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# Wellbore Strengthening While Drilling Above and Below Salt in the Gulf of Mexico

J. R. Smith and F. B. Growcock, M-I SWACO

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## Abstract

Increasingly, operators have to drill wells through intervals with narrow drilling windows, *i.e.*, the pressure gap between wellbore failure (collapse) and fracture is very small. This often results in breaching or fracturing of the wellbore, which generally leads to loss of costly fluid and time. This is particularly true when using NAF (non-aqueous fluids), which are costlier and propagate fractures more readily than water-based drilling fluids. These high-risk drilling operations present themselves in a number of situations, such as drilling through depleted formations and drilling shale and/or sand formations in close proximity to salt. To manage these challenges, operators are increasingly recognizing the value of wellbore strengthening techniques to mitigate the fracture potential of a well. Hoop-stress enhancement is one such technique.

Hoop-stress enhancement can be attained by inducing shallow fractures in a formation with elevated wellbore pressure and simultaneously forcing large particles into the fractures to keep them propped and in a stressed state. When whole drilling fluid is treated with these relatively large particles, the particle-size distribution (PSD) of the drilling fluid must be monitored continuously. Wet-sieve analysis (WSA) can be used to help maintain the correct concentrations and sizes of the proppant materials.

Extended directional wells (> 30,000-ft measured depth) in the Gulf of Mexico Mississippi Canyon field are being drilled successfully using this hoop-stress enhancement strategy. The experiences described in this paper demonstrate that this wellbore strengthening technique can mitigate fracturing of at-risk formations and reduce or eliminate losses of drilling fluid.

## Introduction

Downhole loss of drilling fluid, or "mud", is one of the biggest economic challenges while drilling, especially in Gulf of Mexico (GOM) deepwater. Losses occur when the drilling fluid weight requirement to overcome the pore pressure needed to stabilize the wellbore exceeds the fracture gradient of the formations. Perhaps the most difficult challenge is drilling through depleted reservoirs. As reserves decline, a drop in pressure occurs, which weakens hydrocarbon-bearing rocks; however, the surrounding interbedded, low-permeability rocks (shales) might maintain their pore pressure leading to pressure variations in the formation. Drilling depleted zones becomes difficult, and in some instances, virtually impossible because the fluid density required for hole stability of the shale exceeds the fracture gradient of the depleted sands. Hoop-stress enhancement (labeled here "CSE" for Circumferential Stress Enhancement) offers the potential to strengthen the weak zones and access these difficult reserves. Some of the economic value of this strategy for wellbore strengthening includes the following applications/benefits:

- Reduced drilling-fluid losses in deepwater drilling
- Improved well control
- Ability to successfully drill depleted zones (reserves)
- Possible elimination of casing strings
- Less drilling fluid lost when running casing
- Reduction of drilling fluid lost while cementing

Previous studies have investigated wellbore strengthening with a view to preventing hole collapse or fracturing. One of the most effective approaches to wellbore strengthening involves physical separation of the wellbore from downhole pressures; such approaches include sealing techniques with fluids or products and isolation of the wellbore with casing or expandable liners. Thermal methods involve using temperature changes to alter the stress state around the wellbore.1 Chemical approaches include using invert emulsion drilling fluids to draw water out of the formation and intercalating inhibitors to stabilize clays so that they react less rapidly with water.

A fourth approach, mechanical wellbore strengthening, involves stressing of the wellbore using elevated pressures. The 1992 paper by Fuh et al.[2] discusses the concept of adding granular particles to the drilling fluid to seal fractures and prevent losses; Fuh's paper states that this could only work in permeable rocks where leak-off into the rock allows a cake to build in the fracture. Other studies, including Morita and Messenger,[3,4] have invoked the concept of using fractures to cause stress changes in the rock, introducing the idea that fractures could increase the hoop stress around the wellbore. Alberty and McLean[5] discuss how mud-cake deposition in the fractures can affect near-wellbore stresses and give field examples suggesting large increases in fracture resistance. Sweatman et al.[6,7] have taken this concept and developed chemical treatments that could be squeezed into fractures to prop them open and seal them. A recent paper by Aston et al.[8] discusses the use of wellbore-strengthening fluids using sized particles to bridge the fractures while drilling depleted sands, thus enhancing the hoop stress and enabling drilling of wells with elevated wellbore pressures. This hoop or circumferential stress enhancement (CSE) technique, also known as “stress caging,” has gained considerable attention in the last few years.

This paper focuses on CSE applications in depleted sands above and below salt in the GOM. Drilling fluids were designed to effectively strengthen wellbores in zones with narrow drilling windows between wellbore collapse and fracture, while simultaneously maintaining low gel-strengths and shear-viscosity profiles. The combination of wellbore strengthening and effective ECD management led to substantial reduction in drilling fluid losses compared to past drilling operations in these areas.

## The Circumferential Stress Enhancement (CSE) Concept

The induced-fracture approach uses small fractures in the wellbore wall which are held open using bridging particles – Loss Prevention Material (LPM) – near the fracture opening. The bridge must have a low permeability that can provide pressure isolation. Provided the induced fracture is bridged at or close to the wellbore wall, an increase is created in the hoop stress around the wellbore – sometimes referred to as a “stress cage” effect. The intention is to achieve this hoop-stress enhancement continuously during drilling by adding sized particles to the drilling fluid system, creating a “designer drilling fluid.”[5] The concept is illustrated in **Fig. 1** and **2**.

Some lessons learned from previous field applications include”[5]

- It is possible to achieve increases in effective wellbore strength of approximately 1,000 psi with fracture widths as small as 1 mm, and a fracture radius of about 1 m.
- A short fracture (at least a short propped length) is best because if the propped length of fracture is too long, it can re-open. Additionally, a wider fracture would be needed to achieve the same strength increase.
- Softer rocks require larger fracture widths.

LPM need to be strong enough to resist closure stresses. Calcium carbonate and graphite are types of particles used for wellbore strengthening in the GOM. Properly sized for the estimated fracture width, these particles will bridge near the fracture mouth and produce a near-wellbore CSE. An opening width of 1 mm requires a PSD in the range of colloidal clays up to values approaching 1 mm.

Equally important is that the plug be sealed quickly; it is important to mitigate fracture growth very quickly when it starts. This can be accomplished by additions of high concentrations of bridging additives, a wide range of particle size distribution, and producing a bridge that props open and seals the induced fractures.

The main engineering challenge is to maintain the desired particle sizes in the fluid during drilling. If the particles are too small to bridge near the fracture mouth, the fracture could still become sealed by the buildup of mud filter cake inside the fracture. Should that occur, the compressive stress generated at the wellbore would be lower after the fracture is sealed, resulting in little CSE, and the fracture itself will tend to extend much further than desired, resulting in increased risk of fracture reopening.

Interestingly, fracture gradients observed in sands are usually higher than predicted by theoretical models.[5] This seems to be related to the presence of the drilling fluid solids and the deposition of mud cake.

Using sized calcium carbonates in NAF (non-aqueous fluids), there have been successful applications of CSE drilling fluids, reducing and eliminating drilling fluid losses while drilling through sands found above and below salt in the GOM.

Additional observations from field experiences are:

- The fluid must contain a smooth/continuous range of particle sizes ranging from clay size (around 1 µm) to the required bridging width.

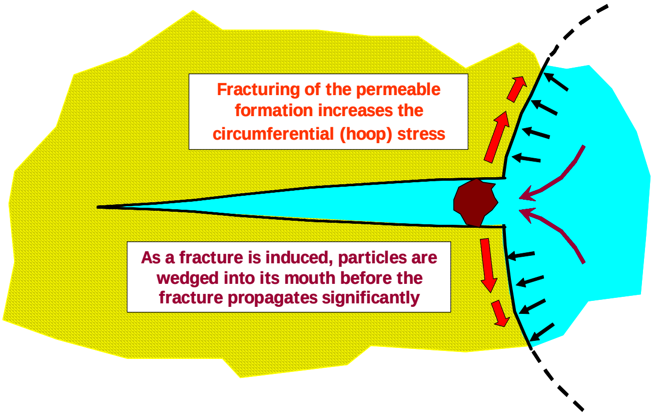

**Fig. 1 – Circumferential stress can be enhanced by generating shallow fractures and simultaneously bridging them with large, tough particles.**

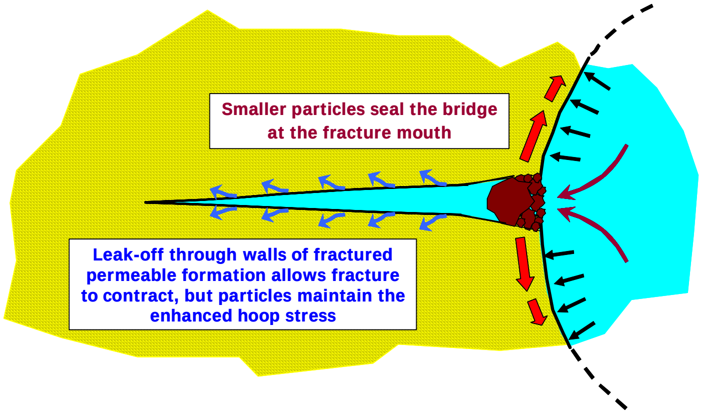

**Fig. 2 – To sustain the enhanced circumferential stress, smaller particles must seal the bridge to permit fluid in the fracture to leak off into the permeable formation and enable the fracture to close on the bridging particles.**

- Ideal packing theory (where cumulative PSD is proportional to the square root of particle size) is useful for selecting the optimum size distribution in low-weight drilling fluids used in proprietary software programs.
- Another approach uses $D_{10}$ to $D_{90}$ methodology, where the particles in the size range between $D_{10}$ and $D_{90}$ in the PSD are used to fill the estimated fracture width at the wellbore (**Fig. 3**).
- High particle concentrations are best, generally targeting 15 to 30 lb/bbl of bridging mix to achieve a successful seal.
- Fracture sealing has been successful at up to 275°F and 4,000 psi overbalance pressure while drilling the zones of interest in the GOM.
- Controlled drilling to avoid pressure spikes and giving careful attention to ECD while drilling to stay within the limits of the wellbore strengthening design will create a successful bridge with minimal drilling fluid losses.
- The use of alternative bridging materials, such as sized synthetic granular graphite, has been successfully integrated into the CSE fluid to seal wider fractures.

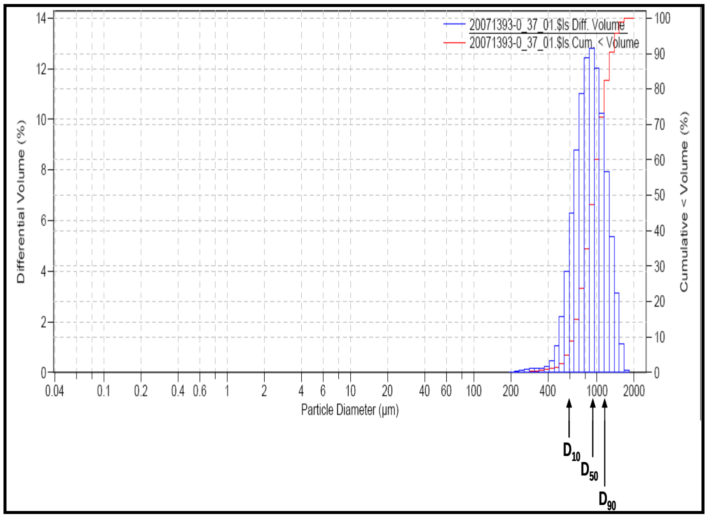

**Fig. 3 - Example of $D_{10}$ to $D_{90}$ methodology.**

## Engineering Considerations

To run the CSE drilling fluid requires non-standard drilling practices. To maintain the correct concentration and size distribution of the large LPM in the drilling fluid, there are two solids control options:

- Bypass Shakers
  - Reuse of LPM
  - Less material
  - Reduced treatments
  - Less waste
- Shakers with screens to screen out system
  - Control of LPM particle size
  - Less build-up of fine system solids
  - Sand removal from system resulting in:
    - Less wear on pump liners
    - Less wear of LWD tools
  - Increase in labor for continuous treatment
  - Increase in waste management
  - Increase in product requirements and logistics

Operators have been successful by loading the circulating system with large solids and maintaining the PSD with continuous additions of the large bridging material to the system while drilling. One such example is shown in **Fig. 4**.

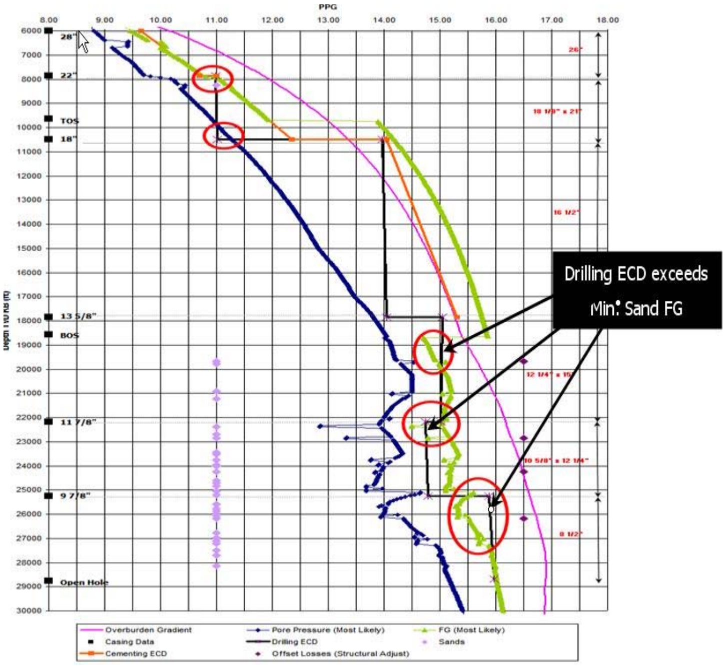

**Fig. 4 – Application of CSE to well with elevated pore pressure approaching (and required mud weight and ECD exceeding) the sand fracture gradient.**

Wet Sieve Analyses (WSA) are performed at the rigsite to maintain PSD targets within the fluid design specifications and to determine what size particles are needed in hourly maintenance of the fluid system. The rule of thumb is 15 to 30 lb/bbl of bridging solids must be kept in the system. These challenges can be overcome successfully by considering the following learning's from past CSE operations:

- To collect cuttings samples, the upper deck of one shaker can be dressed with 175-mesh screens with the omission of the last screen to allow the particles to remain in the system.
- The increase in drilling fluid rheology due to the build-up of drilled solids (low-gravity solids) requires less maintenance than expected by using a non-temperature-dependent NAF fluid to maintain a flat rheological profile and gel strengths across a temperature range from 40 to 150°F.
- Attrition of the bridging solids also needs to be closely monitored using the wet-sieve testing

procedure to maintain the desired PSD.

- Hourly maintenance to the system can be increased or decreased based on the trends observed from wet-sieve testing.
- Fluid density is easily maintained with minimum dilution.
- Based on experience in the GOM, there have been no instances of erosion of the drilling fluid pumps while drilling in this manner.
- Downhole equipment failures have been a problem, but there has been no evidence that the failure was caused by the sized particles in the fluid design.
- Minimal formation damage has been observed from the introduction of these sized particles, especially in naturally-fractured reservoirs.
- Economics are favorable for using large mesh screens to minimize additions of bridging agents.

An example of a PSD gathered from a WSA run is shown in **Fig. 5**.

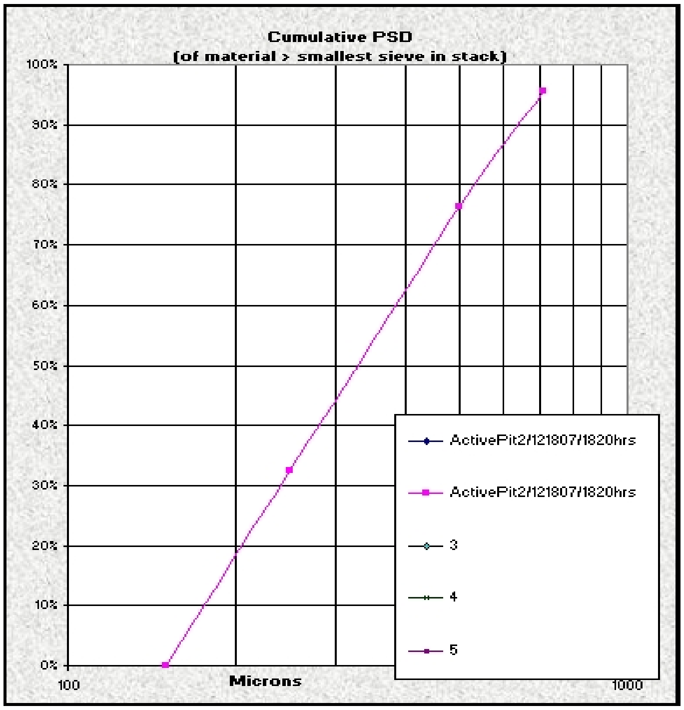

**Fig. 5 – PSD of LPM from Wet Sieve Analysis.**

These observations represent challenges for a successful application using this type of fluid. The challenges should not be underestimated, but, with planning, the system can be successfully run as shown in the examples given below. Field experience to date has shown that interval lengths of at least 14,000 ft can be drilled with acceptable levels of system maintenance and with the rheology and drilling fluid weight kept within an acceptable range.

Drilling fluid pump erosion has not been an issue with marble-grade calcium carbonates blended with graphitic material, as shown in **Fig. 6**.

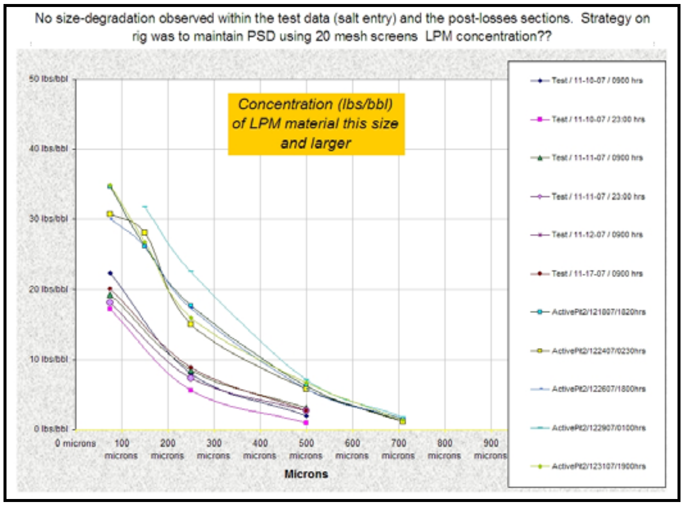

**Fig. 6 – PSD of LPM over several days.**

Formation damage potential requires further study, although in many cases wellbore strengthening is needed only across the non-pay intervals. In terms of economics, the technique is very cost effective, reducing losses and additional rig time if lost circulation occurs.

The engineering can be greatly simplified by using the CSE drilling fluid with regular additions determined by the wet-sieve test results. The section can be drilled at a drilling fluid weight below the fracture gradient, and then subsequently strengthened while drilling using the pre-determined particle sizes in the drilling fluid across the weak zone. These sized particles quickly strengthen the hoop stress of the near-wellbore and have successfully increased formation integrity up to 0.4 $lb_m$/gal, resulting in minimal or no losses while drilling the zone of interest. The CSE remains in place when the pressure is reduced for connections; of course, careful attention must be given when turning the pumps on after making a connection to avoid a spike in pressure that will exceed the maximum pressure of the design. This technique has been used in one of the examples given below.

## CSE High-Angle Hole-Cleaning Techniques

The formation is exposed while drilling to the target strength and generating the CSE. Care must be taken not to exceed the maximum pressure while drilling, tripping in the hole, and running casing.

- The CSE drilling fluid must be maintained with hourly treatments and testing to ensure that the desired particle size is present when inducing a CSE.
- Use good rheology, combined with controlled drilling rates and avoid the use pills, if possible. If a sweep is needed, follow these recommendations:
    - Sweep = 400 ft of annular volume.
    - Sweep = ~3 lb/bbl heavier than system.
    - For < 30° angle use a viscous pill.
    - For > 30° angle use a heavy pill.

- No more than one sweep in the hole.
- Do not use high/low-viscosity pills.

Use good drilling practices, adequate flow rates, and proper fluid maintenance to allow for cuttings transport in deviated wells.

The key variables which influence cuttings transport are:

- Cuttings size
- Cuttings/fluid density
- Drillpipe eccentricity
- Hole size and angle
- Flow rate
- Good low-shear-rate rheology
- Rate of penetration
- Drillpipe rotation
- Hole cleaning sweeps

## Field Experience #1 – Deepwater GOM: CSE above Salt

Mud losses and wellbore stability while drilling offset wells in this area were identified as major challenges to drill a sand section above the salt in this 30,000+ ft well. This 2,600 ft+, 18⅛-in. x 21-in. interval, above salt, was drilled with no mud losses or downtime related to hole stability. Screens of 14-mesh over 20-mesh were used on 6 shakers with one shaker dressed with 175-mesh screens on the top deck in order to catch cuttings samples. The intention was to omit the last screen on the top deck of one shaker in order to allow the fluid and LPM to pass through the 20-mesh screens and be retained in the system. Using this method, cuttings integrity was improved compared to two offset wells using conventional 110–140 mesh screens. An 18-in. liner was set, and the shakers were dressed with 120–140 mesh screens while drilling 7,000+ ft of salt without incident, and 13⅝-in. casing was run. The 12¼-in. x 15-in. salt exit was drilled (4,300+ ft) without incident and an 11⅞-in. liner was run, though the liner hanger failed to set. A second hanger failure required a clamp tool be run below, and a successful cement squeeze was performed to seal the ~300 ft liner lap.

The low-pressure sand section was drilled without losses, followed by a shale section with an expected pressure regression. At this point, a 75-bbl kick was taken and circulated out. This kick required a 0.4 lb/gal increase in density, and the ECD generated from the increased mud weight exceeded the maximum ECD design of the CSE plan. The shale fractured, and severe mud losses were encountered. An expandable liner was successfully run to seal off the fractured zone. The rig had a power drive failure, which was initially thought to have been caused by the high concentration of LPM in the mud. Once the tool came in and was inspected, cement pieces as large as ½ in. were discovered, and it was determined that the cement was the primary cause of the failure. There were two other mechanical failures of downhole tools while drilling this well, but there was no evidence that the LPM caused the failures.

There were zero mud losses in this well while drilling the zones of interest using the continuous application of LPM. More than 19,000 ft was drilled with this technique using 20-mesh screens, which greatly reduced cost in materials and rig time.

## Field Experience # 2 – Deepwater GOM: Increasing Sand Fracture Pressure using LPM

In the following wells, the sand fracture pressure at the wellbore was apparently increased through the addition of appropriate LPM. Calculated sizes of calcium carbonate and granulated synthetic graphite had been added to the synthetic-based drilling fluid (SBM) circulating system up to a total concentration of 24 lb/bbl. . This was to fit the expected microfractures that would develop if the 13.9-lb/gal sand fracture gradient of sands in the upper part of this interval were stressed to 14.2 lb/gal. The interval was drilled with a planned maximum ECD of 14.0-lb/gal ECD and monitored with PWD tools capable of observing changes as small as 0.01 lb/gal. At 1,000-ft TVD from the shoe, the LPM were screened out of the system as planned, as only the sands close to the shoe were deemed to be weak enough to need the treatment.

After drilling ~2,000 ft, additional sands with a fracture gradient of 14.0 lb/gal were drilled using fluid with 14.0-lb/gal ECD. Total fluid loss of 1,542 bbl was observed. Losses were eventually controlled with reduced mud weight and resulting maximum ECD of 13.6 lb/gal, reapplication of the 24-lb/bbl LPM for upcoming sands, and controlled drilling to interval TD. An MDT was run with a confirmation of the loss zone, sand pressure being 14.0 lb/gal, and the upper sands pressure limit (where no losses occurred) was 13.9 lb/gal, as predicted. This validates that the LPM application was able to prevent losses in the upper 13.9-lb/gal sands while drilling with 14.0-lb/gal fluid; and when the LPM was removed from the mud, the lower, 14.0-lb/gal, sands could not withstand an ECD of 14.0 lb/gal.

The next well drilled less than 3 miles from this location was treated with the calculated LPM in the system through this interval where the same sands were to be encountered. The same ECD program was applied with no losses throughout the interval.

The most frequent applications of elevated ECD in these wells have been while running the casing to TD, circulating the casing/liner in the small annulus, cementing, and displacing the heavy cement. Typically, without LPM, 700 to 2,200 bbl of fluid – most averaging 1,500 lb – are lost during these operations in this and other intervals. With the LPM left in the fluids to TD, there were zero losses for the casing job operations.

## Field Experience # 3 – Deepwater GOM: Continuous LPM Treatment with Conventional Screens

Following the 14.7-lb/gal leakoff test (LOT) of the 13⅝-in. casing, the system was treated with calcium carbonates and graphitic materials in the following median size ranges as per the CSE design:

710 microns – 5 lb/bbl
500 microns – 3 lb/bbl
250 microns – 7.5 lb/bbl
40 microns – 5 lb/bbl

110-mesh screens were utilized initially until the build-up of low-gravity solids (LGS) and the associated increment in rheology increased ECD as high as LOT limit. The shakers were screened up to 175 mesh to clean the solids from the system, but the CSE formulation was maintained until the desired TD of the interval was reached. There were no sub-surface losses reported while drilling the interval, though 294-bbl SBM were lost while running and landing the casing on the landing string, and 118 bbl were lost while attempting to circulate the 11⅞-in. liner. The ECD with 4 bbl/min flow rate exceeded the LOT of the 13⅝-in. casing, and circulating was discontinued. SBM loss while cementing and displacing the cement was 2160 bbl. This was attributed to the close tolerance of the casing sizes and the increase in the ECD above the LOT while circulating and cementing casing.

An LOT was performed at the shoe of the 11⅞-in. liner to 15.9 lb/gal. The LPM formulation above was continued in the 10⅝-in. x 12¼-in. hole interval and added to the system on an hourly basis to maintain the formulated concentrations. There were no sub-surface losses reported in the interval.

## Summary

- Circumferential (hoop) stress enhancement (CSE), or stress caging, has been successfully demonstrated in various deepwater drilling operations in the Gulf of Mexico.
- Short fractures are deliberately generated at the wellbore wall, which are simultaneously propped and sealed continuously using a mud treated with LPM of the size and concentration required to generate the desired stress distribution to prevent inducing additional fractures.
- Field applications of CSE techniques have shown significant reductions in losses of synthetic-based muds in depleted sands.
- Engineering and logistics need to be carefully managed to apply CSE continuously in the field.
- The application of this technique is far-ranging and includes avoiding mud losses while drilling depleted sands, running casing, and cementing.
- Wet Sieve Analysis of the fluid is an effective way to monitor and maintain the concentrations of the desired particle sizes in a CSE fluid.

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## Nomenclature

*ECD = Equivalent Circulating Density*
*GOM = Gulf of Mexico*
*CSE = Circumferential (Hoop) Stress Enhancement*
*LPM = Loss Prevention Material*
*LOT = Leakoff Test*
*MD = Measured Depth*
*NAF = Non-Aqueous Fluid*
*PSD = Particle Size Distribution*
*WSA = Wet Sieve Analysis*

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