Reducing Wellbore Stability Uncertainties While Drilling Through Depleted Reservoirs, Case study- Onshore, Niger Delta.

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Abstract

Generally, hydrocarbon production depletes the pore pressures within the sandstone reservoirs while the shale formations retain their original pressures especially in clastic environments. This leads to the narrowing of the safe mud weight window while drilling and increases the probability of the occurrence of wellbore stability issues such as loss circulation, tight spots, stuck pipe and hole collapse during drilling and casing run activities. The study area is predominantly sandstone unites with intercalations of shale formation. Depleted reservoirs were traversed while drilling through the intermediate (12-1/4”) hole section in well-7H. It was drilled with 9.0ppg equivalent mud weight (EMW) and an equivalent circulating density (ECD) of 9.6ppg EMW to the target depth. Wellbore collapse was observed while running casing string (9 5/8”), this prevented the casing string from getting to the hole bottom which led to the abandonment of the hole section and a consequent side-track. This paper presents the lessons learnt and best practices that were used for drilling the side-track well (7Hst) and subsequent wells in the X field. Prior to the drilling of the side-track, a one-dimensional mechanical earth model (MEM) was constructed using petrophysical logs and formation tests of well-7H and other offset wells. Shale pore pressure was derived from gamma-ray, resistivity and sonic logs using the Eaton’s and Bower’s methods, while sand pressures were measured/ estimated from modular dynamic testers (MDTs) and depletion models. The fracture gradient (FG) was derived using Matthew’s and Kelly equation. Shear failure gradient (SGF) was calculated using Modified Lade equations and log derived mechanical rock properties. The post-drill analysis of the offset wells was then calibrated with the drilling events and mud weights used. This revealed that the mud weight used to drill the 12-1/4” hole section in well-7H was inadequate. An optimum mud weight program coupled with close monitoring of ECD is a key requirement to successful well construction in the X field, where several reservoirs at various states of depletion, sandwiched by shale formations are traversed. These have led to several successful drilling operations in the field.

Introduction

The study area is in the western swampy region of the Niger Delta within the shoreface to shelf margin. The field consists of a series of fault assisted dip closures against two major structural building faults. The clastic stratigraphy is predominantly sandstone units within intercalations of shale formation deposited in a wave and tidal dominated deltaic complex during the Miocene age (Fig.1).

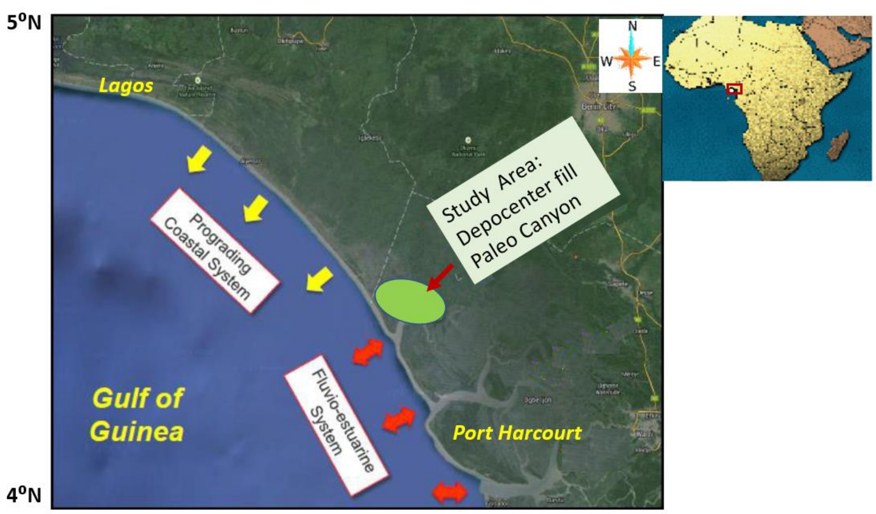

Figure 1. Location map of the study area.

Hydrocarbon production depletes the pore pressures within the sandstone reservoirs while the shale formations retain their original pressures. This leads to the narrowing of the safe mud weight window; drilling through the depleted reservoirs overlain or underlain by undrained formation (shale; with higher pore pressure) safely without having mud loses due to reservoir fracturing in the open hole and at the same time maintaining wellbore stability poses a challenge (Fig.2).

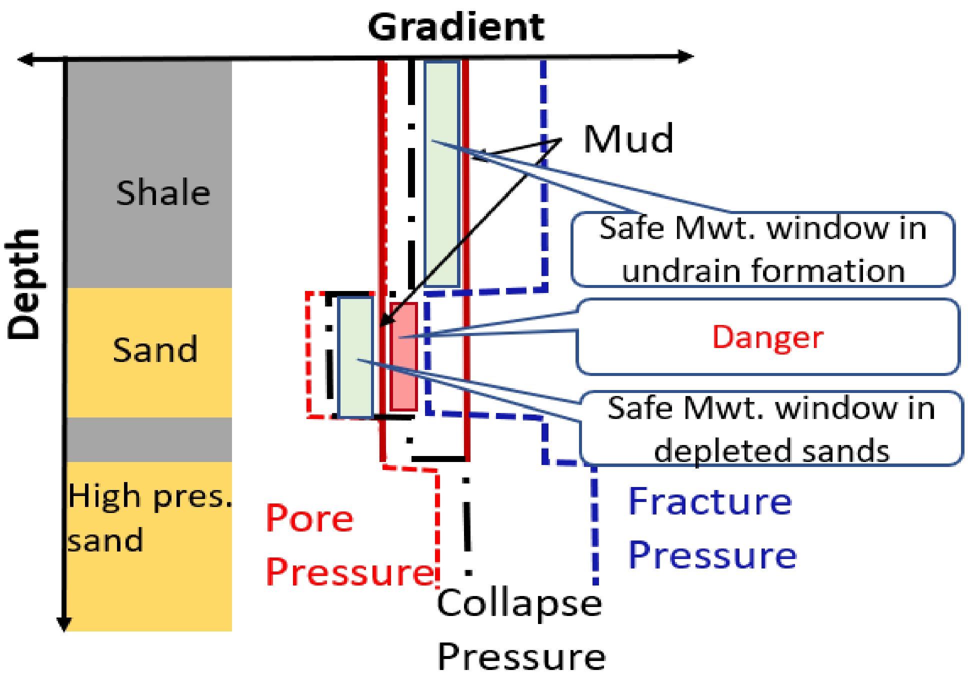

Figure 2. Wellbore stability conditions within shale, depleted sand and high-pressured sand.

Several studies showed that shale formation account for 75% of all formations drilled by oil and gas industry, and 90% of the wellbore stability problems occurs in shale (Ewy and Cook, 1990; Mody and Hale, 1993; Chen et al., 2003; and Coelho at al. 2005). Naturally, each rock is under stress, vertical stress due to overburden exerted by overlying formations and horizontal because of tectonic movements (Amadei, 1984). It is important to note that, a decline in pore pressure associated with fluid withdrawal from the reservoir results in in-situ stresses change within and surrounding the depleted reservoir. It is observed when a well is drilled, the formation around the wellbore must sustain the load that was previously taken by the removed formation. As a result, an increase in stress around the wellbore, and stress concentration will be produced (Zoback et al., 1985, and Roegiers 2002). If the strength of the formation is not strong enough the wellbore will collapse (Narayanasamy et al., 2009).

However, in the clastic stratigraphy of hydrocarbon formation, the shale formation overlain and underlain the sand/sandstone reservoir typically retains its initial pore pressure as the reservoir becomes depleted. Thus, a multi-pressure system is developed; the depleted zone itself and pressure barrier formations above and below the depleted reservoir as shown in figure 2. This can result severe wellbore stability related problems. Reduction in pore pressure in depleted reservoirs usually leads to a corresponding, reduction in fracture gradient, which is usually smaller in magnitude to the depletion (Hubbert and Willis 1957). On the other hand, bounding and inter-bedded shale layers, as well as any isolated and un-drained sands, will maintain their fracture gradient unchanged (Pouria et al., 2016). Thus, it may be difficult or impossible to reduce the drilling fluid density sufficiently to maintain equivalent circulating densities (ECD) below the depleted zone fracture gradient (Fig. 2 and 3).

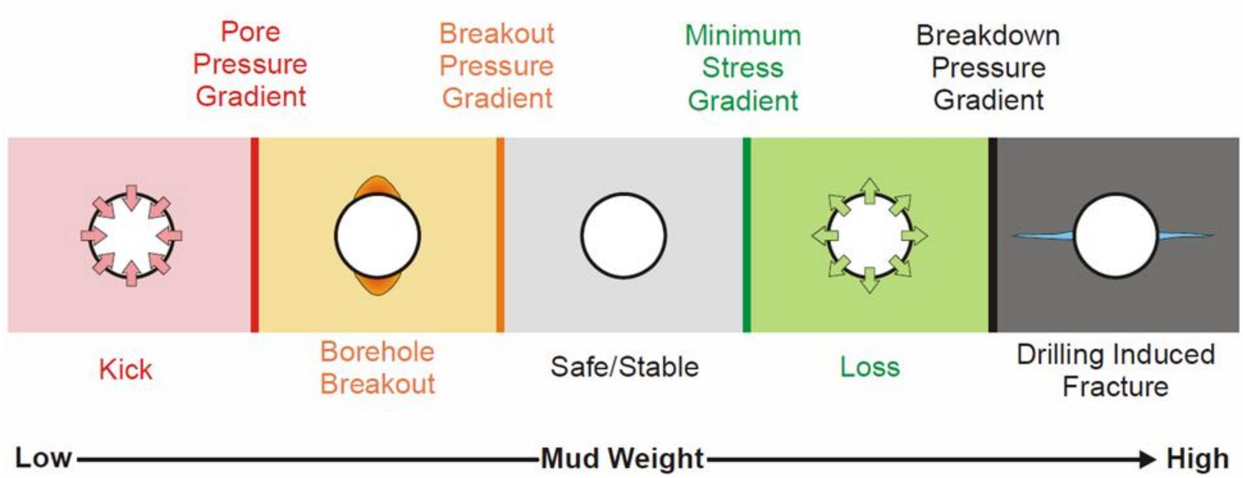

Figure 3. The concept of safe Mud Weight windows for drilling (Rasouli and Evans, 2010).

The depleted reservoir will be fractured leading to lost circulation when the wellbore pressure exceeds the fracture pressure of the formation rock, while wellbore collapse is very likely to occur in the upper shale formation when a lower mud weight is used to prevent lost circulation (Feng et al. 2015). Wellbore stability related issues such as hole collapse, stuck pipe, tight spots, and so on have become more significant in recent years in the E&P industry. This is because more than 70% of the oil and gas produced today comes from secondary or tertiary production (Meng and Fuh, 2010), as well as the increase of drilling more complex well trajectories to increase production (Pouria et al., 2016). The most problematic situation is to drill highly deviated or horizontal wells in reservoirs with large depletion along the maximum horizontal stress direction (Xiaorong et al, 2015). Wellbore instability account for over 40% of all drilling related non-productive time (Zhang and Lang, 2009) which amount over one billion dollars every year (Mohammad, 2012).

Several wellbore stability related issues have been reported in the literature over the years and models already been developed while drilling oil and gas wells (Vernik and Zoback,1990; Mastin et al.,1991; Last et al.,1995; Skelton et al.,1995; Okland and Cook,1998; Willson et al.,1999, 2003; Edwards et al., 2003; Brehm et al., 2006; Lang et al., 2011). The use of these models without the knowledge of the associated simplifications may lead to wrong applications/conclusions. In oil and gas well construction, mud weight should be appropriately selected based on the pore pressure gradient, fracture gradient and wellbore stability prior to setting a casing string.

This paper presents a simplified systematic approach used to overcome wellbore instability challenges encountered while drilling deviated oil producer well through shale formation and depleted reservoirs in the Gab field. The systematic approach combined pore pressure (PP), fracture gradient (FG), and wellbore stability (WBS) models with best drilling practices.

Methodology

The workflow and methodology applied before the drilling of the side track well includes, the building of a one-dimensional Mechanical Earth Model (MEM) using petrophysical logs and formation tests of well-7H and other offset wells. Shale pore pressure was derived from gamma-ray, resistivity and sonic logs using the Eaton's and Bower's methods while sand pressures were measured/estimated from modular dynamic testers (MDTs) and depletion models. The fracture gradient was derived using Matthew's and

Kelly equation. Shear failure gradient was calculated using Modified Lade equations and log derived mechanical rock properties. The post-drill analysis of the offset wells was then calibrated with the drilling events and mud weights used.

Table 1. Dataset Required for Mechanical Earth Model (MEM).

Data Source	Data Required	Remarks
Well logs	Gr, Resistivity, Sonic, Density, MDT/RFT, Image logs, Seismic and velocity	Strength prediction, overburden stress, stress direction and pore pressure.
Drilling	Pore pressure, mud weight, ECD, drilling report, mud log, PWD, and well test.	Calibration to drilling events, surge swab effects, pressure history and cuttings.
Completion/ production	Minifrac, reservoir pressure with time, and sand production recorded.	Calibrate to sand stress and sand production events.
Geology	Structural map/ cross section map and formation tops	Minoinum horizontal stress magnitude, maxium horizontal stress, calibration, world stress map and faults.
Core test	Hole collapse strength, shale (HCS), Shale swlling/fluid compatibility, unconfined compressive strength (UCS)	Strength calibration.

Pore Pressure (PP) Estimation

Formation pore pressure estimation is critically important during well planning/ design. It places constrains upon the design and ultimately the cost of the well. Inaccurate estimation of formation pore pressure can significantly increase the cost of the well, from over-engineering the well design, taking kicks, differential sticking, and lost circulation, to losing hole sections (Greenwood et al., 2007). Pore pressure gradient and fracture gradient are the two most important parameters practically required for determining the mud weight window. The drilling mud is applied in the form of mud pressure to support borehole walls for preventing formation fluid influx (kick) and wellbore collapse during well construction. Thus, having information about pore pressures during drilling and production phases of hydrocarbon reservoirs is of great importance to the E&P industry. Normal pore pressure at depth is equal to a hydrostatic pressure measured with respect to the Earth's surface. Abnormal pressures either over-pressure which is higher than normal or under-pressure which is lower than normal are generated by various mechanisms. Notable among the over-pressure generation mechanism in the hydrocarbon fields are compaction disequilibrium, hydrocarbon generation, thermal expansion, tectonic compression and mineral transformations (Gutierrez et al., 2006).

Formation pore pressure can be obtained using direct or indirect methods. Direct method is expensive and time consuming (Chopra and Huffman, 2006), and can provide information only in few depths along the wellbore within the reservoir. It utilizes formation tester such as modular dynamic formation tester (MDT) or Drill StemTest (DST) to measure pore pressure. indirect methods utilizing measured petrophysical data such as resistivity, sonic and density measurements which respond to the relative differences in porosity and compaction within the over-pressured and under-compacted zones. Several indirect methods have been developed to predict formation pore pressure gradient (Eaton, 1975; Jordan and Shirley, 1996; Lopez et al., 2004; Zhang, 2011). It is important to state that formation pore pressure can be computed from the various techniques by solving the Terzaghi and Peck (1948) equation, which take the form;

Overburden pressure (S) = Matrix stress (σ) + Pore Pressure (P_p) ………. (1)

Among these methods, Eaton method is the most commonly used in predicting pore pressure in wells where sonic or resistivity logs are available. The general form of the equation is:

$P_p = S_v - (S_v - P_n)\,(A_{obs}/A_{norm})^X$ ……….. (2)

Where P_p = the pore pressure; S_v = the total vertical stress (Overburden); P_n = the normal pressure (hydrostatic); A_{obs} = the observed attribute; A_{norm} = the attribute when pore pressure is normal, and X = an empirical constant, 3 for velocity data and 1.2 for resistivity and dc exp.

The equation can also be formulated as following (Zhang, 2011):

$P_{pg} = OBG - (OBG - P_{pn})\,(NCT/\Delta t)^3$ ……….. (3)

Where, P_{pg} = the pore pressure gradient; OBG = the overburden stress gradient; P_{pn} = the normal pore pressure or hydrostatic pressure; Δt = the compressional wave transit time (slowness); and NCT = the normal compacted trend line obtained through fitting a linear or non-linear curve to the compressional wave log data.

To use this equation, overburden stress is calculated using density log. Hydrostatic pressure can also be estimated based on assumption of brine density since after reaching an approximate depth of 90 m, brine is replaced with freshwater in subsurface layers due to decomposition and solution of minerals (Zhang, 2011). Some of the limitations with this technique include that normal compaction trend is developed by plotting the parameter against depth and not plotting the parameter against stress, as it the stress that drives the compaction (Greenwood et al., 2007). The relationships are also only applicable to clean shales and the empirical constants can differ from basin to basin.

Fracture Gradient (FG) Estimation

Fracture gradient is another important parameter required for mud weight design during well planning and drilling operations. According to Schlumberger Oilfield Glossary, it is defined as the pressure gradient required to induce fractures in the rock at a given depth. Meanwhile, fracture pressure is the pressure required to fracture the formation or rock. Thus, fracture gradient is the maximum mud weight that a well can hold without fracturing the formation or causing uncontrolled tensile failures. In other words, it is the upper boundary limit of the mud weight window; hence, if the downhole mud weight is higher than the formation fracture gradient, then the formation will be fractured (tensile failure), thus causing losses of drilling fluid or even lost circulation.

Several empirical and theoretical equations and applications for fracture gradient prediction have already been developed (Hubbert and Willis, 1957: Haimson and Fairhurst, 1967; Matthews and Kelly, 1967; Eaton, 1969; Anderson et al., 1973; Althaus, 1997; Pilkingtonm, 1978; Daines, 1982; Breckels and van Eekelen, 1982; Constant and Bourgoyne, 1988; Aadnoy and Larson, 1989; Wojtanowicz et al., 2000; Barker and Meeks, 2003; Fredrich et al., 2007; Wessling et al., 2009; Keaney et al., 2010; Zhang, 2011; Oriji and Ogbonna, 2012). Hubbert and Willis (1957) proposed the minimum injection pressure theory from which the concept and estimation of fracture gradient came from; this assumes that the minimum injection pressure to open and extend a fracture is equal to the minimum stress:

$P_{min.\ inj.} = \sigma^{ef}_{h} + P_p = \sigma_h$ …….. (4)

where $P_{min\ inj.}$ = the minimum injection pressure; σ^{ef}_{h} = the effective minimum stress; σ_h = the minimum stress; and P_p = the pore pressure.

They further stated that under normal faulting condition, the effective minimum stress is horizontal and has a value of approximately one third of the effective overburden stress. Thus, equation (7) can be written in the following form:

$P_{min.\ inj.} = 1/3\ (\sigma_v - P_p) + P_p$ …….. (5)

where σ_v is the vertical stress.

The determination of horizontal stress is vital, since opening a crack to a certain extension is proportional to the tension created perpendicular to the crack. Matthews and Kelly (1967) introduced a variable of the ''matrix stress coefficient (k_1)'' equivalent to effective stress coefficient, for calculating the fracture gradient of sedimentary formations. Considering the variable- effective stress coefficient, fracture gradient estimation based on the concept of the minimum injection pressure proposed by Hubbert and Willis (1957) takes the form:

$FG = k_0\ (OBG - P_p) + P_p$ ……….. (6)

$k_0 = (LOT - P_p) / (OBG - P_p)$ …….. (7)

where OBG = the overburden stress gradient; P_p = the pore pressure gradient; LOT = leak-off test data, and k_0 = the matrix stress or effective stress coefficient.

In this paper, Matthews and Kelly method was adopted for the prediction of fracture gradient. Normally the fracture gradient in sandstones is lower than that in shale formations. Therefore, depletion rate based on our GAB field experience was considered while estimating the most likely case of fracture gradient in the sandstones reservoirs.

Shear Failure Gradient (SFG) Estimation

Shear failure gradient is simply the pressure gradient at which formation collapses due to insufficient drilling mud weight to support the borehole wall. Thus, wellbore collapse occurs due to shear failure when the weight of drilling mud (drilling fluid pressure) inside the borehole is not enough to hold the wellbore, and wellbore pressure at this point is called collapse pressure.

Rock failure criteria are used to predict wellbore collapse and drilling induced fractures which are the main cause of having wellbore instability. Thus, accurate prediction of shear failure and tensile failure are required for an optimum mud weight selection to avoid any kinds of wellbore instability. Different rock failure criteria have been developed and used for wellbore stability analysis. It includes, Mohr-Coulomb, Drucker-Prager, von Mises, modified Lade criteria and others are proposed in the literature (Simangunsong et al., 2006; Zhang et al, 2006; Maury et al., 1987; Morita et al., 1993; McLean et al., 1990). The Mohr-Coulomb shear-failure criteria is one of the most widely used models for evaluating borehole collapse in different application. This model however neglects the effect of intermediate principal stress and is a linear equation in its nature; as a result, overestimates the minimum mud weight required to avoid formation break-out to occur (McLean and Addis, 1990). However, Fjaer and Ruistuen (2002) demonstrated that intermediate stress has considerable influence on rock strength and those criteria, which cannot consider this effect, are not often able to provide reasonable results. The shear-failure criterion can be expressed as;

$$(\sigma_1 - \alpha_p .P_p) \leq C_0 + (\sigma_3 - \alpha_p .P_p)\tan^2 \varphi \ \ldots\ldots\ldots(8)$$

In this study, modified Lade rock failure criterion was applied for the generation of shear failure gradient used in this work. Meanwhile, this failure criterion postulates that failure occurs when some function of the stress invariants reaches a critical value (Lade, 1977, Ewy,1999). Thus, formulation is:

$$(I_l)^3 / I_3 = 27 + \eta \ \ldots\ldots.. (9)$$

$$I_l = (\sigma_1 + S) + (\sigma_2 + S) + (\sigma_3 + S)$$

Thus, $l_3 = \sigma_1 * \sigma_2 * \sigma_3$
And $S = S_0 / \tan \varphi$; $\eta = 4 (\tan \varphi)^2 (9 - 7 \sin \varphi) / (1 - \sin \varphi)$ ………(10)

Depletion

It is good to know that in most cases, vertical stress is controlled by the weight of the overburden, and not by the pore pressure. In other words, overburden stress is commonly assumed to be constant with reservoir depletion. However, horizontal stress is affected by the pore pressure; as pore pressure decreases, horizontal stress also decreases, although not at the same rate. Stress change affects both collapse and fracture pressures; hence stress decrease may be of about 0.5 ppg for every depletion. Depletion affects sand/sandstones, not shale formations. So safe mud weight window shifts to the sands and remains unchanged in shales, making it difficult without causing reservoir fracturing or lost circulation see figure 2 above.

Theoretical models have been developed to express stress-depletion response of a reservoir, which depends on Poisson's ratio (v) and Biot's coefficient (α) (Aadnoy 1991). In building depletion models, depletion coefficient and critical depletion pressure were considered for efficient mud weight design. Critical depletion for mud weight window is greater or equal to ECD minus ESD tolerance. Depletion coefficient (DC) is simply defined as change in minimum horizontal stress per change in the formation pore pressure over the depleted sand/sandstone reservoir intervals. Mathematically, it is stated as following;

$$DC = \Delta S_{hmin} / \Delta P_p \ \ldots\ldots\ldots..(11)$$

Hence, $\Delta S_{hmin} = \alpha (1\text{-}2v / 1\text{-}v) \Delta P_p$

Therefore,

$$\Delta S_{hmin} = \alpha (1 - k'_0) \Delta P_p \ldots\ldots..(12)$$

$$\Delta S_{hmin} / \Delta P_p = ((1 - k'_0) .\ldots\ldots..(13)$$

Result and Discussions

The one-dimensional Mechanical Earth Model (MEM); a volume with a known earth stresses, rock strengths and material properties built using petrophysical logs, formation tests, leak-off test and drilling events from the well-7H and other offset wells were used to predict how the earth will behave along the sidetrack well location (Fig.4).

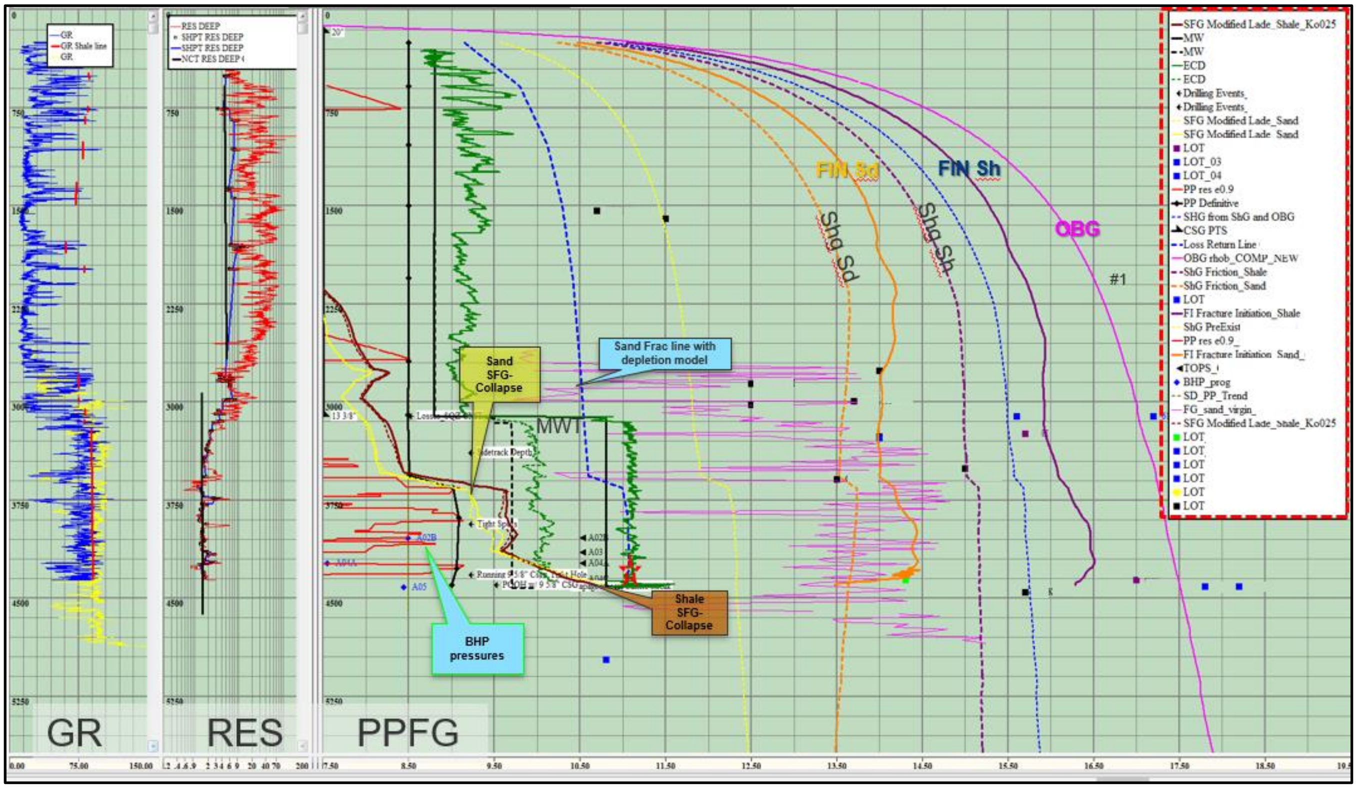

Figure 4. Mechanical Earth Model (MEM) for GAB-7Hst well. *Note: SFG = shear failure gradient, Shg = minimum horizontal stress, FIN= fracture initiation, OBG = overburden gradient, MWT = mud weight.*

The bottom hole pressures obtained in the depleted sandstones reservoirs transverse ranges from 6.5ppg to 8.4ppg, while the maximum shale pore pressures derived from gamma-ray, resistivity and sonic logs using the Eaton's and Bower's methods within the 12-1/4" hole section is 9.0 ppg. The shale shear failure gradient (shale SGF or collapse pressure) calculated using Modified Lade equations varies from 9.7ppg at 4,140'tvd to 10.5ppg at the target depth. The log derived mechanical rock properties, both fracture Initiation (**FIN**) and minimum Stress (**ShG**) for sand and shale are sonic based rock properties modeling calibrated to LOT data.

The study aided in understanding of how to mitigate the challenges faced in drilling well-7H. The MEM generated prior to the drilling of the sidetrack well clearly unveil the reason behind the hole collapsed encountered while running 9-3/8" casing. In general, X field reservoirs pressures are hydrostatic with bottom hole pressure of 8.4ppg except for the producing reservoirs which are mostly depleted with 6.5ppg pressure. Therefore, well-7H 12-1/4" hole section was drilled with 9.0ppg to the target depth at 4,400'TVD. Whereas the shale SGF at 4,140' TVD is 10.5ppg (Fig. 5).

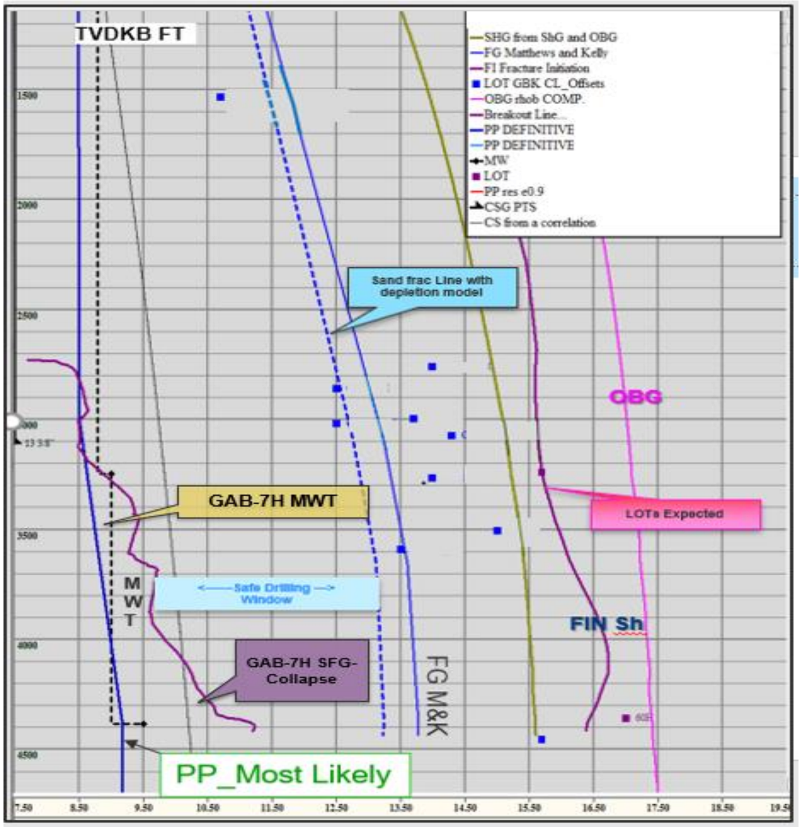

Figure 5. Post drill Mechanical Earth Model (MEM) for well-7H well. *Note: SFG = shear failure gradient, Shg = minimum horizontal stress, FG= fracture gradient, FIN= fracture initiation, OBG = overburden gradient, MWT = mud weight.*

Thus, the mud weight used to drill this hole is insufficient to support the wellbore wall which led to the hole collapse while running casing (Fig. 6).

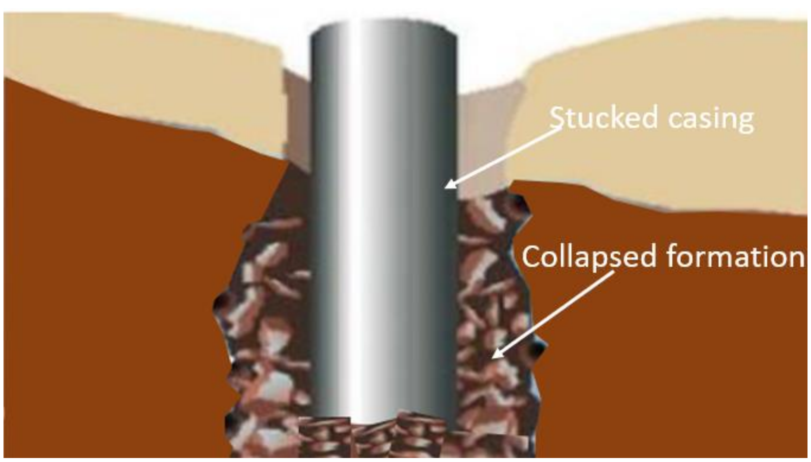

Figure 6. Showing hole collapse observed while running in hole 9-3/8” casing in GAB-7h well.

Based on the MEM models generated, the efficient mud weight window needed to drill the sidetrack well at cost effective manner must be above the shear failure gradient curve and below the fracture pressure in the reservoir. Hence, the minimum mud weight of 10.8ppg is required for the drilling of well-7HST well while keeping the equivalent circulating density (ECD) below 11.2ppg (sand fracture gradient computed) to avoid fracturing the weakest formation along the open hole section.

The new well (7Hst) was sidetracked at 3400' TVD, and the 12-1/4" intermediate hole section drilled with 10.8ppg EMW to 4,300' TVD while maintaining very good hole cleaning. Due to the constraining mud weight window, the mud weight was raised to 11.1ppg on fly about 100' TVD prior to landing the well. This is to ensure equivalent static density (ESD) is enough to prevent shear failure when the pumps are shut off. Also, it is a key strategy prior to pulling the bottom hole assembly (BHA) out of hole.

Conclusion

The MEM built for well-7hst indicates the mud weight used in the 12-1/4' hole section from 4,300'TVD onwards was too low and contributed to the hole collapse observed while running 9-3/8" casing. Mud weight window of a deviated well narrows with decreasing pore pressure gradient during reservoir depletion. Also, depletion reduces frac gradient thus affecting the mud weight window. The Collapse gradient always decreases with reservoir depletion but increases with the increase of horizontal stress.

The information got from the MEM model built, aided in the designing of efficient mud weight which is above the shear failure gradient curve and below the fracture pressure in the depleted reservoir. The new well (7hst) was successfully drilled within the safe operating window, set 9 5/8" casing and cemented same in place, without any geologic non-productive time or well problems such as lost circulation events, tight spots, stuck pipe and hole collapse. The approaches have been adopted in the X field drilling campaign with huge success.

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