. The correlation was further tested using field data and the results were compared with LOT data. The fracture pressure predicted with the correlation was used to establish safe drilling mud weight. Pressure profile trend of an offshore Niger Delta well was established.

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