LOST CIRCULATION SOLUTIONS
FOR PERMEABLE AND FRACTURED FORMATIONS

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ABSTRACT

Loss of drilling fluid to the formation is one of the most costly problems that drillers face during well construction. Common methods used in the past involved incorporating materials in the fluid or in pills to bridge permeable or fractured formations and create filter cake over these bridges. Current technology enables a comprehensive approach that complements these methods but includes with equal emphasis other aspects of the drilling operation: use of best drilling practices, including Managed Pressure Drilling techniques; optimization of hardware configuration and performance; use of drilling fluids that inherently reduce the rate of loss of fluid via enhanced low-shear-rate viscosity; minimization of fluctuations in the fluid's equivalent circulating density; use of wellbore stability models that model rock and fracture mechanics more accurately; and "strengthening" the wellbore.

INTRODUCTION

According to a recent James K. Dodson Co. study (1993-2002 NPT Analysis), instability-related problems account for 44% of Non-Productive Time (NPT) during drilling of oil and gas wells. These problems include lost circulation, stuck pipe, flows, kicks, sloughing shales and wellbore collapse. Of these, lost circulation has been and still is one of the biggest contributors of NPT.

With the advent of extended reach drilling and with the increased emphasis of deepwater drilling during these last few years, lost circulation now accounts for an even larger share of NPT than determined in the 1993-2002 Analysis. The issue of drilling into depleted zones is also increasing in importance as fields mature, and the risks associated with lost circulation are keeping pace. These producing reservoirs often are overlaid and interbedded with relatively impermeable shale layers. Mud densities sufficiently high to stabilize the shales can generate very high overbalances in the accompanying depleted sands. Pressure overbalances have been reported as high as 13,000 psi in the Gulf of Mexico, but more typically are on the order of a few thousand psi, as found in the North Sea. Such high overbalances increase the likelihood and severity of lost circulation.

In addition to the costs associated with lost drilling time, loss of drilling fluid itself to the formation contributes a large – and perhaps underappreciated – cost to the operation. This is particularly true for operations using NAF (non-aqueous fluids), i.e. oil-based and synthetic-based muds (OBM/SBM).

Common methods used in the past to curtail lost circulation have focused primarily on mitigating the problem by incorporating materials in the fluid or in pills to bridge permeable or fractured formations and create filter cake over these bridges to "seal" the loss zone. Indeed, drilling fluid service companies have emphasized the remediative aspects of the technology, i.e. stemming lost circulation after it has occurred. The persistence and continued costliness of lost circulation attests to the limited success of this approach and indicates that this costly, pervasive problem needs to be addressed comprehensively, focusing on preventing it, as well as mitigating it.

FUNDAMENTALS OF LOST CIRCULATION

Lost circulation is classified/categorized to facilitate design of appropriate prevention/mitigation solutions. The most common classification schemes use (a) the rate (or magnitude) of fluid loss and (b) the loss mechanism. The rate of fluid loss may be categorized as seepage (1-10 bbl/hr), partial loss (10-100 bbl/hr) and severe loss (>100 bbl/hr). The loss mechanism may be classified as matrix fluid loss, losses in existing fractures and losses in induced fractures. The loss mechanism classification scheme is recommended because proposed lost circulation solutions must address the source of the problem. Losses can occur in existing open fractures or voids at any time. In existing but closed fractures, losses can occur if the fractures are re-opened, which will happen if the equivalent mud weight exceeds the minimum horizontal stress, S_{hmin}. Fractures are induced when the mud weight exceeds the fracture gradient (FG) of a formation. This is most serious when drilling deviated wellbores or depleted zones. For deviated wellbores, the window between the pore pressure (PP) and FG generally becomes narrower the greater the hole angle. In depleted zones, PP drops as the reserves decline. This invariably weakens the permeable reservoir formations, while the PP of neighboring or interbedded low-permeability rocks (like shale) is affected very little. Thus, with increasing depletion, fracture resistance of the more permeable sections declines, and sometime during the life of the reservoir the mud weight required to support the impermeable sections will likely exceed FG of the more permeable sections.

LOCATION OF THE LOSS ZONE

As important as the type of loss is its location. If losses first occur while drilling ahead, or are accompanied by a change in torque or a drilling break (including the bit dropping), then the losses are likely to be on bottom. If losses occur while tripping or increasing mud weight, then the losses may be off bottom. If necessary, a temperature or spinner survey can be run.

Various strategies may be used to prevent or control lost circulation. It is, of course, best to prevent lost circulation, and much research and development is being devoted to avoidance of induced fractures, as well as minimizing losses in existing fractures and permeable zones. The emphasis on prevention of induced fractures is important because once a fracture has been initiated, it is easier to propagate it and incur continuing fluid losses. The pressure required to lengthen a fracture – a function of S_{hmin} – is less than the fracture initiation pressure (FG); not only does fluid invade at an equivalent mud weight lower than FG, but the invading fluid can also destabilize a larger section around the wellbore. Irrespective of the mechanism, the risk of lost circulation can be reduced by incorporating into the well plan appropriate drilling practices, hardware and drilling fluid.

PREVENTION AND CONTROL OF LOST CIRCULATION

Drilling Practices

Good drilling practices that can serve to prevent or lessen the impact of lost circulation include the following:

- Obtain a good understanding of the rock formations, particularly their history and mechanical properties.
- Minimize Equivalent Static and Circulating Densities (ESD and ECD):
    - Accurately calculate hydraulics profile of the well.
    - Use good hole-cleaning practices.
    - Optimize solids control equipment configuration and performance.
    - Use minimum mud weight while drilling, and increase mud weight slowly when weighting up.
    - Use maximum low-shear-rate viscosity and flat gels.
    - Maintain low fluid loss and thin filter cake.
    - Follow prescribed tripping schedules.
- Use Managed Pressure Drilling (MPD) to reduce ECD.
- Employ Casing While Drilling (CWD) where indicated.

Determining an accurate geomechanical picture of the wellbore is paramount. This means using data and wellbore stability models that generate locally accurate PP, S_{hmin} and fracture gradients, rather than average gradients. In addition, real-time monitoring of downhole pressure and condition of the well and drilled cuttings is essential.

Accurate determination of the ECD at every point in a wellbore is also key to controlling stability of the wellbore. Again, real-time monitoring of the ECD is essential. Some good hydraulics calculation tools are available for this purpose. These also should be able to provide optimum trip velocity and acceleration schedule, to minimize surge and swab pressures. Indeed, trips should always be carried out to minimize shock to the wellbore:

- While tripping in, break circulation at the shoe and approximately every 300 m in open hole.
- Circulate for at least 5 minutes.
- Bring the pumps up slowly after connections.
- Rotate the pipe before turning on the pumps.
- While tripping out, pump out for the first few stands/singles off bottom.
- Keep tripping speeds low across areas of potential lost circulation.
- Consider use of lubricants to reduce drag.
- Consider use of sweeps to clear cuttings from the wellbore prior to POH to run casing. This will minimize cuttings bridges when RIH casing and cementing.
- Use annular fluid velocity that is just sufficient to clean the hole.

- Control ROP to avoid loading the annulus.
- Reduce the length of the exposed loss zone and reduce influx size.

MPD techniques should be investigated to determine if they are economically viable. Unlike Underbalanced drilling operations and Power Drilling, the primary objective with MPD is to obtain a stable wellbore within a narrow operating PP/FG window, and influx of formation fluids is avoided. MPD effectively manipulates the pressure window so that the fluid "walks the line" between wellbore collapse and wellbore failure (fracturing, ballooning) with greater certainty. An important goal of MPD technology is to stretch or eliminate casing points. In a typical MPD application, the fluid system is closed utilizing (a) a Rotating Control Device (RCD) and a drilling choke to restrict and control the exposed wellbore pressure profile, and (b) a casing pump to provide back-pressure when required. However, other configurations are also used, and the range of possibilities is expanding rapidly.

In CWD, a well is drilled and cased simultaneously using standard oilfield casing. The BHA is latched into the bottom joint of casing and is run and retrieved through the casing via wireline. For directional or horizontal wells, the BHA can be fitted with conventional directional equipment, such as mud motors and measurement-while-drilling (MWD) tools. Since these tools are run and retrieved inside casing, they are protected from the harsh downhole environment while in transit. This eliminates problems that typically occur during tripping operations, such as kicks, unintentional sidetracks, casing wear, and wellbore instability due to surge/swab pressures and formation sloughing/swelling.

Hardware

Minimizing hardware restrictions and optimizing hardware performance is equally important. For <u>surface equipment</u>, (a) use solids control equipment that is able to maintain a designed concentration of low-gravity solids in the mud; (b) remove pump strainers; (c) line up surface piping so that at least one mud pump can be rapidly switched to water or seawater; (d) have all surface equipment pressure-tested in advance, and offshore, have the ROV/SSTV check the riser for leaks on a daily basis. The normal procedure would be to check for leaks in the surface equipment before assuming that losses were down hole. There might not be time for this, so constant vigilance on the surface equipment is essential; (e) ensure that no mud transfers, additions, or dilutions are carried out while drilling proceeds towards or in a loss zone.

For <u>downhole equipment</u>, (a) remove bit nozzles if large losses expected; (b) minimize the BHA. No stabilizers and only the minimum number of drill collars and heavy weight drill pipe should be run. Restrict angle build by maintaining high RPM and low weight; (c) avoid running tools with limited flow paths or restrictions where possible. This includes core barrels, MWD, mud motors, floats and survey rings; and (d) avoid running drill pipe casing protectors, as these can swell and act like packers.

Drilling Fluid

Drilling fluids that can help to prevent or mitigate lost circulation create less stress at the wellbore or reduce the rate of loss of fluid into permeable or fractured formations. These fluids are generally very shear-thinning, so that they either possess a yield stress or a very high low-shear-rate viscosity, a low Yield Point and a low high-shear-rate viscosity. Several types of drilling fluids meet at least some of these criteria:

- <u>Conventional Reservoir Drilling Fluid</u> – for reservoirs, of course
- <u>Underbalanced Fluid</u> – depleted zones
- <u>Aphron Drilling Fluid</u> – depleted zones
- <u>Brine-Weighted or Micronized Fluid</u> – deep wells, reservoirs
- <u>Flat Rheology (temp-insensitive) Fluid</u> – narrow PP/FG window, such as deep water and ERD (extended reach drilling)
- <u>Silicate</u>, <u>Aluminate</u>, <u>Ultra-Low Solids</u>, <u>Gilsonite Drilling Fluids</u> – microfractured, fragile shales

Maintaining good drilling fluid properties, regardless of the type of fluid, is also of paramount importance. Key properties for minimizing lost circulation are as follows:

- Keep the mud weight as low as possible yet provide a satisfactory overbalance (and riser margin offshore).
- Maintain gel strengths, yield point, and viscosity at the lowest levels which will effectively clean the hole. High viscosities can increase the ECD to a level that will break down the formation while circulating.

- Maintain low MBT levels.
- Keep fluid loss low to prevent excessive filter cake buildup.

LOST CIRCULATION MATERIALS

Various other techniques can be used to minimize loss of drilling fluid to a formation. The most prevalent of these is the use of Lost Circulation Materials (LCM) in the whole drilling fluid or in 30- to 100-bbl pills that are added regularly, e.g. every 30 to 100 ft, or when losses occur. The solution depends on the type of loss zone expected to be encountered:

- Permeable and Naturally Fractured Zones
  - General Solution - calcium carbonate and other granular materials, supplemented with fibers. An effective prescription:
    - Pill – Blend of 30 ppb sized synthetic graphite + 30 ppb sized $CaCO_3$; in some cases, a broad blend of materials may be used successfully.
    - Whole Mud – Blend of 10 ppb sized synthetic graphite + 10 ppb sized $CaCO_3$.
  - Severe Losses – high-fluid-loss pill perhaps followed by cement, or a permanent and impermeable plug, e.g. cross-linkable pill.
- Another option for Natural (Existing) Fractures:
  Increase Fracture Re-Opening Pressure – synthetic graphite + $CaCO_3$.
- To prevent Induced Fractures:
  Increase Hoop Stress around Wellbore – over-size synthetic graphite + $CaCO_3$.

Even when using LCM in the whole mud, it is prudent to have an LCM pill on hand. A minimum of 100-bbl pumpable volume in a slug pit should be available. This should be mixed at the highest concentration of LCM that the agitators can handle. Additional LCM to 80 ppb can be added by dumping straight into the top of the pits or via big bags. In addition to an LCM pill, it is critical to have a large volume of reserve mud prepared.

WELLBORE STRENGTHENING

Formations can be strengthened several ways:

- Impose a Mechanical Barrier, e.g. expandable screens, cross-linkable plugs
- Dehydrate Water-Sensitive Formation, e.g. use low-water-activity OBM/SBM
- Increase Formation Temperature, e.g. via mud heaters
- Alter Downhole Stresses

Two different, but in many respects complementary, concepts are being used to Alter Downhole Stresses, particularly to control losses while drilling depleted zones: the “StressCage” concept is designed as a preventive treatment for the whole mud system, whereas the “Fracture Closure Stress” concept is designed as a remedial treatment and involves administering pills.

StressCage Concept

Building a “StressCage” involves changing the stress state of the permeable target formation in the near the wellbore, rather than altering the physical strength of the rock itself. LCM is added continuously at relatively low concentrations while drilling. The drilling fluid is overbalanced with respect to the FG of a target formation, thereby inducing shallow fractures – perhaps 6” in length – in the near-wellbore region. Sized bridging particles are driven into a fracture opening, propping it open but bridging it near the fracture mouth. Once isolated, pore pressure within the fracture can leak off into the formation, thereby limiting pressure build-up behind the bridge and any subsequent fracture propagation. This process of driving LCM into a shallow induced fracture has the effect of putting any rock adjacent to the fracture into compression, thereby increasing the hoop stress and increasing the force required to open the fracture further.

The StressCage concept is effective for controlling fracture propagation in permeable zones. It is not generally effective in limiting fracture propagation in impermeable zones, as pore pressures within the sealed fracture cannot leak off into the adjacent rock.

Given that the LCM material needs to form a good propped seal as near to the wellbore as possible, the type and size distribution of particles is critical. The D_{90} of the bridging particles must be matched to the maximum induced fracture width. However, recent work suggests that a D_{50} of the fracture width will suffice. Regardless, the blend has to be designed to minimize fluid loss and give pressure isolation that is sufficient for a lasting seal while drilling. The LCM used should also be physically strong enough to resist the closure stresses involved. At least 15 ppb of LCM material is recommended with this technique. A typical mix is 15 ppb synthetic graphite + 15 ppb sized $CaCO_3$. The overall particle size distribution of the drilling fluid should also range from colloidal to the maximum fracture width.

Basically, this technique relies on the PSD of the LCM -- through top shaker screen selection -- and dilution. However, potentially high loading of fine solids is likely to be an issue with this technique, as the procedure requires the removal of the bottom shaker screens. Hence, this method is likely to be restricted to smaller hole sizes such as 8.5 and 6-inch sections. PSD and treatments may be dictated by the solids control equipment in use at the rig site.

Fracture Closure Stress (FCS) Concept

The FCS process involves creating and subsequently plugging short radial fractures in a weak formation using high-fluid-loss pills after losses have begun. These plugged fractures then act as wedges, increasing the hoop stress around the wellbore enabling higher mud weights to be used without further fracturing. Unlike the StressCage approach, the treatment is applied as a pill containing relatively high quantities of LCM, although in a similar vein this procedure still covers wellbore strengthening using the stress cage process.

FCS is defined as the stress holding fracture faces together, and may be defined conversely as the fluid pressure required to open the fracture. If the mud density is decreased to a point where circulating pressures are less than the FCS, the fracture will close and any losses experienced should cease. Conversely, pressures exceeding this stress will subsequently cause the fracture to re-open and losses will continue.

The rock stress holding the fracture closed is composed of two major elements: (1) minimum principal far-field stress (aka S_{hmin}) created by the overburden pressure; and (2) compressive stress developed at the near-wellbore face due to tangential strains as the wellbore attempts to collapse. The latter is also known as the “hoop stress riser” or StressCage. Of these two stresses, the horizontal stress is the largest to overcome.

Unlike the StressCage method, whereby fracture propagation is minimized by quickly sealing the fracture mouth with material containing a broad PSD and allowing the pore fluid to bleed off into the surrounding rock, the FCS method entails widening the fracture by squeezing into it LCM material of a near-constant size. This subsequently becomes immobile as it “de-waters” (the carrier fluid drains away into the formation). This process prevents transmission of pressure to the fracture tip, thus halting any further propagation. As fracture width increases, the fracture closure stress also increases. In other words, FCS is enhanced by increasing the fracture width so as to compress adjacent rock, not by plugging the tip of the fracture. Losses cannot occur if FCS > ECD. However, if ECD is greater than the FCS, the fracture will widen, the “immobilized” LCM will be by-passed, losses will continue and the fracture will propagate. Further hesitation squeeze treatments should further widen the fractures to a point where the FCS is greater than the calculated ECD of the whole mud while drilling. As a general rule, multiple hesitation squeezes are required in low-permeability rock to maximize fracture width; fewer hesitation squeezes are required in high-permeability formations. Relatively high concentrations of LCM are used: > 100 ppb. The compressive strength of the LCM is not very important, as most of compressive strength of the immobilized LCM derives from the squeeze treatment. High fluid loss is more important, as this will accelerate formation of the immobilized LCM. An advantage of the FCS method is that no attempt is made to control the length of the fracture.

As more discrete volumes of material are used overall, the FCS approach is considered by some to be more adaptable to larger hole sections than the StressCage method, which relies on continuous addition of LCM. With traditional LCM, the FCS approach is limited to application in permeable formations, as is the case for the StressCage approach. However, with cross-linked polymer plugs, the FCS method can also be used in impermeable formations.

WHEN LOSSES OCCUR

If, in spite of everything, lost circulation still occurs, pull to the shoe before attempting an LCM treatment, and carry out pilot tests of the treatment before administering it. General practice calls for having enough open hole volume below the bit to accommodate the full treatment.

Various risks accompany most incidents of lost circulation. Cuttings often settle around the BHA during loss of fluid, and the pipe may become mechanically stuck. Settling cuttings will act as a packer and exacerbate losses below them, so it is prudent always to keep the pipe moving. As loss zones may be at low pressure, differential sticking is also a risk. In addition, reactive clays overlying the loss formation may become unstable if exposed to uninhibited fluids, so it is important to ensure that the clays are chemically stabilized at all times.

If losses occur in a highly permeable gas-bearing formation, even with the annulus closed, the likelihood of gas invasion into the drilling fluid is high. This will cause gas to migrate up the wellbore, displacing the mud in the well. If bull-heading is used, the bull-heading rate must never be less than 600 gpm. It is essential to be able to calculate the hydrostatic pressure in the well at all times. Thus, if it is necessary to pump a fluid into the well, the number of strokes pumped should be recorded to determine the fluid column height and, therefore, the hydrostatic pressure.

GLOSSARY

Depleted Zone Drilling (DZD) – Drilling reservoir sections with high pressure differentials between formations. These invariably involve large pore pressure differentials between permeable and impermeable formations.

D_{xx} – The particle size below which xx % of the particles exist, e.g. for D_{90} = 200 µm, 90% of the particles are of a size less than 200 µm equivalent diameter.

ECD – Equivalent Circulating Density.

FG – Fracture Gradient

Fracture Closure Stress (FCS) – The total compressive stress holding the mouth of a fracture closed. It is the sum of the combined overburden and hoop stress riser stresses. It has also been defined as the force required to initiate a fracture.

Hoop Stress – Induced tangential force around the wellbore by the wellbore fluid when the circumference of the wellbore is increased.

Hoop Stress Riser – Linear elastic response of the near wellbore region of a formation to a fracture. This is often now referred to as a “StressCage.”

PP – Pore Pressure

PSD – Particle Size Distribution, generally determined using laser light scattering.

S_{hmin} – Minimum horizontal stress

StressCage – The increase in near wellbore strength (stress). It has been argued that this is identical to the concept of the “Hoop Stress Riser”.

Wellbore Strengthening – A procedure designed to increase the shear strength of a formation, e.g. using a low-water-activity OBM/SBM, or by physically increasing formation hoop stresses.

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