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A Field Case Example of Wellbore Strengthening Design and Verification Process

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Abstract

Years of production depletion in a heavily faulted and fractured area can lead to increasingly higher drilling fluid loss rates. A process has been developed to design, test and implement a loss-circulation-prevention plan to mitigate losses and strengthen the wellbore.

This paper will describe how pre-existing logging data from offset wells and geomechanical modeling curves were used as inputs into a fracture aperture prediction software program to estimate fracture widths with probabilistic calculations. Once the fracture width profiles were obtained, suitable loss-circulation-material blends and concentrations, based on the software and the existing field database, were recommended to plug the expected fractures and limit or alleviate losses while drilling.

The initial loss–circulation-material blends and concentrations were further verified and optimized with experimental tests using different drilling fluids types and densities. The final optimized loss-circulation-material concentrations and lab tested blends were finally implemented in the field for strengthening the wellbore during drilling of the trouble zones.

This wellbore strengthening planning and design based on existing offset logging, geology and modeling data to estimate fracture widths with probabilistic calculations for loss-prevention-materials blend and concentration design, and further validation and optimization with corresponding laboratory tests are proved to be a practical and effective wellbore strengthening design and field operation process.

Introduction

The mud-weight window serves as a critical design factor for the design of both the well and drilling fluid system. It defines the range between the minimum weight to avoid well collapse (compressive failure) and the maximum mud weight to avoid formation breakdown (tensile fracturing), leading to loss of drilling fluids in the formation drilled. The mud-weight window may be very narrow under certain conditions, thereby requiring expensive design changes or rendering drilling impractical.

The problem of lost circulation is one that can have multiple sources in drilling operations. Leading causes for drilling fluids losses can be itemized as follows: (1) the ever increasing complexity of the wells to reach deeper and less accessible hydrocarbon rich rocks; (2) reduction of the formation fracture gradients due to reservoir depletion from heavily produced formations; (3) narrowing of the drilling margins especially in highly deviated wellbores and in deepwater prospects; (4) commercial constraints to access oil and gas reserves in confined land or lease environment that will only allow drilling in naturally fractured or heavily faulted formations. In many cases one single operation will encounter more than one of these causes in the same interval. When this occurs, a preventative lost circulation plan must address the multiplicity of the root causes and the plan must be developed before the well commences. Pre-planning for lost circulation has proven to be effective in many cases and reduce non-productive time (NPT) and development costs by eliminating the need for re-drilling or sidetracking the wells.

Many of the techniques for preventing lost circulation will fit under the broader term of wellbore strengthening which has been introduced and discussed in numerous industry publications. One such technique is to engineer suitable particle size distribution (PSD) and concentration of granular loss-circulation-materials (LCM) or loss-prevention-materials (LPM) to plug an existing or drilling-induced fracture and to raise the hoop-stress at the wellbore, thus to prevent loss of drilling fluids. The key components of applying this wellbore strengthening technique successfully are:

1. Understand and estimate accurately the size of the fracture(s) aperture. This requires the understanding of formation properties and drilling conditions such as fracture gradient, Young's modulus and equivalent circulating density (ECD).
2. Design appropriate LCM or LPM blends and concentration which can plug the anticipated fracture(s).
3. Verify and optimize, through laboratory testing, the LPM blends and concentrations for optimum strengthening performance.

This paper presents a wellbore strengthening design and verification process, illustrated through a case example from a drilling operation using the above three principal key components. Pre-existing logging data from offset wells and geomechanical modeling curves were analyzed for inputs, with probabilities such as P_{10}, P_{50} and P_{90} values, into fracture aperture prediction software to estimate fracture apertures with probabilistic calculations. Once the fracture width profiles were obtained, suitable blends and concentrations of LPM, based on field experience and software design were recommended to plug the predicted fractures to limit or alleviate losses while drilling. Finally, laboratory tests were performed to verify and optimize the blends and concentration for strengthening performance.

Drilling Program and Area Geology

An extensive logging-while-drilling program for a series of pilot wells was planned to better gauge the depletion levels and the evolution of the wellbore stresses in a highly fractured environment. Early seismic data indicated the presence of significant faulting in the vicinity of the proposed pilot wells. The offset wells loss circulation occurrences in the intermediate sections are thought to be the result of faulting problems at or below the level of seismic resolution.

It is commonly known that some faults will incur losses where others do not. Some data suggests that where faults do intersect, the stress environment can be altered and therefore will promote losses. Imaging log programs provided better understanding of the faulting systems and their structure for the pilot test wells.

Updated wellbore pressures models for each pilot well were also created using recent formation integrity test (FIT) data done on offset wells. New pore pressure and fracture gradient plots were derived from these field measurements on the offset wells.

Drilling Fluid Losses

The faults cited in the previous section were directly classified as a leading cause of loss circulation events in one of the offset wells in the targeted area where the well began ballooning and the 10.0-lb/gal drilling fluid was lost at 9,100 ft. The plan for the upcoming test wells show they will intercept the same faults.

While these wells are to be drilled with a non-aqueous fluid (NAF), it is well known that these fluids are considered to be less auto-healing and forgiving than water-based fluids when it comes to drilling through pre-existing fractures or faults. Thus supplementing the thinner and more lubricating filter cake properties of the NAF as compared to water-based fluids with plastering and sealing additives such as Gilsonite or asphalt material as well as filling agents such as crushed nut plug shells, has shown to be effective when added to the fluid before entering the loss zone. The design wellbore strengthening solutions considered in this paper does not take in consideration the plastering additives, it can however include particulate materials such as nut plug shells.

The other type of loss circulation occurrence in the offset wells is thought to be directly related to the wellbore pressure depletion from ongoing production. In fact, the drilling history in the area combed from information gathered by the operator and the drilling fluids provider indicates that there are high potential losses for the 12,000 to 13,000 ft interval and risk of kicks below 13,000 ft in the production interval. The average drilling fluid lost in the offset wells was calculated to be around 5.7 bbl of drilling fluid per bbl of hole drilled and as high as 8.8 bbl of drilling fluid lost/bbl hole drilled (Figure 1). Considering that the drilling fluid utilized was a NAF, this amount of fluid represents a considerable cost over the number of wells drilled.

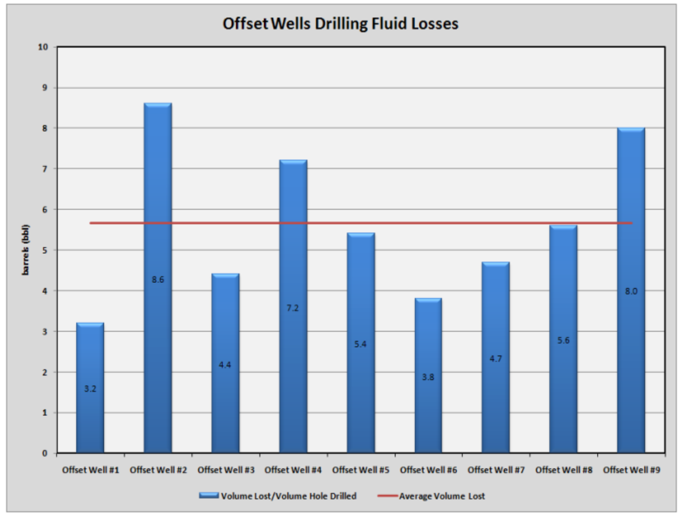

Figure 1: Drilling fluid losses from offset wells.

Wellbore pressures while drilling and running casing or liner were also a main cause of loss circulation in the offset wells. In both cases, the loss mechanism is one of downhole pressures that exceed the minimum horizontal stress considered to be the lowest pressure that the rock can withstand before failure.

When the ECD calculated using the drilling fluids provider proprietary hydraulics software is plotted overlaying the wellbore pressures diagram (figure 2), it becomes clear that induced fractures are more likely to occur below 11,500 ft where the fluid pressure will exceed the minimum horizontal stress.

Similarly, when running casing in the production interval, the ECD generated is also higher than the fracture pressure. The reduced annuli between the open wellbore and the tubing result in an increase in surge pressure that can often exceed that seen during drilling operations. It is very common to consider the casing or liner runs as having the potential to be the worst case for inducing losses.

Direct offset data show that drilling fluids losses are very inconsistent and can occur in the intermediate section as well as in the production interval where high overpressures necessitate spotting heavy drilling fluids pills for tripping out of the hole during normal drilling operations. The displacement of these tripping pills causes the ECD to exceed the formation fracture gradient and often will be the triggering factor for the loss circulation events experienced in many of the offset wells. Hydraulics simulations show the ECD to be much higher than the estimated fracture gradient while pumping these tripping pills and displacing them in the annulus.

The recommendation was made to make the preventative usage of this available hydraulics modeling tool to be available to the field personnel for planning the pumping and displacement of these high density pills in fractured and weakened formations. This would assist in optimizing the drilling practices, develop better pumping schedules and therefore reduce the occurrence of induced losses while displacing the tripping pills.

A simulation for spotting the tripping pill (Figure 3) shows that the ECD's are high enough to induce fracturing and loss circulation at the flow rates considered. Reducing the flow rate while pumping the tripping pills has proven to be an efficient way of controlling the ECD to a level that would prevent opening or propagating fractures.

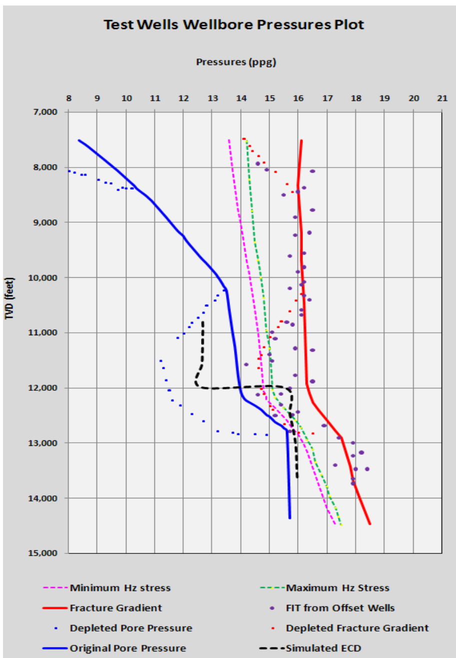

Figure 2: Wellbore pressures and ECD diagram.

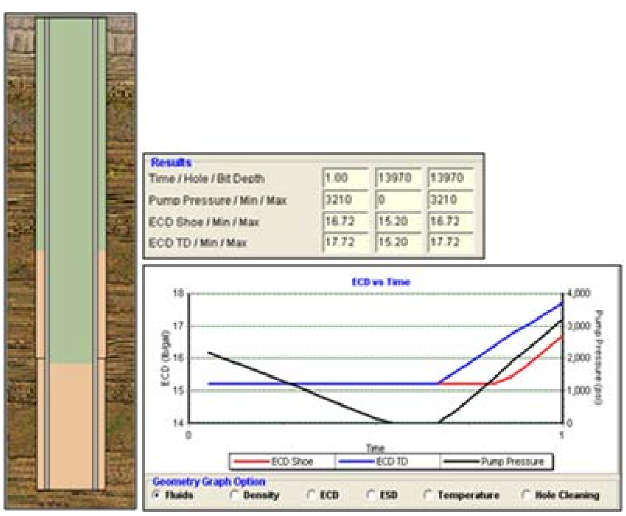

Figure 3: Tripping pill pressures and ECD profiles.

Wellbore Strengthening Modeling

In order to safely drill through pressurized zones and maintain wellbore stability, the equivalent static density (ESD) needs to be higher than the formation pressure at any time. When circulation and friction are applied, the ECD is the controlling element of formation breakdown pressures and must not exceed the predetermined fracture gradient (FG). In many cases, the breakdown or fracturing of the formation is verified while drilling by performing leak off or extended leak off tests (LOT and XLOT) or formation integrity test (FIT). In the present discussed case, LOT's performed on offset wells showed that the formation breakdown pressure (FBP) was closer to the minimum horizontal stress curve than to the FG curve and that this was most likely due to depletion of the reservoir pressure.

The wellbore strengthening process adopted for this case was one of the designer drilling fluids using particulate blends engineered to alter the near wellbore stress state.[1-4] The design relies on probabilistic prediction of the width of the fractures that are created every time the wellbore pressure applied by the circulating drilling fluid or ECD on the formation exceeds the minimum horizontal stress as discussed by Guo et al.[4]

The proprietary software package used for fracture width prediction exists in a form of a spreadsheet template and uses Monte Carlo statistical analysis to generate distribution of possible fracture widths. The program main inputs can be derived from wellbore pressure plots or geomachanical studies and casing designs (minimum horizontal, maximum horizontal stress, overburden pressures, planned mud weight (MW), stress orientation, wellbore inclination). Hydraulics calculations assume the worst case scenario (the highest ECD that the wellbore will experience) and logging or geological data (Young's Modulus and Poisson's Ratio).

A first wellbore strengthening plan was designed for the drilling case. For this purpose the drilling fluid provider's proprietary hydraulics software was used to generate the drilling ECD curves which were plotted in the already existing wellbore pressures diagram (Figure 2). This overlay confirmed the loss circulations events experienced in the field and identified the zone at which loss circulation from induced fractures was the most likely to occur (Figure 2).

For the purpose of the fracture width prediction, it is common practice to add an additional margin to the simulated maximum ECD's of 0.5 lb/gal, and in many cases 1 lb/gal, to account for eventual surge situations when circulation is re-established too abruptly or when pipe is moved downhole too fast. This practice overestimates the fracture widths generated and thus generates LPM blends with particulates slightly larger than needed to account for uncertainties and for down hole particulates mechanical degradation. It should be noted that the particulate blends size distributions that are effective in sealing the larger fractures modeled will also plug the smaller, generated fractures. The PSD of the LPM blend generated with the fracture width and sealing prediction software will be then tested in a laboratory environment to confirm the plugging to confirm the sealing capabilities against the anticipated fracture apertures.

The second wellbore strengthening plan was designed for the loss events occurring when pumping and displacing the tripping pills as mentioned in previous sections. For this case also, the hydraulics software was used to generate the maximum ECD that will be reached when the high-density pill enters the open hole (Figure 3). This value of ECD was once again used in the fracture width prediction software to generate a statistical distribution of fractures that might occur each time this procedure is applied. The recommended LPM blend would need to be present in the drilling fluid at an appropriate pre-determined concentration before the tripping pill is pumped.

The variability of the formation drilled introduces an additional uncertainty that can affect the software analysis. Available logging and geology data for the offset well offers the possibility of approximating some of these data. Figure 4 and Figure 5 illustrate probabilistic distributions for Young's modulus and Poisson's ratio for the considered offsets. A statistical analysis of the supplied Young's modulus and Poisson's ratio curves was made to determine the minimum (P_{10}), most likely (P_{50}) and maximum (P_{90}) values of these properties to be used as inputs in the fracture modeling software.

Once all the necessary data is collected and analyzed, the design of the wellbore strengthening plan itself using the fracture prediction and bridging software can commence. Figure 6 shows an example on how the data of this application was used, the values of the inputs and the generated results for the fracture widths and the associated bridging blend PSD.

The software analysis can be re-run changing one parameter intensity or range to see how that would affect the predictions. The results obtained running multiple simulations for this particular application consistently generated fracture widths between 800 to 1,200 µm. The blends generated by the fracture width prediction and bridging software were then submitted to testing to verify their sealing properties in laboratory conditions and under similar pressure parameters. The testing section of this paper gives details on the apparatus used and the testing procedures.

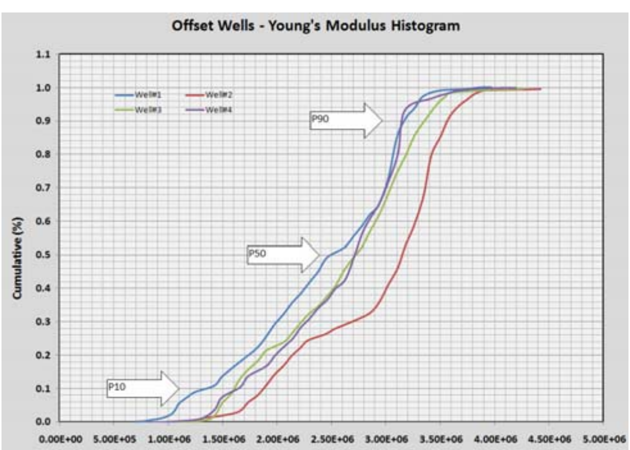

Figure 4: Young's modulus distributions from offset wells.

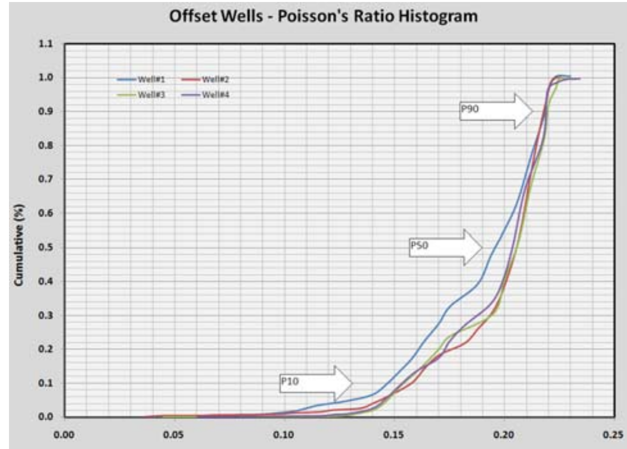

Figure 5: Poisson's ratio distributions from offset wells.

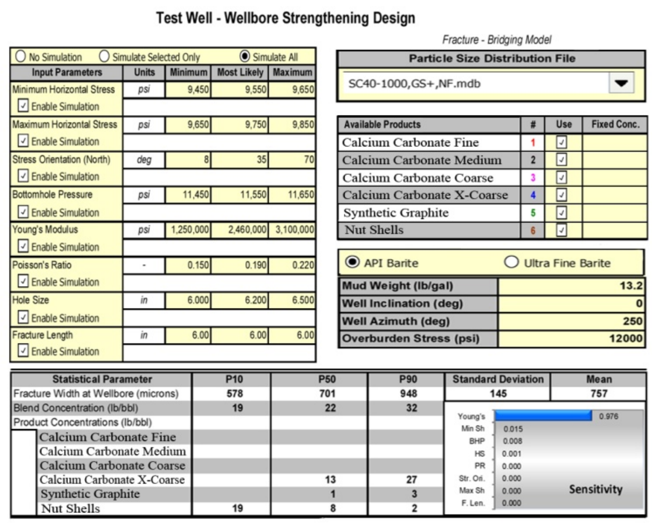

Figure 6: An example of fracture aperture predictions and LPM blend recommendations.

Wellbore Strengthening Laboratory Testing

Once the fracture aperture range is estimated from offset well data and drilling experience, LCM/LPM blends can be designed, tested and optimized to plug the given fracture widths using a laboratory technique. The fracture plugging testing apparatus consists of two circular plates 5-inch in diameter. The gap between the two plates was set to simulate the fracture aperture (Figure 7). The plates are either impermeable or permeable; for this test validation, impermeable plates were used. A constant pump rate was used to inject the fluid containing the LCM/LPM blend into the simulated fracture. The top plate is milled with a ⅜-in. hole in the center while the bottom plate does not incorporate a hole. Fluid entering through the center hole in the top plate is forced between the plates. This method simulates the washing away of any initial fracture sealing material and is also analogous with a remedial treatment.

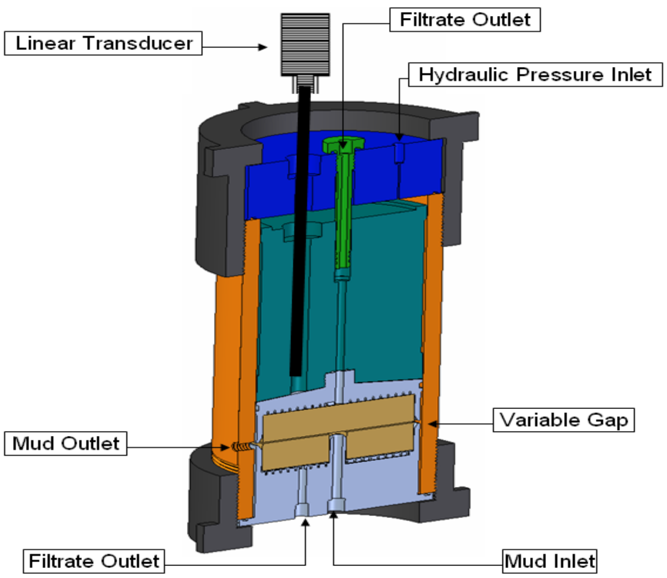

Figure 7: Laboratory setup for fracturing sealing testing and verification.

Various LCM/LPM blends and concentrations were tested to verify and optimize their strengthening performances for plugging fracture apertures of 1,000 to 1,200 microns. For example, Figure 8 shows the testing results as a function of pumping time for a 40-lb/bbl calcium carbonate LCM material (d_{10} = 60 µm, d_{50}= 450 µm and d_{90} = 1,350 µm) were used to plug a 1000-µm fracture between two impermeable plates.

The upper graph shows the conduction loss of fluid to the fracture tip (thick blue line) in milliliters. The black line is the measured fracture width opening in millimeters; the fracture width is adjusted throughout the test by the computer-assisted hydraulic controls applying pressure on the plate. Momentary spikes in the fracture aperture are observed when the failure of fracture seal causes a momentary jump in the fracture aperture. The green line is the filtrate volume in milliliters that has moved through the permeable disk. On an impermeable disk, this value will remain at zero.

The lower plot shows the mud injection or wellbore pressure (red line), the back pressure in blue (or pore pressure at the fracture tip, which is usually set at 500 psi), and the fracture closure pressure in green (which is acting perpendicular to the fracture plane). Lastly, the yellow/orange line in the lower plot is the estimated location of the fracture seal. As can be seen from Figure 8, the effective strengthening pressure, the excessive wellbore pressure over the fracture propagation pressure (500 psi in the test), varied from 700 psi to 1,700 psi.

As shown in Figure 9, a 25-lb/bbl LCM blend of calcium carbonate and medium-grind nut hulls can plug fractures of 1,200-µm aperture and achieve effective strengthening pressure increase from 1,100 to 2,100 psi. This is considerably better than either a 40-lb/bbl LCM containing only calcium carbonate or a 40-lb/bbl LCM blend of cellulosic material and calcium carbonate.

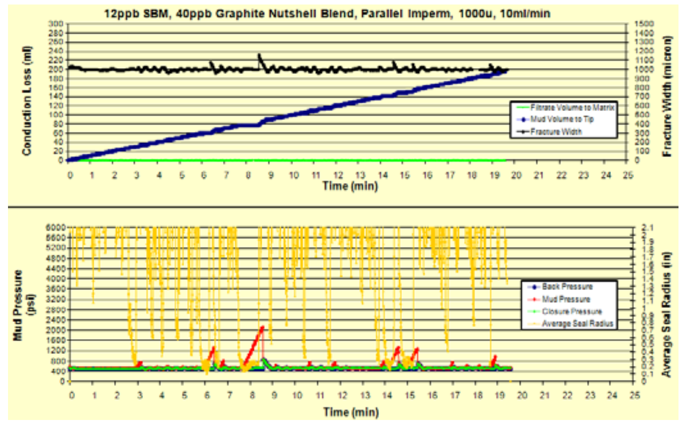

Figure 8 – Fracture sealing and strengthening results for a 1000-µm fracture with a 40-lb/bbl LPM blend in the mud.

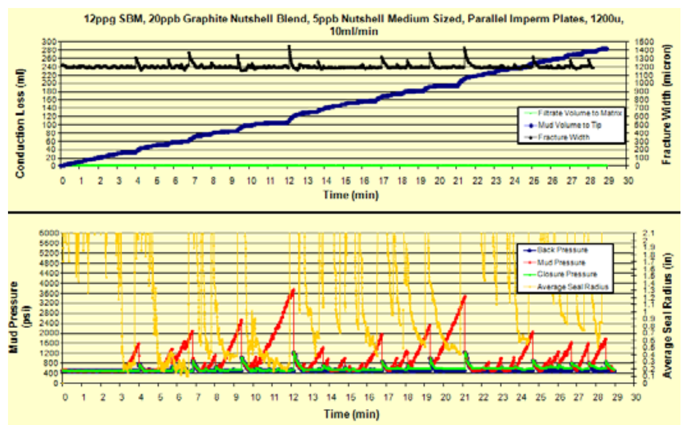

Figure 9 – Fracture sealing and strengthening results for a 1,200-µm fracture with a 25-lb/bbl LPM blend in the mud.

Summary and Conclusions

This paper describes how to design, verify and optimize a wellbore strengthening project demonstrated by a field case example. The key factors of applying this wellbore strengthening technique successfully are:

1. Understand the geology and the nature of the losses. The solutions to natural fractures and induced fractures are different.
2. Estimate the formation properties such as fracture gradient, Young's modulus and equivalent circulating densities (ECD), and the associated uncertainties. This paper presents how pre-existing logging data from offset wells and geomechanical modeling were used to obtain the required information.
3. Estimate the size of the fracture aperture(s). This paper presents a workflow and describes software for predicting fracture widths with probabilistic calculations.

4. Design appropriate LCM or LPM blends and concentration to plug the predicted fractures to limit or alleviate losses while drilling.
5. Verify and optimize, through laboratory testing, LCM blends and concentration for optimum strengthening performance. This paper presents a laboratory fracture plugging testing apparatus to evaluate wellbore strengthening performance of various LCM/LPM blends.
6. Integrate the optimized loss-circulation-material blend at the proscribed treatment concentration to strengthen the wellbore while drilling of the trouble zones.

Acknowledgments

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Nomenclature

ECD	=	*Equivalent Circulating Density*
ESD	=	*Equivalent Static Density*
FBP	=	*Formation Breakdown Pressure*
FG	=	*Fracture Gradient*
FIT	=	*Formation Integrity Test*
LCM	=	*Lost Circulation Material*
LPM	=	*Loss Prevention Material*
MW	=	*Mud Weight*
NAF	=	*Non-Aqueous Fluid*
NPT	=	*Non-Productive Time*
PSD	=	*Particle Size Distribution*
PSI	=	*Pounds Per Square Inch*
µm	=	*Micron*
XLOT	=	*Extended Leak Off Test*

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