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Wellbore Strengthening in HPHT Drilling through Stress Caging: Case Studies from the Niger Delta

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Abstract: ***The difference between the fracture gradient and pore pressure establishes the safe drilling margin. Fracture propagation, drilling-fluid filtration, and depleted formation pressure are major factors that reduce a formation's pressure-bearing capacity. Stress cage theory strengthens the wellbore by balancing wellbore pressure with formation stress. Stress caging increases rock fracture resistance by developing an enhanced hoop stress in the wellbore. This process creates a "stress cage" by generating a hoop of compression around the hole, effectively strengthening the wellbore. This paper outlines the theory and geomechanics underpinning stress caging and presents field data showing how the technique was developed and applied. The data demonstrate increased fracture resistance and added value across various geological contexts. It also explores wellbore strengthening, how stress cage theory can achieve it, and the operational considerations for implementation. Case studies from HPHT exploration in the onshore Niger Delta further demonstrate the value that stress caging can deliver.***

Keywords: HPHT, Stress caging, Poisson's ratio, Kirsch's solution, Shielding, Remedial, LCM, Frac- attack, Niger Delta

1. Introduction

Effective well designs must consider the variations in pore pressure and fracture gradients as depth increases. Engineers carefully plan each hole section to ensure drilling pressure stays below fracture pressure throughout that segment. These designs are created to withstand the maximum anticipated pressures, which are primarily influenced by permeable formations with the steepest pore-pressure gradients. Casing depths are set to isolate formations with fracture gradients insufficient to handle the expected drilling pressure profile. This approach prevents the failure of weak formations and avoids cross-flow between the compromised zone and any high-pressure permeable formations located within the same hole section. The fracture gradient is typically evaluated by measuring the pressure at which losses commence in the hole section. Technology is critical to drilling economics and can reduce costs. Even wells in the same basin with the same geological objective can have substantially different costs. The primary objective of wellbore strengthening is to balance wellbore fluid pressure with formation stress and pore pressure. Fracture extension and propagation, wellbore fluid invasion, and formation pressure depletion can all compromise pressure containment. Prudent technology use helps lower drilling and completion costs. In this context, wellbore strengthening is key to drilling.

Wellbore strengthening (WBS) aims to widen the pressure range a wellbore can withstand by raising the pressure at which significant fluid loss occurs and lowering the pressure at which significant wellbore collapse occurs. This paper translates theoretical concepts into field practice, drawing on case histories from the Niger Delta, where potential high-pressure, high-temperature (HPHT) reservoirs lie beneath the heartland fields.

2. Concept of Stress Caging

The stress caging technique emerged from a better understanding of the phenomenon known as 'Wellbore Ballooning.' This term describes cases in which the wellbore initially loses drilling fluid to the surrounding formation but later recovers it. These recoveries are often mistaken for a well flow event, prompting the crew to take well-control actions, even though they result from the wellbore ballooning effect. Although 'ballooning' suggests that the wellbore is elastic and expands and contracts like a balloon, this is a misconception; the phenomenon is more accurately termed a 'Supercharge Phenomenon.' It occurs because microfractures open and close during drilling. When the drilling fluid's hydrostatic head is slightly below the fracture initiation pressure, the equivalent circulating density (ECD) during drilling can be sufficient to open these fractures. As they open, they absorb mud, causing losses. Once circulation stops, the fractures close and the lost mud returns to the well. The stress caging method strengthens the near-wellbore region by wedging particles into fractures, thereby increasing the formation's fracture initiation pressure. Various wellbore-strengthening concepts have been developed to stabilise wellbores and control mud losses, particularly in sections with narrow mud-weight windows between the wellbore collapse and fracture gradients[1] .

WBS refers to increasing the pressure needed to initiate or break down fractures in the wellbore by propping small fractures in the wellbore wall. This process generates a concentric region of high stress, known as a stress cage, around the wellbore, which enhances fracture resistance[2] (BP). WBS methods include physical techniques like plastering and reducing fluid interaction; chemical techniques that use osmotic mechanisms for pore-fluid management; thermal methods that heat the wellbore to compress rock; and mechanical techniques such as hoop-stress enhancement. Mechanical methods have attracted significant interest and have led to the development of various techniques most commonly associated with WBS. Although exceptions exist, these methods typically do not alter the rock's inherent strength. Instead, they modify stresses at the wellbore, making fractures harder to initiate or propagate. All these methods rely on particulates and generally require a formation permeability of at least 1 mD, allowing pore fluid to bleed

rapidly into the adjacent rock. Consequently, mechanical WBS methods are highly effective in sandstone formations but less effective in shale and carbonate formations[3].The solution is to generate compression wedges that displace the formation at potential weak zones where fractures may grow[5]

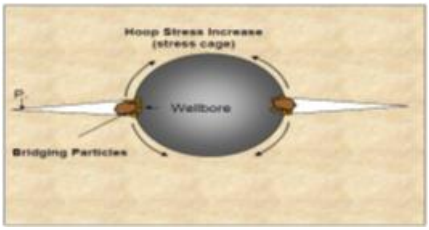


Figure 1: Stress cage schematic[4](Juvan Tovar)

Driving in a few additional wedges creates a compressive hoop around the borehole, making fractures more difficult to initiate (Figure 1). In shales, the bridge must be virtually impermeable to prevent fracture propagation. In permeable formations, such as sands, the bridge can be less perfect because pressure can leak into the rock. For stability, the mud pressure must be less than the difference between the pressure at the fracture tip and the pore pressure.

Supporting evidence includes parallels with impairment to extreme loss of injectivity in water injectors when particulates are not removed from the injection water; loss of injectivity and frac-job failure from early screen-out in propped fracture treatments; and hole-size sensitivity to sanding in producing wells, where smaller hole sizes delay sanding and loss of injectivity when cuttings are reinjected directly into clean sand.

3. Fracture Gradient Theory

Low formation pressure results in low fracture pressure, while a low Poisson's ratio also results in low fracture pressure (Figure 2). Poisson's ratio is the lateral strain response to axial loading. Effective horizontal stress is developed to counteract the Poisson effect. A lower Poisson effect will generate lower effective horizontal stress[5]. Most often, the frac gradient (FG) is considered equivalent to the far-field Shmin value, as in pore pressure/frac gradient (PP/FG) applications and among stimulation practitioners. As a wellbore is drilled, tangential hoop stresses develop in its wall, so the breakdown limit can be several ppg higher than the far-field fracture gradient, also known as the minimum horizontal stress. WBS does not change the far-field fracture gradient or Shmin—and therefore does not change the FG as commonly defined. Instead, it changes near-wellbore hoop stresses, affecting fracture initiation or breakdown pressure[6].

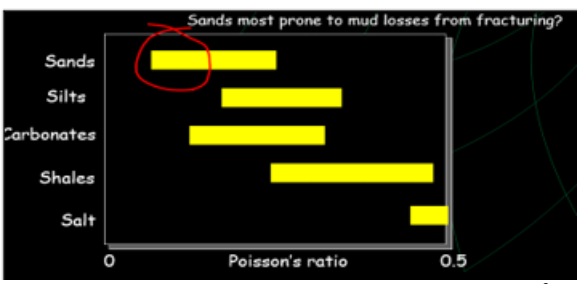


Figure 2: Poisson's ratio of sedimentary rocks after[2] BP

4. Why is Stress caging necessary?

4.1 High Mud Pressure & Formation Breakdown

Mud pressure affects the rock matrix by increasing pore pressure and diminishing effective stress, which can lead to tensile failure and lost circulation. Additionally, mud may infiltrate fractures and bedding planes, potentially causing them to open and propagate, resulting in wellbore instability and induced losses. Ensuring wellbore integrity is critical to avoid downhole issues and minimise non-productive time during drilling. Proper well design involves selecting casing points based on anticipated formation and fracture pressures, ensuring that drilling pressures remain below the fracture pressure of exposed formations. This is achieved by isolating weaker formations with casing before drilling into higher-pressure areas, thus preventing fracturing while maintaining the requisite mud weight for overbalance. Despite these measures, lost circulation remains a prevalent challenge in drilling operations, and WBS is recognised as an effective solution for managing it.

5. Where can Strengthening Help

Applying stress cage theory strengthens the wellbore, allowing drilling with higher mud weights without causing downhole losses. WBS has many applications, listed below.

- Depleted reservoirs pose a challenge: declining pore pressure weakens hydrocarbon-bearing rocks over time, while adjacent low-permeability shales retain their pore pressure. Several situations require drilling through a weaker formation under higher pressure. Drilling through both formations requires reinforcing the weaker layer to prevent downhole complications.
- Deep-water wells often have low frac gradients. The mud column in a long riser adds to hydrostatic pressure, and equivalent circulating density (ECD) can increase as cold water increases mud viscosity. Wellbore strengthening is essential when drilling formations with high pore pressures or in deep water, where the window between pore pressure and fracture gradient is narrow. Deep-water drilling operates within a narrow window, increasing the risk of downhole losses.
- Normally and low-pressure zones open in the same section- The high mud weight needed for normally pressured zones can cause losses or differential sticking in low-pressure zones.
- Increasing hole angle often narrows mud weight window
- Unconsolidated formations
- Fractured formations
- Weak casing shoes
- Reduces the need for multiple casing strings in a well.
- It minimises losses during casing and cementing operations: Even when narrow-window drilling is successful, pressures during casing running and cementing may compromise weak formations. In these situations, fortifying the formation to raise the upper pressure limit is a feasible solution.
- Providing improved well control.
- If a kick occurs, failure of well integrity due to breakdown of a weak formation- during shut-in or while circulating out the kick- could lead to an underground blowout and further complicate well control.

Induced losses occur when drilling mud weight (MW) exceeds the fracture resistance of the geological formations. This is especially critical when drilling HPHT reservoirs, where MW often approaches the minimum horizontal stress (Shmin). Shmin is typically defined as the lowest stress or pressure needed to reopen a fracture. Exceeding Shmin compromises the integrity of permeable reservoir formations but does not affect the pore pressure of adjacent or interbedded low-permeability shale. As a result, drilling is technically challenging: the MW needed to stabilise shale sections exceeds the fracture resistance of sandstone sections[3].

6. How is Stress Caging done

While drilling, the wellbore faces dynamic pressure changes from ECD, surge, and swab effects, which can cause microfractures and lead to fluctuating loss and gain indications. The 'Stress Caging' technique enhances the mud system by incorporating Wellbore Strengthening Materials (WSM) with a specific particle size distribution. This material helps seal microfractures when elevated pressures open them, forming a plug as drilling progresses. An ultra-low fluid-loss mud system subsequently develops a filter cake that prevents fluid from entering these fractures. Once the pressure effects stabilise, the wedged particles keep the fractures open, effectively creating a 'Stress Cage' that reinforces the wellbore. This mechanism ensures fractures do not reopen if the hoop stress around the wellbore equals or exceeds the fluid column pressure, preventing circulation loss even when mud weights surpass the formation's original fracture strength.

Oil major BP pioneered a physical model that demonstrated how mud additives can raise fracture resistance above the conventional minimum horizontal stress. The additives create a 'Stress Cage '- a high-stress region near the wellbore formed when shallow fractures at the wellbore/formation interface are propped open and sealed[5]. Their development depends on several properties, including borehole diameter, fracture width, the range of particle sizes suitable for use as proppant, mud-sealing properties, and formation permeability.

7. The Geomechanics and Physics of Stress Caging

A comprehensive literature study provides numerous examples of contemporary wellbore-strengthening techniques used in practice. Most focus on fractures induced around the wellbore, underscoring the importance of "Fracture-Based Strengthening" techniques. For example, Alberty and McLean (2004) introduced the stress cage concept, explaining that propped and plugged induced fractures increase hoop stress around the wellbore[7]. They state that this increased hoop stress reduces the likelihood of new fractures initiating and may help strengthen the wellbore. Hoop Stress Enhancement involves modifying stress conditions in the formation adjacent to the wellbore rather than changing the rock's inherent physical strength (Figure 3).



Figure 3: Hoop stress in the wellbore

7.1 Several theories have been proposed to explain the methods currently used to mechanically reinforce wellbores and control fracture propagation[3]. Hoop Stress Enhancement, also known as the 'Stress Cage' theory, increases stress near the wellbore, typically by opening fractures to constrict the wellbore and then promptly sealing them while they remain open. The "Fracture Closure Stress" theory uses high-fluid-loss materials to plug and tighten existing fractures, while the "Fracture Propagation Resistance" theory isolates the fracture tip[8] (Figure 4). The design and successful application of a WSM blend that opens and seals fractures suggest that these three theories are complementary in many respects.

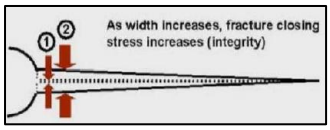


Figure 4: Fracture closure stress method[8] (Dupriest 2005)

7.2 The Physics and Geomechanics

During drilling, operators maintain wellbores in an overbalanced state by selecting a mud weight that ensures a positive pressure margin throughout the open hole. This approach establishes the minimum mud-weight gradient based on the highest formation pressure (PF), resulting in significant overbalancing of other formations intersected by the wellbore, primarily for safety. In these overbalanced sections, the pressure differential pushes the wellbore surface outward, creating compressional normal stress on the wellbore wall. The host rock behaves elastically until failure; when the principal stress reaches the critical tensile strength, hydraulic tensile fractures may develop, as indicated by the local stress trajectories[9].

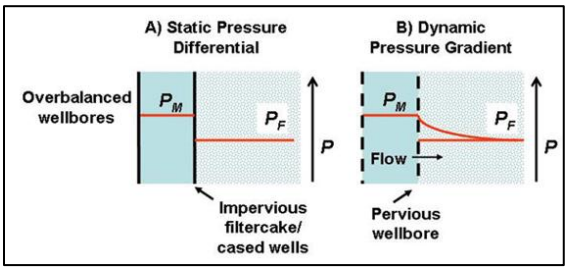


Figure 5: Pressure differential in overbalanced wellbores modified[10]

Figure 5 illustrates the wellbore pressure profiles for (a) static and (b) transient cases. Static situations apply at the first instant of formation penetration by the drill bit and are maintained when a filter cake screens out the pore space. The red lines show the pressure distribution. PM represents borehole fluid pressure, while PF represents formation pressure. This condition also applies to tight formations that cannot effectively transmit pore pressure to the wellbore fluid, as well as to cased wells.

The Stress Cage concept, first proposed by Aston M. S. et al., addresses lost circulation by modifying the hoop-stress and fracture-tip stress fields and balancing wellbore fluid-column pressure against formation stress[11]. It uses Lost Circulation Materials (LCM) to support natural or induced fractures, compress the formation near the wellbore, and increase the surrounding hoop stress (Figure 3). This forms an impermeable plugged zone within the fracture, preventing fluid pressure from propagating from the wellbore to the fracture tip. Consequently, the stress intensity factor at the fracture tip decreases, helping to stabilise the fracture system. Because this factor governs fracture-system stability, it is crucial to the strengthening effect of Wellbore Pressure Control (WPC). It can be determined from the combined formation stresses (SH, maximum horizontal stress), wellbore fluid pressure (P_w), and fracture pressure (P_f) (Figure 6). By compressing the surrounding rock, the process creates a "stress cage" that effectively strengthens the wellbore. When drilling a formation, the wellbore disrupts the stress-field equilibrium and redistributes stress around the borehole, creating concentrated stress and a secondary stress field. Together with the rock's strength, this secondary stress field acts as a natural barrier that protects wellbore integrity. Once fully developed,

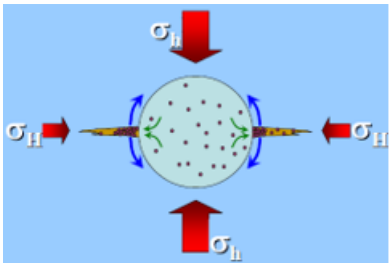


Figure 6: Horizontal stress alignment

its pressure-bearing capacity equals the formation breakdown pressure. The near-wellbore stresses are calculated using a known solution for a circular hole in an elastic plate, first introduced by Kirsch in 1898 under a plane-strain assumption. Assuming the formation is a linear elastic porous material, and the rock surrounding the wellbore is under plane strain, the hoop stress near a vertical wellbore can be expressed using Kirsch's solution (1898), where $\sigma_{\theta\theta}$ is the hoop stress, a, the wellbore radius , x, the far-field point, and θ, the tensile fracture orientation around the wellbore[12]

$$\sigma_{\theta\theta} = \frac{\sigma}{2}\left(1+\frac{a^2}{x^2}\right) - \frac{\sigma}{2}\left(1+3\frac{a^4}{x^4}\right)\cos 2\,\theta$$

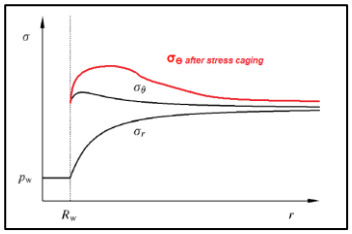


Figure 7: Near-wellbore stress increase with stress caging[4]

The Kirsch solution is the classical elastic model for stress concentration around a circular opening[12]. At the borehole wall, radial stress is governed by wellbore pressure, while hoop and axial stresses vary around the circumference based on far-field stresses, pressure differential, and Poisson ratio (Figure 7). Under anisotropic horizontal stress, the cos(2θ) term creates a two-lobed directional pattern. Under isotropic stress, the directional terms disappear, making the solution more symmetric.

Shahri et al. (2014) explained the formulation for a vertical wellbore, wherein the normal stress component on the fracture surface corresponds to the tangential (hoop) stress, as shown in the equation below[13]. This condition can be generalised by replacing the tangential stress with the normal stress component along the fracture surface for different wellbore trajectories. For example, for a deviated wellbore, we can resolve the stress field from far-field stress components and the wellbore trajectory to find the normal stress component along the fracture surface. Accordingly, we can replace the near-wellbore stress distribution (derived based on the classical Kirsch solution for a deviated wellbore) with the normal stress component along the fracture surface in the following equation:

$$\sigma_{yy}(x) = \frac{\sigma_H - \sigma_h}{2}\left(1+\frac{3a^4}{x^4}\right) - \frac{\sigma_h + \sigma_H}{2}\left(1+\frac{a^2}{x^2}\right) - P_w\frac{a^2}{x^2} - P_f(x)$$

Where σH is SH,σh is Sh, x, the fracture tip distance, P_w, the wellbore pressure and P_f, the fracture pressure.

The amount of trapped stress in the near-wellbore region depends on formation strength, fracture width and length, the bridge position in the fracture opening, and the compressive strength of the bridging materials[7] . Fracture length strongly influences strengthening in geological formations, with horizontal stress anisotropy playing a crucial role. The proximity of SHmax and Shmin affects strengthening potential; closer values indicate reduced potential. Elastic solutions may not accurately reflect the situation, so it is essential to account for shear failure. Additionally, wellbore size affects strengthening, as larger wellbores tend to experience less. While formation modulus determines fracture width and particle size, it does not alter the magnitude of strengthening. For effective strengthening, fractures must be adequately propped at the wellbore wall; otherwise, the strengthening effect diminishes[5].

In short, reducing permeability in permeable zones increases fracture stress near the wellbore and Poisson's ratio. Thus, particle size and composition, along with placement procedure, matter. Accurate input data are also essential. Sealing particles are pushed toward fracture mouths, and when pressure is reduced, the fractures close, improving the seal.

7.3 Effect of formation permeability

In a fully permeable formation with a lower fracture gradient, pore pressure will equal the ECD. In a fully low-permeability formation with a higher fracture gradient, pore pressure will remain unchanged.

7.3.1 In Permeable formations

Within stress cage theory, the particle bridge does not need to be flawless when drilling through permeable formations. Fluid that passes through the bridge seeps from the fracture into the surrounding rock matrix, preventing pressure from building up and triggering fracture propagation. Even if a

filter cake initially forms on the fracture walls, the fracture expands slightly, exposing new surfaces and relieving pressure. In permeable formations such as sandstone, the bridge may be imperfect because pressure can leak into the host rock (Figure 8a).

If the drilling mud contains particles too small to bridge near the fracture opening, the fracture may still seal as filter cake builds up inside it. However, this process is slower, allowing the fracture to extend excessively and making it more difficult to form an effective stress cage while drilling. This is reflected in the mud losses seen with conventional mud systems. In impermeable formations, a notable benefit of ultra-low-fluid-loss muds is a reduced risk of differential pipe sticking.

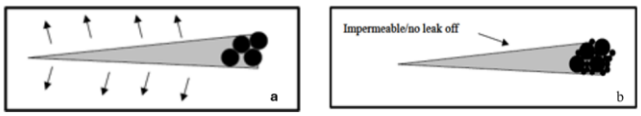


Figure 8 (a): Fracture sealing in permeable rock,
Figure 8 (b) Fracture sealing in impermeable rock after[11]

7.3.2 Low Permeability Formations

When drilling through low-permeability formations, the particle bridge must be nearly impermeable to prevent pressure from reaching the fracture and potentially triggering its propagation. This highlights the importance of using fluids that form filter cakes with minimal fluid loss. When a fracture first forms, mud rapidly flows into it, depositing bridging solids at its mouth. A differential pressure is then needed to hold the bridge in place and realise the stress cage theory during drilling. In shales, the bridge must be nearly impermeable to prevent fractures from propagating (Figure 8b).

8. Raising Frac Limits while drilling: The Stress Caging Approach

As Manshad et al. and other researchers note, mud losses, differential sticking, and the similarly costly effects of wellbore instability cost the global industry hundreds of millions of dollars each year[14]. These issues contribute significantly to non-productive time (NPT) during drilling, regardless of weather conditions. In addition, well-control challenges caused by lost circulation and the risk of dropped objects while jarring stuck pipe pose serious health, safety, and environmental (HSE) hazards. Approaches may be proactive (shielding) or reactive (remedial)[15].

8.1 Shielding

Operators often enhance their mud systems by incorporating materials like sized calcium carbonate and graphite as a preventive strategy. They are increasingly utilising wellbore-shielding technology, which employs a proprietary cellulosic material to create small, deformable aggregates within the drilling fluid. These aggregates form a low-permeability barrier at the fluid-rock interface, limiting fluid invasion across a range of permeabilities and into microfractures up to 3,000 µm. This ultra-low-invasion product is compatible with oil-, water-, and synthetic-based muds and is effective at concentrations as low as 4–12 lb/bbl. The dynamic shielding mechanism adjusts during drilling or circulation to enhance wellbore stability by raising fracture initiation pressure and isolating mud pressure from the surrounding geology, preventing fracture propagation. This technology is essential when drilling through weak sands or silts that necessitate a mud weight exceeding the fracture gradient.

8.2 Remedial

When faced with losses, it is common to introduce loss-circulation pills or to enhance the mud system with increased amounts of bridging or sealing agents, such as graphite and calcium carbonate. While these measures temporarily resolve the issue, they may increase non-productive time (NPT) and costs. Furthermore, traditional loss-prevention additives can contribute to the accumulation of low-gravity solids (LGS), which negatively affect rheological properties and diminish the reusability of quality oil-based drilling fluids. Although calcium carbonate is frequently used as a reservoir bridging agent because it is acid-soluble, its application can also cause formation damage, leading to long-term restrictions on optimal production. Remedial treatment is a static process. It is used when weak sands or silts can initially be drilled with a mud weight below the fracture gradient, but the mud weight must later be increased. The Stress Cage formulation uses induced pressure to 'set' the Stress Cage within the target formation. It commonly mitigates losses in sandy and silty formations during casing operations (which require higher surge pressure) or during cementing, where reduced annular clearance requires a higher equivalent circulating density.

9. Operations: Putting Theory to Practice

Any theory explaining a particular problem is ultimately judged by its practical application. It is where theory meets field application. The objective of WBS is to induce a fracture or enter an existing one and fill it to increase the hoop stress. The material should solidify enough to keep the fracture propped open, increase hoop stress, and plug it to prevent mud from reaching the fracture tip. Examples include cement, high-fluid-loss squeezes, cross-linked materials, etc.

9.1 A potential candidate for WBS must fulfil the following criteria

1) Young's modulus: Formation modulus affects fracture width but not strengthening; higher modulus reduces fracture width.
2) Fracture length is very important for fracture width and affects breakdown pressure in wellbores. Longer fractures can significantly increase both width and breakdown pressure.
3) Stress contrast (SH-Sh) is important for strengthening. Horizontal stress anisotropy affects the increase in breakdown pressure. Knowing both minimum and maximum horizontal stresses is needed for wellbore design.
4) Rock strength and failure significantly affect wellbore strengthening; strong rock can help, while shear failure in weak rock makes higher breakdown pressure less predictable. Under anisotropic stress with elastic behaviour, strengthening increases with fracture length up to 8.1 ppg, with length serving as a proxy for width. In Mohr–Coulomb failure cases, strengthening is ineffective

unless the rock is extremely strong. Under isotropic elastic conditions, it occurs only with very long fractures because the stress contrast around the wellbore is low.

5) For a given frac length, larger hole sizes result in less strengthening, with breakdown potential reduced by up to 46% compared to smaller wellbores. However, larger wellbores can still achieve significant breakdown increases, up to 5.1 ppg for extra-long propped fractures.
6) To improve breakdown resistance, proppant must stay at the fracture opening at the wellbore wall during drilling; proppant deeper in the formation or displaced from the opening may not help.
7) The propping agent must stay at the wellbore wall during drilling; if it moves deeper into or out of the fracture, the strengthening benefit may be lost.

Software that enables the selection criteria for WSM design is based on the parameters that usually affect the fracture width the most[3]:

1) Shmin: Far-field minimum horizontal stress or Fracture Gradient (psi)
2) Pw: Maximum Desired Wellbore Pressure or ECD (psi)
3) Well Inclination or hole angle (deg)
4) E: Young's Modulus (psi)
5) D: Hole Diameter (in.)
6) L: Fracture Length (in.)

Other required parameters can be estimated fairly easily. Poisson's Ratio is generally between 0.1 and 0.35 for sandstone and between 0.3 and 0.5 for shale and mudstone.

10. Wellbore Strengthening Methods

There are two ways to apply a wellbore strengthening treatment to a weak zone:

1) The drilling-ahead method.
2) The Pill method, formation integrity test (FIT) method or leak-off test (LOT) method.

10.1 Drill-ahead method (Shielding)

Treat the entire drilling-fluid system with LCM/G-seal, then drill through the weak zone with LCM in the fluid. Because LCM has large particles, use 20- or 40-mesh screens, or coarser, on the shakers to retain the effective material in the system- or bypass the shakers altogether. Keeping the full particle-size spectrum in the system is desirable and necessary. As the weak zone is drilled, small, short fractures form and are filled and plugged with LCM, sealing and strengthening the zone. As the mud weight (density) increases, additional small fractures form and are plugged.

10.2 Pill method (remedial)

Before drilling out of the shoe, determine the depth of the expected "weak" section. Conduct a formation integrity test (FIT) or leak-off test (LOT). If the shoe test fails, drill through this section with treated mud until reaching a formation with the desired rock strength. Predict the depth using offset wells and other data. All formations below this point should be strong enough to withstand the highest ECD predicted for the remainder of the well. In other words, choose the point where a drilling liner would be set. Drill through the entire weak zone with a low mud weight. Treat the zone with special LCM in a series of FIT squeezes, then continue drilling, increasing the mud weight as needed for pore pressure or hole stability. The risk is that this method is operationally easier, but if the wellbore fails during the FIT test, the fracture may extend so far from the wellbore that it cannot be repaired.

11. Operation Steps for a Squeeze Procedure

1) Drill to the predetermined top of the stronger rock (bottom of the weaker rocks)
2) While drilling, build LCM/G-seal big enough to cover the entire open hole and 100 ft inside the casing.
3) Ensure tool tolerances to prevent plugging.
4) Spot the pill in the open hole and up the casing, leaving 10 bbls in the drill pipe.
5) Perform a series of FITs to drive wedges of the LCM material into the wellbore wall at the weak zones.
6) Pump down the drill pipe at a controlled rate of about ¼ bbl/min.
7) Carefully plot pressure vs time and record volumes pumped and returned (Figure 9).
8) When the pressure/volume line is definitely bending over, stop pumping.
9) If the well breaks down, stop pumping immediately to limit the growth of the fracture.
10) If the fracture gets too far from the wellbore, the method may fail. Bleed the pressure off over about a minute, if possible.
11) If the zone is permeable, wait 5 minutes to do the next
12) FIT to allow any leak-off to occur in the fracture.
13) Repeat until the desired wellbore pressure is achieved.
14) Some mud should have been lost to the formation (not returned when pressure is released). This indicates that mud with the LCM blend was forced into short fractures and leaked off. For a long zone, this might be 2-10 bbls.

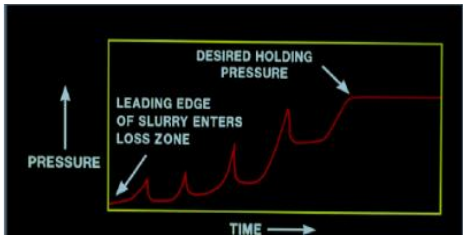


Figure 9: Pressure build-up during a hesitation squeeze

12. How WBS differs from Hydraulic Fracturing

The objective of hydraulic fracturing is to improve permeability. A hydraulic fracture creates a fracture, and the proppant keeps it open (Figure 10a). Proppant comprises sand, water, acids, chemicals, etc. During production, wellbore pressure differential is the drawdown applied (Delta P= SBHP-FBHP) and long-term flowback. The fracture affects far-field conditions.

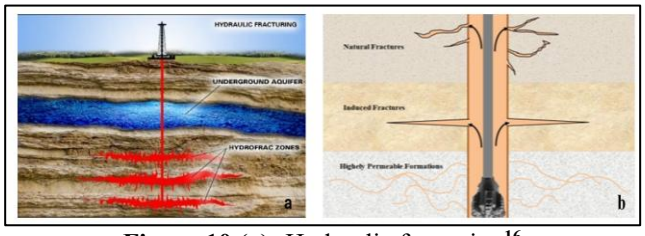


Figure 10 (a): Hydraulic fracturing[16]
Figure 10 (b): Frac Attack Treatment for WBS modified after[17]

The goal of Frac-Attack treatment is to increase hoop stress and reduce permeability. Frac-attack seals the fracture. The frac-attack pill contains (Figure 10b) nano-sized particles in fluid. During drilling, the maximum wellbore pressure differential applied is ECD- ESD minimum. No flowback occurs during the well-drilling process. Hence, better chances of success. The effects are confined to near the wellbore.

13. Case Studies of Stress Caging Using Frac Attack Treatment in Niger Delta HPHT Drilling

Deeper plays in mature acreage are a new frontier for petroleum upstream companies in Nigeria's Niger Delta Basin, helping revive exploration interest in declining blocks of the mature heartlands. The S, K, and G Deep wells were drilled to test the deep gas prospect in the Eastern Swamp of the Niger Delta, beneath the prolific oil and gas fields in the onshore Niger Delta (Figure 11).

The S Deep prospect was explored by re-entering a well drilled in 1971, abandoning its completed intervals, and sidetracking from the old wellbore into the exploration sections. After successfully isolating shallow depleted zones in the production section, the well was deepened using a 6-in inch hole.

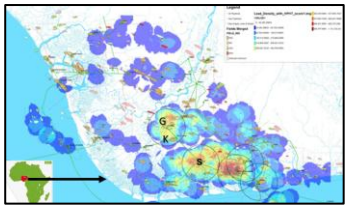


Figure 11: Niger Delta, with locations of S, K & G Deep wells

13.1 What happened in S Deep

After installing the isolation liner, LOT intended to use a packer to separate the casing from the depleted zones, thus minimising the potential for micro-annulus formation. However, the crew could not follow the standard procedure of rotating the drill string before pump initiation because of the packer. During the pump startup, a sudden pressure surge of 1.05 psi/ft was exerted on the formation, leading to rapid fracturing that extended for approximately five minutes until pumping ceased. This event caused total fluid losses, which were managed by lowering the mud weight to 0.60 psi/ft, applying Lost Circulation Material (LCM), and executing a cement squeeze. Drilling was continued to the base of the permeable unit before strengthening the wellbore. After cuttings confirmed the base sand, the well was treated with "Frac-Attack", a specialised wellbore-strengthening treatment for severe losses. The treatment was deployed using a balanced hesitation squeeze, achieving a final stable pressure of 0.88 psi/ft EMW. This was considered sufficient formation strength to continue drilling and can be regarded as a pseudo-limit test for the casing shoe.

13.2 The Unintentional Leak-off Test

The 7" casing was set at 12,803 feet below sea level. A leak-off test was scheduled after drilling 10 feet into the fresh formation. During rat-hole drilling, with mud at a pressure gradient of 0.74 psi/ft (equivalent circulating density: 0.81 psi/ft), sand particles were found in the drill cuttings, even though the bottomhole assembly was not equipped with logging-while-drilling tools (Figure 12).

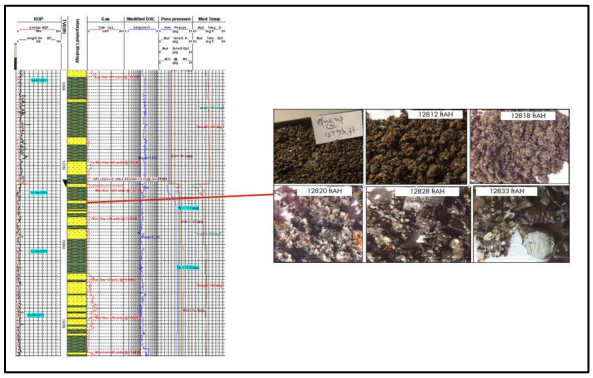


Figure 12: Formation characteristics of the hitherto unknown sands

The planned leak-off test involved isolating the casing and depleted zones using a packer, reducing the risk of micro-annulus formation. During the operation, circulation was interrupted because the drill string could not be rotated, leading to an abrupt pressure increase of 1.05 psi/ft when the mud pumps were started (Figure 13). This surge caused the formation to fracture, which continued for about five minutes until the pumps were halted. Although unanticipated, the test provided valuable lithological strength data for the Niger Delta region, especially near the overpressured interval.

This event was classified as an Extended leak-off test, with pressure persisting beyond the formation breakdown threshold. Data derived for the sandy stratum in S Deep assumed a depth of 12,818 feet above sea level. The measured values are crucial for planning subsequent wells, especially in regions where sand-formation strength is vital. The pre-drill FG prediction for the F1030 sands was 0.819 psi/ft, closely matching the observed 0.82 psi/ft during the LOT. The confirmation of the F1040 base from cuttings led to the application of "Frac-Attack," a specialised treatment aimed to address significant losses and reinforce the wellbore. This treatment employed a hesitation squeeze method, resulting in a confirmed stable pressure of 0.88 psi/ft EMW, which provided adequate formation strength for continued drilling and served as a pseudo-limit test for the casing shoe.

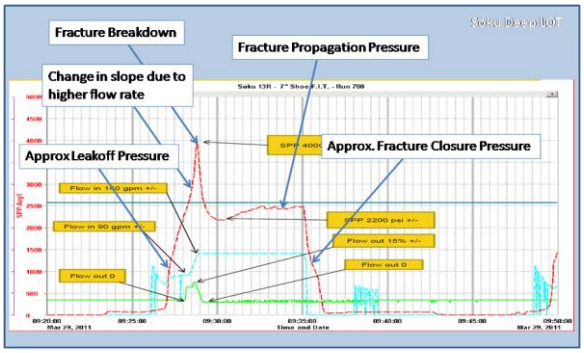


Figure 13: Inadvertent formation breakdown while switching on pumps in S Deep. Standpipe pressure and Volumes vs time while attempting to break circulation prior to planned LOT at 7" casing shoe[18].

The events described above resulted in total mud losses, which we controlled with LCM, MW reduction, and cement. After drilling to the base of the sandy formation, attempted strengthening the wellbore using the "Frac-Attack" severe loss treatment with a hesitation squeeze, achieving a final stable pressure gradient of 0.88 psi/ft. It successfully strengthened the wellbore by 0.06 psi/ft above the measured LOP of 0.82 psi/ft (Table 1).

Table 1: Geomechanical properties observed during the formation breakdown

Value	Pressure (psi)	EMW (psi/ft)
Leakoff Pressure (LOP)	10,584	0.82
Formation Breakdown Pressure (FBP)	13,458	1.05
Fracture Propagation Pressure (FPP)	11,858	0.92
Fracture Closure Pressure (FCP)	10,708	0.84

12.3 The Frac-Attack treatment at S Deep to Control Losses in Sandstone

The Frac-Attack® treatment is a diatomaceous earth blend designed to create a complete seal and strengthen formation integrity[19]. Compatible with all mud systems, it requires no pre-spots, spacers, activators, retarders, or accelerators. It has proven effective in both onshore and offshore environments and has been successfully pumped through all measurement-while-drilling (MWD), logging-while-drilling (LWD), and rotary-steerable system (RWD) motors, as well as small bits. It has also proven effective at controlling underground crossflows and blowouts, often with a single application in the Gulf of Mexico.

12.4 The Frac-Attack Hesitation Squeeze Job to cure the thief zone in S Deep

After pressure-testing the lines to 5,000 psi for 10 minutes, closed the annular preventer and ran injectivity tests at 1, 2, and 3 bpm. Injection began at 2,300 psi, with the pressure stabilising at 1,600 psi. Opened the annular preventer and pumped 10 bbl of spacer ahead, followed by 40 bbl of Frac-Attack LCM pills, 5 bbl of spacer behind, and 20 bbl of mud. Closed the annular preventer and squeezed 63 bbl of mud and spacer ahead, followed by 10 bbl of Frac-Attack pill, into the formation at 1 bpm. Recorded a surface pressure of 1,600 psi. Pumped and squeezed 5 bbl of mud through the kill line to displace the pill from the annulus. Bullheaded 10 bbl of Frac-Attack pill into the formation at 2 bpm (total Frac-Attack bullheaded into the formation was 20 bbl). Commenced a hesitation squeeze of Frac-Attack, increasing pressure in 100 psi stages. Squeezed 3.85 bbl into the formation, achieving a final squeeze pressure of 3100 psi (Figures 14, 15 & 16). Pressure was observed to hold solid. Total mud volume pumped while squeezing was 10.85 bbl. Monitored the final squeeze pressure of 3,100 psi for 2.5 hours; pressure remained constant. Gradually bled off pressure in the well and recovered 1.40 bbl of mud. Bled off pressure in the BOP cavity. Opened the annular preventer and upper pipe rams. Waited four hours for the pill to set. Formation Integrity Test (FIT): Conditioned mud, circulated bottoms up, and recovered Frac-Attack on surface. Flow checked for 15 minutes; well static. Pulled out from 12,833 ftah to 12,791 ftah. Conditioned and completed displacement to 0.74 psi/ft mud; well stable. Increased circulation rate in stages from 150 gpm and 3,000 psi to 247 gpm and 5,830 psi; well stable (no losses). 90% pump-off valve setting at 5,850psi. Simulated ECD = 0.82psi/ft.

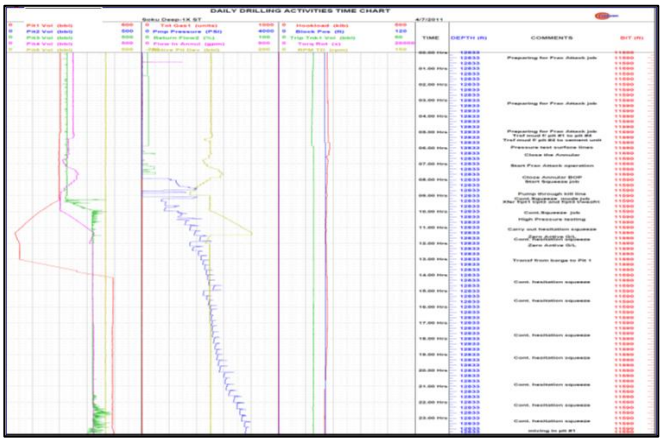


Figure 14: Time log of Frac Attack Treatment

This treatment successfully strengthened the wellbore by 0.06 psi/ft above the measured LOP of 0.82 psi/ft.

12.5 Successful Exploration section drilling (6" hole):

After strengthening the F1040 sand pack through the objective section, we drilled the 6" hole with a static MW of

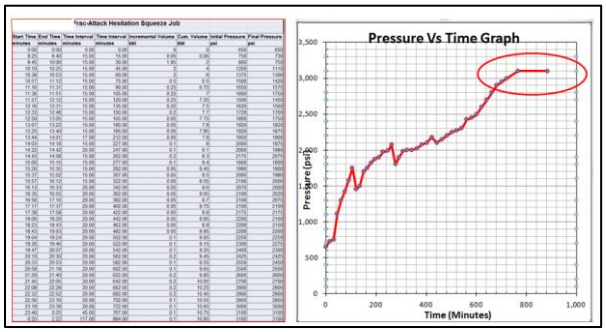


Figure 15: Hesitation Frac-attack details

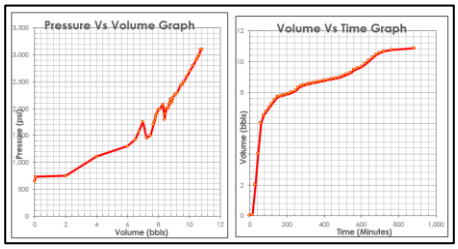


Figure 16: Pressure build-up with volumes and time

0.74-0.76 psi/ft and an ECD of 0.83-0.85 psi/ft. The mud's viscosity and the high pump rates needed to keep the hole clean contributed to the elevated ECD. G-Seals were added to the mud system at 15 lb/bbl. No further mud losses occurred while drilling this section, despite the high ECD. This was attributed in part to the successful use of G-Seals, which create a stress-caging effect around the wellbore, and in part to the formation being stronger than anticipated.

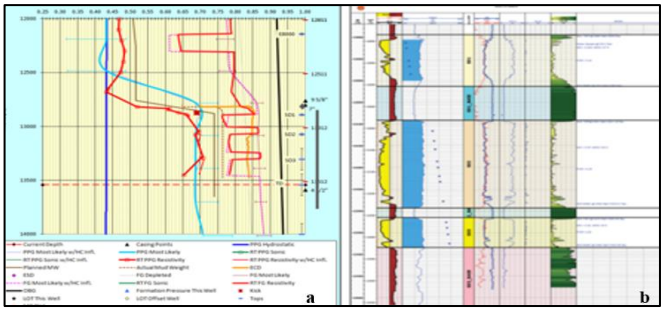


Figure 17(a): Real-time PP-FG plot of S Deep and
Figure 17(b): Petrophysical log of exploration section[18]

Figure 17a shows the real-time, resistivity-based pore and fracture prediction. The target reservoir sands SX1, SX2, and SX3 were encountered and evaluated (Figure 17b); The true strength of the objective section's sand formation remains unknown, partly because G-Seals create a stress-caging effect around the wellbore. The frac attack treatment worked as expected: the treated zone remained subdued without triggering mud losses, indicating that the remedial measure was effective. In addition, we explored three thick sandstones, and shielding successfully built the wall and improved wellbore fracture stress, preventing any loss-circulation events. The real-time fracture gradient prediction in the target sands was 0.78 psi/ft, which is inaccurate (Figure 17a). The real-time pore pressure prediction assumes a constant, uncoupled Poisson's ratio of 0.27, causing it to underpredict fracture stress in overpressured sands.

12.6 Improving the wellbore strength at K Deep Sidetrack

A LOT was performed at the 7" liner shoe and obtained 0.94 psi/ft MWE. While drilling in MPD mode to 15170 ftah, we identified a narrow drilling margin. After acquiring logs and running a lookahead VSP, we strengthened the wellbore with frac-attack treatment, increasing the fracture gradient to 0.971 psi/ft and regaining wellbore integrity. This enabled drilling of the 6" hole to the revised FTD of 15450 ftah through F7 sand (Figure 18). The Frac-Attack deployment strategy in K Deep saved time and money.

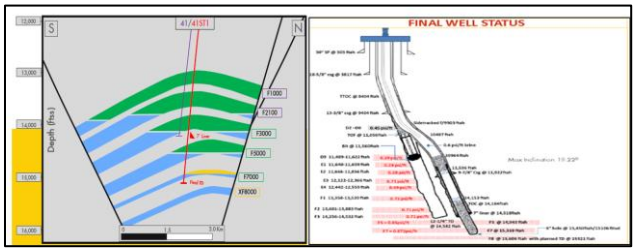


Figure 18: Frac-attack treatment in the sidetrack

12.7 Missed Opportunity

The opportunity cost of not attempting to improve the wellbore has been substantial, as seen in the G Deep well Figure 19). Here, instead of attempting to stabilise the well and improve the drilling margin through stress caging, the team set a contingency liner. This proved costly in the long run, as the well could not reach the PTD because the changed casing scheme could not contain drilling events at deeper depths. A larger hole could have avoided it, but not the premature setting of the contingency liner

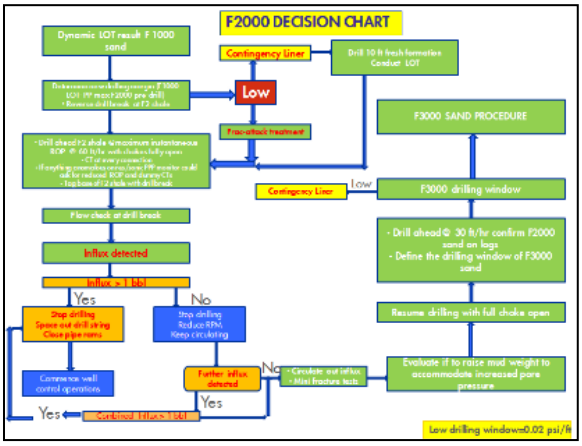


Figure 19: G Operational decision tree

14. Discussion

WBS refers to processes that increase the wellbore's fracture pressure and, in turn, strengthen its integrity. Several complementary wellbore-strengthening concepts have emerged, all based on mechanically reinforcing high-risk zones. These techniques can remediate or prevent lost circulation. Fracture-size effects require careful explanation. In the idealised linear-elastic Kirsch equations, wall stress concentration can appear geometrically scale-independent when normalised by radius. But real rock is not an ideal continuum: larger holes sample a larger population of flaws, create a larger damaged volume, permit more extensive plasticity, and can interact more strongly with bedding, fractures, permeability, and time-dependent weakening. Published borehole-size studies report increasing collapse pressure and poorer stability as diameter increases.

Stress caging enhances horizontal stress formation by using a calculated mixture of sized calcium carbonate and graphitic materials in the drilling fluid[5]. When fractures occur in the rock, these materials help to plug and seal them, reinforcing the hoop-stressed zone. As fractures propagate, vulnerabilities may develop, leading to vertical and lateral compression in the borehole and forming a stress cage.

Bridging materials play a critical role by supporting and sealing fractures against wellbore pressures, typically in permeable formations, causing trapped pressure to dissipate and resulting in fracture collapse. Smaller fractures at the borehole surface generate stress more effectively than those deeper in the formation.

The key elements of a successful stress cage include forming a bridge, reducing pressure behind it, and using an appropriate particle-size distribution in the mud. Fluid flow into fracture faces surpasses flow across the bridge, resulting in minimal fluid loss and maintaining a permeable formation. Fracture length significantly affects stability, with shorter fractures preferable because they help maintain high stress levels at the borehole wall. The sensitivity analysis indicates that shorter fracture lengths provide greater stability, while longer fractures reduce wall stress. To minimise loss volume, seal any induced fractures promptly. Even minor losses can expand beyond standard repair limits, and then the Stress Cage method may not provide a viable solution. Therefore, managing initial loss circulation carefully is vital for successful strengthening. Key inputs for the stress-caging model include dynamic Young's modulus, Poisson's ratio, minimum and maximum stress levels, pore pressure, overburden, hole size, deviation, and operational wellbore pressure. It is crucial to consider depletion effects on mechanical properties and ensure that the particle size distribution of the stress-caging material includes adequately sized particles, as these are necessary to wedge effectively at the fracture mouth.

Poisson's ratio is defined as the ratio of lateral to axial strain in linear elasticity and plays a significant role in axial stress concentration and poroelastic coupling around wellbores. A higher value of Poisson's ratio typically suggests stronger lateral coupling, which can alter the distribution of axial and hoop stresses. Its stabilising effect depends on the specific model and trajectory. Additionally, a higher ratio is linked to Water Saturation Models (WSM) and is associated with poorly drained or more ductile zones, where apparent elastic stability is observed. Key factors such as strength, cohesion, friction, and water sensitivity are critical in this context.

13.1 Best Practice

The recommended concentration and formulation of the Stress Cage material should be in the mud before drilling into the target formation to establish a Stress Cage (dynamic or shielding). This requires reasonable anticipation of pore and fracture pressures before drilling. The target formation is reinforced only up to the maximum induced pressure in the wellbore, which must not exceed the target design strength during the static treatment (static or remedial).

15. Conclusions

When drilling near high-pore-pressure formations or in deep water, WBS is crucial because the margin between pore pressure and fracture gradient is narrow. This is achieved through stress cage theory, which utilises bridging particles and an ultra-low-fluid-loss mud system. Bridging particles, like graphite, interact with an ultra-low-fluid-loss filter cake to quickly form at fracture openings, creating a "stress cage" that compresses surrounding rock and enhances wellbore stability. This process modifies near-wellbore hoop stresses, influencing fracture initiation or breakdown pressure. While preventing pressure invasion is ideal for maintaining fracture gradient, it may not be feasible during overbalanced drilling; thus, the focus is on minimising invasion instead.

Wellbore strengthening techniques mitigate instability risks and enable safe drilling in HPHT environments, as demonstrated in the Niger Delta. Both shielding and reactive wellbore strengthening modes were attempted there, with pronounced success. A major factor in the successful implementation was drilling with controlled parameters to allow stress cages to form, while following HPHT practices because of the small trip margin. The theory of using stress cages to strengthen wellbores has also been developed and successfully demonstrated in the HPHT environment of the Niger Delta, as it was first introduced in the Gulf of Mexico.

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