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Is Your Mud a Fracturing Fluid or a Non-fracturing Fluid? – Preventing Induced Mud Losses by Controlling Spurt Losses

Hong (Max) Wang, Ph.D., P.E., Sharp-Rock Technologies, Inc.

Abstract

From a hydraulic fracturing point of view, conventional drilling mud is a perfect fracturing fluid. This fracturing tendency can substantially reduce the amount of pressure that a wellbore can contain and result in frequent mud losses if no changes are made to the mud.

Recent studies have found that adding particulates to drilling mud in a specific way can convert conventional fracturing mud to a non-fracturing fluid. This is achieved by quantitatively controlling a spurt loss for a particulate sealing fluid to be low enough that a seal for a wellbore crack can be securely formed. Without such control, the fluid invasion would propagate and inflate the crack beyond what the particulates can seal and enable fracturing to continue. A converting engineering process is realized by first characterizing spurt loss control of an standardized particulate fracture sealing formulation at various concentrations against a slot disk; then, based on rock properties of a weak formation, determine a critical invasion volume that can inflate the fracture to a critical sealing width equal to the slot width. A critical concentration of the sealing formulation with a spurt loss equal to the critical invasion volume is then defined as the conversion concentration. When mud is treated with the particulate formulation at or above the critical concentration, the mud can have a spurt loss smaller than the critical invasion volume and the mud is converted into a non-fracturing fluid for the weak formation. When non-fracturing mud is used, induced mud losses can be prevented with a widened mud weight window.

In addition to its use in drilling fluid, this technology can also be used to convert completion fluid, cement slurry, or spacer fluid to prevent lost circulation during operations.

Introduction

Narrow mud weight windows are frequently encountered during offshore and in-field drilling. Because of a narrow mud weight window, wellbore pressure can often exceed the pressure that a wellbore can sustain, causing induced fractures and mud losses. Mud losses of more than 30,000 bbl are common during offshore drilling, which increases drilling costs. A much larger associated cost, however, is the cost of the downtime required to address the mud losses. The time for an offshore rig could cost as much as $1 million per day. In severe conditions, such as drilling a depleted deepwater formation, a natural mud weight window may be so narrow that drilling is considered to be impossible with conventional technologies.

Remedial technologies, such as the "one size fits many" foam wedge enhanced high fluid loss squeeze system[1], can cure lost circulation after it has been encountered. The industry, however, prefers preventative solutions that enable drilling to continue without stops. The technologies currently available in the marketplace for preventing induced mud losses can be dated back to the old days when particulate lost circulation materials (LCM) were arbitrarily added to mud in an attempt to prevent mud losses. DEA-13 studies[2,3] in the 1980s revealed the effects of sealing fractures for strengthening a wellbore, deriving a loss prevention material (LPM) method[4] of attempting to seal a fracture tip to strengthen a wellbore. GPRI studies[5] further verified that some particulate formulations are better than others when sealing fractures for higher wellbore pressure containment. In the LPM wellbore strengthening approach, drilling mud is added with an empirical particulate formulation. In this LPM approach, the formulation of a loss prevention material for an individual well is not normally customized to rock properties of that well.

Rock properties have been part of an individual formulation design since the so called "stress cage" method came into the marketplace[6,7]. With the "stress cage" engineering, a design process considering rock properties is defined. In the design process, a fracture length (often 6 in.) is first assumed in order to calculate a required propping width of the fracture for inducing enough additional hoop stress to contain the needed wellbore pressure. With this calculated fracture width, the designer then attempts to determine the amount of the fracture width-matching propping particulates. Particulates matching this fracture width are needed to maintain the fracture width and induced stress. These large particulates do not form the needed final formulation. The designer also needs to select the other small particulates that should be added to complete the formulation. In order to sustain the induced stress by propping the fractures, the added particulates need to have enough compressive strength to avoid being crushed.

It has been gradually accepted that propping a fracture to induce additional stress can strengthen a wellbore. However, like any other technology, the current strengthening practices have limitations, too. For example, they may only be effective in strengthening permeable formations[7]. From a rock mechanics perspective, lab tests[5] and studies[8-11] have verified that just sealing fractures still can substantially improve wellbore pressure containment. With a naturally high hoop stress, a wellbore can have a huge potential to contain much more pressure than what is only defined by a fracture gradient or the least far field stress. These studies and those existing strengthening practices[4,7] all provide substantial materials for a profound understanding of the subject, resulting in a whole new and more robust wellbore strengthening solution by just sealing fractures.

Conventional Mud – A Perfect Fracturing Fluid

Conventional drilling mud is normally thin, with a low solid content, and contains only very fine particles. It is designed to form only a thin mud cake with a very tight control of fluid loss. These conditions essentially make drilling mud freely enter even a tiny crack. After the mud enters a crack driven by high wellbore pressure, there is nothing in the mud to prevent the crack from growing into a large fracture that may contain thousands of barrels of drilling mud.

Wellbore Fracturing Process with Conventional Mud

Hydraulic fracturing is a process of fluid invasion to inflate and propagate a fracture. Along a wellbore, some initial cracks or small fractures may exist. These cracks either exist naturally or are created during a drilling process. These naturally existing cracks can simply be rock joints that do not close properly as a result of fracture face mismatching. These cracks tend to be very narrow and in a micron range. Some of them, however, can be wide enough to enable conventional mud to enter. From the moment that some of the drilling mud, driven by wellbore pressure, enters a crack, the invading fluid may force the crack to grow longer, wider, and taller. For example, **Figure 1** shows that a crack grows larger in three time instances. At Time 1, the crack is short and narrow. At Time 2, as more fluid enters the crack, it becomes longer and wider. At Time 3, much more fluid enters the crack, and it becomes much longer and wider. How large a fracture can grow depends upon how much of the fluid invades the fracture. With a continuous supply of drilling mud, this fracture would be propagated larger and larger over time. When fluid invasion slows down, this fracturing process also slows down. If the fluid supply into the fracture is totally cut off during this fracturing process, the fracture ceases to grow, and further fracturing can be stopped.

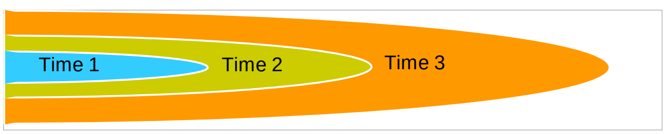

Figure 1. A hydraulic fracture grows larger over time with fluid invasion.

A Dream Fluid for Preventing Induced Mud Losses

Let's assume that we could find a drilling fluid that performs all mud functions but would not flow into cracks; in this case, no hydraulic fracturing would occur. Although some small cracks along the wellbore may be visible while drilling with such a fluid, drilling engineers would not be concerned about them because the fluid could not invade these cracks, and no mud losses would occur. Such a fluid can simply be called a dream fluid. A dream fluid is a non-fracturing fluid. When drilling with a non-fracturing fluid, the mud weight window would always be sufficiently wide.

There is not yet a dream fluid; however, if the cracks are not hydraulically conductive, any fluid can behave as a dream fluid.

The Potential of Improving Wellbore Integrity by Sealing

Figure 2 shows a typical wellbore model to demonstrate how fracture isolation or fracture sealing can substantially improve wellbore pressure containment. In Figure 2, the model can be viewed as two identical pieces of rock forming a wellbore; therefore, there is a fracture between these two identical halves. When this fracture is totally hydraulically non-conductive to the wellbore, after applying confining pressure P_c of such as 10,000 psi to the rock, a wellbore pressure P_w of 2×10,000 psi is required to push the two halves apart. This is attributable to the hoop stress riser caused by the confining pressure and the Roman arch-like rounded shape of the wellbore without flaws. During the process of pressurizing the wellbore, the first 10,000 psi of wellbore pressure is simply restoring the hoop stress back to the confining pressure of 10,000 psi and the second 10,000 psi is reducing the hoop stress to 0 and getting the fracture ready to be opened. This total of 20,000 psi P_w can be called ideal wellbore pressure containment. However, as long as a small portion of this fracture is perfectly hydraulically conductive to the wellbore fluid, the fracture or a flaw takes effect and the wellbore pressure P_w required to push these two halves apart is only 10,000 psi, although the hoop stress is basically unchanged. When the portion of this fracture is only partially hydraulically conductive to the wellbore fluid, the wellbore pressure P_w required to push the two halves apart can range between 10,000 and 20,000 psi. This rock mechanics proven result has been repeatedly verified by GPRI lab tests[5] with core specimens of high, low, and ultra-low permeability.

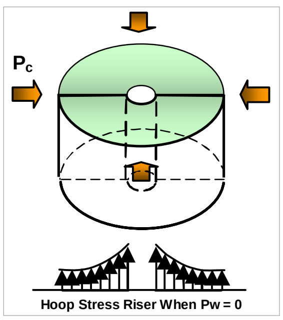

Figure 2. A wellbore model for pressure containment.

In GPRI lab tests, different core specimens were fractured first at a low confining pressure; then, the confining pressure was increased to approximately 500 psi to test the fracture reopening three times by pumping mud or sealing mud with particulate LCM. **Figure 3** shows a split sample.

Figure 3. Split red sandstone core specimen.

Figure 4 shows a recording for injecting mud to reopen the fracture after increasing the confining pressure to 507 psi. With mud only, the fracture is conductive; at an injection pressure of 580 psi, or slightly above the applied confining pressure, the detected confining pressure equalized with the injection pressure, indicating that the fracture has been reopened, and the confining side has communicated with the injection side.

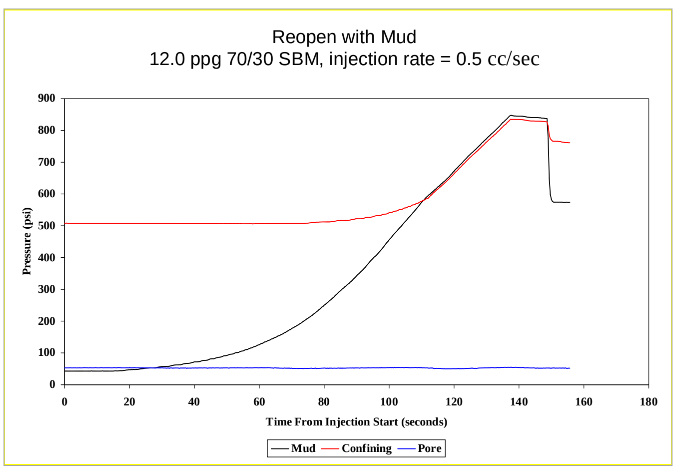

Figure 4. Fracture reopening with synthetic mud.

Figure 5 shows test results for reopening the fracture with sealing mud treated with a particulate LCM. In this example, the injection pressure increased to 1,657 psi at time = 161 seconds before the first large sudden injection pressure decrease. This far exceeds the confining pressure of 500 psi.

Figure 6 shows the injection pressure for reopening the fracture a second time with sealing mud treated with particulate LCM. In comparison with Figure 5, the wellbore pressure containment for both cases was quite similar. The ideal wellbore pressure containment or equivalent wellbore fracture initiation pressure is calculated to be 2×500−50 = 950 psi. The strengthening can be even greater than this ideal wellbore pressure containment defined by the hoop stress.

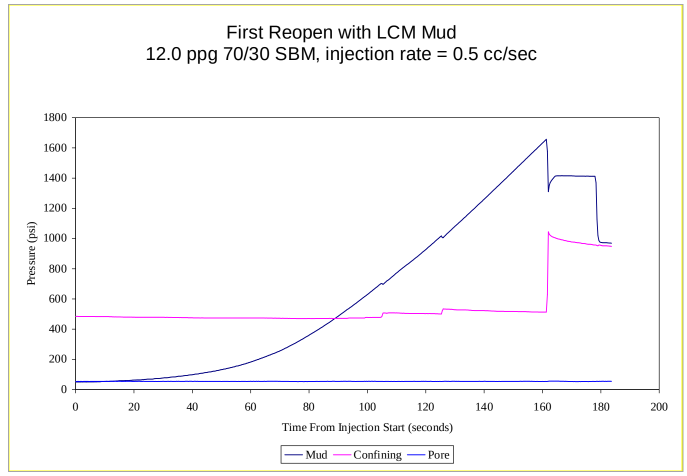

Figure 5. First fracture reopen with mud treated with LCM.

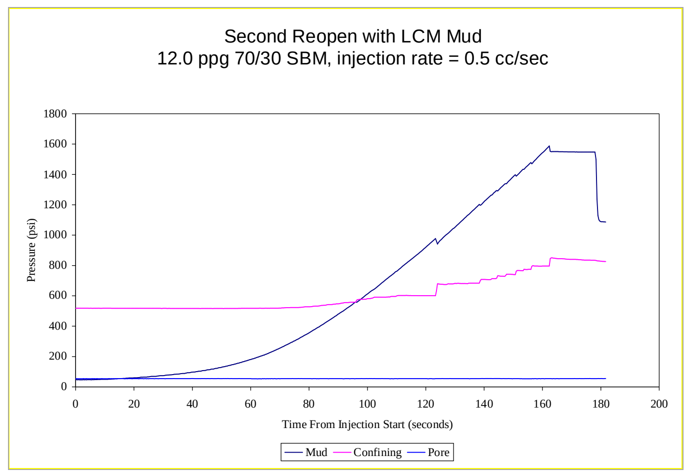

Figure 6. Second reopening results with LCM treated mud.

These tests and in-depth analysis[12] both indicate that maximum pressure containment can substantially exceed what is defined only by a fracture gradient and can be even greater than the ideal wellbore pressure containment when the fractures are sealed.

In the field, this phenomenon has often been observed. For example, in reported LOT results for a field, the LOT values for a depth were spreading across a wide range. **Figure 7** provides a summary of LOT results for an oil field; in this summary, for example, at approximately 1,700 ft, the LOT values range from 10 to 17 ppg. At approximately 5,000 ft, the LOT values range from 14 to 18.5 ppg. It is encouraging that the high bound of these LOT values are even greater than the calculated overburden stress. Studies [9,13] have indicated that only hydraulically conductive cracks or similar flaws can cause these large variations. Because the LOT is usually performed for only approximately 10 ft of new holes out of a casing shoe, the value can be high when there are no hydraulically conductive cracks along the wellbore. However, if there is one fully hydraulically conductive crack, the LOT value can be very low. That LOT values are spread over a large range also indicates that hydraulically conductive cracks often exist, even in such a short interval, and that they are not always perfectly hydraulically conductive. Furthermore, if cracks can be made to be less hydraulically conductive, wellbore pressure containment can be improved. If these cracks can be made to be perfectly hydraulically non-conductive, the high bound of these LOT values or the ideal wellbore pressure containment can be achieved. The large range between the high and low bounds indicated by the red dot line and red solid line in Figure 7 shows the huge potential of wellbore strengthening by sealing wellbore cracks.

This wellbore weakening/strengthening effect has been thoroughly investigated[8-11] based on rock mechanics. A hydraulically conductive crack of 0.1 in. at the wellbore can substantially reduce wellbore pressure containment. For a 5,000 ft wellbore, only one such a crack is needed to substantially reduce pressure containment for the entire wellbore. The probability of penetrating some cracks by a wellbore or of mechanically generating cracks during drilling is very high, and a flawed wellbore should be treated as the baseline for wellbore strengthening.

Forming a Fracture Seal with Particulates

There is no dream fluid. To prevent mud from flowing into cracks or to make these cracks hydraulically non-conductive, attempts can be made to seal the cracks. To maintain fluid properties and to implement a sealing capability into mud, particulate materials, such as LCM, can be added. After they are added, these particulates are suspended in the mud and carried to cracks during drilling. The formation of a particulate fracture seal is actually a filtration process. Particulate-treated mud usually contains both large and small particulates. Even smaller particles, such as barite and clay, may also be present. During the process of fluid flowing into a crack or a small fracture, some fluid and smaller particles can directly pass the fracture mouth and flow into the fracture. However, some particulates larger than the fracture mouth may soon block the fracture mouth. When this occurs, the flow into the fracture is restricted and can only enter the gaps between these large particulates. Further flow into the fracture can carry some small particulates to block these gaps (**Figure 8**). Eventually, the gaps between the particulates are small enough that the clay particles in the mud form a layer of mud cake. As with any filtration process, before forming this mud cake, the flow is in an uncontrolled manner, and the fluid flowing into the fracture contains many different particles. This portion of the fluid is actually a spurt loss, a term already defined by drilling mud engineering. After forming the mud cake, the flow is well-controlled, and only filtrate or clear liquid can slowly pass through the formed seal. There is always some spurt fluid entering a fracture before the particulates seal the fracture. It is obvious that when more particulates are added to the mud, the accumulation of sealing particulates can be realized sooner, and the spurt loss tends to be smaller.

A closer look at this seal formation process reveals that (1) the fluid volume flowing into the fracture before the seal forms is actually a spurt loss, and (2) there is always some spurt loss flowing into a fracture before a seal can form (**Figure 9**).

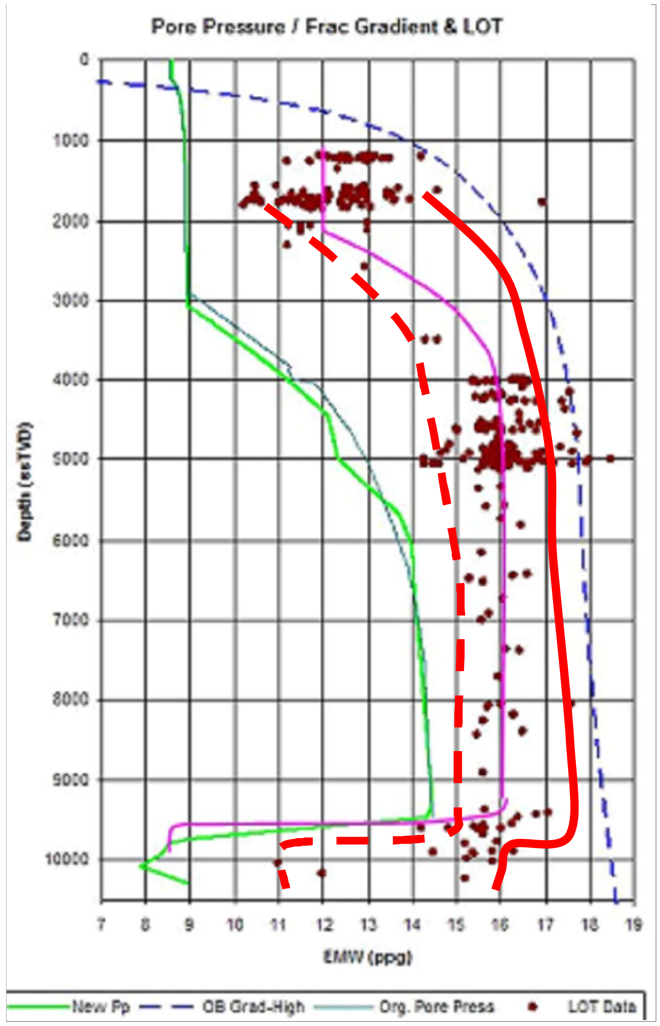

Figure 7. An LOT summary for an oil field.

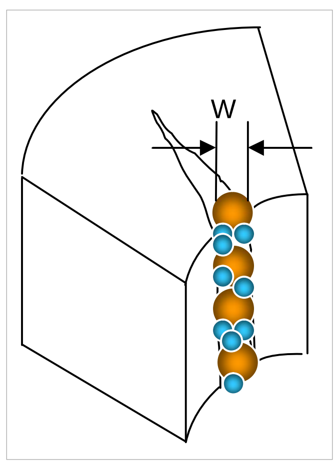

Figure 8. Fracture seal formation is a filtration process.

Although a spurt loss may be very small, it always exists during such a fracture sealing process; consequently, a particulate fracture sealing fluid is not a dream fluid. However, if the spurt fluid flowing into a fracture before the seal forms is relatively small in comparison to what the fracture can tolerate, the sealing fluid is still a non-fracturing fluid. Drilling with such a non-fracturing fluid should benefit from a widened mud weight window.

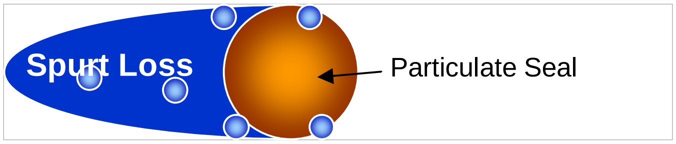

Figure 9. A spurt loss is always associated with seal formation.

Quantify Fracture Sealing Capacity for a Particulate Sealing Fluid

A particulate sealing fluid can be designed to seal a fracture of only up to a certain width, which is the critical sealing width. This critical sealing width is determined by the size of the particulates in the sealing fluid. Obviously, it can be difficult for small particulates to block and seal a substantially wide fracture. However, larger particulates can always block a narrower fracture. For any particulate sealing fluid, the fracture width can eventually extend beyond this critical sealing width if the fracture continues to widen as a result of fluid invasion.

The sealing capacity of a fracture sealing fluid for a designed critical sealing width can be evaluated with an apparatus such as an American Petroleum Institute (API) fluid loss cell or permeability plugging apparatus (PPA) against a slot disk with the same slot width as the critical sealing width. **Figure 10** shows a slot disk.

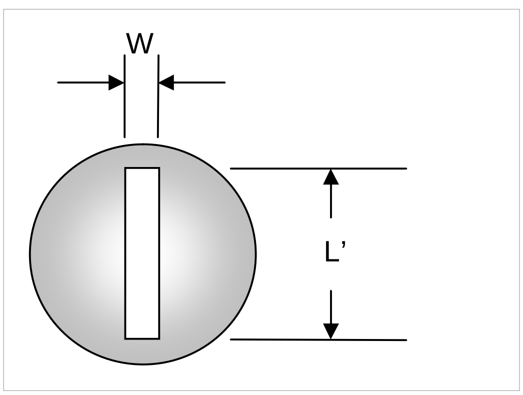

Figure 10. Slot disk with a slot opening of width W and length L' (W = critical sealing width).

When a seal forms on a slot, the cumulative fluid loss of a fracture sealing fluid through the slot disk collected over time can be plotted against the square root of time. Two characteristic periods are typical: a spurt loss period or a curved line and a filtration loss period or a straight line, as shown in **Figure 11**. The spurt loss, indicated as V_{sp} in Figure 11, can be easily determined by extrapolating the straight filtration line back to time zero, according to API Recommended Practice 13I.

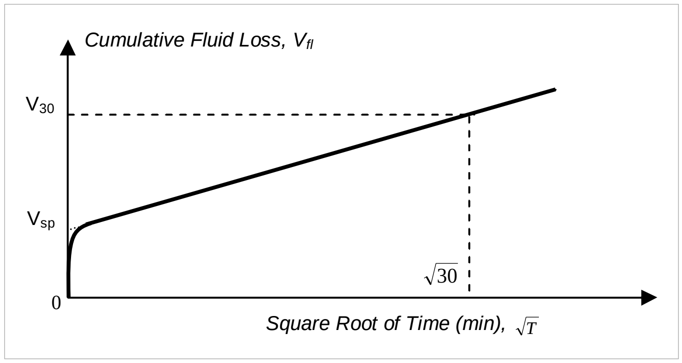

Figure 11. Typical cumulative fluid loss for a fracture sealing fluid tested against a slot disk.

When tested against the same slot disk, a particulate sealing fluid with a smaller spurt loss obviously has a better sealing capacity. When two different slot disks of the same width but different total lengths are used to test different fluids, it is best to compare these spurt losses after they are converted to a unit slot length spurt loss. For example, if a spurt loss tested on a slot disk of a total slot length of 3.5 in. is 7.0 ml, the spurt loss is equivalent to 2.0 ml per in. of slot length. If another spurt loss tested on a different slot disk of a total slot length of 10.0 in. is 15.0 ml, the spurt loss is equivalent to 1.5 ml per in. of slot length. After these two spurt losses are converted to the same slot width, it is clear that the second one indicates a tighter control than the first one.

A spurt loss is meaningful only to its testing filtration medium, however. For example, conventional drilling mud usually has a spurt loss of nearly zero when tested against a filter paper defined in API Recommended Practice 13I. However, when it is tested against a slot disk with a slot width of as 200 microns, all of the mud in the test cell may flow through the slot within seconds. This indicates the mud has an infinite spurt loss against the slot disk. Similarly, a fracture sealing fluid may have a small spurt loss when tested on a 200 micron wide slot, but it may have an infinite spurt loss when tested on a 500 micron wide slot.

This slot disk test is simple, but very important. It can be used to determine whether or not a fracture sealing fluid can seal a fracture of a certain width. It can also measure the amount of a spurt loss flowing through a slot, thereby quantifying the sealing capacity of a fracture sealing fluid for comparison. A dream fluid would have a zero spurt loss over any slot width, whereas conventional mud has an infinite spurt loss over even a very narrow slot, such as 200 microns. A fracture sealing fluid should fall into somewhere between these two extreme examples.

An Optimized Fracture Sealing Formulation for Ultralow Spurt Losses

Both experiment and theory[14] indicate that some sealing formulations can be much more efficient than others. Although it is intuitive that large particulates can block small fractures, to achieve sealing, an appropriate particle size distribution is also necessary. **Figure 12** shows a spurt loss test result for an optimized fracture sealing formulation, shown in **Figure 13**, at various concentrations. It is tested on a slot disk with a slot width of 650 microns (a selected critical sealing width). As shown by Figure 12, the relationship between the spurt loss and the concentration is not linear. Apparently, the sealing efficiency is not a constant at different concentrations. This complicated fracture sealing property makes it difficult to predict a spurt loss based on a nominal particle size distribution.

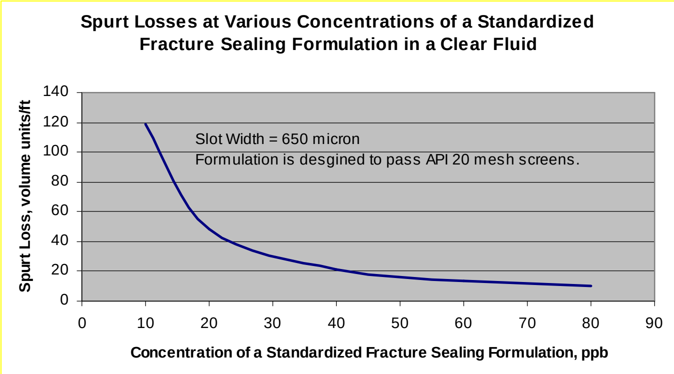

Figure 12. Spurt losses at various concentrations for an optimized fracture sealing formulation for ultralow spurt losses.

Figure 13. Optimized fracture sealing formulation for ultralow spurt losses.

Fracture Widened by Invading Spurt Fluid

Spurt fluid invasion of a fracture is also a hydraulic fracturing process. During this inflating/fracturing process, the in-flowing spurt fluid increases the fracture width. During this fracture widening process, however, various rock can behave differently. In the example shown in **Figure 14**, when the same amount of spurt fluid fractures a formation (Rock 1) with a high Young's modulus under a well condition, the fracture tends to be narrow and long. However, when the same amount of spurt fluid fractures a formation with a low Young's modulus (Rock 2) under the same well condition, the fracture tends to be wide and short. Even for the same rock, different well conditions can also affect this fracturing behavior. This has been thoroughly studied [8,10,15].

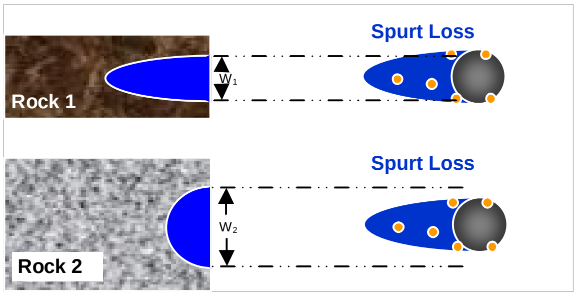

Figure 14. Same spurt fluid invasion may cause different fracture widths.

Similarly, to reach the same fracture width, one fracture can tolerate much more spurt fluid invasion than another. As shown in **Figure 15**, Rock 1 has higher Young's modulus than Rock 2. Rock 1 can tolerate much more spurt fluid with a longer fracture than Rock 2 to reach the same fracture width W under the same well condition.

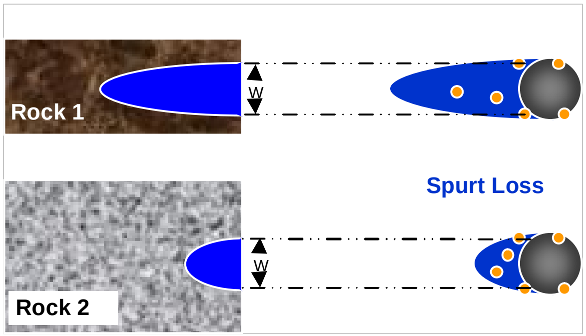

Figure 15. Some fractures tolerate more spurt fluid to reach the same width.

Fracture Sealing Criterion

A dream fluid that will not invade fractures while drilling is not available. Seal formation with a particulate sealing fluid is always associated with spurt fluid, and the spurt fluid invades a fracture before a seal forms. To seal a fracture, we can control a spurt loss to be low enough for the fracture to tolerate. When a spurt loss of a fracture sealing fluid is controlled to be tolerable for a weak formation, induced mud losses can be prevented; such a sealing fluid can be referred to as a non-fracturing fluid. To reliably achieve this outcome, we must know how much spurt loss is tolerable.

Figure 16 shows a fracture sealing process; a fracture mouth of the fracture functions similarly to the slot of a slot disk in terms of accumulation of particulates and formation of a particulate seal. When a fracture sealing fluid with a critical sealing width encounters a fracture, it begins to invade the fracture. At the same time, because of filtration at the fracture mouth, particulates begin to accumulate. During this process, more fluid may flow into the fracture; the fracture is being inflated and widened, and is growing in length. However, before the fracture width increases to the critical sealing width for the fracture sealing fluid, the spurt fluid runs out, and a fracture seal is securely formed. After this, only filtrate can slowly enter this tightly sealed narrow fracture mouth. It is clear that a seal can form when the spurt fluid flowing into the fracture ahead of the seal is not opening the fracture beyond the critical sealing width.

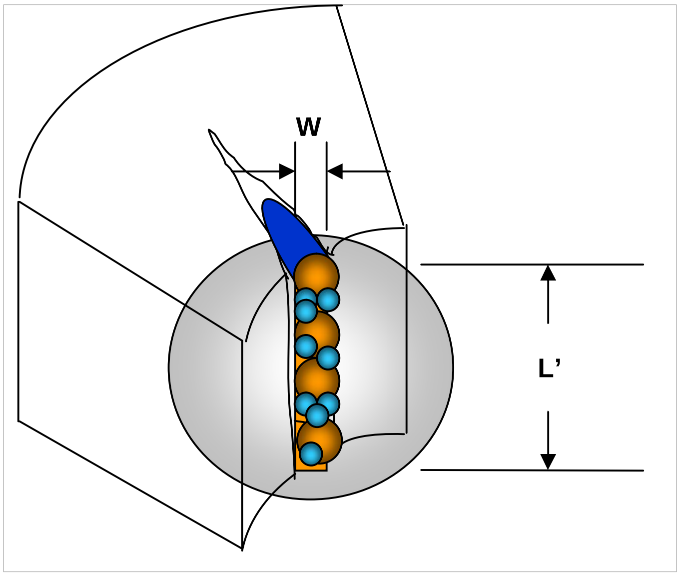

Figure 16. The criterion ensures that a spurt fluid runs out before a fracture is widened to the critical sealing width.

With the understanding of the hydraulic fracturing process and the particulate seal formation process, it is easy to understand that, to securely seal a widening fracture, a seal must form before the fracture becomes wider than what the sealing formulation is capable of sealing or its critical sealing width. The spurt fluid volume required to widen the fracture to the critical sealing width is a critical invasion volume. This is the volume of spurt fluid that a fracture can tolerate before a seal forms. If we can control the spurt loss to be less than this tolerable volume, we can ensure that a seal is securely formed. In other words, if a sealing fluid has a spurt loss larger than this critical invasion volume, a fracture seal cannot form, and the sealing fluid is actually a fracturing fluid. If a fluid has a spurt loss of less than this critical invasion volume, a fracture seal can form and the sealing fluid then is a non-fracturing fluid. The critical sealing width used for the slot width is defined by the sealing formulation.

Determine a Critical Invasion Volume with a Critical Sealing Width

Various rock behaves differently, and it is important to control spurt losses accordingly. Let's assume a hydraulic fracture, as shown in **Figure 17**, to demonstrate how to determine a tolerable volume of spurt fluid invasion. Different fracture configurations require different calculations, but the same logic applies. To have a secure design, the least tolerable amount of spurt fluid invasion from all fracturing calculations should be used to determine how much to control the spurt loss of a fracture sealing fluid.

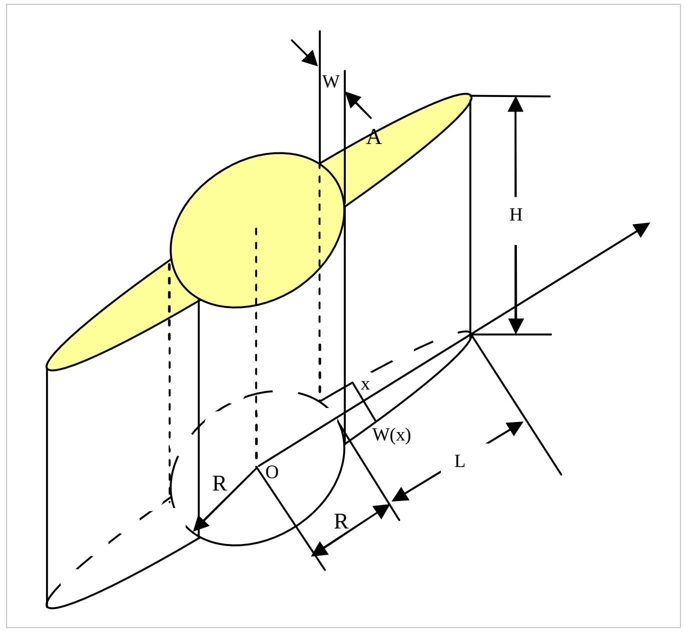

Figure 17. A bi-wing hydraulic fracture along a wellbore.

The length and width of a hydraulic fracture are related. After a width at a location, such as at the wellbore, is defined, the length and even the fracture shape can be defined.

The fracture length L in this method is uniquely defined as following. For the fracture shown in Figure 17 along a wellbore of a radius R, inflated by wellbore pressure P_w against stress S for a rock formation with a Young's modulus of E and Poisson's ratio ν, when the fracture width at the wellbore reaches a critical sealing width W for a fracture sealing fluid, based on fracturing mechanics, the fracture length L is calculated by:

$$L = \sqrt{\left(\frac{W \bullet E}{4(1-\nu^2)(P_w - S)}\right)^2 + R^2} - R$$

The fracture profile is defined by fracture width W(x) at any location x by:

$$W(x) = \frac{4(1-\nu^2)(P_w - S)}{E}\sqrt{(L+R)^2 - x^2}$$

Here, x is the distance from the wellbore center to a point along the fracture centerline, and $R < x \leq R + L$.

The fracture cross section area, A, is calculated by integrating the fracture width W(x) from the wellbore wall to the fracture tip:

$$A = \int_R^{R+L} W(x)dx$$

and the critical invasion volume V is calculated by:

$$V=A*H$$

where H defines the fracture height.

To compare with a spurt loss measured with a slot disk, H can be selected as the slot length L'. It is not necessary to know H for this comparison as long as the selected height is equal to the slot length. They both can be measurements such as 1 ft or 1 in.

The following two examples show how a critical invasion volume can be determined. Except for Young's modulus, Case 1 and Case 2 have the same parameters. **Table 1** summarizes the two cases. The Young's modulus value is 1.5 million psi in Case 1 and 3.0 million psi in Case 2. By the same hydraulic fracturing process, when reaching a 650-micron critical sealing width at the wellbore, the fracture in Case 1 has a fracture length of only 4.8 in., but 16.7 in. in Case 2. Because of the fracture length difference, the tolerable fluid invasion or critical invasion volume for Case 1 is only 1.50 in.^{3}/ft of fracture height. For Case 2, however, this volume is 3.78 in.^{3}/ft. **Figure 18** illustrates this difference. In Case 1, if a fracture sealing fluid has a spurt loss of less than 1.5 in.^{3}/ft of a 650-micron wide slot, this sealing fluid is a non-fracturing for the formation. If sealing fluid has a spurt loss of more than 1.5 in.^{3}/ft, the fluid is a fracturing fluid for the formation. Similarly, in Case 2, the spurt loss of a fracture sealing fluid must be controlled to be less than 3.78 in.^{3}/ft on a 650-micron wide slot to be a non-fracturing fluid for the formation. It is obvious that other factors, such as wellbore pressure and hole size, can affect this critical invasion volume in a similar way. A non-fracturing fluid for one formation at a specific condition may not be a non-fracturing fluid for even the same formation at a more difficult condition, such as a higher wellbore pressure. Therefore, this critical invasion volume must be determined on a case-by-case basis to be cost effective. For an interval, it is best to design a sealing fluid that is sufficient for the weakest formation, but not too much over the required sealing.

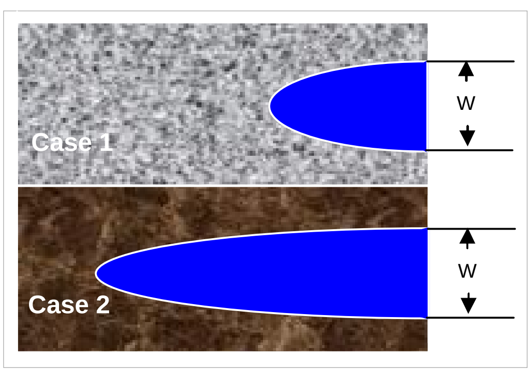

Figure 18. Facture difference between two cases.

Table 1. Uniquely Defined Fracture Length and Tolerable Critical invasion volume

Case	E, 10^6 psi	ν	P_w, psi	S, psi	W, micron	R, in.	L, in.	V, in.^{3}/ft
1	1.5	0.25	8,000	7,000	650	8.5	4.8	1.50
2	3.0	0.25	8,000	7,000	650	8.5	16.7	3.78

A Standardized Fracture Sealing Formulation

Reliable particulate sealing requires sophisticated technologies to be efficient. The same concentration for two random particulate formulations can have totally different spurt losses. Many lab tests show that even an 80 to 100 ppb particulate fluid may have an infinite spurt loss. A particulate mixture formulated at a rig site, based on nominal particle size distributions of each particulate component, cannot ensure the needed sealing performance. It is beneficial to have a standardized formulation that can control an ultralow spurt loss and meet its sealing specifications for each batch.

A tight control of the particle size distribution for a particulate manufacturing process is very difficult because of the variations in raw materials and in the fragmentation and separation processes. Two batches of particulates from the same processing conditions may have different particle size distributions. Even two samples from the same batch can have different particle size distributions. Particulate formulations made based on nominal particle sizes of different particulates may not deliver same sealing results each time. A nominal particle size distribution does not directly mean sealing. It is much more meaningful to focus quality control directly on sealing for the final formulation, rather than on the particle sizes.

To simplify the process of converting drilling mud into a non-fracturing fluid and to ensure the delivery of a reliable sealing performance, an optimized particulate sealing formulation can be designed and standardized. In this way, the formulation can be quality controlled for its ultralow sealing capacity at its manufacturing point. A user of particulates actually needs a fracture sealing function, rather than the particulates. This standardized formulation enables a user of the technology to focus on the sealing function, rather than on the less-controllable and less useful particle size distribution. With such a standardized formulation, the efficiency can be greatly improved and users can focus on what the particles can do, rather than on what they are.

Additional Benefits of the Standardized Formulation

Figure 12 shows the characterized spurt losses at different concentrations for a standardized particulate sealing formulation. It is designed to securely seal fractures of up to 650 microns wide and tested with a slot disk with 650 micron-wide slots. A different standardized formulation can be based on a different size of slot/fracture width. The test fluid for the sealing formulation is a biopolymer-based clear fluid. Laboratory tests show that when clay and/or barite exist in the fluid, the formulation can control the spurt loss even more tightly with the same particulate concentration. **Figure 19** shows the spurt losses at different concentrations for the same formulation in the same clear fluid when weighted with barite to 11.0 ppg (shown in pink). The spurt losses for the unweighted formulation are also plotted for comparison. Other experiments indicate that when the formulation is added to clay-based mud, the spurt loss control becomes slightly tighter. When the concentration of the standardized formulation is determined at a clear fluid condition, because of the possible existence of clay and/or barite in field mud, its field application can be operated in a more controlled manner. This characterization for the standardized formulation greatly simplifies the field applications of this technology.

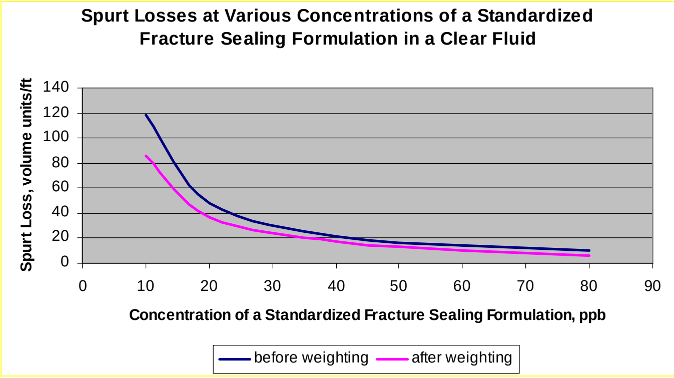

Figure 19. Comparison of spurt losses before and after weighting for a standardized formulation.

Convert Fracturing Mud into a Non-Fracturing Fluid with a Standardized Fracture Sealing Formulation

With a standardized fracture sealing formulation, the mud can be easily converted to a non-fracturing fluid by the following:

1. Calculate the critical invasion volume for tolerable spurt fluid invasion for the weakest formation for a drilling interval, based on the formation properties and drilling conditions.
2. Determine a concentration of the standardized fracture sealing formulation to control the spurt loss to be equal to or less than the calculated critical invasion volume, based on the characterized spurt losses for the sealing formulation.
3. Add and maintain the concentration of the standardized fracture sealing formulation in mud to ensure that the spurt loss is less than the critical invasion volume.

Any changes of conditions, such as hole size or wellbore pressure, may only affect the calculated critical invasion volume, which may in turn require a different a critical concentration. At any time that such a change is needed, it can be easily adapted by altering only the concentration of the sealing formulation. It is not necessary to change to a different particulate material.

Figure 20 uses an example to demonstrate a complete application process of the converting method. In this example, with drilling parameters and rock properties defined, a tolerable critical invasion volume of spurt fluid of 60 units per ft of fracture height is first calculated for the weakest formation for a drilling interval, based on a 650-micron critical fracture width. In the characterized spurt loss plot for the sealing formulation, a volume of 60 units per ft of slot length corresponds to a 17 ppb concentration. To prevent induced mud losses for drilling the interval, with a safety factor, simply add 19 ppb of the sealing formulation to the mud and drill with it. Solid control is not a problem because the standardized formulation is designed to pass an API 20 mesh screen.

When one of the drilling conditions, such as the hole size, is changed before drilling this interval, the calculation can be updated for a new critical invasion volume, which may only alter the needed concentration of the sealing formulation. Assume that a new calculation defines a new critical invasion volume as 40 units per ft; this corresponds to 23 ppb of the sealing formulation. The same sacked fracture sealing material is still good for the drilling, and the same shale shaker screens can still be used. Because there is no substantial effect on logistics, this method allows a last minute change.

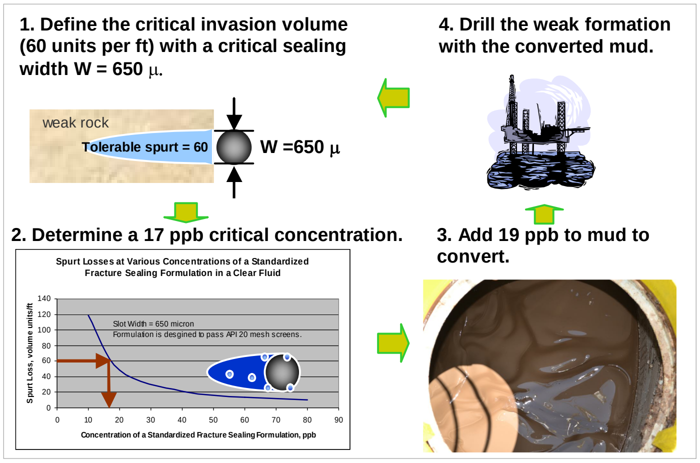

Figure 20. Work process for converting fracturing mud into a non-fracturing fluid.

Designed to Achieve Success Even with Uncertainties

Although many uncertainties are associated with drilling operations, this method enables the use of greater particulate concentrations to offset uncertainties. A greater concentration of sealing particulates can increase sealing reliability, but has little adverse effect on wellbore strengthening. Sealing at the fracture mouth inside a wellbore does not require the particle size to be exactly the same as the fracture width. It can enable fracture sealing as long as the fracture width is less than the critical sealing width. A concentration greater than the critical means that the fractures can be sealed much earlier, before they reach the critical sealing width. This can make the operation even more secure and reliable.

It is normal when some formation properties are not accurately defined. These properties may include formation stresses and Young's modulus. For example, if the horizontal stress is defined as a range of 7,250 to 8,100 psi in a project, to ensure the success of the project, 7,250 psi can be selected. Selecting this lowest stress value can ensure that the designed conversion concentration is sufficient for the worst case scenario. Similarly, when there is uncertainty associated with Young's modulus, the lowest possible value can be used to ensure a safe conversion concentration of the sealing formulation.

Discussions

Quality Control at a Rig Site

This method enables quality control with a PPA or a fluid loss cell against a slot disk for required spurt loss control. It is simple and direct. Other wellbore strengthening methods may rely on checking on particle size distributions, which does not directly reveal whether or not a tight seal can form. Furthermore, particle size distribution is very difficult to measure at a normal rig site.

Solids Contamination during Drilling

During drilling, different particle sizes may naturally come into the mud, and these particles may substantially change the sealing without control. The adverse effect primarily comes from the particles that are larger than the largest particulates in the sealing formulation. Large cuttings in a fracture sealing fluid can accumulate and pile up loosely along a fracture preventing the sealing particles from forming a seal. n impermeable layer on top of the pile. Those finer particles actually can help to provide tighter control of the spurt. The example standard formulation enables the use of shale shaker screens of API 20 mesh. Larger solids can be sieved out, and only finer solids can be retained in the system for a tighter control. Furthermore, because of the standardized formulation, the fluid can be quality controlled for its spurt loss on the same slot disk for any job at a rig site. When more spurt loss control is found to be necessary, this can be accomplished by adding more of the standardized sealing formulation.

Particle Size Degradation

During the circulation of particulate-treated mud, some of the particulates may be shattered and reduced to a smaller size. The design of the standardized formulation addresses this possibility by using more degradation-resistant materials for the formulation. Even with better materials, during the application of this method or similar, particle size degradation still is inevitable. However, the use of shale shakers enables fine particles generated over a drilling process to be incorporated into the mud to offset the loss of the needed particles. Furthermore, a rig site direct spurt loss measurement can easily determine when more sealing particulates should be added. During the application, as long as the spurt loss is still below a specified value, no additional particulates need to be added.

Matrix Permeability

A fracture that is securely sealed with this method can easily maintain its stability regardless of its formation matrix permeability and whether the permeability is substantially reduced by mud or not. This means that the method can be applicable for both sandstone and shale formations.

When a fracture is sealed, the fluid inside the fracture is confined or trapped by higher wellbore pressure, hoop stress, and fracture tip resistance (**Figure 21**). The fracture tip resistance normally is the weakest; otherwise, no fracturing would occur.

When there is sufficient matrix permeability, a sealed fracture can soon be closed by the higher hoop stress as a result of the reduction of fracture pressure through the permeable matrix. If there is not sufficient matrix permeability, the trapped fracture pressure can continue to extend the fracture until the trapped pressure is bled off and the fracture is closed. After a fracture is closed, there is little pressure communication between the wellbore and the fracture tip. The fixed wellbore can behave as if the fracture had never existed. For the same reason, a tighter control of the mud fluid loss for applying this technology is not necessary.

In a worst-case scenario, a fracture would not close properly because of trapped particulates inside the fracture or because of mismatched fracture faces. In this case, the trapped fluid can communicate with the fracture tip. If some filtrate leaks through the formed seal and causes the fracture pressure to gradually increase, the weakest fracture tip can serve as a pressure relief valve to bleed off pressure by extending the fracture whenever it is necessary. Similar observations and discussions can be found in the literature[15].

This mechanism can allow maintaining a long term strengthening effect even if the matrix permeability is as low as in shale.

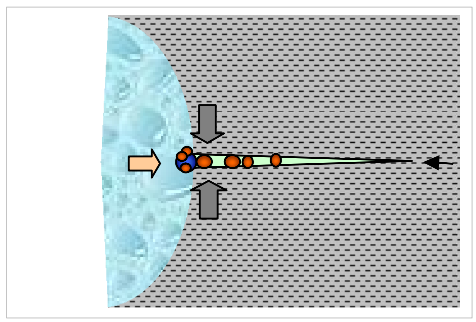

Figure 21. Trapped fracture fluid to be bled off at the weak tip.

Furthermore, with this method, a seal can be designed to form much earlier, before a fracture is widened to the critical sealing width, by having a larger safety factor that requires a greater particulate concentration. This can leave more inflatable fracture volume for accepting filtrate through the formed seal.

In GPRI lab tests[5], high wellbore strengthening effects have been achieved, even with ultralow permeability Pierre I shale.

Sealing Locations

Studies [10,16] have shown that it is preferable for a sealing location to be as near the wellbore as possible. This method is engineered to seal a fracture at the wellbore for the best strengthening effect.

Inside-Wellbore Seal of a Mud Cake Thickness

When a seal is efficiently formed, only one layer of the large particulates is needed. Because of the limited size of the sealing particles used, the seal is expected to have a thickness similar to that of a regular mud cake (normally several hundreds of microns). It is, therefore, not expected that this seal would be easily scraped away by drilling strings. Furthermore, with this sealing fluid in the hole, when a new fracture is generated, a new seal can form immediately to arrest fracture propagation.

Naturally Open Fractures

Naturally open fractures are a network of fractures connected to one another with a fracture pressure equal to the formation pressure. Because of the connectivity of a natural fracture system, fracture pressure tends to remain stable and equal to the pore pressure. Unlike hydraulic fracturing, the width of naturally open fractures usually should not increase much when mud invades the fractures; therefore, this method can still prevent mud losses as long as the fracture openings are not wider than the critical sealing width.

To provide additional mud loss prevention in a naturally fractured formation, the sealing capacity of this standardized sealing formulation can be further extended with the "one size fits many" foam wedges[1] to obtain a better result.

In other formations, exiting cracks/fractures are normally closed as a result of formation stress and may have only a short part of the fractures open because of fracture face mismatching. This probably is true in offshore and younger formations. These tiny and narrow openings penetrated by a wellbore can be in the range of 50 microns wide. The initial narrow fracture width of these closed fractures can be ignored without much error when determining the critical invasion volume when they are deemed to be so small. Furthermore, its effect can be lump-summed into a safety factor for additional control to the spurt loss. If the initial width is not to be ignored, however, it can simply be considered when determining the critical invasion volume. When an initial width is considered, the determined critical invasion volume also tends to be smaller, requiring a tighter control on the spurt loss of a fracture sealing fluid.

Pressure Surge

Pressure surges may be encountered, and this may exert a much greater pressure on the formation. If this is a concern, either the concentration is designed based on this higher surge pressure or a larger safety factor is considered. Both approaches can solve the problem with only a greater particulate concentration.

Application Candidate Wells

Any well that has a concern about lost circulation and is addressed with particulate treated mud can be reviewed for applying this new technology. With a purposely designed particulate formulation and a concentration based on rock mechanics, the mud loss prevention performance is expected to be much improved.

Converting Other Fluids

This innovative method can be used to convert mud into a non-fracturing fluid to prevent wellbore fracturing by mud. Similarly, wellbore fracturing by cement slurry, completion fluid, and drill-in fluid can also be prevented with this method. For cementing, a conversion concentration of a particulate formulation can be determined, based on a cementing condition. The standardized sealing formulation can then be pre-blended with bulk cement before application. The formulation can also be added to a spacer fluid to achieve similar spurt loss control.

Wellbore Stabilization Benefits

A sufficiently high mud weight is necessary to offset the hoop stress that can cause a wellbore to fail or to become unstable. However, in naturally fractured formations, a heavy mud can invade these natural fractures deep and fast, lubricating fractured rock and causing great instability problems. An unconsolidated formation is destabilized in the same manner. This problem can be solved by efficiently sealing these natural fractures.

Many natural fractures are in a micron range, but are large enough to gradually take mud. The size of these fractures falls into the sealing capacity of the standardized fracture sealing formulation. Because of the secured sealing power of the formulation, these natural fractures can be tightly sealed, and the invasion fluid can also be minimized. With such rapid invasion shut-off, weighted mud can then apply the needed pressure to stabilize the wellbore for an extended period. This sealing is especially needed for drilling with water-based mud.

Summary

A method of converting fracturing drilling mud into a non-fracturing fluid to prevent induced mud losses and to obtain a widened mud weight window for drilling either impermeable shale or permeable sandstone formations has been introduced. This new method is to utilize the existing hoop stress around a wellbore to contain wellbore pressure by means of ensuring the mud is capable of plugging those hydraulically conductive cracks before they grow to beyond a selected critical sealing width for the mud.

With a standardized particulate sealing formulation for the selected critical sealing width, the method first calculates a critical invasion volume for a weak formation for a drilling interval with known drilling and rock parameters. Then, a defined concentration of the particulate sealing formulation that can control the spurt loss of the mud to be smaller than the critical invasion volume is added to convert the fracturing mud into a non-fracturing fluid for drilling the weak formation.

The method seamlessly integrates fluid properties with rock mechanics, expressing robust and practical engineering and defining unique solutions. When uncertainty is associated with any parameters, the reliability can be easily maintained by increasing the concentration of the sealing formulation to offset the uncertainty.

The method is easy to apply. With a standardized formulation, shale shakers can be used for solid control. Rig site measurement of spurt losses with a slot disk provides an easy-and-direct method of quality control over converted mud.

With the standardized sealing formulation optimized and quality controlled at the manufacturing point for its spurt losses, a user of the technology can truly focus on what the particulates can do, rather than on what they are.

Nomenclature

API	*American Petroleum Institute*
DEA	*Drilling Engineers Association*
ft	*Feet*
GPRI	*Global Petroleum Research Institute*
LCM	*Lost circulation material*
LOT	*Leak-off test*
LPM	*Loss prevention material*
PPA	*Permeability plugging apparatus*
ppb	*Pound per barrel*
ppg	*Pound per gallon*
psi	*Pound per square inch*
SBM	*Synthetic-based mud*
A	*Fracture cross section area*
E	*Rock Young's modulus*
H	*Fracture height*
L	*Fracture length*
L'	*Slot length*
P_c	*Confining pressure*
P_p	*Pore pressure*
P_w	*Wellbore pressure*
R	*Wellbore radius*
S	*Formation stress*
T	*Time*
V	*Critical invasion volume*
V_{30}	*Fluid loss at 30 min*
V_{fl}	*Fluid loss volume*
V_{sp}	*Spurt loss measured*
W	*Critical sealing width, slot width*
$W(x)$	*Fracture width at point x*
W_1	*Fracture width 1*
W_2	*Fracture Width 2*
x	*Distance from the wellbore center to a point on a fracture centerline*
ν	*Rock Poisson's ratio*

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